Causation Factors for the Banjar Panji No. 1 Blowout

Courtesy F. Sumolang

Neal Adams Services
September 15, 2006
Jakarta, Indonesia

Neal Adams Services

16434 DeLozier Street Houston, Texas 77040
Office 713-849-4323 Fax 713-849-1943
www.nealadamsservices.com
Registered in Texas, Louisiana, Oklahoma, Colorado and New Mexico

Friday, September 15, 2006

PT MEDCO E&P INDONESIA
Attn: Mr. Rico Moegandi, Legal Counsel
Bidakara Office Tower 12-18th Floor
Jl. Jend. Gatot Subroto Kav. 71-93 Pancoran
Jakarta 12870, Indonesia

RE: Report as Per Consulting Services Agreement
Causation Factors for the Banjar Panji No. 1 Blowout

PRIVILEGE IS ESTABLISHED

CONFIDENTIAL, NOT FOR RELEASE EXCEPT BY ABOVE NAMED MEDCO CONTACT PERSON

Dear Mr. Moegandi,

I am very happy to inform you that my report, ***Causation Factors for the Banjar Panji No. 1 Blowout***, has been successfully completed. The issuance of this report completes my assignment as I understand it.

The report contains a substantial amount of technical material. It has been prepared based on documentation made available to me and from discussions with MEDCO personnel. I make myself available to answer any questions that may arise.

Thank you for the opportunity to work on this assignment.

Sincerely,

Neal Adams
M.Sc., P.E., CPP, CHS-III

Copy: Mr. Albertus Alfridijanta
Ms. Siendy Wisandana

Final Report

Table of Contents

Cover Page

Transmittal Letter

Table of Contents

1.0 Executive Summary

2.0 Findings

- 2.1 Introduction
- 2.2 General Findings
- 2.3 Specific Findings

3.0 Forward Recommendations

- 3.1 Introduction
- 3.2 Recommendations
  - 3.2.1 Pertinent Recommended Practices
  - 3.2.2 Training
  - 3.2.3 Operating and Safety Manuals
  - 3.2.4 Contract Language

4.0 Introduction

- 4.1 Introduction
- 4.2 Scope of Work
- 4.3 Work Methodology
- 4.4 Deliverables

5.0 Discussion of Seismic Analyses

- 6.1 Introduction
- 6.2 Discussion of Seismic Analyses

6.0 Discussion of Geological Conditions

- 6.1 Introduction
- 6.2 Analyses of Specific Geological Conditions

7.0 Banjar Panji No. 1 Well Plan

- 7.1 Introduction
- 7.2 General Comments From the Well Plan
  - 7.2.1 Introduction

Final Report

7.2.2 Good Practice and/or Industry Practice
7.2.3 Medici to Control
7.2.4 Offset Wells
7.2.5 Casing Setting Depths
7.3 Specific Comments From the Analysis of the Well Plan

8.0 Discussion of Drilling and Well Control Operations on the Banjar Panji No. 1 Well

8.1 Introduction
8.2 General Comments from the Analyses of the Daily Drilling Reports
8.2.1 Introduction
8.2.2 Rig Operating Efficiency
8.2.3 Cementing
8.2.4 Job Safety Analyses
8.2.5 Leak Off Testing
8.2.6 Casing Setting Depths
8.2.7 Synthetic Oil Based Mud
8.2.8 Kick Drills
8.2.9 Slow Pump Rate
8.3 Specific Comments from Analyses of the Daily Drilling Reports

9.0 Findings Presented According to the Scope of Work

Final Report

1.0 Executive Summary

Lapindo Brantas, Inc. as the Operator of the Brantas Block in East Java planned and drilled the Banjar Panji No. 1 Well. The well was spudded on 9 March 2006. After drilling to 9,297 feet and reaching the Kujung formation, lost circulation was encountered. An attempt was made to pull the drill string out of the hole. A kick was taken when the bit was at 4,241 feet. An underground blowout occurred and subsequently created an above ground blowout.

Primary causation of the blowout was due to numerous operational mistakes as well as errors and omissions. Lapindo violated its own Well Plan by failing to install casing at 6,500 feet and also at ~9,000 feet. The installation of either casing string, with a proper cement job, would have prevented the kick and subsequent blowout.

The kick taken with the bit at 4,241 feet was incorrectly diagnosed and handled by Lapindo. Several attempts were made to kill the flow before Lapindo turned its focus to the stuck pipe. These kill attempts were nearly successful at killing the underground blowout that had developed. It appears that Lapindo did not have the technical competence to recognize that its pumping operations would likely be successful at killing the underground blowout if they had continued.

The numerous errors and omissions by Lapindo in causing the Banjar Panji No. 1 blowout can be considered as negligent, grossly negligent and/or criminally endangering the lives of the crew and surrounding residents as well as endangering the environment.

Lapindo bears the sole responsibility for the blowout.

Final Report

2.0 Findings

2.1 Introduction

Lapindo Brantas, Inc. as the Operator of the Brantas Block in East Java, planned and drilled the Banjar Panji No. 1 Well. The well was spudded on 9 March 2006. After drilling to 9,297 feet and reaching the Kujung formation, lost circulation was encountered. An attempt was made to pull the drill string out of the hole. A kick was taken when the bit was at 4,241 feet. An underground blowout occurred and subsequently created an above ground blowout.

2.2 General Findings

Primary causation of the blowout was due to numerous operational mistakes as well as errors and omissions. Lapindo violated its own Well Plan by failing to install casing at 6,500 feet and also at ~9,000 feet. The installation of either casing string, with a proper cement job, would have prevented the kick and subsequent blowout.

The kick taken with the bit at 4,241 feet was incorrectly diagnosed and handled by Lapindo. Several unsuccessful attempts were made to kill the flow before Lapindo turned its focus to the stuck pipe. These attempts were nearly successful at killing the underground blowout that had developed. It appears that Lapindo did not have the technical competence to recognize that its pumping operations would likely be successful at killing the underground blowout if they had continued.

The numerous errors and omissions by Lapindo in causing the Banjar Panji No. 1 blowout can be considered as negligent, grossly negligent and/or criminally endangering the lives of the crew and surrounding residents as well as endangering the environment.

2.3 Specific Findings

Findings developed from the following sections of the report are summarized here. See the following sections for more detailed information.

Section 3.0 Forward Recommendations

Drilling operations analyzed in this report have been based on opinion, 35 years of experience, academic training and various industrial publications. Specific publications of pertinent value for this investigation include those of the American Petroleum Institute and the International Association of Drilling Contractors. A need exists to itemize each specific reference and its cite location as they pertain to the findings presented in this report.

Training courses should be developed and presented to MEDCO drilling, well planning and other personnel to (1) address this report's findings and (2) ensure competence in well planning, abnormal pressure detection, and casing setting depth selection, specific topics in advanced kick control and other topics.

MEDCO Operating and Safety manuals should be reviewed and, where necessary, enhanced to include the findings of this investigation.

Final Report

MEDCO often employs contracts for drilling and related operations. It is recommended that these types of contracts be reviewed with respect to the lessons learned from the Banjar Panji No. 1 blowout.

Section 4.0 Introduction

None.

Section 5.0 Discussion of Seismic Analyses

An analyses of the seismic data did not identify any direct causes for the blowout.

The analyses did find that drilling the Banjar Panji well in close proximity to numerous faults, one of which was intersected, may have been a contributing cause for the blowout.

Well sites should not be selected in close proximity to faults.

The faults near the Banjar Panji well were probably sealing prior to the well being drilled.

Section 6.0 Discussion of Geological Conditions

The "As Drilled" geology encountered in the well was different than the "As Planned" conditions.

The Operator should have conducted an extensive investigation into this matter as soon as the early signs of differing geologies were observed. A modification of the Well Plan was likely warranted.

Section 7.0 Analyses of the Banjar Panji No. 1 Well Plan

The Well Plan frequently used terms such as "good practice" or "industry practice". The oil industry does not have an accepted body of guidelines that falls into these categories. Operators often use these vague and ambiguous terms when they are not technically competent, or do not wish to devote the required time, to develop their desired guidelines on specific topics.

The Well Plan contains references that Medici will control specific operations. It does not appear that Medici had the authority to control any operations on its own accord. Various contract terms indicates that Lapindo retained ultimate control of all operations.

The Well Plan references two offset wells that may or may not have been used to develop the well plan. Information from these two offset wells should have been included as an attachment to the Well Plan.

A specific casing setting depth program is provided in the Well Plan. No basis is given for the reasoning used to select the casing setting depths. The Plan does not contain any information that indicates that the casing setting depths are optional or that they can be ignored. The Operator's violation of this program caused the well to blowout.

The well plan indicates that the anticipated formation temperatures should be normal but higher than normal temperatures should be anticipated. The Operator's language about temperatures is

Final Report

confusing and vague. It does not allow the rig site supervisors to be able to diagnose anomalies if they occur. Also, the Operator does not specify their basis for indicating that abnormal temperatures may be anticipated.

The Operator indicates in their Well Plan that setting casing at depths identified in their plan is critical and must be done properly. This statement, when viewed from the actual well operations, indicates a weakness on the part of the Operator. The statements suggest that the Operator understands the critical nature of setting pipe at selected depths in the well. However, the actual well site operations where important casing strings were not set indicate (1) the Operator does not comprehend the necessity for proper casing setting depths, (2) the Operator's lack of conviction in following its own Well Plan and (3) the lack of technical competence with Lapindo's engineering group, Medici's engineering group and their rig site supervisors.

The Well Plan and other contract documents require that a Job Safety Analysis be conducted for each new task. The Daily Drilling Reports do not indicate that JSAs were conducted.

Although required in the Well Plan, the Daily Reports do not indicate that drills were conducted for BOP and pit drills, evacuation and H_2S operations.

The Pore Pressure and Fracture Pressure information is incomplete. It does not provide sufficient information to allow a proper well plan to be developed. Also, the basis for the data shown in the Well Plan has not been provided.

The casing program selected for the Banjar Panji well is incorrect for the pore pressure and fracture pressure conditions. However, it is adequate to prevent the blowout if properly implemented.

A proper casing program is provided based on the given conditions. The program uses the only widely accepted procedure.

The Operator's plan for handling shallow gas is inadequate. If a shallow gas kick would have occurred, it would have quickly become a blowout if the Operator's plan were implemented.

The Operator establishes a kick tolerance for the 9-5/8 inch casing seat. This type of information is useless and is employed when the well plan is inadequate to handle the given well conditions.

The Operator did not follow their strict requirements that all kicks should be shut in.

Section 8.0 Discussion of Drilling and Well Control Operations on the Banjar Panji No. 1 Well

A measure of rig efficiency is to compare the actual drilling time to the down time for rig repairs, waiting on parts, etc., this comparison is known as the Efficiency Ratio ("ER"). Consider the case of a properly functioning rig with equipment that has been tested, refurbished by the OEM and has the complete certification paper work from the OEMs. An anticipated ratio of drilling time to down time is in the range of 15:1 to as high as 20:1. This is interpreted to mean that the rig can drill 15-20 hrs per 1 hour of down/repair time.

Drilling time and down time was calculated for the Banjar Panji No. 1 well. The drilling time was 326.5 hours while the down time was 830.5 hours. This gives an ER of 0.391:1 and indicates that

Final Report

the Tiga Musi Masa Java ("TMMJ") No. 4 rig provided a horrible operating efficiency. This poor performance may be unmatched in the modern drilling era.

At some point, the Operator should have notified Medici that they were in default, either by fact or implied, of their IPDM contract. They should have been put on notice.

The Operator should have reconsidered the viability of this well with the TMMJ No. 4 rig. The rig's performance history could suggest that it jeopardized the potential for successfully drilling the well.

No technical reasons were provided in the DDRs, nor could a reason be logically inferred, as to the Operator's extraordinary tolerance to the Drilling Contractor's relentless equipment problems. The Operator's tolerance may be related to the Conflict of Interest issue caused by partial joint ownership of the Operator and the Drilling Contractor.

The Operator should have made the decision to rent mud pumps rather than spend time with repeated attempts to effect repairs. The Drilling Contractor caused the Operator to suffer excessive costs due to the pump problems. The Drilling Contractor received the benefit of having the Operator indirectly pay for refurbishment of junk pumps.

The lack of cementing effectiveness in all casing strings on the Banjar Panji No. 1 well played a key role in the development of the blowout after the kick was taken on 29 May 2006. Casing and cement are required to properly isolate depth zones throughout the well. A casing string without an effective cement sheath is of little value in maintaining control of the well.

The drilling industry, including both the Operators and the Drilling Contractors, has adopted the practice of preparing Job Safety Analyses ("JSA") before each new task. The process is repeated each time a different task is required, even if the task at a prior time had under gone a JSA. The JSA is an active procedure where the crew members involved with the task meet and discuss the task requirements, potential hazards and means to mitigate/avoid the hazards. On any given daily report for a well being drilled, it is common that 2-5 JSAs or more will be conducted per day.

The Daily Drilling Reports ("DDR") for the Banjar Panji No.1 well are noticeably absent of JSAs. It appears that safety meetings were conducted during cementing operations, although these safety meetings were probably a requirement of the cementing company and not originated by the Operator or Drilling Contractor.

In addition to JSAs serving as a safety program, they also serve as an education tool for employees. This education function appears to be of significant importance for the apparently inexperienced crew working on the rig.

Leak off tests were performed on each casing string after the float shoe was drilled. The LOT pressure results shown in the DDRs show the gauges used to capture the pressures resulting in reading variations. As an example, the LOT data for the 16 inch liner had pressure readings from three gauges, all which were different. The LOT program relies on accurate gauge readings, which may not have been in play in this case. Specific data points for plotting the LOT results were available only for the 16 inch liner.

Final Report

Also, LOT interpretation on the 16 inch liner, which was the only casing LOT where the data were available, shows a questionable practice when gathering the data. The LOT should be stopped when the initial leak off is observed. This occurred after approximately three barrels of mud were pumped. However, the Operator continued injection to eight barrels, which would have caused the testing fracture to be extended beyond the length required to achieve a good test. A LOT similar analyses could not be performed on the shallower casing strings as a complete data set was not available.

Improperly selecting the setting depths for casing strings is the cause of most well problems, including kicks, blowouts, stuck pipe and lost circulation. A properly designed and implemented casing setting depth program should avoid these problems or mitigate them if encountered. The casing setting depth program was not properly designed nor was the Well Plan casing setting depths implemented in drilling of the well. This is a major contributing cause of the blowout.

A Synthetic Oil Based Mud ("SOBM") was properly selected to drill the well. This mud system has the capability to avoid or reduce hole difficulties relating to shale hydration normally associated with a water base mud.

A common industry practice is to conduct kick drills on a frequent, but random basis. This achieves a high level of awareness among drilling crew personnel.

The DDRs do not show that any kick drills were conducted while drilling the well. It appears the Operator, who specifies requirements for kick drills, did not appreciate the value of the drills.

Likewise, the pumps are run on a daily basis at a low rate with a recorded pressure. This Slow Pump Rate ("SPR") is required to properly kill a kick. The DDRs do not indicate that SPRs were taken. However, this information is often contained in the IADC tour reports, which have not been made available in this case.

The Regan annular BOP used for the shallow gas section is antiquated and should not be used.

On several occasions, the Operator attempted to use the improper sized downhole equipment for the size of wellhead being used. This type of error indicates a fundamental weakness in the Operator's technical management and engineering groups.

A cement evaluation log should have been run after cementing each casing string.

The BOP configuration used on the surface casing was improper.

The Daily Reports did not contain detailed information concerning the BOP testing. This information is commonly found on many Operator's reports.

It appears the TMMJ crew was poor at drilling operations.

The Operator set pipe too shallow for the three casing strings. This action invalidated the Well Plan. Drilling should have been halted until a new Well Plan could be developed.

Final Report

The 16 inch casing encountered hole problems when running in the hole. The Operator elected to set the pipe at the shallower depth. The proper procedure was to pull the casing out of the hole and condition the hole prior to re-running the casing.

The Daily Reports did not contain all desired information concerning the casing jobs for all three casing strings.

The cement jobs on each casing string were ineffective. This ultimately provided a behind-casing flow path for the blowout fluids.

The Operator used the forbidden practice of reversing out after each open hole cement job.

The LOT procedure for each casing string is questionable.

The Operator did not shut in the well each time that kick signs were observed.

The 150 ton and 350 ton elevators used to run the 13-3/8 inch casing were too worn to properly run the casing.

The 150 ton and 350 ton elevators used to run the 13-3/8 inch casing were far below the minimum acceptable elevator rating of 500 ton, when using the API requirements. This created a life-threatening situation on the rig floor.

The 13-3/8 inch casing consisted of 72 lbf/foot, K-55 grade casing. This had a collapse rating far below the design requirements. The Operator improperly designed this casing string. It could have failed in adverse conditions.

It appears the flange bolts on the BOPs were over stretched and should have been replaced.

The Operator made a fatal mistake by their failure to run the planned casing to 6,500 feet.

The Operator made a fatal mistake by their failure to run the planned casing to ~ 9,000 feet.

The Operator should not have drilled into the Kujung as deep as 9,297 feet without casing.

The Daily Geological reports identified trace magnecious metal samples that appeared to have been ignored by the Operator.

A massive volcanic sand structure was encountered below ~ 6,000 feet to the top of the Kujung formation. This structure was not anticipated. Drilling should have been halted until this structure could be assessed as to its impact on the Well Plan.

The driller failed to identify numerous pressure increases that would have occurred when bit jets became plugged.

The Operator should not have run a used bit back into the well.

A VSP tool was run at 8,629 feet. The VSP is a downward looking seismic tool run on wire line. It has the same capability of any seismic survey with the exception that its depth is more restricted. At

Final Report

the depth the VSP was run, it should have identified any potential geological anomalies in the next 500 feet. The DDR did not provide any information as to the interpretation of the VSP tool.

Lost circulation occurred at 9,297 feet. The Daily Reports do not give an indication as to the severity of the losses.

After losses were observed, the Operator should not have continued pulling out of the hole at 8,700 feet without circulation. This suggests that they were attempting to pump while pulling out of the hole. The drill string should have been left at 8,700 feet or run into the hole to the bottom. The Operator did not realize that a massive lost circulation problem existed and can be effectively treated only when the bit is deep into the well, near the loss source.

