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Design, Installation, and Performance of Big Bore (9-5/8 in.) Completions: 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 (2) ultra high-rate gas wells (+200 MMscf/D) completed in a depleted gas reservoir with 9⅝ in. production tubing and an Open-Hole Gravel Pack (OHGP). Maximizing gas off-take rates from a volumetric drive gas reservoir that possess high flow capacity (kh) require 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 for critical wells. The completions were installed with minimal issues (NPT ≈ 9%) and have produced without incident. The wells are capable of +250 MMscf/D and are currently producing at +220 MMscf/D.

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 MMscf/D range from a production platform with 600 MMscf/D of capacity.

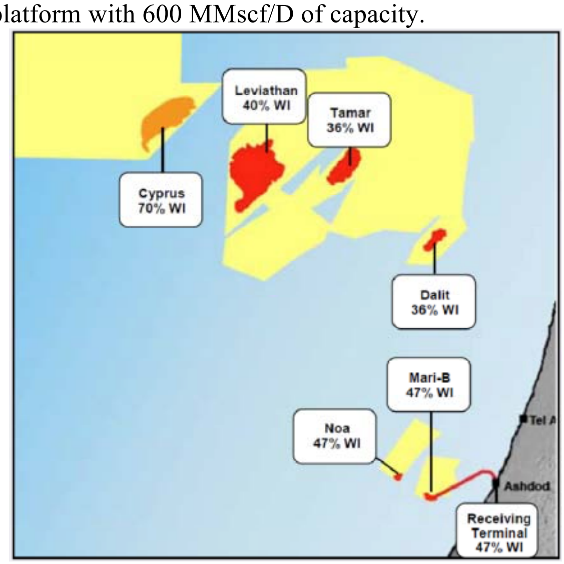


Figure 1 - Location Map

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 (2) new big bore wells were planned and executed in 2010.

By 2009, there were seven (7) wells drilled in the structure (Figure 2). The exploration well, Mari-B #1, was drilled to a depth of 2070 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.

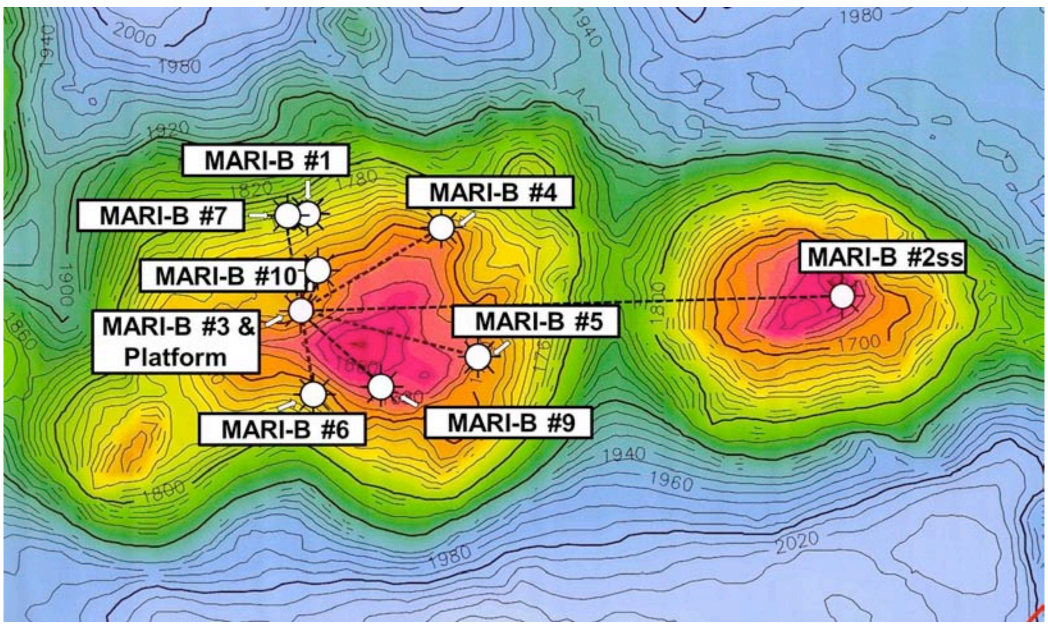


Figure 2 – Well Location Map

Geologic Overview

Structure. The Mari-B structure is a 4-way closure underlain by an evaporate unit.

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 (5) conventional cores were taken. Routine (Table 1) and special core analysis was 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 1 - Summary of Routine Core Analysis

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

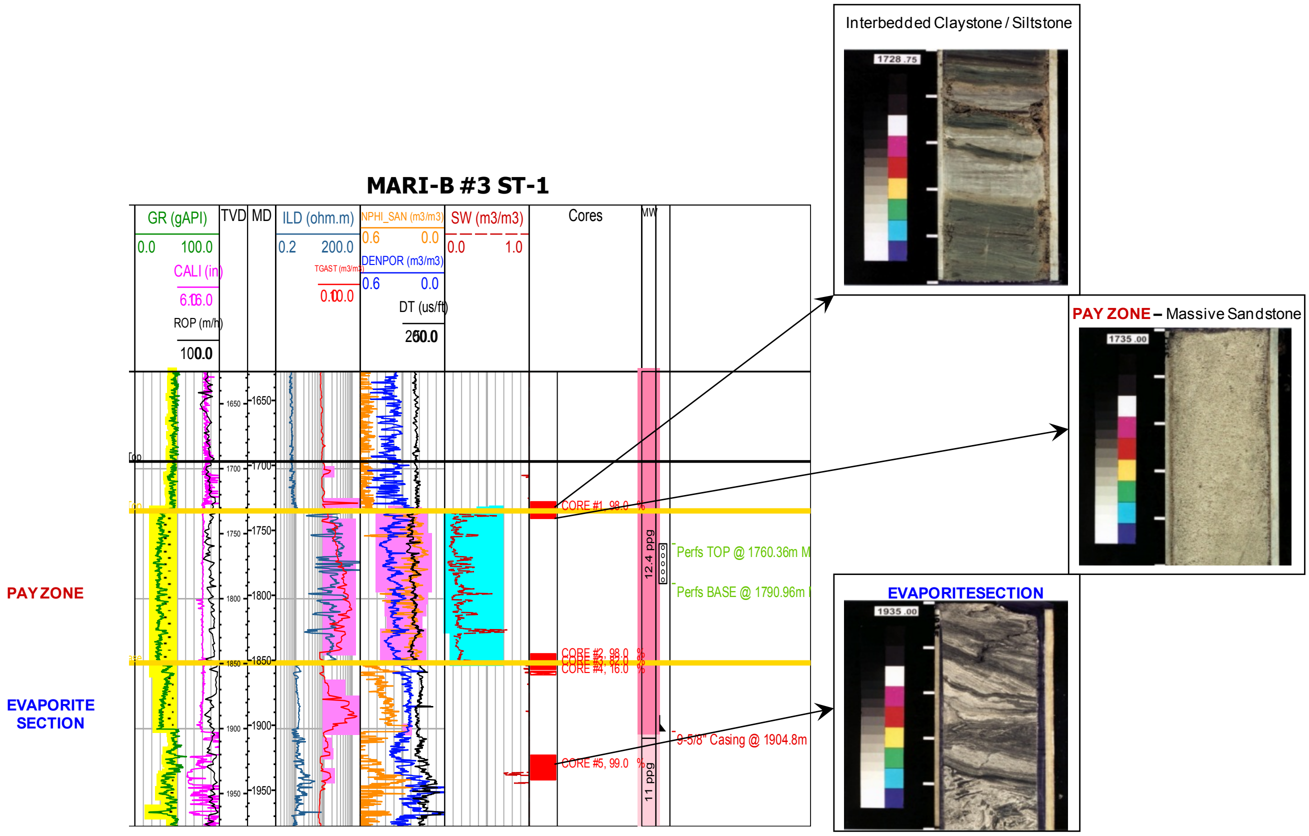


Figure 3 - Yafo Formation Open-Hole Log and Core Photos

Project Statement of Requirements

Problem Statement. Historical Mari-B production is presented in (Figure 4). Predicted decline (Figure 5) at Mari-B from existing ("Base") wells identified the need to develop additional gas deliverability to meet future peak gas sales and to fill the "gap" in 2011-2012 prior to the Tamar project start-up. The graph (Figure 5) demonstrated that the required future production profile could be met by two (2) big bore (9⅝ in. production tubing) gas wells.

