COMMISSION OF INQUIRY
MONTARA WELL HEAD PLATFORM
UNCONTROLLED HYDROCARBON RELEASE

COMMONWEALTH OF AUSTRALIA

DECLARATION UNDER THE STATUTORY DECLARATIONS ACT 1959

I, **Christopher Allan Wilson** care of Level 1, 162 Colin Street, West Perth in the State of Western Australia, Drilling Superintendent, make the following declaration under the *Statutory Declarations Act 1959 (Cth)*:

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1 I make this declaration in response to the request from the Montara Commission of Inquiry (**the** Commission) into the uncontrolled release of oil and gas from the Montara Wellhead Platform in the Timor Sea to provide evidence in relation to specified areas of interest relevant to the Commission's Terms of Reference.

Current position

2 I am engaged by PTTEP Australasia (Ashmore Cartier) Pty Limited (**PTTEPAA**) as a Senior Drilling Engineer/Drilling Superintendent and have been in that position since about January 2007.

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Qualifications and work experience

3 I hold a Bachelor of Science majoring in geology (obtained from Curtin University in 2001) and a Masters of Petroleum Engineering (obtained from the University of New South Wales in 2004).

4 My work experience is as follows:

(a) from August 2003 to September 2006 I was contracted to Apache Energy for 4 years as a Night Drilling Supervisor and Senior Drilling Supervisor on Jack-up and Semi Submersible Mobile Offshore Drilling Units (or MODUs) (North West Shelf and Bass Strait);

(b) from September 2006 to December 2006 I was contracted to Apache as a Senior Drilling Engineer planning an extended reach platform well for 3 months;

(c) prior to working for Apache I worked from January 2003 to July 2003 on contract for Woodside as a Drilling Engineer planning a jack-up platform well and a workover on the Legendre Platform for 7 months;

(d) from April 2001 to October 2002 I held various contract Night Drilling Supervisor positions with OMV, Santos, Anadarko and AGIP;

(e) from April 1998 to April 2001 I worked as a Project Planning Coordinator and Drilling Engineer on a variety of projects managed by Labrador Petro Management Pty Ltd; and

(f) in January 1990 to April 1998 I worked as an Operations and Wellsite Geologist for WAPET (now Chevron) including developing an online Drilling Management and Learning system for Chevron in PNG for 12 months.

The Montara Development Project

5 PTTEPAA is developing the Montara, Skua, Swift/Swallow Fields in the East Timor Sea. The development of these fields is referred to as the Montara Development Project and is located about 690 km west of Darwin, Northern Territory, near the Ashmore Cartier reef.

6 The Montara Development Project involves four production wells including the H1-ST1 well (**H1 Well**), in the Montara Field, two production wells in the Skua Field and three production wells in the Swift/Swallow Field.

7 The Montara Development facilities include a wellhead platform (**WHP**) at the Montara Field.

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Atlas Drilling

8 Shortly before I was engaged by PTTEPAA, Atlas Drilling (S) Pte Ltd (**Atlas Drilling**) was contracted by PTTEPAA for the Montara Drilling campaign, including the construction of the H1 Well, on the Montara WHP.

9 Atlas Drilling owns the *West Atlas* jack-up drilling rig (***West Atlas***), which is a type of MODU.

My responsibilities

10 When I joined PTTEPAA I reported to the Project Manager of the Montara Development, Duncan Clegg (**Mr Clegg**).

11 Between about January 2007 and June 2007 I held the position of acting Well Construction Manager in addition to the position of Senior Drilling Engineer. In the role of acting Well Construction Manager my responsibilities included:

(a) completing contractual negotiations with Atlas Drilling;

(b) developing planning schedules;

(c) developing tender documents and tender review with PTTEPAA's contracts department;

(d) hiring of Drilling Engineer & Subsea Engineer;

(e) reviewing of field and offset data including offset drilling problems;

(f) preparing well timing schedule and cost estimates;

(g) working with Atlas Drilling on rig design issues and inspection regime;

(h) working with Methanol Australia (MEO) on rig sharing agreement;

(i) ordering of long lead items; and

(j) overall management of the Well Construction Team.

12 In about June 2007 Craig Duncan was appointed PTTEPAA's Well Construction Manager (**Mr Duncan**). From that time I took on the role of Senior Drilling Engineer for the Montara Development. During the development of the Well Construction Management Framework

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(described below) it was decided that the role of Senior Drilling Engineer would move to Drilling Superintendent for the operations phase of the Montara Development Project.

13 My responsibilities as Senior Drilling Engineer include:

(a) designing wells;

(b) preparing well programs;

(c) establishing contracts, procuring equipment and organising logistics; and

(d) risk and change management.

14 My responsibilities as a Drilling Superintendent include:

(a) holding the Pre-Spud Meeting;

(b) supervising ongoing operations including the holding of morning meetings, morning and afternoon calls to the *West Atlas*, reviewing of reports issued from the *West Atlas*;

(c) managing day to day logistics of equipment and personnel movement;

(d) managing daily cost and schedule updates;

(e) managing risk and change control;

(f) routine liaison with Atlas Drilling on safety and operational issues;

(g) developing a Drilling Supervisor Induction program that consisted of a ½ day presentation and workshop as well as a hard copy manual; and

(h) delivering the Drilling Supervisor Inductions to Noel Treasure (PTTEPAA Senior Drilling Supervisor), Craig Klumpp (PTTEPAA Drilling Supervisor) and Paul O'Shea (PTTEPAA Senior Drilling Supervisor) on 27 February 2008, and later to Lindsay Wishart (PTTEPAA Drilling Supervisor) and then to Brian Robinson (then a PTTEPAA Drilling Supervisor).

15 Whenever the *West Atlas* was working on the Montara Development Project, either Mr Duncan or I was on call 24/7. I was on call for about 20 days a month and Mr Duncan was responsible for 10 days a month. I would also physically visit the *West Atlas* and WHP, about every 3 to 4 months in order to see for myself how operations were progressing and to maintain visibility and relationships with the offshore personnel.

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The well construction team and roles

16 The PTTEPAA people who reported to me were:

(a) Noel Treasure – Senior Drilling Supervisor

(b) Paul O'Shea – Senior Drilling Supervisor

(c) Lindsay Wishart – Drilling Supervisor

(d) Craig Klumpp – Drilling Supervisor

(e) Brian Robinson – Drilling Supervisor

Communication within PTTEPAA

17 The following communications took place within PTTEPAA in accordance with PTTEPAA Well Construction Management System (**WCMS**) – Construct, Services or Abandon Well Process, Activity 4.1.4, Tasks 3 and 4 (**Process Manual**):

(a) a morning e-mail was received – usually before 0700hrs (WST) from the PTTEPAA Drilling Supervisor offshore that contained all of the relevant morning reports (discussed in more detail in the following point). Additionally the morning e-mail had a summary of the previous 24 hours operations. This was broken down to HSE (STOP Card statistics and a description of any incidents), Medics Daily Record, Operations summary (summary of what has happened "online" over the previous 36 hours), comments and activities (detailed boat locations, any offline work or equipment preparation that has occurred and finally a section of outstanding equipment issues;

(b) the reports e-mailed would consist of;

(i) Daily Drilling Report (**DDR**)- The DDR includes a description of critical path or online events with respective durations rounded to the nearest 30 minutes. It also includes basic information concerning safety, materials, drilling equipment and drilling parameters. The DDR is similar to the official report prepared by Atlas Drilling, commonly known as the "IADC report";

(ii) Personnel on Board (**POB**) (this was also e-mailed the previous day by the *West Atlas* Radio Operator once updated after the crew change helicopter);

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(iii) Mudlogging Daily Report;

(iv) Daily Mud Report;

(v) STOP Card Report;

(vi) Bulk Report; and

(vii) Directional Surveys.

(c) between 0730 and 0745hrs (WST) every day of the week I had a "morning call" telephone call with the offshore PTTEPAA Drilling Supervisor. This call was used to expand on information within the morning e-mail and it is also an opportunity for me to ask any questions arising from the morning e-mail. Sometimes Atlas Drilling's Offshore Installation Manager (**OIM**) would be involved or listen to the call. Additionally the 7 day lookahead was discussed in detail to plan personnel and boat movements. The morning call was also the opportunity for the PTTEPAA Drilling Supervisor to detail any issues that had arisen from the morning meeting held on the *West Atlas* with Atlas Drilling and the service company personnel. Mr Duncan would make the morning call if I did not make it or if I was not on duty;

(d) a daily e-mail is received from the PTTEPAA Offshore Logistics Coordinator issuing the 7 day lookahead to PTTEPAA personnel, Atlas Drilling (Including the Rig Manager, Toolpusher, Barge Engineer, Singapore HR etc.) and all 3rd party contractors. The Process Manual references a 10 day look ahead – this is the same document however the front page only covered 7 days to keep the font readable on an A4 page. The data that feeds into the front page extends to 10 days and beyond;

(e) between completing the morning call and before 0900hrs I prepared and distributed a morning update e-mail. This e-mail went to all PTTEPAA personnel, all 3rd party contractors and to Atlas Drilling (Rig Manager). The morning update e-mail outlined HSE, Operations, Vessels and comments and look ahead for the next 24 hours. This morning update was issued every day of the week;

(f) at 0900hrs Monday to Friday a morning meeting was held at the PTTEPAA project office in Perth and was chaired by PTTEPAA's Well Construction Manager (**WCM**). This meeting was attended by the Atlas Drilling Rig Manager, Donald Millar (**Mr Millar**), the PTTEPAA's onshore Well Construction Team and any interested invited 3rd party

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contractors. The meeting reviewed the past 24 hour operations and logistics before noting the look ahead for the next 24 hours of operations and logistics. Once the drilling discussion was complete, each person at the meeting had the opportunity to discuss what they had been working on or to raise any issues of concern. These meetings usually lasted between 20 Minutes and an hour. The meeting was not "minuted", however I noted most of what was discussed in my note book;

(g) throughout the day numerous phone calls and e-mails would be made or sent between myself and the PTTEPAA Drilling Supervisor and the PTTEPAA Offshore Logistics Coordinator. Additionally numerous phone calls and e-mails would be made or sent between myself and the Atlas Drilling Rig Manager. This occurred 7 days a week;

(h) ad hoc meetings were held as required to discuss operational or safety issues with Atlas Drilling

(i) on an ad hoc basis as operations dictated the following reports would also be e-mailed to me within 24-48hrs of the activity being completed:

   (i) Bottom Hole Assemblies (**BHA**) Report (with each new BHA run in the hole);

   (ii) Bit Report (after a drill bit is recovered from the hole);

   (iii) Casing Report (after running casing);

   (iv) Cement Report (PTTEPAA Report – not Halliburton Report) after cementing casing (which would include the FIT/LOT Report) or after setting a cement plug;

   (v) Statement of Facts for the *West Atlas* and the work boats (after each rig move); and

   (vi) Rig Positioning Report; and

(j) Drilling Programs and Change Control Forms were issued via the Montara Development Project Document Controller. The distribution of these documents included internal PTTEPAA personnel and Atlas Drilling personnel – both onshore and offshore.

Communication with Atlas Drilling

18 The main person I dealt with at Atlas Drilling was the manager of the *West Atlas*. The rig managers were:

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(a) Graeme Robertson from January 2007 to May 2008;

(b) Brian Robinson from May 2008 to June 2008;

(c) Eddie Fitzgerald from June 2008 to January 2009; and

(d) Donald Millar from January 2009 to January 2010.

19 I also had some communications with Atlas Drilling's operations manager(s), Bruce Worthington and later David Gouldin and HSEQ manager(s) who were each based in Singapore.

20 Mr Millar:

(a) was the main person I dealt with and I had day to day contact with him. He was Perth based and had a small office in a different building but close to my office;

(b) attended the daily morning meetings in the PTTEPAA offices in Perth during operations (being the meetings described above at paragraph 16(f);

(c) attended additional meetings as required to cover such activities as rig moves, well testing, safety matters, safety case revisions and anything not covered in the morning meetings;

(d) was in charge of all Atlas Drilling personnel on the *West Atlas*; and

(e) reported to Bruce Worthington and later David Gouldin (both based in Singapore).

21 The person in charge on the *West Atlas* was the OIM. All personnel on board the *West Atlas* fell under the OIM's responsibility, this included Atlas Drilling personnel, contractors' personnel and the PTTEPAA offshore staff.

Key documents to manage the Well

22 The key documents in managing the construction of the Montara wells including the H1 Well were:

(a) the MODU Safety Case as revised (**West Atlas Safety Case**);

(b) the Well Construction Management Framework (**WCMF**) (ie Well Construction Management Framework – D41-502432 Rev 3; 23 June 2009);

(c) the Well Construction Standards (**WCS**) (ie Well Construction Standards – D41-502433 Rev 2; 13 March 2009);

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(d) the Process Manual;

(e) the Basis Of Well Design (**BOWD**) (ie Montara Development Basis of Well_Design - Montara H1 - TM-CR-GEN-E-150-00008 Rev 0; July 2008);

(f) Well Operations Management Plan (**WOMP**) (ie Montara H1 Well Operations Management Plan - TM-CR-MON-G-150-00002 Rev 0; 3 November 2008);

(g) the contract between PTTEPAA and Atlas Drilling for Atlas Drilling to provided services to PTTEPAA including the construction of the H1 Well;

(h) the Drilling Program (**DP**) (ie. Montara GI, H1 & H4 (Batch Drilled) Drilling Programme – TM-CR-MON-B-150-00001; Rev:2; 6 January 2009);

(i) the Drilling and Completion Program (**DP 1B**) (i.e. Montara Phase 1B Drilling and Completion Programme - TM-CR-MON-B-150-00003 **Rev: 0**; 30 June 2009);

(j) forward plans (Instructions To Drillers); and

(k) the Atlas Drilling Well Control Manual (**ADWCM**).

