Successful Drill Cuttings Reinjection (CRI) Case History With Multiple Producing Wells On A Subsea Template Utilizing Low Cost Natural Oil Based Mud

J. Reddoch, SPE, Apollo Services, and C. Taylor, British Gas, and R. Smith, SPE, Consultant

Abstract
This paper covers the drill cuttings reinjection engineering and operating techniques utilized by British Gas and Apollo Services, on the three year Tunisian Miskar project off the coast of Sfax, Tunisia. At the time of this writing, the subsea template phase has been completed, which included the drilling and cuttings injection on the first 7 wells over a subsea template. A platform was installed in the last quarter of 1994 and the second drilling phase of this project began in March of 1995. Ten (10) wells have been drilled to date and the cuttings have been disposed of in four (4) wells annuluses. The last three (3) wells were drilled while producing seven (7) wells.

Environmental regulations prohibited the dumping of oil based mud in the sea. Thus, if British Gas wanted the high penetration rates and, limited hole problems achieved by utilizing low cost, natural oil based mud; then cuttings reinjection presented the cost effective alternative.

All waste, from 10 wells, has been successfully pumped down four of the annuli with great success. Insignificant downtime has been experienced due to the injection process, even at instantaneous penetration rates in excess of 200 meters per hour on 12 1/4 inch hole. The CRI contractor rigged up and operated, with one man per 12 hour tower, the cuttings transfer system, the cuttings grinding/slurrification system and the triplex pump cuttings injection system. Over 2000 meters of limestone/claystone was encountered in each well while drilling and injecting successfully, (in the frac mode), into an impermeable claystone formation.

Addressed in this paper are:

1. Well Planning with information on multiple well template drilling producing, as it relates to cuttings reinjection.
2. Injection well disposal design and planning, including multiple well casing points, for development drilling while producing.
3. Requirements for surface equipment, personnel and commissioning.
4. Field Results and Data with adjustments for unplanned events.
5. Economics of CRI and natural oil base verses synthetic (psuedo) oil mud.
6. Conclusions and recommendations for future work.

Introduction
The Miskar project is located 75 miles ESE of the coast of Sfax, Tunisia (Fig. 1) of Northern Africa. The Tunisian Government mandated zero discharge of oil. The targets required drilling directionally thru highly reactive formations. These formations are most economically drilled utilizing natural oil based muds. A significant savings was foreseen utilizing natural oil base mud with successful Cuttings Reinjection to drill the wells, as opposed to utilizing water base or synthetic (psuedo) oil mud.

The project called for drilling 11 or more directionally drilled wells over a 3 year period (Fig. 2) commencing in the 1st quarter 1993. The first 8 wells were drilled and temporarily plugged via a jackup over a template, while the platform, pipeline and onshore processing facilities were built. All of the wells utilized mud line suspension hanger systems. The platform was installed in the last quarter of 1994. A jack up rig was moved back onto the platform to tie back the first wells for production. As of the writing of this paper, tiebacks have been completed and simultaneous production and drilling operations are in progress.

To date, all liquids and cuttings have been disposed of with no discharge to the environment and/or plugging or breaching.

This paper is comprised of 7 sections. Introduction, Well Plans provides details of well plans, with information on
SUCCESSFUL DRILL CUTTINGS REINJECTION (CRI) CASE HISTORY WITH MULTIPLE PRODUCING WELLS ON A SUBSEA TEMPLATE UTILIZING LOW COST NATURAL OIL BASED MUD

Template drilling as it relates to cuttings reinjection. Injection Engineering Specifications provides specific design criteria of the wells for successful cuttings injection and considerations for communications between wells when drilling and producing simultaneously. Surface Equipment Consideration identifies the requirements of British Gas for equipment and personnel to be provided to meet its requirements. Field Results and Data provides an overview of the drilling and cuttings injection results of the first 9 wells, with modifications due to actual field conditions as opposed to planned. Cost Analysis of natural oil base mud with CRI vs pseudo/synthetic mud. Conclusions summarizes the overall experiences realized from the project and provides recommendations for future operations.

