

# **Recommendations for Australian Government Commission of Inquiry Montara Well Head Platform Uncontrolled Hydrocarbon Release**

Report to:

**World Wide Fund for Nature Australia (WWF)**

Montara Oil Spill – Drilling and Well Control Issues

Reference No: 122304, Version 2

Prepared by:



**HARVEY**  
**CONSULTING, LLC.**

*Oil & Gas, Environmental, Regulatory Compliance, and Training*

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Email: [sharvey@mtaonline.net](mailto:sharvey@mtaonline.net)

Phone: (907) 694-7994

Fax: (907) 694-7995

PO Box 771026  
Eagle River, Alaska 99577

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## 1. Executive Summary

This analysis responds to a request by World Wide Fund for Nature–Australia (WWF) for a review of all the materials that were submitted to the Australian Government in regards to the Commission of Inquiry for the Montara Well Head Platform Uncontrolled Hydrocarbon Release.

This analysis concludes that:

- PTTEP’s Montara well H1 temporary suspension design and installation, and subsequent re-entry procedure was not completed in a manner consistent with “good oil field practices.”
- International oil and gas industry and regulatory standards require continuous well control to be in place for all wells that have penetrated the hydrocarbon bearing zones, using the minimum safety practice of a continuous “two-barrier” control system.
- Montara well H1 was suspended on March 7, 2009 without an approved temporary suspension permit; that came from the Designated Authority (DA)<sup>1</sup> two days later, after-the-fact.
- On March 9, 2009 the DA approved a temporary well suspension plan that was not consistent with “good oil field practices,” nor was it consistent with Australia’s longstanding prescriptive technical standards found in *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production*. These standards were replaced in 2004 with a more generic “good oil field practices” standard.
- The technical criteria used by the DA to approve the H1 well drilling, completion, and suspension applications is unclear, and the DA’s submittal to the Commission of Inquiry provides no technical justification, engineering data, or analysis to support that their decisions were, in fact, consistent with “good oil field practices.”
- The fundamental question to be answered by the Commission of Inquiry is whether PTTEP’s application to fill H1 with brine and place a temporary cap (PCCC) on it was “good oil field practice.” A review of minimum regulatory standards from Norway, Canada and the USA, and even Australia’s longstanding prescriptive standards in the *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production*, without question, show that it is not. ALERT Well Control’s final assessment of H1 as “controlled and secured” with a “two-barrier” plug system installed is further evidence that the initial plan did not meet “good oil field practice.”
- Agency technical review of well completion plans, temporary well suspension plans, and re-entry procedures appeared to be hurried, incomplete, and absent of safety and environmental peer review by coordinating agencies such as RET<sup>2</sup> and NOPSA.<sup>3</sup>
- Failure to properly cement the 244mm (9-5/8”) intermediate casing contributed to the blowout. The absence of any technical information on cement quality and integrity, and the absence of a submission from the responsible cement contractor, warrants inquiry.
- On August 20, 2009 the *West Atlas* drilling rig re-entered H1 to tie it back into the wellhead control system. Delays and problems tying in the well resulted in the *West Atlas* moving from H1 to gas

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<sup>1</sup> The Designated Authority (DA) for the Territory of Ashmore and Cartier Islands offshore area was delegated to the Northern Territory Department of Regional Development, Primary Industry, Fisheries and Resources (DRDPPIFR), hereinafter referred to simply as “DA.”

<sup>2</sup> Offshore Resources Branch, Resources Division, Commonwealth Department of Resources, Energy and Tourism (RET)

<sup>3</sup> National Offshore Petroleum Safety Authority (NOPSA)

injection well GI, and later to production well H4, leaving H1 uncapped, while the drilling staff's attention was focused on tying in wells GI and H4.

- When the uncapped H1 well blew out, the *West Atlas* drilling rig was working over H4, holding a heavy string of 508mm (20") casing. The 508mm (20") casing had to be set down before the *West Atlas* could be moved back to commence any well control operations on H1. This caused further delay in providing emergency response to H1.
- Major, late changes in the Montara Platform Topside Module installation schedule, well design, and wellhead control tie-in plans and procedures appears to have contributed to hastily prepared, major changes of engineering and safety design plans, and an incomplete, uncoordinated agency review of these major design changes.
- The Montara Platform Topside Module installation delay should have triggered a multi-agency coordinated, peer-reviewed, technical, safety and environmental assessment to evaluate the potential risks associated with the proposed batch drilling program and the inability to immediately tie newly drilled wells into the platform wellhead control system.
- Australia's 2004 *Australian Petroleum (Submerged Lands) (Management of Well Operations) Regulations* replaced the longstanding list of prescriptive technical requirements found in *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* with a more generic "good oil field practices" showing standard to obtain an oil and gas well permit.
- Misapplication of the "good oil field practice" standard by both the operator and the approval agencies appears to have contributed to the incident.
- Absent the prescriptive technical standards listed in *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production*, it is not clear what technical standards the agencies relied on to approve the Montara H1 well application.
- If the prescriptive standards listed in *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* were still used, the well suspension application would have required a series of cement plugs in the casing, meeting a minimum "two-barrier" industry well control standard.
- Other international regulatory systems for the oil and gas industry include prescriptive engineering principles and standards, as a minimum threshold, while providing "regulatory flexibility" by allowing an operator to propose new technology or practices for agency review that "meet or exceed" the basic minimum standards. In this way, the minimum technical standards are not compromised; they are only improved by new technology and new practices.
- Oil spill plans and well control plans (including relief well and well capping plans) should have been prepared, reviewed, and approved in advance of drilling and completion operations.
- The H1 oil spill plan was not approved by DEWHA<sup>4</sup> until March 6, 2009, after the first phase of the well was drilled. Phase 1 drilling for H1 started on January 18, 2009 and ended on March 7, 2009. There was no approved oil spill plan in place during that time.
- Other international countries require relief well and well capping plans to be prepared in advance of drilling. In this case, required relief well implementation was delayed while a rig was located, contracts were negotiated, and the relief well rig was transported to the site. Advanced planning would have likely shortened this response time, and identified other viable options.

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<sup>4</sup> Australian Commonwealth Department of Environment, Water, Heritage and the Arts (DEWHA)

- Attempting to control a catastrophic well blowout is serious, highly technical, dangerous work. During a catastrophic emergency, is not the time to be searching for well control experts, starting well control plans from the beginning, or negotiating contracts for a relief well rig. This should be done in advance to expedite emergency response.
- Copies of all original designs, applications, approvals, and findings should be provided to the Commission of Inquiry for independent review. A thorough independent analysis of all the facts is not possible without being able to examine the original source documents.
- The expertise, training, and qualifications of all personnel involved (industry and agency) warrants examination.
- Of urgent and primary concern to the Commission of Inquiry should be the existing safety status of all the other wells on the Montara Wellhead Platform. While H1 is now, reportedly, secured with a two-barrier system, it is not clear if the other wells are safely secured. Batch drilling programs, by nature, are subject to repetitive flaws. Flaws encountered on H1 could have been repeated in the other wells, and this warrants inquiry. The Commission of Inquiry should also examine whether similar well safety concerns could exist on other offshore platforms.

## 2. Introduction

This analysis responds to a request by World Wide Fund for Nature–Australia (WWF) for assistance in reviewing in the materials that were submitted to the Australian Government regarding the Montara Well Head Platform Uncontrolled Hydrocarbon Release<sup>5</sup> Commission of Inquiry, and were made publically available on the Commission website as of February 2010. Because this analysis is limited to materials made publically available at that time, it does not include any additional information, data or analysis that may have been submitted to the Commission of Inquiry that was not publically available as of February 2010.

While the Commission of Inquiry examination scope is broader than the technical issues related to drilling and well control (e.g. oil spill response, human health impacts, environmental impacts), this report is only focused on the technical issues related to drilling and well control. Other issues subject to inquiry were addressed in WWF’s December 2009 “Submission to Montara Commission of Inquiry.”

Recommendations, observations, and questions raised in this report are based on 23 years of experience as a Petroleum and Environmental Engineer and are highlighted in colored text boxes.

## 3. Objectives

This report was commissioned under WWF Contract Reference No.: 122304, “Montara Oil Spill – Drilling and Well Control Issues.” The objectives set forth in the contract read:

*“Review all the materials that have been submitted for the Montara Oil Spill Inquiry and draft a letter from WWF to the Commission responding to each of the Terms of Reference (Tor) related specifically to detailed technical issues related to drilling and well control. Make technical recommendations regarding best practices regarding drilling and well control.”*

<sup>5</sup> The term “Uncontrolled Release” is used by the Commission of Inquiry. In this report, synonymous terms used will include “well blowout” or “blowout.”

Additionally, WWF requested that the report include conclusions on whether the operator followed Australian regulations and how Australian regulations compare with best industry practice or other international regulations.

#### 4. Term of Reference No. 1

*“Investigate and identify the circumstances and likely cause(s) of the Uncontrolled Release.”*

**H1 Tie-in Operations Caused Blowout:** The Montara H1 well “Uncontrolled Release” occurred one day after the *West Atlas* drilling rig moved over the well to tie it back into the Montara Wellhead Platform wellhead control system.

The information provided by both PTTEP Australasia (Ashmore Cartier) Pty Ltd. (PTTEP) and Atlas Drilling (S) Pte Ltd. (Atlas Drilling) confirms that the H1 “Uncontrolled Release” occurred one day after the *West Atlas* drilling rig moved over the well to tie it back into the Montara Wellhead Platform. The plan was to tie H1 into the platform wellhead control system and finish the second phase of drilling (production interval).

At the time of the incident, there was considerable speculation about whether the *West Atlas* drilling rig (*West Atlas*) was drilling the Montara H1 well (H1)<sup>6</sup>, drilling a neighboring well, or completing H1. PTTEP should have clearly articulated in early press releases that the uncontrolled release originated from well H1, the well had been unplugged and left open to atmosphere, and the rig was working on tying in wells G1 and H4 when the incident occurred.

On August 20, 2009 the *West Atlas* re-entered H1 to tie it back into the wellhead control system. Delays and problems tying in the well resulted in the *West Atlas* moving from H1 to gas injection well GI, and later to production well H4, leaving H1 uncapped, while the drilling staff’s attention was focused on tying in wells GI and H4.

When the uncapped H1 well blew out, the *West Atlas* drilling rig was working over H4, holding a heavy string of 508mm (20”) casing. The 508mm (20”) casing had to be set down before the *West Atlas* could be moved back to commence any well control operations on H1. This caused further delay in providing emergency response to H1.

The history leading up to the blowout is summarized as follows:

Between January and April 2009 the *West Atlas* batch drilled the Montara production wells (H1, H2, H3, H4)<sup>7</sup> and gas injection well (GI) down to the 244mm (9-5/8”) intermediate casing, and then suspended each well on the Montara Wellhead Platform.<sup>8</sup>

On January 18, 2009 well H1 was spudded (started) and on March 6, 2009 well H1’s 244mm (9-5/8”) intermediate casing was set.<sup>9</sup>

On March 7, 2009 well H1 was temporarily suspended and a 244mm (9-5/8”) intermediate casing Pressure Control Corrosion Cap (PCCC)<sup>10</sup> was installed.<sup>11</sup>

<sup>6</sup> Montara H1 well was side tracked, and later renamed Montara H1 ST1. For simplicity in this report the well is simply called “H1”.

<sup>7</sup> Atlas Drilling, Submission No. 1501.0001.0002

<sup>8</sup> PTTEP, Submission No. 1000.0001.0034

<sup>9</sup> Atlas Drilling, Submission No. 1501.0001.0002

<sup>10</sup> Also commonly referred to as a temporary abandonment cap on a mudline suspension system or “TA”.

Atlas Drilling reports that on March 12, 2009, PTTEP formally issued a change control order to the well suspension plan. PTTEP changed the plan to remove the requirement to set a cement plug and instead only install a 244mm (9-5/8") intermediate casing PCCC.<sup>12</sup> This change order was issued after-the-fact, after the well had already been suspended and the decision had already been made not to set a cement plug.

On April 21, 2009 the *West Atlas* left the Montara Wellhead Platform to conduct exploration drilling at other locations.<sup>13</sup>

On August 19, 2009 the *West Atlas* returned to the Montara Wellhead Platform to tie in H1, H2, H3, H4, and GI wells.<sup>14</sup>

On August 20, 2009 the *West Atlas* skidded over H1 and commenced well tie-in work.<sup>15</sup> The 340mm (13-3/8") surface casing threads were found to be corroded and scaled. Leaving H1 uncapped, the drilling staff's attention for the next 12 hours turned to tying in wells GI and H4. On August 20, 2009 and into August 21, 2009 the *West Atlas* skidded over GI, and then to well H4 to commence well tie-in work.<sup>16</sup>

On August 21, 2009 the H1 well Uncontrolled Release (otherwise commonly referred to as a "blowout") commenced.<sup>17</sup> Atlas Drilling reports an estimated kick of 40 barrels of fluid and an unknown quality of gas were released, activating gas alarms and emergency response.<sup>18</sup> When the alarms sounded, the *West Atlas* was over well H4, not H1. This required the *West Atlas* to lay down the 508mm (20") casing that was just cut off from H4 before the rig could be move back to well H1, further delaying response to the Uncontrolled Release.<sup>19</sup>

Atlas Drilling reports that plans were made to run PTTEP's cementing contractor's down-hole packer into well H1 to secure it, once the *West Atlas* could be activated. The down-hole packer was never set. No records were provided to the Commission of Inquiry from the cement contractor to explain the sequence of events from its point of view.

PTTEP concludes that the most likely cause of the Uncontrolled Release was a flow of hydrocarbons that originated from a cement channel in the 244mm (9-5/8") intermediate casing shoe track and inside the 244mm (9-5/8") intermediate casing string.<sup>20</sup>

The casing shoe track, if properly cemented, plugs off hydrocarbon entry into the bottom of the well. If improperly cemented, the casing shoe track can provide a conduit for hydrocarbons to enter the well. PTTEP believes that casing shoe track was improperly cemented.

The H1 well was drilled to a total depth of 3,796m (12,454'). The reservoir pressure encountered at this point is not specified in the submittals; data on the reservoir pressure is key to understanding the pressure forces placed on the casing and casing shoe equipment at that depth.

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<sup>11</sup> Atlas Drilling, Submission No. 1501.0001.0002

<sup>12</sup> Atlas Drilling, Submission No. 1501.0001.0002

<sup>13</sup> PTTEP, Submission No. 1000.0001.0034

<sup>14</sup> Atlas Drilling, Submission No. 1501.0001.0004

<sup>15</sup> Atlas Drilling, Submission No. 1501.0001.0004

<sup>16</sup> Atlas Drilling, Submission No. 1501.0001.0005

<sup>17</sup> Atlas Drilling, Submission No. 1501.0001.0005

<sup>18</sup> Atlas Drilling, Submission No. 1501.0001.0005

<sup>19</sup> Atlas Drilling, Submission No. 1501.0001.0006

<sup>20</sup> PTTEP, Submission No. 1000.0001.0041-42

The 244mm (9-5/8") intermediate casing string was drilled at a high angle through 1,187m (3,894') of a pressured hydrocarbon zone. The failed 244mm (9-5/8") intermediate casing shoe track was 3m (10') above the oil-water contact,<sup>21</sup> providing a pathway for hydrocarbons to enter the well through the failed shoe float collar valve. The 244mm (9-5/8") casing shoe track sitting at the base of this casing string was subject to the pressure forces encountered at the total well depth of 3,796m (12, 454'). The reservoir pressure encountered at the casing shoe warrants inquiry.

PTTEP rules out flow from the 244mm (9-5/8")/ 340mm (13-3/8") annulus as a cause, based on information obtained during the relief well operations.<sup>22</sup> PTTEP reports the H1 relief well was designed to intersect the 244mm (9-5/8") casing; when it intersected, the hydrocarbons were controlled by pumping mud into the 244mm (9-5/8") casing. A relief well eventually controlled well H1.

PTTEP indicates that a PCCC on the 244mm (9-5/8") intermediate casing may have had held a slight backpressure on the well sufficient to contain the flow. PTTEP assumes that when the PCCC was removed, the pressure flow regime changed, allowing higher bottom hole pressure fluids behind the 244mm (9-5/8") intermediate casing to leak through a poor cement job at the casing shoe, into the 244mm (9-5/8") intermediate casing, past the brine in the casing string, and up to the surface of the platform floor.

This means that the weight of the brine left in the hole when the well was temporarily suspended was inadequate to counteract the highest potential reservoir pressure expected in the well. As a fundamental engineering design principle, brine systems should be properly weighted to assist in well control.

**Existing Risks at Other Wells:** While H1 is now secure, are the other wells on the platform secure? Are there drilling and completion design, construction, and safety issues that warrant immediate attention, because batch drilling programs, by nature, are subject to repetitive flaws.

Of urgent and primary concern to the Commission of Inquiry should be the existing safety status of all the other wells on the Montara Wellhead Platform. While H1 is now, reportedly, secured with a two-barrier system, it is not clear if the other wells are safely secured. Batch drilling programs, by nature, are subject to repetitive flaws. Flaws encountered on H1 could have been repeated in the other wells, and this warrants inquiry. The Commission of Inquiry should also examine whether similar well safety concerns could exist on other offshore platforms.

The Commission of Inquiry is directed to the "Conclusions and Recommendations" section of this report for recommendations on additional points of inquiry. Most of the detailed technical analysis is found in response to Term of Reference No. 3, and is not repeated here for efficiency.

## 5. Term of Reference No. 2

*"Review the adequacy and effectiveness of the regulatory regime applicable to operations at or in connection with the Montara oil field, including under the Offshore Petroleum and Greenhouse Gas Storage Act 2006, and including the adequacy and effectiveness of all safety, environment, operations and resource management plans, and other arrangements approved by a regulator and in force at relevant times."*

<sup>21</sup> PTTEP, Submission No. 1000.0001.0041-42

<sup>22</sup> PTTEP, Submission No. 1000.0001.0041

**Elimination of Prescriptive Standards:** It is recommended that the Commission of Inquiry seriously consider whether the elimination of prescriptive standards was a root cause of this incident.

In 2004 Australia revised its oil and gas regulations [*Australian Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004*] to remove the requirement to meet Australia's longstanding list of prescriptive technical standards found at *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production*.

In 2006, Australia's laws pertaining to offshore oil and gas development were amended to address greenhouse gas issues. The 2004 *Australian Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004* are required by *The Offshore Petroleum and Greenhouse Gas Storage Act 2006* and are administered by the DA for this case.

As a more "modern" alternative to a prescriptive list of standards, in 2004, Australia decided to allow industry substantially more flexibility in preparing their applications. The 2004 *Australian Petroleum (Submerged Lands) (Management of Well Operations) Regulations* set a goal of promoting new technology and new best practices, but merely required the operator to demonstrate that its application met "good oil field practice."

In theory, the 2004 regulatory scheme can work, but its success is dependant on an applicant that is experienced, trained, and qualified to select and implement the best available technology and practices (i.e. "good oil field practice"). It's also dependant on the agency approving the application being staffed with personnel who are experienced, trained, and qualified to determine if "good oil field practice" has, in fact, been selected, and who are also capable of making any needed recommendations for alternative solutions and practices.

In the event that the applicant is not experienced, trained, and qualified to make that initial assessment, or for reasons of cost control, time saving, or other business advantage, the applicant does not propose "good oil field practice," it is then incumbent on the agency to make some very difficult decisions on the permit application.

At a minimum, the agency must engage in a technical debate with the applicant about what truly is "good oil field practice." A technical debate can be challenging for agency staff when faced with late, rushed applications and highly paid oil and gas staff and consultants contending their application is worthy of approval. Nonetheless, agency staff must be able to make the difficult decision of denying the application, or approving it subject to "good oil field practice" stipulations. Agency staff must have the expertise and qualifications to defend their position and provide high quality advice to industry.

