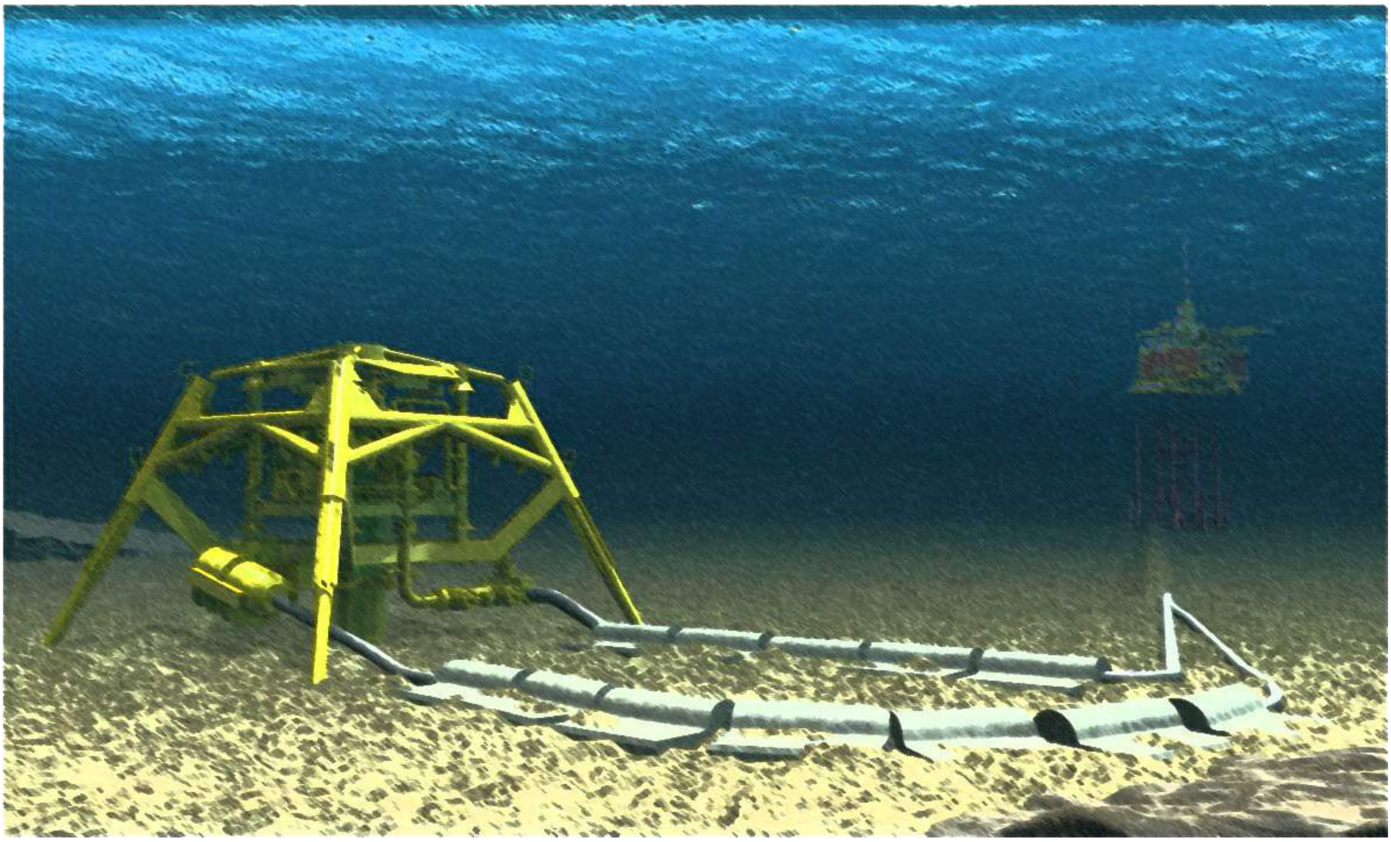
Multi-Well ConductorProspectus

Conductor Sharing New Technology (multiple wells through single conductor/wellhead)



Improving the Economics of Stranded Hydrocarbon Reservoir Tie-backs for Wet or Dry Trees

OILFIELD INNOVATIONS

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New Conductor Sharing Technology for Improving Economics of Stranded Reserves

by Clint Smith[a] and Bruce Tunget[b]

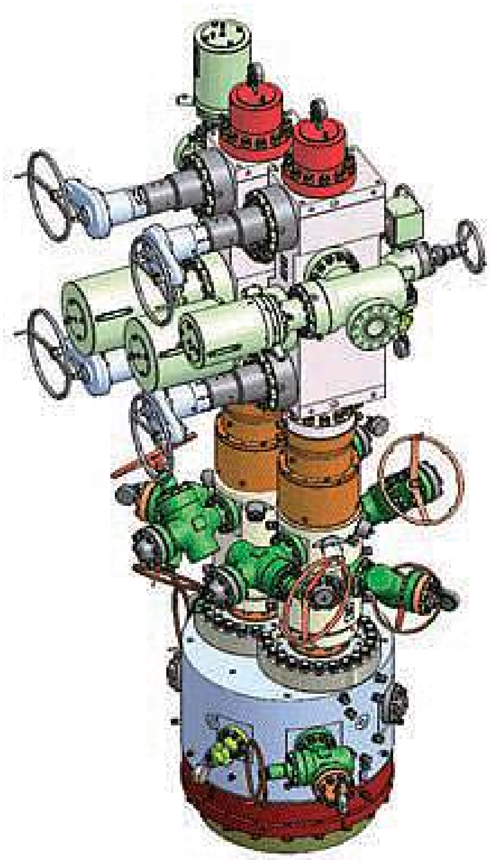

Figure 1 - Magnus Conductor Sharing (Hicks, 2009)

Abstract: To understand why competitive markets, proven technologies and conventional practices do not develop stranded offshore hydrocarbons deposits of 3 to 15 million barrels oil equivalent (OGA, 2016)[21], it is important to understand that "Controllable Cost" is the primary driver preventing said development. In a world where hydrocarbon prices are set by onshore fracking, the price is unlikely to increase in the near future and, thus, controllable cost reduction is required. Stranded offshore hydrocarbons deposits of 3-15 million barrels oil equivalent will continue to be uneconomic until the development "cost" is substantially reduced. Obvious technologies, like subsea tie-backs, have already been included within previous uneconomic development proposals. Marginally reducing cost by tweaking various components of subsea tie-backs is unlikely to make stranded hydrocarbons economic. As Einstein said, insanity is doing the same thing over and over again and expecting a different result. If you ignore the jargon, subsea infrastructure is not necessarily complex but it is always expensive and, thus, forms part of the problem. Developing stranded hydrocarbons requires new technology that can access multiple stranded hydrocarbon discoveries while reducing subsea infrastructure to a single wellhead, pipeline, riser and control umbilical. Amalgamating multiple laterally separated stranded hydrocarbon pools to single point-A-to-point-B pipeline, riser and control umbilical not only decreases subsea infrastructure cost but can also increase reserves associated with the investment. With the above terms of reference in mind, Oilfield Innovations proposes the new technology of integrating proven wellhead splitting and sharing technology (see Figure 1) into a single subsea conductor used to batch-drill and batch-complete multiple well bores concurrently. Extended reach wells may be drilled to multiple stranded hydrocarbon pools from a from a single wellhead. Additionally, Oilfield Innovations propose that a subterranean high pressure separator, used for water disposal at the wellhead, can be added to substantially reduce water disposal costs and increase reserves for multiple stranded reservoirs. Oilfield Innovations have initially identified 100 opportunities in the UK North Sea where two (2) or more small pools (i.e. more than 200 stranded discoveries) can be tied-back with such new technology.

Introduction

Uneconomic "small" offshore hydrocarbon discoveries are substantially larger than economic onshore discoveries, wherein "small" refers to discoveries of 3 million to 15+ million barrels oil equivalent in the North Sea (OGA, 2016)[21].

When a stranded pool of hydrocarbons is discovered, subsea development and tie-back to existing infrastructure is evaluated, but the small economic size does not justify the subsea infrastructure cost, tariffs, waste water disposal, well count and drilling costs.

To address the issue the UK North Sea has been working on standardization for twenty years, initially through CRINE and now through the trade association Oil and Gas UK. While plug-and-play standardization of existing subsea infrastructure can reduce costs, it is unlikely to make small pools of hydrocarbons economic in an industry driven by onshore fracking.

Fracking has existed since the 1940's and is nothing new. Many tried to make shale fracking work and failed, but in recent years new fracking technologies have been able to increase shale productivity to the level that is it displacing offshore oil and gas.

World Oil reported in March 2017, "Exxon Mobile is diverting about one-third of its drilling budget this year to (onshore) shale fields that will deliver cash flow in as little as three years, said Chairman and CEO Darren Woods"[27].

Efforts to standardise and lock in existing technology to create marginal cost reductions are unlikely to make offshore

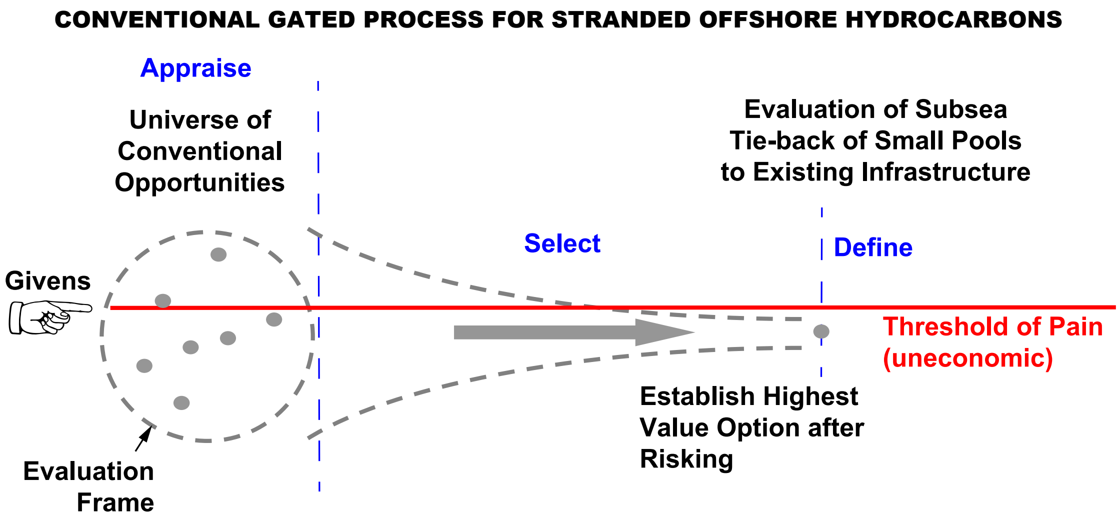

Figure 2 - Small Pools and Conventional Gated Process (Hopper, 2016)[18]

oil and gas more competitive.

To survive current prices, offshore oil and gas needs to develop new technologies that can be competitive with new fracking technologies used in shale plays.

Subsea infrastructure may need standardisation, but oil and gas drilling represents at least half of the development costs and has used plug-and-play standardization for decades.

Various sized connections and tubular sizes for drilling and completion equipment have plug-and-play standardisation through API and ISO, wherein vendors wishing to sell tooling or equipment ensure compatibility with those standards.

This prospectus explains how proven technologies, like Figure 1 Conductor Sharing, can be adapted and combined with proven Extended Reach Drilling (ERD) technology to provide a step change in the cost of developing stranded offshore hydrocarbons.

Changing the paradigm of uneconomic stranded offshore hydrocarbons discoveries requires a step-change in cost that can only occur with "new technology" that minimises subsea infrastructure, waste water disposal, well count and drilling costs.

Accordingly, to understand how new technology can be implemented it is important to understand past and present industry processes and initiatives.

Conventional Development Process

The oil and gas industry uses a linear gated decision making process shown in Figure 2, wherein the appraisal phase specifies the givens and defines a frame that bounds field proven solutions. A universe of established opportunities is generated that lies within the frame and rigorous step wise process is used to establish the highest value option during the select phase (Hopper, 2016)[18].

Every undeveloped stranded hydrocarbon discovery will have been subjected to the Figure 2 process one or more times after its discovery.

The rigorous linear nature of industry's gated process does not consider new technologies and cannot easily accommodate new information so, commonly, when change is necessary the project either presses on regardless or goes into a major recycle, which significantly increases the risk of cost and schedule overruns (Hopper, 2016)[18].

Ernst & Young (2014)[18] evaluated 365 mega projects and concluded that 78% of European upstream projects faced delays and 65% faced cost overruns, with the average overrun of 53%. Nandurdikar (2014)[18] in a presentation to IPA, came to a similar conclusion and found that E&P megaprojects had a success rate of 22% compared with a success rate of 52% in other industries. The inflexible and rigid approach adopted by industry to the project management is one of the causes of these project failures (Hopper, 2016)[18].

Accordingly, cost overruns have come to be expected to the extent that every conventional aspect of hydrocarbon development is risked until stranded pools of hydrocarbon appear uneconomic due to risk multiplication factors associated with the gated process and deficiencies of existing offshore technology.

Risk reduced recoverable hydrocarbon forecasts are multiplied by stagnate free market price forecasts, limited by West Texas fracking, to calculate a discounted (reduced) net present value. The net present value is compared to risked (inflated) controllable development costs that use the limitations of existing technology and assume cost overruns and schedule delays to determine whether, or not, development of

Previous Initiatives

1994 – CRINE

- Original report 1994 on back of dramatic decrease in oil price to $15 (62% drop from 1990 to 1994).
- CRINE Network established 1994 – 1999 supported by the industry on a part time basis and Operator driven.
- 1994 report made 6 recommendations (Codes, Standards and Specifications/ Technical Standardisation/Commercial Standardisation/ Regulatory/ Cultural Change/ Drilling Practices Committee).
  - Same themes highlighted by CRINE such as standardisation, simplification & collaboration….
- Large report but deemed high level, mixed feedback on the success of CRINE.
- No evidence or legacy of CRINE today except Terms and Conditions which were adopted by LOGIC.

1998 Follow On CRINE report

- Around Oil price drop from $25 to $12 (52%).
- Project and Procurement Managers Conference report, 1998:
  - Applying the philosophy of CRINE to FPSO, Subsea and Deep-water.
- Industry sponsored event.
- Focus on Functional Specifications, but never adopted by industry.

Other Initiatives

- Majority of other initiatives such as:
  - Oil & Gas Industry Task Force commenced 1999 till2001.
  - LOGIC commenced 2000 – now part of Oil and Gas UK (2007).
  - PILOT commenced 2000 - now part of MER (OGA 2015).
- Similar trend followed where work groups never really followed through to provide detailed solutions and adopt a longer term approach.
- Only provided high level recommendations.

OIL&GAS UK

Conclusion: No visibility of long term solutions being implemented and adopted

Figure 3 - Previous Initiatives (Duthie, 2016)[25]

a stranded pool of hydrocarbons is economic.

Recognising the inherent problems of a rigorously linear process and an inability to develop small pools of North Sea hydrocarbons, the Figure 3 initiatives attempted to rectify some of the issues.

Previous UK North Sea Initiatives

Figure 3, which is taken directly from an Oil and Gas UK presentation, shows that each price cycle since 1994 has caused a number of North Sea initiatives, from which Duthie[25] (2016) states that no visible long term solutions were either implemented or adopted.

With regard to the present price cycle, it is important to recognise that important structural changes are taking place in, for example, US reliance on energy imports where shale plays and new fracking technological advancements are displacing offshore hydrocarbons (Dale, 2015)[26].

After a complete oil price collapse in 1986, oil rebounded and cycled around $20 per barrel for about 20 years.

Structural changes caused by fracking of shale plays have the realistic possibility of causing oil price to cycle around $40 per barrel for decades.

Accordingly, it is important to remember that significant changes may be necessary for the offshore oil and gas to compete with onshore shale and, therefore, previous and present initiatives to reduce cost are critical to the survival of the offshore oil and gas industry.

The 1994 CRINE report made six recommendations to standardise specifications, technical, commercial, regulatory, cultural and drilling practices.

In 1998 project and procurement managers recommended application of CRINE to FPSO, subsea and deepwater.

The LOGIC and PILOT projects and various industry task forces have occurred after the turn of the century.

Now, more than twenty years after it conception, Figure 4 describes how Oil and Gas UK are presently attempting to reduce subsea infrastructure costs and risks using standardisation.

The previous efforts were obviously worthwhile because they are being continued in present initiative that will be important in the development of stranded pools of hydrocarbons, but it is important to recognise that present initiatives are not addressing all factors preventing development of stranded hydrocarbon discoveries.

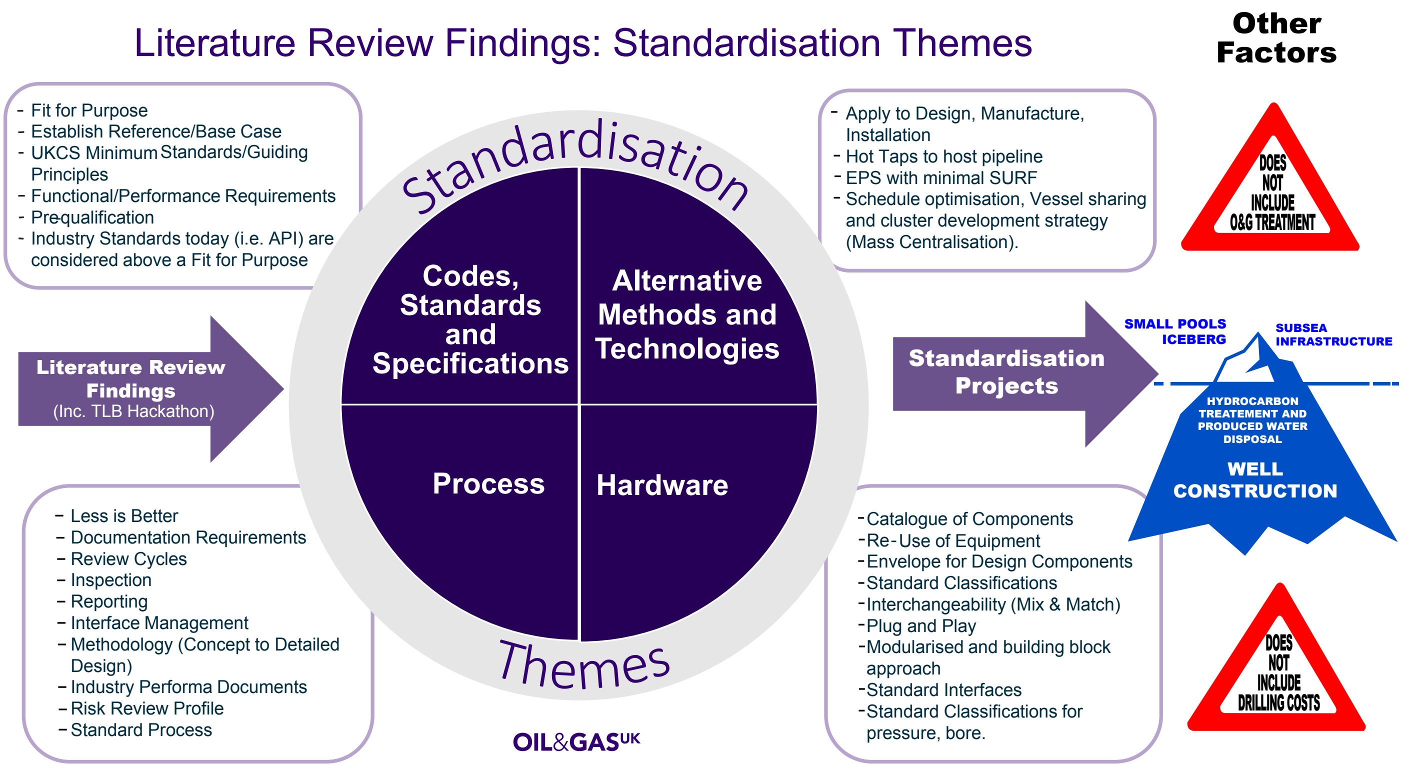

Figure 4 - Oil and Gas UK Subsea Standardisation (Plug-and-Play) Theme (Duthie, 2016)[25]

An "Iceberg" of Other Factors

Standardisation is important, but stranded offshore hydrocarbon development may require reducing various portions of subsea infrastructure to an absolute minimum quantity of standardized lower cost piping, hoses and valves.

Figure 4 depicts Oil and Gas UK's efforts to addresses many important aspects of subsea infrastructure that are critical to stranded hydrocarbon tie-back, but it does not include the costs of drilling or oil and gas treatment.

