

# Potential Show Stopper Regarding the Use of Cement in Deepwater Drilling in Gulf of Mexico

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June 27, 2010

**Background:** Cement is a quasi-hard material that is 8X to 10X stronger in compression than tension. It has been the industry standard for sealing oil wells for decades. As deepwater drilling progresses in the Gulf of Mexico (and worldwide), there is an increasing need for much higher strength “cements” and significant research has been devoted to this area in past decade.

MMS (Minerals Management Services) had projects ongoing in 2001-2002 to determine industry cements to produce a tight seal in an annulus (Ref: Long Term Integrity of Deepwater Cement Systems Under Stress/Compaction Conditions, Report 3 Issued Nov 19, 2002 by Cementing Solutions).

The University of Michigan was very successful in prototype development of ultra-high performance cements (UHPC) with various “fiber reinforcements” including finely ground quartz, steel fiber (0.008 inch diameter by 0.5 inch long) with super plasticizer to create dense packing material cement with high proportions of tricalcium aluminate and tricalcium silicate.

The idea of steel (or fine gravel) fibers to prevent microcracks from propagating in cements works well and also has been investigated by Air Force Research Labs for Rapid Runway Repair (RRR Program). Instead of crack propagation beginning at 600 psi to 800 psi (shear stresses) the first crack did not propagate until a range of 2,400 psi to 3,200 psi.

At the same time (1999 - 2001), the offshore industry (Shell Exploration and Production Technology) was already drilling deeper (setting records) with a new casing option called Solid Expandable Tubular Liner System, or SET Liner (see *Drilling Contractor* March/April 2001). The underlying concept is to basically drill a hole and run two sets of pipe (one inside the other). The oil industry calls the outside pipe a casing and the inside pipe (smaller diameter) a “liner,” or expandable casing.

The concept behind expandable casing is the cold-working of steel tubulars (use of a special tool to deform the inside pipe against the outside pipe to get a metal to metal seal all the way up the well bore to stop a wellhead blowout). You can also add your favorite elastomeric coating to get better adhesion between the pipes called clad to remove tolerances and get a super seal. The special tool that deforms the inside pipe is called an expansion cone. The expansion cone moves from the bottom to the top of the string. At the top of the liner string is a special liner-hanger joint that includes an external elastomeric coating or seal (variants of this maybe referred to as a “locking ring” or “locking seal” at the top of the well bore (prior to gas/oil going into BOP). At the bottom, the expandable liner is run well past the outside casing and you cement the liner in place, expand the hanger joint and mill out shoe.

Expandable Cased-Hole Liner (CHL) System can also be installed in older or damaged well to repair casing over several thousand feet, resulting in a liner that can be drilled through and causes minimal hole reduction. To fix the problem, you may also require cement squeeze jobs or liner packer hangers or both to stop gas/oil leakage (i.e., necessary hydraulic integrity).

What happened in ultra-deepwater wells (over 5000 ft water depth), the drilling operator was using every casing string option (cementing smaller pipes inside smaller pipes) available in well design, yet going deeper requires more casing points than there were sizes. To solve this problem, the major oil companies started using SET Liners (with liner hanger joint somewhere down hole) to go deeper by letting the SET technology “piggyback” inside the standard casing options. You could start using much longer tubulars and if you were encountering high gas pockets you still had multiple sealing points/options as long as you used SET Liners within the standard casing runs. Shell Oil Company installed a record length SET Liner within a 16-inch casing in South Texas (Joseph Prospect). It is the only way that deepwater drilling can be enabled. In Nov 1999, Halliburton Energy Services’ Integrated Solutions Group, working as lead contractor for Chevron USA Production Company, installed in the West Cameron 17 field just outside Louisiana State waters.

