UK Central North Sea Tertiary & Cretaceous Roknowledge study (Q3054)

(UK Blocks 21, 22, 23, 28, 29, 30)

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Shell CNS Tertiary and Cretaceous Roknowledge™ study

Executive Summary

The Shell CNS Tertiary and Cretaceous Roknowledge™ study has been produced by Ikon Science as a seismic rock physics database and interpretation guide which provides easy access to reliable, consistent and auditable regional rock physics parameters to aid a better understanding of seismic rock properties, trends and correlations for Tertiary formations (Horda, Balder, Sele, Lista, Maureen) and Cretaceous-Chalk formations (Ekofisk, Tor, Hod) within the study area covering Quad 21/22/23/29/30 of the UK Central North Sea (CNS). The study contains data drawn from a total of 35 wells. Trends and various seismic rock property relationships are established through both a multi-well and a single-well approach. The primary objectives are to :

1) Reduce data mining and preparation time for Quantitative Interpretation (QI) projects,
2) Ssupport prediction of seismic rock properties where data is limited or missing (in particular missing Shear sonic log data),
3) Enable direct comparison of the seismic response from different fluid scenario's for the study wells,
4) Identify optimum seismic (sub)stack for seismic interpretation,
5) Expand the user base for common rock / fluid scenario's modelling activities to non-QI specialists
6) Permit geoscientists to make informed decisions as to the best attribute to select for seismic inversion in order to highlight hydrocarbon sweet-spots.

The results indicate the presence of regional acoustically soft/hard shales and high/low porosity reservoir rocks. Local variations in rock type outside the regional averages are identified, which require further refinement beyond the regional scope of this study. Such to gain additional localised understanding of the impact of rock type variations on the seismic response.

Additional fluid saturations other than the insitu, brine, 80% oil and 90% gas (and 80% condensate where appropriate) can be created with regional oil/gas/condensate property maps and local pressure & temperature conditions.

There is a strong focus on the QC aspects to establish the validity of the results through the creation of synthetic log curves for comparison with the actual measured curves. Zones where artificial log data is created to ensure complete coverage of the logged interval, is captured through so-called Edit-Flag curves. The quality of the infill data is often so realistic that it is difficult to identify.

The 35 wells are selected with a special attention on, in particular, shear data coverage (12 wells).

Limitations of the study are in part driven by limited petrological data, which allowed only a single set of 'dirty' quartz (Tertiary) and limestone (Maureen & Chalk) mineral properties.

The results are delivered as a RokDoc (version 5.6.3) project file, a master spreadsheet and numerous QC powerpoint files.

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Chapter 1 – Introduction

1.1 General Introduction

The Central North Sea (CNS) is an established and prolific hydrocarbon province. In more than forty years of activity, the CNS area has accounted for 29% of the exploration wells drilled in the UK North Sea, and over a quarter of all exploration and appraisal wells. The pre-Cretaceous plays of the CNS have yielded approximately 10% of the total UK North Sea discovered resources (Erratt et al., 2005).

The CNS is both a structurally and stratigraphically complex area due to the complex rift system. The majority of exploration in the region has targeted the Jurassic and Triassic reservoirs with considerable proven reserves present in fields such as Argyll, Forties, Montrose, Nelson, Scoter and Shearwater (both Nelson and Scoter are natural gas and condensate fields). The geology of the basin has been subjected to increasingly detailed scrutiny throughout the last 40 years, and a thorough review can be found in the Millennium Atlas (Evans et al., 2003).

A regional rock property database will aid in the de-risking of prospects. Specifically, this study seeks to provide regional property trends and significantly reduce the uncertainty associated with seismic data by using well data to inform, calibrate and constrain rock physics models.

Aims and Objectives

The aim of this study is to provide an easy-to-use rock physics reference source, created using data from 35 wells to illustrate Tertiary and Cretaceous-Chalk formation (non-)reservoirs present in the study area covering Quad 21/22/23/29/30 of the UK CNS. The study provides a regional rock property database and atlas that subsurface professionals concerned with quantitative interpretation can use to help them to quickly and easily understand the likely behaviour and seismic character of rocks of different fluid-fill, burial depth and material properties.
It will be invaluable to the seismic interpreter, petrophysicist, reservoir geophysicist and any other professional interested in rock properties. In summary the primary objectives can be listed as

1) To reduce data mining and preparation time for Quantitative Interpretation (QI) projects,
2) To support prediction of seismic rock properties where data is limited or missing (e.g. missing Shear sonic log),
3) To enable direct comparison of the seismic response from different fluid scenario's for the study wells,
4) To identify optimum seismic (sub)stack for seismic interpretation,
5) To expand the user base for common rock / fluid scenario's modelling activities to non-QI specialists
6) To permit geoscientists to make informed decisions as to the best attribute to select for seismic inversion in order to highlight hydrocarbon sweet-spots.

Study Area and Well Database

The Shell CNS Tertiary and Cretaceous Roknowledge™ study area focuses on blocks 21, 22, 23, 29, 30 and incorporates 35 wells, 12 of which have measured shear data. The area of interest covers parts of the Central Graben, which branches into a Western Central Graben and Eastern Central Graben, separated by the Forties-Montrose High. It should be noted that the main Graben - High structures predate the Base Cretaceous Unconformity and the intervals of interest for this study lie shallower than that. So, strictly speaking the intervals of interest are not in the Graben or on the Highs. The following map shows the distribution of the wells across the study area and the individual wells are summarised in Table 1.1.

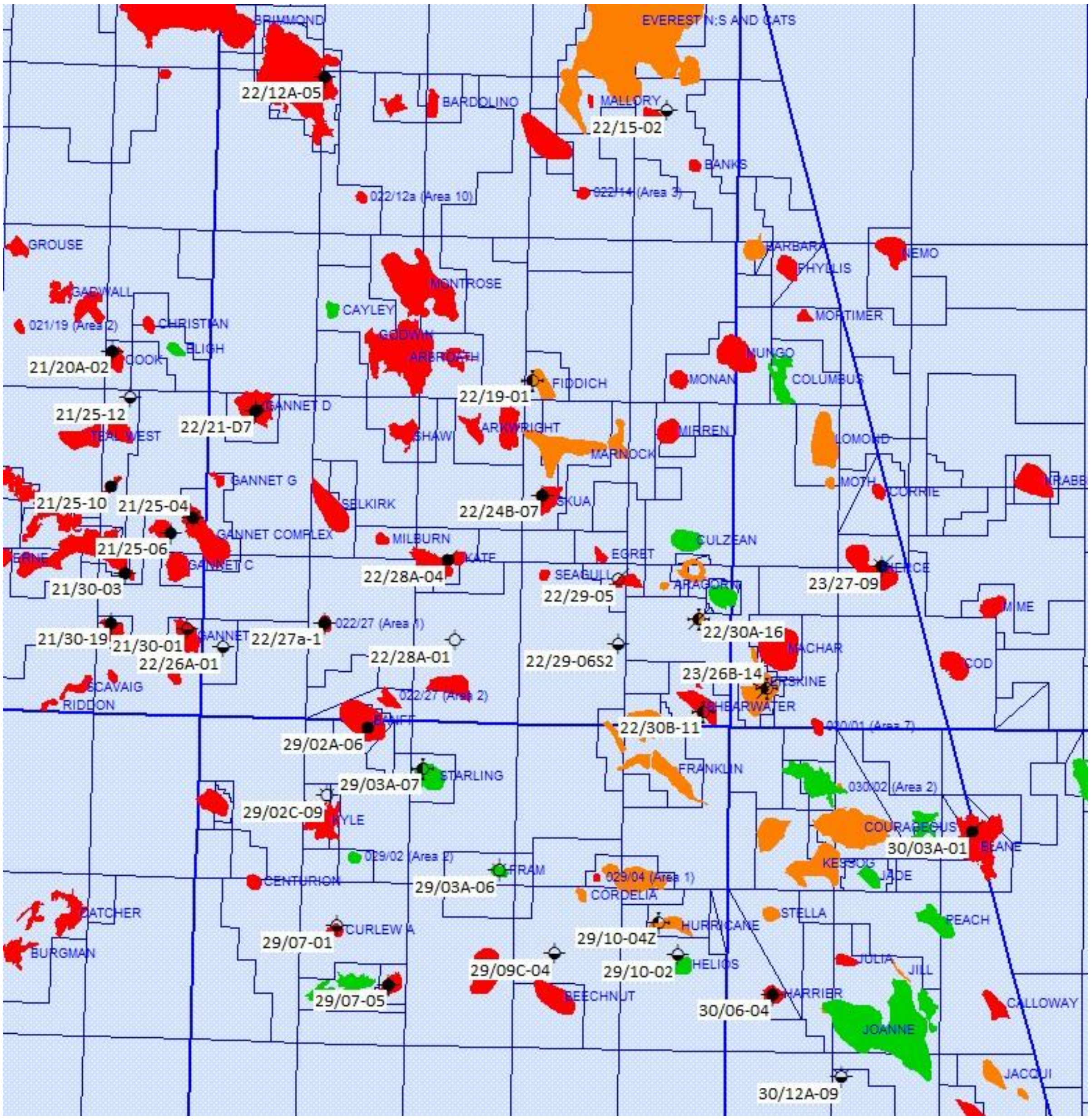

Figure 1.1a - Map of the 35 wells included in the Shell CNS Roknowledge™ Study

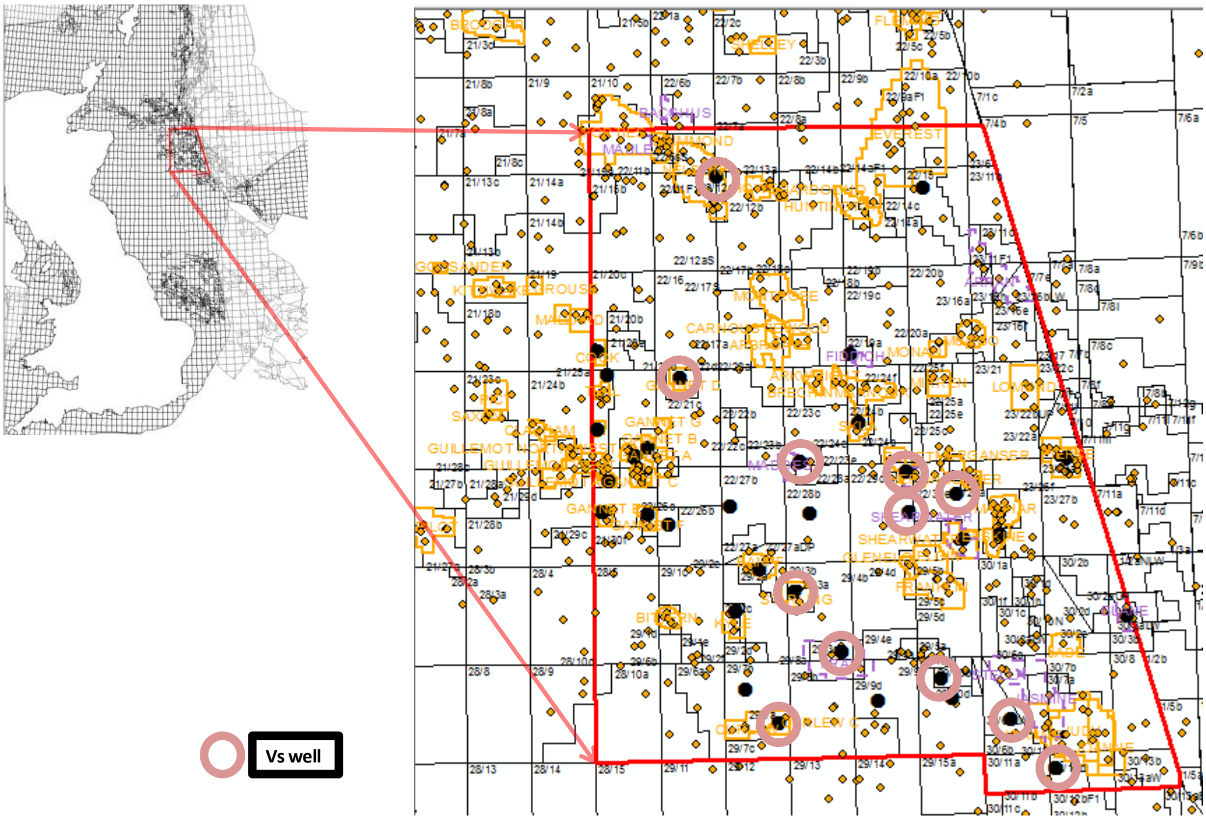

Figure 1.1b - Map of the 35 wells with Vs-wells highlighted

The CNS Coordinate Reference System (CRS) parameters and the polygon coordinates are listd below

ED_1950_TM_0_N [ED50 / TM 0 N [1311_23090]
Projection: Transverse_Mercator
False_Easting: 500000.000000
False_Northing: 0.000000
Central_Meridian: 0.000000
Scale_Factor: 0.999600
Latitude_Of_Origin: 0.000000
Linear Unit: Meter
GCS_European_1950
Datum: D_European_1950

Easting (X)	Northing (Y)
547632.2	6400354
622166.3	6401309
659530.2	6278466
659622.7	6276025
622794.5	6274789
622578.1	6282208
549037.9	6280707
547632.2	6400354

Well List	Completion Date	Field	Basin List	Block List	Show Type within IOI	Base of Hod Fm MD (ft)	Shear Data
21/20A-02	1983	Cook	Western Platform	21	No show	10353.00	No
21/25-04	1983	Gannet A	West Central Graben	21	Oil and Gas	8290.00	No
21/25-06	1984	Gannet B	Western Platform	21	Oil and Gas	8070.00	No
21/25-10	1992	Teal South	Western Platform	21	No show	8038.55	No
21/25-12	1993	Unassigned	Western Platform	21	Oil	9435.72	No
21/30-01	1969	Gannet F	West Central Graben	21	Oil	7405.00	No
21/30-03	1981	Guillemot	Western Platform	21	No show	7149.14	No
21/30-19	1992	Gannet E	Western Platform	21	Oil	8584.00	No
22/12A-05	1990	Nelson	Forties-Montrose High	22	Oil	7970.00	Yes
22/15-02	1988	Unassigned	East Central Graben	22	No show	11243.00	No
22/19-01	1984	Unassigned	East Central Graben	22	Condensate	11213.06	No
22/21-D7	2001	Gannet D	West Central Graben	22	Oil	9216.00	Yes
22/24B-07	1986	Skua	East Central Graben	22	No show	11678.00	No
22/26A-01	1981	Gannet F	West Central Graben	22	No show	8875.00	No
22/27A-01	1984	Unassigned	West Central Graben	22	No show	13174.00	No
22/28A-01	1988	Unassigned	West Central Graben	22	Residual Gas	14150.03	No
22/28A-04	1998	Madoes	Forties-Montrose High	22	Oil	13950.48	Yes
22/29-05	1994	Heron	East Central Graben	22	Oil	14620.00	Yes
22/29-06S2	1996	Unassigned	East Central Graben	22	Oil	15036.00	Yes
22/30A-16	1997	Scooter	East Central Graben	22	No show	14837.00	Yes
22/30B-11	1994	Shearwater	East Central Graben	22	Oil and Gas	13202.00	No
23/26B-14	1990	Erskine	East Central Graben	23	Gas	14737.00	No
23/27-09	1992	Pierce	East Central Graben	23	Oil	8594.00	No
29/02A-06	1991	Banff	West Central Graben	29	Oil	5284.00	No
29/02C-09	1994	Kyle	West Central Graben	29	No show	10931.00	No
29/03A-06	1999	Fram	West Central Graben	29	Condensate	9032.00	Yes
29/03A-07	2003	Starling	West Central Graben	29	Condensate and Oil	9203.00	Yes
29/07-01	1977	Curlew A	West Central Graben	29	Oil	9620.00	No
29/07-05	1993	Curlew C	West Central Graben	29	Oil	9093.00	Yes
29/09C-04	1987	Unassigned	West Central Graben	29	No show	11723.00	No
29/10-02	1983	Puffin	Puffin Terrace	29	Oil	10404.00	No
29/10-04Z	1995	Unassigned	West Central Graben	29	Oil	10490.00	Yes
30/03A-01	1989	Blane	East Central Graben	30	Oil	11380.00	No
30/06-04	2003	Harrier Shallow	West Central Graben	30	Condensate	10700.00	Yes
30/12A-09	2001	Unassigned	West Central Graben	30	No show	10814.00	Yes

Table 1.1 - Summary of the 35 wells included in the Shell CNS Roknowledge™ Study

The focus of the study was on the Formations of Tertiary-Palaeogene and Cretaceous-Chalk age (see next chart), no further (Member) sub-division was made:

Formation (Fm)

- Horda Fm
- Balder Fm
- Sele Fm
- Lista Fm
- Maureen Fm
- Ekofisk Fm
- Tor Fm
- Hod Fm

Lithostratigraphic column Central North Sea

This article shows the **lithostratigraphic column** of the Central North Sea (CNS). The formations and groups in this column may be equivalent to formations and groups in surrounding areas.

Age	Group	Formation	Member
Neogene	Nordland Group		
	Westray Group	Lark Formation	
Paleogene	Stronsay Group	Horda Formation	Grid Sandstone Member
			Tay Sandstone Member|Frigg Sandstone Member
	Moray Group	Balder Formation	Odin Sandstone Member
		Sele Formation	Gannet Sandstone Member
			Cromarty Sandstone Member
			Bittern Sandstone Member
			Forties Sandstone Member
	Montrose Group	Lista Formation	Andrew Sandstone Member
		Maureen Formation	Maureen Sandstone Member
	Chalk Group	Ekofisk Formation	
		Tor Formation	
		Hod Formation	
Cretaceous		Herring Formation	
		Plenus Marl Formation	
		Hidra Formation	

Benefits to Shell

1. Improved knowledge of local and regional rock properties, their trends and the resulting seismic amplitude responses in the Central North Sea.
2. Derived end member trends and calibrated Rock Physics Models (RPM) can be used to predict rock properties where well-data are limited, thereby increasing exploration success and reducing the risk of drilling dry holes in the area.
3. The lithological and fluid properties database provides a look-up table that ensures relevant material properties are used in geo-modelling workflows.

Data Types Used

1. Wireline log suite – Vp, Vs, density (Rhob), gamma ray (GR), resistivity, compensated neutron/ neutron porosity, caliper and delta Rhob (DRHOB).
2. Insitu pressure and temperature data
   including Ikon GeoPressure study – North Sea Central Graben Ph1
3. Core data – routine core analysis (where available)
4. Fluid data – salinity, gas/oil ratio, oil and gas gravity
5. Checkshot and deviation surveys
6. Formation tops (Markers)
7. Well reports – composite log, final well report, mud log

1.2 Shell CNS Tertiary and Cretaceous Roknowledge™ Study Workflow

Log data were petrophysically conditioned prior to any rock physics modelling. Approximately one third of the wells in the area contain measured Vs data, with all wells showing good borehole conditions and correlatable reservoir facies. Seismic Rock Property analysis and interpretation was performed using Ikon Science's RokDoc® software suite. Using multi-well analysis, depth(TVDml[1])-Vp and depth(TVDml)-PhiT relationships were derived along with Vp-Rhob, Vp-Vs, Vp-PhiT and PhiT-Rhob for brine saturated sandstones, chalk, tuff and shale lithologies when identified within the Horda, Balder, Sele, Lista, Maureen, Ekofisk, Tor and Hod formations. Derived trends were placed in the context of published relationships which have been accepted industry-wide. The generalised workflow of this study is outlined below:

1. Wells were chosen in consultation with Shell with consideration given to the quality of data and to the spatial and vertical coverage of the area and intervals of study.
2. Log data were QC'd and petrophysically interpreted to provide high quality consistent input for subsequent modelling and interpretation.
3. Well data were loaded into RokDoc® and provided the interactive database of this study.
4. A visual QC of the raw log data was undertaken and notes made of any obvious data issues such as gaps in the log data, missing shear log data, sections of considerable wash-out / bad-hole etc. Initial "quick-look" Vp-Rhob and Vp-Vs cross-plots were constructed for each working interval to identify any bad data that sat off the established Rock Physics trends of Gardner for Vp-Rhob plots and Greenberg-Castagna for Vp-Vs plots. Any bad data was highlighted using a polygon and removed from the Rock Physics Analysis. If present, thin streaks of cemented reservoir sands were also removed from the log data.
5. Information supplied by Shell and collated from well reports was interpreted and analysed to determine the most likely fluid properties across the region, per interval and as a function of depth. Brine, oil and dry gas fluid sets were defined for every formation (regardless of whether reservoir is present) for the purpose of creating the end member trend curves. Based on the inferred salinity (including WBM), API (including OBM), GOR and gas gravity, fluid properties were computed using the FLAG 11 algorithms (Fluid Algorithms for Gassmann consortia, University of Houston) and stored in the RokDoc database.
6. Mineral sets were then created for each well. The petrophysics defined four minerals: quartz, calcite, shale and tuff. For quartz, a non-pure "dirty" value of 2.635 g/cc was supplied by Shell in recognition that the sand will not be 100% quartz for use in the Rock Physics stage of the study. A total porosity system was employed throughout the project and Shell supplied a constant dry clay value that was used to represent the shale component of the rock. The tuff mineral only occurred in the Balder Formation and after first applying a cut-off of Volume_Tuff > 0.7, the cleanest tuff points were used to calculate the average Vp, Vs and Rhob values that were in turn used to update the mineral sets.
7. Formation tops supplied by Shell were loaded into RokDoc® and used to define the eight working intervals used throughout the study. The Petrophysics cut-offs for reservoir sections were used to define our reservoir intervals. Invasion correction and Gassmann fluid substitution were only performed in working intervals that had viable reservoir present within the formation.
8. Gassmann fluid substitution was performed to 100% brine conditions for all wells with a complete Vp, Vs and Rhob set of logs.
9. Multi-well rock properties were plotted to identify regional trends and to enable the generation of end member trend curves, which were then used to create modelled logs in the case of unavailable or poor quality log data. Only 100% Brine filled data were used during the

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[1] TVDml indicates True Vertical Depth below mudline, measured from the seabed.

multi-well phase of the study. An SWT=1 cut-off was applied to any wells with an incomplete Vp, Vs and Rhob set of logs (i.e. that had not yet been fluid substituted to brine).

10. Any bad or missing Vp data was filled using the regional multi-well modelled logs. A new Vs and Rhob log was then modelled from Vp. In certain instances, where Vs was not available and Vp could not be directly fluid substituted to 100% Brine, the modified Gassmann method was applied (Mavko et al., 1997) to ensure that any hydrocarbons were first removed from the Vp log prior to modelling a new Vs and Rhob log. In cases where the Vp log was missing or of bad quality over part of a hydrocarbon interval with good Rhob log, a local, well based hydrocarbon bearing relation between Vp and Rhob was derived to fill the missing parts of the Vp log.
11. All 35 wells were fluid substituted to 100% brine, 80% oil, 80% condensate (where appropriate) and 90% gas fluid cases for the clean reservoirs in each well.
12. 1-D synthetics were generated using two wavelets supplied by Shell (SEG Normal Polarity), for the insitu, 100% brine, 80% oil, 80% condensate and 90% gas fluid cases.
13. An average set of Vp, Vs and Rhob values were taken from the fluid substituted data for all the fluid cases in each reservoir sand defined by the clean sand cut-offs.
14. Single interface blocky AVO modelling and elastic contrast analysis was carried out using the average sets created for the limestone, sand and shale present in the different working intervals. The plots were used to investigate the expected top reservoir AVO response, elastic attributes and the variation of these properties with different fluid cases for each of the working intervals.
15. Outputs of the multi-well analysis, depth trend work and single-well analysis plus a compilation of the fluid properties, rock properties and derived trends were collated to produce a CNS Roknowledge™ database (Excel .xls file).

1.3 Report Structure and Overview

The main body of Shell CNS Tertiary and Cretaceous Roknowledge™ study is composed of four chapters. This chapter 1 introduces the study, outlines its scope and provides an overview of how the study has been compiled, as well as introducing some of the theory and methods behind rock physics, and how these techniques are used by geoscientists to perform quantitative interpretation. Chapter 2 presents the methodology employed during the single and multi-well analysis while Chapter 3 provides the structure of the comprehensive review of each of the 35 wells (see Appendix G, p.224). These chapters provide pertinent rock properties and their depth-trends, as well as a discussion of the results and an explanation of the observed trends and anomalies. Chapter 4 presents simple workflows that will enable a subsurface professional to tailor the study to their specific exploration needs. The appendices contains details on the methods used for the petrophysical analysis and conditioning of the log-data, as well as the formulae for derived log relationships from the multi-well analysis. A petrophysical and pay summary report is also supplied separately for each well.

Chapter 2 – Methodology

Rock physics analysis was performed on a well-by-well basis. The quality control aspect of the single well analysis involves making a caliper minus bit size log to investigate hole conditions and identify areas of washed-out data. In cases where the data are missing or poor quality, the Vp log was filled using the regional multi-well modelled logs and the Vs and Rhob logs were modelled from Vp. Multi-well analysis seeks to generate regional trends, correlations and predictive equations for the different lithologies found in this study.

For consistency, all wells with shear data were fluid-substituted to brine prior to the derivation of any regional mulit-well trends and relationships. An SWT=1 cut-off will be applied to any wells with an incomplete Vp, Vs and Rhob set of logs (i.e. that had not yet been fluid substituted to brine) to ensure that no hydrocarbon effects were included in the derivation of the trends). VpVs analysis was necessary to generate synthetic shear data where no, or poor quality, measured data were available.

Gassmann fluid substitution of the reservoir interval to 100% brine, 80% condensate (where appropriate), 80% oil and 90% gas was performed, with the resulting properties then used to generate blocky AVO models and synthetic seismic gathers for the various saturating-fluid scenarios.

Chapter 3 – Single Well Reports (see also Appendix F – Single Well reports)

For each of the 35 study wells, synthetic log curves and seismic gathers for the various saturating-fluid scenarios have been analysed and presented. This step provides an indication of the seismic character that would be expected at the top-reservoir under various saturating-fluid conditions and as a function of angle of incidence for the sandstone reservoirs. In addition, for the sandstone reservoirs contained within the Horda, Balder, Sele, Lista and Maureen working intervals, blocky AVO models have also been created and elastic contrast plots generated. These illustrate the change in the contrast between the overburden shale and reservoir property for different saturating fluids e.g. the contrast in acoustic impedance (defining the zero incidence reflectivity), the contrast in elastic impedance (defining a far stack reflectivity), often associated with fluid fill or perhaps the contrast in MuRhob, an angle independent rock property, typically related to lithology variations. These plots can be used to quickly assess the sensitivity of different elastic properties to changing fluid fill.

Chapter 4 – User Guide

Modelling of log data within the Roknowledge™ study was undertaken with a view to capturing regional trends. In some cases it is evident that specific intervals or wells fall as outliers to these regional trends. If the focus for the user is an outlying formation, well or even sub-region, it can be useful to define new multi-well rock physics templates. The method for creating these is outlined, showing the end user how to use the results within the custom RokDoc User Programmer script to generate a new set of end-member and synthetic logs for either a study or pseudo well. Workflows for creating Block AVO models, Average sets, Pseudo wells and customised rock physics models are also presented in Chapter 4 of this report.

Chapter 5 – Summary

Summarises the results

Chapter 6

Lists the references quoted in this report

Appendix A – Units, Colour Key

Provides further background on units, colour key,

Appendix B – Petrophysical Analysis

Describes the petrophysical interpretion and conditioning of the log data to ensure that consistently derived rock properties were used throughout the study

Appendix C – Multi-well trends

Summarises all trends derived in the multi-well section of the project and describes how to use them.

- C.2 Multi-well analysis (100% Brine Bearing data)
- C.3 Multi-well analysis (Gassmann Fluid Substituted data)
- C.1 Using these multi-well trends

Appendix G – User Programmer Scripts

Details the RokDoc user programming scripts for that have been used to automate key steps in the Rock Property Analysis computations

- G.1 – Invasion Correction
- G.2 – End-Member and Synthetic Logs
- G.3 – End-Member Gassmann Fluid Substitution
- G.4 – Modelled Vs and RHOB (from Vp_FSUB_BRINE_GP)

Appendix D – Glossary of Terms

Gives an overview of the terms used in the report and relevant context for using the results

Appendix E – Known Issues

Describes know software and technical issues that the user should be aware of when using the results of this study.

Appendix F – Single Well reports

Provides the single well reports a part of this report

Rock Property Database

The rock property database is found in the master spreadsheet (see Annex H.3) and details the Vp, Vs and Rhob properties of the rocks found in the 35 wells included in this study. Information is provided on a per-well basis for ‘clean’ minerals present in each of the formations: dry clay; tuff;

dirty quartz and dirty calcite for in situ fluid conditions as well as modelled fluid scenarios (for the sandstone and chalk formations) of 100% brine, 80% condensate, 80% oil and 90% gas. From the Vp, Vs and Rhob data, many other elastic properties can be derived.

Fluid Property Database

The fluid property database is found in the master spreadsheet (see Annex H.3) and details the physical properties of the fluids found in the 35 wells included in the study. Information relating to brine, oil, condensate and gas properties are provided with reference to:

1. The well name
2. The reservoir formation name
3. The mid-point reservoir pressure and temperature conditions

The properties catalogued in the fluid database are summarised in the following table:

BRINE	OIL	Condensate	Gas
Input : Salinity, Output : density, Vp and bulk modulus	Input : GOR, oil API, oil gas gravity, Output : density, Vp, bulk modulus and bubblepoint value	Input : GOR, oil API, gas gravity, Output : density, Vp and bulk modulus	Input : Gas gravity, Output : density, Vp and bulk modulus

1.4 RokDoc® Terminology

The .rok file provided with the Shell CNS Roknowledge™ written report contains all of the data used in the study. All rock physics analysis and modelling was performed using the RokDoc® platform (version 5.6.3); the following definitions and terminology are provided to enable the user to navigate the .rok file and appreciate some of the terms used throughout the work. For a more complete set of RokDoc® definitions and workflows, please refer to the RokDoc® user's manual.

Shell log naming Terminology

***_INSITU**	Represents insitu conditions as measured, but with invasion correction applied if necessary. If needed, bad data zones have been removed earlier (*_EDIT). Note that *_INSITU replaces the historically often used "_VIRGIN". Typically, only the density log is invasion corrected
***_EDIT**	Temporary edited logs that will constitute the input to the next workflow steps
***_FSUB_BRINE**	Gassmann substituted curve to 100% brine reference conditions
***_FSUB _OIL**	Gassmann substituted curve to 80% oil reference conditions
***_FSUB _CONDENSATE**	Gassmann substituted curve for 80% condensate reference conditions
***_FSUB_GAS**	Gassmann substituted curve for 90% gas reference conditions
***_GP**	'Geophysically Processed' – a countinuous curve generated from *_EDIT (if edits were needed), *_INSITU (if invasion correction was necessary) with all gaps filled with regional/local trends, appropriate to the local lithology. The log should then be continuous.

Within this study *_CR indicates logs that have been filled with a spline function.

Specifically, the following sequence is followed:

1. ***_EDIT**
2. ***_INSITU**
3. ***_GP**

The "Geophysically Processed" *_GP curve is a well established QI deliverable and represents the final set of logs in the .rok database.

Vp-Vs-Rhob Sets

Vp-Vs-Rhob sets comprise compressional, shear and bulk density logs. The set of logs pertaining to the insitu conditions of the well bear the suffix '_INSITU'. Following fluid substitution, new Vp-Vs-Rhob sets are generated, with logs appropriately suffixed to reflect the modelled fluid fill.

Vp, Vs and Rhob Sets (Wells **with** Shear data)	Vp, Vs and Rhob Sets (Wells **without** Shear data)
INSITU	INSITU
FSUB_BRINE	INSITU_GP
FSUB_BRINE_GP	FSUB_BRINE _GP
FSUB_OIL_GP	FSUB_OIL_GP
FSUB_CONDENSATE_GP	FSUB_CONDENSATE_GP
FSUB_GAS_GP	FSUB_GAS_GP
FSUB_INSITU_GP	FSUB_INSITU_GP

Average Sets

Average values of Vp, Vs and Rhob are determined for reservoir rocks and shale and are used in certain modelling procedures, such as blocky AVO, when the aim is to study simple idealised two-half space scenarios; for example to model the AVO response of a clean shale overlying a clean sand. The lithologies considered in this study are sandstone, tuff, limestone and shale with the following cut-offs used to isolate clean examples of each:

Sandstone:	Volume of quartz	> 0.7
Shale:	Volume of shale	> 0.7
Tuff:	Volume of Tuff	> 0.7
Limestone:	Volume of Lime	> 0.9

The average sets for every reservoir are provided in the master spreadsheet.

Mineral Sets

Mineral sets describe the properties of a rock's constituent minerals, from which the bulk properties of the lithology are derived. Mineral sets may be edited to reflect the subtle variations which exist between specific formations. The physical properties of quartz and calcite, on the other hand, do not vary much as a function of depth and non-pure "dirty" values were supplied by Shell in recognition that the sand will not be 100% quartz and the limestone will not be 100% calcite. A total porosity system was employed throughout the project and Shell supplied a constant dry clay value that was used to represent the shale component of the rock. The tuff mineral only occurred in the Balder Formation and after first applying a cut-off of Volume_Tuff > 0.7, the cleanest tuff points were used to calculate the average Vp, Vs and Rhob values that were in turn used to update the mineral sets. Mineral sets were recalled in order to perform fluid substitution, the generation of synthetic seismic traces and other related functions.

Fluid Sets

Fluid sets describe the properties of the fluids which may saturate a rock; they may vary from well-to-well and as a function of pressure and temperature (i.e. depth). It is necessary to constrain fluid properties in order to accurately perform fluid substitution modelling. Fluid properties are derived from well reports and petrophysical analysis using the **FLAG 11 algorithms**. This allows an accurate prediction of fluid properties, and the correct assignment of fluid sets, for discrete reservoir intervals which exist under certain pressure and temperature regimes.

Markers

The markers for the wells in this study were supplied by Shell and are consistent across all the wells in the study.

Working Intervals

Eight working intervals were defined within each of the 35 study wells and a summary list is provided in Table 1.2. Where present, all eight working intervals were considered for the rock physics analysis; however, not all wells penetrate all intervals and not all intervals will be present at all well locations.

Super Group	Work interval
Tertiary	Horda Fm
	Balder Fm
	Sele Fm
	Lista Fm
	Maureen Fm
Cretaceous	Ekofisk Fm
	Tor Fm
	Hod Fm

Table 1.2 - Generic working interval list

Log Colouring

The following colour codes are helpful to quickly distinguish one data from another:

- All in situ measured data are displayed in black
- Modelled logs generated from empirical relationships are displayed in **purple**
- All 100% brine saturated logs are displayed in **blue**
- All 80% condensate saturated logs are displayed in **orange**
- All 80% oil saturated logs are displayed in **red**
- All 90% gas saturated logs are displayed in **green**

1.5 Rock Physics Theory and Methods

What is Rock Physics?

Rock physics is a quantitative discipline that seeks to describe reservoir rocks by appealing to properties such as porosity, rigidity, compressibility and other physical parameters that control the transmission and reflection of seismic waves through the subsurface. By establishing and quantifying seismic-to-reservoir property transforms and their uncertainties, predictive models can be developed so that critical reservoir properties may be detected seismically.

Accurate correlation between rock properties and seismic attributes will benefit aspects of seismic interpretation including forward modelling, inversion and attribute analysis. Armed with information on lithology, porosity and saturating fluid, the interpreter is able to add a quantitative dimension to their workflow. Typical application of rock physics yields answers to questions such as:

- What are the velocity-porosity, velocity-density and compressional velocity-shear velocity relations in various lithologies and pore-fills?
- How robust would seismic AVO response be in situations of varying porosity, pore-fills and reservoir thickness?
- How different would AVO anomalies be for different pore fluids?
- How can regional depth trends be used to constrain rock physics models, study the expected seismic signature of reservoir-overburden interfaces and identify anomalous lithologies? E.g. away from well control.
- What seismic characteristics, or attributes, may be useful in distinguishing hydrocarbon bearing sands from brine-sands and shale?

Prior to performing any rock physics modelling, well-data need to be petrophysically conditioned in order to ensure that the inputs used for any modelling had been consistently interpreted. Eight working intervals were defined and used throughout the study and petrophysical analysis was performed on each of these intervals whenever penetrated by any of the study wells. DST testing, core analysis, mud/gas log and lithology descriptions were incorporated into the analysis when these data types were available. Formation evaluation (CPI) processing using Geolog software resulted in a detailed well-log interpretation for each zone. Details of the petrophysical methods applied to the well-data can be found in the appendix of this report.

Data Calibration and Cross-Plot Analysis

A primary task in a rock physics study is firstly to calibrate well-logs, and then model AVO attributes from the log data before cross-plotting various attributes from the geological units of interest. Cross-plots are used to:

- Understand how the measured well-logs are related.
- Determine the resolution of the rock properties in the various lithologies of the study area.
- Investigate the sensitivity of various attributes to fluid effects.
- Model velocity constraints such as Vp/Vs ratios and AVO analysis of seismic data.
- Contribute to quantitative interpretation of seismic attribute sections in order to understand which attributes are best for describing a given reservoir.

Relationships between compressional (Vp) and shear (Vs) velocity are key to the determination of lithology from seismic or sonic log data, as well as for direct seismic AVO identification of pore fluids. However, in legacy wells, Vs data was not commonly logged and often needs to be modelled from measured Vp logs, which is another typical task of rock physics studies. Most Vs predictions can be performed by:

1) Use of the Greenberg-Castagna formula (Greenberg and Castagna, 1992) or by establishing other locally calibrated relationships between Vp, Vs and porosity.
2) Applying Gassmann's (1951) equations to map relationships established in 1) to other pore-fluid states.

In this study, the following trend relations were defined for the end-member lithologies (Shale, Sandstone, Tuff, Limestone):

- PhiT-Depth (TVDml) – Reservoir lithologies only
- Vp-Depth (TVDml) – All lithologies
- Rhob-Vp – All lithologies
- Vs-Vp – All lithologies
- PhiT-Vp – Reservoir lithologies only
- Rhob-PhiT – Reservoir lithologies only

These trend relationships were found for every formation in the study interval for all eight working intervals. Synthetic (brine-filled) Vp, Vs, Rhob logs were generated for the end-member lithologies using the trends relations. These were then used to fill the Vp log, enabling Vs and Rhob modelled logs to be generated from the Vp log (Vp_INSITU_GP or Vp_FSUB_BRINE_GP), using Backus averaging for the Vp and Vs log and arithmetic averaging for the Rhob log.

Only 100% brine bearing log data was plotted during the multi-well analysis, thus removing the influence of any hydrocarbon-bearing data on the regional trends.

Where required, polygons were defined to differentiate between hard/soft shales and low/high porosity reservoir rocks (Sandstone / Chalk).

Basic Seismic Reflectivity and AVO Analysis

Snell's law is a theoretical foundation of reflection seismology, and illustrates the relationships between angles of incidence α_i, reflection and refraction α_r and the corresponding velocities on either side of the interface, V_i and V_r.

$$\frac{\sin\alpha_i}{V_i} = \frac{\sin\alpha_r}{V_r}$$

The magnitude of the energy in the reflection depends on the contrast in elastic parameters across an interface and on the angle of incidence. The acoustic impedance contrast across a boundary controls normal-incidence seismic reflectivity, where the reflection coefficient is given by:

$$R_c = \frac{AI_2 - AI_1}{AI_2 + AI_1} = \frac{\rho_2 V_{P2} - \rho_1 V_{P1}}{\rho_2 V_{P2} + \rho_1 V_{P1}}$$

where subscripts 1 and 2 refer to discrete half-space layers on either side of the interface, where layer 1 is the upper and layer 2 is the lower. AI is the product of density and Vp, and ρ is density.

AVO (amplitude versus offset) or rather AVA (amplitude versus angle) is described by the Zoeppritz equations (1919). As a result of the complicated nature of the Zoeppritz equations, several simplifications have been derived, in particular approximations for the PP reflection coefficient. Aki and Richards (1980) derived a simplified form by assuming small layer contrasts, which is described as:

$$R(\theta) = A + B\sin^2\theta + C\sin^2\theta\tan^2\theta$$

Where:

$$A = 0.5\left(\frac{\Delta V_P}{V_P} + \frac{\Delta\rho}{\rho}\right)$$
$$\cong 0.5\Delta\ln\rho V_p$$
$$= 0.5\Delta\ln AI$$

$$B = 0.5\frac{\Delta V_p}{V_p} - 2\left(\frac{V_s}{V_p}\right)^2\left(2\frac{\Delta V_s}{V_s} + \frac{\Delta\rho}{\rho}\right)$$
$$\cong 0.5\left[\Delta\ln V_p - 2\Delta\ln\rho V - \Delta\ln\rho_s\right]$$, assuming Vp/Vs ≅ 2.
$$= 0.5\left[\Delta\ln\rho V_p - 2\Delta\ln\rho V_s\right]$$
$$= 0.5\left[\Delta\ln AI - 2\Delta\ln SI\right]$$

And

$$C = 0.5\frac{\Delta V_p}{V_p}$$

where *R(θ)* is the reflection coefficient at the incidence angle θ, V_P is the average of the P-wave velocity on the two sides of the interface, V_S the average S-wave velocity, ρ, the average density, *AI* is the Acoustic impedance and *SI* is the Shear Impedance. Δ denotes the difference or contrast across the interface for the relevant parameter. The Aki-Richards approximation holds for offset angles up to 50° (Fatti et al., 1994).

It is important to identify a number of terms that are related to AVO responses, and also to understand the difference between AVO gradient and AVO response. The AVO gradient is the difference in reflection coefficient over the difference in sine squared of the incidence angle. On a plot of amplitude against $\sin^2\theta$, if the cross-plotted line inclines from upper-left to lower-right, it will be defined as negative or softening gradient, meanwhile, the positive or hardening gradient trends from lower-left to upper-right. 'Positive or brightening AVO' describes the situation where there is an increase in absolute amplitude with offset, whereas the opposite situation is referred to as 'negative or dimming AVO'.

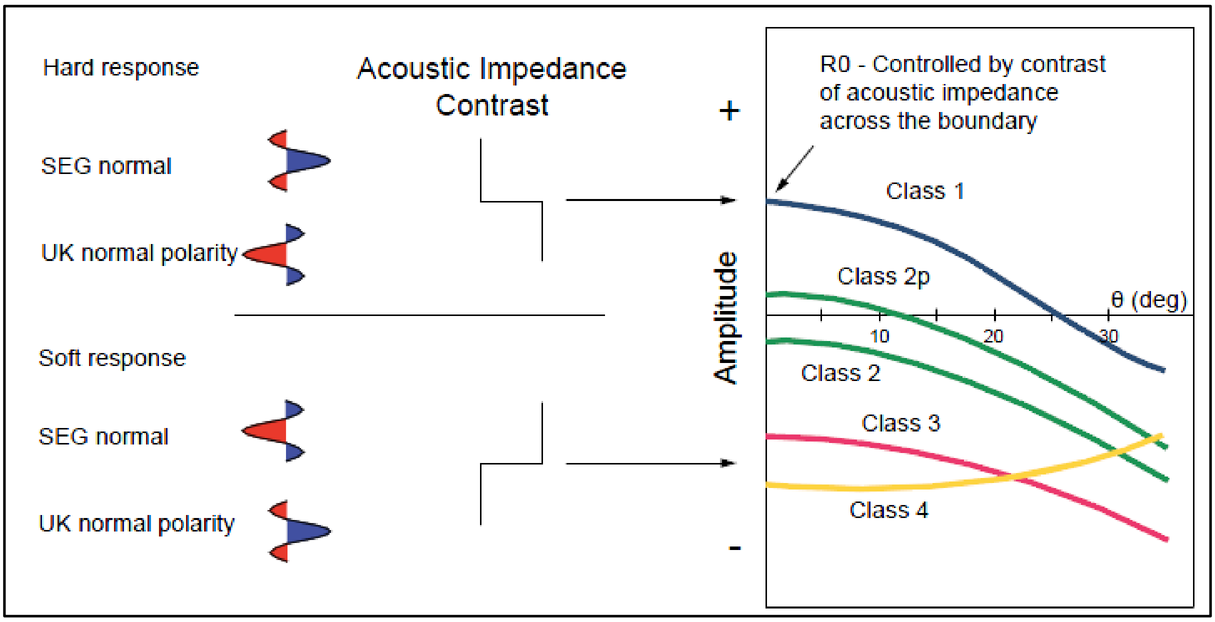


Figure 1.2 - The AVO Classes (modified after Rutherford and Williams, 1989)

There are six categories of AVO response in seismic interpretation, based on lithology and fluid type. Rutherford & Williams (1989) first classified shale and brine sand AVO responses into three types (I, II and III):

- **Class I** responses are characterised by a relatively 'soft' to 'hard' (positive AI contrast) interface associated with decrease in amplitude with angle. The amplitude turns negative at angles greater than half the offset angle.
- **Class II** responses have small normal incidence amplitudes (between +/- 0.02 R0), but the AVO effects leads to highly negative amplitudes at far offsets. It was suggested that the small positive Class II responses should be termed **Class IIp** by Ross and Kinman (1995). The amplitude turns negative at angles less than half the offset angle.
- **Class III** responses have large negative impedance contrasts and the negative gradient leads to increasing amplitude with angle.

A Class IV AVO response was introduced by Castagna and Swan (1997). It has a negative intercept but positive gradient. The absolute amplitude value decreases as offset increases. Class V and VI AVO responses relate to AVO responses with a positive intercept and a positive gradient and the class VI response has the higher intercept value.

Fluid Substitution

One of the most powerful uses of rock physics is to perform fluid substitutions in recorded well log data, to assess 'what if' scenarios. For instance, a brine-saturated zone of a well-log can be modelled to simulate an oil-saturated case. This section focuses on fluid substitution, which is the key to understanding and predicting how seismic velocity and impedance depend on pore fluids. Gassmann's (1951) equations are the most applicable model for fluid substitution in siliciclastic rocks at seismic frequencies.

$$\frac{K_{sat}}{K_{ma}-K_{sat}}=\frac{K_{dry}}{K_{ma}-K_{dry}}+\frac{K_{fl}}{\phi(K_{ma}-K_{fl})}$$

where K_{ma} is the bulk modulus of the solid matrix or grain material, K_{dry} is the effective bulk modulus of dry rock or frame, K_{fl} is the bulk modulus of the pore fluid and ϕ is the porosity. The analogous relation for the shear modulus is given by Gassmann as:

$$\mu_{sat}=\mu_{dry}$$

There are two fluid effects that must be considered in a fluid substitution problem: the change in rock bulk density, and the change in rock compressibility. Gassmann's equations provide a way to calculate the bulk modulus of a fluid-saturated porous medium using the known bulk modulus of the solid matrix, of the frame, and of the pore fluid. For a rock, the solid matrix consists of the rock-forming minerals, the frame refers to the rock sample with empty pores (dry rock), and the pore fluid can be gas, oil, water, or a combination of these phases.

The use of Gassmann's equations requires the following assumptions:

- It works best at sufficiently low frequency such that the wave-induced pore pressures throughout the pore space have time to equilibrate during a seismic period.
- The rock, both the matrix and the frame, is macroscopically homogeneous and isotropic. All the pores are interconnected or communicating.
- The fluid-bearing rock is completely saturated

In rock physics studies, the fluid-saturated bulk modulus and shear modulus are calculated from measured wireline log-data (Vp, Vs and density) from which the dry rock modulus can be determined.

Given the porosity (ϕ), the matrix modulus (K_{ma}) and the fluid modulus (K_{fl}), the dry bulk modulus (K_{dry}) can be derived from the equations:

$$K_{dry}=\frac{K_{sat}\left(\frac{\phi K_{ma}}{K_{fl}}+1-\phi\right)-K_{ma}}{\frac{\phi K_{ma}}{K_{fl}}+\frac{K_{sat}}{K_{ma}}-1-\phi}$$

The K_{dry} model provides a useful QC tool for preliminary results, enabling the user to generate plots (K_{dry}/K_{ma} *vs.* Porosity) to assess the pore stiffness of the reservoir material, and subsequently establish the sensitivity of the rock to fluids. It is a two-part process in which the first step is to establish all components from well-log data and fluid information and then use Gassmann's equation to calculate the dry rock bulk modulus, K_{dry}. The second step involves calculating the effect of substituting a new fluid.

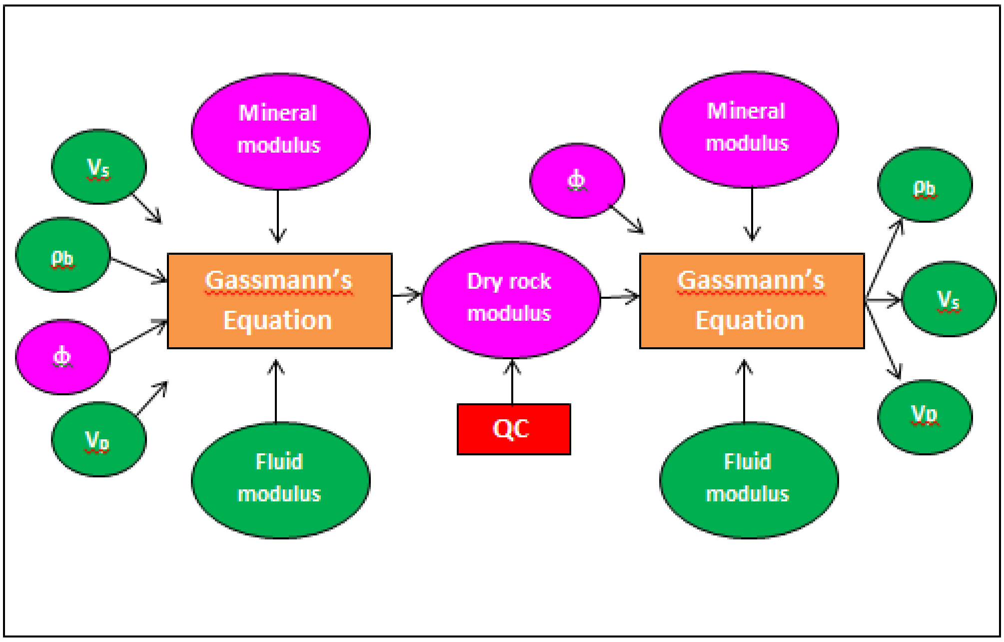


Figure 1.3 - Workflow of Gassmann's fluid substitution

Single Interface AVO Modelling (Blocky AVO) and Elastic Contrast plots

Single interface AVO modelling is undertaken to model the seismic response across a lithological interface. Amplitudes are modelled as a function of incidence angle, by using Zoeppritz equation (Zoeppritz, 1919). The inputs for this function are average, or 'blocky', values of Vp, Vs and density for discrete geological layers. The results of the single interface AVO modelling from well 29/09C-04 in the CNS for the Top Lista Formation for all the fluid substituted cases is shown in fig 1.4. It can be seen that there is a modelled class I response for the 100% brine and 80% oil cases and a modelled class IIp response for the 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.

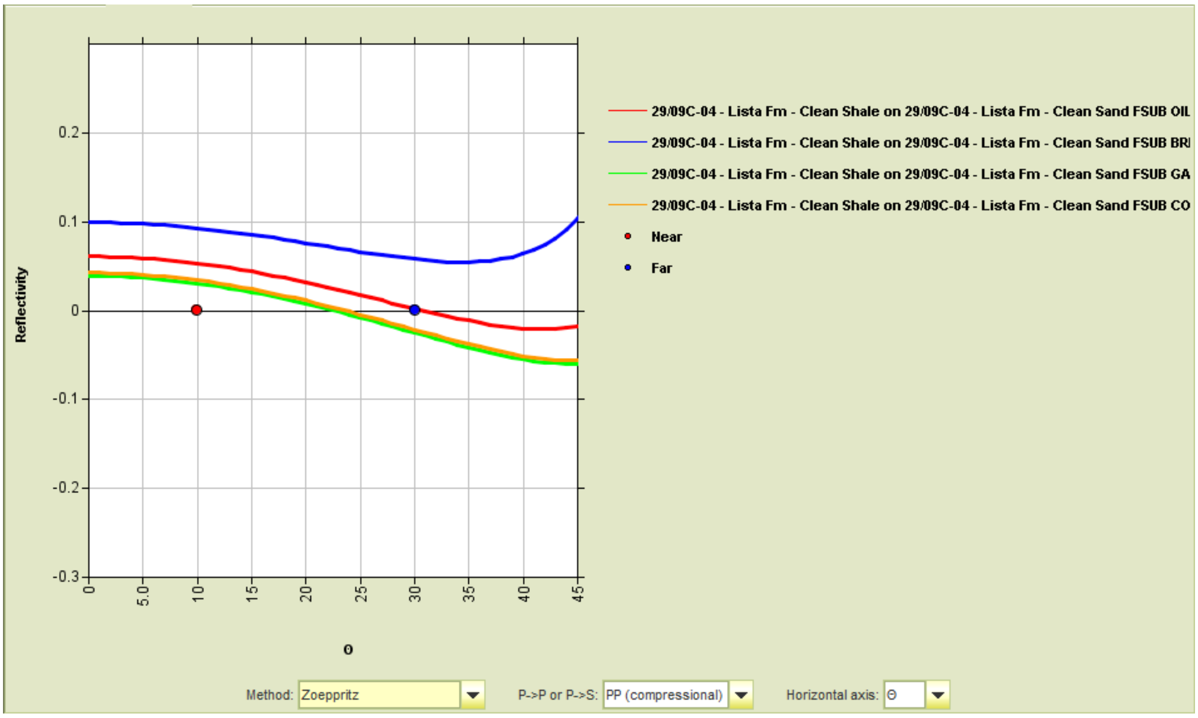


Figure 1.4 - The results of the single interface AVO modelling for Lista Fm Shl on Sst from well 29/09C-04.

For each of the fluid substituted cases (100 brine, 80 oil, 80 condensate, 90 gas) an elastic contrast analyser plot was generated. Each plot describes a specific interface and represents the change in elastic properties across the interface e.g. the acoustic impedance contrast that controls the zero incidence reflectivity and so on. For the plots presented in this study, relative variations in the different elastic properties across the selected interface occur as a result of changing fluid fill (e.g. fluid substitution to brine, oil, condensate and gas). These plots therefore provide the interpreter with a quick look assessment of the sensitivity of different elastic properties to changing fluid fill and as such an early indication of which inversion products might be of use for reservoir characterisation studies.

1D Seismic Modelling

1D synthetic gather generation is based on the same function as single interface AVO modelling. It allows a more accurate interpretation in the 1D well domain, because synthetic gathers are used to model the seismic response of fluid and lithological variations in the well log data, as opposed to averaged properties across a single interface. In order to generate a synthetic gather, it is necessary to convolve the reflectivity series generated from P and S sonic and density logs with a wavelet.

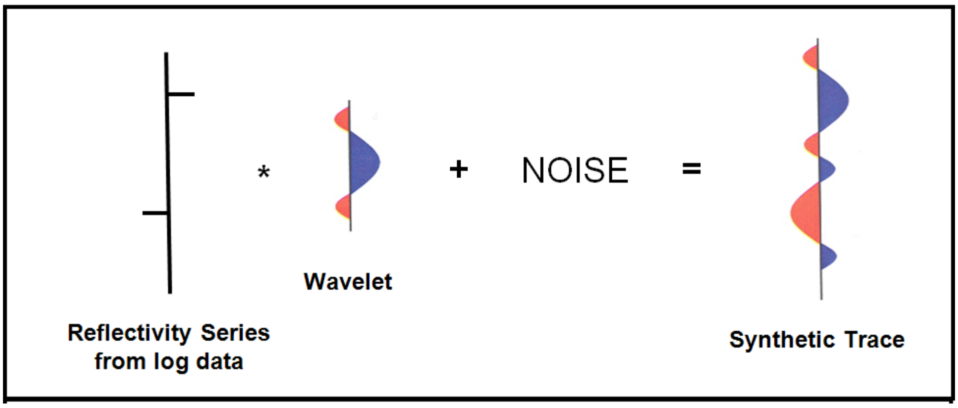
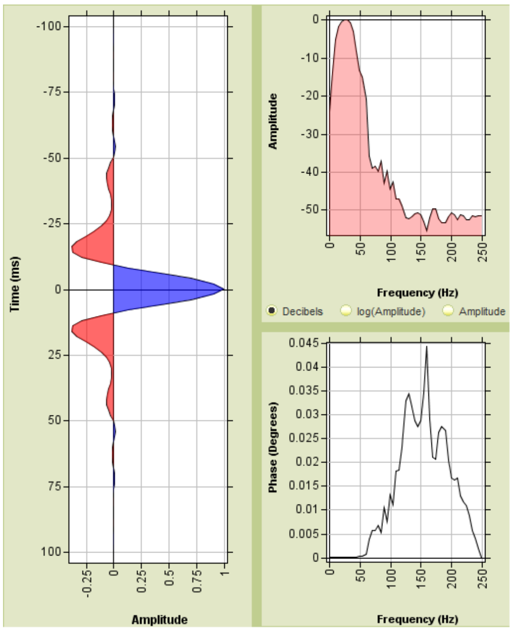


Figure 1.5 - The convolution model

In order to calculate synthetic seismic for AVO analysis, Shell supplied two zero phased wavelets: a marine streamer wavelet and a broadband wavelet (as shown in Figure 1.6). SEG polarity convention, where an increase in acoustic impedance is a positive number represented by a blue peak, was employed. Shell's seismic data typically follows the negative Shell polarity convention, where an increase in acoustic impedance is displayed as a negative number. When generating the synthetic gathers in this study, the Zoeppritz reflectivity calculation algorithm is used, with the default display showing 0º to 45º at an increment of 3º.

(a)


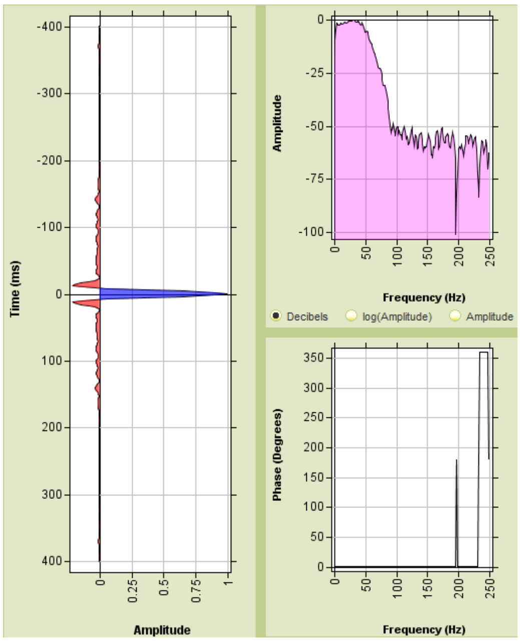
(b)


Figure 1.6(a) Marine streamer wavelet and (b) broadband wavelet

Depth Trends

Understanding the geologic trends and constraints in an area of exploration will reduce the uncertainty in rock properties, especially away from well control, and therefore reduce the uncertainties in seismic reservoir prediction. It will also improve the ability to predict hydrocarbons, in areas with little or no well-log information, when modelling the expected change in seismic response as a function of depositional environment or burial depth. Seismic amplitude contrasts and AVO responses change with depth, because the acoustic contrasts between sands and shale are depth dependent. In this study, we focus on the effect of burial depth on the physical properties of wave propagation velocity and density, for sandstones and shale and porosity for reservoir rocks.

Velocity-depth trends are important in quantitative seismic interpretation because the trends for sandstones and shale can be used to investigate the expected seismic signatures of sand-shale interfaces as a function of depth. It also allows to identify anomalous lithologies or diagenetic zones (e.g. cemented horizons). Similarly, over-compacted zones related to uplift can be recognised, and erosion thickness can be estimated (Avseth et al., 2005). Additionally, expected brine-saturated velocity-depth trends can be applied to detect seismic velocity anomalies related to hydrocarbons (e.g. Avseth et al., 2003). Density-depth trends as a complement of velocity-depth relationship also play an important role in providing an estimate of the rock properties needed to model seismic signatures with depth and where these contrasts disappear, the so-called Amplitude and AVO 'floor'.

1.6 Summary

Rock physics is a predictive risk-reduction tool which is highly valuable in exploration and production. It emphasises a quantitative understanding of seismic amplitude variations in order to validate the presence of hydrocarbons and give additional information during prospect evaluation and reservoir characterisation. AVO analysis is one of the most powerful techniques using rock physics, as amplitudes can be explained in terms of rock and fluid properties which therefore allows a prediction of lithology and fluid from seismic data.

In rock physics studies, limitations arise from not knowing what happens to physical rock properties as we move away from the high resolution but spatially limited picture provided by wells. This can result in potentially spurious trends and transformations being used to model 'what-if' scenarios. Fluid substitution is the best known example, and involves the prediction of seismic velocities and impedances which result from varying fluid saturations within reservoir rocks. It can be used to extrapolate and model the conditions that might exist away from the well locations, and then to compute synthetics to explore how seismic signatures might change. This workflow is particularly useful when we wish to understand the seismic response of fluids and facies that are not represented in the wells. Depth trend analysis is another typical rock physics approach which is used to study the expected seismic signatures as a function of depth. The results of depth trend analysis provide estimates of the parameters needed to model expected seismic responses with depth for sandstones and shales. Therefore, the depth trends allow us to understand the scope for discriminating pore fluids and lithologies at different depths.

Last but not least, a common way to perform quantitative analysis of seismic attributes is through forward modelling. In this study, this is achieved by creating a synthetic model in the well domain (1D synthetic gathers), to interpret seismic signatures and AVO responses at the top of potential reservoirs.

Chapter 2 – Methodology

This chapter will detail the workflow used to produce the results shown in 'Chapter 3 - Single Well Interpretations'. It is important to emphasise that there are a series of PowerPoint's supplied with the project and these PowerPoint's show the progression of the log data through the workflow for every well. There is also a PowerPoint to describe the multi-well analysis and every plot made for the multi-well analysis is contained within this PowerPoint.

The general structure of this chapter is:

- Single well Rock Physics Analysis – Part 1
- Multi well Rock Physics analysis
- Single well Rock Physics Analysis – Part 1

2.1 – Single Well Rock Physics Analysis - Part 1

Chapter 2.1 will explain the methodology behind part 1 of the single well rock physics and sets out how the results derived from this section of the project will be used in the multi-well analysis in Chapter 2.2 of the project.

The workflow of the first stage of the single well rock physics was to;

- Load the raw log data and perform a visual QC of the data, taking note of any obvious data issues and then use cross-plots to highlight any bad data before editing it out of the logs;
- Define mineral sets for every formation in each of the 35 study wells;
- Determine the fluid properties across the region and define brine, oil, condensate and dry gas fluid sets for every formation in all 35 of the study wells;
- Define reservoir intervals;
- Perform invasion correction on appropriate reservoir intervals;
- Carry out Gassmann fluid substitution to 100% brine conditions for all the wells where measured Vs data was available

The objective of this part of the workflow was to prepare the logs for use in the multi-well analysis.

Raw data QC

The first part of the workflow involved loading the log data into RokDoc and visually inspecting the log data to spot any obvious issues left after Petrophysical evaluation that could influence the rock physics analysis. This was done by creating a well log panel with all the basic logs, as shown for this example well;

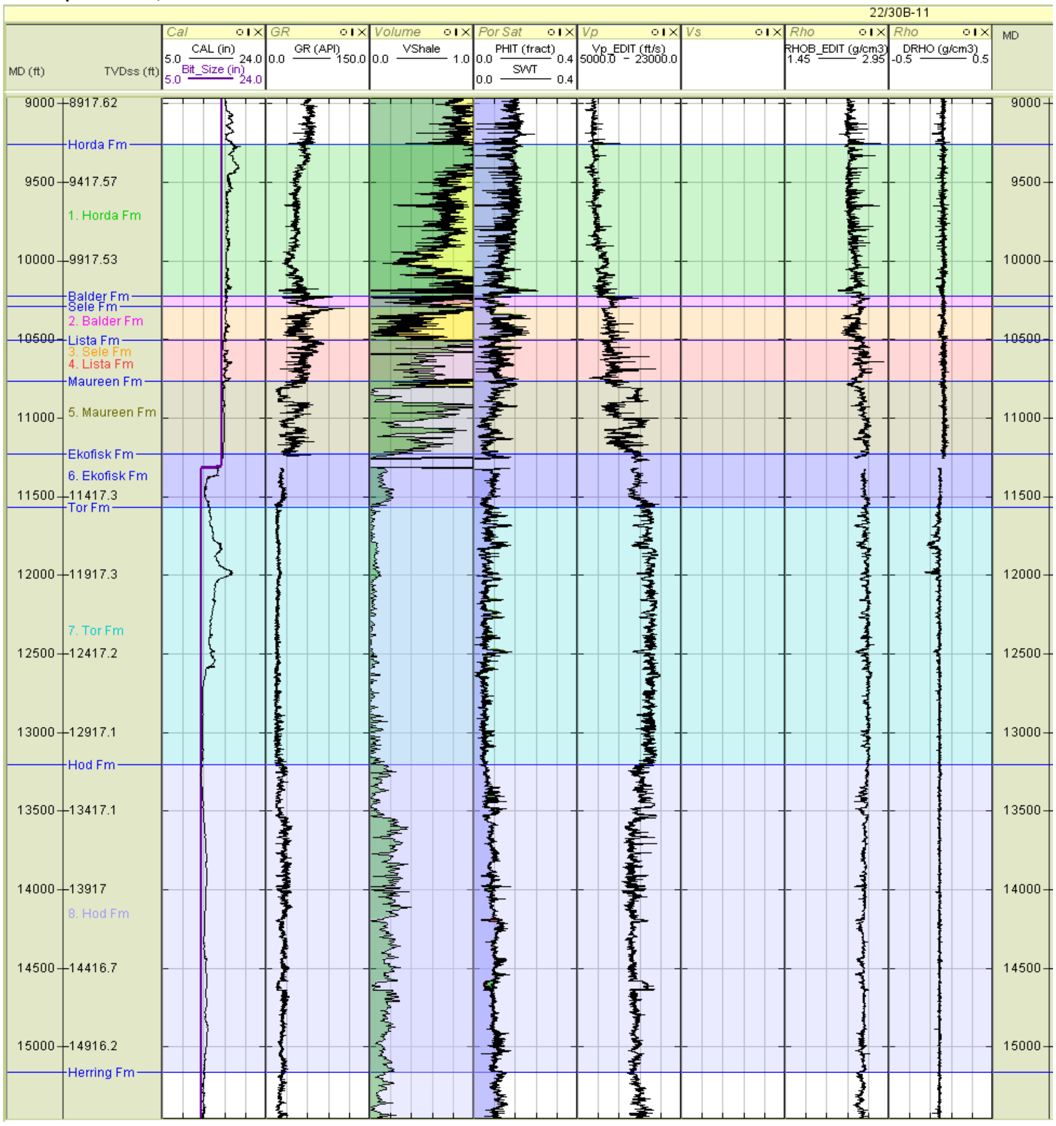


Figure 2.1.1 - Raw data at well 22/30B-11.

The raw data well log panel was composed of the GR log, volume fraction set, saturation set and porosity log, Vp log, Vs log and Rhob log. The logs are given a suffix of EDIT1 to denote that some edits have been applied to the data during the petrophysics stage of the project.

The caliper log was included to show the variation in hole size and a bit size log was included to show the expected value of the hole size. The bit size log was derived using information from the well reports/composite logs and in the sections where the caliper log had a much higher value than the bit size, it was suspected that the hole was washed-out (bad hole) and care was taken whilst interpreting these sections in the initial log editing phase of the project.

The DRHO log is also included to show whether any density correction was applied to the density log and this is another useful measure of identifying washed out zones of bad hole.

As an example, the visual inspection of the data at well 22/30B-11 revealed the following issues;

- There was no measured shear log present at this well. A Vs log was modelled from Vp later on in the workflow.
- There were gaps in the petrophysics (volume fraction set, porosity and Sw logs), GR and Vp data in the Ekofisk Fm. This was due to a casing change at 11247 ft MD and there was a small amount of washout evident below this casing change. The gap in the Vp and density logs will be modelled from regional trends and filled later on in the workflow.
- There were also small gaps in the Vp Log in the Lista and Maureen Fm.
  These small gaps were not immediately visible, but were detrimental when creating synthetic seismic responses.
- The caliper log demonstrated that the bore hole was in good condition across the remaining working intervals with exception of the top section of the Horda Fm and the top section of the Tor Fm.
- The DRHO log looked generally well behaved over all of the working intervals.
- The issues from this well were resolved during the course of the workflow and all issues from the other wells in the project were also resolved during the course of the rock physics workflow.

Log editing and auditing strategy

At this point in the study, our strategy for carrying out the log editing was finalised and it is explained below in the flow diagram. The red dots denote the steps at the workflow with edits that resulted in the final log edit curves in Single Well Rock Physics - Part 2;

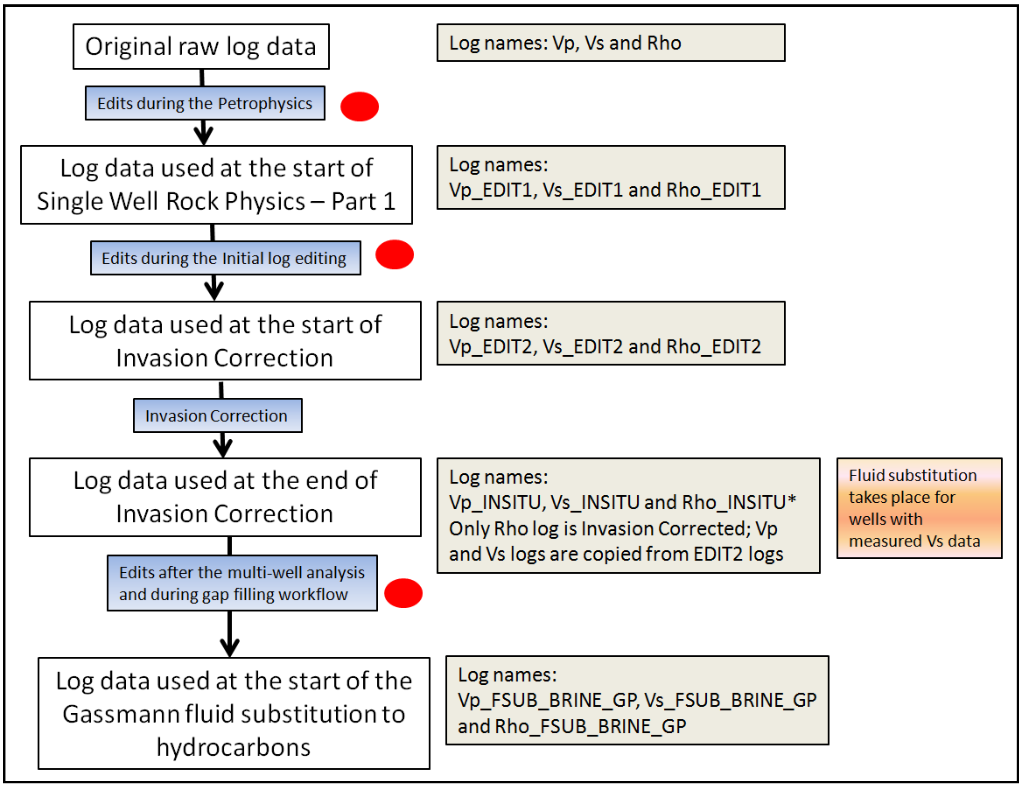


Figure 2.1.2 - Log editing workflow. The log editing script was run at the end of Part 2 of the Rock Physics

Initial log editing

The first quantitative look at the log data was carried out in the initial log editing phase of the project and documented in the accompanying PowerPoint's. This was done by constructing quick-look QC cross-plots for each interval in the well in order to identify bad data that sat off the established rock physics trends of Gardner (Sandstone) and Mavko (Limestone) for Vp-Rhob plots and Greenberg-Castagna for Vp-Vs plots. Any bad data was highlighted using a polygon and removed from the rock physics analysis.

An example of good data in the initial log editing is shown below for the Vp-Rhob plot for the Maureen Fm in well 22/30A-16;

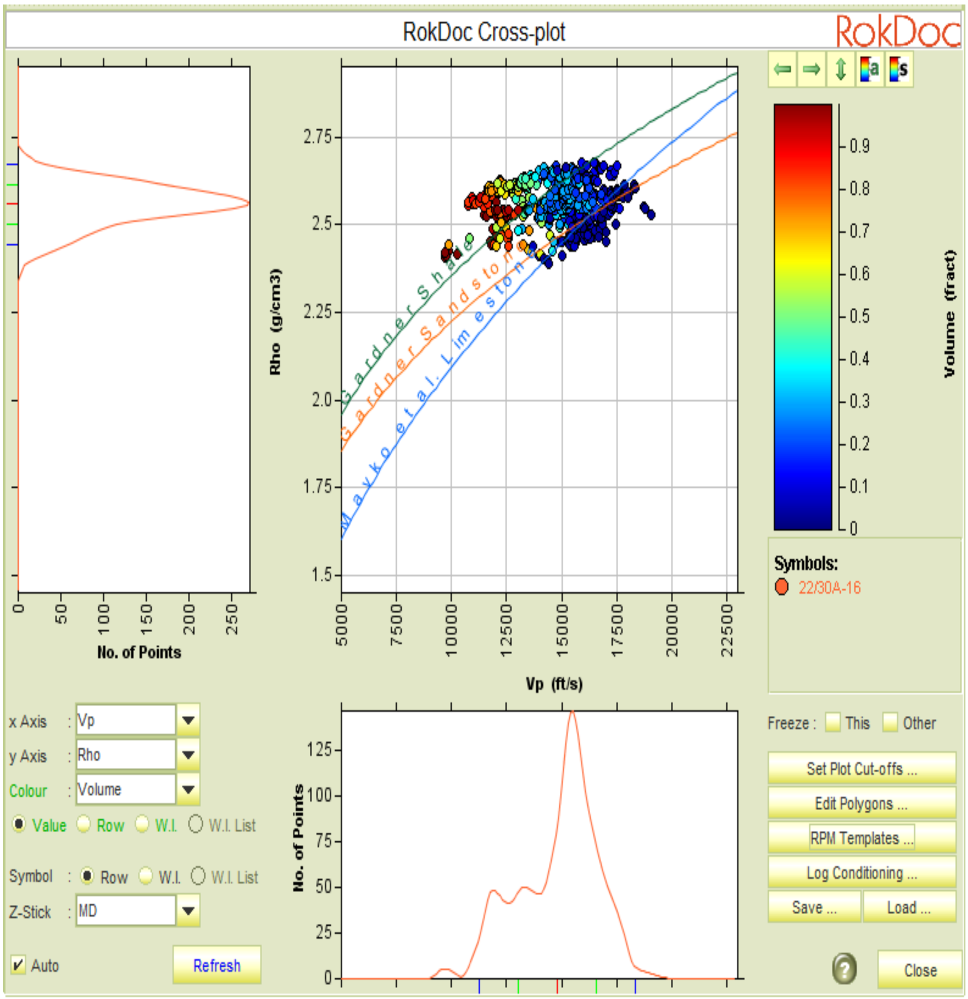


Figure 2.1.3 - Vp-Rhob cross-plot and well log panel for the Balder Fm in well 22/30A-16. The green line represents the Gardner shale relationship, the orange line represents the Gardner sandstone relationship and the blue line represents the Mavko limestone relationship.

No log data needs to be removed from the Vp and Rhob logs in the Maureen Fm at well 22/30A-16. However not all log data was as well behaved as Sandstones in this formation. An example of bad data identified by the initial log editing is shown below for the Vp-Vs plot for the Balder Fm in well 22/30A-16;

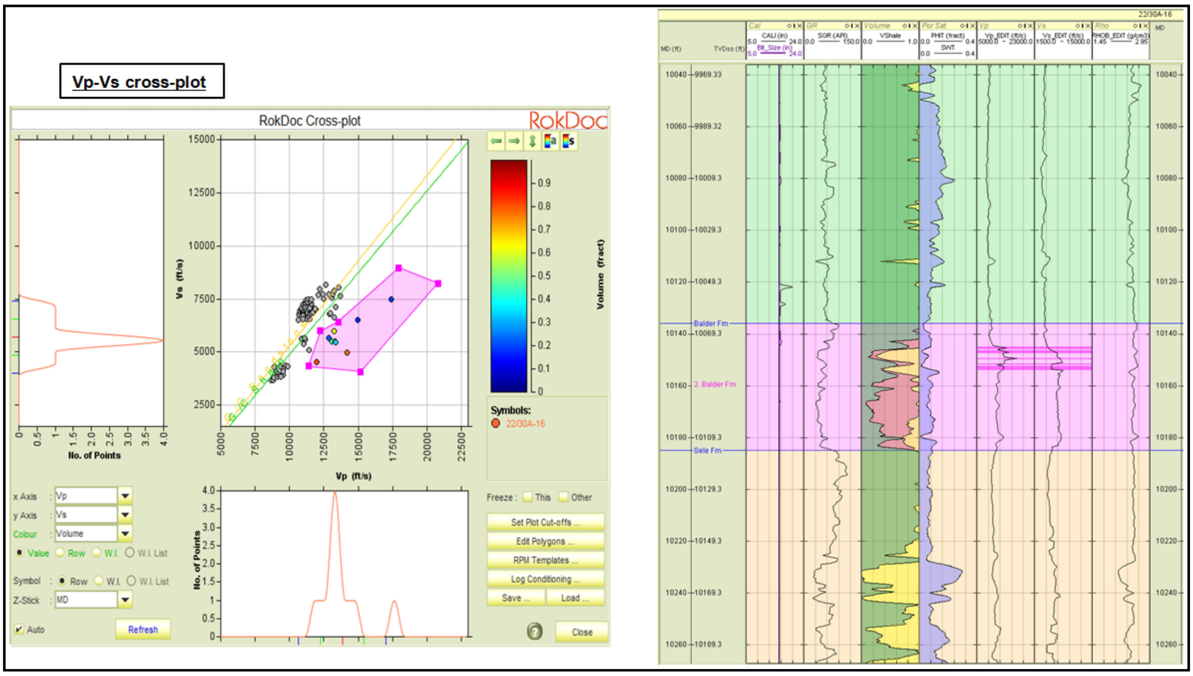


Figure 2.1.4 - Vp-Vs cross-plot and well log panel for the Balder Fm in well 22/30A-16. The pink polygon highlights bad data in the Vp and Vs logs and this data was removed from the logs at this stage of the project. The green line represents the Greenberg-Castagna shale relationship and the yellow line represents the Greenberg-Castagna sandstone relationship.

The log data highlighted by the pink polygon was removed from the Balder Fm in Well 22/30A-16. This process was repeated wherever bad data was found in every well in the project. The gaps were eventually filled using regional trends derived from the multi-well analysis in the Single Well Rock Physics - Part 2 of the project.

Definition of mineral sets

The next stage of the workflow involved defining the mineral sets that were used in the Gassmann fluid substitution part of the project. There were four minerals defined within the petrophysics of this project; these minerals are quartz, calcite, shale and tuff. For quartz and calcite, both of these minerals were considered to be constant over the study area and every mineral set was given the same non-pure value for quartz and calcite. This 'Dirty' value represents a sensible non-pure mineral value supplied by Shell in recognition that the sand will not be 100% quartz and the limestone will not be 100% calcite.

Clean (default) mineral properties for Quartz and Calcite

Type	Ko	Mu	Rho	M	Vp	Vs	Colour
Quartz	36.6	45	2.65	96.6	19,808.458	13,519.741	
Shale	11.4	3	2.35	15.4	8,398.688	3,706.907	
Calcite	76.8	32	2.71	119.467	21,783.305	11,273.931	

'Dirty' mineral properties for Quartz and Calcite

Type	Ko	Mu	Rho	M	Vp	Vs	Colour
Quartz	38.9	35.3	2.635	85.967	18,739.576	12,008.315	
Shale	11.4	3	2.35	15.4	8,398.688	3,706.907	
Calcite	60	25	2.71	93.333	19,253.903	9,964.842	

Figure 2.1.5 - This figure displays the 'Dirty' quartz and calcite properties that were used in the project.

For the shale properties, a total porosity system is being used in this project and we need to use dry clay values to represent the shale component of the rock. The dry clay value was supplied by Shell and was taken to be constant across the project.

The only one of the four minerals whose properties were not taken to be constant in the mineral set for each well was the tuff mineral and the tuff mineral only occurred in the Balder Fm. The clean tuff mineral properties were found by using a clean tuff cut-off of Volume_Tuff>0.7 to isolate the clean-est tuff points then taking the average Vp, Vs and Rhob values and using those values to update the mineral sets. This meant that a mineral set was defined for each well individually with the only change between wells being the tuff properties. An example of the values that are input to a mineral set is provided below for well 22/12A-05.

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

In addition to the following Tuff values derived specifically at this well;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	12.43	4.68	2.328	9,292	4,653

Figure 2.1.6 - This figure displays the mineral properties that comprise of the mineral set at well 22/12A-05.

It is important to note that the mineral sets could only be defined at this point in the project for the wells that had measured Vs data. For the wells without measured Vs data, the mineral sets were de-fined in the later part of the rock physics workflow after the gap-filling and missing curves workflow was completed.

Definition of fluid sets

The fluid sets that modelled the elastic properties of the reservoir fluids were also defined in this part of the workflow. These fluid sets were defined for every interval in every well and were used in the Gassmann fluid substitution workflow in the later part of the project. The fluid sets are defined using the FLAG11 fluid property calculators (Source – Rock Physics Lab, University of Houston & Centre for Rock Abuse, Colorado School of Mines) and the inputs needed to the fluid property calculator are shown below.

These fluid parameters are:

- Reservoir Temperature
- Reservoir Pressure
- Salinity (ppm)
- Gas Oil Ratio (v/v)
- Oil API (API_od)
- Gas Gravity

The log image files were used to collate all the available bottom hole temperature data values recorded when the well was logged. These values were corrected using the “simple correction” – determined by the time since circulation in each well and both the corrected and uncorrected temperature values for each well were plotted and compared to the regional and field temperature trends (supplied by Shell for the CNS). These plots were evaluated individually and the most appropriate temperatures used during the petrophysics evaluation of each well.

The mid-point of each working interval was determined from the working interval markers and a mid-point formation temperature was determined based on the same temperature trend used during the petrophysical evaluation.

Ikon Geopressure used the same mid-point formation depths to provide a point value for pressure in each of the formations in each of the 35 wells (irrespective of reservoir being present in the formation). Reservoir pressures were determined from analysis of direct pressure measurements within the reservoir units and constrained by local offset wells. Shale pressures were determined through the use of pressure gradients and the mid-point depths. The pressure gradients were constrained by direct pressure measurements taken in isolated permeable units within the shale's. Individual temperature and pressure plots, showing the mid-point formation values used in the study are provided in the PowerPoint documentation and also in a separate Excel spreadsheet. The Salinity, Gas Oil Ratio, Oil API and Gas Gravity properties were all found from well reports and also were defined by Shell in the absence of information from well reports. All the fluid parameters have been documented within the PowerPoint's and master spreadsheet.

There were separate fluid property calculators required for brine, oil and gas and these are shown below, where the Global Gas Model was used for calculating the gas properties.

(Geo)Spatial interpolation (e.g. Kriging) of the well-based fluid properties and Pressure&Temperature data from the Master Excel workbook allows fluid properties to be computed for locations away from well control.

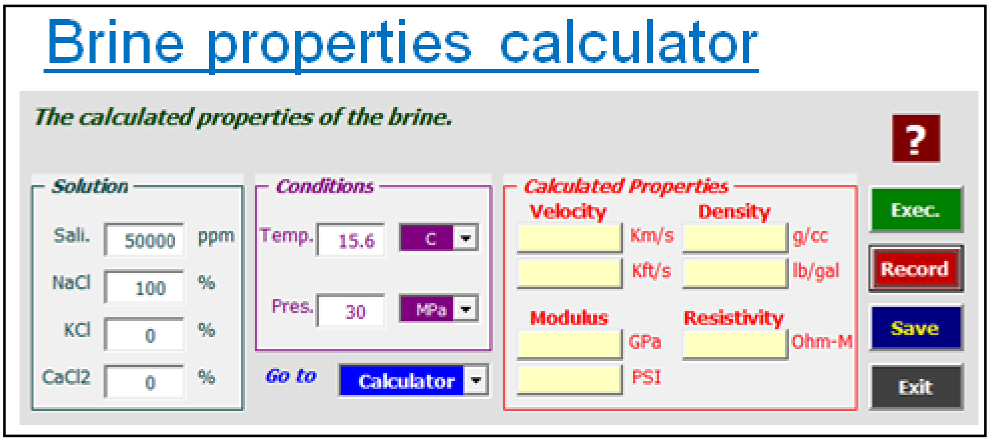


Figure 2.1.7 - This figure displays the brine properties fluid calculator.

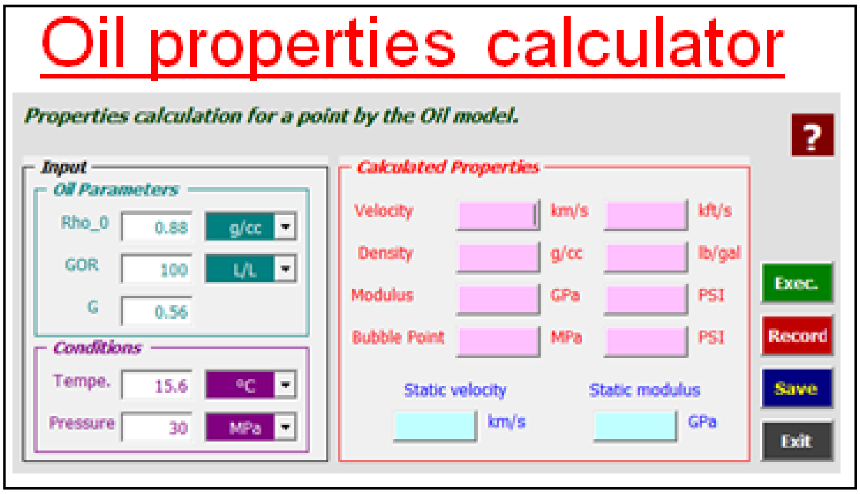


Figure 2.1.8 - This figure displays the oil properties fluid calculator.

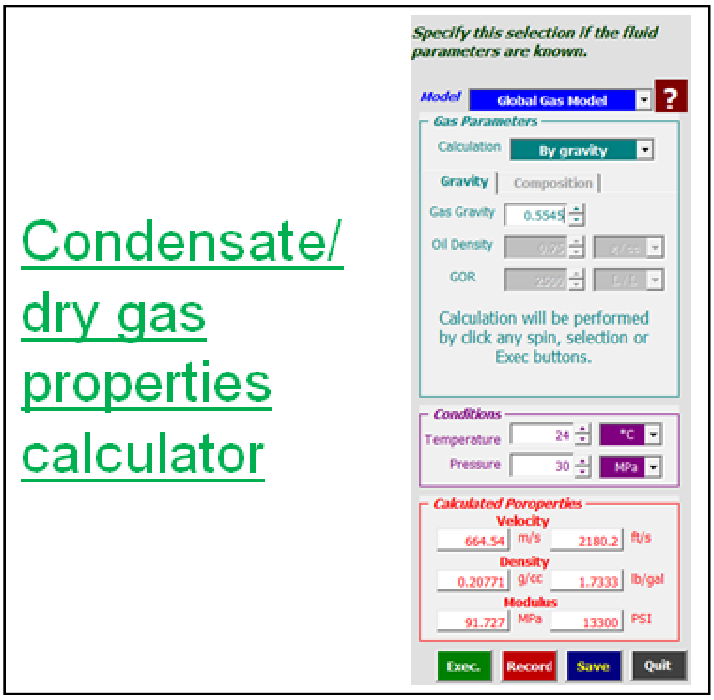
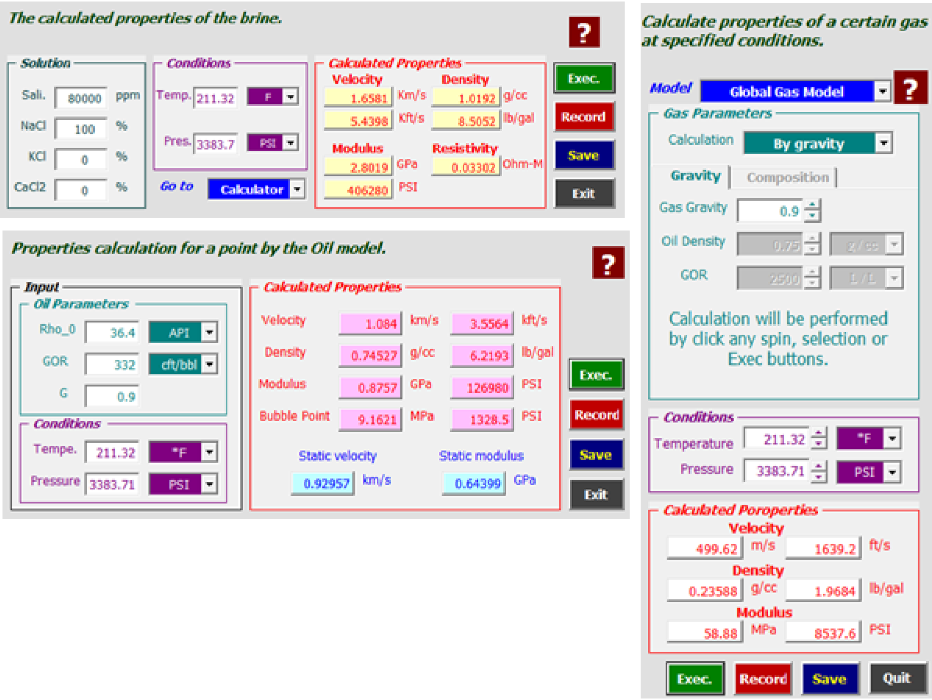


Figure 2.1.9 - This figure displays the gas properties fluid calculator, using the Global Gas model.

The fluid sets were then calculated by inputting the fluid parameters into the fluid calculators and updating the default fluid set in RokDoc with the resulting fluid properties. An example of this is given below for the Sele Fm in well 22/12A-05;

Well 22/12A-05 – Sele formation



The density and Vp values are updated in the fluid set and the bulk modulus will be recalculated as a result.

Fluid Type	Rho	Vp	K
Water	1.019	5,439.8	2.802
Oil	0.745	3,556.4	0.876
Gas	0.236	1,639.2	0.059

Figure 2.1.10 - This figure displays the fluid set calculated for the Sele Fm in well 22/12A-05. This fluid set was used in the Gassmann fluid substitution workflow later in the project.

Reservoir intervals

At this stage of the workflow, reservoir intervals were defined for each well based on the petrophysical reservoir cut-offs supplied by Shell for each formation. Invasion correction and Gassmann fluid substitution were only performed in working intervals that had viable reservoir present within the formation. An example of reservoir classification is provided below for well 22/27A-01 and it was decided that any formations with less than 10ft of reservoir would be classified as non-reservoir, as is the case in the Horda Fm at this well.

Well	Formation	Porosity cut-off	Shale Volume cut-off	Gross Reservoir (ft)	Net Reservoir (ft)	Reservoir interval present
22/27A-01	Horda Fm	PHIT >= 0.15	VSH<=0.4	747	6	No
22/27A-01	Balder Fm	PHIT >= 0.12	Vol_Sand> =0.6	110	42.5	Yes
22/27A-01	Sele Fm	PHIT >= 0.12	VSH<=0.5	561	284.25	Yes
22/27A-01	Lista Fm	PHIT >= 0.10	VSH<=0.4	173.13	79.25	Yes
22/27A-01	Maureen Fm	PHIT >= 0.08	VSH<=0.45	491.87	233.5	Yes
22/27A-01	Ekofisk Fm	PHIT >= 0.06	VSH<=0.4	283.61	108.5	Yes
22/27A-01	Tor Fm	PHIT >= 0.03	VSH<=0.2	1723.39	559	Yes
22/27A-01	Hod Fm	PHIT >= 0.03	VSH<=0.4	919	604.75	Yes

Sand Volume cut-off used in Balder Fm. This will exclude non-reservoir Shale and TUFF.

Figure 2.1.11 - Reservoir classification at well 22/27A-01.

Reservoir cut-offs are slightly wider than those used to define the clean end-member lithologies (see section 2.2)

Invasion correction

This section of the workflow dealt with the process of correcting the density log for the effects of drilling mud invading the porous reservoir formations and this invasion correction was carried out at the majority of the thirty five wells in the project. In this study, the effects of invasion correction on the sonic logs was not taken into account.

At each well the relationship between drilling mud and formation density was first established to ascertain whether invasion correction was required. If the drilling mud was of the same kind as the reservoir fluid (water-based mud and water-filled reservoir or oil-based mud and oil bearing reservoir) then the invasion effect was likely to be minimal and the invasion correction was not performed in these cases. On the other hand, if the drilling mud was of a different kind than the reservoir fluid (e.g. water-based mud in a hydrocarbon bearing reservoir or an oil-based mud in a water or gas bearing reservoir) then the invasion effect was likely to be more substantial and the invasion correction was performed in these cases.

An example of defining the relationship between drilling mud and formation fluid is provided below for well 29/03A-06 and these tables are provided in the supplementary PowerPoint's for every well.

Well	Drilling Mud	Reservoir contents	Invasion correction needed?
29/03A-06	Oil-based mud	Brine-bearing in Horda Fm, Condensate-bearing in Sele Fm	Yes – only needed in the Horda and Sele Formations since these are the only two reservoirs in this well.

Figure2.1.12 - Example of invasion correction table at well 29/03A-06.

A log programmer script was required to run the invasion correction and this script is included in the appendix of the written report.
The invasion correction method works in the following way:

- Calculate the density of the uninvaded virgin zone (RhobVirginFluid) using insitu saturation and calculated fluid densities.
- Calculate apparent fluid density using modified porosity equation, utilising grain density information and measured porosity
- Calculate RhobFluidA which is the apparent fluid density, clipped at the end member fluid densities
- Calculate the invasion 'Rhob difference' by subtracting RhobVirginFluid from RhobfluidA
- Calculate the invasion corrected density log by subtracting the difference from the measured Rhob log. This creates the RHOBB_INSITU log and represents the density log without any effects of drilling mud.
- The RhobFluidA and RhobVirginFluid logs provide a QC of the mud filtrate values (RhobFluidA) and the reservoir fluid values (RhobVirginFluid) applied during the invasion correction calculation.

The script carried out invasion correction individually at each of the eight working intervals and required the following inputs, as shown in the table below for well 22/28A-04;

Formation	Rho_mineral (g/cc)	Rho_filtrate (g/cc)	Rho_water (g/cc)	Rho_oil (g/cc)	Rho_gas (g/cc)
Horda	2.65	0.85	1.01	0.661	0.379
Balder	2.65	0.85	1.006	0.656	0.203
Sele	2.65	0.85	1.003	0.654	0.206
Lista					
Maureen					
Ekofisk					
Tor					
Hod					

Figure 2.1.13 - Example of invasion correction parameters at well 22/28A-04.

The clean mineral values (Rho) are used consistently with the PP evaluation.

The invasion correction results are shown for every well within the accompanying PowerPoint and the resulting invasion corrected density log is named 'Rhob_INSITU'. In general the correction are small, but any resulting porosity changes could have an effect in later fluid substitutions as they affect the frame strength.

At this point in the workflow, the existing Vp and Vs logs are copied and renamed 'Vp_INSITU' and 'Vs_INSITU' to represent the latest edited versions of the Vp and Vs logs. This completed an INSITU log set which was used in the Gassmann fluid substitution workflow in the next section of the project.

Gassmann fluid substitution to 100% brine conditions

Gassmann fluid substitution to 100% brine conditions was only carried out for the twelve wells that had measured Vs data at this point in the workflow. The starting point for the Gassmann fluid substitution to the 100% brine bearing conditions was a set of Vp, Vs and Rhob logs at insitu saturation conditions. This Vp-Vs-Rhob set was named 'INSITU' and Gassmann fluid substitution was only performed on these logs in the reservoir intervals at each well. Gassmann fluid substitution was performed to output the following fluid cases in each reservoir interval in every well;

Final saturation: 100% water: Suffix = FSUB_BRINE

Gassmann fluid substitution was performed using the Log Fluid Sub (Gassmann Dry Rock Modelling) tool in RokDoc. The first tab in the module was the Initial to Dry tab and the relevant default (clean) mineral and fluid properties for the particular working interval were selected at this stage (Insitu). The working interval was also selected at this point and all the working intervals with the reservoir cut-offs applied (these are given a suffix of reservoir) are available in the RokDoc project.

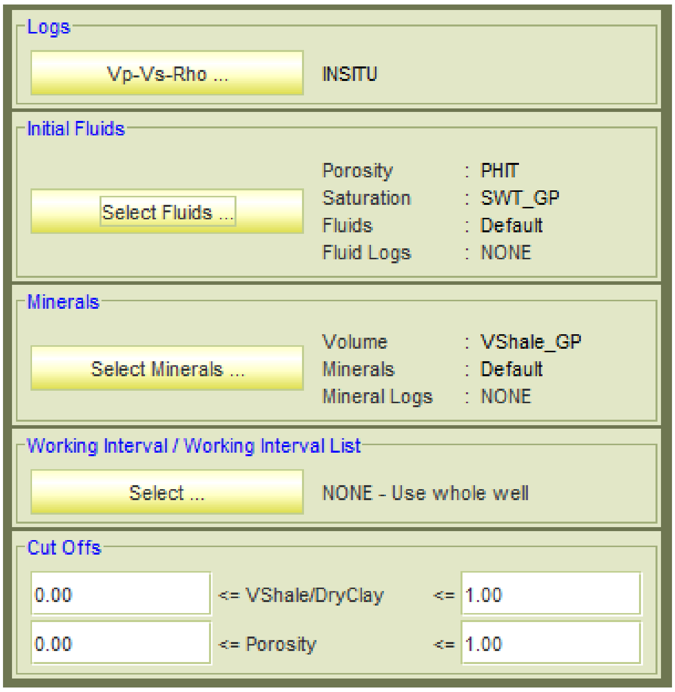


Figure 2.1.14 - Initial to Dry tab in Gassmann fluid substitution

The next tab in the module is the Dry Rock Modelling tab and at this point, we were able to see quality control plots of the dry rock frame parameters versus porosity. We were also given the choice about the model bounds and the dry rock modelling method in this tab. The 'Use Dry Rock Bound Constraints' was selected every time for the dry rock modelling method whereas the upper model bound was turned off on every occasion.

A lower model bound was selected and this moved all the points sitting below the lower model bound up onto the lower model bound on the Kdry/Kmin vs. porosity cross-plot. The lower bound value was chosen in order to correct any data points with anomalously low Kdry/Kmin values in comparison to the main cluster of data points, as these could introduce abnormally large fluid effects due to the weak rock frame expressed by the low Kdry. This is illustrated below on the example dry rock plots. All of the relevant cross-plots and information on the model lower bound selected are available within the PowerPoint's.

An example of the Dry Rock QC plots is provided below;

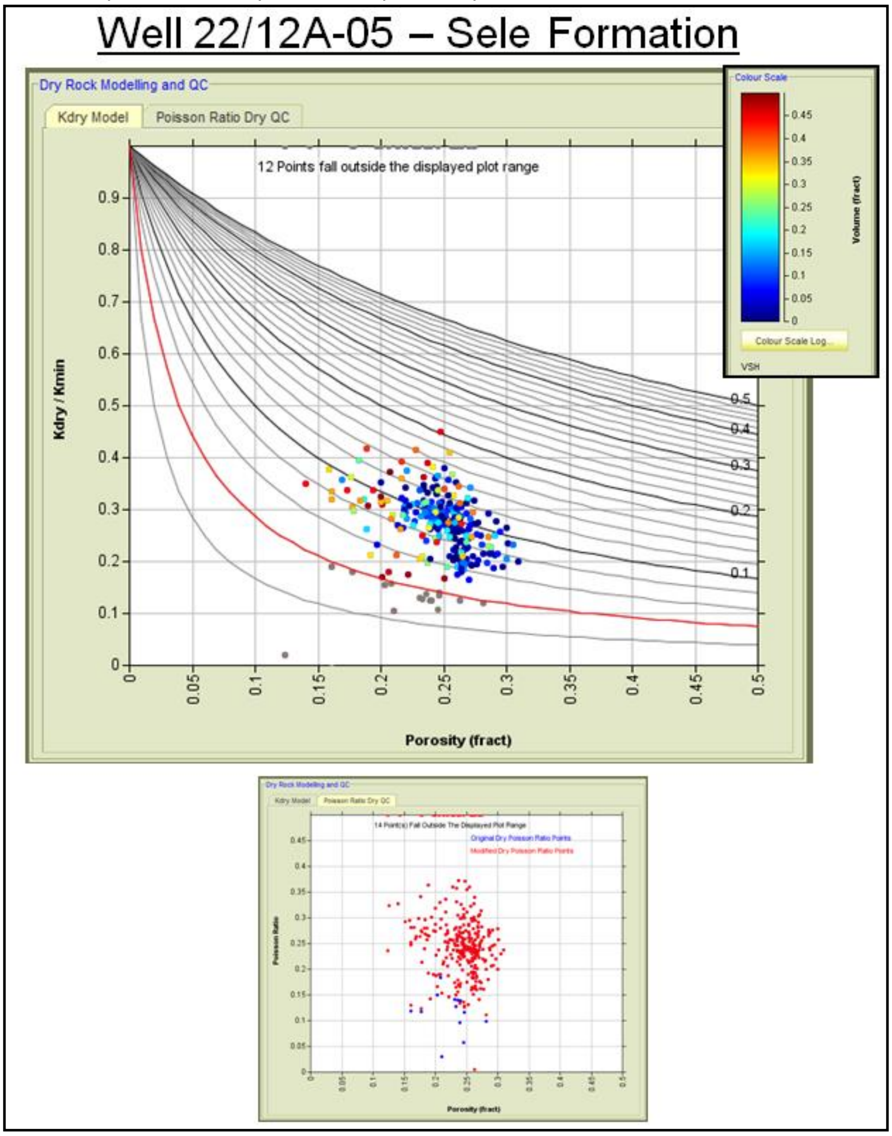


Figure 2.1.15 - Dry Rock QC Plots for the Sele formation in well 22/12A-05. The upper plot shows Kdry/Kmin vs. porosity and it is coloured by shale volume with a blue colour representing the cleanest sand points and a red colour representing the siltier sand points. The lower plot shows Poisson's ratio vs. porosity. Anomalous points outside the bound are coloured grey.

The workflow of selecting the relevant fluid set, mineral set and working interval on the Initial to Dry tab, selecting the lower model bound on the Dry Rock Modelling tab and then finally the final fluid saturations was repeated in every working interval with a viable reservoir in the well. The results of Gassmann fluid substitution at well 22/12A-05 are displayed below;

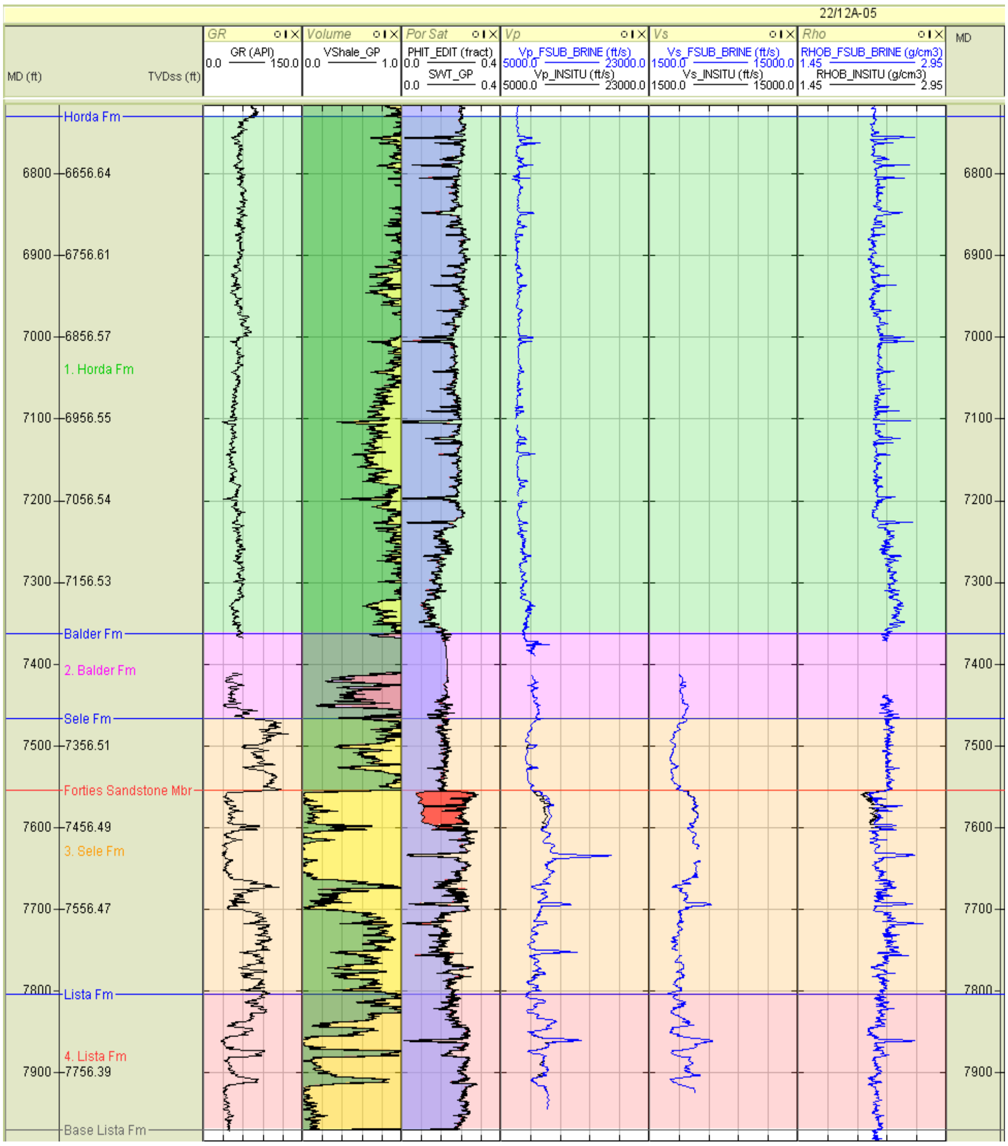


Figure 2.1.16 - Well log panel for 100% brine bearing data (blue coloured logs) and insitu measured log data (black coloured logs) at well 22/12A-05.

The fluid substituted results show that there was a slight increase in Vp and density over the hydrocarbon bearing zone when the logs are 100% Brine saturated. This 100% brine bearing data for the twelve wells with measured Vs data was now ready for the multi-well analysis section of the project. For wells without measured Vs data, a water saturation cut-off was applied to the multi-well plots in order to exclude the hydrocarbon bearing data points but include the 100% brine bearing points and this is explained in more detail in the next section of the report.

2.2 – Multi-well analysis

Chapter 2.1 previously explained how the raw log data for all thirty five wells in the project were conditioned in the same manner to make each well suitable for multi-well analysis. Chapter 2.2 will now explain the methodology behind the multi-well analysis section of the project and how the results derived from this section of the project will be key in the rock physics analysis of each well later in the project.

The key principle of the multi-well analysis is that all of the thirty five wells in the project are in the same condition and thus we can derive any regional lithology trends using consistent data. This point for our project (and all major regional studies) is only using 100% brine bearing log data in the multi-well analysis. This will remove the influence of any hydrocarbon-bearing data on the regional trends.

The previous chapter explained how twelve of the wells had measured Vs data and we were able to use Gassmann fluid substitution to produce a set of 100% brine bearing logs. These were named 'FSUB_BRINE' in accordance with Shell's specified naming convention and these logs were used in the multi-well analysis without using any SWT cut-offs.

For the other twenty three wells where there were no measured Vs data available and Gassmann Fluid Substitution could not take place, a saturation cut-off of SWT=1 was applied to the measured log data so that only 100% brine bearing log data points would be selected to be used in the multi-well analysis. These logs were still in their 'INSITU' conditions and the saturation cut-off was needed in order to exclude hydrocarbon-bearing data from the regional trend analysis.

The table below highlights which of the wells have measured Vs data and have been Gassmann fluid substituted to 100% brine conditions.

Well	Measured Vs data	Well	Measured Vs data	Well	Measured Vs data
21/20A-02	No	22/24B-07	No	29/02A-06	No
21/25-04	No	22/26A-01	No	29/02C-09	No
21/25-06	No	22/27A-01	No	29/03A-06	Yes
21/25-10	No	22/28A-01	No	29/03A-07	Yes
21/25-12	No	22/28A-04	Yes	29/07-01	No
21/30-01	No	22/29-05	Yes	29/07-05	Yes
21/30-03	No	22/29-06S2	Yes	29/09C-04	No
21/30-19	No	22/30A-16	Yes	29/10-02	No
22/12A-05	Yes	22/30B-11	No	29/10-04Z	Yes
22/15-02	No	23/26B-14	No	30/03A-01	No
22/19-01	No	23/27-09	No	30/06-04	Yes
22/21-D7	Yes			30/12A-09	Yes

Table 2.2.1 - Table to show the measured Vs distribution in the study wells

Following preparation of the log data for use in the multi-well analysis, rock physics relationships (y(x)) were derived for the study and these are listed below;

- PhiT-Depth (TVDml)
- Vp-Depth (TVDml)
- Rhob-Vp
- Vs-Vp
- PhiT-Vp
- Rhob-PhiT

The depth reference is below mudline (seabed), TVDml, to account for the varying water depth and acknowledge the fact that the seis ic rock properties for normal compacting rocks are sensitive to the vertical effective stress, which is linked to TVDml and not TVDss.

These relationships were found for every formation in the study interval and thus they were found for eight working intervals.

These eight working intervals and their dominant lithologies are listed below;

- Horda Fm: Sandstone and Shale
- Balder Fm: Sandstone, Tuff and Shale
- Sele Fm: Sandstone and Shale
- Lista Fm: Sandstone and Shale
- Maureen Fm: Sandstone, Limestone and Shale
- Ekofisk Fm: Limestone
- Tor Fm: Limestone
- Hod Fm: Limestone

NB - Minor lithologies were found in some intervals but not included in the analysis

The derived multi-well trends were used to reconstruct and model logs later on in the project, and as such should represent the clean end member lithologies throughout each interval. To do this, further cut-offs were applied to the multi-well analysis cross-plots and these are listed below for each lithology encountered in the study interval;

Tertiary working intervals (Horda, Balder, Sele, Lista and Maureen Fm)

- Clean Sand - Vol_Sand > 0.7
- Clean Shale - VSh > 0.7
- Clean Tuff - Vol_Tuff > 0.7

Cretaceous working intervals (Ekofisk, Tor and Hod Fm)

- Clean Limestone - Vol_Lime > 0.9

Sandstone and limestone are classified as reservoir intervals whereas shale and tuff are classified as non-reservoir intervals in this project. The following regression types; PhiT-Depth, PhiT-Vp and Rhob-PhiT, were only fitted for reservoir trends

Multi-well strategy

The strategy for deriving the multi-well trends for this project was to initially start with simple linear trends (Robust Walden regressions) and then increase the complexity of the trends where linear regressions were unable to adequately capture the observed geological variation or where depth ranges exceeded those over which a linear trend might be plausible. Point density plots were used for each cross-plot in order to analyse how well the trends fitted the data clouds. These cross-plots are included in the multi-well analysis PowerPoint but will not be included in this report.

After the first iteration of deriving the multi-well trends, it became clear that for the Depth trend relationships there was a large variation of the rock properties with depth. More than one depth trend would therefore be needed to capture this variation in the rock properties with depth.
This variation in rock properties with depth was captured in our study by using two porosity trends for the sandstone and limestone lithologies (i.e. - for the Sele Fm, we found a high porosity and low porosity trend for the PhiT-Depth cross-plot, perhaps related to sorting trends) and two shale trends for the shale lithology (i.e. - for the Sele Fm, a hard and soft Shale trend was defined).

These trends were interpreted by applying polygons on the cross-plot in order to highlight the data points required to define each trend in the well log plots. For the high porosity and low porosity trends that were derived from the PhiT-Depth cross-plot, the same points were used to derive the high porosity and low porosity trends on the Vp-Depth cross-plot ensuring commonality between the derived trends. The dual porosity and hard/soft shale trends will be clearly shown on the cross-plots in the upcoming 'depth trend analysis' section of the report.

The final version of the multi-well analysis (after several iterations of trend fitting) used the following fitted trends for the rock physics relationships;

- PhiT-Depth(TVDml): Dual porosity trends in some formations. Robust Walden regressions.
- Vp-Depth(TVDml): Dual porosity trends and hard/soft shale trends in some formations. Robust Walden regressions.
- Rhob-Vp: Logarithmic trends in limestone and tuff and a polygon guided power law fit in sandstone and shale.
- Vs-Vp: Robust Walden regressions in Tertiary working intervals and non-linear trends in Cretaceous working intervals.
- PhiT-Vp: Second order polynomial fixed at zero porosity using the 'dirty' quartz/calcite Vp value.
- Rhob-PhiT: Robust Walden regressions fixed at zero porosity using the calcite/quartz Rhob value used in the Petrophysics. This is not consistent with the zero porosity value used in the PhiT-Vp regression (dirty quartz/limestone). However, the approach taken for the Rhob-PhiT regression is more consistent with the Petrophysical evaluation (Rho mineral could change where supported by core data).

The complete set of cross-plots including point density plots and explanation of trend fitting can be found in the accompanying multi-well analysis PowerPoint.

A summary table of formations which required dual porosity trends is also provided below for both of the depth trend plots;

PhiT-Depth(TVDml)

Working Interval	Sandstone	Limestone
Horda Fm	One trend required	
Balder Fm	One trend required	
Sele Fm	Dual porosity trend	
Lista Fm	Dual porosity trend	
Maureen Fm	Dual porosity trend	Dual porosity trend
Ekofisk Fm		Dual porosity trend
Tor Fm		Dual porosity trend
Hod Fm		Dual porosity trend

Table 2.2.2 - Table showing formations with a dual porosity trend for the PhiT-Depth(TVDml) x-plots.

Vp-Depth(TVDml)

Working Interval	Sandstone	Limestone	Shale
Horda Fm	One trend required		Hard/Soft trend
Balder Fm	One trend required		One trend required
Sele Fm	Dual porosity trend		Hard/Soft trend
Lista Fm	Dual porosity trend		Hard/Soft trend
Maureen Fm	Dual porosity trend	Dual porosity trend	Hard/Soft trend
Ekofisk Fm		Dual porosity trend	
Tor Fm		Dual porosity trend	
Hod Fm		Dual porosity trend	

Table 2.2.3 - Table showing formations with a dual porosity trend for the Vp-Depth(TVDml) x-plots.

Synthetic logs created from trends (see p.85) is an essential QC to establish whether dual trends are required or not. Consistent over-/underestimation of, rather than random scatter around, the measured curves is a clear signal that the elastic properties of the rocks can't be captured with a single trend.

Lastly it should be noted that the multi-well regional trends are valid only for this region of the Central North Sea and provide an '80%' regional solution to the local rock physics trends at each well.

If the regional trend does not provide an acceptable match to the local rock physics trends at a well then further calibration to the local trends is required. A workflow to explain how to calibrate the regional rock physics models to local rock physics trends is provided in the Chapter 4 - User Guide.

A summary of the key cross-plots from the multi-well analysis PowerPoint is presented in the next section of the report.

Depth trend analysis: PhiT-Depth plots - All plots coloured by well

Horda Fm - Clean Sandstone - Only one trend required

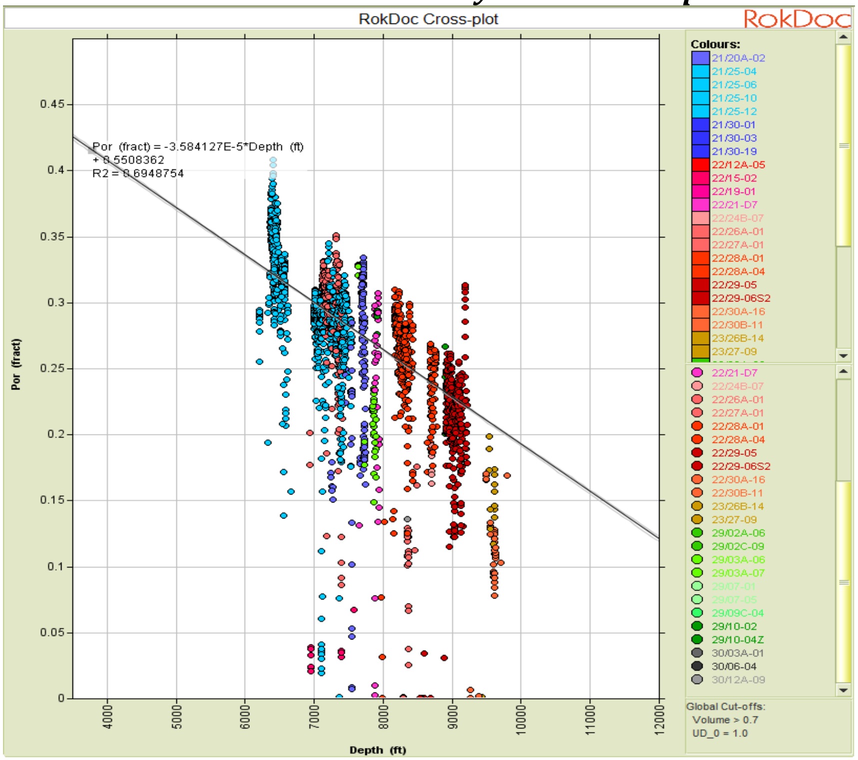


Figure 2.2.1 - PhiT-Depth(TVDml) cross-plot for clean sandstone points in the Horda Fm

Balder Fm - Clean Sandstone - Only one trend required

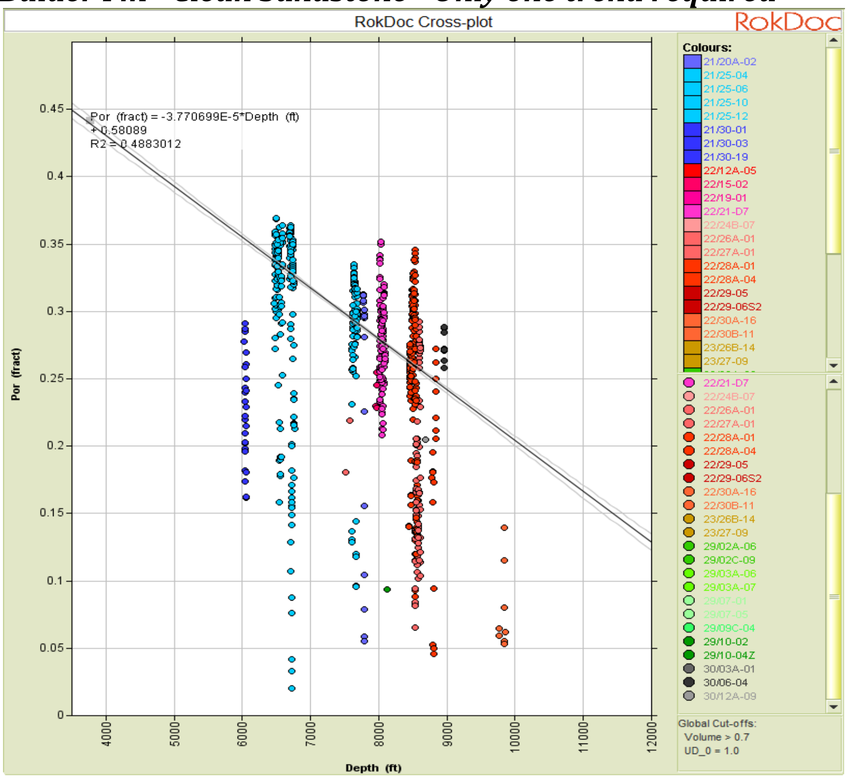


Figure 2.2.2 - PhiT-Depth(TVDml) cross-plot for clean sandstone points in the Balder Fm

Sele Fm - Clean Sandstone - Dual porosity trends required

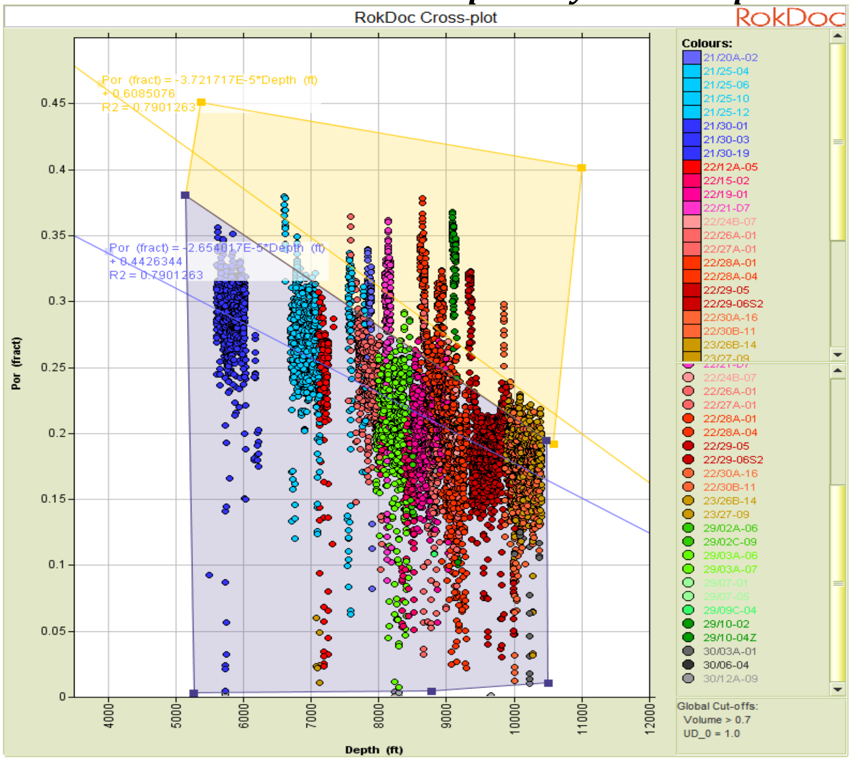


Figure 2.2.3 - PhiT-Depth(TVDml) cross-plot for clean sandstone points in the Sele Fm

Lista Fm - Clean Sandstone - Dual porosity trends required

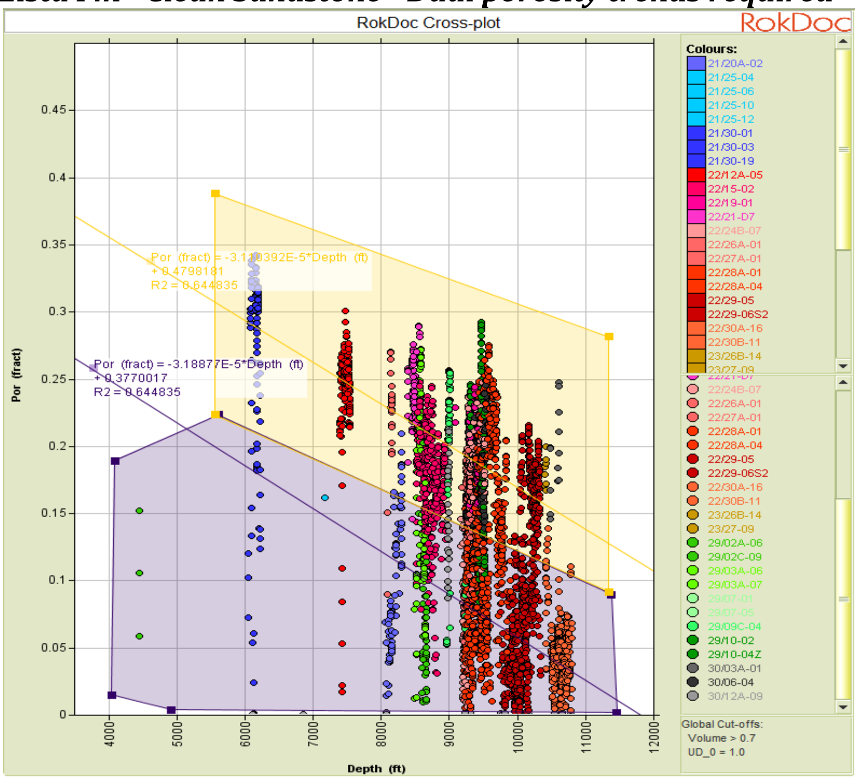


Figure 2.2.4 - PhiT-Depth(TVDml) cross-plot for clean sandstone points in the Lista Fm

Maureen Fm - Clean Sandstone - Dual porosity trends required

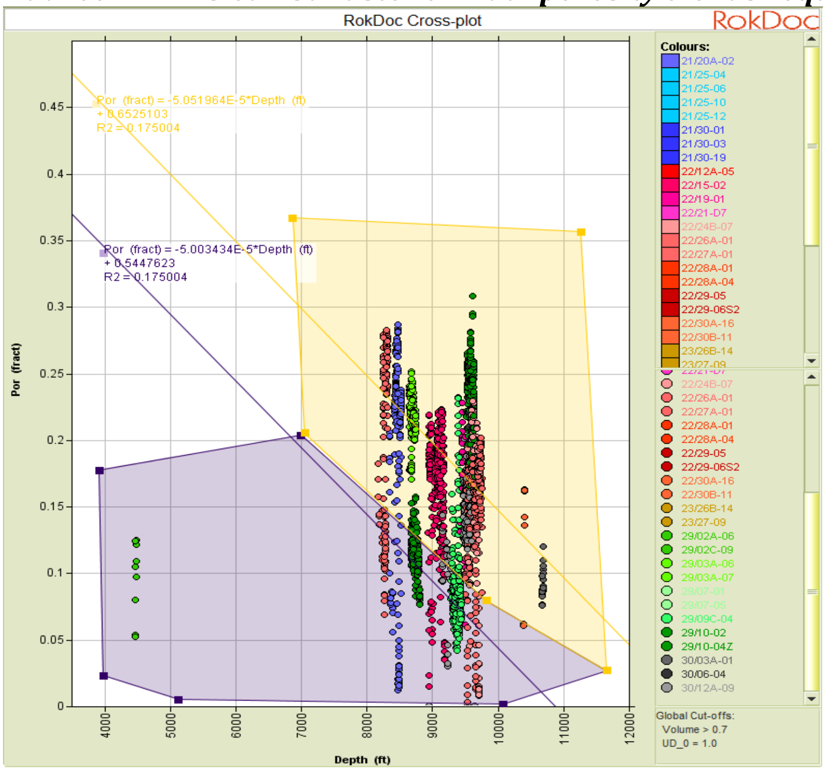


Figure 2.2.5 - PhiT-Depth(TVDml) cross-plot for clean sandstone points in the Maureen Fm

Maureen Fm - Clean Limestone - Dual porosity trends required

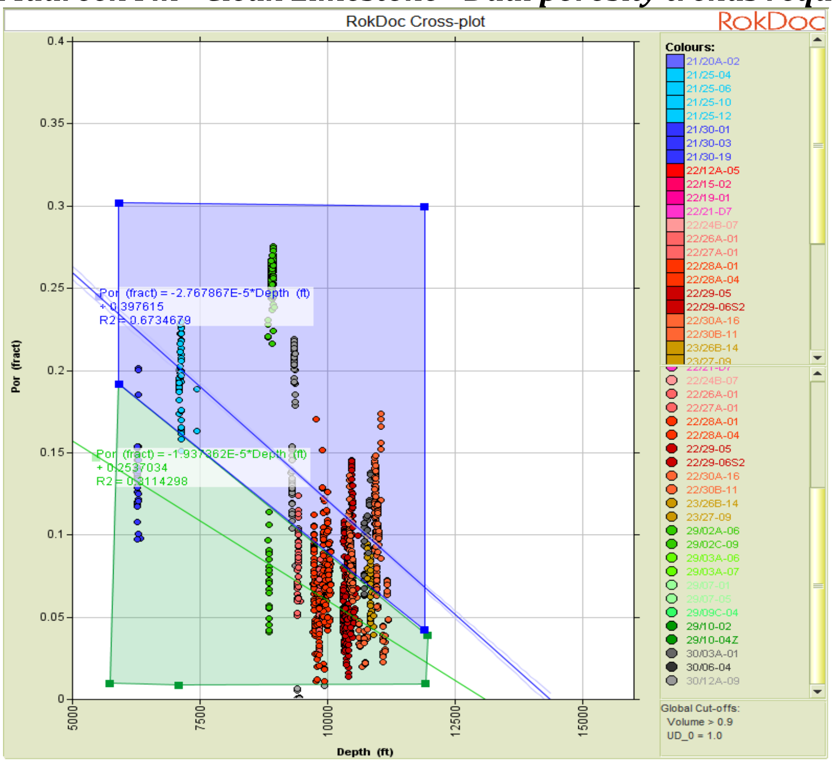


Figure 2.2.6 - PhiT-Depth(TVDml) cross-plot for clean limestone points in the Maureen Fm

Ekofisk Fm - Clean Limestone - Dual porosity trends required

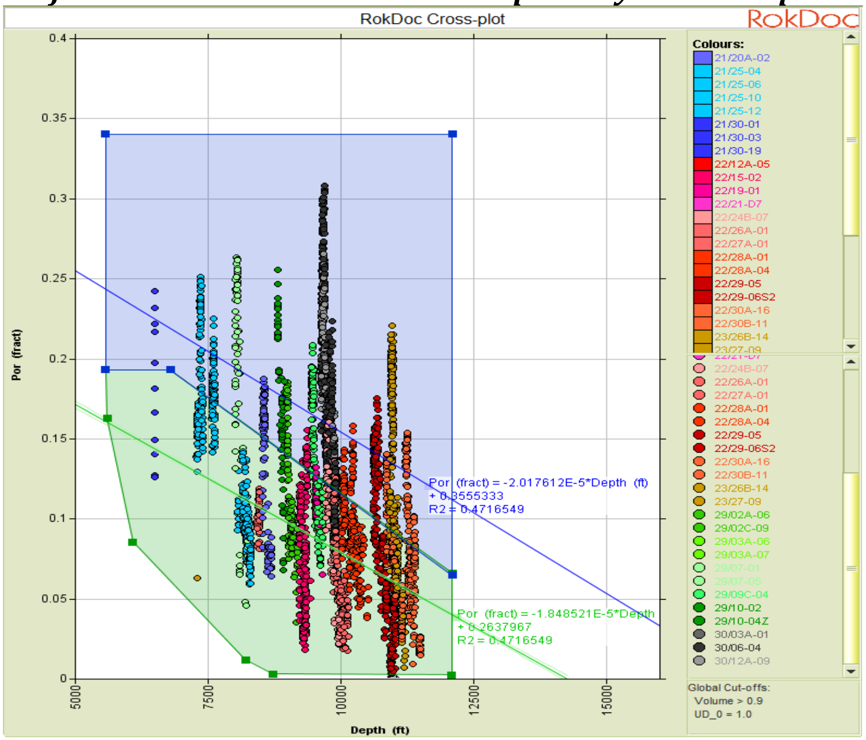


Figure 2.2.7 - PhiT-Depth(TVDml) cross-plot for clean limestone points in the Ekofisk Fm

Tor Fm - Clean Limestone - Dual porosity trends required

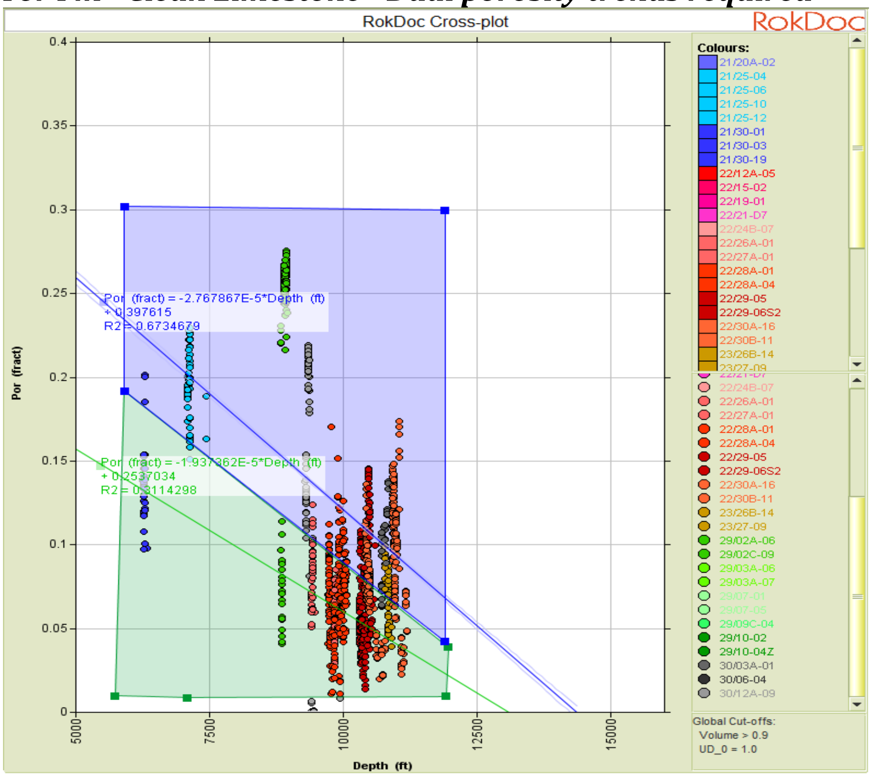


Figure 2.2.8 - PhiT-Depth(TVDml) cross-plot for clean limestone points in the Tor Fm

Hod Fm - Clean Limestone - Dual porosity trends required

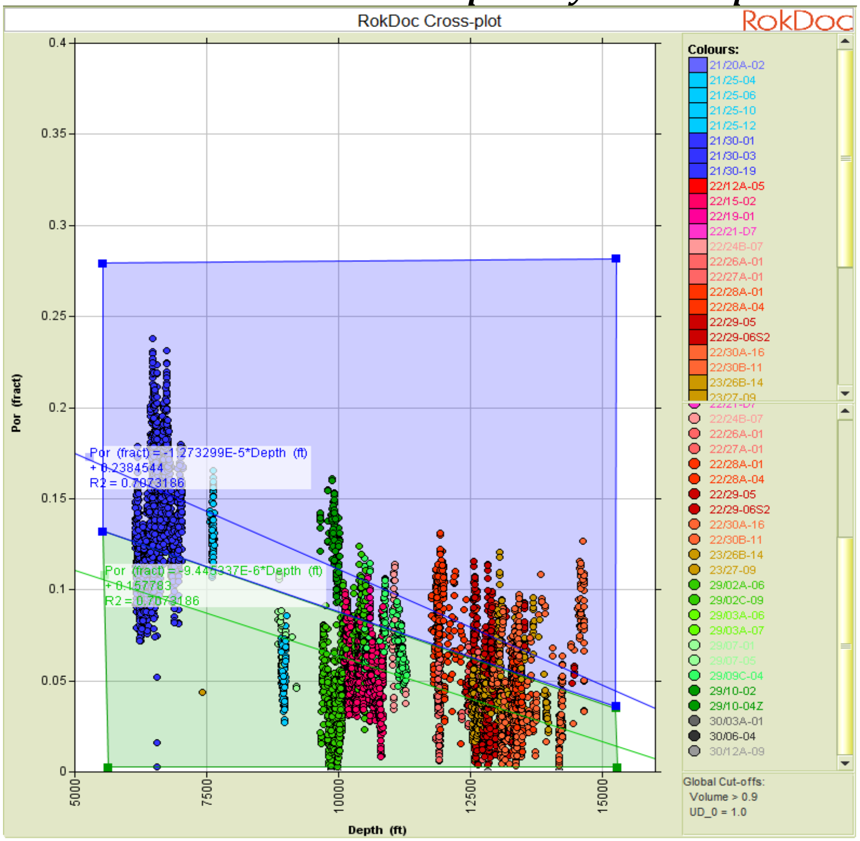


Figure 2.2.9 - PhiT-Depth(TVDml) cross-plot for clean limestone points in the Hod Fm

PhiT-Depth plots summary

The PhiT-Depth plots included in this section are the summary cross-plots for reservoir lithologies in each of the eight working intervals in the study. The derived trends are displayed on the plots and included in the appendix of the report.

