Arena Offshore, LLC
South Timbalier Block 172
OCS-G 1256, Well No. C003 ST00 BP00

Proposed Recompletion Procedure
01/26/2011
Revision 0.0

Well Location Information:

SL (Slot C):	5,559’ FSL and 999’ FWL of ST 172
Well TD:	8,250’ MD / 7,914’ TVD
Current PBTD:	8,164’ MD / 7,832’ TVD
Water Depth:	106’
RKB to THF:	±83.95’ (62.95’ ORKB w/ Penrod 90)
RKB to WL:	±127’ (106’ ORKB w/ Penrod 90)
RKB to ML:	±237’ (216’ ORKB w/ Penrod 90)

Tubular Information:

Drive Pipe:	30” x ⅝” wall @ 367’ MD / TVD
Surface Casing:	10 ¾”, 40.5#, K-55, BTC @ 3,500’ MD / 3,379’ TVD
Production Csg:	7”, 26#, P-110, XL @ 8,250’ MD / 7,914’ TVD
Tubing (existing):	2⅞”, 6.5#, N-80, 8rd
Tree (existing):	National 3” 5M w/ 3 ½” 8rd Lift Thrds & 2⅞”, EU 8rd Suspension Threads
Tubing (proposed):	2⅞”, 6.5#, 13Cr, 95Ksi, K-Bear
Tree (proposed):	2 9/16”, 5M w/ 2⅞” EUE 8rd Lift Thrds & 2⅞” K-Bear Suspension Threads
Drillpipe:	3 ½”, 13.3#, S-135, IF

NOTE: See attached Current and Proposed Wellbore Sketches

Directional Information:

Well Geometry:	Build and Hold

Objective:

Permanently abandon the current completion, pull production tubing and production packer. Recomplete with a gravel pack completion in the “C11a” Sand.

Current Completion Interval:

Sand:	"C11b" Sand
Current Perfs:	8,038' to 8,053' MD / 7,712' to 7,727' TVD
BHP estimate (psi / ppg):	3,449 psi / 8.6 ppg
SITP:	585 psi
FTP:	80 psi
Last Production Date:	3/19/2008
Last Well Test Data:	

Date	FTP	MCF/D	BOPD	BWPD	SITP
11/12/2010	80	0	0	0	585

Proposed Completion Reservoir Information:

Sand:	"C11a" Sand
MD Perforations:	7,940' to 7,955'
TVD Perforations:	7,619' to 7,633'
MASP	2,531 psi*
BHP (psi / ppg):	3,408 psi / 8.6 ppg
BHT:	150º F
Hole Angle:	17º
Lat/Long @ top perforation:	Lat: 28° 31' 34.02" N Long: 90° 36' 18.11" W

***MASP = (Formation Pressure) – (Gas Gradient) (TVD_{Sand})**
MASP = (8.6*0.052*7619) – (0.115*7619) = 2531 psi

Pre-Job Requirements

- Conduct & Document pre-well intervention operations and safety meeting per BOEM regulations.
- A Well Control Drill shall be performed at least once per week with each crew as per BOEM requirements, and recorded on the IADC Report.
- NPDES Discharge Data Report must be sent in weekly with the Morning Daily Reports.
- Ensure rig sign with Operator's name, OCS-G number and well are in place.
- Ensure approvals have been received before initiating any well work.
- Test BOP's every **7 days** as per BOEMRE regulations.

Recompletion Procedure:

1. Mobilize the Seahawk 2602 MODU to the ST 172 "C" platform. Shut in producing wells. Jack up, rig up and prepare to intervene on Well #C003.

2. Open tree valves and record SITP (if any). Check the 2⅞" x 7" annulus for pressure and bleed off same, filling with seawater:

3. R/U pump and lines to the 2⅞" tubing and attempt to establish injection. Bullhead 9.5 ppg $CaCl_2$ down the tubing for 2 tubing volumes (including the casing volume below the production packer) to kill the "C11b" Sand production zone.

