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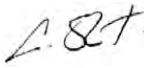
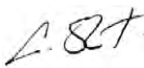
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1. INTRODUCTION

1.1 Project Description

On the 29 September 2011, the “National Offshore Petroleum Safety Authority” (NOPSA) of Australia appointed Mr. Colin Stuart, Managing and Technical Director of “Stuart Wright Pty Ltd” (SWPL) as Expert Witness in relation to NOPSA’s investigation into the uncontrolled release of hydrocarbons from the Montara Jacket Platform on the 21 August 2009.

The role of Expert Witness as defined by NOPSA is:

1. to thoroughly review and analyze all documents provided by NOPSA;
2. to form an expert opinion on nine (9) omissions identified by NOPSA on the part of the Operator “PTTEP Australiasia (Ashmore Cartier) Pty Ltd” (PTTEPAA) that led to the eventual uncontrolled release of hydrocarbons; and
3. to document the findings within a written report.

This document is “Volume 1” of the full report, and is one of a total three (3) volumes submitted to NOPSA on Friday 17 February 2012, to meet the obligations of the Expert Witness.

The report is confined to the areas of specialized knowledge of the Expert Witness, with clear, supported and cited references from the available evidence provided by NOPSA, and quoting also from codes and industry standards utilized to help define the term “good oilfield practice”.

1.2 Overall Report Structure

1. The Expert Witness’s opinion on nine (9) omissions identified by NOPSA on the part of the Operator PTTEPAA that led to the eventual uncontrolled release of hydrocarbons is presented in a written report comprising of three (3) volumes that must be read together for completeness:

Volume 1

Volume 1 contains an introduction and states the background regarding the appointment of the Expert Witness.

Volume 1 also includes a “Timeline of relevant facts and events” focusing on the approvals PTTEPAA received from the NTDRDPIFR to undertake Montara Development activities from commencement of operations to the H1ST1 blowout event.

Finally, Volume 1 provides the reader with background information relating to good oilfield practice and industry standards in the following areas of direct relevance to the investigation:

1. Cementation - Zonal isolation in Oil and Gas Wells;
2. Suspension, and Plug and Abandonment (P&A); and
3. Risk Assessment.

Volume 2

Volume 2 documents the Expert Witness’s response to each question posed by NOPS relating to each of the nine (9) omissions identified by NOPS on the part of the Operator PTTEPAA, which led to the eventual uncontrolled release of hydrocarbons. This document is structured in nine (9) individual chapters, each addressing the nine omissions in sequential order.

Volume 3

Volume 3 addresses the Well Integrity condition of the H1-ST1 well at various critical stages of construction, suspension, and re-entry. The Expert witness has used the proprietary Stuart Wright Pte Ltd’s **WAI[®]** (**Well Assessment of Integrity Tool**) to explain the condition of the H1-ST1 well at these different stages. The Well Integrity condition is shown in a visual chart format using the WAI[®] process. There are two WAI[®] charts in A0 size.

The SWPL WAI[®] process is a comprehensive review platform used to drive a “forensic” assessment of the candidate wells’ integrity status, and can be applied to all stages of wells’ investigation and asset-wide risk assessment and management. The SWPL WAI[®] process

captures the subsurface environment data, well architecture (as-built condition), and as required, the production historical data of a well in an integrated view, and represents this data in the form of a WAI[®] chart.

For the purpose of this investigation, the WAI[®] process is used to assess the Well Integrity condition of the H1 and H1-ST1 Wells, represented in the form of two (2) charts as follows:

1. WAI[®] #1 – An integrated assessment of the Well Integrity status for the Construction and Abandonment of H1 Well, and subsequent Well Integrity status for the Construction and Suspension of H1-ST1 Well.
2. WAI[®] #2 – An integrated assessment of the Well Integrity status for the Re-entry of H1-ST1 Well to the Blowout Event.

Volume 3 also includes the “Timeline of relevant facts and events” focusing on the approvals PTTEPAA received from the NTDRDPIFR to undertake Montara Development activities from commencement of operations to the H1ST1 blowout event. In addition, where an activity is performed by PTTEPAA as Operator without prior approval from the NTDRDPIFR, or where it deviates from the approval given by the NTDRDPIFR, this is recorded in the Timeline. The Expert Witness has also recorded on the timeline comments specifically relating to points in time where Risk Assessments should have been performed using good oilfield practice.

Finally, Volume 3 contains the Expert Witness response to specific queries from NOPSA raised during the course of the Expert Witness investigation period.

1.3 Scope of Work

The Expert Witness has performed the following in the preparation of this report:

1. Reviewed all available evidence provided by NOPSA;
2. Provided a written report with opinions based upon the nine issues listed below; and
3. Provided a signed witness statement to NOPSA to be relied upon in a criminal proceeding.

The Expert Witness addresses the following issues below specifically under report Volume 2:

1. **Failure to use the correct volume of tail cement**

- a. An assessment of all documentation provided by NOPSALOGO relating to the failure to use the correct volume of tail cement when cementing the 9 5/8 inch casing shoe in H1-ST1 Well on 7 March 2009.
- b. Whether the failure to use the correct volume of tail cement when cementing the 9 5/8 inch casing shoe in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons.
- c. What other practicable steps could have been undertaken by PTTEP to prevent the use of an incorrect volume of tail cement?
- d. What would good oilfield practice have been in this situation?

2. **Pumping the wrong volume of cement**

- a. An assessment of all documentation provided by NOPSALOGO relating to the risks to the well integrity caused by pumping the wrong volume of cement into the 9 5/8 inch casing shoe in the Montara H1-ST1 Well.
- b. Whether the failure to pump the correct volume of cement into the 9 5/8 inch casing in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons.
- c. What other practicable steps could have been undertaken by PTTEP to prevent pumping the wrong volume of cement.
- d. What would good oilfield practice have been in this situation?

3. **Over displacement of cement**

- a. An assessment of ALL documentation provided by NOPSALOGO relating to the over displacement of cement within and around the 9 5/8 inch shoe of the Montara H1-ST1 Well.
- b. Whether the over displacement of cement within and around the 9 5/8 inch casing shoe of the Montara H1-ST1 Well, resulting in the creation of what is termed a 'wet cement shoe', increased the risk of an uncontrolled release of hydrocarbons.
- c. What other practicable steps could have been undertaken by PTTEP to prevent the over displacement of cement?
- d. What would good oilfield practice have been in this situation?

4. **Failure to verify the casing shoe was a barrier**

- a. An assessment of ALL documentation provided by NOPSAs relating to the failure to verify the 9 5/8 inch casing shoe as a barrier in the Montara H1-ST1 Well.
- b. Whether the failure to verify the 9 5/8 inch casing shoe was a barrier in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons.
- c. What other practicable steps could have been undertaken by PTTEP to prevent the failure to verify the casing shoe was a barrier?
- d. What would good oilfield practice have been in this situation?

5. **Failure to pressure test the 9 5/8 inch cement casing shoe**

- a. An assessment of ALL documentation provided by NOPSAs relating to the failure to pressure test the 9 5/8 inch cement casing shoe in the Montara H1-ST1 Well after 7 March 2009.
- b. Whether the failure to pressure test the 9 5/8 inch cement casing shoe after 7 March 2009 in the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons.
- c. What other practicable steps could have been undertaken by PTTEP to prevent the failure to pressure test the 9 5/8 inch cement casing shoe?
- d. What would good oilfield practice have been in this situation?

6. **Failure to install the 13 3/8 inch MLS PCCC**

- a. An assessment of ALL documentation provided by NOPSAs relating to the failure to install the 13 3/8 inch MLS PCCC on the Montara H1-ST1 Well between 7 March 2009 and 21 April 2009.
- b. Whether the failure to install the 13 3/8 inch MLS PCCC on the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons.
- c. What other practicable steps could have been undertaken by PTTEP to prevent the failure to install the 13 3/8 inch MLS PCCC?
- d. What would good oilfield practice have been in this situation?

7. **Corrosion of the threads on the 13 3/8 inch mudline hanger**

- a. An assessment of ALL documentation provided by NOPSAL relating to the corrosion of the threads on the 13 3/8 inch mudline hanger of the Montara H1-ST1 Well.
- b. Whether the failure to install a PCCC on the 13 3/8 inch mudline hanger of the Montara H1-ST1 Well was one of the direct causes of the blowout, in that it led to the corrosion of the threads on the 13 3/8 inch mudline hanger.
- c. What other practicable steps could have been undertaken by PTTEP to prevent the corrosion of the threads on the 13 3/8 inch mudline hanger?
- d. What would good oilfield practice have been in this situation?

8. **Removal of the 9 5/8 inch MLS PCCC**

- a. An assessment of ALL documentation provided by NOPSAL relating to the removal of the 9 5/8 inch MLS PCCC onto the Montara H1-ST1 Well on 20 August 2009 or 21 August 2009.
- b. Whether the removal of the 9 5/8 inch MLS PCCC from the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons.
- c. What other practicable steps could have been undertaken by PTTEP to reduce the risk, as low as reasonably practicable (ALARP), arising from the removal of the 9 5/8 inch MLS PCCC?
- d. What would good oilfield practice have been in this situation?

9. **Failure to reinstall the 9 5/8 inch MLS PCCC**

- a. An assessment of ALL documentation provided by NOPSAL relating to the failure to reinstall the 9 5/8 inch MLS PCCC onto the Montara H1-ST1 Well on 20 August 2009 or 21 August 2009.
- b. Whether the failure to re-install the 9 5/8 inch MLS PCCC onto the Montara H1-ST1 Well increased the risk of an uncontrolled release of hydrocarbons.
- c. What other practicable steps could have been undertaken by PTTEP to reduce the risk, ALARP, arising from the failure to reinstall the 9 5/8 inch MLS PCCC?
- d. What would good oilfield practice have been in this situation?

The Expert Witness has, as guided in the instructions from NOPSALOGO addressed the following:

1. Expert opinion on:
 - a. Each of the omissions stated above;
 - b. Whether the omissions would increase the risk of an uncontrolled release of hydrocarbons;
 - c. The practicability of the steps suggested to reduce the risks; and
 - d. What good oilfield practice would have been in this situation?
2. The opinion evidence:
 - a. Is clearly expressed and not argumentative in tone;
 - b. Identifies with precision the factual premises upon which the opinion is based;
 - c. Explains the process of reasoning by which the expert reaches the opinion expressed in the report; and
 - d. Is confined to the area or areas of the expert's specialized knowledge.
3. The opinions in the report must so far as possible be supported by references to the following and if not the omission should be specifically indicated in the report:
 - a. The available evidence provided;
 - b. Appropriate codes, standards or authoritative texts cited in the report
4. The report must include or have attached:
 - a. The expert's qualifications which must be detailed so as to be held as being properly qualified to give the opinions;
 - b. A statement of the questions or issues the expert was asked to address;
 - c. The factual premises upon which the report proceeds, identifying any assumptions; and
 - d. A list of all the literature, documents and other materials
 - i. Used in make the report; or
 - ii. That the expert has been instructed to consider
5. The report will also include or have attached:
 - a. A timeline of relevant events from 26 January 2009 to 21 August 2009
 - b. Drawings or sketches, which need not be to scale, to support the experts opinions and findings.

1.4 Input Data Summary

1.4.1 Kick-Off Meeting

A meeting was organized between NOPSA and the Expert Witness in Singapore on the 29 September 2011. During the meeting, NOPSA provide a document including an overview of the Engagement Letter titled: “Expert Witness Report Requirements”.

NOPSA also formally handed over to the Expert Witness certified documents including:

1. 10 Folders of documents;
2. “Certified Documents Receipt Form”, signed in the presence of a representative from the Singapore Police Force;
3. List of “Assumed Facts – Montara Wellhead Platform”; and
4. List of Acronyms.

1.4.2 Technical Queries

“Technical Queries” (TQ) raised from time to time by the Expert Witness to NOPSA are compiled, documented, and summarized in the table below. All TQs are attached in Section 6 in Volume 3 of this report.

No.	Description	Date
1	TQ_30291_ NOPSA_001 Response to Montara Investigation Action Items	23-Dec-11
2	TQ_30291_ NOPSA_002 Response to Montara Investigation Action Items	19-Jan-12

Table 1: Summary of Technical Queries

1.4.3 Data Received from NOPSA

Client specific data was received in stages from NOPSA, and summarized in the table below. Appendix B contains the complete list of data received from NOPSA.

Materials handed over by NOPSA on the 29 September 2011 and 24 October 2012 are provided with “Evidence Numbers” (EV). However, materials handed over by NOSPAs on the 25 January 2012 did not contain EV references.

For the purpose of referencing NOPSA documentation within ALL three volumes of this report, documents received on the 29 September 2011 and 24 October 2012 will be quoted using the EV system, and documents received on the 25 January 2012 will be quoted using SWPL’s internal document referencing system. Appendix B contains the complete list of documents received from NOPSA.

No.	Description	Date
1	Material Handover by NOPSA #1	29-Sep-11
2	Material Handover by NOPSA #2	24-Oct-12
3	Material Handover by NOPSA #3	25-Jan-12

Table 2: Summary of Data received from NOPSA

1.4.4 Statement on Quality of Input Data

The Expert Witness at each stage of the investigation reviewed in detail the input data provided by NOPSA, and provides comments on the quality of input under Volume 2 of this report. The following two examples demonstrate a systemic lack of completeness and consistency across the documents prepared by the involved parties and supplied to NOPSA.

1.4.4.1 Montara WHP Accurate Drawings

The DDRs regularly mentioned a reference to “Wellhead Deck Level”, however no drawings supplied for this study contains a reference to such a “Wellhead Deck Level”.

1.4.4.2 PTTEPAA Daily Drilling Reports

No accurate drawing is available within any PTTEPAA document provided by NOPSAL showing the drilling rig elevation over the Montara WHP. This fact, together with errors on the PTTEPAA DDR, dated 20 August 2009, [EV0000555], regarding the rotary table elevation, compounded the uncertainty in establishing reference heights of the accuracy required in this investigation. However, for the purpose of this investigation the rotary table elevation level used is as per that stated in the H1-ST1 Tie-back Forward Plan, dated 19 August 2009, [EV0000058], as being 45.75 m AHD.

In view of the above, the Expert Witness has exercised his experience and judgment whenever an assumption is made during the course of the investigation, and is documented accordingly within relevant sections of the report.

1.4.5 Data Requested but Not Received from NOPSAL

The Expert Witness has requested certain input information from NOPSAL regarding the subject set out under §1.4.5.1 below, but has received guidance from NOPSAL that this information will not be provided, nor were they able to be located by NOPSAL.

1.4.5.1 Schematics of 9 5/8" and 13 3/8" PCCC

1. No manufacturer's specification data of PCCC used on the West Atlas has been provided.
2. A document termed "Vetco Operating and Service Procedure Vetco OPS-03001 (Mudline Suspension System Tieback)" was located as a reference document to the PTTEP Montara Phase 1B (Drilling & Completion Program, Rev-0 Jun 2009).
3. NOTE: With Reference to Vetco OPS-03001, the 13-3/8" Corrosion Cap was not designed to be pressure rated, in contradiction to statements made to NT by PTTEPAA.
4. It should be highlighted that the "Vetco Operating and Service Procedure (Vetco Doc no: OSP03001)" should not be taken as the definitive "final approved Assembly Drawings".

2. BACKGROUND OF MONTARA DEVELOPMENT PROJECT

2.1 Discovery to Temporary Abandonment of H1-ST1

2.1.1 Ownership

The Montara oil and gas resource, hereinafter known as “Montara field”, is located in the Timor Sea, approximately 690 km West of Darwin Australia, and in water depths ranging between 76m to 90m. It comprises an interpreted 55m gas cap on a 13.4m oil leg trapped within a fault block, with estimated reserves of 38,000,000m³.

The Montara field AC/P7 was first discovered by BHP in 1988 and the Retention Lease AC/RL3, hereinafter known as “the Lease”, was granted later in 1997. In 2001, “Coogee Resources (Ashmore Cartier) Pty Ltd” (CR), acquired 50% interest in and operatorship of the Lease and the Montara field was further appraised by Montara-3, the third well, drilled in the field, in April 2002. As a result of this appraisal, a preliminary “Montara Field Development Plan” was developed and submitted to the “Northern Territory Department of Business Industry and Resource Department” (NTDBIRD) on 12 March 2003. The Montara Preliminary Field Development Plan described the initial preferred development concept of the Montara field which included, staged drilling of three production wells, one gas injection well, subsea trees, flowline, umbilicals and a “floating production storage and offloading facility” (FPSO).

In September 2003, CR acquired the remaining 50% interest and became the sole holder of the Lease. CR then re-submitted a revised copy of the preliminary Montara Field Development Plan based on NTDBIRD responses received and continued to conduct further evaluation studies, aimed to increase the robustness of its plans for the proposed field development. Changes that came through from CR’s continuous improvement efforts included:

1. To utilize four (4) single horizontal wellbores drilled from a wellhead platform, hereinafter known as “Montara WHP”, located North of the field;
2. To drill the horizontal sections close to the oil water contact to delay and minimize gas encroachment;

3. To re-inject produced gas at the top of the Montara structure using a single gas injection well;
4. To use a FPSO.

Based on the above changes, CR updated the second submission to reflect the results of subsequent studies that led to changes in the selected development concept and contemplated the integrated nature of the Montara field development in a combined development project including the Swift and Skua fields. In October 2006, CR submitted the Montara Field Final Development Plan with an application for the grant of a production license in respect of the blocks of the AC/RL3 Retention Lease.

On 13 February 2007, CR submitted to NOPSA the Operator Registration for Montara, the FPSO and WHP, including associated wells, equipment and secondary lines. Ten (10) days later, NOPSA accepted CR as the facility operator under the *Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996*, (MOSOF).

On 11 February 2009, CR changed its name to "PTTEP Australasia (Ashmore Cartier) Pty Ltd" (PTTEPAA), and retained the same, Australian Business Number (ABN), Australian Company Number (ACN), status, assets and obligations when it was named CR.

2.1.2 Facilities for the Montara Field Development Project

Montara Wellhead Platform

As detailed in the Montara Field Final Development Plan submitted in October 2006, the preferred development option for the Montara field is to use a wellhead platform to locate the dry wellheads and a tie back to a FPSO for processing of the production stream and storage and offloading of the crude oil. On 30 June 2008, the Montara WHP, which has six (6) well slots (refer to Figure 1), was installed on location, north western end of the field, close to the interpreted crest of the Montara Structure.

West Atlas Mobile Offshore Drilling Unit

“ATLAS Drilling (S) Pte Ltd” (ATLAS), a wholly owned subsidiary of “Seadrill Management Pte Ltd” (SEADRILL), had been the operator of the facility known as “West Atlas Mobile Offshore Drilling Unit” (WA MODU) for the Montara Development Project. ATLAS was appointed the Drilling Contractor by CR to shoulder the operational and OHS contractual responsibilities during the drilling of the Montara WHP wells. The contract commenced on 15 September 2007 and ended on 1 November 2009.

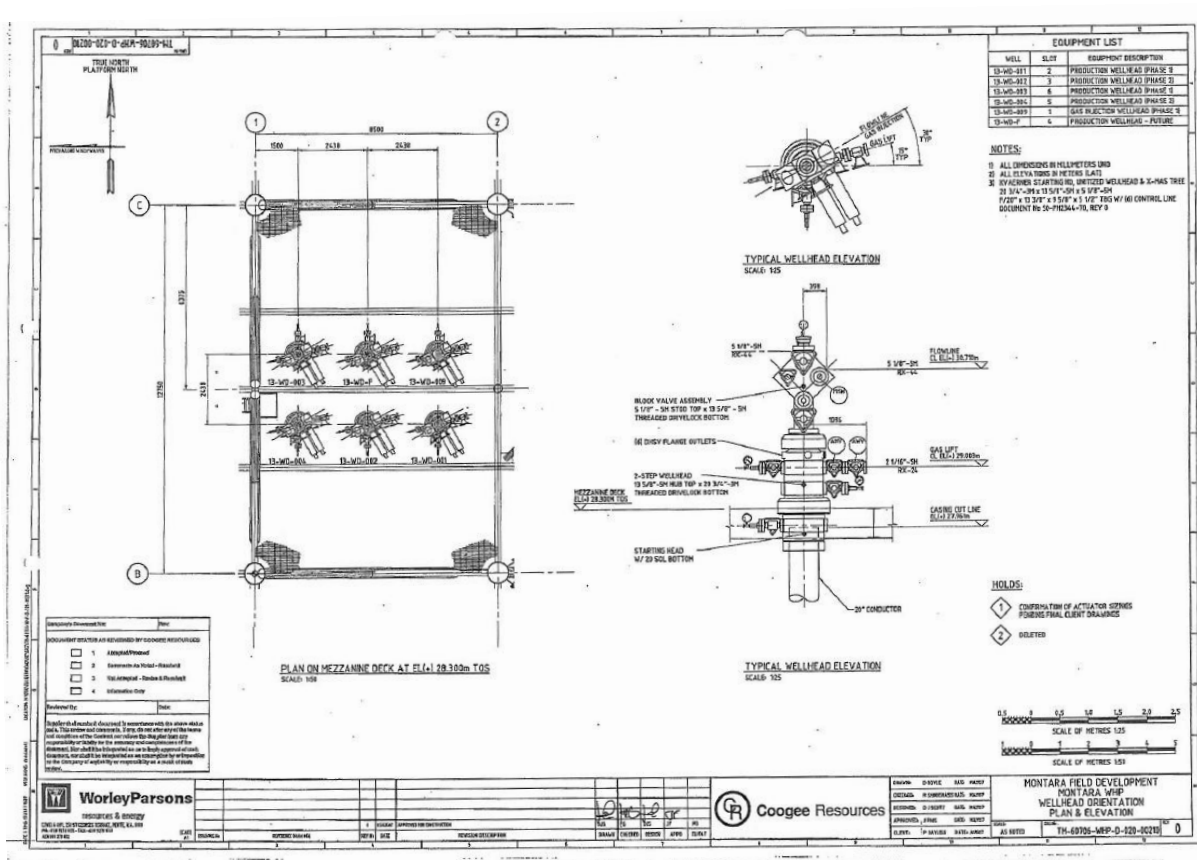


Figure 1: Montara WHP Mezzanine Deck Well Slots Layout

On 15 January 2009, the WA MODU was positioned over the Montara WHP, with no topsides installed, for the purpose of drilling four (4) oil and gas production wells and one gas injection well. Five (5) wells, H1-ST1, H2, H3-ST1, H4 and GI, were batched drilled to the 9 5/8" casing shoe and suspended. Upon suspending all of the 5 wells, on 21 April 2009, PTTEPAA released the WA MODU from drilling operations on the Montara WHP.