**Reference for SET Technology:**

[http://www.pe.tamu.edu/schubert/public\\_html/ERD/Literature%20search/3.%20Casing%20Wear/67770.pdf](http://www.pe.tamu.edu/schubert/public_html/ERD/Literature%20search/3.%20Casing%20Wear/67770.pdf)

SPEI/IADC 67770, presented in Netherlands

‘Solid Expandable Tubular Technology – A Year of Liners’

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**Remarks:** The SPEI/IADC 67770 paper mentions 15 jobs were successful and three jobs were unsuccessful. There were problems with threaded pipe connections breaking (due to high stress concentrations). The SET Liner system which has the most experience is the 7 5/8 inch x 9 7/8 inch casing. SPEI/IADC 67770 shows the geometry of a monobore (single string) in Figure 7, using the 7 5/8-inch x 9 7/8-inch casing but with a 10-inch BOP (possibly referring to Cameron’s 10,000 psi rated BOP which does not have the DWHC well hub connector but only costs \$158,000 versus \$300,000+ for full-blown DWHC BOP?

Interestingly, the *Drilling Contractor* (March/April 2001) makes the following statement: “The next generation SET Systems may allow the equivalent of a ‘monodiameter’ well to be drilled, in which the same hole size is drilled from surface to total depth (TD).”

So let’s see what BP/MMS may have done with this technology regarding Deepwater Horizon and the Macondo Well.

**A. BP Deepwater Horizon and Macondo Well Installation**

Previous commentary (on [www.oildrum.com/node/6660](http://www.oildrum.com/node/6660) for description of wellhead drilling installation) and drawings submitted to Congress regarding the BP Drill Plan showed it should be a standard multi-casing installation at the well bore (using 36-inch casing down to 225 ft) to support the BOP and running/cementing casing, but it is also noted BP drilled an ultra-deep

“monodiameter” well by running a single 7 5/8-inch x 9 7/8-inch casing (liner) all the way from the BOP to TD” (Total Well Depth) which I assume (until noted otherwise) was run inside a 16-inch casing and a 22-inch casing as shown on the drawings. There may have been an additional liner added later perhaps after hitting the initial high gas pocket! BP may not have used any locking ring (the seal at the seabed is the extensive as regards the cement foundation involving the 36-inch casing) but the weak link is the well bore hub/casing BOP interface into the BOP which are a series of machined segments to clamp onto the DWHC wellhead hub (using hydraulic pressure). However, the actual BP well bore piping installation and/or engineering drawings had to be either approved by MMS, or changes were made “on the fly” by BP without the knowledge of MMS.

Anadarko’s CEO Jim Hackett was quoted last Friday as saying: “The mounting evidence clearly demonstrates that this tragedy was preventable and the direct result of BP’s reckless decisions and actions.” Anadarko owns 25% of the Macondo Well. Assuming we have only a single well bore pipe casing, look what happens thermally to the cement job when BP changes out the drilling mud for seawater.

### **B. Well bore Piping Length Changes Due to Temperature By Replacing Warm Heavy Drilling Mud with Cold Seawater To Under-balance Well**

When the cement job (reported as a peculiar “nitrided” cement which may mean fiber reinforced) was completed, BP operators waited sixteen hours (instead of normal 24 hours) for the cement to set. BP had poured in drilling fluid to push the cement out of well bore and fill the gap around the pipe and “bond” pipe to rock in formation. At this point the cement may or may not have set, but BP put in a cement plug. Although there was some rising pressures in the drill pipe, BP decision maker said to replace the expensive drilling mud with seawater assuming the well was capped. This may be partially responsible for the deep-well blow-out particularly if the cement has not yet fully set.

### **C. Potential Showstopper In Using Cement for Single Well Casing or Using SET Technology in Deepwater Wells**

**Remark:** Since the Government is not releasing any significant engineering data or mud logs (by design) on anything, the following calculations are estimates only and subject to change without notice, suggesting there are major technical issues remaining with respect to protocols for disconnecting a drilling rig from an ultra-deep well. That having been said, a monobore well installation with no liner and locking ring (BP Deepwater Horizon installation) is an unmitigated design disaster which raises serious questions about who in MMS/Gov approved any such deviations from the submitted BP Drill Plan identified to Congress, or did BP proceed without waivers, or what really happened?

With a cement plug in place at the bottom of the high pressure well , the plan was to recover the expensive drilling mud by replacing it with seawater and the drilling rig could disconnect from the riser piping until such time as BP decided to bring the well into production. However, look what happens when relatively warm drilling mud (180 F) was replaced with cold seawater at 50 F. The temperature of the bottom of this reservoir could have been 262 F (at 18,000 ft) to more than 350 F, if the reservoir pressure was in excess of 13,000 psi, or the well was drilled beyond 20,000 ft.

