MICROHOLE

HIGH-PRESSURE JET DRILL FOR COILED TUBING

FINAL REPORT

TR-117

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TEMPRESS®			18858 – 72ND Ave S. Kent, WA 98032 Tel: 425.252.8120 Fax: 425.252.8123	Document No.: **TR-117** **Microhole High-Pressure Jet Drill for Coiled Tubing**	

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ABSTRACT

Tempress' Small Mechanically-Assisted High-Pressure Waterjet Drilling Tool project centered on the development of a downhole intensifier (DHI) to boost the hydraulic pressure available from conventional coiled tubing to the level required for high-pressure jet erosion of rock. We reviewed two techniques for implementing this technology (1) pure high-pressure jet drilling and (2) mechanically-assisted jet drilling. Due to the difficulties associated with modifying a downhole motor for mechanically-assisted jet drilling, it was determined that the pure high-pressure jet drilling tool was the best candidate for development and commercialization. It was also determined that this tool needs to run on commingled nitrogen and water to provide adequate downhole differential pressure and to facilitate controlled pressure drilling and descaling applications in low pressure wells.

The resulting Microhole jet drilling bottomhole assembly (BHA) drills a 3.625-inch diameter hole with 2-inch coil tubing. The BHA consists of a self-rotating multi-nozzle drilling head, a high-pressure rotary seal/bearing section, an intensifier and a gas separator. Commingled nitrogen and water are separated into two streams in the gas separator. The water stream is pressurized to 3 times the inlet pressure by the downhole intensifier and discharged through nozzles in the drilling head. The energy in the gas-rich stream is used to power the intensifier. Gas-rich exhaust from the intensifier is conducted to the nozzle head where it is used to shroud the jets, increasing their effective range.

The prototype BHA was tested at operational pressures and flows in a test chamber and on the end of conventional coiled tubing in a test well. During instrumented runs at downhole conditions, the BHA developed downhole differential pressures of 74 MPa (11,000 psi, median) and 90 MPa (13,000 psi, peaks). The median output differential pressure was nearly 3 times the input differential pressure available from the coiled tubing. In a chamber test, the BHA delivered up to 50 kW (67 hhp) hydraulic power. The tool drilled uncertified class-G cement samples cast into casing at a rate of 0.04 to 0.17 m/min (8 to 33 ft/hr), within the range projected for this tool but slower than a conventional PDM. While the tool met most of the performance goals, reliability requires further improvement.

It will be difficult for this tool, as currently configured, to compete with conventional positive displacement downhole motors for most coil tubing drill applications. Mechanical cutters on the rotating nozzle head would improve cutting. This tool can be easily adapted for well descaling operations.

(continued)

A variant of the Microhole jet drilling gas separator was further developed for use with positive displacement downhole motors (PDM) operating on commingled nitrogen and water. A fit-for-purpose motor gas separator was designed and yard tested within the Microhole program. Four commercial units of that design are currently involved in a 10-well field demonstration with Baker Oil Tools in Wyoming. Initial results indicate that the motor gas separators provide significant benefit.

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EXECUTIVE SUMMARY

The downhole intensified jet drilling tool developed by Tempress generates high-velocity gas-shrouded fluid jets to enhance underbalanced coiled tubing drilling and scale milling.

Tempress surveyed available jet cutting data to determine jet pressures required to erode conventional oil and gas producing formations, mineral scales and cement as used in wells. The survey showed that 70 MPa (10,000 psi) jets will provide reliable jet erosion performance. Tempress selected hydraulic performance specifications for a downhole intensifier (DHI) that will provide this pressure downhole when operated on conventional coiled tubing drilling equipment.

Tempress also concluded that the jet drilling tool should operate on two-phase (water and nitrogen or air) to maximize hydraulic power available at the BHA and to allow underbalanced drilling operations. To maximize jet performance, the BHA needs to incorporate a downhole gas separator to ensure that only water is intensified and used for jetting. The separated gas-rich flow can also be used to power the intensifier and shroud the high-pressure jets for increased cutting range.

A bottomhole assembly (BHA) review was carried out to select the most promising configuration for commercial Microhole drilling applications and to finalize hydraulic performance specifications. Two BHA configurations were evaluated; (1) mechanically-assisted jet drilling incorporating a steerable positive displacement downhole motor (PDM) and a downhole intensifier and (2) a pure high-pressure jet drilling tool utilizing the downhole intensifier.

The mechanically-assisted jet drilling BHA would incorporate a conventional PDM, which turns a special bit, modified to incorporate high-pressure fluid jet nozzles. Between the PDM and the bit would be a gas separator and intensifier that operate as described above. Applications would include horizontal drilling, extended reach drilling, bi-center bit drilling and under-reaming. A review of positive displacement motors revealed that no commercially available PDMs were capable of handling the higher downhole differential pressures required for effective jet drilling. Current PDM seals and bearings restrict their use to relatively low differential pressures thereby restricting the intensified jet pressure and drilling performance. The PDM would need to be modified with a custom high-pressure seal and heavy-duty bearings. A dual-flow mechanical drill bit with high pressure jet ports and low pressure gas ports would also need to be developed for mechanical-assisted jet drilling. For steering applications this tool would incorporate a bent sub between the PDM and DHI assembly. Steering would be limited to large radius curves because of the length of the BHA and long bit-to-bend distance imposed by locating the DHI below the PDM. For these reasons, the mechanically-assisted jet drilling option was deferred for later development.

The second alternative investigated in this program was for a DHI powering a pure high-pressure rotary jet drill, similar to Tempress' rotary jet milling tools already in commercial use for well cleaning. This configuration was selected for prototype development. This configuration results in a simple, more compact BHA that can be used to drill short radius curves and horizontal wells. The BHA consists of a self-rotating multi-nozzle drilling head that drills a 3.625-inch hole, a high-pressure rotary seal/bearing section, a 2.75-inch intensifier, a 2.75-inch gas separator and a 2.75-inch screen sub. This tool is based on a 2.125-inch DHI tool also under development for high-pressure jet descaling operations for our partner, Trican Well Services of Alberta, Canada.

At 70 MPa, the Microhole compact high-pressure rotary jetting tool is capable of drilling moderate to high permeability formations, which effectively includes all conventional unfractured oil and gas producing formations and most mineral scales found in production tubing. High-pressure jet drilling can also be used for lateral well extensions within permeable producing formations.

The high-pressure jet drilling BHA is much shorter than a PDM BHA allowing steering through shorter radius curves than is currently possible with motors. Short-radius drilling is an important cost-reduction objective because more drilling can take place within the producing formation and because hole cleaning problems in the build section are minimized. The high-pressure jet drill would also extend lateral reach by reducing the applied bit weight. This tool configuration should find broad application for underbalanced drilling of ultra-short radius and extended reach horizontal wells within production zones and for removing scale from existing wells without damaging the well tubulars.

The high-pressure jet drill uses the degassed output from the gas separator and downhole intensifier to generate high-velocity jets. The tangential orientation of the nozzles causes the nozzle head to spin negating the need for a separate downhole motor. The gassy discharge from the intensifier is also directed to the nozzle head where it is used to shroud the water jets for improved cutting performance. Future configurations of the high-pressure jet drilling BHA can easily incorporate a bent coupling between the DHI and jet drill for steering.

The Microhole high-pressure jet drilling BHA was designed, assembled and functionally tested at Tempress' facilities in Kent, Washington. The prototype Microhole gas separator and intensifier endured over six hours of operation at simulated downhole operational conditions in a test chamber. The prototype BHA was tested at operational pressures and flows on the end of 2000 m (6600 feet) of conventional 2-inch coiled tubing in a test well at our partner's R&D facility in Red Deer, Alberta, Canada. The BHA developed output differential pressures up to 74 MPa (10,700 psi, median) and 90 MPa (13,000 psi peaks), with 31 MPa (4500 psi) pump pressure, 25 MPa (3600 psi) BHA inlet differential pressure, 1.9 MPa (280 psi) well head pressure. This performance was achieved at flow rates of 263 lpm (69 gpm) water and 9.7 scmm (340 scfm) nitrogen. At these operating conditions the high-pressure jet drill BHA delivered 56 hydraulic horsepower downhole, which is 30% of the hydraulic power provided to the BHA. The Microhole jet drilling BHA drilled class-G cement samples cast into casing at a rate of 2 to 10 m/hr (8 to 33 ft/hr). Efficiency was limited by intensifier seal leakage. Drilling rate was initially within the range predicted for this tool. Drilling rate dropped off sharply, most likely due to nozzle plugging. These difficulties can be readily corrected in the future by more frequent servicing.

The projected drilling rate of this BHA in the target formations is 7 m/hr (22 ft/hr). This is significantly slower that the typical ROP of conventional displacement downhole motors (PDM) of 31 m/hr (100 ft/hr). Given the lower ROP, the higher cost and complexity, and the higher pumping pressure required for the high-pressure jet drilling BHA, we believe that it will be difficult for this tool to compete with a PDM for coiled tubing drilling except in niche markets. The addition of small cutters on the rotating nozzle head may improve ROP. In addition, the Microhole high-pressure jet drilling BHA can be easily adapted for removing hard scale buildup from existing wells, improving their productivity.

The downhole gas separator used for the Microhole jet drilling BHA is based on work accomplished at Tempress for jet descaling operations with commingled nitrogen and water. We soon learned that this tool has other applications, including removing gas from two-phase drilling fluids sent to a positive displacement motor (PDM). The gas allows controlled pressure drilling and provides gas lift for cuttings in low-pressure wells without damaging the formation. However, the gas has detrimental effects on PDM life and performance. Separating the gas ahead of the PDM can provide the benefits of gas without much of the penalties to the PDM. A fit-for-purpose 2.875-inch motor gas separator was designed and yard tested within the Microhole program. Four commercial 2.875-inch units of that design are currently involved in a 10-well field demonstration with Baker Oil Tools in Wyoming. Initial results indicate that the motor gas separators provide significant benefits to the customer.

MICROHOLE JET DRILLING

The overall goal of the Microhole program is to help reduce the cost and footprint of in-field drilling operations in the United States. The U.S. Department of Energy estimates that 2/3rds of all oil discovered in the U.S. remains in the ground and half of that (218 billion barrels) is in reservoirs shallower than 5000 feet[1]. Lower cost drilling can make these untapped reserves economically viable. Small diameter coiled tubing drilling technology can help to achieve this goal.

Tempress has developed a number of jetting tools for use on small diameter coiled tubing. Tempress proposed to investigate whether jetting tools could be used for infield drilling operations as suggested by the Microhole program. Jet drilling requires high pressures for effective cutting of rock. Conventional coiled tubing has a limited pressure rating, insufficient for effective jet drilling in oil/gas formations. Therefore, Tempress proposed the development of a downhole intensifier for coiled tubing drilling applications. The intensifier boosts the pressure available at the end of the tubing to a level that is capable of eroding rock.

In Tempress Technical Report TR-72, “Microhole Jet Drilling System, Configuration and Integration,” we discussed the pressure and hydraulic power requirements for effective jet erosion of rock. We determined that the addition of gas to the flow increases the differential pressure available downhole and provides pressure control options in low pressure wells, reducing formation damage and improving annular flow. A numerical model of two-phase circulation during coiled tubing drilling and a two-phase hydraulic model of the downhole intensifier were then used to specify hydraulic operating parameters for these tools. We selected a configuration for the jet drilling BHA. Following is a brief summary of the findings in that report.

Pressure and Power Available at the BHA

The use of relatively small diameter coil causes frictional pressure losses that limit the pressure and hydraulic power available at the BHA. An existing Tempress two-phase coiled tubing drilling circulation model was expanded to determine the pressure and power available downhole while circulating commingled water and nitrogen for coiled tubing drilling of directional wells. The model accounts for circulating pressure losses and hydrostatic pressure changes in the coil and annulus.

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[1] US DOE Financial Assistance Announcement of Funding Opportunity, Microhole Development II, DE-PS26-04NT1548-00, issued 2 August 2004, p. 4.