These plots show that it was only data from the Horda Formation and Balder Formation that didn't require a dual porosity trend to model the sandstone points in this study whilst every other formation required dual porosity trends.

The polygons used to model the dual porosity trends are included on the cross-plots. For the clean sandstone points, the high porosity points were captured by the orange coloured polygon whilst the low porosity points were captured by the purple coloured polygon. For the clean limestone points, the high porosity points were captured by the blue coloured polygon whilst the low porosity points were captured by the green coloured polygon. These points highlighted by the polygons were used to represent the corresponding points on the Vp-Depth plots: the high porosity trend corresponds to the low Vp trend whilst the low porosity trend corresponds to the high Vp trend. The Vp-Depth plots are shown in the next section of the report.

Depth trend analysis: Vp-Depth plots - All plots coloured by well

Horda Fm - Clean Sandstone - Vp-Depth - Only one trend

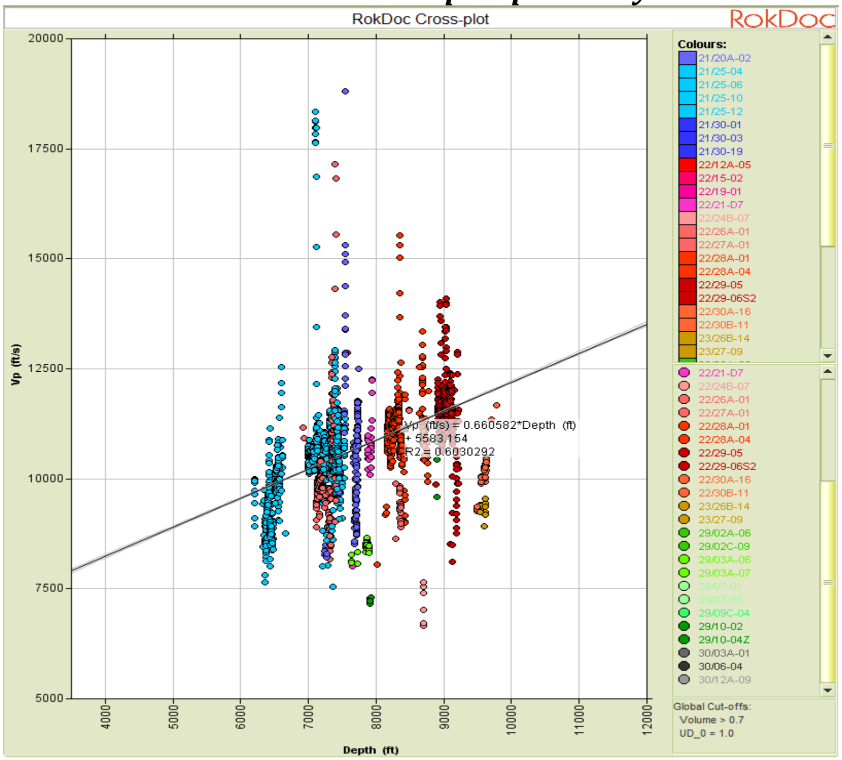


Figure 2.2.10 - Vp-Depth(TVDml) cross-plot for clean sandstone points in the Horda Fm

Horda Fm - Clean Shale - Vp-Depth - Hard and soft shale trends

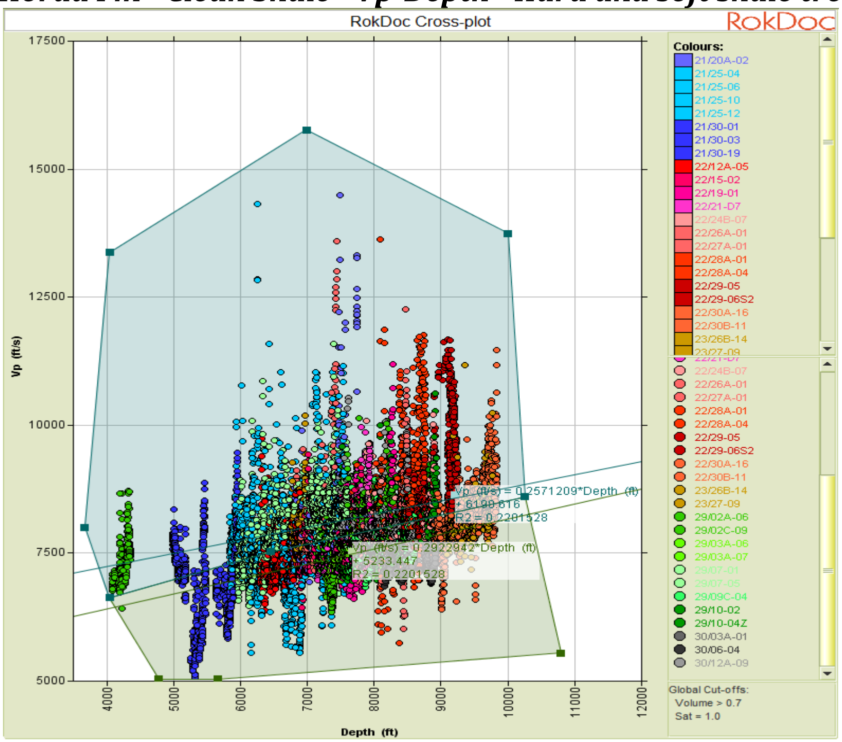


Figure 2.2.11 - Vp-Depth(TVDml) cross-plot for clean shale points in the Horda Fm

Balder Fm - Clean Sandstone - Vp-Depth - Only one trend

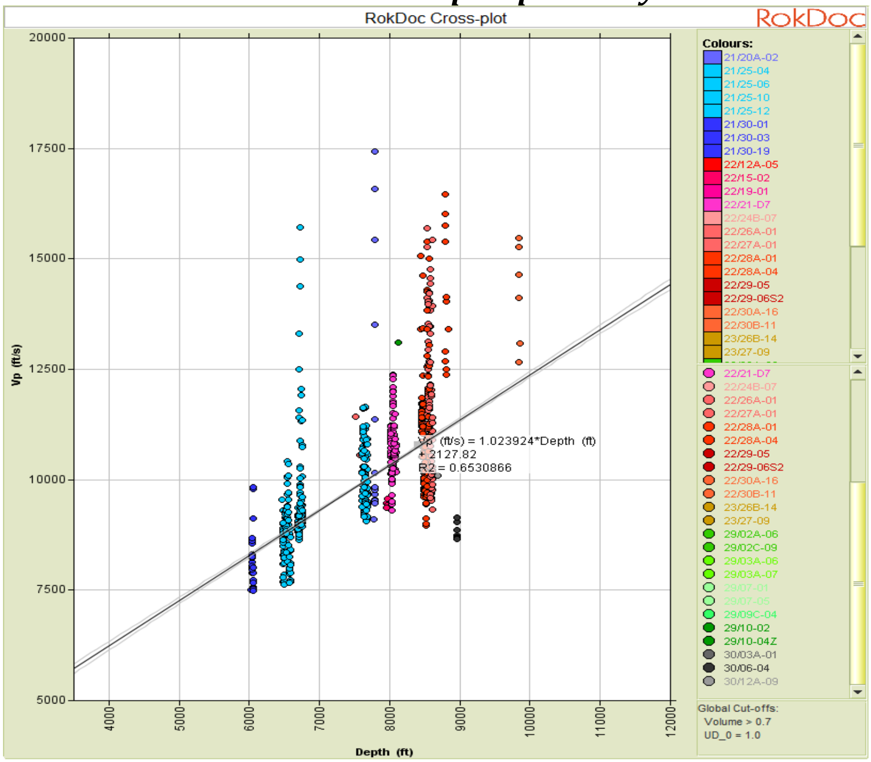


Figure 2.2.12 - Vp-Depth(TVDml) cross-plot for clean sandstone points in the Balder Fm

Balder Fm - Clean Shale - Vp-Depth - Only one trend

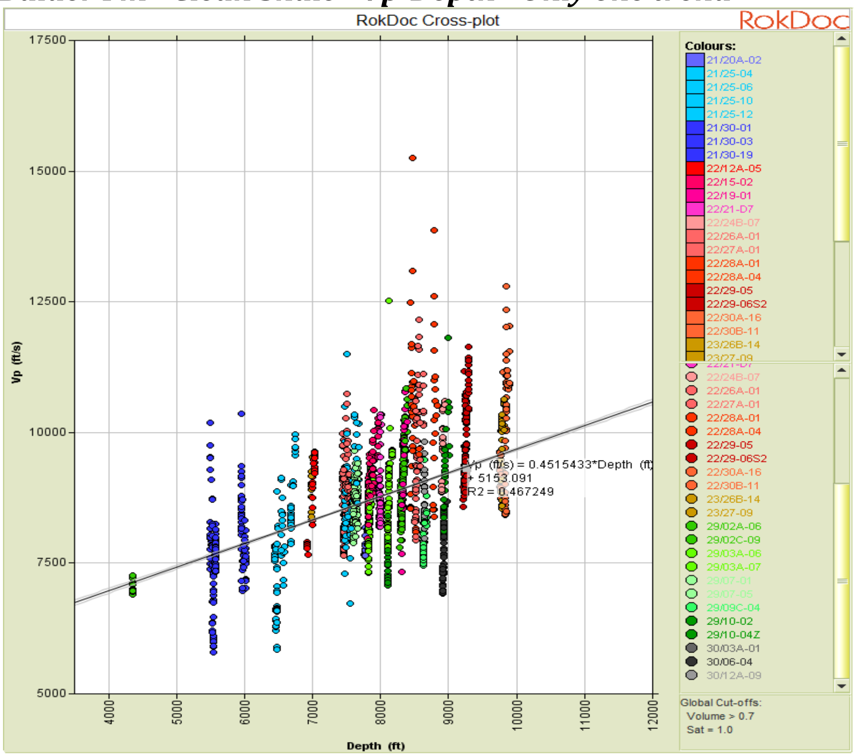


Figure 2.2.13 - Vp-Depth(TVDml) cross-plot for clean shale points in the Balder Fm

Balder Fm - Clean Tuff - Vp-Depth - Only one trend

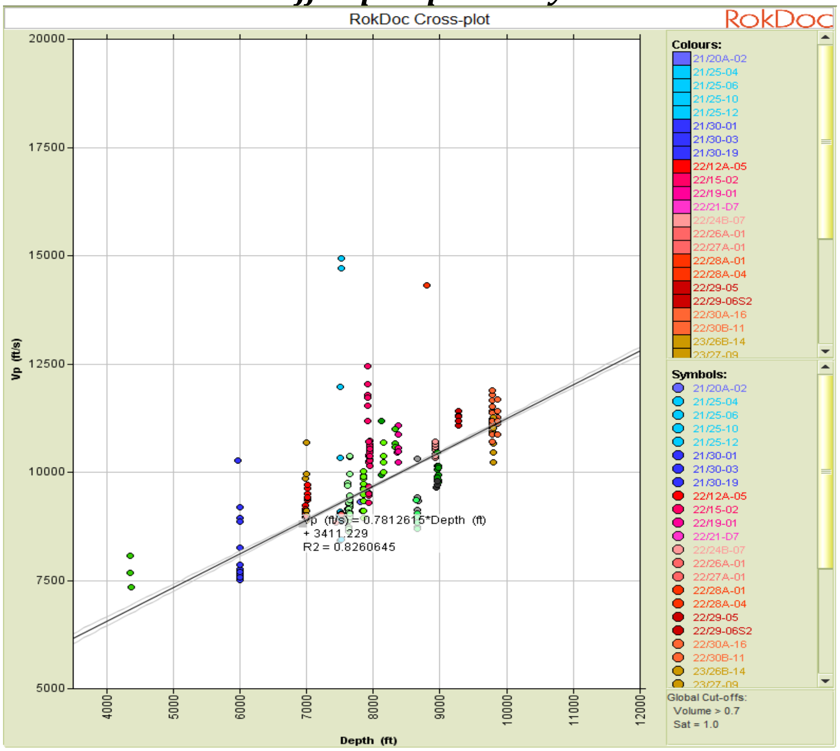


Figure 2.2.14 - Vp-Depth(TVDml) cross-plot for clean tuff points in the Balder Fm

Sele Fm - Clean Sandstone - Vp-Depth - Two porosity trends (PhiT-Depth based)

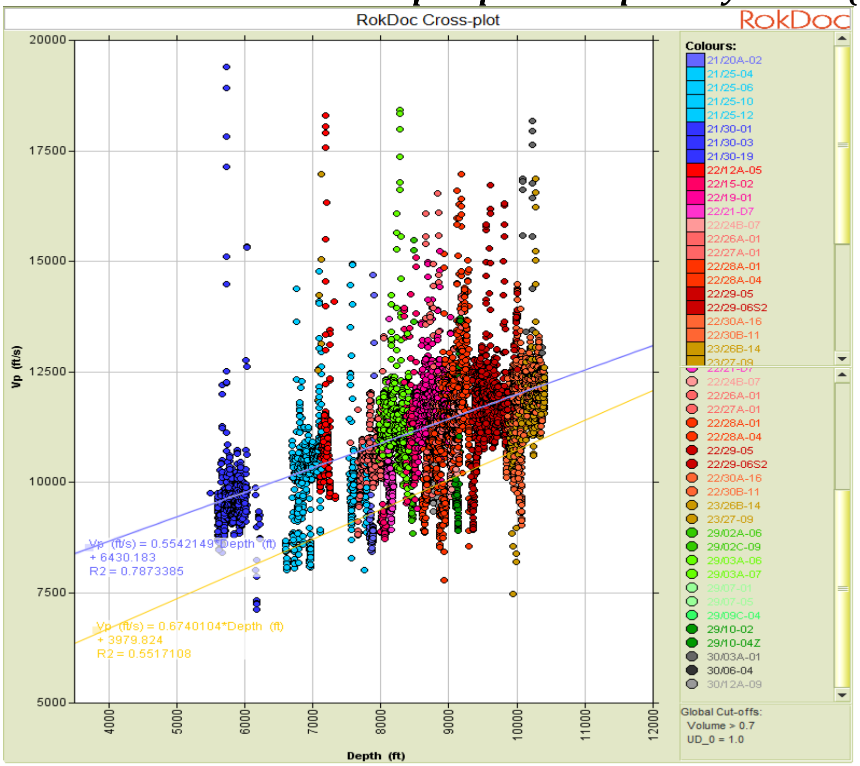


Figure 2.2.15 - Vp-Depth(TVDml) cross-plot for clean sandstone points in the Sele Fm

Sele Fm - Clean Shale - Vp-Depth - Hard and soft shale trends

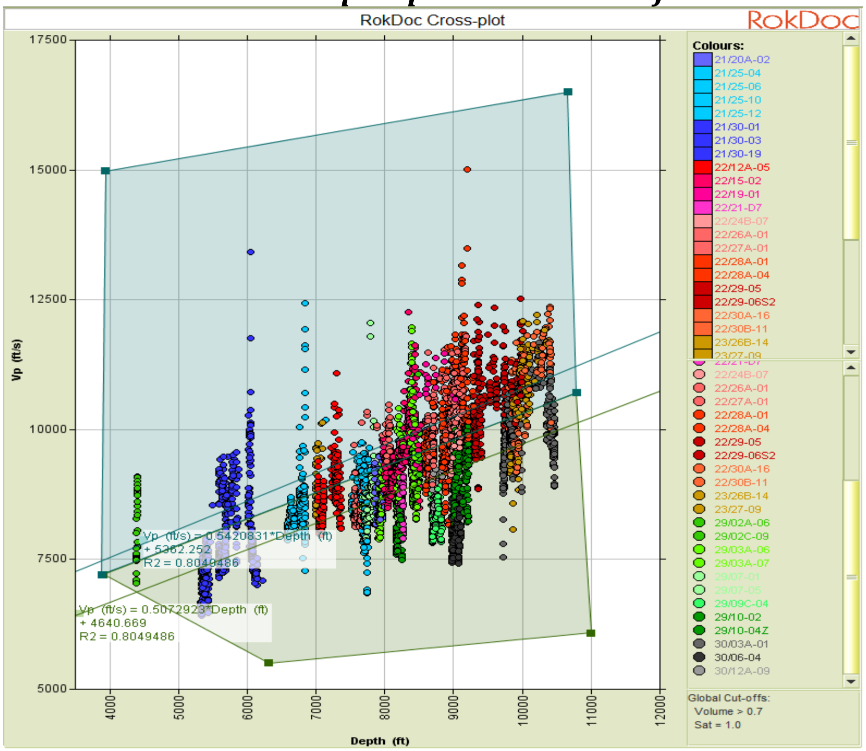


Figure 2.2.16 - Vp-Depth(TVDml) cross-plot for clean shale points in the Sele Fm

Lista Fm - Clean Sandstone - Vp-Depth - Two porosity trends (PhiT-Depth based)

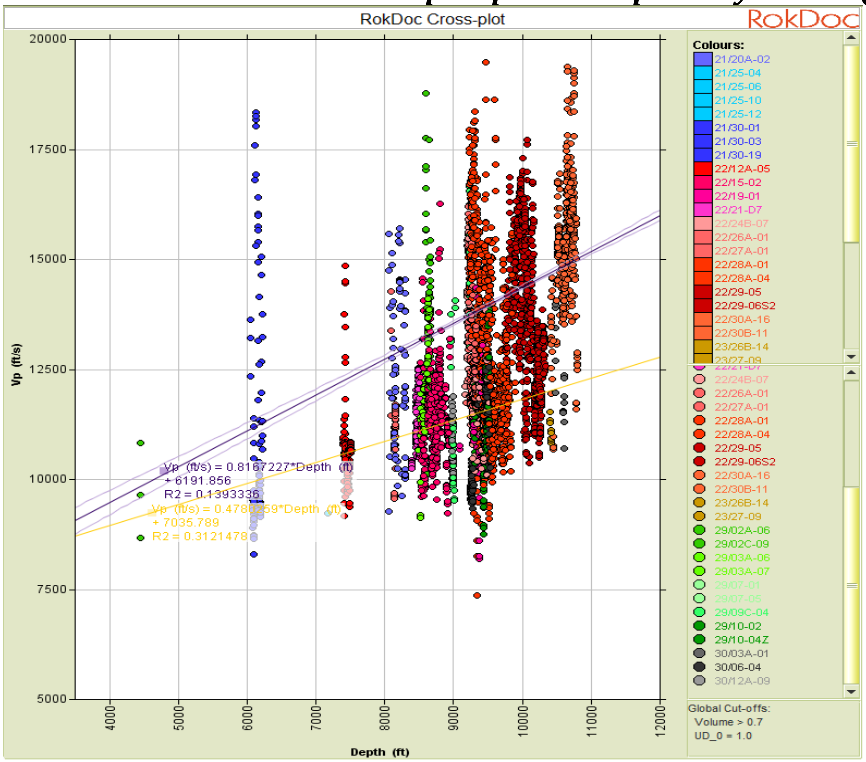


Figure 2.2.17 - Vp-Depth(TVDml) cross-plot for clean sandstone points in the Lista Fm

Lista Fm - Clean Shale - Vp-Depth - Hard and soft shale trends

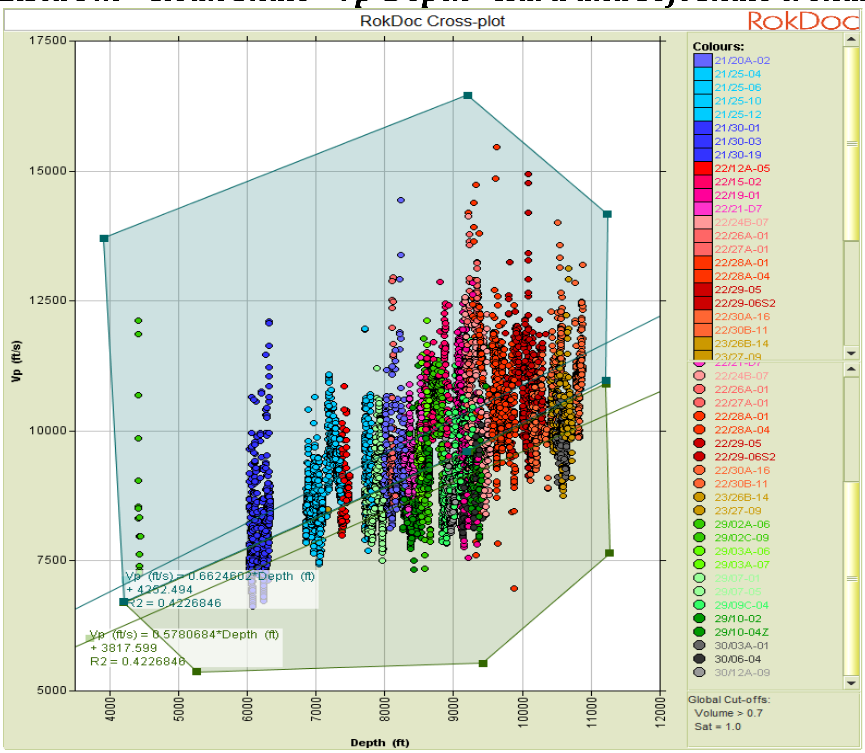


Figure 2.2.18 - Vp-Depth(TVDml) cross-plot for clean shale points in the Lista Fm

Maureen Fm - Clean Sandstone - Vp-Depth - Two porosity trends (PhiT-Depth based)

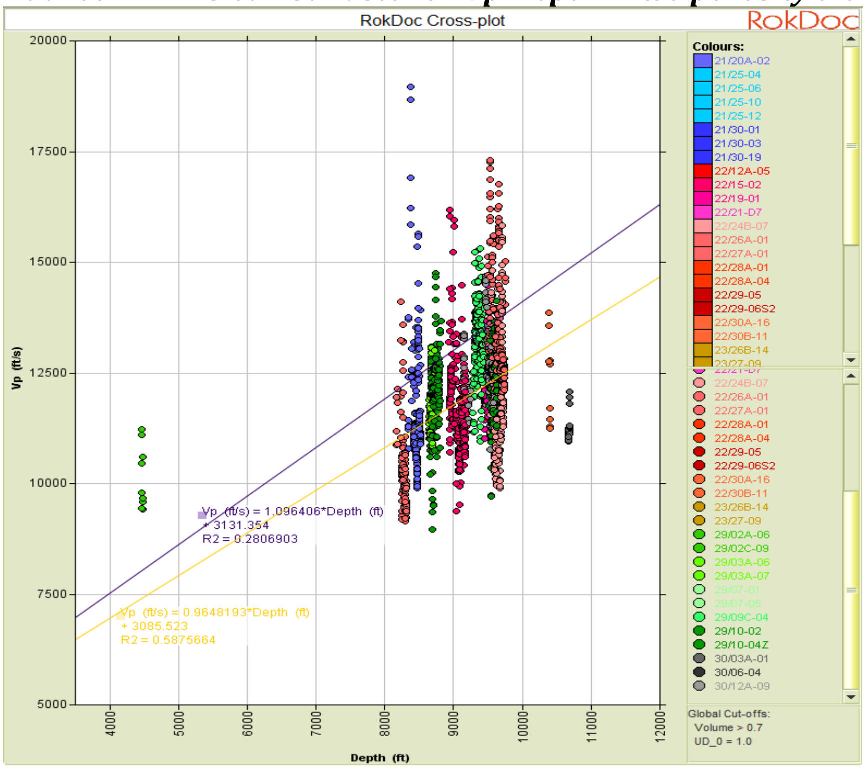


Figure 2.2.19 - Vp-Depth(TVDml) cross-plot for clean sandstone points in the Maureen Fm

Maureen Fm - Clean Shale - Vp-Depth - Hard and soft shale trends required

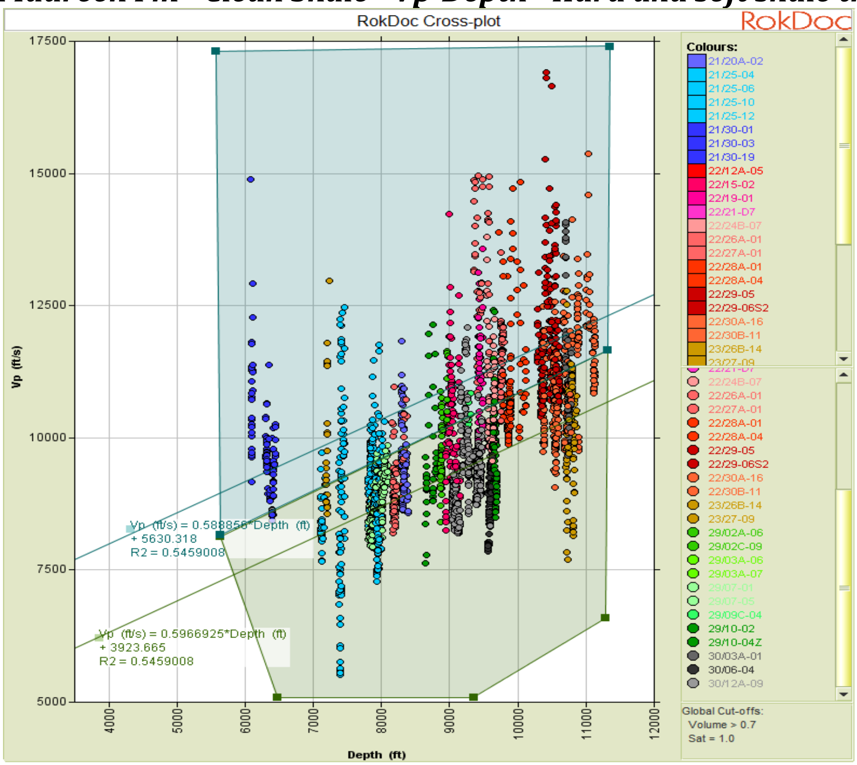


Figure 2.2.20 - Vp-Depth(TVDml) cross-plot for clean shale points in the Maureen Fm

Maureen Fm - Clean Limestone - Vp-Depth - Two porosity trends (PhiT-Depth based)

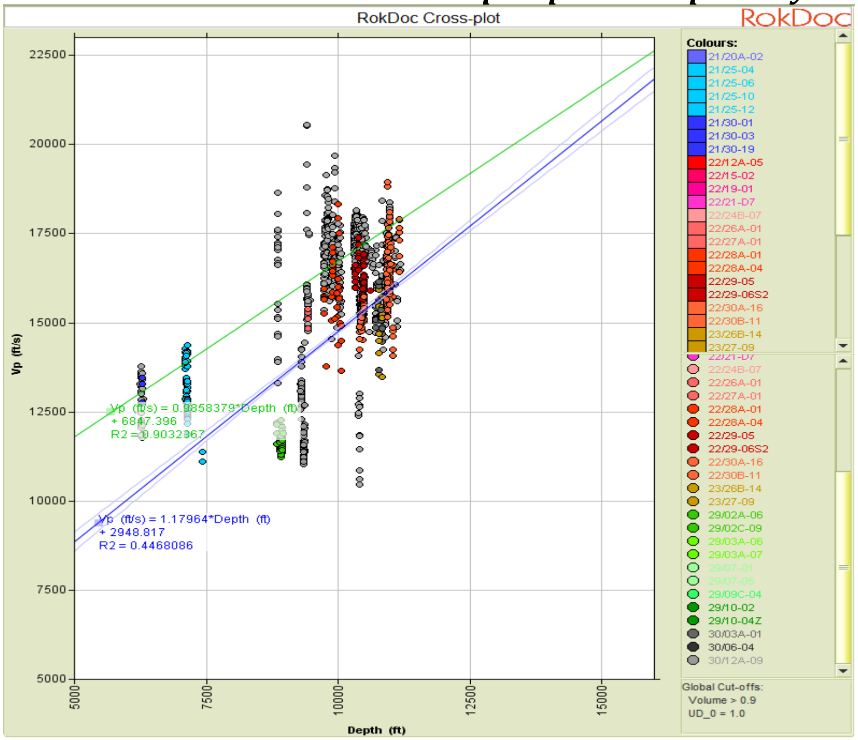


Figure 2.2.21 - Vp-Depth(TVDml) cross-plot for clean limestone points in the Maureen Fm

Ekofisk Fm - Clean Limestone - Vp-Depth – Two porosity trends (PhiT-Depth based)

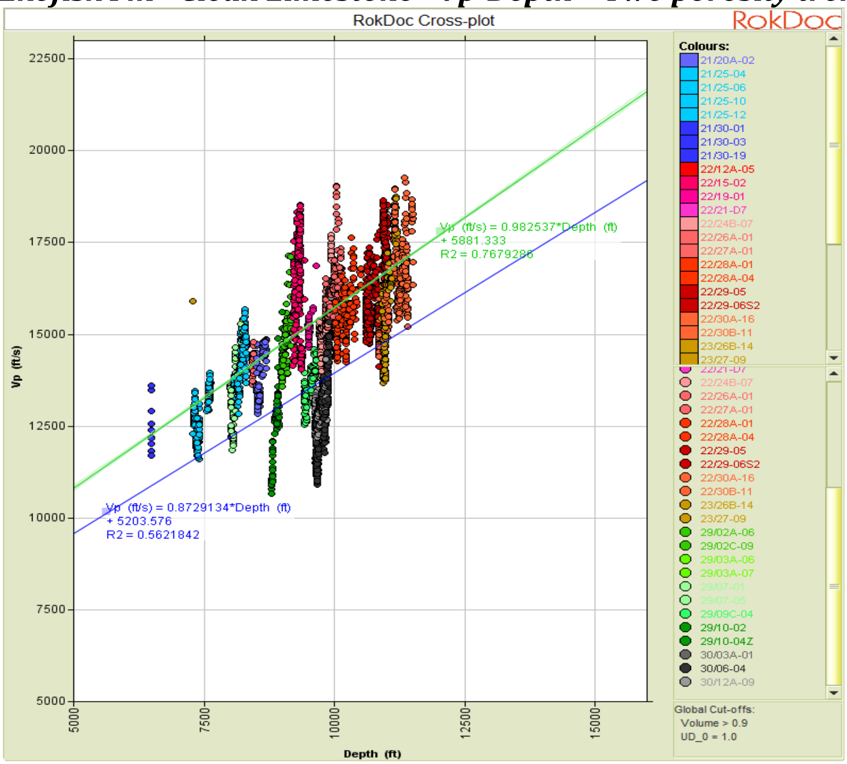


Figure 2.2.22 - Vp-Depth(TVDml) cross-plot for clean limestone points in the Ekofisk Fm

Tor Fm - Clean Limestone - Vp-Depth - Two porosity trends (PhiT-Depth based)

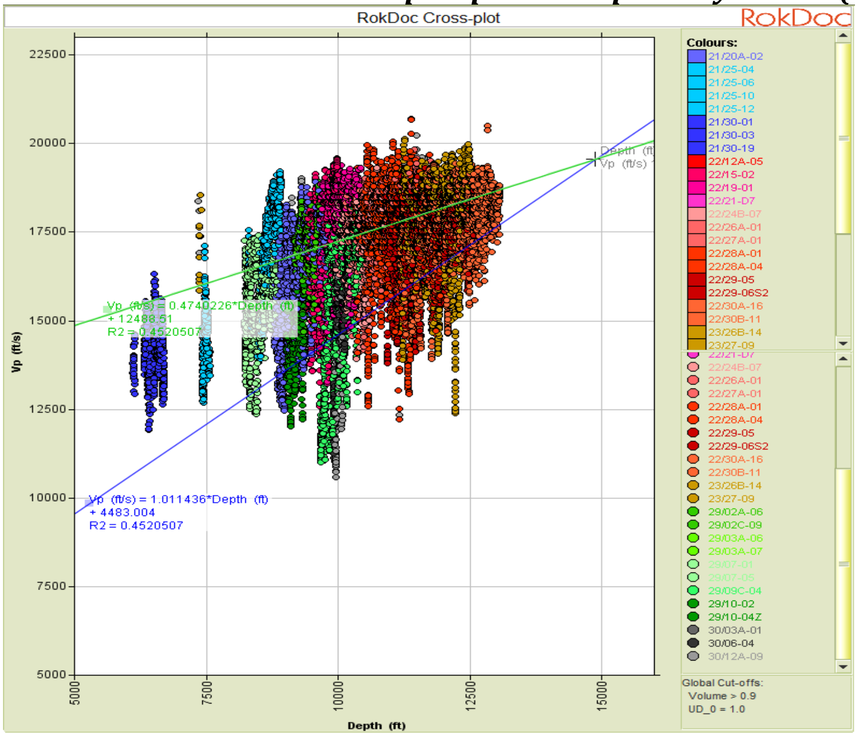


Figure 2.2.23 - Vp-Depth(TVDml) cross-plot for clean limestone points in the Tor Fm

Hod Fm - Clean Limestone - Vp-Depth - Two porosity trends (PhiT-Depth based)

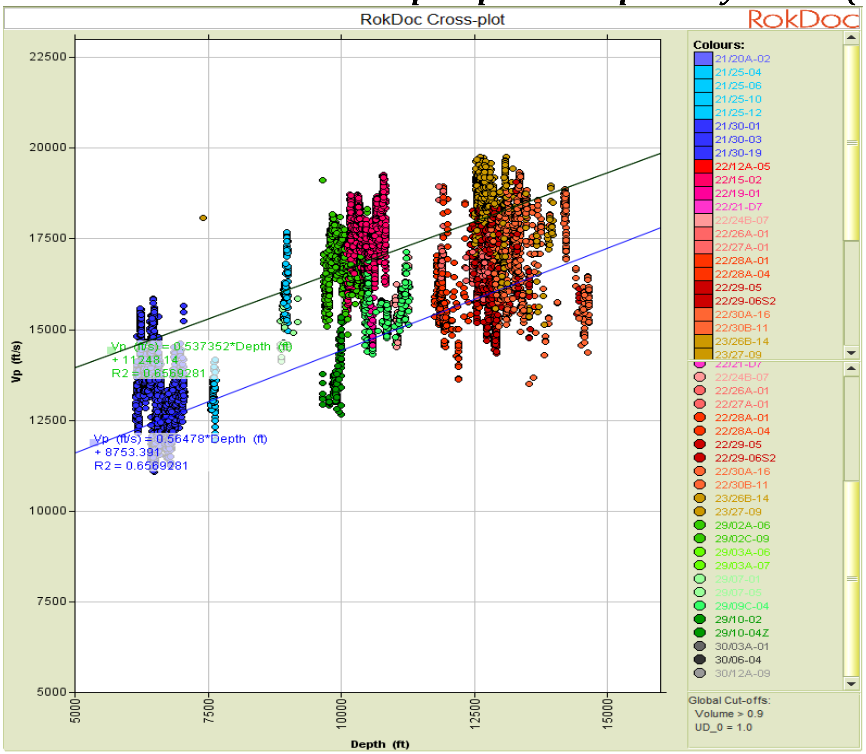


Figure 2.2.24 - Vp-Depth(TVDml) cross-plot for clean limestone points in the Hod Fm

Vp-Depth plots summary

The Vp-Depth plots included in this section are the summary cross-plots for reservoir and non-reservoir lithologies in each of the eight working intervals in the study. The derived trends are displayed on the plots and included in the appendix of the report.

These plots show that four of the five intervals containing shale required hard and soft shale trends to model the data.

The polygons used to model the hard and soft shale trends are included on the cross-plots. For the clean shale points, the hard shale points were captured by the turquoise coloured polygon whilst the soft shale points were captured by the brown coloured polygon.

The Rhob-Vp plots are shown in the next section of the report. Only one trend was derived for these rock physics relationships.

Multi-well rock physics analysis: Rhob-Vp plots - All plots coloured by well

Horda Fm - Clean Sandstone - Rhob-Vp - Power law fit (black line)

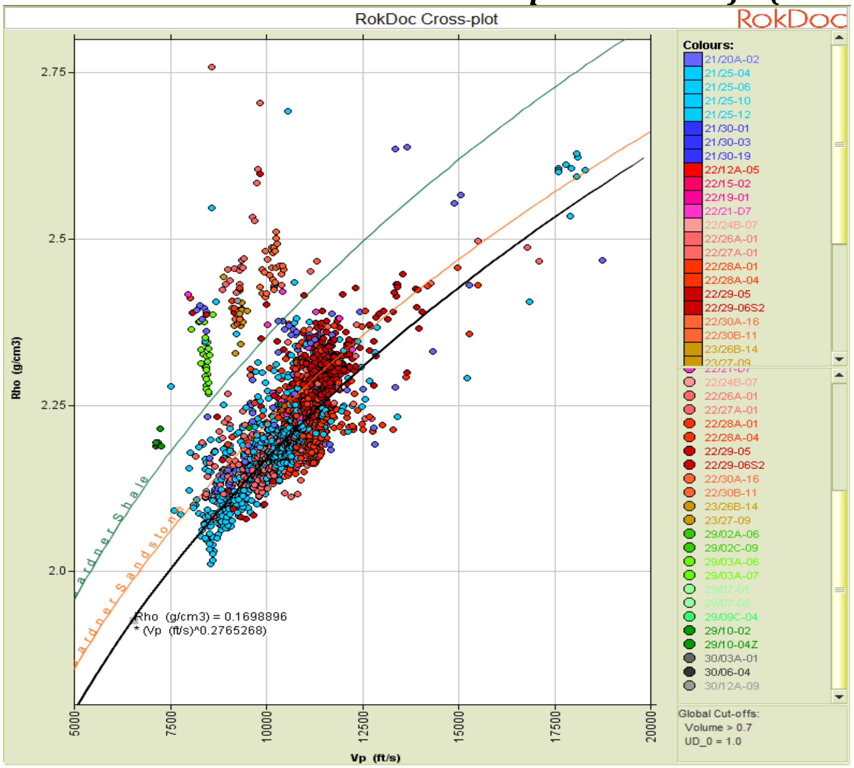


Figure 2.2.25 - Rhob-Vp cross-plot for clean sandstone points in the Horda Fm

Horda Fm - Clean Shale - Rhob-Vp - Power law fit (black line)

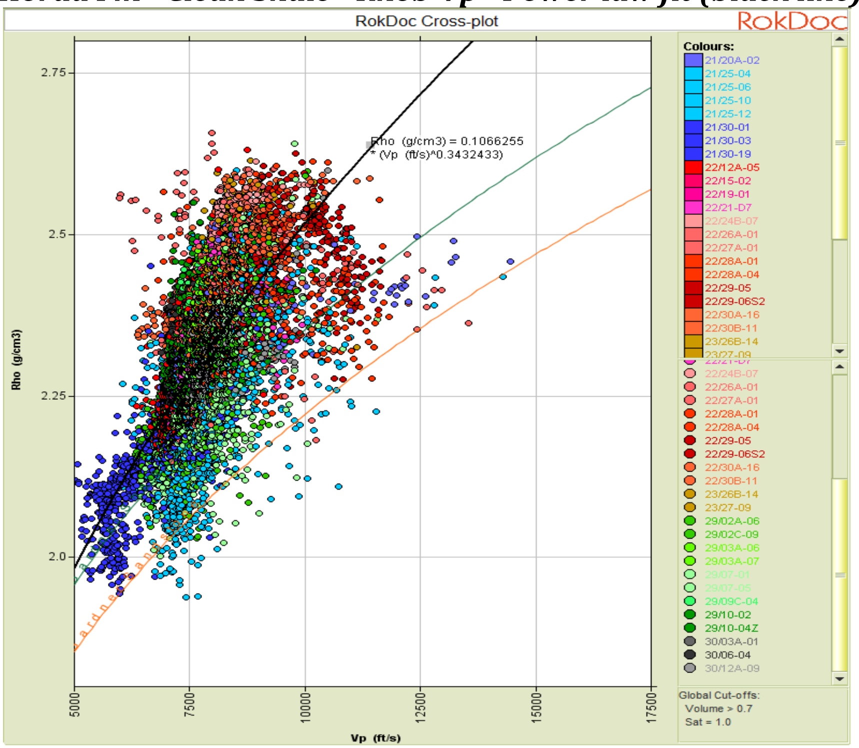


Figure 2.2.26 - Rhob-Vp cross-plot for clean shale points in the Horda Fm

Balder Fm - Clean Sandstone - Rhob-Vp - Power law fit (black line)

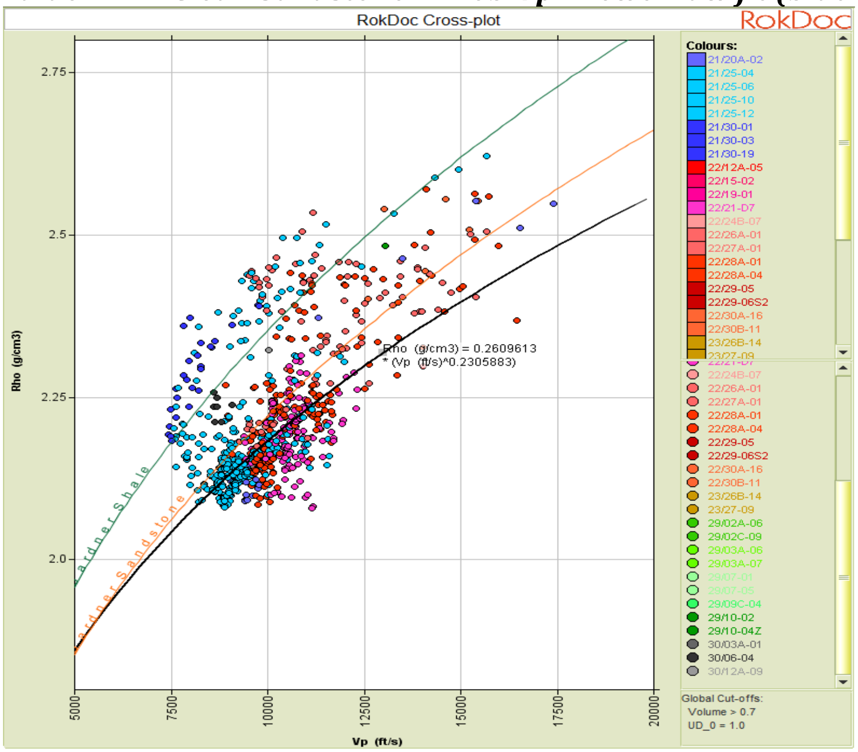


Figure 2.2.27 - Rhob-Vp cross-plot for clean sandstone points in the Balder Fm

Balder Fm - Clean Shale - Rhob-Vp - Power law fit (black line)

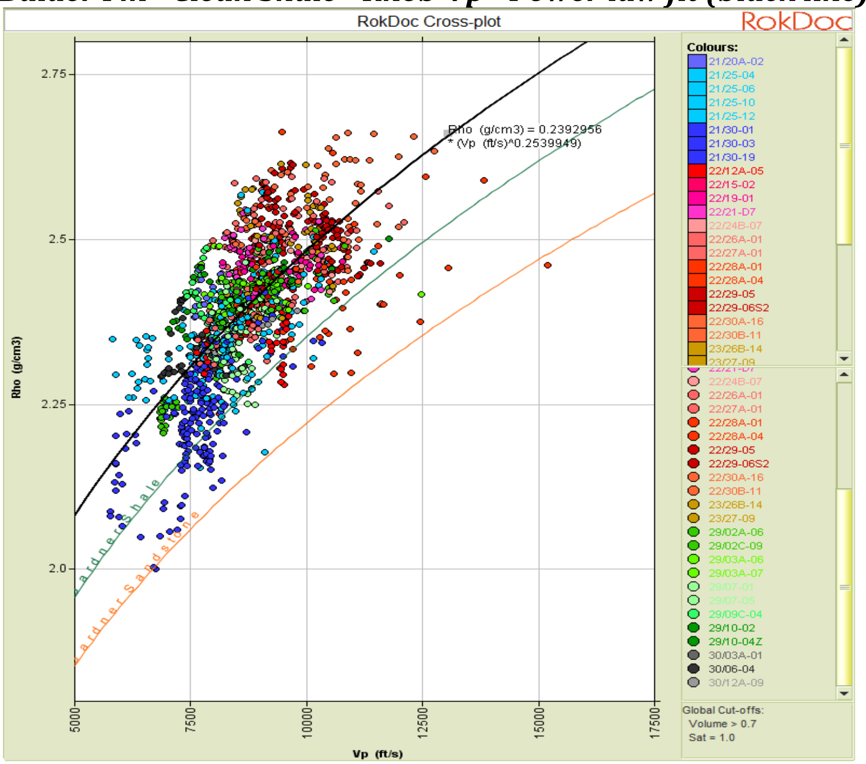


Figure 2.2.28 - Rhob-Vp cross-plot for clean shale points in the Balder Fm

Balder Fm - Clean Tuff - Rhob-Vp - Logarithmic fit (red line)

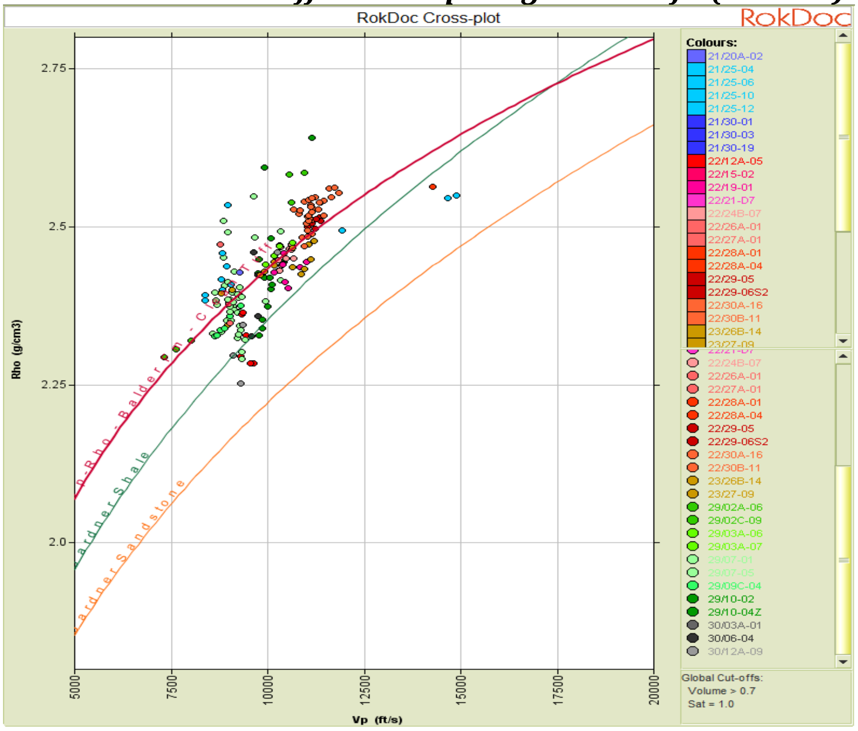


Figure 2.2.29 - Rhob-Vp cross-plot for clean tuff points in the Balder Fm

Sele Fm - Clean Sandstone - Rhob-Vp - Power law fit (black line)

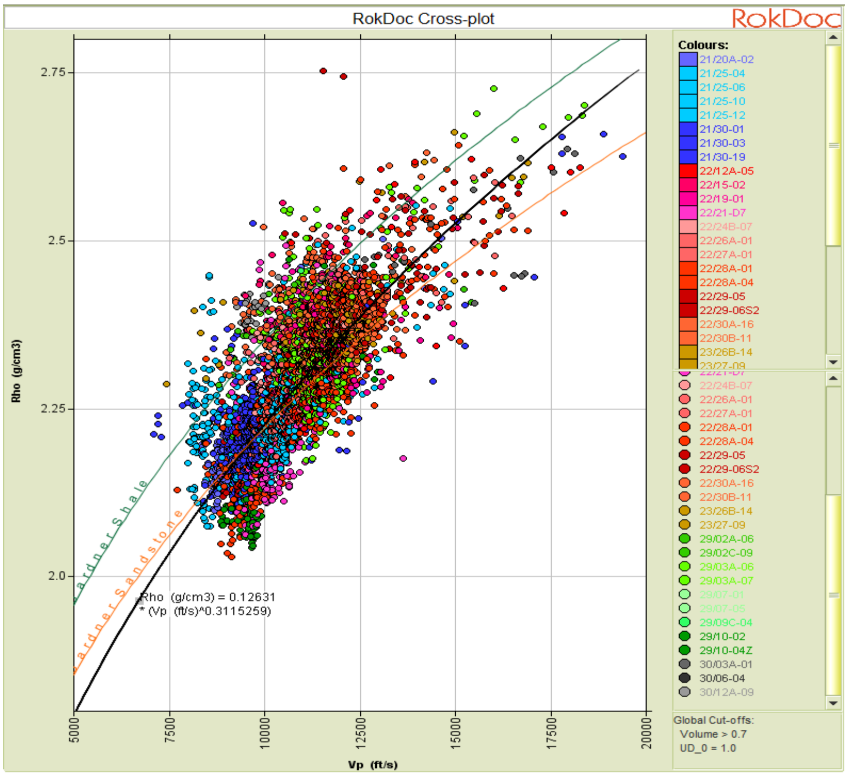


Figure 2.2.30 - Rhob-Vp cross-plot for clean sandstone points in the Sele Fm

Sele Fm - Clean Shale - Rhob-Vp - Power law fit (black line)

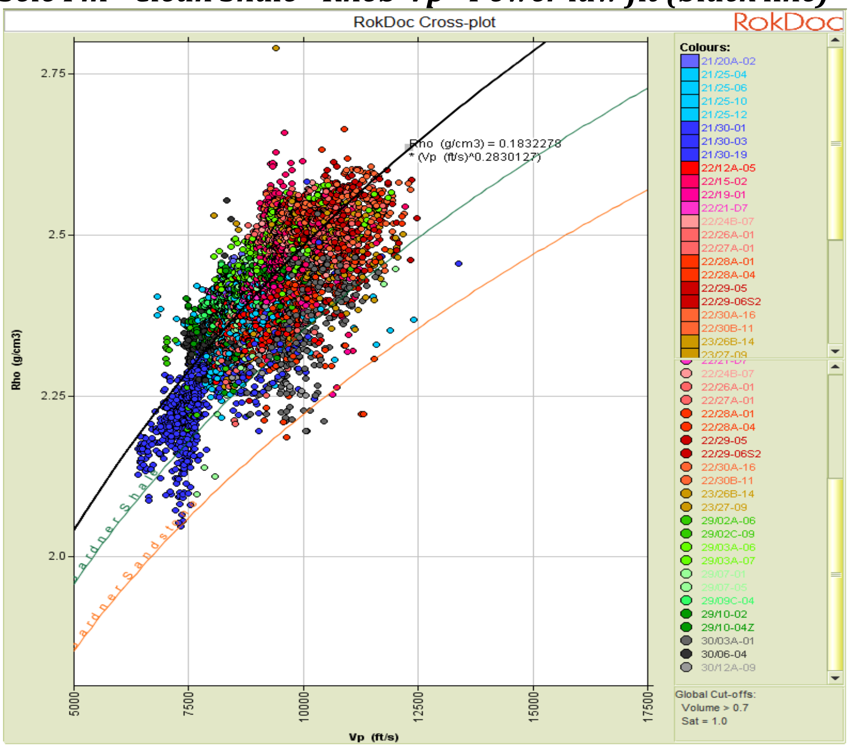


Figure 2.2.31 - Rhob-Vp cross-plot for clean shale points in the Sele Fm

Lista Fm - Clean Sandstone - Rhob-Vp - Power law fit (black line)

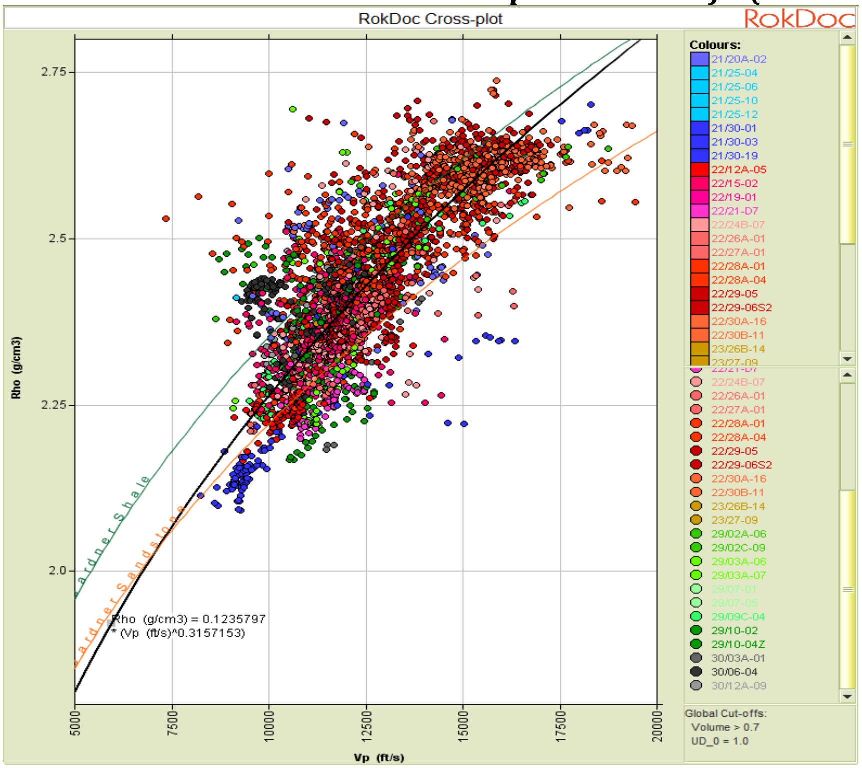


Figure 2.2.32 - Rhob-Vp cross-plot for clean sandstone points in the Lista Fm

Lista Fm - Clean Shale - Rhob-Vp - Power law fit (black line)

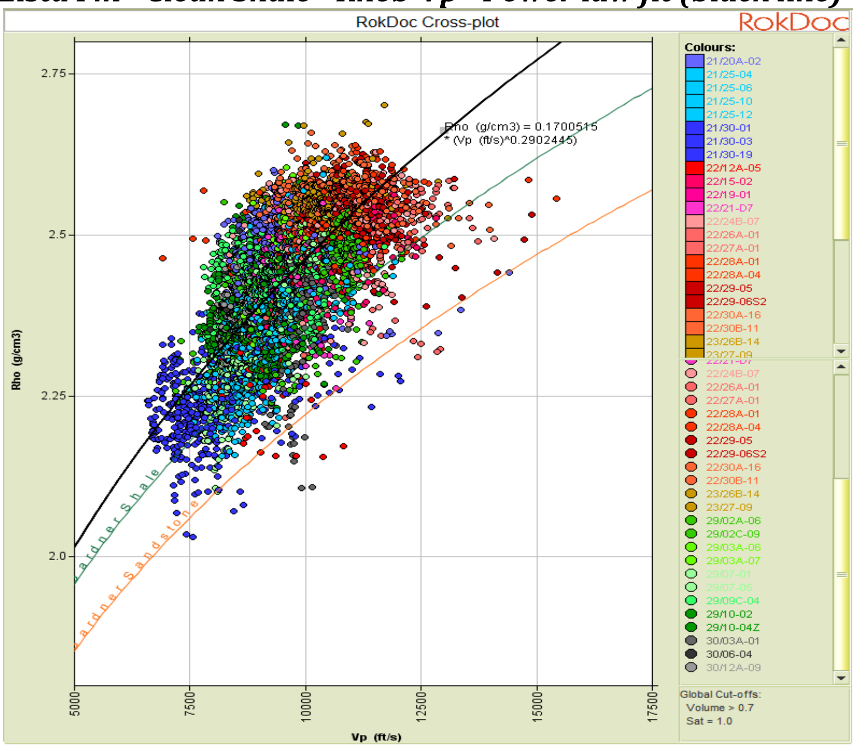


Figure 2.2.33 - Rhob-Vp cross-plot for clean shale points in the Lista Fm

Maureen Fm - Clean Sandstone - Rhob-Vp - Power law fit (black line)

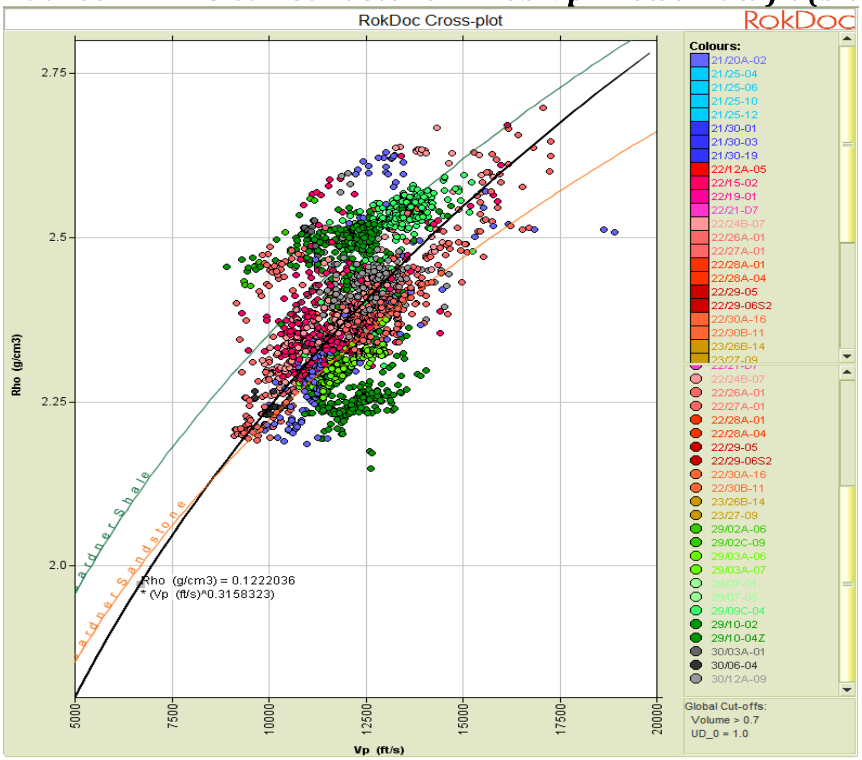


Figure 2.2.34 - Rhob-Vp cross-plot for clean sandstone points in the Maureen Fm

Maureen Fm - Clean Shale - Rhob-Vp - Power law fit (black line)

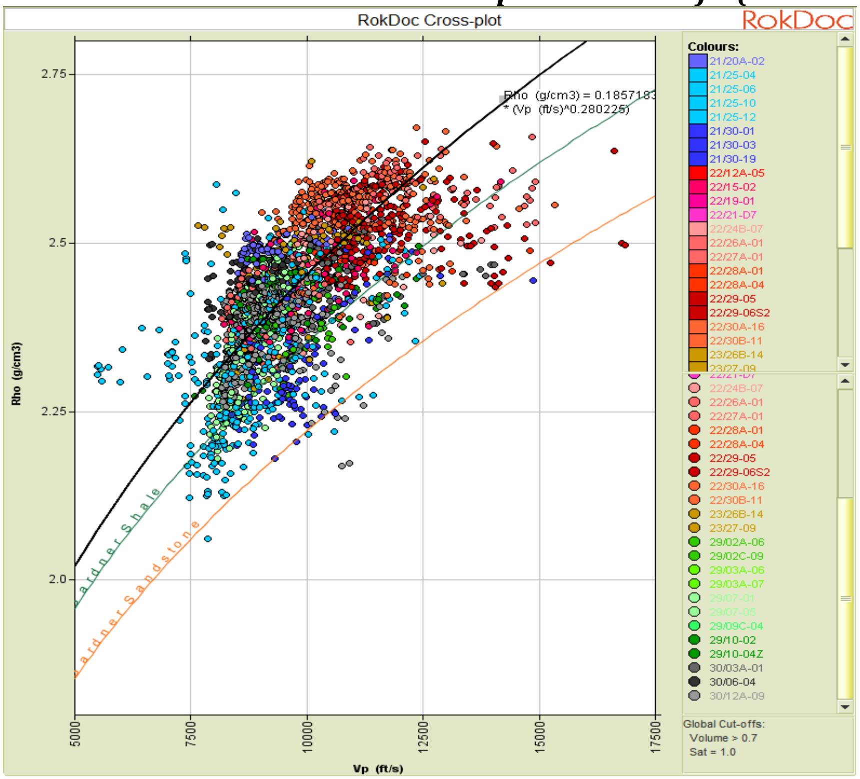


Figure 2.2.35 - Rhob-Vp cross-plot for clean shale points in the Maureen Fm

Maureen Fm - Clean Limestone - Rhob-Vp - Logarithmic fit (grey line)

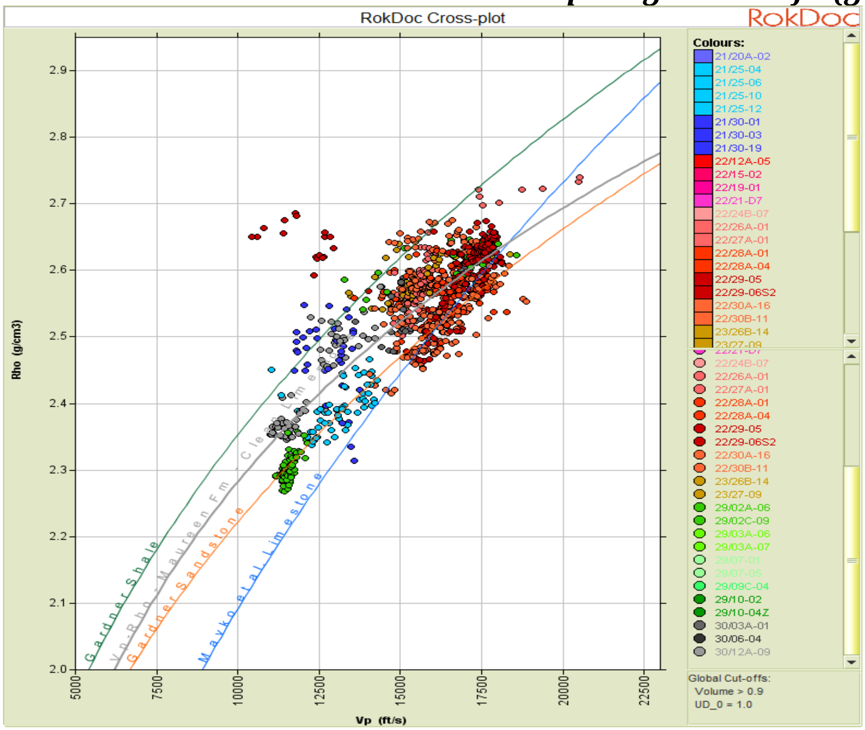


Figure 2.2.36 - Rhob-Vp cross-plot for clean limestone points in the Maureen Fm

Ekofisk Fm - Clean Limestone - Rhob-Vp - Logarithmic fit (grey line)

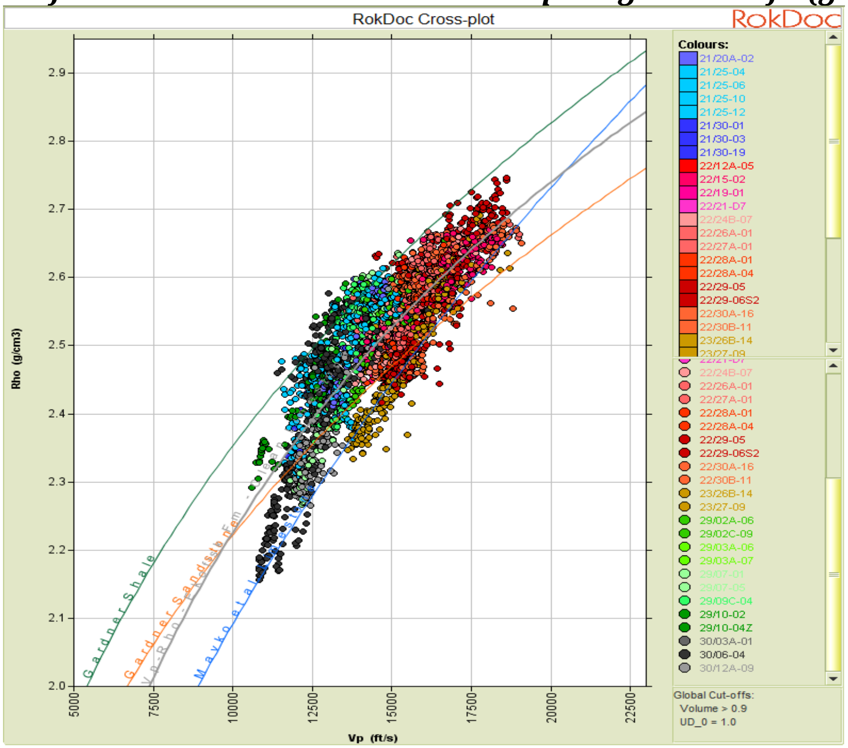


Figure 2.2.37 - Rhob-Vp cross-plot for clean limestone points in the Ekofisk Fm

Tor Fm - Clean Limestone - Rhob-Vp - Logarithmic fit (grey line)

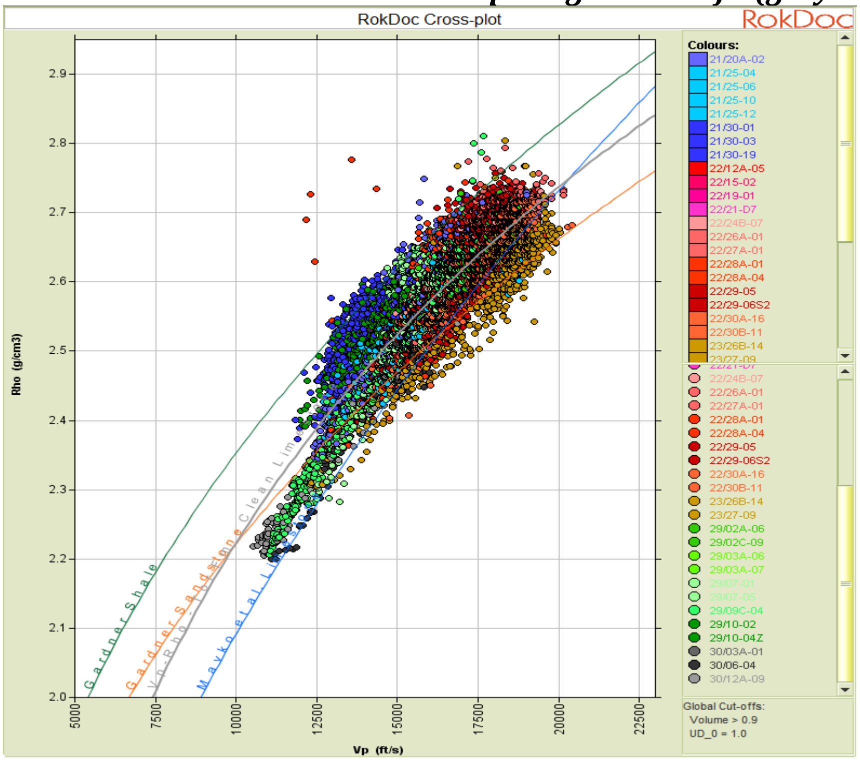


Figure 2.2.38 - Rhob-Vp cross-plot for clean limestone points in the Tor Fm

Hod Fm - Clean Limestone - Rhob-Vp - Logarithmic fit (grey line)

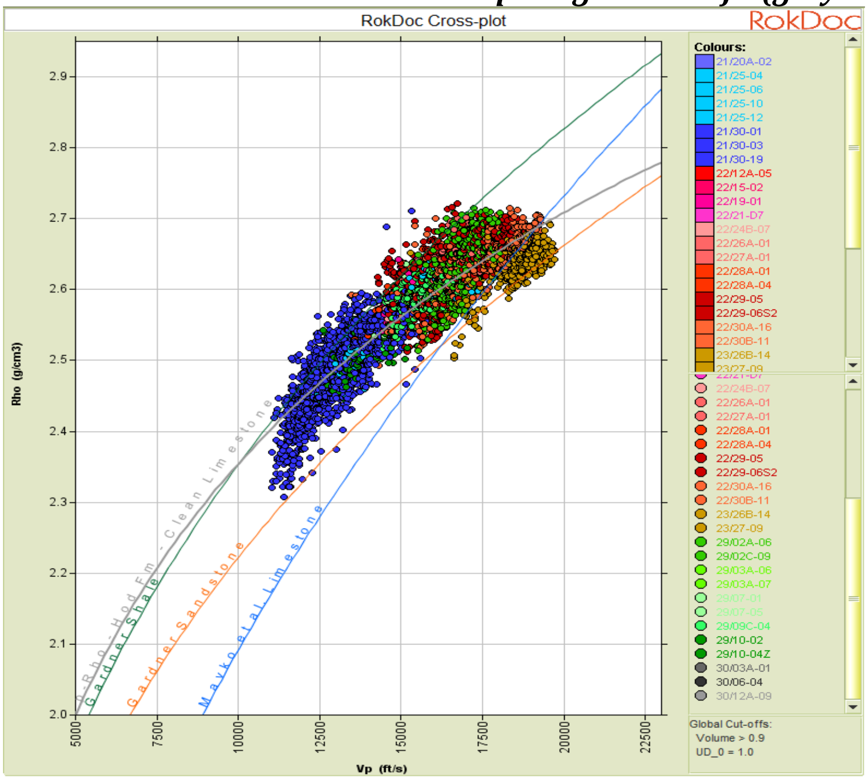


Figure 2.2.39 - Rhob-Vp cross-plot for clean limestone points in the Hod Fm

Rhob-Vp plots summary

The Rhob-Vp plots included in this section are the summary cross-plots for reservoir and non-reservoir lithologies in each of the eight working intervals in the study. The derived trends are displayed on the plots and included in the appendix of the report.

These plots show a single trend was valid to model the Rhob-Vp relationship in each formation in this section of the Central North Sea.

It is clear that in some cases the fitted trends show a consistent over estimation of the predicted Rhob for very low Vp / Rhob (High PhiT) points. In case where this is of particular interest, a specific, possibly non-smooth sub-trend for these high PhiT intervals is advised to improve the predictability.

The Vs-Vp plots are shown in the next section of the report. There were only twelve wells with measured Vs data so there are less data points in the plots than all of the other cross-plots. Only one trend was derived for these rock physics relationships except for the clean sandstone in the Lista Fm and Maureen Fm where a linear and non-linear trend were derived in order to take into account the sometimes calcitic nature of these sandstone points.

Multi-well rock physics analysis: Vs-Vp plots - All plots coloured by well

Horda Fm - Clean Sandstone - Vs-Vp - Robust Walden regression (black line)

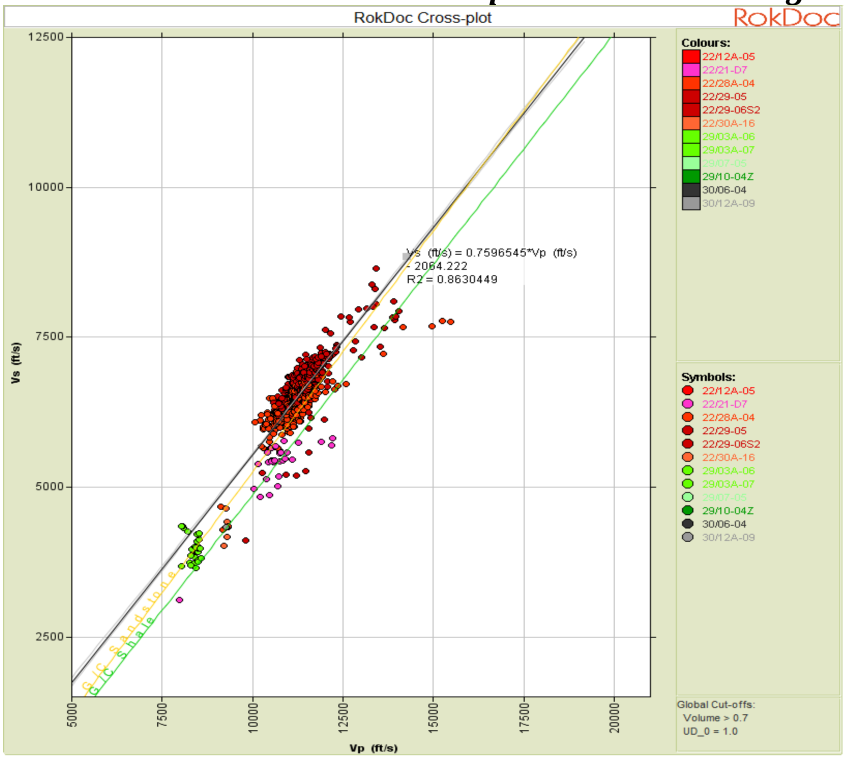


Figure 2.2.40 - Vs-Vp cross-plot for clean sandstone points in the Horda Fm

Horda Fm - Clean Shale - Vs-Vp - Robust Walden regression (black line)

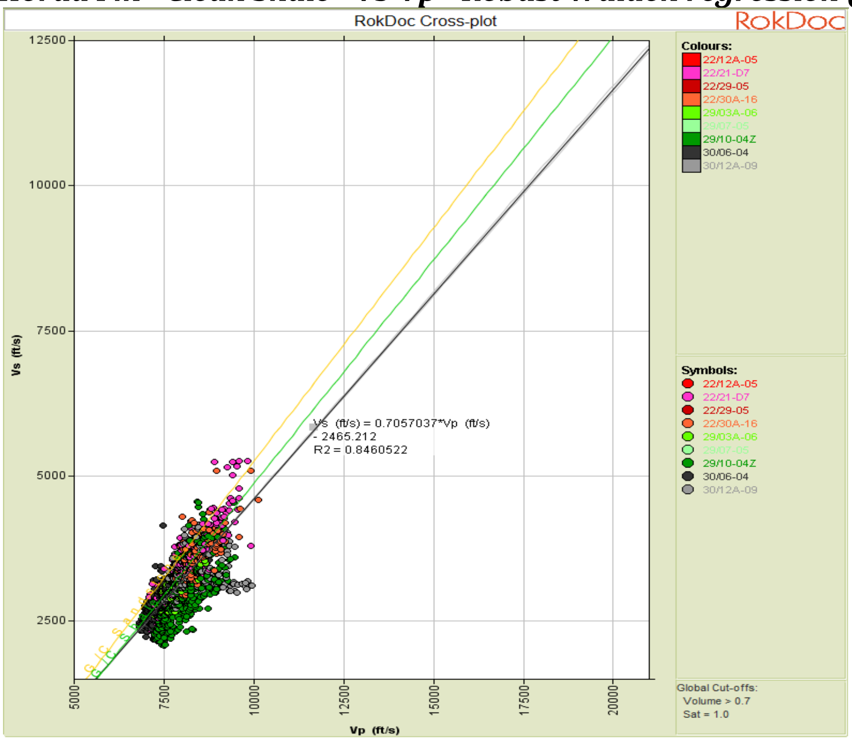


Figure 2.2.41 - Vs-Vp cross-plot for clean shale points in the Horda Fm

Balder Fm - Clean Sandstone - Vs-Vp - Robust Walden regression (black line)

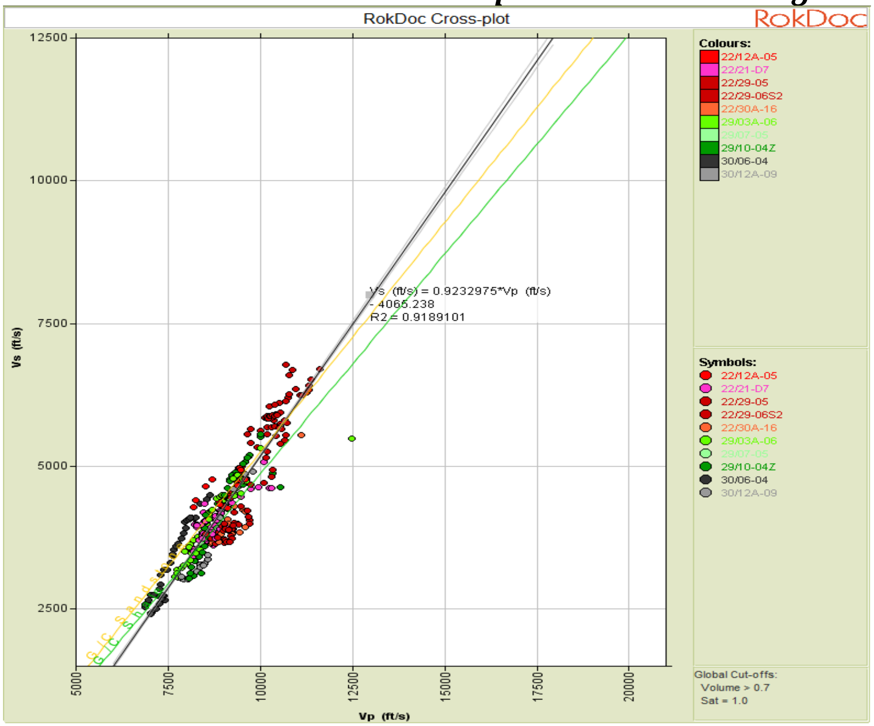


Figure 2.2.42 - Vs-Vp cross-plot for clean sandstone points in the Balder Fm

Balder Fm - Clean Shale - Vs-Vp - Greenberg-Castagna sand line

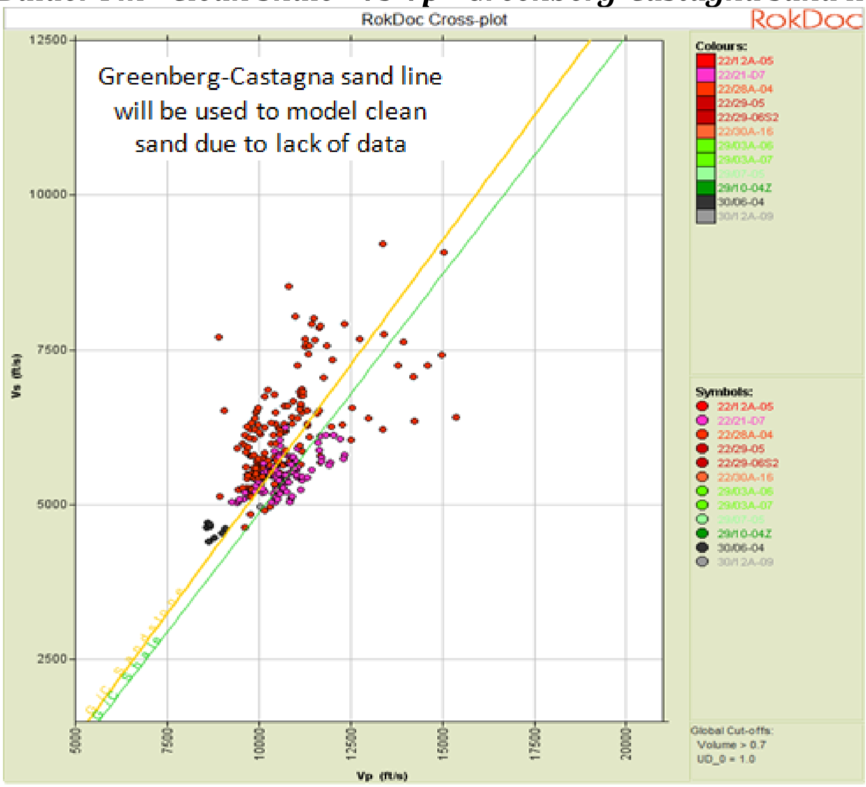


Figure 2.2.43 - Vs-Vp cross-plot for clean shale points in the Balder Fm

Balder Fm - Clean Tuff - Vs-Vp - Robust Walden regression (black line)

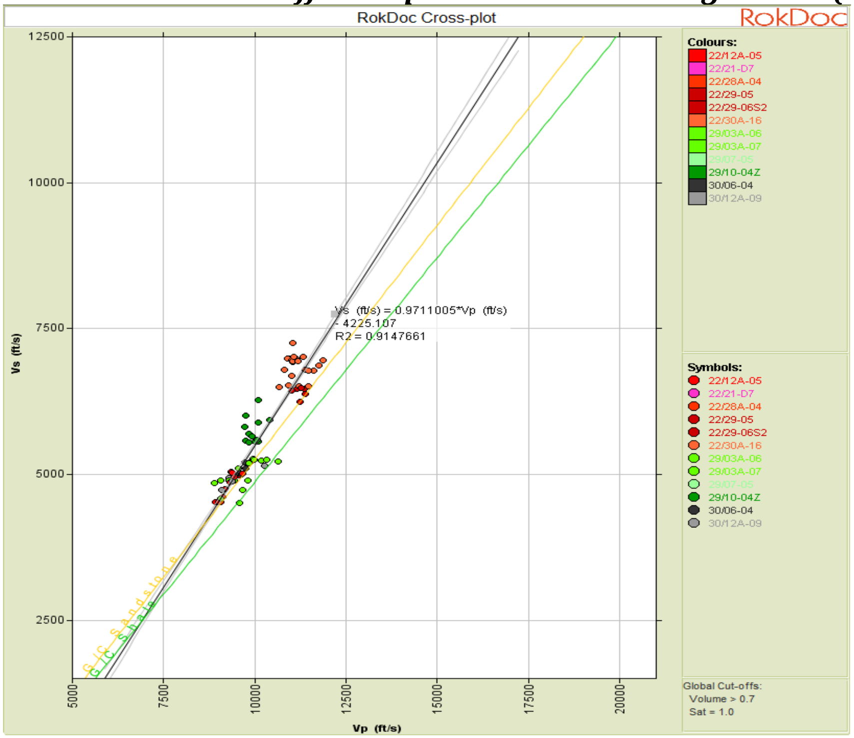


Figure 2.2.44 - Vs-Vp cross-plot for clean tuff points in the Balder Fm

Sele Fm - Clean Sandstone - Vs-Vp - Robust Walden regression (black line)

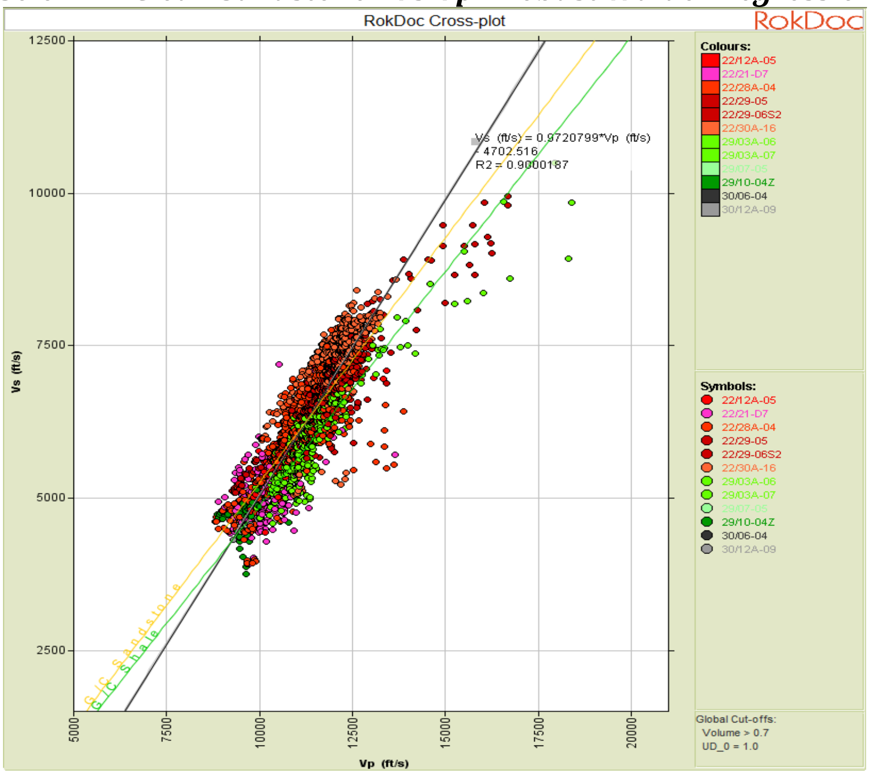


Figure 2.2.45 - Vs-Vp cross-plot for clean sandstone points in the Sele Fm

Sele Fm - Clean Shale - Vs-Vp - Robust Walden regression (black line)

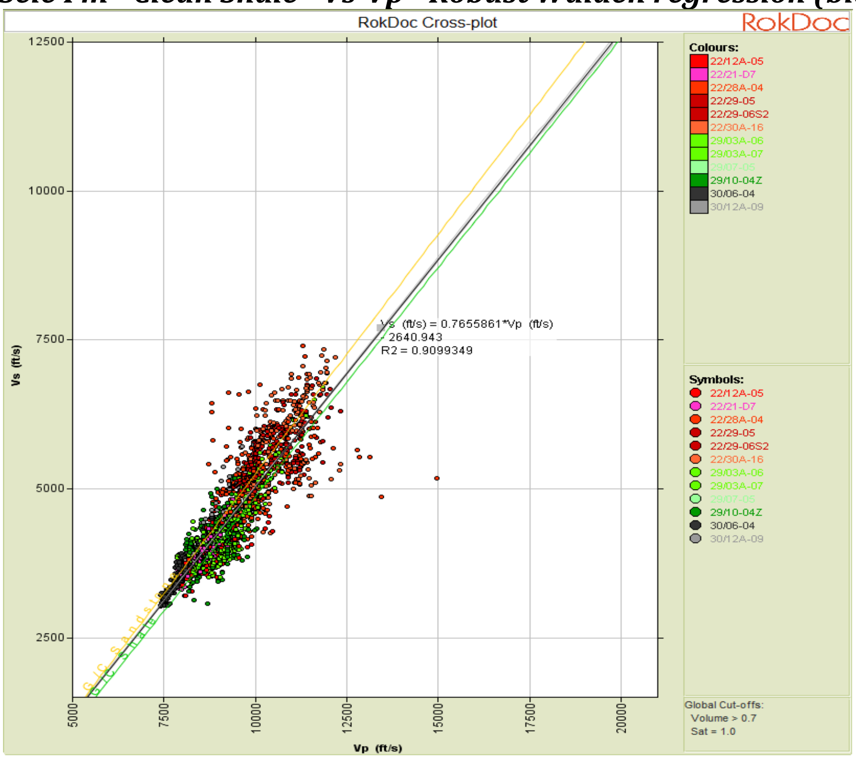


Figure 2.2.46 - Vs-Vp cross-plot for clean shale points in the Sele Fm

Lista Fm - Clean Sandstone - Vs-Vp - Two porosity trends (PhiT-Depth based)
HighPhiT - Robust Walden regression (orange line) and LowPhiT - 2nd order polynomial trend (purple line)

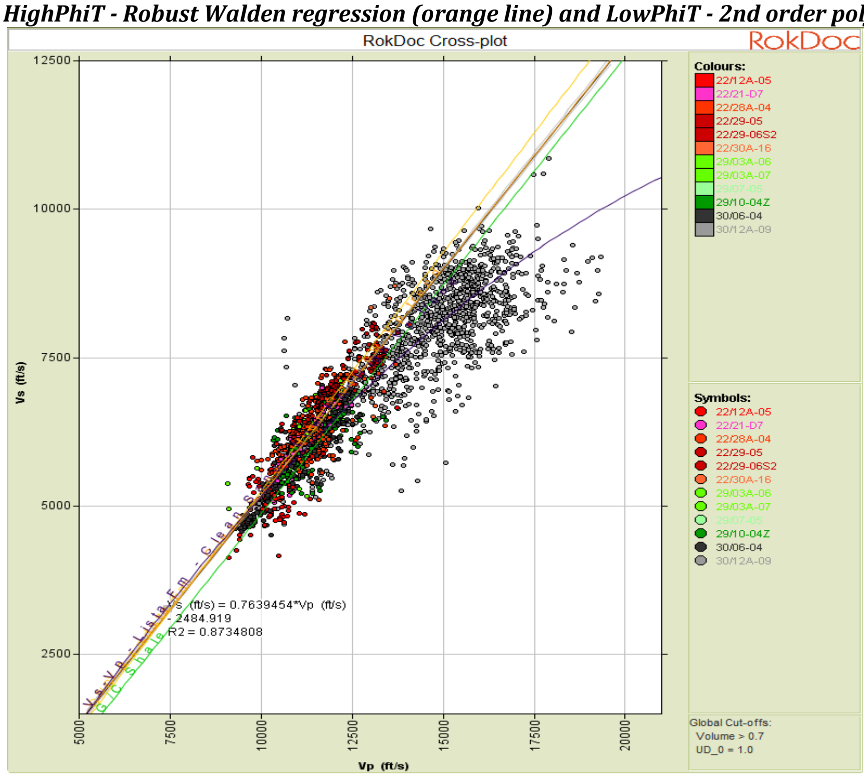


Figure 2.2.47 - Vs-Vp cross-plot for clean sandstone points in the Lista Fm

Lista Fm - Clean Shale - Vs-Vp - Robust Walden regression (black line)

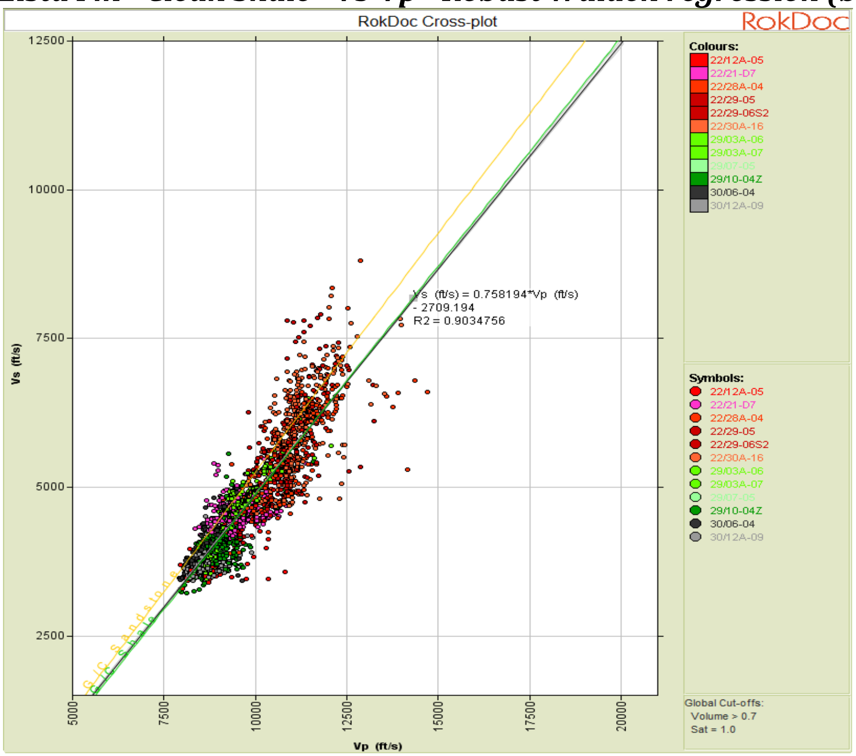


Figure 2.2.48 - Vs-Vp cross-plot for clean shale points in the Lista Fm

Maureen Fm - Clean Sandstone - Vs-Vp - Two porosity trends (PhiT-Depth based)

HighPhiT - Robust Walden regression (orange line) and LowPhiT - 2nd order polynomial trend (purple line)

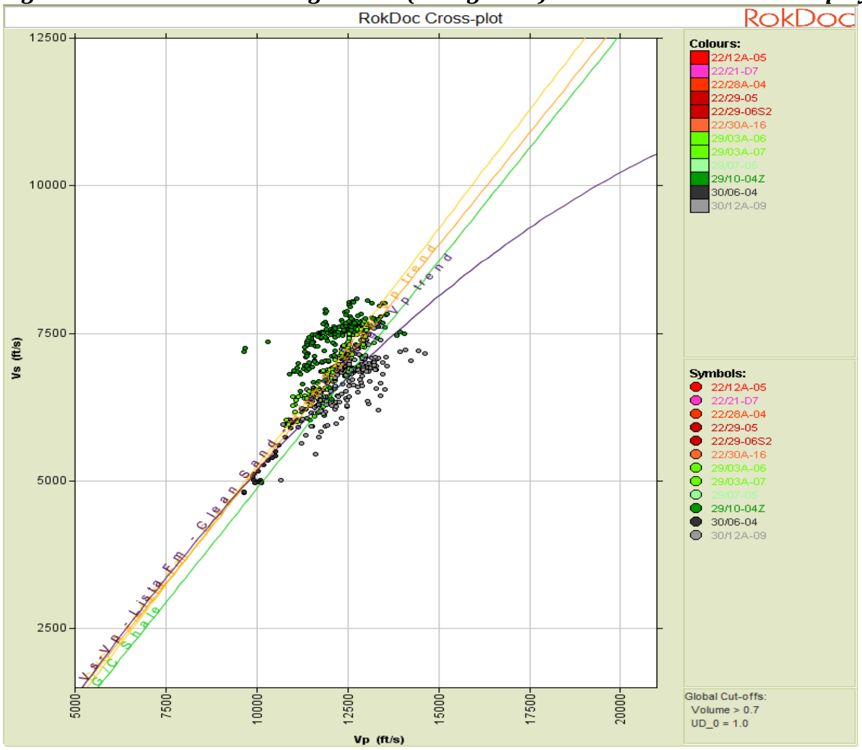


Figure 2.2.49 - Vs-Vp cross-plot for clean sandstone points in the Maureen Fm

Maureen Fm - Clean Shale - Vs-Vp - Robust Walden regression (black line)

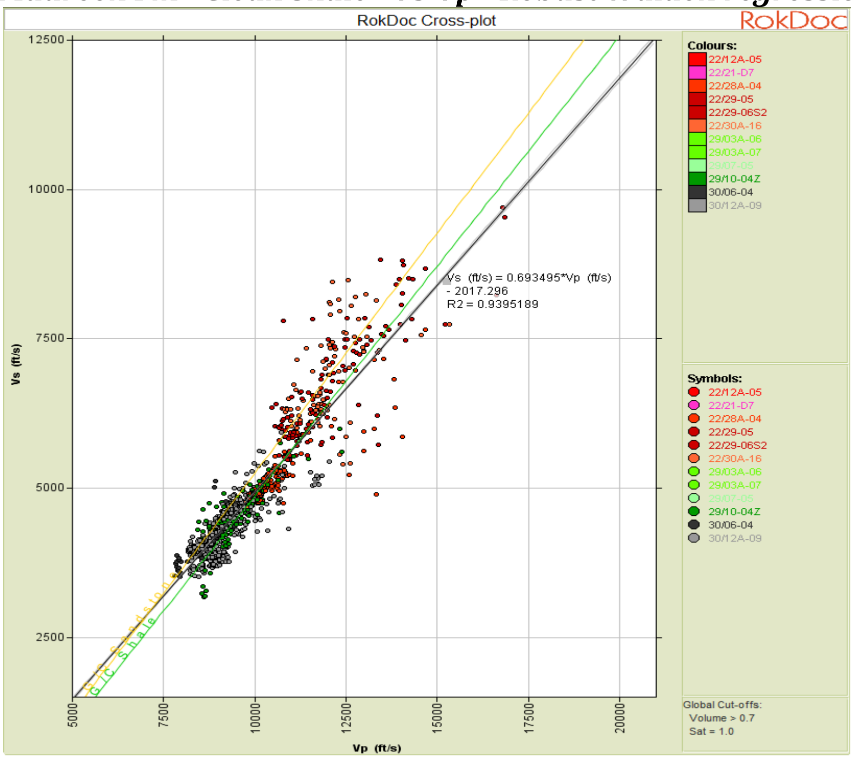


Figure 2.2.50 - Vs-Vp cross-plot for clean shale points in the Maureen Fm

Maureen Fm - Clean Limestone - Vs-Vp - 2nd order polynomial trend (grey line)

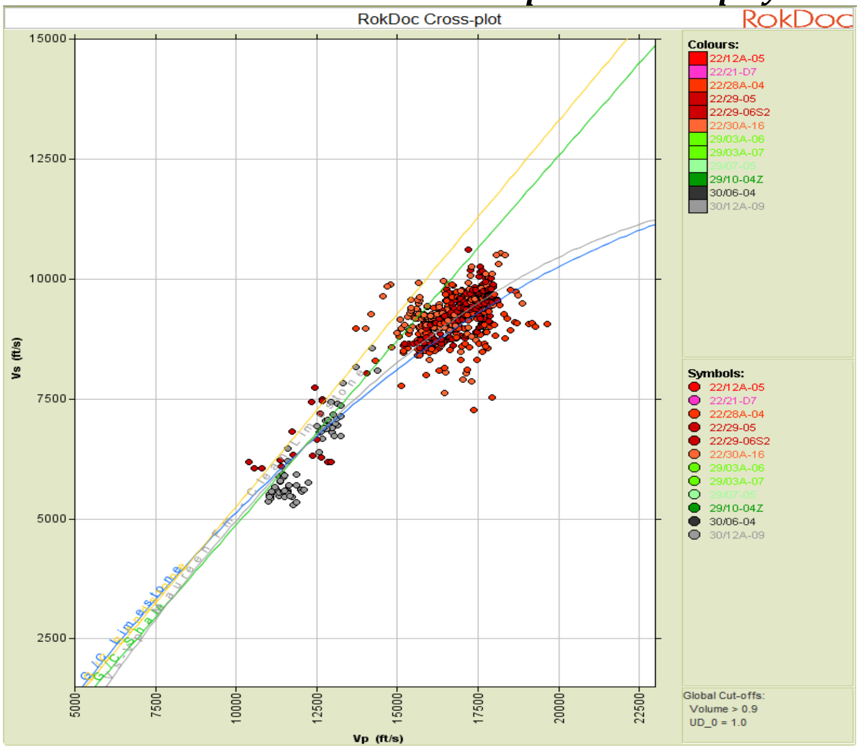


Figure 2.2.51 - Vs-Vp cross-plot for clean limestone points in the Maureen Fm

Ekofisk Fm - Clean Limestone - Vs-Vp - 2nd order polynomial trend (grey line)

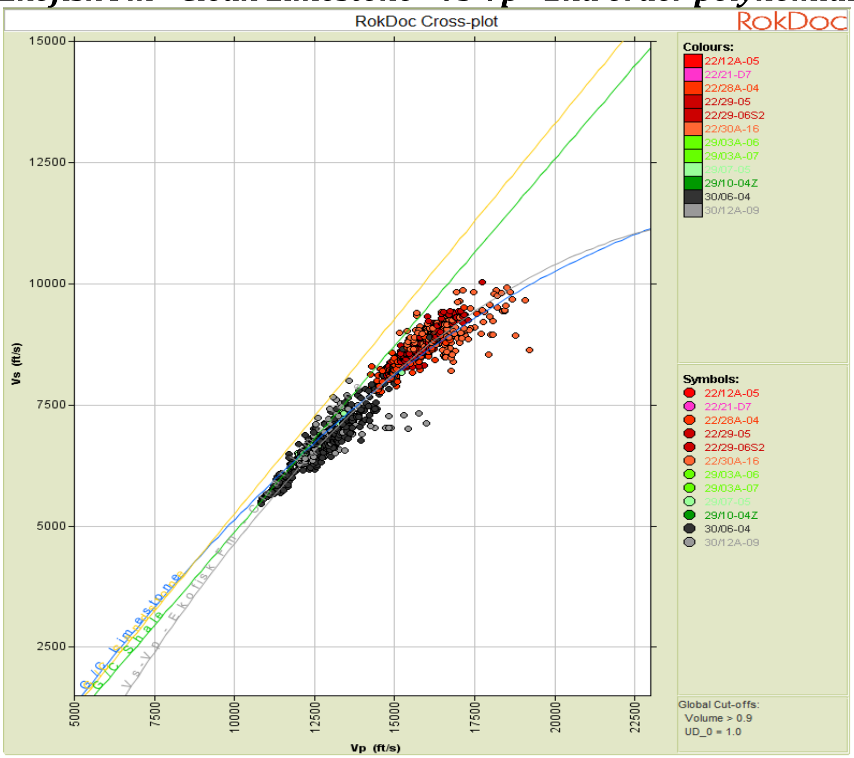


Figure 2.2.52 - Vs-Vp cross-plot for clean limestone points in the Ekofisk Fm

Tor Fm - Clean Limestone - Vs-Vp - 2nd order polynomial trend (grey line)

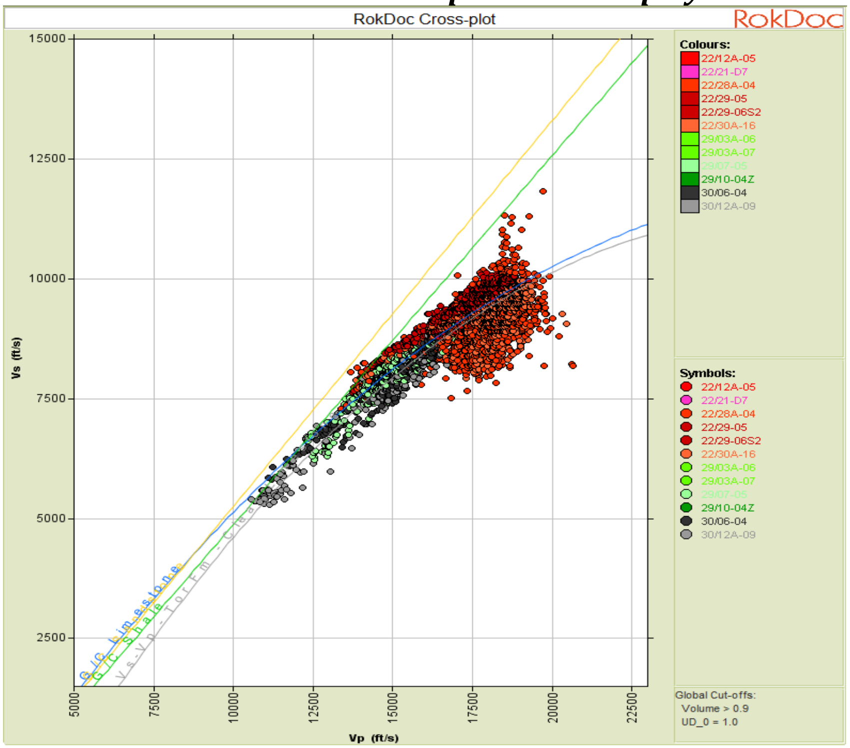


Figure 2.2.53 - Vs-Vp cross-plot for clean limestone points in the Tor Fm

Hod Fm - Clean Limestone - Vs-Vp - 2nd order polynomial trend (grey line)

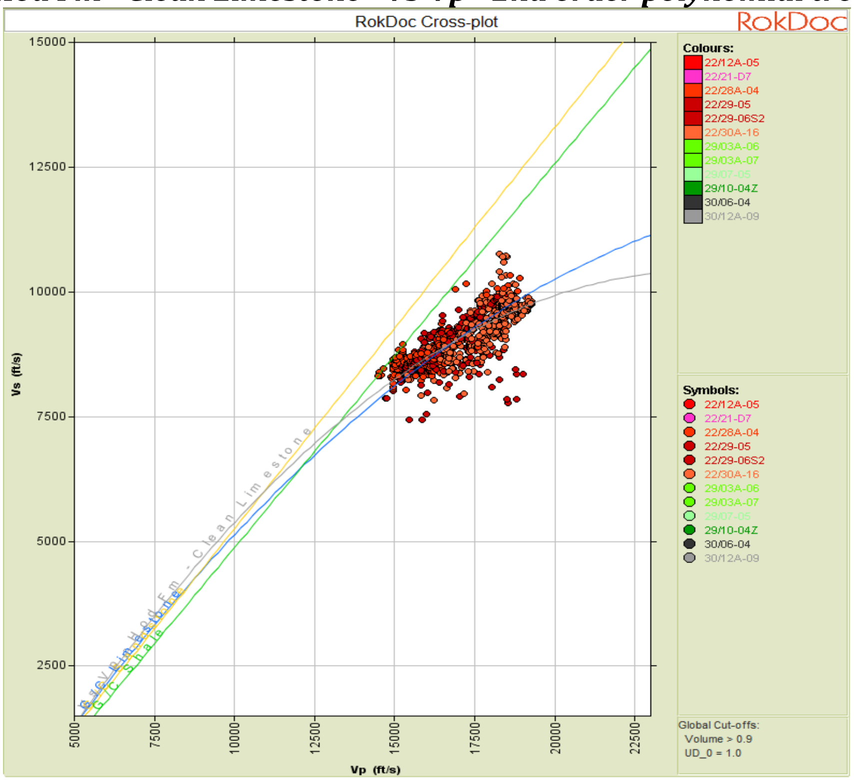


Figure 2.2.54 - Vs-Vp cross-plot for clean limestone points in the Hod Fm

Vs-Vp plots summary

The Vs-Vp plots included in this section are the summary cross-plots for reservoir and non-reservoir lithologies in each of the eight working intervals in the study. The derived trends are displayed on the plots and included in the appendix of the report.

These plots show a single trend was valid to model the Vs-Vp relationship in almost all of these formations in this section of the Central North Sea.

The multi-well trend coefficients were converted into Greenberg-Castagna coefficients (the units are changed from ft/sec to km/sec) for use in the Modified Gassmann module later in the project. This is achieved as follows:

Where relationship is linear (y = ai1x + ai0 form) –
ai1 (gradient) remains constant
ai0 is divided by 3280.8399 (feet contained within one kilometre)

Where relationship is 2nd order polynomial (y = ai2x^2 + ai1x + ai0 form) –
ai2 is multiplied by 3280.8399
ai1 remains constant
ai0 is divided by 3280.8399.

It also shows that the common *linear* relationship between Vp and Vs is not the optimum to capture the geological variations in Limestone and Lista / Maureen Sandstones.

The PhiT-Vp plots are shown in the next section of the report. Only one trend was derived for these rock physics relationships.

Multi-well rock physics analysis: PhiT-Vp plots - All plots coloured by well

Horda Fm - Clean Sandstone - PhiT-Vp
Second order polynomial fixed at zero porosity using the 'dirty' quartz Vp value

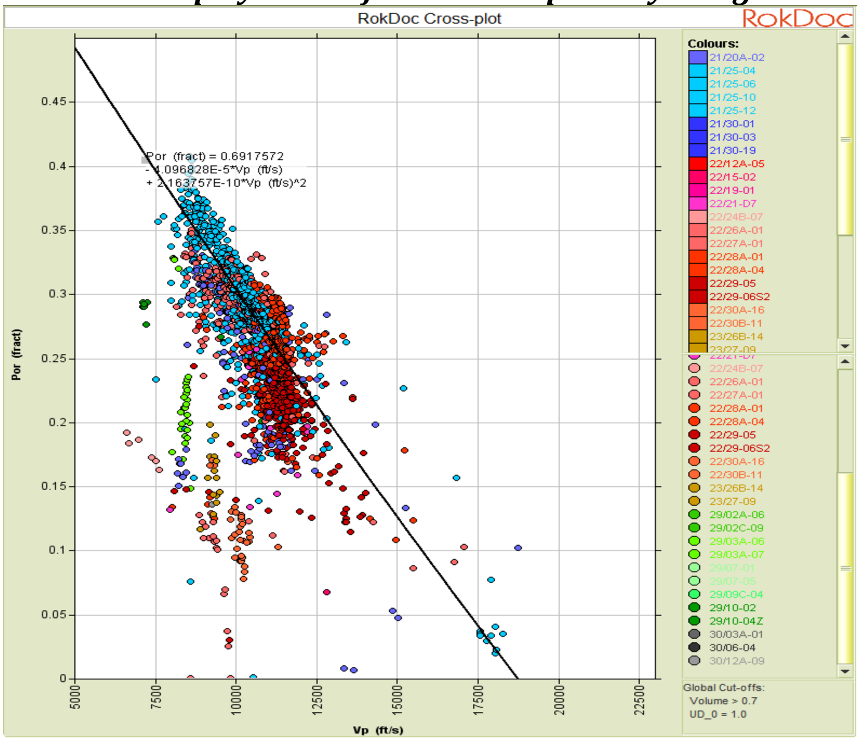


Figure 2.2.55 - PhiT-Vp cross-plot for clean sandstone points in the Horda Fm

Balder Fm - Clean Sandstone - PhiT-Vp
Second order polynomial fixed at zero porosity using the 'dirty' quartz Vp value

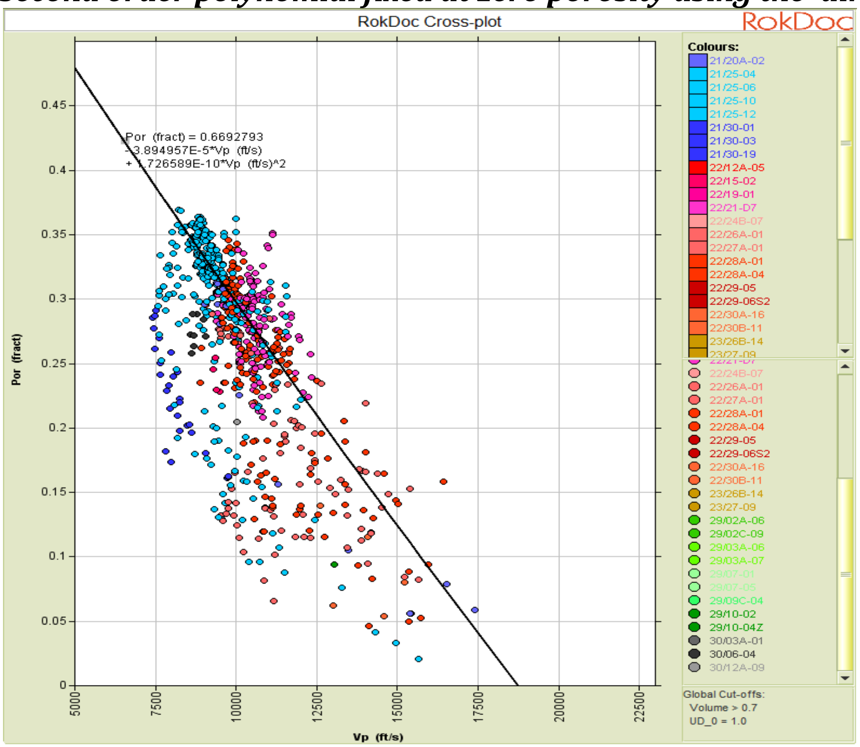


Figure 2.2.56 - PhiT-Vp cross-plot for clean sandstone points in the Balder Fm

Sele Fm - Clean Sandstone - PhiT-Vp
Second order polynomial fixed at zero porosity using the 'dirty' quartz Vp value

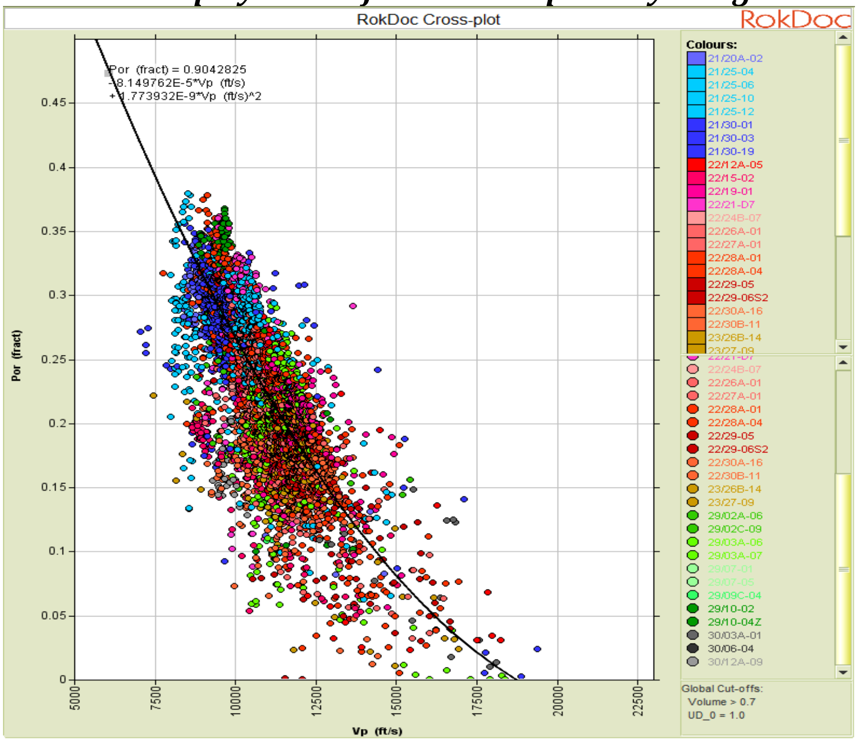


Figure 2.2.57 - PhiT-Vp cross-plot for clean sandstone points in the Sele Fm

Lista Fm - Clean Sandstone - PhiT-Vp
Second order polynomial, not fixed at dirty quartz Vp value

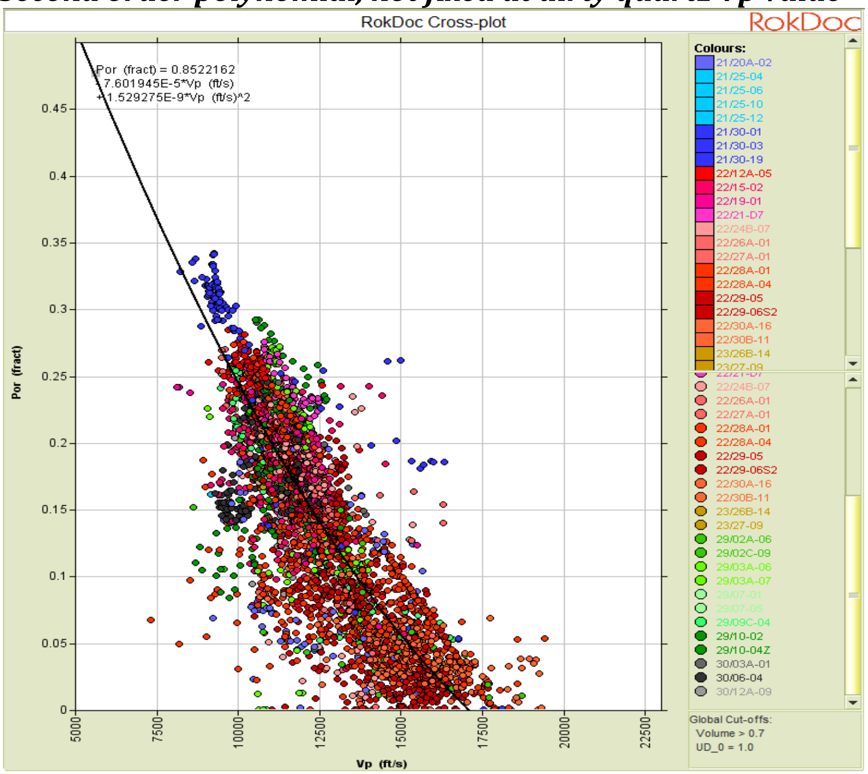


Figure 2.2.58 - PhiT-Vp cross-plot for clean sandstone points in the Lista Fm

Maureen Fm - Clean Sandstone - PhiT-Vp
Second order polynomial fixed at zero porosity using the 'dirty' quartz Vp value

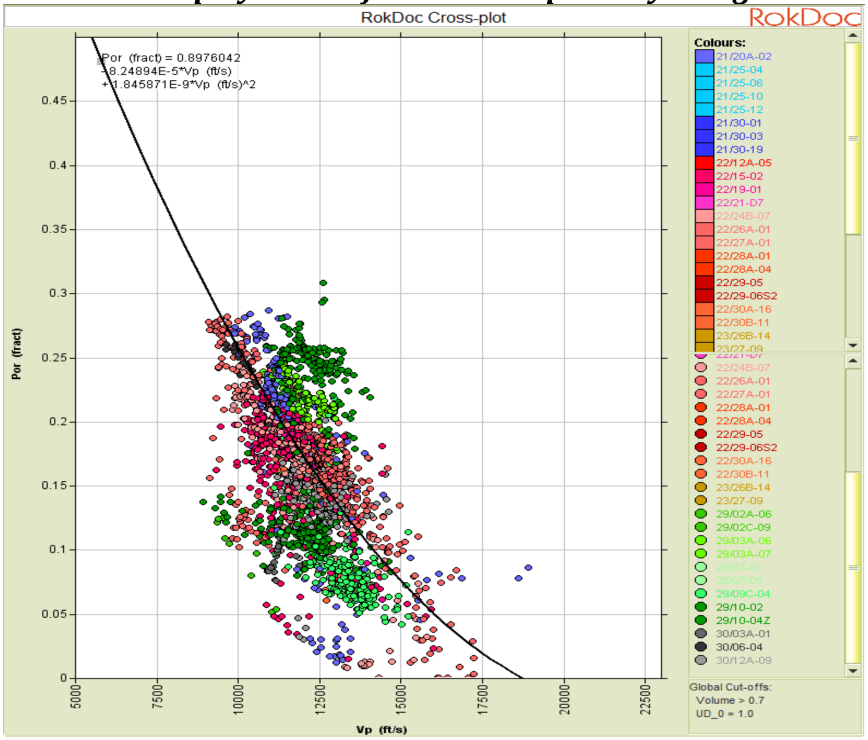


Figure 2.2.59 - PhiT-Vp cross-plot for clean sandstone points in the Maureen Fm

Maureen Fm - Clean Limestone - PhiT-Vp
Second order polynomial fixed at zero porosity using the 'dirty' calcite Vp value

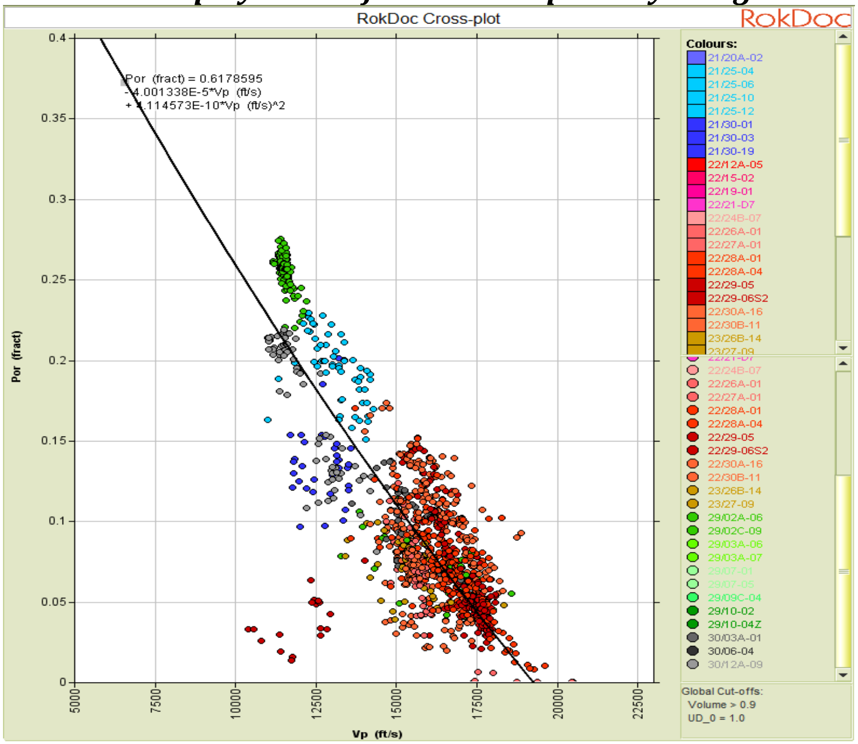


Figure 2.2.60 - PhiT-Vp cross-plot for clean limestone points in the Maureen Fm

Ekofisk Fm - Clean Limestone - PhiT-Vp
Second order polynomial fixed at zero porosity using the 'dirty' calcite Vp value

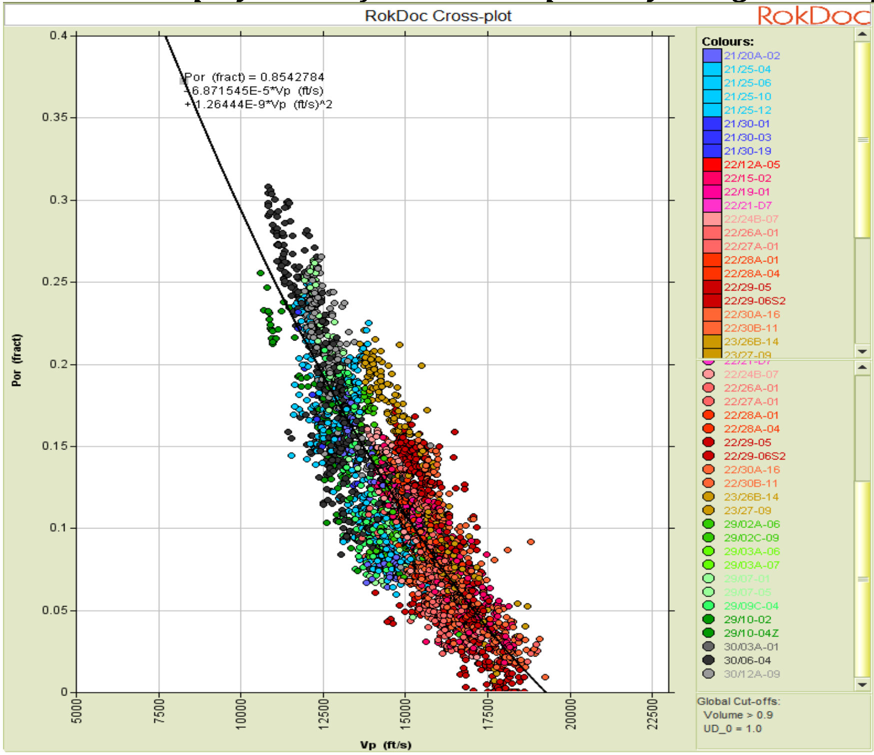


Figure 2.2.61 - PhiT-Vp cross-plot for clean limestone points in the Ekofisk Fm

Tor Fm - Clean Limestone - PhiT-Vp
Second order polynomial fixed at zero porosity using the 'dirty' calcite Vp value

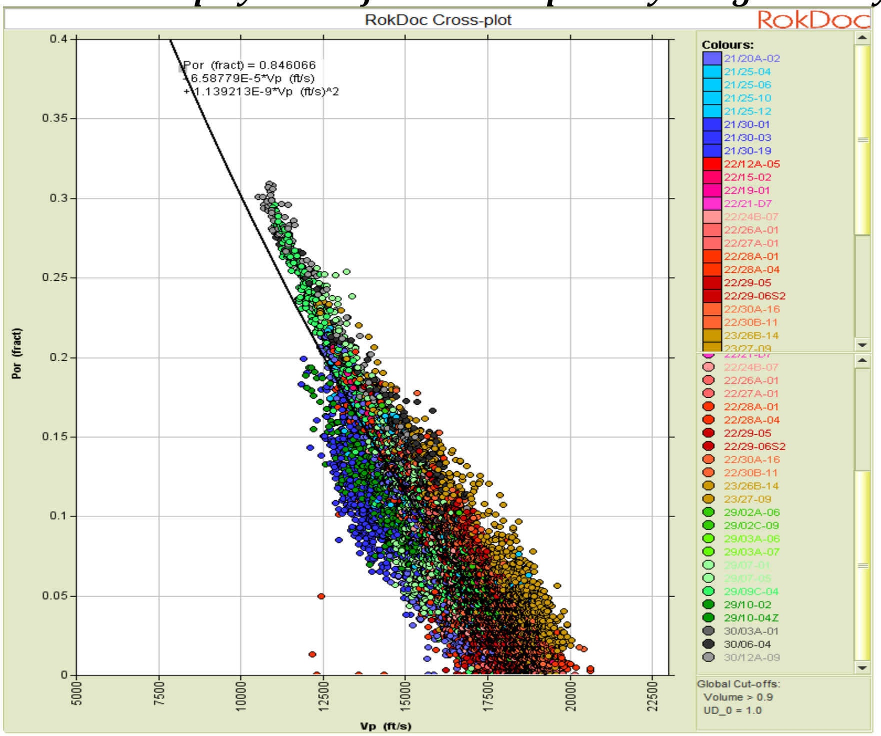


Figure 2.2.62 - PhiT-Vp cross-plot for clean limestone points in the Tor Fm

Hod Fm - Clean Limestone - PhiT-Vp
Second order polynomial fixed at zero porosity using the 'dirty' calcite Vp value

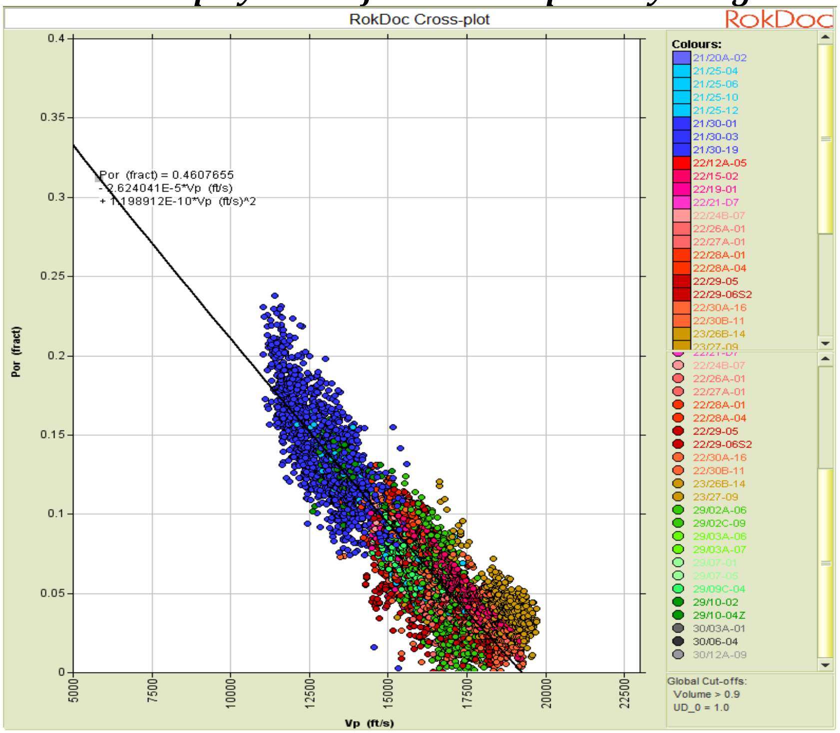


Figure 2.2.63 - PhiT-Vp cross-plot for clean limestone points in the Hod Fm

PhiT-Vp plots summary

The PhiT-Vp cross-plots included in this section are the summary cross-plots for reservoir lithologies in each of the eight working intervals in the study. The derived trends are displayed on the plots and included in the appendix of the report.

