**COMMISSION OF INQUIRY**
**MONTARA WELL HEAD PLATFORM**
**UNCONTROLLED HYDROCARBON RELEASE**

**COMMONWEALTH OF AUSTRALIA**

**DECLARATION UNDER THE STATUTORY DECLARATIONS ACT 1959**

I, Craig Neil Duncan of care of Level 1, 162 Colin Street, West Perth in the State of Western Australia, Well Construction Manager, make the following declaration under the *Statutory Declarations Act 1959 (Cth)* as follows:

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**Table of topics – Craig Duncan**



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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 the Well Construction Manager and have been in that position since about June 2007.

3 I am the Well Construction Manager for PTTEPAA's Montara Development Project.

**Qualifications and work experience**

4 I have extensive experience in the oil and gas industry and I hold a Graduate Diploma (obtained in about October 2001) and Graduate Certificate in Petroleum Engineering (obtained in about April 2005) from the University of New South Wales.

5 My work experience is as follows:

(a) I started work in the oil and gas industry on 16 November 1977 as a roustabout;

(b) From 1977 until 1986 I worked my way up through various positions for drilling contractors;

(c) From 1986 to 1990 I worked in the gold mining industry starting a company that manufactured carbon regeneration kilns;

(d) In 1990 I returned to the oil and gas industry and worked for a drilling contractor as a driller in Brunei;

(e) From 1992 to 1993 I worked for a specialist drilling company dedicated to optimising drilling techniques in extended reach wells;

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(f) In 1993 I joined Apache Energy Limited as a consultant in Perth, initially as a drilling supervisor offshore and eventually as a drilling superintendent;

(g) From July 2006 to October 2006 I completed a number of small consulting jobs before joining Oil Search in October 2006 in a staff position to work on a two well program offshore Yemen as drilling superintendent. This campaign was successfully completed in 2007;

(h) I left Oil Search in May 2007 and joined PTTEPAA (then Coogee Resources) as Well Construction Manager in about June 2007.

**The Montara Development Project**

6 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.

7 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.

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

**Atlas Drilling**

9 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.

10 Atlas Drilling owns the *West Atlas* jack-up drilling rig (***West Atlas***), which is a type of Mobile Offshore Drilling Unit (or MODU).

11 Atlas Drilling is part of the Seadrill group of companies headquartered in Norway. The jack-up rig division is based in Singapore.

12 The Seadrill office in Singapore provided centralised support to the rigs in the Asia Pacific region, including the *West Atlas*. This support included operations management, marketing, marine and engineering expertise plus HSE and accounting functions.

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**My responsibilities**

13 When I was engaged by PTTEPAA I reported to the Project Manager of the Montara Development Project. Initially that was Duncan Clegg and from about January/February 2009 it was Narangpol Solo Suthapintu. Since 21 August 2009 I have reported directly to PTTEPAA's Chief Operating Officer (**COO**) Andy Jacob (**Mr Jacob**).

14 My responsibilities now, and at all times since I was engaged by PTTEPAA, include the management and supervision of well operations including:

(a) designing wells;

(b) preparing well programs;

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

(d) risk and change management.

15 Whenever the *West Atlas* was working on the Montara Development Project, either Chris Wilson, PTTEPAA's Drilling Superintendent, or I was on call 24/7. I was on call for about 10 days a month and Mr Wilson was responsible for 20 days a month. I would also physically visit the *West Atlas* and WHP, about every 2 to 3 months in order to see for myself how operations were progressing and to maintain visibility and relationships with the offshore personnel.

**The well construction team, their qualifications and roles**

16 When I was engaged by PTTEPAA the core of the well construction team existed. Chris Wilson had been with PTTEPAA for about six months and PTTEPAA had a logistics co-ordinator who had been with PTTEPAA for a number of years. PTTEPAA also had a team of completions engineers. However, in order to prepare for and undertake the drilling campaign of the Montara Development Project it was necessary to recruit a number of other people.

17 I was involved in the recruitment of these additional members of the well construction team.

18 Members of PTTEPAA's well construction team were recruited on the basis of their experience and to ensure that the team had a variety of skills available to it.

19 After consulting with PTTEPAA's exploration manager, I initially recruited an operations geologist in about June-August 2007. He had excellent experience with geosteering, a skill we expected to require.

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20 I was involved in the hiring of two graduate engineers, the first in December 2007 and the second in November 2008.

21 As to drilling supervisors:

(a) Paul O'Shea was contracted in November 2007 and spent about two months in PTTEPAA's West Perth office before commencing an offshore rotation as a senior drilling supervisor;

(b) other drilling supervisors were contracted as required to support drilling operations. Noel Treasure and Craig Klumpp commenced in March 2008 and Lindsay Wishart in April 2008. Brian Robinson was engaged in March 2009;

(c) the drilling supervisors were selected for their experience which was varied. Noel Treasure, Paul O'Shea and Lindsay Wishart had all worked as drilling supervisors in the past. Craig Klumpp and Brian Robinson had not worked as drilling supervisors but had both worked in senior positions with drilling contractors; and

(d) the drilling supervisors each had between 12 and 30 years oil field experience. In addition to experience, each drilling supervisor was required to have a current well control certificate and a current HUET (*Helicopter Underwater Escape Training*) card.

22 The PTTEPAA people who reported to me were:

(a) Chris Wilson – Drilling Superintendent

(b) Keith Brand – Senior Completions Engineer

(c) Richard Stear – Operations Geologist

(d) Chris Glennon – Procurement & Logistics Coordinator

(e) Angus Meredith – Completions Engineer **

(f) Gary Watkins – Completions Engineer **

(g) Mathieu Higgins – Drilling Engineer ***

(h) Steven Loveless – Drilling Engineer ***

(i) Natalie Scarffe – Shorebase Coordinator – Darwin

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(j) Lisa Lam – Procurement & Logistics Assistant

(k) Noel Treasure – Senior Drilling Supervisor *

(l) Paul O'Shea – Senior Drilling Supervisor *

(m) Lindsay Wishart – Drilling Supervisor *

(n) Craig Klumpp – Drilling Supervisor *

(o) Brian Robinson – Drilling Supervisor *

23 The usual work rosters for the above people were as follows:

* Worked offshore on a 21 day rotation.

** Worked both in the office and offshore as required.

*** Worked offshore for 21 days plus one week in the office.

**Communication within PTTEPAA**

24 There were three main forms of communication within the well construction team. They were email, telephone and face to face meetings. The following communication took place between PTTEPAA and Atlas Drilling personnel, in accordance with PTTEPAA's WCMS – Construct, Services or Abandon Well Process, Activity 4.1.4, Tasks 3 and 4 of the Construct, Service or Abandon Well Process standard or manual (**Process Manual**) (ie Construct, Service or Abandon Well Process Management Standard – D41-502434 Rev 2; 13 March 2009):

(a) Email communications were common:

(i) the main email of significance was the provision of daily reports from the *West Atlas*. This email included the Daily Drilling Report (**DDR**), mud reports, bulk reports and the daily Personnel On Board (**POB**) list. It also included a description of what was going on which was intended to be background to the day's activities;

(ii) this email went to a number of people within the well construction team;

(iii) another important email was the 7 day look ahead which was generated on the *West Atlas* by the PTTEPAA drilling engineers. This spreadsheet outlined the next seven

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days' plans for well construction, personnel movements and vessel/helicopter movements;

(iv) this email went to an extensive distribution list including third party contractors and Atlas Drilling; and

(v) the person responsible for day to day operations, either Mr Wilson or I depending on who was on duty, would also generate a morning update email intended to give a one page summary of what had happened the day before and what was planned. This was distributed widely to PTTEPAA, Atlas Drilling and third party contractors. There were also a number of emails throughout the day as in any organisation;

(b) telephone calls were less formal:

(i) there was a scheduled morning call between the *West Atlas* and the person responsible for day to day operations, either Mr Wilson or I, depending on who was on duty. This call was a review of events and plans and normally took about 15 minutes;

(ii) normally there was an afternoon or evening call to the *West Atlas* as well;

(iii) calls to and from the *West Atlas* were generally to the Senior Drilling Supervisor, either Mr O'Shea or Mr Treasure depending on who was on duty; and

(iv) telephone calls to Atlas Drilling personnel (generally to the *West Atlas* Manager Mr Millar) were not scheduled but took place on average at least once each day between either Mr Wilson or me; and

(c) meetings were held at 0900 WST every week day morning at PTTEPAA's project office in Perth:

(i) the morning meeting would include the well construction team in the office (ie onshore), Mr Millar plus invited third party contractors on an as required basis; and

(ii) people attending this meeting had normally already read the morning update email. These meetings were an opportunity to brain storm problems and ensure that all were involved and aligned for the days work. The morning meeting normally took between 20 minutes and 1 hour. The meeting reviewed the past 24 hours operations and reviewed operations planned for the next few days. Once the drilling discussion was

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complete, each person at the meeting had the opportunity to discuss what they had been working on or to raise any issues of concern.

