16/1-7
Discovery Evaluation Report
(West Cable)

Licence: PL001b / PL242

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1 Summary

The 16/1-7 well is a vertical exploration well that was drilled to test the West Cable prospect in spring 2004. The well discovered a 14m light oil column reservoired in the Middle Jurassic Sleipner Formation. Wireline-log and pressure data define an oil-water-contact, which coincides with a small 4-way closure.

The mean hydrocarbon volumes proven by this well within the 4-way dip closure are estimated to be as follows:

16/1-7 Discovery		Hydrocarbons In Place	Recoverable Hydrocarbons
Oil	$x10^6$bbl ($x10^6sm^3$)	**10.3 (1.64)**	**4.1 (0.66)**
Ass Gas	$x10^9$ scf ($x10^9sm^3$)	**9.8 (0.28)**	**3.9 (0.11)**
MOEB	$x10^6$bbl ($x10^6sm^3$)	**12.0 (1.90)**	**4.8 (0.76)**

The 16/1-7 discovery implies that two nearby 4-way-dip closures (one north and one southwest of 16/1-7) also have a high likelihood of containing trapped hydrocarbons, with estimated recoverable volumes around 6 and 2MOEB respectively.

These volumes (individually or collectively) are deemed to be too small to be commercially developable at this time.

The pre-drill West Cable prospect concept envisaged hydrocarbons reservoired in Mid Jurassic (Sleipner Fm) reservoirs trapped in a large rollover antiform in the hanging-wall of a major north-south trending fault. It was recognised that for commercial size volumes to be trapped, an effective lateral-seal across this fault was essential, as a crestal 4-way dip closure was small. The chance-of-success for this outcome was assessed to be 32%. The well demonstrated that this lateral seal was not effective, leaving just the small crestal 4-way dip closure with hydrocarbons.

The well was drilled in Licence PL001b, close to the boundary with Licence PL242, and well costs were split 50:50 between the licences (figure 1.1). The well fulfilled the drilling commitment of the PL242 licence. Both Licences PL001b and PL242 are operated by Esso (50%), with Statoil (50%) as the other licensee.

The basic well information is shown on figure 1.1

2 Introduction

This report describes the evaluation of the hydrocarbons discovered by well 16/1-7. The well was drilled to test the West Cable prospect in the spring of 2004, and discovered a 14m light oil column reservoired in the Middle Jurassic Sleipner Formation.

3 Location and Licence Details

The well was drilled in block 16/1 on the east flank of the South Viking Graben. It was drilled in Licence PL001b, close to the boundary with Licence PL242, and well costs were split 50:50 between the licences (figure 1.1). The well fulfilled the drilling commitment of the PL242 licence. Both Licences PL001b and PL242 are operated by Esso (50%), with Statoil (50%) as the other licensee.

4 Well Results against Predrill expectations

The pre-drill West Cable prospect concept envisaged hydrocarbons reservoired in Mid Jurassic (Sleipner Fm) reservoirs trapped in a large rollover antiform in the hanging-wall of a major north-south trending fault. It was recognised that for commercially interesting volumes to be trapped, an effective lateral-seal across this fault was essential, as a crestal 4-way dip closure was too small. A pre-drill map, cross-section and basic prospect information is illustrated on figure 4.1.

The pre-drill chance-of-success (COS) was assessed to be 32%, based on:

			Comments
Reservoir	Presence	1	Sleipner Fm ubiquitous in neighbourhood wells
	Effectiveness	0,6	Fair chance that reservoir will have poor productivity
Trap	Presence	1	Trap geometry confidently imaged on 3D seismic
	Effectiveness	0,6	relies on x-fault seal to east
Charge	Presence	1	Draupne source rock proven effective in neighbourhood
	Effectiveness	0,9	Chance that migration route will be inadequate
Geol Chance of Success (GCOS)		**0,32**	

Whilst the 32% GCOS describes the chance of making a discovery, the chance of exceeding a 30MOEB threshold for economic success was 27%.

The well confirmed that the reservoir was present and mini-DST data showed that it was effective. The presence of hydrocarbons also demonstrated that the charge and migration were effective. The presence of trapped hydrocarbons in the small crestal 4-way dip closure demonstrated that a trap is present, but that the lateral seal across the fault to the east was not effective. The hydrostatic reservoir pressure measured in the well suggests that this bounding fault is not a pressure barrier, and is interpreted not to be a barrier to fluid flow. As such, this is interpreted to be the reason for ’failure’ of the West Cable trap concept.

Secondary prospectivity in Tertiary, Upper Jurassic and mid Jurassic (Hugin Fm) reservoirs was recognised in the pre-drill assessment. All had possible trapping geometries at the well location, but no trapped hydrocarbons were encountered at any of these levels. No Upper Jurassic or Hugin Fm sands were seen in the well.

5 Reservoir

5.1 Lithology, Stratigraphy and Environment of Deposition

The top of the Sleipner Formation (2952mkb) is picked at the top of a 3m coal that overlies 95m of Mid Jurassic (Lower-Mid Callovian) sandstones in this well. The upper 14m of these sandstones are oil bearing. The combined interpretation of the biostratigraphy, petrography (figures 5.1 and 5.2) and log character suggest that these sands were deposited in a fluviatile/flood plain environment.

The log character of the gross 95m sand package is divided into two distinctly different units (figure 5.2), a 55m lower blocky unit (2995-3050mkb) and a more interbedded upper unit (40m, 2955-2995mkb), which appears to coarsen-up from its base. The uppermost 14m of this upper unit is hydrocarbon bearing. The well sits around 25m down from the crest of the trap, such that it is the upper 40m of this upper reservoir unit in which the hydrocarbons of this discovery are trapped.

No sandstones were encountered in the Upper Callovian interval (Hugin Fm equivalent) or the Upper Jurassic sections in this well.

5.2 Reservoir Data gathered in 16/1-7

No conventional core was taken in this well. 32 (of 75) sidewall cores were recovered, of which only 10 were sandstone facies (figure 5.5).

LWD and wireline logs form the basis for the interpretation of the reservoir quality in this discovery. The 16/1-7 log suite is tabulated below:

Hole Section	Mud	LWD Log suite	Wireline Log suite		Interval (mMDkb)
17 ½”	WBM	GR / MPR			225 - 1279
12 ¼”	OBM	GR / MPR /ORD / CCN / APX			1286 - 2561
8½”	OBM	GR / MPR /ORD / CCN / APX			2561-2749
		GR / MPR /ORD / CCN / APX			2749 - 3186
			Run 1	GR/HDIL/ZDL/CN/XMAC	3183 – 2552
			Run 2	VSP	3180 – 50
			Run 3A	RCI Pressures	3044 – 2957
			Run 3B	RCI Pressures & Samples	2977.5 - 2964
			Run 4	MREX	3030 – 2945
			Run 5A	Straddle Packer	2957
			Run 5A	Straddle Packer	2957 – 2964.5
			Run 6A	Sidewall Cores	3165 – 2575
			Run 6B	Sidewall Cores	3165 - 2574

5.3 Petrophysical Evaluation

The CPI logs form the basis for the reservoir parameters described below and are illustrated on figure 5.3.

Gross Reservoir Thickness and Net: Gross

The Net:Gross assessment of this reservoir is summarised on figures 5.3 and 5.4. A 50% Vshale cut-off defines net sand, to which a 9% porosity cut-off is applied to derive net reservoir.

Of the entire 131m Sleipner Formation interval (2952-3083mkm), 82.6m (64%) comprises net sand.

Of the upper 40m in the well, 25.7m (64%) is net reservoir. This represents the reservoir within structural closure, and provides the 'most-likley' Net:Gross input to resource assessment. The minimum (60%) is close to the net:gross of the entire Sleipner formation, whilst the maximum (80%) reflects the net:gross of the 14m oil-column interval in the well.

Porosity
As described in the preceding section, a 9% porosity threshold is used to determine net reservoir.

The average porosity of the upper 40m of the Sleipner Formation in this well is around 17.5% (which is the most-likley input to volume estimation). This is close to the average porosity calculated for the entire net reservoir (17%). A fairly narrow range (16-22%) is used to reflect the porosity for the volume assessment. (Logs (figure 5.5) show that porosities range from 10 25% in the 16/1-7 reservoir).

Permeability and Recovery Factor
Permeability in this reservoir is calculated from three sources, which are summarised on figure 5.5:

- three 'Mini' DSTs (Baker-Atlas' RCI straddle-packer assembly to evaluate three 1m intervals in the oil-bearing zone (2957mkb, 2964.5mkb and 2959.5mkb))
- the mobility data gathered during the RCI pressure data acquisition
- the MREX log

The combined assessment of all these data suggest that the permeabilities range from 50-500mD, which are in-line with expectations for this reservoir in the area.

These permeabilities suggest that this reservoir might sustain potentially commercial flow rates.

The recovery-factor for volume-assessment is dependent on the development scenarios (Section 9). Given its small size, the only feasible solution is a tieback with no injected reservoir pressure support. In such a case, recovery-factors in the order of 30-40-50% may be expected (assuming aquifer support). Water or gas injection may raise the recovery slightly, but is not deemed justify for these small volumes.

Hydrocarbon Saturation
The average oil saturation (So) in the 14m column is 57% (based on the log evaluation, figure 5.5). The three mini-DSTs suggest oil-saturations of 76, 73 and 56%, which vary predictably with the reservoir quality variations (porosity & permeability) observed on the logs. (The saturations may be slightly conservative given the thin-bed averaging effects and the relatively low resistivity response of the reservoir.)

The log interpretation uses a Rw based on the measured salinity from the water sample (2977mkb).

The oil-saturation (So) input to the volume assessment is 50-60-80%, which reflects the expected So variation according to the expected range of reservoir quality.

Oil-Water-Contact Definition
Pressure data measured with the RCI tool clearly defines a free-water-level (oil-water-contact) at 2969.9mkb (2940msl) in the 16/1-7 well (figure 5.6). This agrees with the contact predicted from log interpretation (figure 5.3).

The reservoir oil fluid density from this gradient is 694kg/m^3. The accuracy from the points and column height predicts a range of uncertainty of around ±30kg/m^3.

6 Trap

6.1 Trap Geometry

The oil in the 16/1-7 well is trapped in a small 4-way dip closure, in the hanging-wall of a major normal fault (figure 6.1). The 4-way closure has around 40m of relief from its crest (2900msl) to a saddle towards the south, which appears to lie at the same depth as the 2940msl OWC seen in the well.

The pre-drill West Cable prospect trap-model that the 16/1-7 well was drilled to test invoked effective seal across the major fault to the east to allow much greater column heights and larger volumes to be trapped (figure 4.1). The 14m column and normal pressure in the well demonstrates that this lateral seal did not occur (to be specific, it doesn’t occur to a depth greater than the 2940msl OWC seen in the well).

A listing of the principal formation tops in 16/1-7 is shown on figure 6.2.

6.2 Well Tie & Seismic Interpretation

There is a confident tie of the 16/1-7 well to the ES9402re99 3D seismic survey (inline 2290 / xline 2020). The geophysical logs, synthetic seismogram and tie to seismic from the Tertiary to TD are illustrated in figures 6.3 and 6.4. The figures illustrate that the Top of the Chalk, the Base Cretaceous, Top Heather and Top Triassic are all clearly visible seismic events correlating to clear impedance breaks on the log data, and these are all confidently interpreted away from the well across the discovery.

The top of the Sleipner Formation reservoir (2923.5msl/ 2567msTWT) lies in the follow-cycle beneath the strong Top Heather event. Top sand lies beneath a very low-impedance coal unit, but this is too thin to be discretely resolved. The impedance contrast between the reservoir sands and surrounding shale is small, such that discrete seismic imaging of top sand is unlikely (typical for the region).

The top Sleipner Formation reservoir TWT structure map is shown in figure 6.5.

The Mid Jurassic section (bounded by the Heather and Triassic events) thickens east of the well in towards the major fault (figure 6.6). In this thickened zone, the top reservoir is interpreted to stay in the follow-cycle beneath the Heather, which implies an element of syn-rift thickening of the reservoir.

An alternative deeper interpretation is also possible, retaining a constant reservoir isopach above the Top Triassic. This model would imply that the reservoir is entirely pre-rift and does not thicken across the faults. In the saddle at the south of the 16/1-7 4-way closure, there is negligible difference between the two interpretations, so the depth conversion and rock-volumes from this second model are not documented here.

There is a high chance that all 4-way closures in this area have trapped hydrocarbons like 16/1-7. There is another closure 3km north of 16/1-7, and a smaller one 1.5km southwest of the well (figure 6.5).

6.3 Depth Conversion

The TWT interpretation described above is depth converted using a well-based function to Base Cretaceous and an interval velocity versus depth function from Base Cretaceous to the Top Sleipner reservoir. This simplistic depth conversion is deemed appropriate here because of the small area of closure around the well.

The functions used are as follows:
1) Sea-level - Base Cretaceous isopach = (1.799 x Base Cretaceous TWT(ms)) – 1605
2) Base Cretaceous – Top Sleipner isopach = (BCret-Sleipner isochron (ms) x 1.4156) +7.21

This provides the top Sleipner reservoir Depth structure map that is shown in figure 6.5. This map is used to generate the 'most-likley' rock-volumes for this assessment

In addition to the depth conversion method described above, a range of depth conversion methods was applied to the interpretation to investigate the range of possible saddle-depths, to try and establish if the saddle depth is coincident with (and controlling) the 2940msl OWC seen in the well. Twelve differing combinations of seismic and well-based velocities were used. Of these, all predict the saddle to lie within 20m of the contact. Eight predicted saddle depths within 10m of the contact, one gave a saddle which was around 15m deeper (implying underfilled 4-way) and three gave saddles 15m shallower (implying fill below the saddle, and seal against the fault to the east). Our interpretation of this analysis is that the saddle is controls the OWC seen in the well.

The range of depth structure maps that are output from the process described above provides a range of (min-max) rock-volume outcomes for the 16/1-7 structure, which are input to the volume assessment.

The absolute depth-prediction accuracy for this area is deemed to be about 20-30m. The main limitation controlling this is the highly variable thickness of the sandstones in the Grid formation. Without a very accurate understanding of the form of these (relatively high velocity) sands, the accuracy of the depth conversion of the underlying section is unlikely to be better than ca 20m. These sands appear to be thick above the undrilled 4-way closure 2km north of 16/1-7, so there is some uncertainty as to if that structure is as high relief as it appears (may be some pull-up effect in TWT, which would reduce relief when accurately depth converted).

6.4 Gross Rock Volume (GRV)

The GRV of the 16/1-7 four-way-dip closed trap is tabulated below, with the min-ML-max range reflecting the range of different depth conversions used to create the depth map

16/1-7 4-way closure				
	Depth	GRV[1]		
		Min[2]	ML[2]	Max[2]
Crest (msl)	2900			
Saddle (msl)	2940	18.1	27.7	46.7

[1] $x10^6 m^3$
[2] Range provided from three different depth maps as described in section 6.3

As stated in section 6.2, given the discovered oil in the 16/1-7 four-way closure, there is a high likelihood that the other 4-way closures in the neighbourhood also contain trapped oil. The rock-volumes (derived from the base-case depth map) for these are described below.

