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Design, Qualification, and Installation of Openhole Gravel Packs: Mari B Field, Offshore Israel

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Abstract

A case history from Offshore Israel is presented that describes the successful delivery of two ultra high-rate gas wells (>200 MMscf/D) completed in a depleted gas reservoir with 9⅝-in. production tubing and an openhole gravel pack (OHGP). Maximizing gas off-take rates from a volumetric drive gas reservoir that possesses high flow capacity (kh) requires large internal diameter (ID) tubing coupled with efficient sand face completions. When sand control is required, the OHGP offers the most efficient as well as the most reliable, long-term track record of performance. A global study of wells completed with 9⅝-in. production tubing ("big bore") determined that this design concept was feasible and deliverable in a short time frame while still maintaining engineering rigor. The paper will highlight key accomplishments within various phases of a completion delivery process with particular emphasis on the sand control design, testing and execution. The completions were installed with minimal issues (NPT ≈ 9%) and have produced without incident. The two wells, Mari-B #9 and #10, achieved a peak gas rate of 223 and 246 MMscf/D, respectively.

Introduction

Operated by Noble Energy, the Mari-B field was discovered by the Yam Tethys co-venture group (Noble Energy Mediterranean Limited, Delek Drilling LP, Delek Investments and Properties Ltd., and Avner Oil Exploration L.P.) in 2000 in 796 feet (243 meters) of water at a total depth of 5,905 feet (1,800 meters). Mari-B is part of a group of fields (**Figure 1**) in the offshore waters of Israel in the Pliocene stratigraphic-structural play, part of the Pleshet Basin. Original gas-in-place estimates range from 1.2 to 1.3 trillion cubic feet (Tcf). In 2004 the field began producing at gas rates in the 100-150 million standard cubic feet/day (MMscf/D) range from a production platform with 600 MMscf/D of capacity.

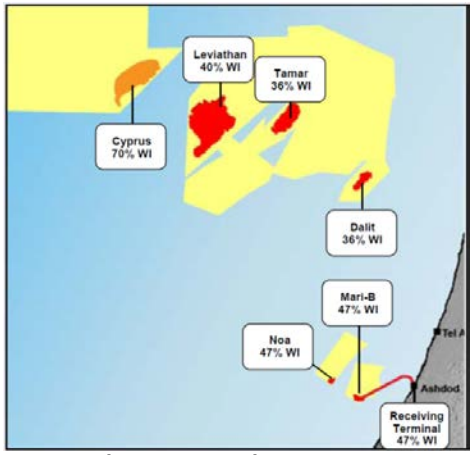


Figure 1 - Location Map.

The gas is sold to various customers with the Israel Electric Corporation consuming the majority for power generation. Since 2004 as more electrical generation stations were converted to dual fuel and many smaller customers converted to

natural gas, the peak demand had risen to over 500 MMscf/D by 2009. As Israel began to see the benefits of burning natural gas, the market expanded. Because the Mari-B field was depleting quickly with higher demand, it was apparent the existing wells would not be able to meet the peak gas demand by the summer of 2010. Therefore two new big bore wells were planned and executed in 2010.

By 2009, there were seven wells drilled in the structure (**Figure 2**). The exploration well, Mari-B #1, was drilled to a depth of 2,070 m and encountered 171 m of pay section before reaching the gas/water contact (the only well on the structure to do this). This well was not kept as a producer and was "twinned" by the Mari-B #7 production well. The Mari-B #2 was an appraisal well drilled into the eastern lobe of the structure and was kept as a subsea tieback to the Mari-B Platform. This well is now shut-in due to mechanical issues. Mari-B #3 well was drilled as a straight hole close to the apex of the structure. The Mari-B #4, #5 and #6 wells were all deviated wells drilled from the platform.

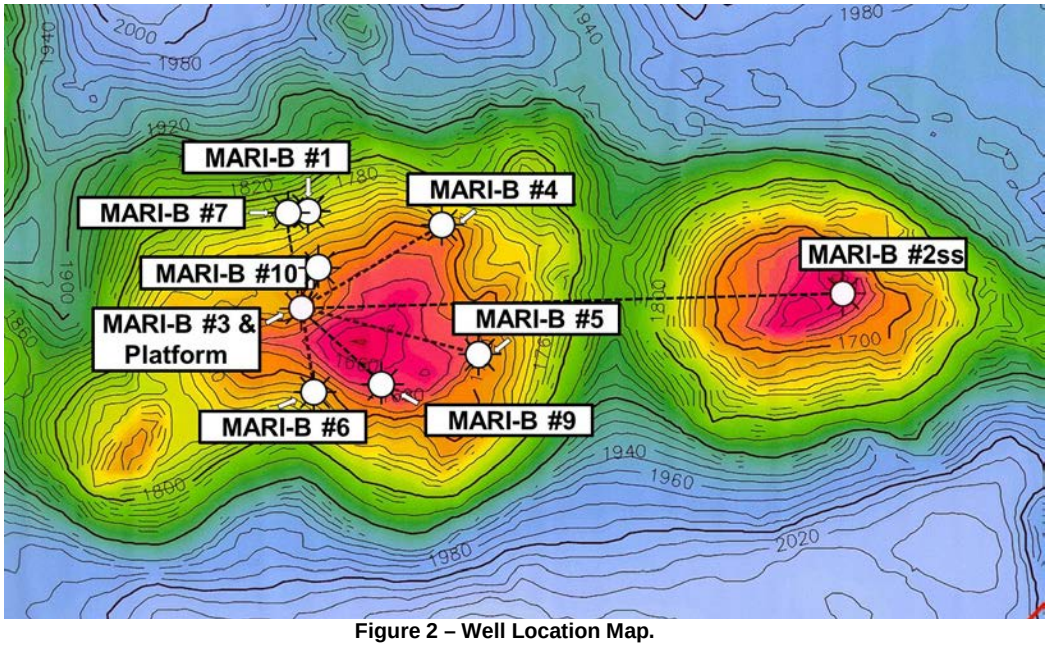


Figure 2 – Well Location Map.

In order to meet the gas delivery rates and schedule the following objectives were established by the planning team:

- Efficient sandface completion to promote long-term production
- Maximize gas rates
- Control and minimize sand production
- Nil to minimum NPT
- No incident rates

Subsequently, these objectives were used to develop criteria for the drilling and completion phases.

Drilling and Completion Overview

The drilling and completion phases required discrete and specific criteria. The final completion installation was predicated upon delivering production rates greater than 200 MMscf/D for up to 2 years (followed by ≥20 years of possible injection service). The following (**Table 1**) summarizes the objectives as set by the engineering team.

Table 1 – Drilling & Completion Objectives for Mari-B Gas Wells
Drilling Objectives
• Nil to minimal fluid loss in a depleted reservoir (*i.e.,* 2-3 lb/gal less than initial) • Produce a stable wellbore in order to successfully deploy gravel pack equipment and effect a 100% gravel pack • Ability to weight-up drilling system without compromising filtercake quality • Drill gauge hole and ability to underream to 12¼ in. • Use of an aqueous-based system to minimize environmental risks and meet local regulations
Completion Objectives
• Minimal skin attributed to residual filtercake • Mitigate risk of plugging gravel and sand control screen • Eliminate need for a breaker treatment post-gravel pack • Eliminate use of an acid-based breaker system • Use of a RDF that minimizes formation damage attributed from inherent solids, viscosifiers, inhibitors, etc.

The key parameters that were considered for the completion design are listed in **Table 2.**

Table 2 – Completion Design Parameters				
Parameter	**Units**	**Min**	**mL**	**Max**
Water Depth	ft		800	
Interval Depth	ft		6085	
Deviation at Sandface	degree		<20	
Gross Formation Thickness	ft	30	145	145
True Vertical Thickness	ft	30	145	145
Net-to-Gross Ratio	%		>90	
BHP initial	psi		3400	
BHP current	psi		2270	
BHP abandonment	psi		1200	
SITP current	psi		1960	
BHT	°f		150	
Condensate	bbl/MMscf		0.017	
Produced Water	bbl/MMscf		0	
Water of Condensation	bbl/MMscf		0.2	
Gas Gravity			0.557	
CO_2	mol %		0.095	
H_2S	mol %		0.0	
N_2	mol %		0.1	

Reservoir Overview

Reservoir and Seal

The reservoir formation is interpreted as being Yafo sandstone, deposited in moderate water depths. The overlying seal is predominantly claystone and shale and the reservoir is immediately overlain by intercalated sands and shales. The top of the reservoir is faulted in places and there are signs of leakage.

