

## Comparison of Under-balanced and Managed-Pressure Drilling Techniques

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### Abstract

Difficulties often experienced in drilling wells using conventional overbalanced drilling methods have encouraged operators to look for alternative techniques. This paper will discuss two technologies that offer several advantages over conventional overbalanced methods if applied in the proper conditions. These concepts are under-balanced drilling (UBD) and managed-pressure drilling (MPD).

Under-balanced drilling was initially adopted for resolving drilling problems, but it soon became evident that this technique could also minimize reservoir damage. In spite of its many benefits, UBD has not been embraced by the industry as readily as would have been expected. This reluctance has been due to high equipment rental costs and limitations on application of the technique offshore, either due to regulations limiting hydrocarbon flaring or formation instability. As an intermediary mitigation, MPD was developed.

This paper focuses on defining each technique, where each should be used, and what benefits can be expected. Differences between the two techniques concerning equipment requirements and reservoir characterization potential also will be analyzed. Results from UBD and MPD case histories will be used to qualify the results from these operations

### Introduction

Each of the above-mentioned techniques has its place, and which solution is applicable depends on the problems anticipated. MPD cannot match UBD in terms of minimizing formation damage, allowing characterization of the reservoir, or identifying productive zones that were not evident when drilled overbalanced, yet when the objective is simply to mitigate drilling problems, MPD can often be as effective and more economically feasible. MPD is also preferable where wellbore instability is a concern, when there are safety concerns due to high H<sub>2</sub>S release rates, or when there are regulations prohibiting flaring or production while drilling. The IADC has defined managed pressure drilling as “an adaptive drilling process used to precisely control the annular profile throughout the wellbore. The objectives are to ascertain the downhole pressure environment limits and to manage the annular pressure profile accordingly.”<sup>1</sup>

The definition for a UBD operation is “when the hydrostatic head of a drilling fluid is intentionally designed to be lower than the pressure in the formations being drilled, the operation is considered underbalanced drilling.”<sup>2</sup>

There is some debate in the industry as to what constitutes MPD and UBD and whether one is a subset of the other. While all drilling can be considered a form of “managed pressure drilling” (since the pressure must be controlled or “managed” for safe drilling), for the purposes of this paper, the differentiation is made based on whether the target bottom hole circulating pressure is maintained below the pore pressure throughout the open hole section (UBD), or equal to or marginally above pore pressure (MPD). Additionally, the objective in MPD is to preclude influx from the formation during the drilling operation, while the opposite is the case with UBD.

### Comparison of UBD and MPD

Even though MPD and UBD offer management of wellbore downhole pressures during drilling, the two methods differ technically in how this is accomplished. Whereas MPD is designed to maintain bottomhole pressure slightly above or equal to the reservoir pore pressure (i.e. overbalanced or at balanced drilling), UBD is designed to ensure that bottomhole pressure (BHP) is always below the reservoir pore pressure (i.e. underbalanced drilling), and thus, induces formation fluid influx into the wellbore, and subsequently, to the surface.

A comparison of the two methods can be performed by considering the objectives for the project, the equipment requirements and potential benefits/risks of each method.

It has been established that MPD is used primarily to resolve drilling-related problems, although some reservoir benefits also may be achieved. This is not surprising as any effort to decrease the degree of overbalance, and thus, the impact of drilling fluid on virgin formations usually will initiate some positive reservoir benefits. UBD, on the other hand, has long been employed to provide solutions to both drilling-related and reservoir-related problems.<sup>3,4</sup> Thus, one can deduce that the critical difference between UBD and MPD lies in the degree of resolution attainable with each method for both the drilling-related and reservoir/production-related problems.

MPD is often seen as easier to apply compared with full UBD operations. Often in non-reservoir sections, MPD design requirements may determine that a simpler equipment package will satisfy safety considerations for the well, and therefore, the day rate would be reduced compared to using full underbalance. As has been described, equipment requirements for both operations vary considerably, depending

on the design parameters of the project. In many instances, the same equipment setup is necessary for UBD as well as MPD methods. The distinguishing difference concerns the fact that smaller-sized separation equipment can be used for the MPD setup, as large fluid influx is not expected during drilling. Additionally, due to the fact that wellhead pressure changes are used to control MPD operations, some level of automation of the surface systems is needed for quick, uninterrupted reaction to changes in downhole conditions. This type of automation could be required to enhance UBD operations as well.

Comparison of the benefits of the two methods can be described separately in terms of the drilling-related and reservoir/production-related benefits.

The major reason for companies to explore alternative drilling techniques such as UBD and MPD has been the incapability to drill the well using conventional overbalanced drilling (OBD) methods. Drilling problems that have driven the adoption of UBD or MPD in the past include:

- the need to eliminate or minimize formation damage
- small formation pressure/fracture gradient window
- desire to minimize well cost by:
  1. minimize fluid losses
  2. eliminate differential sticking
- increasing rate of penetration
- extending bit life, etc.
- Increase safety in drilling operations.

