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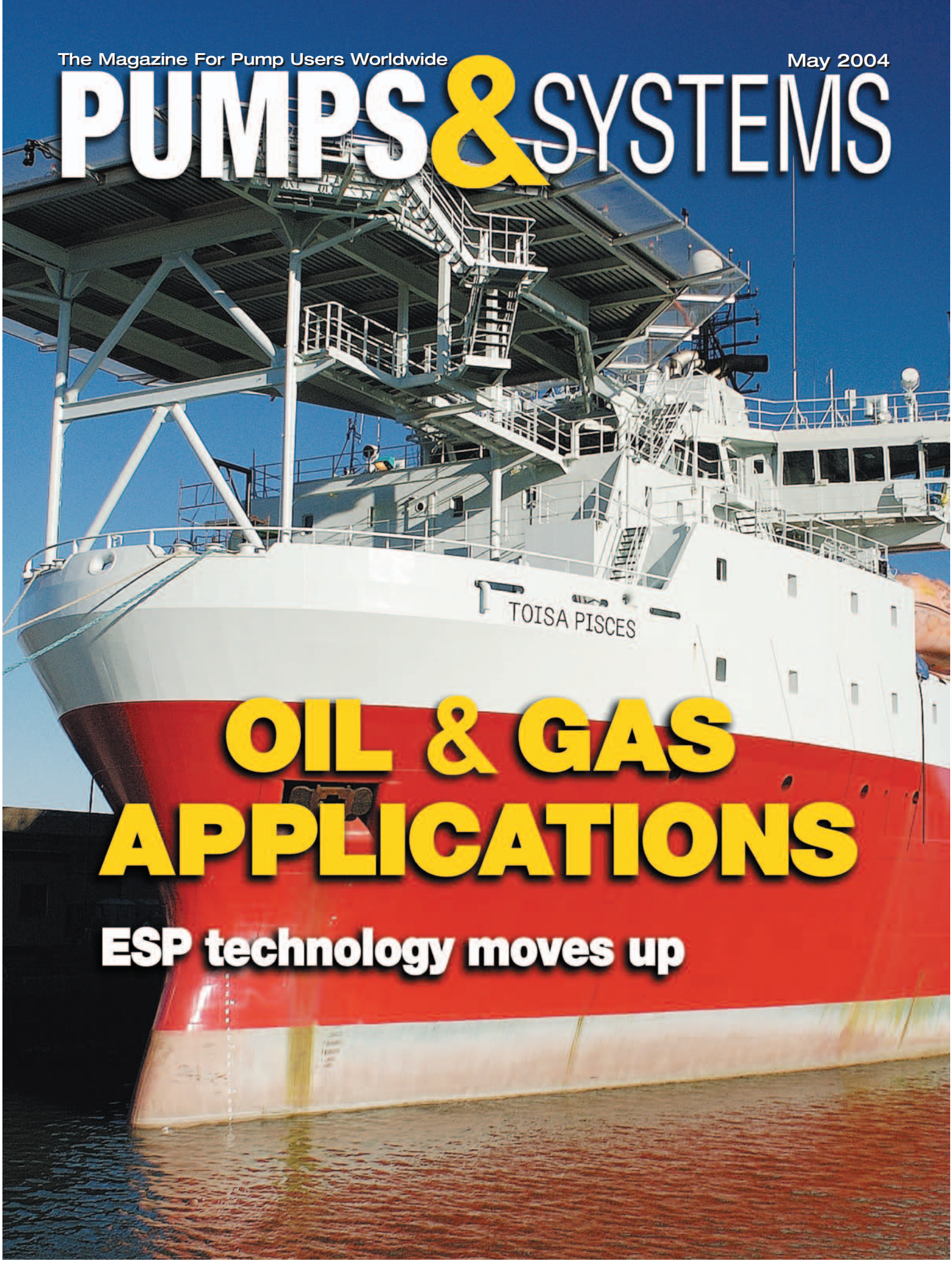
PUMPS & SYSTEMS



OIL & GAS APPLICATIONS

ESP technology moves up

Used in a variety of petroleum and industrial applications, electric submersible pump (ESP) systems are now providing specific solutions to a wide range of surface fluid-movement applications. Once relegated to downhole operations only, ESP technology has moved on up to find its place in the sun.

The Downhole Connection

In the oil and gas industry, ESP units are the fastest-growing pumping technology, and are often considered the high-volume and depth champion among artificial lift systems. On a cost-per-barrel basis, they're considered to be both economical and efficient. An ESP requires very little surface space, is well- suited for offshore applications and works well in both highly deviated and vertical wells.

ESP systems incorporate an electric motor and multistage centrifugal pump unit (Figure 1) run on a production string and connected back to the surface control mechanism and transformer via an electric power cable. When other lift systems seem to be over-matched by heavy columns of oil, or when large volumes of water are needed to be pumped-off a well to free gas production, the ESP is usually the system of choice.

