A Deepwater Breakthrough:
The Launch Window for Dual Gradient Drilling Technology

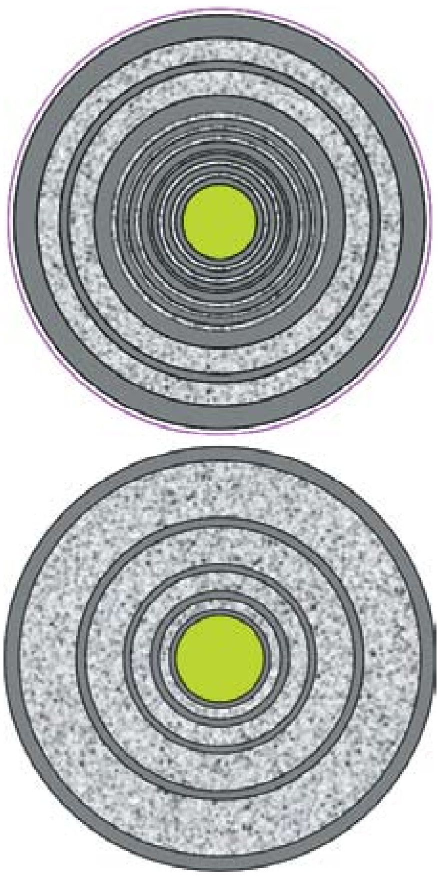

Figure 1 – Typical deepwater casing design vs. optimal design

What is an "undrillable" well?

Before 1947, any prospect located beyond the shore was undrillable. Before 1960, any prospect in 1,000 ft of water was undrillable. In 1986, the economics of $10/bbl oil made most prospects undrillable.

About every 20 years the industry faces a new phalanx of undrillable challenges, and this new century arrived with its share.

Today, in ultradeepwater, a set of interconnected factors can result in the "almost undrillable" label being applied to a potential big producer. The narrow margin between pore pressure and fracture gradient demands several casing and liner strings. These multiple strings diminish the conduit size for production and getting them into place extends flat time. See **Figure 1**. Every day costs roughly $750,000 or more – an investment that is justified only by the promise of high production rates and robust oil demand. Also lurking downhole are unpleasant natural phenomena like unstoppable tar intrusions and mud-drinking rubble zones, not to mention high-pressure gas pockets, depleted sands, and the mysteries of ballooning. All these issues can contribute to someone having a bad day.

The well designers and the drilling managers who face these almost undrillable prospects share the same long-standing wish list:

1. Overcome the narrow pore pressure fracture gradient (PPFG) margin.
2. Drill larger holes deeper with fewer casing strings.
3. Manage downhole pressures on the fly while drilling through sand, shale, salt, rubble, and tar.
4. Achieve all of the above while maintaining or improving Chevron's stringent standards for safety, well control, and environmental protection.

Taking Water Out of the Way

In February 2010, Chevron confirmed its decision to fulfill this wish list by giving the green light to a full-scale Dual Gradient Drilling (DGD) technology deployment project. While the configuration of the DGD system may look like a radical departure from conventional deepwater systems, the engineering behind it is anything but radical. In fact, DGD operations have much in common with the predecessor of all offshore drilling: the land rig, where the surface reference is truly at the surface.

Unlike a land operation, deepwater drilling requires a long riser filled with drilling fluid. The hydrostatic pressure imposed by this long column of fluid in the riser effectively shrinks the PPFG margin. Further, as the mud returns from the seabed to the surface, it becomes chilled and sluggish due to surrounding water temperatures. The impact of temperature on rheological properties translates into higher pressures when initiating circulation or tripping in the hole. The narrow PPFG margin is very sensitive to even slight increases in pressure, so drillers compensate by running multiple liners to case off the vulnerable areas.

The DGD system is different. The riser is filled with an 8.6 ppg fluid (equivalent to seawater density), while the wellbore is filled, as usual, with weighted mud. See **Figure 2**. With this configuration, the riser fluid now blends with its seawater environment in terms of hydrostatic pressure, and drilling conditions begin to resemble those of a land job. In other words, DGD technology takes the water out of the way.