Well Plans
A 12 well template (Fig. 3) was set by the IT Angel Jack Up Rig. Special provisions were added to the IT Angel for holding the injection well risers horizontally without axial tension, while supporting the riser of the drilled well (Fig. 4). The wells (Fig. 5) were spudded with a 20" bit ahead of a 36" hole opener. The 36" holes were drilled to 25 meters below the mud line and the 30" holes were drilled to 100 meters below the mud line. 24/30 inch tapered conductor strings were run and cemented in place. Mud Line suspension hangers and backout joints were installed in the conductor/casing strings. 17-1/2" holes were drilled directionally to approximately 1400 meters TVD. 13-3/8" surface casings were run and cemented back to surface. 121/4" holes were drilled directionally to approximately 25 meters above the reservoir, with oil mud. The exception to this was that the first 12-1/4" hole was drilled with water base, to prepare a template well for injection. 9-5/8" casings were run and cemented, without bringing cement all the way to the 13-3/8" casing shoe. At least 300 meters of open formation was left to dispose cuttings slurries into. Cuttings injection was initiated when drilling the 12-1/4" section on the second well. 8-1/2" holes were drilled to TD and cored. A 7" liner was run and cemented in place, leaving temporary internal cement plugs in place for later tie back of the wells, after the platform was installed.

The wells drilled and a typical directional plan is shown in (Fig. 6). Days verses depth and casing points are depicted in (Fig. 7). Planned mud program, fracture gradient and pore pressure points are shown in (Fig. 8).

Well Lithology, Pore Pressure, Mud Weight, Fracture Gradient and Casing Points (See Figs. 7 and 8) were developed for the project.

Fracture analysis work of offset wells was analyzed for this project, but was inconclusive. Initial injection pressure was estimated to be 1200 psi based on the minimum estimated pressure required to initiate miniature fractures in the rock. Claystone has virtually no porosity/permeability. All of the injection work would either be in a ballooning or a fracturing mode. Therefore, we expected that pressures could rise substantially to open the formation and to keep it open.

The Salambo shale/claystone formation was chosen for disposal (Fig. 9), primarily because of the well plans for casing points, lack of other desirable types of formations available and for depth reasons. The Salambo shale formation is an impermeable claystone, with an affinity for water. Although inconclusive fracture analysis work was done prior to the project, past experience with cuttings injection provided confidence that the project would be successful. Once the first well's cuttings were disposed of, we would have actual field data to modify the design of all future well disposals, if necessary. Cuttings boxes were provided as a contingency, as part of the package, in case the injection project did not go as planned. We could collect cuttings and hold them until another injection annulus/formation was established for the drill cuttings disposal. The cuttings boxes were never used.

Proximity Of Well Path To Injection Point
The wells were checked for the possibility of communications. (See Fig. 10). The surface holes were directionally planned to aid in reaching the target economically. The closest horizontal separation of well bore to an injection point was 300 meters. This was deemed to be adequate distance to provide for safe injection without communication to a new well bore or for simultaneous drilling and production operations.

Hydrostatic Control
Since the pore pressure was lower than the minimum anticipated slurry hydrostatic head, an adequate hydrostatic column of cuttings slurry would be present at all times to kill the annulus pressure. No annulus well control problem was anticipated. Double gate valve by check valve control is a standard and would be utilized for additional well control measures.
The original casing design (Fig. 11) called for safe injection pressures of up to 2500 psi utilizing no more than 70% of burst and collapse strength, considering outside normally pressured environment on the surface casing and a column of gas in the intermediate casing. Burst on the surface casing was the limiting component. The risers were designed for freestanding use, with no axial tension in site specific weather environments. Due to the actual fracture pressures required, we ran stronger surface casing on subsequent wells, to increase the safe working pressure to 3500 psi.

Area Faulting
The area was reviewed for faults and fractures. None were evident in the preplanning survey and none were encountered in the actual operation.

Erosion Contingencies
A standard well head (Fig. 12) and mud line suspension system was chosen for the project. The CRI contractor surveyed the openings of the mud line suspension hanger to make sure that erosion would not degrade the strength of the system and to make sure that there was an adequate opening to convey the slurry without plugging. It is standard policy not to inject over 3 BPM and usually to inject at 1.5 BPM. At these rates sand erosion velocities (200 feet/min.) are not reached and no problems were anticipated with either the well head, intermediate string or with the mud line suspension system. Since we grind cuttings to less than 100 microns and use the proper rheological control, we were not concerned with plugging the openings of the mud line suspension system. After the risers were pulled and inspected, no erosion was noted in any of the equipment.

