STATE-OF-THE-ART OF AUTOMATION FOR GAS WELL DELIQUIFICATION

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ABSTRACT

Automation of artificial lift systems is essential for effective management of deliquification for gas wells. There are at least fifteen forms of artificial lift in use for gas well deliquification. Often more than one method must be used in a given field because some methods are preferable earlier in a well's life and others are better later on. Also some wells may be straight and some may have dog-leg severity; some may have more solids production than others; and some need to have more or less fluid produced for deliquification.

Production Operators must have effective tools for gas well operation, surveillance, problem detection, control, and optimization. And, to be effective, there can't be a different tool for each form of artificial lift; there must be commonality of approach.

This paper reviews the current state-of-the-art in automation of gas wells, with a clear eye on the needs of the Production Operators for understandability, functionality, ease of use, and economics.

INTRODUCTION

From Wikipedia comes the following definition for state-of-the-art. The state of the art is the highest level of development, as of a device, technique, or scientific field, achieved at a particular time. It also applies to the level of development (as of a device, procedure, process, technique, or science) reached at any particular time usually as a result of modern methods.

Our intention with this paper is to focus on the "state-of-the-art" of production automation systems for gas well deliquification. We recognize that not all automation systems attain the level of "state-of-the-art" so we offer the following challenges to the industry:

- To Operating Companies. Know the state-of-the-art of production automation systems, know the advantages of using these systems, and wherever possible insist on obtaining and using these systems to optimize your gas well deliquification processes and systems.

- To Service/Supply Companies. If you offer state-of-the-art production automation systems for gas well deliquification, highlight these systems and their advantages to your Operating Company customers. If your systems are not state-of-the-art, strive to reach this goal for the mutual advantage of yourself and your customers.

- To Others. If you offer production automation services such as system definition, design, testing, integration, installation, commissioning, training, and support, strive to offer state-of-the-art services and assure your customers, whether they be Operating Companies or Service/Supply Companies, that you both recognize the value of state-of-the-art and strive to meet this standard in all of the services you provide.

Before we can expect you to provide or use state-of-the-art systems, we must define what this entails. Much of the information in this paper is based on information contained a text book on gas well deliquification.[1]

PLACING THE PROBLEM IN PERSPECTIVE

To place the problem in perspective, at least fifteen different forms of artificial lift are used for gas well deliquification. These are defined in a web site developed by artificial lift experts in the industry[2]. These include:

- Sucker rod pumping.
- Progressing cavity pumping.
- Electrical submersible pumping.
- Hydraulic pumping.
- Tubing plungers.
- Casing plungers.
- Soap sticks.
- Batch chemical.
- Continuous chemical.
- Velocity strings.
- Surface compression.
- Continuous gas-lift.
- Intermittent gas-lift.
- Heaters.
- Cycling, stop cocking, or intermitting.

In addition to these fifteen methods, other combinations, permutations, and even new methods are being advanced on a very frequent basis. Each of these methods, and new ones that are or will be developed, have both unique and also many common requirements. A state-of-the-art production automation system must meet the unique requirements while also meeting the common requirements in ways that most beneficially assist Production Operators to attain understandability, functionality, ease of use, and economics.

An important reason for this is that many gas fields contain a range of gas well operations, with varying deliquification requirements. It is very common that one form of artificial lift can not provide adequate deliquification for all wells in a field. Wells vary in hole size, depth, deviation, bottom-hole pressure, gas production rate, liquid production rate, and many other characteristics. Also, some wells may be early in their production life cycle whereas others are late in theirs. Some may produce well with velocity strings, chemicals, or plungers, while others may require pumping, gas-lift, or other methods.

So, it is common that an Operator, in a gas field, must (or at least should) use more than one type or artificial lift to optimize gas well deliquification. It is easy to image the complications that arise if a different form of production automation system must be used for every different type of artificial lift.

This paper will first focus on the common requirements that must be met by a production automation system to provide best service for all of these artificial lift methods. It will then highlight the most important unique requirements that must be provided for each form of artificial lift.

COMMON REQUIREMENTS OF A STATE-OF-THE-ART AUTOMATION SYSTEM

We'll discuss these common requirements in the following order:

- The equipment, starting at the well head and working back through the communication system to the production office, that is required to physically implement a production automation system.

- The general applications that are needed in all production automation systems. These applications must be common to all systems; but it must be necessary to "configure" them to meet the specific needs for gas well deliquification operations.

- Unique applications that are needed for each type of artificial lift. While these applications are unique, they must be fully compatible with the general applications and with each other, so they can all "plug and play" in the same production automation environment.

- Issues that must be understood and addressed for the successful implementation of all production automation systems. Often an automation system will "sink or swim" depending on how well these issues are understood and managed.

AUTOMATION EQUIPMENT

This is the hardware and "systems" that are required to implement a production automation system. The "good news" is that there is usually wide flexibility in choice of this equipment, as long as important guidelines are understood and followed.

Instrumentation

The fundamental axiom of production automation is for anything to be optimized, it must be controlled, and to be controlled, it must be measured. Thus, instrumentation to measure production variables is the cornerstone. And a state-of-the-art production automation system must use state-of-the-art instruments to measure pressure, temperature, flow rate, position, status, etc.

There are several types of instruments, each of which can be satisfactory for a state-of-the-art system. These include analog devices, digital devices, and others. For a short treatise on this, refer to Reference No. 1.

Most instruments in common use require wires to transmit analog or digital signals from the instruments that are installed on the wellhead, flowline, or production facility, to an electronic device where the signals are processed. More on this is covered in a later section. New technology is using wireless methods to transmit signals from the measurement point to the electronic system. The obvious advantages are that no wires, conduits, or ditches, are required, so the installation and maintenance costs are reduced. Obtain the services of an experienced instrumentation engineer in planning a state-of-the-art production automation system.

Flow Measurement

Often in gas production systems, very accurate flow measurements are required for custody transfer. The benefits of accurate flow measurement are obvious. And an electronic flow measurement system is much more accurate than conventional instrumentation that depends on separate measurements of pressure, differential pressure, and temperature (see Reference 1 for more discussion of this).

Controls

Optimization requires control of measured variables. Depending on the type of artificial lift system being used, it may be necessary to control the start/stop of a pumping system, the release of a plunger, the rate of chemical or gas injection, etc. Some pumping systems may require fixed-speed or variable-speed control to optimize the performance of the pump, the bottom-hole pressure, and the resulting liquid and gas production rates.

Most systems require control systems for safety; e.g. safety shut-in of a facility if there is a potential over pressure, high level, etc.

Control devices may be mechanical, pneumatic, hydraulic, or electronic. The choice depends on the specific application and its requirements. Refer to Reference No. 1 for further discussion of control options.

RTU's and PLC's

RTU's (remote terminal units) or PLC's (programmable logic controllers) are typically small, electronic devices mounted at the wellhead, on a pipeline, or at a production facility. Their fundamental purpose is to communicate with the measurement instruments and convert the input signals to engineering units of pressure, differential pressure, temperature, position, speed, etc. This information may be stored in the device and than transmitted on to a host automation system described in the next section.