The inability to measure the drill pipe displacement is another indication that the loss was severe.

Continuing to pull pipe while losses were occurring reduces well bore pressures by a reduction in mud hydrostatic pressure and swab pressure.

The shut-in pressure readings of 350 psi on the drill pipe and 450 psi on the casing indicate the kick influx was not from zones entirely below the bit. It the kick influx was below the bit, pressure readings would be consistent on the drill pipe and casing. A likely interpretation is that the kicking zone is near the depth of the bit. The Operator incorrectly diagnosed the depth of the kick influx based on the shut in drill pipe and casing pressures.

The volumetric method is not a recognized method for removal of kick fluids from the well bore, unless the kick fluids are all below the bit. The kick and hole did not indicate any characteristics that would require implementation of the volumetric method. When not required, this method should not be used as it easily leads to a worsening of the situation. As a best case, the volumetric method can be used until the kick fluids are above the bit, at which time the driller's method should be used.

The well did not die as suggested by the DDR. The likely scenario is that an underground blowout ("UGBO") was in progress. The flow path was probably vertically in the poorly cemented casing annulus. Gas bubbling observed soon after this observation confirms that a UGBO was in progress. The likely flow origin was proximate to the bit's location at 4,291 feet and the flow exiting from the hole path was the 13-3/8 inch liner seat at 3,580 feet. The loss of 300 barrels of mud further supports the argument that an UGBO was in progress. It should have been considered by competent rig site personnel.

The pipe was pulled from 4,245 feet to 4,241 feet before sticking. An interpretation of down hole behavior at this point is important but can't be assessed due to brevity of information in the DDRs.

The Operator did not recognize that the priority was the kick and underground blowout potential and not the stuck pipe or the loss circulation. At this time, loss circulation zones were at the bottom of the hole below 9,270 feet and also at a relatively shallow depth, perhaps at the casing seat.

The bubbles around the surface at the rig site were the first clear indicator that an UGBO was in progress.

The changes in bubble height indicate the flow is being gas lifted, and not flowing large volumes

Final Report

due to source pressure. A more important interpretation is that the kick source is not abnormal pressured.

The Operator does not appear to have recognized that he was pumping directly into the UGBO flow stream and was having a significant effect on the blowout. If pumping had continued, the blowout may have been killed at this time.

The rig's mud inventory appears to have been poorly managed that caused the frequent requirements to stop operations and mix mud. Also, the Operator's focus was on the loss issue and not the blowout issue. If the focus had shifted to the blowout, the blowout may have been killed.

The focus was improperly shifted from pumping a LCM mud to cement for solving the loss problem.

Cement should never be pumped in a live well environment. It has no conceivable chance of success and is more likely to aggravate the situation by plugging the drill string.

The Operator was too obsessed with the stuck pipe problem while disregarding the on-going UGBO. By this time, the UGBO had become an above ground blowout ("AGB").

Rather than running a Free Point Survey, the Operator should have run a temperature log to identify the behind casing flow scenario.

The Operator did not recognize that sticking inside the 13-3/8 inch liner to 3,580 feet was highly unlikely unless the most recent circulations carried large volumes of rock cuttings up the casing. The Operator did not recognize the importance of the rock cuttings.

Operations to cut and remove drill pipe started. The plan was to abandon the well.

At this point, it is almost incontrovertible that the Operator was grossly inexperienced to handle this situation. Their actions to cut pipe and attempt a well abandonment were, as a minimum, negligent. This type of action to plug the well is not recommended by any technical publications that are recognized world wide.

The operation undertaken by the Operator has no precedence in the recorded history of blowout events, based on an analysis of a blowout database that contains over 3,500 blowout histories.

Actions taken by the Operator from this point forward borders on criminal negligence as it endangered personnel, the rig and the surrounding environment.

Final Report

3.0 Forward Recommendations

3.1 Introduction

During the course of this investigation, several pertinent forward recommendations have been developed. They are presented in the following section.

3.2 Recommendations

3.2.1 Pertinent Recommended Practices

Drilling operations analyzed in this report have been based on opinion, 35 years of experience, academic training and various industrial publications. Specific publications of pertinent value for this investigation include those of the American Petroleum Institute and the International Association of Drilling Contractors. A need exists to itemize each specific reference and its cite location as they pertain to the findings presented in this report.

3.2.2 Training

Training courses should be developed and presented to MEDCO drilling, well planning and other personnel to (1) address this report's findings and (2) ensure competence in well planning, abnormal pressure detection, and casing setting depth selection, specific topics in advanced kick control and other topics.

3.2.3 Operating and Safety Manuals

MEDCO Operating and Safety manuals should be reviewed and, where necessary, enhanced to include the findings of this investigation.

3.2.4 Contract Language

MEDCO often employs contracts for drilling and related operations. It is recommended that these types of contracts be reviewed with respect to the lessons learned from the Banjar Panji No. 1 blowout.

Final Report

4.0 Introduction

4.1 Introduction

On 29 May 2006, the Banjar Panji well blowout. The MEDCO Board of Directors has commissioned an investigation as to causation of the blowout and to develop guidelines, based on lessons learned from the event, to be used on future wells as a means to prevent the reoccurrence of a similar event. Neal Adams Services ("NAS") was commissioned to conduct this investigation and prepare a report to the Board of Directors of MEDCO Energi.

To accomplish this objective, MEDCO has provided NAS with an extensive range of pertinent documentation. It is currently believed that the documentation provided by Lapindo is adequate to accomplish the objectives of this investigation. Should other documentation or information become available after this investigation is completed, it will be reviewed. If necessary, this report may be enhanced to reflect the findings from this new material.

4.2 Scope of Work

A Scope of Work ("SOW") has been developed and has served as the guide for conducting this investigation. The Scope of Work follows:

1. Perform a general review of the well bore diagram, highlights and chronology already provided and any additional records provided during the defined work period.

2. Identify possible causes contributing to the loss of control of the well.

3. Perform a preliminary analysis to determine one or more likely sequences of casual factors leading to current well control conditions.

4. Identify possible means for avoid recurrence of these causes and results in future operations, and comment on whether these means are generally considered routine industry practices.

5. As practical, identify methods and data needed to perform a more complete analysis and confirmation of what happened and why.

Section 9 contains a description of findings applicable to each item in the Scope of Work. The findings used to satisfy the Scope of Work in Section 9 were developed in prior sections of this report.

4.3 Work Methodology

The work methodology used to complete this report includes (1) detailed study of numerous documents provided by MEDCO to NAS, (2) technical discussions with MEDCO personnel and (3) a site visit to view the Banjar Panji No. 1 blowout. This report, *Causation Factors for the Banjar Panji No. 1 Blowout*, was written and submitted to MEDCO. Subsequent presentations were made to various groups within the MEDCO group.

Final Report

4.4 Deliverables

This report has been delivered to the above referenced contact person in the form of a digital file.

Final Report

5.0 Discussion of Seismic Analyses

5.1 Introduction

An investigation has been conducted of the seismic data and analysis acquired at a time prior to drilling of the Banjar Panji well. Although this analysis does not appear to have any direct cause of the blowout, it was necessary to study the technical area. Interpretation of the seismic data was conducted by MEDCO at a prior time and reviewed by NAS. It appears that MEDCO's interpretation is correct.

5.2 Seismic Analysis

A seismic survey and analysis was conducted over part of the Brantas Block at a prior time. Figure 5.1 shows the location of the seismic lines shot in the Banjar Panji – Porong area.

Figure 5.2 shows the shot line most proximate to the site location for the Banjar Panji well. Pertinent faults have been emphasized with red lines by the MEDCO seismic group. A prime fault intersects the Banjar Panji well at 4,610 feet to 5,520 feet. The type of faulting seen in Figure 5.2 is common to salt or mud diapirs.

It is likely that most of the faults shown in Figure 5.2 are sealed, primarily due to the hydratable clays in the shale deposition region. The faults should remain sealed and not pose any drilling problems unless some tectonic activity occurs.

Drill site selection in a faulted area such as that shown in Figure 5.2 must be done with caution. Faults can be associated with lost circulation and unstable hole conditions. Kick fluids can move through sections of a fault if unsealed.

It is recommended to avoid selected a drill site in an area proximate to a fault(s). If a requirement for drilling exists, the recommended approach is to select a site in a fault-free area and directional drill to the primary target. Proper planning is important and should involve individuals from seismic, geology and drilling groups.

Final Report

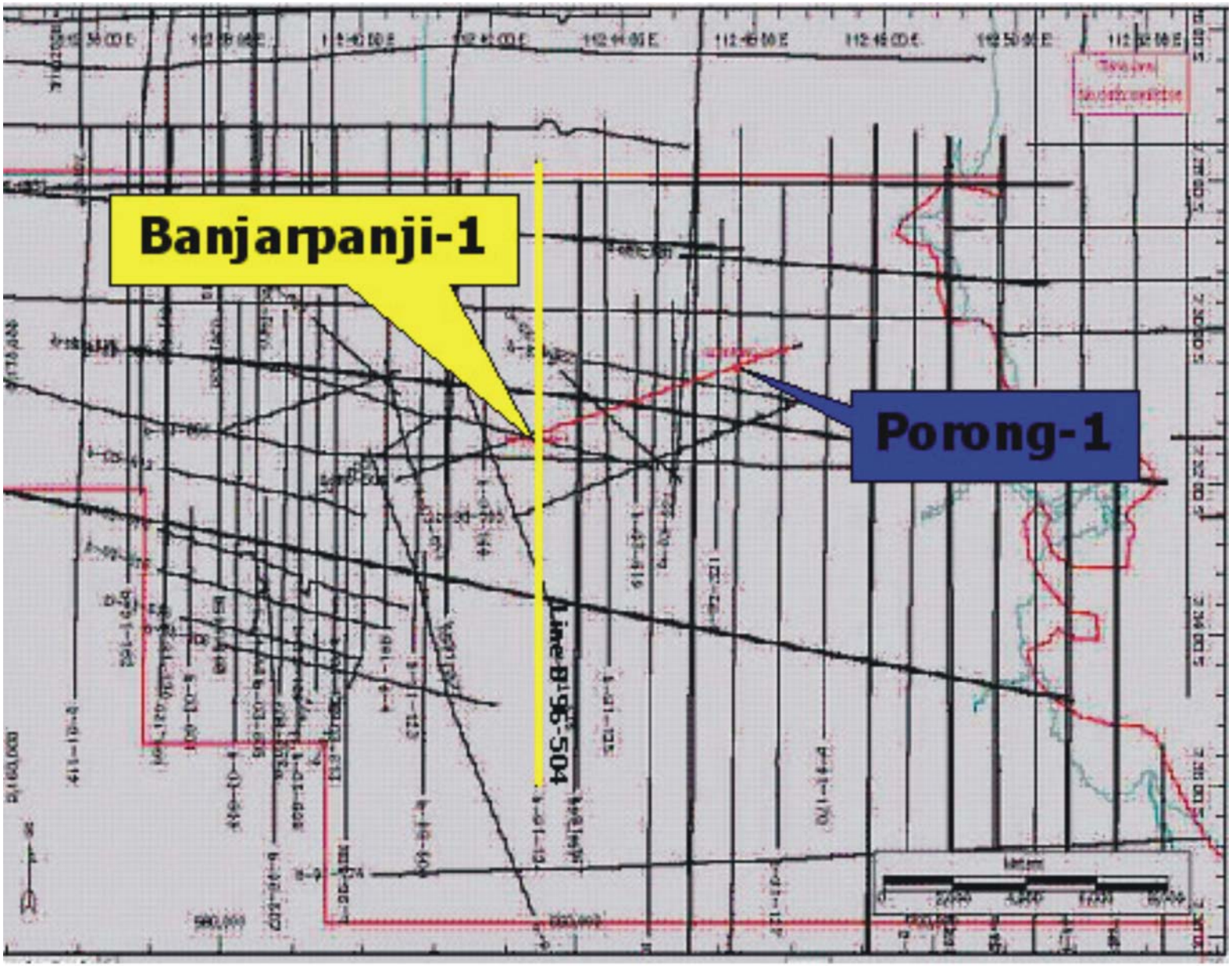


Figure 5.1 Shot Lines in the Brantas Block

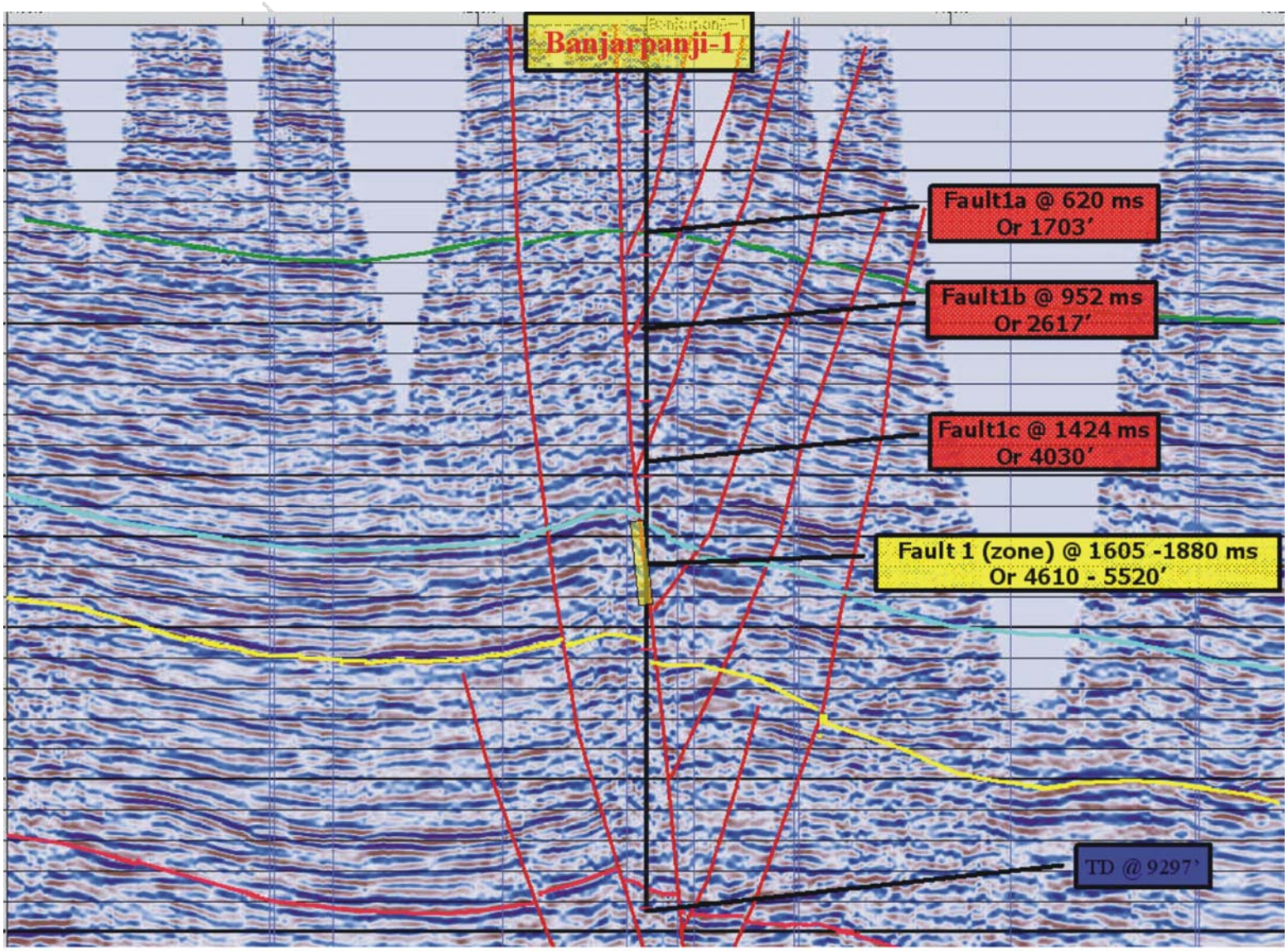


Figure 5.2 Seismic Data Showing Faults and the BJP well.

6.0 Discussion of Geological Conditions

6.1 Introduction

The geology in the area of the Banjar Panji well has been extensively studied by MEDCO's geology group. Their work has been reviewed. Pertinent parts of their work have been incorporated in this report.

The most important geological factors affecting the planning and drilling of a well are the formation (pore pressure) and the formation rock strength (fracture pressure). These two pressures control minimum and maximum mud weights, mud and cement programs, and casing setting depth selection. Also, they can affect hole stability and well control.

6.2 Analyses of Specific Geological Conditions

Figure 6.1 illustrates the "As Planned" and "As Drilled" geology. The figure also shows the Porong 1 well, which was used as an offset guide. It is quickly apparent that the "As Drilled" geology in the Banjar Panji No. 1 well is substantially different than the "As Planned" geology. The region below ~6,000 feet is comprised of volcanic sandstone. Also, the 0 – 1,500 feet region shows variations.

The substantially different geological conditions between "As Planned" and "As Drilled" should have given rise to intensive discussions and a re-evaluation of the Well Plan as soon as the new conditions were observed. The Well Plan for the Banjar Panji well "As Planned" would probably require some modification before the well could be safely drilled. However, uncertainty associated with the geology in the deeper hole section made it unlikely that the well could be confidently drilled and not pose hazards. The available information used in preparing this report does not contain any indication that Lapindo gave any consideration to the necessary modifications to the Well Plan.

