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**WELL BLOW-OUT ASSESSMENT EXPERTISE
BANJAR PANJI-1 - Sidoarjo, East Java, Indonesia
[Operator: Lapindo Brantas Inc.]**

**PRELIMINARY REPORT
on the
FACTORS and CAUSES
IN THE LOSS OF WELL BANJAR PANJI-1
for**

The Directors of Medco Energi International

**DOCUMENT 1.1
COPY Nr. 001 – Lukman Mahfoedz, MEPI CEO**

14th August 2006

by

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1.0 CONCLUSIONS

1.1 Conclusion – Principal Cause

The loss of Well Banjar Panji-1, Brantas Block, Onshore East Java, Indonesia on or abouts the 2nd June 2006 due to an internal blow-out incident while under the operational management of the Block's Operator, Lapindo Brantas Inc. can be directly, and immediately prior to its loss, attributed to the decision to remove the drill-string from the well bore beginning at midnight on the 28 May 2006 while the well was in an unstable condition requiring curing of lost circulation experienced at 13.00 hrs on the 27 May 2006 while drilling 12-1/4" hole at a depth of 9,297 ft rtkb. *This action was incompetent and in contravention of good well control practice ("good oilfield practices")*. Continuing to pull pipe from the hole even as the well was taking losses *is regarded as reckless and negligent*, in my opinion.

It is my opinion that had the drill-string not been pulled out of the hole at such a premature moment, in accordance with competent well control practice, the security and integrity of the well would have been safe-guarded.

1.2 Conclusion – Contributing Factors

There were, during the planning, contracting, engineering, design, programming and preparation phases for the well, and in other phases of its execution, contributing factors which in part, or as a whole, if carried out differently, would in all probability have avoided the catastrophe of the internal blow-out incident occurring.

The main contributing factors were :

- (i) The probable weakening or fracturing of formations on and in the vicinity of the 17-1/2" Hole during cementing of the 13-3/8" Casing at 3,595 ft rtkb between 29 and 30 April 2006.
The lack of remedial action following losses while cementing was neglectful and in contravention of "good oilfield practices" and BPMigas Recommended Practice 401 a) 5.
- (ii) The fracturing of formations in the vicinity of 4,241 ft rtkb during kick control activities on 28 May 2006.
- (iii) Drilling ahead past "8500 ft" *in the neglect of* well control constraints and a partner's (Medco) warnings with the 13-3/8" Casing set shallower than programmed and no further casing having been set prior to entering the Kujung (Reservoir Target) Formation. *This action could be regarded as reckless.*
- (iv) The omission of the 11-3/4" Casing Liner programmed to be set at 6,537 ft rtkb. Had this casing been set the sloughing clays below the 13-3/8" Casing seat would all have been covered and well control measures more easily applied.
- (v) The decision, in the IDPM Drilling Program, to set 9-5/8" Casing "inside the Kujung Carbonate". This was *a technical error due to a lack of competence or experience* with drilling Abnormally Pressured formations where potential "pressure reversal zones" and over-pressured transition zones should not be permitted to be in connection

with each other. The Drilling Program was thus flawed in this respect and probably led to a mind-set that mis-construed the limitations imposed on the well by the pressure regime to be encountered and the consequences of failing to isolate the different regimes above and below a major geological unconformity. There was a lack of detailed attention paid to the analysis of pore pressures, formation strength and temperatures over these critical horizons in preparation for the well, in my opinion.

These factors are further described in the body of this report and provide a basis for a learning exercise for future operations.

1.3 Hierarchy of Default

This report attempts to allocate the seriousness of errors of commission, or omission, in a judgmental hierarchy. Where something has gone wrong and an opinion of its seriousness can be judged the following hierarchy has been used in descending order of seriousness (written in bold italics) :

- ***"reckless" "negligent"*** **Wilful misconduct (?); negligent**
- ***"incompetent" "neglect"*** **Contrary to or neglectful of recommended, good oilfield or certified practices**
- ***"lack of competence or experience"*** **Limitation of knowledge in specific area or acting in a capacity outwith span of competence**
- ***"technical error"*** **Where there may be debate but a decision turns out to be incorrect even 'tho there are contradictory current practices.**

1.4 Note – Scope of Report

This (Preliminary) Report covers TPC's Scope of Work per contract Appendix "A" Items 1. a. , b. , and c. – "What happened and What went wrong?". Further content from the scope, itemised page 13 herein, will be completed at a later date.

