RPSEA 1402

Ultra Deepwater Dry Tree System for Drilling and Production

Stage 2 Summary Report

H08130-G-RPT-GN-15003

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1 Introduction

RPSEA has funded work to develop a dry tree semisubmersible (DTS) that can be cost competitive with a Spar through their program "Ultra-Deepwater Dry Tree System for Drilling and Production in the Gulf of Mexico". The RPSEA program consists of 2 stages of work:

1) Stage 1: develop payload and platform configurations for two study cases. The objective is to develop the configuration and perform high level assessment in global motions, riser stroke, and constructability to support decision making to determine the concept that moves onto Stage 2.
2) Stage 2: further develop the platform configuration with a more detailed analysis and model testing of the selected concept.

This document summarizes Stage 2 work performed by Houston Offshore Engineering (HOE) using the Paired-Column Semisubmersible (PC SEMI) concept. The scope of work for Stage 2 included the following:

1) Technical coordination and project management
2) Update Basis of Design as required
3) Perform global performance analysis (motions, offsets and air gaps) to validate base case and prepare for model test correlation
4) Perform mooring analysis to validate base case and prepare for model test correlation
5) Perform stability analysis to validate base case
6) Develop hull scantling design for base case and perform preliminary global structural analysis to confirm global structural design for base case
7) Perform local structural analysis for one or two critical hull structural detail to confirm connection design
8) Prepare structural weight estimate with weight breakdown suitable to fabrication cost estimate
9) Prepare preliminary hull structural drawings to document hull scantlings
10) Perform top-tensioned riser (TTR) analysis to calculate tensioner stroke, verify riser strength, evaluate riser fatigue (preliminary fatigue analysis) and evaluate riser clashing. Address seabed arrangement and surface wellbay arrangement and perform high level riser clash to ensure global analysis is not affected.
11) Size length of stress joint and tension joint based on preliminary fatigue life at threaded connection
12) Perform high level steel catenary riser (SCR) strength and fatigue analysis for a single SCR configuration to confirm compatibility of concept with SCRs
13) Prepare preliminary drawings for wellbay arrangement, seafloor well pattern arrangement and TTR configuration
14) Prepare preliminary marine systems arrangement drawings
15) Prepare high level marine systems design philosophy

16) Perform constructability review for hull structure and topsides integration. Constructability reviews shall include inquiries to a hull fabricator and a topsides integration yard.
17) Perform high-level hull transportation analysis
18) Compare calculation results to design criteria
19) Prepare cost estimates (Class 2, +/- 30% accuracy) and level 2 schedule for preferred execution plan
20) Perform model testing as follows:
    a) Prepare test specifications for wind tunnel and wave tank testing
    b) Manage test subcontracts for wind tunnel and wave tank testing
    c) Perform test correlation for wind tunnel and wave tank testing
21) Develop hull and mooring configuration and sizing for up to two sensitivity cases
22) Develop plan for Phase II
23) Perform technology readiness review
24) Summarize results in a summary report and presentation

The deliverables defined for inclusion in the Stage 2 summary report include

- Global performance analysis results
- Mooring analysis results
- Stability analysis results
- Riser analysis results
- Hull structural analysis results and structural weight estimate
- Schedule
- Pre-service constructability review
- Summary of technology readiness review

2 Abbreviations and Definitions

ABS	-	American Bureau of Shipping
API	-	American Petroleum Institute
BOEMRE	-	Bureau of Ocean Energy Management, Regulation and Enforcement
CG	-	Center of Gravity
DTS	-	Dry Tree Semisubmersible
DNV	-	Det Norske Veritas
FPI	-	Floating Production Installation
ft	-	Feet
GoM	-	Gulf of Mexico
HOE	-	Houston Offshore Engineering
HIPPS	-	High Integrity Pressure Protection System
kips	-	1,000 lbs force
ksi	-	Kips (kilopounds) per square inch
mbopd	-	Thousand barrels oil per day
mbpd	-	Thousand barrels per day
mbwpd	-	Thousand barrels water per day
mmscfd	-	Million standard cubic feet per day
MMS	-	Minerals Management Service
MODU	-	Mobile Offshore Drilling Unit
MWL	-	Mean Water Line
psi	-	Pounds per square inch
RAO	-	Response Amplitude Operator
RPSEA	-	Research Partnership to Secure Energy for America
SCR	-	Steel Catenary Riser
SEMI	-	Semisubmersible
st	-	Short tons
TOC	-	Top of Column
TTR	-	Top Tension Riser
tvdss	-	Total vertical depth sub surface
UCF	-	Upper Column Frame
USCG	-	United States Coast Guard
VCG	-	Vertical Center of Gravity
VIM	-	Vortex-induced motion
VIV	-	Vortex-induced vibration

3 Paired Column Semisubmersible Concept Description

The semisubmersible hull form used for this work is the Paired-Column Semisubmersible developed by HOE. The hull form uses traditional semisubmersible hull components (i.e. columns and pontoons) with the columns arranged in pairs. Figure 3.0-1 compares the traditional semisubmersible hull to the Paired-Column Semisubmersible hull.

Arranging the columns in pairs de-couples traditional semisubmersible dependences such as:

- Wide column spacing for stability and narrow column spacing for deck support
- Heave natural period and pontoon width
- Pre-service draft constraints and preferred final installation draft

The hull configuration can be optimized because of the flexibility of the column arrangement, which results in:

- Improved heave motions
- Improved deck structure efficiency
- Improved hull-deck interface
- Improved motions at SCR hang-off locations

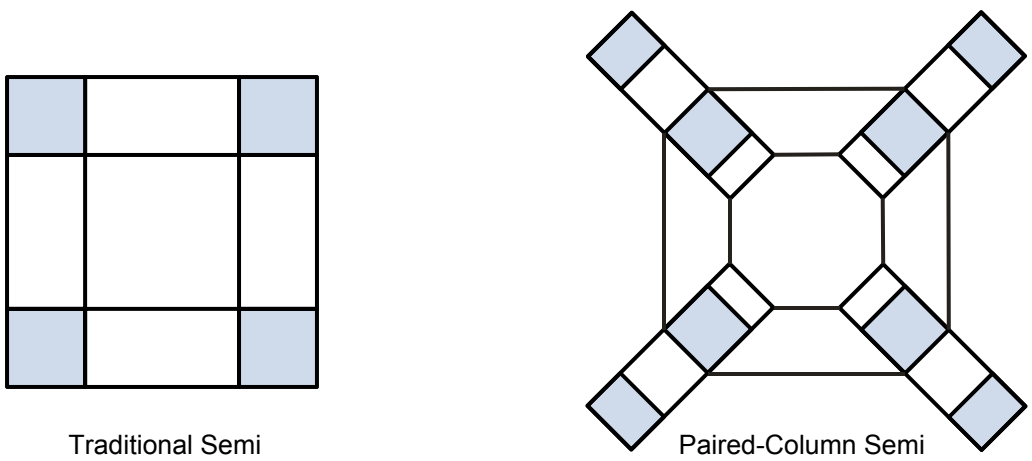

Figure 3.0-1 Comparison of Traditional Semisubmersible and Paired-Column Semisubmersible Hull Arrangement

4 Design Basis

The design basis was developed by RPSEA in conjunction with HOE and other Stage 1 participants. The design basis is summarized in Table 4.0-1.

Table 4.0-1 Summary of Design Basis Data and Criteria

	Data or Criteria		Comments
	Base Case	**Sensitivity Case**	
Water Depth	8,000 ft	8,000 ft	
Throughput	Oil: 100 mbopd Gas: 50 mmscfd Total Fluids:120 mbpd	Oil: 75 mbopd Gas: 38 mmscfd Total Fluids: 90 mbpd	
Water Injection	80 mbwpd	60 mbwpd	At 5,000 psi
Reservoir Depth	27,000 ft	27,000 ft	tvdss
Production TTR	12	9	Dual casing, 9,000 psi shut-in pressure.
Wellbay Slots	16	12	One dedicated slot for drilling riser.
Export Risers	1 oil, 1 gas, 1 spare	1 oil, 1 gas	
Satellite Well Risers	6 x 8” 5,000 psi	4 x 8” 5,000 psi	Satellite production using HIPPS
Water Injection Risers	2 x 10” 5,000 psi	1 x 10” 5,000 psi	Manifold at seafloor to serve injector wells
Umbilicals	6 x 6”	4 x 6”	
Topsides Payload	7,000 st facilities 10,000 st drilling 2,275 st tensioners	5,600 st facilities 8,000 st drilling 1,750 st tensioners	Operating weights, excludes deck steel, includes drilling fluids.
TTR Tension	11,000 st	8,400 st	Production + drilling
SCR & Umbilicals	6,000 st	3,600 st	
Dead Oil	500 st	400 st	

Other key assumptions and criteria from the design basis include the following:

- Hull is classed and must satisfy USCG and MMS, now BOEMRE, requirements
- Air gap requirement is based on a minimum air gap of 5 ft to bottom of deck steel in 100-yr hurricane conditions
- The platform must satisfy global response criteria given in Table 4.0-2
- The mooring system will be designed according to API RP-2SK and API RP-2SM for polyester systems. In addition, a 10% safety margin is applied for the polyester rope.

- Metocean conditions include hurricane, loop current, combined hurricane and loop current, winter storm and fatigue sea states. Hurricane conditions are based on API RP 2INT-MET Central Gulf criteria.

Table 4.0-2 Global Response Criteria

Response	Conditions with Safety Criteria B	Conditions with Safety Criteria A
Combined Pitch & Roll (single amplitude)	10 degrees (intact)	4 degrees (intact)
Horizontal Acceleration (at top deck, single amplitude, includes gravitational component due to pitch & roll)	0.35 g	0.15 g
Max. Offset – Intact	5% of water depth	
Max. Offset – Damaged	7% of water depth	

5 Configuration Description

The design basis was used to develop a complete platform configuration including topsides, drilling, top-tensioned risers, SCRs, umbilicals, hull and mooring. A high-level summary of these major components is presented in this section. Full details are provided for the base case and a tabular comparison summary is provided for the sensitivity case at the end of this section.

5.1 Topsides

The topsides developed for this study provide realistic layouts using data provided in the design basis. The realistic layouts are used for accurate input to global analysis in the form of wind area, wind center of pressure, deck structural weight and overall topsides weight and center of gravity.

General arrangements of the topsides layouts are provided for the base case in Appendix B and the drawing numbers are shown in Table 5.1-1. Final dimensions and weights of the topsides are summarized in Table 5.1-2.

Table 5.1-1 General Arrangement Drawing Numbers

	Drawing Number
Upper Deck - Plan	H08130-G-DWG-GN-1001-01
Mezzanine Deck – Plan	H08130-G-DWG-GN-1002-01
Lower Deck – Plan	H08130-G-DWG-GN-1003-01
Top of Columns - Plan	H08130-G-DWG-GN-1004-01
Looking East – Elevation	H08130-G-DWG-GN-1005-01
Looking South – Elevation	H08130-G-DWG-GN-1006-01

The general design philosophy for the topsides is based on providing adequate deck area for safe, maintainable, and operator-friendly facilities. The Paired-Column Semi concept provides excellent opportunities for good topsides layouts with open, 2-level decks and plenty of deck area for efficient arrangement of the drilling rig on the upper deck level.

It is not uncommon for conceptual design projects to develop initial estimates of topsides facilities and deck area that are aggressively small, which has a negative impact on project execution when design changes are required to accommodate increases in payload. The layouts developed in this study are sufficiently conservative (based on the square footages given by RPSEA) to minimize the impact of normal design development during future project phases.

In addition to deck area requirements for equipment, access and maintenance, additional area is required to accommodate top-tensioned risers. Riser spacing is determined based on surface tree spacing and riser clashing. Once the minimum riser spacing is estimated, the wellbay layout is determined based on the number of risers specified by RPSEA.

Table 5.1-2 Summary of Topsides Facility Weight Data

Item	Equipment and Bulks	
	Dry (st)	Operating (st)
Base Case		
Drilling(1)(2)	4,000	7,000
Facilities and Utilities(1)	5,120	7,168
Deck Structure(3)	5,400	5,400
Tensioners(4)	2,275	2,275
Total	**16,795**	**21,843**
Sensitivity Case		
Drilling(1)(2)	3,200	6,000
Facilities and Utilities(1)	4,120	5,768
Deck Structure(3)	4,640	4,640
Tensioners(5)	1,750	1,750
Total	**13,710**	**18,158**

Notes:
(1) Weights for drilling rig have been provided by RPSEA. A ROV has also been added to Facilities and Utilities.
(2) Drilling bulks and reserve mud on the topsides are included under equipment and bulks. Drilling does not include fluids stored in the hull.
(3) Steel weight estimated by HOE includes 15% contingency. Includes helideck weight (200 st). Does not include upper column frame.
(4) Tensioners weight includes (11) production and (1) drilling tensioners.
(5) Tensioners weight includes (9) production and (1) drilling tensioners.
(6) Weight of future topside equipment, associated deck structure and future flowline loads are assumed to be included in RPSEA payload requirement.

The general arrangement of the equipment was established based on considerations such as operability and functional requirements, environmental conditions, and safety and hazards prevention concerns. The prevailing wind direction is assumed generally from the southeast towards the northwest. The flare boom is positioned at the north side of the platform, while the living quarters and helideck are located at the south side. In general, the process equipment or hazardous equipment is located on the lower deck toward the flare-boom (north side), and the utility or non-hazardous equipment is located toward the living quarter area (south side).

The drilling rig is located on the upper most deck level in order to facilitate easy installation. Drilling support equipment (power generation, mud pumps, drilling utilities, etc.) are located in a designated location on the production deck to reduce the overall platform vertical center of gravity. The drilling crew quarters are assumed to be included in the permanent quarters. The deck layout provides space for the temporary rig crew

quarters building in the laydown areas, which can be removed when not in use. The wellheads in the center well-bay area are housed between the upper and lower decks, and are to be supported with a riser tensioner system supported from the upper column frame.

The open drain system is located below the lower deck on the north side of the wellbay. The hull pontoons will store the following fluids: drill water, brine completion fluid, diesel fuel and potable water. Methanol storage is located in the hull at the top of the northwest column.

5.1.1 Base Case Layout Description

The layout incorporates a rectangular shaped deck that has 2 levels: an upper deck (approx. 245 ft (E/W) X 217.5 ft (N/S)) with the top of deck steel at 116 ft above mean water level; and the lower deck (approx. 245 ft (E/W) X 217.5 ft (N/S)) with the top of deck steel at 66 ft above mean water level. A mezzanine area (approx. 97.5 ft (E/W) x 120 ft (N/S)) is located on the southwest side of the platform between the upper and lower decks at elevation 91 ft above mean water level. The total deck area for the platform including the mezzanine is approximately 118,275 ft^2. The separation distance between the decks is 50 ft. The production deck top of steel is equal to the top of outer hull column and 6 ft above the inner column hull.

The layout includes a 3 x 6 wellbay that provides 18 slots for 12 top-tensioned risers and 1 dedicated drilling slot. This arrangement allows a single deployment of the drilling riser to drill 12 wells for top-tensioned risers.

5.1.2 Sensitivity Case Layout Description

The layout incorporates a square shaped deck that has 2 levels, each (approx. 210 ft (E/W) X 210 ft (N/S)). The top-of-steel upper deck is at 116 ft above mean water level and the top-of-steel lower deck is at 66 ft above mean water level. A mezzanine area is not required for this case. The total deck area for the platform is approximately 88,200 ft^2. The separation distance between the decks is 50 ft. The production deck top of steel is equal to the top of steel of outer hull column and 6 ft above the inner column hull.

The layout includes a 3 x 4 wellbay that provides 12 slots for 9 top-tensioned risers and 1 dedicated drilling slot. The arrangement still allows a single deployment of the drilling riser to drill 9 wells for top-tensioned risers.

5.1.3 Topsides Structure

For a semisubmersible, the primary structure supporting the topsides is part of the global structural system including the hull and deck. Global loads on the hull are resisted by the hull structure and deck structure as a system.

For a large dry tree facility, it is common to provide an upper column support frame (UCF) as part of the basic structural system. The UCF is designed to take squeeze/pry loads from the hull.

However, the execution plan must also be considered when developing the overall conceptual design. Topsides integration by lifting multiple modules can benefit from the UCF, which provides temporary support as the modules are set.

The proposed structural system includes a large, single-piece open-truss deck structure supported by deck posts on the hull columns. The deck structure is conservatively designed to take all hull squeeze pry loads in addition to the topsides loads and riser tensions. This assumption will result in a conservative estimate of structural weight, but provides a deck with the flexibility to work with several integration options, including a quayside lift.

Basic truss row locations are indicated on the arrangement drawings (see drawing list in Table 5.1-1). These truss locations have been coordinated between various disciplines to satisfy structural framing requirements, hull column spacing, and equipment layout.

The deck structural weight is a critical component of the overall hull sizing basis. In addition, the deck structure represents an important cost item when estimating overall platform costs. A conceptual estimate was developed using in-house tools and previous project benchmarks. The important feature of these estimating tools is that the evaluation takes into account the function of the deck steel rather than applying a uniform weight per unit area to the entire deck area. In addition, the deck structural estimate takes into consideration the column span for large semisubmersibles. The span between column supports is an important and nonlinear factor when sizing truss members.

The deck structural weight estimates are shown in Table 5.1-2. This weight estimate includes primary, secondary and tertiary steel, including typical local reinforcements at lift points in the primary structure.

5.2 Riser Configuration and Payload

The top-tensioned riser configuration is shown in Figure 5.2-1. The riser top tension for 8,000 ft water depth is 2,017 kips for each production riser, based on a specified tension factor of 1.3. The drilling riser is a 21” outside diameter casing and has a specified top tension of 1,978 kips, which assumes that buoyancy elements are included to reduce the tension supported by the platform.

The total riser payload for the base case is based on 11 production risers plus 1 drilling riser and equals 11,137 st. Details regarding TTR spacing in the wellbay and at the seafloor are discussed in Section 6.3.

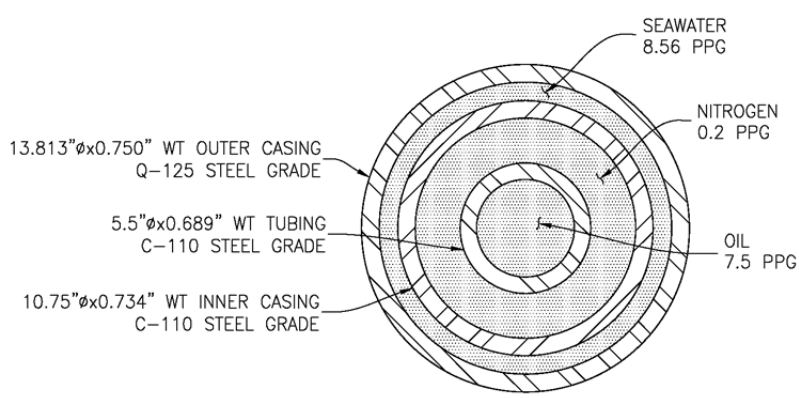

Figure 5.2-1 Top-Tension Production Riser Configuration

5.3 SCR and Umbilical Payload

The SCR and umbilical payload for the base case is summarized as follows:

- Tieback SCR: 8.625” x 0.812”, Six at 310 st each
- Water Injection SCR: 10.75” x 1.0”, Two at 490 st each
- Oil Export SCR: 18” x 1.1”, Two at 910 st each
- Gas Export SCR: 18” x 1.1”, One at 530 st each
- Umbilicals: 6.0”, Six at 120 st each
- Total Vertical Payload: 5,910 st

SCRs are hung off of riser porches attached to the pontoons. Risers carrying hydrocarbons are primarily located on the north and west pontoons and water injection risers on the east pontoon.

Umbilicals are pulled through pull tubes and the vertical tension is supported at the top of the pull tube. The pull tubes are located near inboard columns.

In general, the Paired-Column Semi concept provides ample locations to support a large number of SCRs and umbilicals and the preferred SCR hang-off location on the pontoon structure is relatively close to the center of platform pitch and roll rotation compared to traditional semisubmersible hull arrangements.

5.4 Overall Payload Summary

Table 5.4-1 gives an overall payload summary for the base case including topsides, drilling, TTRs, SCRs, umbilicals and stored fluids. Figure 5.4-1 presents the overall payload in graphical form. The total base case payload is approximately 39,000 st. Please note company reserve is included in the total topsides weight.

Table 5.4-1 Base Case Payload Summary (Sizing Basis)

Items		Base Case Payload	
Design Life	yrs	20	
Integration		Quayside	
Water Depth	ft	8,000	
Design Oil Production Rate	KBP	100	
Peak Gas Processing Rate @500 GOR	MCFD	50	
Max. Produced Water rate	KPD	40	
Max. total fluids processing rate	KPD	120	
Peak Water Injection Rate @ 5,000 PSI	KPD	80	
Number of TTRs + DR		12 + 1	
Number of SCRS: Production + Water Injection		6 + 2	
Number of Export Risers		3	
Number of Umbilicals		6	
DR Drilling Riser tension (vert. each) x O.D	DR 1	1,000 st 21" O.D.	
TTR Top Tension Riser tension (vert. each) x O.D x WT	TTR 1 thru 12	921.5 st 13.813" O.D. x .75" WT outer 10.75" O.D. x .734" WT inner 5.5" O.D. x .689" WT tubing	
Deck Dimension (estimate)	Upper Deck	245' (E/W) x 217.5' (N/S)	
	Lower Deck	245' (E/W) x 217.5' (N/S)	
Wellbay Slots		18	
Deck Height (BOS subcellar deck to TOS main deck)	ft	55'	
Deck primary+secondary steel weight	st	5,400	
		Operating Wt	Dry Weight
Facility & quarters weights	st	7,168	5,120
Drilling Weight	st	7,000	4,000
Tensioners	st	2,275	2,275
Total Topside Weight (facility+quarters+ deck+company reserve)	st	21,843	16,795
DR + TTR Vertical Loads(initial+ future)	st	11,137	
SCR+Umbilicals at Pontoon Vertical Loads(initial+ future)	st	5,910	
Dead oil storage in hull (not incl. in total system payload)	st	500	
Hull storage (not incl. in total system payload)	st	3,000	
Total System Payload (Facility+deck+Reserve+SCR's+Umbillicals, initial+future)	st	**38,890**	

Note: total riser payload for the base case is based on 11 production risers plus 1 drilling riser and equals 11,137 st

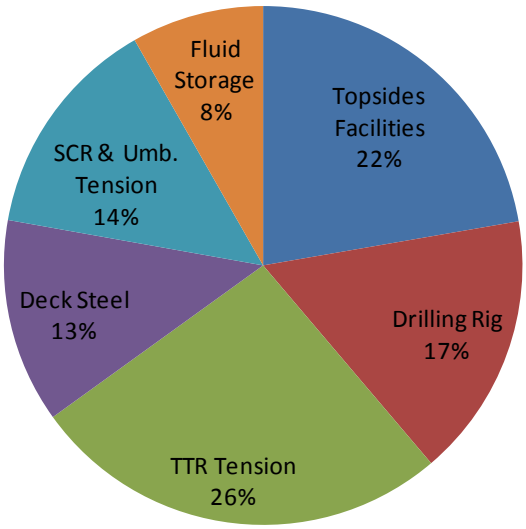

Figure 5.4-1 Base Case Payload Summary in Graphical Form

5.5 Hull Configuration

A tabular summary of the base case hull configuration is provided in Table 5.5-1. Figures 5.5-1 and 5.5-2 provide a sketch of the base case hull configuration.

The arrangement of the columns in pairs is readily apparent in the plan view in Figure 5.5-1. All of the topsides payload and TTR payload are efficiently supported off of the inner columns with minimal span (165 ft center to center). The other significant payload components are also efficiently supported by the hull: fluid storage in hull compartments and SCRs on riser porches on the pontoons. The outer columns are spaced further apart as required to meet stability requirements and to improve platform motions.

Table 5.5-1 Base Case Hull Configuration Summary

Water Depth	(ft)	8,000
Draft	(ft)	175.0
Displacement	(st)	98,579
Inner Column Span (center to center)	(ft)	165
Inner Column Size (length x width)	(ft)	44 x 32
Outer Column Size (length x width)	(ft)	44 x 42
Outer Column Height	(ft)	241.0
Pontoon width (molded)	(ft)	37.0
Pontoon height (molded)	(ft)	26.0
Deck Dimension	(ft)	245' (E/W) x 217.5' (N/S)
Deck height (BOS to TOS)	(ft)	50.0
Deck clearance from MWL	(ft)	66.0
Facilities, utilities, and drilling	(st)	15,443
Prod. Riser tension @ upper column frame	(st)	11,137
Total topsides payload	(st)	26,580
Total weight (excludes riser tension)	(st)	77,386
Vertical C.O.G from keel	(ft)	110.8
Mooring vertical load	(st)	4,143
SCR and Umbilical Vertical Load	(st)	5,910
PR and DR tensioner stiffness	(kips/ft)	20.0
Total vertical stiffness (11 PR + 1 DR)	(kips/ft)	240.0
Heave period (No Risers / All Risers)	(sec)	22.5 / 18.5
Roll period (No Risers / All Risers)	(sec)	32.5 / 35.6
Pitch period (No Risers / All Risers)	(sec)	32.3 / 35.4

Note: Total weight includes facilities, utilities, drilling, deck steel, hull steel, marine systems, stored fluids and water ballast.

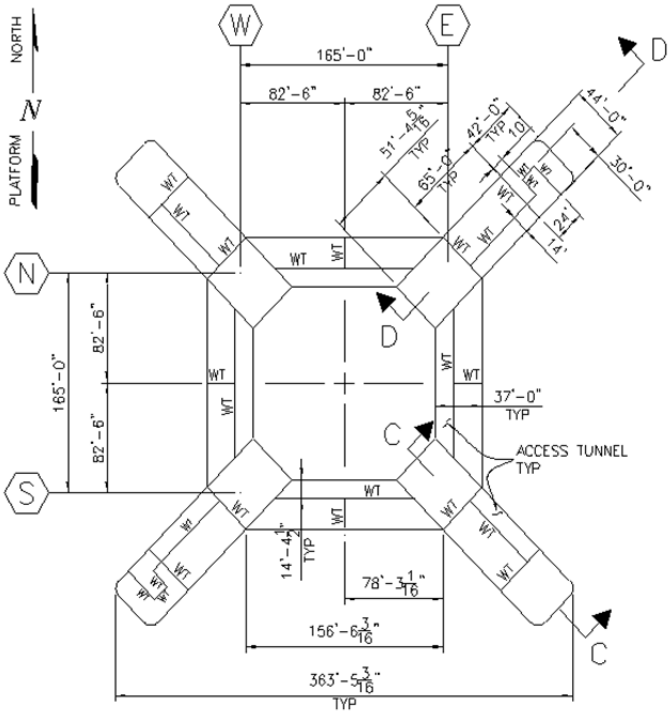

Figure 5.5-1 Base Case Hull Configuration – Plan

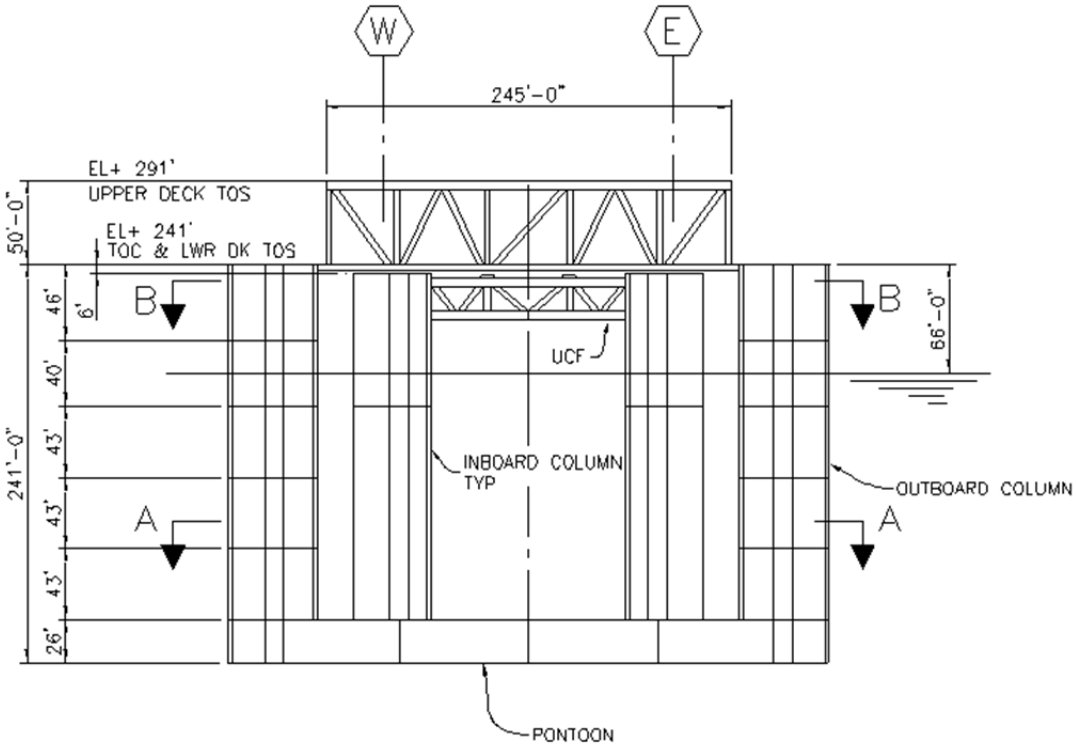

Figure 5.5-2 Base Case Hull Configuration - Elevation

5.6 Mooring Configuration

The mooring configuration is comprised of 14 mooring lines, each utilizing a chain-polyester-chain arrangement. The mooring configuration is not symmetric because of the unbalanced loads from the SCRs and umbilicals. The total unbalanced load is 440 st west and 100 st north. The unbalanced load also results in two basic mooring line sizes as summarized in Table 5.6-1. The component sizes are within the range of sizes previously delivered for Gulf of Mexico projects. In particular, the polyester rope size of 10-5/8” is the same size used for the Mad Dog spar.

Table 5.6-1 Base Case Mooring Configuration Summary

	East Lines	West Lines
Platform Chain (Chain size includes 3/8” corrosion allowance. Length is outboard of fairlead)	6-1/8” 150 ft	5-7/8” 150 ft
Polyester Rope	10-5/8” 11,800 ft	10-1/4" 11,800 ft
Ground Chain (Chain size includes 3/8” corrosion allowance.)	6-1/8” 300 ft	5-7/8” 300 ft

5.7 Sensitivity Case Configuration

A hull configuration was also developed for a sensitivity case with reduced throughput, drilling payload and riser payload. Table 5.7-1 shows the sizing basis for the sensitivity case presented in comparison to the base case. The total system payload is 30,180 st compared to the base case amount of 38,890 st.

Table 5.7-2 summarizes the sensitivity case hull configuration in comparison to the base case. The displacement reduces from 98,579 st (base case) to 89,834 st (sensitivity case). The reduced displacement is primarily achieved through reductions in column dimensions and pontoon width.

Table 5.7-2 summarizes the sensitivity case mooring configuration in comparison to the base case. The fourteen (14) mooring lines in the base case are reduced to thirteen (13) mooring lines for the sensitivity case. Four (4) of the thirteen (13) lines are located on the southeast corner. Each remaining corner has three (3) lines each.