In Australia, the approving agency (the "Designated Authority" (DA)) is also the resource development agency. The DA has the unenviable position of promoting oil and gas development while also constraining its implementation by permit approvals and denials. This dual mission creates the stage for potential conflicts of interest.

**Lack of Agency Review and Approval Criteria to Support 2004 Regulations:** It is recommended that the Commission of Inquiry evaluate the agencies' technical review standards and the criteria used to support the new 2004 regulations. The question of whether the lack of clear technical standards for the staff to rely on was a root cause of this incident should be further investigated.

While the DA contends throughout its submittal that PTTEP's applications met "good oil field practice" consistent with the 2004 regulatory standard, the DA did not provide any technical, written engineering assessment to support this conclusion. And although the DA may have in its record a technical finding document that clearly articulates why it believes PTTEP's H1 applications met the "good oil field practice" standard, that technical finding (if it so exists) was not provided. A technical document that supports the DA's conclusion that PTTEP's applications met "good oil field practice" is a critical piece of information needed for this inquiry.

**Critical Technical Analysis Documents Missing from DA Submittal:** A written, technical engineering assessment of the Montara H1 well applications and an agency decision of fact and finding was nowhere to be found in the hundreds of pages of agency submittals to the Commission of Inquiry. The DA submittals asserted that "good oil field practice" was met, but no technical documents or other evidence to support that conclusion was provided.

In its submittals the DA provides a full copy of the pre-existing *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* (replaced in 2004 by the more generic "good oil field practices" showing standard), but it does not explain why these standards were not, at least in part, reviewed or relied upon when assessing the H1 applications. If agency staff did not consult these longstanding Australian technical standards, what standards did they use to evaluate the H1 applications?

The 2004 regulations establish undefined regulatory standards, subject to broad discretion, debate, and interpretation. Whereas, prescriptive standards provide basic, fundamental, minimum standards that serve as a regulatory "floor." Minimum standards can be improved on by applying "good oil field practice" when the applicant demonstrates to the agency that a technique or standard exceeds the "floor." This method is the basis for most international oil and gas regulation; international systems are founded on the idea of "best practice."

For example, Norway's regulations<sup>23</sup> allow new technology and methods to be used, but require careful review and testing of those methods before use.

*"Section 8, Qualification and use of new technology and new methods*

*Where the petroleum activities **involve use of new technology or new methods, criteria shall be prepared with regard to development, testing and use in order to fulfill the requirements to health, environment and safety.** The criteria shall be representative of the relevant operational conditions, and the technology or the methods shall be adapted to already accepted solutions.*

***Qualification or testing shall demonstrate that applicable requirements can be fulfilled by use of the relevant new technology or new methods** [emphasis added]."*

<sup>23</sup> Relating to Design and Outfitting of Facilities in the Petroleum Activities ("The Facilities Regulations") of the Petroleum Safety Authority Norway (PSA), Norwegian Pollution Control Authority (SFT), Norwegian Social and Health Directorate (NSHD).

**“Good Oil Field Practice”:** The DA’s submittals to the Commission of Inquiry do not detail any engineering manuals, databases, lists, or regulatory guidance documents that staff relied on to make the determination that the Montara H1 applications met the “good oil field practices” standard.

As explained more thoroughly later in this document,<sup>24</sup> if the basic minimum engineering standards listed in *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* were used, the well suspension application would have required a series of cement plugs in the casing, meeting a minimum “two-barrier” industry well control standard, and likely averting this incident.

The 2004 regulations should have been supported by technical guidance for agency staff to use when making a “good oil field practice” determination. Major revisions to Australia’s regulatory regime for oil and gas operations, such as what occurred in 2004, should have been coupled with a rigorous review of international regulation regimes, to determine the successes and pitfalls of abandoning minimum prescriptive technical standards.

**International “Good Oil Field Practice”:** Other international regulatory systems for oil and gas development include fundamental prescriptive engineering principles and standards, as a minimum threshold, while providing “regulatory flexibility” by allowing an operator to propose new technology or practices for agency review that “meet or exceed” the basic minimum principles.

Throughout this analysis, examples of international oil and gas regulations are cited from Norway, Canada, and USA, as examples of regulatory systems that couple a basic prescriptive list of standards with the opportunity for the operator to improve on those standards by applying to use a technology or practice that exceeds the minimum prescriptive standards. In this way, there is at least a minimum standard that must be met, with no debate.

Agencies should routinely amend their list of prescriptive standards to keep up with new technology and practices as they evolve, but even if the prescriptive list of standards is outdated in the regulations, this does not prevent agency personnel from adding a more stringent requirement in the approval decision, if they become aware of new “good oil field practices” prior to formal adoption of regulatory amendments.

**Root Cause:** The fundamental question to be answered by the Commission of Inquiry is whether PTTEP’s application to fill H1 with brine and place a temporary cap (PCCC) on it was “good oil field practice.” A review of minimum regulatory standards from Norway, Canada, and the USA, which is provided below, without question shows that it is not. ALERT Well Control’s final assessment of H1 as “controlled and secured” with a “two-barrier” plug system installed is further evidence that the initial plan did not meet “good oil field practice.”

Canada’s regulations provide an example to draw from. Canada’s Oil and Gas Drilling and Production Regulations require:

*“WELL CONTROL*

35. *The operator shall ensure that adequate procedures, materials and equipment are in place and utilized to minimize the risk of loss of well control in the event of lost circulation.*

36. *(1) **The operator shall ensure that, during all well operations, reliably operating well control equipment is installed to control kicks, prevent blow-outs and safely carry out all well activities***

<sup>24</sup> See sections on Terms of Reference No. 3 and No. 4.

**and operations, including drilling, completion and workover operations.**

(2) *After setting the surface casing, the operator shall ensure that **at least two independent and tested well barriers**<sup>25</sup> **are in place during all well operations.***

(3) ***If a barrier fails, the operator shall ensure that no other activities, other than those intended to restore or replace the barrier, take place in the well.***

(4) *The operator shall ensure that, during drilling, except when drilling under-balanced, one of the two barriers to be maintained is the drilling fluid column.*

37. *The operator shall ensure that pressure control equipment associated with drilling, coil tubing, slick line and wire line operations is pressure-tested on installation and as often as necessary to ensure its continued safe operation.*

38. *If the well control is lost or if safety, environmental protection or resource conservation is at risk, the operator shall ensure that any action necessary to rectify the situation is taken without delay, despite any condition to the contrary in the well approval” [emphasis added].<sup>26</sup>*

PTTEP’s attempt to argue that the 244mm (9-5/8”) PCCC and brine constitute a “two-barrier” system is clearly faulty. The PCCC does not constitute an adequate independent well barrier, as part of a “two-barrier” system. And even if one were to assume that the 244mm (9-5/8”) PCCC did somehow constitute an adequate independent well barrier, as part of a “two-barrier” system, once it was removed, there was no longer a two-barrier system in place. This is a clear breach of “good oil field practice.”

According to Canadian regulation at § 36(3), in the event of a failed barrier, no other activities other than those intended to restore or replace the barrier should take place. Diverting the *West Atlas* rig and crew to the G1 and H4 wellhead tie-in jobs, leaving H1 uncapped, without a “two-barrier” system in place, was a clear breach of “good oil field practice,” according to Canadian standards.

To establish “good oil field practice,” multiple plugs should have been set downhole to create a “two-barrier” system, or a BOP with the capability to pull the 244mm (9-5/8”) PCCC through the BOP, thereby maintaining continuous control during the well re-entry procedure, should have been installed.

Clearly PTTEP’s well control experts, ALERT Well Control, understand the concept of what constitutes an industry standard “two-barrier” control system. ALERT Well Control finally secured H1 with kill mud, cement, and a two barrier plug system made up of two mechanical plugs (one set at 2,000m and a second at 1,800m); ALERT Well Control tested the mechanical plugs the well, and then placed a PCCC on the well.<sup>27</sup> From this submission, it is very clear that ALERT Well Control does not recognize a PCCC as a primary well control barrier that should be used to meet one to the two barrier control system components.

Additionally, Canada requires well completions to meet the following standards:

**“WELL COMPLETION**

46. (1) *An operator that completes a well shall ensure that*  
 (a) ***it is completed in a safe manner** and allows for maximum recovery;*

<sup>25</sup> Whereas, “barrier” is defined in Canadian Regulation as “...any fluid, plug or seal that prevents gas or oil or any other fluid from flowing unintentionally from a well or from a formation into another formation.”

<sup>26</sup> Canada Oil and Gas Drilling and Production Regulations, effective December 2009.

<sup>27</sup> PTTEP, Submission No. 1000.0002.0025

- (b) *except in the case of commingled production, each completion interval is isolated from any other porous or permeable interval penetrated by the well;*
- (c) *the testing and production of any completion interval are conducted safely and do not cause waste or pollution;*
- (d) *if applicable, sand production is controlled and does not create a safety hazard or cause waste;*
- (e) *each packer is set as close as practical to the top of the completion interval and that the pressure testing of the packer to a differential pressure is greater than the maximum differential pressure anticipated under the production or injection conditions;*
- (f) *if practical, any mechanical well condition that may have an adverse effect on production of oil and gas from, or the injection of fluids into, the well is corrected;*
- (g) *the injection or production profile of the well is improved, or the completion interval of the well is changed, if it is necessary to do so to prevent waste;*
- (h) *if different pressure and inflow characteristics of two or more pools might adversely affect the recovery from any of those pools, the well is operated as a single pool well or as a segregated multi-pool well;*
- (i) **after initial completion, all barriers are tested to the maximum pressure to which they are likely to be subjected;** and
- (j) *following any workover, any affected barriers are pressure-tested [emphasis added].”*

Additionally, Canada requires offshore wells to be installed with an extra measure of protection once they are completed as production wells (this holds true for Norway and the USA as well):

*“SUBSURFACE SAFETY VALVE*

47. (1) *The operator of an **offshore development well capable of flow** shall ensure that the well is equipped with a fail-safe subsurface safety valve that is designed, installed, operated and tested to prevent uncontrolled well flow when it is activated [emphasis added].”*

Of note, Norwegian Regulations require operators to identify the barriers required to prevent risk.

*“Section 1, Risk reduction*

*In risk reduction as mentioned in the Framework Regulations Section 9 on principles relating to risk reduction, the party responsible shall choose technical, operational and organizational solutions which reduce the probability that failures and situations of hazard and accident will occur.*

*In addition barriers shall be established which*

- a) *reduce the probability that any such failures and situations of hazard and accident will develop further,*
- b) *limit possible harm and nuisance.*

**Where more than one barrier is required,** *there shall be **sufficient independence** between the barriers.*

**The solutions and the barriers that have the greatest risk reducing effect shall be chosen based on an individual as well as an overall evaluation. Collective protective measures shall be preferred over protective measures aimed at individuals**” [emphasis added].<sup>28</sup>

“Section 2, Barriers

*The operator or the one responsible for the operation of a facility, shall stipulate the strategies and principles on which the design, use and maintenance of barriers shall be based, so that the **barrier function is ensured throughout the life time of the facility.***

**It shall be known what barriers have been established and which function they are intended to fulfil, cf. Section 1 on risk reduction, second paragraph, and what performance requirements have been defined in respect of the technical, operational or organisational elements which are necessary for the individual barrier to be effective.**

*It shall be known **which barriers are not functioning or have been impaired.***

*The party responsible shall take necessary actions to correct or compensate for missing or impaired barriers [emphasis added].”*

According to Norway’s regulations at § 2, the barrier function must continue **uninterrupted**. Clearly diverting the *West Atlas* rig and crew to the G1 and H4 wellhead tie-in jobs, leaving H1 uncapped and without a “two-barrier” control system in place, was a clear breach of “good oil field practice.”

Norway’s Petroleum Safety Authority Regulations<sup>29</sup> require the following barriers and risk management systems to be put into place as best industry practice for preventing accidents at an offshore facility.

“Section 47, Well barriers

**Well barriers shall be designed such that the well integrity is ensured and the barrier functions are working as intended in the lifespan of the well.**

**Well barriers shall be designed so that unintentional well influx and outflow to the external environment is prevented, and so that they do not obstruct well activities.**

**When a well is temporarily and permanently abandoned, the barriers shall be designed so as to provide for well integrity for the longest period of time that the well is expected to be abandoned, inter alia so that outflow from the well or leakages to the external environment do not occur.**

**When a well is plugged, it shall be possible to cut the casing without harming the surroundings.**

**Well barriers shall be designed so that their performance can be verified [emphasis added].”**

<sup>28</sup> Norwegian Petroleum Directorate Regulations Relating to Management in the Petroleum Activities (the Management Regulations), 2001.

<sup>29</sup> Regulations Relating to Design and Outfitting of Facilities in the Petroleum Activities (“The Facilities Regulations”) of the Petroleum Safety Authority Norway (PSA), Norwegian Pollution Control Authority (SFT), Norwegian Social and Health Directorate (NSHD).

“Section 48, Well control equipment

**Well control equipment shall be designed and shall be capable of being activated so as to provide for barrier integrity as well as well control.** In the case of drilling of top hole sections with riser or conductor, equipment with capacity to conduct shallow gas and formation fluid away from the facility until the personnel has been evacuated shall be installed.

Floating facilities shall have an alternative activation system for activating critical functions on the blow out preventer for use in the event of evacuation.

Floating facilities shall also have capacity to disconnect the lower marine riser package after the shear ram has cut the work string.

The pressure control equipment used in well interventions shall have remote control valves with mechanical locking devices in closed position. The well intervention equipment shall have a remote control blind/shear ram as close to the christmas tree as possible [emphasis added].”

“Section 53, Equipment for completion and controlled well flow

**Equipment in the well and on the surface shall be designed to handle controlled well flow,** cf. section 11 on materials.

**The well flow line and the annulus shall be equipped with necessary down hole safety valves (SCSSV) and with necessary equipment to monitor well parameters.**

During well testing it shall at all times be possible to control the well flow through the work string and the choke manifold [emphasis added].”

“Section 54, Christmas tree and well head

**Christmas trees and well heads shall be designed so as to provide for prudent production, re-entry, well intervention and well control.**

The christmas tree shall have at least two main valves, and at least one of these shall be of an automatic type [emphasis added].”

**Lack of Coordinated Safety Review:** The Montara Platform Topside Module installation delay should have triggered a multi-agency safety and environmental assessment to examine the potential risks associated with the newly proposed batch drilling program and new Topside Module installation plans. The inability to immediately tie newly drilled wells in to the platform wellhead control system significantly increased the risk factor for the Montara wells. The lack of a coordinated, peer-reviewed technical, safety, and environmental assessment to evaluate and identify the risks of this major design change appears to have contributed to the incident.

Australian regulations require numerous safety, environmental, and technical assessments to be completed by various agencies; yet the quality of the assessments, the level of communication between agencies, and potential “gaps” between regulatory jurisdictions are worthy of inquiry.

The agency submittals from the DA, the National Offshore Petroleum Safety Authority (NOPSA), and the Offshore Resources Branch, Resources Division, Commonwealth Department of Resources, Energy and Tourism (RET) indicated a lack of coordinated review. Technical review of well completion plans, temporary well suspension plans, and re-entry procedures appeared to be hurried, incomplete, and absent of safety and environment agency peer review.

Major, late changes in the Montara Platform Topside Module installation schedule, well design, and wellhead control tie-in plans and procedures appears to have contributed to hastily prepared engineering and safety design plans.

NOPSA's submittal stated that the DA failed to conduct a proper technical review before issuing decisions on the H1 applications. NOPSA believes it would be better suited to serve as the approving agency in the future, but NOPSA's submittal does not explain if its safety review of the Topside Module addressed the delay in well control system tie-ins as a major potential well control risk. Nor did NOPSA explain if its safety review identified the fact the increase in rig moves needed to complete a batch drilling and completion program would increase risk to the topside facility and the safety of rig personnel (for which NOPSA has clear responsibility).

NOPSA denies any responsibility for well safety issues and points out this is a DA responsibility. . Yet, NOPSA does not explain how the increased risk to personnel resulting from the delayed Topside Module was satisfactorily mitigated by its *Safety Case* approval. As described later in this paper, it appears that these issues materially contributed to the incident, and therefore warrant inquiry.

**Drilling Delay Should Have Been Considered for Risk Mitigation:** The Commission of Inquiry should consider if the Montara wells were actually drilled from top to bottom and tied into the Topside Module wellhead control system as originally planned, instead of drilled in a batch drilling program, would this incident have been averted? Should the drilling program have been delayed until the Topside Module was available?

Agencies assigned to carry out oversight responsibilities must have mutual professional and technical respect for one another. They must effectively communicate and call on each other to provide technical assistance and peer-review. And they must conduct multi-agency review processes that bridge potential "gaps" between regulatory jurisdictions. It appears that the lack of agency coordination materially contributed to the incident. This warrants inquiry.

By comparison, Norway's regulations<sup>30</sup> require the operator to conduct a risk analysis of ***what affect drilling and well activities will have on the total risk*** of the facilities. This is clearly an area that NOPSA and the DA should be working together on to examine the entire Montara Platform Development as a whole.

Norway regulations read:

*"Section 14, Analysis of major accident risk*

***Quantitative risk analyses and other necessary analyses shall be carried out to identify contributors to major accident risk, including showing***

a) ***the risk connected with planned drilling and well activities, and show which effect these activities have on the total risk on the facility.***

<sup>30</sup> Norwegian Petroleum Directorate Regulations Relating to Management in the Petroleum Activities (the Management Regulations), 2001.

- b) *the effect of modifications and the carrying out of modifications on the total risk,*
- c) *the risk connected with transportation of personnel between the continental shelf and shore and between facilities.*

*The analyses shall in addition be used to set conditions for operation and to classify areas, systems and equipment with respect to risk” [emphasis added].*

Coordinated risk analysis and safety review required by Norway’s regulations<sup>31</sup> seeks a lower risk design:

*“Section 4, Design of facilities*

*Facilities shall be based on robust and the simplest possible solutions and shall be designed so that*

- a) *they can withstand loads as mentioned in Section 10 on loads, load effects and resistance,*
- b) the major accident risk becomes as low as practically possible,**
- c) failure of a component, a system or one single mistake does not lead to unacceptable consequences,**
- d) *the main safety functions, as mentioned in Section 6 on main safety functions, are maintained,*
- e) *transport and handling of materials can take place efficiently and safely, cf. Section 12 on handling of materials and transport routes, access and evacuation routes,*
- f) *provision is made for a sound working environment, cf. Chapter III-II on design of work areas and accommodation spaces,*
- g) *operational prerequisites and limitations are duly complied with,*
- h) *there are adequate provisions in place to ensure health and hygiene on board,*
- i) *provision is made for the lowest possible risk of pollution,*
- j) *provision is made for fully satisfactory maintenance.*

*Measures to protect facilities against fire and explosion shall be based on a strategy.*

*The areas on the facility shall be classified in such way that design and location of areas and equipment contribute to reducing the risk related to fire and explosion.*

*Areas where personnel are staying, or where equipment of significance to safety is placed, shall not be within reach of waves with an annual probability greater than  $1 \times 10^{-2}$ . [emphasis added]”*

*“Section 7, Safety functions*

**Facilities shall be equipped with necessary safety functions** *which at all times are able to*

- a) **detect abnormal conditions,**
- b) **prevent abnormal conditions from developing into situations of hazard and accident,**
- c) **limit harm in the event of accidents.**

*Requirements to performance shall be set in respect of safety functions.*

*The status of safety functions shall be available in the central control room [emphasis added].”*

<sup>31</sup> Norwegian Petroleum Directorate Regulations Relating to Management in the Petroleum Activities (the Management Regulations), 2001.