Injecting even small quantities of nitrogen into the drilling fluid (water) has several benefits, not least of which is the higher differential pressure available downhole. Underbalanced drilling makes it possible to increase the pressure differential from inside the coil to the borehole to over 28 MPa (4000 psi) with 28-35 MPa (4000 – 5000 psi) surface pump pressure, by reducing fluid friction and lowering the density of fluid in the annulus. This analysis showed that the maximum power available occurs around 300 lpm water flow and 15 scmm nitrogen. The maximum pressure available at the BHA drops continuously with flow rate due to friction losses.

Cuttings Transport

Turbulent flow with low viscosity drilling fluid (water) should ensure that a cuttings bed does not build in the horizontal and inclined sections of the hole[2,3]. These factors must be balanced with the surface pumping pressure capacity, coil size and hydraulic power requirements of the motor and DHI. Even when the flow is turbulent, some large cuttings may accumulate in the hole requiring wiper trips.

At high gas flow rates and low mean velocity, the flow can stratify, which reduces the water velocity and cuttings transport. A Froude number analysis indicated that the potential for stratified gas/water flow is low.

Cuttings may also accumulate in the casing where the flow area increases and velocity slows. Adding a small amount of gas substantially increases vertical velocity in casing, which improves cuttings transport. Pills of high viscosity fluid may be used to periodically sweep the casing if cuttings are not coming to surface.

High-Pressure Jet Erosion of Rock

Formation Characteristics

The jet drilling tool must generate sufficient pressure to enable effective erosion of rock. Jet drilling and erosion data consistently show that rock removal rates are linearly proportional to jet pressure above an initial threshold pressure. The threshold pressure for oil bearing rock[4] formations is 60 MPa or less. Tempress has selected 70 MPa for operation of high-pressure jet drill. At this pressure, jet erosion will be effective in all conventional, unfractured oil and gas producing formations and will be

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[2] Leising, L.J. and I.C. Walton (1998) "Cuttings transport problems and solutions in coiled tubing drilling," SPE39300, presented at IADC/SPE Drilling Conference, Dallas, March 3-6, Society of Petroleum Engineers, Richardson Texas.
[3] Okrajni, S.S. and J.J. Azar (1986) "The effects of mud rheology on annular hole cleaning in directional wells," *SPE Drilling Engineering*, August 297-308.
[4] Bear, J (1972) *Dynamics of Fluids in Porous Media*, Dover Publications, New York.

effective in about half of sedimentary rock types. Over 75% of the overlaying formations drilled through for oil and gas exploration and production are impermeable shales[5], which are not effectively eroded by high-pressure jets. Therefore, jet drilling should only be considered for lateral well extensions in conventional producing formations.

Jet drilling at pressures of 30 to 100 MPa has been shown to be effective over a broad range of permeable and impermeable sedimentary rock types that may be encountered while drilling for oil and gas[6]. The pressure required for short radius lateral drilling within an oil producing formation will be lower than this range because these formations tend to have high matrix permeability which reduces the threshold pressure required for jet erosion.

Rate of Penetration

The rate of jet erosion is related to the specific productivity, which is determined from the ratio of volumetric rock removal rate to jet hydraulic power. Specific productivity for jet erosion of medium to high permeability rock is in the range of 0.1 to around 1 mm^3/J.

Increased jet traverse rate has also been shown to enhance jet cutting productivity[7]. The specific productivity increases rapidly to a peak known as the critical velocity. At higher velocities the specific productivity drops off slowly. A jet drilling tool should be designed to operate at or above the critical velocity for maximum effectiveness. The critical traverse velocity for Wilkeson sandstone is about 3 m/s where the specific productivity is about 1.2 mm^3/J. Specific productivity drops to about 0.8 mm^3/J at traverse velocities above 8 m/s.

The Microhole jet drilling tool uses a 6-jet nozzle head that is designed to operate at around 3000 rpm. This provides a maximum traverse rate of 14.5 m/s (48 f/s) at the outer jet operating on the circumference of a 92-mm (3.625-inch) diameter hole. The inner jets move at 2 to 12 m/s (7 to 39 ft/s). The traverse rate for the outer jet is higher than the critical value for Crow's Wilkeson sandstone but this configuration puts all jets in the range where jet erosion is highly efficient.

Compiled threshold pressure and specific productivity data were used to estimate high pressure jet drilling rates at 75 kW (100 hhp). The drilling rates were corrected for rotary speed. At 70 MPa

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[5] Steiger, R.P. and P.K. Leung (1992) "Quantitative determination of the mechanical properties of shales," *SPE Drilling Engineering*, September, p. 181.
[6] Maurer, W.C. J.K. Heilhecker and W.W. Love (1973) "High-pressure drilling," *J. Pet. Tech*, July, pp. 851-859.
[7] Crow, S.C.(1972) "A theory of hydraulic rock cutting," Int. J. Rock Mech. Min. Sci., V.10, 567-584.

(10,150 psi) jet pressure, the projected drilling rate averages 12 m/hr (39 ft/hr) or 0.2 m/min (0.66 ft/min).

Jet Dissipation Effects

Submerged, non-cavitating fluid jets are subject to rapid dissipation due to turbulent mixing of the jet with the ambient fluid. A jet discharged in air has an effective range that is one or two orders of magnitude greater than that of a submerged jet. Momentum transfer from the jet is proportional to the density of the dissipating medium. A model of jet range that assumes that pressure dissipates in proportion to the square root of the density of the ambient medium was used. The model agrees reasonably well with observations at the limits of 100% ambient air and 100% ambient water. Adding gas around the jet provides a “shroud” that extends jet effective range. Under downhole conditions, the gas is at elevated pressure and has higher density thus limiting the benefit of gas shrouding. For example, at 10 MPa downhole pressure, gas shrouding will increase the submerged jet range by a factor of about 3. At 1 MPa downhole pressure, gas shrouding will increase submerged jet range by a factor of around 10.

Fluid jets that contain mixed gas and water break up rapidly upon exiting the nozzle. This is caused by the rapid reduction in fluid pressure at the nozzle exit that causes the gas to expand. In addition, the momentum of the jet is proportional to the density of the jetting fluid. To be effective at erosion of rock, the fluid jet must contain as little gas as possible.

BHA CONFIGURATION OPTIONS

In Tempress Technical Report TR-72, “Microhole Jet Drilling System, Configuration and Integration,” we evaluated two BHA configurations in terms of performance benefits and commercial potential:

- Mechanically-assisted high-pressure jet drill that uses high-velocity fluid jets to reduce cutter loads and increase rate of penetration. In this configuration, the intensifier would be run below a conventional positive displacement motor.
- Pure high-pressure jet drilling that uses a high-speed jet rotor tool to drill rock without any mechanical cutters. These tools are much shorter than mechanical drill motors allowing drilling of short radius holes.

Each of the configurations uses two-phase flow to create underbalanced drilling conditions. A gas separator above the intensifier separates the water and gas in the bottomhole assembly so that only degassed water issues from the jets to maximize erosion performance. The downhole intensifier uses the energy in the separated gas-rich flow to further pressurize the degassed water stream. The high-pressure water is converted to high-velocity jets in nozzles incorporated into a drilling head or modified bit. The gas is discharged into the borehole at the tool face to "shroud" the jets thereby increasing their effective cutting range. Following is a brief review of the rational used for the selection of a BHA configuration for the Microhole tool.

Pure High-Pressure Jet Drill

Multiple Nozzle Head Design

The design of a pure jet-drilling nozzle head requires that the jets cut all of the rock face beneath the tool for the tool to advance. This is best accomplished by a spinning nozzle head with one or more jets arranged at an angle to the axis. This causes the jet(s) to cut radially, as well as axially, to create an open volume ahead of the tool as the nozzle head spins and advances.

We determined that multiple smaller jets have a greater effective radial range than a single jet with the same total flow area and hydraulic power. The effective coverage increases as the square root of the number of jets so that four jets have twice the radial coverage of a single jet with the same flow area. The Microhole nozzle head employs 6 jets arranged to provide full coverage of the nozzle head.

Jet Rotor

Since the nozzle head is, in effect, an impulse turbine, it must be supported by bearings and seals. The rotating nozzle head is supported by a proprietary bearing and seal arrangement that we call a "jet rotor". The jet rotor bearing assembly consists of a thrust and a radial bearing. The thrust bearing is pressure balanced and handles the axial load from the internal intensified fluid pressure. The radial bearing handles side loads generated by residual nozzle head imbalance and occasional contact with the borehole bottom. The rotary seal contains the high internal pressure at high rotation rate. The thrust bearing and rotary seal together form a patented pressure balanced seal configuration that is used on several other Tempress commercial jet rotor well cleaning tools.

The impulse turbine nozzle head can have an unacceptably high run-away speed. To control this, Tempress jet rotors also incorporate a speed governor assembly that limits the nozzle head rotation rate.

Mechanically-Assisted Jet Drill

For mechanically-assisted jet drilling the DHI is located below a conventional PDM drill motor. The energy remaining in the drilling fluid after powering the motor is used by the intensifier to generate the high pressure required for effective jet erosion. A mechanically-assisted jet bit incorporates high-pressure jets to cut the rock and mechanical cutters to cut the ridges of rock that remain. If a portion of the rock is too hard to cut with the jets, the mechanical cutters ensure that drilling continues.

The mechanical power available from a small PDM is limited by both the torque capacity and the flow rate. For example, the maximum mechanical power capacity of a Baker 2.875-inch Navi-Drill X-treme PDM is 43 kW (58 hp) at a flow rate of 450 lpm (120 gpm) and pressure drop of 8 MPa (1160 psi). For comparison, the 2.75-inch diameter high-pressure jet drill has delivered up to 50 kW (67 hhp)of jetting power (see Second Yard Test later in this report).

Pressure Limitations of PDMs

Currently available PDM motors are not designed to operate on pressures above about 14 MPa (2000) psi, with most limited to 10 MPa (1500 psi). This is less than half the pressure required to run the intensifier at the power levels required for effective jetting. The main limitations of conventional PDMs are the seals, bearings and coupling shaft. Although it is possible to modify motors to run on water at higher pressures using heavy-duty bearings and seals and a flexible coupling shaft, the seal designs on commercially available PDMS will not provide the pressure capacity required for the downhole intensifier application. Modifying a motor for this application would be a significant developmental project in itself.

Nitrogen Compatibility

Tempress surveyed 16 motor suppliers to evaluate nitrogen compatibility and performance characteristics of small-diameter motors that are suitable for Microhole drilling. A number of these motors are specifically rated for nitrogen service. The nitrogen rated motors typically have a larger clearance between stator and rotor to allow for swelling of the elastomeric stator in the presence of nitrogen. The primary issues related to motor reliability with nitrogen are (1) over speed of the motor when off-bottom, (2) increased vibrational loading because gas in the annulus reduces dampening and (3) nitrogen degradation of the elastomeric stator.

Directional Drilling Considerations

Mechanically-Assisted Jet Steering

There are operational challenges with locating the motor above the downhole intensifier. In particular, the distance from the bit to the bend in the motor housing is increased by the length of the intensifier. This reduces the possible dogleg severity (DLS) and makes short radius directional changes more difficult. In addition, the intensifier requires that the steering tools (in addition to the motor) operate at higher internal pressures than is customary.

Jet Steering

Jet drilling tools do not require side thrust to initiate changes of direction. Jet drilling heads utilize an enhanced form of point-the-bit steering. Since the jets cut ahead of the bit, a jet drilling tool with a bent housing preferentially enlarges the borehole on one side. The tool advances in the direction cleared by the jets. Fluid jet drilling direction is influenced by variations in hardness of the formation. Fluid jets preferentially cut the softer material causing the drill to deflect in that direction. This effect allows geosteering in high permeability oil or gas producing zones or for coal bed methane extraction. In these cases, the tool is more likely to stay within the producing formation rather than drill out of it.

Dogleg Severity

Bent-housing motors create curved boreholes during oriented slide-drilling. To drill straight, the bent-housing motor must be rotated slowly by an orienter since coiled tubing cannot be rotated. The motor bent housing must bend in the opposite direction as it rotates through the angle build sections. A bending stress analysis was performed to determine the maximum dogleg severity (DLS) that can be safely traversed.

The pure jet drilling BHA configuration is less than half the length of a mechanically assisted jet drilling BHA and comparable to a compact PDM motor. The pure jet drilling BHA can drill a curve with a radius of under 32 m (100 ft) allowing the tool to stay within a producing formation. Simply by changing the adapter between the downhole intensifier and the jet drill, the tool can be converted from straight-hole drilling to directional drilling. Since jet drilling requires lower torque, hole straightness will be improved over PDM mechanical drilling.

