

Review

An Overview of Flow Assurance Heat Management Systems in Subsea Flowlines

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Abstract: The enormous cost of handling the challenges of flow assurance in subsea wells, flowlines, and risers, especially in deepwater applications, has necessitated a proactive approach to prevent their risk of occurrence. To ensure that transportation of the hydrocarbon is economical and efficient from the subsea wellhead to the processing units, a flow assurance heat management system is relevant in the design and planning of a fluid transport system. Consequently, the advancement of new technologies to serve the increasing need by exploring the technologically challenging and hostile subsea fields is of great importance. A comparative study on heat management systems in flowlines was conducted from the top five publishers (Elsevier, Springer, Taylor & Francis, Wiley, and Sage) based on the number of publications to determine the level of work done by researchers in the last decade, the figures from the study showed the need for scientific research in the field of active heating. Additionally, a review was implemented to ascertain the likely advantages and drawbacks of each technique, its limitations concerning field applications and then recommend suitable cost-effective technique(s). The active heating system gives the most cost-effective solution for subsea deepwater fields.



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Keywords: heat management; passive insulation; active heating; flowline; flow assurance; deepwater

1. Introduction

Petroleum industry investments are capital intensive and can only be justified by the optimal exploitation of oil and gas at a minimum cost. The industry is driven by technological innovations with enormous resources committed to discovering ways of mitigating production problems. Best practices regarding reservoir management, production surveillance, environmental management, and operations safety are evolving, all driven by the quest for competitive advantage and profit maximization [1]. However, production problems present enormous challenges for field operators owing to the prohibitive cost of mitigation, opportunity loss cost for downtime, and startup problems. Routine wax cutting, scale treatment, depressurization for hydrate removal, foam, and emulsion treatment are disincentives to any production system. In subsea operations where process conditions are unfavorable, flow assurance challenges have become a global issue. There is a need for a proactive production surveillance system for monitoring and timely detection of production problems and also for problem characterization [2,3].

Effective production surveillance system requires knowledge of changes in basic production parameters like temperature and pressure evolution, flow rate, Gas–Oil Ratio (GOR), fluid characteristics, Basic Sediment and Water (BS & W), sand production, etc. Among these variables, temperature and pressure evolution conveys a lot of information on what is happening down-hole or along flowlines. This information if duly analyzed can provide timely insight on developing oilfield problems for control purposes. However, accurate prediction of temperature and pressure is difficult owing to the complexity of multiphase flow typical of oilfields operations.

1.1. Gathering Systems

Gathering systems consist primarily of flowlines, valves, and fittings necessary to convey well effluent from the wellhead to the separating facilities at the flow station [4,5]. Depending on the distance of distribution, the system may contain one or more lines or a separate line to each well. Accessory equipment may include gross production metering devices, corrosion inhibitors, and chemical injectors connected automatically to the valves and chokes. Free gas may be removed from the gathering manifold or casing head into a field gas gathering system. The gathering manifold can be more complex if a fluid injection is done in the field. From the gathering manifold, fluid may be routed to a High-Pressure (HP) or Low-Pressure (LP) test header to separators or a common well test line. In terms of design, there is no difference in the calculations of a pipeline or a flowline and the two terms are synonymous. In the industry, it is commonly understood that a flowline refers to an inter- or intra-field multiphase line transporting oil, gas, and water coming from production wellheads to the manifold [6,7]. Flowlines do also carry gas for gas-lift, gas for disposal, or injection water. The diameters of the flowline vary from 2" up to 12" to 14", whereas a pipeline means a pipe connecting the offshore field(s) to onshore facilities for oil or gas export, and with larger-diameter pipes, carrying single-phase hydrocarbon fluids.

1.2. Flow Assurance

Flow assurance is the capacity to generate multiphase fluids from the reservoirs to processing plants in a technically and economically viable way throughout the field's life [8]; the production goal seeks to guarantee the most favorable flow rates at an anticipatable condition in all production equipment carrying produced fluids beginning at the reservoir–wellbore to the treatment/refinery facility [9]. In recent years, flow assurance is seen as the most critical task in the subsea energy production and systems operation [10–12] that causes financial losses based on production interference and destruction in flowline or surface facilities due to solid deposits [13,14]. It is employed to the petroleum flow path during all stages of production, including system selection, surveillance, detailed design, operation troubleshooting, increased late-life recovery, etc. [15,16]. In subsea systems, the flowline usually comes before a riser that connects from the sea bottom to the production topsides [11]. The production riser system becomes longer as the water depth increases resulting in a higher operating flowline pressure because of the hydrostatic riser's head [11]. Therefore, it is easier for hydrates to be formed in fluids with the same temperature and a higher pressure [11,17].

The flow assurance targets or areas of interest in industrial oil production include wax (paraffinic deposition), asphaltene deposition, hydrate formation, erosion, emulsion, heat issue, multiphase flow, corrosion, and sand ingress. These occur as a result of temperature and pressure drop [18] and they tend to block/foul off production equipment during normal hydrocarbon production or transportation. At reservoir conditions, involving high temperatures (70–150 °C) and high pressures (50–100 MPa), paraffin solubility in oil is sufficiently high to completely dissolve the wax molecules in the oil, and the crude oil with low viscosity act as a Newtonian fluid [19,20]. As the crude oil production progresses, the oil leaving the reservoir is transported through subsea tubing-flowlines having cold surfaces, heat is swiftly lost to water if the pipe wall is not protected with a good insulation layer [11]. Additionally, when production fluid temperature inside the flowline gets too low because of loss of heat, hydrocarbon, and water could form hydrates to plug fluid flow. In addition, wax begins to precipitate and settles on the flowline wall if the fluid temperature becomes too low [11,21,22]. In the following, some of the major flow assurance issues and solutions are explained.

1.2.1. Waxes

Wax is a higher molecular weight and saturated organic substance [23], which is moderately soluble in the condensate and black oils liquid phase [24]. Wax mainly consists of hydrocarbon normally between $C_{18}H_{38}$ and $C_{70}H_{142}$ [25–27]. When the waxy crude oil temperature decreases to below its solubility limit in oil, the Wax Appearance Temperature (WAT) or cloud point might be reached [28,29]. *Pour point* is simply the minimum temperature that the fluid stops to flow and the crude oil becomes “frozen solid” [17,30], and the waxy crude oil properties increase with the wax content [31]. Oil in the flowline cools quiescently during unplanned and planned shutdown operations to the ambient temperature which is less than the pour point [31].

Based on this, the waxy crude oil undergoes a transformation of phase from a liquid state exhibiting Newtonian behavior to a gel-like shape showing non-Newtonian flow behavior [32–35]. The notable wax prevention and remediation techniques are active heating, passive insulation, wax inhibitors, Pour Point Depressants (PPDs), dispersants, cold flow, wax eater, choke cooling, and mechanical method.

1.2.2. Hydrates

Hydrates are ice-like crystals that consist of light hydrocarbons (methane, ethane, propane, carbon dioxide, hydrogen sulfide, nitrogen, etc.) and water [11,36–38]. Hydrate is formed from hydrocarbon fluids and water that can plug the flowline if untreated. The formation of hydrates is at a relatively low temperature and high pressure and the hydrates' physical properties are close to those of ice [39–41]. When a plug is created, urgent action is needed to remedy the situation that may visibly cause production downtime. Therefore, it is significant to operate and design a subsea flowline system to successfully manage the risk of hydrate [42–44]. The common solutions are heat management (active heating, passive insulation), Thermodynamic Hydrates Inhibitor-THI.

(Mono Ethylene Glycol—MEG, Methanol—MeOH), Low Dosage Hydrate Inhibitor-LDHI (Kinetic Hydrates Inhibitor—KHI, Anti-Agglomerants—AAs), mechanical method, dead oil circulation, cold flow, and depressurization.

1.2.3. Asphaltene

Asphaltene is a class of compound in crude oil that is soluble in light aromatic but are insoluble in n-heptane [25,45,46]. Asphaltene contains the majority of the inorganic component of hydrocarbon fluid [25,26], which includes nitrogen and sulfur, and metals such as vanadium and nickel [25,26]. All hydrocarbon crude contains a certain level of asphaltene and it only becomes an issue during production when they are not stable [25,26]. The stability of Asphaltene is dependent on the ratio of asphaltene to stabilizing factors like resins and aromatics in the crude oil [25]. Pressure has the biggest impact on asphaltene stability [25] and Asphaltene Onset Pressure (AOP) is the pressure at which asphaltene begins to settle out in the flowline [46]. Asphaltene can be unsettled by the introduction of some kind of acid or completion fluids and by elevated temperature observed during the refining activities of crude oil [25,26].

In summary, the glaring asphaltene issues mostly happen downstream because of high heat or blending [25,26]; their solutions are chemical injection and mechanical methods.

1.2.4. Scales

Scales are solid mineral deposit normally form from produced saltwater. The inorganic scale is a stick, hard mineral precipitate from a brine solution [23]. Scales are also crystals deposited from the available concentration of brine in the reservoir due to pressure, pH, and temperature variation in the fluid production system [23]. There exists a large variety of these solids, which may form anywhere from the reservoir to the production system [23]. Methods for scales prevention are chemical inhibition squeeze treatment and Downhole Chemical Injection (DHCI); other methods of injection is by Nanoparticles [47,48].

Figure 1 summarizes the flow assurance's solution flowchart for wax, hydrates, and asphaltene.

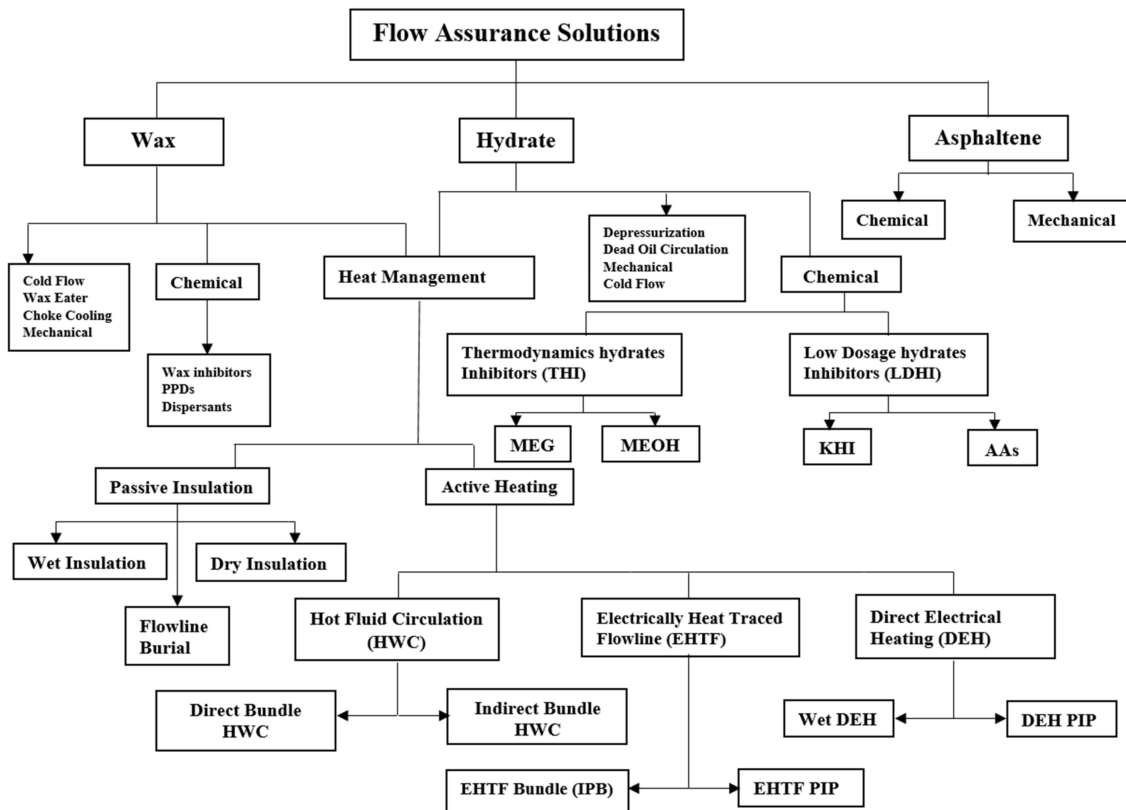


Figure 1. Flow assurance solutions for subsea flowlines.

