From: DWH, AsstDriller (Deepwater Horizon)
Sent: Saturday, February 06, 2010 7:12 AM
To: DWH, Toolpusher (Deepwater Horizon)
Subject: WELL ADVISOR.xls
Attachments: WELL ADVISOR.xls

Exhibit No. 4805
Worldwide Court Reporters, Inc.

Transocean

Welcome to Well Advisor

A Well Review Checklist	**Comments:**
B Input Kick Tolerance Data	Enter data in Kick Tolerance sheet first.
C Well Overview	**ENTER DATA IN YELLOW CELLS ONLY**
D Maximum Pressure @ Wellhead	Revised 1st April 2009.
E Pore Pressure, Mud & Fracture Weights Chart (Click PP,MW & FP tab)	
F Well Control Preparation Checklist	
G Post Well Review	
H Conversions	For your queries contact
Help	woq@mail.deepwater.com

WELL REVIEW CHECKLIST

Rig Name
Well Name

A
1
2
3'
4
5
6'
B
7'
8
9
10'
11a
11b
11c'
12a
12b
12c
13
14
15'
C
16'
17'
18a'

Location Assessment
Review the well location, well trajectory profile and plan view in the well program.
Provide a Mooring analysis as appropriate. (Floater)
Provide a riser analysis and/or review conductor tension for the location as appropriate. (Floater) '
Review/discuss Well Specific Operating Criteria. (Floater)
Are there any outstanding issues with the site survey/foundation data? (Jack Up)
For re-entries or workovers, determine the airgap of rigs which previously worked on the well and adjust accordingly.'
Well Control - Shallow Gas (Prior to BOP)
Has a satisfactory Shallow Gas assessment been performed which addresses the Transocean shallow gas policy? '
Has a seismic map showing surface and bottom hole locations been provided?
Has a bright spot analysis been performed?
Is there a possibility of encountering a shallow reservoir?
Has the planned well location been moved to avoid shallow gas or potential shallow water flows?
Has there or will there be a pilot hole drilled? A pilot hole should be drilled to the casing point in areas of possible shallow gas.
Has a shallow gas contingency plan been developed?

Does the contingency plan reflect the method of well control?

Does the contingency plan allow for rapid well detection, securing of the unit, activation of the de
luge system and evacuation of personnel with simple yet specific instructions?'
In areas of potential shallow gas a non-ported float valve should be run in the BHA.
For casing drilling, a dual high pressure differential opening float collar should be used.
Diverter-less drilling will require a dispensation from Transocean well control policy.
For casing drilling, a dual high pressure differential opening float collar should be used.

Diverter-less drilling will require a dispensation from Transocean well control policy.
Where applicable, Bit nozzles and BHA should allow for LCM to be pumped without clogging.
Are plans in place for the diverter system to be function tested?
Has the diverting procedure been formalized and posted, with the crew trained in implementation through regularly conducted drills?'
Well Control - General.
If differences exist between standard Transocean practices and the operator requirements, has a brid
ging document been prepared and approved? Are rig specific well control procedures in place?'
Has a review of operator and Transocean offset data been performed?
(To include mud weights used, casing shoes, drilling problems, any well control problems, highlights, lowlights)'
On production platforms are plans in place for nearby wells to be monitored for signs of pressure at the annuli? '

Rig A					Operator	Client A
123456					Date	1-Jan-08

YES	NO	N/A	Well Con Ref #	Comments
				Audit
				Audit'
				Audit'

wcg@mail.deepwater.com

18b
18c
19a
19b'
20
21
22
23a'
23b'
23c'
24
25
26
27
D
28
29
30
31
32
33'
E
34a
34b
35a
35b
35c
35d
35e
36'

Are there existing plans to avoid other well paths?

Are any SIMOPS planned on the platform which may affect well operations?
Has a temperature profile been provided?

Are well control equipment rubber goods/elastomers suitable for the expected circulating temperature? '
Are Lithology and Stratigraphy columns including depth uncertainty available?
Have pore pressure and fracture gradient profiles been provided?
Compare these profiles with the leak off/formation integrity tests planned for each section.
Is the planned Kick Tolerance greater than 50bbls in each hole section of the well?
Refer to Well control manual for exemption procedure & required levels of dispensation.
Determine the max anticapated wellhead pressures possible for each section and compare with BOP rating.
'

Determine the max anticapated wellhead pressures possible for each section and compare with Wellhead rating.
'

Determine the max anticapated wellhead pressures possible for each section and compare with casing burst pressures for each relevant section.'
Review the proposed BOP pressure test schedule and casing pressure test schedule.
Review the ram configuration for the well or each hole section as applicable.
Review the kill and choke line configurations.
Are any Well Control Dispensations required?
Drilling Hazards
Is there the potential for boulder-beds or channels?
Is there the potential for lost circulation? Is a mitigation plan in place?
Are any faults expected to be encountered?
Is any H_2S expected to be encountered?
Is any CO_2 expected to be encountered?
What other formation hazard potential is know to exist? (Differential sticking, Over pressured shale's) '
Well Construction
The drilling program should be made available well in advance for review.
Ensure that all parties have the same and latest version.
Ensure that any amendment is properly communicated to Onshore and Offshore personnel.

The drilling program should be made available well in advance for review.
Review offset data as per item #17 above.
FLUIDS: Review the fluids planned WBM/OBM/SBM for the well from the following perspectives:
(i) environmental containment
(ii) safety concerns & availability of MSDS
(iii) maximum weights capable of being stored on board,
(iv) compatibility with rubber goods / elastomers,
(v) LCM on board
FLUIDS: Are there any cuttings cleaning or zero discharge requirements which may require installation and rig modification?'

Audit

Audit

37a'
37b'
38
39'
40
41'
42
F
43
44'
45'
46
47
48
49
50'

CASING: Is the casing design similar to offset wells? Is there a contingency liner or other contingency plan in place? '
CASING: If casing program is significantly different (shoe depths, number of casing/liner strings, w
all thickness, diameter, grade, TOC), ascertain reasoning. '
CEMENT: Review the cement thickening time vs. planned mixing, displacement time and offset data
CEMENT: Establish minimum WOC time before removing stack. (Special attention necessary when a slip and seal type wellhead is in use)'
CEMENT: Review the expected ECDs during cementing vs. leak off test and fracture gradient
CEMENT: Discuss the cement placement method -- are any problems foreseen with regard to equipment or operation? '
CEMENT: Is there a contingency plan for top up job in place? (Jack Up)
Rig Site Operations
What is the maximum anticipated hook load? (versus equipment limitations).
Discuss drillpipe & landing string tensile rating – Review the allowable tensile capacity versus depth & overpull requirement.
Discuss any other potential equipment limitations versus the planned well program: (derrick, drawworks, rotary table, TDS, mud pumps, other). '
Are any Simultaneous Operations planned? A separate SIMOPS study may be required.
Manned Platform (Jack Up) – Are Emergency Procedures and operating parameters in place?
Well Testing operations will require a separate series of meetings (HAZID/HAZOP) and/or CWOP.
Work over operations will require a separate series of meetings / HAZID / HAZOP.
Critical or non-standard operations such as HPHT, surface BOPs or managed pressure drilling will req
uire a separate series of meetings / HAZID / HAZOP.'