25 During operations on the *West Atlas*, the PTTEPAA drilling supervisors prepared a forward plan to communicate requirements to the crew and service companies. These plans were updated as events changed and generally only covered the next day or so of operations. Each plan is shown to Atlas Drilling's Offshore Installation Manager (**OIM**) on the *West Atlas* for his comment and confirmation before it is issued. The WCMS (described below) refers to these plans as *Instructions To Drillers*. The plans are not normally sent to PTTEPAA's office for review.

26 When not on board the WHP and *West Atlas* I received a number of reports from the *West Atlas* in order to monitor and supervise the operations. The main report was the DDR.

27 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".

28 Additional operational reports received included casing, cementing, mud, bulk, directional drilling, POB, incident and safety reports.

**Communication with Atlas Drilling**

29 The main personnel from Atlas Drilling who I communicated with on the Montara Development Project were:

(a) Donald Millar, the rig manager of the *West Atlas*;

(b) with respect to contractual matters, Simon Johnson, the Atlas Drilling marketing manager, who was based in Singapore; and

(c) Atlas Drilling operations managers, Bruce Worthington and later David Gouldin, who were based in Singapore.

30 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 close to my office;

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(b) attended the daily morning meetings in the PTTEPAA offices in Perth during operations (being the meetings described above at paragraph 24(c))

(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.

31 My relationship with Mr Millar was professional, constructive and supportive. I have a lot of respect for Mr Millar.

32 The person in charge on the *West Atlas* was the OIM. All personnel on board the *West Atlas* fell under the OIM's responsibility.

33 The OIM was responsible for six personnel groups on the *West Atlas*:

(a) the drilling group which was headed by the Tool Pushers and which looked after drilling operations;

(b) the deck crew which was headed by the barge engineer and which operated cranes for supply purposes and did non-technical maintenance like cleaning and painting;

(c) the maintenance department which was headed by a maintenance supervisor and which managed the power generation and technical maintenance of the *West Atlas*;

(d) the catering crew which was headed by the chief steward and which managed accommodation and messing arrangements;

(e) safety and medical support personnel; and

(f) client personnel - the client group, PTTEPAA in this case, which included client personnel like the drilling supervisors along with geologists and third party contractors like the cementing engineers.

**Key documents to manage the H1 Well**

34 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**);

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(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);

(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) the 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 provide services to PTTEPAA including the construction of the H1 Well;

(h) the Drilling Program (**DP**) (ie. Montara GI, H1 & H4 (Batch Drilled) Drilling Program – 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 Program - TM-CR-MON-B-150-00003 **Rev: 0**; 30 June 2009);

(j) the Seadrill Well Control Manual; and

(k) forward Plans (Instructions To Drillers).

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

36 There are other documents produced by contractors and others that address that and other matters and which relate to the construction of the Montara wells including the H1 Well.

37 The West Atlas Safety Case Revision was prepared by Atlas Drilling in consultation with PTTEPAA and acted as a bridging document between the PTTEPAA Well Construction Management System 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.

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38 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.

39 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*.

40 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*.

41 When I was engaged by PTTEPAA, there was little documentation in place for the management of well construction operations. In late 2007 I engaged Angus Knowles at Uzma Consultants, a consultant who had experience in preparing well design and construction documentation. In consultation with Mr Knowles, the well construction team and I generated and prepared the PTTEPAA Well Construction Management System documents.

42 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 Well Construction Manager (**WCM**), Drilling Superintendent, Drilling Supervisor, Drilling Engineer, Completions Engineer, Well Test Engineer and Materials and Logistics Supervisor.

43 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 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.

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44 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.

45 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.

46 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.

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

48 The WOMP illustrates how the Well Construction Management System 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.

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

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

51 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.

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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.

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

53 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.

54 The DP and DP 1B generation process involved Mr Wilson for drilling and the completions engineers.

55 When the document draft was ready, I would review it and mark up any changes I considered necessary. These changes were then discussed and if agreed, incorporated into the release document.

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

57 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.

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

59 Original documents, revisions to original documents and change control notices were all distributed by the PTTEPAA document control 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***

60 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.

61 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

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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.

62 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".

63 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.

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

**Knowledge of the key documents**

65 Having been closely involved in the generation of the WCMS materials, I had a good understanding of the document and contents. The main document I referred to was the WCS. I reviewed all the WCMS documents in May 2009 to check that references to Coogee Resources had been replaced by PTTEPAA.

66 I also had a good understanding of the other key documents to which I have referred in paragraph 34 above.

**Drilling terminology**

67 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) surface casing or string, including:

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

(ii) 340mm ($13^3/_8$") diameter casing;

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(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;

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

(i) Christmas Tree – this is the term used for a collection of valves forming the control mechanism at the top of a well in order to produce oil or gas. The term originated from the need for several valves in a vertical stack on early wells and they looked a bit like a steel "Christmas Tree".

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***Cementing***

68 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*

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

70 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.

71 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.

72 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.

*Shoe track*

73 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.

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

75 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.

76 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.

77 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.. CND

78 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.

79 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.

80 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.

81 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.

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

83 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.

84 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*

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

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86 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.

87 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*

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

89 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.

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

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

92 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.

93 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.

94 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.

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

96 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 CND

(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.

97 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.

98 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.

99 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.

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

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

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

103 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".

104 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.

105 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

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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.

106 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.

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

108 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.

109 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.

110 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.
>
> **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 ifit should become necessary

111 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.

112 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 *Petroleum Submerged Lands Act* (PSLA). 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

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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**

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

114 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.

115 "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.

116 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.

117 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**

118 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.

119 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.

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

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

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

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

**Drilling, displacement and completion fluids**

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

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

126 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.

127 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.

128 Two types of completion fluids are brine and seawater.

129 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.

130 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) |

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| | |
|---|---|
| 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.

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.

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

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132 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)"*

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

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

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

136 Section 2.3.1 of the Atlas Drilling Well Control Manual 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**

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

138 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<br>• Wellbore fluid stable at surface, provided it can be monitored<br>• Wireline set plugs in the tubing that have been pressure tested<br>• RTTS type packer that has been pressure tested<br>• Master valve<br>• 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:

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

| **Barriers during Temporary Suspension** | |
|---|---|
| **Barrier Type** | **Description** |
| **Permanent** | • Cement Plug<br>• Permanent Packer with no controlled internal flow path<br>• Cemented Casing |
| **Temporary** | • BOP closed and locked on drill pipe or tubing<br>• *Retrievable Packers*<br>• Wireline Plugs<br>• Fluid with a hydrostatic head greater than formation pressure, provided that the liquid level and density can be monitored and maintained.<br>• 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**<br>**Not surface plugs** | • Tagging with sufficient force to confirm the top of good cement<br>• Tagging pressure must equal the equivalent of 3500KPa (500 psi)<br>• 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 |
| ***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<br>• 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 |

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

140 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:

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| Barrier Type | Description |
|---|---|
| Permanent | • Pressure tested cement Plug (min 30m in length)<br>• *Permanent Packer with no controlled internal flow path and cement on top*<br>• Cemented Casing with proven TOC<br>• Hanger Packer<br>• Tubing Seals<br>• 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,<br>*or*<br>• 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.<br>• 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. |
| Perforations | • A cement plug shall be spotted and extend from at least from 30m below to at least 30m above the top perforated interval<br>or<br>• 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.<br>• 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.<br>• 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.<br>• 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.<br>• No annular space which extends to the seabed shall be left open to drilled hole below the annular space. |

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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.