State-of-the-art RTU's and PLC's are much more than this. They may receive commands from the host system to, for example, start/stop a pump, change the rate of gas or chemical injection, etc. And, in many cases, they may contain logic so they can execute control decisions on their own. For example, an RTU on a sucker rod pumping well, also called a rod pump controller, may contain sophisticated logic to start a pump, monitor its operation on a continuous basis, gather and process information to evaluate the performance of the pump, and stop the pump as a significant amount of gas begins to enter the pump, or if other problems arise. An RTU on a gas-lift well may contain logic to adjust the rate of gas-lift injection to optimize production from the well.

Typically, different RTU's or PLC's are used for each different type of artificial lift. Or, the same or similar physical RTU or PLC "boxes" may be used, but the logic in them will be different for each type of artificial lift.

This is preferred over trying to "force fit" one RTU or PLC to serve multiple types of artificial lift systems.

However, in a state-of-the-art production automation system, all RTU's or PLC's must have a common ability to communicate with the host automation system. They may communicate in various ways including radio, hardwire, telephone, satellite, etc. They may use different generic protocols (languages) such as MODBUS, ODBC, OPE, and ISO Controller Area Network. But they should not use proprietary protocols developed and supported by only one company. This is necessary so one host system can communicate with many different types of RTU's or PLC's on many different types of wells and artificial lift systems. The host system can do that by having the ability to recognize and communicate in these different languages. Refer to Reference No. 1 for more discussion of RTU's and PLC's. Specifically refer to Table 15-2 for information on various communication methods between RTU's and PLC's with host production automation systems.

Host Systems

Host production automation systems are normally built on personal computers, although they may use UNIX or other computer architectures. While a production automation system may employ many types of instruments, flow measurements systems, control devices, RTU's, PLC's, and communication methods, all of these come together in the host system. A state-of-the-art host production automation system should be able to provide all (or at least most) of the General Applications and Unique Applications discussed late in this paper.

The host system provides the "window" by which the Engineers, Production Operators, Well Analysts, Technicians, and others can monitor, control, diagnose, and optimize their wells and production systems. For there to be a state-of-the-art production automation system, these people must be able to use one system, with a common user interface and many common features.

There are many host systems in the Petroleum Industry that do not meet this requirement. They may be designed to provide only General Applications, or only Unique Applications for one type of artificial lift system. If a field has multiple types of artificial lift systems, it would need several different host systems. This is not good. However, there are several companies that offer state-of-the-art host production automation systems that provide a full suite of General Applications and a wide variety of Unique Applications. Where possible, these host systems should be chosen for use in a state-of-the-art production automation system.

Communications

Information must be communicated at several levels in a state-of-the-art production automation system:

- Between instruments and controllers and the RTU's or PLC's.
- Between RTU's or PLC's and the host automation system.
- Between the host automation system and the general production automation user community such as management and staff in the Division or Corporate offices.
- Between the host automation system and other computer systems, often using the World Wide Web.
- Between other computer systems and the production user community.

See Reference No. 1, Table 15-3 for various communication standards and Table 15-4 for various communication protocols. As information is communicated, it must be done safety and reliably. Refer to Table 15-5 for common methods of data transmission security.

Database

Typically, most production automation systems deal with real-time, current information. But in many cases, there is value in storing and being able to retrieve historical information. A state-of-the-art system can interface with a database to store minute-by-minute data (or even more frequent if necessary) for months or years. One common data storage device is a PI relational database that can store millions of records and permit them to be easily retrieved for after-the-fact analysis.

Other

Some companies produce "other" systems such as production equipment models, reservoir simulators, etc. A state-of-the-art production automation system can feed data to these systems and retrieve results, models, simulations, etc. from them using standard communication technology such as the Microsoft COM object interface system.

GENERAL APPLICATIONS

These general applications are (or at least may be) common to most production automation (or SCADA) systems. Normally, no specific system needs to be chosen to provide these general applications, as long as they are all compatible with one another and incorporate the unique requirements discussed in the next section.

Also, it must be possible to configure or adjust these applications to meet the needs for gas well operations. And, it may be required to implement these applications in the language of choice of the Production Operation. It may be necessary to implement the user interface in English, Spanish, Russian, Arabic, or some other language as used by the local Production Operating staff. A state-of-the-art system should be configurable in the desired language. (Of course, the underlying software may be written in the language of choice of the system developer; usually this is English.)

The purpose of this section is to briefly discuss the specific requirements of the most common general applications. These are all discussed in more detail in Reference No. 1.

User Interface

The user interface provides the window to the information and applications in the system. Most state-of-the-art systems use an interface that is similar to the Windows interface provided by Microsoft. It is essential that the same interface (or same "look and feel" as some refer to it) is used for all of the General Applications and Unique Applications, so the users of the system only need to learn one approach.

Scanning

Many production automation systems serve tens or hundreds of wells and associated production facilities. In most cases, the automation system gathers information from these wells and facilities by polling or scanning them on some frequency. The frequency will depend on the type and speed of the communications used between the host system and the RTU's or PLC's. It may vary from a few seconds to many minutes. In some cases, the RTU's or PLC's can initiate communication with the host system when there is need to communicate. This could be on the occurrence of a critical alarm, or the need for new control parameters.

When the host system detects a problem on a routine scan, it can request additional information from the RTU or PLC to further define the problem and provide diagnostic information to the users of the system. Also, some systems are programmed to gather special information on a specific frequency or on the occurrence of some event. For example, during a well test, the system may gather special information on the performance of the well and its artificial lift system, so the system can determine the well and system performance and determine parameters for optimization of the system.

Alarming

A primary function of production automation systems is alarming. In state-of-the-art systems, there are at least three classes of alarms.

- Class I. These are generally available on all SCADA systems. They are based on comparison of the value of a process variable with an alarm limit. For example, pressure too high or too low, flow rate too high or too low. The challenge is that unless the alarm limits are carefully chosen and used, the system may generate too many alarm message; more than the user can handle. This can make the process ineffective.

- Class II. These are generated for specific types of well operations or artificial lift systems. They are normally based on a combination of measurements or events. For example, if a pressure is too low and a corresponding flow rate is too high, this could indicate a leak. When these are well designed, they can provide beneficial insight into particular operating problems. Specific examples are presented in the section on Unique Applications.

- Class III. These are generated when the actual performance of a production or artificial lift system deviates from the expected performance based on a model or simulation of the system. For example, if the actual efficiency of a pumping system, under the current operating conditions, is less than the efficiency predicted by a model of the system, this may indicate a problem with the pump, or with inflow from the formation to the wellbore.

Alarms can be reported in various ways:

- They can be reported when they occur, or when they occur on “n” consecutive scans.
- They can be included in an alarm report at selected time(s) of day.
- They can be reported historically; e.g. the frequency of a specific alarm on a daily basis.