The WA MODU returned to the Montara WHP on 17 August 2009 to commence re-entry and tie-back operations of 5 wells, for the purpose of drilling the 8 ½" open hole section, and completing them subsequently.

2.1.3 Planning and Construction Phases of H1/H1-ST1

2.1.3.1 Planning Phase H1/H1-ST1

In July 2008, CR issued the Montara Development “Basis of Well Design” (BOWD) for the Montara H1 Well. Subsequently, the “Montara GI, H1 and H4 (Batch Drilled) Drilling Programme” – TM-CR-MON-B-150-00001 Rev 0, hereafter known as the “Drilling Programme Rev 0” was issued for use on 30 September 2008.

Several revisions had been made to the Drilling Programme Rev 0 and the following table describes the changes made in each revision.

Rev #	Document Revision Description	Issued for Use	Date Issued
0	Assumed the Platform Topsides In Place and the wells Batch Drilled and Completed .	Yes	30 September 2008
1	Assumed the Platform Topsides Not in Place and the wells Drilled sequentially to the 9 5/8” casing shoe and Suspended . The well surface and target locations, formation tops, and directional profile were not changed. The well design had been changed to include an MLS that will allow the wells to be suspended below the top of the jacket.	Not Generally Issued	28 November 2008
2	Assumed the Platform Topsides Not in Place and the West Atlas Conductor Deck Extension used without the conductor tensioner. This allowed the wells to be batch drilled. All three wells will be Batch Drilled to 9 5/8” casing shoe and Suspended . The well surface and target locations, formation tops, and directional profile, have not changed.	Yes	6 January 2009

Table 3: Description of Drilling Programme Revisions

Batch Drilling Sequence – Well Phases

Operations	Well
Move in & Rig Up	GI
Drill 660mm (26") Hole	GI, H4, H1
Run & Cement 508mm (20") Conductor	GI, H4, H1
Drill 445mm (17 ½") Hole	GI, H4, H1
Run & Cement 13 3/8" Casing	GI, H4, H1
Nipple Up BOP's, Riser and Diverter	GI, H4, H1
Drill 311mm (12 ¼") Hole	H1 & H4
Drill 311mm (12 ¼") Hole	GI
Run & Cement 244mm (9 5/8") Casing	H1 & H4
Run & Cement 244mm (9 5/8") Casing	GI
Suspend Well	All
Rig down & Move out	GI

Table 4: Drilling Programme Description of Batched Drilling Sequence of Operations for GI, H1 and H4

2.1.3.2 Construction Phase of H1/H1-ST1

The WA MODU which was positioned over the Montara WHP, spudded the H1 well on 18 January 2009.

The H1 well had a 20" (508mm) conductor set at 150.5m MDRT, a 13 3/8" (340mm) casing set and cemented in the 17 ½" (445mm) hole section, at 1637m MDRT, and finally a 12 ¼" (311mm) hole section directionally drilled, which intersected the top of the reservoir, directly into the gas cap at 2935m MDRT.

Drilling of the 12 ¼" (311mm) hole section continued through the gas cap ending at an inclination of 90° to find the oil reservoir and in the attempt, encountered poor quality ("dirty sands") at +/- 3602m MDRT. The well was then steered upwards to intersect oil in a cleaner reservoir where the Gas Oil Contact (GOC) was found at 3840m MDRT. On 27 February 2009, an application to sidetrack the H1 well was submitted to the NT and was approved on 2 March 2009. A cement plug was placed across the penetrated gas zone at the total depth (TD) of the well, followed by a kick off plug set shallower. The side track (H1-ST1)

was later kicked off at 3130m MDRT and the H1-ST1 well was eventually landed in good quality oil sands, at a TD of 3796m MDRT.

The 9 5/8" (244mm) casing was subsequently run and cemented in place, with the shoe at 3796m MDRT and plugs bumped. However, the floats failed following a bleed off to 200psi (9.5bbl), from a 4000psi casing pressure test. There was a rapid increase of surface pressures to 1300psi, accompanied by a 7bbl flow back. A total of 16 bbl of inhibited seawater was re-displaced into the well and pressure was held on the casing for some hours prior to bleeding the well pressure to zero psi.

2.1.4 Suspension Phase of H1-ST1

An application to commence the suspension of Montara H1-ST1 development well by PTTEPAA was made to the NT on 6 March 2009. The suspension was said to be in accordance with the Drilling Programme Rev 2 which had been submitted and approved.

As per page 22 of the document *"Submission – PTTEP Document Submission – Regulatory Approvals -3.pdf"*, it was planned for the well to be suspended in two stages. *"Stage 1 will involve the cementing and pressure testing of the 9 5/8" (244mm) casing followed by the installation of a pressure containing suspension cap. Stage 2 will involve the recovery of the 13 3/8" (340 mm) casing above the MLS and the installation of a second pressure containing suspension cap followed by the recovery of the 20" (508mm) casing above the MLS and the installation of a further suspension cap."*

On 7 March 2009, Stage 1 suspension of H1-ST1 was carried out immediately as planned, following the period of time that pressure was held on the well following the displacement of SW into the shoe of the 9 5/8" (244mm) casing. The 9 5/8" (244mm) casing was backed out at the MLS and a PCCC was installed. Subsequently, the WA MODU skidded over to H4 to commence operations.

NT's approval of the planned Stage 1 suspension (Figure 2) in response to the application sent on 6 March 2009 was later received by PTTEPAA on **9 March 2009**. An additional application to perform Stage 2 suspensions on H1-ST1 was submitted on 12 March 2009 where the attachment had clearly shown that a 13 3/8" (340mm) "Pressure Containing"

PCCC would be installed. See Figure 3. It is in the Expert's opinion highly unusual for approvals to be given on only a partial suspension programme.

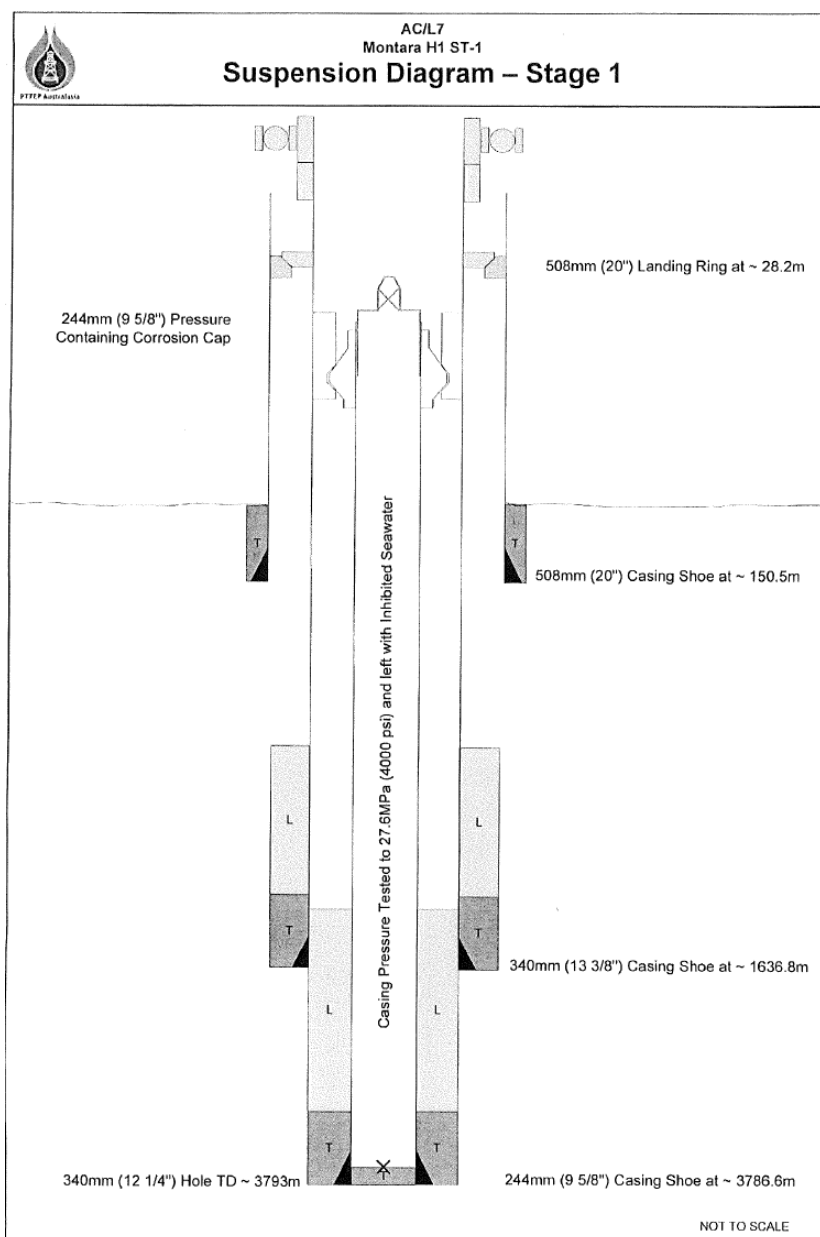


Figure 2: Stage 1 Suspension Plan found on Pg 23 of "Submission – PTTEP Document Submission – Regulatory Approvals -3.pdf"

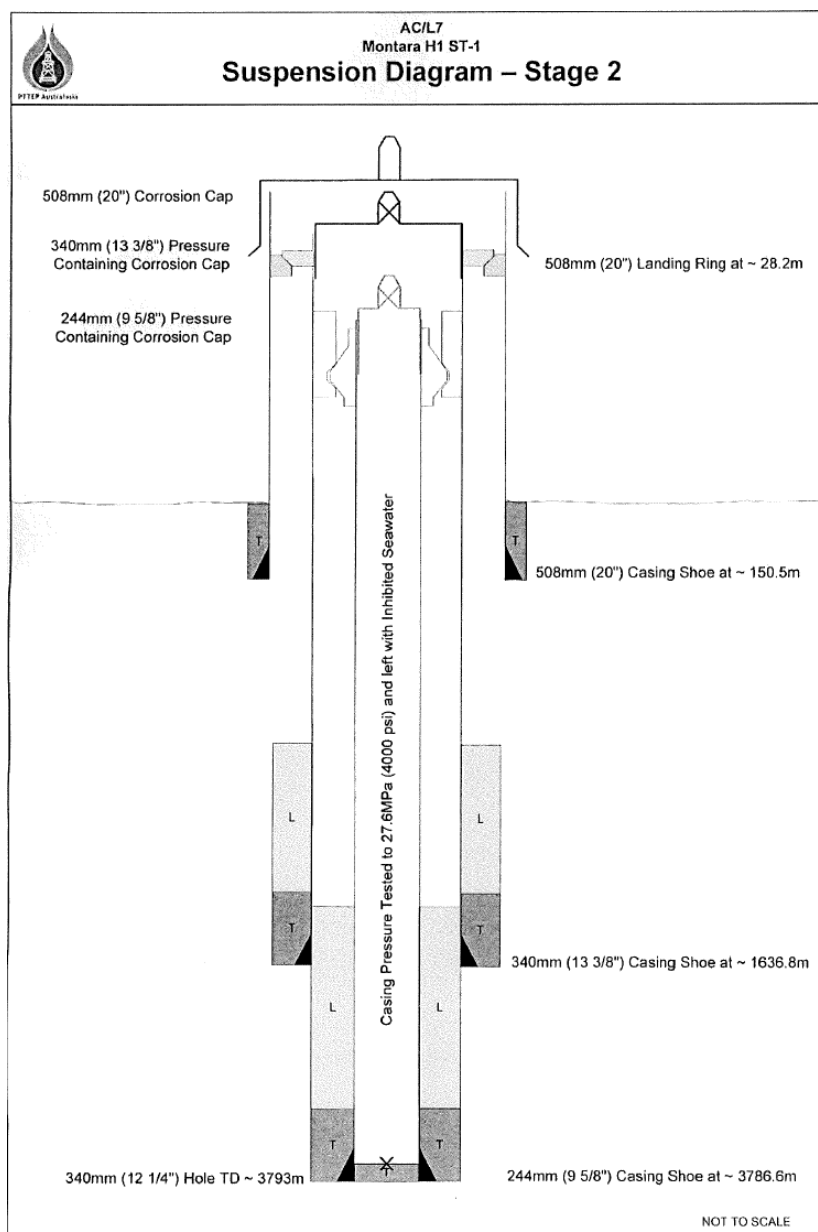


Figure 3 : Stage 2 Suspension Plan found on Pg 32 of "Submission – PTTEP Document Submission – Regulatory Approvals -3.pdf"

Stage 2 of H1-ST1 suspension was conducted on 16 April 2009, as an **offline activity**. The 20" (508mm) conductor and 13 3/8" (340mm) casing was backed out above the MLS hanger by some means not utilising the drilling rig. The 20" (508mm) MLS trash cap was installed over the MLS hanger but not the 13 3/8" (340mm) PCCC, **contrary to what has been reported in the DDR and the Re-Entry Programme. The fact of the 13 3/8" (340mm) PCCC not being installed was not known until the well was re-entered on 20 August 2009.**

2.2 Tie Back and Re-entry of Montara WHP Wells

2.2.1 Tieback and Re-entry of H1-ST1

On 17 August 2009, the WA MODU returned to the Montara WHP. Tie back and re-entry operations of H1-ST1 and four (4) other wells, with the purpose of drilling the horizontal section of the wells and finally completing the wells for production, commenced on 19 August 2009 after the WA MODU was pinned at the final location. PTTEPAA issued a *"Montara Platform Forward Plan, number 1b – 20 inch tie back for 19 August 2009, Version 2.0."*

WA MODU had its drilling package above the H1-ST1 well by 4:30am on 20 August 2009 and subsequently, the 20" (508mm) trash cap was removed. It was reported at this juncture, in DDR#12 ["EV0000555"], that the 13 3/8" (340mm) PCCC had not in fact been installed as recorded at the time of well suspension and that the 13 3/8" (340mm) casing hanger threads were found to have rust and scale on them. A decision from the onshore management team was made to clean the tie back threads (ID) of the VETCO 13 5/8" (346mm) MLS casing hanger on H1-ST1.

As a result of the scale build up on the 13 3/8" (340mm) PCCC on the H1-ST1 well, a supplementary plan was issued by PTTEPAA *"Montara Platform Forward Plan, number 1b – 20 inch tie back for 19 August 2009, Versions 2.0"* (EV0000758) was issued. The 9 5/8" (244mm) MLS PCCC was then removed from the H1-ST1 well after it was reported that it had tested negative for pressure under the PCCC and as per the supplementary plan.

After the cleaning of the 13 3/8" (340mm) MLS hanger threads, the 20" (508mm) conductor riser was installed and rough cut on the H1-ST1 well before the drilling package skidded over to the G1-ST1 at about 5:00pm, without re-installing the 9 5/8" (244mm) PCC on the H1-ST1 well. The H1-ST1 well at this juncture was full of SW as per the operational description in DDR#12 ["EV0000555"]. No BOP or other surface barrier was installed on the well at this stage.

2.2.2 Well Flow in H1-ST1

On 21 August 2009, at 5:30am, 12.5 hours after the rig had skidded away from H1-ST1, to well H4, the gas alarm sounded. The H1-ST1 was observed to “burp” approximately 6.4m³ of oil/ oily water and the flow was “deemed to be temporary”, according to the PTTEPAA DDR.

At 6:00am, a meeting was held to discuss well control options with onshore management where a decision was made to skid the WA MODU drilling package over the H1-ST1 and run a RTTS packer, to provide a mechanical barrier to flow.

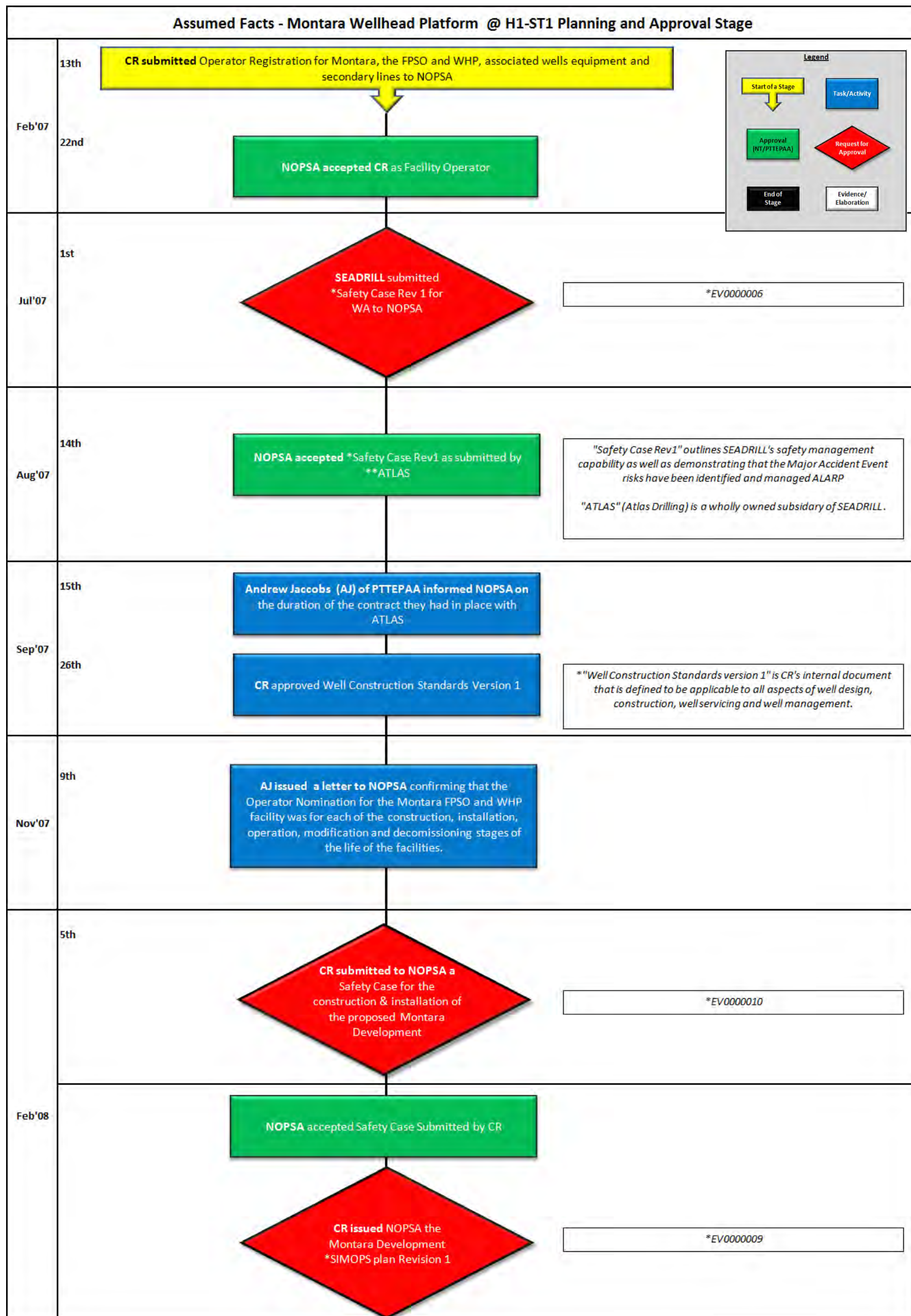
At 7:23am, before skidding operations could commence, the H1-ST1 well started flowing again, with such force that a column of oil and gas was blowing into the underside of the WA MODU rig floor. An uncontrolled release of hydrocarbons which posed significant and immediate threat to the health and safety of rig personnel should the oil and gas ignite had taken place on well H1-ST1.

At 7:45 am, the WA OIM ordered the immediate evacuation of 52 non-essential personnel from the WA MODU as well as the personnel on board another vessel within close vicinity. A total of 17 personnel stayed behind on the WA MODU with the intention of regaining control of the H1-ST1 well, however it soon became clear that their health and safety were at risk should the oil and gas ignite. These 17 personnel evacuated the WA MODU and made their way to a safe location.

A factual timeline of events for the H1-ST1 well, divided into four stages (Planning and Approval, Construction, Suspension and Re-entry), as understood during the course of this investigation, is shown in the following four sub sections.

2.3 Factual Time Line of Events – H1-ST1 Planning and Approval Stage

The following section describes the timeline of events in chart format, commencing with the Operator Registration for Montara through to the blowout itself. The timeline is based on the NOPS supplied document “Assumed Facts”.