23 The documents that made up the PTTEPAA Well Construction Management System were the WCMF, WCS and the Process Manual.

24 When I joined PTTEPAA, there was little documentation in place for the management of well construction operations. After Mr Duncan was appointed Well Construction Manager, I was involved with PTTEPAA's well construction team and a consultant engaged by PTTEPAA in generating and preparing PTTEPAA's Well Construction Management System (**WCMS**) documents.

25 The WCMF standard is an interface document between the PTTEPAA management systems and the standards needed for well construction. The WCMF standard links the PTTEPAA corporate system to the well construction requirements and includes detailed job descriptions for the positions of WCM, Drilling Superintendent, Drilling Supervisor, Drilling Engineer, Completions Engineer, Well Test Engineer and Materials and Logistics Supervisor.

26 The purpose of the WCS is to provide standards for all aspects of well design, construction, testing, abandonment and intervention that involve a risk to safety, quality or integrity. The WCS are applicable to all aspects of well design, well construction, well servicing and well abandonment. We

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generated and prepared the WCS through a series of reviews and workshops with the well construction team. However, the WCS was not a prescriptive set of rules to cover every possible scenario but includes processes to risk assess and manage scenarios not considered between document revisions.

27 I applied the WCS to the process of identifying, assessing and managing the risks associated with the drilling, suspension and completion of the Montara production wells, including when:

(a) formulating and approving the drilling programs (including the drilling and completion programs);

(b) managing the implementation of the drilling programs by the POB the *West Atlas*; and

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

28 The Process Manual provides a detailed description of the construction, service or abandon well process which is applicable to all PTTEPAA's drilling, completion, testing, abandonment and well intervention activities. It sets out the various activities involved in the well construction process, the details of the various component tasks and the relative timing of tasks.

29 The BOWD was required to communicate well requirements/objectives from the PTTEPAA sub surface group to the well construction team and included information such as the planned surface location, target locations, formation tops, expected formation pressures, risks to consider based on offset well data or seismic interpretation and the well evaluation requirements.

30 I was also involved in preparing the WOMP in respect of the drilling and completion of each of the Montara production wells.

31 The WOMP illustrates how the WCMS ensures that drilling activities in respect of the wells meet regulatory requirements, specifically that:

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

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

32 During operations on the *West Atlas*, the PTTEPAA Drilling Supervisors prepared a forward plan to communicate to the crew and service companies the details of the work to be done for the next phase of the well construction operations (as scheduled by the DP (or later the DP 1B)). The forward plans

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contained sequential practical instructions on the well construction operations. These plans were updated as events changed and generally only covered the next day or so of operations. Sometimes revised or supplemented forward plans were developed if circumstances changed.

33 Each forward plan is agreed with the OIM before it is issued. If there was an issue with a forward plan that could not be resolved offshore, Mr O'Shea or Mr Treasure would call me to discuss the issue and I would discuss the issue with Atlas Drilling's rig manager (Mr Millar) if his input or approval was required. The WCMS (described below) refers to these plans as *Instructions To Drillers*. The plans are not normally sent to PTTEPAA's office for review unless there was an issue that could not be resolved offshore with consultation between the PTTEPAA's Drilling Senior Supervisor and Atlas Drilling's OIM or some additional expertise is required from the onshore staff. If the Senior Drilling Supervisor (Mr O'Shea or Mr Treasure) needed additional expertise from onshore staff, he would telephone me (or Mr Duncan).

34 The West Atlas Safety Case Revision was prepared by Atlas Drilling in consultation with PTTEPAA and established the interface between the PTTEPAA WCMS and Atlas Drilling's documents for the management of the *West Atlas*, including:

(a) the West Atlas Marine Operations Manual; and

(b) the West Atlas SD1 Operations Procedures Manual.

35 There were 2 Safety Cases, as respective revisions, relevant to the incident:

(a) the Montara Development Construction And Installation Safety Case. This safety case was applicable to Montara facilities including the WHP which was developed by PTTEPAA. It included a revision covering simultaneous operations (Document No. TM-CR-GEN-G-090-00006 July 2009 Rev: 3 (SIMOPS Safety Case); and

(b) West Atlas Safety Case Revision Montara SIMOPS Addendum - Forming Part of the West Atlas Safety Case for Operations on Wells in the Vulcan Sub Basin - Territory of Ashmore and Cartier Islands - Document No: HSE SCR WA 070002, Rev 0, 4 August 2009 which was developed by Atlas Drilling. This included a revision covering simultaneous operations.

36 Section 4.3.2 of the West Atlas Safety Case Revision states that the OIM is responsible for the management of safety on the *West Atlas*.

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37 As at 21 August 2009, the activities were operating under the SIMOPS Safety Case which makes the OIM the top of the command and control organisation for any simultaneous operations of the WHP and the *West Atlas*.

38 I was involved in preparing and overseeing compliance with the drilling programs.

39 The drilling program is effectively a step by step procedure for drilling a well.

40 At the beginning of the drilling program is a list of all the relevant documentation that drilling supervisors need to have off-shore. The drilling supervisors are required to acknowledge when they have all the relevant documentation by ticking and signing where indicated in the drilling program. The last section of the drilling program before the figures and appendices is the Potential Hazards. This section is a report from the Well Construction Hazards database. At the back of the drilling program are relevant figures, diagrams and geological information. The appendices section contains more detail on the specific sections of the well such as casing, cement, directional drilling, drilling fluids etc.

41 The DP was revised three times in response to changes in requirements.

42 The drilling of the reservoir section of the horizontal wells, the running of the sand screens and completions was covered by a further revision of the DP to DP 1B that was issued with "As Built" information after the wells had been suspended.

43 I was the author of the drilling component of the DP and others, including Mr Keith Brand, Mr Gary Watson and Mr Gus Meredith provided completions input.

44 When the document draft was ready, Mr Duncan reviewed it and marked up any changes he considered necessary. These changes were then discussed and if agreed, incorporated into the release document.

45 When the document was considered ready for issue, it was upgraded to revision zero, the first version to be released.

46 Changes to the DP were then either covered by the change control process for minor or single point changes or by issuance of a new revision if the scope of change was significant. The objective was to have a user friendly document that personnel could use and refer to in order to execute the work.

47 A change control form was not raised for a document revision as a new revision to the document involved repeating the entire approval process.

48 Original documents, revisions to original documents and change control notices were all distributed by the PTTEPAA Montara Project Document Management Process. This process involved sending the original documents to persons listed to receive them and to then send any revisions or change control notices to the original recipient so that they could maintain an up to date copy of the document.

Changes to the DPs

49 The change control process for the DP is described in Section 9, Activity 4.1.8, of the Process Manual and was managed under PTTEPAA's Montara Project Document Management System.

50 If anybody identified something that they thought needed to be changed, they could raise it for consideration and if considered appropriate I would approve the change, using a Change Control Request Form. The Change Control Request Form outlined what the change was, the cost impact and health and safety impact. Any changes were recorded using a convention in the file name that identified the well by its accounting code (AFE) and then a sequential number.

51 We differentiated between a change of significance and a change of insignificance. A change of significance would be something like moving a casing shoe or doing something which was a material change to the drilling program. An insignificant change might be a typo, someone's typed "5½ inches" instead of "5 inches".

52 I also regarded as insignificant changes of specific equipment selection such as a drill bit or changes to preparations to be done to make sure that casing or other equipment was "fit for purpose". Examples of this included ensuring that all casing and tie backs were in good condition, clean and free of corrosion.

53 Insignificant matters did not need to go through the change control process.

54 Once complete, I would send the Change Control Request Form to Mr Duncan for approval.

55 The approved Change Control Request Form was then sent to PTTEPAA's Montara Development document controller and issued to the personnel that received the DP.

Knowledge of key documents

56 Having been closely involved in the generation of the DP, I had a good understanding of it and its contents. I referred to the DP every day.

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57 I referred regularly (weekly at least) to the WCS. I used the WCS to plan a well to ensure that the well met the minimum design criteria (including casing and cement design, abandonment and directional surveying).

58 I also regularly referred (on average once every one to two months depending on what activities were ongoing at the time) to the Process Manual. I would review the Process Manual when particular tasks were to be undertaken. For example, if planning a well test (not a common activity) I would refer to the list of tasks required to prepare a well testing program set out in the Process Manual.

Drilling terminology

59 Various equipment and processes were involved in drilling the Montara wells, including:

(a) the WHP which comprises two main parts. The Jacket is the lattice structure connected to the seabed. The Topsides Module - which includes controls, process equipment and a helicopter deck - is attached to the Jacket;

(b) the *West Atlas*;

(c) casing or string of casing, including:

(i) 508mm (20") diameter casing;

(ii) 340mm (13 3/8") diameter casing;

(iii) 244mm ($9^5/_8$") diameter casing;

(d) the annulus which is a space between two conduits, typically the space between the drill pipe or casing and the wellbore or the space between two pipes.

(e) Mud Line Suspension (**MLS**) which is a tool that comprises part of the casing string that retains a full bore inside diameter, incorporates a hanger part to support the weight of the casing string and a running tool part which seals to form a hydraulically competent connection between the running tool and the hanger. The purpose of the MLS is to provide a means to support casing strings and suspend the well temporarily such that the well can be returned to service in the future;

(f) **PCCC** or pressure containing corrosion cap;

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(g) a blow-out preventer (**BOP**) is a set of hydraulic controlled rams or elements which can close around a pipe and isolate the pipe from the reservoir;

(h) batch drilling and sequential drilling - the drilling of a well can be broken down into a series of tasks or operations performed in sequence. This is sometimes described as the drilling sequence of operations. There are certain points in the sequence where it is practical to interrupt the sequence of operations. For example, once a certain casing string has been set and cemented, it is practical to interrupt the sequence. Batch drilling is where a number of wells are drilled and the sequence of operations on one well is interrupted allowing work to be undertaken on the same sequence of operations on a different well. Batch drilling has some benefits including optimal use of drilling fluids and equipment supply. It also has a disadvantage in that interrupting the sequence of operations on one well comes at a time cost for the rig to be moved from one well to the next. It is generally accepted that the advantages of batch drilling outweigh the disadvantages and batch drilling is preferred to sequential drilling.

Cementing

60 Cementing an oil well requires a certain amount of engineering at the design stage plus the application of procedures and practices during execution.

Slurry design

61 For the H1 Well there were different functions for the cement slurry and each function had be addressed in the design of the slurry.

62 The design required a tail cement slurry that would inhibit the formation of gas channels across the reservoir interval and up into the regional sealing shale. We also required a less dense lead cement slurry that would isolate exposed wellbore fluids.

63 The objective was to use the higher density tail cement slurry in the reservoir and a lighter lead slurry in the formations above the tail slurry and extending above the 340mm (13 ⅜") casing shoe. The density of the cement is often about 1.9sg for the tail slurry and 1.55sg for the lead slurry.

64 The slurries were designed to set at different times and those times were temperature dependant. This allowed the maintenance of hydrostatic pressure (described below) during the time that the cement was setting.

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Shoe track

65 In order to install a string of casing into the wellbore there are a number of components required. The bottom 1 to 3 joints of casing form what is known as the shoe track.

66 The lowermost item of the shoe track is the casing shoe. This is where the steel casing ends.

67 To make it easier to slide into the wellbore, the casing shoe is given a slightly rounded off profile. The material that provides the rounded shape is usually cement but it may also be a composite plastic or even machined aluminium. The important function is that it must be robust enough to guide the casing over any ledges or imperfections in the wellbore yet be able to be drilled out after the casing is cemented.

68 Often the casing shoe has a float valve in it making it a casing float shoe. In the case of the H1 Well the casing shoe did not incorporate a float valve.

69 Above the casing shoe there are between one and three joints of casing. These joints form a spacer between the casing shoe and the float collar. The longer the spacer, the longer the shoe track..

70 Above the spacer joints is the float collar. This is a short section of casing that incorporates a built-in landing point for cement displacement plugs and one or more float valves. In the case of the H1 Well, the float collar incorporated two float valves.

71 The float valves, either in the casing shoe or the float collar, are one way valves that allow passage of fluid from inside the casing but prevent its return. There are a number of proprietary float valve designs. The most common designs are a poppet type valve and a flapper type valve.

72 With the float collar used for H1 Well we had two flapper type valves and a small piece of plastic pipe which held the flappers open. While that is in place, the flappers are open and fluid can come back up through the shoe track. This is known as a self filling or auto filling float collar. A ball would normally be dropped inside the casing and when the ball hits the top of the hold open pipe, pressure from above causes a retaining lug to shear. The small pipe that holds the flappers open is then displaced down the hole allowing the flapper valves to shut converting the valve from auto fill to conventional one way valves. In the case of the H1 Well the ball was pre-installed.

73 The space inside the casing below the float collar and above the casing shoe is expected to be left filled with cement. This is known as the shoe track volume and is important for cement displacement calculations.

74 The cementing process has several elements and takes a number of hours to complete (explained below).

75 During the cementing process, cement is pumped into the casing to exit into the annulus between the outside of the casing and the inside of the hole that has been drilled. During, and for a period after the cement has been pumped, it remains liquid.

76 The hydrostatic pressure generated by the fluids outside the casing is generally greater than the hydrostatic pressure on the inside of the casing, which would cause the cement to flow into the casing after displacement if it were not restrained by the float valves in the float collar and/or casing shoe.

Circulate fluid

77 Prior to cementing, drilling fluid equivalent to 110% of the casing volume is circulated through the casing.

78 This circulation serves two purposes. The casing volume is greater than the annulus volume so circulating 110% of the casing volume ensures that drilling fluid on bottom is cycled out of the hole and it can be checked for wellbore fluid influx prior to committing to cement.