Well Permitting
The Tunisian Government was open to cuttings reinjection as a disposal alternative. The plans of disposal were approved with the plan for exploration and development. Standard requirements for safe injection were outlined in the plan (Fig. 13).

Data Acquisition
A critical element in drill cuttings reinjection is accurate real time data collection, timely analysis of data, knowledgeable listening to the hole and quick response to danger signals. The following form was used for the injection project (See Fig. 14). Data collection was used to improve the injection operation and to prevent plugging/breaching throughout the project. Based upon this data, modifications were made to the casing program on well #3 and to the pumping methods (continuous vs displacement).

Surface Equipment Considerations
British Gas required one conductor to supply comprehensive cuttings injection services, i.e. catching, collecting, conveying, grinding, slurrification, and injection of the cuttings. There was no allowance for adding personnel or equipment, at the operators expense to adequately perform the contract.

Three areas of concern for British Gas was:
1) The ability of the contractor to process the cuttings and inject them as fast as the rig generated them, without slowing or shutting down the rig.
2) What particle size would be achieved that would not plug or breach the formation?
3) Would a mill be required for grinding the limestone fine enough or would the CRI contractors modified centrifugal pump degrade the particles adequately?

Little work had actually been done successfully with mills. The majority of the hole was limestone, but the smaller hole sizes and penetration rates thru the limestone limited the quantity and process rates of limestone to be ground. The CRI contractor had a proven mill to back up it's modified centrifugal pump (CSP) design thus providing a contingency for ungrindable solids. The contractor's mill was to be provided after the first well, if the CRI contractor could not grind the limestone cuttings fine enough at required process rates.

To meet the requirements of the contract, Apollo provided the following equipment flow diagram (Fig. 15 and 16). The cuttings are transferred by the screw conveyors to the cuttings slurry unit. One Apollo centrifugal shredding pump (CSP) is designed to grind all cuttings, including the limestone. The other CSP pump is for back up only, which gives the system 100 per cent redundancy. The cuttings slurry is passed across a positive shaker and any cuttings ground fine enough, pass thru the screen and are gravity fed to a holding tank. Any cuttings which are not ground fine enough are automatically sent back to the first CSP for further grinding. Cuttings slurries under 100 microns are then injected down hole by the Triplex Injection Pump.

The design of the CSP units provides for an extremely high rate of grinding. It is this grinding capability that provided fine particle size slurries, passed 100 per cent thru an automatic sizing system, even at high drill rates (Figs. 17 and 18). Without a high grinding rate the solids would build
Field Results and Data
The rig was mobilized on March 16, 1993. The cuttings reinjection equipment was mobilized on March 24, 1993. Due to short lead times, equipment was mobilized via air and water shipments. Upon clearing customs, the equipment was rigged up, while the surface and intermediate holes were being drilled on the first well. In spite of short lead times, the equipment was thoroughly tested, commissioned on water based cuttings and operationally ready when oil base mud was brought on board. The drilling reached instantaneous rates of 200 meters per hour on the 12-1/4" hole sections. Cuttings tonnage ranged from 10 to 45 tons per hour. No significant down times were encountered in any of the hole sections.

Drilling progressed at substantially higher rates than contracted for. Due to the higher injection pressures and drill rates experienced, maintenance of the triplex injection unit increased on later wells. However, the cementing unit was successfully used as the planned back up to the triplex injection package. Injection data is summarized in (Fig. 19).

Well No. 2 was injected into the annulus of Well No. 1. Pressures reached 2700 psi and broke back (Fig. 20). British Gas decided to plug this well's annulus and prepare another well for disposal, rather than risk complete shut off of the fracture system. If complete closure of the fracture system occurred, then there would be no way to cement the annulus by bullheading cement, which is necessary for temporarily abandoning the well prior to bringing in the platform. The lowest pressure recorded was 750 psi. This is anticipated to be when the slurries moved into the small carbonate formation. Well No. 3 was injected into the annulus of Well No. 2 (Fig. 21). Again, injection pressures reached 2800 psi. This well's annulus was also cemented. To provide a higher strength casing safety factor and to allow more well's wastes to be disposed of into one well's annulus, higher strength casing was run on Well No. 3. Well No's 4 thru 8 were injected into the annulus of Well No. 3 successfully (Figs. 22 thru 26), well within safety parameters.