4. Monitor the 2⅞" x 7" annulus for pressure while injecting down the tubing.

5. Close SCSSV and set blanking plug in Cameron hanger profile. Test the blanking plug to 1,000 psi for 5 minutes. N/D tree and confirm landing thread's size and type.

   NOTE: Have Cameron representative on location to prep hanger hold downs for backout while production tree is off. Visually inspect condition of tubing head.

6. Install 2⅜" x 3 ½" variable bore rams in both upper and lower ram bonnets. N/U 13⅝" 10M BOP stack. Test BOP's and related equipment to 250/5,000 psi as per BOEMRE regulations on 2⅞" tubing and 3 ½" drillpipe.

7. Remove blanking plug. Dress rig floor to pull 2⅞" tubing. Make up landing joints into hanger.

   NOTE: Have 8rd thread protectors (w/ closed end) sourced and at rig for pulling tubing.

   NOTE: Test tubing for NORM on location prior to shipping to shore.

   NOTE: Have slickline on location to jet cut tubing in the event that the production tubing seals cannot be pulled free of packer.

8. Back out hanger hold down pins, take overpull and pull tubing out of production packer.

9. PU and pull tubing to rig floor. Close Hydril and bullhead all annular fluids into the formation, displacing the annulus and tubing with 9.5 ppg $CaCl_2$. Monitor wellbore for

losses and spot pill above the production packer if necessary. POOH and lay down 2⅞", 6.5#, N-80, 8rd production tubing, control line, safety valve and all accessories.

10. Pick up Backer SC-1 packer retrieving tool and TIH picking up 3 ½", 13.3#, S-135, IF drillpipe to the top of the packer at ± 7,700' MD.

11. Latch packer, pick up and pull free. POOH racking back workstring and L/D Baker SC-1 packer.

12. M/U 6⅛" bit and scraper for 7" 26# casing. TIH on 3 ½" drillpipe to the top of the second production packer at ± 7,970' MD. Circulate the wellbore clean and POOH with bit and casing scraper.

13. M/U and RIH with EZSV retainer for 7", 26# casing on 3 ½" drillpipe to ± 7,967' MD.

14. Set retainer and test backside to 1,000 psi for 5 minutes. Establish injection rates into the "C11b" formation. Sting out and mix and pump 8 bbls of Class H (47 ft^3, 50sks, 1.07 ft^3/sk) cement plus additives and displace to within 10 bbls of the end of the workstring. Sting back in and squeeze cement beneath the retainer, into the perforations, permanently abandoning the "C11b" sand, leaving a 86 ft cement plug from 7,967' to 8,053' MD.

15. Sting out of the retainer and reverse out 1 ½" workstring volumes. POOH with workstring and EZSV stinger.

16. R/U electric line unit and lubricator on BOP's and test to 500 psi. M/U 2 ft of 3⅜" OD (4 SFP) E-Line perforating guns and RIH to top of EZSV at ± 7,967' MD. P/U and perforate from 7,964' to 7,966' MD. POOH.

17. Pressure up and confirm guns have fired by establishing injection into the wellbore. M/U EZSV for 7", 26# casing on electric line setting tool and RIH and set at ± 7,959' MD. POOH and R/D electric line.

18. M/U stinger for 7" EZSV and RIH on 3 ½" drillpipe. Sting into EZSV, test backside to 1,000 psi for 5 minutes. Establish injection rates into the perforations. Sting out and mix and pump 17 bbls of Class H (93 ft^3, 100 sks, 1.07 ft^3/sk) cement plus additives and displace to within 10 bbls of the stinger. Sting back into the retainer and squeeze cement beneath for a remedial block squeeze..

19. Sting out of the retainer and reverse out 1 ½" workstring volumes. Circulate and filter 9.5 ppg $CaCl_2$ completion fluid and POOH with workstring and L/D stinger.