These plots show a single trend per formation is valid to model the PHIT-Vp relationship in almost all of these formations in this section of the Central North Sea.

Again, like for the Rhob-Vp trends, it can be observed that these PhiT-Vp trends underpredict the PhiT for some intervals with high PhiT (low Vp).

The Vp value for dirty quartz is 18,740 ft/sec and the Vp value for dirty calcite is 19,253 ft/sec. This represents the mineral point value at zero porosity.

Rhob-PhiT plots summary

The Rhob-PhiT cross-plots are not shown in the next section of the report. Since PhiT has been calculated from Rhob, the relationship will be almost linear and these cross-plots can be found in the multi-well analysis PowerPoint supplied with the project. In the Rhob-PhiT cross-plots, the intercept of the line is fixed at the mineral value used in the Petrophysics (Rhob=2.65g/cm^3 for quartz and Rhob=2.71g/cm^3 for calcite), as opposed to the ‘dirty’ quartz value (2.635g/cm^3).

Cross-plot views

All of the cross-plots shown in this section of the report have their views saved within the Master RokDoc project to save time creating the plots for a Shell end-user of the project. To load a view from the archive of saved views, simply click on the Load button at the bottom right hand corner of the cross-plot and select one the views in the dialog.

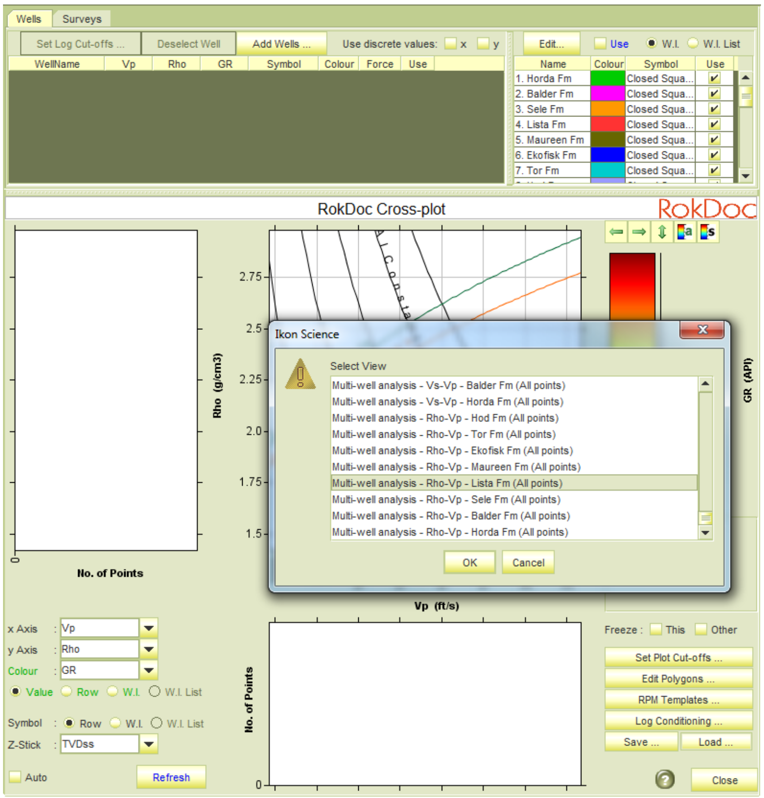


Figure 2.2.64 - Example of saved views for this section of the project. NB - It can take several minutes to load a view due to the large number of logs saved in the cross-plot.

For this section of the project, all the views are saved as 'Multi-well analysis' and then the name of the specific view.

There are no volume cut-offs applied to these cross-plots and the views display all of the points within the working interval (apart from hydrocarbon-bearing zones in wells with no measured Vs log data). To change the volume cut-offs to the desired clean lithology, the end-user needs to firstly make the required volume logs active and then apply the clean lithology cut-offs.

The polygons that have been used in this section of the multi-well analysis have also been saved within the RokDoc project and can be accessed by selecting the 'Edit Polygons' button on the plot.
The next section of the report explains how these regional trends were used to create a set of synthetic logs.

Creating the synthetic logs from regional trends

Using the regional trends derived for each formation, the objective is now to create a set of modelled synthetic logs for use in log conditioning, extension and replacement. These synthetic logs will only use the inputs of depth and the volume curves and hence the synthetic logs could be created at any location, not just at the wells.

The derived synthetic logs can be used to identify well data which plot significantly away from the regional trends. They are therefore useful in understanding wells which are anomalous and likely to give AVO or impedances responses which could give rise to spurious AVO interpretation.

The synthetic logs were created as following; firstly the regional trends derived within the multi-well section of the project were used to create a series of end-member trends for each lithology. End-member logs were then generated using two models, as described by the following workflows for reservoir and non-reservoir;

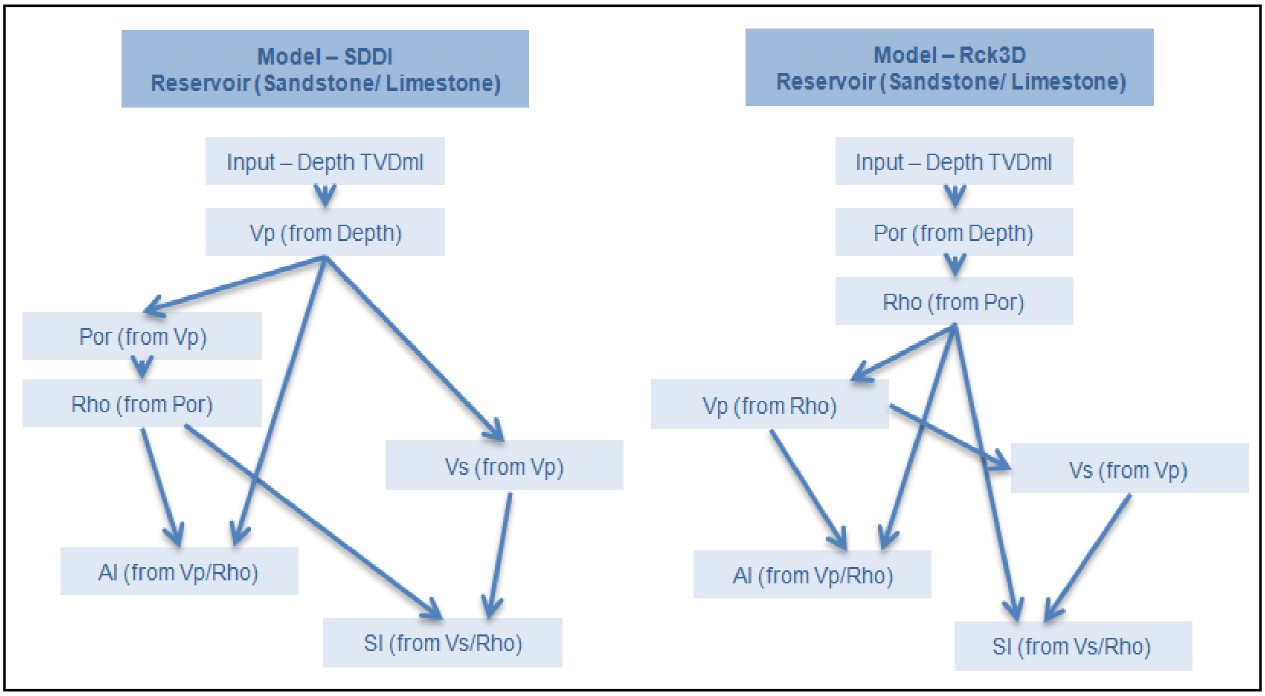


Figure 2.2.65 - Shell specified SDDI and Rck3D reservoir workflows for synthetic end-member trends

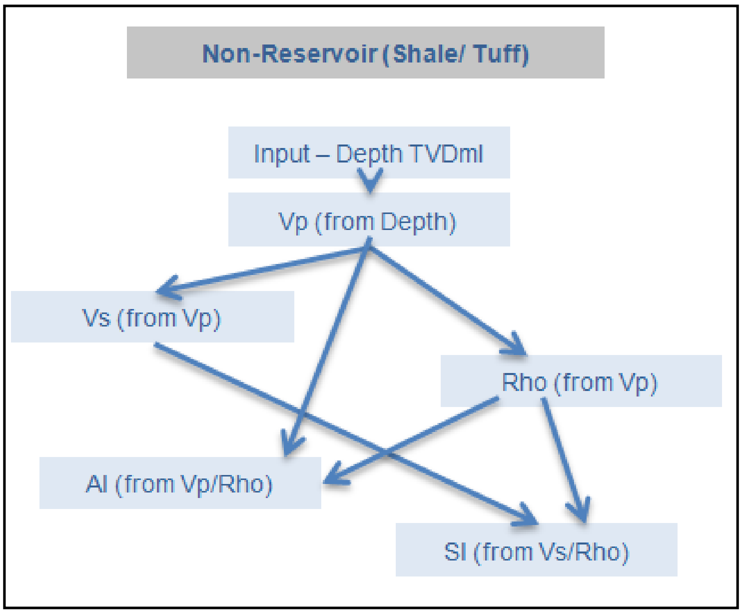


Figure 2.2.66 - Shell specified non-reservoir workflows for synthetic end-member trends

Synthetic logs were then created by mixing the end-members trend logs using the petrophysical volume logs (e.g. VShale, Vol_Lime etc) to represent the final mix of end-member lithologies. This was performed using a combination of Backus (Vp, Vs) and arithmetic averaging (Rhob). The final stage was to fluid substitute intervals exceeding the reservoir porosity cut-off to 80% Oil, 80% Condensate and 90% Gas bearing fluid cases using the previously derived fluid properties.

This was performed with a User Programmer script in RokDoc for the Synthetic log generation and fluid substitution.

Incorporating the dual porosity and hard/soft shale trends into the synthetic logs

In a large number of instances, multiple end-member trends were required within the multi-well analysis to represent soft/hard shale trends, and low/high porosity reservoir trends.

In order to model the synthetic log data at each well, the distribution of each end member trends down the entire length of the well was required. This has been achieved by the use of an 'End-member Flag' curve.

The 'End-member Flag' curve is a binary representation of the dual porosity or hard/soft shale trend distribution throughout. Values are given below for each of the three lithologies.

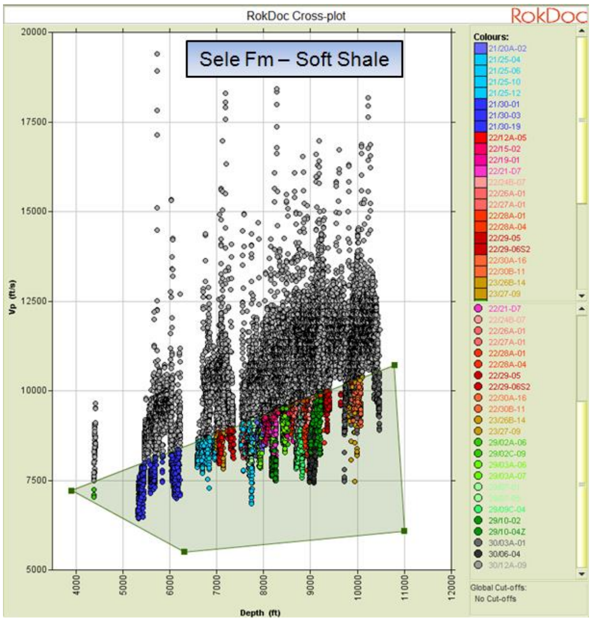
Lithology	Value	Trend
Shale	*0*	*Soft*
Shale	*1*	*Hard*
Sandstone	*0*	*Low Porosity*
Sandstone	*1*	*High Porosity*
Limestone	*0*	*Low Porosity*
Limestone	*1*	*High Porosity*

Figure 2.2.67 - Binary system for deriving 'End-member Flag' curves to model dual porosity and hard/soft shale distribution within each well.

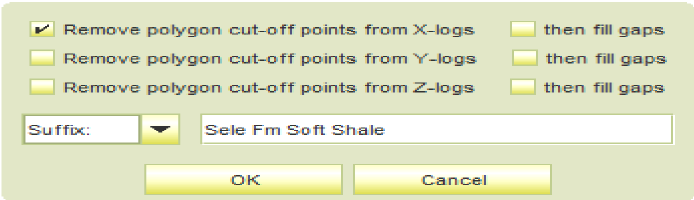
The 'End-member Flag' curves were created using the same polygons as were used to derive the dual trends in the multi-well analysis. An example of the shale trends in the Sele Fm is demonstrated below.

The method works as follows;

- The soft shale polygon was applied to all the data on the Vp-Depth cross-plot in the Sele Fm. [NB - All the data points in the Sele Fm were selected for the 'End-member Flag' curve as the curve needed to be continuous over the Shale data range for this method to work.]



- The log conditioning option was selected in the cross-plot and the cut-off points were excluded from the depth logs then the depth logs were saved with the gaps in the logs in the Sele Fm.



- This created a depth log with null values at depths where there is a hard shale trend and log values at depths where there is a soft shale trend.
- The depth curve with gaps was then converted to a binary 'End-member Flag' curve using the formula; **IF 'DEPTH LOG' = $null THEN 1.0 ELSE 0.0 END**
- The same method was applied to all four intervals with two shale trends present.
- The same method was then applied to make the sandstone and limestone 'End-member Flags' with the only difference being that the cross-plot was now PhiT-Depth not Vp-Depth and the low porosity points polygon was selected.
- All three of the 'End-member Flag' curves show variation between 0 and 1 but this was thought likely to make the binary curve too noisy to use to create a realistic modelled log.
- It was therefore decided that the 'End-member Flag' curves would be blocked. This was done by smoothing the curve with a rectangular function of width = 20ft to create the smoothed curve.
- The smoothed curve was then turned into a blocked curve using the formula;
- IF 'smoothed curve' > 0.5 THEN 1.0 ELSE 0.0 END.
- This created the final 'Blocked' curve which was used in the scripts to create the modelled logs.

These blocked 'End-member Flag' curves provide the input into the scripts that were used to calculate the synthetic logs and ensured that the correct dual porosity and hard/soft shale trend was used in the relevant section of the well.

An example of a complete set of 'End-member Flag' curves is provided here for well 21/20A-02.

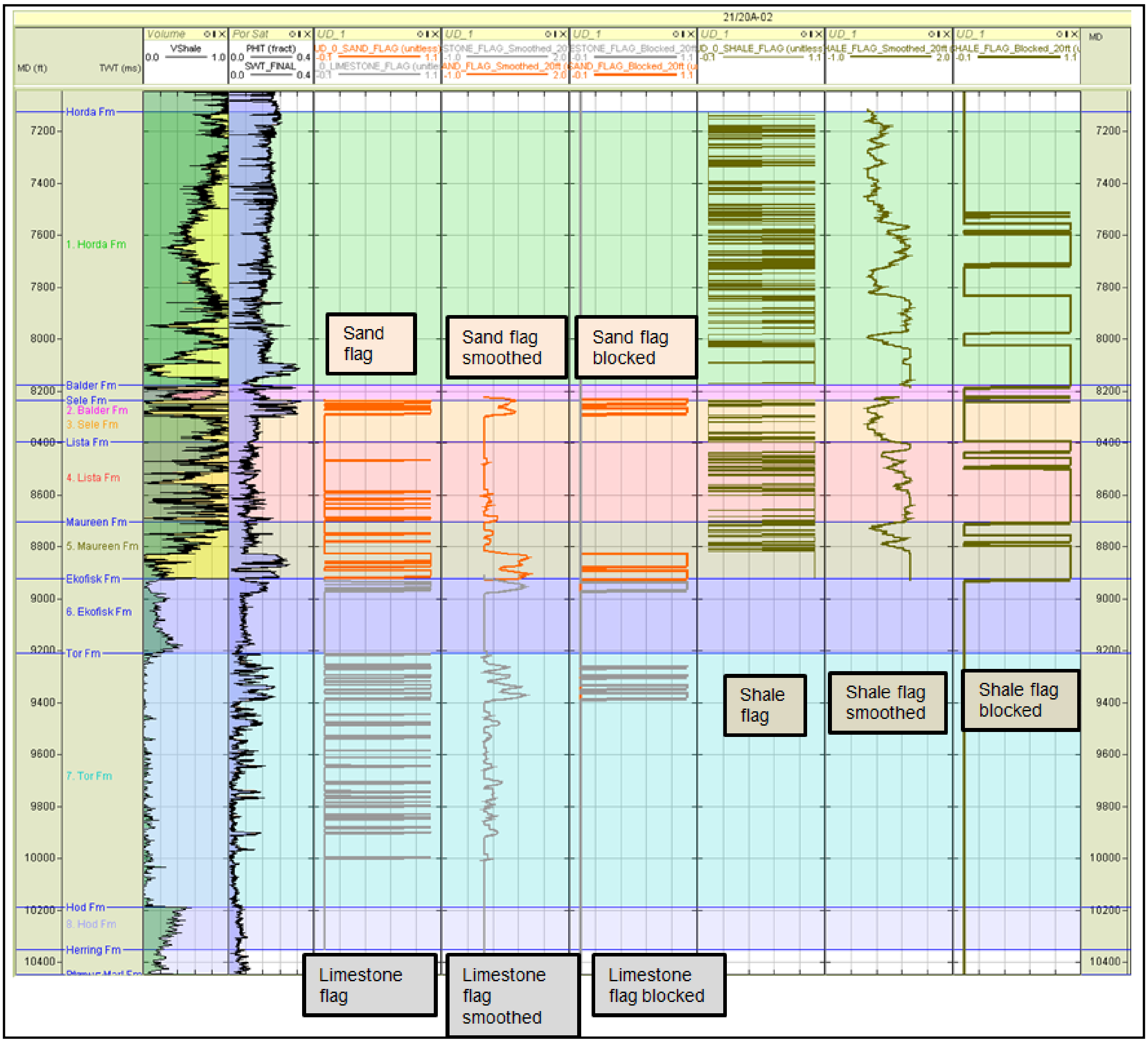


Figure 2.2.68 - Example of 'End-member Flag' curves for sandstone, limestone and shale.

These 'End-member Flag' curves were then used in the User Programmer script in RokDoc for the Synthetic log generation and fluid substitution. The scripts are included in the appendix of the report.

An example of a complete set of synthetic curves is provided here for well 21/25-10.

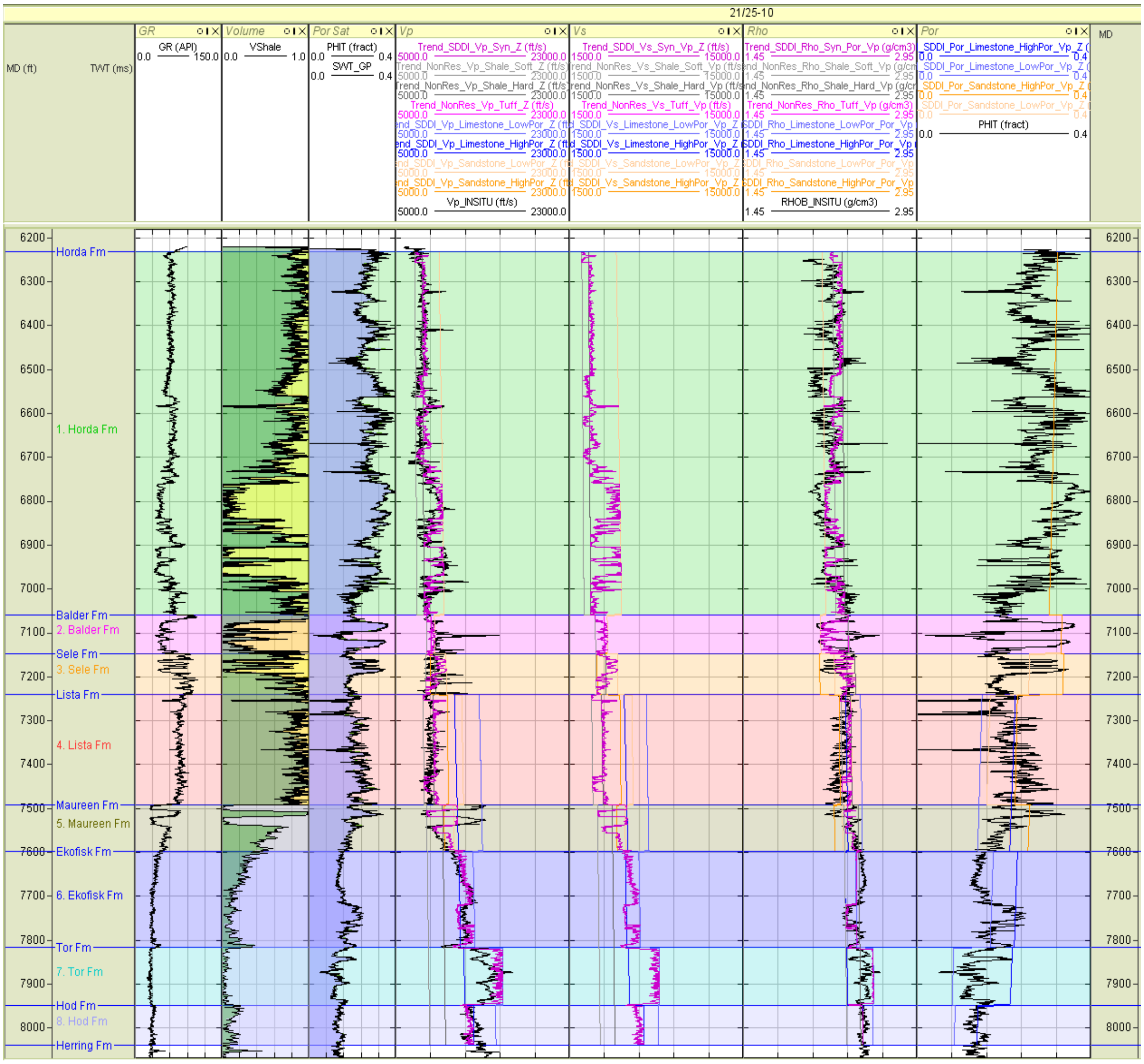


Figure 2.2.69 - Example of synthetic curves at well 21/25-10.

It is clear that the overall character of the measured curve (black) is very well represented by the synthetic curve (purple). But locally, e.g. two zones at the top of the Maureen Fm show significant coherent deviations from the measured curve, both below the assigned (dark-blue) end-member trend . Based on the match with the 'low PhiT' limestone end-member trend curve (light blue), one could argue that the end-member classification could be improved with a local refinement for these two zones or perhaps a reclassification from high porosity chalk (dark-blue) to low porosity chalk (light blue).

Rock physics relationships were modelled for clean lithologies for all thirty five wells using a consistent set of brine-bearing data points. The regional trends were used to create a set of synthetic logs that highlight the places where the measured log data deviate from the regional trends.

The next step in the project is Single Well Rock Physics - Part 2 where the regional trends were used to model missing Vp, Vs and Rhob log data and condition the data towards the latter/more interpretive end of the rock physics workflow.

2.3 – Single Well Rock Physics Analysis - Part 2

Section 2.2 previously explained how the multi-well analysis section was able to analyse all thirty five wells in the project at the same time to produce regional trends and how these regional trends were used to create synthetic modelled logs at every well. Chapter 2.3 will now explain the methodology behind the second part of the single well rock physics section of the project and how the results derived from this section of the project were key in the analysis of each individual well in Chapter 3 of the project.

Log conditioning - Introduction and strategy

The first stage of this section of the project was to fill in any missing log data using synthetic data modelled from the regional trends and create a set of complete gap-filled Vp, Vs and Rhob logs that were taken forward into the rock physics analysis workflow.

It is important to remember that the regional trends were derived to model 100% brine bearing data points and thus were only valid in modelling missing data over 100% brine bearing sections of log data. There were cases where the presence of hydrocarbons means the regional trends were not applicable in modelling missing sections of log data. The strategy for dealing with these cases will be explained in this introductory section and is shown the flow diagram below;

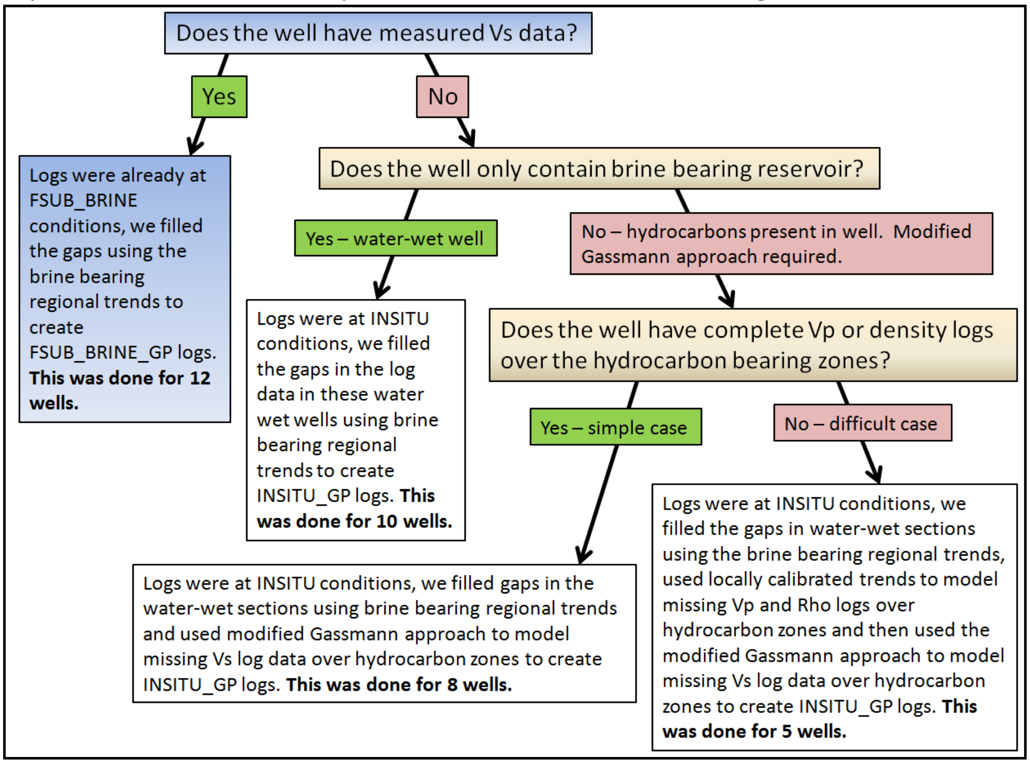


Figure 2.3.1 - Flow diagram detailing the gap filling strategy

As previously mentioned in the multi-well analysis section, there were only twelve wells with measured Vs data. These twelve wells have already been Gassmann fluid substituted to 100% brine bearing conditions and the logs were named with a suffix of 'FSUB_BRINE'. It was straightforward to fill in the missing log data at these wells since all of the missing data was simply filled with the 100% brine bearing regional trends and this created a set of Vp, Vs and Rhob logs named with a suffix of 'FSUB_BRINE_GP' to denote that all the gaps in the logs had been filled.

This method was used on the following twelve wells;

22/12A-05	22/21-D7	22/28A-04	22/29-05	22/29-06S2	22/30A-16
29/03A-06	29/03A-07	29/07-05	29/10-04Z	30/06-04	30/12A-09

Table 2.3.1 - Table to show which wells were already at 100% brine bearing conditions

As previously mentioned in the multi-well analysis section, there are twenty three wells that do not have measured Vs data. We were not able to Gassmann fluid substitute these twenty three wells to 100% brine bearing conditions and the logs were still in their insitu saturations thus were named with a suffix of 'INSITU'. The method for filling the gaps in the logs at these twenty wells depended on the distribution of hydrocarbons in the well and whether there was any missing log data over a hydrocarbon bearing zone.
For ten of the twenty three wells at insitu conditions, the wells were water-wet wells with no hydrocarbons present and in these cases, we simply filled the gaps in the logs and modelled the missing Vs log with the 100% brine bearing regional trends. This created a set of Vp, Vs and Rhob logs named with a suffix of 'INSITU_GP' to denote that all the gaps in the logs have been filled for these wells.

This method was used on the following ten wells;

21/20A-02	21/25-10	21/30-03	22/15-02	22/24B-07
22/26A-01	22/27A-01	23/26B-14	29/02C-09	29/09C-04

Table 2.3.2 - Table to show which wells had no Vs data and were water wet wells

For the other thirteen of the twenty three wells, at insitu conditions the wells had hydrocarbons present. The Vs log was modelled over a hydrocarbon zone using the modified Gassmann approach for Vs prediction and this will be explained in more detail later in report. There were eight of these thirteen wells where there was no Vs data over a hydrocarbon zone and a full set of measured Vp and Rhob logs so it was straightforward to use the modified Gassmann approach in these cases. This created a set of Vp, Vs and Rhob logs named with a suffix of 'INSITU_GP' to denote that all the gaps in the logs have been filled for these wells.

This method was used on the following eight wells;

21/25-04	21/25-06	21/25-12	21/30-01
21/30-19	22/30B-11	29/07-01	29/10-02

Table 2.3.3 - Table to show which wells had no Vs data, had hydrocarbons present and had a complete set of Vp and Rhob logs over the hydrocarbon zones

For the last five wells, there were both gaps in the Vp or Rhob logs and missing Vs log data over a hydrocarbon zone. These gaps in Vp or Rhob logs were small and will be described later in the report. The method for filling these gaps in the Vp or Rhob logs was to use a locally calibrated trend in that particular formation then continue with the modified Gassmann approach at these wells to eventually generate a set of Vp, Vs and Rhob logs named with a suffix of 'INSITU_GP' to denote that all the gaps in the logs have been filled for these wells.

This method was used on the following five wells;

22/19-01	22/28A-01	23/27-09	29/02C-06	30/03A-01

Table 2.3.4 - Table to show which wells had no Vs data, had hydrocarbons present and did not have a complete set of Vp and Rhob logs over the hydrocarbon zones

Once the logs are at INSITU_GP with all the gaps filled, they were then Gassmann fluid substituted to 100% brine conditions and this brought all the wells to the same point in the workflow as all of the wells that already had FSUB_BRINE_GP logs. Mineral sets were also derived for the wells without measured Vs data at this stage in the project.

Log conditioning - Basic Workflow

The log conditioning workflow uses the steps that are described below in the flow diagram;

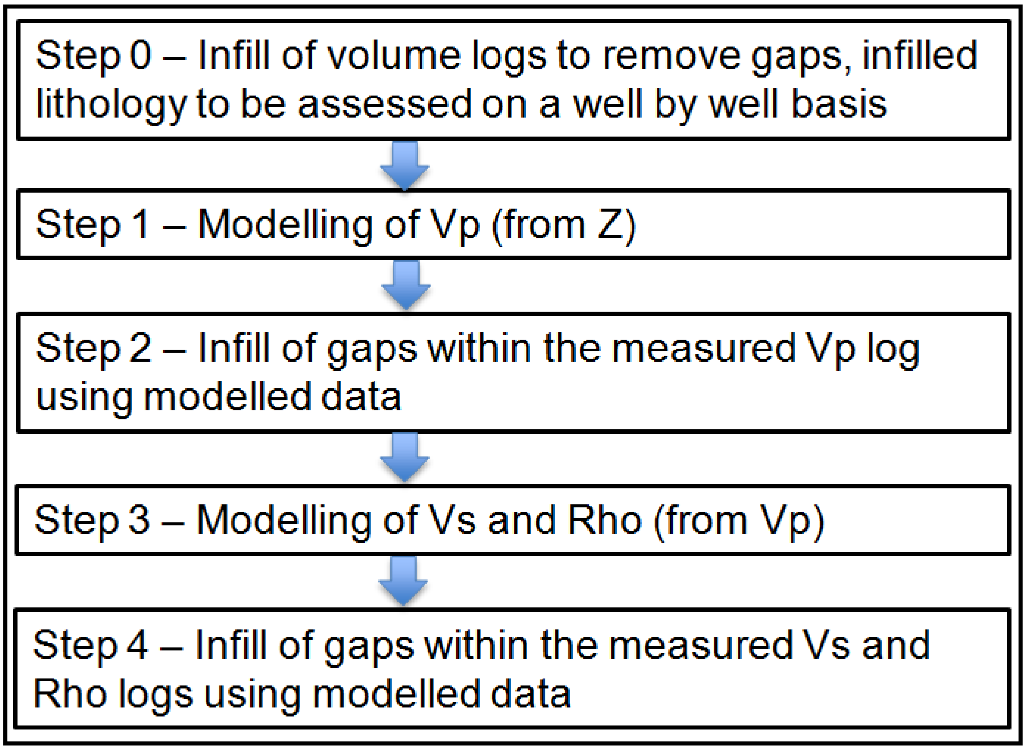


Figure 2.3.2 - Log conditioning workflow

This was the generic workflow for log conditioning and it was changed depending upon the nature of the gaps and hydrocarbon distribution at each well. The modified Gassmann approach and the special cases where there was missing Vp and Rhob data over hydrocarbon zones will be documented in an extra section at the end of this workflow.

Step 0 was a preliminary step for this workflow and involved filling in any gaps in the petrophysics. This produced continuous volume logs that were used as the inputs to the end-member/synthetic scripts. The gaps in the petrophysics were caused by casing changes in the well where no wireline log data was recorded over these sections. Lithology information from the composite log was used to guide the infilling of the volume curves over these sections. The volume log with the relevant lithology was set to equal one over these missing sections in the absence of more detailed information. An example of step 0 is supplied below for well 22/21-D7:

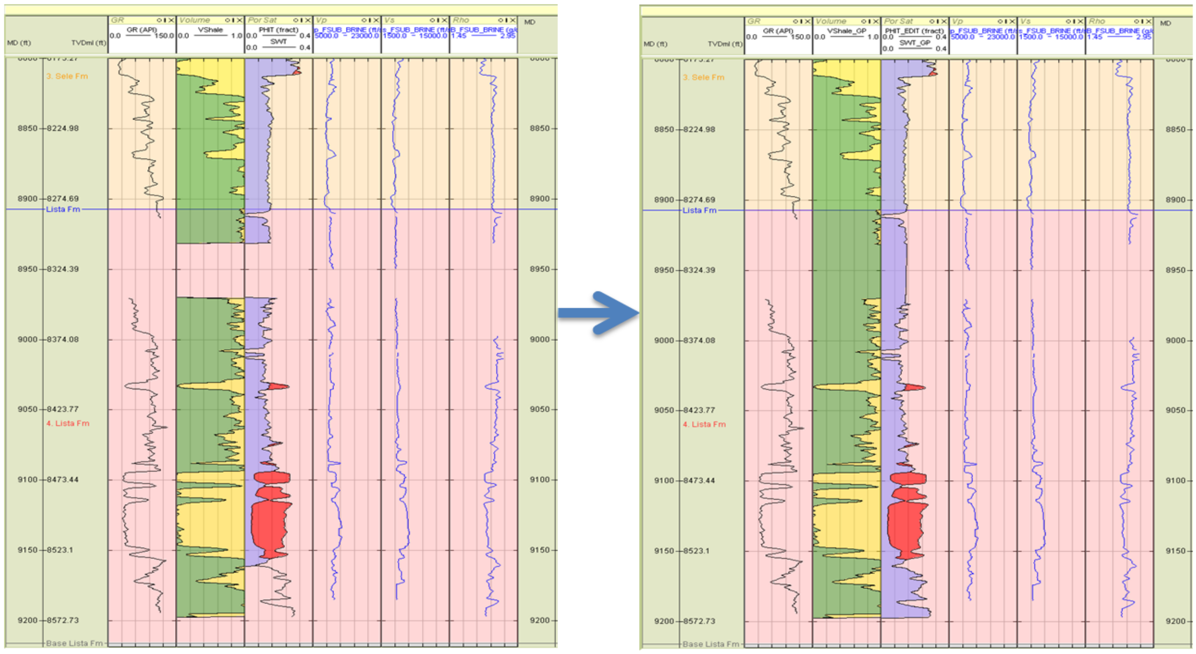


Figure 2.3.3 - Example of infilling the volume curves and porosity log at well 22/21-D7

As soon as Step 0 was complete then we were able to move onto Step 1 of the workflow. Step 1 was actually carried out in the multi-well analysis section of the project as it was in this section of the project that the synthetic logs were created. In our modelling workflow, we used the logs modelled from the SDDI method as our synthetic modelled Vp log and the modelled log data provided a good match to the measured log data on most occasions.

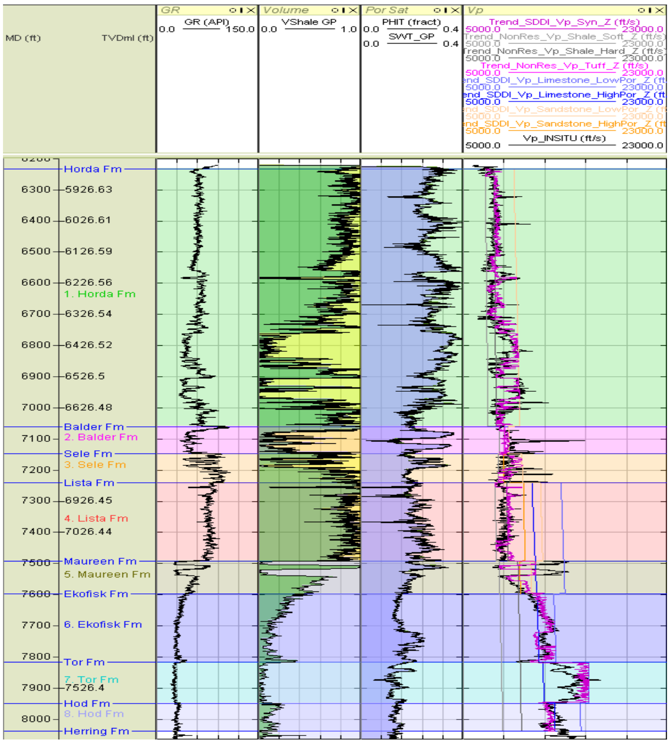


Figure 2.3.4 - Synthetic Vp log (purple) and measured Vp data (black) at well 21/25-10

Step 2 consisted of the actual infilling of the gaps within the measured Vp log with our modelled data. This was done in the relevant working intervals using the following formula in RokDoc;

```
IF 'measured Vp log' = $null THEN Trend_SDDI_Vp_Syn_Z  ELSE 'measured Vp log' END
```

[where the 'measured Vp log' = either Vp_INSITU or Vp_FSUB_BRINE]

The output of this process was a Vp log named either Vp_INSITU_GP or Vp_FSUB_BRINE_GP depending on the well. An example of step 2 is supplied below for well 21/25-10. There are small gaps in the Vp_INSITU log within the Lista Fm and these are shown by red highlights on the well log panel. The synthetic regional Vp log 'Trend_SDDI_Vp_Syn_Z' is displayed in the next track along and coloured purple to indicate it is a modelled log. The gaps in Vp_INSITU are infilled with synthetic regional Vp log and this created the gap filled Vp_INSITU_GP log.

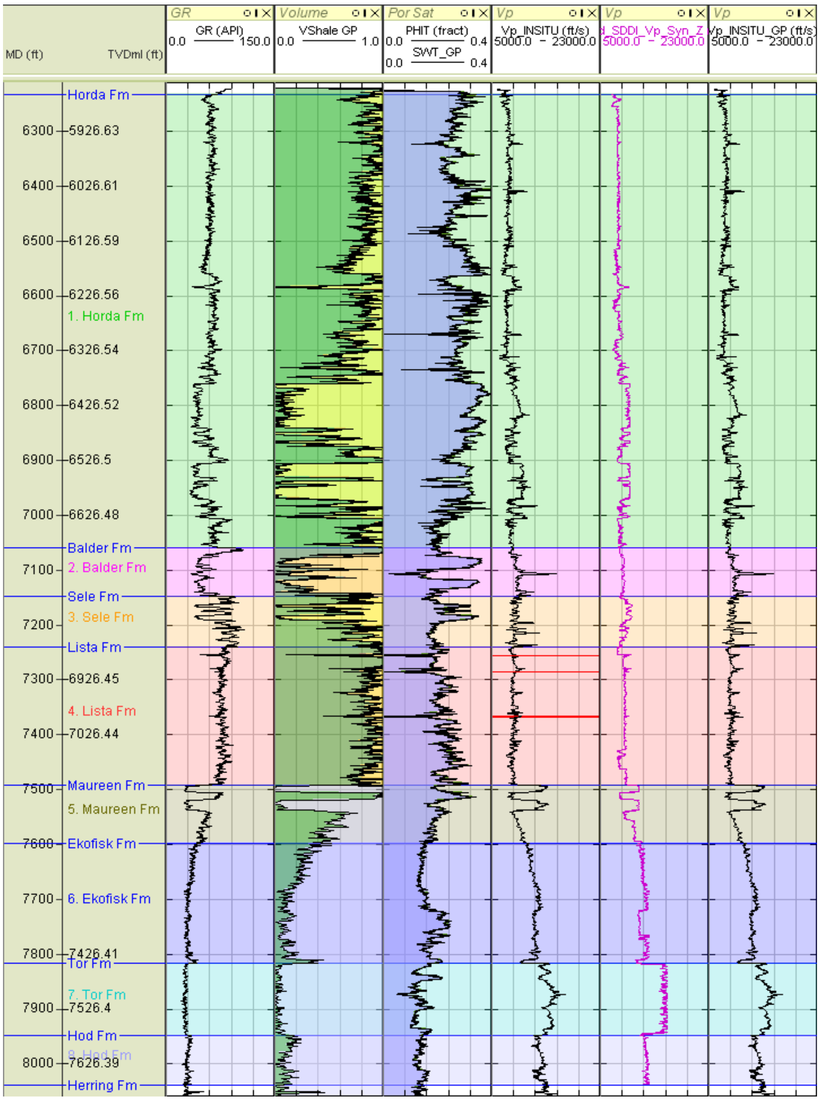


Figure 2.3.5 - Example of infilling the Vp log over red intervals with the regional synthetic log 'Trend_SDDI_Vp_Syn_Z' at well 21/25-10. NB - Any gaps above the study interval were also filled at the point using a spline function so the Vp log was continuous in the well and this was needed to use with check-shots later in the project.

Now that a gap-filled Vp log was available, Step 3 of the workflow was able to commence and this step involved modelling the Vs and Rhob logs. Since a complete Vp log was available, this log was used as the input to the modelling rather than the synthetic seismic logs from the multi-well section and therefore the Vs and Rhob modelled logs were generated from the Vp log (Vp_INSITU_GP or Vp_FSUB_BRINE_GP) using Backus averaging for the Vs log (as specified by Shell) and arithmetic averaging for the Rhob log (as specified by Shell).

An example of step 3 is given below for well 29/09C-04.

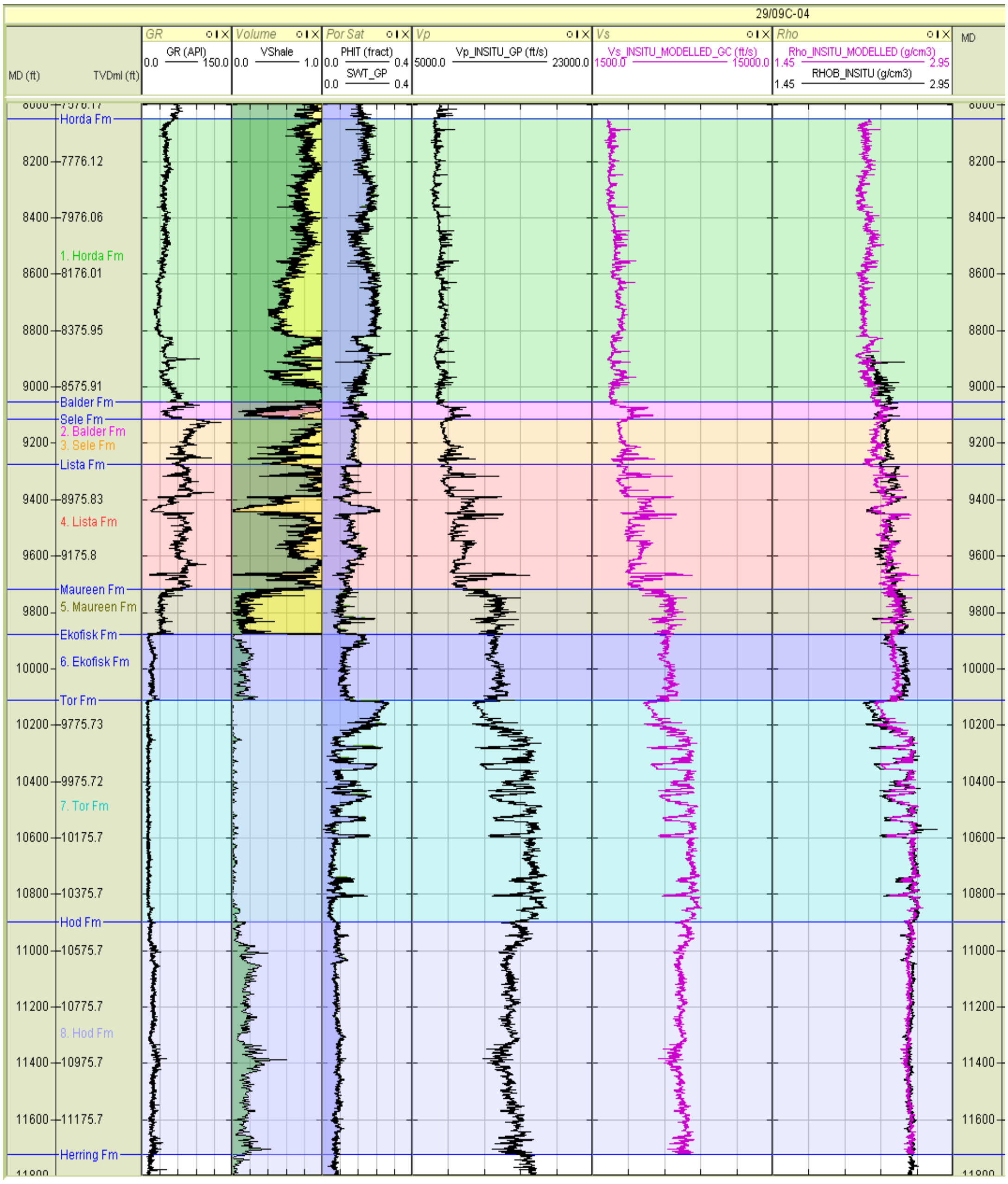


Figure 2.3.6 - Example of modelling the Vs and Rhob logs from the gap-filled Vp log at well 29/09C-04. The modelled Vp and Rhob logs are coloured in purple. This well has no measured Vs data and therefore the Vs log at this well will be entirely modelled Vs data.

Step 4 consisted of the actual infilling of the gaps within the measured Vs and Rhob logs with our modelled data. This was done in the relevant working intervals using the following formula for Vs and Rhob logs in RokDoc;

Vs log

```
IF 'measured Vs log' = $null THEN 'modelled Vs log' ELSE 'measured
Vs log' END
```

[where the 'measured Vs log' = either Vs_INSITU or Vs_FSUB_BRINE and the 'modelled Vs log' = either Vs_INSITU_MODELLED_GC or Vs_FSUB_BRINE_MODELLED_GC]

Rhob log

```
IF 'measured Rhob log' = $null THEN 'modelled Rhob log' ELSE 'meas-
ured Rhob log' END
```

[where the 'measured Rhob log' = either Rhob_INSITU or Rhob_FSUB_BRINE and the 'modelled Rhob log' = either Rhob_INSITU_MODELLED or Rhob_FSUB_BRINE_MODELLED]

The output of this process was a Vs log named either Vs_INSITU_GP or Vs_FSUB_BRINE_GP and a Rhob log named either Rhob_INSITU_GP or Rhob_FSUB_BRINE_GP depending on the well.

An example of step 4 is supplied below for well 22/12A-05.

There were gaps in the Vs_FSUB_BRINE log within all four formations in this well and these are shown by red highlights on the well log panel. The modelled Vs log 'Vs_FSUB_BRINE_MODELLED_GC' is displayed in the next track along and coloured purple to indicate it was a modelled log. The gaps in Vs_FSUB_BRINE were infilled with the modelled Vs log and this created the gap filled Vs_FSUB_BRINE_GP log.

There were gaps in the Rhob_FSUB_BRINE log within the Horda Fm and Balder Fm in this well and these are shown by red highlights on the well log panel. The modelled Rhob log 'Rhob_FSUB_BRINE_MODELLED' is displayed in the next track along and coloured purple to indicate it was a modelled log. The gaps in Rhob_FSUB_BRINE were infilled with the modelled Rhob log and this created the gap filled Rhob_FSUB_BRINE_GP log.

This gap filling exercise created a set of INSITU_GP or FSUB_BRINE_GP logs at every well in the study.

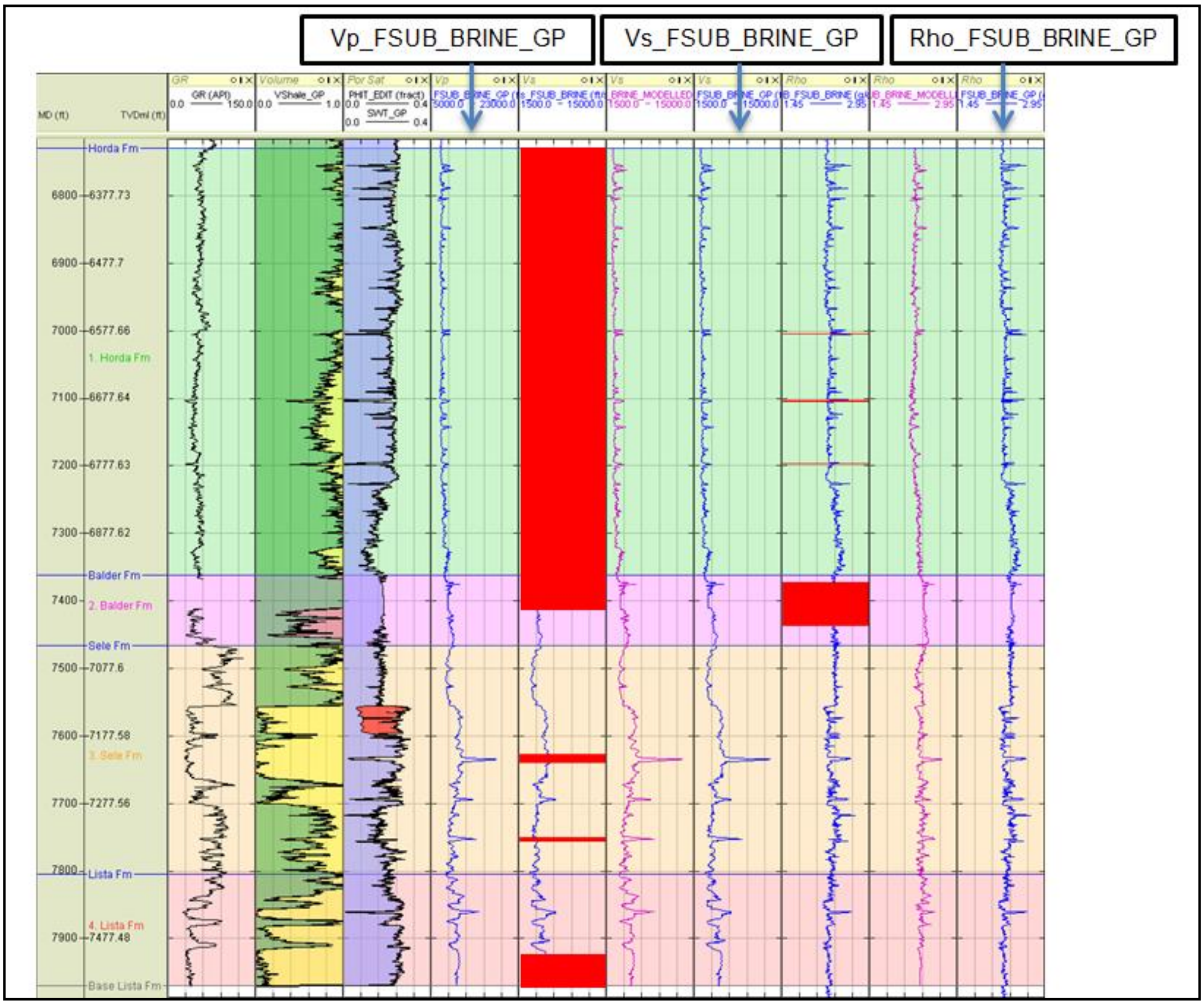


Figure 2.3.7 - Example of infilling the Vs and Rhob logs log with the modelled Vs and Rhob logs at well 22/12A-05.

Log conditioning - Modified Gassmann approach

The basic gap filling workflow that was just explained didn't cover the modified Gassmann approach (Mavko et al., 1997) and the modified Gassmann workflow will now be explained in this section.

The modified Gassmann approach is a method for modelling missing Vs data over hydrocarbon zones and we needed to apply this approach in thirteen of the thirty five wells in the study.

An example of the more straightforward case for using modified Gassmann is shown below for Well 21/25-04. In this well, the missing Vp and Rhob data can be filled with regional trends since it sits outside the hydrocarbon bearing zone. The missing Vs data was modelled with modified Gassmann since it sits within a hydrocarbon zone in the Horda Fm.

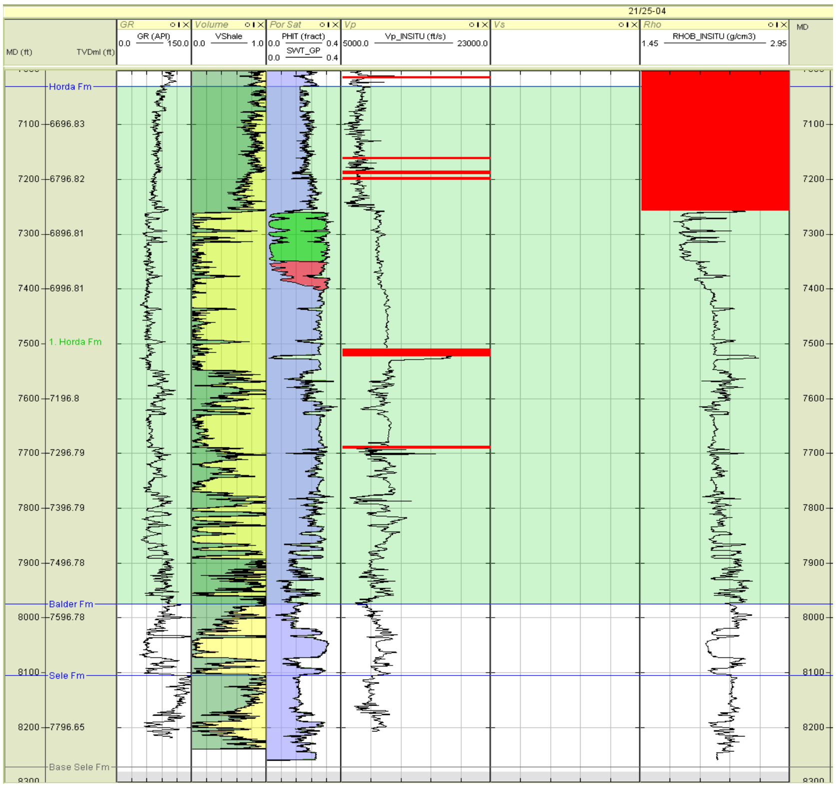


Figure 2.3.8 - Well 21/25-04 has missing Vs data over a hydrocarbon zone in the Horda Fm so 100% brine bearing regional trends will not work in this zone and therefore the modified Gassmann approach was used in this well.

The modified Gassmann approach for Vs prediction was parameterized using the calibrated Greenberg-Castagna coefficients updated for the Horda Fm from the multi-well analysis (see Vp-Vs summary, p.78).

Default G/C Coefficients

For velocities in km/s — Reset Values

Lithology	ai2	ai1	ai0
Shale	0	0.77	-0.867
Dolomite	0	0.583	-0.078
Limestone	-0.055	1.017	-1.03
Sandstone	0	0.804	-0.856

Updated G/C Coefficients

For velocities in km/s — Reset Values

Lithology	ai2	ai1	ai0
Shale	0	0.706	-0.751
Dolomite	0	0.583	-0.078
Limestone	-0.055	1.017	-1.03
Sandstone	0	0.76	-0.629

Figure 2.3.9 - This shows that the default Greenberg-Castagna coefficients were updated to the Greenberg-Castagna coefficients found in the multi-well section of the project during the modified Gassmann workflow. The Greenberg-Castagna coefficients have been converted from ft/sec to km/sec to use in this workflow.

The modified Gassmann approach for Vs prediction was then optimized to find the modified Gassmann fitting parameter to constrain the model. A summary of the Greenberg-Castagna coefficients and a table of the modified Gassmann fitting parameters used in the project was included in the 'Modified Gassmann tab' of the Master Spreadsheet.

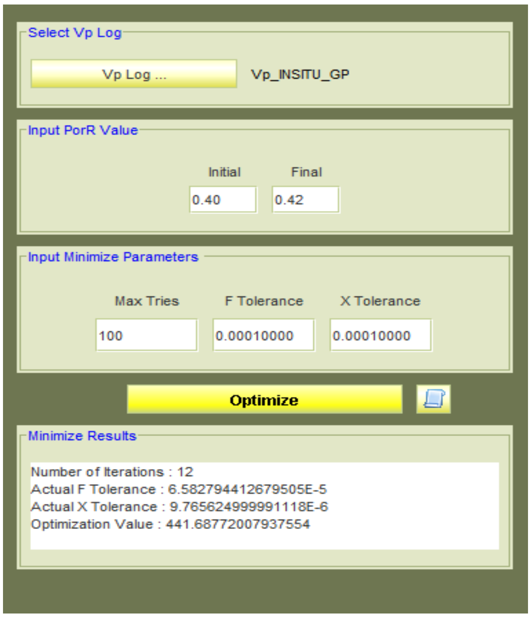


Figure 2.3.10 - This box shows the derivation of the modified Gassmann fitting parameter in the Horda Fm in Well 21/25-04.

The modified Gassmann approach for Vs prediction was run at well 21/25-04 using the parameters selected below;

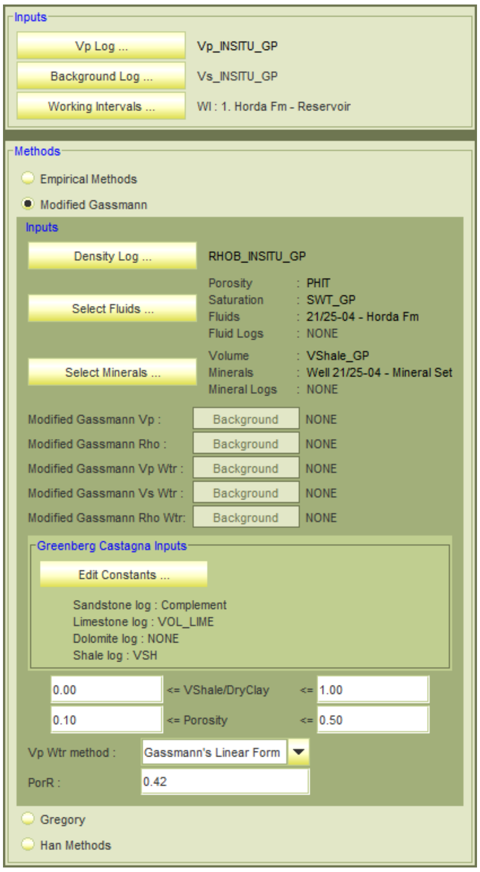


Figure 2.3.11 - This box shows the modified Gassmann method parameterised in the Horda Fm in Well 21/25-04.

The modified Gassmann module outputs the Vs log predicted over the hydrocarbon zone. For the other formations in the wells where there are no hydrocarbons present, ie - the Balder Fm and Sele Fm at well 21/25-04, the missing Vs log data was modelled with the 100% brine bearing trends therefore the two logs need to be combined. At well 21/25-04, the Vs log over the Horda Fm was modelled using the modified Gassmann approach and the Vs log over the Balder Fm and Sele Fm was modelled using the 100% brine bearing regional trends. The final output log of the modified Gassmann approach was called Vs_INSITU_GP and it was coloured purple to denote that it was an entirely modelled log.

The modified Gassmann module also outputs an estimate of the Vp and Rhob log predicted over the hydrocarbon zone. These were used as a quality control measure since if they matched with the measured Vp and Rhob logs then this showed that the modified Gassmann approach was producing a valid estimate of the Vs log over the hydrocarbon zone.

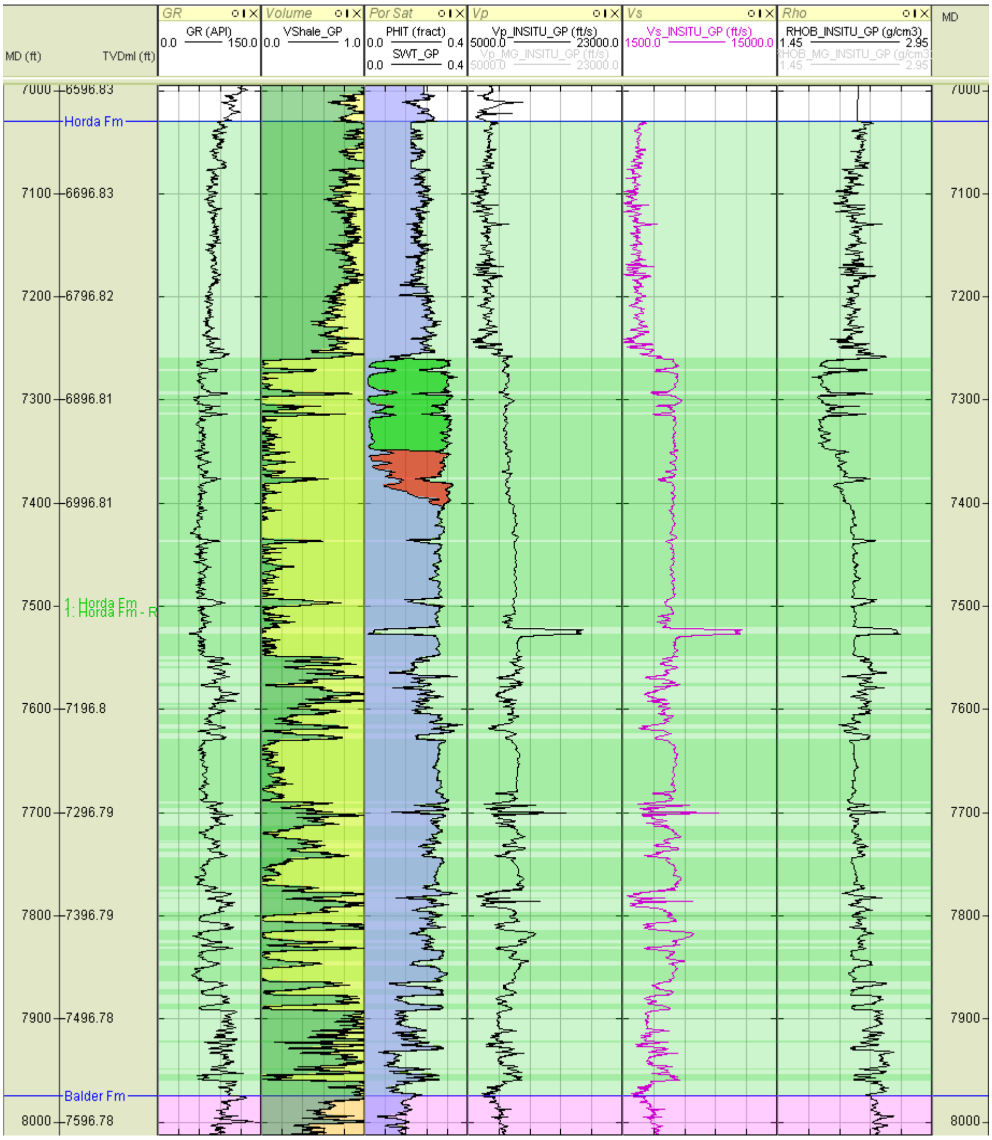


Figure 2.3.12 - Vp and Rhob estimate (grey logs) from the modified Gassmann module at well 21/25-04. Both logs were a close match to the measured data at this well.

Log conditioning - Special cases

The modified Gassmann approach did not work when there was a gap in the measured Vp or Rhob log data over the hydrocarbon zone. In the thirteen wells that required the modified Gassmann approach, this was an issue in five of those wells and those wells were named earlier on in this section of the report. However these gaps in the measured Vp or Rhob data over the hydrocarbon zone are relatively minor in the context of the project.
These gaps are summarised in the table below;

Well	Formation	Gap in ... log	Thickness (ft)
22/19-01	Sele	Rhob	~8
22/28A-01	Hod	Vp	~12
23/27-09	Tor	Rhob	~5
29/02A-06	Tor	Vp	~18
30/03A-01	Maureen	Rhob	~18

Table 2.3.5 – This table shows the gap thicknesses in the Vp and Rhob logs.

Each of these special cases is dealt with individually and details can be found in the accompanying single well rock physics - part 2 PowerPoint's, but typically involved deriving a local hydrocarbon filled trend between Vp-Rhob, which could be used to fill the gap in one with the other as there were no cases where both Vp & Rhob were missing in a hydrocarbon bearing interval.

Log conditioning - Quality control measures for the gap filling workflow

In some wells, it was found that the synthetic regional logs (ie - 'Trend_SDDI_Vp_Syn_Z') for Vp and the modelled synthetic logs for the Vs and Rhob logs were not always overlaying the measured data due to the nature of the regional trends. It was suggested that if the gaps in the measured log data were being filled by the modelled log data that wasn't perfectly overlaying the measured data then we could potentially have been creating false impedance contrasts and introducing erroneous spikes into the reflectivity series.

We found that the best way to monitor the infilling of gaps within the Vp, Vs and Rhob logs was to compare the zero-offset trace generated from gaps filled with modelled log data (INSITU_GP) and gaps filled with spline data (INSITU_GP_CR).

The logic behind this was that if the modelled log data provides a similar zero-offset trace to the spline data fit then this indicated that filling gaps with the modelled regional trend data was not causing spikes that are influencing the synthetic reflectivity since the spline function is the simplest way of filling the gaps in the log data. The streamer wavelet was used to generate the zero-offset trace. The streamer and broadband wavelets were also used to generate synthetic gathers in the latter stages of the workflow.

To advance with this workflow, we first needed to create spline-filled curves for the Vp and Rhob logs. Here is an example for well 21/25-10 and in this case, the Vp_INSITU log is filled with a spline function to create the Vp_INSITU_GP_CR log and the Rhob_INSITU log is filled with a spline function to create the Rhob_INSITU_GP_CR log.

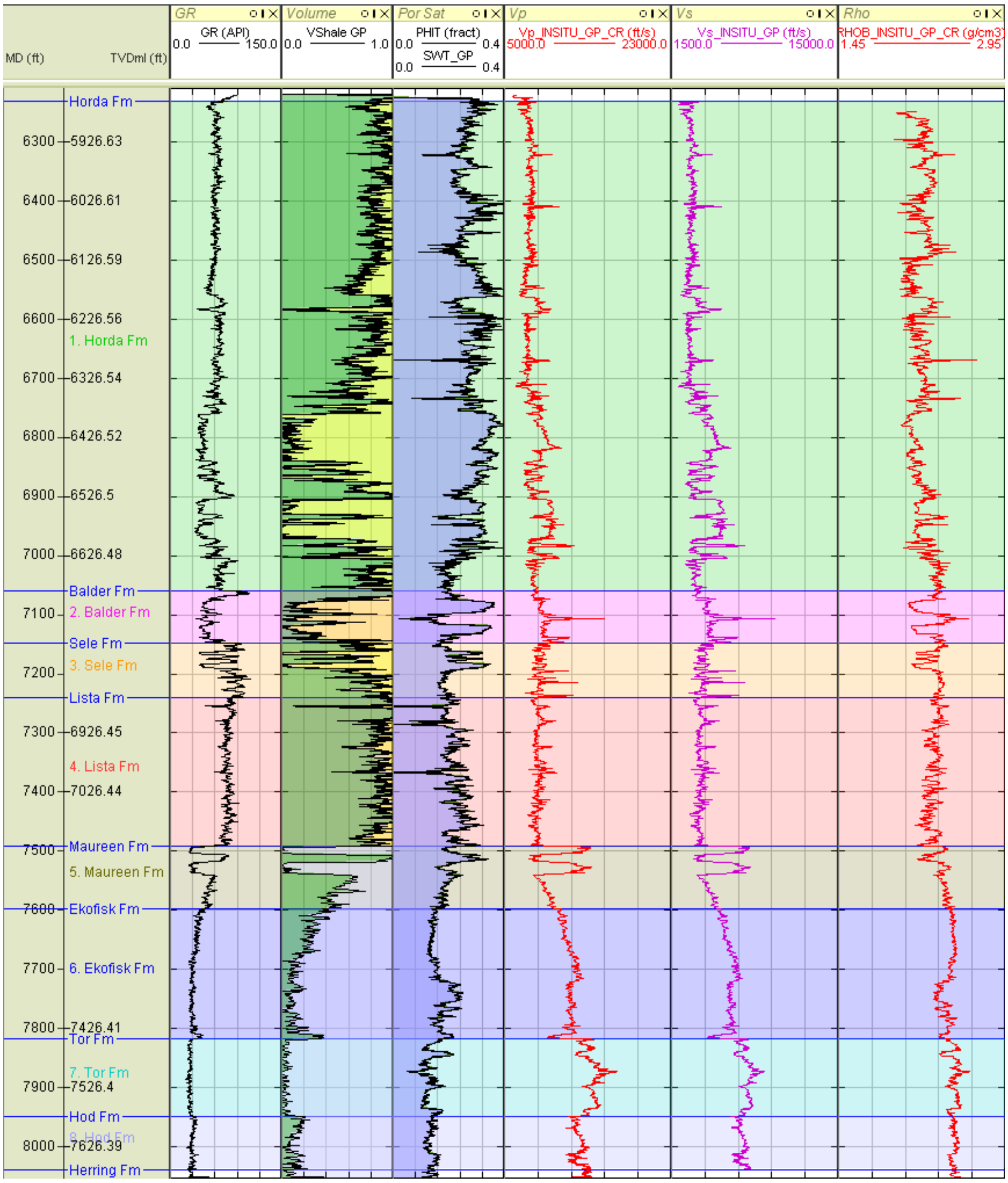


Figure 2.3.13 - Well log panel showing the spline-filled curves at well 21/25-10.

The spline curves shown in Figure 2.3.13 are from Step 5 of the gap-filling workflow (see Single Well Rock Physics - Part 2 QC-PPT). The earlier steps of this workflow (Steps 1-4) highlight the gaps in the well log data on the well log panels and detail how these gaps are filled with regional trends at each well. The same gaps are filled in Step 5 by the spline curves. Within the RokDoc project, it is possible to identify the spline-filled gaps in the log data by underlaying the spline filled curves below the pre-gap filled curves (FSUB_BRINE for wells with measured Vs data or INSITU curves for wells without measured Vs data).

The next stage of this workflow involved creating a Time-Depth relationship for all of the wells so we could generate the zero-offset traces. This was done using the check-shot data supplied by Shell and the Vp_INSITU_GP log to do the conversion. The check-shot data has been loaded as supplied by Shell and it has not been subjected to any detailed quality control measures so this must be taken into consideration for a project end-user.

This Time-Depth conversion was named 'Time-Depth conversion'.

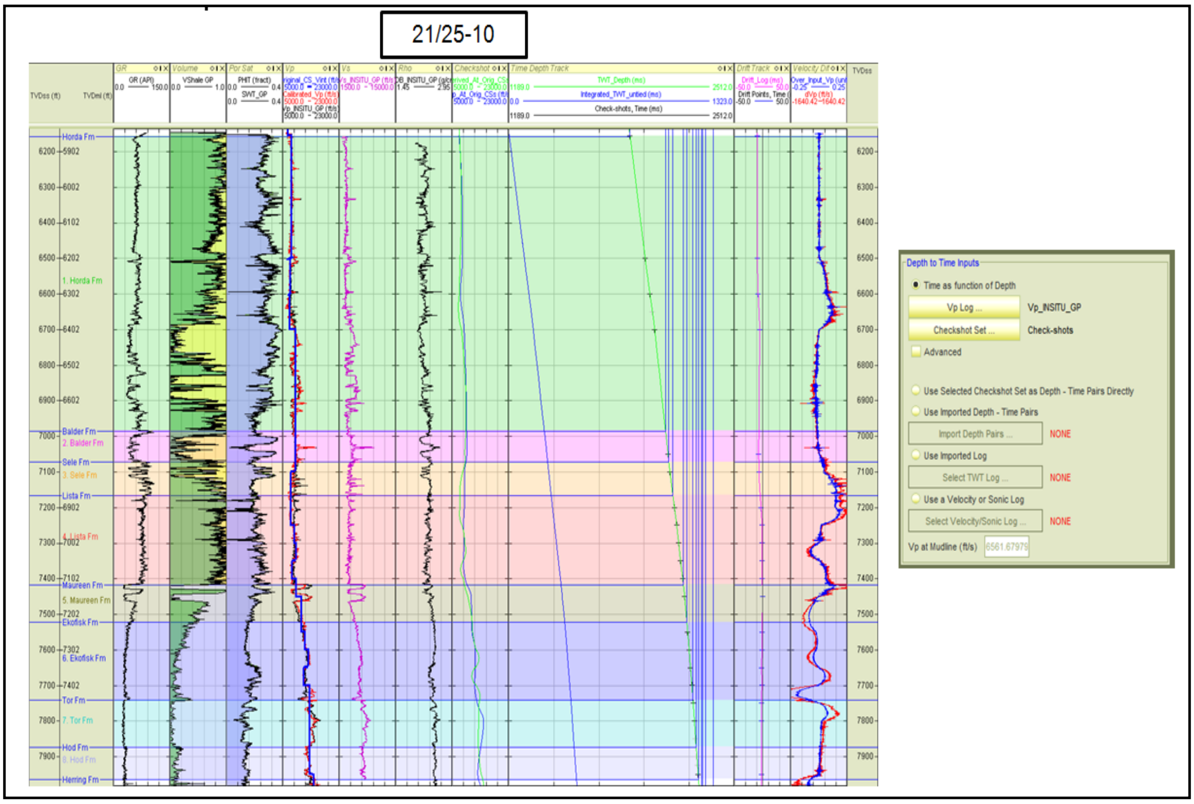


Figure 2.3.14 - Creating a Time-Depth relationship using Vp_INSITU_GP log at well 21/25-10.

NB - For the twelve wells with measured Vs data, Vp_INSITU_GP log was not available since the gap filled Vp log was Vp_FSUB_BRINE_GP. In these cases, a temporary Time-Depth conversion was made and named 'Time-Depth conversion (Temp)' so that the zero-offset trace QC could take place at this stage of the project. A permanent Time-Depth conversion was created later in the workflow using the Vp_FSUB_INSITU_GP log that was created after Gassmann fluid substitution to hydrocarbons and insitu conditions in these twelve wells with measured Vs log data. This Time-Depth conversion was named 'Time-Depth conversion'.

After the Time-Depth conversion was completed for all wells then we were able to produce zero-offset traces for modelled and spline-filled methods of filling the gaps in the log data.
An example of these zero-offset traces is supplied below for well 21/25-10. The last track shows the Trace Difference and this was simply calculated using the log calculator functionality to subtract the trace with the gaps filled by the spline function from the trace with gaps filled using modelled log data.

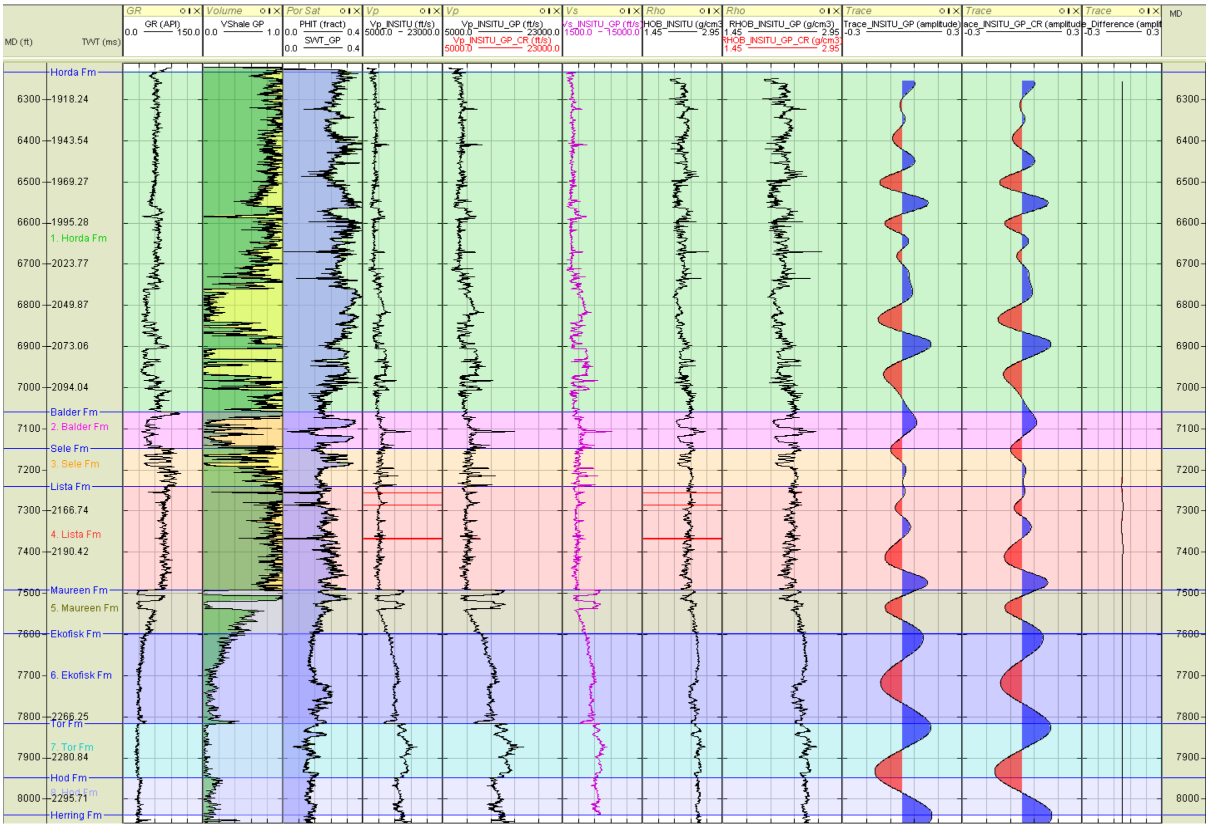


Figure 2.3.15 - Well log panel showing the zero-offset traces generated at well 21/25-10. The trace in the first of the trace tracks represents the logs whose gaps have been filled using the modelled data with regional trends, the trace in the second of the trace tracks represents the logs whose gaps have been filled using the spline function and the trace in the third of the trace tracks represents the difference between the previous two traces.

In this example and for most of the wells in the study, the difference between the two zero-offset traces was minimal and this gave confidence that the gap filling using the modelled log data was not introducing spikes into the gap filled data that were taken through to the latter stages of the rock physics analysis.

For the rare occasions where the modelled data was introducing spikes into the measured log data, the spline functions have been used to fill the gaps instead and this has been documented in the accompanying PowerPoint's called 'Single Well Rock Physics - Part 2'. This occurs in wells 22/21-D7 and 22/26A-01.

Log conditioning - Gassmann fluid substitution to 100% brine conditions

For the twenty three wells that originally had no measured Vs data, Gassmann fluid substitution to 100% brine bearing data was then carried out and this ensured that a set of Vp, Vs and Rhob logs with a suffix of 'FSUB_BRINE_GP' were available for all wells. The remaining mineral sets were also found and this set of logs was then used in further Gassmann fluid substitution work.

Gassmann fluid substitution from 100% brine conditions to hydrocarbon cases

The starting point for the Gassmann fluid substitution to the hydrocarbon cases and back to insitu saturations was a set of gap-filled 100% brine bearing Vp, Vs and Rhob logs. This Vp-Vs-Rhob was named 'FSUB_BRINE_GP' and an example is provided below for well 22/27A-01.

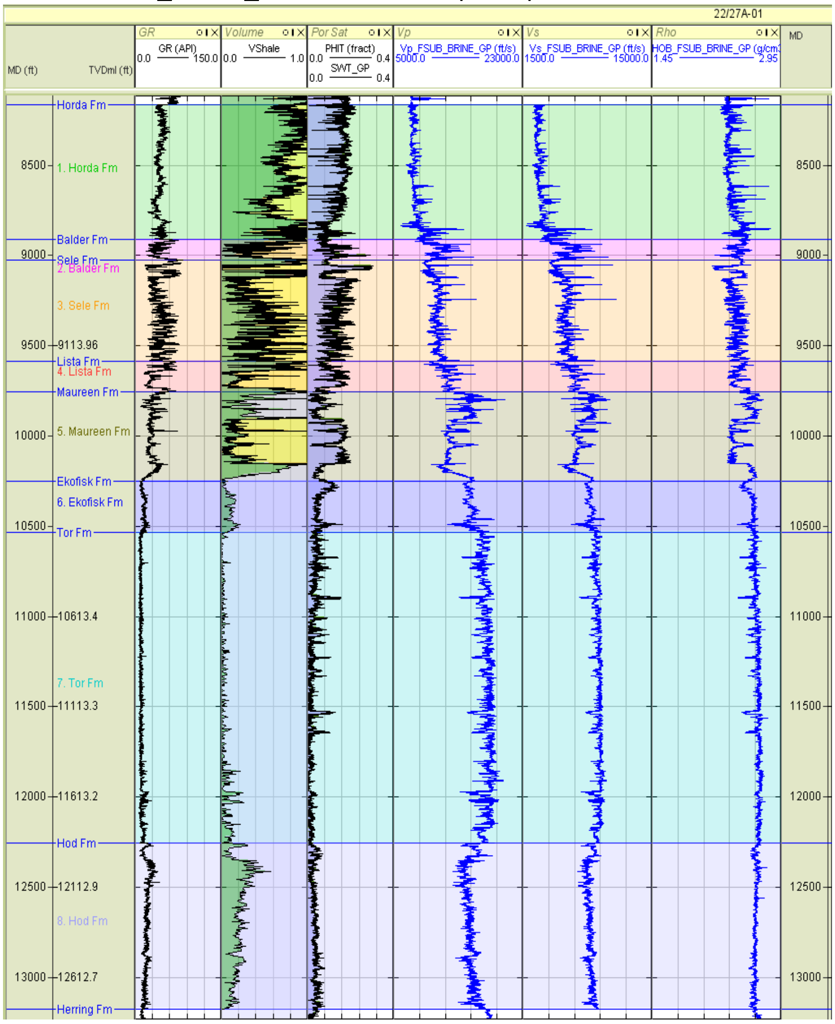


Figure 2.3.16 - Well log panel for 100% brine bearing data at well 22/27A-01.

Gassmann fluid substitution was performed to output the following fluid cases in each reservoir interval in every well;

- Final saturation: 80% oil, 20% water: Suffix = FSUB_OIL_GP
- Final saturation: 90% gas, 10% water: Suffix = FSUB_GAS_GP
- Final saturation: 80% condensate, 20% water: Suffix = FSUB_COND_GP*
- Final saturation: INSITU conditions: Suffix = FSUB_INSITU_GP

* NB - Gassmann fluid substitution to 80% condensate saturation was only performed in the wells that required a condensate fluid set. RokDoc functionality does not allow condensate saturation to be selected directly so a saturation set representing 80% condensate was created and can be found in the RokDoc project (see definition of fluid sets, p.35).

The Gassmann fluid substitution was again only performed in working intervals where there was a viable reservoir present. The reservoir was defined on the basis of cut-offs provided by Shell during the petrophysics stage of the project and an example of defining the reservoir is provided below for well 22/27A-01;

Well	Formation	Porosity cut-off	Shale Volume cut-off	Gross Reservoir (ft)	Net Reservoir (ft)	Reservoir interval present
22/27A-01	Horda Fm	PHIT >= 0.15	VSH<=0.4	747	6	No
22/27A-01	Balder Fm	PHIT >= 0.12	Vol_Sand>=0.6	110	42.5	Yes
22/27A-01	Sele Fm	PHIT >= 0.12	VSH<=0.5	561	284.25	Yes
22/27A-01	Lista Fm	PHIT >= 0.10	VSH<=0.4	173.13	79.25	Yes
22/27A-01	Maureen Fm	PHIT >= 0.08	VSH<=0.45	491.87	233.5	Yes
22/27A-01	Ekofisk Fm	PHIT >= 0.06	VSH<=0.4	283.61	108.5	Yes
22/27A-01	Tor Fm	PHIT >= 0.03	VSH<=0.2	1723.39	559	Yes
22/27A-01	Hod Fm	PHIT >= 0.03	VSH<=0.4	919	604.75	Yes

Sand Volume cut-off used in Balder Fm. This will exclude non-reservoir Shale and TUFF.

Figure 2.3.17 - Reservoir classification at well 22/27A-01. If there is less than 10ft of reservoir within a working interval then it is classified as being non-viable reservoir.

Gassmann fluid substitution was performed using the Log Fluid Sub (Gassmann Dry Rock Modelling) tool in RokDoc. The first tab in the module is the Initial to Dry tab and the relevant mineral and fluid properties for the particular working interval were selected at this stage. The working interval was also selected at this point and all the working intervals with the reservoir cut-offs applied (these are given a suffix of reservoir) are available in the RokDoc project

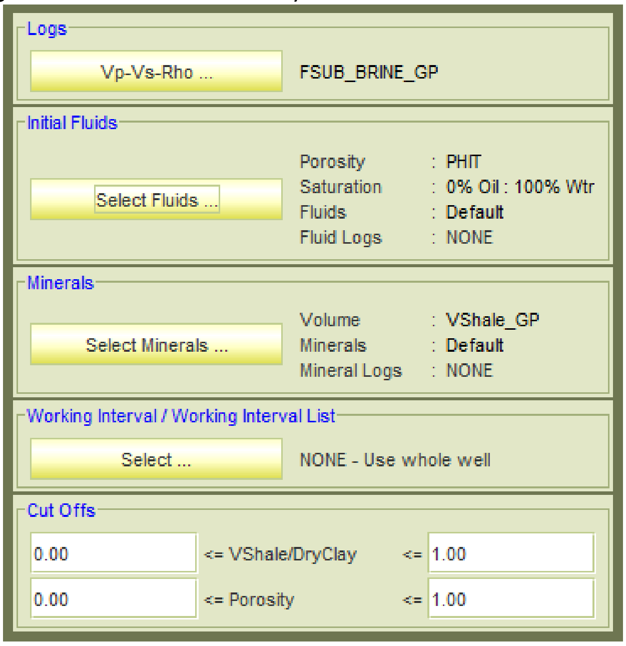


Figure 2.3.18 - Initial to Dry tab in Gassmann fluid substitution

The next tab in the module is the Dry Rock Modelling tab and at this point, we were able to see quality control plots of the dry rock frame parameters versus porosity. We were also given the choice about the model bounds and the dry rock modelling method in this tab. The 'Use Dry Rock Bound

Constraints' was selected every time for the dry rock modelling method whereas the upper model bound was turned off on every occasion. The same lower model bound was selected as the previous fluid substitution to 100% brine conditions and the Kdry/Kmin vs. porosity cross-plot often showed the effects of points plotting below the lower model bound that had been moved up onto the lower model bound. All of the relevant cross-plots and information on the model lower bound selected are available within the PowerPoint's. An example of the Dry Rock QC plots is provided below;

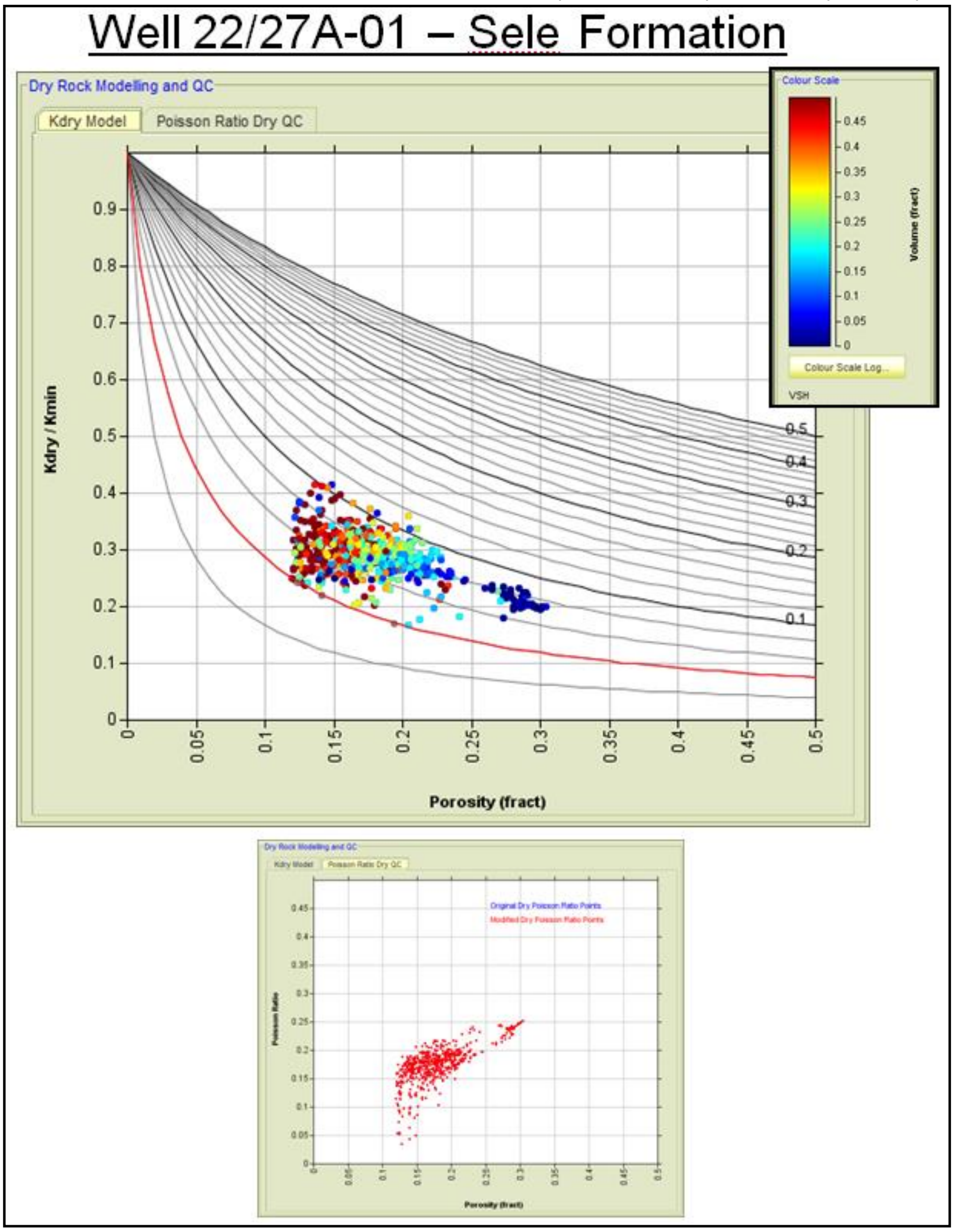


Figure 2.3.19 - Dry Rock QC Plots for the Sele formation in well 22/27A-01. The upper plot shows Kdry/Kmin vs. porosity and it is coloured by shale volume with a blue colour representing the cleanest sand points and a red colour representing the siltier sand points. The lower plot shows Poisson's ratio vs. porosity.

The workflow of selecting the relevant fluid set, mineral set and working interval on the Initial to Dry tab, selecting the lower model bound on the Dry Rock Modelling tab and then finally the final fluid saturations was repeated in every working interval with a viable reservoir in the well. The results of the Gassmann fluid substitution at well 22/27A-01 are now displayed below;

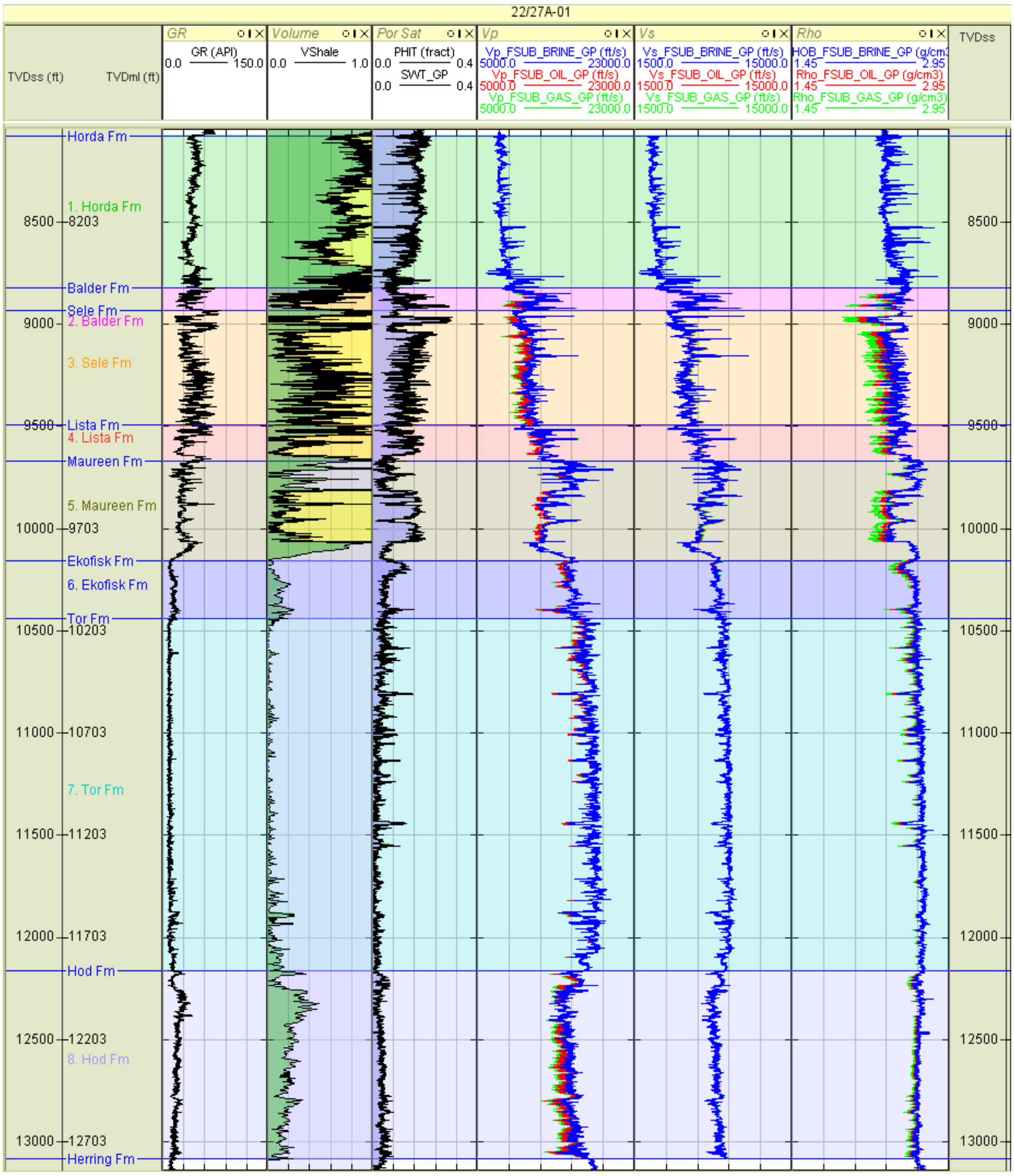


Figure 2.3.20 - Well log panel for 100% brine bearing data (blue coloured logs), 80% oil bearing data (red coloured logs) and 90% gas bearing data (green coloured logs) at well 22/27A-01. NB - Fluid substituted data was also available for insitu conditions at this stage of the project too but is not shown on the well log panels.

Since there was a Vp_FSUB_INSITU_GP log now available at this point in the study, the remaining Time-Depth relationships were calculated for the twelve wells with measured Vs data.

The fluid substituted results at well 22/27A-01 show that there was a slight decrease in Vp and density log values for the oil fluid case and a larger decrease in Vp and density log values for the gas fluid case. As would also be expected, there was a larger fluid effect in higher porosity sections of the well such as the Sele Fm, Lista Fm and Maureen Fm whilst there was a much smaller fluid effect in the lower porosity sections of the well such as the Ekofisk Fm and Tor Fm. No fluid substitution was carried out in the Horda Fm at well 22/27A-01 since it was not considered to be a viable reservoir interval.

Synthetic gathers, elastic logs and reflectivity series

Elastic logs were generated using the Log Elastic Properties functionality in RokDoc for all fluid cases at every well. The elastic logs selected in this study were;

- Acoustic impedance
- Shear impedance
- Poisson's ratio
- Vp/Vs ratio*

* Vp/Vs ratio was created in the log calculator

Synthetic gathers were also created using the wavelets supplied by Shell;

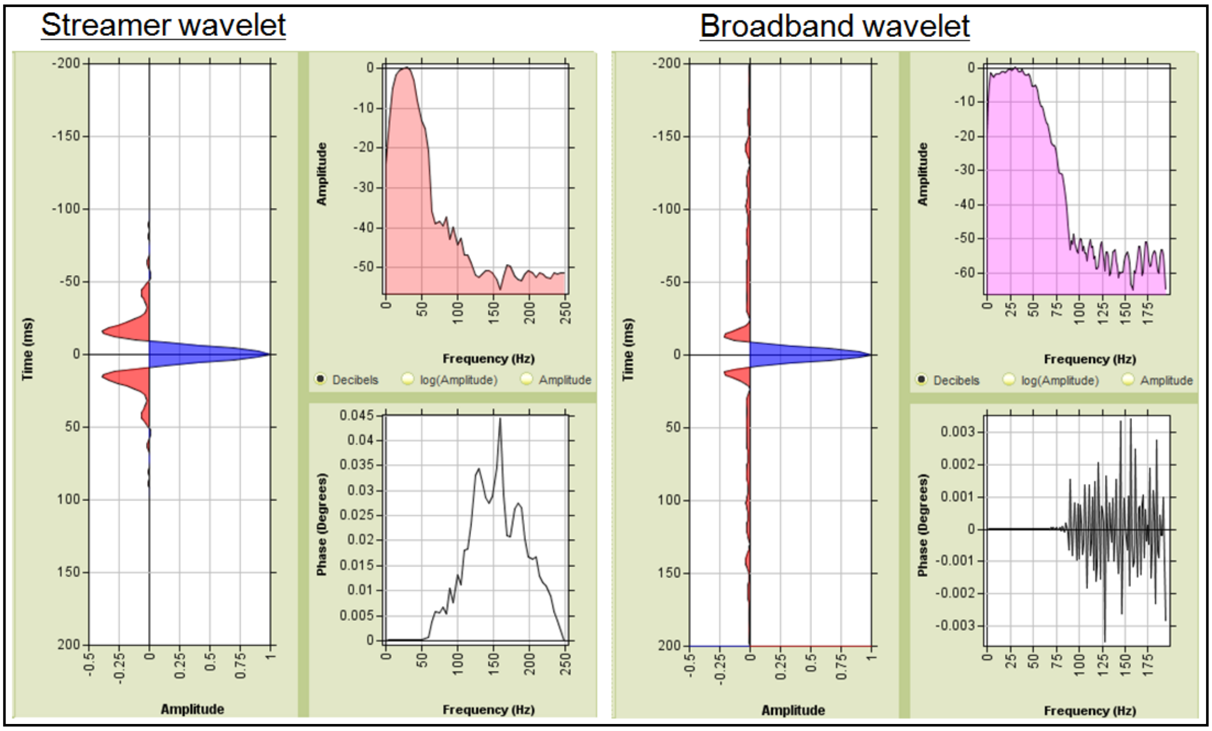


Figure 2.3.21 - The two wavelets supplied by Shell that were used in generating the synthetic gathers

The well log panel below shows the elastic logs and synthetic gathers produced for well 22/27A-01. This well log panel is provided in this section of the report just as an example of the workflow and all of the interpretation/key images of the fluid/AVO effects for each individual well will be given in Chapter 3 of the report in the Single Well Analysis section.

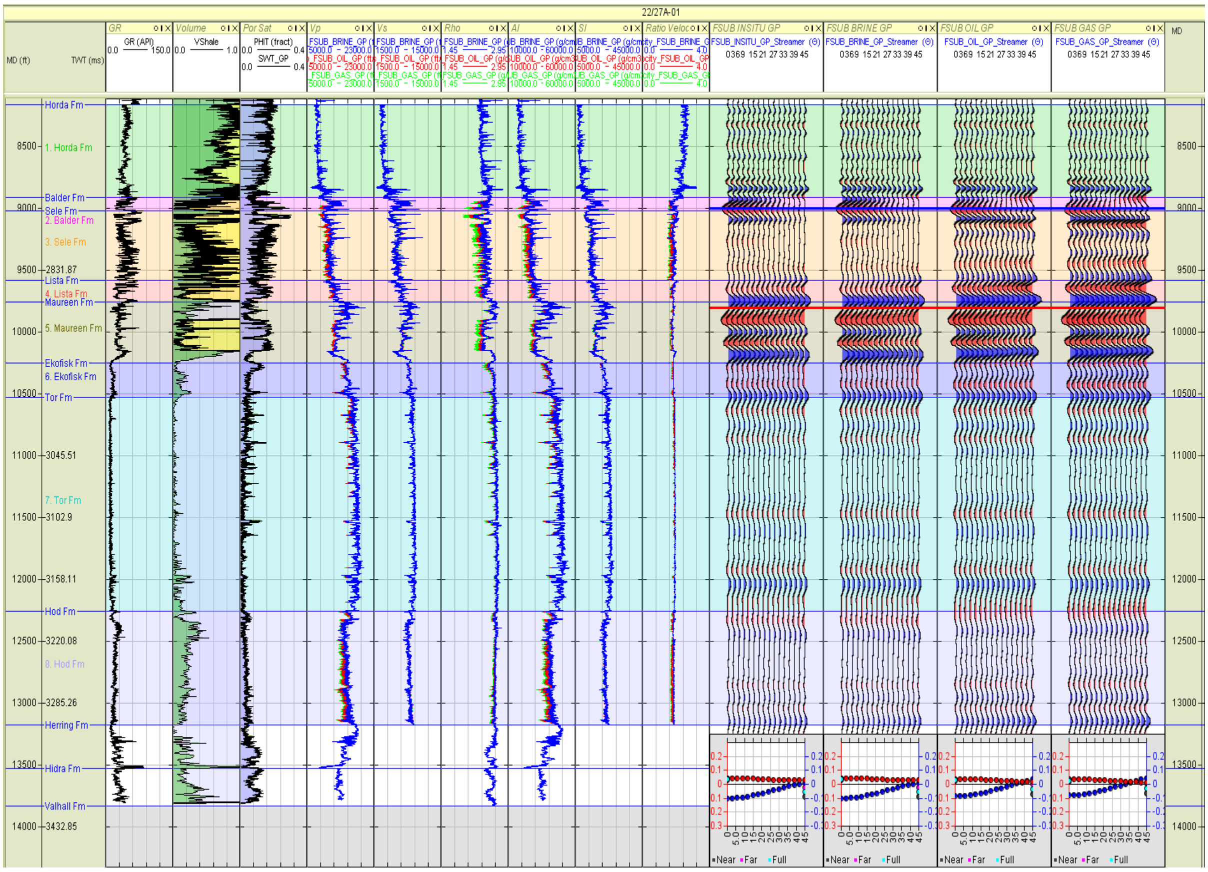


Figure 2.3.22 - Example of complete well log panel at well 22/27A-01; the streamer wavelet was used to calculate the synthetic gathers. The tracks contain GR log, volume fraction set, saturation set and porosity log, Vp logs, Vs logs, Rhob logs, AI logs, SI logs, Vp/Vs logs, FSUB_INSITU_GP gather, FSUB_BRINE_GP gather, FSUB_OIL_GP gather and FSUB_GAS_GP gather.

At this point in the study, a reflectivity spike series that represented the acoustic (normal) impedance and shear impedance reflectivity were created in the RokDoc project for each of the fluid cases. A reflectivity spectrum was also created from the INSITU_GP gathers at each well and this shows the reflectivity spike series at angles of 0, 10, 20, 30 and 40 degrees for the INSITU_GP synthetic gather.

NB - It is important to note that the Vs log for twenty three wells will consist entirely of modelled data and this should be kept in mind when focusing on any elastic attributes that use the Vs log such as Vp/Vs ratio and any non-zero incidence synthetic gathers.

Average values

The last part of the workflow was to find representative clean sand and shale average values that could be used to create 1D blocky halfspace AVO models for the Tertiary and Cretaceous sections of the wells.

The method of finding these averages in the Tertiary intervals was to use Vp-Rhob and Vp-Vs cross-plots to isolate the clean sand (for each fluid case) and clean shale data points and a clean lithology cut-off of Volume>0.7 was used for both of these lithologies. The clean sand average values were only taken if there was a viable reservoir interval present in that formation.

It was possible to find the statistics on the cross-plot and this was shown on the cross-plot below;

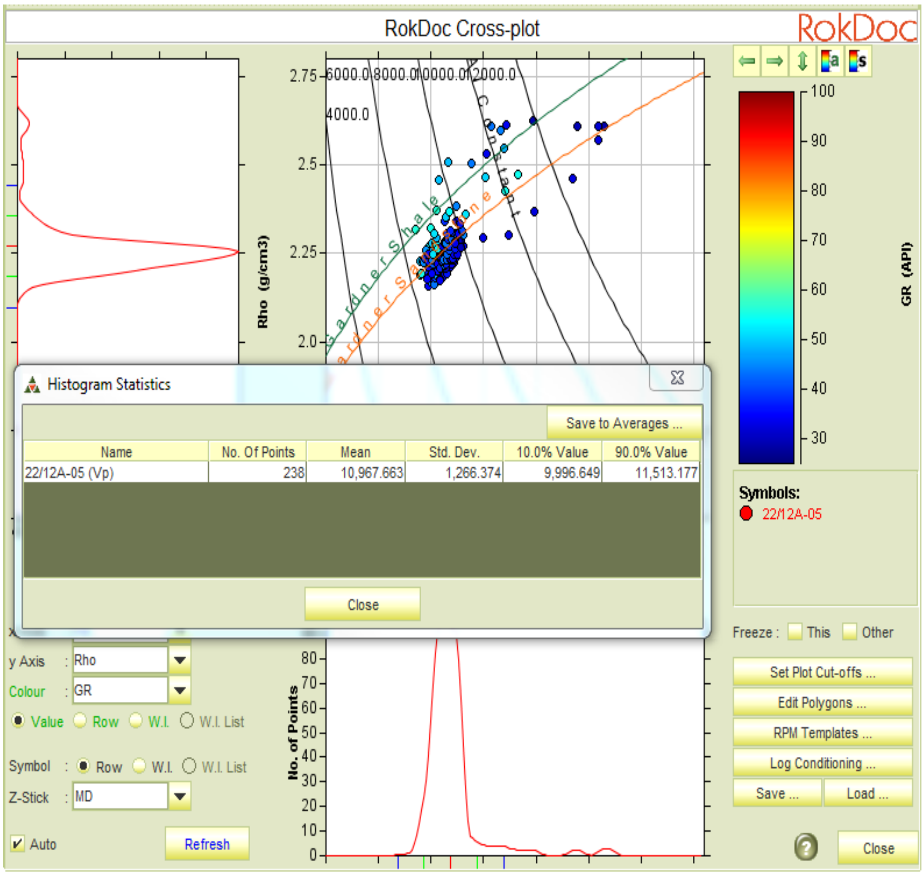


Figure 2.3.23 - Vp-Rhob cross-plot with the statistics box used to make averages

This process was carried out manually for all of the wells and the average values were recorded in the project in the form of averages. These values were also recorded in the PowerPoint's and the master spreadsheet that have been supplied with the project. An example of the averages recorded in the Tertiary intervals is supplied below for well 21/20A-02.

Name	Well	Vp Mean	Vs Mean	Rho Mean	Vp Std Dev	Vs Std Dev	Rho Std Dev	Colour
21/20A-02 - Balder Fm - Clean Shale	21/20A-02	7,809.38	3,140.173	2.416	190.809	155.163	0.036	
21/20A-02 - Balder Fm - Clean Tuff	21/20A-02	9,428.698	4,842.9	2.407	737.741	696.397	0.047	
21/20A-02 - Horda Fm - Clean Sand FSUB_BRINE	21/20A-02	10,425.135	5,714.802	2.249	1,556.024	1,143.037	0.107	
21/20A-02 - Horda Fm - Clean Sand FSUB_GAS	21/20A-02	9,361.204	5,952.293	2.073	1,929.271	1,136.182	0.171	
21/20A-02 - Horda Fm - Clean Sand FSUB_OIL	21/20A-02	9,526.287	5,802.392	2.181	1,821.432	1,140.063	0.131	
21/20A-02 - Horda Fm - Clean Shale	21/20A-02	7,748.608	3,106.828	2.324	823.205	590.342	0.062	
21/20A-02 - Lista Fm - Clean Sand FSUB_BRINE	21/20A-02	12,371.266	6,596.028	2.487	1,706.9	1,063.931	0.084	
21/20A-02 - Lista Fm - Clean Sand FSUB_GAS	21/20A-02	12,037.411	6,663.891	2.438	2,117.266	1,070.883	0.138	
21/20A-02 - Lista Fm - Clean Sand FSUB_OIL	21/20A-02	12,087.915	6,622.087	2.468	1,988.828	1,066.003	0.105	
21/20A-02 - Lista Fm - Clean Shale	21/20A-02	9,365.225	4,425.779	2.47	793.061	598.962	0.043	
21/20A-02 - Maureen Fm - Clean Sand FSUB_BRINE	21/20A-02	11,723.071	6,306.827	2.338	1,481.977	878.559	0.123	
21/20A-02 - Maureen Fm - Clean Sand FSUB_GAS	21/20A-02	11,025.625	6,480.469	2.212	1,808.447	828.19	0.183	
21/20A-02 - Maureen Fm - Clean Sand FSUB_OIL	21/20A-02	11,145.454	6,375.483	2.287	1,733.223	858.304	0.148	
21/20A-02 - Maureen Fm - Clean Shale	21/20A-02	9,374.466	4,510.392	2.478	687.545	482.402	0.033	
21/20A-02 - Sele Fm - Clean Sand FSUB_BRINE	21/20A-02	9,165.097	4,217.557	2.173	1,086.028	1,047.602	0.073	
21/20A-02 - Sele Fm - Clean Sand FSUB_GAS	21/20A-02	7,830.99	4,434.633	1.959	1,383.069	1,017.412	0.118	
21/20A-02 - Sele Fm - Clean Sand FSUB_OIL	21/20A-02	8,041.549	4,298.15	2.09	1,323.413	1,036.426	0.091	
21/20A-02 - Sele Fm - Clean Shale	21/20A-02	8,605.003	3,914.171	2.419	299.582	232.163	0.024	

Figure 2.3.24 - Example of the clean sand and shale average values for well 21/20A-02.

Further averages were also found to represent clean limestone average values in the Cretaceous intervals and the average values of the overburden and underburden lithology.
At this point in the study, we created overburden and underburden working intervals. The overburden working interval included data 300ft above the top of the Horda Fm whilst the underburden working interval included data 300ft below the base of the Hod Fm.

The method of finding the clean limestone averages was to use Vp-Rhob and Vp-Vs cross-plots to isolate the clean limestone points (for each fluid case) and a clean lithology cut-off of Vol_Lime>0.9 was used for the limestone lithology. The clean limestone average values were only taken if there was a viable reservoir interval present in that formation.

NB - There were intervals in the Tertiary where limestone was present and for these cases, this method was used but with a clean lithology cut-off of Vol_Lime>0.7 to compensate for the lack of clean limestone points in some wells.

The method of finding the overburden and underburden averages was to use Vp-Rhob and Vp-Vs cross-plots to highlight the points sitting in the overburden and underburden working intervals. The INSITU measured log data was selected for these averages and in places where no log data was available then no averages were taken in these sections. No cut-offs were applied to the cross-plots and these averages are simply there to represent the likely seismic properties immediately above and below the study interval.

NB - It must be remembered that no detailed rock physics QC has been done in these intervals and these average values are provided as a guide.

Blocky AVO models

The clean sand and shale averages were then used to make blocky AVO plots to identify the likely seismic response over a particular shale/sand interface in the Tertiary section of the wells. These plots are displayed and analysed for every Tertiary reservoir interval in Chapter 3 of the report. An example of the blocky AVO plots is provided below for well 21/20A-02;

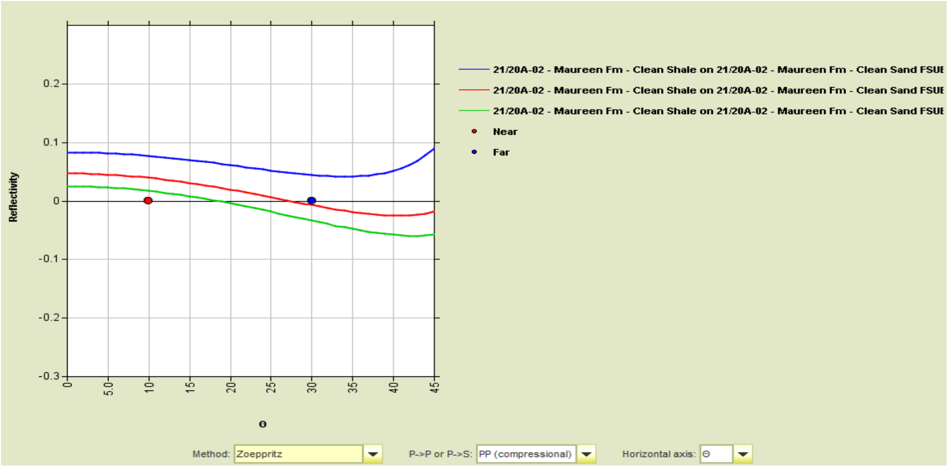


Figure 2.3.25 - Example of blocky AVO plot in the Maureen Fm in well 21/20A-02.

This AVO plot shows that the reflectivity at the shale/sand interface in the Maureen Fm will change from a class I AVO response for brine bearing reservoir saturations to a class IIp AVO response for oil and gas bearing reservoirs.

Blocky AVO plots were also produced for the Cretaceous working intervals even though there is only one lithology in these sections. The interfaces analysed are as follows and the key point is that the brine-filled reservoir provides the overburden layer at two of the three interfaces;

Interface 1

Maureen Shale / Ekofisk Limestone (Brine, Oil, Gas and Condensate)

Interface 2

Ekofisk Limestone (Brine) / Tor Limestone (Brine, Oil, Gas and Condensate)

Interface 3

Tor Limestone (Brine) / Hod Limestone (Brine, Oil, Gas and Condensate)

Log Edit Audit curves

The very last part of the workflow was to run the script to highlight at what stage of the workflow logs were edited (as per the flow diagram in Chapter 2.1). Log edits were performed in three major phases recorded using the following log names;

- Data removed during petrophysical stage (EDIT_RAW_EDIT)
- Data removed prior to multi-well analysis (EDIT_RAW_INSITU)
- Data modelled in following multi-well analysis (EDIT_RAW_INSITU_GP)

These are the curves are shown in the last three tracks of the well panel below for well 22/28A-01;

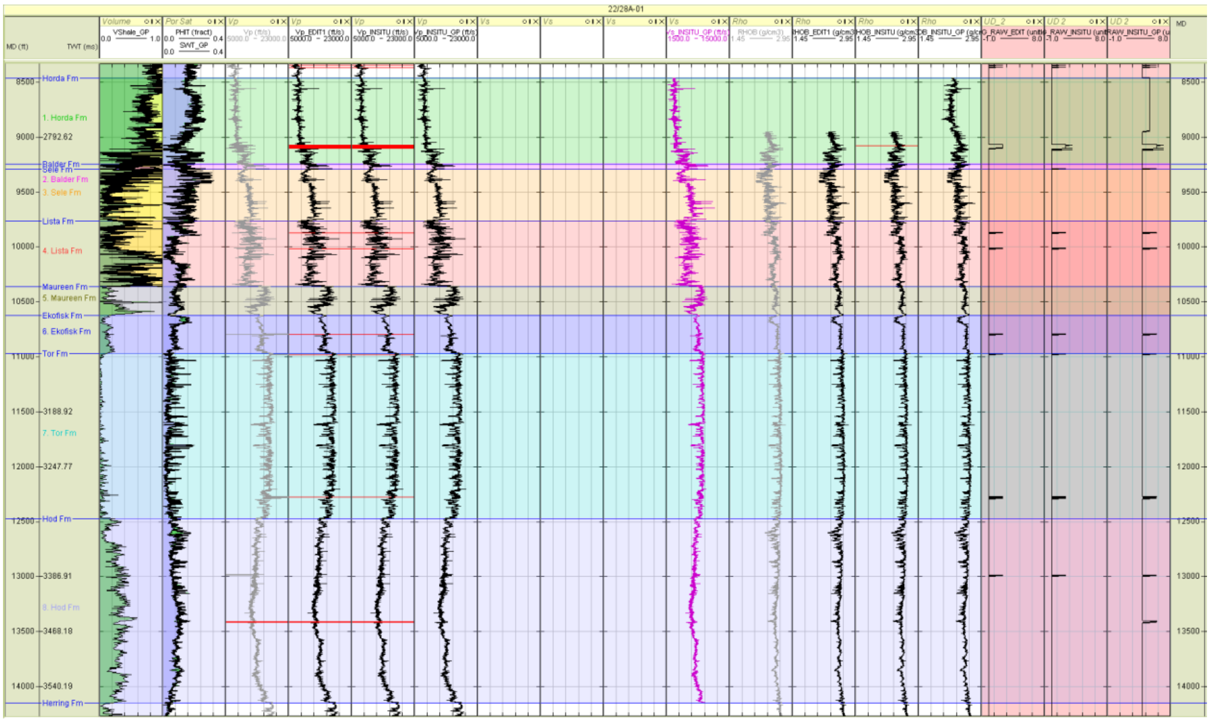


Figure 2.3.26 - Log edit audit curves for well 22/28A-01. The edit log classification is 0=No edit, 1=Edit in Rhob, 2=Edit in Vp and 4=Edit in Vs. ***The classification is cumulative so a value of 3 means there has been edits in the Vp and Rhob logs, a value 5 means there has been edits in the Vs and Rhob logs, a value of 6 means there has been edits in the Vp and Vs logs and a value of 7 means edits in all logs.***

Multi-well trend analysis using fluid substituted data

Following completion of the rock physics workflow, it was also in the project scope to consider the multi-well analysis with Gassmann fluid substituted data over the reservoir intervals.

The following rock physics relationships (y(x)) were to be considered;

- Vp-PhiT
- Rhob-PhiT
- AI-PhiT

for the following fluid cases;

- 100% Brine - FSUB_BRINE_GP logs selected
- 80% Oil - FSUB_OIL_GP logs selected
- 90% Gas - FSUB_GAS_GP logs selected

These relationships were found for every formation in the study interval and thus they were found for eight working intervals.

These eight working intervals contained the following reservoir lithologies;

- Horda Fm: Sandstone
- Balder Fm: Sandstone
- Sele Fm: Sandstone
- Lista Fm: Sandstone
- Maureen Fm: Sandstone and Limestone
- Ekofisk Fm: Limestone
- Tor Fm: Limestone
- Hod Fm: Limestone

Both lithology and porosity cut-offs are applied to the data to ensure only fluid substituted points that are regarded as clean formation are selected for this analysis.

- Horda Fm: Vol_Sand>0.7, PhiT>0.15
- Balder Fm: Vol_Sand>0.7, PhiT>0.12
- Sele Fm: Vol_Sand>0.7, PhiT>0.12
- Lista Fm: Vol_Sand>0.7, PhiT>0.10
- Maureen Fm (Sandstone): Vol_Sand>0.7, PhiT>0.08
- Maureen Fm (Limestone): Vol_Lime>0.9, PhiT>0.08
- Ekofisk Fm: Vol_Lime>0.9, PhiT>0.06
- Tor Fm: Vol_Lime>0.9, PhiT>0.03
- Hod Fm: Vol_Lime>0.9, PhiT>0.03

In this report, an example of the multi-well trends is shown for the Lista Formation. However a full set of cross-plots and trends can be found in the accompanying PowerPoint (Multi-well analysis - Modelled data) and the Master Spreadsheet.

Vp-PhiT plots - All plots coloured by well

Lista Fm - Clean Sandstone - Vp-PhiT - Linear trend required - FSUB_BRINE_GP

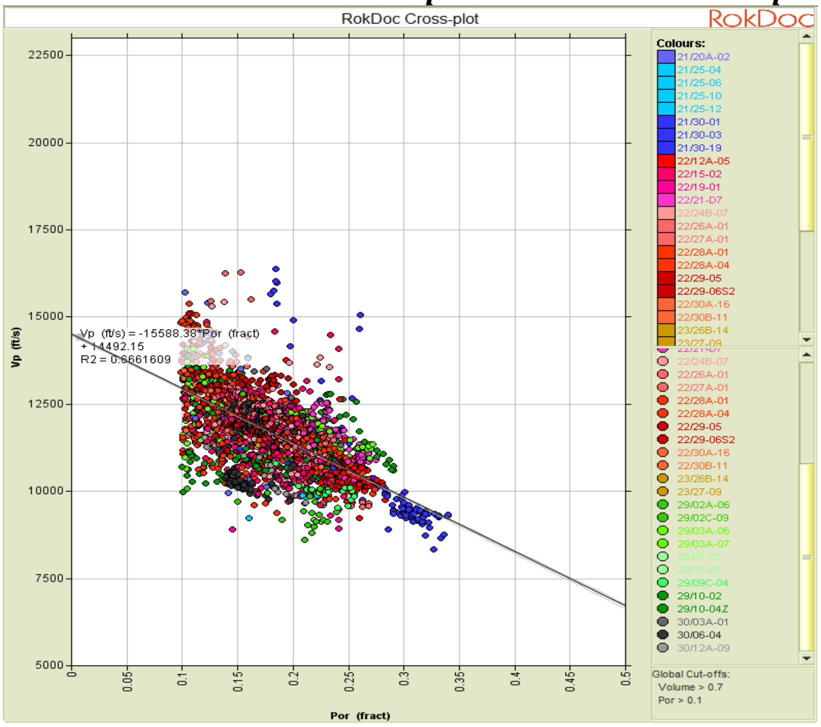


Figure 2.3.27 - Vp-PhiT cross-plot for 100% Brine saturated clean sandstone points in the Lista Fm

Lista Fm - Clean Sandstone - Vp-PhiT - Linear trend required - FSUB_OIL_GP

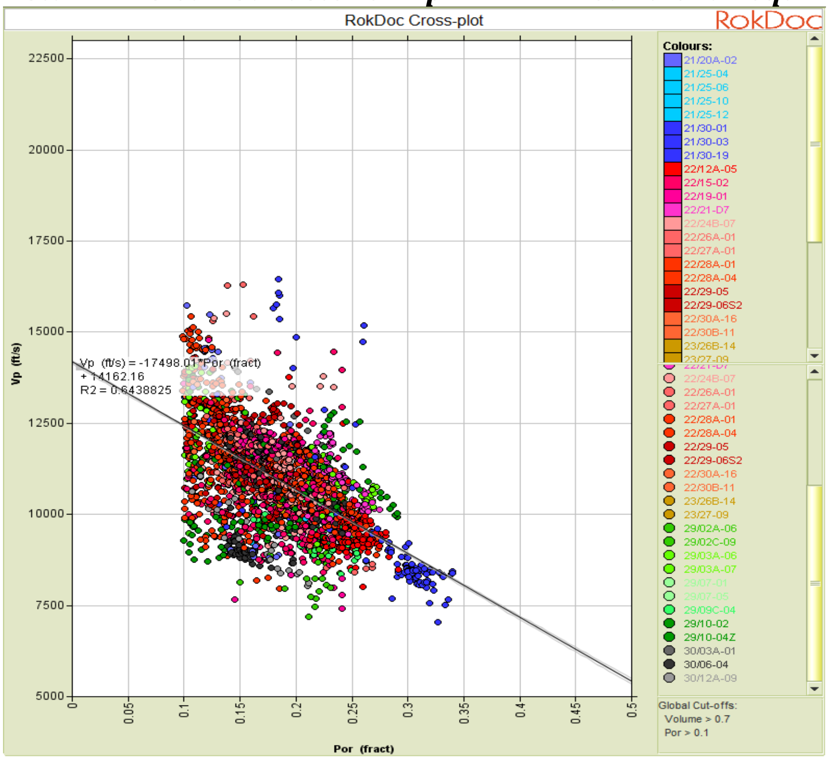


Figure 2.3.28 - Vp-PhiT cross-plot for 80% Oil saturated clean sandstone points in the Lista Fm

Lista Fm - Clean Sandstone - Vp-PhiT - Linear trend required - FSUB_GAS_GP

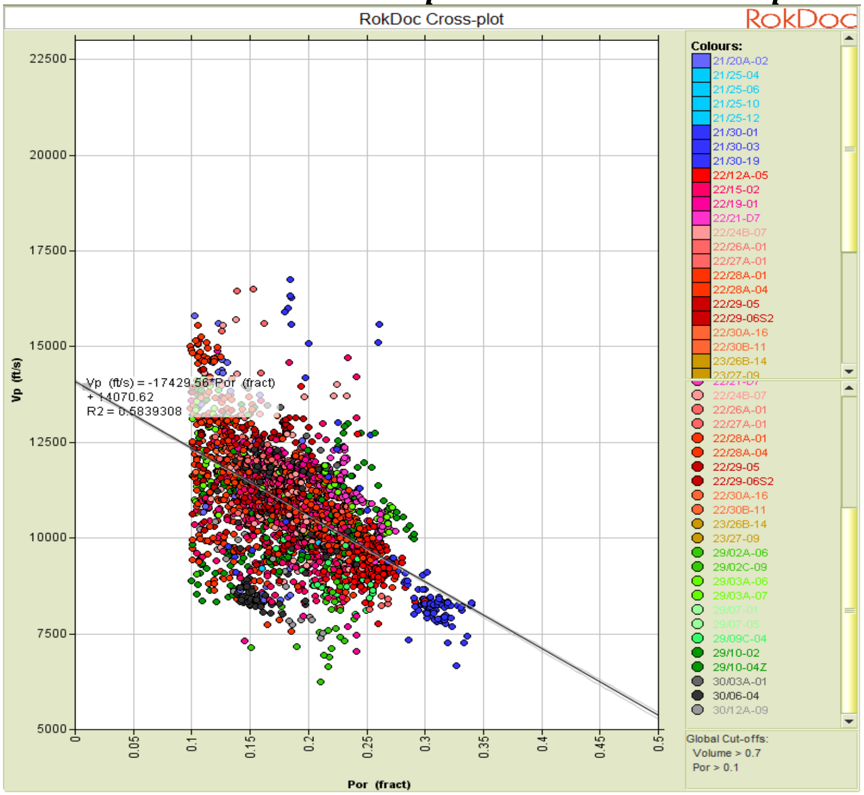


Figure 2.3.29 - Vp-PhiT cross-plot for 90% Gas saturated clean sandstone points in the Lista Fm

Vp-PhiT plots summary

The Vp-PhiT plots included in this section are the summary cross-plots for reservoir lithologies in the Lista Fm in the study for all the fluid cases. The derived trends in each of the eight working intervals in the study are included in the Master Spreadsheet and appendix of the report.