Slurry properties (Fig. 27) were closely monitored. Slurry properties ranged from 9.5 to 12.5 ppg, depending on the amount of barite passed to the waste stream. Funnel Viscosities were controlled between 60 to 80 seconds per quart. Solids ranged from 20 to 30 per cent. The limestone formation was extremely water conscious, Id Vis was used for viscosifying the limestone when needed. Claystones/shales required little chemical adjustment.

No communication was experienced between the well bores or back to surface and no plugging of the annulus/formation was experienced. Both continuous and batch slurry injection practices were used. However, due to the highly sensitive nature of the claystone to water, we discontinued water displacement sweeps and worked under a continuous injection mode for the remainder of the project. Even when we were waiting on cuttings for up to 30 days, the properties of the slurries were controlled to eliminate the possibility of settlement in the annulus. At the end of the first drilling phase, injection annuli were displaced and bullhead plugged with enough cement to provide for a 300 meter cement plug (Fig. 28).

The wells were T & A'd and casing/conductors backed out.

Cost Analysis
Cost of Synthetic/Psuedo Oil Mud

<table>
<thead>
<tr>
<th>Hole Size</th>
<th>Losses Footage</th>
<th>Cost/Meter</th>
<th>Total Cost</th>
</tr>
</thead>
<tbody>
<tr>
<td>12-1/4&quot;</td>
<td>Shaker Loss 1670m</td>
<td>£ 21.58</td>
<td>£ 36038</td>
</tr>
<tr>
<td></td>
<td>Hole Loss 1670m</td>
<td>£ 82.00</td>
<td>£ 136940</td>
</tr>
<tr>
<td>8-12&quot;</td>
<td>Shaker Loss 450m</td>
<td>£ 30.18</td>
<td>£ 13581</td>
</tr>
<tr>
<td></td>
<td>Hole Loss 450m</td>
<td>£103.55</td>
<td>£ 46597</td>
</tr>
<tr>
<td>Total Cost</td>
<td>Of Lost Psuedo Oil Mud</td>
<td></td>
<td>£233156</td>
</tr>
</tbody>
</table>

Cost of Diesel Oil Mud Usage With CRI 40 days x 3,000/day £120000

Additional cost disparity considerations for using psuedo oil mud, not added to the total cost of lost synthetic (psuedo) oil mud, were: Additional solid controls and rental equipment to reduce mud lost, daily maintenance cost differences, additional trips to clean/scrape casing prior to cement work, and losses due to mishandling or lost constrictors.

Conclusions
1. Template drilling with CRI is a viable alternative on fast track programs in tough downhole drilling environments.
2. CRI can be extremely successful as long as proper engineering is performed and operations are conducted by experienced contractors.
3. Mud line suspension systems work well in Cuttings Reinjection operations as long as enough open area is provided and cuttings are slurrified properly.
4. Apollo CSP mills grind limestone formations adequately with out special mills.

5. Manning requirements and downtime can be minimized with a properly designed and commissioned system.

6. Claystone formations accept the waste slurries as long as the injection well is properly designed to continue forcing the fractures and particle size/rheologies are carefully controlled. Continuous injection methods should be utilized and water minimized on these type formations.

7. 300 meter displacements are adequate for protection against communication between the injection formation in claystones and other well paths.

8. Oil base mud with CRI is very economical compared to synthetic (psuedo) oil mud on this type of project.

9. Given the same drilling practices i.e., rig solids control, triplex pumps, drill pipe, personnel, etc.; drill rates with natural oil base mud can mirror drill rates with synthetic (psuedo) oil mud.

10. Rig cement pumps are adequate for planned back-up to the triplex injection skid.

Acknowledgments
The authors would like to thank the managements and staff of British Gas Exploration & Production, Phillips Petroleum and Apollo Services for their total support of this project initiative. Significant "team" assistance was afforded by the drilling engineering and operations groups of British Gas Exploration and Production, the Apollo operations team and all personnel associated with the rig/well operations.