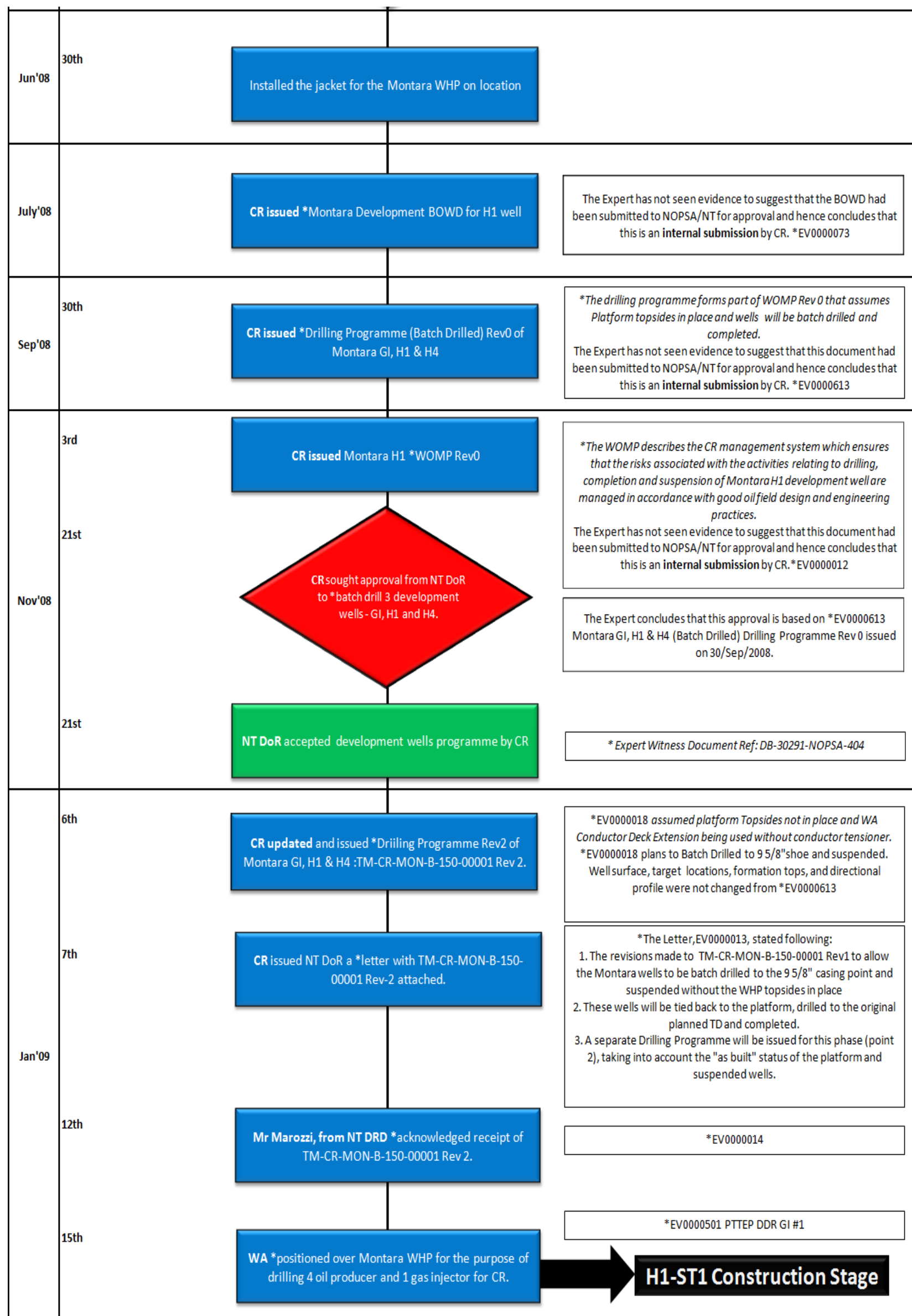
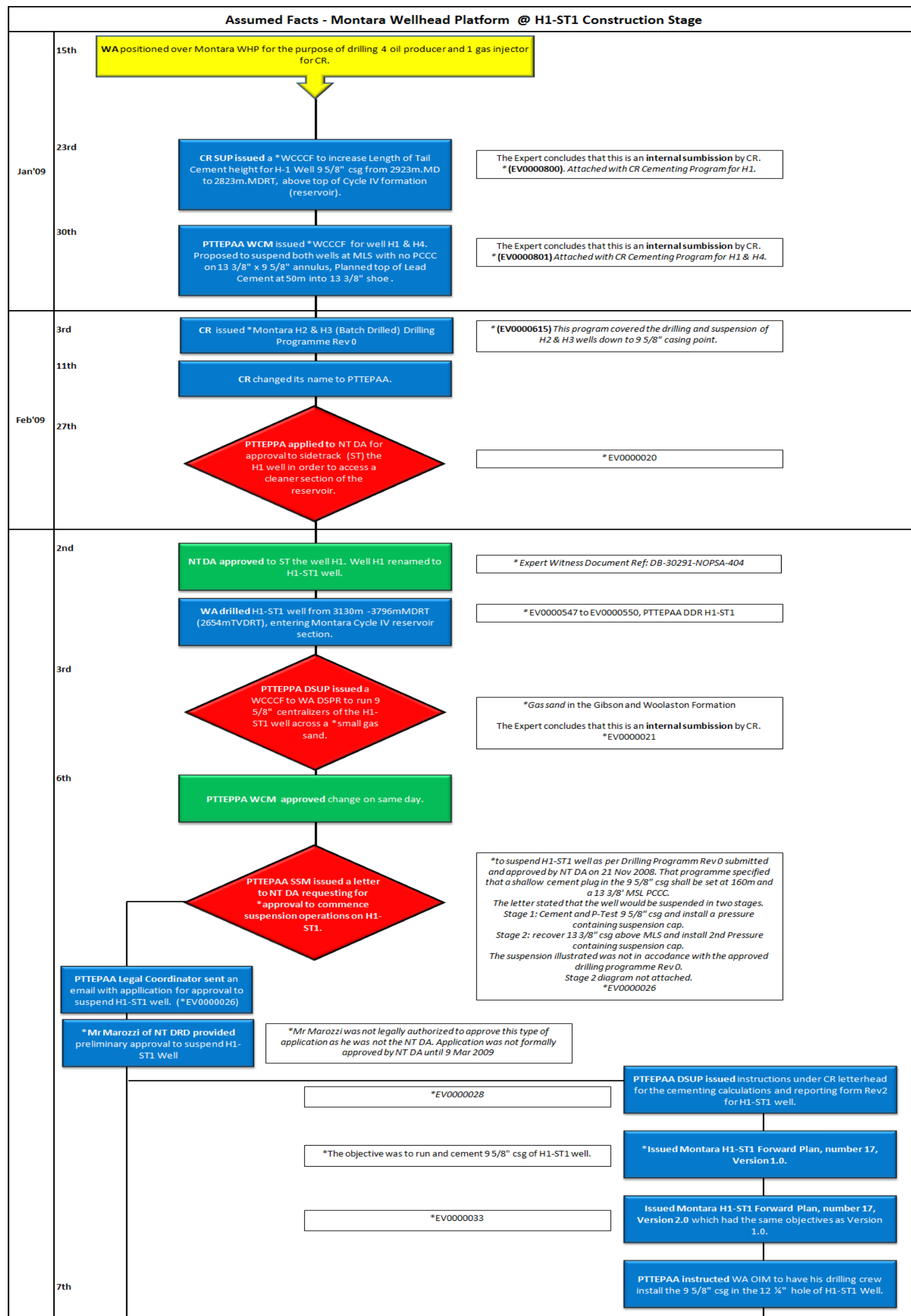


Figure 4 : Timeline of Events - H1-ST1 @ Planning and Construction Stage

2.4 Factual Time Line of Events – H1-ST1 Construction Stage



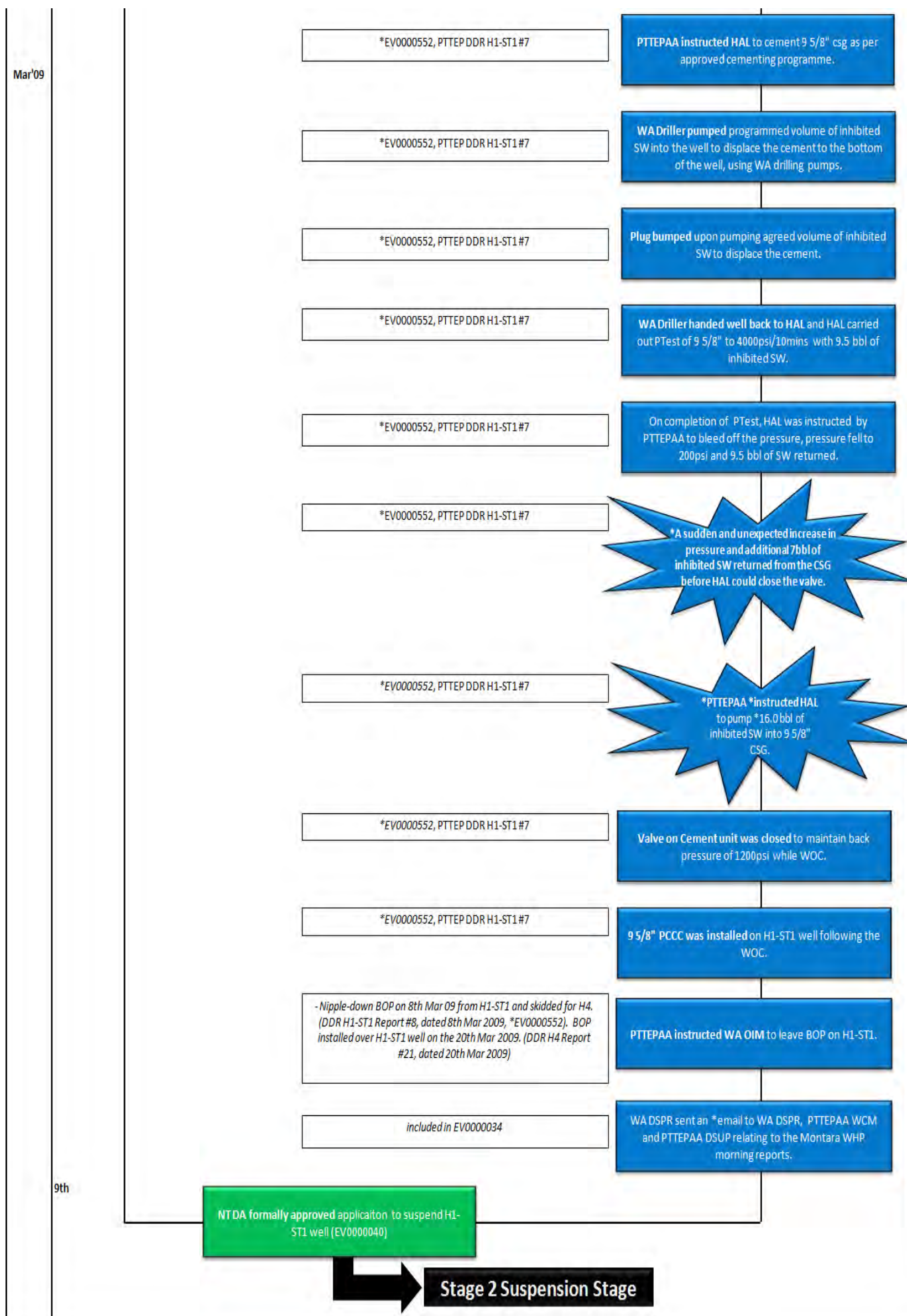
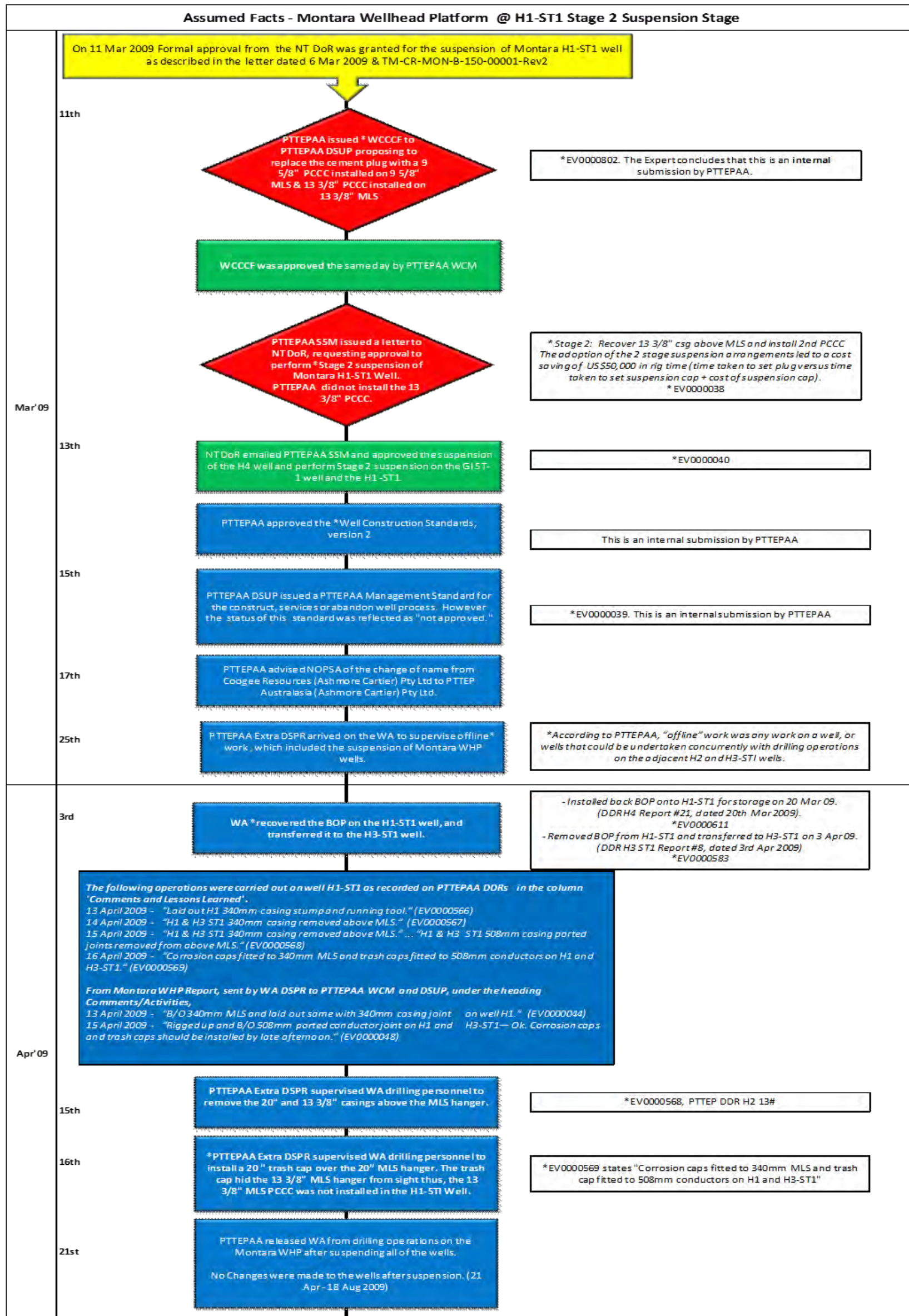


Figure 5 : Timeline of Events - H1-ST1 @ Construction Stage

2.5 Factual Time Line of Events – H1-ST1 Stage 2 Suspension



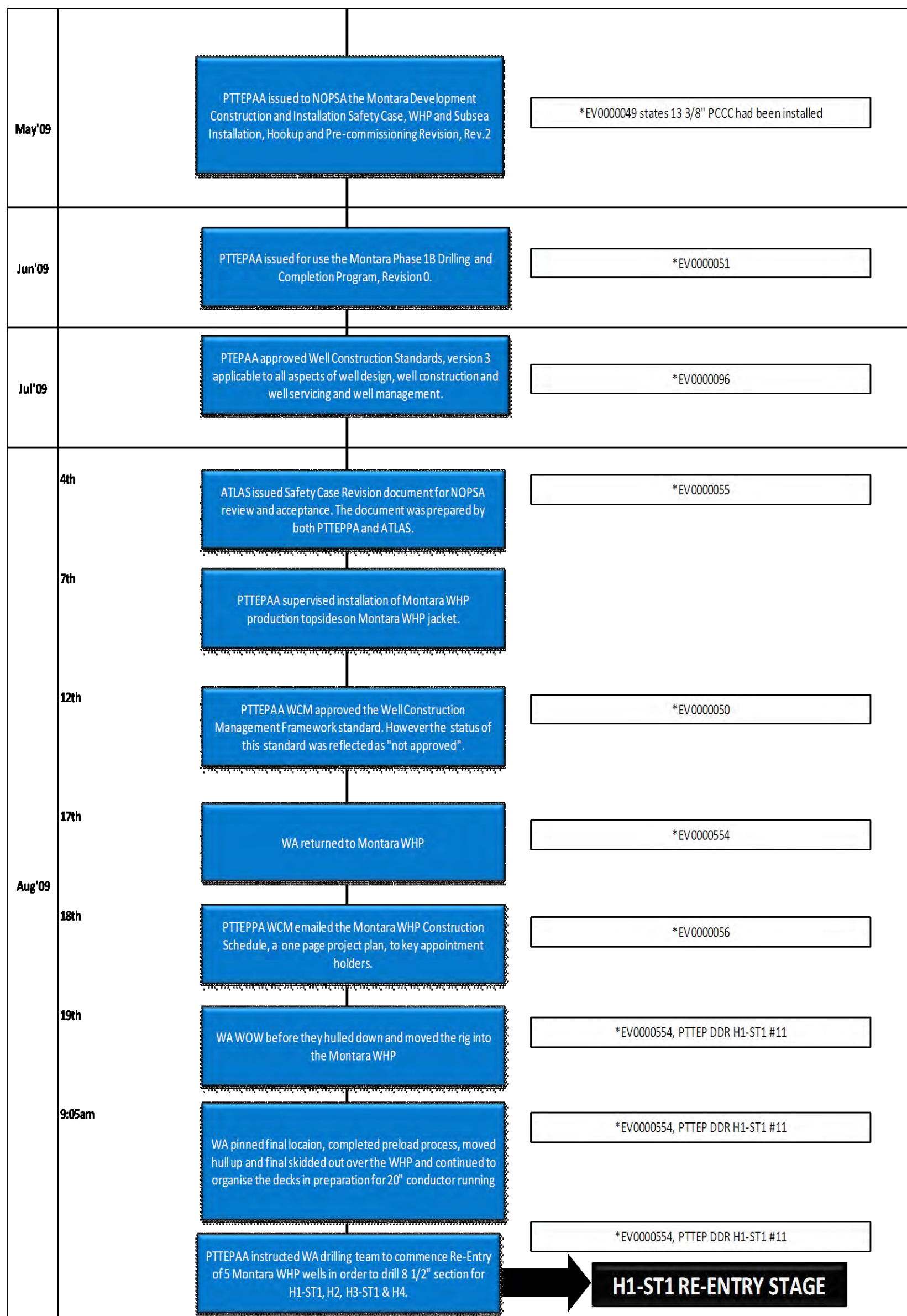
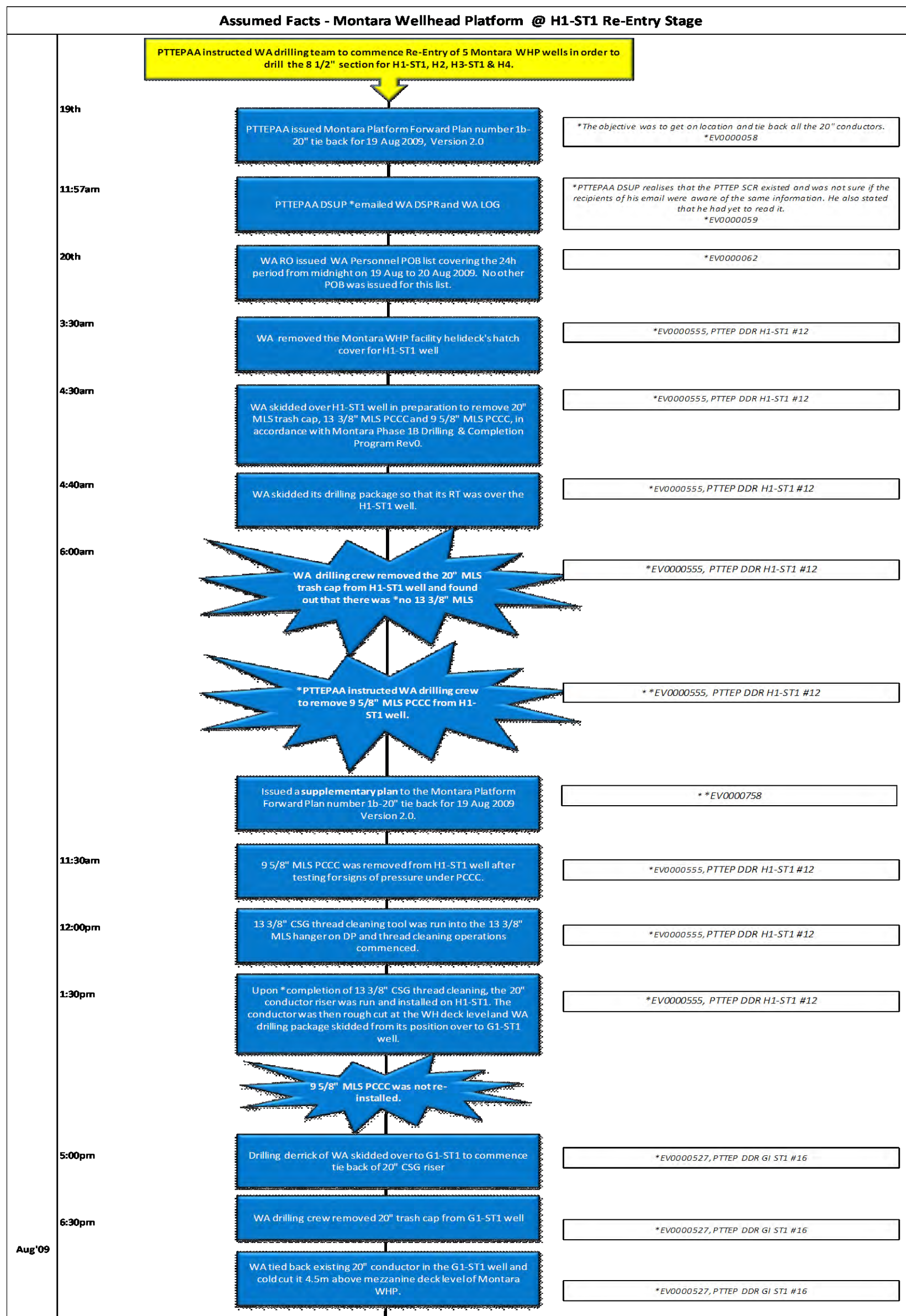