1.3. Heat Management Systems

Heat management systems is a practice of maintaining the fluid temperature inside the flowline well above the Hydrates Formation Temperature and WAT [49,50]. The heat management system is regarded as very valuable in flow assurance solutions due to its cost-effectiveness [50]. As the oil and gas fields progress into deep water [51], there is an increasing demand for a heat management system to stop the formation of hydrates and wax in the subsea systems [51]. Therefore, a good heat management plan is selected based on the needed cooldown time, water depth, U-value, and temperature range [51]. The heat management systems consist of active heating and passive insulation. The active heating system uses external heat sources like hot water, direct electrical, and electrically heat-traced flowline to warm the produced fluid [49] while the passive insulation system utilizes material like Mineral wool and Polyurethane with a low thermal conductivity to lower heat loss to the environment [49]. A heat management system flowchart is seen in Figure 2 below.

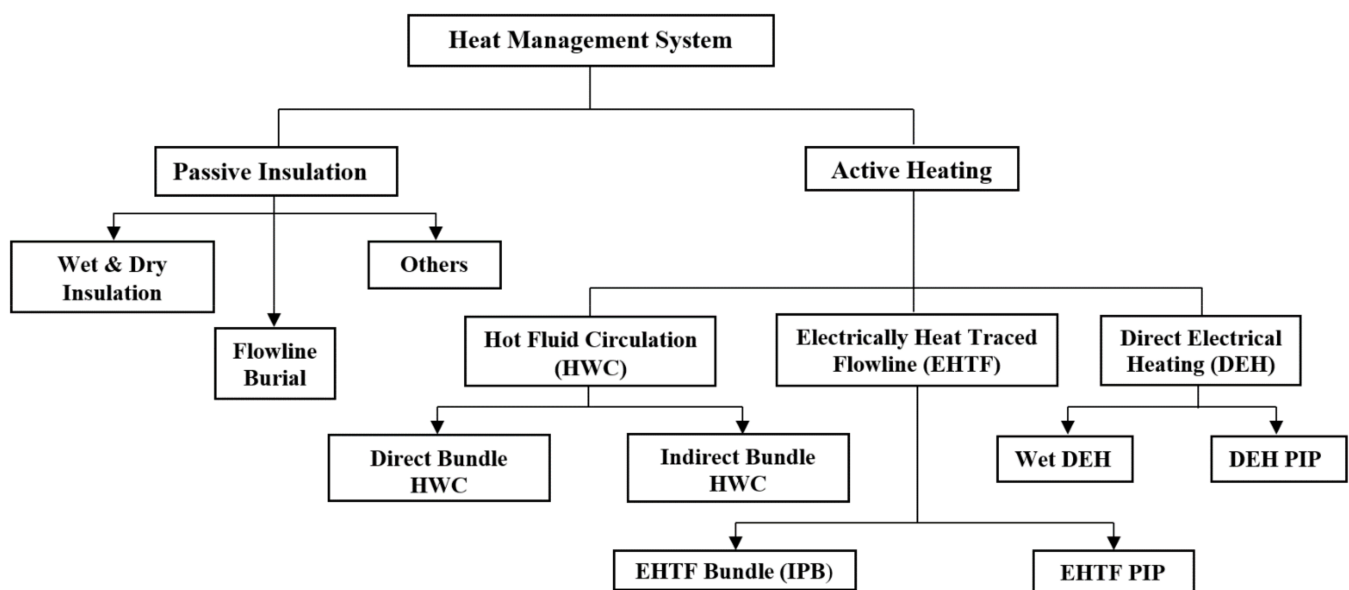


Figure 2. The heat management system in the subsea flowlines.

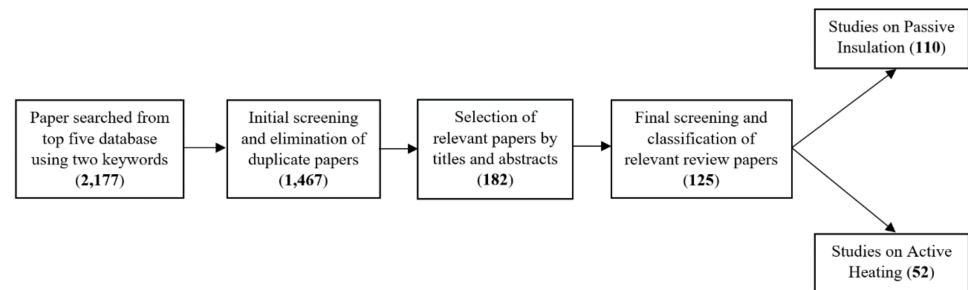
In the last ten years, the design and operation of flowline heat management systems are increasing in preventing impediments caused by hydrates and wax deposition [49]. The flow efficiency in flowline insulation is affected by the distinctive issue of heat transfer [52]. Consequently, the hydraulic behavior of the subsea flowline fluid controls the thermal or heat performance of the production system [51,53]. Conversely, it indirectly influences the hydraulic design through the effect of temperature on the properties of the fluid such as viscosity, GOR, and density [51,53,54]. One of the most significant aspects of flowline design is in the prediction of temperature profile along the flowline during the thermal design process [51,55,56]. This is because temperature details are needed for flowline analyses including corrosion protection, lateral or upheaval buckling, expansion analysis, wax deposition, and hydrate prediction analysis [51,57–61]. Often, the solids deposit (wax, asphaltene, hydrate, and scales) determines the conditions of thermal and hydraulic designs [62–64]. To preserve a minimal fluid temperature above the wax and hydrates depositional temperatures in the flowline, layers of insulation are included in the flowline [11,51,53]. The thermal design comprises of both transient state and steady-state transfer analyses [51]. Therefore, the temperature profile in the subsea flowline system must be higher than the conditions for HFT and WAT [51]. To confirm the effectiveness of the active heating device and insulation coating that suits all operational scenarios, it is very important to study both transient state and steady-state analyses [51,53,65].

1.4. Methodology

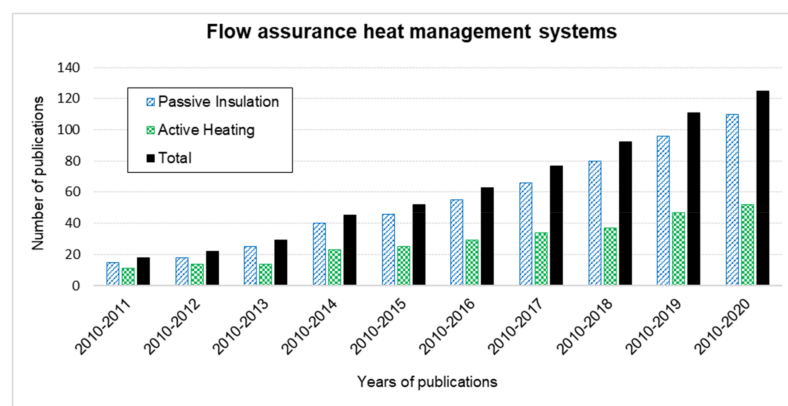
In light of the above, the objective is to conduct a detailed study to discover the level of work done by researchers globally on heat management systems in flowlines from the last decade and to also review the heat management techniques in the subsea flowline. Reviewing the heat management technique is to compare their advantages and drawbacks, identifies their limitations to field applications, i.e., water depth, and then recommends suitable cost-effective techniques.

The study on heat management systems was done to evaluate and validate the popularity of the subject by researchers, data were collected in the last ten years (2010–2020) from the databases of the top five publishers (Elsevier, Springer, Taylor & Francis, Wiley, Sage) of the largest toll-access publishers [59,66] using two keywords (Heat AND Flowline, Thermal AND Flowline). The top five publishers in the largest toll-access publishers were assessed based on their number of publications. After data collection using keywords, screening, and elimination of duplicates were done to determine the relevant articles, and

subsequently, one hundred and twenty-five (125) relevant articles were finally screened, selected, and classified into passive insulation and active heating as seen in the workflow of Figure 3a. A comparison of the heat management systems from Figure 3b below shows that approximately 42% (52 articles) of the total work done by researchers was in active heating while 88% (110 articles) in passive insulation. This number is low for active heating when compared with passive insulation. Thus, the need for more technical efforts and scientific research in the area of active heating as the quest for hydrocarbon move into deeper water.



(a)



(b)

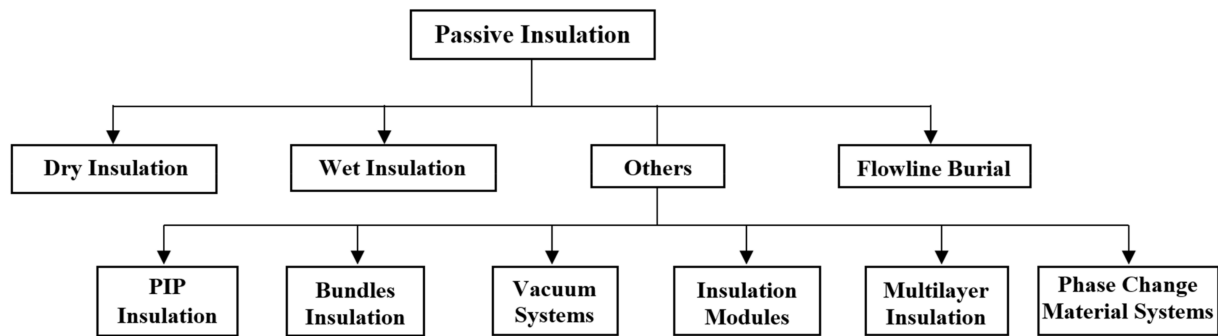
Figure 3. (a) Workflow for screened papers. (b) Number of publications for heat management in flowline from the top five publishers.

2. Passive Insulation

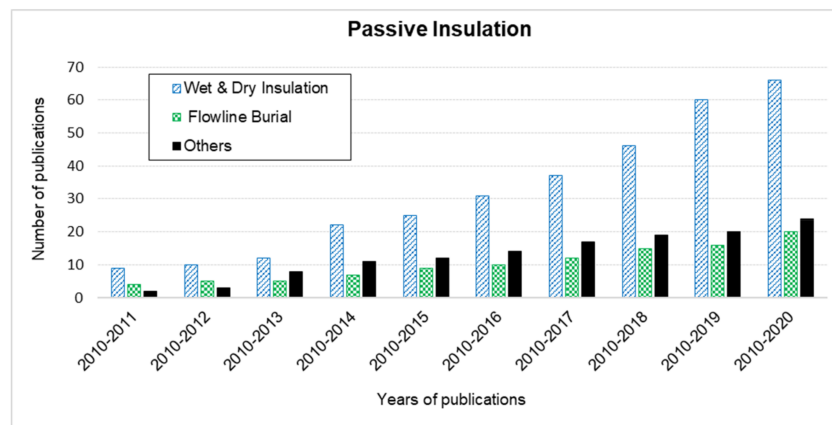
The new boundaries for subsea petroleum exploitation are the ultra-deepwater (about 3000 m) [53]. This demands pipes in the end (around 25 years) that can withstand the hostile environmental and mechanical request [53]. One important ingredient for passive insulation is to evade the hydrates and wax deposition in flowlines [53]. Hydrocarbon fluid flow preservation and the capacity to start over the production system during subsea deepwater oil and gas production is a major concern [53,67]. Heat management of the hydrocarbon effluent has been observed in the past 5–10 years as the most accustomed tool for curbing obstruction in the flowlines [53].

