Trans.I.Mar.E., Vol.100, pp.87–100

Development of Pumps for the Marine and Offshore Oil Industries

A. G. Sheil, HNC, CEng, MIMechE **and D. M. Manson,** BSc, CEng, MIMechE
Weir Pumps Ltd

SYNOPSIS

This paper discusses two of the major activities of pumping machinery manufacturers in support of the needs of the marine and offshore oil industries and ship and platform builders. First there is the improvement of the products for general applications where the most important features are performance, reliability and price. Secondly there are the areas requiring new and alternative technology, but still with performance and reliability as the most important criteria. The marine market for standard products is increasingly competitive and the manufacturers' opportunity to meet the challenge evolves mainly around improved production engineering and evolvement of ranges which suit modern production techniques. The general duty equipment on platforms and rigs requires pumps similar to those used on ships. The offshore oil market, however, demands additional highly specialized products in its role as an operating production and/or processing plant, as opposed to the role of a ship as a means of transport. Many of the U.K.'s offshore oil fields are now past peak production, with an increasing number of wells ceasing to flow naturally. This, combined with changes in the interpretation of regulations and the discovery of many smaller, marginal and more difficult to produce oil fields, has lead to the pumping industry being presented with a new set of pumping requirements. This paper reviews the background to and the changes that have taken place in fire pump system design philosophy and the currently installed alternative systems. It examines the development of the Weir downhole pumpset, considering its design, application and installation, as well as the unit's suitability for use in conjunction with the new 'wireline' intervention methods now used in subsea applications.

INTRODUCTION

Standard general-duty pumping equipment is required for all types of ship, offshore platform and oil rig. The pressures on manufacturing industry for higher standards of performance and reliability, coupled with lower prices, are fuelled by competition between companies, and between countries, for available business. This applies to manufacturing at all levels, including shipbuilding and pump making.

Progress in these areas is aided by improved design techniques, materials and production technology. As the cost of the product falls and the cost of the production equipment rises, it is essential to standardize to obtain greater volume production. One way of achieving this is to look at other applications and industries to obtain the best interchangeability of products.

In parallel with the development of standard equipment there is a requirement for new and alternative technology, especially in the offshore oil production industry.

As many of the recently discovered smaller marginal fields are now entering their development phase, a new generation of smaller, lighter and less expensive offshore production platforms is emerging. Changes in the design philosophy of these offshore structures has had significant knock-on effects on much of the traditional pumping equipment, none more so than fire water pumps. Currently, the most commonly used arrangement offshore, is the vertical-line-shaft bowl pump, driven by a diesel engine via a right-angled gear box. In recent years, however, a significant number of new units have been supplied where the drive system is situated remotely from the pump and head gear. These systems can be split into two types, the hydraulic-drive system and the dedicated diesel-generator-drive system.

With many of the existing offshore oil fields now past peak production, an increasing number of wells are ceasing to flow naturally. Combined with the development of smaller marginal low-energy fields, this has led to increasing use of secondary oil recovery techniques and, in particular, pumped artificial lift systems. With this has arisen the requirement for a more reliable, flexible and robust form of downhole pump. To this end a hydraulic-turbine-driven downhole pumpset has been developed.

This paper examines the background to and the development of the unit, considering its design and suitability for use, in conjunction with the new 'wireline' well intervention methods currently in use in subsea applications.

A. G. Sheil served an engineering apprenticeship with Harland Engineering, now part of Weir Pumps Ltd, covering all aspects of pump and motor manufacture. He obtained HNCs in mechanical engineering at Coatbridge Technical College and in electrical engineering at Rutherford Technical College, Newcastle. He has worked in areas with responsibility for market research, product planning, product management and sales, and he is currently General Manager of the Industrial and Marine Sales Department of Weir Pumps Ltd.

D. M. Manson graduated in mechanical engineering at The University of Strathclyde in Glasgow after serving an apprenticeship with Weir Pumps Ltd. He had extensive field experience as an Investigations/Commissioning Engineer with Weir Pumps Ltd before joining the Sales Department for the 'Weir hydraulic turbine driven downhole pump'. He was appointed as Manager for Downhole Pump Projects in 1985 and as Sales Manager for Downhole and Sub-Sea Equipment in 1987.

STANDARD PUMPS FOR GENERAL DUTIES

The general duty centrifugal pump in its various arrangements has evolved throughout this century, and in terms of the different arrangements or styles available, the efficiency of the hydraulic performance and the normal materials of construction, there has been little change over the last 20 years.

Optimization of hydraulic design features to give high operating efficiency and minimum use of power and material development for long life within the limits of acceptable cost will continue to progress, but the great majority of components will still be made from the range of iron, bronze and steel alloy materials presently available, with some use of plastics where the mechanical and thermal characteristics are acceptable.

The area of major investment of design effort and capital is in the redesign of pump ranges to obtain standardization of components across a large number of pump arrangements, and to design these to make the best use of the latest production technology. The end product of this effort will be equipment of equal or better quality and technical performance, with a greater number of possible arrangements and materials available at a substantially reduced cost.

In terms of R&D and concept development there is little that is new, but this type of development is of greater importance to the health and survival of the industry than individual new concept products or features. The degree of success in terms of benefit to manufacturers and users depends entirely on the quality of planning based on product and market research.

The centrifugal pump has a greater variety of factors affecting its design and the different sizes and arrangements required than most types of industrial machinery. Flow rate, head generated and speed are the main parameters, but many other factors including suction pressure, the nature and temperature of the liquid to be pumped and pump position/arrangement have to be taken into account in design optimization.

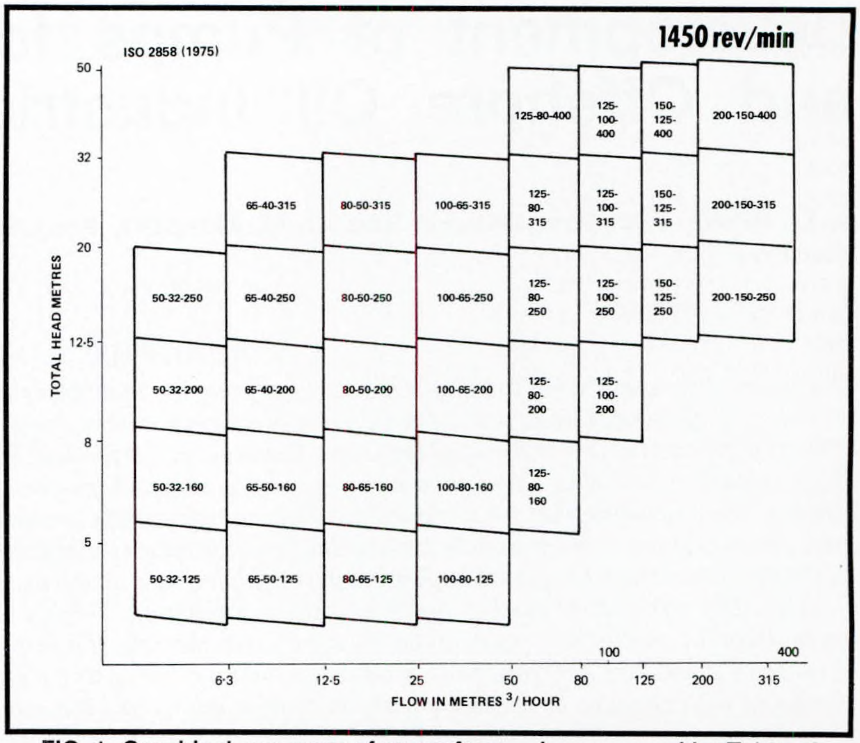

FIG. 1: Graphical summary of pump frame sizes covered by Table of nominal duty points

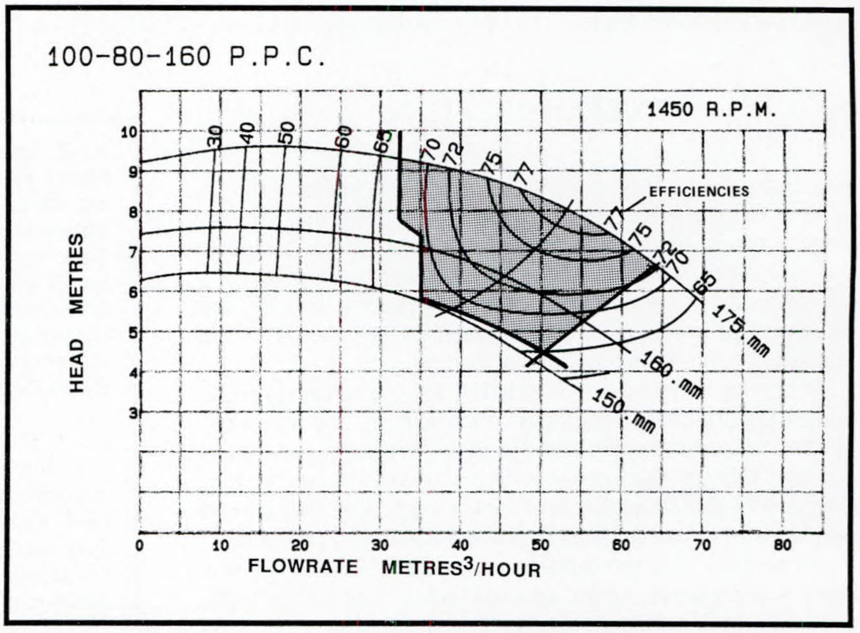

FIG. 2: Example of normal boundaries of duty coverage

To obtain the production volumes needed to justify investment in the latest production technology, the planning needs to take account of the requirements of all industries using similar pumps.