It is important to mention here that while UBD has the potential to eliminate formation damage, MPD can be designed only to reduce it compared to conventional overbalanced drilling. Nonetheless, residual damage in the near-wellbore area after drilling is still likely. Residual formation damage of a MPD well can be as high as that of a conventionally-drilled overbalanced well.

Additionally, both UBD and MPD have the potential to reduce drilling-fluid costs significantly through the use of cheaper, lighter fluid systems, and elimination or significant reduction of mud losses.

Two of the primary reasons cited for selecting MPD over UBD are 1) wellbore instability concerns during UBD, and 2) desire to reduce equipment requirements to improve cost efficiency. However, basing the decision only on these criteria ignores the possibility that significant reservoir benefits also could be realized with UBD and that equipment requirements really depend on the reservoir to be drilled, since MPD may require an almost equivalent setup as UBD.

The reservoir-related or production-related benefits of UBD (and to a much lesser extent MPD) are significant when compared with conventional OBD. Primarily, these benefits are seen through higher productivity of UBD wells.

In fact, reduction in damage to the reservoir compared with conventional OBD in some MPD wells has been recognized in the industry only recently. UBD, on the other hand, has had a much longer track record for maximizing well productivity, thereby ensuring higher sustained production rates compared to conventional wells. Historically, many wells that have been classified as UBD have in fact actually

been MPD wells where some portion of the drilling was underbalanced; however, overbalanced conditions occurred often or were used for completing a well drilled underbalanced. This had the effect of reducing or even eliminating any productivity gains from UBD, and therefore, in many instances, it appeared that UBD had little or no impact on reduction of formation damage and improved productivity.

High productivity wells in a reservoir means that a minimum amount of pressure drawdown is required to meet field production targets.<sup>5</sup> This helps maximize hydrocarbon recovery from the reservoir by lowering the abandonment pressure. Even with extended periods of exploitation of the reservoir, the undamaged well outperforms the damaged wells in terms of recoverable reserves.

The incremental benefit of UBD wells as a function of wellbore skin factor has shown in the short term that there is not a significant difference in the cumulative production from wells with much lower skin factors because of constraints with surface handling facilities, etc. These differences increase in the intermediate term, and then, begin to decline subsequently. Thus, an MPD well that is designed to reduce reservoir damage to some residual value (other than full cleanup to zero skin) will ultimately underperform a UBD well with skin factor of zero.

One additional reservoir benefit of UBD compared to MPD is its capability to conduct comprehensive evaluations during drilling. Due to deliberate suppression of reservoir influx during MPD identification of productive intervals as well as some petrophysical properties, these productive zones cannot be evaluated directly. We note that the use of logging-while-drilling (LWD) and measurement-while-drilling (MWD) tools provide the means for determining some reservoir properties directly. However, it is only a properly executed UBD job that has been designed for reservoir fluid inflow that provides a platform for full evaluation of reservoir parameters, including the presence of possible nearby boundaries during drilling.

To be able to perform this evaluation, an adequate data acquisition system is essential.

A system for reservoir characterization in UBD or automated control for MPD, would require capability to monitor all pressure, temperature, level, and flow-rate information normally associated with the surface separation package. Additionally, wellbore hydraulics and reservoir behavior simulation would be required for a complete process. It would also need capability to accept, manage, store and display bottomhole, mud-logging and rig-site data and integrate the data for ease of analysis and interpretation.

### **UBD or MPD Candidate?**

Proper candidate selection is critical to the success of both UBD and MPD projects. It is essential that the main project objectives are identified at the beginning of the project, not only to ensure that they can be achieved, but also to determine which technique — UBD or MPD — is most appropriate for the candidate well or reservoir.

The candidate selection process consists of analyzing geomechanical and petrophysical information to determine whether or not a particular well and/or reservoir is a potential candidate by evaluating some of the main reservoir and wellbore characteristics. These include the type of formation damage and the possible effect UBD would have on its mitigation, wellbore stability, potential for stuck pipe, hard rock drilling and possible rate of penetration (ROP) improvement, lost circulation problems, presence of sour gas, and operational feasibility. Preliminary wellbore-hydraulics modeling must be performed to determine the operational feasibility; i.e., if underbalanced (UB) conditions are possible and can be maintained throughout the entire hole section while maintaining adequate hole cleaning and satisfying the downhole motor limits. If there are multiple candidates, characteristics of each of these would be compared, and an initial ranking would be performed according to the key variables that would have the highest potential for success and the least chance of risk.

Once it has been concluded that a particular prospect is a candidate or is ranked high among a group of prospects, then the optimal UB technique would be selected. Next, an evaluation of the potential production improvement will be investigated. Reservoir properties play the most important role in the success of UBD, since reservoir modeling will determine how much formation production might be expected while drilling UB. Different scenarios are then modeled, the results of which are used in both the detailed wellbore-hydraulics flow modeling and the economics evaluation.