20. Close blind rams and pressure test the 7" casing to 4,000 psi for 30 minutes on chart.

21. N/D BOP's and remove existing National 6" 5M x 10" 5M tubing head and replace with Cameron 7 1⁄16" 5M x 11" 5M tubing head. Test void to 3,115 psi (50% of the collapse rating of the 7", 26#, P-110 Production Casing).

22. N/U 13⅝" 10M BOP's stack. Set test plug and test break to 5,000 psi.

23. M/U **15'** x 4⅝" OD, 12 SPF perforating guns on TCP assembly.

24. TIH, closing fas-fill valve to establish 1,000 psi underbalance to the "***C11a"*** Sand using an estimated ***BHP of 3,408 psi (8.6 ppg EMW) @ 7,940' TVD***.

25. TIH, tag EZSV and position gun on depth. Set packer and test backside to 1,000 psi. R/U control head and choke manifold. Test surface equipment to 5,000 psi.

26. With choke closed, drop bar and perforate the ***"C11a" Sand interval 7,940' to 7,955' MD.*** Record SIDPP for 30 mins.

27. Cycle Omni valve to circulate position and reverse circulate 2 DP volumes or as needed to circulate out any gas influx. Cycle valve to well test position and monitor for fluid loss down DP.

28. Confirm losses with Arena's office prior to reducing fluid weight or spotting HEC pill.

29. Open packer bypass and reverse out a minimum of 2 DP volumes. Monitor well for fluid loss. With well stable, unseat packer and monitor for fluid loss.

30. POOH above perforations and monitor well for 15 mins.

31. POOH with TCP assembly. Download gauge data and e-mail to Arena's office for review.

32. Pick up and TIH with ***"C11a"*** gravel pack assembly.

33. Hold safety meeting with rig crew. Lightly dope pin end only with paintbrush while tripping workstring. Use same breaks on trips. Rabbit DP while tripping in hole at ***<u>90 sec per stand</u>***. Care should be taken to pick up and set down on slips as lightly as possible to prevent assembly from jarring. Before entering perforations, record pick up and slack off weights. Tag EZSV retainer @ ***7,959' MD.*** Pick up and space out gravel pack assembly at neutral weight with workstring pups spaced out when connection is 2'-3' above rotary table where service tool is in the weight down position.

34. If fill is encountered on bottom, POOH.

35. Hold pre-job safety meeting between Company rep., rig crew, and service companies. Discuss rigging up, sequence of pumping events and potential hazards of high pressure pumping. Test all lines to 8,000 psi.

36. Set gravel pack packer at ±***7,886' MD***.

37. Rig up service company pump equipment and lines. Include Safety Pop-off Valve in lines for all high rate/pressure-pumping applications.

38. Verify P-max calculations with gravel pack tool supervisor. Test lines to **8,000 psi**. Set Work String Pop-offs @ **7,000 psi**. Note: Set Casing Pop-offs @ **3,500 psi**.

39. Position tool in reverse position and pump the following pickle treatment:

- 110 gals Pipescrub + 500 gals 15% Fe Acid

40. Pump acid to within 5-10 bbls of crossover port and reverse out same, capturing returned volume for disposal.

41. Place tool in circulating position and establish circulation rates, recording all rates, volumes and pressures:

Pump Rate (BPM):	DPP (psi)	CP (psi)
0.5		
1.0		
2.0		

42. Place tool in weight down, circulating position with choke closed and establish injection rates into formation, recording all rates, volumes, and pressures.

Pump Rate (BPM):	DPP (psi)	CP (psi)
0.5		
1.0		
2.0		

43. Perform Reverse Test..

44. Place crossover tool in reverse position and spot acid treatment to within 5 bbls of x-over.

a.	750 gals of 10% HCl + additives
b.	Displace acid with ***9.5 ppg*** $\boldsymbol{CaCl_2}$.