Standardization of flow, head and speed coverage has evolved for horizontal end-suction long coupled pumps for land-based general industry and for the chemical industry in particular. This incorporates a degree of dimensional standardization for the overall dimensions of the standard sizes, to give interchangeability between different manufacturers' units, but does not cover standardization of pump components, although separate standards do cover sizes of glands and mechanical seal housings.

The market for horizontal end-suction long coupled pumps offers the manufacturer the prospect of significant volume production and the basis for a comprehensive range. The International Standards Organization, a world-wide federation of national standards institutions, has issued a standard ISO 2858, which covers pump duties and dimensions and is a sound basis for coverage of a range of performances (see Fig. 1).

Pump sizes are spaced to ensure that all required technical and operational parameters can be met within the range of operation of each size. The next size is then available, also with a suitable performance, at a point before the first unit's capability will have deteriorated to an unacceptable level. Given this type of coverage planning, there is always a suitable unit to meet a particular duty.

Perhaps the major difference between the new philosophy and the old is that pumps were designed for specific duties for small market sectors, and ranges tended to have gaps and be badly spaced. It was alright if you wanted a size which was standard but if not you either accepted poor performance or paid for a special unit. Traditionally, requirements for standardization, particularly at sea where the ship had to carry spares for survival on long journeys, meant reducing the number of sizes to the point where many were operating under conditions far removed from the original design point. Whilst this would reduce the number of pump and spares sizes on the particular ship, over-standardization might create more need for spares. Pumps running under suction conditions beyond their capability, or churning at flows much lower than their normal design, are notably subject to vibration and erosion and are likely to have severely limited lives, or not to work when most needed.

As an example of overlap and interface between pump sizes, Fig. 2 shows the head and flow coverage of one size, the 100-80-160 hydraulic design as manufactured by the authors' company. The boundaries at which the next pump size would normally be used in terms of optimum efficiency and other parameters are shown and it can be seen that the optimum efficiency range of the pump coincides closely with the area of normal commercial use. Such a coverage gives the ability to meet performance requirements within the range covered in a manner which is sound in terms of all engineering aspects.

Note that the boundary parameters are not rigid, as different demands may arise in special applications, including special suction performances, wider pump flow ranges and margins for future increases in head or flow, but an even and logical spacing of frame sizes does give a better prospect of getting a 'best compromise', even on such applications. The interpretation of this coverage into an actual range, as manufactured, is shown in Fig. 3.

This example comprises 32 frame sizes, which provide a sound basis for hydraulic coverage. Such a range can be extended if required by the manufacturer. Coverage of this scope of pump range requires a high level of investment but, once made, variants incorporating some or all of the frame sizes can be developed to meet requirements of various industries and applications.

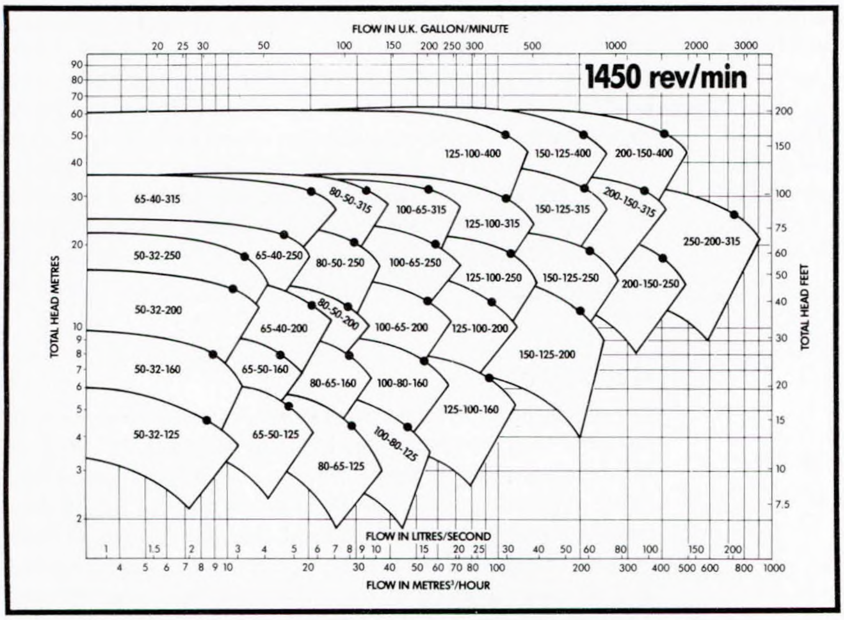

FIG. 3: Coverage of pump range as manufactured

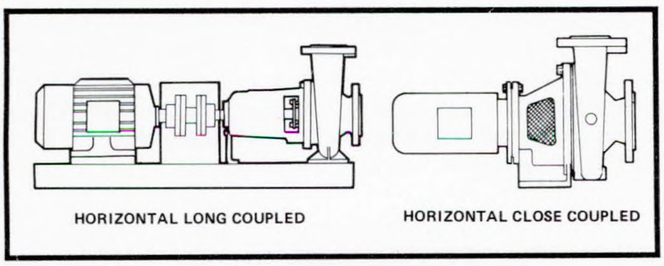

FIG. 4: Horizontal pumps

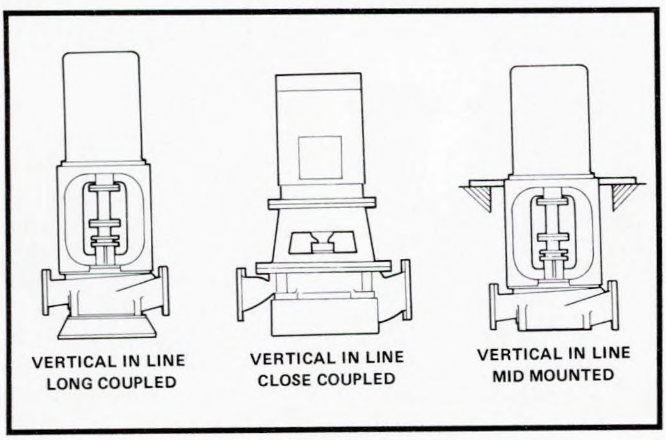

FIG. 5: Vertical in-line pumps

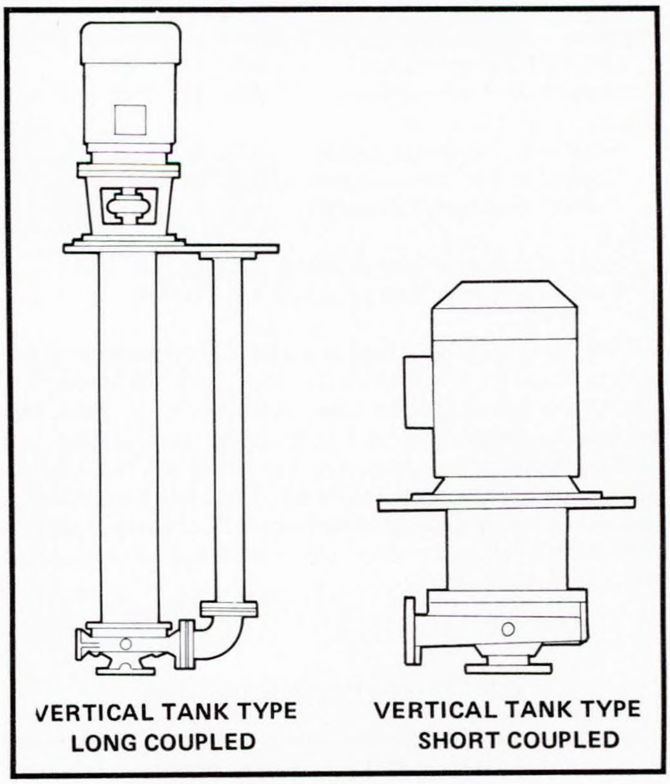

FIG. 6: Vertical tank-type pumps

Horizontal long coupled and close coupled (Fig. 4), vertical long coupled, close coupled and mid mounted (Fig. 5), and vertical short and long suspended tank types (Fig. 6) are some of the variants using the same range of hydraulics and permutations of types of seal, of open and closed impellers and of a wide range of materials, which become possible with the increased standardization, spreading the production costs across larger volumes of products. Modern machining centres give very high standards of accuracy and repeatability and are programmable to enable different product sizes to be handled as required (see Fig. 7).

The quality and reliability of units from such a range of standardized products is potentially excellent because the number of units made and tested produces a reliable data base, the volume to be made justifies good quality pattern equipment and tooling, which enhances the quality of the finished product and gives good repeatability, and operational feedback from a large product population gives the possibility of achieving long-term reliability.

