Abstract

The Jubilee Field is a unitized deepwater oil development located approximately 60 km offshore Ghana. The field was discovered in June 2007 with first production achieved on November 28, 2010. This paper reviews the field’s reservoir description, gives an overview of the static and dynamic reservoir modeling process used to plan the first phase of field development, and describes how the uncertainty inherent in these models was reduced using dynamic data from long term interference testing conducted prior to field startup. Interference test results were used to evaluate inter-well reservoir connectivity over distances of several kilometers in a subsea environment and played an integral role in the reduction of uncertainty. This paper also describes the Phase 1 development strategy and reviews Jubilee waterflood performance.

Introduction

The Jubilee Field is located 60 km offshore Ghana in water depths averaging 1200 meters (Fig. 1). The field was discovered by Kosmos in June 2007 with the Mahogany-1 exploration well and contains two primary reservoir intervals, the Upper and Lower Mahogany. Fig. 2 is a type log showing the current and initial reservoir zonation nomenclature. The seventeen well Phase 1 development program targets the two most volumetrically significant reservoirs in these intervals, the MH4 (UM3) and the MH1 (LM2), and comprises nine producers, six water injectors, and two gas injectors. Fig. 3 shows the Phase 1 development well locations relative to the Jubilee Field unit boundary and the developed reservoir outlines. The dynamic inter-well connectivity and water injectivity levels achievable during waterflood were identified early on as key reservoir uncertainties. A June 2008 DST in the Mahogany-2 appraisal well had indicated potential compartmentalization within the Lower Mahogany interval. To reduce these uncertainties a four well long term interference test was initiated in the MH1 (LM2) reservoir in May 2009, eighteen months prior to field startup. Results from the interference testing established pressure continuity through the reservoir over distances exceeding 5 km, reduced the uncertainty in original-oil-in-place (OOIP), and confirmed pre-test water injectivity estimates. Field startup occurred November 28, 2010 and production has continued to ramp up as additional Phase 1 wells have been brought on line. A static and dynamic reservoir model uncertainty analysis constrained with a history match through January 2011 of the interference test pressures and only the first two months of field performance significantly reduced the uncertainty associated with Phase 1 waterflood performance. The work described in this paper was performed by a Kosmos-led multi-disciplinary Integrated Project Team (IPT) that included team members from Kosmos, Tullow, and Anadarko.

Reservoir Description

The exploration of the Tano Basin and the discovery of the Jubilee Field have been described previously by others (Ref. 1). The Mahogany-1 (M-1) exploration discovery well location was selected to test Late Cretaceous Turonian fan objectives identified with 3D seismic data. The well was drilled to a total depth of 3,802 m TVDss and encountered an estimated 98 m of net oil-bearing pay within a 271 m gross interval. The Hyedua-1 (H-1), Mahogany-2 (M-2), and Hyedua-2 (H-2) appraisal wells were drilled by the end of 2008 and confirmed a 250 m average gross interval of stacked, amalgamated turbidite channel and fan sands with net pay intervals ranging from 20 – 100 m TVD. Fig. 4 is an RMS amplitude extraction on the Mahogany Fan from 2009 showing the Jubilee Field unit boundary and the locations of the discovery and appraisal wells.

Zonation

The Upper and Lower Mahogany sections comprise the two primary hydrocarbon bearing intervals within the Jubilee Field (Fig. 2). A regionally extensive shale section separates the two intervals with an oil column pressure offset of 150 psi.
Fig. 5 is an oil excess pressure plot based on MDT pressures from three of the initial wells showing the six oil reservoirs and the two main oil-water contacts identified within the field. Fig. 6 is a cross reference to the reservoir zonation nomenclatures in use since field discovery. The MH4 (UM3) reservoir in the Upper Mahogany and MH1 (LM2) reservoir in the Lower Mahogany were the focus of the Phase 1 development program (Fig. 3).

**Rock Properties**

A total of 427 m of whole core was recovered from four cored wells (Fig. 7). Core measurements yielded pay interval porosities averaging 21% and permeabilities of several hundred mD. Fig. 8 is a porosity / permeability cross-plot showing the range of core measurements from the M-1 discovery well and the H-1 and H-1BP01 appraisal wells. The formation pore volume compressibility of 1.5 Msips obtained from core measurements is consistent with a well consolidated formation.

