SPE 858

PRODUCTION
CONTROL

Gas Well Automation

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Abstract

The design and operation of an automated gas flow and well control system is discussed. The system, designed to reduce operating costs and improve operating efficiency, presently controls 44 gas completions in the Bastian Bay field, Plaquemines Parish, in the marshes of South Louisiana. All wells are controlled from and connected with a central control station via buried multiconductor cable. The reasons remote control is desirable in this field are discussed, the design requirements are listed, the operation of the system is described and the advantages and disadvantages of the system selected are cited.

Introduction

There has been a recent growing tendency for oil companies to reduce or eliminate routine manual labor through the use of equipment designed to operate remotely, unattended and automatically. Systems are presently available for oil field use that can accomplish almost any desired function, limited only by the imagination of the engineer and the amount of investment a company wishes to make. It is the job of the engineer to selectively utilize systems that are practical in application and yet reasonable in cost. The primary function of any automation system is to increase operating efficiency and reduce operating costs.

The object of this paper is to review the process by which automation equipment was selected for a large South Louisiana gas field, to describe the automation system selected and to outline its advantages and disadvantages.

Description of Field

Fig. 1 shows the geographical location of the Bastian Bay field, Plaquemines Parish, La. It is located in the Mississippi River delta area, approximately 70 miles southeast of New Orleans. Tenneco Oil Co., acting as operator for Tennessee Gas Transmission Co., operates 44 gas wells located within an area of approximately 8 sq miles. The field is located in a salt marsh adjacent to the Gulf of Mexico and is accessible only by boat. It is also approximately 12 miles from the nearest boat landing or supply point. All wells in the field were drilled from shallow-water, barge-mounted drilling rigs, and all wells are connected through a series of dredged access canals. Fig. 2 shows the field layout and location of the wells and canals. The water depth throughout the field is primarily dependent upon the tide, but ranges from 4 to 8 ft.

In this field conservation units are formed about most of the wells, which result in varying working and royalty interests for each completion. Therefore, each gas completion produces through an individual heater and low temperature separation unit, and its production is separately metered. The condensate passes through individual positive volume meters and is then commingled into a condensate pipeline gathering system. The gas is measured by orifice

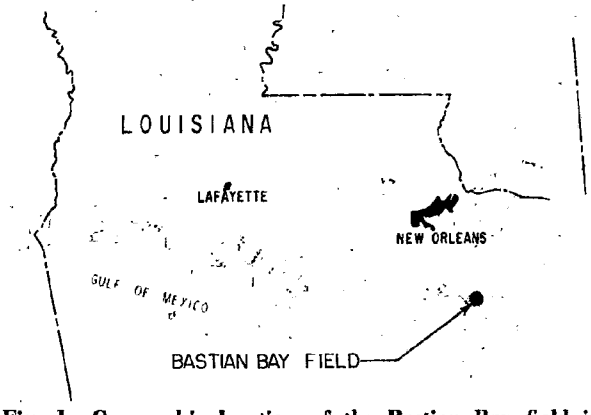

Fig. 1—Geographic location of the Bastian Bay field in South Louisiana.

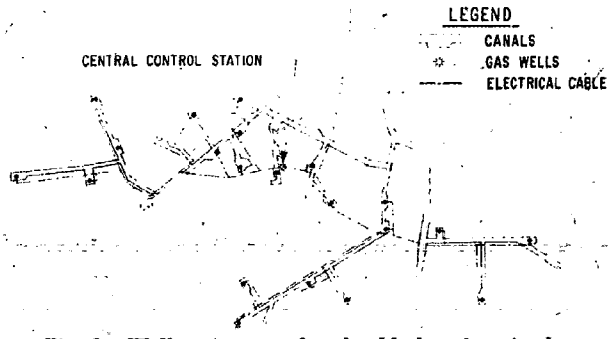

Fig. 2—Well, access canal and cable locations in the Bastian Bay field.

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meter and then commingled into a gas pipeline gathering system. Production units are on platforms located near the wellhead as is practical. Distances from production units to wellheads vary from 120 to 1,300 ft. Both the gas and condensate are collected and further processed at central gathering facilities where the gas is delivered to sales and the condensate to stock tanks. Because the marsh will not support normal foundation loads, all facilities are placed on concrete or timber pile platforms.