79 The second purpose is a check of the casing to ensure that any debris that may have been left in the casing and may cause a blockage of the float valves in the casing shoe track is removed.

Launching the plugs

80 After the drilling fluid is circulated and the surface cement lines pressure tested, the cementing process begins.

81 The first step is to launch the bottom plug. This is a displacement plug with elastomeric wiper fins to wipe the casing clean ahead of the cement.

82 This plug has a built in membrane designed to rupture after the plug reaches the float collar.

83 After the bottom plug has been launched, the lead slurry is pumped into the casing followed by the tail slurry.

84 As the cement is mixed and pumped the drilling supervisor monitors the operation and causes samples of the cement slurries to be taken for later evaluation.

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85 When the tail slurry has been pumped, the top plug is launched. The top plug also has wiper fins designed to wipe the casing clean of cement but it does not have a rupture mechanism. The top plug is a solid plug.

86 With the release of the top cement plug the next part of the operation is the displacement. In this operation, fluid is pumped above the top plug to displace or push it to the float collar.

87 Two types of pumps are used for this process. These are known as the cement pumps and the rig pumps.

88 A cement unit is a small volume very high pressure pump with cement mixing capabilities. The rig pumps are high volume high pressure pumps that can pump much bigger volumes of fluid than the cement pumps. The volume pumped by the rig pumps can be measured and monitored a number of ways:

(a) each stroke of the rig pump delivers a given volume. Stroke counters are fitted to the pumps and stroke counter displays are on the rig floor and within the mudlogging unit; and

(b) the rig pumps pump fluid from a mud tank. The volume of the mud tank is monitored by two independent systems – the Atlas Drilling monitoring system and the mudlogging monitoring system.

89 Because of the differences in the capacity of the cement pumps and the rig pumps, the cement pumps are only used to pump cement into the casing above the bottom plug. The rig pump is used to pump the displacement fluids into the casing above the top plug. This means that the cement column can be put into place much faster than would be the case if the cement pump were used for that purpose. Using the rig pump in this way also means that wet cement will be delivered to its planned position.

90 When the bottom plug reaches the float collar during displacement a small pressure increase is often noted indicating that the membrane in the bottom plug has ruptured.

91 Continued displacement of the cement forces the cement out of the shoe track into the annulus rising towards a planned top of cement (**TOC**) depth.

92 The volume of fluid used for displacement is calculated as accurately as possible.

93 Prior to running the casing several joints are callipered internally to check what the average inside diameter of the pipe is. It is quite normal for the calliper dimensions to be larger than the nominal

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values published in casing tables. This calliper inside diameter measurement is used to calculate the casing volume.

94 Checks are also made of the mud pump efficiency so that a corrected pump stroke volume is used for displacement.

95 The net result is that cement displacement figures are important so that the drilling team know, by reference to the number of pump strokes, when to expect the top plug to reach the float collar and "bump".

96 Just before the expected number of pump strokes, the pump rate is slowed to allow the drilling team to more accurately monitor the pressure within the casing. This is known as the final cement displacement circulating pressure and is an important part of calculating the height of the cement within the annulus.

97 It happens occasionally that instead of sealing at the float collar as intended, the top plug fails to seal. If that were to occur cement would be pumped past the float collar. In order to avoid displacing all of the cement from the shoe track, the rule of thumb is to pump the calculated displacement volume and if no bump of the cement displacement plug is seen, limit further pumping to 50% of the shoe track volume. This ensures that cement is left in the shoe track if the top plug fails to seal.

98 When the plug bumps, it typically seals on the inside diameter of the casing and because it cannot pass the float collar, the pressure within the casing increases.

99 At this point a cement unit will commence pressure testing the casing as set out in section 9.2 of the WCS.

100 After the pressure test is completed, pressure is bled off inflow testing the float valves. Cemented casing tested in this manner is considered a permanent barrier as per section 5 of the WCS.

101 Item 1.1.31 of the West Atlas SD1 Operations Procedures Manual sets out procedures to be followed in the event of float valve failure post cementing. Essentially the cement is to be held in place while it sets.

102 Points 15 and 16 of item 1.1.31 of West Atlas SD1 Operations Procedures Manual stated that:

15. Observe for return flow from the line broken off in the previous step.

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NOTE: If the floats fail, the valve must be closed to prevent the cement from flowing back inside the casing.

16. Observe the annulus flow or pressure for 8-12 hours after cementing or until a compression strength of 500 to 700 psi is reached to determine whether or not to remove the BOP stack entirely. The BOP may be **partially** nippled down, as long as enough is left to control and kill the well if it should become necessary

103 Cement plugs are intervals of cement within a casing string and are referred to as a Barrier per section 5 of the WCS. Although cemented shoe casings could be described as cement plugs, they are referred to as "cemented casing" because they are located at points in the casing where there is cement inside the shoe track and in the annulus surrounding it.

104 The verification of a cement plug can either be by pressure testing or weight testing ("tagging" - weight testing pressure must equal the equivalent of 3500kPa) – both options are industry practice and were also part of the *Schedule of Specific Requirements direction* under the *Petroleum (Submerged Lands) Act* (**P(SL)A**). Testing a plug by tagging does not always guarantee the integrity as a channel may have formed through the plug. Pressure testing can also be ambiguous depending on where the plug is set – if set deep in the well (inside cemented casing) the volume to pressure-up and test will not be a lot different to the volume required to test the casing. Installing a mechanical barrier such as a PCCC provides a visible pressure containing barrier that has been engineered and manufactured to withstand a know pressure – 10,000psi in the case of the 244mm (9⅝") PCCCs and 5000 psi for the 340mm (13 ⅜") PCCCs used for the Montara wells.

Pore pressure & fracture pressure - H1 Well

105 The pore pressure of the H1 Well was listed in the BOWD as Normal - 1.04sg.

106 This figure was provided by the Montara Project geologist David Thornton. To me, the word "normal" was of more importance than the numerical pressure value.

107 "Normal pressure" is equivalent to that of seawater which is usually considered to be 1.03sg. When the field discovery wells were evaluated, the reservoir pressures were resolved to be slightly less than sea water.

108 The fracture pressure in the H1 Well was listed in the BOWD as being 1.40sg near the reservoir. This is the fluid density which at reservoir depth could result in fracture break down of the formations. This figure was an estimate.

109 These pore and fracture pressure figures mean that the H1 Well would be overbalanced to formation if the well was filled with sea water.

Hydrostatic pressure

110 Hydrostatic pressure is the pressure exerted by a fluid at rest. In the context of well construction, it is the pressure exerted by the fluid in the well at a particular vertical depth in that well.

111 The pressure can be calculated as the vertical depth * the fluid density * gravity. At any point in the well, gravity and vertical depth can be considered constant. As density is the only variable it is common to refer to the reservoir pressure in a well in terms of density.

112 This allows easy comparisons between reservoir or formation pressures and mud densities.

113 If the mud hydrostatic pressure is greater than the formation pressure, the mud within the well is said to be "over balanced" to formation.

114 If the formation pressure is greater that the hydrostatic pressure due to the mud then the mud is said to be "under balanced".

115 An unrestrained, and under balanced situation leads to an influx of formation fluids into the well.

Drilling, displacement and completion fluids

116 Typically there are three main types of fluids used in well construction operations: drilling fluids, displacement fluids and completion fluids.

117 Most drilling operations use a drilling fluid (**Mud**) to transport rock fragments from the well, cool the drill bit and to provide hydrostatic pressure to support the hole being drilled.

118 Often, the Mud is comprised of water and various chemicals which help to stabilise the rock formations being drilled. The fluid properties of the Mud are engineered specifically for a particular hole section and are often adjusted during the drilling process to respond to wellbore conditions.

119 The completion fluid might come into contact with the producing formations so it is kept clean to reduce the risk of contaminating the reservoir. Much of the completion fluid will not contact the reservoir formations and has corrosion inhibitors added to slow degradation of the well casing and completion components.

120 Two types of completion fluids are brine and seawater.

121 The difference between brine and seawater is that brine is salty water and the salt may or may not be sodium chloride. Typically sea water is about 35,000 - 39,000 parts per million of chloride and the weight is about 1.03 sg.

122 Section 6.6 of the WCS states that:

6.6 Primary Well Control

Formation Integrity Tests or Leak off Tests shall be carried out below each pressure containment casing shoe on all wells.

For development wells the FIT/LOT may be omitted on the production casing string.

Kick tolerance shall be calculated for all pressure-containment casings using the following parameters:

- Maximum anticipated reservoir pressure
- Gas gradient of 0.23 SG (0.1 psi/ft) unless the actual is known
- 700 kPa (100 psi) surface handling safety margin

The following kick tolerance limits shall be applied:

Condition	**Minimal Acceptable Kick Tolerance**
For wells in which the reservoir pressure is known and the mud hydrostatic pressure exceeds this known pressure then the most likely cause of a well control incident is swabbing	$0.75m^3$ (5 bbls)
For wells in which the reservoir pressure is uncertain	$3.18m^3$ (20 bbls)

While drilling, a detailed ongoing assessment of the actual kick tolerance shall be conducted. Drilling must not continue with a kick tolerance below the levels stipulated in the Drilling Program (and as defined above).

The mud loggers should continuously monitor pore pressure indicators during drilling operations and report increasing trends. On critical wells an on-site pore pressure prediction contractor should be considered.

The following minimum stock levels shall be maintained onboard during exploration or appraisal drilling:

- Enough cement and additives to set a 150m (500 ft) plug in open hole 406mm (16")or smaller.
- Enough weighting materials and additives to raise the active mud system by 0.12 SG (1.0 ppg)

Primary well control shall be carried out in accordance with the Registered Operator Well Control Manual. Any additional procedures and deviation shall be specified in the Vessel Safety Case Revision.

Primary well control shall be maintained at all times during conventional drilling operations. The programmed mud gradient shall exceed the highest pore pressure gradient of the exposed permeable formations with a minimum static overbalance of 1,000 kPa. (143 psi)

When the pressure margins between pore pressure and fracture gradient are narrow, the ECD shall be calculated continuously.

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During exploration drilling, to detect the transition from normally pressured formations to abnormally high pressured formations, the following characteristics of the formation lithology and the formation fluid content shall be continuously monitored:

- Gas levels in the drilling fluid return
- The shape of shale cuttings in returns
- FEWD log response
- The change in temperature and salinity of the drilling fluid return
- Indications of bore hole instability or torque and drag

Flow checks shall be performed in the following circumstances using the Registered Operator's procedures unless otherwise specified in the Safety Case Revision. In addition to the requirements of the Vessel Safety Case the following must be flow checked:

- Any indications of downhole gains or losses
- Immediately a known hydrocarbon bearing objective is penetrated
- Prior to POH, prior to pumping a slug, at the last casing shoe, just prior to pulling the BHA and if trip displacement is incorrect
- Drilling breaks in the reservoir section exceeding 1.5m (5 ft) in length
- Prior to dropping a survey or dropping a core ball

The Drilling Supervisor shall include any special or additional requirements for flow checks in the Instructions to Drillers.

If the fluid volume to fill the hole is not correct, a further flow check shall be performed and the bit shall be returned to the bottom and bottoms up circulated before continuing.

The trip tank shall be used while tripping.

123 However, in a cased hole, nothing is "exposed".

124 Section 11 of the WCS states that:

"The density of any completion fluid, workover fluid or packer fluid must be designed to balance formation pressure at the top perforation plus, as a minimum, 1000Kpa (143psi)"

125 Section 5 WCS (set out in full below) refers to "fluids" being overbalanced to formation.

126 Displacement fluids are used in the cementing and do not typically come in contact with open hole.

127 The WCS does not expressly deal with the characteristics of any displacement fluids.

128 Section 2.3.1 of the ADWCM states, without defining "drilling fluids", that "all drilling fluids be of sufficient density to contain formation pressure". This requires all "drilling fluids" to be overbalanced to formation pressure.

Barriers

129 Section 2 of the WCS defines "barriers" to mean "any means of preventing an uncontrolled release or flow of well bore fluids to surface".

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MONTARA WELL HEAD PLATFORM
UNCONTROLLED HYDROCARBON RELEASE

130 Section 5 of the WCS states:

During drilling, completion, testing, intervention and other open hole operations the following barriers shall be maintained in the annulus:

- Two proven barriers between hydrocarbon bearing permeable zones and the surface
- One proven barrier between permeable fresh water bearing zones and surface

Barriers during Completion, Testing , Intervention and Other Open Hole Operations	
Barrier Type	**Description**
Proven	• Each annular or ram BOP • Wellbore fluid stable at surface, provided it can be monitored • Wireline set plugs in the tubing that have been pressure tested • RTTS type packer that has been pressure tested • Master valve • Lubricator

Temporary suspension is where the MODU or well intervention vessel remains on location. The following minimum number of tested, independent barriers shall be installed on annulus and tubing/casing above the highest open hydrocarbon zone or over-pressured water zone:

Heavy Weather	**Heavy Lifting** **Move Rig Over Well** **Remove/Install BOP/Xmas Tree**	**Drilling/Completion/Testing or Intervention Operations**
1 permanent and 1 temporary	1 permanent or 2 temporary	2 temporary

Barriers during Temporary Suspension	
Barrier Type	**Description**
Permanent	• Cement Plug • Permanent Packer with no controlled internal flow path • Cemented Casing
Temporary	• BOP closed and locked on drill pipe or tubing • Retrievable Packers • Wireline Plugs • Fluid with a hydrostatic head greater than formation pressure, provided that the liquid level and density can be monitored and maintained. • Closed SSSV that has been tested

A single temporary barrier may be used for temporary suspension, provided that petrophysical logs and other data confirm beyond doubt that no hydrocarbon zones or over-pressured water zones are present in either the wellbore or annuli.