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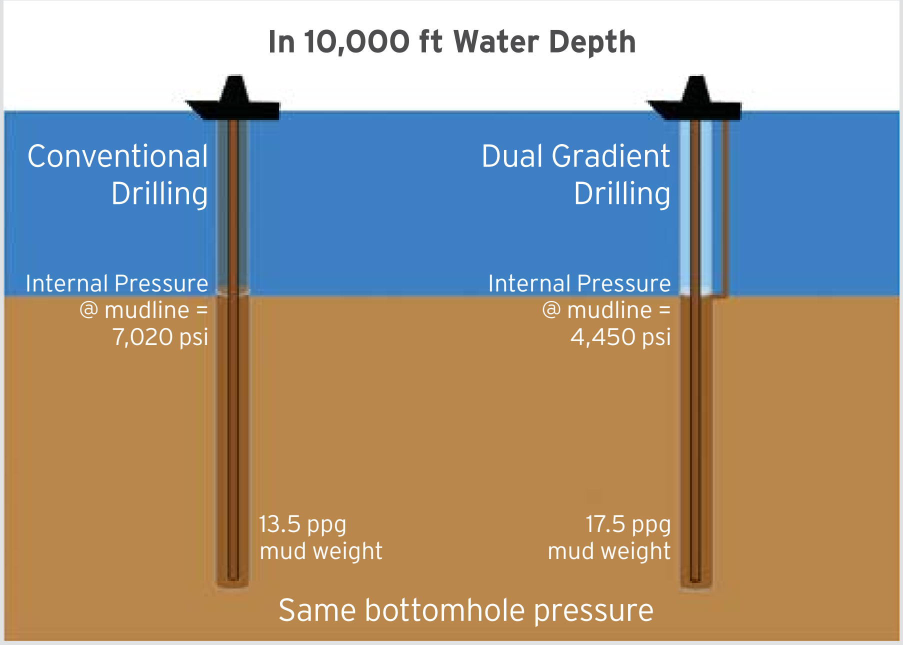

Figure 2 – Comparison between conventional and DGD configurations

The central theme to deepwater drilling is coping with the PPFG margins, and the proponents of DGD have illustrated the benefits the system offers by plotting and comparing single gradient and dual gradient pressures below the mudline. This graph tells a convincing story, and the success of the SubSea MudLift Drilling Joint Industry Project (SMD JIP) field trial in 2001 adds credibility to the concept. See **Figure 3**.

How does the mud return from the wellbore to the surface if it does not go up the riser?

It passes through a series of subsea components. There are a series of specialty joints situated above the blowout preventer (BOP). Uppermost is a subsea rotating device (SRD). The purpose of the SRD is to form a mechanical barrier that separates the mud in the wellbore from the seawater or seawater density fluid in the drilling riser. It will ordinarily operate with a very low differential pressure across it, but is capable of containing pressure from either above or below it to about 1,000 psi. The SRD diverts the mud in the annulus through a solids processing unit (SPU), that ensures that all cuttings and debris are small enough not to plug the mudlift pump (MLP) and return lines.

From there, the drilling fluid enters the MLP installed on the riser above the BOPs. This is the “heart” of the system.