141 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).

142 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.

143 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.

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

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

146 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.

147 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.

148 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.

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149 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.

150 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.

151 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**

152 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.

153 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.

154 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".

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

156 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;

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

(d) 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.

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157 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.

158 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.

159 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 Programs – original plan and revisions***

160 The original plan for the Montara field development was to have the WHP Topsides in position and for the *West Atlas* to be positioned adjacent to the completed WHP to drill and complete the wells by batch drilling.

161 This plan was unable to be executed due to issues with the contracted construction vessels which resulted in the WHP Topsides not being installed as originally planned.

162 This resulted in the DP being revised to incorporate two phases.

163 The first phase was to drill and suspend the wells at the 244mm (9⅝") casing point prior to the WHP Topsides installation and the second phase was the continuation of drilling and completion of the wells after installation of the WHP Topsides.

164 The DP was initially revised in November 2008 to incorporate the fact that the WHP Topsides would not be in place and the wells sequentially drilled down to the 244mm (9⅝") casing shoe and

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suspended and then revised in January 2009 to reflect that the wells were to be batch drilled down to the 244mm (9⅝") casing shoe and suspended.

165 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 (9⁵/₈") casing*

166 The original design of the H1 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.

167 A review of the drilling program was conducted and on about 30 January 2009 I received a Well Construction Change Control Form No D65005A 003 from Mr Wilson that addressed an issue that arose from that review.

168 This identified that we did not have enough PCCCs to cover all the MLSs and that if neither a PCCC or well head was in place, the TOC for the 244mm (9⁵/₈") casing should be extended further than was originally programmed. This change was to extend the cement up into the 340mm (13³/₈") casing shoe so that there was an effective seal within the annulus at that point.

169 This change would reduce risk of release through the 340mm (13 ⅜") x 244mm (9⅝") annulus.

**Change from cement plug to PCCC - H1 Well**

170 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) PCCCs protect the threads required to subsequently tie back the casing strings at the end of the MLS from corrosion. The WCS says that PCCCs should be used on a MLS;

(d) PCCCs allow pressure below the PCCC to be checked prior to removal, whereas cement plugs do not;

(e) 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

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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;

(f) 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

(g) the original drilling program only contemplated one PCCC cap being available (which would be used in GI). Nor did it 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 PCCCs were considered to be an improvement on the original plan.

171 However, because PTTEPAA did not originally have enough PCCCs 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.

172 After a suitable 244mm (9⅝") PCCC became available, a change control 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.

173 The 244mm (9⅝") PCCC became available shortly before the 244mm (9⅝") casing on the H1 Well was due to be run and a change was communicated to the Drilling Supervisor by email from Chris Wilson dated 3 March 2009 and was reflected in the forward plans on the *West Atlas*.

**March 2009**

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

175 Mr Wilson and I shared the day to day operational responsibility for rig operations.

176 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:

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## 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

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

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- **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 3.97$m^3$ (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)

**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. END

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.

177 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 was made to the Designated Authority 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.

178 Mr Wilson sent an email to the DA on 6 March 2009 that included a suspension diagram which showed the presence of a 244mm ($9^5/_8$") PCCC. This was to alter the Stage 1 suspension, which only allowed for the installation of the 244mm ($9^5/_8$") 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.

179 Suspension Diagram - Stage 1 was as follows:

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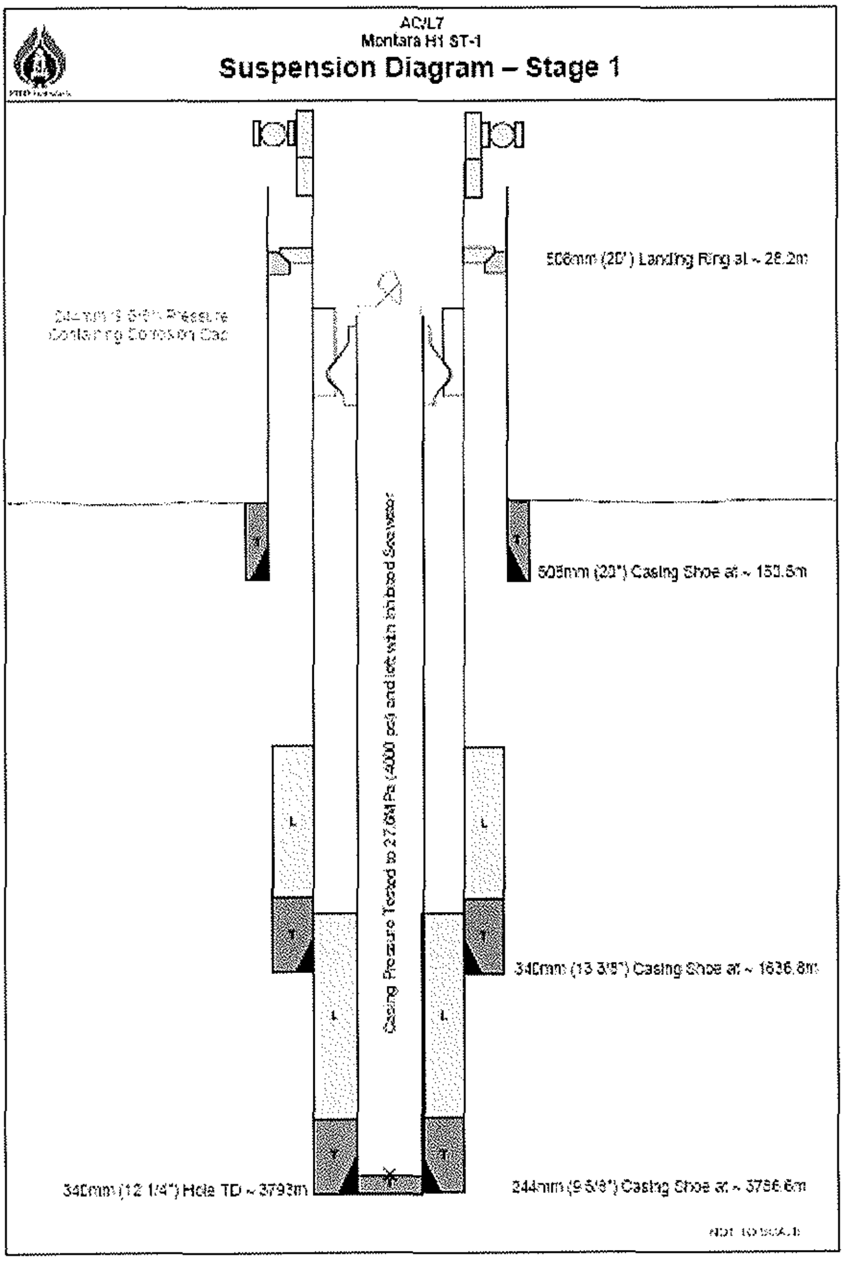



180 The Designated Authority gave the verbal approval on 6 March 2009.

181 On 7 March 2009 I read the DDR dated 6 March 2009. I was aware from that report that on 6 March 2009 the 244mm ($9^5/_8$") casing was run into the H1 Well without reported problems until sometime between 18:00 hrs and 21:00 hrs when circulation was required. A ball had been pre-installed in the casing string so that if the pumps were engaged, the float valves would convert from auto fill to conventional valves. The 6 March 2009 DDR recorded:

CND

*" ... continued to RIH casing washing down each joint from 2620m to 3208m with 1.2m³/min at 2.48MPa. Average running speed = 12 joints/hr. Note: Once washing down was commenced the self filling shoe and float lost the self filling function."*

182 I was also aware from DDR dated 6 March 2009 that the float valves were functional at that time on 6 March 2009.

183 Mr Wilson was on duty on the weekend of Saturday, 7 and Sunday, 8 March 2009.

184 By convention, on weekends Mr Wilson 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 Wilson on either Saturday, 7 or Sunday, 8 March 2009.