“Section 32, Emergency shutdown systems

Facilities shall have an **emergency shutdown system which is able to prevent situations of hazard and accident from developing and to limit the consequences of accidents**, cf. Section 7 on safety functions. The system shall be able to perform the intended functions **independently** of other systems.

The emergency shutdown system shall be designed so that it will go to or remain in a safe condition in the event of a failure which may prevent the functioning of the system. The emergency shutdown system shall have a simple and unambiguous command structure. The system shall be capable of being activated manually from release stations located at strategic places on the facility. It shall be possible to activate functions manually from the central control room so that the facility is brought to a safe condition in the event of failure in the programmable parts of the system.

Emergency shutdown valves shall be installed which are capable of stopping streams of hydrocarbons and chemicals to and from the facility, and which isolate the fire areas on the facility [emphasis added].”

“Section 9, Plants, systems and equipment

Plants, **systems and equipment shall have a design which is robust** and as simple as possible, so that

- a) **the possibility of human errors or mistakes is limited**,
- b) they or it can be **operated, tested and maintained without danger to personnel and with the lowest possible pollution risk**,
- c) they are or it is suitable for use and capable of withstanding the loads they or it may be subjected to during operation.

Plants, systems and equipment shall be marked in order to provide for safe operation and fully satisfactory maintenance [emphasis added].”

**Emergency Pre-planning:** Well control of a catastrophic well blowout is serious, highly technical, dangerous work. Relief well and well capping plans should be developed prior to drilling a well. During a catastrophic emergency, there is insufficient time to be searching for well control experts, starting well control plans from the beginning, or negotiating contracts for relief well rigs. This must be done in advance to expedite emergency response.

Other countries, such as Norway, Canada, and the USA, require oil spill plans and well control plans (including relief well and well capping plans) to be prepared, reviewed, and approved in advance of drilling and completion operations. The H1 oil spill plan was approved **after** the first phase of the well was drilled, and H1 relief well implementation was delayed while a rig was located and transported to the site.

Drilling relief wells (or conducting well capping operations) is very serious, highly technical, dangerous work. Plans for a relief well (or well capping operation) must be thought out in advance of drilling a well. While a detailed, technical plan with exact specifications cannot be developed until an incident actually occurs, the operator can produce basic well control plans. The operator can also pre-identify and pre-arrange terms with well control experts and relief well rigs. Negotiating with experts and rig operators

while an emergency is occurring diverts the operator's response focus to contractual arrangements, which delays response and limits options.

## 6. Term of Reference No. 3

*“Assess the performance of relevant persons<sup>32</sup> in carrying out their obligations under the regulatory regime.”*

PTTEP's submittal to the Commission of Inquiry<sup>33</sup> states that it manages well integrity risks by using:

- (1) PTTEP Well Construction Standards;
- (2) PTTEP Well Construction Management System; and
- (3) PTTEP Well Operations Management Plan.

PTTEP states that its Well Construction Standards include standards for all aspects of well design, construction, testing, abandonment, and intervention that involve a risk to safety, quality or integrity.<sup>34</sup> PTTEP's Well Construction Standards, Well Construction Management System, and Well Operations Management Plan were not available for this review. These documents are needed for the inquiry.

PTTEP states that its Well Operations Management Plan (WOMP) meets the *2004 Australian Petroleum (Submerged Lands) (Management of Well Operations) Regulations*.<sup>35</sup>

**Topside Installation Delay:** Montara Wellhead Platform Topside Module installation delay appears to have resulted in major, late changes to the well design and completion plans, and appears to be a significant contributing factor to the well blowout.

The Montara Wellhead Platform was made in two parts: (1) Jacket and (2) Topsides Module. The original plan was to install the Topsides Module in July-August 2008.<sup>36</sup> The Topsides Module was not installed in 2008, as planned. Instead, only the Jacket was installed at the Montara field location, and secured in place by September 2008.<sup>37</sup> Absent the Topsides Module, the wells could not be drilled and tied-in directly to the wellhead control system. The Topsides Module was not installed until August 7, 2009.<sup>38</sup>

This change in installation schedule triggered a major change in well completion plans. Rather than drilling the well from start to finish (continuously equipped with a blowout preventer stack), the well was only partially drilled. Drilling stopped once intermediate casing was set. The well was temporarily suspended, awaiting installation of the Topsides Module.

**Hasty Well Planning:** The well planning effort appears to have been constrained by a short timeframe. A major late change in platform facility installation plans triggered major changes in well design. This, coupled with a transition of operators, appears to have lead to hasty well planning.

<sup>32</sup> Relevant persons are persons who have engaged at any time in petroleum-related operations at the Montara Wellhead Platform that may have contributed to the cause(s) of the Uncontrolled Release, including but not limited to: the titleholder or a former titleholder of AC/L7 permit, a present or former owner or operator of the Montara Wellhead Platform, a present or former owner or operator of a drilling rig, a drilling contractor or a supplier or installer of plant or equipment.”

<sup>33</sup> PTTEP, Submission No. 1000.0001.0002

<sup>34</sup> PTTEP, Submission No. 1000.0001.0002

<sup>35</sup> PTTEP, Submission No. 1000.0001.0002

<sup>36</sup> PTTEP, Submission No. 1000.0001.0036

<sup>37</sup> PTTEP, Submission No. 1000.0001.0036

<sup>38</sup> PTTEP, Submission No. 1000.0001.0037

The Designated Authority (DA) for the Territory of Ashmore and Cartier Islands offshore area was delegated to the Northern Territory Department of Regional Development, Primary Industry, Fisheries and Resources (DRDPFR), hereinafter referred to simply as “DA.”

H1 was spudded<sup>39</sup> on January 18, 2009.<sup>40</sup> The well plan was submitted to the DA in November 2008. Thus, the well plan was submitted just two months prior to spud.

The application to suspend H1 was submitted on March 6, 2009. The DA gave approval to suspend the well on March 9, 2009. According to both the DA’s records<sup>41</sup> and Atlas Drilling submission, **the well was actually suspended on March 7, 2009**, which was **two days before PTTEP received DA approval to suspend the well**.

**Hasty Well Suspension Revisions:** Further inquiry is needed on why H1’s suspension plan was submitted so late, and why such a hurried, hasty approval was requested on March 6, 2009. Why was the original November 2008 well suspension plan, which included additional cement barriers, not used?

This means PTTEP submitted a new, revised well suspension plan one day before it planned to actually suspend the well on March 7, 2009, providing the agency with inadequate time for technical review or approval. It is not clear why well suspension plans and procedures changed, from what they were agreed to back in November 2008 when H1 was originally approved.

According to PTTEP’s submission, it appears that the original H1 well permit approval of November 2008 required additional cement plugs to be placed in the 244mm (9-5/8”) intermediate casing string prior as part of the temporary abandonment procedure; [although this fact needs to be confirmed by inspection of the actual permit application and DA approval documents that were not made available for public review]. This conclusion is reached based on PTTEP’s statement that:

*“At the time of the March 2009 suspension, an amendment to the Drilling Program was implemented by the Well Construction Manager and Drilling Superintendent (in accordance with the Change Control requirement in the Well Construction Standards) to **replace the 244mm cement plug with the 244mm pressure containing corrosion cap and the 340mm pressure containing corrosion cap** [emphasis added].”<sup>42</sup>*

Incongruously, the DA concluded that removing the cement barrier from the well suspension plan would not “*affect the physical aspect of the wellbore*”. The DA concluded:

*“On 6 March 2009, PTTEP submitted an application for the Stage 1 suspension of the Montara H1-ST1 well and advice of a change to the well plug from cement to a pressure containing cap. The Director of Energy as delegated of the Designated Authority **determined that the change to the well plug did not affect the physical aspect of the wellbore so as to attract application of reg 17(1) of the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004**, and no further approval was necessary for that purpose...Approval was subsequently granted pursuant to reg 17(1)(d) in accordance with the PTTEP letter of 6 March 2009...<sup>43</sup> [emphasis added].”*

<sup>39</sup> Commenced drilling.

<sup>40</sup> PTTEP, Submission No. 1000.0001.0034

<sup>41</sup> DA, Submission No. 4000.0001.0481

<sup>42</sup> PTTEP, Submission No. 1000.0001.0045

<sup>43</sup> DA, Submission No. 4000.0001.0017

This explanation from the DA is confusing because Reg 17(1) requires DA approval for any change to a well suspension plan. PTTEP submitted a change to a well suspension plan pursuant to Reg 17(1), and the DA ultimately approved it two days after that well was actually suspended.

**Well Suspended Without Agency Approval in Place:** PTTEP should not have proceeded with an actual change to the H1 well suspension procedure without advanced agency approval.

Under *Australian Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004* at § 17 (1)(d) a well may not be physically suspended until the suspension procedure is approved by the DA.

*“17Approval*

*(1) A titleholder must not commence any of the following well activities, that lead to the physical change of a wellbore, without the approval of the Designated Authority:*

- (a) well drilling;*
- (b) testing;*
- (c) well completion;*
- (d) abandonment or suspension of a well;*
- (e) well intervention[emphasis added].”*

According to PTTEP’s and DA’s records this requested change was made on March 6, 2009, and actually implemented on March 7, 2009, without DA approval. According to the DA’s records, the DA approved this change (to replace the 244mm cement plug with the 244mm pressure containing corrosion cap and the 340mm pressure containing corrosion cap) via approvals issued on March 9, 2009<sup>44</sup> and later again on March 13, 2009 after-the-fact.

The reasons for this late application and hasty approval should be investigated. As well as the reasons for why PTTEP and Atlas Drilling suspended the well without DA approval of the procedure.

While, ultimately, the DA approved an inadequate temporary well suspension plan. A late revision to the suspension procedure and a hurried technical review by the DA may have contributed to this decision making.

**After-the-Fact Approvals Should Not Be Granted:** The DA should not have issued an after-the-fact approval allowing the H1 temporary suspension plans to be modified, and the cement plugging requirements to be eliminated.

The DA should not have approved the application after-the-fact. Not only was PTTEP’s March 6, 2009 application to change the H1 temporary suspension plans inconsistent with “good oil field practice” that is based on a minimum “two-barrier” control system, but also PTTEP’s actions to actually, physically make this change at the well, absent agency approval, is in clear contradiction to Australian regulation. The DA receives daily drilling reports, and should have known that this well was already suspended before it issued its approval. This brings into question how closely the DA was actually watching the Daily Drilling Reports on H1 as it was drilled.

<sup>44</sup> DA, Submission No. 4000.0001.0481

PTTEP states that well H1 was drilled and completed according to the following documents:<sup>45</sup>

- PTTEP's Drilling Program entitled "Montara GI, H1 & H4 (Batch Drilled) Drilling Program Document Number TM-CR-MON-B-150-00001 Rev 0" dated **September 2008**.
- PTTEP Well Operations Management Plan Document for H1 Number TM-CR-MON-G-150-00002 Rev 0 dated **November 7, 2008**, approved 8 business days later on November 19, 2008.<sup>46</sup> This application is for the Top Hole Section of the well only up to an including setting 244mm (9-5/8") intermediate casing and temporarily suspending the well until the Topside Module was available for the well to be tied-in.

The DA reports a **revision** to the Batch Drilling Program for wells H1, GI and H4 was submitted on **January 7, 2009**.<sup>47</sup> PTTEP does not list this permit application. The DA does not state when this revision was approved, or what the design change included. This revision came only 11 days before H1 was spudded on January 18, 2009. The DA states that this revision did not "...*affect the physical aspect of the wellbore, so no further approval was necessary.*"<sup>48</sup> The purpose and the nature of the amendment is unclear warranting further review. Again, no actual applications or amendments were provided for public review, therefore it is not possible to independently confirm the significance of the January 7, 2009 change.

- PTTEP submitted **applications to suspend H1 on March 6, 2009 and March 12, 2009**.

PTTEP only provides the dates that the H1 well suspension applications were submitted to the DA; it does not disclose when they were approved. The DA does disclose the date it approved the H1 suspension application; it was **March 9, 2009**, two days after the well was actually suspended.<sup>49</sup>

The DA lists a subsequent approval on March 13, 2009, approving a second amendment to a well suspension procedure for a well that had been physically suspended 6 days prior, on March 7, 2009.

**H1 Phase 1 Drilled Without Requisite Environment Plan:** It appears that first Phase of the H1 well was drilled without the required Environment Plan approved by the DA.

The DA reports that it received a letter from PTTEP on April 8, 2009 seeking confirmation as to whether or not the Montara H1 Environmental Plan had been approved. The DA reports that the Environmental Plan was assessed by the Senior Petroleum Operations Officer, who recommended its approval by the Director of Energy. Approval was granted on **April 9, 2009**. Therefore, ***the Environment Plan for H1 was approved three months after the well was spudded*** on January 18, 2009. This was the second after-the-fact approval made by the DA for H1. Why was an Environment Plan not in place when H1 was drilled? What is the point of an after-the-fact environmental plan? This issue warrants further inquiry.

**Oil Spill Plan Not Approved:** The H1 oil spill plan was not approved by DEWHA until March 6, 2009, after the first phase of the well was drilled.

Oil spill plans and well control plans (including relief well and well capping plans) should have been prepared, reviewed, and approved in advance of drilling and completion operations. The H1 oil spill plan was not approved by DEWHA until March 6, 2009, after the first phase of the well was drilled. Phase 1

<sup>45</sup> PTTEP, Submission No. 1000.0001.0033

<sup>46</sup> DA, Submission No. 4000.0001.0013

<sup>47</sup> DA, Submission No. 4000.0001.0013

<sup>48</sup> DA, Submission No. 4000.0001.0016

<sup>49</sup> DA, Submission No. 4000.0001.0014

drilling for H1 started on January 18, 2009 and ended on March 7, 2009. There was no approved oil spill plan in place during that time.

**Lack of Technical Review on H1 Phase 2 Re-entry Plan:** H1's phase 2 re-entry plan was approved in four business days, with no apparent technical or safety peer review by RET or NOPSA.

PTTEP reports that it submitted the "Montara Phase 1B Drilling and Completion Program Document Number TM-CR-MON-B-150-00003 Rev 0" in June 2009. This document served as the permit application for the drilling program for the horizontal reservoir sections of the H1 well. This application apparently covered the re-entry in H1 to tie in the well and drill out the remaining section of the well beyond the 244mm (9-5/8") casing and into the production zone. Again, this actual permit application or approval was not available for public review, and warrants Commission of Inquiry verification as to scope and approval requirements.

The DA lists this same permit application as being received on July 7, 2009, rather than in June 2009. This discrepancy shows the importance of the Commission of Inquiry obtaining all the original documents for its own review. Absent a copy of the original documents, it is not possible to verify which date is correct.

Nonetheless, the DA shows that it issued a rapid approval in only *four* business days, on July 13, 2009.<sup>50</sup> The quick turnaround brings into question the thoroughness of the DA's technical review, and explains why no other agencies opinions were sought for peer-review (but should have been).

**Key Well Data:** H1 was drilled to a total depth of 3,796m (12,454') with three strings of casing.

H1 was drilled to a depth of 3,796m (12,454').<sup>51</sup> The casing program included:

- **Conductor casing:** 155m (508') of 508mm (20") casing cemented from the casing shoe to the surface;<sup>52</sup>
- **Surface casing:** 1,637m (5,371') of 340mm (13-3/8") casing cemented from the casing shoe to the surface; and<sup>53</sup>
- **Intermediate casing:** 3,796m (12,454') of 244mm (9-5/8") casing cemented from the 9-5/8" casing shoe back up to the 13-3/8" casing.<sup>54</sup>

The gas-oil contact was located at 2,609m (8,560') True Vertical Depth (TVD).<sup>55</sup>

Major mud losses were encountered through the Lower Johnson and Upper Puffin formations from 1,707m (5,600').

<sup>50</sup> DA, Submission No. 4000.0001.0013

<sup>51</sup> PTTEP, Submission No. 1000.0001.0036

<sup>52</sup> PTTEP, Submission No. 1000.0001.0034

<sup>53</sup> PTTEP, Submission No. 1000.0001.0035

<sup>54</sup> PTTEP, Submission No. 1000.0001.0036

<sup>55</sup> True vertical depth

**Intermediate Casing Setting Depth:** Intermediate casing is typically set **prior** to drilling through the hydrocarbon-bearing zone to transition the surface casing to the production casing for protection of oil, gas, and freshwater zones, and **to seal off** anomalous pressure zones, **lost circulation zones**, and other drilling hazards. It appears, based on the data provided, that intermediate casing was set over a zone of lost circulation and a hydrocarbon bearing zone. Based on the severity of the lost circulation problems, an additional string of intermediate casing may have been warranted prior to drilling into the hydrocarbon zone. Multiple strings of intermediate casing are necessary in some cases.

Intermediate casing is typically set prior to drilling through the hydrocarbon-bearing zone, and is commonly used as a transition from the surface casing to the production casing for protection of oil, gas, and freshwater zones. Intermediate casing is also used to seal off anomalous pressure zones, lost circulation zones, and other drilling hazards. A drilling engineer may need to set hundreds or thousands of feet of intermediate casing to: isolate unstable hole sections (to prevent collapse); isolate high or low pressure zones; isolate geologic “thief” zones prone to robbing mud from the well bore (lost circulation); put gas or saltwater zones behind pipe before drilling into the production zone; or provide additional wellbore structure.

**H1 Casing Design:** The H1 well design, which included setting a single string of intermediate casing at a high angle across a known thief zone into a high pressure hydrocarbon bearing zone to a depth of 3,796m (12,454’), warrants technical scrutiny.

PTTEP’s submission verifies that the H1 244mm (9-5/8”) intermediate casing shoe was not set above the hydrocarbon interval. Instead the hole was drilled to make room to set the intermediate casing cut through 1,187m (3,894’) of the hydrocarbon zone, at a high angle direction. The intermediate casing was set deep, well beyond the serious reported mud losses at 1,706m (5,597’). It passed through the gas-oil contact at 2,609m (8,560’) and went 1,187m (3,894’) more into the hydrocarbon zone, landing about 3m (10’) above the oil-water contact. Thus, the intermediate casing essentially penetrated the entire hydrocarbon bearing zone.

Rather than serving as a transitional casing to put the lost circulation zones at 1,706m (5,597’) behind pipe, the intermediate casing had to both contain the problematic lost circulation zone, and also serve as casing for a long horizontal section through the pressurized hydrocarbon zone.

Section 503 of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* included prescriptive instruction on how to appropriately design the casing setting depth. Because this prescriptive standard is no longer in place, it is not clear what casing setting depth criteria was used in the design of this well. However, this point is worthy of further investigation.

**High angle Casing Strings are Difficult to Cement:** High angle sections of casing are notoriously difficult to cement. High angle casing strings often require additional remedial cementing treatment, careful evaluation, and intervention if a cement seal is not initially obtained.

The inability to initially obtain a cement seal at the base of the well (in the casing shoe track) could have created a pathway for hydrocarbons to enter the well from the bottom. However, it is common knowledge in the oil and gas industry that high angle sections of casing are notoriously difficult to cement. High angle casing strings often require additional remedial cementing treatment, careful evaluation, and intervention if a cement seal is not initially obtained.

After an initially failed cement job, there was no indication that any quality control or quality assurance procedures were taken to verify the remedial actions to address cement failure were successful. In addition to addressing the failed casing shoe float valve, PTTEP should have also questioned the quality of cement achieved behind pipe in the high angle section of the well.

**Live Wells:** All wells drilled into hydrocarbon zones must be treated as live wells, with the potential to flow hydrocarbons to the surface, unless technical evidence is collected to prove otherwise.

The complexity of this well and the mere fact that it penetrated a pressured hydrocarbon zone containing gas and oil should have warranted PTTEP and Atlas Drilling to treat this well as a “live” well, with potential for hydrocarbon flow. The need for pressure barriers to be installed to “safe-out” the well while it was suspended, and the need to set a BOP as part of the re-entry procedure, should have been standard well control procedure.