The extent of component standardization will depend on the detailed construction selected by the particular manufacturer, but as an example of the potential using the pump arrangements illustrated in Figs. 4, 5 and 6, the following significant components have potential for standardization.

Component options

Impeller	-	Closed vane	A
Impeller	-	Open vane	B
Casing	-	End suction - with foot	C
Casing	-	End suction - no foot	D
Casing	-	In-line branches	E
Gland/cover	-	Packed gland	F
Gland/cover	-	Mechanical seal	G
Gland/cover	-	Wet bearing + seal	H
Neck rings			I
Renewable plates			J

Pump arrangements

Fig. 4				
Horizontal long coupled	A/B	C	F/G	I/J
Horizontal close coupled	A/B	D	F/G	I/J
Fig. 5				
Vertical in-line long coupled	A/B	E	H	I/J
Vertical in-line close coupled	A/B	E	F/G	I/J
Vertical in-line mid mounted	A/B	E	H	I/J
Fig. 6				
Vertical tank-type long coupled	A/B	D	H	I/J
Vertical tank-type close coupled	A/B	D	H	I/J

We have thus described a major development activity, which although not glamorous deals with the change of philosophy essential to the pump manufacturer to enable him to remain competitive and support the shipbuilding and platform building industries in a way which will help them to reduce costs. As such, ranges are developed on a standard basis and an increasing number of variants will become available at costs which reflect standard, rather than special, design and manufacturing processes.

OFFSHORE FIRE PUMPS

The primary functions of an offshore production platform are drilling for, producing and processing, petroleum products. Whilst it is of paramount importance that this is done in a safe manner, it must be recognized that the fire-fighting system, although vital, may not appear at the top of the list of facility priorities.

In designing the new generation of offshore structures, which are generally smaller and lighter than those of 10 years ago, it is quite possible that only limited deck space is available directly above the fire pump caissons, or that the available space is in a hazardous area. Either of the above scenarios makes the use of a conventional drive system, i.e. diesel engine driving a pump through a right-angled vertical gearbox, less practical and generally requires that the dedicated generator set/electric motor or the hydraulic motor drive systems are considered.

Also, in recent years, with the changes in interpretation of regulations governing offshore fire-fighting equipment, many of the fire-fighting systems on existing offshore installations require or have required upgrading. In this case the problems posed in finding suitable and available space can be far more acute than in the design of a new installation. In many cases the use of either of the two systems, as mentioned above, may be the only solution to an otherwise insurmountable problem.

It is unlikely that a clear-cut situation will exist regarding the optimum system and it is the responsibility of the topside facilities engineer to evaluate fully each of the systems and select the option which best suits the needs of each particular platform.

Regulations

Fire-fighting systems used in offshore installations must conform to government legislation in the form of 'Offshore Installations (Fire Fighting Equipment) Regulations 1978'. These regulations state how the various parts of the offshore installation should be protected and, as a rule, do not go into the detailed design of the pumping equipment or system, but deal in generalities, laying down constraints to ensure that most offshore fire-fighting systems conform to the same general pattern.

The regulations governing the design of the system determine the head and flow requirements of the pumpsets. In almost all cases the specification against which the fire pumps are designed, calls for the units to be compliant with API 610 (centrifugal pumps for general refinery service) and NFPA 20 (standard for the installation of centrifugal fire pumps). Since neither of these specifications was prepared with the design of

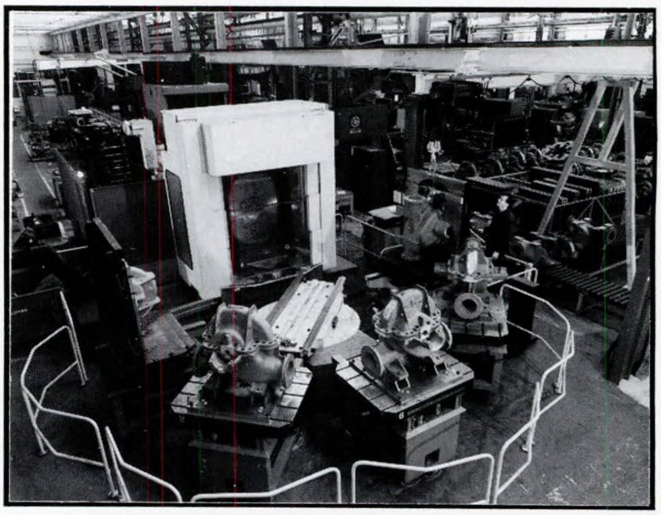

FIG. 7: Multiple pallet machining centre

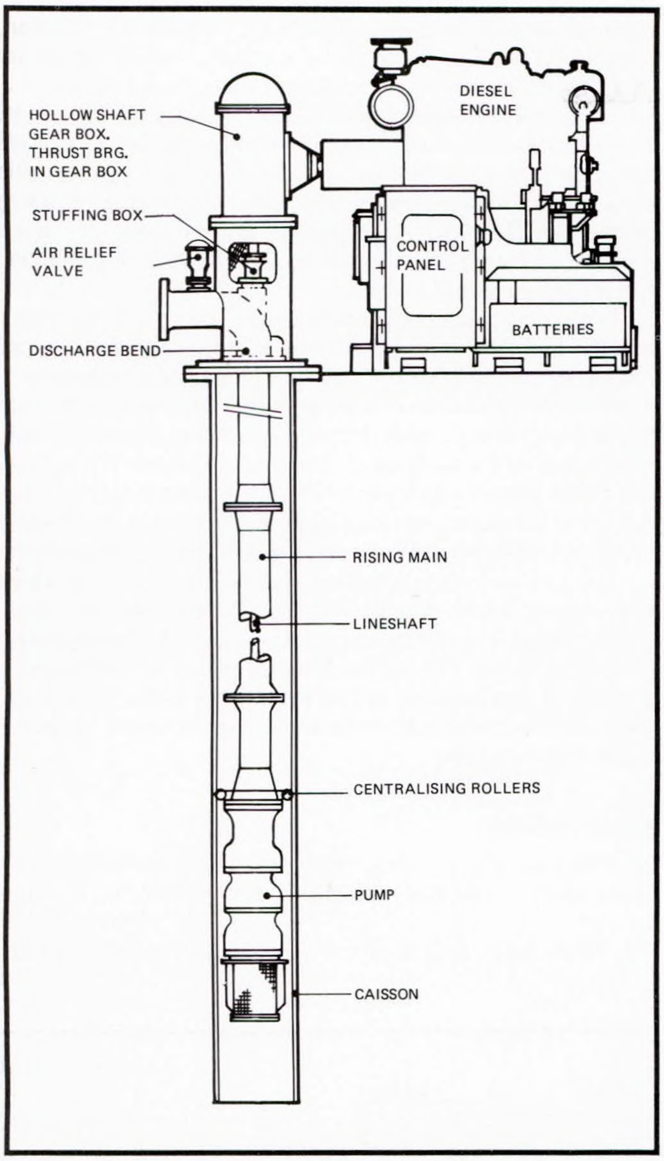

FIG. 8: Conventional shaft-driven fire pumpset

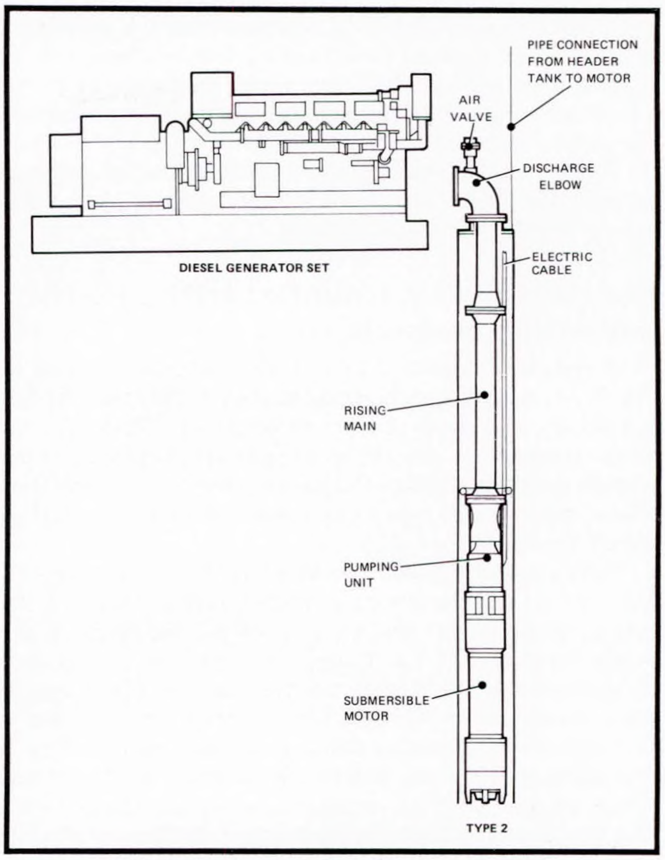

FIG. 9: Dedicated diesel generator unit

offshore fire pumps in mind, the pump vendor will be asked, in addition, to comply with specifications prepared by the contractor working on the specific topside facilities design.

Description of fire pumps

Offshore fire pumps are required to lift seawater onto the platform and deliver it to the fire-fighting system in sufficient quantity and with sufficient pressure to comply with the aforementioned 'Offshore Installation (Fire Fighting Equipment) Regulations 1978'.

