Application For
Permit to Drill

DRILLING PROGRAM

OCS-G-23018 #1
Atwater Valley 138
“Sturgis North Prospect”

ENSCO 7500

CHEVRON USA
DEEPWATER EXPLORATION AND PROJECTS

December 2007

TABLE OF CONTENTS

BLOWOUT PREVENTION

1. Applicable Federal and State regulations will be adhered while drilling of this well.
2. Drilling Contractor will have BOP test procedures on file. Test BOPs at low pressure (200-300 psi) and at high pressure as listed on APD Info Sheet at least every fourteen (14) days. BOP's will not be tested prior to drilling out each casing shoe unless the 14 day test requirement is due. This is provided the previously approved test pressure meets the approved test pressure for the next hole section. The blind rams will be tested initially and such that no more than 30 days shall elapse between tests. Blind ram test pressure will be that of the last casing string set at that time. BOP test pressures will be recorded on pin recorder and put in file. Each test and pressure will be noted in IADC Report. BOP's will be functioned weekly per MMS requirements and documented on the Tour Report.
3. Well control drills (pit drills) shall be performed weekly with each crew (well conditions permitting) on-board in accordance with current MMS Regulations. Results will be recorded on Tour Reports. A copy of the well control procedure will be posted on the rig floor
4. Prior to drilling out, all casing will be tested as shown on APD cover sheet (Form: MMS-123S), adjusted for current mud weight. Results of these tests will be recorded on IADC Report.
5. Separate full opening safety valves and inside BOPs are required for each size drill pipe in use and are to be tested bi-weekly with BOPs.
6. No ported floats shall be run if the lower manual kelly valve on the top drive is not strippable.
7. The maximum casing pressure which can be used during well killing operations will be posted near the driller.
8. Use drill pipe floats at all times during normal drilling operations. Check with your supervisor before leaving a float out, if such becomes necessary.
9. Prior to spud, be sure all toolpushers, drillers and crews are thoroughly familiar with and understand Chevron procedures for handling well kicks and possible blowouts. A list of personnel on board the rig who have completed approved well control courses will be maintained. The list will show names, job titles, specific training, names and dates of courses completed.
10. Before a trip, mud shall be properly conditioned by circulating bottoms up, or if circulating is not considered necessary, document on the IADC Report as required in 30 CFR Part 250.60.
11. On trips, the annulus shall be filled before the change in the mud level decreases the hydrostatic pressure 75 psi or every 5 stands of drill pipe, whichever gives a lower decrease in hydrostatic pressure. Post the number of stands of drill pipe and drill collars to be pulled and the equivalent fill-up requirements. Driller will constantly observe PVT and trip tank volume to ensure safe hole conditions. A trip book showing amount pulled and fill-up required will be maintained.
12. Keep continuous record of amounts used to fill hole on trips.
13. Conduct and document Pre-Operations Safety Meetings at the beginning of drilling operations.

WELL CONTROL

The diverter system and BOP stack will be installed as shown in this program document. The rig will have a hydraulic accumulator system which is supplied by electric pumps. Well Control procedures to be utilized are as follows:

Well control procedure while drilling below 22" casing (hard shut-in/choke closed).

At first indication of a kick the Driller will:

1. Sound the alarm.
2. Pick up off bottom and shut down the pumps.
2. Shut the well in using the Driller's Chair WELL CONTROL BUTTON.
   - The WELL CONTROL BUTTON closes annular and opens both bleed valves.
   - Verify the well is shut in (check riser and choke manifold set-up)
3. Record pressures.
4. Notify the Ensco 7500 DP control room, the Ensco OIM and Chevron Drilling Representative of Alert Drilling Status.
5. Space out drill pipe for potential hang-off on the middle pipe ram.
6. If deemed necessary, close middle pipe ram and hang-off. Ensure that EDS (Emergency Disconnect System) is properly configured.
7. Open annular and close bleed valves if hang off procedures are followed.
   - If influx is near stack, displace stack gas by pumping down kill line through upper kill valves out bleed off valves and up choke line before opening annular preventer.
8. Open lower inner and outer choke line valves.
9. Bump float and record SIDPP. Bleed off any trapped pressure.
10. The kick will be circulated out using a constant bottomhole pressure method based on the surface pressure, and the size of the influx.

Well control procedures while tripping below 22" casing (hard shut-in/choke closed).

At the first indication the well is flowing the Driller will:

1. Sound the alarm.
2. Install a full opening safety valve in the open position and spaceout for potential hang off on the middle pipe rams. Close the safety valve.
3. Shut the well in using the Driller's Chair "WELL CONTROL BUTTON"
   - The WELL CONTROL BUTTON closes the annular and opens both bleed valves.
   - Verify the well is shut in (check riser and choke manifold set-up)
4. Record pressures.
5. Notify the Ensco 7500 DP control room, the Ensco OIM and Chevron Drilling Representative of Alert Drilling Status.
6. Appropriate action to kill the well depends on surface pressure, depth of bit, and size of influx.

DRILLING NOTES

1. When necessary to work pipe, keep pipe moving up and down. Rotating alone is not considered sufficient.
2. While drilling, use steel rotary hose or 7500 psi test rubber hose.
3. Fully describe damaged or lost equipment on Tour Reports.

CEMENTING

1. Have lab test all cement slurries designed for use in well.
2. Record number of hours circulating and conditioning mud prior to pumping cement on all casing strings on Morning and IADC Report.
3. Record on IADC Report if pipe was reciprocated and/or rotated during cement job.
4. Based on actual depths the cement volumes will be recalculated and adjusted.

CEMENTING SHALLOW WATER FLOW ZONES IN DEEP WATER WELLS

The cementing program for the conductor and surface casings for this well has been evaluated and designed considering the best practices contained in API RP 65. Best practices utilized are included in the procedures section.

1. The location was selected to minimize drilling of formations which could trap shallow pressure in the riserless interval, by interpreting shallow seismic and offset information. However, a shallow water flow (SWF) potential has been identified on seismic at +/-4473' RKB. All fluids pumped during the cementing operations are designed to keep a pressure overbalance in the openhole at all times. Volumes of pad mud and cement at the rigsite are sufficient to cover contingencies due to mechanical problems or higher than expected pore pressures to avoid displacing the wellbore to seawater.
2. A 28" conductor string is set to prevent losses while drilling and cementing with weighted fluids in the next conductor hole section, where 22" casing is run.
3. The ROV will be on bottom to monitor throughout the riserless drilling and cementing of the 28" and 22" casing strings. The ROV will remain on bottom after the cement jobs to ensure there is no flow.

POLLUTION PREVENTION AND CONTROL

1. Pollution and waste disposal in drilling operations shall follow guidelines established in 30 CFR Part 250.40. Additionally we will follow guidelines concerning discharges that are spelled out in NPDES General Permit No. GMG290132, or as stated in permit.

MINIMUM MUD QUANTITIES

CHEMICAL	BELOW SURFACE HOLE
Barite	sufficient to raise mud density 0.5 ppg

*Gel 200 sacks
* During water-based mud use only

DRILLING MUD COMPONENTS

The drilling mud will contain some or all of the following:

Fresh Water	Polysaccharide	Defoamer
Bentonite	Pregelatinized Starch	Sodium Bicarb
Barite	Xanthum Gum	Lime
Sodium/Potassium Hydroxide	Gilsonite	Sapp
Lignite	Ground Nut Hulls/Mica	Polyacrylamide
Chrome Lignosulfonate	Calcium Carbonate	Polyacrylate
Detergent	Ultra Seal (cellulose fiber)	Lime/Gypsum
PAC	IO (Synthetic Oligomer)	Polymerized Fatty Acids
Blended Acids (proprietary)	Calcium Chloride	Olic Acid
Organphillic Clay	1618 Olefin	NaCl (sodium chloride)
PHPA	ampoteric polymer (Clay Seal or Clay Trol)	
Graphite	Diatomaceous Earth	