The Report is based on conclusions drawn from an examination of documentary evidence combined with minor, but sufficient, analysis to rely on the conclusions. Where additional analysis is required to justify or confirm the conclusions this has been noted in the report. Meetings with Medco's Geological and Drilling Staff at their Bidakara offices also aided in the understanding of the events that took place during the well.

2.0 WHAT HAPPENED and WHAT WENT WRONG ?

2.1 Events during the Planning and Preparation Phase

2.1.1 Pore and Formation Strength Pressure Analysis

The Drilling Program for Banjar Panji-1 was prepared as part of an Integrated Drilling Project Management Contract Scope of Work by PT Medici Citra Nusa, the outsourcing contractor for the Work.

Technical analysis of the offset wells, Wunut-2 (*data not viewed*) and Porong-1, and especially Porong-1 which was the closest relevant well since it had penetrated the Early Miocene Carbonate S IV Primary Objective (Kujung Formation) of Banjar Panji-1, was not adequately carried out and used in the well programming for Banjar Panji-1.

In Abnormal Pressured Formation Drilling, of which this well is a classic case (similar to HTHP Wells), the analysis of both Pore Pressure and Formation Strength Capacity is critical. Although pore pressure and formation strength analysis is routinely carried out when planning any well additional analysis and effort is required in Abnormally Pressured wells since there is often the presence of formation pressures which are close to formation strength capacity and there are present so-called (pressure) "transition zones" where "abnormal pressures" exist above lower pressured zones once the high pressure zone has been traversed. This gives rise to delicate and critical well control issues while drilling and requires careful planning for choosing casing setting depths.

Porong-1 evaluated the Kujung Formation with an FMT run discovering a formation pore pressure of 6,999 psig at 8,572 ft rtkb (8,535 ft SS) with a fluid gradient of 0.394 psi/ft (*to resolve this fluid type*). Using this as a regional pressure in the Kujung this would give a pore pressure of 6,936 psig at 8,376 ft SS, Top Miocene Carbonate S IV in Banjar Panji-1 or 0.824psi/ft (15.85 lb/gal) equivalent gradient.

This pore pressure is neither mentioned in Section 4.3 of the Drilling Program nor represented on the Pore Pressure analysis chart of Section 3.5 of the Drilling Program. **Note: this pore pressure is very close to the Formation Strength Capacity at these depths.**

There was a lack of detailed technical analysis of pore pressures, formation strength capacities and temperature, as represented in the drilling program, appropriate in the preparation for designing and engineering an Abnormally Pressured Well as this.

2.1.2 9-5/8" Casing Setting Depth

The decision to set the 9-5/8" Casing Shoe "inside the Kujung Carbonate" was a technical error, in my opinion, and shows *a lack of competence or experience* with Abnormally Pressured drilling practice. The Kujung Carbonate is the (porous and permeable) reservoir target sealed by the overlying (over-pressured) formations, in this case the Early Miocene Unconformity. **At no time should these potential reservoir pressures have**

been risked to be exposed to open formations above the "transition zone". Furthermore, since a "pressure reversal" is to be expected within the (porous and permeable) reservoir zone it is unsafe to enter this zone with high density mud (used to control abnormal pressures in the transition zone). It is imperative that the well be consolidated at this stage in order to permit safer and more flexible drilling conditions over the reservoir section. The appropriate casing setting depth for this hole section, prior to entering the Primary Objective Kujung Carbonate, should have been the transition zone prior to and as close to the Top Miocene Carbonate S IV as possible. All efforts should have been focused on means for operationally determining this casing setting point.