The unit's mode of operation calls for long periods of idleness with short intermittent runs and, unlike other pumping plants, they experience a wide fluctuation in demand with a relatively high number of stop/starts, and of course the pumpsets are required to be totally reliable.

In the three configurations, as outlined previously, the unit will be a completely self-contained package with all the motive power being supplied by a suitably sized diesel engine rated to NFPA 20. The engine package would come complete with all necessary equipment to start and control the unit during operation.

The engine would be started by using D.C. batteries charged via the platform's electrical supply, with a back-up hydraulic or pneumatic starting system. The diesel engine and system cooling water is supplied by the fire pump via a cooling harness complying with the requirements of NFPA 20.

Conventional shaft-driven suspended units

This arrangement is as shown in Fig. 8 and consists of a vertical line shaft pump driven by a diesel engine via a right-angled gearbox. The unit is generally located on the platform's 'lowest deck' and has a suspended length of approximately 30 m for North Sea applications.

The suspended pumping unit is a conventional multistage borehole type, with a performance characteristic compliant with NFPA 20, and is capable of generating sufficient head to overcome static and friction heads whilst providing the specified fire ring main pressures. The rising main and line shaft system are supplied in sections, the length of which is determined by lateral critical speed considerations and the headroom available in the cellar deck area for installation.

The authors' company design philosophy is that the line shaft system would be designed to conform with 'stiff shaft' principles, i.e. that all lateral critical speeds will be above 125% of pump running speed. The adoption of this philosophy assists in achieving the required high reliability.

The pumpset is suspended from a soleplate onto which the delivery bend is fitted, this bend incorporating the restriction bush and stuffing box assembly to effect shaft sealing.

In this option a hollow-shaft right-angled gearbox is mounted directly above the delivery bend on a simple support stool. This gearbox houses the pump and line shaft thrust bearing, and the axial position of the impellers, allowing for any line shaft 'stretch', is set by a simple adjusting nut on the end of the pump line shaft. An alternative using a solid-shaft gearbox with a separate thrust bearing may be considered.

The drive to the gearbox comes from the diesel engine via a flywheel-mounted clutch coupling and a splined carden shaft. The clutch reduces the load on the engine starting system while the splined carden shaft caters for any relative movements between the diesel and gearbox shafts caused by thermal growth vibration or torque reaction.

Dedicated diesel generator set driving electric submersible pumpsets

A typical arrangement of this configuration is shown in Fig. 9 and consists of a wet winding submersible motor driving a multistage borehole pump compliant with NFPA 20. To ensure adequate cooling the motor is located below the pump with motor shaft sealing effected by a mechanical seal. For ease of assembly the pump and motor shafts are connected by a muff-type coupling.

Submersible electric motors used in conventional applications are fitted with a flexible bellows piece at the bottom of the motor, which caters for any expansion of the motor fluid caused by heating. To improve the motor's reliability, substitution of this bellows piece and monitoring of the pressure-containing capability of the wet winding motor is recommended. To achieve this a small bore pipe (1/4 inch) is connected to the motor and to a header tank at the surface, which allows condition monitoring using the header tank's fluid level, and provides a positive pressure on the wet winding motor mechanical seal, thus precluding the ingress of sea water in the event of mechanical seal failure.

The rising main will be flanged with the section length being determined by the available installation headroom. Generally, the electric cable is clamped to each section of rising main. To minimize lateral movement of the pumpset within the caisson, particularly during installation, guide rollers are normally fitted immediately above the pump.

The unit is suspended from a soleplate onto which the delivery bend is fitted and the soleplate is secured to the caisson by foundation bolts. The motor power supply cables are hard wired, i.e. coupled directly, to the remotely located dedicated diesel generator set. This hard-wired system greatly reduces the starting kVA requirements of the system thus providing system soft start, i.e. as the diesel generator set is started the generator and motor run up to speed together.

Hydraulic-motor-driven suspended units

Fig. 10 shows this option in its 'split' configuration used to reduce the hydraulic power transmission losses. The required generated head is 'split' between the suspended unit and the topside booster pump. (Units have been supplied where all the head is generated in the suspended pump, but this is the exception rather than the rule.) The suspended unit illustrated is a single-stage bowl pump directly coupled to a hydraulic motor.

As with the previous two options, the pumpsets would be sized to comply with NFPA 20. The residual pump thrust is carried by the thrust bearing located in the hydraulic motor. As the sealing of the oil/water interface is vital to the reliable operation of the unit, a tandem seal arrangement is used with a barrier chamber between the seals. A small bore line (1/4 inch) is taken from this chamber, run to the surface and connected to a header tank. This ensures that the pressure in the chamber is always greater than sea water pressure, and consequently, in the unlikely event of seal failure, system leaks are oil to water.

Tank-level monitoring confirms the integrity of the seals and the hydraulic oil system. The surface-mounted diesel-driven hydraulic-powered oil pump and the submerged hydraulic motor can be of either the triple-screw or swash-plate piston pump design, with the power oil being supplied to the submerged motor via a concentric tubing system. The supply and return pipework are joined at spiders located between the rising main flanges, with the length of the rising main sections being determined by the available installation headroom.

The surface hydraulic power system is self-contained and skid mounted with the diesel-engine-driven hydraulic fluid supply pump and all the necessary tanks, oil filtration and cooling systems. The surface booster pump, to increase the pressure to that required in the fire main, is a standard single-stage double-entry axially split unit driven from the back end of the diesel engine.

Conclusions

When finally selecting the best option for a particular application, a great many factors need to be taken into account.