Reporting

All state-of-the-art SCADA systems produce reports. These must be designed for the specific information required for each gas production process. Examples include:

- Current reports: reports of current information on individual wells or groups of wells.
- Daily reports: reports that summarize each well’s performance or production and the production of a group of wells.
- Historical reports: reports that summarize each well’s performance or production on a weekly or monthly basis.
- Special reports: reports that contain special information such as well tests, artificial lift performance, etc.

A state-of-the-art system allows each report to be configured, sorted, totaled, and provided with statistical analysis, as required by the users of the system

Trending and Plotting

Trends are plots of process variables, or calculated variables, vs. time. They provide insight into changes in well parameters or performance over time. Examples are pressure vs. time, flow rate vs. time, well test rates vs. time, etc.

Plots show x vs. y data and provide insight into how one dependent variable, or a combination of variables, is affected by changes in the independent variable. An example is gas production rate vs. gas or chemical injection rate.

Displays

Displays are schematic representations or actual picture of production facilities, flowline systems, artificial lift systems, etc. They show the values of variables that relate to the display. For example, a display of a production separator may show the gas outlet rate, the oil or condensate outlet rate, the water outlet rate, the pressure, and the fluid level in the separator.

Many displays contain control options. The user can start or stop a pump by clicking on a start or stop button. He can change an injection rate by entering the desired rate and clicking on a download button.

Data Historians

The use of a database was discussed earlier. Most SCADA systems don’t include a data historian themselves, but they can transmit information to a historian on a regular scheduled basis, or when commanded to do so by an event or the user of the system.

UNIQUE APPLICATIONS FOR EACH TYPE OF ARTIFICIAL LIFT

While the general applications may be common across many different production automation and SCADA systems, the unique applications for each type of artificial list system must be just that, unique, to meet the specific requirements for monitoring, control, diagnosis, design, and optimization of that system.

These applications do share certain features in common, but each one must provide the unique services needed by its particular form of artificial lift. The purpose of this section is to briefly highlight some of the key features of these unique applications. These are all discussed in much more detail in Reference No. 1.

Sucker Rod Pumping

Sucker rod pumping is the most used method of artificial lift on oil wells and many gas wells. Figure 1 illustrates a typical sucker rod automation set up.

- Measurements. Primary measurements are the load on the polished rod and its position. With this information, the system can determine the amount of work being performed by the pump, the degree of pump fillage, and many other useful parameters. Secondary measurements may include casing pressure, unit vibration, and whether or not there is a leak in the stuffing box.

- Control. Pumping units are started and stopped by the automation system. They can be stopped if there is a problem such as high load, low load, etc. They can also be stopped temporarily if the fluid level has been pumped down so the pump barrel is no longer full. This is referred to as pump-off control. The pump is then started after a period of idle time to resume the pump operation.

- Unique Hardware. Special wellhead RTU's called pump-off controllers or rod pump controllers are used to monitor the pump operation, provide the start/stop controls, gather pumping information, and transmit this to the host production automation system.

- Unique Software. Special software is used to determine the pump performance and check for pumping problems. Some systems use measured parameters from the rod pump system to accurately calculate the daily liquid production rate. See Figure 2 for a typical sucker rod load vs. position plot.

- Specialized Alarms. Many alarms may be generated. Four of the most important are:

  - Run time too short. The well may not be producing as much as expected; possible inflow problem.
  - Run time too long. The well may be producing more than expected, or the pump may be leaking.
  - Position signal problem. The measured position is not sufficiently close to the predicted position.
  - Calibration problem. The design program is not sufficiently calibrated with the measurements.

- Surveillance. The system strives to detect problems so they can be quickly diagnosed and solved.

- Analysis. Pumping information is analyzed to determine stress in the sucker rods, load on the beam, torque on the gear box, "thermal" average motor loading, is the downhole pump sticking or leaking, etc.

- Design. Sucker rod design programs select the optimum pump size, pumping speed, and stroke length.

- Optimization. Optimization can occur when the design program is calibrated to measured pump data. When this occurs, the optimum pump size, pumping speed, stroke length, pumping unit size, and motor size can be selected to optimize production at optimum capital and operating cost. Optimization includes using the above considerations to reduce failure rates (run lives of 2 - 4 years may be acceptable depending on conditions), but not to over-design to the extreme to eliminate most failures but require excess equipment costs.

Progressing Cavity Pumping

Progressing cavity pumps (PCP's) can do a better job of handling gas and solids than most other types of pumps. They can not withstand high temperatures or highly aromatic fluids and they can produce a limited head so their depth is limited. They can be driven by rotating sucker rods or downhole electrical submersible pump motors.

- Measurements. Primary measurements are tubing pressure, tubing temperature, casing pressure, flow rate (if possible), and torque and RPM of the sucker rod. When downhole motors are used, the pump intake pressure and temperature are measured. The production rate divided the polished rod RPM times the Pump Constant (production with no pump slip) is often monitored as one measure of the fit between the rotor and stator.

- Control. PCP's must not be allowed to pump-off as this can lead to excessive temperatures that can damage the elastomers used on the pump stators. Pumps must be stopped before pump-off occurs or variable speed drives must be used to limit the production rate so that pump-off doesn't occur. Pump-off may be indicated by monitoring measured flow rates or downhole pressures.

- Unique Hardware and Software.   PCP's uses wellhead RTU's to control the rod rotation and torque, or to interface to the downhole motor.

- Specialized Alarms. PCP software can detect and report specialized alarms to indicate the problems listed below, and others. These alarms and trend plots of operating variables are used for routine surveillance.

  - A hole in the tubing.
  - Pump-off at an unexpected time.
  - A rod and/or rotor failure.
  - A plugged flowline.
  - A flow restriction or gas build-up in the casing/tubing annulus.
  - High rod torque
  - No flow

- Analysis. Comparison of current pump performance with modeled performance is used to analyze the PCP system. There is a system called PCP-RIFTS[3] (PCP Reliability Information and Failure Tracking System) that is used to evaluate PCP failures, determine their causes, and make improvements for the future.

- Design and Optimization. Most production automation systems don't contain PCP design and optimization programs, but there is at least one excellent PCP design and optimization program available in industry[4]. It can be interfaced to the automation system. Design must include the looseness of fit when the pump is built, in anticipation that the stator rubber will swell to some degree when in operation in well conditions. Installation must include spacing the pump off the tag bar so that when the pump is loaded, the rotor is evenly spaced in the pump stator.

Electrical Submersible Pumping

Electrical submersible pumps (ESP's) can lift large volumes of fluid from significant depths. They are used for gas well deliquification when larger quantities of water must be produced to recover the gas, such as several 100 bpd of fluid production. However test programs with ESP's with production rates down to as low as 40 bpd have been made. Problems include handling large volumes of gas, handling solids, and withstanding high temperatures. Although not as critical as with PCP operation, ESP systems perform better with continuous operation as opposed to pumping off or requiring frequent shut-downs due to facility constraints.   Figure 3 shows a typical ESP automation set up.

- Measurements. Three types of measurements are used with ESP's:

  - Surface variables: tubing pressure, casing pressure, flow rate (if possible), and sand production (if pertinent).
  - Electrical parameters: current, voltage, current and voltage imbalance, and power consumption.
  - Downhole variables: pump intake pressure and temperature, motor winding temperature, motor shaft vibration, and others.