Although the Drilling Program identified the Potential Drilling Hazards and drew significant attention to these as Critical Issues the programme was however flawed in the conclusions drawn and decisions made on this issue. The seeds of misconstruing the physical constraints in the well and decision-making based on this (mis)understanding were probably sown from this stage onwards thus influencing decision-making during the execution of the well (see Section 2.2) and making it likely that the well would fail at some point, as early Abnormally Pressured and HTHP wells have failed in the past with various Operators.

2.2 Events during the Execution (Drilling) Phase

2.2.1 Casing Seat Selection and Casing Setting Depths

In general, well execution did not follow the Drilling Program as far as implementing casing setting depths for one reason or another or, as far as can be deduced, for no particular logical reason at all:

26" hole was drilled shallower than prognosed (to 1,195 ft rtkb versus 1,237 ft rtkb programmed);

The Daily Drilling Report from Energy Mega Persada, tbk ("EMP") of the 21 March 2006 stated at 20.00 hrs "Called casing point at 2304 ft instead of 3200 ft as per drilling programme." referring to the 16" Liner and giving no reason therefore;

Furthermore the 16" Liner then held-up at 2,184 ft rtkb and the report of 25 March stated "Decided to call casing setting point in this depth @ 2184ft, proceed perform cement job." The Liner was not properly cemented and had to be squeezed;

On 29 April 2006 the Daily Drilling Report stated "POOH to run casing", when at a depth of 3,595 ft rtkb and referring to 13-3/8" Casing, without providing reasons therefore. The 13-3/8" Casing was programmed to be set at 4,537 ft rtkb. This was the last casing set in the well and, albeit that the mud density was continuously being raised to counter sloughing hole, and it is

possible (*without further analysis*) to envisage that this decision did consolidate the hole no reasoning or discussion was transmitted by report or otherwise as to the reasons for the decision;

Elimination of the 11-3/4" Liner, prognosed to be set at 6,537 ft rtkb to cover "Over Pore Pressure Transition", was discussed in a Technical Meeting of 28 April 2007 (sic) and noted in a "Memorandum Summary of Meeting for Banjar Panji" dated Jakarta, May 01, 2006. The note states:

"... Lapindo's team informed that the kick tolerance calculations number allows drilling upto "8500 ft" and proposed to eliminate casing 11-3/4". Medco's team agreed that proposal with reason:

- "As informed by Lapindo Brantas's geologist, there is no weak zone or reactively shale that creates loss circulation or caving problem in the interval 3500' – 8500'.
-
- In case encounter caving indication the drilling will be stopped and set 11-3/4" prior continues to drill deeper... "

However, after this date and with the setting of 13-3/8" casing shallower than prognosed, the 11-3/4" Liner appears to have been "forgotten about" since, in all discussion in Memos and Correspondence following this phase only the 9-5/8" Casing is discussed and referred to! Although there may not have been any clay sections that reacted with oil-based drilling fluids the extensive open-hole section, and penetration of the Kujung, which could have produced brine similar to, or the same as, that in Porong-1 could have been envisaged as a lithological/fluids risk to the open hole section. Casing seat selection is not a question, solely, of pressure tolerance!

Casing seat depth selection is, operationally in Exploration Wells, a critical and sensitive decision point and usually involves robust discussion (and sometimes argument) amongst drilling personnel, geologists and geophysicists, partners and petroleum engineers about the merits of calling a halt, where everyone agrees "they are" in the well and consolidating the well at a given point with reference to the Drilling Program. This communication does not seem to have taken place in the drilling of Banjar Panji-1 except in the latter stages of drilling 12-1/4" hole for 9-5/8" Casing.

It is thus unclear:

- Who was making casing setting depth decisions?
- For What reason changes were made to the Drilling Program? and
- Were these changes authorised by the Operator and, if so, by Who?

