# Montara H1 ST1 Well Release

## Incident Report

Document No: #143203

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<tr>
<th>Revision</th>
<th>Date</th>
<th>Reason for Issue</th>
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<td>0</td>
<td>02/10/09</td>
<td>Issued to NOPSA</td>
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<td>A</td>
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## 1. DEFINED TERMS

<table>
<thead>
<tr>
<th>Term</th>
<th>Meaning</th>
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<tbody>
<tr>
<td>Atlas</td>
<td>Atlas Drilling (S) Pte Ltd, a subsidiary of Seadrill Ltd</td>
</tr>
<tr>
<td>BOPs</td>
<td>Blow Out Preventers</td>
</tr>
<tr>
<td>CST</td>
<td>Central Standard Time</td>
</tr>
<tr>
<td><strong>Designated Authority</strong></td>
<td>The Northern Territory Department of Regional Development, Primary Industry, Fisheries and Resources exercising, under delegation, powers of the Designated Authority in respect of the Territory Of Ashmore &amp; Cartier Islands offshore area under the Offshore Petroleum and Greenhouse Gas Storage Act 2006</td>
</tr>
<tr>
<td>ERG</td>
<td>PTTEPAA’s Emergency Response Group</td>
</tr>
<tr>
<td>GOC</td>
<td>Gas-Oil Contact</td>
</tr>
<tr>
<td>H1 Well</td>
<td>Montara H1-ST1 Development Well</td>
</tr>
<tr>
<td>Halliburton</td>
<td>Halliburton Australia Pty Ltd</td>
</tr>
<tr>
<td>Java Constructor</td>
<td>Java Constructor construction barge</td>
</tr>
<tr>
<td>MODU Facility</td>
<td>West Atlas Jack-Up Mobile Offshore Drilling Unit Facility</td>
</tr>
<tr>
<td>MODU Safety Case</td>
<td>Atlas’ Safety Case and Safety Case Revision For The MODU Facility Operations In Relation To The Montara Development Wells</td>
</tr>
<tr>
<td>MOSOF Regulations</td>
<td>Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996</td>
</tr>
<tr>
<td>OIM</td>
<td>Offshore Installation Manager</td>
</tr>
<tr>
<td>POB</td>
<td>personnel on board</td>
</tr>
<tr>
<td>PTTEPAA</td>
<td>PTTEP Australasia (Ashmore Cartier) Pty Ltd</td>
</tr>
<tr>
<td>NOPSA</td>
<td>National Offshore Petroleum Safety Authority</td>
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<tr>
<td>SIMOPS</td>
<td>simultaneous operations</td>
</tr>
<tr>
<td>SMS</td>
<td>safety management system</td>
</tr>
<tr>
<td><strong>Well Management Regulations</strong></td>
<td>Petroleum (Submerged Lands) (Management Of Well Operations) Regulations 2004</td>
</tr>
<tr>
<td>WHP</td>
<td>Montara Wellhead Platform</td>
</tr>
<tr>
<td><strong>WHP Construction</strong></td>
<td>PTTEPAA’s Safety Case For The Construction And Installation Stage In The</td>
</tr>
</tbody>
</table>

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2. INTRODUCTION

2.1. PURPOSE OF THIS REPORT

In accordance with Regulation 46(2)(c) of the Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996 (“MOSOF Regulations”), PTTEP Australasia (Ashmore Cartier) Pty Ltd (“PTTEPAA”) notified NOPSA on 21 August 2009 of an uncontrolled release of petroleum liquids and hydrocarbon vapour from the Montara H1-ST1 development well (“H1 Well”) located at the Montara Wellhead Platform (“WHP”) facility.

PTTEPAA submitted a written report of this dangerous occurrence to the National Offshore Petroleum Safety Authority (“NOPSA”) on 25 August 2009 (Our Ref: #142366) which included the information on the incident that is required by NOPSA’s Determination made under MOSOF Regulation 46(2)(c) other than items 20 and 21.

As contemplated by NOPSA’s Guidance on Notification and Reporting of Accidents and Dangerous Occurrences, this report is PTTEPAA’s full report to NOPSA on this incident which includes the information required by items 20 and 21 of the Determination made under MOSOF Regulation 46(2)(c), namely:

(i) a root cause analysis; and
(ii) actions to prevent recurrence of incident with responsible party and completion date.

2.2. DESCRIPTION OF INCIDENT

The incident involves an uncontrolled release of petroleum liquids and hydrocarbon vapour emanating from the H1 Well, without ignition.

The H1 Well is located at the WHP facility in production licence AC/L7 in the Timor Sea, approximately 690 kilometres west of Darwin. The WHP is located in 77 metres of water. The coordinates of the WHP and the H1 Well are set out below.

<table>
<thead>
<tr>
<th>Montara WHP</th>
<th>Well H1 ST1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Latitude</td>
<td>12° 40’ 20.5” S</td>
</tr>
<tr>
<td>Longitude</td>
<td>124° 32’ 22.3” E</td>
</tr>
</tbody>
</table>

The West Atlas Jack-Up Mobile Offshore Drilling Unit facility (“MODU facility”), operated by Atlas Drilling (S) Pte Ltd (“Atlas”), was positioned alongside the WHP facility on 19th August 2009 for the primary purpose of carrying out a drilling and completion program for the Montara
development wells and a secondary purpose of providing accommodation and access for personnel intending to complete electrical pre-commissioning work on the WHP facility.

On 21 August 2009 at 0530 hours (CST) there was a small release (estimated at approximately 40bbls) of hydrocarbons from the H1 Well. The MODU facility’s drilling package was centred over the Montara H4 development well at the time of the incident. After the initial release of hydrocarbons, preparations were made to skid the MODU facility’s drilling package over the H1 Well. At 0723 hours (CST) a further uncontrolled release of hydrocarbons from the H1 Well occurred and continued unabated. All 69 personnel on board proceeded to abandon the MODU facility utilising its life boats and were safely evacuated to a nearby facility and subsequently to Darwin. The H1 Well continued to flow a mixture of oil, water, condensate and gas.

2.3. CURRENT SITUATION

The well release from the H1 Well is not ignited. Currently, the uncontrolled well is emitting a quantity of oil, gas and water, including water vapour, into the environment. The stream is impacting the underside of the cantilever of the MODU facility. The cantilever of the MODU facility’s derrick is skidded across the helideck of the WHP facility. The hatch in the WHP facility’s helideck above the H1 Well (only) is open, leaving a clear path for the well fluids to pass through that gap, where those fluids are then impinging on the underside of the MODU facility’s drill floor and causing collection of a gas cloud in the bottom of the drill derrick. Hydrocarbon liquid fallout is leading to pooling of oil on the WHP facility’s helideck which is draining overboard.

Another MODU facility, the West Triton, also operated by Atlas, is being used to drill a relief well with the objective of “killing” the uncontrolled well by intersecting the original well and allowing drilling fluids to be injected, cutting off the flow of hydrocarbons from the original well to the current release location at the WHP facility. Current scheduling indicates achievement of the relief well objective in early October 2009. Once the kill fluid in the H1 Well is confirmed to be an effective barrier stopping the flow of hydrocarbons, the intention is to arrange for personnel to board the WHP facility with the objective of utilising a slickline unit to set plugs in the H1 Well.

2.4. WELL INTEGRITY AND SAFETY MANAGEMENT

2.4.1. MANAGEMENT OF WELL INTEGRITY RISKS

PTTEPAA manages well integrity risks by implementing the Well Construction Management component of its business management system. The PTTEP Australasia Well Construction Standards are part of this PTTEP Australasia Well Construction Management System. The purpose of the Well Construction Standards is to provide minimum standards for all aspects of well design, construction, testing, abandonment and intervention that involve a risk to safety, quality or integrity. The Well Construction Standards are applicable to all aspects of well design, well construction and well servicing and well abandonment.
PTTEPAA’s Well Construction personnel applied the PTTEPAA Well Construction Standards to the process of identifying, assessing and managing the risks associated with the drilling, suspension and completion of the Montara field development wells, including when:

a) formulating and approving the drilling programs;

b) supervising the implementation of the drilling programs by the MODU facility personnel; and

c) managing the implementation of any changes or deviations from those drilling programs.

PTTEPAA prepared a Well Operations Management Plan (“WOMP”) in respect of the drilling and completion of each of the Montara development wells. The WOMP illustrates how the PTTEPAA Well Construction Management system ensures that drilling activities in respect of the wells meet the requirements of the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004 (“Well Management Regulations”), specifically that:

(i) the design and implementation of downhole activities is in accordance with an accepted well operations management plan; and

(ii) risks are identified and managed in accordance with sound engineering principles and good oil field practice.

Following the ‘roadmap’ format advocated by the Western Australian regulator at the time of inception of the Well Management Regulations, the WOMP describes the PTTEPAA management system applicable to maintaining the integrity of, and managing the risks associated with, well operations, by directing the user to the PTTEPAA Well Construction Standards and Drilling Programs.

2.4.2. MANAGEMENT OF SAFETY RISK

The process of managing hazards associated with well operations is interfaced with the process of managing the health and safety of persons at the facility utilised for carrying out the well operations. The objective of this interface is to reduce the safety risk associated with well integrity hazards to as low as reasonably practicable.