For long terms suspension and abandonment requirement refer to Section 14.

Barriers must be verified in-situ as follows:

Barrier Type	**Verification**
Cement Plug **Not surface plugs**	• Tagging with sufficient force to confirm the top of good cement • Tagging pressure must equal the equivalent of 3500KPa (500 psi) • Or Pressure testing to 7000 KPa (1000PSI) over leak off
Cement plug on bridge plug	• Tag bridge plug then pressure testing to 7000 KPa (1000PSI) over leak off after setting cement plug

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Annulus Cement	• Waiting until the surface cement (tail) samples are set, providing that the cement job proceeded normally and a clear pressure differential was observed prior to bumping the plug • The differential pressure must confirm that the TOC is a minimum of 50m above any hydrocarbon or over-pressured water zone
All Other Barriers	• By either pressure or inflow testing

131 *"Open hole"* operations involve drilling beyond some existing casing so that there is some uncased hole exposed.

132 Sections 14.1 and 14.2 of the WCS relevantly state:

14.1 Long Term Suspension

Long Term Suspension is when the MODU leaves the well site. Wells must be suspended so that they can be abandoned with rig less intervention to meet the standards below.

Two permanent tested barriers must be installed in the annulus and well bore above any hydrocarbon zone or over pressured zone. The following are permanent barriers:

Barrier Type	Description
Permanent	• Pressure tested cement Plug (min 30m in length) • Permanent Packer with no controlled internal flow path and cement on top • Cemented Casing with proven TOC • Hanger Packer • Tubing Seals • Annular Master Valve

14.2 Abandonment

Two permanent tested barriers must be installed in the annulus and well bore above any hydrocarbon zone or over pressured zone. Abandonment Programs must comply with the following:

Section	Requirement
Open hole	• Cement plugs shall be placed with a minimum of 30m of cement above and a minimum of 30m below any significant oil, gas or fresh water zones
Casing	• Where there is open hole below the casing shoe a cement plug shall be placed extending a minimum of 30m above and 30m below the casing shoe, or • A cement retainer with effective back pressure control shall be set >10m and <30m above the casing shoe with a cement plug calculated to extend at >30m below and >15m above the retainer. Where lost circulation conditions exist a permanent type bridge plug should be set <45m above the shoe with >15m of cement on top. • Intervals of cased hole between cement plugs shall be filled with fluid suitably inhibited to prevent the corrosion of casing string.
Potentially productive zones behind casing	• All must be cemented off.
Casing Stubs inside Casing	• A cement plug shall be placed to extend >10m above >40m below the stub. A retainer may be used in setting the required plug.

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Section	Requirement
Perforations	• A cement plug shall be spotted and extend from at least from 30m below to at least 30m above the top perforated interval or • A cement retainer set in the casing not more than 45m above the top of the perforated interval with a cement plug extending at least 15m above the retainer provided the perforated interval is isolated from open hole below or subject to the above if a succession of retainers are used to isolate a series of perforated intervals. • The top-most retainer requires a minimum of 15m of cement placed above it. This plug must be tagged or pressure tested to a minimum of 3500KPa (500psi) above the leak-off or estimated fracture gradient at the point of injection.
Liners	• A cement plug shall be placed immediately above each liner hanger to extend >30m above the hanger. • This plug must be tagged or pressure tested to 3500KPa (500psi) above the leak off or estimated fracture gradient at the point of injection.
Surface	• All casing strings on wells to be abandoned shall be severed below the seabed. • A surface cement plug >45m in length shall be placed in the innermost casing string extending to the seabed with the top of the plug <45m below the seabed. • No annular space which extends to the seabed shall be left open to drilled hole below the annular space.

For offshore wells, a seabed survey and subsequent cleanup by ROV shall be conducted and noted in the IADC Drilling Report. A video shall be made and sent to the Drilling Superintendent.

A well abandonment schematic shall be prepared at the wellsite and sent to the Drilling Superintendent for final drafting together with full details of the components. The schematic shall include all relevant dimensions and equipment serial numbers to ensure traceability.

A corrosion cap should be installed on the MLS.

A trash cap should be installed on the conductor or the subsea wellhead.

133 Neither section 5 nor section 14 of the WCS expressly mention pressure containing corrosion cap but, instead, refer to 2 different types of functionally similar casing seals. These are RTTS type packers (section 5) and tubing seals (section 14).

134 These seals like pressure containing corrosion caps are also manufactured devices machined to withstand manufacturer's specified amounts of pressure and designed to be inserted into and removed from wells as required.

135 RTTS packer stands for "Retrievable Test Treat and Squeeze" packer and they work by essentially squeezing an elastima element against the inside of the casing to form a seal.

136 The tubing seals are O rings fitted to a tubing hanger to form a seal within a machined surface in a well head.

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137 A pressure containing corrosion cap uses O rings to form a seal within a machined surface within a MLS hanger.

138 The tubing hanger has a flow path through the middle which must be plugged to form a seal. Typically the plug is a tubing hanger plug (very similar in design to a pressure containing corrosion cap) and secured into place within the flow path of the tubing hanger.

139 The RTTS packer and the pressure containing corrosion cap both have mechanical valves that allow for pressure testing or fluid to be pumped below the barrier and serve to form a seal that can be removed as required.

140 The pressure containing corrosion cap is at surface and threaded onto the MLS hanger and the RTTS packer is designed for use at points deeper into the well. The pressure containing corrosion cap also protects the threads required for tie back from corrosion that might occur through exposure to the elements.

141 Each of a RTTS packer, tubing hanger and pressure containing corrosion cap are designed to allow the pressure beneath them to be checked and released while they are in place.

142 Each of a RTTS packer, tubing hanger and pressure containing corrosion cap are designed so that they can be installed through a BOP if that is required.

143 The WCS lists possible barriers by their functional characteristics. Accordingly references to tubing hanger and RTTS packer in the WCS are essentially interchangeable and are synonyms for pressure containing corrosion caps in the context of a choice as a barrier.

Temporary and long term suspension and abandonment

144 Section 5 of the WCS defines temporary suspension by reference to the MODU staying on the well site and to four anticipated scenarios when drilling work would be temporarily suspended. Section 5 sets out the necessary barriers in each of those scenarios.

145 Sections 14.1 and 14.2 of the WCS address Long Term Suspension and Abandonment and set out the barrier requirements in each of those circumstances.

146 A Long Term Suspension is "when the MODU leaves the well site". Section 14.1 of the WCS then refers to the wells being "suspended so that they can be abandoned with rig less intervention".

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147 When section 5 of the WCS was prepared it was not intended to describe all eventualities involving a temporary suspension.

148 When section 14 of the WCS was prepared, it was intended to apply to the anticipated situation where:

(a) a sub sea well is suspended at a sea bed wellhead;

(b) the drilling rig leaves the site; and

(c) the well in that situation may be left for years waiting for a decision to complete the well or it may be abandoned.

149 The objective in our "long term suspension" part of the WCMS was to ensure that a well suspended for a long period on the seabed was suspended robustly such that a MODU did not have to be mobilised to abandon the well. The alternative, if a robust suspension has been conducted, is to use a ROV to cut the wellhead at seabed level to abandon the well permanently.

150 The WCS were not intended to provide a prescriptive set of rules, nor to provide standards for every scenario that may have been encountered during a well operation. The WCS are a component part of the WCMS, the focus of which is ongoing risk management that is specific to conditions encountered in each particular well operation, assessment of those risks and appropriate decisions being made. Part 1.3 of the WCS allows for the WCM to risk asses any deviation in accordance with the Well Construction Risk Management Process and approve that deviation. This is what occurred in the case of the H1 Well.

151 The scenarios in section 5 of the WCS are, however, more applicable to the Montara well suspension scenario than section 14 of the WCS. The Montara well suspension scenario was, in essence, a temporary suspension. The suspension of H1 did not involve any abandonment of the well but the MODU was leaving the site. The MODU was planned to return after Topsides installation.

152 When the DP was changed and the H1 Well was suspended the intention was to always return to the wells, including the H1 Well, with the MODU. In other words, the wells were not suspended so that they could be abandoned without the intervention of the MODU. So, while the MODU did leave the well site the suspension of the wells did not meet the other criteria defining a long term suspension.

H1 Well Specifics

Overview of Drilling Programmes – original plan and revisions

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153 The DP was revised 3 times:

(a) The initial DP (Revision 0) was written to drill the wells through the WHP Topsides. The wells were planned to be batch drilled;

(b) Revision 1 was developed based on the WHP Topsides not being in place. The initial plan at that stage was to utilise the conductor deck extension to allow access to all the well slots and drill the wells sequentially. Whilst the Revision 1 program was undergoing an internal review additional wellhead equipment had been sourced allowing the wells to be batch drilled per the original program. Revision 1 was not widely issued

(c) Revision 2 was issued reverting back to batch drilling without the WHP Topsides in place.

154 The DP 1B addressed the completion of the wells after the suspension (incorporating the drilling of the reservoir section of the horizontal wells and the running of the sand exclusion screens) and was issued with "As Built" information after the wells had been suspended.

The cementing plan for the 244mm ($9^5/_8$") casing

155 The original design of the well contemplated a well head at surface. However, it was recognised that if there was no well head at surface the design of the Montara wells in suspension needed review.

156 A review of the drilling programme was conducted and on about 30 January 2009 I prepared Well Construction Change Control Form No D65005A 003 that addressed an issue that arose from that review.

157 This identified that we did not have enough PCCC's to cover all the MLS's we had installed and that if neither a PCCC or well head was in place, the top of cement for the 244mm ($9^5/_8$") casing should be extended further than was originally programed. This change was to extend the cement up into the 340mm ($13^3/_8$") casing shoe so that there was an effective seal within the annulus at that point.

158 This change would eliminate any formation open to the annulus.

Change from cement plug to pressure containing corrosion cap - H1 Well

159 When designing the Montara well program my preference was to design the program on the basis that PCCCs would be used as a barrier rather than cement plugs because:

(a) in my experience PCCCs are effective barriers;

(b) I considered that PCCCs were barriers that would comply with sections 2 and 5 of the WCS;

(c) corrosion caps protect the threads required to subsequently tie back the casing strings at the end of the MLS from corrosion;

(d) the WCS says that a corrosion cap should be used on a MLS;

(e) PCCC's allow pressure below the PCCC to be checked prior to removal, whereas cement plugs do not;

(f) if cement plugs are used within un-cemented casing, a situation can arise during the drill out of that plug where right hand torque applied to the cement can result in left hand torque applied to the casing above. This left hand torque can result in the casing backing out and loosing pressure integrity. Using a PCCC avoids the risk of damaging the 244mm (9⅝") casing when drilling out a cement plug;

(g) if a problem was identified such as pressure below a PCCC then an alternative course of action could be taken. In the case of the 244mm (9⅝") PCCC, trapped pressure below could be managed by nippling up the BOP on the 340mm (13 ⅜") casing and removing the PCCC in controlled conditions; and

(h) the original drilling program only contemplated one PCCC being available (which would be used in the GI well). Also, the original drilling program did not include bringing cement up inside the 340mm (13 ⅜") shoe on the 244mm (9⅝") cement job. Bringing cement up inside the 340mm (13 ⅜") shoe effectively provided a closed chamber in the 340mm (13 ⅜") x 244mm (9⅝") annulus and two PCCC's were considered to be an improvement on the original plan.

160 However, because PTTEPAA did not originally have enough PCCC's in inventory and available for all of the wells (namely Montara GI, H1 Well and Montara H4), the DP was designed to set a cement plug from 160m to 115m in the 244mm (9⅝") casing of the H1 and H4 wells.

161 On 25 February 2009 I received an email from Mr O'Shea querying whether it was proposed to change the DP so that a PCCC would be installed on the 244mm ($9^5/_8$") casing instead of a cement plug in the 244mm ($9^5/_8$") casing. Shortly later, a 244mm (9⅝") PCCC became available. On 3 March 2009 I emailed Mr O'Shea advising him that a PCCC would be installed on the 244mm ($9^5/_8$") casing instead of a cement plug in the 244mm ($9^5/_8$") casing and further details would be given to him shortly.

162 A Change Control Form to the DP was issued to remove the planned cement plug in the H1 Well and replace it with PCCC. We made this change because, for the reasons that I have already explained, this was a safer and more compliant design. It also replicated the design in the DP for the GI well. We didn't have enough PCCCs to do it on all the Montara wells: we had allocated one for the GI well and ended up with enough to do two, so we allocated the second of them to the second well, the H1 Well.

March 2009

163 I was in Perth between 1 and 12 March 2009.

164 Mr Duncan and I shared the day to day operational responsibility for rig operations.

165 In about early March 2009, the drilling being undertaken in the H1 Well reflected the stages set out in paragraphs 5.23, 5.24 and 5.29 of the DP. These stages were:

5.23 Run 244mm (9 5/8") Casing – Montara H1

196) Hold JSA and rig-up TESCO Casing Running tool (dressed to run 244mm (9 5/8") casing) to the TDS.

197) Run 244mm (9 5/8") casing per casing tally (Appendix 3).

- PDC Drillable float and shoe with sharkbite installed above the float.
- After making-up the shoe track (with baker-loc) fill with mud to check for flow through.
- Fill each joint of casing with mud whilst running in the hole
- Monitor the trip tank closely firstly due to hydrocarbon zone being open (Montara Formation) and secondly for surge effects on the lower Johnson and Puffin inducing losses.
- Record up and down weights every 5 joints and compare against the torque and drag modeling.

198) Make-up the 244mm (9 5/8") MLS joint.

199) Run in the hole with the casing on the 244mm (9 5/8") landing string

200) Wash down the last joint of casing and land out the casing on the MLS

- Space out so that the cement head is at the rig floor level.