Reference

Metric Conversion Factors
1 barrel (bbl) = 0.1589 m³
1 foot (ft) = 0.3048 m
.345 pound per gallon (ppg) = 1000 kg/m³
1 pound (lb) = 0.453 kg
1 pound per square inch = 0.069 Bar
Typical Slurry Properties

Viscosity 50 - 80 funnel visc. (sec/qt)
Solids Ratio 20 - 30 %
Weight 10.5 - 12.5 ppg
Particle size 100 micron or smaller (90%)
Retort oil .5 - 2% oil; if oil mud cuttings
Yield Point 20 - 25 lbs/100 sq.ft.

(FIG.27)

MISKAR DEVELOPMENT WELL A-1
FINAL WELL SCHEMATIC

(FIG. 28) 234
WELL | INJECT | Bbls Injected | Slurry Wt. | Injection Pressure (ps| | Injection Rate (BPM) | Dates | Method | Depth
---|---|---|---|---|---|---|---|---
2 | 1 | 10409 | 10.2 - 12.4 | 900-2700 | 1.5 - 3.0 | 6-13 / 7-17 | continuous | 4592
3 | 2 | 8940 | 10.0 - 12.6 | 900-2800 | 1.5 - 2.8 | 7-18 / 10-1 | continuous | 4887
4 | 3 | 9478 | 10.6 - 12.0 | 400-2800 | 1.5 - 3.0 | 10-2 / 11-16 | continuous | 4941
5 | 3 | 18773 | 10.0 - 13.3 | 1000-2750 | 1.5 - 3.0 | 11-17 / 1-25 | continuous | 4941
6 | 3 | 11022 | 10.3 - 11.5 | 1000-2700 | 1.0 - 3.5 | 1-26 / 4-19 | continuous | 4941
7 | 3 | 14960 | 10.7 - 12.3 | 1500-2750 | 1.5 - 2.6 | 4-20 / 8-1 | continuous | 4941
8 | 3 | 9277 | 10.3 - 11.7 | 2000-2900 | 1.3 - 2.6 | 8-2 / 9-20 | continuous | 4941
Total | | 63510 | | | | | |
Well #8, injected into Well #3