	Northern 4-way		**SW 4-Way**	
	Depth	**GRV[1]**	**Depth**	**GRV[1]**
Crest (msl)	2930		2920	
Saddle (msl)	2990	38.0	2960	12.6

[1]$x10^6 m^3$

The extreme maximum-case upside to the 16/1-7 discovery would be if the contact seen in the well were actually controlled by lateral sealing down to this depth across the major fault to the east. However, the chance of occurrence of this is considered extremely low given:

1. the coincidence of cross-fault leak depth being the same as the 4-way saddle depth is highly improbable, and
2. the lack of any overpressure in the well implies that there is no effective pressure seal across the fault to the east, implying that the fault is not a fluid barrier (at least in the aquifer)

As such, this model is regarded more as a separate (high-risk) prospect rather than a realistic upside 16/1-7 discovery-case. (The Gross-Rock-Volume within this trap down to 2940m) is calculated to be around 75-150x10^6 m^3 (wide range due to uncertainty on top reservoir seismic pick and truncation against fault).
The extent and volumes associated with the cases described above are illustrated on figure 8.1.

7 Hydrocarbon Fluids

The hydrocarbons in 16/1-7 were sampled from 2965mkb (figure 7.1) during the RCI run with the RCI tool (figure 7.1). A water sample was also obtained (2977.5mkb), which was described in section 5.

Analysis onshore revealed the oil samples were contaminated with 14% oil-based-mud. An attempt has been made to correct the fluid composition and properties for this contamination (figures 7.2 and 7.3).

The measured and corrected properties are outlined in the following table:

16/1-7 oil Properties (as measured and after correction for 14% OBM contamination)			
	Contaminated Sample	**Corrected (Uncontaminated**	
	Measured	**ResLab**	**ProTherm**
Psat, bar	250.5		273.0
Bo at 300 bar, m3/sm3	1.487		**1.544**
Density at 300 bar, kg/m3	664.0		622.3
Viscosity at 303.6 bar, mPa-s	0.415		0.300
Flash GOR, scm/scm	153.2	179.1	**166.9**
Stock tank oil density, kg/scm	839.8	844.0	798.3
Gas gravity	0.790	0.790	0.798

The reservoir oil is slightly under-saturated, and has a corrected saturation pressure (273bar) that is 27bar below the reservoir pressure (300bar). Gravity segregation calculations suggests that a bubble-point depth (Gas-Oil-Contact) would lie around 200m shallower than where sampled (2965mkb). Since the crest of the structure is only about 25m updip of the well, this implies that there is limited chance of a free gas cap in this structure.

The corrected Bo is estimated to be 1.544, with a range of ± 0.05 (input to volume calculations).

The oil density (estimated from the sample) at reservoir conditions is calculated to be 622kg/m^3. This is significantly lower than the 694kg/m^3 calculated from the gradient of the RCI pressure data through the oil column (section 5.3). The difference is believed to reflect the uncertainties in PVT properties associated with the OBM contamination.

8 Hydrocarbon Volumes

The reservoir, trap and fluid parameters described in the preceding chapters are input to generate estimates of In-Place and Recoverable hydrocarbon volumes in the 16/1-7 discovery as tabulated below:

16/1-7 Discovery			Min (P_{99})	Most Likely	Max (P_1)
Gross Reservoir Thickness		m		130	
Gross Rock Volume		$x10^6m^3$	18.1	27.7	46.7
Net : Gross		%	60	64	80
Average Porosity		%	16	17.5	22
Permeability		mD	30	100	500
Oil Saturation		%	50	60	80
Bo		m^3/m^3	1.49	1.54	1.59
GOR		Scf/bbl	160	167	180
			P_{90}	**Mean**	**P_{10}**
In Place Hydrocarbons	**Oil**	$x10^6bbl$ ($x10^6sm^3$)	**6.9 (1.10)**	**10.3 (1.64)**	**14.4 (2.29)**
	Ass Gas	$x10^9$ scf ($x10^9sm^3$)	**6.6 (0.19)**	**9.8 (0.28)**	**13.7 (0.39)**
	MOEB	$x10^6bbl$ ($x10^6sm^3$)	**8.0 (1.27)**	**12.0 (1.90)**	**16.7 (2.66)**
Rf Oil		%	30	40	50
Rf Associated Gas		%	30	40	50
Recoverable Hydrocarbons	**Oil**	$x10^6bbl$ ($x10^6sm^3$)	**2.7 (0.42)**	**4.1 (0.66)**	**5.8 (0.93)**
	Ass Gas	$x10^9$ scf ($x10^9sm^3$)	**2.5 (0.07)**	**3.9 (0.11)**	**5.6 (0.16)**
	MOEB	$x10^6bbl$ ($x10^6sm^3$)	**3.1 (0.49)**	**4.8 (0.76)**	**6.8 (1.07)**

The same reservoir and fluid parameters are combined with single-point GRV estimates to provide the (mean) resource estimates for the two neighbouring four-way-dip closures as follows:

			Northern 4-way	SW 4-Way
Gross Rock Volume		$x10^6m^3$	38.0	12.6
In Place Hydrocarbons	**Oil**	$x10^6bbl$ ($x10^6sm^3$)	12.7 (2.02)	4.1 (0.65)
	Ass Gas	$x10^9$ scf ($x10^9sm^3$)	12.0 (0.34)	3.9 (0.11)
	MOEB	$x10^6bbl$ ($x10^6sm^3$)	**14.7 (2.34)**	**4.8 (0.76)**
Recoverable Hydrocarbons	**Oil**	$x10^6bbl$ ($x10^6sm^3$)	5.8 (0.81)	1.7 (0.26)
	Ass Gas	$x10^9$ scf ($x10^9sm^3$)	4.8 (0.14)	1.6 (0.04)
	MOEB	$x10^6bbl$ ($x10^6sm^3$)	**5.9 (0.93)**	**1.9 (0.30)**

The equivalent volumes trapped in the hangingwall prospect to the east of the discovery are estimated to be in the region of 50-100MOEB in place.

The different volume cases are illustrated in map form on figure 8.1.

9 Potential for Development

An evaluation of possible development scenarios and commercial viability has been undertaken for the 16/1-7 discovery.

Two cases have been assessed:
1. a 'most-likely' case (10 MOEB recov) that represents volumes proven in 16/1-7 plus the northern 4-way closure
2. a 'high-case' (29 MOEB recov) that includes the prospect to the east in the fault hangingwall (equates to the 'extreme-maximum' case described in section 6.4)

The input and reservoir assumptions are shown on figure 9.1.

The most-likely case assumes production from two wells (yielding ca 5 MOEB each) tied to Grane platform (figure 1.1) through a single 8" flowline. The high case would be drained from 4 producer wells (yielding around 7 MOEB each), also tied to Grane. Neither case is large enough to justify injection for reservoir pressure support.

The development planning and cost-bases are outlined on figure 9.2, and show that the combined Capex + Opex costs are around $22/bbl and $12/bbl for the base and high cases respectively. The high unit costs of the both of these are clearly not commercially attractive at this time as tieback, or for that matter, as standalone, developments.

The assessment also considered the option of joint-development with other nearby opportunities (including the Hanz discovery in 25/10 and the Draupne prospect in the footwall to the east of 16/1-7). It is clear that these assets do not contribute to significantly reduce the development costs of each other because they each have the same high unit-development cost issues (due to low volumes and resource density). Thus, even collectively, these do not form an attractive development opportunity at this time.

The conclusions of this evaluation (figure 9.3) are therefore:
1. The volumes discovered by the 16/1-7 well are not economically viable as a standalone or a tie-back development
2. Synergy opportunities with surrounding undeveloped discoveries and prospects do are limited due to marginal volumes and significant tieback distances

List of Associated 16/1-7 Reports

- Final well report (ExxonMobil, June 2004)

- End of well report MWD, directional drilling & mud logging (Baker Hughes Inteq, July 2004)

- Cross-Multipole array acoustilog (XMAC) Slowness Processing – VpVs (Baker Atlas, June 2004)

- Borehole seismic report velocity analysis, acoustic log calibration & rig source VSP (VS Fusion, June 2004)

- Borehole seismic survey (Baker Atlas, 2004)

- Petroleum geochemistry (Applied Petroleum Technology AS, June 2004)

- Final Report PVT and composition analysis of RCI sample, Field West Cable, Well 16/1-7 (Reslab, 4.11.2004)

- West Cable 16/1-7, Transfer & Validation of RCI samples, Offshore report (Reslab, 24.11.2004)

- Petrography from SWC Thin Sections (Reslab 2004, Report in prep)

- Conventional Core Analysis from SWC's (Reslab 2004)

16/1-7 Discovery Evaluation

Well Location and Fact Sheet

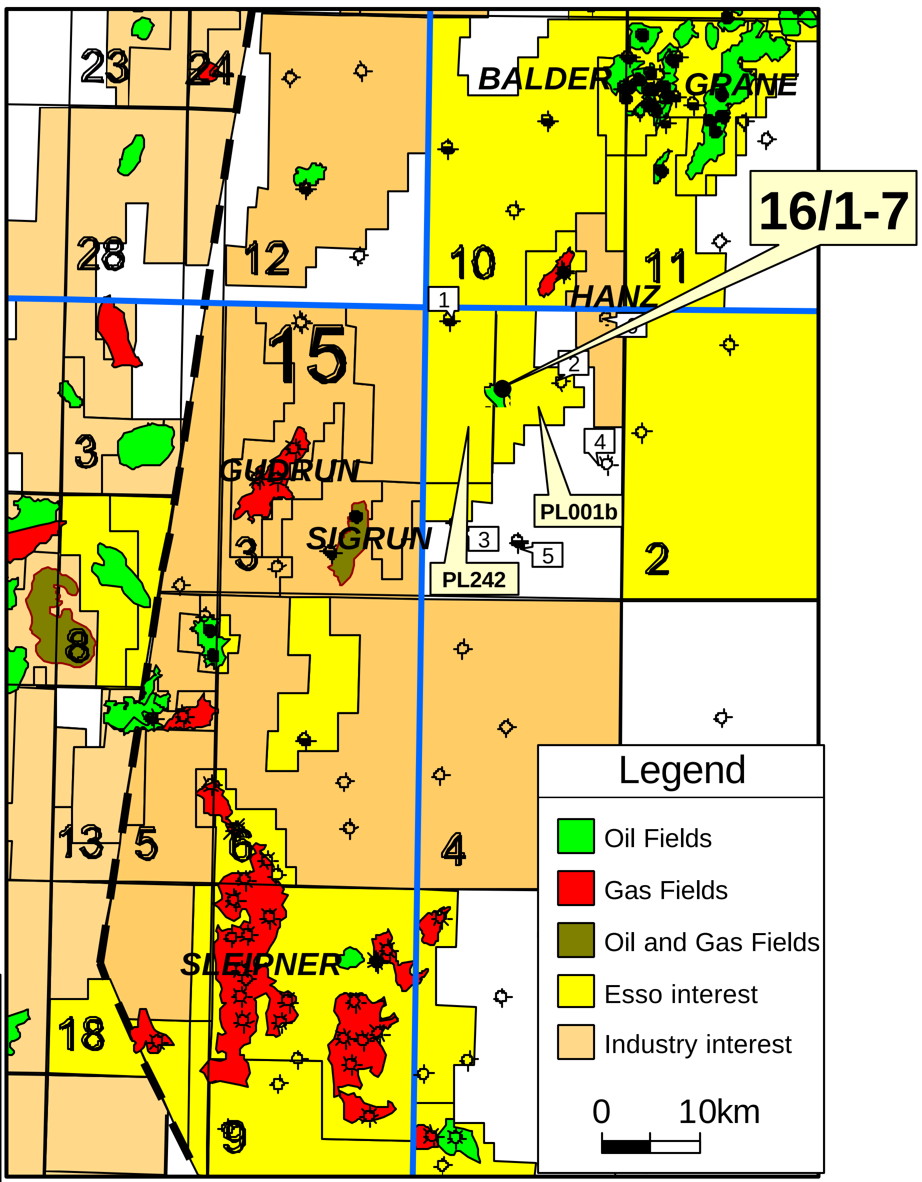
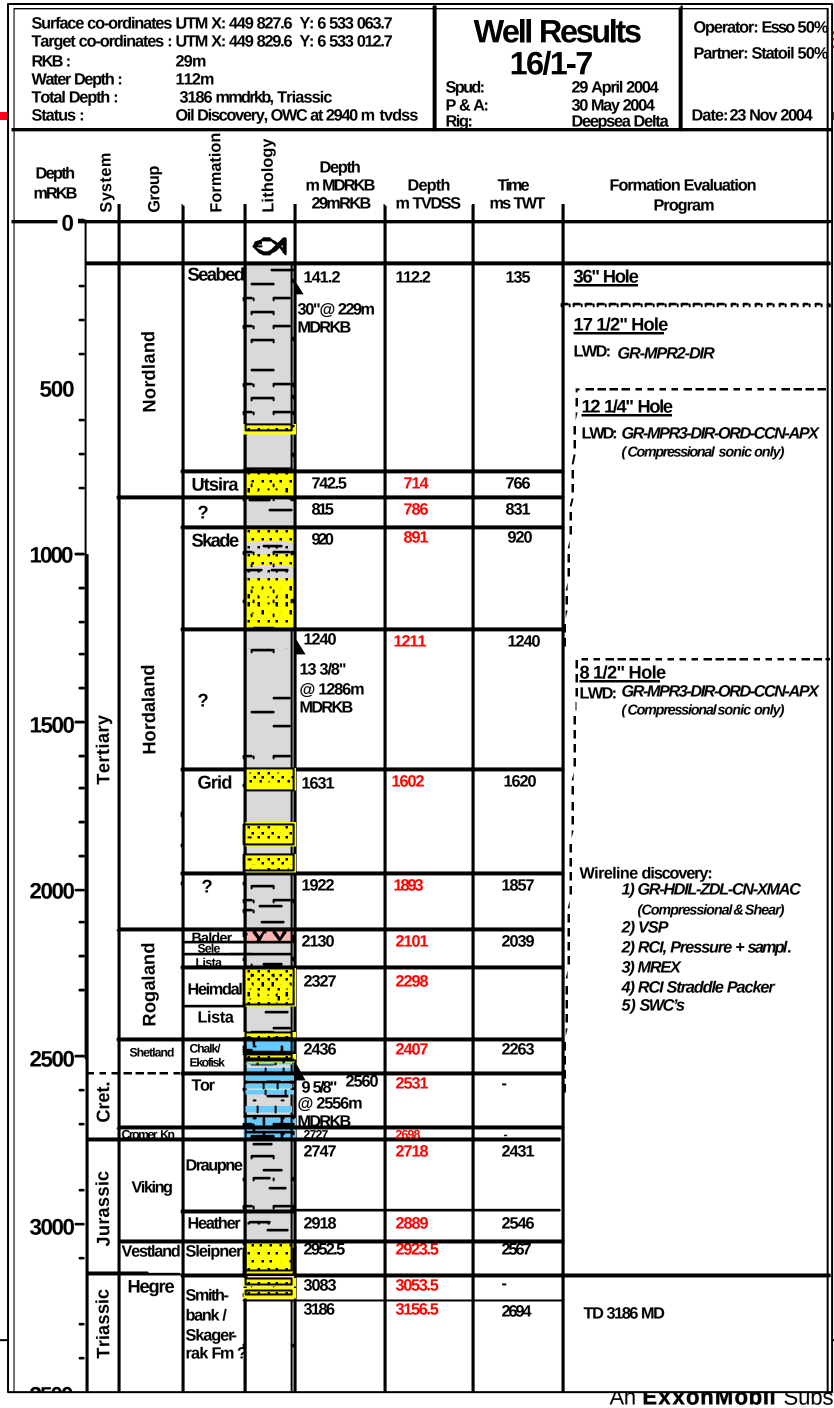