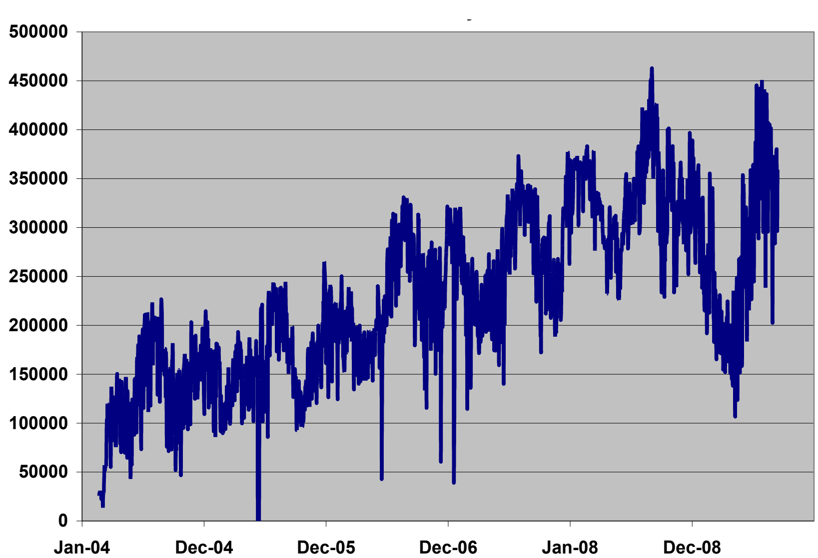


Figure 4 - Mari-B Historical Daily Production

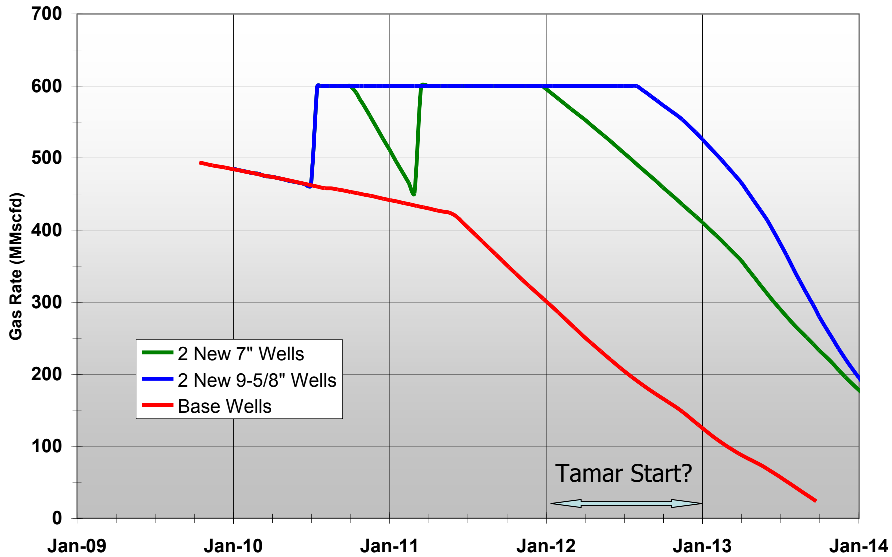


Figure 5 - Mari-B Well Deliverability Scenarios

Key Project Deliverable. Drill and complete two (2) wells each capable of safely and reliably producing gas at rates of up to 250 MMscf/D. Production from the first well must commence no later than June 1, 2010.

Completion Guiding Principles

A set of principles was developed to guide the completion design. These principles were largely based on learnings from other successful high-rate gas well developments.

Table 2 - Completion Guiding Principles

Priority	Description
1	Mari-B success – build on successful designs of past Mari B wells; in particular Mari-B #7 • Casing program • Wellhead system (use same supplier) • Sand face equipment (use same supplier)
2	Simplicity of design: • Operational excellence • Avoidance of major NPT events • Achieve well integrity and reliability
3	Field Proven Equipment • Select equipment with a track record in the field • Preference towards equipment qualified and deployed by Major Operators
4	Qualified Equipment • Interrogate Supplier's qualification and testing documentation • Endeavor to have all critical equipment qualified
5	Rigorous QA/QC Program (Critical Equipment) • Design Reviews • Manufacturing QA/QC Plans • Factory Acceptance Test and Stack-ups • Shop Inspection, Assembly, and Test QA/QC Plans • Third Party Witness
6	Bona Fide Contingency Plans & Equipment • Equipment and services field proven and/or qualified • Equipment, tools, services purchased and readily available • Detailed procedures written for implementation

Completion Delivery Process

The completion guiding principles were coupled to a completion delivery process which is comprised of four (4) sequential phases. Each phase identifies key tactics considered imperative to the successful delivery of the completion. This process diagram is useful for: identifying / prioritizing / assigning completion team responsibilities; supplier discussions; peer reviews and management reviews.

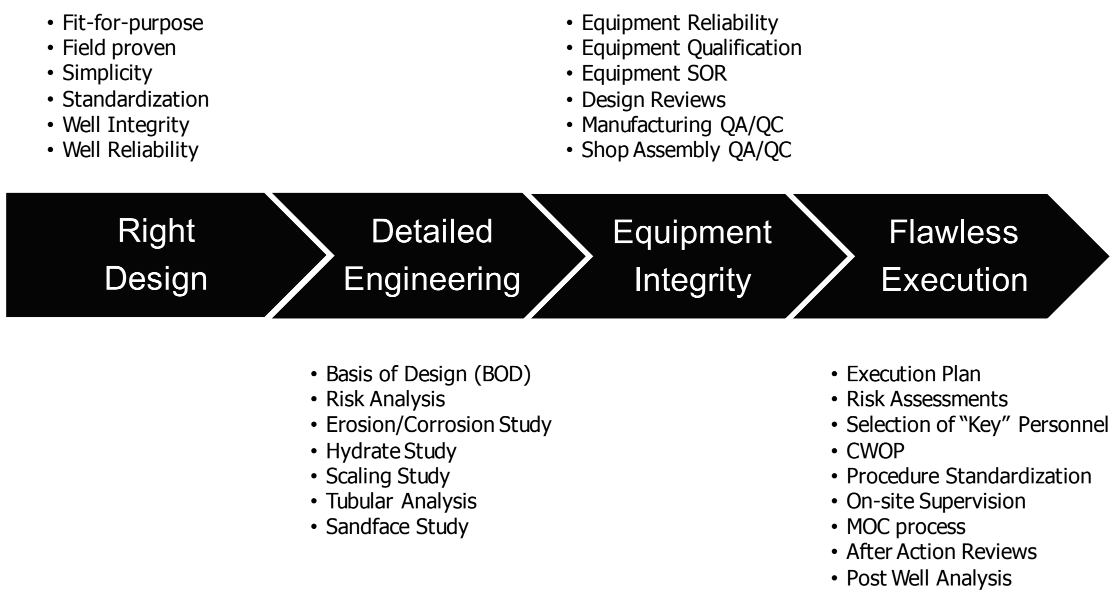


Figure 6 - Completion Delivery Process for "Critical" Wells

This paper will highlight and briefly expound on one or more of the key tactics accomplished within each of the phases (Table 3).

Table 3 – Highlighted Key Tactics of the Completion Delivery Process

Right Design	Detailed Engineering	Equipment Integrity	Flawless Execution
• Big Bore Feasibility Study	• NODAL* Analysis • Flow Assurance – Erosion & Corrosion	Equipment Qualification: • BPV • Liner Packer & Seals • RDIF	• On-site Supervision • Post Well Analysis

Right Design

Big Bore Feasibility Study. Prior to sanctioning the big bore completions, a study was commissioned to ensure technical feasibility. The scope of the study was to assess the technical feasibility of a big bore (9⅝ in. production tubing) completion design concept for new drills on the Mari-B platform. The primary scope of the feasibility study was to undertake preliminary engineering reviews to ensure that no "show stoppers" existed for the proposed design concept.