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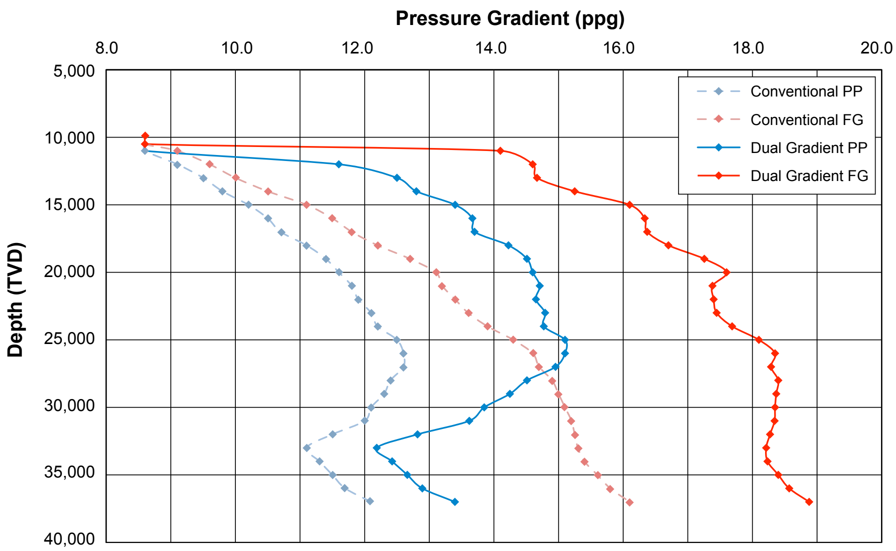

Figure 3 – Conventional deepwater PPFG plot compared to DGD PPFG plot

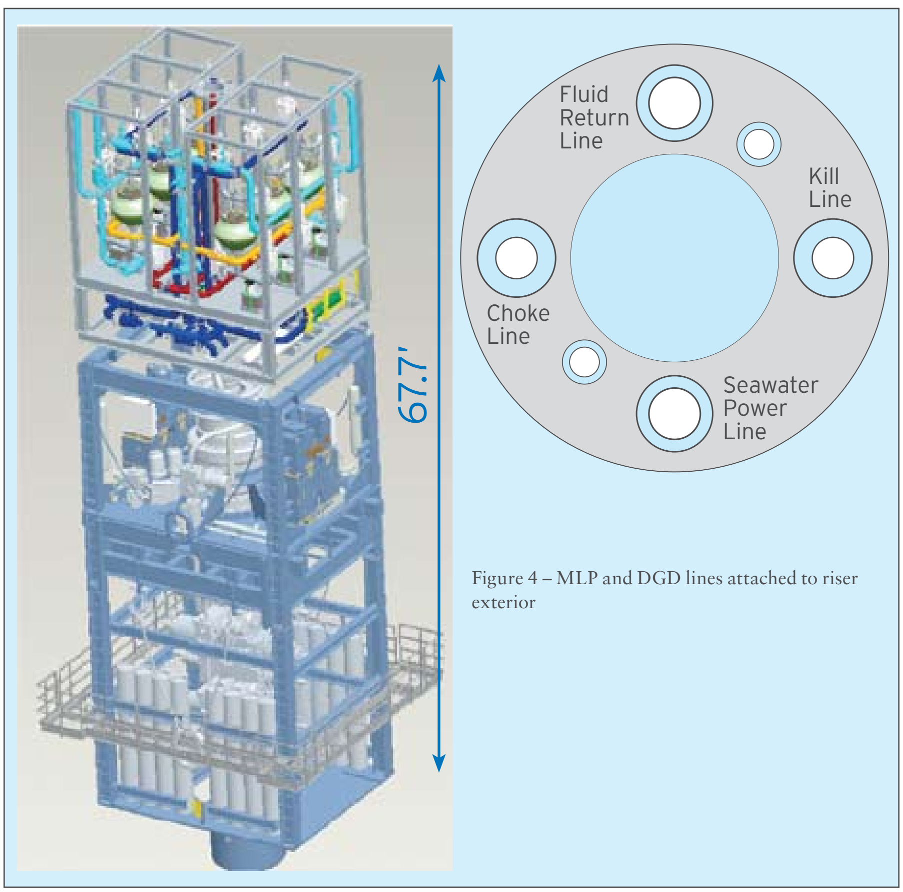

Figure 4 – MLP and DGD lines attached to riser exterior

The MLP sends the fluid up a separate 6-in. ID return line that is attached to the riser exterior, like the choke and kill line. See **Figure 4**. The rig surface mud pumps are used to pump seawater down another line on the riser. This seawater is the "power fluid" that activates the MLP's six diaphragm chambers and allows the MLP to continuously pump mud. All six chambers can be operated simultaneously or they can be segregated into groups of three or two in the event of the failure of one, two, or even three chambers. This redundancy will help ensure continuous operations.