Figure 6 : Timeline of Events - H1-ST1 @ Suspension Stage

2.6 Factual Time Line of Events – H1-ST1 Re-Entry Stage



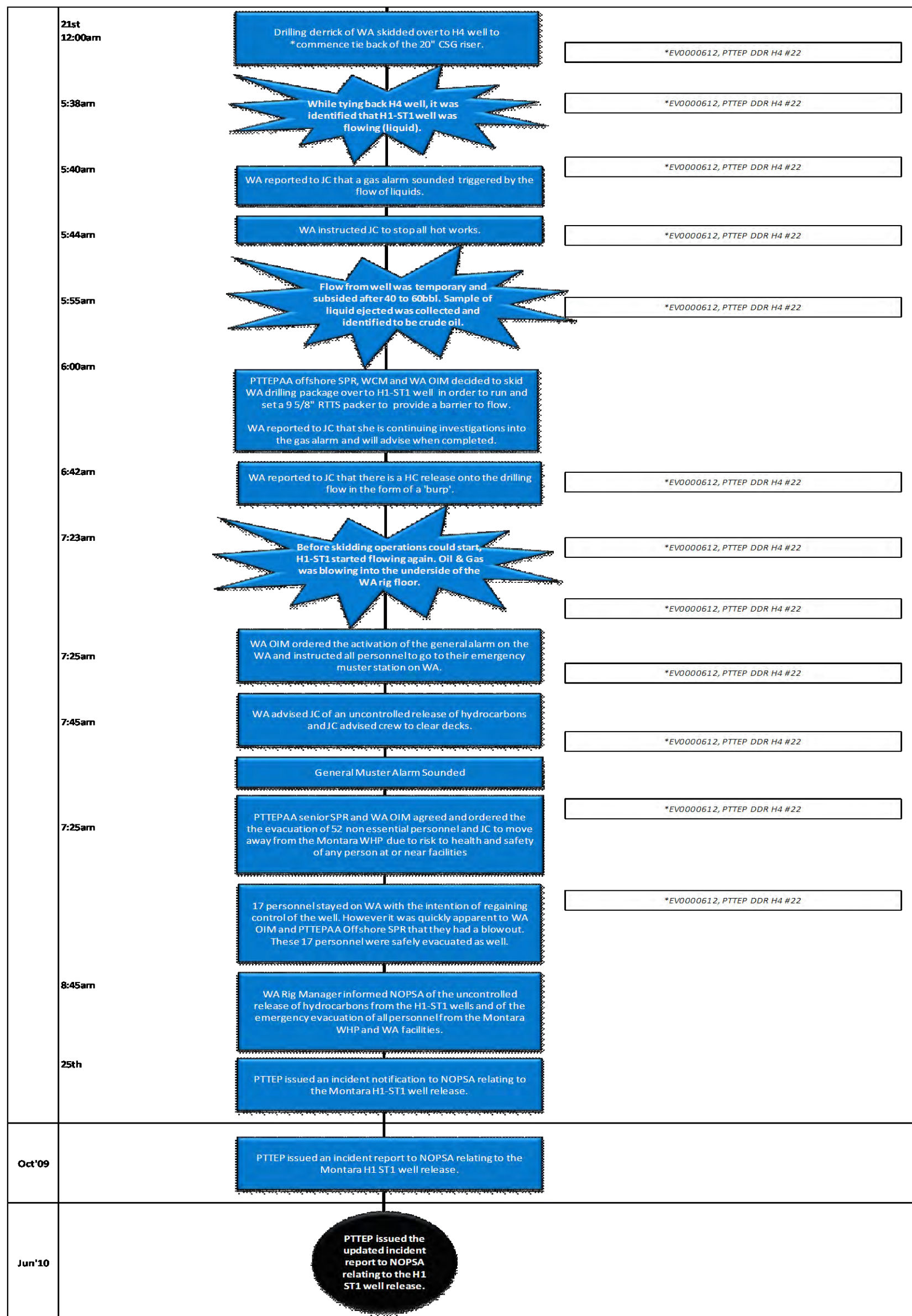


Figure 7 : Timeline of Events - H1-ST1 @ Re-Entry Stage

2.7 Official and Internal Submissions by Coogee Resources/ PTTEPAA

OFFICIAL SUBMISSIONS TO NT DA BY PTTEPAA					FROM DOCUMENTS REVIEWED
#	SW S/N	NOPSA S/N	DATE ISSUED	DOCUMENT TITLE	DESCRIPTION
1	DB-30291-NOPSA-004	EV0000010	30-Jun-08	Coogee Resources-Montara Development-Construction & Installation Safety Case/WHP Hookup & Precommissioning Revision Rev 0	This is a revision to the Montara Consturction and Installation Safety Case Ref1.This safety case revision covers all anticipated hookup, mechanical and compeltions and precommissioning activities for the WHP in the Montara Field.
2	DB-30291-NOPSA-006	EV0000011	30-Sep-08	Coogee Resources-GI, H1 & H4 (Batch Drilled) Drilling Program Rev 0	This is the original drilling program written based on platform topsides in place and the wells to be batch drilled and completed.
3	DB-30291-NOPSA-007	EV0000012	3-Nov-08	Coogee Resources-Montara H1-Well Operations Management Plan (WOMP)	Describes Coogee management system which ensures that the risks associated with the activities relating to the drilling, completion, and suspension of the Montara H1 development well are managed in accordance with good oil field design and engineering practices.
4	DB-30291-NOPSA-008	EV0000018	6-Jan-09	Coogee Resources-GI, H1 & H4 (Batch Drilled) Drilling Program REV:2	This is 2nd Revision of the Drilling Programme and is based on the Platform Topsides not in place and the West Atlas Conductor Deck Extension being used without the conductor tensioner.
5	DB-30291-NOPSA-009	EV0000013	7-Jan-09	Letter from Ian Paton, Subsurface Manager, Coogee Resources to Mr Jerry Whitfield, DoE	In this letter, PTTEPAA informs NTDA of the changes made to the Original Drilling Prgoramme to allow wells to be batched drilled, suspended with no platform topsides in place.
6	DB-30291-NOPSA-010	EV0000014	7-Jan-09	Coogee Resources-GI, H1 & H4-AC/L7-Revised Drilling Program	This is a transmittal advice.
7	DB-30291-NOPSA-015	EV0000803	3-Feb-09	Coogee Resources-Montara H2 & H3 (Batch Drilled) Drilling Program	This is the drilling program for the batch drilling and suspension of Montara H2 and H3 wells down to the 9 5/8" casing point.
8	DB-30291-NOPSA-016	EV0000020	27-Feb-09	Email from Chris Wilson to West Atlas Supervisor- Application for Approval to sidetrack Montara H1-AC-L7	Email approval from NT DA to sidetrack H1 Well. Application received by NT DA on 27 February 2009
9	DB-30291-NOPSA-018	EV0000026	6-Mar-09	Letter addressed to Jerry Whitfield from Ian Paton-PTTEP AA	Application letter to NT DA for approval to suspend Montara H1 -ST1 Development Well in two stages.
10	DB-30291-NOPSA-028	EV0000038	12-Mar-09	Letter addressed to Mr Jerry Whitfield frim Ian Paton, PTTEPAA	Application letter to NT DA for approval to perform stage 2 suspension of Montara H1-ST1 Well.
11	DB-30291-NOPSA-030	EV0000040	13-Mar-09	Email addressed to Ian Paton from Jerry Whitfield- Approval to Suspend Montara H4 & perform Stage 2	NT DA approval to suspend the Montara H4 well and perform Stage 2 suspensions on the Montara GI ST-1 well and the Montara H1 -ST1 well in AC/L7.
12	DB-30291-NOPSA-034	EV0000049	15-May-09	Montara Development Construction and Installation Safety Case for the WHP & Subsea Installation Rev 2	This is a 2nd Revision of EV0000010.
13	DB-30291-NOPSA-036	EV0000051	30-Jun-09	PTTEP Australasia Pty Ltd-Montara Development Project- Montara Phase1B Drilling & Completion Program	Montara Phase 1B: Re-entry drilling and completion program by PTTEPAA

Table 5 : List of Official Submissions to NTDA by PTTEPAA from Documents Reviewed

INTERNAL SUBMISSIONS BY PTTEPAA FROM DOCUMENTS REVIEWED					
#	SW S/N	NOPSA S/N	DATE ISSUED	DOCUMENT TITLE	DESCRIPTION
1	DB-30291-NOPSA-011	EV0000015	23-Jan-09	Coogee Resources-Well Construction Change Control Form -Change Control D65005A 001	Issued to increase the length of Tail Cement for the 9 5/8" Casing to increase the TVD height of the cement above the top of the reservoir
2	DB-30291-NOPSA-012	EV0000016	23-Jan-09	Coogee Resources-Cementing Program-Montara H1 No Topsides	Cementing Program for H1 Well with No Topsides. This is an attachment to the WCCCF D65005A 001.
3	DB-30291-NOPSA-013	EV0000017	30-Jan-09	Coogee Resources--Well Construction Change Control Form- Montara H1 & H4- Change Control D65005A 003	Issued to suspend H1 and H4 at the MLS. No PCCC will be installed, leaving annulus (12 1/4"x 9 5/8") open at surface. A lead cement was added to the programme to cement the annulus 50m into the previous casing shoe.
4	DB-30291-NOPSA-017	EV0000021	3-Mar-09	Email from Chris Wilson-Preliminary Copy of Change Control-Montara H1, H4, H2 & H3	Issued to run 9 5/8" casing centralizers across a small gas sand in the Gibson and Woolaston Formation.
5	DB-30291-NOPSA-019	EV0000028	6-Mar-09	Coogee Resrouces - Workbook containing 6 worksheets including cement calculations	Cementing calculations and Reporting Form Revision 2 Issued on 6 March 2009
6	DB-30291-NOPSA-020	EV0000029	6-Mar-09	PTTEPAA - "Montara H1-ST1, Forward Plan #17-Run and Cement 9 5/8" 6 March 09 Version:1.0	Instructions to run and cement the 9 5/8"casing of the H1-ST1 well.
7	DB-30291-NOPSA-021	EV0000030	6-Mar-09	Excel spreadsheet in the name of PTTEP Australasia & Schlumberger- Montara H1 ST1 MWD Surveys	Montara H1-ST1 Measurement Whilst Drilling (MWD) Surveys.
8	DB-30291-NOPSA-022	EV0000072	6-Mar-09	Coogee Resources Advantage Drilling Fluids Report 6 March 2009	Drilling Fluids Report.
9	DB-30291-NOPSA-023	EV0000032	7-Mar-09	Organisation Chart-Montara Development Project Chart dated 7 March 2009	Organization chart from PTTEPAA.
10	DB-30291-NOPSA-024	EV0000033	7-Mar-09	Montara H1-ST1 Forward Plan #17-Run & Cement 9 5/8 Casing 7 March 09 Version 2.0	Revised instructions to run and cement the 9 5/8"casing of the H1-ST1 well.
11	DB-30291-NOPSA-025	EV0000034	8-Mar-09	Email from West Atlas Drilling Supervisor to Craig Duncan and Chris Wilson-Montara WHP Morning Reports	Email from ATLAS to PTTEPAA on WHP Morning Report.
12	DB-30291-NOPSA-053	EV0000802	12-Mar-09	PTTEPAA - Well Construction Change Control Form - Change Control D65005A 006	Issued to change suspension plan for H1.
13	DB-30291-NOPSA-029	EV0000039	15-Mar-09	Management Standards: PTTEPAA Construct, Service or Abandon Well Process	PTTEPAA Management Standard to construct, services or abandon well.
14	DB-30291-NOPSA-032	EV0000044	14-Apr-09	Email-West Atlas Drilling Supervisor to Duncan, Craig, Wilson Chris- 2009/04/13 Montara WHP Reports	Email form ATLAS to PTTEPAA on Montara WHP report for 13 April 09
15	DB-30291-NOPSA-033	EV0000048	16-Apr-09	Email-West Atlas Drilling Supervisor to Duncan, Craig, Wilson Chris- 2009/04/15 Montara WHP Reports	Email form ATLAS to PTTEPAA on Montara WHP report for 15 April 09
16	DB-30291-NOPSA-037	EV0000096	6-Jul-09	PTTEPAA - Well Construction Standards, Standard ID: D41-502433-FACCOM Version 3	Standard applicable to all aspects of well design, well construction and well servicing and well management
17	DB-30291-NOPSA-038	EV0000054	1-Aug-09	15 Page document PTTEP Organisation Charts 1 August 2009	Documents containing various organization charts by PTTEPAA.
18	DB-30291-NOPSA-035	EV0000050	12-Aug-09	PTTEPAA Management Standard: Well Construction Management Framework Standard ID	PTTEPAA Management Standard
19	DB-30291-NOPSA-040	EV0000056	18-Aug-09	Email: Re Schedule Update West Alias from Attachment 18/08/2009 & 21/08/2009-Email related to to the conduct of drilling operations on the Montara H1-ST1	Email by PTTEPAA on the Montara WHP Construction Schedule.
20	DB-30291-NOPSA-041	EV0000058	19-Aug-09	e-Document-PTTEP Australasia-Montara platform, Forward plan #1b-20 Tie back 19th Aug 09-PTTEP SCR	Program to get on location and tie back all the 20" conductors from the 5 wells.
21	DB-30291-NOPSA-044	EV0000062	20-Aug-09	e-Document-List of Personnel Onboard West Atlas MDOU between 20 Aug 2009 and 21 Aug 2009	West Atlas Personnel on Board (POB) list, from midnight on 19 August 2009 until midnight 20 August 2009.

Table 6 : List of Internal Submissions by PTTEPAA from Documents Reviewed

3. GOOD OILFIELD PRACTICE FOR WELLS

This section of the report provides the reader with background information relating to good oilfield practice and industry standards in the following areas of direct relevance to the investigation:

1. Cementation - Zonal isolation in Oil and Gas Wells;
2. Suspension, and Plug and Abandonment (P&A); and
3. Risk Assessment.

3.1 Reference Standards

Where the Expert Witness refers to 'Good Oilfield Practice' or 'Good Industry Practice' in his statements and opinions within all three (3) volumes of this report, these are drawn from the relevant guidelines, recommended practices, standards and regulations from the following industry bodies:

PSLA	Petroleum Submerged Lands Act (Australian Regulation)
ISO	International Standards Organisation
API	American Petroleum Institute
NORSOK	Norsk Søkkel Konkuranseposisjon (Norwegian Standard)
CFR	Code of Federal Regulations in the Outer Continental Shelf -USA
SWPL	Expert Witness with over 31 years experience in the Oil and Gas industry

It should be noted that most Operators would give the opinion that API standards are a minimum standard for good oilfield practice and in some cases claim that their internal corporate standards exceed API.

3.2 Cementation - Zonal Isolation

Good practices for zonal isolation by cementation in wells should meet two key objectives. The first is to prevent and/or control flow from permeable formations, just prior to, during and after **cementing** operations. Uncontrolled flow from permeable formations can cause serious Well Control events that may threaten the safety of personnel, environment, and

result in loss of business assets and reputation. The second objective is to minimise the occurrence of annular flow, or more commonly termed Sustained Casing Pressure (SCP), during the **Production** phase of wells. The prevalence of SCP is a serious industry challenge.

Achieving success in meeting zonal isolation objectives is through a process that considers the full well life cycle and begins at the Well Planning and Design phase, continues to the physical execution of cementing operations during Well Construction, and the validation of the cement in place as a competent barrier to safeguard against well flow during the Production and Abandonment phases respectively.

The following discussion is to provide NOPSAs with an understanding of fundamental Standards for good cementing and zonal isolation which are followed by most Operators and accepted as 'Good Industry Practice'. This important background information will assist NOPSAs to understand more clearly the answers given to the nine (9) questions.

3.3 Well Planning and Design Considerations

3.3.1 Evaluation of Well for Flow Potential

Before the commencement of drilling, all Operators should attempt to identify and analyze all formations to be drilled for their flow potentials. API STANDARD 65-2, Section B.1, recommends three (3) main techniques for achieving this as follows:

1. Site Selection

- a. Encounters with potential flow zones can be minimised by diligently selecting a site that is able to achieve the target depth while minimizing the risk of encountering a flow. Primarily, this is accomplished through accurate review, analysis and interpretation of available shallow and deep hazards data, and assimilation of this information to the drilling program, especially if offset well information is available.

2. Shallow Hazards

- a. Identification and evaluation of hazards through the use of shallow seismic surveys obtained over potential wellsites can aid the operator in proper site selection. If available, shallow seismic data from offset wells or adjacent fields where shallow flows occurred should be used to verify the analysis.

3. Deeper Hazards

- a. Similar to shallow hazards, such hazards can be identified through seismic interpretation and/or analysis of offset wells or fields.

As stated in NORSOK D-010, the isolation of these hazards must be ensured for abandonment, or for the duration of *well suspension* if applicable, by enforcing a strict two (2) barrier philosophy.

3.3.2 Expected Wellbore Pressure and Temperature

According to API STANDARD 65-2, Section 5.6.4, accurate predictions of static and circulating cementing temperatures have the single and greatest effect on the performance of the cement slurry and therefore the success of the operation. These estimations are often available in the study of offset wells or through thermal modelling performed by the Operator.

Also available for reference from the API are temperature schedules that provide estimations of circulating cement temperatures. These schedules are prepared using wells in shallow water for vertical or near vertical wellbores with low deviation (see API TR 10TR3, Temperatures for API Cement Operating Thickening Time Tests, 1993 Report from the API Task Group on Cementing Temperature Schedules). **These API schedules should not be used for wells that vary significantly from these basic parameters of water depth and wellbore profile, in particular these schedules do not apply to horizontal wellbores.**

For wells where the API temperature schedules do not apply, an estimation of circulating cement temperature data can be obtained using temperature recording devices that are made up in the drillstring or dropped into the drillstring and run on clean-up trips.

Once this data is available, the cement slurry should be designed to perform acceptably over the anticipated range of temperature values that may arise based on the defined temperature range.

3.3.3 Expected Well Conditions

As stated in B.2.1 of API STANDARD 65-2, after evaluating the well for its ability to flow, detailed well planning can begin. An optimum well plan for these conditions incorporates the following features, inter alia:

1. an understanding of pore pressures, fracture gradients, and required mud weights;
2. a casing plan that addresses limitations imposed by pore pressure, fracture gradient, wellbore stability, and other operational concerns;
3. a cementing plan that provides for short- and long-term isolation of potential flow zones;
4. evaluation of the impact of potential thermal pressure (APB) in subsea wells;
5. selection of drilling fluid(s) that will best control wellbore pressures and enhance cementing success;
6. a hydraulics plan that provides for adequate wellbore cleaning and control of static and dynamic wellbore pressures;
7. a barrier design that provides for control of all pressures that may be encountered during the life of the well;
8. a contingency plan that addresses wellbore instability and unintended gains and losses of fluids;
9. adherence to regulations;
10. a means to thoroughly and effectively communicate the plan to the personnel that will execute it.

3.3.4 Cementing Plan

As stated in B.2.4 of API STANDARD 65-2, Short- and long-term isolation of potential flow zones requires proper cementing planning and execution. Listed below are several aspects of well planning that may affect the success of primary cementing operations. These items are covered in more detail in Section 5 of API STANDARD 65-2:

1. hole size and shape (washouts and annular dimension),
2. selection of mud for filter cake and rheological properties,
3. drilling fluid conditioning,
4. spacers,
5. cement slurry design,
6. pump rates,
7. centralization,
8. testing/evaluation plan.

3.3.5 Barrier Design

The barrier philosophy as stated in section B.2.7 of API STANDARD 65-2 is, in general, in good agreement with the NORSOK D-010 standard. The API STANDARD 65-2 states that, *“the operational goal of any well design is to provide sufficient barriers between formations and between those formations and the surface”*. A well’s barrier plan should include maintaining well control via hydrostatic pressure from fluids, selection and use of well control equipment, and the placement of cement or other mechanical barriers in the well. The well centre design (i.e. wellhead, BOP equipment, riser, etc.) should include a minimum of two barriers available during any operation to prevent uncontrolled flow from the well to the atmosphere. The barrier design should incorporate the following elements:

1. ability to withstand the maximum anticipated wellbore pressure,
2. ability to be tested for function and leaks,
3. failure of a single barrier will not result in uncontrolled flow from the well,
4. the operating environment is within the design specifications of the barrier element.

3.4 Cementing Practices and Factors Affecting Cementing Success

3.4.1 Slurry Design and Testing

3.4.1.1 Lead and Tail Cement

According to section 5.7.2 of API STANDARD 65-2, lead and tail cements are routinely placed in the annulus during primary cementing operations. Lead cement can be formulated to meet various criteria ranging from economical filler systems to high performance design. Lower density lead cement is used because it will have lower hydrostatic pressure thus avoiding or minimizing losses of cement to the formation. Tail cements are typically mixed without extending components and thus have a higher density.

Design of the cement must be carefully considered to cover the potential flowing formations. Lead cement not normally designed to cover potential flowing formations could be design to control flow. Doing so may require special formulations. Design for lead slurry to cover formations with a potential to flow is the same as slurry design to cover hydrocarbon bearing zones.

It is important to note that if the potential flow zone is covered by a tail slurry with a lead slurry above that, the static gel strength developed on the lead slurry may reduce the hydrostatic pressure exerted on the potential flow zone before the tail slurry reaches a static gel strength of 500 lbf/100 ft². The significance of 500 lbf/100 ft² static gel strength is explained in greater detail in section 3.4.1.4. This situation requires additional assessment and adjustment to design and operating parameters.

Test methods for determining the performance of cement are described in API RP 10B-2 (ISO 10426-2), API RP 10B-3 (ISO 10426-3), API RP 10B-4 (ISO 10426-4), and API RP 10B-6 (ISO 10426-5). These methods should be modified, as closely as possible, to the conditions to which the cement will be exposed during placement across the potential flowing zones requiring isolation. Temperature/ pressure schedules should be devised for conditioning and curing the cement for these tests.

3.4.1.2 Thickening Time

According to section 5.7.4 of API STANDARD 65-2, the thickening time is the time that a cement slurry is judged to be pumpable under conditions simulating those found downhole during placement. Slurries are designed for the specific set of conditions found in the well and for the designed pumping schedule (rates) to be employed during cementing operations.