PTTEPAA was responsible for the design of the H1 Well and the formulation of the Drilling Program that set out the operations required to construct the H1 Well and recorded a risk assessment of the hazards associated with the operations to construct the H1 Well. Atlas is responsible for the execution of the drilling operations in compliance with the MODU facility safety case revision. PTTEPAA’s Well Construction Standards provide that any conflicts between the PTTEP Australasia Well Construction Standards and the standards of the operator of the MODU facility carrying out the well operations must be detailed in the Safety Case Revision for the MODU facility which must specify the standard (PTTEP Australasia or MODU Facility Operator) that must be used.
Prior to the commencement of the MODU facility’s Montara Development drilling campaign, PTTEPAA facilitated a HAZID workshop in order to ensure that the personnel of Atlas and other third party well services providers were informed of the PTTEPAA Well Construction Standards and the hazard identification and mitigation carried out in the process of designing the Montara field development wells. Following this workshop, a revision to the MODU facility’s safety case was prepared for review and approval by Atlas and PTTEPAA, and submission to NOPSA. The MODU facility safety case revision for the Montara Development drilling campaign identifies the techniques for ongoing hazard identification and risk management as being the Atlas’ Safety Management System in place at the MODU facility and the PTTEPAA Well Construction Management System pertaining to the design of the wells. The safety case revision is the mechanism by which those two systems are interfaced. It provides that Atlas’ Drilling Operations Manual and PTTEPAA’s Drilling Programs are the reference documents for well operations carried out at and by the MODU facility, and that the latter will prevail in the event of conflict.

This safety case revision functions as the direction to all personnel, whether engaged by Atlas or PTTEPAA, to manage safety risk associated with well hazards by carrying out well operations in accordance with the MODU facility’s safety management system and the PTTEPAA Drilling Programs. The safety case revision contains Atlas’ agreement to apply the PTTEPAA Drilling Program and the PTTEPAA Well Construction Standards when utilising the MODU facility’s safety management system to the ongoing identification, assessment and mitigation of well control hazards. It also states that Atlas’ JSA process is to be applied to the use of equipment supplied by PTTEPAA for well operations and that the storage and handling of equipment on the MODU facility is subject to Atlas procedures.

The MODU facility safety case revision also establishes the organisational structures and communications protocols that are the mechanism by which the PTTEPAA Drilling Program is implemented by the MODU facility operator using well equipment and well services free-issued to Atlas by PTTEPAA for use in the course of the MODU operations on the wells. The MODU facility’s organisation structure (as referenced in its SMS) is set out in Appendix 1. This structure is adopted through the MODU facility safety case revision process with the objective of ensuring that the interface of the PTTEPAA well construction management system with Atlas’ drilling operations management system is effective in achieving the objectives of the PTTEPAA Drilling Programs in a manner that is without risk to the health and safety of personnel at the facility. PTTEPAA contracts the services of Drilling Supervisors (who report to the Drilling Superintendent and Well Construction Manager contracted by PTTEPAA). PTTEPAA’s Drilling Supervisors carry out the role of on-site supervision and verification of the well operations managed by Atlas at the MODU facility, in particular that those operations are carried out in accordance with the Drilling Programs and the WOMP approved under the Well Management Regulations. The Drilling Supervisors have a line of communication with the MODU facility’s Offshore Installation Manager (“OIM”). This enables the Drilling Supervisor to assist the MODU facility OIM to manage the third party well services contractors and to ensure that the workforce (MODU crew and services contractors) understand and implement the requirements of the PTTEPAA Drilling Program. The Drilling Supervisors and the OIM refer to the PTTEPAA Drilling Program (including any deviations or changes thereto implemented via the change control process in the PTTEPAA Well Construction Standards) and use it to settle the ‘Instructions to
Drillers’ which the OIM then communicates to the MODU drilling crew (who report to the OIM) and third party well services providers engaged in the well operations.

2.4.3. WELL OPERATIONS REGULATORY APPROVALS

Pursuant to clause 17(1)(a) of the Well Management Regulations, the Designated Authority approved:

a) the drilling of the H1 Well as detailed in PTTEPAA’s drilling program entitled Montara GI, H1 & H4 (Batch Drilled) Drilling Program Document Number TM-CR-MON-B-150-00001 Rev 0 dated September 2008;

b) the sidetracking of the H1 Well as detailed in PTTEPAA’s application submission dated 27 February 2009;

c) the suspension of the H1 Well as detailed in PTTEPAA’s application submissions dated 6 March 2009 and 12 March 2009; and

d) the drilling the horizontal reservoir sections of, and completion of, the H1 Well as detailed in PTTEPAA’s drilling program entitled Montara Phase 1B Drilling and Completion Program Document Number TM-CR-MON-B-150-00003 Rev 0 dated June 2009.

Pursuant to clause 8(1)(a) of the Well Management Regulations, the Designated Authority approved PTTEPAA’s WOMP for the H1 Well, Document Number TM-CR-MON-G-150-00002 Rev 0 dated November 2008.

2.4.4. SAFETY REGULATORY APPROVALS

The operator of the WHP facility (which includes the H1 Well) under the MOSOF Regulations is PTTEPAA. PTTEPAA’s Safety Case for the construction and installation stage in the life of the WHP facility (“WHP Construction Safety Case”) was accepted by NOPSA on 5 May 2008.

The operator of the MODU facility under the MOSOF Regulations is Atlas. Atlas revised its NOPSA-accepted Safety Case for the MODU facility’s operations in relation to the Montara development wells, and that Safety Case Revision was accepted by NOPSA on 26 February 2008. The Atlas Safety Case together with the Atlas Safety Case Revision are hereinafter collectively referred to as the “MODU Safety Case”.

A revision to the WHP Construction Safety Case for the WHP facility’s hook-up and pre-commissioning phase (including for simultaneous operations (“SIMOPS”) with the MODU facility and the construction vessel facility operated by Clough (“Java Constructor”)) was accepted by NOPSA on 18 August 2008 and 16 June 2009. A revision to the MODU Safety Case for the SIMOPS with the WHP facility and the Java Constructor, was also accepted by NOPSA. These safety case revisions detail the SIMOPS between the WHP facility and the MODU facility, including establishing the applicable SIMOPS matrix that applies in relation to activities taking place on the WHP facility whilst the MODU facility is in position at the WHP facility. The SIMOPS matrix was formulated to ensure consistency with the SIMOPS matrix of the MODU facility as provided for in the MODU facility’s SMS. This safety case revision notes that hook-up
or pre-commissioning work on the WHP facility will be carried out in accordance with the
PTTEPAA SIMOPS procedure but this incorporates restrictions on that work during MODU
operations involving cantilevering/skidding of the MODU facility’s derrick and requires the
Permits to Work issued under the PTTEPAA WHP facility SMS in respect of that work to be
counter-signed by the MODU facility’s permit authority. Relevantly, this safety case revision
also stipulates that in the event of an emergency, personnel at the WHP facility are required to
muster in response to the MODU facility’s alarm and that the MODU facility’s OIM will direct
those persons to either evacuate from the WHP facility or from the MODU facility with the
MODU facility being their primary means of evacuation.

3. BACKGROUND EVENTS

3.1. MONTARA FIELD DEVELOPMENT DRILLING

The development plan for the Montara Development involves the drilling and completion of ten
wells, five of which drilled in the Skua and Swift/Swallow oil fields and completed subsea and
the other five drilled in the Montara oil field and completed with dry wellheads at a wellhead
platform installed at the Montara field location. The drilling and completion of these wells was
originally planned to take place as two campaigns; the initial campaign involving four of the
subsea wells and three of the platform wells; and the second campaign, to be executed six
months after first oil, involving one subsea well and two platform wells.

The Jacket for the WHP facility was launched at its Montara field location on 30 June 2008 and
then secured to the seabed with drilled and grouted piles during July and September 2008. The
original plan to install the topsides module for the WHP facility in July-August 2008 was aborted
due to issues with contracted construction vessels. This unplanned change in the installation
sequence resulted in the drilling programs for the Montara field development wells being revised
from their original basis of drilling and completion after WHP topsides installation to the
amended basis of two phases, the first phase being drilling and mud-line suspension to be
carried out commencing approximately January 2009 and the second phase being continuation
of drilling and completion of the wells after installation of the WHP topsides in approximately
June 2009. The West Atlas performed drilling operations for Vermilion Oil and Gas Australia
Pty Ltd (“Vermilion”) and East Puffin Pty Ltd (“East Puffin”) during the last quarter of 2008 and
the first quarter of 2009.

In January 2009 East Puffin decided to revise its commitment to the West Atlas MODU facility
with the result that PTTEPAA agreed to re-commence its utilisation of the West Atlas MODU
facility in direct continuation of Vermilion rather than in direct continuation of a subsequent
period of utilisation by East Puffin. This unplanned change resulted in PTTEPAA bringing
forward the second campaign of development wells such that the drilling programs for the
Montara field were further revised so each phase – firstly the top-hole drilling and suspension
phase and secondly the horizontal drilling and completion phase - would involve all five Montara
field development wells. Prior to the installation of the WHP topsides, the Montara field
development wells where batch drilled as two distinct batch drilling programs, the first in respect
of Montara GI, H1 and H4 and the second in respect of Montara H2 and H3.
Over the period January to April 2009 the West Atlas was over the WHP facility jacket drilling each of the Montara development wells down to the 9-5/8” casing point at which point they were suspended. The West Atlas then left the WHP facility jacket on 21 April 2009 to carry out drilling operations for East Puffin and exploration drilling at other PTTEPAA title locations.

The WHP topsides were installed on the jacket on 7 August 2009. On 19 August 2009 the West Atlas was positioned at the WHP facility for the purposes of commencing the horizontal drilling and completion of the Montara field development wells.