Figure 1.1



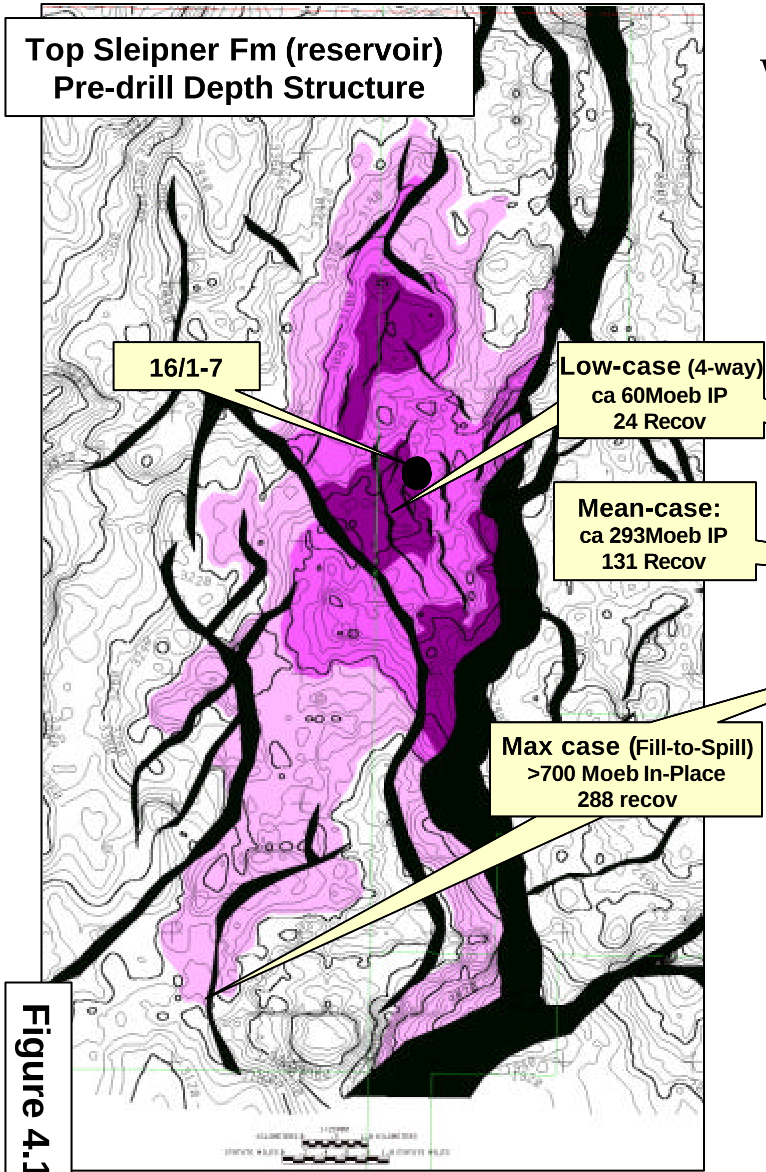
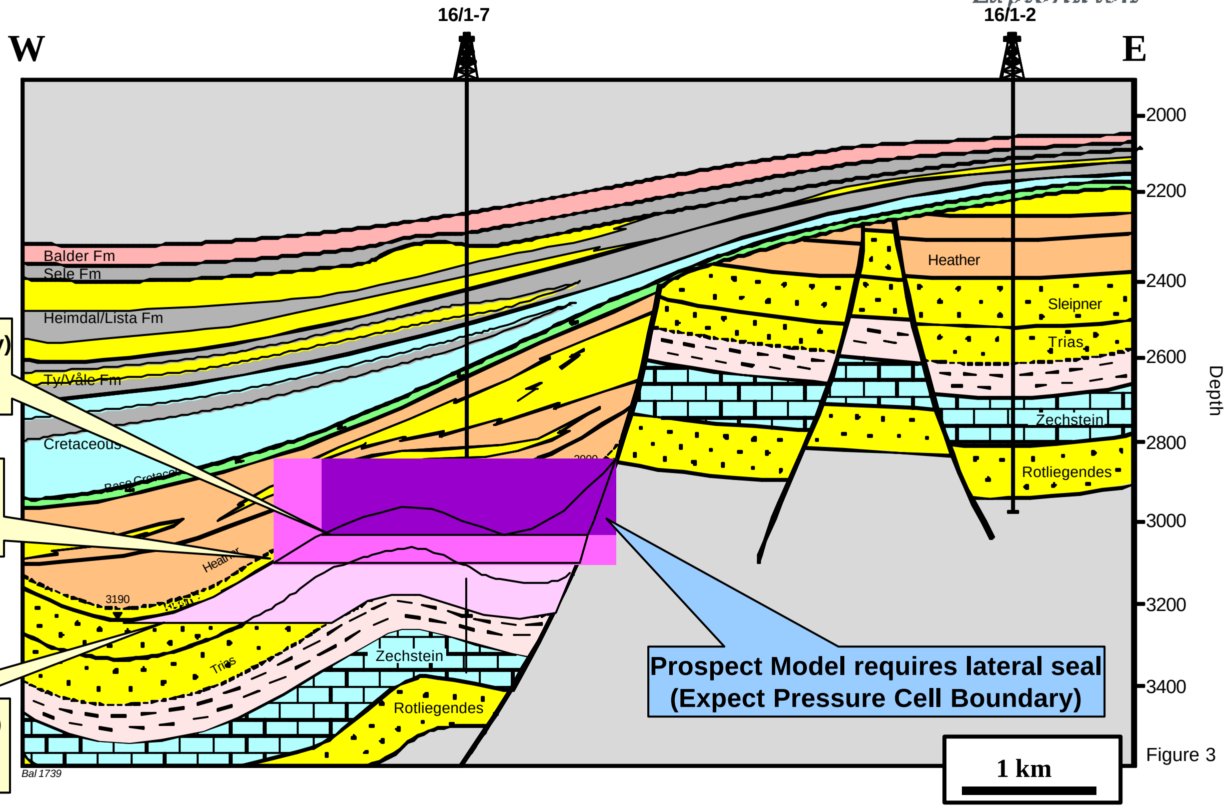


Figure 4.1



Target: Light oil in Sleipner Fm sands in Hangingwall rollover, requiring x-fault seal to east (for > min case)

Key Technical Risks: Lateral Seal (x-Fault to E) & Reservoir Quality

Pre-drill Assessment:

Volumes: Success Case Mean recov = 131MOEB

Chance of Success: **Geol:** 32% **Econ:** 21% (>30MOEB)

16/1-7 Discovery Evaluation

Reservoir: Bio-, Litho- and Sequence Stratigraphy

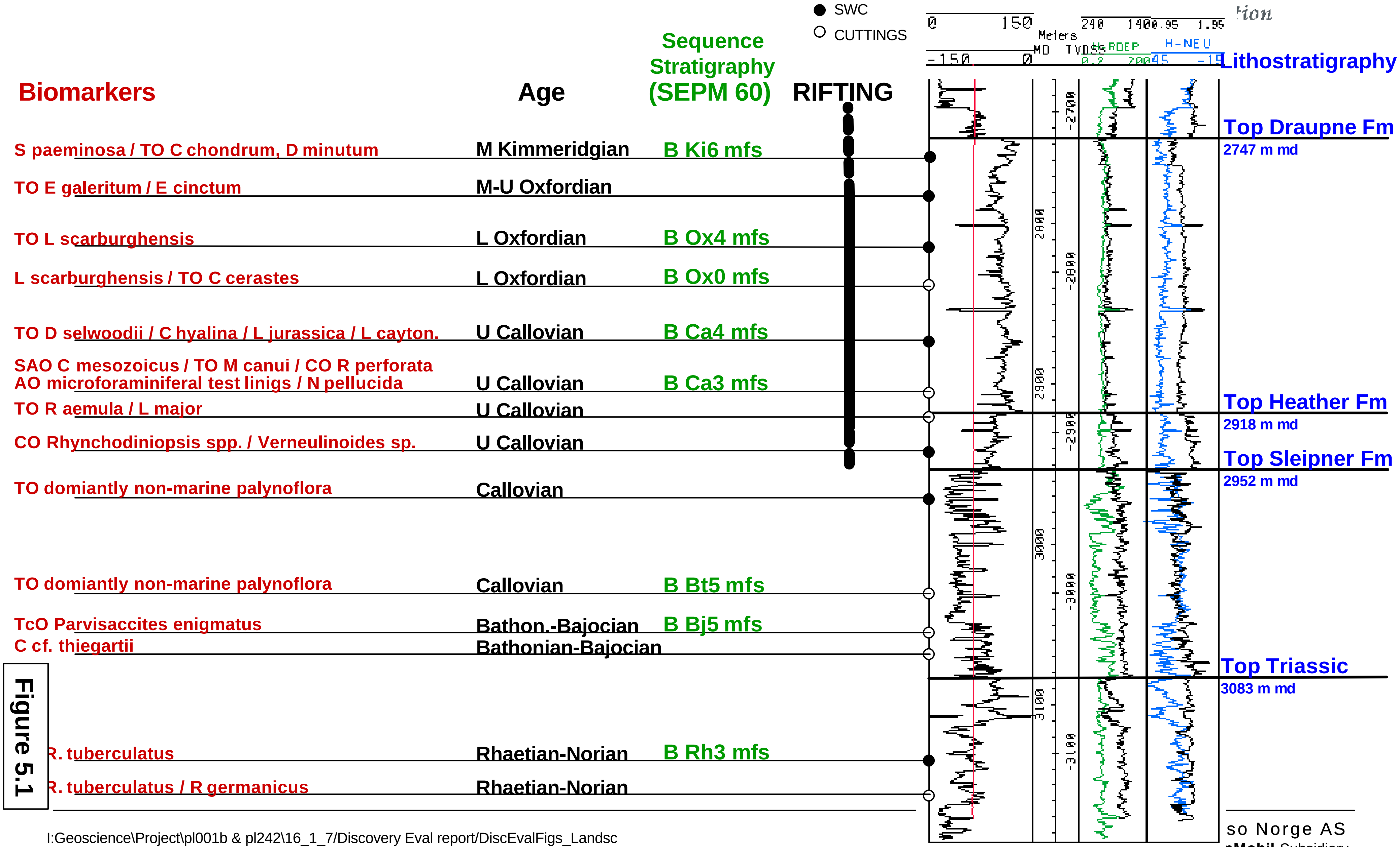


Figure 5.1

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16/1-7 Discovery Evaluation

Reservoir: Petrography

Interpretation:

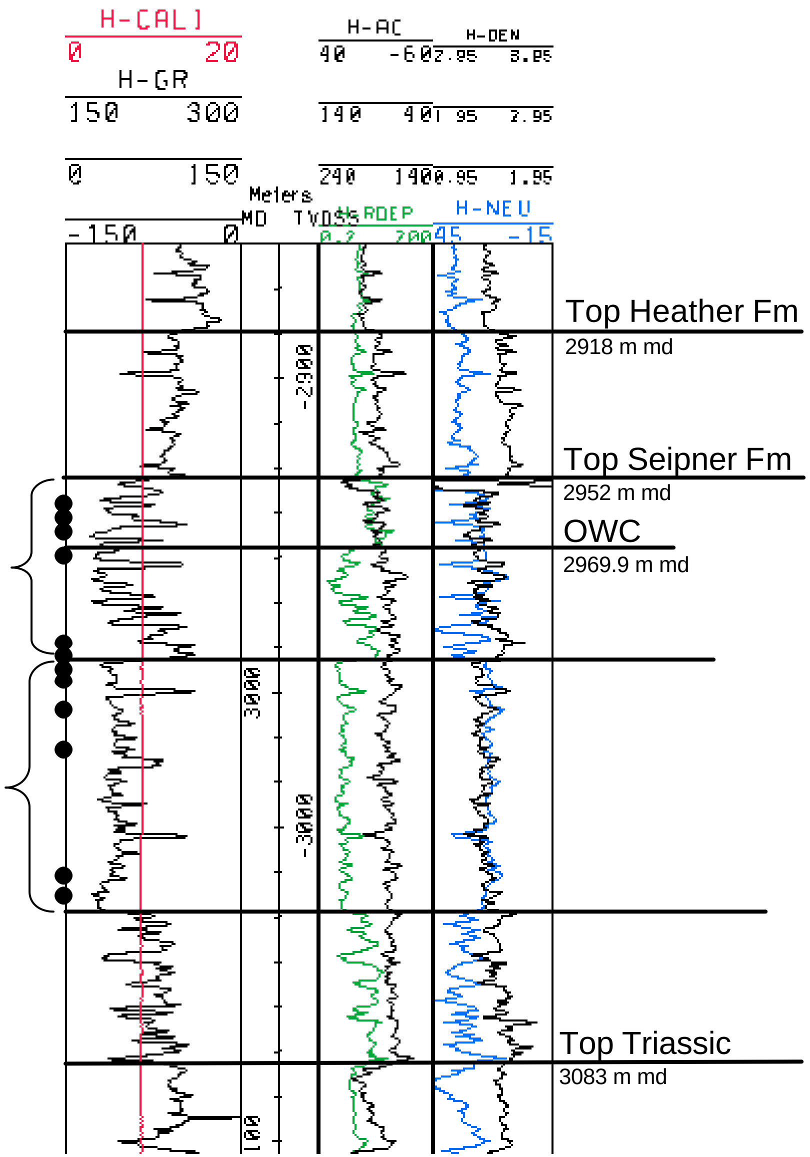
- **Poor sorting and roundness suggests the sands are texturally immature**
- **The variety of facies and diversity of fragments suggests that both units are probably deposited in fluviatile conditions**

Upper Unit (2955-2995mkb, Upward Coarsening Sands)

- **med gr (poorly rounded), mod sorted subarkoses with abundant clay laminations, clay fragments, organic fragments**
- **coarse to med gr (poorly rounded), poorly sorted sublithic sandstones with abundant igneous rock fragments, clay and organic fragments**

Lower Unit (2995-3050mkb Blocky Sands)