Passive insulation in the operation and design of subsea flowlines is very important because of the unfavorable low temperature and high-pressure conditions; such an environment creates stringent needs for optimal insulation [68–71]. The passive insulation system of heat management is flowline insulation with materials of low thermal conductivity like polypropylene, polyethylene, polyurethane, extruded polystyrene, fiberglass, mineral wool, rubber, glass-reinforced plastic, Vacuum Insulation Panels (VIPs), and aerogel [50,72–74], to control and reduce the loss of heat from the crude oil to the surrounding [50,75,76]. Some insulation types are dry and wet insulations, flowline burial, Pipe-In-Pipe (PIP), and others [50,77,78] (Figure 4a). With separated flowline operating

conditions, aside from installation approaches and cost, the option of insulation materials is reliant on the material properties like density, mechanical strength, thermal conductivity, water absorption, flexibility, aging, and corrosion resistance [65,79–82]. The usual thermal insulation is mostly manufactured in few format types like composite syntactic, brown foam, and syntactic [81,83–86].



(a)



(b)

Figure 4. (a) Passive insulation system in the subsea flowline. (b) Number of publications for passive insulation from the top five publishers.

Results from the study on passive insulation systems for the past ten years compared the different insulation systems as seen in Figure 4b. It showed 58 % (66 articles) effort for wet and dry insulation, 19% (20 articles) for flowline burial, and 23% (24 articles) for others that included pipe in pipe, bundle, vacuum systems, phase-change materials, and multilayered insulation.

2.1. Wet Insulation

The insulation of subsea flowline with wet insulating material does not require external protection to stop the entering of water or water entrance is very small and so cannot affect the properties of insulation [82]. Wet insulation employs materials such as polypropylene, syntactic polyurethane, polyurethane, multilayered, and syntactic polypropylene with low heat transfer coefficients of about $2 \text{ W/m}^2 \text{ K}$ [82,87]. Deepwater insulation mostly uses polypropylene and polyurethane materials [82]. Additionally, plastic or glass matrix enhances the insulation properties of syntactic materials for appreciable depth capacities [88,89]. Finally, it is appropriate for coating insulation material with additional materials [9,82,90,91]. Table 1 lists the properties of wet insulations.

Table 1. Summary of wet insulation properties.

Insulation Material	U-Value W/m ² K	Density (kg/ m ³)	Water Depth (m)	Service Temperature (°C)	Citations
Polyurethane (PU)—Solid.	0.20	1153.33		115.60	
Polypropylene (PP)—Solid	0.22	897.03	2743.20	143.30	
Syntactic PU	0.12–0.15	608.70–848.98	91.40–2743.20	55–115.60	[82]
Syntactic PP	0.13–0.22	592.68–800.92		115.60	
Syntactic Phenolic	0.08	496.57		200	
Syntactic Epoxy	0.10–0.14	592.68–720.83	1828.80–2743.20	71.11–100	
Polypropylene (PP)—Solid	0.22	900	3000	145	
Polypropylene (SPP)—syntactic PPF (e.g., carizite)	0.13–0.22	600–800	-	115	
Polypropylene (RPPF)—Reinforced Foam combination	0.16–0.18	600–800	600–3000	115–140	
Polyurethane (PU)—Solid	0.19–0.20	1150		115	
Polyurethane (SPU)—Syntactic (plastic beads)	0.12–0.15	750–780	100 at 115 °C 300 at 90 °C	70–115	
Polyurethane (GSPU)-Glass Syntactic	0.12–0.17	610–830	2000–3000	55–90	[51,92]
Polyurethane(RPUF)—Reinforced Foam combination	0.08	448	-	-	
Phenolic Syntactic	0.08	500	-	200	
Epoxy Syntactic	0.10–0.14	590–720	2000–3000	75–100	
Epoxy Syntactic with Mini Spheres	0.12	540	-	75	

2.2. Dry Insulation

Dry insulation materials are polyurethane foam and mineral with better heat transfer coefficients of around $1 \text{ W/ m}^2 \text{ K}$ are widely deployed for onshore and shallow water applications [50,87,93]. With dry insulation, the loss of heat to the environment is low and the hydrocarbon temperature is adequately maintained to reduce depositional issues [49]. Nevertheless, water ingress worsens the dry insulation performance [49] or degrades the insulation properties, and hence the need for a PIP system (Figure 5).

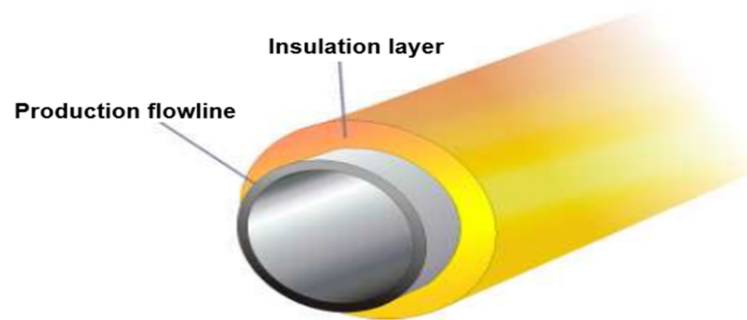


Figure 5. Schematic view of a dry insulation system.

2.3. Flowline Burial

Flowline burial is simply a heat insulation system where the flowline is buried or having rocks, grits, or seabed material placed over them below the mudline [50,51]. Flowlines are usually buried in subsea deepwater fields for on-bottom stability, thermal insulation, and also safeguarding from trawling and dropped objects [49]. In flow assurance heat management systems, flowline burial is considered one of the best cost-effective heat management techniques for onshore, shallow and deep water [50,51,87]. Flowline burial is particularly selected for a project and is dependent on soil properties, geological hazards, Pressure Volume and Temperature (PVT) characteristics, and basic structures [49,94,95]. Even if subsea soil provides good insulation, the porous materials like grits, seabed materials, and rocks only give little or no insulation due to water ingress into the spaces thereby allowing heat transfer by convection to the surroundings [51]. The subsea flowline burial is either fully or partially buried [51,96]. Comparing both methods, a partially buried flowline offers less insulation effect to the fully buried flowline [51,97,98]. Additionally, the partially buried flowline (trenched flowline) encounters lower heat loss than the bared flowline but greater than the buried flowline [51,99,100].

Flowline burial has the edge of utilizing the soil good heat capacity that acts as both heat storage and sinks [50]. Therefore, a buried insulated flowline has a greater heat capacity than a PIP system with extended cooldown time [49] while the installation cost of a buried insulated flowline is roughly 35–50% higher than that of a PIP technique [49,101,102]. In the course of the shutdown time before the advent of hydrates nucleation or gelling of wax, a buried flowline has four times higher retention capacity for heat than a PIP system [50,103,104]. This can be an important reduction in the overall project for long flowline systems [49]. Some other merits of flowlines burial system include more option on installation vessels and contractors, more options on the vendor for the fabrication of flowline, when compared to PIP system gives a slower cooldown time during shutdown and a likelihood of single flowline repair [49], and also provide a reduced time and enhanced schedule for first oil [49,105,106]. Oh et al. [107] carried out laboratory experiments to ratify some numerical and analytical models [50,108–111]. Figure 6 shows the comparison between burial depth and U-value for both bared and a coated polypropylene foam flowline [51]. It is also important that challenges like upheaval buckling and seafloor buckling are examined during the design of a good scouring depth for flowline burial [51,112,113].

2.4. Others

The other insulation systems being deployed for insulation or currently undergoing development are:

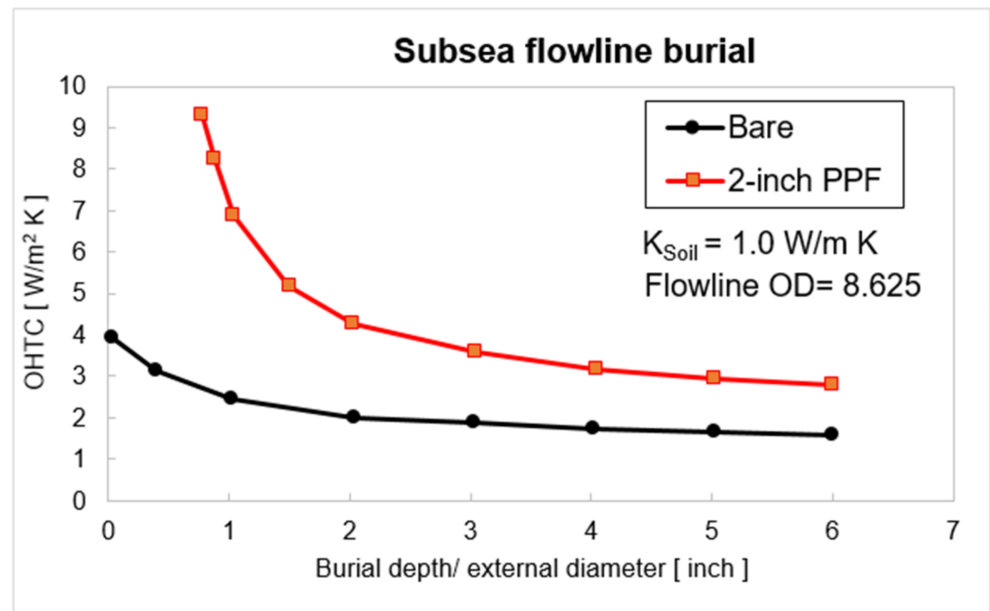


Figure 6. Compares flowline U-values for coated two-inch polypropylene foam against burial depth [114].

2.4.1. PIP Insulation

PIP insulation is a single-insulated inner flowline centrally located inside an outer protective pipe [49], between the protective outer pipe and inner pipe, there is an annular space for insulation to prevent heat losses from the flowing fluid [115]. Different insulation materials like aerogel, mineral wool, vacuum or inert gas, and Polyurethane Foam (PUF), etc. occupy the annulus connecting the pipes [82], as seen in Figure 7. The PIP insulation is an upgrade of the dry insulation to stop the ingress of water into the insulation layer for superior performance [49,50,116,117].

The PIP systems are well-known solutions to flow assurance issues [49]; for this reason, several works are described on the different outlook of bundled flowlines and PIP systems [49,118]. The need for thermal insulation and mechanical load is important as the depth of water increases [49]. Consequently, the demand for thicker insulating material to ensure the integrity and durability of the flowline due to the hostile environmental conditions [49]. PIP insulation system is a technique of achieving a U-value of $1 \text{ W/m}^2 \text{ K}$ or less [51,72] and hence partial vacuum is added to decrease the heat transfer coefficients to around $0.5 \text{ W/m}^2 \text{ K}$ [50,87,119], producing an effective system for fluid flow management [50,120]. Flowlines in PIP configurations were essentially constructed in the Gulf of Mexico to obtain high heat insulation for flow assurance purposes [72]. Having the internal fluid warm helps to reduce paraffin deposition and stop the formation of a hydrate plug, which can compel the production flow. Table 2 gives the materials' insulation for the PIP system, its U-values, insulation thickness, and properties [72].

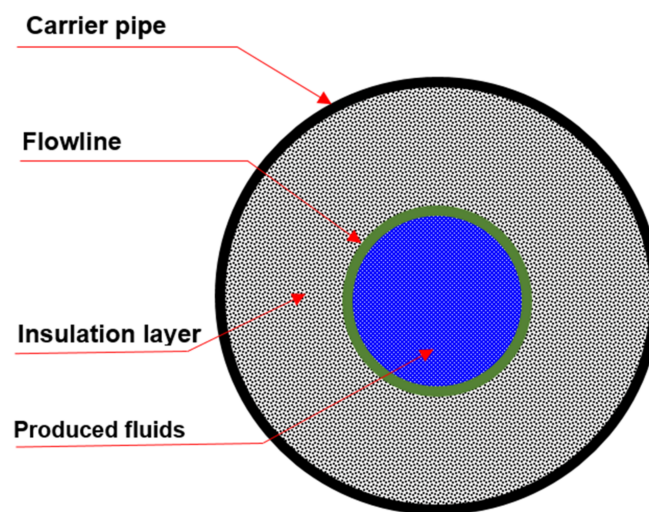


Figure 7. Pipe-in-pipe (PIP)-insulated systems [121].