The author previously investigated big bore (9⅝ in. production tubing) concepts for BP Trinidad & Tobago (BPTT) during the appraise phase (CVP process) of the Cannonball development.[1] Ultimately, the big bore design concept was not selected for Cannonball for a myriad of reasons.

A summary of the study is as follows:

The feasibility study included a global review[2,3,4,5,6,7,8,9,10,11,12,13] of ultra high-rate gas wells which included nine (9) areas and over 130 wells (Figure 7). The completion designs reviewed included the conventional "big bore" (9⅝ in. production tubing) design, a variable bore (9⅝ in. x 7 in. production tubing) design as well conventional designs with 7 in or 7⅝ in. production tubing.

The description of each completion type is as follows:

Conventional Big Bore Design. A conventional design is production tubing installed inside of production casing; in this particular case, 9⅝ in. production tubing is installed inside of 13⅜ in. production casing. A significant feature of this design is the utilization of fit-for-purpose 9⅝ in. completion equipment; namely the Christmas tree and downhole safety valve (SCSSV). This design concept has been utilized by ExxonMobil in development of the giant North Field, offshore Qatar.

Variable Big Bore Design. The typical design difference of the variable design is the utilization of either a 6⅜ in. or 7 in. bore tree and 7 in. completion accessories (e.g., SCSSV, nipple profiles, downhole gauge). This concept has been utilized on a number of high-rate gas developments; namely: Woodside's Perseus wells; Conoco-Phillips Bayu-Undan project, and Shell's Ormen Lange.

In the case of the Perseus wells, qualified 9⅝ in. completion equipment did not exist at that time, and due to space constraints, 9 in. trees would not fit in the well bay area.

In the case of Bayu-Undan, all the 7 in. completion had already been purchased after which the design was changed to 9⅝ in. tubing to meet deliverability requirements.

In the case of the Ormen Lange, the development is subsea and the largest subsea tree was 7 in. (nominal bore).

Design Concepts. Various design concepts were assessed for: well performance modeling (deliverability); flow assurance (erosion), as well as design assurance (qualified and field proven equipment). The concepts assessed are illustrated in Figure 8. For each of these concepts, all hole sections and casing sizes would remain essentially unchanged from the existing Mari-B #7 well design. The maximum production rates were determined using NODAL* analysis and are listed on Figure 8. The rates presented are the estimated rate at the time of Tamar start-up (January 1, 2012) and assume a reservoir pressure of 1500 psi and a flowing wellhead pressure of 870 psi.

Selected Design Concept. Following multiple technical and management reviews, the "Right Design" was the conventional (Concept D in Figure 8) design: Conventional Big Bore Design with a 9⅝ in SCSSV and a 9 in. bore Christmas tree.