Extended Reach Drilling

Both configurations considered in this project will extend the reach of coiled tubing drilling by reducing the weight-on-bit (WOB) required to drill.

BHA Configuration Summary

An analysis of high-pressure jet drilling and mechanically-assisted jet drilling was carried out to determine design specifications for the downhole intensifier and to determine the BHA components that will be required for two different configurations. A downhole intensifier model was coupled with a coiled tubing drilling circulation model to determine the nominal operating parameters. The analysis showed that flow rates and surface pressures are compatible with current coiled tubing drilling practices. Two-phase flow or clear water flow at the proposed rates will provide turbulent transport of cuttings in both the vertical and horizontal sections of the hole.

A review of jet drilling data shows that 70 MPa (10,150 psi) jets will allow high-pressure jet drilling at economic rates in conventional, non-fractured, oil and gas producing formations. The same jet pressure will allow mechanically-assisted jet drilling in a broader range of formations.

Pure High-Pressure Jet Drilling

Pure high-pressure jet drilling uses a more compact BHA that can facilitate drilling of short radius laterals. The jet drilling head is easier to steer than a mechanical drilling head and requires nominal thrust for extended reach drilling. High-pressure jets preferentially cut the softer material ahead of the bit allowing the jet drilling tool to geosteer within producing formation. For example, the tool could be provided with a slight build tendency to track along the top of the producing formation. This approach will be limited to drilling lateral wells within conventional oil and gas producing zones with high matrix permeability.

Mechanically-Assisted Jet Drilling

Mechanically-assisted jet drilling could increase drilling rates with small motors by a factor of five and increase the lateral reach of the drill by about 25%. The DHI would reduce mechanical bit vibration by reducing cutter loads and the intensifier hydraulics would limit overspeed of the motor when operating on two-phase flow.

Mechanically-assisted jet drilling requires development and operation of specialized high-pressure motors. The motor will be placed above DHI to limit the required motor operating pressure and to reduce motor complexity. In this configuration, the PDM operating pressure must be at least 30 MPa (4350 psi) above ambient to generate 70 MPa (10,000 psi) jets. The required PDM operating pressure is more than twice the pressure rating of existing motors. This configuration also extends the BHA length and reduces steerability.

Configuration Selection

Despite the performance advantages offered by mechanically assisted jet drilling, we have determined that the effort and expense required to develop a high-pressure PDM in addition to the downhole intensifier, gas separator and jet drill, was beyond the financial and time scope of this program. Therefore, the Microhole jet drilling BHA utilizes pure jet drilling technology. Future work could adapt a PDM and dual-passage mechanical bit to the Microhole jet drilling BHA.

JET DRILLING BHA DESIGN

Designs of the components of the jet drilling bottomhole assembly were based on the existing 2.125" Downhole Intensifier (DHI) assembly built for Trican Well Services. That tool was designed for high-pressure jet cleaning of existing wells that are clogged with hard scale deposits. The DHI tool was designed to run on low-pressure and high-pressure coiled tubing and generate up to 100 MPa (14,500 psi) median outlet differential pressures. For the Microhole program, we added improvements that were identified in the DHI program. These improvements included additional dynamic seals on the intensifier moving parts, longer stroke of intensifier moving parts and a simplified intensifier gas passage arrangement to eliminate misassembly. In addition, the Microhole jet drilling tool required a different drilling head assembly that provides control of advance rate to avoid contact between the rotating nozzle head and the bottom of the hole.

Figure 1 illustrates the resulting Microhole jet drilling BHA. The combined BHA length is 3.75 m (148 in). The following Tempress engineering assembly drawings are included by reference:

- 30082 Screen Sub Assembly – 2.75
- 30074 Gas Separator Assembly - 2.75
- 30066 Intensifier Assembly – 2.75
- 30055 Drill Assembly – 2.75
- 30134 Nozzle Head Assembly – 3.625"

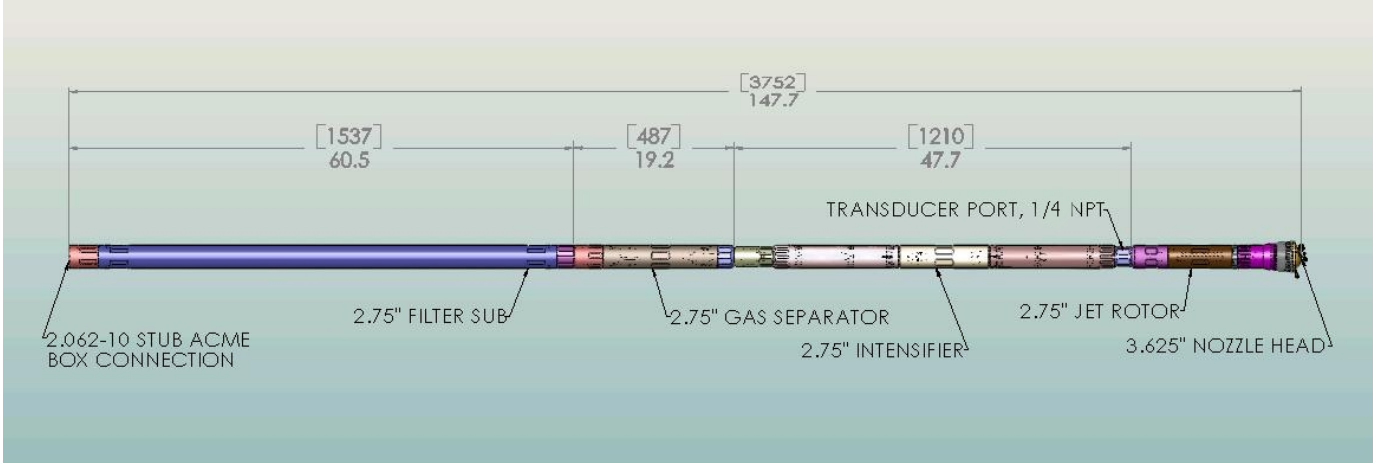

Figure 1. External view of 2.75" bottomhole assembly for jet drilling 3.625" hole.

The Microhole jet drilling BHA is designed to operate on pressurized nitrogen gas and water as required for underbalanced well drilling and well descaling operations. Up to 30 scmm of N2 and 250 lpm water can be used at up to 30 MPa (4350 psi) inlet pressure (above downhole ambient).

This Microhole jet drilling BHA overcomes three typical problems of jet drilling with two-phase fluids and coiled tubing. First, a fluid jet that contains gas tends to break up immediately as it exits a nozzle and loses kinetic energy rapidly. Second, a fluid jet discharging in liquid has several orders of magnitude less effective range than a jet discharging in air. Third, to be effective at cutting harder materials, a fluid jet must have high velocity, which is produced by high pressure. Coiled tubing has limited pressure capability and incurs considerable pressure losses at higher flow rates.

This BHA uses a downhole gas separator to divide two-phase flow into a gassy primary stream and a water secondary stream. The separator removes virtually all of the gas from the secondary stream. The secondary water stream is then intensified downhole and discharged through nozzles in the jet drill at about 2.5 times the inlet pressure. Thrust from the offset jets rotates the nozzle head and a hydrokinetic speed limiter in the jet rotor controls the rotation speed. The gassy primary stream, which is still at system pressure in the separator, is directed to the primary side of the intensifier where it provides the power to intensify the secondary stream. After delivering virtually all of its power in the intensifier, the gassy primary stream is directed through passages in the jet drill to the nozzle head where it is used to shroud the high pressure waterjets thereby increasing their effective range. The result is a very high pressure pure water jetting tool for underbalanced drilling that:

- separates the gas and water,
- uses the pressurized gas to intensify the pressure of the water
- uses high-velocity spinning waterjets to cut ahead of the tool
- uses the spent gas to shroud the waterjets for maximum jetting effectiveness
- provides spent gas for cuttings transport
- creates low downhole pressure to minimize formation damage

Following is a description of the major BHA components. Since the nozzle head is the cutting edge of this tool and everything that follows is there to make the nozzle head more effective, our descriptions starts there.

Nozzle Head

The 3.625-inch 6-jet nozzle head is shown in Figure 2. The nozzles are arranged and sized to provide full coverage of the tool face. The tangential orientation of the nozzles causes the nozzle head to rotate due to jet reaction thrust. The nozzles are removable for easy servicing or replacement. Six passages conduct gas-rich flow from behind the nozzle head to exit points directly adjacent to each nozzle. This provides the gas shrouding required for extending the range of a submerged jet. Gas also exits around the perimeter of the rotating nozzle head. This aids in forming a low density environment below the nozzle head for extending the range of the submerged jets. Excess gas is vented through holes in the side of the tool. The leading edge of the tool body incorporates a wear ring made of a hardened metal. The outermost jet cuts just ahead of the wear ring. The innermost jet crosses the axis of rotation ensuring everything is cut ahead of the tool.

Figure 2. 6-jet nozzle head and gage ring.

Jet Rotor

The jet rotor allows the nozzle head to self-rotate (see Figure 3). The jet rotor conducts the intensified water discharge from the intensifier directly to the rotating nozzle head. It also conducts the gas-rich discharge from the intensifier to a plenum behind the nozzle head to be used for jet shrouding. The axial thrust load on the rotor shaft created by the high internal pressure is carried by a patented pressure-balanced bearing system. The thrust bearings are wear resistant and self-compensating for pressure changes. A pressure balanced rotary seal is also provided in the jet rotor. The tangential jets in the nozzle head can cause the rotor to spin too rapidly causing excessive heat and wear. To prevent rotor overspeed, the jet rotor incorporates a speed governor (patent pending) that controls rotor speed. At design operating conditions, the rotor spins at about 3000 rpm.

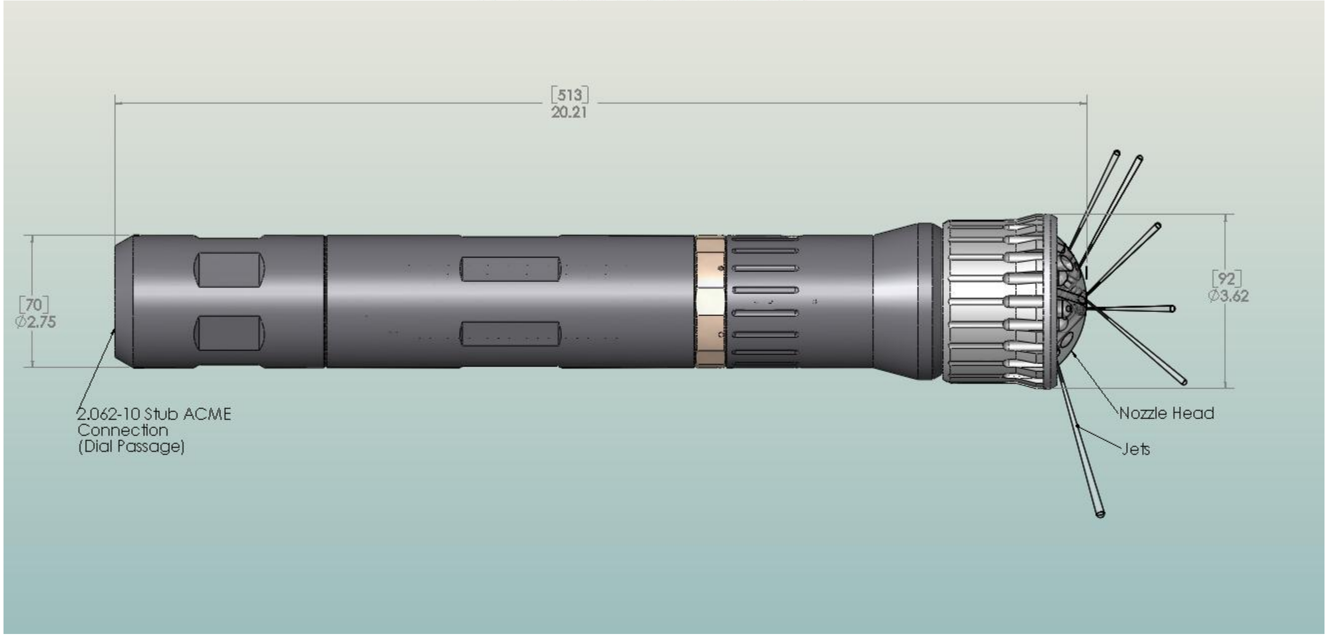

Figure 3. Microhole jet rotor assembly

Downhole Intensifier

Theory of Operation

A schematic of an intensifier is shown in Figure 4. The intensifier operates by applying low pressure to a large area piston that drives a smaller area piston to boost the pressure. The DHI design uses a double-acting intensifier to provide continuous operation. The DHI can be described in terms of its area intensification ratio, which is the ratio of areas of the large piston and small piston. The output pressure is amplified in this ratio while the high pressure outlet flow is reduced in proportion to the intensifier area ratio. In practice, there are pressure losses through the fluid passages that reduce the pressure ratio and hydraulic efficiency of the tool.