If there are multiple candidates that have been evaluated in detail, a final comparison is performed, and the potential impact of benefits and limitations of applying UBD are compared so that the best candidate can be selected.

UBD does not solve all problems, and the key to project success is a correct determination of the wells where the technology is most applicable. The importance of this evaluation will be seen if the well objectives primarily focus on providing drilling solutions since MPD might prove to be a more economical solution.

The final qualification for an underbalanced candidate depends on the economical evaluation, which establishes the possible cost difference between UBD, MPD and conventional OB drilling, and it is here that the quantified productivity improvement becomes an important factor. It is at this time that other technologies such as stimulation are compared with the possible results from underbalanced drilling. In **Fig. 1**, an example is shown comparing the economics for a well where UBD and MPD are considered as alternatives to conventional drilling. This example is based on actual data from a field where MPD was performed as well as conventional drilling, and UBD was being evaluated to see if the production gain would outweigh the added cost of achieving full underbalanced conditions, which would be maintained throughout the drilling and completion phase, so that formation damage would be eliminated. The costs used are based on the actual well cost for the MPD and offset conventional well with similar geometries and depths. The

actual well cost for the UBD well will be estimated based on typical costs for UBD services in this area.

The drilling report for each well was used to determine the nonproductive time due to drilling problems as well as to estimated mud losses, number of bit runs required, and ROP. These were taken into account in formulating the economics case for each scenario. For the UBD well, the improved productivity was based on the reservoir properties and logs showing productive formation, the number of bits, ROP, NPT time for the UBD well was taken to be the same as the MPD well. The production with UBD was more than 4 times that from OBD, which had skin damage; also, production starts when the reservoir section is being drilled, since it is assumed that production is sent to facilities. For MPD the production improvement was twice that from conventional drilling. This meant that the UBD case became the best option as shown in **Fig. 1** when the improved productivity was taken into consideration. For the UBD scenario, the net revenue was 21% higher than the one for OBD, and “break even” is reached much earlier than in the MPD or OBD scenarios as a result of the additional benefit of early and higher production. The net revenue for MPD is about 5% higher than the one from conventional. If little or no improvement in production occurred with UBD to balance its additional cost, and only its drilling benefits were considered, then MPD was the best option from an economics standpoint. This would be the scenario where the primary objective is to address drilling problems and reduce NPT and the costs associated with mud losses, where the section drilled is not productive or the reservoir is of marginal quality with low productivity capability, or damage has been found not to be an issue.

MPD can be applied at the surface or in intermediate and/or reservoir well sections, and in all well types as is the case for UBD; however, adequate consideration of the application as well as the equipment requirements are critical, as in some cases, MPD may not be capable of solving the drilling problems encountered. An example of this situation might be when the fracture pressure is too close to the pore pressure or when there are variations in pore and fracture pressures in different intervals within the same open hole. These cases may require the design to consider underbalance in some sections while overbalance in others in order to drill the well economically and successfully.

In some cases, when UBD cannot be applied because it is not technically and/or economically feasible (such as when the wellbore may not be stable or the risk of high release rates of sour gas on surface is possible), MPD could be the best solution.

### Surface Equipment Requirements

Several equipment setups can be derived from a combination of several key equipment components – from simple to the most complex. Many equipment setups are possible, and best practices should always drive the design of the system to appropriately handle the well’s potential safely. This is one key point that has been ignored in some instances to the detriment of the safety of the operation. Key

components of a surface equipment package for underbalanced drilling could include:

- A wellhead rotating control device (RCD)
- A downstream choke-manifold system
- Open or closed fluid-handling systems including downstream fluid-separation package, 3-phase or 4-phase separation systems
- Upstream gas generation and fluid compression/ injection systems
- A geologic sampler.

Note that these equipment systems typically come with auxiliary flow lines, emergency shutdown (ESD) system, pumps, metering devices, data-acquisition systems, holding tanks, mud pits, flare stacks, etc.

A typical UBD setup for addressing drilling problems would include a rotating control device (RCD) plus a choke and open or closed surface separation system. If the reservoir is very depleted, then an upstream gas generation and/or compression system would be required. If the objective of the UBD operation is reservoir focused, typically additional metering, a geologic sampler for continuous reservoir description, and a 3-phase or 4-phase fluid-separation system would be used with an adequate data acquisition system to capture all the surface, rig and bottomhole data.

Surface equipment used in the industry for what is now termed managed pressure drilling can also vary widely. They can vary from a simple wellhead rotating control device tied to rig flow lines to comprehensive UBD-type equipment. Note that as reservoir fluids are not intended at the surface, some MPD operations do not use separation units. However, it is important to remember that in MPD operations as with any overbalanced operation you may need to control “influx” if you go underbalanced, and therefore, you will need to have contingency and well control plans in place.