Supplemental APD Information Sheet

Field	Value
1. OPERATOR NAME	Chevron U.S.A.
5. WELL NAME *(Proposed)*	OCS-G 23018 #1
6. TYPE OF WELL	☑ EXPLORATORY ☐ DEVELOPMENT
11. WATER DEPTH	3,480'
12. ELEVATION AT KB	72'
2. API WELL NO. *(Proposed) (12 Digits)*	TBD
7. SIDETRACK NO. *(Proposed)*	
8. BYPASS NO. *(Proposed)*	
13. H2S DESIGNATION	☐ KNOWN ☐ UNKNOWN ☑ ABSENT
4. TOTAL DEPTH *(Proposed)*	MD: XPC TVD: 24,853'
9. RIG NAME	Ensco 7500
10. RIG TYPE	Semi-Sub
14. H2S ACTIVATION PLAN DEPTH FT *(TVD)*	NA

15. ENGINEERING DATA

Hole Size (in.)	Casing (Indicate if Liner)	Casing Size (in.)	Weight / Grade	Burst Rating / Collapse Rating	Type of Connection	MASP (psi) / MAWP (psi)	Safety Factors B	Safety Factors C	Safety Factors T	Top of Liner MD / TVD	Casing Depth MD / TVD	Shoe PP	Shoe MW	Shoe FG	Well-head Rating (psi)	BOP Size (in)	Rated BOP Working Pressure Annular / Ram (psi)	Test Pressures BOP Annular / Ram (psi)	Test Pressures Casing Test Casing (psi)	Test Pressures Casing Shoe Test (ppg)	Cement ft3	Drilling Fluid Type (oil base, water base, synthetic)
36	Structural Casing	36	726.24	5830	RL-4HC						3,660											Seawater
			X-60	5270																		
		36	373.80	2527	RL-4F																	
			X-52	1050							3,870											
32	Conductor Casing	28	218	2,440	RL-4SL						4,350								n/a	n/a	1045	Seawater
			X-52	950							4,350											
26	Conductor Casing	23	448	12,170	none	10,889					3,602											
			X-80	12,700		11,416	1.23	14.93	7.02		3,602											
		22	328	9,545	H-90D	4,533					3,640											
			X-80	9,457		5,004	2.55	11.93	3.23		3,640											
		22	224.28	6,364	S-90 MT	4,533					4,442											
			X-80	3,873		5,004	1.70	3.62	2.34		4,442											
		22	170.2	3,580	S-60MT	4,533					6,300				15,000	18 3/4	10M	7,500	2,600	11.9	2878	Water Base
			X-60	1,816		5,004	1.10	1.00	1.33		6,300	11.2	11.6	11.9			15M	11,400	(w/ 8.6 ppg)			
21	Surface Liner	18	117.0	6,680	Hydril 511	4,533				5,800	6,300											
			P-110	2,110		5,004	2.30	2.60	6.01													
		17 7/8	93.50	5,380	Hydril 521	4,533				6,300	7,800				15,000	18 3/4	10M	7,000	2,600	14.5	1126	Synthetic Base
			P-110HC	1,270		5,004	1.97	1.33	6.39			11.5	11.6	14.5			15M	11,000	(w/ 11.6 ppg)			
19	Intermediate Liner	16	109.61	10,385	SLSF	10,889				3,592	7,000											
			HCQ-125HP	4,160		11,416	1.05	3.13	2.11													
		16	97.0	8,733	SLSF	10,889				7,000	15,500				15,000	18 3/4	10M	7,000	6,100	16.3	286	Synthetic Base
			HCQ-125	2,990		11,416	1.23	1.05	2.19			13.5	13.6	16.4			15M	11,000	(w/ 13.6 ppg)			
16 1/2	Intermediate Liner	13 5/8	88.2	10,030	SLSF	10,889				15,200	20,890				15,000	18 3/4	10M	7,000	1,900	16.7	236	Synthetic Base
			Q-125HC	5,930		11,416	3.01	1.33	3.20			15.8	15.8	16.7			15M	11,000	(w/ 15.8 ppg)			
13 1/2	Intermediate Liner	11 7/8	71.8	10,720	Hydril 513	10,889				20,450	22,841				15,000	18 3/4	10M	7,000	2,100	16.5	112	Synthetic Base
			HCQ-125	7,190		11,416	4.89	2.01	4.40			15.8	15.8	16.5			15M	11,000	(w/ 15.8 ppg)			
12 1/4	Intermediate Liner	9 5/8	36	4,600		10,553									15,000	18 3/4	10M	7,000	1,500	16.8	136	Synthetic Base
			EX-80	1,370	XPC	11,075	2.74	1.01	10.99	22,350	24,853	16.1	16.1	16.8			15M	11,400	(w/ 16.1 ppg)			
11 3/8	Intermediate Liner	9 3/8	39.0	9,870		10,889								17.2	15,000	18 3/4	10M	7,000	1,200	17.0	113	Synthetic Base
			HCQ-125	4,850	SLF	11,416	4.53	1.89	5.88	22,250	27,000	16.3	16.3				15M	11,400	(w/16.3 ppg)			

Field	Value
16. CONTACT NAME	Christine Beiriger
17. CONTACT PHONE NO.	832-854-4012
18. CONTACT E-MAIL ADDRESS	☑ ☐ cbeiriger@chevron.com

19. Will you maintain quantities of mud and mud material (including weight materials and additives) sufficient to raise entire system mud weight 1/2 ppg or more? ☑ YES ☐ **NO**

20. REMARKS: Choke/kill tested to minimum of MASP +500 psi. *Equal or better casing may be substituted, pending availability

PAPERWORK REDUCTION ACT of 1995 (PRA) STATEMENT: The PRA (44 U.S.C. 3501 et seq. requires us to inform you that we collect this information to obtain well status, well and casing test, and well casing configuration data. MMS uses this information to have accurate data and information on the wells under their jurisdiction and to ensure compliance with approved plans. Responses are mandatory (43 U.S.C. 1334). Proprietary data are covered under 30 CFR 250.118. An agency may not conduct or sponsor, and a person is not required to resond to, a collection of information unless it displays a currently valid OMB Control Number. Public reporting burden for this form is estimated to average 1-1/2 hours per response, including the time for reviewing instructions, gathering and maintaining data, and completing and reviewing the form. Direct comments regarding the burden estimate or any other aspect of this form to the Information Collection Clearance Officer, Mail Stop 4230, Minerals Management Service, 1849 C Street, NW, Washington, DC 20240.

DRILLING PROCEDURE

1. MOL with the ENSCO 7500 semisubmersible rig. Make up jetting BHA and 36” structural casing with Vetco RL-4HC and RL-4F connectors with low pressure wellhead housing. Run subsea and tag mudline at +/- 3562’ RKB.
2. Jet in 36” structural casing and low pressure WH housing with 30” mill tooth bit, motor, and 32” sidewinder to +/- 318’ BML at 3880’ RKB using seawater. Allow casing to soak. Release CADA tool to drill ahead.
3. Drill ahead with seawater and gel sweeps to 4350’ RKB with 30” mill tooth bit, motor, and 32” sidewinder. Spot pad mud and POOH.
4. Run 788’ of 28”, 218 ppf, X-52 casing with Vetco RL-4SL connectors to 4350’. Land hanger in LPWHH and cement casing with nitrogen foamed cement to the mud line using an inner string, taking returns through the 28” supplemental adapter ball valves on the low pressure WH housing. POOH with running tool and inner string. No shallow water flows are expected in this interval, but the ROV will remain on bottom to observe for flow after cement job. Ball valves will be closed by the ROV.
5. Make up 26” mill tooth bit and motor, RIH, drill out approximately 120’ of cement inside the 28” casing, and drill float shoe. Drill ahead to 6300’. Use DKD mud to control shallow water flow as expected at +/- 4473’ RKB. At 6300’, spot pad mud as required for POOH to run and cement 22” casing. POOH with BHA.
6. RIH with 2738’ of 22”, 170 ppf, X-60, and 224 ppf, X-80 casing with Dril-Quip MT S-60 and S-90 connectors and high pressure wellhead housing, and set at 6300’. Cement casing with foamed nitrogen slurry to the mud line using an inner string, taking returns through the 28” supplemental adapter ball valves on the LPWHH. ROV will remain on bottom to observe for flow after cement job. Ball valves will be closed by the ROV.
7. At the conclusion of the 22” cement job, pre-load HPWHH to the LPWHH using the Mechanical Rigid Lock Down running tool. Release tool and POOH with inner string.
8. Run BOP and riser and latch to HPWHH with Vetco SHDH4 connector. RIH and set BOP test plug. Test WH connector and BOP’s to 250/11,000 psi. Test annulars to 250/7500 psi. POOH with test plug. Test 22” casing to 250 psi for 5 minutes and 2500 psi for 30 minutes with seawater against blind shear rams.
9. RIH with 18 1/8” x 21” drilling assembly on rotary steerable system. Drill out approximately 120’ of cement inside 22” casing while displacing seawater to 11.3 ppg SBM. Drill float shoe and 10’ of new formation and conduct leakoff test at 22” shoe to achieve 11.9 ppg EMW. Drill ahead to 7800’. POOH with BHA.
10. RIH with 1500’ of 17.875”, 93.5 ppf, P-110HC casing with Hydril 521 connectors, and 500’ of 18”, 117 ppf, P-110 casing with Hydril 511 connectors to place the shoe at 7800’. Cement the casing using an inner string, and bringing the TOC to 6100’. Set and test seal on the 18” hanger to 2000 psi with 11.3 ppg SBM and POOH with inner string.
11. Make up 16 ½” x 19” drilling assembly on rotary steerable system. Test 18” casing to 250 psi for 5 minutes and 2000 psi for 30 minutes with 11.3 ppg SBM against blind shear rams. RIH and drill out cement and float equipment plus 10’ of new formation. Perform FIT at 18” shoe to 14.5 ppg EMW. Drill ahead to 15,500’. POOH with BHA.
12. Run 8500’ of 16”, 97 ppf, HCQ-125, SLSF casing, and 3400’ of 16.040”, 109.61 ppf, HCQ-125HP, SLSF casing. Set shoe at 15,500’. Cement casing using dual liner wiper plugs, with a minimum of 500’ of cement above the shoe. After cementing, set seal on the 16” hanger and test to 6400 psi with 13.6 ppg SBM. POOH with landing string.
13. Make up 14 ½” x 16 ½” drilling assembly on rotary steerable system. Test 16” casing to 250 psi for 5 minutes and 6100 psi for 30 minutes with 13.6 ppg SBM against blind shear rams. RIH and drill out shoe track and 10’ of new formation. Perform FIT to 16.3 ppg EMW with 13.6 ppg SBM. Drill ahead to 20,900’. POOH with BHA.