Tempress has developed a detailed design for a double-acting DHI capable of providing 70 MPa to a high-pressure jet drill. The intensifier passage geometry has been incorporated into a two-phase hydraulic model that is used to evaluate shift timing, component motions and hydraulic efficiency. The intensifier incorporates long axial flow passages to port the flow to both sides of the intensifier. These passages are subject to turbulent friction pressure losses that cause the hydraulic efficiency of the DHI to decrease with increasing flow rate. At 50 to 75 kW (67 to 101 hhp) output power, the maximum the power efficiency of the intensifier is limited to about 50%.

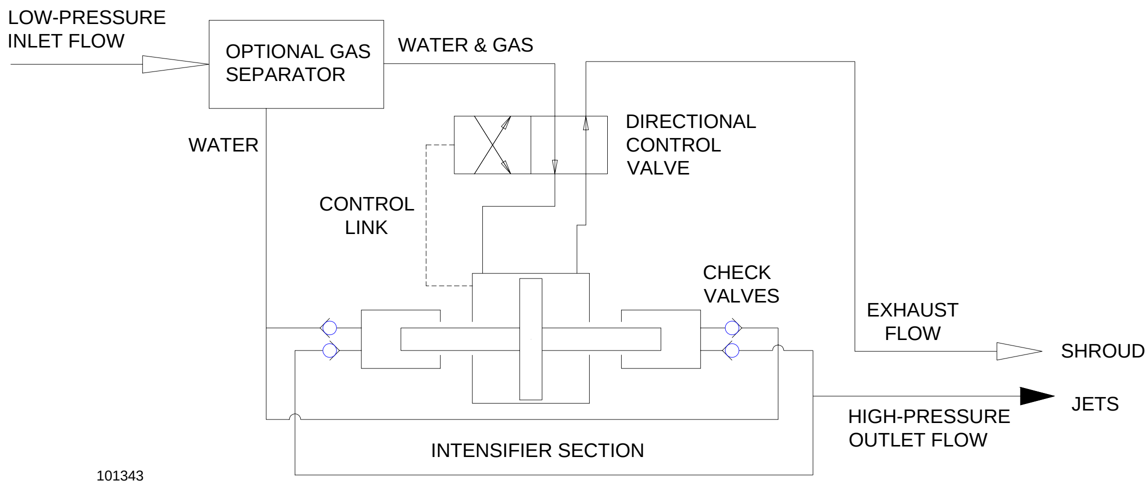

Figure 4. Schematic diagram of intensifier.

Operating Parameters

An existing Tempress detailed numerical computer model for a downhole intensifier was modified and coupled to Tempress' existing downhole circulation model to predict Microhole intensifier performance under various operating conditions. The numerical model accounts for intensifier port timing, pressure drops through the various ports and valves as they open and close, dynamic forces on the moving parts, pressure variations due to changing volumes around the moving parts and variations in density of the compressible fluid as it passes through the intensifier. The intensifier numerical model was used to select preliminary operating conditions and to refine the design of components.

Nominal operating parameters are provided in Table 1. More detailed data is provided in Appendix A.

Table 1. Nominal downhole intensifier operating parameters.

Intensification Ratio	3:1 (effective)
Water Flow	150 - 300 lpm
Gas Flow	10-20 scmm nitrogen
Inlet Pressure	30 MPa
Ambient Pressure	5 MPa
Outlet Pressure	70 MPa
Outlet Flow	40-50 lpm
Outlet Power	50-75 kW

Intensifier Design

Figure 5 shows the intensifier. The double-acting intensifier uses a shift valve arrangement to control motion of the piston/plungers. This allows the intensifier to auto-start from any position.

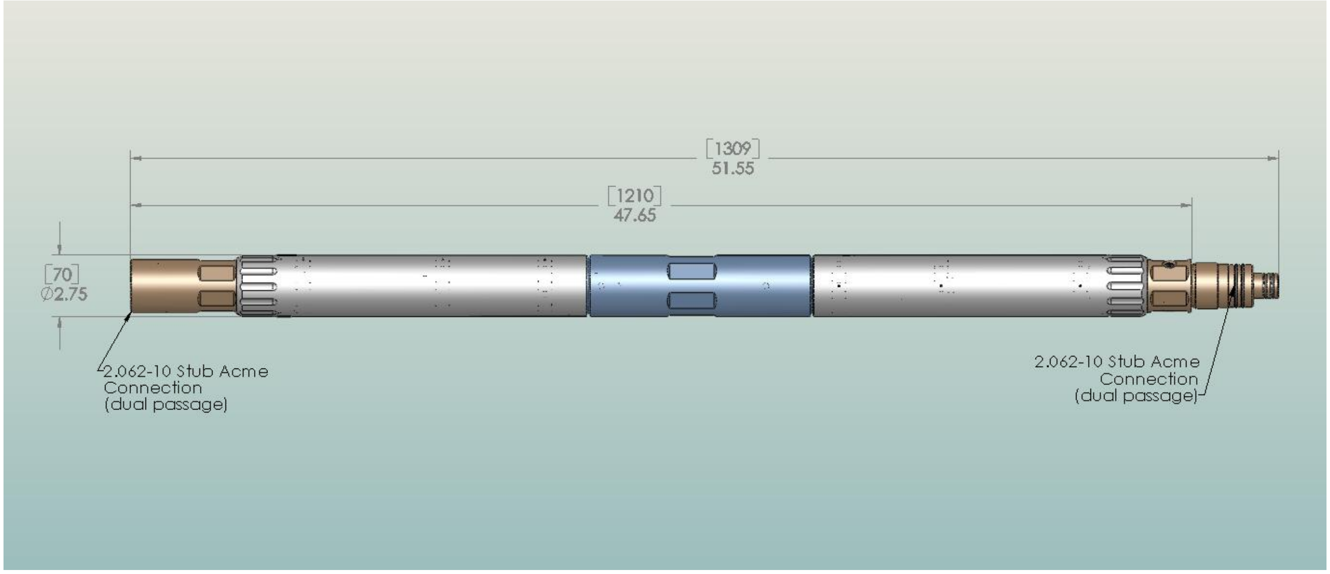

Figure 5. Microhole intensifier.

Gas-rich flow enters through outer passages of the dual passage connection on the left, gives up its power to the piston and shift sleeve in the center section and exits through outer passages of the dual passage connection on the right. The separated secondary water enters the intensifier through the center passage on the left, is intensified by the upper and lower plungers and exits through the center passage on the right. Check valves help to maintain pressure in the outlet passages while piston/plungers reverse direction and the cylinders refill.

The intensifier provides up to 3:1 pressure intensification. To do this, it uses about 83% of the flow to pressurize the other 17%. It accomplishes this with up to 50% power efficiency (hydraulic power out divided by hydraulic power in). The intensifier produces pressures up to 75 MPa (11,000 psi) median pressure above ambient from 25 MPa (3600 psi) inlet pressure (above ambient). Median outlet pressure is used to describe intensifier performance but the outlet pressure fluctuates as the intensifier strokes. The outlet pressure fluctuates from 25 MPa (3600 psi) to 90 MPa (13,000 psi). Therefore, all components subject to these pressure fluctuations must be designed to resist fatigue.

Gas Separator

As discussed above, we determined that the addition of gas enables higher downhole pressure, better cuttings transport and reduced formation damage. We also discussed how gas shrouding the jets significantly improves their effective cutting range. However, fluid jets that contain gas break up rapidly after leaving the nozzle as the gas expands in the jet to ambient conditions. This renders gassy fluid jets ineffective at rock erosion. To deal with this, Tempress incorporated a downhole gas separator into the jet drilling BHA. The gas separator is based on a Tempress patent pending design used in well tubular descaling tools. The separator divides the incoming fluid stream into a water stream and a gas-rich stream.

Two gas separator configurations were created in the Microhole program. The jet drilling BHA utilizes a 2.75" gas separator that separates the water and gas for the intensifier and jet drill. A 2.875" motor gas separator was also designed and built that adapts to existing PDMs and dumps the separated gas-rich stream to the annulus allowing the motor to run on straight water. The 2.875" motor gas separator is discussed separately after the jet drilling BHA discussion.

2.75" Jet Drilling Gas Separator

Figure 6 is a computer model of the gas separator developed for the Microhole jet drilling BHA. The patent pending gas separator uses a turbine to spin a separator drum. Two-phase flow enters the separator (left) and passes through a turbine to a drum. Gas and water separate in the drum due to centrifugal forces and density differences. The water discharges at the drum perimeter and exits via passages to center port of the dual passage connection (right). The gas-rich flow discharges from the center of the drum and exits to outer ports (right). The intensifier attaches directly to the outlet cross-over adapter. Under anticipated operating conditions, the pressure drop through the gas separator is under 1 MPa (145 psi).

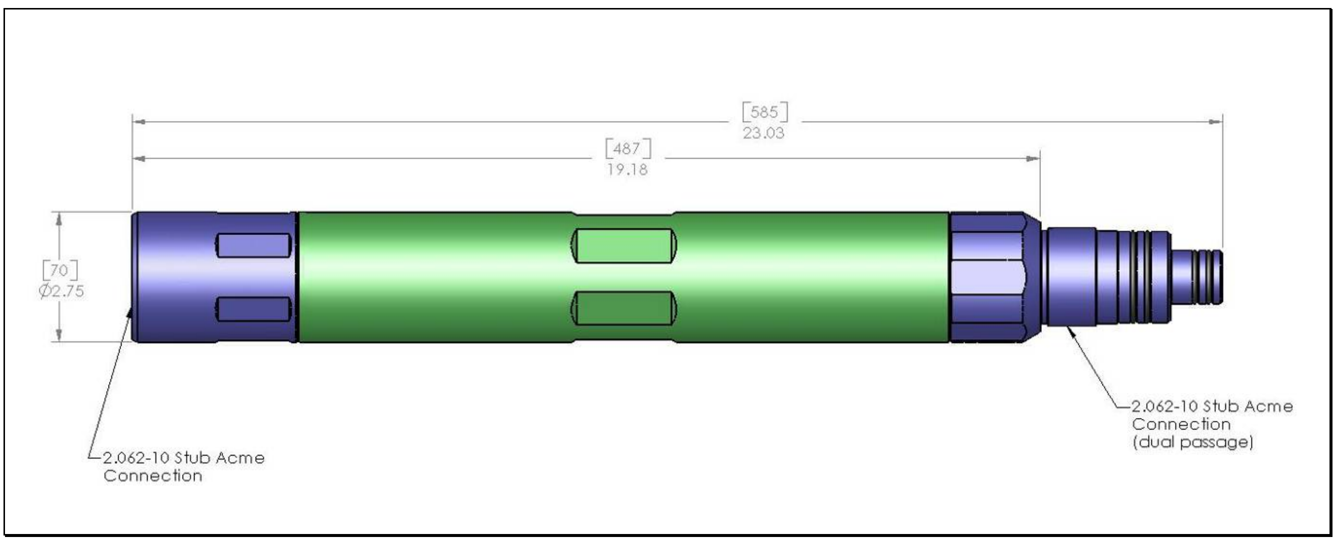

Figure 6. Gas separator used for jet drilling BHA

Screen Sub

Proper operation of the jet drilling BHA requires that the nozzles never plug. Since the nozzles in a high-pressure jetting tool are necessarily small, a screen with openings about one-third the nozzle diameter was selected. The area of the screen is large to block a large volume of particles without becoming plugged.