Transocean
Well Operations Group, Houston

wcg@mail.deepwater.com

Transocean Kick Tolerance

Weak Point Data

Casing/ Liner Size in
18.000
16.000
13.625
11.750
9.88

Operators Kick Tolerance

Weak Point Data

Casing/ Liner Size in
18.00
16.00
13.63
11.75
9.88

Note:
If the KT for a swabbed kick is required, the value of Pf should be taken as the value of the mud hy
' drostatic in use (i.e. the pressure of the swabbed in gas bubble is equal to the hydrostatic of the mud column.'

' This methodology gives a higher KT since no kick intensity is incorporated & should not be confused when dealing with KT calculations.'

Casing Shoe Depths				Open Hole Data		Section TD		Drill String Data			Other Data
		LOT/FIT EMW	Hole Angle @ Shoe	Hole Size	Hole Angle @ TD			Drill Collar Length	Drill Collar OD	Drill Pipe OD	Mud Weight @ TD
TVD ft	MD ft	ppg	°	in	°	TVD ft	MD ft	ft	in	in	ppg
8,969	8,969	12.0	0.0	18.13	0.0	12,250	12,250	300	8.25	6.63	10.10
12,250	12,250	13.6	0.0	18.13	0.0	13,000	13,000	300	8.00	6.63	11.80
15,300	15,300	14.7	0.0	16.50	0.0	14,000	18,000	300	8.00	6.63	12.90
17,000	17,000	15.2	0.0	14.50	0.0	18,500	18,500	300	6.50	5.00	13.30
19,650	19,650	16.1	0.0	12.25	0.0	20,000	20,000	300	4.75	3.50	14.40

Casing Shoe TVD				Open Hole Data					Drill String Data		
		LOT/FIT EMW	Hole Angle @ Shoe	Hole Size	Hole Angle @ TD	Section TD		Max PP	Drill Collar Length	Drill Collar OD	Drill Pipe OD
TVD ft	MD ft	ppg	°	in	°	TVD ft	MD ft	ppg	ft	in	in
8,969	8,969	12.00	0.0	18.13	0.0	12,250	12,250	10.00	300	8.25	6.63
12,250	12,250	13.60	0.0	18.13	0.0	13,000	13,000	11.50	300	8.00	6.63
15,300	15,300	14.70	0.0	16.50	0.0	14,000	18,000	12.00	300	8.00	6.63
17,000	17,000	15.20	0.0	14.50	0.0	18,500	18,500	13.00	300	6.50	5.00
19,650	19,650	16.10	0.0	12.25	0.0	20,000	20,000	14.50	300	4.75	3.50

Units:* *oil field

Annular Back Pressure @ SCR	Choke Operator Error	Kick Intensity	Swabbed Kick	Influx Gradient	KT
psi	psi	ppg		psi/ft	bbls
50	100	0.50	No	0.1	225.1
50	100	0.50	No	0.1	348.7
50	100	0.50	No	0.1	350.9
50	100	0.50	No	0.1	313.9
50	100	0.50	No	0.1	217.2

Other Data

Mud Weight @ TD	Annular Back Pressure @ SCR	Choke Operator Error	Influx Gradient	KT
ppg	psi	psi	psi/ft	bbls
10.10	50	100	0.1	457.0
11.80	50	100	0.1	639.8
12.90	50	100	0.1	747.0
13.30	50	100	0.1	548.1
14.40	50	100	0.1	303.0

Yes

No

Annular Capacity & Volume Around Drill Collars		Annular Capacity Around DP	True Vertical Height Of BHA	TD Vmax Volume Around DP
bbls/ft	bbls	bbls/ft	ft	bbls
0.2530	75.90	0.2765	300	188.6
0.2570	77.09	0.2765	300	271.6
0.2023	60.69	0.2218	300	290.3
0.1632	48.96	0.1800	300	265.0
0.1239	37.16	0.1339	300	180.0
0.0000	0.00	0.0000		
0.0000	0.00	0.0000		
0.0000	0.00	0.0000		
0.0000	0.00	0.0000		
0.0000	0.00	0.0000		

Annular Capacity Around Drill Collars		Annular Capacity Around DP	True Vertical Height Of BHA	TD Vmax Volume Around DP
bbls/ft	bbls	bbls/ft	ft	bbls
0.2530	75.90	0.2765	300	437
0.2570	77.09	0.2765	300	563
0.2023	60.69	0.2218	300	686
0.1632	48.96	0.1800	300	499
0.1239	37.16	0.1339	300	266
0.0000	0.00	0.0000		
0.0000	0.00	0.0000		
0.0000	0.00	0.0000		
0.0000	0.00	0.0000		
0.0000	0.00	0.0000		

Formation Strength @ Shoe	Safety Margin	Pmax	Pf	Hmax	TD Vmax	Weak Point Vmax	Convert Vmax With Boyle's Law to V1
psi	psi	psi	psi	ft	bbls	bbls	bbls
5,597	150	736	6,752	982	264.5	271.6	225.1
8,663	150	997	8,315	1,282	348.7	354.6	369.4
11,695	150	1,282	9,755	1,608	350.9	356.8	427.8
13,437	150	1,530	13,276	1,772	313.9	319.0	322.8
16,451	150	1,587	15,496	1,645	217.2	220.2	233.8

Formation Strength @ Shoe	Safety Margin	Pmax	Pf	Hmax	TD Vmax	Weak Point Vmax	Convert Vmax With Boyle's Law to V1
psi	psi	psi	psi	ft	bbls	bbls	bbls
5,597	150	933	6,370	1,881	513.1	520.1	457.0
8,663	150	1,338	7,774	2,335	639.8	645.7	719.6
11,695	150	2,148	8,736	3,394	747.0	752.9	1008.0
13,437	150	1,945	12,506	3,073	548.1	553.1	594.2
16,451	150	1,635	15,080	2,286	303.0	306.0	333.8

