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Completion Design, Installation, and Performance - Cannonball Field, Offshore Trinidad

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Abstract
The Cannonball field is a one Tcf gas condensate development offshore Trinidad producing at an initial rate in excess of 800 MMcf/D from three wells. The completion design selected was 7⅝ inch production tubing with an open-hole gravel pack (OHGP). The initial well (CAN01) has produced at an initial rate of 320 MMcf/D. The calculated deliverability of this well is 415 MMcf/D. This paper discusses the completion basis of design, detailed engineering assurance of the design, qualification of critical engineered equipment, and actual results.

Introduction
Trinidad's gas production has increased dramatically over the past 10 years. In 1996, local gas production exceeded oil production for the first time as the twin island Caribbean state of Trinidad and Tobago moved from a predominantly oil producing country to a major gas producer. The gas growth has been driven by an increase in local demand and construction of a liquefied natural gas (LNG) infrastructure which now includes four Trains. BP Trinidad and Tobago LLC's (bpTT) share of the gas supply to the local market has grown from less than 350 MMcf/D in 1994 to over 2 Bcf/D by mid-2007 with production coming predominantly from several prolific gas fields located off Trinidad's East Coast (**Fig. 1**).

The Cannonball field is located approximately 35 miles off the southeast coast of Trinidad in 240 ft of water (Fig. 1). The discovery well, Ironhorse-1 ST1, was drilled in 2002. In 2005, a minimal structure (nine slot four pile) production platform was installed and three development wells were drilled and completed with a jack-up cantilever drilling rig. Initial production commenced on March 12, 2006 following pipeline hook-up and commissioning. The Cannonball field was brought on production at a sustained rate in excess of 800 MMcf/D.

SPE 81045[1] published in 2003 and titled "Trinidad's First 500 MMcf/D well: Fact or Fiction?" discussed the Ironhorse discovery well and presented the engineering challenge of an ultra-bore completion (9⅝ inch production tubing). The right scoping process discussed in this paper present the various tubing sizes evaluated and articulates the decision to select 7⅝ inch production tubing.

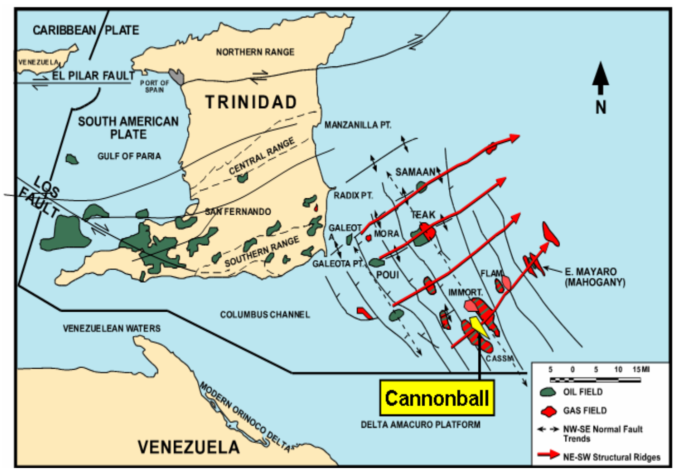

Figure 1 - Location Map of Cannonball Field

Geologic Overview
The Cannonball West gas field is located in the Columbus basin, 35-40 miles off the southeast coast of Trinidad in water depths of 240 feet. It is comprised of a single reservoir unit, the 33 (TP65) sand, situated at -12,334 ft TVDSS (**Fig. A-1**). The accumulation was discovered in 2002 by the exploration well, Ironhorse-1 ST1, which targeted the reservoir down dip in the Sparrow fault block delineated by bright seismic amplitudes (**Fig. 2**). The reservoir was over pressured at 6400 psi with a temperature of 220°F.

The gas is trapped by major extensional faults to the west and east and a stratigraphic updip seal to the southeast. The down-dip limit is a gas / water contact inferred from a seismic "flatspot" that conforms to structure to the northwest of the Ironhorse penetration at -13,000 ft TVDSS. This interpretation is supported by wireline log evidence from the Ironhorse well showing a gas-down-to of at least -12,622 ft TVDSS.

The 33 (TP65) sand reservoir is made up of a number of delta front shelf edge sandstones (Fig. A-2 and A-3), broadly seen as an upper blocky unit (upper shore face sedimentary facies) and a lower inter-bedded sand / shaley sand unit (inner shelf sedimentary facies). The reservoir has a net-to-gross (NTG) of 79%, an average porosity of 18.5% and an average permeability of 265 MD. These log derived properties correlate well to the properties derived from the core cut across part of the interval. High gas saturation (82%) was recorded throughout the gross interval.

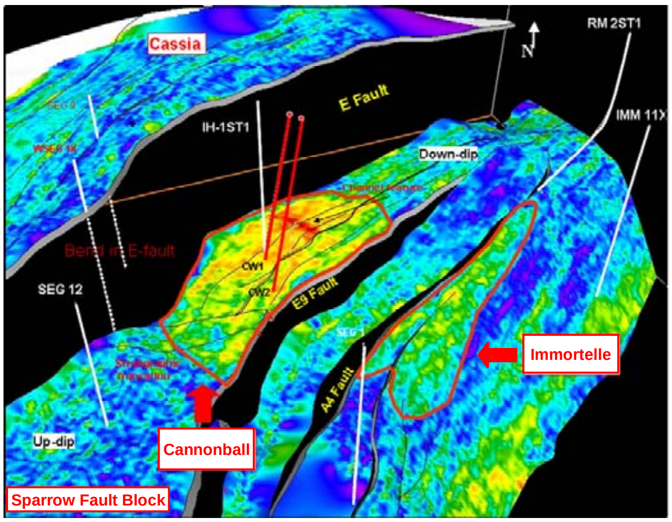

Figure 2 - Cannonball 3D Seismic Section

Project Statement of Requirements (SOR)

The Cannonball field was selected as the next gas field development following the development of the Kapok field.[2] The growing contractual gas demands presented by the LNG infrastructure including the addition of Train 4 (construction completed in October 2005) necessitated a significant gas field development in 4Q2005. The rate requirement for the Cannonball development was a plateau rate of 800 MMcf/D. The plan of development called for the fabrication and installation of an offshore 9-slot drilling platform and a 26" multi-phase pipeline linking it to the Cassia B central processing unit.

The selection of this development scheme is part of a gas infrastructure strategy developed by bpTT in 2002.[3] The strategy is akin to a hub-and-spoke system whereby minimal structure developments are plugged in to a central gathering system via multi-phase flow lines and production is processed at a central processing unit. The Cannonball platform design is a minimal structure (nine slot 4 pile jacket) without production equipment and is a normally unmanned installation (NUI). The Cannonball platform was the first platform to be completely constructed in Trinidad. The strategic objectives set for the wells team were:

- No accidents, no harm to people, and no damage to the environment.
- The access of the recoverable reserves with the minimum number of wells.
- The optimization of the well design to maximize the Net Present Value (NPV) of the assets.
- To ensure that bpTT's contractual gas requirements will be met.

Operating Philosophy. The operating philosophy of a NUI was selected for the Cannonball platform. As such, the wells were designed to require no down-hole interventions prior to final well abandonment. However, in the event of production problems, the platform design would accommodate wireline interventions. The surface production facilities were not designed to handle sand production. Water production was predicted to be limited to the water of condensation (2 bbl/MMcf). In the event of unexpected water production, the Cassia B facility is available for handling significant volumes.

The wells and the production facility were desgined to accommodate remote monitoring of well pressure, temperature, and multi-phase fluid flow rate testing whenever necessary. Flow lines were instrumented to remotely detect and trigger alarms at the onset of any sand production (well shut-in was programmed for a sand detection level of 0.1 lb/MMcf). Well annulus pressures are also remotely monitored and alarmed.

The platform was designed for minimal wireline activities such as running pressure / temperature gauges (in the event of a failure of the permanently installed pressure / temperature quartz gauges) and production logs. Many of the other remote monitoring systems were designed with built-in redundancies to help insure maximum uptime. In the event of an unscheduled shutdown of production, the facilities were designed to allow the remote start-up of the wells. Operations staff would only visit the platform to investigate alarms, operational problems associated with the facility and routine maintenance reasons.

Project Boundary Conditions. The following boundaries were established as the basis for the wells design.

- High Rate and High Reliability Wells.
  - Gas Rate $\geq$ 270 MMcf/D.
  - No unplanned downtime.
  - Wireline interventions only.
- Zero Solids Production.
- Downhole Surveillance.
  - Permanent Downhole Pressure / Temperature Gauge
- Compression Capable.
  - Abandonment pressure as low as 1035 psi.

Well Design

The key requirement for the wells team was to deliver (on schedule) a highly reliable completion that would deliver 280 MMcf/D without any risk of sand production in order to achieve the required plateau rate of 800 MMcf/D (**Fig. 3**). Given the key project requirement to reduce well count and maximize production rate, the wells team decided early on that Cannonball would be designed around the optimal completion. A right scoping process was used to methodically evaluate various well designs to facilitate selection of the design that would best meet the project objectives.

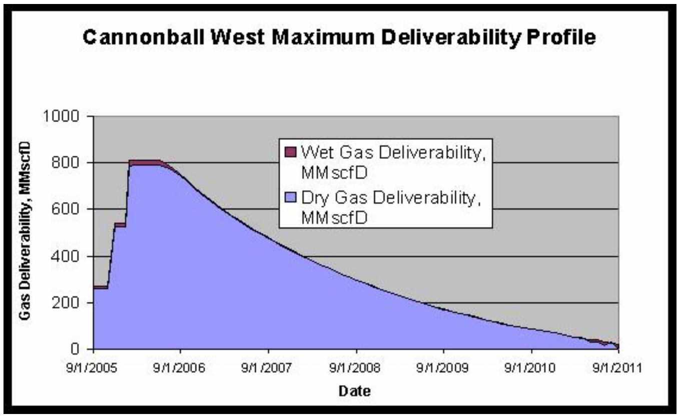

Figure 3 – Cannonball Required Deliverability Profile

NODAL* Analysis. The key parameters for the completion design are summarized in **Tables 1** and **2**. These parameters were used to construct inflow performance relationships based on an open-hole gravel model which was used to evaluate the deliverability of various tubing sizes including 7 inch, 7⅝ inch, and 9⅝ inch (**Fig. 4**). This analysis demonstrated the extraordinary deliverability of a Cannonball well which was 300, 390, and 600 MMcf/D for 7 inch, 7⅝ inch, and 9⅝ inch tubing, respectively.