The screen sub is 2.75 inches in diameter and 1.5 m (61 inches) long. It consists of a tube containing a tubular wedge-wire screen. The screen has 0.1 mm (100 micron, 0.004 inches) spacing between the circumferentially wrapped wires. A filter sock can be installed over the wedge-wire screen if required for easy cleaning and additional separation efficiency.

Motor Gas Separator

As stated above, a second gas separator configuration was created for use on conventional positive displacement downhole motors operating in two-phase flow. Figure 7 is a photograph of the prototype commercial 2.875” motor gas separator (MGS). The design is captured in Tempress assembly drawing 30130. The tool is 17.625” (448 mm) long (shoulder to shoulder) and has 2.375” PAC male and female threads to suit commercially available positive displacement downhole motors. The tool uses an internal spinning drum to separate the gas from the liquid. The gas exits through an orifice and exhausts to the annulus from four upward angled radial ports (visible in photo). The separated water is directed to the main outlet to the motor.

The gas orifice size is selected to suit the application using a motor gas separator performance model to ensure minimal gas reaches the motor under anticipated nominal operating conditions. Generally, a somewhat larger orifice size is selected to ensure that no gas reaches the motor in off-nominal operating conditions. The model is used in the field to adjust operating parameters such as gas and liquid flow rates or wellhead pressure to maximize power to the motor while separating all of the gas. In the event of low gas-to-water ratio or operation with no gas, some water will be lost to the annulus leaving less for the motor. In the event of high gas-to-water ratio, some gas will pass through the motor. These situations are easily mitigated by changing water flow rate according to the model.

Figure 7. 2.875" Commercial Motor Gas Separator (patent pending).

Figure 8 is a schematic diagram of the motor gas separator operating with a positive displacement motor. Input flow from the surface is $Qw + Qg$. The gas-rich flow, $Qws + Qgs$ discharges to the annulus through orifice Atp. Separated water flow, Qwm, exits the separator through fixed openings with area Aso to the PDM. The motor is represented by a fixed orifice with area Amo. The flow split in the separator is related to the separator pressure, Ps, above ambient and the separator pressure, Ps, above the motor inlet pressure, Pm.

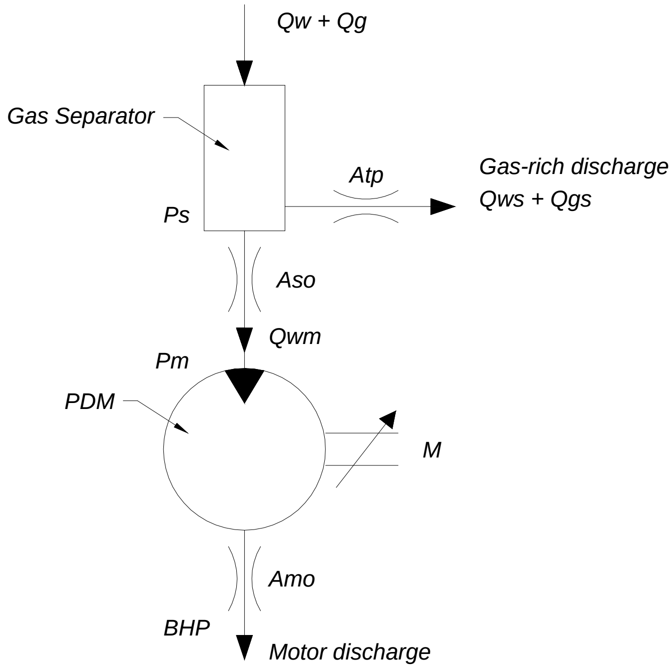

Figure 8. Schematic of gas-separator PDM BHA.

TESTING

Lab Tests

Each BHA component (except the screen sub) was functionally tested at the Tempress laboratory on water only to ensure proper operation before more extensive (and expensive) yard tests with nitrogen. These functional tests are summarized below.

Gas Separator Whirl Tests

Testing with previous gas separators and the prototype Microhole gas separator uncovered a problem with bearing dynamic instability, commonly called "whirl", that could prevent the gas separator from functioning. Bearing whirl is a condition where the spinning drum nutates within its bearings causing it to precess in the opposite direction from shaft rotation. This precession causes the rotation rate to slow dramatically and vibration to increase.

The prototype Microhole gas separator also exhibited bearing whirl after a yard test in November, 2006 (see Yard Tests below). We determined that excessive clearance in the bearings was to blame. The excessive clearance was the result of wear. Wear was the result of material selection. By using hard coatings on radial bearing surfaces and controlling tolerances, we were able to minimize wear and prevent bearing whirl. Spin testing in December, 2006, confirmed this conclusion. Now, spin testing with shop compressed air directed through the stator onto the rotor is the standard way to determine proper functioning of the gas separator.

Gas Separator Spin Test

In March, 2006 we conducted spin tests of the gas separator to determine pressure drop and drum rotation rate. We used a 22 kW (30 hp) centrifugal pump as shown in Figure 9 for these tests. To observe and measure drum rotation rate, a transparent housing was used on the gas separator. At 380 lpm (100 gpm) of water, the pressure drop was 0.83 MPa (120 psi) and spin rate was 5300 rpm.

Recognizing that the flow rate will be different for different applications of the gas separator (jet drill tool or motor gas separator), we designed and built a second turbine stator for higher flow rates. In December, 2006, we measured the pressure drop and drum rotation rate on an improved version of the gas separator using the same 22 kW (30 hp) centrifugal pump as shown in Figure 9. With the "high-flow" stator, the pressure drop was 1.0 MPa (150 psi) and drum rotation rate was 3450 rpm at 780 lpm (205 gpm) of water. With the "low-flow" stator, the pressure drop was 0.69 MPa (100 psi) and drum rotation rate was 5950 rpm at 371 lpm (98 gpm) of water. These were acceptable results.

Gas Separator Dirty Water Tests

Flow going to downhole tools is not always screened. Even with the screen sub, silt will always be present and sand will occasionally enter the system and be run through the BHA. The particulate tolerance of the gas separator was not fully understood. The concern was that a higher concentration of abrasive particles could eventually cause decreasing performance, damage, or failure of the gas separator. Concerns were:

- Larger, heavy particles will separate to the outside of the drum and enter the annular gap around it. These particles may not be able to escape through the small gap at the bottom. They may accumulate and jam the drum.
- Smaller, silt sized particles may embed in the drum bearings and cause excessive buildup and/or wear.
- Very large, gravel sized particles (>1/16") could plug flow passages. This was not tested.

Two dirty water circulation tests were conducted. For the first test in October, 2006, we circulated water containing rust grit, fine silica and course sand at 420 lpm (110 gpm) for 8 hours. Wear rates for bearing surfaces were measured and found to be excessive. Figure 9 shows the technician adding abrasive silica to the circulation tank. The dirty water test setup consisted of the gas separator suspended above a 300 gallon tank and a 22 kW (30 hp) centrifugal pump used to circulate the mixture. Measured amounts of abrasives were poured into the tank and kept suspended by water agitation.

Figure 9. Dirty water circulation test with gas separator.

After the first dirty water test, a number of improvements were implemented, including particle excluders, hardened bearing surfaces and improved flow paths. For the second test in December, 2006, we used the same test setup but a more aggressive mixture of Bentonite, Barite and Portland cement and a higher flow rate to accelerate wear rates. The second test was run at 660 lpm (174 gpm). This test demonstrated that the improvements reduced bearing wear rates to a negligible level. In fact, the mixture was so aggressive that particle erosion of the test pump impeller was the dominant wear factor forcing us to stop the test after only 2 hours. We concluded that the bearing wear issue was solved.

Intensifier and Jet Rotor Functional Tests

The first test run of the Microhole intensifier was on 21 April, 2006. Tempress' laboratory triplex pump is not powerful enough to run the intensifier at full power. By installing a single-jet nozzle test head with a small nozzle on the outlet of the intensifier and by blocking some of the gas discharge ports in the nozzle test head, we could run the intensifier with the lab pump. In this run, the intensifier developed median pressures of 55 MPa (8000 psi) and an intensification ratio in excess of three at 120 lpm (32 gpm) inlet flow. The power efficiency was calculated to be 41%. [Intensification ratio is the median nozzle differential pressure divided by the inlet differential pressure. Power efficiency is the nozzle hydraulic power out divided by the inlet hydraulic power. Hydraulic power is the median differential pressure times the volumetric flow rate.]

Later on 21 April, 2006, we ran the intensifier and jet rotor together with the lab pump. The jet rotor was equipped with an 8-jet nozzle head. Since the total flow area of the 8 jets was much larger than with the single-jet test head, there was no significant intensification at 120 lpm (32 gpm) inlet flow. However, the jet rotor head spun freely. In these tests, the only problem discovered was sticking of the pressure balance seal head in the jet rotor. This problem was easily repaired.

Additional lab functional tests were conducted after making changes to the intensifier and jet rotor and before yard testing.

Yard Tests

Facilities and Equipment

Our partner in the Microhole program, Trican Well Services, maintains a Research and Development facility in Red Deer, Alberta, Canada. The R&D facility is equipped to run two-phase flow tests at high pressure. We conducted 5 test series there with the Microhole jet drilling tool and 2 tests with the motor gas separator. Since this facility is also an equipment maintenance and storage yard, coiled tubing rigs, water pumpers, nitrogen pumpers and nitrogen tankers were readily available for these tests. The R&D facility includes a horizontal pressure chamber (Figure 10 and Figure 11) with hydraulic feed for testing tools under simulated downhole conditions. For pressure drilling tests, the pressure chamber was adapted to include 0.5 m (20 inch) long samples of class G neat cement poured into 4.5” casing. Hydraulic rams drove the tool into the chamber against the pressure snubbing force and provided weight-on-bit (WOB). The pumpers were connected directly to the stinger that passed through seals into the chamber.

Figure 10. Horizontal test chamber and recirculation tank at Trican's Red Deer yard. Test chamber is setup for Microhole instrumented performance tests.

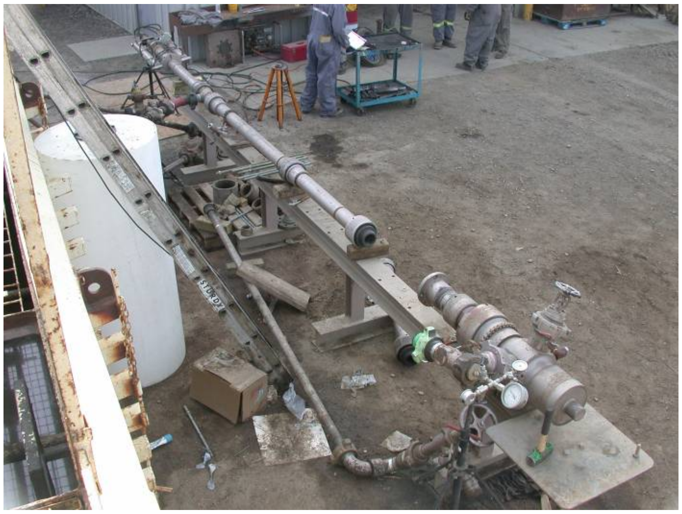

Figure 11. Test chamber opened at sample location.

Trican's R&D facility also has a shallow test well (Figure 12 and Figure 13) in which 4.5" cased samples 12 m (39 ft) long can be suspended. This test well was used with sealed high-pressure lubricators and a choke manifold to simulate coiled tubing operation in much deeper wells. To support these tests, the facility has a large open-top recirculation tank equipped with a gas knock-out feature for two-phase flow. The recirculation tank was used to settle out cuttings from drilling/milling tests.

Figure 12. Microhole BHA being inserted into shallow test well at Trican's Red Deer yard

Figure 13. Trican test well with injector and lubricators installed. Head frame was removed for last yard test.

Test Setups

Instrumented Performance Tests

Since it is not possible to measure intensifier outlet pressures inside of the test chamber or test well, all instrumented performance runs were made with the intensifier exposed. This was accomplished in several ways. In the first yard test, we mounted the BHA to a grating on top of the water supply tank as shown in Figure 14. Backpressure was created inside of the BHA by adding chokes in the gas-rich primary discharge passages in the jet rotor. The jets discharged into air.