Individual gas completions produce at flowing tubing pressures ranging from 3,000 to 5,000 psi, while gas sales line pressure averages 1,000 psi. Individual gas completions produce at rates from 1,500 to 9,000 Mcf/D, with total field gas volumes ranging from 50 to over 260 MMcf/D.

Reasons for Automation

There were a number of unusually good reasons for installing an automation system in the Bastian Bay field.

1. Lease operation by boat requires extra time, labor and expense and often costs two to three times as much as similar land operations.

2. Normally, changes in total sales gas volume would require manual adjustment of the individual production units until the desired total sales gas volume was obtained. In this field, Tenneco is bound by a balancing agreement which requires that withdrawals from a reservoir be rateable by wells; therefore, volume changes could be effected only by adjusting all or most wells. This procedure could require one man two to six hours for every volume change. In addition, changes in gas well allowables, as well as over- and under-production, would require regular individual manual adjustment. Obviously, any system that could control individual well production from a central point could result in sizeable boat-man-day savings and also result in faster volume changes.

3. The majority of the wells were completed prior to the purchase and installation of production facilities. This gave Tenneco the advantage of installing a control system at the same time production facilities were being installed. The entire system could be purchased and installed on a turnkey bid basis.

4. The remote location of the field required that a complete safety shut-in system be installed on each completion. This equipment could be incorporated into the automation system, thereby reducing the required automation investment.

Design Requirements

It was the intention to obtain the simplest, most efficient, well-designed and workable system to remotely control the production units at a minimum cost. The system, however, had to be designed to meet several requirements: (1) the basic information needs of the company; (2) economy; (3) safety; and (4) climatic environment of the salt marsh. These requirements, as seen during the design phase, are summarized:

The system (1) should be capable of remotely opening or closing-in a well, raising or lowering its production rate, and observing its production rate from a central control point; (2) should be readily understood and easily repaired by field personnel, with parts and service easily obtainable; (3) should utilize, on the production platforms, only controls housed in explosion-proof enclosures; (4) should provide for manual operation at each production unit, with or without electrical or pneumatic power; (5) should be a "fail-safe" system; (6) should not require that power be generated at the individual wells or platform sites; (7) should not permit the malfunction or failure of one part of the system to cause other segments or the entire system to become inoperable; (8) should utilize existing equipment to the greatest extent possible; (9) all equipment and materials should be corrosion-resistant, capable of operating in the salt marsh atmosphere; (10) all equipment and materials should be capable of withstanding the action of gnawing rodents and marine borers; and (11) all controls should be rugged enough to withstand normal oilfield usage.

Description of the Control System

Based upon these requirements, the following plan was adopted. The basic system was to be pneumatic, because of the availability, reliability and relative simplicity of such components. Electrical controls were to be added to the basic pneumatic control system only to change or interrupt pneumatic signals.

The Pneumatic System

In addition to operating liquid level and temperature controls, the pneumatic system operates as shown schematically in Fig. 3. The safety shut-in valve on the Christmas tree is a normally-closed diaphragm-operated valve held open by a pneumatic control signal from a pneumatic relay. This control signal, which has its own supply-gas regulator, is either an on or off signal depending upon the pilot signal sent to it from the high-low pressure pilots. This system also has its own supply gas regulator. As long as no upsetting high or low pressure occurs in the production unit or flowline, the pilot pressure is maintained on the pneumatic relay, thereby holding the safety shut-in valve open.

In addition to the high-low pressure pilots, two fusible plugs are located at each end of the production unit skid. In the event of a fire or other high temperature, the fusible plugs will melt, releasing the pilot pressure and shutting in the safety shut-in valve. Even if automation of the field had not been adopted, these pneumatic safety devices would have been required.