Neglecting to set the 11-3/4" Liner (or even the 9-5/8" Casing as it became later) and leaving the hole open from the depth where 13-3/8" casing had been set shallower than programmed to drill-on towards, and penetrate, the abnormally pressured reservoir section (see Section 2.2.2) ***could be regarded as reckless*** given the potential constraints for handling kicks and the sloughing

shales that this casing was intended to protect. It was later, in this hole section at 4,241 ft rtkb, that the well kicked and the pipe stuck, packed-off by sloughing shales, when pulling out of the hole prematurely!!

The originally intended setting of the 9-5/8" Casing post setting an 11-3/4" Liner string became even more critical to set at a depth at or shallower than "8500 ft" as was pointed out by Medco in a Technical Meeting on the 18 May 2006 minuted by A. Rintoko given that the 11-3/4" string had been omitted. A note in the minutes of the meeting states: "However, Operator assures that the hole will not cave by using OBM and they will capable (sic) to handle loss circulation problem." The Operator went on to refer to experience in Porong-1 where difficulties had been experienced with kicks and losses in the Kujung even with 9-5/8" Casing set above the Early Miocene Carbonate. In this, the Banjar Panji-1 case, the Operator was proposing to enter the same formations ***with a longer open-hole section and no adequate casing protection at all!!*** In this the Operator neglected the justifiable technical concerns of a venture participant and was ***technically lacking competence*** when assuring co-venturers that "OBM" alone would prevent the hole from caving.

2.2.2 Drilling Ahead past 8,537 ft rtkb Programmed Casing Point

The "8,500 ft" Casing Point, even 'tho originally programmed to penetrate the Kujung Formation originally prognosed to be at 8,413 ft rtkb, was a critical point for well control reasons (*analyse/verify kick tolerance criteria as calculated by Medco*) as well as for geological/pore pressure reasons in that with the 11-3/4" Liner omitted and the 13-3/8" Casing set shallower than programmed the formation strength at the 13-3/8" Casing shoe did not provide an adequate margin of operational flexibility to combat a kick if taken deeper than "8500 ft" (*to analyse and verify; relying on Medco analysis Note*).

It is not known where the decision to change the programme in this manner originated however there is evidence that a definitive change was made since, the EMP (*Note: why were reports being compiled and transmitted by Energy Mega Persada, Tbk when in fact they should either have originated from the Project Manager PT Medici Citra Nusa or from the Operator Lapindo Brantas Inc.?*) Daily Drilling Report of 22 May 2006 at 02.00 hrs states "Drilling 12-1/4" hole from 8629 ft reached 9-5/8" casing point @ 8750 ft, while increased mw to 15.00 ppg on the last stand drilled." At 04.00 hrs on the 22 May the string was pulled for logging and logging (as if it were end-of-phase logging) continued until 04.00 hrs on the 25 May when the remark "Drill ahead to desire (sic) depth." was noted on the Daily Drilling Report Plan for next 24 hours. The mud weight increase "... on last stand drilled" indicates pulling out of hole for logging and/or casing as it is a common hole-conditioning practice for these purposes.

In my view, based on operational experience, a decision must therefore have been made and communicated to the Lapindo (*?verify IDPM contractual requirements and fact during execution for reporting issues?*) Drilling

Supervisor on site that a change of programme had been made for, on Report no.80 of 27 May the Plan for next 24 hours: comment was "Drilling ahead to casing point @ 9400 ft." Who was the originator of this decision?

It is likely, at this point in time, that Lapindo Brantas Inc., having proposed and discussed setting the 9-5/8" in the May 18 Technical Meeting quote: "... penetrate 10 ft into Kujung formation (+/- 8,500 ft) with max 16 ppg mud and then set Casing 9-5/8"." **neglected** Medco's reminder **and the Medici Drilling Program which, in Section 4.4 "Potential Lost Circulation" states: "Possible pressure reversal from 15.6 ppg to lower mud weight may occur in Kujung formation which could casue loss of hydrostatic (head) and induce for (sic) well kick."** and headed "blindly" towards penetrating the Kujung no matter what the depth and consequences.