<u>Rhob-PhiT plots</u> - All plots coloured by well

Lista Fm - Clean Sandstone - Rhob-PhiT - Linear trend required - FSUB_BRINE_GP

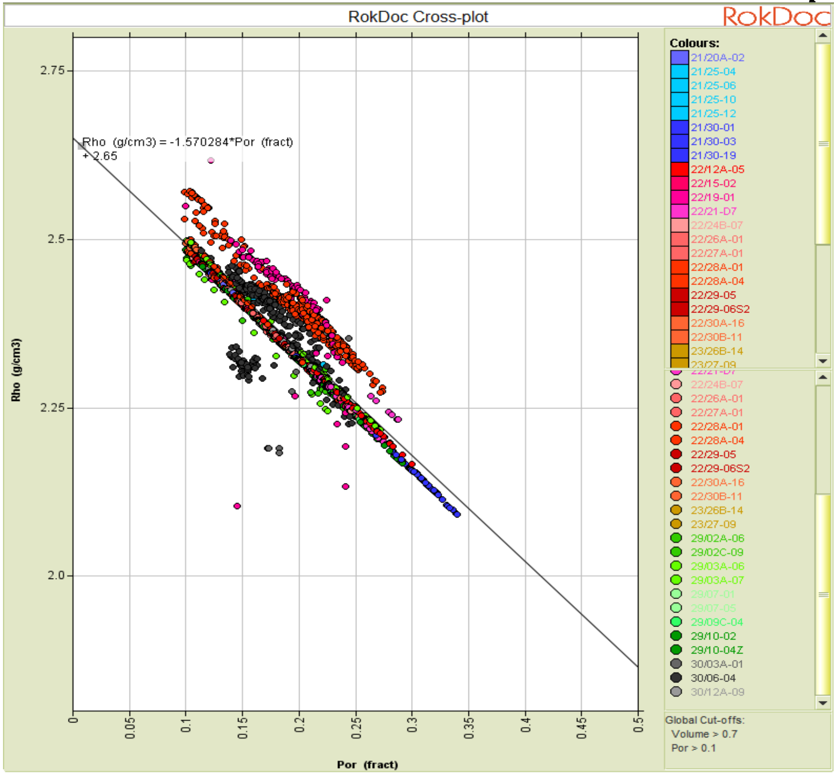


Figure 2.3.30 - Rhob-PhiT cross-plot for 100% Brine saturated clean sandstone points in the Lista Fm

Lista Fm - Clean Sandstone - Rhob-PhiT - Linear trend required - FSUB_OIL_GP

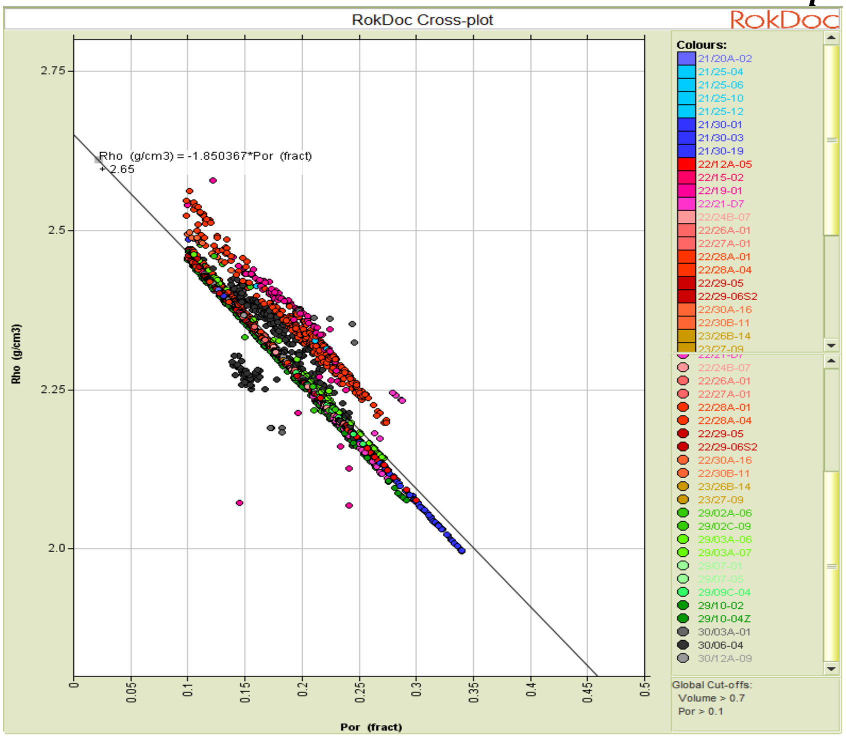


Figure 2.3.31 - Rhob-PhiT cross-plot for 80% Oil saturated clean sandstone points in the Lista Fm

Lista Fm - Clean Sandstone - Rhob-PhiT - Linear trend required - FSUB_GAS_GP

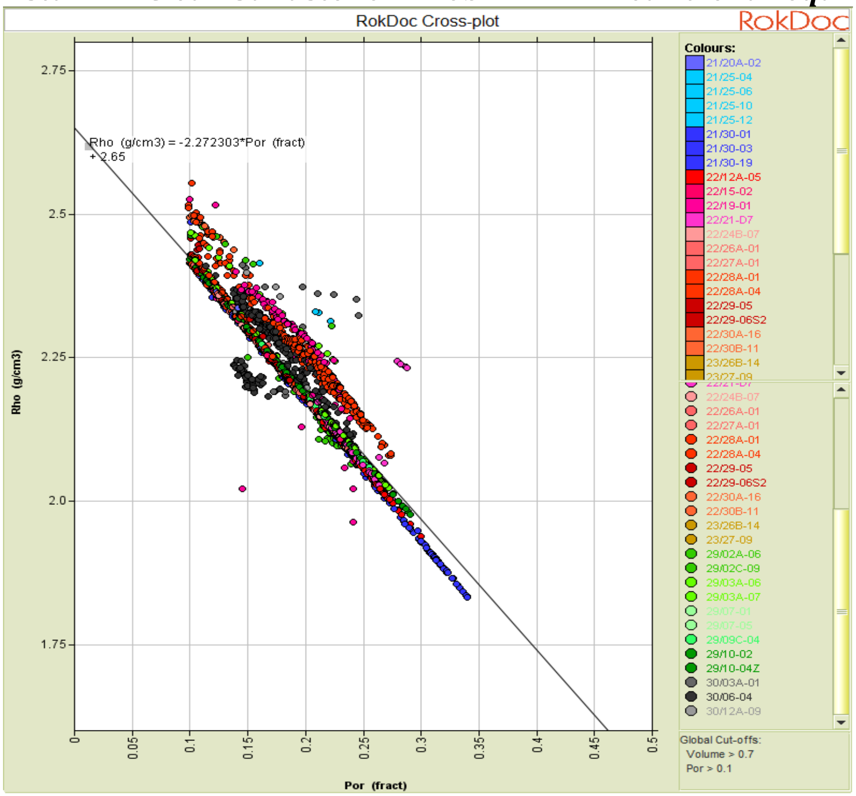


Figure 2.3.32 - Rhob-PhiT cross-plot for 90% Gas saturated clean sandstone points in the Lista Fm

Rhob-PHIT plots summary

The Rhob-PHIT plots included in this section are the summary cross-plots for reservoir lithologies in the Lista Fm in the study for all the fluid cases. The derived trends in each of the eight working intervals in the study are included in the Master Spreadsheet and appendix of the report.

In the Rhob-PHIT cross-plots, the intercept of the line is fixed at the mineral value used in the Petrophysics (Rhob=2.65g/cm^3 for quartz and Rhob=2.71g/cm^3 for calcite).

<u>AcImp-PhiT plots</u> - All plots coloured by well

Lista Fm - Clean Sandstone - AcImp-PhiT - Linear trend required - FSUB_BRINE_GP

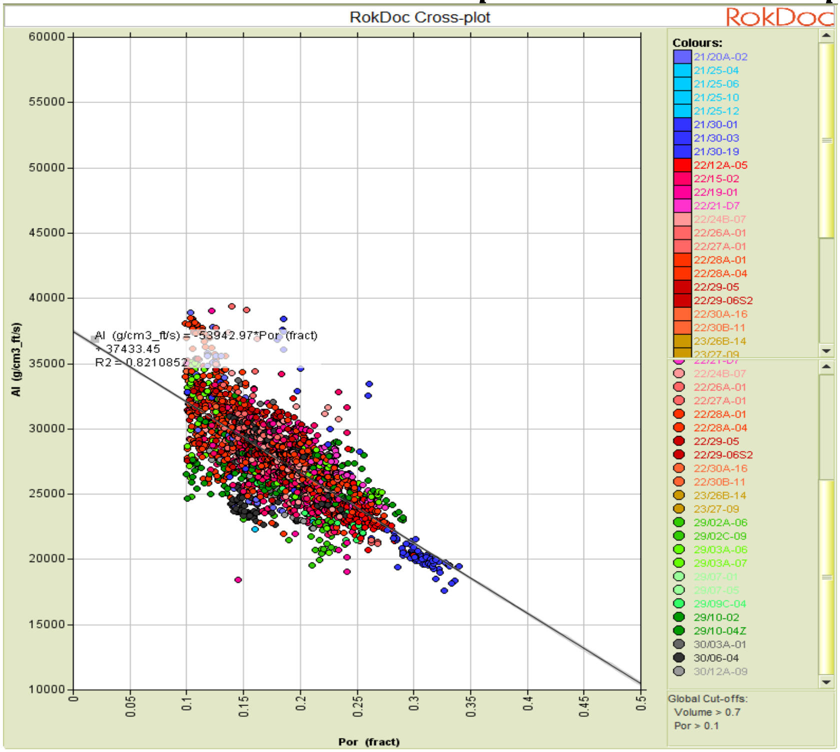


Figure 2.3.33 - AI-PhiT cross-plot for 100% Brine saturated clean sandstone points in the Lista Fm

Lista Fm - Clean Sandstone - AcImp-PhiT - Linear trend required - FSUB_OIL_GP

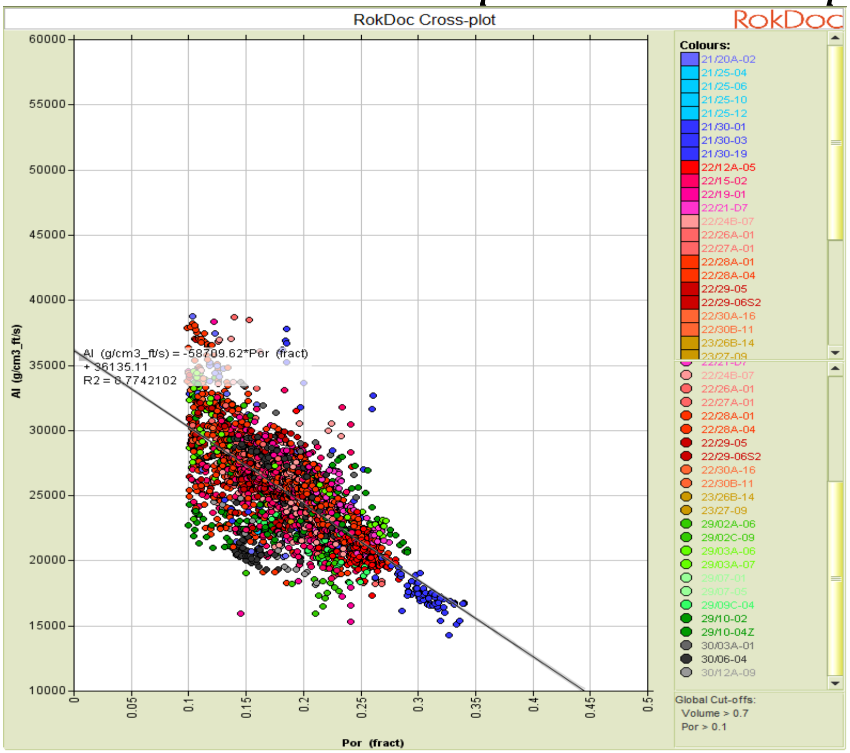


Figure 2.3.34 - AI-PhiT cross-plot for 80% Oil saturated clean sandstone points in the Lista Fm

Lista Fm - Clean Sandstone - AcImp-PhiT - Linear trend required - FSUB_GAS_GP

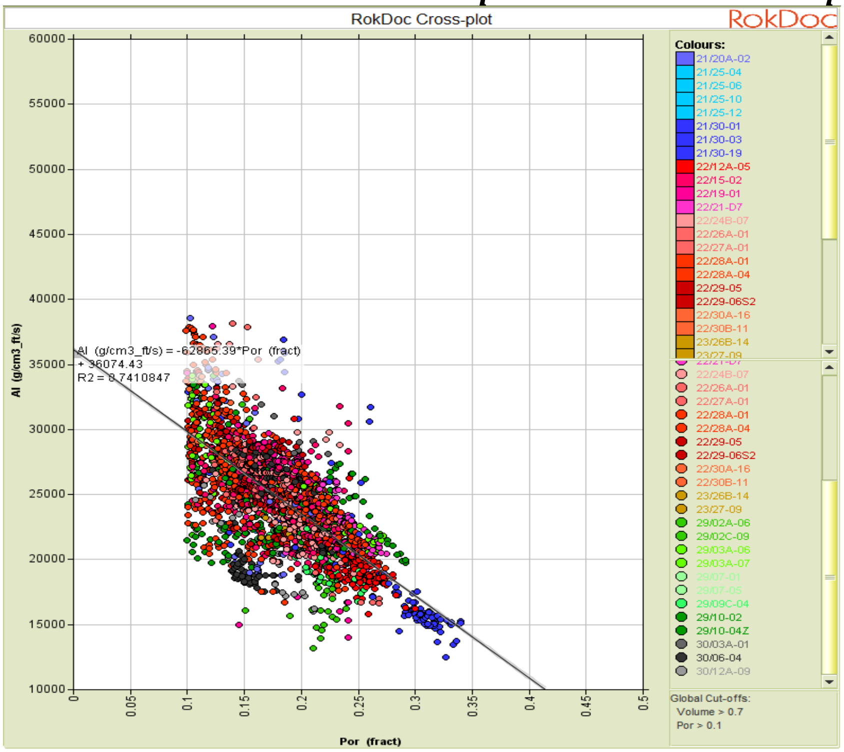


Figure 2.3.35 - AI-PhiT cross-plot for 90% Gas saturated clean sandstone points in the Lista Fm

AI-PhiT plots summary

The AI-PhiT plots included in this section are the summary cross-plots for reservoir lithologies in the Lista Fm in the study for all the fluid cases. The derived trends in each of the eight working intervals in the study are included in the Master Spreadsheet and appendix of the report.

Cross-plot views

All of the cross-plots shown in this section of the report have their views saved within the Master RokDoc project to save time creating the plots for a Shell end-user of the project. To load a view from the archive of saved views, simply click on the Load button at the bottom right hand corner of the cross-plot and select one the views in the dialog.

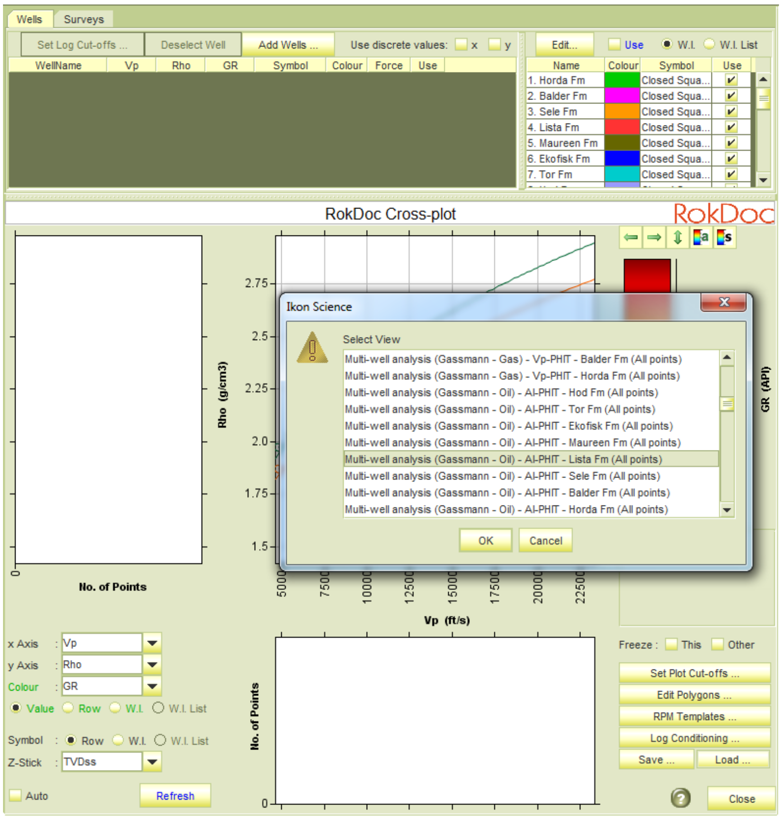


Figure 2.3.36 - Example of saved views for this section of the project. NB - It can take several minutes to load a view due to the large number of logs saved in the cross-plot.

For this section of the project, all the views are saved as 'Multi-well analysis (Gassmann)' and then the name of the specific view and fluid case.

There are no volume or porosity cut-offs applied to these cross-plots and the views display all of the points within the working interval. To change the volume cut-offs to the desired clean lithology, the end-user needs to firstly make the required volume logs active and then apply the clean lithology cut-offs. To set the porosity cut-offs, simply set the cut-offs using the 'Set Plot Cut-Offs' button in the bottom right of the cross-plot since all of the required PhiT logs are selected as active logs in the project.

Further multi-well trend analysis using brine substituted data

Following completion of the multi-well analysis with Gassmann fluid substituted data over the reservoir intervals, further analysis took place of the relationship between Velocity Ratios and Depth for reservoir and non-reservoir intervals.

The following rock physics relationships (y(x)) were to be considered;

- VpVs-Depth(TVDml)

for the following fluid case;

- 100% Brine - FSUB_BRINE_GP logs selected

These relationships were found for every formation in the study interval and thus they were found for eight working intervals.

These eight working intervals contained the following reservoir lithologies;

- Horda Fm: Sandstone and Shale
- Balder Fm: Sandstone, Tuff and Shale
- Sele Fm: Sandstone and Shale
- Lista Fm: Sandstone and Shale
- Maureen Fm: Sandstone, Shale and Limestone
- Ekofisk Fm: Limestone
- Tor Fm: Limestone
- Hod Fm: Limestone

Both lithology and porosity cut-offs are again applied to the data to ensure only fluid substituted points are selected for this analysis.

- Horda Fm: Vol_Sand>0.7, PhiT>0.15
- Balder Fm: Vol_Sand>0.7, PhiT>0.12
- Sele Fm: Vol_Sand>0.7, PhiT>0.12
- Lista Fm: Vol_Sand>0.7, PhiT>0.10
- Maureen Fm (Sandstone): Vol_Sand>0.7, PhiT>0.08
- Maureen Fm (Limestone): Vol_Lime>0.9, PhiT>0.08
- Ekofisk Fm: Vol_Lime>0.9, PhiT>0.06
- Tor Fm: Vol_Lime>0.9, PhiT>0.03
- Hod Fm: Vol_Lime>0.9, PhiT>0.03

The complete set of cross-plots including point density plots and explanation of trend fitting can be found in the accompanying multi-well analysis PowerPoint (Multi-well analysis - VpVs-Depth) and the Master Spreadsheet.

Multi-well rock physics analysis: VpVs-Depth(TVDml) plots - All plots coloured by well

Horda Fm - Clean Sandstone - VpVs-Depth(TVDml) - Only one trend

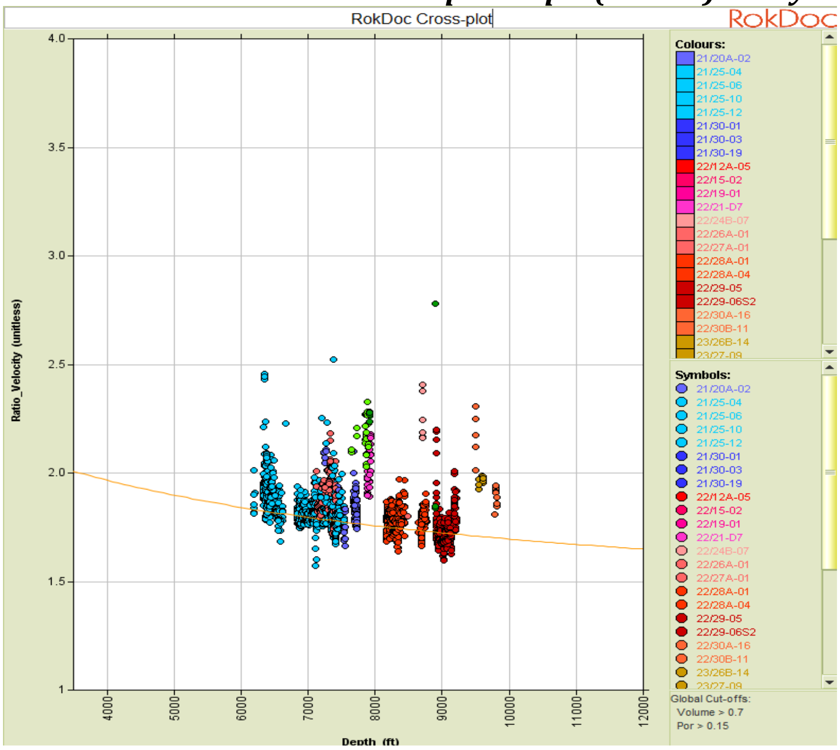


Figure 2.3.37 - VpVs-Depth cross-plot for 100% Brine saturated clean sandstone points in the Horda Fm

Horda Fm - Clean Shale - VpVs-Depth(TVDml) - Hard and soft shale trends

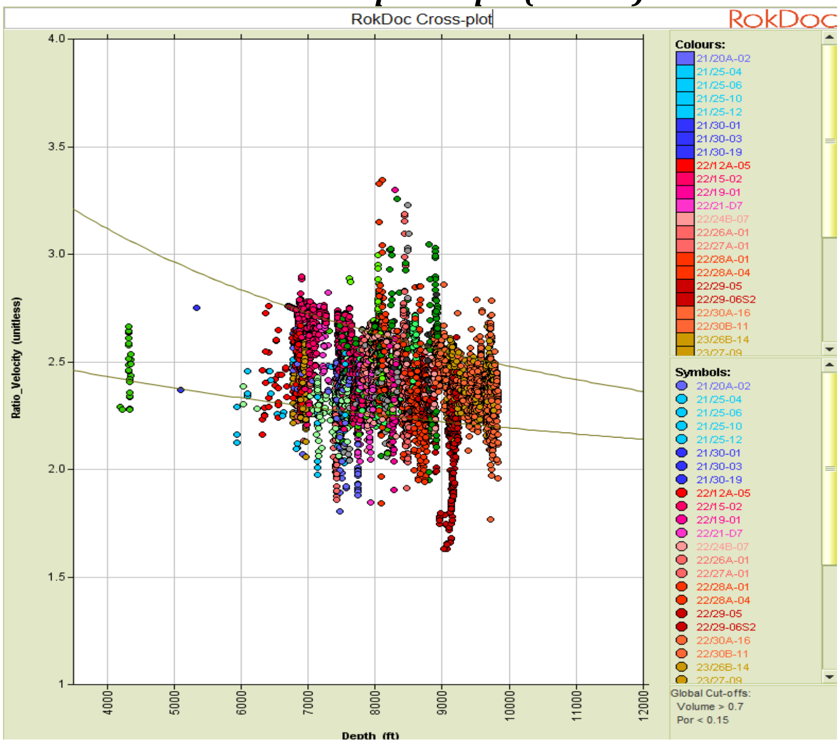


Figure 2.3.38 - VpVs-Depth cross-plot for 100% Brine saturated clean shale points in the Horda Fm

Balder Fm - Clean Sandstone - VpVs-Depth(TVDml) - Only one trend

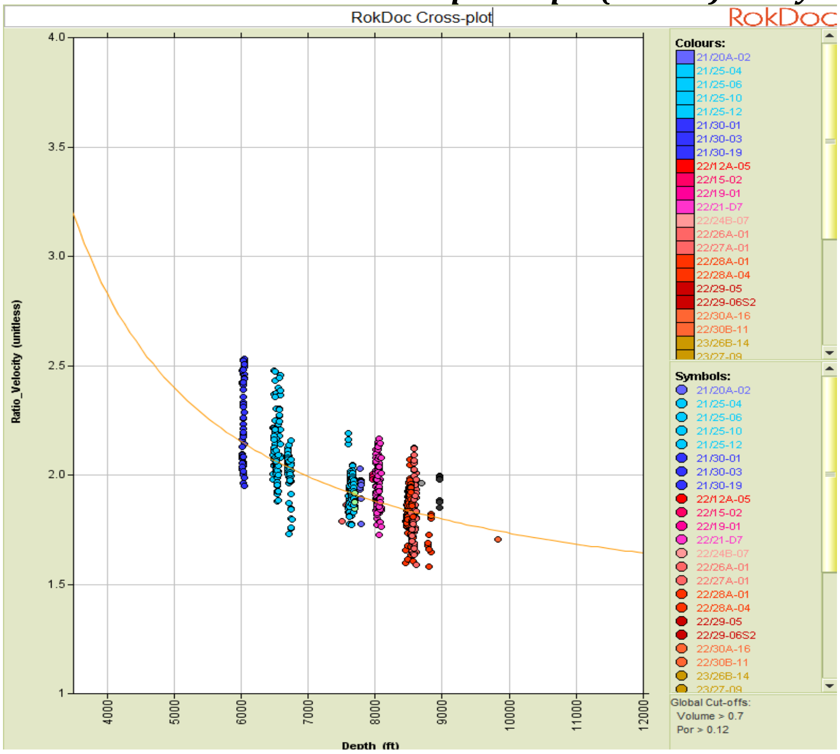


Figure 2.3.39 - VpVs-Depth cross-plot for 100% Brine saturated clean sandstone points in the Balder Fm

Balder Fm - Clean Shale - VpVs-Depth(TVDml) - Only one trend

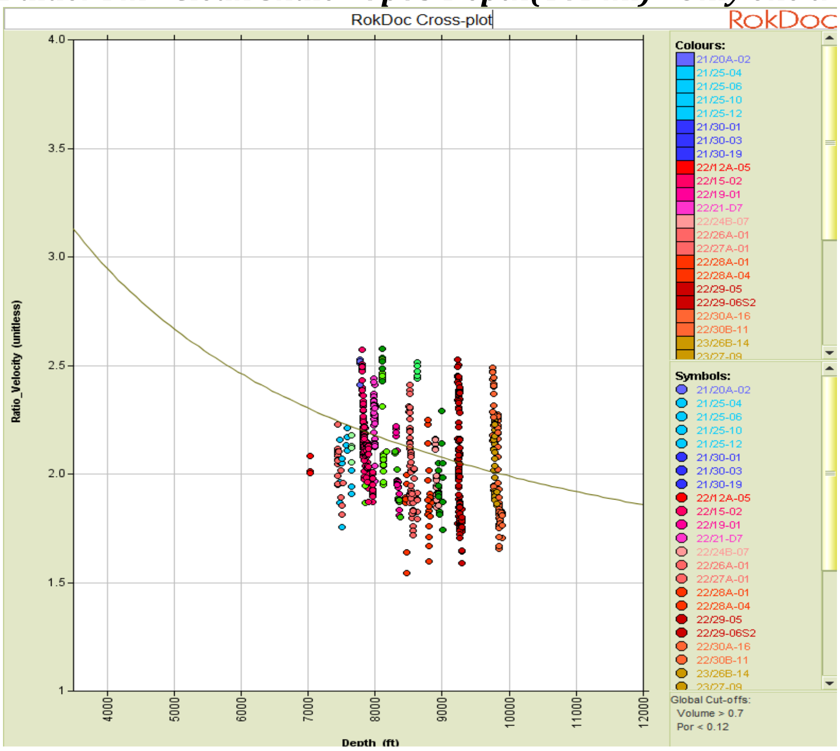


Figure 2.3.40 - VpVs-Depth cross-plot for 100% Brine saturated clean shale points in the Balder Fm

Balder Fm - Clean Tuff - VpVs-Depth(TVDml) - Only one trend

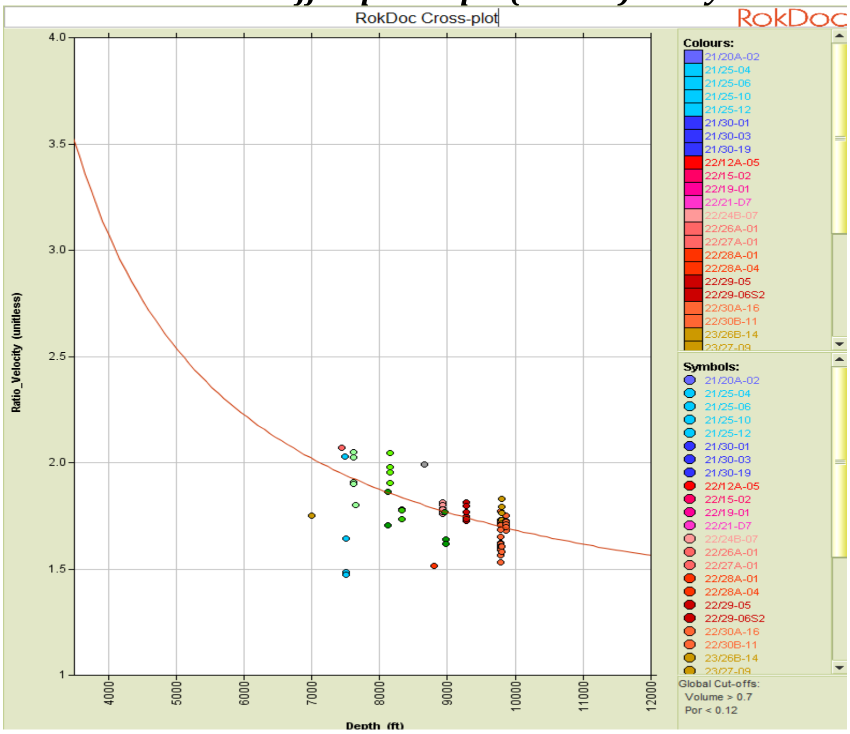


Figure 2.3.41 - VpVs-Depth cross-plot for 100% Brine saturated clean tuff points in the Balder Fm

Sele Fm - Clean Sandstone - VpVs-Depth(TVDml) - Two porosity trends (PhiT-Depth)

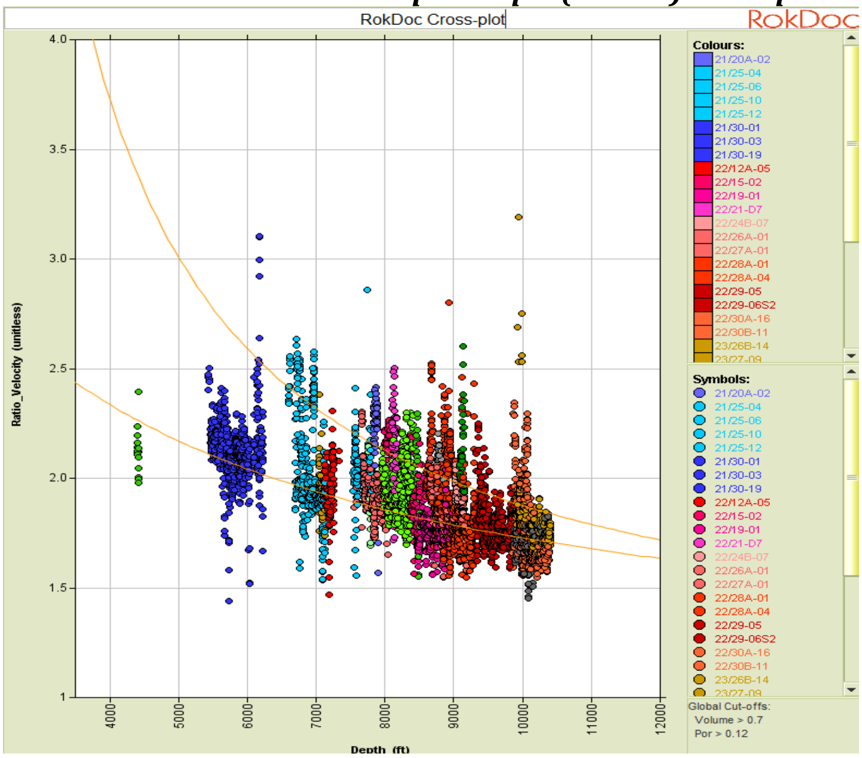


Figure 2.3.42 - VpVs-Depth cross-plot for 100% Brine saturated clean sandstone points in the Sele Fm

Sele Fm - Clean Shale - VpVs-Depth(TVDml) - Only one trend

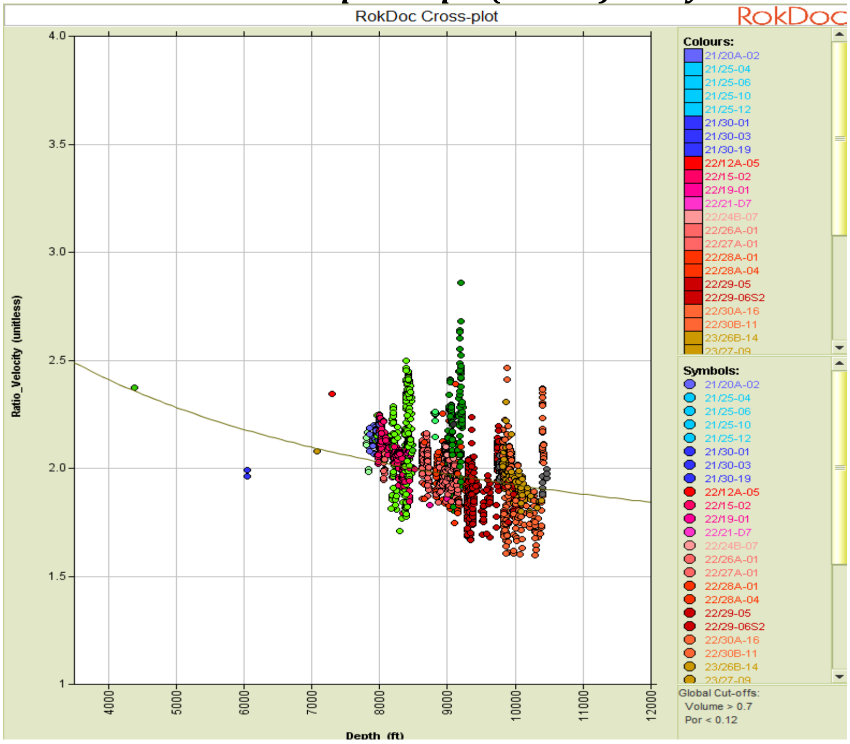


Figure 2.3.43 - VpVs-Depth cross-plot for 100% Brine saturated clean shale points in the Sele Fm

Lista Fm - Clean Sandstone - VpVs-Depth(TVDml) - Two porosity trends (PhiT-Depth)

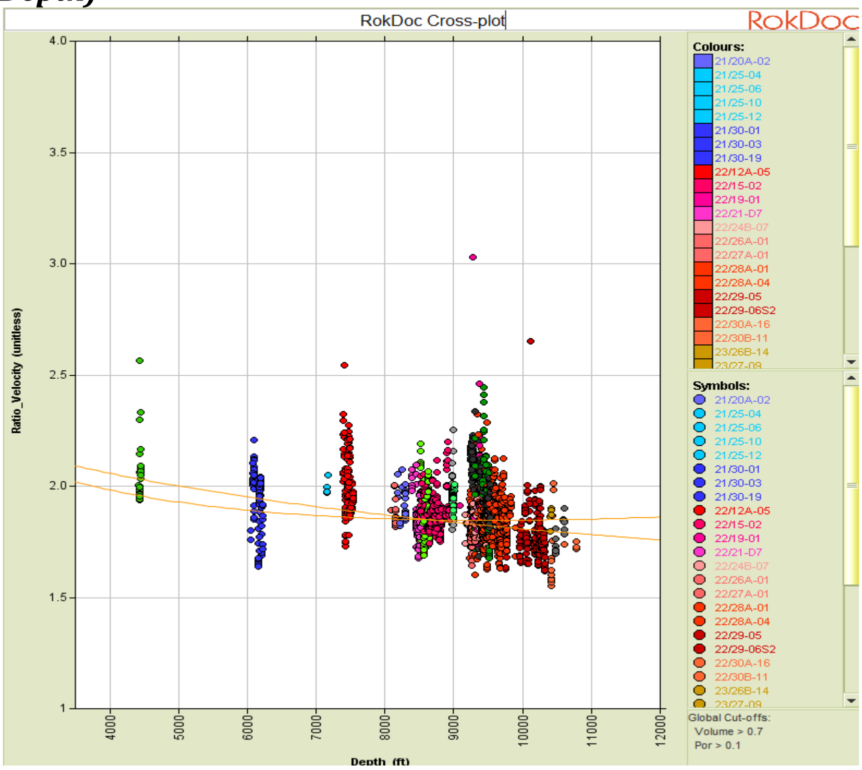


Figure 2.3.44 - VpVs-Depth cross-plot for 100% Brine saturated clean sandstone points in the Lista Fm

Lista Fm - Clean Shale - VpVs-Depth(TVDml) - Hard and soft shale trends

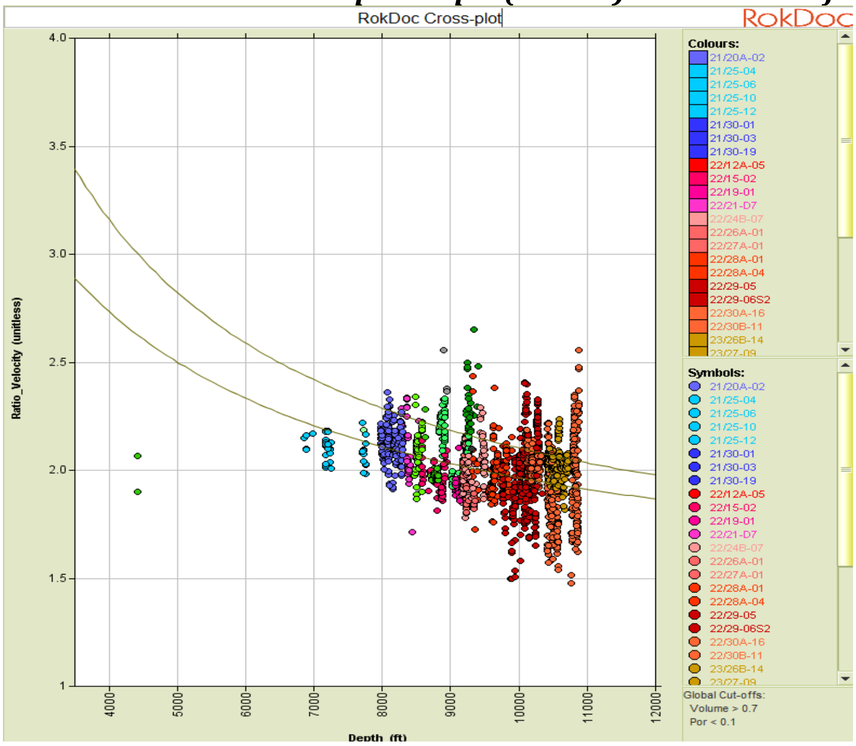


Figure 2.3.45 - VpVs-Depth cross-plot for 100% Brine saturated clean shale points in the Lista Fm

Maureen Fm - Clean Sandstone - VpVs-Depth(TVDml) - Two porosity trends (PhiT-Depth)

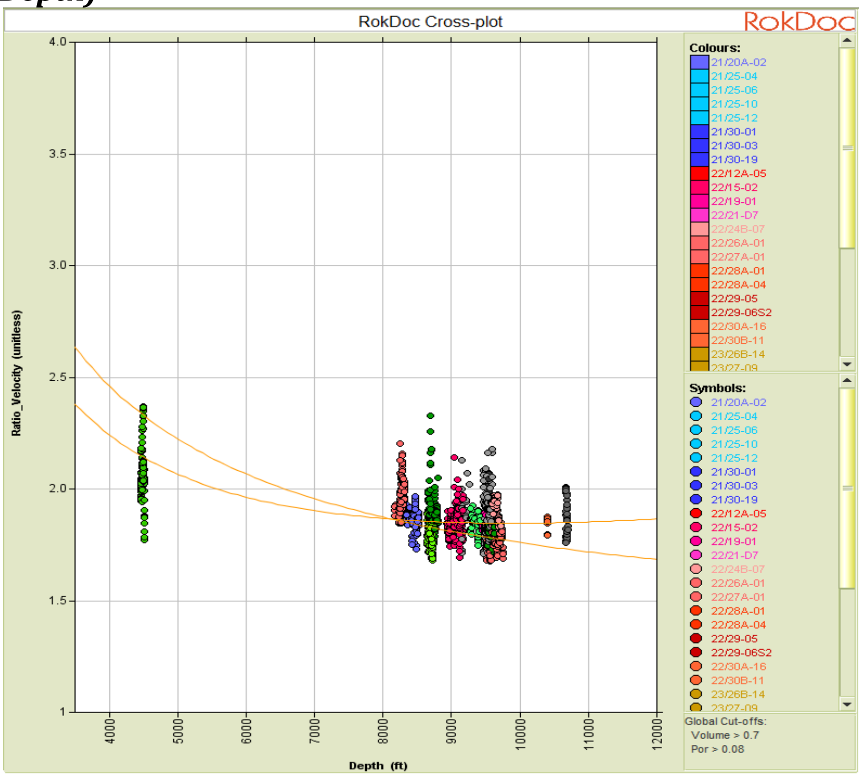


Figure 2.3.46 - VpVs-Depth cross-plot for 100% Brine saturated clean sandstone points in the Maureen Fm

Maureen Fm - Clean Shale - VpVs-Depth(TVDml) - Hard and soft shale trends

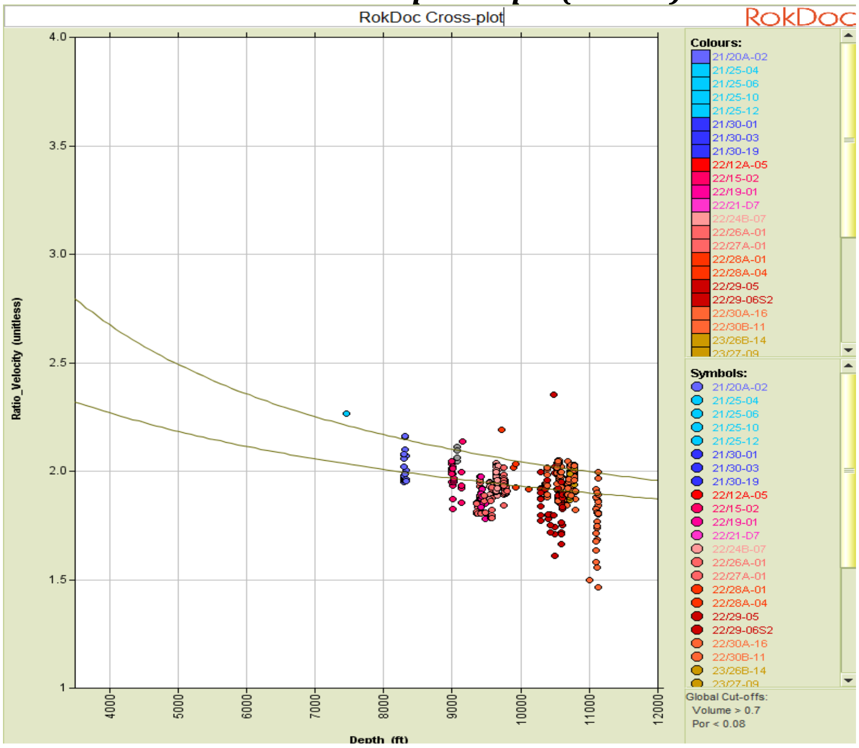


Figure 2.3.47 - VpVs-Depth cross-plot for 100% Brine saturated clean shale points in the Maureen Fm

Maureen Fm - Clean Limestone - VpVs-Depth(TVDml) - Two porosity trends (PhiT-Depth)

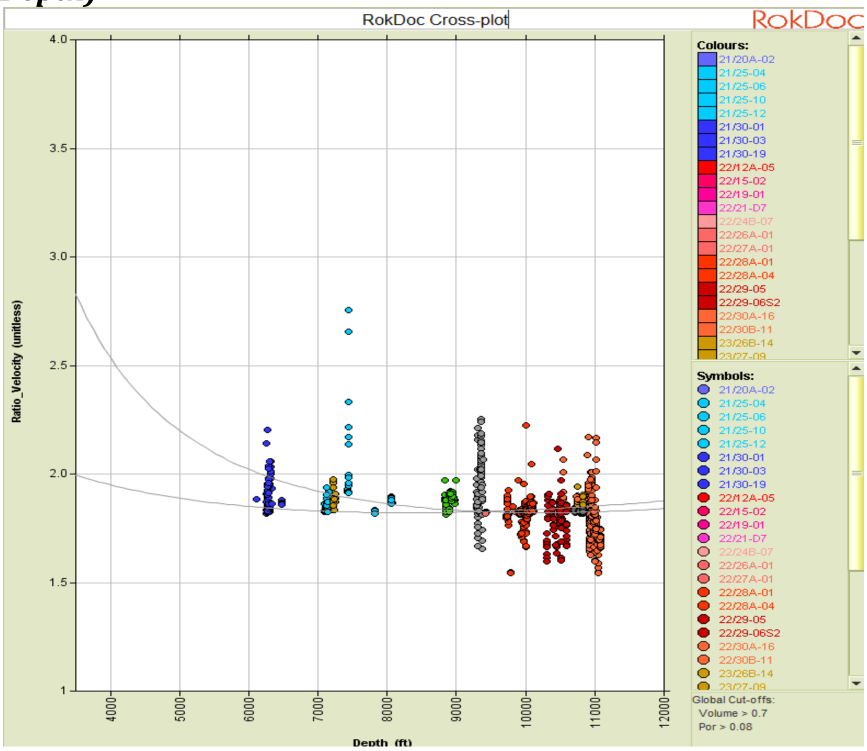


Figure 2.3.48 - VpVs-Depth cross-plot for 100% Brine saturated clean limestone points in the Maureen Fm

Ekofisk Fm - Clean Limestone - VpVs-Depth(TVDml) - Two porosity trends (PhiT-Depth)

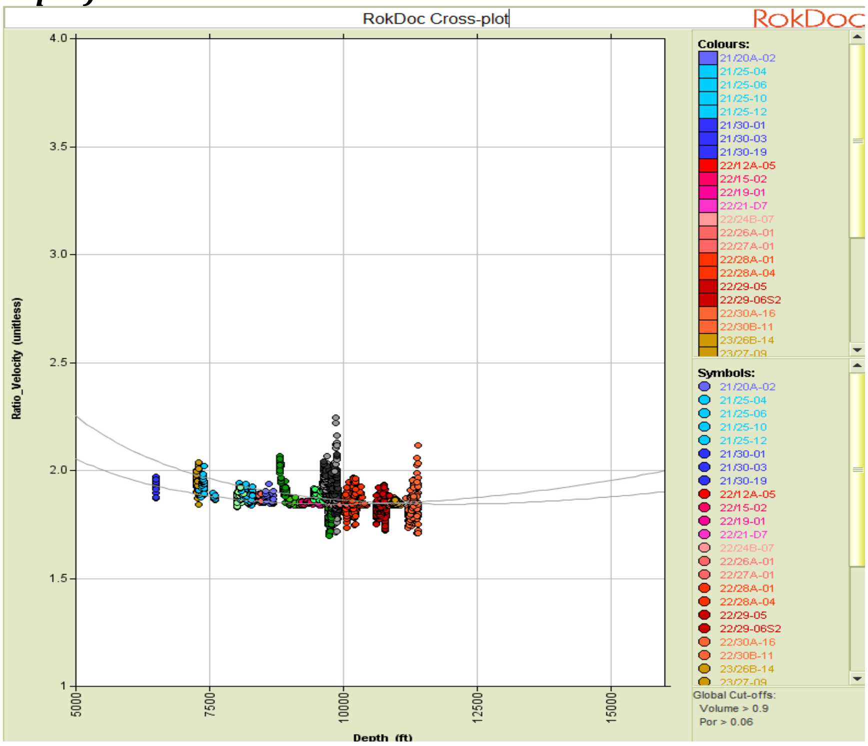


Figure 2.3.49 - VpVs-Depth cross-plot for 100% Brine saturated clean limestone points in the Ekofisk Fm

Tor Fm - Clean Limestone - VpVs-Depth(TVDml) - Two porosity trends (PhiT-Depth)

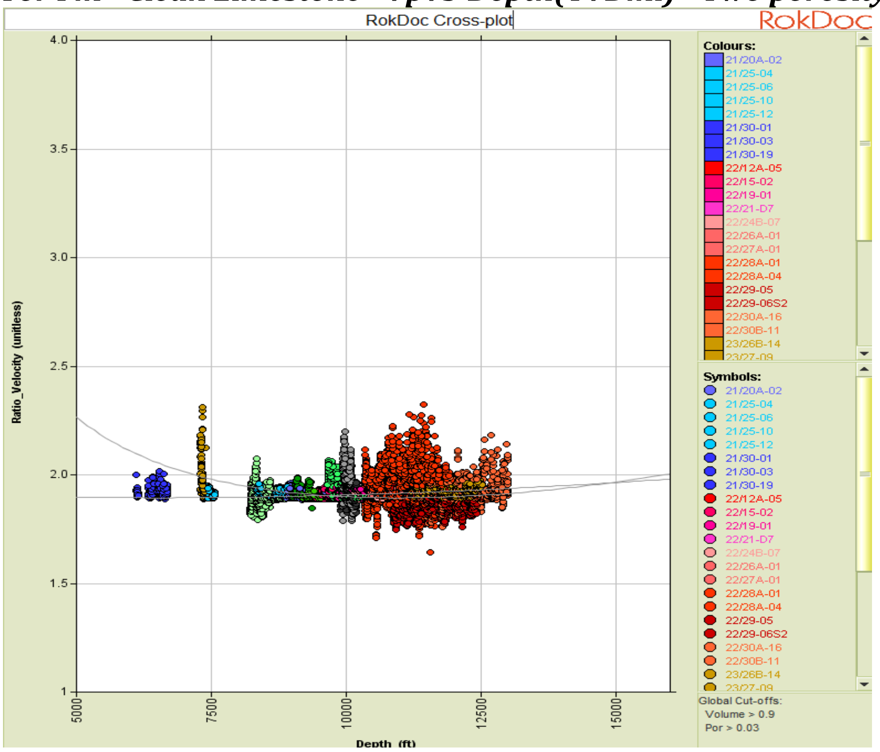


Figure 2.3.50 - VpVs-Depth cross-plot for 100% Brine saturated clean limestone points in the Tor Fm

Hod Fm - Clean Limestone - VpVs-Depth(TVDml) - Two porosity trends (PhiT-Depth)

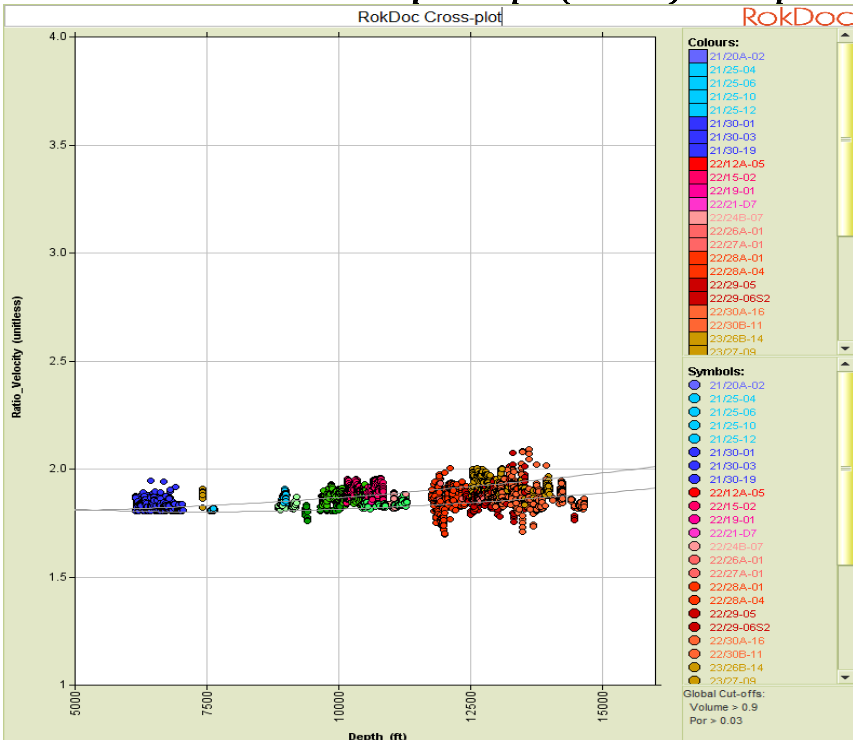


Figure 2.3.51 - VpVs-Depth cross-plot for 100% Brine saturated clean limestone points in the Hod Fm

VpVs-Depth plots summary

The VpVs-Depth plots included in this section are the summary cross-plots for reservoir and non-reservoir lithologies in each of the eight working intervals in the study. The derived trends are included in the Master Spreadsheet and appendix of the report.

Note that for Sands & Shales the common assumption of Vp/Vs=2 seems to be reasonable; Deeper intervals slightly lower and shallower intervals slightly higher (Vs increases more with depth than Vp). Limestones/Chalk generally shows a much lower (1.8-1.9) Vp/Vs ratio, indicative of a relatively faster Vs compared with the Sands & Shales.

Cross-plot views

All of the cross-plots shown in this section of the report have their views saved within the Master RokDoc project to save time creating the plots for a Shell end-user of the project. To load a view from the archive of saved views, simply click on the Load button at the bottom right hand corner of the cross-plot and select one the views in the dialog.

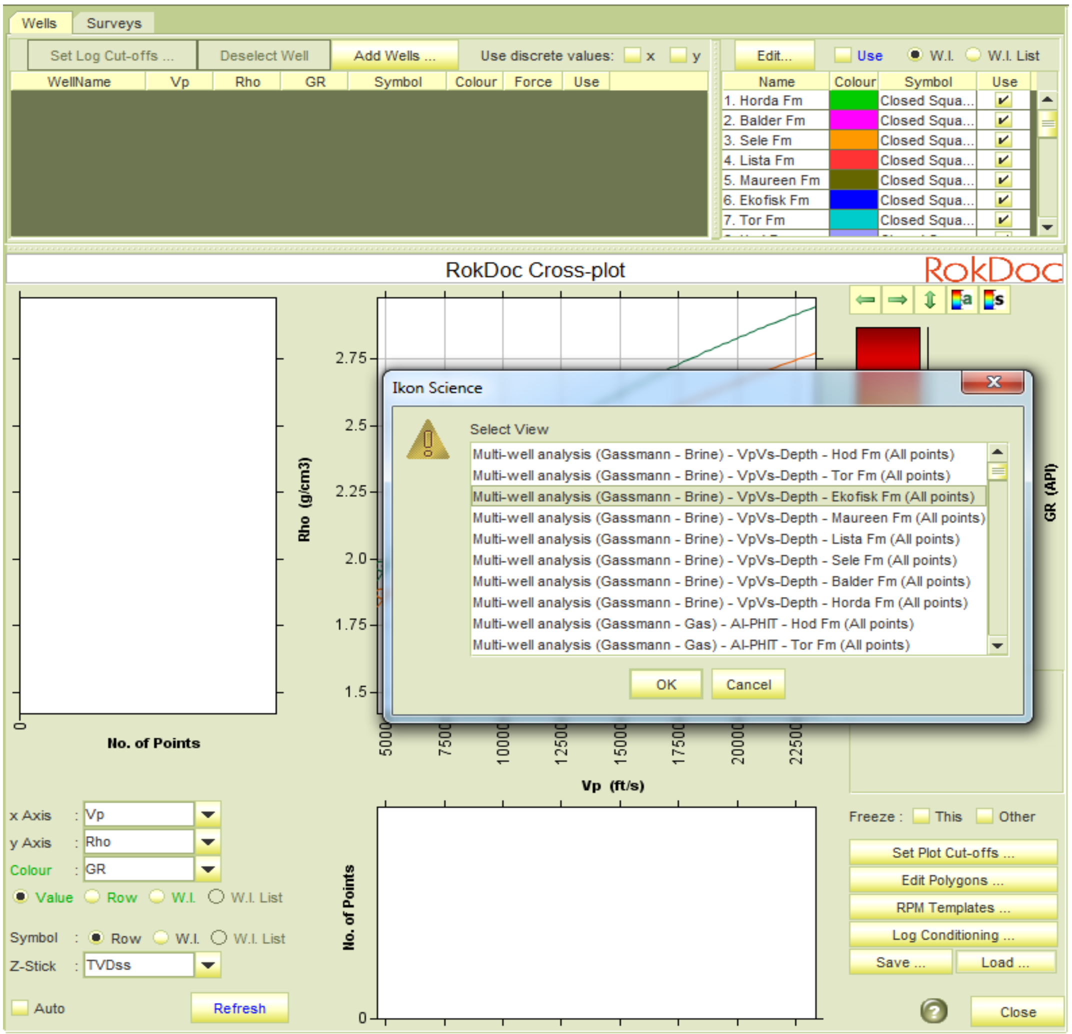


Figure 2.3.52 - Example of saved views for this section of the project. NB - It can take several minutes to load a view due to the large number of logs saved in the cross-plot.

For this section of the project, all the views are saved as 'Multi-well analysis (Gassmann - Brine)' and then the name of the specific view.

There are no volume or porosity cut-offs applied to these cross-plots and the views display all of the points within the working interval. To change the volume cut-offs to the desired clean lithology, the end-user needs to firstly make the required volume logs active and then apply the clean lithology cut-offs. To set the porosity cut-offs, simply set the cut-offs using the 'Set Plot Cut-Offs' button in the bottom right of the cross-plot since all of the required PhiT logs are selected as active logs in the project.

This is the end of 'Chapter 2 - Methodology' and the workflow used to produce the results shown in 'Chapter 3 - Single Well Interpretations' has now been fully explained. It is important to emphasise that there are a series of PowerPoint's supplied with the project and these PowerPoint's show the progression of the log data through the workflow for every well. There is also a PowerPoint to describe the multi-well analysis and every plot made for the multi-well analysis is contained within this PowerPoint.

Chapter 3 – Single Well Reports

Each single well report in Appendix G consist of the following elements:

- General
    - Well Information
    - Objectives
    - Log conditioning overview
    - Invasion correction
    - Log modelling
- P&T data
- Fluid data
- Mineral data
- Petrophysical data
- Well panels
    - Well log panel – measured data
    - Well log panel – log editing and audit
    - Well log panel – synthetic curves
    - Well log panel – fluid substituted logs
- Average Vp, Vs and Rho values - Tertiary
    - Clean Shale values
    - Clean Sand values
- Tertiary reservoirs
    - Well panel – Tertiary reservoirs
    - Formation description - Tertiary reservoirs
- Average Vp, Vs and Rho values - Cretaceous
    - Clean Shale values
    - Clean Limestone values
- Cretaceous reservoirs
    - Well panel – Cretaceous reservoirs
    - Formation description - Cretaceous reservoirs
- Average Vp, Vs and Rho values - Underburden/Overburden sections

The next list gives hyperlinks to each of the single well reports (Appendix G)

- Well: 21/20A-02
- Well: 21/25-04
- Well: 21/25-06
- Well: 21/25-10
- Well: 21/25-12
- Well: 21/30-01
- Well: 21/30-03
- Well: 21/30-19
- Well: 22/12A-05
- Well: 22/15-02
- Well: 22/19-01
- Well: 22/21-D7
- Well: 22/24B-07
- Well: 22/26A-01
- Well: 22/27A-01
- Well: 22/28A-01
- Well: 22/28A-04
- Well: 22/29-05
- Well: 22/29-06S2
- Well: 22/30A-16
- Well: 22/30B-11
- Well: 23/26B-14
- Well: 23/27-09
- Well: 29/02A-06
- Well: 29/02C-09
- Well: 29/03A-06
- Well: 29/03A-07
- Well: 29/07-01
- Well: 29/07-05
- Well: 29/09C-04
- Well: 29/10-02
- Well: 29/10-04Z
- Well: 30/03A-01
- Well: 30/06-04
- Well: 30/12A-09

Chapter 4 – User Guide

Contents:

4.1 – Blocky AVO Modelling

Section details how to create a Blocky AVO Model using existing average sets within a RokDoc project and how to create new average sets based upon a hypothetical scenario.

RokDoc Blocky Modelling allows the user to evaluate average point data and values for single interface modelling. The AVO function is used to model the seismic response across proposed lithological interfaces as a function of incidence angle. By entering lithologies and defining interfaces, the seismic response (as a function of incidence angle) can be calculated, displayed and analysed.

Blocky AVO Scenarios for each reservoir identified within the study wells are contained within Chapter 3. The method for creating these will now be outlined, in addition to highlighting potential additional functionality, using a scenario comparing stratigraphically equivalent reservoirs in neighbouring wells.

Workflow 4.1.1 – Creating a Blocky AVO Model with available Average Sets

An example is shown below, where we will compare the AVO responses of two neighbouring wells for a Sele Formation reservoir (brine- and hydrocarbon-bearing cases).

1. Select ‘Blocky Ops’ > ‘AVO’.

   The Blocky Model AVO module is now shown. Using the first tab ‘AVO inputs’, we will parameterise our chosen display.

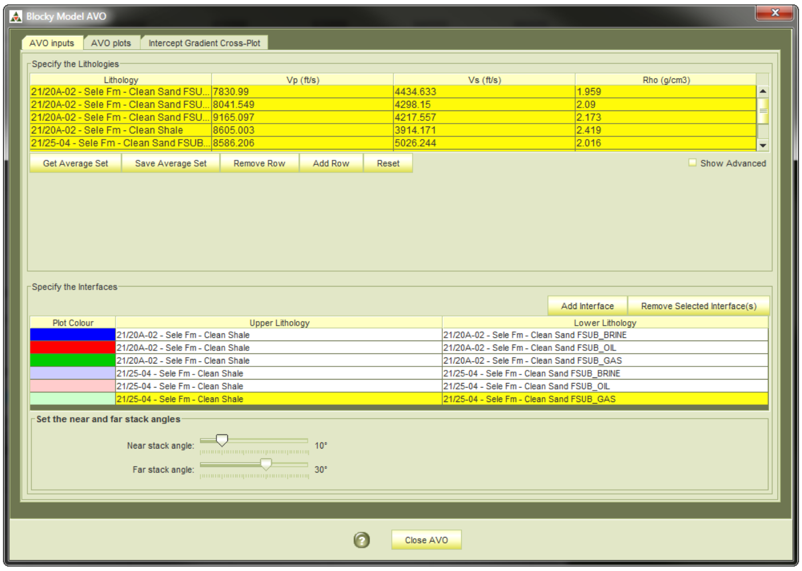
2. On the ‘AVO inputs’ tab, click on ‘Get Average Set’ within the ‘Specify the lithologies’ section.

   The ‘Select Averages’ dialog box is now shown. Listed are all of the average sets stored within the project. In the Roknowledge CNS .rok file, average sets are given for every working interval containing shale and tuff (Balder) within the Tertiary, and for each reservoir (brine- and hydrocarbon-bearing) within the Tertiary and Cretaceous. Any custom average sets the user has created will be also be listed.

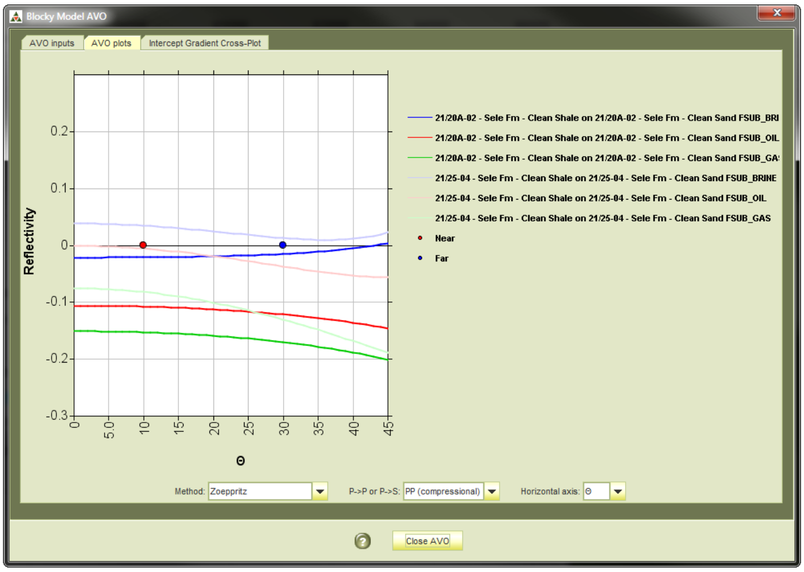
3. Select the average sets of interest (using the Ctrl key) and click ‘OK’. In this example, select the following average sets:

   21/20A-02 - Sele Fm - Clean Shale
   21/20A-02 - Sele Fm - Clean Sand FSUB_BRINE
   21/20A-02 - Sele Fm - Clean Sand FSUB_OIL
   21/20A-02 - Sele Fm - Clean Sand FSUB_GAS
   21/25-04 - Sele Fm - Clean Shale
   21/25-04 - Sele Fm - Clean Sand FSUB_BRINE
   21/25-04 - Sele Fm - Clean Sand FSUB_OIL
   21/25-04 - Sele Fm - Clean Sand FSUB_GAS

4. Next, within the ‘Specify the interfaces’ section of the ‘AVO inputs’ tab, set-up the dialog to list each of the interfaces of interest. Plot colours can be changed to represent the fluid fill of the reservoir represented at the specific interface by clicking on the relevant ‘Plot Colour’ box.



5. Click on the ‘AVO plots’ tab. The Blocky Model AVO plots are now shown.



Further Blocky AVO Models can be created for hypothetical ‘what if’ scenarios. These may either be generated from a pseudo-well (see Chapter 4.2) or within a study well for a reservoir that is not present. The method for creating an average set will now be outlined. In this case we will model the AVO response of a theoretical reservoir within an existing study well, but the workflow is similar for creating an average set within any well.

Workflow 4.1.2 – Creating an Average Set

An example is shown for well 23/27-09, where an average set is created for High-Porosity Sand end-member.

1. Select ‘Multi-well Ops’ > ‘Cross-plots’ > ‘Cross-plot …’.

Averages are created using the 'Cross-plotter' functionality rather than the 'Create Average Sets' dialog, as this allows direct comparison with log data and application of any cut-offs used if necessary (see below). Where creating end-member hypothetical scenarios, alternatively the 'Create Average Sets' dialog can be used.

2. Click 'Add Wells'. Select the well of interest from the 'Select Well' dialog box and click 'OK'.
3. The well is now displayed in the well list. For the chosen well, double-click on the 'Vp' log name. Select the relevant Vp log and click 'OK'. In this example, we are selecting the SDDI model brine-bearing end-member high porosity sandstone log:

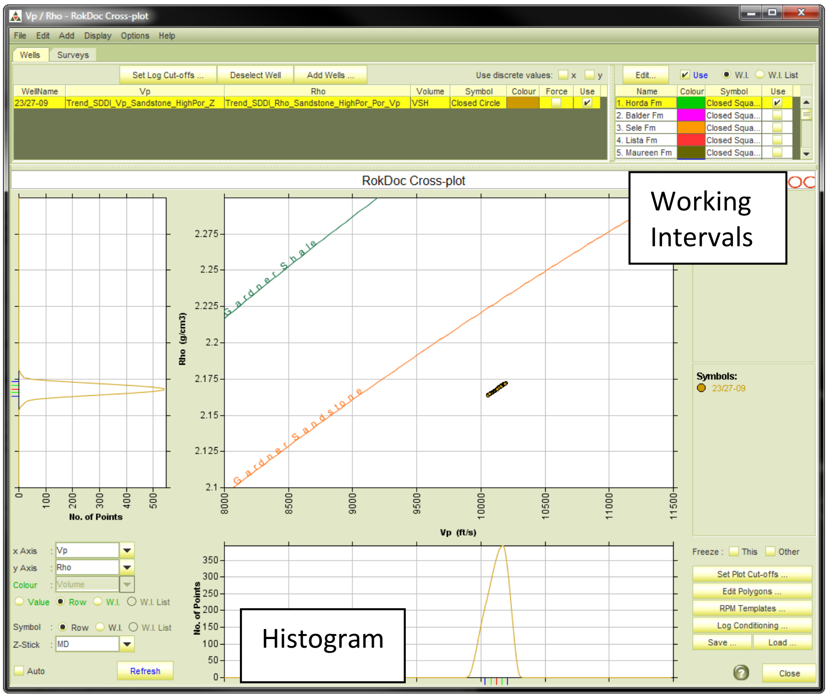
   Trend_SDDI_Vp_Sandstone_HighPor_Z

4. Double-click on the Rho log name. Select the equivalent density log and click 'OK'. For this example, use:

   Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp

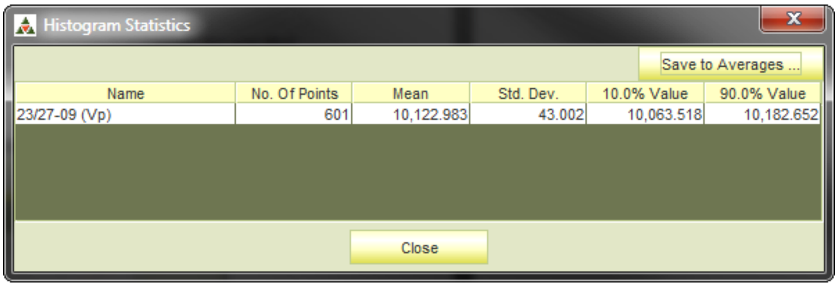
5. Select the working interval of interest on the top right of the cross-plotter. Select the 'Use' check-box. Use '1. Horda Fm' in this example.
6. Click 'Refresh'.

   The cross-plotter is now displaying the data relating to the end-member log over the specified working interval(s). If using a non-end-member log, it would be necessary to apply a cut-off to exclude data points relating to non-reservoir. Cut-offs are applied using the 'Set Plot Cut-offs …' button at the bottom right of the cross-plotter.

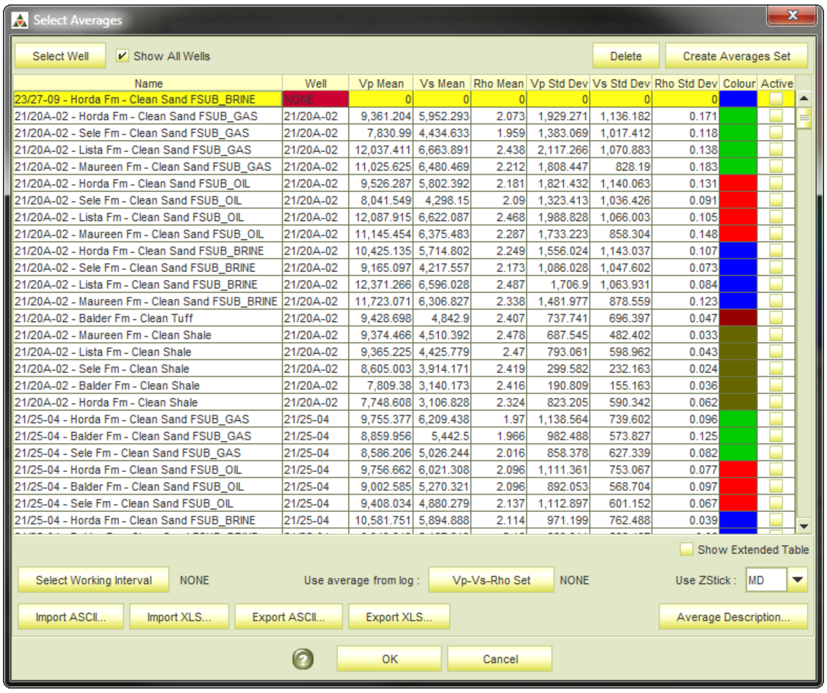


7. Next, right-click within the histogram display in the Vp domain. Select 'Show Statistics …'.

   The Histogram Statistics dialog box is now shown. This display gives a statistical summary of data shown on the cross-plotter in the Vp domain. We will now store this information within a RokDoc average set.



8. Select the row of interest, then click the ‘Save to Averages …’ button.
9. The Select Averages dialog box is displayed. Click ‘Create Averages Set’.
10. A new row is created within the ‘Select Averages’ dialog box. Double click on the ‘Name’ for the new row and enter an appropriate name.



11. Ensure the new row is highlighted and click ‘OK’ to close the dialog.
12. Close the ‘Histogram Statistics’ dialog box by clicking ‘Close’.

    A statistical average relating to the data displayed in the Vp domain on the cross-plotter is now stored within the new average set.

13. Repeat this process to populate the average set in the density domain. However, at the ‘Select Averages’ dialog box, rather than creating a new average set, add the statistical average to the existing average set created earlier within the workflow by highlighting the row and clicking ‘OK’.

    We will now populate the average set with data from the Vs domain. In order to do this, we must first change the cross-plot to display Vp-Vs and select the relevant Vs log.

14. Use the ‘y Axis’ drop-down menu to select the log type ‘Vs’.
15. Double-click on the ‘Vs’ log name in the well list. Select the corresponding Vs log and click ‘OK’. For this example, use:

Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z

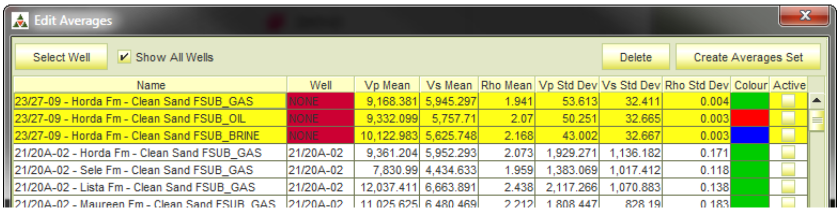
16. Click ‘Refresh’.
17. Repeat the process of populating the average set in the Vs domain.

End-member reservoir logs exist for each study well. Additionally, these logs have been fluid substituted to their hydrocarbon-bearing equivalent end-members (high porosity trends only). Using these logs it is possible to expand the workflow outlined above, to create equivalent oil-, condensate- and gas-bearing average sets.

<u>Log names</u>
Brine-bearing sandstone end-member logs:
Trend_SDDI_Vp_Sandstone_HighPor_Z
Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z
Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp

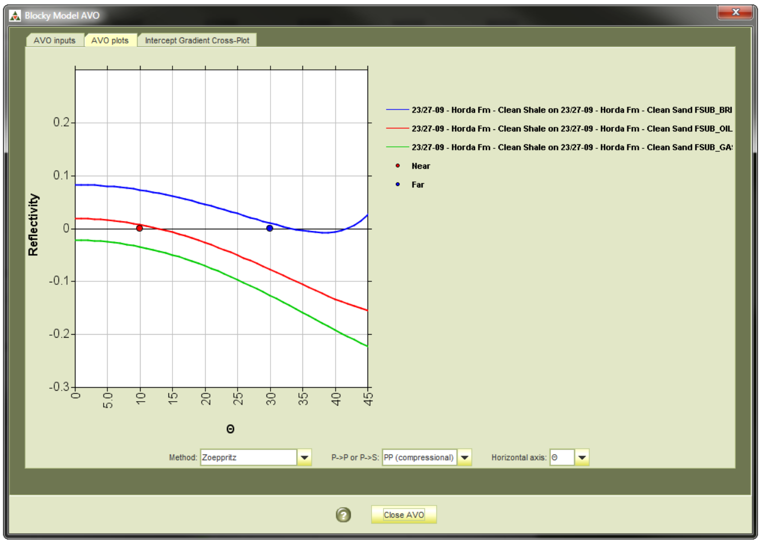
Oil-bearing sandstone end-member logs:
Trend_SDDI_Vp_Sandstone_HighPor_Z_Oil80
Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Oil80
Trend_SDDI_Rho_Sandstone_HighPor_Vp_Z_Oil80

Gas-bearing sandstone end-member logs:
Trend_SDDI_Vp_Sandstone_HighPor_Z_Gas90
Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Gas90
Trend_SDDI_Rho_Sandstone_HighPor_Vp_Z_Gas90



Name	Well	Vp Mean	Vs Mean	Rho Mean	Vp Std Dev	Vs Std Dev	Rho Std Dev	Colour	Active
23/27-09 - Horda Fm - Clean Sand FSUB_GAS	NONE	9,168.381	5,945.297	1.941	53.613	32.411	0.004		
23/27-09 - Horda Fm - Clean Sand FSUB_OIL	NONE	9,332.099	5,757.71	2.07	50.251	32.665	0.003		
23/27-09 - Horda Fm - Clean Sand FSUB_BRINE	NONE	10,122.983	5,625.748	2.168	43.002	32.667	0.003		
21/20A-02 - Horda Fm - Clean Sand FSUB_GAS	21/20A-02	9,361.204	5,952.293	2.073	1,929.271	1,136.182	0.171		
21/20A-02 - Sele Fm - Clean Sand FSUB_GAS	21/20A-02	7,830.99	4,434.633	1.959	1,383.069	1,017.412	0.118		
21/20A-02 - Lista Fm - Clean Sand FSUB_GAS	21/20A-02	12,037.411	6,663.891	2.438	2,117.266	1,070.883	0.138		
21/20A-02 - Maureen Fm - Clean Sand FSUB_GAS	21/20A-02	11,025.625	6,480.469	2.212	1,808.447	828.19	0.183		

Once the average sets have been created, using the complimentary shale Average Set, you will be able to use this information to create a Blocky AVO Model of a hypothetical reservoir using Workflow 4.1.1.



Blocky Model AVO
AVO inputs
AVO plots
Intercept Gradient Cross-Plot
Reflectivity
0.2
0.1
0
-0.1
-0.2
-0.3
0
5.0
10
15
20
25
30
35
40
45
Θ
23/27-09 - Horda Fm - Clean Shale on 23/27-09 - Horda Fm - Clean Sand FSUB_BRI
23/27-09 - Horda Fm - Clean Shale on 23/27-09 - Horda Fm - Clean Sand FSUB_OIL
23/27-09 - Horda Fm - Clean Shale on 23/27-09 - Horda Fm - Clean Sand FSUB_GA
Near
Far
Method: Zoeppritz
P->P or P->S: PP (compressional)
Horizontal axis: Θ
Close AVO

4.2 – Creating a Pseudo Well

Section details how to create a pseudo well and populate it with synthetic log data using RokDoc User Programmer.

A number of workflows exist within RokDoc to create a pseudo well (for example, using trace information from seismic or interpolating log properties between multiple wells by creating a model). This section will outline the method used to create a pseudo well from a basic geological scenario or model, using the trends derived during the multi-well phase of Roknowledge CNS and the RokDoc User Programmer.

Workflow 4.2.1 – Creating a Pseudo Well – Part 1

1. In the Project Viewer, right-click on 'Wells' and select 'Edit Wells …'.
2. The 'Edit Wells' dialog box will open. Click 'Create New Well'.
3. Give the well a suitable name and click on 'Show Selected Well Datum…'.

   The 'Well Datum Editor' dialog is now shown. Typically RokDoc self- populates this dialog using imported log data, but since we are creating a pseudo well, this must be done manually.

4. Uncheck the 'Auto Calc Well Start & Stop' check-box.
5. Populate the 'Well Datum Editor' table. For this example, enter values of '5490' MD (ft) for 'Well Start' and '10125' MD (ft) for 'Well Stop'. Enter reference height of KB above and water depth below Mean Sea Level (MSL).
6. Click 'OK' to close the 'Well Datum Editor' and 'Edit Wells' dialogs.
7. Right-click on the well name in the Project Tree, select 'Display New Well View …' and then click 'OK' to accept the default Well Viewer display.
8. In the Well Viewer, select 'ZStick' > 'MD to TVDkb Conversions' > 'Create MD to TVDkb Conversion'.
9. Toggle 'Vertical Well' and click 'Calculate'.
10. Give the MD to TVDkb Conversion a suitable name, click 'Save' and close the dialog.

    An empty log panel is shown within the Well Viewer for our pseudo well. Next we will populate this panel with data from a geological model. An example geological model (stored as Pseudowells_Markers.xls) is given below:

Stratigraphy	Lithology	MD (ft)
Horda Formation	Shale	5490
Balder Formation	Shale	8508
Sele Formation	Shale (soft)	8788
Forties Member	Sandstone (low porosity)	8950
Base Forties Member		9280
Lista Formation	Shale (hard)	9434
Andrew Member	Sandstone (high porosity)	9500
Base Andrew Member		9650
Maureen Formation	Shale (hard)	9902
TD		10125

11. Select 'Well Data' > 'Markers'.
12. Click the 'Import XLS…' button.

Markers are required to record the top and base of each working interval within the well, and additionally any change in lithology/trend type using the method outlined for this specific workflow. For our RokDoc User Programmer script used later in the workflow to work, it is important that markers follow the stated naming convention:

Marker naming convention

Working intervals (example):

Top – 'Sele Fm'

Base – 'Sele Horda Fm'

Members (example):

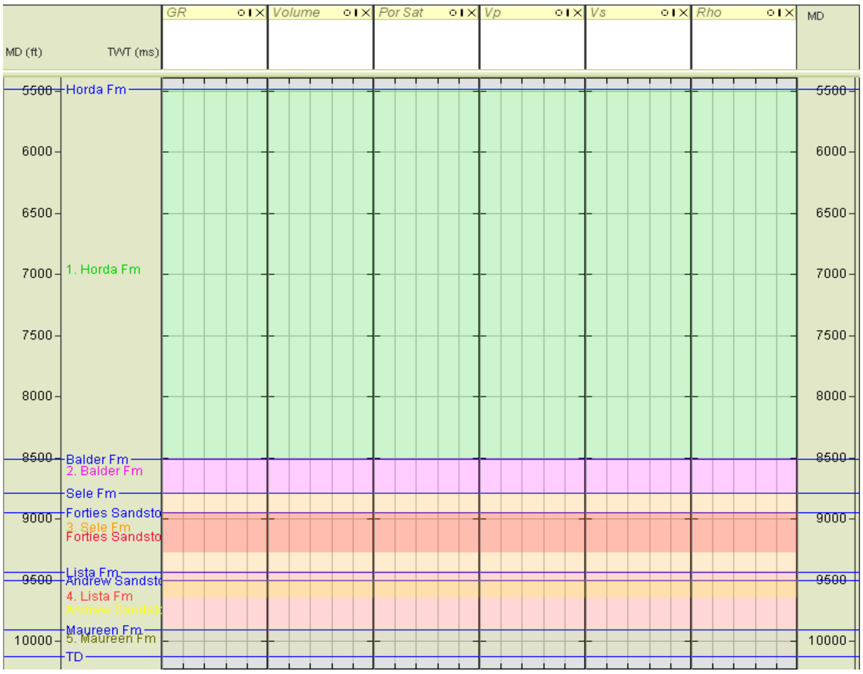
Top – 'Forties Sandstone Mbr'

Base – 'Base Forties Sandstone Mbr'

If unsure, check the naming conventions by opening the 'Working Intervals' dialog box (Ctrl+I). It is also possible to import markers from ASCII or type them in to RokDoc manually.

13. Click on the '…' button and browse to the location of the markers file 'Pseudowells_Markers.xls'. Click 'Open'.
14. Enter a value of '2' in the 'Data Starts on Line:' text entry box.
15. Select Column 'Number 1' for the 'Name' drop-down menu, and Column 'Number 2' from the 'MD' drop-down menu.
16. Select 'ft' for 'Units in file'.
17. Click the 'Read' button.
18. Click 'Activate All' in the lower right-hand corner of the dialog, then 'OK' to exit the Edit Markers dialog.

A basic log panel is now created for our pseudo well. An example is shown below.



NB. (Geo)Spatial interpolation (e.g. Kriging) of the well-based fluid properties and Pressure&Temperature data from the Master Excel workbook allows fluid properties to be computed for locations away from well control.

Workflow 4.2.2 – Creating a Pseudo Well – Part 2 (User Program)

The custom RokDoc User Programmer script used within Roknowledge CNS creates end-member and synthetic logs based upon rock physics templates defined in the multi-well phase of the project (see Chapter 2, Appendix B). The script requires a number of input logs to be specified; well depth TVDml, lithology (volume logs) and trend types (soft or hard shale, low or high porosity reservoir). This workflow deals with creating these input logs and then using the products to generate end-member and synthetic logs within RokDoc User Programmer.

1. Display the Well Viewer created in Workflow 4.2.1.
2. Select 'Well Ops' > 'Z Log Creator …'.
3. Toggle 'TVDml' and click 'Create'.
4. Give the output log a suitable name, click 'Save' and close the dialog.

   We have now created the depth TVDml log. Next we will create a series of pseudo volume logs. A number of methods exist within RokDoc to do so, in this workflow we will use the Log Calculator to create a simple log where volume per formation is either equal to '0' or '1', as consistent with the example geological model specified in Workflow 4.2.1.

5. Select 'Well Ops' > 'Log Calculator'.
6. Click the 'Constant' button, enter a value of '0.0' and click 'OK'.
7. Select a 'Log Type' of 'Volume' from the drop-down menu.
8. Click 'Calculate'.

   We have now created a log with a constant value of '0.0', which will serve as the background log to the volume curve.

9. Click the 'Working Intervals …' button.
10. Highlight the 'Forties Sandstone Member' working interval and click 'OK', closing the 'Select Working Interval / Working Interval List' dialog.
11. On the 'Log Calculator' dialog, click the 'Constant' button, enter a value of '1.0' and click 'OK'.
12. Click 'Calculate'.
13. Repeat steps 9-12 to set a constant value of '1.0' over the 'Andrew Sandstone Mbr' Working Interval.
14. Enter a log name suffix of 'Sand' and click 'Save'.

    We have now created a volume sand log. Using the same technique, create volume logs for shale, tuff and limestone/chalk. In the example, the geological model for our pseudo well states both tuff and limestone/chalk lithologies are not present. However, it is a requirement of the custom RokDoc User Programmer script that a volume log exists for each lithology, so where a given lithology is not present, create a log for the entire well of constant value '0.0'.

    Next we will create a series of end member flag logs. These logs represent the switch between multi-well trends within a formation of constant lithology, as outlined below. Using the Log Calculator once more, we will create a simple log to indicate the appropriate trend, as is consistent with the example geological model specified in Workflow 4.2.1.

    Trend type convention (see Table 2.2.2 & 2.2.3)
    Shale logs:
    - Soft shale = '0.0'
    - Hard shale = '1.0'

Reservoir logs:

Low porosity = ‘0.0’

High porosity = ‘1.0’

Note: where only one lithology type trend exists per formation (for example, Horda Formation shale), use either ‘0.0’ or ‘1.0’.

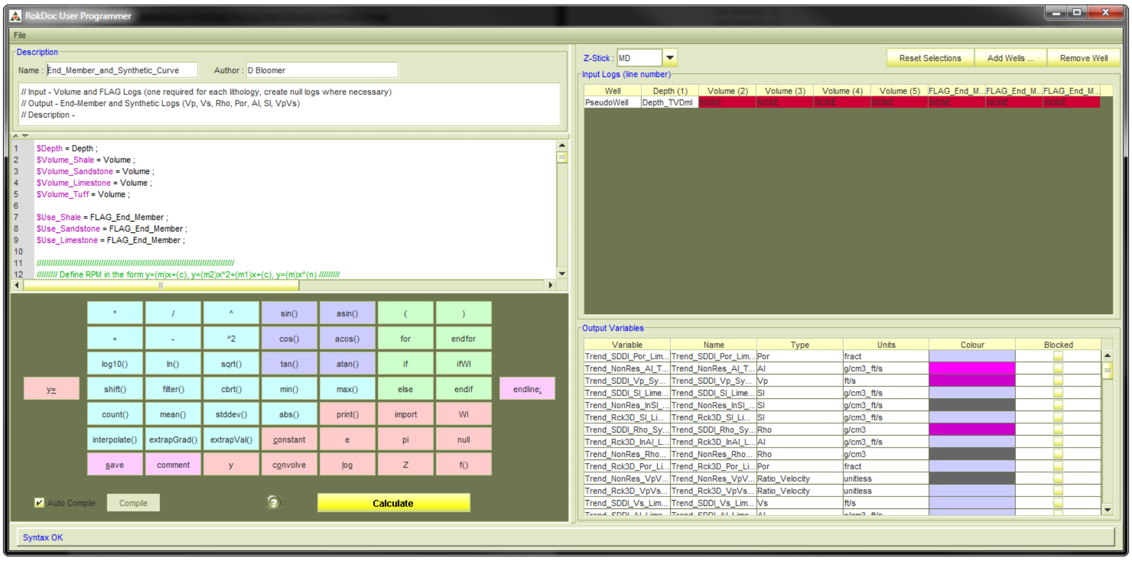
15. Select ‘Well Ops’ > ‘Log Calculator’.
16. Click the ‘Constant’ button, enter a value of ‘1.0’ and click ‘OK’.
17. Select a ‘Log Type’ of ‘FLAG_End_Member’ from the drop-down menu.
18. Click ‘Calculate’.
19. Click the ‘Working Intervals …’ button.
20. Highlight the ‘3. Sele Fm’ working interval and click ‘OK’, closing the ‘Select Working Interval / Working Interval List’ dialog.
21. On the ‘Log Calculator’ dialog, click the ‘Constant’ button, enter a value of ‘0.0’ and click ‘OK’.
22. Click ‘Calculate’.
23. Enter a log name suffix of ‘Shale’ and click ‘Save’.

We have now created the shale trend type log. Repeat this process to create trend type logs for sandstone and limestone/chalk. Once again, it is a requirement of the user program to create a log for each lithology type. Where a given lithology is not present, create a log for the entire well with a constant value of either ‘0.0’ or ‘1.0’. We now have created each of the inputs required to use the custom RokDoc User Programmer script, so will now go on to create the end-member and synthetic logs.

24. In the Project Viewer, select ‘Programmer’ > ‘User Programmer …’.

The RokDoc User Programmer dialog box is now shown. We will load the custom script and then parameterise the inputs using the logs created for our pseudo well.

25. Select ‘File’ > ‘Load …’.
26. Browse to the location of the script ‘End_Member_and_Synthetic_Curve.rokprog’. Click ‘Open’.

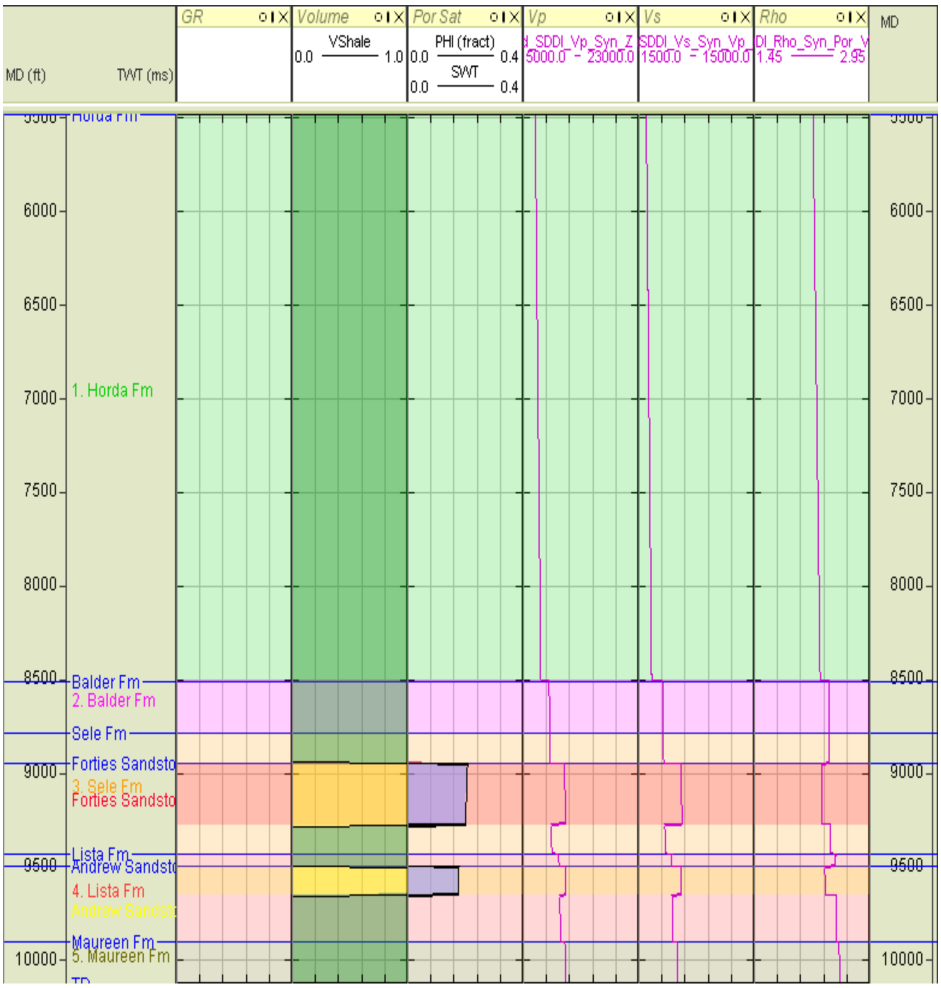


27. Ensure the pseudo well is displayed within the ‘Input Logs (line number)’ section, if it is not; add the well using the ‘Add Wells …’ button.
28. Double-click on the second column for the pseudo well (Depth (1)). Select the depth TVDml log.
29. Repeat this process by moving along each column, choosing the appropriate log. These are:

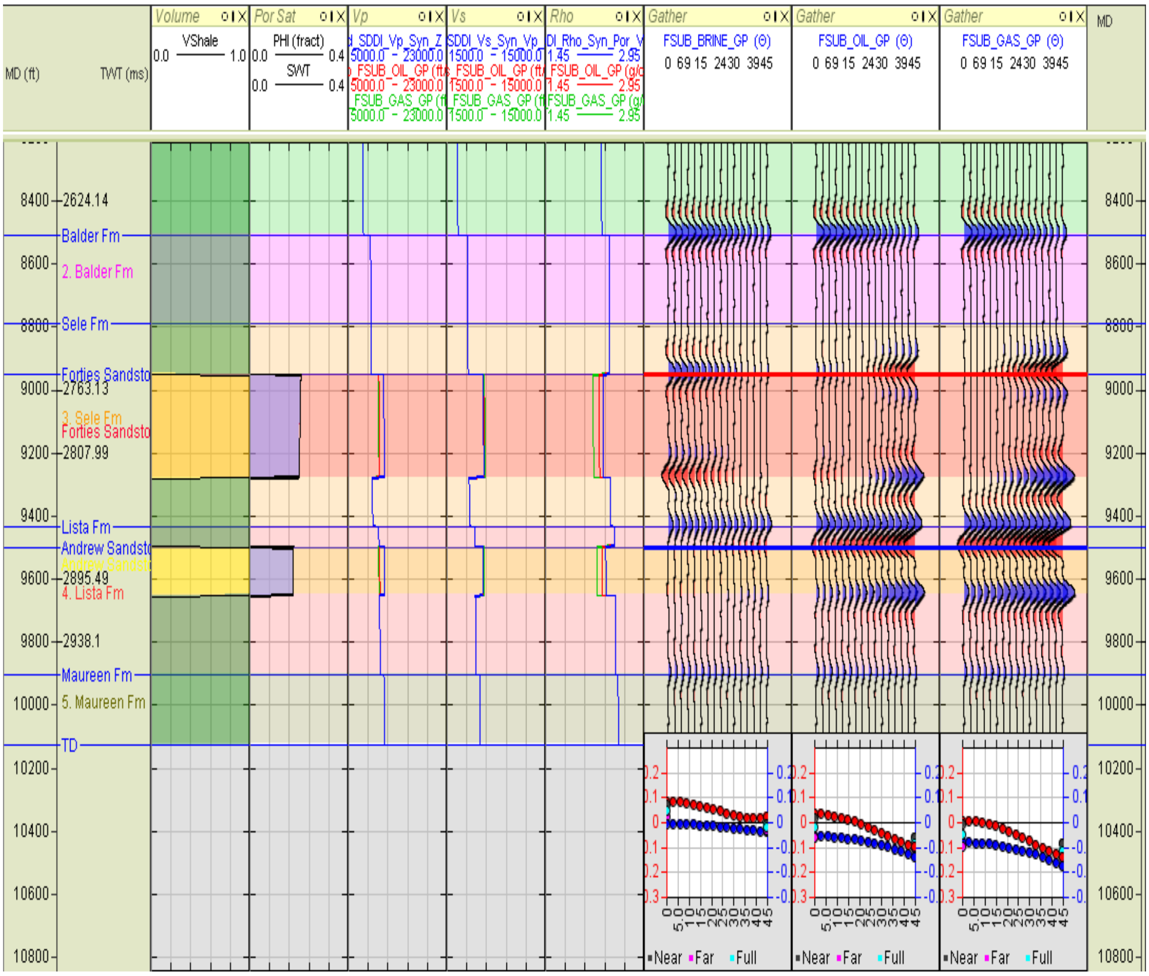
Column	Log
Depth (1)	Depth_TVDml
Volume (2)	Volume_Shale
Volume (3)	Volume_Sandstone
Volume (4)	Volume_Limestone/Chalk
Volume (5)	Volume_Tuff
Trend type (7)	FLAG_End_Member_Shale
Trend type (8)	FLAG_End_Member_Sandstone
Trend type (9)	FLAG_End_Member_Limestone/Chalk

30. Click ‘Calculate’.
31. Once the calculation is complete, close the RokDoc User Programmer.

We have now created a pseudo well, volume fraction set, depth and trend type logs and used the products to create pseudo end-member and brine bearing synthetic logs. The results are shown in the Well Panel display shown below.



To expand this workflow, take the synthetic Vp-Vs-Rho logs and fluid substitute them to oil- and gas-bearing conditions. On completion, you will be able to use the information to create Gathers (or Blocky AVO Model(s)) of the pseudo well reservoirs as shown below.

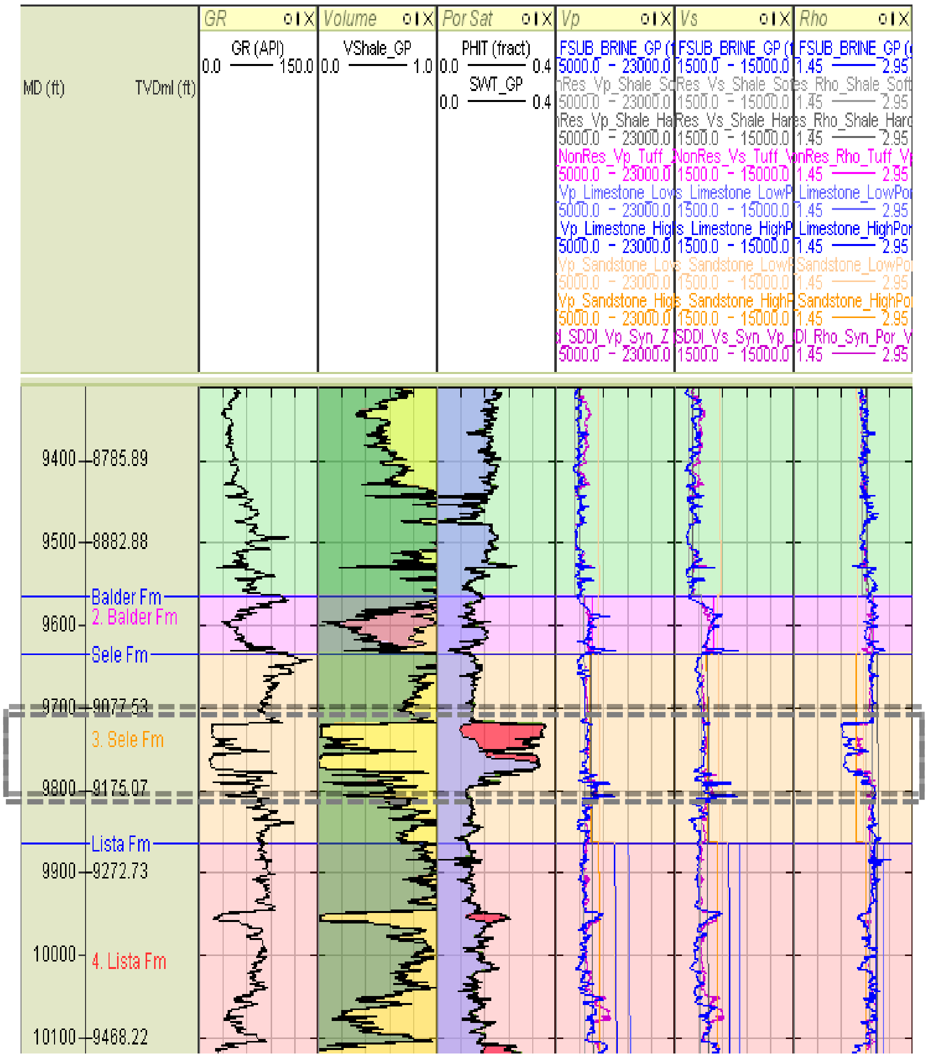


4.3 – Local Calibration of Regional Trends

Section details how to create a custom rock physics model and update the custom RokDoc User Programmer script with the derived trend(s).

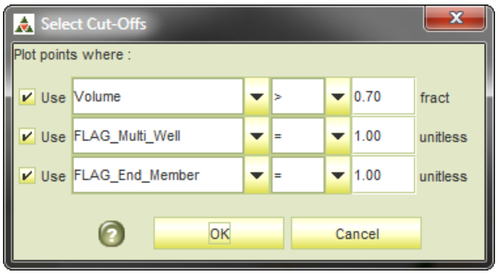
Modelling of log data within Roknowledge CNS was undertaken with a view to capturing regional trends. In some cases it is evident that specific intervals or wells fall as outliers to these regional trends. If the focus of the user is an outlying formation, well or even sub-region, it can be useful to define new multi-well rock physics templates. The method for creating these will now be outlined, showing the end user how to use the results within the custom RokDoc User Programmer script to generate a new set of end-member and synthetic logs for either a study or pseudo well.

The example used in the workflow is from 29/10-04Z. Within this well, end-member and synthetic logs produce a weak match over high porosity sands within the Sele Formation, which are interpreted to be of higher porosity than equivalent sands within the CNS. In this workflow, we will define a locally calibrated rock physics template for the Sele Formation high porosity reservoir sandstone within 29/10-04Z.



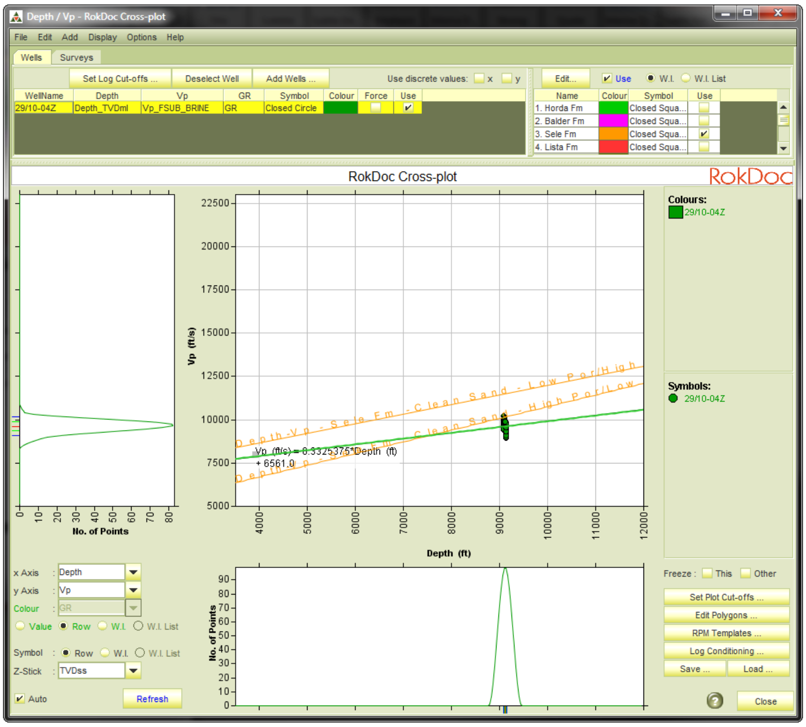
Workflow 4.3.1 – Creating a Custom Rock Physics Model (RokDoc Cross-plotter)

1. Select ‘Multi-well Ops’ > ‘Cross-plots’ > ‘Cross-plot …’.
2. Once the cross-plotter opens, click ‘Load …’.
3. Select the View ‘Depth-Vp Sele Fm’ and click ‘OK’.
4. Click ‘Yes’ to use the RPM template flags, and choose to ‘Load’ data from the selected view.
5. Click ‘Add Wells ..’, select well ‘29/10-04Z’ and click ‘OK’.
6. The well is now displayed in the well list. Double-click on the Vp log name, select the log ‘Vp_FSUB_BRINE’ and click ‘OK’.
7. Click ‘RPM Templates …’ and check the ‘Use’ check-box for the following Rock Physics Model Templates:
   Depth-Vp - Sele Fm - Clean Sand - Low Por/High Vp trend
   Depth-Vp - Sele Fm - Clean Sand - High Por/Low Vp trend
8. Click ‘OK’ to close the ‘Rock Physics Model Templates’ dialog.
9. In the cross-plotter, click ‘Set Plot Cut-offs …’ and set-up the display cut-offs as shown below. If the active Volume log is not ‘VOL_SAND’ or the active FLAG_End_Member log is not ‘SAND_FLAG_Blocked_20ft’, go to the Edit Logs dialog (Ctrl+L) and check the ‘Active’ check-box next to the log name(s).



   The Volume and FLAG_Multi_Well cut-offs are consistent with those used in the multi-well phase of Roknowledge CNS for deriving sandstone reservoir trends. The addition of the FLAG_End_Member cut-off in this workflow is to ensure that the new localised trend is based only upon the high porosity reservoir sandstone data points within the Sele Formation.
10. Right-click in the main cross-plot window and select ‘Best Fit Options’ > ‘Add Best Fit Line’.
11. In the ‘Best Fit Options’ dialog, check the ‘Force Line Through Point’ check-box and enter values for x of ‘0’ and y of ‘6561’ (forcing the trend to give a mudline velocity of 6561 ft/s).
   As there is not enough data to estimate a reliable depth trend, the trend was fixed at the mud line, assuming a water velocity of ~5000 ft/s, at a velocity of 6561 ft/s.
   For additional scenarios in this well, the fact that the gradient is different from the existing end-member Sands doesn’t matter. However, when extrapolating this local rock type to a pseudo well at a different location with a different depth , one might select another approach. E.g. keep-ing the depth gradient the same as the existing High Porosity Sand, but lowering the intercept.
12. Toggle ‘Add Best-fit Y = m*X+c Line’ and click ‘Add Line’.
13. Right-click on the best-fit line and select ‘Selected Line’ > ‘Add Equation To This Line’.
14. Save the best-fit line as a rock physics template by right-clicking on the best-fit line and select ‘Selected Line’ > ‘Save as Rock Physics Template …’.
15. Choose a suitable ‘Rock Physics Template Name’ and click ‘OK.

   The cross-plotter now shows data points relating to the Sele Formation reservoir sandstone, in addition to the Roknowledge CNS rock physics templates (orange), and our custom rock physics template (green). The custom trend line shows a better match to the high porosity sandstones of the Sele Formation than that of the regional trend.



16. Optional: Repeat steps 3-15 to create custom rock physics templates for Vs-Vp, Por-Vp and Rho-Por for Sele Formation high porosity sandstone. It is important that the type of best-fit used is consistent with that used in the multi-well phase of Roknowledge CNS – further details can be found within Chapter 2. This step gives the following series of relationships:

    Vp-Depth (linear trend, fixed at x=0, y=6561)
    Vp = (0.3325375 * Depth) + 6561

    Vs-Vp (linear trend, fixed at x=4747, y=0, see note)
    Vs = (0.9695491 * Vp) – 4602.821

    Por-Vp (2^{nd} order polynomial, fixed at x=18740, y=0)
    Por = (–1.359872E-9 * Vp^2) + (1.91054E-6 * Vp) + 0.4417666

    Rho-Por (linear trend, fixed at x=0, y=2.65)
    Rho = (–1.656171 * Por) + 2.65

    Note: Insufficient data to fit linear trend on data points alone, so best-fit line is fixed to give slope consistent with regional sandstone trend.

We have now defined a series of rock physics templates calibrated to the high porosity Sele Formation reservoir sandstone within 29/10-04Z. The method for using these trends to output an updated end-member and synthetic logs will now be outlined.

Note: The trends defined within workflow 4.3.1 will only allow us to output updated SDDI model end-member and synthetic curves (as shown in Workflow 4.3.2). In order to output both updated SDDI and Rck3D model logs, Por-Depth and Rho-Por rock physics templates would also need to be defined. For further information on the theory behind the synthetic multi-well regional trends, see Chapter 2.

Workflow 4.3.2 – Creating End-Member / Synthetic logs (User Program)

NOTE : Before you proceed: Save a copy of the existing end-member log curves before creating others as the user program script will cause the existing to be overwritten.

1. In the Project Viewer, select 'Programmer' > 'User Programmer …'.
2. Select 'File' > 'Load …'.
3. Browse to the location of the script 'End_Member_and_Synthetic_Curve.rokprog'. Click 'Open'.
4. Uncheck the check-box 'Auto Compile'.
5. Add well '29/10-04Z' to the 'Input Logs (line number)' display using the 'Add Wells …' button.
6. Double-click on the second column for well 29/10-04Z (Depth (1)). Select the 'Depth_TVDml' log.
7. Repeat this process by moving along each column, choosing the appropriate log. These are:

Column	Log
Depth (1)	Depth_TVDml (Depth TVDml)
Volume (2)	VSH (Volume Shale)
Volume (3)	VOL_SAND (Volume Sandstone)
Volume (4)	VOL_LIME (Volume Chalk)
Volume (5)	VOL_TUFF (Volume Tuff)
Trend type (7)	SHALE_FLAG_Blocked_20ft (End Member Trend Type Shale)
Trend type (8)	SAND_FLAG_Blocked_20ft (End Member Trend Type Sandstone)
Trend type (9)	LIME_FLAG_Blocked_20ft (End Member Trend Type Chalk)

The left hand display within the RokDoc User Programmer shows the custom script used to generate the end-member and synthetic log outputs seen within each of the study wells. We will now update this script, overwriting the original rock physics templates with those derived in workflow 4.3.1.

8. Scroll through the script and find the section entitled 'Define RPM in the form y=(m)x+(c), y=(m2)x^2+(m1)x+(c), y=(m)x^(n)' – line 18.

   Within this section of the script, each multi-well relationship is defined by formation. Variables are used to represent the coefficients contained within the relationships in the format stated in the section header. For example:

   Vp = (0.3325375 * Depth) + 6561

   Is represented by:
   $Vp_Z_Sandstone_HighPor_m = 0.3325375 ;
   $Vp_Z_Sandstone_HighPor_c = 6561 ;

9. Scroll further down to find the section '// Sele Formation - contains no sandstone or shale' > '// Brine-Bearing Reservoir Relationships (Sandstone)' > '// High Porosity Trends' – line 191.
10. Update the variables using the relationship coefficients defined in workflow 4.3.1. This should appear as below:

```
// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 1.0 ;
// Low Porosity Trends
$Vs_Vp_Sandstone_LowPor_c = 0.0 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 0.3325375 ;
$Vp_Z_Sandstone_HighPor_c = 6561 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_HighPor_m = -0.00003721717 ;
$Por_Z_Sandstone_HighPor_c = 0.6085076 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_HighPor_m = 0.9695491 ;
$Vs_Vp_Sandstone_HighPor_c = -4602.821 ;
// Shared Trends
// Rho (from Rho-Vp)
$Rho_Vp_Sandstone_m = 0.12631 ;
$Rho_Vp_Sandstone_c = 0.3115259 ;
// Rho (from Rho-Por)
$Rho_Por_Sandstone_m = -1.6561715;
$Rho_Por_Sandstone_c = 2.65 ;
// Por (from Vp-Por)
$Por_Vp_Sandstone_m2 = -0.000000001359872 ;
$Por_Vp_Sandstone_m1 = 0.00000191054 ;
$Por_Vp_Sandstone_c = 0.4417666 ;
```

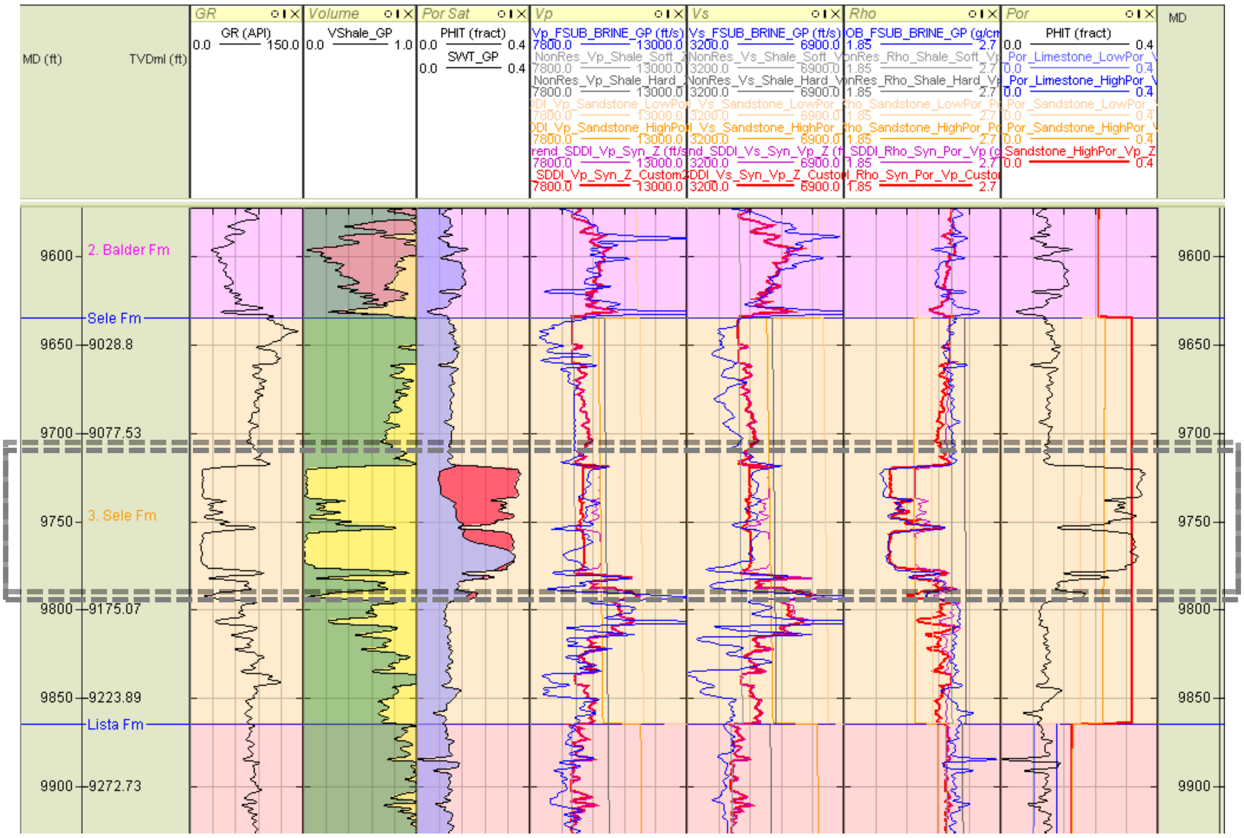
The custom script is configured by default to output the entire suite of end-member and synthetic logs. Our next step will be to reduce the amount of logs output, so that only logs of interest are added to the project.

11. Scroll down to the bottom of the script – line 1414. The final section defines which of the calculated logs are saved and output. Remove each of line from the script with the prefix 'save ($', leaving the four following logs only:

```
1414 save ($Trend_SDDI_Por_Sandstone_HighPor_Vp_Z) ;
1415 save ($Trend_SDDI_Vp_Syn_Z) ;
1416 save ($Trend_SDDI_Vs_Syn_Vp_Z) ;
1417 save ($Trend_SDDI_Rho_Syn_Por_Vp) ;
```

12. Click 'Compile'.
13. In the 'Output Variables' display, give each of the logs a suitable name or suffix (to ensure that the logs output do not replace existing logs within the project) and change the log colour.
14. Click 'Calculate'.
15. Once the calculation is complete, close the RokDoc User Programmer.

The results of incorporating the custom rock physics templates to the custom RokDoc User Programmer script are shown in the Well Viewer below. The FSUB_BRINE_GP logs over high porosity sandstone in the Sele Formation now shows an improved match to the end-member and synthetic logs (red) produced by the script.



4.4 – Interval Specific Fluid Substitution

Section details how to perform fluid substitution within a specified working interval.

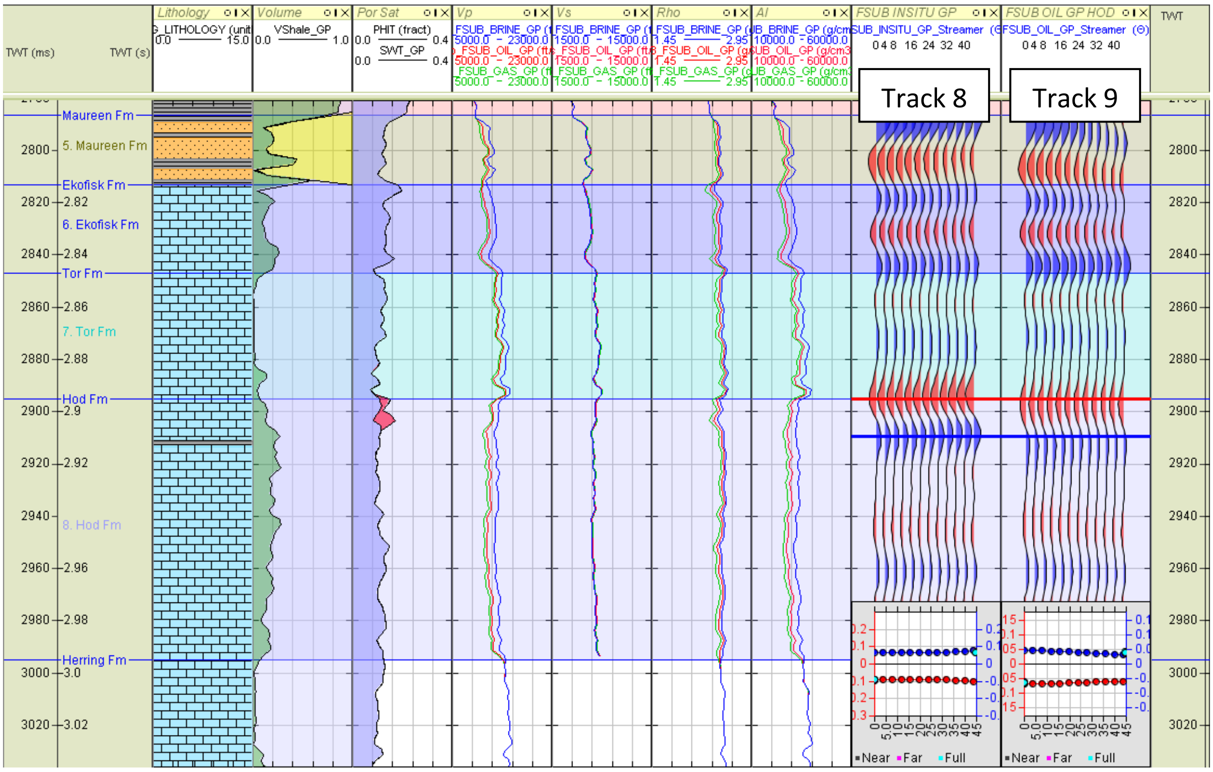
Synthetic gathers contained the Roknowledge CNS .rok file are based on three basic fluid scenarios; insitu, brine- and hydrocarbon- bearing. For the purposes of forward modelling or synthetic well generation, these scenarios may not give the seismic response of interest to the user. This issue is particularly prevalent in Cretaceous intervals, where reservoir (as defined by cut-offs) is often continuous between formations, creating synthetic gathers that give little insight to modelled top formation or reservoir responses. The solution to this issue to perform fluid substitution using the brine- bearing logs as input over a limited depth range as specified by a working interval, and then create synthetic gathers based up on these logs.

The method for performing fluid substitution on a specific interval will now be outlined, in addition to using the generated products to create a synthetic gather.

Workflow 4.4.1 – Creating an Interval Specific Fluid Substituted Log Set

An example is shown for well 29/10-02, where fluid substitution is performed within the Hod Formation to oil- bearing reservoir conditions at a custom saturation. If not modelling to custom saturations, an alternative approach would be to use RokDoc Log Calculator along with the existing logs contained within the project to substitute hydrocarbon- bearing logs in to a background brine- bearing scenario over a working interval.

In the image below, the synthetic gather for the 80% oil- bearing scenario (track 9) produces a weaker amplitude response than synthetic for the relatively low saturation insitu scenario (track 8). In this workflow, we will demonstrate how to create an improved modelled response for the 80% oil- bearing scenario, while using the insitu scenario for calibration.



1. Display the Well Viewer.
2. Select ‘Well Ops’ > ‘Rock Physics’ > ‘Log Fluid Sub. (Gassmann Dry Rock Modelling) …’.
3. Click ‘OK’ to close the ‘WARNING: Dry Clay is being used a mineral’ text box.

   The ‘Log Fluid Substitution (Gassmann Dry Rock Modelling)’ module is now shown. Using the ‘Initial To Dry’ tab - we will select our inputs to the fluid substitution workflow.

4. Click ‘Vp-Vs-Rho …’ to open the ‘Select Vp-Vs-Rho Set’ dialog.
5. Select ‘FSUB_BRINE_GP’ and click ‘OK’ to close.

6. Click ‘Select Fluids …’ to open the ‘Initial Fluids Selector’ dialog.
7. Confirm that the ‘Porosity’ log selected is ‘PHIT’. If not, click ‘Por Log …’ and select the ‘PHIT’.

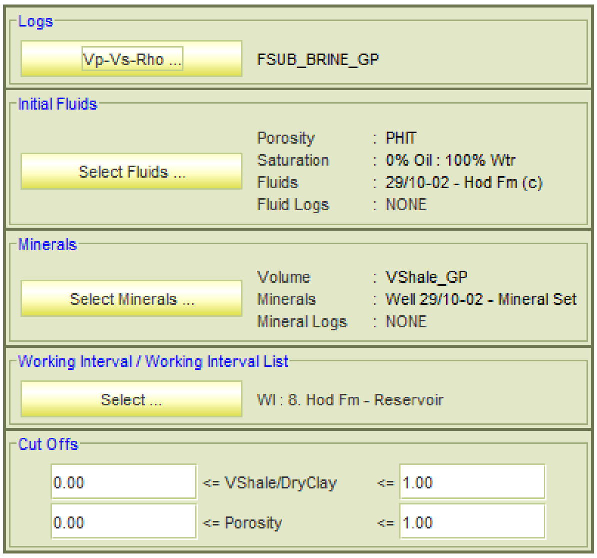
Note: In wells containing casing points, PHIT has often edited to create a complete porosity log throughout the well. In these cases, either ‘PHIT’ or ‘PHIT_EDIT’ can be selected.

8. Check the ‘Initial Saturation Oil’ check-box and enter a value of ‘0’ in the corresponding text box to create a compliment saturation of 100% Water.
9. Click ‘Fluids …’, select the ‘29/10-02 – Hod Fm (c)’ Fluid Set and click ‘OK’ to close.
10. Click ‘Close’ to close the ‘Initial Fluids Selector’ dialog.

11. Click ‘Select Minerals …’ to open the ‘Minerals Selector’ dialog.
12. Confirm that the ‘Volume Set’ selected is ‘VShale_GP’. If not, click ‘Volume Set …’ and select ‘VShale_GP’.
13. Click ‘Minerals …’, select the ‘Well 29/10-02 – Mineral Set’ Mineral Set and click ‘OK’ to close.
14. Click ‘Close’ to close the ‘Minerals Selector’ dialog.

15. Click ‘Select …’ on the ‘Working Interval / Working Interval List’ panel.
16. Select ‘8. Hod Fm Reservoir’ and click ‘OK’ to close to the dialog.

As reservoir cut-offs are specified within the selected working interval, it is not necessary to edit the ‘Cut Offs’ panel. If using a custom working interval, ensure that appropriate cut-offs have been selected. The ‘Initial To Dry’ tab of the ‘Log Fluid Substitution (Gassmann Dry Rock Modelling)’ module should now appear as shown below.

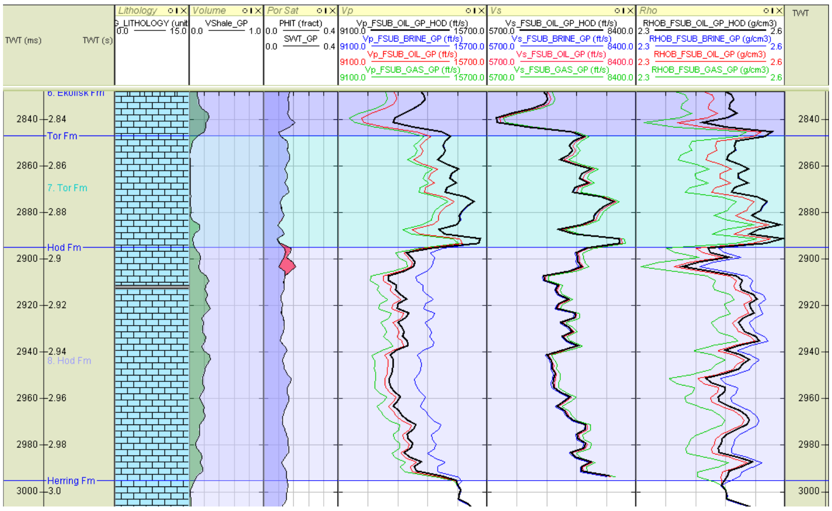


17. Select the ‘Dry Rock Modelling’ tab.

    The Kdry/Kmin vs. Porosity cross-plot for the selected data is now shown. The fluid substitution method used within this workflow is consistent with that performed in the rock physics stage of the workflow (see Chapter 2). Model Bounds used within the fluid substitution workflow vary slightly on a formation and well basis, for further details of the model bounds used see log descriptions or supplementary PowerPoint’s.

18. Confirm the ‘Constant Normalised Pore Stiffness Model’ is selected in the ‘Model Bounds’ panel.
19. Enter a ‘KPhi / KMin Value’ of ‘0.04’ for ‘Bound 1’.
20. Uncheck the check-box for ‘Use Bound 2’ to turn off the upper bound.

21. Select the ‘Dry To Final’ tab.
22. Click ‘Select Final Fluids …’ to open the ‘Final Fluids Selector’ dialog.
23. Check the ‘Final Saturation Oil’ check-box and enter a value of ‘50’ in the corresponding text box.
24. Click ‘Fluids …’, select the ‘29/10-02 – Hod Fm (c)’ Fluid Set and click ‘OK’ to close.
25. Click ‘Close’ close the ‘Final Fluids Selector’ dialog.
26. Click ‘Calculate’.
27. Give the ‘Outputs’ a suitable name and colour, click ‘Save’ and close the module.



A Vp-Vs-Rho set has now been created for the scenario of a brine- bearing well with a 50% oil- bearing Hod Formation reservoir zone. The method for using these logs to create a (Synthetic) Gather within RokDoc will now be outlined.

Workflow 4.4.2 – Creating a (Synthetic) Gather

1. Display the Well Viewer.
2. Select 'Well Ops' > 'Synthetics & Filters' > 'Synthetic Generation (AVO) …'.

   The 'Synthetic Generation (AVO)' module is now displayed.