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

186 On the morning of Sunday 8 March 2009 I saw:

(1) the email update dated 8 March 2009 from the PTTEPAA personnel on *West Atlas* to, amongst other people, Mr Wilson and me that contained a description of events of 7 March 2009, which included three lines of bullet points that read:

- *Tested casing to 27.6MPa – OK, bled off and encountered float failure.*
- *WOC 3 hrs, concurrently changed oil on TDS and cleaned flow lines.*
- *Checked cement integrity – OK. R/D cement head and laid out same.*

and attached the:

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

(b) Advantage Drilling Mud Report dated 7 March 2009; and

(2) the morning update email from Mr Wilson to various people including me, Donald Millar (Atlas Drilling - Perth), Simon Johnson (Atlas Drilling - Singapore) and the *West Atlas* and which included the comment that:

*"checked floats on casing - OK"*.

187 The reports attached to the email update dated 8 March 2009 (ie the DDR and the Mud Report) in conjunction with Mr Wilson's email were the only reports given to me on 8 March 2009.

CND

188 The official report for drilling operations is normally considered to be the Atlas Drilling IADC report. The IADC reports are prepared by the driller and signed by the drillers, the OIM and the drilling supervisor.

189 However, Atlas Drilling IADC report # 6695576 dated 7 March 2009 was not available to me on 7 or 8 March 2009. The report is a large format document and I only received it sometime after 8 March 2009 which was the normal procedure.

190 I was not given a copy of the Halliburton Cementer's report dated 8 March 2009 until after 21 August 2009.

191 Mr Wilson's email indicated to me that the well integrity was satisfactory.

192 To me, the critical comment about the status of the cementing of the shoe casing as at 7 March 2009 is the bullet point in the email update dated 8 March 2009 from the PTTEPAA on *West Atlas* that "*Checked cement integrity – OK*".

193 I read this to mean that a positive step had been taken to check the integrity of the shoe casing cement and that the shoe was a competent barrier.

194 That was consistent with what I understood Mr Wilson's emailed comment "*checked floats on casing - OK*" to mean.

195 The drilling comments section in the Advantage Drilling Fluids Report-7 dated 7 March 2009, mentions *"WOC [Wait on Cement] Retested float... "*.

196 Whilst I did not give this as much weight as the comments in the emails, it also confirmed to me that a test had been performed to check that the cement in the shoe casing formed a competent barrier.

197 "Wait on cement" is a shorthand reference to a delay while the drilling team waited for the cement to cure.

198 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 8.9Mpa. Note: pumped 1.47 m3 and bled off 2.62 m3, suspected float valve failure. Pumped 2.54 m3 back into casing at 9.3MPa."*

CND

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

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

199 It was apparent from the reports that were available to me that the float valves failed in service. However, in the light of the other comments in the reports and emails I did not suspect that the valve failure indicated anything that might have adversely affected the integrity of the cement in the shoe casing.

200 Putting together the comments made in the emails and the DDR and Advantage Mud report that were attached to the email from the PTTEPAA personnel on *West Atlas* that I saw on the morning of 8 March 2009, I considered that the cementing had been completed properly, that the cement in the shoe casing was a competent barrier and the well integrity was not a concern.

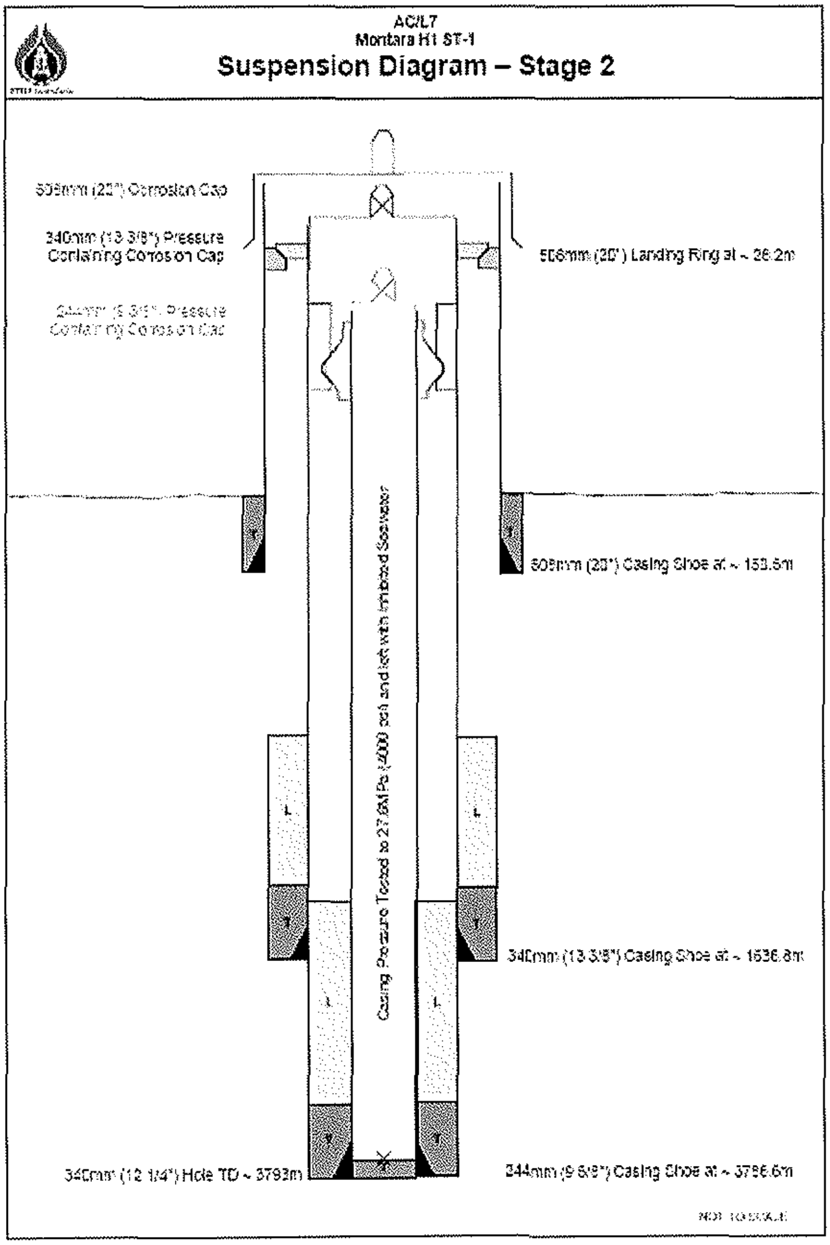
201 The DDR dated 7 March 2009 indicates that the installation of the 244mm (9⅝") pressure containing corrosion cap began on 7 March 2009 at 2200hrs.

202 On 12 March 2009 I signed a Well Construction Change Control Form No D65005A to formalise the verbal approval for the change to the 244mm (9⅝") PCCC and the removal the cement plug in the H1 Well.

203 The process of aural notification (on 6 March 2009) followed by written confirmation of the change (on 12 March 2009) was in keeping with our management of change process.

204 Also on 12 March 2009 an approval was requested to suspend the H1 Well based on Suspension Diagram - Stage 2 including 244mm ($9^5/_8$") and 340mm ($13^3/_8$") PCCCs. Suspension Diagram - Stage 2 was as follows:

CND




### The 340mm ($13^3/_8$") corrosion cap

205 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.

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

207 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.

CND

208 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.

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

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

211 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"*.

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

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

214 On 21 April 2009 Mr Wilson and 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"*.

215 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).

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

216 As at 21 April 2009 and based on the documents that I had received, I thought that the following barriers were in place (and compliant with the WCS) 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

CND

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

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

218 At that time it was planned that the *West Atlas* would return to the H1 Well to start the completion works during July/August 2009.

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

220 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.

221 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.

222 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.

223 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.

224 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.

225 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.

CND

PJ

## 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
    - 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.

CND

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

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.

CND

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

CND

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

226 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.

227 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.

228 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 Atlas Drilling Well Control Manual and commonly practised within the industry.

**20 August 2009**

229 I arrived on *West Atlas* that morning at around 0830 hrs. The purpose of my visit was to review the setup for operations at the WHP, catch up with the drilling supervisors and rig crew. I was on board *West Atlas* to conduct a pre start-up management visit arriving on 20 August and expecting to depart 21 August.

230 When I arrived on the *West Atlas* my understanding of the suspension status of the H1 Well was that nothing had altered since April 2009.