Parameter	Value	Source
Reservoir	Gas Condensate	Logs/Offset fields
Gas-in-Place	±1 Tcf	Estimated
Drive Mechanism	Volumetric	Seismic / Geology
Total Deliverability	800 MMcf/D	Project SOR
CGR – initial	25 bbl/MMcf	Offset fields
CGR – final	12 bbl/MMcf	Offset fields
Produced Water	None	Volumetric drive
Condensed Water	2 bbl/MMcf	Offset fields
BHP initial	6,450 psi	Iron Horse MDT
BHP abandonment	1035 psi	Simulation
Flowing BHP @ abandonment	611 psi	Simulation
BHT	220^{o}F	Ironhorse MDT
Permeability$_{eff}$	165 md	PBU vs. Core Plot
Gas Gravity	0.6137	Offset fields
SITP	5,122 psi	Calculated

Table 1 – Key Completion Design Parameters (Expected Case)

Constituent	Value	Source
C1	93.2 Mole %	Offset fields
C2	3.53 Mole %	Offset fields
C3	1.32 Mole %	Offset fields
IC4	0.29 Mole %	Offset fields
NC4	0.36 Mole %	Offset fields
C5+	0.82 Mole %	Offset fields
CO_2	0.43 Mole %	Offset fields
H_2S	0 ppm	Offset fields

Table 2 – Assumed Gas Composition

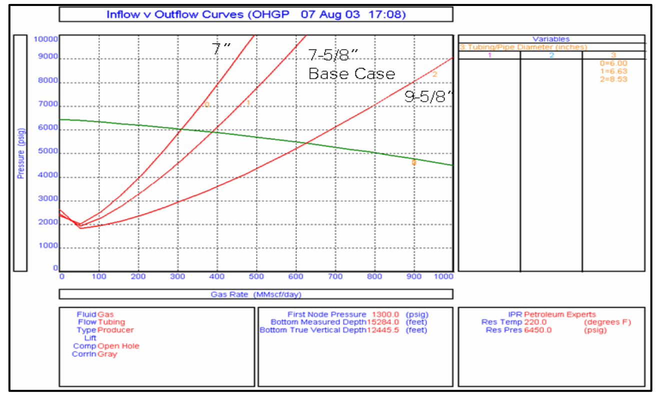

Figure 4 - NODAL* Analysis for Various Tubing Sizes with Open Hole Gravel Pack

Upper Completion Options. Various high rate upper completion designs were evaluated including 7 inch, 7⅝ inch, and 9⅝ inch tubing. In bpTT, 7 inch production tubing is the predominant size for all of the high-rate gas wells. There is one 7⅝ inch production tubing completion in the Mahogany B-13 well, and it was tested to a maximum rate of 247 MMcf/D.[4] There are no 9⅝ inch production tubing completions in Trinidad; however, extreme rate gas wells with 9⅝ inch production tubing completions do exist in other parts of the world.[5, 6] Various 9⅝ inch concepts were evaluated:

- Conventional design where a full string of production tubing is installed inside of production casing.
- Variable bore where the production tubing internal diameter (ID) is larger than the other completion components (e.g., tree bore, SCSSV, nipple profiles, etc.).
- Monobore[7] where the production tubing and all completion components all have the same ID.
- Slim bore where the well flows predominantly through the production casing and then through a short, upper section of production tubing (containing the SCSSV).

These various options were presented in a decision matrix (**Fig. A-4**) and assessed on various project criteria. All of the options were reviewed by a panel of company experts and the decision to select 7⅝ inch production tubing was endorsed. The principal disadvantages of selecting 9⅝ inch production tubing included: lack of fully qualified engineered equipment; the risk of on-time delivery of serial #1 equipment; and the operational execution risk associated with a new well design. In addition, given that the 9⅝ inch design concept was a two (2) well development scenario, there was significant concern about the loss of a well and the impact to the required deliverability profile.

Lower Completion (Sand Face) Strategy. Various sand face options were considered for the lower completion design. These ranged from a natural (barefoot) completion to an OHGP. The principal criterion for the options assessed (**Fig. A-5**) was the ability of the sand face design to reliably deliver extreme rate. Options not considered were:

- Cased hole gravel packs.

- Frac-packs (uncommon in Trinidad due to a lack of stimulation vessels).
- New technologies such as expandable sand screens (ESS).

ESS was not considered because of its unproven track record for long-term reliability in high rate gas environments.

An in-depth sand strength study was performed on plugs from the whole core. The findings of this study concluded that the reservoir could be depleted down to a pressure of ~1700 psi ($\pm$ 15% error bar). A boundary condition of the project was a well design capable of compression (Flowing BHP at abandonment = 700 psi); therefore, the risk of sand production over the life cycle of the well was considered likely.

The natural completion was rejected as being too risky for the project given the geologic and wellbore uncertainties that could exist; further, there was no supporting local evidence to demonstrate the reliability of a natural completion over the life cycle of a high rate gas well in a volumetric reservoir.

The cased and perforated (C&P) scheme has been successfully employed on multiple occasions in bpTT, and in some cases an oriented perforating technique has been used to further mitigate the risk of sand production.[8] A significant deterrent for selection of the C&P for Cannonball was the operational risk of drilling the rat hole necessary for a gun drop technique. Immediately below the 33 sand is a significant pressure ramp. Approximately 400 ft below the 33 sand is a permeable, high-pressure water sand (34 sand) which was penetrated in the Ironhorse well.

The OHGP is the pre-dominant completion design for most of bpTT's high rate gas wells. This technique has been highly successful in delivering extremely high rate and highly reliable gas wells. Ultimately, the more costly OHGP sand face option was selected because it would provide assurance of the highest rate with the least risk of sand production[9] – both key requirements for the project.

Equipment Integrity Assurance

Detailed engineering, equipment qualification, and rigorous quality assurance / quality control (QA/QC) are a business imperative for the design and installation of wells that have critical service conditions and / or significant business impact. To guide the Equipment Integrity Assurance (EIA) effort, wells in Trinidad are classified as Tier 1, Tier 2 or Tier 3 (**Fig. 5**) in a Well Criticality Model (WCM). The y-axis denotes service conditions typically represented by parameters of pressure, temperature, CO_2, H_2S, etc. The x-axis denotes business impact which is typically represented by parameters of production rate, reserves, well costs, etc. The demarcations of each Tier are established by the business unit based on the regional well portfolio and business drivers. In bpTT, the legacy oil fields (low production rates, carbon steel tubulars, gas lift, cost sensitive, etc.) were classified as Tier 1. The high-rate gas fields (+80 MMcf/D, large reserves, contract gas sales, 7 inch production tubing, 13 chrome tubulars, high cost, etc.) were classified as Tier 3 based principally on their business criticality. Once the classification scheme has been established, wells can be classified accordingly. Cannonball was classified Tier 3.

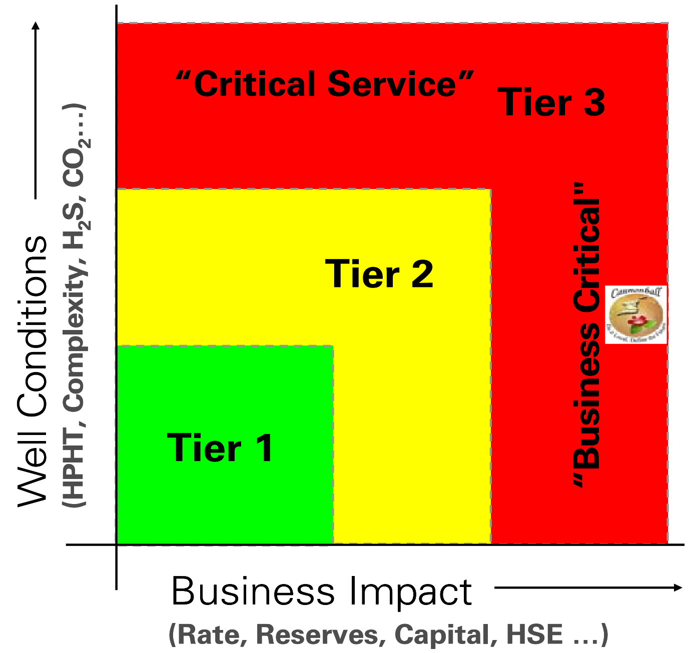

Figure 5 – Well Criticality Model

Each consecutive Tier level encumbers the engineer with more demanding levels of effort regarding equipment integrity assurance. The requirements of each Tier level can be generalized in the table below.

Tier	General Requirements
1	▪ Off-the-Shelf (OTS) equipment ▪ Supplier standard manufacturing Quality Plan (QP) ▪ Supplier standard shop assembly procedures
2	Combination of Tier 1 and Tier 3. The specifying engineer may identify some equipment as critical and apply Tier 3 requirements. A Tier 2 designation has also been used to manage equipment integrity assurance for a well that, for a variety of reasons, is unexpected and does not allow for the time required to fulfill all Tier 3 requirements. In these special cases, there is a desire to at least inspect existing inventory equipment to the requirements of Tier 3 which usually requires an ad-hoc, customized Tier 2 quality plan for the inspection of OTS equipment.
3	▪ Identification of critical equipment (most equipment) ▪ Equipment SORs ▪ Rigorous equipment qualification ▪ Design reviews – preliminary, top level, detailed ▪ Systems Integration Tests (SIT) / Yard Test ▪ Field trials ▪ Customer specific manufacturing QPs ▪ Customer specific shop assembly QPs ▪ Inspection of rental equipment ▪ Complete Well on Paper (CWOP) ▪ Pre-Job Planning Sessions ▪ Technical Limit Sessions

Table 3 – General EIA Requirements of Tier 1, 2 and 3

The remainder of this paper summarizes the Tier 3 effort to provide assurance for the final well design (**Fig. A-6**).

Completion Guiding Principles

A set of principles was developed to guide the completion design. These principles were largely based on the successful track record of bpTT's high-rate gas field wells. Other principles were gleaned from SPE papers that discussed large bore completion design.

- The design and equipment should be consistent with past bpTT high-rate gas well completions.
- Sand management will take place downhole.
- Simplicity (minimize downhole jewelry).
- Equipment that is qualified and field proven.
- Equipment with minimal inspection or maintenance requirements.
- No flow path from tubing to annulus (i.e., circulation devices above packer).

A significant effort was made to adhere to the successful bpTT high-rate gas well completion design; additional engineering assurance, as warranted, was exerted to ensure the Cannonball completion design was qualified and fit-for-purpose.

Detailed Design – Upper Completion

The detailed design of the upper completion included a number of assurance studies as well as the qualification of new or modified critical engineered equipment.

Corrosion. All bpTT high-rate gas wells are completed with 13 chrome production tubing. For Cannonball, a detailed corrosion study was undertaken by company experts to evaluate life cycle corrosion rates and ensure the proper metallurgy selection for OCTG and downhole equipment. The assumed producing characteristics were 0.52 mole % CO_2 (max case) and 0 ppm H_2S in the gas phase in conjunction with liquid water of condensation. One of the major assumptions is no produced water given that the 33 Sand was predicted to be volumetric drive. The corrosion rates for uninhibited carbon steel are presented in the table below and demonstrate that all rates exceed the company limit of 0.1 mm/yr.

Year	Surface (mm/yr)	Bottom Hole (mm/yr)
1	8	13
2	8	11
3	8	9
4	8	9
5	8	9
6	8	9
7	---	---

Table 4 – Predicted CO_2 (0.52 mole % CO_2) Corrosion Rates for Carbon Steel (No Compression Case)

Corrosion inhibition was rejected because of numerous operational issues. These included the requirement to install and maintain a corrosion inhibition system (inconsistent with the operating philosophy of a normally unmanned installation), the requirement to ensure corrosion inhibitor availability of ≥99%, and the limited industry experience of inhibiting extreme rate gas wells. The conclusions of the corrosion study was the confirmation of the API 5CT L-80 13 chrome metallurgy for production tubulars and the recommendation of 13 chrome L-80, AISI 410, and AISI 420 modified for downhole equipment.

Erosion Analysis. The traditional industry approach of calculating erosion rates using API 14E and various C constants was not utilized. Instead, a two year detailed erosion study including computation 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. A complete discussion of the erosion study is beyond the scope of this paper. The key input parameters and assumptions of the erosion study are in **Table 4** and are based on either the well design or local knowledge.

Parameter	Value
Rate 1 (Expected Rate)	280 MMcf/D
Rate 2 (Maximum Rate)	400 MMcf/D
Erosion Node 1 (Tree – BPV)	ID = 6.855" @ surface
Erosion Node 2 (Nipple Profile)	ID = 5.812" @ 1500 ft
Erosion Node 3 (FID)	ID = 4.560" @ 13,160 ft
Material Type	13 chrome Steel
Sand Concentration	0.1 lb/MMcf
Particle Size	50 micron
Sand Shape	Sharp
Flow Regime	Mist

Table 4 - Key Input Parameters for Erosion Calculations

All erosion rate calculations were made using the Sand Production Pipe Saver (SPPS) erosion model from Tulsa University. The erosion rates for three erosion nodes are displayed in **Tables A-1** and **A-2** and demonstrate the change in erosion rates during the life cycle of the well. It should be carefully noted that the erosion rates are presented for two scenarios: "without liquid film barrier" and "with liquid film barrier." This pertains to a protective liquid film on the tubing wall. As can be seen from the data, the presence of a liquid film significantly reduces the erosion rate. In fact, except for a few rates at the tree, all erosion rates for the "with liquid film barrier" are equal to or less than the company erosion limit of 0.1 mm/yr. Thus, a high degree of confidence in the presence of a liquid film was critical to the interpretation of the results. The erosion mitigation measures for the tree are discussed later in this report.