Table 5.7-1 Sensitivity Case Payload Summary (Sizing Basis)

Items		Base Case Payload		Sensitivity Case (if different)
Design Life	yrs	20		
Integration		Quayside		
Water Depth	ft	8,000		
Design Oil Production Rate	KBP	100		75
Peak Gas Processing Rate @500 GOR	MCFD	50		38
Max. Produced Water rate	KPD	40		30
Max. total fluids processing rate	KPD	120		90
Peak Water Injection Rate @ 5,000 PSI	KPD	80		60
Number of TTRs + DR		12 + 1		9 + 1
Number of SCRS: Production + Water Injection		6 + 2		4 + 1
Number of Export Risers		3		2
Number of Umbilicals		6		4
DR Drilling Riser tension (vert. each) x O.D	DR 1	1,000 st 21" O.D.		
TTR Top Tension Riser tension (vert. each) x O.D x WT	TTR 1 thru 12	921.5 st 13.813" O.D. x .75" WT outer 10.75" O.D. x .734" WT inner 5.5" O.D. x .689" WT tubing		
Deck Dimension (estimate)	Upper Deck	245' (E/W) x 217.5' (N/S)		210' (E/W) x 210' (N/S)
	Lower Deck	245' (E/W) x 217.5' (N/S)		210' (E/W) x 210' (N/S)
Wellbay Slots		18		12
Deck Height (BOS subcellar deck to TOS main deck)	ft	55'		
Deck primary+secondary steel weight	st	5,400		4,500
		Operating Wt	Dry Weight	Operating Wt
Facility & quarters weights	st	7,168	5,120	5,768
Drilling Weight	st	7,000	4,000	6,000
Tensioners	st	2,275	2,275	1,750
Total Topside Weight (facility+quarters+ deck+company reserve)	st	21,843	16,795	18,158
DR + TTR Vertical Loads(initial+ future)	st	11,137		8,372
SCR+Umbilicals at Pontoon Vertical Loads(initial+ future)	st	5,910		3,650
Dead oil storage in hull (not incl. in total system payload)	st	500		400
Hull storage (not incl. in total system payload)	st	3,000		2,000
Total System Payload (Facility+deck+Reserve+SCR's+Umbillicals, initial+future)	st	**38,890**		**30,180**

Table 5.7-2 Sensitivity Case Hull Configuration Summary

		Base Case	Sensitivity Case (If Different)
Water Depth	(ft)	8,000	
Draft	(ft)	175.0	175.0
Displacement	(st)	98,579	89,834
Inner Column Span (center to center)	(ft)	165	
Inner Column Size (length x width)	(ft)	44 x 32	42 x 30
Outer Column Size (length x width)	(ft)	44 x 42	42 x 40
Outer Column Height	(ft)	241.0	
Pontoon width (molded)	(ft)	37.0	34.0
Pontoon height (molded)	(ft)	26.0	
Deck Dimension	(ft)	245' (E/W) x 217.5' (N/S)	210' x 210'
Deck height (BOS to TOS)	(ft)	50.0	
Deck clearance from MWL	(ft)	66.0	
Facilities, utilities, and drilling	(st)	15,443	13,518
Prod. Riser tension @ upper column frame	(st)	11,137	8,372
Total topsides payload	(st)	26,580	21,890
Deck steel weight (primary + secondary)	(st)	5,400	4,500
Upper column frame weight	(st)	3,100	2,600
Hull primary steel weight	(st)	21,350	20,496
Hull appurtenance, outfitting, mooring equip.	(st)	3,619	3,139
Hull marine systems	(st)	674	607
Hull fluids including dead oil	(st)	3,500	2,400
Water Ballast (trim plus reserve)	(st)	24,300	26,850
Total weight (excludes riser tension)	(st)	77,386	74,110
Mooring vertical load	(st)	4,143	3,698
SCR and Umbilical Vertical Load	(st)	5,910	3,650
PR and DR tensioner stiffness	(kips/ft)	20.0	20.0
Total vertical stiffness	(kips/ft)	240.0	180.0
Heave period (No Risers / All Risers)	(sec)	22.5 / 18.5	21.8 / 19.1
Roll period (No Risers / All Risers)	(sec)	32.5 / 35.6	33.6 / 36.7
Pitch period (No Risers / All Risers)	(sec)	32.3 / 35.4	33.4 / 36.5

Table 5.7-3 Base Case Mooring Configuration Summary

	Base Case		**Sensitivity Case**	
	East Lines	**West Lines**	**SE Lines**	**NE, NW, SW Lines**
Platform Chain (Chain size includes 3/8" corrosion allowance. Length is outboard of fairlead)	6-1/8" 150 ft	5-7/8" 150 ft	5-3/4" 150 ft	5-1/2" 150 ft
Polyester Rope	10-5/8" 11,800 ft	10-1/4" 11,800 ft	10-1/4" 11,800 ft	9-3/4" 11,800 ft
Ground Chain (Chain size includes 3/8" corrosion allowance.)	6-1/8" 300 ft	5-7/8" 300 ft	5-3/4" 300 ft	5-1/2" 300 ft

6 Verification Analysis

The platform configuration described in Section 5 was verified through analysis as described in this section. In particular, the following analysis was completed:

- Stability analysis
- Global performance and mooring analysis
- Model testing
- Top-tensioned riser analysis
- Hull structural analysis and structural weight estimate

The analysis defined by the Stage 2 scope of work and compared to model testing to verify the design.

6.1 Stability Analysis

The in-place stability analysis of the RPSEA SEMI for the intact and damaged conditions was performed using a VCG of 115.4 ft and a draft of 175 ft which were estimated based on weight management. In-place intact stability is checked at 100 knots wind speed and in-place damage condition is checked at 50 knots wind speed. Two conditions were considered for the transit condition:

1. Ship channel wet tow is at 40 ft draft due to the channel depth restriction. The channel area is a shuttled area, so during the wet tow in channel, intact stability check is performed at 50 knots wind speed and as a robust check, damage stability is checked at 34 knots wind speed. The VCG at 40 ft draft is 165.1 ft.
2. For transit through the open sea after the channel, the SEMI is ballasted down to 60 ft draft and wet towed. During open sea transit condition, intact stability is checked at 70 knots wind speed and damage stability at 50 knots wind speed. The VCG at 60 ft draft is 141.1 ft.

Maximum wind heeling moments at various drafts and different wind speeds were obtained from computer simulations which have been correlated with the wind tunnel test data.

Due to symmetry of the SEMI hull, the compartments only in the NE quadrant were considered for damage stability. The stability analysis results show that the intact and damage stabilities during the in-place and the wet tow conditions (explained above) meet or exceed the criteria per ABS 2008 MODU Rule. This fact is indicated in tabular form in Table 6.1-1. It is concluded from Table 6.1-1, that current hull configuration has adequate stability.

Table 6.1-1 Detailed Result Summaries

Condition	Intact/ Damage	Draft	Vcg	Wind Speed	ABS Compliance
		ft	ft	knots	
In-Place	Intact	175.0	115.4	100	Yes
In-Place	Damage	175.0	115.4	50	Yes
Wet Tow	Intact	60.0	141.1	70	Yes
Wet Tow	Damage	60.0	141.1	50	Yes
Wet Tow	Intact	40.0	165.1	50	Yes
Wet Tow	Damage	40.0	165.1	34	Yes

6.2 Global Performance

Global performance analysis was performed to compute platform motions and offsets. The analysis used the WAMIT software to compute hydrodynamic coefficients and in-house software to calculate platform response. A plot of the typical panel model used for hydrodynamic analysis is shown in Figure 6.2-1.

Surge, heave and pitch motion response amplitude operators (RAOs) are presented in Figures 6.2-2 through 6.2-4. The platform response is compared to a traditional Gulf of Mexico production semisubmersible to highlight the benefits of the Paired-Column Semisubmersible concept. The RAOs were generated for the no riser condition and the full riser condition because the stiffness of the riser system impacts the platform motion. The GoM semisubmersible RAOs is without risers as there are currently no dry tree semis in the Gulf of Mexico.

The surge motion RAO shows a clear benefit compared to a traditional semisubmersible. The peak surge response is significantly lower and the overall response is lower throughout most of the wave period range. The heave motion RAO similarly shows a benefit compared to the traditional semisubmersible in the form of a lower heave response. The heave RAO also clearly shows the impact of the TTR system stiffness on the platform response. When the TTRs are excluded from the analysis, the heave RAO approaches unity for long wave periods because the semisubmersible essentially rides the long-period waves up and down from peak to trough. With the TTRs included, the heave RAO approaches a value less than unity because of the system stiffness. The pitch motion RAO highlights the optimization available with the paired column arrangement. The configuration includes several principal dimensions (inner column spacing and size, outer column spacing and size, etc.) that can be optimized for a particular design basis. In this case, the minimum pitch response occurs at the same period as the peak wave energy for the 100-yr sea state.

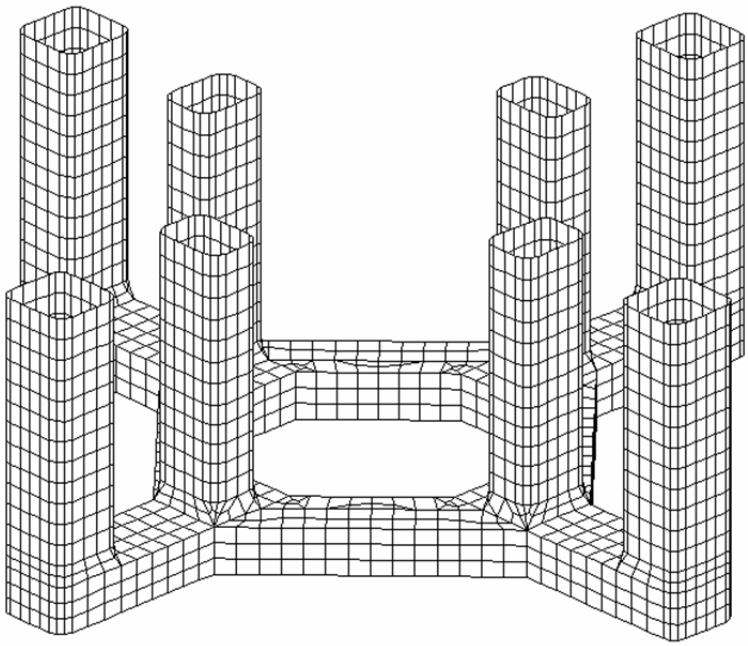

Figure 6.2-1 Panel Model for Hydrodynamic Analysis

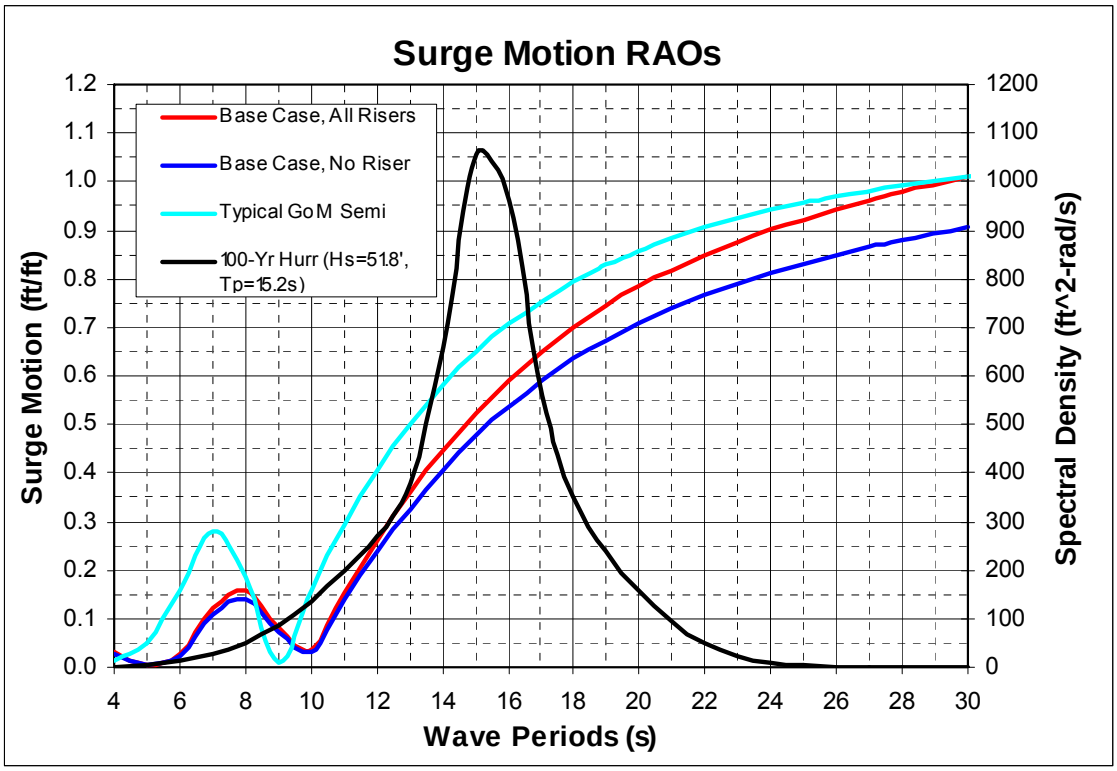

Figure 6.2-2 Surge Motion RAO for Base Case

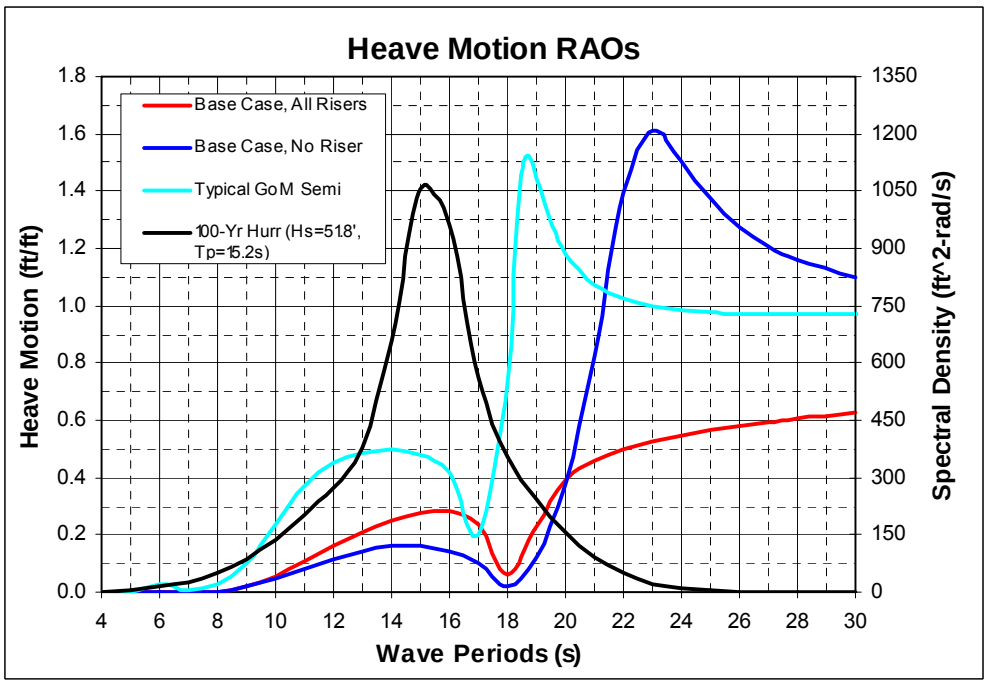

Figure 6.2-3 Heave Motion RAO for Base Case

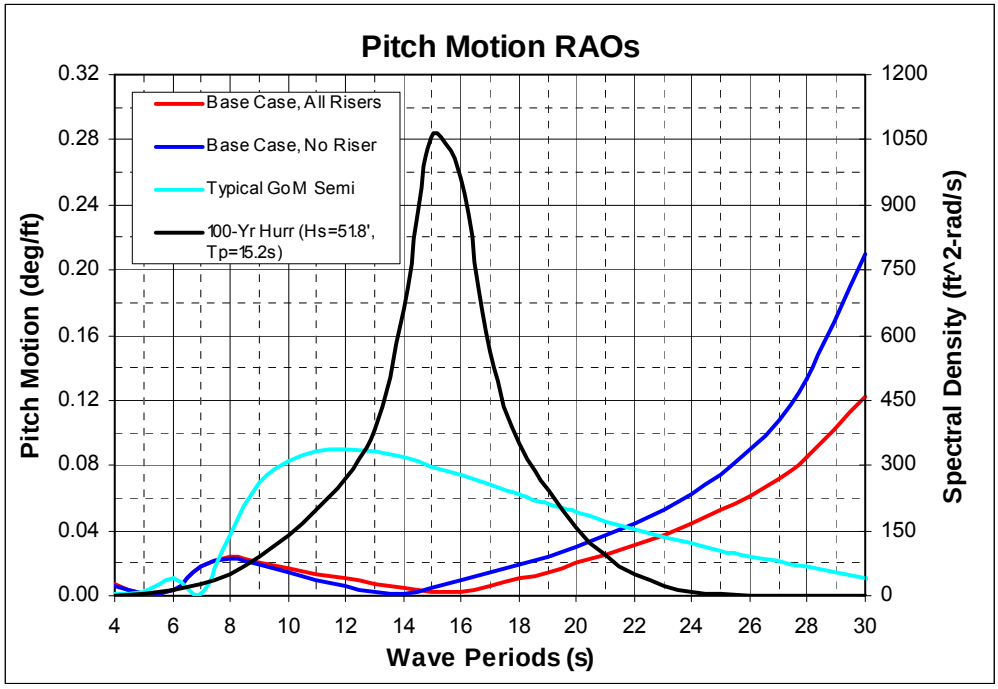

Figure 6.2-4 Pitch Motion RAO for Base Case

Wind force and moment coefficients were developed using WINDOS and a model of the specific hull and topsides configuration developed for this study. Typical force and moment coefficient plots are shown in Figures 6.2-5 and 6.2-6. The critical direction for maximum wind forces and moments is 135 degrees and the center of pressure for this direction is 130 ft above the mean water level. The WINDOS results were used in the global performance analysis for offsets, motions, etc.

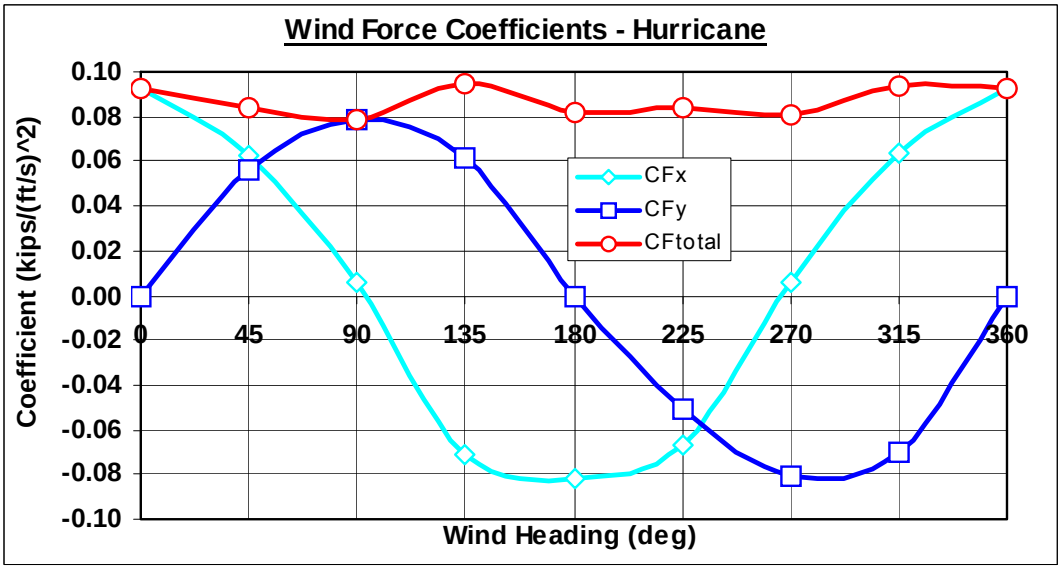

Figure 6.2-5 Wind Force Coefficients for Base Case

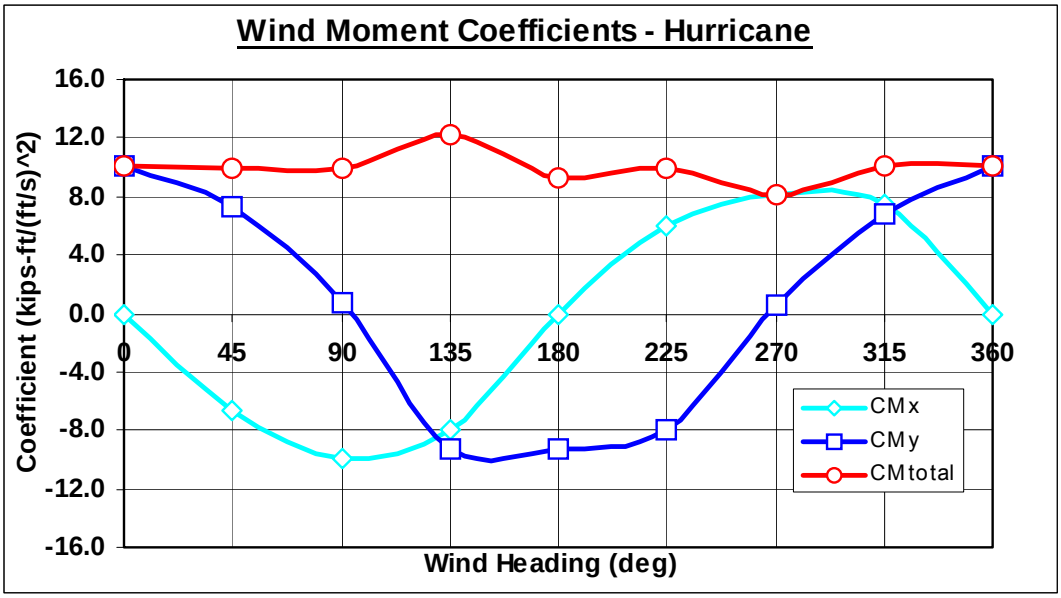

Figure 6.2-6 Wind Moment Coefficients for Base Case

For the global performance analysis, the following key considerations were made:

- Wind and current loads are based on the correlated results after the wind tunnel tests.
- In-place wave basin model test correlation results

The governing cases are summarized for the categories of “A”, “B”, “D” and “S” which are defined as:

- Category “S”: survival (1000 year return period) condition
- Category “B”: design extreme (100 year return period) condition
- Category “D”: one mooring damage condition
- Category “A”: operating condition

Major results as summarized in Table 1.4-1 are summarized as:

- **Maximum Offsets:**
  - In the survival condition, Intact, Category S: 381 ft (4.76% of water depth)
  - In the extreme condition, Intact, Category B: 243 ft (3.04% of water depth)
  - In the extreme condition, one line damaged, Category D: 334 ft (4.17% of water depth)
  - In the operating condition, Intact, Category A: 39.6 ft (0.5% of water depth)
- **Minimum Downward Motions:**
  - In the survival condition, Intact, Category S: -18.68 ft

- In the extreme condition, Intact, Category B: -11.89 ft
- In the extreme condition, one line damaged, Category D: -10.94 ft
- In the operating condition, Intact, Category A: -1.82 ft

- **Maximum Rotations:**
  - In the survival condition, Intact, Category S: 7.75 deg
  - In the extreme condition, Intact, Category B: 6.66 deg (RPSEA criteria: 8 deg)
  - In the extreme condition, one line damaged, Category D: 7.06 deg (RPSEA criteria: 8 deg)
  - In the operating condition, Intact, Category A: 2.16 deg (RPSEA criteria: 4 deg)
- **Minimum Airgaps:**
  - In the survival condition, Intact, Category S: 5.9 ft with respect to (w.r.t.) the lower deck. The gird height is 5 ft, so 10.9 ft is with respect to the top of the lower deck. RPSEA required 0.0 ft w.r.t. top of the lower deck.
  - In the extreme condition, Intact, Category B: 21.1 ft with respect to the lower deck. RPSEA required 5.0 ft w.r.t. the bottom of the lower deck. There are 16.1 ft more than that of RPSEA required.
  - In the extreme condition, one line damaged, Category D: 20.6 ft with respect to the lower deck. RPSEA required 5.0 ft w.r.t. the bottom of the lower deck. There are 15.6 ft more than that of RPSEA required.
  - In the operating condition, Intact, Category A: 55.1 ft with respect to the lower deck
- **Maximum Horizontal Accelerations:**
  - In the survival condition, Intact, Category S: 0.287g at the upper level deck
  - In the extreme condition, Intact, Category B: 0.223g at the upper level deck. RPSEA required is 0.35g.
  - In the extreme condition, one line damaged, Category D: 0.219g at the upper level deck
  - In the operating condition, Intact, Category A: 0.064g at the upper level deck. RPSEA required is 0.15g.
- **Maximum Vertical Accelerations:**
  - In the survival condition, Intact, Category S: 0.093g
  - In the extreme condition, Intact, Category B: : 0.067g
  - In the extreme condition, one line damaged, Category D: 0.063g
  - In the operating condition, Intact, Category A: 0.016g
- **Maximum TTR Strokes:**
  - In the survival condition, Intact, Category S: 31.7 ft

- In the extreme condition, Intact, Category B: 21.3 ft. RPSEA required is 25.0 ft.
- In the extreme condition, one line damaged, Category D: 20.0 ft. RPSEA required is 25.0 ft.
- In the operating condition, Intact, Category A: 3.5 ft

Table 6.2–1 Global Performance Result Summary – Initial + Future SCRs and Umbilicals

Design Parameters	Design Category	Design Data	Governed Case	Intact or Damage
Maximum Offsets	S	381.2 ft (4.76% wd)	1000-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Minimum Downward Motions	S	-18.68 ft	1000-yr hurricane, wave dominate, 180 deg, without wave spreading	Intact
Maximum Rotations	S	7.75 deg	1000-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Min. Airgap (0 to the top of lower deck)	S	10.9 ft	1000-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Maximum Horizontal Acceleration at Upper Level Deck	S	0.287g	1000-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Maximum Vertical Acceleration	S	0.093g	1000-yr hurricane, wave dominate, 180 deg, without wave spreading	Intact
Maximum TTR Strokes	S	31.7 ft	1000-yr hurricane, wave dominate, 180 deg, without wave spreading	Intact
Maximum Offsets	B	243.3 ft (3.04% wd)	100-yr hurricane, wind dominate, 135 deg, without wave spreading	Intact
Minimum Downward Motions	B	-11.89 ft	100-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Maximum Rotations	B	6.66 deg	100-yr hurricane, wind dominate, 135 deg, without wave spreading	Intact
Min. Airgap (5.0 ft w.r.t. bottom of lower deck)	B	21.1 ft	100-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Maximum Horizontal Acceleration at Upper Level Deck	B	0.223g	100-yr hurricane, wind dominate, 135 deg, without wave spreading	Intact
Maximum Vertical Acceleration	B	0.067g	100-yr hurricane, wave dominate, 180 deg, with wave spreading	Intact
Maximum TTR Strokes	B	21.3 ft	100-yr hurricane, wave dominate, 180 deg, with wave spreading	Intact
Maximum Offsets	D	333.9 ft (4.17% wd)	100-yr hurricane, wind dominate, 135 deg, without wave spreading	Damage
Minimum Downward Motions	D	-10.94 ft	100-yr hurricane, wave dominate, 135 deg, with wave spreading	Damage
Maximum Rotations	D	7.06 deg	100-yr hurricane, wind dominate, 135 deg, without wave spreading	Damage
Min. Airgap (5.0 ft w.r.t. bottom of lower deck)	D	20.6 ft	100-yr hurricane, wave dominate, 135 deg, without wave spreading	Damage
Maximum Horizontal Acceleration at Upper Level Deck	D	0.219g	100-yr hurricane, wind dominate, 135 deg, without wave spreading	Damage
Maximum Vertical Acceleration	D	0.063g	100-yr hurricane, wave dominate, 135 deg, without wave spreading	Damage
Maximum TTR Strokes	D	20.0 ft	100-yr hurricane, wave dominate, 135 deg, without wave spreading	Damage
Maximum Offsets	A	39.6 ft (0.5% wd)	10-year winter storm, 135 deg, without wave spreading	Intact
Minimum Downward Motions	A	-1.82 ft	10-year winter storm, 180 deg, without wave spreading	Intact
Maximum Rotations	A	2.16 deg	10-year winter storm, 135 deg, without wave spreading	Intact
Min. Airgap (w.r.t. bottom of lower deck)	A	55.1 ft	10-year winter storm, 135 deg, without wave spreading	Intact
Maximum Horizontal Acceleration at Upper Level Deck	A	0.064g	10-year winter storm, 180 deg, without wave spreading	Intact
Maximum Vertical Acceleration	A	0.016g	10-year winter storm, 180 deg, without wave spreading	Intact
Maximum TTR Strokes	A	3.5 ft	10-year winter storm, 135 deg, without wave spreading	Intact

Based on the highlighted results shown, brief discussions and conclusions are summarized as follows:

- The maximum rotation angles in design extreme sea states have been found to be moderately lower than the RPSEA design base requirement which exceeded the criteria
- The column freeboard has been found to be moderately higher than the RPSEA design base requirement. Even no wave spreading, 10 ft column freeboard can be cut in the future study.
- The maximum horizontal accelerations in design extreme sea states have been found to be significantly lower than the RPSEA design base requirement which exceeded the criteria
- The maximum TTR strokes in design extreme sea states have been found to be moderately lower than the RPSEA design base requirement which exceeded the criteria
- Constructability and quayside integration as well as wet tow and dry transportation will be significantly benefited by 10 ft column freeboard reduction and its compounding knockdown effects
- Overall, it has confirmed the current dry tree semisubmersible design has either met or exceeded RPSEA criteria for API central GoM environment, 8000 ft water depth, application

6.3 Mooring Analysis

The mooring system consists of fourteen (14) mooring lines, two groups of four (4) lines and two groups of three (3) lines. Chain-polyester-chain configuration is used for the mooring system. The mooring configuration is presented in Section 5.6.

The mooring analysis is directly tied to global performance analysis with emphasis on the following aspects:

- Mooring system strength checks
- Polyester rope sea bed clearance checks

Mooring fatigue analysis and mooring foundation analysis were not in the scope of work for this phase.

The mooring system consists of fourteen (14) mooring lines in four groups. These four groups are divided into two pairs. The first pair contains four (4) lines in each group and the second pair contains three (3) lines in each group. Mooring fairleads are located at 161 ft below mean water level (MWL). The mooring system groups are asymmetric due to significant unbalanced SCR and umbilical horizontal loads. The 1st - 2nd, 2nd - 3rd, 3rd - 4th and 4th - 1st mooring groups of the SEMI are 90 deg, 92.5 deg, 90 deg and 87.5 deg apart, respectively, and the mooring lines within the groups are 5 deg apart. Each mooring line consists of platform chain, polyester rope and an anchor chain.

In Table 6.3-1, the definition of categories of “A”, “B”, “D” and “S“ are defined as:

- Category “S”: survival (1000-year return period) condition
- Category “B”: design extreme (100-year return period) condition
- Category “D”: one mooring damage condition

- Category "A": operating condition

The mooring analysis results are summarized in Table 6.3-1 below.

Table 6.3–1 Mooring Analysis Result Summary

Design Parameters	Design Category	Design Loads	Min Required SOF	Min Calculated SOF	Governed Case	Intact or Damage
Maximum line tension at top of platform chain	S	2807 kips	1.00	1.76	1000-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Maximum line tension at top of polyester	S	2765 kips	1.10	1.74	1000-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Minimum line tension at bottom of polyester	S	56 kips			1000-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Maximum line tension at bottom of pile chain	S	2666 kips			1000-yr hurricane, wave dominate, 135 deg, without wave spreading	Intact
Maximum line tension at top of platform chain	B	2149 kips	1.67	2.30	100-yr hurricane, wind dominate, 135 deg	Intact
Maximum line tension at top of polyester	B	2107 kips	1.82	2.28	100-yr hurricane, wind dominate, 135 deg	Intact
Minimum line tension at bottom of polyester	B	133 kips			100-yr hurricane, wind dominate, 135 deg	Intact
Maximum line tension at bottom of pile chain	B	2008 kips			100-yr hurricane, wind dominate, 135 deg	Intact
Maximum line tension at top of platform chain	D	2540 kips	1.25	1.94	100-yr hurricane, wind dominate, 135 deg	Damaged
Maximum line tension at top of polyester	D	2498 kips	1.43	1.92	100-yr hurricane, wind dominate, 135 deg	Damaged
Minimum line tension at bottom of polyester	D	78 kips			100-yr hurricane, wind dominate, 135 deg	Damaged
Maximum line tension at bottom of pile chain	D	2399 kips			100-yr hurricane, wind dominate, 135 deg	Damaged
Maximum line tension at top of platform chain	A	1118 kips	1.67	4.41	10-yr winter storm 135 deg	Intact
Maximum line tension at top of polyester	A	1076 kips	1.82	4.46	10-yr winter storm 135 deg	Intact
Minimum line tension at bottom of polyester	A	550 kips			10-yr winter storm 135 deg	Intact
Maximum line tension at bottom of pile chain	A	977 kips			10-yr winter storm 135 deg	Intact

The mooring analysis results indicate that the mooring systems meet or exceed the design criteria specified in ABS 2009 FPI guidelines, API RP2 SK and API RP2 SM. The minimum line tensions were checked to make ensure that the polyester rope does not touch the ground. This includes the one line damaged condition.

The proposed mooring chain and polyester sizes are over-designed and can be down-sized in the next phase of study. In addition, as indicated in the Global Performance Analysis Report, the hull can be optimized significantly. Therefore the proposed mooring system is adequate for this study and can be optimized in next the phase.