Final Report

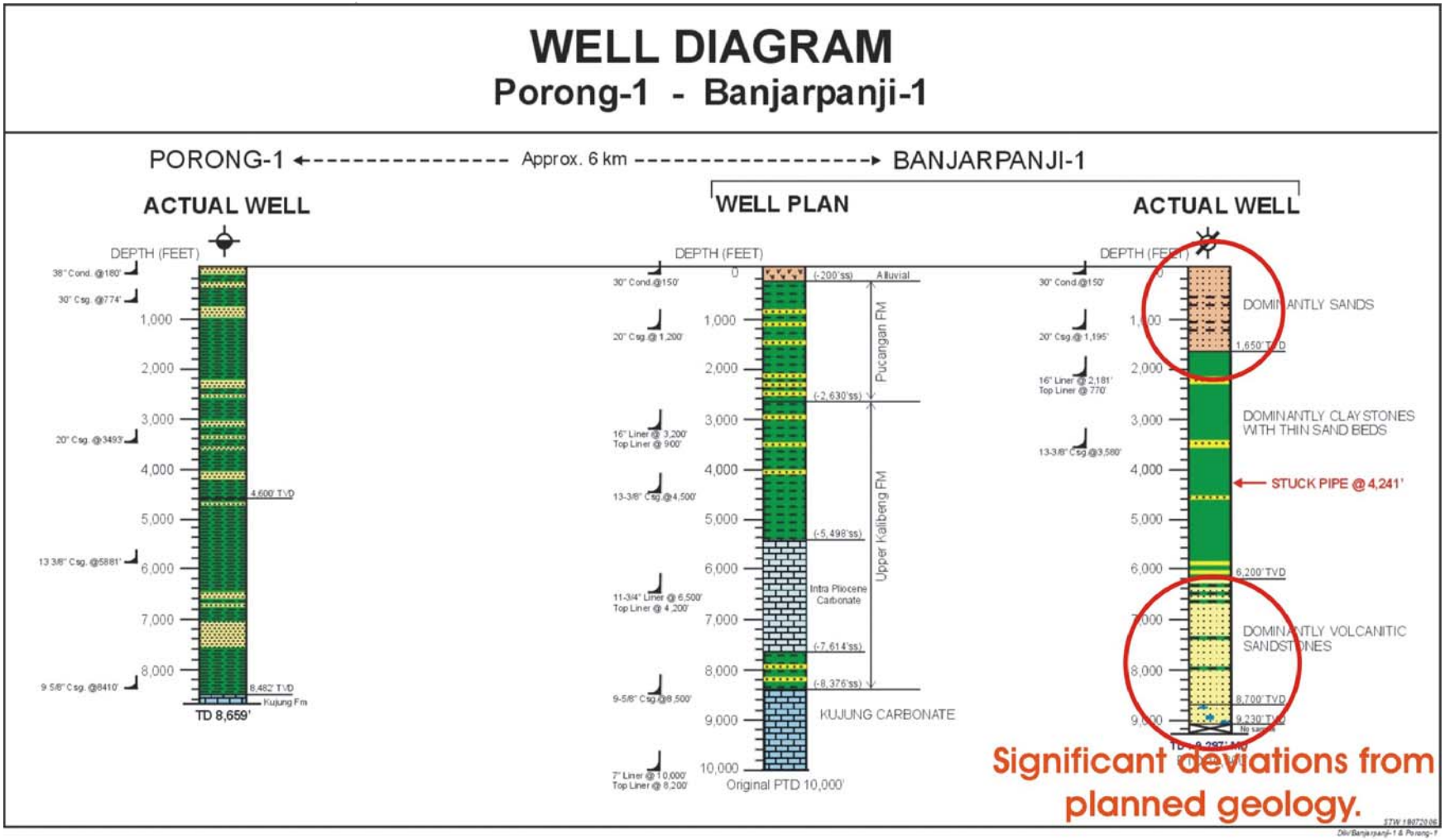


Figure 6.1 Comparison of "As Planned" and "As Drilled" Geology

7.0 Analyses of the Banjar Panji No. 1 Well Plan

7.1 Introduction

The Well Plan is the primary source of information used to complete Section 7. From this source, an analysis of the Well Plan has been completed.

The findings from the analyses fall into two categories. The first category contains general findings that can be applied throughout operations in a running form. The second category contains findings for a specific point in the Well Plan. Both categories are presented in the following sections.

7.2 General Comments From the Well Plan

7.2.1 Introduction

The general comments presented in this Section 7.2 apply to all operations on the BJP well.

7.2.2 Good Practice and/or Industry Practice

The Well Plan frequently used terms such as "good practice" or "industry practice". The oil industry does not have an accepted body of guidelines that falls into these categories. Operators often use these vague and ambiguous terms when they are not technically competent, or do not wish to devote the required timie, to develop their desired guidelines on specific topics.

7.2.3 Medici To Control

The Well Plan contains references that Medici will control specific operations. It does not appear that Medici has the authority to control any operations on its own accord. Various contract terms indicates that Lapindo retains ultimate control of all operations.

7.2.4 Offset Wells

The Well Plan references two offset wells that may or may not have been used to develop the well plan. Information from these two offset wells should have been included as an attachment to the Well Plan.

7.2.5 Casing Setting Depth Selection

A specific casing setting depth program is provided in the Well Plan. No basis is given for the reasoning used to select the casing setting depths. The Plan does not contain any information that indicates that the casing setting depths are optional or that they can be ignored. The Operator's violation of this program caused the well to blowout.

Final Report

7.3 Specific Comments From the Analysis of the Well Plan

Some quotations from the Well Plan are quoted here. Comments are shown following the quotes and are printed in an *italics* print.

Analyses of Banjar Panji No. 1 Well Plan

Report Section No.	Operation/Critique Comments

Lapindo Brantas Inc.

DRILLING PROGRAM
BANJAR PANJI-1

Prepared By
PT. MEDICI CITRA NUSA

IDPM CONTRACTOR

2. GEOLGICAL INFORMATION

The Banjar Panji-1 exploration well is located in Lapindo's working area onshore East Java, near Podong, Sidoarjo. The nearest offset wells that have been drilled are Pojong-1 and Wunut-2, which are located 6.7 km NEE and 1.2 km West of Banjar Panji-1 respectively.

The Well Plan references two offset wells, presumably used as a guide for preparing the Well Plan for the BJP well, as the Porong-1 and Wunut-2 which are located as shown in the above paragraph. The Well PLAN contains some information from the Porong-1 well, most distant from the BJP well. It doesn't appear that the Wunut well was used in planning the BJP well. The well most proximate to the BJP well is usually the most reliable offset well. This practice was not followed in this case. Further the Well Plan did not provide an explanation as to the reason that the Porong-1 well was used in preference to the Wunut well, which is most proximate to the BJP well site.

A good practice with respect to offset wells used to prepare a Well Plan for a proposed well is to attach all available offset well information to the proposed Well Plan. This practice makes the information available at the rig site in the event the proposed well deviates from the plan while drilling. The on site supervision can look to the offset well data for possible information that may be pertinent to the observed departure.

This well is deeper than normal for the area. While normal temperature gradient is expected as in the offset wells, a higher than normal temperature gradient should be anticipated, where bottom hole temperature may reach the extreme of the down hole equipment temperature ratings.

This paragraph conveys a confusing conundrum to field supervisors. It indicates that normal temperatures are expected yet abnormally high temperatures made be encountered. Field supervisors should be provided with the supporting information used to make these statements. Without the proper supporting information, the field supervisors are hindered in performing their job assignments and will not be able to

Final Report

identify and understand temperature anomalies. This responsibility becomes even more critical for any well being drilled in a possible geothermal environment.

The well is expected to penetrate into the **overpressured** formations. More casing and liner strings need to be set at the planned depth. The success to complete this well safely as planned rely significantly on down hole actual conditions and supervisor's diligent to set casing/liner shoe at the right depth. **The need for qualified field supervision and the best pore pressure prediction crew are definitely emphasized in the critical well.**

This paragraph, when viewed from the actual well operations, indicates a weakness on the part of the Operator. The statements suggest that the Operator understands the critical nature of setting pipe at selected depths in the well. However, the actual well site operations where important casing strings were not set indicate (1) the Operator does not comprehend the necessity for proper casing setting depths, (2) the Operator's lack of conviction in following its own Well Plan and (3) the lack of technical competence with Lapindo's engineering group, Medici's engineering group and their rig site supervisors.

3.1 Safety

....

All work is to be conducted in accordance with Lapindo Brantas, Inc and Medici Citra NUSA (MCN) safety policy.

The safety policies of Lapindo and Medici have not been made available for review. If this information should become available, it is believed that numerous violations would be identified, as relates to drilling operations on the BJP well.

Safety meeting should be held on regular basis or prior to any hazardous operation, e.g. casing running, cementing, perforating, testing, etc. attended by all crews i.e.: drilling crews, service companies and MCN Drilling Supervisor.

The DDRs contain only a few notations relative to conducting safety meetings. If proper practice were followed, the few safety meetings noted in the DDRs were initiated by third party contractors rather than Lapindo and/or Medici.

BOP Drill and Pit Drill should be conducted by every shift before and during drilling 8-1/2 inch Pilot Hole, and at anytime on regular basis during drilling of each hole section.

The DDRs do not contain any references to show these drills were conducted.

Evacuation Drill and H_2S Drill should be conducted by every shift on regular basis.

The DDRs do not contain any references to show these drills were conducted.

Responsibilities

The **Medici Drilling Supervisor** is responsible for fully monitoring and control the execution of this drilling program. Medici Drilling Supervisor must adhere to HSE policy and the good drilling practice that will result in the better quality well and cost efficiency. Any deviation to the drilling program requested must be given in writing and approved by Medici Project Manager.

Final Report

This paragraph references "good drilling practices". The oil industry does not have an identifiable or quantifiable document containing "good drilling practices". The American Petroleum Institute ("API") publishes a series of documents known as "Recommended Practices" or ("RPs") that apply to a broad array of specific of topics. The term "good drilling practices" is often used by operators when they don't have the technical capability to identify specific practices to be followed.

With respect to the API's collection of RPs, Lapindo and Medici violated numerous of the API suggested practices. Some violations were of such severity as to have endangered the lives of crew members. Section 8 contains some references to these violations of API RPs.

3.3 Well Bore Schematic

Figures 7.1 and 7.2 show the "As Planned Well Schematic and the "As Drilled Well Schematic". (Figures shown at the end of Section 3.) Figure 7.2 can be used to note that the planned casing strings at 6,500 feet and at ~9,000 feet were not run. Running and cementing either or both pipe strings should have prevented the blowout.

3.5 Pore Pressure, Mud Weight, and Formation Strength

Figure 7.3 shows the anticipated pore pressures and fracture pressures for the BJP well. The Well Plan does not indicate the source of this critical data. The fracture pressures from 0 – 2,000 feet were not provided. Also, the same pressures for the 8,000 feet to 10,000 feet interval were not available. A proper well plan can not be generated without a complete understanding of fracture pressures throughout all sections of the well.

The proposed well schematic shown in Figure 7.1 is improperly designed to address the formation pressures in Figure 7.3. Nonetheless, it is likely this well schematic would have prevented the blowout if it had been properly implemented.

The only published and accepted casing setting depth selection program is found in the book, "Drilling Engineering: A Well Planning Approach" by Neal Adams (1984) and the Society of Petroleum Engineer's new textbook for university undergraduate students. The casing setting depth and well planning sections in this book were authored by Neal Adams.

This technique by Adams has been applied for the formation pressure and fracture pressure data shown in Figure 7.3. The results are shown in Figure 7.4 to Figure 7.8. Casing and/or liner depths are shown. Pipe and hole sizes, not shown here, would be developed on several other variables.

4.1 Shallow Gas

Although at this flank location no shallow gas is expected, there was a shallow gas kick experienced in Well TGA-1 located around the area at around 1,250 feet. An 8-1/2 inch pilot hole is intended as a mitigation plan for the shallow gas hazard. Close monitor on the mud density in and out of hole and gas presence in the mud out are required at all time until the surface casing is set and cemented. Be prepared with sufficient kill mud before drilling the pilot hole and perform good practice for the trip out of the hole.

The Operator's description of shallow gas handling procedures to be employed on the BJP well is inadequate. If these procedures would have become necessary, the

Final Report

shallow gas would have created a surface blowout.

4.4 Potential Lost Circulation

Lost circulation may be encountered when drilling Carbonates. Possible pressure reversal from 15.6 lbs/gal to lower mud weight may occur in Kujung formation which could cause loss of hydrostatic and induce for well kick. This problem was experienced in Porong-1 well. Stop drilling at the right 9-5/8 inch Casing Point or set 9-5/8 inch casing inside Kujung is very critical to the success of handling losses when drilling Kujung formation. Close control over fluid level and any signs of loss circulation should be treated accordingly. Ensure enough stock of LCM materials at the rig site.

This paragraph suggests the Operator realizes the importance of setting the 9-5/8 inch casing and the equally important point of setting it at a precise depth. Unfortunately, the Operator violated their well plan that ultimately caused the BJP blowout.

5.4 Drill 14-1/2 inch X 17 inch Hole and Set 13-3/8 inch Casing

5. Maximum of 10 barrels kick with 0.4 lbs/gal kick tolerance is allowed at shoe.

The Operator establishes a kick tolerance limitation. Unfortunately, they did not recognize that kick tolerance calculations are meaningless and are usually employed by those operators that have developed an improper Well Plan, such as was realized on the BJP well.

5.6 Drill 10-5/8 inch X 12-1/4 inch Hole and Set 9-5/8 inch Casing

Set 9-5/8 inch Shoe inside Kujung Carbonate

2. G&G are to pick 15-20 feet depth inside top section of Kujung Carbonate (Porong-1 indicated first drilling break around 44 feet below Top Carbonate. G&G are requested to confirm on this, otherwise reduce the footage inside Kujung Carbonate to 10-15 feet for safety purpose.

The Operator failed to implement this part of their Well Plan. Their failure leads to the blowout on the BJP well.

6.4.6 Well Control Guidelines

1. After surface casing is set and the BOP stack has been run, the well will be shut-in in the event of a kick. It will not be diverted. DRILLER's METHOD will be used; deviation to this should get Lapindo's approval.

Throughout the well, several occurrences were observed where the well was flowing. Contrary to their requirement in the Well Plan, they did not shut in these kick signs.

8. Blowout drills will be conducted every shift until supervisor is satisfied with all crews' performance, there after weekly for each crew.

The DDRs do not indicated that the Operator's requirements for pit and kick drills were followed.