Stratigraphy from Logs and Cores

The Mari-B #3 was sidetracked and five conventional cores were taken. Routine (**Table 3**) and special core analyses were performed in order to significantly improve the understanding of the reservoir and its properties, conduct detailed engineering studies and improve future completion designs. An illustration of the different reservoir facies and the productive interval is illustrated in **Figure 3**.

Table 3 - Summary of Routine Core Analysis		
Reservoir Property	**Value Range**	**Average**
Permeability (mD)	15 – 18,000	3,600
Porosity (%)	13 – 37	29
Grain Density (g/mL)	2.58 – 2.66	2.64
Water Saturation (%)	11 – 109	52
Oil Saturation (%)	0.4 – 8.5	3
Total Saturation (%)	12 – 120	55

Formation Strength and Sand Production Risk

A core study concluded that "framework sand grains are angular to subangular in shape and loosely consolidated. Grains have a relatively loose, open packing arrangement indicative of minimal burial compaction. Grains have both floating and point-to-point contact in thin section. The low degree of compaction and minimal cementation resulted in poor formation consolidation and mechanical strength, thus, rendering the zone susceptible to mechanical failure during completion and production. Sand control will be necessary in this zone." In addition to these conclusions, several other contributing factors supported sand control of the new wells including: the need for ultra high rate gas and high reliability; risk of sanding with depletion in an over-pressured formation; erosion risks for high rate gas production with sand; and the risk of sanding with water production.

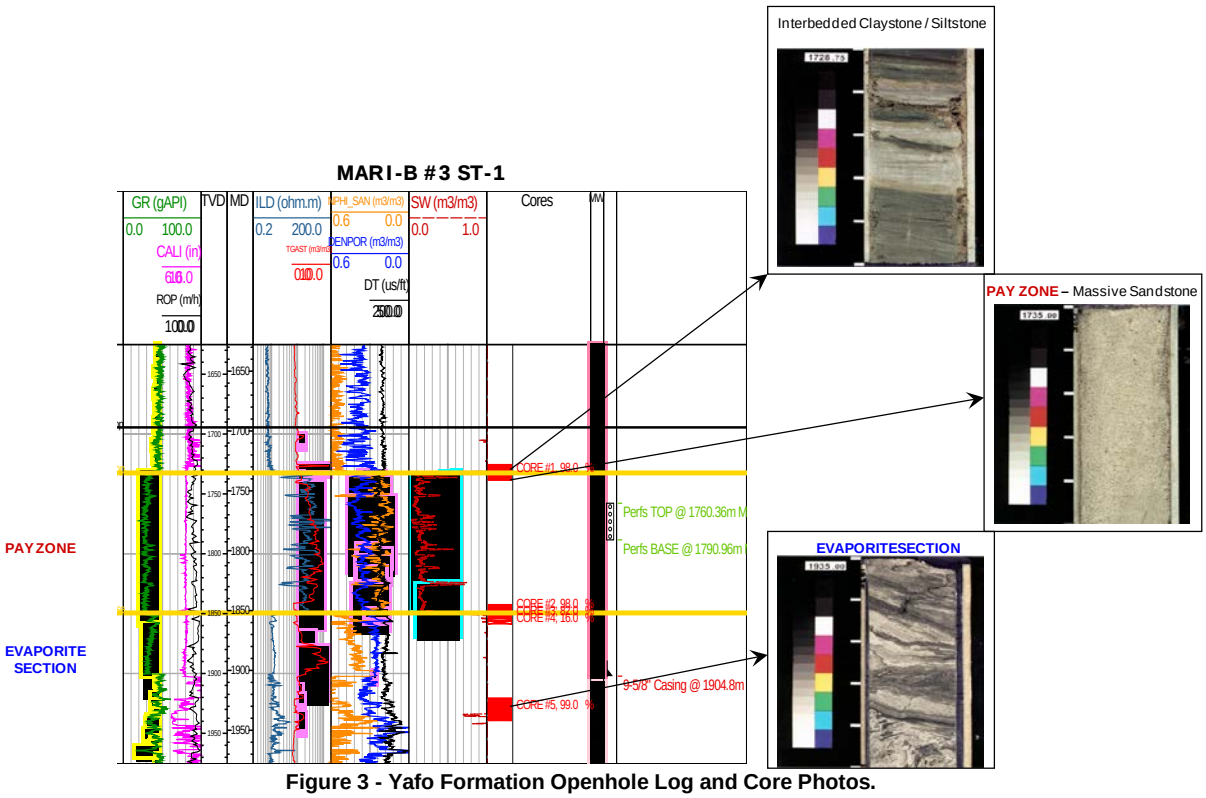


Figure 3 - Yafo Formation Openhole Log and Core Photos.

Lower Completion Concept Select

Of the various sand control options available (i.e., open-hole standalone screens, expandable sand screens and frac packs), the only option that was seriously entertained was the openhole gravel pack (OHGP). A global review (Cannan et al. 1993; McKenna et al. 1993; Teng et al. 1998; Dolan et al. 2001; Benesch et al. 2004; Hartmann et al. 2004; Bourgeois et al. 2006; Healy et al. 2007; Clancey et al. 2007; Benesch et al. 2007; Ledlow et al. 2008; Gunningham et al. 2008; Healy et al. 2008) was made of ultra high-rate gas wells which found the predominant sand control method employed to be the OHGP. The OHGP offers the most efficient and most reliable sand control method with a proven track record. This selection was also consistent with the completion type for the Mari-B #7 which was the last well completed and the best performing well on the platform (±170 MMscf/D).

Fluid Design, Qualification & Testing

RDF Design

A laboratory phase was initiated to design and optimize a reservoir drill-in fluid (RDF), solids-free RDF (SF-RDF), and breaker system using the aforementioned drilling and completion objectives (Table 1) as guidelines. Thus, specific objectives were established for the design and optimization for this pre-planning phase. The RDF system was designed to meet the following:

- Demonstrate relatively good fluid loss with respect to the unconsolidated 3.6 Darcy (average) Yafo Sand
- Provide and/or demonstrate inhibition of potential reactive shale minerals using a compatible inhibitor
- Rheological properties for drilling/under-reaming that effectively removes solids and deposits a homogeneous filtercake
- Use of environmentally acceptable components

In addition, the selected RDF system and subsequent filtercake was designed to achieve the following completion targets:

- Use of a system for RIH with sand control screens that minimizes risk of plugging
- Filtercake degradable by a non-acid component(s) to reduce skin and plugging of gravel/sand control screen
- Ability to use the above component(s) in the gravel pack carrier fluid
- Concurrent with the use of non-acid component(s), provide a delay of not less than four hours to allow POOH with no NPT and nil losses

It should be noted that at the time the Mari-B #7 was drilled, the reservoir pressure had been depleted to 2980 psi as compared to the initial reservoir pressure of 3400 psi. However, at the time this laboratory phase was initiated, the reservoir pressure was depleted to approximately 2270 psi (6.9 lb/gal equivalent reservoir). Consequently, the water-based RDF was

designed for 9.0 lb/gal that would provide sufficient shale inhibition through the brine phase and contain sufficient bridging material to minimize losses, filtrate and spurt, during the drilling phase.

To address and reduce the environmental risk, a water-based RDF was required therefore non-aqueous systems were never considered for use. A potassium chloride (KCl) brine was considered as the base brine for the RDF and for inhibition of clay mineral phases within the Yafo Sand. While no shale material (*i.e.*, whole core) was available to assess, previous field experience showed that a 7 wt% KCl demonstrated effective inhibition of relatively reactive shale rock (*i.e.*, predominantly smectitic). As such, it was decided to use a 7% KCl as the base fluid. Other components included in the test matrix were:

- hydroxypropylated starch
- polyanionic low-molecular-weight cellulose
- organophilic components
- xanthan
- internal breaker
- sized calcium carbonate

A clarified xanthan was selected to provide viscosity as well as hole cleaning and to promote a pseudoplastic system. Sized calcium carbonate was used primarily for effective bridging/fluid loss as opposed to weighting the RDF system as the base brine could readily be adjusted for any unanticipated weight-up requirement.

In an attempt to reduce the logistics of mobilizing products, a polyanionic cellulose was compared to the hydroxypropylated starch and organophilic starch as well in an attempt to assess effective fluid loss and the ability to forego the use of acid.

The test matrix also included assessments for relative rheology, fluid loss and the ability to simulate production without the use of a breaker and external/internal breakers to degrade and dissolve filtercakes formed from the selected RDF systems; a total of seven systems were evaluated.