A four-way dual solenoid valve has been added to the

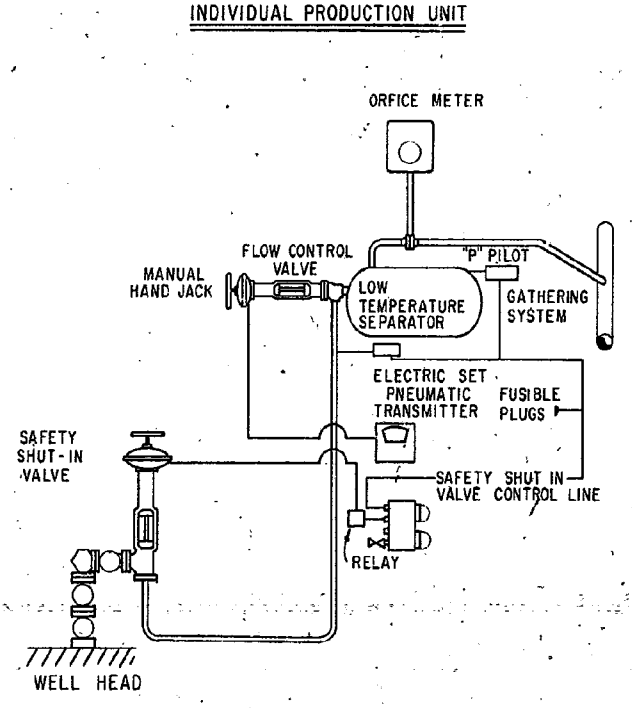

Fig. 3—Schematic diagram of pneumatic control system.

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pilot system. When this valve is electrically opened, the control pilot pressure passes unaffected through the solenoid valve. When closed, the solenoid valve bleeds the control pressure off, causing the relay to release the pressure holding the safety shut-in valve open. The solenoid valve will remain in either the open or closed position depending on the last signal sent to it and is unaffected by loss of electric power. Providing no upsetting high or low pressures affect the pilots, this device permits opening and shutting-in, from the production platform, of the flow at the wellhead.

The safety shut-in valve may also be controlled manually by use of the handjacks on the valve. It may be locked open or shut regardless of any pneumatic signal. In the neutral position, between open and shut, the valve can be operated pneumatically.

The flow control valve is also controlled pneumatically. To open or close this diaphragm-operated valve at the individual production unit, it is only necessary to adjust a manual control on the electric-set pneumatic transmitter. This same valve may also be opened or closed remotely from the central control panel by the use of electric set control. By energizing the electric reversible AC motor in the instrument, the supply pressure to the flow control valve can be adjusted to any desired flow rate. In the event of total loss of both pneumatic and electrical power, the normally closed valve may be opened or shut with the manual handjack located on the flow control valve.

The Electrical System

The addition of electrical controls for telemetry and supervisory function is shown schematically in Fig. 4. Each individual gas completion has a static and differential pressure transmitter located adjacent to a recording orifice meter on the production unit. A corresponding strip chart recorder, located at the control center, continuously records the static and differential pressure from each of these production units. In this way, the total volume being produced from each production unit can be continuously calculated. Observation of the strip chart records also reveals the condition of the flowing well, such as the water and condensate dump cycles, and the operating pressure of the production unit. The orifice meters are presently being used for accounting purposes, but the 16-day strip charts can be used when a suitable integrator is available. This will allow all chart changing to take place in the control center at the panel board. This telemetry function, which includes P and d/P transmitter, recorder and power packs, normally requires 13 w/unit. It operates with a 65 v DC 10 to 50 ma. transmission signal.

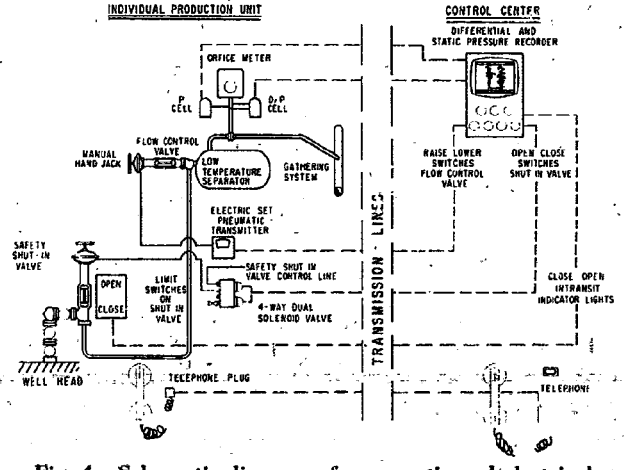

Fig. 4—Schematic diagram of pneumatic and electrical control system.