1. Reliability. It is accepted that the most reliable and the

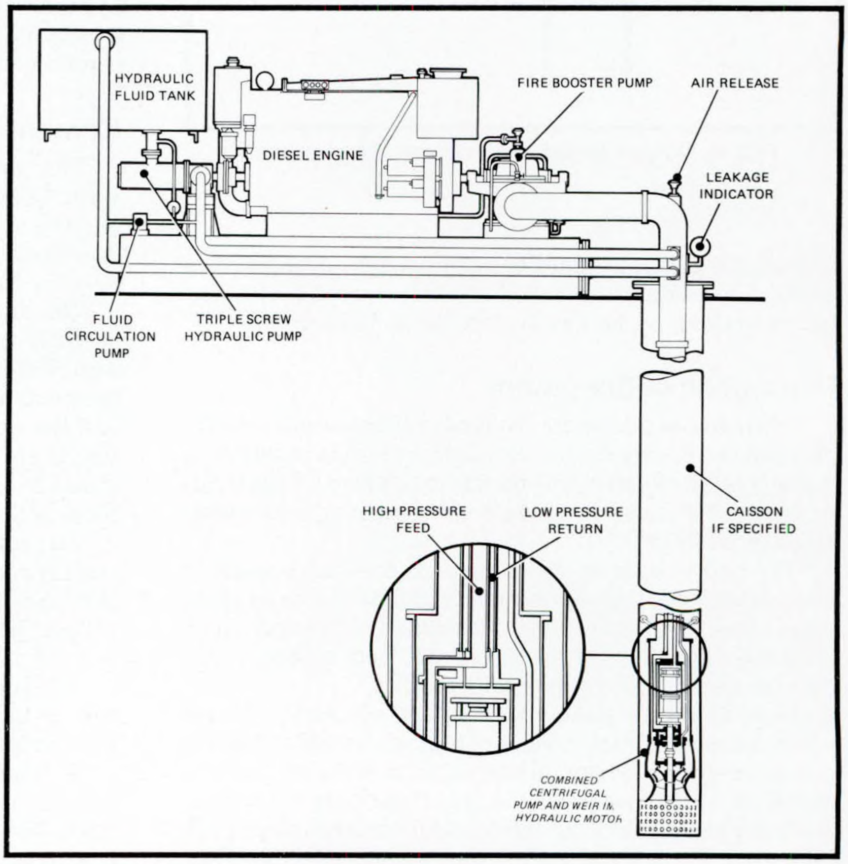

FIG. 10: Hydraulically driven fire pumpset

FIG. 11: 16,000 barrels/day, 315 h.p. downhole pumpset

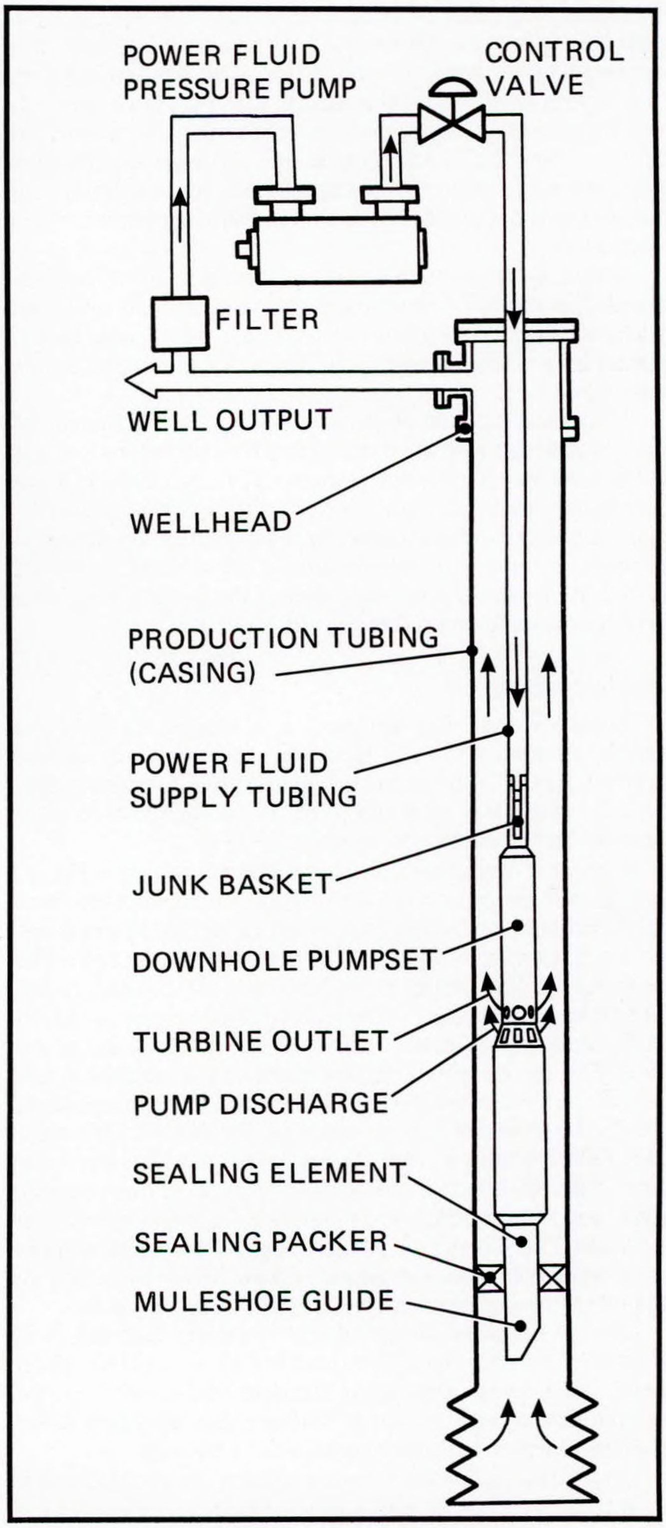

FIG. 12: Downhole pumping system

simplest system is the conventional line-shaft option with the hydraulic drive a close second, and the electric dedicated generator set third.

2. Weight. In the design of offshore structures minimizing the installed weight is extremely important. As with reliability the line shaft option is best, taking up the least space with the minimum weight. The electric dedicated generator set option occupies marginally more space with a slight increase in weight over the line-shaft system, but is considerably lighter and less bulky than the hydraulically powered option.

3. Efficiency. Again, the line-shaft option comes out best, with an efficiency of approximately 80% with the electric pump at 72% and the hydraulic pump option at 76%.

4. Cost. As with the above factors, the line-shaft pump proves generally to be the least expensive. The electric pump is a close second with the hydraulic pump coming an expensive third.

5. Positional flexibility. Here the hydraulic option comes into its own with its ability to be placed almost anywhere on the platform. The electric option, although flexible, has a greater number of constraints placed on its location. The conventional line-shaft option has virtually no flexibility with regard to its location and must be sited directly above the fire pump caisson.

In reviewing the above, unless positional flexibility is of prime importance, the preferred option will, in most cases, be the conventional line-shaft drive. However, each offshore installation is unique and the selected fire pump option will depend greatly on the importance attached to any of the foregoing or other factors.

DOWNHOLE PUMPING

General

As existing oil fields become depleted with increasing watercuts, and many of the new fields currently being discovered having insufficient natural drive to afford free flow production at the required volumes, artificial lift is becoming more extensively used. With substantially lower oil prices prevailing, it is now more important than ever that the selected method of lift is both reliable and provides the necessary flexibility of performance to ensure production targets are met throughout the operating life of the field with the minimum number of well workovers.

Whilst the abovementioned facts are significant in land-based applications, they have a far more marked influence when offshore production systems are being considered, particularly when evaluating subsea artificial lift production systems.

With these considerations in mind, and taking account of their experience with the existing artificial lift methods of gas lift and electric submersible pumps (ESPs), two major U.K. oil companies, together with the U.K. Department of Energy, approached the authors' company to develop an alternative to, or improve existing, pumped artificial lift systems. The result of this study was the development of the hydraulic-turbine-driven downhole pump (see Fig. 11).

Basic system

Since the unit was designed as a flexible, reliable and smaller alternative to ESPs, the applications for which it can be used are similar, with the exception of high-temperature applications where the hydraulic unit, in its standard form, is suitable for operating temperatures of up to 200 °C.

The basic downhole pumping system is shown in Fig. 12 and, as will be mentioned later, there are innumerable variations on the same theme. The power fluid is bled from the well production line and fed through cyclone separators, if required, to achieve the desired level of filtration of 100 p.p.m./100 μm. The power fluid passes to the surface charge pump, and from there, through the control valve or choke down the power supply tubing on which the downhole unit is suspended, and into the turbine. When the useful work has been extracted from the fluid it exhausts into the annulus. The downhole pumpset is installed by using a conventional packer and takes its suction from the well, it then increases it in pressure to overcome the static and friction heads and to provide the required wellhead pressure. The produced fluid discharges from the pump ports to co-mingle with the turbine exhaust and return to surface via the tubing casing annulus and so begin the cycle again.

A significant advantage of this system is that well fluid treatment (i.e. chemical dosing) can be carried out at downhole pump discharge by introducing the required chemicals into the turbine power supply fluid at surface, thus affording easier fluid production and added protection to the well.

It is not proposed to review completely the detailed design of the unit in this paper, although it is worth pointing out a few of the design features unique to the hydraulic-turbine-driven downhole pump. Referring to a basic sectional arrangement sketch of the unit shown in Fig. 13, the power-producing section of the turbine contains blading of the 50% reaction design, incorporating a series of stationary and moving blades of similar chord shape. Use of this concept gives freedom to select operating speeds which are typically 11, 000 rev./min. By using high rotational speeds, the turbine lengths are significantly reduced, for example, the power-producing section of a 260 kW turbine, as shown in Fig. 11, would be approximately 0.5 m. Pump length is also dramatically reduced. By increasing the rotational speed 3-fold the number of pump stages decreases 9-fold.