The highly unconsolidated nature of the Yafo Sand prevented using return permeability as core plugs were difficult to acquire/produce and the subsequent application of confining pressure to these cores yielded a higher risk for test failure. Thus aloxite discs were used as an analog to establish filtercakes and assess filtrate invasion of the RDF systems as well as flow initiation pressures. Based on optical data (**Figure 4**), the Yafo Sand exhibited maximum pores ranging from 200 to 400 microns and common pore sizes that ranged from 30 to 100 microns. However the unconsolidated nature of the core recovered from this sand was surmised to skew the maximum pores as observed/measured optically. Thus, a more realistic maximum likely ranged from 200 to 250 microns. Next, a bridging solids blend was designed using a proprietary software program (Dick et al. 2000) with the resulting data shown below in **Table 4**.

Table 4 - Optimized Bridging Solids Blend for the Yafo Sand

Grade	D10	D50	D90	Percent
Calcium Carbonate 10	0.9	9.8	24.0	3
Calcium Carbonate 20	1.0	19.6	81.0	7
Calcium Carbonate 40	2.7	48.0	196.0	77
Calcium Carbonate 250	56.0	240.0	464.0	13
Totals (Blend):	**3**	**52**	**248**	**100**

This blend was incorporated at a total loading of 30 lb/bbl. A FAO-10 disc was selected to simulate the Yafo Sand as this disc has measured median pores/openings that range from 27 to 77 microns and a maximum pore/opening of 200 microns. As return permeability testing could not be performed, filtercakes were deposited on this medium and relative fluid loss and simulated flowback tests were performed.

The next assessment compared the use of polyanionic cellulose to hydroxypropylated starch and to organophilic starch/carbonate when blending the laboratory-prepared RDF systems. A matrix was formulated which included seven tests. One system incorporated organophilic starch/carbonates and the other six were divided equally with three systems using only hydroxypropylated starch and the other three using only polyanionic cellulose (**Table 5**). The rheological properties of these systems exhibited relatively low plastic viscosity (PV) and elevated yield point (YP) (peusdoplastic) and low-shear-rate viscosity (LSRV). The ratio of PV/YP is typically less than one for a biopolymer viscosified water-based system. The addition of the fluid loss agents at equal concentrations of hydroxypropylated and polyanionic cellulose also yielded a similar ratio. However, with the addition of the polyanionic cellulose, a decrease in the low-end rheology was evident. Both the 6 and 3-rpm readings as well as the LSRV were reduced and when compared to the LSRV of the hydroxypropylated systems was approximately 3.5 times less. This is most likely due to the highly anionic nature of this product. Fluid loss tests were performed for a 16-hour period at approximately 155°F and revealed comparative results for the hydroxypropylated and organophilic systems. However, the systems that utilized the polyanionic cellulose exhibited lower fluid loss – 3.6 mL compared to 4.8 mL – as expected.

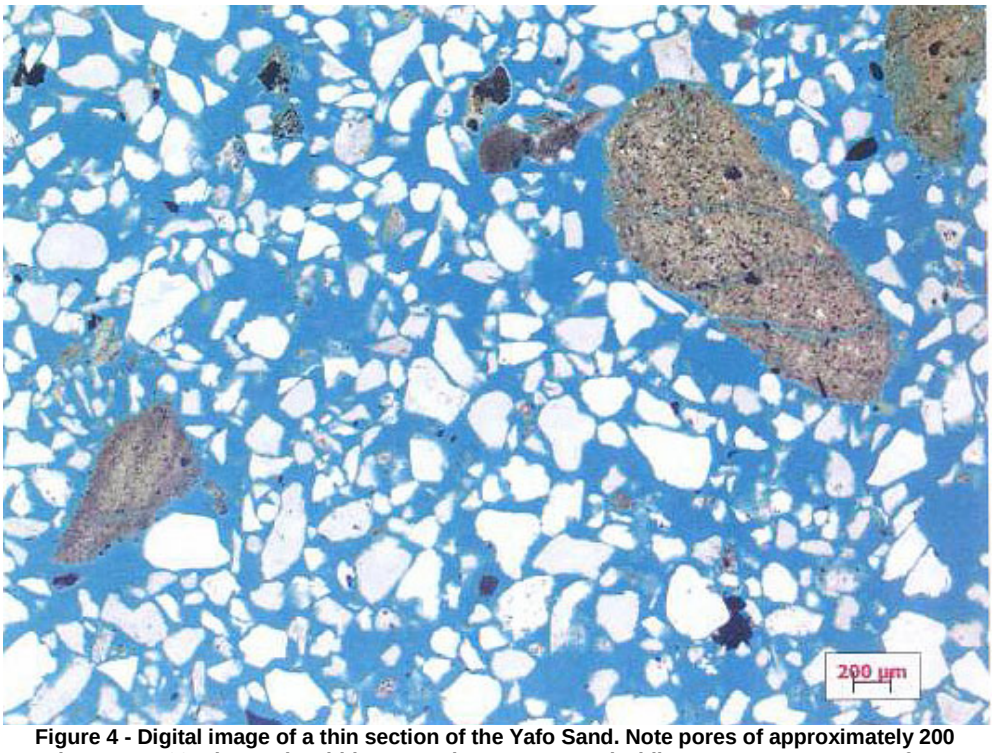


Figure 4 - Digital image of a thin section of the Yafo Sand. Note pores of approximately 200 microns to 400 microns in width are maximum measured while common pores range from approximately 30 to 100 microns.

Table 5 - Comparison of Rheology, Fluid Loss and Simulated Flowback for RDF Systems Using Selected Fluid Loss Additives

Fluid Loss Additive Used in RDF System	Organophilic Starch	Hydroxypropylated Starch	Hydroxypropylated Starch	Hydroxypropylated Starch	Polyanionic Cellulose	Polyanionic Cellulose	Polyanionic Cellulose
Rheology							
600-rpm Reading	77	69	69	69	67	67	67
300-rpm Reading	61	55	55	55	47	47	47
200-rpm Reading	53	48	48	48	38	38	38
100-rpm Reading	41	40	40	40	27	27	27
6-rpm Reading	15	19	19	19	9	9	9
3-rpm Reading	12	17	17	17	7	7	7
10-sec/10-min Gel (lb/100 ft^2)	12 / 14	18 / 21	18 / 21	18 / 21	8 / 11	8 / 11	8 / 11
PV (cP)	16	14	14	14	20	20	20
YP (lb/100 ft^2)	45	41	41	41	27	27	27
LSRV @1 min (cP)	43691	55687	55687	55687	16596	16596	16596
LSRV @2 min (cP)	44491	61687	61687	61687	17796	17796	17796
LSRV @3 min (cP)	44291	61287	61287	61287	17496	17496	17496
Other Test Results							
pH (Direct)	9.6	10.1	10.1	10.1	9.69	9.69	9.69
16-hr Fluid Loss (mL)	4.9	4.8	4.8	4.8	3.6	3.6	3.6
Simulated Flowback Breaker Type	None	None	Acid[2]	Chelant[3]	None	Acid[2]	Chelant[3]
Soak Time at 155°F	n/a	n/a	24 hr	5 day	n/a	24 hr	2 day
% Return to Flow	74	59	43	94	21	9	4

1. *Using 20/40 gravel and a 175-micron screen coupon. All filtercakes formed after hot-rolling at 155°F and fluid loss for 16 hours at 155°F on a FAO-10 disk*
2. *15% HCl + 5% Acetic at initial pH <1*
3. *Amylase plus protonated chelant at initial pH 4.6*

Next, relative or simulated flowback were performed using the aforementioned 16-hour filtercakes (**Figure 5**). Two baseline tests were included where no breaker system was applied. It should be noted that organophilic systems do not require the use of a breaker system as the organophilic components promote preferential flow of hydrocarbons (Ravitz et al. 2005; Napalowski et al. 2008; Ravitz et al. 2009; Trieb et al. 2009; Ezeigbo et al. 2012; Randell et al. 2012). These flowbacks were performed using LVT-200 mineral oil as gas cannot be used with this method/apparatus. This method reports the percent return to flow after application of a breaker system (i.e., acid, chelant, etc.) or no breaker to an initial flow rate. For

these tests the initial or baseline was measured using a combination of aloxite disk, 20/40 gravel and screen coupon. Thus, the baseline was established using a blank aloxite disk (*e.g.*, no filtercake) placed inside an HTHP cell, 20/40 gravel placed on top and a 175-micron screen coupon on top of the gravel whereby flowrates were measured at 1, 2, 4, and 8 psi. The aforementioned array was used to simulate a gravel pack and the LVT-200 was used to simulate hydrocarbon and was flowed in an arbitrary production direction. Using this method, all RDF systems and subsequent removal or dissolution by a breaker system were compared/contrasted using the calculated slopes.