14. Run 5600’ of 13 5/8”, 88.2 ppf, HCQ-125, SLSF casing and set shoe at 20,890’. Set liner hanger and cement liner bringing the top of cement a minimum of 500’ above the shoe. Set liner top packer and test to 2000 psi with 15.8 ppg SBM. POOH with landing string.
15. Make up 12 ¼” x 13 ½” drilling assembly on rotary steerable system. Test 13 5/8” casing to 250 psi for 5 minutes and 1900 psi for 30 minutes with 15.8 ppg SBM against blind shear rams. RIH and drill out shoe track plus 10’ of new formation and conduct leak off test at 13 5/8” shoe to 16.7 ppg EMW. Drill ahead to +/- 23,000’. POOH with BHA. R/U wireline and conduct formation evaluation program for 12 ¼” x 13 ½” hole.
16. RIH with 2400’ of 11 7/8”, 71.8 ppf, HCQ-125 casing with Hydril 513 connectors. Cement liner bringing the top of cement a minimum of 500’ above the shoe, or 500’ above any hydrocarbon bearing sands. Set liner hanger and liner top packer at the conclusion of the cement job. Test liner top packer to 2200 psi with 15.8 ppg SBM. POOH with landing string.
17. Make up 10 5/8” x 12 ¼” drilling assembly on rotary steerable system. Test 11 7/8” casing to 250 psi for 5 minutes and 2100 psi for 30 minutes with 15.8 ppg SBM against blind shear rams. RIH and drill out cement and float equipment plus 10’ of new formation. Conduct LOT at 11 7/8” shoe to 16.8 ppg EMW with 15.8 ppg SBM. Drill ahead to 24,853’. POOH with BHA. RIH with hole-opening BHA to open up +/-150’ 10 5/8” pilot hole to 12 ¼”. POOH.
18. RIH with 2500’ of 9 5/8” Solid Expandable Tubular (SET) EX-80, 36 ppf with XPC connections. Cement to bring the TOC a minimum of 500’ above a gas bearing sand. Expand casing as per Enventure procedure, resulting in final expanded OD of 10.576”. POOH with landing string while expanding. Test liner top to 1600 psi with 16.1 ppg SBM after expanding liner top at 22,350’. Continue to POOH.
19. Make up 9.75” x 11 3/8” BHA with rotary steerable assembly. Test 9 5/8” SET to 250 psi for 5 minutes and 1500 psi for 30 minutes with 16.1 ppg SBM against blind shear rams. RIH and drill out cement and shoe plus 10’ of new formation. Conduct LOT to 16.8 ppg EMW. Drill ahead to 27,000’. POOH with BHA.
20. RIH with 4700’ of 9 3/8” 39 ppf HCQ-125 SLF casing. Cement liner bringing the top of cement a minimum of 500’ above the shoe, or 500’ above any hydrocarbon bearing sands. Set liner hanger and liner top packer at the conclusion of the cement job. Test liner top packer to 1300 psi with 16.3 ppg SBM. POOH with landing string.
21. Make up 8 ½” rotary steerable BHA. Test 9 3/8” casing to 250 psi for 5 minutes and 1200 psi for 30 minutes with 16.3 ppg SBM against the blind shear rams. RIH and drill out cement plus 10’ of new formation and conduct LOT to 17.0 ppg EMW at the 9 3/8” shoe with 16.3 ppg mud. Drill ahead to TD of 31,150’. POOH with BHA. R/U wireline and conduct formation evaluation of 8 ½” hole if necessary.
22. At the conclusion of the above operations, an application will be submitted to either T&A or P&A the well.

REQUESTED WAIVERS

1) 30 CFR 250.402 Securing the Well for Hurricane Evacuation

In order to secure the well for hurricane evacuation, a Dril-Quip subsea drill string hang off tool landed in the subsea wellhead may be used instead of a cement plug, bridge plug or packer. This tool is designed to accommodate closure of the upper VBR rams on a 5-1/2" mandrel with the blind shear rams closed above it. A drill pipe float valve will be run to secure the inside of the drill pipe during evacuation.

2) 30 CFR 250.414 (c) Safe Drilling Margin

Drilling margin between leak-off test and mud weight shall be a minimum of 0.2 ppg from below the 22" shoe through the setting of the 16" liner. The drilling margin shall be a minimum of 0.5 ppg while drilling below the 16" liner.

3) 30 CFR 250.433 (b) Diverter Function

Partial closing of the diverter sealing element shall be considered to be an actuation test. Once movement of the diverter element is observed, the diverter will be reopened. A full closure actuation will be conducted prior to drilling out of all casing shoes and in conjunction with regularly scheduled BOPE function testing operations. Drilling mud will not be circulated through the diverter lines when synthetic based muds are in use.

4) 30 CFR 250.445 (g) Safety Valve for Running Casing

For casing strings where casing lengths are less than the length of the riser, safety valves will not be assembled with crossovers to casing threads.
A safety valve will not be on the rig floor for the casing being run unless the casing string length results in the casing being across the blind/shear rams prior to crossing over to the drill pipe running string.

5) 30 CFR 250.447 (c) BOP Test at Casing or Liner Points

The subsea BOP will not be tested before drilling out each casing string, unless the 14 day test is due or the test pressures for the next hole section are greater than the test pressures for the previous BOP test.

6) 30 CFR 250.448 (b) High Pressure Test for Ram Type BOPs, Choke Manifold and Other BOP Components.

Sweep valves and upper kill line valves (located above the top-most pipe rams, as per stack diagram) shall be tested to the same test pressure as the annular preventers.

7) 30 CFR 250.449 (d and e) Blind Ram Pressure Test

The (upper) blind shear rams will be pressure tested after running casing, to the casing test pressure as stated on the APD Information Sheet. This blind shear ram test will be done concurrently with the casing test when possible. The first five minutes of the casing test will demonstrate the pressure integrity of the blind shear rams. The interval between pressure tests on the upper blind shear ram will not exceed 30 days. The lower blind ram cavity is equipped with casing shear rams and are not designed to hold pressure, therefore will not be pressure tested.

8) 30 CFR 250.449 (b) BOP Stump Test Information

The initial BOP stack stump test will be tested to 250/15,000 psi for the rams and 250/10,000 psi for the annulars. Any subsequent BOP stack stump tests will be conducted to the same pressures. The rams and annular preventers will be tested on 5 7/8" pipe as this is the only size pipe planned to be used for this well.