2.2.3 Pulling Drill String Out of the Hole Prematurely

On the EMP Daily Drilling Report of 28 May 2006 it was reported :

at 17.00 hrs :

"Spotted total 60 bbl LCM, Pooh 4 stands,8737 ft, monitored well through trip tank. Well static. While mud engineer prepared to mix LTOBM, 8 ppg, on mud plan (sic)." [Comment: Note depth at which well assumed to be "static"].

at 00.00 hrs:

"Transfer total 600 bbls, 8 ppg LTOBM to mud tank, proceed mixed and raised mud weight to 14.7 ppg completed." [Comment: Appears to infer that further curing of lost circulation would take place].

at 05.00 hrs:

"Worked pipe, pooh from 8700 ft to 8100 ft without circulation ,overpulled encountered over than 30,000 lbs. Circulated @8100 ft, 50% returned to flow line, max pump pressure allowable at surface @300 psi. Resume pooh to 6500 ft, while filled-up hole through drill string, total volume displacement was hard to counter. Continued pooh to 4500 ft." [Comment: Note statement "50% returned to flow line total volume displacement was hard to counter"; presumeably this, as reported more conclusively in the MI Swaco Mud Reports, was the well CONTINUING TO TAKE LOSSES EVEN WHILE OPERATIONS TO REMOVE PIPE FROM THE HOLE CONTINUED].

On entering the probable top Early Miocene Carbonate (Kujung) formation during the report day of 27 May 2006, when H₂S was encountered at around 9230 ft., at 13.00 hrs on the 27 May it was reported: "Resume drilling from 9283 ft to 9297 ft, lost occurred (sic)." it appears that the predicted "reversal of pressures" in the Drilling Program between the formations overlying, and sealing, the Early Miocene Carbonate and the Kujung formation were encountered and lost circulation resulted.

The lost circulation was initially, "apparently", cured with the spotting of a 60 bbl LCM pill at 17.00 hrs on 27 May when it was reported, post this activity, that the well was static. It appears that further losses were expected (and thus curing this situation had not ceased) since a further 600 bbls of LTOBM was prepared.

Nevertheless following this (following an order or change of orders?) the drill string was then started to be removed from the hole (to 8100 ft) even 'tho the well was monitored as static at 8737 ft, already some 559 ft off bottom. Furthermore the well continued to take losses even as pipe pulling continued. *This action could be regarded as reckless and negligent.*

At this point, under good well control practice, the drill-string should have been run back into the hole to total open-hole depth to verify that the well was static, cure continued occurrence of losses, circulate to consistent mud conditions (and verify no influx fluid contamination in the annulus during the lost circulation curing action had occurred) and check the well's static condition again, prior to any consideration of pulling out of the hole.

Furthermore, the IDPM Drilling Program drew particular attention to the Anticipated Problems and their associated "Alternatives and Mitigation Plan". Over the 12-1/4" Hole Phase the Drilling Program states mitigation criteria as:

3. Avoid swab/surge pressure.
4. Vital to maintain hole full at all times.

These prescriptions were *neglected* during execution.

[Note that the MI Swaco Mud Report, number 83, of the 28 May is more conclusive, if correct, of neglect while pulling out of the hole. It states under "Operations Remarks":

"POOH f/9297 to 4838 ft while pump out. (*whereas the Daily Drilling Report says "without circulation"*) No return, continued POOH to 4246', well flowing, circulation GPM in/out = 164/600, recovered 389 bbls, stop pumping, well kick w/gas 700 unit H₂S. Kill H₂S and flare, kill well w/ 15.5 ppg 40 bbls, open BOP and monitor well, circulation w/trip tank. POOH 1 stand, got stuck on pipe @ 4240 ft. Try reciprocate w/circulation SPM=46. no result, stop reciprocate, spot 40 bbls havis."

Under "Mud Remarks and Treatment" the same report notes:

"* Recovered 389 bbls mud when well flowing. * Total mud loss to formation last 24 hrs = 602 bbl."

It can be inferred from this report that the well was losing mud, as there were no returns while pumping out, and yet PIPE PULLING OPERATIONS CONTINUED.]

