Greg Boyles, The Smart Pumper, USA, examines developments in automation that are enabling engineers to quickly control and monitor artificial lift systems.

AUTOMATING ARTIFICIAL LIFT

As technology continues to fine-tune our products and services, it is hard not to notice wireless remote control devices that are increasingly becoming the norm. From controlling household electronics over the web to digital oilfields in remote areas of the world the professionals working in the automation industry invent to simplify our lives, improve productivity and reduce operational cost. One such automation team has taken its automation effort to a global platform perspective for the oil, gas and water industry that enables process and production engineers to deploy quickly to control and monitor any type of artificial lift system from any part of the world without a daisy chain of costly services.

History

The oil, gas and water industries continuously work toward reducing operational expense and maximising production run times. Pumping wells perfectly is how one achieves the most cost-effective operation where artificial lift is concerned. The time consuming challenge for well managers has been to match pump output to fluid inflow over time. Adding to the challenge are the ever-changing reservoir dynamics that affect inflow and often result in damaged pumps caused by dry pumping.

The automation platform achievement

The goal was to design a powerful PLC that served users as the master controller to any variable frequency drive (VFD) for regulating electric motor speed (regardless of horsepower) as well as regulating hydraulic motors and valves, collecting and responding to data from an array of sensor and metering options. The control is based on actual fluid level in real time to the specific target the user wants to reach and maintain; setting the target level and defining the number of days to reach that target level. The older concepts only second-guessed and acted as a pump off controller.

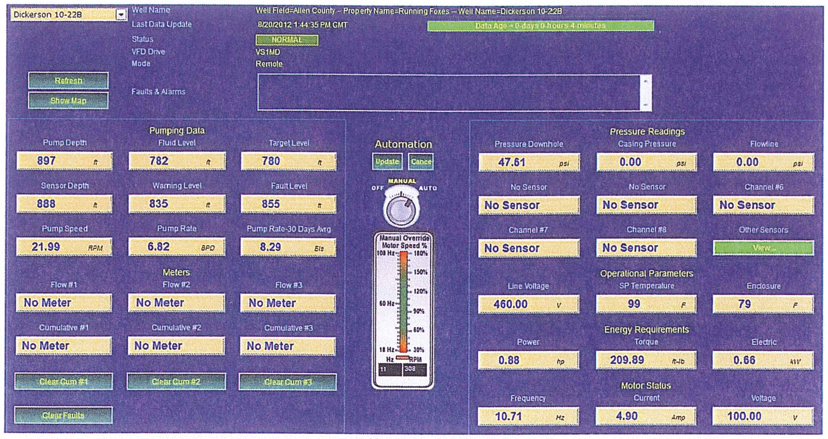


Figure 1. Data retrieved from the online dashboard of a well in Kansas.

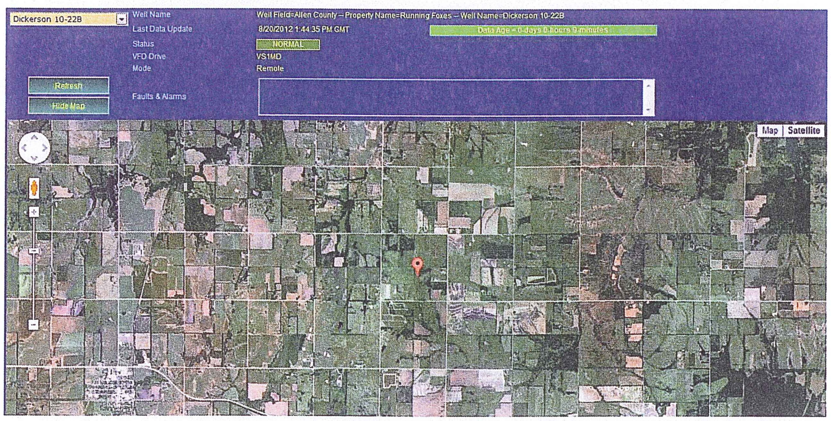


Figure 2. Mapping the location of the well site with the automation tool.