201) Circulate 110% of the casing volume

202) Install X/O pup joint – Vam Top pin x Buttress box

- Required to install the surface cement head onto the 244mm (9 5/8") casing

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203) Retract the blocks to move the Tesco casing running tool out of the way (do not rig the casing running tool down as it will be required to back out the casing from the MLS)

204) Make up the cement head.

- Take slow circulation rate (50SPM)
- Retract the blocks and lay out the Tesco Casing Running Tool offline.

205) Cement casing per program (Appendix 4)

- Monitor for returns
- Displace cement with inhibited seawater
- Ensure cement head is flushed while displacing the cement
- Estimate TOC using differential pressure prior to bumping the plug and report same on the DDR
- Pressure test the casing to 27.5MPa (4000psi) for 10 minutes if plug bumps
- **Offline:** Install the BOP cranes to the BOP's in preparation for nippling down the BOP's.

206) Check that the floats are holding

207) Disconnect the cement head and remove X/O joint of casing

5.24 Secure Well – Montara H1

208) Whilst waiting on cement use the Tesco Casing Running Tool, back-out the 244mm (9 5/8") MLS running tool from the MLS by rotating the casing to the right for 8-9 turns.

- The anticipated torque to back-out the running tool is 2034 – 4745 Nm (1500 – 3500 ft-lbs)

209) Once the running tool is released recover the landing string to surface and lay out same

210) Rig down the Tesco casing running tool

211) Run in the hole with drillpipe to 210m

212) Spot 3.97m^3 (25bbls) of hi-vis

213) Pull out of the hole to 160m

214) Set cement plug from 160m to 115m

215) Pull out of the hole to 115m

216) Circulate hole clean with inhibited seawater

217) Pull out of the hole

218) Wait on cement (both casing cement and also the cement plug)

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5.29 Reduce the pressure in the Diverter Overshot Packer and lift the BOP's clear of the surface wellhead. Suspend Well – Montara H1

267) Skid to Slot 13-WD-003

268) Make-up a 340mm (13 3/8") casing spear and run in the hole.

269) Engage the 340mm (13 3/8") casing and apply right-hand rotation to release the MLS running tool from the hanger.

- The anticipated torque to back-out the running tool is 2034 – 4745 Nm (1500 – 3500 ft-lbs)

270) Recover the casing to surface on the spear and lay out the casing and rack back the spear.

271) Run in the hole with the 508mm (20") Lynx running tool and make-up same to the landing joint.

272) Rotate the 508mm (20") casing to the left to release the landing joint (joint torqued to less than all other joints).

273) Pull out of the hole with the 508mm (20") casing.

274) Lay out the landing joint and rack back the Lynx running tool.

275) **Offline** - Apply "lubriplate" lubricant to the threads on the 340mm and 508mm (13 3/8" and 20") MLS' prior to installing the corrosion cap

276) **Offline** - Make-up 508mm (20") corrosion cap and run in the hole with same on a tugger

Figure 20 shows the suspended status of Montara H1.

166 The approval of the DP (by the Designated Authority - **DA**) had only been given with respect to drilling of the wells and not for suspension. The suspension diagram in the approved DP was only indicative of the proposed future state of suspension. Separate approval (from the DA) was required for suspension. The suspension application was based on well data at the time of the proposed suspension together with a revised suspension diagram.

167 It was planned to install the 244mm (9⅝") PCCC on Saturday, 7 March 2009. To avoid any potential delays or inconvenience in getting approval for that change on a Saturday, a verbal request of the change needed to be made to the DA on the afternoon of Friday, 6 March 2009 to make sure that there was aural approval in place to install the PCCC before the work commenced.

168 On 6 March 2009 I sent an email at approximately 1437 hours [NT Time] to the DA requesting urgent verbal approval of the Stage 1 suspension of the H1 Well. I prepared a suspension diagram which showed the presence of a 244mm ($9^5/_8$") PCCC (**Suspension Diagram - Stage 1**) and attached this to the email. The Stage 1 suspension only allowed for the installation of the 244mm ($9^5/_8$")

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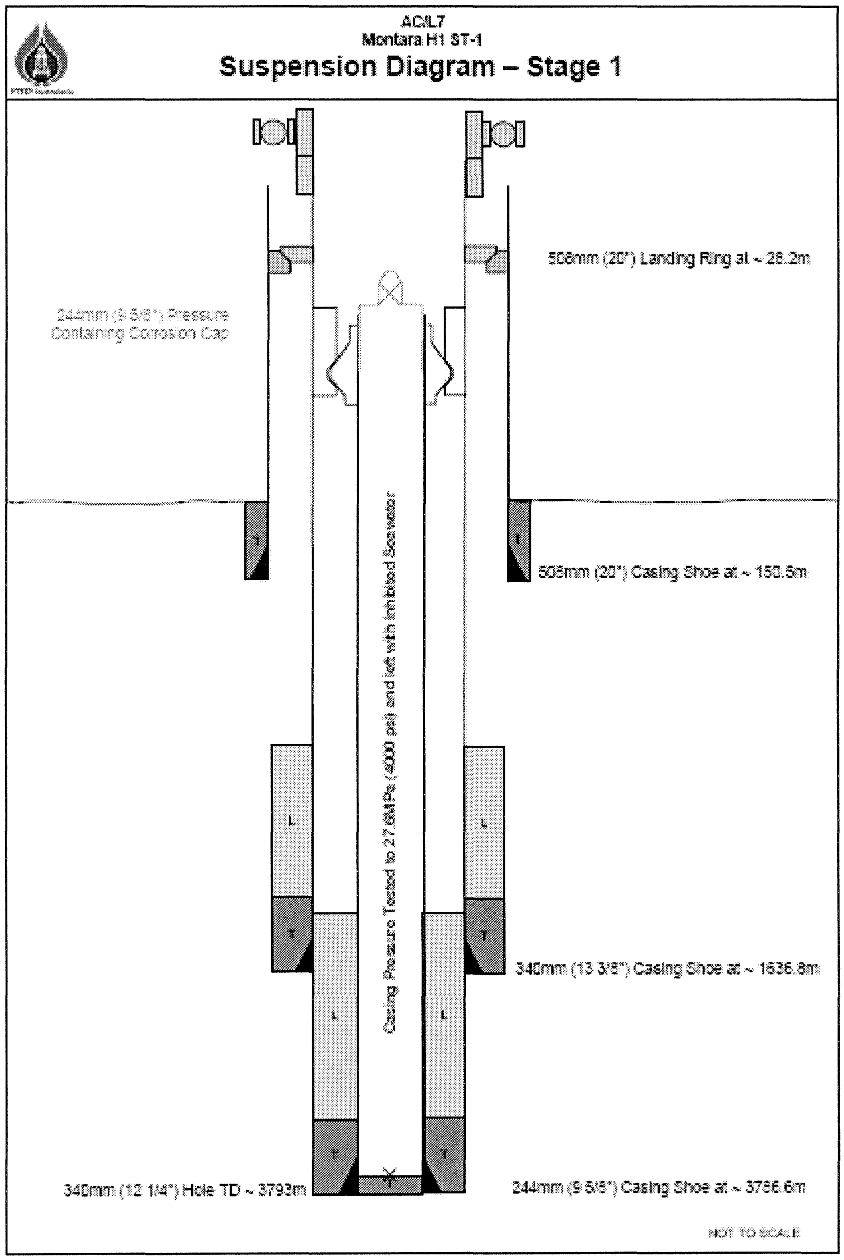
PCCC as the 340mm ($13^3/_8$") casing, wellhead and BOP's would remain in place until the BOP was removed to be installed onto another well being drilled on the WHP. The Suspension Diagram - Stage 1 was as follows:



169 The H1 Well suspension was planned to be the same as the GI well that was already part of the DP.

170 At about 1500 hours (CST) on 6 March 2009 I received an email from the DA granting approval for the suspension of the H1 Well in accordance with the Suspension Diagram - Stage 1 and advising that a formal letter confirming the approval would be issued the following week.

171 I then sent that email to Mr Treasure (who was the PTETPAA Senior Drilling Supervisor on duty on board the *West Atlas*).

172 I was on duty on the weekend of Saturday, 7 and Sunday, 8 March 2009. By convention, on weekends Mr Duncan and I would only speak about work issues if we thought that there was a problem to solve or an opportunity to improve something. I do not recall speaking to Mr Duncan on either Saturday, 7 or Sunday, 8 March 2009.

173 On 7 March 2009 I read the DDR dated 6 March 2009. I was aware from that report that the float valves were functional at that time.

174 The 244mm ($9^5/_8$") shoe float on H1 Well was cemented on 7 March 2009.

175 On 7 March 2009 I was not near my computer most of the day so most of the communication with the rig was via telephone. At approximately 1330hrs I had one or two telephone conversations with Mr Treasure on the *West Atlas*, the substance of which was as follows:

(a) Mr Teasure informed me that:

(i) the cement job was complete and they had pressure tested the casing;

(ii) once the casing pressure test was complete they had bled-off the pressure and when they had nearly bled-off all the pressure they got a rush of fluid and shut the well in at the cement unit and it appeared that the float had failed.

(b) I asked Mr Treasure to apply or hold some pressure and wait on the cement to set.

176 I had a further telephone conversation with Mr Treasure later in the afternoon (I don't recall what time) and he advised me they were keeping the pressure in the casing steady at about 1300psi and waiting on cement.

177 I thought that the 1300 psi figure given by Mr Treasure was reasonable based on some rough calculations I had done some time prior to the job to check final circulating pressure. The pressure had to be sufficient to hold the cement in place while it set therefore the pressure had to be greater than the hydrostatic pressure of the wet cement pumped into the casing but not excessively more than that. I did not have any concern about the pressure being held against the float.

178 I had a further telephone conversation with Mr Treasure later that afternoon / early evening (I think it was about 3 or 4 hours later) and I enquired how the cement was going and he said it had set and they had bled-off the pressure with no flow from the well.

179 It was not my normal practice to ask for details of the amounts of fluids displaced during any part of the cementing process unless I was asked specifically to perform some calculation that would require data from offshore or I wanted to perform that calculation in any event.

180 I do not recall Mr Treasure telling me or me asking him how many barrels of fluid had been initially bled off or how many barrels he pumped back. If I had been asked to perform any calculations it would have been necessary to have relevant data sent to me or relayed to me by Mr Treasure as that data, being the data recorded on the cement unit, is not part of the live data feed that is accessible onshore.

181 In the WCS at section 9.2 it states:

"All surface and intermediate casing strings shall be pressure tested to the design burst pressure but not exceeding 70% of the minimum internal yield pressure, and not less than 5600 kPa (800 psi).

The pressure shall be held for a minimum of 20 minutes, except that for casings sizes > 340mm (13 3/8) and strings with length >500m."

182 That said the *Schedule of Specific Requirements direction* under the *P(SL)A* dated 18 December 1995 Section 503 [Well Casing] Paragraph 14 (c) states that pressure testing requirements include – pressure tests shall be held for as long as necessary (but not less than 10 minutes) to ascertain that there is no continuous pressure drop, and the result recorded in the drillers log.

183 On the morning of Sunday 8 March 2009 I saw the email update dated 8 March 2009 from the PTTEPAA personnel on *West Atlas* to, amongst other people, me that attached the:

(a) PTTEPAA Daily Drilling Report dated 7 March 2009; and

(b) Advantage Drilling Mud Report dated 7 March 2009.

184 The PTTEPAA Daily Drilling Report dated 7 March 2009 mentions:

(a) at 1400- 1500: "*Switched back to Halliburton and pressure tested casing to 27.6Mpa x 10 mins - OK Bled off test pressure to 1.37Mpa then observed pressure rapidly increase to*

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8.9Mpa. Note: Pumped 1.47m^3 and bled-off 2.62m^3, suspected float valve failure. Pumped 2.54m^3 back into the casing at 9.3MPa";

(b) at 1500 - 1800: *"Waited on cement."*

(c) at 1800 - 1830: *"Open casing annulus to atmosphere and confirm no backflow"*.

185 Given my discussions with Mr Treasure on 7 March 2009 there was no need for me to and I did not scrutinize the volumes and pressures relevant to the cementing process recorded in the DDR. I reviewed the DDR to see if there was any obvious errors or issues. There were none.

186 In the Advantage Drilling Fluids Report 7 dated 7 March 2009, drilling comments section, there is mention of *"WOC [Wait on Cement] Retested float..."*.

187 On the morning of Sunday 8 March 2009 I prepared the morning update email in which I made the comment that:

"*When bleeding off the pressure after testing the casing the float appeared to let go. Held pressure on the casing and waited on cement. Prepared to skid and serviced top drive whilst waiting on cement. Checked floats on casing - OK. Released the 9 5/8" casing at the MLS and laid out the landing string*".

188 From my discussions with Mr Treasure on 7 March 2009 and the details recorded in the morning email and the Advantage Drilling Fluid Report, I understood that an inflow test had been done on the 244mm ($9^5/_8$") casing cement and no flow had been seen.

189 The reference in the DDR report to the *"annulus"* was inaccurate given what I had discussed with Mr Treasure and what was reported in the other report and morning email.

190 I did not interpret the expression *"checked cement integrity"* in the morning email to mean that any test other than the inflow test had been done. This was consistent with the discussions that I had had with Mr Treasure on 7 March 2009.

191 It was apparent from the above reports that were available to me and my discussions with Mr Treasure that the float valves failed in service.

192 The *West Atlas* SD1 Operations Procedures Manual deals with the situations of failures of float valves and waiting on cement.

193 Section 1.1.31 (point 15 under procedures) of the *West Atlas* SD1 Operations Procedures Manual says *"NOTE: If the floats fail, the valve must be closed to prevent the cement from flowing back inside the casing."*

194 Putting together the comments made in the DDR and Advantage Mud report and telephone conversations with Mr Treasure, I concluded that the cementing had been completed properly and the well integrity was not a concern.