**Reservoir Fluid Properties**

An initial reservoir pressure of 5295 psia was measured at 3463 m TVDss in the M-1 discovery well and varies across the field from 5000 to 5700 psia as a function of TVD, overburden thickness, and water depth. The reservoir hydrocarbon fluids are under-saturated, moderately volatile black oils. The degree of initial under-saturation ranges from about 1200 psi near the MH1 (LM2) oil-water contact (OWC) to near bubble-point at the highest points in the reservoirs. Stock tank oil gravities ranging from 36 to 38 °API were measured in the lab on uncontaminated reservoir oil samples obtained from drill stem tests (DST’s). Corresponding single stage flash gas-oil ratios (GOR’s) ranged from 1.25 to 1.58 Mscf/STB. The field is currently producing at an average GOR of about 1.2 Mscf/STB. Initial formation volume factors range from 1.57 to 1.69 RB/Mscf. The uncontaminated reservoir oil viscosity measurements range from 0.16 to 0.3 cp at reservoir conditions and vary with solution GOR and oil gravity. A compositional gradient is evident in the field with in situ oil densities ranging from 0.68 g/cc near the MH1 (LM2) reservoir OWC to 0.58 g/cc in the up-dip regions of the MH5 (UM1 / UM2) reservoir (Fig. 5).

**Reservoir Interference Testing**

The Jubilee Phase 1 development program included mid-dip and up-dip producers supported by down-dip water injectors generally over distances of 1 to 5 km, though some of the Lower Mahogany producers are further from their corresponding injectors. Although DST’s of the M-2 and the H-2 wells had established the productivity of the Upper and Lower Mahogany intervals by January 2009, the reservoir injectivity, the dynamic connectivity between injectors and producers, and the degree of aquifer support were still untested. To reduce these uncertainties prior to field startup, a long term interference test was initiated in May 2009.

**Interference Test Geometry**

Fig. 9 shows the locations of the four wells used to conduct the MH1 (LM2) long term reservoir interference test. The M-1 discovery well (completed as the J-09 development well) and the H-1BP01 appraisal well (completed as the J-10wi water injector) were used to introduce production and water injection pressure pulses in the MH1 (LM2) reservoir interval, while the associated pressure responses were recorded in the J-02 and the J-04st1 observation wells. Although each of the four interference test wells contained at least two MH1 (LM2) sand lobes, the correlation and continuity of these lobes between wells was uncertain. Fig. 10 is a simple schematic showing the completion strategy used to maximize the likelihood of measuring a pressure response during the test. Commingled perforations were placed in each of the two main sand lobes present in the J-02 and J-04st1 pressure observation wells. The J-09 DST completion was limited to the lower sand lobe, while separate, isolated water injection tests were conducted in each sand lobe of the J-10wi well.

The program began in May 2009 with a J-09 DST consisting of three flow periods over seven days at rates up to and exceeding 20 MSTB/d after which the well was shut-in. The J-09 DST was followed five months later in October 2009 with a one day multi-rate water injection test in the lower sand lobe of the J-10wi well at rates up to and exceeding 25 MSTB/d. The lower lobe in the J-10wi well was then isolated, the upper sand lobe was perforated, and a similar water injection test was conducted in the upper sand lobe, but with a different injection signature to assist identification in the observation wells.

Continuous downhole pressure measurements were acquired from the mid-dip J-02 and the flank J-04st1 observation wells before the J-09 DST, and continued until late June 2010 when the J-02 well was completed for production. Additional pressure measurements were acquired in the J-04st1 well until early June 2011, six months after field startup, when final preparations were made to put the J-04st1 well on production. The pressure data were acquired in the two observation wells using specially equipped wellheads with pressure gauges queried acoustically from sea level by boat at periodic intervals to download the recorded data.

**Test Results**

Fig. 11 shows the pressure responses measured in the J-02 and J-04st1 pressure observation wells in response to the J-09 DST and the lower and upper sand lobe water injectivity tests in the J-10wi well. Because the interference testing was
conducted in a static reservoir prior to field startup and due to the high quality of the reservoir interval, small pressure changes could be observed through the reservoir over distances exceeding 5 km.