2.4.2. Bundle Insulation

Bundles are mainly applied for combined flowlines installation inside a carrier pipe or outer jacket [51]. The bundle systems are akin to the PIP systems other than that bundles contain several pipes [85,122–124]. Figure 8 shows the flowline bundle configuration. Bundle systems give appealing solutions to a broad scope of the issues of flow assurance by presenting a cost-effective technique and also the likelihood of circulating a medium for heating [51]. The additional benefits are as follows: it allows for multiple flowlines installation into a single pipe design [51]; the outer pipe is utilized to withstand subsea hydrostatic pressure in deepwater [51]; finally, bundles permit the introduction of monitoring devices and heated pipes [72]. The bundles' drawbacks are its length limit (shallow water installations) and the demand for a comfortable launch and fabrication location [72].

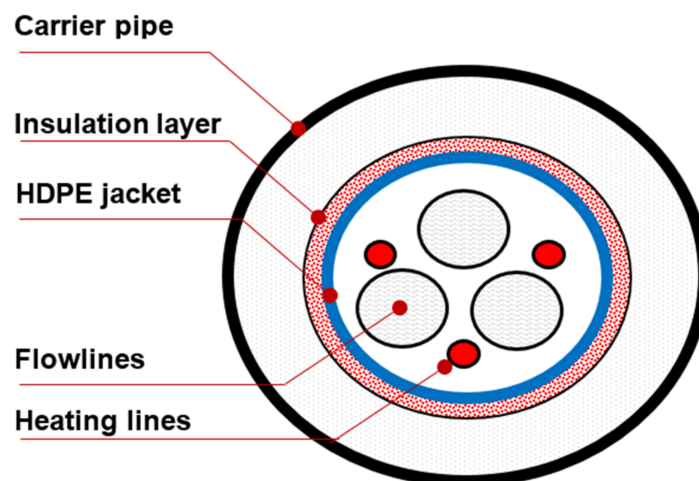


Figure 8. Flowline bundle configuration (adapted from Bai et al. [72]).

The first known installation of the PIP technique was by the Indonesian Pertamina offshore in 1973 [72]. Until 2000, 103 miles of PIPs and bundles were built in the North Sea, which is about 1% of the total flowline population; The Gulf of Mexico has so far utilized 64 miles of bundles and PIPs [72,125]. Nearly 50 flowline bundles are installed in the North Sea by a Controlled Depth Tow Method (CDTM) [72], and the earliest installation was at Murchison field in 1980 [72].

Table 2. Thermal Properties of Pipe-In-Pipe Insulation Materials.

Insulation Material	Density (Kg/m ³)	Thermal Conductivity (W/m K)	U-Value (W/m ² K)	Annulus Gap (if any)	Maximum Temperature (° C)	Comments	Citations
Mineral Wool	140	0.037	1.60	Clearance	700	Rockwood or Glava, always combine with reflective Mylar film.	
Aluminum Silicate Microsphere	390–420	0.1	3.90	None	1000+	Commonly known as fly ash, introduce to charge the annulus.	
Thermal Cement	900–1200	0.26	-	None	200	Presently been studied by a Joint Industry Project, to have collapse resistance with a decrease in pipe wall thickness.	[51,72,92]
LD PU Foam	60	0.030	0.76	None	147	Prefabricated as a double-jointed or single system for the replacement project of Erskine.	
HS PU foam	150	0.04	1.20	None	147		
Microporous Silica Blanket	200–400	0.02	0.40	Clearance	900	Cotton blanket, glass, titanium fibers and calcium-based powder.	
Closed-Cell Polyurethane Foam (CCPUF)	48.06–96.11	-	-	-	-	-	
Open-Cell Polyurethane Foam (OCPUF)	32.03–64.07	-	-	-	-	-	
Polyisocyanurate Foam (PIF)	28.83–32.03	-	1.08	-	-182.78–148.89	-	[82]
Extruded Polystyrene	96.11	-	1.47	-	-182.78–73.88	-	
Fiberglass	56.06–88.10	-	1.36	-	-17.78–454.44	-	
Mineral Wool	139.36	-	1.42	-	700	-	

2.4.3. Vacuum Systems

Vacuum Insulated Tubing (VIT) was initiated in the search to enhance better heat retention [50]. The VIT or Vacuum Insulated Panels systems are upgrades of the PIP methods [50], having a slim space kept at a vacuum state to decrease the transfer of heat from the hydrocarbon to the surroundings [50,126]. The VIT is identified with a low U-value of 0.008 to 0.36 W/m² K [50,126,127]. VITs were successfully used in the Gulf of Mexico deepwater fields to prevent hydrate plugging and wax deposition and to manage annular pressure buildup during the crude oil transport process [127,128]. The Norman and Alaska production fields deployed the VIT techniques to control the issues of flow assurance [50,126,129–131]. They are seen as expensive when compared to other passive insulation techniques [50,126,131–133] but might be favorable in areas like the Gulf of Mexico with a high cloud-point temperature [50,127]. Table 3 provides the vacuum insulation properties.

Table 3. Thermal properties of vacuum systems.

Insulation Material	Density (Kg/m ³)	Thermal Conductivity (W/m K)	U-Value (W/m ² K)	Annulus Gap (if any)	Maximum Temperature (° C)	Comments	Citations
Vacuum Insulation Panels (VIPs)	60–15	0.016–0.008	0.26	Clearance	160	The foam of the shells is made with aluminum foil under the condition of vacuum and utilizes gas absorbing “getter” pills for free gas.	[51,72,92]
Vacuum Insulation Panels (VIPs)	59.27–144.17	-	0.20–0.31	-	160	-	[82]

2.4.4. Insulation Modules

Insulation modules are made up of manufactured segments of insulations that are connected to the insulation structure without being joined to it directly [85]. The composite syntactic and syntactic foams are the most commonly applied materials for the insulation technique [85,134,135]. One advantage of this technique for riser application is geometry modifications to suit both riser and additional lines [85]. Insulation is commonly fastened by straps or bolts and can be disconnected during the life span [85]. Insulation is normally joined by constructing various molded segments of materials all over the structures for most riser tower subsea applications [85,136,137].

2.4.5. Multilayer Insulation

The multilayer insulation system is a sub-units of the integral insulation technique [85] and comprises various insulation layers [85,138,139]. The usual designs have syntactic foam layer, blown foam layer, and solid layer [76], and individual layer conduct a particular role [85,140].

The layer straight above the corrosion protective layer is comprised of the solid layers that resist temperature [85], syntactic layers supply fine insulation properties and hydrostatic support [85,141,142], and the blown foam layers are the outside layers with the finest properties of insulation [85]. The blown foam is usually exposed to a pronounced lesser temperature than the internal layers due to thermal gradient across the pipes [85]. The other types of layers frequently added in the multilayer insulation system is the adhesive layer that assists in joining and strengthening layers which preserve the outside layer from destruction [85,143–145]. The advantage of multilayer insulation is that

the density and thickness of the individual layer may be adjusted to match the specific application [85,146–148].

2.4.6. Phase Change Material Systems

Phase Change Material (PCM) is a material that delivers latent heat during a phase change transformation [149]. The PCM is seen between the insulation material and flowline, to ensure it is above the temperature of phase change during system operation [149]. Material external insulation thickness gives the system's Overall Heat Transfer Coefficient (OHTC) [149,150], and for this reason, a high insulation material performance must be selected to restrict the thickness of the layers to reduce the increase of the outer pipe diameter [149,150]. During a shutdown operation, the latent heat release will increase the normal cooldown period from 3–5 days [149]. Nonetheless, where there is a very long period of shutdown above the cooldown time performance, a flowline restart may result in a big problem [149]. Since the system is capable of storing and releasing a large quantity of heat, the system would as well demand to recover the same energy quantity to reach steady-state conditions [149,151,152].

To improve PCM systems, PCM multilayer insulation was used and it is the addition of PCM- or PCM-matrix composite material in multilayered flowline [8,81]. PCM can keep a large quantity of latent heat at a liquid state and liberate it during a phase change process [81]. By this special quality, it has captivated further concerns in the evolution of novel insulation solution [81]. Alawadhi [153,154] discovered that the heat loss in the flowline can be notably decreased for an insulation system with PCM because of the latent heat released during phase change [81]. An integration of convention insulating layers and PCM can give the best design [155,156]. Despite showing better insulation features, PCM application is limited by a likely liquid phase escape to the surroundings [81]. This gives difficulty during installation and to subdue these problems [81], a structured plan centered on PCM-matrix composite material was suggested [81]. The PCM-matrix composite comprises a matrix of polymer material and Microencapsulated PCM (MicroPCM) fragments distributed in spheres' form in the matrix [81,157]. It is also described as a unique porous media with composite heat transfer properties [81].

Figure 9 shows the application of passive insulation systems for PIP, wet, flexible, and bundles. The towed bundles are constructed in water depth below 500 m [72] whereas the PIP and wet insulation can be used for water depths of up to 2000 m [72]; the U-value of the PIP flowline is relevant to most required U-values [72]. Table 4 compares the different passive insulation systems.

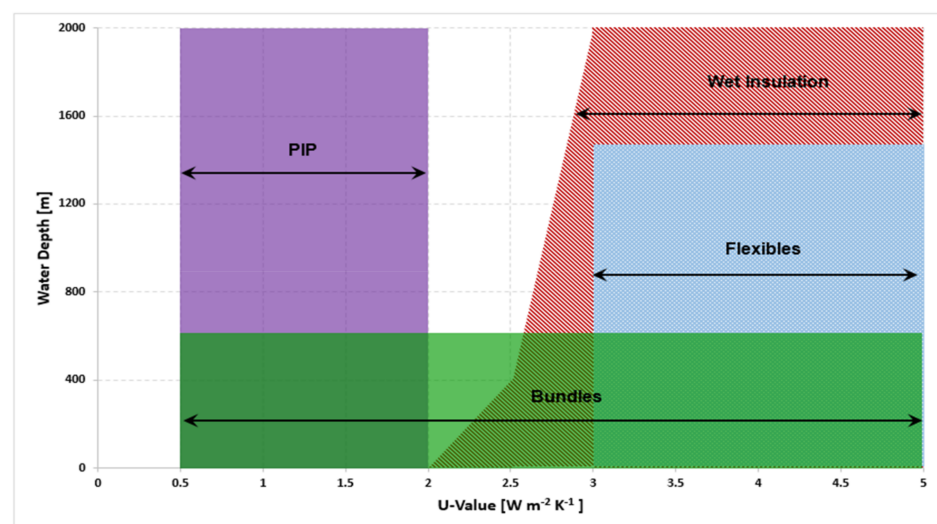


Figure 9. Passive insulation system applicability (adapted from Watson et al. [158]).

Table 4. Comparison of the different passive insulation systems.