The single steel casing going from the BOP to the bottom of the well is a good conductor of heat. The steel casing possibly drilled through many layers (horizons) of oil/gas, sand, rock, sand lenses, etc. (Government will not disclose the well bore mud logs which will show a roadmap of how bad this situation may be). But as you drill deeper, the temperature of the piping/well bore increases. At the seabed, the water/well bore hub may be 41 F, but at the bottom of the well bore the temperature is > 260 F (and could well be over 400 F). If we make the conservative assumption that the temperature gradient is linear, then the average temperature of the pipe is  $(260 + 40)/2 = 150$  degrees F. After the cement plug was completed the drilling mud continued to be circulated, so the cement (in contact with the formation rock) reached a thermal equilibrium between a mean of 210 F and 260 F (part in contact with rock).

**Watch how much the single well piping contracts when much colder seawater initially replaces the hot drilling mud, because we have a single pipe length of almost four miles.** This is called a “thermal shock” loading, because cold seawater is quickly pumped into the well bore (not time to come to thermal equilibrium) and cools the well bore pipe causing it to contract. (The key is that we have such a long pipe length because it is a deepwater well). To find how much the pipe length contracts all we need to know is the coefficient of thermal expansion for steel and the temperature change when the pipe has hot drilling mud versus cold seawater. We assume the warmer drilling mud has doubled the initial temperature of the seawater to 100 F.

The formula is:

(New Pipe Length) = (Initial Pipe Length) x (Temp Difference) x  
(Coefficient of Thermal Expansion)

Initial Pipe Length (well bore) = 13,180 ft = 158,160 inches =  $1.582 \times 10^5$   
inches

Temp Difference = (210 – 100) F = 110 F

Coefficient of Thermal Expansion (Steel) = 0.0000094 in/(in-F) =  $9.4 \times 10^{-6}$   
(in/in-F)

New Pipe Length =  $(1.582 \times 10^5) \times (110) \times (9.4 \times 10^{-6}) = \mathbf{163.6 \text{ inches! (13.6 ft)}}$ .

### **Check on Thermal Capacities of Seawater and Steel:**

To see if there is sufficient thermal capacity of the seawater to cool down the steel pipe we compare the specific heat and thermal capacity of the seawater versus steel casing (pipe).

The specific heat of seawater is 1 BTU/(lb - F°).

The specific heat of steel is 0.108 BTU/(lb - F°).

**Therefore, seawater has 10X the specific heat of steel.**

The total heat flow (thermal capacity) in BTUs for a given fluid/material is

$Q$  (heat flow) =  $W$  x (Thermal Capacity) x (Temperature Difference).

The total heat flow for the seawater is  $Q = (1,059,727 \text{ lb}) \times (1 \text{ BTU}/(\text{lb} - \text{F}^\circ)) \times (\text{Temp Diff}) = 1,059,727 \text{ BTU}/\text{F}^\circ \times (\text{Temp Diff})$

The total heat flow for the steel pipe is  $Q = (705,130 \text{ lb}) \times (0.108 \text{ BTU}/(\text{lb} - \text{F}^\circ)) \times (\text{Temp Diff}) = 76,154 \text{ BTU}/\text{F}^\circ \times (\text{Temp Diff})$

**Therefore, seawater has 13.9X thermal capacity of steel in the BP well bore installation!**

This means the seawater has sufficient capacity to rapidly cool the monobore piping when replacing the drilling mud causing the monobore to significantly contract.

**Strains in Concrete Plug at Bottom of WellBore:**

**Of course, the worst thing you can possibly do is to place concrete in tension!** We have just demonstrated that in a deep water (monobore) installation where seawater replaces the drilling fluid, the axial strain in tension of the concrete would be on the order of

(axial strain) = (change in length of concrete plug)/length of bottom concrete plug (est. < 100 ft)

axial strain (tension) = (13.6 ft)/ 100 ft) = 0.136 (**Cement fails totally in tension at strains of 0.02 to 0.033 for high strength!). It can develop microcracks at 0.01 to 0.02.** Normally, one does not drill 100 feet below the well bore, but cement is squeezed out at the bottom of the well bore and up the outside of the single casing.

where I am assuming that 53 bbls of “nitrided cement” were used and 50% went into casing and 50% went into cement plug at bottom and about 1,800 ft of riser casing was filled with cement.

