AUTOMATION HISTORY OF THE WILLARD UNIT CO2 PROJECT: A CASE STUDY

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INTRODUCTION

ARCO Oil and Gas Company's Willard Unit is located in the Wasson San Andres Field, Yoakum County, Texas. Waterflood operations began in 1965 with tertiary (alternating water-CO2) operations beginning in January, 1986 in the southern part of the unit. There are currently 335 producers, 270 injectors, 13 test stations, one central battery, and two water injection plants. Automation was installed first in 1973 and has progressed in three primary steps. This paper highlights that progression by discussing its utilization and results.

INITIAL AUTOMATION

In 1973, the main project area test stations (Nos. 1 - 9) were equipped for automated well testing. Each test station was equipped with two to seven three phase test separators, three way valves with actuators, turbine meters, and net oil computers. Each well was tested a minimum of once every five days. A daily morning report indicated whether the test was normal as compared to the previous month's average. The wells could be automatically and/or manually put into test and would automatically switch out of the vessel during high level or high pressure conditions. In addition, several key control points in the test stations were monitored with end devices for alarm status'.

The remaining test stations (Nos. 10 - 14) located in the northern part of the unit (called the Headwaters Area) and the central battery also had a limited number of end devices installed to obtain key alarms.

All project area alarms were hard wired into a central control computer located in the production office which triggered a printer with an audible tone. During normal office hours a secretary was responsible for acknowledging alarms and notifying the appropriate personnel. After hours an automatic dialing system notified a night rider via a handheld phone that an alarm existed, but he had to return to the office to obtain details. Headwaters area alarms were monitored via rotating red beacon lights located at each test station. This system worked well with some limitations.

Several wells during this time had low pressure fiberglass flowlines installed so butterfly valves with electro-hydraulic actuators were installed near the wellheads which would close if the pressure switches sensed a preset high or low pressure. There were no visible or audible alarms, nor was there a preventive maintenance schedule to check and/or calibrate the switches.

At this time the Willard Unit was operated by two production supervisors, six producing well pumpers, one injection/battery supervisor, and three injection pumpers. The daily well test reports were used by the pumpers as an aid to indicate that there might be a problem with a well. The automation was not utilized to the extent that any manpower was reduced, significant savings realized, nor production maximized except to slightly increase reaction time to upsets and/or failures. This state of automation continued until 1986.

PHASE II

The CO2 Project initiated several new stages of automation. First, to better monitor and control the CO2 injection, a distributed control system (DCS) was installed based upon the economics of the project. The system consists of a remote terminal unit (RTU) at each well looped to a master terminal unit (MTU) at each test station with a master control unit (MCU) at the office. The units are connected via communication loops and gateways, but are capable of stand alone process and logic functionality. The system can be divided into essentially three systems: automatic well testing, injection control, and facility alarms.

The old well test system was replaced by the DCS with the additional capabilities to see real time test status', remotely remove and/or place wells into test, and report the last 30 tests on each well. The information also came out in a format which enhanced uploading the information into ARCO's mainframe production allocation system (PARS).

The injection system automation allows for control based upon a set rate with a wellhead high pressure override to prevent fracturing the wells. It also constantly monitors the system giving real time well status, rate, and pressure. Wells can be shut in from the office manually or automatically if a leak is sensed by a rapid increase in rate or decrease in pressure. This latter function has been highly effective in recognizing and minimizing leaks. A daily morning injection report is printed and saved in a format which allows it to be loaded into PARS.

The DCS system also gives real time status' of the test and production vessels, oil tanks, water tanks, injection pump pressures, off production alarms if a test vessel does not indicate a dumped volume within a preset time, total gas and fluid volumes from each test station, and $CO2$ delivery volumes and pressures from each supply source. The alarms which now come into the office are much more operationally functional due to graphical presentations on a management control system console (MCS), but the notification process did not change.

During this same period, programmable logic controllers (PLC) were installed on LACT units, vapor recovery units, and injection pumps to improve flexibility and reduce electrical failure costs. There was also a PLC installed for additional alarms at the central battery in lieu of a more expensive MTU. However, the PLC's were tied into the DCS to transmit alarms back to the office.

Pump-off controllers (POC) were first installed at this time. Every well was separately evaluated, and 75 wells economically justified a POC based upon a standard criteria of electrical savings, reduced failure, and production increases. Typical AFIT economics showed an average payout of 1.4 years and a 76.4% investor's rate of return based upon $15.00 per barrel oil. A supervisory control and data acquisition (SCADA) system was installed which scanned the wells hourly. The POC's were maintained and set by engineering technicians so that in essence they pumped the wells from the office.

Additional flowline shutdown valves were installed, and all were wired such that a violation of the pressure settings would close the valve, shut the unit down, and illuminate an indicator light. A yearly PM program was started with the exception of wells located near public access which were placed on a monthly PM program.

During this time, organizational changes resulted in two supervisors, eight pumpers who had producers and injectors, and the addition of one instrument technician. Actual automation utilization was still minimal insofar as setting priorities, reducing manual inspection of wells, and in fact head count in the Willard Unit increased by one. However, the POC's and PLC's did realize savings and the DCS helped to significantly increase reaction time to leak alarms. This system basically remained the same until 1992.

PHASE III

In 1992, a commitment was made to again increase the level of automation with the goal of reducing operating costs while maintaining safety and environmental standards. To this end, additional automation was installed and job duties were redefined to capitalize on this new emphasis.

First, an automatic dialer with voice synthesizer was installed. Field personnel are called on the mobile radio/phone system to immediately notify them in specific terms (i.e. test station no. 1 production separator high level) of all alarms. To ensure that an alarm is received, each alarm has to be acknowledged by an operator or it will repeat itself every five minutes until it is acknowledged.

Secondly, modifications were made in the DCS system to more closely monitor injection line pressures such that slight decreases over a preset time span will signal a leak alarm. Additional pressure switches were installed on injection well casings to alarm at a preset pressure . These changes allow the majority of the routine injection system monitoring and troubleshooting to be performed from the office.

The third step was to redefine the traditional pumper's job duties to reflect an emphasis on utilizing automation to "pump" wells. To this end, the eight pumpers were replaced by five production technicians. The technicians were trained and progressively acclimated into a role from which they use the automation to prioritize their work. This personnel reduction also helped to justify the final major automation investment.

The last major automation package included the installation of POC's and stuffing box leak detectors on all project area producers and approximately half of the Headwaters area producers. A new SCADA system was installed which constantly scans the wells, monitors the leak detector and motor valve position status', provides alarm notification of these devices, and enables wells to be remotely shut-in. AFIT economics of this package showed a 1.9 year payout and a 61.2% investor's rate of return based upon $20.00 per barrel oil.

To aid the production techs in evaluating their wells the DCS reports were modified and placed on a personal computer. More information is available and in several formats that can be easily loaded to laptops. It has also further enhanced the loading of well history data into PARS.

A last automation modification was the installation of a new generation RTU in the Headwaters Area test stations for alarm notification. The units enabled us to add more alarms, monitor analog and digital outputs, perform diagnostics, and remotely initiate scans. The units communicate via radios to a PC which is also linked to the autodialer for alarm notification.

CONCLUSION

The current operating environment dictates the maximization of personnel involvement and cost control while maintaining safety and environmental compliance. ARCO Oil and Gas Company has opted to utilize automation to accomplish these goals in the Willard Unit. The production techs are still in transition at the writing of this paper so the results of full implementation are still forthcoming. However, initial results look very promising.