Removing drill-pipe, the conduit for ensuring the placement of the primary well control barrier, the drilling mud, in the drilling of oil and gas wells while a well is in an unstable well control situation (losing mud, the primary barrier, from the wellbore or taking fluids, "kicks", into the wellbore) or when the condition of the primary barrier throughout the well system is unknown is *a fundamental technical error in competent well control practice (incompetent)*. Ignoring the fact that lost circulation continued to occur but

without taking measures to cure these and stabilise the well before pulling out of the hole *is regarded as reckless and negligent, in my opinion.*

It is concluded that this is the principal cause of the loss of the well which later occurred during attempted well killing operations at a depth of 4241 ft rtkb on 28 May 2006 for, if pipe had not been removed from the hole to a shallower depth the well would more easily have been controlled and the opportunity for further remedial operations would have continued to be in place such as curing lost circulation zones, squeeze cementing lost circulation zones, circulating heavier mud, placing cement plugs over the transition zone, plugging the well at depth etc.

Continuing to pull the string from the hole it was noted on the EMP Daily Drilling Report of 29 May 2006 (cf. contrast this wording with MI Swaco Mud Report No 83 quoted above):

at 08.00 hrs:

"Continued POOH to 4241 ft, circulated, indication of well kick, well kick, shut in well,..."

between 08.00 and 12.00 hrs:

"Pre-recorded data, SIDP=350 psi, SICP=450 psi. Preparation to kill well by utilized volumetric method, bled 19 bbls, pressure up CP to 450 psi, MW 14.7 ppg, burned gas out through gas flare, applied method twice, well died. Contaminated fluid (sic) and mud mixed with trace water caused mud weight reduced to 8.9 ppg. Observed well through trip tank, total lost since 05.00 hrs around 300 bbls." [Comment: Note Drill Pipe and Annulus pressures exceed the previously reported maximum allowable at surface of 300 psi.]

During working stuck-pipe, shortly thereafter at 04.30 hrs on the 29 May, "a 3.5 ppm H₂S concentrated arose at surface", presumably the later reported surface break-out of fluids away from the well.

The well kicked either because contaminated fluid in the bottom of the hole section of the 559 ft left open when 4 stands of pipe were pulled during activities to cure losses lightened the mud column enough and there was consequently gasified fluid percolating up the well and/or, in pulling pipe with the well unstable in the condition at which a decision was made to remove pipe at 8700 ft rtkb, the act of pulling pipe, or the speed at which it was pulled, caused a pressure drop to swab the well in during these operations upto a depth of 4241 ft rtkb and further formation fluids to be entrained into the well bore below the bit while, if the MI Swaco report is correct, the well was still losing mud to the formation (i.e. there was flow from open formations into the well bore and losses or the well bore continued to lose mud alone). (*further analysis required to check; data to be requested:- Geolograph readings, pipe pulling speed, swab pressures etc.*) ***but reports are sufficient evidence since a kick did take place.***

One might justifiably question why, during pulling pipe, the trip tank procedures normally followed in good well control practice did not indicate that the well was taking fluid?

- Were the correct procedures being followed or was there *neglect* in using this practice?
- Were the possum belly tank and pump system in working order?
- Were there errors in the use, measurement, control and recording of the trip tank during pipe pulling operations?

(to verify IADC Reports; request additional data/documentation etc.)

2.2.4 Well Kicking and the Compromise of Wellbore Integrity (Compromised during Well Kick at 4241 ft and/or during running and cementing of 13-3/8" Casing)

On the Daily Drilling Report of 28 May 2006 it was noted that the maximum allowable pump pressure (or maximum allowable annulus surface pressure) was 300 psi. The mud weight in use at that time was 14.7 ppg according to the MI Swaco Mud Report. During the well kick encountered on 28 May with a shut-in drill-pipe pressure recorded of 350 psi at 4241 ft this is an additional 0.0825 psi/ft (or 1.59 ppg) making a total equivalent pressure on the well-bore of 16.3 ppg. The casing annulus pressure was recorded as 450 psi making an additional 0.106 psi/ft (or 2 ppg) but we cannot deduce the pressure at bottom hole from this reading since the fluids content in the annulus are unknown. The leak-off-test at commencement of drilling 12-1/4" hole below the 13-3/8" casing was measured as 16.4 ppg. **The pressures exerted on the wellbore at this depth, when taking account of dynamic pressure losses while circulating, were thus probably sufficient to fracture the formation.** *(further data – pump pressure charts, mud records etc. - and analysis required to confirm with certainty).*

The evidence suggests, since the MI Swaco mud report notes continuing losses, that the wellbore integrity was definitely lost at this stage (with 14.7 ppg mud in the hole) and may well have been compromised at an earlier phase in the well.

