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Data Overload in Artificial Lift well Management.

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Good data is critical to how we operate our artificially lifted wells, however data overload can reduce the efficiency of how we provide an optimally run operation. A single ESP well can have 20 or more key data streams associated with its operation. These include surface data, well test data, surface electrical data and downhole gauge data. In addition to this data the operator may need to perform further calculations or launch the data into well performance software to gain a full understanding of how the well is performing.

With streams of data arriving over real time data transmission systems the operator's workload has increased dramatically and his or her ability to manage each well individually is compromised. They are arguably faced with too much information to process efficiently.

In order of precedence the operator requires to know

1) Is the well is producing or not?
2) Is the well producing within it and its ESP's capabilities
3) Is the well is producing optimally or not?

If the answer is yes to the above questions then no action is needed and the operator can concentrate on wells that require attention. If the answer is no then the operator needs to be informed in the simplest manner possible what action can or should be taken to rectify the problem.

Intelligent processing of data and simple data presentation is required to provide the ESP operator with information on what actions to take.

This paper discusses the automation of ESP well management, addressing the industry's requirement to reduce and simplify the workloads involved in the gathering and analysis of downhole and surface operational data to ultimately improve ESP well operation.

Introduction

Monitoring artificially lifted wells was initially limited to observation of the electrical parameters, wellhead pressure and occasionally a fluid level reading or a downhole pressure reading. Well performance was monitored by well testing as and when available.

Advances in measurement technology have made ever increasing amounts of real time information available for monitoring both pump and well performance. Parameters such as surface gross liquid or multiphase flow, multiple downhole pressure readings, temperature and vibration are becoming more common. New generation motor controllers rely more commonly on processors to control their operation. These provide a huge amount of information on how the electrical system is performing.

Each piece of equipment installed in the well bore has limitations in its operation. These constraints may be for temperature, electrical or hydraulic reasons. The well itself will have limitations on drawdown due to the performance and physical characteristics of the reservoir. To provide ultimate protection against ESP failure or well problems and to maximise production all of these limitations must be monitored. This is not always economical or practical.

The balance of electrical & hydraulic systems in an ESP well makes analysing the data a complicated process. Hydraulic performance is influenced by electrical performance and vice versa. The interaction between the two is rarely linear and so responses in the well bore are dependent on not only well performance but also the characteristics of the performance curves of the lifting equipment.

The amount of information required to properly monitor and optimise each well is growing as technology advances. In addition to this the number of artificially lifted wells in operation is increasing. This is arguably resulting in data overload, where the technologies invested in are not being used to their full potential. Wells are not always being monitored as closely as they should be, unless something critical happens to production such as ESP failure or serious well problems.

Data Gathering

Manual data gathering in fields with high numbers of pumping systems is labour intensive and time consuming. The data logs from each individual technology must be downloaded, formatted and in most cases trended to view performance changes. An ESP well will typically have 20 or more parameters from 3 or more monitoring devices. If each measurement is logged every 5 minutes this equates to almost 6,000 data points per well, per day.

SCADA or data transmission systems can be implemented to automatically feed the data from the well site to control room or office based engineers. Data can be sent by radio, satellite or telephone network. Assuming the same rate of transmission as stated above and a population of 100 wells, this requires the transmission of almost 600,000 points of date per twenty four hour period. Monitoring at a frequency of once per minute increases this data volume to 2.88million data points per day.

Analysis packages in the form of data historians with data trending tools help to manage the volume of data, but ultimately each well's data must be surveyed by an engineer to ensure it is producing optimally and that the lifting equipment is operating within its capability.

Improving the Efficiency of Data Management

At the Control Room

The volume of data described above can be rationalised in day to day monitoring. The operator faced with a high number of wells would be able to conduct a more efficient day to day evaluation of performance if the data was filtered to the following core information

1) Which wells are producing and which have shut down?
2) What caused the shut downs and which wells can be restarted immediately without further endangering the equipment or well.
3) Which of the running ESPs are producing sub optimally?
4) What can be done to improve the production from the non optimised wells within the constraints of the ESP and well performance capability?
5) What action needs taking for the wells which cannot be restarted immediately?

Steps 3 & 4 can be further automated so that suggestions on how to improve production can be presented automatically to the operator. This would further improve the efficiency of filtering the large volumes of data.

With this basic information to hand the operator can prioritise the workload so as to maximise production without the need to review the actual streaming data. Only when a truly troublesome well problem occurs are all the data required to conduct a full analysis.