6.4 Wind Tunnel Correlation

"Measured" results are taken from the wind tunnel test results and "Correlated" results are from the correlated WINDOS model. From the graphs presented in the "Measured" and "Correlated" results, good agreement was observed.

For the above water, in-place tests, wind tunnel tests have been performed for the in-place operating condition only. To obtain the correlated wind forces and moments for the in-place hurricane condition, following methodology was adopted:

1. Numerical Simulation Model is correlated with the measured data for the in-place operating rig.
2. Pipe rack and Setback is then removed from this model and simulations are run to obtain wind loads for the hurricane condition.

Measured current induced moments for the wet tow condition were corrected to remove the effects of Lift force being off center.

6.4.1 In-Place Wind and Current Loads

The in-place wind forces and moments and current forces and moments as a function of wind/current headings have been illustrated in Figures 6.3-1 to 1.2-7. From these figures, good agreements have been observed. There are a few factors which may affect the results and are summarized as follows:

- Lifting forces and the lifting force centers: In the numerical model, the lifting force center was assumed to be acting at the center. In the model tests, lifting force centers are typically slightly off center, which are difficult to locate and identify.

- Wind speed profile: It is not possible to create the perfect wind speed profile matching exactly to the profile of the API formula. There will always be some variations (Section 4.3). As long as the variations are within the specified limits, they are considered acceptable from a practical point of view. However, the deviations of wind speed profile have some effects on the measured results and should be noted. Proper corrections should be taken into account for wet tow conditions as the topsides elevations are very high.

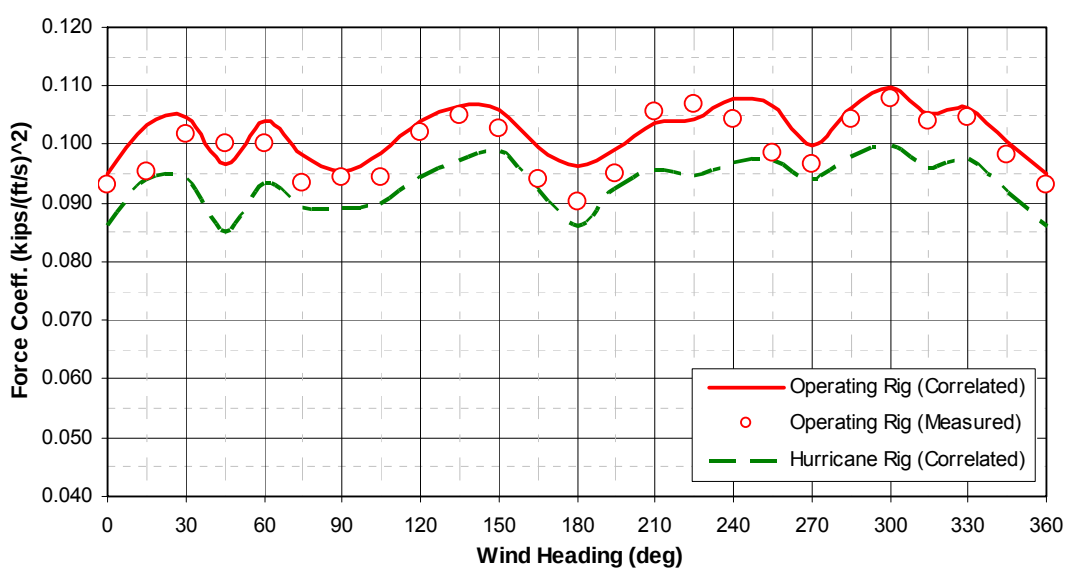

Figure 6.3-1 Wind Force Coefficients – In-Place

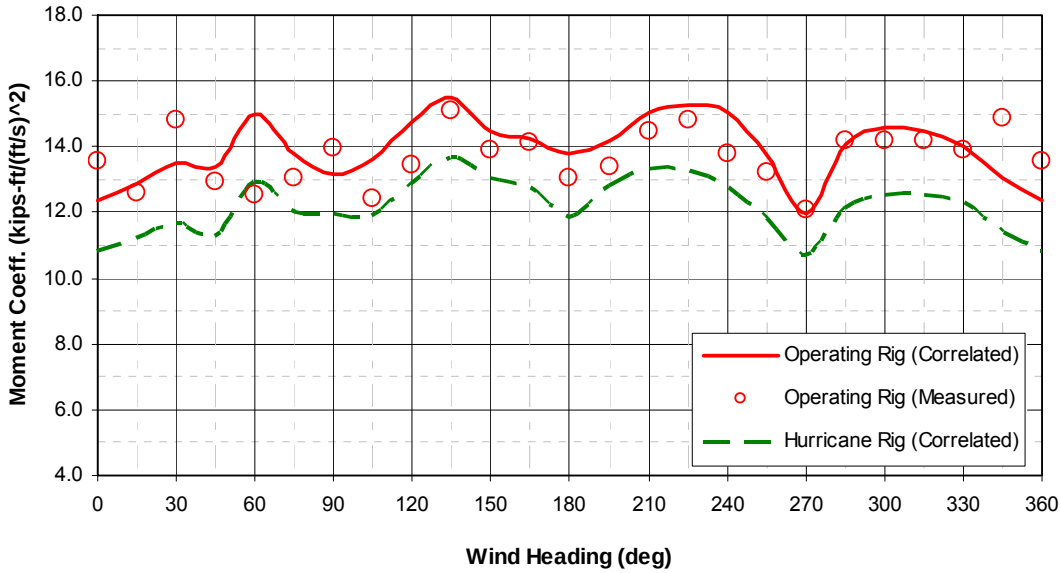

Figure 6.3-2 Wind Moment (Roll+Pitch) Coefficients – In-Place

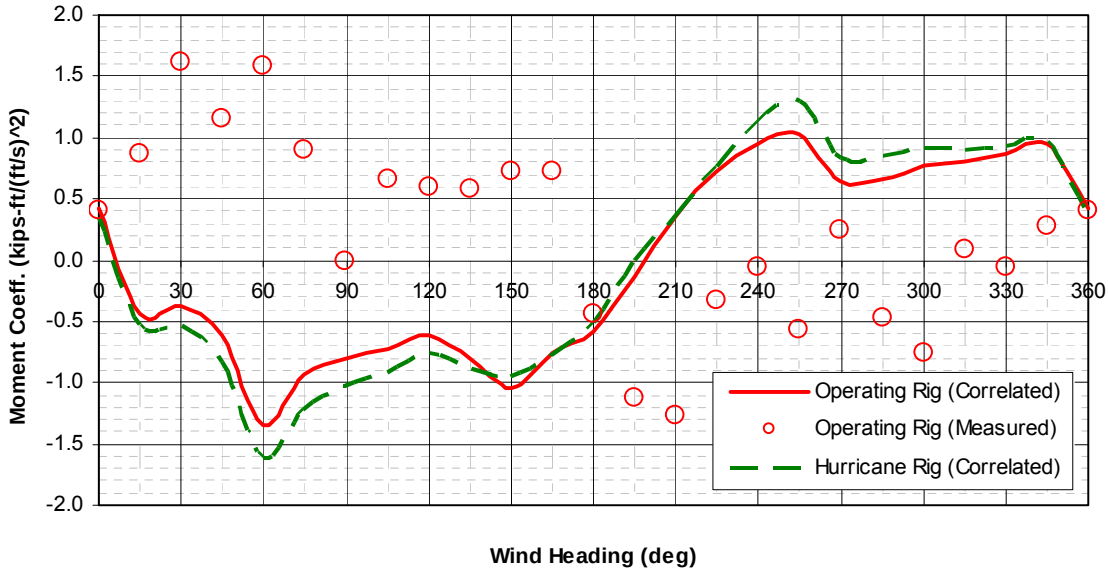

Figure 6.3-3 Wind Yaw Moment Coefficients – In-Place

Table 6.3–1 Measured and Correlated Wind Force and Moment (Roll+Pitch) Coefficients – In-Place

	Wind Force Coefficients			Wind Moment (Roll+Pitch) Coefficients		
Wind Heading	Operating Rig Correlated	Hurricane Rig Correlated	Operating Rig Measured	Operating Rig Correlated	Hurricane Rig Correlated	Operating Rig Measured
deg	kips/(ft/s)^2	kips/(ft/s)^2	kips/(ft/s)^2	kips-ft/(ft/s)^2	kips-ft/(ft/s)^3	kips-ft/(ft/s)^2
0	0.0950	0.0861	0.0932	12.39	10.82	13.56
15	0.1035	0.0941	0.0952	12.88	11.24	12.61
30	0.1045	0.0942	0.1017	13.52	11.70	14.83
45	0.0967	0.0852	0.1002	13.37	11.30	12.92
60	0.1042	0.0934	0.1002	14.98	12.91	12.53
75	0.0982	0.0894	0.0935	13.76	12.04	13.03
90	0.0954	0.0893	0.0943	13.18	11.96	13.97
105	0.0985	0.0899	0.0944	13.60	11.92	12.43
120	0.1040	0.0943	0.1020	14.75	12.87	13.44
135	0.1065	0.0973	0.1049	15.49	13.69	15.12
150	0.1059	0.0988	0.1028	14.49	13.04	13.93
165	0.0995	0.0921	0.0940	14.26	12.76	14.10
180	0.0962	0.0859	0.0901	13.81	11.83	13.06
195	0.0993	0.0926	0.0949	14.21	12.81	13.36
210	0.1037	0.0957	0.1056	15.02	13.35	14.49
225	0.1042	0.0946	0.1069	15.27	13.25	14.80
240	0.1079	0.0969	0.1042	15.07	12.77	13.77
255	0.1064	0.0972	0.0985	13.74	11.79	13.23
270	0.0997	0.0939	0.0967	11.94	10.70	12.11
285	0.1063	0.0978	0.1043	14.06	12.14	14.20
300	0.1096	0.0998	0.1080	14.60	12.53	14.17
315	0.1053	0.0960	0.1041	14.47	12.56	14.16
330	0.1062	0.0977	0.1045	14.02	12.32	13.92
345	0.1005	0.0918	0.0982	13.03	11.37	14.86

Table 6.3–2 Measured and Correlated Wind Yaw Coefficients – In-Place

	Wind Yaw Moment Coefficients		
Wind Heading	Operating Rig Correlated	Hurricane Rig Correlated	Operating Rig Measured
deg	kips-ft/(ft/s)^2	kips-ft/(ft/s)^3	kips-ft/(ft/s)^2
0	0.4179	0.3495	0.4065
15	-0.4337	-0.5409	0.8760
30	-0.3784	-0.5333	1.6208
45	-0.6170	-0.8320	1.1613
60	-1.3445	-1.6204	1.5787
75	-0.9326	-1.2215	0.9058
90	-0.8096	-1.0298	-0.0154
105	-0.7172	-0.9234	0.6564
120	-0.6077	-0.7618	0.6022
135	-0.8094	-0.8805	0.5871
150	-1.0409	-0.9404	0.7293
165	-0.7574	-0.7734	0.7243
180	-0.5876	-0.5179	-0.4357
195	-0.1404	-0.0103	-1.1264
210	0.3523	0.3665	-1.2650
225	0.7289	0.7531	-0.3297
240	0.9428	1.1272	-0.0595
255	1.0293	1.3032	-0.5678
270	0.6428	0.8357	0.2392
285	0.6540	0.8506	-0.4654
300	0.7695	0.9236	-0.7624
315	0.8019	0.8990	0.0831
330	0.8696	0.9257	-0.0569
345	0.9543	0.9703	0.2768

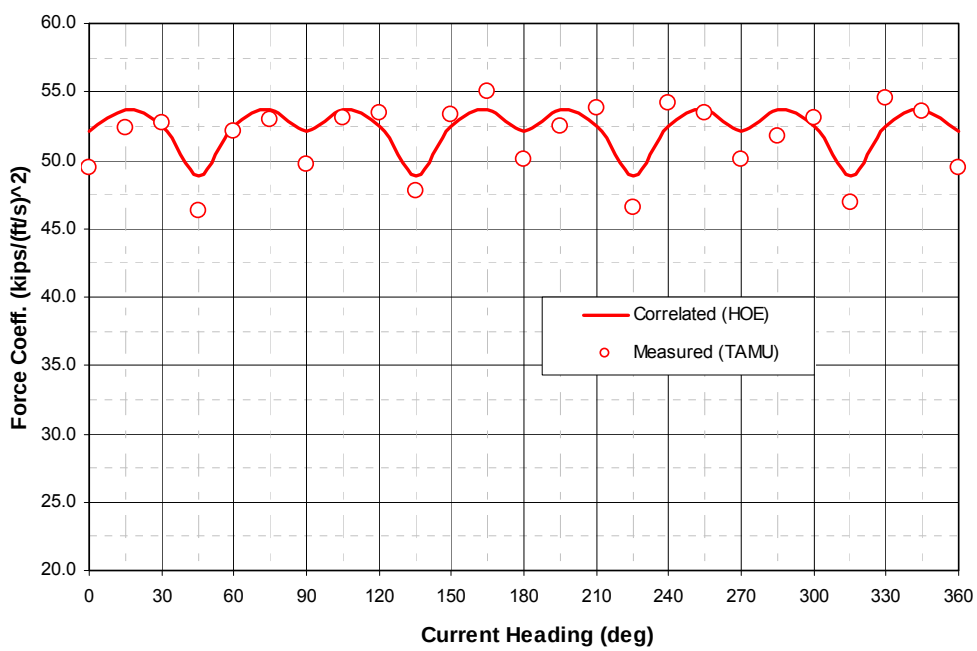

Figure 6.3-4 Current Force Coefficients – In-Place

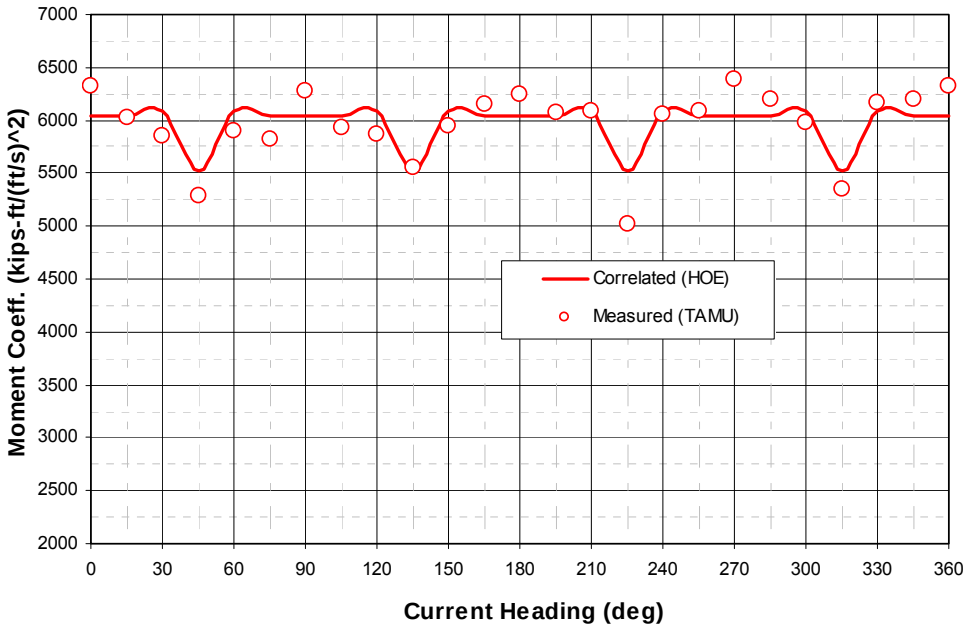

Figure 6.3-5 Current Moment (Roll+Pitch) Coefficients – In-Place

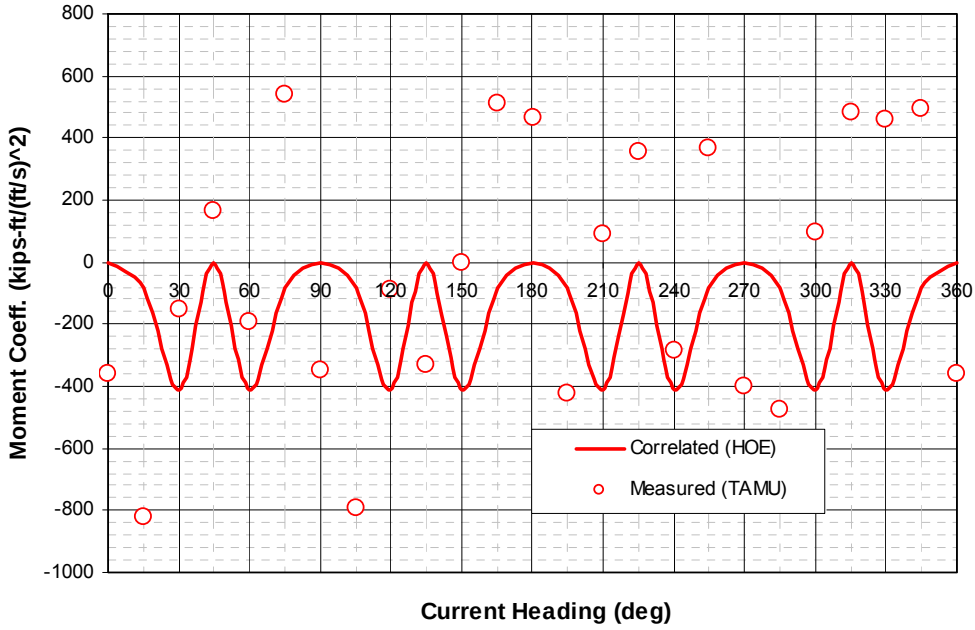

Figure 6.3-6 Current Yaw Moment Coefficients – In-Place

Table 6.3–3 Measured and Correlated Current Force and Moment Coefficients – In-Place

Current	Horizontal Force Coefficient		Roll+Pitch Moment Coeff.		Yaw Moment Coeff.	
Heading	Correlated(HOE)	Measured(TAMU)	Correlated(HOE)	Measured(TAMU)	Correlated(HOE)	Measured(TAMU)
(deg)	kips/(ft/s)^2	kips/(ft/s)^2	kips-ft/(ft/s)^2	kips-ft/(ft/s)^2	kips-ft/(ft/s)^2	kips-ft/(ft/s)^2
0	52.1	49.4	6041	6317	0.0	-360.0
15	53.7	52.4	6040	6020	-80.5	-821.5
30	52.5	52.7	6083	5856	-409.2	-154.0
45	48.9	46.3	5528	5287	0.0	166.0
60	52.5	52.1	6083	5894	-409.2	-191.0
75	53.7	53.0	6040	5813	-80.5	539.6
90	52.1	49.7	6041	6276	0.0	-348.2
105	53.7	53.0	6040	5932	-80.5	-790.0
120	52.5	53.4	6083	5872	-409.2	-90.2
135	48.9	47.8	5528	5546	0.0	-331.0
150	52.5	53.3	6083	5946	-409.2	0.2
165	53.7	55.1	6040	6155	-80.5	510.7
180	52.1	50.0	6041	6253	0.0	465.2
195	53.7	52.5	6040	6073	-80.5	-421.6
210	52.5	53.9	6083	6081	-409.2	90.5
225	48.9	46.6	5528	5013	0.0	355.9
240	52.5	54.2	6083	6063	-409.2	-287.4
255	53.7	53.5	6040	6096	-80.5	368.6
270	52.1	50.0	6041	6391	0.0	-401.4
285	53.7	51.8	6040	6197	-80.5	-475.6
300	52.5	53.0	6083	5973	-409.2	95.1
315	48.9	46.9	5528	5354	0.0	482.4
330	52.5	54.5	6083	6166	-409.2	461.7
345	53.7	53.6	6040	6203	-80.5	496.5

6.4.2 Wet Tow Wind and Current Loads

The wet tow wind forces and moments as a function of wind headings are illustrated in the Figures 6.3-7 and 6.3-12. Only even-keel conditions are considered in this section. From these figures, good agreements between measured and correlated forces have been observed. The uncertain lifting force center and wind speed profile variation on the wet tow wind and current loads are more pronounced.

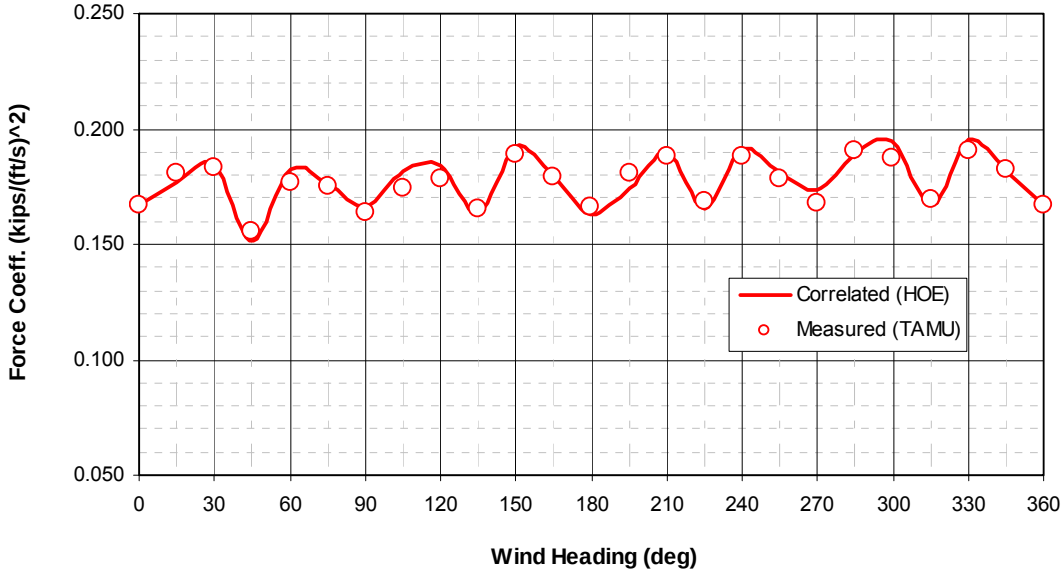

Figure 6.3-7 Wind Force Coefficients – Wet Tow Condition, Even Keel

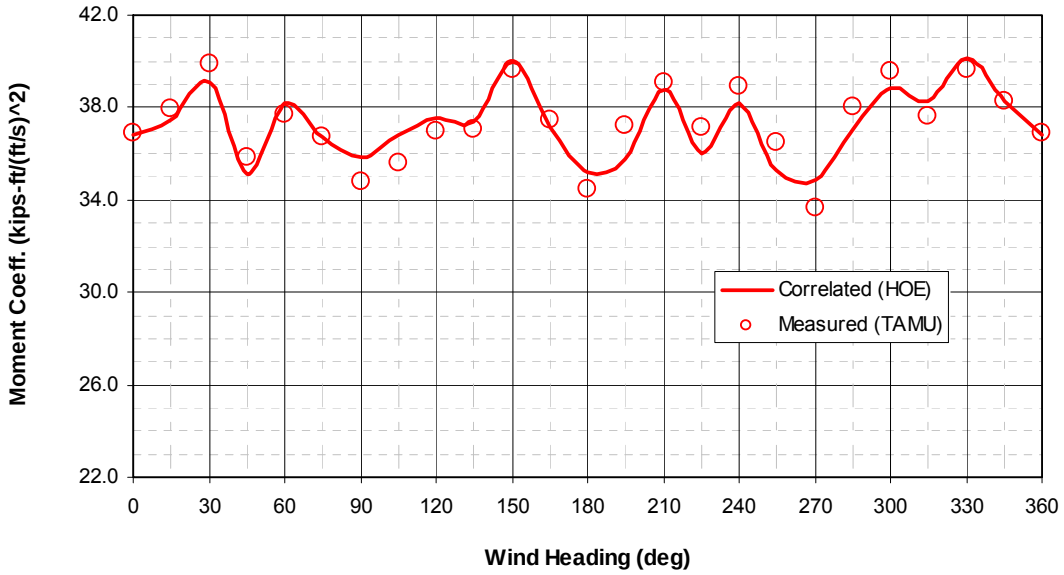

Figure 6.3-8 Wind Moment (Roll+Pitch) Coefficients – Wet Tow Condition, Even Keel

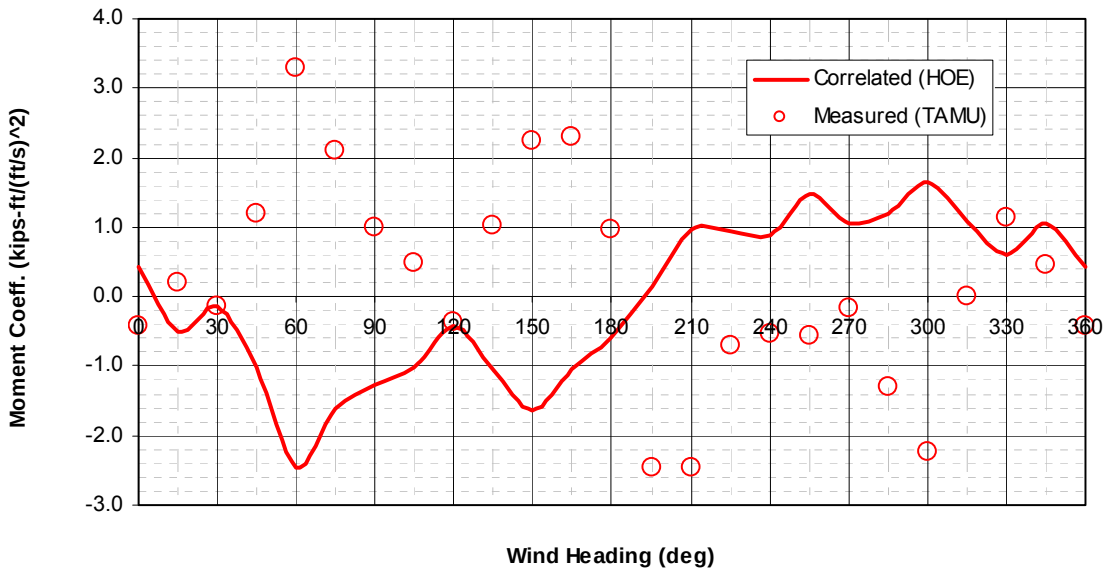

Figure 6.3-9 Wind Yaw Moment Coefficients – Wet Tow Condition, Even Keel

Table 6.3-4 Measured and Correlated Wind Force and Moment (Roll+Pitch) Coefficients – Wet Tow

	Force Coefficients		(Roll/Pitch) Moment Coefficients	
Wind Heading deg	HOE Correlated kips/(ft/s)^2	TAMU Measured kips/(ft/s)^2	HOE Correlated kips-ft/(ft/s)^2	TAMU Measured kips-ft/(ft/s)^2
0	0.1668	0.1670	36.8305	36.9179
15	0.1771	0.1806	37.4391	37.9491
30	0.1846	0.1835	39.0593	39.9084
45	0.1520	0.1559	35.1368	35.8384
60	0.1822	0.1767	38.2197	37.7110
75	0.1759	0.1750	36.7769	36.7046
90	0.1666	0.1636	35.8238	34.7867
105	0.1817	0.1748	36.8368	35.5989
120	0.1839	0.1785	37.5513	36.9635
135	0.1627	0.1651	37.3479	37.0437
150	0.1921	0.1886	39.9700	39.6175
165	0.1800	0.1793	37.1672	37.4621
180	0.1630	0.1665	35.2025	34.4895
195	0.1748	0.1813	35.7576	37.1974
210	0.1902	0.1879	38.7277	39.0595
225	0.1651	0.1686	36.0314	37.1253
240	0.1913	0.1884	38.1675	38.9050
255	0.1805	0.1784	35.2876	36.4841
270	0.1735	0.1677	34.9041	33.6416
285	0.1892	0.1908	37.0637	37.9978
300	0.1946	0.1877	38.8801	39.6104
315	0.1672	0.1698	38.2574	37.6613
330	0.1957	0.1904	40.1741	39.6124
345	0.1820	0.1827	38.2530	38.2428

Table 6.3-5 Measured and Correlated Wind Yaw Moment Coefficients – Wet Tow

	Yaw Moment Coefficients	
Wind	HOE	TAMU
Heading	Correlated	Measured
deg	kips-ft/(ft/s)^2	kips-ft/(ft/s)^2
0	0.4366	-0.4201
15	-0.5121	0.2037
30	-0.1442	-0.1287
45	-1.0163	1.2046
60	-2.4643	3.2790
75	-1.6066	2.0871
90	-1.2586	0.9921
105	-1.0120	0.4863
120	-0.4264	-0.3764
135	-1.0558	1.0150
150	-1.6283	2.2512
165	-1.0509	2.3066
180	-0.6007	0.9602
195	0.1386	-2.4542
210	0.9722	-2.4608
225	0.9276	-0.7088
240	0.8742	-0.5452
255	1.4680	-0.5521
270	1.0425	-0.1585
285	1.1960	-1.3078
300	1.6496	-2.2454
315	1.0930	0.0177
330	0.6082	1.1442
345	1.0417	0.4689

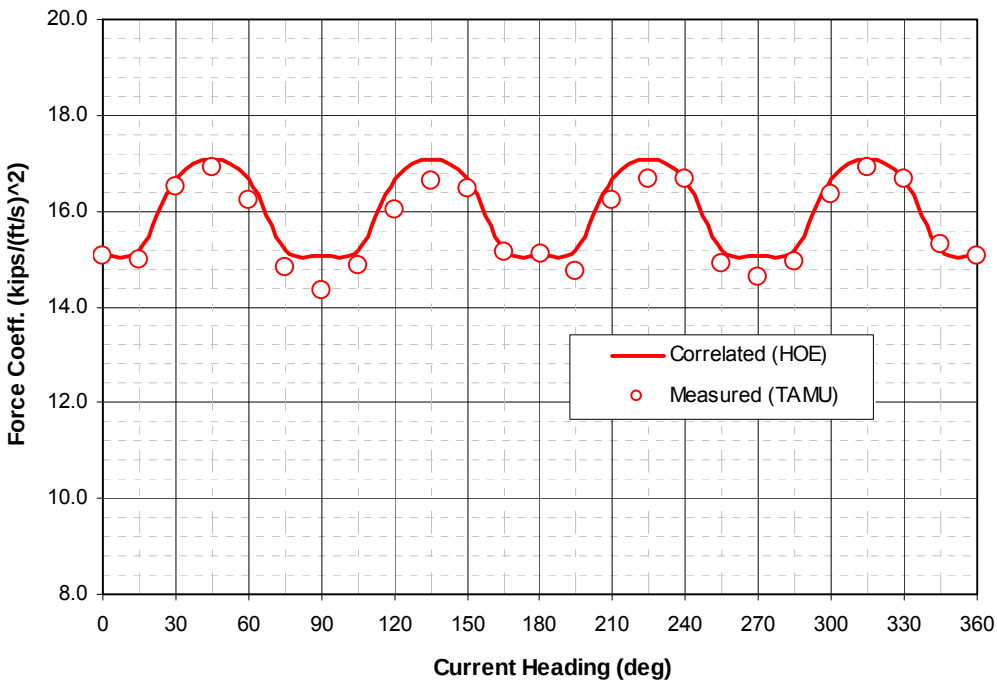

Figure 6.3-10 Current Force Coefficients – Wet Tow, Even Keel

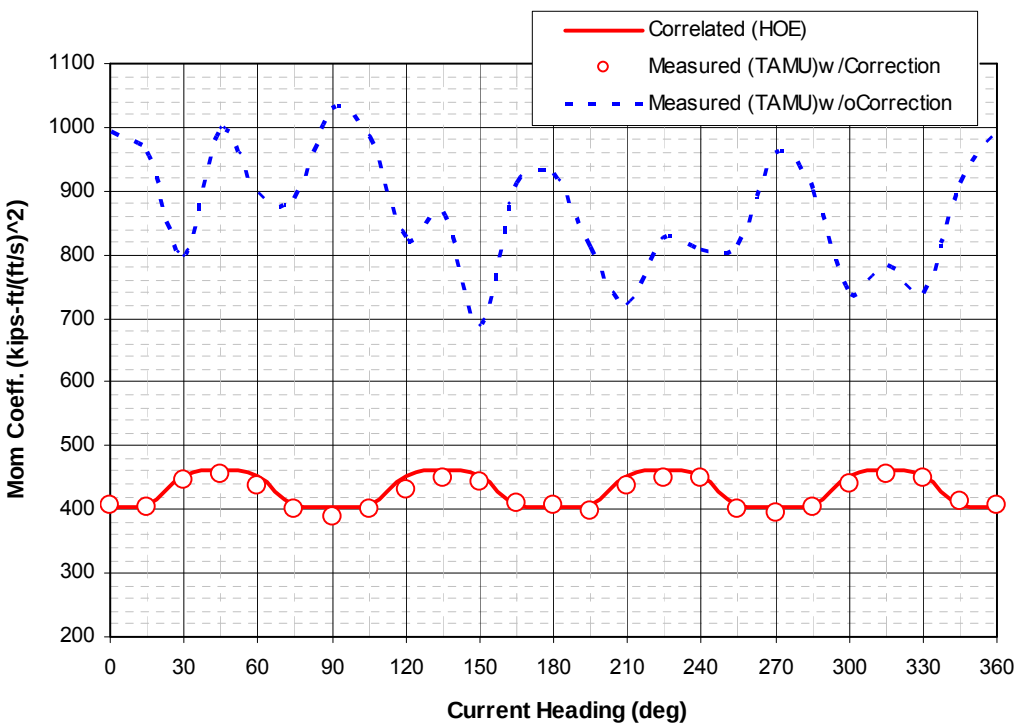

Figure 6.3-11 Current Moment (Roll+Pitch) Coefficients – Wet Tow, Even Keel

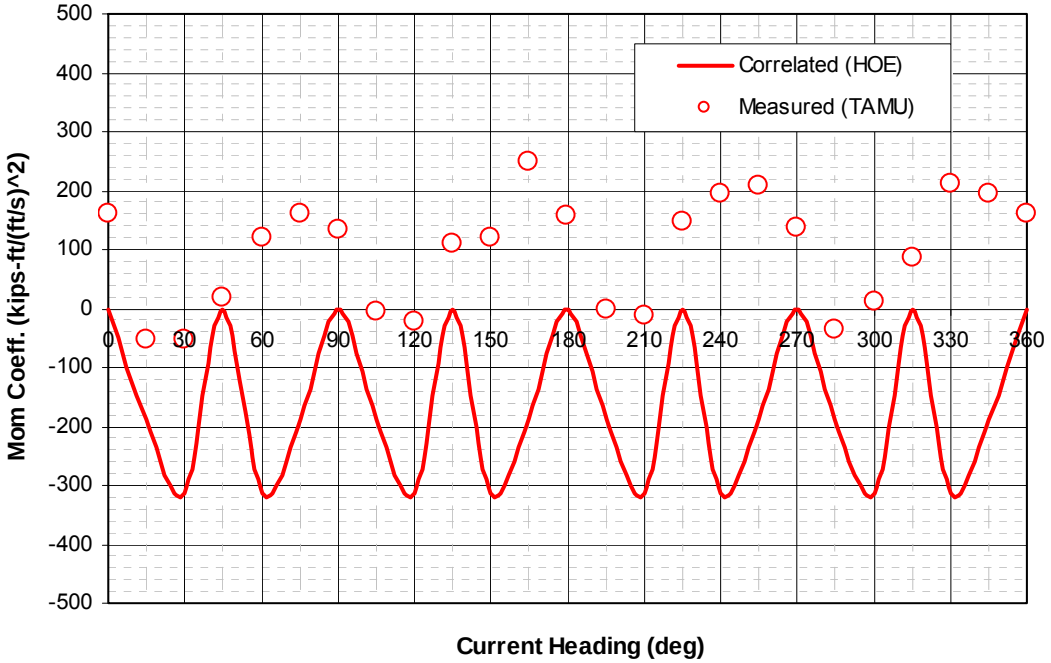

Figure 6.3-12 Current Yaw Moment Coefficients – Wet Tow, Even Keel

Table 6.3-6 Measured and Correlated Current Force and Moment Coefficients – Wet Tow