To be effective, a liquid film must be at least one-half (½) the particle diameter. In the case of Cannonball, the expected particle size was 50 microns; thus, a liquid film greater than 25 microns was required. A separate study using a pipeline simulator was undertaken to precisely determine the film thickness throughout the entire length of the well bore (**Fig. A-7**), Fig. A-7 clearly indicates the presence of a liquid film greater than 25 microns. The conclusion of the comprehensive erosion study was that the Cannonball wells could be safely produced at rates up to 400 MMcf/D.

Scale. BPTT has not experienced any problems associated with scale in any of the gas fields.

Hydrates. The Cannonball wells were to develop some of the highest pressured gas reservoirs in the history of bpTT. A hydrate study was undertaken to identify potential hydrate issues.

The gas composition assumed is listed in **Table 5**. The mudline temperature was assumed to be 68°F. The key results of the study are presented in **Figs A-8** and **A-9**. The conclusions of the study were:

- During normal operations there is no risk of hydrate formation.
- During short term shut-in (1 minute) the temperature in the well does not cool enough to enter the hydrate region.
- During long term shut-in (1 year) the well is 7°F inside the hydrate region at the mudline.
- It is highly unlikely that hydrates will form when equalizing the SCSSV with sea water.
- 15 wt% monoethylene glycol (MEG) will inhibit the sea water at 5900psi and 68°F (worst case scenario at mudline).
- It is unlikely that a hydrate blockage would occur when using the equalizing feature of the valve due to the volume of water and potentially high temperatures above the valve.

Constituent	Mole %
CO_2	0.43
Methane	93.2
Ethane	3.53
Propane	1.32
Isobutane	0.29
N-butane	0.36
Pentane	0.82

Table 5 - Input Parameters for Hydrate Study

Production Tubing. A detailed tubing design and triaxial stress analysis was undertaken by company experts. The load cases and tubing string profile are listed in **Tables A-3** and **A-4**. The flowing temperature profiles are presented in the figure below. Note that the highest flow rate does not correspond to the highest tubing temperature, presumably because of Joule-Thomsom cooling associated with the lowered surface tubing pressure.

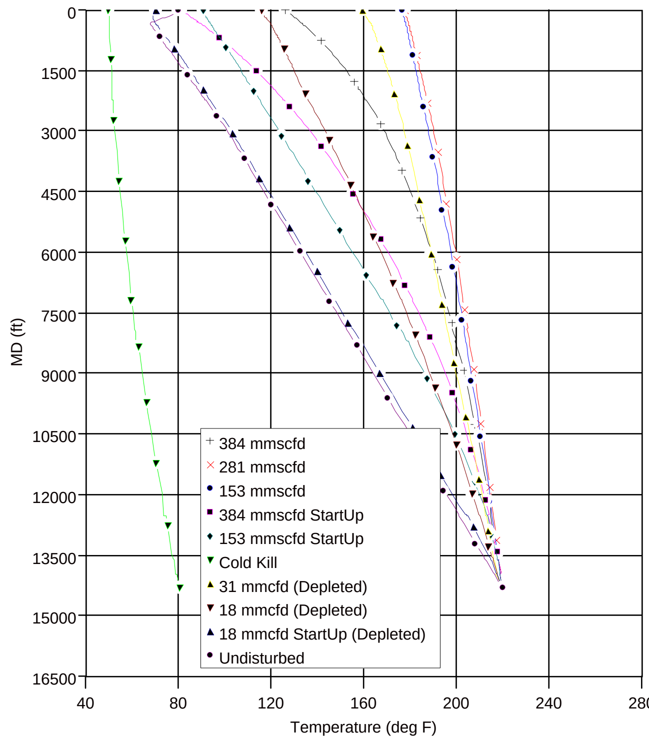

Figure 6 - Temperature Profiles for Operations used in Tubing Load Cases

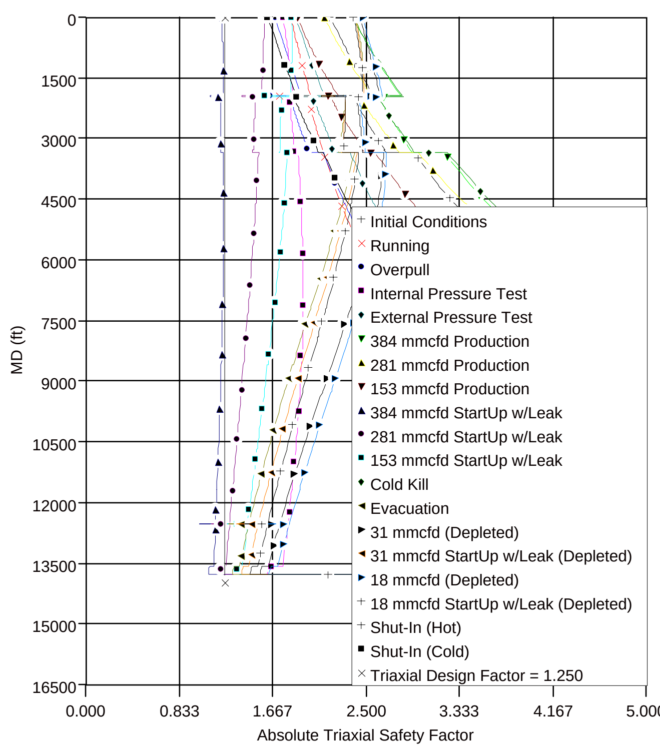

Figure 7 - von Mises Safety Factors for Production Tubing, Unlatched Packer

Fig. 7 presents the von Mises safety factors for the load cases as computed by tubing design analysis software. Selected (usually corresponding to intermediate flow rates) load cases have been omitted from the plot for better viewing. The presentation of triaxial (von Mises) safety factor vs. depth was selected, rather than the von Mises ellipse, in order to display all components of the tubing string (tubing as well as accessories) simultaneously. By comparing Fig. 7 with the depths in Table A-4, the weaker accessories and lower 7 inch portion of the tubing string can be readily discerned.

Viewing Fig. 7, the load cases corresponding to "Start-up with Tubing Leak" all fall near or outside the design ellipse, even for depleted production. This extreme load case represents the following scenario:

- The well is shut-in for a long time, and during shut-in, a small leak in the tubing or accessories allows reservoir pressure to migrate to the surface in the tubing annulus.
- The leak (A-annulus) pressure goes unnoticed.
- The well is then placed on production after the extended shut-in.

The external pressure differential consisting of the leak external and the drawn down flowing tubing pressure internal, coupled with high tension in the tubing near the surface (thus the flow cases at 10 minutes), is sufficient to collapse the tubing near the surface. This extreme case can occur but was considered highly unlikely. The load scenario can be prevented by a judicious operating practice of annulus pressure monitoring. This risk was mitigated by writing operational procedures that would not allow a well start-up in cases where annulus pressure exceeded a threshold level.

Fig. 8 plots axial safety factors as a function of measured depth. This plot is useful in that it includes connection integrity. Aside from the tubing leak load case detailed above, all safety factors are acceptable.

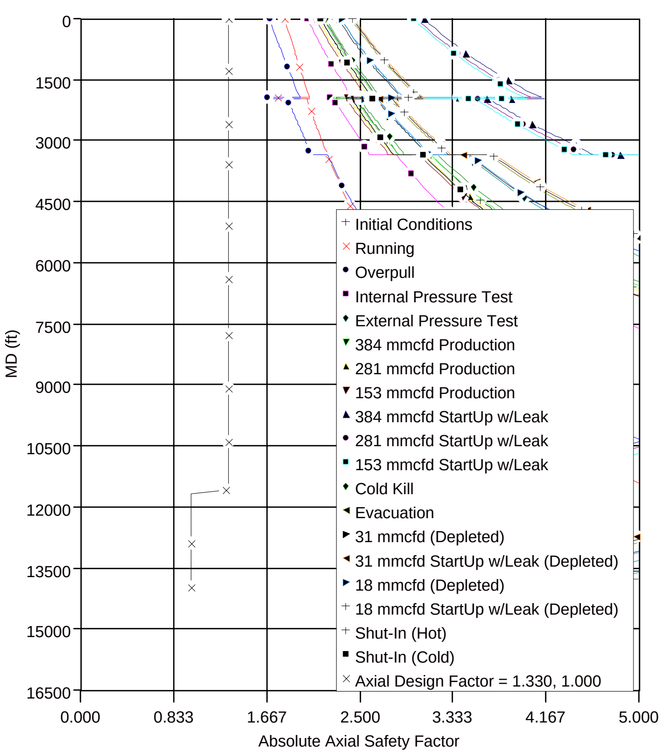

Figure 8 - Axial Safety Factors (All Load Cases) for Production Tubing, Unlatched Packer

Tree. Early in the project definition, a decision was made to specify a full-bore tree that would not impose any internal diameter (ID) restrictions with respect to the 7⅝ inch production tubing ID (6.625 inch). The basic tree description is described in the table below.

Tree Description	ID (inch)
7-1/16 inch 10,000 psi single vertical block	7.0625
7-1/16 inch 10,000 psi single wing outlet	7.0625
Tubing Hanger BPV profile	6.8550

Table 6 - Tree Description with Internal Dimensions

As mentioned previously, the erosion rates at the tree were identified as a concern. Therefore, company experts and the University of Tulsa conducted detailed erosion studies including CFD modeling. The metallurgy of the tree was specified as a low-alloy (2¼ chrome) base metal with full cladding (standard thickness = ⅛ inch or ~3mm) of Inconel 625 on all flow-wet surfaces. To assure the final tree design (geometry) and clad thickness, a CFD study investigated two known erosion hot spot regions: namely, the "corner" (intersection of the vertical bore of the tree with the horizontal wing section) and "outlet" (**Fig. 9**). The standard, as-machined corner radius is 0.030 inch. This sharp corner, however, is prone to very high erosion rates which can erode the cladding and penetrate into the low-alloy base material; this could lead to undesirable corrosion-erosion. The area of concern can be significantly reduced if the corner is rounded. CFD modeling (**Fig. 10**) investigated a corner radius of ¼ and ½ inch. Erosion in the "outlet" section is less severe and is strongly influenced by the radius of the "corner".

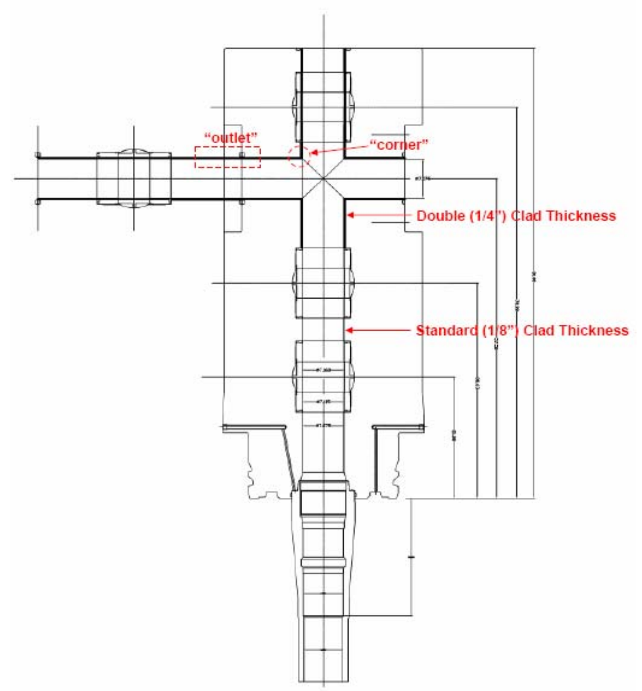

Figure 9 - Tree Schematic with Clad Thickness Identified

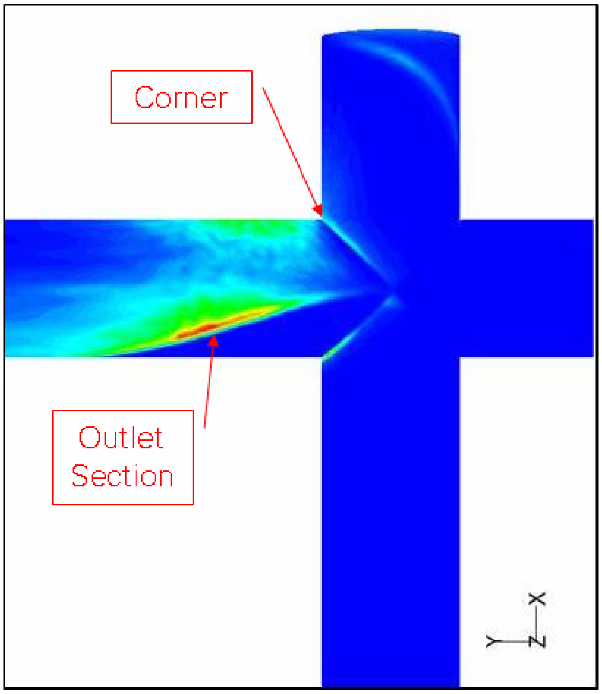

Figure 10 - Representative Erosion Pattern Near Intersecting Pipes

The CFD erosion results were used to calibrate SPPS erosion rates which enabled the calculation of cumulative wastage over the life cycle of the well; an example is presented in **Fig. 11**. A summary of cumulative, life cycle wastage is summarized in **Table 7**.