Check on Axial (Tensile) Stress: (Failures at 400 to 600 psi in tension)

(Axial Stress) = (Young’s Modulus) x (Axial Strain) = (6000) x (0.136) = 816 psi > 600 psi

Obviously, if you cement a pipe vertically into cement and pull the pipe, the cement bond to the steel pipe will break. But in BP's geometry, the entire cement plug could easily have totally fractured, which is why the "sudden and massive" influx of gas into the pump room/diverter flow lines.

**Once the cement plug/seal fails you now have the mechanism to destroy a BOP internally.** In the case of the Deepwater Horizon, the drill pipe pressures were about 5,200+ psi. Essentially you are now firing an 11,000 lb (fragmented cement piston pushing seawater) projectile at the internal parts of the BOP shear/blind rams, at velocities probably exceeding 60 ft/sec. It will not only take out the shear rams (even if they are closed), it would also impact the top flange with an impact force on the order of:

3,273,858, lbs (which exceeds the static (tension) flange rating of the std 15,000 psi Cameron BOP which is 3,000,000 lbs), and significantly exceeds the 900,000 lb static weight of BOP. **This implies the BOP was pushed off the wellhead (3,273,858 > 900,000).**

### **Computation of Rigid Body Dynamic Impact Force of Water Cannon on Top BOP Flange:**

The reservoir pressure is assumed to be between 9,000 psi and 13,000 psi (similar to published graphs on another Mississippi Canyon project) and consistent with drilling depths of 20,000 ft. (unless you hit an oil/gas channel). The internal diameter of the well casing is 7.953 in (thick-walled). The geometry looks like a "water cannon" of the cement seal fails in the 9 7/8-inch casing. Now the weight of all the water/cement below the BOP is coming up to impact the shear rams (if closed) and the top flange of the BOP. The force pushing on the water in the pipe is:

$$(\text{Pressure}) \times (\text{Pipe Area}) = (13,000) \times (12.41 \text{ in}^2) = 161,300 \text{ lbs.} = F$$

The weight of water and cement was estimated to be (density of seawater is 64 lb/ft<sup>3</sup>)

$$\text{Weight (lb)} = (11406 \text{ ft}) \times (0.086 \text{ ft}^2) \times (64 \text{ lb/ft}^3) + (1774 \text{ ft}) \times (6.7 \text{ lb/ft}) = 62,779 + 11,886 = 74,665$$

The mass would be  $M = W/g = 74,665/32.2 = 2,318.8$  slugs.

The acceleration is:

$$dx^2/dt^2 = F/M = 161,300/2,318.8 = 69.6 \text{ ft/sec}^2$$

The velocity is

$$V = 69.6 (t) \text{ (ft/sec)}$$

Explosive waterjet impact times are on the order of  $t = 0.020$  seconds to  $0.130$  seconds based on author's prior experience and full-scale testing. Assuming the water is incompressible (estimate only), the dynamic impact force would be: (correct flow for water going up riser and not impacting flange with Ratio = 0.71)

$$F = MV/t = (2318.8) \times (69.6) / (0.020) = 8,069,424 \text{ lbs (upper bound)} \times (0.71) = 5,729,291 \text{ lb}$$

$$F = MV/t = (2318.8) \times (69.6) / (0.130) = 1,241,450 \text{ lbs (lower bound)} \times (0.71) = 881,429 \text{ lb}$$

Since the BOP weighs 900,000 lb (dry), the BOP may or may not have "popped like a cork".

**It appears that in either case, the BOP shear rams would have been totally destroyed if they were closed.** It is possible the wellhead hub may be cracked. For the high-end estimate, the BOP would have been blown-off wellhead and top flange destroyed. For the low-end estimate, the BOP possibly was pushed up and fell back onto the wellhead hub (may have cracked wellhead hub and significantly damaged the stub piping), but wellhead flange should be intact. This is a very complicated fluid mechanics problem which would require modeling with a supercomputer and it would still probably not be resolved without seeing the internal damage to the BOP.