The RDF systems formulated with polyanionic cellulose were compared to baselines where no breaker was applied as well as to two breaker systems, acid based and a chelant based, which included amylase for degrading the polymers used as fluid loss additives. The acid breaker was blended as HCl plus acetic. In this simulation of the field application, the acid was not targeted for stimulating as the Yafo is predominantly quartz. The chelant plus amylase was formulated to dissolve the calcium carbonate and degrade the starch, respectively, both components of the residual filtercake. In addition, as chelants and enzymes are relatively slow-acting compared to inorganic and organic acids, it was surmised that this chemistry would provide a delay such that these components could be incorporated as part of the gravel packing carrier fluid and/or as a post spot if the gravel packing tool was convertible to allow a suitable pumping path. For these tests, the acid-based breaker was applied for 24 hours and the chelant plus amylase breaker for two and five days.

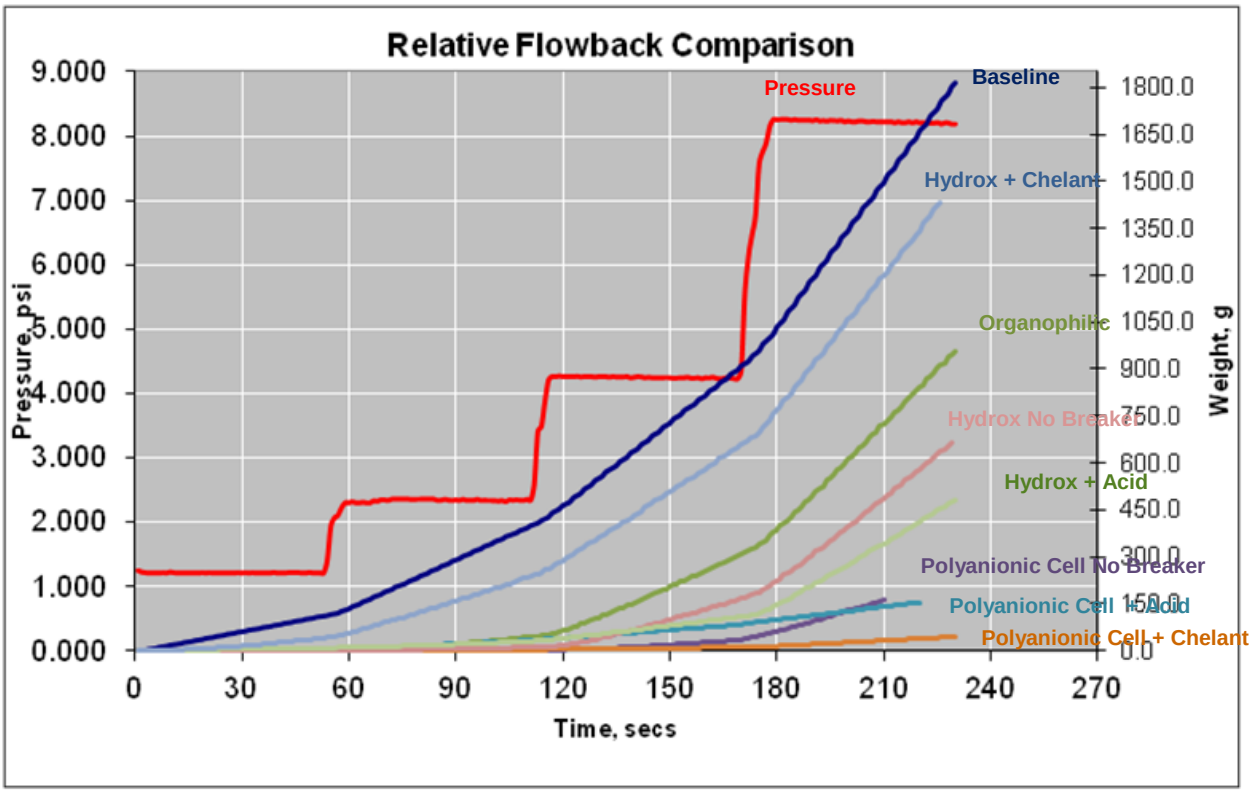


Figure 5 – Comparison of relative flowback for selected RDF systems with and without breaker systems.

The results (Table 5) show that the organophilic-based RDF system while demonstrating a relatively high return to flow, approximately 74 percent, could not be considered for use as the initial start-up or kick-off of a well required bullheading the tubing volume (*e.g.*, KCl brine) through the gravel pack and residual filtercake and as this system is hydrophobic would mitigate this process. The relatively low percent return to flow for tests where polyanionic cellulose was incorporated into the RDF exhibited incompatibility with the protonated breaker systems (*i.e.*, pH less than 5.5). The baseline RDF with polyanionic cellulose yielded approximately 21 percent return to flow. A comparison of the chelant plus amylase breaker system and the acid system showed return of the initial flow of 9 percent and 4 percent, respectively. The combination of the polyanionic cellulose and protonated chemistry most likely resulted in precipitation and yielded a more tenacious filtercake. In comparison the RDF that utilized hydroxypropylated starch exhibited a return to flow of approximately 59 percent. The application of an acid system yielded a return to flow of 43 percent and may be attributable to the lack of proper additives, volume, and/or concentration used. Although acid was not a desired breaker system; it was, however, considered as a baseline for these tests. The use of the chelant-based breaker system yielded 94 percent return to flow.

It is evident from these relative tests that the polyanionic cellulose, when incorporated into the RDF system at only 3.5 lb/bbl, yielded a more tenacious filtercake that was relatively more difficult to remove and degrade. It was also concluded that the use of the chelant-based system plus an internal breaker would provide less risk and promote degradation of the

polymers in the residual filtercake specifically the hydroxypropylated starch. In addition, the use of relatively slow-acting chemistry or chelants would allow incorporation into the gravel pack carrier system.

As a final interpretation of the relative flowback testing, the pressure required to initiate flow with respect to the residual filtercake, gravel, and screen coupon was also assessed. The pressure required to initiate flow or effluent for each RDF, with and without a breaker system, can be approximated from the x-axis, the baseline (no filtercake), and each other. A measureable difference is apparent for the hydroxypropylated RDF where a five-day chelant soak was used and all other RDF systems and/or breakers. In addition, the flow rate at each pressure was greater for this combination of breaker system and hydroxypropylated RDF.

Based on the test results, the optimized RDF formulation is shown in **Table 6**. Note that this system included an internal breaker that was used to enhance localized degradation.

Table 6 - Optimized 9.0 lb/gal RDF

Products	Conc.	Units	Primary Function
7% KCl	0.9507	bbl	Density
Xanthan	1.25	lb/bbl	Polymer Viscosifier
Hydroxypropylated Starch	7.0	lb/bbl	Fluid Loss Control
Magnesium Oxide	0.5	lb/bbl	Maintain pH
Calcium Carbonate 10	1.0	lb/bbl	Bridging
Calcium Carbonate 20	2.0	lb/bbl	Bridging
Calcium Carbonate 40	23.0	lb/bbl	Bridging
Calcium Carbonate 250	4.0	lb/bbl	Bridging
Biocide	0.19	lb/bbl	Pre-treat water
Oxygen Scavenger	0.54	lb/bbl	Scavenger for breaker
Internal Breaker	2.0	lb/bbl	Localized degradation of polymers

The final objective was to assess delay. The carrier fluid section tested relative delay of the chelant based-systems when incorporated into the gravel pack carrier system.

Solids-Free Reservoir Drill-In Fluid (SF-RDF)

A solids-free version of the RDF or SF-RDF was formulated and optimized for use as a liner or screen running system. This system excludes the calcium carbonate bridging material and uses the brine phase to attain a target density. The target density is typically equal to or up to 1.0 lb/gal heavier than the RDF. This density difference promotes an effective openhole displacement whereby the RDF and nearly all residual is removed; commingling it mitigated reduces the interface. This density difference also allows for a head-to-head displacement thus eliminating an additional spacer. The SF-RDF is also formulated more viscous than the RDF at all measured shear points, typically 1.5 times that of the RDF which aids and promotes an effective displacement of the residual RDF from the open hole. Typically this displacement is designed to push the tail of the RDF above the casing shoe and above the area where the packer is set. The elevated viscosity of the SF-RDF also helps to reduce losses in the event that the filtercake is disturbed. The SF-RDF is spotted in the open hole on the last trip prior to screen running whereby the casing is displaced to clear brine fluid after the drillstring is pulled above the open hole. The solids-free nature of this system is also intended to prevent plugging when the screen system is run into the wellbore/open hole. **Table 7** shows the laboratory formulation used to blend a 9.5 lb/gal SF-RDF.