At the Well Site

The field based ESP engineer or production operator is the ultimate point of contact with the well and ESP equipment. He or she is required to manage the well locally by making changes to electrical and hydraulic settings, typically WHP, CHP, frequency and perhaps flow line pressure. He or she must be aware of any alarm levels present when making adjustments to the well or ESP controller. It is imperative that all the information on the well is to hand as the operational changes are made effective. Typically this data is presented to the operator in numerical format only, and may also be from devices scattered around the well site.

The data must display in a simple and effective manner so as the operator can observe clearly see what effects the operation changes he or she is making is having on the well. If the format of display is easily understood the operator need not have an in depth knowledge of each of the parameters. An analogy of this would be the gauges used on a car dashboard to display status of the engine condition. Having the data contained in one display or data logger would aid the engineer to operate the well. Currently he may have reading devices at the ESP controller and others at the wellhead which makes operating the well a tricky or multi-person process.

Alarming and Exception Reporting

Remote data management systems may employ exception reporting on the data streams being recieved. The exception reporting takes the form of multi level alarm situations to warn of current or impending critical operating conditions. These alarms are usually set during the commissioning start up period, and to remain effective require constant updating as well conditions change.

If levels are set too "tight" i.e. too close to the normal operating condition, undesired alarm conditions will present an overload of exception reports. This is a common occurrence which can lead to ineffective use of the remote data as alarms are ignored or wrongly acknowledged.

If the levels are set too "loose" i.e. with excessive difference between operating condition and alarm level, the well and lifting equipment runlife may be compromised.

The span between a tight and a loose alarm will vary from well to well. The most effective way to set efficient exception reporting is to calculate scenarios for each parameter that are the result of undesired operating conditions. The calculations must be updated frequently as changing well conditions change the validity of the set point.

For example:-

Pump Intake Pressure
The following criteria must be considered when setting an effective low pump intake pressure alarm set point.

Dependents and sub dependents

- Maximum allowable well drawdown
    - Sand production
    - Gas Coning
    - Water Coning
    - Casing collapse pressure

- Volume of free gas at the pump intake
    - Produced Fluid Bubble Point
    - Gas to Fluid Ratio
    - Temperature
    - Gas handling capability of the pump
    - Gas Separator efficiency

- Maximum allowable ESP flow rate
    - Frequency
    - Motor HP available
    - Amperage Ratings

It can be seen from this example that effective setting of the alarm level requires significant calculation, a degree of knowledge about both the electrical and hydraulic performances and time and effort to run sensitivities for different operating conditions.

If a well model is created and run in real time the alarm set point for intake pressure can be set automatically with the answer to two questions. The limiting values can then be constantly calculated based on the current well conditions making the protection level more effective and less prone to false alarming.

1. What is the maximum draw down allowable on the well

2. What is the maximum permitted free gas volume at the pump intake.

From answers to these two questions a minimum allowable pump intake pressure can be calculated that takes into account all of the above dependents and sub dependents.

Alternatively the bottom hole flowing pressure can be calculated in real time and assigned an individual set point independent from the ESP operational constraint.

Each well parameter has its own individual dependents, some more in-depth than others, but all interdependent on the interaction between the well and lift system performances.

Critical parameters required to maximize well protection and production are as follows

1. Well draw down (or flowing bottom hole pressure)
2. Total Liquid Flow rate
3. Water Cut
4. GOR or GLR
5. Wellhead Pressure
6. Flow line Pressure
7. Casing Head Pressure

Critical parameters required to maximize ESP protection are as follows

1. Motor Temperature (oil or winding)
2. Pump Intake Pressure
3. Pump Discharge Pressure
4. Pump Discharge Temperature
5. Pump Flow rate
6. Vibration
7. Amperage of each electrical phase
8. Voltage of each electrical phase
9. Frequency
10. Backspin detection
11. Free Gas at the Pump Intake
12. Solids entering the pump

It can be seen from the above listings that not all the parameters are directly measured by devices at the well site, and not all of the parameters are measured constantly. For example Well Head Pressure may be provided by a dial type guage rather than a real time transducer transmitting the signal to a processor. Water cut and surface rate may be intermittent readings from well testing.
To provide maximum protection, and hence runlife, the parameters should be monitored in real time or inferred and validated against known data values.

Automation

The following information is required to design a fit for purpose ESP system for the well conditions.