Current	Horizontal Force Coefficient		Roll+Pitch Moment Coeff.		Yaw Moment Coeff.	
Heading	HOE	TAMU	HOE	TAMU	HOE	TAMU
(deg)	kips/(ft/s)^2	kips/(ft/s)^2	kips-ft/(ft/s)^2	kips-ft/(ft/s)^2	kips-ft/(ft/s)^2	kips-ft/(ft/s)^2
0	15.1	15.1	405	407	0.0	162.1
15	15.2	15.0	408	404	-187.1	-52.2
30	16.7	16.5	451	445	-314.6	-51.0
45	17.1	16.9	462	457	0.0	19.9
60	16.7	16.2	451	438	-314.6	119.6
75	15.2	14.8	408	401	-187.1	160.6
90	15.1	14.4	405	387	0.0	133.7
105	15.2	14.9	408	401	-187.1	-4.6
120	16.7	16.0	451	432	-314.6	-23.7
135	17.1	16.6	462	449	0.0	111.4
150	16.7	16.5	451	444	-314.6	119.4
165	15.2	15.1	408	409	-187.1	248.2
180	15.1	15.1	405	407	0.0	159.0
195	15.2	14.7	408	398	-187.1	-2.9
210	16.7	16.2	451	438	-314.6	-10.9
225	17.1	16.7	462	450	0.0	147.0
240	16.7	16.7	451	450	-314.6	193.8
255	15.2	14.9	408	402	-187.1	209.5
270	15.1	14.6	405	395	0.0	135.9
285	15.2	15.0	408	404	-187.1	-35.9
300	16.7	16.3	451	441	-314.6	11.6
315	17.1	16.9	462	456	0.0	86.1
330	16.7	16.7	451	450	-314.6	213.0
345	15.2	15.3	408	413	-187.1	194.1

6.5 Wave Basin Correlation

Only in-place wave basin tests for PC SEMI were conducted in Offshore Technology Research Center (OTRC), starting in March 2010 and completing in April 2010. The model test examined the PC Semi global behavior for in-place intact conditions. The extreme sea states have been tested which are summarized as follows:

- 1000-year hurricane, wave dominant, middle Tp and unidirectional waves
- 1000-year hurricane, wave dominant, middle Tp, unidirectional waves and significant wave height with reduction factor 0.9
- 1000-year hurricane, wave dominant, middle Tp and multi-directional waves
- 100-year hurricane, wave dominant, middle Tp and unidirectional wave
- 100-year hurricane, wave dominant, middle Tp and multi-directional waves

The waves, winds and currents are non-collinear. With respect to the wave direction, the wind and current directions are at -15 deg and +15 deg away from the wave, respectively. In order to simplify the model set-up and take a slightly conservative approach, co-linear of waves, winds and currents was assumed for model tests. Two wave headings were tested: 135 and 180 degrees.

The main test objectives include:

- To confirm dry tree (DT) SEMI design for central GoM post-Katrina environment application including 1000-year hurricanes
- To confirm that the Ram Style tensioner stroke is within the design range, total stroke ≤25 ft in 100-year hurricanes (similar to a Spar)
- To confirm that the minimum airgap is sufficient, minimum airgap (to the bottom of lower deck) is larger than 5 ft in 100-year hurricanes
- To verify numerical predictions of in-place global responses, including platforms offsets, vertical motions, rotation angles, riser strokes, minimum airgaps and deck accelerations
- To quantify some of the non-linear damping forces, which are important factors for heave, roll/pitch angles, riser strokes and minimum airgaps and offset calculations
- To determine the correlation and peak response factors for the final DT SEMI design

Instead of physical winds, wind forces were simulated using a dynamic sting with the specified wind dynamic spectrum. Current forces were applied with a constant winch, instead of physical currents. All SCRs and Umbilicals were combined into an equivalent SCR, three (3) TTRs were combined into one (1) equivalent TTR, and all moorings at a corner were combined into one equivalent mooring. Wind forces and moments were obtained from the wind tunnel tests.

For all tests, the model scale is 1:76.56, which indicated TTRs, moorings and SCRs having truncations. Since OTRC has a deep basin, TTRs could have much less truncations than those of moorings and SCRs. Table 6.4-1 presents a summary of the test program.

Table 6.4-1 Summary of the DT SEMI Wave test Program

Test Descriptions	Headings deg	Unidirectional Waves	Multi-directional Waves	Remarks
Static pulling tests (6-DOF)	135 & 180	-	-	at 100-yr & 1000-yr mean offsets
6-DOF free decay tests	135 & 180	-	-	at 100-yr & 1000-yr mean
Regular waves	135 & 180	√		at 100-yr mean offset
White noises	135 & 180	√		
1000-yr hurr., wave dominant	135 & 180	√		at 1000-yr mean offset
1000-yr hurr., wave dominant	135 & 180		√	at 1000-yr mean offset
1000-yr hurr., wave dominant (0.9*Hs)	135 & 180	√		at 1000-yr mean offset
100-yr hurr., wave dominant	135 & 180	√		at 100-yr mean offset
100-yr hurr., wave dominant	135 & 180		√	at 100-yr mean offset

The test results confirmed the numerical predictions obtained in global performance analysis prior physical model tests. The maximum offsets, downward motions, maximum rotational angles, minimum airgaps, maximum horizontal and vertical accelerations and maximum TTRs strokes of the measured and predicted agreed well.

The airgap measured time series contained many water splashes. Unfortunately the wave probes cannot identify which are green waters and which are splashes. This makes it very difficult for the wave probe instruments to make corrections for the measured data. It could be very misleading to rely solely on the measured time series.

To make the measured data useful, video records were reviewed and corrections made manually for any large questionable measurements. As this phenomenon was anticipated from previous experience, two cameras were installed in pre-selected locations to monitor the two up-wave wave probes and two down-wave probes. The grades have been pre-painted on the columns near the wave probes. These videos were timed simultaneous with the measured airgap time series and can be slowed down or frozen to visually identify the highest water level. For all the 1000-year and 100-year hurricanes, manual corrections on the wave records were carefully carried out.

In addition to good agreement between the numerical predictions and wave basin testing, the following conclusions were noted:

- The maximum rotation angles in design extreme sea states have been found to be moderately lower than the RPSEA design base requirement which exceeded the criteria
- The column freeboard has been found to be moderately higher than the RPSEA design base requirement. Even no wave spreading, 10 ft column freeboard can be cut in the future study.
- The maximum horizontal accelerations in design extreme sea states have been found to be significantly lower than the RPSEA design base requirement which exceeded the criteria
- The maximum TTR strokes in design extreme sea states have been found to be moderately lower than the RPSEA design base requirement which exceeded the criteria
- Wave spreading has virtually no effect on heave motions, vertical accelerations, and maximum TTRs strokes. Wave spreading has minor reduction effects on max offsets and rotation angles; wave spreading has small (about 5%) to medium (about 10%) reduction effects on horizontal accelerations; wave spreading has significant effects on minimum airgap (significantly less than those measured in unidirectional runs).

- Overall, it has confirmed the current dry tree semisubmersible design has either met or exceeded RPSEA criteria for API central GoM environment, 8000 ft water depth, application

6.6 Top-Tensioned Riser Analysis

6.6.1 Configuration

The top-tensioned riser configuration from the mud line to the wellbay is shown in Figure 6.3-1. The riser consists of a tieback connector and stress joint at the connection to the wellhead and a tensioner with tension joint at the connection to the platform. All components of the TTR are within the range of equipment sizes and configurations previously delivered on existing floating platforms. The casing material was specified in the design basis as Q125 (yield strength = 125 ksi) which has not previously been used on existing TTRs but is currently being qualified through another technology program. More details regarding assumptions and criteria used to develop the TTR configuration are contained in the design basis which is included as Appendix A.

The tensioner stroke (25 ft), minimum stiffness (20 kips/ft) and weight (350 kips) were specified in the design basis. Other details regarding the tensioner equipment were not specified but the design is based on existing tensioner equipment. The conceptual layout of the tensioner is shown in Figure 6.3-2. The tensioner is supported at two elevations within the upper column frame spaced approximately 33 feet apart. The tensioner includes a conductor that interfaces with the rollers and hydro-pneumatic cylinders and moves with the riser. The riser tension joint interfaces with the conductor through centralizers and an interface structure for the primary tension load. This arrangement keeps the riser stroke vertical relative to the platform and takes both tension and bending within the tensioner equipment. A keel joint is not required. The tensioner system can handle the bending loads without the bending loads being transferred back to the tensioner cylinders as the bending goes into conductor component, which is of large diameter and stiff (relative to the TTRs), and is supported by rollers in the tensioner assembly. The bending is not transferred to the cylinders.

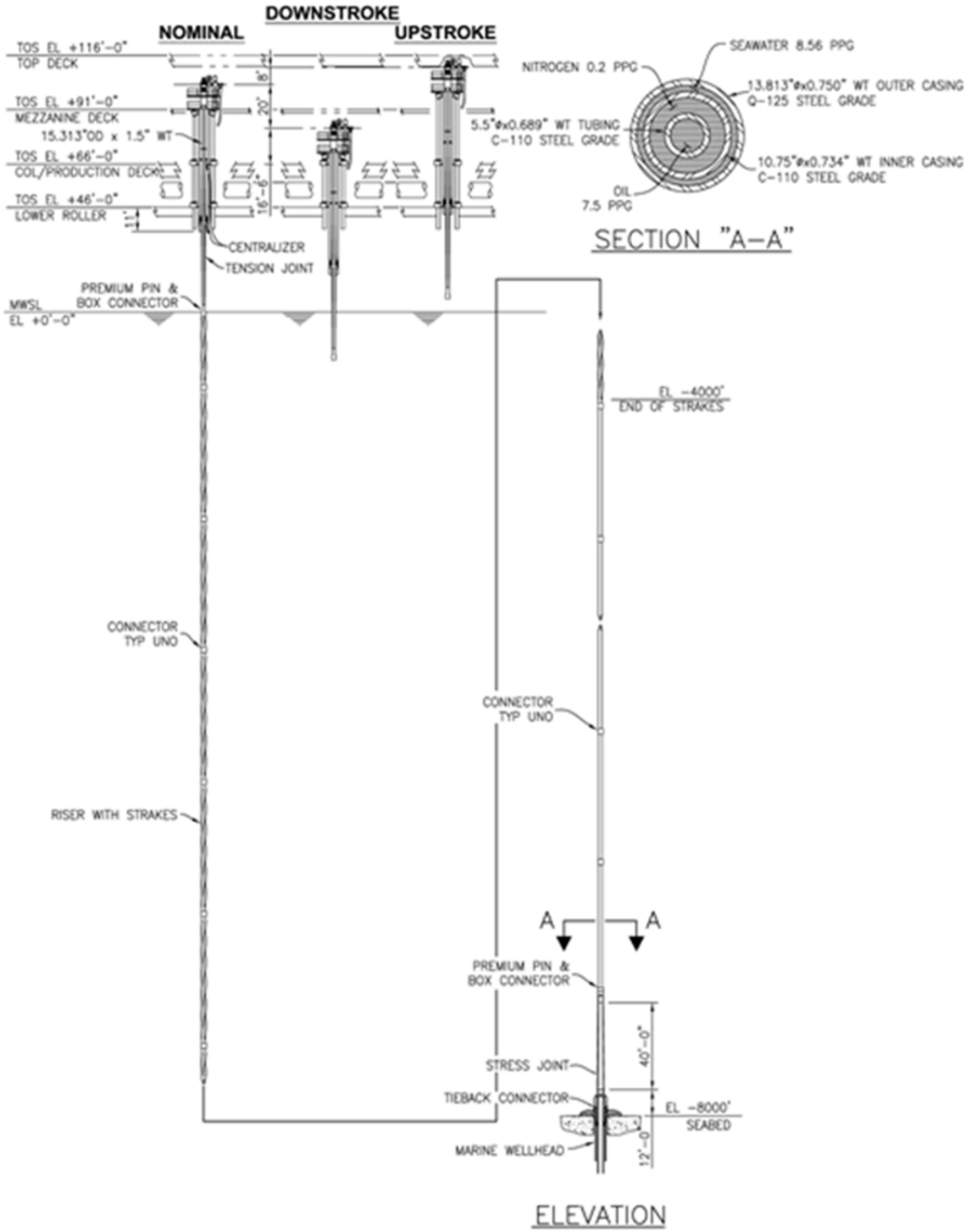

Figure 6.3-1 Top-Tensioned Riser Configuration

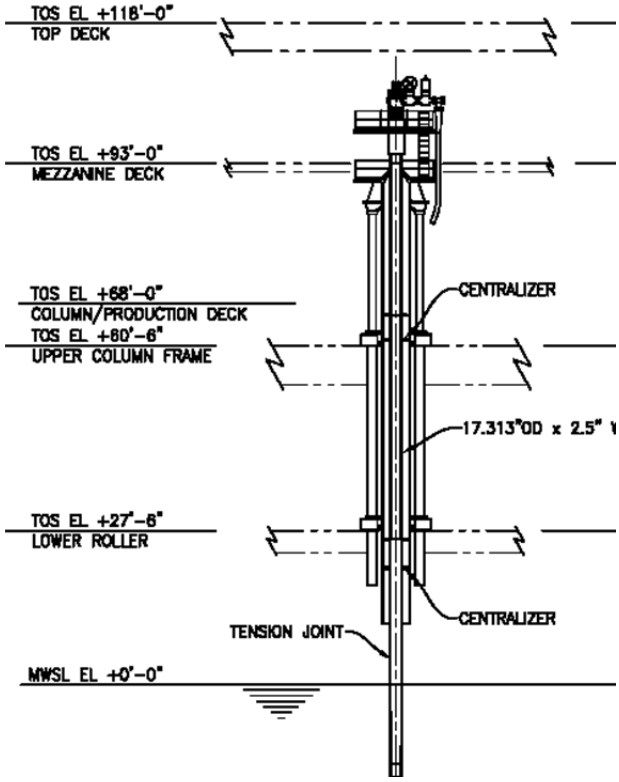

Figure 6.3-2 Conceptual Tensioner Arrangement

A conceptual study for the TTR system considered arrangements with and without the keel guide. Although the keel guide reduces the bending loads on the TTR at the tension joint, the results of the conceptual study indicated that the better arrangement in terms of functionality and cost was an arrangement without the keel guide. This arrangement eliminates the keel joint and tapered stress joint at the keel guide location. In addition, this arrangement eliminates the structures required to take the keel loads into the hull primary structure (i.e. a keel guide support frame). Another benefit is that with the proposed arrangement, there is open water between the tensioner support location above the waterline all the way down to the wellhead at the mud line. Compared to a truss spar that requires heave plates, a keel tank and multiple guides along the length of the spar hull, operations to run and retrieve risers or to move equipment through the water column will be much less complicated for the proposed semisubmersible configuration.

6.6.2 Well Pattern

TTR stroke and clashing analyses are dependent on the well pattern in the well bay and at the sea floor. The surface wellhead slots are arranged in three rows, each of which has six (6) slots, for a total of eighteen (18) slots. The minimum spacing is 15 ft on the surface and 33 ft on the seafloor. The maximum bottom splay is 40 ft. The wellhead arrangement is shown in Figure 6.3-3.

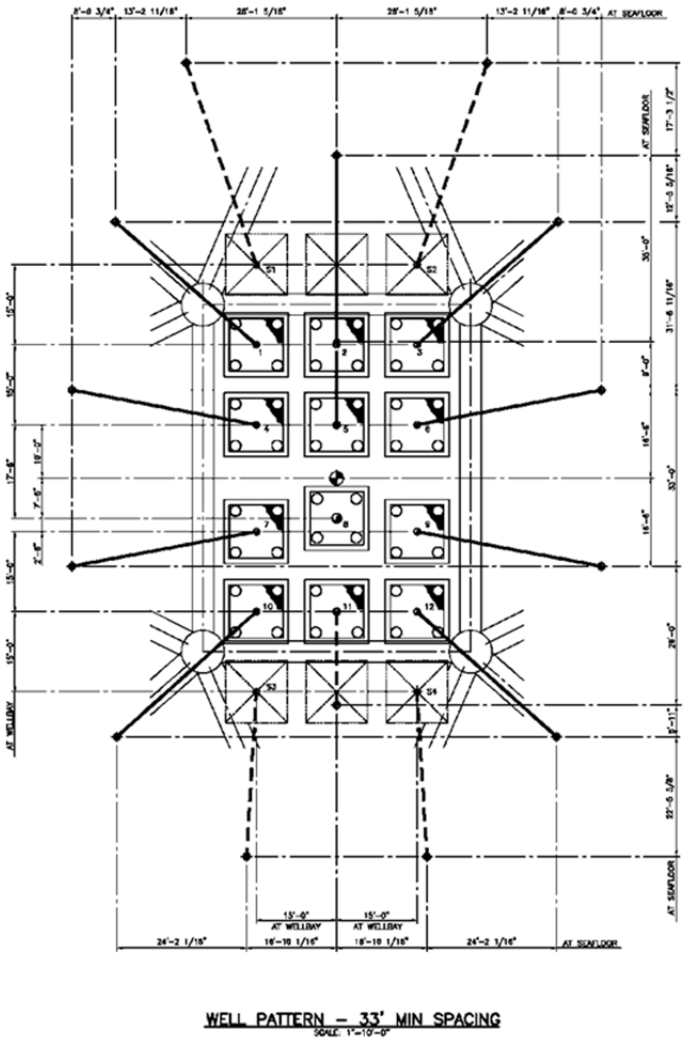

Figure 6.3-3 TTR Wellhead Arrangement

6.6.3 TTR Stroke Analysis

The riser system was analyzed using the riser dynamic finite element program Flexcom. Flexcom is the leading three-dimensional nonlinear time domain finite element program for the analysis of a wide range of compliant and rigid offshore structures. Platform motion time series were generated through global performance analysis of the coupled platform, mooring and riser system. These motions were applied to the Flexcom riser model along with the corresponding wave and current loads. The Flexcom analysis computed the dynamic motion and stress of the riser induced by the platform motions and associated wave and current loads on the riser. A typical stroke time series is shown in Figure 6.3-3.

The results of the stoke analysis indicated that a total stroke of 23 ft is required from the tensioner system (up stroke = 7.1 ft, down stroke = 15.9 ft). This stroke analysis includes the effects of thermal growth, pressure growth, tide, motions, tension variation, analysis allowance, design allowance, etc. The total stroke is

within the required limit of 25 ft. Other cases were also considered including mooring damage and TTR shut-in with leak. The calculated total stroke for shut-in with a leak is 26.7 ft.

It is important to note that the 23-ft stroke reported above was for an extreme sea state (100-yr hurricane). For the most severe operating condition, the total stroke is less than 7 ft, of which only 3.4 ft is due to platform motion. Not only does the proposed semisubmersible meet the TTR stroke limit requirements, but also the stroke during normal operating conditions is small.

For survival conditions (e.g. mooring damage), the tensioner system is designed to limit riser stroke with a hard stop. Two conditions are expected to result in contact with the hard stop: 1) 100-yr hurricane plus 1 mooring line broken (down stroke), and 2) temporary conditions during shut-in with a tubing leak resulting in excess thermal and pressure grown (up stroke). In both cases, the integrity of the riser is maintained.

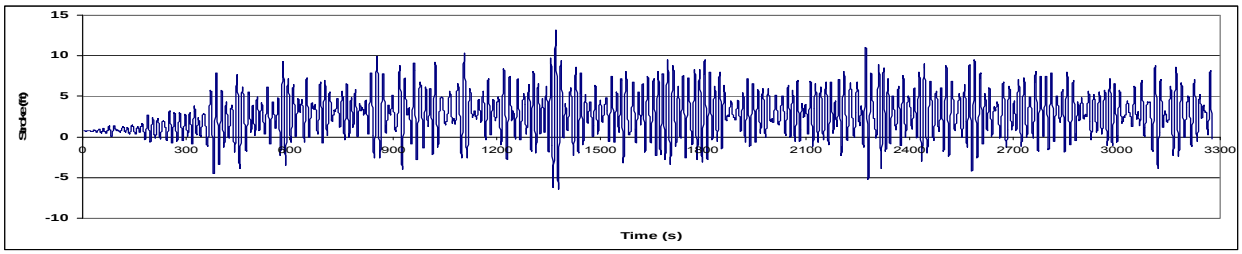

Figure 6.3-4 Typical Stroke Time Series, 100-yr Hurricane

6.6.4 TTR Preliminary Interference Analysis

Interference analysis was run for the following cases with max loop current:

- Drilling - production riser pair
- Production - production riser pair

Results present the clearance (edge to edge) from the sea floor to the riser top. A top spacing of 15 ft and a bottom spacing of 33 ft is assumed for all cases.

Table 6.3-5 TTR Interference Analysis Results

Case	Minimum Clearance	Elevation Location
Upstream drilling riser – downstream production riser	8.9 ft	6000 ft
Upstream production riser – downstream drilling riser	11.6 ft	7366 ft
Production riser – production riser	10.3 ft	7130 ft

6.6.5 TTR Strength Analysis

The strength of the TTR was confirmed using the same Flexcom analysis described in Section 6.3.3 for riser stroke. Strength analyses were performed for five (5) cases shown in the load case Table 6.3-6. The maximum stress for the stress joint, standard joint and tension joint was found in load case SI-3, while the maximum strength utilization varied between load cases SI-2 and SI-3. The stresses found in each load case were below the allowable. A typical plot of stress along the length of the TTR is shown in Figure 6.3-5.

Table 6.3-6 Riser Strength Analysis Load Case Table

Case Reference	Riser Condition (Fluid/Pressure (psi))			Design Environment	Allowable Stress Factor
	Outer Casing	Inner Casing	Tubing		
SI-1	Seawater/50	Nitrogen/50	Oil/9000	10-yr Winter Storm	1.0
SI-2	Seawater/50	Nitrogen/50	Oil/9000	100-yr Hurricane	1.2
SI-3	Seawater/50	Nitrogen/50	Oil/9000	1000-yr Hurricane	1.5
SIL-1	Seawater/50	Oil/9000	Oil/9000	10-yr Winter Storm	1.2
SIL-2	Seawater/50	Oil/9000	Oil/9000	100-yr Hurricane	1.5

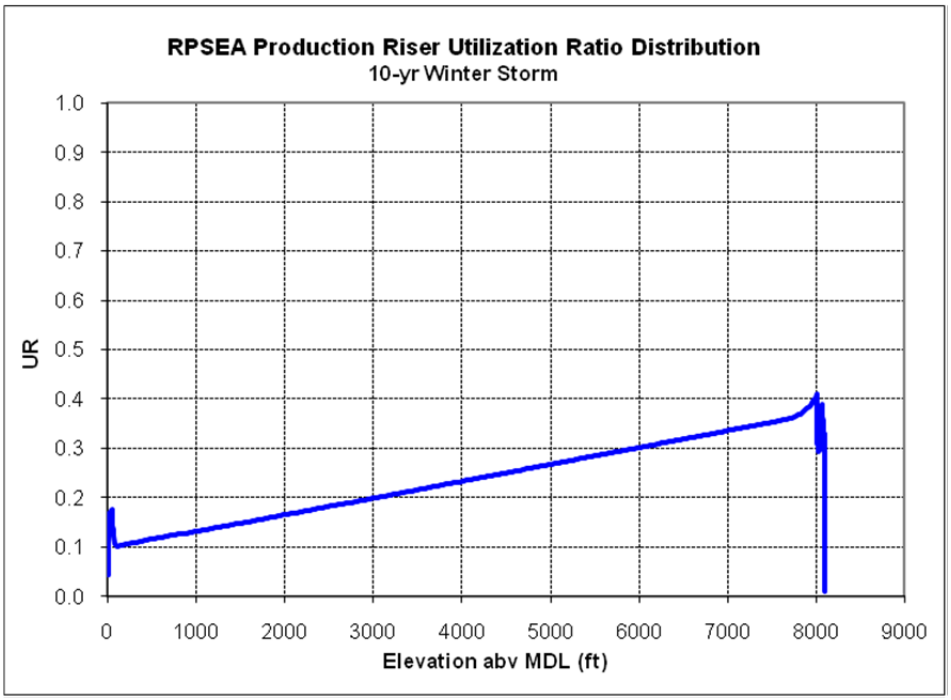

Figure 6.3-5 Typical TTR Stress Envelope

6.6.6 Wave Fatigue Analysis

Wave fatigue analysis was run for 14 fatigue bins. DNV-E curve and DNV-B1 with SCF=1.2 is used in the fatigue lift calculation. Omni-direction was assumed in the analysis.

The analysis shows the production riser has sufficient fatigue life at the stress joint top, tension joint bottom, and standard joint welding location.

6.7 Steel Catenary Riser Analysis

6.7.1 Strength Analysis

Strength analysis was run for both the 8 in tieback and the 18 in gas export SCRs. No bottom compression is present for the gas export SCR in 1000-yr hurricane condition. The results also show the tieback and gas export SCRs have adequate strength during operating, extreme and survival conditions.

6.7.2 Fatigue Analysis

The analysis results show that the tieback SCR has sufficient fatigue life at welding location. Fatigue life is 540 years and 506 years at touch down point for near and far field, respectively

6.8 Hull Structural Analysis and Structural Weight Estimate

Hull structural design is performed to verify the estimated hull weight and to further develop the conceptual design of the DTS for the hull primary structure. After the hull principal dimensions and compartmentation are determined from hull sizing and stability analysis, a preliminary hull scantling and weight is developed. This scantling design is then further verified through global finite element analysis to verify adequate strength and buckling capacity for the in-service conditions.

The scantling design was developed for the Base Case configuration (see Figure 5.5-1 & 2) and a preliminary global finite element analysis was performed. The analysis provided confirmation that the structural estimates from hull sizing and from hull scantling design are acceptable, which further confirms that the PC Semi configuration documented in this study is feasible and properly sized for offshore GoM.

The hull scantlings developed for this study include reasonable margins and contingencies appropriate to the conceptual stage of design. Typical stress hot spots at the various connections are recognized and can be solved in detailed design. Scantling design optimization should be considered by introducing more ballast storage in the outboard columns. This will relieve shear in the arms between the column pairs and relieve stresses in the tie-frame connections. However, the current scantling provides a conservative hull design and weight for this study.

6.8.1 Hull Scantling Design

The initial hull scantling design for the primary hull structure has been completed in accordance with the ABS and DNV Classification rules and guides. The scantling design tools and processes are the same as used for the world's deepest TLP, the Magnolia TLP in the Gulf of Mexico as well as SEMIs such as Nakika and the Deepwater Nautilus. The tools have also been used on projects classed by ABS and on projects classed by DNV. The scantling design process is summarized as follows:

1) Develop design head pressures for each structural component
2) Select plate thicknesses, stiffener sizes and spacing and girder sizes and spacing based on classification rules for minimum scantlings
3) Estimate total hull primary structure weight from base scantling weight using applicable allowances and contingencies appropriate for conceptual design

6.8.2 Global Structural Analysis

Global structural analysis is performed in ANSYS to confirm the initial structural scantlings by computing global finite element stresses to verify the plates, girders and stiffeners for strength and buckling. Global structural analysis includes the following steps:

1) Finite element model development
2) Control Group Selection
3) Mass calibration
4) Design wave selection
5) Load and boundary condition development
6) Finite element analysis
7) Post processing to identify controlling conditions
8) Strength and buckling checks

6.8.2.1 Finite Element Model

An integrated global structural model was utilized for this analysis. The model included a simplified deck model, along with a fine-meshed model of the hull. All shells and plates in the hull are modeled as SHELL63 elements, and all girders and stiffeners are modeled as BEAM 44 elements with appropriate sectional offsets. In general, the model contains one element for each structural panel (bounded by stiffeners and girders).

An isometric view of the model is shown in Figure 6.8-1.