Chart Data

in
18.00
18.00
16.00
16.00
13.63
13.63
11.75
11.75
9.88
9.88

TVD ft	
4,080	7.1
8969	7.1
4080	7.2
12250	7.2
5500	7.3
15300	7.3
4080	7.4
17000	7.4
12500	7.5
19650	7.5
	7.6
	7.6
	7.7
	7.7
	7.8
	7.8
	7.9
	7.9
	8.0
	8.0

Pore Pressure
Mud Weight
LOT

1	Rig Name	
2	Operator	
3	Rig Type	
4	Type of Well	
5	Well Name	
6	Country	
7	Well Location	
8	Well Profile	

Weak Point Data
Casing or Liner

28	Casing
29	Casing
30	Liner
31	Casing
32	Liner
33	
34	
35	
36	
37	

Open Hole

	Inches
38	17.50
39	13.00
40	12.25
41	8.50
42	6.00
43	
44	
45	
46	
47	

For Hydrate, if Water Depth >1000ft

Rig A
XYZ
Floater
Development
Deep 1
GOM
Open Water
Vertical

9	Well TD, TVD
10	Water Depth
11	Air Gap
12	Wellhead Depth
13	Gas Density
14	Fresh/Sea Water

Size Inches	Shoe TVD ft	Inc °	LOT/FIT ppg	Liner Top TVD ft	Open Hole Data Size Inches
18.00	8,969	0	12.0		18.13
16.00	12,250	0	13.6		18.13
13.63	15,300	0	14.7	5,500	16.50
11.75	17,000	0	15.2		14.50
9.88	19,650	0	16.1	12,500	12.25

Hazards / Critical Success Factors for Well Operations

Salt Domes
Salt Domes
Hole Cleaning
Lost Circulation
Gas/Oil/Water Kick

Lost Circulation
Soft Unconsolidated Sediments
Abnormal Pr Zone
Reservior

Well Overview

20,000	ft
4,000	ft
80	ft
4,000	ft
0.1	psi/ft
8.6	ppg
Units:	oil field

Section TD

TVD ft	MD ft	Inc °
12,250.00	12,250.00	0
13,000.00	13,000.00	0
14,000.00	18,000.00	0
18,500.00	18,500.00	0
20,000.00	20,000.00	0

Rig Managers Comments

Refer to offset well X

15
16
17
18
19
20

DC OD Inches
8.25
8.00
8.00
6.50
4.75

Drilling Fluid

WBM
OBM
OBM
OBM
OBM

Well Environment		Non Standard
Specify Non Std Operation		MPD
Proposed Completion		Well Test
Expected Reservoir Fluid		Condensate
Associated Reservoir Fluid		Water

DP OD Inches	MW @ TD ppg	Max PP ppg	Transocean KT bbls
6.63	10.10	10.0	225
6.63	11.80	11.5	349
6.63	12.90	12.0	351
5.00	13.30	13.0	314
3.50	14.40	14.5	217

Casing/Liner

	Size Inches	Weight lbs/ft	MW ppg
48	18.00	133	8.4
49	16.00	72	10.1
50	13.63	60	11.8
51	11.75	53.5	12.9
52	9.88	35	13.3
53			
54			
55			
56			
57			
58			

62 Total 'RISK' Score=

21	Start Date	2-Oct-09
22	Planned Days	60
	Forecast End Date	1-Dec-09
23	BOP rating (psi)	10,000
24	Wellhead Rating (psi)	10,000
25	Max Temp at Well TD	151° C
26	Max Circ Temp @ BOP	85° C
27	Seabed Temperature	5° C

Operators KT	MW - PP Margin	Over- Balance	MAASP [no SF]	Max Press @ BOP	Max Press @ Surface
bbls	ppg	psi	psi	psi	psi
457	0.1	64	886	5,108	5,108
640	0.3	203	1,147	6,882	6,474
747	0.9	655	1,432	7,744	7,336
546	0.3	289	1,680	11,064	10,656
303	-0.1	-104	1,737	13,488	13,080

Casing/LinerWeight	Landing String Weight		Estimated Hook Load	LS Ten Cap 90%	Landing String Concern?
lbs	lbs/ft	lbs	lbs	lbs	
566,771	55.8	198,441	765,212	1,000,000	OK
497,451	55.8	192,526	689,977	1,000,000	OK
481,973	55.8	251,560	733,534	1,000,000	OK
554,962	55.8	182,785	737,747	1,000,000	OK
199,389	55.8	555,740	755,130	1,000,000	OK

HIGH RISK WELL

Type of Rig	Risk
Jack-Up	2
Floater	3

Type of Well	Risk
Wildcat	3
Exploration	2
Appraisal	2
Development	2
Completion	2
Workover	1
Units	
Oil Field	
Metric	
SI	
Well Location	**Risk**
Open Water	3
Platform	2
Subsea Field	2
Well Profile	**Risk**
Directional	2
Horizontal	2
Multilateral	3
Vertical	1
Well Environment	**Risk**
Deepwater	2
HPHT	10
Non Standard	10
Slim Hole	3
Standard	1
Under Balance	5
Proposed Completion	
Complete	
Well Test	
P & A	
Suspend	
Expected Reservoir Fluid	**Risk**
Condensate	4
Formation Water	2
Gas	3

Hazards	Risk
Abnormal Pr Zone	2
Ballooning	2
Basement Drilling	2
Bathymetry	2
Buried Faulting or Channels	2
Chaotic Zone	2
Chemo-synthetic Communities	2
CO2	2
Debri	2
Depletion	2
Dogleg Severity	2
Faults	2
Gas/Oil/Water Kick	2
H2S	2
Hole Cleaning	2
Hydrates	2
Land/Mud Slides	2
Lost Circulation	2
Pipelines	2
Reservior	2
Salt Domes	2
Seabed Expulsion Features	2
Shallow Gas	2
Shallow Water Flow	2
Shipwrecks	2
Soft Unconsolidated Sediments	2
Stuck Pipe Risk	2
Transition Zone	2
Tripping	2
Wellbore Stability	2
Drilling Fluid	**Risk**
SW	1
OBM	3
WBM	1
Brine	1
Drill - In Fluid	1
Non Standard	
SBOP	
CAPM	
Riserless on Jack up	
Under balance	

Landing String

	Casing	Liner
BF	lbs	lbs
0.87164	198441	0
0.84566	192526	0
0.81968	186612	251560
0.80287	182785	0
0.79676	181394	555740

59	**Pressure @ BOP**
60	Seabed Temperature
61	Hydrate Equilibrium Temperature

Notes:

Casing weight calculation uses TVD, well inclination is not considered.