195 On 11 March 2009 I received from Mr Treasure the completed casing and cementing report (prepared by Mr Treasure) dated 6 March but updated following completion of the cementing on 7 March 2009. I looked very briefly at the report but did not scrutinised the figures. There was no need for me to scrutinise the figures, given the events of 7 March 2009 as I have described above. The report contains a pumping schedule. This schedule records fluid type, volume, pressure and comments on the cementing operation. This schedule recorded that 16.5bbls of fluid had been pumped back into the 244mm ($9^5/_8$") casing after the float failed and that the final pressure prior to stopping pumping was 1350psi.

196 On 11 March 2009 I prepared Well Construction Change Control Form No D65005A-006. This form describes a change to the method of suspension of the H1 Well.

197 The revised suspension method consisted of: cemented casing shoe , a column of inhibited sea water, 244mm ($9^5/_8$") and 340mm ($13^3/_8$") PCCC's and a 508mm (20") trash cap on top. A trash cap is a non pressure containing cover to prevent debris entering the well.

198 The Change Control Form did not include instructions on when the 244mm ($9^5/_8$") and 340mm ($13^3/_8$") PCCC's should be installed in the H1 Well and whether the PCCC's should be pressure tested. The manufacturer's instructions for the installation of the PCCC's was supplied to the PTTEP Drilling Supervisor so the caps could be installed as per the manufacturer's instructions. I assumed that those instructions would call for an in situ pressure test after installation and I did not note prior to sending out the manufacturers instructions that they themselves do not call for the PCCC's to be pressure tested once installed.

199 The considerations for the amendment were discussed between Mr Duncan and me in the form of a risk assessment. The following points were raised:

(a) pressure containing corrosion caps allow pressure below the cap to be checked prior to removal, whereas cement plugs do not;

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(b) the risk of damaging the 244mm ($9^5/_8$") casing when drilling out a cement plug;

(c) a 244mm ($9^5/_8$") pressure containing corrosion cap was available; and

(d) protect the threads on the MLS.

200 I received the original signed Change Control Form on 12 March 2009. I scanned the Change Control Form and attached the relevant documents and sent that to PTTEPAA's Montara Development document controller with instructions to distribute it to the same people who had received the DP.

201 Also on 12 March 2009 an application was made to the DA to suspend the H1 Well based on Suspension Diagram - Stage 2, including the installation of the 340mm ($13^3/_8$") PCCC. Suspension Diagram - Stage 2 was as follows:

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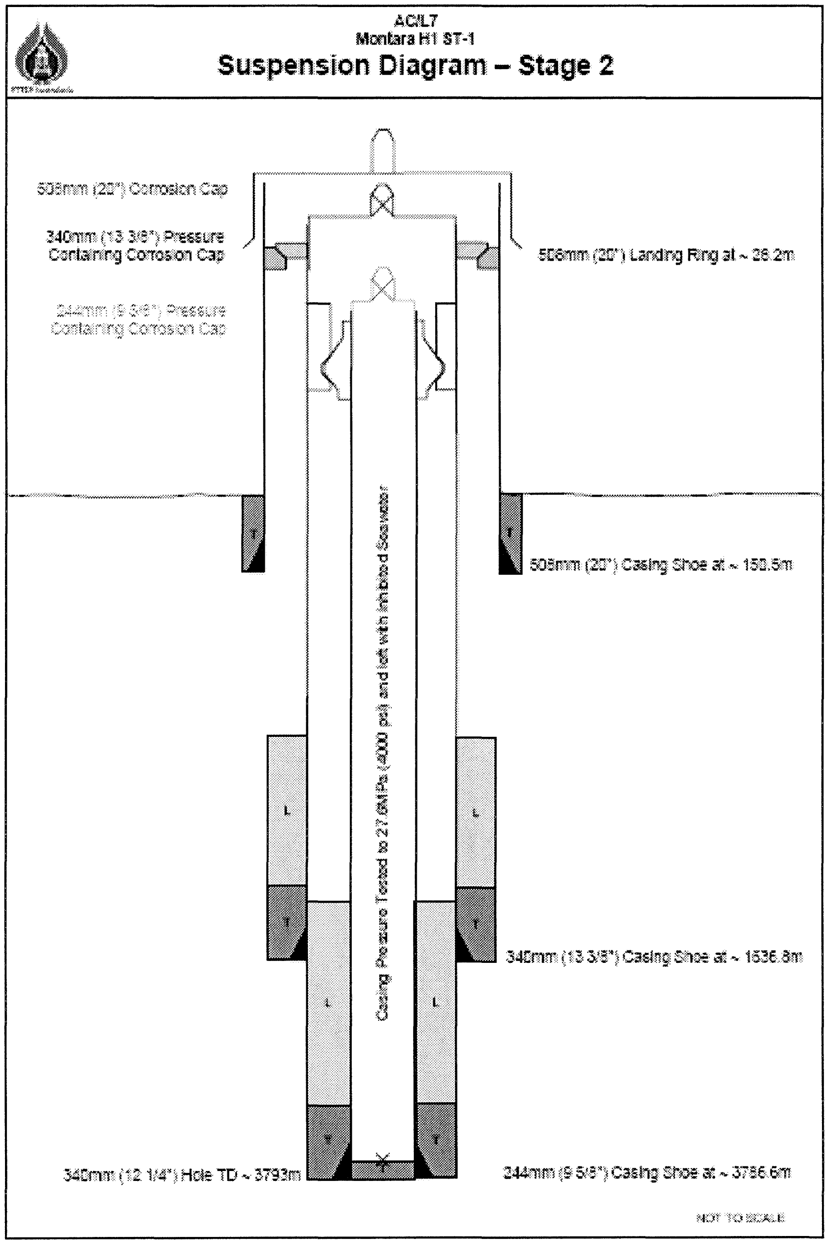

202 The application to perform the Stage 2 suspension was approved by the DA on 19 March 2009 and the approval was then forwarded to Mr Treasure on the *West Atlas*.

The 340mm ($13^3/_8$") PCCC

203 The revised DP intended that a PCCC would be screwed into the 340mm (13 ⅜") MLS hanger threads at surface on the 340mm (13 ⅜") casing.

204 On 8 March 2009 the 340mm (13 ⅜") casing above the MLS was still screwed into the MLS hanger.

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205 This was left in place as a BOP parking point on the H1 Well. The BOP could be landed on the 340mm (13 ⅜") braden head whilst the rig drilled top hole sections in Montara H2 & H3, wells not originally planned for when the DP was issued. This resulted in the scheduling of the installation of the 340mm (13 ⅜") PCCC on the H1 Well for some time after the BOP and the MLS hanger being removed.

206 The installation of a 340mm (13 ⅜") PCCC on the H1 Well is noted in the comments section of the DDR-14 from Montara H2 dated 16 April 2009 and reporting on the activities for 16 April 2009.

207 That DDR says (on page 3): *"Corrosion caps fitted to 340mm MLS and trash caps fitted to 508mm conductors on H1 and H3-ST1".*

208 The Montara H2 DDR-14 dated 16 April 2009 arrived on shore on 17 April 2009.

209 On 17 April 2009 I received an email from PTTEPAA staff on the *West Atlas* saying the PCCCs were installed. The e-mail was the morning update e-mail that contains the morning reports that is sent in by 0700hrs each day. Under the section "Comments/Activities" the third bullet point is *"Corrosion caps and trash caps installed by on wells H1 and H3-ST-1".*

210 A Trash Cap sits on the top of the 508mm (20") casing and is a non pressure containing cover to prevent debris entering the well.

211 I therefore prepared the Suspension As-Built (drawing) showing the well suspended with the 340mm (13 ⅜") PCCC in place.

212 On 21 April 2009 I received by email the DDR from Montara H2 dated 20 April 2009 that stated in the operations section between 0600 and 0700 hrs *"Note: Now all 5 wells secured and protected".*

213 Based on those DDRs I thought that the 244mm (9⅝") PCCC and the 340mm (13 ⅜") PCCC had been installed on the H1 Well as set out in the DP (as revised by change control).

214 Online activities are items that are usually performed by the drilling team. They usually involve the use of the derrick or the rig floor personnel. This is what is reported in the time breakdown on the IADC report and also the Daily Drilling Report. Offline activities are jobs that are done at the same time as online activities. An example of this may be the installation of a trash cap, which can be done with an air hoist and a roustabout may be done at the same time as casing is being laid out on an adjacent well.

Suspension status of the H1 Well and the plan for the completion of the wells

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215 As at 17 April 2009 and based on the documents that I had received and on my previous telephone discussions with Mr Treasure, I thought that the following barriers were in place and would remain in place during the suspension of the H1 Well and prior to the commencement of work to prepare the well for the next stage of drilling:

(a) a cemented shoe;

(b) displacement fluids within the 244mm (9⅝") casing (which provided hydrostatic pressure greater than the pore pressure);

(c) 244mm (9⅝") pressure containing corrosion cap;

(d) cement within the 340mm (13 ⅜") x 244mm (9⅝") casing annulus; and

(e) 340mm (13 ⅜") pressure containing corrosion cap.

216 I also thought based on the documents that I had received that a 508mm (20") Trash Cap was in place on the H1 Well.

217 The *West Atlas* returned to the Montara WHP on 19 August 2009.

218 After initial preparations for work, the initial work scope was to re-establish the top 20 meters of the casing and MLS back to where the well head was going to be. This involves a tie back of casing strings.

219 Next, the BOPs were to be nippled up again and pressure tested. Then the drilling assembly was to go in and the shoe track and plug drilled out, followed by the horizontal section and then to carry on with our program as contained in DP 1B.

220 During the tie back we had to tie back 3 casing strings. Firstly we had to tie back the conductor. The conductor was strong enough to support the weight of all the loads including the BOPs which were about 90 tons. With the conductor installed we would cut that accurately to height and then install the first wellhead section. The first wellhead section elevation would dictate the stack up height for all the other items. The 340mm ($13^3/_8$") casing would have been tied back and its annular sealed off and then the 244mm ($9^5/_8$") casing tied back and sealed off and at that point we would have nippled up to BOPs and started pressure testing.

221 The plan was to take off the trash cap, nipple up the 508mm (20") conductor with a PCCC on the 340mm ($13^3/_8$") casing and a PCCC on the 244mm ($9^5/_8$") on that well.

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222 Within the drilling program, DP 1B, section 5.6 on page 29 covers the removal of the trash cap, installation of the conductor and installation of the braden head or initial wellhead section.

223 The planned steps to tie-back the 508mm (20") casing on the H1 Well were set out in paragraph 5.6. The planned steps to remove the 340mm (13 ⅜") PCCC and tie back the 340mm (13 ⅜") casing on the H1 Well were set out in paragraph 5.16 of the DP 1B and the planned steps to remove the 244mm (9⅝") PCCC and tie back the 244mm (9⅝") casing on the H1 Well were set out in paragraph 5.17 of the DP.

5.6 Tie-back 508mm (20") casing – Montara H1 ST-1

15) Remove the trash cap from the well using a tugger
    - Check the threads on the 508mm (20") conductor
16) Rig-up to run 508mm (20") conductor
17) Make-up the landing string (Figure 28) and run in the hole
18) Carefully make-up the Leopard connection on the MLS and engage the anti-rotation tabs
19) Rough cut the casing above the mezzanine deck and recover the landing string.
20) Skid to well slot 13-WD-009 (Montara GI)
21) **Offline** cut the 508mm (20") casing at 4.661m above the platform main deck (Figure 28) with a cold cutter and recover the cut-off.
22) **Offline** install the Braden Head and orient per Appendix 5 (Due North or parallel to the aft of the rig pointing starboard). Record wellhead serial number on the DDR
23) **Offline** install Aker debris cover P/N 585776-P5

5.16 Tie-back 340mm (13 3/8") casing – Montara H1 ST-1

173) Run in the hole with the corrosion cap running tool.
174) Make up the TDS before engaging the running tool onto the corrosion cap (this will allow for any pressure below the corrosion cap to be observed on the standpipe and then bled-off through the choke manifold)
175) Engage the corrosion cap and check for any pressure below the corrosion cap. Note any pressure on the IADC and the DDR. Bleed-off any pressure via the choke manifold.
176) Remove the corrosion cap by rotating clockwise for 8-9 turns with a torque of 2034 - 4745Nm (1500-3500 ftlbs) and recover same to surface.
177) Rig-up to run 340mm (13 3/8") casing
178) Make-up the MLS tieback tool to the landing string
    - Confirm all seals are intact

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- Lubricate seals with Jet Lube AP-5 or equivalent. DO NOT use pipe dope or lubricant containing metal particles.

179) Run in the hole with the MLS tieback tool and space-out to ensure that no casing couplings are in the vicinity of the surface wellhead

180) Lower the tieback tool onto the MLS and apply 0.9 to 2.2MT weight down and mark the pipe at the rotary table

181) Rotate the string to the right 9.5 to 10.5 turns maintaining constant weight down on the string with a torque of 3390 to 5424Nm (2500 – 4000 ftlbs). The string should have moved 89mm down.

182) Hydrotest the tieback by filling the casing with water.

183) Install the casing slips (Aker P/N W85859-133EA-2W). The slips are fully installed when the distance from the top of the slips to the top of the starter head is 216mm (8.52")

184) Install the cold cutter and cut the 340mm (13 3/8") casing 127mm (5") [+/- 3mm (0.12")] above the top surface of the starter head ensuring the outer edge has a bevel per Aker Procedures 61-PH2059-70 (M176).

185) Once the casing is cut recover the landing string to surface.

186) Change from casing elevators to drillpipe elevators and make-up the pack-off running tool complete with the pack-off (P/N W85860-133A-2Q).