As shown in Figure 3, previous industry efforts began with standardisation, whereby standardising the piping, hoses and valves of subsea infrastructure is a good place to start, but it is only the tip of the iceberg and, unfortunately, it is the hidden part of an iceberg that sinks ships or, in this case, stranded hydrocarbon developments.

Half, or more, of small pool development costs and risks are associated with connecting the reservoir to subsea infrastructure through the wing valve of the production tree, which is not considered by the Figure 4 standardisation plan.

Like the tail-wagging-the-dog, subsea infrastructure engineers have included subsea trees in Figure 4 because they want to select the subsea production tree to fit their piping and hose connections without considering the substantial effect on well construction costs.

Standardising subsea production trees may actually increase development costs by locking in current technology and preventing, for example, conductor sharing technology used on production platforms. Also, regardless of whether new or conventional technology is used, the subsea production tree comprises critical drilling and completion equipment that can favourably or adversely affect half, or more, of the project costs, wherein selection of the most economic subsea tree requires competence in drilling and completion.

The other half, or less, of costs and risks are subsea infrastructure and hydrocarbon treatment and/or water disposal equipment. Subsea infrastructure is important but hydrocarbon treatment and/or water disposal are more likely to prevent the development of stranded hydrocarbon pools.

Hydrocarbon treatment will depend upon the composition of oil and/or gas in place with any tie-back and commingling of fluids with existing infrastructure production being either viable or unviable.

Disposal of produced water is a variable that limits a stranded hydrocarbon discovery's production life and its recoverable reserves.

Accordingly, the hidden parts of the iceberg preventing stranded offshore hydrocarbon development are typically well construction costs, hydrocarbon treatment and water disposal, which are substantially more important than standardising and locking-in established but old subsea technology.

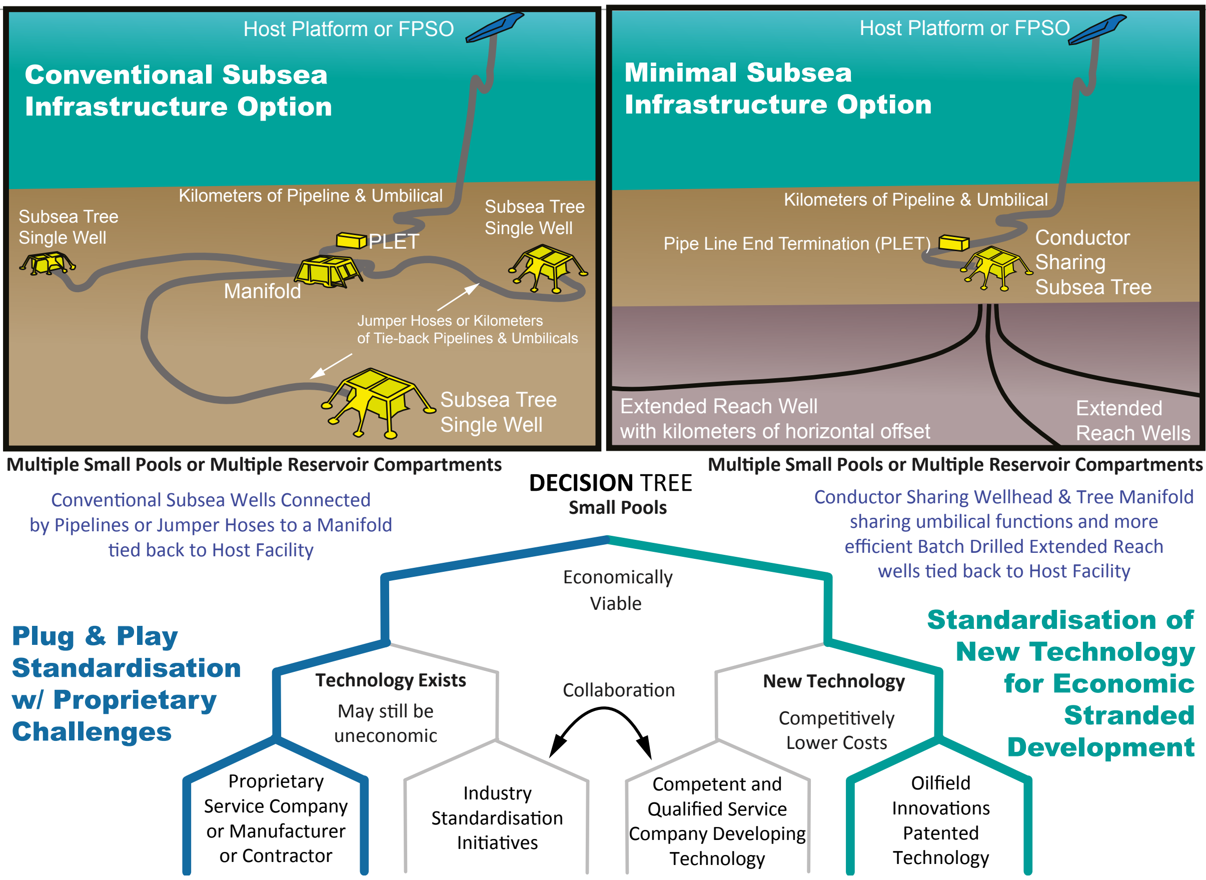

Figure 5 - Conventional Tie-back versus ERD to Common Tie-back Point

Old versus New Technology

The left of Figure 5 shows established older technology that can be standardised to lock-in both its benefits and deficiencies, using conventional subsea development ties-back of multiple small pools or a compartmentalised reservoir with multiple wells connected to a production manifold that commingles flow through a pipeline to a host facility. The host facility can be a platform or a floating production, storage and off-loading (FPSO) facility.

Controlling a conventional manifold and multiple subsea production trees can involve a complex system of umbilical lines with numerous bundles and complex interconnections that can be very expensive.

Conventional tie-backs to a central manifold are typically considered with respect to the need for more than one well to fully develop a compartmentalised reservoir or multiple small pool reservoirs separated by kilometres.

Such evaluations will have already been considered at least once after discovery of a stranded hydrocarbon pool.

The first step in any development effort is to seek cost reductions and/or efficiency increases from service companies, manufacturers and/or contractors and, thus, it is likely that cost reductions comparable to those associated with standardisation may already have been factored into previous economic analysis.

Accordingly, standardisation can reduce risk and improve the economics of stranded offshore hydrocarbons, but standardizing established older technologies is unlikely to cause previously uneconomic discoveries to be developed.

Alternatively, the right of Figure 5 illustrates that a new technology can comprise adapting and combining standards and field proven technologies like conductor sharing wellheads and extended reach drilling to create a new standard that can be adapted and combined by a qualified vendor and/or service provider.

Oil and gas can learn from others industries. For example, computing and software industries are extremely competitive, yet Microsoft® has released the source code to an open-source operating system, based on Debian GNU/Linux, that runs on network switches (Williams, 2016)[28]. If Microsoft® can dump its proprietary software in favour of open source Linux, an oil and gas service provider can use the same philosophy to facilitate deployment of its new technology.

Accordingly, as is explained on the following pages, total development cost of the right side of Figure 5 could be +/-30% less than that of the left side of Figure 5, wherein a Service Provider who manufactures the new technology could open source the connection interfaces to allow standardisation of the new technology to quickly establish its prominence and widespread usage within the oil and gas industry.

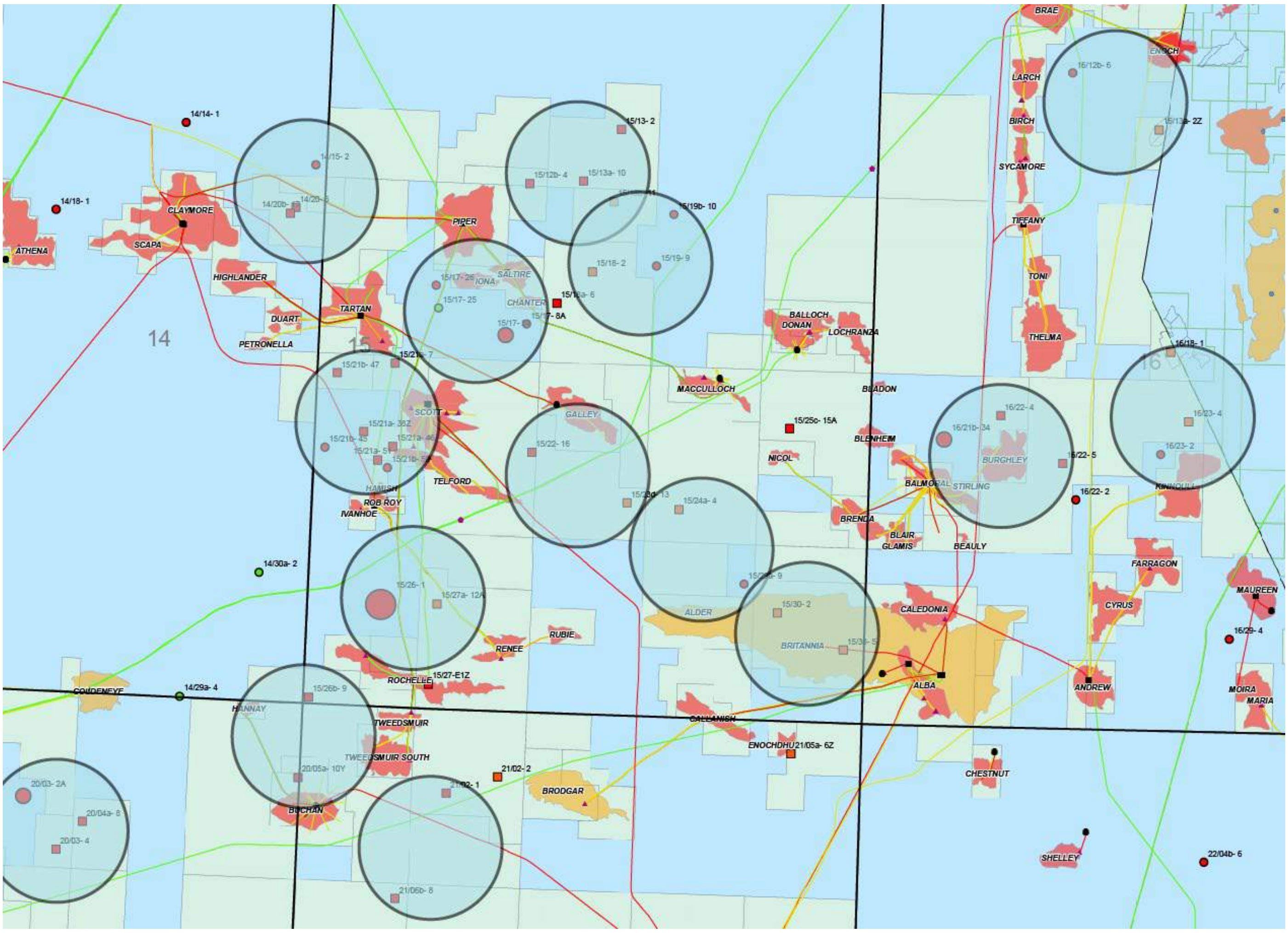

Figure 6 - Examples of Small Pools withi a 5km Extended Reach Drilling Radius (OGA,2016)[21]

SNS	Northern North Sea	Moray Firth	Central North Sea	Total
18	17	27	38	100

Table 1 - Small Pools withi a 5km Extended Reach Drilling Radius (see Appendix A for UK North Sea)

Pooling Stranded Discoveries

Reducing risk and increasing net present value can require increasing recoverable reserves by amalgamating or pooling stranded discoveries using commingled flow and a single tie-back to existing infrastructure.

Figure 6 shows groups of two or more small pools within a 5 kilometre radius, wherein looking at the entire UK North Sea, at least 100 such instances can be found, as shown in Table 1.

The Figure 6 excerpt of the OGA[21] map in Figures 24-27, of the appendix, show that a 5 kilometre extended reach well can access two or more small pools from a single location, wherein a conductor sharing wellhead could produce laterally separated reservoirs to a single pipeline with a single control umbilical to reduce cost.

The Central and Moray Firth portions of the UK North Sea have the most opportunities for connecting multiple small pools with a commingled single tie-back to existing infra-structure.

Using extended reach drilling, a single subsea wellhead above a conductor sharing arrangement can access multiple small pools to at least double the recoverable reserves as-sociated with the economics and, thus, can reduce risk and increase net present value.

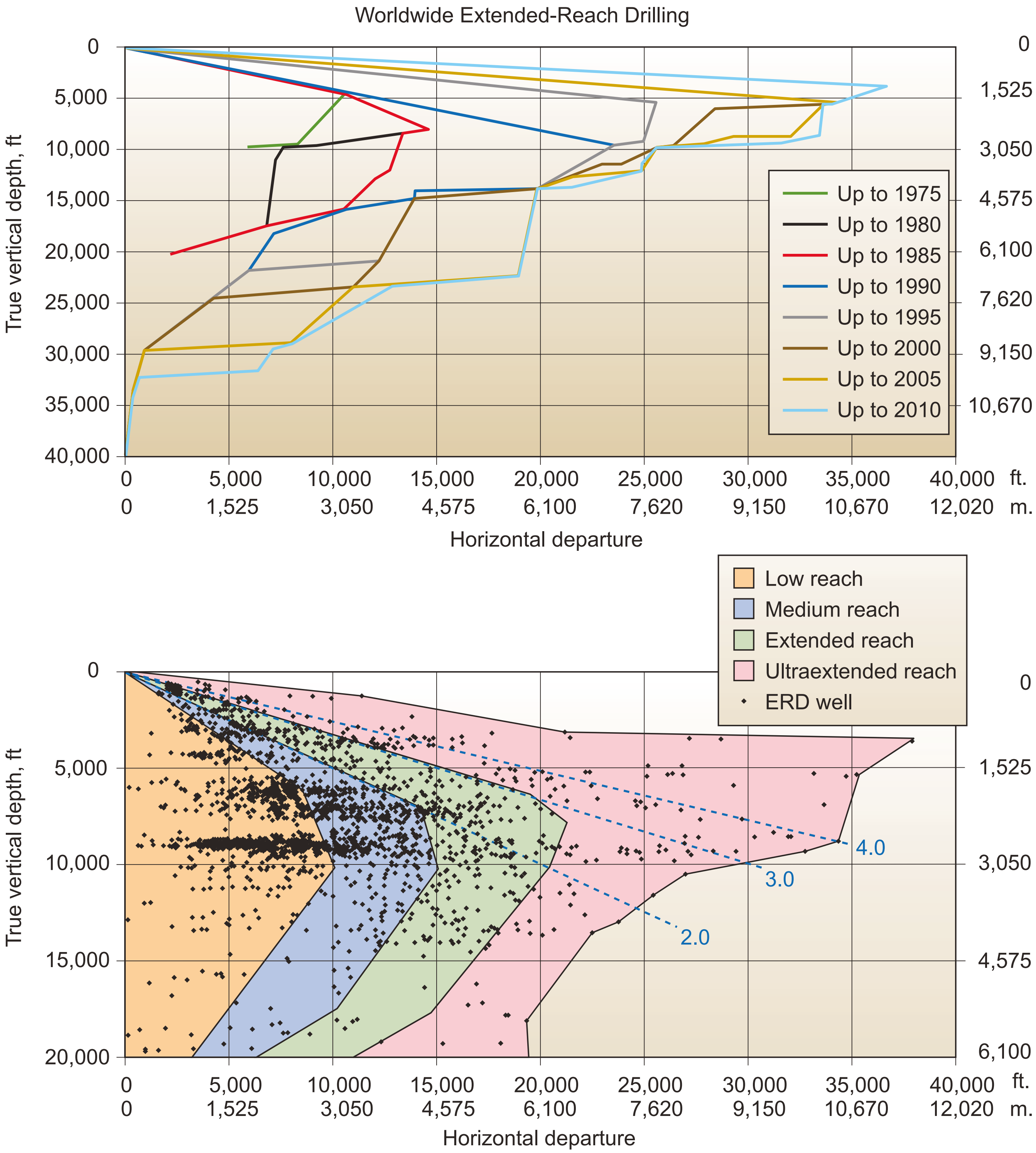

Figure 7- 2010 Extended Reach Well Limits and Classifications (Bennetzen, 2010)[22]

Extended Reach Drilling

Figure 7 shows two graphs illustrating the horizontal departure of extended reach drilling (ERD), wherein the upper graph depicts the progressive technology increases from 1975 to 2010 while the lower graph shows the categories of ERD.

Figure 7 also clearly shows that five (5) kilometres horizontal departure from the wellhead was an average extended reach well almost a decade ago.

Accordingly, the five (5) kilometre radii in Figure 6 and Figures 24-27 represents an average extended reach horizontal departure from the sea bed wellhead and indicates that it is possible to drill such distances with current technology to connect two or more small pools with a single tie-back to existing infrastructure.

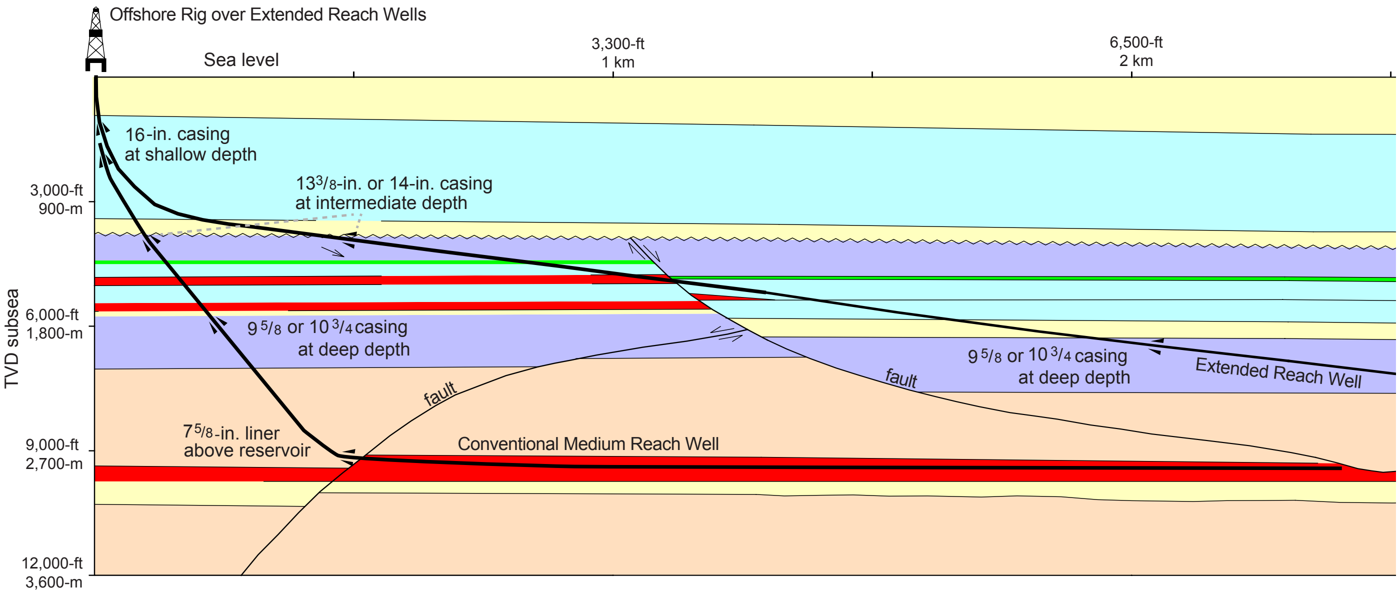

Figure 8 - Heel of an Extended Reach Well (Allen, 1997)[23]

Extended reach drilling is more costly and time consuming than, for example, the low or medium reach categories shown in Figure 7; however, Oilfield Innovations have invented a method of batch drilling the same section for up to three (3) wells to reduce the cost of ERD wells by immediately applying lessons from one well to the next and avoiding the costly process of changing bottom hole assemblies (BHA).

Batch Drilling

Conventional big-bore 18 ¾ inch subsea wellhead systems are capable of hanging 16 inch, 14 or 13 ⅜ and 10 ¾, 9 ⅞ or 9 ⅝ inch casing strings, wherein Oilfield Innovations have devised a way to batch drill and batch set each of these casing sections.

For example, Figures 8 and 9 show the heel and toe sections of an extended reach well with a 5 kilometre departure, wherein after setting surface casing three (3) back-to-back 17 x 20 inch bi-centre bit (see Figure 36) hole section can be drilled and followed by the running of three back-to-back 16 inch casing strings for significant time and cost savings.