' ' While drilling the well the kick tolerence should be re-calculated for the actual LOT & mud weights.'

' ' If seabed temperature is less than the hydrate equilibrium temperature then hydrate remediation may be required.'

Risk Score

<15
15-25
>25

Transocean, Well Operations Group, Houston :wog@deepwater.com

1789 psi
5.0° C
18.0° C

Low Risk
Med Risk
High Risk

67'
69'

63
64
65
66
68
70

Well Type
>50 bbls
25 bbls to 50 bbls
<25 bbls

ALERT MESSAGES

High Risk Well. Please refer to Operations Manager & Well Operations Group
Non Standard. Inform Operations Manager & Well Operations Group for Program Review
Max Surface Pressure Exceeds 80% of BOP Rating
Max Surface Pressure Exceeds 80% of Wellhead Rating'
Refer to HPHT Checklist. Temperature in Excess of 150° C
Refer to HPHT Checklist. Possible BOP Pressures in Excess of:'
Hydrate Remediation May Be Required - Check With Operator

Floater
Development

Exploration & Apprasial

OIM and Rig Manager Performance Informed
Operations Managers Performance Informed
Division Manager Approval or Business Unit Director of Operations Performance Approval

10000' psi'

Bottom Supported Development

Exploration & Apprasial

Oil	2
Associated Reservoir Fluid	Risk
CO_2	2
H_2S	5
Water	

MPD
HPHT>15000 psi

Casing

Liner

Risk Score

Well Location	3
Type of Well	2
Well Environment	10
Non standard operation	10
Well Profile'	1'
Reservoir Fluid	4
Associated Reservoir Fluid'	0'
Add 5 for Temp in Excess of 150° C	5
KT	
KT	
KT	
KT	
KT	

KT	
Salt Domes	2
Hole Cleaning	2
Lost Circulation	2
Gas/Oil/Water Kick	2
Lost Circulation	2
Soft Unconsolidated Sediments	2
Abnormal Pr Zone	2
Reservior	2

Maximum Pressure @ BOP & Surface

Oil Field Units

Open Hole Size

Last Casing Shoe

Inches	TVD ft
18.13	8,969
18.13	12,250
16.50	15,300
14.50	17,000
12.25	19,650

Maximum Wellhead Pressure & Surface Pressure For Well=

Minimum BOP Requirements=

Shoe Strength

ppg
12.0
13.6
14.7
15.2
16.1

*PSI below the **Maximum Working Pressure** if exceeded, the next higher rated equipment should be used.*

i.e. With a 500 psi safety factor & a 9,600 psi calculated BOP/Surface pressure, then 15,000 psi (15M) equipment should be used.'

Equipment Safety Factor 500 **psi**

Section TVD		Mud Weight	Pore Pressure		Gas Density
psi	TVD ft	ppg	ppg	psi	psi/ft
5,597	12,250	10.1	10.0	6,370	0.1
8,663	13,000	11.8	11.5	7,774	0.1
11,695	14,000	12.9	12.0	8,736	0.1
13,437	18,500	13.3	13.0	12,506	0.1
16,451	20,000	14.4	14.5	15,080	0.1

15M

Minimum Surface Equipment Requirements=

Equipment Safety Factor:

MIP= Maximum Internal Pressure

MP= Maximum Pressure

2M=	2000
3M=	3000
5M=	5000
10M=	10000
15M=	15000
20M=	20000

BOP Below Rotary Table: **4,080 ft**

Pressure @ Shoe	MIP @ BOP			MP @ Surface	
	Weak Point	**No Weak Point**	**Max Pressure With WP.**	**No Weak Point**	**Max Pressure With WP.**
psi	**psi**	**psi**	**psi**	**psi**	**psi**
6,042	**5,108**	**5,553**	**5,108**	**5,145**	**5,108**
7,699	**7,846**	**6,882**	**6,882**	**6,474**	**6,474**
8,866	**10,573**	**7,744**	**7,744**	**7,336**	**7,336**
12,356	**12,145**	**11,064**	**11,064**	**10,656**	**10,656**
15,045	**14,894**	**13,488**	**13,488**	**13,080**	**13,080**
	14893.98	13488	13488	13080	13080

15M

BOP

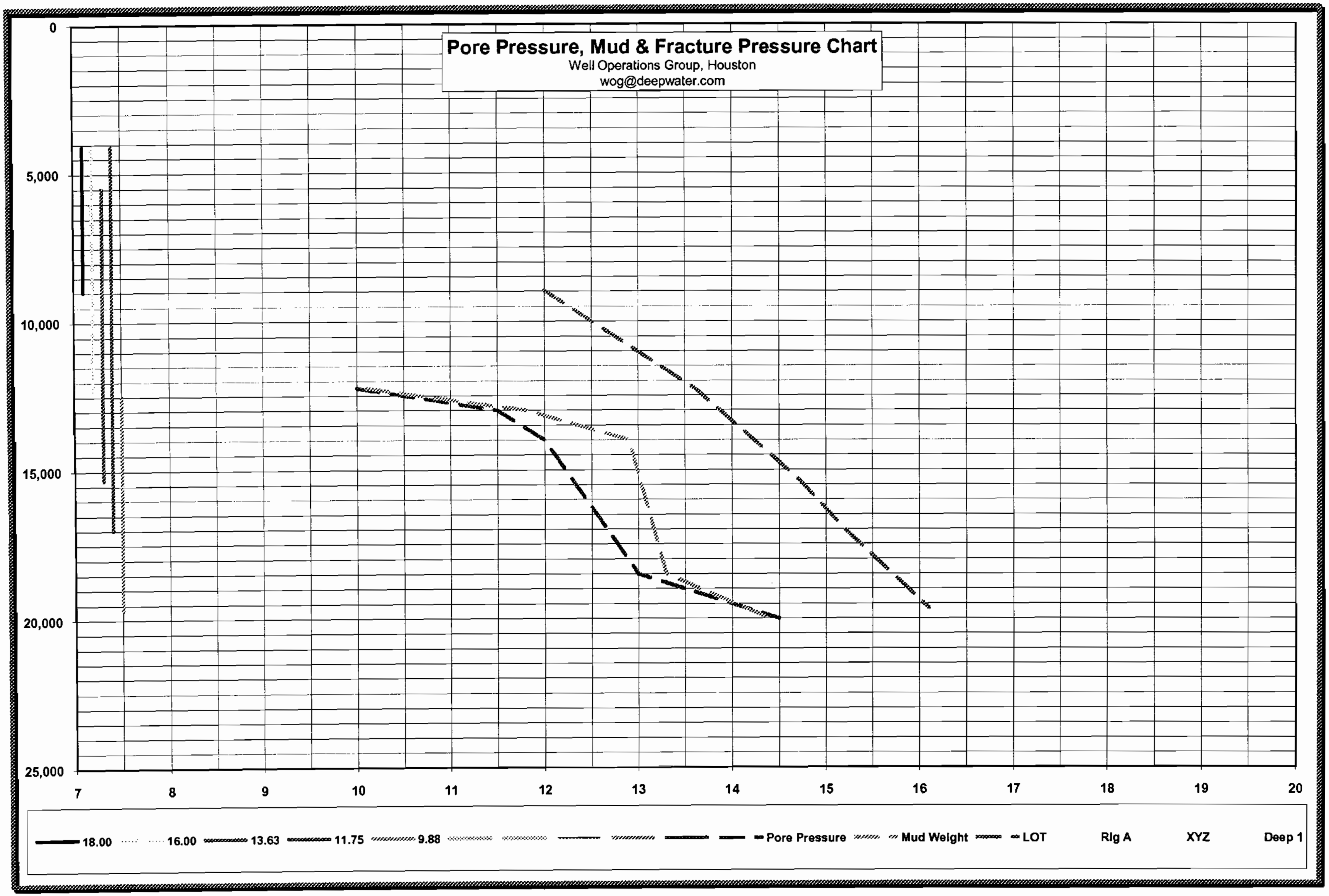
0	2000	0
0	3000	0
0	5000	0
0	10000	0
1	15000	1
2	20000	1