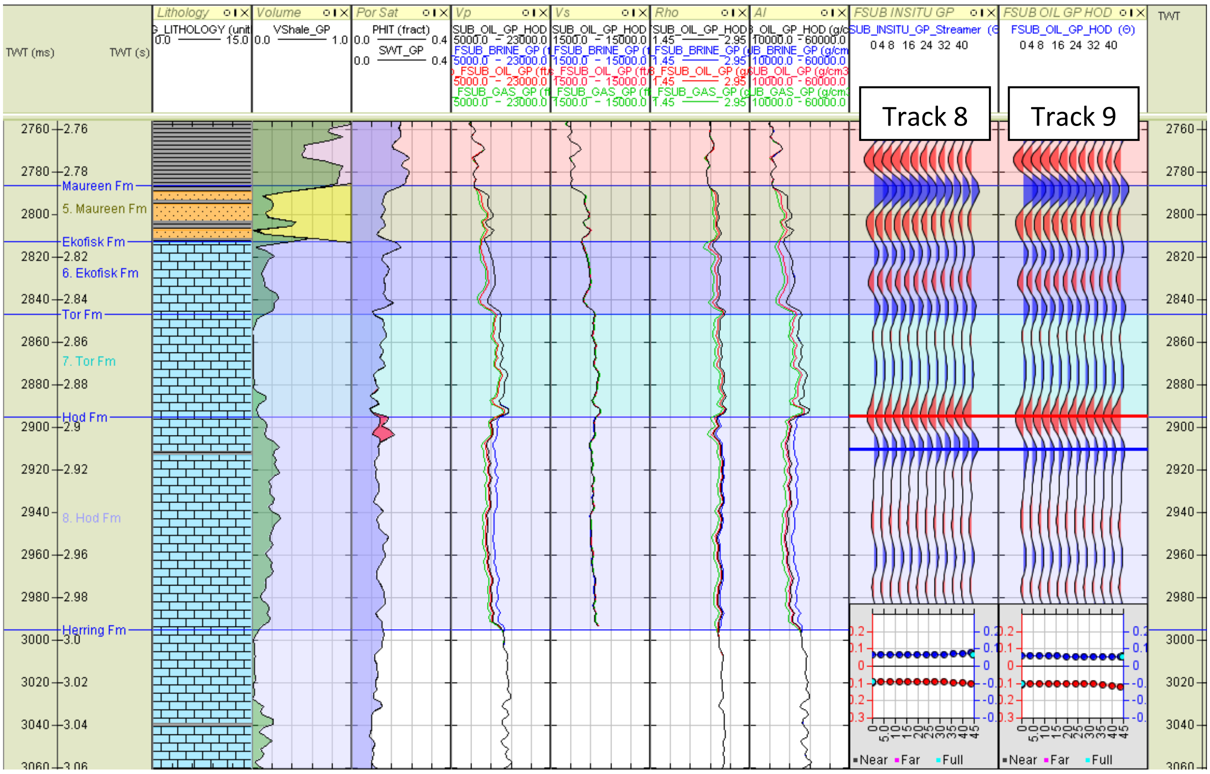
3. Click 'Vp-Vs-Rho …', select the Vp-Vs-Rho set created in Workflow 4.4.1 and click 'OK'.
4. Click 'Wavelet …' and select an appropriate wavelet.

   The 'Streamer' wavelet is used by default within 'Well Views' contained in the Project, and throughout this report.

5. Click 'Calculate'.
6. Give the Gather a suitable name and click 'Save Gather'.
7. Right-click on a 'Gather Track' within the Well Viewer and select 'Select Gather 1 …'.
8. Highlight the Gather created in Step 6 of the workflow and click 'OK'.
9. Drag an Attribute Line within the Gather Track to the amplitude anomaly associated with the top Hod Formation contact.

   Note: If the line contained within the Attribute Plot is not visible , update the display scale by right-clicking within the Attribute Plot and selecting 'Left axis' (for example) >'Set scale …'.

   The created Gather is now shown within the Well Viewer as shown below (track 9). The modelled response observed at the top of the Hod Formation is now comparable with that of the insitu fluid case (track 8), highlighting the suitability of this method to better model synthetic responses throughout the Cretaceous.



Chapter 5 – Summary

The aim of this project was to provide an easy-to-use rock physics reference source (a regional rock property database and atlas) for the Tertiary and Upper Cretaceous Chalk reservoirs of part of the UK Central North Sea: Quadrants 21, 22 and the northern part of Quadrants 28 and 29. This compilation can be used to provide data on rock properties for different fluid-fill and burial-depth scenarios, required for forward modelling seismic response or for inversion of observed seismic data to infer reservoir properties and fluid fill, or any application where a prediction of rock properties is needed but well control is limited.

Thirty-five wells were chosen for study, ranging in date from 1969 to 2003, with the majority from the 1980s and 1990s. Only in the latter period did shear velocity logs begin to become routinely available, so significant attention to modelling shear response was required. Extensive QC and conditioning was applied to all the input log data on a well-by-well basis. Missing or poor-quality log data have been replaced with modelled logs, based on multiwell trend analyses.

The stratigraphic interval under consideration can be divided into the Horda, Balder, Sele, Lista, Maureen, Ekofisk, Tor and Hod Formations. Multiwell analyses have been made for each interval, including total porosity against depth ml, Vp against depth ml, density against Vp, Vs against Vp, total porosity against Vp and density against total porosity. In some of these cases more than one trend was required to capture the data; for example, the total porosity – depth cross-plot required the use of two trends, one for low porosity and the other for high porosity. These cross-plots have all been saved and can be retrieved from the project and modified as the user requires, for example to define new trends in specific areas.

Whether effective reservoir is found in these formations varies from well to well. Where reservoir is present, Gassmann substitution has been applied to create logs over the reservoir intervals for end-member cases: 100% brine, 80% oil and 90% gas saturation. For every well, AVO blocky models and AVO synthetics have been created for the different fluid fills. Tabulation has been made of average Vp, Vs and density values for in situ, brine, oil and gas cases for all the reservoir intervals in all the wells. In addition, a fluid property database has been constructed containing the properties of all the fluids documented in the 35 study wells, with information on stratigraphic interval, pressure and temperature.

Logs in the digital database include those for in situ, brine, oil and gas cases. In this area of the North Sea, hard streaks are often seen in logs, probably due to the presence of calcite. They are not likely to be laterally continuous.

For forward modelling, functionality is available to create pseudo wells with any desired stratigraphy and lithology as a function of depth, and populate the rock properties from the multiwell trends in the database. Gassmann substitution can then be applied to these pseudo wells to any desired fluid saturation, and AVO models and synthetics constructed.
As mentioned above, regional rock property trends have been defined across the set of wells, but software is also provided to allow the user to modify these trends where needed to describe the behaviour of specific intervals in particular wells that are outliers to the general population.

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Ikon Science would like to acknowledge the contribution of the following people in the production of Shell CNS Tertiary and Cretaceous Roknowledge™ study.

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Appendix A – Units, Colour Key

Units

Units:	**IMPERIAL**
Depth	ft
Vp	ft/s
Vs	ft/s
Rho	g/cm^3
GOR	scf/stb
Oil API	API
Gas Gravity	Air = 1
Mu	GPa
K	GPa
Temperature	Deg F
Pressure	psia
Porosity	fract
Acoustic Impedance	g/cm3_ft/s
Shear Impedance	g/cm3_ft/s
Gradient Impedance	g/cm3_ft/s
Permeability	mD
Salinity	ppm

Colour Key:

Gas	
Condensate	
Oil	
Brine	

Appendix B – Petrophysical Analysis

All well-data used in the Shell CNS Tertiary and Cretaceous Roknowledge™ study were petrophysically interpreted and conditioned to ensure that consistently derived rock properties were used throughout the study. The first stage of this process involved log data processing and quality-control check, and was followed by data interpretation and formation evaluation.

Often more than one petrophysical processing technique exists for the estimation of reservoir parameters. In these instances, the selection of the best method is based on the quality and availability of log-data.

B.1 Log-Data Preparation and Quality Control

The following steps were required to process the raw data prior to formation evaluation:

Depth alignment: Depth discrepancies can occur between successive logging runs. To correct for this, the density log was used as the reference and the other services where depth shifted to match.

Log Editing: Data above the casing point and below first reading were removed. The logs were also edited to remove spurious measurements such as spikes caused by cycle skipping or tool failure.

Log Splicing: Composite logs were created by splicing together the data from each logging run. Repeat sections (when available) were also spliced into the main logging run when the data quality could be improved by doing so.

Environmental corrections: Where appropriate, log measurements were subjected to environmental correction processes to compensate for down-well changes in temperature, borehole conditions, diagenetic effects etc.

B.2 Formation Evaluation

The following techniques and data were used in the petrophysical workflow to help constrain and calibrate log interpretations.

Routine core analysis: Conventional core data were acquired for wells and were used to calibrate porosity values. The core data was depth-shifted to match the wireline data.

Drill-stem tests: When available, these were used to provide information on the fluids saturating the reservoir formations.

RFT pressure data: Formation pressure data were acquired in order to identify oil/water or gas/oil contacts and to allow a comparison with log-based fluid-contact interpretations.

Water analysis: Formation water salinity was available for certain wells and provides the information necessary to determine formation water resistivity.

Prior to calculation of the petrophysical results, a badhole flag was generated based on the differential caliper and density correction logs. This was used to switch between different methods of calculation where poor hole condition had an adverse effect on log response.

B.3 Petrophysical results:

Shale volume (Vsh): The shale volume was calculated by using a combination of the gamma ray log (GR) and neutron-density cross-plots.

Total porosity (Phit): Porosities were calculated from density and where no density was available, Sonic method.

Water saturation (Swt): The Archie equation method was used to calculate water saturation

Electrical properties of a, m and n: These parameters are required in Archie's law to relate the electrical conductivity of a sedimentary rock to its porosity and brine saturation. Values were either determined by special core analysis, or assumed based on theoretical relationships.

Formation water resistivity (Rw): This was calculated using a combination of water salinity data from the wells in the study and those nearby and the Pickett-plot method.

Reservoir Summation: Sand, Reservoir and Pay flags together with zonal averages were generated based on the following cutoffs:

Horda Fm	PHIT >= 0.15	VSH<= 0.40	SWT <= 0.5
Balder Fm	PHIT >= 0.12	VSH<= 0.40	SWT <= 0.5
Sele Fm	PHIT >= 0.12	VSH<= 0.50	SWT <= 0.5
Lista Fm	PHIT >= 0.10	VSH<= 0.40	SWT <= 0.5
Maureen Fm	PHIT >= 0.08	VSH<= 0.45	SWT <= 0.5
Ekofisk Fm	PHIT >= 0.06	VSH<= 0.40	SWT <= 0.5
Tor Fm	PHIT >= 0.03	VSH<= 0.20	SWT <= 0.5
Hod Fm	PHIT >= 0.03	VSH<= 0.40	SWT <= 0.5

Appendix C – Multi-well trends

All trends derived in the multi-well section of the project are summarised in this section of the appendix. The full list of trends can also be found in the Master Spreadsheet.

C.1 Using these multi-well trends

A guide for using these multi-well trends in regional and local calibration is provided in Chapter 4 of this report.

C.2 Multi-well analysis (100% Brine Bearing data)

These trends are derived after the initial log conditioning stage of the project and used to fill any gaps in the log data.

- Clean Shale cut-off; VSh > 0.7
- Clean Sandstone cut-off; Vol_Sand > 0.7
- Clean Tuff cut-off; Vol_Tuff > 0.7
- Clean Limestone cut-off; VSh > 0.9

Working Interval = Horda Fm

Cross-Plot	Lithology	Trend
Vp-Depth	Shale (hard)	Vp (ft/s) = 0.2571209 * Depth TVDml (ft) + 6198.616
Vp-Depth	Shale (soft)	Vp (ft/s) = 0.2922942 * Depth TVDml (ft) + 5233.447
Vs-Vp	Shale	Vs (ft/s) = 0.7057037 * Vp (ft/s) - 2465.212
Rho-Vp	Shale	Rho (g/cm3) = 0.1066255 * Vp (ft/s) ^ 0.3432433
Vp/Vs-Depth	Shale (hard)	Vp/Vs = 0.2922942 * Depth TVDml (ft) + 5233.447 / 0.7057037 * (0.2571209 * Depth TVDml (ft) + 6198.616) - 2465.212
Vp/Vs-Depth	Shale (soft)	Vp/Vs = 0.2922942 * Depth TVDml (ft) + 5233.447 / 0.7057037 * (0.2922942 * Depth TVDml (ft) + 5233.447) - 2465.212
Vp-Depth	Sandstone	Vp (ft/s) = 0.660582 * Depth TVDml (ft) + 5583.154
Vs-Vp	Sandstone	Vs (ft/s) = 0.7596545 * Vp (ft/s) - 2064.222
Rho-Vp	Sandstone	Rho (g/cm3) = 0.1698896 * Vp (ft/s) ^ 0.2765268
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.611234 * Por (fract) + 2.65
PHIT-Depth	Sandstone	Por (fract) = -3.584127E-5 * Depth TVDml (ft) + 0.5508362
PHIT-Vp	Sandstone	Por (fract) = 2.163757E-10 * Vp^2 (ft/s) - 4.096828E-5 * Vp (ft/s) + 0.6917572

Working Interval = Balder Fm

Cross-Plot	Lithology	Trend
Vp-Depth	Shale	Vp (ft/s) = 0.4515433 * Depth TVDml (ft) + 5153.091
Vs-Vp	Shale	Vs (ft/s) = 0.9232975 * Vp (ft/s) - 4065.238
Rho-Vp	Shale	Rho (g/cm3) = 0.2392956 * Vp (ft/s) ^ 0.2539949
Vp/Vs-Depth	Shale	Vp/Vs = 0.4515433 * Depth TVDml (ft) + 5153.091 / 0.9232975 * (0.4515433 * Depth TVDml (ft) + 5153.091) - 4065.238
Vp-Depth	Tuff	Vp (ft/s) = 0.7812615 * Depth TVDml (ft) + 3411.229
Vs-Vp	Tuff	Vs (ft/s) = 0.9711005 * Vp (ft/s) - 4225.107
Rho-Vp	Tuff	Rho (g/cm3) = 0.52428 * lnVp (ft/s) - 2.39628
Vp/Vs-Depth	Tuff	Vp/Vs = 0.7812615 * Depth TVDml (ft) + 3411.229 / 0.9711005 * (0.7812615 * Depth TVDml (ft) + 3411.229) - 4225.107
Vp-Depth	Sandstone	Vp (ft/s) = 1.023924 * Depth TVDml (ft) + 2127.82
Vs-Vp	Sandstone	Vs (ft/s) = 0.80416 * Vp (ft/s) - 2808.005
Rho-Vp	Sandstone	Rho (g/cm3) = 0.2609613 * Vp (ft/s) ^ 0.2305883
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.607725 * Por (fract) + 2.65
PHIT-Depth	Sandstone	Por (fract) = -3.770699E-5 * Depth TVDml (ft) + 0.58089
PHIT-Vp	Sandstone	Por (fract) = 1.726589E-10 * Vp^2 (ft/s) - 3.894957E-5 * Vp (ft/s) + 0.6692793
Vp/Vs-Depth	Sandstone	Vp/Vs = 1.023924 * Depth TVDml (ft) + 2127.82 / 0.80416 * (1.023924 * Depth TVDml (ft) + 2127.82) - 2808.005

Working Interval = Sele Fm

Cross-Plot	**Lithology**	**Trend**
Vp-Depth	Shale (hard)	Vp (ft/s) = 0.5420831 * Depth TVDml (ft) + 5362.252
Vp-Depth	Shale (soft)	Vp (ft/s) = 0.5072923 * Depth TVDml (ft) + 4640.669
Vs-Vp	Shale	Vs (ft/s) = 0.7655861 * Vp (ft/s) - 2640.943
Rho-Vp	Shale	Rho (g/cm3) = 0.1832278 * Vp (ft/s) ^ 0.2830127
Vp/Vs-Depth	Shale	Vp/Vs = 0.5420831 * Depth TVDml (ft) + 5362.252 / 0.7655861 * (0.5420831 * Depth TVDml (ft) + 5362.252) - 2640.943
Vp-Depth	Sandstone (high)	Vp (ft/s) = 0.6740104 * Depth TVDml (ft) + 3979.824
Vp-Depth	Sandstone (low)	Vp (ft/s) = 0.5542149 * Depth TVDml (ft) + 6430.183
Vs-Vp	Sandstone	Vs (ft/s) = 0.9720799 * Vp (ft/s) - 4702.516
Rho-Vp	Sandstone	Rho (g/cm3) = 0.12631 * Vp (ft/s) ^ 0.3115259
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.608423 * Por (fract) + 2.65
PHIT-Depth	Sandstone (high)	Por (fract) = -3.721717E-5 * Depth TVDml (ft) + 0.6085076
PHIT-Depth	Sandstone (low)	Por (fract) = -2.654017E-5 * Depth TVDml (ft) + 0.4426344
PHIT-Vp	Sandstone	Por (fract) = 1.773932E-9 * Vp^2 (ft/s) - 8.149762E-5 * Vp (ft/s) + 0.904825
Vp/Vs-Depth	Sandstone (high)	Vp/Vs = 0.6740104 * Depth TVDml (ft) + 3979.824 / 0.9720799 * (0.6740104 * Depth TVDml (ft) + 3979.824) - 4702.516
Vp/Vs-Depth	Sandstone (low)	Vp/Vs = 0.5542149 * Depth TVDml (ft) + 6430.183 / 0.9720799 * (0.5542149 * Depth TVDml (ft) + 6430.183) - 4702.516

Working Interval = Lista Fm

Cross-Plot	Lithology	Trend
Vp-Depth	Shale (hard)	Vp (ft/s) = 0.6624602 * Depth TVDml (ft) + 4252.494
Vp-Depth	Shale (soft)	Vp (ft/s) = 0.5780684 * Depth TVDml (ft) + 3817.599
Vs-Vp	Shale	Vs (ft/s) = 0.758194 * Vp (ft/s) - 2709.194
Rho-Vp	Shale	Rho (g/cm3) = 0.1700515 * Vp (ft/s) ^ 0.2902445
Vp/Vs-Depth	Shale (hard)	Vp/Vs = 0.6624602 * Depth TVDml (ft) + 4252.494 / 0.758194 * (0.6624602 * Depth TVDml (ft) + 4252.494) - 2709.194
Vp/Vs-Depth	Shale (soft)	Vp/Vs = 0.5780684 * Depth TVDml (ft) + 3817.599 / 0.758194 * (0.5780684 * Depth TVDml (ft) + 3817.599) - 2709.194
Vp-Depth	Sandstone (high)	Vp (ft/s) = 0.4780259 * Depth TVDml (ft) + 7035.789
Vp-Depth	Sandstone (low)	Vp (ft/s) = 0.8167227 * Depth TVDml (ft) + 6191.856
Vs-Vp	Sandstone (high)	Vs (ft/s) = 0.7639454 * Vp (ft/s) - 2484.919
Vs-Vp	Sandstone (low)	Vs (km/s) = -0.05682 * Vp^2 (km/s) + 1.026375 * Vp (km/s) - 1.031692
		Vs (ft/s) = -1.731888E-5 * Vp^2 (ft/s) + 1.026375 * Vp (ft/s) - 3384.816515
Rho-Vp	Sandstone	Rho (g/cm3) = 0.1235797 * Vp (ft/s) ^ 0.3157153
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.622425 * Por (fract) + 2.65
PHIT-Depth	Sandstone (high)	Por (fract) = -3.110392E-5 * Depth TVDml (ft) + 0.4798181
PHIT-Depth	Sandstone (low)	Por (fract) = -3.18877E-5 * Depth TVDml (ft) + 0.3770017
PHIT-Vp	Sandstone	Por (fract) = 1.529275E-9 * Vp^2 (ft/s) - 7.601945E-5 * Vp (ft/s) + 0.8522162
Vp/Vs-Depth	Sandstone (high)	Vp/Vs = 0.4780259 * Depth TVDml (ft) + 7035.789 / 0.7639454 * (0.4780259 * Depth TVDml (ft) + 7035.789) - 2484.919
Vp/Vs-Depth	Sandstone (low)	Vp/Vs = 0.8167227 * Depth TVDml (ft) + 6191.856 / - 1.731888E-5 * (0.8167227 * Depth TVDml (ft) + 6191.856)^2 + 1.026375 * (0.8167227 * Depth TVDml (ft) + 6191.856) - 3384.816515
Vp-Depth	Limestone (high)	Vp (ft/s) = 1.17964 * Depth TVDml (ft) + 2948.817
Vp-Depth	Limestone (low)	Vp (ft/s) = 0.9858379 * Depth TVDml (ft) + 6847.396
Vs-Vp	Limestone	Vs (ft/s) = -2.212974E-5 * Vp^2 (ft/s) + 1.21382 * Vp (ft/s) - 4983.408
Rho-Vp	Limestone	Rho (g/cm3) = 0.594 * lnVp (ft/s) - 3.18998
Rho-PHIT	Limestone	Rho (g/cm3) = -1.673549 * Por (fract) + 2.71
PHIT-Depth	Limestone (high)	Por (fract) = -2.767867E-5 * Depth TVDml (ft) + 0.397615
PHIT-Depth	Limestone (low)	Por (fract) = -1.937362E-5 * Depth TVDml (ft) + 0.2537034

PHIT-Vp	Limestone	Por (fract) = 4.114573E-10 * Vp^2 (ft/s) - 4.001338E-5 * Vp (ft/s) + 0.6178595
Vp/Vs-Depth	Limestone (high)	Vp/Vs = 1.17964 * Depth TVDml (ft) + 2948.817 / -2.212974E-5 * (1.17964 * Depth TVDml (ft) + 2948.817 $)^2$ + 1.21382 * (1.17964 * Depth TVDml (ft) + 2948.817) - 4983.408
Vp/Vs-Depth	Limestone (low)	Vp/Vs = 0.9858379 * Depth TVDml (ft) + 6847.396 / - 2.212974E-5 * (0.9858379 * Depth TVDml (ft) + 6847.396 $)^2$ + 1.21382 * (0.9858379 * Depth TVDml (ft) + 6847.396) - 4983.408

Working Interval = Maureen Fm

Cross-Plot	Lithology	Trend
Vp-Depth	Shale (hard)	Vp (ft/s) = 0.588856 * Depth TVDml (ft) + 5630.318
Vp-Depth	Shale (soft)	Vp (ft/s) = 0.5966925 * Depth TVDml (ft) + 3923.665
Vs-Vp	Shale	Vs (ft/s) = 0.693495 * Vp (ft/s) - 2017.296
Rho-Vp	Shale	Rho (g/cm3) = 0.1857183 * Vp (ft/s) ^ 0.280225
Vp/Vs-Depth	Shale (hard)	Vp/Vs = 0.588856 * Depth TVDml (ft) + 5630.318 / 0.693495 * (0.588856 * Depth TVDml (ft) + 5630.318) - 2017.296
Vp/Vs-Depth	Shale (soft)	Vp/Vs = 0.5966925 * Depth TVDml (ft) + 3923.665 / 0.693495 * (0.5966925 * Depth TVDml (ft) + 3923.665) - 2017.296
Vp-Depth	Sandstone (high)	Vp (ft/s) = 0.9648193 * Depth TVDml (ft) + 3085.523
Vp-Depth	Sandstone (low)	Vp (ft/s) = 1.096406 * Depth TVDml (ft) + 3131.354
Vs-Vp	Sandstone (high)	Vs (ft/s) = 0.7639454 * Vp (ft/s) - 2484.919
Vs-Vp	Sandstone (low)	Vs (km/s) = -0.05682 * Vp² (km/s) + 1.026375 * Vp (km/s) - 1.031692
		Vs (ft/s) = -1.731888E-5 * Vp² (ft/s) + 1.026375 * Vp (ft/s) - 3384.816515
Rho-Vp	Sandstone	Rho (g/cm3) = 0.1222036 * Vp (ft/s) ^ 0.3158323
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.608069 * Por (fract) + 2.65
PHIT-Depth	Sandstone (high)	Por (fract) = -5.051964E-5 * Depth TVDml (ft) + 0.6525103
PHIT-Depth	Sandstone (low)	Por (fract) = -5.003434E-5 * Depth TVDml (ft) + 0.5447623
PHIT-Vp	Sandstone	Por (fract) = 1.845871E-9 * Vp² (ft/s) - 8.24894E-5 * Vp (ft/s) + 0.8976042
Vp/Vs-Depth	Sandstone (high)	Vp/Vs = 0.9648193 * Depth TVDml (ft) + 3085.523 / 0.7639454 * (0.9648193 * Depth TVDml (ft) + 3085.523) - 2484.919
Vp/Vs-Depth	Sandstone (low)	Vp/Vs = 1.096406 * Depth TVDml (ft) + 3131.354 / -1.731888E-5 * (1.096406 * Depth TVDml (ft) + 3131.354)² + 1.026375 * (1.096406 * Depth TVDml (ft) + 3131.354) - 3384.816515
Vp-Depth	Limestone (high)	Vp (ft/s) = 1.17964 * Depth TVDml (ft) + 2948.817
Vp-Depth	Limestone (low)	Vp (ft/s) = 0.9858379 * Depth TVDml (ft) + 6847.396
Vs-Vp	Limestone	Vs (ft/s) = -2.212974E-5 * Vp² (ft/s) + 1.21382 * Vp (ft/s) - 4983.408
Rho-Vp	Limestone	Rho (g/cm3) = 0.594 * lnVp (ft/s) - 3.18998
Rho-PHIT	Limestone	Rho (g/cm3) = -1.673549 * Por (fract) + 2.71
PHIT-Depth	Limestone (high)	Por (fract) = -2.767867E-5 * Depth TVDml (ft) + 0.397615
PHIT-Depth	Limestone (low)	Por (fract) = -1.937362E-5 * Depth TVDml (ft) + 0.2537034
PHIT-Vp	Limestone	Por (fract) = 4.114573E-10 * Vp² (ft/s) - 4.001338E-5 * Vp (ft/s)

		+ 0.6178595
Vp/Vs-Depth	Limestone (high)	Vp/Vs = 1.17964 * Depth TVDml (ft) + 2948.817 / -2.212974E-5 * (1.17964 * Depth TVDml (ft) + 2948.817)² + 1.21382 * (1.17964 * Depth TVDml (ft) + 2948.817) - 4983.408
Vp/Vs-Depth	Limestone (low)	Vp/Vs = 0.9858379 * Depth TVDml (ft) + 6847.396 / -2.212974E-5 * (0.9858379 * Depth TVDml (ft) + 6847.396)² + 1.21382 * (0.9858379 * Depth TVDml (ft) + 6847.396) - 4983.408

Working Interval = Ekofisk Fm

Cross-Plot	Lithology	Trend
Vp-Depth	Shale	Vp (ft/s) = 0.588856 * Depth TVDml (ft) + 5630.318
Vs-Vp	Shale	Vs (ft/s) = 0.693495 * Vp (ft/s) - 2017.296
Rho-Vp	Shale	Rho (g/cm3) = 0.1857183 * Vp (ft/s) ^ 0.280225
Vp/Vs-Depth	Shale	Vp/Vs = 0.588856 * Depth TVDml (ft) + 5630.318 / 0.693495 * (0.588856 * Depth TVDml (ft) + 5630.318) - 2017.296
Vp-Depth	Limestone (high)	Vp (ft/s) = 0.8729134 * Depth TVDml (ft) + 5203.576
Vp-Depth	Limestone (low)	Vp (ft/s) = 0.982537 * Depth TVDml (ft) + 5881.333
Vs-Vp	Limestone	Vs (ft/s) = -2.553698E-5 * Vp^2 (ft/s) + 1.342143 * Vp (ft/s) - 6253.14
Rho-Vp	Limestone	Rho (g/cm3) = 0.74272 * lnVp (ft/s) - 4.61654
Rho-PHIT	Limestone	Rho (g/cm3) = -1.677809 * Por (fract) + 2.71
PHIT-Depth	Limestone (high)	Por (fract) = -2.017612E-5 * Depth TVDml (ft) + 0.3555333
PHIT-Depth	Limestone (low)	Por (fract) = -1.848521E-5 * Depth TVDml (ft) + 0.2637967
PHIT-Vp	Limestone	Por (fract) = 1.26444E-9 * Vp^2 (ft/s) - 6.871545E-5 * Vp (ft/s) + 0.8542784
Vp/Vs-Depth	Limestone (high)	Vp/Vs = 0.8729134 * Depth TVDml (ft) + 5203.576 / -2.553698E-5 * (0.8729134 * Depth TVDml (ft) + 5203.576 $)^2$ + 1.342143 * (0.8729134 * Depth TVDml (ft) + 5203.576) - 6253.14
Vp/Vs-Depth	Limestone (low)	Vp/Vs = 0.982537 * Depth TVDml (ft) + 5881.333 / -2.553698E-5 * (0.982537 * Depth TVDml (ft) + 5881.333 $)^2$ + 1.342143 * (0.982537 * Depth TVDml (ft) + 5881.333) - 6253.14

Working Interval = Tor Fm

Cross-Plot	Lithology	Trend
Vp-Depth	Shale	Vp (ft/s) = 0.588856 * Depth TVDml (ft) + 5630.318
Vs-Vp	Shale	Vs (ft/s) = 0.693495 * Vp (ft/s) - 2017.296
Rho-Vp	Shale	Rho (g/cm3) = 0.1857183 * Vp (ft/s) ^ 0.280225
Vp/Vs-Depth	Shale	Vp/Vs = 0.588856 * Depth TVDml (ft) + 5630.318 / 0.693495 * (0.588856 * Depth TVDml (ft) + 5630.318) - 2017.296
Vp-Depth	Limestone (high)	Vp (ft/s) = 1.011436 * Depth TVDml (ft) + 4483.004
Vp-Depth	Limestone (low)	Vp (ft/s) = 0.4740226 * Depth TVDml (ft) + 12488.51
Vs-Vp	Limestone	Vs (ft/s) = -2.28136689E-5 * Vp² (ft/s) + 1.238671 * Vp (ft/s) - 5526.247
Rho-Vp	Limestone	Rho (g/cm3) = 0.74353 * lnVp (ft/s) - 4.62711
Rho-PHIT	Limestone	Rho (g/cm3) = -1.681826 * Por (fract) + 2.71
PHIT-Depth	Limestone (high)	Por (fract) = -2.52572E-5 * Depth TVDml (ft) + 0.3942969
PHIT-Depth	Limestone (low)	Por (fract) = -9.372E-6 * Depth TVDml (ft) + 0.1406966
PHIT-Vp	Limestone	Por (fract) = 1.139213E-9 * Vp² (ft/s) - 6.58779E-5 * Vp (ft/s) + 0.846066
Vp/Vs-Depth	Limestone (high)	Vp/Vs = 1.011436 * Depth TVDml (ft) + 4483.004 / -2.28136689E-5 * (1.011436 * Depth TVDml (ft) + 4483.004)² + 1.238671 * (1.011436 * Depth TVDml (ft) + 4483.004) - 5526.247
Vp/Vs-Depth	Limestone (low)	Vp/Vs = 0.4740226 * Depth TVDml (ft) + 12488.51 / -2.28136689E-5 * (0.4740226 * Depth TVDml (ft) + 12488.51)² + 1.238671 * (0.4740226 * Depth TVDml (ft) + 12488.51) - 5526.247

Working Interval = Hod Fm

Cross-Plot	Lithology	Trend
Vp-Depth	Shale	Vp (ft/s) = 0.588856 * Depth TVDml (ft) + 5630.318
Vs-Vp	Shale	Vs (ft/s) = 0.693495 * Vp (ft/s) - 2017.296
Rho-Vp	Shale	Rho (g/cm3) = 0.1857183 * Vp (ft/s) ^ 0.280225
Vp/Vs-Depth	Shale	Vp/Vs = 0.588856 * Depth TVDml (ft) + 5630.318 / 0.693495 * (0.588856 * Depth TVDml (ft) + 5630.318) - 2017.296
Vp-Depth	Limestone (high)	Vp (ft/s) = 0.56478 * Depth TVDml (ft) + 8753.391
Vp-Depth	Limestone (low)	Vp (ft/s) = 0.537352 * Depth TVDml (ft) + 11248.14
Vs-Vp	Limestone	Vs (ft/s) = -2.3837095E-5 * Vp^2 (ft/s) + 1.171225 * Vp (ft/s) - 3974.697
Rho-Vp	Limestone	Rho (g/cm3) = 0.51197 * lnVp (ft/s) - 2.36269
Rho-PHIT	Limestone	Rho (g/cm3) = -1.645595 * Por (fract) + 2.71
PHIT-Depth	Limestone (high)	Por (fract) = -1.273299E-5 * Depth TVDml (ft) + 0.2384544
PHIT-Depth	Limestone (low)	Por (fract) = -9.445337E-6 * Depth TVDml (ft) + 0.157783
PHIT-Vp	Limestone	Por (fract) = 1.198912E-10 * Vp^2 (ft/s) - 2.624041E-5 * Vp (ft/s) + 0.4607655
Vp/Vs-Depth	Limestone (high)	Vp/Vs = 0.56478 * Depth TVDml (ft) + 8753.391 / -2.3837095E-5 * (0.56478 * Depth TVDml (ft) + 8753.391)^2 + 1.171225 * (0.56478 * Depth TVDml (ft) + 8753.391) - 3974.697
Vp/Vs-Depth	Limestone (low)	Vp/Vs = 0.537352 * Depth TVDml (ft) + 11248.14 / -2.3837095E-5 * (0.537352 * Depth TVDml (ft) + 11248.14)^2 + 1.171225 * (0.537352 * Depth TVDml (ft) + 11248.14) - 3974.697

C.3 Multi-well analysis (Gassmann Fluid Substituted data)

These trends were derived after Rock Physics stage of the project had been completed on brine, oil and gas fluid substituted data.

Working Interval = Horda Fm

Porosity cut-off; PHIT > 0.15, Reservoir cut-off; Vol_Sand>0.7

100% Brine Bearing data - FSUB_BRINE_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 16,720 * Por (fract) + 15,290
Rho-PHIT	Sandstone	Rho (g/cm^3) = -1.612 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm^3_ft/s) = -52505 * Por (fract) + 38,102

80% Oil Bearing data - FSUB_OIL_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = -16,583 * Por (fract) + 14,422
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.901 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -53,322 * Por (fract) + 35,684

90% Gas Bearing data - FSUB_GAS_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 16,973 * Por (fract) + 14,470
Rho-PHIT	Sandstone	Rho (g/cm3) = -2.324 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -56,451 * Por (fract) + 35,270

Working Interval = Balder Fm

Porosity cut-off; PHIT > 0.12, Reservoir cut-off; Vol_Sand>0.7

100% Brine Bearing data - FSUB_BRINE_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 14,502 * Por (fract) + 14,904
Rho-PHIT	Sandstone	Rho (g/cm^3) = -1.608 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm^3_ft/s) = -46,295 * Por (fract) + 35,064

80% Oil Bearing data - FSUB_OIL_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = -16,900 * Por (fract) + 13,938
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.877 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -54,851 * Por (fract) + 35,065

90% Gas Bearing data - FSUB_GAS_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 17,915 * Por (fract) + 14,147
Rho-PHIT	Sandstone	Rho (g/cm3) = -2.310 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -60,381 * Por (fract) + 35,387

Working Interval = Sele Fm

Porosity cut-off; PHIT > 0.12, Reservoir cut-off; Vol_Sand>0.7

100% Brine Bearing data - FSUB_BRINE_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 18,005 * Por (fract) + 15,099
Rho-PHIT	Sandstone	Rho (g/cm^3) = -1.587 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm^3_ft/s) = -57,679 * Por (fract) + 38,352

80% Oil Bearing data - FSUB_OIL_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = -17,531 * Por (fract) + 14,265
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.843 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -55,362 * Por (fract) + 35,586

90% Gas Bearing data - FSUB_GAS_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 18,711 * Por (fract) + 14,382
Rho-PHIT	Sandstone	Rho (g/cm3) = -2.315 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -62,640 * Por (fract) + 35,831

Working Interval = Lista Fm

Porosity cut-off; PHIT > 0.10, Reservoir cut-off; Vol_Sand>0.7

100% Brine Bearing data - FSUB_BRINE_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 15,588 * Por (fract) + 14,492
Rho-PHIT	Sandstone	Rho (g/cm^3) = -1.570 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm^3_ft/s) = -53,943 * Por (fract) + 37,433

80% Oil Bearing data - FSUB_OIL_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = -17,498 * Por (fract) + 14,162
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.850 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -58,710 * Por (fract) + 36,135

90% Gas Bearing data - FSUB_GAS_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 17,430 * Por (fract) + 14,071
Rho-PHIT	Sandstone	Rho (g/cm3) = -2.272 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -62,965 * Por (fract) + 36,074

Working Interval = Maureen Fm

Porosity cut-off; PHIT > 0.08, Reservoir cut-off; Vol_Sand>0.7

100% Brine Bearing data - FSUB_BRINE_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 11,492 * Por (fract) + 14,016
Rho-PHIT	Sandstone	Rho (g/cm^3) = -1.600 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm^3_ft/s) = -47,995 * Por (fract) + 36,940

80% Oil Bearing data - FSUB_OIL_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = -11,067 * Por (fract) + 13,292
Rho-PHIT	Sandstone	Rho (g/cm3) = -1.878 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -48,153 * Por (fract) + 34,871

90% Gas Bearing data - FSUB_GAS_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Sandstone	Vp (ft/sec) = - 8,739 * Por (fract) + 12,842
Rho-PHIT	Sandstone	Rho (g/cm3) = -2.303 * Por (fract) + 2.65
AI-PHIT	Sandstone	AI (g/cm3_ft/s) = -48,792 * Por (fract) + 34,040

Working Interval = Maureen Fm

Porosity cut-off; PHIT > 0.08, Reservoir cut-off; Vol_Lime>0.9

100% Brine Bearing data - FSUB_BRINE_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Limestone	Vp (ft/sec) = - 26,452 * Por (fract) + 18,304
Rho-PHIT	Limestone	Rho (g/cm^3) = -1.654 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm^3_ft/s) = -85,722 * Por (fract) + 48,323

80% Oil Bearing data - FSUB_OIL_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Limestone	Vp (ft/sec) = -28,566 * Por (fract) + 18,053
Rho-PHIT	Limestone	Rho (g/cm3) = -1.935 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm3_ft/s) = -92,194 * Por (fract) + 47,293

90% Gas Bearing data - FSUB_GAS_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Limestone	Vp (ft/sec) = - 28,442 * Por (fract) + 17,960
Rho-PHIT	Limestone	Rho (g/cm3) = -2.351 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm3_ft/s) = -95,393 * Por (fract) + 46,750

Working Interval = Ekofisk Fm

Porosity cut-off; PHIT > 0.06, Reservoir cut-off; Vol_Lime>0.9

100% Brine Bearing data - FSUB_BRINE_GP logs

Cross-Plot	**Lithology**	**Trend**
Vp-PHIT	Limestone	Vp (ft/sec) = - 23,434 * Por (fract) + 17,596
Rho-PHIT	Limestone	Rho (g/cm^3) = -1.672 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm^3_ft/s) = -81,152 * Por (fract) + 46,920

80% Oil Bearing data - FSUB_OIL_GP logs

Cross-Plot	**Lithology**	**Trend**
Vp-PHIT	Limestone	Vp (ft/sec) = -25,046 * Por (fract) + 17,248
Rho-PHIT	Limestone	Rho (g/cm3) = -1.934 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm3_ft/s) = -86,766 * Por (fract) + 45,794

90% Gas Bearing data - FSUB_GAS_GP logs

Cross-Plot	**Lithology**	**Trend**
Vp-PHIT	Limestone	Vp (ft/sec) = - 25,113 * Por (fract) + 17,183
Rho-PHIT	Limestone	Rho (g/cm3) = -2.334 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm3_ft/s) = -91,647 * Por (fract) + 45,615

Working Interval = Tor Fm

Porosity cut-off; PHIT > 0.03, Reservoir cut-off; Vol_Lime>0.9

100% Brine Bearing data - FSUB_BRINE_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Limestone	Vp (ft/sec) = - 32,287 * Por (fract) + 19,116
Rho-PHIT	Limestone	Rho (g/cm^3) = -1.650 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm^3_ft/s) = -110,000 * Por (fract) + 51,544

80% Oil Bearing data - FSUB_OIL_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Limestone	Vp (ft/sec) = -36,335 * Por (fract) + 19,135
Rho-PHIT	Limestone	Rho (g/cm3) = -1.927 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm3_ft/s) = -123,678 * Por (fract) + 51,514

90% Gas Bearing data - FSUB_GAS_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Limestone	Vp (ft/sec) = - 36,771 * Por (fract) + 19,150
Rho-PHIT	Limestone	Rho (g/cm3) = -2.331 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm3_ft/s) = -124,314 * Por (fract) + 51,170

Working Interval = Hod Fm

Porosity cut-off; PHIT > 0.03, Reservoir cut-off; Vol_Lime>0.9

100% Brine Bearing data - FSUB_BRINE_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Limestone	Vp (ft/sec) = - 44,594 * Por (fract) + 19,606
Rho-PHIT	Limestone	Rho (g/cm^3) = -1.620 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm^3_ft/s) = -141,512 * Por (fract) + 52,928

80% Oil Bearing data - FSUB_OIL_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Limestone	Vp (ft/sec) = -52,915 * Por (fract) + 19,862
Rho-PHIT	Limestone	Rho (g/cm3) = -1.892 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm3_ft/s) = -165,235 * Por (fract) + 53,483

90% Gas Bearing data - FSUB_GAS_GP logs

Cross-Plot	Lithology	Trend
Vp-PHIT	Limestone	Vp (ft/sec) = - 55,786 * Por (fract) + 19,990
Rho-PHIT	Limestone	Rho (g/cm3) = -2.308 * Por (fract) + 2.71
AI-PHIT	Limestone	AI (g/cm3_ft/s) = -179,241 * Por (fract) + 54,009

Appendix D – Glossary of Terms

AAI

Absolute Acoustic Impedance is a deterministic inversion method where an accurate low frequency trend is imposed on a relative inversion to give absolute values of impedance.

Acoustic impedance (*AI*)

$$AI = V_P * \rho$$

The physical property whose change determines reflection coefficients at normal incidence, that is, seismic P-wave velocity multiplied by density. Because reflection coefficients change with angle, the term elastic impedance is sometimes used when referring to non-normal incidence situations.

Aki Richards (PP) approximation

$$Rpp(\theta) = A + B\sin^2\theta + C\sin^2\theta\tan^2\theta$$

$$A = \frac{1}{2}\left(\frac{\Delta Vp}{Vp} + \frac{\Delta\rho}{\rho}\right) \qquad B = \frac{1}{2}\frac{\Delta Vp}{Vp} - 2\left(\frac{Vs}{Vp}\right)^2\left(\frac{\Delta\rho}{\rho} + \frac{2\Delta Vs}{Vs}\right)$$

$$C = \frac{1}{2}\frac{\Delta Vp}{Vp}$$

Where:

Rpp(ϴ*)* = P-wave reflection coefficient at given incidence angle (ϴ*)*

Vp = Average P-wave velocity (average of Vp_1 and Vp_2)

Vs = Average S-wave velocity (average of Vs_1 and Vs_2)

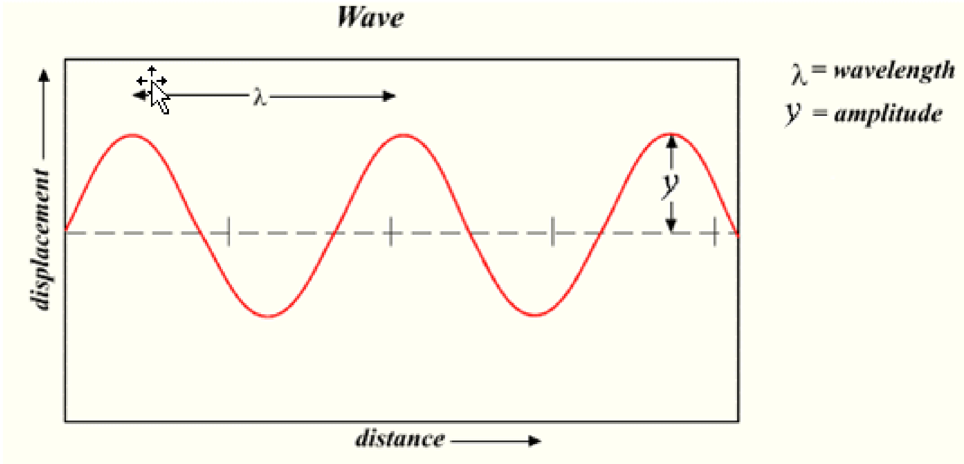
ρ = Average density (average of ρ_1 and ρ_2)

ϴ = Angle of incidence

$\Delta Vp = Vp_2 - Vp_1$

Amplitude

Amplitude is a non-negative measure of a wave's magnitude of oscillation, that is, the maximum departure of a wave from its average value.



Angle of incidence

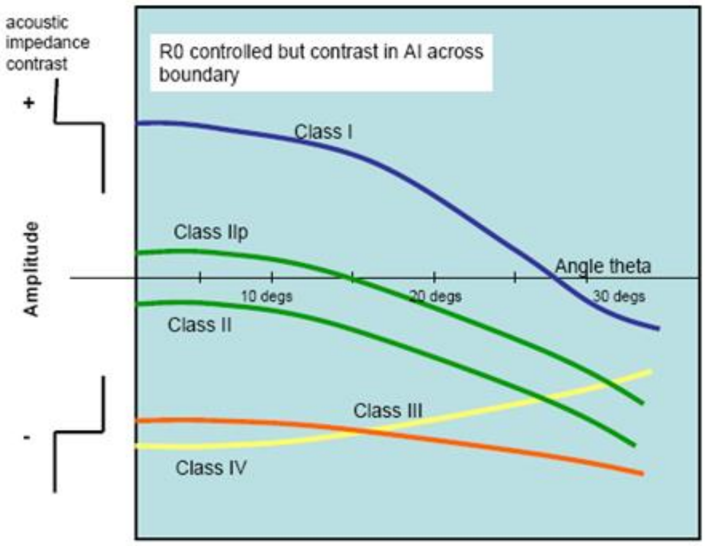
The acute angle that a raypath makes with the normal to an interface. This is the same angle that an approaching wave-front makes with the interface in an isotropic medium. In the anisotropic case, it is the angle between the raypath and the normal, the raypath not necessarily being perpendicular to the wave-front.

AVO (or AVA)

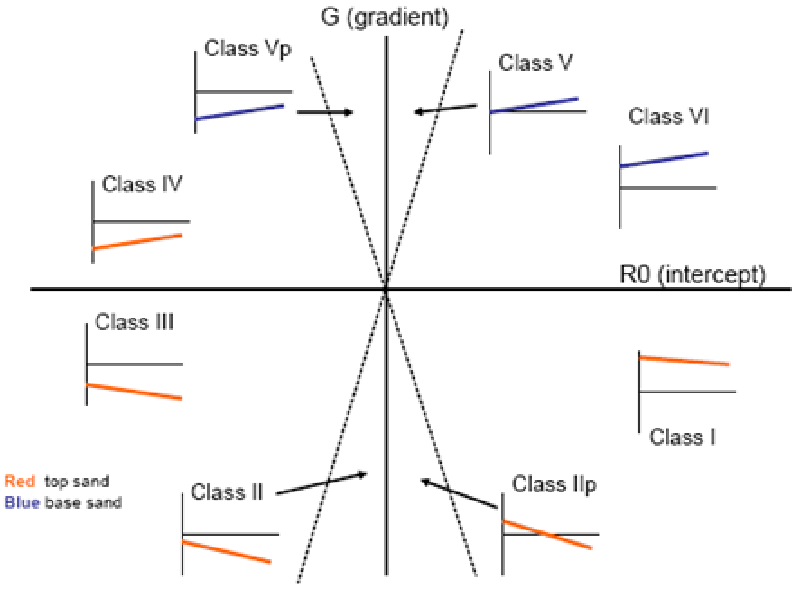
Amplitude Variation with Offset (or Amplitude Variation with Angle).

AVO (or AVA) Classes

The Rutherford and Williams (1989) shale-on-brine-sand AVA responses are outlined in the schematic below.



These responses translate to points in intercept-gradient space, and can be visualized as follows:



Bortfeld PP approximation to Zoeppritz

$$Rpp(\theta) = \frac{1}{2}\ln\left(\frac{Vp_2\rho_2\cos\theta_1}{Vp_1\rho_1\cos\theta_2}\right) + \left(\frac{\sin\theta_1}{Vp_1}\right)^2 \left(Vs_1^{\,2} - Vs_2^{\,2}\right)\left[2 + \frac{\ln\left(\frac{\rho_2}{\rho_1}\right)}{\ln\left(\frac{Vs_2}{Vs_1}\right)}\right]$$

Bulk Modulus (*K*)

The bulk modulus describes the response in a material's volume that results from a change in the stress acting on it. It is therefore a measure of how stiff a material is.

$$K = Vp^2\rho - \frac{4Vs^2\rho}{3}$$

Density (*ρ*)

Mass per unit volume. Density is typically reported in g/cm^3 (solid materials) or pounds per gallon (drilling mud) in the oil field.

Deterministic Inversion

A recursive inversion scheme that is constrained by a subsurface model.

Elastic Impedance (*EI)*

Since reflection coefficients change with angle, the term elastic impedance is sometimes used when referring to non-normal incidence situations.

$$EI = Vp_0\rho_0\left[\left(\frac{Vp}{Vp_0}\right)^{1+\sin^{2\theta}}\left(\frac{Vs}{Vs_0}\right)^{-8K\sin^2\theta}\left(\frac{\rho}{\rho_0}\right)^{1-4K\sin^2\theta}\right]$$

Where:

ϑ is the incidence angle

Vp is the P-wave velocity

Vs is the S-wave velocity ρ is the density, and

$K = Vs^2/Vp^2$

Vp_0, Vs_0 and ρ_0 are the averages of Vp, Vs and density, respectively.

Gardner's Equation

An empirical relationship that computes density from sonic data.

$$\rho = dVp^f$$

where *Vp* is in km/s and *d* and *f* are constants that vary with rock type.

Gas Oil Ratio (*GOR*)

The ratio of produced gas to produced oil.

Gamma Ray log (*GR*)

A well log that records natural radioactivity. Gamma ray logs are particularly helpful in sediments, mainly reflecting the shale content since the radioactive minerals tend to concentrate in clays and shales. The log is useful for correlations between wells.

Gassmann Equation

A fluid substitution workflow named after Fritz Gassmann, a Swiss geophysicist.

(i) from in situ saturation to dry rock

$$K_{dry} = \frac{K_{sat}\left(\frac{\phi K_0}{K_{fl}} + 1 - \phi\right) - K_0}{\frac{\phi K_0}{K_{fl}} + \frac{K_{sat}}{K_0} - 1 - \phi}$$

(ii) dry rock to fluid substitution case

$$K_{sat} = K_{dry} + \frac{\left(1 - \frac{K_{dry}}{K_0}\right)^2}{\frac{\phi}{K_{fl}} + \frac{1-\phi}{K_0} - \frac{K_{dry}}{K_0^2}}$$

Gassmann (Linear)

Using the critical porosity concept, the ratio of the saturated fluid and mineral moduli are used to estimate the change in bulk modulus due to fluid substitution at a given porosity (after Mavko et al

(1997)). Using this information, the hydrocarbon saturation effect can be removed from Vp and Density in a method independent from Vs.

$$\Delta M_{Gassmann}(\varphi) = \Delta K_{Gassmann}(\varphi) \approx \frac{\varphi}{\varphi R^2}\Delta K_{fluid}$$

Where:

$\Delta M_{Gassmann}(\varphi)$ = change in p-wave modulus due to fluid effect at a given porosity

$\Delta K_{Gassmann}(\varphi)$ = change in bulk modulus due to fluid effect at a given porosity

φ = porosity

φR = critical porosity

ΔK_{fluid} = change in bulk modulus due to fluid effect

Gassmann (Modified – for Vs prediction)

A Vs prediction workflow used in non- brine saturated reservoir rocks. The method uses the following steps to determine Vs:

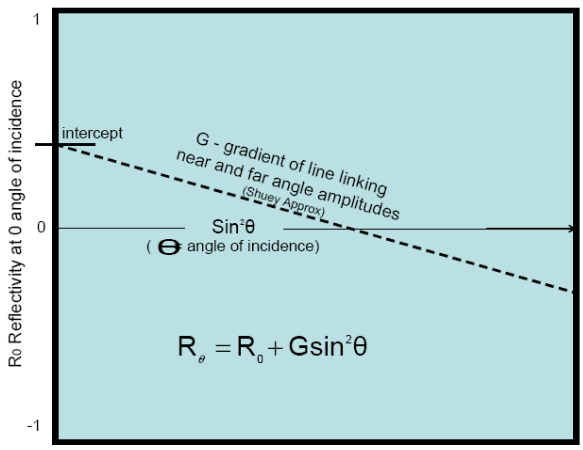
- Linear Gassmann approach used to take Vp and Density logs to brine saturated conditions (independent of Vs, see Gassmann (Linear)).
- Vs predicted from brine saturated Vp using multi-mineral Greenberg Castagna constants, after Greenberg and Castagna (1993).
- Vp, Vs and Density fluid substituted to insitu saturations using Gassmann approach (see Gassmann Equation).

Optimisation of the critical porosity constant (PorR) is performed through minimisation of error between the input and calculated Vp insitu using a least squares regression.

Gradient (G)

The straight line between the near angle amplitudes to those at any other angle of incidence. Shuey's approximation of the Zoeppritz equations.

$$R\theta = R_0 + \sin^2\theta$$



Gradient Impedance (GI)

Inputs: Vp, Vs, Rho, K, Vp average, Vs average, Rho average

$$GI = Vp_0 \rho_0 \left[\left(\frac{Vp}{Vp_0} \right) \left(\frac{Vs}{Vs_0} \right)^{-8K} \left(\frac{\rho}{\rho_0} \right)^{-4K} \right]$$

Gradient Stack

Also known as the slope (B) in the Aki Richards (PP) approximation. The AVO gradient can be approximated using the near and far angle stacks, provided information regarding the average angle is known. It is calculated as follows:

$$GradientStack = \frac{(FarStack) - (NearStack)}{(\sin^2(FarAngle)) - (\sin^2(NearAngle))}$$

Greenberg/Castagna

An empirical relationship, derived from Gulf of Mexico data, for computing shear-velocity (*Vs*) from compressional-velocity (*Vp*) in a water saturated environment. Castagna et al. (1993) give a review of the subject.

Hydrostatic Pressure (P_{hydro})

The force per unit area exerted by a column of fresh water measured from the surface down to a given depth. Abnormally low pressure might occur in areas where fluids have been drained, such as a depleted hydrocarbon reservoir. Abnormally high pressure might occur in areas where the burial of sediments has occurred at such a rate that the dewatering process has not reached equilibrium.

Intercept

An attribute describing the reflectivity at zero angle of incidence. See schematic under 'Gradient (G)'.

Inversion

A model derived from reflectivity data to describe the subsurface that is mutually consistent with the input data.

Inversion means solving for a spatial distribution of parameters which could have produced an observed set of measurements. Often, calculating acoustic impedance from the seismic reflectivity data, which are then taken as representing the earth's reflectivity (also see AAI and RAI).

Lambda (λ)

Lambda is one of two Lamé parameters - the other being Mu. Lambda can be defined in terms of Vp, Vs and Rho as follows:

$$\lambda = Vp^2\,(\rho - 2Vs^2)\rho$$

Lithology

The macroscopic nature of the mineral content, grain size, texture and colour of rocks.

MD / AHD

Measured Depth / Along Hole Depth – the depth measured along the well-bore, below the Kelly Bushing (see schematic under TWT).

MSL

Mean sea-level.

Net to Gross (N/G)

A first approximation of reservoir quality. In a stratigraphic interval that includes a reservoir, this ratio measures the relative thickness of the cumulative effective reservoir beds to the total thickness of the interval.

Permeability

A tensor describing a material's ability to transmit fluids, for geological materials this quantity is typically measured in Darcie's and may span many orders of magnitude.

Porosity (φ)

The amount of void-volume, per unit gross volume, of a rock. Porosity can be composed of fracture-voids and pores, and may be expressed as a percentage, decimal or fraction. Total porosity describes the void-volume of the whole rock volume, including isolated pores and mineral-bound fluid. Effective porosity describes only the void-volume component which may contribute to fluid flow.

Porosity (Total to Effective)

$$\theta_e = \theta_t - V_{sh}\, x\, \theta_{tsh}$$

Where:

θ_e is effective porosity

θ_t is total porosity

Vsh is volume shale

θtsh is total shale porosity

Poisson's Ratio (σ)

The ratio of the transverse contractional strain to longitudinal extensional strain that results from an applied stress. A perfectly elastic and isotropic material has a Poisson's ratio of 0.5.

$$\sigma = \frac{V_p^2 - 2V_s^s}{2(V_p^2 - V_s^2)} \qquad \sigma = \frac{3k - 2\mu}{2\mu + 6k}$$

Pressure Gradient

The change in pressure per unit of depth, typically expressed in units of psi/ft or KPa/m. Pressure increases predictably with depth in areas of normal pressure. The normal hydrostatic pressure gradient for freshwater is ~0.433 psi/ft and 0.465 psi/ft for water with 100,000 ppm total dissolved solids (a typical Gulf Coast water).

Probabilistic Inversion

An inversion scheme that uses probability density functions (PDFs) and Bayesian estimation theory to constrain the data prior to seismic inversion. Any number of realisations are computed and the optimistic (P10), most likely (P50) or pessimistic (P90) estimations can be output.

Pseudo-shear

Pseudo-shear is a weighted stack of two seismic volumes performed in such as way as to minimize the fluid effect in the seismic data. This is commonly used for structural interpretation where AVO is known to reduce confidence in interpretation of the top reservoir. The pseudo-shear volume is calculated as follows (Mallick et al., 2000):

$$R_S \approx \frac{1}{2}\left[A - \left[\frac{FarStack - NearStack}{\sin^2(\theta_{far}) - \sin^2(\theta_{near})}\right]\right]$$

$$R_S \approx \frac{1}{2}\left[A - \left[\frac{FarStack - NearStack}{\sin^2(\theta_{far}) - \sin^2(\theta_{near})}\right]\right]$$

As an approximation one can substitute the intercept stack (*A*) for the near stack.

P-wave or compressional wave velocity (*Vp*)

A P-wave is an elastic body wave in which particles oscillate in the direction of wave propagation. P-waves are studied in conventional seismic reflectivity data. P-waves incident on an interface, at any angle other than at normal incidence, can produce reflected and transmitted S-waves which are known as converted waves.

$$Vp = \sqrt{\frac{K + \left(\frac{4\mu}{3}\right)}{\rho}}$$

Relative Acoustic Impedance (RAI)

An inversion where the low frequency trend is ignored resulting in the computation of relative impedance values.

Resistivity (*Ω*)

The ability of a material to resist electrical conduction. It is the inverse of conductivity and is measured in Ohm.m. Resistivity is a property of the material, whereas the resistance also depends on the volume measured. In the general case, the resistivity is the electric field divided by the current density and depends on the frequency of the applied signal.

Saturation (*Sat*)

The relative amount of water, oil and gas in the pores of a rock, usually expressed as a percentage of available pore-volume.

Shear Modulus (μ)

An elastic constant for the ratio of shear stress to shear strain. The shear modulus is one of the Lamé constants and sometimes is referred to as the modulus of rigidity.

$$\mu = V_s^2 \rho$$

Shear Impedance (SI)

$$SI = Vs.\rho$$

Shuey's PP, approximation to Zoeppritz

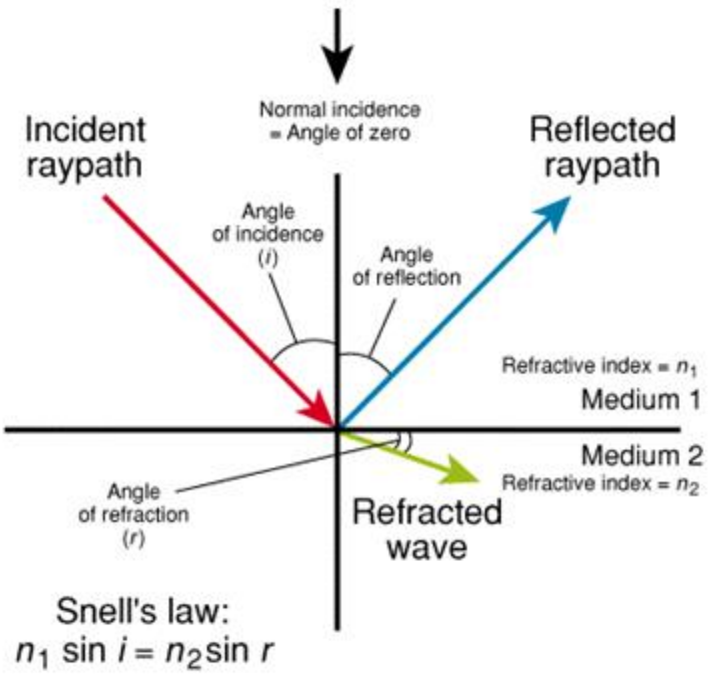
$$Rpp(\theta) = A + B\sin^2\theta$$

$$A = \frac{1}{2}\left(\frac{\Delta Vp}{Vp} + \frac{\Delta\rho}{\rho}\right)$$

$$B = \frac{1}{2}\left(\frac{\Delta Vp}{2Vp}\right) - 2\left(\frac{Vs}{Vp}\right)^2\left(\frac{\Delta\rho}{\rho} + 2\frac{\Delta Vs}{Vs}\right)$$

Snell's law

Snell's law describes the relationship between the angle of incidence and the angle of refraction of a wave or ray.



Stochastic Inversion

A probabilistic inversion scheme where multiple equi-probable property models of the subsurface are generated from the same data. These models are compatible with the well and seismic data and retain the high spatial frequencies. See Haas and Dubrule (1994) for an outline of the method.

S-wave or shear wave velocity (*Vs*)

An elastic body wave in which particles oscillate orthogonal to the direction of wave propagation. Shear waves can not propagate through fluids.

$$Vs = \sqrt{\frac{\mu}{\rho}}$$

S-waves are generated by most land seismic sources, but not by air guns. P-waves that impinge on an interface at non-normal incidence can produce S-waves, which in that case are known as converted waves. S-waves can likewise also be converted to P-waves. S-waves travel more slowly than P-waves and cannot travel through fluids as fluids do not support shear. Recording of S-waves requires receivers coupled to the Earth. Shear wave splitting is useful in the determination of rock properties such as fracture density and orientation.

TVDkb

True Vertical Depth Kelly Bushing – Depth measured vertically below the Kelly Bushing (see schematic under TWT).

TVDml

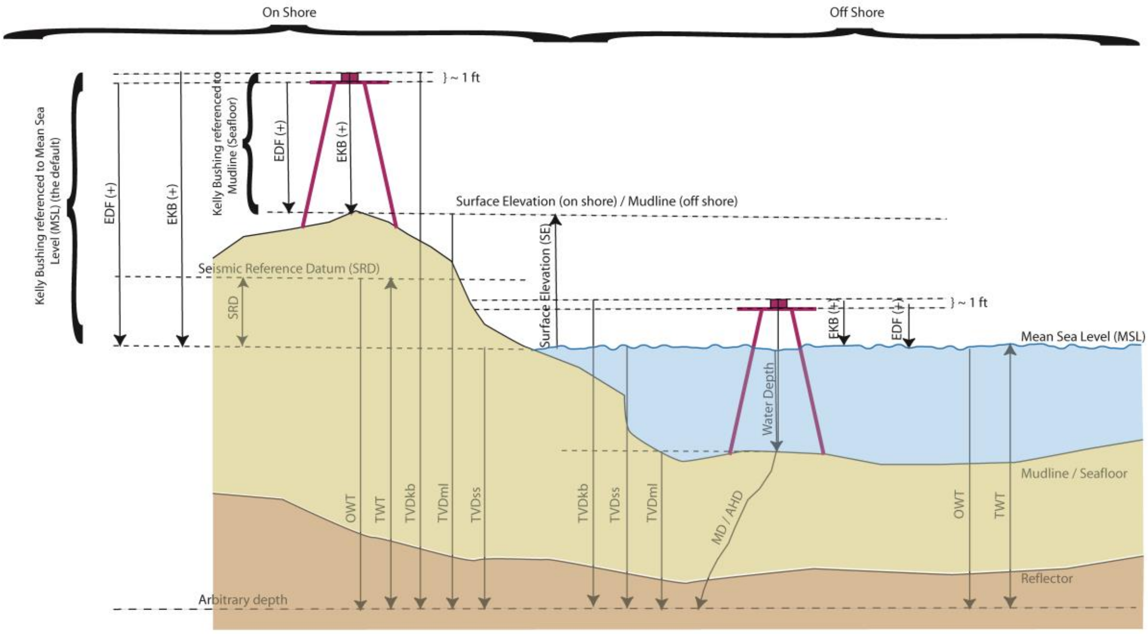
True Vertical Depth mud line – Depth measured vertically below the Mud Line/Surface Elevation (see schematic under TWT).

TVDss

True Vertical Depth sub sea – Depth measured vertically below Mean Sea Level (see schematic under TWT).

TWT

Two-Way-Time – the 'there-and-back' travel-time measured below the Seismic Reference Datum.



Zoeppritz equation

Equations that express the partition of energy when a plane wave impinges on an acoustic-impedance contrast. In the general case for an interface between two solids when the incident angle is not zero, four waves are generated: reflected P-wave and S-wave and transmitted P-wave and S-wave. The partition of energy among these is found from four boundary conditions which require continuity of normal and tangential displacement and stress. Snell's law states:

$$\frac{\sin\theta_{P1}}{V_{P1}} = \frac{\sin\theta_{S1}}{V_{S1}} = \frac{\sin\theta_{P2}}{V_{P2}} = \frac{\sin\theta_{S2}}{V_{S2}}$$

This defines all angles. Beyond the critical angles for P- and S-waves, the respective refracted waves vanish. The increase in reflection energy near the critical angle is sometimes referred to as the wide-angle phenomenon and is sometimes exploited in seismic surveying. Because no provision was made in the equation's derivation for the head waves, these equations do not give head-wave amplitudes or correct values beyond the critical angle.

Appendix E – Known Issues

A number of issues are known to exist within the Shell CNS Roknowledge project which an end user should be aware of. These relate to both software issues within the version of Ikon Science RokDoc in which the project was created (version 5.6.3 – some issues may be fixed when the project is loaded in to subsequent releases) and underlying technical issues.

Software Issues

Fluid and Mineral Colours

On loading the project within RokDoc, the default colours are used for fluids and minerals within the Well Panel Viewers despite standard Shell colours being specified within the Project Settings. To correct this issue:

1. Select 'Project Data' > 'Project Settings …'.
2. Select the 'Fluids' tab.
3. Within the 'Fluid Colours' dialog, double-click on any 'Colour' box.
4. Select 'Cancel' on the 'Colour Picker' dialog box.
5. Select the 'Minerals' tab.
6. Within the 'Mineral Colours' dialog, double-click on any 'Colour' box.
7. Select 'Cancel' on the 'Colour Picker' dialog box.
8. Close the 'Project Settings' dialog box by clicking 'OK'.

Log Fluid Substitution (Gassmann Dry Rock Modelling)

When performing Gassmann Dry Rock Modelling within RokDoc, it is a requirement that a 'Complement Log' is used within the specified Saturation Set. It is recommended that the 'Water Saturation Log' is set to be compliment. To correct this issue:

1. Within the 'Initial Fluids Selector Dialog', select 'Saturation Set …'.
2. Highlight the 'SWT_GP' Saturation Set.
3. Highlight 'Water Saturation Log' within the 'Fluid Type' Column.
4. Select 'Remove Saturation Log' button.
5. Select 'Create Complement Log' button.
6. Close the 'Select Saturation Sets' dialog by clicking 'OK'.

To perform log fluid substitution to Gas Condensate bearing conditions, the functionality does not exist to select a fluid type of 'Gas Condensate' within the 'Final Fluids Selector' dialog. In these cases, it is necessary to use a Saturation Set with a 'Condensate Saturation Log' set at a constant value. To create a Saturation Set for log fluid substitution to Gas Condensate bearing conditions:

1. Select 'Well Ops' > 'Log Calculator …'.
2. Select 'Constant', enter value of chosen fluid saturation in the text box and click 'OK'.
3. Select a 'Log Type' of 'Sat' from the drop-down menu.
4. Click Calculate.
5. Choose a suitable log name suffix and click 'Save'.
6. Close the 'Log Calculator' dialog.
7. Select 'Well Data' > 'Saturation Sets …' (Ctrl+H).

8. Select 'Create New Saturation Set'.
9. Double-click on the 'Name' text box and enter a suitable name.
10. Highlight the Fluid Type 'Condensate Saturation Log' and click 'Add Saturation Log'.
11. Highlight the log created in Step 5 and click 'OK'.
12. Highlight the Fluid Type 'Water Saturation Log' and click 'Create Complement Log'.
13. Click 'OK' to close the 'Edit Saturation Sets' dialog.

Cross-Plot Views/ Active Logs

When loading RokDoc Cross-plot Views, it is important to be aware that although the correct cut-offs have been applied for the desired view, a cut-off will assume that the correct active log is selected for the specified log type. For example, when displaying the Vs-Vp multi-well relationship for shale, by default the View will have cut-offs applied of 'Volume'>0.7 and 'FLAG_Multi_Well'=1.0. In this case, it is important to ensure that the active Volume is 'VSH'.

Units

Shell standard (imperial) units are used for all deliverables supplied within the RokDoc project. However, intermediary steps in the workflow require the use of non-standard units in certain stages:

1. Within the Greenberg Castagna Constants functionality (used in the Modified Gassmann for Vs prediction workflow), constants must be stated in units of km/s.
2. When using the User Programmer Custom Scripts to perform Gassmann fluid substitution of end-member logs to oil, gas condensate and gas bearing conditions, projects units of m/s must be specified for velocity.

Technical Issues

Checkshot Sets

Quality control of supplied checkshot data highlighted that on occasion the data is less than ideal for use in generating time-depth conversions, either due to sparse sampling of data points or partial coverage over the interval of interest. It is advised that prior to performing a well to seismic tie, the user ensures the quality of checkshot data is sufficient for this purpose. The check shot data used for the creation of the synthetic panels was the 'as recorded' in combination with the VP_INSITU_GP, which may result in in small mismatches when the panels are used to tie the well-to-seismic ties.

For the twelve wells with measured Vs data, Vp_INSITU_GP log was not available to create zero-offset synthetic trace QC, since the gap filled Vp log at that stage was the brine replaced Vp_FSUB_BRINE_GP. In these cases, a temporary Time-Depth conversion was made and named 'Time-Depth conversion (Temp)' so that the zero-offset trace QC could take place at this stage of the project. A permanent Time-Depth conversion was created later in the workflow using the Vp_FSUB_INSITU_GP log that was created after Gassmann fluid substitution to hydrocarbons and insitu conditions in these twelve wells with measured Vs log data. This Time-Depth conversion was named 'Time-Depth conversion'.

Wet Shale Log Fluid Substitution (Gassmann Dry Rock Modelling)

Initial log fluid substitution performed as part of the workflow for wells with measured Vs, taking log data to 100% brine bearing conditions for use in multi-well analysis (see Chapter 2a for further details), was performed using wet shale mineral properties in combination with total porosity. Investigations showed that the results were insensitive to the clay mineral type used.

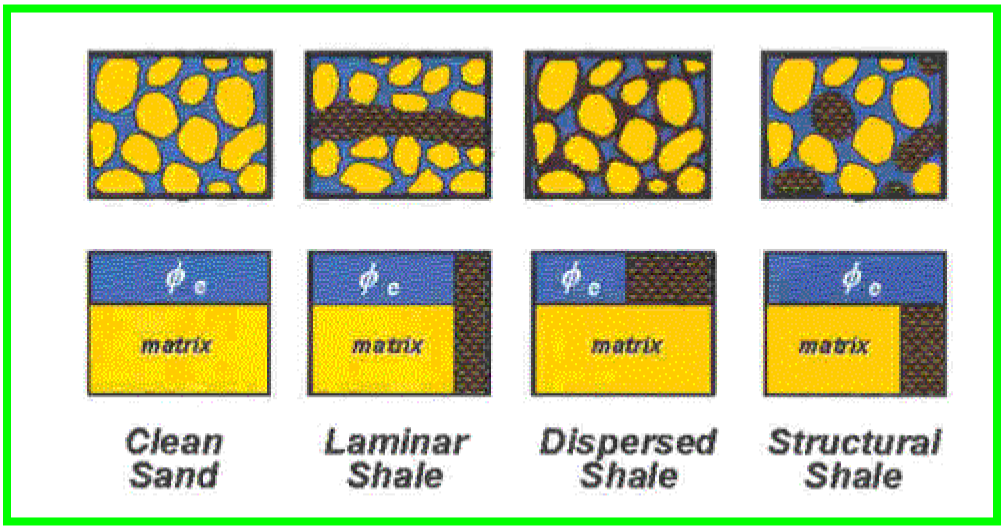
Total versus Effective porosity –

Use of Total Porosity for Shaly Sand Model Applications

Following industry best practice, all porosity values in this study are total porosities (Phi_T) that were determined during the Petrophysical Evaluation and are subsequently used as an integral part of the sand acoustic property model. For the respective formations, the sand model was calibrated for endmember quality sands - which means that only small amount of clay is in these rocks. Presence of such small amounts of clay can lead to less stiff grain material if some of the ductile clays are in a load bearing position (leading to a lower Vp and Vs towards zero porosity). It can also lead to a slightly lower critical porosity given the presence of small grains and fines that can reduce sorting. Hence, a Vp(Phi_T) trend for such a slightly shaly formation will (when compared to a perfectly clean sand) feature a slightly lower Vp at a given porosity and overall slightly lower porosities (assuming that the amount of compacting stress is similar and quartz cementation does not play a major role in porosity loss). The same applies to Vs.

The situation becomes more difficult when dealing with low NtG shaly sands for which the amount of (microporous) clay becomes so large that a significant amount of the total porosity will be 'non-effective'. When forward modeling such intervals with the here derived clean sand and shale endmember trends and regressions, both must be appropriately mixed. Please note that the term shale itself describes a medium that on the microscale is heterogeneous - our definition of shale is that or a rock that consists of a microporous clay matrix in which hard (and non porous) silt particles are embedded. A simple approach would be to model the endmember sands in a first step, and to perform fluid substitution in them as needed. Then the shale properties for this location and depth are modeled. In the final step, the Backus Averaging method is applied to mix the sand and shale endmembers into an effective 'shaly sand' medium. This approach assumes that clean endmember sands and shales are interlaminated on a fine scale (too fine to be modeled as separate sand and shale layers). This simple and robust approach should be the default way to forward model shaly sands

In addition to being a key part of the above described thin shale lamina, clay can also be 'dispersed', i.e., preferably occupying and occluding pore space or it can be 'structural', i.e., be in a load bearing position replacing more ductile quartz or feldspar grains in the sand matrix. On the well logs that do not resolve this microstructure between sand and shale, and that we deem representative for the shaly sands we want to model, a petrophysical 'shaly sand analysis' needs to be performed first to understand what fraction of clay is in which structural role. We typically use the Thomas and Stieber approach that is implemented in Techlog in a comprehensive way and to some extend also in RokDoc. Using, if possible, core calibrated logs, we need to establish zones for which the rock has reasonably uniform properties. This is because compaction or cementation effects that manifest themselves when looking at data from large depth ranges can smear-out the data on the Thomas Stieber triangle crossplot. When determining endmember properties we ideally are looking at one 'rock type' at a time and not at a huge mix between laminated, dispersed and sometimes even structural clay (see figure below) - otherwise finding the endpoints gets more tricky.



After performing this analysis, we will have established in addition to the total porosity a 'sand fraction porosity' Phi_{SAND} that estimates what the porosity of the below-log resolution sands in the investigated shaly sand package is. This quantity will be larger or equal to Phi_T. We further will have estimated a 'non-effective' shale porosity during this analysis by cross-plotting Phi_T versus Vshl and extrapolating to Vshl = 1. The intercept value at $Vshl$=1 is the required Phi_{shl} , just as the value at $Vshl$ = 0 corresponds to Phi_{SAND}. We note that we now can calculate an effective porosity that fulfills this equation: $Phi_T = Phi_E + V_{shl} * Phi_{shl}$.

Note that for Xstream model calibration the user must provide Phi_{SAND} for both the 'SDDI model' as well as the 'Sand Shale Mix Model'. The Xstream user documentation (see

XStream documentation on *Petrophysics*) refers to this as *MatrixPorosity* that corresponds to the 'porosity of the sand fraction of the matrix'. The user guide further advises in Eq. 27 and 34 that the sand fraction porosity is related to a 'bulk porosity' as Phi_{SAND} = 'bulk porosity' / 'sand fraction'. This means that the Xstream 'bulk porosity' must be equivalent to the effective porosity (unless Phi_{shl} was zero, in which case $Phi_T = Phi_E$). But using the Phi_{SAND} that comes directly out of the Thomas Stieber analysis seems to be the more straightforward way to provide input to these models.

In summary:
The following procedure to follow to convert the available Phi_T (curves and averages) to Phi_E :

- X-plot Phi_T against Vshl
- Find intercept at V_{shl} = 1 : Phi_{shl}
  Find intercept at V_{shl} = 0 : Phi_{sand}
- $Phi_E = Phi_T - V_{shl} * Phi_{shl}$

End-member trends:
Note that for the clean sand trends the term $V_{shl} * Phi_{shl}$ is very small and $Phi_{sand} \cong Phi_E \cong Phi_T$

Mineral values for Zero-Porosity end point

There is an inconsistency in the value for of mineral properties used in the petrophysical evaluation / invasion correction / Gassmann fluid substitution to brine / mult-well cross-plots and Gassmann substitution to final HC fluid scenario's, see also chapter 2, section 2.1 – p.29, section 2.2 – p.43 and section 2.3 – p.91).

- **PP-evaluation**
  Clean mineral (Rho) for most wells, but possibly vary per well, e.g. per core info.
- **Invasion correction**
  Consistent with the PP evaluatio
- **Gassmann fluid substitution to Brine**
  Clean mineral properties
- **Multi-well x-plot**
  Clean mineral (Rho) for Rho-PhiT x-plot – linked to PP evaluation
  Dirty mineral (Vp) for Vp-PhiT x-plot at zero PhiT
- **Gassmann fluid substitution to HC fluid scenarios**
  Dirty mineral

The differences are small, but these should be mentioned.
Future studies will include a interative PP evaluation step that can incorporate any changes in the mineral properties should such become apparent from the multi-well analysis.

Appendix F – Single Well reports

Well: 21/20A-02

General

Well Information
Shell operated exploration well spudded, completed and abandoned in 1983. The well encountered oil in the Upper Triassic (Fulmar Formation), and is the discovery well for the Cook field.

Objectives
The well was drilled in a down flank position on the Cook structure with a primary objective of evaluating Upper Triassic sands, and secondary objectives of evaluating Middle Triassic sands, Upper Cretaceous chalk and Palaeocene sands. The secondary objectives within the Palaeocene and Cretaceous were present but wet.

Log conditioning overview
Only minor log conditioning required due to good log data quality within this well. Caliper log shows washout within the Horda Formation as is common due to its unconsolidated nature. Thin calcite stringers in the Horda Formation are seen on the density log, but are not apparent on the Vp log. Data relating to these intervals was consequentially removed.

Invasion correction
Invasion correction has been performed on the density log within all formations with the exception of the non-reservoir forming Balder Formation. The drilling mud used within this well was oil-based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda Formation for Vp and within the Horda and Tor Formations for density. A complete Vs log is modelled in the absence of measured shear log data.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 21/20A-02 is displayed in the figures below;

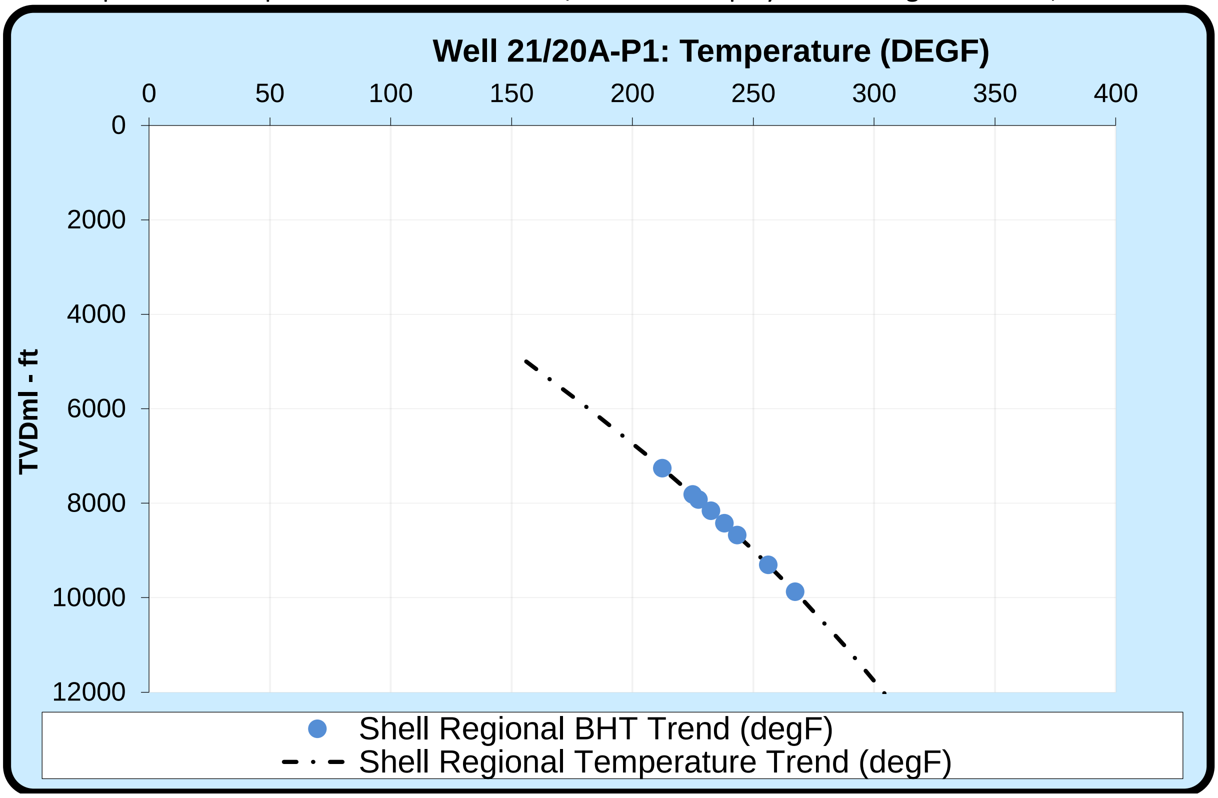


Figure 3.1.1 - Temperature data at Well 21/20A-02

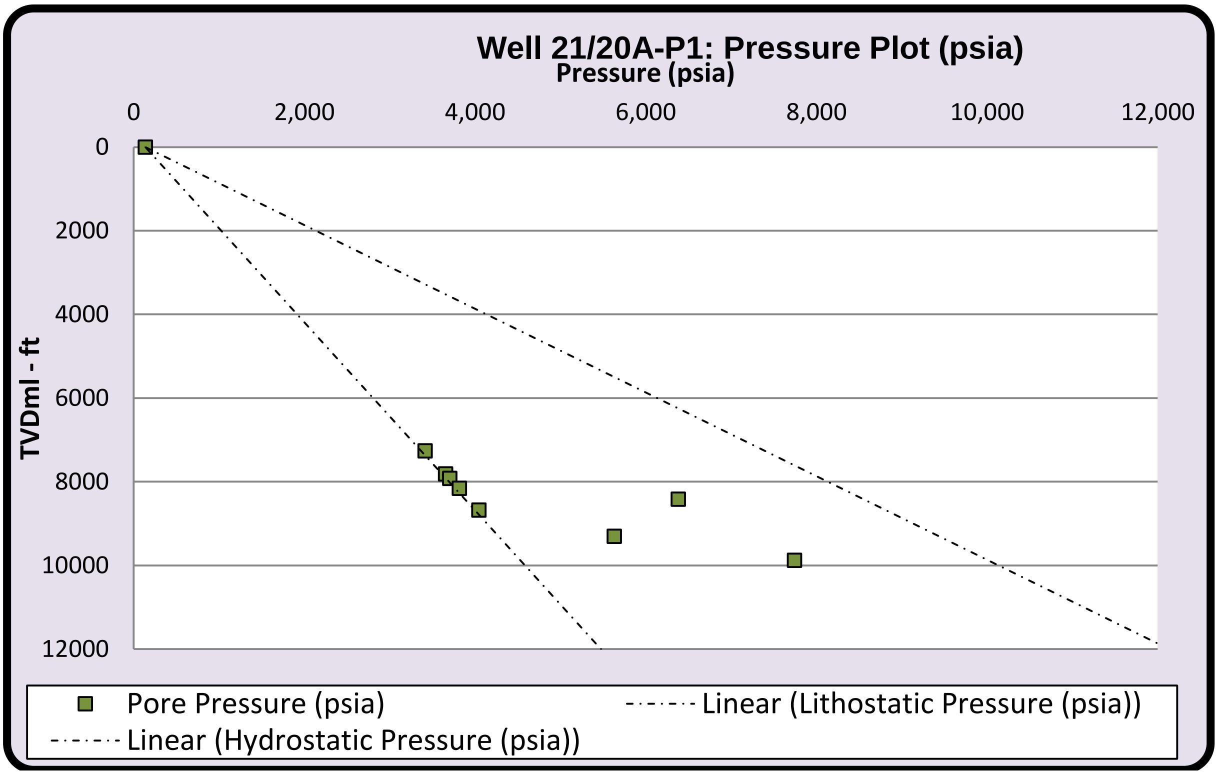


Figure 3.1.2 - Pressure data at Well 21/20A-02

The temperature and pressure data for the formation mid-points in Well 21/20A-02 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
21/20A-02	Sea Bed	391.0	308.0	0.0	39.2	137.1	137.1	137.06	0.00
21/20A-02	Horda	7651.0	7567.7	7259.7	212.4	3367.6	3415.6	7396.78	3981.15
21/20A-02	Balder	8206.1	8122.7	7814.7	225.0	3614.6	3656.6	7951.81	4295.19
21/20A-02	Sele	8315.1	8231.7	7923.7	227.4	3663.1	3705.1	8060.80	4355.67
21/20A-02	Lista	8549.7	8466.3	8158.3	232.5	3767.5	3817.5	8295.35	4477.85
21/20A-02	Maureen	8812.7	8729.3	8421.3	238.2	3884.5	6384.5	8558.31	2173.80
21/20A-02	Ekofisk	9066.3	8982.8	8674.8	243.5	3997.4	4047.4	8811.90	4764.54
21/20A-02	Tor	9698.3	9614.7	9306.7	256.3	4278.5	5634.5	9443.77	3809.22
21/20A-02	Hod	10269.5	10185.8	9877.8	267.4	4532.7	7745.0	10014.84	2269.81

Table 3.1.1 - Summary of mid-point temperature and pressure data at Well 21/20A-02

Fluid data

A summary of the fluid set parameters at Well 21/20A-02 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
21/20A-02	Horda	95000	730	39.2	0.71	0.71
21/20A-02	Balder	95000	730	39.8	0.71	0.71
21/20A-02	Sele	95000	730	39.9	0.71	0.71
21/20A-02	Lista	95000	730	40.2	0.71	0.71
21/20A-02	Maureen	95000	730	40.5	0.71	0.71
21/20A-02	Ekofisk	95000	730	40.7	0.71	0.71
21/20A-02	Tor	95000	730	41.4	0.71	0.71
21/20A-02	Hod	95000	730	42.0	0.71	0.71

Table 3.1.2 - Summary of fluid parameter data at Well 21/20A-02

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.1.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	12.89	5.25	2.41	9,429	4,843

Table 3.1.4 - Tuff properties used at Well 21/20A-02

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
21/20A-02	Horda	PAY	1054.000	0.000	0.000	0.000	0.000	0.000	0.000
21/20A-02	Horda	RES	1054.000	86.500	0.082	20.368	0.235	0.968	0.185
21/20A-02	Balder	PAY	56.170	0.000	0.000	0.000	0.000	0.000	0.000
21/20A-02	Balder	RES	56.170	7.500	0.134	2.091	0.279	0.944	0.020
21/20A-02	Sele	PAY	161.803	0.000	0.000	0.000	0.000	0.000	0.000
21/20A-02	Sele	RES	161.803	46.080	0.285	13.181	0.286	0.968	0.117
21/20A-02	Lista	PAY	307.350	0.000	0.000	0.000	0.000	0.000	0.000
21/20A-02	Lista	RES	307.350	24.000	0.078	3.520	0.147	0.982	0.199
21/20A-02	Maureen	PAY	218.650	1.000	0.006	0.231	0.231	0.488	0.219
21/20A-02	Maureen	RES	218.650	94.250	0.431	19.369	0.206	0.974	0.162
21/20A-02	Ekofisk	PAY	288.600	0.000	0.000	0.000	0.000	0.000	0.000
21/20A-02	Ekofisk	RES	288.600	222.500	0.771	20.473	0.092	0.990	0.169
21/20A-02	Tor	PAY	975.400	0.000	0.000	0.000	0.000	0.000	0.000
21/20A-02	Tor	RES	975.400	550.650	0.565	44.574	0.081	0.991	0.014
21/20A-02	Hod	PAY	167.000	0.000	0.000	0.000	0.000	0.000	0.000
21/20A-02	Hod	RES	167.000	135.250	0.810	6.953	0.051	1.000	0.302

Table 3.1.5 - Petrophysical parameters used at Well 21/20A-02

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

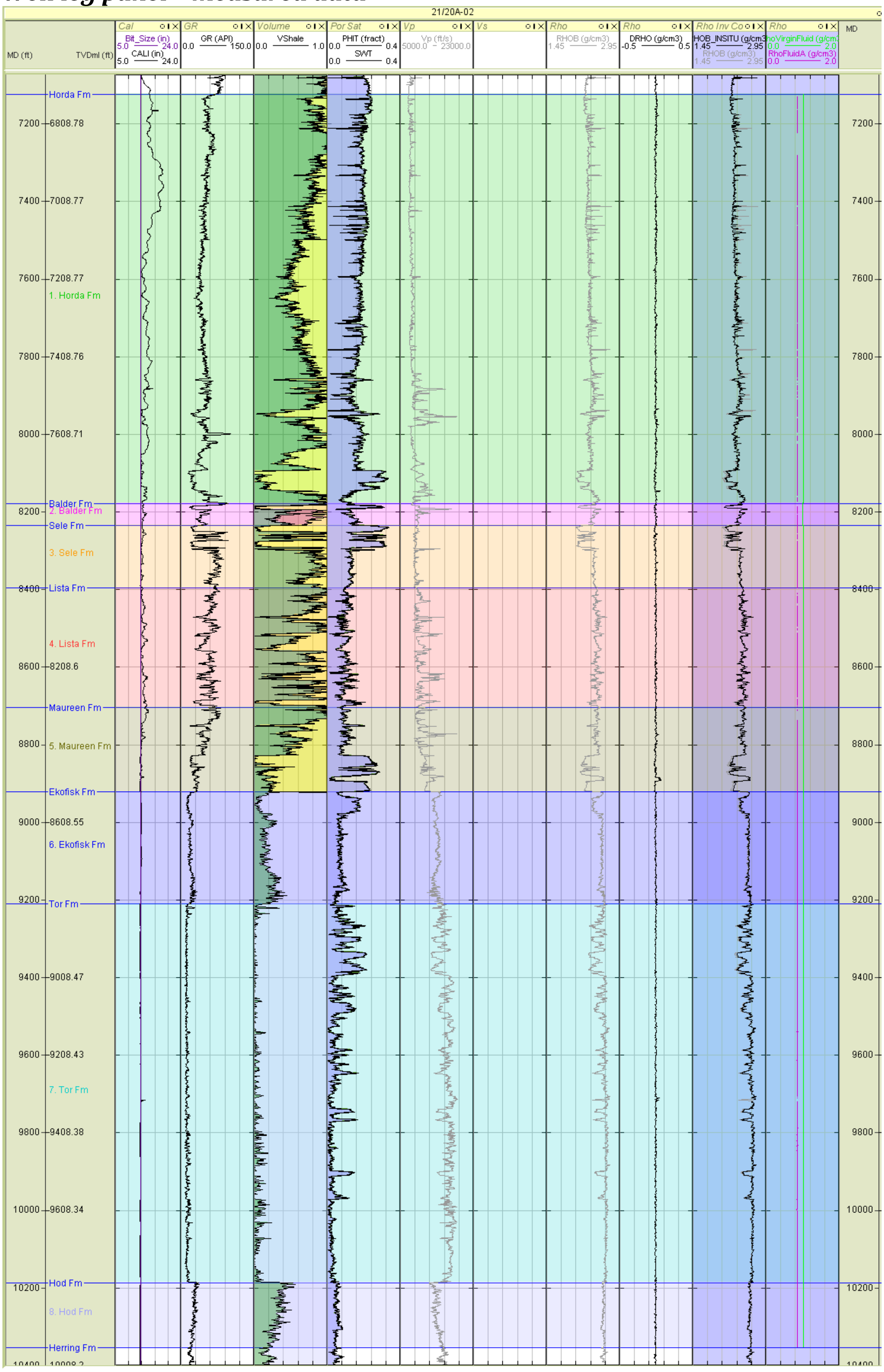


Figure 3.1.3 - Well Panel: Measured data and invasion correction for well 21/20A-02.

Well log panel – log editing and audit

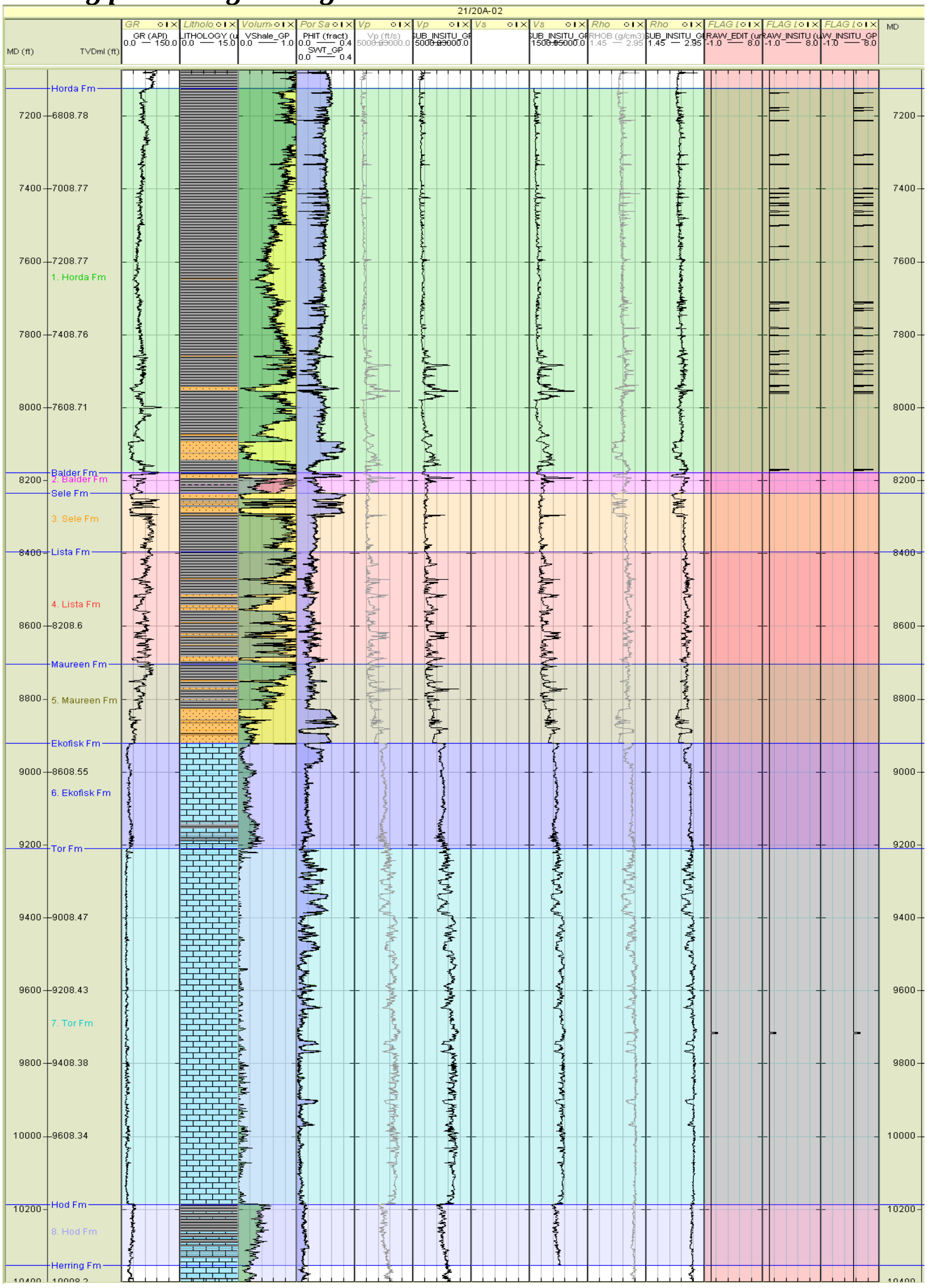


Figure 3.1.4 - Well Panel: Log edits for well 21/20A-02.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

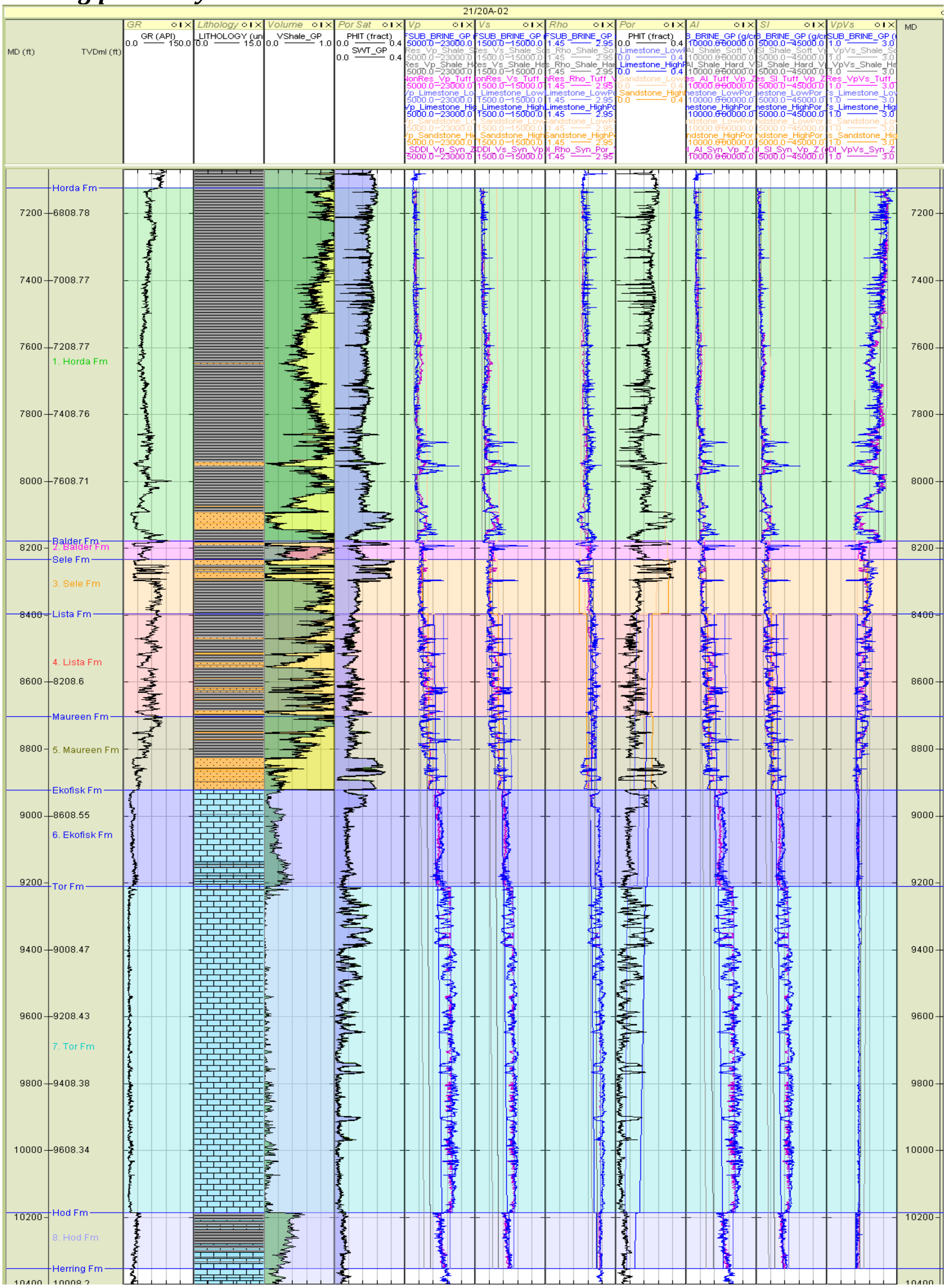


Figure 3.1.5 - Well Panel: End-member and synthetic logs for well 21/20A-02.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

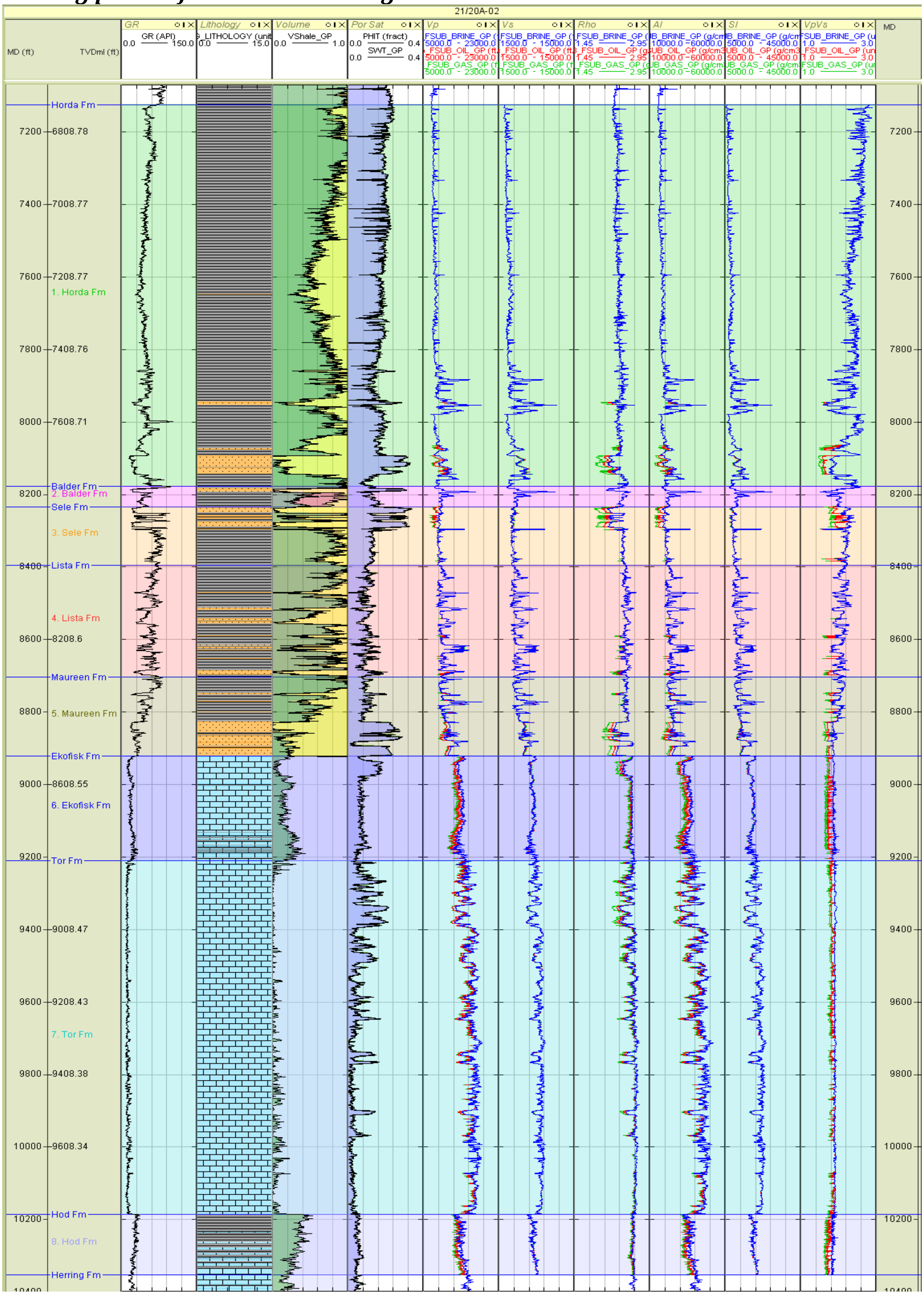


Figure 3.1.6 - Well Panel: Fluid substituted and elastic logs for well 21/20A-02.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 21/20A-02 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/20A-02	Horda	7749	3107	2.32
21/20A-02	Balder	7809	3140	2.42
21/20A-02	Sele	8605	3914	2.42
21/20A-02	Lista	9365	4426	2.47
21/20A-02	Maureen	9374	4510	2.48

Table 3.1.6 - Clean shale properties at Well 21/20A-02

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/20A-02	Horda	100% Brine	10425	5715	2.25
21/20A-02	Balder	100% Brine			
21/20A-02	Sele	100% Brine	9165	4218	2.17
21/20A-02	Lista	100% Brine	12371	6596	2.49
21/20A-02	Maureen	100% Brine	12371	6596	2.45
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/20A-02	Horda	80% Oil	9526	5802	2.18
21/20A-02	Balder	80% Oil			
21/20A-02	Sele	80% Oil	8042	4298	2.09
21/20A-02	Lista	80% Oil	12088	6622	2.47
21/20A-02	Maureen	80% Oil	11145	6375	2.29
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/20A-02	Horda	90% Gas	9361	5952	2.07
21/20A-02	Balder	90% Gas			
21/20A-02	Sele	90% Gas	7831	4435	1.96
21/20A-02	Lista	90% Gas	12037	6664	2.44
21/20A-02	Maureen	90% Gas	11026	6480	2.21

Table 3.1.7 - Clean sand properties at Well 21/20A-02 for each fluid case

Tertiary reservoirs – Well panel

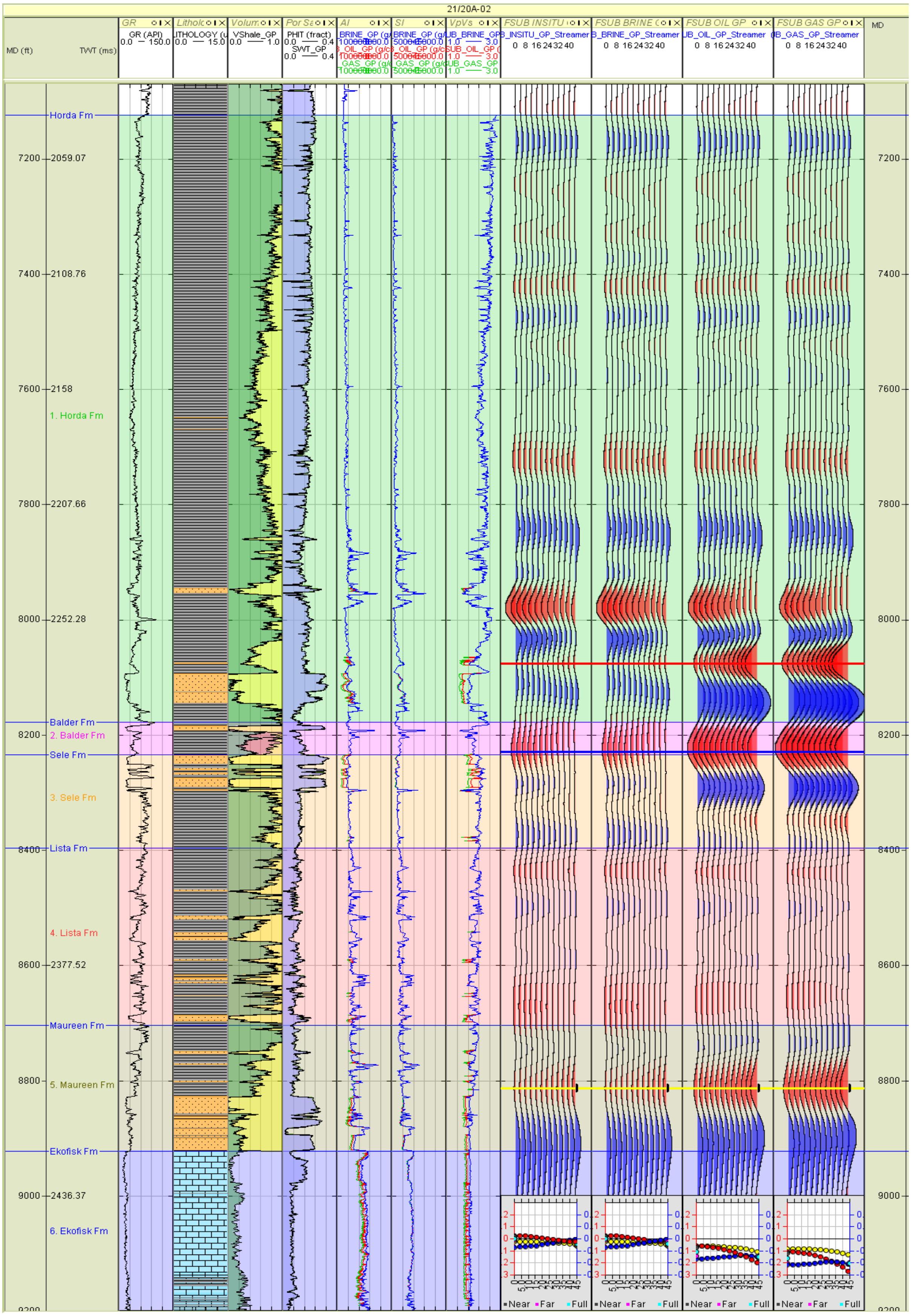


Figure 3.1.7 - Well Panel: Tertiary reservoirs for well 21/20A-02. Wavelet: Streamer

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir within the formation is primarily a clean blocky sandstone approximately 50 feet thick occurring towards the base of the interval, overlain by a silty interval containing thin shales. Net reservoir is approximately 87 feet containing porosities of 18-33%.
- Blocky AVO shows a modelled class I response for the 100% brine case, and a marginal class I/IIp response in both the 80% oil and 90% gas cases. The response varies from that observed within the synthetic gathers, where a marginal class I/IIp AVO response is seen in the 100% brine case, and a class III response in the 80% oil and 90% gas cases. This difference is likely caused in part due to both wavelet interference and the silty nature of the geology overlying the top reservoir contact.
- Elastic Contrast Analysis shows contrasts are generally positive in the 100% brine case, but become increasingly negative with addition of hydrocarbons, showing similar contrasts in both the 80% oil and 90% gas cases. Mu and MuRho show the least sensitivity to fluid changes, whilst Lambda and LambdaRho show the most sensitivity to fluid effects.

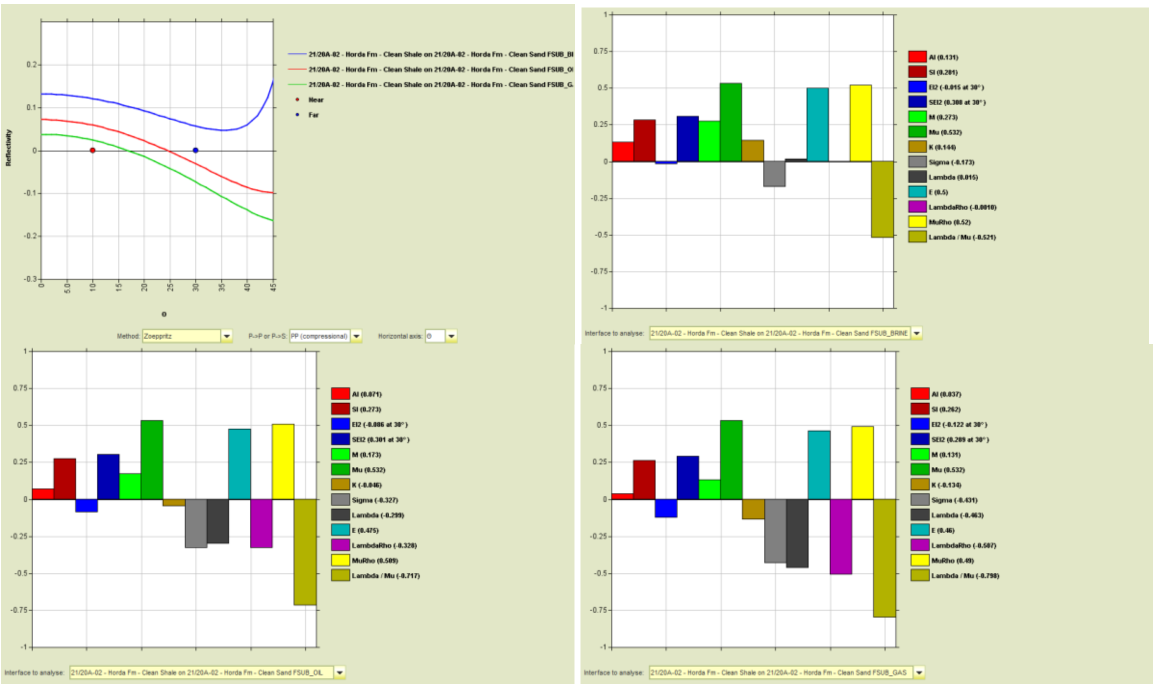


Figure 3.1.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 21/20A-02

Sele Formation

- Reservoir formed by a number of clean blocky sands towards the top of the interval separated by thin shale intervals, net reservoir is approximately 46 feet. The uppermost reservoir sand is overlain directly by tuffaceous shale.
- Blocky AVO shows a modelled low gradient class IV response for the 100% brine case showing weak reflectivity, and a class III response for the 80% oil and 90% gas cases in turn - reflectivity increasing with the addition of hydrocarbons. Synthetic gathers created at the well location show a class IV top reservoir response in all fluid cases, matching the response given by Blocky AVO modelling of a Balder Formation tuff on Sele Formation sand contact.
- Elastic Contrast Analysis shows contrasts are negligible in the100% brine case, generally becoming negative with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda and LambdaRho show the most sensitivity to fluid effects.

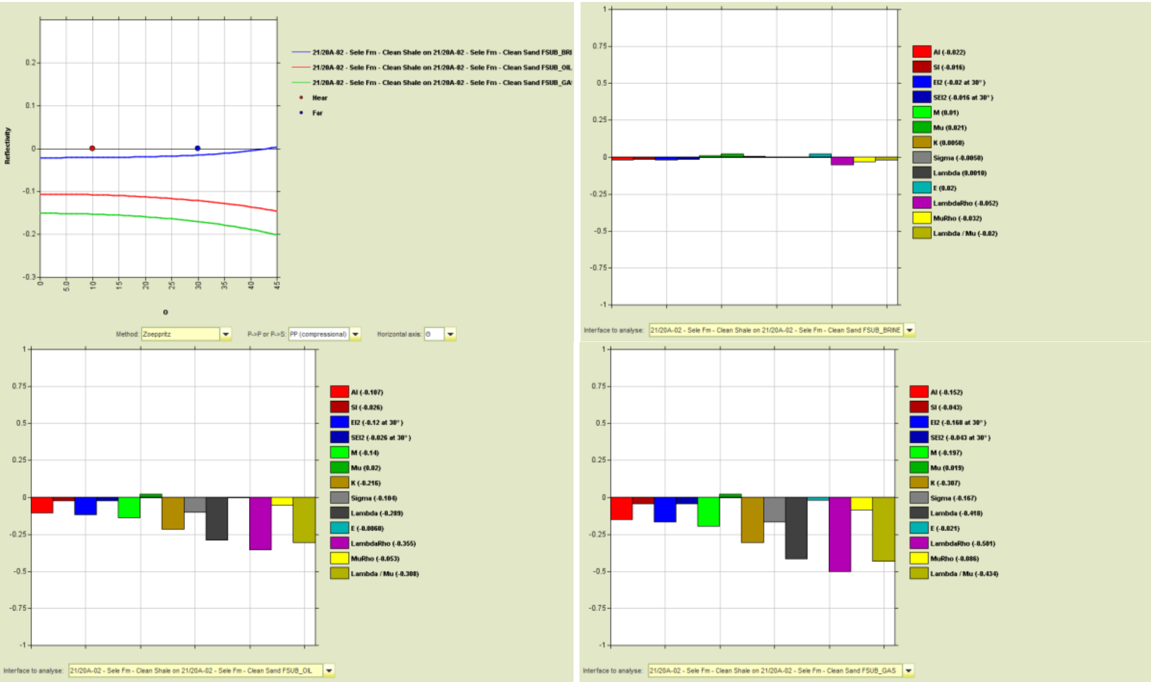


Figure 3.1.9 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 21/20A-02

Lista Formation

- Reservoir comprises a number of thin (up to approximately 12 feet thick) discrete sand bodies separated by shale throughout the interval. Net reservoir is approximately 24 feet and contains porosities of around 5-10%.
- Blocky AVO shows a modelled class I response for the 100% brine, 80% oil and 90% gas cases in turn, where reflectivity decreases with the addition of hydrocarbons. Synthetic gathers show the presence of no defining seismic events over the Lista Formation, which is likely due to the limited vertical extent of reservoir sands and low porosities limiting the potential for fluid effects.
- Elastic Contrast Analysis shows contrasts are mainly moderate and positive in the 100% brine case, showing little effect to the addition of hydrocarbons. Lambda and LambdaRho shows the most sensitivity to fluid effects.

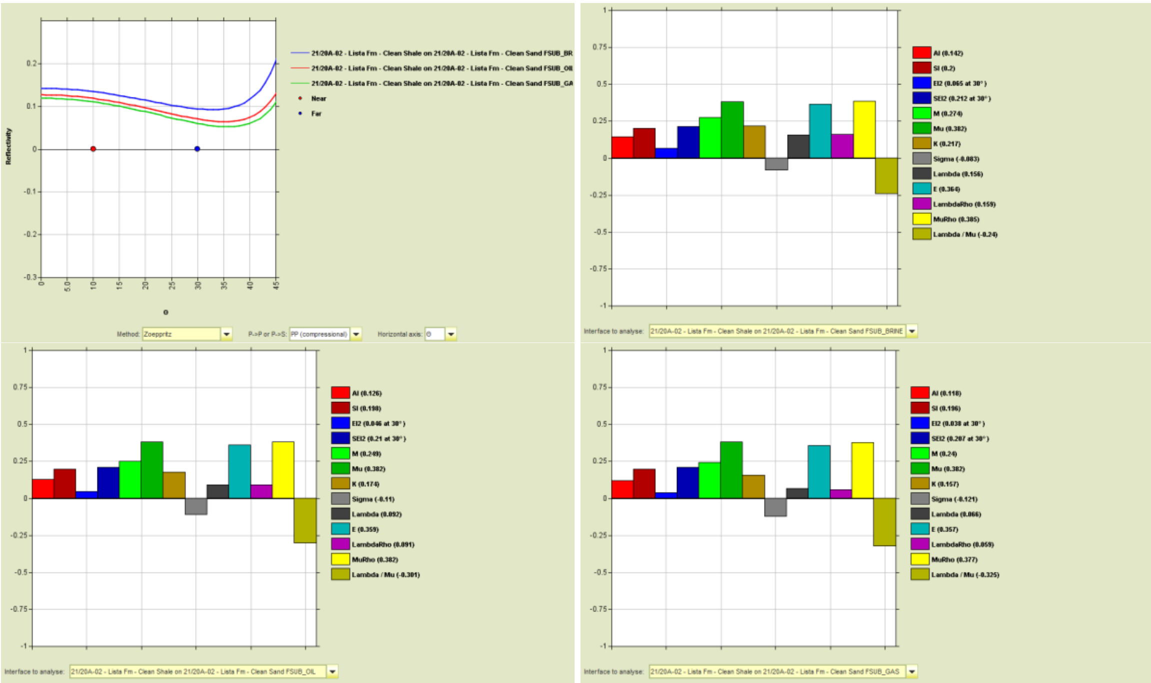


Figure 3.1.10 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 21/20A-02

Maureen Formation

- Reservoir is formed by stacked blocky sandstones towards the base of the interval, becoming increasingly shaley with depth. The reservoir is overlain by a silty shale and overlies chalk of the Ekofisk Formation. Reservoir thickness (net) is approximately 94 feet, with porosities of 20-30%.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases, whereas the 90% gas case shows a marginal class I/IIp response. The response varies slightly to that observed within the synthetic gathers, where a class III response is seen in all fluid cases. This variance is likely due to wavelet interference caused by a number of intra-reservoir reflectors.
- Elastic Contrast Analysis shows contrasts are mainly moderate and positive in the brine case, showing little effect to the addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda and LambdaRho show the most sensitivity to fluid effects.

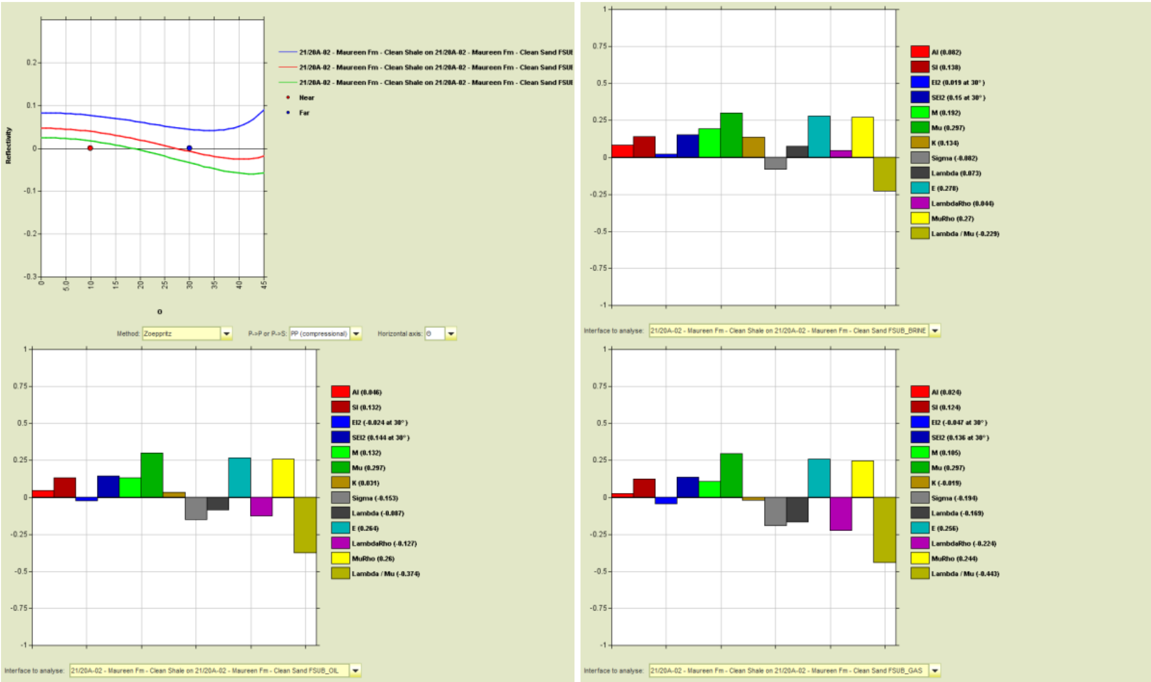


Figure 3.1.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 21/20A-02

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 21/20A-02 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/20A-02	Ekofisk	100% Brine	13774	7380	2.48
21/20A-02	Tor	100% Brine	16000	8701	2.58
21/20A-02	Hod	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/20A-02	Ekofisk	80% Oil	12949	7438	2.44
21/20A-02	Tor	80% Oil	16096	8669	2.60
21/20A-02	Hod	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/20A-02	Ekofisk	90% Gas	12743	7530	2.39
21/20A-02	Tor	90% Gas	16461	8647	2.61
21/20A-02	Hod	90% Gas			

Table 3.1.8 - Clean limestone properties at Well 21/20A-02 for each fluid case

Cretaceous reservoirs

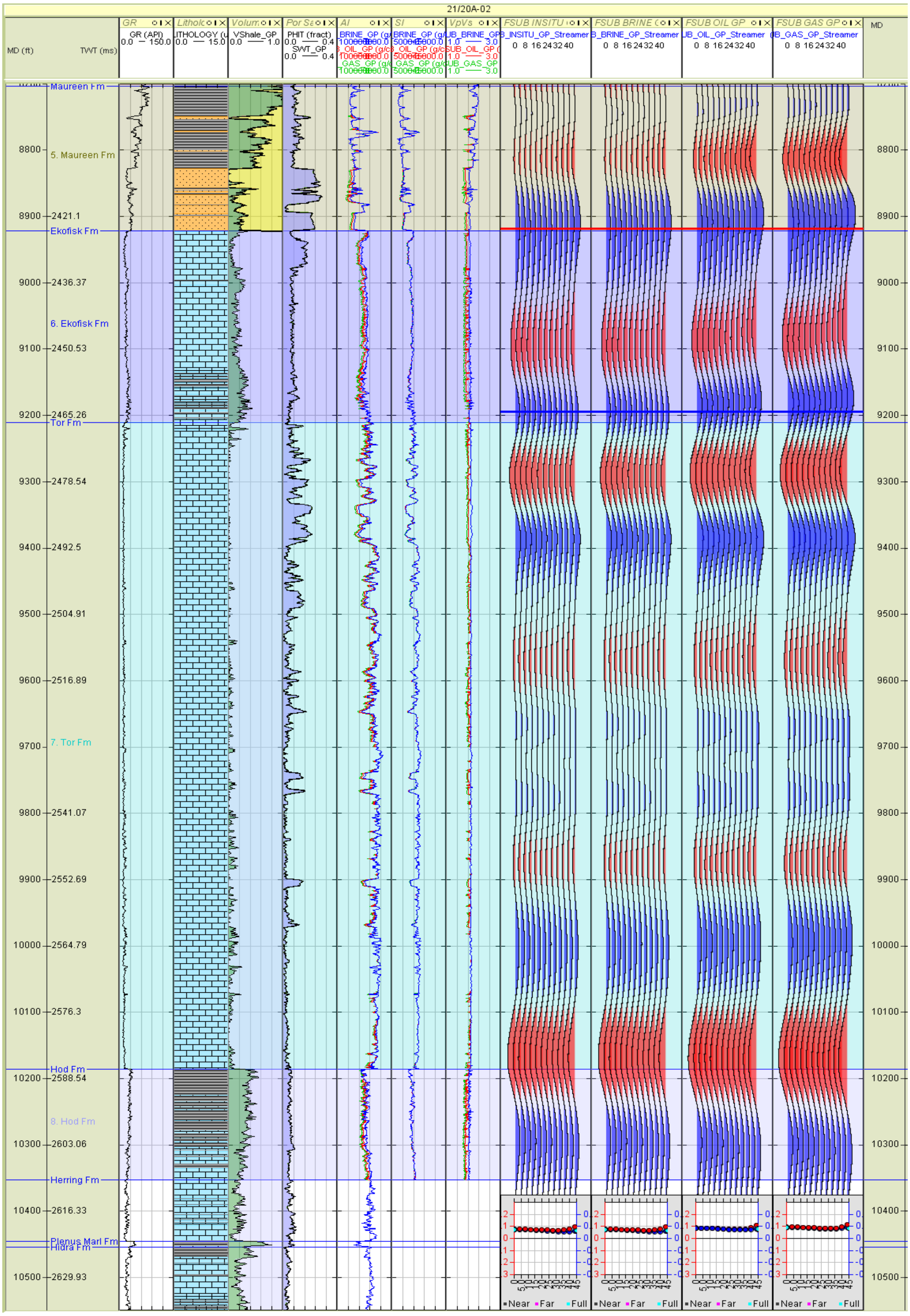


Figure 3.1.12 - Well Panel: Cretaceous reservoirs for well 21/20A-02. Wavelet: Streamer

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir is formed from a zone of higher porosity (approximately 10-18%) at the top of the interval, and likely represents a phase of chalk reworking. The Ekofisk Formation reservoir directly underlies the reservoir sandstone of the Maureen Formation separated by a thin low porosity chalk interval. Net reservoir is approximately 223 feet.
- Blocky AVO modelling shows a class I response predicted in all fluid cases, where reflectivity decreases with the addition of hydrocarbons. Synthetic gathers give an AVO class consistent with Blocky AVO modelling. However, reflectivity increases moving from the 100% brine to the 80% oil and 90% gas cases. This difference is likely due to increased fluid effects within softer sands of the Maureen Formation dominating the synthetic response.
- Elastic Contrast Analysis shows contrasts are generally moderate and positive in the 100% brine case. Moving to a hydrocarbon bearing case, many constants show little sensitivity to fluid effects, while Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

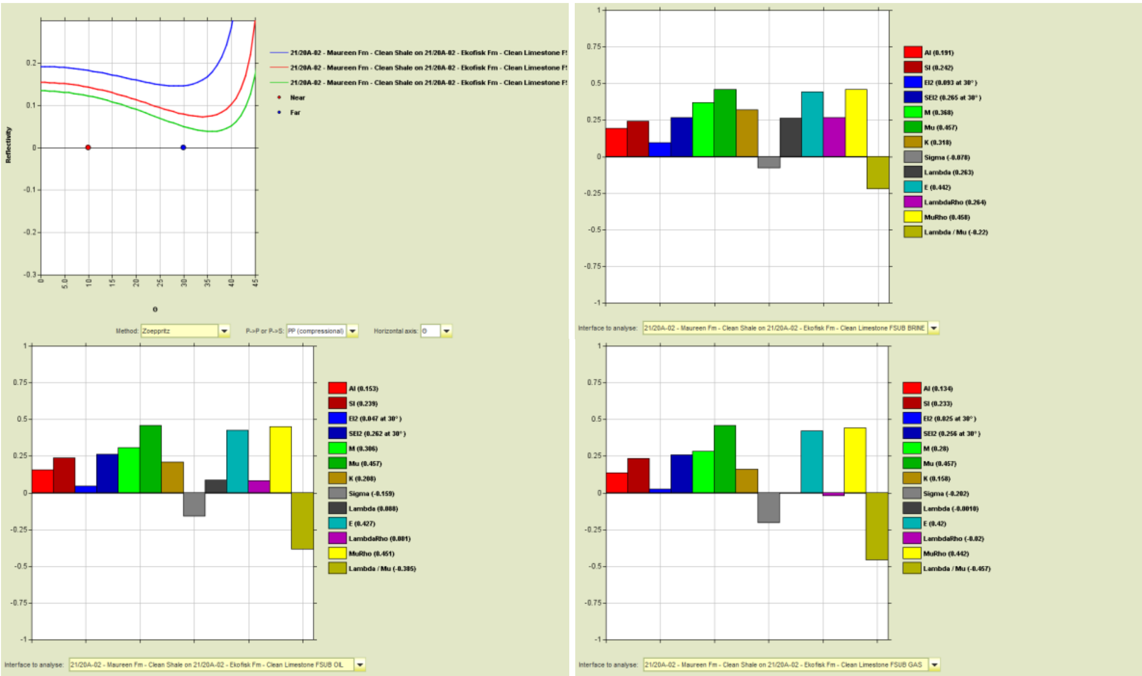


Figure 3.1.13 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 21/20A-02.