Generally, drilling shallow geology is relatively easy but running casing can be challenging. Picking-up, handling and laying down bottom hole assemblies (BHA) is also time consuming and costly.

Oilfield Innovations have invented a whipstock system that can be rotated within a conductor sharing arrangement to allow drilling of hole-sections, pulling-out-of-the-hole (POOH) and racking back the BHA followed by rotating the whipstock and running-in-the-hole (RIH) to drill the next section.

By rotating a whipstock in a conductor sharing arrangement, three 17 x 20 inch hole sections can be drilled in succession and followed by running three 16" inch casing sections, wherein the relatively short drilling time, large hole size and heavy drilling mud maintain the hole until each of the casing strings are run and cemented after sequentially rotating the whipstock to select one of the three boreholes.

Running and cementing three 16 inch casing strings removes time normally spent waiting on cement hardening since the first cement job will have hardened by the time the last cement job is carried out.

The efficiency gains of repeatedly doing the same task in batches allows the lessons from the previous job to be immediately applied to the next job.

Accordingly, significant time and cost is saved by picking up and laying down the same BHA once for three wells and the same casing running equipment and the same cementing equipment once for three wells.

Additionally, speciality crews who are typically brought to the rig to run casing are mobilised and demobilised once and used in close succession to minimise daily crew costs, daily rental costs and transportation costs to and from the rig.

Depending upon the geology, the same savings can be realised on the 14 ½ x 17 ½ inch bi-centre bit (see Figure 36) and 13 ⅜ or 14 inch casing section.

In instances where, for example a fault (see Figure 8) or other geologic issue increase the probability of time dependent hole instability, the 12 ¼ inch hole section can be drilled and 9 ⅝ or 10 ¾ inch casing run and cemented before rotating the whipstock to begin the next batch drill and case section. The same time savings for the BHA will be applicable and

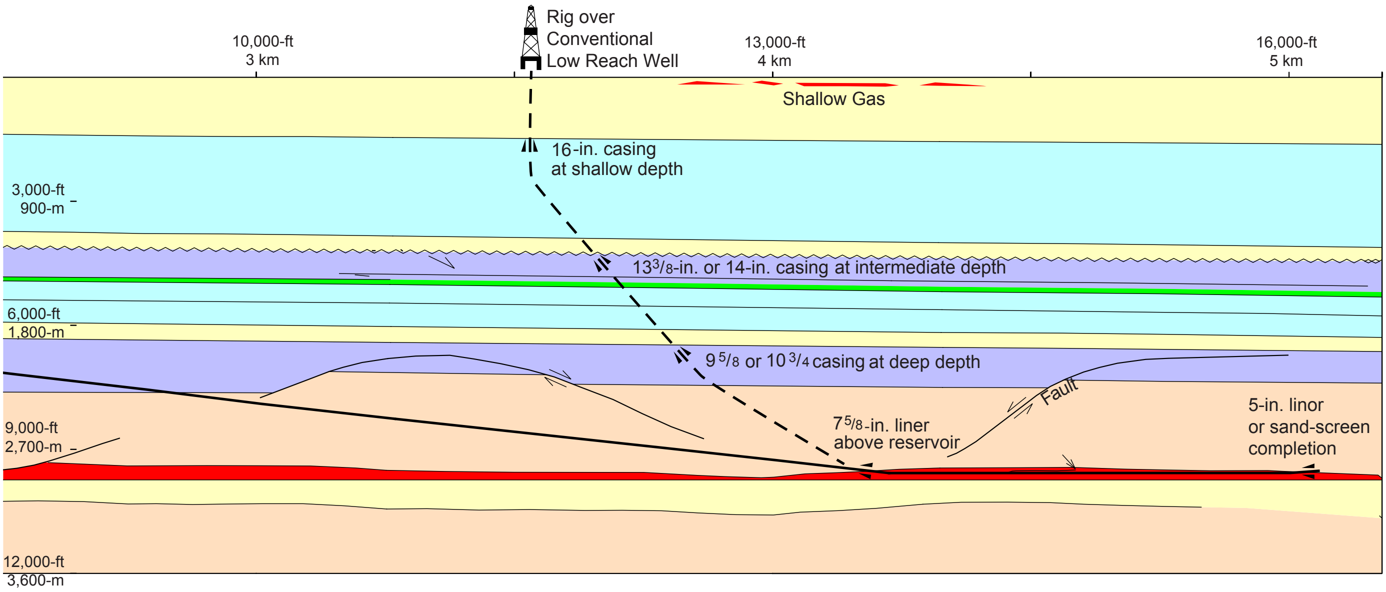

Figure 9 - Toe of an Extended Reach Well compared to Conventiional Well (Allen, 1997)[23]

the casing costs will increase marginally for rigging up and down, but rig moves are avoided and the lessons learned on one hole-section can be applied to the next to reduce both risk and cost.

Drilling Challenges

Extended reach wells are more challenging than common low to medium reach wells because proper drilling practices are critical to success.

Batch drilling and casing off hole-sections has the advantage of immediately correcting any mistakes made on the previous operations and repeating any successes on the next operation, whereby ERD becomes much easier, faster and lower cost.

Additionally, geologic and hole instability uncertainties can be reduced by adjusting or keeping drilling fluid properties based upon the information gained in the previous hole section passing through approximately the same geologic time periods.

Drilling and well construction challenges are often driven by the unknown, wherein perceived problems may not exist and/or over-compensation or under-compensation for real problems can exacerbate the challenges.

Batch drilling and casing the first hole-section will uncover real challenges or dispel expected challenges that never materialise, wherein the second and third batched drilled and cased hole section will learn from the first hole section to lower well cost. This is particularly advantageous when, for example, a medium reach hole-section can be drilled first and followed by a more challenging extended reach well hole-section.

Comparison to Conventional Wells

Conventional medium reach wells (see Figure 8) are common place and are considered average risk. Typically, subsea locations are selected to avoid any shallow gas and reduce well complexity and comprise conventional low reach wells like that shown in Figure 9.

Drilling technology has advanced to the level that boring through rock is relatively straight forward and it is the “flat-times” for casing and other operations carried out between boring that are driving cost, whereby Oil and Gas UK are currently carrying out studies to measure “flat-times” in an effort to improve efficiency.

As shown in Figures 8 and 9, casing locations are selected primarily according to the geologic formation and true vertical depth and, therefore, the same number of casings can be required for a low, medium or extended reach well. Because the “flat-times” between drilling operations are driving costs more than the boring of rock, when properly executed, extended reach wells are not necessarily that much more expensive.

It is the casing and “flat-times” that are primarily controlling cost and, therefore, the cost of wells are not the ratio of their drilled lengths.

Accordingly, drilling consecutive sections for multiple extended reach wells of 5 kilometres horizontal displacement can have a significantly lower cost than drilling multiple low reach wells with 5 kilometres of tie-back pipeline and umbilical.

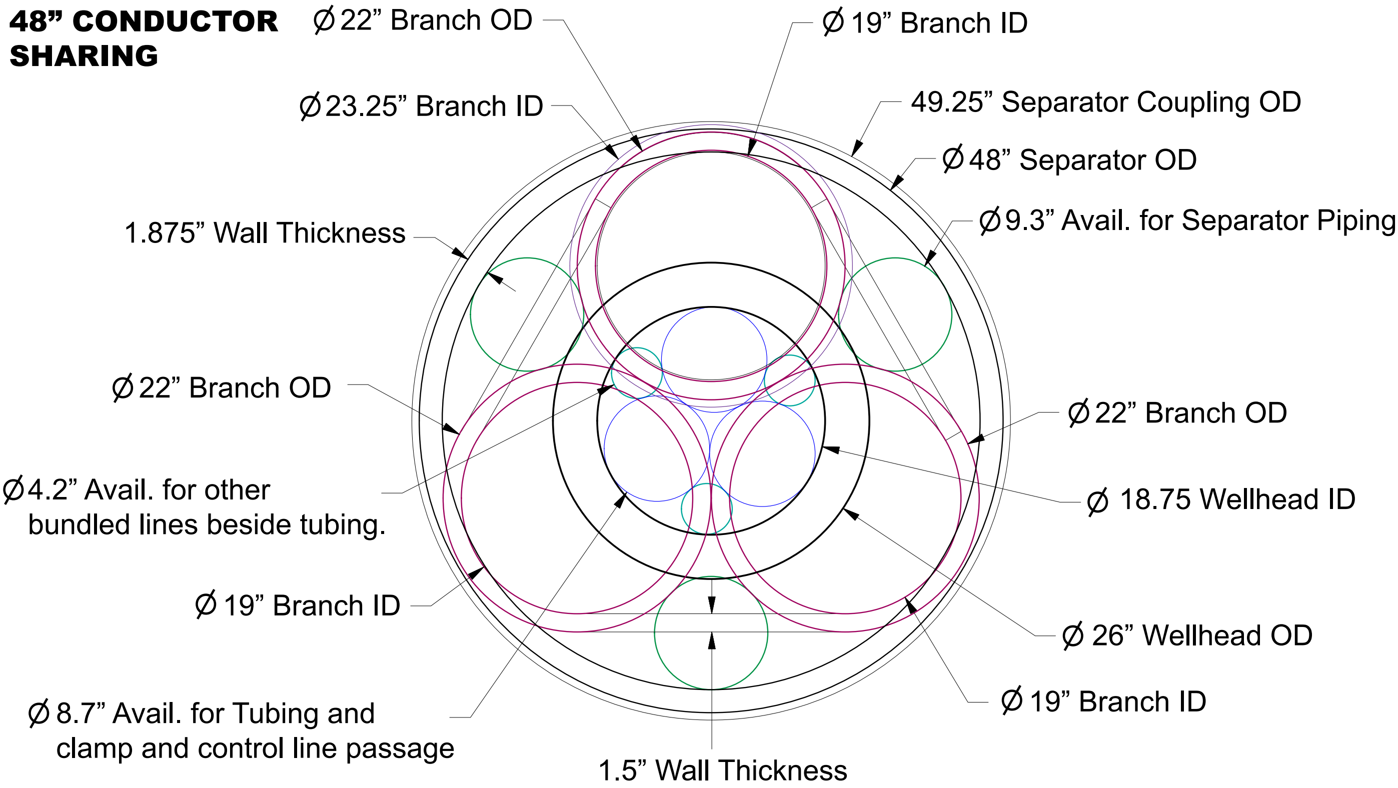

Figure 10- Plug and Play 48" Cloverleaf Conductor Sharing Specification

New Conductor & Casing Sharing Technology

Oilfield Innovations' new technology adapts existing standards and, therefore, uses standardised sizes and interfaces in in a new way within the accepted boundaries of current established specifications.

Oilfield Innovations' have nicknamed our patented casing sharing technology the "*Magic Crossover*" (see Figures 15 and 16) and our patented conductor sharing technology the "*Cloverleaf*" (see Figures 10-11, 13-14 and 19), wherein both are compatible with standard wellhead and extended reach drilling technologies usable with subsea trees, to enable tie-back of multiple pools of stranded hydrocarbons through a single pipeline.

With regard to the "*Cloverleaf*" technology specification in Figure 10, numerous examples of multiple wells through a single conductor exist, like the North Sea Magnus wellhead and trees depicted in Figure 1, and three conductor sharing North Sea Britannia wellhead and production trees in Figure 12, whereby such technology has been documented by many authors (Sund[5], 1997; Dharaphop[6], 1999; Tuah[7], 2000; Anchaboh[8], 2001; Faget[9], 2005; Santos[10], 2006; Matheson[11], 2008; Hicks[1], 2009; Damasena[2], 2014; Terimo[13], 2016).

Offshore platforms have developed conductor sharing because they lacked slots for additional wells and, unfortunately, the technology has never been translated to a subsea arrangement until Oilfield Innovations patented a subsea conductor sharing arrangement that uses a rotatable bore selector whipstock to select a one of up to three well bores.

As previously described, the technology allows concurrent drilling of multiple wells using batched drilled hole-sections accessed by a rotatable bore selector whipstock as shown in Figure 11.

Where the North Sea Magnus Field used 46 inch conductors (Hicks, 2009)[1] a subsea version of the conductor sharing could use a 48" conductor to provide three conventional 22 inch wellhead casing hanger systems in a "*Cloverleaf*" pattern accessible using a rotatable bore selector whipstock through an 18 ¾ inch conventional wellhead housing as shown in Figures 10 and 11.

Figure 10, shows that the equivalent internal diameter of three (3) 9 ⅝ inch casings (8.7 inches) can be accommodated through and 18 ¾ inch subsea wellhead housing for three conventional tubing strings with associated control lines and clamps.

Accordingly, casings can be hung-off below the whipstock with three (3) independent tubing strings passing through an 18 ¾ inch wellhead housing internal diameter.

As depicted in Figure 11, Oilfield Innovations proposes that a conventional big-bore subsea wellhead housing and casing hanger system be split by a rotatable whipstock arrangement to select which well bore will be entered. New technology development does not get any simpler nor more adaptable to standardisation that allows rapid development and widespread usage.

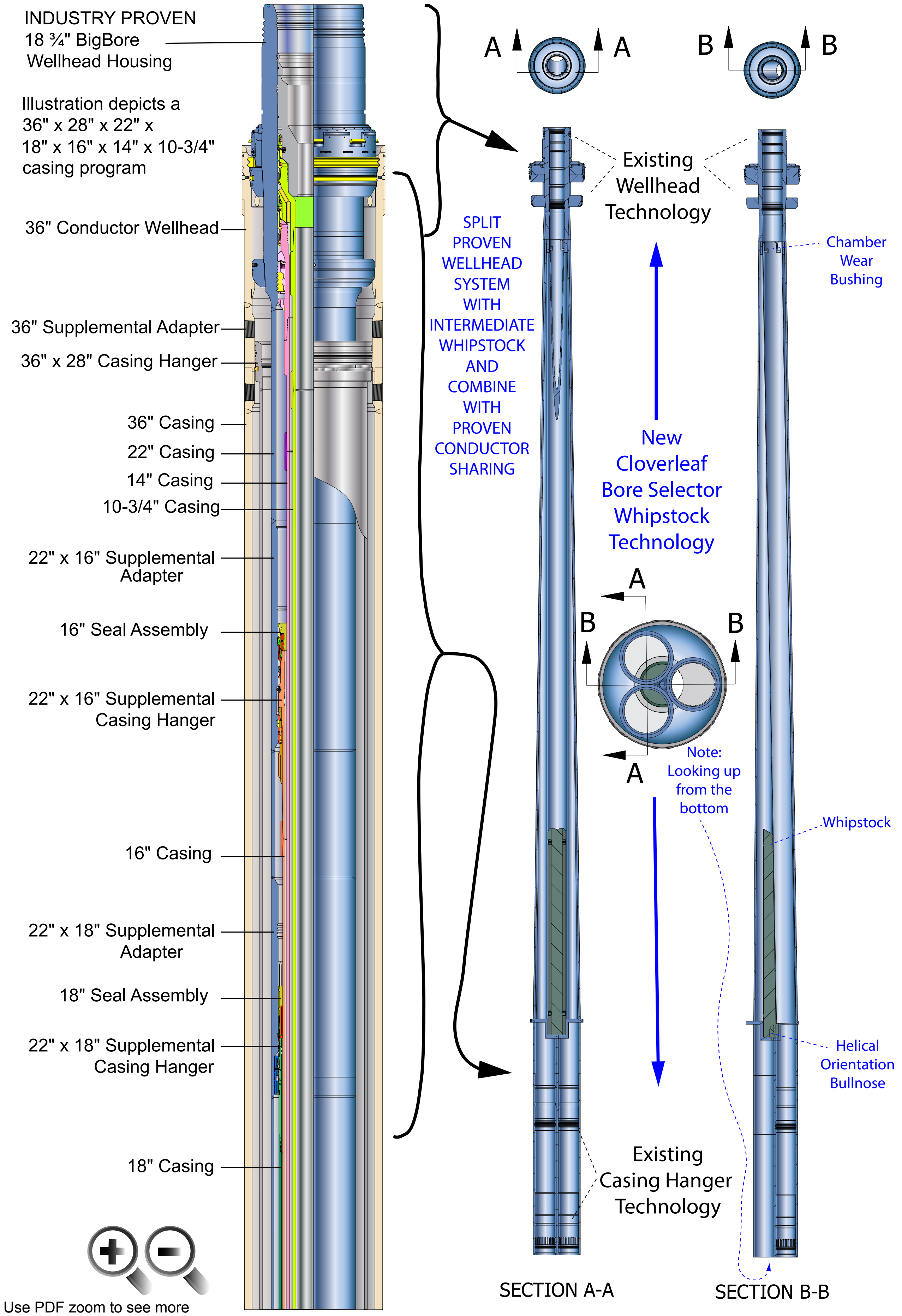

Figure 11 - New Cloverleaf Whipstock Technology

Figure 12 - Britannia Triple Wellhead Arrangement (Matheson, 2008)[11]

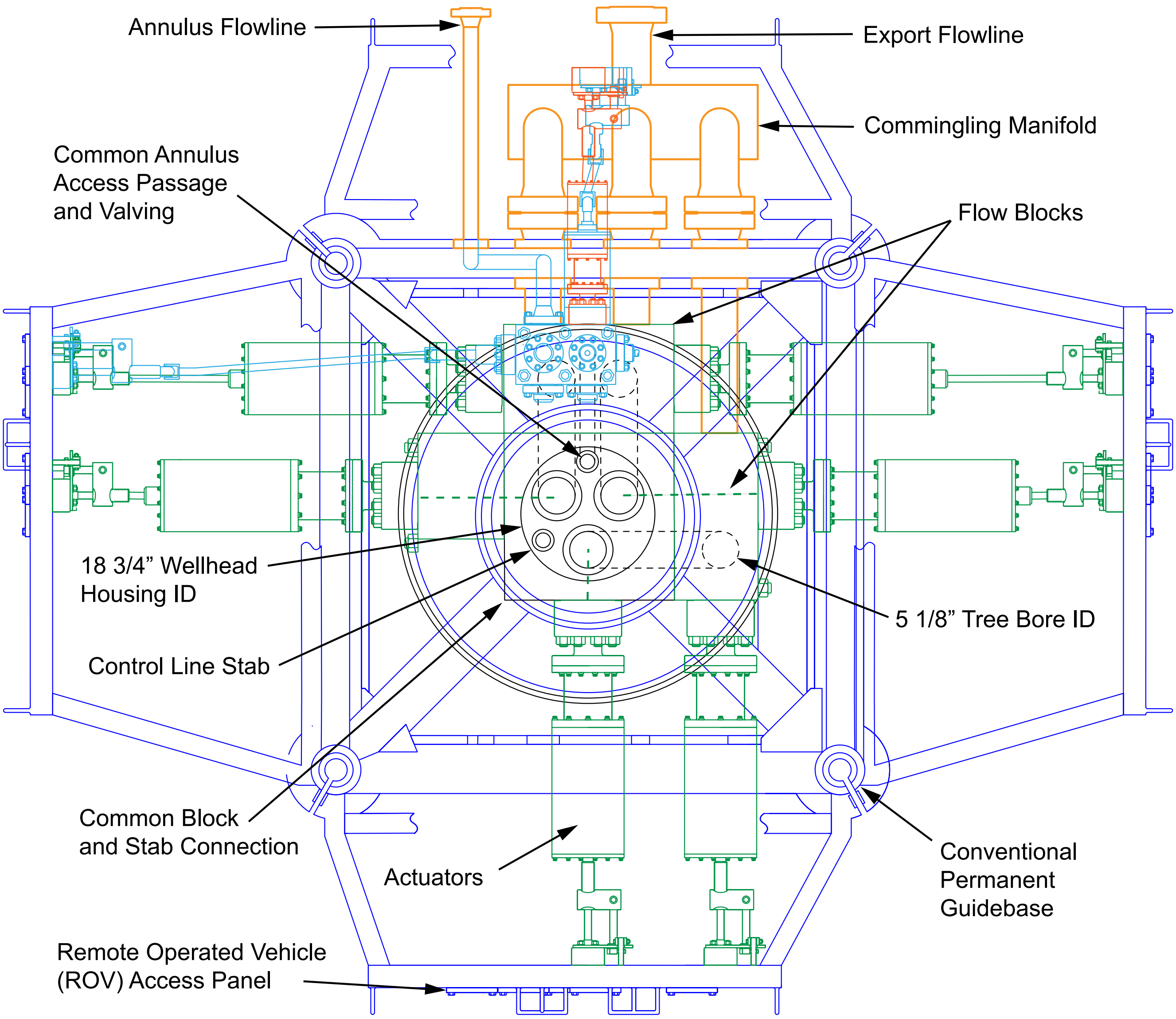

Figure 13 - Theoretical Plan View of a Conductor Sharing Subsea Tree

An example of a three-well conductor sharing arrangement is shown in Figure 12 for the UK North Sea field Britannia (Matheson, 2008)[11]. The existence of a proven three well surface conductor sharing arrangement indicates that subsea conductor sharing is feasible using, for example, the conductor sharing subsea arrangement illustrated in Figure 13.