Table 7 - Optimized 9.5 lb/gal SF-RDF

Products	Conc.	Units	Primary Function
22% KCl	0.995	bbl	Density
Xanthan	2.25	lb/bbl	Polymer Viscosifier
Hydroxypropylated Starch	4.0	lb/bbl	Fluid Loss Control
Magnesium Oxide	0.5	lb/bbl	Maintain pH
Biocide	0.19	lb/bbl	Pre-treat water

Prior to pumping the SF-RDF a production screen test (PST) is performed in the field (Sorgard et al. 2001; Svoboda 2002). This quality control method requires a coupon cut from the same filtration media that is utilized as part of the sand control system (*e.g.*, wire-wrap, premium weave, etc.). This SF-RDF system was then used to assess relative plugging of the sand control screen. Based on the volume of the wellbore and open hole, two 1-L volumes were used and flowed through the same coupon to assess the potential to plug the sand control screen. Plugging is defined as the inability to flow one liter through the coupon when using 20-psi differential to air. This event is referred to as a FAIL. Thus the specification for this test is a PASS versus FAIL for each one-liter volume and is not predicated upon time. The laboratory results are shown in **Table 8**.

Table 8 – Plugging test for SF-RDF

No.	Volume (mL)	Time (sec)	Result
1	1000	9.57	PASS
2	1000	13.4	PASS

Two consecutive one-liter volumes of the laboratory SF-RDF did not plug a coupon that represented the sand control screen. The ratio of 2000 mL for the 2-in. diameter coupon can be used to expand/extend to the actual length, diameter and volumes for the completion, whereby, the laboratory volume/area used is greater than the volume/area of the actual completion.

Completion Brine

The completion brine selected was a single salt potassium chloride brine for simplicity and shale inhibition. The displacement to completion fluid from RDF inside the casing was designed to include a series of cleaning spacers to remove the RDF and leave the metal tubulars water wet. The entire displacement sequence was simulated using proprietary hydraulics software to optimize fluid volumes for pump pressures, contact time and to minimize fluid interface.

Packer Fluid

Packer fluid chemicals were selected for corrosion inhibition considering metallurgy and anticipated temperatures. A standard treatment package consisting of an oxygen scavenger, biocide and corrosion inhibitor selected using a database of compatible products at bottomhole temperature for the production tubing metallurgy.

Corrosion Testing

Corrosion testing was performed to establish the corrosion rate of the 9.1-lb/gal chelant/enzyme breaker system and the completion brine system. Tests were performed for 7 and 21 days (168 and 504 hours) with and without the addition of a corrosion inhibitor.

The 316L coupons were weighed and photographed and then placed in glass bottles with the fluid samples for aging at 147°F. After the 7 and 21-day time periods the coupons were cleaned, weighed and photographed. Microphotographs were also taken to capture any corrosion effects that were not immediately visible. **Table 9** demonstrates that the corrosion rates were well below the required limit of 5 mils per year (mpy).

Table 9 - Measured Corrosion Rates for Breaker and Completion Brine Systems

Fluid	Initial pH	Final pH	Time (hr)	mpy
Breaker System	6	6.08	168	0.1
Breaker System with Corrosion Inhibitor	6	6.05	168	0.13
8.6-lb/gal KCl	7	8.54	168	0.11
Breaker System	6	6.08	504	0.05
Breaker System with Corrosion Inhibitor	6	6.05	504	0.04
8.6-lb/gal KCl	7	8.54	504	0.03

Gravel Pack Design

Sand Screens. The sand screens selected were premium mesh 175 micron; centralization was added to ensure adequate stand-off from the underreamed (12¼-in.) borehole.

Proppant. 20/40 Synthetic proppant was selected for gravel pack sand.

Carrier Fluid

The planned short and vertical production intervals provided a relatively low risk environment for gravel packing, especially water packing. To maximize breaker access to the filter cake, the enzyme and chelant components were incorporated as part of the gravel pack carrier fluid. This would provide immediate, intimate and adjacent contact with the residual filter cake. This specific chemistry (e.g., pH) was also designed to activate the internal breaker which was added to the RDF before the drilling phase thus incorporating this component as part of the filter cake.

It was critical to establish that this component as designed for filtercake destruction would not result in premature degradation that may compromise the gravel pack due to losses during pumping. To simulate the gravel packing process and potential breakthrough, a test sequence was established using a proprietary dynamic high-temperature, high-pressure (HTHP) apparatus. The matrix was designed to simulate a series of dynamic and static conditions with an aged filter cake that simulated the drilling and completion operations. This dynamic HTHP (**Figure 6**) is similar to a conventional HTHP; however, it is equipped with a shaft that allows rotation at a predetermined rate up to approximately 800 rpm. Fluid loss is monitored continuously throughout the test to document a breakthrough event whereby the filter cake fails to restrict the loss of a fluid/system.

It was decided that the following sequence (**Table 10**) of pressure, rotation and time would simulate the deposition of the filter cake, displacement, circulation of gravel and a static period whereby the workstring is POOH to close the fluid loss valve.

A test was initiated by simulating the drilling of the reservoir or deposition of a filter cake on the FAO-10 aloxite at 650 rpm. The test was converted to a static test to simulate the filtercake formation between drilling and the gravel pack operation. For the gravel pack, the equivalent of 1 ppa with the breaker system were placed inside the cell using the rotating

shaft at 120 rpm to simulate pumping of the gravel pack. Finally, a static fluid loss was monitored to simulate retrieving the washpipe through the mechanical fluid loss control device. **Figure 7** shows the results of this test.

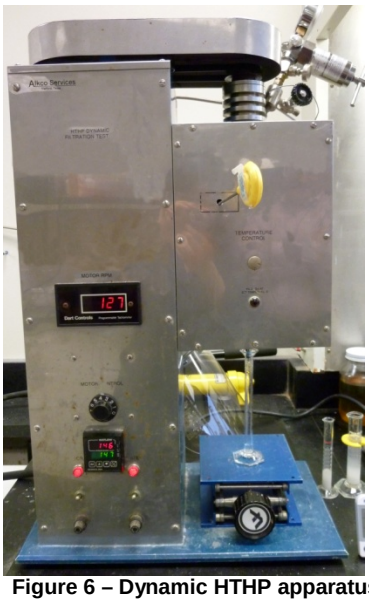


Figure 6 – Dynamic HTHP apparatus collecting fluid loss.

Table 10 – Sequence of Events to Simulate Downhole Activities

Step	Field Procedure Simulated	Pressure (psi)	Temp (°F)	Rotation (rpm)	Time (hr)
1	Drilling	500	147	650	4.0
2	Tripping pipe	500	147	none	11.0
3	Circulating BU	600	147	650	1.0
4	Decant RDF			none	
5	Add gravel pack slurry			none	
6	Gravel Packing	500	147	120	0.5
7	POOH	300	147	none	3.0

From the data (Figure 7), no premature breakthrough or increase in fluid loss was evident throughout the duration of the dynamic and static phases that would be considered indicative of premature degradation of the residual filter cake.