- Control. Primary control consists of starting, stopping and overload/underload shut-downs. Special control logic can be used to limit production rates by controlling back pressure when a fixed speed drive is used, or controlling motor speed when a variable speed drive is used. Typically the system will automatically restart after an underload shut-down but a manual restart will be required after an overload shutdown, after some inspections. Also, special logic can be used for start up of sandy wells. See Figure 4.

- Unique Hardware and Software. All ESP's have a fixed speed or variable speed controller that primarily provides start-up and safety shutdown. Usually, a separate wellhead RTU is used to gather the information listed above and execute control commands via the controllers.

- Specialized Alarms. ESP software can detect:

  - Low production rate. There may be a risk of motor overheating due to inadequate cooling.
  - Very low production rate. There may be a risk of downthrust of the bearings.
  - High production rate. There may be a risk of excessive drawdown and sand influx.
  - Very high production rate or starting against no tubing fluid load. There may be risk of upthrust on the bearings.
  - High motor temperature.
  - High motor shaft vibration.

- Surveillance and Analysis. Surveillance is performed by monitoring for special alarms and watching trend plots. Analysis is performed to determine how the well is performing, how the ESP pump system is performing, and how the two are working together as a system. See Figure 5 which indicates how the well and ESP pump are working as a system. Further surveillance is provided with ESP-RIFTS[5] (ESP Reliability Information and Failure Tracking System) that is used to evaluate ESP failures, determine their causes, and make improvements for the future.

- Design and Optimization. Most production automation systems don't contain "on board" design and optimization" software, but there excellent programs available in Industry that can be linked to the automation system.

Hydraulic Pumping

Two types of hydraulic pumping systems are used: jet pumps and hydraulic piston pumps. The systems may be open (the injected fluid is combined with the produced fluid downhole) or closed (the injection fluid is kept separate from the produced fluid). World wide hydraulic pumps compose only a percent or two of the total artificial lift market so they may be considered as satisfying certain niche operations that are difficult to achieve with other systems.

- Measurements and Surveillance. The following parameters are measured and monitored:

  - Flowing wellhead pressure.
  - Wellhead injection pressure.
  - Wellhead power fluid injection rate
  - Wellhead temperature.
  - Production choke position.
  - Surface pump status, suction, and discharge pressure

- Control. Control options include;

  - Surface pump status (on/off).
  - Surface pump speed.
  - Production choke position.

Tubing Plungers

Tubing plungers are used extensively for gas well deliquification. They are relatively low cost, they can be installed without a rig or pulling unit, they don't required external power as they are operated by the pressure in the well itself, and they work in highly deviated wells. Several different types of plungers are used. See Figure 6.

Feasibility for conventional plunger operation may include a gas ratio of ~400 Scf/Bbl per 1000 Feet and a pressure requirement of operating casing pressure reaching or exceeding 1 ½ times the surface downstream pressure. The operating casing pressure would have to be achieved in a reasonable amount of time, perhaps no more than 1 hour. Tubing plunger operation may include “continuous operation” where the plunger component(s) can fall against the flow with a shut-in of only a few seconds and “conventional operation” where the well is shut-in to allow plunger fall and pressure rise later in the life of the well.

- Measurements. Typical measurements include the ones listed below and several others. See Figure 7.

    - Tubing pressure.
    - Casing pressure.
    - Differential pressure.
    - Plunger arrival at the surface.

- Control. Much work has been done to develop optimum plunger control systems. The goal is to optimize the gas production per plunger cycle.

- Unique Hardware and Software. Specialized wellhead RTU’s are used that gather the pertinent information and provide the desired control to optimize the “on” and “off” cycles.

- Specialized Alarms. Special alarms include:

    - High plunger velocity. This may indicate tha the plunger didn’t reach bottom or that is is coming up dry with no liquid production.
    - High number of cycles per day. This may indicate that the plunger is wearing and losing efficiency.
    - High tubing pressure.

- Surveillance and Analysis. Monitoring focuses on the key alarms and trend plots. Analysis is performed to assure that the gas production rate remains above the critical velocity.

- Design and Optimization. This is focused on determining the best type of plunger to use and the optimum plunger control logic.

Casing Plungers

Automation of casing plungers is similar to automation of tubing plungers. Casing plungers are used in tubing-less completions. The main issue is that there is no annulus where gas pressure can accumulate to help lift the plunger, but the larger area of the plunger allows the plunger/liquid slug to be lifted with very low well pressures (even 20-30 psi).

Soap Sticks, Batch Chemical, and Continuous Chemical

Three methods are used to introduce chemical into gas wells to assist with deliquification.

- Soap sticks are periodically dropped in the tubing.
- Chemical is injected down the casing/tubing annulus in batches or is pushed down the tubing in batches.
- Chemical is injected continuously down a capillary string below the end of the tubing.

The goal is to inject the chemical at the right frequency or rate, and at the desired depth, so the well can maintain gas production velocity above the critical velocity.

- Measurements and Control. Measurements include tubing pressure, casing pressure, gas production rate, chemical injection pump status (of/off), and chemical injection frequency of rate. The chemical injection frequency or rate is controlled to keep the gas velocity above critical. Dropping of soap sticks or chemical injection batch frequencies or constant injection rates can be automated and monitored.

Velocity Strings

In some cases, a smaller tubing size is used to increase the gas flow velocity above critical. Monitoring consists of measuring the tubing pressure and gas production rate so the velocity can be compared with the calculated critical velocity. When it is no longer possible to achieve critical velocity, a smaller tubing must be installed, or, some other form of artificial lift must be considered. A small string installed too soon will create friction back pressure, which slows production just as liquid loading does in a larger string.

Surface Compression

Surface compression systems are often used to reduce the wellhead pressure as low as possible to enhance the gas production rate, keep liquids in the vapor state, and to boost the gas pressure so it can flow to the production system. Compression combined with most any other deliquification system enhances the operation of the other systems.

- Measurements and Analysis. Measurements include wellhead pressure, gas production rate, compressor discharge pressure, and compressor status. The gas production velocity is compared with critical velocity to determine if the production needs to be augmented by chemical injection, use of a plunger, or some other method.

Continuous Gas-Lift

The concept for low liquid rate gas wells is that the sum of the injection and produced gas rate must exceed the critical rate to eliminate liquid loading.

Gas-lift has several advantages for gas well deliquification:

- It likes gas; the more the better.
- It can be installed in any well deviation and well depth.
- Downhole equipment can be installed by wire line.
- It can handle some sand production.
- Just enough gas can be injected to maintain critical velocity, plus some safety factor
- It isn't necessary to cycle wells; they can produce 100% of the time.

Disadvantages or challenges are:

- A source of high pressure gas is needed for injection.
- A good control system is needed.
- Close surveillance is important.

- Measurements. Primary measurements are:

    - Gas injection rate and pressure.
    - Production pressure.
    - Gas production rate.