Pressure responses from the DST flow periods in the lower sand lobe of J-09 were detected in both observation wells less than a week from the beginning of the initial flow period. After the final J-09 DST shut-in, pressures in the observation wells began equilibrating to a post flow average reservoir pressure approximately 5 psi below initial. With a distance between J-04st1 and J-09 of only 1.4 km, the J-04st1 minimum observed pressure fell below the post DST average reservoir pressure and began building after an initial decline. Pressures measured in the more distant J-02 well, located 5.4 km down-dip, remained above the post DST average reservoir pressure and continued to fall as reservoir pressure equilibrated, confirming the absence of significant aquifer support.

Within two to three days of initial injection, clear indications of both the lower and upper lobe J-10wi water injection periods were seen in the J-02 well, located 1.8 km away. A single pressure response to water injection was seen within a week of injection start further up-dip in the J-04st1 observation well, located 6 km from J-10wi. The single J-04st1 pressure response potentially indicates that only one of the J-10wi injection sand lobes was in pressure communication with the J-04st1 or that the two injections pulses had amalgamated over the 6 km distance. Prior to field startup, a history match of the dynamic reservoir model to these interference test pressures was used to reduce the uncertainty in MH1 (LM2) reservoir OOIP volumes and define the most likely lateral extent and vertical transmissibility of the shale interval between the upper and lower MH1 (LM2) sand lobes.

**Static and Dynamic Reservoir Uncertainty Modeling**

An integrated static and dynamic reservoir uncertainty analysis was performed to quantify the range of original oil in place and Phase 1 development ultimate recovery estimates associated with reservoir description input data uncertainties (Fig. 12). Unlike a simple Monte Carlo analysis of the volumetric oil in place calculation with recovery factor treated as an uncertainty, this approach rigorously captured the effects of not only the static uncertainties impacting original oil in place, but also the dynamic uncertainties and reservoir flow physics determining ultimate recovery.

**Static Reservoir Modeling**

The IPT subsurface team constructed 540 discrete fullfield Jubilee static geomodel realizations using a Petrel uncertainty workflow (Fig. 12, upper left). Key static model input uncertainties for each of the six reservoir intervals included net to gross (NTG), permeability and porosity distributions, initial water saturation distribution, and OWC depth.

Low, mid, and high NTG maps were constructed for each of the six reservoirs and used to condition the distribution of reservoir pay facies. Low, mid, and high variograms were used to distribute porosity within the pay facies. Permeabilities were distributed using a cloud transform to approximate the core based permeability / porosity relationship (Fig. 8). Initial water saturations were distributed in a similar fashion using a core based water saturation / porosity relationship. The combination of three NTG maps, three porosity variograms, and ten realizations for each NTG / porosity combination gave a total of ninety static geomodels for each of the six reservoirs. Allowing these descriptions to vary independently by reservoir resulted in a total of 540 fullfield static model realizations. The initial OWC location in each reservoir was also allowed to vary, with larger ranges specified for reservoirs without drilled contacts or contacts that could be inferred from MDT pressures.

Since it was impractical to upscale and carry all 540 static models through dynamic flow simulation, the fine scale models were screened at the reservoir level and a subset of descriptions was selected for flow modeling. A reservoir connectivity index (C.I.) quantifying the degree of pay continuity was calculated for each of the ninety fine scale realizations at the reservoir level and cross-plotted against realization OOIP (Fig. 12, upper middle). The IPT subsurface team used these crossplots to select nine static model realizations (three C.I. levels for each of three NTG levels) from the ninety realizations available for each of the six reservoirs. The team interrogated each of the selected reservoir level realizations to ensure their validity, choosing alternate realizations when necessary. The selected realizations were then upscaled for use in dynamic flow simulation. Allowing the nine reservoir level descriptions to vary independently for each of the six reservoirs resulted in a total of fifty-four fullfield upscaled static model realizations carried into dynamic flow modeling.

**Dynamic Reservoir Modeling**

The fifty-four fullfield upscaled static model realizations were carried into dynamic reservoir flow modeling as discrete input uncertainties and incorporated in a performance prediction uncertainty analysis of the Phase 1 development program. The performance prediction uncertainty analysis was constrained by a history match of the pressure responses measured during the long term interference test (Fig. 12).