Tor Formation

- Reservoir occurs as patchy zones of higher porosity (approximately 10-20%) throughout the uppermost half of the Tor Formation. The formation is encased by relatively shaley chalks of the Ekofisk and Tor Formations. Net reservoir is approximately 551 feet.
- Blocky AVO shows a modelled class I response for all fluid cases, with reflectivity decreasing in the 80% oil and 90% gas cases. Synthetic gathers show similar class I AVO responses, with reflectivities increasing in both hydrocarbons cases comparative to the 100% brine case. This is likely due to the observed patchy porosity causing wavelet interference over the reservoir zone.
- Elastic Contrast Analysis shows consistent weak positive contrasts in the 100% brine case, generally showing little effect to the addition of hydrocarbons. Mu shows the least sensitivity to fluid effects, whilst Lambda and LambdaRho show the most sensitivity to fluid effects.

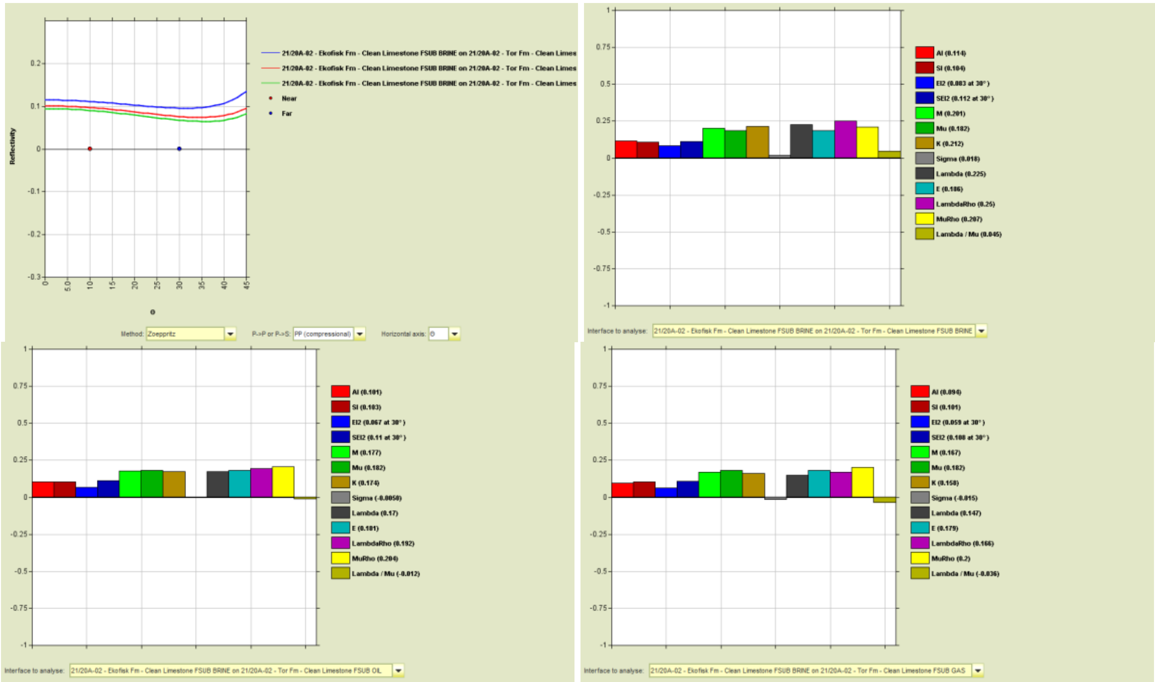


Figure 3.1.14 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 21/20A-02.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 21/20A-02 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/20A-02	Overburden	Shale	7359		2.28
21/20A-02	Underburden	Limestone	14242		2.62

Table 3.1.9 - Overburden and underburden properties at Well 21/20A-02.

Well: 21/25-04

General

Well Information
Shell operated appraisal well for the Gannet A field. Spudded, completed and abandoned in 1983, the well encountered oil and gas in the Horda Formation (Tay Member).

Objectives

The objectives for well 22/28a-4 were to prove and test oil in the Fulmar and Skagerrak sands and also to confirm the presence of oil bearing sands in the Tay Formation.

Log conditioning overview
Log conditioning within the well is entirely focused towards the uppermost Horda Formation. The caliper log indicates significant borehole washout, resulting in erroneous density measurement and the complete removal of the log over this section. Otherwise, log data was of good quality with no log conditioning required.

Invasion correction
The drilling mud used within this well was water based, requiring invasion correction to be performed on the density log exclusively within the oil and gas bearing Horda Formation.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda Formation for Vp and density. In the absence of measure shear log data, a complete Vs log is modelled using Modified Gassmann methodology due to the presence of hydrocarbons within this well.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 21/25-04 is displayed in the figures below;

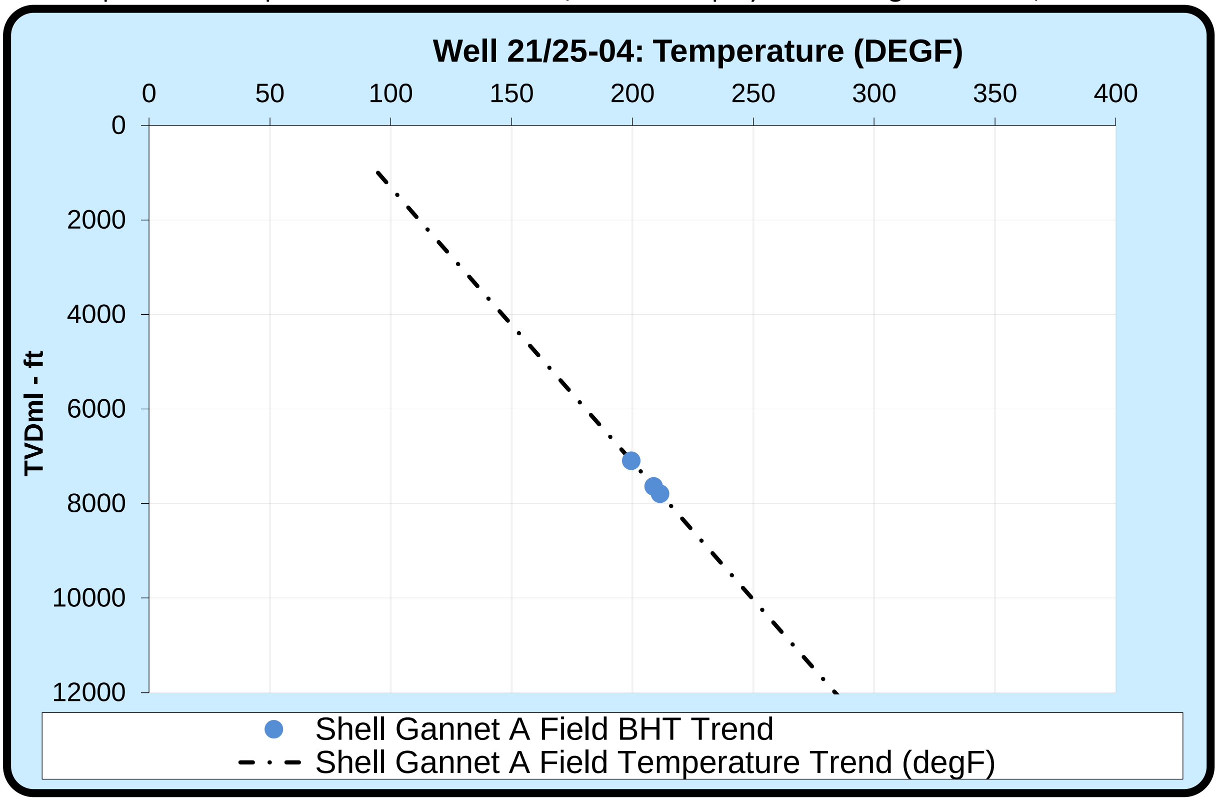


Figure 3.2.1 - Temperature data at Well 21/25-04

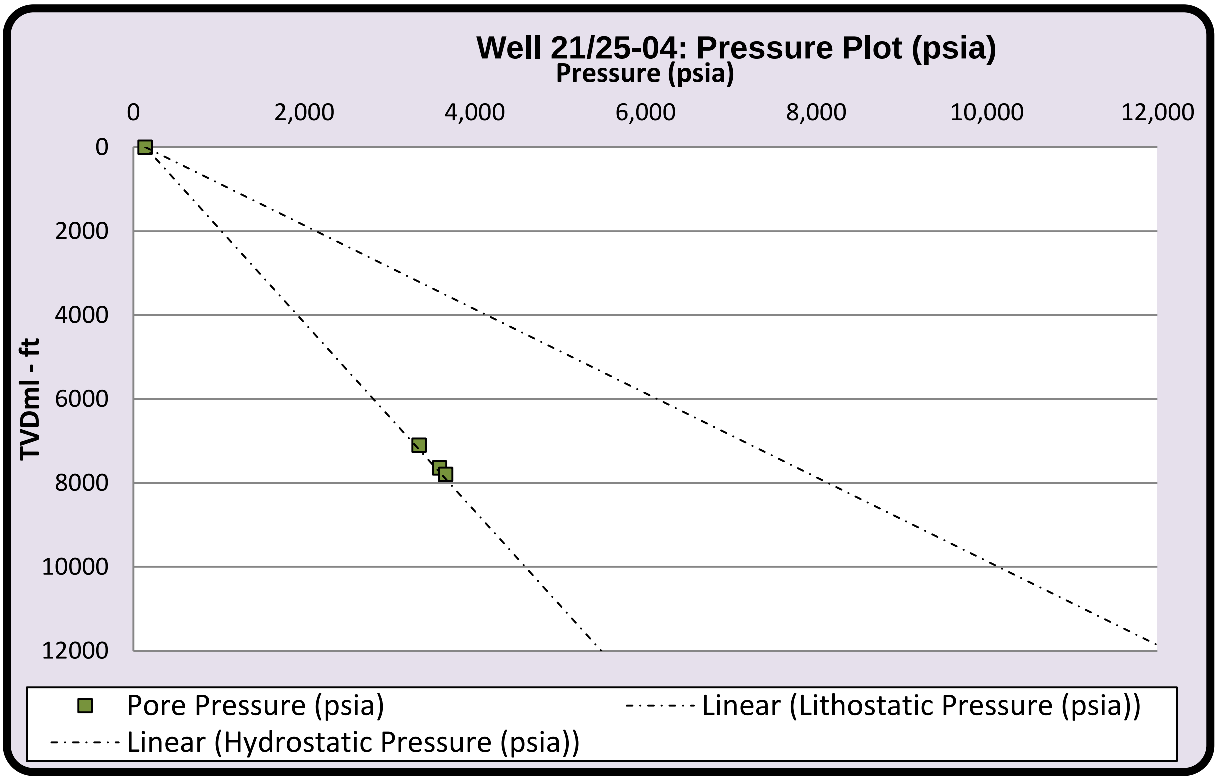


Figure 3.2.2 - Pressure data at Well 21/25-04

The temperature and pressure data for the formation mid-points in Well 21/25-04 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
21/25-04	Sea Bed	403.0	313.0	0.0	39.2	139.3	139.3	139.28	0.00
21/25-04	Horda	7502.5	7412.3	7099.3	199.6	3298.5	3348.5	7238.59	3890.11
21/25-04	Balder	8040.1	7949.8	7636.8	208.9	3537.7	3590.7	7776.10	4185.43
21/25-04	Sele	8197.6	8107.2	7794.2	211.6	3607.7	3660.7	7933.48	4272.78

Table 3.2.1 - Summary of mid-point temperature and pressure data at Well 21/25-04

Fluid data

A summary of the fluid set parameters at Well 21/25-04 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
21/25-04	Horda	78000	969	40.6	0.74	0.74
21/25-04	Balder	104000	730	39.6	0.71	0.71
21/25-04	Sele	104000	730	39.8	0.71	0.71

Table 3.2.2 - Summary of fluid parameter data at Well 21/25-04

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.2.3. - Constant mineral properties used in this project

There is no Tuff present in this well.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
21/25-04	Horda	PAY	945.000	117.000	0.124	36.758	0.314	0.152	0.071
21/25-04	Horda	RES	945.000	475.000	0.503	137.368	0.289	0.758	0.100
21/25-04	Balder	PAY	130.100	0.000	0.000	0.000	0.000	0.000	0.000
21/25-04	Balder	RES	130.100	63.500	0.488	17.903	0.282	0.975	0.124
21/25-04	Sele	PAY	184.900	0.000	0.000	0.000	0.000	0.000	0.000
21/25-04	Sele	RES	184.900	28.500	0.154	6.947	0.244	0.961	0.239

Table 3.2.4 - Petrophysical parameters used at Well 21/25-04

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

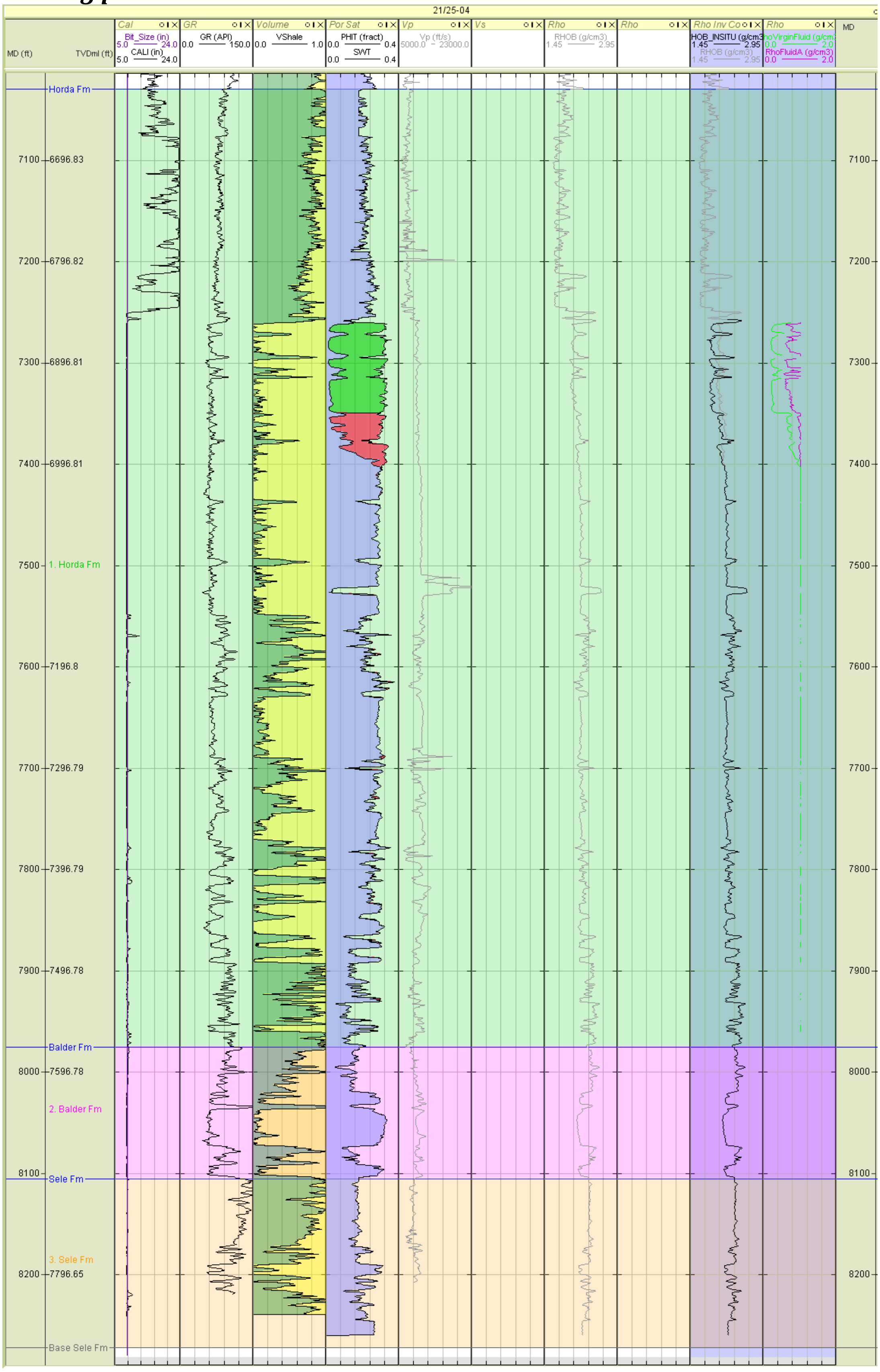


Figure 3.2.3 - Well Panel: Tertiary reservoirs for well 21/25-04.

Well log panel – log editing and audit

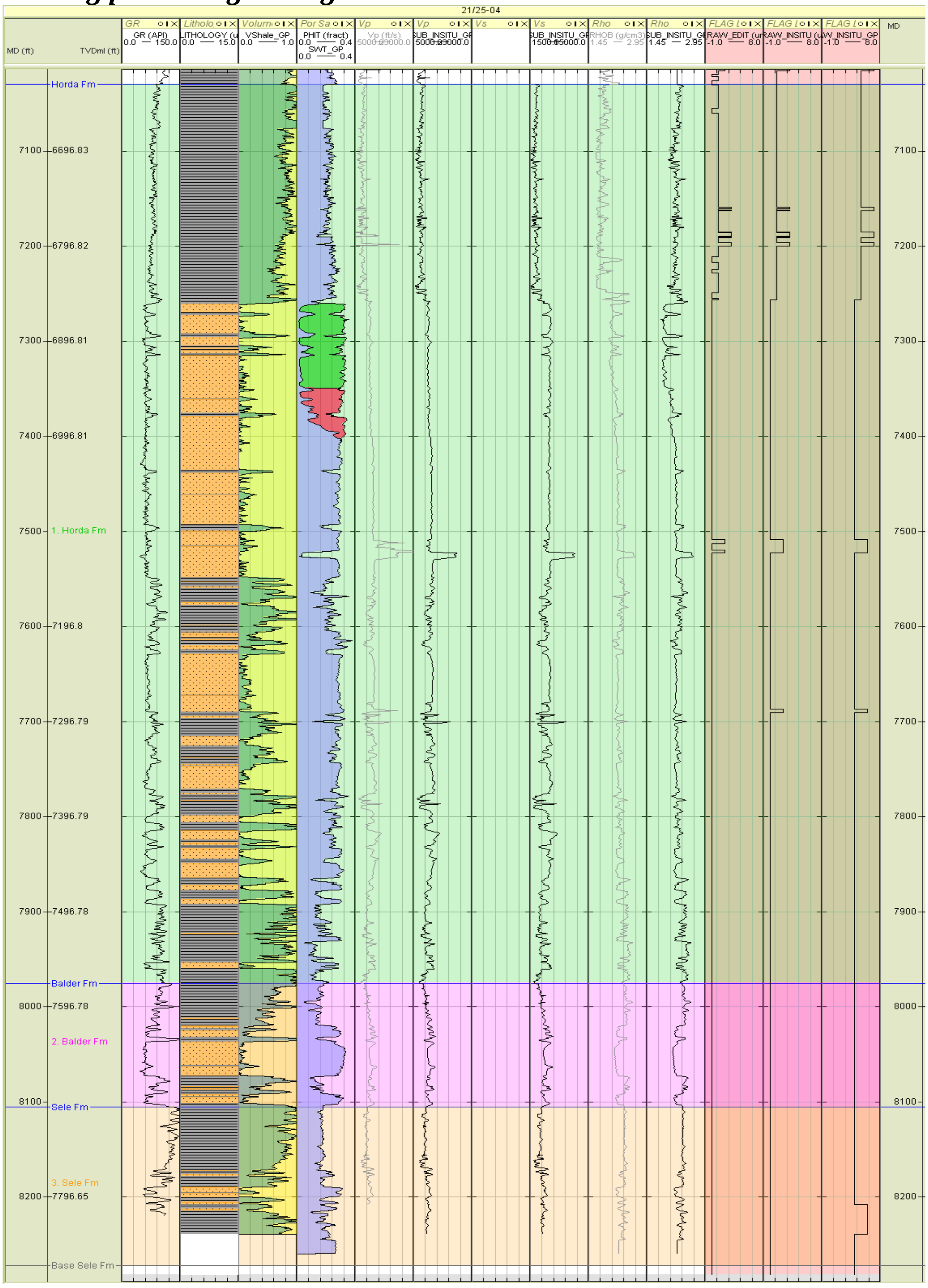


Figure 3.2.4 - Well Panel: Log edits for well 21/20A-04.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

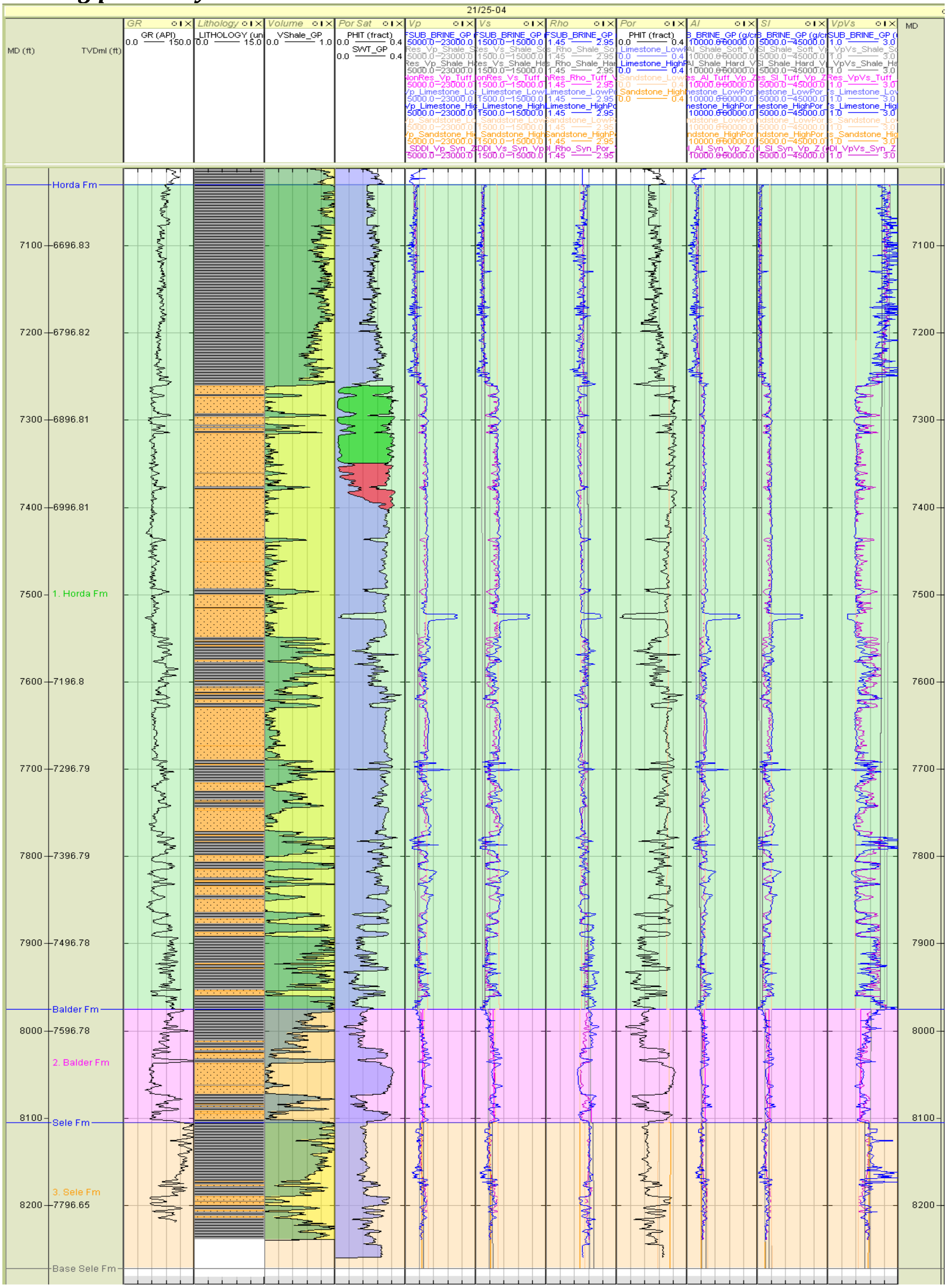


Figure 3.2.5 - Well Panel: End-member and synthetic logs for well 21/25-04.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

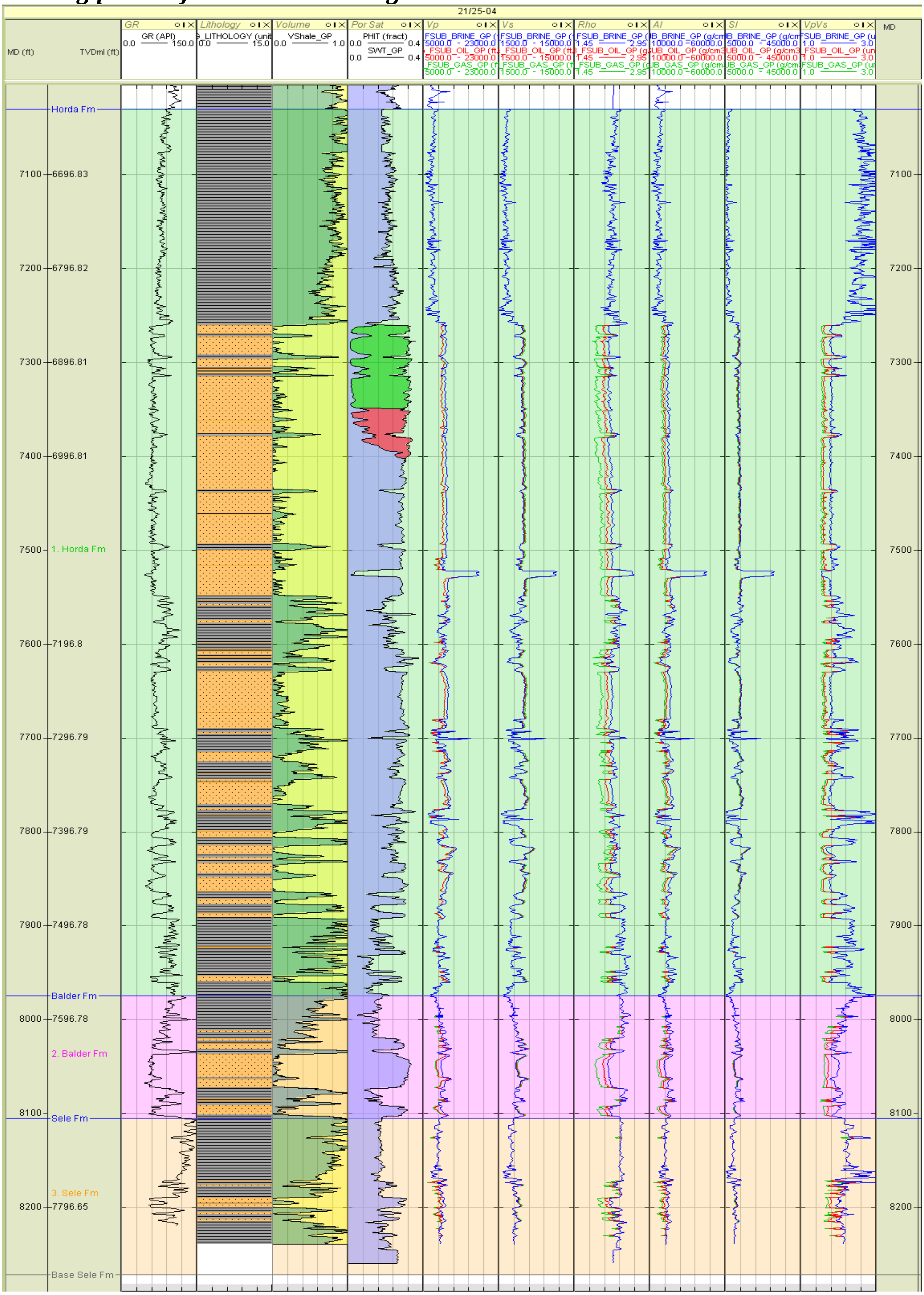


Figure 3.2.6 - Well Panel: Fluid substituted and elastic logs for well 21/25-04.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 21/25-04 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-04	Horda	7828	3162	2.27
21/25-04	Balder	8802	4089	2.40
21/25-04	Sele	8526	3842	2.37

Table 3.2.5. - Clean shale properties at Well 21/25-04

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-04	Horda	100% Brine	10582	5895	2.19
21/25-04	Balder	100% Brine	9950	5168	2.18
21/25-04	Sele	100% Brine	9817	4792	2.22
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-04	Horda	80% Oil	9757	6021	2.10
21/25-04	Balder	80% Oil	9003	5270	2.10
21/25-04	Sele	80% Oil	8789	4880	2.14
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-04	Horda	90% Gas	9755	6209	1.97
21/25-04	Balder	90% Gas	8860	5443	1.97
21/25-04	Sele	90% Gas	8586	5026	2.02

Table 3.2.6 - Clean sand properties at Well 21/25-04 for each fluid case

Tertiary reservoirs

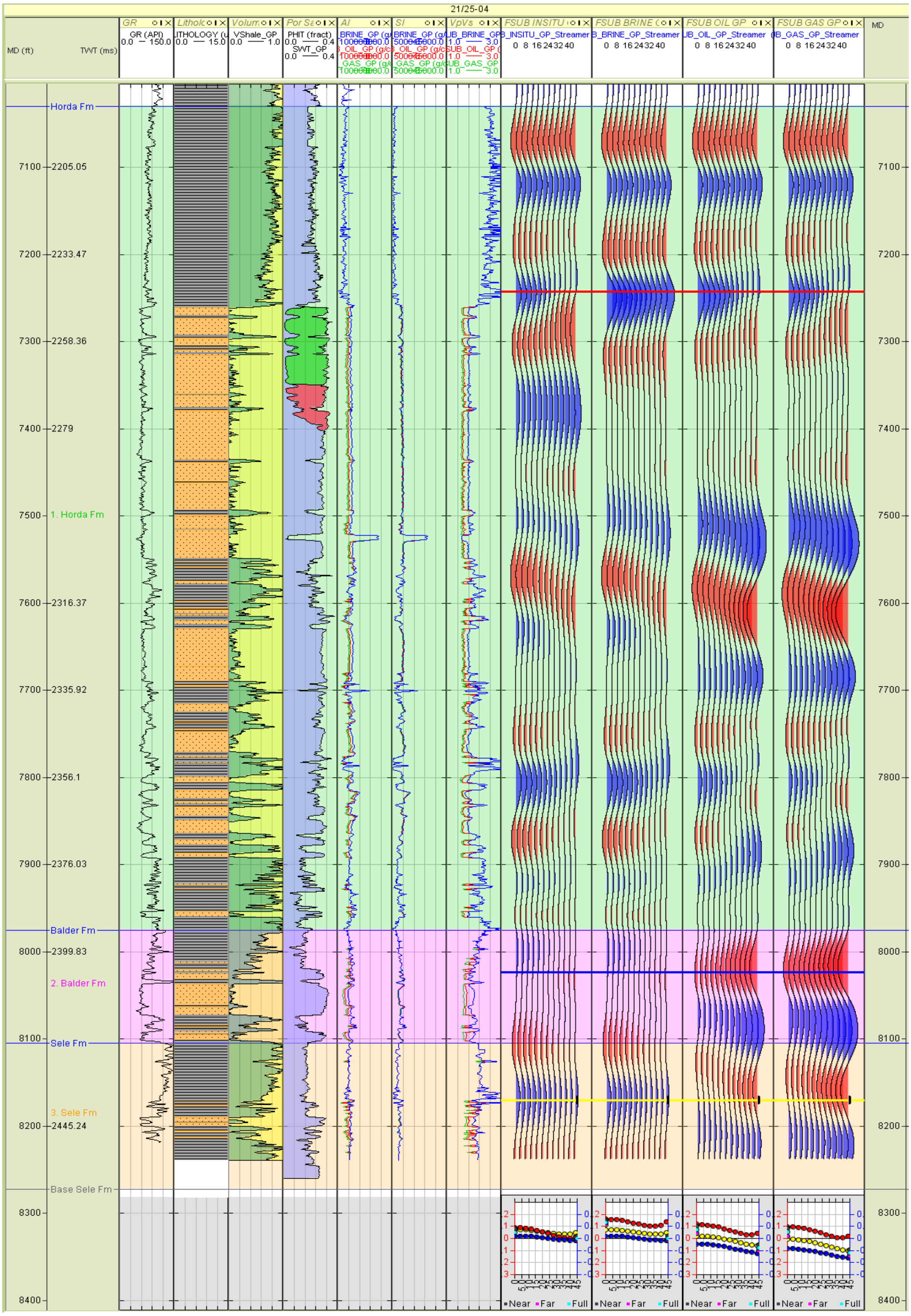


Figure 3.2.7 - Well Panel: Tertiary reservoirs for well 21/25-04. Wavelet: Streamer

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir formed by number of sandstone bodies of the Tay Member, becoming increasingly affected by intra-reservoir shale with depth. Net reservoir is approximately 475 feet containing porosities of 25-36%.
- Blocky AVO shows a modelled class I response for the 100% brine case, and a marginal class I/IIp response for the 80% oil and 90% gas cases. A corresponding response is observed within the synthetic gathers, although the effective phase reversal observed at high incidence angles is reduced, likely due to the presence of intra-reservoir shales.
- Elastic Contrast Analysis shows contrasts are typically strong and positive in the 100% brine case, and in all but a few cases show insensitivity to fluid effects. Mu and MuRho show the least sensitivity to fluid changes, while Lambda and LambdaRho show the most sensitivity to fluid effects.

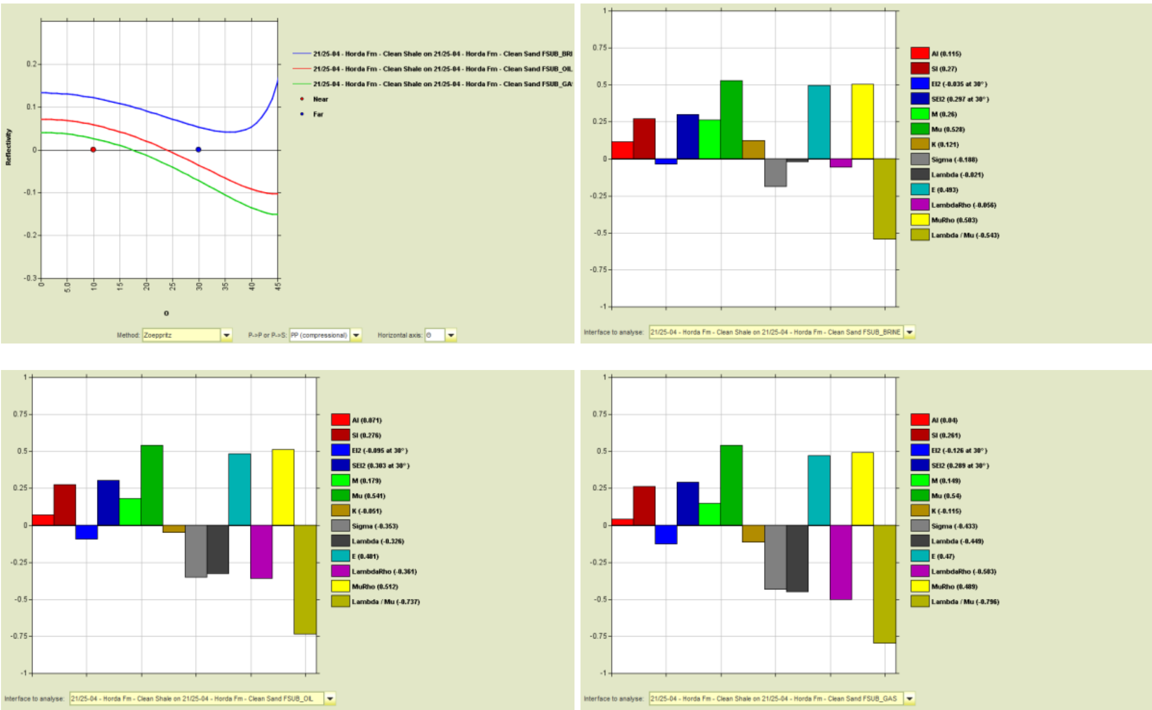


Figure 3.2.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 21/25-04.

Balder Formation

- Reservoir within the formation formed by sands containing two shaling up sequences present at the top and base of the interval. The upper reservoir shales up in to the overlying Horda Formation shale, with a clean blocky sand is observed at the base. Thin intra-reservoir shale is present throughout the reservoir. Net reservoir is approximately 64 feet containing porosities of 26-33%.
- Blocky AVO shows a modelled low gradient marginal class I/IIp response for the 100% brine case, and a class III response for both the 80% oil and 90% gas cases. A corresponding response is observed within the synthetic gathers, where low amplitudes are associated with the top reservoir contact in the absence of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are weak in the 100% brine case, becoming increasingly pronounced with the addition of hydrocarbon fluid fill. Mu shows the least sensitivity to fluid changes. Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

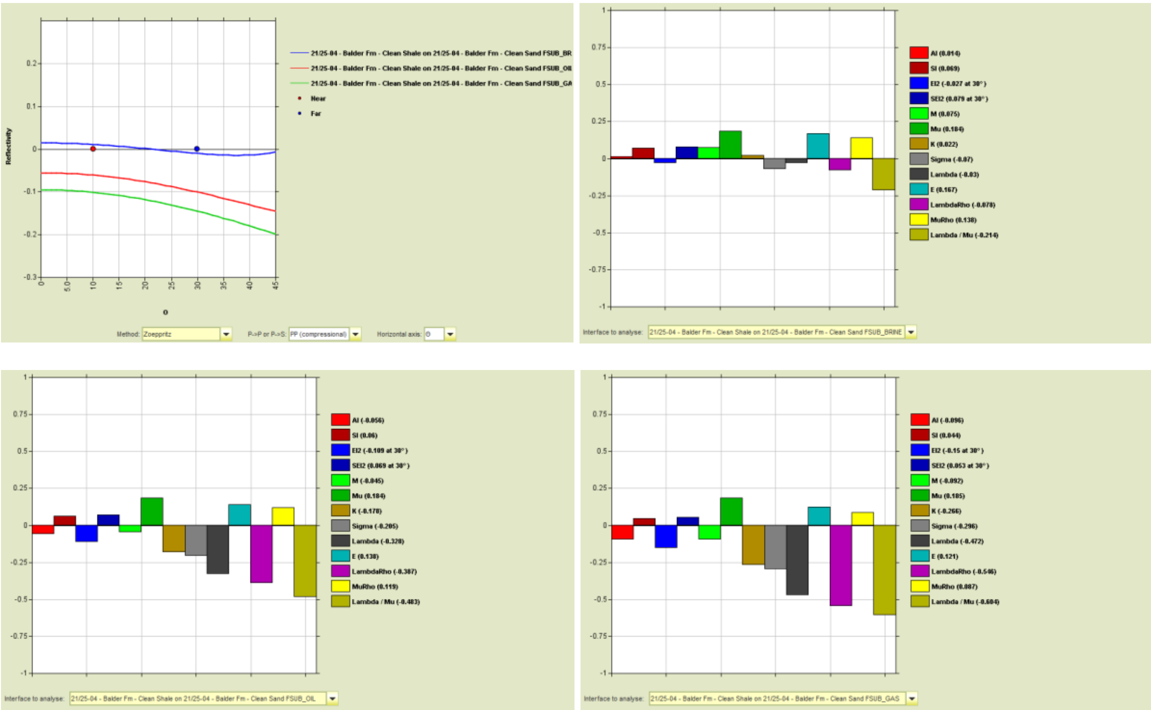


Figure 3.2.9 - Blocky AVO Model and Elastic Contrast Analysis for the Balder Formation in well 21/25-04.

Sele Formation

- Reservoir is formed by a number of thin sands (approximately 3-11 feet thick) separated by silty intervals towards the centre of the formation. It is unclear what lies beneath the reservoir as the well terminates just below the apparent reservoir base. The reservoir is overlain by thick clean shale. Net reservoir is approximately 29 feet with porosities of 17-32%.
- Blocky AVO shows a modelled class I response for the 100% brine case, and class II and III responses for 80% oil and 90% gas cases respectively. Within the synthetic gathers, corresponding AVO responses are observed for all fluid cases.
- Elastic Contrast Analysis shows contrasts are often moderate and positive in the 100% brine case, and become increasingly negative in the 80% oil and 90% gas cases. Mu shows the least sensitivity to fluid changes, while Lambda and LambdaRho show the most sensitivity to fluid effects.

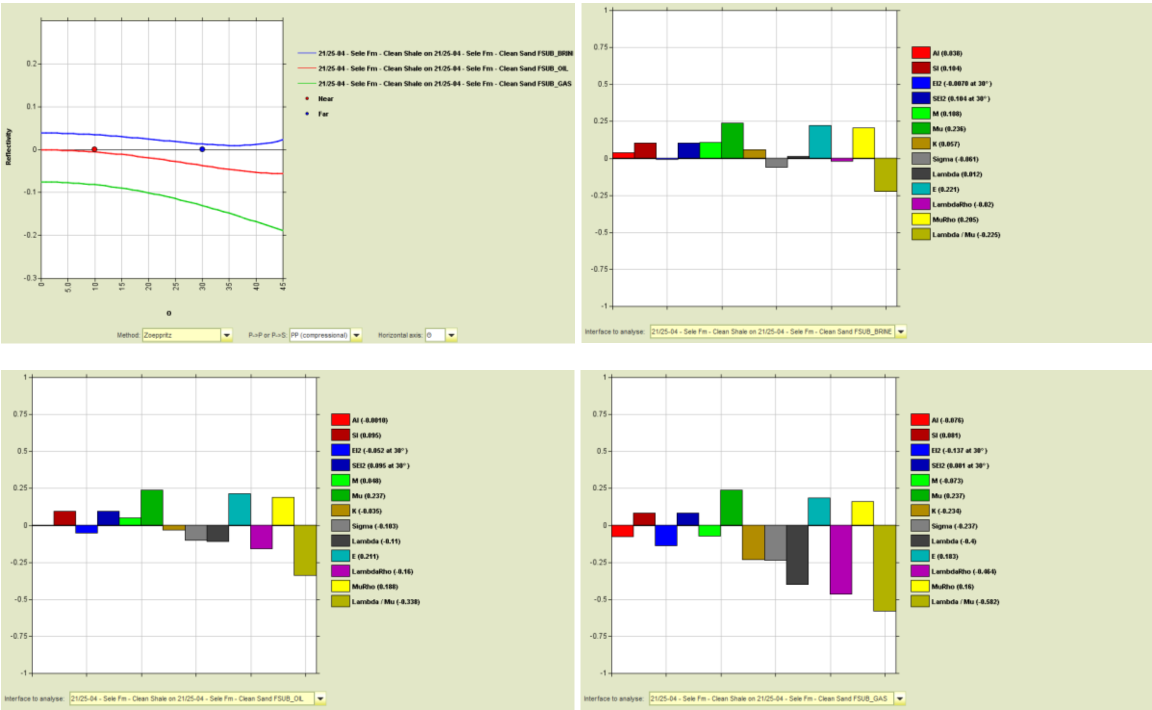


Figure 3.2.10 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 21/25-04.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/02A-06 is provided below;
There is no Cretaceous section at this well.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 21/25-04 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-04	Overburden	Shale	7457		
21/25-04	Underburden				

Table 3.2.7 - Overburden and underburden properties at Well 21/25-04.

Well: 21/25-06

General

Well Information
Shell operated appraisal well for the Gannet B field. Spudded, completed and abandoned in 1983, the well encountered oil and gas in the Horda Formation (Tay Member).

Objectives
The well was drilled to evaluate Palaeocene sands and Upper Cretaceous chalk. The Palaeocene Horda Formation (Tay Member) was present encountering oil and gas .The Balder Formation (Odin Member), Sele Formation (Gannet, Forties Members) and Upper Cretaceous Chalk Group were present but wet.

Log conditioning overview
Log data quality within the well is generally of good quality. The caliper log shows only localised borehole washout in the Horda Formation, although some concern is raised by the density and density correction log, both of which contain spikes throughout the well. Thin calcite stringers below the resolution of the density log were removed.

Invasion correction
Invasion correction performed on the density log solely within the oil and gas bearing Horda Formation. The drilling mud used within this well was water based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Sele, Lista and Ekofisk Formations for Vp and within the Horda and Lista Formations for density. In the absence of measured shear log data, a complete Vs log is modelled using Modified Gassmann methodology due to the presence of hydrocarbons within this well.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoint's.

P&T data

The temperature and pressure data for Well 21/25-06 is displayed in the figures below;

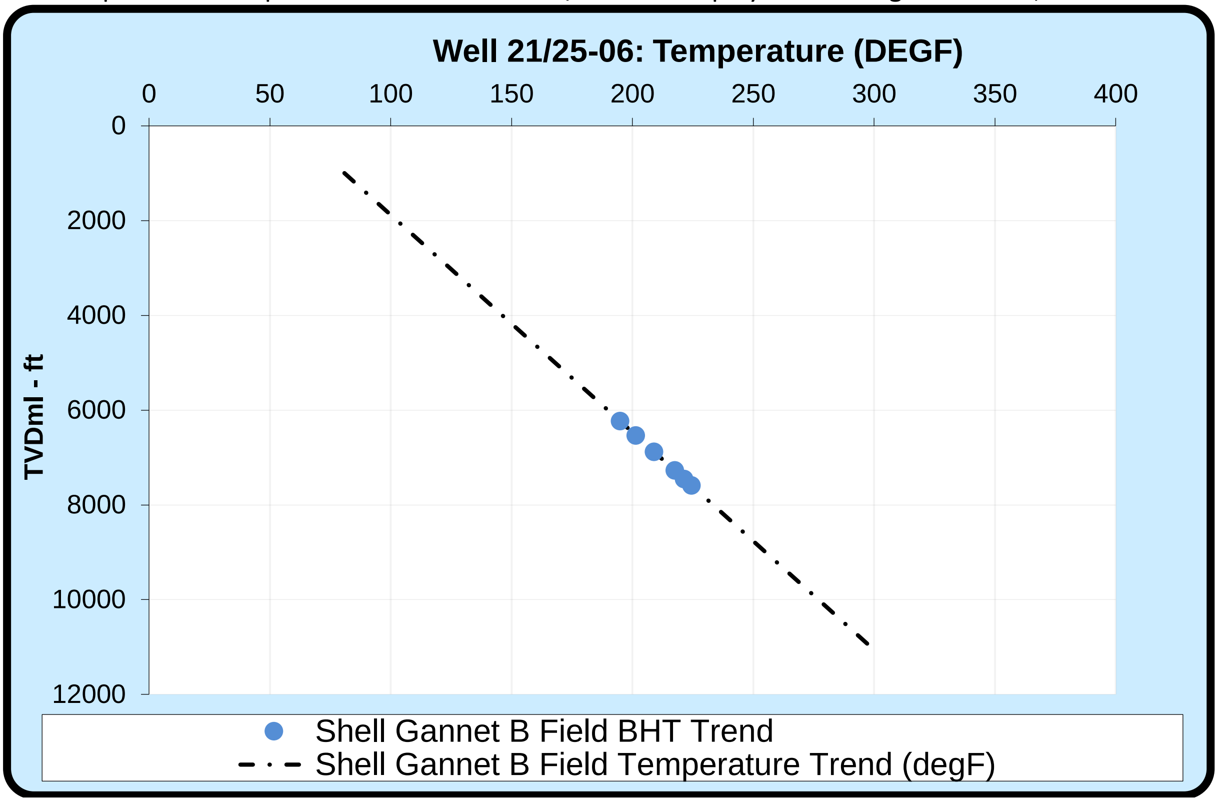


Figure 3.3.1 - Temperature data at Well 21/25-06

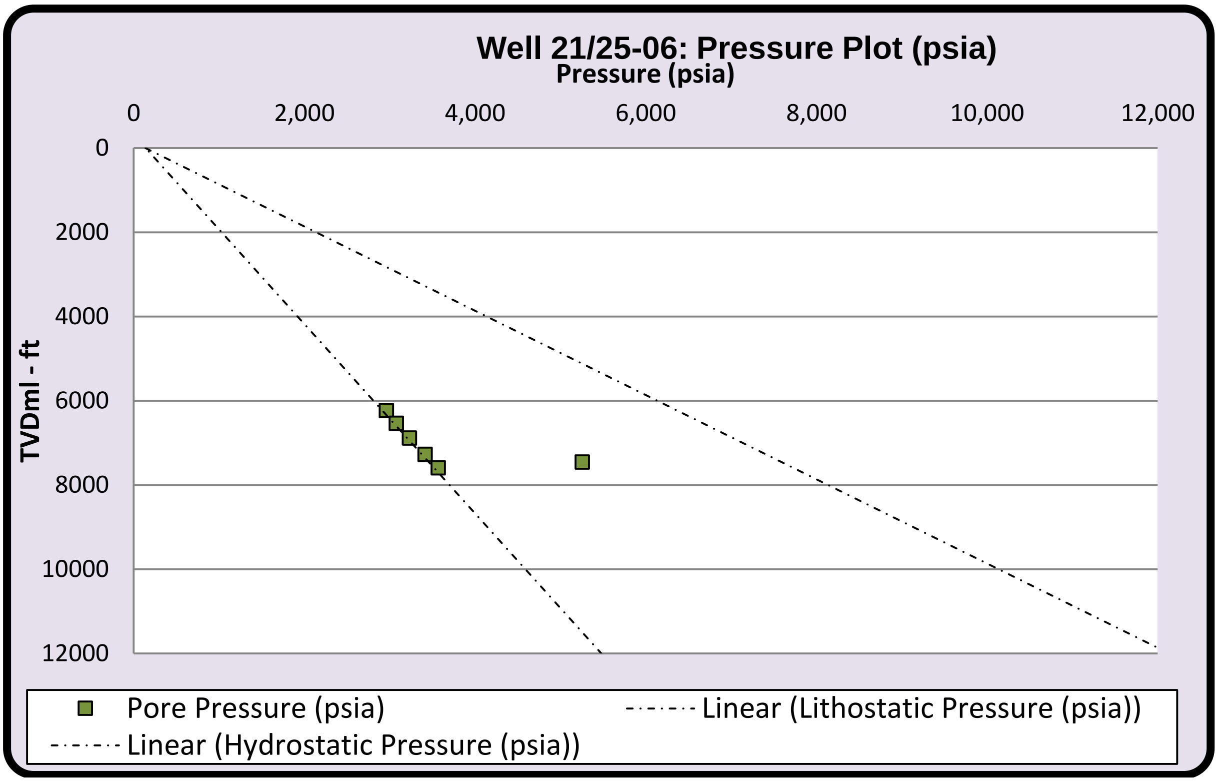


Figure 3.3.2 - Pressure data at Well 21/25-06

The temperature and pressure data for the formation mid-points in Well 21/25-06 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
21/25-06	Sea Bed	399.0	317.0	0.0	39.2	141.1	141.1	141.06	0.00
21/25-06	Horda	6634.0	6551.2	6234.2	194.9	2915.3	2963.3	6375.23	3411.96
21/25-06	Balder	6933.0	6849.9	6532.9	201.4	3048.2	3078.2	6673.98	3595.77
21/25-06	Sele	7283.5	7200.1	6883.1	209.1	3204.1	3234.1	7024.21	3790.14
21/25-06	Lista	7676.5	7592.8	7275.8	217.6	3378.8	3418.8	7416.91	3998.09
21/25-06	Maureen	7855.5	7771.6	7454.6	221.5	3458.4	5258.4	7595.70	2337.32
21/25-06	Ekofisk	7994.0	7909.6	7592.6	224.5	3519.8	3569.8	7733.70	4163.91
21/25-06	Tor	399.0	317.0	0.0	39.2	141.1	141.1	141.06	0.00
21/25-06	Hod	6634.0	6551.2	6234.2	194.9	2915.3	2963.3	6375.23	3411.96

Table 3.3.1 - Summary of mid-point temperature and pressure data at Well 21/25-06

Fluid data

A summary of the fluid set parameters at Well 21/25-06 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
21/25-06	Horda	782	40.0	0.83	0.83	782
21/25-06	Balder	730	38.4	0.71	0.71	730
21/25-06	Sele	730	38.8	0.71	0.71	730
21/25-06	Lista	730	39.2	0.71	0.71	730
21/25-06	Maureen	730	39.4	0.71	0.71	730
21/25-06	Ekofisk	730	39.6	0.71	0.71	730
21/25-06	Tor	782	40.0	0.83	0.83	782
21/25-06	Hod	730	38.4	0.71	0.71	730

Table 3.3.2 - Summary of fluid parameter data at Well 21/25-06 Mineral data

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.3.3 - Constant mineral properties used in this project

There is no Tuff present in this well.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
21/25-06	Horda	PAY	450.000	50.750	0.113	16.976	0.334	0.235	0.086
21/25-06	Horda	RES	450.000	63.000	0.140	20.819	0.330	0.304	0.124
21/25-06	Balder	PAY	148.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-06	Balder	RES	148.000	72.500	0.490	22.464	0.310	0.973	0.161
21/25-06	Sele	PAY	553.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-06	Sele	RES	553.000	428.000	0.774	111.918	0.261	0.980	0.162
21/25-06	Lista	PAY	233.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-06	Lista	RES	233.000	3.250	0.014	0.598	0.184	0.749	0.261
21/25-06	Maureen	PAY	125.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-06	Maureen	RES	125.000	26.125	0.209	4.537	0.174	0.924	0.330
21/25-06	Ekofisk	PAY	152.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-06	Ekofisk	RES	152.000	129.845	0.854	22.530	0.173	0.950	0.150

Table 3.3.4 - Petrophysical parameters used at Well 21/25-06

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

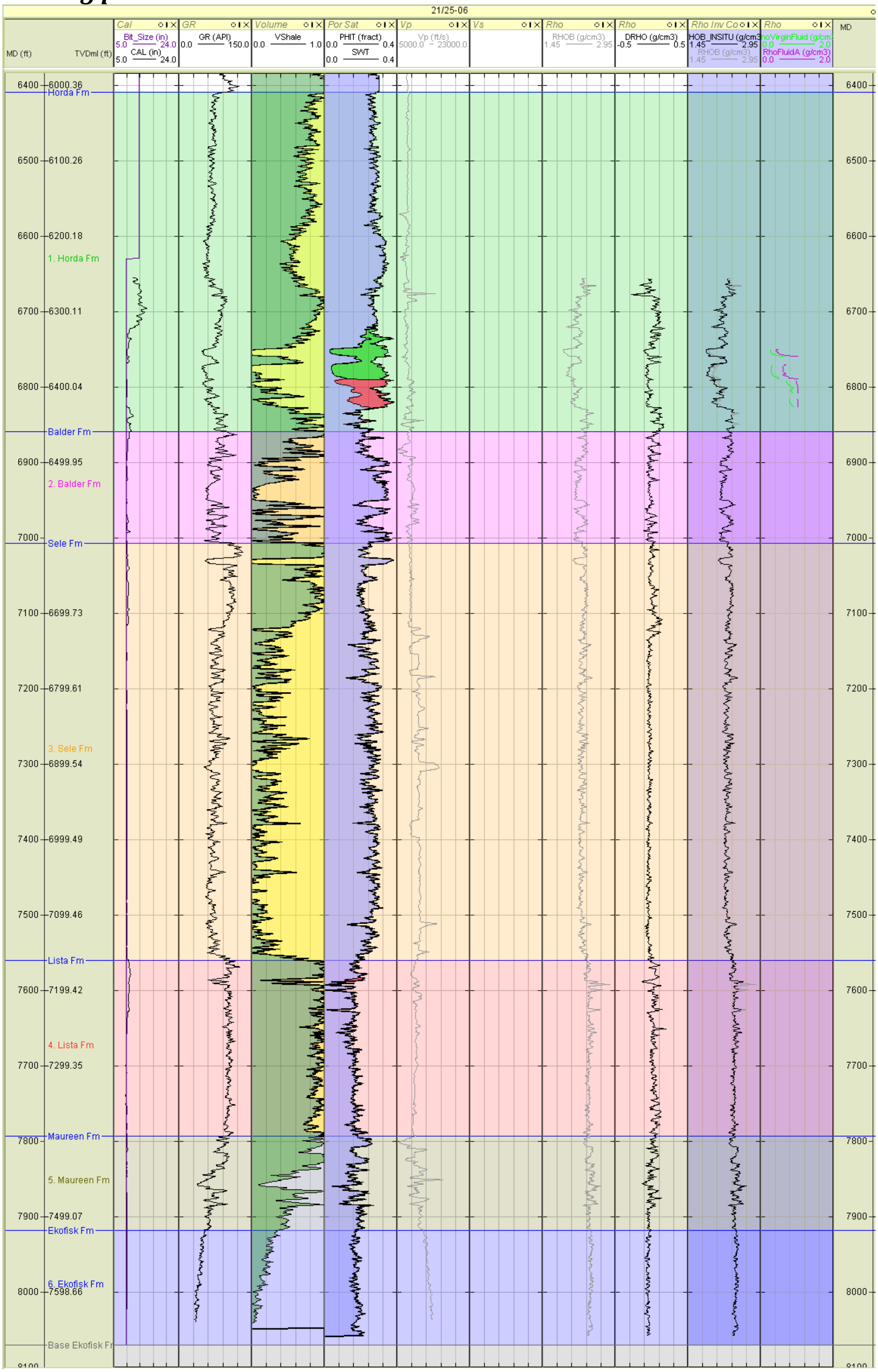


Figure 3.3.3 - Well Panel: Measured data and invasion correction for well 21/25-06.

Well log panel – log editing and audit

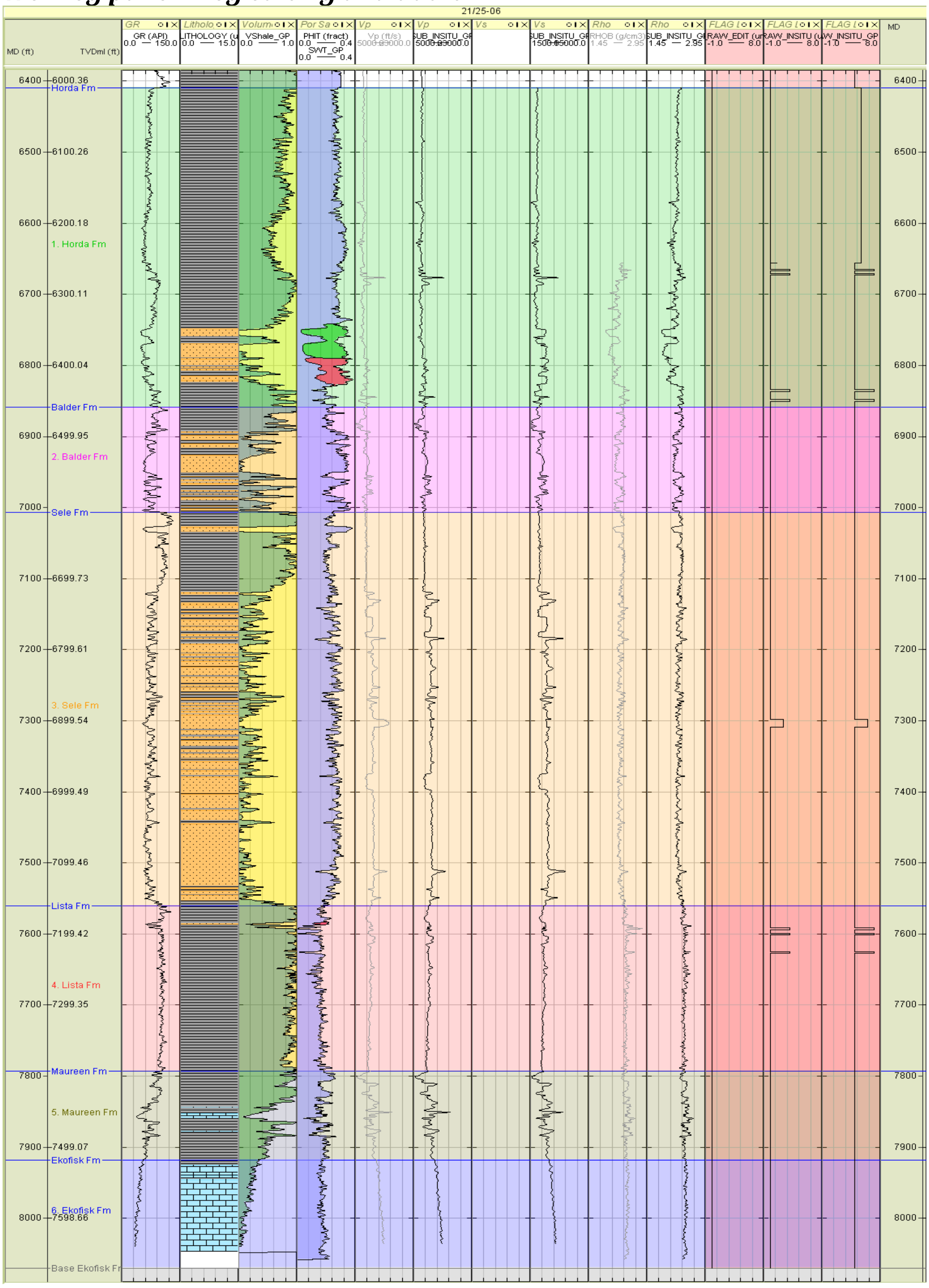


Figure 3.3.4 - Well Panel: Log edits for well 21/25-06.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

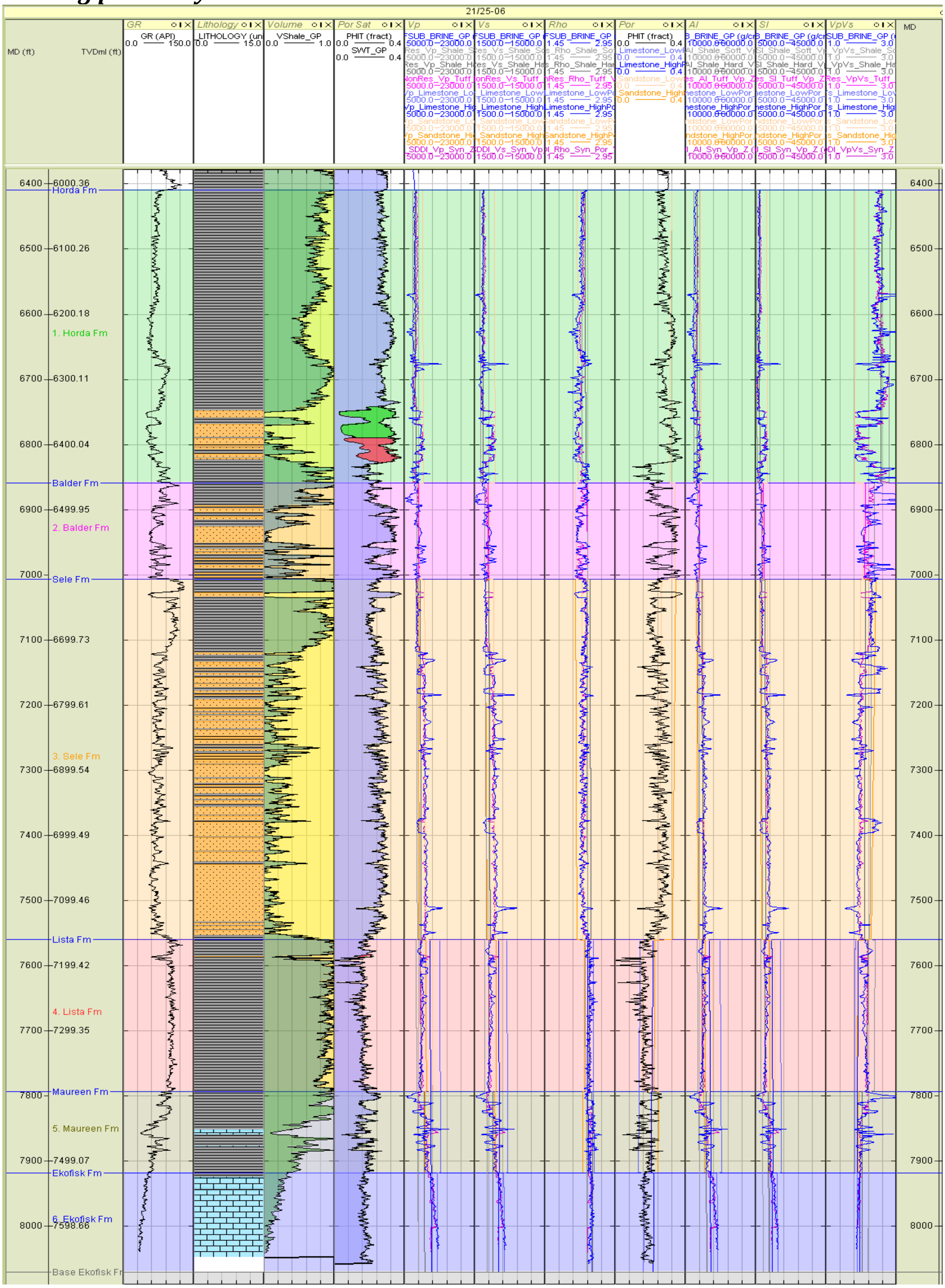


Figure 3.3.5 - Well Panel: End-member and synthetic logs for well 21/25-06.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

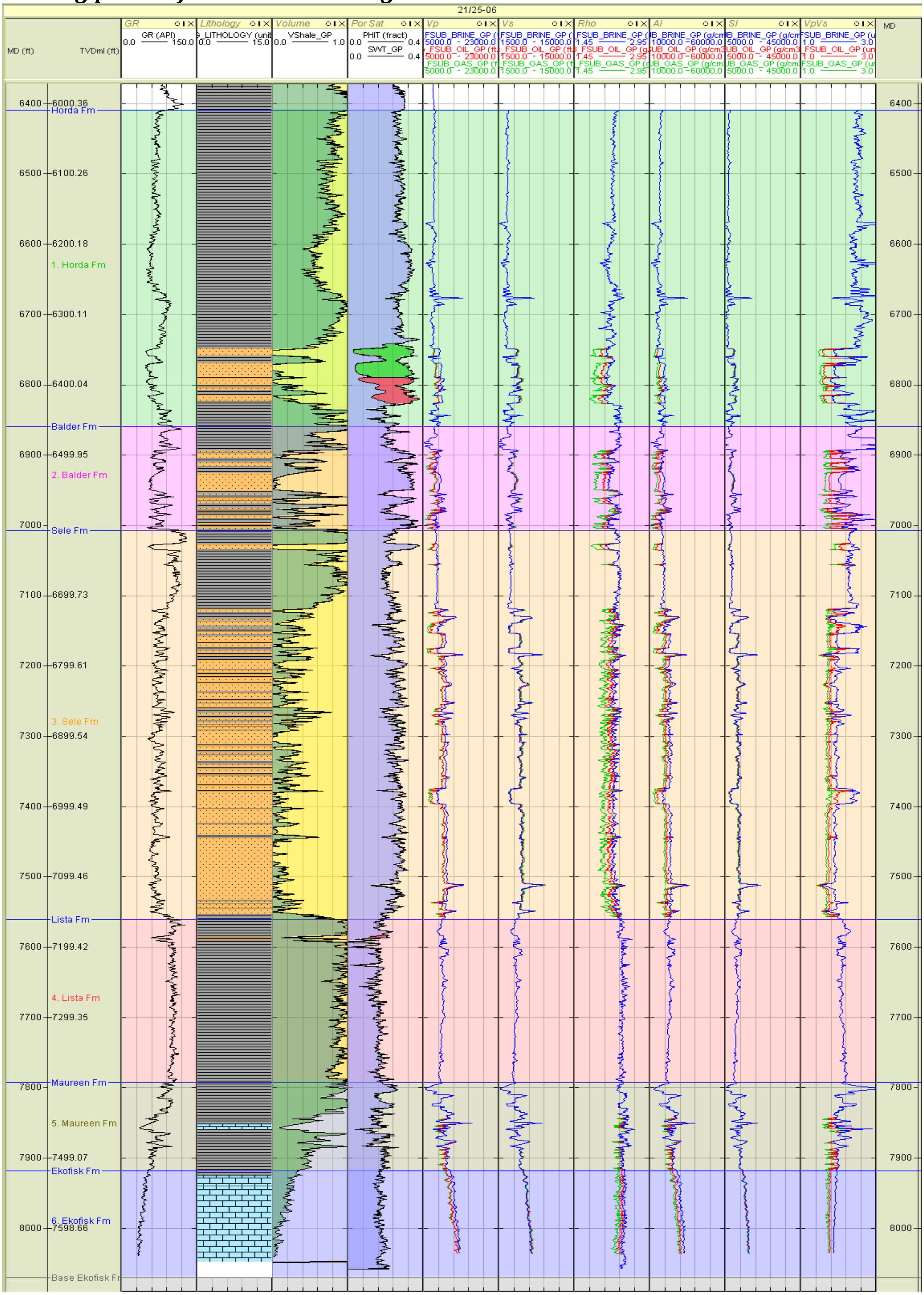


Figure 3.3.6 - Well Panel: Fluid substituted and elastic logs for well 21/25-06.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 21/25-06 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-06	Horda	7559	2989	2.23
21/25-06	Balder	7449	2852	2.29
21/25-06	Sele	8264	3645	2.32
21/25-06	Lista	9438	4474	2.40
21/25-06	Maureen	8903	4149	2.41

Table 3.3.5 - Clean shale properties at Well 21/25-06

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-06	Horda	100% Brine	9263	4875	2.11
21/25-06	Balder	100% Brine	8840	4229	2.16
21/25-06	Sele	100% Brine	10250	5247	2.24
21/25-06	Lista	100% Brine			
21/25-06	Maureen	100% Brine	10436	4983	2.46
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-06	Horda	80% Oil	8138	4999	2.01
21/25-06	Balder	80% Oil	7655	4322	2.07
21/25-06	Sele	80% Oil	9408	5340	2.16
21/25-06	Lista	80% Oil			
21/25-06	Maureen	80% Oil	9392	5027	2.42
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-06	Horda	90% Gas	7996	5191	1.87
21/25-06	Balder	90% Gas	7384	4490	1.92
21/25-06	Sele	90% Gas	9305	5502	2.04
21/25-06	Lista	90% Gas			
21/25-06	Maureen	90% Gas	8960	5101	2.35

Table 3.3.6 - Clean sand properties at Well 21/25-06 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-06	Maureen	100% Brine	10,436	4,983	2.46
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-06	Maureen	80% Oil	9,392	5,027	2.42
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-06	Maureen	90% Gas	8,960	5,101	2.35

Table 3.3.7 - Clean limestone properties at Well 21/25-06 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

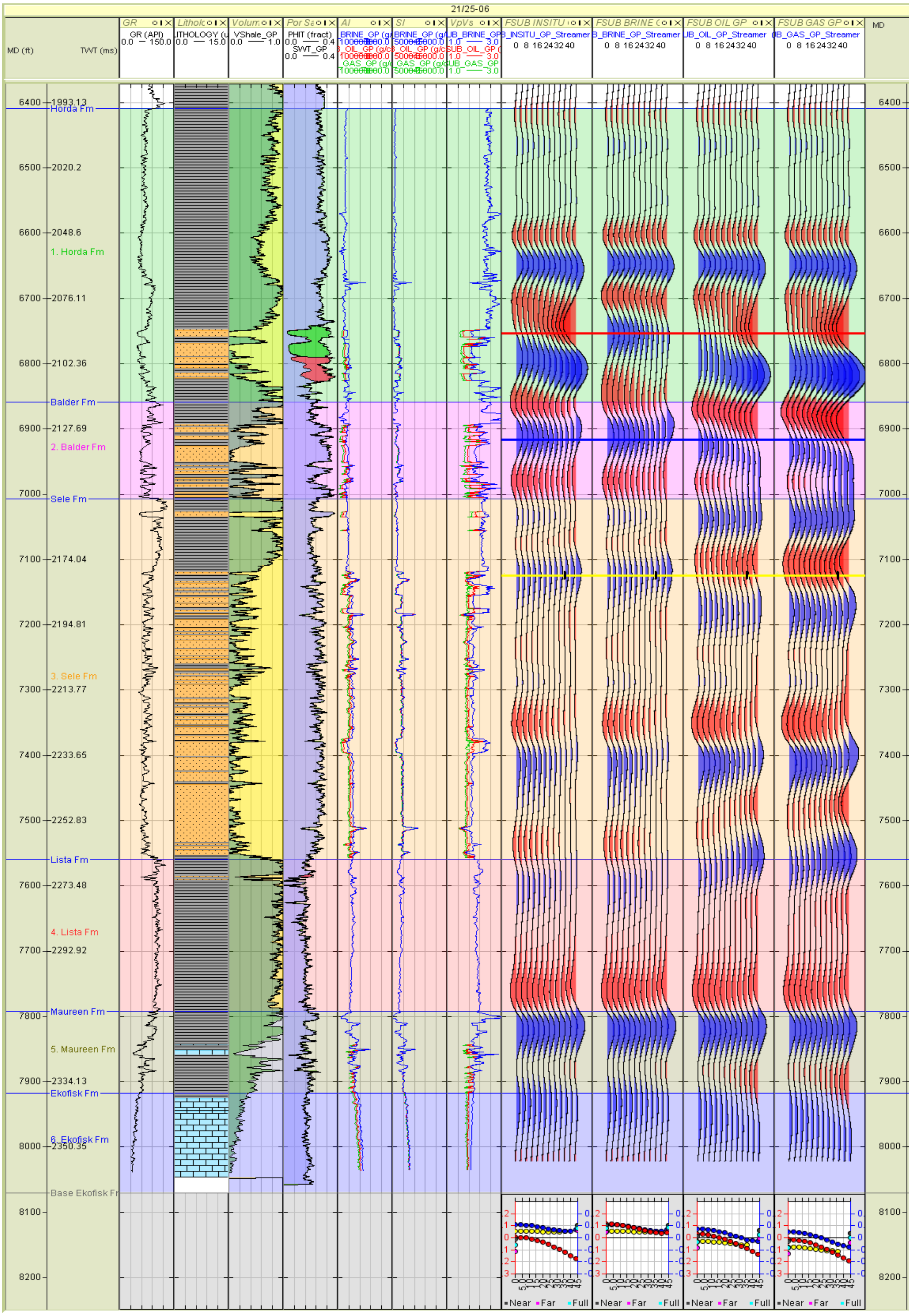


Figure 3.3.7 - Well Panel: Tertiary reservoirs for well 21/25-06. Wavelet: Streamer

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir formed by blocky sandstone with intra-reservoir shales towards the bottom of the formation. Reservoir is bound to the top and base by silty shale. Net reservoir is approximately 63 feet containing porosities of 25-37%.
- Blocky AVO shows a modelled class I response for the 100% brine case, a class II response for the 80% oil case and class III response for the 90% gas case. Within the synthetic gathers, the 100% brine and 80% oil cases show a class I AVO response, and the 90% gas case shows a marginal class II response. This variation between the modelled and synthetic gather responses is likely due to wavelet interference caused the silty lithology present at top reservoir contact and presence of intra-reservoir shale.
- Elastic Contrast Analysis shows contrasts are often positive in the 100% brine case, becoming strongly negative in the 80% oil and 90% gas cases. Mu shows the least sensitivity to fluid changes, while Lambda and LambdaRho show the most sensitivity to fluid effects.

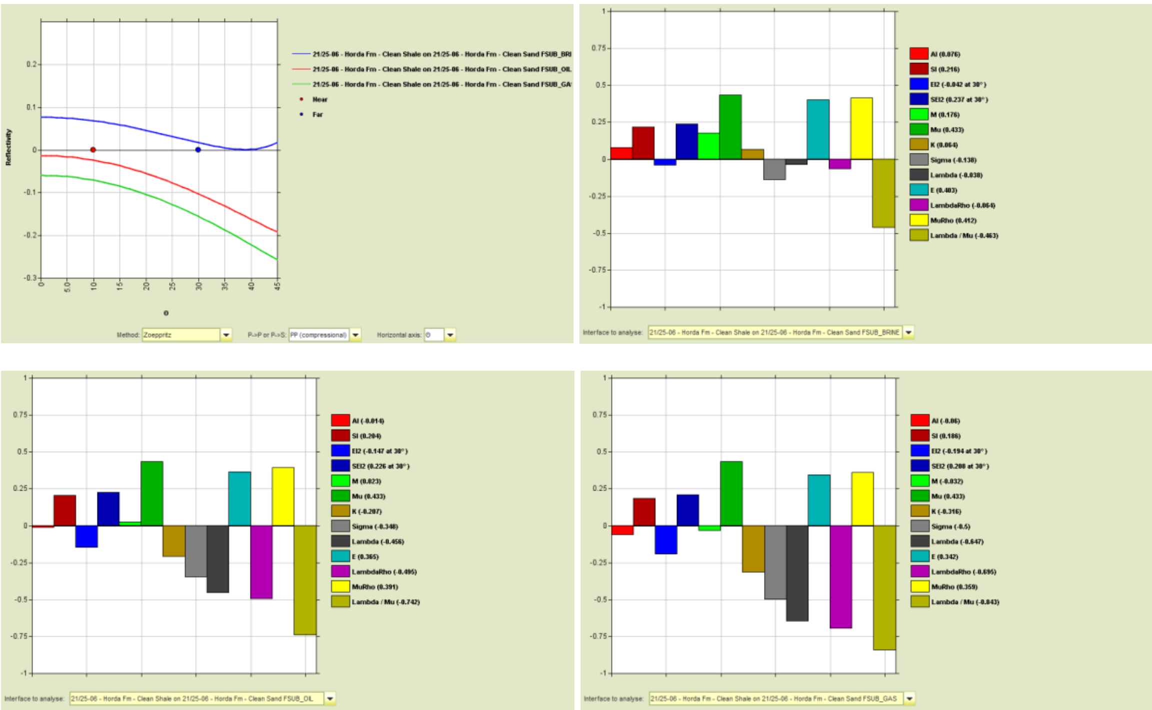


Figure 3.3.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 21/25-06.

Balder Formation

- Reservoir formed by interlayered sands and shales throughout the interval, individual sand bodies range from 2-28 feet in thickness. Reservoir sands are encased within shale, but lie in close vertical proximity to reservoir of the Horda and Sele Formations. Net reservoir is approximately 73 feet with porosities of 31-37%.
- Blocky AVO shows a modelled class I response for the 100% brine case, and class III responses for both the 80% oil and 90% gas case. Within the synthetic gathers, a class I AVO response is seen in the 100% brine case, a marginal class I/IIp response in the 80% oil case and class IIp response in the 90% gas case. Variation is likely due wavelet interference caused by the close proximity to the overlying Horda Formation base reservoir and presence of intra-reservoir shale.
- Elastic Contrast Analysis shows contrasts are usually moderate and positive in the 100% brine case, becoming increasingly negative with the addition of hydrocarbons. Mu shows the least sensitivity to fluid changes. Lambda and LambdaRho show the most sensitivity to fluid effects.

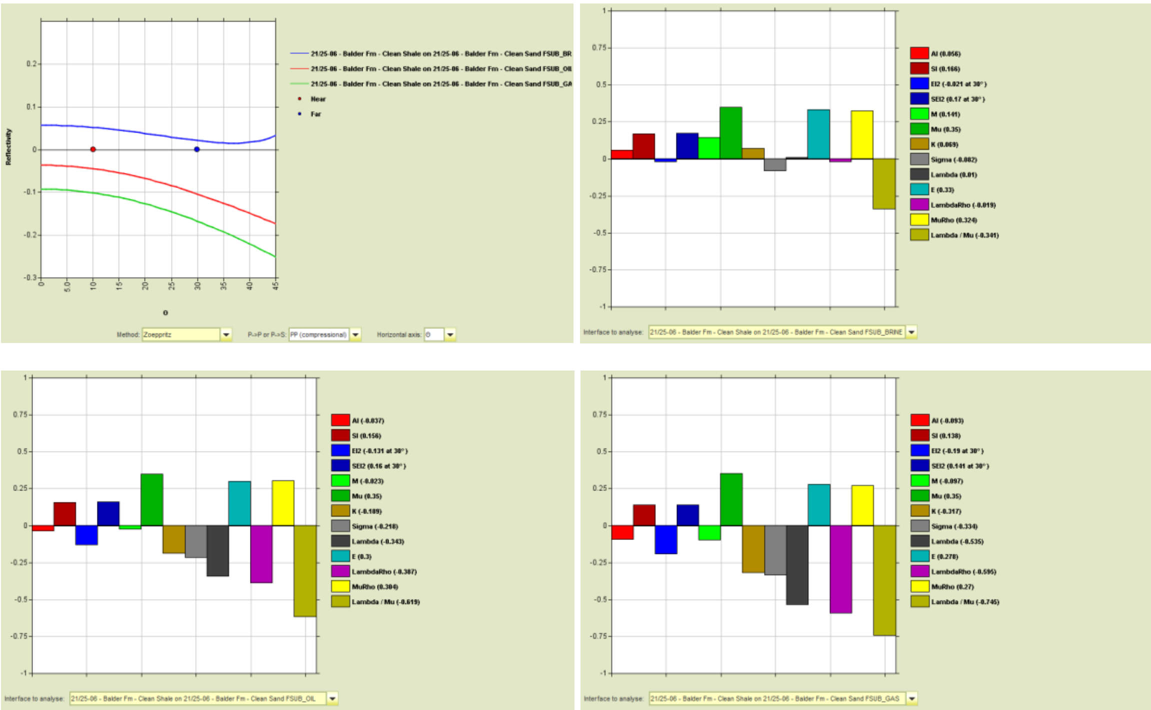


Figure 3.3.9 - Blocky AVO Model and Elastic Contrast Analysis for the Balder Formation in well 21/25-06.

Sele Formation

- Reservoir within the formation falls within two clusters, an upper thin clean sand of the Gannet Member and lower thick sand exhibiting shaling up of the Forties Member. The upper Gannet Member sandstone lies in close proximity to overlying Balder Formation reservoir, with relatively clean shale contacts observed elsewhere. Net reservoir within the entire formation is 428 feet. Porosities of 34-38% are observed within the Gannet Member, and 22-32% within the Forties Member.
- Blocky AVO shows a modelled class I response for the 100% brine case, a marginal class I/IIp response for the 80% oil case, and class II response for the 90% gas case. Within the synthetic gathers, neither sandstone member exhibits the modelled response. The seismic signature of the Gannet Member appears to be highly influenced by the overlying Balder Formation reservoir showing a low gradient class I AVO response. The Forties Formation shows a top reservoir AVO class I in the 100% brine case, and class III response in both the 80% oil and 90% gas cases, with the observed difference likely to be caused through constructive wavelet interference caused by internal reservoir reflectors.
- Elastic Contrast Analysis shows contrasts are usually moderate and positive in the 100% brine case, showing relative insensitivity to fluid effects. Mu shows the least sensitivity to fluid changes. Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

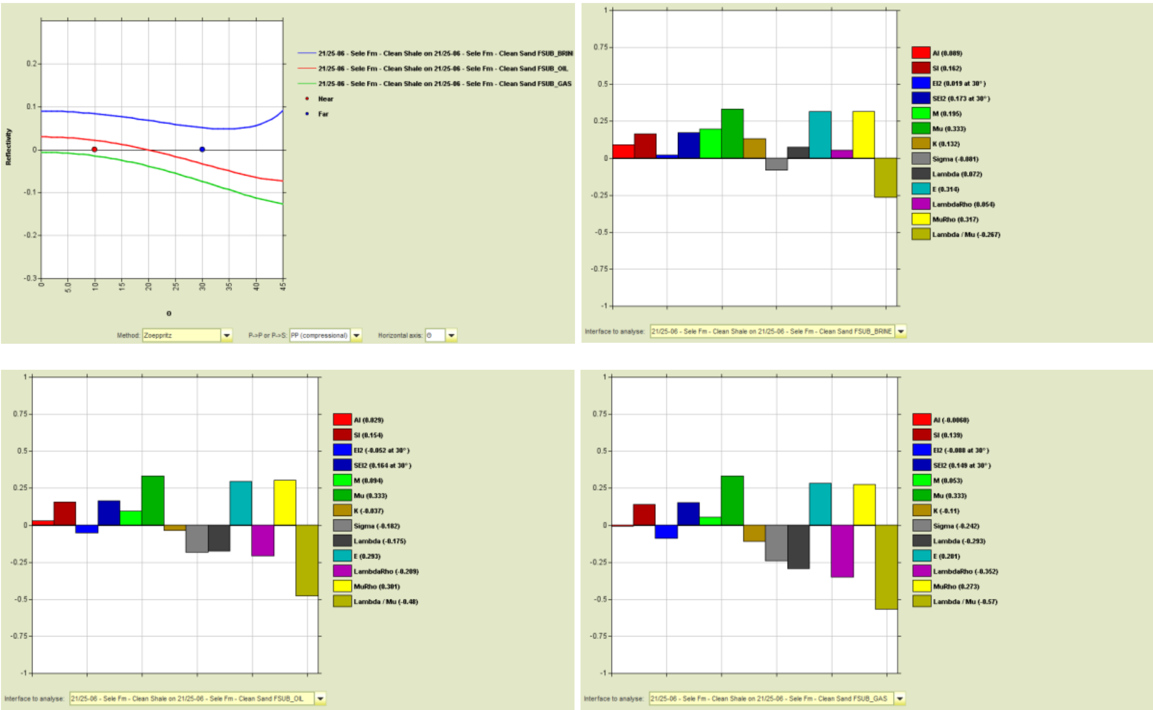


Figure 3.3.10 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 21/25-06.

Maureen Formation

- Reservoir formed by a thin limestone section in the middle of the interval and a calcareous shale towards the base of the interval, net reservoir is approximately 26 feet.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases and a modelled class II response for the 90% gas case, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the 100% brine case, but contrasts generally become negative for most attributes with the addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda and LambdaRho show the most sensitivity to fluid effects.

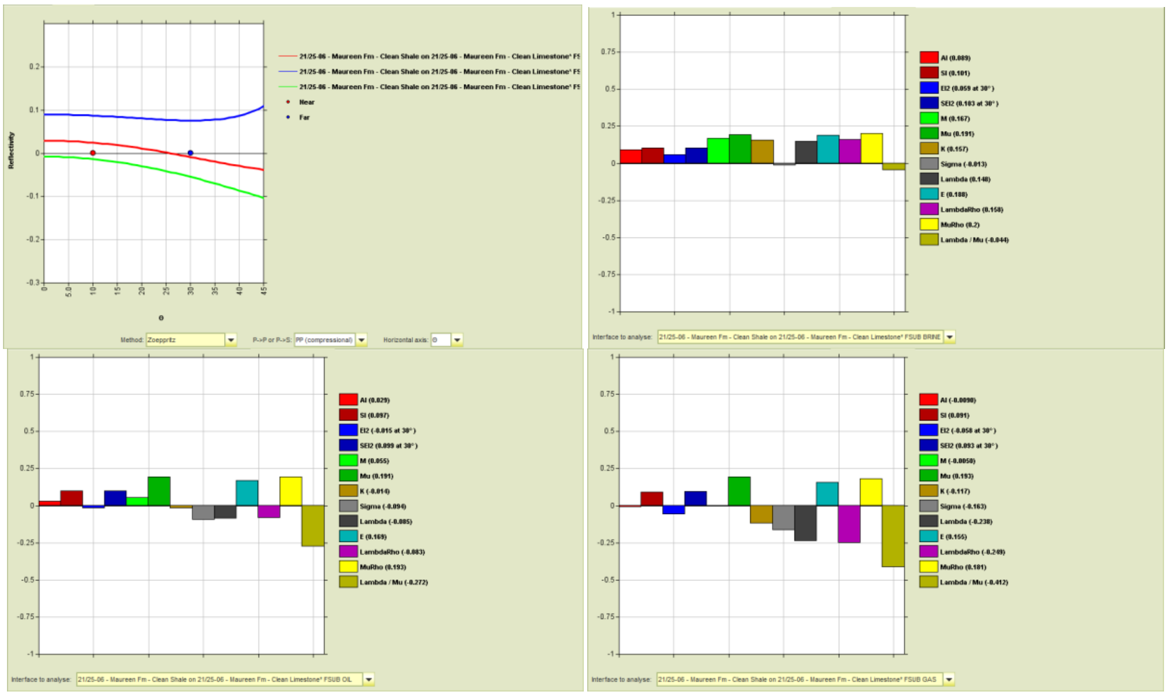


Figure 3.3.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 21/25-06.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 21/25-06 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-06	Ekofisk	100% Brine	13393	7147	2.42
21/25-06	Tor	100% Brine			
21/25-06	Hod	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-06	Ekofisk	80% Oil	12733	7229	2.36
21/25-06	Tor	80% Oil			
21/25-06	Hod	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-06	Ekofisk	90% Gas	12701	7362	2.28
21/25-06	Tor	90% Gas			
21/25-06	Hod	90% Gas			

Table 3.3.8 - Clean limestone properties at Well 21/25-06 for each fluid case

Cretaceous reservoirs

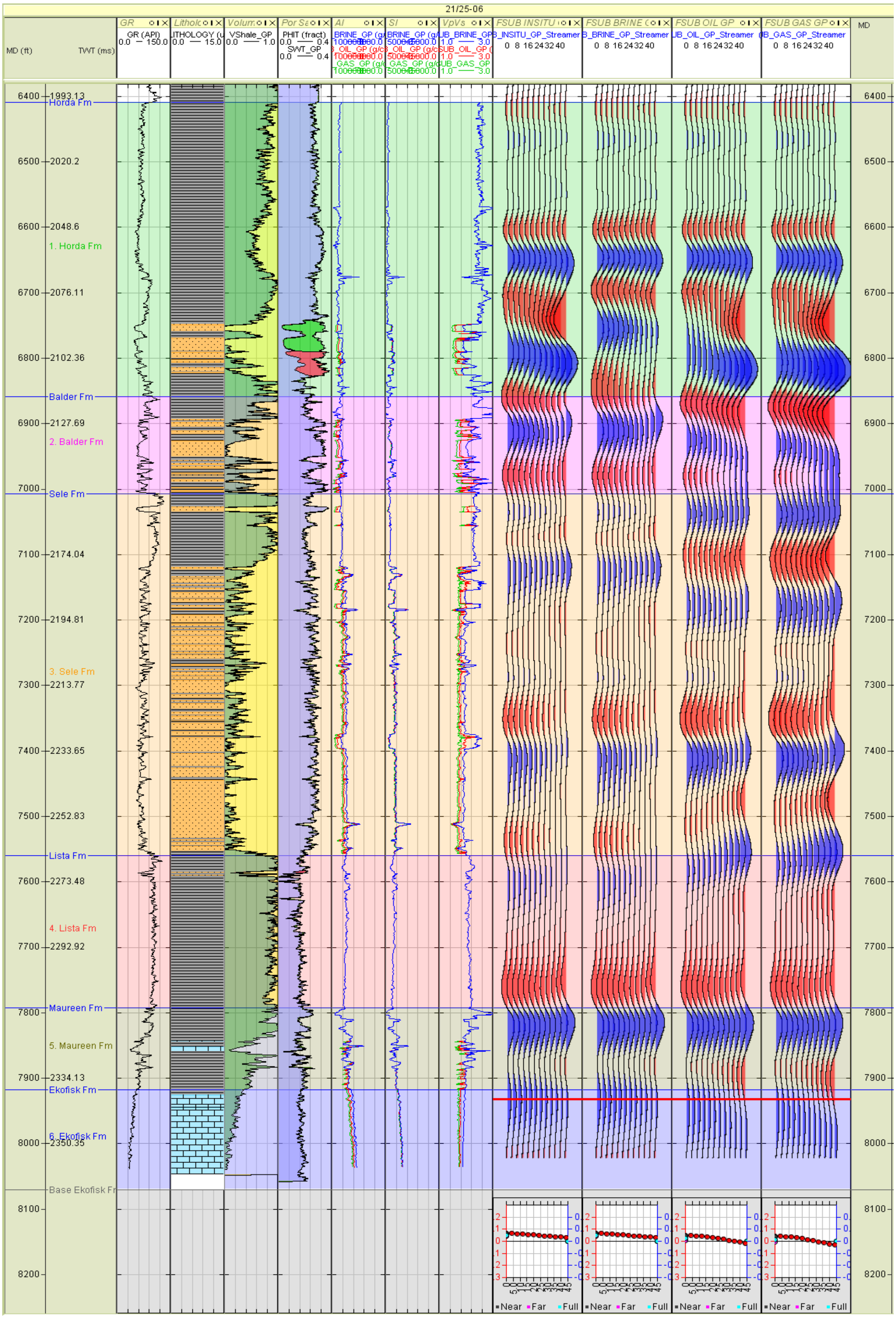


Figure 3.3.12 - Well Panel: Cretaceous reservoirs for well 21/25-06. Wavelet: Streamer

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir only partially exposed as well terminates within the Ekofisk Formation. The interval shales up in to the overlying chalk reservoir of the Maureen Formation, and contains relatively high porosities of around 14-23%. Net reservoir is approximately 193 feet.
- Blocky AVO modelling shows a class I response predicted in each fluid case. Within the synthetic gathers, a corresponding class I AVO response is observed for each fluid case, with the additional presence of a phase reversal occurring in the 80% oil and 90% gas cases at high incidence angles. This is likely due to wavelet interference with the base reservoir response of the overlying Maureen Formation reservoir.
- Elastic Contrast Analysis shows contrasts are often strong and positive in the 100% brine case, but show little sensitivity to fluid effects. Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

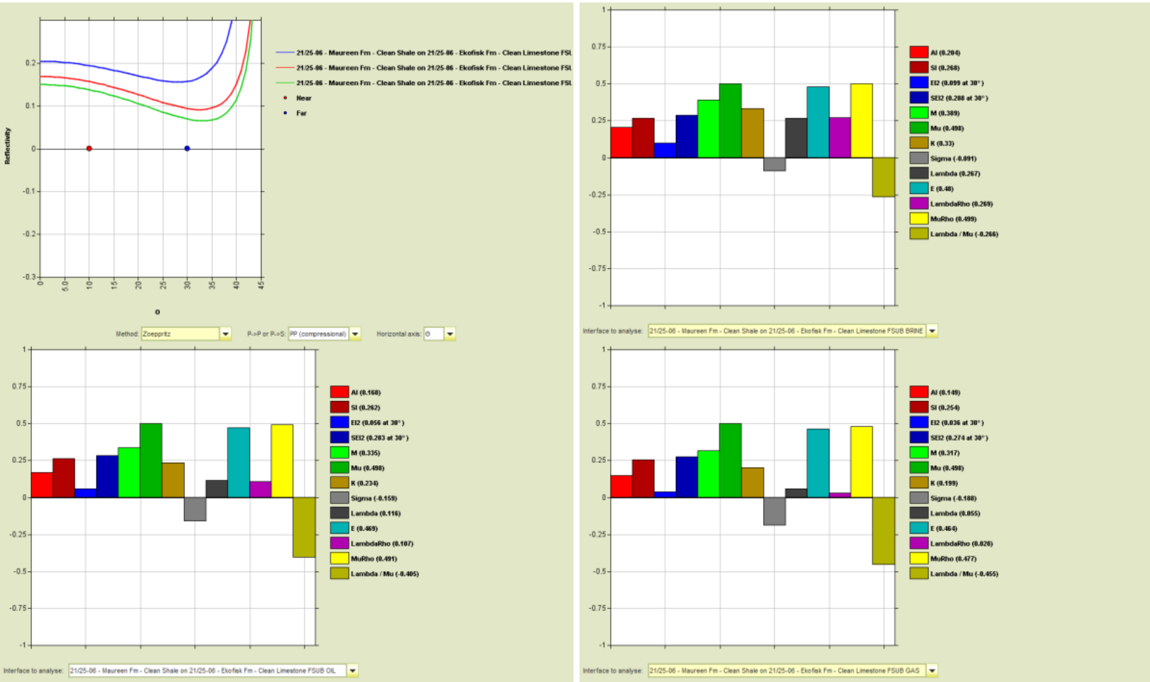


Figure 3.3.13 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 21/25-06.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 21/25-06 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-06	Overburden	Shale	7508		
21/25-06	Underburden				

Table 3.3.9 - Overburden and underburden properties at Well 21/25-06.

Well: 21/25-10

General

Well Information

Shell operated exploration well spudded, completed and suspended in 1992. The well was the discovery well for the Teal South field, encountering oil in the Upper Jurassic Fulmar Formation and Triassic Skagerrak Formation. The well was re-entered and completed in 1996 as an oil producer for the Teal South field.

Objectives

The well was drilled with the primary objective to evaluate a dip closure with a potential stratigraphic extension, within the Upper Jurassic Fulmar Formation and Triassic Skagerrak Formation. The well encountered both formations which were oil-bearing. The secondary objective was to evaluate the Horda Formation (Tay Member) and Sele Formation (Forties Member). Reservoirs within the Horda Formation (Tay Member), Balder Formation (Odin Member) and Sele Formation (Cromarty Member) were present but wet.

Log conditioning overview

Only minor log conditioning required due to good log data quality within this well. Caliper log shows minor washout at the start of the logging run towards the top of the Horda Formation, resulting in the density log being clipped. Thin calcite stringers in the Lista Formation seen on the density log were not apparent on the Vp log, with data relating to these intervals being removed.

Invasion correction

The drilling mud used within this well was water based, so invasion correction was not required due the absence of hydrocarbons present over the study interval.

Log modelling

In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Lista Formation for Vp and density. A complete Vs log is modelled in the absence of measured shear log data.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 21/25-10 is displayed in the figures below;

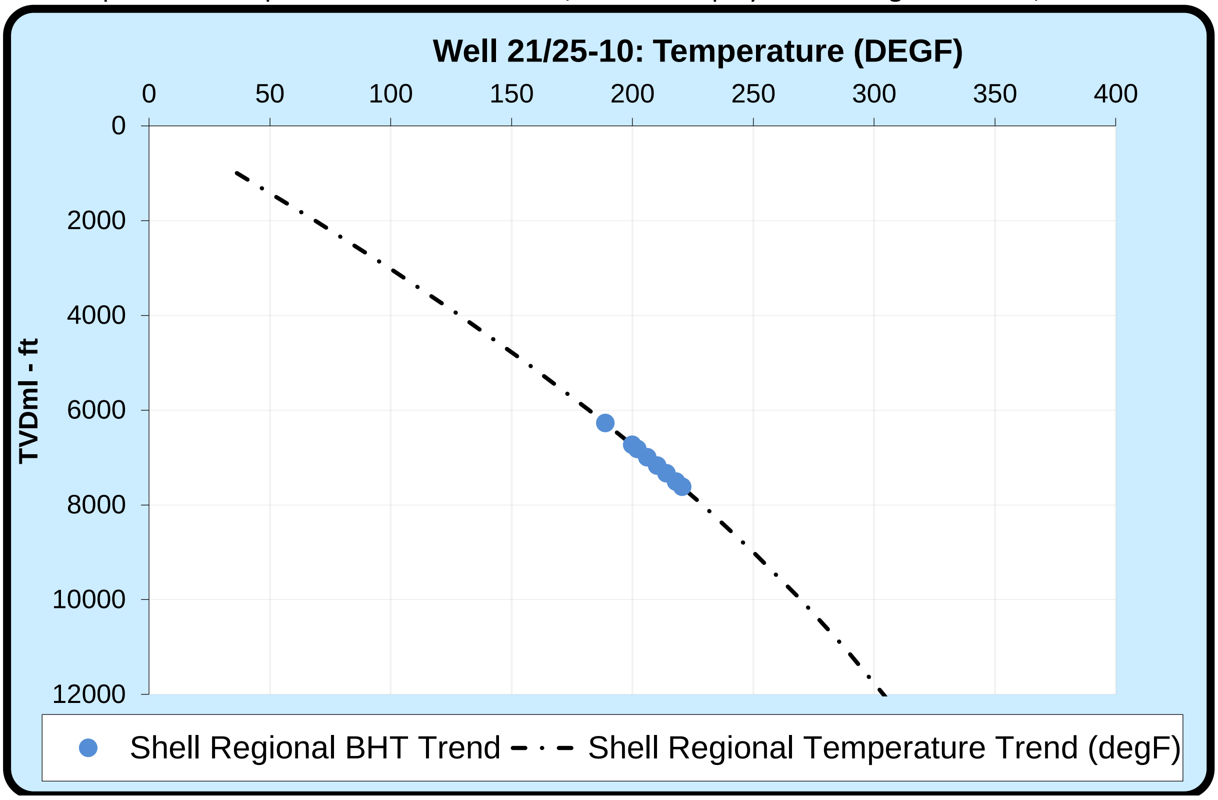


Figure 3.4.1 - Temperature data at Well 21/25-10

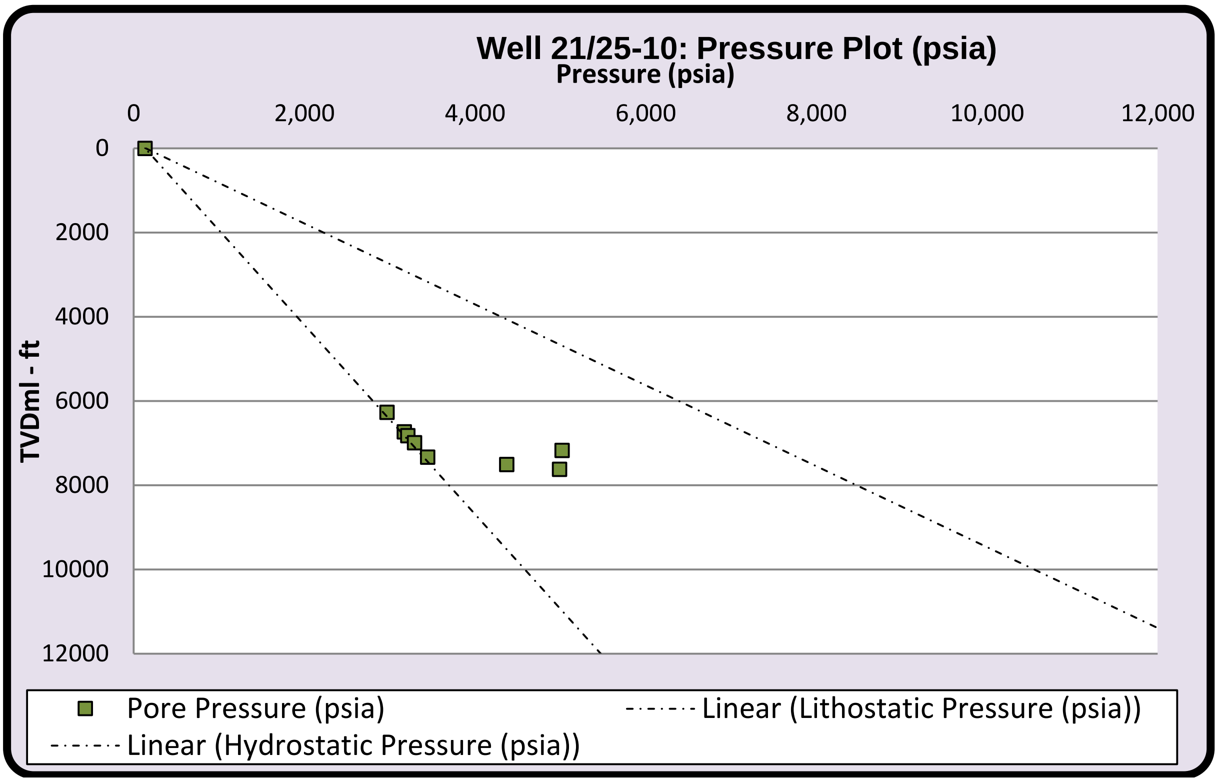


Figure 3.4.2 - Pressure data at Well 21/25-10

The temperature and pressure data for the formation mid-points in Well 21/25-10 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
21/25-10	Sea Bed	373.0	298.0	0.0	39.2	132.6	132.6	132.61	0.00
21/25-10	Horda	6646.1	6570.6	6272.6	188.8	2923.9	2968.9	6405.25	3436.31
21/25-10	Balder	7104.0	7028.5	6730.5	200.0	3127.7	3173.7	6863.08	3689.41
21/25-10	Sele	7194.5	7119.0	6821.0	202.1	3167.9	3213.9	6953.57	3739.63
21/25-10	Lista	7366.5	7290.9	6992.9	206.2	3244.5	3294.5	7125.55	3831.08
21/25-10	Maureen	7545.0	7469.4	7171.4	210.4	3323.9	5023.9	7304.04	2280.14
21/25-10	Ekofisk	7707.5	7631.9	7333.9	214.1	3396.2	3446.2	7466.53	4020.32
21/25-10	Tor	7883.0	7807.4	7509.4	218.1	3474.3	4374.3	7641.97	3267.70
21/25-10	Hod	7993.7	7918.1	7620.1	220.6	3523.6	4993.1	7752.74	2759.64

Table 3.4.1 - Summary of mid-point temperature and pressure data at Well 21/25-10

Fluid data

A summary of the fluid set parameters at Well 21/25-10 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
21/25-10	Horda	81000	730	38.1	0.71	0.71
21/25-10	Balder	81000	730	38.6	0.71	0.71
21/25-10	Sele	81000	730	38.7	0.71	0.71
21/25-10	Lista	81000	730	38.9	0.71	0.71
21/25-10	Maureen	81000	730	39.1	0.71	0.71
21/25-10	Ekofisk	81000	730	39.3	0.71	0.71
21/25-10	Tor	81000	730	39.5	0.71	0.71
21/25-10	Hod	81000	730	39.6	0.71	0.71

Table 3.4.2 - Summary of fluid parameter data at Well 21/25-10 Mineral data

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.4.3 - Constant mineral properties used in this project

There is no Tuff present in this well.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
21/25-10	Horda	PAY	827.840	0.000	0.000	0.000	0.000	0.000	0.000
21/25-10	Horda	RES	827.840	176.000	0.213	56.772	0.323	0.963	0.087
21/25-10	Balder	PAY	88.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-10	Balder	RES	88.000	56.000	0.636	15.631	0.279	0.952	0.172
21/25-10	Sele	PAY	93.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-10	Sele	RES	93.000	22.750	0.245	6.702	0.295	0.955	0.190
21/25-10	Lista	PAY	251.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-10	Lista	RES	251.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-10	Maureen	PAY	106.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-10	Maureen	RES	106.000	49.000	0.462	9.195	0.188	0.959	0.167
21/25-10	Ekofisk	PAY	219.000	0.000	0.000	0.000	0.000	0.000	0.000
21/25-10	Ekofisk	RES	219.000	212.250	0.969	35.399	0.167	0.931	0.164
21/25-10	Tor	PAY	131.920	0.000	0.000	0.000	0.000	0.000	0.000
21/25-10	Tor	RES	131.920	131.170	0.994	17.659	0.135	0.961	0.032
21/25-10	Hod	PAY	89.630	0.000	0.000	0.000	0.000	0.000	0.000
21/25-10	Hod	RES	89.630	89.630	1.000	12.368	0.138	0.901	0.118

Table 3.4.4 - Petrophysical parameters used at Well 21/25-10

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

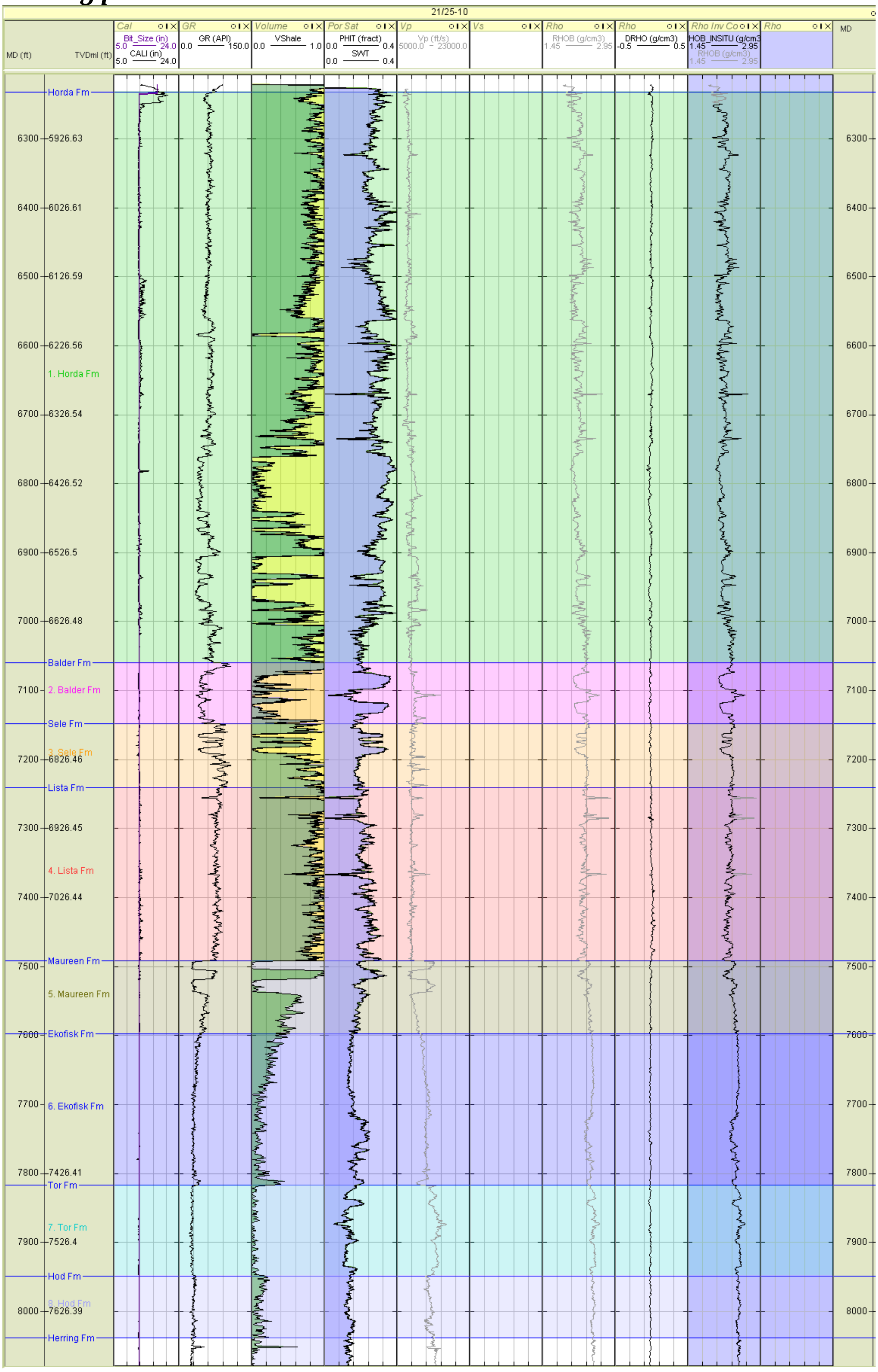


Figure 3.4.3 - Well Panel: Measured data and invasion correction for well 21/25-10.

Well log panel – log editing and audit

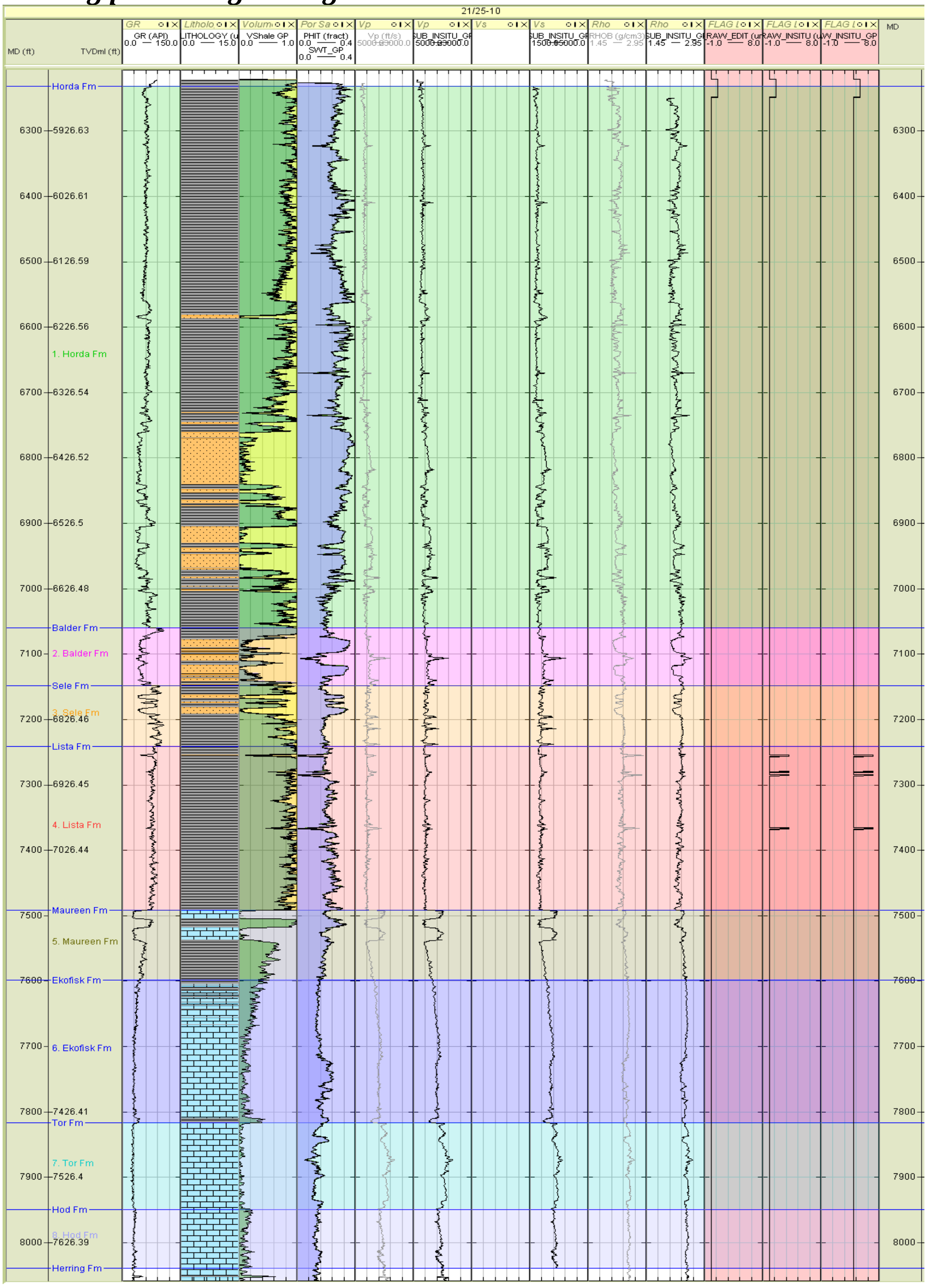


Figure 3.4.4 - Well Panel: Log edits for well 21/25-10.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

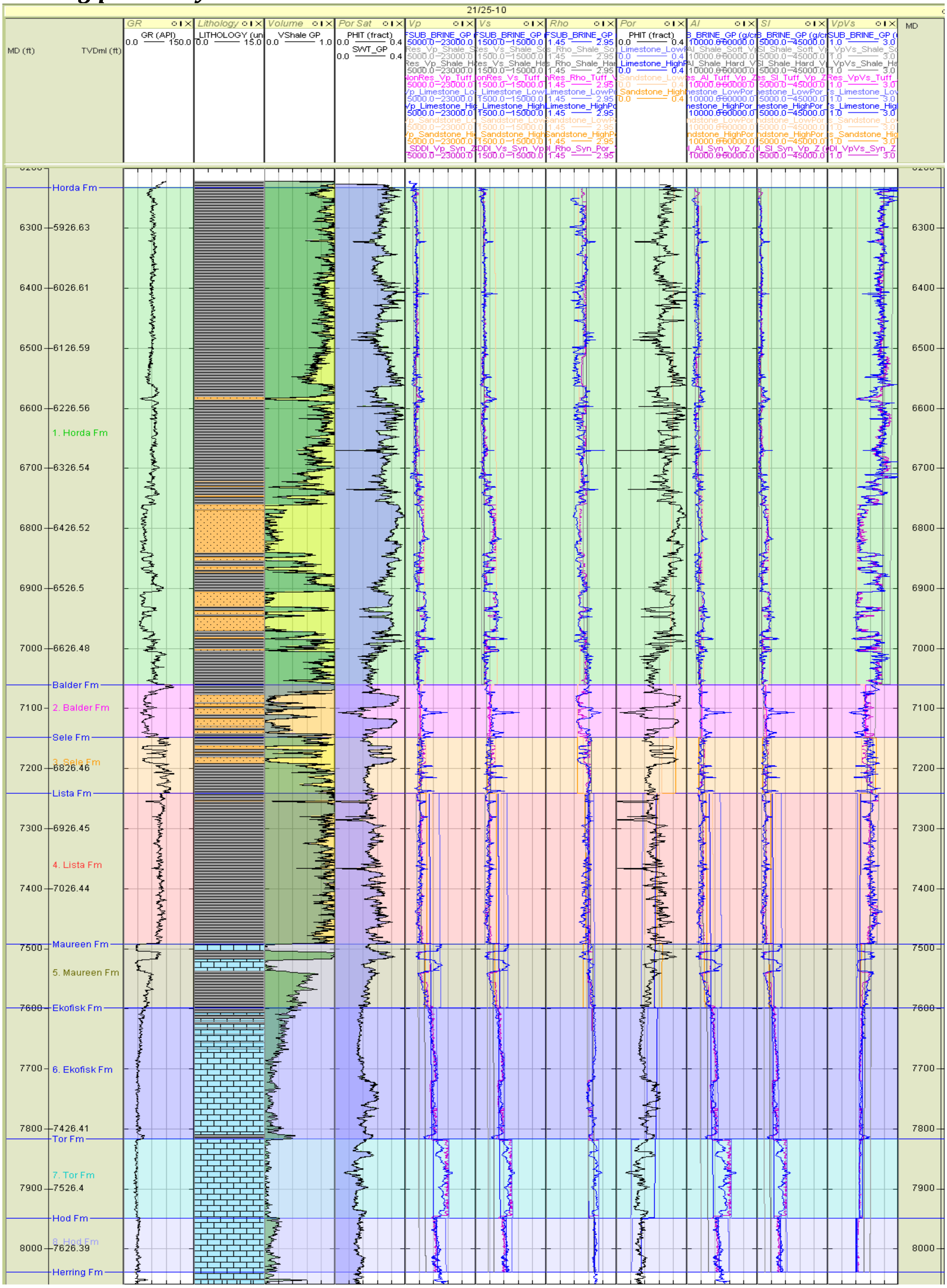


Figure 3.4.5 - Well Panel: End-member and synthetic logs for well 21/25-10.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

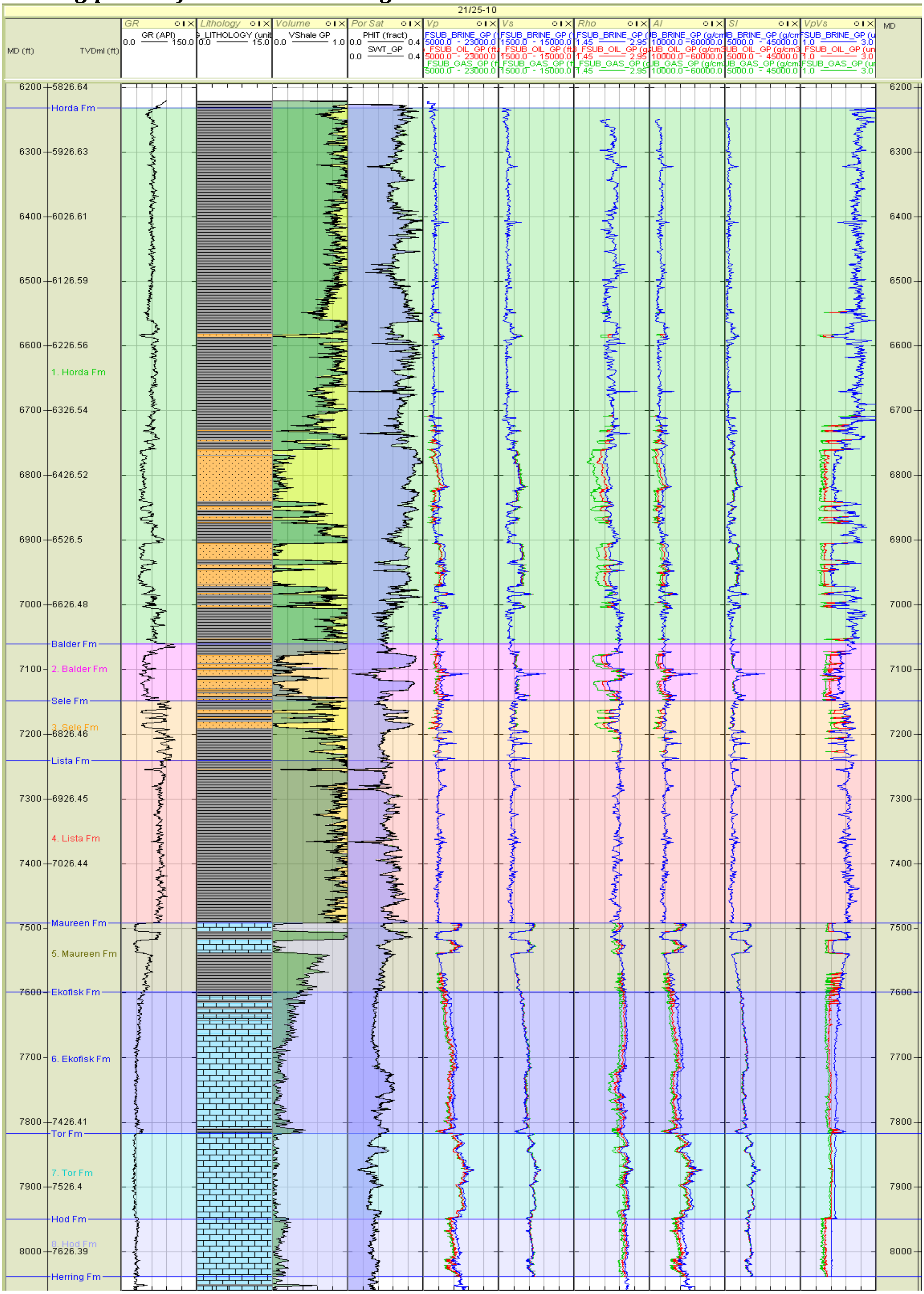


Figure 3.4.6 - Well Panel: Fluid substituted and elastic logs for well 21/25-10.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 21/25-10 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-10	Horda	7796	3122	2.22
21/25-10	Balder	8580	3859	2.33
21/25-10	Sele	8636	3938	2.35
21/25-10	Lista	8569	3814	2.30
21/25-10	Maureen	8405	3800	2.26

Table 3.4.5 - Clean shale properties at Well 21/25-10

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-10	Horda	100% Brine	9478	5062	2.14
21/25-10	Balder	100% Brine	9710	4935	2.21
21/25-10	Sele	100% Brine	9128	4191	2.15
21/25-10	Lista	100% Brine			
21/25-10	Maureen	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-10	Horda	80% Oil	8488	5174	2.05
21/25-10	Balder	80% Oil	8739	5021	2.13
21/25-10	Sele	80% Oil	8153	4283	2.06
21/25-10	Lista	80% Oil			
21/25-10	Maureen	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-10	Horda	90% Gas	8315	5382	1.89
21/25-10	Balder	90% Gas	8536	5178	2.00
21/25-10	Sele	90% Gas	7996	4448	1.91
21/25-10	Lista	90% Gas			
21/25-10	Maureen	90% Gas			

Table 3.4.6 - Clean sand properties at Well 21/25-10 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-10	Maureen	100% Brine	13,134	7,127	2.39
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-10	Maureen	80% Oil	12,465	7,207	2.34
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-10	Maureen	90% Gas	12,336	7,337	2.26

Table 3.4.7 - Clean limestone properties at Well 21/25-10 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

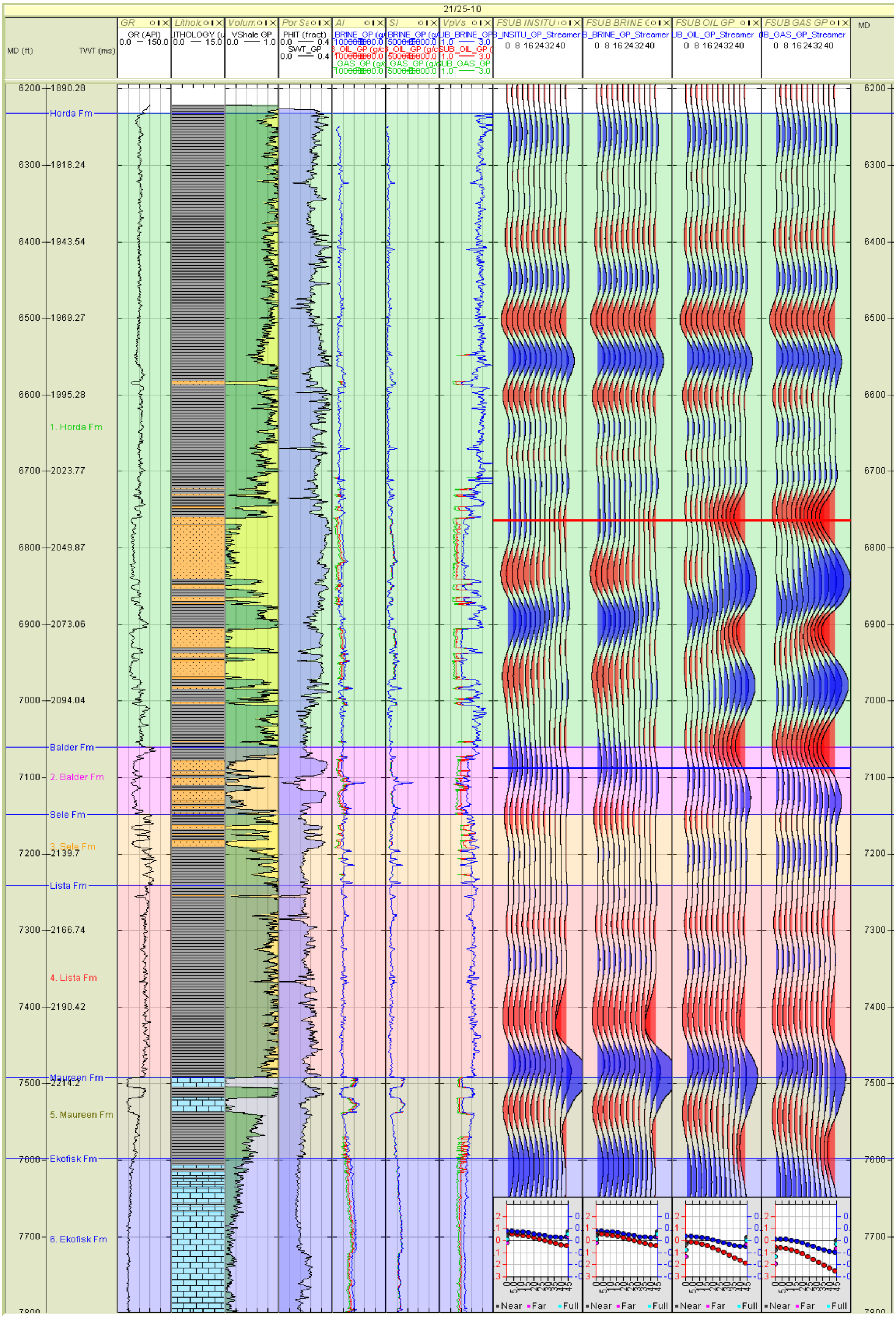


Figure 3.4.7 - Well Panel: Tertiary reservoirs for well 21/25-10. Wavelet: Streamer

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir formed by number of stacked clean blocky sands spread throughout the formation, but broadly falling within two main clusters separated by thick shale intervals. Net reservoir is approximately 176 feet containing porosities ranging from 29-40%.
- Blocky AVO shows a modelled class I response for the 100% brine case, a class II response for the 80% oil case and class III response for the 90% gas case. Within the synthetic gathers, a comparable AVO response is observed in each fluid case at top reservoir.
- Elastic Contrast Analysis shows contrasts are usually strong and positive in the 100% brine case, becoming strongly negative in the 80% oil and 90% gas cases. Mu shows the least sensitivity to fluid changes, whereas Lambda and LambdaRho show the most sensitivity to fluid effects.