Heat Management Technique	Advantages	Drawbacks	U-Value (W/m ² K)	Citations
External Integral Insulation (Multilayer Insulation included)	<ul style="list-style-type: none"> – Acceptable for a complete design. A high-resistance temperature. – Multilayer technique could modify the design to attain preferred properties. – Limitless depth of water for a solid system. 	<ul style="list-style-type: none"> – Hard to detach. – There is a limit on the insulation level. – There is no buoyancy with a solid system. – Demand for a set time. – Restriction on thickness. 	1.7–5.0	
Insulation Bundle/ Module Systems	<ul style="list-style-type: none"> – The housing of additional lines. – Could be removed in the course of service. – Cheaper than the PIP system. – Easy implementation on flowline. – Lower depth of water than PIP. 	<ul style="list-style-type: none"> – The module gaps may cause convection current. – A huge material quantity is needed, which can be evaded. – Geometry could have insulation difficulty. 	2.0–8.00	[51,85]
PIP Insulation	<ul style="list-style-type: none"> – Finest properties of insulation excluding vacuum. – Depth of water limit based on vessel installation capability. 	<ul style="list-style-type: none"> – Costly fabrication and installation. – Impossible to reel a few PIP systems. 	0.3–1.5	
Vacuum Systems	<ul style="list-style-type: none"> – Best properties of insulation. – Transfer of heat is only by radiation. 	<ul style="list-style-type: none"> – Once the external pipe is ruptured, the pipe section loses insulation properties. – The effort is needed to conserve vacuum. – The vacuum level in the annulus is continually observed. 	<0.01	
Burial Trenching	<ul style="list-style-type: none"> – Neighboring soil supplies part of the insulation. – Supplies on-bottom stability for flowlines. 	<ul style="list-style-type: none"> – Impractical to bore trench for burial. – Employed only for lying pipes in the mudline. – Location affects the thermal conductivity of the soil. – Unpredictable thermal performance due to changes in the properties of the soil and troubles predicting or measuring them. 	Insulation layers + soil insulation	

Table 4. Cont.

Heat Management Technique	Advantages	Drawbacks	U-Value (W/m ² K)	Citations
Thin Film/Multilayer[159]	<ul style="list-style-type: none"> – It gives good thermal resistance with a VIT combination. – The layer total thickness is below 3 mm. 	<ul style="list-style-type: none"> – Poor thermal storage creates quick cooldown, desirable for the manifold, wellbore tubing, Christmas trees, flowlines, and jumpers. 	Applied in Shell Oregano and Serrano, BP Marlin.	
Conventional Insulation	<ul style="list-style-type: none"> – It has simple constructions. – Construction costs are low. – Life cycle costs low. – Has higher inspection reliability. 	<ul style="list-style-type: none"> – May not able to sustain the product's temperature above WAT for long flowline. – Once there is a product leak, it leaks into the environment. 	-	
PIP Insulation	<ul style="list-style-type: none"> – It has maintenance and operational flexibility – Suitable containment of a product from leaking. – Environmental safety due to management of oil in the occurrence of an inner flowline failure. – Monitoring of the annulus for confirmation of a leak or PIP degradation is easy. – Low chances of breakdown or leakage in both pipes. – Lower chance of product being discharged to the surrounding than a solitary wall pipe. 	<ul style="list-style-type: none"> – Design and construction are more difficult than insulated single wall pipe. – It has monitoring issues linked to bulkheads, spacers, or shear rings. – Restricted capacity to check and monitor conditions of outer protective pipe. – The repair costs of PIP for a total containment failure are about 25% higher than a similar case of insulated single wall pipe. – The VIT-PIP is expensive and not appropriate where other PIP can be used as a replacement. 	-	[50]
Flowline Burial	<ul style="list-style-type: none"> – The period of heat containment is high. – The construction and laying are simple. – Low costs of construction. – Life cycle costs are low. 	<ul style="list-style-type: none"> – Once there is a product leak, this leaks into the environment and cause degradation. – When the wax is formed, chemical inhibitors or external heat are needed. 	-	
Phase Change Material (PCM)	<ul style="list-style-type: none"> – During shutdown operation, latent heat release will increase cooldown times by 3–5 days. – Heat loss in flowline can be noticeably reduced for insulation systems containing PCM [153,154]. – PCM–matrix composite material improves installation problems because of phase change property [81] 	<ul style="list-style-type: none"> – Long shutdown period over cooldown time performance. – A flowline restart can become a big problem. – Direct use of PCM insulation layers is restricted to likely escape of its liquid-phase to the surrounding temperature [81]. 		[149]

3. Active Heating

Oil and gas production is inherently a risky business and how this risk is managed will effectively determine its success. Flow assurance issues are part of these risks and with most of the conventional fields already being produced, operators are facing in the past 15 years increasing issues in developing fields that have changed from stand-alone host structures and largely concentrated resources to scattered ones with tie architectures to existing facilities or shores [160]. In the last 10 years [161], the numbers of long tie-backs doubled [162]. Truly, long tie-backs to existing infrastructures (higher than 10 miles for oil fields and 30 miles for gas fields) are planned, from a cost perspective, as they give entry to far reserves circumventing new topside installation [161]. By venturing further and into deeper subsea, together with growing flow assurance issues associated with fluid characteristics (hydrates, wax, high viscosity, pour point) as well as flowing conditions (temperature, pressure, flow rate), have expanded conventional flow assurance methods wax and hydrate prevention which included passive insulation to its limits, forcing the use of conventional or hybrid loop architecture (e.g., depressurization, dead oil circulations, and chemical injection to its limits) at elevated costs [160].

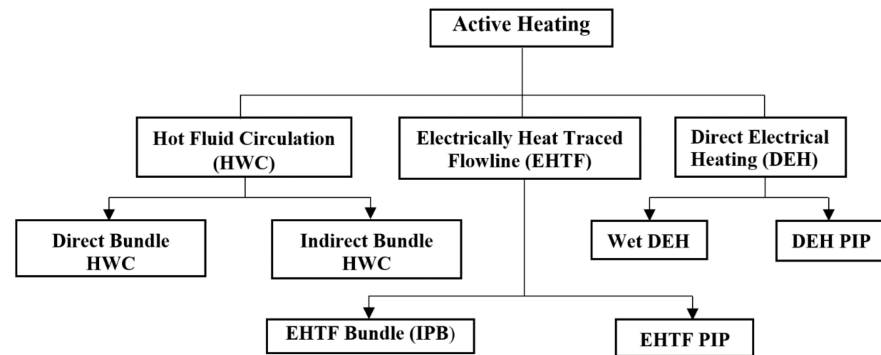
In this situation, active heating looks good enough as a cost-effective alternative for both subsea in-field and long tie-back developments [160]. From a technical viewpoint, the use of active heating permits transient and steady-state operations simplification of highly complex fluids by managing wax, hydrates, high viscosity and pour point issues with continuous or discontinuous heating [160]. The conservation and line start over by active heating method permit the change to a single line framework that presents significant cost gains through a reduction in the number of flowlines from a conventional circuit system with chemical injection and dead oil circulation [160,163–165]. The active heating system involves the external addition of heat to the production flowline by an electrical heat source or circulated hot water [166,167]. The active heating technique is an attractive, economical, and effective solution for flowline heat management systems particularly in subsea deepwater fields where flowline pressure and temperature conditions are unfavorable [49,50]. For most fields, the goal is to stay above the region of 15 to 40 °C [161]. Therefore, the active heating method is used for many situations in flowlines [49,76], such as the prevention of cooldown and warming up of non-flowing systems like (e.g., during shutdown or startup) [49,168], sustaining and increasing temperature while flowing [49]; decreasing the need for chemical injection [49,76]

Compared to passive insulation, active heating can sustain the hydrocarbon fluid temperature beyond the hydrates and wax formations temperatures over long periods [49,76]. Three heating systems exist; Hot Water Circulation (HWC), Electrically Heat-Traced Flowline (EHTF), and Direct Electrical Heating (DEH) as shown in Figure 10a. A study on active heating systems in the last decade compared the different heating systems as shown in Figure 10b. There is 48% (25 articles) research work on Hot Water Circulation (HWC)-PIP and Bundle, 46% (24 articles) for Direct Electrical Heating (DEH)-Wet DEH and DEH PIP and 6% (three articles) for Electrically Heat-Traced Flowline (EHTF)-EHTF Bundle (IPB) and EHTF PIP.

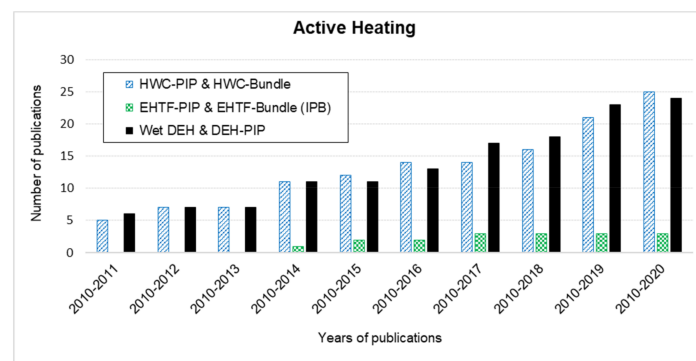
3.1. Wet Insulated Hot Water Pipe in Pipe

The Hot water circulation technique is a field-proven technology for flowline heating mostly employed for deepwater operations [49]. For this type of system, the production fluid becomes heated by the hot water that goes round in a little heating pipe through a conduction and convection process [49,50]. The heating technology depends on the circulation of hot water (fluid) in a close region to the production flowline in the annular space (Hot Water PIP) [160]. Hot water circulation systems usually operate in a loop as the water needs to be recirculated back to the topsides [160]. Generally, the hot water technique uses heat exchangers with an extended secured tube having production fluid on the inner part and the heating medium on the outer part of the tube [48,49,160,169] (Figure 11); also the water may be injected into the well at the extremity of the system but creates a

constraining coupling between the production and injection systems [170]. The heater located near the subsea wellhead or over the processing facility on the surface heats the hot water [49].



(a)



(b)

Figure 10. (a) Active heating system for subsea flowline. (b) Number of publications for active heating systems from the top five publishers.

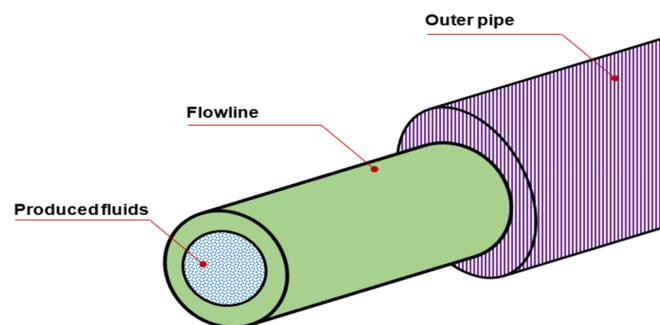


Figure 11. Wet insulated Hot Water PIP (adapted from Basilio et al. [171]).

3.2. Hot Water Bundle (Direct or Indirect)

A hot water bundle is a carrier pipe within which any combination of individual flowlines and umbilical components are carried and there is hot water distribution in close vicinity to the production flowline in an assigned line [160]. Bundles with dry insulation having U-values of $0.5 \text{ W/m}^2 \text{ K}$ are highly efficient insulation systems [161]. Two types of Bundle HWC used in shallow waters are direct heating by annulus circulation and indirect heating circulation through dedicated hot water lines (Figure 12a,b).

The direct HWC systems incorporate the production flowline contain in an insulated sleeve pipe with hot water flowing in the annulus [161]. The hot water can either be injected into water injection wells or returned to the topsides through a separate return line [161].

The indirect HWC system operates through the use of heat supplied by dedicated hot water supply and return flowlines to maintain the temperature in the production flowlines [161]. The production and hot water lines are inside the insulation layer that is filled with a low-pressure gas such as nitrogen [161,172].