The well test service vessel Toisa Pisces is shown prior to commissioning in the Gulf of Mexico. Installed on a lower deck *(see inset)* are four SPS units from Wood Group ESP. Each of them is rated for 1000 HP. Two are used for water injection *(foreground)* and two for crude oil transfer *(far background)*

Daylight Shines On Downhole Pump Technology

Greg Dover, Denbury Resources, Inc., Gabriel Delgado-Saldivar, Maritima de Ecologia S.A. de C.V., and Neil Ferrier, Wood Group ESP, Inc.

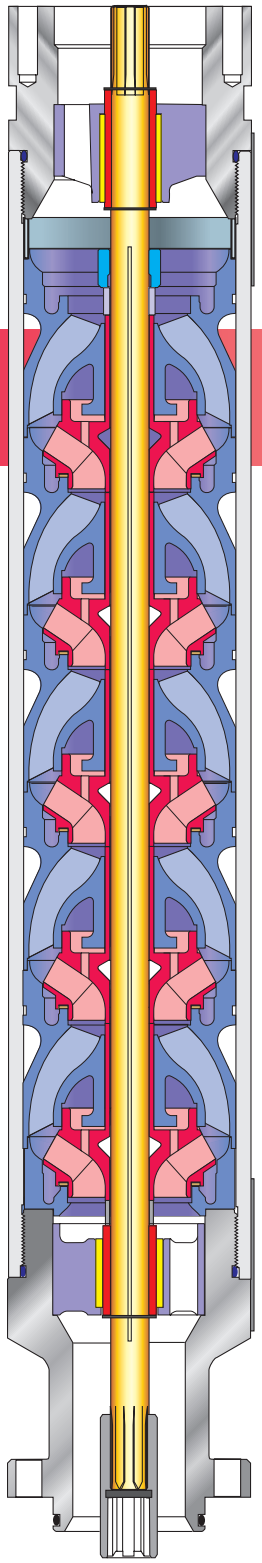
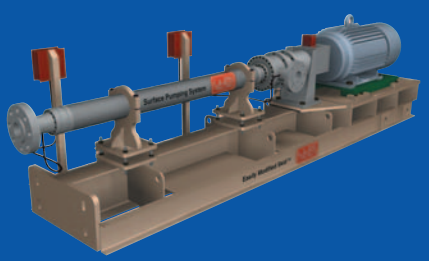


Figure 1. A mixed-flow, multistage centrifugal pump

Discovering multiple surface applications for multistage centrifugal electric submersibles. . .

By nature, these rugged downhole systems are required to work in hostile environments. Wells deeper than 12,000 ft. can be produced efficiently with these pumps, which can be used in casing as small as 4.5" outside diameter. Production rates range from 2 to 2000 GPM (70 to 64,000 BFPD), and variable-speed drives add pump rate flexibility. Modified equipment and special features allow sand and abrasive particles to be pumped without adverse effects.

Multistage centrifugal pumps consist of stages with rotating impellers and stationary diffusers cast from a Ni-resist high-nickel iron containing destruction-resistant properties. For severe environments, optional tungsten carbide radially stabilized and corrosion-resistant pump materials, including various stage coatings and boron diffusion hardening processes, are available. The impeller is mounted on a shaft made of either Nitronic 50 or other high-strength corrosion-resistant nickel-based alloy or stainless steel.



The SPS Alternative

Building on rugged oilfield ESP technology, the SPS™ Surface Pumping System from Wood Group ESP has developed a reputation as a low-maintenance, cost-effective alternative to vertical turbine, split-case and positive displacement units. These systems feature a direct-drive, multistage centrifugal design ideally suited for most high-pressure, high-volume and environmentally sensitive applications.

Offering a low surface profile coupled with quiet vibration-free operation, the SPS unit is available in electric, gas or diesel powered versions. These systems can typically handle up to 2,000 GPM (64,000 BFPD) and discharge pressures ranging up to 6,000 PSI. This versatile and reliable pumping system features design flexibility that facilitates onsite installation and maintenance with minimal site preparation.

Due to limited well-casing diameters, the lift or head developed by an individual stage is relatively low. This requires stages to be stacked together to meet the lift requirements for various applications. At each stage, the rotating impeller adds velocity to the fluid stream by centrifugal force and tangential redirection at the impeller outside diameter. The stationary diffuser converts this high-velocity energy to pressure as it redirects the flow to the next impeller. Diffusers also act as a bearing surface, providing additional stability to the pump shaft.

On the Surface

The petroleum industry has historically used positive displacement (PD) reciprocating pumps for a wide range of surface fluid-handling applications. With higher flow rates, some companies have also employed centrifugal split-case (S-C) pumps.