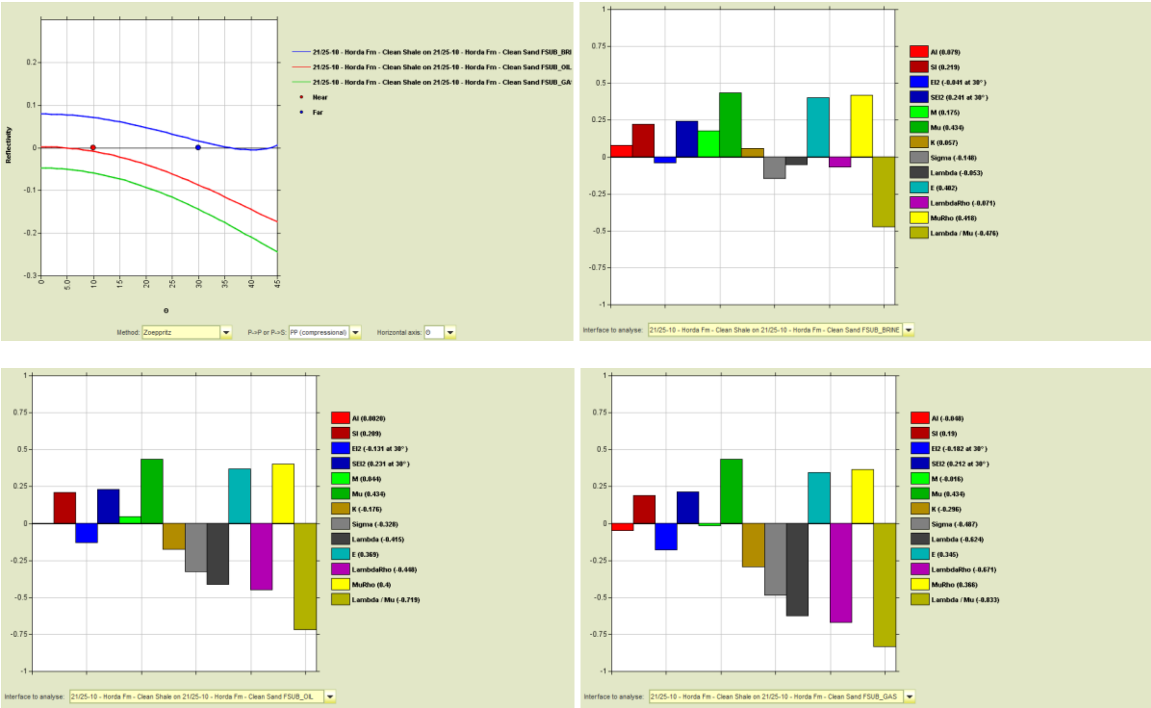


Figure 3.4.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 21/25-10.

Balder Formation

- Reservoir formed through a series of stacked thin sands and shales throughout the interval, forming two zones of high porosity up to approximately 37%. Reservoir is overlain by shales of the Horda and Balder Formations and extends with depth in to reservoir of the Sele Formation, which shows a similar character. Net reservoir is approximately 56 feet.
- Blocky AVO shows a modelled class I response for the 100% brine, with both the 80% oil and 90% gas cases showing a modelled class III response. Within the synthetic gathers, a class I AVO response is seen in the 100% brine case, a marginal class I/IIp response in the 80% gas case and class IIp response in the 90% gas case. It is apparent there are some effects of wavelet interference, manifested through negative reflectivities in far offsets in the 100% brine response. This is likely due to the stacked nature of the reservoir, and close proximity to reservoir of both the Horda and Sele Formations.
- Elastic Contrast Analysis shows contrasts are typically weak and positive in the 100% brine case, becoming strongly negative with the introduction of hydrocarbons. Lambda and LambdaRho show the most sensitivity to fluid effects. Mu shows the least sensitivity to fluid changes.

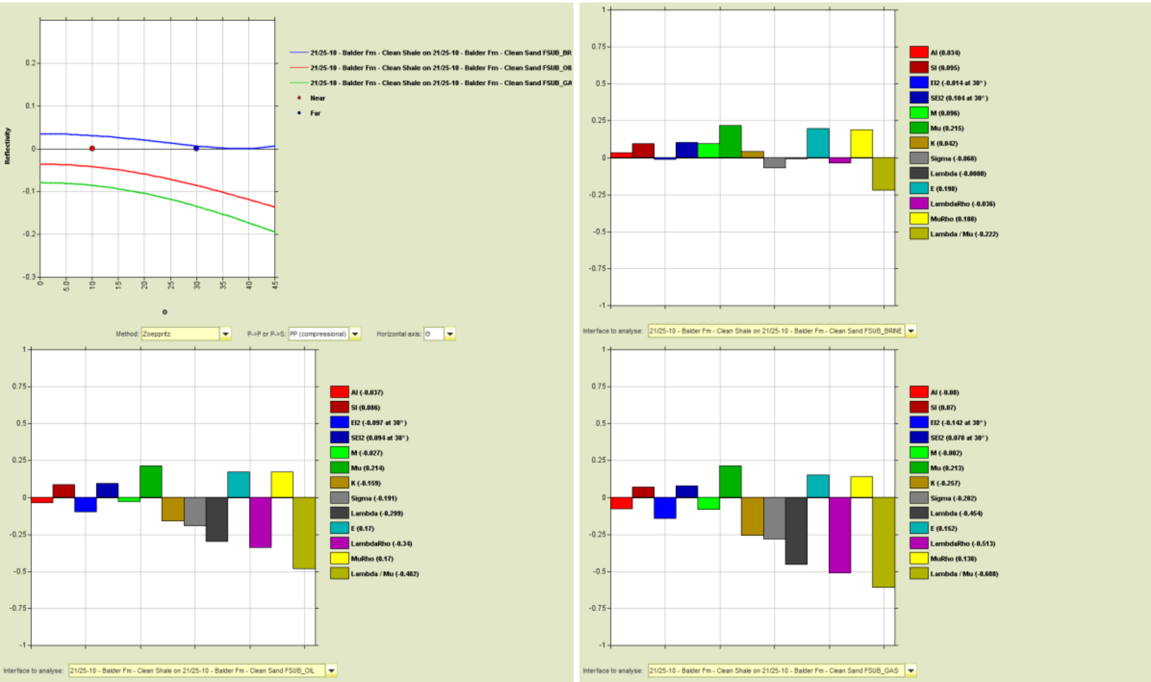


Figure 3.4.9 - Blocky AVO Model and Elastic Contrast Analysis for the Balder Formation in well 21/25-10.

Sele Formation

- Reservoir formed by three thin sands separated by shale towards the top of the formation. Reservoir character is similar to the overlaying Balder Formation reservoir, and overlies a thick shale succession. Net reservoir is approximately 23 feet containing porosities of around 33%.
- Blocky AVO shows a modelled class IV response for the 100% brine case showing low reflectivity at all incidence angles, and a modelled class III response for both the 80% oil and 90% gas cases. Within the synthetic gathers, each of the fluid cases shows a class IV AVO response. The variation observed in the 80% oil and 90% gas cases is likely due to wavelet interference caused by the base reservoir response of the overlying Balder Formation.
- Elastic Contrast Analysis shows contrasts are negligible in the 100% brine case, becoming moderately negative with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, while LambdaRho shows the most sensitivity to fluid effects.

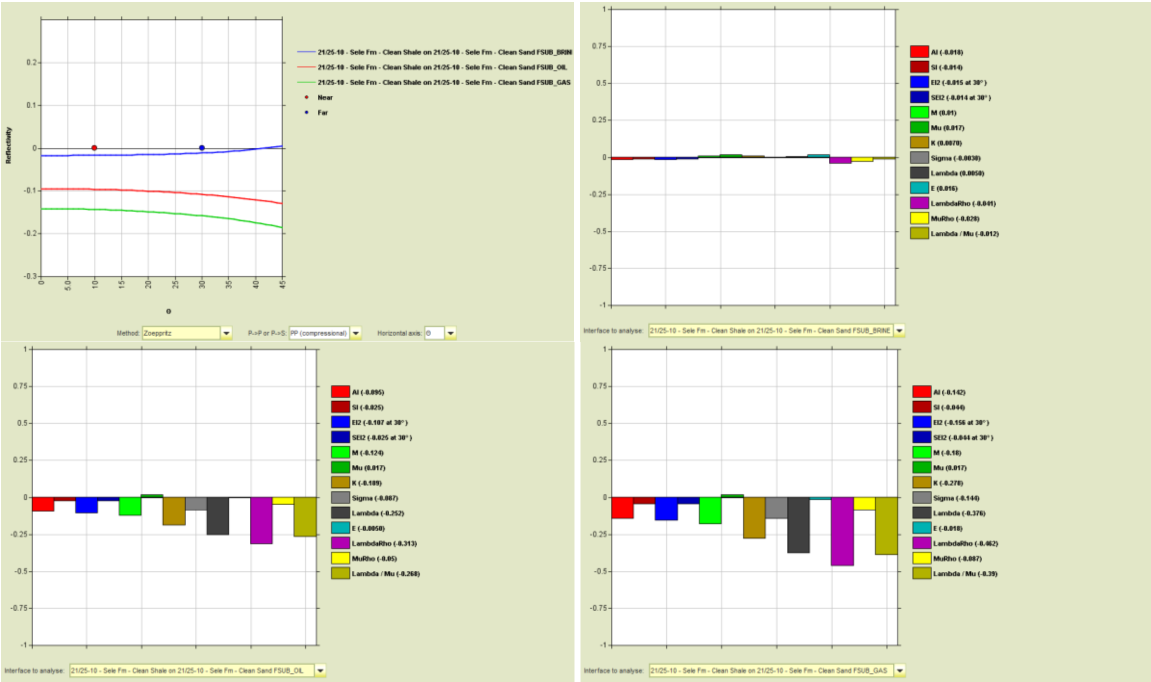


Figure 3.4.10 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 21/25-10.

Maureen Formation

- Reservoir formed by two thin limestone sections in the upper section of the interval and a mixture of limestone and shale towards the base of the interval, net reservoir is approximately 49 feet. The two thin limestone sections in the upper section of the interval are acoustically hard in relation to the surrounding shale and produce a positive impedance contrast on the synthetic gathers.
- Blocky AVO shows a modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the 100% brine case, and contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda and LambdaRho show the most sensitivity to fluid effects.

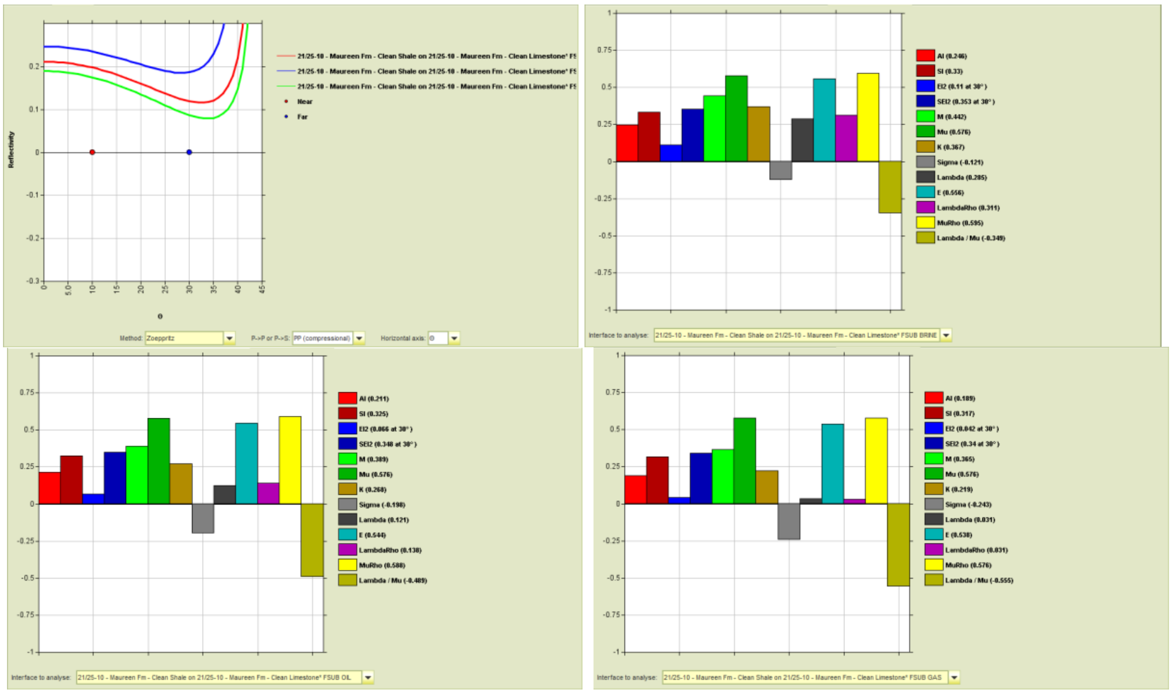


Figure 3.4.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 21/25-10

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 21/25-10 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-10	Ekofisk	100% Brine	12398	6461	2.41
21/25-10	Tor	100% Brine	14438	7597	2.49
21/25-10	Hod	100% Brine	13332	7387	2.49
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-10	Ekofisk	80% Oil	11503	6532	2.36
21/25-10	Tor	80% Oil	13854	7654	2.45
21/25-10	Hod	80% Oil	12300	7442	2.46
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-10	Ekofisk	90% Gas	11333	6653	2.27
21/25-10	Tor	90% Gas	13768	7745	2.40
21/25-10	Hod	90% Gas	11938	7528	2.40

Table 3.4.8 - Clean limestone properties at Well 21/25-10 for each fluid case

Cretaceous reservoirs

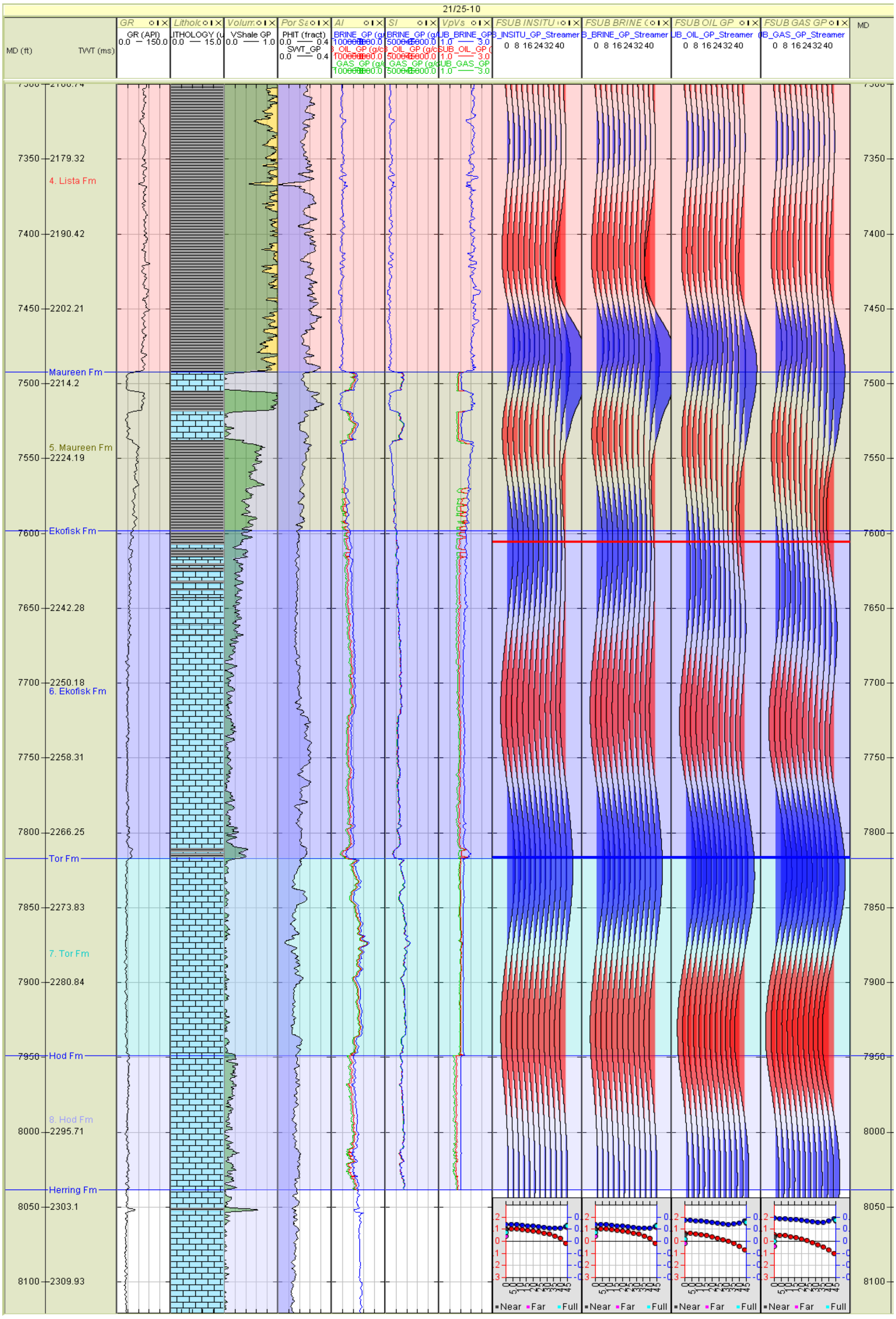


Figure 3.4.11 - Well Panel: Cretaceous reservoirs for well 21/25-10. Wavelet: Streamer

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a zone of high porosity (approximately 18-26%) towards the base of the Ekofisk Formation. The formation exhibits shaling up in to the overlying chalk reservoir of the Maureen Formation, giving a net porosity of approximately 213 feet.
- Blocky AVO modelling shows in each of the 100% brine, 80% oil and 90% gas cases, a class I response is predicted. A corresponding AVO response is observed within the synthetic gathers, although negative reflectivities occur in the 80% oil and 90% gas cases at high incidence angles, likely caused by wavelet interference created with the base reservoir response within the overlying Maureen Formation reservoir.
- Elastic Contrast Analysis shows contrasts are generally strong and positive in the 100% brine case. Although many contrasts show little sensitivity to the presence of hydrocarbon fluid fill, Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

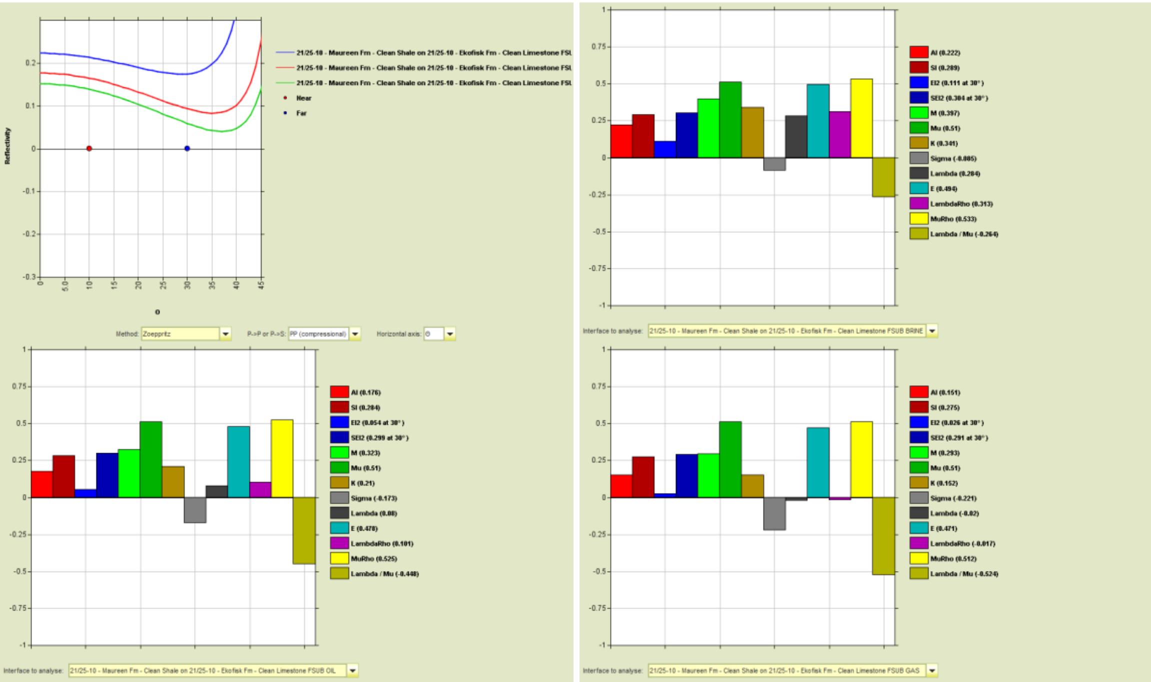


Figure 3.4.12 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 21/25-10.

Tor Formation

- Reservoir occurs as patchy zones of higher porosity (approximately 13-22%) throughout the interval. The formation is formed by clean chalk, but is bordered by the relatively silty chalks of the Ekofisk and Hod Formations. Net reservoir is approximately 131 feet.
- Blocky AVO modelling shows a class I response for each fluid, with reflectivity increasing with the addition of hydrocarbon fluid fill. Within the synthetic gathers, an equivalent class I AVO response is observed where reflectivity decreases with the addition of hydrocarbons. Soft chalks of the Ekofisk Formation dominate the seismic response in this case due to their increased fluid effects.
- Elastic Contrast Analysis shows contrasts are generally weak and positive in the 100% brine case. Moving to the 80% oil and 90% gas cases, many contrasts become muted and even negative in some cases. Mu and MuRho show the least sensitivity to fluid effects, while Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

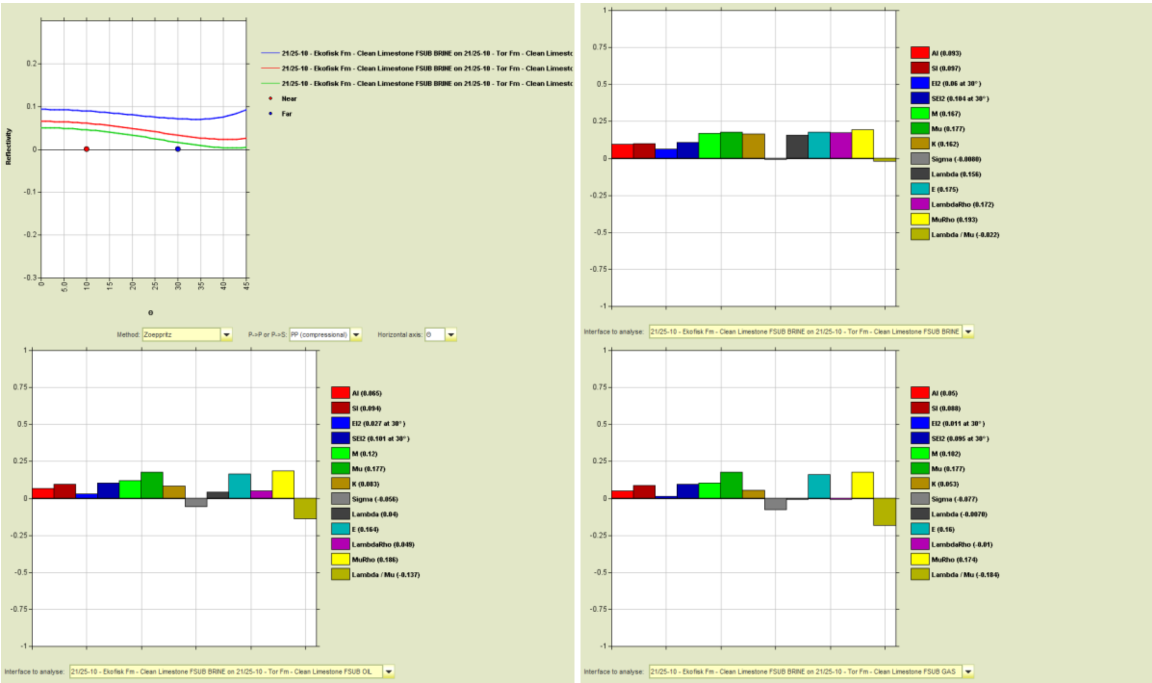


Figure 3.4.13 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 21/25-10.

Hod Formation

- Reservoir formed by a relatively silt chalk showing zones of higher porosity (approximately 14-17%). Bounding the formation are relatively clean chalks of the Tor and Herring Formations. Net reservoir is approximately 90 feet.
- Blocky AVO modelling shows a class III response seen in the 100% brine, 80% oil and 90% gas fluid cases, each exhibiting a low gradient. Within the synthetic gathers, comparable AVO responses are observed.
- Elastic Contrast Analysis shows contrasts are often weak and negative in the 100% brine case. With the addition of hydrocarbons, many constants become strongly negative. Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects, while MuRho shows the least sensitivity to fluid effects.

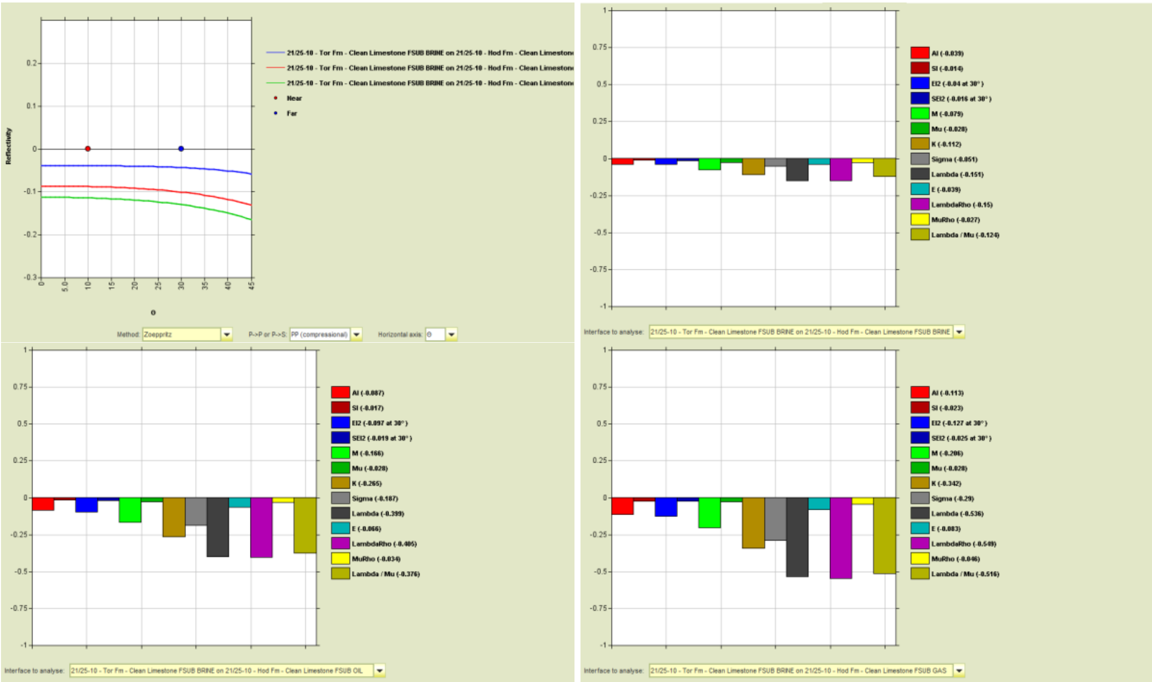


Figure 3.4.14 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 21/25-10.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 21/25-10 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-10	Overburden	Shale			
21/25-10	Underburden	Limestone/Shale	12956		2.52

Table 3.4.9 - Overburden and underburden properties at Well 21/25-10.

Well: 21/25-12

General

Well Information
Shell operated exploration well, spudded in 1992, then completed and abandoned in 1993. This well encountered oil shows within the Upper Cretaceous Chalk Group.

Objectives
The well was drilled on the edge of a platform to test shallow marine sandstones of the Upper Jurassic Fulmar Formation in a salt induced faulted dip closure. The Upper Cretaceous Chalk Group was present encountering oil within the Ekofisk and Tor Formations. Reservoir quality sands were present within the Horda Formation (Tay Member) and Sele Formation (Cromarty Member) but wet.

Log conditioning overview
Caliper log indicates issues with borehole rugosity mainly focused within the Horda and Maureen Formations. Only minor log conditioning was required, with data being removed from the Vp and density logs at the start of the logging run and associated with a small spike towards the base of the Horda Formation.

Invasion correction
Invasion correction of the density log performed in the hydrocarbon bearing Ekofisk and Tor Formations. The drilling mud used within this well was water based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda Formation for Vp and density. Due to the absence of measured shear log data, a complete Vs log is modelled using Modified Gassmann methodology due to the presence of hydrocarbons within this well.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 21/25-12 is displayed in the figures below;

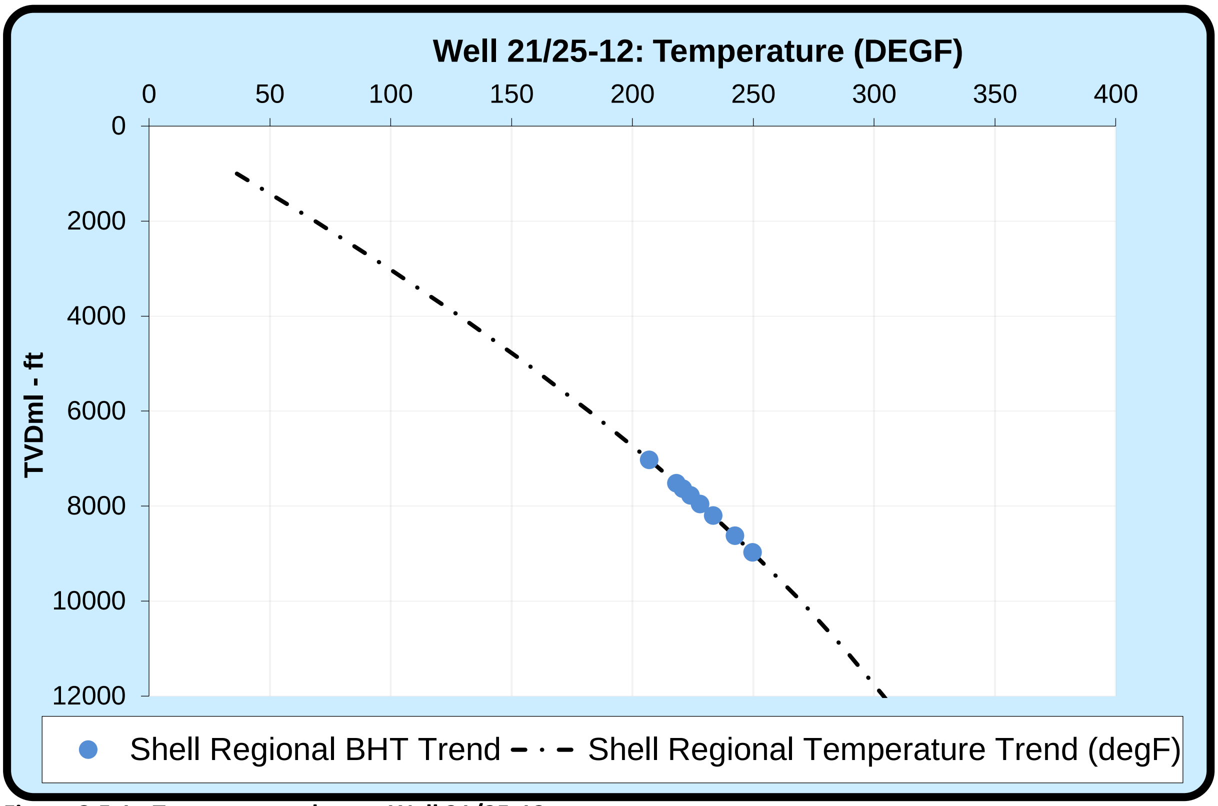


Figure 3.5.1 - Temperature data at Well 21/25-12

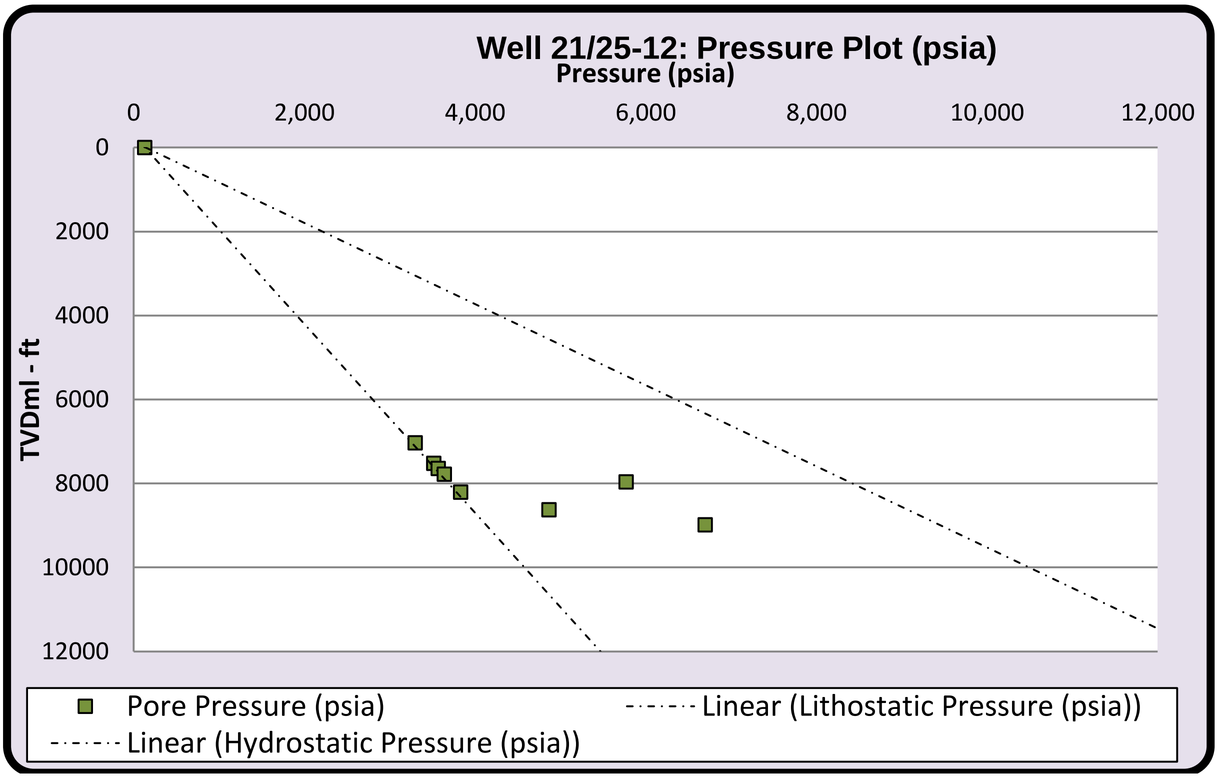


Figure 3.5.2 - Pressure data at Well 21/25-12

The temperature and pressure data for the formation mid-points in Well 21/25-12 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
21/25-12	Sea Bed	370.0	295.0	0.0	39.2	131.3	131.3	131.28	0.00
21/25-12	Horda	7435.7	7324.3	7029.3	207.0	3259.3	3300.3	7160.61	3860.28
21/25-12	Balder	7925.1	7813.7	7518.7	218.3	3477.1	3520.1	7650.02	4129.90
21/25-12	Sele	8042.1	7930.8	7635.8	221.0	3529.2	3572.2	7767.04	4194.85
21/25-12	Lista	8183.0	8071.6	7776.6	224.1	3591.8	3641.8	7907.84	4265.99
21/25-12	Maureen	8363.9	8252.5	7957.5	228.1	3672.4	5772.4	8088.78	2316.41
21/25-12	Ekofisk	8611.1	8499.7	8204.7	233.5	3782.4	3832.4	8336.01	4503.63
21/25-12	Tor	9031.9	8920.4	8625.4	242.5	3969.6	4869.6	8756.71	3887.11
21/25-12	Hod	9385.3	9273.7	8978.7	249.7	4126.8	6699.0	9110.02	2410.97

Table 3.5.1 - Summary of mid-point temperature and pressure data at Well 21/25-12

Fluid data

A summary of the fluid set parameters at Well 21/25-12 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
21/25-12	Horda	58000	819	32.0	0.71	0.71
21/25-12	Balder	58000	730	39.5	0.71	0.71
21/25-12	Sele	58000	730	39.6	0.71	0.71
21/25-12	Lista	58000	730	39.8	0.71	0.71
21/25-12	Maureen	80000	730	40.0	0.71	0.71
21/25-12	Ekofisk	80000	730	40.2	0.71	0.71
21/25-12	Tor	80000	730	40.7	0.71	0.71
21/25-12	Hod	80000	730	41.1	0.71	0.71

Table 3.5.2 - Summary of fluid parameter data at Well 21/25-12 Mineral data

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.5.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	14.16	7.21	2.45	10,221	5,629

Table 3.5.4 - Tuff properties used at Well 21/25-12

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
21/21-12	Horda	PAY	923.350	0.000	0.000	0.000	0.000	0.000	0.000
21/21-12	Horda	RES	923.350	86.500	0.082	20.368	0.235	0.968	0.185
21/21-12	Balder	PAY	55.530	0.000	0.000	0.000	0.000	0.000	0.000
21/21-12	Balder	RES	55.530	7.500	0.134	2.091	0.279	0.944	0.020
21/21-12	Sele	PAY	178.530	0.000	0.000	0.000	0.000	0.000	0.000
21/21-12	Sele	RES	178.530	55.500	0.311	13.608	0.245	0.912	0.206
21/21-12	Lista	PAY	103.480	0.000	0.000	0.000	0.000	0.000	0.000
21/21-12	Lista	RES	103.480	0.000	0.000	0.000	0.000	0.000	0.000
21/21-12	Maureen	PAY	258.420	0.000	0.000	0.000	0.000	0.000	0.000
21/21-12	Maureen	RES	258.420	21.000	0.081	2.291	0.109	0.976	0.306
21/21-12	Ekofisk	PAY	236.110	0.000	0.000	0.000	0.000	0.000	0.000
21/21-12	Ekofisk	RES	236.110	233.940	0.991	27.756	0.119	0.895	0.082
21/21-12	Tor	PAY	605.380	8.500	0.014	1.796	0.211	0.475	0.015
21/21-12	Tor	RES	605.380	513.380	0.848	56.932	0.111	0.816	0.009
21/21-12	Hod	PAY	101.470	0.000	0.000	0.000	0.000	0.000	0.000
21/21-12	Hod	RES	101.470	98.470	0.970	5.944	0.060	0.953	0.130

Table 3.5.5 - Petrophysical parameters used at Well 21/25-12

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

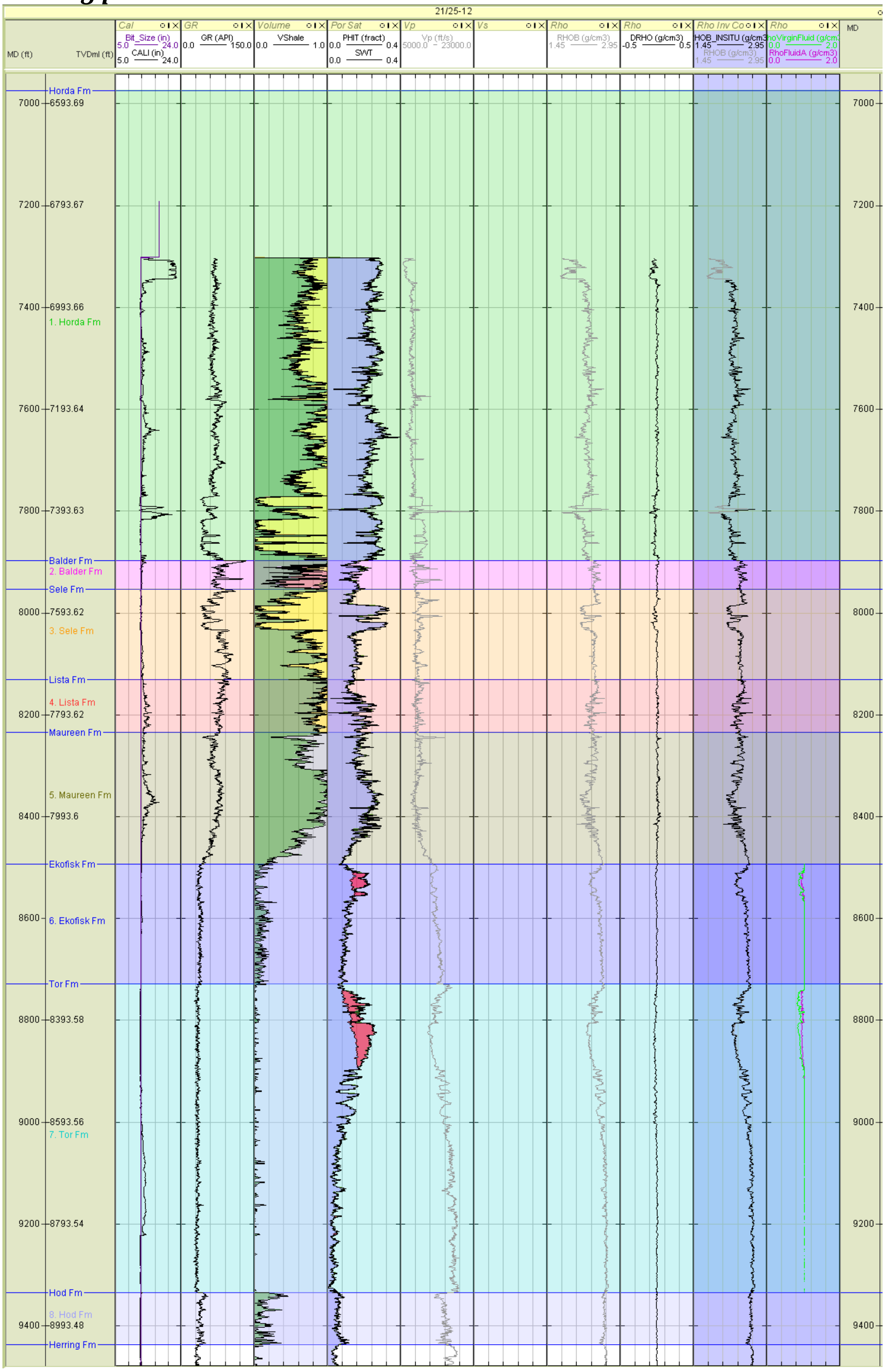


Figure 3.5.3 - Well Panel: Measured data and invasion correction for well 21/25-12.

Well log panel – log editing and audit

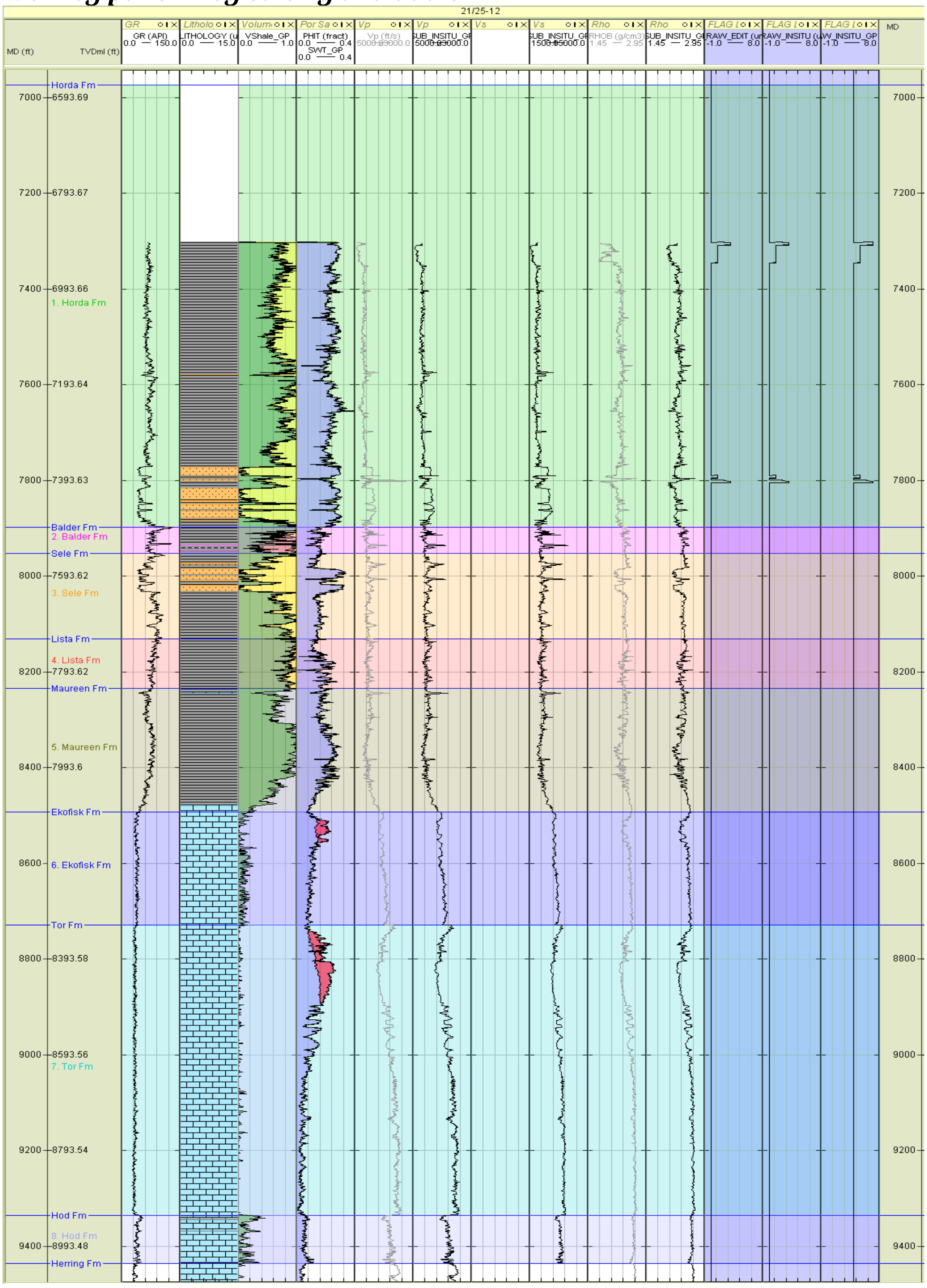


Figure 3.5.4 - Well Panel: Log edits for well 21/25-12.

<u>Legend</u>

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

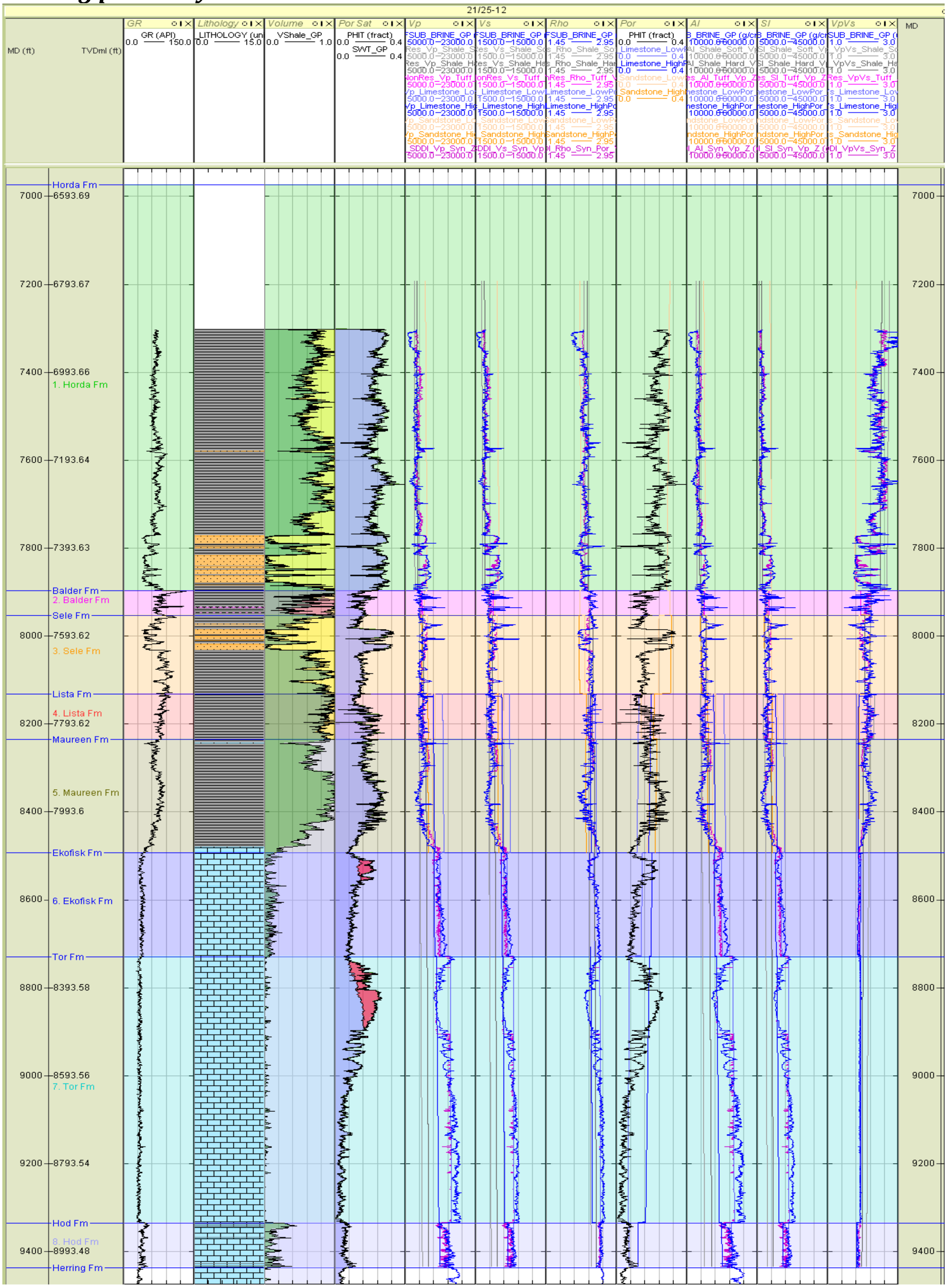


Figure 3.5.5 - Well Panel: End-member and synthetic logs for well 21/25-12.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

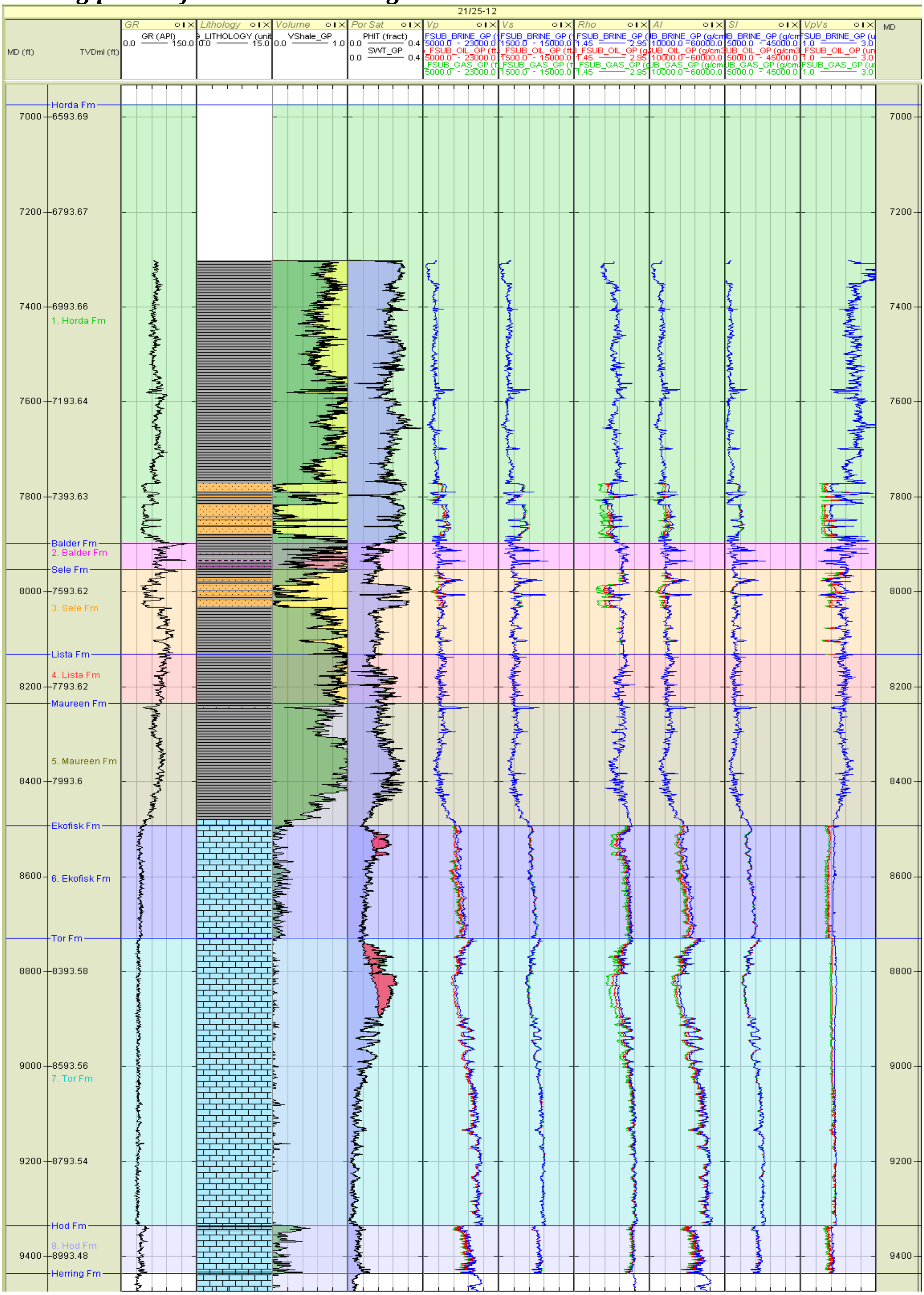


Figure 3.5.6 - Well Panel: Fluid substituted and elastic logs for well 21/25-12.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 21/25-12 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-12	Horda	7638	3032	2.26
21/25-12	Balder	8625	3917	2.40
21/25-12	Sele	8789	4055	2.40
21/25-12	Lista	9235	4321	2.38
21/25-12	Maureen	8922	4165	2.32

Table 3.5.6 - Clean shale properties at Well 21/25-12

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-12	Horda	100% Brine	10511	5839	2.21
21/25-12	Balder	100% Brine			
21/25-12	Sele	100% Brine	10305	5294	2.23
21/25-12	Lista	100% Brine			
21/25-12	Maureen	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-12	Horda	80% Oil	9799	5930	2.15
21/25-12	Balder	80% Oil			
21/25-12	Sele	80% Oil	9567	5374	2.16
21/25-12	Lista	80% Oil			
21/25-12	Maureen	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-12	Horda	90% Gas	9686	6124	2.02
21/25-12	Balder	90% Gas			
21/25-12	Sele	90% Gas	9486	5517	2.05
21/25-12	Lista	90% Gas			
21/25-12	Maureen	90% Gas			

Table 3.5.7 - Clean sand properties at Well 21/25-12 for each fluid case

Tertiary reservoirs – Well panel

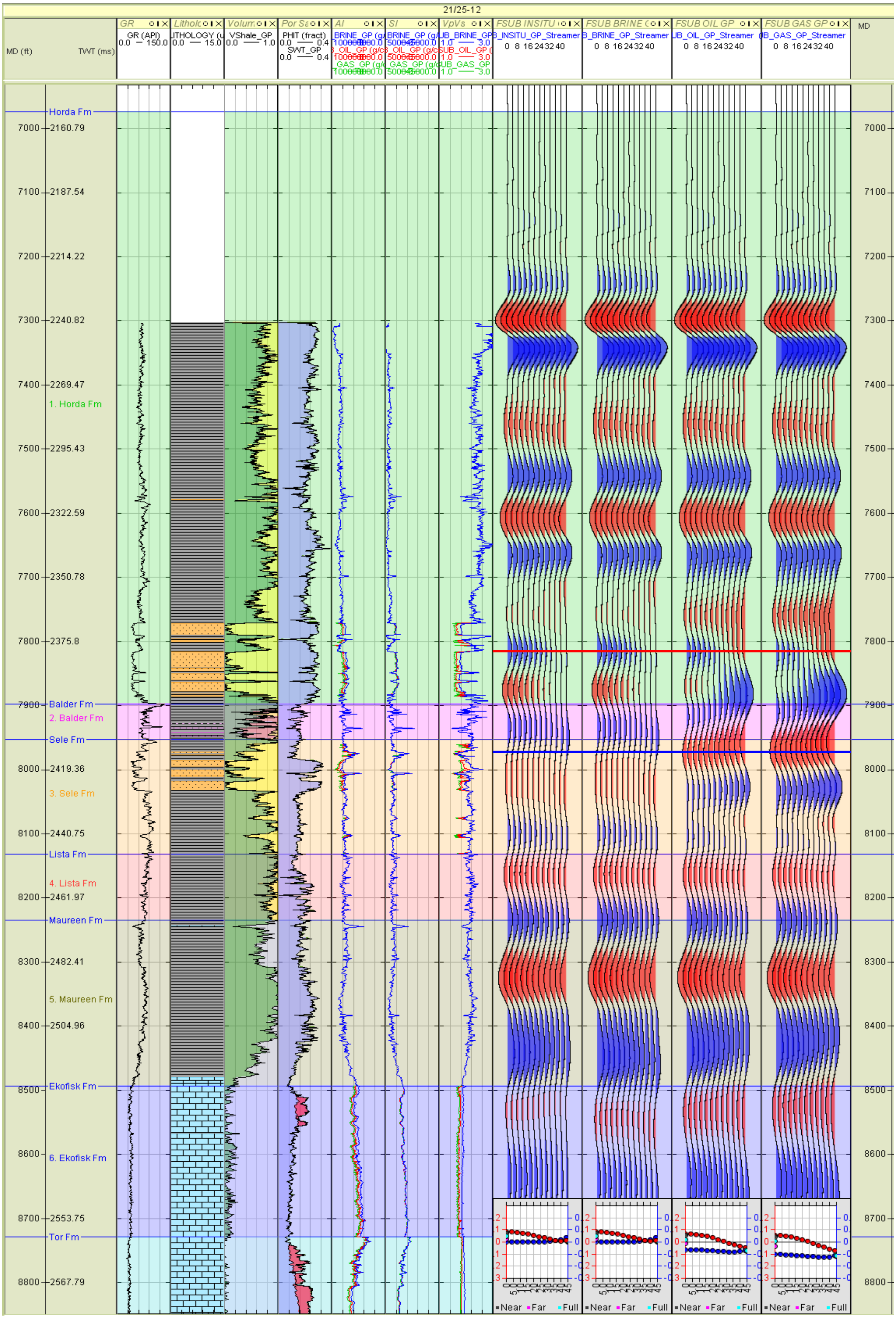


Figure 3.5.7 - Well Panel: Tertiary reservoirs for well 21/25-12. Wavelet: Streamer

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir formed by number of stacked clean blocky sandstones at the base of the interval ranging from 2-30 feet in thickness. The reservoir forming part of the interval is overlain by a silty shale. Net reservoir is approximately 92 feet and has porosities of 25-31%.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases, the 90% gas case shows a marginal class I/IIp response. Within the synthetic gathers, although many of the reservoir sands are prone to wavelet interference/ below seismic resolution, comparable AVO responses are observed at a depth associated with the thickest reservoir sand in each fluid case.
- Elastic Contrast Analysis shows contrasts are generally strong and positive in the 100% brine case. Mu and MuRho show the least sensitivity to fluid changes, while Lambda and LambdaRho show the most sensitivity to fluid effects.

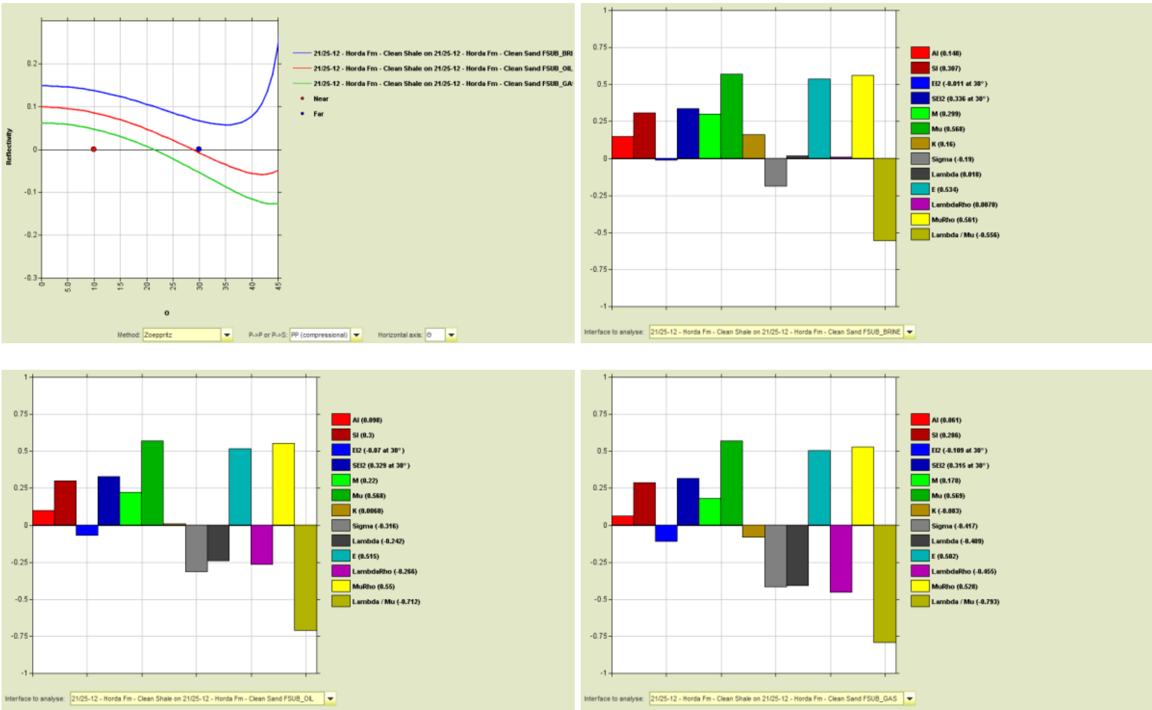


Figure 3.5.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 21/25-12.

Sele Formation

- Reservoir within the formation is composed of a number of stacked clean blocky sandstones towards the top of the interval. The reservoir is overlain by silty and tuffaceous shales of the Balder and Sele Formations, and overlies clean shale. There is approximately 56 feet of net reservoir containing porosities of approximately 32%.
- Blocky AVO shows a modelled class I response for the 100% brine, a class II response for the 80% oil case and a class III response for the 90% gas case. Within the synthetic gathers, a top reservoir seismic response is only resolvable with the addition of hydrocarbons, with 80% and 90% gas cases giving a class III AVO response. The observed difference is likely due to wavelet interference caused by more prominent changes in elastic contrast at the base of the tuffaceous shale, and base reservoir in the absence of any hydrocarbon fluid fill.
- Elastic Contrast Analysis shows contrasts are generally weak and positive in the 100% brine case, becoming negative in the presence of hydrocarbons. Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects. Mu shows the least sensitivity to fluid effects.

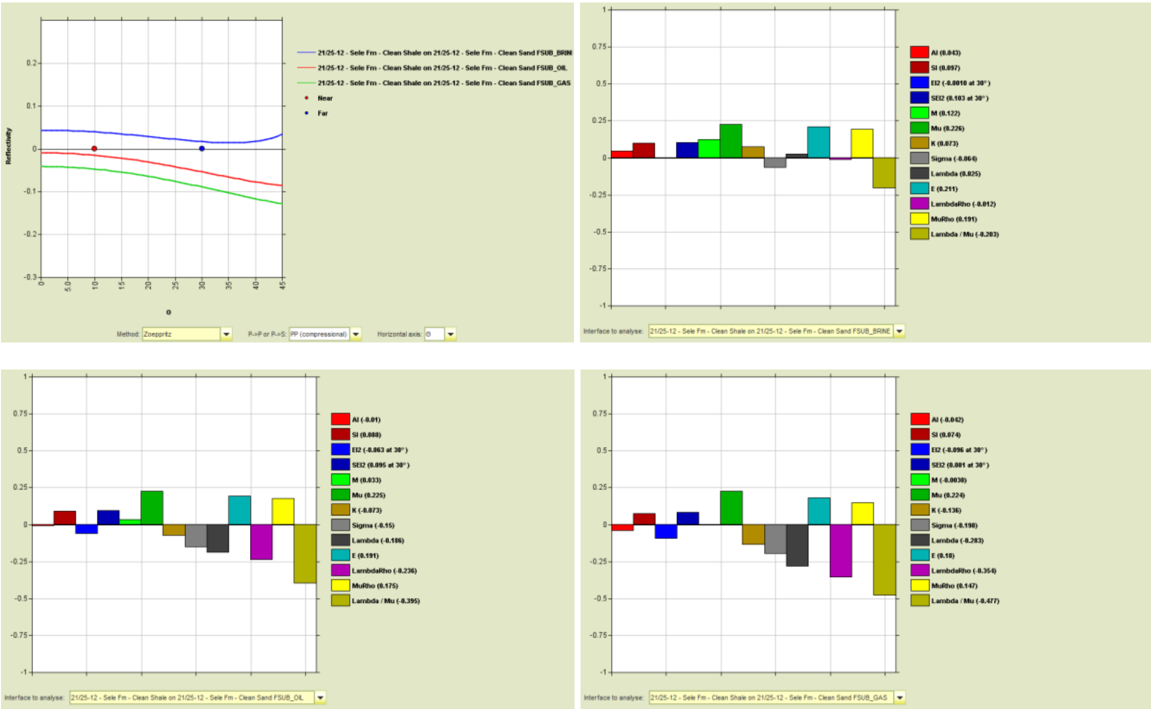


Figure 3.5.9 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 21/25-12.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 21/25-12 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-12	Ekofisk	100% Brine	14075	7545	2.50
21/25-12	Tor	100% Brine	16114	8425	2.55
21/25-12	Hod	100% Brine	16233	8745	2.62
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-12	Ekofisk	80% Oil	13226	7598	2.47
21/25-12	Tor	80% Oil	15780	8467	2.52
21/25-12	Hod	80% Oil	15580	8770	2.60
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/25-12	Ekofisk	90% Gas	13034	7684	2.41
21/25-12	Tor	90% Gas	15755	8532	2.48
21/25-12	Hod	90% Gas	13029	7681	2.41

Table 3.5.8 - Clean limestone properties at Well 21/25-12 for each fluid case

Cretaceous reservoirs

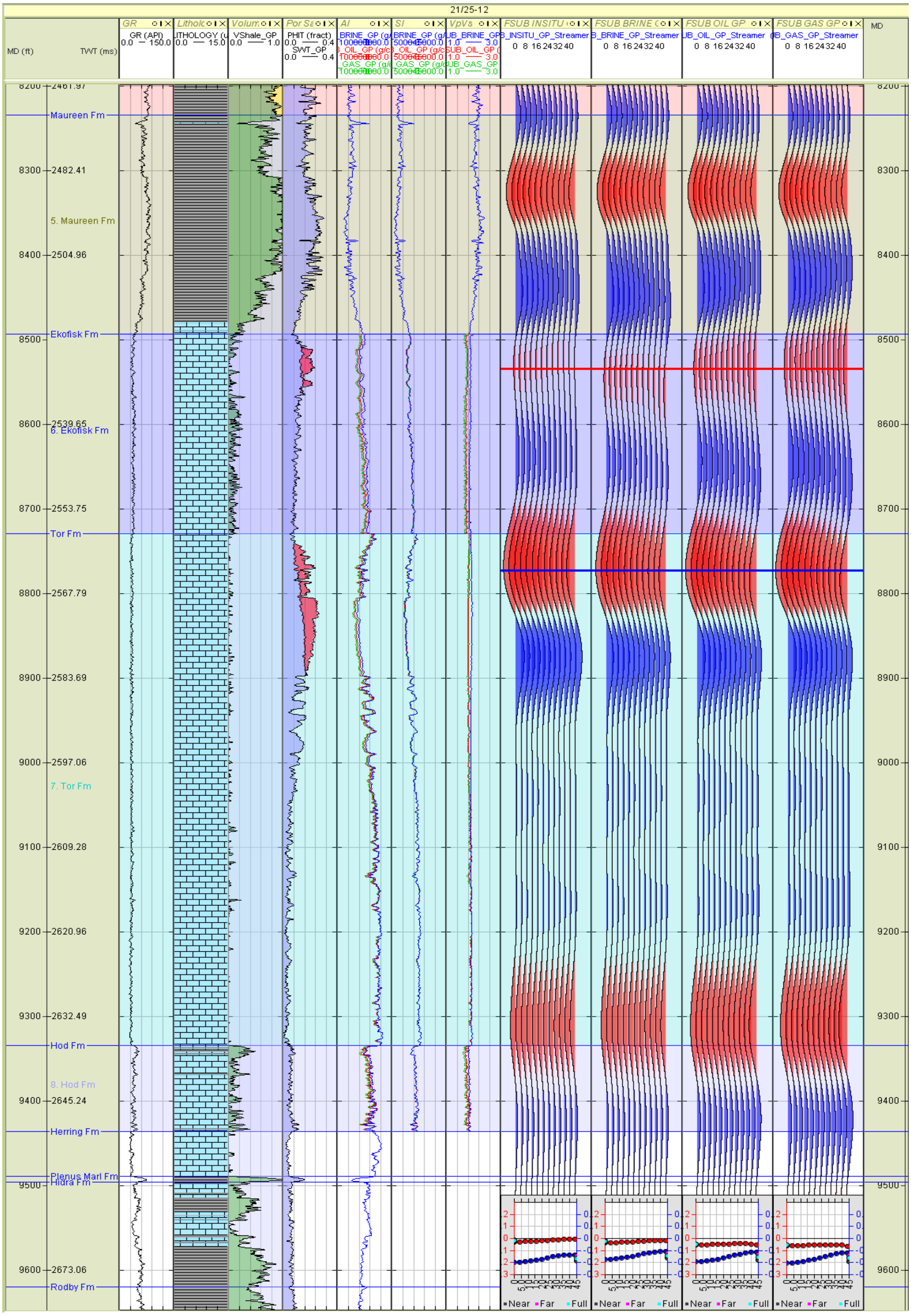


Figure 3.5.10 - Well Panel: Cretaceous reservoirs for well 21/25-12. Wavelet: Streamer

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir is composed of a zone of high porosity chalk (approximately 15-23%) at the top of the interval, likely formed through a phase of reworking. Internally within the reservoir, isolated zones of lower porosity are present. The reservoir is separated from the overlying Maureen Formation by a thin low porosity chalk zone. The base Maureen Formation shows shaling up from silty chalk in to clean shale. Net reservoir is approximately 234 feet.
- Blocky AVO modelling shows a class I response predicted in each fluid cases, with reflectivity decreasing with the addition of hydrocarbon fluid fill. A contrasting response is seen within the synthetic gathers, where a uniform class IV AVO response is observed. This is likely caused by the top reservoir reflector being sourced by a porosity rather than lithology change, and the influence of wavelet interference caused by intra-reservoir low porosity zones.
- Elastic Contrast Analysis shows strong positive contrasts are frequent in the 100% brine case. In the 80% oil and 90% gas cases, contrasts typically are reduced although remain positive. Mu and MuRho show the least sensitivity to fluid effects, while Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

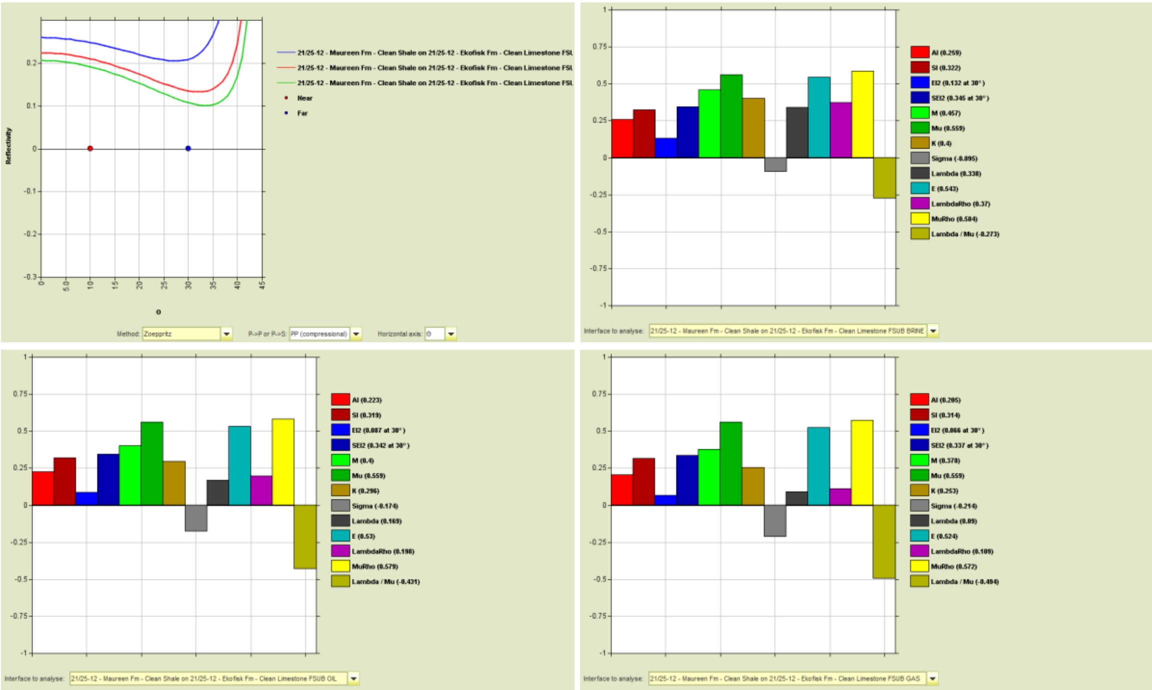


Figure 3.5.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 21/25-12.

Tor Formation

- Reservoir formed by a zone of high porosity chalk (approximately 13-26%) towards the top of the interval. A number of intra-reservoir lower porosity zones occur, which increase in number towards the base of the reservoir zone. The interval is overlain by low porosity chalk of the Ekofisk Formation. Net reservoir is approximately 513 feet.
- Blocky AVO modelling shows a class I response predicted in the 100% brine, 80% oil and 90% gas cases, while reflectivity decreases with offset. In contrast, synthetic gathers show a class IV AVO response in each fluid case. This is likely due to the reflection event marking a change in porosity within the Tor Formation, rather than the modelled Ekofisk on Tor Formation chalk response modelled.
- Elastic Contrast Analysis shows contrasts are weak and positive in the 100% brine case, becoming relatively dimmer in the presence of hydrocarbons. LambdaRho and Lambda/Mu show the most sensitivity to fluid effects. Mu shows the least sensitivity to fluid effects.

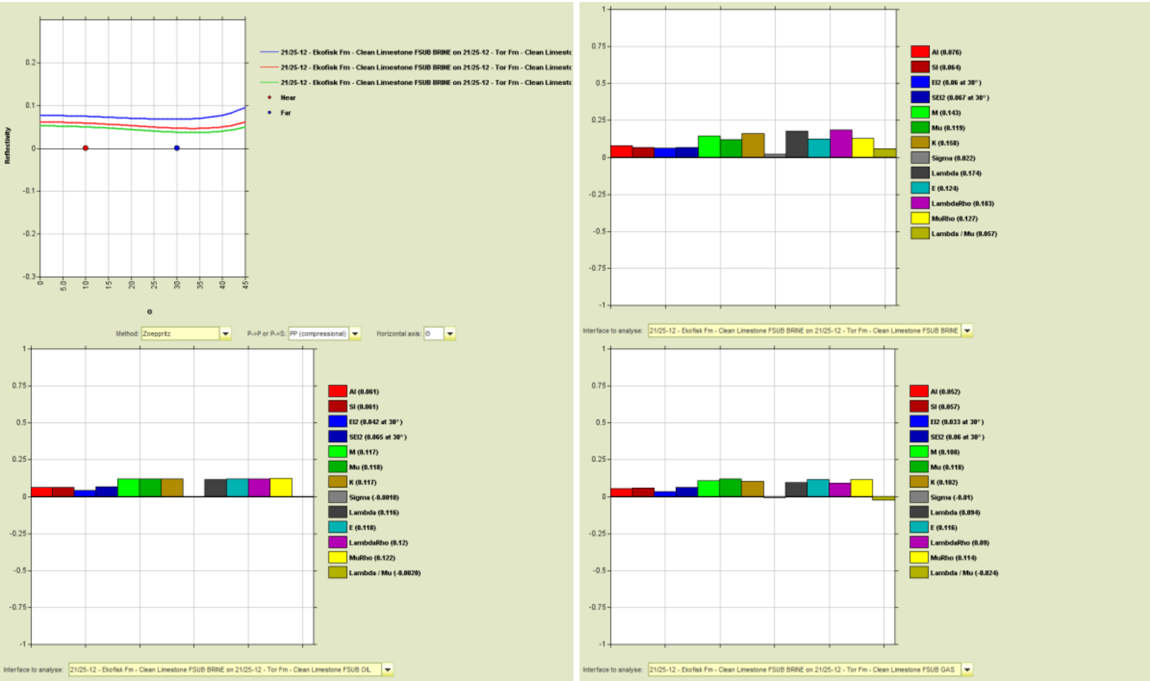


Figure 3.5.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 21/25-12.

Hod Formation

- Reservoir formed by a relatively silty chalk showing moderate porosity (approximately 8-11%). The reservoir is surrounded by the relatively clean chalks of the Tor and Herring Formations. Net reservoir is approximately 98 feet.
- Blocky AVO modelling shows a class I response in the 100% brine case, a class II response in the 80% oil case, and class IV response in the 90% gas case. Within the synthetic gathers, a consistent class IV AVO response is observed for all fluid cases. The variation is likely due to the synthetic gathers correctly showing the response of the porosity increase observed, whereas the Blocky AVO modelling is based upon averages of porosity throughout both formations.
- Elastic Contrast Analysis shows contrasts are negligible in the100% brine case, becoming increasingly negative with addition of hydrocarbons. Lambda and LambdaRho show the most sensitivity to fluid effects.

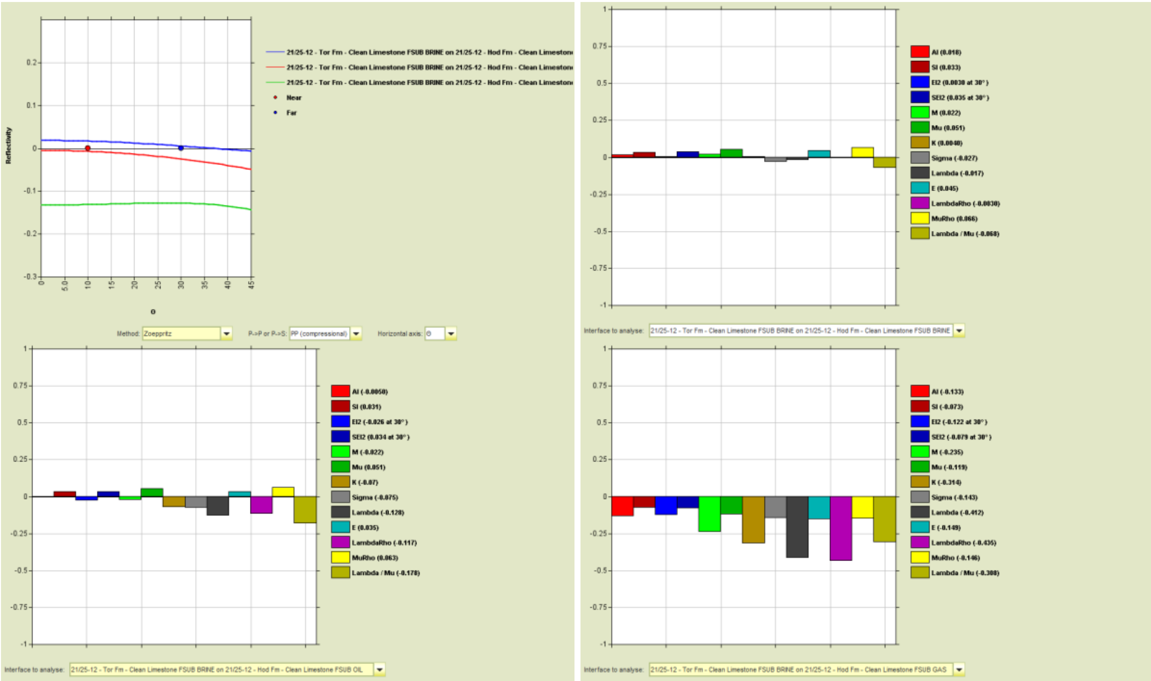


Figure 3.5.13 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 21/25-12.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 21/25-12 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/25-12	Overburden				
21/25-12	Underburden	Limestone/Shale	13349		2.59

Table 3.5.9 - Overburden and underburden properties at Well 21/25-12.

Well: 21/30-01

General

Well Information
Shell operated exploration well spudded, completed and abandoned in 1969. The well encountered oil in the Balder Formation (Odin Member) and Sele Formation (Cromarty, Forties Members), and is the discovery well for the Gannet F field.

Objectives
The well was drilled to evaluate a salt induced dome. A number of Palaeocene reservoirs were present, each encountering oil. The Upper Cretaceous Chalk Group was present also but wet.

Log conditioning overview
Good log quality removes the requirement for any significant log editing, with only a few spikes removed from the Vp log towards the top of the Balder Formation. Caliper log and density correction logs imply a degree of borehole rugosity within the shaley sections causing some spiking.

Invasion correction
The drilling mud used within this well was water based. Invasion correction of the density log performed in the Balder and Sele Formation where oil was encountered.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Balder Formation for Vp and density. A complete Vs log is modelled using Modified Gassmann methodology due the absence of measured shear log data.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 21/30-01 is displayed in the figures below;

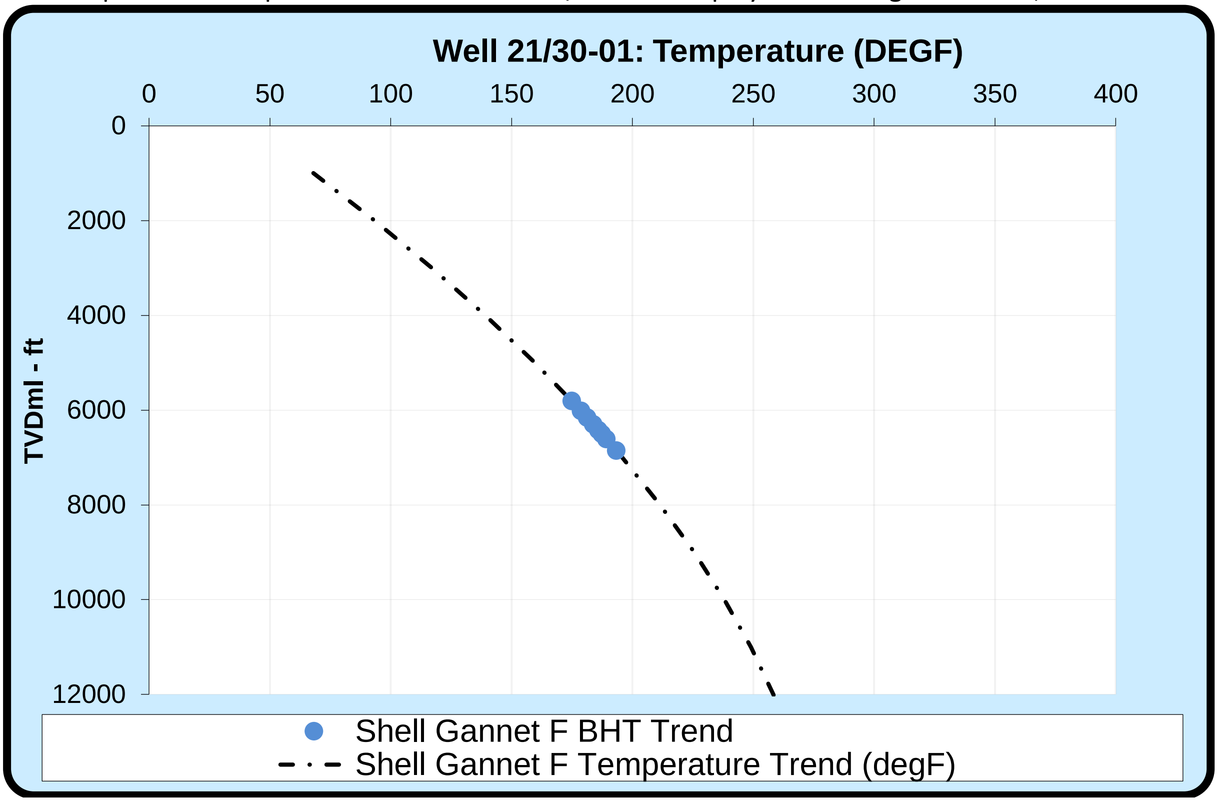


Figure 3.6.1 - Temperature data at Well 21/30-01

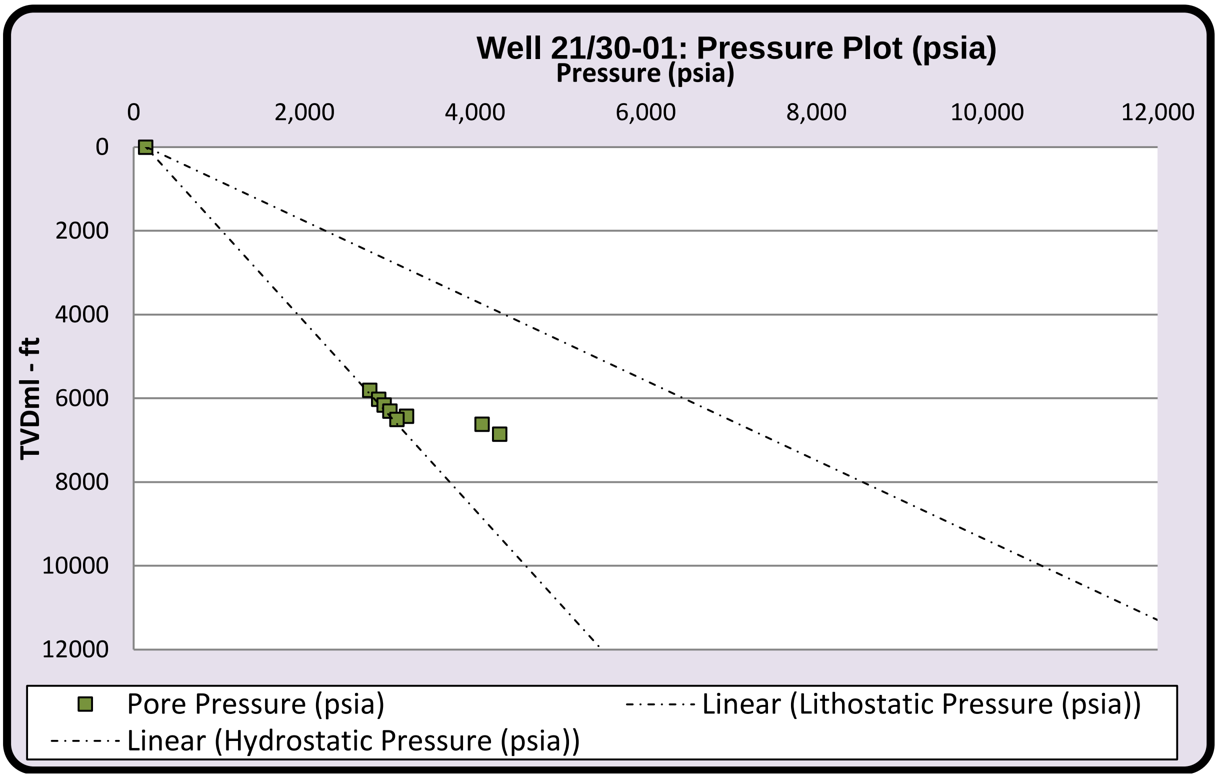


Figure 3.6.2 - Pressure data at Well 21/30-01

The temperature and pressure data for the formation mid-points in Well 21/30-01 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
21/30-01	Sea Bed	405.0	319.0	0.0	39.2	142.0	142.0	141.96	0.00
21/30-01	Horda	6208.5	6122.5	5803.5	174.9	2724.5	2769.5	5945.41	3175.92
21/30-01	Balder	6422.0	6336.0	6017.0	178.8	2819.5	2872.5	6158.96	3286.44
21/30-01	Sele	6564.5	6478.5	6159.5	181.4	2882.9	2935.9	6301.46	3365.52
21/30-01	Lista	6704.5	6618.5	6299.5	183.9	2945.2	3005.2	6441.46	3436.22
21/30-01	Maureen	6826.5	6740.5	6421.5	186.0	2999.5	3199.5	6563.46	3363.93
21/30-01	Ekofisk	6909.6	6823.6	6504.6	187.4	3036.5	3086.5	6646.51	3560.03
21/30-01	Tor	7018.1	6932.1	6613.1	189.3	3084.8	4084.8	6755.01	2670.25
21/30-01	Hod	7260.0	7174.0	6855.0	193.4	3192.4	4289.8	6996.96	2707.14

Table 3.6.1 - Summary of mid-point temperature and pressure data at Well 21/30-01

Fluid data

A summary of the fluid set parameters at Well 21/30-01 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
21/30-01	Horda	78000	730	37.6	0.71	0.71
21/30-01	Balder	78000	730	37.9	0.71	0.71
21/30-01	Sele	78000	440	37.0	0.8	0.8
21/30-01	Lista	78000	730	38.2	0.71	0.71
21/30-01	Maureen	78000	730	38.3	0.71	0.71
21/30-01	Ekofisk	78000	730	38.4	0.71	0.71
21/30-01	Tor	78000	730	38.5	0.71	0.71
21/30-01	Hod	78000	730	38.8	0.71	0.71

Table 3.6.2 - Summary of fluid parameter data at Well 21/30-01

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.6.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	10.56	2.82	2.33	8,133	3,606

Table 3.6.4 - Tuff properties used at Well 21/30-01

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
21/30-01	Horda	PAY	321.090	0.000	0.000	0.000	0.000	0.000	0.000
21/30-01	Horda	RES	321.090	0.000	0.000	0.000	0.000	0.000	0.000
21/30-01	Balder	PAY	106.000	4.000	0.038	1.311	0.328	0.374	0.009
21/30-01	Balder	RES	106.000	29.250	0.276	7.551	0.258	0.811	0.108
21/30-01	Sele	PAY	179.000	3.000	0.017	0.942	0.314	0.409	0.000
21/30-01	Sele	RES	179.000	102.750	0.574	26.069	0.254	0.894	0.299
21/30-01	Lista	PAY	101.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-01	Lista	RES	101.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-01	Maureen	PAY	143.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-01	Maureen	RES	143.000	8.250	0.058	1.410	0.171	0.999	0.385
21/30-01	Ekofisk	PAY	23.110	0.000	0.000	0.000	0.000	0.000	0.000
21/30-01	Ekofisk	RES	23.110	23.110	1.000	3.531	0.153	0.890	0.139
21/30-01	Tor	PAY	193.890	0.000	0.000	0.000	0.000	0.000	0.000
21/30-01	Tor	RES	193.890	193.890	1.000	18.997	0.098	0.995	0.019
21/30-01	Hod	PAY	290.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-01	Hod	RES	290.000	290.000	1.000	41.833	0.144	0.999	0.109

Table 3.6.5 - Petrophysical parameters used at Well 21/30-01

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

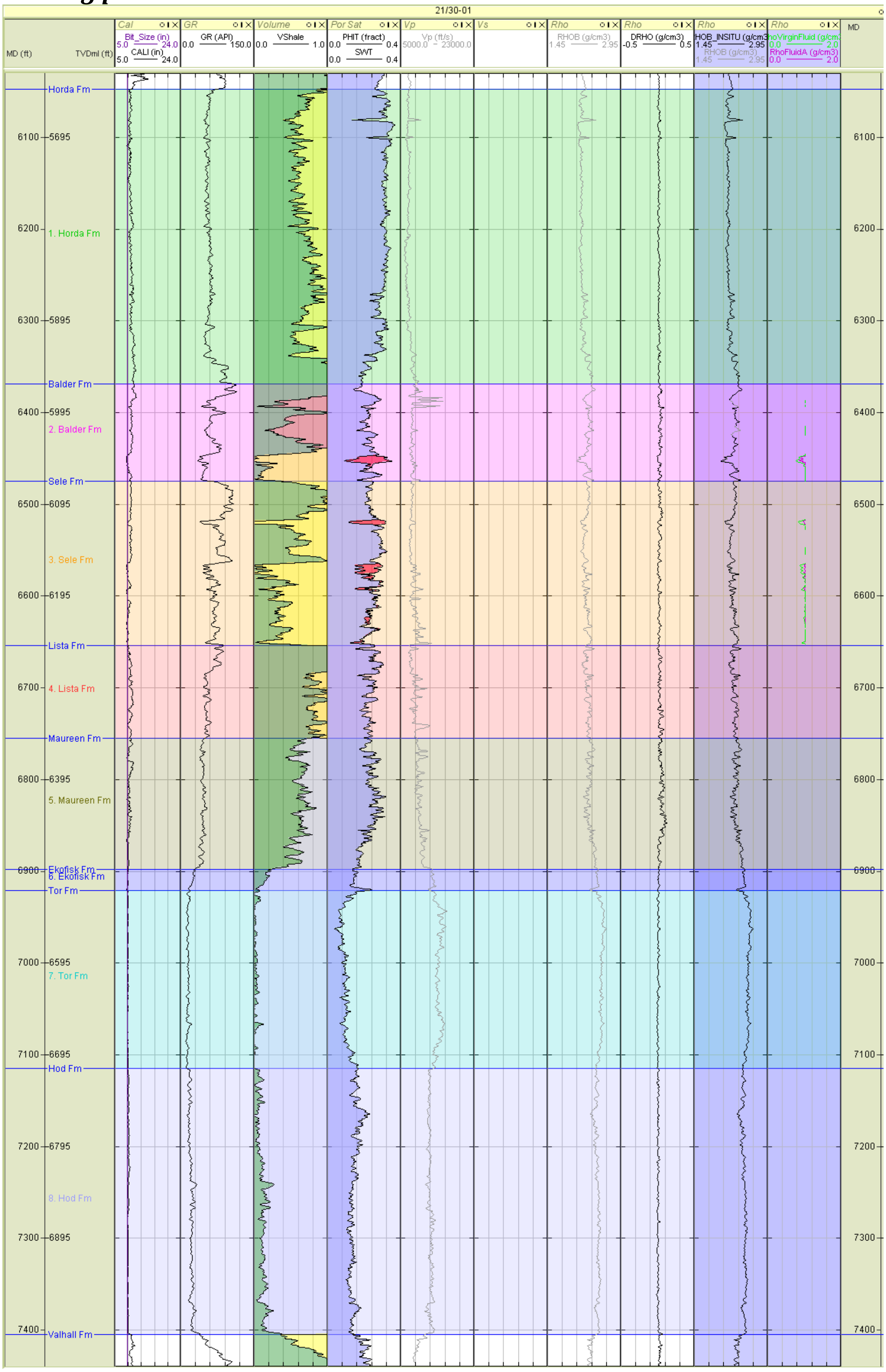


Figure 3.6.3 - Well Panel: Measured data and invasion correction for well 21/30-01.

Well log panel – log editing and audit

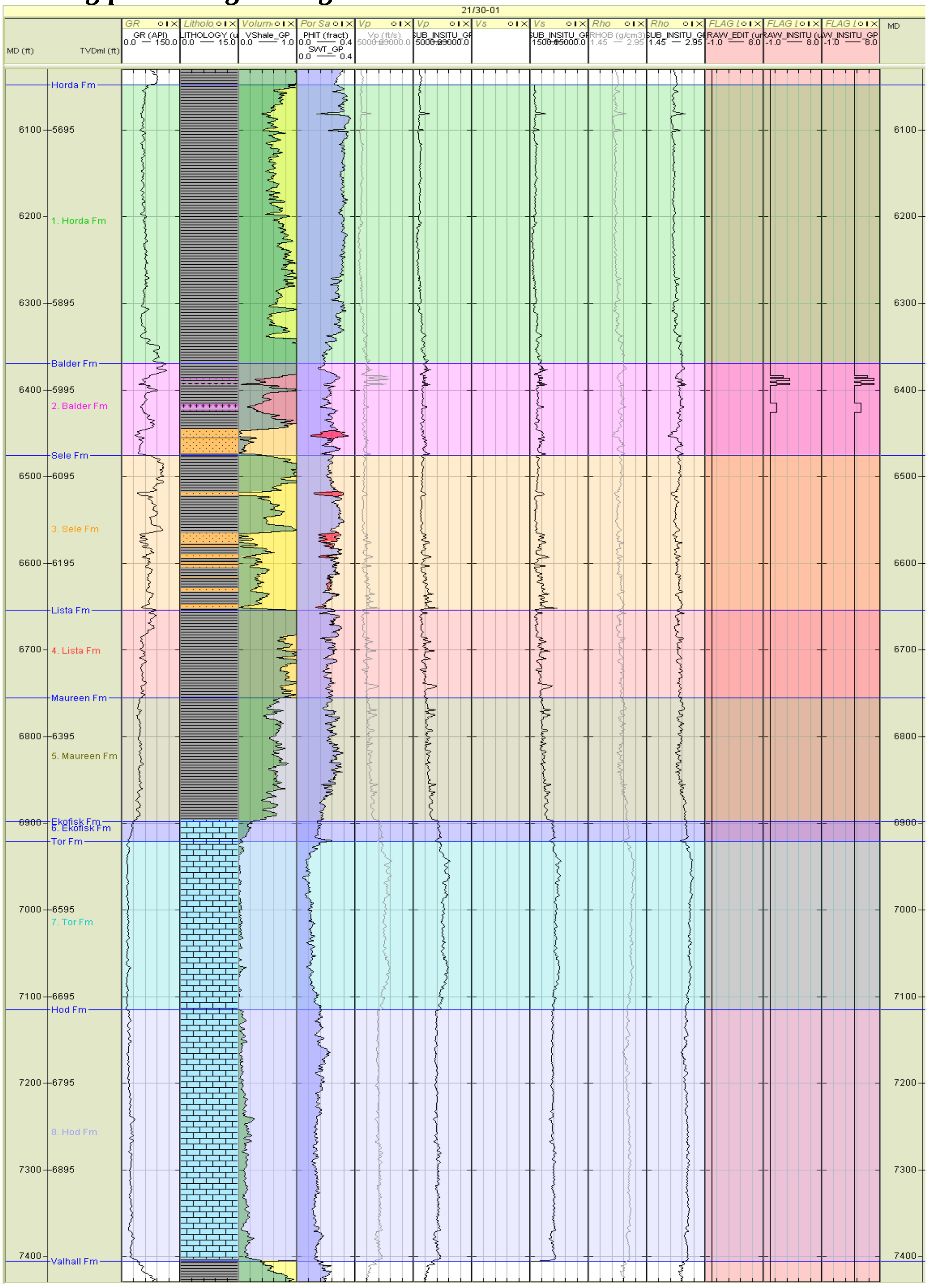


Figure 3.6.4 - Well Panel: Log edits for well 21/30-01.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

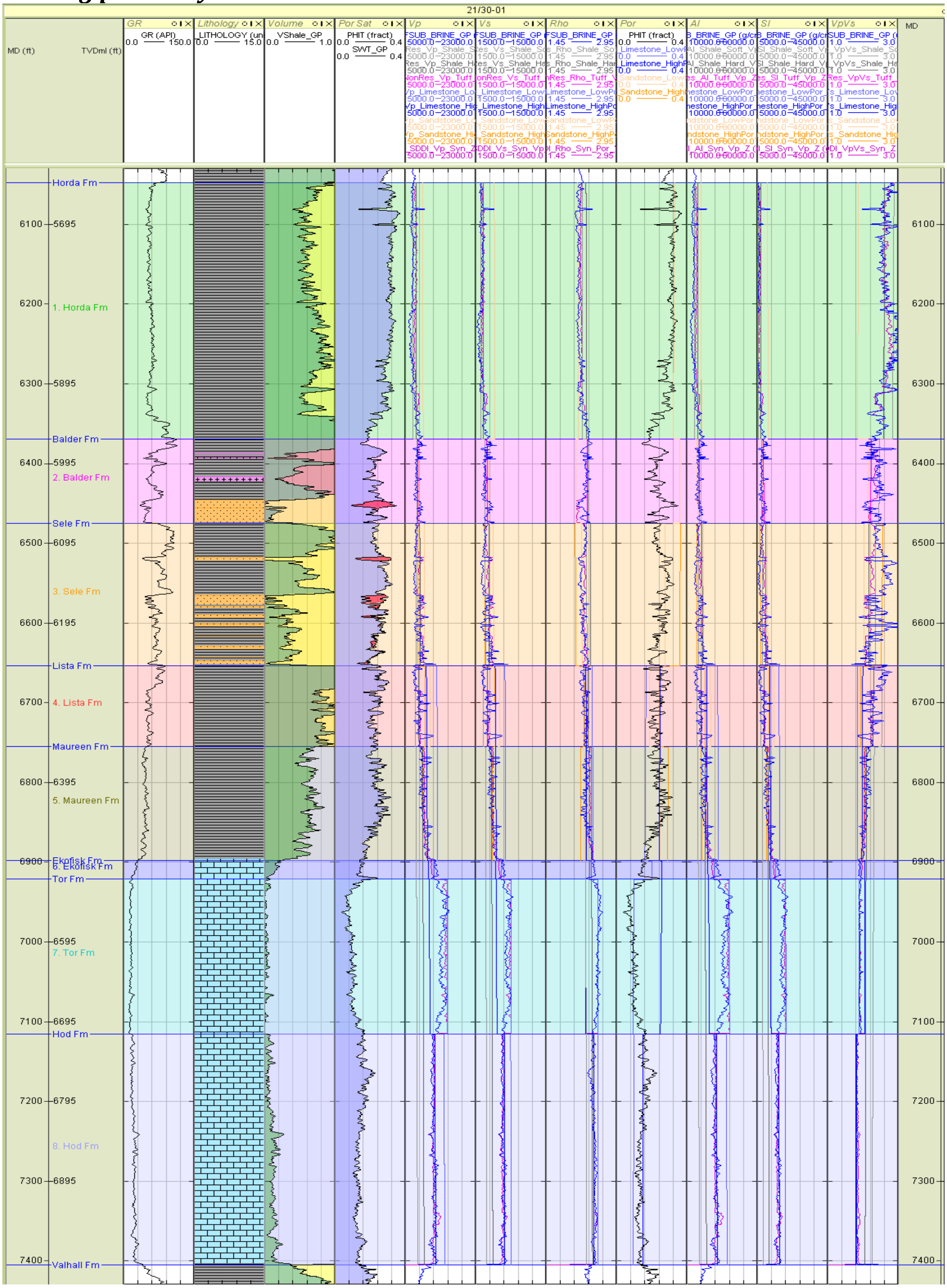


Figure 3.6.5 - Well Panel: End-member and synthetic logs for well 21/30-01.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

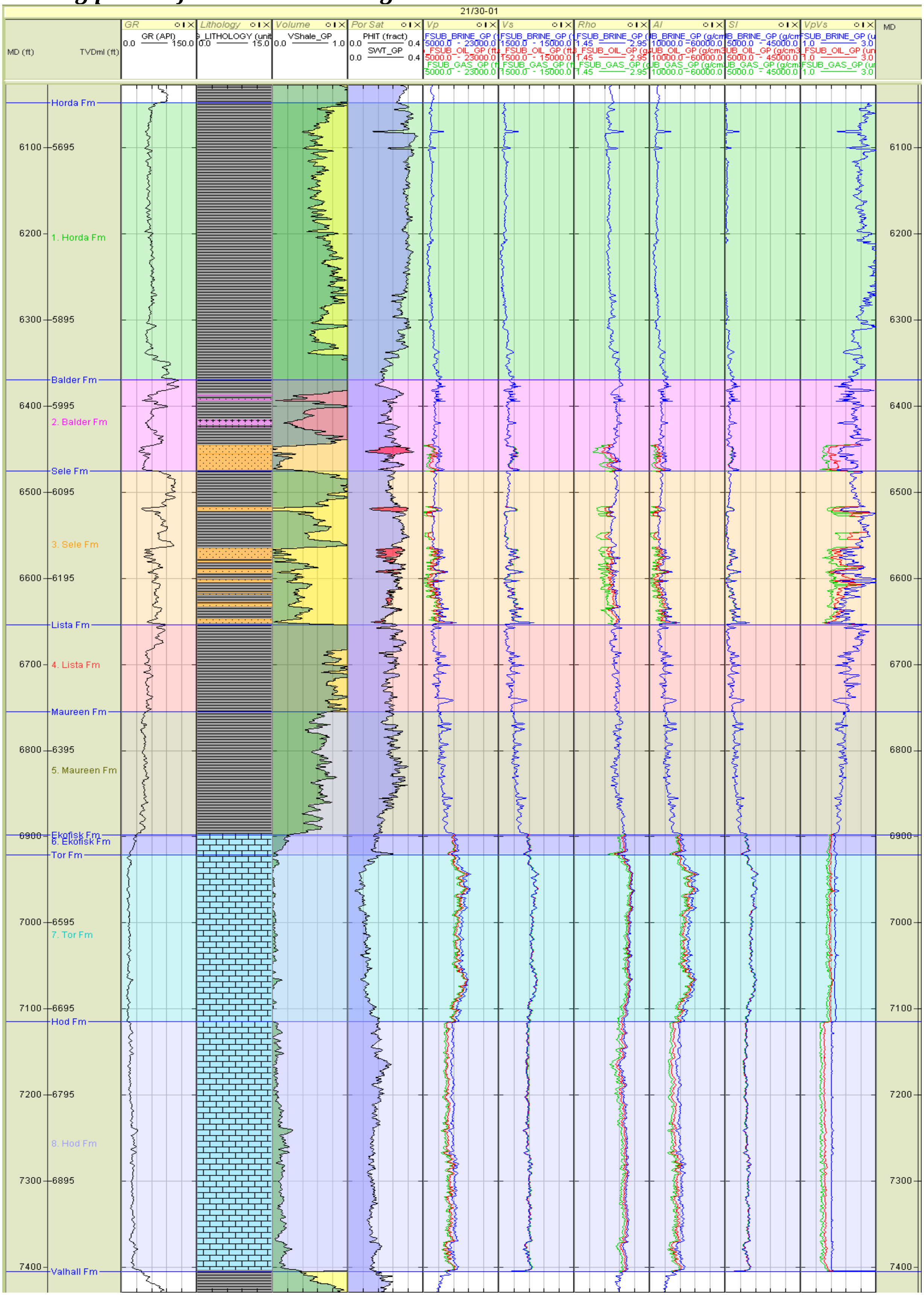


Figure 3.6.6 - Well Panel: Fluid substituted and elastic logs for well 21/30-01.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 21/30-01 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-01	Horda	6886	2501	2.18
21/30-01	Balder	8017	3356	2.30
21/30-01	Sele	7547	3071	2.26
21/30-01	Lista	8309	3620	2.27
21/30-01	Maureen	9216	4357	2.29

Table 3.6.6 - Clean shale properties at Well 21/30-01

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-01	Horda	100% Brine			
21/30-01	Balder	100% Brine	8634	3879	2.23
21/30-01	Sele	100% Brine	9145	4214	2.25
21/30-01	Lista	100% Brine			
21/30-01	Maureen	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-01	Horda	80% Oil			
21/30-01	Balder	80% Oil	7236	3944	2.16
21/30-01	Sele	80% Oil	8196	4271	2.19
21/30-01	Lista	80% Oil			
21/30-01	Maureen	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-01	Horda	90% Gas			
21/30-01	Balder	90% Gas	6663	4064	2.04
21/30-01	Sele	90% Gas	7675	4401	2.06
21/30-01	Lista	90% Gas			
21/30-01	Maureen	90% Gas			

Table 3.6.7 - Clean sand properties at Well 21/30-01 for each fluid case

Tertiary reservoirs – Well panel

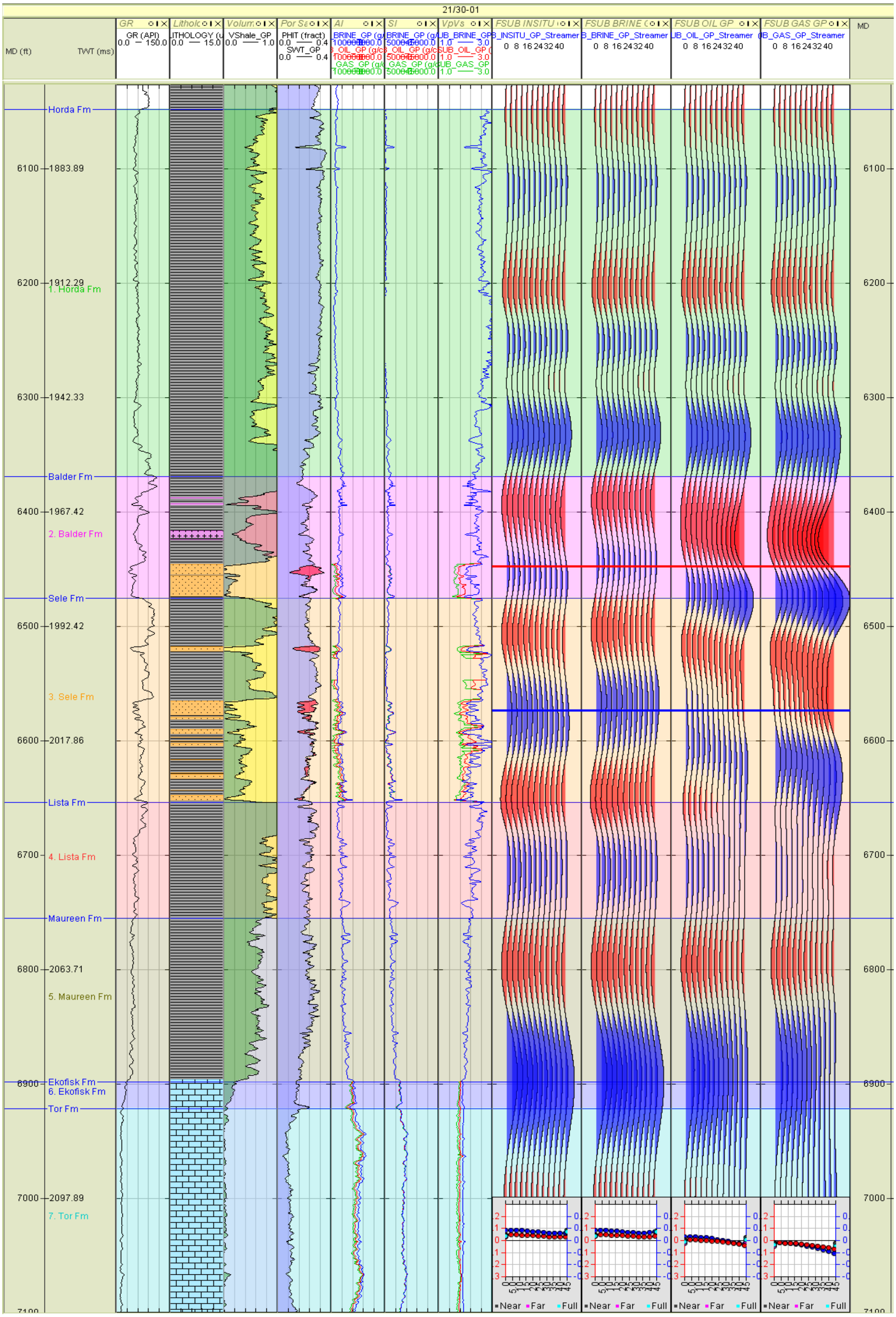


Figure 3.6.7 - Well Panel: Tertiary reservoirs for well 21/30-01. Wavelet: Streamer

Formation description - Tertiary reservoirs

Balder Formation

- Reservoir formed by clean blocky sandstone at the base of the interval approximately 29 feet in thickness (net reservoir). The reservoir is overlain by tuffaceous shale of the Balder Formation, and overlies shale of the Sele Formation.
- Blocky AVO shows a modelled low gradient class I response for the 100% brine case showing low reflectivity, the 80% oil and 90% gas cases show a modelled class III response. Within the synthetic gathers, a class I AVO response is seen in the 100% brine case, a class II response in the 80% oil case and class III response in the 90% gas case. It is likely this variation is caused by wavelet interference from the contact between shale and tuff towards the top formation.
- Elastic Contrast Analysis shows contrasts are generally weak and positive in the 100% brine case, often becoming strongly negative with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda and LambdaRho show the most sensitivity to fluid effects.

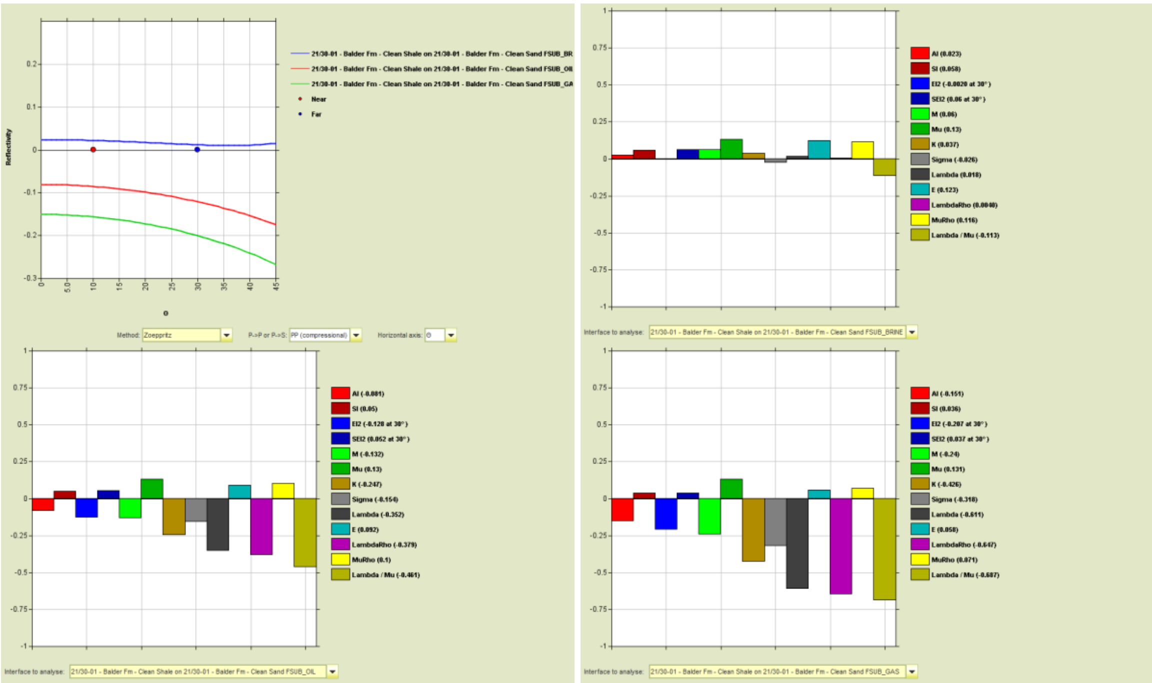


Figure 3.6.8 - Blocky AVO Model and Elastic Contrast Analysis for the Balder Formation in well 21/30-01.

Sele Formation

- Reservoir formed through two main sections, a thin (approximately 6 feet) sand towards the top of the interval and a silty blocky sandstone at the base of the interval. The reservoir is encased by shale, has a net reservoir of approximately 103 feet and porosities of 24-31%.
- Blocky AVO shows a modelled class I response for the 100% brine case, a marginal class I/IIp response for the 80% oil case, and class III response for the 90% gas case. Within the synthetic gathers, analogous AVO responses are observed in for the more vertically extensive blocky sandstone. However, the overlying thin sandstone cannot be resolved due to wavelet interference caused by neighbouring reservoirs within the Balder and Sele Formations.
- Elastic Contrast Analysis shows contrasts largely moderate and positive in the 100% brine case, becoming increasing negative with the addition of hydrocarbons. LambdaRho and Lambda/Mu show the most sensitivity to fluid effects. Mu shows the least sensitivity to fluid effects.

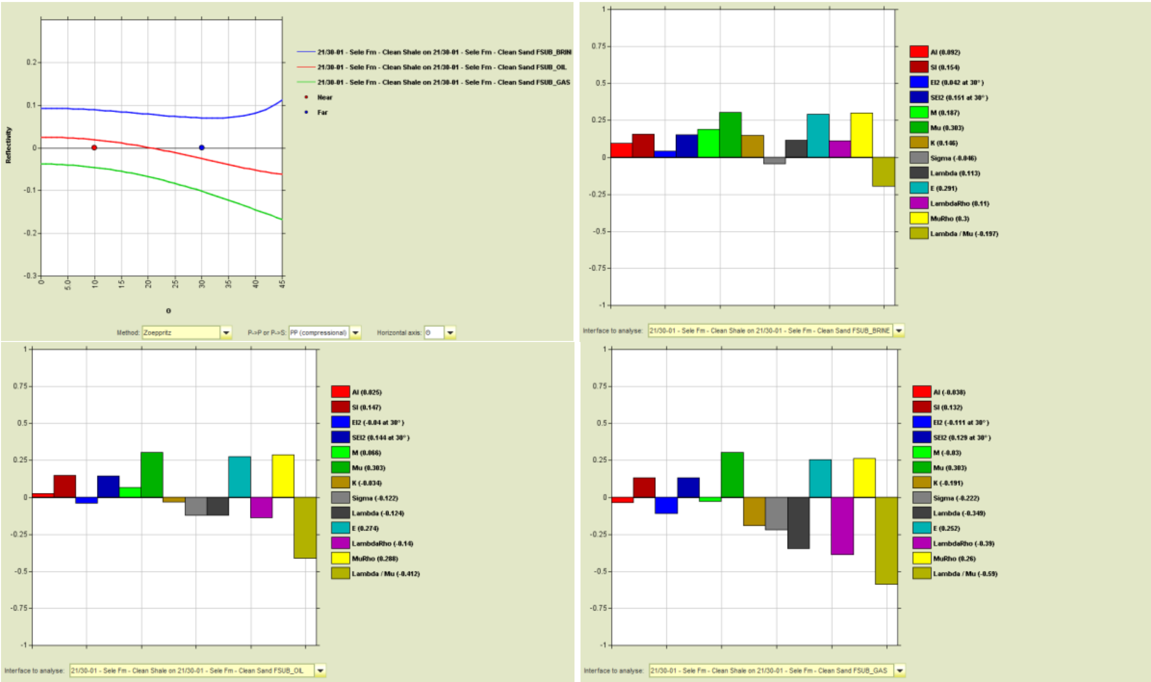


Figure 3.6.9 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 21/30-01.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 21/30-01 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-01	Ekofisk	100% Brine	12393	6455	2.40
21/30-01	Tor	100% Brine	14275	7482	2.54
21/30-01	Hod	100% Brine	12093	6667	2.44
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-01	Ekofisk	80% Oil	11577	6524	2.35
21/30-01	Tor	80% Oil	13399	7522	2.52
21/30-01	Hod	80% Oil	10943	6728	2.40
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-01	Ekofisk	90% Gas	11391	6645	2.27
21/30-01	Tor	90% Gas	13033	7586	2.47
21/30-01	Hod	90% Gas	10481	6827	2.33

Table 3.6.8 - Clean limestone properties at Well 21/30-01 for each fluid case

Cretaceous reservoirs

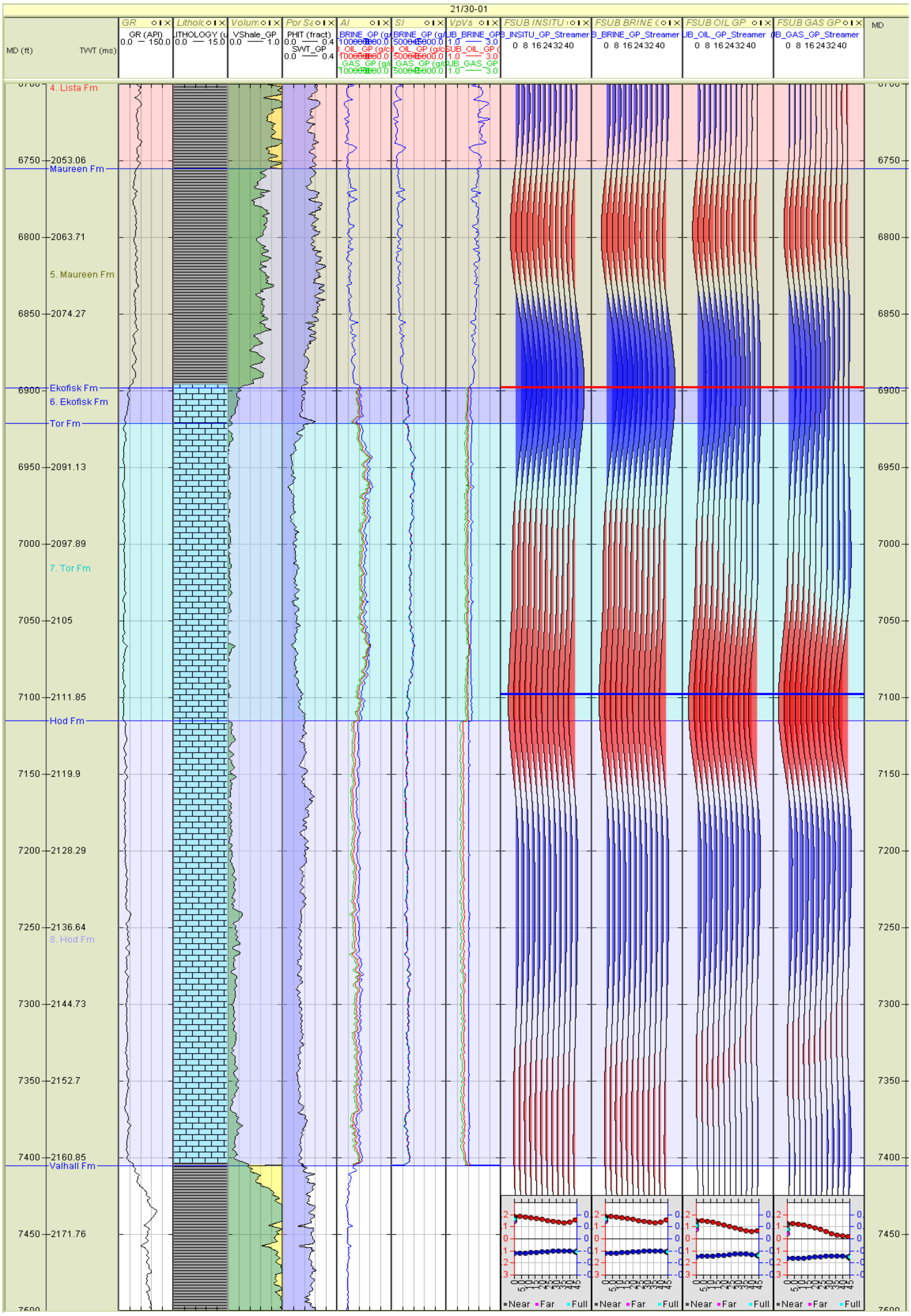


Figure 3.6.10 - Well Panel: Cretaceous reservoirs for well 21/30-01. Wavelet: Streamer

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir chalk runs throughout the formation, which is relatively thin at approximately 23 feet (net). The reservoir on average contains a porosity of 15%, which increases to approximately 25% at the boundary with the Tor Formation. Calcareous silt of the Maureen Formation overlies the interval.
- Blocky AVO modelling shows a class I response predicted in all fluid cases, where reflectivity decreases with the addition of hydrocarbons. Synthetic gathers give an AVO class consistent with Blocky AVO modelling. Both the Ekofisk and Tor Formation share a common top reservoir seismic response.
- Elastic Contrast Analysis generally shows moderate positive contrasts in the 100% brine case. Moving to the 80% oil and 90% gas bearing case, many constants show insensitivity to fluid effects, while Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

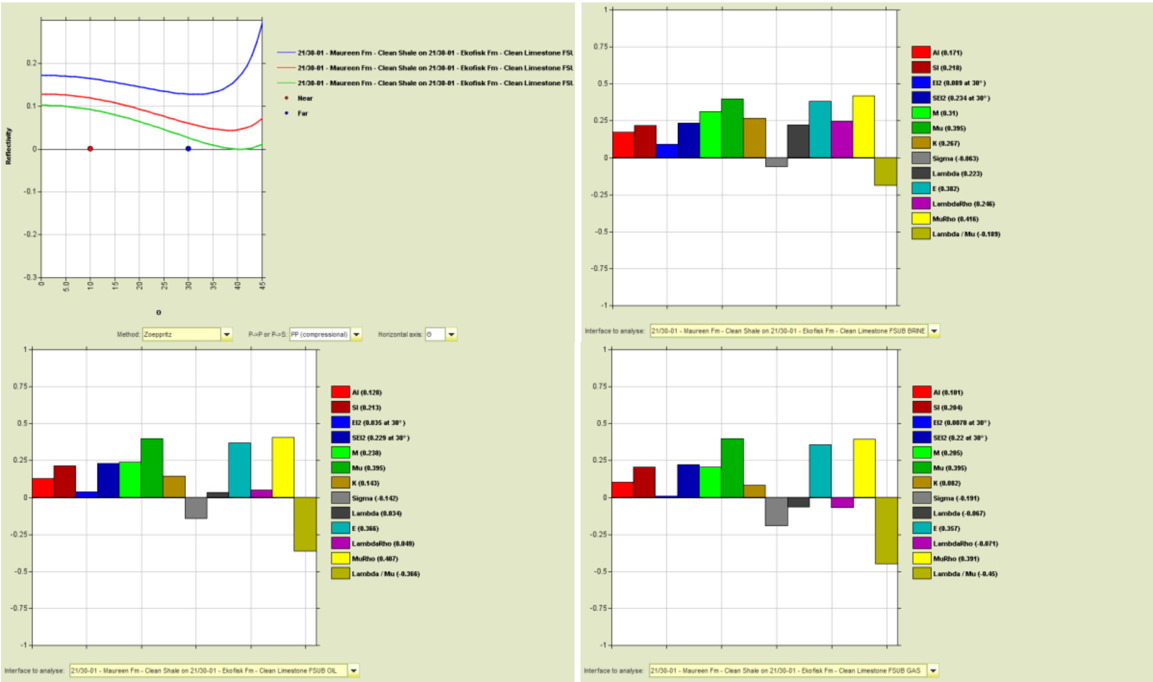


Figure 3.6.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 21/30-01.