The use of excessive safety factors in thickening time design should be avoided. Excessive safety factors can cause delayed strength development, long periods of gelation and increased likelihood of solid segregation. These factors may present a higher potential for flow from the formation before the cement has adequate strength to prevent it.

3.4.1.3 Fluid Loss

According to section 5.7.5 of API STANDARD 65-2, Control of fluid loss plays a key role in preventing flow. Loss of fluid from the slurry is a contributing factor in the loss of the overbalance pressure controlling flow. The rate of fluid loss is dependent on the overbalance pressure, the permeability of the formation, the condition of the drilling fluid cake (including its permeability), and the fluid loss characteristics of the cement. There are numerous fluid loss agent additives available, such as synthetic and natural polymers, copolymers, latex, and blends thereof.

Fluid loss testing should be conducted according to API RP 10B-2/ISO 10426-2. It is not possible to make specific recommendation on the fluid loss rate as it depends on many factors; however a low fluid loss agent is a requirement where there is potential to flow.

3.4.1.4 Static Gel Strength

According to section 5.7.8 of API STANDARD 65-2, static gel strength development is one of the factors that contribute to the decrease in hydrostatic pressure. As a gelled fluid interacts with the casing and borehole wall, it starts to develop a gel strength which develops progressively as the chemical reaction between the cement and water takes place. Ultimately the cement slurry starts to lose its ability to transmit hydrostatic pressure. Static gel strength development also contributes to the ability of the slurry to suspend the solids in the slurry under static conditions. Calculating the Critical Static Gel Strength (CSGS) and then

measuring the Critical Gel Strength Period (CGSP) is one of the methods to evaluate the impact of gel strength development on the potential to resist wellbore fluid influx.

CSGS is defined as the static gel strength of the cement that results in the decay of hydrostatic pressure to the point that pressure is balanced (hydrostatic equals pore pressure) across the potential flowing formation(s).

$$\text{CSGS} = (\text{OBP})(300) \div (L/D_{\text{eff}})$$

- *OBP* is the initial calculated overbalance pressure
- *300* is the conversion factor
- *L* is the length of the cement column above the flow zone (ft)
- *D_{eff}* is the effective diameter (in.) = *D_{OH}* - *D_c*
- *D_c* is the outside diameter of the casing (in.)
- *D_{OH}* is the diameter of the open hole (in.)

Experimental data has shown that gas cannot freely move through cement that has static gel strength ranging from 250 to 500 lbf/100 ft² or more (Tinsley, J.M et al, August 1980). The conservative upper end of this range had been adopted by the industry as the acceptable limit. If the CSGS is lower than 500 lbf/100 ft², it indicates a situation where there is a high probability that formation fluids will enter the wellbore during cementing hydration, if those permeable formations exist across the cemented interval. Vice versa, if the CSGS is approaching 500 lbf/100 ft², it indicates a situation where there is a low probability that formation fluids will enter the wellbore during cementing hydration. With the exception of density, changing the properties of the slurry will not affect the CSGS. The CSGS could only be increased by increasing the hydrostatic overbalance on the potential flow zone, which is achieved by decreasing the length of the cement column above the top of the flow zone, increasing the open hole size or decreasing the casing size.

CGSP is defined as the time period starting when laboratory measurement indicate the slurry has developed CSGS and ending when they show it has developed 500 lbf/100 ft².

With severe flow potentials, the CGSP of the slurry should be minimized to the extent possible. A **CGSP of 45 minutes or less** (measured at the temperature of the potential flow zone) has proven effective.

Static gel strength development is highly dependent on the temperature, chemical and physical nature of the cement being used and any additives in the slurry. Additives used to shorten the CGSP and to control other properties can shorten the gel strength development.

The Expert Witness's interpretation of the CGSP is explained in Figure 8 below.

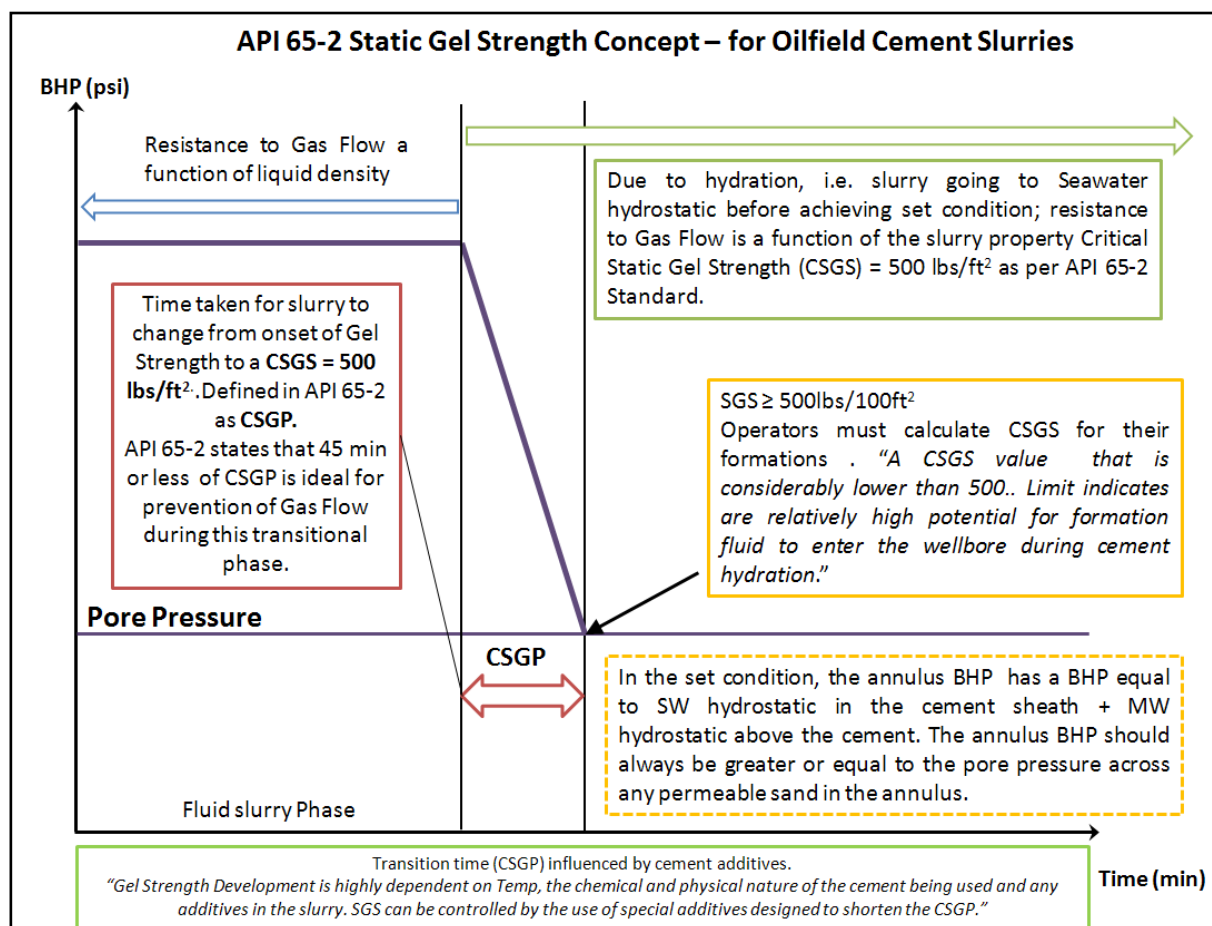


Figure 8: Interpretation of API 65-2 Static Gel Strength Concept for Oilfield Cement Slurries

3.4.1.5 Compressive and Sonic Strength

According to section 5.7.9 of API RP 65-2, compressive strength is the force per unit area required to mechanically fail the cement and sonic strength is calculated by measuring the velocity of sound through the sample. Both compressive and sonic strength are considered synonymous. Development of a minimum of 50 psi compressive or sonic strength is required to consider cement a barrier element. The compressive or sonic strength also impact the WOC requirements for drill out and can also be important when considering long term well integrity.

3.4.2 Wellbore Preparation and Conditioning

3.4.2.1 Hole Quality

According to section 5.2 of API STANDARD 65-2, a hole caliper log is a recommended prerequisite for any primary cementing job design to confirm the volume of cement slurry required to fill the annulus to the designed top of cement in the annulus (TOC). The actual hole size should also be known to allow proper calculations of friction pressure, both during the cementing operation and when running casing. It is also necessary to calculate the centralizer requirements and from centralizer calculations, to calculate flow regimes and rates recommended for effective mud removal. The hole caliper should be of sufficient quality to make the necessary calculations. When conditions prohibit the use of a hole caliper log, a fluid caliper may provide a gross measurement of the hole's circulating volume. Sonic callipers may also be used.

3.4.2.2 Rathole

According to section 5.8.2.5 of API STANDARD 65-2, Rathole beneath the casing shoe can lead to contamination of cement during placement, or mud can swap with the cement after placement. These can result in poor strength development, pockets of mud, or a wet shoe. Rathole length should be minimized or filled with cement or some other type barrier materials (densified drilling fluid) to prevent this.

3.4.2.3 Centralizer Program

According to section 5.8.3.2 of API STANDARD 65-2, centralizing the casing across the intervals to be isolated helps optimize drilling fluid displacement. In poorly centralized casing, cement will follow the path of least resistance. As a result, the cement flows on the wide side of the annulus, leaving drilling fluid in the narrow side. In a deviated and in particular a horizontal wellbore, standoff is even more critical to prevent a solids bed from accumulating on the low side of the annulus, and also free water from the cement slurry forming on the high side of the casing. This results in bypassed mud channels and inability to achieve zonal isolation. Centralization is necessary to improve flow all around the pipe and

aid in mud removal. The recommended standoff should be determined from computer modelling of mud removal and will vary with well conditions.

3.4.3 Cement Job Execution

3.4.3.1 Pipe Movement

According to section 5.9.6 of API STANDARD 65-2, Pipe reciprocation and rotation can assist in effective mud removal. Pipe movement assists in mud removal by altering the flow path of the mud, spacer(s), and cement slurry. Pipe movement can also help to break the gel strengths of mud that may otherwise be bypassed by the spacer and slurry. Operators must determine if the pipe strength is sufficient to allow for rotation.

3.4.3.2 Displacement

According to section 5.9.10 of API STANDARD 65-2, over-displacing if the plug does not bump should be discussed prior to job execution. Volumes in excess of 50% of the capacity of the shoe track **should not be exceeded** when pumping additional fluid over calculated displacement volume. When compressible fluids are used for displacement, the volume required for bumping the plug will be greater than the volume measured in the displacement tanks on the cementing unit. If there is a technical or operational need to bump the plug (e.g. pressure test casing, operate hydraulic hardware, etc) then either a measured or calculated compressibility factor should be taken into consideration when determining the surface volume to be pumped.

3.4.4 Post Cementing Evaluation

According to 7.3 of API STANDARD 65-2, verification of the cement in the annulus (Top of Cement) in agreement to the design plan can be based upon volumetric returns or verified by known wireline measurement techniques.

In order to effectively evaluate a job, one should determine if the objective of the operations had been met. These objectives will vary depending on the cement job. Field evidence of the cement job include record of spacer density and rheology, slurry density control, pump rates, pump pressures and observed returns which conform to the cementing plan. Multiple

recording techniques are available which include temperature, noise, acoustic and ultrasonic cement logs. Interpretation of cement logs is highly subjective. The quality of the cement bond and therefore isolation effectiveness can only be inferred from the downhole (log) measurement. The industry does not have a foolproof way to measure the isolation quality to a 100% accuracy provided by cement behind casing. Direct evidence of a failed cement bond is regularly attained by observation of pressure (SCP) in a production well annulus, or by detection from production data, or other measuring devices such as sonic or temperature logs. API TR 10TR1 gives an overview of the attenuation physics, features and limitations of the various types of cement evaluation logs.

4. P&A AND SUSPENSION REQUIREMENTS

This section of the report describes the standard requirements for P&A and Suspension in Australia, as prescribed by the Petroleum (Submerged Lands) Act 1967, and also describes how other legislative bodies in two other major international offshore oil and gas centres (NORSOK in Norway, and the CFR in the Outer Continental Shelf-USA) legislate requirements for Abandonment and Suspension.

Please note that Volume 2 of this report will document, in the opinion of the Expert Witness, a comparison of the P&A and Suspension efficiency attempted or achieved by PTTEPAA against the requirements for Abandonment and Suspension for the H1-ST1 Well.

4.1 Facts Pertinent with respect to the PSLA

For the purpose of identifying regulations pertaining to Well Operation Management in force at the time of the Montara development, in particular, requirements for the safe Abandonment (for the Montara H1 Wellbore) and Suspension (for the Montara H1-ST1 Wellbore), the following facts are directly relevant and set out below.

In 1980, an Offshore Constitutional Settlement was reached and enacted by the Commonwealth, States and Territories through the Petroleum (Submerged Lands) Act 1967. The result of this legislation forms the framework for jurisdiction of the States/Territories, and remains applicable at the time of the Montara Wellhead Platform event.

In regulatory fulfilment of section 5 of the Petroleum (Submerged Lands) Act 1967, the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004 requires Operators to prepare a Well Operations Management Plan (WOMP) for their activities throughout a well's lifecycle.

4.1.1 Objectives of the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004

With reference to the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004, the object of the Regulation is to ensure that, for petroleum exploration, appraisal and production:

1. *"The design of downhole activities is in accordance with good oil-field practice; and*
2. *Downhole activities are carried out in accordance with an accepted well operations management plan; and*
3. *Risks are identified and managed in accordance with sound engineering principles and good oil-field practice".*

4.1.2 Requirements for Specific Well Activities as part of the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004

With reference to Regulation 17 of the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004, the following are required from the Operator pertaining to conducting well activities by regulation:

1. *"A titleholder (Operator) 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.*
2. *Subregulation (1) applies whether or not:*
 - a. *The titleholder has a current accepted well operations management plan relating to the activity; or*
 - b. *A new well integrity hazard exists that requires the titleholder to vary the titleholder's accepted well operations management plan".*

4.1.3 Impact of Well Integrity hazard or increased risk not identified in well operations management plan as part of the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004

With reference to Regulation 25 of the Petroleum (Submerged Lands) (Management of Well Operations) Regulations 2004, the following are required from the Operator pertaining to conducting well activities by regulation:

1. *"A titleholder (Operator) must not commence/continue a well activity if:*
 - a. *Either:*
 - i. *A well integrity hazard has been identified in relation to the well; or*
 - ii. *There has been a significant increase in an existing risk in relation to the well;**and*
 - b. *The titleholder has not controlled the well integrity hazard or the risk".*

It should also be highlighted that the Act (section 97) also requires a titleholder to carry out operations in accordance with **"good oil field practice"**.

4.2 Relevance of the PSLA for P&A and Suspension Requirements

In view of Section 4.1 above the PSLA regulatory requirements for the development of petroleum related activities in Australia, through the Petroleum (Submerged Lands) Act, requires Operators to conduct P&A and Suspension operations in conformance to good oil field practices and standards, instead of providing detailed specification(s), in Well Integrity terms, of barrier(s) philosophy to achieve required zonal isolation of permeable reservoirs with flow potential.

For the purpose of setting the appropriate framework and providing definitions to "good oil field practice", the sections hereafter set out the minimum requirements, in Well Integrity terms, for P&A and Suspension activities in accordance to relevant International Standards and Recommended Practices.

Please note that Volume 2 of this report will document, in the opinion of the Expert Witness, an assessment of the Well Construction Standard of PTTEPAA measured against these International Standards and Recommended Practices.

4.3 P&A and Suspension Requirements of NORSOK Standard D-010

The NORSOK standards are developed by the Norwegian petroleum industry to ensure adequate safety, value adding and cost effectiveness for petroleum industry developments and operations. Furthermore, NORSOK standards are as far as possible intended to influence oil company specifications and serve as a reference in the authorities' regulations activities.

The NORSOK standards are normally based on recognised international standards, adding the provisions deemed necessary to fill the broad needs of the Norwegian petroleum industry. Where relevant, NORSOK standards are used to provide the Norwegian industry input to the international standardisation process.

The NORSOK standards are developed according to the consensus principle, generally applicable standards, and according to established procedures defined in NORSOK A-001.

4.3.1 Barriers

With reference to the NORSOK Standard D-010, Rev 3 2004, *"Well barriers are defined as envelopes of one or several dependent Well Barrier Elements (WBEs) preventing fluids or gases from flowing unintentionally from the formation, into another formation or to surface"*.

In addition the following individual or combined well barriers shall be a result of well plugging activities:

Name	Function	Purpose
<i>Primary well barrier</i>	<i>First well barrier against flow of formation fluids to surface, or to secure a last open hole.</i>	<i>To isolate a potential source of inflow from surface.</i>
<i>Secondary well barrier, reservoir</i>	<i>Back-up to the primary well barrier.</i>	<i>Same purpose as the primary well barrier, and applies where the potential source of inflow is also a reservoir (w/ flow potential and/ or hydrocarbons).</i>
<i>Well barrier between reservoirs</i>	<i>To isolate reservoirs from each other.</i>	<i>To reduce potential for flow between reservoirs.</i>
<i>Open hole to surface well barrier</i>	<i>To isolate an open hole from surface, which is exposed whilst plugging the well.</i>	<i>"Fail-safe" well barrier, where a potential source of inflow is exposed after e.g. a casing cut.</i>

Name	Function	Purpose
<i>Secondary well barrier, temporary abandonment</i>	<i>Second, independent well barrier in connection with drilling and well activities.</i>	<i>To ensure safe re-connection to a temporary abandoned well, and applies consequently only where well activities has not been concluded.</i>

Table 7: NORSOK D-010 Function and Type of Well Barriers

NORSOK D-010 describes how barrier condition can be established in section 4.2.3 of the standard by “Well barrier acceptance criteria”, defined as *“Technical and Operational requirements that need to be fulfilled in order to qualify the well barrier or WBE for its intended use”*.

In addition, according to section 4.2.4 of the NORSOK D-010 standard, it is stated that *“General technical and operational requirements and guidelines relating to WBEs are collated in tables in Clause 15, which shall be applicable for all type of activities and operations. Additional requirements and guidelines or deviations to these general conditions will be further described in the sections to follow”*.

The methodology for defining the requirements/guidelines for WBEs is shown in Figure 9.

A complete description of general acceptance criteria can be found in Clause 15 of NORSOK D-010 which contains a library of WBE acceptance criteria tables. Several schematics are depicted below for the purpose of stating the “NORSOK D-010 endorsed acceptance criteria” for typical well barriers. PTTEPAA, though not obliged to comply with the NORSOK D-010, since obviously they are operating under Australian law, nevertheless, relied in their management system on similar barriers described in NORSOK D-010. Therefore in the experts’ opinion, it is of relevance to use NORSOK D-010 as one example of “Good Oilfield Practice”.

What follows are the Acceptance Criteria Tables for the following WBE’s:

1. Fluid Column
2. Casing Cement
3. Cement Plug
4. Drilling BOP
5. Casing Float Valves

Features	Acceptance criteria	References
A. Description	<i>This describes the WBE in words.</i>	
B. Function	<i>This describes the main function of the WBE.</i>	
C. Design (capacity, rating, and function), construction and selection	<i>For WBEs that are constructed in the field (i.e. drilling fluid, cement), this should describe</i> <i>design criteria, such as maximal load conditions that the WBE shall withstand and other functional requirements for the period that the WBE will be used,</i> <i>construction requirements for how to actually construct the WBE or its sub-components, and will in most cases only consist of references to normative standards.</i> <i>For WBEs that are already manufactured, the focus should be on selection parameters for choosing the right equipment and how this is assembled in the field.</i>	<i>Name of specific references</i>
D. Initial test and verification	<i>This describes the methods for verifying that the WBE is ready for use after installation in/on the well and before it can be put into use or is accepted as part of well barrier system.</i>	
E. Use	<i>This describes proper use of the WBE in order for it to maintain its function and prevent damage to it during execution of activities and operations.</i>	
F. Monitoring (Regular surveillance, testing and verification)	<i>This describes the methods for verifying that the WBE continues to be intact and fulfils it design/selection criteria during use.</i>	
G. Failure modes	<i>This describes conditions that will impair (weaken or damage) the function of the WBE, which may lead to implementing corrective action or stopping the activity/operation.</i>	

Figure 9: NORSOK D-010 Methodology for defining the requirements/guidelines for WBE

4.3.1.1 Fluid Column

Features	Acceptance criteria	See
A. Description	This is the fluid in the well bore.	NORSOK D-001
B. Function	The purpose of the fluid column as a well barrier/WBE is to exert a hydrostatic pressure in the well bore that will prevent well influx/inflow (kick) of formation fluid.	
C. Design construction selection	1. The hydrostatic pressure shall at all times be equal to the estimated or measured pore/reservoir pressure, plus a defined safety margin (e.g. riser margin, trip margin). 2. Critical fluid properties and specifications shall be described prior to any operation. 3. The density shall be stable within specified tolerances under down hole conditions for a specified period of time when no circulation is performed. 4. The hydrostatic pressure should not exceed the formation fracture pressure in the open hole including a safety margin or as defined by the kick margin. 5. Changes in well bore pressure caused by tripping (surge and swab) and circulation of fluid (ECD) should be estimated and included in the above safety margins.	ISO 10416
D. Initial test and verification	1. Stable fluid level shall be verified. 2. Critical fluid properties, including density shall be within specifications.	
E. Use	1. It shall at all times be possible to maintain the fluid level in the well through circulation or by filling. 2. It shall be possible to adjust critical fluid properties to maintain or modify specifications. 3. Acceptable static and dynamic loss rates of fluid to the formation shall be pre-defined. 4. There should be sufficient fluid materials, including contingency materials available on the location to maintain the fluid well barrier with the minimum acceptable density.	
F. Monitoring	1. Fluid level in the well and active pits shall be monitored continuously. 2. Fluid return rate from the well shall be monitored continuously. 3. Flow checks should be performed upon indications of increased return rate, increased volume in surface pits, increased gas content, flow on connections or at specified regular intervals. The flow check should last for 10 min. HTHP: All flow checks should last 30 min. 4. Measurement of fluid density (in/out) during circulation shall be performed regularly. 5. Measurement of critical fluid properties shall be performed every 12 circulating hours and compared with specified properties. 6. Parameters required for killing of the well .	ISO 10414-1 ISO 10414-2
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. Flow of formation fluids.	