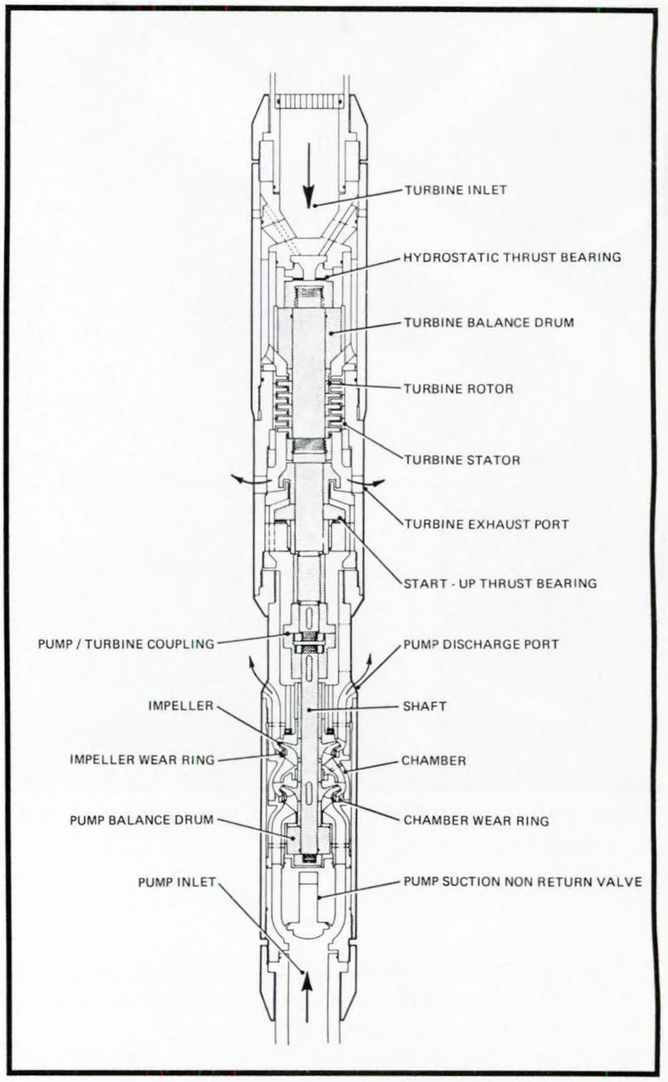

FIG. 13: Sectional arrangement of downhole pump unit

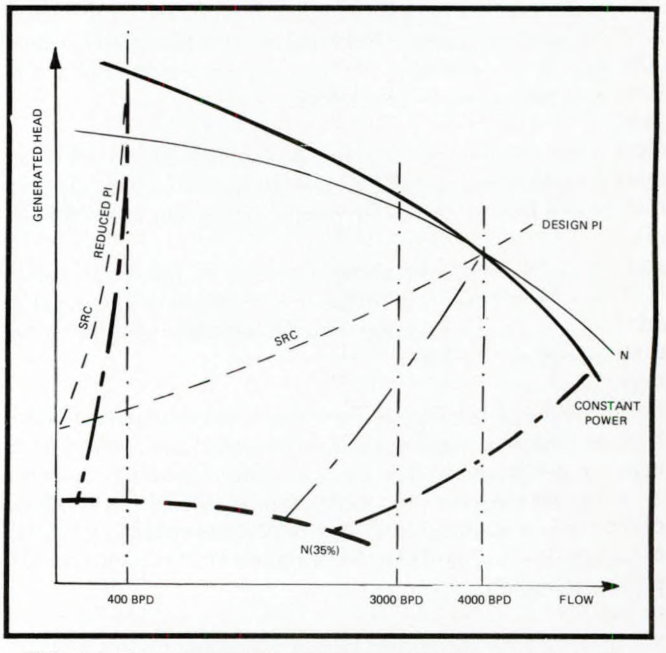

FIG. 14: Pumpset performance operating envelope for 4000 barrels/day

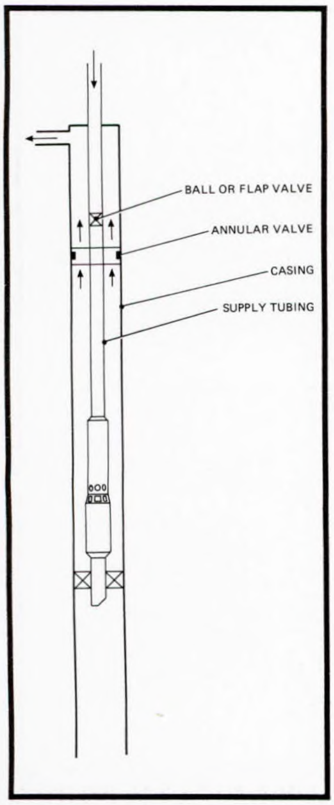

FIG. 15: Conventional onshore completion

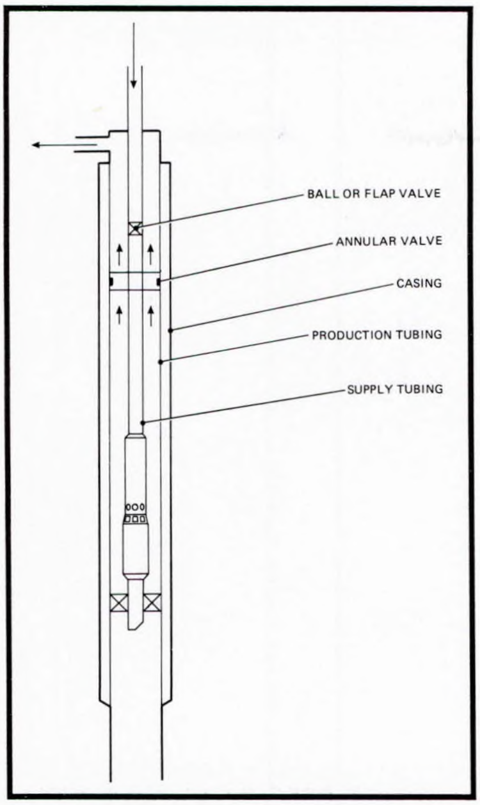

FIG. 16: Conventional offshore completion

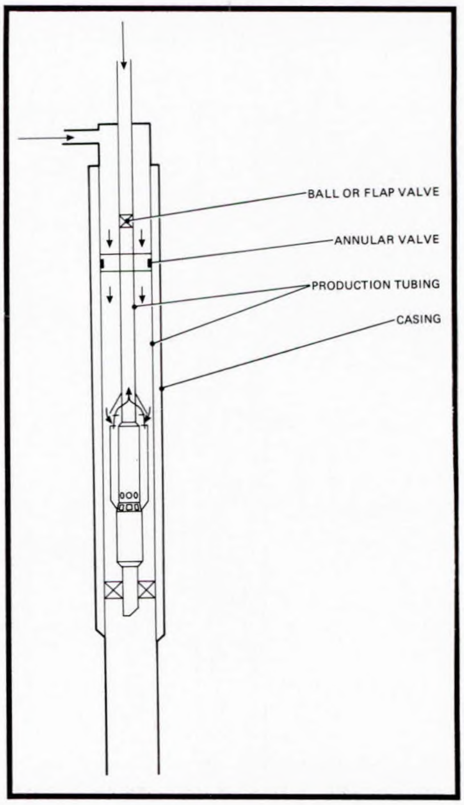

FIG. 17: Reverse offshore completion

The materials of construction used for the downhole pumpset, Duplex alloys for pressure-containing and hydraulic components, Stellite 6 for the turbine rotors, stators and parts subject to abrasive wear and K Monel or Inconel 625 for the shafts, have been selected by using the experience gained on similar pumping applications within the oil industry. They are particularly suited to the highly saline, harsh, aggressive and corrosive environments experienced downhole, where significant quantities of dissolved solids exist and/or where a high level of H_2S is present. These high-grade materials can be used cost-effectively because of the significant reduction in unit size. For example, the hydraulic-turbine-driven downhole pumpset is approximately one-tenth the length of an equivalent electric submersible pump. Recent field information indicates that a current installation is experiencing H_2S levels of approximately 200 p.p.m. Use of lower-quality materials in this type of application can only lead to severe corrosion in an extremely short time, with resultant premature equipment failure.

When designing the interface between the drive unit and the driven unit, particular attention was paid to the potentially troublesome area of mechanical sealing. This is of critical importance, particularly in applications where it is anticipated that the well will produce significant quantities of sand. As can be seen from Fig. 13, the arrangement used completely eliminates all mechanical seals.

A further advantage of this design is that it allows a quantity of the relatively clean power fluid to be bled off prior to being exhausted into the annulus. This spent power fluid is fed via the pump casing/bowl annulus into the main journal bearings of the unit, which ensures that these journal bearings are flushed with clean fluid and always operate in the hydrostatic mode, thus ensuring a stiff and well-supported rotor. With this design, and using the materials described previously, we would not profess to have eliminated the problem of erosion or failure caused by sand production, but with proper selection of the unit, the pump is given the best chance of survival whilst operating in an extremely harsh and aggressive environment.

The pumpset is fitted with a 'start-up thrust bearing'. This handles the thrust loads experienced during 'start-up' and 'run-down' and has proved particularly effective. Field experience has shown that over a 6 month period, when a unit was deliberately stopped and started in excess of 400 times, the wear on the start-up bearing was approximately 10% of that allowable, and on the 'working thrust bearing' neither wear nor indeed surface contact of any description was evident.

The axial balance of the unit whilst operating is achieved by the use of two conventional balance drums, one located in the pump and the other in the turbine, with the residual thrust being absorbed by the hydrostatic thrust bearing located at the top end of the turbine. The use of this method ensures that satisfactory axial balance of the rotor always exists throughout the entire range of operation.

Fig. 14 illustrates the performance flexibility of the pumpset, the operating envelope of which can be broadly described as being from 10 to 130% flow, with a speed range of down to 35%. The required output from the well is achieved by adjusting, at the surface, the pressure and flow of the power fluid being fed to the wellhead. Flexibility in performance is vital, not only to cater for the changing production requirements of the field, but also to match the changing well performance over the installed life of the unit.

This wide flexibility in performance was put into practice in an installation where, because of changing well conditions, the well output fell from 4000 barrels/day to 400 barrels/day, later recovering to approximately 3000 barrels/day. This fluctuation in well output was mainly a result of increasing and