The dynamic uncertainty analysis was performed using the EnABLE history matching and uncertainty analysis tool coupled with an ECLIPSE black oil reservoir simulation model. The IPT subsurface team identified the key dynamic model
input uncertainties and assigned appropriate min and max values for each. The static model realization was specified using six separate pairs of NTG and connectivity uncertainties (one pair for each reservoir). Low, mid, and high values were specified independently for each of the twelve NTG and connectivity uncertainties resulting in fifty-four possible fullfield static geomodel realizations (3 NTG choices x 3 connectivity choices x 6 reservoirs). Within the MH1 (LM2) reservoir, the lateral extent and transmissibility of the shale interval separating the upper and lower sand lobes were varied in ECLIPSE as continuous input uncertainties. Continuous transmissibility multipliers ranging from zero to one were also applied across potentially sealing subzone interfaces identified from seismic data within the two major Phase 1 reservoirs. Continuous global permeability multipliers were applied by reservoir to adjust the average permeability level while preserving the permeability variation from the static model. Other continuous input uncertainties included residual oil saturation to water, Sorw, residual oil saturation to gas, Sorg, and Corey relative permeability exponents for oil and water. Endpoint relative permeability values for water and gas were treated as continuous dependent uncertainties calculated as functions of Sorw and Sorw. Formation pore volume compressibility and vertical permeability were also included as continuous uncertainties. Separate ranges of completion skin were considered for producers, water injectors, and gas injectors.

The ECLIPSE simulation runs included a history match of the long term interference test followed by a prediction of Phase 1 development performance. The J-09 and J-10wi wells were placed on rate control during the long term interference testing periods while matching the simulated pressure responses in the J-02 and J-04st1 observation wells to the recorded pressure histories. Wells were placed on THP (tubing head pressure) control during the prediction phase of the simulation.

The uncertainty analysis began with several dozen ECLIPSE model scoping runs made through the long term interference test and Phase 1 development life of field predictions using EnABLE to vary the dynamic model input uncertainties over their specified ranges. The ability to bracket observed field history with simulated values from the scoping runs provided a quick check on the validity of the static reservoir models and the input uncertainty ranges. Fig. 13 compares the simulated observation well pressures from all of the simulation runs with the actual values recorded in the field.

Match points placed on the observation well pressure histories and prediction confidence points placed on reservoir and fullfield simulated OOIP and ultimate recovery were used to build and continuously update a proxy model of the ECLIPSE flow model as each simulation run was completed. EnABLE then used the proxy model to select input uncertainty values for subsequent ECLIPSE runs to simultaneously improve both the proxy model and the ECLIPSE history match. At periodic intervals the proxy model was run through several thousand prediction cycles to generate prediction confidence intervals (P90/P50/P10) for OOIP and ultimate recovery honoring user specified input uncertainty distributions refined with history match results. The process ended when several acceptable history matches had been obtained and the prediction confidence intervals on OOIP and ultimate recovery had converged. Fig. 14 shows the interference test observation well pressure matches obtained for the three best match runs.

After the prediction uncertainty analysis was complete, a cross plot of ultimate recovery vs. OOIP for all of the ECLIPSE simulation runs was used to select three simulation runs to represent low, mid, and high fullfield outcomes for Phase 1 recovery and OOIP (Fig. 15). Each point on the cross plot corresponds to a specific ECLIPSE simulation run result and Petrel geomodel realization. The point color corresponds to the quality of the history match, with red points representing the best matches. The vertical and horizontal dashed lines are P90, P50, and P10 confidence intervals for ultimate recovery and OOIP calculated from the proxy model. Simulation runs representing low, mid, and high outcomes were selected for best match runs nearest the intersections of the ultimate recovery and OOIP confidence intervals. The selected simulation runs were then reviewed at the well level by the IPT subsurface team to ensure that they represented reasonable history matches and life of field performance predictions.