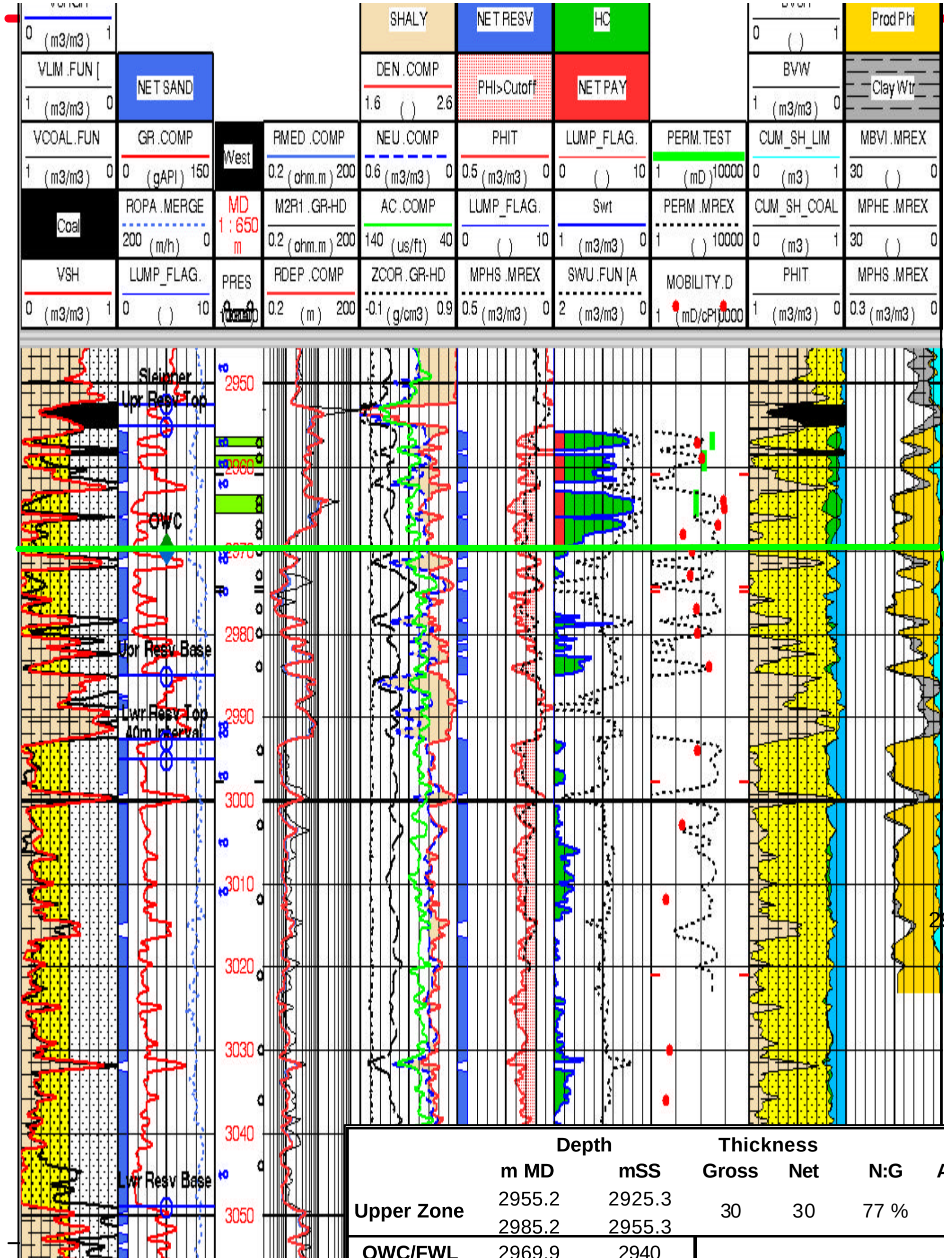
- **med gr (poorly rounded), mod sorted subarkoses with abundant clay laminations, clay fragments, organic fragments**
- **coarse to med gr (poorly rounded), poorly sorted arkosic sandstones with abundant igneous and organic fragments**

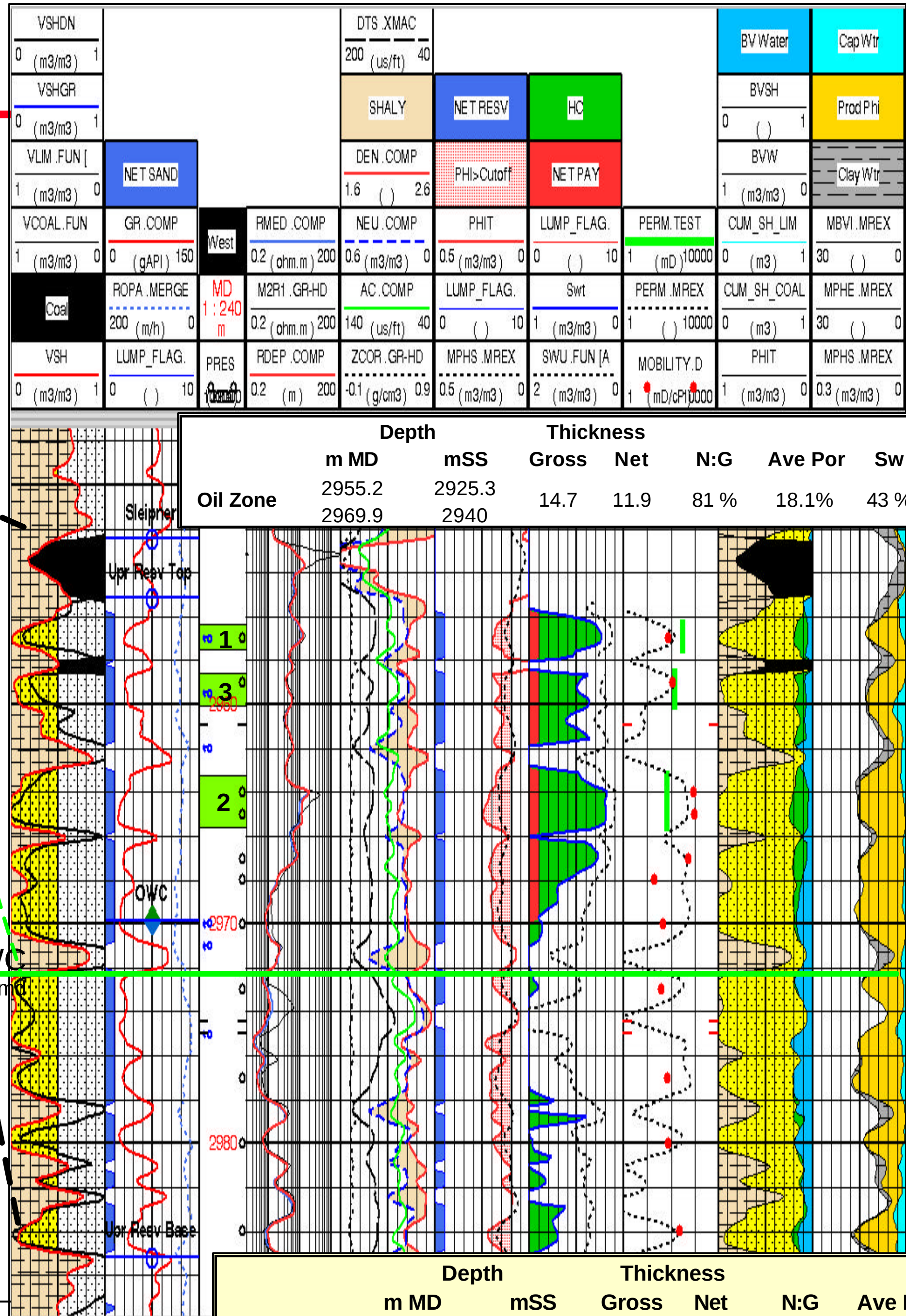


(Evaluation based on thin sections from SWC)

Figure 5.2

16/1-7 Discovery Evaluation - Sleipner Fm CPI logs





	Depth		Thickness				
	m MD	mSS	Gross	Net	N:G	Ave Por	Sw
Oil Zone	2955.2 2969.9	2925.3 2940	14.7	11.9	81 %	18.1%	43 %

	Depth		Thickness			
	m MD	mSS	Gross	Net	N:G	Ave Por
Upper Zone	2955.2 2985.2	2925.3 2955.3	30	30	77 %	17.5%
OWC/FWL	2969.9	2940				
Lower Zone	2992.8 3049	2962.9 3019.1	56.2	51.2	91%	16.7%

	Depth		Thickness			
	m MD	mSS	Gross	Net	N:G	Ave Por
Top 40m	2955.2 2995.2	2925.3 2965.3	40	25.7	64 %	17.5%

Figure 5.3

I:Geoscience\Project\pl001b & pl242

16/1-7 Discovery Evaluation

Reservoir: Net to Gross

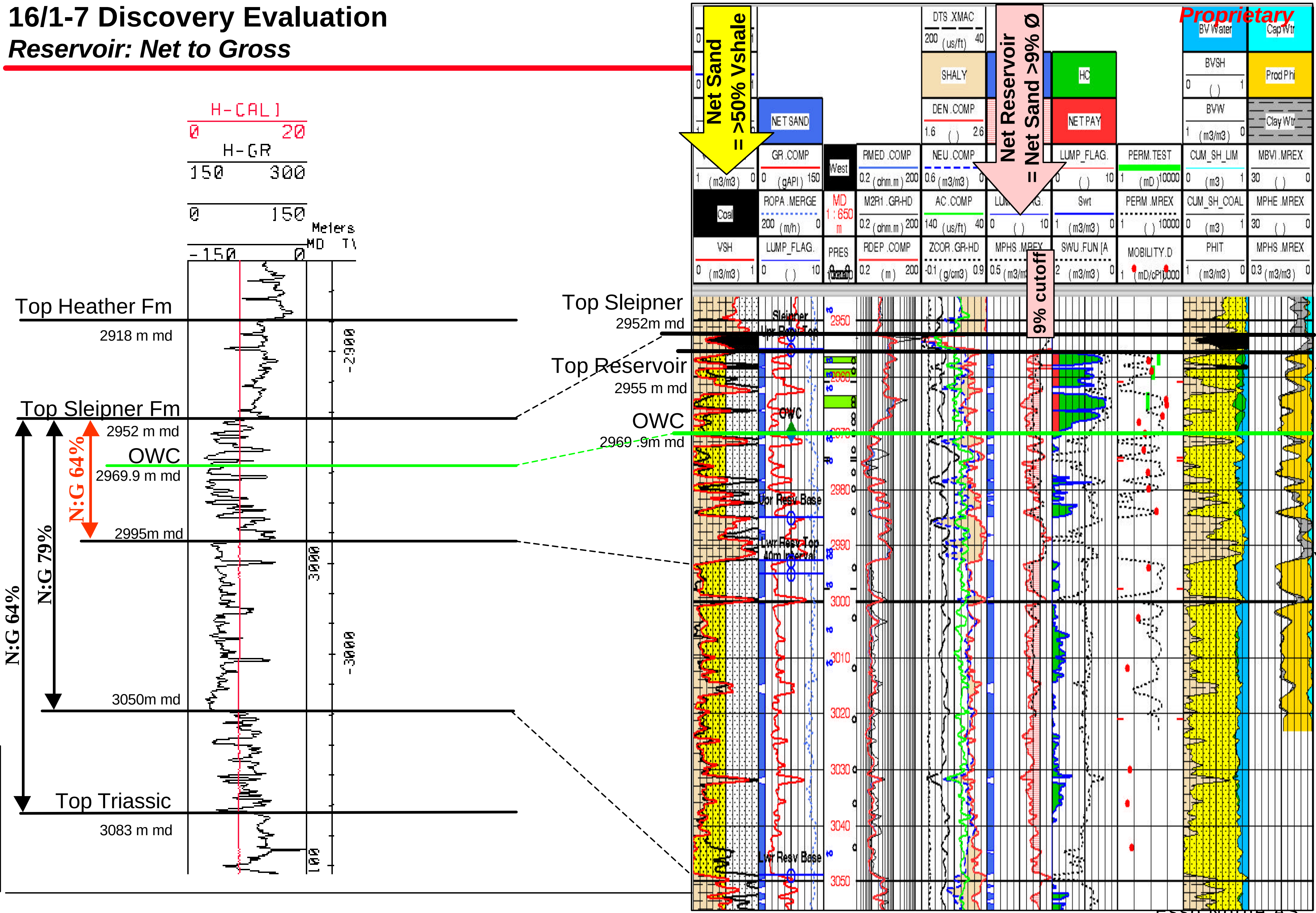
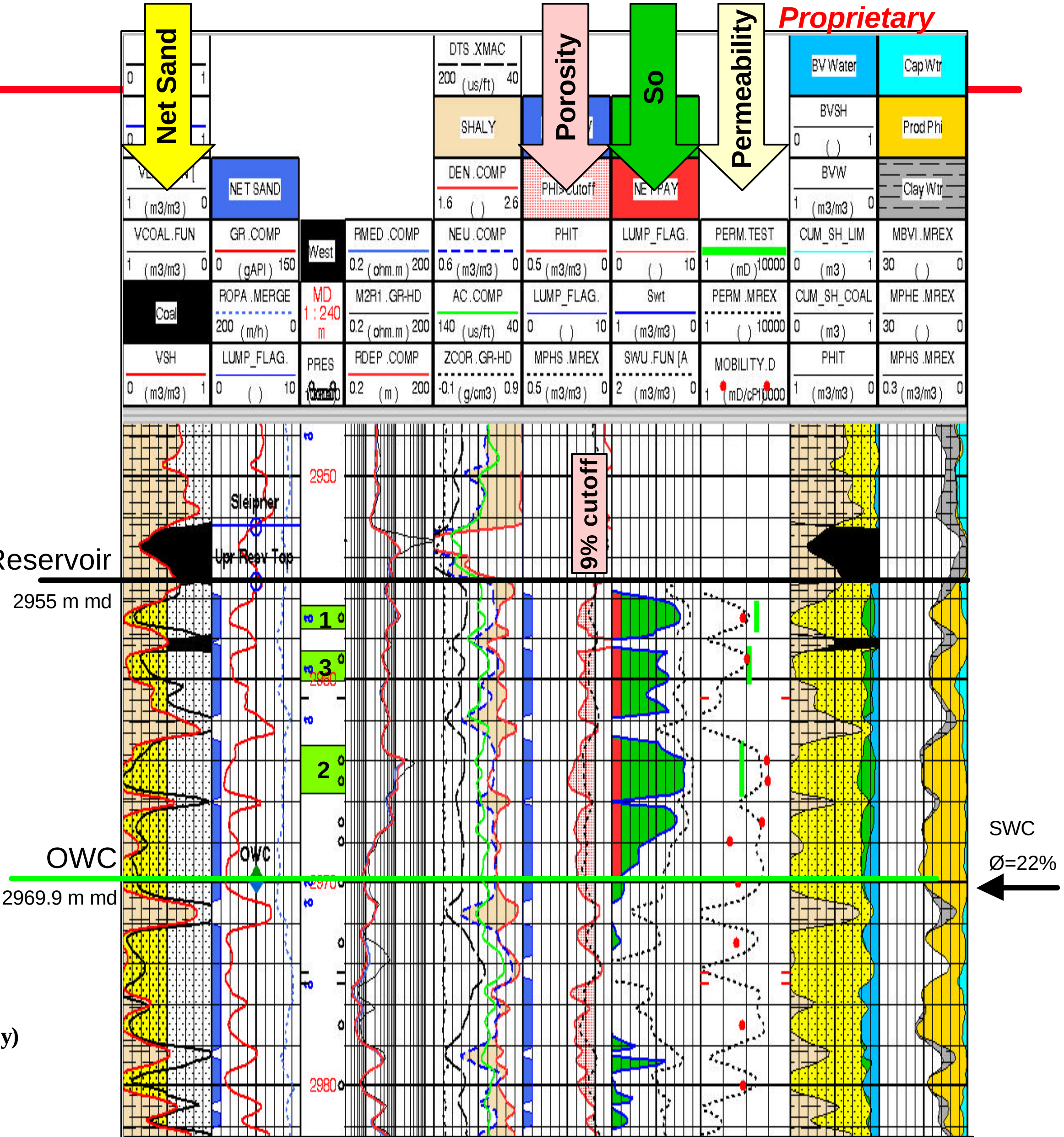


Figure 5.4

I:Geoscience\Project\pl001b & pl242\16_1_7/Discovery Eval report/DiscEvalFigs_Landsc

Esso Norge AS
An **ExxonMobil** Subsidiary

16/1-7 Discovery Evaluation
Reservoir: Porosity & Permeability



Test 1: 2956.4-2957.5mMD, 1.1m, Avgs: Vsh 7.6%, Phi 18.6%, Sw 27%
Test 3: 2959.0-2960.0mMD, 1.5m, Avgs: Vsh 7.0%, Phi 17.0%, Sw 44%
Test 2: 2964.0-2965.0mMD, 2.3m, Avgs: Vsh 4.0%, Phi 21.5%, Sw 24%

Porosity 17-18-28%

- No Conventional Core
- Log Interpretation
  - avg 17-18%
- SWC (75 shots, 32 recovered, 10 in sand)
  - 2 Ø measurements only: 22 and 28%

Permeability 50-150-500

- Log Interpretation
  - K = 50-500 mD
- Tests
  - Mini DST 1, 340 mD
  - Mini DST 2, 150 mD
  - Mini DST 3, 74 mD
  - Observations
    - Able to interpret pressure transient even with very small drawdown
    - Radius of investigation up to 1500 ft (Implies connecctivity)
    - Drawdown limited by severe overbalance in the wellbore
    - Could expect higher rate and better results with lower overbalance

Figure 5.5

16/1-7 Discovery Evaluation

OWC - 16/1-7 RCI Pressure Data

ExxonMobil
Exploration

Contact confidently Defined by Pressure Data….