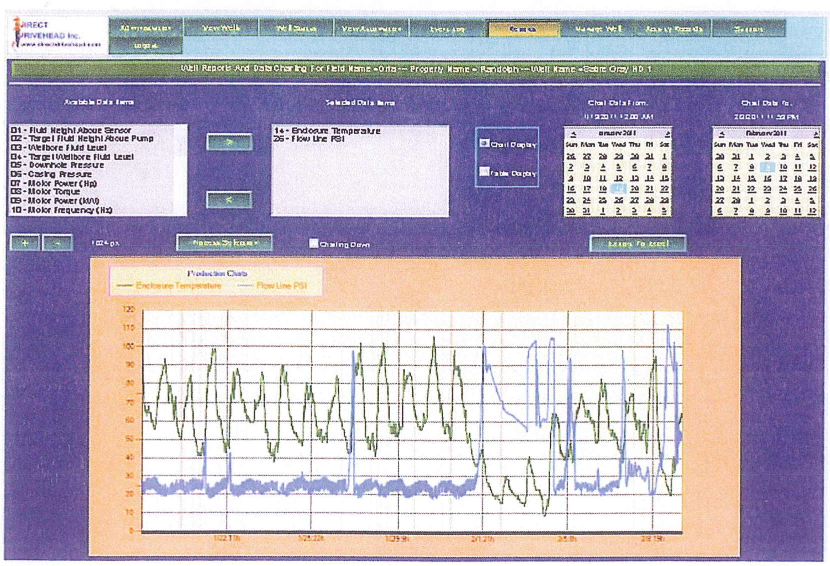


Figure 3. Flowline pressure and enclosure temperature.

Maximising profits could only be achieved, (where artificial lift is concerned), through perfect pumping and collection of important data in real time. The need is a simple to use solution; anyone can afford to automate every well.

Technical solution

A 'plug-n-play' package was created. It is a universal platform combining everything into one PLC with drivers for key components:

- User friendly and easy to set up (desktop control within minutes).
- Controls any motor (electric and/or hydraulic).
- Controls any VFD.
- Can control any form of artificial lift.
- Provides two-way communication, built into its board (cell, radio, satellite).
- Provides secure private network tunnels to companies and country servers.
- Supported by a global network.
- Provides interface to desktop and mobile devices (laptops, tablets, phones).
- Utilises SQL R-2.
- Provides server support.
- Provides multiple hard wired inputs from the start for:
  - Eight analogue definable and scalable channels supporting all A-D sensors such as; PSI, temperature, vibration, water quality (salinity, PH), gas monitoring (H_2S, CO_2, methane, radon) and others.
  - Eight digital definable and scalable channels.
  - Four pulse counters, two with modulation (metering clean and dirty signal).
  - Digital current loops (valve controls).
  - 485 Mod Bus (to allow a series of sensors on one network cable and control the VFD at the same time).
  - RS235 (to allow automation engineers the capability of adding their improvements over time).

Field testing: Trinidad and West Texas

Parrylands Block E in Trinidad, West Indies and Orla South in West Texas high desert.

The Parrylands Field consists of an extremely difficult to produce heavy oil reservoir with sanding issues, which cause reservoir inflow to change virtually minute by minute. It is possibly one of the most difficult to pump dynamic reservoirs to be found. This site also has very high humidity (90%) and hot sun, which also put electronics to the test.

The Orla South Field in West Texas, high desert environment, was also selected for testing because of its remote nature and drastic temperature swings with summer time enclosure temperatures reaching 170 °F in direct sun and wintertime temperatures falling to sub-zero.

Field testing: Staatsolie, Suriname, N.V.

Pilot objective

Compare Smart Pumper™ automation for ease of use, performance, quality control and online web based automation. Compare economic evaluation of same with previously installed wellhead systems. Evaluate, analyse and monitor data transfer rate from remote jungle swamp areas to company desktops and performance of automation.