**Remarks:** Sen. Mary Landrieu (La.) mentioned that there was over 30 years of reliable experience (actually McDermott goes back further than that in offshore industry) in offshore industry. True, but 98%+ of the reliable experience involves design/installation of fixed offshore platforms in less than 500 ft of water. A company called Petro-Marine Engineering probably designed over 300 offshore platforms (Louisiana/Texas), and the design software (called SEAS) is still leased by a company called DATEC in Gretna. In this case, the drill pipe lengths were only on the order of (300 ft) x (12 in/ft) = 3,600 inches. Therefore, the strains in the cement seals for these fixed offshore platforms were only  $3,600/158,160 = 0.023$  (or 2.3%) of the current situation! So, we were indeed quite safe with cement seals for “thirty years.” However, one is comparing “apples to oranges” in comparing the reliability of fixed offshore platforms to semi-submersibles operating in 5,000+ ft of water (drilling to what depths below seabed?).

### **Conclusions:**

1. The heat transfer problems associated with running monobore drill installations with/without liners (including the standard multi-casing wellhead installations to drilling installations in deepwater) **may be a showstopper, if seawater rapidly replaces the drilling mud when the rig is making preparations to leave – who looked at the heat transfer issues with well bore piping changes?** Replacing the warm/hot drilling mud with cold seawater can contract the well bore piping, and may readily crack the cement plug. This possibly causes failure of various cement bonds when the 9 7/8 inch casing contracts from the temperature change, because it results in placing the **cement plug/cement seals in tension!** It appears BP/Partners went after a leading edge technology in several areas without implementing the basic requirements (liner and locking ring required). What happens to the 16-inch casing and 18-inch casing? How hot is the well bore?
2. There are major issues with respect to which cement seals are intact in the BP Deepwater Horizon (if this is truly a monobore installation with no liner), as well as with respect to the drilling rig string/casing having pulled up on the BOP wellhead connector when it lost position and/or capsized. Does anybody have any test data on this condition, to see if cement seals between 36-inch casing can remain intact as against a

portion of the annular cement, maybe in tension? With either no/single liner and no locking ring, the BP design looks to be flawed, with no back-up safety systems if the cement plug fails. The BOP can be taken out by the drill string buckling and cement projectiles coming through the riser, if pressures are at 5,000+ psi. If the cement plug breaks loose, the internal BOP shear rams can be easily wiped-out by dynamic impact forces of cement resulting from a high-pressure formation blow-out.

3. There is probably **no integrity left of any internal seals within the BOP**, which is now basically just a thick-wall cylindrical shell. Was there only a 10,000 psi rated BOP which was refurbished in the Deepwater Horizon installation? Federal regulations should require all deepwater installations to have a new Cameron DWHC BOP (or equivalent) with armored cables and the super shears until an acceptable redesign can be tested for ultra-deep wells.
4. **Replacing drilling mud with seawater in ultra-deep wells may be an unacceptable situation which leads to blow-outs in ultra-deep monobore wells.** It can exist in both deep drilling on land and offshore and probably has resulted in setting the initial conditions for numerous high- pressure oil/gas well blowouts (i.e., the euphemism of “loss of well control”). An entirely new material is needed for current cement technology for ultra-deep wells. Well bore piping in the last 2,000 ft may require a special thermodynamic design to mitigate piping length changes due to quenching with seawater. Perhaps, it is better to leave the drilling mud in the well as a “sunk cost”. Drilling operators need to have much better tools a (software/sensor package) when replacing drilling mud with seawater.
5. Obviously, a rigorous, transient heat transfer analysis (simulation) should be done on each proposed deepwater well, as well as the current ultra-deepwater well completion protocols actually employed – do we have standardized procedures or not ? **We could be sitting on a number of deepwater ticking time bombs if they involve monobore SET technology (beyond depths of 20,000 ft)**, even if this technology is used with various options for a liner. In particular, how have the Russians addressed this problem in ultra-deep wells, or have they?