Figure 14. Microhole jet drilling bottomhole assembly mounted on top of water supply tank with pressure transducers attached.

In subsequent yard tests, except the last, we installed just the jet rotor in the test chamber using an adapter that sealed the BHA to the lubricator as shown in Figure 15. In the last yard test, we used the same adapter to seal the jet rotor into the test well. These arrangements allowed access to the intensifier pressure ports for installation of pressure transducer(s) and accurate measurement of intensifier performance.

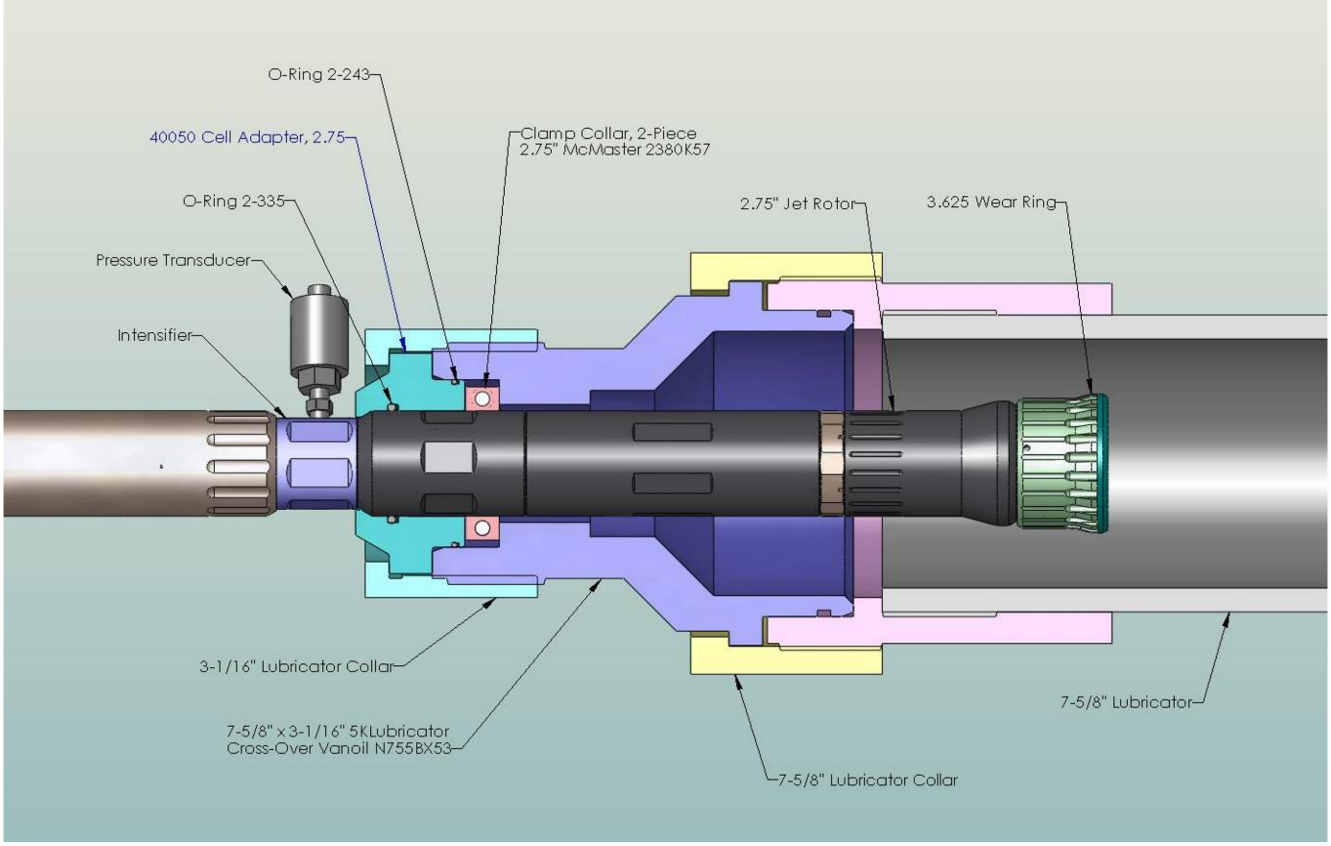

Figure 15. Test well flange seal arrangement

Drilling Tests

Drilling tests were conducted in the test chamber and in the test well. No intensifier pressure measurements could be made in either test configuration. Intensifier performance data for drilling tests was inferred from available pump pressures and flows and chamber/well head pressures as compared with instrumented performance tests at comparable operating conditions.

For chamber drilling tests, a 20” (0.5 m) long section of 4.5” casing was filled with class G neat cement. The chamber was opened up as seen in Figure 11 and the sample inserted between flanges. The jet drilling BHA was sealed up in the lubricators.

For well drilling tests, a coil rig with 2000 m of 2.00” OD by 0.175” wall steel coiled tubing and a tubing injector were used. The injector was suspended over the well with a crane (Figure 13). Two 3 m (10 ft) lengths of 7.625” lubricators connected and sealed the injector to the well head. The BHA was attached to the coil tubing connector and loaded into the lubricators from below before assembly to the well head.

Figure 16 illustrates the flow schematic for the well drilling tests. The computer and pressure transducers on the intensifier were used for the jet drill instrument run only.

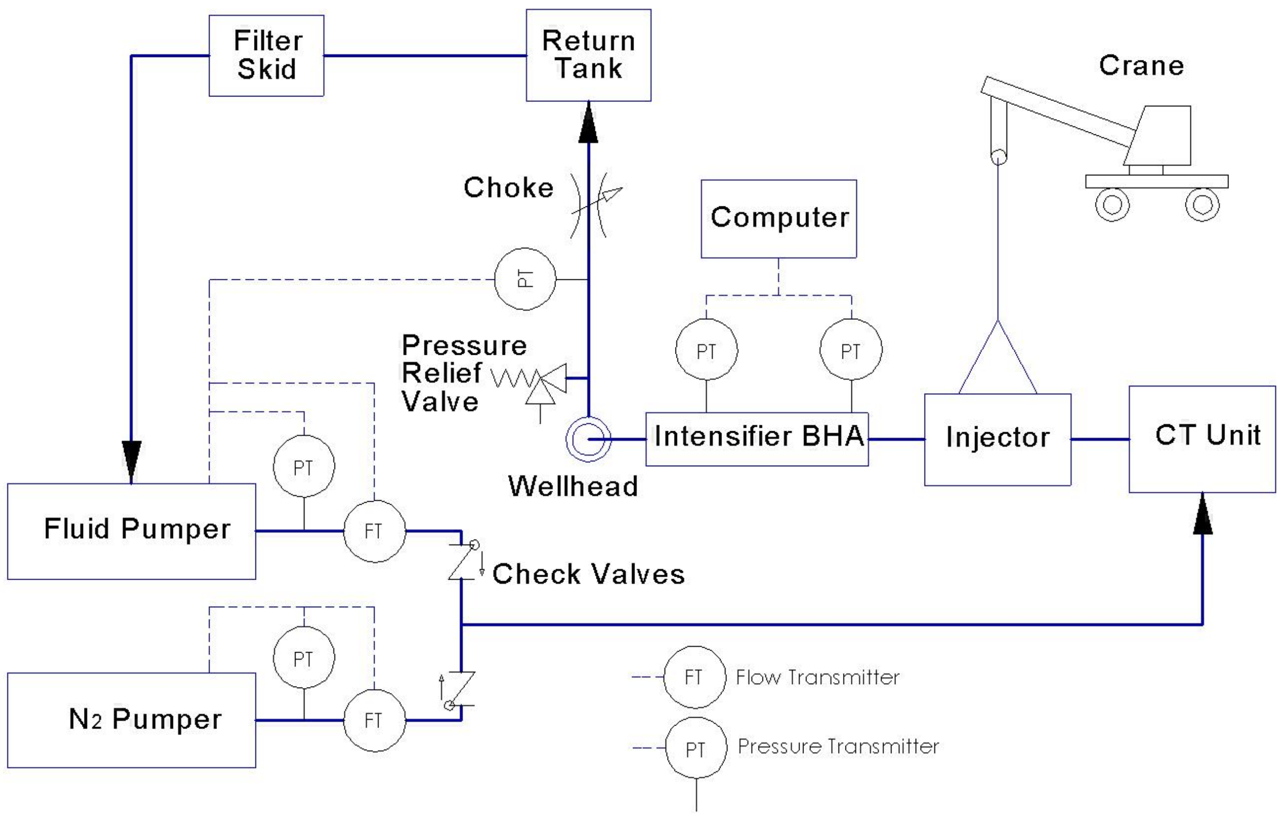

Figure 16. Test well flow schematic diagram

Instrumentation

Transducers and pressure gages were used to measure flows and pressures of interest. Trican's data acquisition system logged the following at a sample frequency of 1 per second:

- Choke line pressure (back-pressure in well)
- Water pump flow rate
- Water pump discharge pressure (representative of both pumps)

During instrumented performance tests, Tempress' data acquisition system logged the following at a sample frequency of 10,000 per second:

- BHA inlet pressure
- Intensifier secondary outlet pressure

The following data was logged manually from verbal reports:

- Nitrogen pump flow rate
- Choke valve setting

Filtration

The tank suction line was fitted with multiple 50 micron filter bags. The BHA screen sub was fitted with a 100 micron wedge-wire screen. The nozzle head was fitted with a 200 micron last-chance screen.

Flushing

The water and nitrogen were circulated through the surface lines and coil prior to testing to remove accumulated debris and corrosion products. Before sealing the BHA into the lubricators, jet condition, nozzle head rotation and intensifier stroking were observed by jetting into air.

Safety Protocol

Safety Meeting

Before each day of testing, a safety briefing was held. All personnel at the meeting signed a log sheet.

Pressure Test

Pressure lines and coiled tubing were tested for leaks to 110% of the anticipated maximum operating pressure. The test well and discharge line to the choke valve were pressure tested to 10 MPa.

Jet Drill Yard Test Results

Following is a brief summary of each test.

First Yard Test

The first yard test of the Microhole jet drilling bottomhole assembly in Budget Period 1 was carried out in late April, 2006. Details of this test are contained in Tempress Technical Report TR-086.

Upon successful completion of the first intensifier and jet rotor functional lab tests in April, the Microhole BHA was taken to Red Deer for full flow testing with water and nitrogen. Testing was conducted in the test chamber and in air. The tests showed that the tool operates properly on commingled water and nitrogen at various ratios and pressures. We completed over one hour of testing at various pressures and flows. The gas separator performed flawlessly. The intensifier produced up to 59 MPa (8600 psi) median differential pressure across the nozzle with 20 MPa (2900 psi) median differential input pressure. Peak differential pressures were over 70 MPa (10,000 psi). The tool developed 46 kW (62 hhp) at the nozzle. By reducing the nozzle sizes and increasing the flow slightly, we would be able to reach our goal of 70 MPa median differential pressure across the nozzles in future tests. The performance and reliability goals also appeared to be achievable.

Mechanical problems encountered during this test are reviewed in the full test report along with suggested design modifications.

Second Yard Test

The second yard test of the Microhole BHA in Budget Period 1 was conducted in June, 2006. Details of this test are contained in Tempress Technical Report TR-096.

In this test we demonstrated that the Microhole jet drilling bottomhole assembly develops high powered, high pressure fluid jets capable of cutting cement while operating on commingled water and nitrogen. We completed ¾ hour of run time at various flows and pressures. The intensifier produced up to 60 MPa (8700 psi) median differential pressure across the nozzle with 31 MPa (4500 psi) differential input pressure. Peak nozzle differential pressures were over 83 MPa (12,000 psi). Maximum hydraulic power output through the nozzles was 50 kW (67 hhp) exceeding the 46 kW (62 hhp) developed in the previous yard test with the 8-jet nozzle head. However, there were problems that prevented us from completing the test program.

The gas separator performed flawlessly. The jet rotor seal head chipped causing excessive leakage. To continue testing, the seal head was replaced. Three intensifier seal tubes leaked excessively and were also replaced. The performance tests were completed but output pressures were lower than expected due to these leakage issues. The intensifier piston/plunger assembly failed catastrophically during the drilling test after drilling about one inch of cement. Corrective actions were identified and implemented.