This is especially true when there are different pressure regimes that may be encountered, and the area is unknown. At times, a separation package is required to safely handle influx or to minimize time spent on conventional well control during an MPD operation. When designing the system, safety and drilling efficiency must be addressed adequately.

For the most basic MPD operation, the equipment will include a rotating control device, which is tied into the flow lines of the drilling rig. Any influx from the reservoir is treated as a kick (as in conventional drilling), and well control operations are initiated.

Where downhole pressure control is desired, both a rotating control device and a dedicated manual or automated choke system is required. As previously mentioned, any reservoir fluid influx is treated as a kick, and conventional well control operations are initiated with the kick being circulated out. Often, rig well control equipment is used as with conventional overbalanced drilling operations.

When the margins between the pore pressure and fracture gradient are narrow, the system can benefit from an automated control system. In this case, the equipment required (in addition to the RCD and an automated choke system) would be metering of the fluids in and out, bottomhole and surface

pressures, and a control system, which may have different levels of complexity. Full automation of the choke manifold system means that bottomhole pressures (BHP) can be strictly controlled so that losses and kicks are minimized during drilling. Any reservoir-fluid influx is treated as a kick, and well-control operations are used to circulate the kick out through the rig well control equipment. With an automated choke and control system where very careful monitoring of flow into and out of the reservoir is performed, any kick can be detected very early, and often, may be circulated out without initiating full kick-control procedures, since the volume may be on the scale of trip gas, depending on the sensitivity of the system; however, this degree of automation has yet to be fully implemented. As experience grows and the optimum equipment, metering, detection and control system are put in place and tested, further reliance may be placed on automation. However, these systems will need redundancy and personnel supervision with safety contingencies in place to ensure safe drilling operations.

If there is a high possibility of formation influx, it may be more efficient to add a surface separation package. The need for a downstream fluid-separation system assumes that there is the potential for fluid influx from the reservoir during drilling due to several reasons; i.e., very narrow or inverse pore pressure/fracture gradients, intervals with different pore pressures or an extremely high permeability reservoir, all with the potential for high production that could overwhelm a rig’s well control equipment system. In this case, an adequate separation system is utilized to optimize the drilling of these formations, since it will be possible to circulate kicks with the separation package with added safety procedures and fluids handling systems. The reservoir influx will, therefore, be processed and handled safely by this pressurized separation package. However, the well will be kept in an overbalanced condition if possible, and influx will be treated as a risk that can be neutralized with the pre-planned presence of a surface separation package for handling of any effluents.

If the formations are depleted, then upstream gas-generation and fluid-compression/injection systems may be needed to obtain the lower degree of overbalance needed to stay within the pore and fracture pressures through the depleted reservoir sections. The need for the gas generation and/or compression system is always dictated by the reservoir pressure and the available drilling-mud system.

Thus, the surface equipment chosen for an MPD project will depend on several objectives as well as subjective factors, including:

- understanding of reservoir potential
- current reservoir pressure
- average permeability of the reservoir layers
- when lower ECD is required (i.e. with upstream injection of lighter fluid – gas)
- presence of H<sub>2</sub>S and other sour gases in the reservoir fluid
- exploratory well environment
- potential to go underbalanced during the drilling process
- when hydrostatic alone will not serve as barrier to reservoir influx

- quality of rig equipment
- insufficient history for high level of confidence in system automation, etc.

Besides the key MPD equipment outlined above, additional auxiliary components are also used for MPD and can include emergency shutdown (ESD) systems, rig-injection pumps, back-pressure or make-up pumps, data-acquisition-and-display systems, flow-metering devices, pressure valves, etc.

Use of the dynamic pressure control or automated choke control method with MPD allows influxes to be controlled more quickly and safely and with less surface pressure than an MPD operation without the automated system.

### MPD Case History – Offshore

To address the severe lost circulation problems faced by the operators in this offshore North Sea field, underbalanced drilling had been implemented.<sup>6</sup> This technique appeared to offer one possible solution for meeting the challenges of drilling through the highly fractured caprock to get to the reservoir. The operators of this field had experienced severe pressure control and lost circulation problems, which had resulted in the suspension of several wells during attempts to access the reservoir targets. Drilling these wells with conventional means was not possible because of the small margin between pore pressure and fracture gradient. The primary issues to be addressed for this project were the drilling problems.