### 3.2. MONTARA H1-ST1 WELL TOPHOLE DRILLING AND SUSPENSION

The operations performed in respect of the H1 Well by the MODU facility prior to its departure from the WHP facility in April 2009 were the drilling the 12-1/4” section into the top of the reservoir, running and cementing the 9-5/8” casing and the suspension of the well.

The Montara Phase 1B Drilling and Completion Program (Rev 0, June 2009) for the horizontal drilling and completion of the Montara field development wells states that the tophole drilling and suspension of the H1 Well carried out in March 2009 was as follows:

- Montara H1 was spudded on the 18th January 2009 as a horizontal production well from the WHP facility jacket.
- A 508mm (20”) conductor was set at 150.5m, and the 445mm (17-1/2”) hole section was drilled to TD.
- The 340mm (13-3/8”) casing was run, with tight spots encountered at 1089m, 1094m, 1148-1170m, 1263m, 1320m which required washing and reaming with 1.89m3/min and 5rpm to pass.
- Casing was set with the shoe at 1637mMD and plugs bumped. After tripping in with a 311mm (12 ¼") drilling assembly a FIT was performed to 1.25sg EMW.
- Drilling continued and major losses were encountered through the lower Johnson and upper Puffin (from 1706.5m) and the well was re-displaced to seawater.
- A trip was made for a cement stinger and cement plug #1 was set. A re-run 311mm (12-1/4") bit was drilled to 2118mMD, where it was pulled out of hole for poor ROP.
- A replacement bit was then run to section TD, encountering the Montara Cycle-IV reservoir sand at 2935mMD. The well was landed as proposed, but did not intersect clean reservoir. It was decided to drill ahead, identify the good oil-bearing sand and use this opportunity to clearly define the gas-oil contact (“GOC”). Both were achieved with good reservoir identified from 3676mMD and the GOC contact confirmed to be at 2609mTVD.
- Two cement plugs were then set off bottom (Plugs #2 and #3), where plug #3 was tagged at 3130mMD.
• The well was sidetracked at 3234mMD (and its name changed to Montara H1-ST1), where the rotary steerable tool failed, requiring a trip. Once back on bottom, the hole was drilled to the new section TD, landing the well at 90.3° within the oil-bearing sand.

• The 244mm (9-5/8") casing was subsequently run, with tight spots encountered from 2620-3208m and again at 3529m and 3587m; the shoe was set at 3796mMD and plugs bumped however the floats failed. Pressure was held on the casing until the cement had set.

• The 244mm (9-5/8") casing was backed out at the MLS and a pressure containing corrosion cap was installed. Offline the 340mm (13-3/8") casing was backed out at the MLS and a pressure containing corrosion cap was installed. The 508mm (20") conductor was backed out at the MLS and a trash cap was installed.

Appendix 2 contains the diagram of the suspension status of the H1 Well that was included in the aforementioned Montara Phase 1B Drilling and Completion Program (Rev 0, June 2009). Appendix 3 contains the applications made to the Designated Authority on 6 March 2009 and 12 March 2009 for approval to suspend the H1 Well, which set out diagrams of each of the two phases of the well’s suspension.

4. SEQUENCE OF EVENTS

4.1. INCIDENT

The drilling derrick of the MODU facility was skidded over the WHP facility and work commenced on the H1 Well on 20 August 2009. The 20" conductor trash cap and 9.5/8" pressure containing corrosion cap were removed from the well, threads were cleaned on the 13.3/8" casing and a section of 20" conductor pipe was connected. After this the derrick was skidded over and work completed on wells GI ST1 and H4. At approximately 05:30 hours CST on 21 August 2009 a flow of oil estimated at 40 – 60 barrels from the H1 Well was observed. The MODU facility alarm activated and personnel at the MODU facility and the WHP facility mustered. The flow of hydrocarbons from the H1 Well was observed to subside. The MODU facility management and the PTTEPAA Drilling Supervisors conferred and decided to initiate operations to skid the derrick back over the H1 Well in order to set a plug with a view to preventing further outflow from the well. While work was in progress to skid the derrick back over the H1 Well, an uncontrolled release of oil, gas and water occurred from H1 Well at 07:23 hours CST. This was observed to be of greater pressure and volume than the initial release event. The MODU facility alarm activated and personnel again went to muster stations. The decision was made to abandon the MODU facility using the MODU facility lifeboats. A “black shutdown” of the rig was initiated. The planned electrical work on the WHP facility had not been commenced at the time of the incident. The WHP facility is yet not commissioned and therefore no power sources were present.

The following table contains a summary of the sequence of key relevant events related to the operations of the MODU facility in respect of the H1 Well which has been prepared following the investigation of this incident. This summary covers both the first phase of H1 Well operations described in section 3.2 and the second phase of H1 Well operations which, as described in
section 3.1, were commenced after the topsides module was installed on the WHP facility on 7 August 2009 and the MODU facility was positioned at the WHP facility on 19 August 2009.

<table>
<thead>
<tr>
<th>Date / Time (CST)</th>
<th>Event</th>
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<tbody>
<tr>
<td>July 2008</td>
<td>Installed jacket for WHP facility.</td>
</tr>
<tr>
<td>September 2008</td>
<td>West Atlas MODU facility drilled and grouted remaining piles for jacket of WHP facility.</td>
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<tr>
<td>October 2008 - 18/1/09</td>
<td>West Atlas MODU facility carries out drilling operations for Vermillion and for PTTEPAA at an exploration well location.</td>
</tr>
<tr>
<td>18/1/09</td>
<td>West Atlas MODU facility spudded H1 Well.</td>
</tr>
<tr>
<td>19/2/09</td>
<td>West Atlas MODU facility started drilling 12 ½” hole section of H1 Well.</td>
</tr>
<tr>
<td>27-28/2/09</td>
<td>West Atlas MODU facility drilled the H1 Well hole through, and confirmed fluids contacts within, the Montara reservoir. It then plugged back the H1 Well and set cement pluds.</td>
</tr>
<tr>
<td>1/3/09</td>
<td>The well was renamed as H1 ST1. West Atlas MODU facility kicked off a sidetrack of the H1 Well, drilled to 3796m BRT and set the 9 5/8” casing string at 3786m BRT and cemented with top of cement above 13 3/8” casing shoe.</td>
</tr>
<tr>
<td>7/3/09</td>
<td>West Atlas MODU facility temporarily suspended H1 Well with 13 3/8” casing set and cemented at 1637m and 9 5/8” casing set and cemented at 3786m. The H1 ST1 well was suspended. A 9 5/8” pressure containing anti-corrosion cap and 20” trash cap were fitted.</td>
</tr>
<tr>
<td>8/3/09-20/04/09</td>
<td>West Atlas MODU facility carries out drilling operations on other Montara development wells.</td>
</tr>
<tr>
<td>21/04/09</td>
<td>West Atlas MODU facility demobilised from the WHP jacket location.</td>
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<tr>
<td>21/04/09 - 18/08/09</td>
<td>West Atlas MODU facility carries out drilling operations for East Puffin and for PTTEPAA at exploration well locations.</td>
</tr>
<tr>
<td>7/8/09</td>
<td>WHP topsides module installed on jacket by Java Constructor.</td>
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19/8/09  West Atlas mobilized from PTTEPAA’s exploration well location in AC/P40 back to the Montara location and positioned over the WHP facility to carry out operations for the drilling of the horizontal section and completion of the H1 Well as part of a batch drilling program.

20/8/09 03:30  West Atlas MODU facility removed the WHP facility helideck’s hatch cover for H1 Well.

04:30  West Atlas MODU facility skidded its drill package so that its rotary table was over H1 Well.

06:00  West Atlas MODU facility removed 20" trash cap. It was identified that there was no 13-3/8" pressure-containing anti-corrosion cap and that rust and scale were present on the 13 3/8" tie-back connection. Operations commenced to clean up the 13 3/8" tie-back connection. MODU facility picked up 2 strands heavy weight drill pipe and made up thread cleaning tool BASIL.

11:30  West Atlas MODU facility removed 9-5/8" pressure-containing anti-corrosion cap from H1 Well. No trapped pressure observed. No flow observed.

12:00  West Atlas MODU facility ran BA51L tool to clean 13 3/8" tie-back connection.

13:30  West Atlas MODU facility tied back the existing 20" conductor and rough cut it 1m above mezzanine deck level of the WHP facility.

17:00  West Atlas MODU facility skidded its drill package so that its rotary table was over the GI ST1 well. H1 ST1 hatch cover was left on helideck.

18:30  West Atlas MODU facility removed the 20" trash cap from the GI ST1 well.

19:30  West Atlas MODU facility tied back the existing 20" conductor in the GI ST1 well and cold cut it 4.5m above mezzanine deck level of the WHP facility.

00:00  West Atlas MODU facility skidded its drill package so that its rotary table was over the H4 well and readied to commence intervening in the H4 well. Proceeded to remove trash cap, tie back 20" conductor and cold cut conductor about 1m above mezzanine deck of the WHP facility.

21/8/09 05:38  Flow from H1 Well observed by MODU facility personnel. Estimated at 40 – 60 bbls. Flow stopped but bubbles were seen through column. General alarm of West Atlas MODU facility activated. Personnel mustered.
05:55 All clear given by OIM of West Atlas MODU facility – personnel stood down from muster stations.

06:00 Meeting held between PTTEPAA personnel and Atlas personnel to review situation and to decide forward course of action. Decision made to skid the MODU facility’s cantilever back over the H1 Well and set a RTTS packer in the H1 Well.

07:23 H1 Well started flowing again, but at much greater rate than before.