Final Report

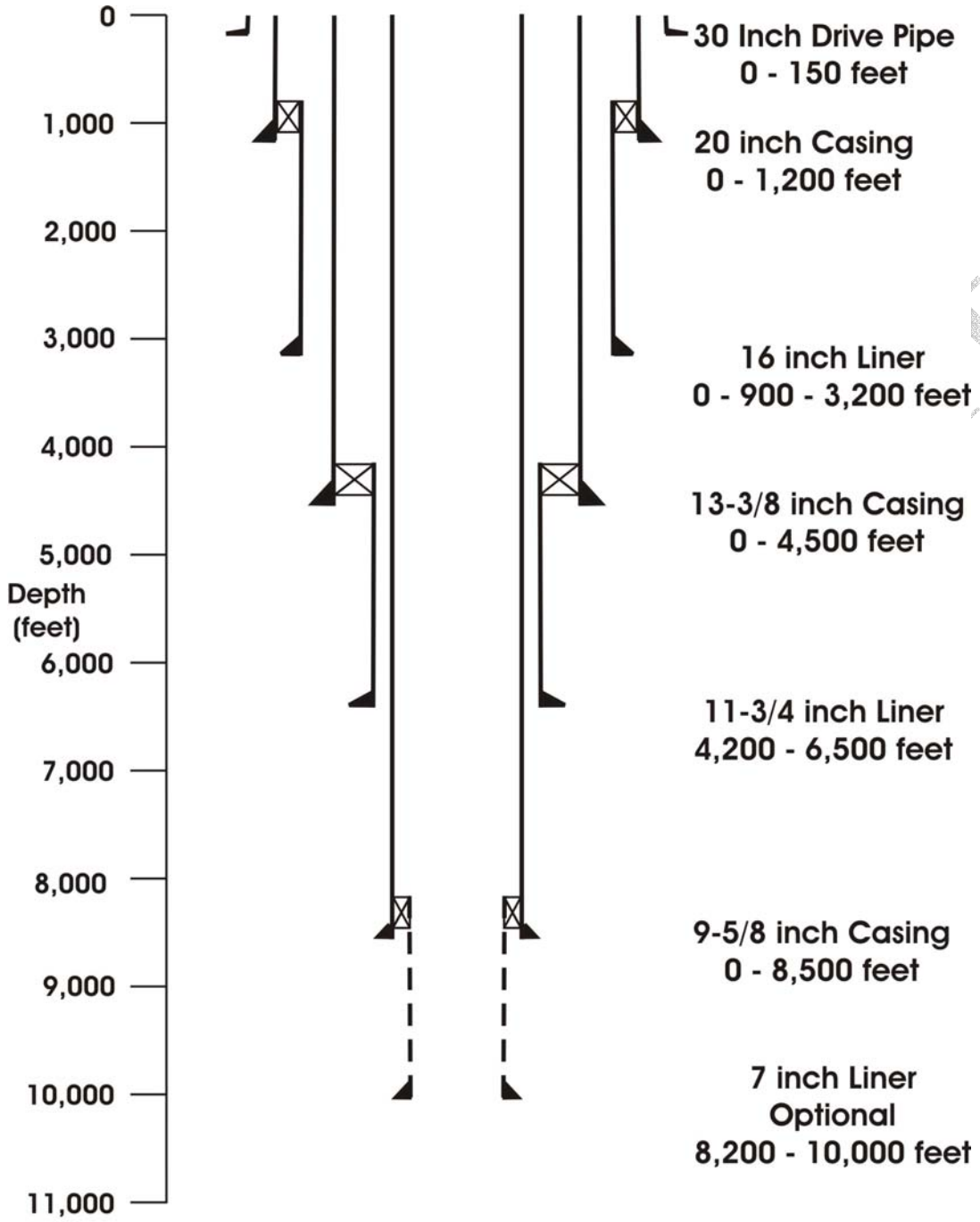


Figure 7.1 "As Planned" Well Schematic

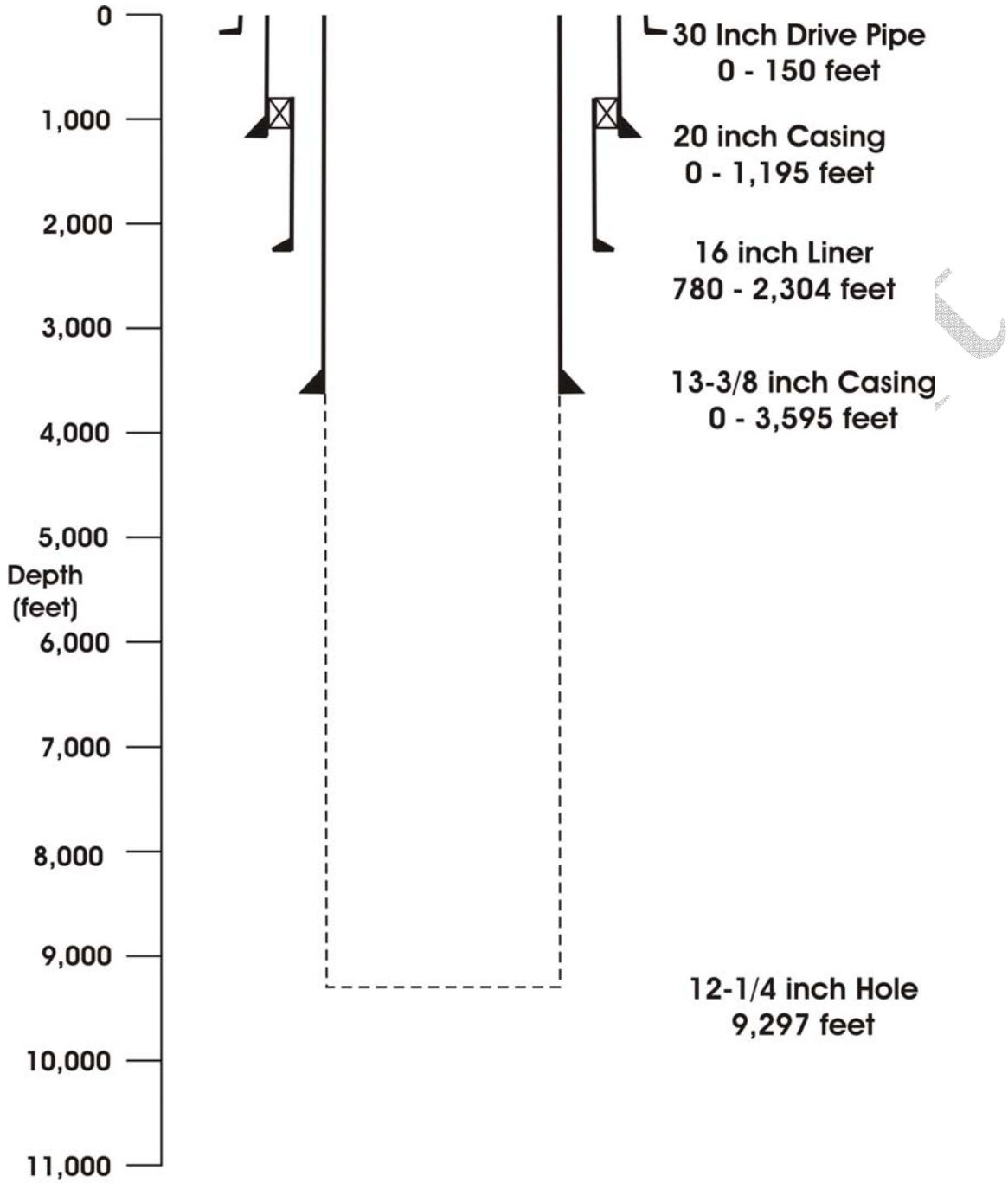


Figure 7.2 "As Drilled" Well Schematic

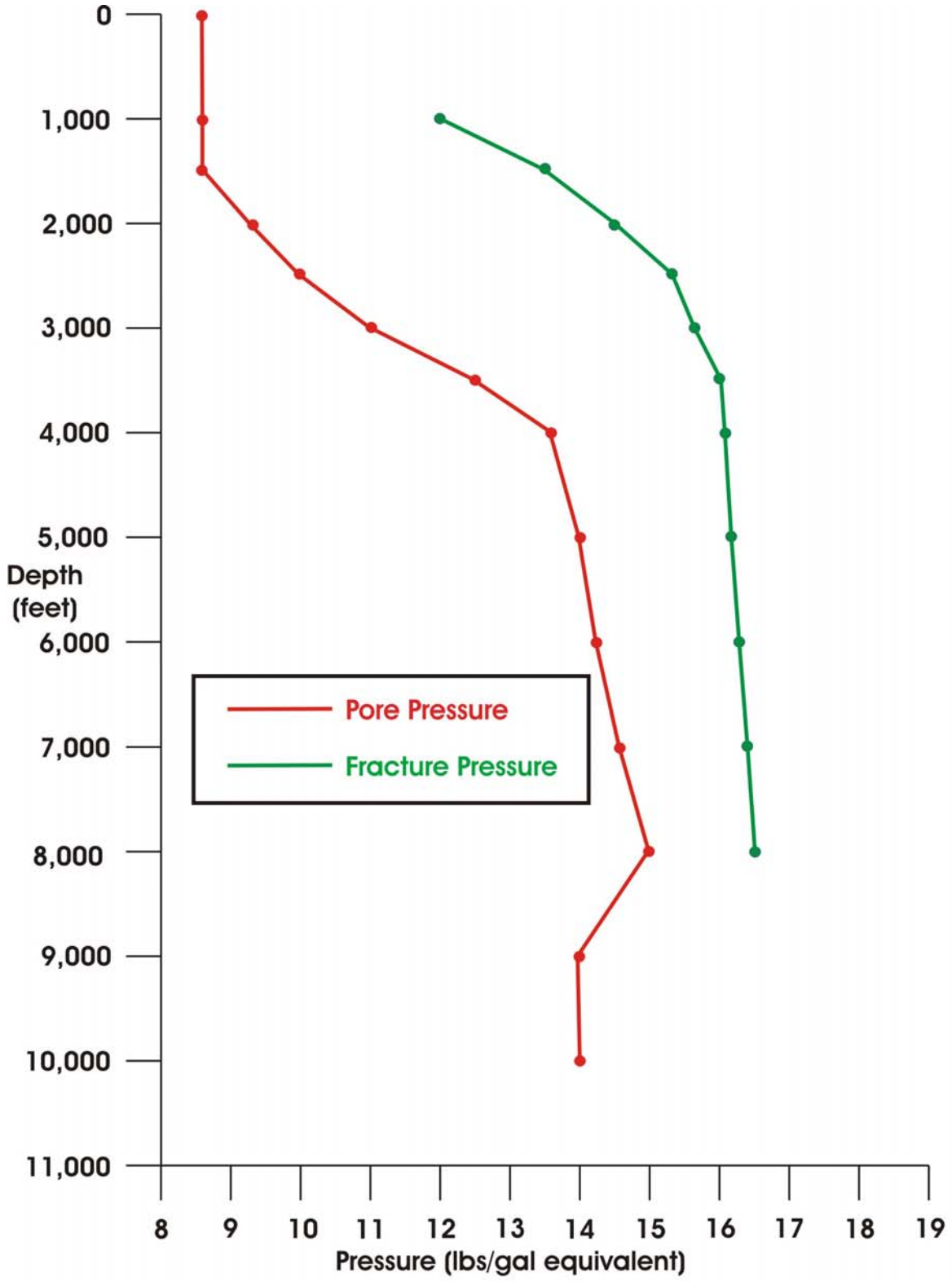


Figure 7.3 Anticipated Pore Pressure/Fracture Pressue Conditions for the Banjar Pangi 1 Well