9) 30 CFR 250.449 (h) BOP Function Test

The upper (Hydril) blind shear ram and lower (Hydril) casing shear ram will be function tested on a (14) day cycle between the required 30 day pressure tests.

Required 7-day function test of annular preventers will be alternated between the two (2) annular preventers on the Ensco 7500. A single annular preventer will be function tested during each function test required between the normal 14 day pressure tests to reduce the number of closures on the annular rubber. During pressure testing, both annulars will be function tested.

10) 30 CFR 250.449 BOP Pressure Test

The ENSCO 7500 BOP stack is equipped (from top down) with 2 annular preventers, 1 blind shear ram, 1 casing shear ram (not pressure sealing), 1 – 7" x 4-1/2" variable bore ram, 1 - 5 7/8" fixed ram, 2 – 7" x 4 -1/2" variable bore rams. The lower most VBR ram (fourth ram) is an inverted test ram. Therefore, only the first, second and third pipe rams will be available for well control purposes.

- After latch-up of the stack, the initial BOPE pressure test will be conducted with a BOPE test plug in order to pressure test the wellhead connector and the pipe rams to the maximum test pressure (250 / 11,000 psi) for the well. The annular preventer will be pressure tested to 250 low and 7500 psi high on this initial pressure test. Subsequent BOPE pressure tests will be performed using the lower most BOPE Test Ram to the test pressures stated on the APD sheet for each individual hole section.

- In the event of tapered string operations, the VBRs will be pressure tested to the pressures stated on the APD information sheet (for each hole section) against the largest drill pipe size in use. The smallest drill pipe size in use will be tested against one (1) VBR. The annular will be pressure tested against the smallest size pipe in use, only.

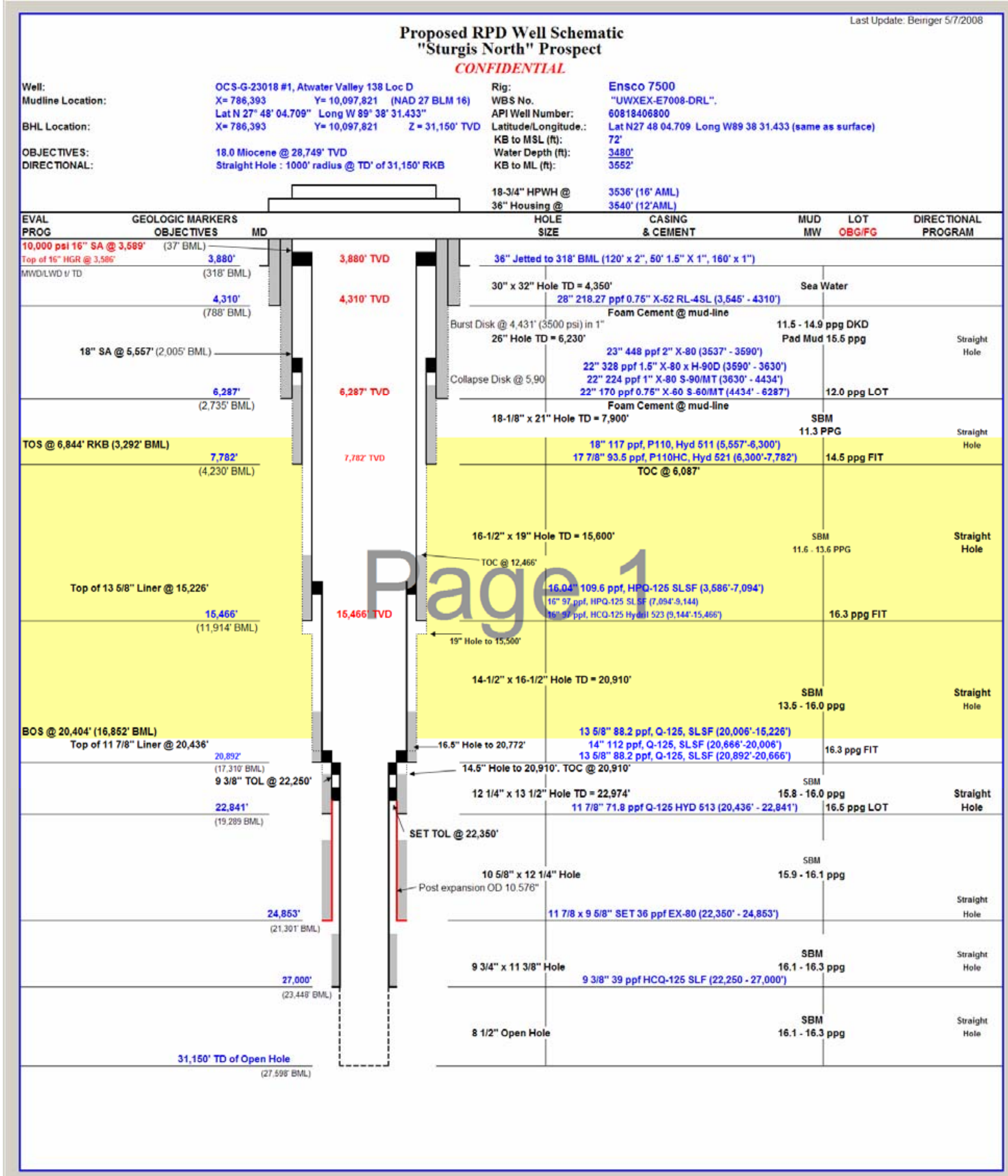
11) 30 CFR 250.461 (c) Measurement while Drilling

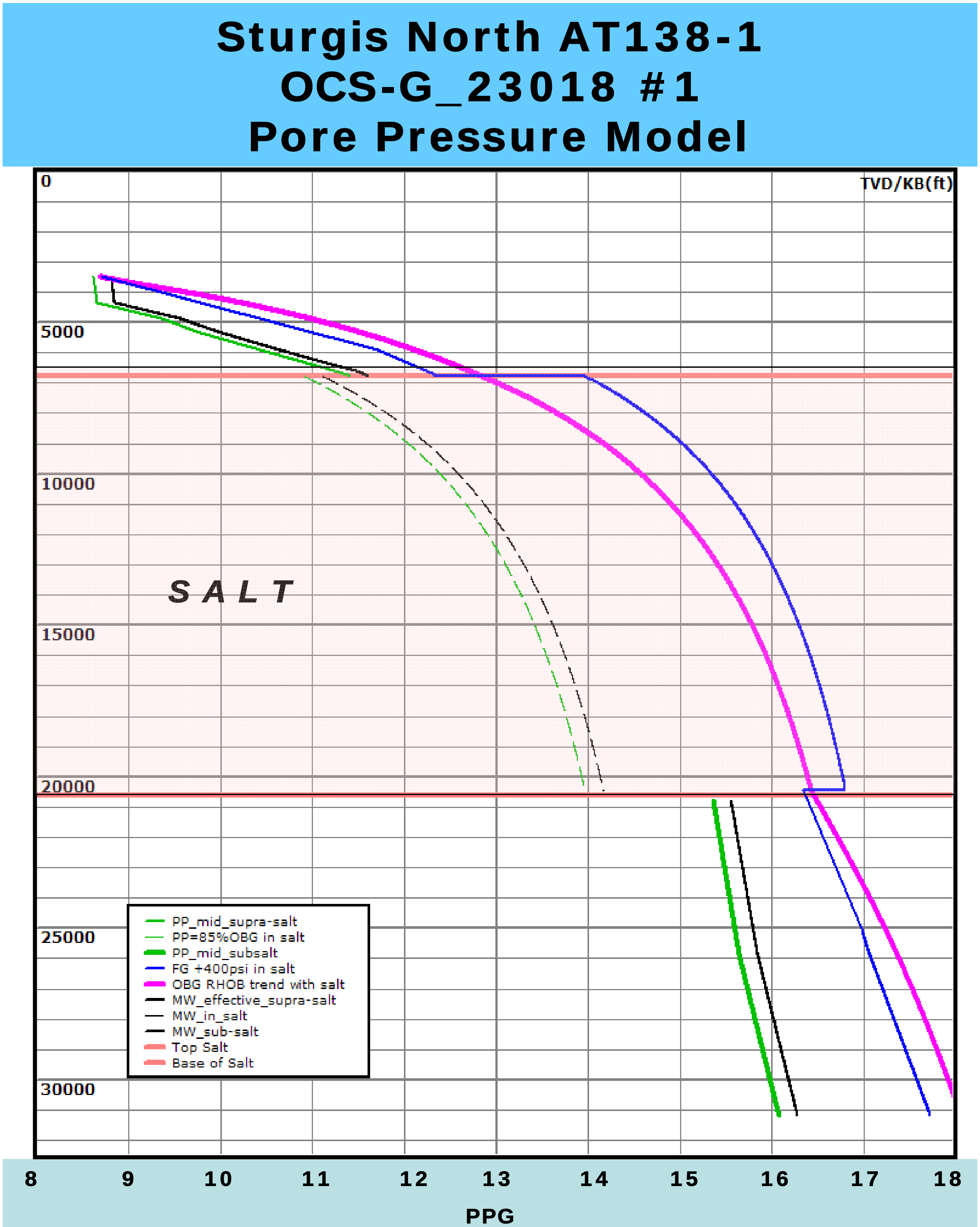
In the event a composite MWD survey is run and is valid, a multi-shot (or single shot) survey shall not be required at casing points or TD.