Appendix 4 contains a diagram of the suspension status of the H1 Well as observed by personnel on the MODU facility when operations on the well commenced on 20 August 2009.

4.2. EMERGENCY RESPONSE TO INCIDENT

When the initial uncontrolled release of hydrocarbons from the H1 Well was observed at 0538 hours (CST) on 21 August 2009, the MODU facility general alarm was activated calling for a full muster. At the time of the initial release, three personnel were on the Mezzanine deck of the WHP facility and all other personnel were on the MODU facility. All personnel mustered to the muster stations on the MODU facility. The flow stopped and the personnel were stood down from the muster stations at 0555 hours. The OIM of the MODU facility and the PTTEPAA Drilling Supervisor notified the PTTEPAA Drilling Superintendent onshore at 0600 hours.

After the second uncontrolled release of hydrocarbons the MODU facility general alarm activated at 0723 hours. The OIM of the MODU facility and the PTTEPAA Drilling Supervisor made a further call (0730 hours) to PTTEPAA Drilling Superintendent advising of the change of circumstances and the decision to fully evacuate the MODU facility. The PTTEPAA Drilling Superintendent called PTTEPAA Emergency Response Group (“ERG”) Leader at 0735 hours. All personnel were on the MODU facility at that time and mustered to the muster stations on the MODU facility. Non-essential personnel were evacuated using the MODU facility’s life boats at 0745 hours. The MODU facility’s main engines and all power were shut down.

All remaining personnel were evacuated from the MODU facility in the third life boat at 0810 hours. The life boats went to the supply vessel, Lady Audrey, situated approximately 700 metres away from the MODU facility. The entire POB complement of the MODU facility (69 personnel) was safely accounted for on board the Lady Audrey by 0850 hours. The personnel were then transferred from the Lady Audrey to the Java Constructor.

The ERG was initiated and assembled in the PTTEPAA Emergency Response room by 0800 hours. Next of kin of evacuated personnel were notified by the ERG and Atlas emergency response group. Between 1200 hours and 1715 hours, 62 personnel were evacuated from the Java Constructor by helicopter to Truscott and by fixed wing aircraft to Darwin. The remaining personnel remained on the Java Constructor to assist with observations and communications with the ERG. The ERG remains active on a 24 hour basis until further notice.
PTTEPAA was informed by Atlas that an Atlas employee working on the MODU facility at the time of the incident suffered minor skin irritation which was subsequently diagnosed as being caused by contact with hydrocarbons.

5. LIMITATIONS ON INVESTIGATION

The investigation of the incident has been carried out by document review (refer to Appendices and section 8 for Document References) and by speaking with PTTEPAA personnel and Halliburton personnel.

The investigation of the incident for the purposes of this report has been constrained by:

(a) Inability to carry out a visit to the workplace at the MODU facility; and

(b) The MODU facility operator declining to allow its personnel to speak to PTTEPAA for the purposes of PTTEPAA’s investigation of the incident.

PTTEPAA is not in a position to properly assess the incident from the perspective of MODU facility’s Safety Case revision as the consideration of the application of the MODU facility’s SMS to the drilling operations for the H1 Well requires access to information that is either (a) on board the MODU facility or (b) in the possession of the MODU facility operator and/or the within the knowledge of its personnel.

6. IMMEDIATE CAUSE

It is currently not possible to utilise the WHP facility and the MODU facility to inspect the condition of the H1 Well for the purposes of assessing the probable reasons for the loss of well integrity on 21 August 2009. Therefore PTTEPAA has made an assessment of the probable cause utilising information records and by speaking with personnel in its Well Construction/Drilling department.

The identification of the immediate cause of the hydrocarbon release firstly requires an assessment of the probable source of the flow. PTTEPAA has assessed that there are two probable sources of the flow, one being that the flow is coming up the 9-5/8” casing in the H1 Well, the other that the flow is coming up the 9-5/8” x 13-3/8” annulus in the H1 Well. Whilst PTTEPAA has no definitive evidence that the flow is emanating from inside the 9 5/8” casing, PTTEPAA has designed its relief well drilling program on the basis that it regards the inside of the casing as being the most likely flow path.

PTTEPAA has assessed three possible causes of the uncontrolled hydrocarbons flow from the H1 Well.

1. Flow of hydrocarbons coming up the 9-5/8” casing due to a channel in the cement in the casing shoe track.
2. Subsurface seismic activity resulting in a rupture of the casing in the H1 Well.
3. Flow of hydrocarbons coming up the 9-5/8" x 12-1/4" open hole section and then up the 9-5/8" x 13-3/8" annulus due to a channel in the cement.

Flow of hydrocarbons coming up the 9-5/8" casing due to a channel in the cement in the casing shoe track

PTTEPAA’s opinion is that it is most likely that the flow of hydrocarbons is coming up the 9-5/8" casing due to a channel in the cement in the casing shoe track. The evidence shows that the H1 Well was stable for about 5½ months without containment on the annulus prior to the loss of well control on 21 August 2009, indicating that there was no annular flow during that period. This makes an internal flow commencing approximately 72 hours after a change in condition (i.e. intervention in the well) more likely than an annular flow in the present circumstances. This conclusion is supported by PTTEPAA’s visual observations of the composition of the flow from the well.

PTTEPAA has concluded that the observed characteristics of the hydrocarbons emanating from the well support an internal flow. The initial observed flow from the well had a high oil fraction then dwindled to mainly gas / water. Oil flows from a channel in cement in a gas cap are unlikely. A channel in the cement would most likely expose a significant section of the gas cap in addition to the oil leg. An exposed gas bearing sand would flow gas in preference to oil. Reservoir modelling results indicate that a point source influx into the casing would very quickly cut gas. The 9-5/8" casing shoe was placed in the reservoir about 3m TVD above the oil water contact. If the leak source was past the casing shoe track then it would be expected that initial flow would be mainly oil. Reservoir modelling of the theory that the flow is from inside the casing suggests that within a day of the flow commencing, the single point drawdown would cut increasing amounts of gas and some water with reducing oil fractions. Thus the nature of the flow, as visually observed, is such that it closely follows what would be expected of a flow through the casing shoe track. In summary, whilst PTTEPAA cannot definitively confirm the source of the flow, the nature of the observed flow since 21 August 2009 is more consistent with an internal flow path than an external one.

In concluding that the flow path of hydrocarbons is most likely internal within the 9-5/8" casing, PTTEPAA has also considered the constructed condition of the H1 Well at suspension in March 2009, and the condition of the H1 Well evident from the operations on 20-21 August 2009 in terms of pressure containing barriers.

1. There was no wellhead installed on the H1 Well at the time of the uncontrolled flow. This is because the H1 Well was in the process of being drilled and completed. The MODU facility’s BOPs were not set on the H1 Well. No trapped pressure was observed following the removal of the 20" trash cap or the 9/5/8 pressure containing anti-corrosion cap. The PTTEPAA Drilling Program does not require the setting of BOPs during the well operations that were in progress at the time of the incident. The ‘batch’ Drilling Program does not call for the setting of BOPs until further along in the program at the point at which the 8"1/2 hole is to be drilled. Consistent with the Drilling Program, the Atlas Drilling Manual for the MODU facility also does not call for the setting of BOPs until the commencement of drilling at the highest known hydrocarbon-bearing interval in the well.
trajectory as assessed at the time of designing the well and recorded in the Drilling Program.

2. There was no pressure containing caps installed at time of the uncontrolled flow.

a) The 13-3/8” pressure containing anti-corrosion cap was required by the Drilling Program but not installed at the time of the March 2009 suspension of the H1 Well. PTTEPAA’s investigation of this incident has determined that, in March 2009, personnel on the MODU facility discovered that a valve in the cap designated for use in the H1 Well was rusted up. It would appear that this is the reason why the cap was not installed in the well. The Drilling Superintendent was however advised by the Drilling Supervisor on the MODU Facility, in an email advice of offline activities at the time of the March 2009 suspension, that the cap was installed. The Drilling Superintendent therefore prepared the Suspension As-Built Diagram (included in the June 2009 Drilling Program) showing the well suspended with the 13-3/8” pressure containing cap.

b) The 9-5/8” pressure containing anti-corrosion cap was removed on 20 August 2009 for operations to clean up 13-3/8” corroded casing threads in the H1 Well. No trapped pressure or flow was observed following its removal. The decision to remove the 9-5/8” cap followed the discovery of the corroded 13-3/8” casing threads and was required in order to enable the BA51L brush tool to be used to carry out the cleaning operation. The 9-5/8” cap was not re-installed before skidding the drilling package to the H4 well. However, re-installation of that cap was not required by the Drilling Program due to the nature of the ‘batch’ tie-back operations. The deviation from the Drilling Program on 20 August 2009 (for the operations to clean up the corroded 13-3/8” casing threads in the H1 Well) resulted in approximately 15 hours without a pressure containing cap on the 9-5/8” casing before the uncontrolled flow. However, there would in any event have been approximately 8-10 hours without a pressure containing cap on the 9-5/8” casing if the tie-back operations had proceeded on 20 August 2009 as per the Drilling Program absent the deviation.