Pressure - psi x 1,000; Volume - bbls x 1,000

Pressure
Cumulative Volume

08/02/94  08/12  08/22  09/01  09/11/94

Days

Fig. 26
Well #5, injected into Well #3

Fig. 23

Well #6, injected into Well #3

Fig. 24

Well #7, injected into Well #3

Fig. 25
### MISDAR PROJECT
**GENERIC WELL DESIGN**

<table>
<thead>
<tr>
<th>O.D.</th>
<th>SURF</th>
<th>PROD</th>
<th>PROD LHR</th>
<th>PROD LHR</th>
<th>PROD LHR</th>
</tr>
</thead>
<tbody>
<tr>
<td>18-5/8&quot;</td>
<td>12-5/8&quot;</td>
<td>9-5/8&quot;</td>
<td>7&quot;</td>
<td>7&quot;</td>
<td>7&quot;</td>
</tr>
<tr>
<td>N/S</td>
<td>9-5/8&quot;</td>
<td>4-1/2&quot;</td>
<td>1.40</td>
<td>1.40</td>
<td>1.40</td>
</tr>
<tr>
<td>GRADE</td>
<td>K-55</td>
<td>K-55</td>
<td>3,540</td>
<td>3,540</td>
<td>3,540</td>
</tr>
<tr>
<td>THREAD</td>
<td>BUST</td>
<td>BUST</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
<tr>
<td>DEPTH (TO REREB)</td>
<td>1000'</td>
<td>4500'</td>
<td>5450</td>
<td>5300</td>
<td>5300</td>
</tr>
<tr>
<td>DEPTH (TO TTR)</td>
<td>200'</td>
<td>797'</td>
<td>797'</td>
<td>797'</td>
<td>797'</td>
</tr>
<tr>
<td>ASP DRILLING (PSI)</td>
<td>310'</td>
<td>310'</td>
<td>310'</td>
<td>310'</td>
<td>310'</td>
</tr>
<tr>
<td>ASP PRODUCTION (PSI)</td>
<td>N/A</td>
<td>N/A</td>
<td>600'</td>
<td>600'</td>
<td>600'</td>
</tr>
<tr>
<td>FRAC GRADIENT (PPG)</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
</tr>
<tr>
<td>MD (TO TD) (FT)</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
<td>11.0</td>
</tr>
<tr>
<td>COLLAPSE LOAD (LW &amp; PW)</td>
<td>475</td>
<td>475</td>
<td>475</td>
<td>475</td>
<td>475</td>
</tr>
<tr>
<td>COLLAPSE LOAD (FORM &amp; PW)</td>
<td>N/A</td>
<td>N/A</td>
<td>3000</td>
<td>3000</td>
<td>3000</td>
</tr>
<tr>
<td>TENSILE (GIPS)</td>
<td>68</td>
<td>68</td>
<td>68</td>
<td>68</td>
<td>68</td>
</tr>
<tr>
<td>BURST (PSI)</td>
<td>2500</td>
<td>2500</td>
<td>2500</td>
<td>2500</td>
<td>2500</td>
</tr>
<tr>
<td>COLLAPSE (PSI)</td>
<td>670</td>
<td>670</td>
<td>670</td>
<td>670</td>
<td>670</td>
</tr>
<tr>
<td>TENSILE (GIPS)</td>
<td>14.7</td>
<td>14.7</td>
<td>14.7</td>
<td>14.7</td>
<td>14.7</td>
</tr>
<tr>
<td>BS TEM</td>
<td>1.31</td>
<td>1.31</td>
<td>1.31</td>
<td>1.31</td>
<td>1.31</td>
</tr>
<tr>
<td>BS COLL (MW)</td>
<td>3.35</td>
<td>3.35</td>
<td>3.35</td>
<td>3.35</td>
<td>3.35</td>
</tr>
<tr>
<td>BS COLL (FORM)</td>
<td>N/A</td>
<td>N/A</td>
<td>1.12</td>
<td>1.12</td>
<td>1.12</td>
</tr>
<tr>
<td>BS TOP BURST DRILLING</td>
<td>2.59</td>
<td>2.59</td>
<td>2.59</td>
<td>2.59</td>
<td>2.59</td>
</tr>
<tr>
<td>BS TOP BURST PROD</td>
<td>30.4</td>
<td>30.4</td>
<td>30.4</td>
<td>30.4</td>
<td>30.4</td>
</tr>
<tr>
<td>BS BOTTOM BURST PROD</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
<td>N/A</td>
</tr>
</tbody>
</table>

*COMPLETION FLUID WEIGHT = 11.6 PPG AND BACK-UP GRADIENT = 9.0 PPG*

(FIG. 11)

---

### MISKAR DEVELOPMENT WELL A-3
**CONSTRUCTION REPORT**

(FIG. 12)

(FIG. 12)

227
- Discuss Origin of Cuttings (Well, Footage Drilled with Oil Base)
- Calculate Volume of Cuttings to be Injected (Not Slurry Volume)
- Slurry Procedure (Include Volume of Cutting Per Volume of Carrier Fluid) (Water 3 to 1 cuttings)
- Slurry Weight (ppg.) (10.5-12.5ppg)
- Maximum volume of Cuttings to be Maintained on Board at any time. 100bbls.
- Description of Surface Equipment Involved (Process Flow Schematic) (See our plan View)
- Calculate Fracture Gradient Shoe of Annulus
- Address Maximum Surface Injection Pressure Imposed on Casing (Rule of thumb expected pressure + 50% Minimum)
- Log Showing Possible Injection Interval(s)
- Geologic Discussion (Geology of Injection Interval, Any Shallow Hydrocarbon Zones, and Any Faulting that could Transmit Injection Back to Surface)
- Mud and/or Cutting must be followed by some Type of Water or Completion Fluid
- Monitor Pressures on Nearby Wells (Pressure Recorder)

(FIG. 13)

<table>
<thead>
<tr>
<th>Injection Log, 24 hours</th>
</tr>
</thead>
<tbody>
<tr>
<td>Batch #</td>
</tr>
<tr>
<td>---------</td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
<tr>
<td></td>
</tr>
</tbody>
</table>

Precious Barrels Pumped: ______ bbl.
Total Barrels Pumped: ______ bbl.

(FIG. 14)