12) NTL No. 2005-G05 Deepwater Ocean Current Monitoring on Floating Facilities

Chevron owns six (6) – 75 kHz Acoustic Doppler Current Profile (ADCP) units all of which were purchased prior to September 2004. A waiver is requested to continue the use of this 75 kHz ADCP system for the duration of this well. This system monitors ocean currents to a depth of 603 meters / 1,978'. In addition we will install an on bottom current meter at this location as per Section A (2) of this NTL.

WELLBORE SCHEMATIC




Sturgis North AT138-1
OCS-G_23018 #1
Pore Pressure Model
TVD/KB(ft)
0
5000
10000
15000
20000
25000
30000
SALT
PP_mid_supra-salt
PP=85%OBG in salt
PP_mid_subsalt
FG +400psi in salt
OBG RHOB trend with salt
MW_effective_supra-salt
MW_in_salt
MW_sub-salt
Top Salt
Base of Salt
8
9
10
11
12
13
14
15
16
17
18
PPG

CASING DESIGN

Casing Design Criteria
Deepwater Gulf of Mexico
APD

String	Conductor & Surface Casing				Intermediate Casing/Liner		
Criteria	**Loading**	**Tubular strength**	**Design factor**		**Loading**	**Tubular strength**	**Design factor**
Burst	1. **Gas kick** **Internal**: 80% gas column on top of 20% mud column calculated from OH TD to RKB. If OH > 10,000' a 50/50 gradient will be used. (gas gradient 0.10 psi/ft) **External:** Formation pressure **2. Pressure test** **Internal**: Test pressure plus test fluid column (see Casing & Liner Test Pressure Calculations.doc) **External**: formation pressure	**1. Sweet-service*** API burst rating or Heavy-wall burst rating **2. Sour-service**** API burst rating or VME burst rating	**1. Sweet-service** 1.10 **2. Sour-service** 1.20		**1. Gas Kick** **Internal**: 50% gas column on top of 50% mud column calculated from OH TD to RKB (gas gradient by Young-Nagy equation) **External**: formation pressure **2. Pressure test** **Internal**: Test pressure plus test fluid column (see Casing & Liner Test Pressure Calculations.doc) **External**: formation pressure 3. **Shoe fracture** **Internal**: Frac. Pressure at shoe with mud to surface **External**: formation pressure	**1. Sweet-service*** API burst rating or Heavy-wall burst rating **2. Sour-service**** API burst rating or VME burst rating	**1. Sweet-service** 1.10 **2. Sour-service** 1.20
Collapse	**1. Lost return** **Internal**: Full seawater column to surface, a gradient higher than SW may be used (equivalent to the drilling MW column drop to balance the lowest exposed pore pressure). **External**: Drilling mud **2. Cementing** **Internal**: Drilling mud **External**: Cement slurry in place	API collapse rating or approved high collapse rating	1.00 or 0.85 for good cement section		**1. Lost return Internal**: Full seawater column to surface, a gradient higher than SW may be used (equivalent to the drilling MW column drop to balance the lowest exposed pore pressure). **External**: Drilling mud **2. Cementing** **Internal**: Drilling mud **External**: Cement slurry in place	API collapse rating or approved high collapse rating	1.00 or 0.85 for good cement section
Tension	**1. Running in hole** : Buoyant weight	The lesser of API pipe tension rating or connection tension rating	1.60		**1. Running in hole** : Buoyant weight	The lesser of API pipe tension rating or connection tension rating	1.60

- H_2S partial pressure < 0.05 psi ** H_2S partial pressure >= 0.05 psi

Casing Design Criteria
Deepwater Gulf of Mexico
APD

String	Production Casing/Liner				Tubing		
Criteria	**Loading**	**Tubular strength**	**Design factor**		**Loading**	**Tubular strength**	**Design factor**
Burst	1. **Tubing leak near surface** **Internal:** Tubing leak pressure from production shut-in **External**: Open hole - formation pressure. Cased hole - mud weight the production liner/casing was run in.	**1. Sweet-service*** API burst rating or Heavy-wall burst rating **2. Sour-service**** API burst rating or VME burst rating	**1. Sweet-service** 1.10 **2. Sour-service** 1.20		**1. Service Load** **Internal:** Max. pressure from production shut in (equal to initial flowing pressure) **External:** Packer fluid	**1. Sweet-service*** API burst rating or Heavy-wall burst rating **2. Sour-service**** API burst rating or VME burst rating	1.20
Collapse	**1.Fluid Drop** **Internal:** Fluid drop equivalent to abandonment pressure. Internal fluid gradient equal to produced oil or gas gradient. **External:** Drilling mud **2. Cementing** **Internal**: Drilling mud **External**: Cement slurry in place	API collapse rating or approved high collapse rating	1.00 or 0.85 for good cement section		**1. Full void pipe** **Internal:** Fluid drop equivalent to abandonment pressure. Internal fluid gradient equal to produced oil or gas gradient. **External:** Packer fluid	API collapse rating or approved high collapse rating	1.00
Tension	**1. Running in hole**: Buoyant weight	The lesser of API pipe tension rating or connection tension rating	1.60		**1. Running in hole:** Buoyant weight	The lesser of API pipe tension rating or connection tension rating	1.60

- H_2S partial pressure < 0.05 psi ** H_2S partial pressure $>= 0.05$ psi

CHEVRON DEEPWATER WEO

Casing and Liner Test Pressure Calculations

There are 5 possible test pressures that need to be calculated for casing and liner test pressures. The first is based on the MMS regulations (see Appendix 1). The second test pressure is the Maximum Anticipated Wellhead Pressure (MAWP). The MAWP is calculated from the Maximum Anticipated Surface Pressure (MASP). The third and forth test pressures deal with running liners. The fifth test pressure is based on the expected shoe strength of the casing/ liner being drilled out.

When there are stacked or nested liners in a well, it is extremely important to reconfirm that all future test pressures are recalculated to determine the exact pressure on the lapped shoes. This is called Step #6. The actual pressure the shoe will see must then be reduced by the "drill-out-mud-weight" hydrostatic pressure of that string and determine the equivalent surface pressure.

1. 70 % of Casing API Burst Rating: Account for differential between mud weight inside casing and backup pore pressure, typically calculated at top and bottom of string as well as at point of lowest back-up pore pressure. Minimum value calculated governs.

2. MAWP: For subsea wells, calculation of MAWP (internal) resulting from voiding the entire wellbore 50% to gas and 50% to drilling fluid from hole interval TD to rig floor. This may need to be calculated for a number of hole intervals if the casing is not lapped to determine highest MAWP. The surface applied pressure required for the casing pressure test, to match the calculated maximum MAWP (internal) would be calculated by subtracting the hydrostatic of the drilling mud in the choke line from the calculated MASP.

3. Liner Lap – Initial: The pressure test for a liner must be to a surface pressure that exceeds the calculated fracture pressure of the previous casing or liner shoe set, before the liner was run by 500 psi. This is the initial calculation.