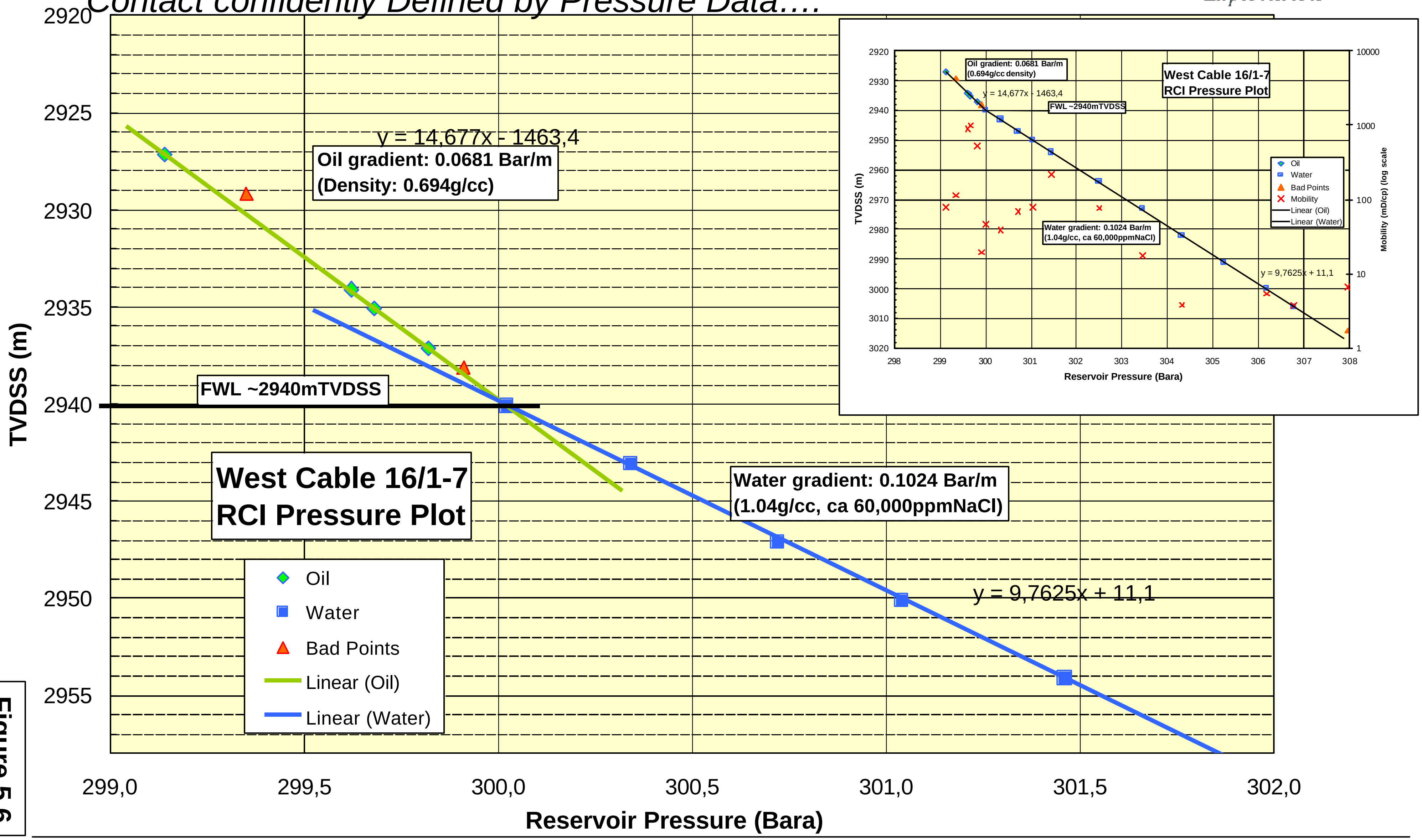
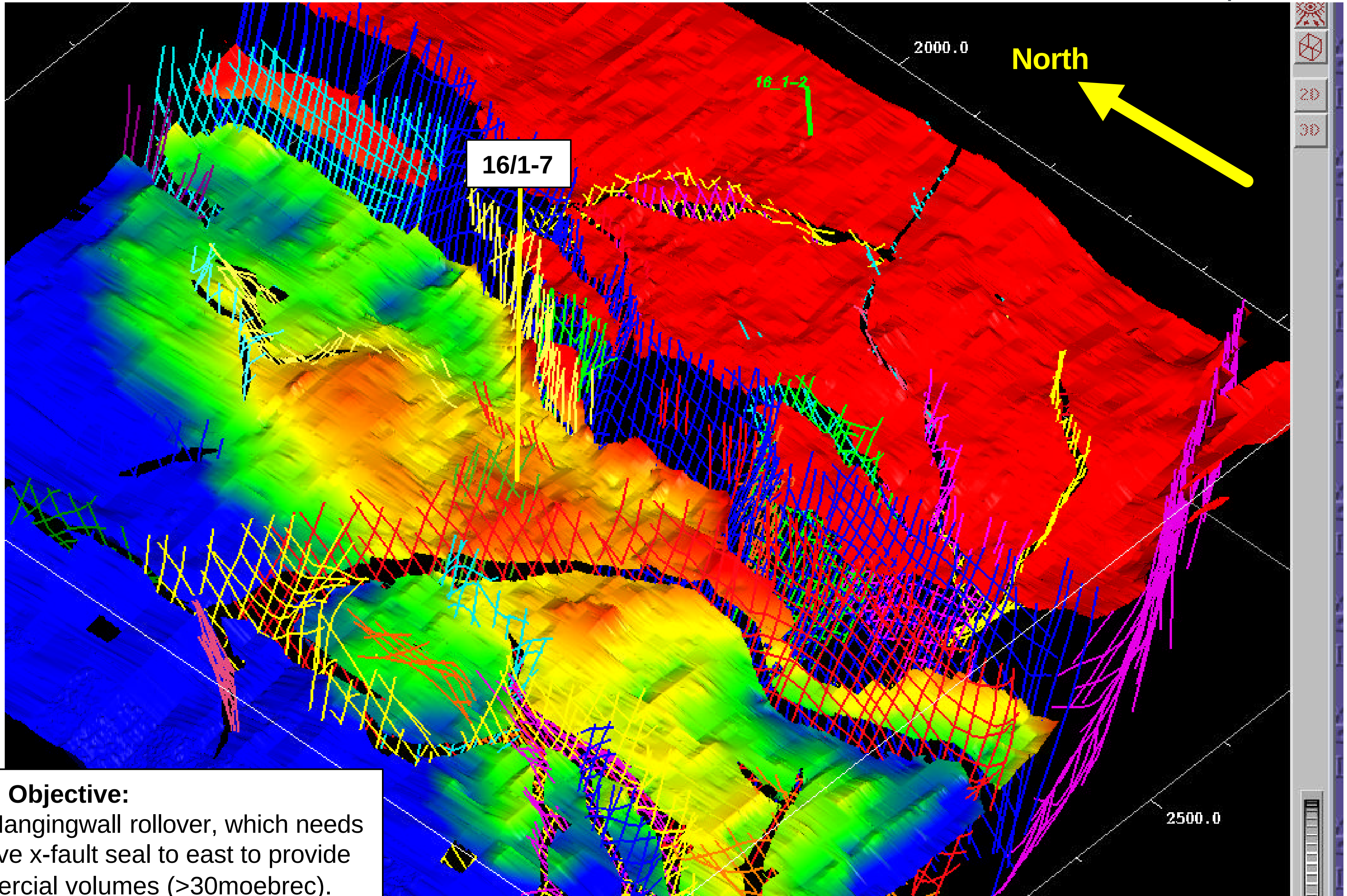


Figure 5.6

16/1-7 Discovery Evaluation

Trap Geometry - Perspective View of Top Triassic TWT Structure



16/1-7 Objective:
Test Hangingwall rollover, which needs effective x-fault seal to east to provide commercial volumes (>30moebrec).

Figure 6.1

16/1-7 Discovery Evaluation

16/1-7 Well Tops Listing

ExxonMobil
Exploration

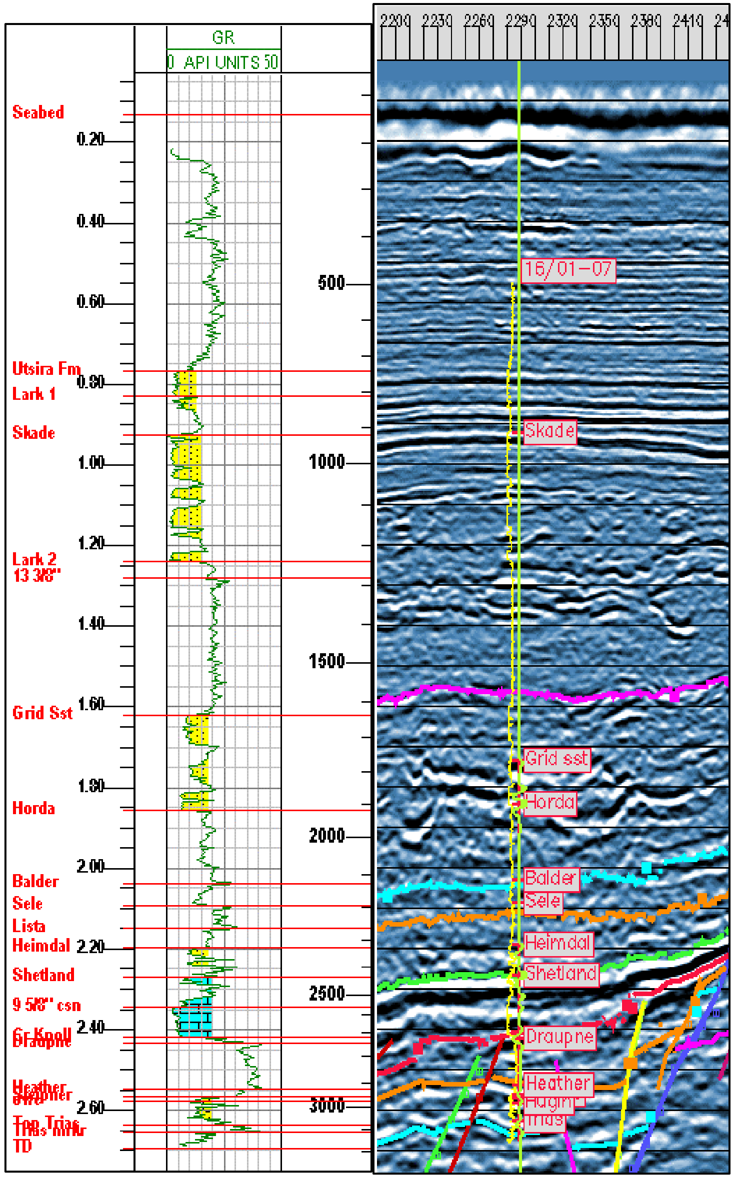


Figure 6.2

	Depth mkb	Depth msl	CKS* TWT
Seabed	141,2	112,2	0,151
Utsira	742,5	713,5	0,766
U.Lark	815	786	0,831
Skade	920	891	0,92
L.Lark	1240	1211	1,24
Grid Fm Sst	1631	1602	1,62
Horda	1922	1893	1,857
Top Balder Tuff	2130	2101	2,039
Top Sele	2197,5	2168,5	2,093
U.Lista	2263	2234	2,149
Heimdal	2327	2298	2,196
Base Heimdal	2399	2370	2,242
Top Shetland	2436	2407	2,271
Tor Chalk	2560	2531	2,344
Cromer Knoll	2727	2698	2,419
BCU / Draupne	2747	2718	2,431
Heather	2918	2889	2,546
Top Sleipner	2952,5	2923,5	2,567
Top Trias	3083	3054	2,638
Trias mrkr	3113	3084	2,656
TD	3186	3157	2,694

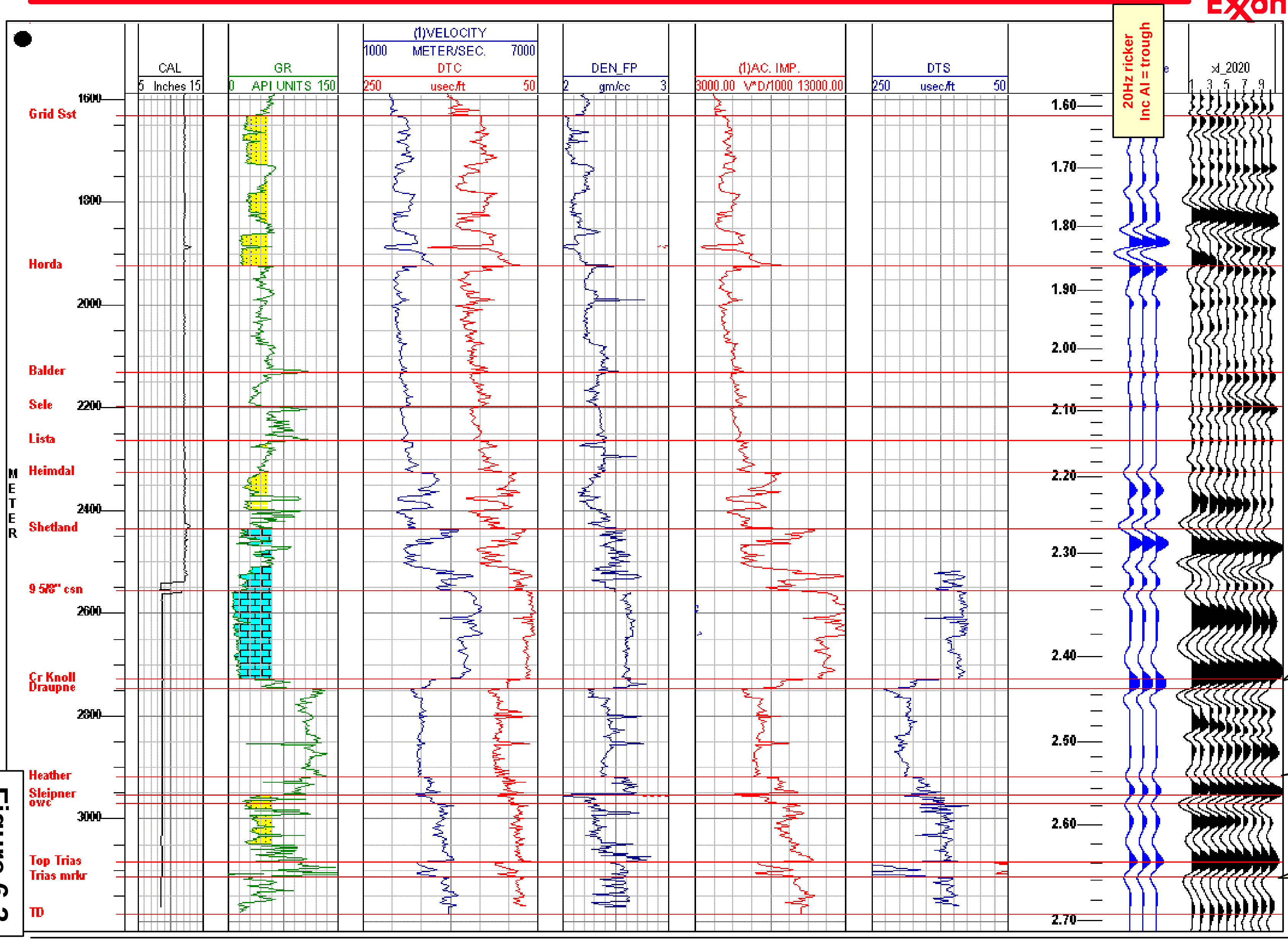
KBE:	29	ES9402re98
X.	449827,6mE	IL: 2290
Y	6 533 063,7mN	XL: 2020