187) Whilst rigging-up to run the pack-off clean out the cavity above the slips in the starter head in preparation to run the pack-off.

188) Install the pack-off per Aker Procedures 61-PH2059-70 (M176).

189) Pressure test the pack-off to 10.9MPa (1584 psi) – 70% of the collapse pressure of the casing for 10 minutes

190) Once successfully pressure tested engage the pack-off

191) Recover the pack-off running tool

192) Change out the 340mm (13 3/8") pack-off running tool for the 244mm (9 5/8") pack-off running tool.

5.17 Tie-back 244mm (9 5/8") casing – Montara H1 ST-1

193) Run in the hole with the corrosion cap running tool.

194) Make up the TDS before engaging the running tool onto the corrosion cap (this will allow for any pressure below the corrosion cap to be observed on the standpipe and then bled-off through the choke manifold)

195) Engage the corrosion cap and check for any pressure below the corrosion cap. Note any pressure on the IADC and the DDR. Bleed-off any pressure via the choke manifold.

196) Remove the corrosion cap by rotating clockwise for 8-9 turns with a torque of 2034 - 4745Nm (1500-3500 ftlbs) and recover same to surface.

197) Rig-up to run 244mm (9 5/8") casing

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198) Make-up the MLS tieback tool to the landing string.

- Confirm all seals are intact
- Lubricate seals with Jet Lube AP-5 or equivalent. DO NOT use pipe dope or lubricant containing metal particles.

199) Run in the hole with the MLS tieback tool and space-out to ensure that no casing couplings are in the vicinity of the surface wellhead

- Install a 340mm x 244mm (13 3/8" x 9 5/8") casing centralizer below the surface wellhead as the 244mm casing will be cut without the casing slips in place.

200) Lower the tieback tool onto the MLS and apply 0.9 to 2.2MT weight down and mark the pipe at the rotary table

201) Rotate the string to the right 9.5 to 10.5 turns maintaining constant weight down on the string with a torque of 3390 to 5424Nm (2500 – 4000 ftlbs). The string should have moved 89mm down.

202) Hydrotest the tieback by filling the casing with water.

203) Install a water head bushing on the casing complete with a side entry sub and a TIW.

204) Pressure test the casing to 27.5MPa (4000psi) for 20 minutes to check the integrity of the MLS connection.

NOTE: This will pressure test the entire 244mm (9 5/8") casing string.

205) Nipple-down from the casing pressure test

206) Install the cold cutter and cut the 244mm (9 5/8") casing 509mm (20.04") [+/- 3mm (0.12")] above the top surface of the starter head ensuring the outer edge has a bevel per Aker Procedures 61-PH2059-70 (M176).

207) Recover the landing string

208) Change from casing elevators to drillpipe elevators (whilst installing the wellhead)

209) Install the unitized Aker Wellhead per the Aker procedure 61-PH2059-70 (M176). Orient the wellhead per the wellhead orientation procedure (Appendix 5)

210) Pressure test the neck seals against the 340mm (13 3/8") casing to 10.9MPa (1584 psi) – 70% of the collapse pressure of the casing for 10 minutes.

211) Pressure test the cavity between the starter head and the unitized wellhead to 10.9MPa (1584 psi) – 70% of the collapse pressure of the casing for 5 minutes.

212) Install the 244mm (9 5/8") slip landing guide (Figure 30)

- The slip landing guide will consist of a cut-off joint of 244mm (9 5/8") casing with 3 guides welded to the inside base. The guide will be lowered through the unitized wellhead and mate-up with the already cut 244mm (9 5/8") casing. The slip landing guide will allow the slips to be wrapped around the casing and lowered into the wellhead without snagging-up on the already cut casing.

213) Install the casing slips (Aker P/N W85716-095A-3W). The slips are fully installed when the distance from the top of the slips to the top of the unitized wellhead is 703mm (27.66")

214) Once the slips are installed remove the slip landing guide.

215) Make-up the pack-off running tool to drillpipe (a minimum of 3T weight is needed to set the pack-off)

216) Install the pack-off per Aker Procedures 61-PH2059-70 (M176).

217) Pressure test the pack-off to 22.96MPa (3330 psi) [70% of the collapse rating of the casing] for 10 minutes

218) Once successfully pressure tested engage the pack-off

219) Take 4.5T overpull to confirm that the pack-off is engaged.

220) Recover the pack-off running tool

221) Skid to slot 13-WD-001 (Montara H4)

222) **OFFLINE:** Install the tree Jig (Figure 31) to allow construction to take measurements for the flow lines. Once measurements have been taken nipple down the jig

223) **OFFLINE:** Remove one manual 52mm (2 1/16") side outlet valve and replace with two hydraulic actuated 52mm (2 1/16") side outlet valves for the 244mm (9 5/8") annulus gas injection manifold tie in. Confirm with Production/Construction crew on correct side of unitized wellhead for the Gas Injection manifold tie in as well as hydraulic actuator orientation for hydraulic control line tie in.

224) **OFFLINE:** Install the 4.5m high pressure riser using a double drive lock adaptor to the unitized wellhead (Figure 32).

225) **OFFLINE:** Install the drive-lock adaptor (loose) and cross-over spool onto the riser in preparation for the BOP's. When the rig is tying back the last well (H3) the BOP's should be able to skidded towards the H1 well and made-up to the drive-lock assembly

224 Paragraph 5.17 of the DP 1B shows that the 244mm (9⅝") casing would be exposed to atmosphere when the 244mm (9⅝") PCCC was removed.

225 As the DP planned a batch drilling program the 244mm (9⅝") casing would be exposed to atmosphere while the 244mm (9⅝") casing was tied back on other wells.. This could take 24 hours or so.

226 This exposure to atmosphere is consistent with convention on surface wellhead type operations where allowances are made for BOP removal after cement has set as contemplated in the ADWCM and commonly practised within the industry.

227 This plan meant that:

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(a) the 244mm ($9^5/_8$") PCCC would not have been removed until all of the 340mm ($13^3/_8$") casings had been tied back; and

(b) had pressure been observed under 244mm ($9^5/_8$") PCCC then the wellhead could have been installed on the 340mm ($13^3/_8$") casing and the BOP's installed. Having surface pressure control equipment in place would have allowed for more options when dealing with pressure under the PCCC.

20 August 2009

228 Between 0745hrs and 0815hrs on 20 August 2009 I was in the PTTEPAA project office in Perth having my normal morning telephone discussion with Mr O'Shea on the West Atlas. Mr Duncan, who was on the *West Atlas* on 20 August 2009 joined that discussion and told me that when the 20" trash cap had been removed earlier that morning it was discovered that the 340mm ($13^3/_8$") pressure containing corrosion cap had not been installed.

229 Mr Duncan asked me if I knew that the 340mm ($13^3/_8$") PCCC had not been installed and I said I did not know that. We then discussed the following matters:

(a) the need to find out why the 340mm ($13^3/_8$") PCCC had not been installed;

(b) the corroded condition of the 340mm ($13^3/_8$") MLS tie-back threads and the impact on the ability to tie-back the 340mm ($13^3/_8$") casing with the threads in that condition;

(c) removing the 244mm ($9^5/_8$") PCCC to allow the BA51L Brush tool to be run to clean-up the threads;

(d) the 340mm ($13^3/_8$") tieback threads needed to be cleaned at that time as this was the only time the threads were going to be visible. Once the 506mm (20") conductor was tied back the threads would not have been visible and a judgment as to the cleanliness of the threads would have been difficult and risky;

(e) the planned removal of the 244mm ($9^5/_8$") PCCC was to be conducted within a day pursuant to the DP 1B and therefore removing it now would only be a sequencing change and would not affect the undertaking of the DCP otherwise;

(f) making sure a check for pressure below the 244mm ($9^5/_8$") PCCC be made prior to removal in accordance with the DP 1B; and

(g) if pressure under the 244mm ($9^5/_8$") PCCC was detected further assessment would need to be undertaken of the risks and the program for the safe removal of the PCCC developed.

230 The procedure for the removal of the PCCC is covered in the DP 1B. Section 5.17, steps 194 and 195. Below is a copy of these steps;

"Make up the TDS before engaging the running tool onto the corrosion cap (this will allow for any pressure below the corrosion cap to be observed on the standpipe and then bled-off through the choke manifold)

Engage the corrosion cap and check for any pressure below the corrosion cap. Note any pressure on the IADC and the DDR. Bleed-off any pressure via the choke manifold."

231 After the telephone discussion with Mr O'Shea and Mr Duncan, I understand that Mr O'Shea issued an supplementary forward plan to cover the change in plan.

232 No Change Control Form was issued for the following reasons;

(a) the 244mm ($9^5/_8$") PCCC was planned to be removed anyway within 24 hours and the status of the H1 Well would have been the same. This was considered to be a re-sequencing of operations not a change to design;

(b) the H1 Well was cased and cemented and to the best of our knowledge at the time satisfied the barrier requirement for temporary suspension under Section 5 of the WCS; and

(c) the change in sequence was not considered to be a significant change for the purposes of the change management process in the Process Manual.

233 I do not recall whether the scheduled 0900 hours meeting was held on 20 August 2009.

234 On 20 August 2009 during the scheduled afternoon telephone call with Mr O'Shea he told me that they had checked for pressure under the 244mm ($9^5/_8$") PCCC, no pressure, gas or flow had been observed, the 244mm ($9^5/_8$") PCCC had been removed, and the cleaning of the 340mm ($13^3/_8$") MLS threads had been completed.

21 August 2009

235 At 0430 hours on 21 August 2009 I received a telephone call from Mr O'Shea who said:

(a) that there had been a release of hydrocarbon from the H1 Well;

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(b) it appeared the H1 Well had "burped" and about 40bbls of hydrocarbons had been released;

(c) the *West Atlas* was currently over the H4 well slot with 2 joints of 20" casing to lay out; and

(d) the proposal was to skid over to the H1 Well and run an RTTS packer in the H1 Well to prevent any further flow.

236 I agreed with the proposal made by Mr O'Shea and asked if Mr Duncan was appraised of the situation and Mr O'Shea told me he was.

237 At 0455hrs I called the NTDPIFM Oil Spill phone number that is listed in the front of the DP 1B. There was no answer so I left my name and number and the details of what had happened. Immediately after this call I proceeded to the PTTEPAA project office.

238 At 0600hrs Mr O'Shea called me again and said that the H1 Well was flowing again and all personnel had been sent to muster. Immediately after this I called the PTTEPAA ERG leader.

Specific questions raised by the Commission

239 I have been asked by the Commissioner to provide my views about various matters.

240 I have already set out my knowledge about the situation at the time of various events occurring.

241 Nevertheless, to address the Commissioner's questions, I have reviewed with the benefit of the knowledge that the uncontrolled release did in fact occur on 21 August 2009, the documents that I refer to in my statement, including forward plans, DDRs, Advantage Drilling Fluid Reports and IADC reports and in particular the following documents:

(a) Forward plans issued on 5 and 6 March 2009 (version 1.0 and version 2.0)

(b) PTTEPAA's DDR of 7 March 2009;

(c) PTTEPAA H1 ST1 244mm ($9^5/_8$") Cementing Report of 6 March 2009;

(d) Atlas Drilling's IADC report # 6695576 of 7 March 2009;

(e) Halliburton Cementer's report of 8 March 2009;

(f) ADWCM; and

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(g) West Atlas Cementing Intermediate Casing Procedure.

242 Based on my interpretation of those materials, I have drawn some conclusions about what might have occurred in relation to some of the matters that I have been asked by the Commissioner, which I set out below.

Possible explanation of the cementing and pressure testing

243 I have already set out my knowledge about the situation as at 7 and 8 March 2009. That is, I considered that the offshore personnel had carried out the appropriate procedure (in terms of the WCS and the Atlas Drilling's *West Atlas* SD1 Operations Procedure Manual and good oilfield practice) when confronted with an unexpected apparent in service failure of the float valve, ie they maintained appropriate pressure to keep the cement in place while it set and advised me of the steps that they were taking. I also considered from the materials and information that was provided to me at that time that despite the in service failure of the valves, the cementing of the 244mm ($9^5/_8$") shoe casing had been correctly completed providing a competent barrier, to which pressure had been applied and maintained whilst waiting for the cement to set, followed by an inflow test. Further, I considered with the state of knowledge at that time that none of the documents sent from the *West Atlas* alluded to any possible incompetence of the cemented shoe casing when reapplying pressure and none of the telephone conversations with personnel on the *West Atlas* indicated that this had happened.

244 The Halliburton Cementer's report of 8 March 2009 (**Halliburton Report**) notes final casing pressure of *"687psi"* and *"17:51 BLEED OFF CSG STRING 3.5BBLS BACK, 0PSI"*.

245 I did not see the IADC report # 6695576 dated 7 March 2009 until some months after the cementing was completed.

246 In the IADC report # 6695576 dated 7 March 2009 is an entry of 1800 – 18:30 which states *"Retest Float Good. R/D CMT head and CMT lines."*

247 Those entries do not indicate anything to suggest that the shoe cement was not a competent tested barrier.

248 I do not consider that the pressure test for 10 minutes duration was of any consequence on the cement job or the float failure. Although required by the WCS, I do not consider that testing for 20 minutes would have made no difference.

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249 In my opinion, pressure testing of the casing after waiting on cement does not necessarily provide a clear cut test of the integrity of the shoe casing. This is because pressure testing after waiting on cement can be dependent upon how successful the re-pressuring was prior to waiting on cement (ie if the top plug was landed back in place and some overpressure applied). If a pressure test is performed pressure should be applied to 500psi over formation leak-off pressure to ensure the cement is a suitable barrier and integrity still exists.