- Well completion details
- PVT details
- Well Inflow Performance Relationship
- Well test details
- Fluid mixture properties

This information is gathered during the design process and used by the application engineer to design the ESP. A typical ESP design program will calculate a number of unmeasured parameters from the input data so that it can “choose” a suitable ESP design. The application engineer can then manipulate the data to enhance the design for changing well conditions over the life of the lift system.

If one applies this philosophy to real time data provided by well site and downhole measurements, parameters that are unmeasured can be inferred in real time by software. This enables automation of a well model that can be used to provide information on key parameters that are not typically measured by devices in the well bore.

It is important that any calculated or inferred data is constantly cross referenced against actual operating conditions. This process must be self checking so as not to provide false information to the operator.

Typical key unmeasured (in real time) parameters that can be used to enhance ESP and well protection are

- Water Cut
- Flow Rate through the pump
- Flowing Bottom hole pressure / Draw Down
- Free Gas At Pump Intake
- Pump power requirement
- Surface Rate (if not measured)

When a software model of the well is programmed into a system the model can be used to predict scenarios of operation. This enables automated settings of alarm and trips for undesired well conditions.

For example, maximum and minimum allowable flow rates for the pump can be processed from measured pump delta pressure vs. the pressure / head curve of the particular ESP in the well. (See figure 1). If a pressure vs. flow curve is programmed into the well model and pump delta P is measured by a downhole gauge, flow rate can be limited to the pump range.

As frequency is changed, the alarm levels can be automatically updated to the new pump curve based on the increased range available, thereby automating the process of refreshing the alarms to new operating conditions.

Reduce Data Analysis Workflows

The following workflows can be implemented by a data processing unit that automatically reviews the data streams from the well site and downhole measuring devices.

1) Provide the operator with high level information to simplify management of multiple well fields. Each well assigns itself with a status based on the real time comparison of measured data vs. the well model containing inferred information.

- Well OK - No action required

- Well OK -Optimisation potential
    - Suggest Frequency or WHP for maximum production within the operation constraints of the well and equipment.

- Well OK **-**Alarm Present
    - List alarm parameter and trend historical data

- Well Conditions Changed Significantly
    - Well test required
    - Check well for fluid leaks, blocked or broken pump, wear.

- Well stopped – trip present
    - Shut down on critical value
    - List parameter and trend the historical data

The status of each well vs. its production potential can be used to prioritize an action list to optimise operations.

2) Calculate key parameters that are not measured by well site devices. Cross reference the calculated data with measured data using a well model for validation. As well conditions such as GOR, water cut, PI or reservoir pressure changes the model will highlight when a well test it required.

3) Set alarm points automatically based on the limitations of the well and ESP equipment.

- **a.** Minimum Bottom Hole Flowing Pressure
- **b.** Minimum Intake Pressure
- **c.** Maximum Motor temperature
- **d.** Maximum and Minimum Pump Flow rate
- **e.** Maximum Wellhead Pressure
- **f.** Maximum Discharge Pressure
- **g.** Maximum Vibration
- **h.** Maximum and Minimum Amps
- **i.** Maximum Volts
- **j.** Maximum Motor horsepower
- **k.** Maximum Free gas at the pump intake
- **l.** Minimum Fluid Level above the Pump intake
- **m.** Maximum Flow line Pressure
- **n.** Maximum Frequency

4) Update alarms set points automatically for known or intended changes in operation. E.g. Frequency changes.

5) Provide real time sensitivity results automatically on control parameters such as frequency and wellhead pressure to aid in optimisation. This will provide the operator with the maximum allowable operating frequency within the constraints of well and pump performance and therefore guidelines for optimisation opportunities.

Conclusions

Consolidate all the well site information into one place for the well site engineer to view. This will provide one central point at the well site to gather and display all the well information to minimise the requirement to gather data from multiple devices.

Simplify the information presented to the well site operator so as he or she can see clearly what is happening to the parameters with a quick glance.

Provide real time measurements on key parameters by use of transducers at the well site rather than manual readable gauges at different locations..

Provide surface flow rate measurement if possible.

Enable the well site operator with the same information as the ESP expert or petroleum engineer in charge of the well.

Automate the process of data interpretation through intelligent reporting systems which highlight the status of the well without the need to survey the data.

Calculate key performance indicators such as bottom hole flowing pressure, and pump flow rate and provide them to both control room and well site personnel.