Tree Section (Radius)	Rate (MMcf/D)	Cumulative Wastage (mm)
Corner (0.030 inch)	390	1.979
Corner (0.030 inch)	280	1.547
Outlet	390	0.986

Table 7 - Cumulative Wastage at Tree Corner and Outlet

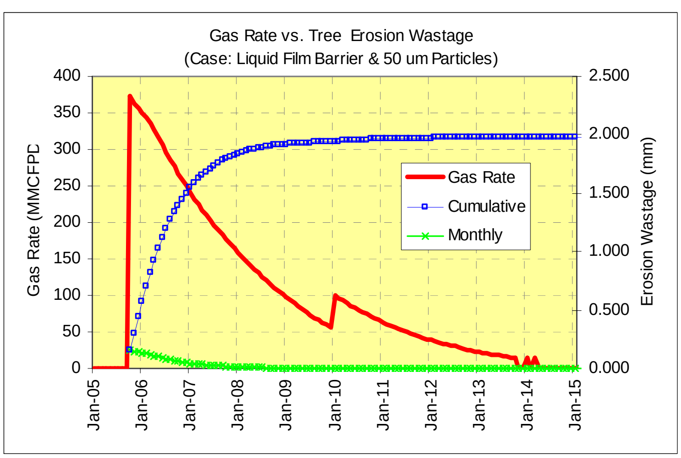

Figure 11 - Cumulative Wastage at Corner with Initial Rate of 390 MMcf/D

The worst case is the corner at maximum rate (390 MMcf/D) in which the cumulative, life cycle wastage is 1.979 mm. This amount of wastage would result in ~1 mm of clad thickness remaining. Given the uncertainty in the calculations and input parameters, a conservative decision was made to specify a corner radius of ½ inch and two clad thickness layers (2 x ⅛ inches) above the upper master valve (Fig. 9).

SCSSV. The requirements specified for the tubing retrievable SCSSV are listed **Table 8**.

Type	Self-Equalizing
Design Specification	API 14A
Class of Service	Class 2: Sandy Service
API Monogram	Yes
Endurance Test (Rogaland-style)	Yes
High Rate Gas Slam Closure	Yes
Field Proven Design	Yes
bpTT Field Experience	Highly Preferred

Table 8 - Requirements Specified for SCSSV

The maximum differential across the flapper was estimated to be 5900 psi, and the maximum burst load during a well kill was estimated to be 6500 psi. This resulted in the selection of a 10,000 psi rated valve. It should be noted that bpTT had numerous installations (high-rate gas wells) of the same type valve but in a 5,000 psi rated version. Only the high rate gas slam closure required additional qualification testing. The worst case scenario – absolute open flow (AOF) – resulted in calculated superficial gas velocities of 307 and 262 ft/sec at setting depths of 1500 ft and 2000 ft, respectively. The Equipment Statement of Requirements (SOR) specified a requirement of 300 ft/sec. The selected valve had been qualified to only 200 ft/sec. Following engineering studies, modifications were made to the existing flapper design. The valve was tested at the Advantica Flow Centre (**Fig. 11**) located in the United Kingdom. It was successfully slam tested to a maximum rate of 485 ft/sec. Subsequently, this design passed the API 14A Class 2 Sandy Service certification test at the Southwest Research Institute located in San Antonio, Texas, USA.

Figure 11 – Test Apparatus at Advantica Flow Centre

Permanent Downhole Gauge. The Cannonball surveillance plan specified the requirement for a permanent downhole gauge (PDHG) for real-time pressure and temperature monitoring. One of the key concerns for the Cannonball PDHG installation was the above normal temperature (220°F) when compared to other bpTT installations (maximum recorded temperature locally was 195°F). An internal report[10] compiled by company experts concluded the following:

- Gauge reliability is dependent on temperature.
- System failure is not primarily due to gauge failure but to cable and connector failures.
- For current generation gauges gauge survivability is 90% for temperatures <220°F and 74% for temperature >220°F.
- High temperatures (>220°F) exploit weaknesses in cables and connectors; so improvements should focus on these components and not primarily on the gauge.

The equipment (mandrel and quartz gauge) provisionally selected was based primarily on a single supplier's excellent track record for performance and reliability as evidenced by 43 bpTT installations where only one failure had been recorded to date. Additional selection criteria included in-country capability and track record for service and technical support. A survey of current gauge performance data, consultation with subject matter experts, an in-country installation and capability assessment, as well as a technical peer review all reinforced the completions team selection. An emphasis was placed on QA/QC to mitigate the risk associated with the manufacturing and installation of the gauge, connectors and cable.

Detailed Design – Lower Completion

The detailed design of the lower completion included the selection and qualification of engineered equipment as well as the design of a carrier fluid system for a high temperature application. A summary of the predicted Cannonball sand face completion parameters is presented in the **Table 9**.

Well	CAN01	CAN02	CAN03
Reservoir Pressure (psi)	6,450	6,450	6,450
Bottom Hole Temperature (°F)	220	220	220
Hole Angle (deg)	19	21	32
Top of Sand (ft, TVD)	12,327	12,176	11,933
Total Depth (ft, MD)	12,988	13,499	14,081
Gross Thickness (ft, TVD)	277	282	317

Table 9 – Predicted Cannonball Sand Face Design Parameters

Sand Distribution Analysis. A Laser Particle Size Analysis (LPSA) was performed on core plugs from the 33 sand whole core from the Ironhorse well. The results are discussed in detail in the following sections and summarized together with data from other fields in bpTT for comparison. The 33 sand LPSA is shown in **Fig. 12**. Overall, the sands in bpTT have very poor sorting with high fines content (**Table 10**). The 33 sand was better sorted and had less fines than the other sands in bpTT gas field developments demonstrated by:

- 33 sand uniformity coefficient (d40/d90) is much smaller than the average uniformity coefficient that is seen in other bpTT developments (this could be caused by the uncertainity of only half of the sand interval being cored).
- The 33 sand d50 is much larger than the other fields.

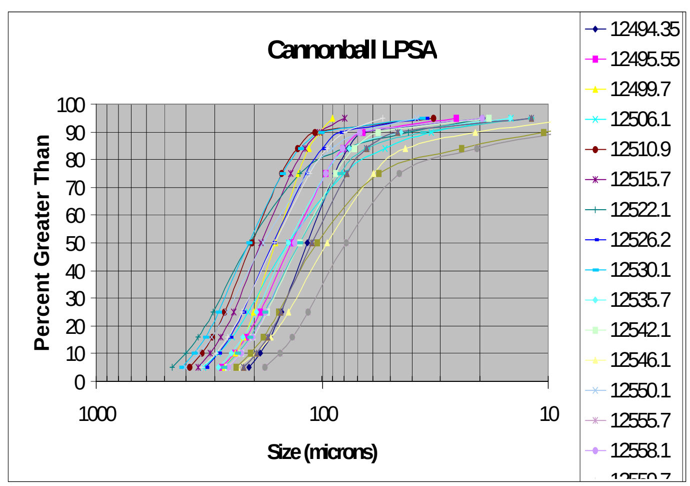

Figure 12 - Cannonball 33 Sand Laser Particle Size Analysis

Field	Cannonball	Immortelle	Amherstia	Mahogany
Sand	33	21	24	23
d10	255	238	168	167
d50	140	91	92	59
d95	56	10	7	3
d10/d95	4.6	23.8	24	55.7
d40/d90	3.5	8	7	11

Table 10 - BPTT Major Gas Field Sand Distribution Summary

Sand Retention Testing. A series of sand retention tests were carried out on different sizes of gravel. The sand samples that were used consisted of both massive (large grain) and laminated (small grain) sand samples from the Iron Horse 33 sand core. The following gravels were tested:

- 30/50 Ottawa.
- 30/50 ceramic proppant.
- 20/40 Ottawa.
- 20/40 light weight proppant.
- 16/30 intermediate-strength proppant.

The following parameters were measured:

- Pressure drop across sand + proppant + screen and across sand.
- Solids concentration of effluent vs. time.
- LGSA of particulate in effluent.

Fig. 13 shows the sand retention results that were obtained for both the massive and laminated sands.

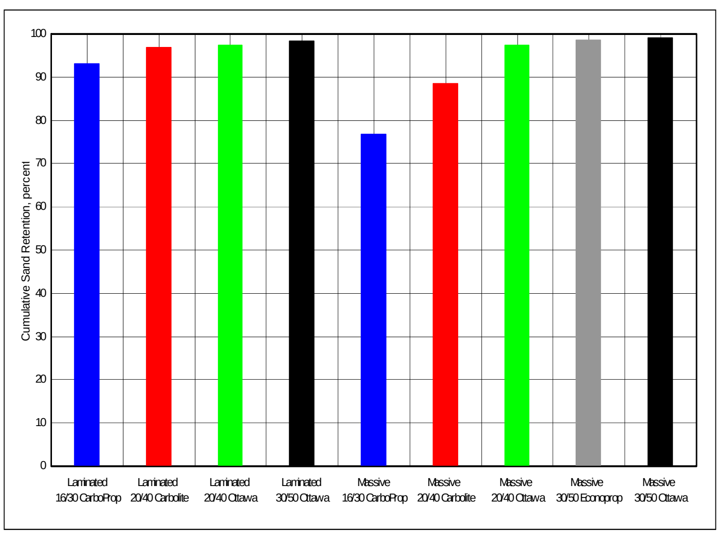

Figure 13 – Sand Retention Results for 33 Sand

The results show that:

- 30/50 Ottawa gravel retained both sands, but it plugged with the laminated sands due to small grain intrusion.
- 30/50 ceramic proppant controlled the massive sand very well, but it took longer for the larger grains to be stripped out to flow.
- 20/40 Ottawa is suitable for both the massive and laminated sands.
- The massive sands were not controlled by the 20/40 light weight proppant or anything larger.
- The laminated sands bridged on all the proppants but best with the Ottawa.

Based on the results of this testing, 20/40 Ottawa was considered the optimum gravel for the 33 sand. However, the 30/50 ceramic proppant was selected principally due to the lack of core coverage over the lower portion of the 33 sand which was viewed to be finer grained. It was viewed that the 30/50 gravel provided assurance of retaining the finer grained sand. In addition, it was viewed that the synthetic proppant would facilitate drill-in fluid (DIF) filter cake lift off, and 30/50 ceramic proppant was a compromise between filter cake clean-up and absolute solids control.

Shale Reactivity. A shale reactivity study was performed to assess the impact of the 33 shale reactivity on the Cannonball completion design. The following tests and analysis were performed on shale samples from the Ironhorse well.