    Optional measurements include:

    - Gas injection temperature.
    - Production temperature.
    - Liquid production rate, if possible.
    - Downhole variables, if possible, including downhole pressure and gas passage through the operating gas-lift valve or orifice.

    Some gas lift systems utilize gas injection around the end of the tubing with no gas-lift valves in the system.

- Control. The primary control objective, once the well is unloaded (liquid has been produced out of the casing/tubing annulus) is to inject the right amount of gas to maintain or slightly exceed critical velocity.

- Unique Hardware and Software. A special wellhead RTU is used to gather the information, determine the amount of gas needed to maintain critical flow, and control this rate of gas injection.

- Specialized Alarms and Surveillance. Several special alarms are used for gas-lift surveillance.

  - Injection pressure heading or instability. See Figure 8.
  - Production pressure heading or instability.
  - Injection gas freezing.
  - Gas blowing around, as through an upper gas-lift valve or a tubing leak.

- Analysis and Optimization. The three primary goals of gas-lift are:

  - Inject the gas as deep as possible in the well.
  - Inject it at a steady rate.
  - Inject it at the optimum rate to maintain critical velocity.

  This is best done by analyzing the downhole performance. See Figure 9.

- Design. There two primary design steps in gas-lift:

  - Design the spacing of the gas-lift mandrels so the well can be unloaded to bottom.
  - Design the gas-lift valves to open and close at the right pressures and pass the desired amount of gas.
  - When no valves are used, a procedure to first rid the well of fluids is considered and gas is injected around the end of the tubing.

  There are several good gas-lift design programs available in Industry to accomplish these objectives. They can be linked to the automation system. At this time, the SNAP program (Ryder Scott) allows the design of gas-lift for a gas well in terms of gas well parameters instead of adapting an oil well design program to the problem with a high GLR.

Intermittent Gas-Lift

Unlike continuous gas-lift, with intermittent gas-lift, gas is injected in cycles to produce "slugs" of liquid. Is is used for low pressure or low flow rate oil wells. It is rarely used for gas well deliquification. Where it is, there are two control methods:

- Intermittent or cycle control were gas injection is turned on and off for each cycle.
- Choke control where gas is injected continuously at a low rate and the cycle action is controlled by the opening and closing of the downhole injection valve.

Plunger lift is similar to intermittent gas-lift and some intermittent gas lift operations can be designed to operate with plungers included to help eliminate liquid slug fall-back.

Heaters

Heaters, in the form of electrical submersible pump cables in the well, are sometimes used to heat the gas to prevent condensation of water. The primary measurements and associated control are gas production rate and pressure to compare measured production rate vs. critical flow, and the electrical current provided to create heat. This method requires condensed water only as the source of loading as heating of salt water would soon create salt bridges in the well.

Cycling

Cycling, stop clocking, or intermitting is sometimes used when liquid loading first starts. The primary measurements and associated control are gas production rate and pressure to compare measured production rate vs. critical flow, and control of the cycling operations. This is normally thought of being a temporary method of continuing production until a more suitable form of artificial lift is added. However it is not uncommon.

PRODUCTION AUTOMATION ISSUES

There are a number of issues that must be understood and addressed to have a successful state-of-the-art production automation system. Even if the best automation equipment, general applications, and unique applications are used, the system may fail if these issues are ignored or not addressed fully and correctly.

The purpose of this section is to highlight these most important issues and how to address them. These are discussed in much more detail in Reference No. 1.

Typical Benefits

Typical benefits of state-of-the-art production automation systems arise in the following areas:

- Increased production by:
  - Early detection and correction of unplanned downtime.
  - Maintaining peak operating efficiency.
  - Keeping flow rate above critical velocity.
  - Maintaining production until the economic limit is reached

- Reduced operating costs by:
  - Using fewer people for routine operations.
  - Using less automotive, boat, or helicopter transportation.
  - Optimizing use of energy.
  - Optimizing use of expendables such as chemicals.

- Reduced maintenance costs by:
  - Keeping systems operating within safe operating envelopes.
  - Detecting and addressing problems before they become failures.

- Reduced capital costs by:
  - Deploying the right type and size of artificial lift system for each well.
  - Not over designing systems.

- Artificial lift specific benefits, such as:
  - For sucker rod systems: 7% more production, 20% energy reduction, 35% maintenance cost reduction.
  - For electrical submersible pumping: 3% more production.
  - For gas-lift: 5% more production, 10% less gas injection, reduced compressor CAPEX.

- Improved safety by:
  - Operators visit wells less frequently.
  - Causes of problems are known in advance, before going to the well.

- Improved environmental protection by:
  - Immediately, remotely stop production if a leak is detected.

- Improved personnel performance by:
  - Users gain a better understanding of well and artificial lift system operation.
  - Automation can be used as a good recruiting tool.

Potential Problem Areas

There are several potential problem areas that must receive attention to avoid pitfalls that can lead to under acceptance or outright failure of a production automation system.

- Automation system design. An important principle is to keep the automation system design simple, but not too simple. It should not be too complex as this leads to excessive complications and costs. But it must be detailed enough to achieve the benefits listed above. If it doesn't, it won't be fully accepted and used.

- Instrumentation selection. Instruments provide the measurements that are fundamental to the system.

Accuracy and high reliability are more important than low cost.

- Automation hardware and software selection. RTU's and PLC's should be selected for each specific application; i.e. for each type of artificial lift, each type of production facility, etc. But they must be able to communicate with a common host production automation system. And the host system must support all of the forms of artificial lift and production facilities that are used in the production system.

- Environmental protection. Often gas production operations occur in extreme environments of climate, temperature, etc. This is also an area where high reliability is more important than low cost.

- Communications. The communications system should be designed by a person expert in communications; it must support close to a 100% communication success rate.

- Project team. The project team is discussed in the section on staffing. It must have the confidence of the full user community and the support of management.

- Integration into the organization. The production automation system must support the entire organization. It will fail if it is perceived as the "pet project" of one engineer.

Justification

Every company has its own economic criteria for evaluating and justifying projects. These primarily consider the economic benefits and the CAPEX and OPEX costs discussed in the next sections. They should also consider the intangible benefits that are difficult to state in monetary terms but may be equally or more important. These include health, safety, security, environmental protection, and staff development and support.

- The impact of time. It is important to consider that benefits occur over time, and the size of certain benefits such as production increases, cost savings, etc. will change over time. Also, technology changes rapidly and it is likely that components of the automation system will need to be upgraded or replaced every few years.

- Acceleration vs. increased recovery. Some automation functions help to increase production. But is this acceleration, that is obtaining the production sooner, or is it an increase in the ultimate recovery? Acceleration occurs when the same total production can be obtained sooner due to higher production rates or less downtime. Increased recovery occurs when the abandonment reservoir pressure can be lowered by producing the "last gas" from the reservoir. Determination of acceleration vs. increased recovery often requires input from several people including Reservoir Engineering.

- The role of pilot tests. Some companies are reluctant to commit large projects without proof of the costs and benefits. It is true that all fields are different. Production automation equipment, logic, and technology have been proven in many applications and do not need to be pilot tested and proven again. However, the successful application of production automation in a given field depends on many factors that may need to be demonstrated before launching on a full-scale implementation. Also, if new technology is being used, it must be proven before broad implementation.