Third Yard Test

In September 2006, Tempress and Trican conducted the third yard test of the 2.75" Microhole jet drill bottomhole assembly at the Trican R&D facility. The objectives of this round of testing were to 1) demonstrate drilling in a cement sample at input pressures compatible with standard drilling operations using conventional low-pressure coiled tubing, and 2) demonstrate 8 hours of endurance operating at the same downhole conditions.

In this test the Microhole jet drilling bottomhole assembly drilled to the wall of 4.5" casing containing 5-month old cement. The average drilling rate was over 30 m/hr (100 ft/hr). The BHA performed flawlessly. Intensifier performance was improved over the previous yard test.

During the 2nd segment of the drilling test, progress stopped. As we retracted the tool to investigate the problem, pump pressure rose rapidly to about 45 MPa and choke pressure dropped. Drilling progress stopped when the increased snubbing pressure overloaded the hydraulic rams and damaged the test stand. The pressure apparently rose due to cuttings blocking the annulus. Testing was concluded and the 8-hour endurance test was not accomplished.

Fourth Yard Test

In December 2006, Tempress and Trican conducted the fourth yard test of the 2.75” Microhole jet drill bottomhole assembly (BHA) at the Trican R&D facility. The objectives of this round of testing were to 1) demonstrate drilling in a cement sample at input pressures compatible with drilling operations using conventional low-pressure coiled tubing, 2) demonstrate 8 hours of endurance operating at the same downhole conditions, and 3) to collect accurate BHA performance data at various flow conditions at pump pressures up to 35 MPa with applied back-pressure up to 5 MPa to simulate downhole conditions. At these conditions, the median nozzle differential pressure should exceed 70 MPa as required to cut many formations.

In this test, the Microhole jet drilling bottomhole assembly ran for a total of 6.5 hours at pressure, of which 5 hours were without interruption. Testing ended when the nozzle head cracked and could no longer hold pressure.

Intensifier performance was improved over the previous yard tests. The average intensification ratio was 3.0 and the average net efficiency was 42% during the performance test. The jets produced up to 40 kW net power and up to 62 MPa peak (55 MPa median) differential pressure with 18 MPa input differential pressure.

We were unable to start the drilling test due to problems with the coil tubing injector. Pump pressure was limited to 28 MPa due to the pressure rating of the 1.75” coil provided for the test.

Fifth Yard Test

From 23 May through 1 June, 2007, Tempress and Trican tested the 2.75” Microhole jet drill bottomhole assembly (BHA) at Trican’s R&D facility. Tests were run in a shallow test well with sealed lubricators and choke manifold to simulate deeper drilling conditions. Please refer to Tempress Technical Report TR-114 for detailed description of the tests. Following is a summary of those tests.

The Microhole jet drill BHA was run at pump pressures up to 31 MPa with well head pressure (WHP) applied with surface choke valve up to 5 MPa. The jet drilling BHA ran for a total of 6 hours at pressure and drilled 7 meters of uncertified class G cement. In the first cement sample, the tool drilled one meter at an average rate of 10 m/hr (33 ft/hr). In the second cement sample, the tool started drilling at 5.4 m/hr (18 ft/hr) and the rate slowed to an average rate of 2 m/hr (7 ft/hr).

Specific productivity for these tests ranged from 0.06 to 0.45 mm^3/J. In a threshold pressure test performed at Tempress for a previous project[8], we determined that Portland cement was cut at 0.15 mm^3/J with a 70 MPa (10,000 psi) waterjet. The Microhole tool exceeded that specific productivity rate by a factor of three near the beginning of the drilling test. The drilling rate slowed due to nozzle plugging and sluggish nozzle head rotation. The tool cannot drill effectively if nozzles are plugged and/or the head is not rotating properly. Nozzle plugging was a result of the last chance screen becoming overloaded with particles and fracturing, allowing particles through to plug nozzles. Excessive quantity of particles accumulated in the last chance screen due to the failure of several small, critical parts in the intensifier during the drilling tests. Sluggish nozzle head rotation is likely the result of excessive pressure behind the nozzle head overloading the jet rotor thrust bearing and jet plugging. The excessive pressure behind the nozzle head is due to high volume flow rate around and through nozzle head ports resulting from the expansion of spent gas to ambient conditions. Corrective actions for these issues have been identified.

In a separate run, with many of the failed critical parts replaced, data was collected on intensifier performance at various flows and back pressures (without drilling). Performance testing revealed that the intensifier provides intensification ratios of up to 3:1. The BHA output median differential pressures were up to 74 MPa (10,800 psi) and peak pressures were 90 MPa (13,000 psi) with 31 MPa (4500 psi) pump pressure, 25 MPa (3600 psi) BHA inlet differential pressure, 1.9 MPa (280 psi) WHP and flow rates of 263 lpm (69 gpm) water and 9.7 scmm (340 scfm) nitrogen. At these operating conditions, the jet drill BHA delivered 42 kW (56 hhp) downhole hydraulic power and about 30% efficiency. Efficiency was compromised by a significant leak in a high-pressure seal tube and by check valve problems (discovered later). These issues can be easily mitigated by regular replacement of these relatively inexpensive components.

Comparison with PDM Drilling

To gain some perspective, we searched the literature for examples of coiled tubing drilling with conventional PDMs and mechanical bits. From Table 2, the average sustained drilling rate data for coiled tubing and conventional motors in various formations is 31 m/hr (100 ft/hr). This includes both weighted and underbalanced fluids and mostly horizontal extensions of existing wellbores. When wiper trips and other non-productive activities are considered, the average drops to 14 m/hr (45 ft/hr).

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[8] **Tempress Technical Report TR-073, Threshold Pressure Test, June, 2004.**

The Microhole BHA drilled at a sustained rate of 10 m/hr (33 ft/hr) for a 1 meter section, about one third the average sustained rate for PDM drilling.

Table 2. Coiled Tubing Drilling with PDM

Ref	Location	Field or Well	Formation	Fluid	PDM Dia	Direction	Sustained Drilling Rate		Average Rate (incl. wiper trips)	
							m/hr	ft/hr	m/hr	ft/hr
1	New Mexico, Colorado	San Juan basin, wells 1-7	Shales & coal	weighted mud	4.75 & RSS	vertical & deviated			21	68
2	Sharjah, UAE	Well 18		N_2 & H_2O	2.875		60	197	7	23
2	Algeria	Hassi Messaoud	Cambrian Sandstone		2.875	horizontal			3	9.5
2	Other (not specified, from Figures 2 and 3)					horizontal	26	85		
3	Prudhoe Bay, Alaska	Sadlerochit, Ivishak	Sands	biopolymer	2.875		21	69	9	30
3	Prudhoe Bay, Alaska	Sadlerochit, Ivishak	Shales	biopolymer	2.875		6	20	3	10
4	SE Alberta	Crestar 102 Hz Jenner 15-14-21-8 W4M	Glauconitic "OO" Pool	underbalanced	3.75	horizontal			13	44
4	SE Alberta	Crestar Jenner 16-14-21-8 8W4	Glauconitic "OO" Pool	underbalanced		horizontal			11	34
4	SE Alberta	Crestar Majorville 10-30-18-19 W4M	Glauconitic	underbalanced		horizontal			9	29
4	SE Alberta	Crestar Majorville 11-31-18-19 W4M	Glauconitic	underbalanced		horizontal			17	56
4	SE Alberta	Crestar Majorville 6-31-18-19 W4M	Glauconitic	underbalanced		horizontal			13	42
5	New Mexico	San Juan basin	Sandstone & coal	polymer	4.75	vertical			24	80
6	Taber, Alberta	Mobil HZ Turin 13-18-11-16W4	Glauconitic	underbalanced	3.375	horizontal	60	197	18	57
6	Taber, Alberta	Mobil HZ Turin 14-13-11-17W4	Glauconitic	underbalanced	3.375	horizontal	26	84	20	64
6	Taber, Alberta	Mobil 103 HZ Taber N 9-2-11-16W4	Glauconitic	underbalanced	3.375	horizontal	24	78	16	52
6	Taber, Alberta	Mobil 102 HZ Taber N 15-2-11-16W4	Glauconitic	underbalanced	3.375	horizontal	28	92	25	80
						Averages	**31**	**103**	**14**	**45**

References for Table 2:

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4. Borbely, Brazier, Giddings and Cox, Crestar Energy, Canadian Fracmaster, "Coiled Tubing Horizontal Underbalanced Drilling Project; Costs and Operational Analysis," SPE 38399, 1997.
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Motor Gas Separator Yard Tests

On 24 and 25 May, 2007, Tempress and Trican tested a second generation 2.875" motor gas separator (MGS) at the Trican's R&D facility. Tests were run in the shallow test well with sealed lubricators and choke manifold to simulate deeper drilling conditions. Please refer to Tempress Technical Report TR-118 for detailed description of those tests. Following is a summary of those tests.

The motor gas separator (MGS) was tested with a Baker Oil Tools 2-7/8" VIP motor in the Trican Red Deer Test well. Tests were also carried out with and without the MGS installed. The MGS was equipped with a 0.25" diameter gas port designed for shallow well applications. This gas port is significantly larger than used previously for testing and operations in deep wells. The tests confirm that two gas port sizes should cover all operating conditions anticipated during operation with a 2-7/8" motor.

Flow tests confirmed that MGS does not generate a significant pressure differential when operated at the motor design flow rates. These tests were used to verify the MGS numerical model. Cement milling tests showed that additional water flow rate can be used to compensate for water bypass though the gas port when operating on straight fluid. The tests also showed that the pump pressure response to milling torque and stalls is the same with the MGS installed when running straight fluid. The addition of gas increases the time required for pump pressure to respond to stalls and increased torque, but the response is still large enough to determine that the motor is milling or is stalled.

A video showing MGS operation with a motor at surface was made during the tests. The video confirms proper MGS operation under these conditions. The open-air run of the MGS/PDM combo clearly showed that the separator removed gas from the flow to the motor. The video is available on the Tempress website, www.tempresstech.com.

The MGS/PDM combination drilled the first 40 foot length of cemented casing at an average rate of 0.7 m/min running water only. About 1 meter was drilled in the second 44 foot length of cemented casing at an average rate of 0.1 m/min.

Motor Gas Separator Field Trials

A second generation motor gas separator (MGS) was designed to address issues uncovered during the lab dirty water tests of the prototype Microhole 2.75" gas separator. Four commercial 2.875" motor gas separators were fabricated outside of the Microhole program based on the second generation design. One of these tools was tested within the Microhole program at the Red Deer facility as reported above. These tools are currently undergoing field trials in Colorado and Wyoming with Baker Oil Tools (BOT). Though not funded by the Microhole program, a summary of these field trials is included here because these tools are a direct development of the Microhole program.

Wyoming Wells

As of this report, the motor gas separator (MGS) had been run on three wells in Wyoming with a PDM to mill sand, scale and partially collapsed casing at well perforations. The typical job is milling obstructions at 5200 m (17,000 ft) or more in hot (200^{o} C, 400^{o} F) wells. Commingled nitrogen and fluid are run to keep the well unloaded to prevent formation damage. Typical jobs require several motors and mills because of stator damage while milling with commingled flow.

The MGS allows substantially higher fluid rates to help with milling and higher gas rates to help lift the fluid. Typical job parameters are:

- Well Depth: 5450 m (18,000 ft)
- Coil: 5793 m (19,000 ft) 1-3/4 inch OD, tapered 0.156 inch to 0.109 inch wall
- Motor BOT model MV-1, 2-7/8 inch, 5.5 MPa (800 psi) nominal differential pressure while drilling
- Fluid: water/2% KCl
- Fluid rate: 320 to 450 lpm (2 to 2.8 bpm)
- N2 rate: 20 to 30 scmm (700 to 1000 scfm)
- Casing: 4-1/2 inch, 17lb/ft, 95 mm (3.74 inch) ID
- BHT: 177 to 200 ^{o}C (350-400 ^{o}F)

The BHA includes:

- dual backpressure valve
- H-E coiled tubing jars
- hydraulic disconnect
- dual circulation sub
- motor gas separator
- BOT 2-7/8 inch VIP or Xtreme mud motor
- bladed Opticut bit

A 4.4 mm (0.175 inch) gas orifice was placed in the MGS based on our circulation and MGS model. Milling rates were reasonable in all cases, but surface pumping problems meant that it took several trips and motors to complete each well.