Switches on the control center panel permit regulation of the volume through each production unit. Depressing these switches energizes the reversible AC motor on the electric-set pneumatic transmitter and positions the diaphragm-operated flow control valve. In this way, the volume from any production unit can be adjusted to meet current volume requirements. When energized, this device is rated at 4 w, 110 v AC. Fig. 5 shows the control system for an individual production unit.

In the same manner, open and close switches located on the panel at the control center energize the four-way dual solenoid to open or shut-in the safety shut-in valve. To ensure that the safety shut-in valve has actually completed this open or shut-in function, limit switches located on the safety shut-in valve light up indicator lamps on the panel to show the open, close, or in-transit position of this valve. In this way, personnel at the control center can be assured that the safety shut-in valve has actually completed its required function. When energized, the solenoid is rated at 10 w, 110 v, DC.

Telephone communication has also been provided at each production unit. When the explosion-proof phone and plug-in jack are connected into the line at the production units, a buzzer sounds and a signal light flashes on the panel at the control center. To answer an incoming call from any part of the field, it is necessary to depress the phone key on the panel board and communication is established. By depressing another key, the phone conversation can be put through an amplifier and into an outdoor speaker system. Since personnel are not continuously on duty in the control center, this provision allows personnel to work in its proximity and still maintain contact with the field. The same amplifier system may also be used as a paging system. The communication system operates on a 24-v DC system. Fig. 6 shows the control center panel and telephone.

Electrical cable used throughout the field is a double-sheathed telephone-type cable suitable for direct burial. It consists of an outer polyethylene jacket, a corrugated copper inner shield with an additional inner polyethylene jacket. Inside this is a core wrapped with a non-hygroscopic tape. The individual conductors are color coded and polyethylene insulated and consist of solid 19 AWG gauge wire. Forty splices were required and all were installed above ground in telephone-type splice cases. The splice cases are mounted vertically on timber piles driven into the marsh. The entire cable system is air pressured and purged to reduce cable breathing and the possibility of condensation of moisture. The use of air pressuring equipment also helps to locate leaks when they occur. Each production unit requires seven pairs of conductors to trans-

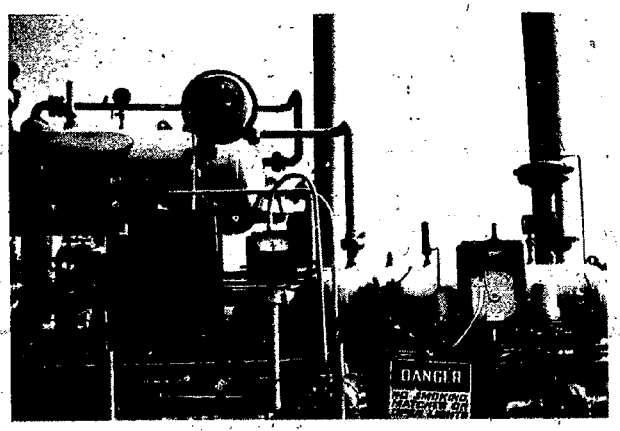

Fig. 5—Typical control system installation.

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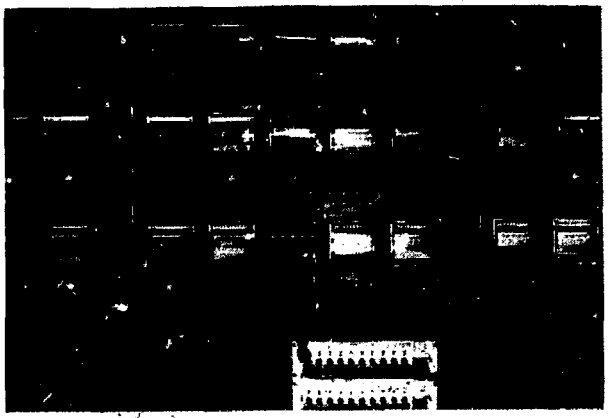

Fig. 6—Central control panel board showing recorders indicating lights, control buttons and telephone. Panel cover has been removed to show distribution and fuse panels.

mit signals and data plus one conductor for a communication line. The smallest cable used in this system has 12 pairs, which left room for spares and expansion.