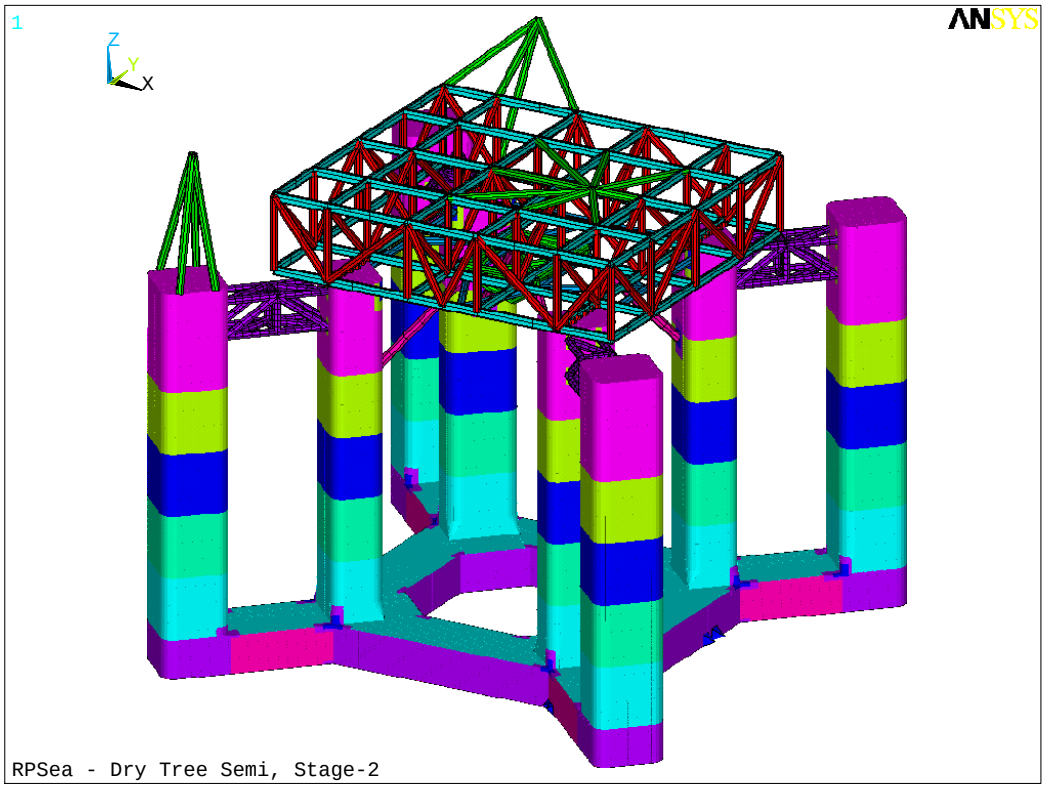

Figure 6.8-1 Isometric View of Hull Analysis model

6.8.2.2 Control Group Selection

Fifteen groups of elements are selected to facilitate stress result interpretation. The locations, throughout the hull, represent the critical areas of interest in the structure. More groups can be defined in detailed design phases. However, the 15 groups have shown to be satisfactory for conceptual design. A brief description of location with elements selection is shown in Table 6.8-1 below with an isometric view in Figure 6.8-2. Note that groups C04 and C05 represent the same location, which is the connection of the outboard column to the supporting structure (arm). Two groups are used because two different connections are modeled. Group C04 continues the column corner radius through the connection. Group C05 transitions the column corner radius to a point at the connection to the arm.

Control Group ID	Descriptions
C01	Arm side at keel & pontoon connection
C02	Arm side at top & pontoon connection
C03	Arm side at keel & OB column connection
C04	Arm side at top & OB column round conn.
C05	Arm side at top & OB column knuckle conn.
C06	Pontoon top at center inb & outb.
C07	Pontoon side at top inboard knuckle
C08	Inb column connection to top of pontoon
C09	Kneebrace connection
C10	Tie frame connection at inb. column
C11	Tie frame connection at outb. column
C12	UCF connection to inb. column
C13	Deck to inb. column connection
C14	Arm top at center and inb. Column
C15	Keel plate at knuckle arm knuckle

Table 6.8-1 Control group Location Descriptions

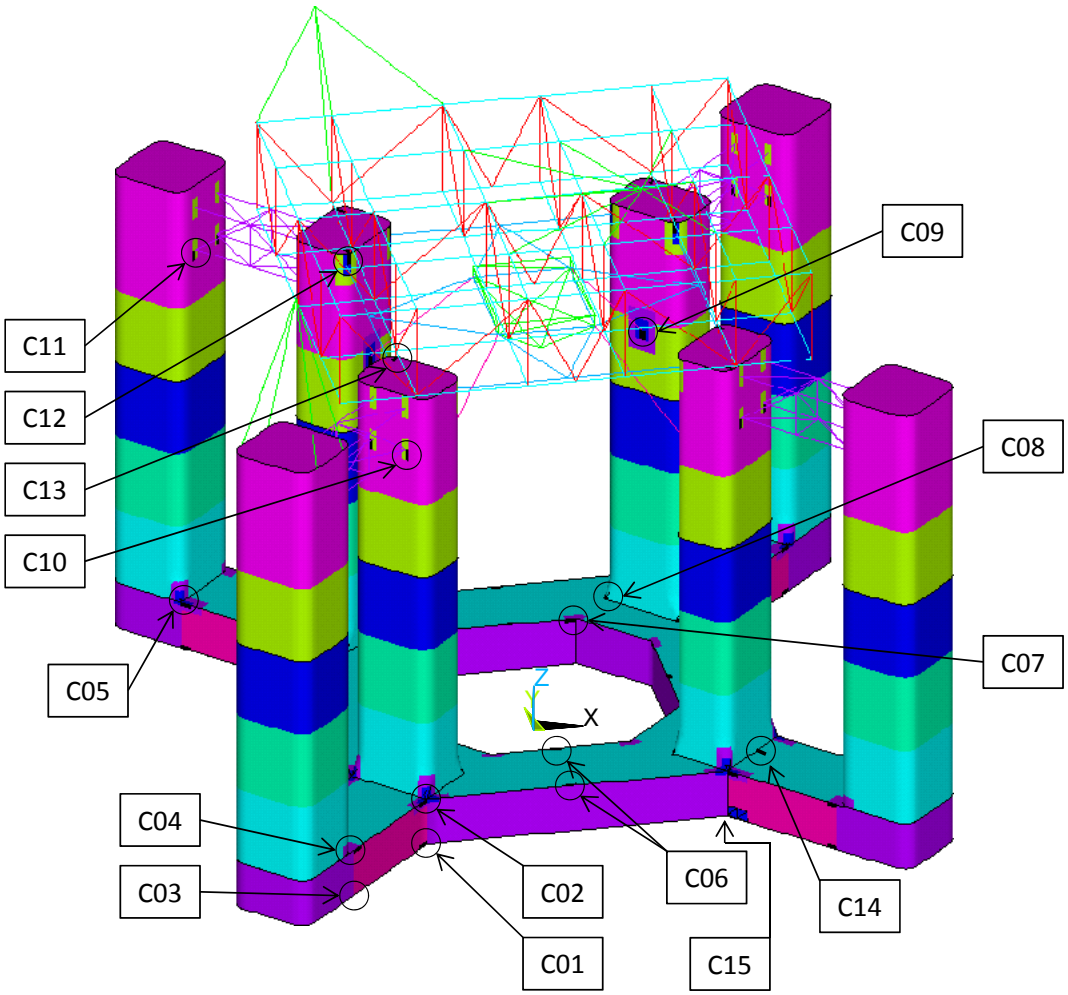

Figure 6.8-2 Control Group Identification

6.8.2.3 Mass Calibration

Mass calibration of the model was performed in ANSYS to adjust mass and CG location to match the key figures summary table and sizing basis for the specific platform configuration. Reaction forces for the static and dynamic conditions were checked and verified to be within a tolerance of 1% and 3%, respectively.

6.8.2.4 Design Wave Selection

Global structural strength analysis is performed using design waves, regular waves that are calibrated to give the same response as the extreme response determined from spectral analysis. Design waves were provided by the Global Performance group from which four design waves were selected for the hull, based on the following maximum primary loadings:

- Deck acceleration, which controls the connection of the hull to the deck

- Hull squeeze/pry forces, which control the column to arm and column to pontoon connections

Table 6.8-2 Design Waves for Global Strength Analysis

Load Case #:	Wave condition:	Regular wave height (ft):	Period: (sec)	Heading (degree)	Dominant Loading
1	1 year storm	28.6	7.0	0, 22.5 & 45º	Pry/squeeze
2	100 year hurricane	93.9	16.0	45º	Horizontal acceleration
3	100 year hurricane	100.4	18.0	0º	Horizontal acceleration
4	100 year hurricane	102.8	20.0	0º	Horizontal Acceleration

6.8.2.5 Loads and Boundary Conditions

The vertical mooring loads are applied as forces on the top of columns at the chain jack locations. For the lateral mooring constraints, 10% of the vertical mooring loads is taken and applied as spring elements at the fairlead locations.

The water plane stiffness of the SEMI is modeled as vertical springs at the keel of all columns around the column outer shell perimeter.

Hydrodynamic loads are developed by the global performance group for application to the global structural model. The wetted elements from the global structural analysis model are used directly as WAMIT panels for hydrodynamic analysis. In addition, the mass matrix from the calibrated structural model is transferred directly to WAMIT for analysis. This process ensures compatible loads and accelerations in the integrated hydrodynamic/structural analysis.

6.8.3 Analysis Results

Detailed results of the global in-place analysis are presented in the form of datasheets and corresponding ANSYS stress plots. An example Von Mises stress plot of combined (static and dynamic) stress of the keel plating is shown in Figure 6.8-3.

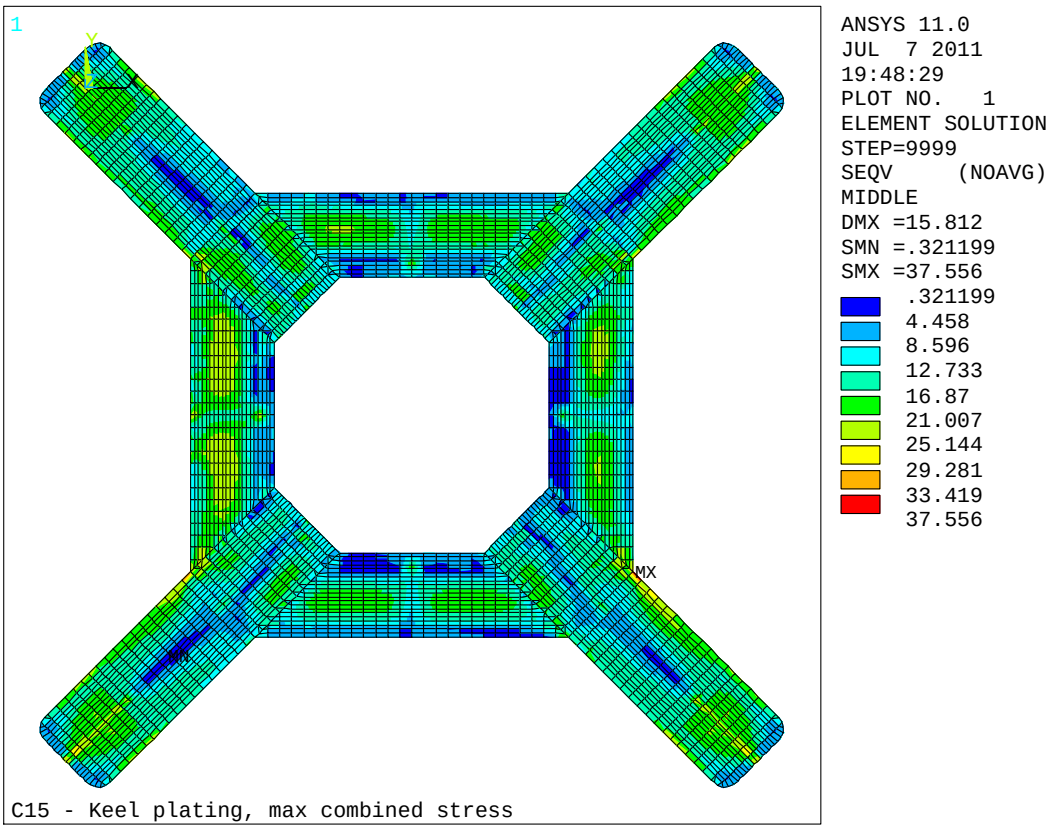

Figure 6.8-3 Plan View of Keel Plating Combined stress

All control groups resulting stresses are reviewed in detail to identify load combinations for controlling stress plots. The scan results for all control element groups are shown in Table 6.8-3 and 6.8-4 for the operating and hurricane conditions, respectively.

Table 6.8-3 Maximum Operating stresses per Control Group

Group nr.	Heading: (degree)	Wave height (m)	Period: (sec)	Element number:	node number:	Phase angle (deg):	σstatic:	σcombined:	Ratio: (σc / σs)
C01	0	28.6	7	86574	71900	-5	30.2	37.1	1.23
C02	0	28.6	7	87016	75790	-20	37.6	43.7	1.16
C03	0	28.6	7	86704	75073	-150	20.3	21.8	1.07
C04	0	28.6	7	127628	108544	135	21.4	29.2	1.36
C05	22	28.6	7	86716	75776	110	32.5	38.9	1.20
C06	0	28.6	7	41226	36556	-30	13.7	16.5	1.21
C07	0	28.6	7	122025	107512	-30	8.5	13.2	1.54
C08	22	28.6	7	67728	59702	-175	14.6	16.3	1.12
C09	22	28.6	7	154361	136993	30	20.5	23.0	1.12
C10	0	28.6	7	75873	67896	150	14.9	27.6	1.86
C11	45	28.6	7	142888	126518	10	27.5	34.8	1.27
C12	22	28.6	7	37241	33102	25	28.0	31.5	1.12
C13	0	28.6	7	35843	32238	140	27.6	36.5	1.32
C14	22	28.6	7	126136	111260	30	20.7	25.1	1.22
C15	0	28.6	7	85188	74955	-5	30.3	37.6	1.24

Table 6.8-4 Maximum Hurricane stresses per Control Group

Group nr.	Heading: (degree)	Wave height (m)	Period: (sec)	Element number:	node number:	Phase angle (deg):	σstatic:	σcombined:	Ratio: (σc / σs)
C01	45	93.9	16	86574	74955	-70	30.2	38.4	1.27
C02	0	93.9	16	86586	75658	-5	39.7	49.7	1.25
C03	0	100.4	18	86704	75073	-20	20.3	26.3	1.30
C04	0	93.9	16	87383	72962	-10	22.6	33.5	1.48
C05	45	100.4	18	6229	4471	-30	31.5	43.5	1.38
C06	0	93.9	16	41223	36387	-5	13.7	19.4	1.42
C07	22	93.9	16	81780	71930	-160	8.9	15.5	1.75
C08	0	102.8	20	67728	59702	35	14.6	19.9	1.36
C09	22	93.9	16	113970	101265	40	20.6	24.1	1.17
C10	0	93.9	16	35028	31566	-135	16.0	27.3	1.71
C11	45	93.9	16	22156	19631	-145	29.7	38.3	1.29
C12	45	102.8	20	117744	104410	100	25.7	34.7	1.35
C13	45	93.9	16	35843	32238	-115	27.6	45.4	1.65
C14	0	100.4	18	126509	111260	10	20.5	23.8	1.16
C15	45	93.9	16	85188	74955	-70	30.3	38.6	1.27

The typical allowable stress for the operating condition is 0.6Fy for component stresses and 0.7Fy for Von Mises (equivalent) stress. For the hurricane condition, the allowable stress is typically 0.8Fy for component stresses and 0.9Fy for Von Mises stress. The minimum yield strength of the hull grade steel is not yet specified but is usually 50 or 60 ksi.

All but one control group satisfy the 100-yr hurricane requirements for material grade 50 and the results of this analysis are typical for the level of detail and stage of design. The operating condition results indicate that a few locations may require grade 60 steel (e.g. C01, C05, C13 and C15). However, more refined analysis of the local reinforcements will be used to finalize the design, which may use grade 50 steel, grade 60 steel or a casting depending on the local analysis

results. All of these solutions are conventional to existing semisubmersible hull forms operating in the Gulf of Mexico.

Control group C02, located at the connection between the inboard column, the ring pontoon and the structure that supports the outboard column, is a good example of where a casting may be the best solution. However, further detailed design may confirm that this is not required.

The stresses in all other structures (i.e. pontoon and columns) are similar to values obtained on other projects prior to detailed design, indicating that more detailed analysis will confirm the overall structural design.

Control groups C04 and C05 are at the same location but a different connection is modeled at each location. The column radius at C04 extends into the top of arm/ pontoon, which resulted in a cleaner design with lower stresses. Therefore, the transition connection to a sharp corner (C05) may not be used in further detailed design. The analysis results for group C04 meet the allowable stress requirements for operating and extreme conditions using grade 50 steel and is therefore the recommended detail for this connection. Results for group C05 can be disregarded.

This global analysis captures the global structural behavior of the hull but the identified load cases and cut boundary loads can be used for local model analysis. As the hull structure is prone to fatigue damage due to the dynamic wave loading during its service life, global spectral fatigue analysis shall need to be performed in the detailed engineering phase to identify the fatigue sensitive locations. After completion of the first cycle of global fatigue analysis, it may be appropriate to include castings at the column to top of pontoon and/or column to arm connections.

6.8.4 Global Analysis Conclusions and Recommendations

The conclusions and recommendations from global structural analysis are:

1) The initial scantling design is acceptable and the weight estimates for the hull are acceptable budget values for the final hull as-built weight
2) Local analysis should be performed for the deck to column connection, the upper column frame to column connection and the inboard column to pontoon connections to finalize the local reinforcements required
3) The connection of the outboard column to the supporting structure should use a detail where the rounded column corner continues through the connection (group C04)
4) A casting should be evaluated for the connection of the inboard column to the top of pontoon (group C02). A casting may also be considered for the inboard column to the bottom of pontoon (groups C01 and C15), however it is expected that the final local design will not require a casting.

7 Constructability

7.1 Hull Structure

The hull structure is comprised of traditional stiffened plate panels common in many different floating systems. The hull configuration presented in this report consists mainly of flat panels for simplified fabrication. The flat panels are especially beneficial for fabrication yards with existing panel-line assembly equipment that can efficiently assemble stiffeners to plate panels prior to subsequent assembly steps.

The hull scantlings (plate thickness, stiffener sizes and girder sizes) were developed assuming conventional hull materials with specified minimum yield strength equal to 50 ksi. Plate thicknesses are designed in standard sizes and most of the plating is less than 2” thick with the exception being localized insert plates and intersections of major structural components or concentrated load foundations. Stiffener sizes are also selected from commonly available shapes. Girders are fabricated “T” sections and the girder spans are very reasonable because of the arrangement of the structural panels. In particular, the paired-column arrangement results in column sizes that are relatively small (e.g. 44’ x 42’ for base case outboard column) compared to other column/pontoon based floating hull systems with similar displacement (e.g. semisubmersibles and tension leg platforms).

The typical construction sequence for the hull includes the following steps:

1) Stiffeners are assembled to plate to form basic stiffened panels
2) Girders are installed to complete the basic subassembly
3) Subassemblies are assembled into blocks based on the lift capacity of the fabrication yard
4) Blocks are assembled into the complete hull either in a dry dock or on land nearby a skid way for offloading the hull onto a transport vessel

A typical block fabrication and assembly sequence is shown in Figure 7.1-1. In general, the block sizes, material usage, plate and shape sizes and overall structural arrangements are well suited to fabrication at many worldwide locations. Any fabrication yard or shipyard with experience assembling medium to large hulls for floating production facilities would be capable of building the proposed semisubmersible configuration.

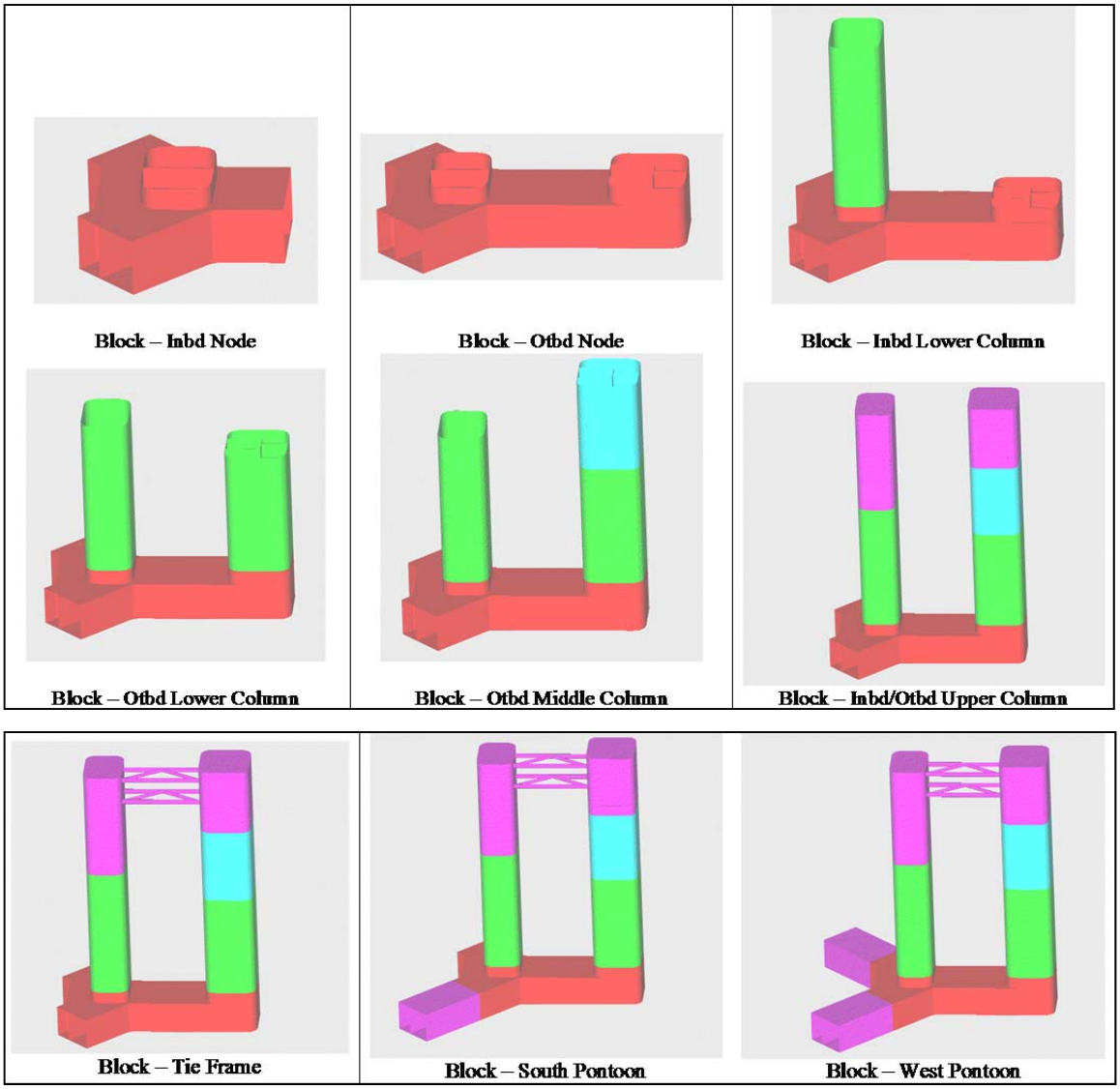

Figure 7.1-1 Typical Block Fabrication and Assembly

7.2 Topsides Integration

Multiple options were considered for topsides integration including quayside lifting, offshore lifting and float over. For this report, the feasibility of quayside lifting was confirmed conceptually using the geometry, hook height, capacity and reach of the Kiewit Heavy Lifting Device (HLD). Figures 7.2-1 and 7.2-2 show the elevation and plan view of the HLD next to the platform. The Figures are not intended as a representation of an actual lift.

The deck is assembled using two primary lifts. The drilling rig, quarters and flare would typically be assembled as separated lifts. In the topsides arrangements developed for this study, the quarters and drilling support equipment would be included in the two primary deck lifts and the drilling skid base and derrick would be a separate lift. Kiewit has confirmed the ability to do the two primary lifts.

Although the hull columns are not shown in the plan view in Figure 7.2-2, it should be noted that the main structure of the HLD fits between the outboard columns, which improves the minimum clearance between the crane booms and the hull structure.

The primary purpose of the preliminary integration study was to confirm that quayside integration is feasible. Future stages will review the topsides integration in more detail. As design is completed and additional information on equipment and locations are provided Kiewit may have an option for a one piece lift

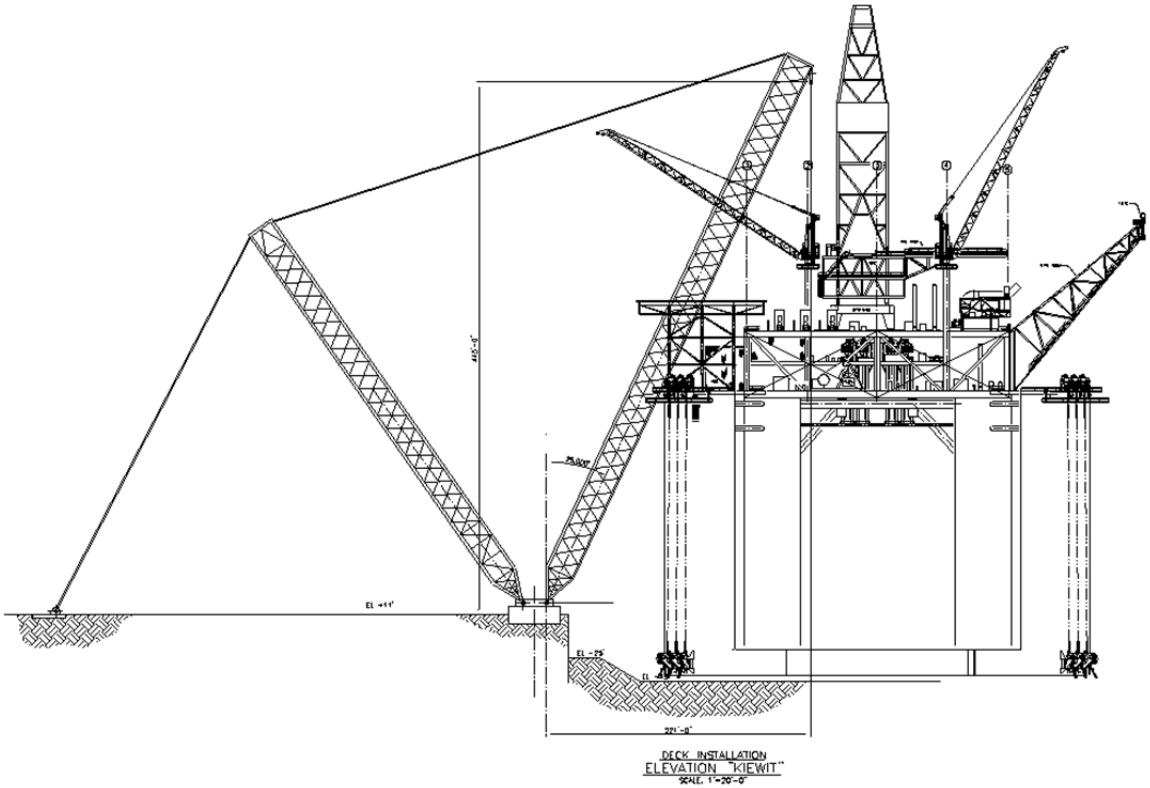

Figure 7.2-1 Quayside Topsides Integration Using Kiewit SLD - Elevation View

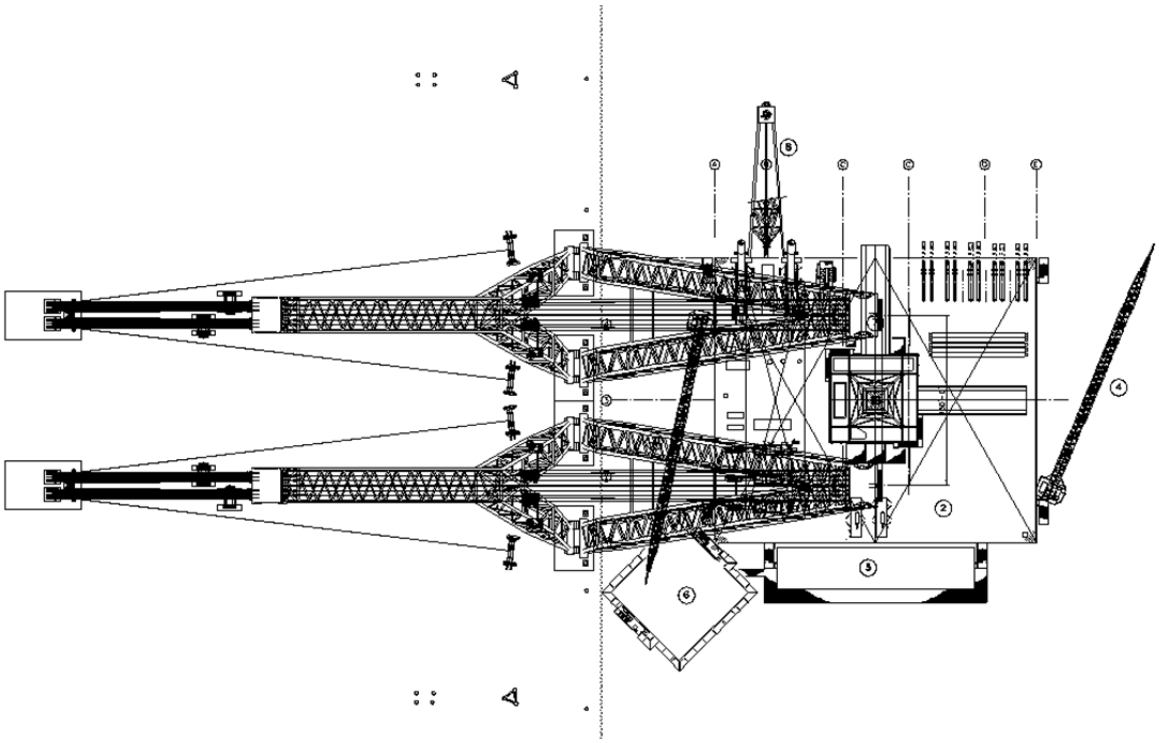

Figure 7.2-2 Quayside Topsides Integration Using Kiewit SLD – Plan View

8 Schedule

The project schedule incorporates from FEED to Platform Integration, Installation and Commissioning. The schedule duration is approximately four (4) years and does not include any assumptions for subsea architecture or storm activity. Schedules are normally adjusted in the GoM to avoid any major installation activities during hurricane season, for this reason, storm activity was not included.

FEED is assumed to begin in January 2011 preceding Detailed Design. FEED is not included in the cost and the same FEED time is assumed for both the hull and topsides design. The FEED assumes:

- Sufficient engineering is completed during FEED to provide a highly accurate steel determination. This includes preparing submittals for Main Scantling Approval (AFD, Approved for Design). With this approach, as much as 70% of the primary steel can be ordered within two months of commencement of detailed design.
- Primary steel drawings and details are provided with input and review by topsides
- Enough work is completed during FEED design so that purchase orders can be placed for long lead hull equipment very soon after project execution. For example, commonly, the long lead items for the hull are its mooring equipment and associated components.
- Hull marine systems operating methodologies are completed during FEED and P&IDs for marine systems are developed to the point of AFD.
- Model testing (wind tunnel and wave tank testing, etc.) based on FEED design is complete
- Mooring system main sizes and components are defined to the point of AFD.

The schedule is separated into subsections for the topsides, hull, mooring, foundations, and top-tensioned risers. With the present time allotments for engineering design and construction, the hull is scheduled to arrive at the integration yard approximately twelve (12) days before the topsides is ready for integration.

The schedule is based on past projects and is comparable to existing facilities of the same size in the Gulf of Mexico. The schedule assumes Far East hull construction and topsides construction in the GoM.