Surface Equipment

0	2000	0
0	3000	0
0	5000	0
0	10000	0
1	15000	1
2	20000	1

2M	3M	5M	10M	15M	20M

2M	3M	5M	10M	15M	20M



Pore Pressure, Mud & Fracture Pressure Chart
Well Operations Group, Houston
wog@deepwater.com
0
5,000
10,000
15,000
20,000
25,000
7
8
9
10
11
12
13
14
15
16
17
18
19
20
18.00
16.00
13.63
11.75
9.88
Pore Pressure
Mud Weight
LOT
Rig A
XYZ
Deep 1

WELL CONTROL PREPAREDNESS CHECKLIST

BOPS

1
2
3
4
5
6'
7'
8
9
10
11
12
13
14
15
16
17
18
19

SUBSEA SPECIFIC

20'
21'
22
23'
24'
25'
26
27'

What is the pressure rating of the BOP rams?
What is the pressure rating of the BOP bag type/annular preventer?
What is the maximum operating temperature for the elastomers in the BOP(s) ?
Are preventers (& elastomers) suitable/certified for H2S service?
Has the ram configuration been agreed with the client?
Is the working pressure of the annulars known with any necessary reduction in closing pressure pre-d etermined for large diameter casing (prevent exceeding collapse rating)?'
Does the ram configuration take into account future well operations (running casing / well testing etc)? '
Are casing rams required and are they available?
What are the maximum hang-off weights for each applicable ram, both fixed and variable? Has this been documented?
Is the shearing force confirmed to be sufficient to cut all of the tubulars in use?
Have Shearing procedures been discussed, agreed and procedures put in place?
Are plans in place for when non-shearable tubulars are across the stack (TRA / TSTP)?
Are stack-up drawing available and distances to rams from the rotary up to date?
Are there any sharp bends in choke or kill lines? If so are "Targets" installed?
Is the rig prepared for stripping operations?
Have stripping procedures been agreed?
Are the crews familiar with the function and operation of the stripping tank?
Is BOP third party certification up to date?
Are copies of all applicable certification & test records available?

Are there acoustic and ROV back-up controls for the BOP? Are there procedures in place for functioning the stack using these back-up controls?'
Is the exact location and function of the pressure and temperature sensors mounted on the subsea BOP clearly understood? '
Is there a glycol injection system in the sub sea choke line? Where necessary, is this addressed in the procedures?
Do the procedures address the type of fluid to be maintained in the choke & kill lines and address a ny required displacement prior to circulating a kick?'
Are the procedures in place and clearly understood for accurately measuring choke line friction, kick circulation rate and initial SICP?'
Is the procedure for flushing gas trapped below the annular after circulating out a gas kick in place and clearly understood? '
Have shallow gas hydrates been considered as a well control hazard in deepwater well planning?
Where applicable, are there procedures in place (which are clearly understood) to ensure BOP and rel ated equipment functionality in case you are operating in Arctic / freezing conditions?'

28'

ACCUMULATOR UNIT

29'
30'
31
32

CHOKE MANIFOLD

33
34
35
36'
37
38
39
40'
41
42
43
44'
45

MUD-GAS SEPARATOR (POOR BOY)

46
47
48'
49
50
51
52
53
54

Where applicable, have Emergency Disconnect Sequences for all applicable scenarios been developed. (To include subsea test trees and non-shearables across the stack, e.g., drilling, running casing, B HA across BOP, wire line, bit above the stack, during well control operations)'

Is the accumulator system designed such that the loss of an individual bottle and/or bank would not result in more than 25% loss of the total accumulator system capacity, i.e. isolation valves installed?'
Is a back-up power supply available to maintain accumulator pressure in case of failure of the prima ry power source? (e.g. electric pump connected to emergency generator)'
Can bag type/annular preventer closing pressure be regulated from the drill floor remote panel?
Are copies of all applicable certification and up to date test records available?

What is the pressure rating of the choke manifold on: (1) HP side (2) buffer side
Is the choke manifold suitable/certified for H2S service?
Are wall thickness tests conducted regularly and are the results available?
Can the Mud gas separator low pressure gauge be read from the choke position? If not, what plans are in place to monitor this gauge during a well kill operation?'
Is the remote panel on drill floor fully operational?
When were the chokes last inspected?
Are the chokes regularly flushed?
Do the procedure's clearly address how the choke manifold should be lined up while drilling to allow for a hard shut-in? '
Is there a line-up schematic for all of the various rigfloor manifolds posted on the drill floor?
Is a spare set of chokes and needles & the necessary tools to install available on-site?
Are chokes equipped with bleeder valves?
Is there a contingency for glycol/methanol injection to inhibit hydrates? Is this addressed in the procedures?'
Are copies of all applicable certification and up to date test records available?