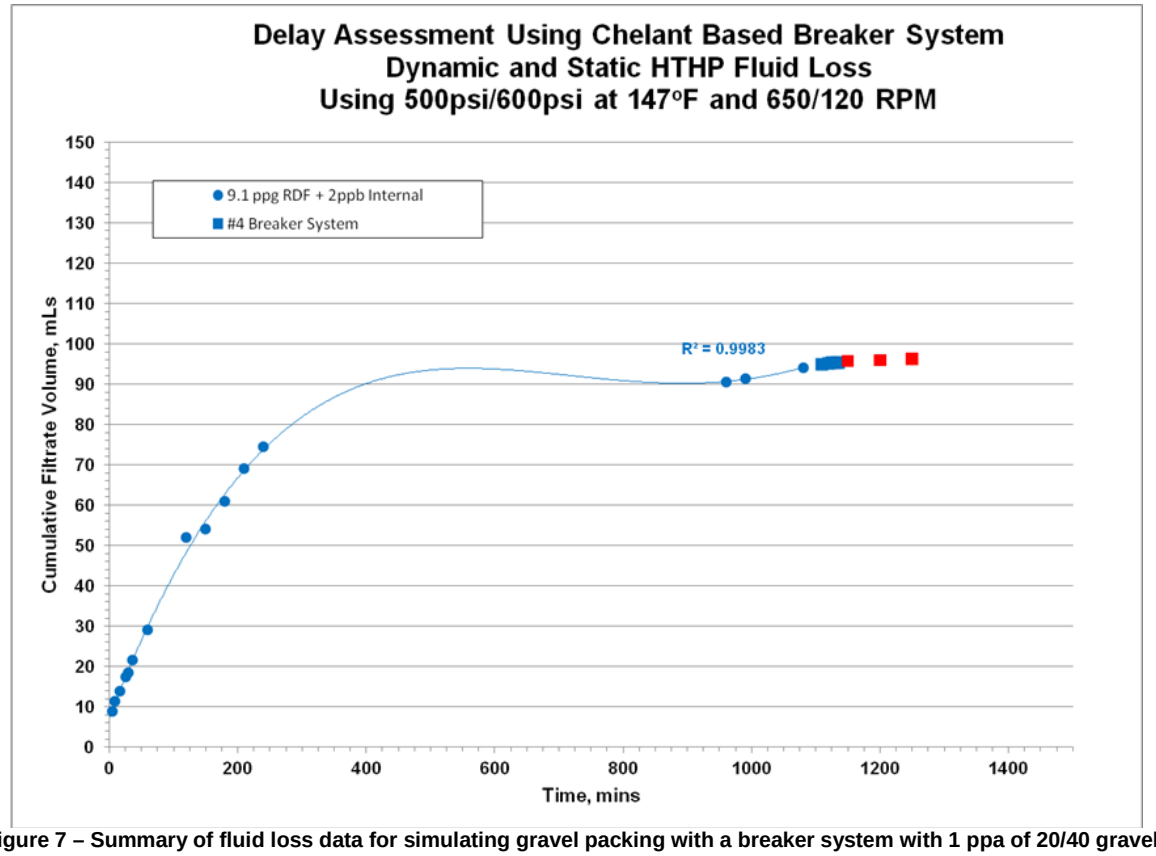


Figure 7 – Summary of fluid loss data for simulating gravel packing with a breaker system with 1 ppa of 20/40 gravel.

QA/QC of Fluids in the Field During Operations

Several QA/QC protocols were performed on the fluid systems (RDF, SF-RDF, completion brine and breaker/carrier fluid) during field execution to ensure compliance with the laboratory test protocols which minimize damage mechanisms to the reservoir. These QA/QC steps also established standardization of fluid operational procedures in the Mari B field.

The QA/QC protocols included specification sheets identifying acceptable properties for fluids prior to shipping to the rig site as well as confirming properties once received. The tables were completed by the technical specialist and witnessed. Each batch of fluid mixed was tested prior to loading on inspected transport vessels. The rig systems also received inspections to avoid contamination of fluids. During drilling, properties were reported and maintained as specified in the program. Key QA/QC procedures were established for the following activities/phases:

- Mixing Preparation — Mixing and transfer system cleanliness
- RDF — Density, rheology, pH and fluid loss
- SF-RDF — Density, rheology, pH and production screen test
- Completion Brine — Density, total suspended solids, clarity
- Breaker System — Base brine density, total suspended solids and clarity; breaker chemistry activity

Execution

The importance of flawless execution is obvious as this is where the "rubber meets the road." Even with the right design, detailed engineering and equipment integrity, a single human act can imperil all of the hard work performed prior to this critical phase. Constant supervision and focus on both the procedure and final goal is paramount. Project engineers facilitated Complete Well on Paper (CWOP) sessions and detailed procedure reviews (most hosted in the Supplier's facility where the equipment was easily accessible) with key supplier personnel and company wellsite supervisors. Learning from mistakes and successes (yours and others) is one of the most important tactics of flawless execution. This includes during and after the job. The purpose of the after-action reviews is to capture lessons learned in order to immediately improve on subsequent operations and/or improve future designs, procedures and operations. A detailed review of all the lessons learned is outside the scope of this paper; however, a couple of examples of several key tactics are described below.

- On-Site Supervision
- After-Action Reviews

On-Site Supervision

Significant effort was put into the inspection, assembly and test of the gravel-pack equipment. A Shop Quality Plan (QP) was developed and implemented which required witnessing by company wellsite supervisors. QA/QC procedures and plans were not only developed for tangible and rental items, but also for the completion fluids. **Figure 8** is an example of a Fluid QA/QC inspection sheet that was utilized to ensure that the SF-RDF pill, which is spotted in the open hole prior to gravel packing, met the specified acceptance criteria. Screen plugging during gravel packing can result from contaminated (solids laden) fluids left in the open hole which can lead to screen erosion during pumping – a catastrophic failure. The screen plugging test of the clean pill was witnessed by the company wellsite supervisor. The test results are documented on the inspection sheet (verifying document) and is signed-off by the company wellsite supervisor.

Screen Plugging Test

noble energy

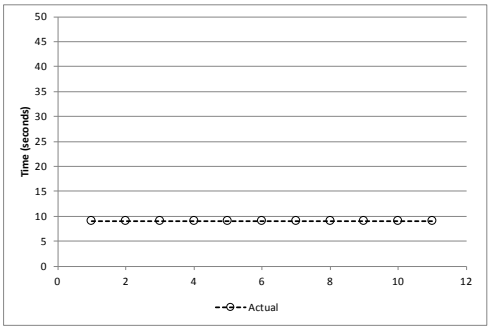
Field: Mari B
Well: #9
Actual Sand Screens: 175 um EXCELFLO
Screen Coupon: 175 um (provided by Weatherford)
Fluid: 9.2 ppg FLOPRO RDF
Screen: 175 um
Lab Appartus: Modified HPHT Cell (175 mls)
Test Date: 2-Jun-10
Lab Tech:

Requirements
Approximately 2000 mls (calculated 01-Jun-2010).

Acceptance / Rejection Criteria
No increasing trend in times (per 01-Jun-2010).

Test Data

Volume (mLs)	Aliquot	Time (secs) Actual	(F) Temp	Comments
175	1	9	82	
175	2	9	82	
175	3	9	82	
175	4	9	82	
175	5	9	82	
175	6	9	82	
175	7	9	82	
175	8	9	82	
175	9	9	82	
175	10	9	82	
175	11	9	82	
1925				



"red" = input data

Figure 8 – SF-RDF QA/QC Inspection Sheet.

After-Action Review (Lessons Learned - Gravel Packing Operations)

Even with the most careful planning and process, problems always occur. Usually these problems are a result of poor communication and even the simplest things can jeopardize the execution.

On the first gravel packing operation, the gravel pack slurry return tank was sent on another job for different operator; thus, it was not available for the first gravel pack (Mari-B #9). The purpose of a slurry return tank is to measure the amount of sand reversed-out after the job. This amount is subtracted from the total amount sand pumped to determine how much sand was left in the hole. Four other methods / contingencies were planned to cover this function. They were as follows:

1. **Non-radioactive densitometer (NRD)**. A NRD was utilized to measure the proppant concentration in the slurry. However, the NRD proved to be inaccurate for proppant loadings less than 1 ppa (the designed proppant concentration). The NRD measured over 17,000 lb of proppant pumped; however, only 10,000 lb was actually pumped.
2. **Re-stress.** Re-stressing (after reversing out) would be a positive indication that there was sufficient blank coverage and potentially a good annular pack, which is the primary objective. Without knowing the actual amount of sand remaining in the well, the re-stress would be one indicator of a good pack.
3. **Gravel Pack Log.** A gravel pack log conveyed on the washpipe was designed to evaluate the quality of the gravel pack and identify any voids. Unfortunately, due to logistical issues, this tool was also not available for the first gravel pack.
4. **Contingency Plan.** A contingency plan was to take slurry returns back to the active pit system. However this was not considered feasible due to the small pit volumes (±600 bbl) as well as the possibility of uncontrolled losses after the job due to the depleted reservoir pressure and the need to have completion fluid available.

As detailed above, returns were set-up to go overboard due to the small pit volume and lack of return catch tank. However, the return line had inadvertently been placed in to the active system. The returns were shut down shortly after getting the fluid moving during reverse out, to move the returns to the overboard positions. This shut-down was not communicated to the engineer in charge, and only came out during the after-action review. The authors believe that during the shutdown, the proppant was allowed to fall back and settle around the crossover tool. After the well was reversed clean, the tool was moved back into the circulating position to re-stress the pack. At this time the tool became “sticky”, requiring over 100,000 lb of overpull to free the tool. The re-stress and ensuing post-gravel pack breaker treatment were eliminated due to tool issues. A contingency clean-out run was performed.

Ultimately, the lack of communication could have caused a severe NPT event. This risk (sticky crossover tool or failure of the post-gravel pack breaker treatment module) was identified during the operational review, and contingency procedures were put in place to ensure that the reliability and productivity of the well was not put in jeopardy.