6. How does one **quantify the shear bond strength of a cement bond between a casing and the rock in a reservoir formation at 9,000+ psi at 20,000+ ft** and temperatures greater than 350 F? Is there any such data – how were the lab tests done?  
There is a need to standardize the cement formulations and training for U.S. ultra-deepwater drilling and “cements.” **Cement properties can vary by 50% (on land)**, depending on who is doing it and how they do it!
7. It appears the oil companies were running way ahead of MMS in terms of SET Technology implementation, and MMS had little or no control regarding the installations. It is unclear how there can be any suitable reliability with OHL System unless it is an extension of standard hanger system, **and a bottoms-up (component level) reliability analysis together with a full FEMCA (Failure Modes and Effects Analysis) per tailoring the MIL-Standard used by DOD, has been performed. This does not exist today.**
8. Shell Deepwater Operations may have one of the most conservative approaches of all the majors to ultra-deep drilling, and Shell has one of the best oil patch research centers. **Shell’s Joseph Prospect installation (or whatever Shell recommends) should be the minimum standards and configurations for deepwater drilling and installations in U.S. waters.** If we just have to get back out there drilling to save jobs, let’s do it with the full knowledge that numerous more safety issues need to be addressed. There should be a Federal Regulator/nominee/team of consultants on the drilling rig, empowered by Federal Law to “Hit the Kill Button” with no questions asked during the final well completion or drilling rigs leaving the scene.
9. **Redesign the ultra-deepwater BOP** after a full functional specification is developed, including all failure modes and how to mitigate all major well-blow outs from damaging the BOP. Reliability should be triply redundant as a goal. How can a BOP mitigate a drill string buckling inside the BOP? Drill strings can easily buckle in an ultra-deep well if well casing is over 20,000 ft. I do not see where this issue has been addressed.

10. **Develop a significantly improved (carbon nanotubes?) cement** or entirely new material for bonding at high temperature and pressure to fifty+ different layers of formations (data to be developed from mud logs), to withstand pressures greater than 15,000+ psi (match to API standards for flanges, valves and piping).
11. **Immediate review of all current ultra-deep wells (land/sea) to determine if there are heat transfer issues** with respect to either how it was completed, tested or installed, as well as pull the files on all offshore wells having well control problems. Determine shut-in criteria now for all problem wells. Determine if proper pressure tests of well bore integrity were done, and who is permitting “workovers”? Do well workovers now mean that there is a significantly deeper drilling than the public is being told?
12. There should be a **fully automated system to notify the U.S. Coast Guard** in case of any major fire on a rig. Any fire on a rig must be immediately reported – no longer the call of the Rig Captain. There should be a Comm Protocol which can be activated by any crew member on the Drilling Rig with regards to fires onboard drilling rigs and all offshore platforms.
13. Since President Obama approved BP’s total liability at \$20 Billion, this would only pay for people’s condo losing 50% of their resale value (already happening) in Miami (much less than entire Florida or Gulf Coast) and who is going to compensate the States for loss of tourism? Florida’s impacts for the next 12 months could be \$60 Billion to \$100 Billion a year. If this occurs for the next ten years, Florida’s losses alone will be over \$500 Billion from just loss of tourism. **Why does \$20 billion constitute a real settlement?** It remains a possibility that BP, Chevron, Shell, Anadarko and others are heavily involved in an “ultra-deepwater” drilling program (since late 1990s) at the direction of the U.S. Government, and essentially the deepwater (> 4,000 ft depths) of the Gulf of Mexico just may be the “mother of all oilfields”. Does the U.S. Government (taxpayer) carry the burden of all restorations costs (whatever that means) above \$20B as well as all future liabilities from ultra-deepwater drilling/production? Does it pay for all homes abandoned if the US Government orders permanent evacuations of a given locale, due to unacceptable air quality? What

are the threshold airborne/ground concentrations of the VOCs which will mandate an evacuation? **Let's see what happens to people in Venice, La. and Grand Isle, La. by mid-August – they are living on the lead edge of possible coming major air quality issues.**