The hydrostatic pressure of the fluid column in the return line is isolated from the wellbore and it is mechanically impossible for the fluid in this line to backflow through the MLP. Because the mud is pumped up a 6-in. line rather than through the large diameter riser, bottoms up can be achieved more quickly. The mud properties and cuttings do not degrade from extended exposure to cold temperature or long circulation times. The simplified diagram in **Figure 5** shows the flow path from the wellbore and through the MLPs. See Figure 5.

Been There, Done That

This is not the first time Chevron has been involved in designing dual gradient technology for use in deep water. Between 1996 and 2001, several companies, Chevron among them, participated in the SMD JIP, an effort that culminated in the first and only successful field trial of DGD technology.[1,2] Several drilling contractors took part in the initial stages of the SMD JIP. When the candidate well for the field trial was identified, Diamond Offshore offered a second generation semisubmersible that could be modified for the trial run. The heart of the test system – the MLP – was designed and fabricated by GE Oil & Gas (Hydril Pressure Control).

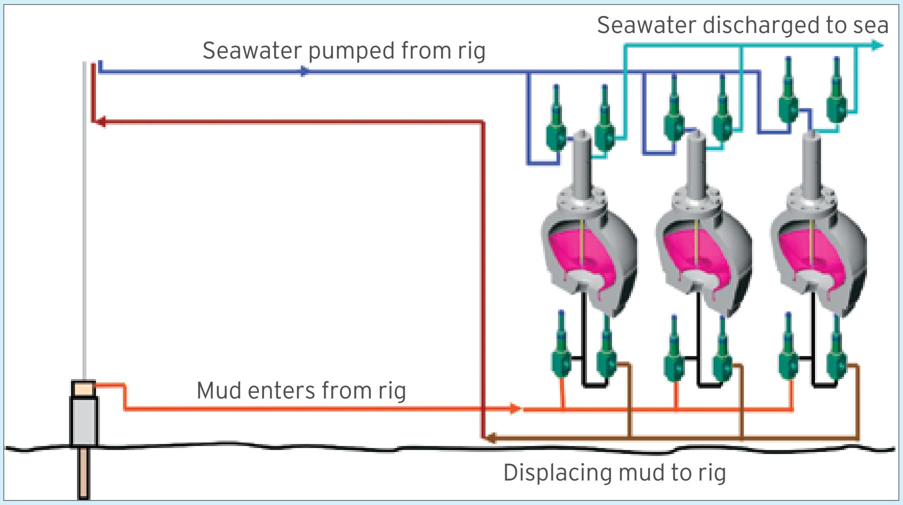

Figure 5 – Flow path from the wellbore and through the MLPs

On 4 September 2001, onboard the *Diamond New Era*, the start switch on the world's first dual gradient system was activated in the Gulf of Mexico (GOM). This successful field trial, conducted in about 1,000 ft of water, demonstrated that the DGD concept could definitely move from the drawing board to real subsea conditions. See **Figure 6**. Field trial participants put the system through its paces: circulating, drilling, tripping, running casing, cementing, and well control simulations. Aside from some instrumentation issues at the outset, the system performed as designed and even better than expected.

The event was widely publicized at industry conferences. All SMD JIP team members were honored as recipients of the Hart's Special Meritorious Awards for Engineering Innovation in 2002, and the historic field trial seemed to promise a new pathway through deepwater drilling challenges. But though the DGD technology had proven itself, its time had not yet arrived. The rig modifications and paradigm shifts needed to put DGD to work in deep water were perceived as too extensive, too costly, or just too complex. And while the level of deepwater drilling activity was increasing, for most operators at this time, the deepwater portfolio was not mature enough to warrant the investment DGD would require.

Those who took part in the SMD JIP remained true believers, but the industry was not ready to make this technological leap.