231 The trash cap was removed as per step 15 in DP 1B but I was not present when that occurred.

232 Once the trash cap was removed it was apparent that the 340mm (13 ⅜") PCCC was not installed and that some surface corrosion of the threads had occurred. CND

233 I did not know about the missing 340mm (13 ⅜") PCCC until after my arrival on West Atlas on the morning of 20 August 2009.

234 When we were notified that the H1 Well did not have a PCCC on 20 August 2009, it was a surprise to me.

235 The absence of the 340mm (13 ⅜") PCCC raised 2 issues. First, why was there no 340mm (13 ⅜") PCCC in place? Secondly, what needed to be done going forwards?

236 I was in the PTTEP office on *West Atlas* when a phone call was placed to Mr Wilson advising him that there was no 340mm (13 ⅜") PCCC on the H1 Well. I discussed by telephone with Mr Wilson that we would need to find out what happened regarding the missing 340mm (13 ⅜") PCCC. The events of the morning of 21 August altered my priorities.

237 Mr Wilson and I discussed what we considered the best course of action to be and we agreed that we would need to determine why the PCCC had not been installed and follow up with Mr Millar later.

238 The concern about the missing 340mm (13 ⅜") PCCC was earmarked for later review. The well had at that time been suspended for 5½ months and there was no evidence of anything to be concerned about from an imminent well safety perspective. Also some of the personnel who should have been involved in installing the 340mm (13 ⅜") PCCC were onshore, meaning that enquiries with them would be delayed.

239 My priority was to deal with the current situation.

240 It was reported to me that there was evidence of some scale or corrosion on the tie back threads on the 340mm (13 ⅜") MLS hanger. This corrosion was likely to have been caused because the 340mm (13 ⅜") PCCC had not protected the threads.

241 The MLS tieback tool has two sealing mechanisms. One is a metal to metal sealing face and the other in an O ring seal. Both of these sealing mechanisms are important to the integrity of the seal for the tie back.

242 Unless the corrosion on the tie back threads on the 340mm (13 ⅜") MLS hanger was removed the subsequent casing integrity on tie back was at risk.

243 I knew that unless the 244mm (9⅝") PCCC was removed there was insufficient access to clean the corroded threads properly.

CWD

244 An additional benefit of removing the 244mm (9⅝") PCCC at that time was the ability to inspect the effectiveness of the corrosion removal. This ability would be lost if the 508mm (20") conductor was installed at that stage as planned.

245 A plan was devised to alter the planned well tie back sequence in order to clean the 340mm (13 ⅜") tie back threads to address this issue.

246 My thinking was that this action was the right thing to do because:

(a) It would give us the best chance of making good the 340mm (13 ⅜") casing tie back threads and seal surfaces;

(b) It was a rescheduling of planned operations, because the 244mm PCCC was planned to be removed within a day of the removal of the trash cap; and

(c) the 244mm (9⅝") casing was also planned to be exposed to atmosphere for some time after the 244mm (9⅝") PCCC was removed and that might be for 24 hours before any additional barrier was in place,

and was made in the context of the information that was conveyed to me showing that the shoe casing was a competent barrier, the H1 Well cement displacement fluid was overbalanced to the reservoir and if there had been any change in the fluid status since cement placement on 7 March 2009, this would be evident and managed by checking for trapped pressure below the 244mm (9⅝") PCCC before its removal.

247 I expected Mr Wilson to discuss the change in sequence with the *West Atlas* rig manager Mr Millar but did not do so myself.

248 I discussed the cleaning of the 340mm (13 ⅜") threads with Paul O'Shea (Drilling Supervisor) and left it to him to communicate the proposed change of tasks to the OIM and gain his agreement.

249 I was not present when the 244mm (9⅝") PCCC was removed but this occurred around mid day on 20 August 2009.

250 Removing a PCCC after it has been in place for some time is an operation that can be undertaken under controlled conditions. The corrosion cap running and retrieving tool has O-rings on the inside diameter of the tool to seal on the neck of the PCCC. It also has a shaft facing downwards to push the poppet valve off seat. When the poppet valve is pushed off seat, any trapped pressure will be released into the drill string. From within the drill string excess fluid pressure can be measured and bled off. CND

Document TM-CR-MON-150-00003 dated 6 July 2009 being the Montara Phase 1B Drilling & Completion Program (DP 1B) covers removal of the PCCC. Whilst no pressure is expected, precautions are always taken to ensure that the task is managed with minimal risk to personnel. Had there been any trapped pressure evident, I am confident that the persons on the rig would have stopped the job to re evaluate the options.

251 Based on the well status of the H1 Well, the planned exposure to atmosphere whilst the tie backs were undertaken and the absence of any physical evidence of a change in fluid status, there was no compelling reason to re-install the 244mm (9⅝") corrosion cap.

252 Approximately 15 hours passed on 20 and 21 August 2009 without a PCCC on the 244mm (9⅝") casing of the H1 Well. Under the DP a period of time was required to install the tie back casing, during which the 244mm (9⅝") casing was planned to be exposed to atmosphere.

253 A gas detector was used as was appropriate prior to PCCC removal. Some small bubbles were detected. The gas detected did not register any hydrocarbons.

**21 August 2009**

254 On the morning of 21 August, I awoke and dressed into my coveralls before going to the PTTEP office on *West Atlas*. This was at about 0515hrs.

255 I was taking stock of what was happening when at about 0538hrs, the general alarm sounded.

256 I went to my muster station and heard a PA announcement stating that the alarm was not a drill.

257 Shortly afterwards, one of the drilling supervisors, Brian Robinson came up to the lifeboat station wearing his lifejacket. I asked him what had happened and he stated that "the well has unloaded". I asked him which one and he said H1. He said that he thought it was coming from the well annulus as the flow was coming up the 508mm (20") conductor and seemed to be falling in on itself.

258 I think that there was a PA announcement asking me to go to the radio room but I may be mistaken. In any event I went to the radio room as that was where our personnel were going to be and where the OIM was.

259 As the reports started to come through I realised that we had at the very least, a reportable release, ie one in which 80 litres of hydrocarbons is discharged into the marine environment. I did not know the extent of the release at that time but it was reasonable to assume that it exceeded 80 litres.

CND

PA

260 I asked our drilling engineer / logistics person to get a camera and start getting some photographs of the release for analysis.

261 I went down to the WHP with Brian Robinson and a Atlas Drilling assistant driller to see the well area. We reported in to the radio room via telephone as we boarded the WHP as per procedures. The well was not flowing. We could hear bubbling from the top of the conductor. We could not see down into the conductor as there were misty vapours restricting view. A check with the gas detector indicated high concentrations of hydrocarbons. We tidied up a few loose objects and returned to *West Atlas*.

262 My thought process as to cause at that time was that the well had probably started to flow from the shoe track, because:

(a) an annulus flow was possible however given that the 340mm (13 ⅜") PCCC had not been installed and that annulus had been unprotected for 5½ months, and no flow the day before I thought that the coincidence required for a strong flow that morning was very unlikely.

(b) I could envisage a small worm hole through cement in the shoe track allowing an influx into the well. However, with no flow the day before demonstrating an overbalance condition in the well, that too was unlikely; and

(c) of the two main possibilities, option (b) above was clearly the most likely but the reason for the well starting to flow was unknown.

263 I thought that if (b) above was in fact the case, we had to get a plug in the well quickly whilst we still had substantial hydrostatic pressure in the well.

264 I reported back to the drilling supervisor and the OIM with my analysis of the situation. It was decided to try to move the rig back across to H1 Well and install a RTTS packer in the 244mm (9⅝") casing. This would take some time to get in place.

265 A phone call was made to Mr Wilson in Perth by the drilling supervisor, Paul O'Shea to let him know what was going on.

266 Preparations to shift the rig over the top of the H1 Well were underway.

267 I went down with the tool pusher or the OIM to address the crew who were still mustered in the galley. We outlined what we knew and what we were going to try to do to rectify the situation. The OIM advised everyone to stay awake for a while in case the situation got worse. CND

268 I then took some notes and went to check how large the slick looked.

269 At about 0723 hrs, the well started to flow again. The flow was significant and it looked like there was a substantial oil component being discharged.