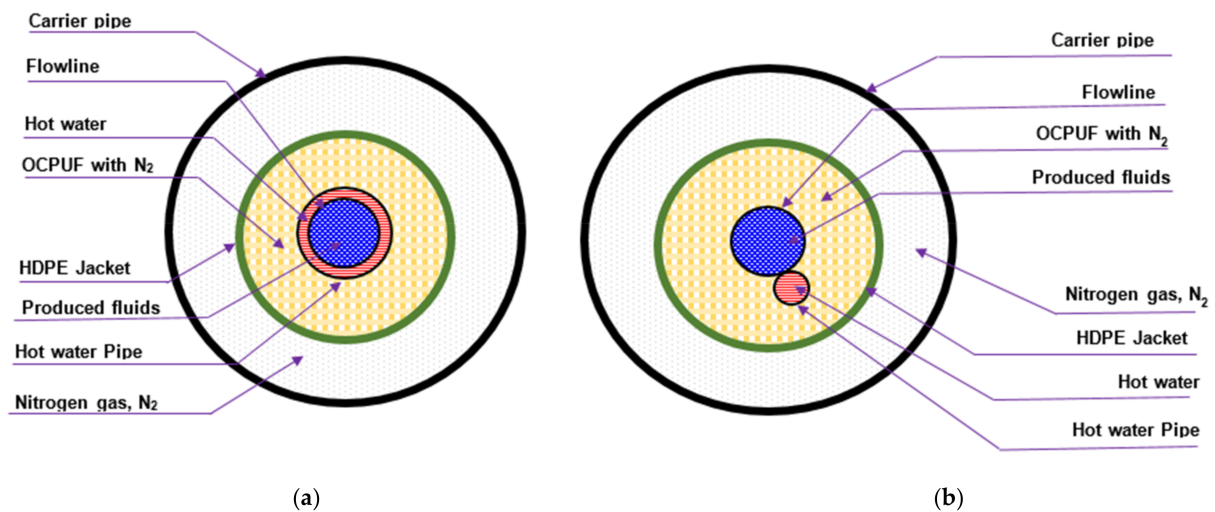


Figure 12. Hot water insulated flowline bundle system with (a) direct heating (b) indirect heating (adapted from Zhang et al. [173]).

Comparing both solutions, direct hot water heating is more efficient in terms of heat transfer [161]. Nonetheless, other criteria are less favorable [161]. Among others, the volume of water is greater with direct heating and thus tank size required at the topside in addition to pumping requirement [161]. The indirect hot water-heated bundle also has the multipurpose heating lines as an advantage that can be used for water injection or produced water re-injection [161].

Hot water circulation technology was used in Conoco Phillips' Britannia fields and Statoil's Gullfak [50,167]. Brown et al. [174] narrated the design and execution of the UK North Sea, Britannia 15 km subsea hot water heated bundle project [49]; regarded as the finest solution for preventing the formation of hydrates and wax [49]. Zhang et al. [166] discussed the problems associated with hot water heated production flowline bundle designs [49], by two case studies of offshore West African developments [49]. The authors analyzed and compared two key design possibilities such as direct and indirect heating [49]. It was concluded that direct heating gives a better heat transfer than indirect heating while indirect heating provides reduced heat loss to the surrounding [49]. In terms of cost, the indirect heating bundle has the edge of a smaller bundle size and lower cost [59]. To reduce the flow rate limit because of a high-pressure drop, the flowline size has the flexibility to be increased for indirect heating than for direct heating [49]. Girassol field development was another West Africa installation of production bundle located offshore Angola in 1400m of water reported by [49,161,175], and stringent operating requirements observed because of the need for adaptability and issues of flow assurance [50]. The advantages and drawbacks of hot water circulation systems for wet insulated and bundle systems is highlighted in Table 5.

Table 5. Advantages and drawbacks of Wet and Bundle HWC.

	Advantages	Drawbacks	Citations
Design	<ul style="list-style-type: none"> – HWC- bundle can integrate insulation with good thermal performance with U-value from 0.6–6 W/m² K. – HWC system is used to adequately warm the production fluid during steady-state or restart a line with issues of pour point. 	<ul style="list-style-type: none"> – Conventional HWC-PIP has relatively low wet insulation performance, U-values varies from 3–6 W/m² K. – Only used during steady-state production in practice. High power requirements for preservation, and therefore conventional operations are usually preferred. 	
Fabrication	<ul style="list-style-type: none"> – HWC-Bundle structure presents the advantage of limited thermal expansion and low risk of lateral buckling, as well as good resistance to accidental impacts (dropped objects, trawl gear impact) 	<ul style="list-style-type: none"> – HWC-PIP is prone to thermal expansion and lateral buckling due to hot water circulation in the annulus. 	
Installation	<ul style="list-style-type: none"> – HWC-PIP diameter and water depth are only limited by installation vessel capabilities. 	<ul style="list-style-type: none"> – HWC-PIP can be installed by S-lay and J-lay. Reel lay for small diameters only would require specific development. – HWC-bundle construction necessitates a dedicated bundle assembly plant (long with specific equipment) and can only be installed by towing up to 500 m water depth 	[160]
System Efficiency/Reliability	<ul style="list-style-type: none"> – Possible combination with hot fluid from more process units on the topside. This is advantageous when the hot water is produced from a heat recovery system using production fluid heat or from fire heaters fed with production gas. 	<ul style="list-style-type: none"> – A large footprint is required on the topside for heat recovery and water treatment systems. – The injected water needs to be treated to avoid corrosion issues inside the circulation path. For both pipe-in-pipe and bundle, the material selection is also driven by any long-term corrosion concerns in the annulus. – No possibility for redundancy of HWC-PIP. The heating apparatus being the pipe itself has flowline integrity as the main design criteria. Redundancy can be envisaged for HWC bundles but would require an additional circulation line in the bundle structure. 	

3.3. Direct Electrical Heating-Wet Insulated Flowline (Wet-DEH)

DEH is based on the principle of direct circulation of single-phase alternating current, at a typical frequency of 50–60 Hz, in limited flowlines wall thickness due to skin effect and returned through a piggyback cable [100,160]. With the DEH system, the heated flowline in a single-phase Alternating Current (AC) loop is the active conductor and with a forward conductor powered cable [176], placed side by side near the pipe being heated as shown in Figure 13 below [176–178]. The system of heating is provided from the power supply located at the topsides [176]. Electrical heating does not require storage facilities like the hot water circulation heating systems and applies to small size flowline such as PIP or wet insulation flowlines [71,149]. In general, heat is generated by the Joule effect from the current circulating in the flowline wall [49,179,180].

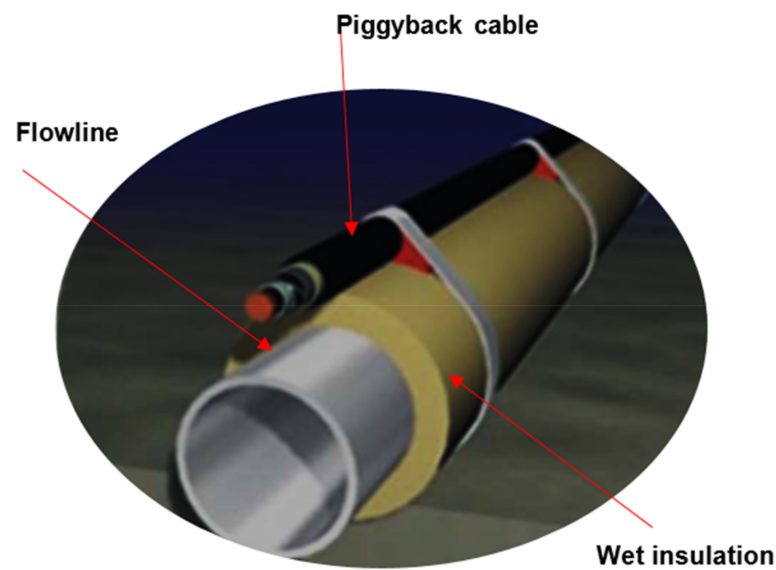


Figure 13. Configuration of Wet-DEH system.

The DEH circuits are normally designed to work as an open system to mitigate AC corrosion risk, therefore a significant part of the injected current flows through seawater instead of the steel pipe [160,176].

The DEH system was initially established in 1996–1997 by a Joint Industry Project, JIP (Sintef Energy Research and Nexans Norway) found on the patent of Statoil [176]. To sustain the needed temperature of the production fluid, DEH up until now has been employed in almost twenty different projects in the Norwegian North Sea [160,176]. The technique had recorded successes with validated laboratory tests and simulated results [176]. Also successfully installed the Chevron Lianzi project on a 43 km flowline in 1070 m water depth [161]. The DEH wet insulated system advantages and drawbacks for the flowline are explained in Table 6.

Table 6. DEH wet insulated flowline advantages and drawbacks.

	Advantages	Drawbacks	Citations
Design	<ul style="list-style-type: none"> – Steel flowline direct heating effect of Joule – Small U-value of 2.5 W/m² K – Extended heated circuits of approximately 50 km. – Large flowlines diameter of up to 30" inner diameter. 	<ul style="list-style-type: none"> – High linear power, voltages, and currents (1500 A). – The demand for 3-1 phase adaption. – Big cathodic system protection is needed. – The flowline corrosion design requires an electric field occurrence. 	
Fabrication	<ul style="list-style-type: none"> – It is field proven. 	<ul style="list-style-type: none"> – Line pipes sorting by magnetic permeability. – Piggyback cable protection and strapping. 	[176]
Installation	<ul style="list-style-type: none"> – J-Lay, S-Lay and Reel Lay. 	<ul style="list-style-type: none"> – Application limited to deep water (up to 1000 m water depth). 	
System Efficiency	<ul style="list-style-type: none"> – It is field proven. 	<ul style="list-style-type: none"> – Low electrical efficiency of 30–60%. – The low heating efficiency of 50–75%. – It is not efficient for continuous heating. 	
Reliability/ Reparability	<ul style="list-style-type: none"> – The cord and its components are possibly retrofitted/ restored. 	<ul style="list-style-type: none"> – There is no redundancy. 	
Design	<ul style="list-style-type: none"> – Heating by joule effect directly in flowline steel – It can be used for both preservation and remediation if designed for such an objective [161]. – Low U-value (≥ 2 W/m² K) [161]. 	<ul style="list-style-type: none"> – Low thermal performances (U-value of 3 to 6 W/m² K) due to flowline wet insulation. – High electrical power requirement (50–150 W/m) [161]. 	
Fabrication	<ul style="list-style-type: none"> – Field proven [161]. 	<ul style="list-style-type: none"> – In a significantly inductive system, apparent power is high compared to active power. – Water depth is limited by piggyback cable qualified to date for 1100 m maximum. 	[160]

Table 6. Cont.

	Advantages	Drawbacks	Citations
Installation	<ul style="list-style-type: none"> – Wet-DEH can be installed either by S-Lay, J-Lay, or by Reel Lay. – Installation of wet-DEH is either by Reel or S-Lay [161]. 	<ul style="list-style-type: none"> – Non-homogeneous longitudinal and circumferential heating, depending on steel material electromagnetic properties (pipe sorting required) and coupling with piggyback cable. 	
System Efficiency	<ul style="list-style-type: none"> – Field proven [161]. 	<ul style="list-style-type: none"> – Low efficiency: Heating efficiency is 50–70% due to low thermal performances and Electrical is 30–60% due to the open system electrical circuit, power flowing through seawater, electromagnetic coupling, and inductive effects. – Low operability: Wet-DEH calibration and control is challenging. No accurate adjustment of the power alimentation and temperature control of the line is achievable. 	
Reliability/Reparability	<ul style="list-style-type: none"> – DEH components can be replaced or retrofitted on already installed wet insulated pipes if anticipated at the design stage. 	<ul style="list-style-type: none"> – No possibility for redundancy of the DEH system. – A/C corrosion risk, complex open-loop design with anodes. Regular inspection and maintenance are required. 	

Lastly, the heating efficiency of the wet-DEH system is small due to the small electrical efficiency of the pipe (energy lost mostly due to power lost in seawater and Joule effect in the DEH piggyback cable) and low thermal insulation capacity which is calculated to be 30–60% [160,176]. Such systems for uninterrupted heating solutions are not the best bet for a large amount of power required from the topside [176]. But the idea of the system is robust, field-proven, and is used for lengthy and big diameter flowline installation [176].