	Task Name	Duration	Start	Finish
1	07121-1402b - Dry Tree Semisubmersible	1016 days	Mon 1/3/11	Mon 11/24/14
2	Project Start	1 day	Mon 1/3/11	Mon 1/3/11
3	Topsides Ready for Integration	858 days	Mon 1/3/11	Wed 4/16/14
8	Hull	850 days	Mon 1/3/11	Fri 4/4/14
9	Hull Front End Engineering Design	221 days	Mon 1/3/11	Mon 11/7/11
32	Detailed Engineering	264 days	Fri 10/7/11	Wed 10/10/12
51	Follow-on Engineering	10 mons	Tue 9/11/12	Mon 7/15/13
52	Hull Fabrication	629 days	Tue 11/8/11	Fri 4/4/14
62	Platform Hull Integration, Topsides Lift and Set	95 days	Fri 4/4/14	Fri 8/15/14
71	Mooring (Chain-Poly-Chain)	528 days	Mon 1/17/11	Wed 1/23/13
72	Mooring C-P-C FEED Engineering	198 days	Mon 1/17/11	Wed 10/19/11
75	Mooring C-P-C Detailed Engineering	147 days	Thu 10/20/11	Fri 5/11/12
81	Follow-on Engineering	8 mons	Mon 5/14/12	Mon 1/14/13
82	Mooring C-P-C Fabrication	330 days	Thu 10/20/11	Wed 1/23/13
89	Mooring Equipment and Lines Delivered	0 days	Wed 1/23/13	Wed 1/23/13
90	Foundations (Suction Anchor Piles)	570 days	Thu 5/5/11	Wed 7/10/13
91	FEED Engineering	132 days	Thu 5/5/11	Fri 11/4/11
95	Detailed Engineering	406 days	Wed 12/21/11	Wed 7/10/13
102	Follow-on Engineering	8 mons	Fri 7/6/12	Fri 3/8/13
103	Top Tensioned Risers	922 days	Mon 1/3/11	Tue 7/15/14
104	Front End Engineering Design	198 days	Mon 1/3/11	Wed 10/5/11
107	Detailed Engineering	208 days	Thu 10/6/11	Mon 7/23/12
113	Follow-on Engineering	18 mons	Tue 7/24/12	Tue 1/28/14
114	Top-Tensioned Risers Fabrication	526 days	Tue 7/10/12	Tue 7/15/14
120	Installation, Integration and Commissioning	358 days	Thu 7/11/13	Mon 11/24/14

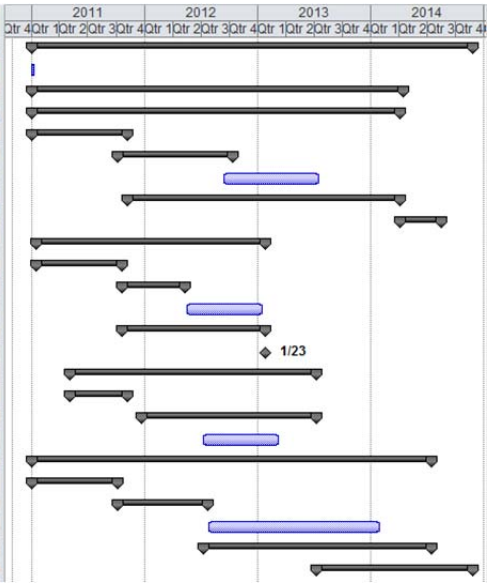

Figure 8-1 Schedule

9 Technology Readiness

Technology gaps were discussed during the "Dry-Tree Semi Technology Readiness Review" workshop on 02 March 2010 by industry Subject Matter Experts (SMEs). Issues were noted and recorded during this meeting. They were given a priority to move the concept forward to a Major Capital Project.

Of the issues noted, some revolved around the competitiveness of the concept. These issues are important to move to a major capital project but can also be resolved during concept selection or can be included in a sensitivity study. Items noted which may be included in sensitivity studies are comparison of heave RAOs to Spar, sensitivity to deck load, sensitivity to riser stiffness, sensitivity to shallower water depth and maximum riser configuration. Sensitivity studies will not be proposed for additional follow on work unless specifically requested.

Additional items not proposed for follow on work that do include key systems to address before utilizing in a Major Capitol Project include riser material and riser tensioners. The riser tensioners should be available in 2011. Risers in 10,000 ft water depth are being researched.

The proposed tasks for follow on study of the DT SEMI include VIM, Fatigue, Riser Equipment, Approval in Principle, Stability and Topsides Layout. Topsides layout was not a part of the current scope of work as the present study was designed to support hull and riser development.

Table 9-1 Tasks Proposed for Follow On Study

TASK	ACTIVITY
VIM	• Hull Structure • Risers
Fatigue	• Detailed fatigue on mooring side loads
Approval in Principle	• Risk Assessment • Any changes to standard inspection routine • Third party verification of global motions
Stability	• Transit stability
Topsides layout	• Rig and topsides interface • Well bay and platform work access • Umbilical requirements

10 Conclusions and Recommendations

Hull configurations for a dry tree semisubmersible have been developed and confirmed for Central GoM metocean conditions in 8,000 ft water depth. The hull concept utilized is the Paired Column Semisubmersible. The hull configuration consists of conventional stiffened plate structures without any moving structural components or novel structural connections. Similarly, the mooring system is conventional and utilizes chain and polyester rope sizes within the range of what has been previously delivered for existing platforms.

Global performance and riser analysis have confirmed that the configuration has suitable motions for dry tree support and drilling operations. Maximum riser stroke requirements for the 100-yr hurricane conditions is less than 25 feet, which is compatible with existing field-proven riser tensioning technology. The riser system does not require a keel joint so there is open water between the wellbay and the seafloor. The arrangement of the risers provides flexibility in the riser spacing at the wellbay and at the seafloor. In addition to compatibility with top-tensioned risers, the hull concept provides excellent support for steel catenary risers due to low surge motion, low roll/pitch motion and hang-off locations close to the center of the platform.

The paired-column arrangement allows for an efficient deck structural design because of the structural support from the inner columns. The topsides can be integrated through several methods, including quayside integration with the Kiewit Special Lifting Device. The option of quayside integration significantly reduces the scope of offshore installation and hook-up. The fully integrated platform can be towed offshore to the installation site and hooked up to mooring and risers using conventional methods.

Feasibility of the dry tree semisubmersible has been demonstrated. Future work should improve definition of the configuration through more detailed analysis and testing. The following activities are recommended in the next stage of work:

1. Reduce column freeboard by 10 ft according to wave basin and global performance analysis results.
2. Either outer column sizes and/or outer column separation distance can be significantly reduced which could result in reducing hull steel weight as well as water plan area and improve heave motions. Parametric study on outer column sizes and outer column separation distance is recommended for next phase study
3. The current topsides payload specified by RPSEA was relatively large. It is recommended to investigate the suitability and applicability of Paired-column semisubmersible hull for relatively small topsides payload
4. Since the current paired-column semisubmersible hull has relatively deep draft, it is recommended to perform VIM tests to investigate behaviors of the paired-column semisubmersible hull in strong current conditions
5. In addition to mooring system strength analysis, mooring fatigue analysis is recommended for next phase
6. Foundation system analysis and design are also recommended for next phase

Appendix A

RPSEA Design Basis

RPSEA 1402

Ultra Deepwater Dry Tree System for Drilling and Production

Conceptual Design Premise

H08130-G-DBN-GN-15001

Rev	Date	Document Status	Originator	Checked	Approved
D	11/08/10	Updated to Include Comments	M. Mackenzie	P. Poll	
C	4/9/09	Updated per ongoing engineering	C. Brown	P. Poll	
B	2/17/09	Preliminary with comments incorporated	C. Brown	P. Poll	
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1 Introduction

Conceptual studies are being conducted for the design of a dry tree semisubmersible concept (SEMI) for ultra deep water Gulf of Mexico. As part of this work, SEMI configurations will be developed for two cases: 1) Base case payload at 8,000 ft water depth and 2) Sensitivity case payload at 8,000 ft water depth.

This document summarizes the conceptual design premise for the SEMI configurations. For conceptual engineering, many assumptions are required to fully define a specific configuration. Several different SEMI configurations will be developed and compared during a selection process. The RPSEA design basis (file *RP 1402 Design basis 5 031309.doc*) provides input data with the overall objective of ensuring that each SEMI configuration can be compared on an equal basis. This design premise combines the input data from the RPSEA design basis with additional assumptions necessary to fully design the SEMI configuration. In addition, a brief conceptual design methodology is included in Section 11.

2 Abbreviations and Definitions

ABS	-	American Bureau of Shipping
API	-	American Petroleum Institute
ASME	-	American Society of Mechanical Engineers
BOP	-	Blow Out Preventer
CG	-	Center of Gravity
DB	-	Design Basis
FPI	-	Floating Production Installation
GOR	-	Gas to Oil Ratio
HP	-	High Pressure
MMS	-	Minerals Management Service
MODU	-	Mobile Offshore Drilling Unit
ROV	-	Remotely Operated Vehicle
RPSEA	-	Research Partnership to Secure Energy for America
SCR	-	Steel Catenary Riser
SEMI	-	Semisubmersible
TBD	-	To Be Determined
TOC	-	Top of Column
TTR		Top Tension Riser
USCG	-	United States Coast Guard
VIM	-	Vortex-induced motion
VIV	-	Vortex-induced vibration

3 Global Configuration

3.1 Overall Field Architecture

The field architecture defines platform north relative to true north and shows departure headings for SCRs and umbilicals. Figure 3-1 shows the Base Case and Figure 3-2 shows the Sensitivity Case.

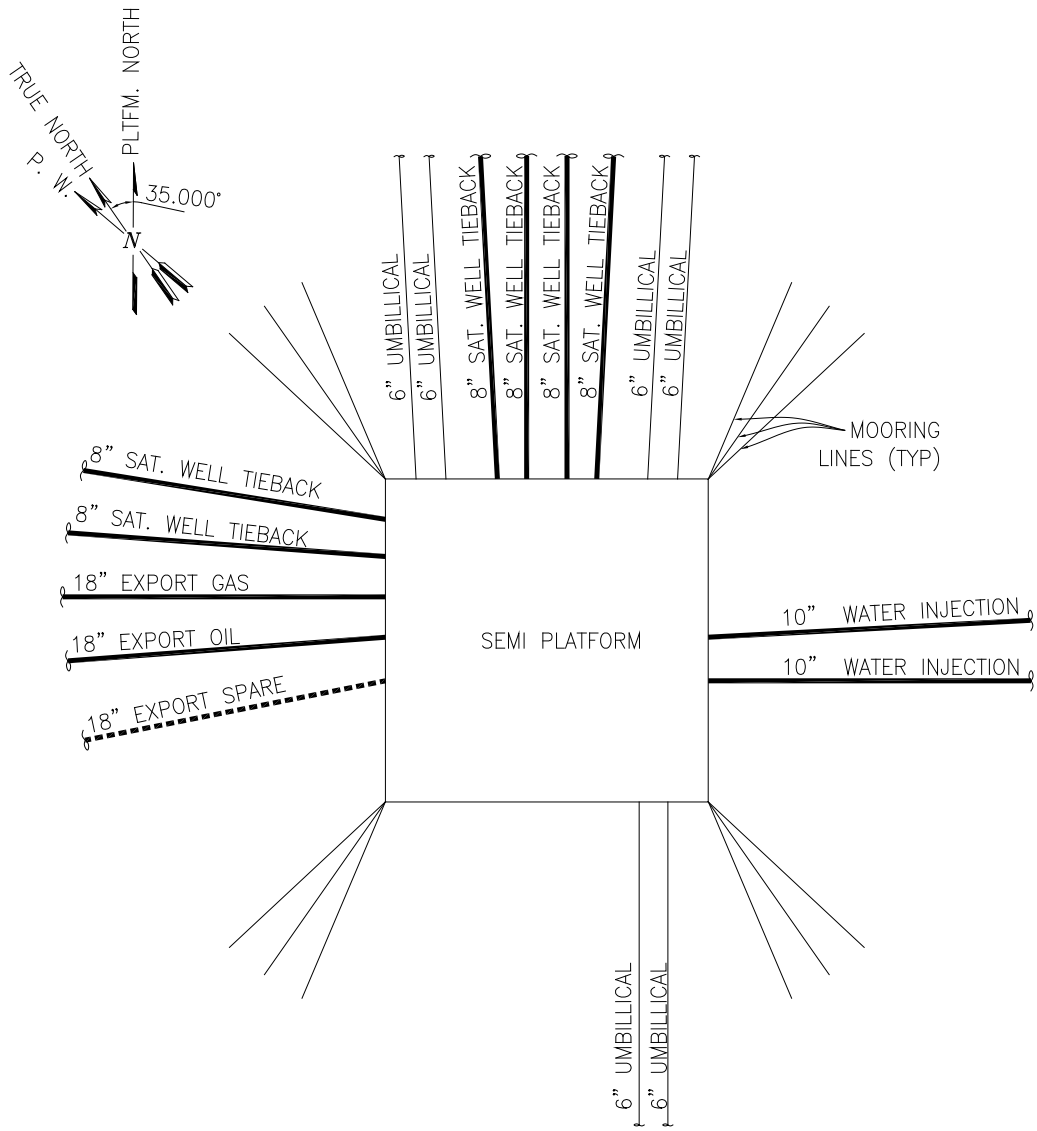


Figure 3-1 Base Case Field Layout

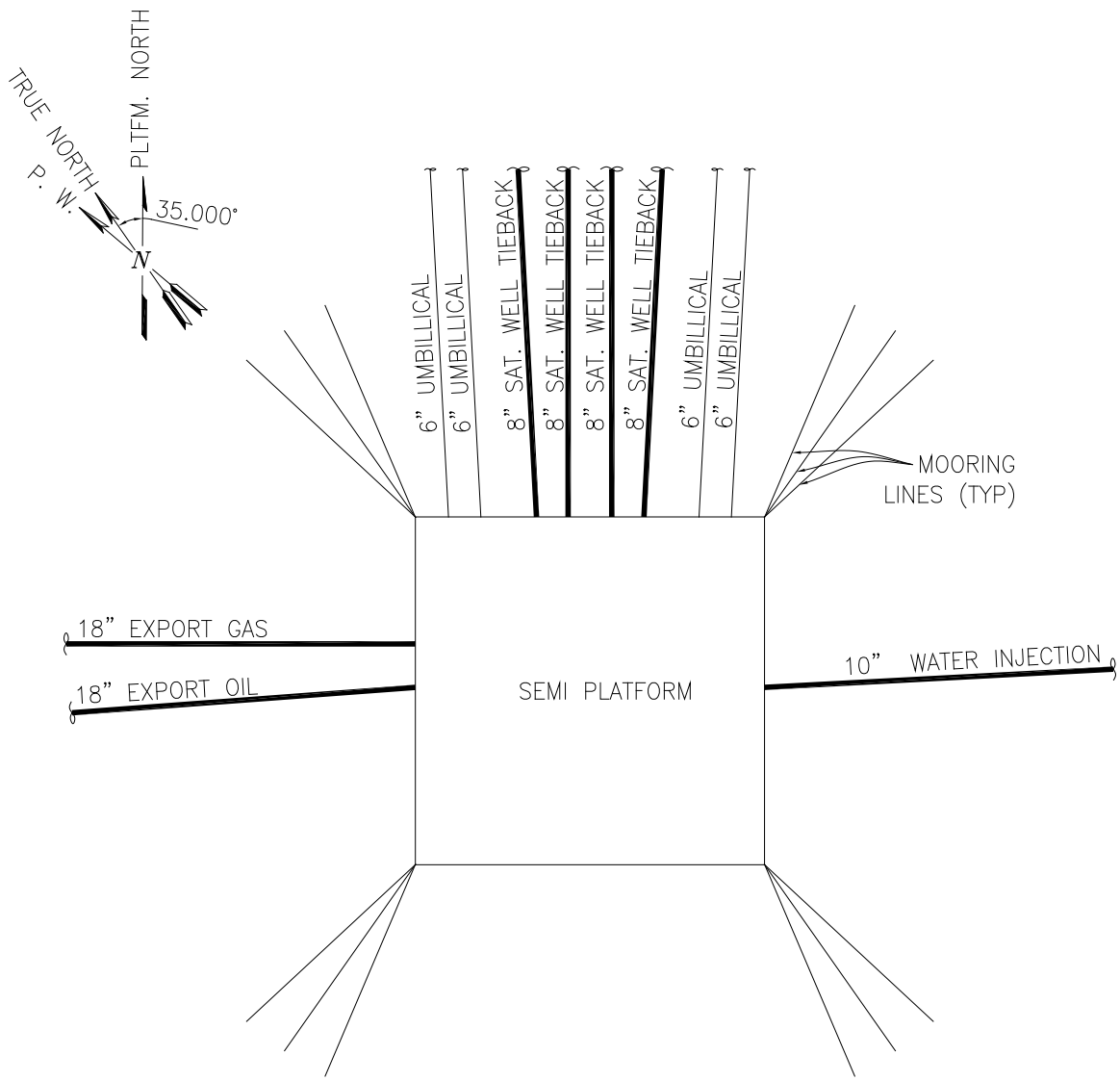


Figure 3-2 Sensitivity Case Field Layout

3.2 Global Platform

In general, the hull must support functional requirements of the topsides, drilling and subsea systems. These functional requirements are captured in the following sections and are based on RPSEA requirements. Two payloads at the same water depth will be considered.

The platform will be designed for a 20-year service life.

3.3 Futures and Reserves

Generally the operator may specify that the floating system provide additional payload capacity for future expansion. In this study, the weight of future

topsides equipment, associated deck structure and loads associated with future flowlines are assumed to be included in the RPSEA payload requirement. Company Reserve is also assumed to be included in the RPSEA payload requirement.

3.4 Global Codes and Standards

The SEMI design shall comply with Gulf of Mexico regulatory requirements (including USCG and MMS), industry codes and recommended practices. The hull and mooring design shall meet ABS classification requirements.

4 Topside Facilities

The hull must provide adequate payload capacity to support the topsides weight and adequate trim ballast capacity to allow a topsides center of gravity envelope of +/-10 ft horizontal and +/- 5 ft vertical.

Topsides weight information is provided in the RPSEA design basis in the form of an equipment list from the OGM (Oil and Gas Manager) software for the specified throughput. The OGM output is a starting point for the topsides in this study and the following notes shall be considered in the design and layout of the topsides:

- Although the primary deck steel is included in the OGM output, the weight estimate is not based on the specific hull concept used in this study and shall be replaced by a weight estimate developed specifically for the Paired Column SEMI hull.
- The OGM model is a SPAR and the risers and trees are assumed to be supported by riser buoyancy cans. Thus, tensioner weight and riser loads on the structure are not considered in the OGM summary data.
- The equipment sizes (length x width) and weights are given. However, the VCG for the equipment skids are not given. The VCG for a module shall be taken 3 ft above the equipment baseline in order to estimate overall VCG.
- The projected wind surface area shall be developed during the study based upon the deck layout developed to match the hull.

Topside weights include dry and operating values. Dry values will be used for all pre-service conditions and operating values will be used for in-place conditions.

Table 4-1 summarizes design basis data for all cases. Table 4-2 provides a summary-level reconciliation of the weight and area output from the OGM software with the input data to be used for this study.

For layout purposes, the allocated area given by RPSEA for the total square footage of the platform will be used. The square footage will include space required for each system including equipment, maintenance, access area, escape routes, ROV and associated equipment and crane laydown areas.

Storage of fluids in or on the hull to support topsides or drilling facilities is optional.

The deck structural weight shall be estimated based on total operating weight and area requirements. The deck structural estimate may be based on using 60 ksi specified minimum yield strength material. Both open truss and deck box structural configurations are acceptable.

The sensitivity case is derived from the base case to achieve a high-level objective of approximately 10,000 st less total operating payload. The topsides facilities shall be modified by reducing the facilities dry and operating weights by 1,000 st and 1,400 st, respectively. The total deck area requirement shall be reduced by 12,500 ft^2. Steel weight and wind area adjustments shall be estimated during the study.

Table 4-1 Summary of Key Input Data for Topsides

Item		Base	Sensitivity	Comment
Water depth (ft)	(ft)	8,000	8,000	
Design life (years)	(yrs)	20	20	
Total Operating Payload (including deck structure)	(st)	22,443	18,158	Note 1
Total Dry Weight (including deck structure)	(st)	17,395	13,710	
Vertical CG (above lower deck)				
Operating	(ft)	TBD	TBD	Note 2
Dry	(ft)	TBD	TBD	Note 2
Process Requirements				
Oil process production rate	(kbpd)	100	75	
Max. produced water rate	(kbpd)	40	30	
Max. total fluids processing rate	(kbpd)	120	90	
Peak gas processing rate @500 GOR	(mmcfd)	50	38	
Peak water injection rate	(kbwpd)	80	60	
Max. water injection pressure	(psi)	5,000	5,000	
Dead oil storage	(st)	500	400	
Sizing Parameters				
Total area required	(sq ft)	108,359	95,859	
Wind area and cp (N-S)	(sq ft, ft)	TBD	TBD	By Contractor
Wind area and cp (E-W)	(sq ft, ft)	TBD	TBD	By Contractor
Reservoir Information				
Reservoir depth (tvdss)	(ft)	27,000	27,000	
Max. (initial) reservoir pressure	(psi)	16,000	16,000	
Max. temperature at wellhead	(^{o}F)	190	190	
API gravity (deg)	(deg)	30	30	
Dry Tree Wells				
Shut-in Tubing Pressure	(psi)	9,000	9,000	At top of riser
Max. per well oil rate	(kbpd)	16	16	
Production TTRs	(#)	12	9	Dual casing well conductors
Wellbay Slots	(#)	16	12	One slot sized for HP drilling riser service
Wellbay configuration		TBD	TBD	By contractor to fit SEMI configuration
Wellbay spacing		TBD	TBD	By contractor based on no clashing criteria

Notes: (1) Total operating payload includes facilities, utilities, quarters, drilling rig, flare, riser tensioners, deck structure (includes helideck) and variable loads in topsides and rig. Excludes riser tensions and hull storage.

(2) To be supplied by Hull Contractor. The VCG of individual process equipment to be estimated as 3'-0" above the deck that the equipment is located on.

Table 4-2 Adjustments of OGM Topside Weight and Deck Area for Base Case Payload

Component	Weight (st) Dry	Weight (st) Operating	Area (sq ft)	Comments
Total Topsides per OGM data	**18,136**	**25,390**	**95,741**	includes drill rig, deck steel, process equipment buildings & conginencies.
Exclusions (items subtracted out from OGM data)				
Drill rig	6,634	9,287	29,500	dry weight includes 25% contingency in OGM data. Operating weight scaled from dry weight as in OGM data. Area is without maintenance factor.
Deck steel	6,533	9,146		dry weight includes 25% contingency in OGM data. Operating weight scaled from dry weight as in OGM data.
Well bay area			4,356	OGM data appears to single level area. No maintenance area included.
Subtotal	**4,970**	**6,958**	**61,885**	
Additions required (items to be added to OGM data)				
Drill rig from RPSEA	4,000	7,000	37,194	Operating load includes hook load and setback. Excludes drilling fluid storage. Area includes derrick/substructure footprint envelop for all wellbay slots, drilling module area. Pipe storage is assumed to be on top of drilling modules. Note that footprint envelop includes wellbay area for top deck.
ROV	150	210	3,500	Includes area for ROV, control shed, maintenance and access area, etc.
Riser tensioners	2,275	2,275		12 production plus 1 drilling riser tensioner, each assumed to be 175 st.
Subtotal	**11,395**	**16,443**	**102,579**	
Concept-specific additions required to be added by Contractor				
Deck steel	6,000	6,000		Primary, secondary and tertiary steel, excluding steel for skidded equipment or components and buildings. Contractor to add 200 st for helideck (from OGM's deck steel data) to the estimated deck structural weight.
Wellbay area			5,780	Two levels at 50 ft x 115.6 ft. One level already included in Drill Rig footprint.
	17,395	**22,443**	**108,359**	Actual layout provides 106,600 sq ft, 2 levels at 245 ft x 217.5 ft

Notes:
1. Other payload items to be considered by Contractor include drilling fluid storage (3,000 st located either in hull or topsides), TTR tensions, SCR tensions, umbilical tensions and dead oil storage (500 st located either in hull or topsides).
2. Contractor to add pipe rack area if top of drilling module is not accessible for pipe storage.
3. Quarters is assumed to be 3 levels and 36 feet high.

5 Drilling System

The platform shall provide adequate payload capacity to support the drilling system weight and associated loads. The hull shall also provide adequate trim ballast capacity to allow positioning of the drilling rig over any wellbay slot with no constraints on drilling sequence. Hook load is included in the drilling total operating load.

The drilling rig is at maximum drilling condition only when located at the dedicated drilling slot. The rig can be located at any slot but the drilling variable loads will be reduced so that additional trim ballast is not required for this condition.

Tables 5-1 and 5-2 summarize key drilling rig parameters relevant to developing the SEMI configuration. More detailed data for each rig, as provided by RPSEA, is included in Appendix A.

Table 5-1 Drilling Rig Summary

Rig Component/Parameter		Base	Sensitivity
Total rig operating payload	st	10,000	8,000
Dry weight – Derrick/Substructure	st	2,040	1,700
Dry weight – Drilling Modules	st	1,960	1,412
Variable load – Derrick/Substructure	st	720	680
Variable load – Drilling Modules	st	2,280	2,208
Hull storage	st	3,000	2,000
Vertical CG above skid beams			
Derrick/Substructure Dry weight	ft	60	60
Derrick/Substructure Variable load	ft	95	95
Vertical CG from bottom of module			
Drilling Modules Dry weight	ft	16	16
Drilling Modules Variable load	ft	22	22
Hook Load (included in variable load)	lbs	2,000,000	2,000,000
Set Back (included in variable load)	lbs	1,000,000	1,000,000
Total vertical depth capacity	ft	27,000	27,000
Total engine horsepower (drilling rig power separate from topsides main power generation)	hp	8,600	8,600
Draw works	Hp	4,200	4,200
Top Drive	ft-lbs	63,000	63,000
Mud System	qty	4	4
Pressure	psi	7,500	7,500
Pump horsepower (each)	hp	2,200	2,200
capacity	bbls	8,000	8,000
density	ppg	15	15
Bulks - cement	ft^3	8,800	8,800
Bulks – barite and other	ft^3	10,000	10,000
BOP weight	st	150	150

Note: Total operating payload includes hook load and setback.

Table 5-2 Wind Area Parameters for Hull and Mooring Sizing

Rig Component/Parameter		Base		Sensitivity	
		Operating	Hurricane	Operating	Hurricane
Drilling Modules					
E-W	sq ft	3,335	3,335	3,335	3,335
N-S	sq ft	4,292	4,292	4,292	4,292
Derrick/Skidbase/Substructure					
E-W	sq ft	9,261	6,842	9,261	6,842
N-S	sq ft	8,334	5,929	8,334	5,929
Center of Pressure					
Drilling Modules (elevation above bottom of module)					
E-W	ft	18.8	18.8	18.8	18.8
N-S	ft	18.8	18.8	18.8	18.8
Derrick/Skidbase/Substructure (elevation above skid beams)					
E-W	ft	96.8	78.4	96.8	78.4
N-S	ft	100.5	85.4	100.5	85.4

Notes:

1. Setback is considered for Operating condition.
2. E-W wind area is the area facing the wind from North to South.
3. N-S wind area is the area facing the wind from West to East.
4. E-W CoP is the pressure center of area facing the wind from North to South.
5. N-S CoP is the pressure center of area facing the wind from West to East.
6. These wind areas and CoPs are based on drawing "H08130-G-0011-01-0A.dwg".
7. Substructure shading effect is considered for calculating Modules N-S wind area.
8. Pipe rack on top of DSM is not considered for calculation of wind area and CoP of Modules.

6 Top-Tensioned Riser System

6.1 General Description

The dry tree top tensioned riser system includes production and drilling risers. The riser system extends from the seabed elevation at the subsea wellhead, through the water column, splash zone, air gap and terminates in the wellbay at the surface tree.

The data for configuration and sizing is listed in Table 6-1. Additional requirements follow in Sections 6.3 for the Production Riser and 6.4 for the Drilling Riser. The objective is to ensure compatibility of minimum riser sizing and payload for all concepts. The minimum riser sizes and top tension shall be agreed for consistency. Additional increases (e.g. thickness increase at interface locations, etc.) may be required for compatibility with a particular SEMI configuration.

The riser system is analyzed using riser dynamic finite element program Flexcom. Flexcom is the leading three-dimensional nonlinear time domain finite element program for the analysis of a wide range of compliant and rigid offshore structures. The program uses an industry-proven finite element formulation, incorporating a 3D hybrid beam-column element with fully coupled axial, bending and torque forces, for reliable and accurate modeling of slender offshore structures.

6.2 Codes and Standards

The top tensioned riser system shall be designed in accordance with the following codes, and standards, as applicable.

<u>General criteria:</u>

- *Recommended Practice for Design, Selection, Operation and Maintenance of Marine Drilling Riser Systems* (API RP 16Q), 1993.
- *Recommended Practice for Design of Risers for Floating Production Systems (FPSs) and Tension-Leg Platforms (TLPs)* (API RP 2RD), 1998.
- *Specification for Design of Marine Drilling Riser Equipment* (API Specification 16F), 2004.
- *Specification for Wellhead and Christmas Tree Equipment* (API Specification 6A), latest edition.
- *Rules for the Construction of Pressure Vessels* (ASME VIII, Section 1 and 2), 2008.
- ASME Section II, ASME Material Specification.
- ASME Section V, ASME Nondestructive Examination.
- ASME Section IX, ASME Welding and Brazing Qualifications.
- ASME Section X, ASME Fiberglass-Reinforced Plastic Pressure Vessels.

- *Specification for Subsea Wellhead and Christmas Tree Equipment* (API Specification 17D), 1992.
- *Design Rules for Steel Structures, Curve* B (NS 3472), 2004.
- *Recommended Practice for Design and Operation of Completion / Workover Riser Systems* (API Specification 17G), 2005.
- *Offshore Riser Systems* (DNV-OSS-302), Det Norske Veritas, 2003
- *Riser Interference* (DNV-RP-F203), Det Norske Veritas
- *Riser Collision* (DNV-RP-F205), Det Norske Veritas, 2004

<u>Tension, Collapse and Burst</u>

- *Bulletin on Formulas and Calculations for Casing, Tubing, Drill Pipe, and Line Pipe Properties-Sixth Edition* (API Bulletin 5C3), 1999.

<u>Allowable Stress Limits</u>

- API RP 2RD, latest edition.

<u>Fatigue</u>

- *Fatigue Design of Offshore Steel Structures* (DNV RP-C203), Det Norske Veritas, 2008
- *Riser Fatigue* (DNV-RP-F204), Det Norske Veritas, 2005

Table 6-1 Production Riser Requirements

Data	Production Riser	
	Base	Sensitivity
Pipe Geometry and Material		
Inner casing OD (in.)	10.750	
Outer casing OD (in.)	13.813	
Steel Grade (ksi)	Q125 KSI for casings / Q110 KSI for tubing	
Wall thickness mill tolerance	-10% / +10%	
Corrosion Allowance (in.)	0.125	
Maximum Pressures on Top of the Riser		
Pressure Test (psi)	9000	9000
Shut-In Pressure (psi)	9000	9000
Gas Kick Pressure (psi)	9000	9000
Operating Production Pressure (psi)	2500	2500
Fluid Weights		
Sea Water (ppg)	8.56	
Nitrogen (ppg)	0.2	
Completion Fluid (ppg)	15.0	
Oil (ppg)	7.5	
Service Life		
Service Life	20	
Fatigue Safety Factor	10	
Internal Tubing		
External Diameter (in.)	5.50	
Weight (lbf/ft)	35.4	35.4
Wall Thickness (in.)	0.689	0.689
Top-tension Calculation		
Min. top tension factor	1.3	

6.3 Production Riser System Configuration Assumptions

The top tensioned production riser system design parameters and assumptions are as follows:

- Subsea connector: Hydraulic subsea wellhead system. Wellhead elevation for tie-back connector is 10 ft above mud line.
- Stress joint: Tapered pipe section with hydraulic connector upper body profile on bottom and threaded connection on top

- Production Riser: Dual casing production riser (two casings plus production tubing).
- Production riser joints without integrated buoyancy.
- The temperature of the product in the tubing above the mud line is:
    - Medium: 68ºFminimum, 190ºF maximum
    - High: 68ºF minimum, 275ºF maximum
- VIV suppression will be determined
- Tubing hanger at mud line level
- Tensioner: The interface between the hull and the TTR shall include a hydropneumatic tensioner with 25 ft stroke capacity. For analysis purposes, the tensioner stiffness shall have a minimum nominal value of 20 kips/ft and the tensioner weight shall be 175 st each. The cylinder friction value will be in the range of 0.008 to 0.010.
- Keel guide interface to production riser, as required. For keel damping the coefficient of friction will be 0.3.
- Surface tree: 15 st total weight including jumpers, miscellaneous items, and margin.
- The top-tension calculation shall be based on seawater in the outer annulus (i.e. between the outer casing and inner casing) and nitrogen in the inner annulus (i.e. between the inner casing and the tubing).
- Strakes will be applied to the production risers assuming 50% coverage. For bare riser joints (no strakes), Cd = 1.0. For straked riser joints, the following hydrodynamic properties will apply:
    - Equivalent OD = 1.125 x base pipe OD
    - Drag Cd= 1.35 (based on equivalent OD)
    - Added mass Cm= 1.2 (based on equivalent OD)
- Fatigue analyses will assume DNV “E” S-N curve, SCF 1.3 and factor of safety 10.

The workover riser system is the same as the production riser system except that surface tree is removed and a workover spool is installed to connect the riser to the surface BOP stack and equipment. The workover BOP is rated for 10,000 psi and weighs 60 st.

6.4 Drilling Riser System Configuration Assumptions

The drilling riser system consists of a single high-pressure barrier for containing well bore fluids and pressures between the subsea wellhead and the surface BOP. The drilling riser top tension is 1,000 st and tensioner stiffness is 20 kips/ft. The drilling riser tensioner weight is 175 st. Drilling riser dry weight is 2,400 st and wet weight is 400 st.