270 I was on the main deck and found the drill crew hurrying back towards their muster stations. One guy offered to go up the derrick to help but the toolpusher (I think) and I told him no and to head directly to muster stations.

271 In my lifejacket and other personal protective equipment, I went back to the control room. We looked at the situation and it was getting a little worse.

272 Now the OIM is in charge of the rig and all POB including myself fall under his command in an emergency. That said, there was a good working relationship between the OIM and the drilling supervisors and a similarly good working relationship between the drilling supervisors and myself. I also had a good working relationship with Donald Millar, the rig manager.

273 The OIM decided to evacuate non essential personnel and the drilling supervisors and I concurred with that decision.

274 At one point the OIM was talking to Donald Millar on the telephone advising of the situation. I was called over to the phone to give Mr Millar my analysis of the situation. It was brief and not encouraging.

275 A cloud of gas and oil vapour started to drift across the deck of the rig on the port aft quarter. The OIM ordered the main engines shut down. This was prudent as the port aft quarter is where the engine exhausts are located and despite spark arrestors, keeping the engines running increased the risk of a fire.

276 With the main engines shut down the rig went onto the emergency generator. I think that we lost the telephone circuits at that time which was disappointing.

277 I recall enquiring if the rig could still skid the cantilever with the main engines shut down. The answer was no.

278 Our status at that time was:

(a) the well was blowing out;

CND

(b) we had no BOP's installed;

(c) we were not located over the top of the well;

(d) with main engines down we could not skid over the top of the well;

(e) if the source of the blow out was what I suspected, we were cased all the way to reservoir so there was little chance of the well bridging and stopping the flow of its own accord;

(f) I was concerned that if the flow was through a relatively small pathway in residual cement in the shoe track that erosion would only enlarge the pathway. That meant that the blow out was more likely to get worse than better; and

(g) we still had about 20 POB.

279 We discussed the situation and I stated my opinion that given our status, full abandonment of the rig was the best course of action. There was no prize for staying on board if we subsequently lost people.

280 The OIM and drilling supervisors agreed and the OIM ordered evacuation of the rig.

281 I mentioned to Paul O'Shea to bring our mobile satellite telephone. We had one available mainly for use in cyclone season. Paul brought that phone with him to Life boat # 3.

282 Once we were strapped in and the final muster taken, we abandoned the rig in lifeboat # 3. This left one boat intact on the rig, Lifeboat # 4.

283 Lifeboat #3 stalled on the decent but whatever difficulty that existed with the lifeboat was quickly fixed and the decent continued without further incident.

284 Once in the water and away from the rig we made our way to Lady Audrey, a supply boat on standby in the area.

285 Paul O'Shea made a call to Mr Wilson from the lifeboat to let him know that all POB were safely evacuated from *West Atlas*.

286 From that point, we went into action responding to the incident.

**Specific questions raised by the Commission**

**Possible explanation of the cementing issues arising on 7 March 2009**

287 I have been asked by the Commissioner to provide my views about the cementing and pressure testing carried out on the H1 Well, in particular in relation to the apparent failure of the Float Shoe and/or CND

Float Collar non-return valves for the 244mm (9⅝") casing of the H1 Well and/or the backflow of hydrocarbons and/or other substances following the release ('bleeding off') of pressure after the 'bumping of plugs' in the 244mm (9⅝") casing of the H1 Well.

288 I have already set out my knowledge about the situation as at 7 and 8 March 2009. That is, I considered from the materials that were 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

289 Nevertheless, to address the Commissioner's question, I have reviewed the forward plans, Advantage drilling reports and IADC report and in particular the following documents:

(a) PTTEPAA Daily Drilling Report of 7 March 2009;

(b) PTTEPAA H1 ST1 244mm (9⅝") Cementing Report of 6 March 2009;

(c) West Atlas IADC report of 7 March 2009;

(d) Halliburton cement report Montara H1 ST1 9.625in Production Csg FARPACK 8 Mar 09.xls;

(e) Atlas Drilling Well Control Manual; and

(f) West Atlas / SD1 Operations Procedures Manual

290 Based on my interpretation of those materials, I have drawn some conclusions about what might have occurred in relation to the cementing of the H1 Well 244mm (9⅝") casing on 7 March 2009, which I set out below.

**Installing 244mm (9⅝") casing into H1 Well - 6 & 7 March 2009**

291 The casing was run acceptably, however, there were a few problems listed in the DDR dated 7 March 2009:

(a) some tight hole was encountered at 3726m MD. This is not unusual and can usually be circulated past.

(b) the handle on a pin securing the Flush Mounted Spider (FMS) failed and the FMS had to be removed by stripping it over the top of the casing when set in the rotary slips; and

(c) the Casing Drive System (CDS) jammed on the casing and removal required laying out some casing and replacing the stuck components.

CND

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292 Despite this the casing was landed on depth and the casing circulated 110% of its volume as required.

**Cement Calculations**

293 I consider that, having reviewed all of the relevant calculations and with the benefit of hindsight that the cement calculations were incorrect.

294 The concept of taking top of tail cement above top reservoir was both in the DP (2923.5m on the planned directional profile was 30m TVD above top reservoir) and increased in change control D65005A 001 to a depth of 69m TVD above top reservoir.

295 A draft cement design from Halliburton, our cementing contractor to Mr Wilson on 28 January 2009 included the revised top of cement in the calculations. It also included the original casing measured depth of 3,373m as per program because at that time the well had not been drilled to total depth and the final bottom depth remained unknown.

296 Unfortunately, it appears that the calculations performed in the field referenced not the top of cement as intended in the DP and subsequently revised in the change control D65005A 001 but the difference between programmed top of cement and programmed shoe depth. This apparent error resulted in a calculated tail slurry length of 550m instead of a tail slurry length of 1052.5m as would have been calculated if the top of cement reference had been honoured and the bottom varied to suit the as drilled shoe depth parameter. This apparent error was duplicated by all the personnel who calculated the cement volumes.

297 The 311mm hole section was drilled to a depth of 3796m for geological reasons not 3,373m as programmed.

298 The consequence of this apparent error was that insufficient tail cement slurry was pumped to bring the top of the tail slurry above the top of the reservoir as intended in the DP and revision to DP.

299 However, this apparent error did not have an impact on the well control incident that subsequently occurred.

300 This apparent error was not identified until after 21 August 2009 and upon review of the situation in the light of the uncontrolled release and in an attempt to determine what might have caused the release.

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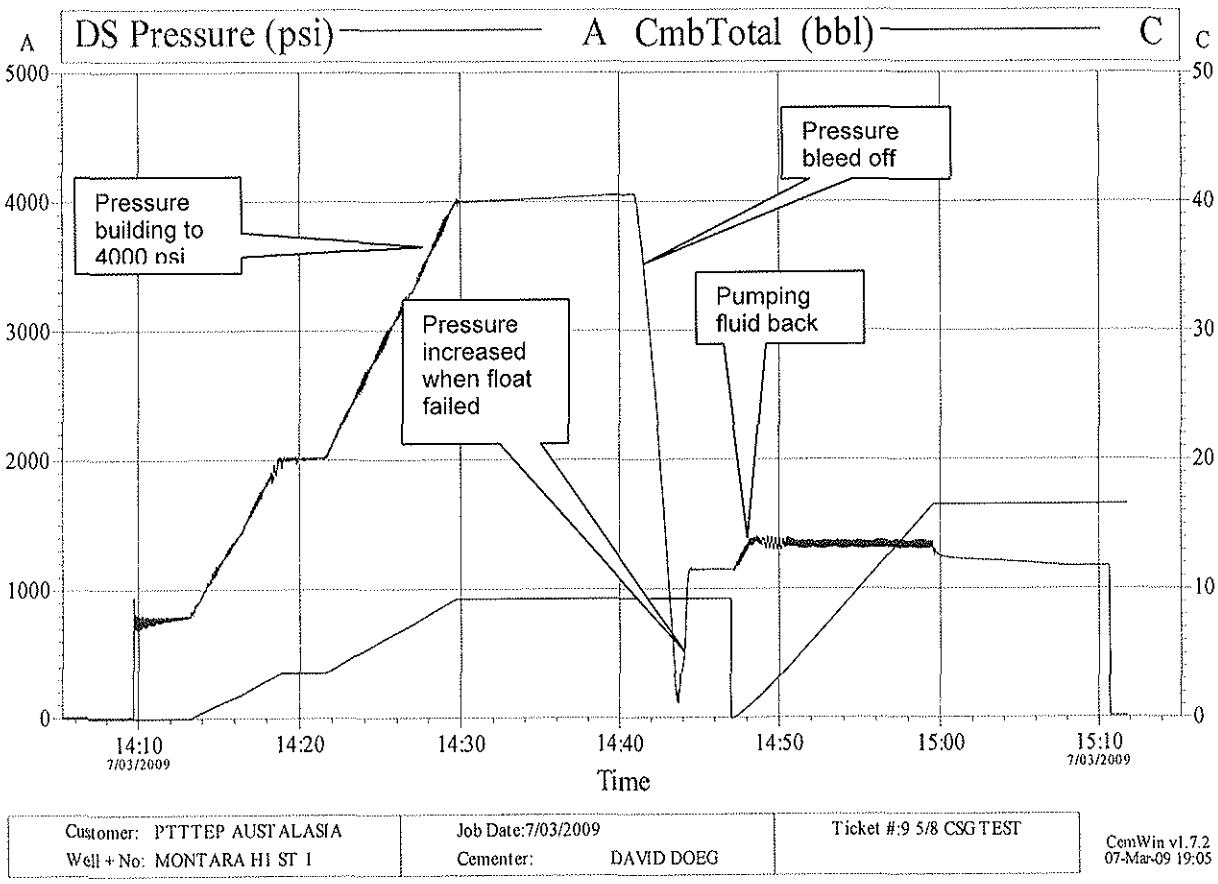
**Pressure Testing Casing**