3.4. Direct Electrical Heating-Pipe-In-Pipe (DEH-PIP)

DEH-PIP works on the same principle as Wet-DEH except that current is supplied at the middle of the flowline and returned through the carrier pipe instead of a piggyback cable [176] (Figure 14). The DEH for PIP was initially developed for hydrates remediation means nonetheless the tool is as well used for flowline heating in the course of fields' development, i.e., continuous heating and/or field production shutdown [172,176,181].

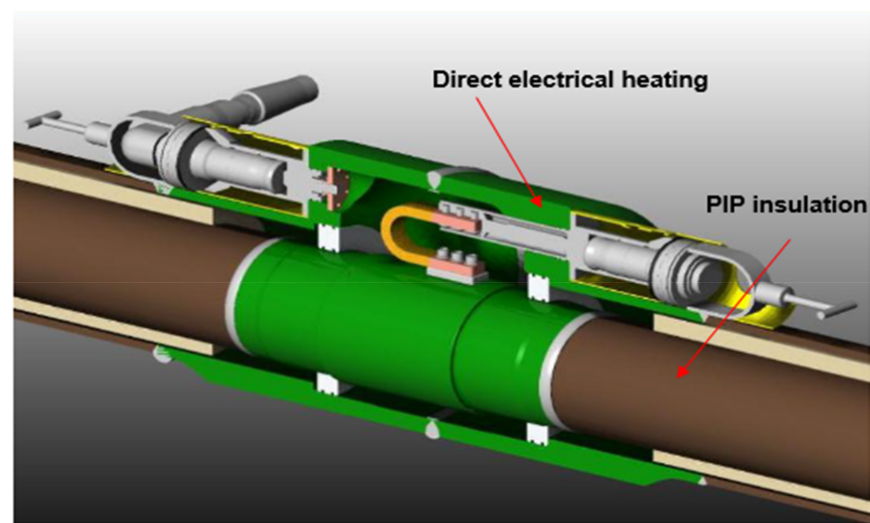


Figure 14. Subsea DEH-PIP system (adapted from Candelier et al. [176]).

When compared to the Wet-DEH insulation system, this solution gives a higher power efficiency due to [176], no links to the seawater, credit for skin effects and proximity; PIP insulation decreases thermal losses.

Nonetheless, specially designed parts like non-metallic bulkheads are vital for the system and this looks confined to only average lengths because extensive lengths result in larger annulus width with higher voltage [176,182]. Table 7 compares the advantages and drawbacks.

Table 7. Advantages and drawbacks of DEH-PIP compared to Wet-DEH.

	Advantages	Drawbacks	Citations
Design	<ul style="list-style-type: none"> – The size of the voltage is 3 kV. – It has a good thermal performance of 2–0.5 W/m² K. 	<ul style="list-style-type: none"> – High linear power and currents (1500 A) – Small flowline lengths' – Lengthy power cord needed for mid flowline electricity provision site. 	
Fabrication	<ul style="list-style-type: none"> – It is field-proven. 	<ul style="list-style-type: none"> – Required for special bulkheads and water stops. 	
Installation	<ul style="list-style-type: none"> – J-Lay and Reel Lay is preferred. – For deepwater application. 	<ul style="list-style-type: none"> – S-Lay is not preferred. 	[176]
System Efficiency	<ul style="list-style-type: none"> – The high heating efficiency of up to 95%. 	<ul style="list-style-type: none"> – Comparatively small electrical efficiency of about 70%. – It does not appeal to continual heating. 	
Reliability/ Reparability	<ul style="list-style-type: none"> – The cord and its components are possibly retrofitted/restored. 	<ul style="list-style-type: none"> – There is no redundancy 	
Design	<ul style="list-style-type: none"> – High thermal performances (U-value of 0.6 to 2 W/m² K) provided by dry insulation in PIP annulus. 	<ul style="list-style-type: none"> – Low thermal performances (U-value of 3 to 6 W/m² K) due to flowline wet insulation. – Limited maximum heated length with a single power supply which needs to be located at the mid-point of the line due to risk of electrical arcing between the flowline and carrier pipe. 	
Fabrication/ Installation	<ul style="list-style-type: none"> – PIP arrangement mechanical robustness (resistance to accidental loads, thermal expansion, buckling). 	<ul style="list-style-type: none"> – - 	[160]
System Efficiency/Reliability	<ul style="list-style-type: none"> – High efficiency: Heating efficiency is 95–100% due to better thermal insulation. 	<ul style="list-style-type: none"> – Low operability: DEH-PIP is not qualified for continuous operation during production. – Electrical efficiency remains relatively low in practice (50–70%) and long static power umbilicals are required for power supply at the mid-point of the flowline. 	

3.5. Electrically Heat-Traced Flowline-Pipe-In-Pipe (EHTF-PIP)

The EHTF- PIP technique was developed in the last decade. The inner pipe in the PIP assembly is installed with three-phase insulated heat-traced wires and it terminates in a star end socket [176], consequently avoiding the desire to return the current back to the topside power generation equipment [160]. The production/inner flowline receives heat by conduction through the Joule resistive effect from the three-phase cord [176].

EHTF-PIP combines the heat trace cable's higher efficiency with the reeled subsea PIP's higher thermal performance for both preservation and continuous heating during production [71,160], as seen in Figure 15.

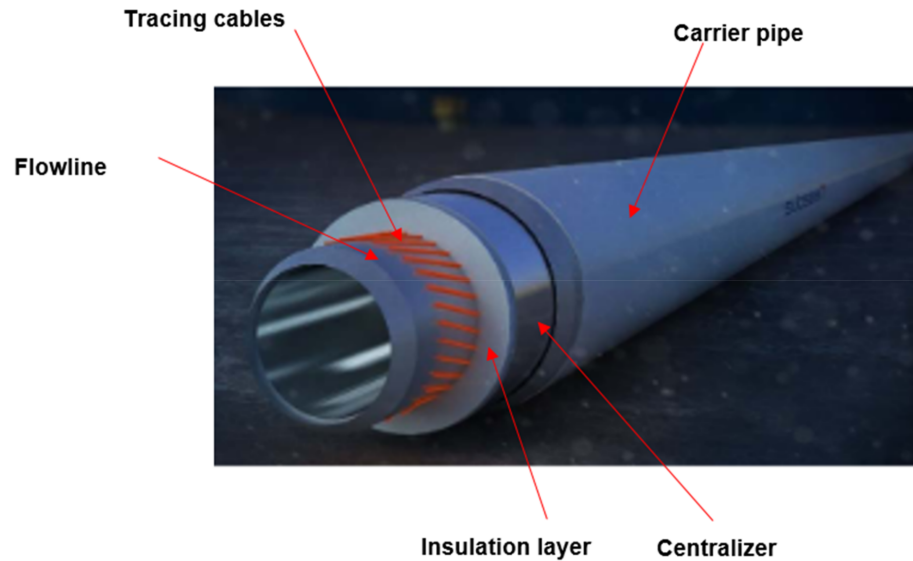


Figure 15. EHTF-PIP subsea systems.

Heat tracing cables are directly laid on the flowline, below the insulation layer, providing a very high heating efficiency. Fiber Optic Cable (FOC) is also incorporated in the system to permanently monitor the internal fluid and cables temperature all along the flowline through a Distributed Temperature Sensing (DTS) system [160]. The application of EHTF-PIP for maximum size flowlines (ID 12 inch) is currently restricted to just a small distance (about 25 km) and low-medium voltage (1–3.6 kV) used cords [176]. The EHTF-PIP is presently qualified for only installation requiring towing and reel lay technique [176]. The installation method is very important for the technology used during heating as the amount of field wire slices is reduced [176]. However, the reel lay is permitted for only restricted pipe inner diameters of about 12", therefore bigger production or inner flowlines installation will demand other installation techniques [176].

The world's first EHTF-PIP was installed in 2012 for the Islay development in the North Sea, after a formal technology evaluation and qualification process completed with TOTAL in 2009 [160]. Table 8 gives the advantages and drawbacks of EHTF-PIP.

In conclusion, the design of the EHTF-PIP is controlled by the need for use in distinct operating conditions [176]. The power provided to EHT-PIP is produced by the essential generator [176].

Table 8. Advantages and drawbacks of EHTF-PIP.

	Advantages	Drawbacks	Citations
Design	<ul style="list-style-type: none"> – Low linear power and currents. Low to medium voltages of 1–3 kV. – A good thermal performance of 2–0.5 W/m² K. – FOC system application. 	<ul style="list-style-type: none"> – Limited flowline length/ little heating loops of approximately 25 km. – The flowline inner diameter restricted to about 12 inches. 	
Fabrication	<ul style="list-style-type: none"> – Option for thorough electrical testing before installation–Test is carried out onshore. 	<ul style="list-style-type: none"> – The amount of FOC and wire splices is important for every pipe stalk. – The EHTF technique need unique installation equipment. – Unique waterstops/bulkheads is needed. 	
Installation	<ul style="list-style-type: none"> – The EHTF system is preinstalled onshore in spool base 	<ul style="list-style-type: none"> – Installation method for Reel Lay limited-it is not feasible for S-Lay or J-Lay 	[176]
System Efficiency	<ul style="list-style-type: none"> – A great heating efficiency of about 95%. – Good electrical efficiency of 90%. – It is used for continual heating. – FOC allows for effective heating system control. 	<ul style="list-style-type: none"> – There are no significant drawbacks 	
Reliability/ Reparability	<ul style="list-style-type: none"> – Good reliability is ensured by a redundancy of up to 300%. 	<ul style="list-style-type: none"> – The EHTF technique is subjected to varying loads in the course of the flowline life span. – It is not repairable after installation. 	
Design	<ul style="list-style-type: none"> – Dry insulation in the annulus of the PIP provides good thermal performance of U-value from 0.6–2 W/m² K. – Dry insulation with a partial vacuum in the annulus of the PIP gives a good thermal performance of U-value less than 0.5 W/m² K [161]. 	<ul style="list-style-type: none"> – Flowline diameter is limited to 12" ID by reel lay vessel capabilities. 	[160]

Table 8. Cont.

	Advantages	Drawbacks	Citations
Fabrication/ Installation	<ul style="list-style-type: none"> – Homogenous longitudinal and circumferential heating of the fluid – PIP arrangement and mechanical robustness (resistance to accidental loads, thermal expansion, buckling) – Reel Lay is favored [161] – It is field-proven [161]. 	<ul style="list-style-type: none"> – PIP is heavy and consequently, maximum water depth is limited depending on pipe size and reel lay vessels capabilities 	
System Efficiency	<ul style="list-style-type: none"> – High heating efficiency: 90–100% tracing cables are in direct contact with the flowline, and therefore the production fluid is below the high-performance thermal insulation. – Electrical system is primarily resistive (minimum capacitive and inductive effects): no specific apparent power requirement. Hence, electrical efficiency of the system is high (around 90%) – Accurate fluid temperature monitoring all along the flowline through the optical fibers [183]. – Heated length up to 50 km with a single power supply at one end of the flowline. – Low power consumption (below 50 W/m) [161]. 	<ul style="list-style-type: none"> – 	
Reliability/Reparability	<ul style="list-style-type: none"> – Better operability: The heating power is correctly controlled and exactly adjusted. – High redundancy: typically up to 300%, with one cable out of the four installed within the system is sufficient to heat the flowline. – Possibility to mitigate cold spot issues with local trace heating of critical components (jumpers, in-line tees, PLETs) – High redundancy and flexibility with separate activation and online temperature monitoring [161]. 	<ul style="list-style-type: none"> – Repair not possible with tracing wires once installed subsea. However, components are well protected within the carrier pipe and a high level of redundancy is provided. 	