3. There was no cement plug set inside the 9-5/8” casing at time of the uncontrolled flow. It was not installed at the time of the March 2009 suspension of the H1 Well. Due to the availability of pressure containing anti-corrosion caps and the identification of the risk of damaging the 9”5/8 casing when drilling out a cement plug, at the time of the March 2009 suspension an amendment to the Drilling Program was implemented by the Well Construction Manager and Drilling Superintendent (in accordance with the Change Control requirement in the Well Construction Standards) to replace the 9-5/8” cement plug with the 9-5/8” pressure containing cap and the 13-3/8” pressure containing cap. Appendix 5 contains a copy of the Change Control. The Designated Authority approved the suspension of the H1 Well without the cement plug inside the 9”5/8 casing. The application to the Designated Authority for suspension approval showed the 9-5/8” pressure containing cap and the 13-3/8” pressure containing cap installed, as set out at Appendix 3.
4. The 9-5/8" casing float collar (which includes two check valves within the collar) was installed in the H1 Well at the time of the March 2009 suspension. Backflow of hydrocarbons through the shoe track during the cementing job suggests that the valves in the float collar failed because they did not hold pressure. This was discussed by the Drilling Superintendent and the Drilling Supervisor and the decision was made to instruct the crew to hold pressure on the casing until the cement had set. After releasing pressure, no pressure differential or flow was observed. Therefore, there was no reason to suspect at that time that the backflow had compromised the cement job; however, it is possible that the backflow contaminated the cement in the shoe track creating a channel in the cement inside the casing.

PTTEPAA’s assessment is that the above-mentioned MODU facility well operations relating to the constructed condition of the H1 Well at suspension in March 2009, together with the removal of one of the pressure containing barriers in the H1 Well during the 20 August 2009 operations, evidences the most probable immediate causation of the uncontrolled flow of petroleum liquids and hydrocarbon vapours being released from the well bore to surface. Appendix 7 contains a schematic representation of the H1 Well indicating the location of the pressure containing barriers referred to in the corresponding numbered paragraph above.

Subsurface seismic activity resulting in a rupture of the casing in the H1 Well

Subsurface seismic activity resulting in a rupture of the casing in the H1 Well (or otherwise contributing to an under-balance situation in the well) has been considered as a possible cause following a report by the Drilling Supervisor that, while onboard the WHP facility at approximately 2330 hours on 20 August 2009, he felt it ‘shake’. PTTEPAA has not investigated this report by interviewing all personnel on board the facilities on 20 August 2009, but has made an inquiry of the information maintained by Geoscience Australia regarding earthquakes and the available information does not indicate any such material seismic events in the vicinity at the relevant time.

Flow of hydrocarbons coming up the 9-5/8" x 12-1/4" open hole section and then up the 9-5/8" x 13-3/8" annulus due to a channel in the cement

For the external flow to be via the 9-5/8" x 12-1/4" open hole section and then up the 9-5/8" x 13-3/8" casing annulus due to a channel in the cement would require the 9-5/8" x 12-1/4" open hole section to be poorly cemented. In this regard:

a) once the cement was set in the 9-5/8" casing flow back was not observed and therefore it is unlikely that the 9-5/8" casing is leaking; and

b) with cement tending to flow on the low side, it can be extremely challenging to obtain a uniform cement job on a horizontal well. The 9-5/8" casing track in the H1 Well was originally planned without the long near horizontal section but the well it did not intersect good reservoir at Top Gas at 2935mMD. As a result the well was sidetracked and drilled near horizontal to 3796mMD.
These two factors could lead to a conclusion that a poor cement job has resulted on the high side of the 9 5/8” casing suggesting that a likely pathway of the hydrocarbons could be via a channel in the cement in the 9-5/8” x 12-1/4” open hole section and then up the 9-5/8” x 13-3/8” annulus. The cementing job for the H1 Well involved two different slurry mixtures – lead cement and tail cement. The required total volume of cement in order to ensure that the tail cement covers 50m above Top Gas (assuming 20% excess) is 199bbls. Following the sidetracking of the H1 Well, the Well Construction Manager and Drilling Superintendent implemented an amendment to the Drilling Program in order to ensure that the cementing program implemented on the MODU facility met this volume requirement. This amendment to the Drilling Program was effected in accordance with the change control process required by the PTTEPAA Well Construction Standards. Appendix 6 contains a copy of the Change Control. However, the cementing records indicated that this Change Control was not implemented on the MODU facility such that only 132bbls was displaced. This indicates that there is only lead cement across the top section of the reservoir. Tail cement sets first. As the tail cement did not meet the volume requirement for covering the Top Gas, there was possibly a period, when the lead cement was setting, during which full hydrostatic pressure was not maintained across gas bearing intervals and gas could have broken through to surface as worm holes. This is considered less likely than the first-mentioned cause given the factors outlined above.

7. ROOT CAUSE ANALYSIS

PTTEP has examined the most probable immediate causation of the uncontrolled flow from the H1 Well in order to assess the root cause of the well operations that established the causative factors noted in section 6 above.

1. PTTEPAA quality assurance procedures were not applied in relation to the procurement of well materials. The quality control inspection of critical well equipment inventory bound for, and then on, the MODU facility did not identify problems with the materials sufficiently in advance of the time that is required by the Drilling Program for use in a well. Deficient application of the MODU facility safety case revision requirements for quality control inspection of equipment supplied by third parties to PTTEPAA and free-issued to Atlas for use in MODU facility operations.

2. Deficient application of the requirements of the MODU facility safety case revision by personnel on the MODU facility as evidenced by the failure to implement risk-assessed changes made to the PTTEPAA Drilling Program that were directed as a result of the PTTEPAA Well Construction Change Control process.

3. Informal and ineffective communications between PTTEPAA’s Well Construction supervisory personnel onshore and PTTEPAA Drilling Supervisors on the MODU facility and between PTTEPAA Drilling Supervisors and the personnel of the MODU facility operator.
8. ACTIONS TO PREVENT RECURRENCE

IMMEDIATE ACTIONS

In responding to the incident on 21 August 2009, the ERG ensured that all construction work in the vicinity of the WHP facility had stopped and that facilities and vessels in the vicinity moved a safe distance away from the WHP facility.

The status of operations conducted at the MODU facility on 20 and 21 August 2009 immediately prior to the commencement of the uncontrolled flow from the H1 Well mean that, at the time of the abandonment of the MODU facility, the other Montara development wells at the WHP facility were left in a suspended condition with either a cement plug plus a pressure containing cap in place or two pressure containing caps in place, with the 20” trash caps remaining removed from the GI ST-1 well and the H4 well (as well as from the H1 Well).

ACTIONS TAKEN TO PREVENT A RECURRENCE WHEN DRILLING OPERATIONS RECOMMENCE AT ANY MODU FACILITY POSITIONED AT THE WHP FACILITY

PTTEPAA has firstly undertaken a review of the suspension status of the other Montara development wells at the WHP facility in order to assess whether there are any well hazards indicated by the constructed condition of those wells that present a well control risk.

- H2 well remains with a mud-line suspension covered with 508mm (20”) trash cap at Boat Landing Level of the WHP facility. Below the trash cap the 340mm (13-3/8”) pressure containing anti-corrosion cap is in place. There is a cement plug set in the 9-5/8” casing from 160m back to 115m.

- H3 well remains with a mud-line suspension covered with 508mm (20”) trash cap at Boat Landing Level of the WHP facility. Below the trash cap the 340mm (13-3/8”) pressure containing anti-corrosion cap is in place. There is a cement plug set in the 9-5/8” casing from 160m back to 115m.

- H4 well has had the 508mm conductor tied back and cold cut approx 1m above the Mezzanine Deck of the WHP facility. The 340mm (13-3/8”) pressure containing corrosion cap is in place. There is a cement plug set in the 9-5/8” casing from 160m back to 115m.

- GI well has had the 508mm conductor tied back with a 610mm section in it. Above the 610mm section the 508mm conductor has been cold cut 4.5m above the Helideck of the WHP facility. Both a 340mm (13-3/8”) and a 244mm (9-5/8”) pressure containing anti-corrosion cap are in place.

PTTEPAA has reviewed the Halliburton-generated 9-5/8” casing top of cement calculations for each of the wells and updated the suspension diagrams to include the top of cement calculations. Appendix 8 contains these suspension diagrams and top of cement calculations. Based on this review, PTTEPAA has assessed that the risk of a similar incident occurring when MODU facility operations recommence at the WHP facility for intervention in the other Montara development wells at the WHP facility is as low as reasonably practicable.
Secondly, PTTEPAA has considered the root causes of the well operations noted in section 7 above as establishing the causative factors of the incident, and has adopted the following actions to prevent recurrence.

<table>
<thead>
<tr>
<th>Action</th>
<th>By Whom</th>
<th>By When</th>
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<tbody>
<tr>
<td><strong>Well Construction Management System</strong></td>
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<tr>
<td>Initiate a review of PTTEPAA’s Well Construction Standards and development well Drilling Programs with the objective of assessing the technical opportunities for improvements to the methodology of utilisation of MODU facility well control equipment during intervention on suspended development wells. Make any appropriate recommendations arising from the review to the MODU facility operator.</td>
<td>Chief Operating Officer</td>
<td>31 October 2009</td>
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<tr>
<td>Initiate a review of PTTEPAA’s implementation of the PTTEPAA Well Construction Management System with the objective of assessing the adequacy of the check and review steps on Drilling Program and Drilling Program Change Control implemented by the Well Construction Manager and the Drilling Superintendent under the Well Construction Standards In particular, consider implementing:</td>
<td>Chief Operating Officer</td>
<td>30 November 2009</td>
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<tr>
<td>• further check and review steps on Drilling Program and Drilling Program Change Control implementation by:</td>
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<td>o requiring sign-offs by the Drilling Supervisor and the MODU facility OIM of the implementation of safety critical steps in the Drilling Program;</td>
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<tr>
<td>o requiring Change Control documentation to be counter-signed by the Drilling Supervisor and the MODU facility OIM evidencing implementation of the change; and</td>
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<tr>
<td>o adding an interface with the PTTEPAA HSE Department for auditing of the implementation of the Change Control; and</td>
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<tr>
<td>• a requirement that all MODU facility operations, including off-line operations, are recorded in the Daily Drilling Report. Revise Management System documents to incorporate any improvements recommended by the review. Make any appropriate recommendations to the MODU facility operator regarding the MODU facility SMS that arise from the review.</td>
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## MODU Facility Safety Management System

1. Initiate a review of the MODU facility safety case revision process to assess:
   - the adequacy of the HAZID and Induction workshops as mechanisms for communicating the requirement to interface the Titleholder’s Drilling Program and Well Operations Management Plan with the MODU facility’s operational and safety management systems; and
   - the process of Drilling Supervisor and OIM supervision of the implementation of the Drilling Program by the MODU facility personnel.