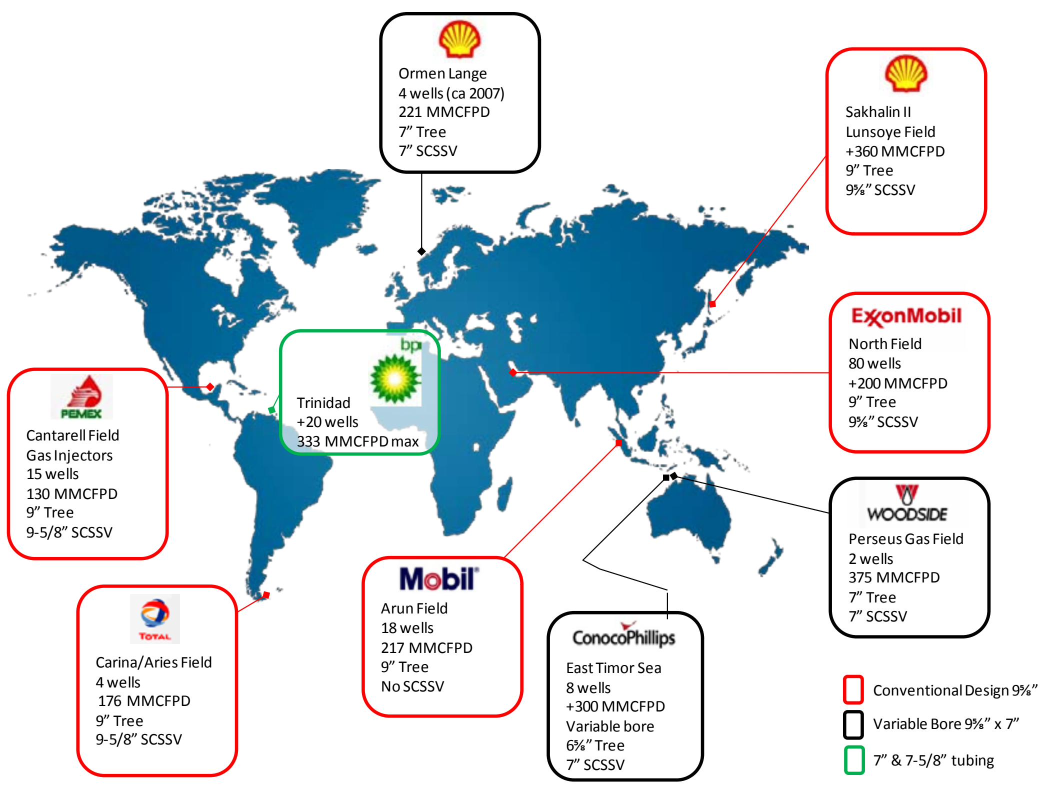


Figure 7 – Global View of Ultra High-Rate Gas Wells

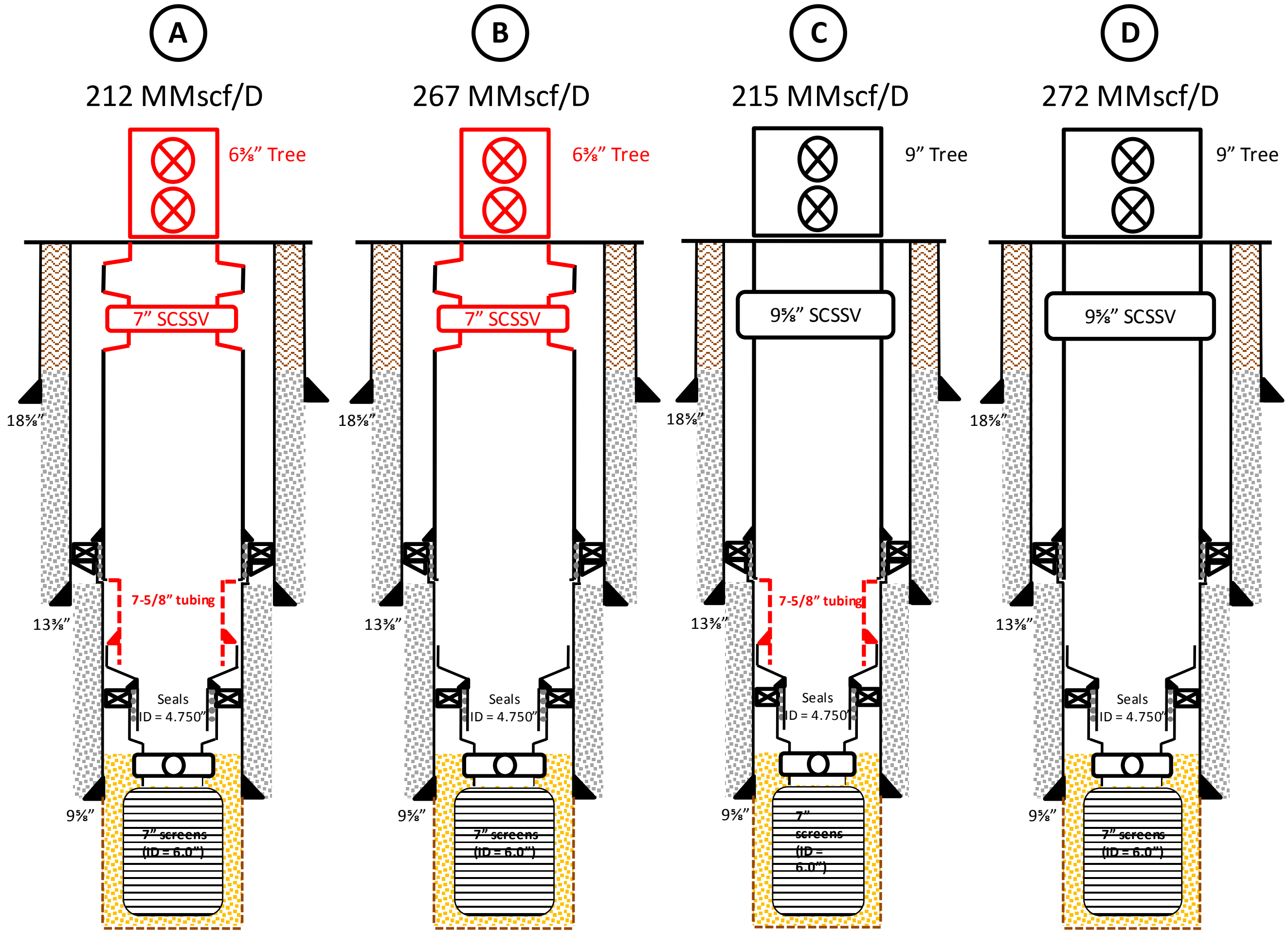


Figure 8 - Big Bore (9⅝" Production Tubing) Completion Concepts (24 in. casing not depicted)

Detailed Engineering

The next phase in the completion delivery process is Detailed Engineering. This is probably the most important phase of the completion delivery process. Without the Detailed Engineering, it is very difficult to execute the Right Design. Detailed Engineering is where the project engineers, equipment Subject Matter Experts (SMEs) and the Supplier's technical experts make a difference. Three (3) examples of the key tactics accomplished in this phase are as follows:

- Completion Basis of Design (BOD)
- NODAL* Analysis
- Flow Assurance

Completion Basis of Design (BOD): A summary of the key completion design parameters are presented in Table 4.

Completion Key Design Parameters. The key design parameters for the new wells were identified as:

- Well design capable of both production and injection service.
- Well design life of ±3 years as high rate producer, ±25 years as swing injector / producer.
- Sand control is required.
- Solids production (continuous basis) must be negligible (< 0.1 lbs/MMscf) and particle size must be < 50 µm.
- Well design must be erosion and corrosion tolerant (given typical erosion assumptions).
- Real-time downhole surveillance is desirable but not business critical.
- Reservoir abandonment pressure of 1200 psi should be used; this pressure is assumed for optimal injection and to avoid fault activation.

Table 4 - 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	bbls/MMscf		0.017	
Produced Water	bbls/MMscf		0	
Water of Condensation	bbls/MMscf		0.2	
Gas Gravity			0.557	
CO2	Mol %		0.095	
H2S	Mol %		0.0	
N2	Mol %		0.1	

Based on the feasibility studies several operational completion design parameters were also identified. They included the following:

- The 9⅝ in. casing to be set 5± meters inside the reservoir section.
- The reservoir interval must be under-reamed to 12¼ in.
- The reservoir interval must be vertical to low angle ($\leq 20^o$).
- Only 50$\pm$ meters (150 ft) of reservoir interval will be drilled / completed.

NODAL* Analysis. A well deliverability analysis was performed for the various design options. A commercially available NODAL analysis program was used to evaluate the various design options for various cases (Table 5). The well deliverability for each design concept is presented in Table 6; the various cases represent different cases in the life of the project. The maximum rate, at well start-up, is 340 MMscf/D from the conventional big bore well; the rate for this well design drops to 275 MMscf/D (Δ = 65 MMscf/D) if a 7⅝ in. stinger is required (to avoid flow-thru-casing). The rate difference between the conventional and variable is small (≈10 MMscf/D); however, the gas velocities are extremely high for the variable bore which will likely result in unacceptable erosion rates.

Table 5 – Case Descriptions for NODAL* Analysis

Case	Description
1	Maximum rate at initial well start-up (April-May 2010).
2	Maximum rate at compression start-up.
3	Maximum rate at Tamar start-up (Jan. 1, 2012)
4	Maximum rate at minimum reservoir pressure (1200 psi) for gas storage.

Table 6 - Deliverability Rates for Design Concepts

			Gas Rate (MMscf/D)			
Case	Reservoir Pressure (psi)	Flowing WHP (psi)	"A" Variable Big Bore 7⅝ Stinger	"B" Variable Big Bore Flow-thru-Csg	"C" Conventional Big Bore 7⅝ Stinger	"D" Conventional Big Bore Flow-thru-Csg
1	2100	1250	275	330	275	340
2	1900	870	285	340	290	350
3	1500	870	200	230	200	240
4	1200	870	110	140	120	145

Flow Assurance – Erosion, Corrosion, Sanding, Scale & Liquid Loading. Flow assurance is a very broad subject and requires very detailed engineering. Two examples of detailed engineering for erosion and corrosion types of flow assurance are discussed briefly below. A future paper is planned to provide a more in-depth review of the flow assurance work.

Flow Assurance – Erosion. The erosion potential of ultra high-rate gas wells is a critical concern and the rigorous approach to assessing this risk has been previously reported by the Author.[13] The scope of the erosion study was to report the erosion rate predictions and document the inputs, assumptions, methodology, conclusions and recommendations for the proposed Mari-B big bore well concepts; namely the "Conventional" Big Bore and the "Variable" Big Bore. This study did not cover the choke or the piping downstream of the choke. The traditional industry approach of calculating erosion rates using API 14E and various C constants was not utilized. Instead, a detailed erosion study including Computational Fluid Dynamics (CFD) modeling was undertaken to accurately determine the maximum safe production rates and to identify equipment modifications that may be necessary to reduce excessive erosion over the life cycle of the well.

The program used to calculate sand erosion rates was the Sand Production Pipe Saver (SPPS). This program was developed by the University of Tulsa's Erosion / Corrosion Research Center (E/CRC). The SPPS computer program predicts erosion rates in wells that produce sand, and includes the effects of both the carrier fluid and sand. This computer program calculates sand erosion rates in several pipe geometries such as elbows and tees for sand producing wells. SPPS is also able to predict erosion for cases of direct impingement. The software is capable of computing penetration rates as well as threshold velocities. SPPS has also been extended to predict penetration rates in straight pipes, contractions, and sudden expansions. Noble Energy joined the Tulsa E/CRC Consortium in July 2009 thereby obtaining access to the SPPS program.

The key results are discussed as follows. The erosion rates at the three (3) identified hotspots (Christmas tree, SCSSV and FLCV) are presented for one (1) rate case in Figure 9. The red font indicates erosion rates that exceed an erosion limit of 0.1 mm/year. From an erosion perspective, the "Conventional" design is highly preferred. However, in all cases the erosion rates at the FLCV exceeded the erosion limit. All erosion rates presented herein were calculated based on an assumption of continuous sand production (concentration = 0.1 lbs/MMscf) of 50 micron sand particles (semi-rounded). The erosion calculations were critical in determining the right design for the proposed completion. Based on these results the "Conventional Big Bore Design" is the best completion option.