CAPEX

The initial capital expenditures of a production automation project are relatively easy to determine; normally based on bids. More difficult to estimate are the amounts and timing of future capital expenditures to replace or upgrade initial equipment. Typical capital expenditures are for:

- Instruments.
- Controls.
- Wellsite systems (e.g. RTU's, PLC's., controllers).
- Wiring and installation.
- Communications.
- Servers.

- Desktop computers or computer upgrades.
- Software licenses.
- Related services that may be considered as capital expenses.

OPEX

Typical operating expenses include:

- Information technology support.
- Project management.
- Systems integration.
- Telecommunication fees.
- Web hosting services.
- Software leasing fees.

Design

Production automation systems need to be carefully designed to avoid cost and time over runs, and falling short of meeting important expectations.

- People. All stakeholders must be involved in the design process, including engineers, operators, management, and support staff. Each group has needs that must be met by the system for them to accept and support it.

- Process. All companies have project processes. These should be followed; failing to do so can compromise support from management and project planners. And if the established processes aren't followed, the staff may revert to doing things the "same old way" and the advantages of the automation system will be forfeit.

- Technology. New technology can be enchanting. However, production automation systems should be designed with technology that is "fit for purpose;" not necessarily the "latest and greatest" just because it's there. Technology that is "tried and tested" will be more cost effective over the long term, unless a "new technology" is needed to provide a necessary functionality and it has been tested and proven for this application.

Installation

Installation of a production automation system requires careful planning, often long before the physical installation starts. Steps in the process include:

- Obtain historical data about the wells and their production.
- Set up test servers.
- Load historical data into the host system.
- Conduct site acceptance testing.
- Install the instruments.
- Install and configure the RTU's, PLC's, and controllers.
- Install and configure the communications.
- Commission the host automation system.
- Customize and configure the host.
- Install the client software.
- Train all users and support staff.

Security

Assure security of physical automation equipment and proprietary information.

- Field devices. Instruments, RTU's, PLC's, controllers, and communications equipment in remote locations must be secured to prevent theft, vandalism, and unauthorized access.

- Host systems. Protect host systems from unauthorized access, recognizing that they will be connected to communications with field devices, user terminals, remote offices, and the internet.

Staffing

A successful production automation system should be supported by at least three teams or classes of teams. These teams and their composition are shown in Table 1.

- Steering Committee. This committee must provide the overall priority, justification, direction, and focus on the automation projects in a given Operating Company or Division. A key member of management must be on this committee. The committee should be let by a corporate or division Automation Champion.

- Automaton Team. This team is responsible for execution of the project. It is led by the lead automation engineer responsible for this automation system. It has members with special skills in instrumentation, field control systems, communications, computer hardware and software, and training.

- Surveillance Team. This team is responsible for routine use of the system. There may be separate teams for each field served by the system. Members will include engineers, well analysts, operators, well service personnel, maintenance staff, etc.

Training

At least three levels of training are required. See Table 2.

- Aware. Management and others who must understand and support the system need to be made *aware* of its purpose, benefits, costs, justification, capabilities, and support requirements.

- Knowledgeable. Engineers and supervisors must be *knowledgeable* in the detailed aspects of the system and the skills and training needed by those who must operate and use the system.

- Skilled. Engineers, well analysts, operators, and others who use the system on a day-to-day basis must be *skilled* in making full use of the system and its features and functions to operate, control, diagnose problems, and optimize the wells and production systems.

  There is some risk if well control is fully turned over to an automation system and the results and set points are not frequently monitored or checked. Some systems may wander off optimum operation but still continue to produce with no interruptions. To insure this does not happen, some frequency of inspection is required for best operation.

Commercial vs. In-House

In former days, there weren’t many Service/Supply Companies producing production automation systems so some Operating Companies built their own systems.[6] These days, the situation has shifted where few Operating Companies develop and maintain their own system; they rely on systems developed by Service/Supply Companies. This is appropriate as long as the automation systems they produce and support are state-of-the-art systems as expounded in this paper.

SUMMARY

Considering the value of oil and gas, the costs of staff and services, and the negative impact of liquid loading on gas production and recovery, the case for production automation is compelling.[1] Hopefully the case has been made that the cost of using state-of-the-art systems is well justified. This is a case where quality is more important than low cost.

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Table 1
Production Automation Teams

		Teams		
Staff Position	In House Staff?	Steering	Automation	Surveillance
Champion	If possible	Facilitator	Advisor	
Management	Definitely	Chair		
Project engineer	If possible	Yes	Chair	
Engineering	If possible	Yes	Yes	Yes
Automation specialists		Yes	Yes	
Technicians	If possible		Yes	
Automation support			Yes	
Operations	If possible	Yes	Yes	Yes
Maintenance	If possible	Yes	Yes	Yes
Well analysis	If possible	Yes	Yes	Chair
Well servicing				
Accounting/finance		Yes		
Others/service company			Sometimes	Sometimes

Table 2
Production Automation Teams

	Training Level Required			
Staff Position	Aware	Knowledgeable	Skilled	Comments
Champion			■	Know entire system
Management	■			
Project engineer		■		
Engineering		■		
Automation specialists			■	Know entire system
Technicians			■	Know components
Automation support			■	Know support
Operations		■		
Maintenance			■	Know components
Well analysis			■	Know applications
Well servicing	■			
Accounting/finance	■			
Others/service company	■	■		Depends on job