301 During the displacement of the cement on 7 March 2009, the pressures seemed to be close to expected. That is to say, there was a pressure increase as the cement was displaced from the casing and the pre bump pressure indicated that a substantial cement volume was located above the shoe track.

302 The DDR reports a pre bump circulating pressure of 7.9 ~ 10.0 MPa. ( 1145 ~ 1450 psi ) and that the bump was confirmed with 13.7 MPa ( 1987 psi ). This is in line with expectations.

303 Pressure testing of the casing was then transferred to the Halliburton cementing unit. The initial pressure at the cement unit was a little under 5.5 MPa (800 psi) as read from the graph in Halliburton cement report Montara H1 ST1 9.625in Production Csg FARPACK 8 Mar 09.xls.




304 The handover pressure was somewhat less than the pressure recorded on the drill floor using the mud pumps. I assume that some fluid was bled off whilst lines were changed over.

305 With the cement unit pumping to pressure test the casing, the pressures and volumes pumped were consistent with good sealing plugs and normal casing expansion. The pressure was taken to 13.8 MPa (2000 psi) and held for a few minutes. A steady pressure with no pumping was consistent competent

CND

casing and cement displacement plugs sealing properly. After a few minutes at the lower pressure, the the pumps were then used to bring the pressure test up to 27.6 MPa (4000 psi) as per program.

306 Forward plan #17 dated 6 March 2009 revision 1 covers the running and cementing of the 244mm casing on the H1 Well. The casing test is described using the duration from the DP which is 10 minutes.

307 The duration of the pressure test was as per the DP but insufficient for the WCS. This was an error in the DP that was not picked up during the review process.

308 Points 14 to 20 include the setting of a cement plug in the upper part of the casing as originally required in the DP.

309 In the WCS at section 9.2 it states:

**9.2 Casing Pressure Testing**

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 casing sizes ≥ 340mm (13.3/8") and strings with length <500m.

310 The reference to pressure testing for 10 minutes in the DP was incorrect. The 20 minutes referenced in the WCS at section 9.2 should have applied. (Note that the 10 minute figure was the minimum value prescribed in the Schedule of Specific Requirements direction under the *Petroleum (Submerged Lands) Act*, now no longer in force).

311 To form an opinion about whether the pressure test duration was a contributing factor in the subsequent uncontrolled release, I have considered the data obtained during the pressure testing. Based on that review I consider that pressure testing for 10 minutes rather than 20 minutes was not a contributing factor in the subsequent uncontrolled release.

312 Extrapolating from the data recording the well pressure throughout the testing there was likely to have been a continuing increase in the pressure for the 10 minutes after the testing period (which is consistent with the heat of the chemical reaction in the cementing process) and demonstrating casing integrity and no apparent leak.

313 Upon completion of the pressure test, displacement fluid was bled off to the cement unit's measuring tanks.

CND

314 During the bleed down process the pressure reached about 0.82 MPa (120 psi), when there was a sudden change and the pressure started to increase. This increase was interpreted as a float valve failure and the fluid was shut in at the cement unit. The shut in pressure stabilized at about 8.3 MPa (1200 psi) .

315 My interpretation of the sudden pressure increase is that the float valves were working correctly but failed in service with between 6.9 MPa and 7.6 MPa pressure differential across the valve. It should be noted that the valve is rated for at least 20.7 MPa pressure differential according to the manufacturer's specifications.

316 In terms of volumes pumped and returned by the cement unit, the initial shut in pressure when the cement unit was engaged was about 5.17 MPa. There would have been some fluid compression / casing expansion to hold that pressure. The cementing job log reports that after waiting on cement, the shut in pressure was released for a 3.5bbl return. From that I would estimate that we probably had about 4bbls of trapped pressure at the initial cement unit pressure of 750psi.

317 During the casing test, a further 9.25bbls of fluid was added to the casing to increase the casing test pressure to 27.6 MPa.

318 When pressure was released at the cement unit after the casing test but before the float valves failed, I would have expected 13 ~ 14 bbls of fluid to have been returned. It is not unusual to get a little more fluid returned than pumped because the fluid expands as it heats up.

319 The volume of fluid returned to the cement unit before shut in after the float failed was recorded at 16.5bbls in the cementer's job log.

320 I understand that once the personnel on the cement unit realized that the pressure was increasing instead of decreasing as expected they shut in the well at the cement unit. The additional 2 ~ 3 bbls of fluid returned once the float valve failed is reasonable and to me indicates good reactions to an unplanned event.

321 I would also expect that for the shut in pressure to increase from about 0.83 MPa to about 8.3 MPa, without pumping from surface would only be achieved by an additional influx from the casing shoe in the order of 3bbls.

322 Up until the point where the float valves failed, the top plug and bottom plug should have remained on seat in the landed position. The Top plug and possibly the Bottom plug would tend to work as a floating piston within the casing and move up the casing once there was a fluid influx from below. CND

323 Using the above interpretations of the reported flows, the top cement plug may have been displaced up the casing by about 6 bbls.

324 The cementers records then show that fluid was then pumped back into the casing at a steady pressure of around 9.0 MPa to a volume of 16.5bbls.

325 There was no further pressure bump and the pump back was stopped at 16.5bbls.

326 When pumping fluid back into the well one would expect to see a pressure increase when the top plug reseated at the float collar. This pressure increase was not seen. This suggests that either there was plug bypass or that something other than the float valves had failed. There could have been a casing failure however that is unlikely. It is most likely that the plugs failed to seal when they reached the float collar.

327 This could indicate that by pumping fluid back into the well without pressuring up on the casing once the top plug should reasonably have seated, cement might have been displaced from the shoe track. Pumping 16.5bbls of fluid could mean that about 9 ~ 10 bbls of fluid was pumped into the shoe track. If that did occur, it would be a volume that exceeds the shoe track volume making it likely that the cement in the shoe track was displaced out of the shoe.

328 After pumping the 16.5bbls of fluid back into the well, the system was shut in and the cement allowed to set.

**Waiting on Cement**

329 After waiting on cement, the casing pressure was released and 3.5bbls of fluid returned at the cement unit.

330 The well was flow checked and there was no flow.

331 Apart from an inflow test, no further pressure testing of the casing was attempted. If the above analysis of the cementing sequence is correct, it is likely that an attempt to pressure test the casing after the cement had set would have failed.

**Testing Shoe Cement Integrity**

332 In the drilling comments section of the Advantage Drilling Fluids Report -7- of 7th March 2009 it is stated, *"WOC (Wait on Cement) Retested float..."* This note is also made in the IADC report filled in by the driller.