In the first well, a clear Potassium (K)-Formate brine was used with a sufficiently high density in order to minimize surface pressure and the risk of hole collapse. While drilling the well under-balanced, it was found that the produced fluid was primarily water. This was a problem since continuing to drill underbalanced with a controlled influx would add more water to the active water based drilling fluid system effectively decreasing the K-Formate concentration and mud weight. It was decided to drill the remainder of the well at balance minimizing formation influx which would eliminate produced water and keep the drilling fluid properties. This changed the project plan while drilling the first well from full UBD mode to managed pressure drilling (MPD) mode in order to avoid thinning out the mud system, and thereby, increasing surface backpressure requirements. By balancing the formation pressure throughout the last part of the well, further thinning of the rather expensive K-Formate brine was avoided. The liner was run and cemented successfully at balance, allowing access to drilling the reservoir overbalanced.

Based on the lessons learned from the first well, it was planned to drill the cap rock in the second well at balanced pressure. The work scope was expanded, however, to include drilling the reservoir section at balanced pressure as well to test the feasibility of this technology. The reservoir is very productive with high permeability, and near wellbore damage was not thought to be a significant consideration. Additionally, it was expected that there would be the potential for depleted reservoir zones in conjunction with prolific reservoir sections, therefore, MPD appeared to offer a better

solution than UBD.

This well also became a test case, since if MPD proved viable, then this would pave the way for drilling more challenging reservoirs in the field using this technology in the future. The first section through the caprock was drilled successfully in two runs with the K-Formate drilling fluid and a targeted bottomhole pressure. The open hole was then sealed off with a 7-in. liner and cemented at balance similar to the first well.

When drilling the 6-in. hole with the K-Formate brine, it became apparent that the formation was becoming increasingly unstable with time. This created problems cleaning the hole properly in view of the limited flow rate available, hole conditions deteriorating with time, and pack-off situations that had occurred. Ultimately, it was decided to plug and abandon the first section, and drill a new sidetrack. It was suspected that the mud might be creating the problems, and it was decided to use a proven oil-based mud (OBM) system. The openhole sidetrack with a motor assembly was used to enable higher-angle doglegs, and the hole condition seemed stable during this time. Drilling at balanced conditions proceeded. At this time, no further problems were experienced, and the remainder of the reservoir section was drilled uneventfully at balanced pressure.

The pressure envelope for the reservoir drilling was fairly large in this case; therefore, auto choke control was not critical. The bottomhole ECD varied in moments up to 0.05 sg (10 bar) with manual operation (**Fig. 2**) of the hydraulically actuated, remote-controlled chokes. It was determined that for tighter margins an automated choke-control system would be required.

The implementation of MPD technology allowed the operator to drill previously abandoned wells, which could not be drilled with conventional means. It was found that full UBD was not needed to address the drilling problems, and at balanced or slightly overbalanced pressure was the best option for overcoming the drilling problems encountered in reaching the target depths both through the caprock as well as the reservoir section. The success of the drilling of these wells has enabled the following best practices to be established:

In this project, since the initial plan was for underbalanced drilling, a pressurized separation vessel was part of the equipment setup (**Fig 2**). This added flexibility to decision making, especially at this stage where there were many unknowns. The use of this equipment was invaluable for starting up these MPD operations in an area where all reservoir parameters were not known. This allowed the determination of many design requirements that can now be optimized in future MPD units on the same field.

### MPD Case History – Onshore

In the previous field case, it was seen that MPD was adopted after it was found that it would satisfy the requirements and objectives of the project better than the UBD that had originally been implemented. In contrast for this case history, one of the main conclusions that will be seen is that even though MPD resulted in successfully overcoming the

drilling problems, UBD should be attempted in several future wells to evaluate the productivity gains that could be made by avoiding formation damage.

MPD was applied in this multi-well project in Southern Mexico to drill a deep, depleted, fractured, and compartmentalized reservoir with widely variable pore pressures that were creating significant challenges during the drilling process. The case history described here used an equipment Setup for MPD with a manual choke system rather than an automated choke seen in **Fig. 3**.

The main objectives for this project were to design a flexible drilling system to cover the wide range of pressures (pressure gradients from 2 to 8.34 ppg), to minimize the amount of overbalance because of the low margin between the pore and fracture pressures, and to reduce or eliminate problems such as differential sticking and lost circulation. Moreover, MPD was implemented to precisely manage the bottomhole pressure, reduce fluid and solids invasion to the formation, and prevent hydrocarbon and H<sub>2</sub>S production to surface.

Some of the challenges included designing a stable drilling fluid for the expected depths and high temperatures, implementation of H<sub>2</sub>S monitoring and control, reservoir-pressure uncertainty and hole instability, which were due to mechanical stresses and not chemical sensitivity.

Complete reservoir sections were drilled using MPD techniques in wells with known reservoir pressures. If reservoir pressure was unknown, the wells were drilled with an 8.34-ppg drilling fluid until fractures were encountered; consequently, fluid loss was detected, and reservoir pressure was estimated from the static fluid level. Then, MPD operations were designed and implemented using this calculated reservoir pressure.