Total power requirements for the entire electrical system average less than 14 w/production unit, or less than 600 w total.

Features of the Control System

The system is designed to provide safe, reliable operation. It satisfies all of the design requirements set forth earlier. In addition to those items, the following features should be pointed out.

1. The system is basically of modular design permitting easy plug-in expansion of the system.
2. Failure of electrical power does not disturb the flow rates of the wells or the operation of the safety shut-in system.
3. An indication of the position of the safety shut-in valve is provided at the control center.
4. A telephone communication system is provided.
5. The cable is air pressurized and purged, minimizing the possibility of cable breathing and condensation. In addition, the buried cable is less vulnerable to lightning, fires and other surface damage.
6. The flow rate of the wells and the condition of the flow is continuously recorded at the control center. By scanning the control panel, the operational status of the gathering system and all wells can be observed. In addition, the strip charts can serve as accountable records of the individual well's volume.
7. The information received at the control center and the control of production is compatible with and can be connected to additional supervisory controls for operation over telephone lines and/or microwaves. This permits the control center, in effect, to be located almost anywhere.

Difficulties Encountered

In the process of installing and operating this system, difficulties have been encountered from time to time. This is to be expected. Some of these difficulties are discussed.

In some instances, cables were not buried deep enough to prevent damage from boats and marsh buggies. Cables should be buried 5 to 6 ft beneath canals and 3 to 4 ft beneath marshes.

Some difficulty was encountered with condensation in cables as a result of cable arriving on location too far in advance of its use. The cable should be kept dry during storage and installation and should be pressurized as soon as possible.

In some cases where cables were buried in the same ditches with flowlines between wellhead and production unit, the heat of the flowline (150F+) caused insulation to melt, shorting the circuits. Cables from wellhead to production platform should be buried in separate ditches.

From time to time, salt crystals formed in junction boxes and caused shorts. Various anti-moisture and anti-corrosion sprays are presently available to reduce or eliminate this problem.

Restrictions or high pressure drops have caused poor control action on vents and supply gas lines to solenoids and other pneumatic devices. Control lines should be properly sized, and in addition, instrument vents and bleeds should be rain-proof and screened against insects.

In some instances, repair operations were undertaken in the field which should have been performed by trained service personnel. Ensure that competent service personnel and repair facilities are locally available and use them as necessary instead of depending entirely upon field personnel.

The pneumatic system as presented is a constant-bleed type, that is, when an upsetting high or low pressure occurs to trip the high-low pressure pilots, they continue to bleed off a small amount of gas. This is not a significant problem.

Economics

Because the purchase and installation of this system were based on turnkey bids and because the work was accomplished with other construction in the same field at the same time, substantial savings were realized.

The total system cost approximately $5,000/production unit, including all equipment, controls, cable and installation. Since automation equipment was installed at the same time as production equipment, no before and after automation operating expense figures are available for comparison or calculation of a payout. However, six personnel were operating 21 active completions in 1961, while 60 active completions plus a central hydrocarbon recovery facility are now being operated with essentially the same number of personnel.

Conclusion

Automation of lease facilities can benefit producing companies by reducing operating costs and improving operating efficiency when used to maximum advantage. The system described in this paper provides all necessary equipment for supervision, measurement and control of individual production units from a centrally located control center. It also includes other operating advantages such as a reliable communication system and a fail-safe design at a relatively reasonable cost. There are numerous other ways to automate production facilities; the choice should be balanced between the requirements of the operator and the cost of the system.

Acknowledgment

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EDITOR'S NOTE: A PICTURE AND BIOGRAPHICAL SKETCH OF H. J. FITZGIBBON APPEAR ON PAGE 897.

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