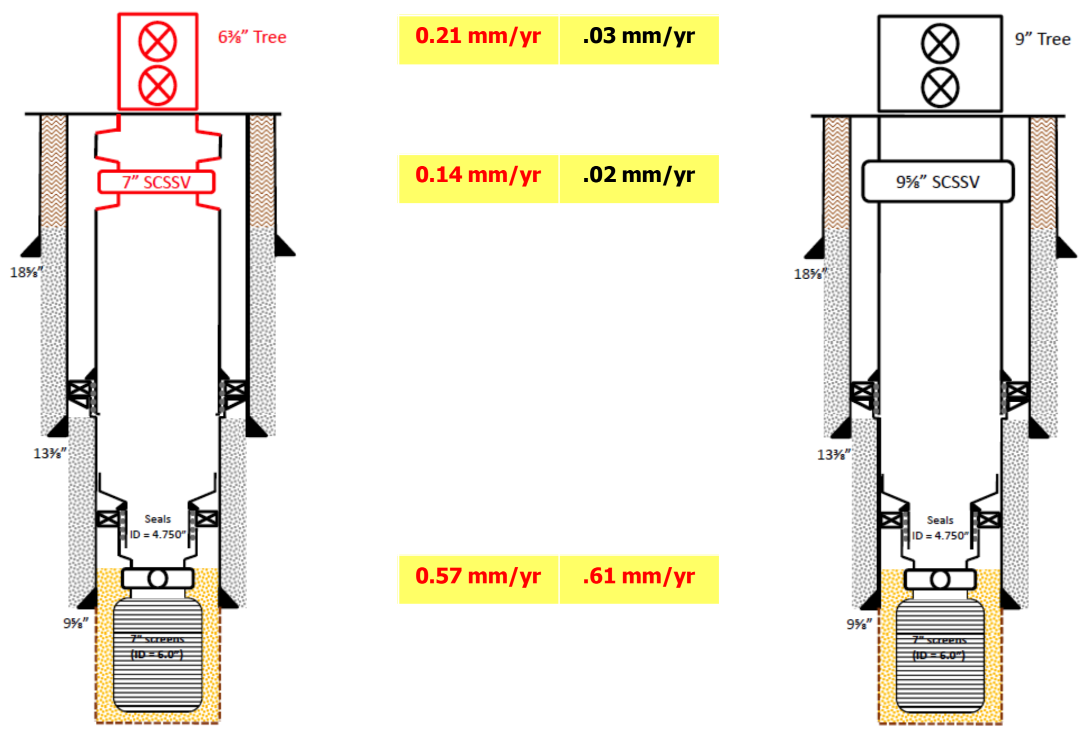


Figure 9 – Erosion Rates at 200 MMscf/D

Flow Assurance – Corrosion. The scope of the corrosion study was to evaluate the corrosion rate predictions for production as well as injection service, and document the inputs, assumptions, methodology, conclusions and recommendations for the proposed Mari-B big bore (9⅝ in.) well concepts. A significant design consideration of any ultra high-rate gas well (+200 MMscf/D) is the risk of synergistic erosion-corrosion. In corrosive environments, erosion limits (typically 0.1 mm/yr) must be strictly applied otherwise there is a risk of synergistic erosion-corrosion (which can exceed the predicted uniform corrosion rates). The analyses herein are focused on both production and injection service. The Mari B new drills contemplate both production and injection service. At the time of the study, it was envisaged that Tamar gas would be inejcted into the Mari-B reservoir for gas storage purposes. A 25 year service life was considered and the base case tubular design premise was low alloy carbon steel (L-80) OCTG.

Production Service. Based on the recommendation of several corrosion experts, the Gas Well Corrosion (GWC) model by University of Louisiana at Lafayette (ULL) was considered. The GWC model was developed at the Corrosion Research Center at ULL. The latest version is referred to as 5V3S. This version was introduced in 1999. The Corrosion Research Center provides an opportunity for a company not in the ULL Corrosion Model Consortium to model a gas-condensate well at a nominal cost. The GWC model is used to develop a technical report which provides a complete physical description of the well and the predicted tubing life. The rate scenarios evaluated were the same as those used in the erosion study. For the corrosion study, the GWC model only examined two (2) scenarios. The summarized pitting corrosion rates from the GWC model are listed in Table 7.

Table 7 - Pitting Corrosion Rates

Production Case	"Pitting" Corrosion Rate (MPY)	"Pitting" Corrosion Rate (mm/yr)	Tubing Life* (years)
200 MMcfd	18.2	0.462	+30
266 MMcfd	54.7	1.389	10
*Tubing Life is defined as full penetration of the tubing wall.			

The combination of CO_2, low condensate rates and extremely high gas velocities resulted in corrosion rates for L-80 tubing that could potentially compromise well integrity (due to wall loss from uniform corrosion) over the required design life (25 years). The recommendation was made to use 13 Chrome tubing. The incremental cost was USD $1.3 million.

Equipment Integrity

The next phase in the completion delivery process is Equipment Integrity. The importance of this process is simple, but not necessarily easy. Even if the Right Design is selected and the Detailed Engineering is rigorous; unqualified or improper equipment can lead to flawed execution and / or equipment failure. As experienced Industry veterans move-up and out of operations or retire, new but inexperienced talent comes into the Industry. Thus, it is imperative that constant supervision and verification is on-site (in the shops and field bases) during the inspection, assembly and test of critical equipment and assemblies to ensure that procedures, processes and policies are rigorously followed. The quote often cited during this phase is "Trust but Verify."

Since reliability is one of the primary design parameters for these completions, validating equipment design and functionality play a very critical role. Three (3) examples of this validation process are detailed below.

- Equipment Qualification: BPV
- Equipment Qualification: Liner Hanger / Packer & Production Seals
- Equipment Qualification: RDIF

Equipment Qualification - Back Pressure Valve (BPV). Considerable engineering effort, which is beyond the scope of this paper, was dedicated to the design, selection and qualification of the BPV system. The final decision was made to equip the tubing hanger with a BPV profile, and procure the necessary BPV equipment for use during the initial completion and / or for future workover operations. The industry has traditionally utilized the Type 'H' back pressure valve equipped with a two-way check. The largest size of this equipment type was not determined; however, it is believed to be available in sizes up to 6 in. For big bore wells, the Industry has adopted the use of a wireline set BPV which utilizes conventional wireline equipment (lock mandrels and landing nipples) or other specialized equipment. Following technical reviews, it was determined that the SRP BPV plug was a qualified system that had a demonstrated run history for 9 in. trees and offered the best dimensional fit for the Mari-B wells. The Christmas tree supplier had an existing tubing hanger design that accomdated the selected BPV. For technical due diligence a stack-up test (Figure 10 and Figure 11) was conducted to ensure fit, form and function.

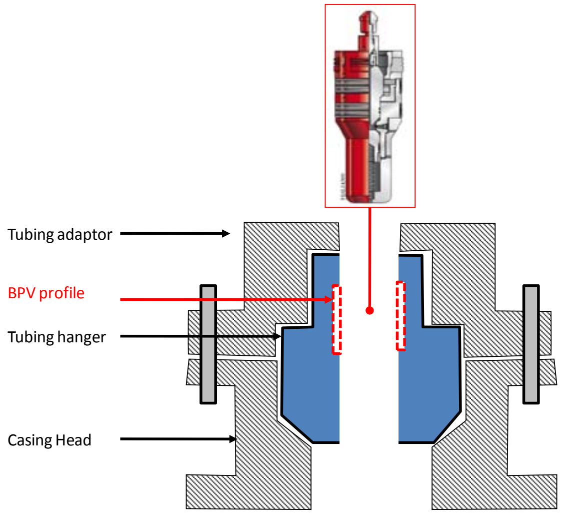


Figure 10 – Stack-up Sketch of Tubing Hanger and BPV

Figure 11 – Stack-up Test of Tubing Hanger and BPV

Equipment Qualification - Liner Hanger Packer & Seals. In the case this of this well design, the liner hanger packer was considered a production packer in terms of service criticality. The Equipment Statement of Reqiurements (ESOR) identified the requirement for the liner hanger / packer to be qualified to ISO 14310 Validation Grade V0 and have an extensive, field-proven run history. Two suppliers offered designs that met this requirement. Once the supplier was selected, the majority of the technical assurance process was focused on qualification of the production seals (Figure 12) to ensure reliability for the long design life given both production and injection service. The testing protocol required a temperature range (thermal cycle) from ambient (≈70^{o}F) to 150^{o}F with a pressure differentials of 100 to 1500 psi. The acceptance criteria were defined as "bubble tight" also commonly referred to as "V0". Testing identified the need to change one of the materials in the seal stack. Once changed, the material stack passed all of the testing protocol.