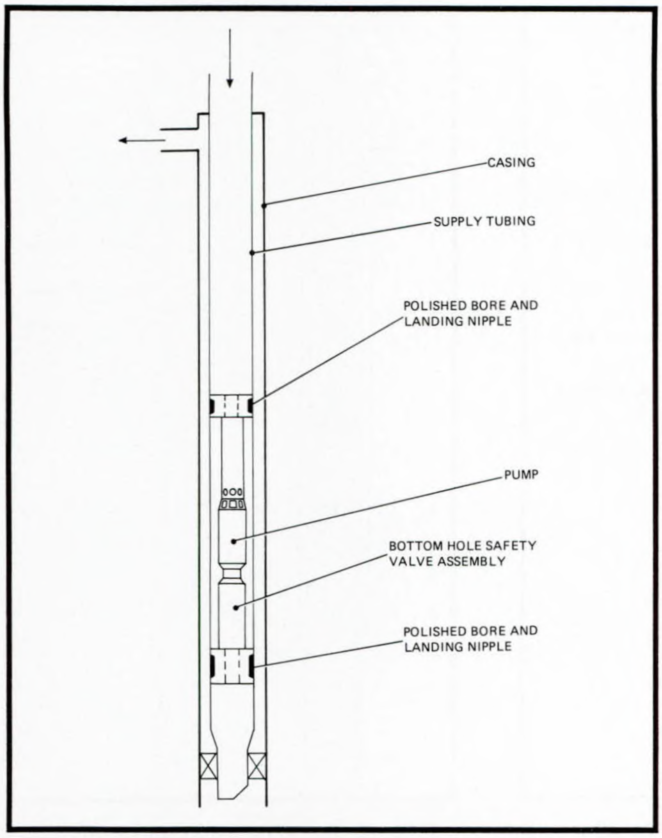

FIG. 18: Conventional wireline completion

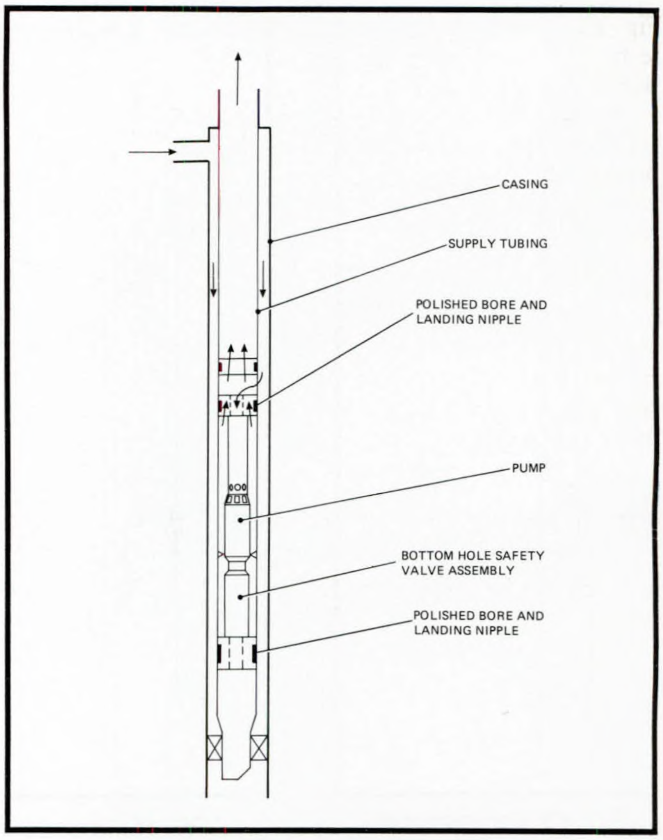

FIG. 19: Reverse wireline completion

decreasing well performance, with the quantity and pressure of power fluid being fed to the downhole machine to all intents and purposes remaining constant. The downhole pumpset was, therefore, absorbing all the hydraulic power being fed to it, increasing and decreasing in speed, and thus maximizing the well output for the given available power.

Power fluid systems

There are a wide range of possible alternative power fluid systems, and the basic system discussed previously uses a dedicated charge pump, i.e. one charge pump driving one downhole pump. Depending on the system, however, it is possible to drive two, three or four downhole pumps from a single charge pump, or indeed to use high-pressure fluid from an existing source, i.e. an injection manifold. The power fluid may be degassed oil, produced water, a mixture of both, or suitably treated sea water.

Completions

As stated earlier, the completion designs which can be used for the Weir system are many and varied and will be largely dependent on the location, local legislation and operating company policy or preference. This has been borne out by the many completion designs used for the units supplied to date.

Fig. 15 shows the conventional completion suitable for onshore use, with operation as described previously. It is this design which has been, or will be, used on the majority of the units supplied to date. Its installation is simple and quick and it is the least expensive of the completions examined.

For use in an offshore environment, or a location where hydrocarbon flow in the casing annulus is not permitted, it is proposed that an extension to the above is used, namely the installation of a concentric production tubing string, shown in

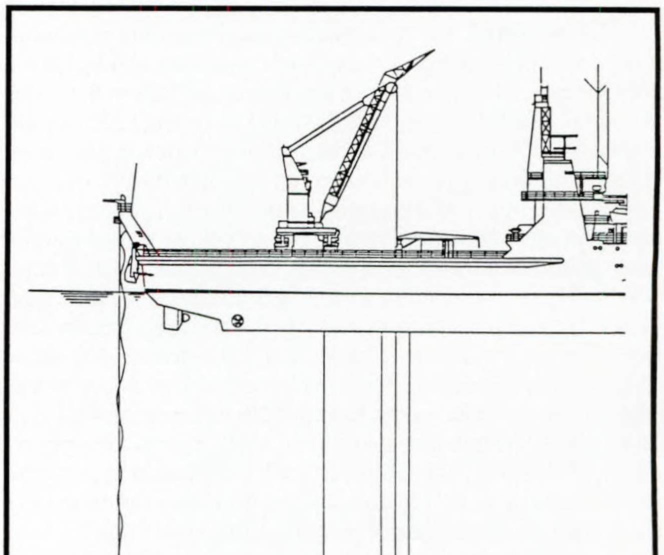

FIG. 20: Subsea wireline system

Fig. 16. In many instances this is the least expensive of the technically acceptable solutions available for the well completion design.

Frequently, production, operations or engineering personnel prefer to limit the path of hydrocarbons to a single production string. In this case, simply by use of a flow crossover, the paths of the power fluid and produced fluid are reversed (see Fig. 17).

This brings us to the next logical step in completion design, which is 'wireline'.

The previously discussed completions have all been tubing conveyed. This necessitates the use of an expensive workover rig to remove the pumpset from the well, and requires that the well be killed prior to any work being performed in pulling the pumpset from the well. Despite the fact that the unit is designed for longevity, it is still important that the intervention method should be as simple and inexpensive as possible.

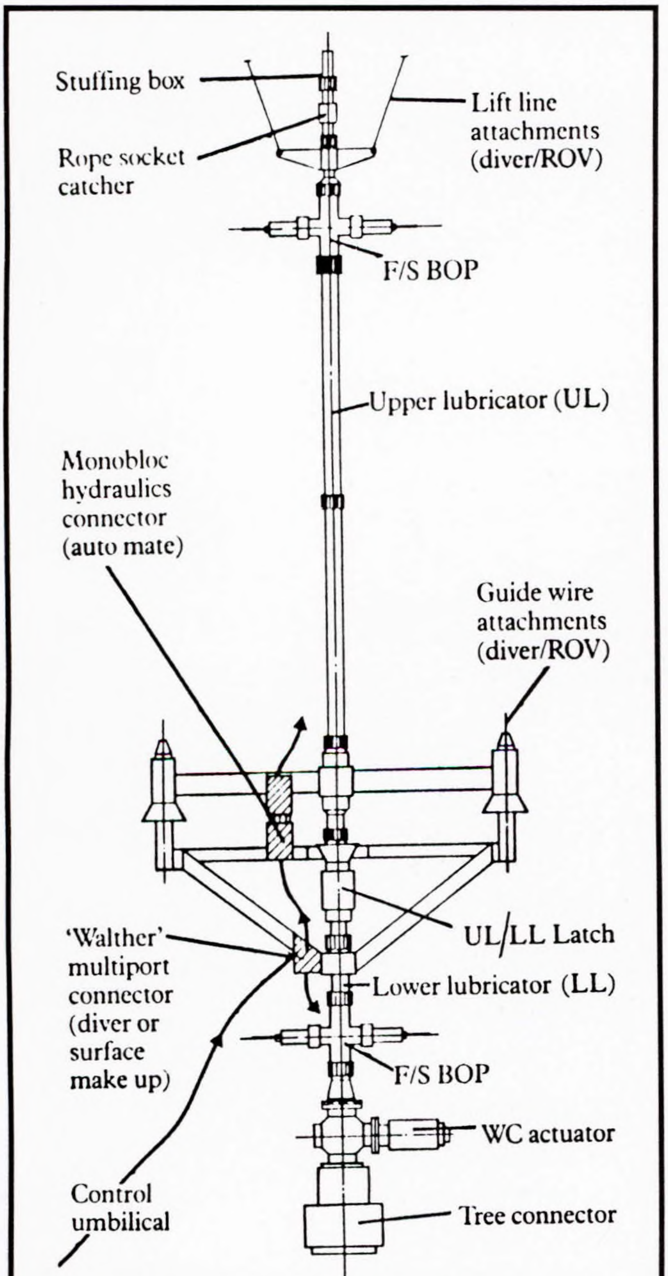

FIG. 21: Subsea lubricator stack

Taking advantage of the significant size and weight reductions achieved in the design, and whilst working in conjunction with various operators and service companies, a completion design suitable for 'wireline' installation and retrieval has been developed.

The completion uses standard wireline tools and completion components and has been developed in two basic forms.

1. Using the standard downhole unit with the conventional flow paths, i.e. power down the centre tubing with the produced fluid and exhaust turbine fluid co-mingling and returning via the tubing/casing annulus (see Fig. 18).
2. Using the standard downhole unit with a 'flow crossover' fitted to the turbine inlet. This arrangement uses an additional 'polished bore' but allows the fluid flow paths to be reversed and generally provides a more efficient production system to that described in 1 above by making best use of the areas to flow (see Fig. 19).

The length of the complete pumpset is approximately 12 ft, which includes the flow crossover mentioned in 2 above. It may, therefore, be installed in either configuration in the well by using a conventional wireline set up with standard lubricator, running and pulling tools, etc. With the pumpset weighing only approximately 400 lb, it can be run into or pulled from the well on 'slick line', thus eliminating the problems associated with the more difficult to run braided lines.