What is the maximum gas handling capacity of the MGS?
What is length of "U" tube mud seal?
Is the U-tube seal adequate to prevent blow through to the shakers when circulating out an expected kick size'
What is the temperature rating?
What is the pressure rating?
Is the MGS suitable/certified for H2S service?
Are "as-built" drawings of the separator available on site?
Has a Low pressure (e.g. 15 psi) gauge been fitted and is it readable by the choke operator?
Is the liquid seal drained and flushed after use?

55'
56
57

DEGASSER (VACUUM or ATMOSPHERIC)

58
59'
60
61

RIG FLOOR EQUIPMENT

62'
63'
64
65
66
67
68
69

WIRELINE OPERATIONS / PRESSURE CONTROL EQUIPMENT

70
71
72
73
74'
75'

MUD PITS & MUD MIXING SYSTEM

76'
77
78'
79'
80
81'
82'

Is there a hot mud fill up line for the MGS (to limit loss of density of mud in the U-tube with hydrocarbon liquids)?'
Is there a contingency for blow through to the shakers?
Are copies of all applicable certification and up to date test records available?

Are specification and as built drawings available on site?
Has the impact of the venting point on the hazardous area classification and potential H2S release been considered?'
Is the degasser suitable/certified for H2S service?
Are copies of all applicable certification available?

Are full bore Kelly Cocks and inside BOP (Gray-valve(s)) available for all applicable sizes of DP (and DCs) located on the rig floor, fully functional and stored in open position? '
Are x/overs available on the drill floor to easily install during a well control event while handling casing and DC's?'
Are all well control subs tested in the direction of flow expected during a well control event?
Is the test frequency at least equal to the BOP test frequency?
Are the tests recorded in the daily drilling reports?
When was the last test performed to full rated working pressure?
Are all components suitable/certified for H2S service?
Are copies of all applicable certification available?

Has the proposed wireline equipment been evaluated as being suitable for the planned operation?
Can the cable be stripped out under pressure?
Is the wireline BOP capable of forming a seal on the cable in use?
Can the cable be sheared in all situations?
Is the function of the stuffing box understood? (Is it rated for stripping operations or is it only rated for sealing on a static cable?)'
If a well control situation occurs when using a wireline side entry sub, are procedures in place for shutting in the well with the cable above and if applicable across the rigs BOPs?'

Is a clear mud-pit diagram available, i.e. low-and high pressure system as well as all valves and with suction/overflow lines clearly identified?'
Can the system mix weighing material directly into the active tank?
What is the mud mixing capability for an appropriate range of mud weight increases? E.g. How much ti me is required to weight up the hole volume by 1ppg? This information is essential when determining which well control method to use in addition to being a measurement of the efficiency of the mixing system.'
Are the minimum stocks of weighting material/Cement/LCM/sulphide scavenger available on site at all times?'
Are maintenance & calibration records available?
Have all of the mud logging sensors been calibrated & synchronised in conjunction with the rig sensors?'
Have clear paths of communication been developed and agreed with the mud logging representatives onboard and any other applicable third parties?'

83'

EMERGENCY GENERATOR

84
85'

DRILLS

86
87
88
89

WELL CONTROL PROCEDURES

90
91
92'
93
94'
95
96
97
98

SHALLOW GAS

99'
100
101
102'
103
104
105'
106
107

Are all overboard valves isolated and controlled using the permit to work system? This must include all overboard valves on the drainage system.'

Are key safety systems connected to the emergency generator?
Does this include: "navigation lights", accommodation area, emergency route lights, fire and gas ala rm system, communication system, BOP control system, fire pumps, bilge and ballast pumps?'

Are plans in place for drilling / pit / tripping & stripping well control drills?
Has the strip force required through the annular preventer been recorded for reference?
Are choke-drills held frequently and recorded?
Are H2S-drills held frequently and recorded?

Has the preferred well control method been determined in conjunction with the client?
Who is in charge of well control operations?
In the event of a kick, have the actions, roles and responsibilities been clearly identified in the procedures and clearly communicated to all? (who does what)'
Is the method of shut-in clearly established?
Are shut-in procedures for the various well control scenarios laid down and are they on display at the driller's position?'
What is the procedure with regards to pre-kick sheets?
Who makes calculations?
Who verifies?
Where are copies kept?

Has a satisfactory Shallow Gas assessment been performed which addresses the Transocean shallow gas procedures? '
Has a seismic map showing surface and bottom hole locations been provided? Has a bright spot analysis been performed?
Is there a possibility of encountering a shallow reservoir? Has the planned well location been moved to avoid shallow gas or potential shallow water flows?
Has there or will there be a pilot hole drilled? A pilot hole should be drilled to the casing point in areas of possible shallow gas.'
Has a shallow gas contingency plan been developed?
Does the contingency plan reflect the method of well control?
Does the contingency plan allow for rapid well detection, securing of the unit, activation of the de luge system and evacuation of personnel with simple yet specific instructions?'
In areas of potential shallow gas a non-ported float valve should be run in the BHA.
For casing drilling, a dual high pressure differential opening float collar should be used.

108
109'
110'

DRILLING PROGRAM

111'
112'
113'
114'
115'
116
117
118
119
120'
121
122
123
124'
125'
126
127
128

Where applicable, Bit nozzles and BHA should allow for LCM to be pumped without clogging.
Are plans in place for the diverter system to be function tested and where feasible pressure tested? '
Has the diverting procedure been formalized and posted, with the crew trained in implementation through regularly conducted drills?'

Is the planned operation standard or non-standard such as managed pressure drilling, high pressure high temperature, surface BOP etc?'
If non-standard operations are planned, have specific procedures been developed? Do these procedures address the method of well control to be used in all instances? Has a joint operations/bridging do cument been prepared with the client agreeing on the methods of well control?'
If differences exist between standard Transocean proceduress and the operator requirements, has a br idging document been prepared and approved? Are rig specific well control procedures in place?'
Has a review of operator and Transocean offset data been performed? (To include mud type, mud weights used, casing shoes, drilling problems, any well control problems, highlights, lowlights)'
On production platforms are plans in place for nearby wells to be monitored for signs of pressure at the annuli? '
On production platforms, have all encompassing emergency evacuation plans been developed?
Are there existing plans to avoid other well paths?
Are any SIMOPS planned on the platform which may affect well operations?
Has a temperature profile been provided?
Are well control equipment rubber goods/elastomers suitable for the expected circulating temperature? '
Has a geological column been provided indicating the type and depth of the expected formations?
Have pore pressure and fracture gradient profiles been provided? Compare these profiles with the leak off/formation integrity tests planned for each section.
Is the planned Kick Tolerance greater than 50bbls in each hole section of the well? Refer to Well control manual for exemption procedure & required levels of dispensation.
Determine the max anticipated wellhead pressures possible for each section and compare with BOP & wellhead rating. '
Determine the max anticipated wellhead pressures possible for each section and compare with casing burst pressures for each relevant section.'
Review the proposed BOP pressure test schedule and casing pressure test schedule.
Review the ram configuration for the well or each hole section as applicable.
Are any other Well Control Dispensations required?