Two fluid systems were designed to cover the entire range of pressures — a recyclable high-temperature foam system for the 2.0 to 5.0 ppg range and a nitrified-fluid system for the 4.0 to 8.34 ppg range. Both fluid systems were interchangeable since the same polymers at different concentrations were used and could be easily controlled to mix the base fluid and the chemical injection to generate and break the foam.

Control of the BHP was based on precise selection of critical operation parameters such as injection flow rates, fluid properties, and chemical injection control. During MPD operations, important variables were measured, recorded, and displayed at the rigsite and/or transmitted to other locations allowing engineers to monitor the ongoing operations. This enabled adjustments to the main operational parameters to be made in order to satisfy the target BHP; since it was necessary to closely and accurately control the BHP since the degree of overbalance or underbalance would be determined by precise measurement of net losses and gains of both liquid and gas.

The successful implementation of MPD in this project included improvement of the process from:

- 1) lessons learned while drilling very challenging hole sections with changing hole conditions
- 2) increased ROP (although this was controlled to avoid hole cleaning problems);

- 3) drilling times were approximately 50% less for sections where MPD was implemented when compared with other OBD wells in the area.

When the wells were brought on for production, the clean-up times for these wells were also reduced by about 15%.

MPD proved to be an effective solution for the drilling problems the operator was facing, and at the same time, it showed some of the potential benefits of UBD resulting from the improvements in production. Because of these successes, this technique is being evaluated for future implementation in a fully underbalanced mode.

### UBD Case History

In this offshore implementation of UBD, the objective was to compare the reservoir performance of underbalanced drilling with conventional overbalanced offset wells. If UBD improved productivity sufficiently to prove economic feasibility, then UBD would be considered in the further exploitation of this reservoir.

The well was highly deviated and was to traverse two sandstone reservoirs that were normally pressured with little depletion. Based on the offset data, the depths and characteristics of these sandstones were reasonably known. When drilling underbalanced through these formations, it became apparent that the first zone was not present in this area of the field. The second reservoir was penetrated, and gas production commenced, increasing as drilling progressed. Reservoir characterization was performed, and it was found that the upper section had better permeability compared to the lower section. Before reaching TD, the well intersected an additional sandstone layer unexpectedly. This zone was higher up than had been expected from the offset well and was not part of the original objective for this well; however, it proved productive, although analysis showed that it was not as prolific as the first section.

With UBD, it was found that the improvement in productivity was 2.5 times that of the offset well, however, as can be seen in Fig 4, after the well reached TD, there was a short period of overbalance. After this period of overbalance, it was found that the formation damage decreased the productivity of the zones. After producing for a period of time, the formation did clean up to some extent; however, the overall productivity was reduced by 25%. It is clear that once the underbalanced drilling begins, if an overbalanced event is allowed to occur, the reservoir productivity is damaged and does not recover.

In many conventional underbalanced operations without this reservoir focus, a pay interval is drilled mostly underbalanced, but often some overbalance drilling occurs. The result of this temporary overbalance is often overlooked and never quantified. Using the reservoir analysis process with its detailed data acquisition and analysis capability, it is possible to quantify the effect of these periods of overbalance.

As pay is intersected in an underbalanced environment, the measured bottomhole pressure is used to predict the production rates. These production rates are compared with measured surface production rates that have been

synchronized and lagged to bottomhole sandface conditions. The calculated rates are predicted by adjusting the permeability, height, and reservoir pressure to match the measured rates. Skin damage is assumed to be non-existent if underbalanced conditions are maintained when drilling the formation. Transients in the reservoir are taken into consideration so that as the well penetrates a formation the initial “flush” production behavior is modeled as well as later production as the zone is penetrated further, and eventually, fully penetrated. Different transients are calculated for each zone traversed, and the reservoir model parameters are varied to obtain the best match. Consideration to different reservoir scenarios is given, and interpretation is made of the best model that describes the reservoir behavior seen.

In this example as sometimes happens, an unplanned pressure event throws the system into overbalance, even though it is only for a relatively short period of time. After underbalanced conditions are returned, the damage to the reservoir can be determined by adjusting the skin factor to a non-zero value. Typically, the formation will clean up and so the model allows for an initial skin to model the period right after the damage and a residual skin after the clean-up period.

Throughout the drilling of the underbalanced well, the rate and pressure data were analyzed, and the formation properties determined. In the plot in **Fig. 4**, an excerpt from the data that have been normalized is shown. The bottomhole pressure, actual measured rate, and calculated predicted rate with zero skin (assuming no damage) and with damage are plotted. Due to continuous analysis, it was seen that after a period of overbalance, some reservoir impairment was sustained, although with continued production, some of this damage was cleaned up.

## Conclusions

When determining whether UBD or MPD should be applied as a solution, the benefits and limitations of each should be both qualitatively and quantitatively considered, and a decision should be reached depending on the merits of each technique.