3.6. Electrically Heat-Traced Flowline-Bundle or Integrated Production Bundle (IPB)

The IPB is a certified adaptable assemblage of risers that depends on the Integrated Service Umbilical (ISU) field-proven technology and further technologies patent [149]. IPB combines passive insulation, gas lift hoses, and active heating [149]. It is a concept based on elements construction with different roles all over a big production bore at the center that is a usual ultra-deepwater adaptable riser structure [149], as seen in Figure 16. IPB is employed in adaptable pipes for static and dynamic riser flowline application to give solutions to the flow assurance issues [160]. Syntactic polypropylene foam is the insulation material [149]. The layers of insulation are either composed of spiraled strips or thick fillers joined all over the core structure in S-Z [149]. The S-Z insulation technique is a field-proven technology [149]. IPB has been used with steel tubes to provide hot gas lift injection at the riser base, and electrical tracing cables to heat the internal fluid and optical fibers for temperature monitoring through DTS [160].

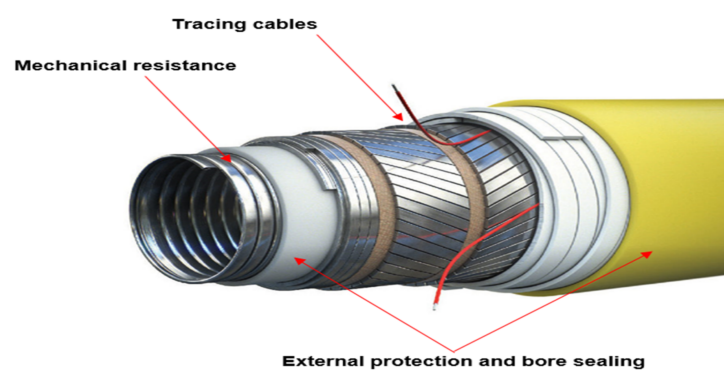


Figure 16. A schematic view of IPB Structure.

Two IPB installation projects for TOTAL West Africa were successfully delivered by Technip [160]. Another IPB deepwater Papa Terra project in Brazil has been manufactured and is currently being installed and commissioned [160]. Ansart et al. [160] shows the advantages and drawbacks which are summarized in Table 9.

Table 9. Advantages and drawbacks of IPB.

	Advantages	Drawbacks	Citations
Design/Fabrication/Installation	<ul style="list-style-type: none"> Active heating for dynamic risers, faced with a major flow assurance issue: Joule-Thomson effect and for static flowline applications. 	<ul style="list-style-type: none"> Low thermal performances (U-value of 3 to 6 W/m² K) similar to wet insulation. IPB internal diameter limited to approximately 11–12", depending on insulation requirements, due to present overall diameter manufacturing limitations 	
System Efficiency	<ul style="list-style-type: none"> High electrical efficiency of tracing cables (around 90%) 	<ul style="list-style-type: none"> Heating efficiency remains around 40 to 60%. 	[160]
Reliability/Reparability	<ul style="list-style-type: none"> High operability with temperature monitoring by optical fibers. Redundancy of 25 to 100% for tracing cables in the bundle arrangement. 	<ul style="list-style-type: none"> Tracing cables cannot be repaired or replaced subsea. 	

IPB gives an efficient solution for active heating using electrical tracing, extending over most of the application envelope of flexible pipe for infield production lines in both flowlines and risers application [160].

4. Discussion

There is a need for heat management systems as hydrocarbon exploitation approaches the next frontiers. Solutions to paraffin and hydrates are not limited to flowlines, the whole system is considered for heating requirement [161]. Active heating or passive insulation system is needed to evade paraffin plug and hydrates formation inside the flowline. The preservation of fluid flow during the steady and transient state is the main worry during the subsea hydrocarbon production system operation.

A general study on heat management systems in subsea flowlines from the top five publishers based on numbers of publications in the last decade was done. The result showed that 42 % (52) of the total papers published by researchers were in active heating while 88% (110) in passive insulation. This figure indicates a low research effort in active heating when compared with passive insulation.

The review of the heat management systems for the conventional passive insulation showed that wet insulation has U-values of $2 \text{ W/m}^2 \text{ K}$ [49,82,87]. The dry insulation gives a superior U-value of $1 \text{ W/m}^2 \text{ K}$ [49,50,87,93], but water ingress deteriorates its performance and degrades insulation properties, and hence the need for a PIP system. Due to the limitations of the use of dry insulation in subsea flowlines, PIP systems are deployed to stop water from entering the insulation for a better insulation performance [50]. The flowlines burial is regarded as one of the best heat management cost-effective technologies in solutions for issues of flow assurance [50,87] but is less effective down deepwater [50]. The buried flowlines have a better heat capacity than a PIP system with an extended cooldown time [49] while the installation cost for buried insulated flowlines is roughly 35–50% higher than that of a PIP technique [49,101,102]. Throughout shutdown time, buried flowlines provide four times higher retention capacity for heat than the PIP systems [50,103,104]. Some other benefits of flowlines burial system include more option on installation vessels and contractors, more options on the vendor for the fabrication of flowline, when compared to PIP system gives a slower cooldown time during shutdown and a likelihood of single flowline repair [49], and also provide a reduced time and enhanced schedule for first oil [49].

Bundle systems give an appealing solution to a large span of the challenges of flow assurance by supplying a cost-effective technique [51], and also its ability to circulate a medium for heating [51]. Further benefits are; allowing for multiple flowlines installation in a single pipe design [51], and the outer pipe is used to withstand subsea hydrostatic pressure in deep water [51], and bundles allow the introduction of monitoring devices and heated pipes [72]. The bundle's drawbacks its length limit (shallow water) and the desire for a comfortable launch and fabrication location [72].

In the search to enhance heat retention, VIT is established [50]. VIT is a remodeled PIP design system with an annulus at vacuum conditions that reduce the transfer of heat from the crude oil to the environment [50,126]. The VITs are regarded as expensive when compared to other passive insulation systems [50,126,131–133] but are favorable in regions where crude oil has a high cloud point [50]. The advantage of the insulation modules for flow line applications is geometry modifications to suit both riser and additional lines [85]. Multilayer systems have the advantage that the density and thickness of individual layers may be adjusted to fit the specific purpose [85]. For PCM systems, during shutdown operation, latent heat release will increase cooldown times by 3 to 5 days [149]. However, where there is a very long period of shutdown above the cooldown time performance, a flowline start over may result in a big problem [149].

For active heating, technologies are done with HWC and DEH flowline systems, benefiting from substantial track record and maturity [160]. The diameter and water depth of HWC-PIP are limited by installation vessel capabilities and are also prone to thermal expansion and lateral buckling due to hot water circulation in the annulus [160]. HWC-

bundle combines high-performance thermal insulation and limited thermal expansion with low risk of lateral buckling as well as good resistance to accidental impacts [160]. Comparing HWC-bundle solutions, Direct HWC-bundle is more efficient than the indirect HWC-bundle in terms of heat transfer [161], but other conditions are less favorable [161] such as the volume of water that is higher with direct heating and therefore the size of the needed tanks at topsides level as well as pumping requirement [161]. Additionally, the indirect hot water heated bundle has the multipurpose heating lines as an edge which is used for water injection or produced water re-injection [161]. For Wet-DEH system, it has low heating efficiency due to the pipe's low electrical efficiency and low thermal insulation capacity [160,176]. Therefore, the system is not the better choice for continual heating solutions in high power demands on the topside [176]. The DEH-PIP was developed for hydrated remediation, but the technology is also used for flowline heating during field development [172,176,181]. DEH-PIP compared to Wet-DEH insulation system gives a higher power efficiency [176] because there is no link with the seawater and the PIP insulation decreases thermal losses. However, DEH-PIP requires designed components like bulkheads that are limited to medium lengths because longer lengths result in large annulus width and higher voltage for electrical isolation reasons [176,182]. New technologies were evolved on heat tracings components for rigid EHTF-PIP or flexible EHTF-Bundle (IPB) flowlines active heating based on operational experience from HWC and DEH systems and feed-back to enhance overall heating performances of the active system [160].

This improved efficiency and the fact that the tracing cables heating system is disconnected from the flowline itself contrary to the DEH system, allows better control and adjustment of the power supplied to the fluid and hence greatly clarifies operations and reduces related production costs [160]. Additionally, EHTF-PIP and IPB technologies can be integrated to efficiently heat the fluid from the subsea wellheads to topsides, thereby solving likely cold spot issues [170]. The likelihood of continuous heating the production fluid all along its path with EHTF systems and a low power consumption gives the flexibility and chance to choose different field architecture and operating philosophy of single line architecture rather than the conventional loop systems [160].

This single line architecture lowers chemical injection and power requirements, causing a cost reduction in the overall operating and capital expenditures of the flowlines [160,176]. Disconnection of the heating apparatus and the production flowline gives a high level of robustness and redundancy to the system [160]. The reliability of the system is additionally increased by the chance of constantly monitoring the temperature of the fluid through an optical fiber, both during transient and steady-state conditions [160].

In closing, conventional passive insulation systems are not the most suitable cost-effective techniques for subsea deepwater long-distance transportation of crude oil and it would demand additional supporting methods to convey hydrocarbon at short downtime [50]. Active heating systems are the game-changer within the subsea deepwater industry that has opened doors to various field architectures and operating philosophies leading to a global cost reduction [161].

5. Conclusions

Subsea deepwater and ultra-deepwater hydrocarbon field development have increased several flow assurance problems. The extension of the operating procedures and application is practically not suitable from subsea shallow to ultra-deep water. Good flow assurance technique is necessary during the designing and development phase of the subsea field projects to mitigate and manage hydrates and wax issues in the flowline systems. The trend from the study showed the need for technical efforts and scientific research in the field of active heating as the production exploration of the petroleum energy fields advances into deep water.

Based on the review, some key conclusions were highlighted:

- Both passive insulation and active heating systems are field-proven technologies to sustain fluid temperature well above the HFT and WAT of the hydrocarbon.

- There is no single technology or architecture that suits all fields, the best solution is based on data analysis and a specific company's objectives, constraints, and philosophy. Therefore, it is necessary to have an established fit for purpose heat management systems.
- The passive insulation systems though not most suitable for long-distance deepwater operations are always combined with the active heating system to prevent excessive heat loss. However, combining two or more heat management technologies is found to be very effective for flow assurance management in the industry.
- From a cost perspective, active heating systems are the most cost-effective for sub-sea deepwater fields because it can cause a cost reduction in capital and operating expenditures due to the use of a single line architecture instead of a conventional loop which consequently lowers chemical injection and power requirement.

Finally, there is an ongoing effort to develop a model for thermo-hydraulic analysis in the flowline. This would give its user the choice of multiphase models to use for pressure and temperature distribution predictions and the accuracy of the predicted data generated is subject to the built PVT models. In the end, will aid field operators in carrying out proactive production surveillance that will save the company considerable cost.

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Abbreviations

DEH	Direct Electrical Heating
DTS	Distributed Temperature Sensing
EHTF	Electrically Heat Traced Flowline
FOC	Fiber Optic Cable
GOR	Gas–Oil Ratio
HFT	Hydrate Formation Temperature
HWC	Hot Water Circulation
IPB	Integrated Production Bundle
KHI	Kinetic Hydrates Inhibitor
LDH	Low-Dosage Hydrate Inhibitor
MEG	Mono Ethylene Glycol
MeOH	Methanol
OHTC	Overall Heat Transfer Coefficient
OPEX	Operating Expenditure
PCM	Phase Change Material
PIP	Pipe In Pipe
PPD	Pour Point Depressant
PPF	Polypropylene Foam
PUF	Polyurethane Foam
PVT	Pressure Volume Temperature
THI	Thermodynamic Hydrates Inhibitors
VIT	Vacuum insulation Tubing
WAT	Wax Appearance Temperature

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