In recent years, pressure to reduce initial capital expenditures, coupled with the desire to lower ever-increasing maintenance costs and reduce environmental impact, has encouraged the industry to evaluate alternative fluid handling technologies including the Wood Group's SPS technology.

The SPS unit incorporates the same high-efficiency pumps that have been used for decades in downhole applications. For over 15 years, it has been utilized as a cost-effective and reliable solution in the petroleum industry for produced water injection applications. More recently, the SPS product line has been expanded to handle higher and lower flow rates and pressures, with different material and design configurations to match an increasingly diverse installation base. As a result of successful application in new markets, these units have become a popular alternative for many services where plunger (triplex, quintiplex), split-case centrifugal or vertical turbine pumps (VTP) were previously employed.

A large percentage of problem pumps are simply oversized—leading to unreliable, and inefficient operation.

Selection

When design consultants and facilities engineers evaluate various pumping technologies for specific applications, numerous considerations come into play. Among the most important are initial and life cycle costs, including maintenance requirements, environmental impact, efficiency and the ability/flexibility for changing duty conditions with minimal investment.

Table 1 provides a comparison of surface pumping systems to both positive displacement reciprocating and centrifugal split-case pumps. While some of the issues listed impact initial design considerations, others provide a comparison of long-term operational differences.

Making a Case for the Technology

Over the last few years, this surface pumping system technology has proven to be an effective alternative in numerous fluid-handling applications in petroleum, mining and other industrial operations. In petroleum, for example, it's been employed for the following:

- Produced water injection
- Produced water disposal
- Waterflood injection
- Pipeline booster
- CO_2 flood injection/ booster
- Crude oil transfer
- Cavern storage pumps
- LPG/NGL/Amine gas services
- Condensate transfer
- FPSO fluid handling
- Power fluid pumps for downhole jet/piston pumps

Here are some examples of the technology's versatility:

Gas Processing/Amine Service

Liquid amine, a derivative of ammonia, is used in the gas-sweetening process. Acidic gases, through a chemical reaction, are absorbed and pumped through a series of exchangers, towers and concentrators. The amine solution must be carried at certain pressures in order for the gas sweetening to take place. Once the process has occurred, the amine solution is reclaimed and recycled.

A Big Lake, TX operator, like many others, has historically used small PD pumps to move the liquid and to maintain pressures in gas plant amine applications. The operator found the PDs costly to operate, as they:

- consistently leaked expensive amine, which required costly remediation;
- required constant modification to meet changing plant and process conditions;
- were prone to vibration, causing piping fatigue;
- cost between $500 and $1,500/month to maintain and required excessive attention from maintenance crews; *and*
- required extra capital to install 100-percent backup in an attempt to eliminate plant downtime (increasing pump availability, but also boosting maintenance expenses).

In a field test, the operator replaced a small PD pump with an SPS unit rated for 20-75 HP (Figure 2). At the end of the first five months of service, the operator determined that the SPS unit provided comparable efficiencies while eliminating amine leakage, environmental issues, vibration, expensive maintenance hours and costly modifications to meet new plant and process conditions. Additionally, due to routine maintenance cost and lost product inherent with the PD pump, the purchase price of the new surface pumping unit had a payout of less than one year.

This operator is in the process of replacing the small PD pumps in all of his gas plants with SPS centrifugal pumps. He also is considering replacing larg-

Issue	SPS	PD	S-C
Capital cost	Low	Low	High
Whole life cost	Low	High	Moderate
Up time	High %	Low %	High %
Down time	Low %	High %	Low %
Daily/weekly maintenance	No	Yes	No
Downtime per repair	Low	Moderate	High
Cost of repair	Low	Moderate	High
System efficiency	Moderate	High	Moderate
Noise level	Low	High	Low
Vibration	Low	High	Low
Pulsation	Nil	High	Nil
Sealing (qty)	Mech. Seal (1)	Packing (3 or 5)	Mech. Seal (2)
Environmental leakage	Virtually Nil	High	Virtually Nil
Flexibility to changing flow/pressure	High	Moderate	Low

Table 1. SPS vs. other surface pumping technologies

Figure 2. SPS unit in service at a liquid amine facility

er PD pumps with larger SPS units rated for 1000 HP.

CO_2 Flood Project/Pipeline Booster

A pipeline operator in Little Creek, MS, was using two 700 HP compressors rated for 32 MMCF/D on a tertiary CO_2 flooding project. Low product density reduced the ratings to 27 MMCF/D. The compressors were expensive to purchase, complicated to install (requiring extensive site preparation), costly to operate (with large power requirements), maintenance intensive (resulting in loss of CO_2 injection during downtime), and very large and noisy.