Provide exception reporting on key inferred parameters

- Water Cut
- Pump Flow Rate
- Flowing Bottom hole pressure / Draw Down
- Free Gas at the pump intake
- Pump power requirement

Validate and cross check inferred parameters against hydraulic and electrical measurements to enable simple optimisation and trouble shooting.

Provide real time sensitivities of optimisation potential that are fully checked against well and equipment limitations for the conditions of operation.

Appendices

Parameter	Device
Motor Frequency	Motor Controller
Phase A Volts	Motor Controller
Phase B Volts	Motor Controller
Phase C Volts	Motor Controller
Phase A Amps	Motor Controller
Phase B Amps	Motor Controller
Phase C Amps	Motor Controller
Volts Unbalance	Motor Controller
Current Unbalance	Motor Controller
Mode	Motor Controller
Backspin Lockout	Motor Controller
A – B Volts	Motor Controller
B – C Volts	Motor Controller
A – C Volts	Motor Controller
Under load	Motor Controller
Overload	Motor Controller
Start Delay	Motor Controller
Lock out	Motor Controller
Voltage Imbalance	Motor Controller
Current Imbalance	Motor Controller
Power Factor	Motor Controller
Intake Pressure	Gauge Controller
Discharge Pressure	Gauge Controller
Intake temperature	Gauge Controller
Motor Temperature	Gauge Controller
Vibration	Gauge Controller
Current Leakage	Gauge Controller
Well Head Pressure	Surface Transducer
Flow Line Pressure	Surface Transducer
Casing Head Pressure	Surface Transducer
Gross Flow	Surface Transducer

Table 1.
Typical data points transmitted per well via remote monitoring systems

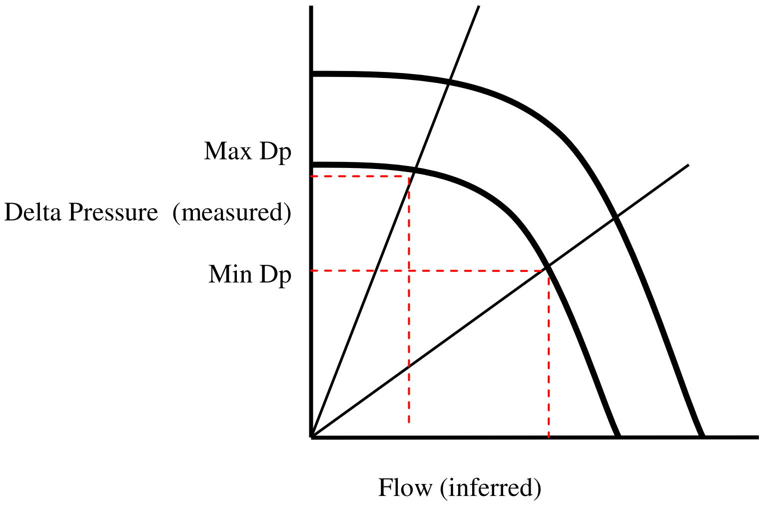
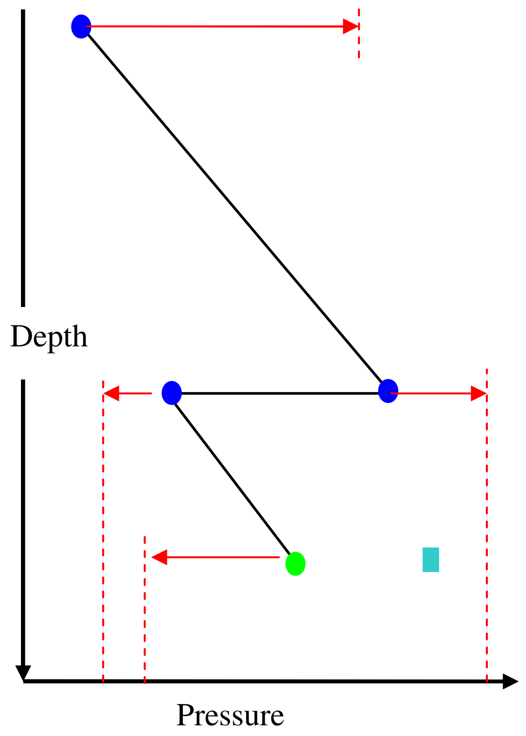


Figure 1
Pressure vs. Flow curve



Measured Data
Calculated Data
Well Test Data
Alarm Points

Figure 2 –
Measured and Inferred Pressure Alarm Points.

References