MPD and UBD both address drilling problems, reducing NPT by minimizing losses, and differential sticking and the time associated with well control events typically associated with conventional overbalanced drilling. Where the primary drivers are reservoir related, UBD has been found to be the best option. Reservoirs benefiting most from UBD are those formations prone to damage. Additionally, if reservoir characterization while drilling is of importance then underbalanced drilling is the option that should be selected.

However, when the drivers are primarily related to solving drilling problems, MPD may prove to be more economical than and just as efficient as UBD in mitigating the problems. UBD can be more costly than MPD due to additional equipment that may be required to achieve and maintain underbalanced conditions. Additionally, in some regions regulatory limitations offshore, and unstable formations preclude the use of UBD. Additionally, MPD allows a high level of drilling optimization.

The field cases selected for this paper have shown scenarios where the project was initially planned to be underbalanced but were switched to MPD based on the project drivers and the well conditions. The cases have also shown situations where MPD was implemented, but reservoir performance encouraged the consideration of UBD. It is important to implement lessons learned and be flexible in the project plan to best address the situation faced. A tendency that should be avoided is to preclude one method over the other solely based on subjective considerations. UBD is often viewed as complex and more costly by the industry, and rejected in favor of MPD. MPD cannot match UBD in terms of minimizing formation damage/improved productivity and allowing characterization of the reservoir; and this aspect needs to be considered in the technical and economic comparison of the methods before a final decision is made.

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## SI Metric Conversion Factors

$$\begin{aligned} &^{\circ}\text{F} \text{ (}^{\circ}\text{F} - 32\text{)}/1.8 = ^{\circ}\text{C} \\ &\text{ft} \times 3.048^* \quad \text{E} - 01 = \text{m} \\ &\text{in} \times 2.54^* \quad \text{E} + 00 = \text{cm} \\ &\text{psi} \times 6.894\,757\text{E} + 00 = \text{kPa} \\ &\text{gal} \times 3.785\,412 \text{E} - 03 = \text{m}^3 \\ &\text{ft} \times 3.048^* \quad \text{E} - 01 = \text{m} \\ &\text{bbl} \times 1.589\,873 \text{E} - 01 = \text{m}^3 \end{aligned}$$

\*Conversion factor is exact.

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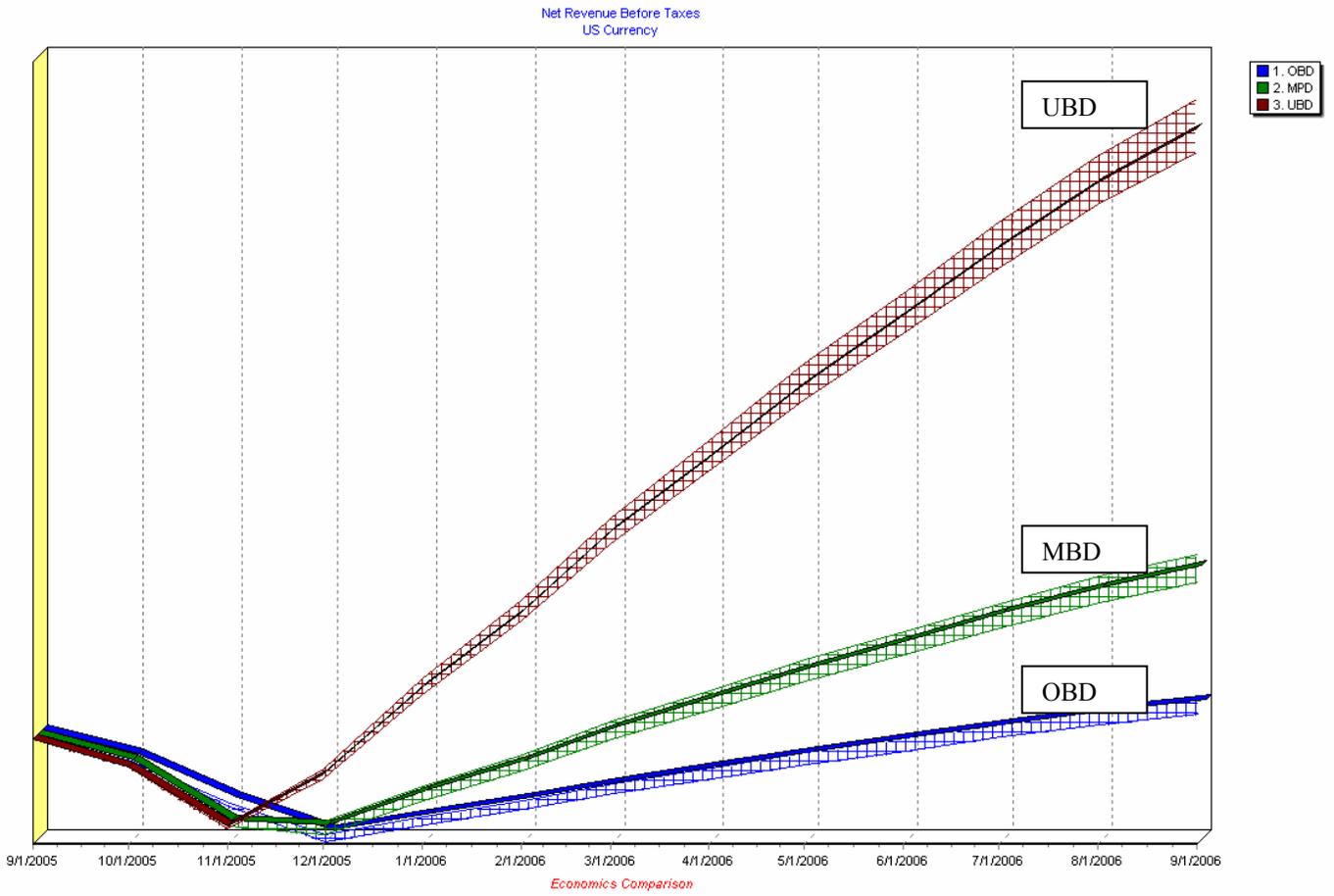