Fast Forward

Fast forward to 2006. Operators and drilling contractors had gained significant experience with deepwater conditions and had overcome many of the initial issues. New and refined technologies helped minimize the risk associated with shallow water flows, and new drilling vessels were built specifically to handle even the deepest water depths being considered. Chevron and a few other operators successfully drilled wells lying below 10,000 ft water depths, setting new standards for safety, performance, and production.

Total depths (TD) for these deepwater wells often hovered around 25,000 to 30,000 ft. The long, long column of mud from the rig floor to TD imposed equivalent circulating densities (ECDs) of 0.5 to 1.0 ppg over surface mud weight making drilling that much more difficult. Managing the PPFG margin remained the chief challenge. Contingency liners were run so often that they are no longer truly a contingency.

The driller's wish list remained the same but the wells were not giving respite in terms of complexity. The difficulties of tackling these wells led many deepwater engineering groups to revisit DGD concepts. Beyond the successful SMD JIP field trial, several other dual gradient options had been devised and even tested, but were found wanting. These included the use of a centrifugal pump system, a gas dilution approach, and an infusion of glass beads, to mention a few.

In late 2006, Chevron's deepwater drilling group began a systematic examination of their operations in deep

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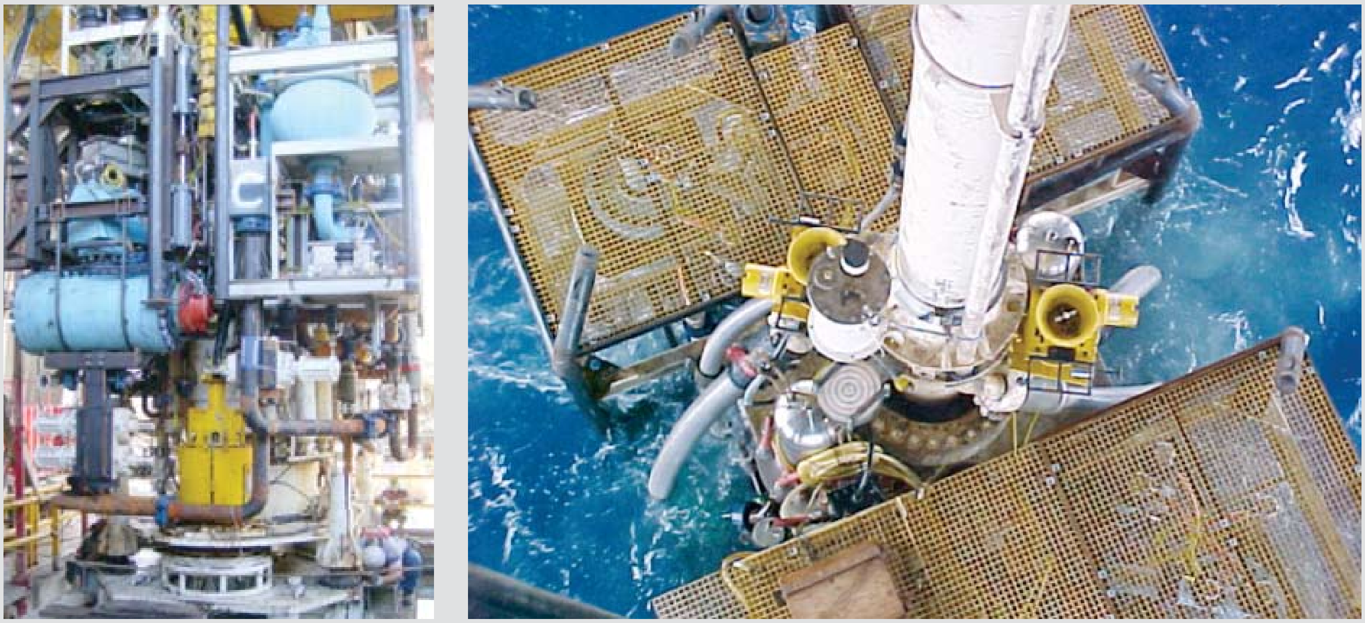

Figure 6 – SMD JIP system before deployment on *Diamond New Era* in 2001

water, determined to make them safer, more predictable, and ultimately less costly. While much advancement was made in tubulars, rigs, and methods, no large step-change technology had been implemented to answer all the objectives. A small group of original JIP participants within Chevron proposed revisiting the DGD landscape to evaluate the usefulness of the technology in the new drilling environment. By mid-2007, several efforts were under way to detail the economics and some of the more daunting technical tasks.