POST WELL REVIEW GUIDELINE

* The purpose of conducting a post well performance review is to actively demonstrate to the client
Transocean's commitment to team performance & continual improvement. The primary objective is gauge
and understand the client's operational performance perspective and to openly discuss any underlyi
ng problems or issues which subsequently can be addressed. The reviews should be conducted after ea
ch well is concluded and should be seen as a supplement to existing performance review tools such as the SQA. '

* The purpose of this sheet is to provide an outline/guidline for conducting a performance review wi
th the respective client at the end of each well. The items suggested are by no means an exhaustive
list but should serve to illustrate typical discussion topics which should be raised by the Perfor
mance Rig Manager. This is a tool for the Performance rig manager and can be used to assist with post well reviews.'
* Information deemed from and recorded for and during the post well review can serve as a beneficial
tool for future performance discussions with the client.'

PREPARATION

* Current technical issues? (Being addressed?)
* Current personnel issues. (Being addressed?)
* Downtime statistics
* Safety statistics
* Environmental statistics
* Key rig performance data:

POTENTIAL DISCUSSION TOPICS

* Client perception of performance on the rig?
* Actual flat spot performance

* Overall team performance

* Opportunities for improvement

- Riser tripping speeds
- Tubular tripping speeds
- Tubular P/U L/D times
- BHA handling performance
- BOP testing performance
- Rig up times (Csg/riser/testing/cementing)
- Waiting on Cement timing
- Slip and cut times
- OFFLINE operations (time savings)
- What does the client focus on?
- What has the client focused on?
- What is important to the client?

- What went well? What didn't go well?

- What went well? What didn't go well?

- Procedural
- Equipment related
- Logistics

POST WELL REVIEW DATA SHEET

Rig Name	Rig A
Operator	XYZ
Rig Type	Floater
Water Depth	4000

SAFETY & ENVIRONMENTAL

Well:	Deep 1	Start Cards
	YTD	

PERFORMANCE

Well Performance	Drilling
Planned days, (AFE)	
Actual days	
Efficiency	
	Transocean DT
	Client NPT

KEY SERVICE INDICATORS

Well Control Events	
Event #	1
Kick size (bbls)	
Kick intensity (ppg)	

Casing Operations

Casing size	R/U to run csg Actual (hrs)	Avg(hrs)

Type of Well	Development	Well Environment
Well Name	Deep 1	Non Std Operation
Country	GOM	Completion
Well Location	Open Water	

SIC	RWC	MTC	FAC	EVDS	EVDM

Completion	Well testing

Non Productive Time
Rig DT (minus SS)
Rig Subsea DT
Total Transocean DT
Client DT
3rd party
WOW
Total Operator NPT
Total Well DT

Hours	% of Well

Year to Date Performance	YTD (%)

Well Control Event Management Summary

2	3	4

Run Casing

Actual (ft/hr)	Avg(hrs)

R/D & clear rigfloor

Actual (ft/hr)	Avg(hrs)

BOP Operations
Run#

1
2

Non Standard
MPD
Well Test

Date of Review
Planned TD (ft TVD) 20000
Actual TD (ft TVD)

Near Miss	Manhours	TRIR

Major Transocean Downtime Summary

Major Client NPT Summary

Operation	R/up For Riser Handling		Riser Handling		R/dwn From Riser Handling	
	Actual (hrs)	Avg(hrs)	Actual (ft/hr)	Avg(hrs)	Actual (hrs)	Avg(hrs)
Run Riser						
Pull Riser						

Run Riser

Pull Riser'

* Can we better assist the client meet their well objectives?

* Pre-planning

* Personnel Performance / Requirements

* Scheduled preventative maintenance (Make Client aware of any required shut-down periods in advance)'

- Client downtime
- 3rd party downtime

- DWOP / CWOP / Pre-spud meetings
- Well Advisor
- Well Control preparation checklist

- Problem areas?
- Additional requirements?'
-

Tripping & picking up drillpipe (unrestricted)

	Crew 1	Crew 2
RIH (ft/hr)		
POH (Ft/hr)		
P/U DP (ft/hr)		
L/D DP (ft/hr)		

GENERAL COMMENTS

What went well? What didn't go well? Opportunities for improvement? Client perception of performance?'

Crew 3	Crew 4	Average

3
4

BOP Testing

Test	Actual (hrs)
1	
2	
3	
4	

Average (hrs)

Offline Operations
Operation Performed

Time Saved (hrs)

Conversions

Depth

1	ft	=	0.381m	m
5,000	m	=	16,404ft	ft

Volume

10 Gallons (US)		=	0.0	m^3
			37.9	Litres
50 Barrels (US)		=	7.9	m^3
			7,948.5	Litres
25	m^3	=	157.3	Barrels (US)
15,100	Litres		95.0	
1	m^3	=	264.2	Gallons (US)
300	Litres		79.3	

Pressure

264 psi	=	1,820.3	kPa
		18.2	bar
2.3 kPa	=	0.3	psi
		0.023	bar
200 Kg/cm^2	=	19,620.0	kPa
		2,644.6	psi
53 bar	=	5,300.0	kPa
		768.5	psi

Mud Weight

1.60	Kg/l	=	13.3	ppg
13.3 ppg		=	1,593.3	Kg/m^3
			1.60	Kg/l
1,200	Kg/m^3	=	10.0	ppg

Pressure Gradient

0.4567 psi/ft	=	10.3	kPa/m
		0.1	bar/m
11 kPa/m	=	0.4863	psi/ft
		0.1	bar/m

Mud Weight to Pressure Gradient

12.0	ppg	=	0.624	psi/ft
1.5 Kg/l		=	0.6495	psi/ft
			0.1472	bar/m
50.0	lb/ft^3	=	0.3472	psi/ft
1000 Kg/m^3		=	0.4340	psi/ft
			9.82	kPa/m

Flow Rate

100 gpm	=	0.4	m^3/min
		378.5	Litres/min
10 bpm	=	1.6	m^3/min
		1,590	Litres/min
2 m^3/min	=	528.4	gpm
		12.6	bpm
300 Litres/min	=	79.3	gpm
		1.9	bpm

Annular Velocity

500	ft/min	=	152	m/min
100	m/min	=	328	ft/min

Force

50,000
10,000

Mass

50,000
213,570
210
210

210

Pipe Weights

45.0
45.0

lbs	=	22,250	D-Newtons
D-Newtons	=	22,472	lbs

lbs	=	22,700	kg
kg	=	470,409	lbs
Long Tons	=	213,570	kg
Short Tons	=	190,688	kg
Metric Tons	=	210,000	kg
		462,546	lbs

lbs/ft	=	67.1	kg/m
kg/m	=	30.2	lbs/ft

Transocean, Well Operations Group, Houston :wog@deepwater.com

Well Advisor HELP

A Well Review Checklist

All items in list to be addressed as applicable.