The primary differences between surface and subsea production trees comprises annulus access and the ability to actuate valves both hydraulically and with a remote operated vehicle (ROV).

Figure 13 illustrates a scaled version of 48" Cloverleaf subsea conductor sharing arrangement depicting how a common central block can be bored to accommodate flow blocks and actuators for a three well subsea production tree.

Flow from the three (3) separate well wells can be directed from the flow blocks to a commingling manifold or, alternatively, individually to a conventional subsea manifold.

The Cloverleaf three well arrangement has a common annulus passageway between the three wells that can also be accessed through an annulus flowline in a conventional manner.

The Figure 13 arrangement fits within a conventional permanent guide base having 72 inch radius guide posts for blowout prevention stacks (BOPs), wherein the arrangement of tree and BOPs can be seen in Figures 33 and 35 of the appendix.

To further reduce cost, the tree can be configured as a vertical tree with light well intervention vessel (LWIV) access to the three individual well bores via a subsea lubricator (see Figure 37) to allow the rig to drill the well and go off contract, with a lower cost LWIV setting the tree and performing hook-up operations.

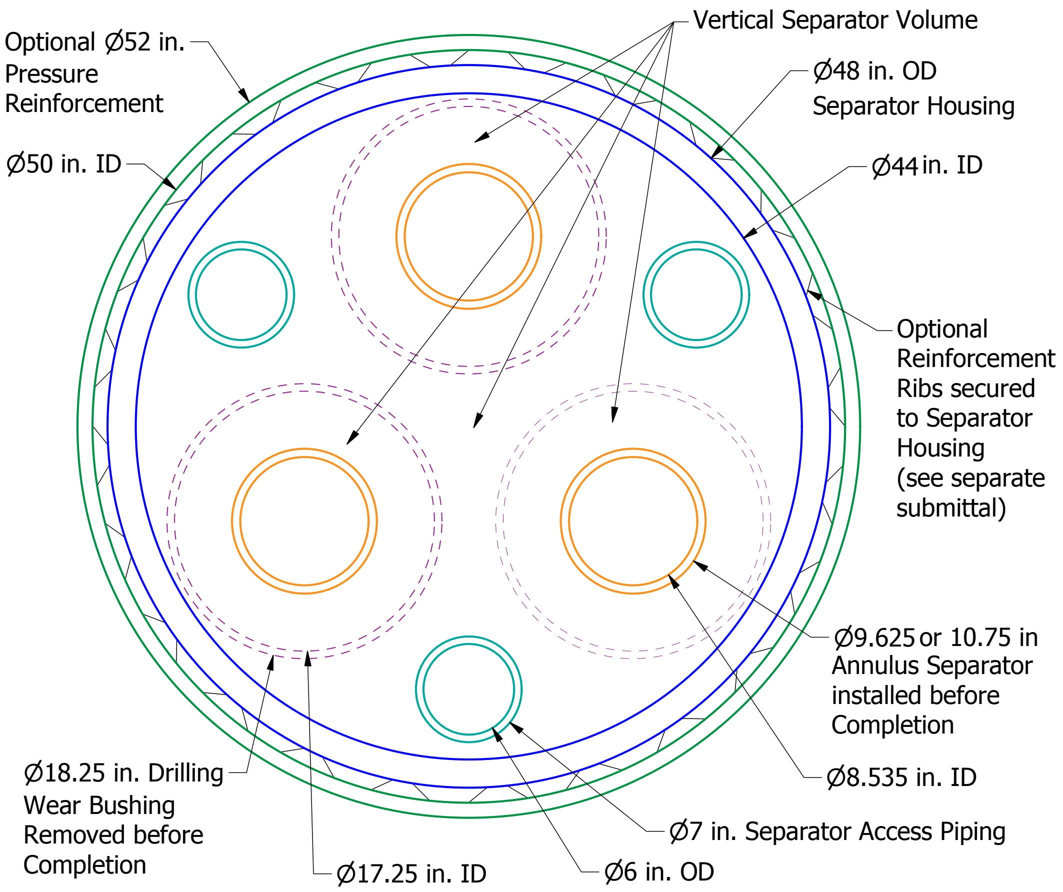

Figure 14 - Cloverleaf Vertical High Pressure Water Disposal Separator

Large Diameter High Pressure Conductors

One of the downsides of large diameter piping is a relatively low pressure rating. Fortunately, Oilfield Innovations have also patented solutions to this dilemma as shown in Figure 14, which is described in more detail with another prospectus on our website.

Low burst and collapse pressure rating for large diameter piping are associated with the propensity of large diameters pipe expansion and compression, respectively. Oilfield Innovations have patented the principle driving ribs between conductors to compress a large diameter inner pipe and expand a larger diameter outer pipe, to form a composite large diameter structure that has high pressure and bending strength.

For instance, as described in Figure 29 of the appendix, 52 inch conductor can be jetted into the seabed on the temporary guide base on the temporary guide base. A 50 inch hole opener (RHO, 2017)[32] with a 24 inch pilot bit can then drill a hole for a 48" inner conductor that can pass through a standard 49 ½" rotary table to fit within the 52 inch outer conductor to provide substantial bending resistance for the Figure 13 subsea tree.

With regard to pressure rating, the API 5CT pressure rating for X-80 grade pipe with 1.875 wall thickness shown in Figure 10 is rated to 5,500-psi (374-bar) while 110-ksi material would be rated to 7,500-psi (510-bar).

The Figure 14 patented solution to increase conductor pressure ratings can, for example, use a 36 inch pilot bit with a 56 inch hole opener to bore a hole for one (1) inch wall thickness 52" outer conductor run and cemented with the Temporary guide base as shown in Figure 28.

A Figure 14 Cloverleaf with a 48 inch diameter and conventional reinforcement ribs comprising, for example, conventional solid blade casing centralizers attached to casing can expand the 52" outer conductor that will marginally compress 48" ribbed inner conductor to create a metal-to-metal contact composite wall with 12,000-psi burst pressure assuming an 80% efficiency for an API 5CT calculation.

Figure 14 enhanced bending and pressure rating can facilitate the double independent wall safety factors necessary for the downhole vertical separator arrangement that can be installed below the Cloverleaf whipstock technology to dispose of waste water.

The separator can be managed and cleaned through 7 inch access piping as shown in Figure 14. Water disposal can occur in various ways, wherein it is possible to install the Figures 15 and 16 "*Magic Crossover*" arrangement (further explained in a separate prospectus on our website) within one of the well bores to inject water into the same horizon

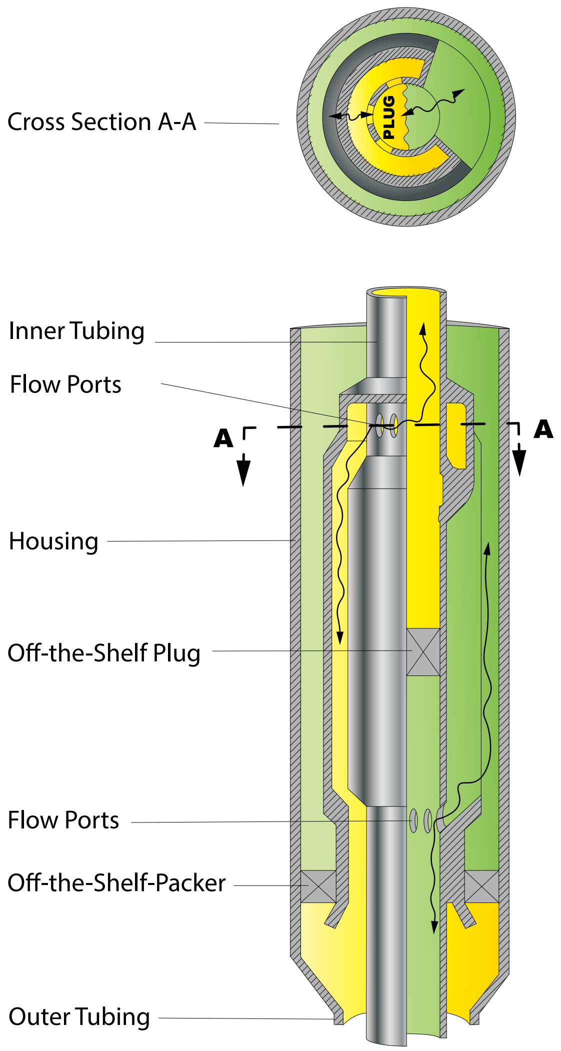

Figure 15 - Magic Crossover Simplification

from which it came to, effectively, sweep the reservoir and increase hydrocarbon production (see Figures 18 and 20).

Magic Crossover (2-for-1 Well Costs)

Landing surface casing within a conventional profile below the Figure 14 separator and landing a 9 ⅝ or 10 ¾ inch casing within a conventional profile above the separator can maximise separator volume and provide both annulus monitoring and the ability to produce and inject through a single casing string using the Figure 16 "*Magic Crossover*" arrangement. This is accomplished with independent concentric flow for both production and injection through the same casing. Please note that additional detailed information on our Magic Crossover is contained within another prospectus on our website.

Figures 15 and 16, illustrate how a simple crossover with no moving parts can be used between conventional completion equipment to flow two differently pressured flow streams through a single wellbore, wherein the flow streams can flow in the same or opposite directions.

Use PDF zoom to see more

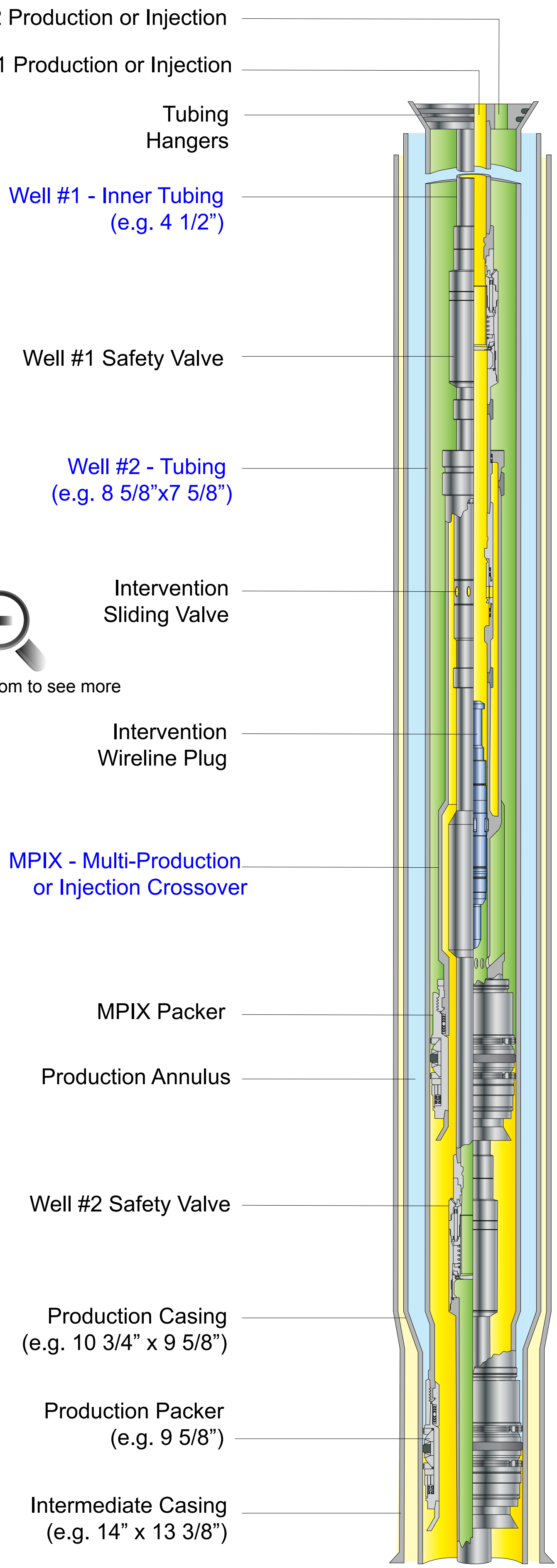

Figure 16 - New Casing Sharing Tecnhology

Figure 17 - Troll Subsea Separation Pilot (Tveter, 2015)[24]

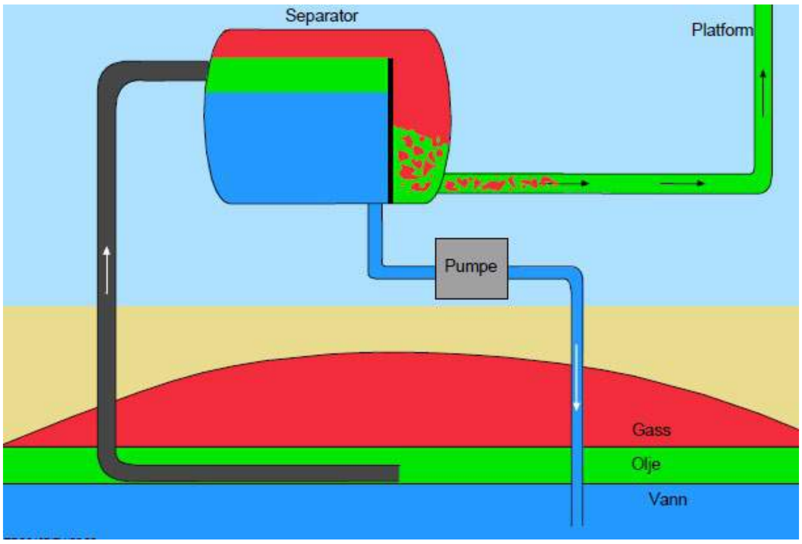

Figure 18 - Troll Subsea Separation Pilot (Tveter, 2015)[24]

Downhole Separation

As shown in Figure 17, Statoil have used subsea separation in Norway on the Troll field (Tveter, 2015)[24]. Looking at the size of the separator relative to the people shown in the Figure 17 photo, and considering the double shell nature of a sea bed separator, an equivalent or larger internal volume for the Figure 14 separator can be achieved with a vertical depth greater than the length of the Figure 17 Troll horizontal separator.

As shown in Figure 18, fluids produced from the reservoir are directed into the high pressure water knock-out separator with two phase flow down the pipeline and water disposal comprising re-injection of produced water back into the aquifer below the reservoir.

Tveter[24] describes in Figure 20 that subsea water separation and disposal prior to entering the pipeline extends the life of the field and increases recoverable reserves.

Accordingly, adding downhole separation can be a significant improve the economics of developing stranded hydrocarbons.

Cloverleaf Vertical Downhole Separator

Figure 19 describes how the Figure 11 separation of the wellhead housing connector and casing hangers can be further separated to create a downhole vertical separator, while Figure 10 shows the available space for separator piping. Please note that a conventional single well subterranean vertical separator and/or monopod jacket vertical separator are explained in our High Pressure Conductor Prospectus.

As depicted in Figure 19, produced fluids from the wells can be directed to a Cloverleaf downhole vertical separator where gravity separates the lighter hydrocarbons from the heavier water.

Hydrocarbons are taken from the top of the Figure 19 vertical separator and produced water is taken from the lower portion of the vertical separator, wherein the down comer plate and length of the hydrocarbon entry and exit piping would be designed according to the gas-to-oil ratio of the hydrocarbons.

To provide a clearer depiction, Figure 19 shows disposed water being pushed into the overburden, however, space for three 7 inch separator pipes shown in Figure 14 exists and can comprise the hydrocarbon pipe feeding the separator, the hydrocarbon export pipe feeding the pipeline and the water disposal pipe which can pump water from the bottom of the separator and, for example, use the Figure 16 “Well #2 Production or Injection” Magic Crossover flow stream to dispose of water into the water leg of the reservoir being produced, which provides the same functionality as Figure 18 without the cost of a disposal well.

With regard to barriers, Figure 14 describes use of Oilfield Innovations patented pressure reinforced double separator hull, which can be cemented within the shallow overburden such that the double hull, cement and overburden insulated vertical separator can provide approximately reservoir temperature export fluids when the heat exchanger nature of the wells running through the separator and the mass transfer of heat from disposed water are considered. Each well uses a common pressure integrity monitoring annulus, which is separate from and runs through the vertical separator within the insulation of cement and surrounding overburden to maximise the temperature and increase the flow assurance properties before hydrocarbons enter the tie-back pipeline.

Piping separate from the wells may be accessed from above via the lubricator of a light well intervention vessel (see Figure 37) to allow cleaning and maintenance of the vertical separator, wherein a light well intervention vessel could use coiled tubing to clean out the separator periodically if, for example, it became filled with produced solids.

Because a subterranean separator can be, for example, 500-ft or 152 metres in height, it can handle a large volume of fluids and produced solids, wherein optical fibre temperature and pressure monitoring of the separator volume can provide sufficient data to manage

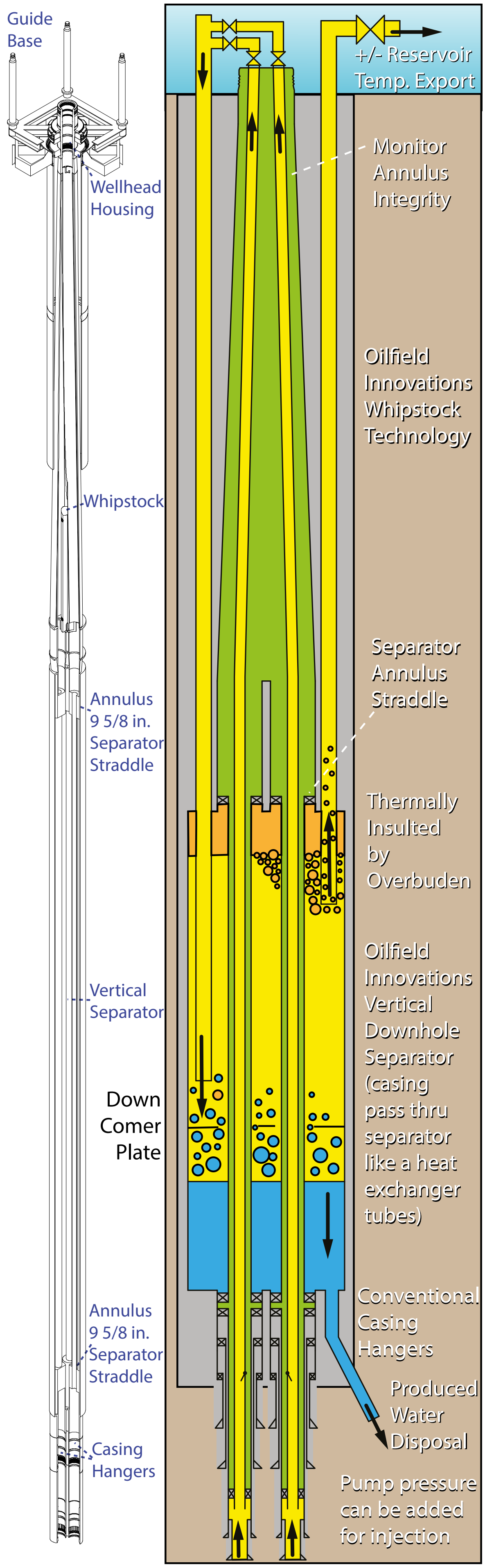

Figure 19 - Cloverleaf Vertical Separator

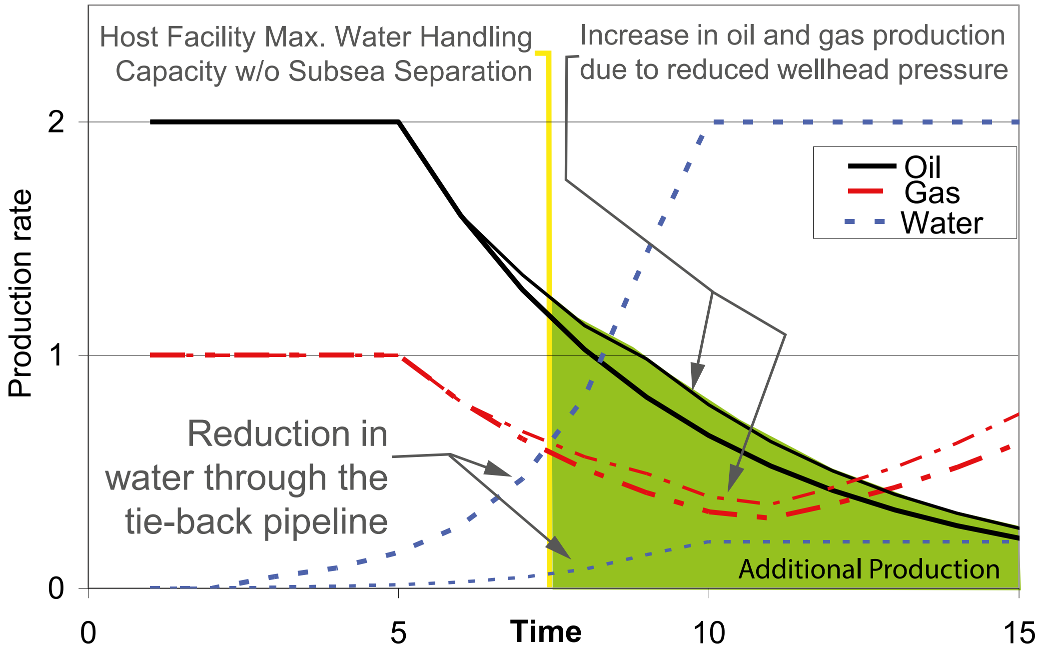

Figure 20- Troll Subsea Separation Pilot (Tveter, 2015)[24]

the separator and determine whether, or not, it needed to be cleaned out.