2. Make any appropriate recommendations arising from the review to the MODU facility operator for:
   - revising the methodology for MODU facility safety case revision preparation and content;
   - titleholder training on MODU facility safety case revision implementation in particular during extended duration drilling campaigns where workforce turnover may be increased; and
   - MODU facility operator communication of safety case revision requirements to MODU facility personnel.

| Well Construction Manager | 31 December 2009 |

## Communication

- Undertake a review of the communication processes that are currently operative in relation to MODU facility operations for well construction to identify any improvements to those processes whether by changing the current process or by training personnel in compliance with the current process. This review should encompass communication processes applicable as between PTTEPAA’s Well Construction supervisory personnel onshore and PTTEPAA Drilling Supervisors on the MODU facility and as between PTTEPAA Drilling Supervisors and the personnel of the MODU facility operator.
- Revise Management System documents to incorporate any improvements recommended by the review.
- Make any appropriate recommendations to the MODU facility operator regarding the MODU facility SMS that arise from the review.

| Chief Operating Officer | 30 November 2009 |
### Audit

<table>
<thead>
<tr>
<th>Undertake a third party independent audit of PTTEPAA MODU-based supervisory personnel (Drilling Supervisors) implementation of:</th>
<th>Chief Operating Officer</th>
<th>31 December 2009</th>
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<tbody>
<tr>
<td>• safety critical components of the Well Construction Management System such as Change Management.</td>
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<tr>
<td>• supervision of MODU facility operator’s implementation of MODU facility safety case revision requirements for interface with the PTTEPAA Drilling Program and Well Operations Management Plan.</td>
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<tr>
<th>Ensure that PTTEPAA HSE management planning incorporates a regular process of both internal and independent third party auditing of the effectiveness of both the MODU facility operator’s implementation of the MODU facility’s SMS (in particular integration with the Drilling Programme) and the Well Construction Department’s implementation of the Well Construction Management Standards.</th>
<th>HSE Manager</th>
<th>31 December 2009</th>
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<tr>
<td>Develop an HSE audit plan for PTTEP Drilling Operations that focuses on:</td>
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<td>• inquiry in to the effectiveness of checks in assessing the level of compliance with the PTTEPAA Drilling Program and Well Operations Management Plan on the MODU facility; and</td>
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<tr>
<td>• an SMS review of the MODU facility from the perspective of the quality of the implementation of systems, processes and procedures in particular in relation to the identification and treatment of well hazards.</td>
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### Competency and Training

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<tr>
<th>Competency and Training</th>
<th>Chief Operating Office</th>
<th>31 December 2009</th>
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<tbody>
<tr>
<td>Carry out a review of the selection of Employees and Contractors for PTTEPAA Well Construction activities to determine whether the assessment of the competency of Drilling Supervisors is appropriate including identifying training pre-requisites for well operations risk management.</td>
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<tr>
<td>This review should include an assessment of the safety-critical training mandated by the Well Construction Management system to ensure that it incorporates all of the following items:</td>
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<td>- Well Control;</td>
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<td>- Well Integrity Hazard Management; and</td>
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<td>- Safety Leadership.</td>
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### Quality Assurance and Quality Control

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<tr>
<th>Quality Assurance and Quality Control</th>
<th>Chief Operating Officer</th>
<th>31 December 2009</th>
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<tbody>
<tr>
<td>Initiate a review of the implementation of PTTEPAA Well Construction Management System's Procurement and Logistics Procedures to determine whether the quality assurance checks of well equipment are appropriate and integrate with the procedures applied under the PTTEPAA Corporate Procurement and Logistics function.</td>
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<tr>
<td>Initiate a review of the implementation of the MODU facility’s procedures for quality control check of equipment prior to utilisation in well operations.</td>
<td>Well Construction Manager</td>
<td>31 December 2009</td>
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</table>

The actions in this plan should be carried out utilising the advice and services of specialist drilling and well control contractors as appropriate.

This action plan will require review and, as appropriate, revision after PTTEPAA is in a position to assess the information obtained:

a) during the course of the operations currently in progress to drill the relief well and plug the H1 Well;

b) after a site visit to the workplace onboard the MODU facility; and

c) from the MODU facility operator and/or its personnel.
9. DOCUMENT REFERENCES

Montara Development Safety Case for Construction and Installation, TM-CR-GEN-R-090-00004, Rev 1

Montara Development Construction and Installation Safety Case Revision comprising:


Seadrill West Atlas Safety Case, Rev 1, July 2007

Seadrill West Atlas Safety Case Revision, HSE SCR WA 070002, Rev 3, January 2008

Montara Wells Daily Drilling Reports

PTTEP AA Well Construction Management Framework, D41-502432-FACCOM, Rev 3
PTTEP AA Well Construction Standard, D41-502433-FACCOM, Rev 2
PTTEP AA Construct, Service or Abandon Well Process, D41-502434-FACCOM, Rev 2


Montara GI, H1 & H4 (Batch Drilled) Drilling Program, TM-CR-MON-G-150-00001, Rev 0, September 2008


Montara Development Phase 1B Drilling and Completion Program, Rev 0, June 2009

Well Construction Change Control Forms, Montara Development Wells

Organisation Chart – PTTEPAA Montara Development Project, March 2009

Organisation Chart – West Atlas MODU facility SMS

NOPSA Report – Planned Inspection Exit Brief West Atlas, ID 304.

Appendix 1
Atlas Drilling West Atlas MODU Safety Case Organisation Chart
Figure 2.3: West Atlas Offshore Organisation Structure
Appendix 2
H1 Well Suspension Diagram in June 2009 Montara Phase 1B Drilling and Completion Program
AC/L7
Montara H1 ST-1
Suspension Diagram – As Built

RT-AHD 35.20m

508mm (20") Corrosion Cap
340mm (13 3/8") Pressure Containing Corrosion Cap
244mm (9 5/8") Pressure Containing Corrosion Cap

508mm (20") Landing Ring at ~ 28.2m

508mm (20") Casing Shoe at ~ 150.5m

340mm (13 3/8") Casing Shoe at ~ 1636.8m

Casing Pressure Tested to 27.6MPa (4000 psi) and left with Inhibited Seawater

Plugs bumped – floats did not hold
311mm (12 1/4") Hole TD ~ 3796m

244mm (9 5/8") Casing Shoe at ~ 3786.1m

NOT TO SCALE
Appendix 3

H1 Well Suspension Approval Applications to Designated Authority 6 March 2009 and 12 March 2009
6 March 2009

Mr Jerry Whitfield
Director of Energy
Northern Territory Department of Regional Development Primary Industry Fisheries and Resources
5th Floor, Centrepoint Building
48-50 Smith Street Mall
DARWIN NT 0800

Dear Jerry

Application for approval to suspend Montara H1 ST-1 development well, AC/L7

We refer to our earlier email of today's date.

PTTEP (Ashmore Cartier) Pty Ltd ("PTTEP") hereby applies pursuant to regulation 17 of the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004 for the approval of the designated Authority to commence suspension of the Montara H1 ST-1 development well in accordance with the Drilling programme (TM-CR-MON-B-150-0001 REV 2) submitted and approved on 21 November 2008.

The well will be suspended in two stages. Stage 1 will involve the cementing and pressure testing of the 244mm casing followed by the installation of a pressure containing suspension cap. Stage 2 will involve the recovery of the 340mm casing above the MLS and the installation of a second pressure containing suspension cap followed by the recovery of the 508mm casing above the MLS and the installation of a further suspension cap. Schematics for Stage 1 and Stage 2 of the suspension are attached.

Yours sincerely,

[Signature]

Ian Paton
AC/L7
Montara H1 ST-1
Suspension Diagram - Stage 1

508mm (20") Landing Ring at ~ 28.2m

244mm (9 5/8") Pressure Containing Corrosion Cap

508mm (20") Casing Shoe at ~ 150.5m

340mm (13 3/8") Casing Shoe at ~ 1636.8m

340mm (12 1/4") Hole TD ~ 3793m

244mm (9 5/8") Casing Shoe at ~ 3786.6m

NOT TO SCALE
12 March 2009

Mr Jerry Whitfield
Director of Energy
Northern Territory Department of Regional Development Primary Industry Fisheries and Resources
5th Floor, Centrepoint Building
48-50 Smith Street Mall
DARWIN NT 0800

Dear Jerry

Application for approval to suspend Montara H4 and perform Stage 2 suspensions on Montara GI ST-1 and Montara H1 ST-1 development wells, AC/L7

PTTEP (Ashmore Cartier) Pty Ltd ("PTTEP") hereby applies pursuant to regulation 17 of the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004 for the approval of the Designated Authority to commence suspension of the Montara H4 development well in accordance with the Drilling programme (TM-CR-MON-B-150-0001 REV 2) submitted and approved on 21 November 2008.