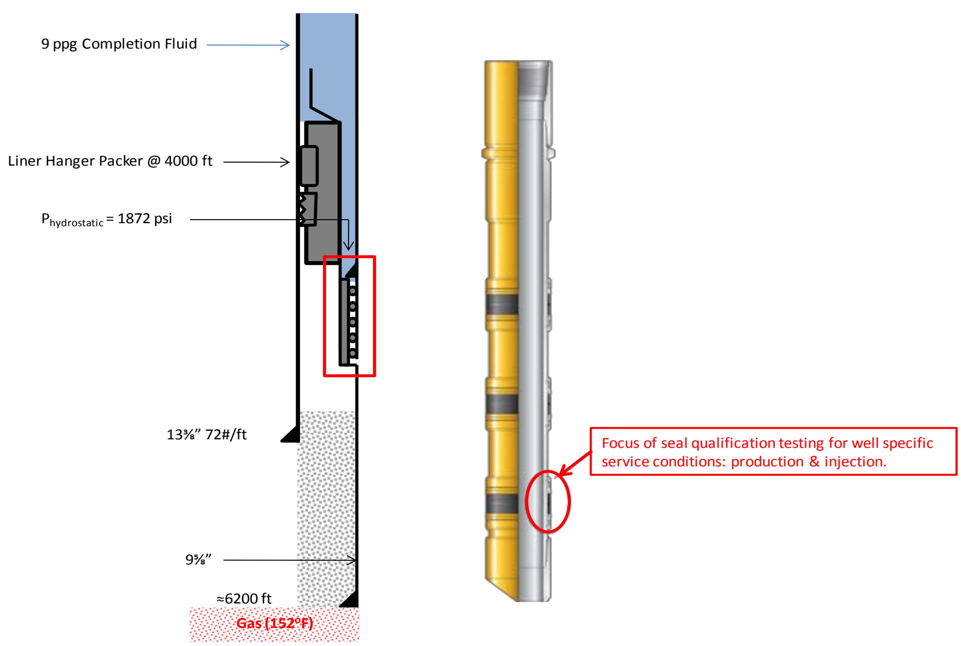


Figure 12 – Liner Hanger / Packer and Production Seal Configuration

Reservoir Drill-in Fluid (RDIF). At the time of the Mari-B #7 OHGP the reservoir pressure was ≈2980 psi; however, at the time of this design, the reservoir pressure had declined to 6.8 ppge. Thus, the lightest weight RDIF based on a KCl formulation was specified and a final RDIF density of 9.0 ppg or less was targeted so as to minimize losses (a potential source of formation damage) to the formation during the drilling and completion phase. A test matrix was developed to assess relative rheology, fluid loss and the ability to degrade and dissolve filtercakes formed from selected RDIF systems; a total of seven systems were evaluated.

The key objectives of the RDIF were:

- Maintain good fluid loss
- Potential to eliminate the use of acid as a post completion breaker system
- Use of KCl as a primary inhibitor for any reactive shale
- Provide a delay for the use of any recommended breaker system of not less than four (4) hours and no more than four (4) days

The RDIF system that was selected was a water-based RDIF system that uses hydroxypropylated starch and xanthan for fluid loss control and viscosity respectively. Sized calcium carbonate ($CaCO_3$) is the primary bridging agent for fluid loss control. A breaker system for filtercake removal is utilized prior to placing the well on production. Figure 13 illustrates the results of the two (2) primary breaker systems. The two primary breaker systems evaluated were as follows:

- Acid based (15% HCl + 5% Acetic, pH <1)
- Chelant (for dissolving carbonate) plus amylase (for digesting starch).

The percent return-to-flow for the acid breaker was 43% (24 hours of soak time at 155°F) and for the chelant breaker 94% (5 days of soak time at 155°F).

Selected RDIF and Breaker System. Based on the chelant flow back results and a strong design bias to avoid acid breakers; the chelant was selected as the breaker.

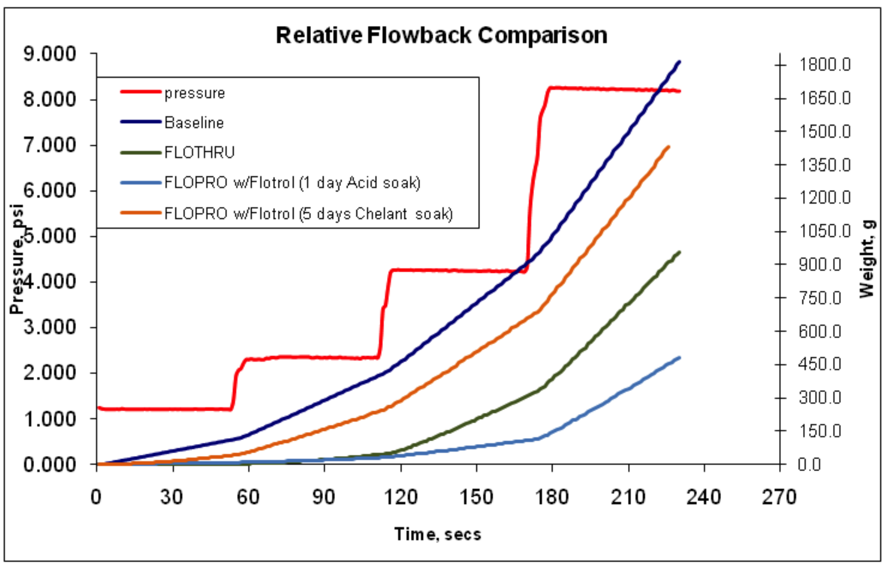


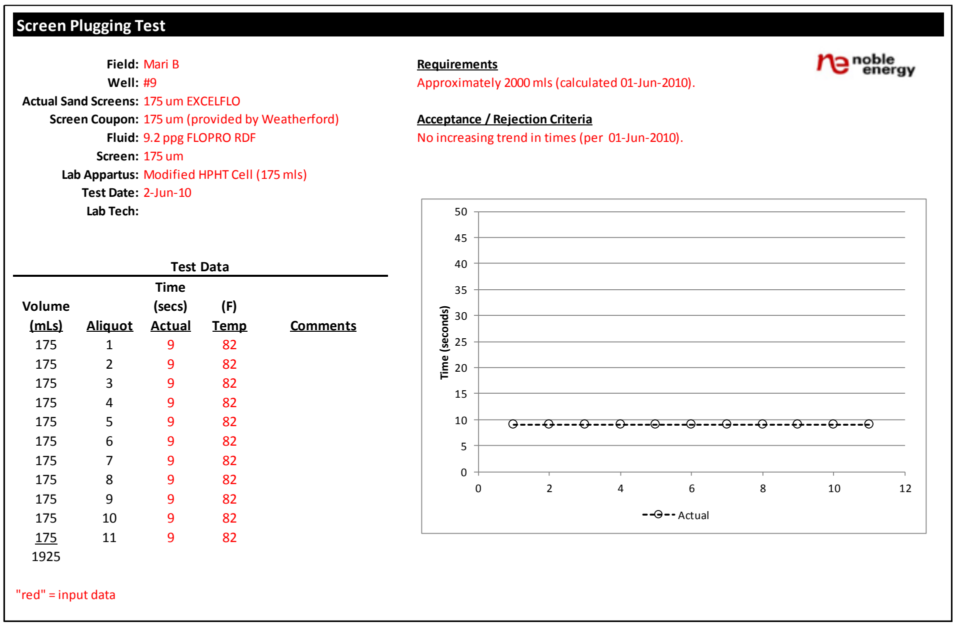
Figure 13 – RDIF Breaker Flowback Comparison

Flawless 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 well site 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 witness by Company well site supervisors. QA/QC procedures and plans were not only developed for tangible and rental items, but also for the completion fluids. Figure 14 is an example of a Fluid QA/QC inspection sheet that was utilized to ensure that the solids free RDIF pill ("clean pill"), which is spotted in the open hole prior to gravel packing, met the acceptance criteria specified by the Authors. 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 catstrophic failure. The screen plugging test of the clean pill was witnessed by the Company well site supervisor. The test results are documented on the inspection sheet (verifying document) and is signed-off by the Company well site supervisor.