Also, hydrocarbons from three (3) separate small pool reservoirs could be commingled in the separator together with any necessary chemical additions within the insulated near reservoir temperatures of the vertical separator to improve mixing and associated flow assurance through the tie-back pipeline.

Metering of each of the wells and sampling taken when one or more of the wells is shut-in can be used for allocations and determination of the properties and qualities of the hydrocarbons from each previously stranded hydrocarbon pool.

Increased Recoverable Reserves

Developing stranded hydrocarbon pools is not necessarily strictly a cost cutting exercise. It also involves increasing the recoverable reserves as shown in the Troll subsea separation example of Figure 20.

Stranded hydrocarbon development economics can often be impeded by the host facility's inability to handle produced water, wherein the economics of stranded hydrocarbons normally considers early cessation of production due to produced water, before reservoir pressure is fully depleted.

In Figure 20, Tveter[24] depicts how the subsea disposal of produced water allows higher production rates that reduce wellhead pressure and increase recoverable reserves by reducing the volume of water through the tie-back pipeline below the water handling capabilities of the host facility.

Accordingly, additional production added by downhole separation can be added to the economics of small pools to increase their viability.

The Large Impact of Three Small Innovations

Previous industry standardisation initiatives are critical for growth of an industry, but standardisation will not necessarily improve the economics of small pools unless innovation occurs within said standardisation.

Oilfield Innovations can provide three small innovations within present standardised systems that can have a large positive impact on the development of stranded offshore hydrocarbons.

Our Cloverleaf conductor sharing technology provides the relatively small adaptation of standardised technology comprising splitting a standard subsea wellhead housing and hanger systems with a rotatable whipstock to allow conventional extended reach wells that remove the need for tiebacks to a central manifold.

Our Magic Crossover technology provides the relatively small adaptation of standardised technology comprising crossing over concentric flow streams to allow conventional completion jewellery to control the internal tubing diameter of two differently pressured fluid stream flowing in the same or opposite directions.

Our Large Diameter High Pressure conductor technology provides the relatively small adaptation of tubular standards comprising the use of ribbing to engage one conductor within another conductor to increase its bending, burst and collapse pressure capabilities significantly.

Combining these three small innovations has the significant impact of reducing development cost by reducing subsea

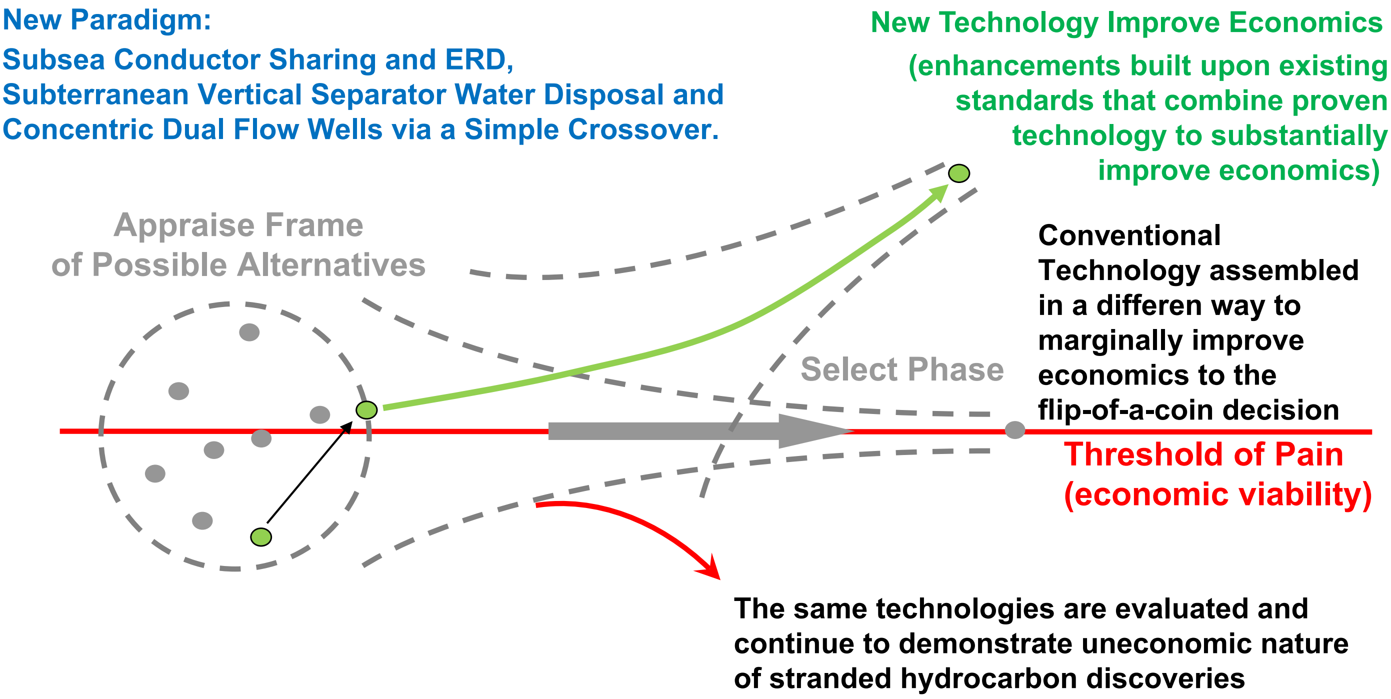

Figure 21 - New Plug-and-Play Paradigm (Iterative Approach, Hopper, 2016)[18]

infrastructure to an absolute minimum while providing the ability to access multiple differently pressured small pools and/or fault blocks through a single wellhead.

Oilfield Innovations' Cloverleaf can provide three autonomous wells while our Magic Crossover can provide two differently pressure flow streams through each autonomous well to, thus, provide six (6) separate differently pressured flow streams through a single wellhead, whereby each of the six (6) separately pressured flow streams can be flowed through a high pressure thermally insulated water knock-out vertical separator that can provide a commingled chemically treated hydrocarbon flow stream to a single tie-back pipeline.

Oilfield Innovations three small adaptations could be standardised to better facilitate widespread use and development of supporting new technologies that can be used to reduce costs, increase recoverable reserves and develop stranded offshore hydrocarbons.

New Paradigm

As illustrated in Figure 21, the three possible outcomes of further evaluating development of stranded hydrocarbon discoveries are that previous development scenarios are repeated and fail, new scenarios of using marginally less expensive approaches provide marginal economics or new technology is developed that make stranded hydrocarbons discoveries economic despite the normal risks of offshore development.

Because fracking technologies will limit the price of oil and gas for some time, development of stranded offshore hydrocarbons requires a new paradigm that substantially changes the economics of tie-backs to existing infrastructure.

With Oilfield Innovations' limited adaptation of existing standardized technologies, a new paradigm can be created with limited risk that substantially changes the economics using batch (assembly line) drilling techniques, utilisation of previous wasted well bore space and downhole water separation and disposal before two (2) to six (6) separately pressured hydrocarbon streams enter a single tie-back pipeline with a single umbilical using a combined subsea tree and manifold.

Oilfield Innovations may be a two man dog-and-pony-show that may lack the credibility necessary to single-handedly create such technology, but we own the patents and we are looking for commercial entities with sufficient credibility, experience and funding to bring enormous amounts of stranded offshore hydrocarbon to market.

Commercial considerations could be agreed to open source connection interfaces to Oilfield Innovations' patented technology to allow any vendor to interface with the new technology, wherein the legal rights associated with the patents could be managed by a service provider such that the interfaces are standardized in an open source manner.

Providing large and small service providers with access to interfacing with the new technology would improve the likelihood of acceptance, create competition and keep costs as low as reasonably practicable.

For example, Shell released the technology of bi-centre bits (see Figure 36) and now most bit companies produce bi-centre bits using standardized API rotary connections.

The North Sea has since the booms of the 1970's and early

Commercialization Components

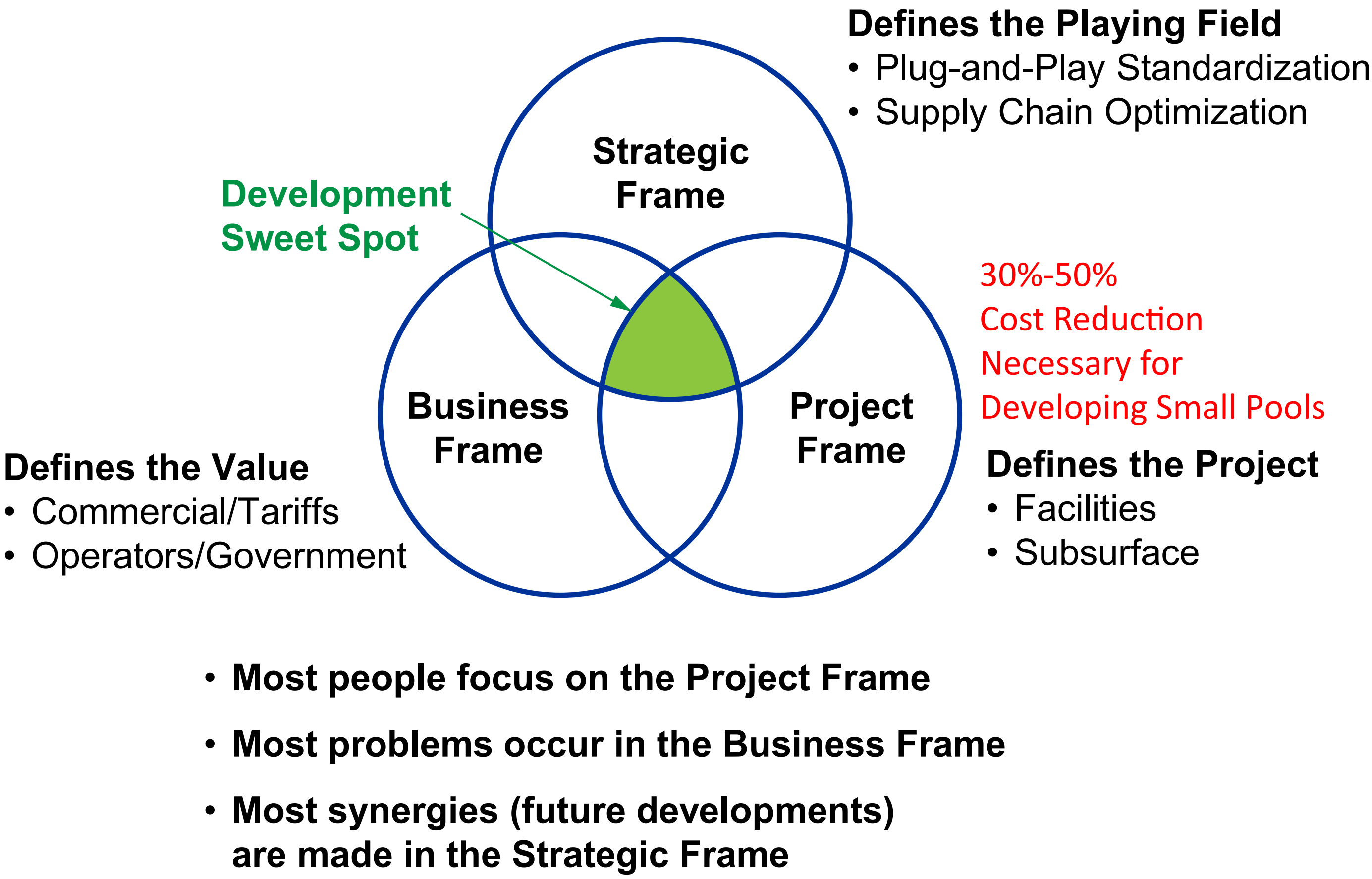

Figure 22 - Commercialisation Components, Hopper, 2016)[18]

1980's been relatively resistant to change and, therefore, creating a standard that is distributed worldwide could provide the necessary use in other countries to influence its acceptance in the North Sea.

Required adaptations proposed herein are relatively minor and lower in cost than other innovations that have provided step changes in performance.

For example, Oilfield Innovations are proposing splitting a subsea hanger system, adapting a whipstock and making a crossover according standardised pipe sizes, whereas the step changes in extended reach drilling between 1975 to 2010, shown in Figure 7, required complete retooling of drilling systems from rotary kelly drilling to top-drives, positive displacement fluid motors and rotary steerable systems, albeit each involved a sequence of understandable and acceptable changes that were built upon API standards for rotary connections.

Commercialisation

As illustrated in Figure 22, the sweet spot for small pool development requires solving issues in the project, business and strategic frames, wherein collaboration between Oilfield Innovations and OGTC could provide two of the three necessary characteristics for development.

Most people, including Oilfield Innovations, focus on the technical aspects of the project.

Plug-and-play open sourcing could be used to focus on the strategic frame.

As a micro-company, the business frame is beyond Oilfield Innovations' control and we are looking for investors. Plug and play open sourcing is one idea, but we are open to any commercial arrangement.

As described in Figure 23, a business case can be built by identifying various UK North Sea small pools, see Figures 24 to 27, which can analysed and evaluated to provide business cases that may further influence industry to develop and use the technology.

Standards can be selected and amalgamated under a single plug-and-play standard for industry use with the proposed

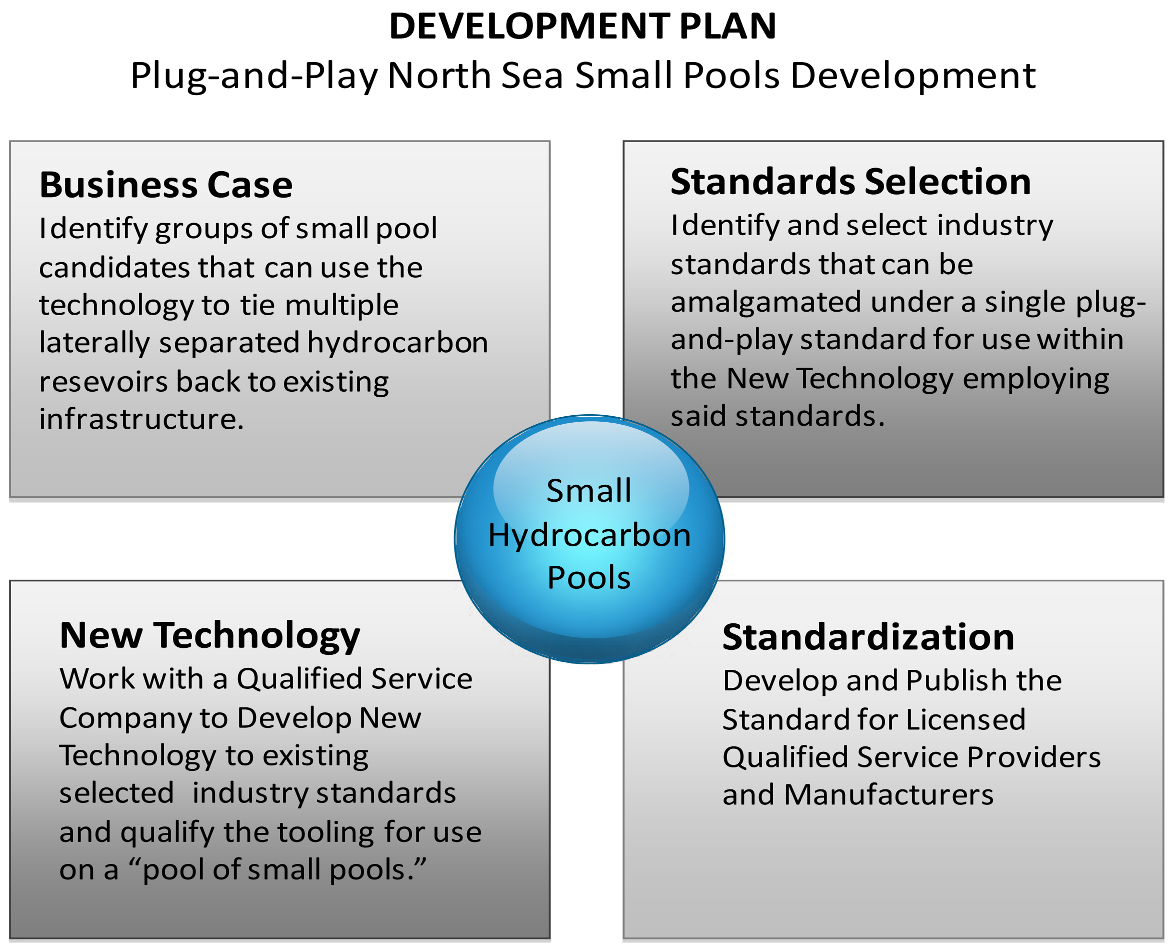

Figure 23 - Plug-and-Play Approach to Subsea Casing and Conductor Sharing Technologies

new technology, as further described in Figure 23.

In addition to assisting with creation of an open source plug-and-play specification, Oilfield Innovations are also qualified to identify business casings within the 100 opportunities identified in Table 1 and Figures 24 to 27.

Oilfield Innovations' new technology can easily be developed and qualified by qualified service companies.

Commercially, Oilfield Innovations need to recoup their patent investment costs with the potential for a relatively small return on investment once the technology is successful, while the United Kingdom needs the tax revenue generated by developing small pools.

Oilfield Innovations will accept virtually any viable commercial proposal and can assign control of their patents to any entity who can fund and manage development and the business provided we can recoup our patent costs.

Accordingly, the new technology can be standardized and published for use by qualified vendors and service providers as further stated in Figure 23.

As our new technologies requires minimum adaptations and works within standardised oil and gas technologies as well as conventional proprietary technologies, it is a good fit with OGTC's call for plug-and-play innovations.

Conclusion

"Small" offshore hydrocarbon discoveries are substantially larger than many economic discoveries. "Small" refers to the pool's economic development size and not necessarily oil and gas in place. As offshore small pools are substantially larger than remaining pools of onshore hydrocarbons, the key to developing offshore hydrocarbons is reducing cost and improving recovery.

When a small pool of hydrocarbons was discovered, subsea development and tie-back options to existing infrastructure were evaluated and, therefore, the small economic size of the stranded hydrocarbons did not justify the subsea infrastructure cost, tariffs, waste water disposal, well count or drilling cost options evaluated.

Standardizing plug-and-play approaches which have already proved uneconomic is unlikely to reduce cost sufficiently to develop stranded hydrocarbons and a new approach to development is required.

Also, costs for developing small pools of offshore hydrocarbons must be competitive within current pricing set by onshore fracking.

Accordingly, a new paradigm is needed for developing small pools of offshore hydrocarbons; however, said paradigm cannot significantly deviate from existing standards upon which the oil and gas industry is built.

Oil and gas drilling have used plug-and-play standardization for decades. The various sizes of tooling for drilling and completion have been standardized through API and ISO such that conventional extended reach drilling technology can be used to eliminate tie-backs to a central subsea manifold.

Also, conventional conductor sharing can be adapted to subsea applications using Oilfield Innovations rotatable whipstock bore selector to improve drilling and casing efficiency using hole-section batch operations.