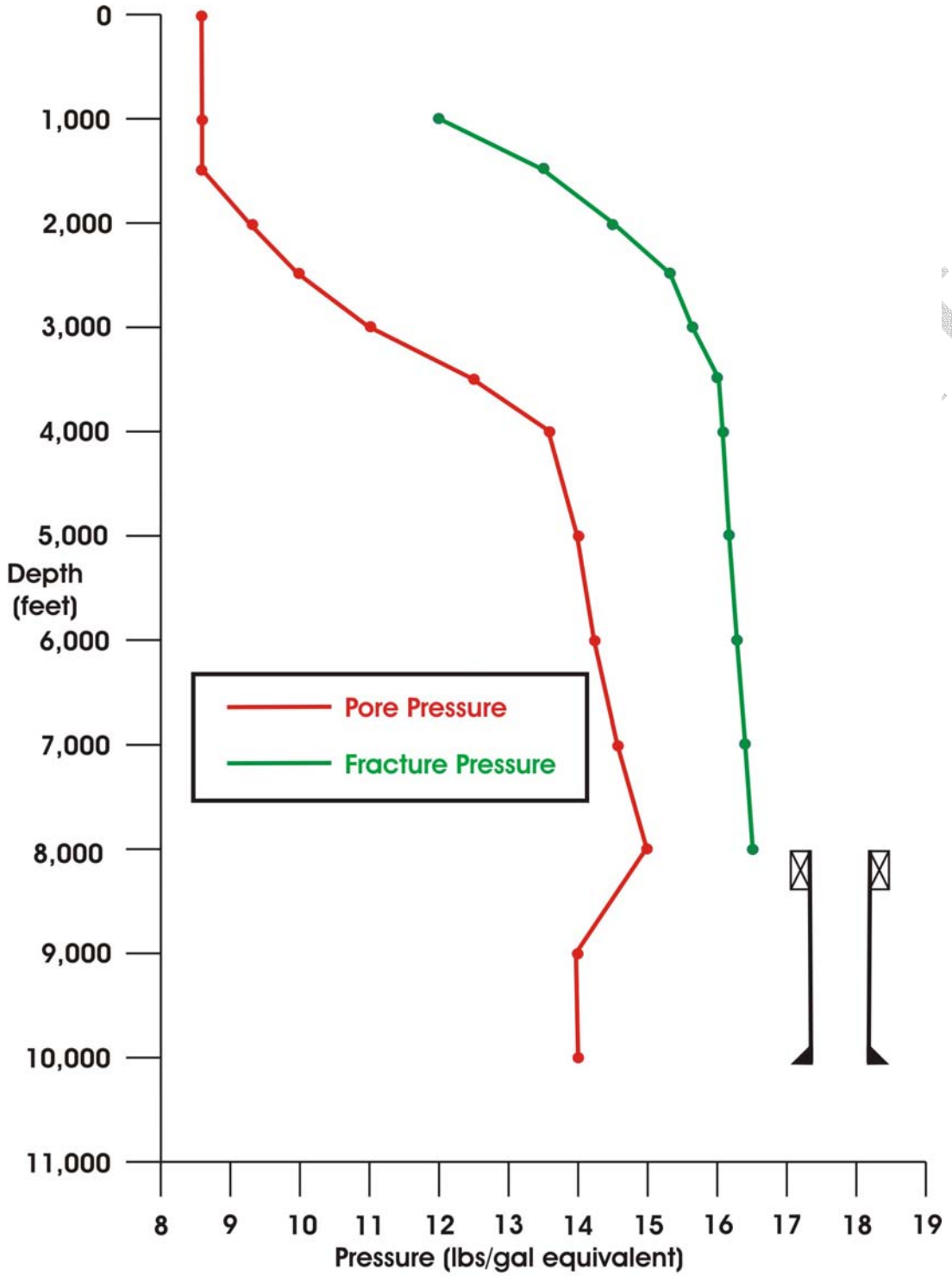


Figure 7.4 Bottom Liner Based on Pore Pressure and Fracture Pressure

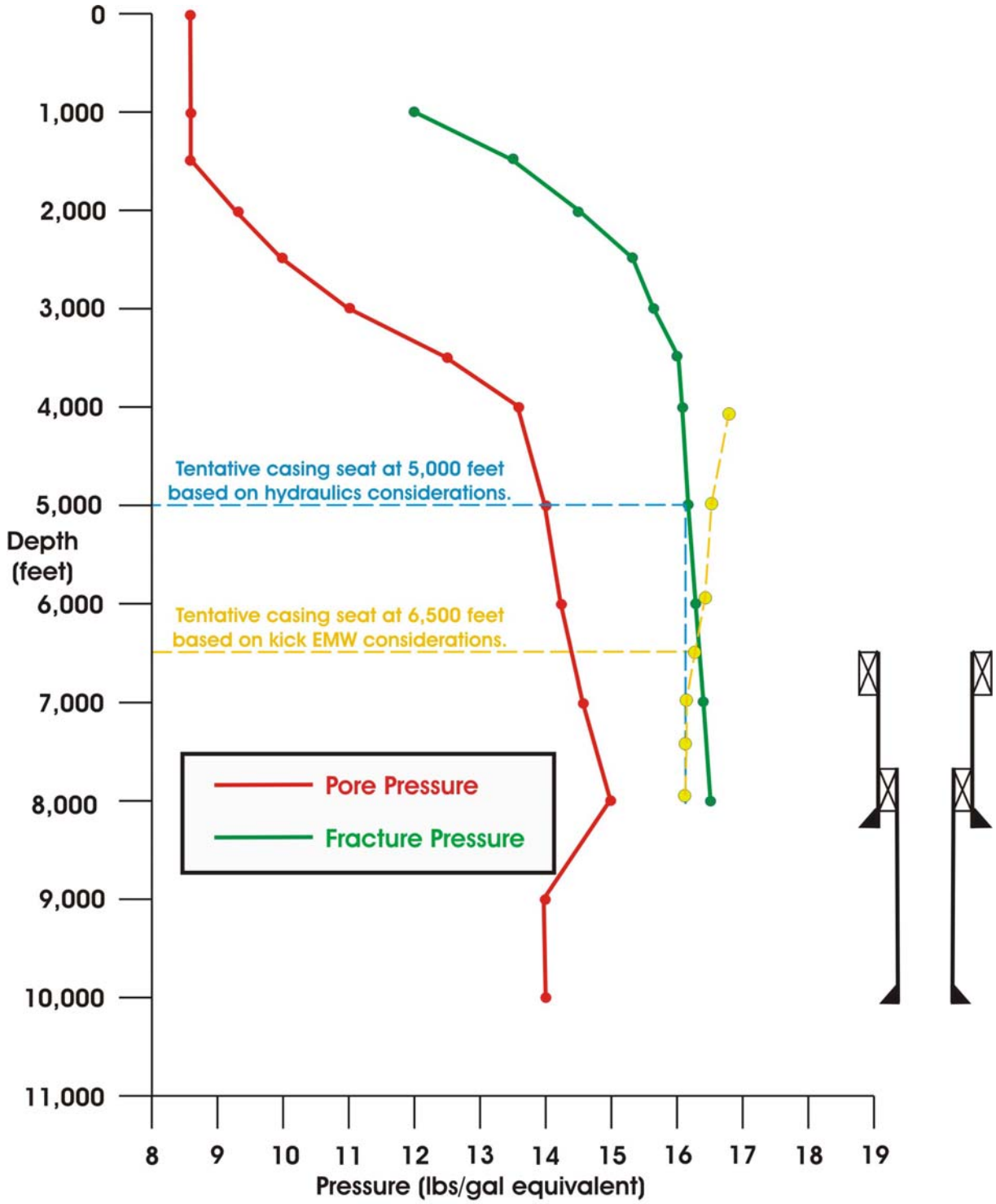


Figure 7.5 Planned Liner Based on Pore Pressure and Fracture Pressure

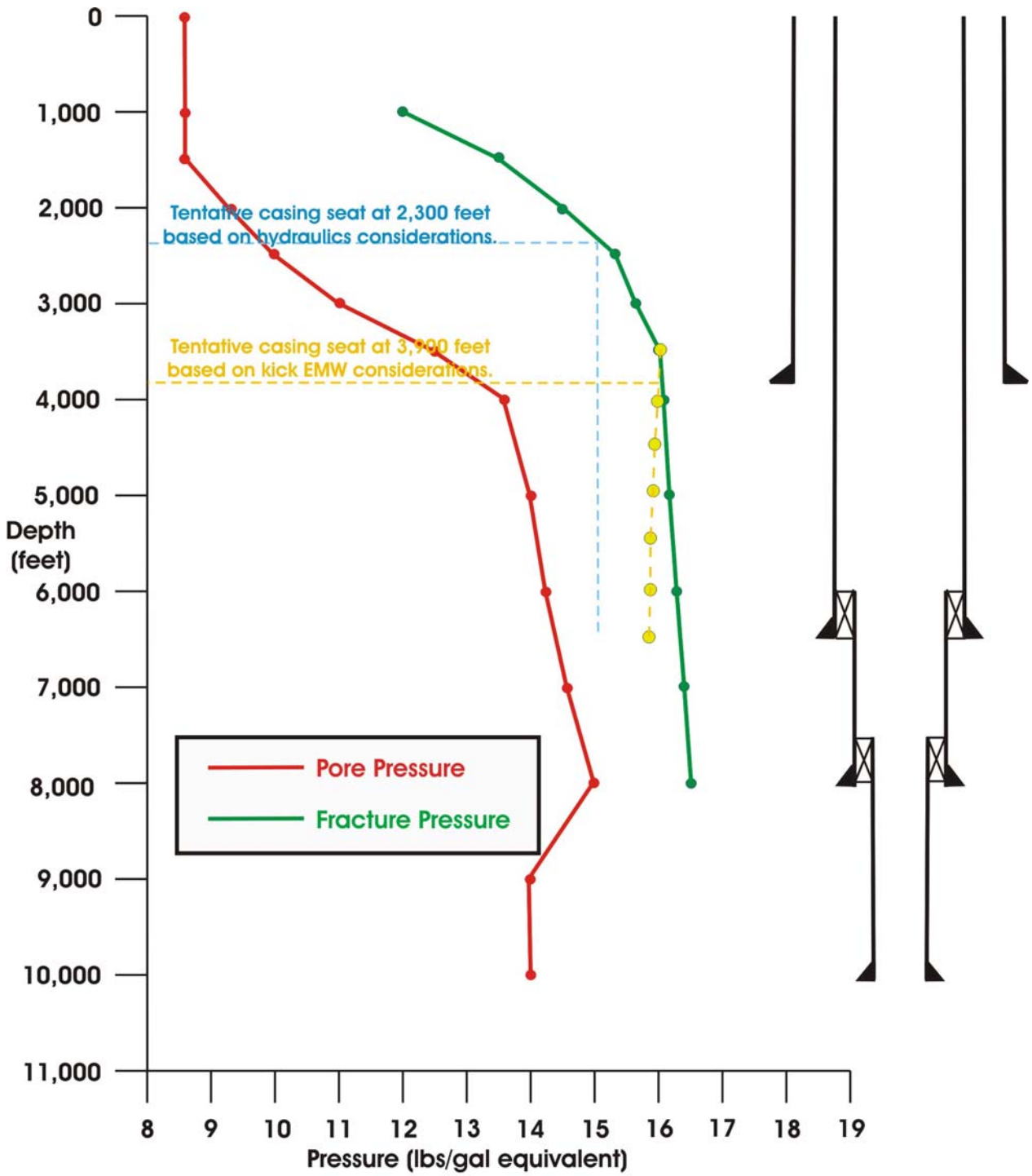


Figure 7.6 Casing program Based on Pore Pressure and Fracture Pressure

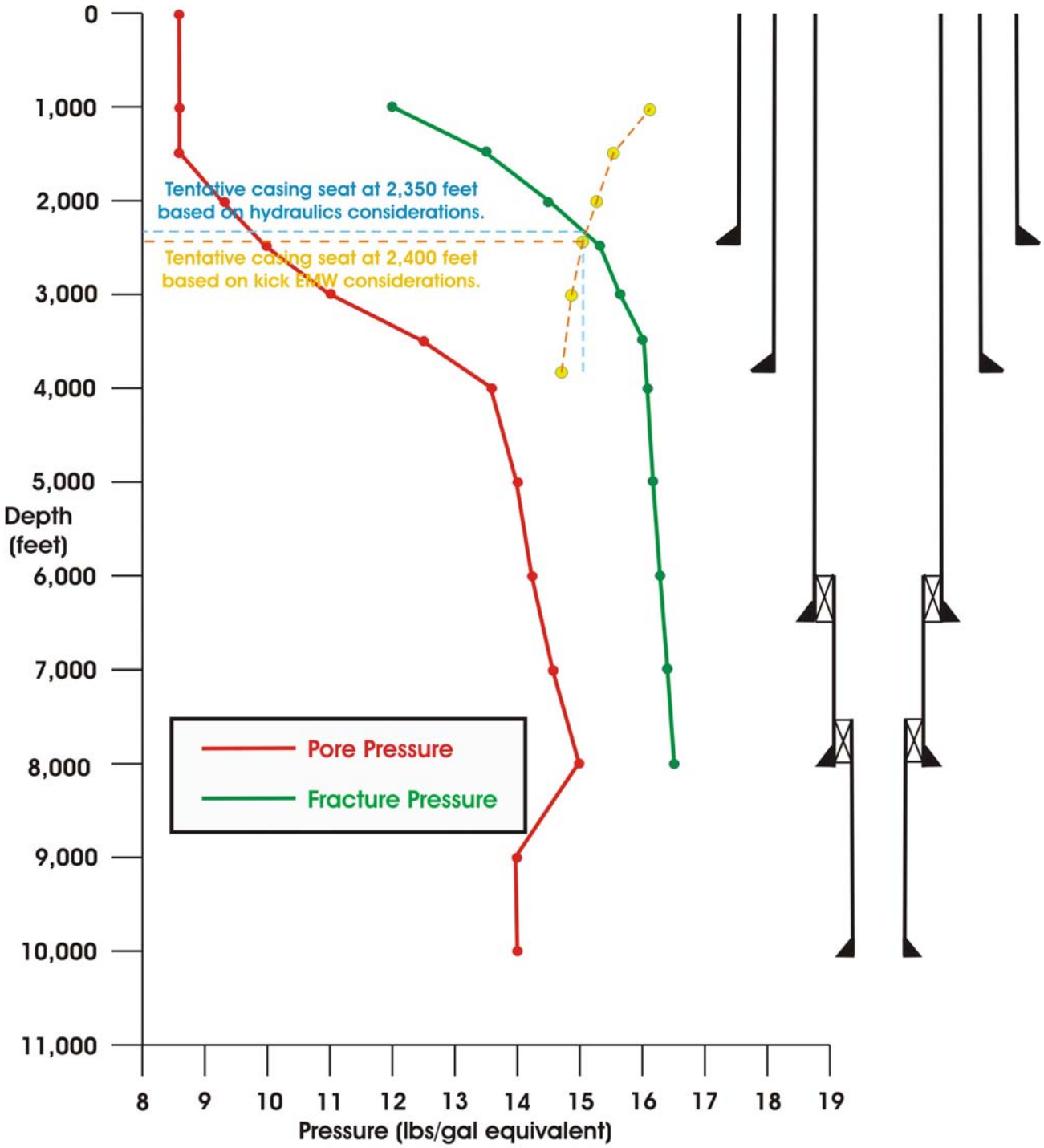


Figure 7.7 Shallow Casing Based on Pore Pressure and Fracture Pressure Conditions

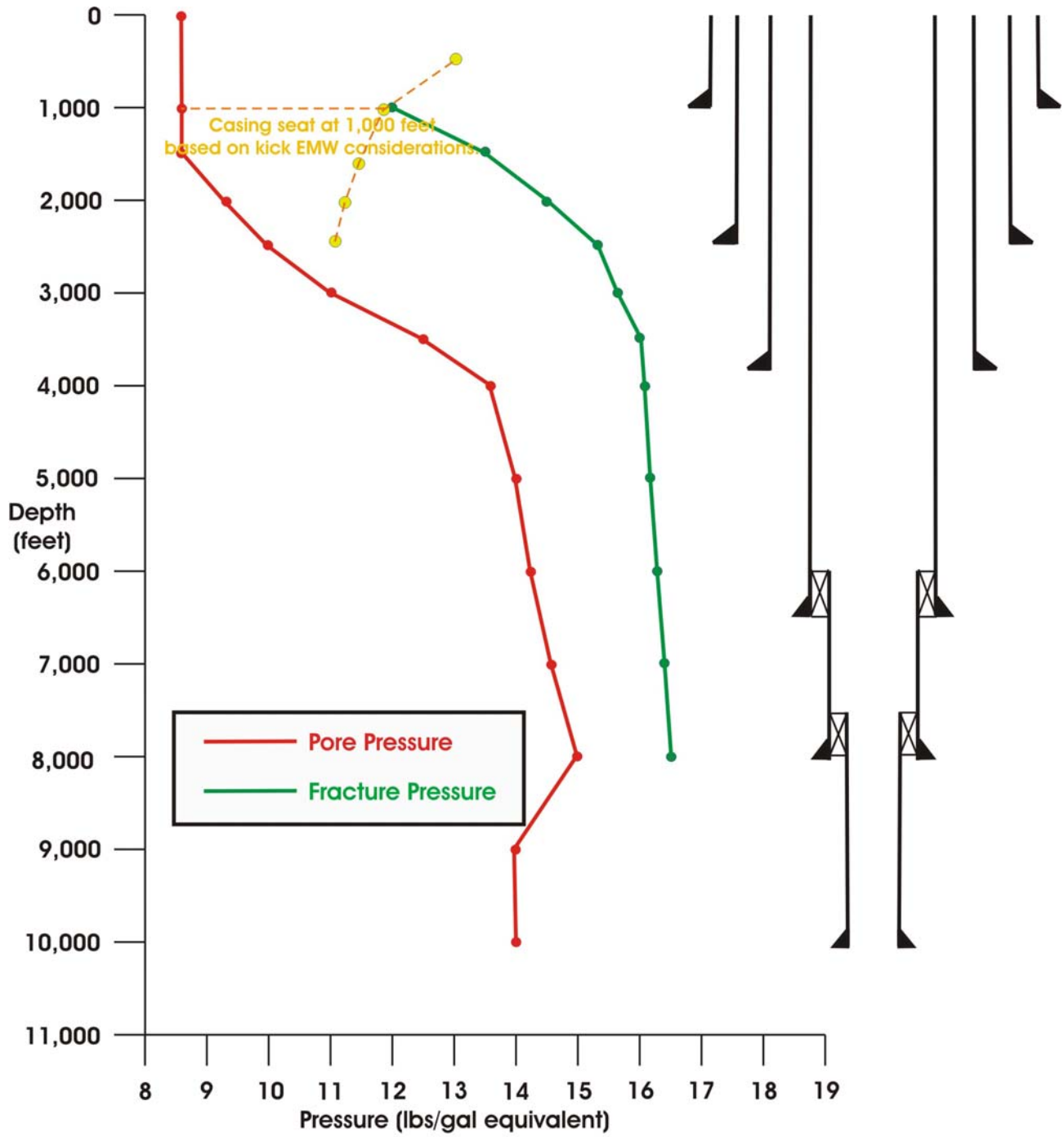


Figure 7.8 Surface Casing Based on Pore Pressure and Fracture Pressure Conditions

8.0 Discussion of Drilling and Well Control Operations on the Banjar Panji No. 1 Well

8.1 Introduction

The Daily Drilling Reports ("DDRs") contain the primary source of information used to complete Section 8. From this primary source, an analysis of drilling and well control operations has been completed.

The findings from the analyses fall into two categories. The first category contains general findings that can be applied throughout operations in a running form. The second category contains findings that are specific to a day or an event. Both categories of findings are presented in the following sections.

8.2 General Comments From Analyses of the Daily Drilling Reports

8.2.1 Introduction

The general comments presented in this Section 8.2 apply to all operations on the Banjar Panji well ("BJP").

8.2.2 Rig Operating Efficiency

A measure of rig efficiency is to compare the actual drilling time to the down time for rig repairs, waiting on parts, etc., this comparison is known as the Efficiency Ratio ("ER"). Consider the case of a properly functioning rig with equipment that has been tested, refurbished by the OEM and has the complete certification paper work from the OEMs. An anticipated ratio of drilling time to down time is in the range of 15:1 to as high as 20:1. This is interpreted to mean that the rig can drill 15-20 hrs per 1 hour of down/repair time.

Drilling time and down time was calculated for the Banjar Panji No. 1 well. The drilling time was 326.5 hours while the down time was 830.5 hours. This gives an ER of 0.391:1 and indicates that the Tiga Musi Masa Java ("TMMJ") No. 4 rig provided a horrible operating efficiency. This poor performance may be unmatched in the modern drilling era.

At some point, the Operator should have notified Medici that they were in default, either by fact or implied, of their IPDM contract. They should have been put on notice.

The Operator should have reconsidered the viability of this well with the TMMJ No. 4 rig. The rig's performance history could suggest that it jeopardized the potential for successfully drilling the well.

No technical reasons were provided in the DDRs, nor could a reason be logically inferred, as to the Operator's extraordinary tolerance to the Drilling Contractor's relentless equipment problems. The Operator's tolerance may be related to the Conflict of Interest issue caused by partial joint ownership of the Operator and the Drilling Contractor.

Final Report

The Operator should have made the decision to rent mud pumps rather than spend time with repeated attempts to effect repairs. The Drilling Contractor caused the Operator to suffer excessive costs due to the pump problems. The Drilling Contractor received the benefit of having the Operator indirectly pay for refurbishment of junk pumps.

8.2.3 Cementing

The lack of cementing effectiveness in all casing strings on the Banjar Panji No. 1 well played a key role in the development of the blowout after the kick was taken on 29 May 2006. Casing and cement are required to properly isolate depth zones throughout the well. A casing string without an effective cement sheath is of little value in maintaining control of the well.

8.2.4 Job Safety Analyses

The drilling industry, including both the Operators and the Drilling Contractors, has adopted the practice of preparing Job Safety Analyses ("JSA") before each new task. The process is repeated each time a different task is required, even if the task at a prior time had under gone a JSA. The JSA is an active procedure where the crew members involved with the task meet and discuss the task requirements, potential hazards and means to mitigate/avoid the hazards. On any given daily report for a well being drilled, it is common that 2-5 JSAs or more will be conducted per day.

The Daily Drilling Reports ("DDR") for the Banjar Panji No.1 well are noticeably absent of JSAs. It appears that safety meetings were conducted during cementing operations, although these safety meetings were probably a requirement of the cementing company and not originated by the Operator or Drilling Contractor.

In addition to JSAs serving as a safety program, they also serve as an education tool for employees. This education function appears to be of significant importance for the apparently inexperienced crew working on the rig.

8.2.5 Leak Off Testing

Leak off tests were performed on each casing string after the float shoe was drilled. The LOT pressure results shown in the DDRs show the gauges used to capture the pressures resulting in reading variations. As an example, the LOT data for the 16 inch liner had pressure readings from three gauges, all which were different. The LOT program relies on accurate gauge readings, which may not have been in play in this case. Specific data points for plotting the LOT results were available only for the 16 inch liner.

Also, LOT interpretation on the 16 inch liner, which was the only casing LOT where the data were available, shows a questionable practice when gathering the data. The LOT should be stopped when the initial leak off is observed. This occurred after approximately three barrels of mud were pumped. However, the Operator continued injection to eight barrels, which would have caused the testing fracture to be extended beyond the length required to achieve a good test. A LOT similar analyses could not be performed on the shallower casing strings as a complete data set was not available.

Final Report

8.2.6 Casing Setting Depths

Improperly selecting the setting depths for casing strings is the cause of most well problems, including kicks, blowouts, stuck pipe and lost circulation. A properly designed and implemented casing setting depth program should avoid these problems or mitigate them if encountered. The casing setting depth program was not properly designed nor was the Well Plan casing setting depths implemented in drilling of the well. This is a major contributing cause of the blowout.

8.2.7 Synthetic Oil Based Mud

A Synthetic Oil Based Mud ("SOBM") was properly selected to drill the well. This mud system has the capability to avoid or reduce hole difficulties relating to shale hydration normally associated with a water base mud.

8.2.8 Kick Drills

A common industry practice is to conduct kick drills on a frequent, but random, basis. This achieves a high level of awareness among drilling crew personnel.

The DDRs do not show that any kick drills were conducted while drilling the well. It appears the Operator, who specifies requirements for kick drills, did not appreciate the value of the drills.

8.2.9 Slow Pump Rates

Likewise, the pumps are run on a daily basis at a low rate with a recorded pressure. This Slow Pump Rate ("SPR") is required to properly kill a kick. The DDRs do not indicate that SPRs were taken. However, this information is often contained in the IADC tour reports, which have not been made available in this case.

Final Report

8.3 Specific Comments from Analyses of the Daily Drilling Reports

Analyses of Drilling Operations

Report Date	Hours	Operation / Critique Comments	Downtime Day / Cum. (hrs)
		March, 2006	
		DDR(s): Daily Drilling Report(s)	
		DGR(s): Daily Geological Report(s)	
9	15.5	Spudded well at 1330 hrs. Drilled 8-1/2 inch pilot hole to 1,020 ft.	
10	4		
		An important issue with respect to shallow gas handling efforts is that shallow gas kicks almost certainly become blowouts in a matter of seconds. It is not possible to take a shallow gas kick and kill it with conventional procedures that would be used for a kick from a deeper interval.	
	2	Circulated the hole.	
	3.5	Pulled out of hole while pumping.	
	0.5	Prepared BHA with 26 inch bit.	
	9	Repair 29-1/2 inch annular BOP.	9/9
	5	Safety precaution of run in hole with kill string while waiting on parts for annular packing element replacement. ETA location March 10, 2006 at 1000 hrs will accompany by Regan annular engineer.	5/14
		The decision to mobilize a Regan annular engineer was appropriate. It is assumed that the Operator used OEM parts for annular repairs.	
		The Regan annular preventer is used on this well as a BOP for controlling shallow gas blowouts. The Regan annular BOP has a poor performance record for this type of application. For this reason, most operators appear to have elected to use other manufacturers such as Shaffer, Cameron or Hydril.	
11	14	Repair 29-1/2 inch annular BOP. Dismantled the inner and outer rubber, clean up, proceed with reassembly.	14/28
		It is somewhat unusual that both the inner and outer rubbers were bad, unless the BOP had been stored improperly and not used in some time.	
	4	Enlarged hole to 26 inch to 170 feet.	
	6	Installed inner rubber, proceed to nipple up 20" bell nipple and return flow line. Took time due to inside inner rubber smaller than OD string stabilizer and bit diameter.	6/34
		This type of technical accounting is unusual and seldom overlooked by operators. The inner diameter of the rubber should have been apparent in Regan's literature stored on the rig. This error could occur if the drilling contractor did	

Final Report

not have the proper Regan documentation at the rig site or failed to consult the documentation.

12	4	Continue nipple up bell nipple and flow line.	
	17	Drilling with 26 inch bit to 856 feet.	
	3	Mud pumps broke down.	3/37
13	4.5	Worked on mud pumps.	
	5.5	Drilled 26 inch hole to 922 feet.	4.5/41.5
	3	Worked on mud pumps.	3/44.5
	6.5	Drilling to 1,195 feet.	

The Well Plan called for the casing to be set at 1,237 feet. No reasons were given in the DDRs for setting it shallower at 1,195 feet.

The footage of 42 feet between the planned depth of 1,237 feet and the actual setting depth of 1,195 feet is not large but could be viewed as a precursor to the Operator's failure to comply with the Well Plan.

	2	Circulated the hole.
	2.5	Short trip.
	0.5	Run in hole to circulate.
14		No report.
15		No report. (Run and cement 20 inch casing during 14 and 15 March.)

These two missing reports should have contained information required to assess the effectiveness of the cement job. In a critical well, a Cement Bond Log "CBL)" or Cement Evaluation Log ("CEL") or similar type of tools should have been run. This log is necessary in the decision making process as to the possible requirement for some type of remedial cementing operation.

16	8	Final cut on 30 inch and 20 inch casing.
	3	Installed and tested well head.
	1	Installed adapter flange.
	4	Nipple up BOPS with blind rams on the bottom and the pipe rams on the top.

This BOP configuration should not have been used by the Operator as it did not always provide a barrier in the event of failure of any of the BOP stack components.

	7	Fabricated bell nipple.
	3	Install kill and choke lines.
17	4	Continue to nipple up kill and choke lines.
	1.5	Make up test plug and start BOP testing.
	7.5	Pressure tested the BOPs.

The DDR does not provide BOP testing details as if often common practice among operators. Without these details, a proper analysis can not be performed.