Figure 10: Fluid Column Well Barrier Element Acceptance Table (Ref: Clause 15.1 NORSOK D-010 Standard, Rev 3, 2004)

4.3.1.2 Casing Cement

Features	Acceptance criteria	See
A. Description	This element consists of cement in solid state located in the annulus between concentric casing strings, or the casing/liner and the formation.	
B. Function	The purpose of the element is to provide a continuous, permanent and impermeable hydraulic seal along hole in the casing annulus or between casing strings, to prevent flow of formation fluids, resist pressures from above or below, and support casing or liner strings structurally.	
C. Design, construction and selection	1. A design and installation specification (cementing programme) shall be issued for each primary casing cementing job. 2. The properties of the set cement shall be capable to provide lasting zonal isolation and structural support. 3. Cement slurries used for isolating permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. The cement placement technique applied should ensure a job that meets requirements whilst at the same time imposing minimum overbalance on weak formations. ECD and the risk of lost returns during cementing shall be assessed and mitigated. 5. Cement height in casing annulus along hole (TOC): 5.1 General: Shall be 100 m above a casing shoe, where the cement column in consecutive operations is pressure tested/the casing shoe is drilled out. 5.2 Conductor: No requirement as this is not defined as a WBE. 5.3 Surface casing: Shall be defined based on load conditions from wellhead equipment and operations. TOC should be inside the conductor shoe, or to surface/seabed if no conductor is installed 5.4 Casing through hydrocarbon bearing formations: Shall be defined based on requirements for zonal isolation. Cement should cover potential cross-flow interval between different reservoir zones. For cemented casing strings which are not drilled out, the height above a point of potential inflow/ leakage point / permeable formation with hydrocarbons, shall be 200 m, or to previous casing shoe, whichever is less. 6. Temperature exposure, cyclic or development over time, shall not lead to reduction in strength or isolation capability. 7. Requirements to achieve the along hole pressure integrity in slant wells to be identified.	ISO 10426-1 Class 'G'
D. Initial verification	1. The cement shall be verified through formation strength test when the casing shoe is drilled out. Alternatively the verification may be through exposing the cement column for differential pressure from fluid column above cement in annulus. In the latter case the pressure integrity acceptance criteria and verification requirements shall be defined. 2. The verification requirements for having obtained the minimum cement height shall be described, which can be • verification by logs (cement bond, temperature, LWD sonic), or • estimation on the basis of records from the cement operation (volumes pumped, returns during cementing, etc.). 3. The strength development of the cement slurry shall be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. For HPHT wells such equipment should be used on the rig site.	
E. Use	None	
F. Monitoring	1. The annuli pressure above the cement well barrier shall be monitored regularly when access to this annulus exists. 2. Surface casing by conductor annulus outlet to be visually observed regularly.	WBEAC for "wellhead"
G. Failure modes	Non-fulfilment of the above requirements (shall) and the following: 1. Pressure build-up in annulus as a result of e.g. micro-annulus, channelling in the cement column, etc.	

Figure 11: Casing Cement Well Barrier Element Acceptance Table (Ref: Clause 15.22 NORSOK D-010 Standard, Rev 3, 2004)

4.3.1.3 Cement Plug

Features	Acceptance criteria	See						
A. Description	The element consists of cement in solid state that forms a plug in the wellbore.							
B. Function	The purpose of the plug is to prevent flow of formation fluids inside a wellbore between formation zones and/or to surface/seabed.							
C. Design, construction and selection	1. A design and installation specification (cementing program) shall be issued for each cement plug installation. 2. The properties of the set cement plug shall be capable to provide lasting zonal isolation . 3. Cement slurries used in plugs to isolate permeable and abnormally pressured hydrocarbon bearing zones should be designed to prevent gas migration. 4. Permanent cement plugs should be designed to provide a lasting seal with the expected static and dynamic conditions and loads down hole 5. It shall be designed for the highest differential pressure and highest downhole temperature expected, inclusive installation and test loads. 6. A minimum cement batch volume shall be defined for the plug in order that homogenous slurry can be made, to account for contamination on surface, downhole and whilst spotting downhole. 7. The firm plug length shall be 100 m MD. If a plug is set inside casing and with a mechanical plug as a foundation, the minimum length shall be 50 m MD. 8. It shall extend minimum 50 m MD above any source of inflow/ leakage point. A plug in transition from open hole to casing should extend at least 50 m MD below casing shoe. 9. A casing/ liner with shoe installed in permeable formations should have a 25 m MD shoe track plug.	API Standard 10A Class 'G'						
D. Initial verification	1. Cased hole plugs should be tested either in the direction of flow or from above. 2. The strength development of the cement slurry should be verified through observation of representative surface samples from the mixing cured under a representative temperature and pressure. 3. The plug installation shall be verified through documentation of job performance; records fm. cement operation (volumes pumped, returns during cementing, etc.). 4. Its position shall be verified, by means of: <table><thead><tr><th>Plug type</th><th>Verification</th></tr></thead><tbody><tr><td>Open hole</td><td>Tagging, or measure to confirm depth of firm plug.</td></tr><tr><td>Cased hole</td><td>Tagging, or measure to confirm depth of firm plug Pressure test, which shall a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and b. not exceed casing pressure test, less casing wear factor which ever is lower If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.</td></tr></tbody></table>	Plug type	Verification	Open hole	Tagging, or measure to confirm depth of firm plug.	Cased hole	Tagging, or measure to confirm depth of firm plug Pressure test, which shall a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and b. not exceed casing pressure test, less casing wear factor which ever is lower If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.	
Plug type	Verification							
Open hole	Tagging, or measure to confirm depth of firm plug.							
Cased hole	Tagging, or measure to confirm depth of firm plug Pressure test, which shall a. be 7000 kPa (~1000 psi) above estimated formation strength below casing/ potential leak path, or 3500 kPa (~500 psi) for surface casing plugs, and b. not exceed casing pressure test, less casing wear factor which ever is lower If a mechanical plug is used as a foundation for the cement plug and this is tagged and pressure tested the cement plug does not have to be verified.							
E. Use	Ageing test may be required to document long term integrity.							
F. Monitoring	For temporary suspended wells: The fluid level/ pressure above the shallowest set plug shall be monitored regularly when access to the bore exists.							
G. Failure modes	Non-compliance with above mentioned requirements and the following: a. Loss or gain in fluid column above plug. b. Pressure build-up in a conduit which should be protected by the plug.							

Figure 12: Cement Plug Well Barrier Element Acceptance Table (Ref: Clause 15.24 NORSOK D-010 Standard, Rev 3, 2004)

4.3.1.4 Drilling BOP

Features	Acceptance criteria	See
A. Description	The element consists of the wellhead connector and drilling BOP with kill/choke line valves.	NORSOK D-001
B. Function	The function of wellhead connector is to prevent flow from the bore to the environment and to provide a mechanical connection between drilling BOP and the wellhead. The function of the BOP is to provide capabilities to close in and seal the well bore with or without tools/equipment through the BOP.	
C. Design construction selection	1. The drilling BOP shall be constructed in accordance with NORSOK D-001. 2. The BOP WP shall exceed the MWDP including a margin for killing operations. 3. It shall be documented that the shear/seal ram can shear the drill pipe, tubing, wireline, CT or other specified tools, and seal the well bore thereafter. If this can not be documented by the manufacturer, a qualification test shall be performed and documented. 4. When running non shearable items, there shall be minimum one pipe ram or annular preventer able to seal the actual size of the non shearable item. 5. For floaters the wellhead connector shall be equipped with a secondary release feature allowing release with ROV. 6. When using tapered drill pipe string there should be pipe rams to fit each pipe size. Variable bore rams should have sufficient hang off load capacity. 7. There shall be an outlet below the LPR. This outlet shall be used as the last resort to regain well control in a well control situation. 8. HTHP: The BOP shall be furnished with surface readout pressure and temperature. 9. Deep water: 9.1. The BOP should be furnished with surface readout pressure and temperature. 9.2. The drilling BOP shall have two annular preventers. One or both of the annular preventers shall be part of the LMRP. It should be possible to bleed off gas trapped between the preventers in a controlled way. 9.3. Bending loads on the BOP flanges and connector shall be verified to withstand maximum bending loads (e.g. highest allowable riser angle and highest expected drilling fluid density.) 9.4. From a DP vessel it shall be possible to shear full casing strings and seal thereafter. If this is not possible the casings should be run as liners.	NORSOK D-001 API RP 53
D. Initial test and verification	See Annex A, Table A.1.	
E. Use	The drilling BOP elements shall be activated as described in the well control action procedures.	
F. Monitoring	See Annex A, Table A.1.	
G. Failure modes	Non-fulfillment of the above mentioned requirements (shall) and the following: 1. See Annex A, Table A.2.	

Figure 13: Drilling BOP Well Barrier Element Acceptance Table (Ref: Clause 15.4 NORSOK D-010 Standard, Rev 3, 2004)

4.3.1.5 Casing Float Valves

Features	Acceptance criteria	See
A. Description	The element consists of a tubular body with pin and box threads and an internal one-way valve.	
B. Function	The purpose is to prevent flow of fluids from the well bore up the casing/liner during installation of casing/liner and to allow for circulating the well.	
C. Design construction selection	1. The element shall allow for pumping fluids down the casing/liner but prevent any flow in the opposite direction. 2. The element shall withstand expected burst, collapse and axial loads including design factors. 3. The working/sealing pressure of the element shall be equal to the maximum expected differential pressure across the element plus a defined safety factor. 4. The element shall function at expected well bore conditions with regards to differential pressure, temperature and fluid characteristics.	ISO 10427-3
D. Initial test and verification	1. Specifications and performance shall be documented by vendor. 2. Should be inflow-/function tested during casing/liner running.	
E. Use	Shall be installed according to vendor's procedure.	
F. Monitoring	Not applicable after initial testing.	
G. Failure modes	1. Failure to install according to procedure. 2. Failure to inflow test.	

Figure 14: Casing Float Valves Well Barrier Element Acceptance Table (Ref: Clause 15.41 NORSOK D-010 Standard, Rev 3, 2004)

4.3.1.6 Corrosion Caps

No acceptance criteria have been provided in the NORSOK D-010 Standard, Rev 3, 2004 for Corrosion Caps. However, as stated in section 4.2.3.3 of the NORSOK D-010, *“Well barrier acceptance criteria are technical and operational requirements that need to be fulfilled in order to qualify the well barrier or WBE for its intended use”*. It can be claimed then that “Good Oilfield Practice” would dictate that Corrosion Caps can qualify as a well barrier provided they are designed, selected and/or constructed such that:

1. *“it can withstand the maximum anticipated differential pressure it may become exposed to;*
2. *it can be leak tested and function tested or verified by other methods;*
3. *no single failure of well barrier or WBE leads to uncontrolled outflow from the borehole/ well to the external environment;*
4. *re-establishment of a lost well barrier or another alternative well barrier can be done;*

5. *it can operate competently and withstand the environment for which it may be exposed to over time;*
6. *its physical location and integrity status of the well barrier is known at all times when such monitoring is possible”.*

4.3.2 Sidetracking, Abandonment and Long Term Suspension

The focus of Section 9 of the NORSOK Standard D-010, Rev 3 2004 covers requirements and guidelines pertaining to Well Integrity for:

1. Temporary suspension of well activities and operations
2. Temporary/permanent abandonment of wells
3. Permanent abandonment of a section of a well (slot recovery, side-tracking) to construct a new wellbore with a new geological well target.

4.3.2.1 Suspension

According to section 9.3.6 of the NORSOK Standard D-010, Rev 3 2004, suspension of operations requires the same number of well barriers as other abandonment activities. Additionally, NORSOK D-010 states the need for WBE testing, and verification, can be compensated by **monitoring** of its performance, such as fluid level/pressure development above well barriers. In such a case, NORSOK D-010 endorses well fluids as a qualified WBE.

4.3.2.2 Temporary Abandonment

According to section 9.3.7 of the NORSOK Standard D-010, Rev 3 2004, it shall be possible to re-enter temporarily abandoned wells in a safe manner. Integrity of materials used for temporary abandonment should be ensured for two (2) times the planned abandonment period. Hence, a mechanical well barrier may be acceptable for temporary abandonment, subject to type, planned abandonment period and subsurface environment.

4.3.2.3 Permanent Abandonment

According to section 9.3.8 of the NORSOK Standard D-010, Rev 3 2004, permanently plugged wells shall be abandoned with an eternal perspective. There shall be at least one well barrier

between surface and a potential source of inflow, unless it is a **reservoir** (contains hydrocarbons and/ or has a flow potential) where **two well barriers** are required.

Permanent well barriers shall extend across the full cross section of the well, include all annuli. Hence, a WBE set inside a casing, as part of a permanent well barrier, shall be located in a depth interval where there is a WBE with verified quality in all annuli.

Open hole cement plugs can be used as a well barrier between reservoirs. It should, as far as practicably possible, also be used as a primary well barrier.

4.3.2.4 Sidetracking

According to section 9.3.5 of the NORSOK Standard D-010, Rev 3 2004, the original wellbore shall be “**permanently abandoned**” prior to a side-track.

4.4 P&A and Suspension Requirements of the Code of Federal Regulations (CFR) in the Outer Continental Shelf

The document 30 CFR 250, Subpart Q, contains the regulations of the Bureau of Safety and Environmental Enforcement (BSEE) Offshore program that govern oil, gas, and sulphur exploration, development, and production operations on the Outer Continental Shelf (OCS).

4.4.1 Barriers

According to 30 CFR 250.174, BSEE states that the Operator 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".*

4.4.2 Abandonment and Long Term Suspension

4.4.2.1 Long Term Suspension

According to 30 CFR 250.174, BSEE states that for **temporarily** abandoning a well, the following must be conformed to:

1. *"Adhere to the plugging and testing requirements for permanently plugged wells listed in the table in §250.1715, except for §250.1715(a)(8). The Operator does not need to sever the casings, remove the wellhead, or clear the site;*
2. *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;*
3. *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".*

PERMANENT WELL PLUGGING REQUIREMENTS	
<i>If you have—</i>	<i>Then you must use—</i>
<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 currently open and not previously squeezed or isolated.</i>	<i>(i) A method to squeeze cement to all perforations; (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 (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. (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; (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; (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; (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 (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>
<i>(4) A casing stub where the stub end is within the casing.</i>	<i>(i) A cement plug set at least 100 feet above and below the stub end; (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 (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>
<i>(5) A casing stub where the stub end is below the casing.</i>	<i>A plug as specified in paragraph (a)(1) or (a)(2) of this section, as applicable.</i>
<i>(6) An annular space that communicates with open hole and extends to the mud line.</i>	<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>
<i>(7) A subsea well with unsealed annulus.</i>	<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>

PERMANENT WELL PLUGGING REQUIREMENTS	
<i>If you have—</i>	<i>Then you must use—</i>
<i>(8) A well with casing.....</i>	<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>
<i>(9) Fluid left in the hole.....</i>	<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>
<i>(10) Permafrost areas.....</i>	<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 (ii) Cement plugs designed to set before freezing and have a low heat of hydration.</i>

Table 8: Plugging Requirements as per 250.1715

4.4.2.2 Abandonment

According to 30 CFR 250.174, BSEE states that for permanently abandoned wellbores, in particular with zones in the open hole, *“cement plug(s) must be set from at least 100 ft below the bottom to 100 feet above the top of oil, gas, and fresh-water zones to isolate fluids in the strata”*.

4.5 P&A and Suspension Requirements of PTTEPAA Well Construction Standards

4.5.1 Barriers

With reference to Section 5 of the approved PTTEPAA Well Construction Standards (referenced by NOPSAs as [“EV0000096”]), it is stated that during drilling, completion, testing, intervention and other open hole operations, the following barriers shall be maintained in the annulus:

1. *“Two proven barriers between hydrocarbon bearing permeable zones and the surface*
2. *One proven barrier between permeable fresh water bearing zones and surface”*

Furthermore, barrier verification, as stated by PTTEPAA, must be verified in-situ as follows:

Barrier Type	Verification
<i>Cement Plug (Not surface plugs)</i>	1. <i>Tagging with sufficient force to confirm the top of good cement</i> 2. <i>Tagging pressure must equal the equivalent of 3500KPa (500 psi)</i> 3. Or <i>Pressure Testing to 7000 KPa (1000 psi) over leak off</i>
<i>Cement Plug on bridge plug</i>	1. <i>Tag bridge plug then pressure testing to 7000 KPa (1000 psi) over leak off after setting cement plug</i>
<i>Annulus Cement</i>	1. <i>Waiting until the surface cement (tail) samples are set, providing that the cement job proceeded normally and a clear pressure differential was observed prior to bumping the plug.</i> 2. <i>The differential pressure must confirm that the TOC is a minimum of 50m above any hydrocarbon or over-pressured water zone</i>
<i>All Other Barriers</i>	1. <i>By either pressure or inflow testing</i>

Table 9: PTTEPAA Well Construction Standard Barrier(s) Verification

4.5.2 Abandonment and Long Term Suspension

4.5.2.1 Long Term Suspension

Long Term Suspension, as defined by PTTEPAA, is *“when the MODU leaves the well site”*. Wells must be suspended so that they can be abandoned with rig less intervention to meet the standards below.

Accordingly, for Long Term Suspension, *“two permanent tested barriers must be installed in the annulus and wellbore above any hydrocarbon zone or over pressured zone”*. The following are permanent barriers:

Barrier Type	Description
<i>Permanent</i>	<i>1. Pressure tested cement plug (min 30m in length)</i> <i>2. Permanent Packer with no controlled internal flow path and cement on top</i> <i>3. Cemented Casing with proven TOC</i> <i>4. Hanger Packer</i> <i>5. Tubing Seals</i> <i>6. Annulus Master Valve</i>

Table 10: PTTEPAA Long Term Suspension Barrier Types

4.5.2.2 Abandonment

Two permanent tested barriers must be installed in the annulus and wellbore above any hydrocarbon zone or over pressured zone. For the purpose of open hole Abandonment, in the case of the 12 ¼" (311mm) OH of the H-1 wellbore Abandonment, the Abandonment Programme must comply with the following:

Section	Requirement
<i>Open hole</i>	<i>1. Cement plugs shall be placed with a minimum of 30m of cement above and a minimum of 30m below any significant oil, gas or fresh water zones</i>

Table 11: PTTEPAA Abandonment Requirements

5. RISK ASSESSMENT AND MANAGEMENT

This section of the report provides the reader with background information relating to good oilfield practice and industry standards in the area of Risk Assessment, including the available tools for conducting Operator Risk Assessments. The methodologies used by the Expert Witness to conduct Risk Assessments are also explained in this section within the context of industry standard practice.

5.1 Introduction

There has been a major growth in interest over the last decade to improve an organization's ability to deal with uncertainty, especially with its negative impact at the organization level. This has led to the development and application of standards, systems, tools, methodologies and processes which fall under the broad classification of "Risk Management". The methods, definitions and goals vary widely according to whether the management of risk is within the context of finance, insurance, engineering, project management, industrial processes, safety, or public health and safety.

It is important to distinguish between the management of financial risks, itself a specialized area which has evolved to manage specific business risks related to the Finance and Insurance industries and mainly concerned with monetary gains and losses, and the management of operational risks, which within this report relates to the coordination of activities to direct and control an organization with regard to risks inherent in its day to day operations in order to deliver its business objectives.

Operational Risk Management in general is evolving to overcome a lack of consistency in firstly the definition, and secondly the implementation and practice of risk and Risk Management as it relates across different industries. Recent trends indicate an appetite by stakeholders across various industries at large to adopt a more consistent approach to risk and Risk Management, evidenced by the release of the International Standards Organization document, "International Standard ISO/FDIS 31000 Risk Management – Principles and guidelines" (ISO/FDIS 31000:2009).

For the offshore oil and gas industry operational Risk Management, hereafter referred to as Risk Management, is regulated by a safety case regime in many countries. This activity has driven the

development of numerous regulations, standards and guidelines that prescribe and advise organizations on the best way to manage their operational risks. The recent events in major oil & gas producing areas including offshore Australia [Montara, National Offshore Petroleum Safety Authority (NOPSAs) - Australia, 2009], the Gulf of Mexico in the USA [Macondo, Bureau of Ocean and Environmental Management Regulation and Enforcement (BOEMRE) - USA, 2010] and offshore Norway [Gullfaks, Petroleum Safety Authority (PSA) - Norway, 2011] have given cause for each country's relevant petroleum authority to revisit the subject of Risk Management with their key stakeholders. In particular, the Norwegian PSA have explicitly stated that the *"industry does not have the right tools for incident assessment."* [Source: PSA Website: <http://www.ptil.no/news/accident-investigations-are-opportunities-for-learning-article6884-79.html>]. There has been much activity to review Risk Management as it relates to each regulatory regime as a minimum, including the extent to which regulatory compliance is mandated and demonstrated by operators to safeguard against the risk of similar events in the future, in countries with and without a prescriptive regulatory regime. Central to the Risk Management process is Risk Assessment which is associated with the overall process of risk identification, risk analysis and risk evaluation.

5.2 Definitions

The Oxford English Dictionary defines the term Risk as "a situation involving exposure to danger", and in singular "the possibility that something unpleasant or unwelcome will happen." Risk Assessment is then defined as "a systematic process of evaluating the potential risks that may be involved in a projected activity or undertaking."

There exists within the Risk Management discipline a myriad of different definitions of risk and Risk Assessment depending on the specific industry and context to which the term is applied, reflecting the need for standardization across common lines. **The most recent innovation is for risk to be defined in terms of the effect of uncertainties on objectives whilst previous definitions have focused on risk as being the chance of something happening that will have an impact on objectives.**

Risk is defined by the International Standards Organization document, "International Standard ISO/FDIS 31000 Risk Management – Principles and guidelines" (ISO/FDIS 31000:2009) as the:

“...effect of uncertainty on objectives.”