Changing the paradigm of uneconomic small pools of offshore hydrocarbons discoveries requires not only minimising subsea infrastructure and improving drilling performance but also limiting well count and managing produced waste water disposal.

Disposing of produced water before it reaches the tieback pipeline can increase recoverable reserves and minimise development costs, wherein increased recovery and lower costs can make small pools of hydrocarbons more economic.

Oilfield Innovations can open source our patented technology in a supply chain plug-and-play manner, wherein the legal rights afforded by our patents can provide supply chain control during and after standardization to ensure competitive pricing.

The supply chain organisation who controls our patents would have the legal right to make critical standardization decisions and control quality assurance of the standard.

For example, for quality control purposes, a patent control supply chain organisation could license use to only qualified vendors who adhere to the publish standards.

Accordingly, Oilfield Innovations technologies are 100% plug-and-play compatible.

Three minor standardized tweaks to industry proven technology comprising:

- a split conventional wellhead with an intermediate rotatable whipstock and “cloverleaf” shaped conductor sharing arrangement,
- a “magic” crossover that allows discrete control of two flow streams through the same wellbore, and
- “ribbing” that can be used to create large diameter high pressure conductors which can be used to retain larger hole sizes at well total depth, facilitate monopod jackets in deeper water depths and/or provide double walled subsea or subterranean vertical separators,

can change the paradigm of North Sea small pools development without significantly deviated from standard industry practice.

Insanity is doing the same thing over and over again, and expecting a different result (Albert Einstein).

It is unlikely that North Sea small hydrocarbon pools can be changed without doing something different and it is important to work within the boundaries of present industry standards.

Oilfield Innovations can offer minor changes, which can be standardized in a plug-and-play manner within proven industry standards, that can change the way small pools of hydrocarbons are developed.

If our ideas are of interest, we would be pleased to discuss how they could be further developed. For additional information please read our accompanying submittals.

Further Information

Addition detailed information on the Oilfield Innovations' Conductor Sharing Technology described above is included in Appendix A, please provide this document to your engineers and we would be happy to answer any further queries. For additional information or further queries please contact Clint Smith or Bruce Tunget at the below email addresses.

Notes and references

[a] *Clint Smith is Professional Engineer in the State of Texas, began working in the Drilling, Intervention and Well Operations in 1978 and lives in Houston, Texas, USA; Curriculum Vitae (CV) available upon request; clint@oilfieldinnovations.com*

[b] *Bruce Tunget earned a PhD. and MSc in Mineral Economics and a BSc in Mineral Engineering from the Colorado School of Mines, is a Chartered Financial Analyst, began working in Drilling, Intervention and Abandonment Operations in 1982 and lives in Aberdeen, Scotland; Curriculum Vitae (CV) available upon request; bruce@oilfieldinnovations.com*

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APPENDIX A

Additional Terms of Reference

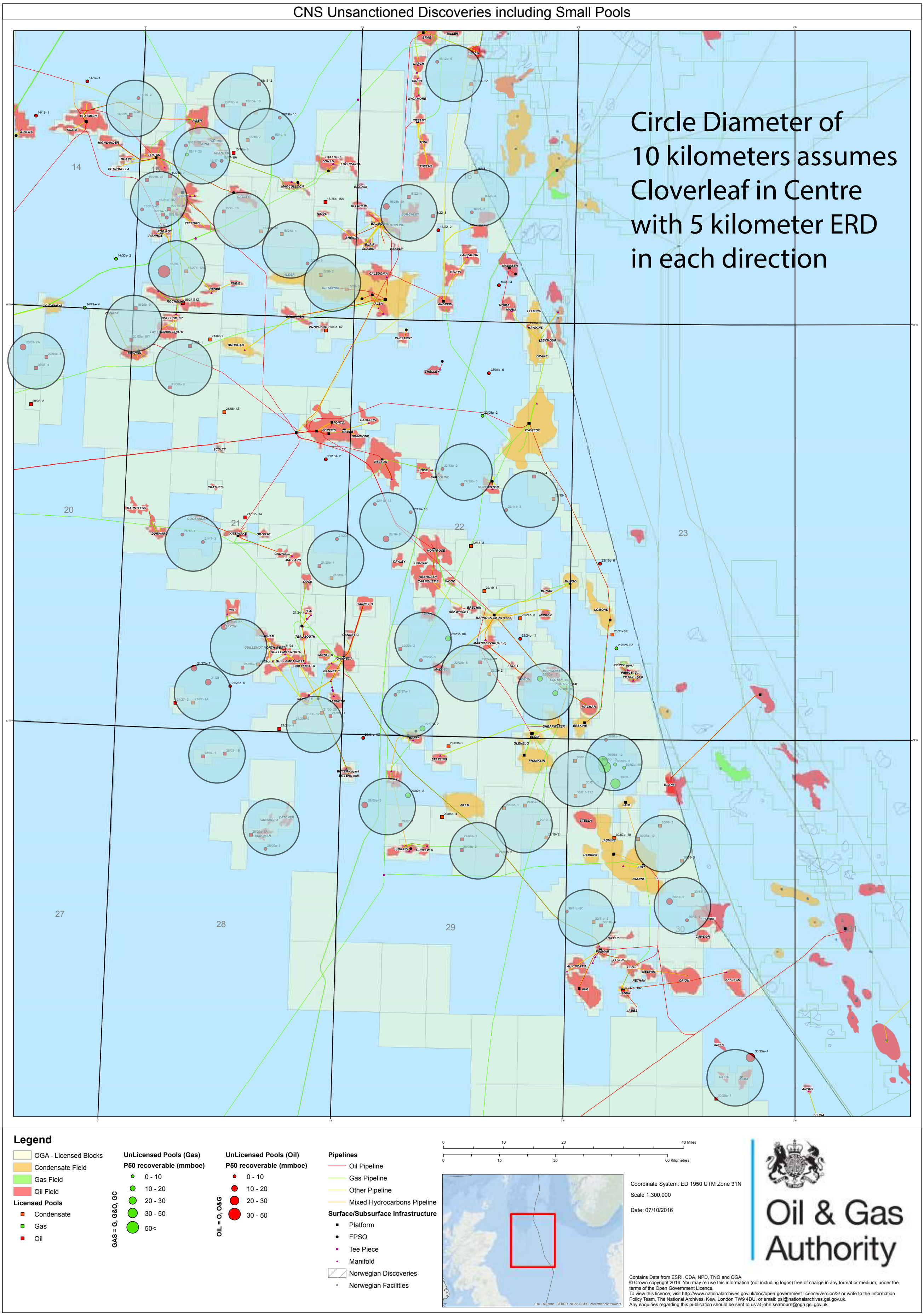

Figure 24 Central North Sea Small Pools Map (OGA, 2016)[21]

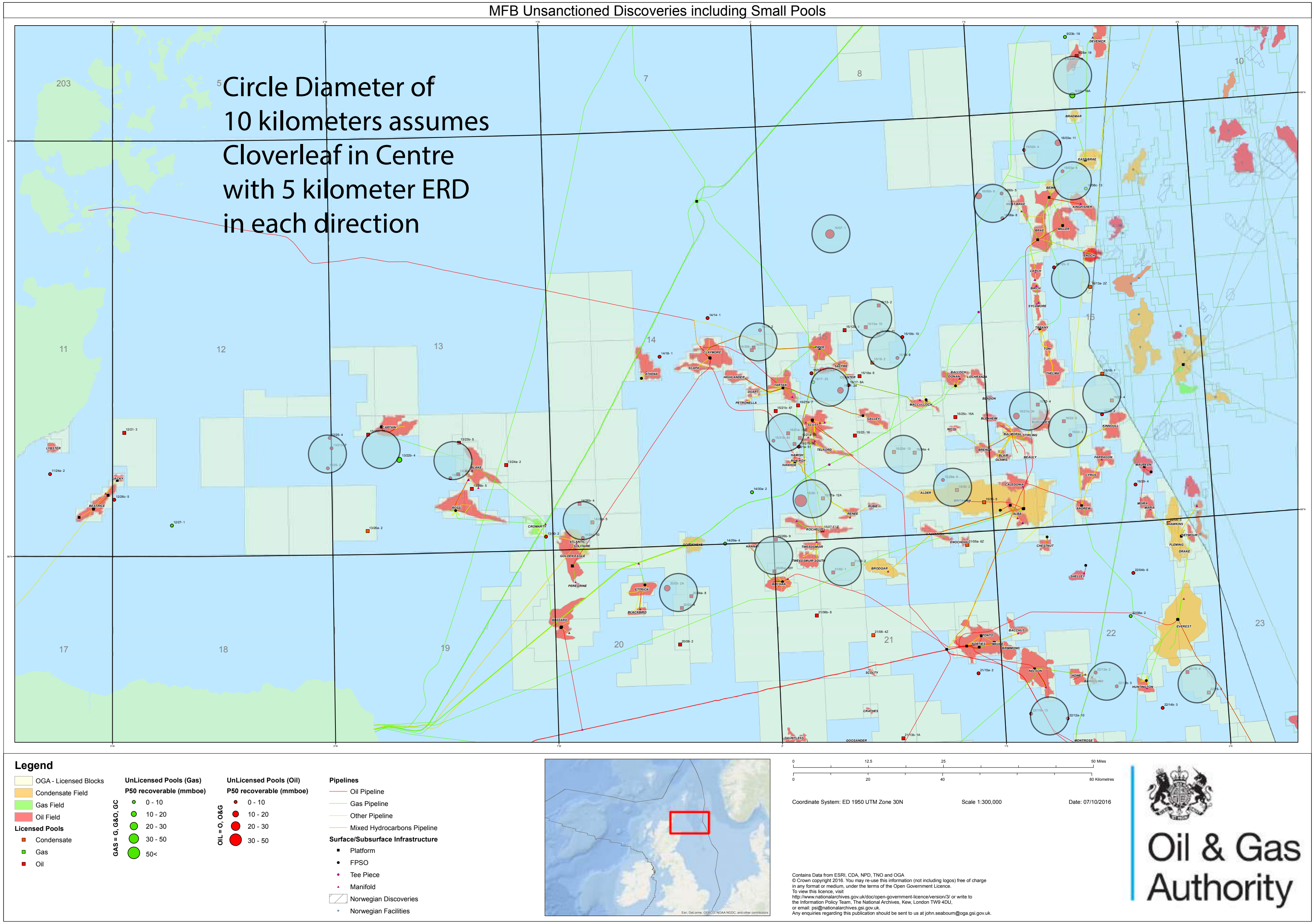

Figure 25 - Moray Firth Small Pools Map (OGA, 2016)[21]

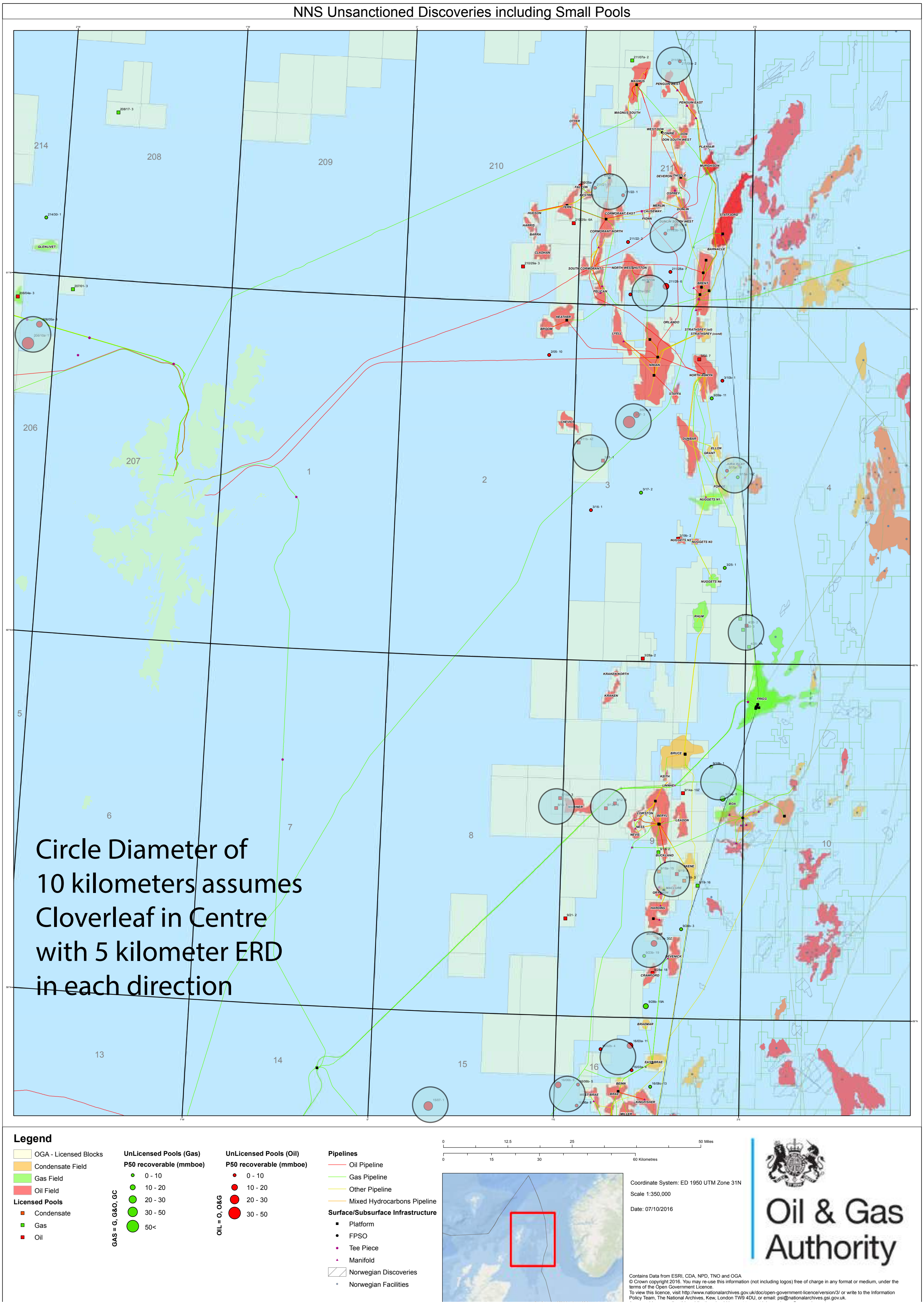

Figure 26 - Northern North Sea Small Pools Map (OGA, 2016)[21]

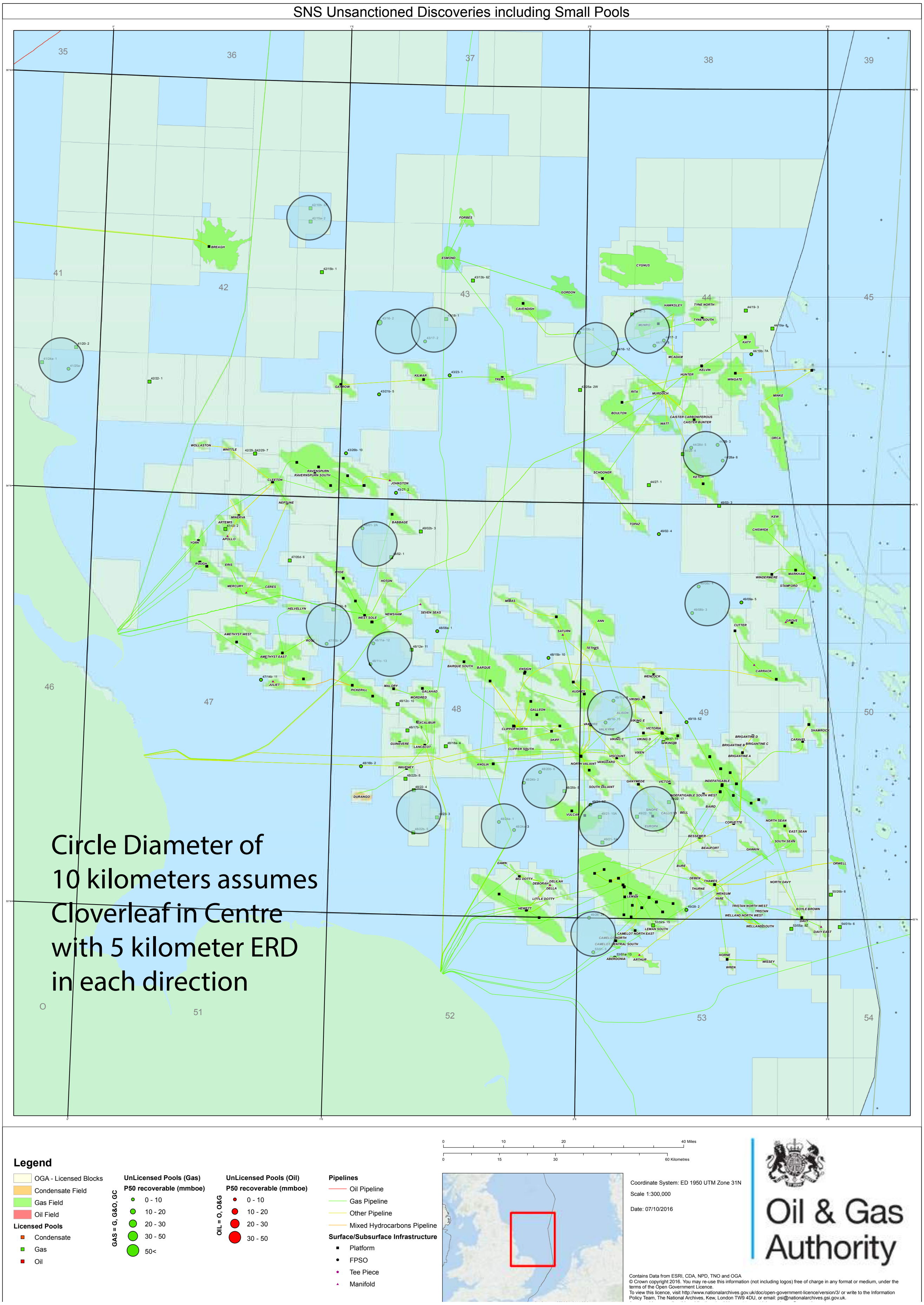

Figure 27- Sothern North Sea Small Pools Map (OGA, 2016)[21]

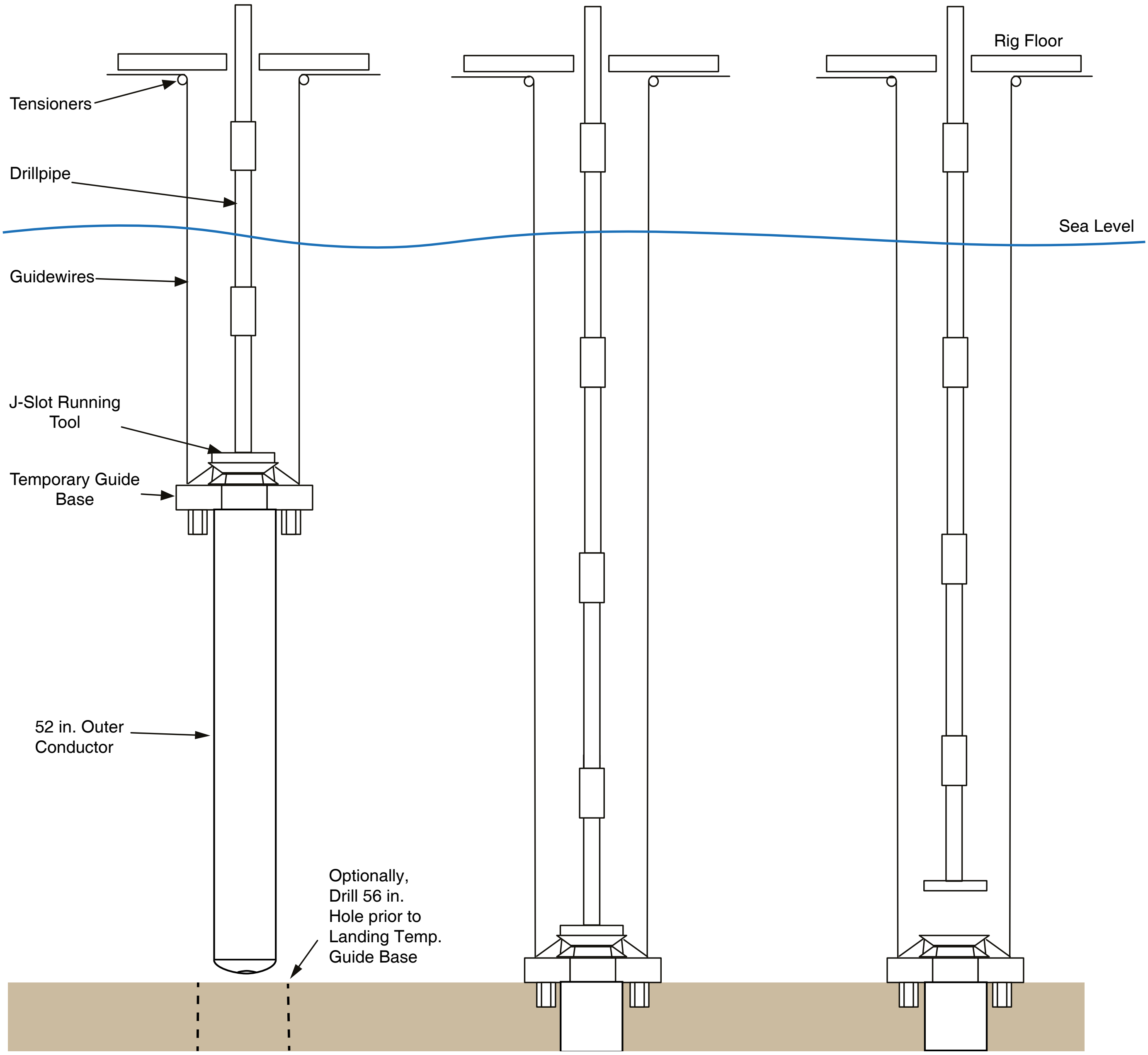

Figure 28- Installing Temporary Guide Base

Installation Sequence

For those unfamiliar with subsea well operations, Figures 28 through 35 describe the installation process for Oilfield Innovations "Cloverleaf" new well technology.