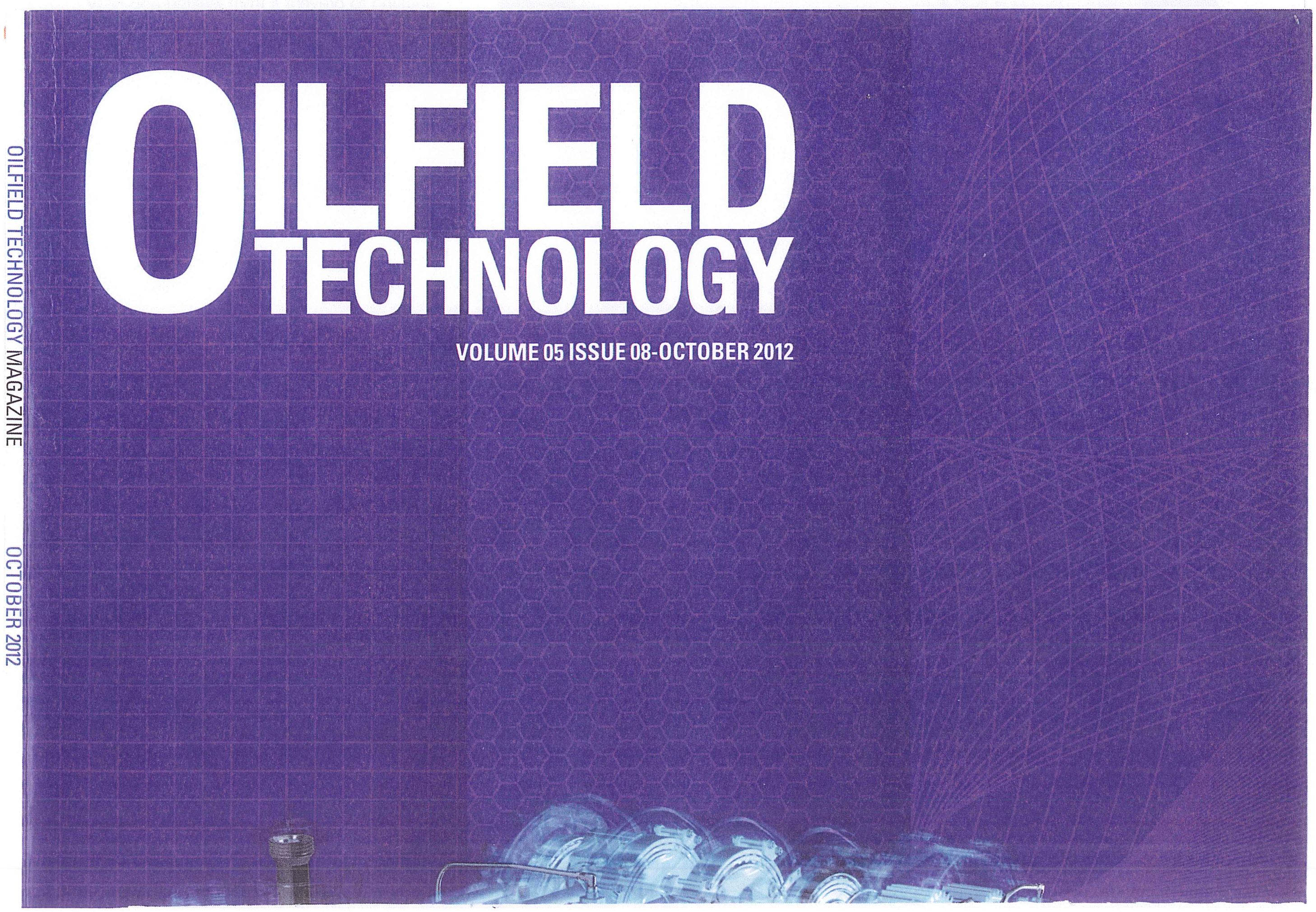
Background

Prior to the pilot, the well performance was monitored on a monthly basis by petroleum engineers (PE) in the respective oilfields based on flow tests, pressure tests, service information and other historical data for optimisation purposes. Reservoir engineers (RE) also used pressure data to monitor well behaviour, and periodically request a pressure build test be performed by testing teams so that necessary reservoir calculations and predictions could be undertaken.