Drilling of the 311mm hole section on Montara H4 is ongoing and total depth for this hole section is expected to be reached over this coming weekend followed by the running of the 244mm casing. Once the casing is in place the well will be suspended per the H4 Suspension diagram attached.

Once Montara H4 is suspended the rig will then commence the stage 2 suspension of Montara H1 ST-1, as per the attached suspension diagram. The stage 2 suspension of Montara GI ST-1 will also be conducted at this time under the approval issued on February 18, 2009 (Ref WH2009/0005, C09.018.dm).

Yours sincerely

Ian Paton

Level 1, HPPL House, 28-42 Ventnor Avenue, West Perth, WA, 6005, Australia Tel.: (+61 8) 9483 9483 Fax.: (+61 8) 9483 9484
Postal Address: PO Box 7311, Cloisters Square, Perth, WA, 6850, Australia
AC/L7
Montara H1 ST-1
Suspension Diagram – Stage 2

508mm (20") Corrosion Cap
340mm (13 3/8") Pressure Containing Corrosion Cap
244mm (9 5/8") Pressure Containing Corrosion Cap

508mm (20") Landing Ring at ~ 28.2m

508mm (20") Casing Shoe at ~ 150.5m

340mm (13 3/8") Casing Shoe at ~ 1636.8m

340mm (12 1/4") Hole TD ~ 3793m
244mm (9 5/8") Casing Shoe at ~ 3786.6m

NOT TO SCALE
508mm (20") Corrosion Cap

340mm (13 3/8") Pressure Containing Corrosion Cap

508mm (20") Landing Ring at ~ 28.2m

Cement Plug #1 from 160m to 115m

508mm (20") Casing Shoe at ~ 150.7m

340mm (13 3/8") Casing Shoe at ~ 1631m

244mm (9 5/8") Casing Shoe at ~ 3495m

NOT TO SCALE
Appendix 4

H1 Well Suspension Diagram: as observed upon commencement of intervention on 20 August 2009
Montara H1 ST-1
Suspension Diagram – As Built

Casing Pressure Tested to 27.6MPa (4000 psi) and left with Inhibited Seawater

Plugs bumped – floats did not hold

244mm (9 5/8") Casing Shoe at ~ 3786.1m

340mm (13 3/8") Casing Shoe at ~ 1636.8m

508mm (20") Casing Shoe at ~ 150.5m

508mm (20") Landing Ring at ~ 28.2m

311mm (12 1/4") Hole TD ~ 3796m

244mm (9 5/8") Casing Shoe at ~ 3786.1m

NOT TO SCALE
Well Construction Change Control Form

<table>
<thead>
<tr>
<th>Well</th>
<th>Montara H1</th>
</tr>
</thead>
<tbody>
<tr>
<td>Date</td>
<td>11/03/09</td>
</tr>
<tr>
<td>Requested By</td>
<td>Chris Wilson</td>
</tr>
<tr>
<td>Proposed Change #</td>
<td>Change Control D65005A 006</td>
</tr>
</tbody>
</table>

Basis for proposed change:
Change to suspension plan for Montara H1.

Details of proposed change:
The Drilling Program TM-CR-MON-B-150-00001 Rev 2 described the suspension of Montara H1 as having 1 cement plug in the 9 5/8" casing near surface and a 20° suspension cap installed.

Due to the availability of pressure containing suspension caps, the cement plug will now be replaced with a 9 5/8" pressure containing suspension cap installed on the 9 5/8" MLS. A 13 3/8" pressure containing suspension cap will also be installed on the 13 3/8" MLS.

The 20° suspension cap will still be installed per the original program. A suspension diagram showing the suspension configuration is attached.

HSE impact of proposed change:
Improved well integrity during suspension and re-entry operations.

Cost impact of proposed change:
Saving of US$50,000 in rig time (time taken to set plug versus time taken to set suspension cap + cost of suspension cap)

Approved by:  

[Signature]  
12-3-09

PTTEP Australasia

Conditions:
AC/L7
Montara H1 ST-1
Suspension Diagram – Stage 2

508mm (20") Corrosion Cap
340mm (13 3/8") Pressure Containing Corrosion Cap
244mm (9 5/8") Pressure Containing Corrosion Cap

508mm (20") Landing Ring at ~ 28.2m
508mm (20") Casing Shoe at ~ 150.5m
340mm (13 3/8") Casing Shoe at ~ 1636.8m

Casing Pressure Tested to 27.6MPa (4000 psi) and left with Inhibited Seawater

340mm (12 1/4") Hole TD ~ 3793m
244mm (9 5/8") Casing Shoe at ~ 3786.6m

NOT TO SCALE
Appendix 6 – Well Construction Change Control D65005A 003, January 2009
# Well Construction Change Control Form

<table>
<thead>
<tr>
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<th>Montara H1 &amp; Montara H4</th>
</tr>
</thead>
<tbody>
<tr>
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<td>30/01/09</td>
</tr>
<tr>
<td>Requested By:</td>
<td>Chris Wilson</td>
</tr>
<tr>
<td>Proposed Change #:</td>
<td>Change Control D65005A 003</td>
</tr>
</tbody>
</table>

## Basis for proposed change:

The suspension of the H1 and H4 wells will require the wells to be suspended at the MLS. No pressure containing caps will be installed and this leaves the annulus between the 311mm (12 ¼") hole and the 244mm (9 5/8") casing open at surface. A lead cemented has been added to the program that will fill the annulus from the top of the tail cement up into the 340mm (13 3/8") casing by 50m – effectively sealing off the open hole annulus.

## Details of proposed change:

A low viscosity lead slurry has been designed by Halliburton that will fill the open hole annulus from the top of the tail cement up into the 340mm (13 3/8") casing. The weight of the tuned spacer ahead of the cement will also be reduced to reduce the overall ECD throughout the cement job. This design of lead cement has been used in similar situations before.

## HSE impact of proposed change:

Secures the open hole annulus prior to well suspension.

## Cost impact of proposed change:

US$120,000 for the additional cement and cementing chemicals.

## Approved by:

[Signature]

COOGEE RESOURCES

Conditions:
## Cementing Program

<table>
<thead>
<tr>
<th>Hole &amp; Casing Size</th>
<th>Type</th>
<th>Desc</th>
<th>Recipe</th>
<th>Cement Tops &amp; Bottoms</th>
<th>Weight (SG)</th>
<th>Yield (ft³/sk)</th>
<th>XS Cmt (hrs)</th>
<th>Thick Time (hrs)</th>
<th>Job Time (hrs)</th>
<th>BHST (degC)</th>
</tr>
</thead>
<tbody>
<tr>
<td>660mm (26&quot;)</td>
<td>G</td>
<td>Tail</td>
<td>CaCl₂ 1.0% BWOC Seawater 5.18 gal/sk NF-6 0.25 gal/10bbls</td>
<td>TOC 119.00m BOC 150.70m</td>
<td>1.91</td>
<td>1.17</td>
<td>300</td>
<td>2.30</td>
<td>1.57</td>
<td>16</td>
</tr>
<tr>
<td>445mm (17 1/2&quot;)</td>
<td>G</td>
<td>Lead</td>
<td>Drillwater 11.14 gal/sk Gascon 469 1gal/sk SCR 100L 3gal/10bbl NF-6 0.25 gal/sk</td>
<td>TOC 1,167.50m BOC 1,517.50m</td>
<td>1.5</td>
<td>2.11</td>
<td>50</td>
<td>4.38</td>
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<td>64</td>
</tr>
<tr>
<td>311mm (12-1/4&quot;)</td>
<td>G</td>
<td>Lead</td>
<td>Drillwater 12.72 gal/sk Halad 413L 5 gal/10bbls SCR-100L 4gal/10bbls Gascon 469 1.2 gal/sk NF-6 0.25 gal/10bbls</td>
<td>TOC 1,567.50m BOC 2,823.50m</td>
<td>1.45</td>
<td>2.42</td>
<td>25</td>
<td>5.30</td>
<td>5.22</td>
<td>98</td>
</tr>
</tbody>
</table>

### Comments on Cementing Program

**SPACERS**

- 508mm (20") Casing: 12.7m³ (80bbl) Seawater followed by 3.2m³ (20bbl) Seawater plus dye ahead of cement.
- 340mm (13 3/8") Casing: 12.7m³ (80bbl) Drillwater ahead of cement.
- 244mm (9 5/8") Casing: 12.7m³ (80bbl) Tuned spacer ahead of the cement

**EXCESSS**

To be applied to open hole only.

**JOB TIMING**

Job time shown is the total job time including pressure test, bottoms up (BU) circulation, mixing and pumping cement, releasing plugs and displacing cement. The timing is based on a displacement rate of 6 bpm for lead slurry, 4 bpm for tail slurry, 8 bpm for BU circulation, spacers and displacement. 30 minutes is allocated for pressure testing and 10 minutes to displace and bump plugs.