Screen Plugging Test

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 14 – Solids Free RDIF 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. Even the simplest things can jeopardize the execution.

On the first gravel packing operation, the [gravel pack] slurry return 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 (4) other methods / contingencies were planned to assist in the 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 lbs of proppant pumped; however, only 10,000 lbs 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 bbls) as well as the possibility of uncontrolled losses after the job due to the depleted reservoir pressure and the need to have completion fliud 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 cross-over 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 lbs of overpull to get free. The re-stress and ensuing post-gravel pack breaker treatment were eliminated due to tool issues.

Ultimately, the lack of communication could have caused a severe NPT event. A contingency clean-out run was performed.

This risk (sticky cross-over 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 cross-over tool.

Mari-B #9 did not pump a post acid stimulation. However, the productivity results validated our breaker plans 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, RD)
- 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 (3) ways: Non-Radioactive Densitometer (NRD); Radioactive Densitometer (RD); 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 would be considered a “text book” 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 15) was selected and installed on the Mari-B platform. There was limited space for various completion equipment which made for a very challenging operation.

Figure 15 – Platform Workover / Drilling Rig on Mari-B Platform

Completion Phases. The completion operations were broken down into sequential phases (Table 8) to drive focus with regard to the detailed pre-job planning, detailed procedures and contingency plans.

Table 8 – Completion Operational Phases

Phase	Operation
1	Wellbore Clean-out
2	Displacement from WBM to Seawater to RDIF
3	Drill Reservoir Section
4	Under-ream Reservoir Section
5	Displace from RDIF to SF-RDIF 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 16) 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 9.

Table 9 - Completion Time Analysis

Well	Total Actual (hours)	Total NPT (hours)	Scope Change NPT (hours)	Rig NPT (hours)	Normalized NPT (hours)	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. The scope change NPT for both wells, was the down time associated with platform shut-in requirements for ND BOPs / NU Tree operations. As described in the Introduction section, the Mari-B platform provides over 40% of the natural gas required for Israel demand. During these operations, a total platform shut-down was required. Noble management made the decision (to meet gas demand) at certain times, to shut down rig operations until gas demand warranted this operation. In some instances, only 4-6 hour windows were allowed per week to perform this 16-24 hour operation. Figure 17 is a picture of the 9 in. tree; this image re-enforces the time required for the installation operation.