The long term interference test significantly reduced the pre field startup uncertainty in the MH1 (LM2) reservoir OOIP and pressure continuity between the interference test wells. The difference between the P10 and P90 OOIP values expressed as a fraction of the P50 OOIP was 40% lower for the interference test constrained MH1 (LM2) reservoir than the MH4 (UM3) reservoir, which was not part of the interference testing. The interference test match also provided valuable information regarding the inter-well correlation and OOIP of the MH1 (LM2) upper and lower sand lobes. In the best match simulation runs the lower sand lobe in the J-10wi and the J-02 were pressure isolated from the upper sand lobes in these wells, with the lower sand lobe terminating just up-dip of the J-02 well. Fig. 16 shows the reservoir compartments resulting from the history match. Subsequent detailed seismic mapping at the subzone level has confirmed that this is a possible lower unit geometry. In light of these results and given more time and budget, a similar interference test in the Upper Mahogany would also likely have proved to be very valuable.

Waterflood Performance History

The Jubilee Field was brought on production on November 28, 2010 with the startup of the J-02 production well (Fig. 17). Water injection began three days later with injection into the J-12wi well (Fig. 18). Over the following months, additional Phase 1 producers and water injectors were brought on line as they were completed. J-06st1 was the last well
brought on line, starting up in October 2011. Sustained field gas injection began in April 2011 into the J-16gi gas injector following commissioning of the gas injection system. By the end of October 2011 the field had produced over 20 MMSTB of oil and field production and injection rates had reached approximately 80 MSTB/d of oil, 200 MSTB/d of water injection, and 95 MMscf/d of produced gas injection. The field was producing at a stabilized solution GOR of 1.2 Mscf/STB and a zero water-cut. Field ramp-up has been below that planned due to schedule slippage caused by completion issues in the J-01 well, the absence of a third water injection pump until August 2011, and lower than predicted productivity in a few Upper Mahogany interval wells.

The Phase 1 development program consists of nine producers, six water injectors, and two gas injectors and targets the MH1 (LM2) and MH4 (UM3) reservoirs (Fig. 3). In both reservoirs the water injectors are located down-dip supporting producers in both mid-dip and up-dip locations, with distances between water injectors and producers ranging from 1 to 5 km. All produced gas in excess of fuel requirements is injected up-dip in the MH4 (UM3) reservoir. To minimize the potential of gas breakthrough in the up-dip producers, the total gas injection stream is currently being injected into the J-16gi well, the furthest up-dip of the two gas injection wells. The second gas injection well, the J-17st1gi, was located down-dip of a seismic dim separating the two gas injectors in case the up-dip gas injector proved to be located in a limited reservoir volume. For similar reasons, the J-03 producer was placed up-dip of the seismic dim to provide additional reservoir voidage for J-16gi injection if necessary. Stabilization of the J-16gi’s gas injection rate and WHP suggests that there is pressure continuity across the seismic dim.

Water/oil mobility ratios derived from Jubilee SCAL and PVT experiments were favorable for waterflooding ( < 1 in both reservoirs). Gravity drainage is also likely to play a role in the recovery process due to high permeabilities, low in situ oil viscosities, and the SW-NE reservoir dip. Due to the uncertainty of aquifer support, the FPSO water injection system was sized to provide full voidage replacement. To maximize pressure support for high rate up-dip producers under these conditions as well as offset any injection losses, excess water injection capacity was also included to allow for an initial period of over-injection. This was in response to early reservoir simulation results that predicted large viscous pressure drops between injectors and producers.

The interwell pressure communication observed in the pre-startup MH1 (LM2) long term interference test has been born out by waterflood performance of both Phase 1 reservoirs. Pressure buildups obtained prior to the start of water injection show no evidence of constant pressure boundaries. After the start of water injection constant pressure boundaries are required to match pressure buildups in most of the producers. Clear indications of water injection support located over 5 km away have been seen in the up-dip J-09 MH1 (LM2) producer (Fig. 3). Prior to the startup of the J-11wi injector designed to support the J-07st1 MH4 (UM3) producer, a constant pressure boundary was seen in a J-07st1 pressure buildup. The only active water injector in the reservoir at that time was the J-12wi, designed to support the J-08 producer in another channel system and located nearly 4 km away from J-07st1 (Fig. 3).