- X-Ray Diffraction (XRD) analysis (shale/silt/cuttings).
- Capillary Suction Time (CST) analysis.
- Shale swelling tests.

The sample depths ranged from 12,280 to 12,610 ft MD (**Table 11**).

	Core	Core	Cuttings		
Mineral (weight %)	Siltstone 12,552 ft MD	Shale 12,534 ft MD	12,280 ft to 12,310 ft MD	12,400ft to 12,430 ft MD	12,580 ft to 12,610 ft MD
Quartz	77	62	50	27	72
Potassium Feldspar	3	--	3	1	1
Plagioclase Feldspar	9	4	6	4	3
Illite	6	19	16	28	7
Kaolinite	4	13	11	20	6
Chlorite	1	2	--	--	--
Illite/Smectite	--	--	12	17	5
Total Clay (%)	11	34	39	65	18

Table 11 - Shale X-Ray Diffraction

It is important to note the absence of Illite/Smectite minerals in the shale. This shows that the shale is relatively stable. It should be noted that X-ray diffraction was conducted on some of the cuttings from the reservoir in the event that the 10¾ inch casing could not be set in the 33 sand and the 32 shale was exposed (overpressured at 13.6 ppg). Although Illite/Smectite is present in these cuttings, the accuracy of these results is questionable as the precise origin of the cuttings was uncertain.

Based on linear swellmeter and CST testing, the addition of 2-3% KCl to the $CaCl_2$ or $CaCl_2/CaBr_2$ brines lowered shale swelling and shale dispersion. The brine selected for the Cannonball project was 10.5 ppg $CaCl_2$ with 3% KCl.

Return Permeability Testing. All of the fluids expected to be exposed to the 33 sand were tested independently and in the order that the sands would be exposed to them. Both massive (k=400 md) and laminated (k=100 md) sands were sampled and tested with nitrogen. In general, return permeability testing with nitrogen gives lower values than oil.

The brine that was tested was 10.5 ppg $CaCl_2$ brine with 3% KCl. The DIF tested was made from this brine with typical additives used in brine packages. The carrier fluid was 75 lb/1000 gal HEC, and the breaker was added last to complete the fluid package.

Fig. 14 shows the return permeability of both the Cannonball massive and laminated sands with a water-based DIF, 30/50 gravel, and internal breaker. The return permeabilities range from 24 to 43%, and the laminated sand exhibited the highest return permeability.

Kapok return permeability results for 20/40 gravel are also plotted. It should be noted that for the Kapok gravel pack, there was a breaker for both the filter cake and HEC. For the Cannonball gravel pack, there was a breaker for the HEC only.

The Kapok testing sequence also involved the addition of a (post gravel pack) filter cake removal treatment. The addition of the filter cake removal treatment increased the return permeability significantly to approximately 51%. The conclusion can be drawn that a higher return permeability could be achieved if a filter cake removal treatment was added to the Cannonball completion.

However, no filter cake removal treatments were planned for Cannonball due to the following reasons:

- OHGPs clean up on their own over time while the filter cake removal treatment accelerates production for about 30 days (Mahogany B-13).
- The Cannonball wells are tubing constrained; therefore, a post gravel pack treatment may not prove beneficial.
- Kapok had a total of ten (10) OHGP completions, and none were treated for filter cake removal.
- The performance of the Kapok wells was considered a success; therefore, a decision was made to not spend any additional time or money on additional testing.

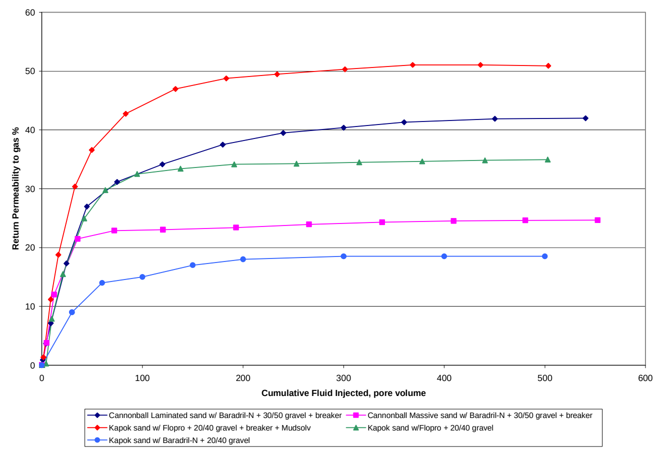

Figure 14 - Return Permeability Comparison

Gravel Carrier Fluid. The completions team design bias for the gravel pack carrier fluid was HEC because it had been the carrier fluid for all previous OHGPs in bpTT. The following design specifications were provided to the service company:

- At least 50 cp in the first 4 hours.
- < 5 cp after 24 hours.
- 20% sand settling in 30 minutes.

The service company conducted a variety of tests on different HEC loadings and breaker packages in order to optimize the viscosity and sand settling time at the required temperature of 205°F (predicted bottom hole treating temperature). It was also vital that the test results be repeatable. **Fig. 15** shows that after 4 hours a viscosity of 50 cp was obtained. and after 18-20 hours, a viscosity of less than 5 cp was obtained. It was found that the enzymes that are usually used (Kapok) die at 200°F, so a new breaker had to be used for Cannonball. During the testing, it was also discovered that $CaCl_2$ brine created a more viscous fluid at the same gel loading than NaCl.

Fig. 16 shows that 20% of the gravel settles in 4 minutes at 200°F which does not meet the expectations that were stated above. This means that if there are problems during the gravel pack, the service tool would have to be picked up to reverse position and the gravel reversed out because of the fast settling rate.

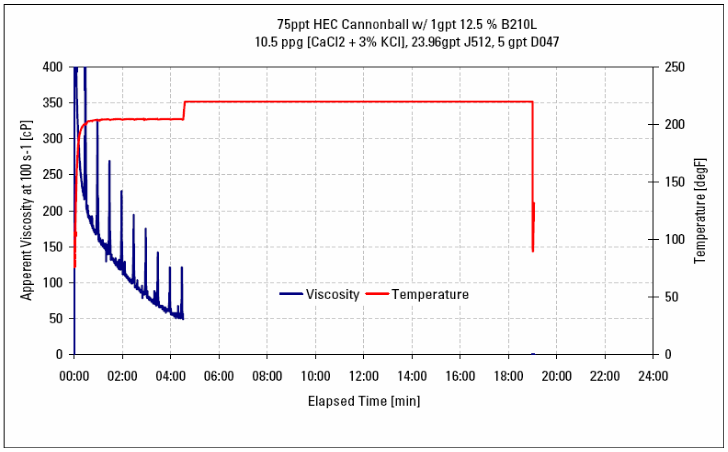

Figure 15 - 75 lb/1000 gal HEC Rheology Curve

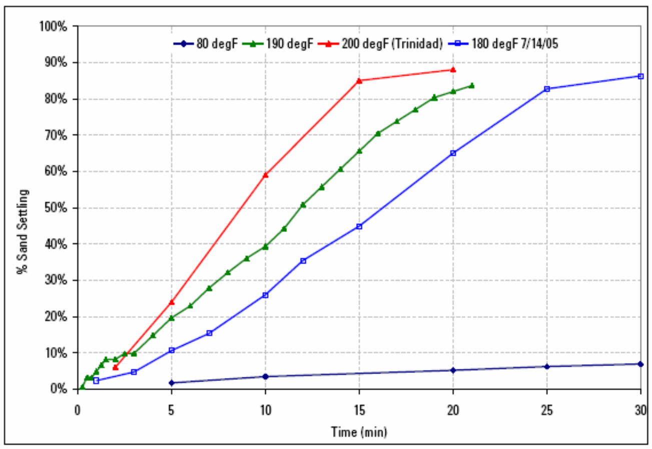

Figure 16 - Sand Settling Time 75 lb/1000 gal HEC

Screen Selection. On first inspection, the Cannonball wells looked appropriate for circulation type gravel packs and a conventional screen system. This would allow the use of a larger base pipe for the same hole size resulting in increased productivity. However, assurance of a complete gravel pack was the primary design consideration, and alternate path (shunt tube) technology screen was selected. The benefits of alternate path technology are listed below:

- Enables gravel packing operations to commence without pumping a LCM pill if moderate losses occur.
- Will allow packing below a bridge if the well bore collapses or if the shale is found to be reactive.
- Is consistent with the successful Kapok lower completion basis of design and procedures.

The sand screens are expected to see significant loading from depletion from 6450 psi to 611 psi ($\Delta p \approx 5800$ psi). A recommendation[11] from company experts was to specify a base pipe with a collapse resistance of 5568 psi (0.96 x depletion, Δp) for the deviated Cannonball wells. Based on these requirements, 20 lb/ft, 13Cr80 base pipe (collapse = 6786 psi) was selected for the premium screens which provided a nominal safety margin.

Based on the depletion philosophy described above, wire-wrapped screens were not desirable, as the screen will lose structural integrity due to deformation / collapse as depletion occurs. The most desirable type of screen was a direct-wrapped screen. However, due to supply chain issues, a direct-wrapped screen with alternate path technology was not a commercial option at the time of the Cannonball development. Therefore, a premium mesh screen was selected. If collapse should occur as depletion loading increases, the premium mesh will collapse onto the base pipe and have a higher likelihood of maintaining sand control (as compared to a wire-wrapped screen jacket).

It is considered a good practice to specify a filter media size to retain the formation sand in the event of an incomplete gravel pack. Alternate path technology was invented to improve the success rate of achieving a complete gravel pack (no voids). Kapok adhered to these design principles and utilized a premium (weave filter media) type screen with alternate path technology.

The OHGP screen that was specified for Cannonball (based on slurry testing and sanding software) was a shrouded 5½ inch 20 lb/ft 13CR80 SLHT-S 175 micron premium screen with two transport tubes and two packing tubes. It should be noted that 115 micron was standard for past screen designs in bpTT.

Formation Isolation Device. A formation isolation device (FID) was incorporated into the Cannonball lower completion design for the following reasons:

- Prevents fluid loss to the formation after installation of the gravel pack.
- Isolates the reservoir while running the upper completion.
- Allows the displacement of under-balanced fluid to initiate flow or to use a lower weight packer fluid.
- Was part of the Kapok lower completion design.

The standard FID that had been used on bpTT high rate gas wells was a 8 inch OD 5,000 psi 13 chrome FID with a 4.56 inch ID. This FID has been used in the Kapok and Mahogany developments with good results. For Cannonball, the pressure rating of this valve became a weak point in the gravel pack design and controlled the sand-out pressure limitations (gravel pack packer was rated to 10,000 psi). The FID was positioned inside the 10¾ inch casing and would not be subjected to depletion loading from the reservoir; thus, the collapse rating was not considered a major issue during the well's life cycle. Another FID design used in the North Sea and West Africa was selected for Cannonball. It had a thicker outer sleeve (OD = 8.18 inch) that provided a 6500 psi collapse resistance but otherwise used the same parts as the Kapok design. This FID design allowed a higher screen-out pressure during the gravel pack.

Gravel-Pack / Production Packer. The Cannonball completion and casing design required a new 10¾ inch x 6 inch gravel-pack / production packer. A number of contributing factors drove the decision for a new packer design:

- Heavy wall production casing (10¾ inch 65.7 lb/ft) above top of reservoir was required to avoid casing collapse at the end of well life from a high pressure shale immediately above 33 sand.
- A bpTT design bias of simplification (eliminated the need to stack a permanent production packer on top of the gravel pack packer).
- Significant packer loads from tubing movement and pressure differentials during the well life cycle.

The requirement to meet the V0 design validation grade of ISO 14310 / API 11D1 was driven by the following factors:

- Critical service (high pressure).
- Business critical (high reliability required to meet gas delivery requirements for LNG gas contracts).
- Critical engineered equipment must be fully qualified.
- Long service life (15 years with compression).
- Gravel-pack packer to serve as the production packer.