The breaker fluid (chelant) was pumped as part of the gravel packing fluid. If either of the above risks were experienced, the chelant would already be in place without requiring the acid stimulation module of the crossover tool.

Mari-B #9 did not pump a post acid stimulation. However, the productivity results validated our breaker plans as defined in the detailed engineering phase.

The lessons learned from these operations included (but not limited to) the following:

- Have the correct equipment available (sand return tank, radioactive densitometer, radio headsets, gravel pack log)
- Utilize more reliable method of measuring proppant loading (mass balance, radioactive densitometer
- Improve communication. Require single point-of-contact (SPOC) for all operations for the service company.

Based on the previous well’s learnings, the next well (Mari-B #10), proppant loading was measured three ways: non-radioactive densitometer; radioactive densitometer; and load cell (mounted on sand silo). Based on these results, the load cell was the best method. Mari-B #10 was pumped without incident and was considered a “textbook” operation.

Operations

Background

The oilfield infrastructure in Israel to support offshore and deepwater rig operations is nascent. Most equipment and personnel are dispatched from other regions (Egypt, Italy and the UK). A complete discussion of all the pre-job planning and rig operations is beyond the scope of this paper.

Platform Rig

A platform workover / drilling rig (**Figure 9**) was selected and installed on the Mari-B platform. There was limited space for the various completion equipment which made for a very challenging operation.

Figure 9 – Platform Workover / Drilling Rig on Mari-B Platform

Completion Phases

The completion operations were broken down into sequential phases (**Table 11**) to drive focus with regard to the detailed pre-job planning, detailed procedures and contingency plans.

Table 11 – Completion Operational Phases

Phase	Operation
1	Wellbore Clean-out
2	Displacement from WBM to Seawater to RDF
3	Drill Reservoir Section
4	Underream Reservoir Section
5	Displace from RDF to SF-RDF to Completion Fluid
6	Run and pump OHGP
7	Run Upper Completion
8	ND BOPs/NU Tree
9	Flow Back

The actual rig operations were performed, tracked and evaluated by phase. An after-action review was held with key Supplier personnel to determine potential improvements and key lessons learned. An action tracker and lessons learned log were utilized to capture the results and eliminate potential NPT on the next well.

As-Built Completion

The as-built completions (**Figure 10**) were delivered as designed.

Operational Performance

The results (operational performance) of the Mari-B new drill wells are considered an overwhelming success. The project was delivered under-budget and on schedule. A summary of the completion time analysis is presented in **Table 12**.

Table 12 - Completion Time Analysis

Well	Actual Time (hr)	Total NPT (hr)	Scope Change NPT (hr)	Rig NPT (hr)	Normalized NPT (hr)	Normalized NPT
Mari-B #9	647.5	232.0	188.0	0.0	44.0	9.6%
Mari-B #10	521.5	120.0	75.5	24.5	20.0	4.7%
Total	1169.0	352.0	263.5	24.5	64.0	7.3%

The total normalized NPT for both wells was less than 3 days. Normalized NPT is defined as total NPT minus (Rig + Scope Change NPT). Scope change NPT is defined as any non-productive time that was not originally AFE'd (that did not originate with trouble associated with the well). Scope change NPT is defined as any non-productive time that was not originally AFE'd, that did not originate with trouble associated with the well.

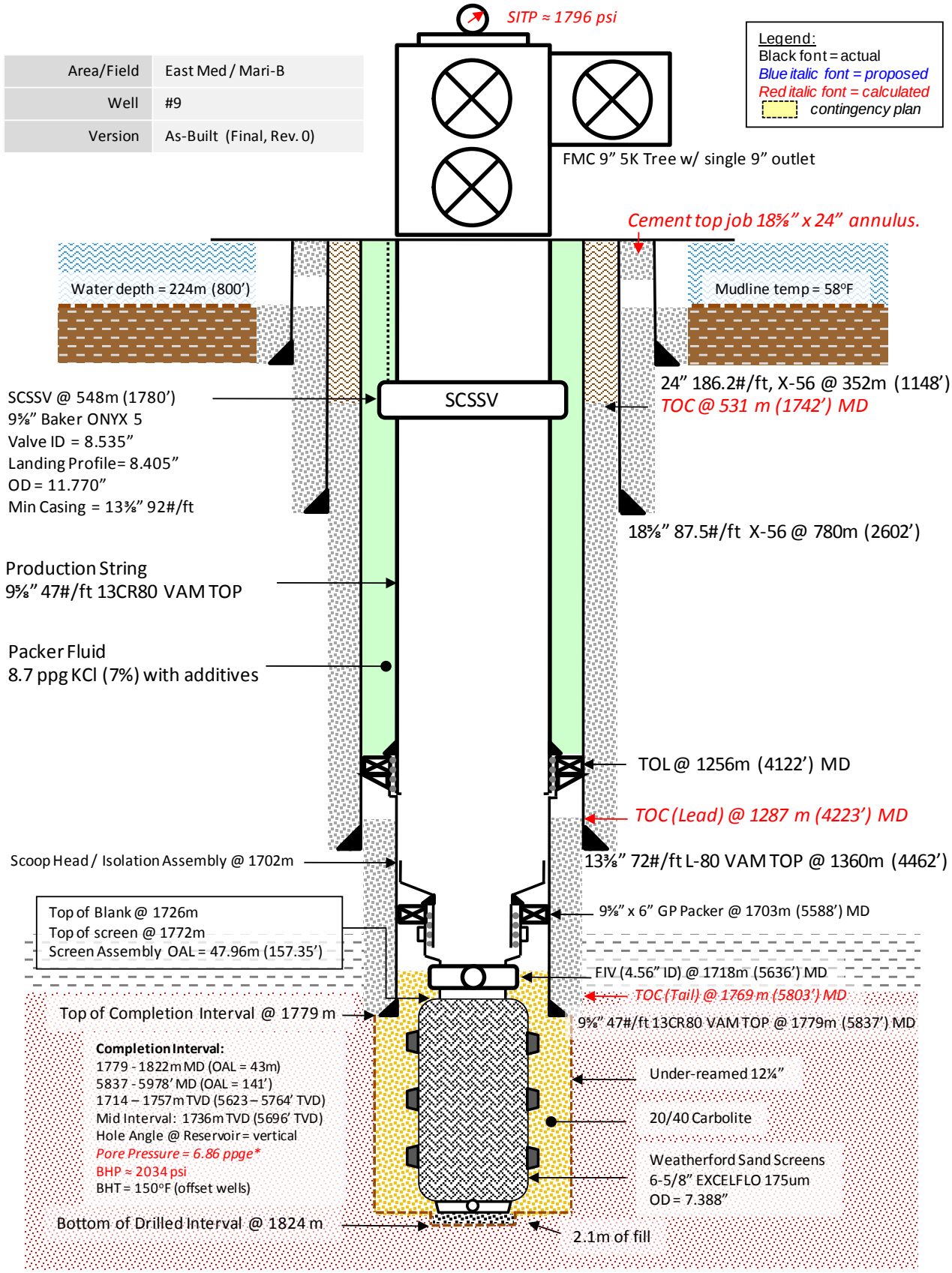


Figure 10 – Mari-B #9 As-Built Completion Schematic.

Well Performance

Because the project was "fast-tracked" from a 2009 start, the facility engineering of new flowlines, ultrasonic flow meters, and the upgrade and tie-in to the existing manifold lagged the drilling and completion campaign by about nine months. The complexity and enormity of the flowline design and installation cannot be understated. Because of the ultra high-rate flow rates required from each well, 14-in. diameter flowlines were necessary for velocity reasons. The design, fabrication, and installation of these enormous flowlines were completed in March of 2011. In the nine months between the completion of the wells and the completion of the new flowlines, each well was produced thru smaller temporary 8-in. flowlines that were borrowed from two of the original wells. Because the new wells had to be produced thru 8-in. diameter flowlines, the gas flow rate had to be limited to about 120 MMscf/d per well. There was a period of several months between the completion of the Mari-B #9 and #10 wells where the #9 well had access to two temporary 8-in flowlines and the production rate reached 220 MMscf/D.

Initial Unloading and Performance

As originally designed with a large overbalance, the completion fluid was allowed to leak-off into the depleted formation. Once sufficient time had passed for the wells to swap over to gas, the wells were brought online and gradually unloaded into the test separator. Initial performance was tracked and the pre-drill NODAL[1] analysis models were adjusted for actual performance. The initial performance from both wells was unexpectedly lower than predicted. The pre-drill NODAL models were based on actual performance from the offset well Mari-B #7 that was completed with an almost identical lower completion. However, initial mechanical skins on the Mari-B #9 and #10 were in the range of 80-100 assuming all the screen was producing. If the assumption was made the wells had a mechanical skin of 10, the associated length of screen that would be flowing would have only been about five meters. Since a production log was not run to assess how much interval was open to flow it will never be know if the initial skins were very high and most of the interval was flowing, or if the skin was low and there was a limited area open to flow.