The wellbore integrity may *(subject to further data – cement report, pumping records, pressure charts, mud inventory, etc. - and analysis)* have been compromised during 13-3/8" Casing Setting and Cementing operations between 29 April 2006 and 30 April 2006 when the 13-3/8" casing string was "circulated and reciprocated" (EMP Daily Drilling Report of 30 May 2006) thus causing surge pressures which could have been sufficient to fracture the formations down to the 17-1/2" hole depth of 3,595 ft rtkb.

The casing was reportedly cemented with a mix of cement slurry weights between 14.2 ppg and 15.8 ppg. Together with pumping pressures and pressure losses there was sufficient pressure exerted on the well bore during circulation

and placement of cement to cause losses. Certainly, injectivity into formations was achieved since, during cementing operations "no returns" were observed at surface and a total of 756 barrels of mud was lost downhole. [The MI Swaco Mud Report No. 55 of 30 April 2006 reported total losses of 795 bbls during these casing and cementing operations.]

With such heavy losses the Operator made no investigation whatsoever to ascertain the cause of the losses or whether the 13-3/8" cementing had been successful. ***This was in contravention of good oilfield practice and BPMigas Recommended Practice for Safe Conduct of Onshore and Offshore Drilling Operations Article 401 Clause a) 5.***

The 13-3/8" Cementation should have been subject to further testing and/or evaluation to ascertain whether there was acceptable cement placement and isolation behind casing and, if not, squeezed to ensure this conformity and isolation.

When the well later "kicked" on the 28 May fractured, or weakened, formations, in such a scenario, in the vicinity would have provided the path for the escape of higher pressured fluids arriving at these depths as a result of percolation or entrainment from swabbing up the wellbore from the Early Miocene Carbonate to the same formations at this depth or other faults or formations deeper in the well and thence the flows observed to surface.

Not recognising the implications of the 13-3/8" casing operation fluid losses to the formation was a ***technical error*** and a ***lack of competence***. It was certainly a lack of good judgment for, if it had been recognised that formation strength had been compromised to less than 16.4 ppg from these depths or deeper then decisions to continue drilling deeper than "8500 ft", missing out the 11-3/4" Casing or when considering the setting depth of the 9-5/8" Casing would possibly have been made in a different light.

Furthermore, the indication of such significant losses during cementing should have, ***under good operating practice***, instigated an investigation, by analysis or cement bond log, into the reasons for the losses and the initiation of remedial cement, or casing/liner/scab-liner procedures to consolidate the well at this juncture. No discussion of this event and its potential consequences took place and no remedial action was initiated in the well to rectify what evidence showed clearly were serious problems in cementing the 13-3/8" Casing. All the more so in that this became the last casing before entering the target Kujung reservoir horizon. The Operator, forgetting, or ignoring, the condition of the 13-3/8" Casing Cementation was ***negligent and reckless***, in my opinion, to then proceed with the well, omit the 11-3/4" Liner and, at the same time, proceed to drill below the "8500 ft" depth at which Medco warned it would pose well control management problems and risks.