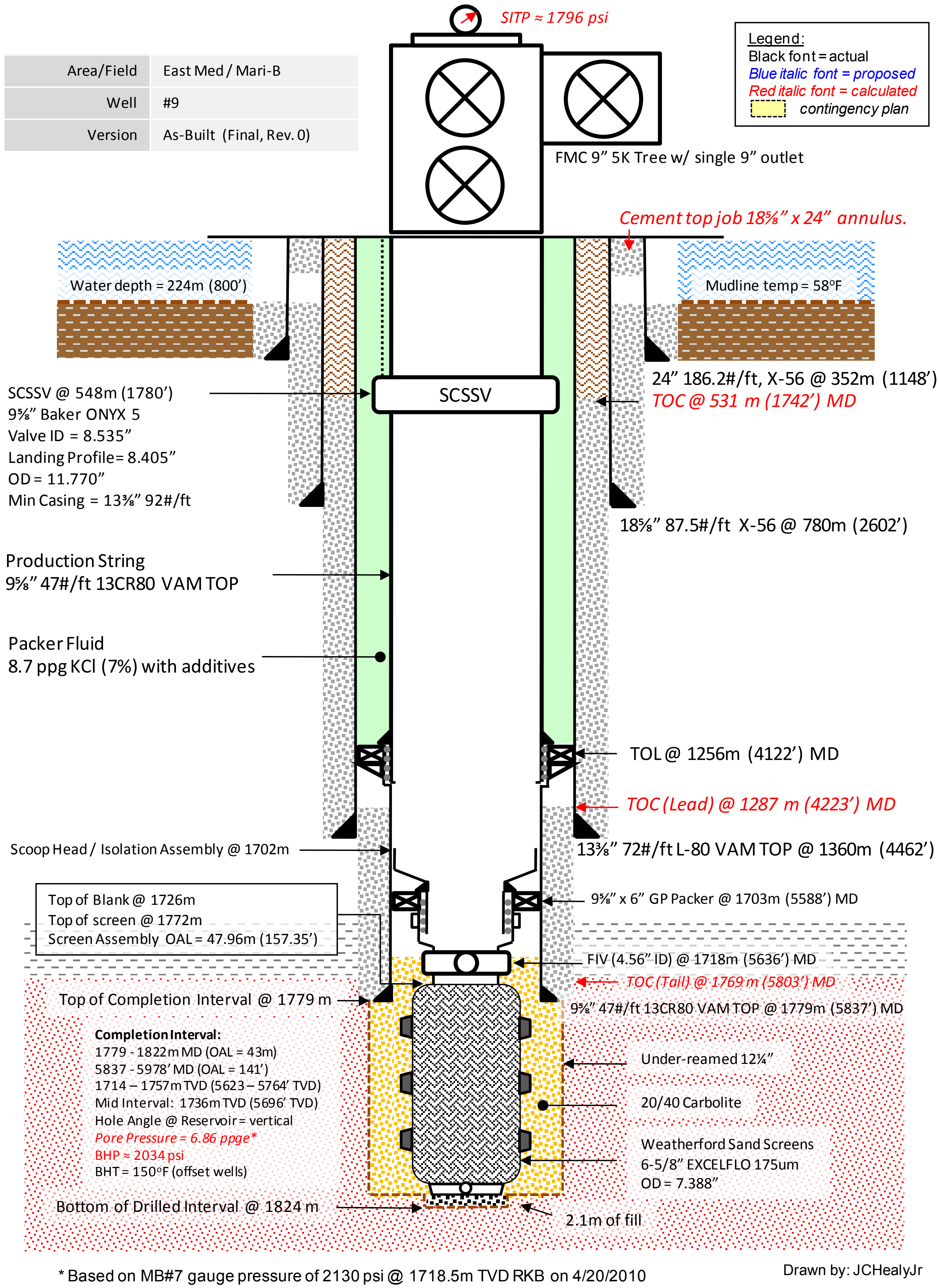


Figure 16 - Mari-B #9 As-Built Completion Schematic

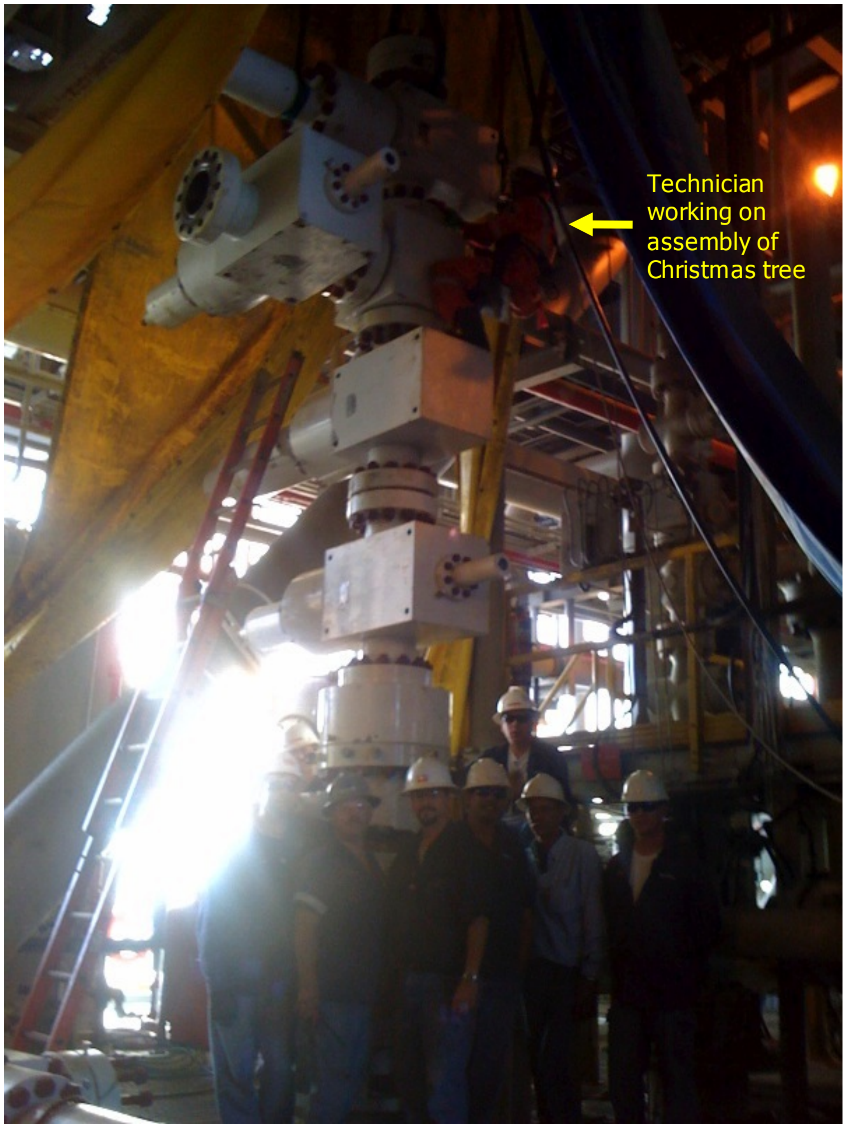


Figure 17 – Assembling the Mari-B Christmas Tree (9 in. 5,000 psi)

Well Performance

General. 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 (9) 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 (9) 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 (2) 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* 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 (5) 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 sand face 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 18 shows the improvement of the sandface Productivity Index (PI) in $MMscfd/psi^2$.

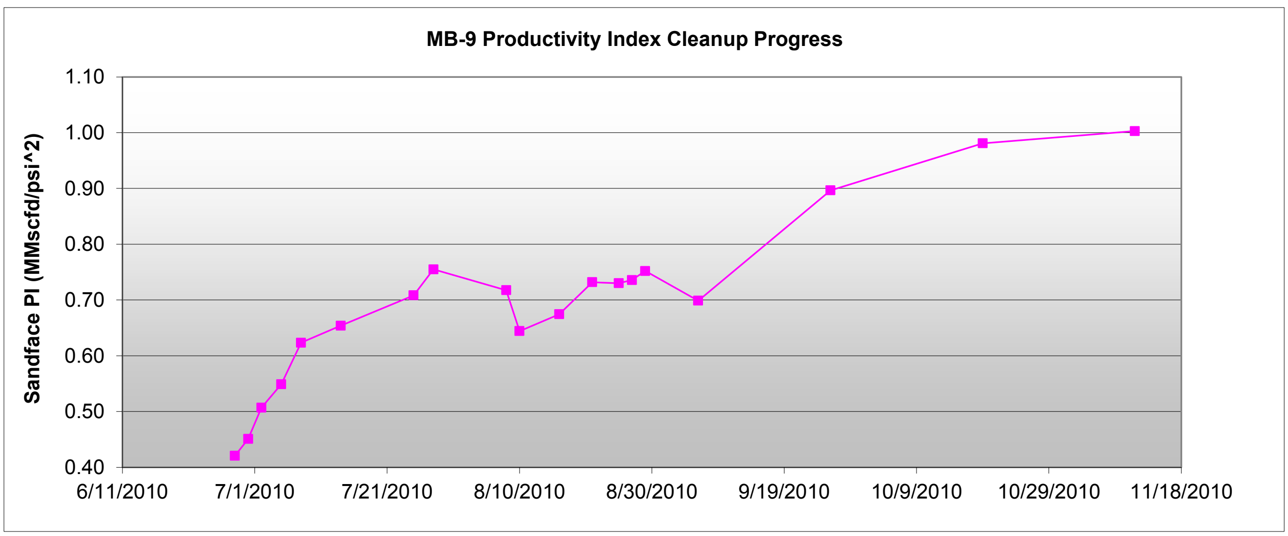


Figure 18 - Mari-B #9 Improvement to Productivity Index vs. Time

While the mechanism of improvement to well performance will never be known it is believed that calcium carbonate ($CaCO_3$) in the RDIF 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 open hole 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 clean up, the Mari-B #9 and #10 have continued to perform extremely well. As the reservoir pressure has declined to 4.8 ppge, the non-darcy coefficient for turbulent skin has increased, but not as much as expected compared to the performance of the older frac-packed wells. Table 10 shows the well performance of the Mari-B #9 and #10.

Table 10 – 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 19) below show the daily production and flowing tubing pressure for the wells since start-up.

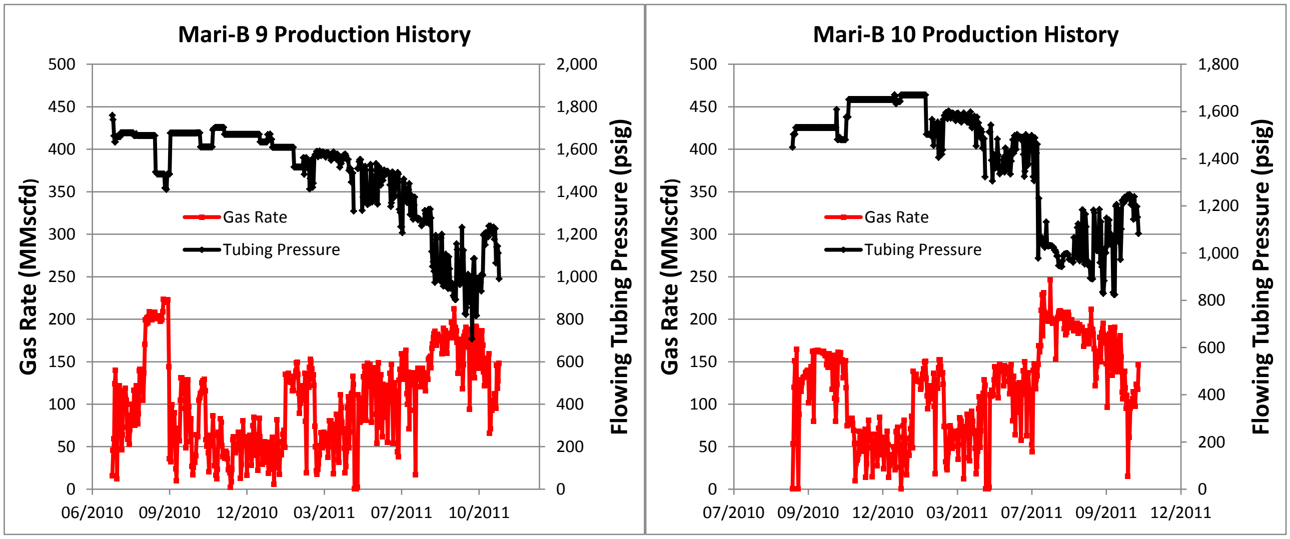


Figure 19 – Daily Production Plots for Mari-B #9 and #10

Conclusions

The fast-track delivery of two (2) 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 successful execution, rate delivery and well reliability.

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Nomenclature

AFE = Authorization for Expenditure
BPV = Back Pressure Valve
bpTT = BP Trinidad and Tobago LLC
CFD = Computation Fluid Dynamics
CGR = Condensate Gas Ratio
CVP = Captial Value Process
FLCV = Fluid Loss Control Valve
LPSA = Laser Particle Size Analysis
NPT = Non Productive Time
mpy = mils (thousandths of an inch) per year penetration
ppge = pounds per gallon equivalent
RDIF = Reservoir Drill-in Fliud
SCSSV = Surface Controlled Subsurface Safety Valve

* NODAL analysis is a mark of Schlumberger

Conversion Factors and Units

1 mm/yr = 39.4 mpy

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