When using this design of completion, to afford protection to the well, a 'deep-set safety valve' is used. The valve is generally set by using wireline below the pump. Several valves are currently available on the market to perform this duty and the actuating force and mechanism vary depending on the design and manufacturer selected.

With the increasing use of subsea production systems, the choice of wireline as a well intervention method is becoming increasingly popular, particularly with the development of subsea wirelining using diving support vessels (DSVs). This technique, as can be seen in Fig. 20, involves the use of a DSV to replace drilling rigs or semi-subs, which are more expensive to hire and time-consuming to mobilize.

Describing the system illustrated in Fig. 21 briefly, the lubricator stack is deployed directly onto the subsea tree, negating the need for a riser. The wireline winch, control system, handling system and controls for the eyeball ROV are all located on the DSV. The DSV is connected to the stack via control umbilicals, guide wires and wireline. The stack has two main parts, the top part shuttles to and from the tree/vessel transporting wireline tools. The bottom stack connects to the subsea tree using the client's own workover tree connector. In the event of an emergency, all connections between the surface vessel and subsea tree are designed such that they can be quickly severed.

Conclusions

Since its inception, the hydraulic-turbine-driven downhole pump has proved that it does and will solve many of the pumping problems associated with producing high-volume wells by artificial lift. There is no doubt that by making use of the above intervention system, combined with the hydraulic-turbine-driven downhole pumps, pumping as a form of artificial lift on subsea production systems can now be considered as a practical, and indeed attractive, method of producing/-developing remote subsea wells.

ACKNOWLEDGEMENTS

The authors would like to thank the Board of Weir Pumps Ltd for permission to publish this paper.

BIBLIOGRAPHY

1. D. Manson, 'Artificial lift by hydraulic turbine driven downhole pumps - its development application and selection'. 1986 SPE Meeting, Beijing (March 1986).
2. G. S. Borland and A. Greig, 'Fire pumps for the oil and gas industry', Fluid Machining for the Oil, Petrochemical and Related Industries, The Hague (I. Mech. E., May 1987).

Discussion

D. NICHOLAS (British Pleuger Submersible Pumps Ltd): I congratulate the authors on the informative paper, particularly the brilliant hydraulic downhole pumping system.

I, however, question the overall conclusion that the most reliable system for Offshore Fire Pumps is line shaft, then hydraulic drive, then electric dedicated generator, in view of our experience with the 420 h.p., 3300 V units, which are on each of four major offshore platforms (supplied 1973/1975) with no major replacements. Each platform has been recently updated by the addition of 750 h.p. electro-submersible units.

We have in fact supplied a number of units offshore as temporary fire pumps due to in-service failure of line shaft pumps.

Recent developments in the design philosophy of Shell Kittiwake were summarized as 'Such is the level of confidence in this approach (high-integrity power generation), that a combined cooling and fire water-pump system is also electrically driven rather than being driven by traditional diesel.'

J. K. GREEN (Worthington Pumping Systems): Mr Manson, I was very interested in the downhole pump with which I was familiar in principle but not in detail. Could you please say a few words about its relationship to the more widely known sea water injection pump? Does it replace or complement it?

A. E. SMITH (Hamworthy Engineering Ltd): ISO 2858, and equivalent British Standard (BS) 5257, define major dimensions, including branch nominal bores. In considering the range graph shown in the authors' paper, some possible problems in adopting this standard are exposed, particularly if operation on 60 cycle supply is considered to be distinct from the 50 cycle supply shown, increasing flow by a factor of 1.2.

Discharge branch velocities become high by any criteria, for the 200–150 series, 7.5 m/s at the apparent best-efficiency point. Normal practice would be to restrict velocities to no more than 3.65 m/s, BS MA 18 gives typical guidance.

The particular pump characteristic drawn (Fig. 3), shows that, for flow rates of up to approx. 70% of BE flow, the head exceeds closed-valve pressure, i.e., the characteristic would be described as unstable.

Again from Fig. 3, the power curve for the pump can be deduced, which shows a steadily rising curve with no apparent peak. Motor ratings are often specified to be sufficient to cover the peak of the power curve, i.e. non-overloading; such a steadily rising power curve leads to installation of excessive motor sizes.

Could the authors comment on the significance of these factors, and whether a pump design based on an analysis of marine market needs, would produce a more optimum solution for the user?

J. CRAWFORD: The authors are to be congratulated on a very interesting and well-presented paper. Such a presentation, however, leaves those attending with very little to discuss/question, as most comments had been adequately covered in the presentation.

I would, however, ask the authors to explain the reference to the junk basket shown in Fig. 12 of the paper, it being noted that filtering arrangements are provided in the power take-off from the well output delivery line. Is this item a requirement as the result of previous experience and is it, as would appear from Fig. 13, part of the pump unit?

With reference to the filter unit shown in Fig. 12, is it concluded that this will be of the Duplex type, thus allowing a regular change-over of filters without shutdown of the power supply to the pumps?

Authors' reply

In answer to D. Nicholas: In common with British Pleuger, we too can point to a number of installations of large submersible pump sets that have operated perfectly for a long time, but there are a number of points that should be noted.

Not all lineshaft pumps are the same and it is wrong to point to a particular installation which has bad experience. Before commenting, we would have to know a number of things about the pump design, i.e., type of bearings used, an enclosed or open lineshaft, a stiff or flexible shaft design, etc.

The Shell Kittiwake decision to specify electric submersibles was taken for a number of reasons, but it should be pointed out the mode of operation of these pumps was almost continuous as they performed the cooling water function in addition to the fire pump duty. This eliminates the normal stop/start operating cycle, which would have a detrimental effect on the reliability of the motor.

As one of the few companies in the world that have supplied fire pumps operating with the three main types of drive system, i.e. lineshaft, submersible motor and hydraulic drive, we feel that we can give a totally unbiased opinion. The order of preference that we have stated from a reliability standpoint is based on many years of field experience across a great many markets and customers.

In answer to J. K. Green: The short answer to your question is that the pumpsets are complimentary. Both water injection and artificial lift are covered by the umbrella of 'secondary recovery techniques.'

In many oil wells where the natural water drive mechanism is not particularly strong, the pressure within the reservoir declines as oil is removed. To assist in maintaining the reservoir pressure, water is injected into the formation at high pressure. Additional benefit is to be gained from a water-injection programme, in some reservoirs, in the form of water sweeping, i.e. as water is forced into the oil-bearing rock, it has the effect of pushing the oil towards the producing wells.

As the proportion of water in the well-produced fluid increases, so the specific gravity and hence the hydrostatic pressure in the well bore becomes greater. This leads to reduced fluid production and, as the water cut continues to increase, in many cases the well may cease to flow. In this case 'secondary recovery' in the form of downhole pumping may be employed to enhance the well production. Here, the hydraulic turbine-driven downhole pump can be installed, with the pump selected, such that the generated pressure and flow rate allows the well, and hence the field production profiles, to be met.

In answer to A. E. Smith: The branch size of any pump has to be optimized if it is to meet a range of duties. The bore of the suction on the 200–150 size gives suction velocities of between 3.5 and 4.2 m/s at four-pole 50 and 60 cycle speeds, which are within the range of velocities used for most modern marine applications.

The maximum velocity in the discharge passage is in the throat of the volute from which the discharge passage progressively increases in size. The discharge flange of a pump will be right for some applications and not others. The discharge pipework size should always be assessed separately from the pump branch size on the basis of the nature of the application and the importance of pressure loss, pipe system weight, etc. A taper piece can be added if necessary between the pump and the pipework. It would not be clever to use the largest branch size possible, since some applications would then require a taper back-down to the pipe diameter.

The stability of the pump curve will vary depending on the specific speed. The pump in the paper is generally stable over the duty range for which it will be applied, and a small degree of instability is unlikely to affect the system because of the stabilizing effect of friction losses and velocity head in each individual pump section of the pipe/valve system.

The power curve again depends, to a significant extent, on the specific speed of the pump, and motors will normally be offered to cover the highest point in the curve, whether this is the end of the curve or some point in the middle. Efforts to provide non-overloading characteristics may well reduce the peak efficiency of the pump, with the result that normal running power may increase.

The author, nevertheless, has some sympathy with the points raised, as it is true that a pump, perfectly tailor-made for an individual application, will be more suitable than a standard pump. Nevertheless, provided the standard pump features are acceptable for the duty, and the pump is correctly applied, the benefits of availability, cost, variety of options available and reliability, will be dominant.

In answer to J. Crawford: Thank you for your generous comments.

The junk basket, as shown in Fig. 12, is installed to catch any debris introduced into the system after the charge pump suction filters. Field experience has shown that debris may 'appear' in the system, particularly during commissioning. The majority of this foreign matter is in the form of 'mill scale' and 'sandwich' that, in the interests of prolonging the downhole life, we do not wish to introduce into the turbine.

With reference to the surface filters, these are only required if the level of contamination is in excess of 100 p.p.m./100 mm. Field experience has shown that 'cyclone separators' provide an adequate level of filtration. However, in the event that no 'underflow' dump is available, it may be necessary to consider the use of Duplex strainers.