CWD

333 Having now reviewed other documents, it appears that the reference to retesting of the "float" is a reference to the IADC report filled in by the driller, but the test that was actually performed was an inflow test that demonstrated no flow.

334 To be effective, an inflow test requires a differential pressure from the well bore to the casing. This condition only exists whilst the cement slurry is liquid and therefore providing hydrostatic pressure. If the cement is set it generates no hydrostatic pressure and the inflow pressure is reduced to reservoir pressure. As the pressure due to the cement displacement fluid exceeded the reservoir pressure there was no differential pressure to generate any flow from the well.

335 As the floats had broken in service it did not test the floats at all.

336 In the Advantage Drilling Fluids Report 7 dated 7 March 2009, drilling comments section, there is mention of *"WOC (Wait on Cement) Retested float..."* The retesting of the float is no doubt a reference to the IADC report filled in by the driller. The test that was performed was in fact an inflow test that demonstrated no flow. It did not test the floats at all.

337 IADC report # 6695576 dated 7th March 2009 is a Atlas Drilling *West Atlas* report covering activities on *West Atlas* for that day. The entry of 1800 – 18:30 in this report states *"Retest Float Good. R/D CMT head and CMT lines."*

338 The PTTEPAA Daily Drilling Report of 7th March 2009 mentions:

(a) at 1400: "*Switched back to Halliburton and pressure tested casing to 27.6MPa x 10mins - Ok Bled off test pressure to 1.37Mpa then observed pressure rapidly increase to 8.96MPa. Note: Pumped 1.47m$^3$ and bled off 2.62m$^3$, suspected float valve failure. Pumped 2.54m$^2$ back into casing at 9.3Mpa.*"; and

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

339 The reference to the casing annulus is a discrepancy. Whilst it is possible that the annulus was closed in using the BOP whilst waiting on cement, it is more likely that the report should have read "*Open casing to atmosphere and confirm no backflow*". If the report had been modified thus it would have been consistent with other reports.

340 The Halliburton Cementers report of 8th March 2009 notes *"17:51 BLEED OFF CSG STRING 3.5BBLS BACK, 0PSI"*.

CND

PJ

341 The Halliburton Cementers report of 8th March 2009 is the most detailed and descriptive of the reports. Although it does not identify the problem, it does set out what had occurred.

342 The cementers report records the final pressure prior to bleed off. It was only 687psi where as at shut in earlier in the day the pressure was 1300 psi. The difference in pressures in what was supposed to be a closed system was an indicator that something was not quite right.

343 The driller has interpreted this as a retest of the float and written it down as such. The DDR has been reported as the annulus was opened to atmosphere and the Halliburton cementer's note *"17:51 BLEED OFF CSG STRING 3.5BBLS BACK, 0PSI"* records that the pressure trapped in the casing was released to atmosphere and that there was no backflow.

344 Based on reading each of those reports and trying to reconcile them, what I believe probably happened is that the pressure trapped in the casing was released to atmosphere and that there was no backflow. In other words, an inflow test was conducted and there was no pressure test done.

345 The Section 8.1 of the Atlas Drilling Well Control Manual has a section titled Waiting On Cement – Surface Stacks which does not require a pressure test of the casing after waiting on cement.

346 The West Atlas / SD1 Operations Procedures Manual section 1.1.31 covers cementing intermediate casing and contemplates a failure of the float valves at step 15 of the procedure. This procedure does not require a pressure test of the casing after a suitable period of waiting on cement.

347 Section 5 of the WCS relating to barriers states that "All other barriers may be pressure tested or inflow tested".

348 The three managing documents referencing casing cementing were complied with because an inflow test was done on the casing after the period waiting on cement. However, after considering the position since the uncontrolled release, I think that that was an inadequate response to the circumstances of 7 March 2009.

349 An appropriate action would have been to pressure test the casing to a pressure at least equal to the expected formation fracture pressure plus a margin. Such a test would properly demonstrate cement integrity if fluids were bypassing the displacement plugs.

350 The need for this appropriate action was not recognised by trained and qualified personnel offshore and communications to both the Atlas Drilling and PTTEPAA office based personnel, including me, did not trigger a request for further confirmation of cement integrity.

CNP

**Pressure testing PCCCs - permanent and tested barrier**

351 The PCCCs have a poppet valve that holds pressure from below. The running and retrieval tool has an internal shaft that holds the poppet off seat whilst the running tool is engaged. This allows for a pressure test during installation and a check for trapped pressure prior to removal. I expected the Drilling Supervisors to apply a test on the PCCC during installation to verify that no O rings had been damaged during the installation process however testing was not included in the DP, which required installation to the manufacturer's procedures. The manufacturer's procedures were included in the documentation sent to the *West Atlas*. I did not know at the time of the installation of the PCCCs but have since discovered that the manufacturer's procedures do not require a pressure test after installation.

352 The PCCCs did not meet PTTEPAA's criteria for a permanent barrier because they were not pressure tested. The PCCCs manufacturer's (Vetco) instructions for the PCCCs did not require any pressure testing of the PCCC in situ.

353 Had we pressure tested the PCCCs on installation then they would have complied with the necessary criteria for a permanent barrier for the purposes of the long term suspension despite it not being included as a specific example in section 14.1.

354 The revision to forward plan #17 dated 7th March 2009 version 2 takes the program revision into account. It details installation of the PCCC (even though that is only documented as a change control on 12 March 2009). It does not describe a pressure test of the PCCC on installation.

355 The absence of pressure testing for the PCCCs on installation was not causative of the uncontrolled release. The PCCCs did not fail under pressure or in any way at all. The PCCC design allowed the pressure underneath the PCCC to be tested before the PCCC was removed. The testing was carried out and the result was that there was no pressure, which was consistent with the H1 Well being overbalanced.

**Absence of a 340mm (13 ⅜") PCCC**

356 I have set out above, based on the DDRs I thought that the 340mm (13 ⅜") PCCC had been installed on the H1 Well as set out in the DP (as revised by change control).

357 Even after enquiry since 21 August 20009, I do not know why the 340mm (13 ⅜") PCCC was not installed on H1.

CMD

358 The absence of the 340mm (13 ⅜") PCCC should have been known when the 508mm (20") trash cap was installed. That fact should have been reported through the usual reporting channels and ultimately I should have been told of the matter (for PTTEPAA) and Donald Millar (on behalf of Atlas Drilling) should also have been told of the situation.

359 The cause of the release remains unknown and I do not think that the uncontrolled release was caused by the absence of the 340mm (13 ⅜") PCCC or the absence of any report about the missing 340mm (13 ⅜") PCCC.

**Re-installing the 244mm (9⅝") PCCC**

360 I consider that the decision not to re-install the 244mm (9⅝") PCCC on 20 August 2009 is justified in the circumstances that existed at that time.

361 While it can be argued that with the benefit of hindsight the 244mm (9⅝") PCCC should have been re-installed, all of the signs from the H1 Well on 20 August 2009 established that the H1 well was stable and secure.

362 The H1 Well was cased and cemented and at the time there was no concern as to the quality of the cement barriers in the well.

363 The displacement fluid was overbalanced to formation.

364 The H1 Well had been static since March 2009 and it could reasonably be expected that any imperfections in the well status would be evident through the presence of pressure or hydrocarbons immediately below the 244mm (9⅝") PCCC.

365 There was no pressure or oil or gas detected when the 244mm (9⅝") PCCC had been removed in the first place and the *West Atlas* was scheduled to return to the H1 Well within a short time, the DP 1B contemplated the 244mm (9⅝") PCCC being removed and remaining off the MLS casing for a significant period.

366 The cause of the release remains unknown and I do not think that the leaving the 244mm (9⅝") PCCC off the MLS casing after it had been removed as programmed in the DP 1B caused the uncontrolled release.

**Communication issues**

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

CND

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

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

370 The facts about the cementing of the shoe float were contained in distributed reports to well qualified people (including me) but it appears that the circumstances did not call on anyone to analyse that information.

371 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.

372 Nevertheless the H1 Well behaved as it was expected based on the communications of the relevant personnel. The reason why the H1 well became underbalanced 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.

Craig Neil Duncan

Declared at Perth the 8th 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