*Checkshot TWT are 6-10ms deeper than Seismic TWT in Jurassic

16/1-7 Discovery Evaluation

16/1-7 Geophysical Logs, Synthetic and Well-Seismic tie (ES9402re98 3D, il 2290, xL 2020)

ExxonMobil
Exploration



CKS TWT shifted 6ms to tie Seismic TWT

B.Cret = two AI drops does not lie at peak, but close to 0-xing

Heather mrkr = Top Heather

True Top reservoir lies close to 0-xing

Triassic mrkr = cycle below top Trias

Figure 6.3

I:Geoscience\Project\pl001b & pl242\16_1_7/Discovery Eval report/DiscEvalFigs_Landsc

16/1-7 Discovery Evaluation

16/1-7 Well Logs and tie to seismic - Reservoir Detail

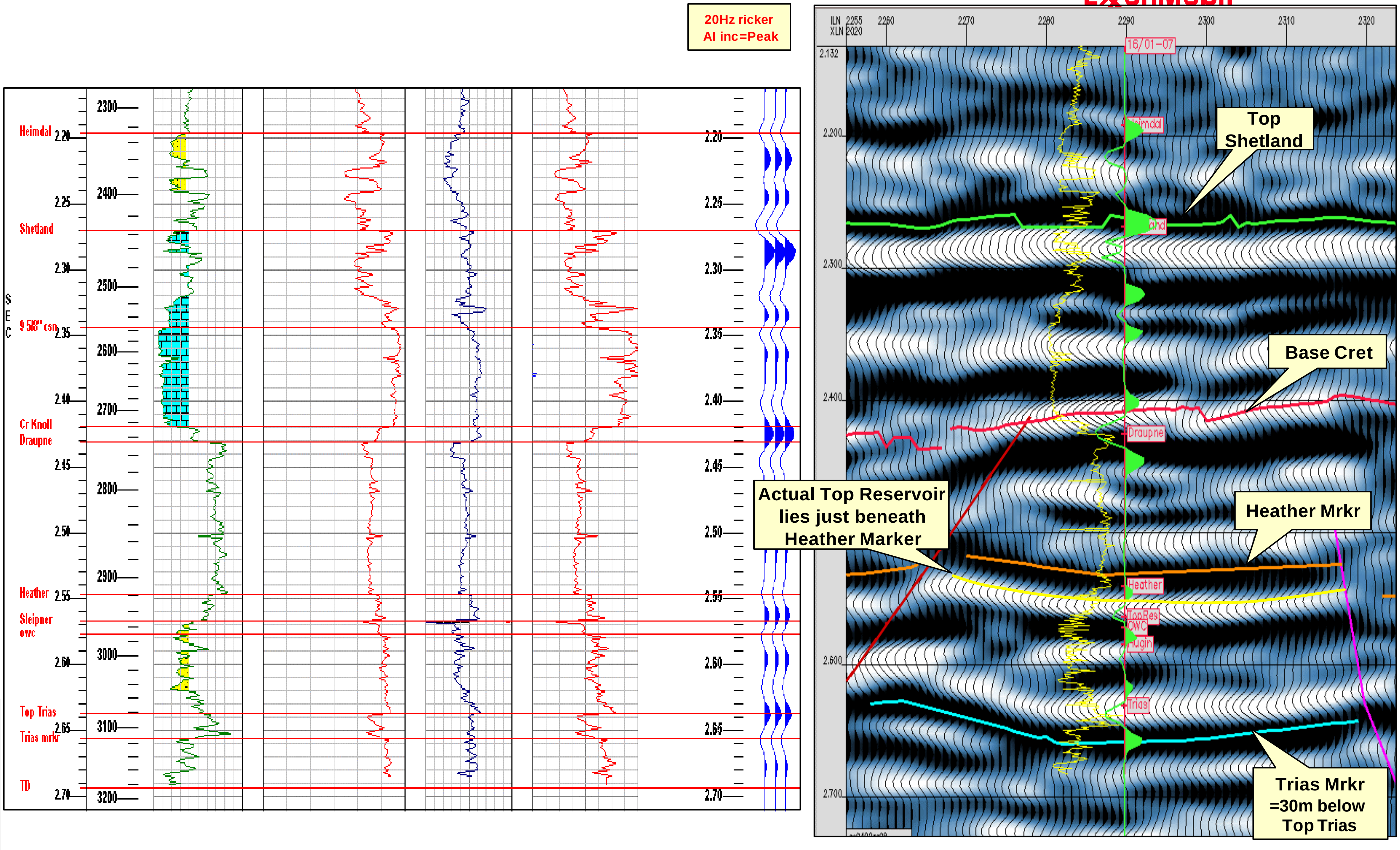
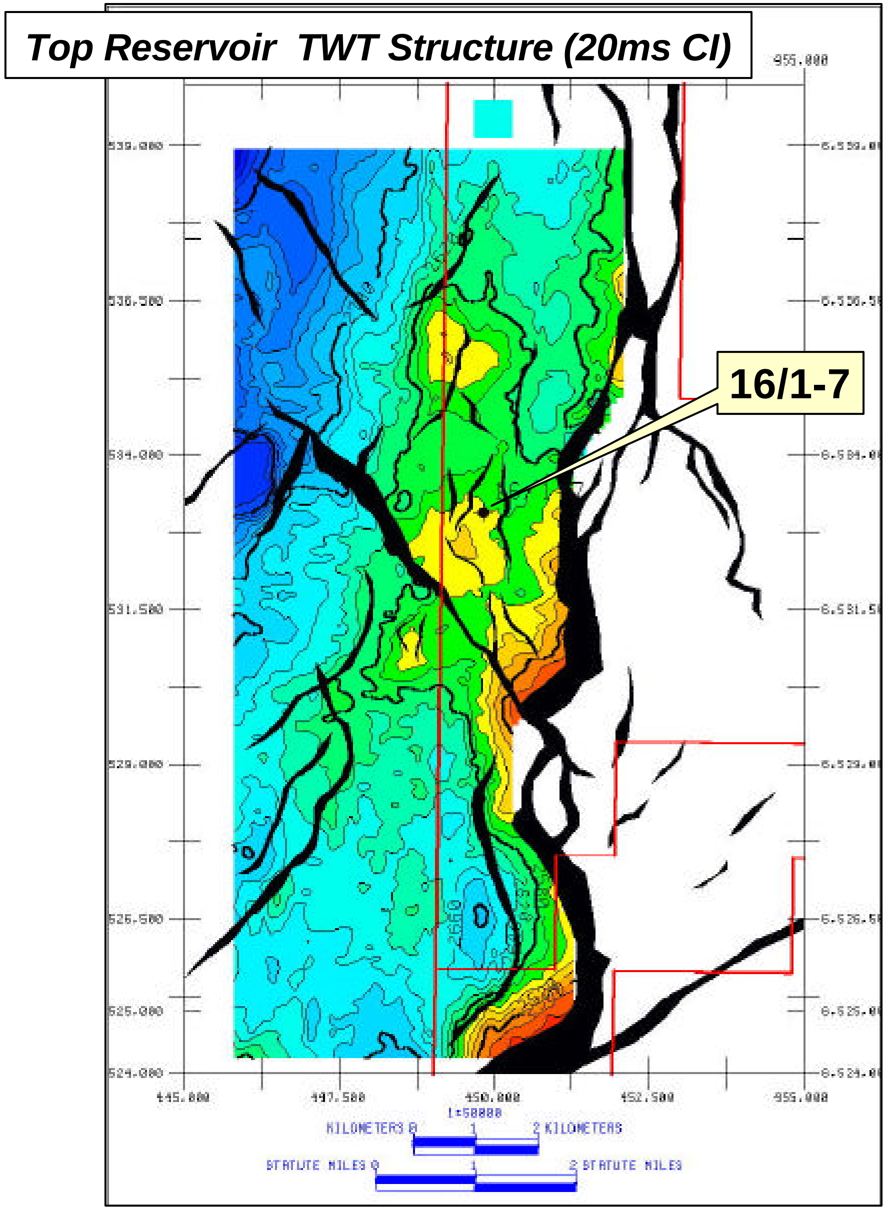


Figure 6.4

Trap: Top Sleipner Reservoir Structure (TWT and Depth)

ExxonMobil



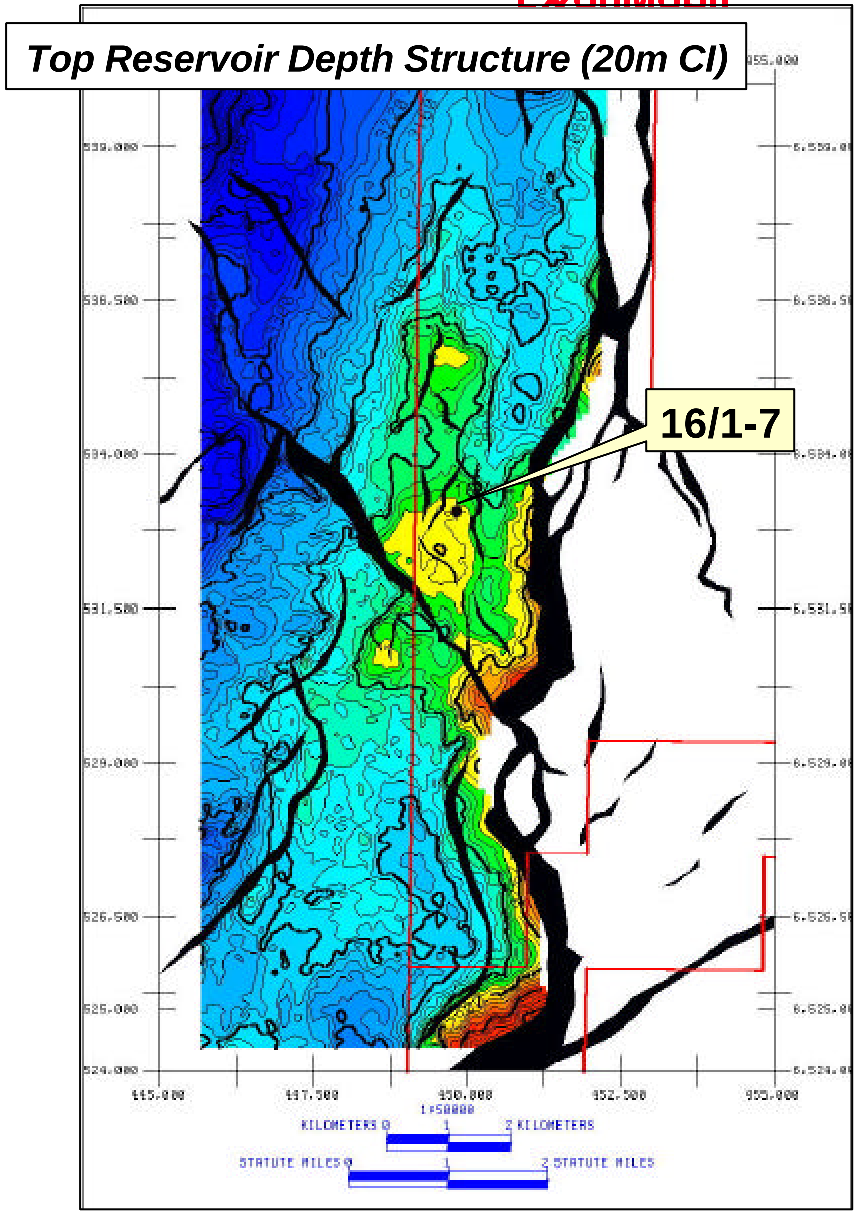


Figure 6.5

16/1-7 Discovery Evaluation

Trap: Top Reservoir Interpretation - Ambiguity away from well

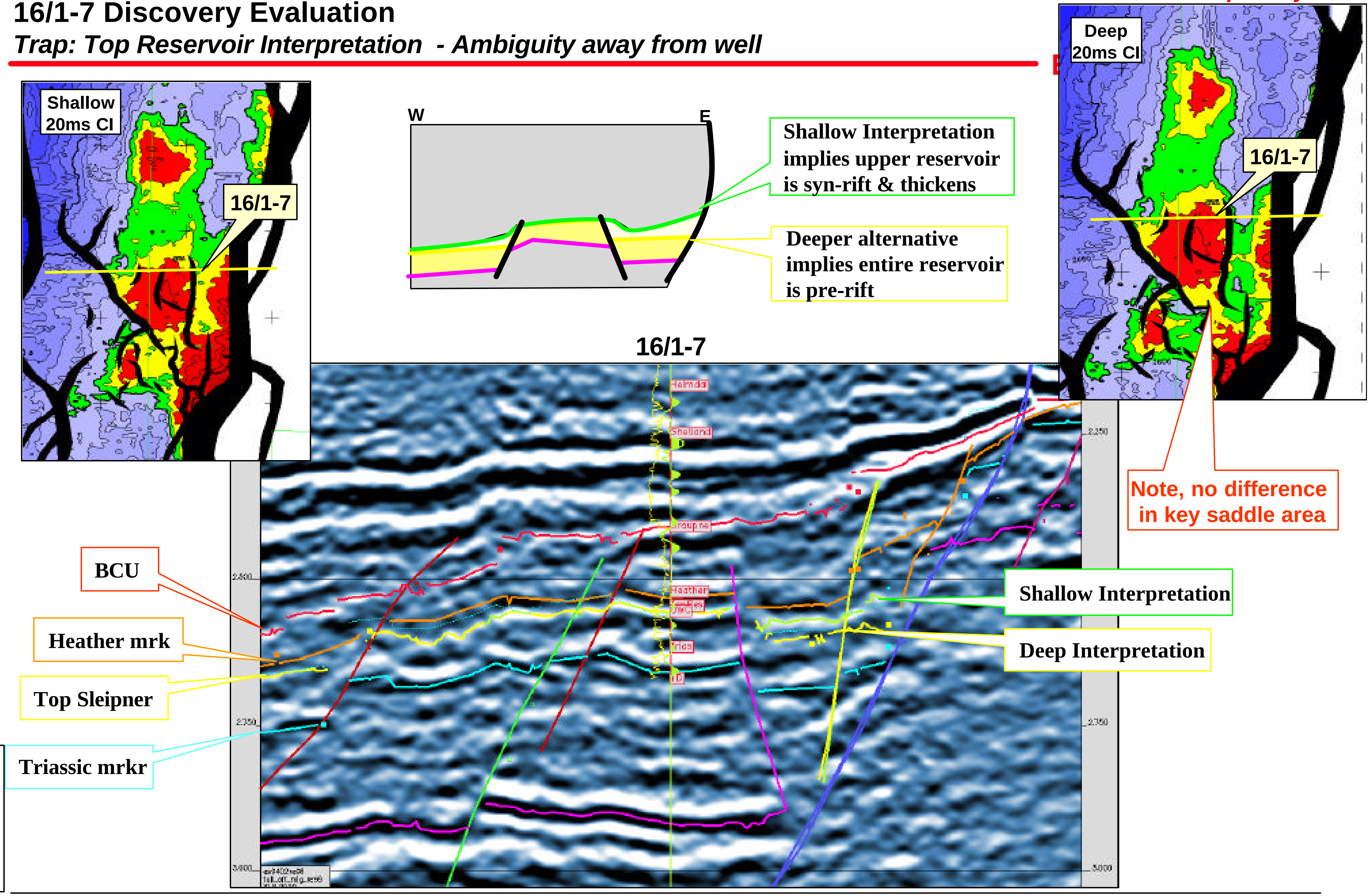
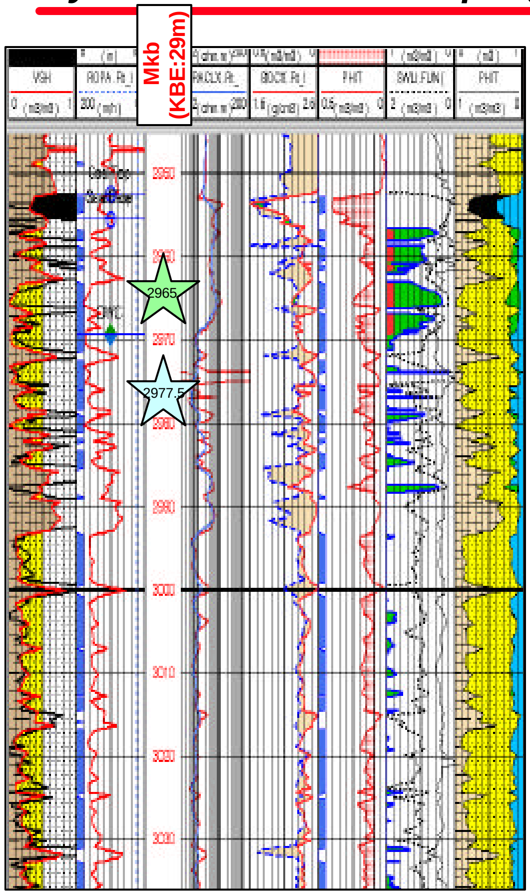