PTTEP states that its Montara Batch Drilling Program does not call for setting BOPs until further along in the program, after the existing casing and conductor strings are tied back and the production wellhead is installed.<sup>56</sup> Clearly this plan is not appropriate for wells where the intermediate casing shoe is set 3m (10’) above the water-oil contact and the casing string is set through 1,187m (3,894’) of hydrocarbon zone, lacking a “two-barrier” control system. This is especially true when known cementing failures have occurred to the only cement plug in place at the base of the well.

PTTEP also reports that “the Atlas Drilling Manual” does not call for the setting of BOPs until immediately before the commencement of drilling at the highest known hydrocarbon-bearing interval in the well trajectory, as assessed at the time of well design and recorded in the Drilling Program.<sup>57</sup> Atlas Drilling is silent on its standard procedure for re-entry and doesn’t explain why it did not use a BOP or recommend one in light of the H1 well history (which it was fully aware of since it drilled the first part of H1).

PTTEP and Atlas Drilling penetrated the hydrocarbon interval in early 2009.<sup>58</sup> Fundamental petroleum engineering principles and practices include the need to maintain well control throughout the well drilling, completion, suspension, and production processes. Once the hydrocarbon zone is penetrated, the alert status for that well is elevated. The well becomes a “live” well, and must be treated as such. Temporary barriers can fail. A redundant system of well control barriers is industry practice.

Although intermediate casing and cement may be set, they don’t create a fail-proof containment system. Best industry practice is to **never** rely solely on annular cement, casing, and brine (inside the casing) to contain a well that has been drilled to a total depth of 3,796m (12,454’), with 1,187m (3894’) passing through the hydrocarbon zone.

**Blowout Preventer (BOP):** A BOP should have been set for H1 re-entry because: the well had already been drilled through 1,187m (3,894’) of the hydrocarbon interval; the well had known cement integrity issues; the well had no additional cement plugs set in the casing; and the well

<sup>56</sup> PTTEP, Submission No. 1000.0001.0043

<sup>57</sup> PTTEP, Submission No. 1000.0001.0043

<sup>58</sup> The drilling log was not available for review but it is estimated that this occurred in February 2009, based on the other sequence-of-event information provided.

had no other surface well control installed. H1 was a “live” production well, warranting a BOP stack to be set for well re-entry.

PTTEP’s plan was to re-enter H1 and later drill out an additional horizontal production interval below the intermediate casing shoe. But as a first step, PTTEP apparently directed *West Atlas* to tie all the Montara wells back into the topside wellhead control system.

It is not clear why PTTEP decided to complete a batch tie in procedure, moving the rig from one well to the next. Risk increases with each surface intervention and rig move.

Nor is it clear why the increased risk associated with batch drilling and tie-in operations was not examined by the DA or NOPSA. While NOPSA states it doesn’t have an obligation to review well control plans, its scope of authority does include the platform facilities and safety of rig personnel, and these multiple rig moves would clearly increase risk to those personnel and facilities.

Section 505(7)(a) of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* historically provided prescriptive instruction on the use of BOPs:

*“The blow-out prevention equipment is not removed until the well has been adequately sealed.”*

Furthermore, any planned re-entries for additional drilling (such the phase 2 H1 drilling program to drill below the intermediate casing) would have required a BOP by Section 505(4).

***Safety Case Review for WHP Installation:*** A thorough review of the WHP installation and well hook-up *Safety Case* review is warranted.

It appears that NOPSA had some role in the WHP Hook-up safety review, but without access to the actual *Safety Case* documents, it is not clear whether NOPSA’s review covered the risk associated with batch drilling and the late well tie-ins due to the Topside Module installations delay. Further inquiry is needed on this point.

PTTEP’s submission does reference the following *Safety Case* approvals received from NOPA:<sup>59</sup>

- **March 5, 2008** Application for acceptance of Montara Facilities Construction and Installation Safety Case, submitted December 7, 2008.
- **August 18, 2008** Application for acceptance of Montara WHP Hook-up & Pre-Commissioning Safety Case, submitted June 25, 2008.
- **June 16, 2009** Application for acceptance of **revision 2** Montara WHP Hook-up & Pre-Commissioning Safety Case, submitted May 15, 2009

<sup>59</sup> PTTEP, Submission No. 1000.0001.0051.

**Number of Well Interventions:** Batch drilling and completion work increases the number of rig moves, and the number of well interventions, increasing risk. Leaving H1 unattended and incomplete, and the rig personnel’s attention focused on the GI and H4 tie-in operations, appears to be a significant contributing factor to this incident.

A logical plan would have been to move the derrick over H1, install a BOP, and complete that well, including the remaining drilling, production casing, and tie-in operations. Beginning work on the H1, disassembling what little protection systems were in place, and then moving the rig off to tie in other wells, leaving H1 unattended and incomplete, and the rig personnel’s attention focused on the GI and H4 tie-in operations, appears to be a significant contributing factor to this incident.

If batch operations must be employed, safety precautions must be taken to ensure that wells are safely secured between each step. Wells should never be left unsecured, as rig operators are routinely diverted to attend to other simultaneous batch operations.

**Temporary Plugging Protocol:** Montara H1 well was not suspended using best industry practices or following longstanding Australian regulatory standards.

The Montara production wells were drilled four to eight months (4-8) prior to being tied-in to the Montara Wellhead Platform. H1 was suspended for approximately 5.5 months. (It was drilled from January to March 2009; tie-in operations started in August 2009). Cement plugs were originally planned to be placed in H1 when it was suspended, but ultimately they were not installed.

While the 2004 Australian oil and gas well regulations, allow industry substantially more flexibility to demonstrate that it is using “good oil field practice,” prior to that time Australian regulations relied on the minimum technical standards listed in *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production*. The basic standards of this schedule are consistent with industry standards and essentially mirror USA standards. While some new technology has been developed since these specific standards were crafted by the Australian government, the basic fundamental engineering principles hold.

**Section 514:** If the prescriptive Australian standard at § 514 was still in place, as a minimum standard, a series of cement plugs would have been installed in the well, averting disaster.

Section 514 of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* historically provided prescriptive instruction on temporary abandonment of cased wells:<sup>60</sup>

**“In a cased hole containing a liner string or strings, a cement plug shall be placed immediately above each liner string hanger to extend at least 30 metres above the liner string hanger. A surface cement plug extending at least 45 metres in height shall be placed in the innermost casing string which extends to the seabed with the top of the plug at a depth no greater than 45 metres below the seabed. The location and integrity of cement plugs shall be verified in an approved manner. Any intervals of cased hole in a well between cement plugs shall be filled with mud fluid of appropriate density suitably inhibited to prevent the corrosion of casing string [emphasis added].”**

<sup>60</sup> The Petroleum (Submerged Lands) Act 1967, Schedule: Specific Requirements as to Offshore Petroleum Exploration and Production – 1995; November 2005 Electronic Consolidation.

Because this prescriptive standard is no longer in place, it is not clear what temporary abandonment criteria was used to design or approve the temporary abandonment. The drilling application and approval documents were not provided for public review as part of this inquiry. However, this point is worthy of further investigation.

**Section 515:** If the prescriptive Australian standard at § 515 was still in place, as a minimum standard, well control would have been required at the surface as part of the well re-entry procedure.

Section 515 of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* required wells to be suspended using Section 514 (unless otherwise approved) and “approved equipment and protection devices shall be installed on the well head to facilitate future re-entry of the well.”<sup>61</sup>

There is nothing in Section 515 that says temporary suspension of an offshore well from a jack-up rig, using a mudline suspension system should only include brine in the casing and a temporary abandonment cap on top of the casing.

Instead of following Australian Offshore Petroleum Exploration and Production standards, PTTEP:

- hung the 244mm (9-5/8”) intermediate casing and 340mm (13-3/8”) surface casing off on the Mud Line Suspension (MLS) system;<sup>62</sup>
- left inhibited seawater in the hole (weighted brine specifications were not provided);<sup>63</sup>
- installed a corrosion cap<sup>64</sup> on the 244mm (9-5/8”) intermediate casing; and<sup>65</sup>
- installed a trash cap<sup>66</sup> on the on the 508mm (20”) intermediate casing.<sup>67</sup>

PTTEP acknowledges that it did not install a corrosion cap on the 340mm (13-3/8”) surface casing,<sup>68</sup> which was required by the H1 suspension application approval.<sup>69</sup> However, PTTEP attributes the failure to place the corrosion cap on the 340mm (13-3/8”) surface casing to the *West Atlas* Drilling Supervisor.<sup>70</sup>

PTTEP points out that the DA approved the H1 well suspension application, but does not highlight that this approval didn’t come in writing until two days after PTTEP had already physically suspended H1 using its new, unilaterally designed suspension techniques.<sup>71</sup> Surprisingly, the DA agreed to a H1 suspension without a “two-barrier” control system, two days later.

PTTEP does not explain or provide any evidence to support that the application to eliminate cement plugs from the H1 temporary well suspension procedures was consistent with “good oil field practice.” Both PTTEP and the DA make this assertion without support or evidence. Further inquiry is needed.

<sup>61</sup> The Petroleum (Submerged Lands) Act 1967, Schedule: Specific Requirements as to Offshore Petroleum Exploration and Production – 1995; November 2005 Electronic Consolidation.

<sup>62</sup> PTTEP, Submission No. 1000.0001.0036

<sup>63</sup> PTTEP, Submission No. 1000.0001.0029

<sup>64</sup> Also commonly referred to in the oil and gas industry as temporary abandonment caps for a mudline suspension system.

<sup>65</sup> PTTEP, Submission No. 1000.0001.0036

<sup>66</sup> Cylindrical device closed on one end that fits over the conductor casing to keep debris out of the well.

<sup>67</sup> PTTEP, Submission No. 1000.0001.0036

<sup>68</sup> PTTEP, Submission No. 1000.0001.0036

<sup>69</sup> PTTEP, Submission No. 1000.0001.0037

<sup>70</sup> PTTEP, Submission No. 1000.0001.0043

<sup>71</sup> PTTEP, Submission No. 1000.0001.0037

PTTEP contends that setting a Pressure Containing Corrosion Cap (PCCC) on top of the 244mm (9-5/8") intermediate casing, instead of setting cement plugs inside the 244mm (9-5/8") intermediate casing, provided better ability to check the well pressure.<sup>72</sup> This explanation is inadequate. PCCCs are temporary abandonment caps used to cover the hole and prevent debris from entering the wellbore. They are not substitutes for downhole cement plugs or mechanical barriers placed in the well to control hydrocarbon flow. PCCCs should not be counted as one of the "two-barrier" elements.

PTTEP should have set both the cement plugs and the PCCCs. These are not mutually exclusive actions. Both prevention measures could have been instituted.

PTTEP also argues that placing a cement plug increases the risk of damaging the 244mm (9-5/8") intermediate casing when the cement plug is drilled out.<sup>73</sup> Drilling out a cement plug, with a BOP in place, is a small risk in comparison to leaving the well with no well control. Cement plugs are commonly set and drilled out; this is a routine procedure.

PTTEP does not explain why it would be so risk averse to drilling out a cement plug, but was willing to accept the catastrophic risk potential of leaving a well unsecured while it sent the rig to tie-in other wells.

It is not clear how PTTEP's risk and safety evaluation criteria and review system works. The logic behind PTTEP's decision to rank drilling out a cement plug as "risky," while, at the same time, electing to batch drill wells (which increases well risk due to multiple well re-entries and multiple rig moves) is unclear. Further inquiry on this point is needed.

**Batch Drilling Risk:** A more conservative approach, from a risk reduction standpoint, would be to avoid batch drilling, and instead drill each well from start to finish, using a BOP control system uninterrupted. In this case, well control would be transferred from the BOP stack to the wellhead control systems at the final tie in.

On September 15, 2009, during the H1 blowout, *The Australian Newspaper*<sup>74</sup> quoted Chief Financial Officer Jose Martins (PTTEP) as stating that Montara H1 well was equipped with a series of plugs and 20 meters of cement, so there must be a fracture in the Montara H1 well allowing a sophisticated system of plugs and concrete to be bypassed. Thus, preliminary reports indicated that the procedure used to temporarily suspend the Montara H1 well failed. Now, with new information from PTTEP, this assertion appears to be incorrect. PTTEP now verifies that it did not set a "sophisticated system of plugs and concrete" in the intermediate casing, as required by Australian regulation.

Atlas Drilling states that PTTEP's Well Construction Standards requires a long-term suspended well (defined as when the drilling rig leaves the site) to have two permanent tested barriers installed in the annulus and wellbore above any hydrocarbon zone or over a pressured zone. These could include a pressure tested cement plug, permanent packer with no controlled internal flow path and cement on top, cemented casing with proven top of cement, hanger packer, tubing seals, and annular master valve.<sup>75</sup> PTTEP has not explained to the Commission of Inquiry why these procedures were not followed, nor has it provided copies of its standards for Commission review. PTTEP's Well Construction Standards, along with Atlas Drilling's Well Construction Standards, should be provided for inquiry.

<sup>72</sup> PTTEP, Submission No. 1000.0001.0044

<sup>73</sup> PTTEP, Submission No. 1000.0001.0045

<sup>74</sup> <http://www.theaustralian.news.com.au>, "Slow-motion Disaster", September 15, 2009.

<sup>75</sup> Atlas Drilling, Submission No. 1501.0001.0003

There was no additional pressure tested cement plug set in the 244mm (9-5/8") intermediate casing, no permanent packer, no evidence of cement evaluation tools to examine the top of cement in the 244mm/340mm casing annulus, no hanger packer, no tubing installed seals, and no annular master valve installed.

**Drilling Contractor's Responsibilities:** The drilling contractor has a responsibility to provide technical advice to its client to ensure that the well is drilled safely and personnel are kept out of harms way.

While Atlas Drilling points out that PTTEP did not follow its own Well Construction Standards that require a long-term suspended well to have two permanent tested barriers installed in the annulus and wellbore above any hydrocarbon zone or over a pressured zone, Atlas is silent on its own well construction standards. According to Atlas Drilling's standards, should a BOP have been in place on well H1 as part of the re-entry procedure?

Atlas Drilling drilled and suspended H1 and was fully aware of challenging reservoir conditions encountered (e.g. lost circulation zone, hydrocarbons and failed casing shoe valves). Moreover Atlas Drilling was physically responsible for suspending H1 and was in possession of a March 12, 2009 change order clearly stating that additional cement plugs were not placed in well H1. Atlas Drilling's submission clearly shows it knew the 340mm (13-3/8") PCCC was missing and the 244mm (9-5/8") cement job was compromised.

When Atlas Drilling removed the 244mm (9-5/8") intermediate casing temporary cap (PCCC), it was aware the lack of controls in place on H1.

Why did Atlas Drilling agree to remove the temporary cap (PCCC) without a BOP in place? Was this contrary to Atlas Drilling's own standard operating procedures, and well control certifications held by its drilling foremen?

Why did Atlas Drilling agree to leave H1 uncapped and move over to work on the GI and H4 well tie-ins, if they had concerns about the control status of the H1 well?

What does Atlas Drilling's (or PTTEP's) operating procedures say about how to "safe-out" a well before moving a rig to another well?

How do the steps taken by Atlas Drilling staff comport with Atlas Drilling's health, safety, environment, drilling, and completion procedures? Does the business climate in Australia allow for, or even encourage, contractors to point out concerns or make safety recommendations to the operator? Can the drilling contractor refuse to take unsafe steps, even if directed by the operator? Are these safe-practice and open-reporting behaviors encouraged or penalized?

Section 513(2) of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* included the prescriptive standard that:

*"...(W)hile drilling operations are being undertaken on a platform, **a well shall not be left in a conditions which in the opinion of the person in command of the platform or the Director, is unsafe.** Prior to the cessation of drilling operations, **even temporarily,** the **well shall be made safe in accordance with good oilfield practice**" [emphasis added].*

Section 513(3) requires that the well be secured at the surface.

Why the drilling contractor and operator left a well unsecured at the surface and moved on to work on other wells, is a critical issue for this inquiry.

**Change Orders:** Major changes in the H1 temporary suspension plan should not have been issued in a change order 5 days after-the-fact.

Atlas Drilling contends that on January 18, 2009, when they spudded (started) H1, the well suspension plan included a 9-5/8" casing shoe and a shallow set cement plug from 160 meters to 115 meters with inhibited seawater above and below the plug.<sup>76</sup> This document needs to be provided for inquiry.

Atlas Drilling reports that on March 12, 2009, PTTEP formally issued a change control order to alter the well suspension plan to leave out a cement plug and only install a 244mm (9-5/8") intermediate casing PCCC.<sup>77</sup> Atlas Drilling also reports that this change order was issued five (5) days after the well had already been suspended on March 7, 2009.<sup>78</sup>

The purpose of a change order is to effectively communicate and obtain the required approvals for operating plans prior to conducting work. Change orders provide instruction from the operator to the contractor.

Typically an important step in a change order review process is to ensure that health, safety, and environmental procedures have been followed, all government regulations have been achieved, and good engineering practices have been followed. This is the time for the contractor to question the technical, safety or environmental aspects of what it is being asked to do by the operator.

Major changes in the temporary suspension well plan should not have been issued in a change order five (5) days after-the-fact, because this action completely defeats the benefit of the change order review and approval process.

One of the basic responsibilities of the drilling contractor is to ensure the safety of its employees. This means that if a problem becomes apparent, the onus is on the drilling contractor to bring its concerns to the attention of its client. If the operator is unwilling to address or resolve the concerns, the drilling contractor needs to report the problem to the appropriate agencies for immediate resolution. Legal reporting requirements for unsafe acts or safety violations is outside the scope of this technical review, but inquiry should ensure that there are sufficient protections in place for individual employees, as well as companies, to freely report safety concerns. Adequate legal protections need to be in place to prevent repercussions to those reporting safety violations. Commission of Inquiry review into these areas is also suggested.

**Failure to Carry Out Approved Suspension Plan:** Failure to install the 340mm (13-3/8") surface casing PCCC delayed H1 tie-in to the Montara Wellhead Platform control system.

Installation of a 340mm (13-3/8") surface casing PCCC was required as part of the March 12, 2009 H1 temporary well suspension approval. Failure to install the 340mm (13-3/8") surface casing PCCC

<sup>76</sup> Atlas Drilling, Submission No. 1501.0001.0002

<sup>77</sup> Atlas Drilling, Submission No. 1501.0001.0002

<sup>78</sup> Atlas Drilling, Submission No. 1501.0001.0002

apparently contributed to rust and scale buildup on the 340mm (13-3/8") surface casing threads, delaying the tie-in to the Montara Wellhead Platform control system.

According to the PTTEP<sup>79</sup> report, thread cleaning operations were required to remove the rust and scale buildup. Atlas Drilling<sup>80</sup> reports that PTTEP drilling supervisors directed the removal of the 244mm (9-5/8") corrosion cap to clean the 340mm (13-3/8") surface casing threads. Atlas Drilling<sup>81</sup> questions the decision to remove the 244mm (9-5/8") corrosion cap for the thread cleaning operation, and questions why the 340mm (13-3/8") surface casing corrosion cap was not installed. PTTEP contends that it was not physically possible to properly clean the 340mm (13-3/8") surface casing threads without removing the 244mm (9-5/8") corrosion cap.<sup>82</sup>

**West Atlas Should Have Stayed with H1:** The rush to move the rig from H1 to tie in other wells (GI and H4) left the H1 well unattended and unequipped to rapidly commence well plugging or other well intervention operations.

Why was PTTEP in such a rush to move the *West Atlas* to another well (GI), and then to production well H4? Why didn't PTTEP clean the 340mm (13-3/8") surface casing threads and move quickly to tie in the well? It is not clear why PTTEP would move the rig from H1 to GI to H4, while a problem on H1 lingered.