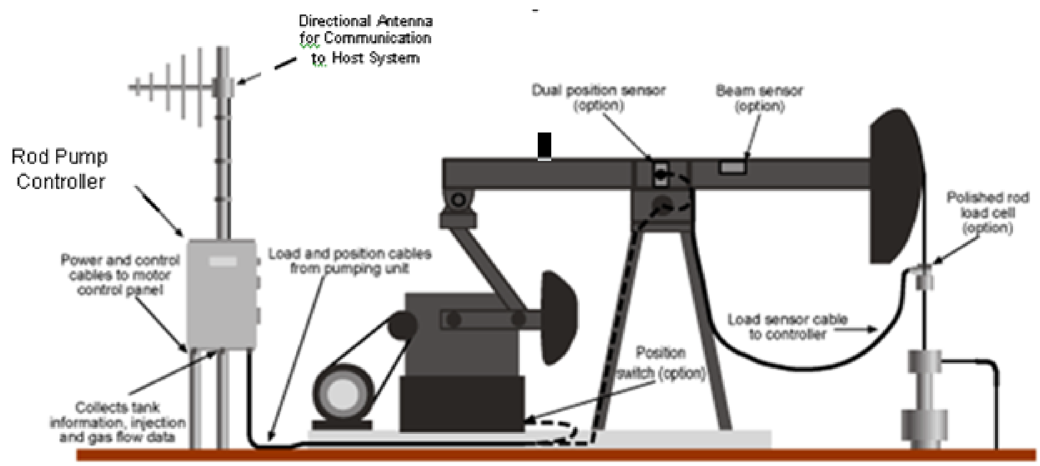

Figure 1- Schematic of Sucker Rod Pumping System Equipped for Automation

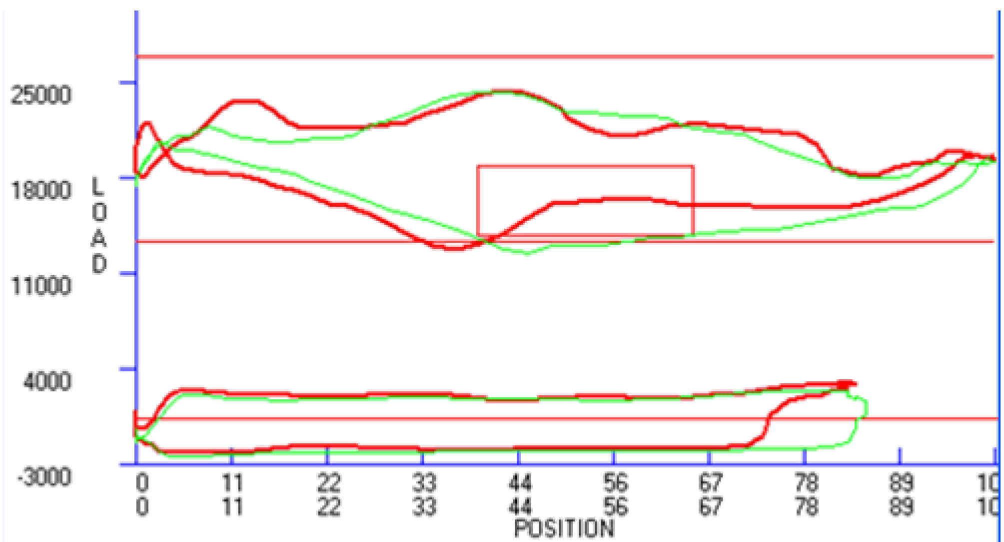

Figure 2 - Plot of Sucker Rod Load vs. Position
Surface Full (Green) and Pump-Off (Red) Card on Top
Downhole Full and Pump-Off Card on Bottom

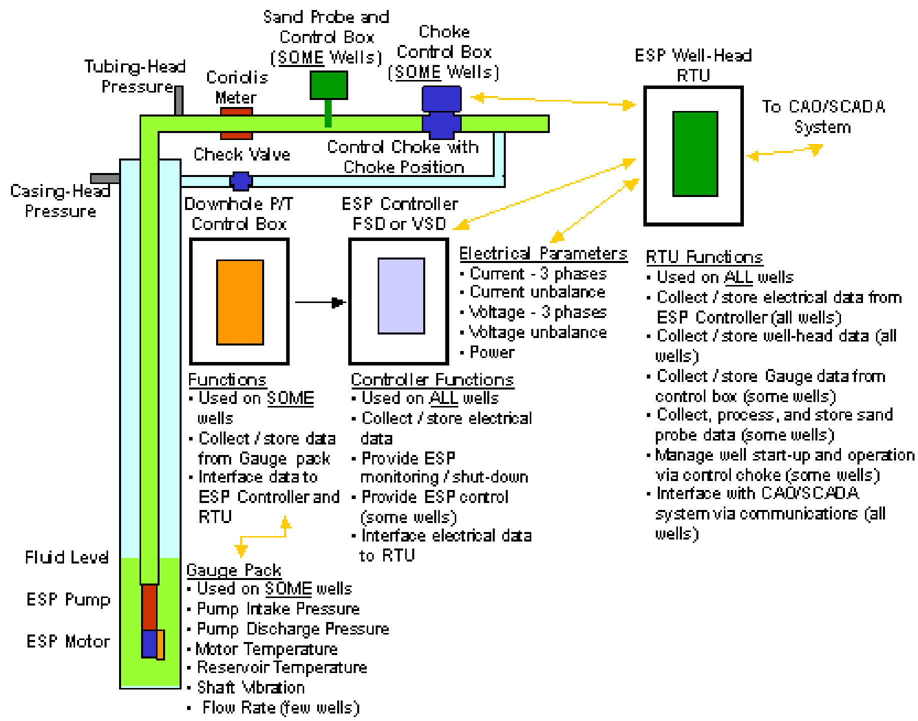

Figure 3 – Schematic of Electrical Submersible Pumping System Equipped for Automation

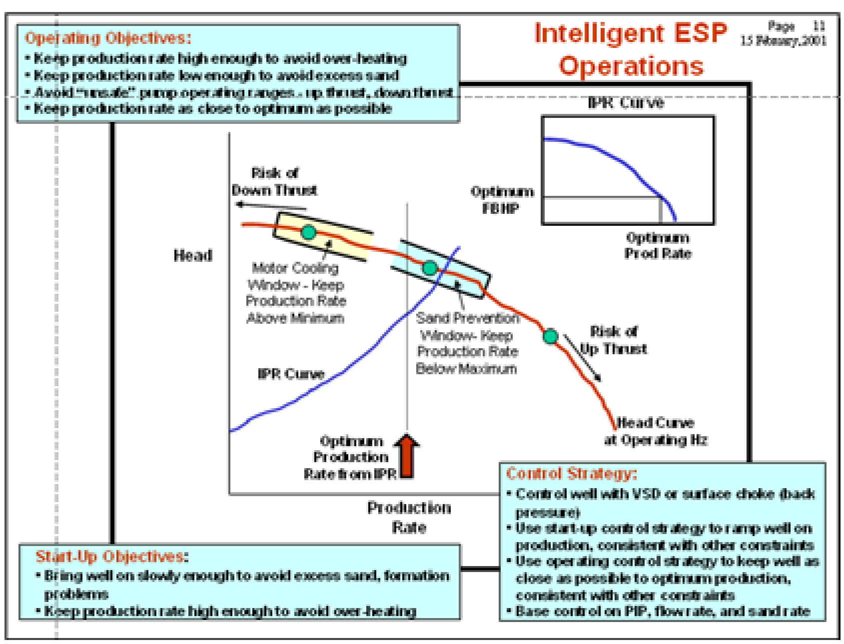

Figure 4 – System Start-UP Guidelines

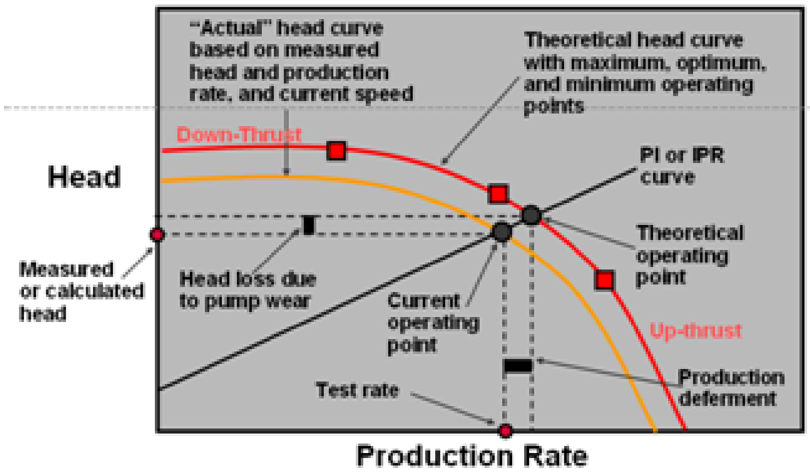

Figure 5 – ESP System Head Curve

Figure 6 – Types of Plungers
A: Conventional grooved, padded and brush plungers (require well shut for plunger fall)
B: Two-piece plunger (components fall against flow)
C: Continuous RapidFlo Pluner (can fall against flow)