Engineers from Wood Group ESP worked with this customer to design a surface pumping system to replace the traditional compressor package. They developed an innovative technology using reliable rotating-shaft seals for this high-pressure, multiphase, non-lubricating environment. Extensive analysis was performed for all components exposed to CO_2.

As a result, permanent, self-lubricating shaft bearing and bushing surfaces were employed throughout the pump assembly. Minor modifications to the plumbing system in the facility were made to ensure dense phase liquid was being delivered to the pump.

The SPS unit (Figure 3) was installed and operated for a period of six months and was then dismantled to analyze and ensure the integrity of all components. In this process, significant improvements were noted.

- It produced 26.7 MMCF/D at 450 HP (22 MMCF/D at 60 Hz) compared to 700 HP required for comparable compressor volume—a 36-percent reduction in HP requirements.
- The unit's purchase price was less than a three-month rental of the compressor package.
- Maintenance requirements/costs were eliminated.
- Site preparation/pad was one tenth the size of the compressor pad.
- Noise levels were dramatically reduced.

This operator needed to move a large volume of CO_2 at high-intake and discharge pressures.

The SPS unit rated for 1000 HP provided a smaller, quieter, more efficient solution, which in turn was easier to install, required less maintenance and was more economical than the original compressor system.

Well test service vessel/ injection and transfer pumps

This is the first known successful installation on a well test service vessel, where four SPS units (rated for 1000 HP) were used to replace two PD pumps for water injection and two API 610 split-cased pumps for crude oil transfer/export.

This system was installed December of 2003. The vessel, the Toisa Pisces, is currently operating in the Gulf of Mexico for PEMEX. Four additional units are being installed on Bourbon Offshore Norway's Bourbon Opale, which will also operate for PEMEX following its conversion. Maritima de Ecologia S.A. de C.V. (Marecsa) has been designing and supervising the construction and conversion of well test service vessels since 1997, and specified the equipment to be installed on both vessels.

Delivery and installation time played an important role in the design and selection of this system. Depending on the complexity and conditions of service, SPS unit turnaround and implementation is typically 12 weeks or less compared with API 610 split-cased pump deliveries of 26-52 weeks.

The reduction of extra inventory costs and the minimal downtime also associated with the SPS unit were important selection factors. Any system downtime in this application can equate to thousands of dollars in lost production.

Flexibility is the key to successful operation of well test service vessels. The SPS unit is modular and can be easily retrofitted to meet unique pumping requirements. In this case, the customer needed the two SPS

Figure 3. SPS unit installed at a CO_2 flood project

transfer pumps to run over a wide operating range in terms of pressure and flow, in order to feed into various existing crude oil pipelines. Similarly, on the injection pumps, the various injection locations have different pressure and flow requirements.

Conclusion

In many cases, SPS units offer inherent advantages, such as low NPSH, lack of pulsation, product containment, volume and pressure flexibility and the lack of high-pressure packing glands that helps eliminate costly maintenance repairs, nuisance shutdowns, product leakage, piping stresses and man-hour consumption.

These systems are flexible and can be easily modified to handle a variety of service requirements. Design adjustments to such items as the seal assembly, elastomers and metallurgy are routinely made to accommodate special applications.

Multistage centrifugal surface pumping systems may have cut their teeth in the petroleum industry, but that's not where they'll stay. As design engineers and operators evaluate costs, maintenance requirements, environmental impact, efficiency and flexibility, they're sure to find a range of other applications—*in many other industries*—where these multi-tasking high-achievers can shine. **P&S**

To ensure reliable bids, furnish a detailed process specification, then confirm that suppliers are quoting a good fit for the service.

Greg Dover is a petroleum engineer with Denbury Resources, Inc., of Plano, TX. He has over 20 years of experience in the industry and has been working on Denbury's CO_2 floods in southwestern Mississippi since 1999. A member of the Society of Petroleum Engineers, Dover holds a B.S. in Petroleum Engineering from the University of Wyoming.

Gabriel Delgado-Saldivar is General Director of Maritima de Ecologia S.A. de C.V. (Marecsa). Mexico-based Marecsa has been designing and supervising the construction and conversion of well test service vessels since 1997. Delgado-Saldivar and his team of engineers recently helped commission the Toisa Pisces, which is owned by Toisa Shipping Ltd (USA/Greece) and operated by Sealion Shipping (U.K.) for PEMEX in the Gulf of Mexico.

Neil Ferrier is Manager of Surface Pumping Systems for Wood Group ESP, Inc., in Houston, TX. A mechanical engineer with 27 years of experience in the pump industry, he served his apprenticeship with Weir Pumps in Scotland. Later, he worked for Mono Pumps Ltd, in Australia, the U.K. and the U.S. Ferrier is a member of the Society of Petroleum Engineers and is a U.S. Patent holder. He's been with Wood Group ESP for four years.

For more information, log on to: www.woodgroup-esp.com.