Long term testing of three systems was initiated. The well shown is 290w05 in the Calcutta Field. Direct Drivehead's Smart Pumper solution turned out to be a low cost automated variable speed lifting option for PCPs that can also provide PEs with FBHP, FBHT, RPM etc. to a desktop from their remote locations saving considerable time in the management of the wells that were so equipped. REs could

Table 1. Cost comparison: existing vs. Direct DriveHead with Smart Pumper Automation

Item	Existing system	DDH + Smart Pumper
Drive Head 7.5 HP	US$ 7555	
Direct DriveHead (rt. angle)		US$ 10 450
VFD	US$ 4564	Included
Stuffing box	US$ 385	Included
Flow tee	US$ 185	Included
3 in. hammer union	US$ 25	Included
Subtotal	**US$ 12 714**	**US$ 10 450**
Pressure sensor	US$ 4322	US$ 800
Carrier	US$ 2712	N/A
Cable (1350 ft)	US$ 3308	US$ 3834
Cable protectors (45)	US$ 1575	N/A
Cable straps (45)	US$ 900	US$ 90
Cable connections	US$ 314	N/A
Smart kit	US$ 400	N/A
Data logger vs. Smart Pumper	US$ 8607	US$ 2750
Surge protection	US$ 584	US$ 584
Subtotal	**US$ 22 722**	**US$ 8058**
Artificial lift system total	**US$ 35 436**	**US$ 18 508**



also remotely activate a pressure build up test and monitor their pressure surveys in real time at their desktop without dispatching crews to go out and start, record, and then return to restart wells after a test period. They could also make real time adjustments to the programmed schedule of build-up and draw-down tests thereby minimising associated production loss.

Analyses of the results

- User friendly web based graphical interface accessible to those with proper user definitions and passwords for specific levels of authority: administrator, field manager, PE, RE, well pumper (operator), electrical, maintenance.
- Administrator access to online web based system was user friendly. Event log, reports, manage well page, and other aspects were easy to navigate.
- Response time when commands to change RPM or shutdown averaged 9.23 sec. and was purely based on Internet connection speed at the company's location.
- Email as well as automated SMS can be programmed. Primary log parameters can be retrieved from the well such as FBHB, FHBT, Volts, Hz, amps, RPM as well as secondary log parameters like torque, theoretical flow and fluid level.
- For the pilot, data flow was sent to a local cell provider Digicel into Internet tunnel in Suriname to Direct DriveHead server in Houston and back.
- Table 1 shows cost comparison between current installed system and Direct DriveHead/Smart Pumper.
- With the automation system installed on 290w05, there was a 21% increase in bbls produced compared to the prior 10 months primarily due to maintaining better actual real time fluid level control.
- Fluid level control via the VFD linked to the Smart Pumper's proportional integral derivative (PID) controller was quite smooth. The point from which there was a perturbation until this was corrected to the target level programmed matches.
- Figure 1 shows the data retrieved from the online dashboard of a well in Kansas. It gives information regarding the number of bbls it is pumping, the target level and the various pressures involved with the pumping.
- The web interface helps to map the location of the well. Figure 2 shows the map of a well in Allen County, Kansas.
- The online interface helps generate graphical reports for various parameters such as temperature, pressure, horsepower, torque, motor amps, parted rods etc. Figures 3, 4 and 5 show some of those reports.
- During the 12 month pilot, there were no maintenance issues that hampered the functionality of the Smart Pumper automation. A 100% uptime was registered. The only issue was that the stuffing box on the drive head required proper rope packing to prevent it from leaking and NOV was asked to lower the weep hole on the housing so the hose to collection bottle would flow more freely; this was done by the manufacturer. Also, a gear noise developed from water penetrating an upper seal; however, the gear continued to operate. The manufacturer has since redesigned the upper seal to prevent water entry.