Final Report

	1.5	Installed wear bushing.	
	7.5	Make drill pipe stands in the derrick.	
	2	Make up 17-1/2 inch bit and run in the hole.	
		The Operator's on site representative included the following comment in the Remarks section of the DDR. The representative is in the best position to observe crew performance.	
		"TMMJ drilling crew, inadequate knowledge on drilling operations, therefore took time to perform all things related to drilling activities."	
		At this point, most Operators may consider some type of action against the Drilling Contractor, to include penalties of some type.	
18	5	Run in the hole to 1,169 feet.	
	4	Drilling cement and formation to 1,205 feet.	
	2	Performed LOT, surface pressure of 188 psi, Equivalent Mud Weight ("EMW").	
		It is doubtful that any pressure gauge used on the rig or by a third party would have the precision to measure down to a single psi unit. The reported LOT pressure of 188 psi must be taken with caution.	
		The data points used for the LOT should have been noted in the DDR.	
	6	Drilling to 1,511 feet.	
	4	Increased mud weight in pits to 10.0 lbs/gal.	
	3	As a safety precaution, pull bit to the casing shoe.	
19	24	Modified and repaired both hoppers, including nozzles.	24/68.5
		The Operator's on site representative noted the following in the DDR Remarks section.	
		"No availability of back up part was a handicap"	
		It is believed that good practice for drilling contractors is to maintain a rig site inventory of replacement parts, particularly for expendable items such as nozzles in the hopper.	
20	5	Working on mud hopper.	5/73.5
	4.5	Mixed 700 barrels of 10.8 lbs/gal mud.	
	3.5	Mixed additional 500 barrels.	
	1	Run in hole to 1,511 feet. Washed down the last stand.	
	5	Drilling to 1,700 feet.	
	5	Drilling to 2,000 feet.	
		The DDR contained the following remark.	
		"To avoid problem which will occur in future, due to utilizing a SOBM, the shale shaker had to be replaced or repaired,	

Final Report

		was not done for the time being."	
21	7	Drilled to 2.200 feet. Increase in background gas.	
	1	Survey.	
	1	Drilling to 2,304 feet, circulation, hole attempting to pack off, finally pulled 25K and pipe became free.	
		The Operator should have assessed the hole's tendency for packing off. The potential for packing off could substantially increase for running the next casing string.	
		It appears that a departure from the forecasted pore pressure had occurred. The failure to interpret this observation, relative to the long term health of the well, was a critical over sight. At this point, the Operator should have determined that the Banjar Panji No. 1 drilling operation was in jeopardy of failure and could result in more substantial adverse effects, such as a blowout, which was realized later.	
	6	Circulated and increased mud weight from 11.8 lbs/gal to 12.4 lbs/gal. Called casing point at 2,304 feet instead of 3,200 feet as per drilling program.	
		The decision to set casing at 2,304 feet instead of the planned 3,200 feet proved to be a terminal error.	
		As a minimum, the Operator should have recognized the long term significance of setting pipe too shallow. This action invalidated the existing Well Plan for the Banjar Panji well. Drilling operations should have been discontinued until a new Well Plan could be developed and approved.	
	4	Pull out of hole while pumping. Run back to bottom.	
	1.5	Circulated and then pulled out of the hole for logging.	
	3.5	Pulled out of hole while pumping.	
22	4	Continued pulling out of hole.	
	5	Wire line logging.	
	2	Prepare to run 16 inch liner.	
	1	Caliper indicted the need to run a 17-1/2 X 20 inch bi-center bit to enlarge hole prior to running the liner.	
	4	Run bi-center bit.	
	6	Reaming to bottom. Indications of packing off, believed to be due to limitations on maximum pump rate.	
	2	Circulated, had caving indications, increased mud weight to 12.6 lbs/gal.	
23	7	Circulated then repaired pump.	7/80.5
	6	Pull out of hole with the drill string while pumping.	
	0.5	Retrieved the wear bushing.	
	2	Rig up liner handling tools.	
	9.5	Running 16 inch liner.	
24	6	Ran 33 joints, 16 inch, K-55 grade, 75 lbs/foot casing. Could not get liner hanger through the well head.	
		The DGR indicates that 4 segments of liner hanger slip dies were broken when attempted to work it through the	

Final Report

		wellhead. Two pieces of die slips were found at the surface and two pieces fell down the hole. This information was absent from the DDR.	
	2	Removed hanger for modifications. Delivered the hanger to a work shop for medications.	2/82.5
		Damage to slip segments requires replacement of the damaged hanger with a new liner hanger. This type of damaged is not repaired but rather is replaced as would be specified by OEM literature.	
		Equipment such as a liner hanger can only be repaired by the OEM. This is widely accepted by the oil industry, regulatory agencies and other certifying bodies.	
		It is inconceivable and unforgivable that the sizing of the liner hanger relative to the inside of the well head had not been identified prior to this problem. As this type of problem had already occurred on several prior instances, an argument can be made that the Operator was incompetent, negligent, or both. Due to the serious nature of this type of over sight, on a repeated basis, the Operator should have taken steps to rectify the deficiencies of its internal technical and management staff, or step down as the Operator of this well.	
	12	Modified the hanger.	12/94.5
	4	Make up the hanger and run in the hole.	
25	3.5	Continued running in the hole with the liner on drill pipe.	
	4.5	Hit a bridge at 1,545 feet. Washed down to 2,144 feet.	
		The casing should have been pulled out of the well so the unstable hole conditions could be addressed.	
	3	Could not get any deeper by washing. Decided to call this depth as the liner set depth. Set the liner bottom at 2,184 feet.	
	3	Spacing out drill string, preparing to cement.	
	4	Cemented the liner. Liner top at 781 feet.	
		The DDR does not contain information on flow returns while cementing. It is not possible to identify if the cement was being properly circulated or if lost circulation may have occurred.	
	2	Clean mud tanks and BOPs.	
	4	Making up drill pipe stands in the derrick.	
26	8	Make up drill pipe stands. Cleaning mud pits. Had bubble in the hole. Observed well for two hours, still bubbled.	
		The wait on cement time, ("WOC") was 18 hours prior to commencing with operations in the well. Considering the cementing density of 12.4 lbs/gal, this WOC time appears to be inadequate and could negate the cement performance at isolated the well.	

Final Report

Bubbles in the hole indicate a gas bearing interval behind the 16 inch casing is not properly cemented. An assessment should have been conducted to identify remedial cementing options.

The Operator followed the common industry practice of squeeze cementing the liner overlap. This effectively masked behind casing problems while having no potential at resolving the problems.

	1	Run in hole and tagged the top of the liner at 770 feet.
	1	Performed injection test.
	4	Preparing squeeze cement.
	3	Cementing.

Liner top squeeze jobs are extremely difficult to properly execute and realize any improvement in cement effectiveness over the length of the liner section. It can be safely assumed that the liner cement was ineffective or non-existent.

	5	Wait on cement.
	1	Lay down circulation head.
	1	Start making up the bottom hole assembly.
27	4	Continued rigging up BHA.
	3	Run in the hole with a bit and start drilling cement. Had to stop drilling due to depletion of drill water.

This lack of water can not be explained with plausibility.

	3	Pumped water.
	2.5	Drilling cement from 700 to 750 feet.
	1.5	Displaced the hole with 12.3 lbs/gal synthetic oil base mud ("SOBM").
	5	Rig up supporting equipment for the SOBM.
28	1	Circulated hole.
	1	Drilled cement to 770 feet.
	1	Circulated 12.3 lbs/gal mud.
	1.5	Pressure tested top of the liner with 500 psi to 12.0 lbs/gal EMW. Pressure bled to 400 psi.

The pressure reduction after cementing usually results from ineffective squeeze cementing.

	2	Make up 14-1/2 inch new bit, run in the hole, resume drilling to 780 feet. Lowered to 798 feet.
	.5	Spotted a high viscosity pill.
	2	Run in hole and tagged cement at 2,135 feet.
	1	Displaced PHPA mud to 12.3 lbs/gal SOBM.
	1	Circulate mud.
	2.5	Attempted to drill cement. Over flowed the shaker screens.
	5	Drilled cement and washed open hole to 2,261 feet. Thick mud over shakers.

The Operator should have run a CBL/CEL type of log to

Final Report

		evaluate cement effectiveness.	
29	5	Washing down to 2,295 feet. Hole packed off. Released pipe after 30 minutes of working the pipe. Large amounts of cement, big pieces observed at the shale shaker.	
	1.5	Attempt to circulate. Pumps not operating properly.	1.5/96
	1	Pumped at low rates.	1/97
	1	LOT with 12.3 lbs/gal mud. Surface pressure of 220 psi, EMW of 14.2 lbs/gal.	
		Rig gauges are not capable of this precision level. The gauges have not been identified which makes it difficult to make an assessment.	
	2	Washed down to 2,290 feet. Hole packed off and tight. Pulled out to 2,153 feet.	
	2	Circulated the hole until it was clean.	
	4.5	Pulled out of the hole.	
	1	Run in the hole to 2,188 feet with open ended drill pipe.	
	0.5	Circulated the mud.	
	1	Pumped 44 barrels of 15.8 lbs/gal cement.	
		An explanation was not provided in the DDR as to the Operator's decision to perform this squeeze job.	
	1	Reverse circulate to clean the string.	
		It is forbidden from a hydraulics perspective to reverse circulate in a open hole environment.	
	1.5	Pull out of the hole with 2 stands and then circulated the normal, long way.	
	0.5	Close rams and squeezed cement.	
30	2	Continue squeeze cementing to 500 psi and then pressure dropped back to 400 psi static.	
		The pressure reduction to 400 psi may indicate less than desired squeeze effectiveness.	
	0.5	Pulled out of the hole with drill pipe.	
	4	Run in hole with 12-1/4 inch bit to 1,664 feet.	
	0.5	Serviced the top drive system.	
	2	Circulate and condition mud, increased to 12.6 lbs/gal. Problems with the centrifugal on the hopper system.	2/99
	6	Circulate while making repairs to the hopper equipment.	6/105
	0.5	Run in the hole and tagged cement to 2,151 feet, drilling soft cement to 2,180 feet.	
	1.5	Circulated bottoms up.	
	3.5	Drill out hard cement to 2, 280 feet.	
	1.5	Repair mud pump.	1.5/106.5
	1	Drilled cement to 2,305 feet.	
	1	Circulate mud prior to performing LOT.	
31	2.5	Conducted a LOT. Surface pressure of 217 psi, EMW 14.5 lbs/gal.	
	1.5	Bleed pressure and rig down.	
	0.5	Repair trip tank.	0.5/107

Final Report

	2.5	Pulled out of hole with the 14-1/2 inch rock bit.	
	1	Make up a 17-1/2 inch bi-center bit.	
	2.5	Run in hole to 2,154 feet.	
	0.5	Repaired possum belly on the shaker tank.	0.5/107.5
	0.5	Pre-job safety meeting.	
	8.5	Repaired pumps and shaker equipment.	8.5/116
	1	Circulated mud.	
	2	Washed down to 2,253 feet. Mud flowing over the shale shakers.	
	1	Pulled back to 2,156 feet and reduced the pump rate.	
		April 2006	
1	2	Had problems with mud pumps and pressure loss.	2/118
	2.5	Repairing rig components.	2.5/120.5
	1	Repairing rig components.	1/121.5
	1	Repairing rig components.	1/122.5
	0.5	Washed downed to 2,195 feet. Problems with Vortex dryer.	0.5/123
	0.5	Cleaned the dryer.	0.5/123.5
	0.5	Pump not working properly.	0.5/124
	0.5	Pulled back to 2,156 feet. Pump problems.	0.5/124.5
	1.5	Pump problems.	1.5/126
	14	Repairing rig components.	14/140
2	10	Repairing rig components.	10/150
	14	Installing additional equipment.	14/164
3	24	Repairing rig components.	24/188
4	24	Repairing rig components.	24/212
5	3	Repairing rig components	3/215
	4.5	Pulled out of hole with a plugged bit. Rubber from internal hole.	4.5/219.5
	16.5	Repairing rig components.	16.5/236
6	24	Repairing rig components.	24/260
7	18	Repairing rig components.	18/278
	1.5	Reaming the hole from 2,200 feet to 2,230 feet.	1.5/279.5
	4.5	Drilling to 2,400 feet, but with impaired pumps.	
8	4	Drilled to 2,542 feet. Pumps broke down.	
	1.5	Pulled out to shoe while pumping.	1.5/281
	3	Repairing rig components.	3/284
	1	Run in hole and washed down the last 2 stands.	1/285
	0.5	Pulled out to the liner shoe while pumping.	0.5/285.5
	0.5	Repairing rig components.	0.5/286
	11	Repairing rig components.	11/297
9	24	No report.	24/321
10	24	No report.	24/345
11	24	No report.	24/369
12	24	No report.	24/393
13	24	No report.	24/417
14	24	No report.	24/441
15	24	No report.	24/465
16	24	No report.	24/489
17	24	No report.	24/513
18	24	No report.	24/537
19	24	Repairing rig components.	24/561
20	24	Repairing rig components.	24/585
21	24	No report.	24/609
22	24	No report.	24/633
23	11.5	Repairing rig components.	11.5/644.5
	3	Circulate hole and condition mud to 13.3 lbs/gal in the pits.	

Final Report

		The mud engineer should have conditioned the mud while pump repairs were underway. This suggests poor planning by the mud engineer and the Operator's on site representative.	
	5	Pulled out of hole, picked up a new bit, run in the hole to 2,185 feet.	
	3	Reaming to 2,246 feet. Repairing rig components.	3/647.5
	1.5	Repairing rig components.	1.5/649
24	24	Repairing rig components.	24/673
25	19	Repairing rig components.	19/692
	2.5	Ream and enlarge hole to 2,578 feet.	
	2	Conditioning the mud.	
	0.5	Drilling 17-1/2 inch bi-center bit to 2, 595 feet.	
26	6	Drill to 3,000 feet.	
	2	Repairing rig components.	2/694
	4	Drill to 3,200 feet.	
	2	Circulate hole clean at 3,200 feet. No influx.	
	3	Pull out of hole to 2,851 feet, circulate, and run in the hole to 3,200 feet.	
	3.5	Drilling to 3,375 feet. Increase in gas. Pore pressure estimate increased from 13.1 to 13.5 lbs/gal.	
	2.5	Repair rig components.	2.5/696.5
	1	Drilling to 3,440 feet.	
27	2	Drill to 3,500 feet.	
		An average kick taken from the 3,500 feet would have resulted in an underground blowout at 1,195 feet which is the depth of the 20 pipe. The LOT was 14.5 lbs/gal and the equivalent mud weight from an average kick would be 15.0 lbs/gal. Drilling should have been halted at this depth.	
	4.5	Circulate the hole, observed well, had small flow returns. Circulate mud for 2 hole volumes. Observed well, again small flow returns. Increased mud to 13.5 lbs/gal gradually.	
		A primary kick indicator of flow returning when the pumps were off was ignored, either intentionally or accidentally. The drilling industry universally requires that the BOP(s) should be closed when a primary kick indicator is observed.	
		In view of the fact that the 20 inch seat was in jeopardy, the Operator exhibit recklessness by continuing with drilling operations. The only viable approach at this time was to plug and abandon the well as it was clearly impossible to reach the target depth of ~10,000 feet with the current well plan.	
		Further, the Operator's Well Plan required that the well should be shut in.	
	1.5	Drill to 3,595 feet.	
	3	Circulate and observe well. Had a flow of 1.4 barrels in 15 minutes.	

Final Report

		The Operator did not shut-in the well as was required by the Well Plan.	
	4	Continued circulation and increased mud weight to 13.8 lbs/gal.	
	3.5	Continued circulation and increased mud weigh to 14.0 lbs/gal.	
	1	Pull out of hole while pumping to 3,175 feet. Had tight hole at 3,415 feet and 3,225 feet.	
	1	Circulated mud. Had increased cuttings on the shaker at bottoms up.	
	1	Run bit to 3,595 feet. Trip tank needs repair.	
	2	Repairing rig components.	2/698.5
	0.5	Directional survey.	
28	6	Observed well. Normal pull out of hole.	
	9.5	Wire line log.	
	1	Repairing rig components.	1/699.5
	1.5	Make up bit and test BHA.	
	3	Run in hole to 2,185 feet.	
	3	Reaming down and enlarging hole to 2,820 feet.	
29	3	Reaming down and enlarging hole to 3,595 feet.	
	1	Circulate while recovering large volume of cuttings at shaker.	
	2	Continue circulation and increased mud weight to 14.2 lbs/gal.	
	5	Pulled out of the hole.	
	0.5	Retrieve wear bushing.	
	1.5	Rig up 13-3/8 inch casing handling equipment.	
	2	Make up casing hanger and did a dummy run to 33.40 feet.	
	1	Pre-job safety meeting.	
	8	Run in hole with 13-3/8 inch, 72 lbs/foot, K-55 grade casing to 1,378 feet.	
30	2	Running to 2,139 feet. Change elevators from 150 ton to 350 ton rated.	2/701.5
		The hook load of 72 lbf/ft casing at 3, 580 feet is 257,700 pounds force or 129 tons. According to API design procedures, the casing elevators must be selected based on a 3.5 design factor. Thus the elevator rating should be 3.5 x 257,700 lbf or 901,950 lbf. The elevator rating that exceeds this value is the 500 ton elevator. The design factor of 3.5 is used to avoid catastrophic failures of the casing at the rig floor level.	
		The Operator used 150 ton elevators initially. This elevator was substantially below the API design level of 500 ton elevators. This selection borders on criminally endangering personnel members working on the rig floor.	
		For unexplained reasons, the Operator changed out the 150 ton spider elevator for a 350 ton unit. Later, they changed out the 350 ton "worn out spider slip" to 150 ton manual slips. The 150 ton rating barely exceeded the pipe load and could easily have failed at any time.	
	1	Well flowing. Shut in the well. Pressure was 0 psi. Bleed	1/702.5