4. Liner Lap – Future: This surface pressure will have to be recalculated at each liner setting depth where the casing in consideration will still be exposed. This calculation should start at the deepest set liner and the corresponding surface pressure (P_A) required when testing the deepest liners shoe. This pressure (P_A) should be used to calculate the necessary test pressure (P_B) of the previously set liner. This pressure (P_B) should be used to calculate the necessary test pressure (P_C) of the previously set line. This continues until the casing in consideration is exposed. The current mud weight utilized for pressure testing the casing/liner must be compared to the future mud weight required during deeper liner lap tests to derive an equivalent surface pressure.

5. Formation Integrity / Leak Off Tests: The casing/liner pressure test must be to a value that exceeds the surface pressure, considering mud weight in use, required to perform a FIT or LOT of the deepest shoe exposed prior to the casing being lapped. The casing pressure test must exceed this surface pressure by 200 psi. The current mud weight utilized for pressure testing the casing/liner must be compared to the future mud weight required during deeper shoe tests to derive an equivalent surface pressure.

6. Recheck of All Calculated Test Pressures – A complete recheck of all final liner test pressures calculated for the well must be made. Each final liner test pressure, starting at the bottom, must be checked against any previously set liners or complete casing strings exposed to the planned liner test pressures. This is to ensure that any exposed liners/ casing strings are properly tested prior to drilling out.

Notes:

- If the final calculated test pressure is higher than 70% of the casing burst, supervisor approval must be obtained.
- If final calculated test pressure is less than 70%, the approved APD (Application for Permit to Drill) acts as a waiver to this governmental requirement.

REQUIREMENTS

The testing requirement for a full string of casing (non liner) back to the wellhead is as follows:

Calculate the test pressure for each step above. The minimum pressure calculated in #1 and #2 is compared to the pressures calculated in #3, #4 and #5. The maximum of these pressures is the required Casing Test Pressure.

The testing requirement for a liner is as follows:

Calculate the test pressure for Steps #3, #4 and #5. The maximum these pressures is the required Liner Test Pressure.

GEOLOGIC PROGRAM LETTER

The **OCS-G-23018 #1 WELL** should be drilled in accordance with the following:

1. API NUMBER:	TBD
2. AFE NUMBER:	UWXEX-E7008-DRL
3. PROJECT GEOLOGIST:	Tonya Bordenave
4. SURFACE LOCATION:	7744’ FSL & 5613’ FEL of Atwater Valley 138 X = 786,387 Y = 10,097,824 (UTM 16) Latitude: N 27 deg 48’ 04.7279” Longitude: W 89 deg 38’ 31.5042” (NAD-27)
5. BOTTOM HOLE LOCATION:	7744’ FSL & 5613’ FEL of Atwater Valley 138 X = 786,387 Y = 10,097,824 (UTM 16) Latitude: N 27 deg 48’ 04.7279” Longitude: W 89 deg 38’ 31.5042” (NAD-27) (same as surface location)
6. TARGETS:	1) Middle Miocene @ 26,000’ TVD 2) Lower Miocene @ 28,840’ TVD
7. TOTAL DEPTH:	31,150’ MD / 31,150’ TVD
8. TOLERANCES:	1000’ radius from Lower Miocene target @ 28,840’ TVD
9. WATER DEPTH:	3490’
10. PRESSURE:	Hydrostatic pressures are anticipated from the mudline at 3490’ to top of salt at approximately 6735’, gradually increasing from 8.6 ppg to 11.3 ppg. A more gradual increase is expected through the salt beginning at 11.0 ppg and increasing to 13.9 ppg at the base of salt at 20,395’ TVD. A sharp increase is anticipated as we come out of salt to 15.3 ppg. The gradient then levels off with a gradual increase from the base of salt to TD with a maximum pore pressure of approximately 16.0 ppg expected at 31,150’ TVD. Within the interval from 25,000’ to 31,000’ TVD there is a possible regression of pore pressure based on some of the offset wells with a maximum regression to 14.5 ppg possible.
11. DRILLING CONTRACTOR:	Ensco 7500
12. PARTNERS:	**CHEVRON CONTACTS**
CHEVRON (OPER.) **ANADARKO** **DEVON** **STATOIL**	John Connor – Office: 832-854-3659, Cell: 713-515-4217 (Drilling Superintendent) Christine Beiriger - Office: 832-854-4012, Cell: 281-841-2288 (Drilling Engineer) Jim Hawkins – Office: 832-854-4869, Home: 281-491-2140 (Operations Geologist) Tonya Bordenave - Office: 832-854-3612, Cell: 713-264-2410 (Project Geologist)

	Dennis Woods – Office: 832-854-3601, Home: 281-492-7202 (Formation Evaluation)
13. SECURITY CLASSIFICATION:	CLASSIFIED SPECIAL from Surface to TD
14. GEOLOGIC CLASSIFICATION:	Exploration
15. GEOLOGIC CONCEPT:	Middle-Early Miocene section of sand rich turbidites deposited within localized salt withdrawal mini-basins on a 3-way salt/fault closure
16. ESTIMATED SPUD DATE:	January 10, 2008
17. CRITICAL DATES:	None

18. EVALUATION PROGRAM:

a. Mud Log: SPERRY-SUN	6,300' TVD to TD (below 22" casing)	Standard Services
b. LWD: SCHLUMBERGER	3,880' TVD to TD (below 36" casing)	GR/RES/PWD
	15,500' TVD to TD	GR/RES/PWD/SonicVision
c. Wireline Logging: SCHLUMBERGER	21,000'TVD to 26,000' TVD:	Optional: GR, CNL, LDT, AIT, DSI, MDT (pressure w/ optional samples), CMR+ , MSCT and OBMI.
	26,000' TVD to TD':	Optional: GR, AIT, CNL, LDT, CMR and MDT (pressure w/ optional samples), MSCT, DSI, OBMI .
d. Velocity Survey:	Zero Offset VSP, Optional: Salt Proximity VSP	
e. Directional Services: SCHLUMBERGER	Bent Housing Motor to 6300' MD then Rotary Steerable to TD.	
f. Wellsite Geologist: CHEVRON	3,880' TVD to TD (below 22" casing)	
g. Wellsite Paleontologists: TBS	On site for 14.5x16.5" hole section (15,500' TVD to TD)	
h. Sidewall Core Analysis: TBA	Optional wireline run in 10 5/8" hole section only.	

RIG AND BOP SPECIFICATIONS

ENSCO

ENSCO 7500

GENERAL INFORMATION
Flag U.S.A.
Owner ENSCO Offshore Company
Manager ENSCO Offshore Company
Previous Name(s)
Year Built 2000 **Builder** TDI Halter Marine - Orange, Texas
Design DPS-2
Classification A. B. S. Maltese Cross A1 Column Stabilized Drilling Unit

MAIN DIMENSIONS
Length 240'
Breadth 228'
Pontoons 50' x 24' x 290'
Moon Pool 20' x 80'
Columns 50' x 35'
Keel to Main Deck 93' 0"
Main Deck Area 240' W x 220' L

MACHINERY
Main Power (6) EMD 20-10G7B/EMDEC – 5,000 HP/each; (6) Baylor 8855YNB – 506, 3,580 KW generator
Power Distribution SCR: Thrusters, (8) DW3000-6, 3,400 ADC, 750 VDC; SCR: Drilling, (12) DW1400-6, 1,500 ADC, 750 VDC
Emergency Power (1) Cat 3512B, 1,476 HP
Thrusters (8) Schottel SRP2020, 3,000 HP/each

OPERATING PARAMETERS
Water Depth 8,000'
Maximum Drilling Depth 30,000'
Air Gap 33' @ 60' drilling draft
Transit Speed 3.5 knots @ 45' draft
Variable Drilling Loads:
Operating Conditions 8,700 s. tons @ 60'
Survival Condition 7,620 s.ton @ 40'
Transit Conditions 3,940 s. ton @ 24'

DRILLING EQUIPMENT
Derrick Dreco 170' x 46' x 40'; 1,928,000 lb gross nominal capacity; 1,500,000 lb static hook load
Drawworks National 1625-UBDE, 3,000 HP; Dretech 15050 Elmagco brake
Rotary Varco RST 605 hydraulic, 60 1/2" opening, 1,000 ton, driven by (4) HT hydraulic motors 10-950
Top Drive: VARCO TDS 8 SA, Rated Capacity: 750 tons, Rated WP: 7,500 psi, Driven by: GEB20 AC Motor, Output Power: 1200 HP, Drilling Torque: 65,500 ft/lbs, Max RPM: 270, Make up/Break out Torque: 100,000 ft/lbs
Drill String Compensator Maritime hydraulic, 1000K CMC
Travelling Block Dreco, 7-60TB-750, 750 ton
Pipe Handling Varco PRS-3i pipe-racker, AR4000 iron roughneck, PS30 slips, BX4 & BX5 elevators
Cementing Dowell Schlumberger
Mud Pumps (3) National 14-P-220, triplex, GE 752; (1) Lewco W446, 320 HP AC riser booster