All of the requisite data was conveyed to the supplier in an Equipment SOR. The packer was delivered on schedule and was successfully qualified to a V0 validation grade. A detailed design review was held with representatives of the company and supplier to verify that the engineering design and qualification testing complied with the Equipment SOR.

Systems Integration Test. As part of the overall effort to deliver fully qualified equipment, the completion team identified an execution risk associated with a serial #1 packer and a complex service tool. Therefore, a requirement was established that a Systems Integration Test (SIT) of the entire OHGP assembly would be performed in a test well. The test objective was to demonstrate the full functionality of the OHGP system which included an anti-swab and filter cake removal treatment feature. The sequential steps of the full operating sequence were defined as:

- Test to be performed with solid laden fluid in the hole at RIH.
- Validate wash down feature by confirming the circulation rate through the tool.
- Set the packer in the specified solid laden fluid system.
- Pressure release the service tool from the packer.
- Locate the packer test position and pressure test the packer.
- Establish circulate position.
- Establish "blank" position.
- Establish reverse position.
- Validate anti-swab feature by maintaining a constant pressure below the packer while moving through all the pre-gravel pack positions.
- Transform the tool into a filter cake removal treatment tool for washing out operation and confirm circulation rate through tool.

In addition, all operational parameters were pre-defined and acceptance / rejection criteria were established in advance of the test.

Every attempt was made to simulate the Cannonball conditions. Two SITs (**Fig. 17**) were performed as indicated in **Table 12**.

SIT	Date	Location
1	Oct 2004	Cameron, Texas
2	April 2005	Cameron, Texas

Table 12 - Schedule of Systems Integration Test of OHGP

The first SIT was a qualified success but was compromised by well debris leftover from a previous test. A benefit of the first SIT was the identification of several minor tool issues which were modified prior to the second SIT. The second SIT was a complete success.

Figure 17 - Test Well Site in Cameron, Texas

Operational Planning and Performance

Operational Planning. Planning was implemented using the following guidelines:

- Rigorous transfer of learnings from similar projects.
- Input and engagement of the entire execution team.
- Assessment of risks.
- Identification of offline and preparation activities through the technical limit process.

The completion was subdivided into four (4) distinct phases of activity: wellbore clean-out (WBCO); sand control; run upper completion; and tree installation / open FID. For each phase, Complete the Well On Paper (CWOP) sessions were done that included a detailed risk assessment and procedure review. The key offshore execution personnel participated in these sessions.

The entire execution team including the rig team conducted a two (2) day technical limit session offsite. In addition to rolling out the execution details to the rig team, the session identified opportunities to optimize the critical path activities.

Operational Execution. The Cannonball completions were installed as designed (Fig. A-6 and **Table 13**). In general, the overall operational execution was considered flawless (**Table 14**). There were, however, a few minor operational issues that resulted in lessons learned.

Parameter	CAN01	CAN02	CAN03
Total Depth (ft, MD)	13,205	13,285	14,290
Completion Length (ft)	231	201	304
Deviation (degrees)	21	21	34
Pack Efficiency (%)	103	107	103

Table 13 – Cannonball Actual Completion Parameters

Parameter	CAN01	CAN02	CAN03
Wellbore Clean-out	2.91	1.91	1.78
Sand Control	8.07	2.35	2.80
Run Upper Completion	3.50	3.42	3.48
Install Tree / Open FIV	2.48	1.38	1.31
Completion Days (Actual)	16.96	9.06	9.37
Completion Days (AFE)	15.2	14.11	14.11
Completion NPT (%)	14.6	≈0.8	≈0.8

Table 14 – Cannonball Actual Operational Performance

On the first well, CAN01, a problem occurred when attempting to set the packer, so it was pulled out of the hole and inspected. Within 48 hours, the investigation team determined that a carbonate plug in the wash pipe had prevented the packer from setting. The team determined that neither the service company nor the packer was responsible for this problem. Therefore, a back-up assembly was run, and the job was completed successfully, as designed.

The operational procedure was modified to include the washing down of the screen (pumping down the wash pipe at miniumu rate) to total depth (TD) to minimize recurrence of the wash pipe plugging problem. It was also decided that the gravel pack logging tools, which provided valuable trouble shooting data, would be run for all future OHGPs. In addition, shunt tube action was observed towards the end of the gravel pack, thereby reinforcing the importance of their use.

On the second well, CAN02, the alternate path technology paid dividends with approximately 50% of the gravel pumping job completed through the shunt tubes. It is surmised that because of a larger rat hole below the casing shoe resulting from the drilling technique used, a sand dune formed and then collapsed when it reached critical mass causing a premature screen-out. The shunt tubes performed as designed and the well was completed five (5) days below AFE.

The third well, CAN03, experienced temporary wash pipe plugging, but this issue was remedied by the modified operational procedure. Early shunt action was also experienced. CAN03 was completed five (5) days below AFE.

The lessons learned, best practices, and overall completion design allowed for the successful delivery of the Cannonball completions. The three (3) completions combined were delivered eight (8) days below AFE.

Well Performance. The actual well performance results for all three Cannonball wells are presented in **Table 15**. Initial production commenced on March 12, 2006 following pipeline hook-up and commissioning. The Cannonball field was brought on production at a sustained rate in excess of 800 MMcf/D and to date there have been no equipment, reliability, nor sand issues.

Parameter	CAN01	CAN02	CAN03
Gas Rate (MMcf/D)	320	295	255
Condensate Rate (bbl/D)	7,000	6,500	5,600
Flowing WHP (psig)	3,143	2,995	3,592
Draw Down (psig)	≈430	≈800	≈500
Mechanical Skin (Low ≈5)	Low	Low	Low
Un-choked Flow Potential (MMcf/D)	415	370	375
Produced Solids	None	None	None

Table 15 – Cannonball Actual Well Performance

Summary

- The Cannonball wells were designed around the optimal completion design to achieve the project objectives.
- The right scoping process and peer reviews assisted in the selection of the optimal design.
- The completion guiding principles focused the detailed design on previous successful bpTT high-rate gas completion designs.
- Identification of the well criticality (Tier 3) provided support for the significant amount of detailed engineering and EIA effort.
- Detailed erosion studies provided technical assurance that enabled extreme production rates (exceeding C factors).
- Flawless execution was accomplished by detailed planning and leveraging operational procedures that had worked on previous projects.
- Actual well performance has met or exceeded the project objectives.
- There has been no equipment, reliability, nor sand issues to date.

Acknowledgements

The authors would like to thank the bpTT management for permission to publish this paper. In addition, we express our thanks and sincere appreciation to our wells team colleagues, all of the technical experts, as well as the service companies who made this development a success.

Nomenclature

AFE = Authorization for Expenditure
BPTT = BP Trinidad & Tobago LLC
BPV = Back Pressure Valve
BHP = Bottom Hole Pressure
BHT = Bottom Hole Temperature
C&P = Cased & Perforated
CGR = Condensate Gas Ratio
CWOP = Complete Well on Paper
DIF = Drill In Fluid
EIA = Equipment Integrity Assurance
FID = Fluid Isolation Device
GWC = Gas Water Contact
HEC = Hydroxyethyl Cellulose
ID = Internal Diameter
LPSA = Laser Particle Size Analysis
MD = Measured Depth
NUI = Normally Unmanned Installation
OCTG = Oil-Country Tubular Goods
OHGP = Open Hole Gravel Pack
OD = Outside Diameter
PDHG = Permanent Downhole Gauge
QA/QC = Quality Assurance / Quality Control
QP = Quality Plan
SOR = Statement of Requirements
SS = Subsea
SCSSV = Surface Controlled Subsurface Safety Valve
TD = Total Depth
TVD = True Vertical Depth
TVDSS = True Vertical Depth Subsea
WHP = Wellhead Pressure