As has been noted by the various Partner companies, the Contractor Group has experienced more recent challenges in reaching the facility design oil rate capacity of 120,000 bbl/d primarily due to producer well completion issues. Oil production at Jubilee has been between 70,000 to almost 90,000 bbl/d during 2011. These issues and an on-going recovery program are reviewed in the companion paper OTC 23428 “Jubilee Field Development – the In-country Activities and their Impact.” However, in summary, the productivity decline observed in some producers is thought to be mainly due to a conservative initial well design with respect to frac-pack sand control proppant and screen sizing, where only early core data was available to make the selections. This appears to have later led to gradual blocking of the sand control equipment due to formation fines migration. Upgraded completion designs are now being installed in sidetracks or workovers of the problematic initial completions.

Conclusions
A long term reservoir interference test conducted in one major reservoir prior to field startup significantly reduced the uncertainty around OOIP, water injectivity, and producer / injector connectivity over distances exceeding 5 km in a deepwater subsea environment. The test results remain an integral component of the dynamic model history match as it is periodically updated with field performance data.

An integrated static and dynamic model uncertainty analysis comprising 100’s of static model realizations and dynamic flow model predictions was successfully used to define field performance prediction uncertainty ranges resulting from multiple static and dynamic input uncertainties. Coupled with a dynamic reservoir simulator, the assisted history matching and uncertainty analysis software was able to identify multiple acceptable history matches of the long term interference test pressures nearly halving the OOIP uncertainty of the tested reservoir.

During its first year of production the Jubilee field has reached sustained field oil rates exceeding 80 MSTB/d and demonstrated the ability to support mid-dip and up-dip producers with down-dip water injection. Constant pressure
boundaries required to match pressure buildup pressure transient analyses after the start of water injection provide conclusive indications of water injection support. Water injection support has been seen in nearly all of the Jubilee producers at distances up to and exceeding 5 km. A Phase 1A development infill drilling program will increase ultimate recovery by improving waterflood sweep efficiency with the addition of up to a total of eight new producers and water injectors.

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References
Figures

Fig. 1 - Jubilee Field location map (June 2011)

![Fig. 1 - Jubilee Field location map (June 2011)](image)

Fig. 2 – Mahogany-1 discovery well type log

![Fig. 2 – Mahogany-1 discovery well type log](image)
Fig. 3 - Phase 1 development well locations

Fig. 4 - Mahogany Fan RMS amplitude extraction showing the M-1 discovery well and H-1, H-2, & M-2 appraisal well locations
Fig. 5 - Oil excess pressure plot for M-1 discovery and H-1 & M-2 appraisal wells showing Jubilee reservoirs

(Reference oil datum = 5588 psia at 3625 m TVDss)
(Reference oil density = 0.64 g/cc)

Fig. 6 - Jubilee field reservoir zonation nomenclature
Fig. 7 – Jubilee Field H-2 appraisal well MH4 (UM3) interval core photos

![Core photos](image-url)

Fig. 8 - Core porosity vs. core permeability crossplot from M-1, H-1, and H-1 BP01 cores

![Core porosity vs. permeability crossplot](image-url)
Fig. 9 - MH1 (LM2) reservoir long term interference test geometry

MH1 (LM2) reservoir outline

J-09 DST

J-10wi injection test

J-02

J-04st1

J-09 (M-1)

1.8 km

3.6 km

1.4 km

Fig. 10 – Interference test completion intervals and observed pressure responses (brackets indicate level of pressure and/or rate measurement)

Upper & Lower J-10wi pulse seen in J-02

J-09 DST production pulse in J-4st1 & J-02

Upper J-10wi injection pulse seen in J-04st1
Fig. 11 – Pressure response measured in J-04st1 & J-02 observation wells resulting from J-09 DST and J-10wi water injection

Fig. 12 - Static and dynamic reservoir modeling uncertainty analysis workflow
Fig. 13 – Simulated vs. actual interference test observation well pressure change (psi) - All runs

Fig. 14 - Simulated vs. actual interference test observation well pressure change (psi) - Three best match runs
Fig. 15 - Phase 1 recovery vs. OOIP cross plot showing low, mid, and high cases selected from dynamic uncertainty analysis

Fig. 16 - MH1 (LM2) interwell flow unit correlations from best match simulation runs

Upper & Lower J-10wi pulse seen in J-02
J-09 DST production pulse in J-4st1 & J-02
Upper J-10wi injection pulse seen in J-04st1
Fig. 17 - Jubilee Field oil rate history

Fig. 18 - Jubilee Field water and gas injection rate history