Extended Well Cleanup

In the months that followed the initial production for each well, the wells gradually improved their performance to the point where they matched the sandface productivity of the Mari-B #7 well with a mechanical skin of around ten ($S \approx 10$). It took months for the performance to improve, but to the delight of the production and completion team, the well productivity ultimately reached the level stated in the project objectives. **Figure 11** shows the improvement of the sandface Productivity Index (PI) in MMscfd/psi^2.

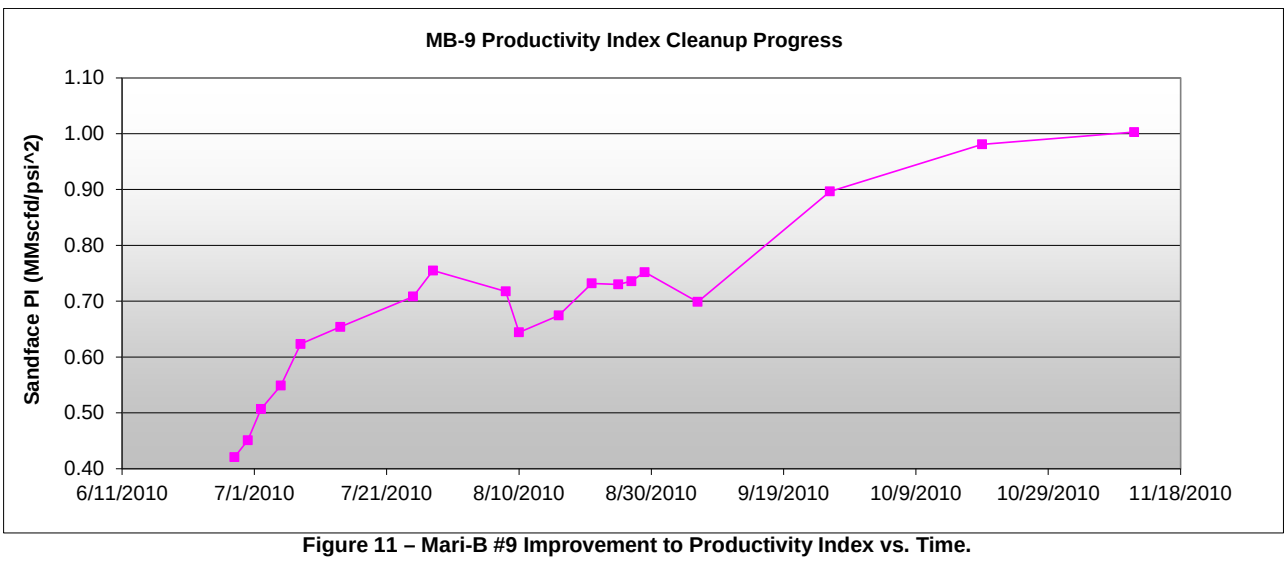


Figure 11 – Mari-B #9 Improvement to Productivity Index vs. Time.

While the mechanism of improvement to well performance will never be known it is believed that calcium carbonate ($CaCO_3$) in the RDF filter cake may have had higher embedment (due to a significantly higher overbalance at the time of completion) as compared to the Mari-B #7. Because the drawdown and associated velocity across an openhole gravel pack is relatively low, it simply took a while to move calcium carbonate back out of the matrix.

Post Cleanup Well Performance

After months of extended cleanup, the Mari-B #9 and #10 have continued to perform extremely well. As the reservoir pressure has declined to 4.8 lb/gal equivalent, the non-Darcy coefficient for turbulent skin has increased, but not as much as

[1] Mark of Schlumberger.

expected compared to the performance of the older frac-packed wells. **Table 13** shows the well performance of the Mari-B #9 and #10.

Table 13 – Key Well Performance Parameters (as of November 2011)			
Parameter	**Units**	**Mari-B #9**	**Mari-B #10**
Peak Gas Rate	MMscf/D	223.1	246.1
Current Gas Rate Range	MMscf/D	65 - 210	65 - 210
Condensate Rate	BCPD	0	0
Water (Condensation) Ratio	BW/MMscf	0.2	0.2
Flowing Wellhead Pressure	psig	1220 - 700	1220 - 700
Mechanical Skin	Dimensionless	12	12
Produced Solids		None	None

Because the Mari-B field sells into a market that has a huge swing in demand (ramp up from 200 – 500 MMscf/D in six hours is common), the wells will also swing enormously over a 24-hour period. That is why the following two graphs showing the production trend for the Mari-B #9 and #10 are very scattered. The graphs (**Figure 12**) below show the daily production and flowing tubing pressure for the wells since start-up.

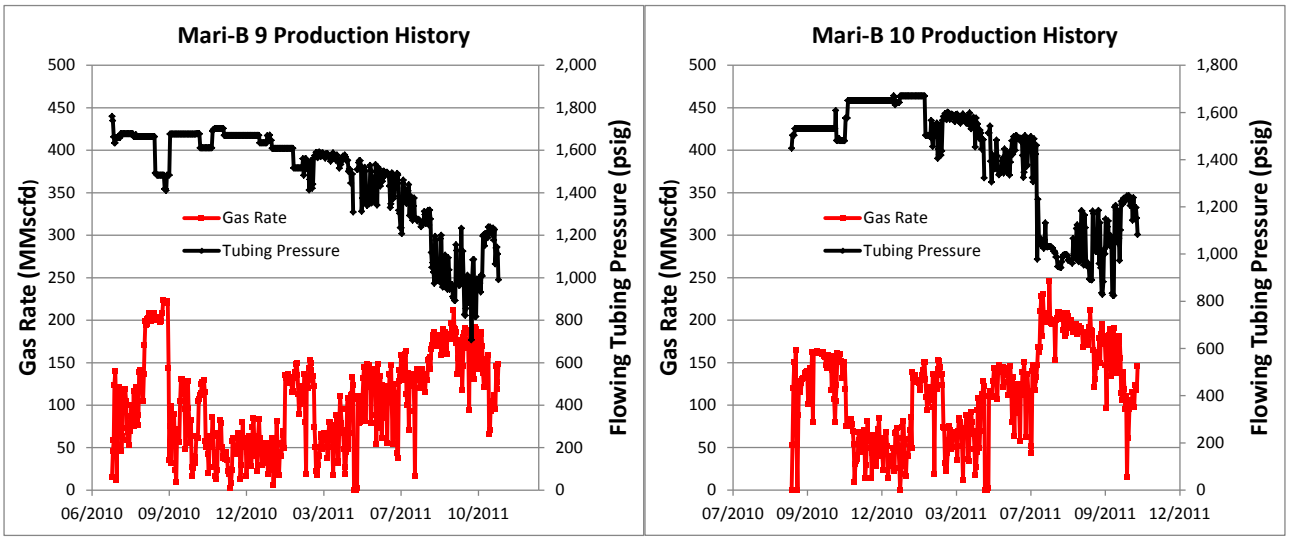


Figure 12 – Daily Production Plots for Mari-B #9 and #10.

Conclusions

The fast-track delivery of two world-class big bore (9⅝-in. production tubing) wells in a remote area was directly attributable to the development and adherence to guiding principles and a completion delivery process. Technical rigor and due diligence in all phases of the completion delivery process is imperative to achieve successful execution, rate delivery and well reliability.

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Nomenclature

AFE = *Authorization for expenditure*
BHP = *Bottomhole pressure*
BHT = *Bottomhole temperature*
LSRV = *Low-shear-rate viscosity*
mpy = *mils (thousandths of an inch) per year penetration*
NPT = *Non-productive time*
Ppa = *pounds per proppant*
POOH = *Pull out of hole*
PV = *Plastic viscosity*

RDF = *Reservoir drill-in fluid*
RIH = *Run in hole*
SITP = *Shut-in tubing pressure*
YP = *Yield point*

Conversion Factors and Units

	1 mm/yr		= 39.4 mpy
lb/100 ft^2	x 4.788 026	E-01	= Pa
bbl	x 1.589 873	E-01	= m^3
cP	x 1.0 *	E+00	= mPa·s
lb/gal	x 1.198 264	E-01	= sg
psi	x 6.894 757	E+00	= kPa

* Conversion factor is exact.

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