NOTE 1 An effect is a deviation from the expected – positive and/or negative;

NOTE 2 Objectives can have different aspects (such as financial, health and safety, environmental goals) and can apply at different levels (such as strategic, organization-wide, project, product and processes).

NOTE 3 Risk is often characterized by reference to potential events and consequences, or a combination of these.

NOTE 4 Risk is often expressed in terms of a combination of the consequences of an event (including changes in circumstances) and the associated likelihood of occurrence).

NOTE 5 Uncertainty is the state, even partial, of deficiency of information related to, understanding or knowledge of an event, its consequence, or likelihood.

Risk Assessment is defined within ISO/FDIS 31000:2009 as the:

“...overall process of risk identification, risk analysis and risk evaluation.”

Simply put, the effective management of risk enables an organization to maximize its opportunities and achieve its objectives.

The following oil and gas regulatory and professional bodies worldwide have adopted a similar definition of “risk” and “Risk Assessment” as the ISO/FDIS 31000:2009 definition in general:

Regulatory Bodies

1. Petroleum Safety Authority Norway (PSA/PTIL) - Norway
2. National Offshore Petroleum Safety Authority (NOPSAs) – Australia
3. UK Health and Safety Executive – United Kingdom Of Great Britain

Professional Bodies

1. A Guide to the Project Management Body of Knowledge (PMBOK) - Chapter 11 - Project Risk Management; Project Management Institute, USA 2002 20 (New edition in 2005) - American National Standard ANSI/PMI 99-001-2004;

2. International Association of Drilling Contractors (IADC) - IADC HSE Case Guidelines Appendix 2 Issue 3.2.1 – 1 May 2009;
3. Norsk Sokkels Konkuranseposisjon (NORSOK) – Standards developed by the Norwegian Technology Centre;
4. Det Norske Veritas (DNV);

5.3 What is Risk Assessment?

The process for managing risk involves coordinating activities to direct and control an organization with regard to risk, and is represented by the diagram under Figure 15 below.

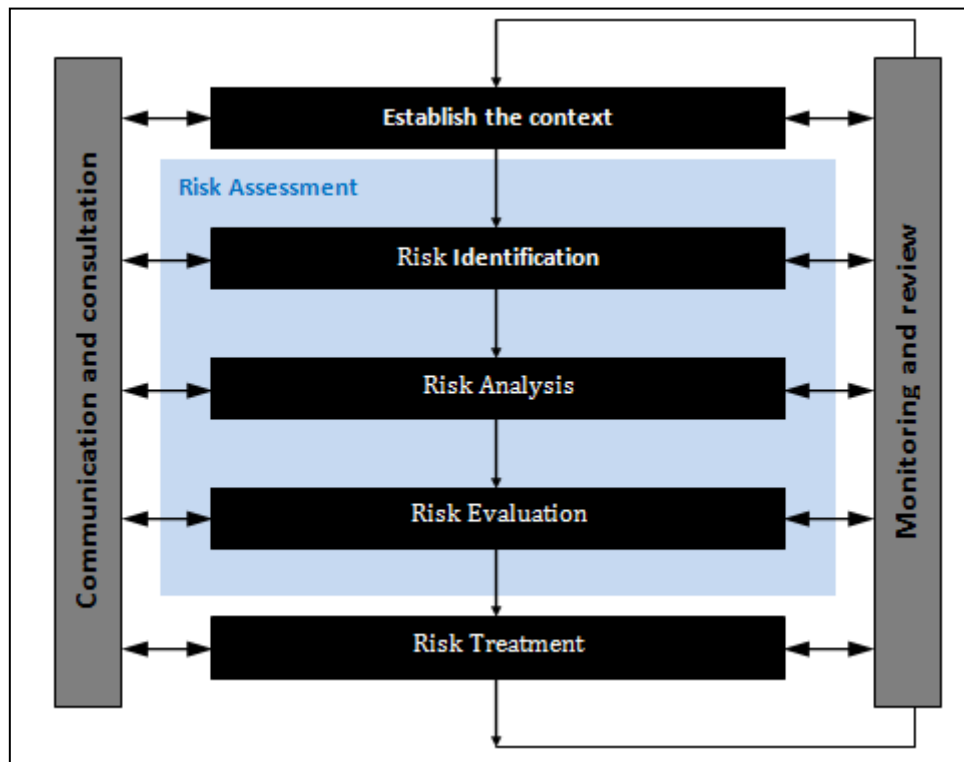


Figure 15: The Risk Management Process

Effective Risk Management involves constant communication and consultation with key stakeholders together with continuous improvement through monitoring and review throughout the entire process. Central to managing risk effectively is through the use a rigorous Risk Assessment process which involves the identification, analysis & evaluation of risk. Each step within the Risk Assessment sub-process within the shaded area is set out in detail hereafter.

Risk identification

Having established the context, the goal of risk identification is to identify sources of risk, areas of impacts, events (including changes in circumstances) and their causes and their potential consequences. The aim of this step is to generate a comprehensive list of risks based on those events that might create, enhance, prevent, degrade, accelerate or delay the achievement of objectives. It is also important to identify the risks associated with not pursuing an opportunity. Comprehensive identification is critical, because a risk that is not identified at this stage will not be included in further analysis.

Identification should include risks whether or not their source is under control of the organization, even though the risk source or cause may not be evident. Risk identification should include examination of the flow-on effects of particular consequences, including cascade and cumulative effects. It should also consider a wide range of consequences even if the risk source or cause may not be evident. As well as identifying what might happen, it is necessary to consider possible causes and scenarios that show what consequences can occur. All significant consequences should be considered.

Suitable risk identification tools and techniques should be applied to meet the objectives and capabilities of the organization, and to the risks faced. Relevant and up-to-date information is important in identifying risks. This should include appropriate background information where possible. People with appropriate knowledge should be involved in identifying risks.

Risk analysis

Risk analysis involves developing an understanding of the risk. Risk analysis provides an input to risk evaluation and to decisions on whether risks need to be treated, and on the most appropriate risk treatment strategies and methods. Risk analysis can also provide an input into making decisions where choices must be made and the options involve different types and levels of risk.

Risk analysis involves consideration of the causes and sources of risk, their positive and negative consequences, and the likelihood that those consequences can occur. Factors that affect consequences and likelihood should be identified. Risk is analyzed by determining consequences and their likelihood, and other attributes of the risk. An event can have multiple consequences

and can affect multiple objectives. Existing risk controls and their effectiveness should be taken into account. **More than one technique may be required for complex applications.**

The way in which consequences and likelihood are expressed and the way in which they are combined to determine a level of risk should reflect the type of risk, the information available and the purpose for which the Risk Assessment output is to be used. These should be consistent with the risk criteria. It is also important to consider the interdependence of different risks and their sources.

The confidence in determination of the level of risk and its sensitivity to preconditions and assumptions should be considered in the analysis, and communicated effectively to decision makers and, as appropriate, other stakeholders. Factors such as divergence of opinion among experts, uncertainty, availability, quality, quantity and ongoing relevance of information, or limitations on modeling should be stated and may be highlighted.

In some circumstances, a consequence can occur as a result of a range of different events or conditions, or where the specific event is not identified. In this case, the focus of Risk Assessment is on analyzing the importance and vulnerability of components of the system with a view to defining treatments which relate to levels of protection or recovery strategies.

Risk analysis can be undertaken with varying degrees of detail depending on the risk, the purpose of the analysis, and the information, data and resources available. The methods used in analyzing risks can be **qualitative**, semi-quantitative or quantitative, or a combination of these, depending on the circumstances. Some methods and the degree of detail of the analysis may be prescribed by legislation.

Consequences and their likelihood can be determined by modeling the outcomes of an event or set of events, or by extrapolation from experimental studies or from available data. Consequences can be expressed in terms of tangible and intangible impacts. In some cases, more than one numerical value or descriptor is required to specify consequences and their likelihood for different times, places, groups or situations.

Risk Evaluation

The purpose of risk evaluation is to assist in making decisions, based on the outcomes of risk analysis, about which risks need treatment to prioritize treatment implementation.

Risk evaluation involves comparing the level of risk found during the analysis process with risk criteria established when the context was considered. Based on this comparison, the need for treatment can be considered.

Decisions should take account of the wider context of the risk and include consideration of the tolerance of the risks borne by parties other than the organization that benefit from the risk.

Decisions should be made in accordance with legal, regulatory and other requirements.

In some circumstances, the risk evaluation can lead to a decision to undertake further analysis. The risk evaluation can also lead to a decision not to treat the risk in any way other than maintaining existing controls. This decision will be influenced by the organization's risk attitude and the risk criteria that have been established.

5.4 Risk Assessment Methods

The methods used in analyzing risks can be **qualitative**, **semi-quantitative** or **quantitative**, or a combination of these, depending on the circumstances.

Qualitative assessment defines consequence, probability and level of risk by significance levels such as "high", "medium" and "low", may combine consequence and probability, and evaluates the resultant level of risk against qualitative criteria.

Semi-quantitative methods use numerical rating scales for consequence and probability and combine them to produce a level of risk using a formula. Scales may be linear or logarithmic, or have some other relationship; formulae used can also vary.

Quantitative analysis estimates practical values for consequences and their probabilities, and produces values of the level of risk in specific units defined when developing the context. Full quantitative analysis may not always be possible or desirable due to insufficient information about the system or activity being analysed, lack of data, influence of human factors, etc. or because the effort of quantitative analysis is not warranted or required. In such circumstances, a

comparative semi-quantitative or qualitative ranking of risks by specialists, knowledgeable in their respective field, may still be effective.

In cases where the analysis is qualitative, there should be a clear explanation of all the terms employed and the basis for all criteria should be recorded. Even where full quantification has been carried out, it needs to be recognized that the levels of risk calculated are estimates. Care should be taken to ensure that they are not attributed a level of accuracy and precision inconsistent with the accuracy of the data and methods employed.

There are a range of tools and techniques that can be used to perform a Risk Assessment or to assist with the Risk Assessment process. Each of these techniques are designed to analyze risks based on a qualitative, semi-quantitative or quantitative approach, or through a combination of each. It may sometimes be necessary to employ more than one method of assessment.

Selection of techniques

Risk Assessment may be undertaken in varying degrees of depth and detail and using one or many methods ranging from simple to complex. The form of assessment and its output should be consistent with the risk criteria developed as part of establishing the context.

In general terms, suitable techniques should exhibit the following characteristics:

1. it should be justifiable and appropriate to the situation or organization under consideration;
2. it should provide results in a form which enhances understanding of the nature of the risk and how it can be treated;
3. it should be capable of use in a manner that is traceable, repeatable and verifiable.

The reasons for the choice of techniques should be given, with regard to relevance and suitability. When integrating the results from different studies, the techniques used and outputs should be comparable.

Once the decision has been made to perform a Risk Assessment and the objectives and scope have been defined, the techniques should be selected, based on applicable factors such as:

1. The objectives of the study. The objectives of the Risk Assessment will have a direct bearing on the techniques used. For example, if a comparative study between different options is being undertaken, it may be acceptable to use less detailed consequence models for parts of the system not affected by the difference;
2. The needs of decision-makers. In some cases a high level of detail is needed to make a good decision, in others a more general understanding is sufficient;
3. the type and range of risks being analysed;
4. The potential magnitude of the consequences. The decision on the depth to which Risk Assessment is carried out should reflect the initial perception of consequences (although this may have to be modified once a preliminary evaluation has been completed);
5. The degree of expertise, human and other resources needed. A simple method, well done, may provide better results than a more sophisticated procedure poorly done, so long as it meets the objectives and scope of the assessment. Ordinarily, the effort put into the assessment should be consistent with the potential level of risk being analysed;
6. The availability of information and data. Some techniques require more information and data than others;
7. The need for modification/updating of the Risk Assessment. The assessment may need to be modified/updated in future and some techniques are more amendable than others in this regard;
8. Any regulatory and contractual requirements.

In practice, Qualitative methods are best used for Risk Assessments of simple facilities or operations, where the exposure of the workforce, public, environment or asset is low. Qualitative Risk Assessments are often a combination of judgment and experience, and structured review techniques. Qualitative Risk Assessments should be carried out with input from those people directly involved with the risk.

On the other hand, Quantitative Risk Assessments (QRA) are undertaken for more complex facilities or activities, or where required by law. QRA is typically used on all activities posing medium or high risk that could result in one or more fatalities. Only personnel with adequate training and experience should undertake quantitative Risk Assessments, though it is critical that all personnel familiar with the operation or facility are involved in the study.

QRA provides a structured approach to assessing risk, whether the risks are human, hardware/software failure, environmental events or combinations of failures and events. QRA identifies high-risk areas; assists in efficient and effective Risk Management and helps demonstrate that risks are managed to a level deemed ALARP.

Various factors influence the selection of an approach to Risk Assessment such as the availability of resources, the nature and degree of uncertainty in the data and information available, and the complexity of the application.

5.5 Available Risk Assessment Techniques

The following table presents a non-exhaustive list of Risk Assessment tools and techniques available for use in Risk Management.

Tools and techniques	Risk assessment process				
	Risk Identification	Risk analysis			Risk evaluation
		Consequence	Probability	Level of risk	
Brainstorming	SA ¹⁾	NA ²⁾	NA	NA	NA
Structured or semi-structured interviews	SA	NA	NA	NA	NA
Delphi	SA	NA	NA	NA	NA
Check-lists	SA	NA	NA	NA	NA
Primary hazard analysis	SA	NA	NA	NA	NA
Hazard and operability studies (HAZOP)	SA	SA	A ³⁾	A	A
Hazard Analysis and Critical Control Points (HACCP)	SA	SA	NA	NA	SA
Environmental risk assessment	SA	SA	SA	SA	SA
Structure « What if? » (SWIFT)	SA	SA	SA	SA	SA
Scenario analysis	SA	SA	A	A	A
Business impact analysis	A	SA	A	A	A
Root cause analysis	NA	SA	SA	SA	SA
Failure mode effect analysis	SA	SA	SA	SA	SA
Fault tree analysis	A	NA	SA	A	A
Event tree analysis	A	SA	A	A	NA
Cause and consequence analysis	A	SA	SA	A	A
Cause-and-effect analysis	SA	SA	NA	NA	NA
Layer protection analysis (LOPA)	A	SA	A	A	NA
Decision tree	NA	SA	SA	A	A
Human reliability analysis	SA	SA	SA	SA	A
Bow tie analysis	NA	A	SA	SA	A
Reliability centred maintenance	SA	SA	SA	SA	SA
Sneak circuit analysis	A	NA	NA	NA	NA
Markov analysis	A	SA	NA	NA	NA
Monte Carlo simulation	NA	NA	NA	NA	SA
Bayesian statistics and Bayes Nets	NA	SA	NA	NA	SA
FN curves	A	SA	SA	A	SA
Risk indices	A	SA	SA	A	SA
Consequence/probability matrix	SA	SA	SA	SA	A
Cost/benefit analysis	A	SA	A	A	A
Multi-criteria decision analysis (MCDA)	A	SA	A	SA	A
¹⁾ Strongly applicable. ²⁾ Not applicable. ³⁾ Applicable.					

Table 12: List of Risk Assessment Methods and Applicability of Tools

5.6 Risk Management

Risk Management, which includes Risk Assessment as defined by ISO is a set of coordinated activities to direct and control an organization with regard to risk.

Risk management should ensure that organizations have an appropriate response to the risks affecting them. Risk management should thus help avoid ineffective and inefficient responses to risk that can unnecessarily prevent legitimate activities and/or distort resource allocation.

To be effective within an organization, risk management should be an integrated part of the organization's overall governance, management, reporting processes, policies, philosophy and culture. The same risk management approach can be adopted for all activities of an organization including projects, defined functions, assets, and products or activities and will in turn strengthen the linkages between these activities and the organization's overall objectives.

Many organizations' existing management practices and processes include components of risk management and many organizations have already adopted a formal risk management process for particular types of risk or circumstances.

Risk management should function within a risk management framework which provides the foundations and organizational arrangements that will embed it throughout the organization at all levels to be successful. The framework assists an organization in managing its risks effectively through the application of the risk management process at varying levels and within specific contexts of the organization. The framework should ensure that risk information derived from these processes is adequately reported and used as a basis for decision making and accountability at all relevant organizational levels.

A key success factor of an organization's risk management is that risk management is part of decision making. Risk management helps decision makers make informed choices. Risk management can help prioritize actions and distinguish among alternative courses of action. Ultimately, risk management can help with decisions on whether a risk is unacceptable and whether risk treatment will be adequate and effective.

It is good industry practice for Operators to consider, based on a risk-ranked approach, performing a risk assessment for every material change to a drilling program at every stage of the

well project life cycle. This facility is generally embedded within an Operator's Management of Change Policy, Guideline, Standards or Procedure as part of the overall operations plan, and guides the activities of the Operator to manage risks that arise during the project.

5.7 Risk Assessment Methods Applied by PTTEPAA and Atlas Drilling

A bridging document “Seadrill-West Atlas safety case revision-Document No. HSE SCR WA 070002 Montara SIMOPS Addendum” [“EV0000055”] had been created to resolve any conflict between the PTTEPAA Well Construction Standards [“EV0000096”] and the Seadrill West Atlas Safety Case [“EV0000006”].

Prior to the Montara drilling campaign, a facilitated SIMOPS HAZID workshop, with involvement from PTTEPAA, Atlas Drilling personnel, and other third party well services providers was conducted and a Safety Case Revision [“EV0000055”] was prepared, and submitted in fulfilment of PTTEPAA’s ongoing obligation to meet the regulatory requirements set forth in the Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996, Part 3.

The bridging document contains details on hazard identification, risk management and change control. As stated in the Safety Case Revision, the PTTEPAA Well Construction Management System was the agreed system used to plan and execute well construction activities at the Montara WHP as for any other drilling activities. Routine and emergency operations on the MODU would be conducted in accordance with the West Atlas Safety Case. The introduction of SIMOPS in the Montara Development introduced another set of Management System interfaces, and the interactions between facilities were covered by existing process and procedures.

Accordingly, an appreciation of the Risk Assessment methods adopted by both PTTEPAA and Atlas Drilling for all activities related to the Montara Development can be found in the following documentation:

1. **Facilities Construction and Installation:** Coogee Resources-Montara Development-Safety Case For Construction And Installation [“EV0000008”]
2. **Simultaneous Operations:** Coogee Resources-Montara Development-SIMOPS Plan [“EV0000009”]
3. **Wellhead Platform Hookup and Pre-Commissioning:** Coogee Resources-Montara Development-Construction & Installation Safety Case/WHP Hookup & Precommissioning Revision [“EV0000010”]
4. **Well Construction Management System:** PTTEPAA Management Standard: Well Construction Management Framework Standard ID [“EV0000050”]

5. **Routine and Emergency Operations on Facility:** Seadrill West Atlas Safety Case
[“EV0000006”]

5.7.1 PTTEPAA Risk Assessment Methods for Facilities Construction and Installation, SIMOPS, and WHP Hookup and Pre-Commissioning

Risk Assessment methods adopted by PTTEPAA for “Simultaneous Operations” [“EV0000009”] and the “Wellhead Platform Hookup and Pre-Commissioning” [“EV0000010”] activities are covered through the Risk Management System in the “Coogee Facilities Construction and Installation Safety Case” [“EV0000010”], as depicted in Figure 16.

The Coogee Resources Management System is a system within the definition given in AS/NZS ISO 9000. The Safety Management System (SMS) that applies to the Montara Development facilities is a component of the Coogee Resources management in which it is referred to as the health, Safety, and Environment Management System (HSEMS). The Coogee Resources HSEMS follows a continuous improvement cycle as shown in Figure 17, which links the specific elements of the HSEMS to the management system model approach provided in AS/NZS 4804:2001.