The DA reports that PTTEP provided a letter on August 26, 2009 that confirmed a wellhead brush tool was used to clean up the threads on the 340mm (13-3/8") and 244mm (9-5/8") mud line suspension systems. The letter also confirmed that at the same time as these cleaning operations were performed, the 508mm (20") conductor casing was installed and rough cut on H1. The *West Atlas* was then skidded over to the GI well, and was later taken to the H4 well, to conduct tie-in operations. Meanwhile, the H1 well was left uncapped, and unattended, while the drilling staff's attention was focused elsewhere.<sup>83</sup>

PTTEP has no explanation for why the 244mm (9-5/8") intermediate casing corrosion cap was not replaced prior to skidding the derrick to the GI well. PTTEP merely states that "seawater remained in the H1 well in order to create a pressure barrier."

While brine provides a hydrostatic head (counter balancing force) to aid in containing reservoir pressure, basic petroleum engineering courses teach that a weighted brine must *never* be used alone to contain reservoir pressure associated with a well that has been drilled through a pressurized hydrocarbon interval. This is especially true for a well drilled 3,796m (12,454') into the earth with a 1,187m (3,894') high-pressure hydrocarbon zone sitting behind the intermediate casing.

When the well blowout occurred, Atlas Drilling reports that plans were made to run PTTEP's cementing contractor's RTTS packer in well H1 to secure it; yet, there was a delay in doing this because the 20" casing that had just been cut off from H4 first needed to be laid down, and then the rig had to be moved back to H1.<sup>84</sup> In the end, the RTTS packer was never placed in H1 and the well continued to blowout. The *West Atlas* should have been left over H1 until the well was properly secured. The fact that the *West Atlas* was working on H4 when the blowout started on H1, delayed emergency response actions, and limited

<sup>79</sup> PTTEP, Submission No. 1000.0001.0038

<sup>80</sup> Atlas Drilling, Submission No. 1501.0001.0005

<sup>81</sup> Atlas Drilling, Submission No. 1501.0001.0006

<sup>82</sup> PTTEP, Submission No. 1000.0001.0038

<sup>83</sup> DA, Submission No. 4000.0001.0008

<sup>84</sup> Atlas Drilling, Submission No. 1501.0001.0006

response options. This is why simultaneous high risk operations should not be conducted by the same drilling crew.

**MLS Cap Removal Timing:** Options to clean the 340mm (13-3/8”) surface casing threads should have been thoroughly examined, and a safe plan should have been developed. Removal of the 244mm (9-5/8”) intermediate casing PCCC without a safety review is not industry best practice.

Removing the trash and PCCC caps on a well, and opening it to atmosphere to clean surface casing threads, with no rig over top and no well control plan in place, is not industry best practice. More information is needed to determine if a thread cleaning plan was developed, if it underwent any safety review, and what it might have contained. None of that information is apparent in PTTEP’s submittal. It is not clear why the PCCC cap would be removed until a safe plan was developed and approved.

**Safe PCCC Removal Technology:** Industry has developed PCCCs that can safely be removed through a BOP or wellhead, maintaining continuous well control throughout the procedure.

To better understand how serious the error is that occurred on H1, one has to understand that with current technology there is no reason to remove the temporary abandonment cap (the PCCC), without having a continuous well control device installed. Vendors currently offer mudline suspension systems and temporary abandonment cap systems that can be installed through a BOP prior to disconnecting the intermediate casing riser. That same temporary abandonment cap can then remain in place while a tie-back wellhead is installed and tested. Once the tie-back wellhead is tested and determined to be safe, a temporary abandonment cap can be safely removed through the tie-back wellhead. Continuous well control is maintained throughout the process. At no time is the well left “uncapped” and open to the atmosphere using this technology.<sup>85</sup>

**Pressure Data:** Wellhead, casing and bottomhole pressure data is not provided. The pressure monitoring system in place at the time of the incident is unclear. All pressure data logs and H1 well drawings showing the exact location where pressure monitoring devices (permanent or temporary) were installed and functioning should be provided.

Both PTTEP and Atlas Drilling deny any evidence of surface wellhead or casing gas pressure at the time they re-entered H1. PTTEP states that after the 244mm (9-5/8”) corrosion cap was removed at 11:30 am on August 20, 2009 there was “no trapped pressure, gas or oil detected or observed.”<sup>86</sup>

Similarly, Atlas Drilling states that “...prior to removal of the 9-5/8 inch PCCC, the well was tested for pressure below the 9-5/8 inch PCCC.” Atlas Drilling reports that there was no pressure detected below the 9-5/8” PCCC. No pressure data logs or charts are provided in the submittals to support these statements.

Yet, PTTEP indicates that the corrosion cap on the 244mm (9-5/8”) intermediate casing may have had held a slight backpressure on the well sufficient to contain the flow, because when removed, it changed the pressure flow regime allowing higher bottomhole pressure fluids behind the 244mm (9-5/8”) intermediate casing to leak inside the well. PTTEP speculates that these fluids leaked though a poor

<sup>85</sup> Plexus Ocean Systems Ltd., manufactures one type of these MLS systems called the TRT-S Mudline Suspension System, GD-001, however, there are other vendors as well.

<sup>86</sup> PTTEP, Submission No. 1000.0001.0039

cement job in the casing shoe at the bottom of the well, into the 244mm (9-5/8") intermediate casing, and up to the surface of the platform floor.

Neither PTTEP nor Atlas Drilling explains the pressure monitoring system in place at the time of the incident. Surface pressure data is not provided. Pressure monitoring is a critical safety component of re-entering a suspended well; that data should be available. All pressure data and H1 well drawings showing the exact location where pressure monitoring devices (permanent or temporary) were installed and functioning should be provided to the Commission.

No information was provided on the average reservoir pressure or bottomhole pressure encountered while drilling to total depth (TD). There was no indication if a bottomhole pressure gauge was installed in the well to monitor the well pressure while suspended. This information should be provided for review.

**Safe Rig Moves:** Producing wells should be properly and safely secured, and pressure should be isolated, prior to moving a rig from one well to another on an offshore platform. Rig move procedures and proper well isolation procedures prior to rig moves warrants further examination.

Five and a half (5.5) hours after the 244mm (9-5/8") PCCC was removed [17:00 on August 20, 2009], the *West Atlas* was moved from H1 to the gas injection well (GI), and then later moved on to producing well H4, to tie those wells into the wellhead control system.

Information is needed to better understand PTTEP's and Atlas Drilling's rig move safety procedures.

The USA requires the operator to ***shut in*** all producible wells located in the affected wellbay below the surface and at the wellhead when: (1) a drilling rig or related equipment is moved on or off a platform, (2) a drilling unit is moved or skidded between wells on a platform, or (3) a mobile offshore drilling unit (MODU) is moved within 500 feet of a platform. This requirement applies to rigs and related equipment used during well-completion, well-workover, and well-decommissioning operations, as well as drilling operations.<sup>87</sup> The well must be shut-in below the surface with a pump-through-type plug, and at the surface with a closed master valve prior to moving well-completion and well-workover rigs and related equipment.

Norway's regulations<sup>88</sup> require the operator to carefully examine manning and competence. In this case, PTTEP hired the *West Atlas* crew to tie in H1. It appears that when complications arose on H1, the *West Atlas* rig, and the crew's attention, was diverted to tie in GI and H4, which created inadequate manning and resources at H1. The Commission of Inquiry should examine the decision making processes behind this series of events. Specifically, was cost savings a factor driving hurried rig moves and wells left in unsafe conditions?

Norway's regulations at § 11 prohibit manning of tasks that are incompatible with each other.

*Section 11, Manning and competence*

*The party responsible shall **ensure adequate manning and competence in all phases of the petroleum activities**, cf. the Framework Regulations Section 10 on organisation and competence.*

<sup>87</sup> Notice To Lessees And Operators of Federal Oil And Gas Leases and Pipeline Right-Of-Way Holders on the Outer Continental Shelf, Gulf Of Mexico OCS Region, NTL No. 2009-G25; United States Department of the Interior Minerals Management Service Gulf of Mexico OCS Region; August 26, 2009.

<sup>88</sup> Petroleum Directorate Regulations Relating to Management in the Petroleum Activities (the Management Regulations), 2001.

*There shall be set minimum requirements to manning and competence in respect of functions*

- a) *where mistakes may have serious consequences in relation to health, environment and safety,*
- b) *which shall reduce the probability of failures and situations of hazard and accident developing further,* cf. Section 1 on risk reduction and Section 10 on work processes.

*In the manning of the various work tasks it shall be **ensured that the personnel is not assigned tasks that are incompatible with each other.***

*The prerequisites that form the basis for the defined manning and competence, shall be followed up.*

*When changes in manning take place, possible consequences for health, environment and safety shall be reviewed” [emphasis added].*

**Gas Detection:** Gas detection data is not provided. The amount, location and type of the gas detection system devices (permanent or temporary) in place at the time of the incident are unclear. The Commission should request information on the location, type and readings from all gas detection equipment.

PTTEP’s time log states that 2 hours after the 244mm (9-5/8”) corrosion cap was removed [13:30 on August 20, 2009], “the H1 well was checked and no *smell* of gas was noted”<sup>89</sup> [emphasis added].

Later at 6.5 hours after the 244mm (9-5/8”) corrosion cap was removed [18:00 on August 20, 2009], PTTEP’s time log states that “the Night Drilling Supervisor visually inspected the H1 well from above and did not note any *smell* of gas.” No information was provided on what type of gas detection system was used (if any) to make this assessment. However, the use of the term “smell” indicates that PTTEP may be just referring to the use of human smell, via a nose, which is completely inadequate to detect low concentrations of natural gas.

There is no indication in the time log that the Night Drilling Supervisor measured the wellhead pressure or used properly calibrated gas detection equipment to check the well status. Nor do the records provide a clear understanding of who was responsible for H1 while the *West Atlas* was working on GI and H4. Further information on what operations were conducted on H1 (if any) while the drilling rig was at GI and H4 needs to be provided.

The records appear to indicate that H1 was just left, uncapped, open, and unattended, which, if true, is astounding. “Good oil field practices,” and standard safety procedures require hydrocarbon wells and potentially high pressure sources of oil and gas, or flammable and explosive vapors, to be isolated.

**Flow and Pressure Barriers:** The seriousness of the H1 well configuration on August 20, 2009 cannot be understated. No well should be left open to atmosphere, without surface well control, and redundant, multiple pressure isolation and/or barrier systems in place.

There was no surface well control. No blowout preventers were installed. And no wellhead control was in place because the well was not tied-back into the Montara Wellhead Platform control system.

<sup>89</sup> PTTEP, Submission No. 1000.0001.0039

PTTEP lists the pressure barriers in place during the H1 suspension as:

- (a) a cement shoe;
- (b) sea water;
- (c) 244mm (9-5/8") PCCC; and
- (d) 508mm Trash Cap.<sup>90</sup>

This list is not representative of industry standard best practice for elements qualifying for a “two-barrier” control system. The list should include: a wellhead control system, cement plug(s), mechanical plug(s), blowout preventers, etc.

The trash cap was removed off the 20” casing. The PCCC was removed off the 9-5/8” casing. The only materials listed in PTTEP’s well completion design that could provide any pressure containment were the casing, cement, and weighted brine left in the hole. But basic well control principles and best industry practices do not rely merely on casing, cement, and weighted brine to provide well control and prevent hydrocarbons from flowing uncontrolled at the surface. Additional barriers are required.

And while the brine, alone, should not serve as an adequate flow barrier, it must be designed to control subsurface pressures. Additives can be mixed in the brine to increase density.

Section 511(1) of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* included the prescriptive standard that:

*“The characteristics and use of the drilling fluid shall provide adequate control of any sub-surface pressures likely to be encountered in the well.”*

No information was provided on the actual weight of the brine left in the 244mm (9-5/8”) casing string, because the driller’s logs were not provided for public review as part of this inquiry. However, this point is worthy of further investigation.

**Float Collar Failure:** A failed float collar valve is a clear indication that a cementing integrity problem occurred. Unless steps were taken to remedy the cement job, and then independently verify the effectiveness of the remedial actions by additional evaluation tools, the integrity of the casing shoe cement plug at the base of H1 should have remained a concern, and a documented risk factor, for this well.

The float collar return valve failed during the 244mm (9-5/8”) intermediate casing job.<sup>91</sup> A float collar is a coupling with built-in float. It is placed near the bottom of a casing string to prevent the heavy cement column in the annulus from flowing back into the casing.<sup>92</sup> The float collar has a one-way valve that is designed to allow cement to flow into the annulus. The valve is supposed to prevent cement from back flowing into the wellbore. However, if the valve fails, cement will backflow into the wellbore, and the cement plug at the base of the well will be compromised.

After displacing the cement in the casing with mud, the casing between the float collar and the shoe should normally be full of cement. Simply put, if done correctly, the casing shoe track should be filled with cement, creating a solid cement plug at the base of the well to prevent hydrocarbon entry into the well. If the casing shoe track is not properly cemented, it creates a pathway for hydrocarbons to enter the

<sup>90</sup> PTTEP, Submission No. 1000.0001.0043

<sup>91</sup> PTTEP, Submission No. 1000.0001.0045

<sup>92</sup> International Centennial Scientific Drilling Program, <http://www.icdp-online.org>

well. In this case, the float collar return valve failed, allowing cement to come back up inside the 244mm (9-5/8") intermediate casing. This situation should have warranted extra concern since the 244mm (9-5/8") intermediate casing was seated only 3m (10') above the oil-water contact, putting the compromised cement job squarely at the base of the hydrocarbon zone.

PTTEP pumped 8 barrels of mud and pressured up to 27.6 Mpa (4,000 psi) to test the 244mm (9-5/8") intermediate casing cement shoe seal.<sup>93</sup> When the pressure was released, 16.5 barrels of fluid returned to the surface, clearly showing that the float collar return valve failed, and that a solid cement bond had not been achieved in the cement shoe track, because more volume returned than was pumped in.

PTTEP reports it instructed *West Atlas* to hold pressure on the casing (at an amount exceeding the Pore Pressure, but the exact pressure amount was not specified), in an attempt to force the cement back through the float shoe.<sup>94</sup> PTTEP reports that pressure was maintained (amount of pressure was not specified) until the cement was set (amount of time was not specified), and when pressure was bled off for the second time, no flow or differential was observed (no pressure charts or flow records were provided).<sup>95</sup>

The amount of pressure placed on the casing shoe to attempt to force the cement back into the shoe track, against a failed valve, and against the hydrocarbon formation pressure, needs further investigation. This pressure is not documented. Was this pressure so great that it potentially fractured the casing shoe, or fractured already partially hardened cement setting up in the annulus, creating a pathway for hydrocarbons to return back into the wellbore? Or did the pressure even exceed the casing burst pressure?

PTTEP reports that when they bled the pressure off for the second time that no flow or differential was observed, but a driller's log was not provided and it is unclear how long this situation was assessed, or if it was even thoroughly assessed.

Section 503(14)(a) of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* historically provided prescriptive instruction on pressure testing of intermediate casing. It required:

*"After cementing and before drilling out for the casing shoe, all surface and intermediate casing strings shall be pressure tested to the design burst pressure as in sub-clause (3)(a) but not exceeding 70% of the minimum internal yield pressure, and not less than 5550kPa."*

Section 503(14)(c) provided prescriptive instruction on how long, at a minimum to hold the pressure test:

*"Pressure tests shall be held for as long as necessary (but not less than 10 minutes) to ascertain that there is no continuous pressure drop, and the result recorded in the drillers log."*

Section 503(15) provided prescriptive instruction on the next step:

*"Drilling operations or operation to complete or test the well shall not commence until a satisfactory result in a pressure test pursuant to sub-clause (14) has been obtained."*

Because this prescriptive standard is no longer in place, it is not clear what pressure testing criteria was used because the drillers logs and cementing logs were not provided for public review as part of this inquiry. However, this point is worthy of further investigation.

<sup>93</sup> PTTEP, Submission No. 1000.0001.0045

<sup>94</sup> PTTEP, Submission No. 1000.0001.0045

<sup>95</sup> PTTEP, Submission No. 1000.0001.0045

**Cement Quality:** High grade cement is needed to obtain a high compressive strength bond, and prevent gas or hydrocarbons from “cutting” through the cement. Further investigation is needed into the cement quality and additives used.

The grade and density of cement is not specified.

Section 502 of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* required the prescriptive standard of API Specification 10, for Materials and Testing of Well Cements. Because this prescriptive standard is no longer in place, it is not clear what cement quality standard was used in the design of well H1. However, this point is worthy of further inquiry.

During the process of setting cement, it is possible for the well to have a hydrocarbon “kick” due to an imbalance in the density of the fluid column as compared to the reservoir pressure, allowing hydrocarbons to mix with the cement. Higher quality, higher density cement grades can be used in the design of a well to prevent this from occurring. More information should be obtained on the grade of cement and the additives used in H1.

There was no information in PTTEP’s submission to verify that the cement plugs and float equipment were compatible, and that the integrity of the shoe track (shoe and float) was checked on the platform deck prior to running it in the hole.

Casing shoe valves can fail, and when this happens remedial cementing action is required. Sometimes valves fail because they were manufactured faulty, but other times valves fail because of the conditions present in the hole. For example, if the valve is subject to extended periods of circulation and high pressure, the valve can washout.

As PTTEP did, the normal procedure is to hold pressure on the casing until surface cement samples are hardened to the required value. The pressure is then released to see if the cement holds. This remedial action is subject to minimum hold times and pressure guidelines.

While PTTEP took a common course of action to pressure up on the casing shoe until the cement set, it appears that it did not follow industry best practices to further evaluate the cement quality. And as pointed out above, there are a number of questions about the pressure and hold time procedures followed on the remedial repair. Further cement evaluation should have been standard procedure to determine if additional remedial action was necessary prior to suspending the well. Cement evaluation records (if performed) should be provided for inquiry.

Section 504(4) of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* historically instructed the operator to notify the DA of any faulty cementing operation.

“If there is any reason to suspect a faulty cementing operation, the Director shall be notified.”

Because this prescriptive standard is no longer in place, it is not clear what notification to the DA was done at time of the cementing problems. However, this point is worthy of further investigation.

**Cementing Procedures:** Further investigation of cementing procedures should occur.

There is very little information in PTTEP's submittal on its standard cementing procedures. For example, the number, type, and location of centralizers are critical to a successful cement job, and are not covered in PTTEP's submittal.

The lack of any submittal to the Commission of Inquiry by PTTEP's cementing contractor is noticeably absent.

Centralizers are necessary to center the casing in the hole and ensure that a concentric cement ring is placed around the pipe, sealing the annular space between the wellbore and the casing. Once the casing is set, there is still drilling fluid inside the casing and in the annular space between the casing and the wellbore wall. Drilling mud is displaced out of the hole by pumping cement down the inside of the casing and up the back side of the annulus.

Poorly centralized casing will allow the cement to bypass the drilling fluid, following the path of least resistance (usually down the wide side of the annulus), leaving drilling fluid behind the casing on the narrow side of the annulus; if this happens, a section of the annulus is not properly cemented/sealed. This can create a pathway for annular communication back into the wellbore, especially if the float shoe and float collar return valves are known to have failed. API standard 10D for casing centralizers is typically used as "good oil field practice." It is not clear what standard was actually used for H1.

**Cement Quality Evaluation:** Additional information is needed to understand what steps were taken to evaluate the cement quality prior to temporarily suspending H1.

A total length of 3,796m (12,454') of 244mm (9-5/8") intermediate casing was installed. Only the bottom portion of this casing was cemented in the hole. And it is unclear how well even the bottom portion of the casing was cemented.