Fig. 1 - Net Revenue before vs. time comparing UBD and MPD with OBD where revenue generated from production is considered.



**Fig. 2 - Equipment rigged up for MPD offshore field case.**



**Figure 3 —Equipment rigged up at location for MPD onshore field case.**

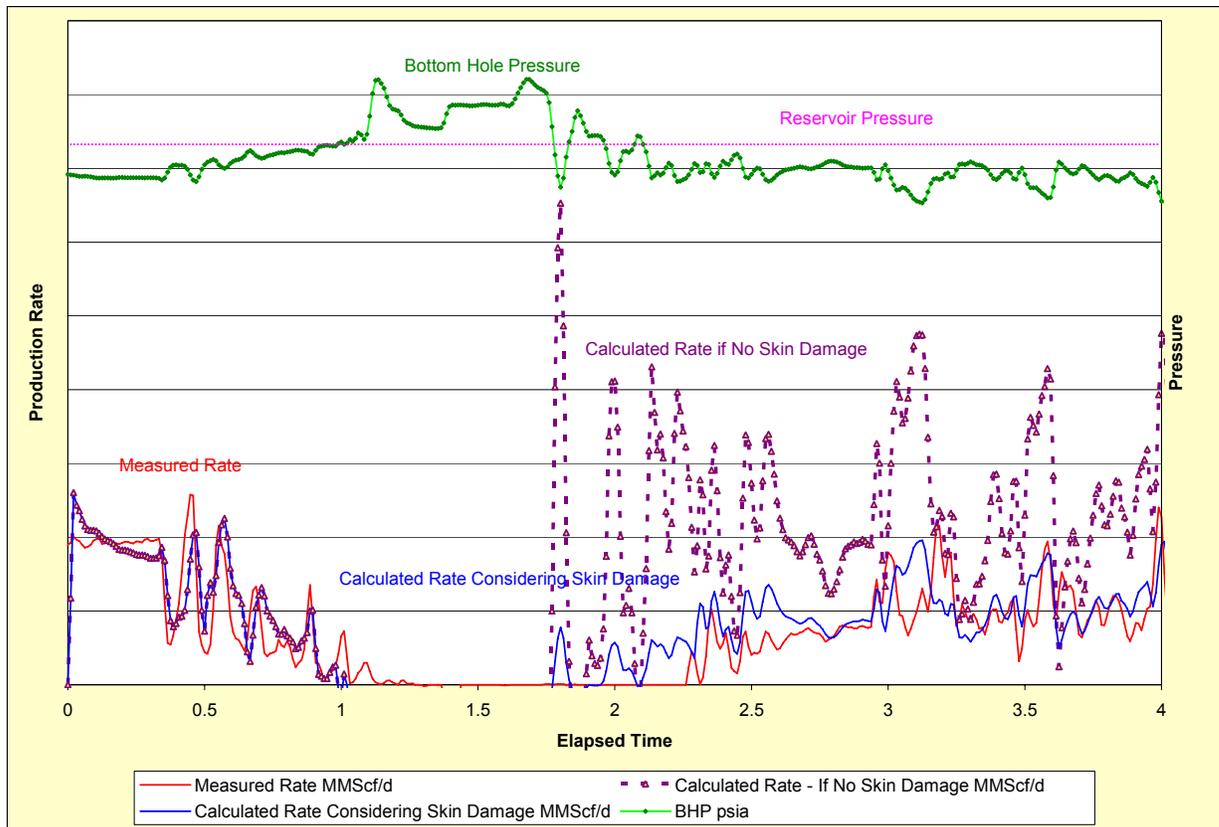


Fig. 4 — UBD RTRE Analysis showing predicted and measured rate along with measured bottom hole pressure.