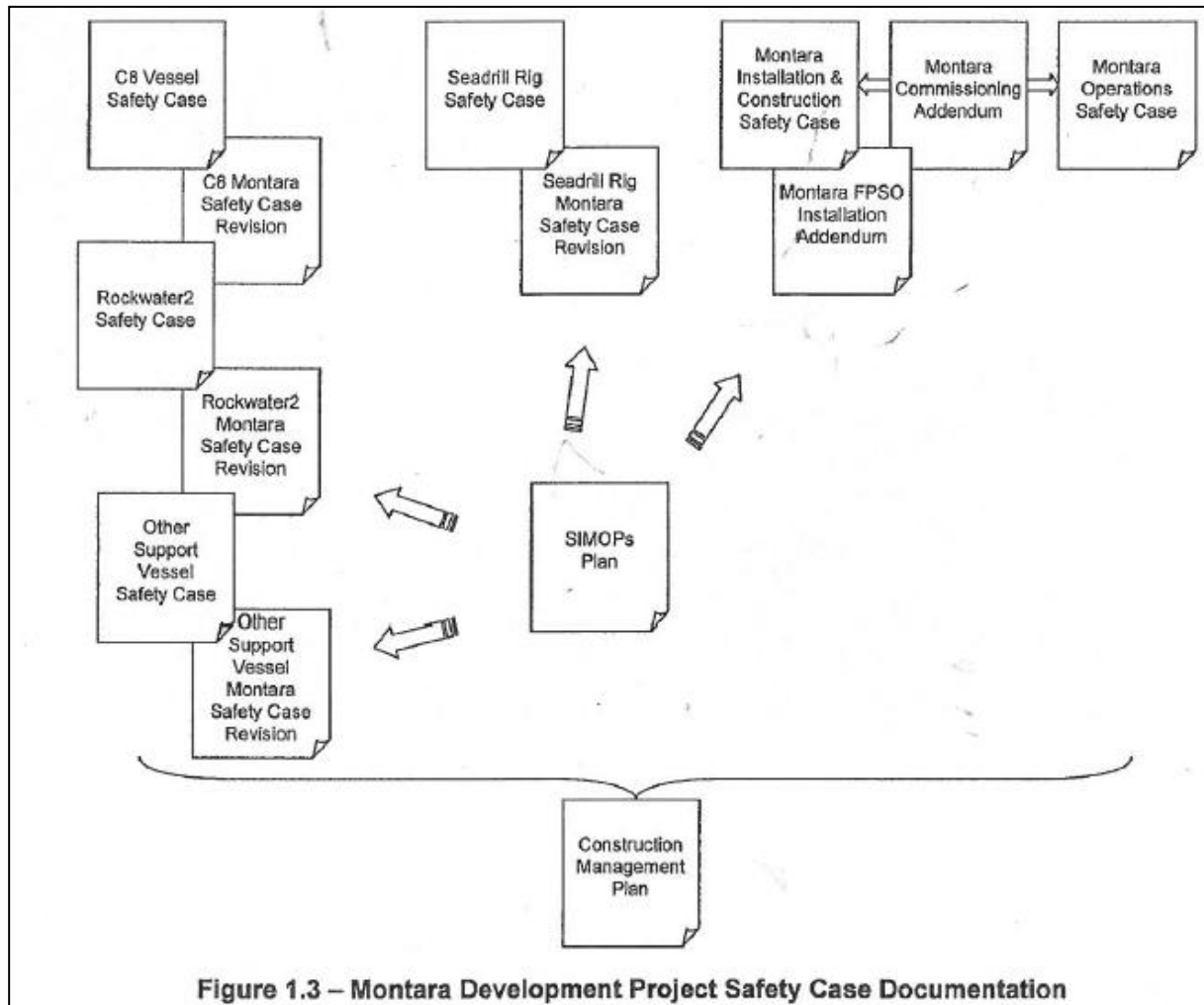


Figure 16: Montara Development Project Safety Case Documentation (Ref: ([EV0000008]
Coogee Resources-Montara Development-Safety Case For Construction And Installation)

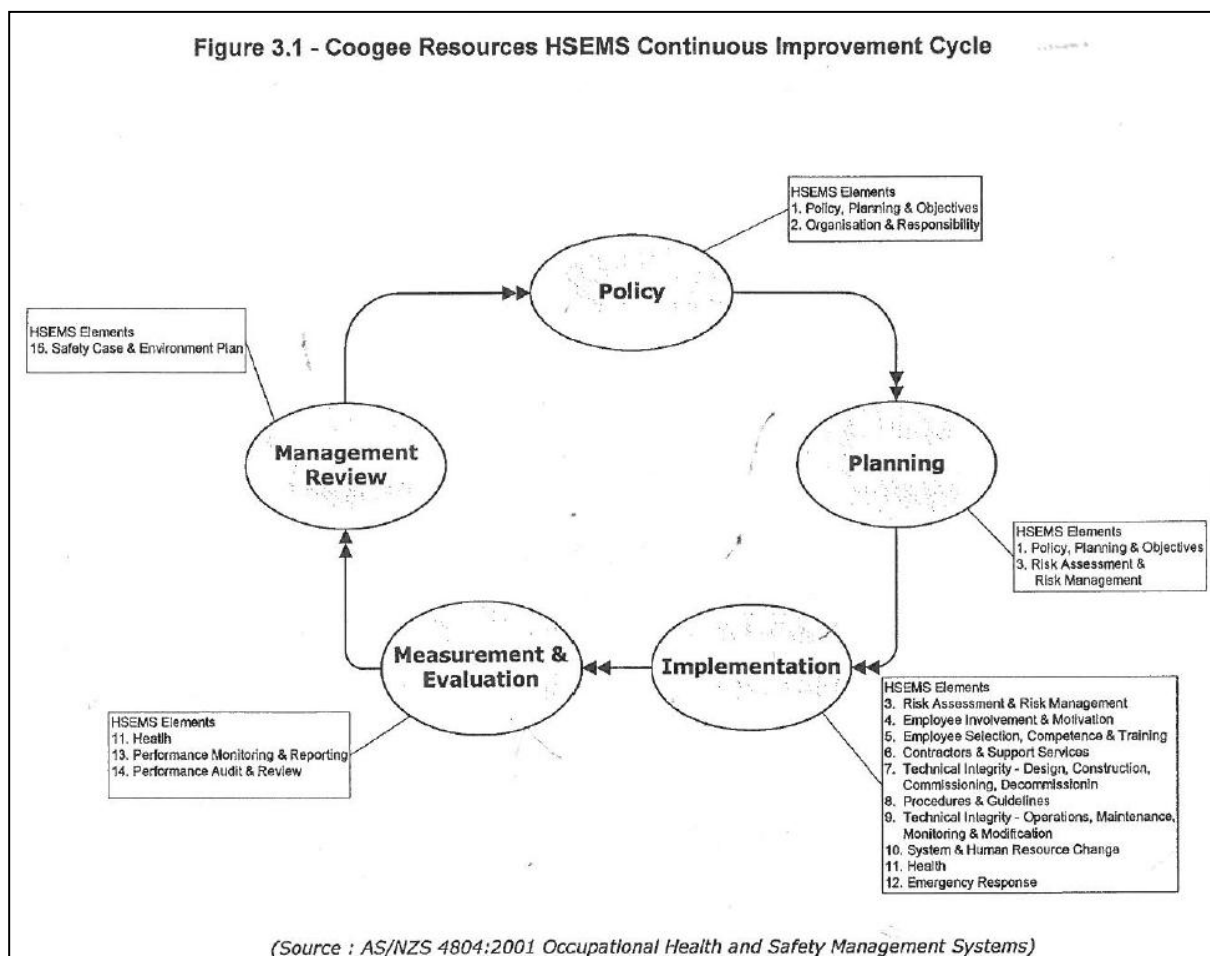


Figure 17: Coogee Resources HSEMS Continuous Improvement Cycle (Ref: [EV0000008] Coogee Resources-Montara Development-Safety Case For Construction And Installation)

5.7.2 PTTEPAA Risk Assessment Methods for Well Construction Management System

As stated in section 3.4 of the Well Construction Management Framework [“EV0000050”], Risk assessment and management is integral with the Well Construction Core Process. The Well Construction Risk Management activities runs parallel and interfaces with the Core Process, but is documented separately to provide a clear assurance of Risk Management.

Though not explicitly stated, the Well Construction Risk Management System follows a continuous improvement cycle to ensure that the implementation and effectiveness of controls put in place to manage Well & Well Test Design, and Operations risks will be ALARP, through the following processes as illustrated in Figure 18.

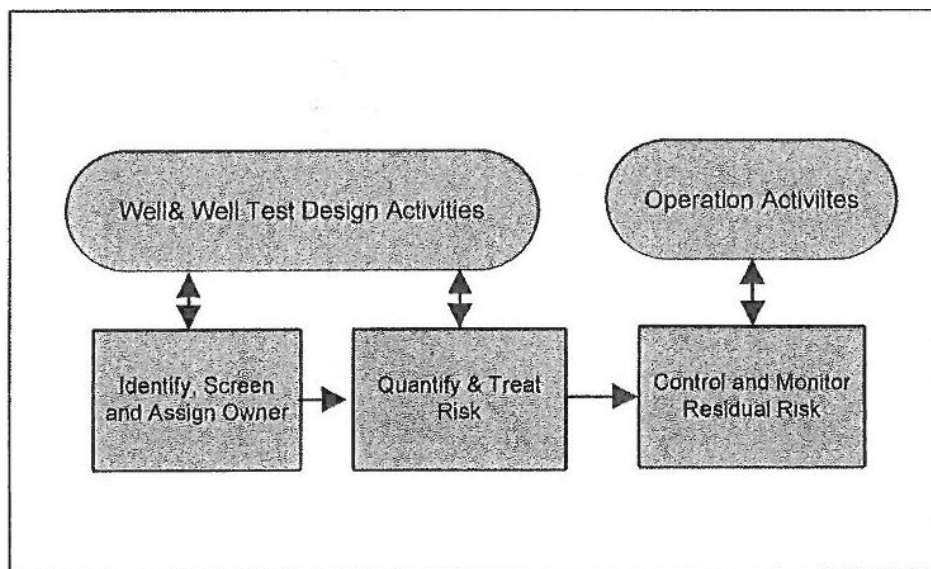


Figure 18: Wells Risk Assessment and Management Process (Ref: [EV0000050] PTTEPAA Management Standard: Well Construction Management Framework Standard ID)

5.7.3 Atlas Drilling Risk Assessment Methods for Routine and Emergency Operations on Facility

As stated in section 2.5.1 in the Seadrill West Atlas Safety Case – Part 2 Safety Management System [“EV0000006”], the Seadrill Risk Management process can be categorised into two (2) areas:

1. The management of hazards associated with the overall design and operation of a process i.e. Hazard Identification (HAZID) or Formal Safety Assessment studies;
2. The management of hazards associated with daily activities i.e. job Safety Analysis (JSA).

The basic Risk Management process remains the same in both cases and is:

1. Systematic **identification** of hazards;
2. **Assessment** of the risk arising from the hazards;
3. Implementation of suitable hazard **controls**;
4. Preparedness for **recovery** in the event of a loss control.

The Seadrill Risk Management Process is presented graphically in Figure 19.

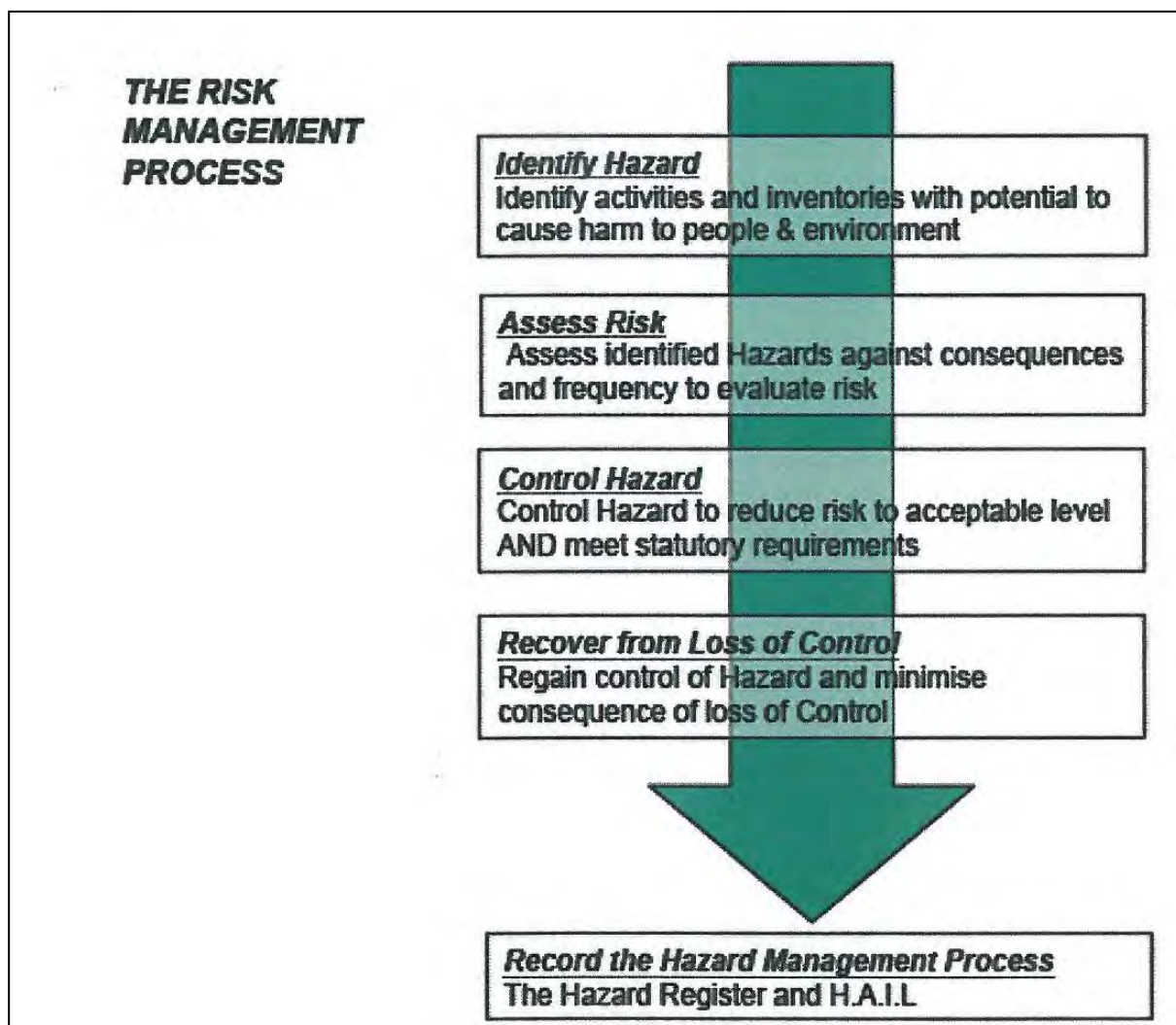


Figure 19: Seadrill Risk Management Process

5.7.4 PTTEPAA Management of Change Process

PTTEPAA's Management of Change (MOC) process can be found in **Section 4.1.8 Change Management** in the *Construct Service or Abandon Well Process* ["DB-30291-NOPSA-401"], one of three documents found in the PTTEPAA *Well Construction Management System.

The activity "Change Management" is defined as a reoccurring activity carried during activity 4.1.1, 4.1.2, 4.1.3 and 4.1.4 (See Figure 20) in response to changes in the Statement of Requirements, Basis of Design or Well Programmes that were brought about by scope changes or unforeseen operational incidents. The tasks defined in the activities are as follows:

1. Identify Requirement for Change and Justify

- a. Complete Change Request complete with justification
- b. Maintain Change Register
- c. Following changes are subjected to change control:
 - i. Changes that significantly increase risks or changes to well objectives, trajectory, pressures, etc.
 - ii. Changes in material specification or requirements including surplus materials or cancellation charges
 - iii. Changes the cost by USD\$0.5M
- d. Proposed changes should be carefully thought through and the change proposer should be prepared to substantiate the change including the gains to be made, the resources required and the impact of not making the change.

2. Engineer Change

- a. Engineer change in accordance with the Well Construction Standards
 - i. Wherever possible, changes are engineered to the same level of details as the original design
- b. Carry out hazard analysis and risk mitigation in accordance with Risk Management Activity
- c. Prepare programme revision if engineer change

3. Record and Disseminate Change

- a. Update the Change Register and e-mail all persons details of the change

- b. Record learning experience in Knowledge Database if applicable (Knowledge Management Activity)

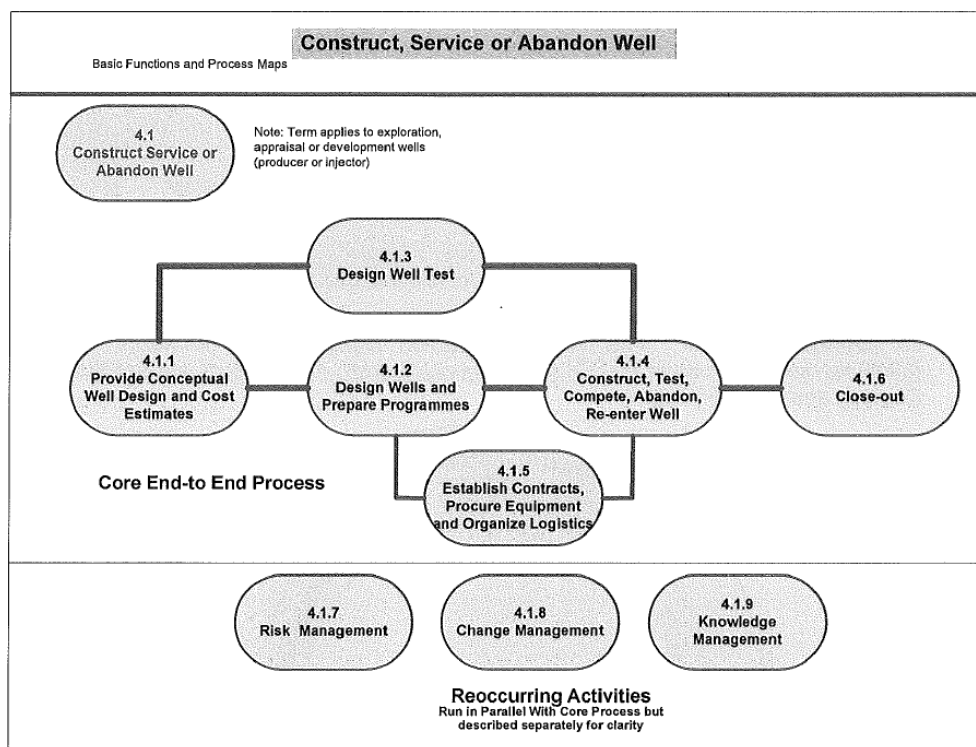


Figure 20 : PTTEP Management System Framework, Develop and Service Wells Process

5.8 Risk Identification via WAI[®]

The Expert Witness has developed the SWPL “Well Assessment of Integrity Tool” (WAI[®]) process, which is a comprehensive review platform used to drive a “forensic” assessment of the candidate wells’ integrity status, and can be applied to all stages of wells investigation and asset-wide risk assessment and management.

The SWPL WAI[®] process captures the subsurface environment data, well architecture (as-built condition), and production historical data of a well in an integrated view. The WAI[®] process then gives an assessment of the well integrity condition by section i.e. tubing, A-B-C annuli, using, construction, production and/or intervention history, and concludes with primary and secondary well barrier assessment for all components of the well architecture. Ultimately the WAI[®] process identifies the most significant **MAJOR HAZARDS** and **TOP EVENTS** for a specific well.

By the WAI[®] process correctly identifying the **SIGNIFICANT MAJOR HAZARDS**, and subsequent **TOP EVENT** (release of the hazard), the **Bowtie** (an endorsed method of the ISO/FDIS 31000:2009 standard’s definition and approach to Risk Assessment) process in a well with existing Well Integrity issues, results in better clarity of the consequences, which in turn produces a realistic assessment of the combination of the event’s Probability versus Impact. Thus the SWPL process leads to an ultimate risk ranking which is supported factually (WAI[®]).

When applied across an asset, and individually on wells over its’ life cycle, an accurate fact-based record of the well integrity condition of a well at any time is achieved.

This tool has been used to document the well integrity condition of the H1ST1 well over its life cycle, and is presented under Volume 3 of this report.

6. References, Codes, Standards, Regulation and Statutory Requirements

A listing of required References, Codes, Standards, Regulation and Statutory Requirements applicable to this report are stated hereafter.

No.	Title of References, Codes and Standards
a	ISO/FDIS 31000:2009 Risk management — Principles and guidelines on implementation, © International Organization for Standardization
b	PSA Norway, 03 March 2010, "Accident investigations are opportunities for learning", Petroleum Safety Authority Norway, Retrieved from the world wide web on 20 th Dec 2011 from: http://www.ptil.no/news/accident-investigations-are-opportunities-for-learning-article6884-79.html
c	A Guide to the Project Management Body of Knowledge (PMBOK) - Chapter 11 - Project Risk Management; Project Management Institute, USA 2002 20 (New edition in 2005) - American National Standard ANSI/PMI 99-001-2004
d	International Association of Drilling Contractors (IADC) - IADC HSE Case Guidelines Appendix 2 Issue 3.2.1 – 1 May 2009
e	Norsk Søkkel Konkuranseposisjon (NORSOK) – Standards developed by the Norwegian Technology Centre
f	Det Norske Veritas (DNV)
g	"Well Integrity in Drilling and Well Operations", NORSOK Standard D-010. Rev 3, August 2004, Standards Norway
h	API Standard 65-2, Second Edition, Isolating Potential Flow Zones During Well Construction December 2010
i	Tinsley, J.M., Miller, E.C., Sabins, F.L. and Sutton, D.L., "Study of Factors Causing Annular Gas Flow Following Primary Cementing," paper SPE 8257 published in JPT, August 1980, pp.1427-1437
j	API TR 10TR3, First Edition, Temperatures for API Cement Operating Thickening Time Tests - 1993 Report from the API Task Group on Cementing Temperature Schedules, 01-May-1999
k	API Recommended Practice 10B-2 (ISO 10426-2), First Edition, Recommended Practice for Testing Well Cements, July 2005
l	API Recommended Practice 10B-3 (ISO 10426-3), First Edition, Recommended Practice on Testing of Deepwater Well Cement Formulations, July 2004
m	API Recommended Practice 10B-4 (ISO 10426-4), First Edition, Recommended Practice on Preparation and Testing of Foamed Cement Slurries at Atmospheric Pressure, December 2004
n	API Recommended Practice 10B-6 (ISO 10426-5), First Edition, <i>Recommended Practice on Determining the Static Gel Strength of Cement Formulations</i> , AUGUST 2010
o	API TR 10TR1, Second Edition, Cement Sheath Evaluation, September 2008
q	Soanes, Catherine, and Angus Stevenson, Concise Oxford English dictionary. New

	York: Oxford University Press, 2004
s	AS/NZS 4804:2001, Occupational health and safety management systems – General guidelines on principles, systems and supporting techniques, November 2001
t	AS/NZS ISO 14001:1996, Environmental management systems— Specification with guidance for use, November 1996
u	AS/NZS ISO 9001:2000, Quality management systems – Requirements, December 2000
v	Vetco Operating and Service Procedure Vetco OPS-03001 (Mudline Suspension System Tieback (no info except montara enquiry)

Table 13: Codes and Standards Applicable for Expert Witness's Investigation

No	Title of Regulations and Statutory Requirements
a	Electronic Code of Federal Regulations, Dec 23 2011, Title 30: Mineral Resources, Chapter II: Bureau of Safety and Environmental Enforcement, Department of the Interior, PART 250--OIL AND GAS AND SULPHUR OPERATIONS IN THE OUTER CONTINENTAL SHELF
b	The authority of the Minister for Resources and Energy Australia, Petroleum (Submerged Lands) (Management of Safety on Offshore Facilities) Regulations 1996, Part 3.

Table 14: Regulations and Statutory Requirements Applicable for Expert Witness's Investigation