While the plan was to cement 244mm (9-5/8") intermediate casing in place up the entire backside and 50m (164') into the 13-3/8" casing shoe to seal the 244mm/340mm annulus,<sup>96</sup> there wasn't any quality control information submitted to the Commission of Inquiry to demonstrate that this actually occurred.

Records submitted by the DA show the H1 well suspension diagram, and the amount of cement is unclear.<sup>97</sup> The annulus in some sections on this well suspension diagrams is labeled "L," but there is no key to indicate what the label "L" means. It is unclear if this means that liquid remained in the annulus in this area or not. This should be examined.

Moreover, PTTEP drilled through the gas-oil contact that was located at 2,609m (8,560') TVD<sup>98</sup> and encountered major mud losses through the Lower Johnson and Upper Puffin formations from 1,707m (5,600').

Cementing the casing annulus across a known "thief zone," where substantial mud losses occur, is known to be very difficult, because the same zone that robs mud in an overbalanced drilling situation will also rob cement as it is pumped up the annulus. It is highly likely that the top of the cement was not placed behind the 244mm (9-5/8") intermediate casing above the mud loss zone at 1,706m (5597'), and very likely that 244mm/340mm annular cement seal was not achieved 50m (164') into the 13-3/8" casing shoe.

<sup>96</sup> Atlas Drilling, Submission No. 1501.0001.0004

<sup>97</sup> DRDPiFR, Submission No. 1000.0001.0043

<sup>98</sup> True vertical depth

Additionally, PTTEP confirms that the 244mm (9-5/8") casing float shoe and float collar return valves failed, compromising the initial 244mm (9-5/8") cement job.<sup>99</sup> PTTEP reports it held pressure on the casing until the cement set. There does not appear to have been any quality control or quality assurance procedures completed (e.g. cement bond log, cement evaluation log, temperature log) or remedial cementing procedures conducted to assure or improve the cement bond quality. Although actual drilling logs and daily reports should be evaluated on this point, and were not available for public review.

The 244mm (9-5/8") intermediate casing was drilled at a high angle, which is very difficult to cement. Verification of cement integrity in a high angle well is a standard operating procedure, because often additional cementing is needed to fill the voids remaining after the first attempt.

There was no information provided on the actual top of cement (TOC) that was achieved behind the 244mm (9-5/8") intermediate casing and whether a good quality, continuous cement seal was achieved all the way up into the 340mm (13-3/8") surface casing.

The quality of the cement should have been further investigated prior to suspending the well to determine if PTTEP's remedial actions firmly cemented the 244mm (9-5/8") intermediate casing shoe and base in place, securing the bottom of the well and closing it off to any potential hydrocarbon entry.

There are numerous industry standard well logging techniques that can be used to examine the quality of the cement bond, including cement bond logs, cement evaluation tools, temperature logs, density logs, etc. There is no information in PTTEP's submission to the Commission of Inquiry showing that these standard quality control and assurance procedures were followed.

**Casing Quality:** Additional information is needed on casing quality.

Additional information is needed on the casing quality.

Section 502 of *The Petroleum (Submerged Lands) Act 1967, Schedule: Specific Requirements as to Offshore Petroleum Exploration and Production* included the API Specification 5, 5AX, and 5AC, for well casing quality. Because this prescriptive standard is no longer in place, it is not clear what casing quality standard was used in the design of this well because the actual H1 well design application and drillers logs were not provided for public review as part of this inquiry. However, this point is worthy of further investigation.

Pipe strength information should include burst strength, collapse resistance, and tensile strength, because to design a reliable casing string you must know the strength of the pipe under different load conditions.<sup>100</sup>

Information should be provided on whether the casing is new or used casing, and if used, the date, condition, and location of prior use and prior service history.

**Operator & Contractor Qualifications and Training:** Operator and contractor qualifications and training should be examined and compared to that required for the roles and tasks assigned.

PTTEP's submissions are silent on staff and contractor qualifications, training, and years of experience to carry out the roles and tasks assigned, with the exception of the ALERT well control staff.

<sup>99</sup> PTTEP, Submission No. 1000.0001.0036

<sup>100</sup> Petroleum Engineering Handbook, Volume II, Drilling Engineering, Society of Petroleum Engineers, 2006.

This inquiry should extend well beyond just an examination of staff proficiency and certification in well control. It should also examine all other aspects of the program; however, listed below is an example of the prescriptive qualifications and training standards that used to be in place in Australia for blowout control.

Section 508 of *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* historically required the prescriptive standard for blowout prevention training and drills to include:

- “(1) Blow-out prevention drills shall be conducted weekly for each drilling crew to ensure that all equipment is operating and that crews are properly trained to carry out emergency duties.*
- (2) All blow-out prevention drills and response times shall be recorded in the drillers log.*
- (3) There shall be displayed on the rig floor a notice providing details of the well control procedures proposed to be followed in the event that indications of a well kick are observed and all drilling crews shall be trained in those procedures.*
- (4) All on-site personnel holding the position of derrickman or more senior, shall attend, at least once every 24 months, an accredited well-control school or refreshers course in well-control and obtain a certificate of proficiency from such school or course. ”*

It is not clear if this type of well control training or certification was in place for the crew that drilled H1.

This example was provided as a key point of illustration; it is not an exhaustive list of the type of training and certification that is normally required for each aspect of a drilling and completion program. There are numerous other certifications and training requirements needed to safely drill and complete a well. They are too numerous to list here.

## **7. Term of Reference No. 4**

*“Review the adequacy and effectiveness of monitoring and enforcement by regulators of relevant persons, under the regulatory regime.”*

**Agency Oversight:** Agency inspection and oversight appears inadequate.

PTTEP’s submittal<sup>101</sup> states the Montara Wellhead Platform was installed in July 2008, and in September 2008 the *West Atlas* drilled and grouted the remaining piles for the jacket of the Montara Wellhead Platform. However, rather than staying at the Montara Wellhead Platform, during October 2008 through January 2009, the *West Atlas* carried out drilling operations for Vermillion and PTTEP at other exploration well locations.<sup>102</sup>

Between January 2009 and April 2009, the *West Atlas* batch drilled the Montara production wells (H1, H2, H3, H4)<sup>103</sup> and gas injection well (GI) down to the 244mm (9-5/8”) casing, and then suspended each well.<sup>104</sup>

<sup>101</sup> PTTEP, Submission No. 1000.0001.0033

<sup>102</sup> PTTEP, Submission No. 1000.0001.0034

<sup>103</sup> Atlas Drilling, Submission No. 1501.0001.0002

<sup>104</sup> PTTEP, Submission No. 1000.0001.0034

On April 21, 2009 the *West Atlas* left the Montara Wellhead Platform to conduct exploration drilling at other locations.<sup>105</sup>

On August 19, 2009 the *West Atlas* returned to the Montara Wellhead Platform to tie in H1, H2, H3, H4, and GI wells.<sup>106</sup>

PTTEP's submittal to the commission<sup>107</sup> states that there was *no inspection or audit of the Montara Wellhead Platform, the drilling rig operations while the West Atlas was over the Montara Wellhead Platform, or the well configuration after the wells were suspended*, and that "no enforcement action had been taken by any regulator in relation to the drilling work"<sup>108</sup> on the Montara Wellhead Platform.

PTTEP states that NOPSAs did conduct an inspection of the *West Atlas* rig from October 6-9, 2009 and that an Improvement Notice was issued by NOPSAs relating to the electrical equipment voltage.<sup>109</sup> This clearly indicates that NOPSAs's safety review scope does include rig related activities, which is a point NOPSAs tries to distance itself from in its submittal.

According to the timeline provided by PTTEP, this inspection would have occurred while the *West Atlas* was drilling at other exploration well locations. Thus, it appears that NOPSAs inspectors did not inspect the *West Atlas* while at the Montara Wellhead Platform operations.

PTTEP also notes that the Australian Commonwealth Department of Environment, Water, Heritage and the Arts (DEWHA) wrote to PTTEP on January 22, 2009 advising of a potential audit of the Montara 4, 5, and 6 wells under the Environmental Protection and Biodiversity Conservation Act of 1999 (EPBC Act).<sup>110</sup> That audit did not occur prior to the Montara H1 well blowout.

PTTEP states it invited the DA to conduct an onsite audit, but no date is provided for that invitation. PTTEP confirms that the audit did not take place prior to the Montara H1 well blowout.<sup>111</sup>

The DA reports that it:

*"...does not conduct physical inspections of operations or well infrastructure during routine operations."*<sup>112</sup>

If the DA does not inspect well operations, then which Australian agency does conduct these important compliance inspections?

The DA argues that:

*"...in line with contemporary regulatory practice the Territory does not conduct physical inspections of drilling and wellhead infrastructure during routine operations. The onus is on the operator to conduct its operations according to approved plans and work programs. Given the*

<sup>105</sup> PTTEP, Submission No. 1000.0001.0034

<sup>106</sup> Atlas Drilling, Submission No. 1501.0001.0004

<sup>107</sup> PTTEP, Submission No. 1000.0001.0056

<sup>108</sup> PTTEP, Submission No. 1000.0001.0056

<sup>109</sup> PTTEP, Submission No. 1000.0001.0056

<sup>110</sup> PTTEP, Submission No. 1000.0001.0056

<sup>111</sup> PTTEP, Submission No. 1000.0001.0056

<sup>112</sup> DA, Submission No. 4000.0001.0003

*‘round the clock’ nature of work on oil rigs, onsite monitoring would place a significant additional burden on both operators and regulators alike.*<sup>113</sup>

Surprisingly, even after a catastrophic blowout of this magnitude, the DA argues that:

*“...It would be possible to place government inspectors on rigs for the purpose of supervising operations and scrutinizing adherence to approved programs. The current regulatory regime allows for the appointment and placement of a petroleum project inspector for that purpose. As stated, however, that measure has not been adopted as part of the contemporary regulatory practice for routine operations. **The adoption of that measure [onsite inspections] would increase project and regulation costs, placing an additional burden on the operators and regulators** [emphasis added].”<sup>114</sup>*

**Routine Inspections and Audits:** Routine onsite inspections and audits are a critical component of a high quality regulatory program. Crafting stringent regulations is only one step in the process. Routine inspections and audits are needed to ensure that regulations and permit stipulations are followed, and to identify technical, safety, or environmental issues.

An initial inspection should have been performed after the Montara Wellhead Platform was installed in July 2008. The drilling rig should have been inspected prior to commencing drilling on the Montara Wellhead Platform, including testing of the blowout preventer system, and a review of well drilling and completion plans and procedures. Audits of drilling logs, casing and cementing records, pressure data, and other well completion records should have been completed between January 2009 and August 2009. And an onsite visit and/or records review (at a minimum) should have been completed in April 2009 to examine the condition of the suspended wells.

On August 21, 2009 the Montara H1 well blowout commenced.<sup>115</sup> Over one year had passed since the Montara Wellhead Platform was installed in July 2008, and not even one onsite inspection had taken place by NOPSA, DEWHA or NTDRDPIFR, according to PTTEP’s records. The agencies, don’t submit records to the contrary.

**Agency Approvals:** The DA’s approvals of H1 well applications are not consistent with “good oil field practices.” In some cases the approvals were issued after-the-fact, and decisions appear to lack a solid technical basis.

For efficiency, the concerns raised in Terms of Reference No. 1 in regards to the DA’s review and approval of the H1 well applications are not repeated here in Terms of Reference No. 4. But these concerns are equally applicable to Terms of Reference No. 4.

**Safety Case Facility Review:** Further investigation of the NOPSA *Safety Case* facility review should be conducted to examine whether the late arrival and late installation of the Topside Module warranted a thorough multi-agency technical and safety review.

Best practice is to ensure that adequate well control plans are in place, if wells are to be drilled and temporarily suspended before surface facilities (wellhead control systems) are constructed.

<sup>113</sup> DA, Submission No. 4000.0001.0012

<sup>114</sup> DA, Submission No. 4000.0001.0048

<sup>115</sup> Atlas Drilling, Submission No. 1501.0001.0007

NOPSA's submission to the Commission of Inquiry points to the DA's oversight failures a key factor in the H1 blowout. NOPSA points out that because the DA administers the *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004*, it was the DA that reviewed and approved PTTEP's Well Operations Management Plan (WOMP), not NOPSA.

NOPSA writes:

*Well integrity failures, arising from inadequate design or execution of the well plan and which were reflected in the titleholders documented submissions and reports, could have been detected by the DA though examination of that documentation.*<sup>116</sup>

NOPSA contends it has the expertise to take over the oversight responsibility for offshore wells, in addition to fulfilling its existing role as regulator of the occupational health and safety of people at or near offshore petroleum facilities.<sup>117</sup>

NOPSA does not explain how their *Safety Case* review of the Montara Platform Facility addressed the late arrival and late installation of the Topside Module, or how the late arrival of the Topside Module increased well related risk.

NOPSA does not explain what steps it took to advise the DA, RET, or DEWHA of that increased risk or to engage stakeholders in a coordinated review, or even engage individual peer-review as appropriate.

While NOPSA denies any responsibility for oversight of subsurface activities inside the wellbore, it clearly has responsibility for surface facilities, including the topside wellhead control systems and the occupational health and safety of people working near them.

NOPSA's last *Safety Case* Approval for the Montara WHP was on June 16, 2009 for the Montara WHP Hook-up & Pre-Commissioning.<sup>118</sup> This shows that

Just because NOPSA does not have specific authority or oversight over the downhole engineering of the well, it is not necessarily relieved of the responsibility of identifying potential surface control hazards, and how those hazards may be interrelated to DA's area of responsibility. Or even more significantly, it is not relieved of identifying how those increased risks could potentially result in safety impacts to drilling rig or platform personnel.

The Topside Module installation schedule change triggered a major change in well completion plans. Rather than drilling the well from start to finish (equipped with a blowout preventer stack the entire time), the well was only partially drilled, and then drilling stopped once intermediate casing was set. The well was temporarily suspended, the BOP was removed, and the H1 tie-in awaited installation of the Topsides Module.

The *Safety Case* review for the Montara Platform Facility should be provided for further investigation.

**Lack of NOPSA Platform Inspection:** A NOPSA inspection of the Montara Platform was warranted during its first year of activity.

<sup>116</sup> NOPSA, Submission No. 3003.0001.0003

<sup>117</sup> NOPSA, Submission No. 3003.0001.0004

<sup>118</sup> PTTEP, Submission No. 1000.0001.0051.

NOPSA argues that it was appropriate for almost a year to pass, from installation of the Montara Platform Jacket (September 2008) to the H1 well blowout (August 2009), without a NOPSA platform inspection. NOPSA argues that an inspection was not needed because:

*“The Montara facility is normally unattended, has no accommodation facilities and was not producing hydrocarbons prior to the uncontrolled hydrocarbon release. Therefore, NOPSA has not inspected the Montara facility prior to the uncontrolled hydrocarbon release.”<sup>119</sup>*

This explanation does not appear to be consistent with NOPSA’s responsibility for regulating the occupational health and safety of people at or near offshore petroleum facilities, based on the fact that people were located at the platform: in September 2008 for the Jacket installation (and potentially working on the platform thereafter); from January 2009 to April 2009 for drilling operations; and in August 2009 for Topside installation and tie-in activities. Drilling operations are conducted 24 hours a day, and normally sleeping quarters are placed nearby. Therefore, clearly people were at the Montara platform working during the period September 2008 to August 2009. Additionally, the platform underwent a major installation, warranting an onsite inspection. If NOPSA did not have the time to even complete its existing facility inspection duties, how can it argue it should take on additional oversight and inspection duties?

Furthermore, to argue that an inspection was unnecessary because the platform was “not producing hydrocarbons” during September 2008 to August 2009 appears to dismiss all other potential safety hazards that could have been identified by an inspector (e.g. electrical, fire, unsafe practices, faulty equipment, etc.).

**NOPSA Rig Inspection:** The safety of methods for connecting a well to the wellhead control system appears to be well within the purview of NOPSA, because NOPSA is responsible for personnel safety (including platform and rig personnel).

NOPSA reports it approved the initial *Safety Case* for the *West Atlas* drilling rig in August 2007, and has inspected the facility four times since August 2007, but did not find any issues of relevance to the H1 blowout. The initial *Safety Case* for the *West Atlas* drilling rig was not provided and should be made available. Further evaluation of the *West Atlas* safety case is warranted to examine NOPSA’s review of safety issues associated with re-entry into a temporarily suspended well; well tie-in procedures; and procedures for well control, when additional drilling or work is required on a well that has already drilled through a hydrocarbon interval. These factors would all directly impact personnel safety, for which NOPSA is clearly responsible.

Furthermore, the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996 (MOSOF Regulations)* and the *Petroleum (Submerged Lands) Act 1967 at § 150XE* specify that NOPSA’s role is to:

- “(c) to promote the occupational health and safety of persons engaged in offshore petroleum operations;*
- (d) to develop and implement effective monitoring and enforcement strategies to secure compliance by persons with their occupational health and safety obligations under this Act and the regulations;*

<sup>119</sup> NOPSA, Submission No. 3003.0001.0013

- (e) investigate accidents, occurrences and circumstances that affect, or have the potential to affect, the occupational health and safety of persons engaged in offshore petroleum operations in Commonwealth waters;...
- (f) to advise persons, ***either on its own initiative or on request***, on occupational health and safety matters relating to offshore petroleum operations;...[and]
- (h) to cooperate with: (i) other Commonwealth agencies having functions relating to offshore petroleum operations; and (ii) State or Northern Territory agencies having functions relating to offshore petroleum operations; and (iii) the Designated Authorities of the States and the Northern Territory [*emphasis added*].”

Facilities covered by NOPSA’s work are defined by the *Petroleum (Submerged Lands) Act 1967* as “...***a structure or installation of any kind***” [*emphasis added*], which would include the Topside Module and all the wellhead control systems. The safety of methods for connecting a well to the wellhead control system appears to be well within the purview of NOPSA. NOPSA doesn’t deny that wells are included in the definition of certain facilities, but argues that in some cases, the facility operator is not the “titleholder” and may have little knowledge or control over the well.<sup>120</sup> Yet in this case, PTTEP is the titleholder and the facility operator for both the Montara wells and platform. Therefore, that argument does not apply.

Thus, the Commission of Inquiry should investigate what best safety practices were identified by NOPSA, especially related to new well tie-ins. What safety risks did NOPSA identify? What recommendations were made by NOPSA to mitigate those risks? Were NOPSA’s recommendations followed?

**NOPSA and DA MOU:** Did NOPSA and DA work cooperatively and professionally to ensure seamless oversight of the Montara Platform operations?

Did NOPSA and DA work cooperatively and professionally to ensure seamless oversight of the Montara Platform operations? Do the agencies have clarity on the point at which DA’s responsibilities end and NOPSA’s begin? Is there clarity about when the DA must seek a NOPSA safety review? Do NOPSA’s procedures include giving safety advice to other agencies? If NOPSA identifies a safety risk, does it share the information, even if unsolicited?

NOPSA points out that the *Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004* do not have a provision for referring the Well Operations Management Plan (WOMP) to NOPSA for consideration or acceptance. NOPSA also reports that there is no “...legislative basis or arrangements which support or underpin NOPSA’s consideration of the safety related aspects of a WOMP.”<sup>121</sup> Yet, this statement appears to be inconsistent with a Memoranda of Understanding (MOU) that is in place between NOPSA and DA to “...*facilitate the appropriate exchange of information, notification and reporting.*”<sup>122</sup>

Furthermore, the Guidelines for Offshore Well Operations (December 2004) clearly state that the DA is expected to seek advice from NOPSA for any significant well safety issues:

*“If the well activity involves any significant safety issues, the **DA will seek advice from NOPSA**, under a Memorandum of Understanding (MOU) between NOPSA and the DA [*emphasis added*].”<sup>123</sup>*

<sup>120</sup> NOPSA, Submission No. 3003.0001.0021

<sup>121</sup> NOPSA, Submission No. 3003.0001.0007

<sup>122</sup> NOPSA, Submission No. 3003.0001.0007

<sup>123</sup> DA, Submission No. 4000.0001.0237

The MOU should be provided for inquiry.