6.5 Operating Conditions

The production/injection riser system is typically designed for the load cases defined in Tables 6-2 and 6-3 for production and workover conditions, respectively. The internal pressure and contents for the production risers are defined in Table 6-4.

The drilling riser system shall be designed for the load cases defined in Table 6-5.

Tables 6-2 through 6-5 are typical requirements for detailed riser design and verification. For purposes of this study, only the nominal operating case will be considered in the design. Damage and workover cases will not be considered.

For interference analysis, the minimum surface-to-surface clearance is two times the outer diameter of the largest riser in the pair being analyzed. Riser interference analysis will consider pairs with drilling riser, production riser, water injection riser and gas injection riser.

Table 6-2 Production Riser Load Case Matrix

Case Reference	Riser Condition	Design Case (see Table 6-4)	Design environment	Allowable Stress Increase Factor
PT-1	Installation Pressure test	1	Operational	1.35
SI-1	Shut-in	2	Operational	1.0
SI-2	Shut-in	3	Extreme	1.2
SID-1	Shut in with tensioner system damage(1)	3	Operational	1.5
WK-1	Well killed	7	Operational	1.0
WK-2		7	Extreme	1.2
SIL-1	Shut-in with Internal Leak	4	Operational	1.2
SIL-2		4	Extreme	1.5

Notes: (1) Uncorrected damage condition (tension as-is after damage).

Table 6-3 Production Riser Load Case Matrix (Workover/Completion)

Case Reference	Riser Condition	Design Case (See Table 6-4)	Design environment	Allowable Stress Increase Factor
WT-1	Workover – Wireline or Coil Tubing	6	Operational	1.0
WB-1	Workover – (no tubing)	5	Operational	1.0
WB-2	Workover – (no tubing)	5	Extreme	1.2

Notes: (1) WB-1 and WD-2 is with the BOP installed.
(2) WT-1 is with the Tree installed.

Table 6-4 Standard Production Riser Fluid and Pressure Contents

Case No.	Design Condition	Internal Pressure At Surface (psi)		Internal Contents		API RP 2D Load Type
		Medium	High	Fluid Type	Weight sg (ppg)	
1	Pressure Test					Operating
	Annulus	9,000	12,500	Seawater	1.00 (8.56)	
2	Operating					Operating
	Tubing	2,500	3,500	Oil	0.90 (7.5)	
	Annulus	50	50	Nitrogen	0.02 (0.2)	
3	Shut In					Extreme
	Tubing	9,000	12,500	Oil	0.90 (7.5)	
	Annulus	50	50	Nitrogen	0.02 (0.2)	
4	Shut In, Tubing leak					Operating & Extreme
	Tubing	9,000	12,500	Oil	0.90 (7.5)	
	Annulus	9,000	12,500	Oil	0.90 (7.5)	
5	Completion or Workover through Riser w/o Tubing					Operating & Extreme
	Annulus	0	0	Completion Fluid	1.50 (12.5)	
6	Workover (Tubing on Hook)					Operating
	Tubing	2,500	3,500	Oil	0.90 (7.5)	
	Annulus	0	0	Completion Fluid	1.50 (12.5)	
7	Well Killed					Operating & Extreme
	Tubing	0	0	Mud	1.50 (12.5)	
	Annulus	0	0	Mud	1.50 (12.5)	

Table 6-5 Drilling Riser Load Case Matrix

Case No.	Riser Condition	Riser Mud Weight and Pressure		Design environment	Allowable Stress Increase Factor
		Base	Sensitivity		
DT-1	Test (intact)	5,000 psi 8.56 ppg	5,000 psi 8.56 ppg	Operational	1.35
DN-1	Normal Drilling (intact)	12.5 ppg	12.5 ppg	Operational	1.00
DN-2	No Drilling (intact)	12.5 ppg	12.5 ppg	Extreme	1.20
DD-1	Normal Drilling (damaged(1))	12.5 ppg	12.5 ppg	Operational	1.50
DK-1	Gas Kick while drilling (intact)	5,000 psi 2 ppg	5,000 psi 2 ppg	Operational	1.20

Notes: (1) Uncorrected damage condition (tension as-is after damage).

6.6 Well Bay and Seafloor Layout

Riser layout will be determined by considering platform well bay size, number of risers, and riser interference. Minimum riser spacing for conceptual engineering will be 25 ft at the seafloor.

6.7 Total TTR Payload

Calculation of the total top tension riser payload for purposes of hull sizing should consider 1 well in drilling mode and the remaining production risers in normal operating conditions. As an example, the Base case has 12 production risers and the total TTR payload shall include 1 drilling riser and 11 operating production risers.

6.8 Material Properties

For riser analysis, the Q110 and Q125 materials shall be assumed to provide the mechanical properties given in Table 6-6.

Table 6-6 Mechanical Properties for Riser Materials

Material	Yield Stress (ksi)	Tensile Stress (ksi)	Elongation (%)	Comments
Q110	110	120	23	Longitudinal direction
Q125	125	140	21	Longitudinal direction

7 Subsea Interfaces

As an interface to the subsea systems, the hull will support umbilicals, flowlines, injection lines and export lines. The SCR and umbilical configuration includes provisions for future expansion and/or additional tie-backs. No additional payload capacity shall be added.

The associated loads and other key data are summarized in Table 7-1. Vertical payload and departure angles are given in Table 7-1. The horizontal departure angle is governed by the field layout given in Section 3.1.

SCRs shall be supported on porches and shall utilize a stress joint or flex element at the connection to the hull. Umbilicals shall be supported at the top of pull tubes that extend to the keel of the hull.

The objective is to ensure compatibility of minimum riser and umbilical sizing and payload for all concepts. The minimum riser and umbilical sizes and vertical shall be agreed for consistency. Additional increases (e.g. thickness increase at interface or touch-down locations, etc.) may be required for compatibility with a particular SEMI configuration.

Table 7 -1 Subsea and Export Interface Summary

	Unit	Base	Sensitivity
Satellite Well Tieback (SCR)			
Quantity	#	6	4
Diameter	in.	8.625	8.625
Thickness	in.	0.812	0.812
Pressure	psi	5,000	5,000
Departure Angle	deg.	12	12
Vertical Payload	st	310	310
Water Injection (SCR)			
Quantity	#	2	1
Diameter	in.	10.750	10.750
Thickness	in.	1	1
Pressure	psi	5,000	5,000
Departure Angle	deg.	12	12
Vertical Payload	st	490	490
Oil Export (SCR)			
Quantity	#	2	1
Diameter	in.	18	18
Thickness	in.	1.1	1.1
Pressure	psi	2,500	2,500
Departure Angle	deg.	14	14
Vertical Payload	st	910	910
Gas Export (SCR)			
Quantity	#	1	1
Diameter	in.	18	18
Thickness	in.	1.1	1.1
Pressure	psi	2,500	2,500
Departure Angle	deg.	14	14
Vertical Payload	st	530	530
Umbilicals			
Quantity	#	6	4
Diameter	in.	6.0	6.0
Vertical payload	st	120	120
Departure Angle	deg.	8	8

Notes:
(1) Quantities shown include all future or reserve lines.
(2) Satellite well tieback SCR pressure assumes pipeline is protected by HIPPS.

8 Metocean Criteria

Metocean data used as the basis for sizing are from information provided by RPSEA. Wind, wave and currents shall be assumed collinear. Wave spreading shall not be considered.

Table 8-1 Environmental Criteria

RPSEA 1402 - Environmental Criteria 4/14/2009

Items		Gulf of Mexico Water Depth = 8000 ft (2438 m)									
		1		2		3		4		5	
		100-yr Hurricane		**Max Loop Current**		**Hurricane Plus Loop Current**		**10-yr Winter Storm**		**1-yr Winter Storm**	
		Design Extreme		Design Extreme		Design Extreme		Maximum Operating Condition		Normal Operating Condition	
Wave		Jonswap		Jonswap		Jonswap		Jonswap		Jonswap	
Gamma		2.6		1.0		2.6		2.0		2.0	
Direction		Omni		Omni		Omni		Omni		Omni	
Significant wave (Hs)	(ft)	51.8		4.0		36.3		18.0		12.0	
Spectral Period (Tp)	(s)	15.4		6.0		13.5		10.7		9.1	
Maximum Wave ht	(ft)	91.5		8.8		64.3		33.5		22.3	
Maximum Crest ht	(ft)	57.8		3.4		39.6		18.5		12.1	
Highest Design Water level	(ft)	3.2		2.1		3.2		1.6		1.3	
Lowest Design Water level	(ft)	-1.4		-1.4		-1.4		-0.7		-1.0	
Subsidence	(ft)	0		0		0		0		0	
Current Profile	(ft)	Normal		Normal		Normal		Normal		Normal	
		Depth (ft)	Vel (ft/s)	Depth (ft)	Vel (ft/s)	Depth (ft)	Vel (ft/s)	Depth (ft)	Vel (ft/s)	Depth (ft)	Vel (ft/s)
		0	5.90	0	8.90	0	7.90	0	1.60	0	1.30
		-164	4.40	-164	8.90	-164	5.90	-100	1.20	-100	1.00
		-328	0.00	-328	8.90	-328	0.00	-200	0.60	-200	0.50
		-8000	0.00	-656	5.60	-8000	0.00	-300	0.30	-300	0.30
				-984	3.50			-8000	0.30	-8000	0.30
				-1968	0.50						
				-2296	0.40						
				-8000	0.00						
Direction from wave	(deg)	omni		omni		omni		omni		omni	
Wind		NPD		NPD		NPD		NPD		NPD	
1 hour @ +33' elevation	(ft/s)	149.6		20.3		110.3		59.0		46.0	
Direction from wave	(deg)	omni		omni		omni		omni		omni	

Notes:
1. Maximum crest height in the table above excludes storm surge and astronomical tide, which is included in highest design water level.
2. Storm surge and tide for the Winter Storm conditions are based on previous GoM projects.
3. Subsidence 0.0 ft was assumed by HOE.

Fatigue Seastates

JONSWAP spectrum with a gamma value of 1.0 should be used for the fatigue sea states presented in Table 8-2 below. The directional distribution is given in Table 8-3.

Table 8-2 Fatigue Seastates

Fatigue Bin	H_s (ft)	T_p (s)	V_w (ft/s)	*V_c (ft/s)	Probability of Occurrence
1	0.75	4.5	16	0.5	0.18038
2	2.5	5.5	20	0.65	0.3925
3	4.5	5.5	24	0.75	0.11887
4	4.5	7.5	24	0.75	0.12406
5	6.5	6.5	28	0.9	0.05908
6	6.5	8.5	28	0.9	0.05082
7	8.5	8.5	34	1.1	0.04211
8	11.0	9.5	38	1.3	0.02162
9	13.75	9.5	46	1.5	0.00518
10	17.5	11.5	56	1.8	0.00473
11	22.5	12.5	72	3.1	0.00068
12	27.5	12.5	88	3.8	0.00014
13	32.5	14.5	104	4.4	0.00003
14	37.5	14.5	116	5.2	0.00003

*Surface Vc, which decreases to zero at 300 ft below surface

Table 8-3 Directional Distribution of Fatigue Seastates

*Wave Direction (deg.)	Probability of Occurrence
0	0.076
30	0.081
60	0.113
90	0.160
120	0.160
150	0.135
180	0.068
210	0.027
240	0.025
270	0.037
300	0.050
330	0.068

(*)Wave direction is the direction the waves are coming from. 0 degrees is from true North, 90 degrees is from East, etc.

9 Hull

9.1 Regulatory requirements

The semi-submersible will be flagged as an American vessel. Therefore, compliance with Gulf of Mexico local coastal authority regulations shall be required. Compliance with the applicable US Coast Guard (USCG) and the Minerals Management Service (MMS) regulations shall be required, as defined in the US Code of Federal Regulations. In addition, the semi-submersible will be classed with the American Bureau of Shipping (ABS) as an ✠A1 Floating Offshore Installation (FOI).

9.2 Codes and Standards

The hull design should satisfy government regulations, industry codes and recommended practices, including:

- *Recommended Practice for Planning, Designing, and Constructing Floating Production Systems* (API RP 2FPS), First Edition, American Petroleum Institute, 2001.
- *Recommended Practice for Planning, Designing, and Constructing Fixed Offshore Platforms – Working Stress Design* (API RP 2A - WSD), Twenty First Edition, American Petroleum Institute, 2000.
- *Guide for Building and Classing Floating Production Installations*, American Bureau of Shipping, 2004. (ABS FPI Guide)
- *Rules for Building and Classing Mobile Offshore Drilling Units*, American Bureau of Shipping, 2006. (ABS MODU Rules)

9.3 Design Criteria

The SEMI shall be designed for the conditions provided in Table 9-1 and meet the design criteria given in Table 9-2.

The hull safety criteria are defined as follows, based on the ABS FPI Guide:

- Category A: Factor of safety = 1.67 (1.43 for von Mises stresses)
- Category B: Factor of safety = 1.25 (1.11 for von Mises stresses)
- Category C: Fatigue factor of safety = 3.0 to 10.0 depending on criticality and inspectability
- Category D: Factor of safety = 1.0

Table 9-1 Global Load Case Matrix

Phase	Condition		Environment	Hull Safety Criteria(1)	Mooring Safety Criteria(1)
Fabrication	Hull Loadout		Calm	A	–
Transport & Installation	Dry Transport		10-yr Route-Specific Wind/Wave/Current	B, C	–
	Float-off		Calm	A	–
	Wet Tow		10-yr Wind/Wave/Current	B, C	–
	Topside Installation		Calm	A	–
In-place	Intact	Operating	1-yr Winter Storm	A	A
	Intact	Operating	Long-term Wind/Wave/Current	C	C
	Intact	Evacuated	100-yr Hurricane	B	B
	Intact	Manned	100-yr Loop Current	B	B
	Damaged	One Mooring Line Missing	100-yr Hurricane	B	B
	Damaged	One Mooring Line Missing	100-yr Loop Current	B	B
	Damaged	One Compartment Flooded	10-yr Hurricane	B	B
	Intact	Evacuated	1000-yr Hurricane	D	D
	Damaged	Two Compartments Flooded	Calm	D	D

Notes:

(1) Hull Safety Criteria and Mooring Safety Criteria are defined in API RP 2FPS, except for Category D. Category A criteria are intended for conditions which exist on a day-to-day basis. Category B criteria are intended for rarely occurring conditions, Category C criteria are intended for the design of the structure against fatigue failure. Category D criteria are intended for survival conditions.

(2) Environmental conditions are provided in the metocean data. 100-yr hurricane conditions shall include wind-dominant and wave-dominant cases.

(3) Both minimum and maximum riser configurations shall be considered for intact Category B cases. The minimum riser configuration shall include one production TTR, one drilling TTR and all export risers. The maximum riser configuration shall include the maximum TTR payload configuration and all SCRs and umbilicals.

Table 9-2 Global Response Criteria

Response	Conditions with Safety Criteria B	Conditions with Safety Criteria A
Semisubmersible In Place		
Combined Pitch & Roll	10 degrees (intact)	4 degrees (intact)
Horizontal Acceleration (at top deck)	0.35 g	0.15 g
Max. Offset – Intact	5% of water depth	
Max. Offset – Damaged	7% of water depth	
Minimum Air gap	5 ft	

Notes:
(1) Horizontal acceleration includes the gravitational component due to pitch and roll.
(2) Maximum heave is the effective vertical motion at corner of vessel including pitch and roll.
(3) Air gap estimates shall account for wave enhancement, hull drawdown, phasing of motions and wave surface elevations and second order effects.

9.4 Stability

The stability will be in accordance with the ABS Guide for Building and Classing Floating Offshore Production Installations 2000. The unit must maintain a positive metacentric height in calm water equilibrium for all conditions. Mooring vertical loads are included in the loading conditions, however mooring restraints are excluded for the purpose of determining stability compliance, except when the mooring system may be detrimental for stability, e.g. in damage mooring line conditions.

9.5 Global Performance Analysis

Heave damping shall include hydrodynamic damping, keel damping and tensioner damping. Hydrodynamic damping shall be calculated according to usual design practice. For tensioner damping, the cylinder friction value shall be in the range of 0.008 to 0.010. For configurations that include a keel guide, the coefficient of friction shall be 0.3 for purposes of keel damping.

9.6 Hull Structures

The hull structure shall be based on 50-ksi specified minimum yield strength material. The hull structural design shall be according to ABS Guide for Building and Classing Floating Production Installations. For sizing purposes, a simplified damaged heel condition is used based on DNV RP-C103: a damaged heel of 17 degrees is combined with a 1-yr operating condition for scantling checks of the pontoons and columns.

Buckling design is based on DNV RP-C201 and RP-C202. Buckling checks will be performed in Stage 2 of the design study.

9.7 Fluid Storage in the Hull

Fluid storage in the hull is acceptable.

9.8 Corrosion Protection

Corrosion protection shall include coatings, cathodic protection, and corrosion allowances as required for the design service life. Hull external plating in the splash zone shall include 0.25 in. corrosion allowance.

9.9 Marine Growth

Marine growth is not considered at this stage.

10 Mooring

The mooring system shall be a permanent, taut catenary system consisting of polyester rope with chain at the foundation pile and at the platform (i.e. chain-polyester-chain configuration).

10.1 Codes and Standards

The following rules and recommended practices shall be followed mooring system design:

- *Guide for Building and Classing Floating Production Installations*, American Bureau of Shipping, 2000, including Supplement 2 (2003) for TLPs and Spars. (ABS FPI Guide)
- *Recommended Practice for Design and Analysis of Stationkeeping Systems for Floating Structures* (API RP 2SK), Second Edition, American Petroleum Institute, 1996.
- *Guidance Notes on the Application of Synthetic Ropes for Offshore Mooring*, American Bureau of Shipping, 1999.
- *Recommended Practice for Design, Manufacture, Installation, and Maintenance of Synthetic Fiber Ropes for Offshore Mooring* (API RP 2SM), First Edition, American Petroleum Institute, 2001.

10.2 Design Criteria

The following principles shall be followed in the design of the mooring systems:

- Maximum design conditions shall be based on the 100-year return period events.
- The mooring system shall be designed to provide extreme offsets within the values outlined in Table 9-2.
- The mooring system design shall take into account any asymmetric loads imparted by the riser systems.
- The mooring system shall be capable of being installed prior to installation of the floating facility.
- Mooring systems shall be designed for “passive” operation, meaning that no adjustment of mooring lines are required to compensate for weather or current conditions.
- Pull over drilling (i.e. the ability to move the hull off location to allow MODU access to wells below the platform) is not required.
- Mooring systems shall be designed to allow infrequent, scheduled movement of the hull position to adjust SCR touchdown points and the portion of the chain located at the fairlead.

- The mooring system shall be designed such that rope section does not contact the soil in the intact mooring line condition.
- Static drag loads acting on the SCRs, umbilicals, and mooring lines are considered. Drag coefficients for the SCRs are based on the assumption that VIV strakes are required for 50% of the full riser length.
- Mooring chain design shall include the API RP 2SK suggested corrosion allowances.
- The mooring system design and analysis will be carried out assuming the following stiffness of polyester ropes:

  Static stiffness = 12 x MBL

  Dynamic stiffness = 28 x MBL

10.3 Mooring Line Design Safety Factors

The mooring safety criteria are defined as follows:

- Category A Intact, Design Environmental Condition

  Factor of safety = 1.84 for polyester, dynamic mooring analysis
- Category B One Line Damaged, Design Environmental Condition

  Factor of safety = 1.43 for polyester, dynamic mooring analysis
- Category C Fatigue factor of safety = 10.0
- Category D Intact, Survival Environmental Condition

  Factor of safety = 1.0.

In addition, the minimum line tensions of the wire or polyester are also checked. The minimum bottom line tension shall be designed to remain positive and to eliminate putting polyester rope on the seabed on the slack side for all 100-year intact conditions.

10.4 Soil Data

Submerged unit weight is 25 lb/ft^3 at the surface, linearly increasing to 40 lb/ft^3 at a depth of 50 ft and a constant value of 40 lb/ft^3 for the remainder of the profile.

Undrained shear strength is 30 lb/ft^2 at the seafloor and linearly increasing with depth at a rate of 8 lb/ft^2/ft.

Strain at 50% of maximum shear stress is 0.020 for the top 40 ft and 0.015 below 40 ft.

11 Conceptual Design Methodology

The previous sections summarized assumptions used to configure and analyze the SEMI configurations developed for this study. This section presents a very brief summary of the software and methods used for conceptual design during the initial stages of the study.

11.1 Topsides

The topsides layouts will be developed in AutoCAD using 2D drawings for plans and elevations to confirm that reasonable space is allocated for all the topsides facilities and drilling activities. The deck structure will be estimated using in-house spreadsheets that consider deck area, deck loading, type of deck loading (uniform area load vs concentrated loads such as riser tension) and span between primary supports (e.g. column spacing).

11.2 Hull Configuration and Sizing

The hull configuration will be developed using in-house spreadsheets calibrated for the Paired Column SEMI concept. The sizing spreadsheets consider in-place and pre-service conditions, both intact and damaged. The resulting configuration will be verified through inter-discipline review (e.g. hull structural scantling for hull weights) and through stability analysis, global performance analysis, mooring analysis and riser analysis as discussed in the following sections.

11.3 Stability Analysis

Stability analysis will be performed using the GHS software for both intact and damage conditions. The hull internal compartmentation, an important consideration in overall hull weight, will be confirmed through stability analysis. Wind loads for stability analysis and global performance analysis will be developed using WINDOS based on the actual topsides layouts developed for this study.

11.4 Global Performance Analysis

Global performance analysis will be performed using coupled analysis program which accounts for coupling effects of mass, damping and loads of moorings and risers on platform hull responses. One unique feature of the program is the ability to deal with TTR's nonlinear vertical stiffness as a function of riser stroke. Since the dry tree semi-submersible platform has 12 Ram-style tensioners, the total vertical stiffness of all tensioners account for significant portion of overall vertical stiffness, therefore it is crucial to have the capability to model the nonlinear tensioner stiffness as a function of riser stroke accordingly.

11.5 Mooring Analysis

Mooring analysis will be performed by using coupled analysis program as described in Section 11.4. The mooring line was modeled by a number of finite elements and their mass, coupled with platform mass. Since the mooring line

consists of chain, polyester and chain, an analysis tool should have the capability to deal with larger elongation members, such as polyester moorings. The traditional formulation on the line extendibility to the first-order approximation is only good for wire ropes and not adequate for polyester moorings. More accurate approximation to 2nd order is important and necessary.

11.6 Hull Structural Verification

The hull primary structural weight will be developed based on hull scantling formulas in classification guidelines. The basic scantling plus allowances calibrated to numerous previous projects. Specific line items and/or allowances are included for reinforcements, major foundations, brackets, details, mill tolerance, weld volume and overall design allowances.

Hull appurtenance and outfitting structural weights are developed using a spreadsheet that calculates weights and allowances for specific items (e.g. riser porches, pump casings) and uses scaled estimates for other items (e.g. anodes based on wetted surface area.

Global structural analysis will be performed using the ANSYS finite element analysis program. The global model will include shell elements for all primary plating and beam elements for all girders and stiffeners. Static and dynamic load cases will be analyzed and the dynamic load cases will include hydrodynamic pressures and motion accelerations from global performance analysis. The integrated hydrodynamic/structural analysis will follow standard in-house procedures for floating offshore systems.

Design waves will be selected based on deck acceleration, hull squeeze/pry, hull racking and paired-column prying forces. Maximum stresses will be selected and used to verify the structural design according to strength and buckling criteria.

11.7 Riser Analysis

Riser analysis will be performed using the FLEXCOM software. Riser is modeled by a number of finite elements. The element length sizing is selected to have finer elements around the junctions of two different cross sections and at locations with large bending moments. The actual pipe-in-pipe riser system is modeled to be represented by a single equivalent riser string. Global motions from coupled analysis are used as input to the riser.

Appendix A

Detailed Drilling System Information from RPSEA

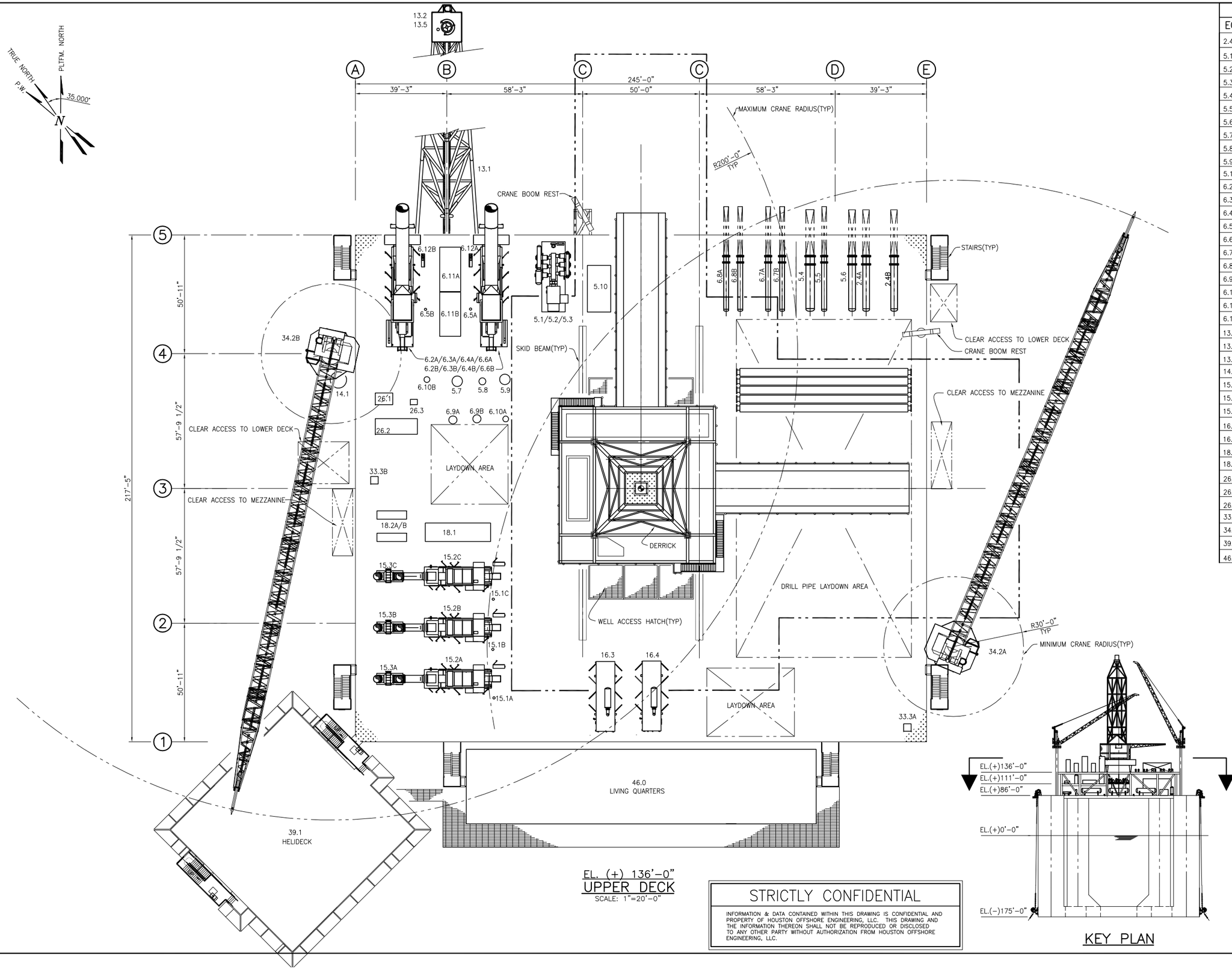
Mid-sized Drilling Rig – Miocene Capability

Capable of drilling and completing dry tree wells inside 9 7/8" casing in reservoirs up to 28,000 feet below sea level in up to 8,000 feet of water.