Temporary Guide Base

Subsea operations generally begin with running of the temporary guide base through which the initial top hole section is drilled.

As depicted in Figure 28, the temporary guide base is run on drill pipe and landed on the sea bed to establish guide lines after the running tool is pulled back to surface.

50” Hole Section

As illustrated in Figure 29, a utility frame attached to the guide wires is used to stab the drilling assembly into the temporary guide base.

In this instance a 24 inch pilot bit and 50 inch hole opener is used to drill the initial top hole section through the 52 inch outer conductor jetted in with the temporary guide base as shown in Figure 28.

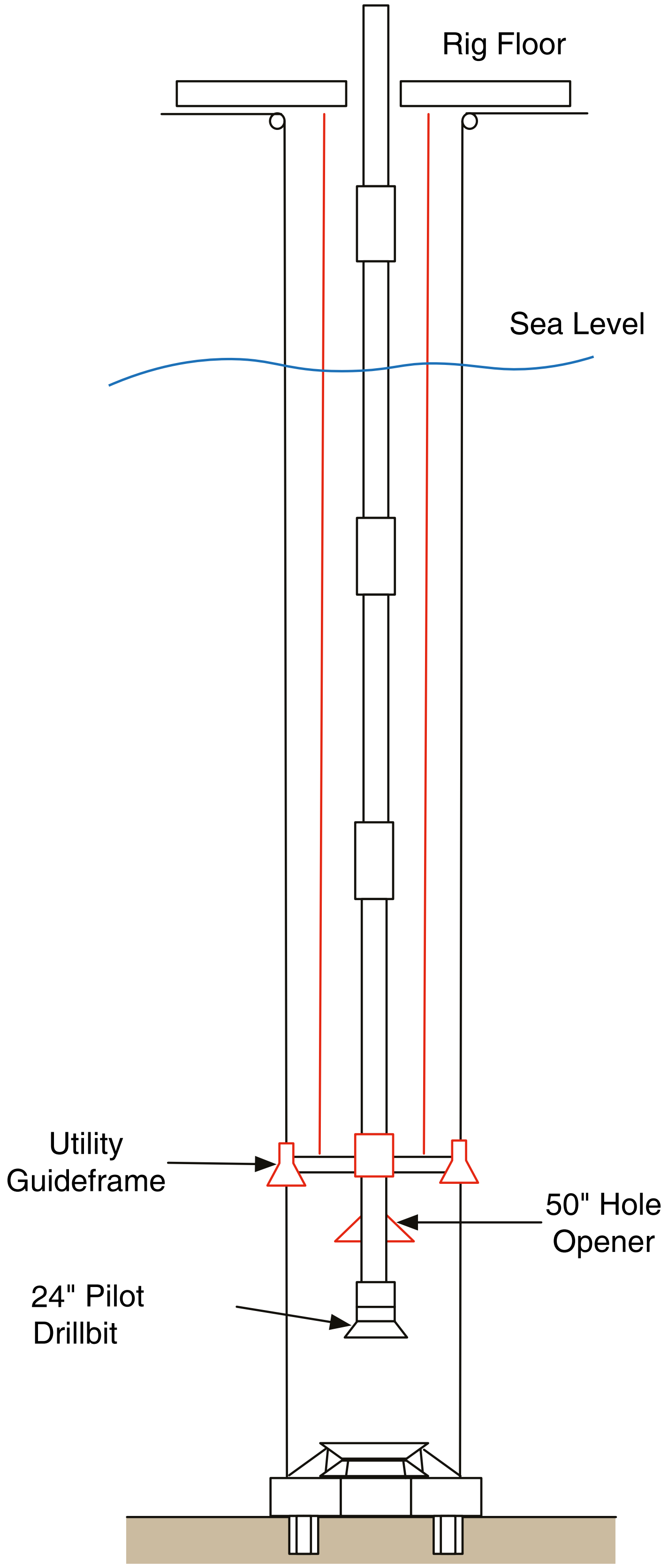

Figure 29- Drilling 52” Hole

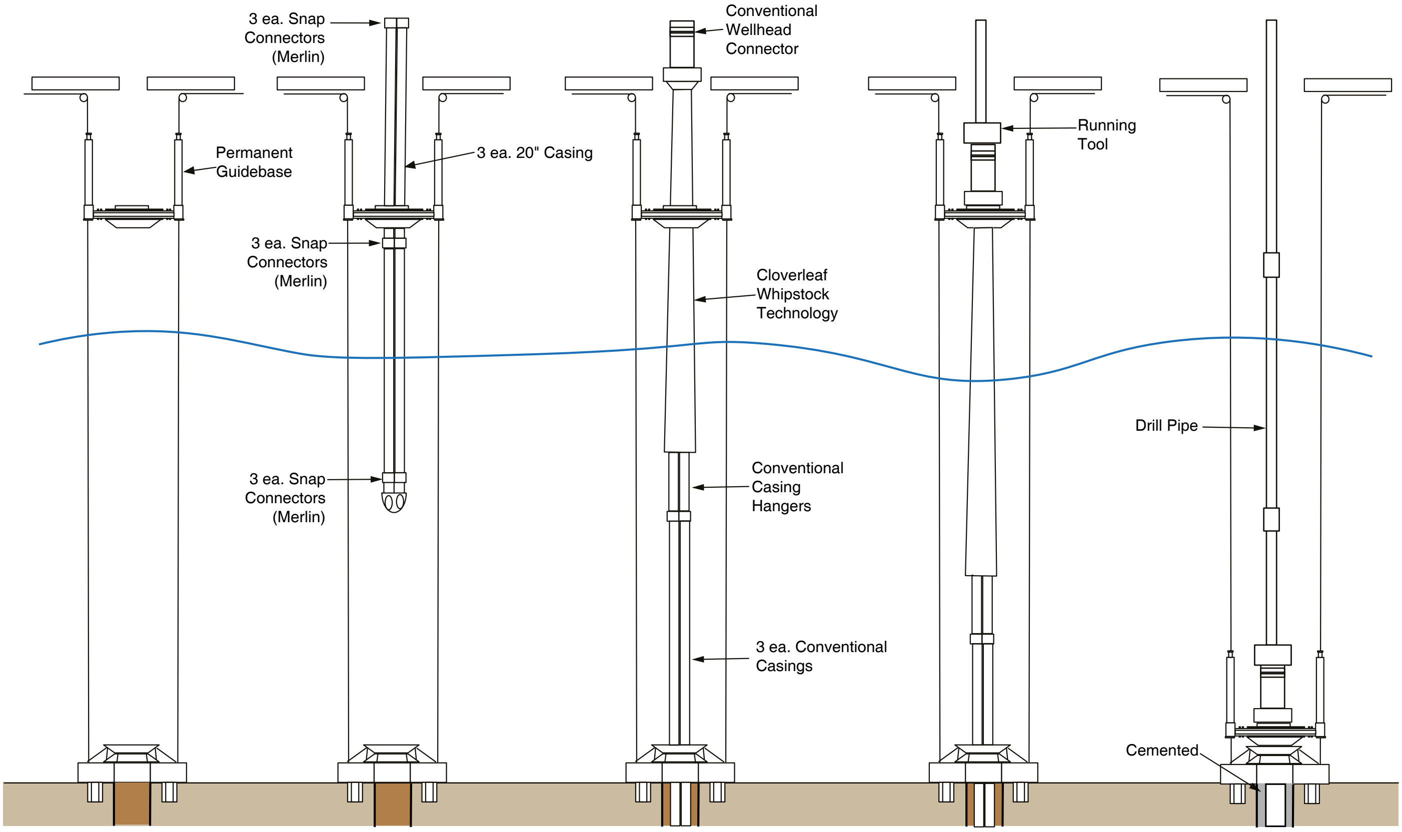

Figure 30- Running Permanent Guide Base and 48” Cloverleaf Multi-Well Conductor

Cloverleaf Whipstock Installation

Figure 30 shows installation of the permanent guide base on the guide wires followed by running casing equipment through the guide base.

Merlin™ snap connectors can be used to run a bundle of three 20 inch casings through the permanent guide base at the same time.

A bundle of three conventional casing hangers at the bottom of the Cloverleaf Whipstock can then be snapped onto the 20 inch casings.

A running tool is then attached to the conventional subsea wellhead at the top of the Cloverleaf Whipstock and the permanent guide base and casing are run into the hole and landed in the temporary guide base.

The entire assembly is then cemented within the open hole.

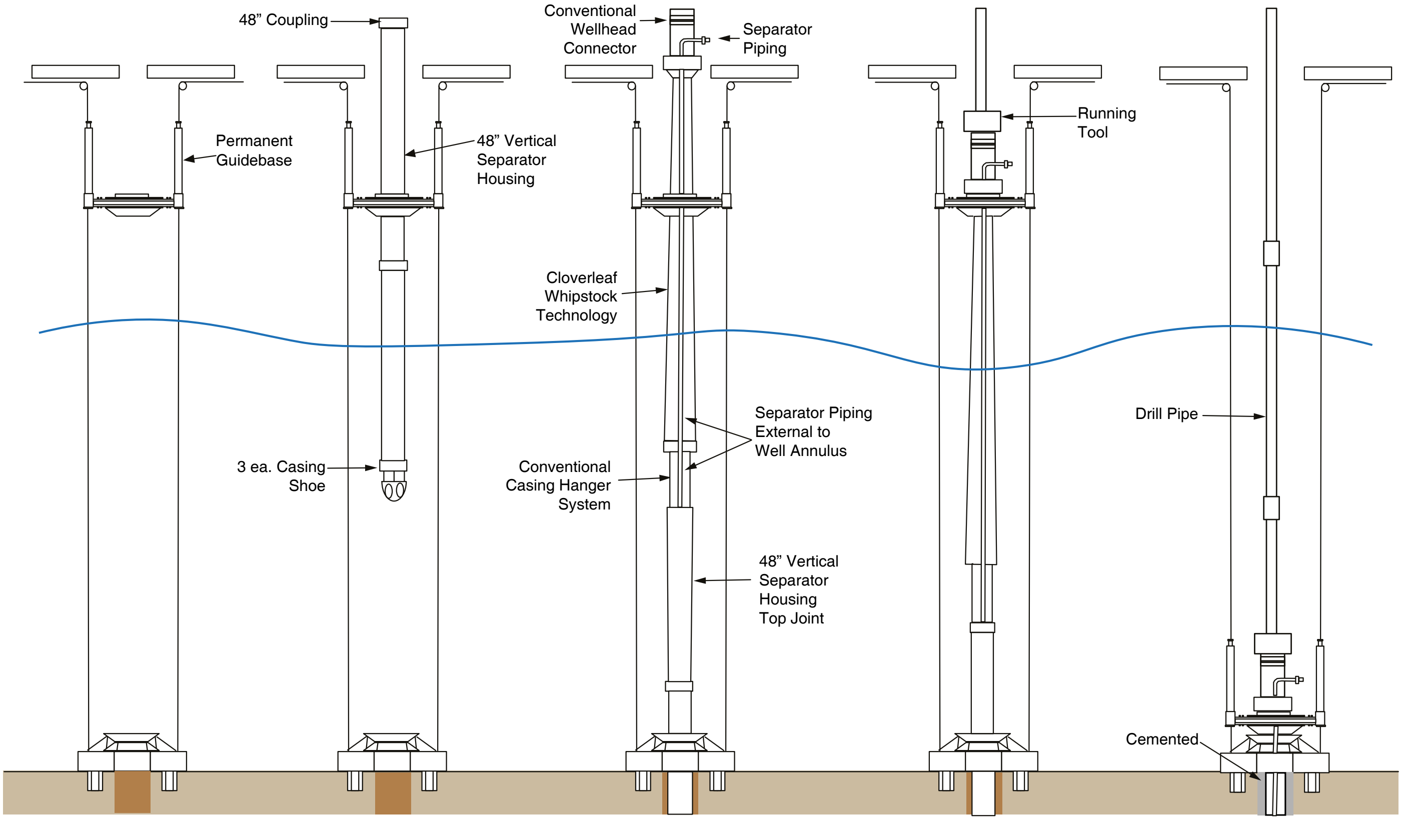

Figure 31- Running Permanent Guide Base and 48” Cloverleaf with 48” Vertical Separator

Installing Cloverleaf and Separator

Figure 31 illustrates installation of the permanent guide base on the guide wires followed by running casing equipment through the guide base.

An assembly with three drill out casing shoes is attached to a 48 inch vertical separator housing run through the guide base. Further 48 inch joints are screwed together using, for example, XLW™ connectors shown in Figure 38 and run in the hole through the permanent guide base.

Once the desired length of 48” pipe for the vertical separator has been run, internal separator piping and guides are run using a false rotary table for make-up of the separator’s internal piping.

Three conventional casing hanger conduits and the Cloverleaf Whipstock are attached to the top joint of the vertical separator with separator piping strapped eternally.

A running tool is then attached to the conventional subsea wellhead at the top of the Cloverleaf Whipstock and the permanent guide base and casing are run into the hole and landed in the temporary guide base.

The entire assembly is then cemented within the open hole.

Floater BOPs and Drilling Operations

Figure 32 depicts the installation of a floating drilling rig's blowout preventers (BOPs) onto the 18 ¾" subsea wellhead.

All equipment is sized for passage through the standard 18 ¾ inch BOP and wellhead internal diameter, whereby the Cloverleaf whipstock is retrieved, rotated and re-inserted through the BOPs to access each of the wells below the Cloverleaf assembly.

With the exception of pulling, rotating and re-inserting the bore selector whipstock, drilling operations continue as they would during any other batch operations.

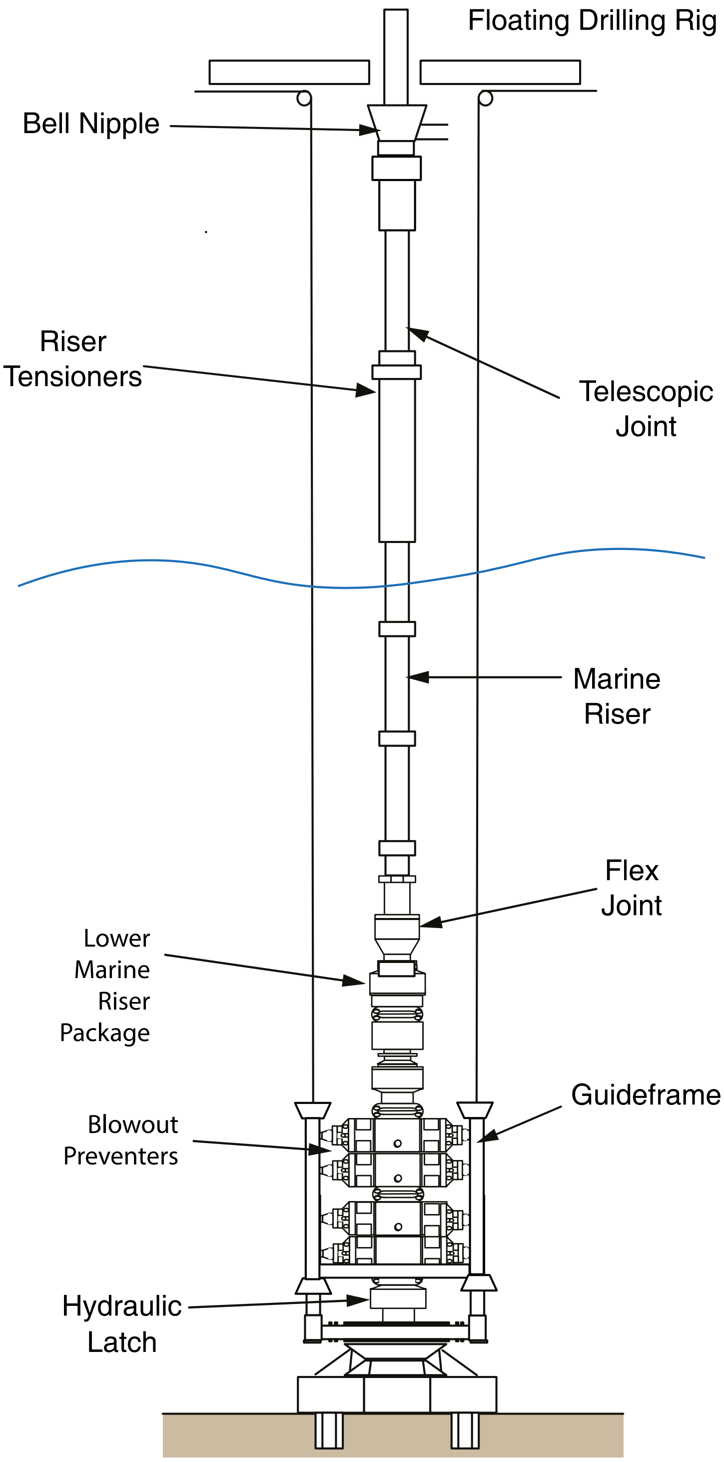

Figure 32- Running BOPs on Floating Rig

Floater BOPs and Completion Operations

Figure 33 shows the installation of a floating drilling rig's blowout preventers (BOPs) on top of the subsea production tree during completion operations.

Either a vertical or horizontal subsea tree can be used.

All completion equipment is sized for passage through the standard 18 ¾ inch BOP and subsea tree, whereby the Cloverleaf whipstock is used to run the completion strings for each of the wells.

The completion strings are hung-off within the Cloverleaf arrangement until all of the completions strings have been run into each well. The rotatable whipstock is then removed and each of the completion strings is lifted and connected to a centralised bundle where control lines and cables are connected, tested and then landed in the wellhead before setting the production packers or, alternatively, using conventional mandrels stabbed into polished bore receptacles (PBRs) attached to the top of each pre-set production packer.

The subsea completion arrangement and trees would be similar to conventional conductor sharing arrangements, which would require design assistance from a qualified vendor.