Final Report

		off pressure, said to be due to ballooning.	
		Ballooning is often used as an explanation for events that appear to be well control related. Some wells have blown out as the Operator believes ballooning was occurring when the facts show the well was kicking.	
	3.5	Running to 2,691 feet. Problems with the spider elevator. Casing slipping.	3.5/706
	2	Change back to 150 elevators due to worn 350 ton elevators.	2/708
	5	Run in hole with 13-3/8 inch casing to 3, 556 feet.	
	1	Make up the casing hanger.	
	1.5	Circulate and reciprocate pipe, pumping at 4 bbls/min to 135 barrels, had 50 barrels losses.	
	1.5	Make up the cement head. Had problem opening and closing low torque valve.	
	1	Drop bottom plug.	
	3	Cemented the well. Had partial losses until displaced 234 barrels and then total losses to the plug bumping. A total of 249 barrels lost while displacing cement. Flow back from ballooning was 50 barrels. Losses while circulating prior to cement of 47 barrels and 47 barrels flow back. While pumping cement, losses of 450 barrels. Total losses of 756 barrels.	
		With these massive mud losses, it is highly unlikely that the cement job was more than marginally effective.	
	1.5	Rigging down.	
		May 2006	
1	1.5	Continue to rig down.	
	7.5	Dry up cellar manually due to equipment failure.	7.5/715.5
	1	Wash BOPs.	
	1	Set hanger packoff.	
	4	Nipple down the flow line.	
	2	Lay down the annular BOP.	
	3.5	Laid down the rams.	
	3.5	Installed FMC Unihead.	
2	3	Finished installed the Unihead.	
	21	Rigging up the BOPs, 13-5/8 inch, 10,000 psi working pressure.	
3	5.5	Completed the installation of the BOPs.	
	1	Rig up Halliburton to test BOPs.	
	0.5	Safety meeting.	
	1	Flush lines with water.	
	0.5	Attempted to test the annular. Leaking flange.	0.5/716
	3.5	Tighten flange bolts.	3.5/719.5
	1	Attempted a retest of the annular. Leaking flange.	1/720.5
	5	Replaced a valve.	5/725.5
	0.5	Attempt to retest the annular. Found leaking.	0.5/726
	2	Tighten flange bolts.	2/728
	0.5	Attempt to retest the annular. Leaking pressure.	0.5728.5
	3	Lay down the test plug. Check flange grooves.	3/731.5
		The BOP testing problems requiring continued tightening of	

Final Report

		the flange bolts is characteristic of over stretched bolts that have exceeded their elastic deformation limit. If this analysis is correct, the bolts should have been discarded and replaced with new flange bolts.	
4	14	Working on the BOPs.	14/745.5
	0.5	Successful test of rams to 7,500 psi.	
	1	Successful test of annular to 5,000 psi.	
	1	Successful test of lower Kelly cock.	
	0.5	Stand pipe leaking.	0.5/746
	0.5	Successful test of lower rams.	
	3.5	Repair the lower Kelly cock.	3.5/749.5
	1	Rig up to the choke manifold.	
	1	Found leaking HCR valve on choke line. Tighten flange bolts.	1/750.5
	0.5	Successful retest of HCR.	
	0.5	Tested Super Choke. Tested manual choke.	
5	2	Tested kill line valve.	
	1	Pressure testing valves.	
	1.5	Pressure testing valves.	
	0.5	Pressure testing valves.	
	1.5	Pressure testing valves.	
	1	Attempted to test TIW valve. Leaked.	1/751.5
	1	Retrieved test plug.	
	4.5	Installed bell nipple.	
	3	Pressure testing valves and stand pipe.	
	1.5	Pressure testing valves.	
	0.5	Pressure testing valves.	
	1	Lay down drill pipe.	
	3	Repairing rig components.	4/755.5
	2	Rig up 12-1/4 inch bit and clean to 194 feet.	
6	2	Run in the hole to 1,128 feet.	
	4	Run in hole to 2,342 feet.	
	1	Run in hole to 3,152 feet.	
	3.5	Failed test of upper stand pipe valve.	3.5/759
	0.5	Retest upper stand pipe valve.	0.5/759.5
	1	Run in hole to 2,490 feet. Tagged cement. Circulate. Found pressure gauges not working.	1/760.5
	0.5	Conduct safety drills.	
	0.5	Conducted choke drill.	
	1	Replaced diaphragms on gauges.	1/761.5
	5	Drilled cement and formation to 3,605 feet.	
	1	Circulate with 14.2 lbs/gal mud. LOT with 14.2 lbs/gal mud to 400 psi. EMW of 16.4 lbs/gal.	
	0.5	Pulled out of hole to 3,269 feet. Trip tank down.	0.5/762
	1.5	Repair trip tank.	1.5/763.5
	0.5	Pulled out of hole to 2,500 feet.	
7	3	Pulling out of the hole to surface.	
	3	Dismantled and layed down the stabbing board.	3/766.5
	5.5	Run in with new 12-1/4 inch bit to 3,400 feet.	
	1.5	Reaming last 2 stands.	
	1.5	LOT. (Figure 8.1) Resume drilling to 3,740 feet. Increased gas.	
	3.5	Circulated and increased mud weight to 14.4 lbs/gal.	
	4.5	Drilled to 4,020 feet while increasing mud weight to 14.6 lbs/gal. Increased connection gas.	

Final Report

	1	Drilled to 4,210 feet. Circulated gas from the well.	
	0.5	Observed well. Static.	
8	0.5	Surveyed well at 4,100 feet.	
	2.5	Drilled ahead to 4,290 feet. Wash pipe leaked.	
	1.5	Pulled out to shoe to repair wash pipe.	1.5/768
	2	Working on rig components.	2/770
	1	Run in hole to 4,290 feet.	1/771
	12.5	Drilled to 5,060 feet. Mud weight of 14.7 lbs/gal.	
	1	Circulated hole prior to survey.	
	1	Performed directional survey.	
	2	Drilled to 5,200 feet.	
9	5	Drilled to 5,200 feet. Mud weight of 14.7 lbs/gal.	
	1	Circulate prior to survey.	
	1	Performed directional survey.	
	1	Drilled to 5,552 feet.	
	1	Pump problems.	1/772
	2	Safety precautions while rig down.	2/774
	14	Repairing rig components.	14/788
10	6	Repairing rig components.	6/794
	1.5	Trip to bottom.	1.5/795.5
	11.5	Drilled to 6,163 feet. ROP decreased from 90 feet per hour to 3 feet per hour.	
	2.5	Circulate hole.	
	1	Perform direction survey.	
	1.5	Pulled out of hole to 4,100 feet.	
11	6	Continued pulling out of the hole. Bit had 1 nozzle lost, 1 nozzle washed out, 2 nozzles plugged.	
	6	Installed new bit and ran in hole to 6,163 feet.	
	1	Circulated.	
	11	Drilled to 6,445 feet.	
12	4	Drilled to 6,478 feet.	
	1	Worked on mud pump.	1/796.5
	9	Drilled to 6,515 feet, while repairing mud pumps.	9/805.5
	7	Drilled to 6,648 feet.	
		The Well Plan specified that a liner would be run to 6,537 feet and cemented. Comments from the DDRs suggest that this plan was in effect until the setting depth was exceeded. The DDRs do not provide any guidance as to the reason the Operator elected to ignore the setting depths provided in its Well Plan.	
		It is more likely than not that the blowout would have been avoided if the 6,537 feet liner set depth had been honored.	
	1	Performed directional survey.	
	2	Drilled to 6,675 feet.	
13	24	Drilling to 7,110 feet.	
14	3	Drilled to 7,135 feet. Circulated the hole.	
	1	Performed directional survey.	
	4	Drilled to 7,212 feet. Wash pipe leaked.	4/809.5
	5	Pulled out of hole. Drill pipe connections highly torqued.	
		Over torqued drill pipe connections usually occur due to inadvertent over torquing by the rig crew or excessive hole torque from unstable down hole conditions. Bad torque	

Final Report

gauges are often the cause of surface over torquing.

	3	Repair the top drive.	3/812.5
	2	Repair rig components.	2/814.5
	4	Pick up additional drill pipe to reach new Total Depth of 8,500 feet instead of 6,500 feet.	
	2	Run in hole to 7,212 feet.	
15	1	Washed to 7,212 feet.	
	17.5	Drilling to 7,433 feet. Wash pipe leaked.	
	4	Repair wash pipe.	4/818.5
	1.5	Replaced wash pipe.	1.5/820
16	3.5	Run in hole, ream to bottom.	
	17.5	Drilling to 7,690 feet.	
	1	Circulate hole.	
	1	Performed directional survey.	
	1	Drilling to 7,710 feet.	

The DGR indicates trace magnecious metal samples were found in cuttings samples from 6,680 feet to present depth. This observation is a departure from the expected conditions in the Well Plan. It warranted further investigation.

17	10	Drilling to 7,990 feet.
	14	No report information.

The DDR contained the following remark:

"Formation still consists of 100% sand stone."

The geological assessment used in the Well Plan did not suggest that the well would encounter this massive sand interval. This observation can only be interpreted to indicate that an unanticipated geological structure had been encountered. Operations should have been halted until this matter could be understood more clearly and the Well Plan could be revised accordingly. The Well Plan was not modified.

18	5	Drilling to 8,040 feet.
	2	Circulated with 14.7 lbs/gal mud.
	1.5	Pulled out of hole with 5 stands.
	2.5	Circulate to condition mud and pull out to 4,300 feet.

The DGR report shows a 20,000 lbf over pull at 4,249 feet.

2	Back reaming from 4,300 feet to 3,800 feet due to high torque.
1	Circulate.
4.5	Pull out of hole. 5 bit nozzles plugged. Install new bit.

The driller should have observed fluctuations in the drill pipe pressure each time a nozzle plugged. It appears the driller did not correctly identify or interpret the pressures.

4.5	Run into the hole.

Final Report

	1	Slip and cut drill line.	
19	1.5	Continued to slip and cut drill line.	
	2	Run in hole with 12-1/4 inch bit to 4,000 feet.	
	1	Ream to 4,300 feet.	
	4	Run in hole to 8,040 feet.	
	5.5	Drilled to 8,070 feet.	
	2.5	Pulled out of hole for 5 stands while pumping.	
	7.5	Pulled out of hole to install new bit.	
20	5	Installed a previously run bit and run in the hole to the shoe.	
		Rerun bits should not be used in a critical well similar to the Banjar Panji well. It is difficult to properly assess prior damage imposed on a rerun bit. A dowhole failure could endanger the success of the well. Any cost saving resulting from running an old bit is insignificant relative to overall wells costs.	
	2	Repair rig components.	
	2	Run in hole to 8,087 feet.	
	15	Drill to 8,350 feet.	
21	7	Drill to 8,440 feet.	
	1	Make up additional stands in the derrick.	
	1	Drilled to 8,460 feet, mud pump failure.	1/821
	1	Safety precaution.	1/822
	5	Repairing rig component. The rubber seals on the suction valves, discharge valves and the seating valves had to be replaced. The DDR indicate the cause for replacements was due to drilling fluid temperature.	5/827
		Temperature was diagnosed as a problem at this point. The anticipated formation temperatures did not suggest that abnormally high temperatures would be encountered. This observation should have been evaluated, with numerous other factors, against the Well Plan.	
	3.5	Run in the hole.	
	3	Drilled to 8,525 feet.	
	0.5	Safety precaution.	0.5/827.5
	1	Repairing rig component.	1/828.5
	0.5	Run in the hole.	0.5/829
	0.5	Drill to 8,550 feet.	
22	4	Drill to 8,581 feet.	
	1	Circulated sample for geologist.	
	2	Drill to 8,629 feet.	
	1	Circulated sample for geologist.	
	1	Picked up 2 stands of drill pipe.	
	12	Drilled to 8,629 feet, which was the 9-5/8 inch casing point (originally planned to 8,750 feet). Increased mud weight to 15 lbs/gal.	
		The DDR indicates casing was to be set at this depth, in accordance with the Well Plan. This setting depth was not honored and casing was never set at any deeper environment. No explanation has been made available as to the Operator's inexcusable departure from the Well Plan.	

Final Report

	1	Circulated the hole.	
	1	Performed directional survey.	
	1	Pulled out of hole to 7,500 feet.	
23	5	Pulled out of hole to 3,500 feet.	
	1.5	Repairing rig components.	1.5/830.5
	3.5	Pulled out of the hole to surface.	
	12.5	Run wire line logs. BHT of 282°F.	
24	24	Run wire line logs and take side wall cores.	
25	16.5	Continue wire line logging. Ran a Vertical Seismic Profile ("VSP").	
		The VSP is a downward looking seismic tool run on wire line. It has the same capability of any seismic survey with the exception that its depth is more restricted. At the depth the VSP was run, it should have identified any potential geological anomalies in the next 500 feet. The DDR did not provide any information as to the interpretation of the VSP tool.	
	4	Make up new 12-1/4 inch bit.	
	1.5	Serviced the top drive.	
	1	Slipped drill line.	
	1	Run in hole to 5,500 feet.	
26	4	Run in hole to 8,200 feet.	
	3	Reamed to bottom.	
	17	Drilled to 8,980 feet with 14.7 lbs/gal mud.	
27	24	Drilling ahead from 8,980 feet to 9,090 feet, performed a shut in test at 9,010 feet, result gas reading similar as previous. Resume drilling from 9,090 feet to 9,230 feet. H_2S probe sensor, located at shale shaker area, detected 25 ppm concentrated H_2S. Drilling crew at rig floor continued performing job by following standard operating procedure, the rest drilling crew evacuated to briefing point. Continued drilling to 9,277 feet.	
		Encountering this level of H_2S gives cause to consider running casing at 9,277 feet.	
		Results of the shut in test were not provided. A logical result is that the test was negative but this can not be confirmed.	
28	2	Drilled formation from 9,277 feet to 9,283 feet.	
	1.5	Circulated the hole clean.	
	2.5	Pick up additional 4 stands of 5 inch drill pipe in the derrick.	
	2	Resume drilling from 9,283 feet to 9,297 feet. Lost circulation occurred.	
		The DDR does not give a description of the severity of the lost circulation incident. This information would be helpful in performing an analysis.	
	4	Spotted a 60 barrel volume of LCM material at the hole bottom. Pulled out to 8,737 feet. Monitored well through the trip tank. Static. Mud engineer mixing LCOBM, 8 lbs/gal, on mud plan.	

Final Report

7 Transfer total of 600 bbls, 8 lbs/gal LTOBM to mud tank, proceed mixed and raised mud weight to 14.7 lbs/gal.

The DDR does not provide sufficient information to assess the mud inventory system prior to the lost circulation incident. The transfer of 600 barrels suggests that the lost circulation was massive.

5 Worked pipe from 8,700 feet to 8,500 feet without circulation. Over pull increasing. Circulated at 8,100 feet with 50% returns. Continue pulling out to 6,500 feet while pumping. Fill hole through the drill pipe. Total volume displacement was hard to counter. Continued to pull to 4,500 feet.

The Operator should not have continued pulling out of the hole at 8,700 feet without circulation. This suggests that they were attempting to pump while pulling out of the hole. The drill string should have been left at 8,700 feet or run into the hole to the bottom. The Operator did not realize that a massive lost circulation problem existed and can be effectively treated only when the bit is deep into the well, near the loss source.

The inability to measure the drill pipe displacement is another indication that the loss was severe.

Continuing to pull pipe while losses were occurring reduces well bore pressures by a reduction in mud hydrostatic pressure and swab pressure.

29 3 Pulled to 4,245 feet. Indication of a well kick. Shut-in the well. High concentration of 500 ppm of H_2S detected surrounding the shale shaker.

4 SIDPP of 350 psi, SICP of 450 psi. Prepared to kill well. Utilized volumetric method. Gas through flare line. Well died. Contaminated fluid and mud mixed with trace water caused mud weight to drop to 8.9 lbs/gal. Total loss of 300 barrels since 0500 hrs.

The shut-in pressure readings of 350 psi on the drill pipe and 450 psi on the casing indicate the kick influx was not from zones entirely below the bit. It the kick influx was below the bit, pressure readings would be consistent on the drill pipe and casing. A likely interpretation is that the kicking zone is near the depth of the bit. The Operator incorrectly diagnosed the depth of the kick influx based on the shut in drill pipe and casing pressures. (See Figures 8.2 and 8.3)

The volumetric method is not a recognized method for removal of kick fluids from the well bore, unless the kick fluids are all below the bit. The kick and hole did not

Final Report

indicate any characteristics that would require implementation of the volumetric method. When not required, this method should not be used as it easily leads to a worsening of the situation. As a best case, the volumetric method can be used until the kick fluids are above the bit, at which time the driller's method should be used.

The well did not die as suggested by the DDR. The likely scenario is that an underground blowout ("UGBO") was in progress. The flow path was probably vertically in the poorly cemented casing annulus. Gas bubbling observed soon after this observation confirms that a UGBO was in progress. The likely flow origin was proximate to the bit's location at 4,291 feet and the flow exiting from the hole path was the 13-3/8 inch liner seat at 3,580 feet. The loss of 300 barrels of mud further supports the argument that an UGBO was in progress. It should have been considered by competent rig site personnel.

The pipe was pulled from 4,245 feet to 4,241 feet before sticking. An interpretation of down hole behavior at this point is important but can't be assessed due to brevity of information in the DDRs.

The mud weight reduction to 8.9 lbs/gal indicates the SOBM at 14.7 lbs/gal had been pumped into a loss zone and that the kick fluid seen at surface was the actual influx fluids, basically a watery mud.

8 Attempted to work pipe free. Unsuccessful.

2 Safety precaution, shut in well. Mixed a spotting pill of 50 barrels at 14.7 lbs/gal with 95 % oil to 5% water ratio.

4 Spot a 40 barrel pill for pipe sticking and wait for the pill to soak.

The Operator did not recognize that the priority was the kick and underground blowout potential and not the stuck pipe or the loss circulation. At this time, loss circulation zones were at the bottom of the hole below 9,270 feet and somewhere in the hole at a relatively shallow depth, perhaps at the casing seat.

1.5 Prepare to run Free Point Survey.

1 While rigging up wire line, H_2S detected around the surface. Evacuated the crew. Bubbling around the surface.

The bubbles around the surface at the rig site were the first clear indicator that an UGBO was in progress.

0.5 Baker cancelled wire line run. Bubble gas contained 5ppm of H_2S arose 40 foot outside flare.

30 9 Observed bubbling around the rig. Gas and water bubbles caused substantial eruptions to 25 feet, elapsed time of 5 minutes between bubbles. Pumped down drill pipe with 230 barrels of 14.7 lbs/gal mud. Bubbles intensity reduced and

Final Report

elapse time between each bubble is longer. Observed maximum bubble of 8 feet height occasionally, normally one foot in height, with 30 minutes elapsed between each bubble.

The changes in bubble height indicate the flow is being gas lifted, and not flowing large volumes due to source pressure. A more important interpretation is that the kick source is not abnormal pressured.