HOISTING EQUIPMENT
Cranage (1) Dreco 72DNS 140, (1) Dreco 72DNS 160; (1) 106' span, 32 ton gantry crane

CAPACITIES
Active Mud Pits 3,625 bbls
Reserve Liquid Mud Storage 8,550 bbls
Bulk Mud/Cement 20,118 cu. ft.
Sacks 4,000 sacks
Drill Water 8,334 bbls
Potable Water 1,066 bbls
Fuel Oil 16,414 bbls

WELL CONTROL SYSTEMS
BOP (6) Ram Hydril 18 3/4" 15 M; dual Hydril annular 18 3/4" 10M GX; (1) Cameron HC 18 3/4" 10 M LMRP; (1) Vetco HD 18 3/4" 15M BOP connect
BOP Handling 700,000 lb BOP cart and elevator, 650,000 lb Xmas tree cart
Control System 5,000 psi BOP connecter Hydril MUX
Riser Details Drill-Quip 21" 2.5 m flanged – 85% Bouyant; 4 1/2" ID C/K lines – 4" ID Booster line; Dual 2 7/8" ID hydraulic conduit lines
Riser Tensioner (8) Retsco, 250 kips / each
Diverter Dril-Quip FDS, 60", 500 psi
Drillpipe 5 7/8" - 26.41 ppf, S-135, XT 57, Range 2 .361wt, 5 7/8" – 27.8 ppf, S-135, XT57, Range 3 .415wt Landing String: 5 7/8" 46.4 ppf, S-135, XT 57 Range 2 .750wt, H-Weight: 5 7/8" 57.42 ppf, HW-95, XT 57
Drillcollars 9 1/2"; 8 1/4", 6 3/4"
TV System
Choke and Kill Manifold 3 1/16" x 15 M psi WOM with power choke dual hydraulic chokes

MOORING
Winches (8) Skagit WMD-52, 3 1/4"
Wire/Chain K4 chain – 1,000' chain
Anchors (4) Vryhof Stevpris MK5, 10 MT

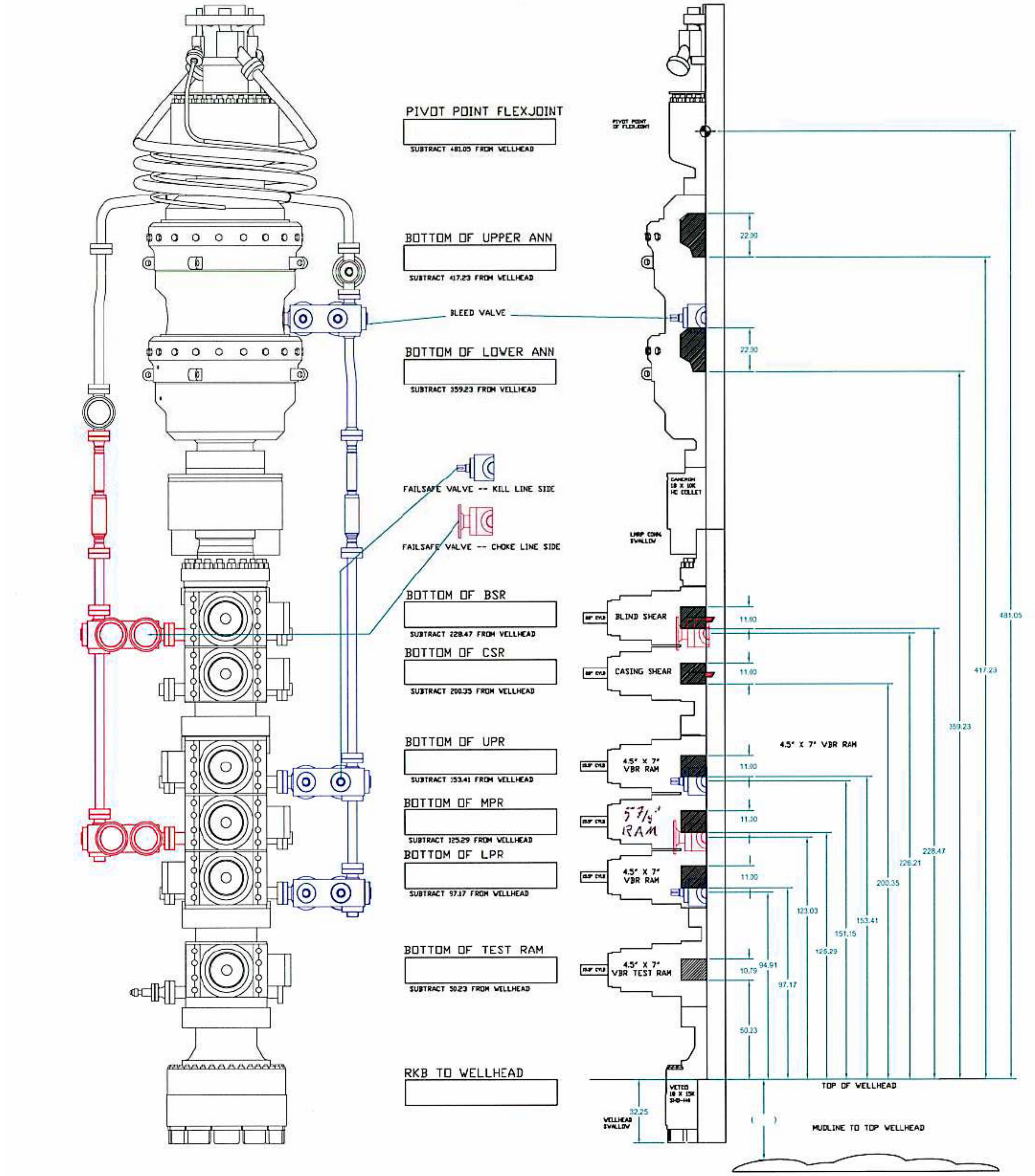
HELIDECK Sikorsky S-61 or S-92, 73' diameter
ACCOMMODATION 118 berths

ADDITIONAL DATA
Mud cleaning facilities: (5) Brandt LCM-3D Cascade, 5.9 G's; (1) Brandt King Cobra 24/3 Mud Conditioner; (2) Brandt DG-10 vaccum type
Sewage treatment: (2) Omnipure units: (1) MX12 and (1) MX15; single point discharge