Rig Payload Live	**About 10,000 short tons - includes dead and live loads**
Derrick	165' clear height with about 2,500,000#'s static hook load capacity 13 5/8" casing load 1,700,000#'s
Substructure	2,000,000#'s hook load in addition to about 1,000,000# setback load
Setback	33,000'
Engines	Four each with total about 8,600 hp
Drawworks	Varco 4,200 hp. 1 ¾" drill-line or similar
Top Drive	Varco TDS 1000 & PH-100. 1,150 hp. Drilling torque 63,000#'s continuous
Work String	5 7/8" 27.9# S-135, XTM 57. TJ ID 4.25" + 6 5/8" 34# 4 1/2" 16.6#
Landing String	6 5/8" plus or minus 50 ft
Mud Pumps	Four each 7,500 psi triplex pumps – 2,200 hp each
Mud & Completion Fluid Capacity	About 8,000 bbls at 15 ppg. Scalable to 12,000 bbls as a function of topsides loads.
Well Kick Fluid	Client to specify ppg, quantity and pit volume philosophy
Riser Liquid Capacity	1,700 bbls without pipe in the 14" ID riser about 9,000 feet water depth
Cased Hole Capacity	2,000 bbls without production tubing in 9 7/8" C110, 62.8# casing about 26,000 feet below mud line
Shale Shakers	Six each Brandt LCM-2D or similar
P Tanks	Four each about 2.200 ft^3 each. Total 15,000 ft^3 plus 10,000 ft^3 barite & gel
Production Tubing	As specified by client. Assume 5 ½"
Completion Fluids	Filters, centrifuges etc as specified in the completion program
Shut-in Tubing Press	10,000 psi oil and 12,000 psi dry gas.
BOP Rams	13 5/8" Four each at 15,000 psi. Surface stack. Other BOPs: 11", 18 ¾" x 15ksi four rams, as specified by client.
BOP Annular	13 5/8" One each at 5,000 psi, 18 ¾" x 10 ksi
Coiled Tubing Operations	Client to specify unit including system, frame and support equipment

Appendix B

Topsides General Arrangement Drawings



EL. (+) 136'-0"
UPPER DECK
SCALE: 1"=20'-0"

KEY PLAN

EQUIPMENT LIST

EQUIPMENT TAG NO.	DESCRIPTION
2.4A/B	PRODUCTION HEAT EXCHANGER STAGE 3
5.1	SKID 1 BASE
5.2	COMPRESSOR (LOW PRESSURE)
5.3	DRIVER
5.4	INTERSTAGE COOLER STAGE 1
5.5	INTERSTAGE COOLER STAGE 2
5.6	INTERSTAGE COOLER STAGE 3
5.7	INTERSTAGE SCRUBBER STAGE 1
5.8	INTERSTAGE SCRUBBER STAGE 2
5.9	INTERSTAGE SCRUBBER STAGE 3
5.10	LUBE OIL CONSOLE
6.2A/B	SKID 1 BASE
6.3A/B	COMPRESSOR (EXPORT GAS)
6.4A/B	DRIVER
6.5A/B	FUEL GAS FILTER SEPARATOR
6.6A/B	GEARBOX
6.7A/B	INTERSTAGE COOLER STAGE 1
6.8A/B	INTERSTAGE COOLER STAGE 2
6.9A/B	INTERSTAGE SCRUBBER STAGE 1
6.10A/B	INTERSTAGE SCRUBBER STAGE 2
6.11A/B	LUBE OIL CONSOLE
6.12A/B	TURBINE PANEL
13.1	FLARE BOOM
13.2	HIGH PRESSURE FLARE TIP
13.5	LOW PRESSURE FLARE TIP
14.1	DEAERATOR
15.1A/B/C	FUEL GAS FILTER SEPARATOR
15.2A/B/C	POWER GENERATOR
15.3A/B/C	WASTE HEAT RECOVERY UNIT
16.3	EMERGENCY GENERATOR
16.4	ESSENTIAL GENERATORS
18.1	EXPANSION TANK
18.2A/B	HEATING MEDIUM CIRCULATION PUMP
26.1	COMPRESSOR AND AFTERCOOLER SKID
26.2	INERT GAS GENERATOR
26.3	NITROGEN BOTTLES QUAD
33.3A/B	FIRE MONITORS
34.2A/B	NON-COUNTERWEIGHTED PEDESTAL CRANE
39.1	HELIDECK
46.0	LIVING QUARTERS

REV	DESCRIPTION	BY	DATE
E	ADDED CRANE BOOM RESTS AND CHANGED DWG NO.	CEB	07/16/10
D	HULL CONFIGURATION UPDATE	CEB	07/15/09
C	HULL CONFIGURATION UPDATE	CEB	05/04/09
B	HULL CONFIGURATION UPDATE	CEB	04/16/09
A	PRELIMINARY	CEB	04/07/09

RELEASE FOR:	DEPT ENGR	PROJ ENGR	DESIGN ENGR	DESIGN LEAD	DATE
PRELIMINARY					
BIDDING					
MATL ORDER					
FABRICATION					

RPSEA Research Partnership to Secure Energy for America

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TBPE REGISTRATION NUMBER F-8656

Houston Offshore ENGINEERING

RPSEA 1402

GENERAL ARRANGEMENT MEDIUM PAYLOAD UPPER DECK PLAN

PROJ NO.	SCALE	DRAWN	DATE	CHECKED
H08130	1"=20'-0"	OWM	02/20/09	

DWG NO.	SHT	REV
H08130-G-DWG-GN-10001	01	E

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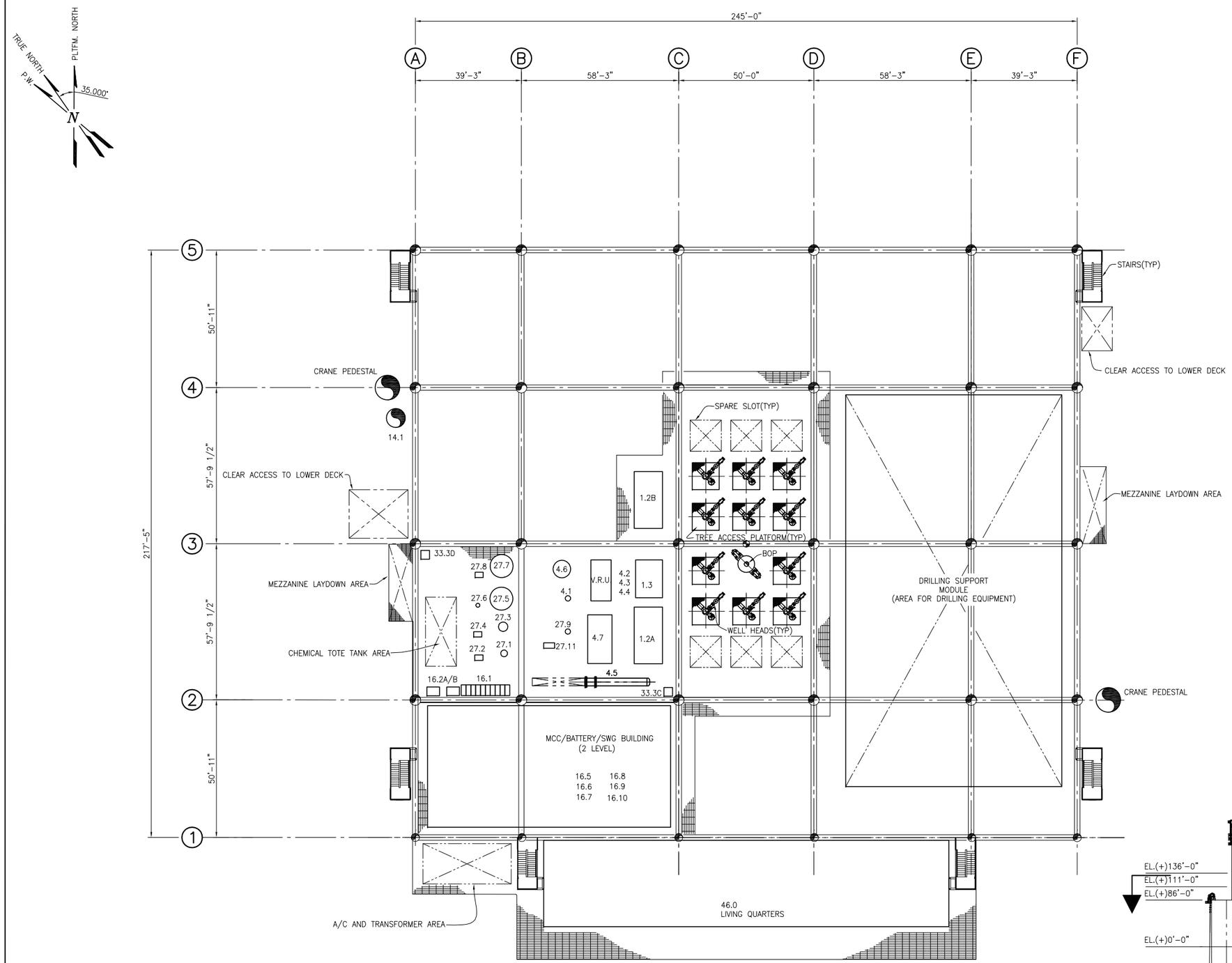
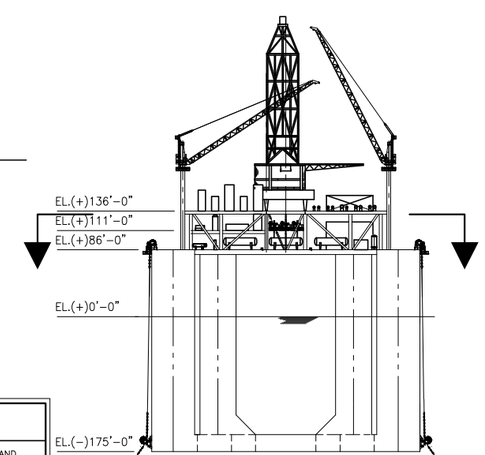
ANSI D - 22 x 34



EL. (+) 111'-0"
MEZZANINE DECK
SCALE: 1"=20'-0"



KEY PLAN

EQUIPMENT LIST	
EQUIPMENT TAG NO.	DESCRIPTION
1.2A/B	PROD MANIFOLDS
1.3	WATER INJ MANIFOLDS
4.1	INLET SCRUBBER
4.2	SKID 1 BASE
4.3	COMPRESSOR(VRU)
4.4	DRIVER
4.5	INTERSTAGE COOLER(VRU)
4.6	INTERSTAGE SCRUBBER STAGE 1
4.7	LUBE OIL CONSOLE
14.1	DEAERATOR
16.1	BATTERY BANK
16.2A/B	BATTERY CHARGER
16.5	LOW VOLTAGE SWITCHGEAR
16.6	LOW VOLTAGE TRANSFORMER
16.7	MEDIUM VOLTAGE SWITCHGEAR
16.8	MOTOR CONTROL CENTER
16.9	VSD LOW PRESSURE GAS
16.10	VSD VAPOR RECOVERY UNIT
27.1	ANTIFOAM STORAGE TANK
27.2	ANTIFOAM TRANSFER PUMP
27.3	ANTISCALE STORAGE TANK
27.4	ANTISCALE TRANSFER PUMP
27.5	GLYCOL STORAGE TANK
27.6	GLYCOL TRANSFER PUMP
27.7	METHANOL STORAGE TANK
27.8	METHANOL TRANSFER PUMP
27.9	OXYGEN SCAVENGER MIXING TANK
27.10	OXYGEN SCAVENGER SOLID STORAGE
27.11	OXYGEN SCAVENGER TRANSFER PUMP
33.3C/D	FIRE MONITORS
34.2A/B	NON-COUNTERWEIGHTED PEDESTAL CRANE
46.0	LIVING QUARTERS

REV	DESCRIPTION	BY	DATE
E	CHANGED DWG NO.	CEB	07/16/10
D	HULL CONFIGURATION UPDATE	CEB	07/15/09
C	HULL CONFIGURATION UPDATE	CEB	05/04/09
B	HULL CONFIGURATION UPDATE	CEB	04/16/09
A	PRELIMINARY	CEB	04/07/09

RELEASE FOR:	DEPT ENGR	PROJ ENGR	DESIGN ENGR	DESIGN LEAD	DATE
PRELIMINARY					
BIDDING					
MATL ORDER					
FABRICATION					

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TBPE REGISTRATION NUMBER F-8656
Houston Offshore ENGINEERING

RPSEA 1402

GENERAL ARRANGEMENT
MEDIUM PAYLOAD
MEZZANINE DECK
PLAN

PROJ NO.	SCALE	DRAWN	DATE	CHECKED
H08130	1"=20'-0"	OWM	02/20/09	

DWG NO.	SHT	REV
H08130-G-DWG-GN-10002	01	E

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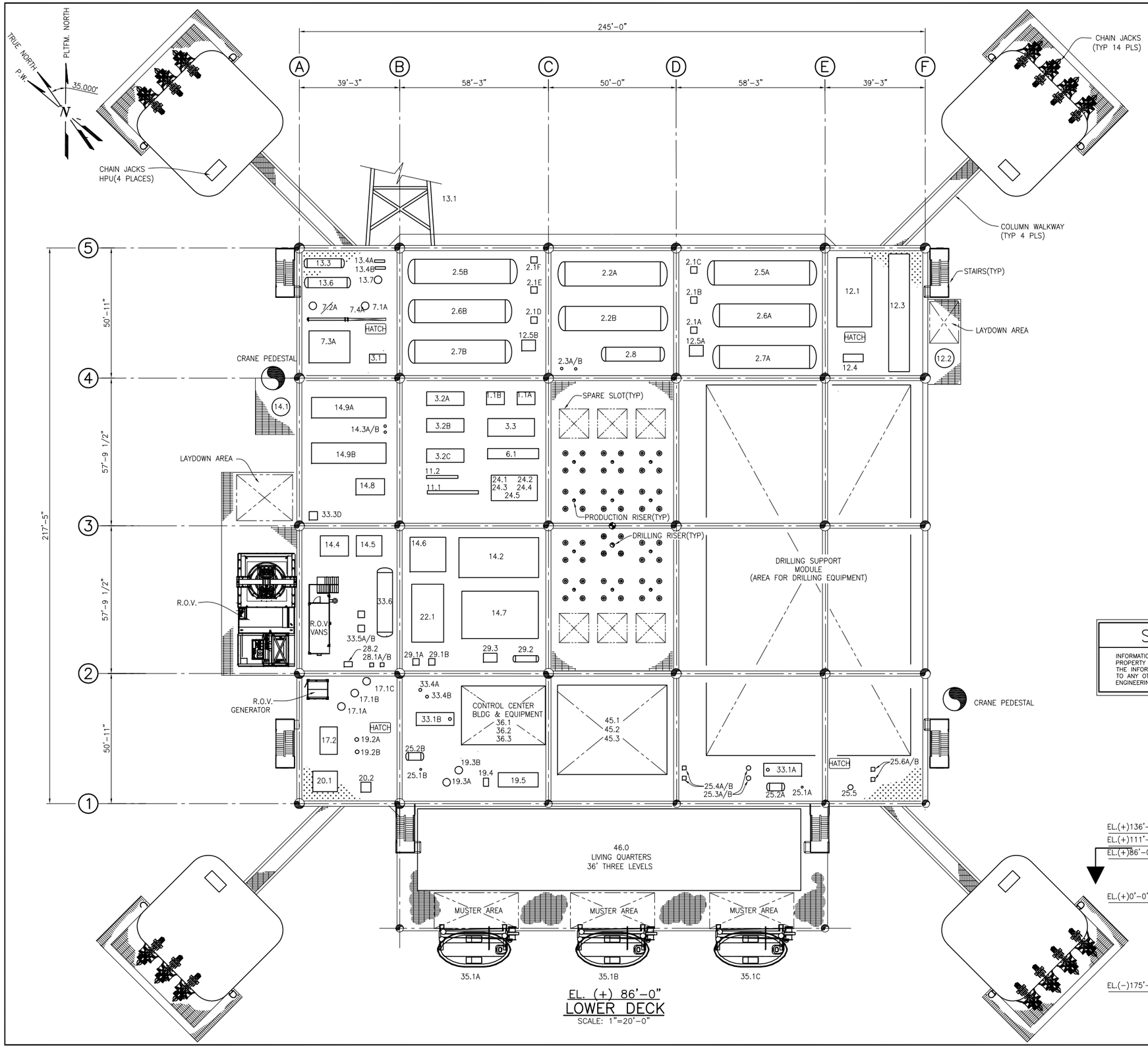
ANSI D - 22 x 34



EQUIPMENT LIST	
TAG NO.	DESCRIPTION
1.1A/B	HYDRAULIC SKID
2.1A/B/C/D/E/F	CRUDE BOOSTER PUMP
2.2A/B	DESALTER
2.3A/B	PRE-FLASH SEPARATOR
2.5A/B	PRODUCTION SEPARATOR STAGE 1
2.6A/B	PRODUCTION SEPARATOR STAGE 2
2.7A/B	PRODUCTION SEPARATOR STAGE 3
2.8	TEST SEPARATOR
3.1	CRUDE COOLER
3.2A/B/C	CRUDE EXPORT PUMPS
3.3	CRUDE METERING SKID
6.1	GAS METERING SKID
7.1A	DEHYDRATION SCRUBBER
7.2A	GLYCOL CONTACTOR
7.3A	GLYCOL REGENERATION SKID-S.G.
7.4A	LEAN GLYCOL/DRY GAS EXCHANGER
11.1	CRUDE EXPORT PIG LAUNCHER
11.2	EXPORT GAS SPHERE LAUNCHER
12.1	DUAL MEDIUM DOWNFLOW FILTER
12.2	FLASH TANK
12.3	FLOTATION UNIT
12.4	HYDROCYCLONE UNIT
12.5A/B	SEPARATED OIL PUMP
13.1	FLARE BOOM
13.3	HIGH PRESSURE RELIEF DRUM
13.4A/B	IGNITION PANEL
13.6	LOW PRESSURE RELIEF DRUM
13.7	OPEN VENT SCRUBBER
14.1	DEAERATOR
14.2	DUAL MEDIUM DOWNFLOW FILTER
14.3A/B	FUEL GAS FILTER SEPARATOR
14.4	SULFATE ION REMOVAL CARTRIDGE FLTR. PKG.
14.5	SULFATE ION REMOVAL CLEAN-UP PACKAGE
14.6	SULFATE ION REMOVAL FEED PUMP PACKAGE
14.7	SULFATE ION REMOVAL MEMBRANE PACKAGE
14.8	VACUUM UNIT

EQUIPMENT LIST	
TAG NO.	DESCRIPTION
14.9A/B	WATER INJECTION PUMP AND DRIVER
17.1A/B/C	SEAWATER LIFT PUMPS
17.2	SEAWATER STRAINER
19.2A/B	FRESH WATER TRANSFER PUMPS
19.3A/B	SEAWATER LIFT PUMP
19.4	SEAWATER STRAINER
19.5	WATER-MAKER
20.1	CHLORINATOR
20.2	DEGASSING TANK
22.1	INSTR. & UTILITY AIR COMP. SKID
24.1	FUEL GAS HEATER
24.2	FUEL GAS PACKAGE BULKS
24.3	FUEL GAS PRE-HEATER
24.4	FUEL GAS SCRUBBER
24.5	FUEL GAS SKID BASE
25.1A/B	DIESEL FILTER COALESCER
25.2A/B	FIRE PUMP DAY TANK
25.3A/B	INLET FILTER COALESCER
25.4A/B	TREATED DIESEL TRANSFER PUMP
25.5	UNTREATED DIESEL LIFT PUMP
25.6A/B	UNTREATED DIESEL TRANSFER PUMP
28.1A/B	SEAWATER DISTRIBUTION PUMPS
28.2	SEAWATER STRAINER
29.1A/B	COOLING MEDIUM CIRCULATION PUMP
29.2	EXPANSION TANK
29.3	PLATE HEAT EXCHANGER
33.1A/B	DIESEL FIREWATER PUMP AND DRIVER
33.3E	FIRE MONITORS
33.4A/B	FIREWATER JOCKEY PUMP
33.5A/B	FOAM PUMP
33.6	FOAM TANK
35.1A/B/C	LIFEBOATS CAPSULES
36.1	CONTROL ROOM
36.2	FIELDBUS CONTROL PANEL
36.3	FIELDBUS SAFETY PANEL
45.1	CONTROL CENTER HOUSING
45.2	LAB AND WORKSHOPS
45.3	POWER DISTRIBUTION EQUIPMENT HOUSING
46.0	LIVING QUARTERS

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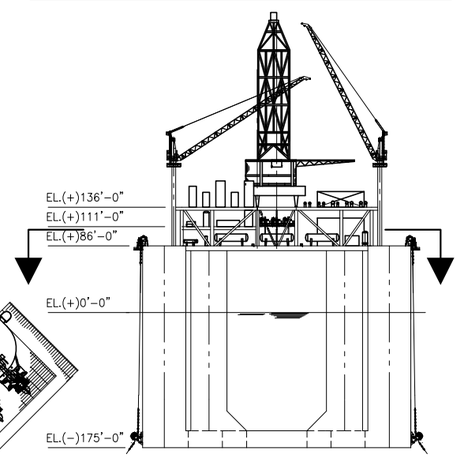

KEY PLAN

REV	DESCRIPTION	BY	DATE
E	CHANGED DWG NO.	CEB	07/16/10
D	HULL CONFIGURATION UPDATE	CEB	07/15/09
C	HULL CONFIGURATION UPDATE	CEB	05/04/09
B	HULL CONFIGURATION UPDATE	CEB	04/16/09
A	PRELIMINARY	CEB	04/07/09

RELEASE FOR:	DEPT ENGR	PROJ ENGR	DESIGN ENGR	DESIGN LEAD	DATE
PRELIMINARY					
BIDDING					
MATL ORDER					
FABRICATION					

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Houston Offshore ENGINEERING

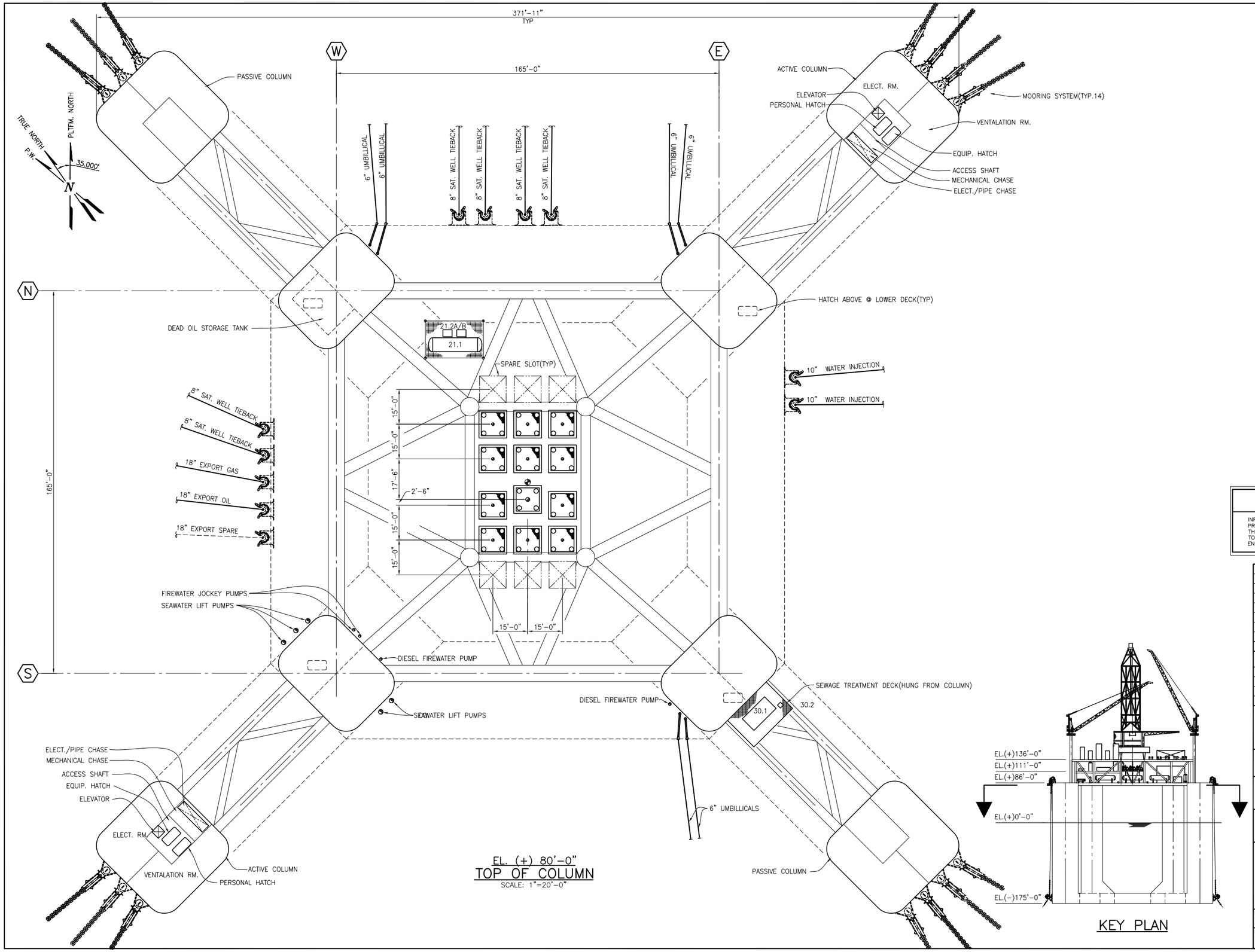
RPSEA 1402

GENERAL ARRANGEMENT MEDIUM PAYLOAD LOWER DECK PLAN

PROJ NO.	SCALE	DRAWN	DATE	CHECKED
H08130	1"=20'-0"	OWM	02/19/09	

DWG NO.	SHT	REV
H08130-G-DWG-GN-10003	01	E

ANSI D - 22 x 34



EQUIPMENT LIST	
TAG NO.	DESCRIPTION
21.1	DRAIN SEPARATOR
21.2A/B	DRAIN SEPARATOR PUMP
30.1	AEROBIC UNIT
30.2	HOLDING TANK

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C	HULL CONFIGURATION UPDATE	CEB	05/04/09
B	HULL CONFIGURATION UPDATE	CEB	04/16/09
A	PRELIMINARY	CEB	04/07/09

RELEASE FOR:	DEPT ENGR	PROJ ENGR	DESIGN ENGR	DESIGN LEAD	DATE
PRELIMINARY					
BIDDING					
MATL ORDER					
FABRICATION					

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Houston Offshore ENGINEERING

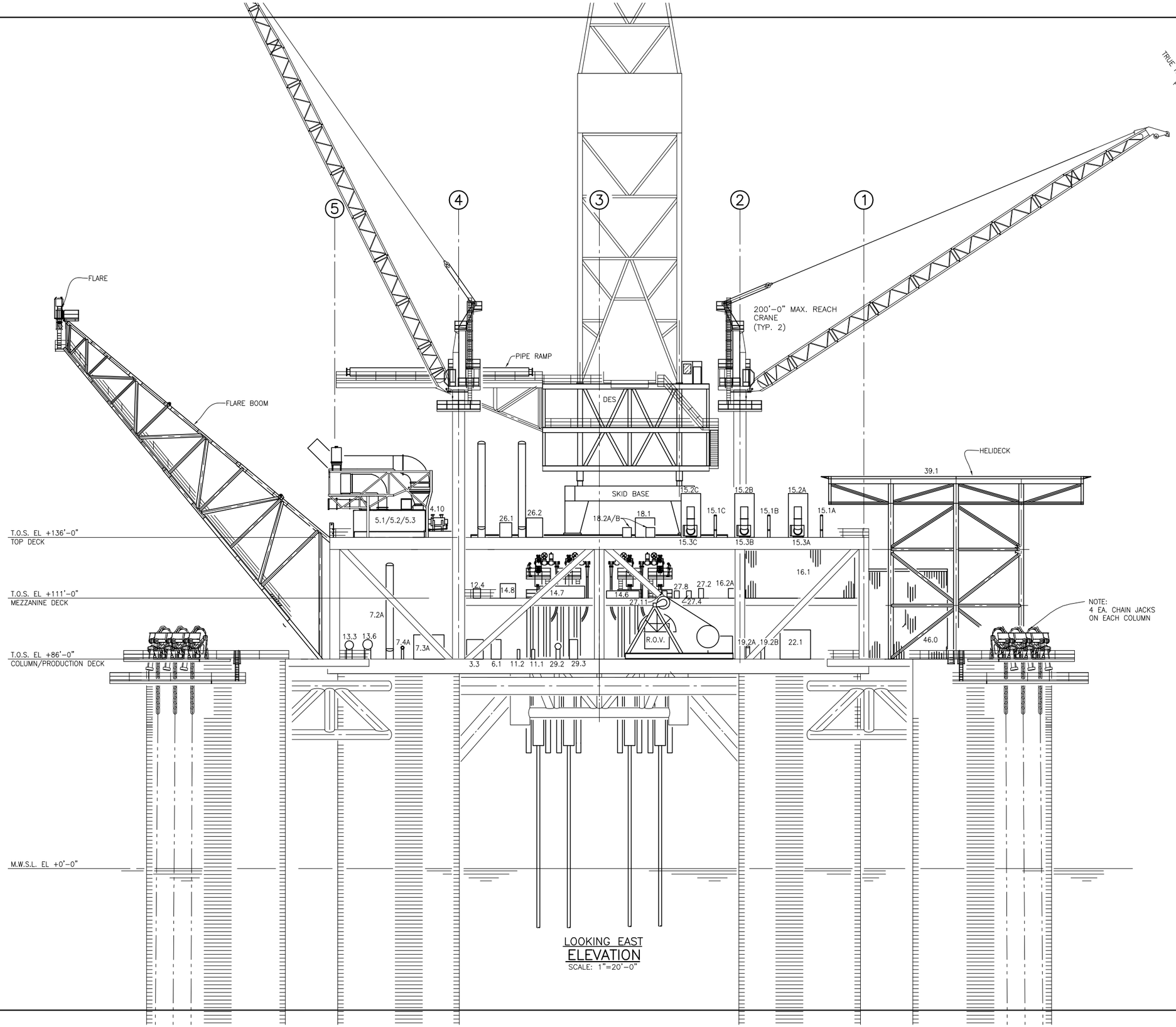
RPSEA 1402

GENERAL ARRANGEMENT MEDIUM PAYLOAD TOP OF COLUMN PLAN

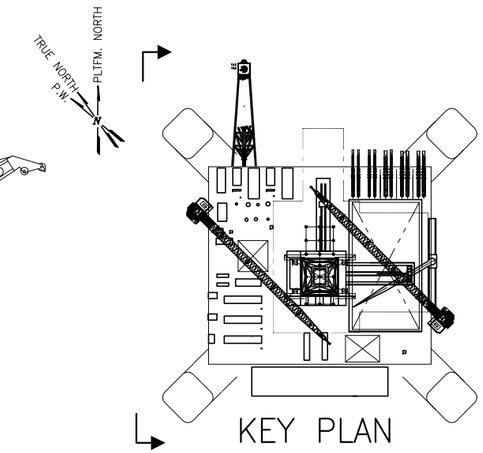
PROJ NO.	SCALE	DRAWN	DATE	CHECKED
H08130	1'=20'-0"	OWM	02/20/09	

DWG NO.	SHT	REV
H08130-G-DWG-GN-10004	01	E

ANSI D - 22 x 34



LOOKING EAST
ELEVATION
SCALE: 1"=20'-0"



KEY PLAN

NOTES:

1. SEE PLAN SHEETS FOR EQUIPMENT LIST AND LOCATIONS.

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Houston Offshore ENGINEERING

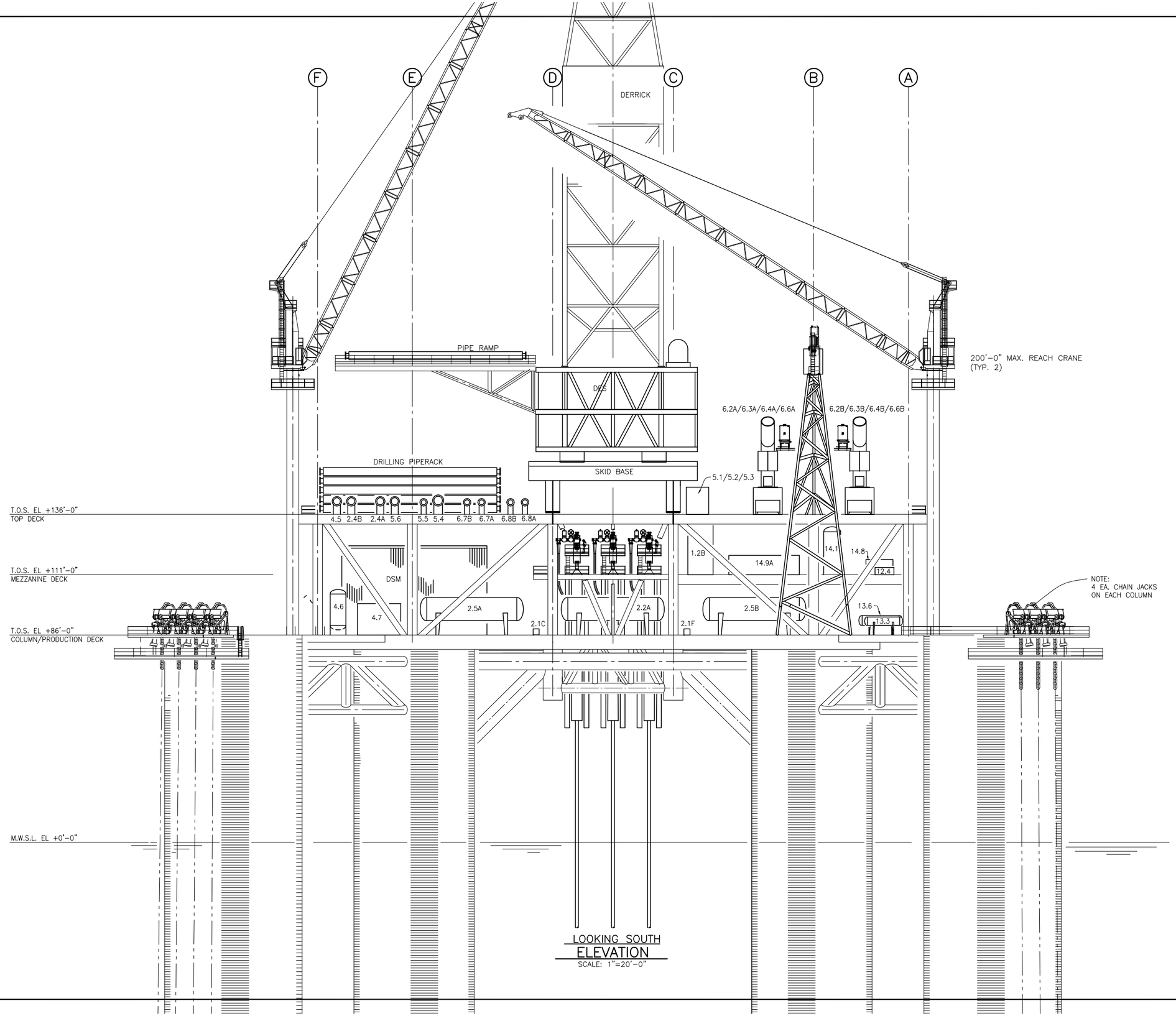
RPSEA 1402

GENERAL ARRANGEMENT
MEDIUM PAYLOAD
LOOKING EAST
ELEVATION

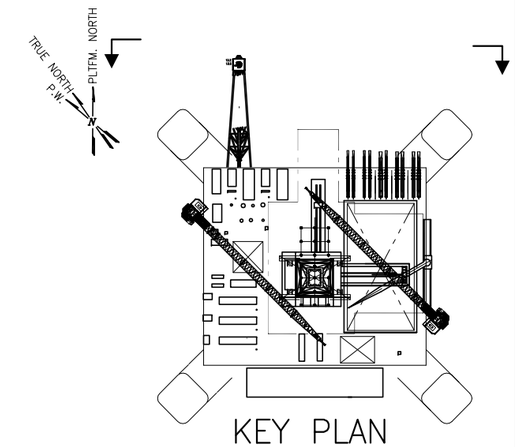
PROJ NO.	SCALE	DRAWN	DATE	CHECKED
H08130	1"=20'-0"	OWM	02/20/09	

DWG NO.	SHT	REV
H08130-G-DWG-GN-10005	01	E

ANSI D - 22 x 34



LOOKING SOUTH
ELEVATION
SCALE: 1"=20'-0"



KEY PLAN

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BIDDING					
MATL ORDER					
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Houston Offshore ENGINEERING

RPSEA 1402

GENERAL ARRANGEMENT
MEDIUM PAYLOAD
LOOKING SOUTH
ELEVATION

PROJ NO.	SCALE	DRAWN	DATE	CHECKED
H08130	1"=20'-0"	OWM	02/20/09	

DWG NO.	SHT	REV
H08130-G-DWG-GN-10006	01	E

ANSI D - 22 x 34