250 Since the incident the Halliburton Report has been made available to me and my interpretation of that report is as follows:

(a) the pressure being bled-off after the casing pressure test (1442 hours);

(b) shortly after this the pressure increased – this would have been after the increase in return flow had been observed - the cement operators shut-in the well at the cement unit. This pressure increase corresponds to the hydrostatic pressure of the cement and drilling fluid in the annulus;

(c) at 1447 hours pumping operations commenced and the pressure increased from ~1100psi to ~1350psi at which point the pressure stopped increasing even though the pumping continued;

(d) at this point it appears that the fluid being pumped into the well could have been bypassing the cement wiper plug and going into the shoe track. This fluid would have likely been a mixture of seawater and cement. The total volume pumped since the float failure was the equivalent to the total volume of fluid bled back after the pressure test and after the float failed (~16.5bbls);

(e) that the pumping should have been shut down once there was an indication that the pressure was not rising within the 244mm ($9^{5}/_{8}$") casing despite the continued pumping of displacement fluid into that casing so that the cement was maintained in position;

(f) the pressure applied when attempting to hold the cement in place while it set was likely to have exceeded the hydrostatic pressure of the wet cement by more than an acceptable amount;

(g) that after pumping just a small volume of fluid the pressure stopped increasing and there is a likelihood that the cement wiper plug was damaged and fluid was bypassing the cement wiper plug and moving into the shoe track. This is likely to have caused a contaminated

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channel within the shoe track. This would then be likely to have created a conduit for the flow (but did not cause the flow);

(h) the final pressure after waiting on cement is recorded as 687psi. This means that the initial pressure of 1300psi bled down by 613psi meaning there was a leak in the system (potentially downhole). This loss of pressure was not reported verbally or in any reports submitted to me;

(i) the inflow test might not, in that context, have established the shoe cement was competent; and

(j) performing a pressure test after the cement had set might have been prudent and capable of testing whether the barrier that was assumed to have been made by cement in the shoe track was competent.

251 However, the inflow test performed after the cement had set was consistent with the H1 well being overbalanced and pressure testing after the cement has been pumped into the shoe track generally would not assist in determining the competence of the shoe track cement if the top and bottom plugs used in the cementing process re-bumped on the float collar.

252 I was not made aware on 7 or 8 March 2009 and all relevant times after that, of:

(a) the pressure bleeding off whilst waiting on cement; and

(b) anything that indicated the possibility of fluid bypassing the top or bottom plugs.

253 If I had been aware of the above information, I would have requested that another pressure test of the casing be performed. I would not normally pressure test casing once the cement is set as there is a risk of compromising the cement integrity in the annulus.

254 The absence of another pressure test meant that, with hindsight and knowing what I now know, the integrity of the H1 Well was not verified.

255 Although there was appropriate communications between Mr Treasure and me on 7 March 2009, there was information that I consider, with the benefit of hindsight, could have been given to me so that I would be better able to make decisions about what needed to be done in the face of the apparent failure of the float valve. In hindsight, the additional information required was about the quantity of fluids that were pumped back into the casing and the variation in the pressures whilst waiting on cement to set.

Barriers for suspension in August 2009

256 I have already set out above the barriers that I thought were in place on 20 August 2009.

257 I consider that best practice with MLS is to suspend using a PCCC on the 244mm ($9^5/_8$") and the 340mm ($13^3/_8$") casing.

258 The 340mm ($13^3/_8$") PCCC seals the annulus space and both the 244mm ($9^5/_8$") and the 340mm ($13^3/_8$") PCCC's protect the tieback threads on the MLS. I therefore consider that the use of the PCCC's was good practice and appropriate in the circumstances.

259 My post incident analysis indicates that the 244mm ($9^5/_8$") casing shoe most probably did not form an adequate primary tested barrier however on the day with the information supplied to me, I had no reason to suspect that it was not an adequate barrier.

Absence of the 340mm ($13^3/_8$") PCCC

260 I have already set out my knowledge about the situation as at 21 April 2009. That is, I considered from the materials that were provided to me at that time that a PCCC had been installed on the 340mm ($13^3/_8$") MLS. The DDRs that I have referred to previously showed that the 340mm ($13^3/_8$") PCCC had been installed off line.

261 I considered that the absence of the 340mm ($13^3/_8$") PCCC:

(a) was serious and I would have investigated the reason why it had not been installed had the hydrocarbon release not occurred the following day; and

(b) led to corrosion forming on the threads of the 340mm ($13^3/_8$") MLS which could have lead to an integrity issue with the installation and tie-back of the 340mm ($13^3/_8$") casing.

262 However, the absence of the 340mm ($13^3/_8$") PCCC did not cause the uncontrolled release. In the context of the other barriers that I thought were in place, the H1 Well was controlled even without the 340mm ($13^3/_8$") PCCC. Even when the 244mm ($9^5/_8$") PCCC was removed the H1 Well was stable without the 340mm ($13^3/_8$") PCCC.

263 I do not know why the 340mm ($13^3/_8$") PCCC was not installed.

264 Nevertheless, to address the Commissioner's questions, I have spoken with Mr Wishart, who has told me that he had a whiteboard in his office on the *West Atlas* on which all programmed off line work was listed and that other personnel could tick off the work if it was completed when he was not on

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shift. Mr Wishart has told me that he used the information on the whiteboard to report offline activities in the comments section of the DDRs.

265 Mr Wishart has told me that the offline activities whiteboard showed that the 340mm ($13^3/_8$") PCCC was installed some time when he was off duty and that he added that as a note to the relevant DDRs.

266 Based on the information from Mr Wishart and my interpretation of those materials, I have drawn the conclusion that

(a) on the *West Atlas* the following personnel should have been aware that the 340mm ($13^3/_8$") PCCC was not installed;

(i) PTTEPAA Senior Drilling Supervisor on the *West Atlas* at the time (Noel Treasure);

(ii) Atlas Drilling Toolpusher; and

(iii) the OIM.

(b) in Perth the following personnel should have been made aware of the absence of the 340mm ($13^3/_8$") PCCC:

(i) me;

(ii) Mr Duncan; and

(iii) Mr Millar;

(c) as there were no indications or reasons after 21 April 2009 to think that the wells were not suspended per the DP and subsequent change control, there was no reason to conduct any form of audit to check that all work that was thought to be performed had in fact been completed;

(d) what may have been expected below the 244mm ($9^5/_8$") PCCC is a small amount of pressure as a result of thermal expansion of the fluid inside the casing due to heating downhole. This would have resulted in a small increase in pressure on the standpipe pressure gauge on the rig floor when the running tool was stabbed into the PCCC. This pressure would have been bled-off via the choke manifold. Once the pressure had been bled-off, no increase or return of pressure should have been observed and no flow should have been observed. If after bleeding off any initial pressure the pressure built back-up, the PTTEPAA offshore team

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would have advised the PTTEPAA Perth based team of the situation. At this stage the 340mm ($13^3/_8$") casing would have been tied back, the wellhead installed and the BOP's nippled-up prior to attempting to remove the 244mm ($9^5/_8$") PCCC;

(e) the 244mm ($9^5/_8$") PCCC did not directly have the ability to measure leakage of the wellbore, however the running tool has an internal probe and neck seals. The neck seals seal over the neck of the PCCC and the internal probe pushes a poppet valve. Any pressure below the PCCC can be recorded and bled-off at surface via the running string. Whilst the running tool has the ability to communicate pressure and allow pressure to be bled-off, its pump through capabilities are limited. If pressure had been detected below the 244mm ($9^5/_8$") PCCC then the 340mm ($13^3/_8$") casing would have been run and the wellhead and BOP's installed. Once the BOP's were installed, one of the elements could have been closed whilst the cap was removed (after any pressure below the cap had been bled-off). Once the cap was off, heavy mud could have pumped into the well at a rate significantly higher (and with less risk of a blockage) than through the PCCC running tool;

(f) the 244mm ($9^5/_8$") PCCC was removed per the instructions in the DP 1B and no pressure was observed. No gas was detected when the PCCC was removed and no flow was observed after the PCCC was removed. Based on all the checks at that point the H1 Well appeared to be static;

(g) once the rig is on location the well falls under a temporary suspension category. According to the WCS – Section 5 only 1 permanent <u>or</u> 2 temporary barriers are required on a well during a rig move over a well (ie moving the derrick). This was satisfied by the cemented casing (at that time this was considered to be a competent barrier). Additionally the ADWCM allows for the BOP's not to be installed on a cased and cemented well once the cement has reached a specified compressive strength or after waiting on cement for 8 hours. The casing had been cemented 6 months earlier and no pressure was found below the 244mm ($9^5/_8$") PCCC and as such there were no indications of any cement integrity problems; and

(h) cemented casing with a displacement fluid inside the casing with no additional barriers within the casing is common on a well that utilises a surface wellhead system (other than a multi-bowl system). Once the cement is in place, tested and set the BOP's are removed to allow for the installation of the next section of the wellhead. The BOP's are then re-installed and tested.

Well drilling operations conducted between 19 and 21 August 2009

COMMISSION OF INQUIRY
MONTARA WELL HEAD PLATFORM
UNCONTROLLED HYDROCARBON RELEASE

267 I have been asked by the Commissioner to provide my views about the well drilling operations conducted in relation to the H1 Well between about 19 and 21 August 2009.

268 I have already set out my knowledge about;

(a) the barriers that were thought to have been in place as at 19 August 2009;

(b) the reasons why the 340mm ($13^3/_8$") threads needed to be cleaned at that point in the operation; and

(c) the standards that were applicable at the time.

269 Based on the information above and my interpretation of the WCS, the Process Manual and ADWCM, I set out below my views:

(a) the personnel on the *West Atlas* on 20 August 2009 followed procedure by notifying me immediately upon observing the H1 Well was not per the "as built" drawings;

(b) the way forward was discussed and risk assessed with me via telephone with Mr Duncan and Mr O'Shea. It is my understanding Mr O'Shea then discussed the change to the DP 1B and current forward plan with the OIM;

(c) the 244mm ($9^5/_8$") PCCC was removed according to procedure and the appropriate pressure, gas and flow checks were performed. All of the checks indicated no pressure, no flow and no gas. After 6 months of being suspended, <u>had</u> hydrocarbons flowed into the well during this period the following would have been observed (but were not);

(i) pressure under the 244mm ($9^5/_8$") PCCC;

(ii) hydrocarbons immediately below the 244mm ($9^5/_8$") PCCC (visible oil); and

(iii) visible flow upon removal of the 244mm ($9^5/_8$") PCCC;

(d) a change control was not issued because this was deemed a change of sequence not a change of substance. That was appropriate in the circumstances. However, there was an auditable documentary chain in place because the forward plan had been revised in consultation with the OIM;

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(e) the removal of the 244mm ($9^5/_8$") PCCC earlier in the drilling sequence reduced the H1 Well to one permanent barrier. However, with the *West Atlas* on location this complied with the WCS. Again that was appropriate;

(f) the removal of the 244mm ($9^5/_8$") PCCC falls within the requirements of the ADWCM where a BOP can be removed from cemented casing as long as the cement is set and meets a 500psi compressive strength, which it did; and

(g) based on the points outlined above it was not necessary for the 244mm ($9^5/_8$") PCCC to be reinstalled after the 340mm ($13^3/_8$") MLS threads had been cleaned. Again, in the circumstances that was an appropriate decision.

Communication between PTTEPAA, Atlas Drilling and Halliburton

270 I consider that the communications between PTTEPAA staff onshore and offshore were very good.

271 I also consider that the communications of PTTEPAA staff onshore and offshore and the Atlas Drilling personnel and the personnel of other contractors was also very good.

272 Those communications were frequent, regular and open. PTTEPAA, Atlas Drilling and each contractor had independent and co-ordinated lines of communication.

273 Communication with Mr Millar were frequent (multiple times per day). This consisted of a face to face meeting daily (Monday to Friday), frequent e-mails and telephone conversations (7 days per week).

274 The communication between Halliburton Australia (Canning Vale office) and PTTEPAA Perth based personnel involved frequent communication between Mr Geste (Halliburton Australia Cement Engineer) and me either by telephone or e-mail. Cementing programs were discussed and distributed frequently and Mr Geste would always seek my input before formally distributing any programs. As required Mr Geste and I would meet face to face to discuss any specific issues. On this basis I do not consider there was any communication failures between Halliburton Australia and myself.

275 However, whilst I consider that communication between the various parties involved in the *West Atlas* operations was generally open and helpful and made at appropriate times, with the benefit of hindsight there appears to be a failure in communication between PTTEPAA personnel on the *West Atlas* and Atlas Drilling personnel that either caused the 340mm ($13^3/_8$") PCCC not being installed or for its absence not to be recorded. The Change Control Form to install the 340mm ($13^3/_8$") PCCC

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was issued to the OIM. Additionally I understand that a verbal instruction was issued by a PTTEPAA Drilling Supervisor (Mr Robinson) to an Atlas Drilling Toolpusher. These instructions appear not to have been followed. However, the absence of the 340mm ($13^3/_8$") PCCC did not cause the uncontrolled release

276 It is possible that one or more people could have identified problems in the well construction operation but none of those problems were by themselves the cause of the uncontrolled release and the absence of identification of problems was more consistent with honest mistake rather than poor communication.

277 The reason why the H1 Well became underbalanced and flowed has not been identified. I do not believe that any communication issues caused the uncontrolled release.

I understand that a person who intentionally makes a false statement in a statutory declaration is guilty of an offence under section 11 of the *Statutory Declarations Act 1959* (Cth), and I believe that the statements in this declaration are true in every particular.

Christopher Allan Wilson

Declared at Perth the 9th day of March 2010

Signature of person before whom the declaration is made

DAMIEN PETER SWINGLER AUSTRALIAN LEGAL PRACTITIONER
Full name, qualification and address of person before whom the declaration is made