**No RET Consultation:** Apparent failure to consult with RET on the well completion and suspension plan changes warrants inquiry. Regulations mandate technical peer review of non-standard well suspension and re-entry practices.

Offshore Resources Branch, Resources Division, Commonwealth Department of Resources, Energy and Tourism (RET) “Guidelines for Offshore Well Operations” state that if the WOMP or well activity involves any significant safety issue, the DA needs to seek advice from NOPSA. Furthermore, under the *Offshore Petroleum and Greenhouse Storage Act (2006)*, DA needs to also consult with RET on drilling operations that include among a list of other things:

*“Proposals and activities falling **outside standard drilling technologies and practices are referred to RET** (and from there to other Commonwealth bodies such as Geoscience Australia) **for additional technical input before any determination on the application is made**” [emphasis added].<sup>124</sup>*

Furthermore, the *Offshore Petroleum and Greenhouse Storage Act (2006)* requires:

*“Major changes...to be evaluated by **both** the Director and RET and received acceptance prior to being adopted” [emphasis added].<sup>125</sup>*

Batch drilling and delayed Topside Module installation are “major changes” to the development plan. Did those go to RET for technical peer review? Was this peer review and consultation initiated by DA and completed? If so, what was the outcome? According to RET’s submission, this peer review did not occur. DA is silent on this topic.

**DA Responsibilities:** Did the DA carry-out its duties and did it consult with other agencies to obtain safety expertise?

The Designated Authority (DA) for the Territory of Ashmore and Cartier Islands offshore area was delegated to the Northern Territory Department of Regional Development, Primary Industry, Fisheries and Resources (DRDPIFR). The DA denies any responsibility in the blowout, maintaining:

*“It is the Territory’s primary submission that: at all material times prior to the uncontrolled release, the Territory appropriately administered the license area within which the Montara wellhead platform is located...”<sup>126</sup>*

<sup>124</sup> DA, Submission No. 4000.0001.0067

<sup>125</sup> DA, Submission No. 4000.0001.0158

<sup>126</sup> DA, Submission No. 4000.0001.0002

The DA acknowledges responsibility for:

*“...the assessment and approval of drilling programs, well operation management plans, and environmental plans submitted by the operator (PTTEP) for the purpose of bringing the Montara-H1 well under control.”*

And, the DA claims:

*“these assessments and approvals were conducted in consultation with the relevant Commonwealth agencies.”<sup>127</sup>*

The DA’s statements that multi-agency consultation was completed appears to be unsupported, based on the records and submissions of the other agencies that provided records to the Commission of Inquiry.

**Prescriptive Regulations versus WOMP: Did Australia’s transition from prescriptive regulations to the WOMP process contribute to the H1 catastrophic failure?**

Historically, *Petroleum (Submerged Lands) (Management of Well Operations) Regulations* referenced a specific list of minimum engineering standards that must be met on a well to obtain a permit. That list is entitled “*Petroleum (Submerged Lands) Specific Requirements as to Offshore Petroleum Exploration and Production.*”<sup>128</sup> As explained in NOPSA’s submission, the *Petroleum (Submerged Lands) (Management of Well Operations) Regulations* were revised in 2004 to “...allow for flexibility of arrangement, to accommodate changes to technologies and other circumstances, while adhering to key legislative principles.” The 2004 regulations now require the operator (in this case, PTTEP) to submit a WOMP for approval, rather than comply with the prescriptive list of regulatory standards. The 2004 regulations require wells to be designed and constructed in accordance with “good oil-field practice”<sup>129</sup> and sound engineering principles.

The DA is responsible for reviewing and approving the WOMP. One would think that the DA staff reviewing the WOMP would have relied on the existing list of basic engineering standards in *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production*, unless the DA developed an updated list of standards for its staff to use. This is not explained in the DA’s submission.

The DA is not clear on what standards they employed to review and approve the Montara Drilling Program WOMP. If the DA did not rely on the fundamental engineering principles and minimum technical standards listed in the *Specific Requirements as to Offshore Petroleum Exploration and Production*, what standards did they rely on?

The DA states that it used regulations and applicable guidelines that were consistent with good oil field practice, but does not explain what those standards were or why it believed consistency with good oil field practice was achieved.<sup>130</sup> The fundamental question of why the DA approved a well suspension plan without placement of additional cement plug barriers, and allowed re-entry into a well with a known compromised cement job and no surface pressure control system in place, is not explained.

<sup>127</sup> DA, Submission No. 4000.0001.0243

<sup>128</sup> DA, Submission No. 4000.0001.0243

<sup>129</sup> Petroleum (Submerged Lands) Act 1967 defines good oil-field practice as meaning “all those things that are generally accepted as good and safe in the carrying on of exploration for petroleum, or in operations for the recovery of petroleum, as the case may be.”

<sup>130</sup> DA, Submission No. 4000.0001.0014

Proper training and qualifications for DA staff would require that staff be provided with a list of minimum standards to use as criteria when assessing a WOMP. These standards should guide all formal written determinations about the technical quality and safety of a WOMP and any subsequent, detailed well applications. The basis for any findings issued by the DA should be written, and clearly describe how minimum standards are met, or how alternative newer technology is more appropriate for use. The DA's technical review, findings, assessment against DA standards, and written approval documents are missing from the inquiry submittals and should be provided. A copy of the DA's standards should be provided for investigation.

**Minimum Technical Standards:** Minimum technical standards are critical. Flexibility can be afforded by allowing new technology or alternatives that have been proven to provide “equal or greater protection” of human health, safety, and the environment.

All international regulatory authorities face the challenge of keeping their regulations current with new technology. Ideally, routine regulatory revisions can be used to keep regulations current with new technology. However, agencies that do not have funding or staff to do frequent regulatory revisions can easily establish minimum engineering and safety standards to set a “floor” on what is expected of the operator, and then add a clause stating that new technology may be approved by the agency if it is proven to provide “equal or greater protection” of human health, safety and the environment. This allows the agency the flexibility to approve new technology without compromising basic minimum standards.

If the prescriptive, minimum standards of the *Specific Requirements as to Offshore Petroleum Exploration and Production* were left in place, or used in a careful fashion to thoroughly examine the proposed WOMP and subsequent drilling applications, then it is very likely that this incident could have been averted. The prescriptive standards (*Specific Requirements as to Offshore Petroleum Exploration and Production*) clearly require cement plugs to be placed in the well when temporarily abandoned; they also clearly require surface wellhead control on wells drilled into hydrocarbon bearing zones.

Absent any citation to documented, accepted technical standards, engineering manuals, or international best practice policies, the DA concludes:

*The Territory has not identified any matter that would suggest poor design in the equipment employed by PTTEP.*<sup>131</sup>

Both NOPSA and DEWHA cite conflict of interest as a primary reason for considering the transfer of well permit approvals from the DA to NOPSA or another agency. NOPSA cites findings from the Piper Alpha disaster that recommended safety oversight to be divorced from the reservoir management aspect of the Petroleum Licensing regime, because there was a conflict of interest between maximizing the recovery of petroleum reserves and safety.<sup>132</sup>

**Standards the DA Should Have Considered in H1 approvals:** The DA should not have approved the H1 suspension permit because it did not contain a “two-barrier” control system.

*The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* at § 513 historically provided very clear guidance on how to temporarily abandon a well.

<sup>131</sup> DA, Submission No. 4000.0001.0009

<sup>132</sup> NOPSA, Submission No. 3003.0001.0010

Section 513<sup>133</sup> states:

*“A well shall not be abandoned or suspended without prior approval, except as provided for in sub-clause (4).<sup>134</sup>”*

*“...Prior to the cessation of drilling operations, even temporarily, the well shall be made **safe in accordance with good oil field practice**” [emphasis added].*

*“...Where casing is being installed, if a well encountered: (a) **hydrocarbons**; (b) abnormally pressured water; (c) unstable coals or shales; (d) **lost returns**; the drilling operations shall be continued to the next scheduled casing point at which point the hole will be logged, cased and **secured at the surface**” [emphasis added].*

*“...An application for approval to abandon or suspend a well shall give the particulars of: (a) the name of the well; (b) the reason for abandonment or suspension; (c) the proposed abandonment or suspension program including the method by which the well shall be made safe; (d) such further information as the Director may require.”*

H1 well penetrated the hydrocarbon zone, encountered serious mud loss while drilling intermediate casing, and was not properly secured at the surface with either a BOP or wellhead control system.

Section 514 of the standard instructs cased wells to be abandoned as follows:<sup>135</sup>

**“In a cased hole containing a liner string or strings, a cement plug shall be placed immediately above each liner string hanger to extend at least 30 metres above the liner string hanger. A surface cement plug extending at least 45 metres in height shall be placed in the innermost casing string which extends to the seabed with the top of the plug at a depth no greater than 45 metres below the seabed. The location and integrity of cement plugs shall be verified in an approved manner. Any intervals of cased hole in a well between cement plugs shall be filled with mud fluid of appropriate density suitably inhibited to prevent the corrosion of casing string”**[emphasis added].

Section 515 of the standard requires wells to be suspended using Section 514 (unless otherwise approved) and:

*“approved equipment and protection devices shall be installed on the well head to facilitate future re-entry of the well.”<sup>136</sup>*

These Australian standards include similar requirements to those found in the USA for suspending wells, including: mechanical plugs, temporary cement, and surface wellhead controls. Temporary suspension plans must be approved by authorities in both Australia and the USA.

<sup>133</sup> The Petroleum (Submerged Lands) Act 1967, Schedule: Specific Requirements as to Offshore Petroleum Exploration and Production – 1995; November 2005 Electronic Consolidation.

<sup>134</sup> Note: sub-clause (4) is an emergency or adverse weather clause that would not apply to the H1 well. Thus, the technique for suspending the H1 well would have required Australian government approval.

<sup>135</sup> The Petroleum (Submerged Lands) Act 1967, Schedule: Specific Requirements as to Offshore Petroleum Exploration and Production – 1995; November 2005 Electronic Consolidation.

<sup>136</sup> The Petroleum (Submerged Lands) Act 1967, Schedule: Specific Requirements as to Offshore Petroleum Exploration and Production – 1995; November 2005 Electronic Consolidation.

Temporary well suspension requirements for the USA are described in the United States Department of Interior, Minerals Management Service (MMS) Regulations at 30 CFR 250.1721, which require a cement plug to be placed in the casing at least 100' long (30.48m):

“§ 250.1721 *If I temporarily abandon a well that I plan to re-enter, what must I do?*  
*You may temporarily abandon a well when it is necessary for proper development and production of a lease. **To temporarily abandon a well, you must do all of the following:***

(a) *Submit form MMS–124, Application for Permit to Modify, and the applicable information required by §250.1712 to the appropriate District Manager and receive approval;*

(b) **Adhere to the plugging and testing requirements for permanently plugged wells listed in the table in §250.1715, except for §250.1715 (a)(8). You do not need to sever the casings, remove the wellhead, or clear the site;**

(c) *Set a bridge plug or a cement plug at least 100-feet long at the base of the deepest casing string, unless the casing string has been cemented and has not been drilled out. If a cement plug is set, it is not necessary for the cement plug to extend below the casing shoe into the open hole;*

(e) **Set a retrievable or a permanent-type bridge plug or a cement plug at least 100 feet long in the inner-most casing. The top of the bridge plug or cement plug must be no more than 1,000 feet below the mud line.** *MMS may consider approving alternate requirements for subsea wells case-by-case;*

[Note to Reader: The difference between a temporarily suspended well and a permanently suspended well is that an extra 150' (45.7m) long cement plug is set in the smallest casing that extends to the mudline with the top of the plug no more than 150' (45.7m) below the mud line.]

“§ 250.1715 *How must I permanently plug a well?*

(a) *You must permanently plug wells according to the table in this section. The District Manager may require additional well plugs as necessary:*

#### ***Permanent Well Plugging Requirements***

<b><i>If you have—</i></b>	<b><i>Then you must use—</i></b>
<i>(1) Zones in open hole</i>	<i>Cement plug(s) set from at least 100 feet below the bottom to 100 feet above the top of oil, gas, and fresh-water zones to isolate fluids in the strata.</i>
<i>(2) Open hole below casing</i>	<i>(i) A cement plug, set by the displacement method, at least 100 feet above and below deepest casing shoe;  (ii) A cement retainer with effective back-pressure control set 50 to 100 feet above the casing shoe, and a cement plug that extends at least 100 feet below the casing shoe and at least 50 feet above the retainer; or  (iii) A bridge plug set 50 feet to 100 feet above the shoe with 50 feet of cement on top of the bridge plug, for expected or known lost circulation conditions.</i>
<i>(3) A perforated zone that is</i>	<i>(i) A method to squeeze cement to all perforations;</i>

<p><i>currently open and not previously squeezed or isolated</i></p>	<p><i>(ii) A cement plug set by the displacement method, at least 100 feet above to 100 feet below the perforated interval, or down to a casing plug, whichever is less; or</i></p> <p><i>(iii) If the perforated zones are isolated from the hole below, you may use any of the plugs specified in paragraphs (a)(3)(iii)(A) through (E) of this section instead of those specified in paragraphs (a)(3)(i) and (a)(3)(ii) of this section.</i></p> <p><i>(A) A cement retainer with effective back-pressure control set 50 to 100 feet above the top of the perforated interval, and a cement plug that extends at least 100 feet below the bottom of the perforated interval with at least 50 feet of cement above the retainer;</i></p> <p><i>(B) A bridge plug set 50 to 100 feet above the top of the perforated interval and at least 50 feet of cement on top of the bridge plug;</i></p> <p><i>(C) A cement plug at least 200 feet in length, set by the displacement method, with the bottom of the plug no more than 100 feet above the perforated interval;</i></p> <p><i>(D) A through-tubing basket plug set no more than 100 feet above the perforated interval with at least 50 feet of cement on top of the basket plug; or</i></p> <p><i>(E) A tubing plug set no more than 100 feet above the perforated interval topped with a sufficient volume of cement so as to extend at least 100 feet above the uppermost packer in the wellbore and at least 300 feet of cement in the casing annulus immediately above the packer.</i></p>
<p><i>(4) A casing stub where the stub end is within the casing</i></p>	<p><i>(i) A cement plug set at least 100 feet above and below the stub end;</i></p> <p><i>(ii) A cement retainer or bridge plug set at least 50 to 100 feet above the stub end with at least 50 feet of cement on top of the retainer or bridge plug; or</i></p> <p><i>(iii) A cement plug at least 200 feet long with the bottom of the plug set no more than 100 feet above the stub end.</i></p>
<p><i>(5) A casing stub where the stub end is below the casing</i></p>	<p><i>A plug as specified in paragraph (a)(1) or (a)(2) of this section, as applicable.</i></p>
<p><i>(6) An annular space that communicates with open hole and extends to the mud line</i></p>	<p><i>A cement plug at least 200 feet long set in the annular space. For a well completed above the ocean surface, you must pressure test each casing annulus to verify isolation.</i></p>
<p><i>(7) A subsea well with unsealed annulus</i></p>	<p><i>A cutter to sever the casing, and you must set a stub plug as specified in paragraphs (a)(4) and (a)(5) of this section.</i></p>
<p><i>(8) A well with casing</i></p>	<p><i>A cement surface plug at least 150 feet long set in the smallest casing that extends to the mud line with the top of the plug no more than 150 feet below the mud line.</i></p>
<p><i>(9) Fluid left in the hole</i></p>	<p><i>A fluid in the intervals between the plugs that is dense enough to exert a hydrostatic pressure that is greater than the formation pressures in the intervals.</i></p>
<p><i>(10) Permafrost areas</i></p>	<p><i>(i) A fluid to be left in the hole that has a freezing point below the temperature of the permafrost, and a treatment to inhibit corrosion; and</i></p> <p><i>(ii) Cement plugs designed to set before freezing and have a low heat of hydration.</i></p>

*(b) You must test the first plug below the surface plug and all plugs in lost circulation areas that are in open hole. The plug must pass one of the following tests to verify plug integrity:*

*(1) A pipe weight of at least 15,000 pounds on the plug; or*

*(2) A pump pressure of at least 1,000 pounds per square inch. Ensure that the pressure does not drop more than 10 percent in 15 minutes. The District Manager may require you to tests other plug(s).”*

In the USA, MMS regulations at 30 CFR 250.517 require surface pressure control (a blowout preventer or wellhead control system) **and** a subsurface safety valve to be installed in all offshore wells once it is completed. This way, if there is any failure of the surface wellhead control, the subsurface safety valve provides a second, redundant safety measure to control the well. If Australian regulators requested PTTEP to delay drilling H1 until after the Toppide Module was in place, H1 could have been drilled from top to bottom with a BOP in place during the entire well operation, and then safely tied-back into the Toppide Module wellhead control system for uninterrupted surface wellhead control. Additionally, a subsurface safety valve could have been installed to provide an extra layer of prevention.

To be clear, if the well was tied-back into the wellhead control system when the *West Atlas* originally moved H1 in early 2009, the cement plug would not have been necessary, because the wellhead control system would have provided the surface control system required by Australian (and similarly by USA) regulation. However, because the Toppide Module was behind schedule and was not installed, H1 could not be tied-back into a wellhead control system when intermediate casing work was completed in early 2009 and the well was ready to be suspended, because one did not exist at the time. There was no BOP left over H1, and because H1 was not tied-back into the wellhead control system (as it should have been by Australian regulation), the well should have been properly temporarily plugged to control pressure.

At the time the well suspension plan was submitted for approval in March 2009, the DA would have known (or have had access to information on H1 by inspecting the driller’s logs to know) that the well had penetrated 1,187m (3,894’) of hydrocarbon interval, encountered serious mud losses at 1,706m (8,560’), had an initially failed cement job and had a failed 244mm (9-5/8”) intermediate casing shoe valve. This well clearly needed surface well control or the installation of cement plugs to ensure continued, reliable, redundant well control. A waiver allowing cement barriers to be removed from the H1 well suspension plan was not technically justified, and was unsafe.

**Regulator Qualifications and Training:** The Commission of Inquiry should examine the training and qualifications of the regulatory staff reviewing and approving well designs and suspension applications.

The DA reports it has “...*professional staff with an understanding of the practical approach required under this legislation.*” The DA goes on to conclude: “*appropriate qualifications and industry experience to undertake regulatory approvals and monitoring processes supported by effective internal structures are key to this*”;<sup>137</sup> yet, the DA provided no information on the actual qualifications or experience of the personnel involved in the Montara H1 permit approvals.

MMS regulations at 30 CFR 250.505 provide USA regulators some discretion to approve well completion methods on a case-by-case basis as long as the “*proposed equipment and procedures will*

<sup>137</sup> DA, Submission No. 4000.0001.0012

*adequately control the well and permit safe production operations.*” This method relies on hiring trained, qualified, and experienced staff capable of reviewing and approving alternative procedures.

However, all governments face challenges in hiring and retaining qualified personnel in regulatory positions. In order to hire and retain qualified personnel government agencies need to offer salary and benefit packages commensurate with those offered by oil and gas companies and their contractors.

**Agency Findings:** Complete copies of all applications, permits, and approvals should be provided to the Commission of Inquiry. A technical review of the standards and procedures used by the agencies should be conducted. The quality of the written agency determinations and findings should be assessed.