* NODAL analysis is a mark of Schlumberger

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Appendix A

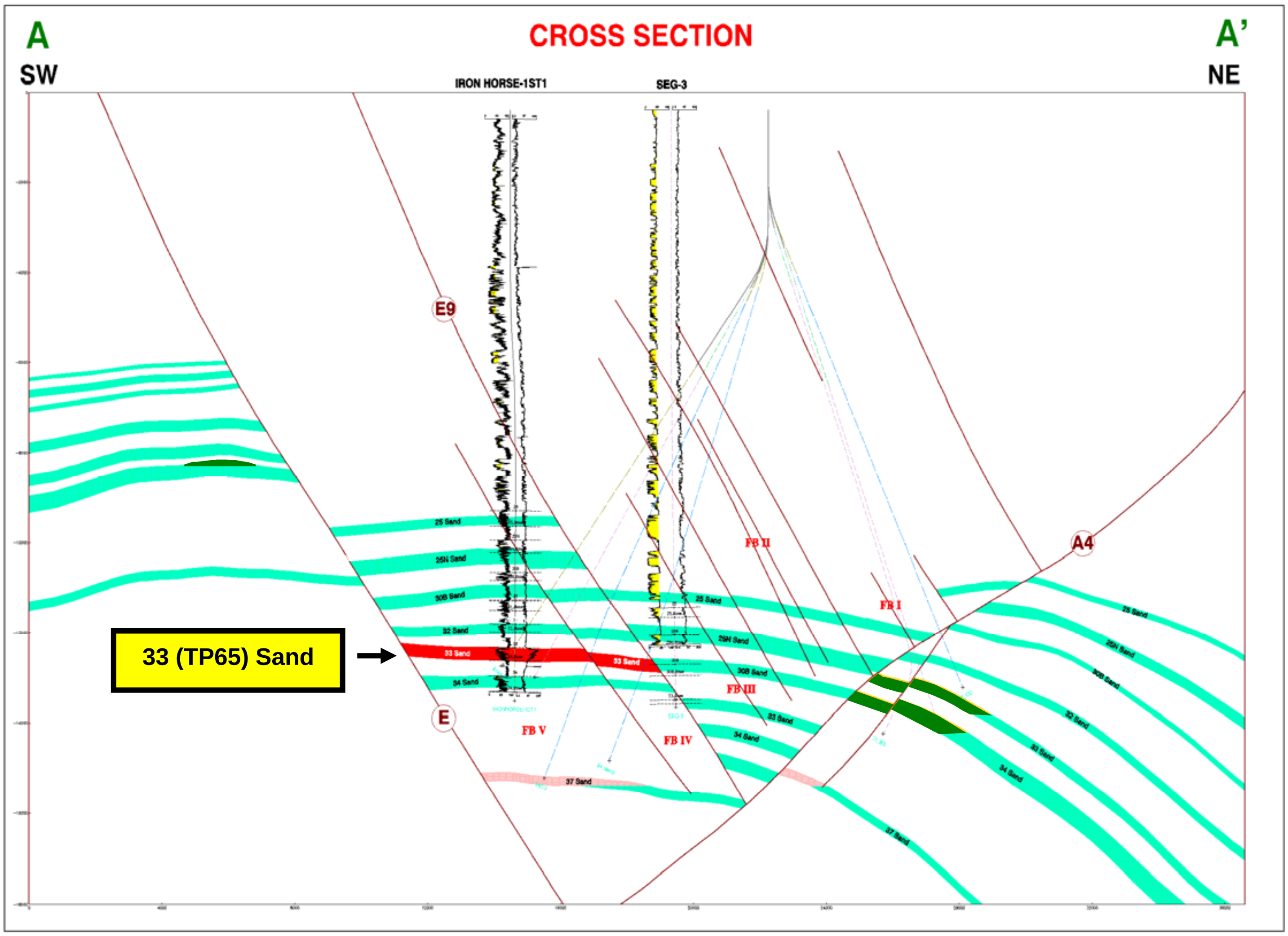

Figure A-1 Geologic Cross Section of 33 Sand and Ironhorse-1 ST1

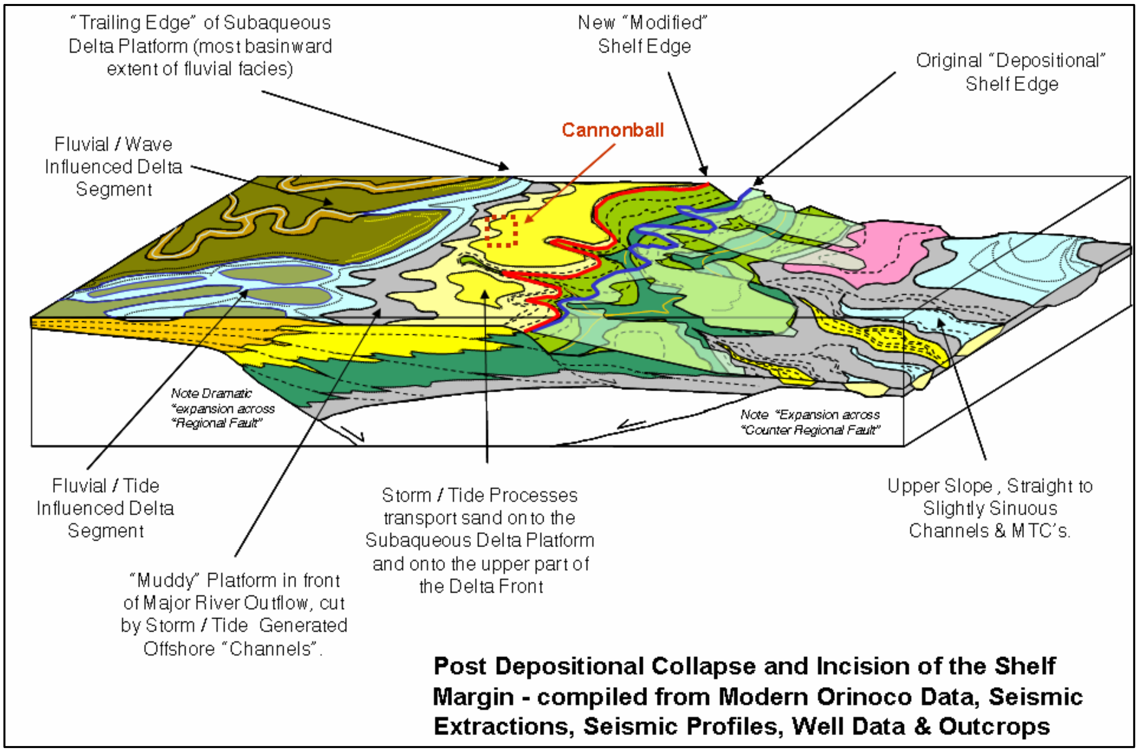

Figure A-2 Cannonball Depositional Montage

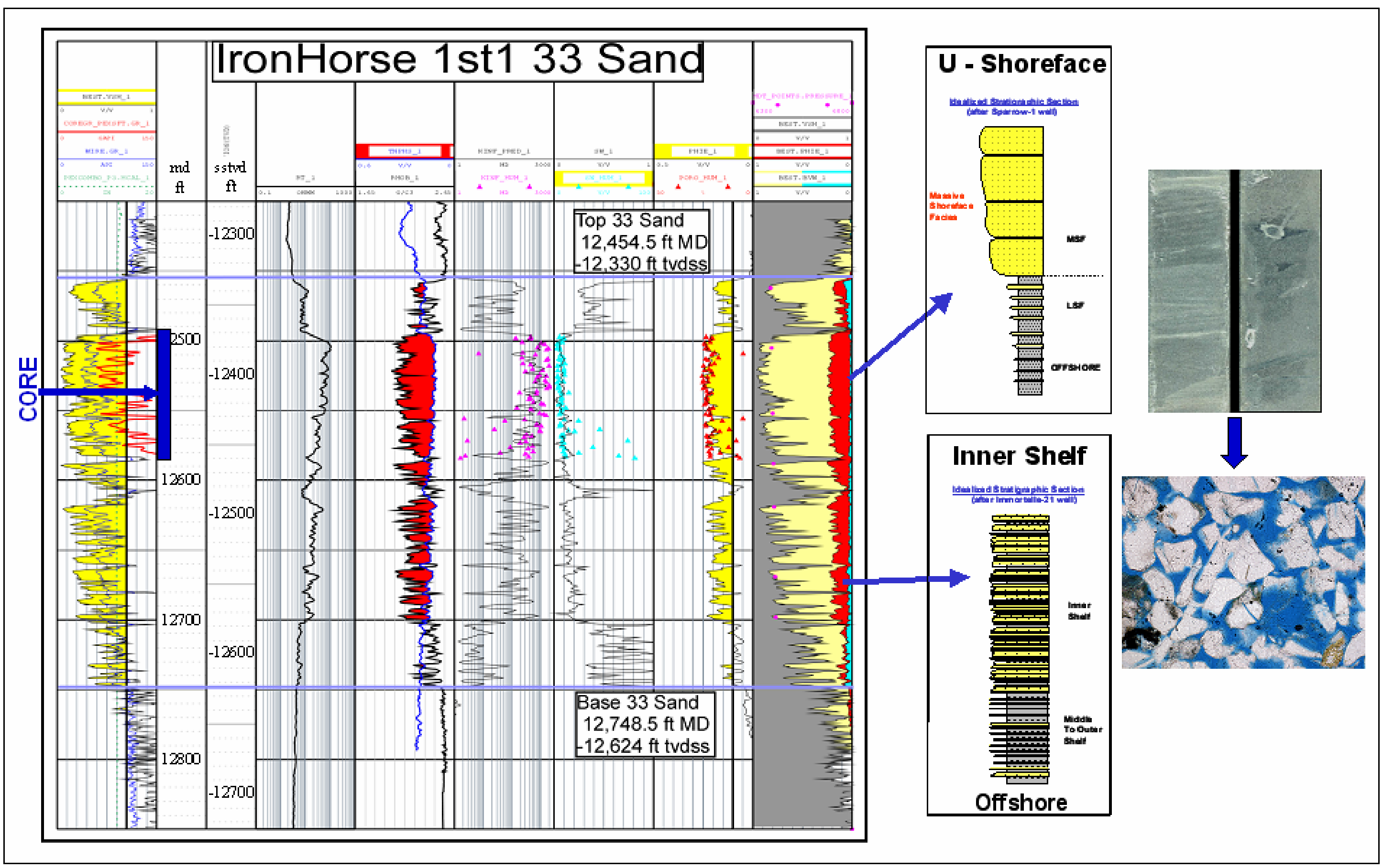

Figure A-3 Cannonball Log Section and Facies Description

	1	2	3	4	5	6
Tubing Size	7"	7-5/8"	9-5/8"	9-5/8"	9-5/8"	9-5/8"
Well Type	Conventional	Conventional	Conventional	Conventional	Slim Bore (Flow Thru Csg)	Slim Bore (Flow Thru Csg)
Upper Compl	Monobore	Monobore	Monobore	Variable Bore	Monobore	Variable Bore
Technical (Equipment)			• SCSSV delivery		• SCSSV delivery • Behind casing gauges	• Behind casing gauges
Technical (Well Design)			• New concept to bpTT	• New concept to bpTT	• Flow thru casing • MOE issue	• Flow thru casing • MOE issue
Commercial (incremental)	3 wells ($5.2 MM)	3 Wells $0 MM	2 Wells = ($0.26 MM) 3 Wells = ($1.94 MM)		2 Wells = $2.74 MM 3 Wells = $3.57 MM	
Project Risk						
Team Recommends		"Base Case" Well Design				

Figure A-4 Upper Completion Option Matrix (Note: Variable Bore is 7" Tree and 7" TR-SCSSV)

	1	2	3	4	5
Type	Barefoot	C&P - Random	C&P - Oriented	Screen Only	OHGP
Casing Strings	4	3	3	4	4
Technical (Sand Prod Risk[1])	No Sand	Sand Prod below 1700 psi	Sand Prod below 369 psi	No Sand	No Sand
Technical (Design Risk) (Execution Risk)		– Drilling rat hole in pressure ramp – Risk of water	– Drilling rat hole in pressure ramp – Risk of water – Risk of oriented perforating	– Lack of core over entire interval – Sorting / Uniformity – Drill-in Fluid sizing – Screen sizing	
Project Assurance (Sand Prod Risk)		– Sand production prior to well abandonment[2]			
Project Assurance (Rate Delivery Risk)				– Plugging of screen – High FLUX / Erosion	– Highest level of assurance for reliable delivery of maximum rates.

Figure A-5 Lower Completion (Sand Face) Option Matrix

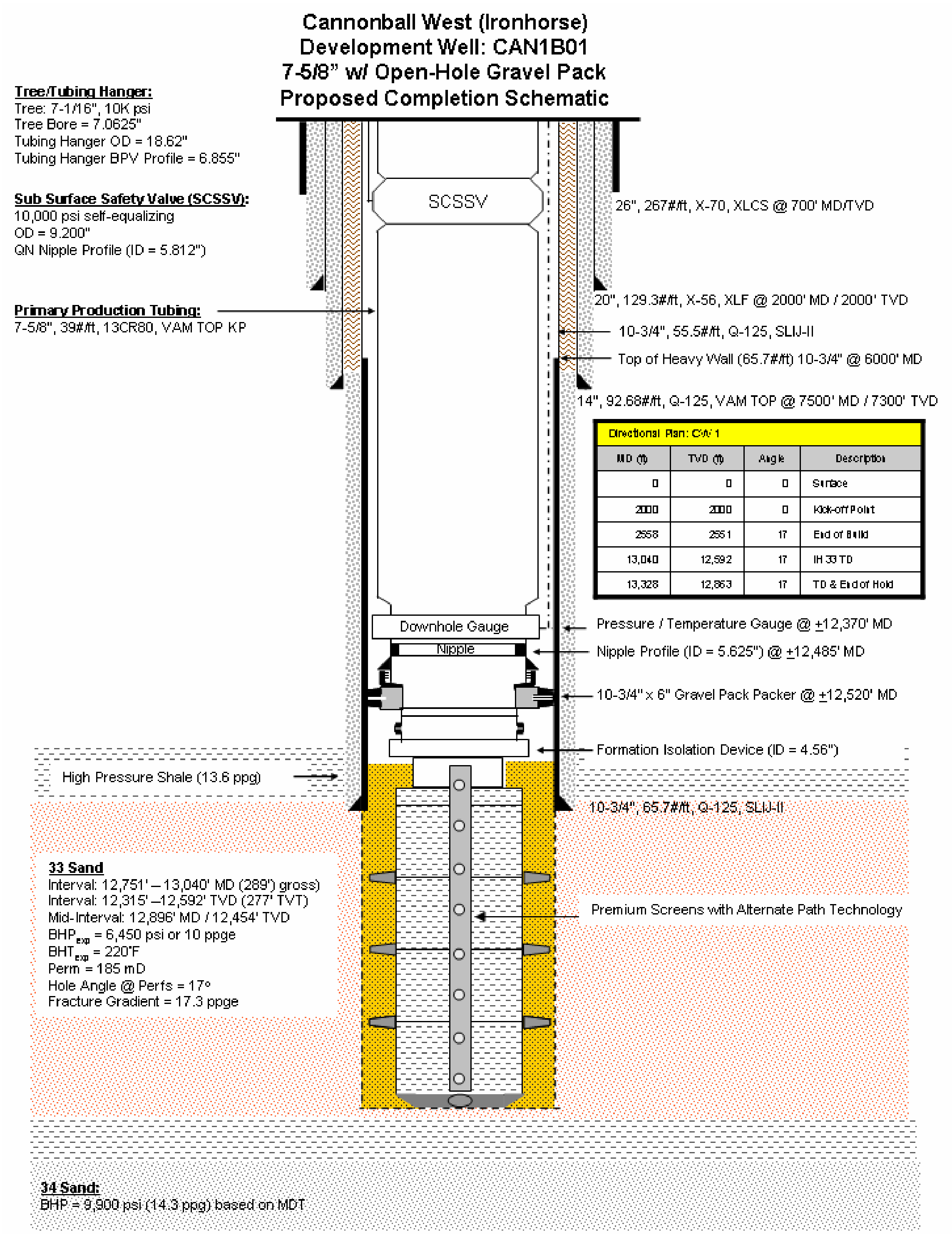

Fig A-6 Proposed Completion Schematic for Initial Cannonball Well

Scenario	1	2	3	4	5	6	7
Reservoir Pressure (psi)	6450	6000	5500	5000	4500	4000	3500
FWHP (psig)	3625	3330	2810	2250	1650	1300	1300
Gas Rate (MMCFPD)	280	280	280	280	280	260	230
Erosion Rates (mm/year)							
Node 1 (Tree)	0.024	0.027	0.035	0.049	0.153	0.305	0.190
Node 2 (Nipple @ 1500' MD)	0.055	0.062	0.077	0.113	0.259	0.420	0.323
Node 3 (FID @ 13,160' MD)	0.134	0.141	0.157	0.177	0.206	0.199	0.154
Node 1 (Tree)	0.004	0.005	0.006	0.010	0.028	0.065	0.040
Node 2 (Nipple @ 1500' MD)	0.009	0.010	0.013	0.020	0.045	0.082	0.065
Node 3 (FID @ 13,160' MD)	0.029	0.027	0.028	0.031	0.037	0.037	0.030

Table A-1 Summary of Results Erosion Rates (mm/yr) at 280 MMcf/D (Expected Rate). The yellow highlighted section is erosion rates without a liquid film barrier. The blue highlighted section is erosion rates with a liquid film barrier. Red font represents erosion rates that exceed BP's erosion limit of 0.1 mm/year.