The value of the tool on these jobs was the ability to provide higher gas flow rates while maintaining milling performance. Higher gas rates reduce the amount of fluid contacting the formation. This substantially reduces the risk of formation damage that can cause loss of the well in these formations.

CONCLUSIONS

High-Pressure Jet Drill

The Microhole high-pressure jet drill has proven that it can provide sufficient pressure downhole for drilling using conventional coiled tubing. The BHA performs well on commingled nitrogen and water. The high-pressure jet drilling tool can provide more power downhole than a conventional PDM. The BHA can produce output differential pressures up to 74 MPa (median) and 90 MPa (peaks) with 25 MPa (3600 psi) input differential pressure. The tool has delivered up to 50 kW (67 hhp) downhole hydraulic power and has run at up to 50% power efficiency.

The major (expensive) components of the BHA have proven to be reliable. Reliability issues still remain for some of the smaller internal parts such as seals, check valves and the last chance screen. Fortunately, these components are inexpensive to replace or maintain. Additional development and testing is required to extend the mean-time-between-failure of these components.

The Microhole high-pressure jet BHA drilled cement samples at 10 m/hr (33 ft/hr). Based on the jetting power levels provided by the Microhole BHA, we estimate that the tool will drill oil and gas producing formations with matrix porosity at a rate of about 6.7 m/hr (22 ft/hr).

For comparison, the PDM/MGS combination drilled two cement samples at 43 m/hr (140 ft/hr) and 6.1 m/hr (20 ft/hr). Coiled tubing drilling (CTD) with comparably sized PDMs can typically provide ROPs of 31 m/hr (100 ft/hr). PDMs also run at lower surface pumping pressures.

Given the cost and complexity of the high-pressure jet drilling BHA, and the higher pumping pressures required, we do not see how it can compete with PDMs for coiled tubing drilling services except in niche markets where a PDM is not appropriate.

Motor Gas Separator

Lab and yard testing, together with field trials to date, have driven continued improvements to the commercial MGS. The tool is reliable and effective. When commingled flow is required for gas lift cuttings transport or downhole pressure control, the MGS allows the PDM to operate as though only water were pumped down the string. This means less vibration and less nitrogen damage to the motor stator. Standpipe pressure response to motor stalling with two-phase flow was slow, the same as if the MGS were not installed. When gas is present, the pump pressure responded more slowly to WOB changes because of gas compressibility in the coil. The pressure response time in water-filled coil was a few seconds while the response time in a coil with two-phase was over a minute. The MGS/PDM combination is relatively tolerant of variations in gas flow rate, motor differential pressure and bottomhole circulating pressure (BHCP).

RECOMMENDATIONS

Jet Drill

There currently exists a substantial world market for coiled tubing well servicing. Tempress has already demonstrated the viability of jet descaling existing 2.875 inch wells with our commercial line of tools. The Microhole BHA can be easily adapted for high-pressure descaling service in larger wells by converting the jet drilling head to a jet milling head. In addition, the advances made with the 2.75" jet drilling tool can be immediately applied to the existing 2.125" predecessor high-pressure jet milling tool.

Tempress plans to commercialize the 2.125" high-pressure jet milling BHA with downhole intensifier for hard scale milling operations. This application allows hard scale removal without risk of damage to downhole valves, capillary tubes or other jewelry. The technology in this tool will be drawn directly from the Microhole development.

Although the projected rates of penetration for the current Microhole high-pressure jet drilling BHA are lower and costs are higher than conventional CTD drilling with a PDM, it may be possible to improve the jet drill's performance and the economic viability by the addition of small mechanical cutters on the nozzle head. Mechanical cutters would help to break off peaks left by the jets thereby improving ROP. The cutters cannot be as large as conventional mechanical bits due to the limited torque available from the jet rotor.

Motor Gas Separator

Four first generation commercial 2.875" motor gas separators are currently participating in a 10-well demonstration program with Baker Oil Tools in Wyoming. At the conclusion of that program the design should be revisited to implement lessons learned. Dependent upon continued successful results in the 10-well demonstration program, Baker Oil Tools, Trican and Tempress intend to offer the MGS for commercial service, initially in North America, and on a phased basis, worldwide.

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APPENDIX A - LIST OF ABBREVIATIONS

Abbreviation	*Meaning*	*Type*
BHA	bottomhole assembly	
ft (‘)	foot	distance
ft-lb	foot pound	torque or work
gpm	gallons per minute	liquid flow
hhp	hydraulic horsepower	power
ID	inside diameter	dimension
in (“)	inch	distance
J	Joule	kinetic energy
KCl	potassium chloride	mud additive
kW	kilowatt	power
lb	pound	mass
lpm	liters per minute	liquid flow
m	meter	distance
MGS	motor gas separator	
min	minute	time
mm	millimeter	dimension
MPa	megapascal	pressure
N2	Nitrogen	gas
Nm	Newton meter	torque or work
OD	outside diameter	dimension
PDM	positive displacement motor	
psi	pounds per square inch	pressure
ROP	rate of penetration	speed
rpm	revolutions per minute	rotation speed
s	second	time
scfm	standard cubic feet per minute	gas flow
scmm	standard cubic meters per minute	gas flow

APPENDIX B - DESIGN BRIEF

Performance Requirements

The following performance requirements are taken from the U.S. Department of Energy, National Energy Technology Laboratory (NETL), Microhole Technology Development II solicitation number DE-PS26-04NT15480-00:

- Borehole diameter: 3.50” (89 mm)
- Minimum depth: 2000 ft (610 m)
- Maximum depth: 5000 ft (1524 m)
- Minimum lateral offset: 1000 ft (305 m)

Borehole Configuration

For analysis purposes, the borehole consists of the following:

- Casing: 5”, 13 lb/ft to kick-off depth
- Open hole: 3.625” below kick-off depth
- Dog-leg severity: 50 deg/100 ft (50 deg/30 m)

Interface Requirements

The jet drilling tool is part of a complete coiled tubing drilling system. The following system characteristics are assumed for this project:

- Drilling fluid: water plus nitrogen (underbalanced)
- Filtration: 100 microns
- Optional additives: solvents (diesel, xylene, terpenes), and friction reducers (polymers)
- Standpipe pressure: 4000 psi (28 MPa)
- Water flow: 26-55 gpm (105-210 lpm) depending upon design case and configuration
- Nominal gas flow: 353 scfm (10 scmm)
- Coiled tubing size: 2.00” OD (51 mm) by 0.188” (4.8 mm) wall
- Coiled tubing material: QT-800 (80,000 psi yield strength)
- Coiled tubing length: 8000 ft (2438 m)

Bottomhole Assembly Requirements

General Requirements

- Nominal tool outside diameter: 2.75” (70 mm)

- Overall length: less than 4 m (157 inches)
- Magnetic: OK
- Proof pressure: 1.5 times nominal operating pressures
- Reliability goal: 72 hours between maintenance
- Last chance screen: 200 micron

Environmental Requirements

- Corrosion: H_2S present
- Temperature: 32 to 300º F (0-150º C)
- Tolerant of ledges and edges in production tubing or casing

Gas Separator Requirements

- Purpose: Separate mixed nitrogen and water inlet flow into primary and secondary outlet streams
- Maximum inlet pressures (above ambient): 32 MPa (4700 psi)
- Inlet flow rates: 138-248 lpm (36-66 gpm)
- Inlet gas fraction (at inlet pressure): 10-25% (by volume)
- Primary outlet stream gas fraction (at pressure): 21-32% (by volume)
- Secondary outlet stream gas fraction: <1% (volume)
- Upper connection: to suit coiled tubing connector
- Lower connection: dual passage, to suit downhole intensifier inlet

Intensifier Requirements

- Purpose: Use energy in primary stream to boost pressure of secondary stream
- Overall length: <5 ft (1.5 m)
- Theoretical intensification ratio: 3.94:1
- Effective intensification ratio: 3.0:1
- Maximum inlet pressures (above ambient): 32 MPa (4700 psi)
- Primary inlet: water only, gas only, or gas and water mixture
- Secondary inlet: water with <1% gas (by volume)
- Primary discharge pressure (above ambient): at least 0.5 MPa (70 psi)
- Median secondary discharge pressure (above ambient): at least 70 MPa (10,000 psi)
- Upper connection: dual passage, to suit gas separator
- Lower connection: dual passage, to suit jet rotor

Jet Rotor Requirements

- Purpose:
  1. conduct secondary flow from intensifier to nozzle head
  2. conduct primary discharge flow from intensifier to gas shroud ports
  3. allow rotation of the waterjet nozzle head
  4. limit maximum rotation speed
- Primary circuit inlet pressure (above ambient): 0.5 MPa (75 psi)
- Average secondary circuit inlet pressure (above ambient): 71 MPa (10,300 psi)
- Maximum secondary circuit inlet pressure (above ambient): 91 MPa (13,200 psi)
- Rotation speed: 2000-5000 rpm
- Connection: dual passage 1-1//2" (custom)

Nozzle Head Requirements

- Purpose:
  1. convert intensified secondary fluid pressure into high velocity jets
  2. conduct gassy primary flow to locations adjacent to jet nozzles to shroud jets
  3. use jet reaction thrust to rotate the jet rotor
  4. Estimated jet core reach: 13 times nozzle orifice diameter (with gas shroud)
- Jet core minimum coverage diameter: 92 mm (3.625")
- Pressures: same as jet rotor
- Secondary separation: Shroud gas flow taken from lowest density location in primary passage

APPENDIX C - PERFORMANCE CALCULATIONS

BHA performance was calculated using measured flow rates and pressures. The intensifier cycle rate was determined from the intensifier outlet pressure signal.

Performance was calculated from the BHA input pressure and the intensifier output pressure (nozzle pressure) and the test well discharge pressure. The input primary differential pressure (*dPp*) is the difference between the measured BHA inlet pressure (*Pi*) and the measured annulus back pressure (*Pb*):

$$dPp = Pi - Pb$$

The secondary output differential pressure across the nozzles (*dPs*) is the difference between the measured median intensifier secondary outlet pressure (*Pn*) and the measured back pressure (*Pb*):

$$dPs = Pn - Pb$$

The net intensification ratio (Ri) is calculated from the inlet differential pressure and outlet differential pressure according to the following formula:

$$R_i = dP_s/dP_p$$

The BHA inlet hydraulic power (*Wi*) is the product of the input primary differential pressure (*dPp*) and total inlet flow of water (*Qw*) and nitrogen (*Qn*):

$$W_i = dP_p*(Q_w+Q_n)$$

The BHA outlet hydraulic power (*Wo*) is the product of the secondary outlet differential pressure (*dPs*) and the nozzle flow rate (*Qo*):

$$W_o = dP_s*Q_o$$

Nozzle flow rate (*Qo*) is calculated from secondary outlet differential pressure across the nozzles (*dPs*), the nozzle total flow area (*TFA*), the nozzle discharge coefficient (*Cd*) and the density of the fluid (ρ) according to the following formula:

$$Q_o = C_d*TFA*(2*dP_s/\rho)^{0.5}$$

Since the nozzle discharge coefficient (*Cd*) used in this formula is estimated, the nozzle flow is validated by comparison with the intensifier secondary displaced flow (*Qs*) minus the jet rotor face seal bleed flow (*Qb*).

$$Qo\ ?=?\ Qs-Qb$$

Secondary displaced flow (*Qs*) is calculated from the intensifier cycle rate (*f*) as determined from the secondary outlet pressure transducer log (2 strokes per cycle), the area of the plunger (*Ap*), the stroke length of the plunger (*Ls*) according to the following formula:

$$Q_s = 2*f*A_p*L_s$$

The jet rotor face seal bleed rate flow rate(*Qb*) is calculated from an estimated jet rotor face seal bleed area (*Ab*) according to the following formula:

$$Q_b = A_b*(2*dP_s/\rho)^{0.5}$$

The net efficiency (ε) of the BHA is the net output hydraulic power through the nozzles (*Wo*) divided by the BHA input hydraulic power (*Wi*):

$$\varepsilon = W_o/W_i$$