Figure 6.6

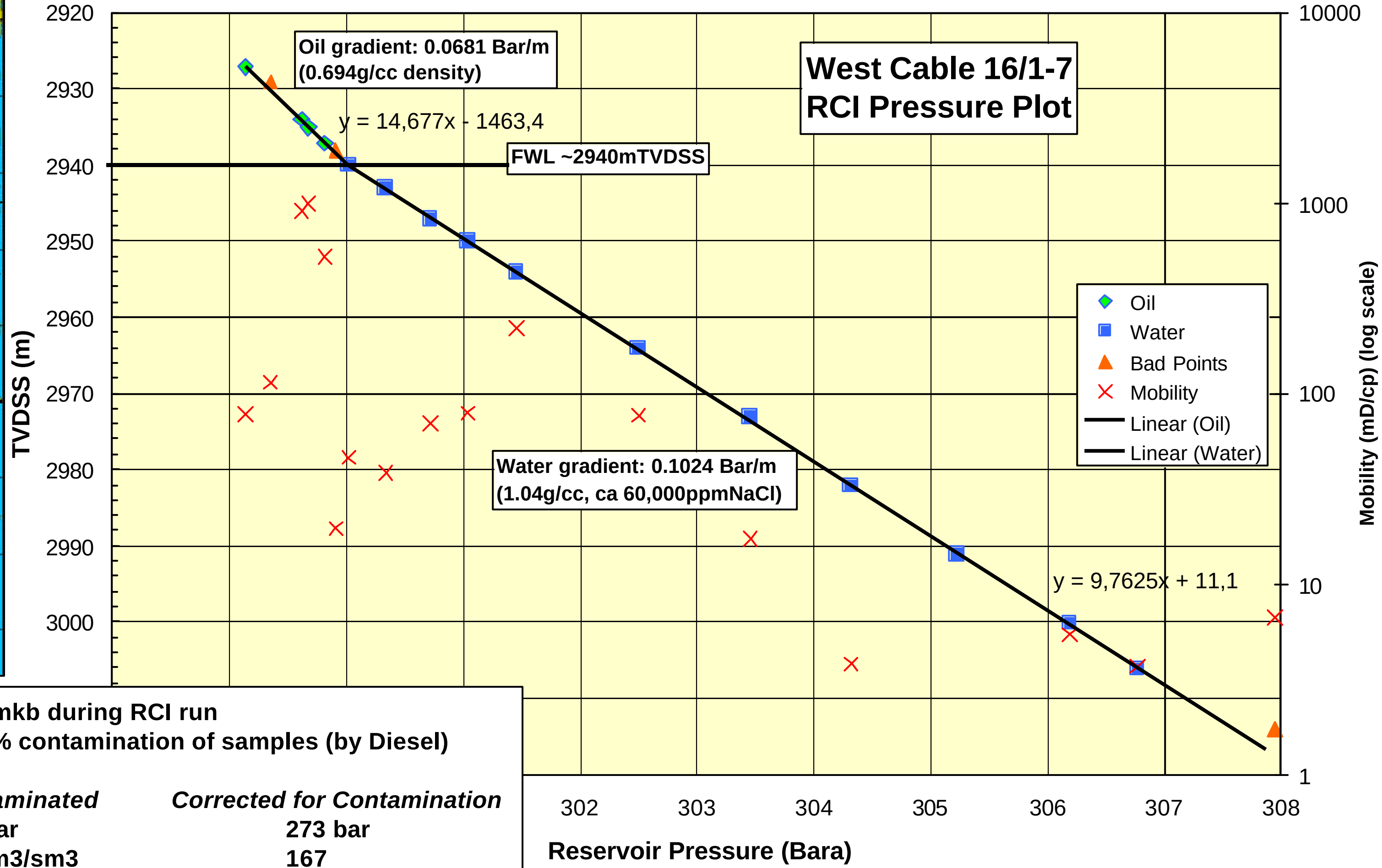
16/1-7 Discovery Evaluation

Hydrocarbon Fluid Sampling

ExxonMobil Exploration



Log Evaluation & pressure data agree on 2940msl OWC



- **Hydrocarbons sampled from 2965mkb during RCI run**
- **Onshore Lab analysis revealed 14% contamination of samples (by Diesel)**

PVT analysis data	***Contaminated***	***Corrected for Contamination***
Psat:	**250 bar**	**273 bar**
GOR:	**153sm3/sm3**	**167**
Bo:	**1.487**	**1.544**
Oil Density (at 300bar):	**0.664g/cc**	**0.622g/cc**
Oil Density (stock tank):	**0.840g/cc**	**0.790g/cc**

Figure 7.1

Bottle TS-64604 Compositional Analysis

COMPONENT	Composition of the stock tank gas					Composition of the stock tank oil				Composition of reservoir fluid			
	Mole %	Weight %	Molecular Weight	Density kg/m^3	LNG m^3	Mole %	Weight %	Molecular Weight	Density kg/m^3	Mole %	Weight %	Molecular Weight	Density kg/m^3
Nitrogen	0.441	0.540	28.02	804.0						0.290	0.092	28.02	804.0
Carbon dioxide	2.483	4.777	44.01	809.0						1.635	0.814	44.01	809.0
Hydrogen Sulphide	0.000	0.000								0.000	0.000		
Methane	73.492	51.532	16.04	300.0		0.218	0.016	16.04	300.0	48.462	8.795	16.04	300.0
Ethane	11.702	15.379	30.07	356.7		0.415	0.058	30.07	356.7	7.846	2.669	30.07	356.7
Propane	6.837	13.178	44.09	506.7	251.8	0.855	0.176	44.09	506.7	4.794	2.391	44.09	506.7
iso-Butane	0.914	2.321	58.12	562.1	40.0	0.335	0.091	58.12	562.1	0.716	0.471	58.12	562.1
n-Butane	2.205	5.602	58.12	583.1	93.0	1.370	0.371	58.12	583.1	1.920	1.262	58.12	583.1
Neopentane	0.008	0.025	72.15	597.0	0.4	0.017	0.006	72.15	597.0	0.011	0.009	72.15	597.0
iso-Pentane	0.528	1.665	72.15	623.3	25.9	1.059	0.356	72.15	623.3	0.709	0.579	72.15	623.3
n-Pentane	0.601	1.896	72.15	629.9	29.1	1.796	0.603	72.15	629.9	1.009	0.824	72.15	629.9
Hexanes, C6 total	**0.369**	**1.360**	**84.4**	**668.6**	**19.7**	**3.643**	**1.430**	**84.3**	**669.4**	**1.487**	**1.418**	**84.3**	**669.2**
n-Hexane	*0.144*	*0.543*	*86.2*	*662.7*		*1.799*	*0.722*	*86.2*	*662.7*	*0.709*	*0.692*	*86.2*	*662.7*
iso-Paraffins	*0.183*	*0.691*	*86.2*	*660.5*		*1.414*	*0.567*	*86.2*	*660.5*	*0.604*	*0.588*	*86.2*	*660.5*
Naphtenes	*0.041*	*0.126*	*70.1*	*748.1*		*0.431*	*0.141*	*70.1*	*748.1*	*0.174*	*0.138*	*70.1*	*748.1*
Heptanes, C7 total	**0.287**	**1.107**	**88.4**	**755.2**	**14.2**	**7.582**	**3.198**	**90.5**	**743.7**	**2.779**	**2.841**	**90.4**	**744.4**
n-Heptane	*0.036*	*0.158*	*100.2*	*686.9*		*1.634*	*0.763*	*100.2*	*686.9*	*0.582*	*0.660*	*100.2*	*686.9*
iso-Paraffins	*0.050*	*0.219*	*100.2*	*689.2*		*1.482*	*0.692*	*100.2*	*690.5*	*0.539*	*0.611*	*100.2*	*690.4*
Naphtenes	*0.142*	*0.531*	*85.4*	*766.8*		*3.175*	*1.273*	*86.1*	*769.1*	*1.178*	*1.147*	*86.0*	*768.9*
Aromatics	*0.058*	*0.198*	*78.1*	*883.1*		*1.291*	*0.470*	*78.1*	*883.1*	*0.479*	*0.424*	*78.1*	*883.1*
Octanes, C8 total	0.107	0.477	101.7	778.4	5.9	9.994	4.792	102.9	777.2	3.485	4.056	102.9	777.2
n-Octane	*0.009*	*0.045*	*114.2*	*707.0*		*1.381*	*0.735*	*114.2*	*707.0*	*0.478*	*0.617*	*114.2*	*707.0*
iso-Paraffins	*0.010*	*0.050*	*114.2*	*704.1*		*1.158*	*0.619*	*114.7*	*709.3*	*0.402*	*0.522*	*114.7*	*709.2*
Naphtenes	*0.060*	*0.269*	*102.2*	*771.8*		*4.335*	*2.099*	*103.9*	*772.2*	*1.520*	*1.787*	*103.9*	*772.2*
Aromatics	*0.028*	*0.113*	*92.1*	*872.0*		*3.121*	*1.340*	*92.1*	*872.0*	*1.085*	*1.131*	*92.1*	*872.0*
Nonanes, C9 total	**0.018**	**0.093**	**118.1**	**776.5**	**1.2**	**7.216**	**3.917**	**116.5**	**790.7**	**2.477**	**3.266**	**116.5**	**790.7**
n-Nonane	*0.002*	*0.011*	*128.3*	*723.0*		*1.220*	*0.729*	*128.3*	*723.0*	*0.418*	*0.607*	*128.3*	*723.0*
iso-Paraffins	*0.006*	*0.034*	*128.3*	*721.1*		*1.596*	*0.953*	*128.3*	*724.2*	*0.549*	*0.797*	*128.3*	*724.1*
Naphtenes	*0.004*	*0.020*	*115.7*	*791.2*		*1.080*	*0.593*	*117.9*	*793.6*	*0.372*	*0.495*	*117.8*	*793.6*
Aromatics	*0.006*	*0.028*	*106.2*	*871.6*		*3.320*	*1.642*	*106.2*	*872.5*	*1.138*	*1.367*	*106.2*	*872.5*
Decanes plus, C10+	**0.008**	**0.050**	**138**		**0.6**	**65.500**	**84.986**	**279**	**867**	**22.380**	**70.512**	**279**	**867**
Sum	100.000	100.000			481.7	100.000	100.000			100.000	100.000		
Mean molecular weight:			22.88					214.7				88.4	
Gas gravity:			0.790										