The checklist is self explanatory and should be used as a reference of critical items to be considered when reviewing an upcoming operation.'

B Kick Tolerance Data

All data should be entered into the YELLOW SHADED cells in the 'KT INPUT' sheet. Leave cells blank if no value is being entered. Do not enter '0' '

INPUTS (Yellow Shaded Cells Only)

Transocean Kick Tolerance Inputs

1' (Column B). Enter the OD of the casing and liner shoes. Typically, start with the shoe of the surfac e casing which is supporting the BOP of after which the BOP is first installed.'
2 (Column C). Enter the TVD of each casing or liner shoe
3 (Column D). Enter the MD of each casing or liner shoe
4 (Column E). Enter the LOT value for the LOT performed at each casing and liner shoe.
5 (Column F). Enter the inclination at each casing or liner shoe
6 (Column G). Enter the size of openhole beneath the casing or liner shoe
7 (Column H). Enter the inclination at TD of the openhole section.
8 (Column I). Enter the TVD of the openhole section
9 (Column J). Enter the MD of the openhole section.
10 (Column K). Enter the BHA length
11 (Column L). Enter the average OD of the BHA.
12 (Column M). Enter the OD of the drillpipe which will be across the shoe having reached TD.
13 (Column N). Enter the mud weight in the hole at the end of each openhole section.
14 (Column O). Enter the typical annular back pressure when performing SCRs (Default = 50psi)
15 (Column P). Enter an allowance for choke operator error (typically 100psi)
16 (Column Q). The kick influx is assumed to be 0.5ppg intensity as per the TO Well Control Manual.
17' (Column R). Select if the kick is due to swabbing. A swabbed kick will assume a kick intensity of zero.'
18 (Column S). The gradient of any influx is assumed to be 0.1psi/ft.

Operators Kick Tolerance Inputs

20' (Column K). For the operator kick tolerance, enter the operator supplied maximum pore pressure predictions.'
21 (Column P). Enter the typical annular back pressure when performing SCRs (Default = 50psi)
22 (Column Q). Enter an allowance for choke operator error (typically 100psi)

NOTE: The operator calculation assumes the kick magnitude = pore pressure rather than mud weight plus a kick intensity factor of 0.5ppg. '

C Well Overview

INPUTS (Yellow Shaded Cells Only)

1 Enter all data in cells N° 1 to 27. Self explanatory.
2 (Column C, N° 28 to 37). Enter casing or liner.
3 (Column H, N° 28 to 37). For liners, enter the top of liner (TVD)
4 For each hole section from N° 38 to 47, select the top two expected hazards as applicable.
5 Enter comments from N° 38 to 47.
6 (Column M, N° 38 to 47). Enter the type of drilling fluid to be used. (For reference only)
7' (Column P, N° 48 to 58). Enter the weight per foot of the casing and landing string. (Only one type of landing string can be used in this approximate calculation)'
8' (Column Q, N° 48). Enter the mud weight used when running the first casing string. This will be used for estimating the hookload when running the first string.'
9' (Column S, N° 48 to 58). Enter the weight per foot or meters of the landing string. (Only one type o f landing string can be used in this approximate calculation)'
10 (Column V, N° 48 to 58). Enter the maximum allowable tension on the landing string.

CRITICAL OUTPUTS

1' TO kick tolerance. Refer to TO well control manual for required levels of dispensation. Less than 50 bbls kick tolerance will require dispensation outwith the rig.'
2 Operator kick tolerance. (For reference only)
3' MW-PP Margin. The amount of overbalance in equivalent mud weight. (ppg difference between pore pressure and mud weight)'
4' MAASP. The maximum pressure allowable at surface before exceeding the fracture gradient at the shoe. No safety factor is included in this calculation.'
5' Max pressure at BOP. This calc provides the max pressure possible at the BOP. The calc takes into ac count either reaching the fracture gradient at the shoe or having gas back to the BOP without excee ding the LOT. (e.g. If the fracture gradient is strong enough full evacuation to gas is possible without breaking down the shoe)'
6' RISK SCORE: This score is weighted based on all of the inputs and is indicative of the complexity of the upcoming operation and required additional program review and support. Alert messages will be triggered based on this score.'

Risk Score	
<15 15-25 >25	Low Risk Med Risk High Risk

Other Outputs

' Hookload estimator. The spreadsheet calculates the approximate hookload expected when running casing or liner and indicates if the max allowable tensile capacity of the landing string may be exceeded.'

' Hydrate Calculation: If the seabed temperature is less than the hydrate equilibrium temperature then hydrate formation is possible. This is an approxiimate indicator only but discussion with the operator should take place.'

Alert Messages

Triggered by risk score. Indicates required level of support / program review.
' Triggered for non-standard operations, additional program review required by 'Well Construction Group"
Triggered if Kick tolerance dispensations required - based on TO calculation.
Triggered if max surface pressure exceeds 80% of BOP rating.
Triggered if max surface pressure exceeds 80% of Wellhead rating.

Triggered for HPHT wells. (Temperature in excess of 150 deg C)
Triggered for HPHT wells.(Pressures in excess of 10,000psi)
Triggered if hydrates may be an issue.

D Maximum Pressure @ Wellhead
For information only - includes locked calculation

E MW, PP & FG Charts.
Charts mud weight, pore pressure and fracture gradient versus depth.

F Well Control Preparation Checklist
All items in list to be addressed as applicable.
The checklist is self explanatory and should be used as a reference of critical items to be considered when reviewing an upcoming operation.'

G Post Well Review Guideline
Suggested guideline for conducting a post well review
Identifies: Preparation required & suggested discussion topics
Provides: Performance data template

H Conversions
Convert to & from oilfield units