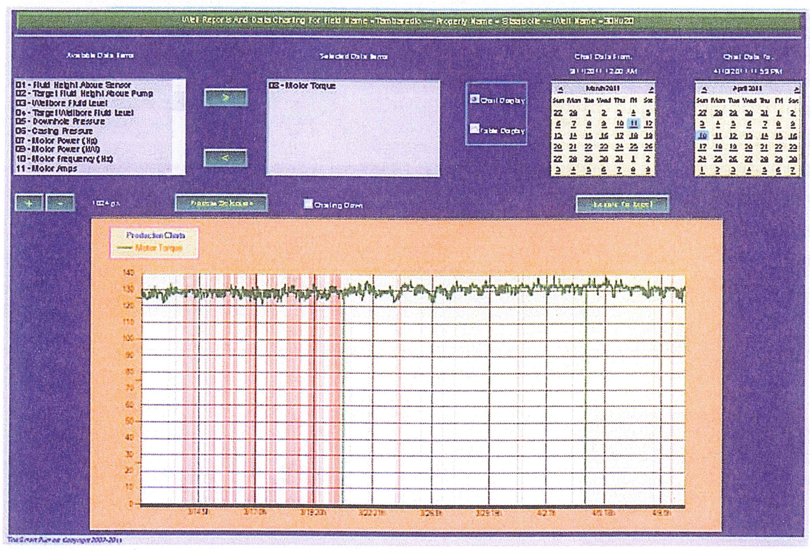


Figure 4. *HP and torque report for 30 days.*

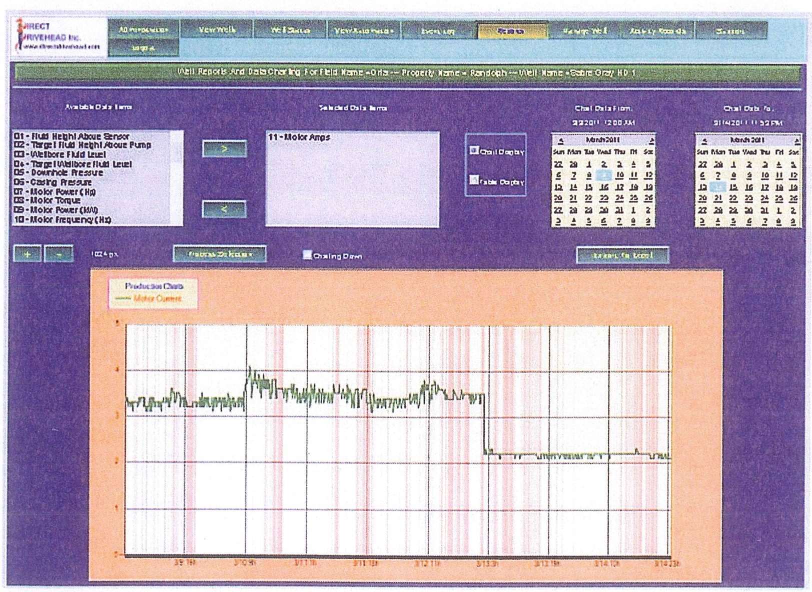


Figure 5. *Motor amps/parted rods.*

Conclusion

Once installed, the automation package virtually immediately transferred the data to the online server with an average 9.23 sec. response time per signal command or data retrieval. With the system installed, a reduction in travel time was realised. Also, the system reduced the cost of sending field operators to the wells, which allowed them to increase the completion of other meaningful tasks by focusing on other field duties. Control of the fluid level to target was accomplished as programmed into the Smart Pumper. It also helped eliminate all unnecessary operator, PE and RE intervention with regard to 'attempting' well optimisation. The system is much cheaper than data loggers that only log data. The installed sensors and cables provided have worked properly for the past 12 months.