**TEMPERATURE**

Temperature gradient is 3.3 deg C/100m + 15 deg C seabed temperature.
## Cementing Program

<table>
<thead>
<tr>
<th>Hole &amp; Casing Size</th>
<th>Type</th>
<th>Desc</th>
<th>Recipe</th>
<th>Cement Tops &amp; Bottoms</th>
<th>Weight (SG)</th>
<th>Yield (ft³/sk)</th>
<th>XS Cmt (hrs)</th>
<th>Thick Time (hrs)</th>
<th>Job Time (hrs)</th>
<th>BHST (degC)</th>
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</thead>
<tbody>
<tr>
<td>660mm (26&quot;)</td>
<td>G</td>
<td>Tail</td>
<td>CaCl₂ 1.0% BWOC Seawater 5.18 gal/sk NF-6 0.25 gal/10bbl</td>
<td>TOC 119.00m BOC 150.70m</td>
<td>1.91</td>
<td>1.17</td>
<td>300</td>
<td>2:00</td>
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<tr>
<td>445mm (17 1/2&quot;)</td>
<td>G</td>
<td>Lead</td>
<td>Drillwater 11.14 gal/sk Gascon 469 1gal/sk SCR 100L 3gal/10bbl NF-6 0.25gal/sk</td>
<td>TOC 1,181.50m BOC 1,531.50m</td>
<td>1.5</td>
<td>2.11</td>
<td>50</td>
<td>5:00</td>
<td>5:30</td>
<td>64</td>
</tr>
<tr>
<td>311mm (12-1/4&quot;)</td>
<td>G</td>
<td>Lead</td>
<td>Drillwater 12.72 gal/sk Halad 413L 15 gal/10bbls SCR 100L 4 gal/10bbl Gascon 469 1.2 gal/sk NF-6 0.25 gal/10bbl</td>
<td>TOC 1,581.50m BOC 2,990.50m</td>
<td>1.45</td>
<td>2.42</td>
<td>25</td>
<td>5:30</td>
<td>5:22</td>
<td>98</td>
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<tr>
<td>Comments on Cementing Program</td>
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</tr>
</tbody>
</table>

**SPACERS**
- 508mm (20") Casing: 12.7m³ (80bbl) Seawater followed by 3.2m³ (20bbl) Seawater plus dye ahead of cement.
- 340mm (13 3/8") Casing: 12.7m³ (80bbl) Drillwater ahead of cement.
- 244mm (9 5/8") Casing: 12.7m³ (80bbl) Tuned Spacer

**EXCESSS**
To be applied to open hole only.

**JOB TIMING**
Job time shown is the total job time including pressure test, bottoms up (BU) circulation, mixing and pumping cement, releasing plugs and displacing cement. The timing is based on a displacement rate of 6 bpm for lead slurry, 4 bpm for tail slurry, 8 bpm for BU circulation, spacers and displacement. 30 minutes is allocated for pressure testing and 10 minutes to displace and bump plugs.

**TEMPERATURE**
Temperature gradient is 3.3 deg C/100m + 15 deg C seabed temperature.
Appendix 7 – Schematic Representation of H1 Well referenced in most probable immediate cause assessment
Schematic representation of H1 Well indicating the programmed installed location of the pressure containing barriers referred to in section 6 of the Report.

Numbers correspond to sub-paragraph numbering in the Report’s description of the assessed most probable immediate causation - Flow of hydrocarbons coming up the 9-5/8" casing due to a channel in the cement in the casing shoe track.
Appendix 8
Montara Wells Suspension Diagrams updated September 2009 with Top of Cement Calculations
AC/L7
Montara GI ST-1
Suspension Diagram – As Built

DEPTHS BASED ON RT-AHD 35.20m

- 508mm (20") Casing Shoe at ~ 150.5m
- 340mm (13 3/8") Casing Shoe at ~ 1637.5m
- 508mm (20") Landing Ring at ~ 28.2m
- 244mm (9 5/8") Casing Shoe at ~ 2860m
- Estimated TOC ~1258m
- Estimated TOC ~1487.5m
- Casing Pressure Tested to 27.6MPa (4000 psi) and left with Inhibited Seawater

Plugs did not bump – floats held
- 311mm (12 1/4") Hole TD 2880m
- 244mm (9 5/8") Casing Shoe at ~ 2860m

NOT TO SCALE
508mm (20") conductor cut ~1m above mezz-deck

No pressure reported below the 9-5/8" pressure containing corrosion cap when removed

311mm (12 1/4") Hole TD ~ 3796m

Plugs bumped – floats did not hold

244mm (9 5/8") Casing Shoe at ~ 3786.1m

508mm (20") Casing Shoe at ~ 150.5m

508mm (20") Landing Ring at ~ 28.2m

550mm (20") Landing Ring at ~ 28.2m

Casing Pressure Tested to 27.6MPa (4000 psi) and left with Inhibited Seawater

340mm (13 3/8") Casing Shoe at ~ 1636.8m

Opticem Simulation

Estimated TOC ~ 1496m

DEPTHS BASED ON RT-AHD 35.20m

Estimated TOC ~ 1158m
AC/L7
Montara H2
Suspension Diagram – As Built

Casing Pressure Tested to 27.5 MPa (4000 psi) and left with Inhibited Seawater

508mm (20") Corrosion Cap

340mm (13 3/8") Pressure Containing Corrosion Cap

508mm (20") Landing Ring at ~ 28.2m

Cement Plug #1 from 160m to 115m

RT-AHD 35.20m

508mm (20") Casing Shoe at ~ 150.5m

Estimated TOC ~1225m

Opticem Simulation

Estimated TOC ~1225m

340mm (13 3/8") Casing Shoe at ~ 1608m

Plugs bumped – floats held
311mm (12 1/4") Hole TD ~ 3290m

244mm (9 5/8") Casing Shoe at ~ 3279.6m

NOT TO SCALE
Montara H3 ST-1
Suspension Diagram – As Built

508mm (20") Corrosion Cap

340mm (13 3/8") Pressure Containing Corrosion Cap

508mm (20") Landing Ring at ~ 28.2m

508mm (20") Casing Shoe at ~ 150.8m

508mm (20") Casing Shoe at ~ 3191.9m

340mm (13 3/8") Casing Shoe at ~ 1635.2m

508mm (20") Corrosion Cap

Inhibited Seawater

Cement Plug #1 from 160m to 115m

Inhibited Seawater

Estimated TOC ~956m Opticem Simulation

Estimated TOC ~1296m

311mm (12 1/4") Hole TD ~ 3203m

Plugs did not bump – floats held

244mm (9 5/8") Casing Shoe at ~ 3191.9m

NOT TO SCALE
AC/L7
Montara H4
Suspension Diagram – As Built

508mm (20") conductor cut ~1m above mezz-deck

340mm (13 3/8") Pressure Containing Corrosion Cap

Cement Plug #1 from 160m to 115m

508mm (20") Landing Ring at ~ 28.2m

508mm (20") Casing Shoe at ~ 150.7m

Estimated TOC ~1256m
Opticem Simulation

Estimated TOC (based on pressures) ~1269m

Estimated TOC (based on volume) ~1521.86m

NOTE: 340mm plug did not bump, and CMT tagged @ 1150m (inside casing)

340mm (13 3/8") Casing Shoe at ~ 1631m

244mm (9 5/8") Casing Shoe at ~ 3440.9m

NOT TO SCALE
Montara GI ST-1 9-5/8” Casing TOC Opticem Simulation

TOC calculations based on a final pressure prior to plug bump / finish of displacement of 1546 psi at 1.80 bpm (76 gpm)

Lead slurry TOC: 1258 mMDRT / 1251 mTVDRT
Tail slurry TOC: 2694 mMDRT / 2555 mTVDRT
Montara H1 ST-1 9-58” Casing TOC Opticem Simulation

TOC calculations based on a final pressure prior to plug bump / finish of displacement of 1450 psi at 4.65 bpm (195 gpm)

Lead slurry TOC: 1158 mMDRT / 1157 mTVDRT
Tail slurry TOC: 3103 mMDRT / 2623 mTVDRT
OptiCem
Calculated Wellhead Pressure
Calculated Wellhead Pressure vs. Liquid Volume

OptiCem
Calculated Wellhead Pressure
Calculated Wellhead Pressure vs. Liquid Volume

Fluids Pumped
1. Montara H1 ST-1 Tuned Spacer E+
2. Montara H1 ST-1 9-58 Lead
3. Montara H1 ST-1 9-58 Tail
4. Inhibited Seawater 1.03 sg

Customer: PTTEP AA
Well Description: Montara H1 ST-1
Job Date: 24-Sep-2009
Sales Order #: PTT.9001.0007.0451

OptiCem v6.4.2
25-Sep-09 09:50

Customer: PTTEP AA
Well Description: Montara H1 ST-1
Job Date: 24-Sep-2009
Sales Order #: PTT.9001.0007.0451

OptiCem v6.4.2
25-Sep-09 09:50
Montara H2 9-58” Casing TOC Opticem Simulation

TOC calculations based on a final pressure prior to plug bump / finish of displacement of 1420 psi at 3.3 bpm (140 gpm)

Lead slurry TOC: 1225 mMDRT / 1222 mTVDRT
Tail slurry TOC: 2708 mMDRT / 2472 mTVDRT
Montara H3 ST-1 9-5/8” Casing TOC Opticem Simulation

TOC calculations based on a final pressure prior to plug bump / finish of displacement of 1550 psi at 3.3 bpm (140 gpm)

Lead slurry TOC: 956 mMDRT / 931 mTVDRT
Tail slurry TOC: 2491 mMDRT / 2382 mTVDRT
Montara H4 9-58” Casing TOC Opticem Simulation

TOC calculations based on a final pressure prior to plug bump / finish of displacement of 1500 psi at 2.65 bpm (110 gpm)

Lead slurry TOC: 1256 mMDRT / 1229 mTVDRT
Tail slurry TOC: 2758 mMDRT / 2358 mTVDRT

OptiCem
Fluid Positions at Job End
Time = 186.06 min, Volume In = 1354.69 bbl