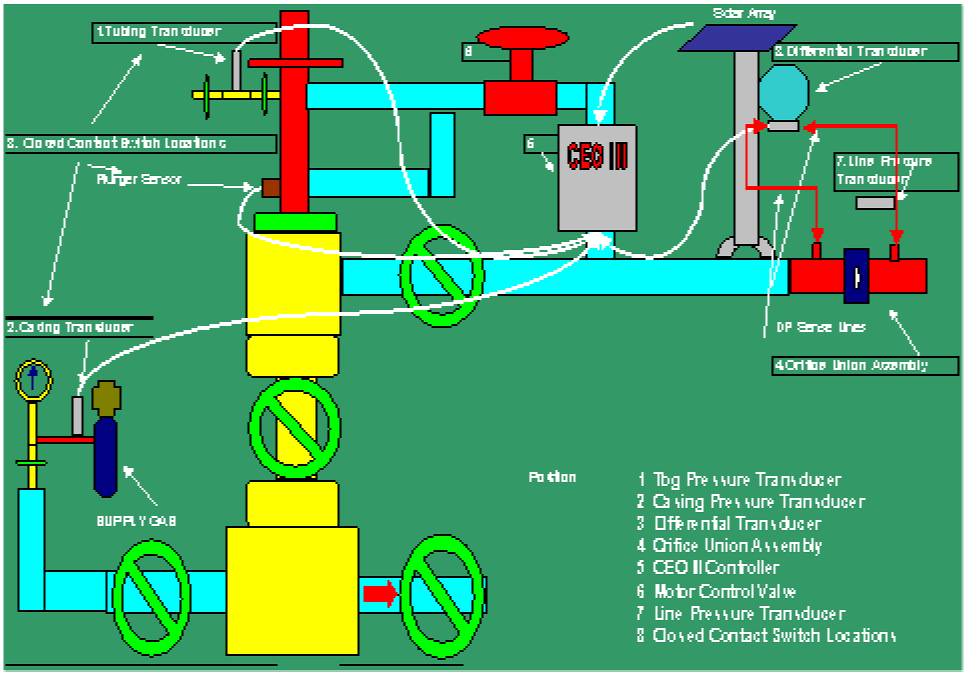

Figure 7 – Schematic of Plunger Lift System Equipped for Automation

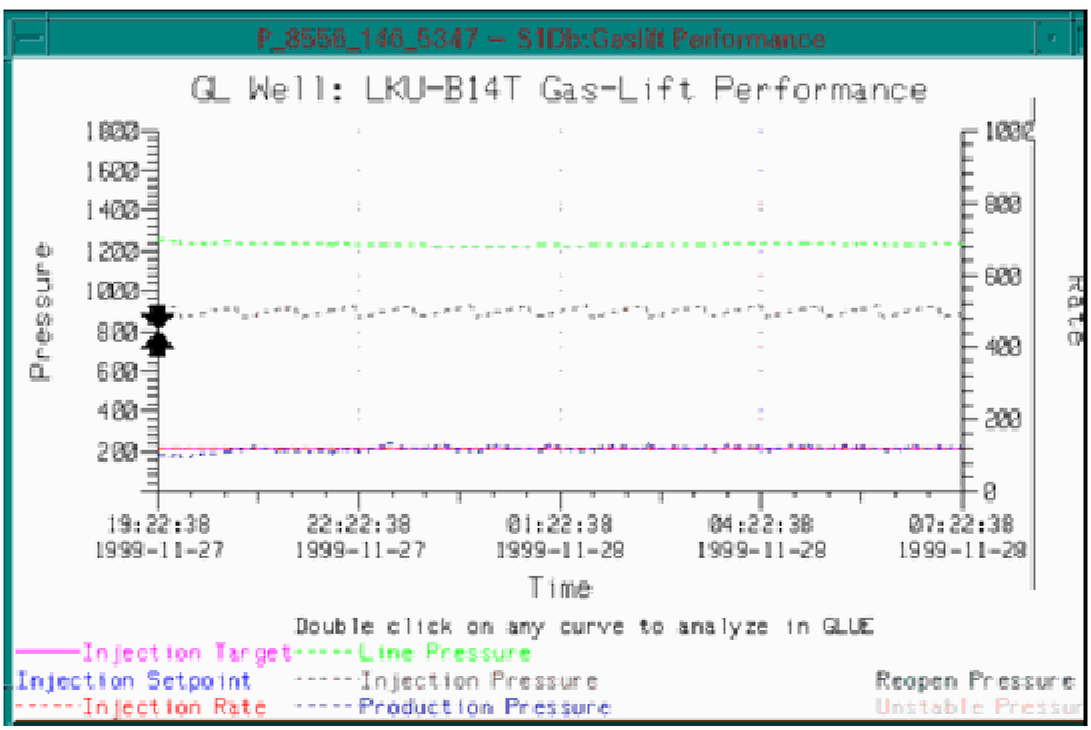

Figure 8 – As-Lift Surveillance Plot Showing Heading Injection Pressure vs. Time

Gas-Lift Analysis Plot

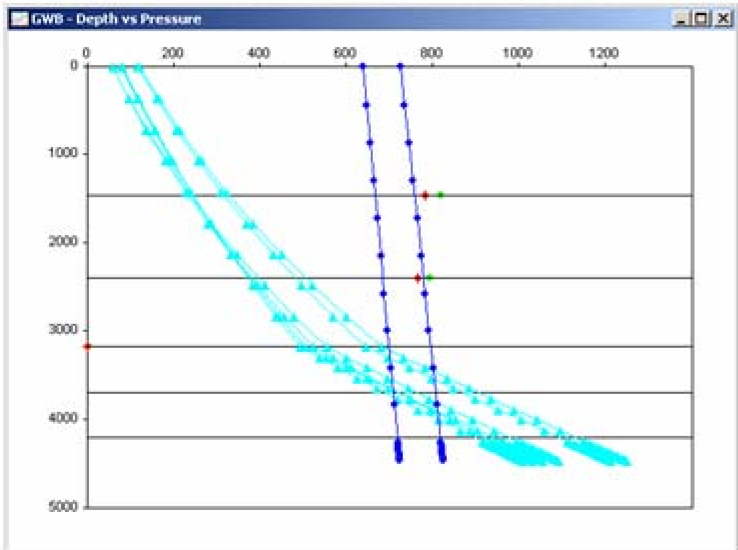

Figure 9 – Showing Downhole Tubing and Casing Pressures vs. Depth