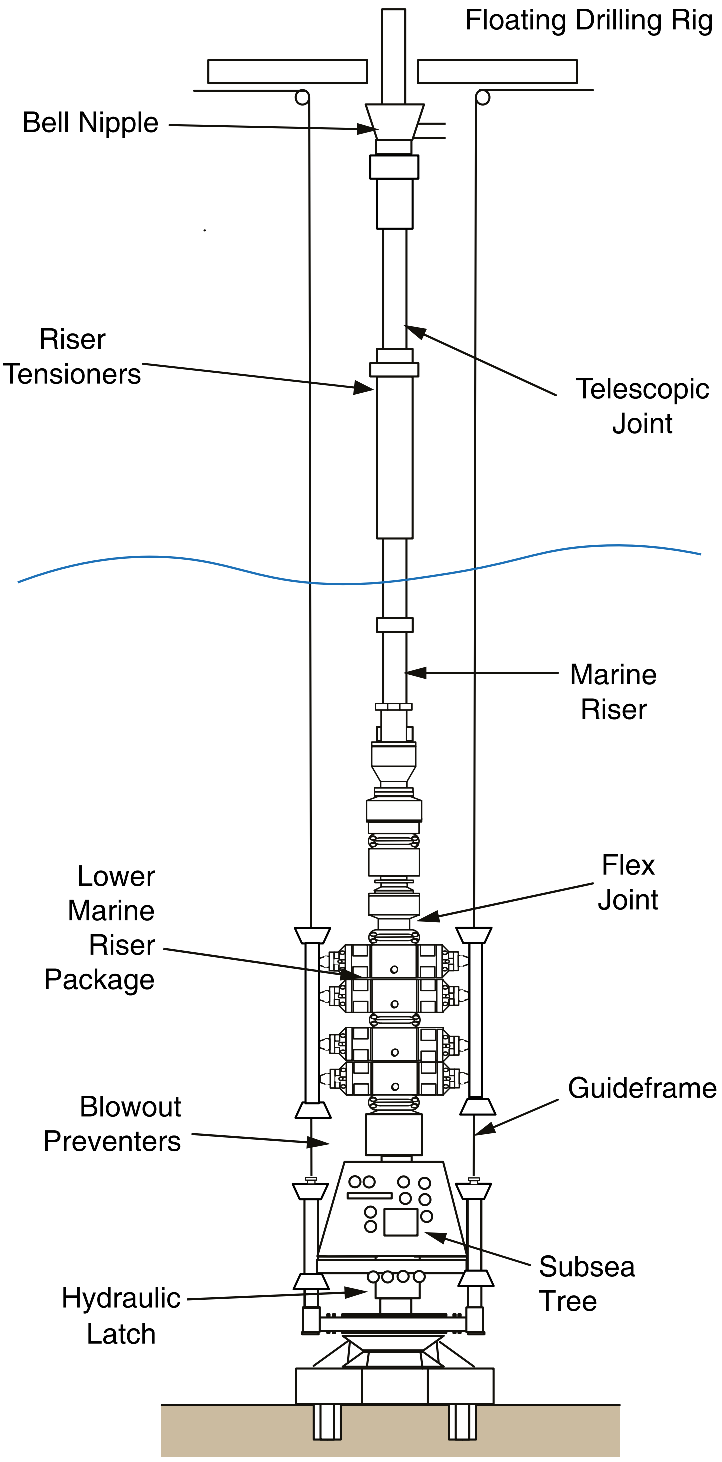

Figure 33- Running Tree on Floating Rig

Jack-up BOPs and Drilling Operations

Figure 34 depicts the installation of a jack-up drilling rig's blowout preventers (BOPs) onto a high pressure riser attached to the 18 ¾" subsea wellhead with a conventional connector.

Many newer jack-ups have begun using 18 ¾ inch BOPs that are suited to such operations.

All equipment is sized for passage through the standard 18 ¾ inch BOP and wellhead internal diameter, whereby the Cloverleaf whipstock is retrieved, rotated and re-inserted through the BOPs to access each of the wells below the Cloverleaf assembly.

With the exception of pulling, rotating and re-inserting the bore selector whipstock, drilling operations continue as they would during any other batch operations.

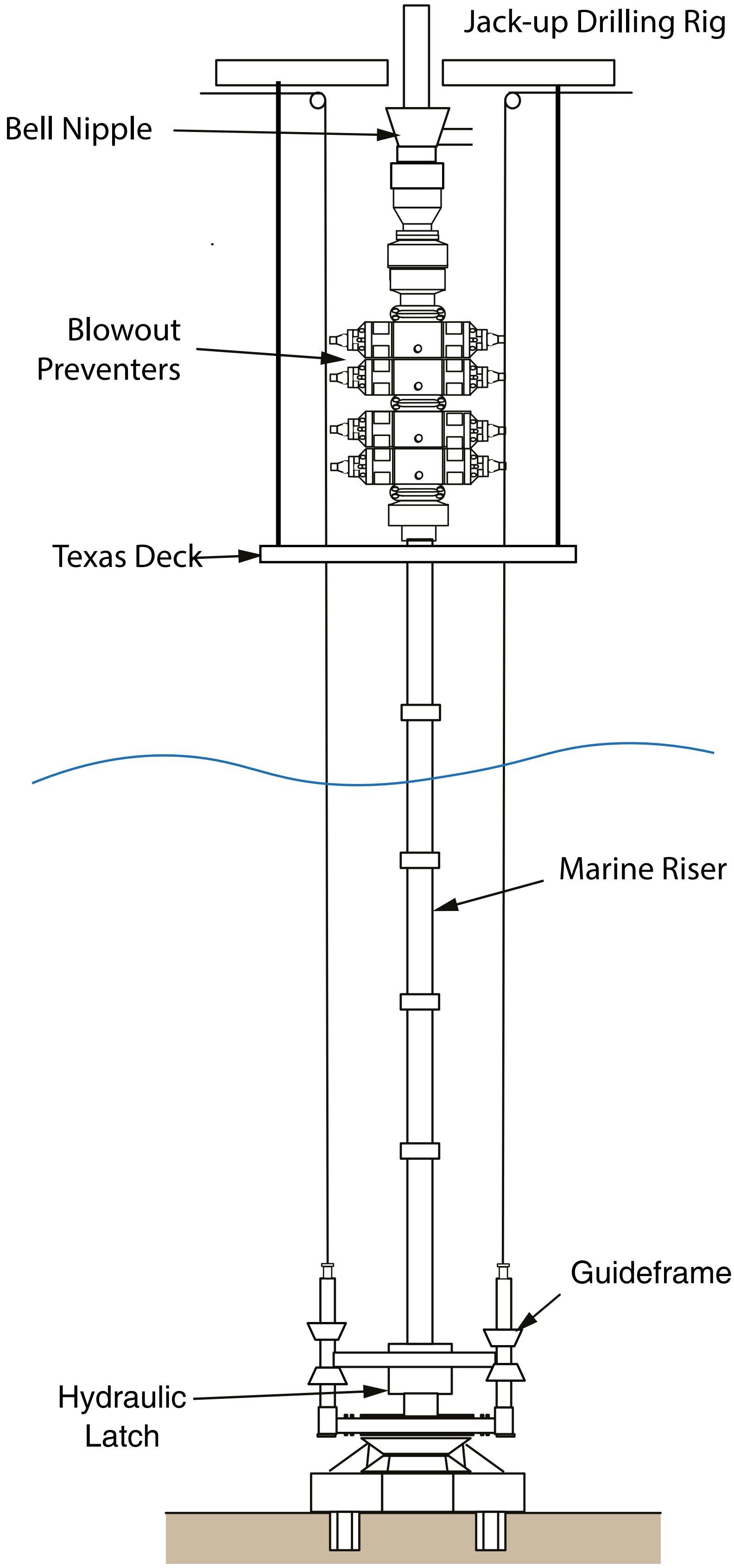

Figure 34- Running BOPs on Jack-Up Rig

Jackup BOPs and Completion Operations

Figure 35 shows the installation of a jack-up drilling rig's blowout preventers (BOPs) on top of the subsea production tree during completion operations.

Either a vertical or horizontal subsea tree can be used.

All completion equipment is sized for passage through the standard 18 ¾ inch BOP and subsea tree, used by newer jack-up drilling rigs, whereby the Cloverleaf whipstock is used to run the completion strings for each of the wells.

The completion strings are hung-off within the Cloverleaf arrangement until all of the completions strings have been run into each well. The rotatable whipstock is then removed and each of the completion strings is lifted and connected to a centralised bundle where control lines and cables are connected, tested and then landed in the wellhead before setting the production packers or, alternatively, using conventional mandrels stabbed into polished bore receptacles (PBRs) attached to the top of each pre-set production packer.

The subsea completion arrangement and trees would be similar to conventional conductor sharing arrangements, which would require design assistance from a qualified vendor.

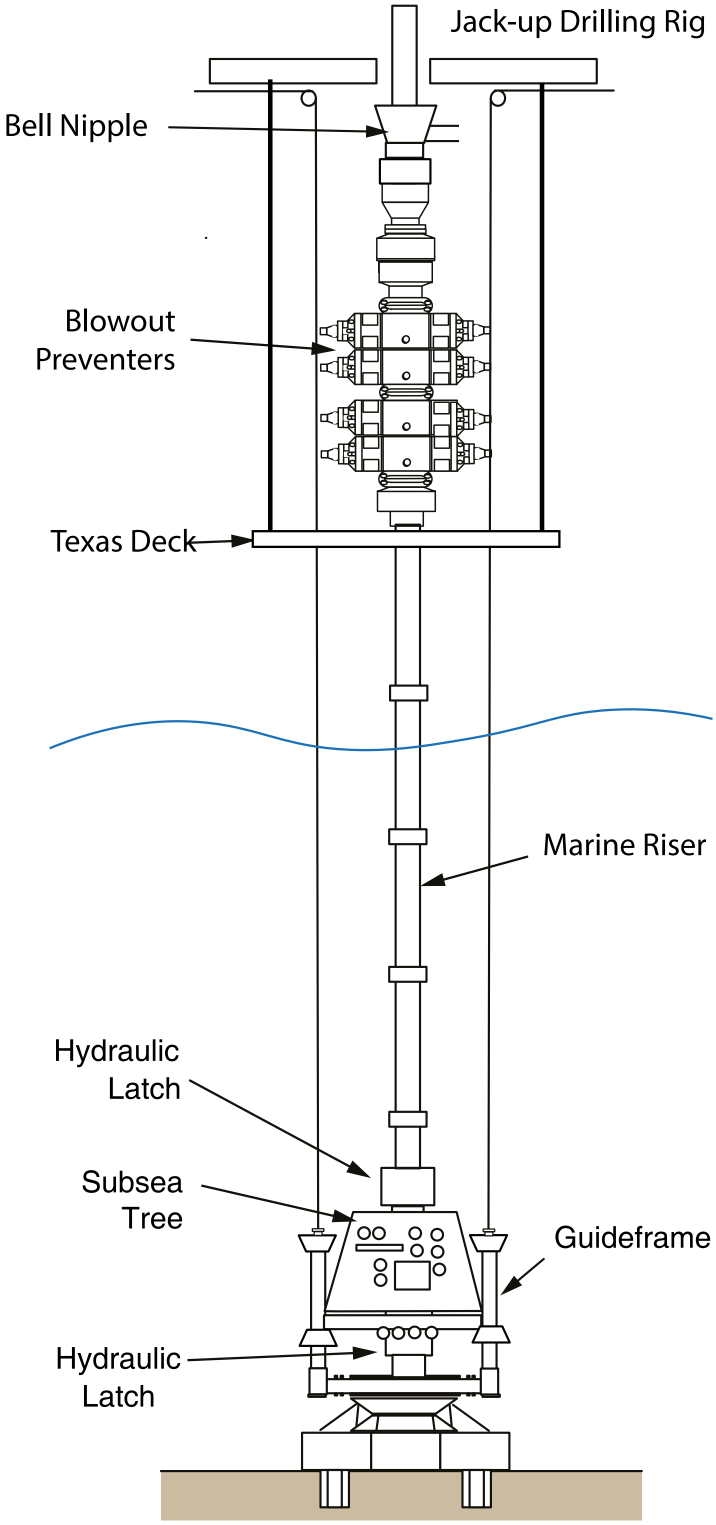

Figure 35- Running Tree on Jack-Up Rig

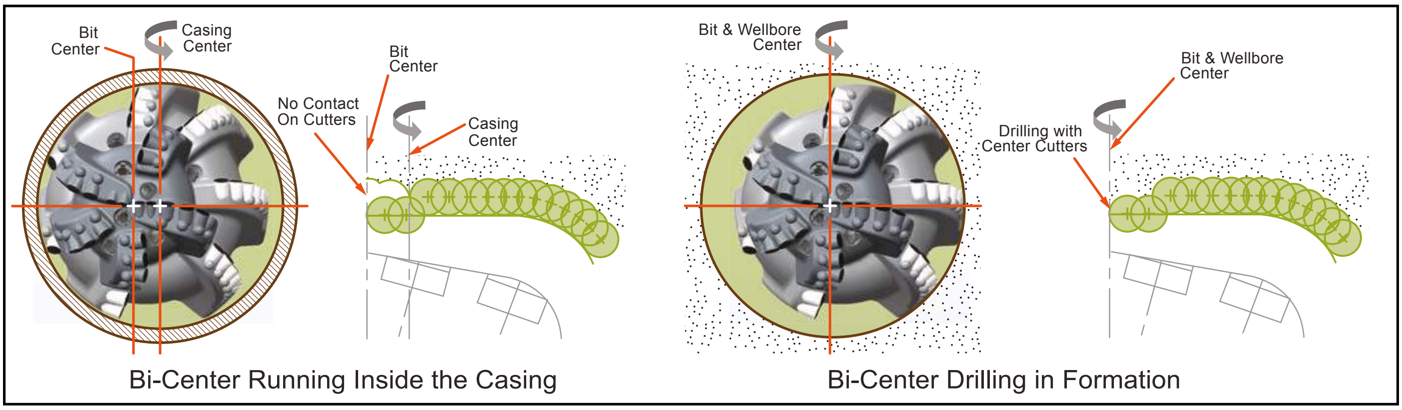

Figure 36- How a Bicentre Bit Works (Varel®, 2017)[29]

Bi-centre Bits

Figure 36 illustrates how a bi-centre bit can drill a larger diameter hole than the casing through which it passes.

Bi-centre bits are an example of how open sourcing new technology can be used to introduce new technology.

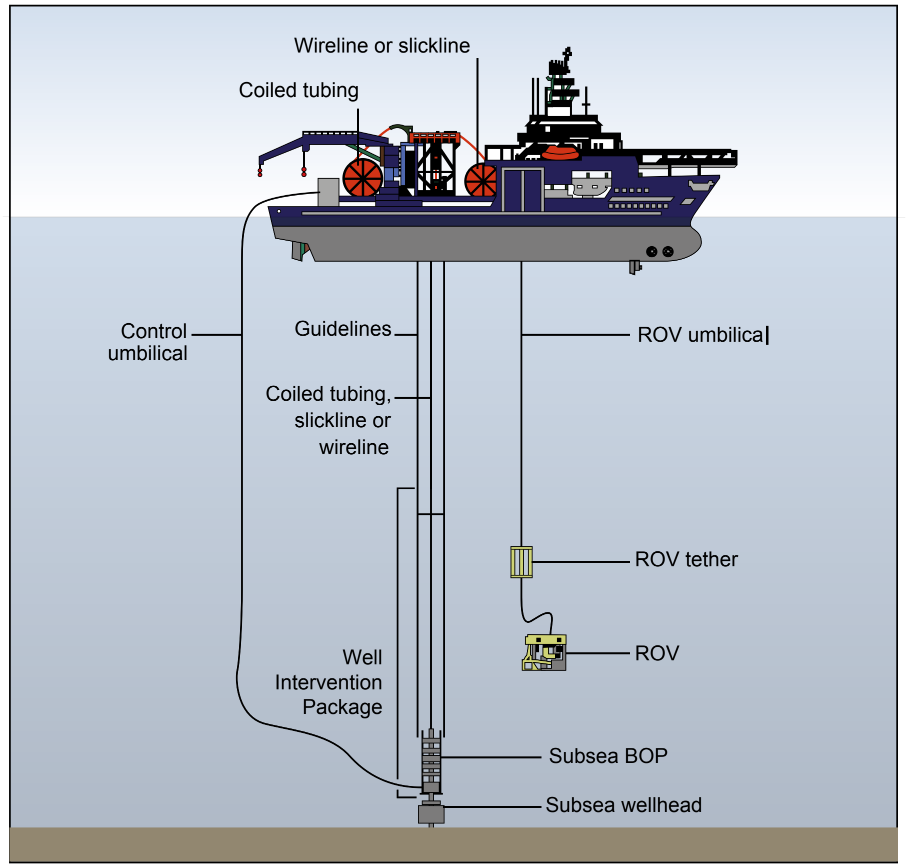

Figure 37- Rigless Light Well Intervention Vessel (LWIV) Equipment (Schlumberger)

Light Well Intervention Vessels

Figure 37 depicts a Light Well Intervention Vessel (LWIV) which can be used to intervene in subsea wells after production has started.

Oilfield Innovations' Cloverleaf technology is compatible with LWIV operations and can be used in instances where commingled flow from multiple wells in amalgamated into a single flow stream downhole or, alternatively, where multiple production strings are passed through the wellhead to separate production trees that are commingled after passing through the production choke manifold.

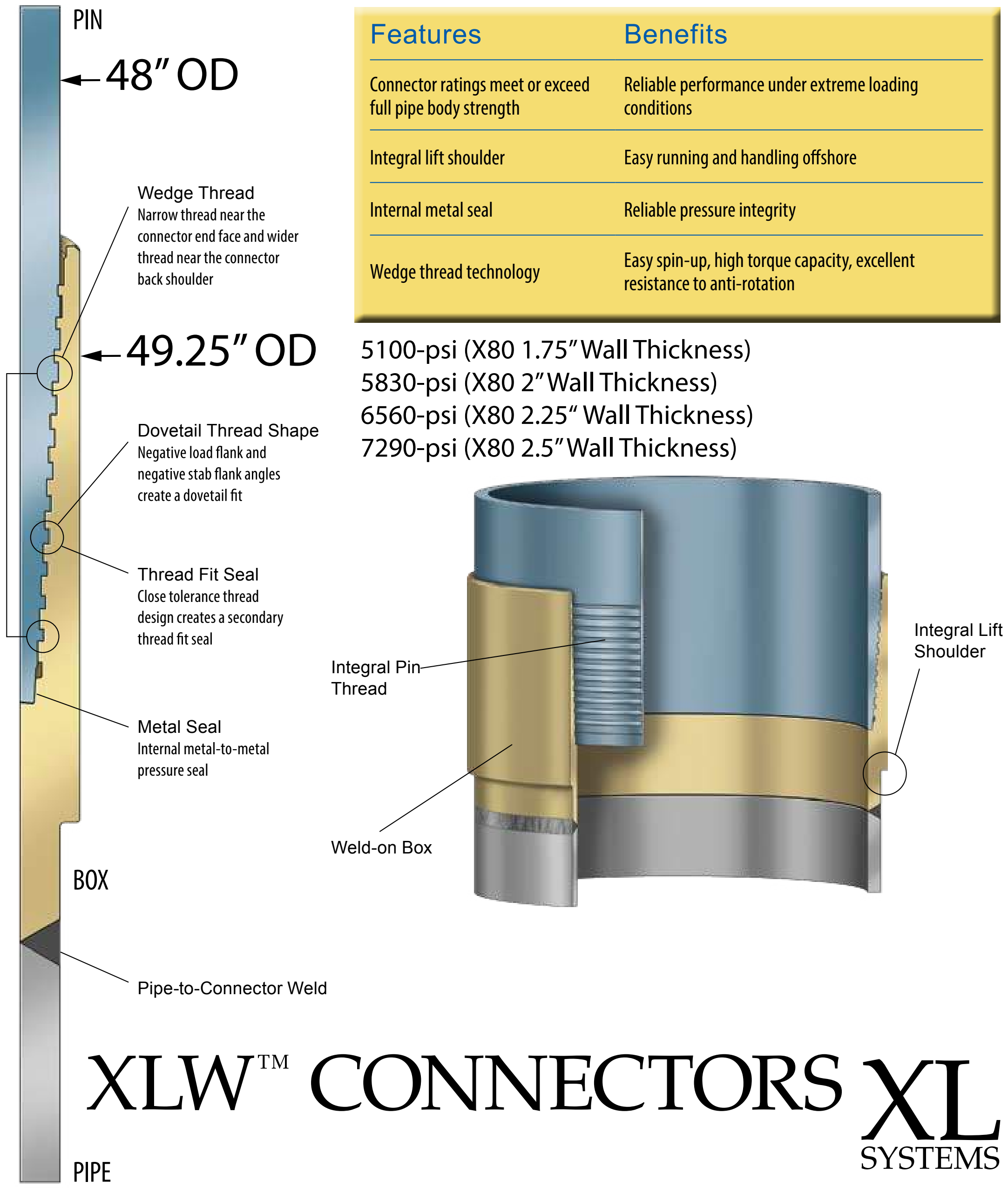

Figure 38- XLW® 48" Pipe Connector (XL Systems, 2017)[31]

Example Conductor Coupling

Figure 38 illustrates an XL Systems™ proprietary connector that is capable of being used within a Cloverleaf downhole separator arrangement.