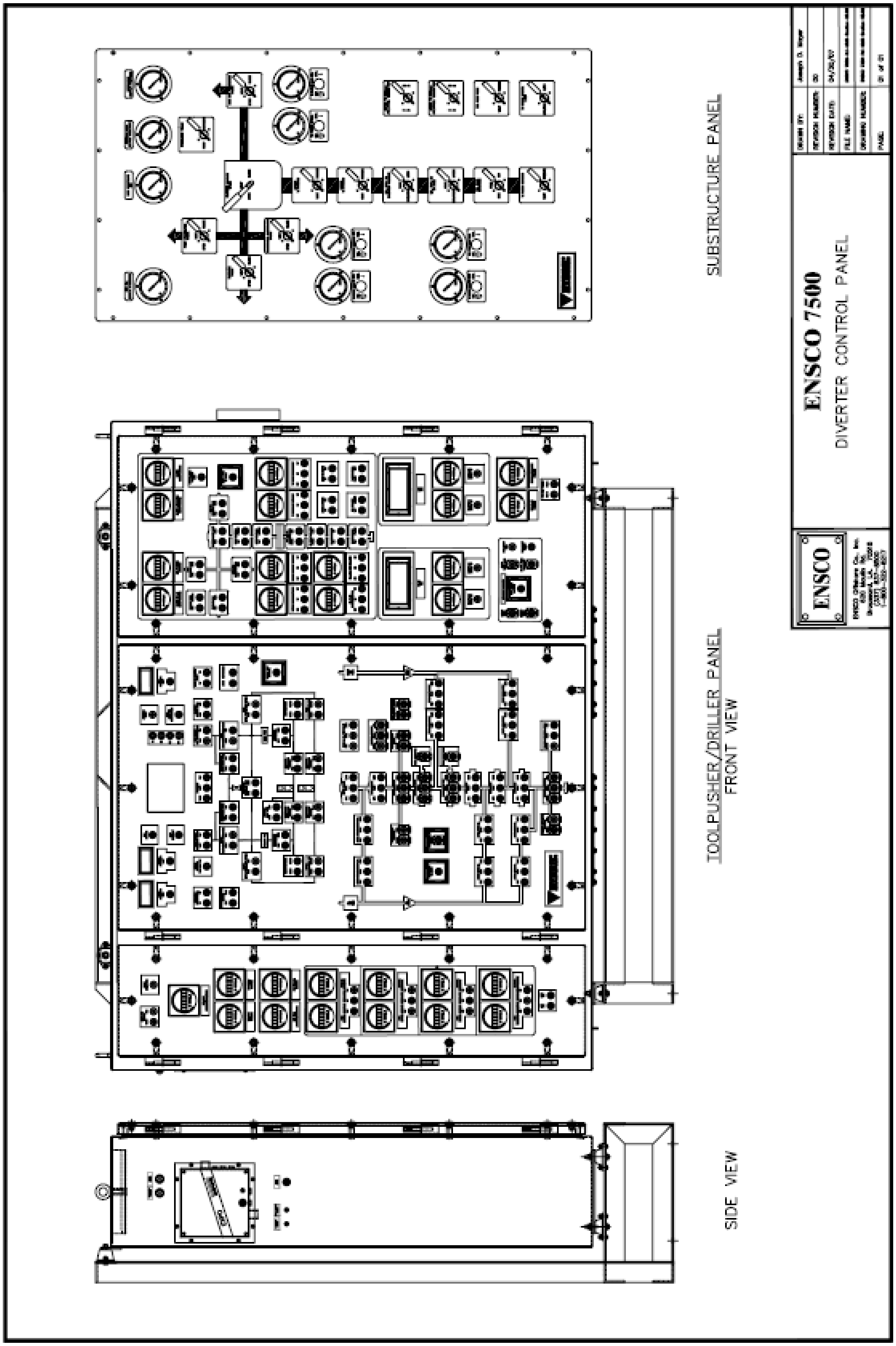
ENSCO North & South America, 14800 St. Mary's Lane, Suite 230, Houston, TX 77079, USA
Tel 281-920-6440 Fax 281- 920-6441 e-mail marketing.na@enscous.com

10/12/2006

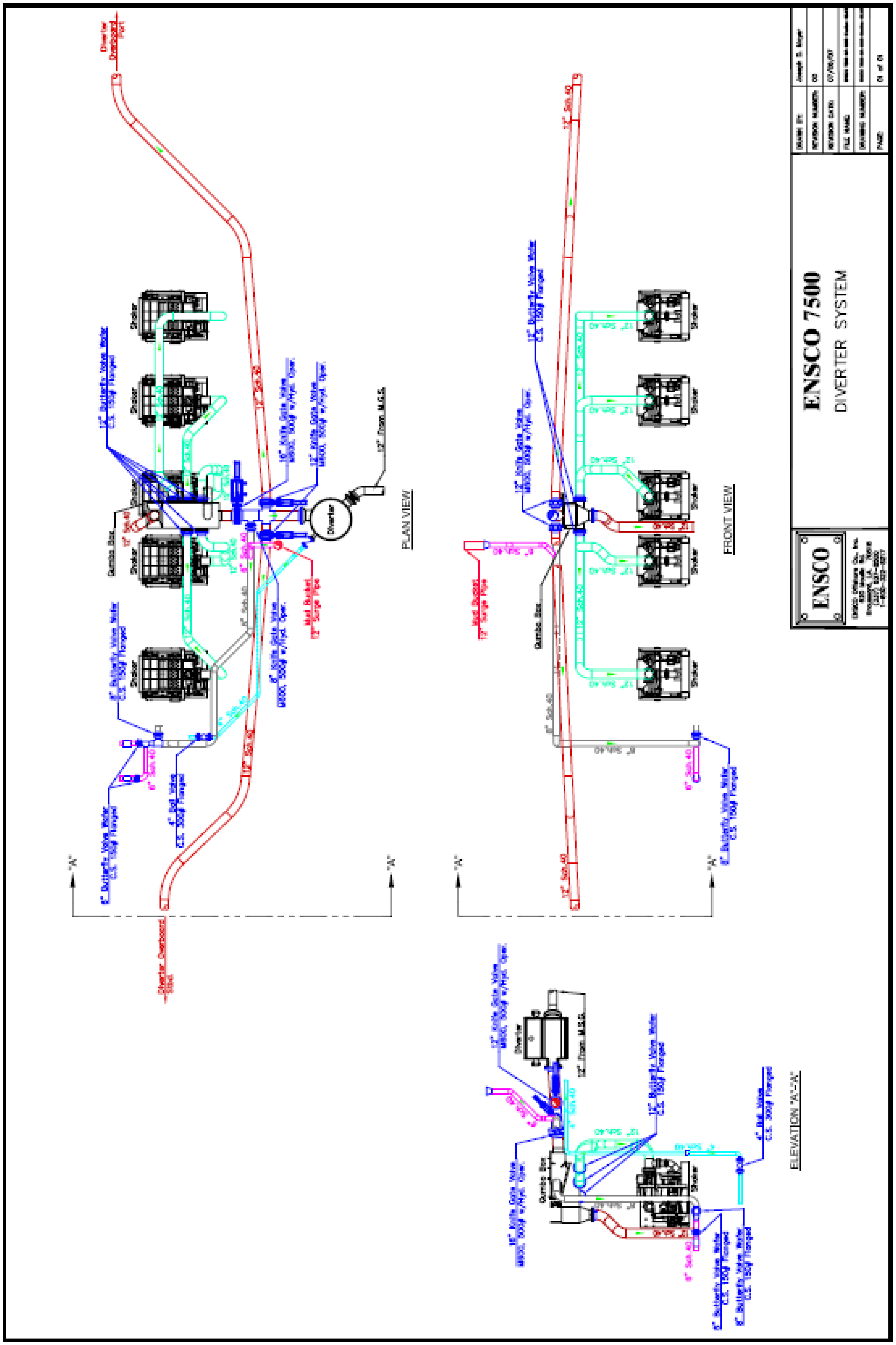
CHEVRON



PIVOT POINT FLEXJOINT
SUBTRACT 481.05 FROM WELLHEAD
BOTTOM OF UPPER ANN
SUBTRACT 417.23 FROM WELLHEAD
BLEED VALVE
BOTTOM OF LOWER ANN
SUBTRACT 359.23 FROM WELLHEAD
FAILSAFE VALVE -- KILL LINE SIDE
FAILSAFE VALVE -- CHOKE LINE SIDE
BOTTOM OF BSR
SUBTRACT 228.47 FROM WELLHEAD
BOTTOM OF CSR
SUBTRACT 200.35 FROM WELLHEAD
BOTTOM OF UPR
SUBTRACT 153.41 FROM WELLHEAD
BOTTOM OF MPR
SUBTRACT 125.29 FROM WELLHEAD
BOTTOM OF LPR
SUBTRACT 97.17 FROM WELLHEAD
BOTTOM OF TEST RAM
SUBTRACT 50.23 FROM WELLHEAD
RKB TO WELLHEAD
BLIND SHEAR
CASING SHEAR
4.5" X 7" VBR RAM
5 7/8" RAM
4.5" X 7" VBR TEST RAM
TOP OF WELLHEAD
MUDLINE TO TOP WELLHEAD
22.00
11.00
10.79
50.23
94.91
97.17
123.03
125.29
151.15
153.41
200.35
226.21
228.47
359.23
417.23
481.05
32.25



SUBSTRUCTURE PANEL
TOOLPUSHER/DRILLER PANEL
FRONT VIEW
SIDE VIEW
ENSCO 7500
DIVERTER CONTROL PANEL
ENSCO



ENSCO 7500
DIVERTER SYSTEM
PLAN VIEW
FRONT VIEW
ELEVATION "A"-"A"
ENSCO
Shaker
Gumbo Box
Diverter