Scenario	1	2	3	4	5	6	7
Reservoir Pressure (psi)	6450	6000	5500	5000	4500	4000	3500
FWHP (psig)	1300	1300	1300	1300	1300	1300	1300
Gas Rate (MMCFPD)	416	403	368	335	299	260	216
Erosion Rates (mm/year)							
Node 1 (Tree)	1.104	1.021	0.802	0.619	0.451	0.305	0.178
Node 2 (Nipple @ 1500' MD)	0.702	0.666	0.649	0.592	0.473	0.420	0.304
Node 3 (FID @ 13,160' MD)	0.417	0.398	0.345	0.297	0.249	0.199	0.145
Node 1 (Tree)	0.209	0.199	0.160	0.127	0.094	0.065	0.038
Node 2 (Nipple @ 1500' MD)	0.109	0.108	0.110	0.105	0.089	0.082	0.061
Node 3 (FID @ 13,160' MD)	0.078	0.072	0.060	0.052	0.044	0.037	0.028

Table A-2 Summary of Results Erosion Rates (mm/yr) at 400 MMcf/D (Technical Limit)

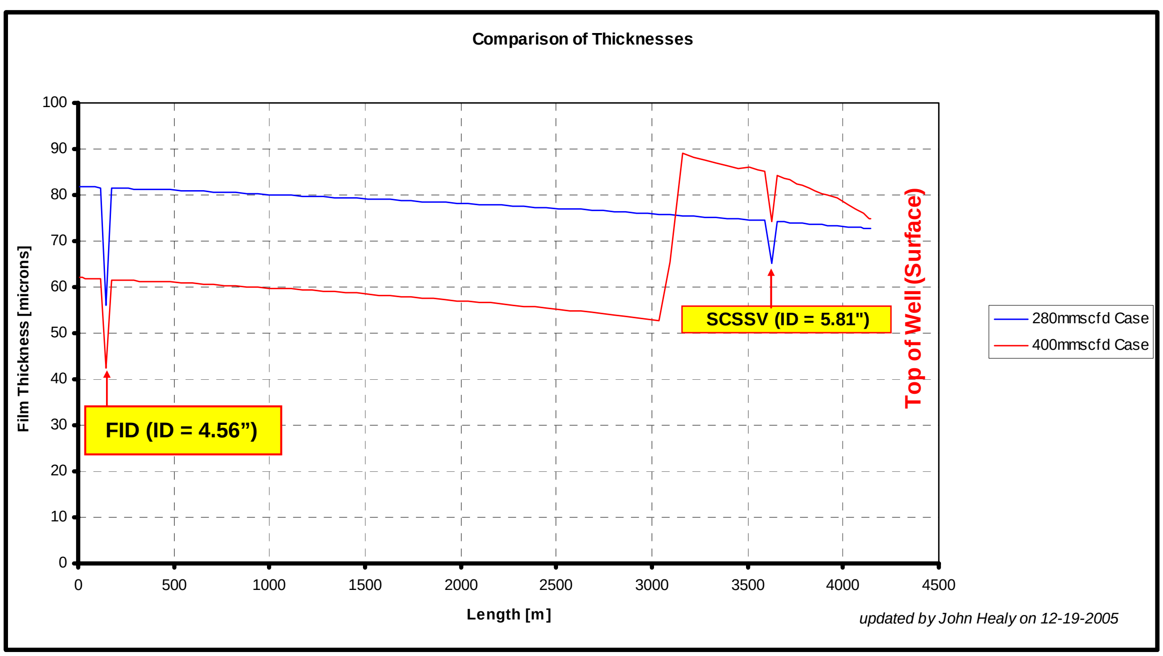

Figure A-7 Plot of Film Thickness from Lower Completion to Surface

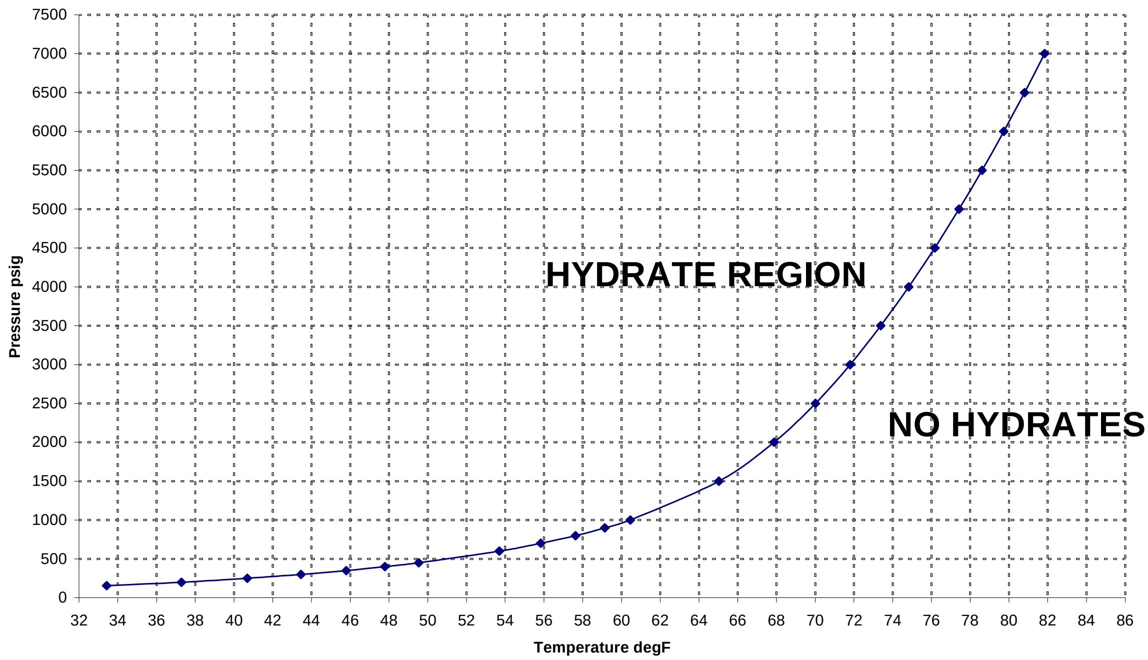

Figure A-8 Hydrate Dissociation Curve for Cannonball (Infochem Model Prediction)

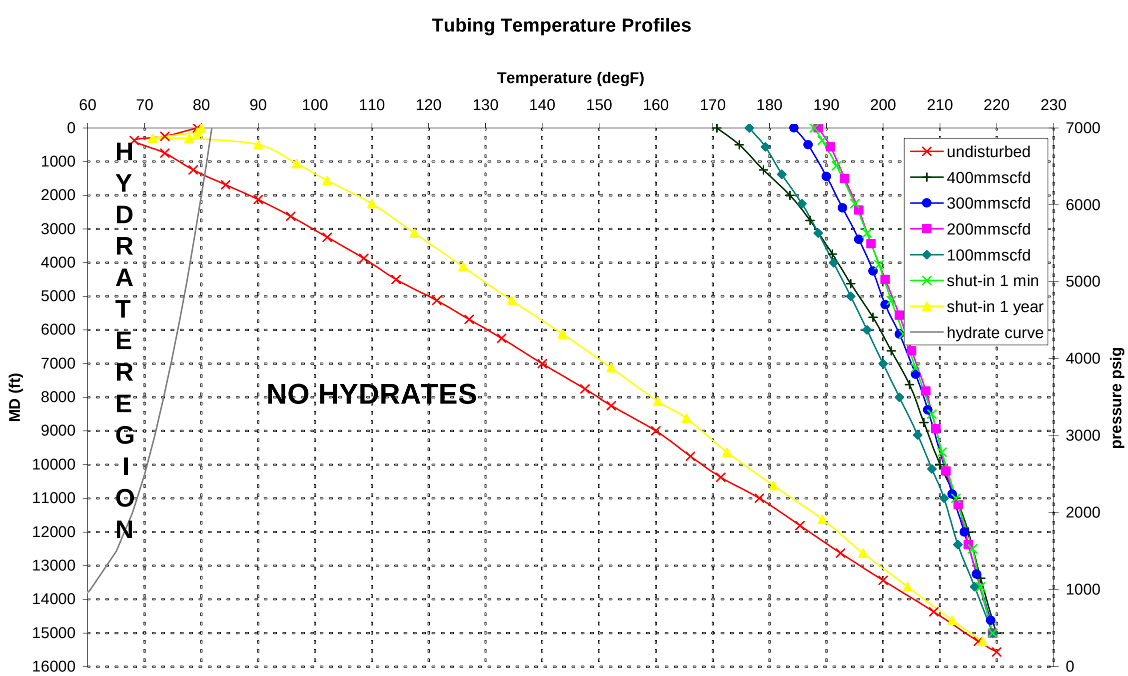

Figure A-9 Tubing Temperature Profiles with Hydrate Dissociation Curve for Cannonball Note: The temperature profiles are vs depth (ft) and the hydrate curve vs pressure (psig)

Load Case	Internal Pressure	External Pressure	Temperature
Running in Hole, 2 f/s	Seawater	Seawater	Undisturbed
Overpull, 100 kips			
Internal Pressure Test	5000 psi over completion fluid	Completion fluid	
External Pressure Test	Completion fluid	1500 psi over completion fluid	
Production	Various steady state rates	Completion fluid	As determined by Wellcat simulation
Start-up with tubing leak	Various rates at 10 minutes	6450 psi over completion fluid	
Cold Kill	1000 psi over seawater at 100 gpm	Completion fluid	
Hot Shut-In	5800 psi over Cannonball gas	Completion fluid	As determined by Wellcat simulation for highest flow rate
Cold Shut-In			Undisturbed
Evacuation	None	Completion fluid	Undisturbed

Completion fluid is 10.5 ppg brine
Cannonball gas uses standard correlations for SG = 0.665
The initial state is completion fluid inside and out at the undisturbed temperature.

Table A-3 Load Cases for Production Tubing

Component	Top (ft.)	Bottom (ft.)	Modeled As
Tubing	30	1967	7-5/8 in., 39 lb/ft, L80, Vam TOP
SCSSV	1967	1976	7 in., 32 lb/ft, L80, Vam TOP
Tubing	1976	12534	7-5/8 in., 39 lb/ft, L80, Vam TOP
Nipple	12534	12537	7 in., 29 lb/ft, L80, Vam TOP
Tubing	12537	13596	7-5/8 in., 39 lb/ft, L80, Vam TOP
Tubing and Accessories	13596	13986	7 in., 32 lb/ft, L80, Vam TOP

Table A-4 Tubing and Accessories as Modeled