14. USGS has stated there are no cracks or leaks in the seabed (at this well location, or all wells in Gulf of Mexico?). Thus, the probability of success of relief wells is said to perhaps be 80%. We shall see in mid-August, but possible we may not know until late November 2010. This well may have drilled beyond 20,000 ft given the extended time quoted to drill the relief wells and no transparency forthcoming from USGS. I have not heard of any signed affidavits by US Officials stating categorically that this well was not drilled beyond 20,000 ft. **Unclear what happened in Top Kill except that there is possibly an underground blow-out at the bottom of the 18-inch casing (3,900 ft down hole) resulting in high pressure oil/gas going into another formation underground (how many more complications do we need?).** This may require an unknown amount of heavy mud to try and seal leaks into secondary formations, so we need all the capacity we can muster in drilling mud capacity and high-pressure mud pumps. Are the relief wells currently producing, or expected to produce, oil and gas requiring extra capacity (enter the Loch Rannoch shuttle tanker)?
15. The Louisiana Offshore Oil Project (LOOP, initially completed in 1980s when a company called Petro-Marine in Gretna was Project Mgr) uses the Louisiana Salt Domes for massive storage of oil. In fact, **it is possible to store significant quantity of oil from the Gulf of Mexico in LOOP,** if there are major worldwide oil disruptions (possibly involving Iranian situation) including further expanding LOOP onshore. The oil being supplied by Mississippi Canyon wells could be tied into LOOP for emergency storage. In fact, if these wells can produce 50,000 bpd and we drill 100 wells in the next five years (Texas over to Alabama), that would go a long way to addressing U.S. energy dependence issues, if coupled to aggressive (micro) nuclear plant development and solar installations. How much are we willing to sacrifice any further?

**16. It is possible we have already lost the battle for the Eastern Gulf of Mexico** – it could be several years to assess the types of environmental damage done, as well as coming significant environmental impacts to the East Coast of the US, Cuba and Mexico. It is not going to ever be the same in our lifetimes. Oil will be reported by August in North Carolina and by Christmas will have traveled across the Atlantic Ocean!? We have never had unrefined crude to these levels from perhaps the Earth's mantle being injected into our lives before. What happens with hurricanes entraining this sheen and stirring up the bottom of the Gulf of Mexico? We need to know how toxic this particular material is, as well as fate and transport. People on beaches should not touch this material or get around it, if not involved in clean-up.

**17. Disposal of this unrefined oil sludge remains a major environmental issue.** Where does it go after placing in plastic bags? Does it react with plastic long term? The Fire Branch (AFRL) at Tyndall AFB should be contacted to burn a small amount of this material to identify the toxicity of airborne contaminants since they are already set-up to do this kind of testing. Let's start getting a handle on the airborne issues in burning massive amounts of this material offshore with regard to airborne plumes coming onshore, before we assume this is safe, because it is not safe near coastal areas. (The plume of a Shuttle launch was capable of peeling the paint off cars if the wind was in the wrong direction at launch, and that is a minor plume issue compared to ongoing massive offshore oilfield burns). It is possible that huge Supercritical Water Reactors (technology developed by General Atomics in San Diego) may be needed for safe decomposing of this material, by converting it to basic carbon dioxide, oxygen, hydrogen, nitrogen, etc. This needs to be addressed as a major environmental issue.

**18. Why did BP reject the use of large “suction pile over the BOP” at the outset, which is a standard technology for anchoring deepwater systems, and one could have been lowered over the entire BOP at the outset!?** Ask the Dutch and any number of other manufactures. The current “containment cap” is nothing but a mini-

version of a “suction pile” that does not go down to the seafloor, and is too small in scale to collect all the oil.

**19. DOD has the only Command and Control Structure on the planet to address the evolving Gulf Oil Spill Crisis (now coming up Florida’s East Coast (see [www.floridaoilspilllaw.com](http://www.floridaoilspilllaw.com)))** – this is way beyond the scope of the Coast Guard and using DOD C-130 assets to spray airborne chemicals (CorExit 9725A) all over the place (which is another major problem). Quit spraying airborne CorExit 9725A until you can produce tests on lab specimens that show toxicity levels. Where is the data? Is the problem that DOD cannot both address a forthcoming Iranian front in conjunction with the Gulf Oil Spill? There are many more questions which remain unanswered.

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