Figure 7.2

16/1-7 Discovery Evaluation

Hydrocarbon Fluid Composition - Effect of correction for OBM contamination

ExxonMobil Exploration

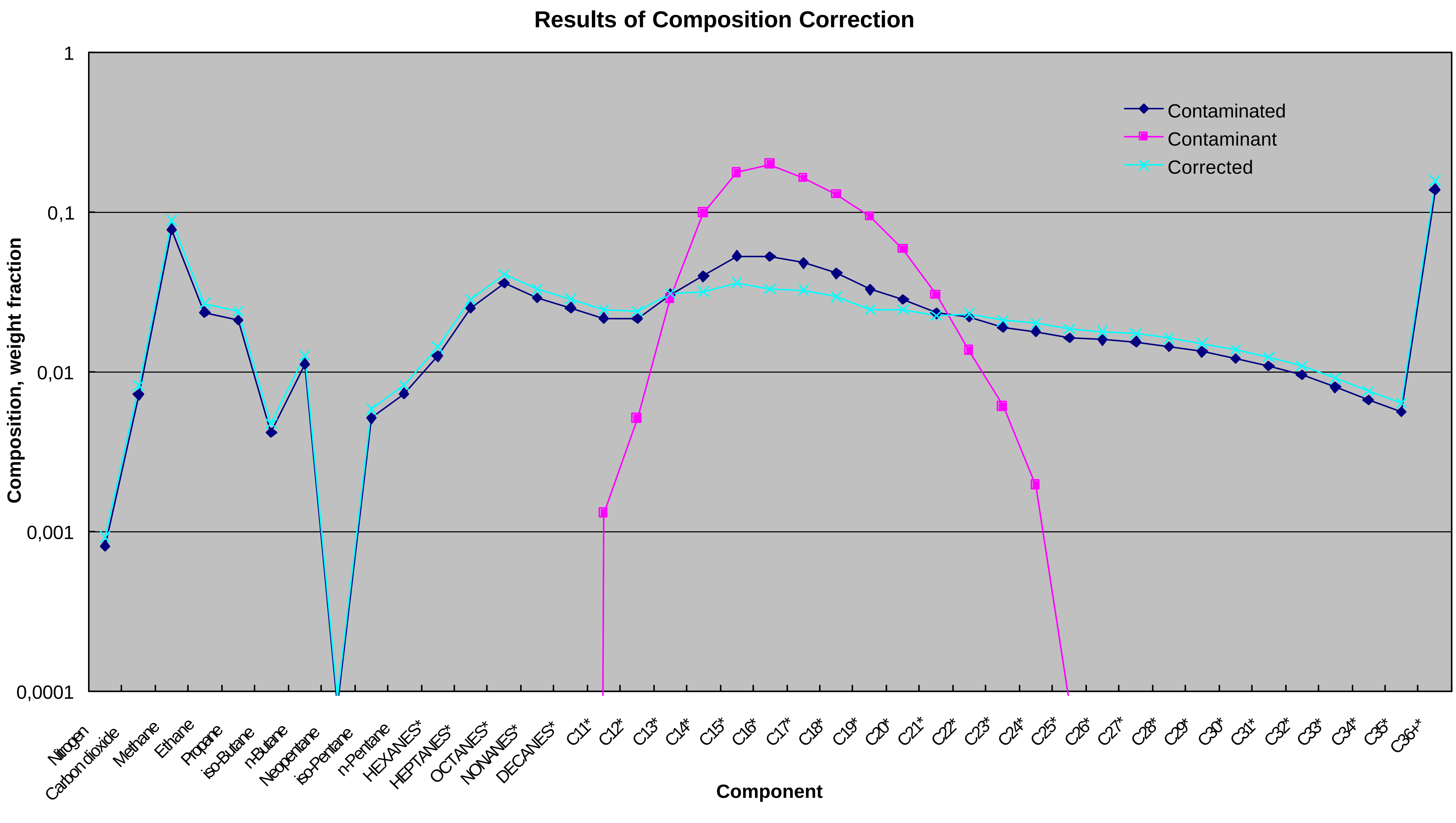


Figure 7.3

16/1-7 Discovery Evaluation

In-Place Volume Estimates - Proven, Most Likely and Extreme Maximum Cases

Proprietary

ExxonMobil

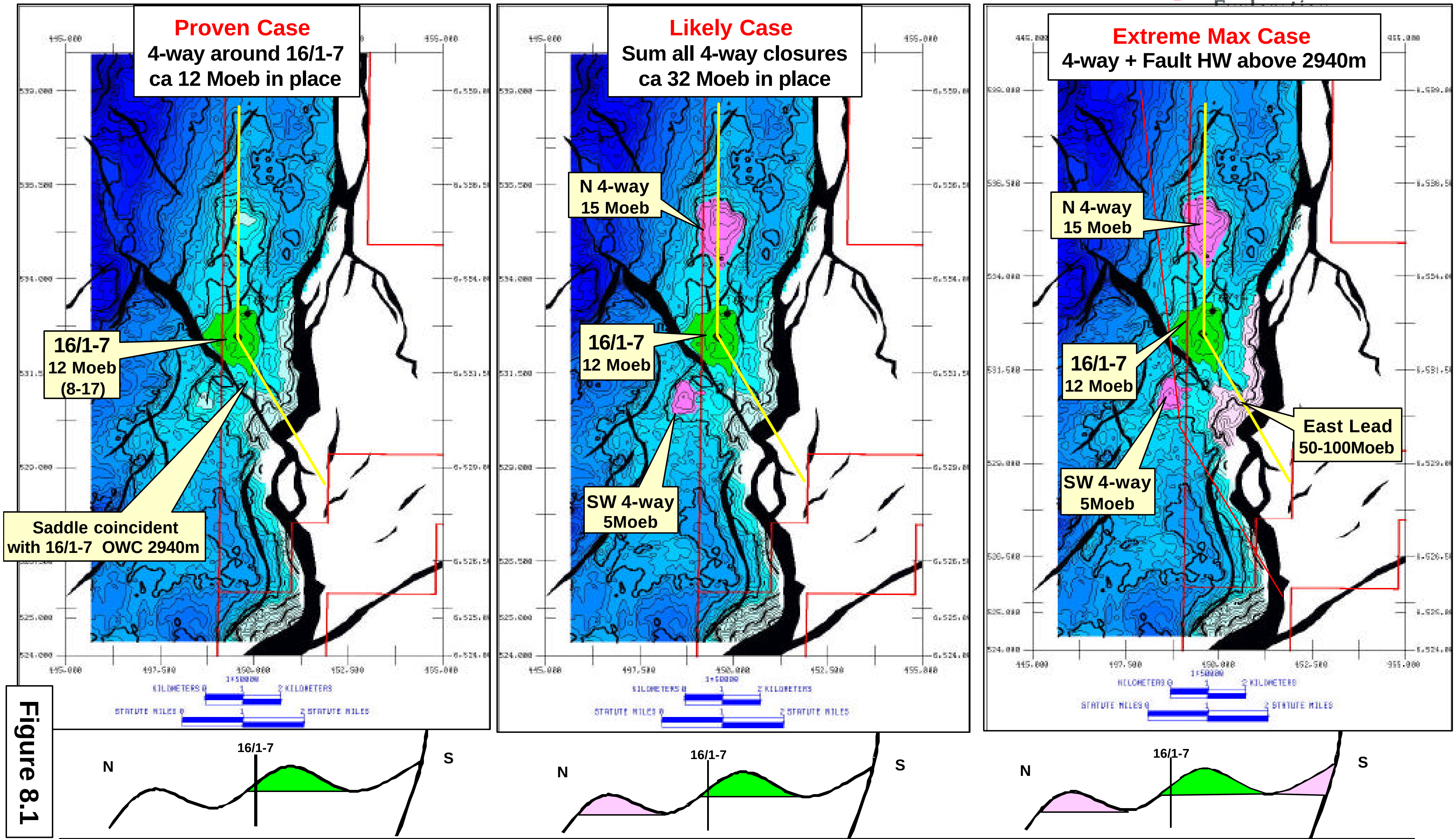


Figure 8.1

16/1-7 Discovery Evaluation

Development Screening - Reservoir Input

ExxonMobil Exploration

Drive Mechanism

- Water injection for pressure support
- 40% RF based on analog data

2 high-angle, near horizontal wells

- Wells productivity potentially a critical issue
- Maintain standoff from water
- Productivity likely dependant on vertical permeability

Well productivity

- No core data and no conventional DST
- Discovery well has 3 mini- DSTs indicating good permeability
- High N/G = 79%
- No production experience from Sleipner formation
- Estimated PI 10 to 20 BOPD/psi from mini-DST
- Up to 10 KBOPD at 1000 psi FWHP

Subsea development

- Nearest field is Grane over 30 km
- Potential for re-use of existing FPSO

Preliminary oil quality data

- RCI samples with 14% OBM contamination
- Corrected GOR is 1060 scf/stb
- Corrected oil gravity is 35 API
- Estimated viscosity is 0.35 cp
- Estimated saturation pressure is 4000 psi
  - risk of gas cap needs to be evaluated with EOS modeling
  - will be evaluated after completion of PVT
  - high uncertainty due to OBM contamination

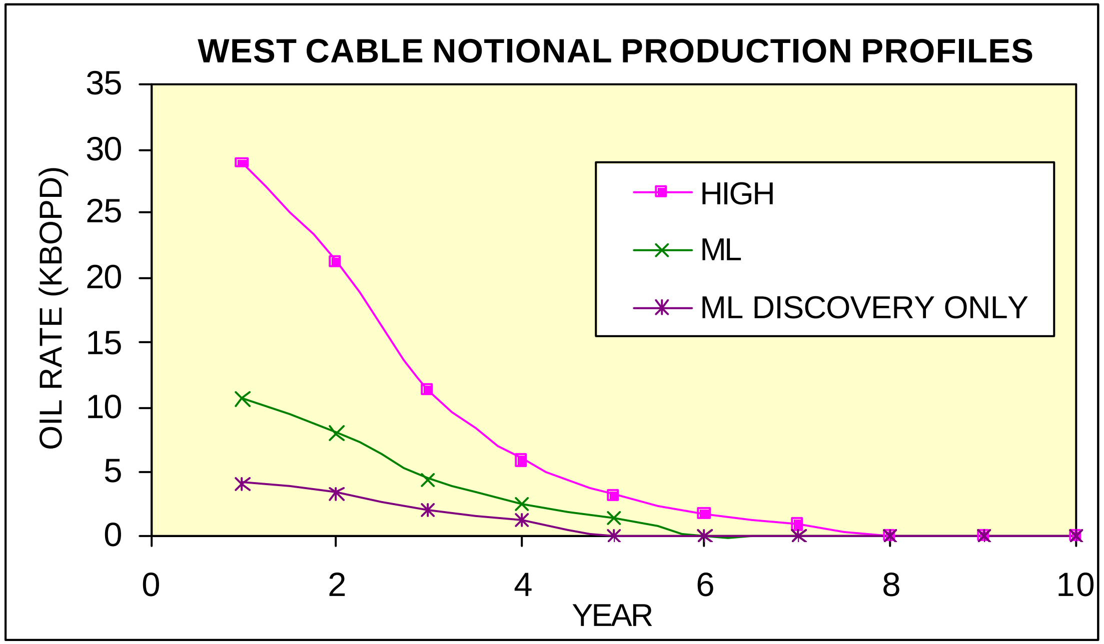


Figure 9.1

16/1-7 Discovery Evaluation

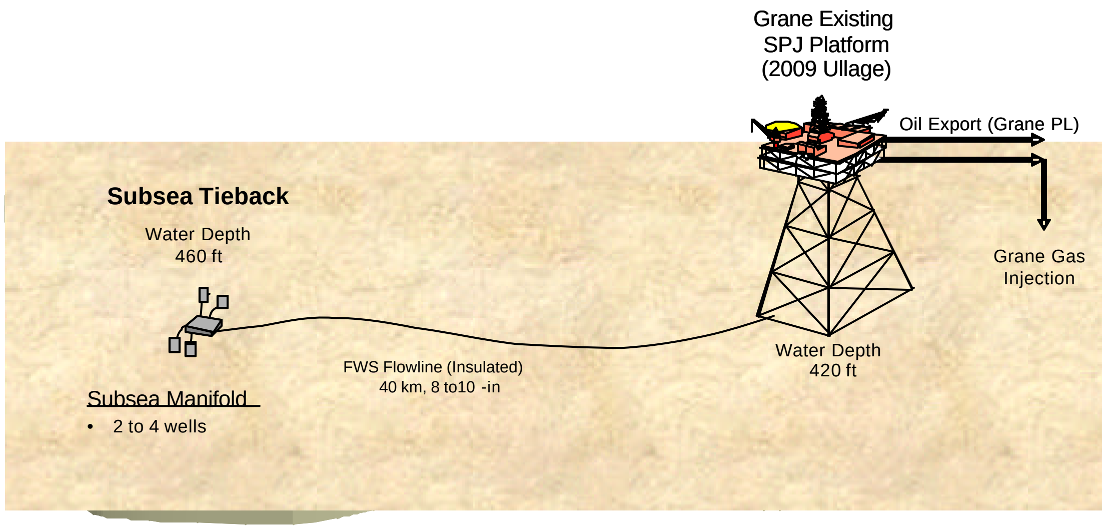
Development Screening - Planning & Commercial Input

ExxonMobil Exploration

Planning Basis

- EM operated oil prospect (PL001B/PL242: EM 50% op., Statoil 50%)
- 2004 CTR (May 2004 oil discovery)
- 2004 CTR (May 2004 oil discovery)
- Development Concept: Subsea tieback to Grane
- Startup in 2009 (Grane ullage available)
- Evaluated Freke subsea tieback option to UK Brae

Development Concept Schematic



Concept Design Basis

Scenario	ML	HS
Recovery, MBOE	10	29
Plateau Rates		
Oil, kbd	11	29
Gas, Mscfd	1	20
Water Inj., kbd		
Wells - Prod.	2	4
- Inj.		
FWS Line	1 x 8-in	1 x 10-in
MBOE/well	5	7

Scoping Level Cost Estimate

$M US Gross (2004)

	ML	HS
Facilities		
- SURF	56	79
- Offshore T&I	24	27
- Engineering	6	7
- Non-Direct	5	6
- PMT (12%)	11	14
- Contingency (30%)	31	40
- SCSA (4%)	4	5
Total	**137**	**178**
Drilling (dev. wells)	**65**	**126**
Total Project	**202**	**304**
Capex/bbl	20.17	10.64
Opex/bbl	1.83	1.79

Cost Basis & Assumptions

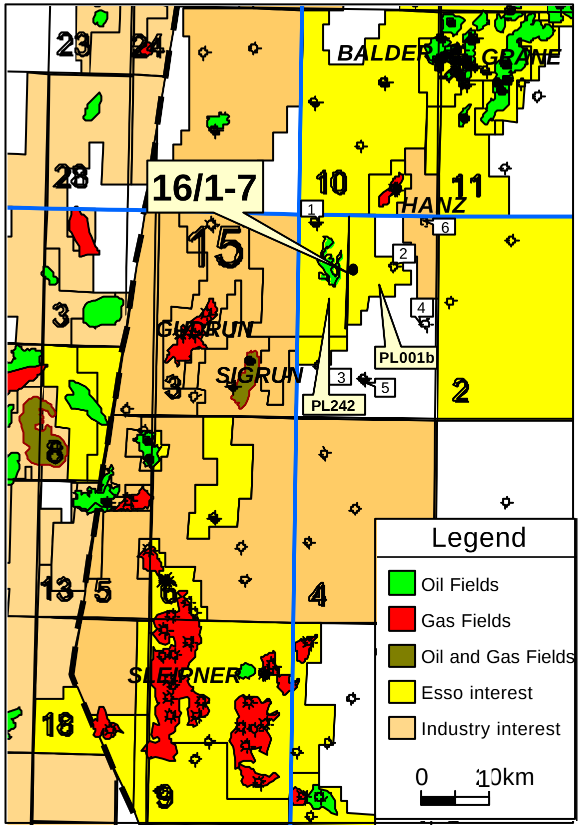
- Facility costs based on C&S cost estimating templates
- PMT based on 12% of base costs
- 30% Contingency applied to facility costs
- 4% SCSA applied to base costs
- Drilling estimates based on Ringhorne analogs

Figure 9.2

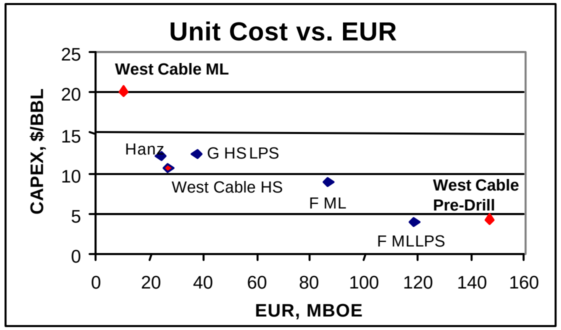
16/1-7 Discovery Evaluation

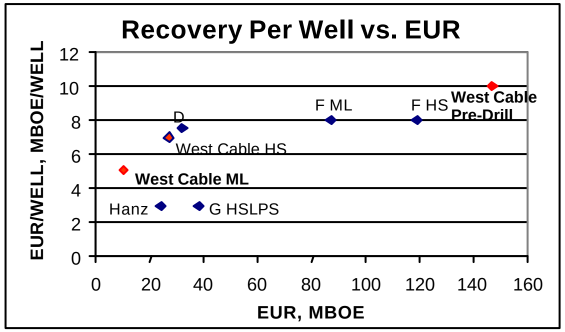
Development Screening - Conclusions

ExxonMobil Exploration



Oil Prospect	West Cable					
Case	ML Oil	V High	High	High Disc	ML	ML Disc
Basis	Pre-Drill	2004 CTR				
License	PL001B/242					
Expiry	2005 - extension with well drill					
WD, m	140					
EMWI	50% op.					
WI Owners	Statoil 50%					
Dev Concept	Grane Tieback	Grane Tieback	Grane Tieback	Grane Tieback	Grane Tieback	Grane Tieback
SU	2009	2009	2007	2008	2009	2009
Oil kbd	40	45	29	18	11	4
Gas, Mcfd	80	37	20	9	1	-
Wells	15	10	4	2	2	1
EUR, MBOE	**147**	**50**	**27**	**23**	**10**	**4**
MBO/well	**10**	**5**	**7**	**12**	**5**	**4**
Capex (Fac) $M	392		178	152	137	
Drillex, $M	249		126	65	65	
Total, $M	641		304	217	202	
Unit Cost, $/bbl	**4.36**		**10.64**	**9.07**	**20.17**	
DCFR, %						
PV, $M						
AVP, $M						





Conclusions:

- **16/1-7 Discovery is not viable on a standalone basis, nor as a tieback**
  - Other prospects/discoveries not viable due to low recovery per well and high unit cost
- **Synergy opportunities are limited – large distances and marginal prospects**
  - Limited gathering system savings and no single drilling center option

Figure 9.3