3.0 HOW DID IT GO WRONG and WHY ?

4.0 NON-TECHNICAL ANCILLARY ISSUES

4.1 Sub-Surface Contracting (Structure and Form) – Outsourcing

4.2 Management of Non-Operated Joint Ventures

5.0 RECOMMENDED PRACTICES ("Do's and Don't's") RELATED TO THIS INCIDENT

6.0 MEANS and RECOMMENDATIONS FOR AVOIDING RECURRENCE

Appendix "A" – List of Documents Consulted

Appendix "B" – Author's Contractual Scope of Work

APPENDIX "A"

DOCUMENTATION CONSULTED

<u>Date</u>	<u>Document</u>
07-08-2006	(i) Huffco Brantas PSC dated 23-April-1990 (ii) Joint Operating Agreement dated 01-May-1992
08-08-2006	(i) Onshore Integrated Drilling Project Management Contract Contract no. CON-0144/DRLG/2005 dated 23-December-2005 (ii) Drilling Program Banjar Panji-1 dated 25-January-2006 (iii) Porong-1 Composite Log (03-Aug-1993 to 02-Nov-1993) (iv) Geological, Geophysical and Correlated Well Lithostratigraphies Porong-1, Banjar Panji-1 Data and Diagrams
09-08-2006	(i) Energy Mega Persada, Tbk Daily Drilling Reports – Banjar Panji-1 – 09/03/06 to 31/06/06 (ii) IADC Drilling Reports – Rig TMMJ N110 No. 01 – Not conforming to proper IADC numbering; manually numbered 01 to 86 – 09/03/06 to 03/06/06 (iii) ModuSpec Report of Survey Land Rig TMMJ No. 1 for Inspection dates 29/09/05 to 05/10/05 – Pages 1-13 (Executive Summary & Conclusion) (iv) MI Swaco Mud Reports (Selected) no.'s 1-88 07/03/06 to 02/06/06 (v) PT Medici Citra Nusa Experiences Letter (PT MCN Letterhead) – Undated (vi) Initial Exposure Advice Letter from STEEGE, Kingston to Lapindo Brantas Inc. re Well Control Incident dated 07/06/06 (vii) Banjar Panji-1 Mud Log (ELNUSA Masterlog) ex Suherman (viii) Banjar Panji-1 Interpreted Electrical Logs 3500 ft rtkb to 8725 ft rtkb. ex Suherman
10-08-2006	(i) Banjir (sic) Panji Intervention Plan Rev 1. 20/06/06 Executive Summary (ii) Medici Personnel – Bid Documents (iii) Technical Correspondence and Notes to File (Medco)
12-08-2006	(i) BPMigas "Recommended Practice for Safe Conduct of Onshore and Offshore Drilling Operations in Indonesia (Rev. February 1994 RP. 6.2.1 93/R) (ii) Technical Correspondence and Notes to File (Medco)
13-08-2006	(i) Technical Correspondence and Notes to File (Medco) (ii) Geological and Geophysical Files (Diagrams, Prospects, Overviews etc.).

APPENDIX "B"

CONTRACTUAL SCOPE OF WORK

[Appendix "A" TPC/Medco Scope of Work]

1. TPC shall provide a professional research service program to generally investigate the problems that occurred during the drilling operations at Banjar Panji #1 exploratory well, located onshore in East Java, Indonesia and to specifically:
 - a. perform a general review of the wellbore diagram, highlights, and chronology already provided and any additional records provided during the defined work period;
 - b. identify possible factors contributing to the loss of control of the well;
 - c. perform a preliminary analysis to determine one or more likely sequences of causal factors leading to current well conditions;
 - d. identify possible means for avoiding recurrence of these causes and results in future operations, and comment on whether these means are generally considered routine industry practice; and
 - e. identify methods and data needed to perform a more complete analysis and confirmation of what happened and why.

and thereafter to address each of the following questions:

- (i) what has exactly happened and how did it happen;
- (ii) whether it was customary in the oil industry practice or very unusual; and.
- (iii) if this was so unusual, how far was it departing from the conventional and established oil practice and how do you quantify/qualify/characterize the deviation therefrom (i.e. major vs minor or gross vs mere negligence);
- (iv) what exactly that should have been done to avoid this incident in the first place;
- (v) the scope and analysis from the drilling practice that covers "do" and "don't" in this specific incident; and
- (vi) further what can you suggest so that next time we will not repeat the same problem again.