Countdown to 2012

In 2008, a new DGD project team was assembled led by Chevron and including AGR Subsea and GE Oil & Gas in key roles. Among those returning to help guide the project was Ken Smith, formerly with ConocoPhillips and the project manager of the successful SMD JIP. Charlie Weinstock, an SMD JIP participant, remarked, "The band got back together," since many original JIP members rejoined the DGD effort. Those members brought with them the important experience and expertise that would help accelerate the design and implementation of the new, ultradeepwater system.

In the past two years, major design and deployment questions have been resolved, including the following:

- The MLP system will be installed "in line" on the riser, as opposed to being set on an independent pad on the seafloor.
- The *Pacific Santa Ana* drillship, currently under construction in South Korea, will be purpose-built for DGD operations.
- The contracts for ancillary components, (e.g., the solids processing unit), have been awarded.
- The Chevron and AGR rig construction and integration specialists are directly involved in every phase of the *Pacific Santa Ana*'s progress, onsite in both Korea and Houston.

The *Pacific Santa Ana* is the fourth vessel constructed for Pacific Drilling in Samsung's yards in Korea. See **Figure 7**. The *Pacific Santa Ana* is a dual derrick, rig and a

Figure 7 – Sister ship to the *Pacific Santa Ana*

Samsung 12000 class vessel. It is due to arrive in the GOM in October of 2011 which fits well with the DGD equipment schedule.

Today, GE Oil & Gas is far along in the design, testing, and fabrication of the MLPs for the first commercial DGD project. Today, a dedicated team of DGD engineers from Chevron's Deepwater Exploration and Projects (DWEP) business unit now office together at the AGR Subsea location in Houston where the DGD project is being managed. These engineers are evaluating the asset portfolio and drilling schedule to determine the best fit for the first DGD well, expected to spud in early 2012.

The project team features drilling and well control experts who helped test the equipment during the field trial. The DGD system is specifically configured to preserve the integrity of current well control operations and equipment. Every operating and well control procedure is subjected to a rigorous HAZOP process. This includes the various equipment and valve "line ups" used for operational modes such as drilling, tripping, and testing. These sessions are regularly attended not only by DGD project team members, but also by subject matter experts from Chevron whose specializations include well control, cementing, packers, drilling fluids, and more.

AGR Subsea, which will manage the deployment and operation of the DGD system for Chevron, is known for the success of its riserless mud recovery (RMR™) technology. There are similarities between the RMR systems and the larger, more complex DGD system that give AGR a strong foundation for launching the first DGD system and then ensuring that its reliability is preserved through meticulous maintenance practices. A training program is in development that will prepare both onshore and rigsite personnel to manage logistics, installation, operations, maintenance, repairs, and, in the near future, the issue of DGD System #2.

If You Build It, They Will Come

The right time for DGD technology is now. Chevron has the portfolio and the value proposition is well understood at the highest executive levels. This value will be realized progressively as confidence in DGD grows, but it is safe to say that certain advantages are immediately clear. Here are the advantages.

- **Improves safety** – restores riser margin (mud is not needed in riser to control the well)
- **Improves drilling performance** – deeper wells can be designed with fewer casing strings
- **Addresses pressure management issues** – can manage pressures precisely and quickly, leading to significant reductions in NPT
- **Enables complementary production enhancement technologies** – fewer casings provide the option for larger casing in reservoir

The advances we make as a result of implementing DGD technology are certain to remove the "almost undrillable" label from many wells, and are also likely to simplify deepwater operations generally. No doubt our search for energy will once again be confronted with new challenges, but for now, the DGD system represents a powerful breakthrough – the culminating achievement in an entire generation of remarkable deepwater technologies.

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