The Operator does not appear to have recognized that he was pumping directly into the UGBO flow stream and was having a significant effect on the blowout. If pumping had continued, the blowout may have been killed at this time.

5 Mixed 16.0 lbs/gal mud mixed with LCM.

The rig's mud inventory appears to have been poorly managed that caused the frequent requirement to stop operations and mix mud. Also, the Operator's focus was on the loss issue and not the blowout issue. If the focus had shifted to the blowout, the blowout may have been killed.

3.5 Mixed 100 barrels of 16.0 lbs/gal mud for displacing after cementing.

The focus was shifted from pumping a LCM mud to cement for solving the loss problem.

1 Pumped 200 barrels of 16 lbs/gal mud.
4.5 Mixed 150 barrels of 16.0 lbs/gal mud.
1 Rig up Halliburton and start mixing slurry to 15.8 lbs/gal.
31 5 Pumped 50 barrels of 15.8 lbs/gal cement slurry followed by 110 barrels of mud.

Cement should never be pumped in a live well environment. It has no conceivable chance of success and is more likely to aggravate the situation by plugging the drill string.

8 Wait on cement while observing the well and bubbles activities at distance from the rig. Bubbles already decreased in activity since the night.
4.5 Mixed 200 barrels of 14.7 lbs/gal mud.
1 Pumped 100 barrels of 15.8 lbs/gal cement slurry.
4 Mixed 150 barrels of 14.7 lbs/gal mud.
1 Injection test below the bit.
0.5 Rig up to run Free Point Survey.

The Operator was too obsessed with the stuck pipe problem while disregarding the on-going UGBO. By this time, the UGBO had become an above ground blowout ("AGB").

Rather than running a Free Point Survey, the Operator should have run a temperature log to identify the behind casing flow scenario.

Final Report

June 2006

1	4.5	Monitor and control muddy water which blew formation fluid from the crater. Attempting to avoid contamination and flooding to the surrounding area well.
	11.5	Run in hole with Free Point Survey. Pipe free from 8% to 40% over the interval of 700 to 3,200 feet. Several depths were 100% stuck.
		The Operator did not recognize that sticking inside the 13-3/8 inch liner to 3,580 feet was highly unlikely unless the most recent circulations carried large volumes of rock cuttings up the casing. The Operator did not recognize the importance of the rock cuttings.
	7	Evacuating unnecessary equipment from drill site.
	1	Rig up back off tools.
2	5	Run in hole with the string shot to 3,526.5 feet.
		Operations to cut and remove drill pipe started. The plan was to abandon the well.
		At this point, it is almost incontrovertible that the Operator was grossly inexperienced to handle this situation. Their actions to cut pipe and attempt a well abandonment were, as a minimum, negligent. This type of action to plug the well is not recommended by any technical publications that are recognized world wide.
		The operation undertaken by the Operator has no precedence in the recorded history of blowout events, based on an analysis of a blowout database that contains over 3,500 blowout histories.
		Actions taken by the Operator from these point forward borders on criminal negligence as it endangered personnel, the rig and the surrounding environment.
	2	Worked pipe prior to firing gun. Fired guns.
	5	Ran an additional string shot. Fired gun. Cracks observed around the rig.
	6	Lay down drill pipe.
3	8	Lay down drill pipe.
	2	Rig down top drive.
	3	Set a cement plug 2,590 to 2,790 feet. Reversed out.
		Reverse circulation should be avoided in open hole situations.
	5.5	Continued to rig down.
	2.5	Mixed and pumped a cement slurry over the interval of 2,100 feet to 2,250 feet.
	1	Pulled out of hole with 5 stands. Reversed out.
		Reverse circulation should be avoided in open hole situations.

Final Report

	2	Waiting on cement. Rig down.
4	2	Wait on cement. Run in hole and tagged top of cement at 2,110 feet. Weight tested with 8K of weight.
	2	Pulled out of the hole.
	2	Prepare to rig down mast.
	11	Continue rigging down.
	2	Lowering the mast.
	5	Rig down mast. **Last Report.**

Final Report

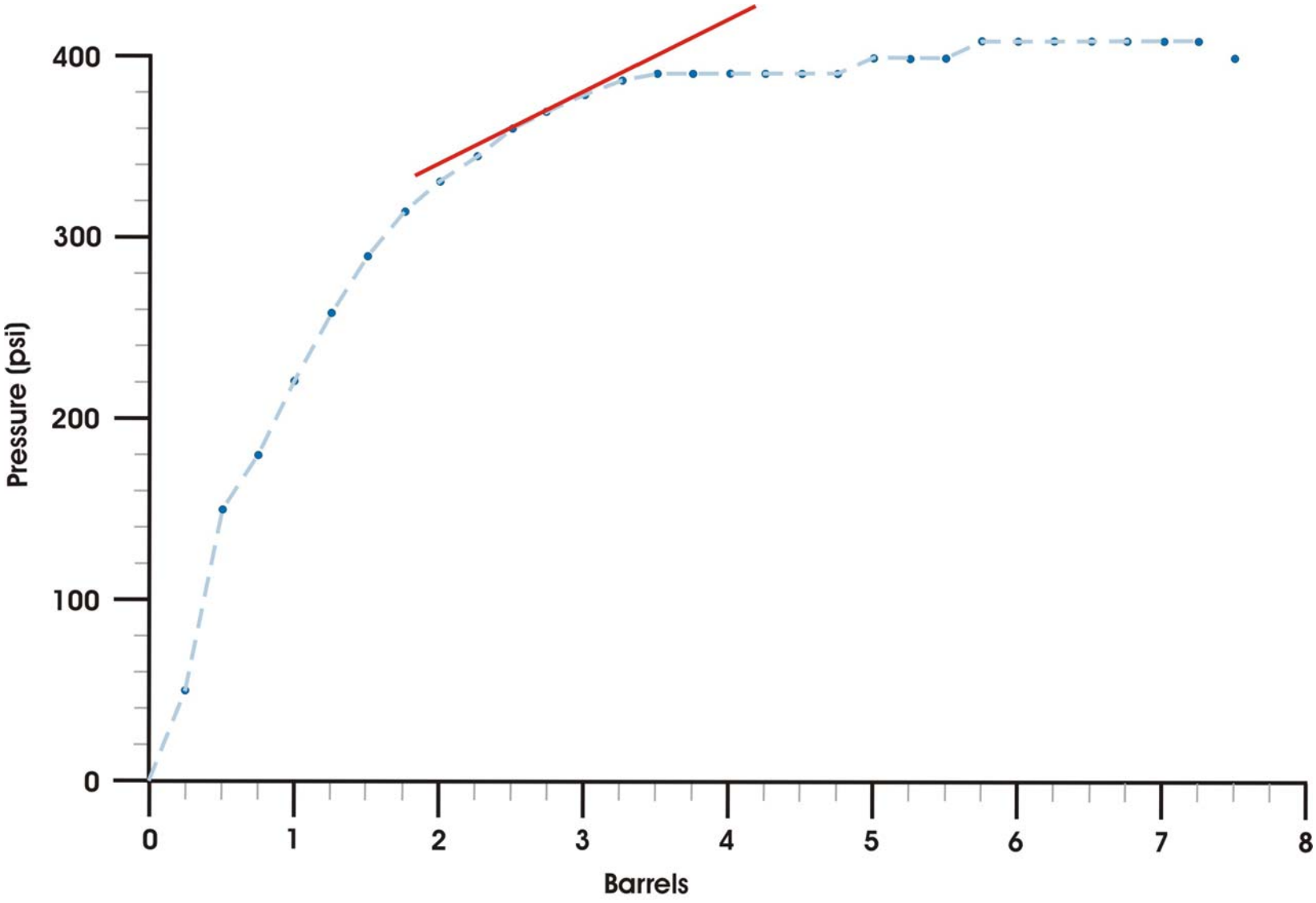


Figure 8.1 Analysis of LOT Data for the 13-3/8 inch Casing.

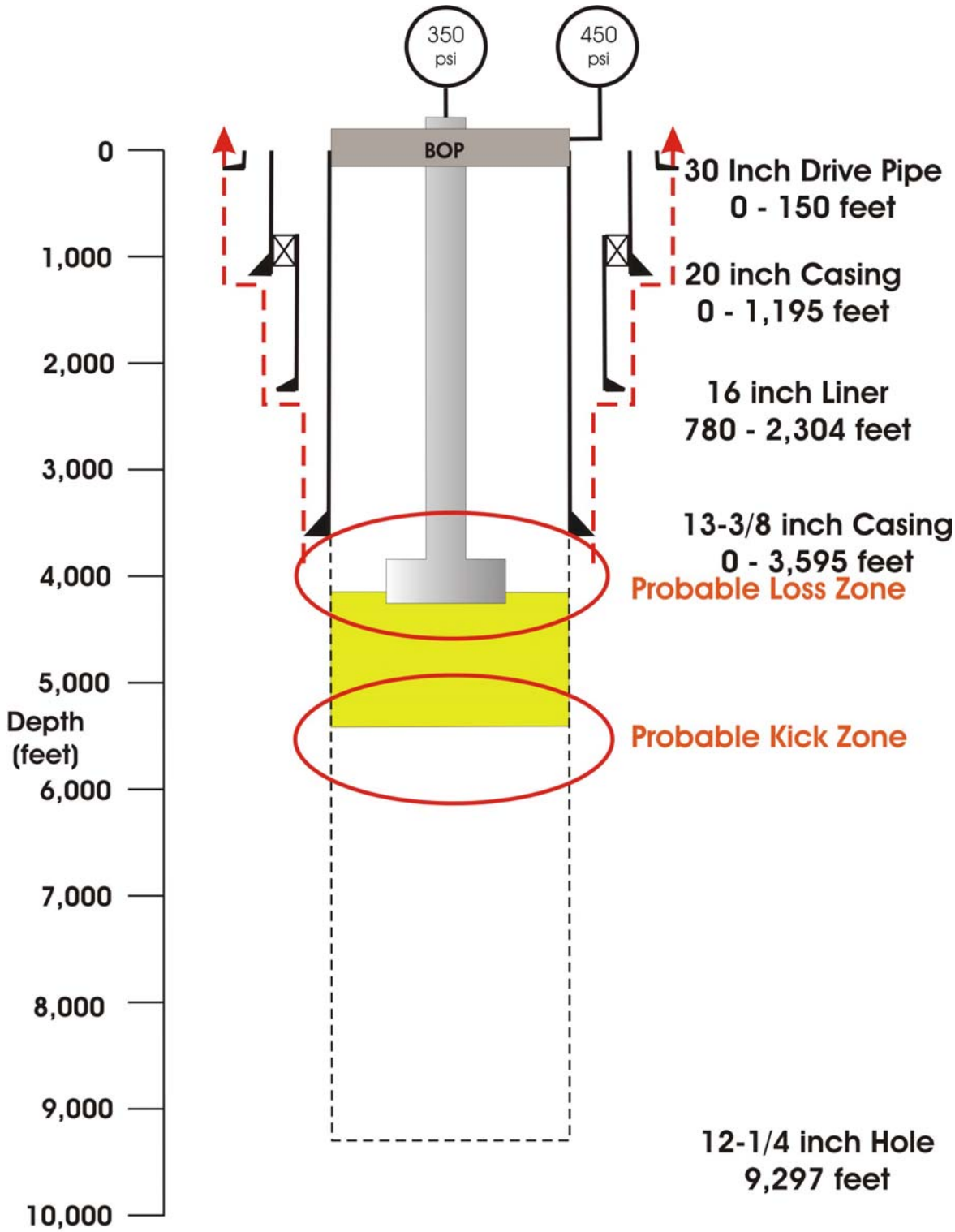
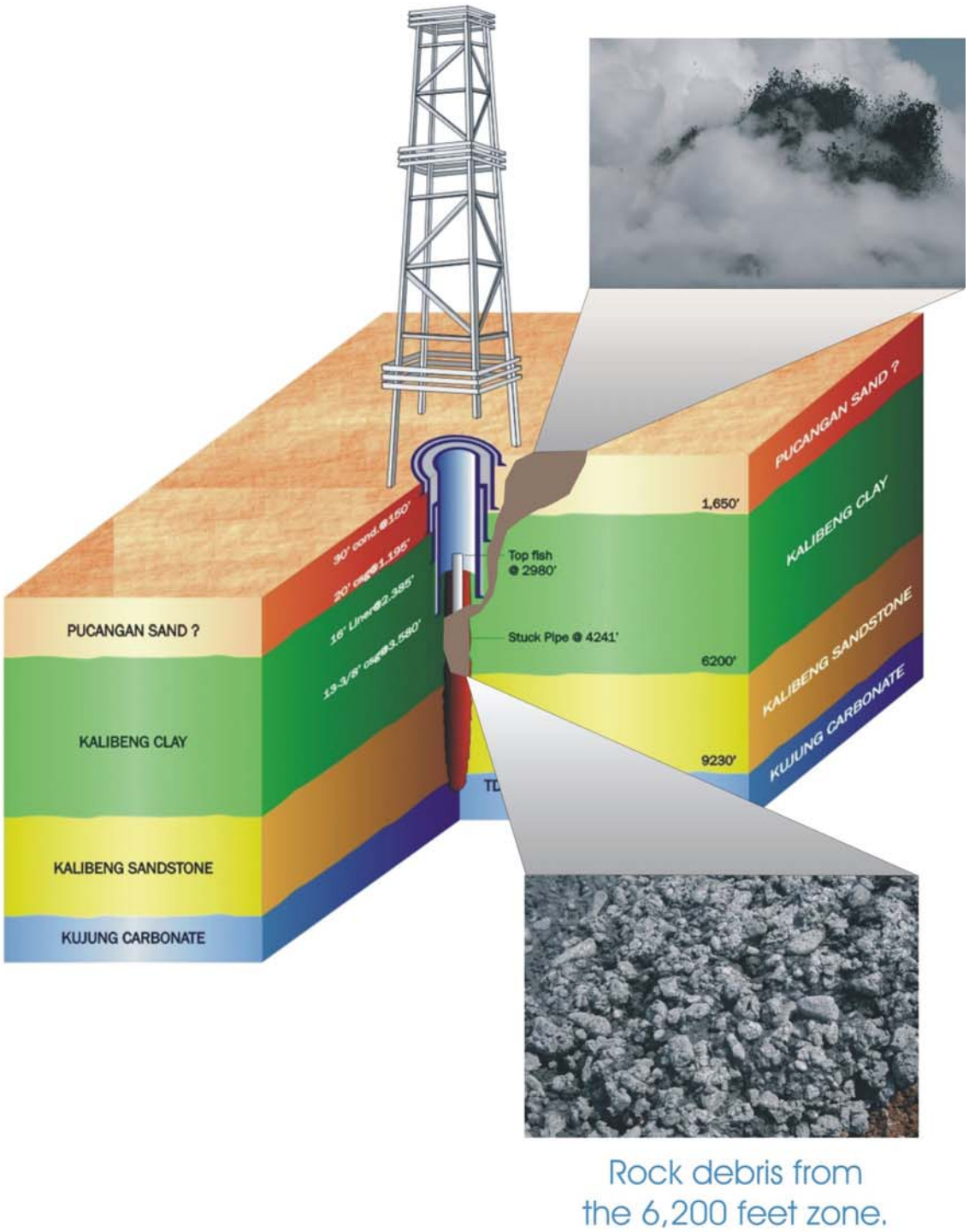


Figure 8.2 Kick Zone and Surface Flow Path



Rock debris from
the 6,200 feet zone.

Figure 8.3 Kick Entry Zone and Flow To Surface

9.0 Findings Presented According to the Scope of Work

During the course of this investigation, numerous findings have been developed. They have been presented in Section 2, 3, 4, 5, 6, 7 and 8. To complete the investigation, these findings previously presented are organized according to the items in the Scope of Work. The Scope of Work is repeated here.

Scope of Work

The following items are contained as the Scope of Work ("SOW").

9.1 Perform a general review of the well bore diagram, highlights and chronology already provided and any additional records provided during the defined work period.

9.2 Identify possible causes contributing to the loss of control of the well.

- *Failure to set casing at ~ 9,000 feet.*
- *Failure to set casing at ~ 6,500 feet.*
- *Failure to properly interpret kick behavior after the kick was taken while at 4,241 feet.*
- *Poor cement bonding efficiency behind all casing strings.*

9.3 Perform a preliminary analysis to determine one or more likely sequences of casual factors leading to current well control conditions.

Other than factors identified in Section 11.2 above, casual factors include the following:

- *Lack of competent engineering by the Lapindo engineering group.*
- *Lack of competent engineering by the Medici engineering group.*
- *Lack of competence by the Lapindo site supervisor.*
- *Lack of competence by the Medici site supervisor.*
- *Failure of Lapindo to understand fundamentals of well control.*
- *Failure of Medici to understand fundamentals of well control.*
- *Failure of Lapindo to properly understand well planning procedures.*
- *Failure of Medici to properly understand well planning procedures.*
- *Failure of Lapindo to properly assess new geological environments as they adversely affected the Well Plan.*
- *Failure of Medici to properly assess new geological environments as they adversely affected the Well Plan.*
- *Failure of Lapindo to interpret seismic data, presence of multiple faults and the inadequacy of selecting a safe drill site that would not be possibly affected by the fault.*
- *Failure of Medici to interpret seismic data, presence of multiple faults and the inadequacy of selecting a safe drill site that would not be possibly affected by the fault.*
- *Failure of Lapindo to give proper consideration to technical suggestions by MEDCO.*

Final Report

- *Failure of Lapindo to give proper consideration to technical suggestions by MEDCO.*
- *Failure of Lapindo to give proper consideration to technical suggestions by Santos.*
- *Failure of Lapindo to avoid a Conflict of Interest by signing a contract with Medici, where both companies had some joint ownership interests.*

9.4 Identify possible means for avoid recurrence of these causes and results in future operations, and comment on whether these means are generally considered routine industry practices.

Means to avoid recurrence of the blowout causes identified in Sections 9.2 and 9.3 are to avoid situations shown in these sections. These means are used by many companies world wide and are supported by numerous technical publications and the API Recommended Practices.

9.5 As practical, identify methods and data needed to perform a more complete analysis and confirmation of what happened and why.

Final Report