Absent a complete set of application and approval documents, it was difficult to decipher the facts of the Montara blowout situation. It was necessary to sift through and puzzle together the incomplete information provided by the operator, the drilling company and the regulatory agencies that were involved. Some facts were disclosed, while others were not. Additionally, some of the submissions made to the Commission of Inquiry provide conflicting information. The Commission of Inquiry should review the quality of the written agency determinations, and examine what technical review standards the agencies are relying on to make decisions. Are permit applications and plans receiving thorough technical review by qualified personnel? Or are they being rushed through the system and “rubber-stamped” with little care? The late arrival of many of the Montara permit applications, and rapid approval, raises serious questions about the quality of the review.

**Daily Drilling Reports:** What level of monitoring and oversight was performed by the DA on H1 well by review of daily drilling reports?

The DA states that Daily Drilling Reports are submitted by PTTEP to the DA and that:

*“These reports allow the Territory to monitor the operations, at least at the level of detail required to be provided in the reports. The assessment of Daily Drilling Reports against approved work programs (drilling programs and WOMPs) allows the Territory to determine progress, performance and compliance.*

*Up to the point of the incident on 21 August 2009, the Territory has assessed all drilling programs and WOMPS as meeting the requirements of the legislations, guidelines and good oil field practice.”<sup>138</sup>*

The DA provides no information to show what level of actual technical review or analysis on the Daily Drilling Reports was performed by the agency staff. Nor does it provide information to show how it confirmed that good oil field practice was performed.

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<sup>138</sup> DA, Submission No. 4000.0001.0028

## 8. Term of Reference No. 5

*“Assess the adequacy of the response to the Uncontrolled Release by the current titleholder of AC/L, the owner and /or operator of the Montara Wellhead Platform, and the owner and/or operator of the West Atlas drilling rig.”*

Selection of the relief well rig, time delays, and relief well intervention methods are appropriate subjects for inquiry. However, looking forward to future well planning, the most important recommendation is to ensure that a more efficient and rapid response is achieved for future incidents with wells.

The Australian Petroleum Production & Exploration Association Limited (APPEA) submits that:

*“Well blowouts do occur. APPEA understands that worldwide, over 500 offshore well blowouts have occurred in the past 50 years of offshore operations.”<sup>139</sup>*

APPEA cites the Norwegian SINTEF Offshore Well Blowout Database that includes 544 offshore blowouts/well releases since 1955.

USA oil spill statistics also show that blowouts occur, and proper well control planning is necessary.

*“From 1971 to 2005, 276 exploration and development blowouts occurred on the OCS while drilling from approximately 34,000 wells. Thirty-three of those 276 blowouts resulted in oil spills of crude or condensate with the amount of oil spilled ranging from, 1 bbl to 350 bbl.”<sup>140</sup>*

This data shows a blowout history of 1 blowout for every 123 wells. A blowout every 123 wells drilled is clearly a “reasonably foreseeable” event.

Canada has determined that blowouts are “reasonably foreseeable” events. Canada’s Oil and Gas Drilling Regulations<sup>141</sup> at Section 79 [Attachment C] require:

**“79. (1) Every operator shall ensure that contingency plans have been formulated and that equipment is available to cope with any foreseeable emergency situation during a drilling program, including**

- (a) a serious injury to or the death of any person;*
- (b) a major fire;*
- (c) the loss of or damage to support craft;*
- (d) the loss or disablement of a drilling unit or a drilling rig;*
- (e) the loss of well control;*
- (f) **arrangements for the drilling of a relief well** should such become necessary;*
- (g) hazards unique to the site of the drilling operation; and*
- (h) spills of oil or other pollutants.”[emphasis added]*

Canada’s Same-Season Relief Well (SSRW) Policy was established by Cabinet Order in 1976.<sup>142</sup>

<sup>139</sup> APPEA, Submission to Commission of Inquiry, December 22, 2009.

<sup>140</sup> Shell Chukchi ODPCP, p.2-15

<sup>141</sup> Canada Oil and Gas Drilling Regulations, current as of October 21, 2009.

<sup>142</sup> Dr. Bharat Dixit, Canada’s Chief Conservation Officer, Regulation of Oil & Gas Activities in the Canada’s Northern Frontier, The Arctic of Canada- Canada’s Evolving Offshore Oil and Gas Industries, Offshore Technology Conference 2007, May 2007, Houston, Texas, USA

*“Since floating offshore drilling operations commenced in the Beaufort Sea in 1976 it has been the **policy of the Government of Canada that an operator not drill into a potentially hydrocarbon-bearing zone, (the risk threshold) without the ability to drill a relief well in the same season in the event of a blowout.***

**This policy is meant to significantly reduce the damage to the environment that would result if an oil blowout continued to release oil through the winter season unchecked.**

*The present procedure is as follows. On September 25, for wells drilled in open water, the status of operations is reviewed and any further operations conducted below risk threshold depth need a separate and distinct approval. This approval depends on weather, the **availability of a relief well platform**, depth of the hole being drilled and other factors. The date, September 25, was chosen as it would allow a period of at least **60 days** to mobilize a relief platform, to drill a relief well and to kill the blowout prior to the formation of 30 cm thick ice.*

*As new drilling systems were introduced to the Beaufort Sea and better ice breaking capability was developed the concept of same season relief well capability<sup>143</sup> was maintained but drilling below the risk threshold depth was occasionally allowed beyond September 25 based on the availability of alternate relief well platforms and capable ice breaking equipment.*

**Three times over the past 15 years an operator has lost control of its well during drilling operations in the Beaufort Sea.** *None of these incidents resulted in an oil blowout or in a serious pollution incident and the operators moved swiftly to control their wells and to contain and remove any contaminants in the Beaufort Sea. **These incidents underscore the need for vigilance and the need for a workable same season relief well contingency plan**”<sup>144</sup>[emphasis added].*

Therefore, Canada requires a relief well rig to be available nearby for immediate intervention. Immediate access to an alternative rig capable of drilling a relief well is critical.

PTTEP’s submittal summarizes the steps it took to negotiate and locate a relief well rig. Locating a suitable, technically capable rig, with qualified crew, and executing a contractual arrangement for an extremely dangerous, hazardous mission, is something that should be planned well in advance.

Similar to Canada, the State of Alaska in the USA requires extensive well control pre-planning. Alaska requires drilling operators to have a written well control plan that includes plans for a relief well, and a plan to cap the well within 15 days.<sup>145</sup>

**Emergency Pre-Planning:** Australia should consider adopting more stringent requirements for well control planning, including plans for a relief well, and a plan to cap the well, as a possible alternative if it is safe to access the platform.

Australia should consider adopting more stringent requirements for well control planning, including plans for a relief well, and a plan to cap the well, as a possible alternative if it is safe to access the platform. In

<sup>143</sup> Same season relief well capability refers to the capability to drill a relief well and control a blowout in the same season in which the original well was being drilled. Same season relief well capability requires the ability to begin mobilization of an alternate relief well drilling system as soon as a blowout occurs, and once relief well operations are started, the ability to conduct those operations on a relatively continuous basis, to a successful conclusion.

<sup>144</sup> A Report to the Minister of Indian Affairs and Northern Development Regarding Issues Arising from the Environmental Impact Review Board Reviews of the Isserik and Kulluk Drilling Program Applications, Prepared by the Beaufort Sea Steering Committee, April 1991.

<sup>145</sup> State of Alaska Regulations at 18 Alaska Administrative Code, Chapter 75.

the case of the H1 well blowout, both PTTEP and NOPSAs determined it was not safe to return to the platform to conduct well capping.<sup>146</sup>

**Avoid Complacency:** Blowouts are reasonably foreseeable consequences of offshore drilling and completion operations.

While blowouts are infrequent, they do occur, and when they do, they are catastrophic.

It appears that one of the root causes of this incident was complacency, because Australia's last major offshore blowout was in 1984. The pre-drill environmental assessment, prepared by URS Australia Pty Ltd., Section 6.4.2.4, assumed that a well control problem was highly unlikely:

*“With current technology, the risk of a well blowout is considered low. There are elaborate monitoring systems to detect potential blowouts and such events can occur only if all the monitoring systems fail and if the casing, wellhead or blow-out preventers (BOPs) fail catastrophically.”*

*“In almost 30 years of operation, the oil and gas industry in Australia has drilled over 1500 exploration and development wells and produced over 3,500 million barrels of oil. ... There have been no blow-outs in Australia since 1984, which is evidence of the technological and procedural improvements that have occurred over the last two decades.”<sup>147</sup>*

**Blowouts Should Be Examined in Safety Case reviews:** Blowouts should be examined as reasonably foreseeable consequences of offshore oil and gas exploration, and should be included in the *Safety Case* assessment for facilities as a primary, catastrophic safety risk.

## 9. Term of Reference No. 6

*“Assess the adequacy of regulatory obligations applicable to the title-holder of AC/L7, the owner and/or operator of the Montara Wellhead Platform, and the owner and/or operator of the West Atlas drilling rig in relation to the response to the incident and make recommendations necessary to improve the regulatory obligations that may be applicable to any future incidents.”*

Please refer to the analysis provided in Terms of Reference No. 2, 3, 4, and 5.

## 10. Term of Reference No. 7

*“Assess and report on the environmental impacts following the Uncontrolled Release using available data and evidence including the outcomes from monitoring activities already underway, review any proposed environmental monitoring plans, and make recommendations on whether any further measures are warranted to protect the environment from the consequences of the Uncontrolled Release.”*

Please refer to WWF's December 2009 submittal to the Commission of Inquiry on this topic and additional material submitted by WWF-Australia to the Commission of Inquiry.

<sup>146</sup> PTTEP, Submittal No. 1000.0002.0005

<sup>147</sup> URS Australia Pty Ltd., Section 6.4.2.4

## 11. Term of Reference No. 8

*“Consider and comment on the offshore petroleum industry’s response to the Uncontrolled Release.”*

As noted above in the analysis under Terms of Reference No. 5, response to a catastrophic blowout is an extremely dangerous and hazardous mission. There are serious human health and liability consequences that other offshore petroleum industry members must consider before jumping in to help. They must cautiously assess the situation and be careful not put their employees in harms way without a well thought out plan and coordinated effort with the operator and agencies directing the response efforts. They must consider if their staff are trained and qualified to respond to this type of incident, and whether their equipment is appropriate and reliable for the response effort. Sending in well meaning, untrained, poorly equipped volunteers can compound a disaster. Whereas, enhancing response assets with well trained and well equipped personnel, that have clearly assigned roles in the incident management structure, can prove beneficial. This requires coordination and planning.

Thus, it is critical to negotiate Memorandums of Agreement and contracts for “mutual response aide” and emergency assistance with other operators and contractors well in advance of an incident. These contractual and liability issues are complex, and require companies to thoroughly vet human health, safety, and environment procedures used by other companies before agreeing to join in on mutual aide contracts. As noted above, both Canada and the USA require this type of advanced planning to ensure that other industry members are not only willing to assist, but also are not prevented from assisting during the crisis because all the paperwork is not in place and their lawyers advise against it.

## 12. Term of Reference No. 9

*“Consider and comment on the provision and accessibility of relevant information regarding the Uncontrolled Release to affected stakeholders and the public.”*

Australia should be applauded for coordinating this Commission of Inquiry and requiring this data to be made public for review and comment. An open and transparent process should be continued as the Commission’s work continues.

However, as noted throughout this paper, and as outlined in the list below, there is a substantial amount of data that should be released to the public to better understand this incident. A thorough independent analysis of all the facts is not possible without being able to examine the original source documents. Additional information that should be made available to the Commission of Inquiry should include:

- Complete copies of all applications, permits, approvals, designs and findings made in connection to the Montara Wellhead Platform and H1 well.
- All *Safety Case* reviews for the Montara Platform Facility and drilling rig.
- The MOU between the DA and NOPSA.
- The standards employed by the DA to review and approve the Montara Drilling Program WOMP.
- The DA’s technical review, findings, and assessment against DA standards, and written approval documents.

- Information to show the actual qualifications or experience of DA personnel involved in the Montara H1 permit approvals.
- Legible well construction diagrams. Some of the information on PTTEP's well construction diagrams is not legible. Solid color blocks cover diagram labels and information on most drawings.
- Records from the cement contractor.
- Atlas Drilling's standard procedure for re-entry into wells; an explanation as to why it did not use a BOP or recommend one in light of the H1 well history.
- Atlas Drilling's Well Construction Standards.
- PTTEP's Well Construction Standards, Well Construction Management System, and Well Operations Management Plan.
- More information to determine if a thread cleaning plan was developed, if it underwent any safety review, and what it might have contained.
- Pressure monitoring data and gas detection system devices in place at the time of the incident.
- Information to better understand PTTEP's and Atlas Drilling's rig move safety procedures.
- Cement quality, casing design and casing quality.
- Drillers logs, well logs, and other data collected while on H1.
- Information to verify that the cement plugs and float equipment were compatible and the integrity of the shoe track (shoe and float) were checked on deck prior to running it in the hole.
- More information on cementing procedures, and how those procedures were implemented including QA/QC.
- Operator, contractor, and agency qualifications and training programs and standards.
- Actual training and qualification records for operator, contractor, and agency staff, to verify qualifications at the time of the incident.

### **13. Term of Reference No. 10**

*“Make recommendations to the Minister for Resources and Energy, and through the Minister for Resource and Energy, other relevant Commonwealth Ministers, regulators and industry, as appropriate, on any measures that might help to prevent similar incidents occurring in the future and any measures that might mitigate the safety, environmental, and resource impacts arising from such an incident. Measures may include improvements to industry practices or applicable regulatory regimes and their administration.”*

Please see the recommendations summarized in the Conclusion and Recommendations section at the end of this report.

## 14. Term of Reference No. 11

*“Consider, assess and make recommendations in relation to any other matter the Commission of Inquiry considers relevant to or arising from the Uncontrolled Release and the prevention of similar events occurring in the future.”*

Please see the recommendations summarized in the Conclusion and Recommendations section at the end of this report.

## 15. Conclusions and Recommendations

### Conclusions

- The seriousness of the H1 well configuration on August 20, 2009 cannot be understated. No well should be left open to atmosphere, without surface well control, and redundant, multiple pressure isolation and/or barrier systems in place. There was no surface well control. No blowout preventers were installed. And no wellhead control was in place because the well was not tied-back into the Montara Wellhead Platform control system.
- The fundamental question to be answered by the Commission of Inquiry is whether PTTEP’s application to fill H1 with brine and place a temporary cap (PCCC) on it was “good oil field practice.” A review of minimum regulatory standards from Norway, Canada and the USA, and even Australia’s longstanding prescriptive standards in the *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production*, without question, show that it is not. ALERT Well Control’s final assessment of H1 as “controlled and secured” with a “two-barrier” plug system installed is further evidence that the initial plan did not meet “good oil field practice.”
- Misapplication of the “good oil field practice” standard by both the operator and the approval agencies appears to have contributed to the incident.
- If the prescriptive standards listed in *The Schedule of Specific Requirements as to Offshore Petroleum Exploration and Production* were still used, the well suspension application would have required a series of cement plugs in the casing, meeting a minimum “two-barrier” industry well control standard.
- The complexity of this well and the mere fact that it penetrated a pressurized hydrocarbon zone containing gas and oil should have warranted PTTEP and Atlas Drilling to treat this well as a “live” production well, with potential for hydrocarbon flow. The need for pressure barriers to be installed to “safe-out” the well while it was suspended, and the need to set a BOP as part of the re-entry procedure, should have been standard well control procedure.
- The Montara Wellhead Platform Topside installation delay resulted in major, late changes to the well design and completion plans. This delay should have triggered a multi-agency coordinated, peer-reviewed, technical safety and environmental assessment to evaluate the potential risks associated with the proposed batch drilling program and the inability to immediately tie newly drilled wells into the platform wellhead control system.
- Batch drilling increases risk increases with each surface intervention and rig move.
- Producing wells should be properly and safely secured, and pressure should be isolated, prior to moving a rig from one well to another on an offshore platform.
- Leaving H1 unattended and incomplete, and the rig personnel’s attention focused on the GI and H4 tie-in operations, appears to be a significant contributing factor to this incident.

- Other international regulatory systems for the oil and gas industry include prescriptive engineering principles and standards, as a minimum threshold, while providing “regulatory flexibility” by allowing an operator to propose new technology or practices for agency review that “meet or exceed” the basic minimum standards. In this way, the minimum technical standards are not compromised; they are only improved by new technology and new practices.
- Major changes in the well plan temporary suspension plan should not have been issued in a change order from the operator (PTTEP) to the drilling contractor (Atlas Drilling) 5 days after-the-fact.
- The rush to move the West Atlas from H1 to tie in other wells (GI and H4) left the H1 well unattended and unequipped to rapidly commence well plugging or other well intervention operations.
- A failed float collar valve is a clear indication that a cementing integrity problem had occurred. Unless steps were taken to remedy the cement job, and then independently verify it by additional evaluation tools, the integrity of the casing shoe cement plug at the base of H1 should have remained a concern, and a documented risk factor, for this well.
- Inspection and oversight appears inadequate. On August 21, 2009 the Montara H1 well blowout commenced. Over one year had passed since the Montara Wellhead Platform was installed in July 2008, and no onsite inspection had taken place by NOPSA, the DA or DEWHA, according to PTTEP.
- PTTEP suspended H1 on March 7, 2009; without DA approval to the well suspension procedure plans. The DA issued after-the-fact approvals on March 9, 2009 and March 13, 2009.
- The Environment Plan for H1 was approved three months after the well was spudded on January 18, 2009
- Oil spill plans and well control plans (including relief well and well capping plans) should have been prepared, reviewed, and approved in advance of drilling and completion operations.
- The H1 oil spill plan was not approved by DEWHA until March 6, 2009, after the first phase of the well was drilled. Phase 1 drilling for H1 started on January 18, 2009 and ended on March 7, 2009. There was no approved oil spill plan in place during that time.
- Other international countries require relief well and well capping plans to be prepared in advance of drilling. In this case, required relief well implementation was delayed while a rig was located, contracts were negotiated, and the relief well rig was transported to the site. Advanced planning would have likely shortened this response time, and identified other viable options.

### **Recommendations**

- Of urgent and primary concern to the Commission of Inquiry should be the existing safety status of all the other wells on the Montara Wellhead Platform. While H1 is now, reportedly, secured with a two-barrier system, it is not clear if the other wells are safely secured. Batch drilling programs, by nature, are subject to repetitive flaws. Flaws encountered on H1 could have been repeated in the other wells, and this warrants inquiry. The Commission of Inquiry should also examine whether similar well safety concerns could exist on other offshore platforms.
- A BOP should have been set for H1 re-entry because: the well had already been drilled through 1,187m (3894’) of the hydrocarbon interval; the well had known cement plug integrity issues; the well had no cement plugs in the casing; and the well had no other surface well control installed. H1 was a “live” production well, warranting a BOP stack to be set. All future well re-entries should require surface well control equipment to be in place.
- Australia should return minimum prescriptive standards to its regulations.

- Agency staff should be provided clear, written technical guidelines for reviewing and approving new technology and practices aimed at “meeting or exceeding” the minimum prescriptive standards.
- All agency “good oil field practice,” permit waivers and technology assessments should be firmly supported by a written technical findings document clearly showing that the technology or practice, is in fact, better than the minimum prescriptive standards.
- An organized process should be established for agency, and independent expert peer-reviews to ensure that it is clear who initiates them, when they must be completed, and who is assigned the lead role.
- Complete copies of all applications, permits, and approvals should be provided to the Commission of Inquiry and independently examined.
- A technical review of the standards and procedures used by the agencies should be conducted.
- The quality of the written agency determinations and findings should be assessed.
- Operator, contractor, and agency qualifications and training should be examined and compared to that required for the roles and tasks assigned.
- An inspection program should be developed and funded, with trained and qualified inspectors to monitor offshore drilling and platform operations on a routine basis.
- Australia should require relief well plans and well capping plans to be prepared prior to drilling.
- Sufficient procedures and protections should be in place for individual employees, as well as companies, to freely report safety concerns.