45. Shift tool to squeeze position and squeeze acid into perforations @ 0.5-1.0 BPM. If break-back does not immediately occur and/or LCM had been spotted previously, allow acid to soak for 10 minutes after pumping ½ of acid volume. Increase rate as break back occurs.

46. With tool in weight down, circulating position with choke closed, perform Step Rate Test with completion fluid, holding each rate for 2 minutes:

Rate (BPM)	Time (mins)	Stage Volume (BBLS)	DPP (psi)	CP (psi)
1.0	2	2		
2.0	2	4		
4.0	2	8		
6.0	2	12		
8.0	2	16		
TOTALS		42		

47. Place crossover tool in reverse position and the following slurry treatment to within 10 bbls of x-over. Shift tool to squeeze position. Pump the slurry schedule at **8 BPM:**

a.	38 bbls of 1.5 PPA completion fluid **(9.5 ppg $CaCl_2$)** containing 2,400 lbs of 30/50 econo-prop (designed for 50 #/ft sand in perforations)

48. Displace with filtered completion fluid until a substantial pressure increase of 1,000-1,500 psi over ***final*** injection pressure. If sand out is not observed, begin reducing rate and taking returns as per the ***Slowdown Schedule*** listed below:

bbls of Slurry on Formation	**Pump Rate and Returns (BPM)**
20	4 BPM (50% sand on formation) w/ no returns
28	Reduce rate to 2 BPM w/ no returns
32	Pump at 2 BPM w/ 1 BPM returns
36	Pump at 2 BPM w/ 2 BPM returns
38	Shutdown

49. Allow pressure to bleed-off into the formation.

50. Place at least 500 psi on annulus (Pumping Supervisor to confirm Delta P due to hydrostatic), place tool in reverse position and immediately begin reversing out any excess sand from the tubing.

51. Reverse 2 additional tubing volumes to ensure tubing is clear.

52. PU to dump seals. If no drag observed while picking up to reverse position, confirm re-stressing pack with Arena's office!

53. Prior to pumping a top out job, seals will be dumped to assure tool is not dragging inside of pack. If required, pump additional sand batches as per Arena's instructions to achieve annular pack.

54. Pull service tool out of packer slowly closing flapper. If fluid loss is observed, be prepared to spot filtered LCM pill. POOH laying down 3 ½" DP and L/D GP service tool.

55. Pull wear bushing. R/U tongs and torque turn equipment. RIH while rabbiting 2⅞", 6.5#, 13 Cr, 95 ksi, K-Bear production tubing and tubular goods according to schematic. See attached tubing schematic for accessory placement.

56. Install safety valve testing the valve connection to **5,000** psi for 15 minutes. TIH strapping control line to tubing with control line clamps. Install tubing hanger. Make up control lines to hanger and test to **5,000** psi for 15 minutes.

57. Tag packer, test annulus to 2,000 psi and obtain space out.

58. Pull seals from packer. R/U slickline and M/U 2.25" OD gauge ring and junk basket. RIH, gauge tubing and POOH. M/U X-Test tool and RIH with tool to X-nipple at ± 7,841' MD. Set tool and test tubing to 3,000 psi. POOH and R/D slickline.

59. Displace tubing and annulus with inhibited 9.5 ppg $CaCl_2$ completion fluid. Displace tubing with nitrogen to establish a 1,000 psi underbalance to the "C11a" zone. ***Note: Use actual BHP gauge data from TCP.***

60. Land out tubing, breaking the flapper with the tubing. Run in hanger hold down pins. Pressure test annulus to **2,000** psi while monitoring pressure on tubing for possible leak.

61. Close SCSSV and bleed off displacement pressure. Set BPV and nipple down BOP's.

62. Nipple up tree. Pull BPV, equalize across and function test SCSSV. Install 2 way check and test tree to 5,000 psi with water. Pull 2 way check.

63. Unload tubing volume to rig's gas buster to confirm well is open.

64. Secure well and prepare to demobilize the Seahawk 2602.