Tor Formation

- Reservoir occurs as zones of higher porosity (approximately 17-25%) at the top and base of the interval. The formation is encased by relatively silty chalks of the Ekofisk and Hod Formations. Net reservoir is approximately 194 feet.
- Blocky AVO shows a modelled class I response for all fluid cases, with reflectivity decreasing with the addition of hydrocarbons, and a phase reversal occurring in the 90% gas case. Within the synthetic gathers, a consistent class I AVO response is observed. The response seen with the synthetic gathers appears to be dominated by the shale on chalk contact at the top Ekofisk Formation, with the top Tor Formation response likely lost through wavelet interference given the reduced contrast in properties and limited vertical extent of the Ekofisk Formation.
- Elastic Contrast Analysis generally shows weak positive contrasts in the 100% brine case, becoming increasingly negative with the addition of hydrocarbons. Mu shows the least sensitivity to fluid effects, while LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

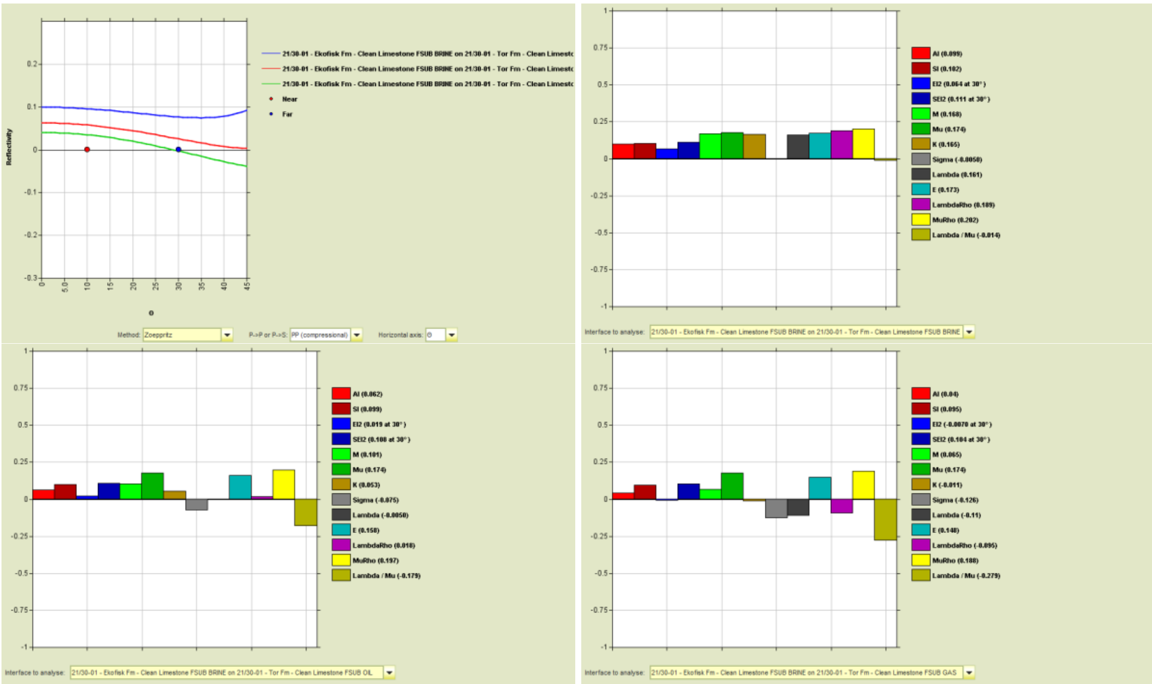


Figure 3.6.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 21/30-01.

Hod Formation

- Reservoir formed by patchy zones of higher porosity (approximately 14-23%) throughout the interval. The formation is overlain by comparable chalk of the Tor Formation and overlies silty sands of the Valhall Formation. Net reservoir is approximately 290 feet.
- Blocky AVO modelling shows a class IV response predicted in each fluid case. Within the synthetic gathers, a corresponding class IV AVO response is observed in all fluid cases.
- Elastic Contrast Analysis shows weak negative contrasts in the 100% brine case, becoming increasingly negative with in the 80% oil and 90% gas cases. The majority of constants show high sensitivity to fluid changes, where Mu shows the least sensitivity to fluid effects.

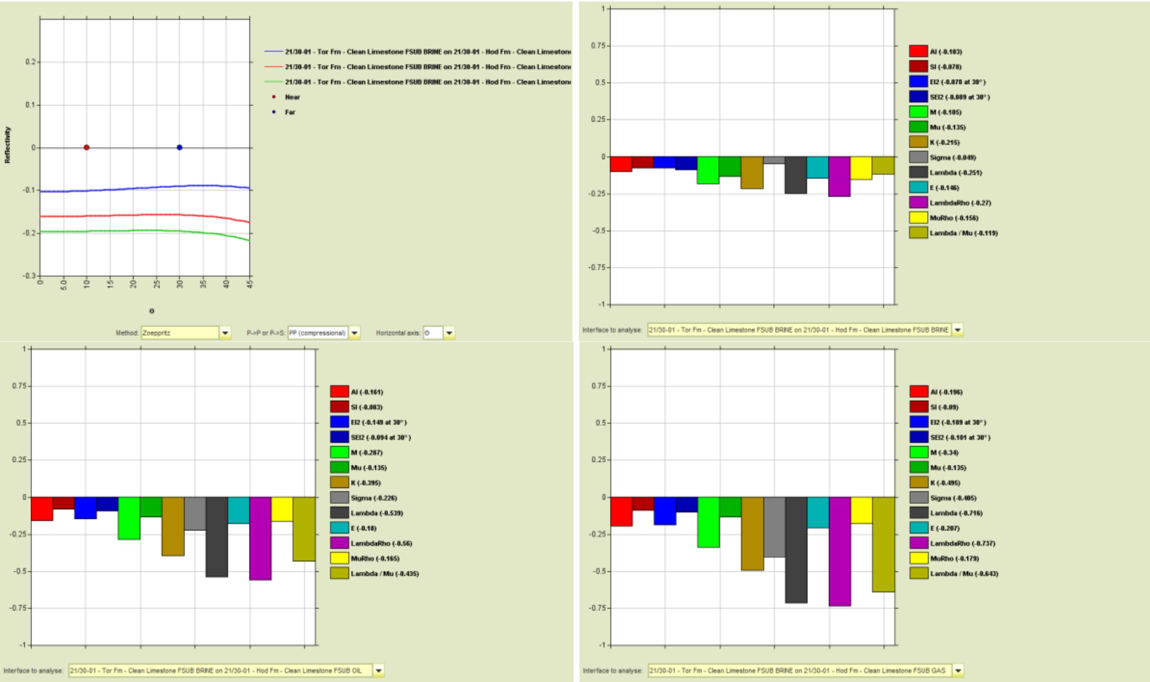


Figure 3.6.13 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 21/30-01.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 21/30-01 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-01	Overburden	Shale	7313		2.20
21/30-01	Underburden	Shale	9115		2.34

Table 3.6.9 - Overburden and underburden properties at Well 21/30-01.

Well: 21/30-03

General

Well Information
Shell operated exploration well spudded, completed and abandoned in 1981. The well encountered oil in the Upper Jurassic Fulmar Formation, and is the discovery well for the Guillemot field.

Objectives
The well was designed to test dip closures at Tertiary and Jurassic levels. The Jurassic objective was a shallow marine sand section prognosed to occur in a rim syncline to the southeast of a salt intrusion. In the Tertiary section, Paleocene sands formed the secondary objective. Secondary targets of the Sele Formation (Forties Member) and Lista Formation (Andrew Member) sands were present but wet.

Log conditioning overview
Only minor log editing performed due to good log quality within the well. Borehole washout is seen to occur at the top of logging run two, and the uppermost Vp and density logs were clipped to remove the associated data.

Invasion correction
The drilling mud used within this well was water based. Invasion correction not required due to absence of hydrocarbons present over the study interval.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda Formation for Vp and density, associated with a casing point. A complete Vs log is modelled due to the lack of measured shear data.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 21/30-03 is displayed in the figures below;

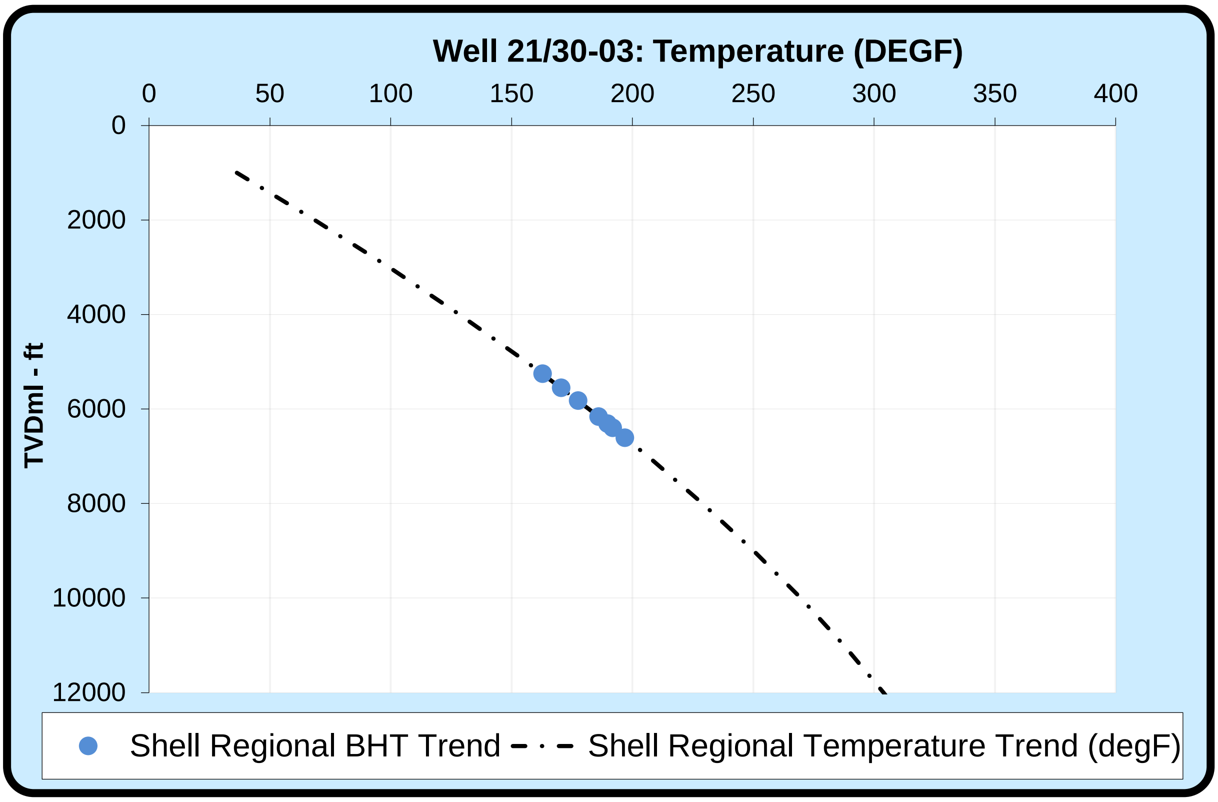


Figure 3.7.1 - Temperature data at Well 21/30-03

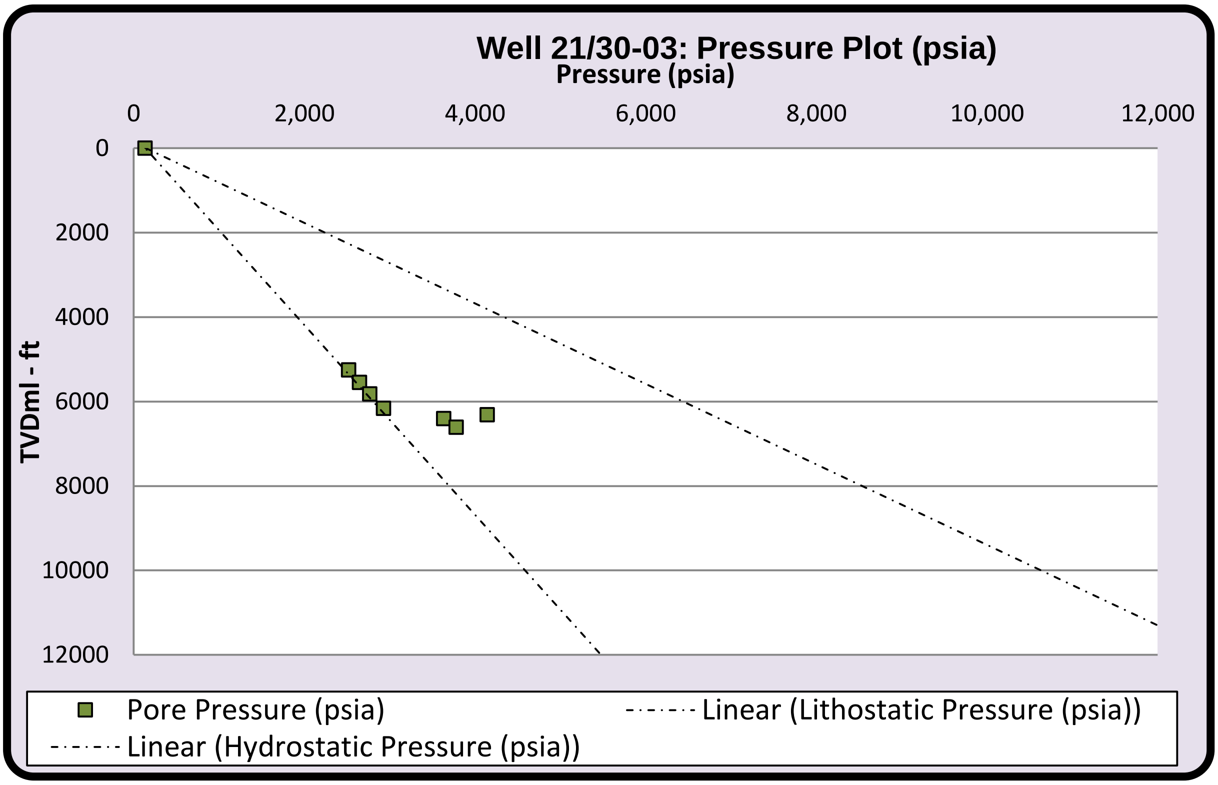


Figure 3.7.2 - Pressure data at Well 21/30-03

The temperature and pressure data for the formation mid-points in Well 21/30-03 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
21/30-03	Sea Bed	390.0	305.0	0.0	39.2	135.7	135.7	135.72	0.00
21/30-03	Horda	5644.6	5559.4	5254.4	162.9	2474.0	2519.0	5390.17	2871.22
21/30-03	Balder	5940.0	5854.8	5549.8	170.6	2605.4	2647.4	5685.57	3038.16
21/30-03	Sele	6213.5	6128.3	5823.3	177.6	2727.1	2769.1	5959.06	3189.95
21/30-03	Lista	6551.4	6466.2	6161.2	186.1	2877.5	2927.5	6296.92	3369.46
21/30-03	Maureen	6699.9	6614.7	6309.7	189.7	2943.5	4143.5	6445.41	2301.88
21/30-03	Tor	6997.6	6912.4	6607.4	197.0	3076.0	3781.0	6536.55	2902.46
21/30-03	Hod	390.0	305.0	0.0	39.2	135.7	135.7	6743.12	2962.11

Table 3.7.1 - Summary of mid-point temperature and pressure data at Well 21/30-03

Fluid data

A summary of the fluid set parameters at Well 21/30-03 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
21/30-03	Horda	75000	730	37.0	0.71	0.71
21/30-03	Balder	75000	730	37.4	0.71	0.71
21/30-03	Sele	75000	798.4	38.3	0.866	0.866
21/30-03	Lista	75000	730	38.0	0.71	0.71
21/30-03	Maureen	75000	730	38.2	0.71	0.71
21/30-03	Tor	75000	730	38.3	0.71	0.71
21/30-03	Hod	75000	730	38.5	0.71	0.71

Table 3.7.2 - Summary of fluid parameter data at Well 21/30-03

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.7.3 - Constant mineral properties used in this project

There is no Tuff present in this well.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
21/30-03	Horda	PAY	494.820	0.000	0.000	0.000	0.000	0.000	0.000
21/30-03	Horda	RES	494.820	0.000	0.000	0.000	0.000	0.000	0.000
21/30-03	Balder	PAY	96.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-03	Balder	RES	96.000	4.500	0.047	1.151	0.256	0.885	0.373
21/30-03	Sele	PAY	451.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-03	Sele	RES	451.000	302.500	0.671	84.956	0.281	0.991	0.169
21/30-03	Lista	PAY	224.720	0.000	0.000	0.000	0.000	0.000	0.000
21/30-03	Lista	RES	224.720	62.470	0.278	17.049	0.273	0.977	0.111
21/30-03	Maureen	PAY	72.280	0.000	0.000	0.000	0.000	0.000	0.000
21/30-03	Maureen	RES	72.280	44.780	0.620	6.503	0.145	0.947	0.166
21/30-03	Tor	PAY	110.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-03	Tor	RES	110.000	109.250	0.993	13.563	0.124	0.998	0.030
21/30-03	Hod	PAY	303.140	0.000	0.000	0.000	0.000	0.000	0.000
21/30-03	Hod	RES	303.140	303.140	1.000	50.396	0.166	0.989	0.126

Table 3.7.4 - Petrophysical parameters used at Well 21/30-03

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

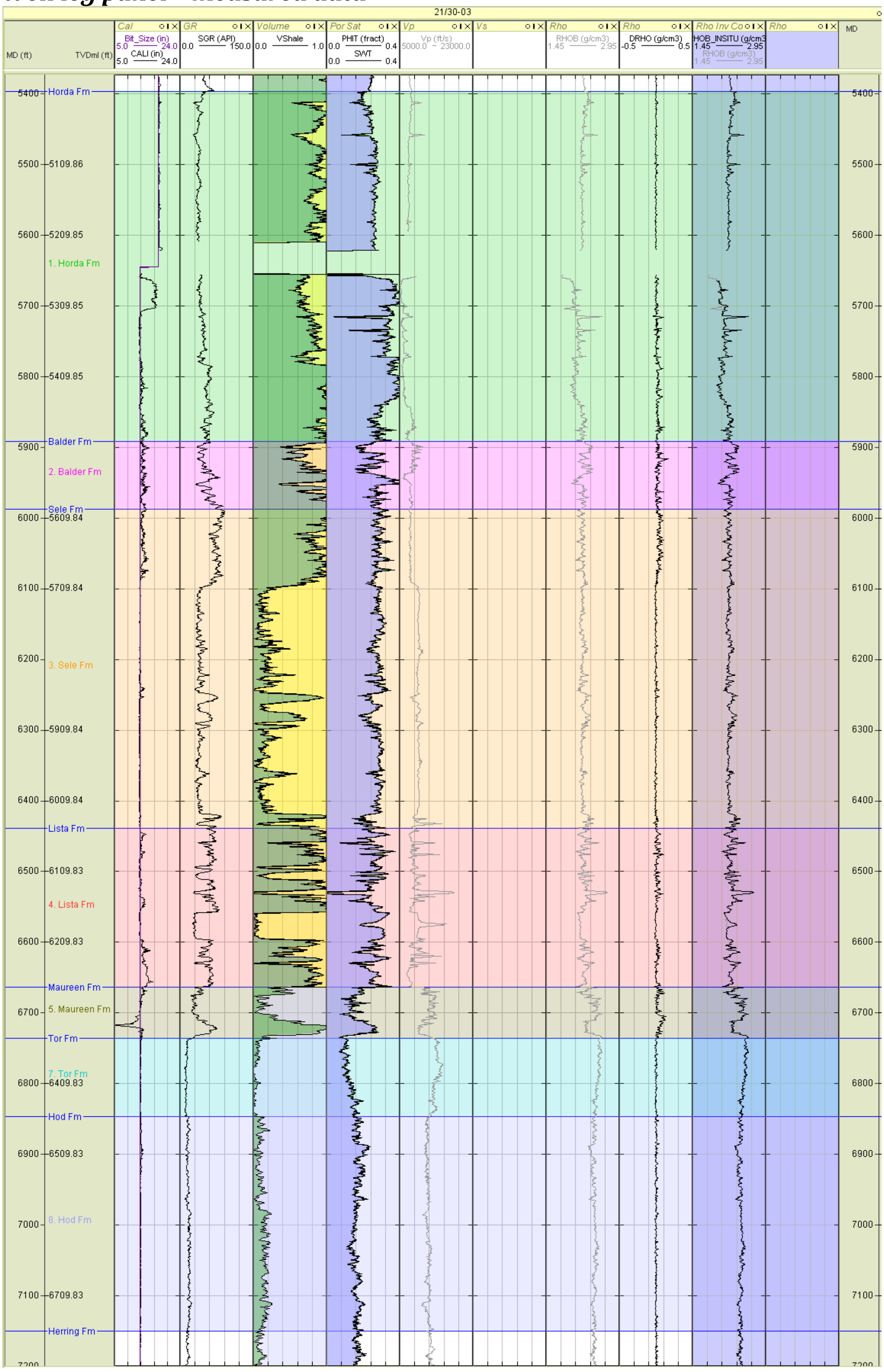


Figure 3.7.3 - Well Panel: Measured data and invasion correction for well 21/30-03.

Well log panel – log editing and audit

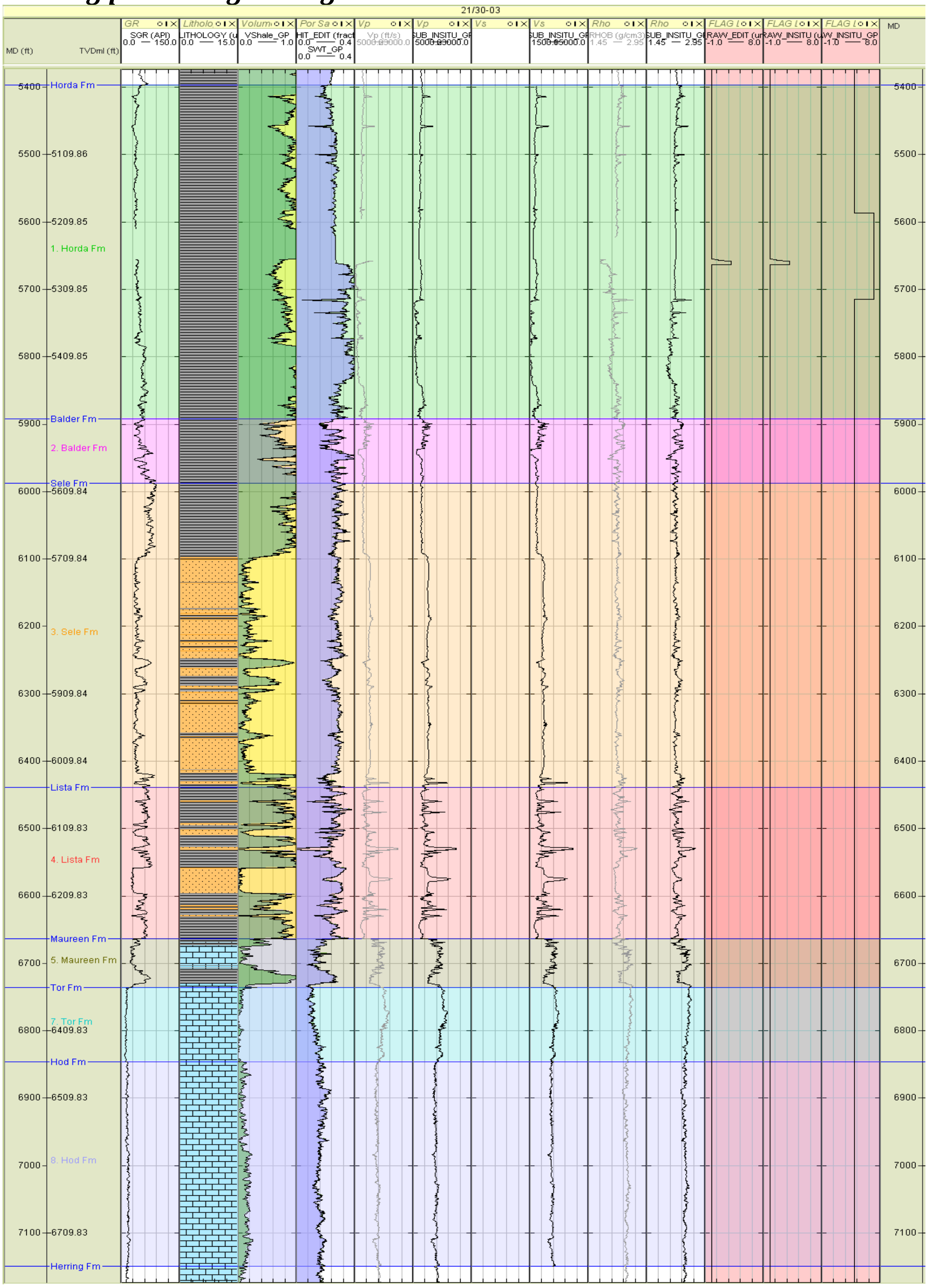


Figure 3.7.4 - Well Panel: Log edits for well 21/30-03.

<u>Legend</u>

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

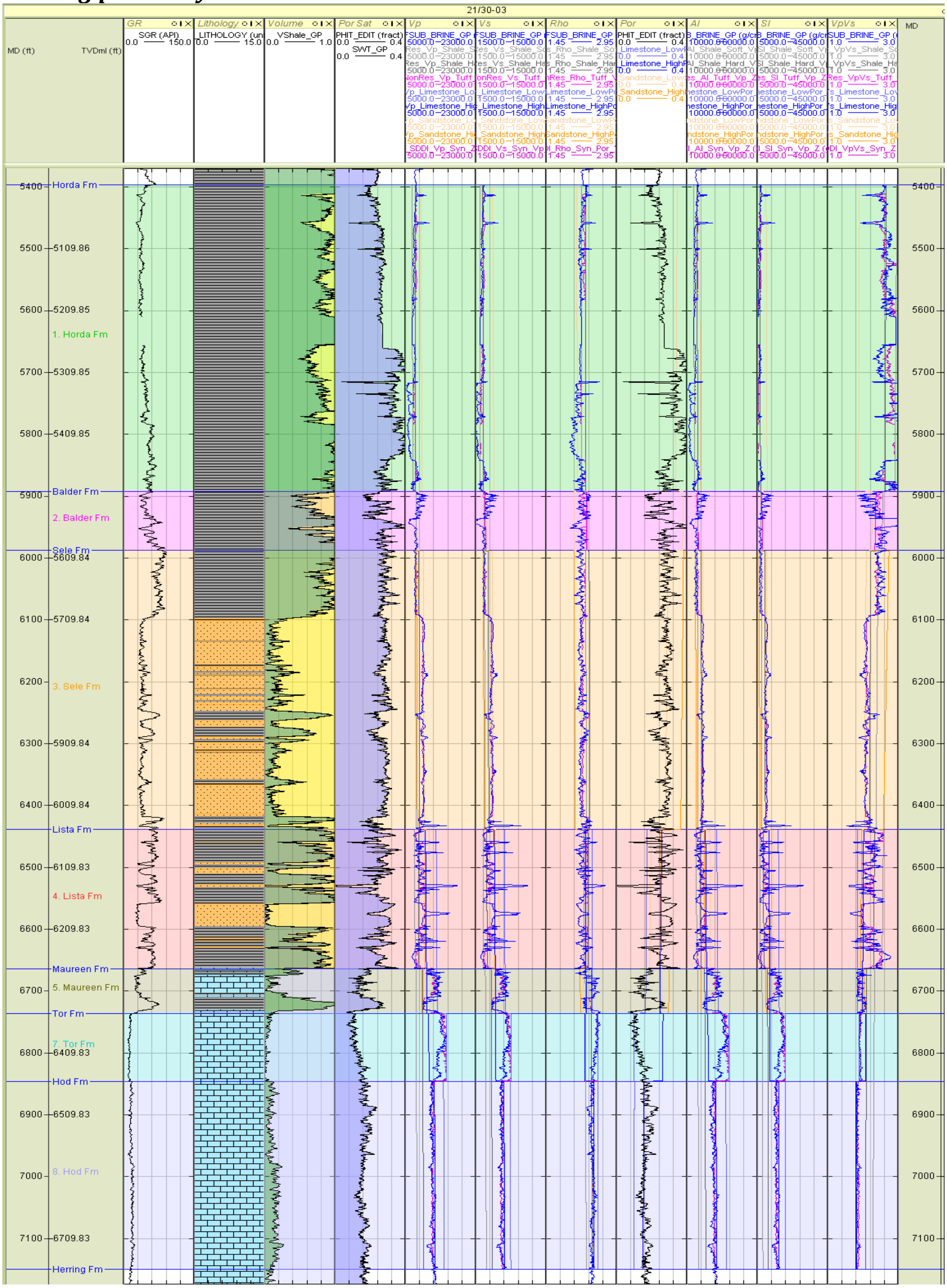


Figure 3.7.5 - Well Panel: End-member and synthetic logs for well 21/30-03.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

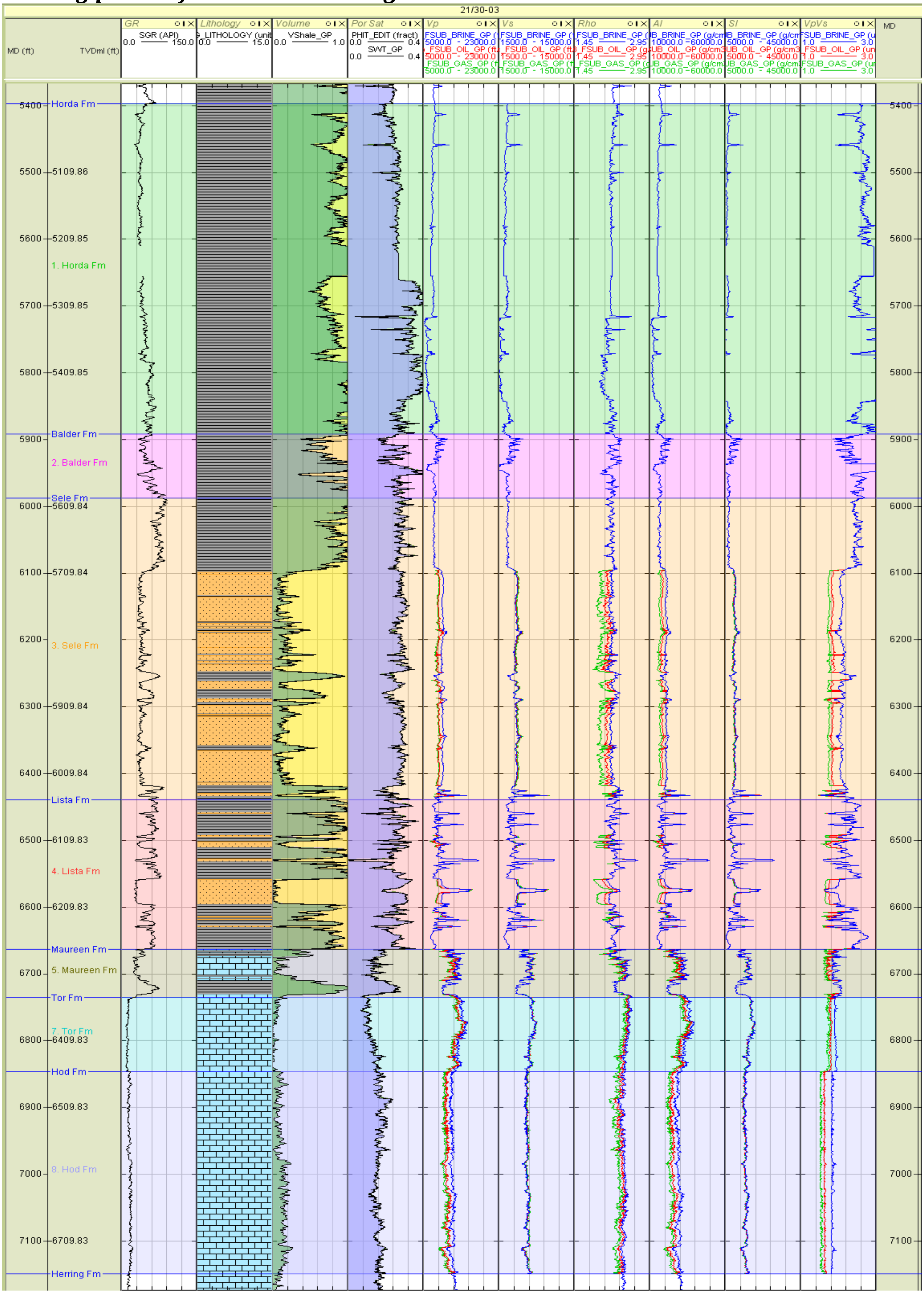


Figure 3.7.6 - Well Panel: Fluid substituted and elastic logs for well 21/30-03.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 21/30-03 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-03	Horda	6864	2444	2.16
21/30-03	Balder	7538	2920	2.21
21/30-03	Sele	7666	3172	2.20
21/30-03	Lista	8049	3426	2.22
21/30-03	Maureen	9828	4800	2.28

Table 3.7.5 - Clean shale properties at Well 21/30-03

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-03	Horda	100% Brine			
21/30-03	Balder	100% Brine			
21/30-03	Sele	100% Brine	9639	4678	2.18
21/30-03	Lista	100% Brine	10846	5773	2.23
21/30-03	Maureen	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/30-03	Horda	80% Oil			
21/30-03	Balder	80% Oil			
21/30-03	Sele	80% Oil	8714	4767	2.10
21/30-03	Lista	80% Oil	10065	5859	2.16
21/30-03	Maureen	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/30-03	Horda	90% Gas			
21/30-03	Balder	90% Gas			
21/30-03	Sele	90% Gas	8547	4919	1.97
21/30-03	Lista	90% Gas	9925	6019	2.04
21/30-03	Maureen	90% Gas			

Table 3.7.6 - Clean sand properties at Well 21/30-03 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-03	Maureen	100% Brine	12,983	6,911	2.45
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/30-03	Maureen	80% Oil	12,135	6,964	2.42
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/30-03	Maureen	90% Gas	11,806	7,052	2.36

Table 3.7.7 - Clean limestone properties at Well 21/30-03 for each fluid case

Tertiary reservoirs – Well panel

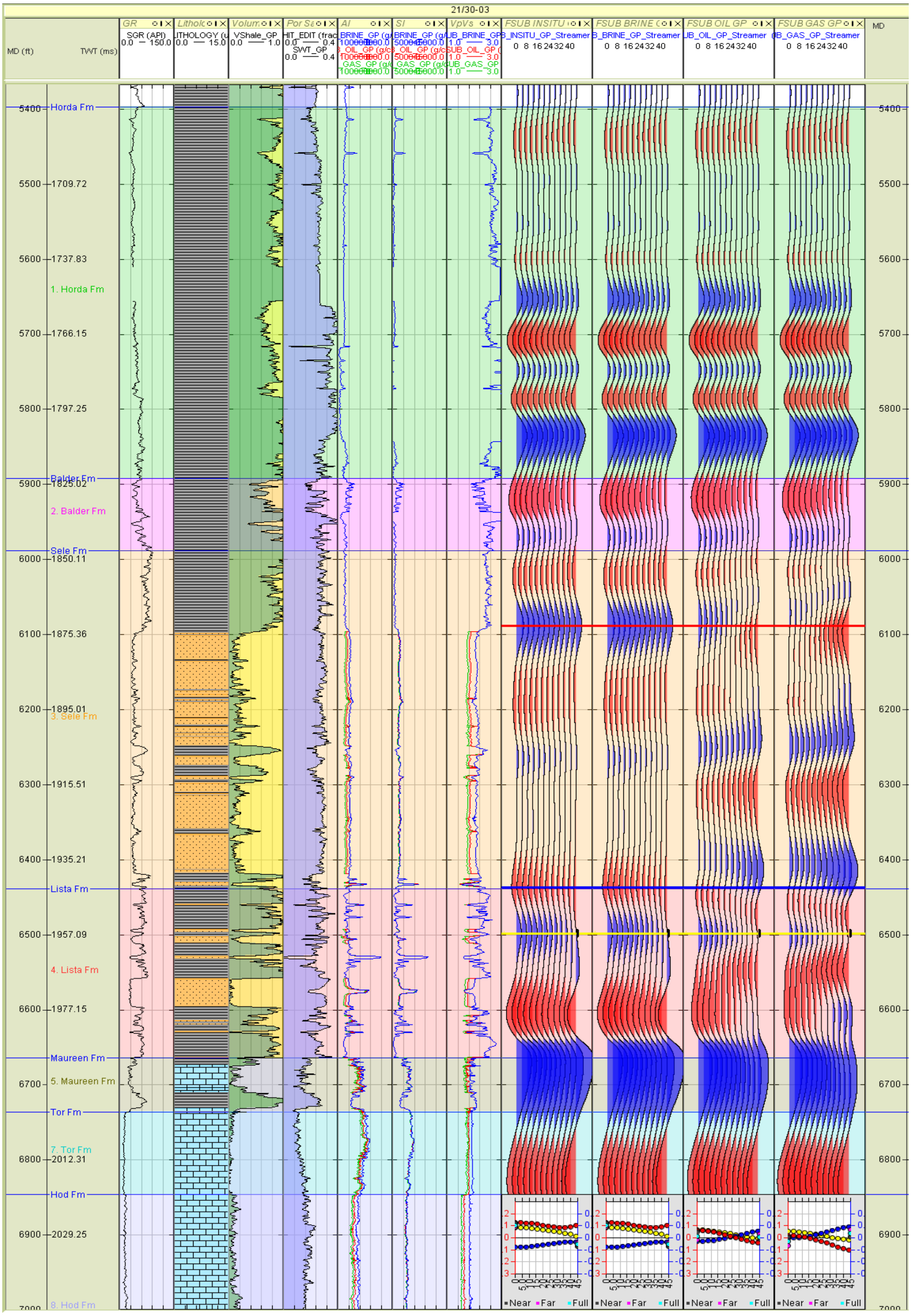


Figure 3.7.7 - Well Panel: Tertiary reservoirs for well 21/30-03. Wavelet: Streamer

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by clean blocky sandstone at the base of the interval. The reservoir is encased by shale and contains two prominent intra-reservoir shale beds. The net reservoir is approximately 303 feet, containing porosities of 29-31%.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases, a class II response is modelled for the 90% gas case. Within the synthetic gathers, comparable AVO responses are observed in the 100% brine and 80% oil fluid cases. The 90% gas case shows a slight contrast with a class IIp AVO response, although the overall similarity highlights the nature of the clean shale on sand contact observed.
- Elastic Contrast Analysis shows contrasts generally positive in the 100% brine case, often becoming negative with the addition of hydrocarbons. Bulk Modulus and LambdaRho show the most sensitivity to fluid effects. Mu shows the least sensitivity to fluid effects.

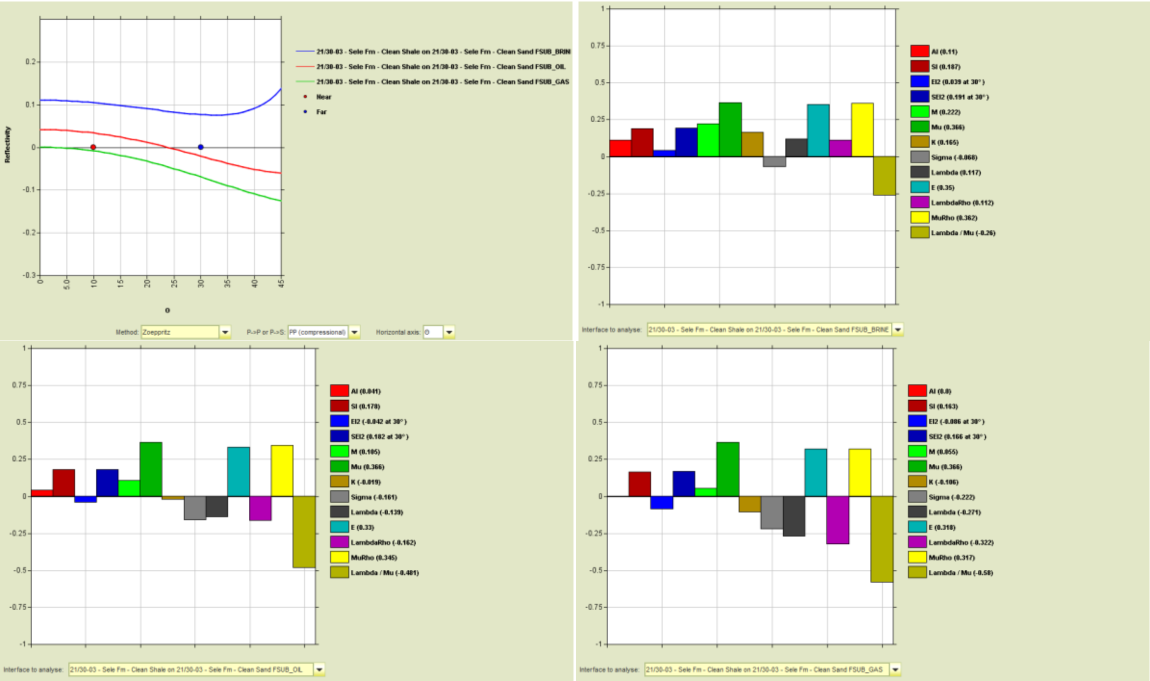


Figure 3.7.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 21/30-03.

Lista Formation

- Reservoir formed by a number of discrete clean blocky sand bodies throughout the interval, ranging from approximately 2-38 feet in thickness. Net reservoir is approximately 62 feet with porosities ranging from 15-32%.
- Blocky AVO shows a modelled class I response for the 100% brine, 80% oil and 90% gas cases in turn, with reflectivity decreasing with the addition of hydrocarbons. Within the synthetic gathers, comparable AVO responses are observed in each fluid case at top reservoir. It is apparent that wavelet interference effects are present for internal reservoir reflectors due to their limited vertical extent and discrete nature.
- Elastic Contrast Analysis shows contrasts are generally positive in the 100% brine case. Lambda and LambdaRho show the most sensitivity to fluid effects. Mu shows the least sensitivity to fluid effects.

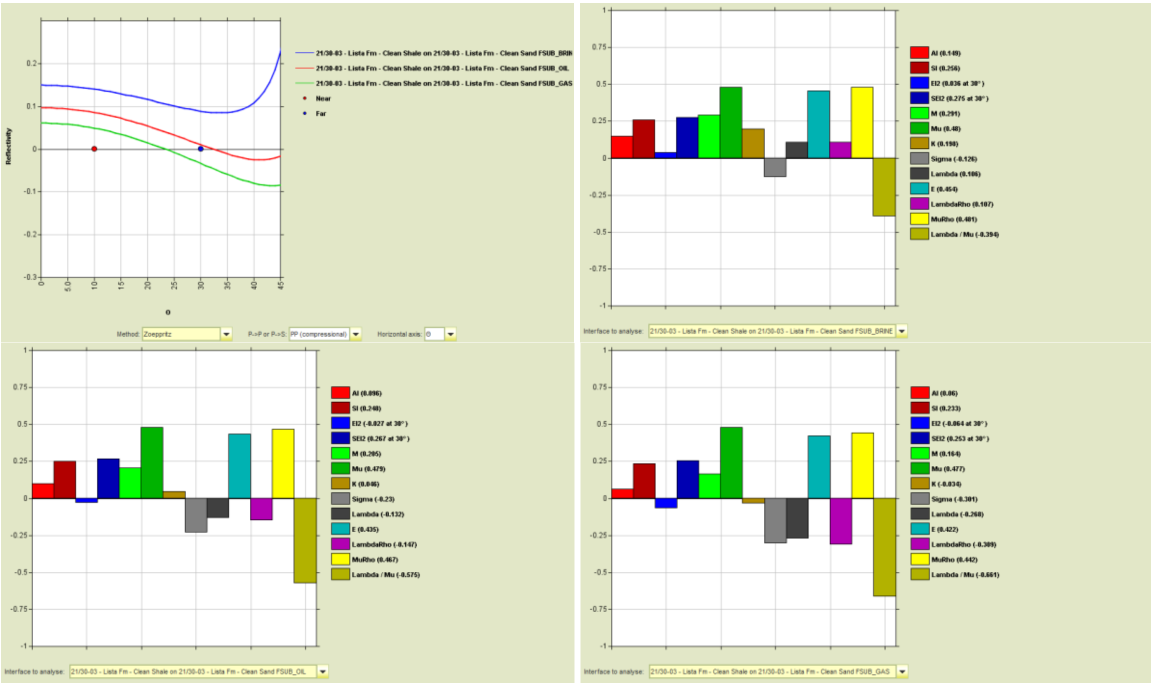


Figure 3.7.9 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 21/30-03.

Maureen Formation

- Reservoir formed by a clean limestone in the upper section of the interval overlain by calcareous shale. Net reservoir is approximately 45 feet.
- Blocky AVO shows a modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the 100% brine case, often decrease in amplitude with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, while Lambda and LambdaRho show the most sensitivity to fluid effects.

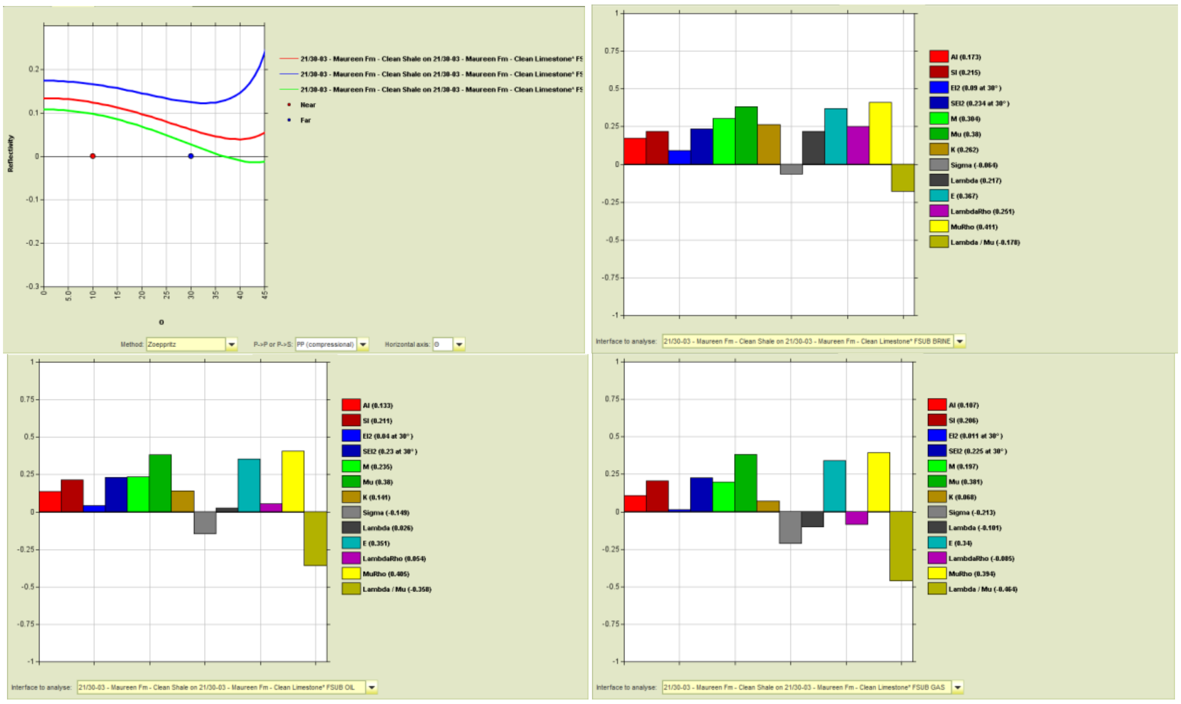


Figure 3.7.10 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 21/30-03.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 21/30-03 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-03	Ekofisk	100% Brine			
21/30-03	Tor	100% Brine	13856	7248	2.50
21/30-03	Hod	100% Brine	11840	6504	2.41
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/30-03	Ekofisk	80% Oil			
21/30-03	Tor	80% Oil	13042	7298	2.46
21/30-03	Hod	80% Oil	10659	6572	2.36
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
21/30-03	Ekofisk	90% Gas			
21/30-03	Tor	90% Gas	12777	7382	2.41
21/30-03	Hod	90% Gas	10250	6687	2.28

Table 3.7.8 - Clean limestone properties at Well 21/30-03 for each fluid case

Cretaceous reservoirs

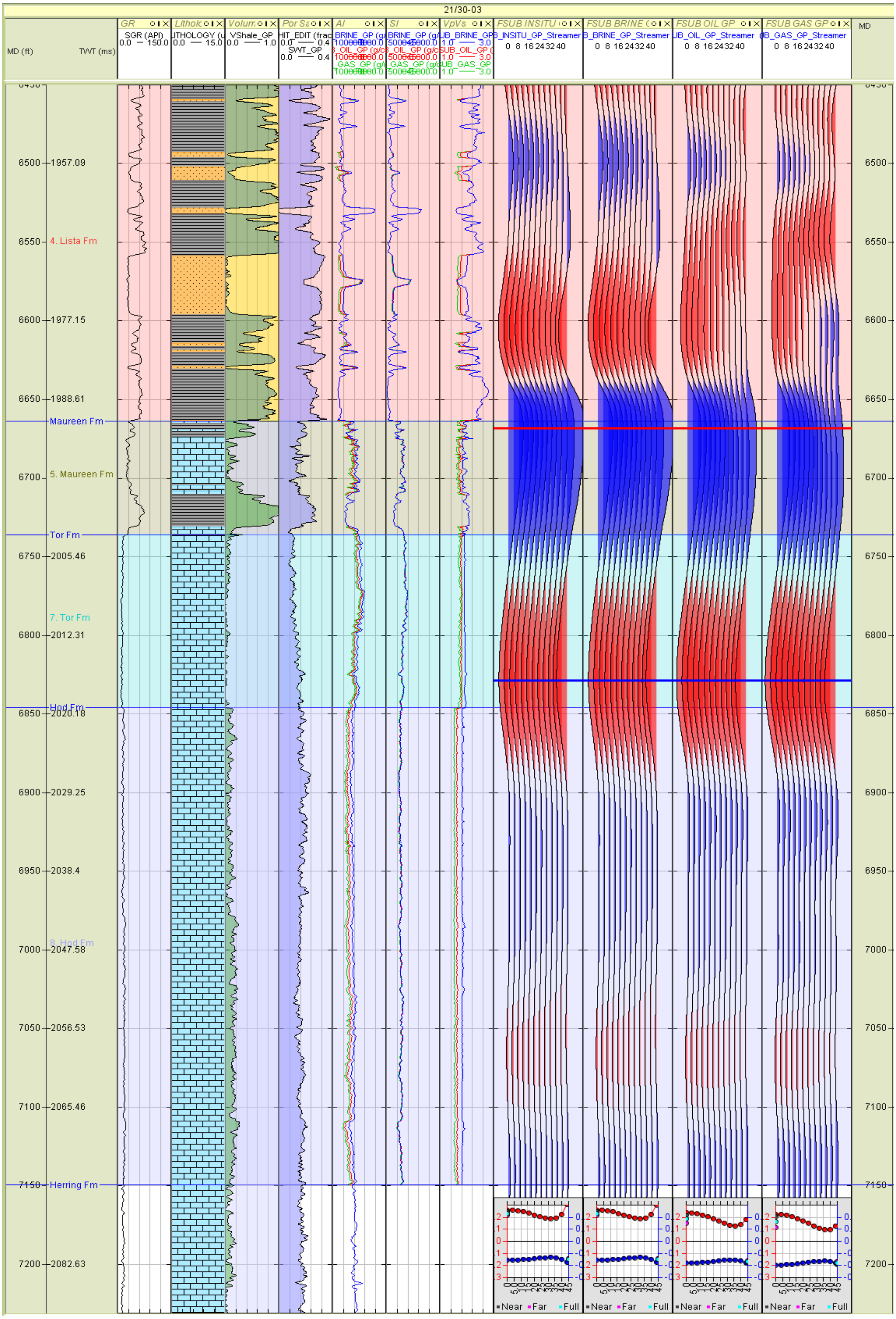


Figure 3.7.11 - Well Panel: Cretaceous reservoirs for well 21/30-03. Wavelet: Streamer

Formation description - Cretaceous reservoirs

Tor Formation

- Reservoir formed by a massive chalk, containing porosities increasing with depth up to approximately 20%. The reservoir is overlain by layered shale and limestone of the Maureen Formation, and underlain by relatively higher porosity chalk of the Hod Formation. Net reservoir is approximately 109 feet.
- Blocky AVO shows a modelled class I response for all fluid cases, with reflectivity decreasing in the 80% oil and 90% gas cases respectively. Synthetic gathers show comparative class I AVO responses in each fluid case. However, it is apparent that the reflection event is formed through constructive wavelet interference of both the Tor Formation top reservoir and the base of a shale layer within the Maureen Formation.
- Elastic Contrast Analysis shows moderate positive contrasts in the 100% brine case, generally showing little effect to the addition of hydrocarbons. Mu and MuRho show the least sensitivity to fluid effects, while Lambda and LambdaRho show the most sensitivity to fluid effects.

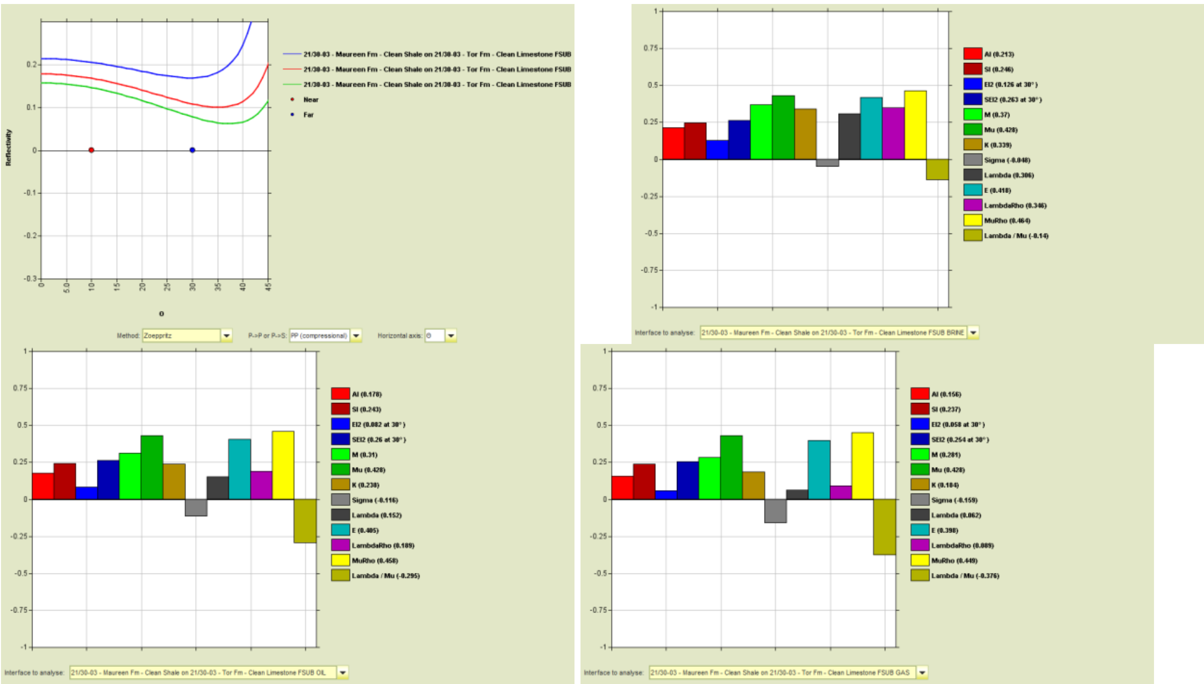


Figure 3.7.12 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Tor Limestone interface in well 21/30-03.

* Ekofisk Fm not present in this well so Maureen Shale used as overburden instead *

Hod Formation

- Reservoir contains patchy zones of higher porosity (approximately 17-23%) throughout the interval. The Hod Formation is overlain by relatively lower porosity chalk of the Tor Formation, and extends in to the Herring Formation, which is similar in character. Net reservoir is approximately 303 feet.
- Blocky AVO shows a modelled class IV response in each of the 100% brine, 80% oil and 90% gas cases. Within the synthetic gathers, comparable class IV AVO responses are observed, with reflectivity increasing as fluid density decreases.
- Elastic Contrast Analysis shows weak negative contrasts in the 100% brine case, in some cases becoming strongly negative with the addition of hydrocarbons. MuRho shows the least sensitivity to fluid effects, while Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

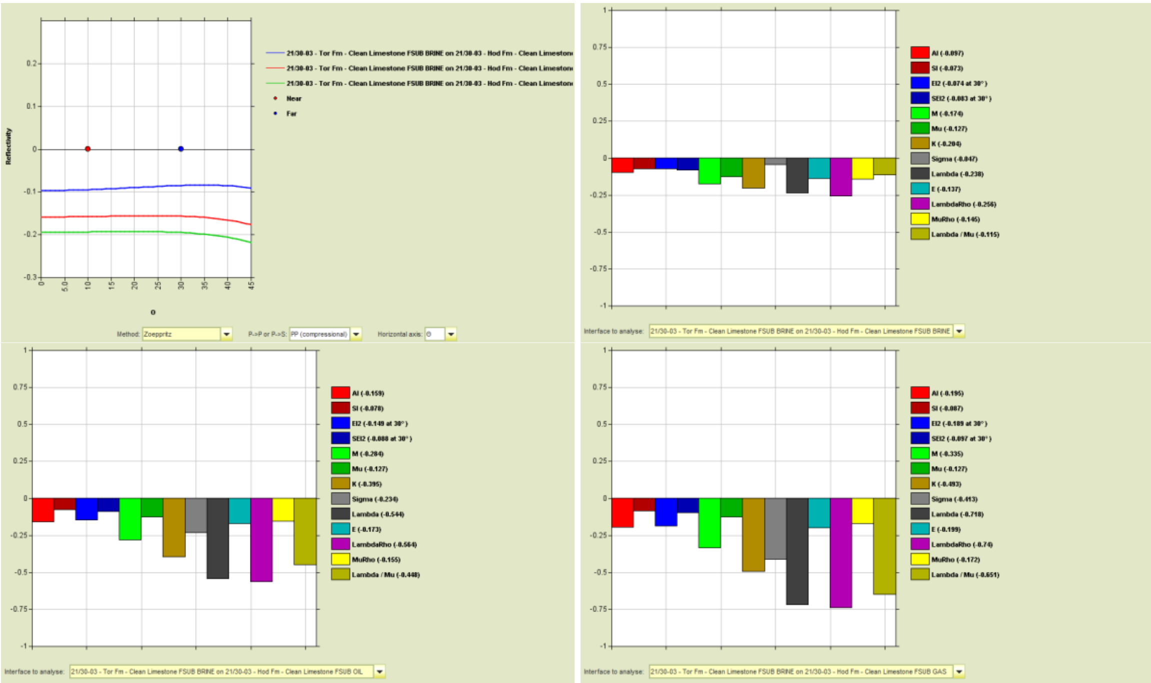


Figure 3.7.13 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 21/30-03.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 21/30-03 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-03	Overburden	Shale	7353		2.19
21/30-03	Underburden	Limestone/Shale	10066		2.35

Table 3.7.9 - Overburden and underburden properties at Well 21/30-03

Well: 21/30-19

General

Well Information
Shell operated exploration well spudded, completed and abandoned in 1992. The well encountered oil in the Sele Formation (Forties Member) within the Gannet E field.

Objectives
The well was drilled with a primary objective to evaluate the Upper Jurassic Fulmar Formation in a stratigraphic trap bordered by a major fault to the south and onlapping the Smith Bank Shale to the west and east. The secondary objective was to evaluate the Sele Formation within the Gannet E field and to verify an oil-water contact on the northern side of the structure. The primary objective was present but wet.

Log conditioning overview
Despite the caliper log indicating significant borehole washout, only minor log editing was required within the well. Small spikes seen on the Vp log, but not the density log were removed within the Sele Formation.

Invasion correction
The drilling mud used within this well was water based, with invasion correction of the density log being required within the oil bearing Sele Formation.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Sele Formation for Vp. A complete Vs log is modelled using Modified Gassmann methodology in the absence of measured shear log data.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 21/30-19 is displayed in the figures below;

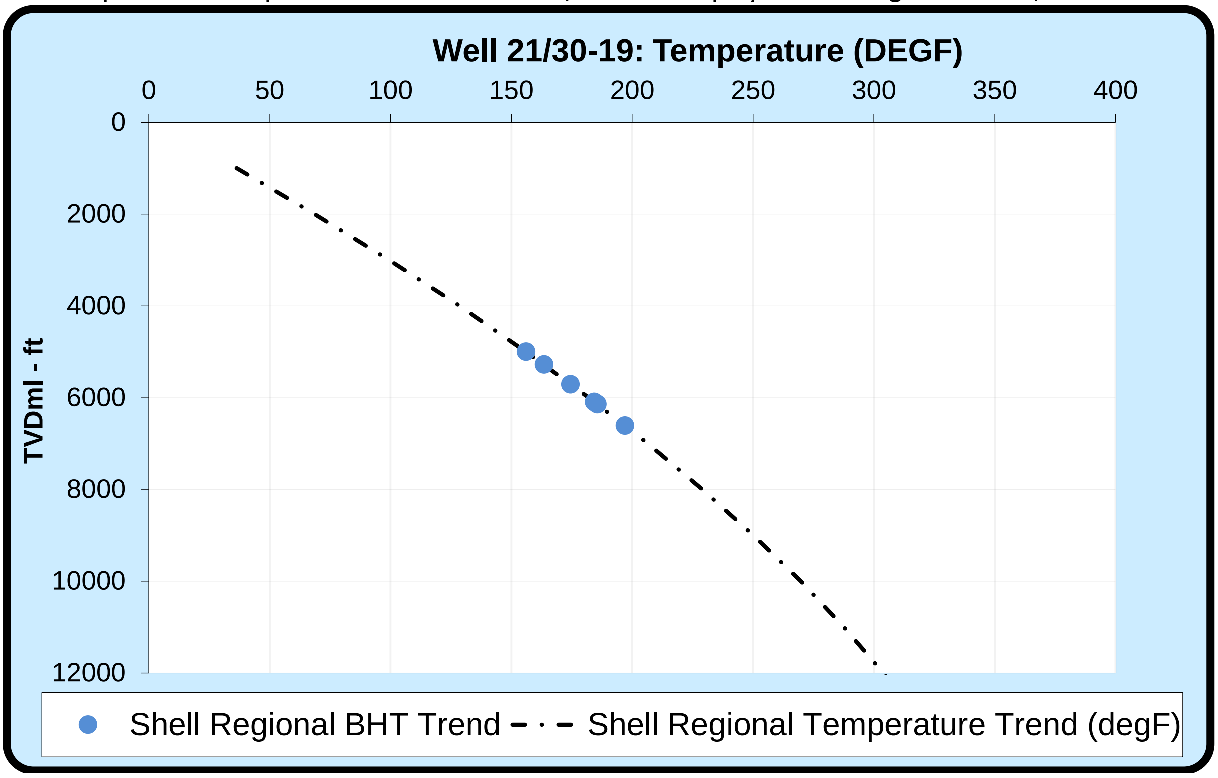


Figure 3.8.1 - Temperature data at Well 21/30-19

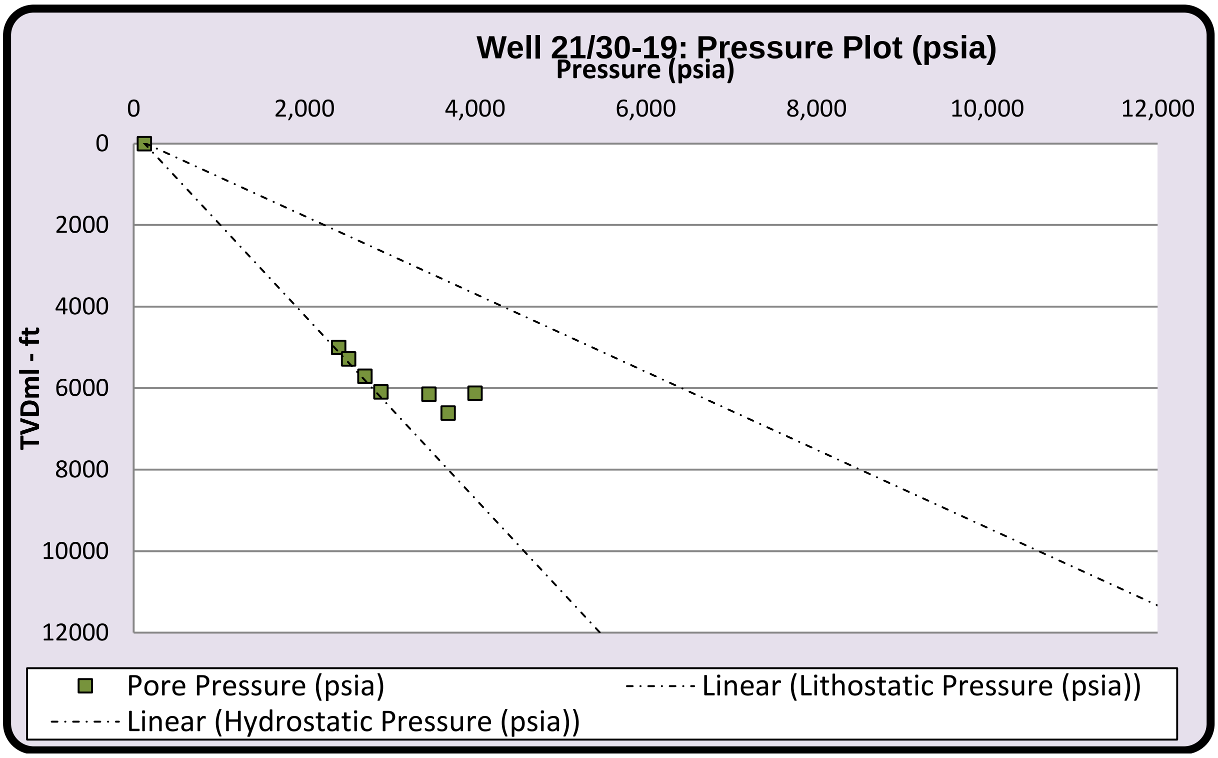


Figure 3.8.2 - Pressure data at Well 21/30-19

The temperature and pressure data for the formation mid-points in Well 21/30-19 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
21/30-19	Sea Bed	364.0	289.0	0.0	39.2	128.6	128.6	128.61	0.00
21/30-19	Horda	5860.0	5288.5	4999.5	156.1	2353.4	2402.4	5128.11	2725.73
21/30-19	Balder	6222.5	5569.8	5280.8	163.6	2478.6	2520.6	5409.43	2888.86
21/30-19	Sele	6794.8	5996.6	5707.6	174.6	2668.5	2710.5	5836.25	3125.75
21/30-19	Lista	7313.3	6382.5	6093.5	184.4	2840.2	2900.2	6222.06	3321.87
21/30-19	Maureen	7351.5	6411.2	6122.2	185.1	2853.0	4003.0	6250.85	2247.85
21/30-19	Tor	7990.0	6901.2	6612.2	197.1	3071.0	3686.8	6274.11	2810.76
21/30-19	Hod	364.0	289.0	0.0	39.2	128.6	128.6	6740.78	3054.01

Table 3.8.1 - Summary of mid-point temperature and pressure data at Well 21/30-19

Fluid data

A summary of the fluid set parameters at Well 21/30-19 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
21/30-19	Sele	68000	115	20.0	0.6	0.6
21/30-19	Lista	68000	730	37.9	0.71	0.71
21/30-19	Maureen	68000	730	38.0	0.71	0.71
21/30-19	Tor	68000	730	38.0	0.71	0.71
21/30-19	Hod	68000	730	38.5	0.71	0.71

Table 3.8.2 - Summary of fluid parameter data at Well 21/30-19 Mineral data

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.8.3 - Constant mineral properties used in this project

There is no Tuff present in this well.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
21/30-19	Sele	PAY	995.500	104.000	0.104	31.037	0.298	0.359	0.110
21/30-19	Sele	RES	995.500	632.000	0.635	182.574	0.289	0.840	0.139
21/30-19	Lista	PAY	41.500	0.000	0.000	0.000	0.000	0.000	0.000
21/30-19	Lista	RES	41.500	0.000	0.000	0.000	0.000	0.000	0.000
21/30-19	Maureen	PAY	35.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-19	Maureen	RES	35.000	4.000	0.114	0.412	0.103	0.997	0.335
21/30-19	Tor	PAY	27.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-19	Tor	RES	27.000	23.250	0.861	2.314	0.100	1.000	0.062
21/30-19	Hod	PAY	1188.000	0.000	0.000	0.000	0.000	0.000	0.000
21/30-19	Hod	RES	1188.000	1185.500	0.998	153.220	0.129	0.957	0.090

Table 3.8.4 - Petrophysical parameters used at Well 21/30-19

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

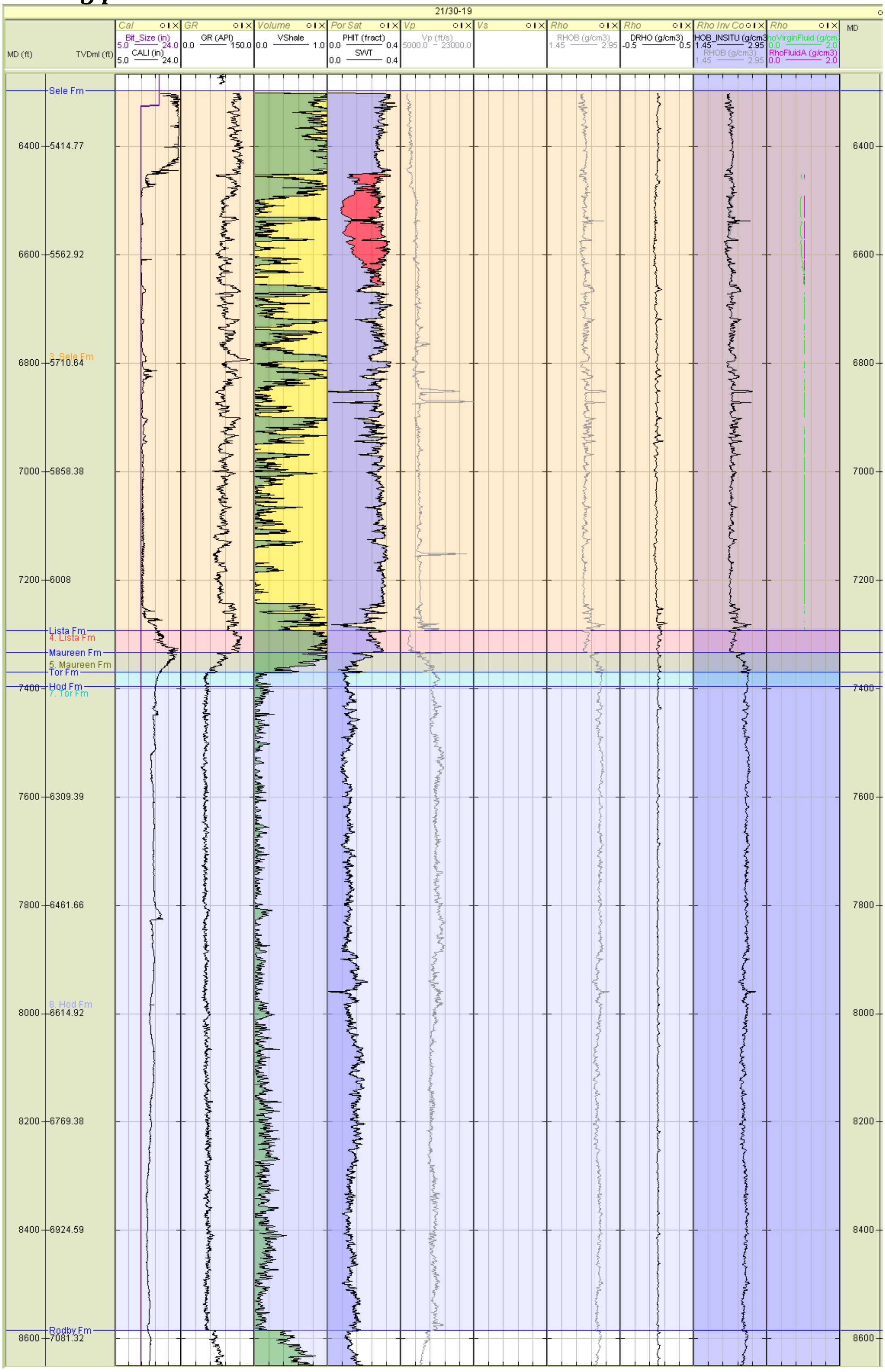


Figure 3.8.3 - Well Panel: Measured data and invasion correction for well 21/30-19.

Well log panel – log editing and audit

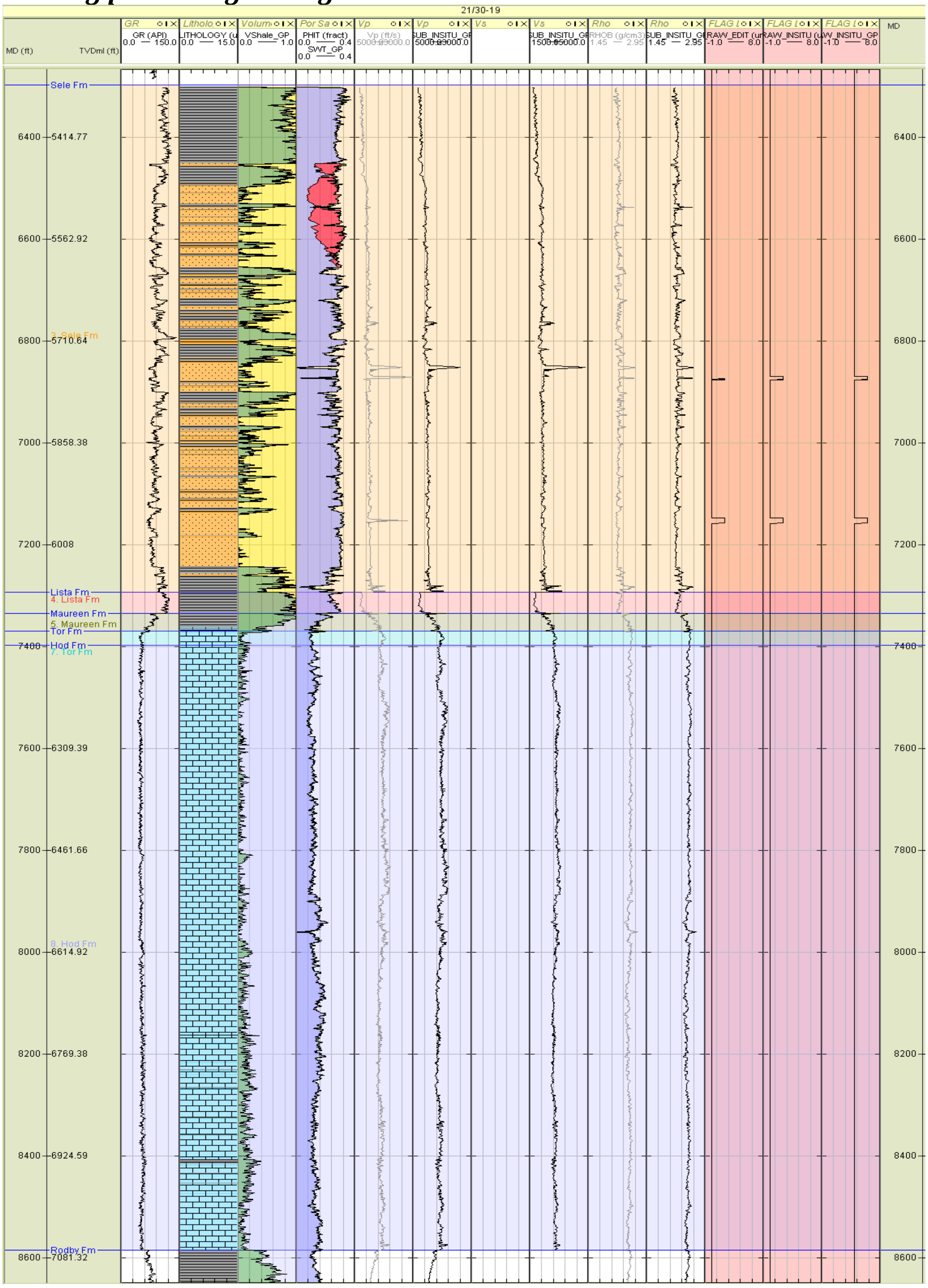


Figure 3.8.4 - Well Panel: Log edits for well 21/30-19.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

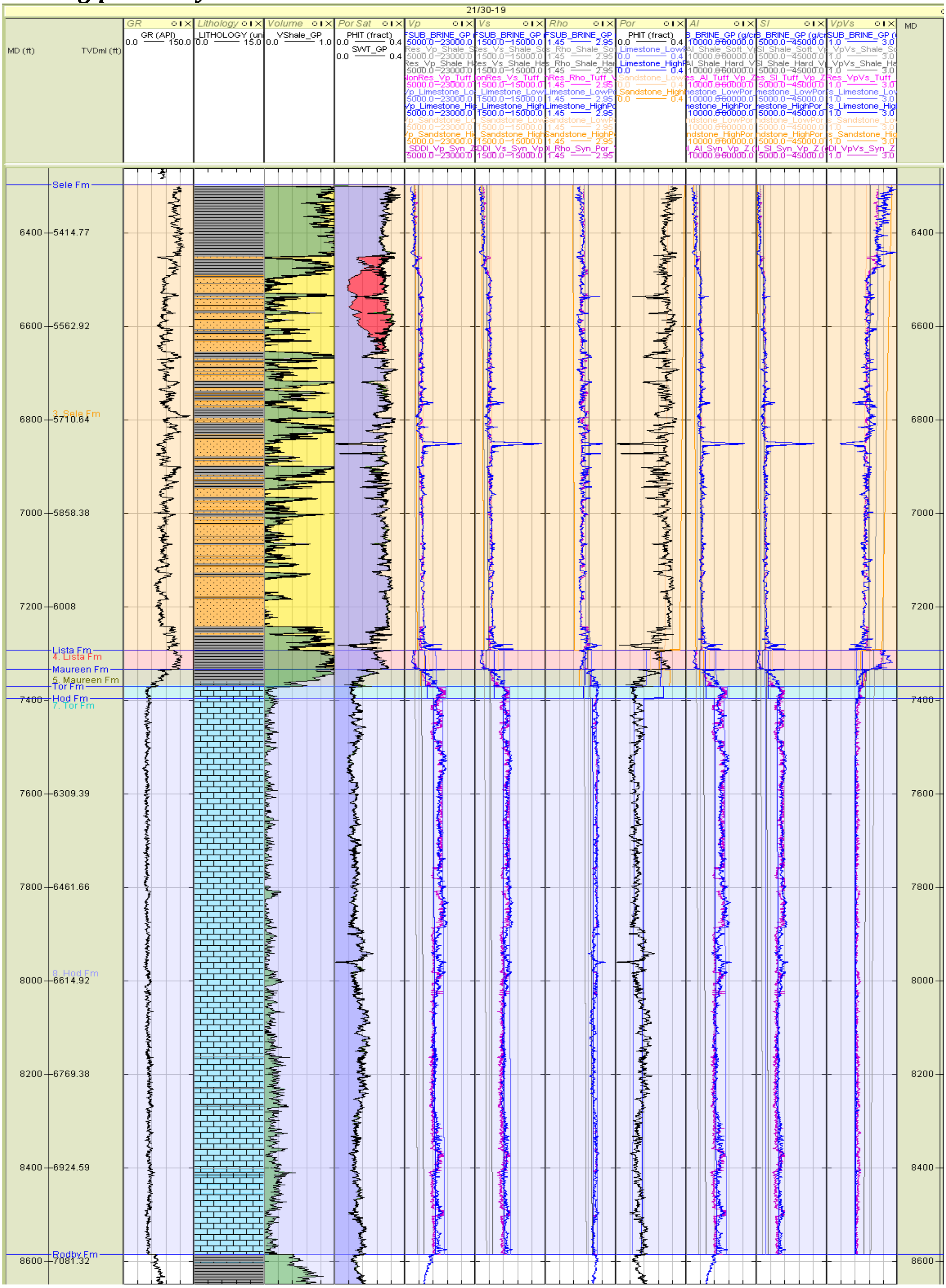


Figure 3.8.5 - Well Panel: End-member and synthetic logs for well 21/30-19.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

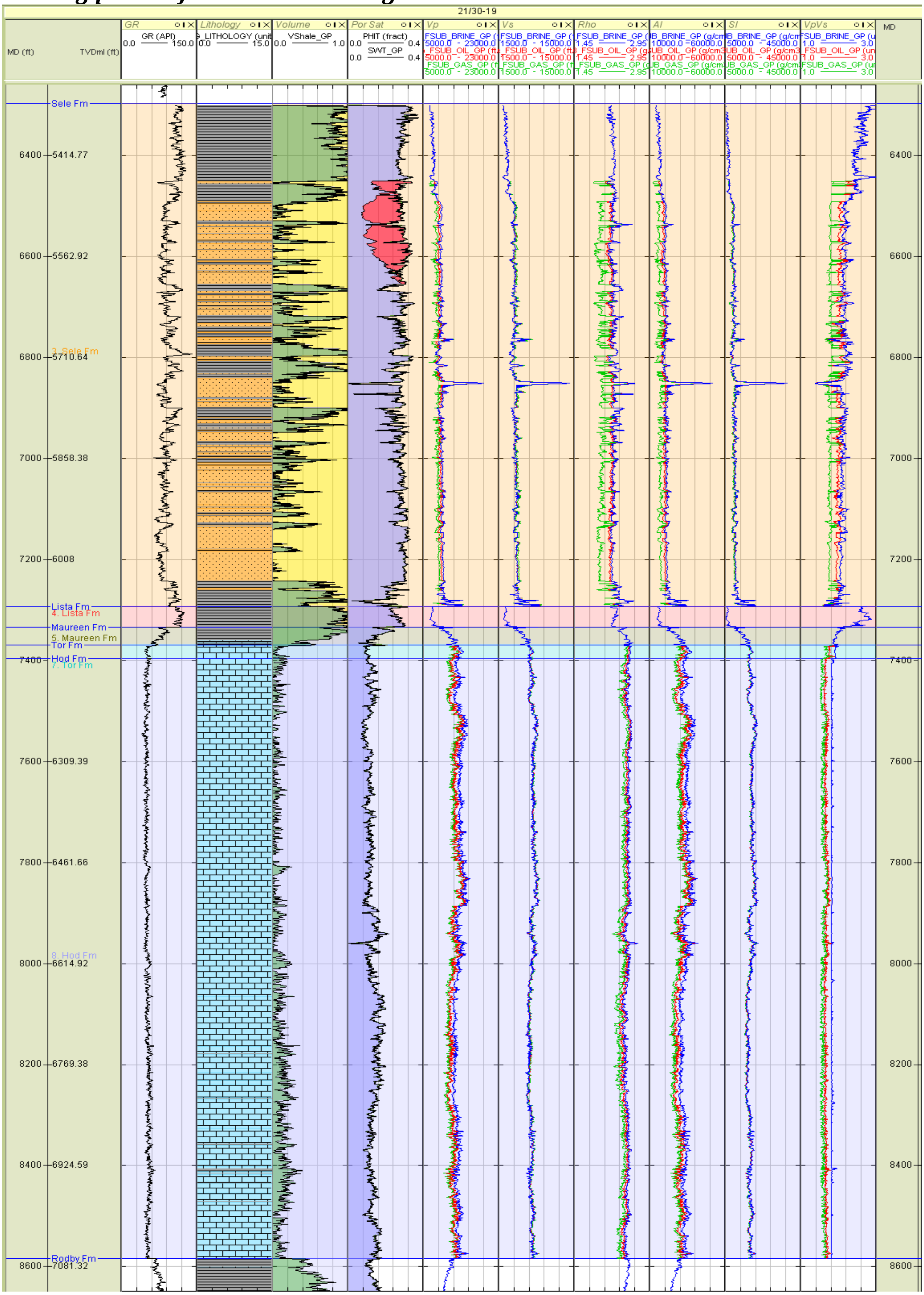


Figure 3.8.6 - Well Panel: Fluid substituted and elastic logs for well 21/30-19.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 21/30-19 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-19	Horda			
21/30-19	Balder			
21/30-19	Sele	7911	3376	2.26
21/30-19	Lista	7258	2812	2.25
21/30-19	Maureen	10855	5519	2.42

Table 3.8.5 - Clean shale properties at Well 21/30-19

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-19	Horda	100% Brine			
21/30-19	Balder	100% Brine			
21/30-19	Sele	100% Brine	9501	4541	2.21
21/30-19	Lista	100% Brine			
21/30-19	Maureen	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-19	Horda	80% Oil			
21/30-19	Balder	80% Oil			
21/30-19	Sele	80% Oil	9053	4577	2.18
21/30-19	Lista	80% Oil			
21/30-19	Maureen	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-19	Horda	90% Gas			
21/30-19	Balder	90% Gas			
21/30-19	Sele	90% Gas	8442	4802	1.97
21/30-19	Lista	90% Gas			
21/30-19	Maureen	90% Gas			

Table 3.8.6 - Clean sand properties at Well 21/30-19 for each fluid case

Tertiary reservoirs – Well panel

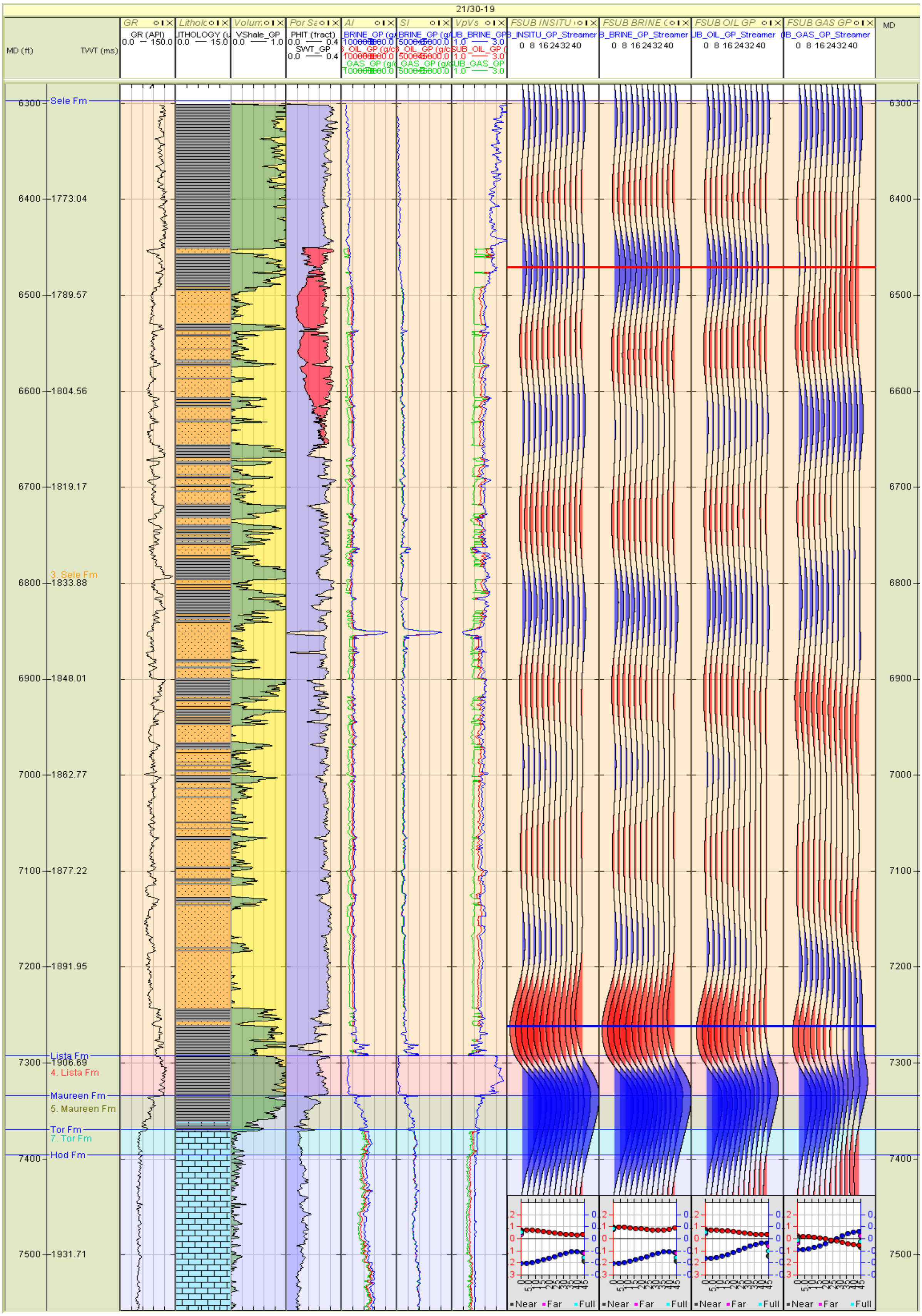


Figure 3.8.7 - Well Panel: Tertiary reservoirs for well 21/30-19. Wavelet: Streamer

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a thick ratty sand overlaid by a shale sequence. The reservoir contains many inclusive shale layers, the most significant of which lies at the top of the reservoir, within the oil column. Net reservoir is approximately 632 feet thick with porosities of around 28-30%.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases, the 90% gas case shows a modelled class III response. Within the synthetic gathers, the AVO response observed for the 100% brine and 80% oil cases remains constant, with the 90% gas case showing a class IIp response. This variation is likely due to wavelet interference given the limited vertical extent of the individual sand bodies and presence of intra-reservoir shale.
- Elastic Contrast Analysis shows contrasts are moderate and positive in the 100% brine case, generally becoming negative with the addition of hydrocarbons. Bulk Modulus and LambdaRho show the most sensitivity to fluid effects. Mu shows the least sensitivity to fluid effects.

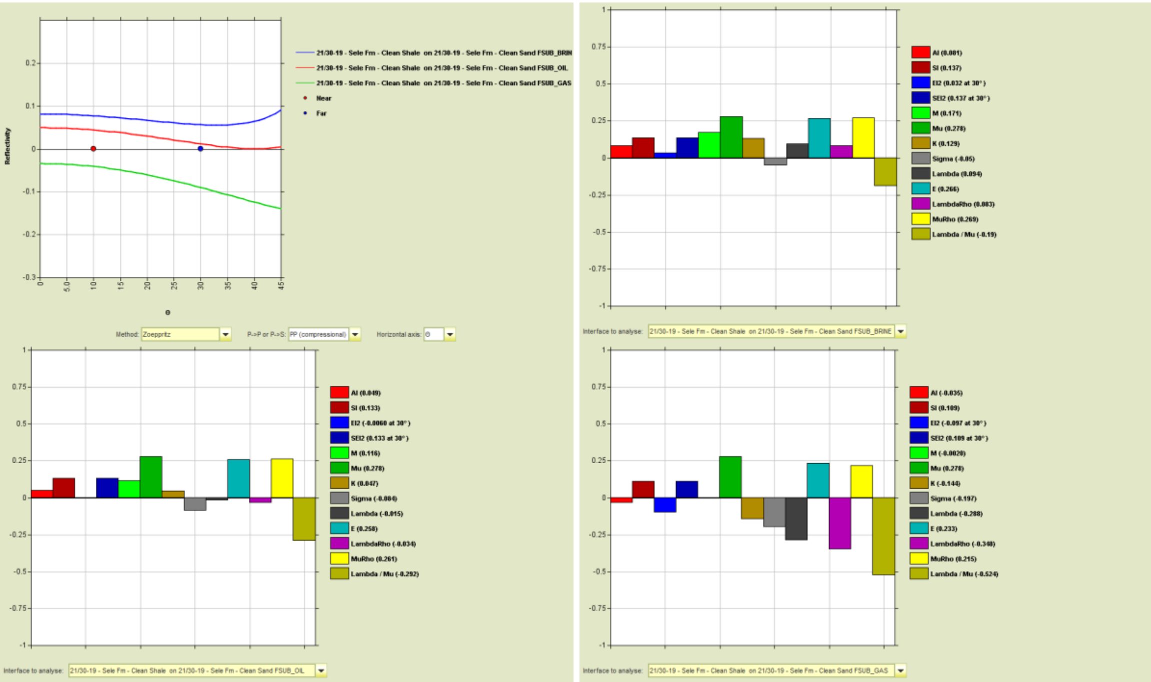


Figure 3.8.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 21/30-19.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 21/30-19 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-19	Ekofisk	100% Brine			
21/30-19	Tor	100% Brine	13816	7231	2.55
21/30-19	Hod	100% Brine	13624	7521	2.51
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-19	Ekofisk	80% Oil			
21/30-19	Tor	80% Oil	12794	7269	2.53
21/30-19	Hod	80% Oil	12637	7573	2.48
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-19	Ekofisk	90% Gas			
21/30-19	Tor	90% Gas	12355	7335	2.48
21/30-19	Hod	90% Gas	12280	7661	2.42

Table 3.8.7 - Clean limestone properties at Well 21/30-19 for each fluid case

Cretaceous reservoirs

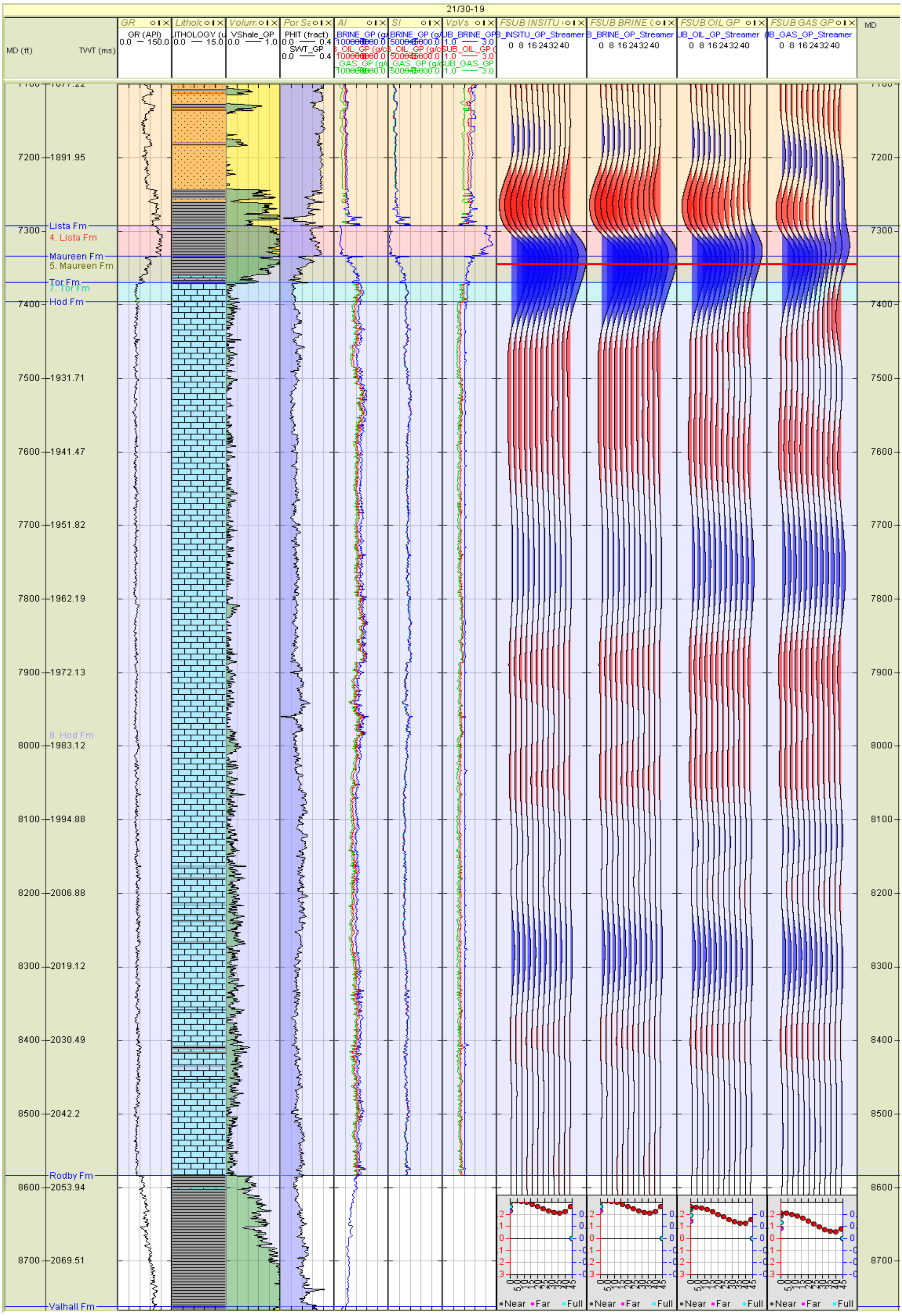


Figure 3.8.9 - Well Panel: Cretaceous reservoirs for well 21/30-19. Wavelet: Streamer

Formation description - Cretaceous reservoirs

Tor Formation

- Reservoir formed by a relatively thin chalk, containing an average porosity of approximately 10%, increasing to 21% within a higher porosity streak at the top of the interval. The reservoir overlies the relatively higher porosity chalk of the Hod Formation, and shales up in to the silty chalk of the Maureen Formation and shale of the Lista Formation. Net reservoir is approximately 23 feet.
- Blocky AVO shows a modelled class I response for the 100% brine, 80% oil and 90% gas cases, with a phase reversal occurring for the 90% gas case. Within the synthetic gathers, a consistent class I AVO response is seen for each fluid case, although comparatively higher reflectivities are seen. It is apparent that constructive wavelet interference has affected the observed response, related to the limited vertical extend of the Lista, Maureen and Tor Formations.
- Elastic Contrast Analysis shows generally positive contrasts in the 100% brine case. With the addition of hydrocarbons, many contrast become muted or even negative. Mu and MuRho show the least sensitivity to fluid effects, while Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

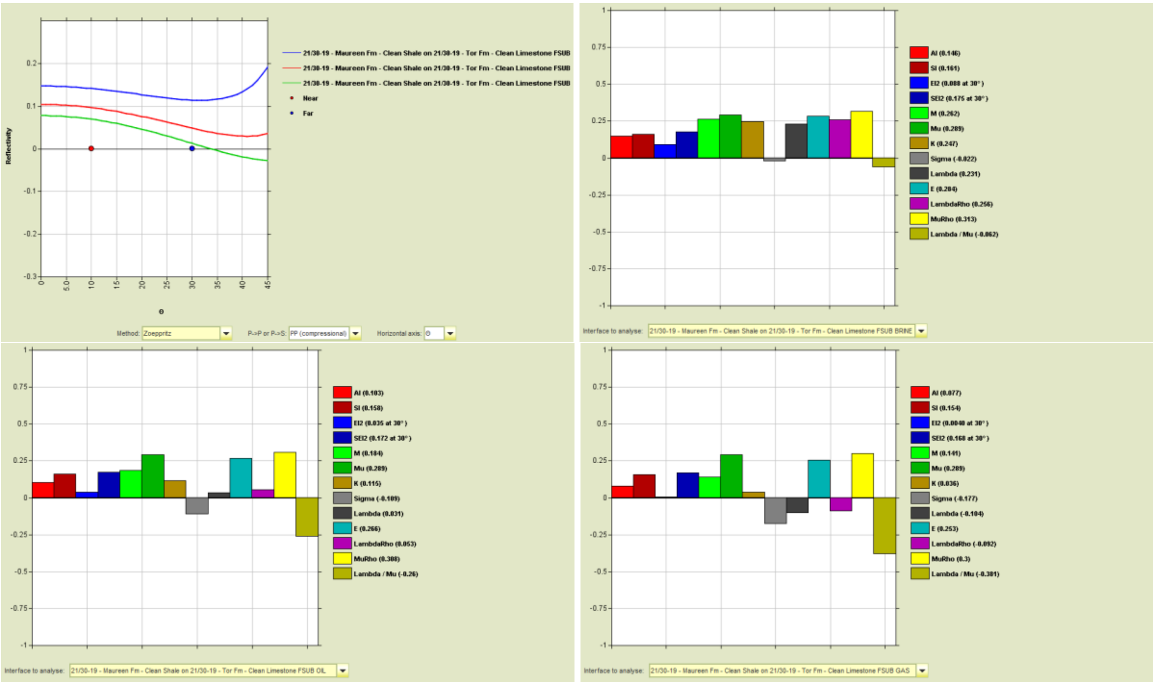


Figure 3.8.10 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Tor Limestone interface in well 21/30-19.

* Ekofisk Fm not present in this well so Maureen Shale used as overburden instead *

Hod Formation

- Reservoir contains patchy zones of higher porosity (approximately 14-22%) mainly focused towards the centre of the interval. The Hod Formation is overlain by the relatively lower porosity chalk of the Tor Formation, and extends in to silty chalks and shale of the Rodby Formation. Net reservoir is approximately 1185 feet.
- Blocky AVO shows a modelled class II response with weak reflectivity in the 100% brine case, and a class III response in both the 80% oil and 90% gas cases. Within the synthetic gathers, the event cannot be resolved using the lower frequency streamer wavelet due to the apparent effects of wavelet interference. This is confirmed by comparison with the higher frequency broadband wavelet synthetic gathers, where a comparable class II AVO response is seen in the 100% brine case, and class III response seen in the 80% oil and 90% gas cases.
- Elastic Contrast Analysis shows contrasts are negligible in the100% brine case, although often show a strong fluid effect becoming increasingly negative in the 80% oil and 90% gas cases. Mu shows the least sensitivity to fluid changes, whilst Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

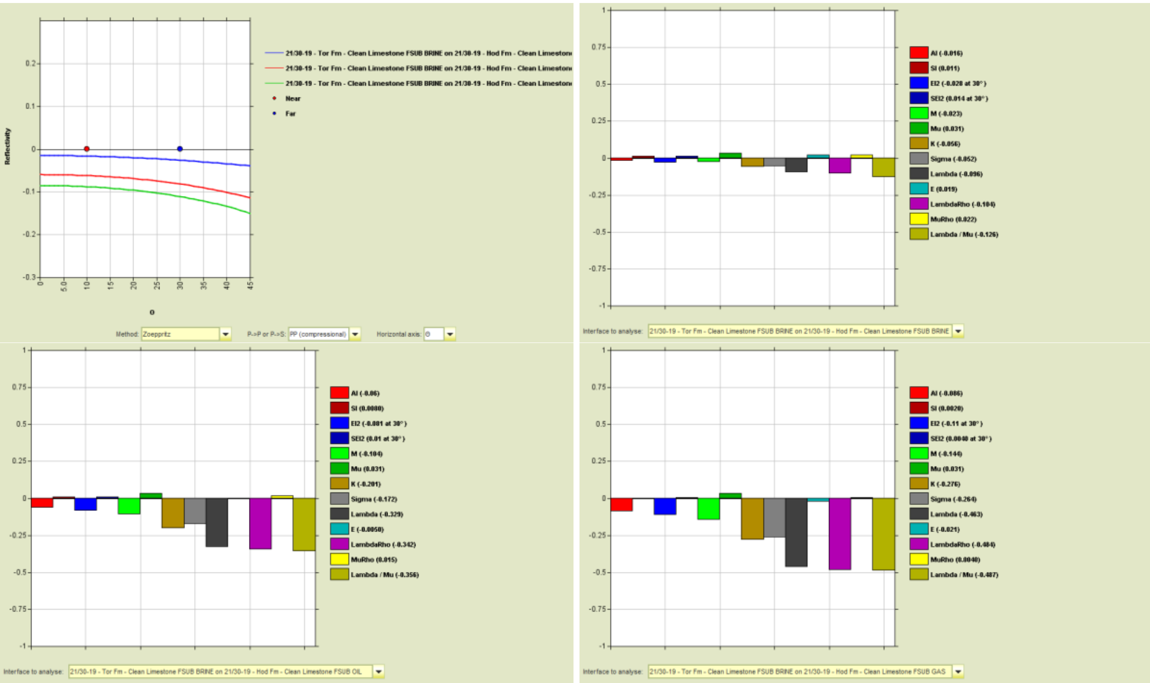


Figure 3.8.11 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 21/30-19.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 21/30-19 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
21/30-19	Overburden	Shale	7435		
21/30-19	Underburden	Limestone/Sand	12054		2.49

Table 3.8.8 - Overburden and underburden properties at Well 21/30-19

Well: 22/12A-05

General

Well Information
BP operated exploration well spudded, completed and abandoned in 1990. The well encountered oil in the Sele Formation (Forties Member).

Objectives
This well was drilled to investigate the extent of the Nelson field. A deviated well path geometry was chosen to avoid a shallow gas anomaly. Oil was encountered within the Sele Formation, with no further reservoir quality reservoirs identified.

Log conditioning overview
Log quality within the well is mostly of a good standard. The density log is clipped at the start of the second logging run due to the effects of bore washout. Minor edits were required due to bad data within the Vs log over the Sele Formation, and to remove calcite stringers not picked up by the density log over the Horda Formation.

Invasion correction
Invasion correction of the density log required within both the oil bearing Sele Formation and brine bearing Lista Formation due to the use of oil based drilling mud within the well.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda and Balder Formation for Vp and density The Vp log was also extended to the base of the Lista Formation. Additionally, gaps were filled in the Vs log within the Sele Formation and the log extended to cover the whole study interval.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 22/12A-05 is displayed in the figures below;

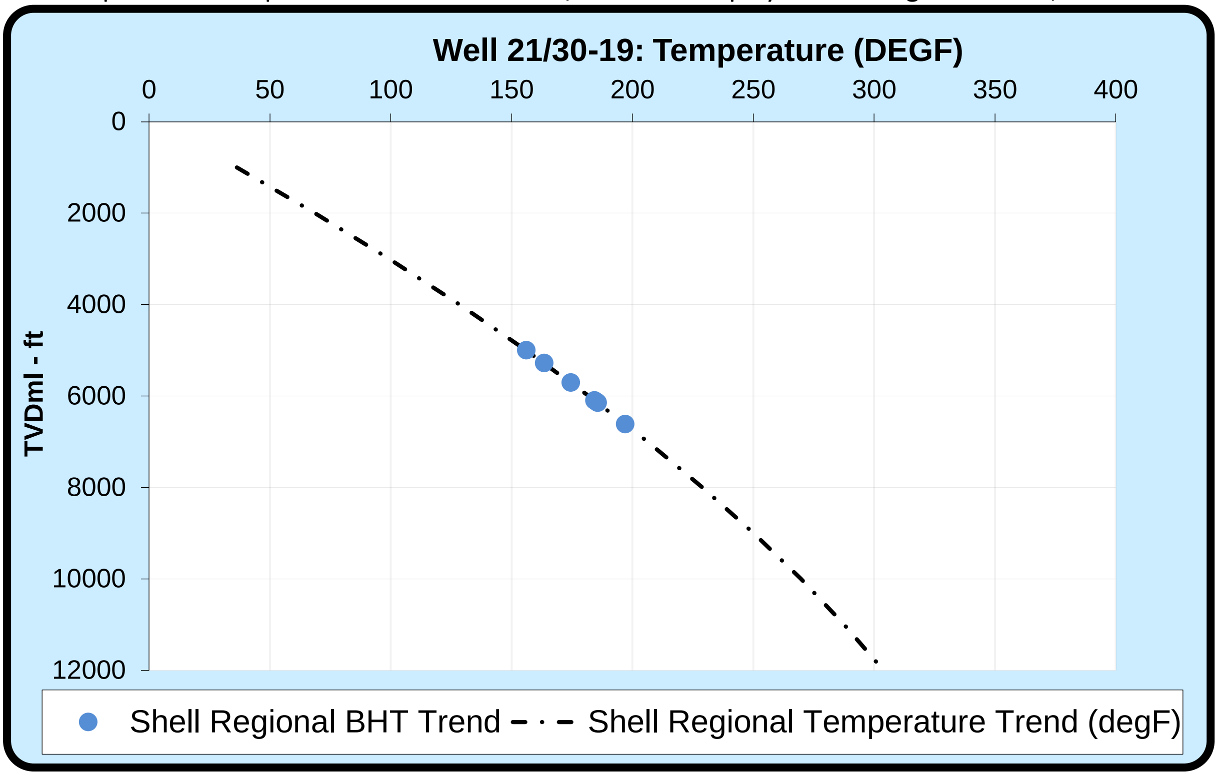


Figure 3.9.1 - Temperature data at Well 22/12A-05

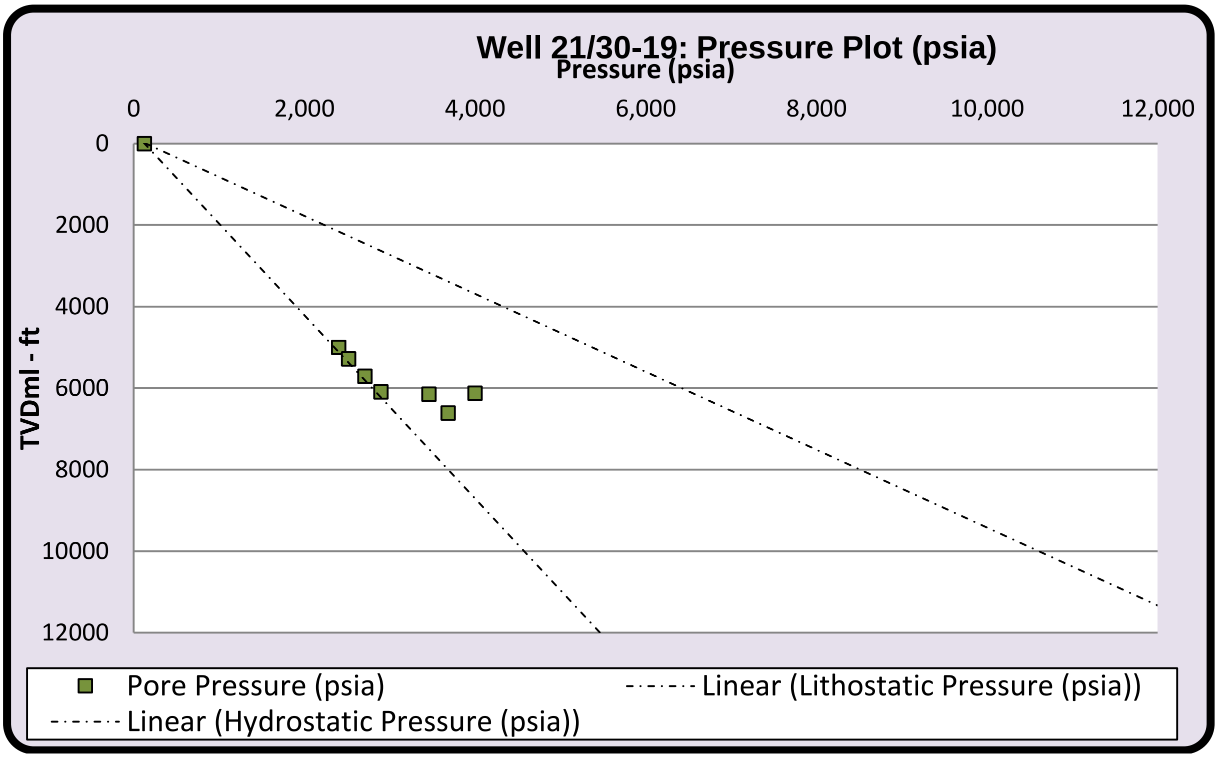


Figure 3.9.2 - Pressure data at Well 22/12A-05

The temperature and pressure data for the formation mid-points in Well 22/12A-05 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/12A-05	Sea Bed	364.2	278.9	0.0	39.2	124.1	124.1	124.11	0.00
22/12A-05	Horda	7046.0	6902.6	6623.7	197.4	3071.7	3088.7	6747.80	3659.14
22/12A-05	Balder	7414.0	7270.5	6991.6	206.2	3235.4	3285.4	7115.73	3830.34
22/12A-05	Sele	7635.0	7491.5	7212.6	211.3	3333.7	3383.7	7336.68	3952.97
22/12A-05	Lista	7887.0	7743.4	7464.5	217.1	3445.8	3495.8	7588.60	4092.79

Table 3.9.1 - Summary of mid-point temperature and pressure data at Well 22/12A-05

Fluid data

A summary of the fluid set parameters at Well 22/12A-05 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/12A-05	Horda	80000	730	38.5	0.71	0.71
22/12A-05	Balder	80000	730	38.9	0.71	0.71
22/12A-05	Sele	80000	332	36.4	0.9	0.9
22/12A-05	Lista	120000	730	39.4	0.71	0.71

Table 3.9.2 - Summary of fluid parameter data at Well 22/12A-05

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.9.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	12.01	4.92	2.317	9,289	4,781

Table 3.9.4 - Tuff properties used at Well 22/12A-05

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/12A-05	Horda	PAY	632.000	0.000	0.000	0.000	0.000	0.000	0.000
22/12A-05	Horda	RES	632.000	0.000	0.000	0.000	0.000	0.000	0.000
22/12A-05	Balder	PAY	104.000	0.000	0.000	0.000	0.000	0.000	0.000
22/12A-05	Balder	RES	104.000	0.000	0.000	0.000	0.000	0.000	0.000
22/12A-05	Sele	PAY	338.000	39.000	0.115	9.899	0.254	0.322	0.081
22/12A-05	Sele	RES	338.000	150.000	0.444	36.111	0.241	0.775	0.161
22/12A-05	Lista	PAY	166.000	0.000	0.000	0.000	0.000	0.000	0.000
22/12A-05	Lista	RES	166.000	103.000	0.620	25.564	0.248	0.980	0.113

Table 3.9.5 - Petrophysical parameters used at Well 22/12A-05

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

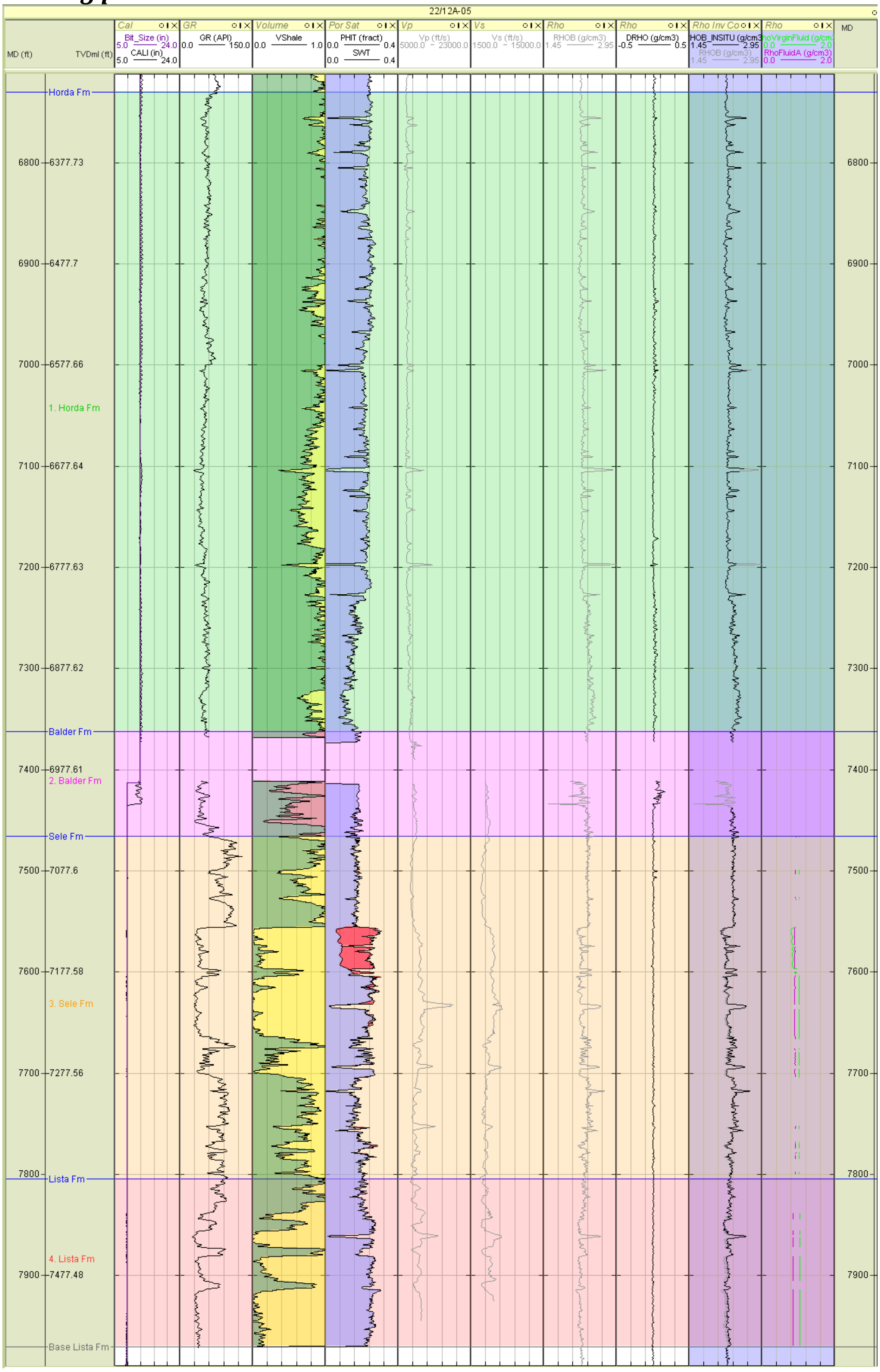


Figure 3.9.3 - Well Panel: Measured data and invasion correction for well 21/12A-05.

Well log panel – log editing and audit

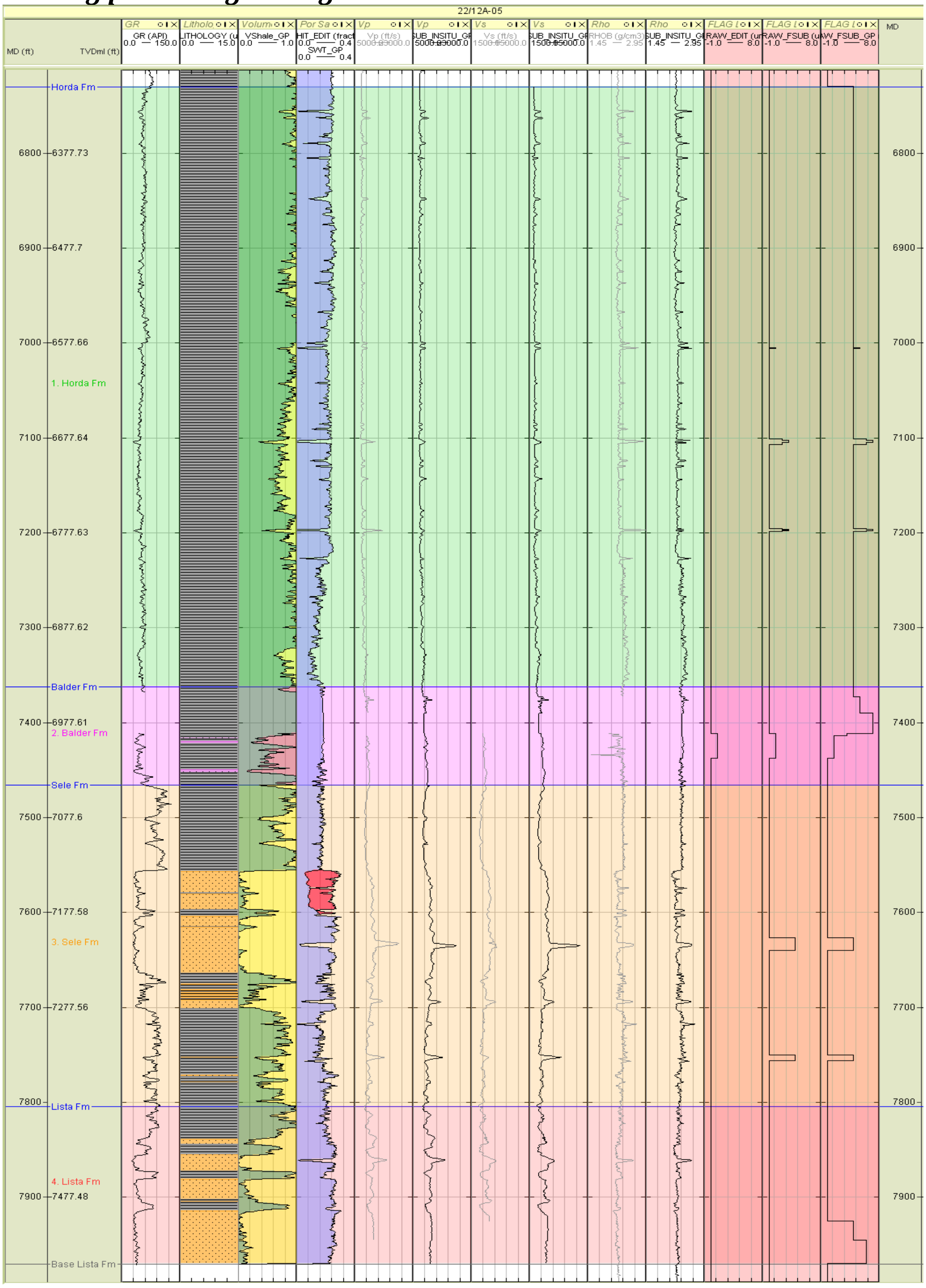


Figure 3.9.4 - Well Panel: Log edits for well 22/12A-05.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

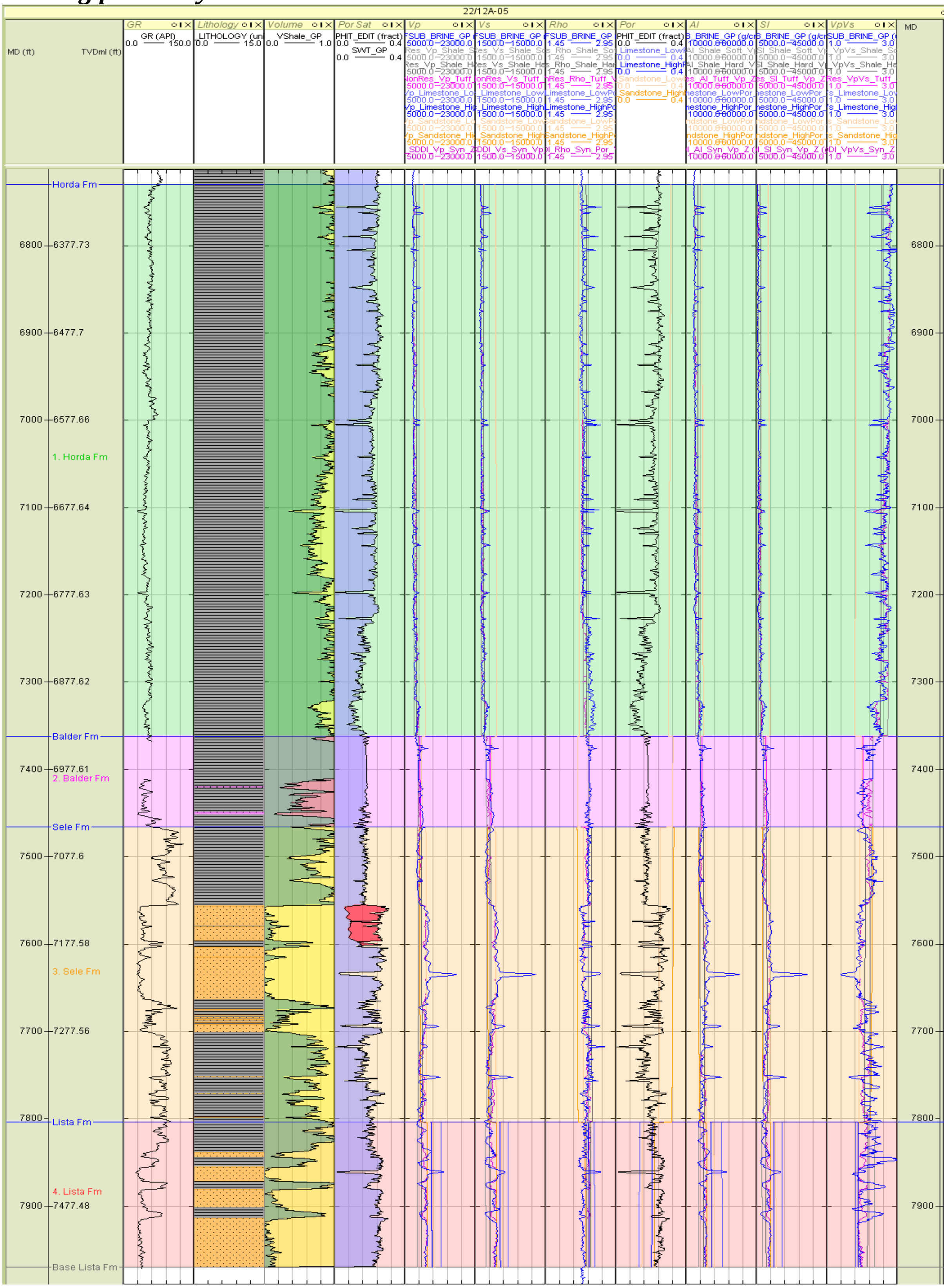


Figure 3.9.5 - Well Panel: End-member and synthetic logs for well 22/12A-05.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

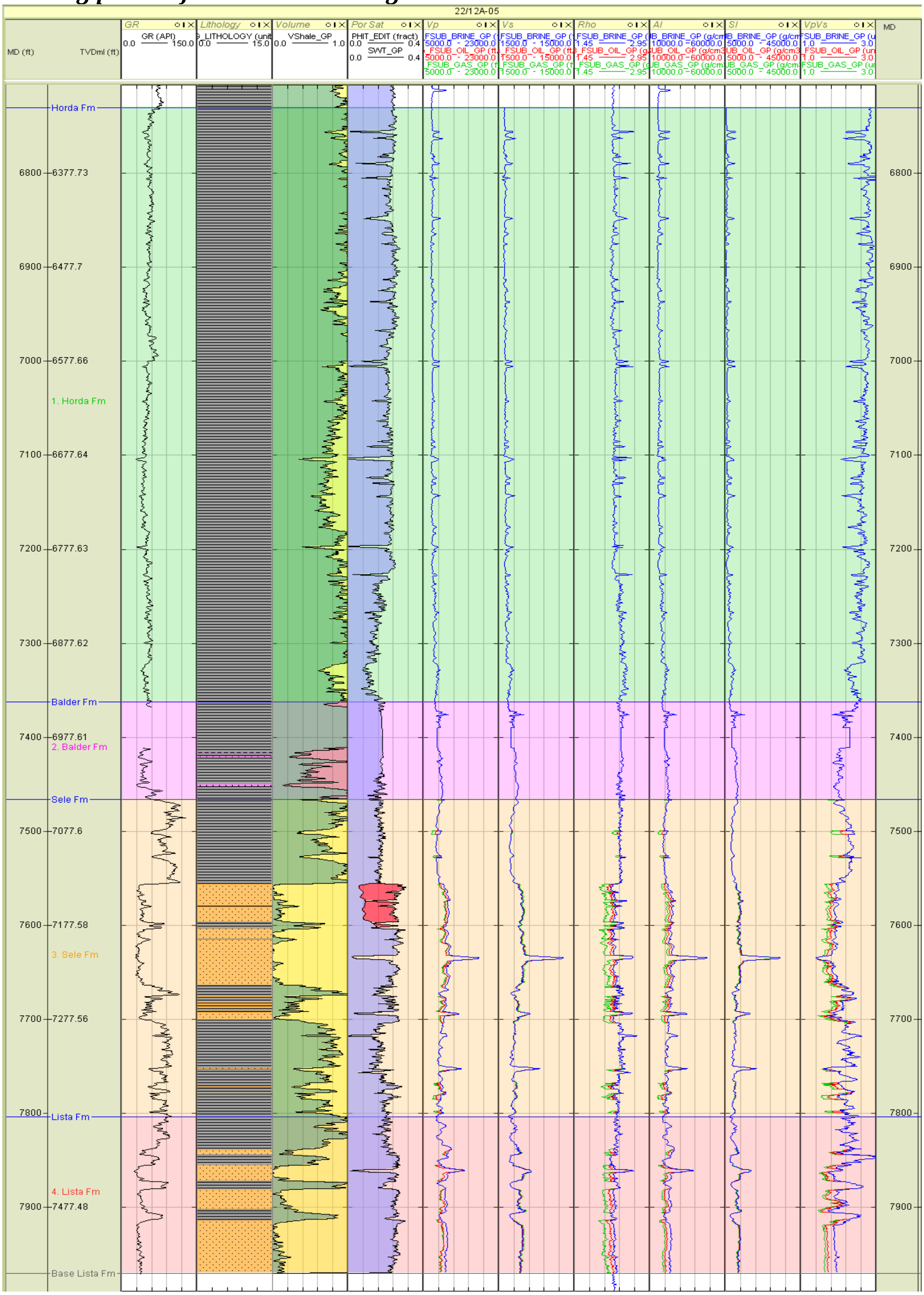


Figure 3.9.6 - Well Panel: Fluid substituted and elastic logs for well 22/12A-05.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/12A-05 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/12A-05	Horda	7310	2755	2.28
22/12A-05	Balder	8957	4649	2.35
22/12A-05	Sele	8686	3895	2.36
22/12A-05	Lista	9012	3805	2.28
22/12A-05	Maureen			

Table 3.9.6 - Clean shale properties at Well 22/12A-05

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/12A-05	Horda	100% Brine			
22/12A-05	Balder	100% Brine			
22/12A-05	Sele	100% Brine	10982	5813	2.27
22/12A-05	Lista	100% Brine	10554	5396	2.26
22/12A-05	Maureen	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/12A-05	Horda	80% Oil			
22/12A-05	Balder	80% Oil			
22/12A-05	Sele	80% Oil	10413	5878	2.22
22/12A-05	Lista	80% Oil	9669	5485	2.18
22/12A-05	Maureen	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/12A-05	Horda	90% Gas			
22/12A-05	Balder	90% Gas			
22/12A-05	Sele	90% Gas	10225	6031	2.10
22/12A-05	Lista	90% Gas	9553	5631	2.07
22/12A-05	Maureen	90% Gas			

Table 3.9.7 - Clean sand properties at Well 22/12A-05 for each fluid case

Tertiary reservoirs

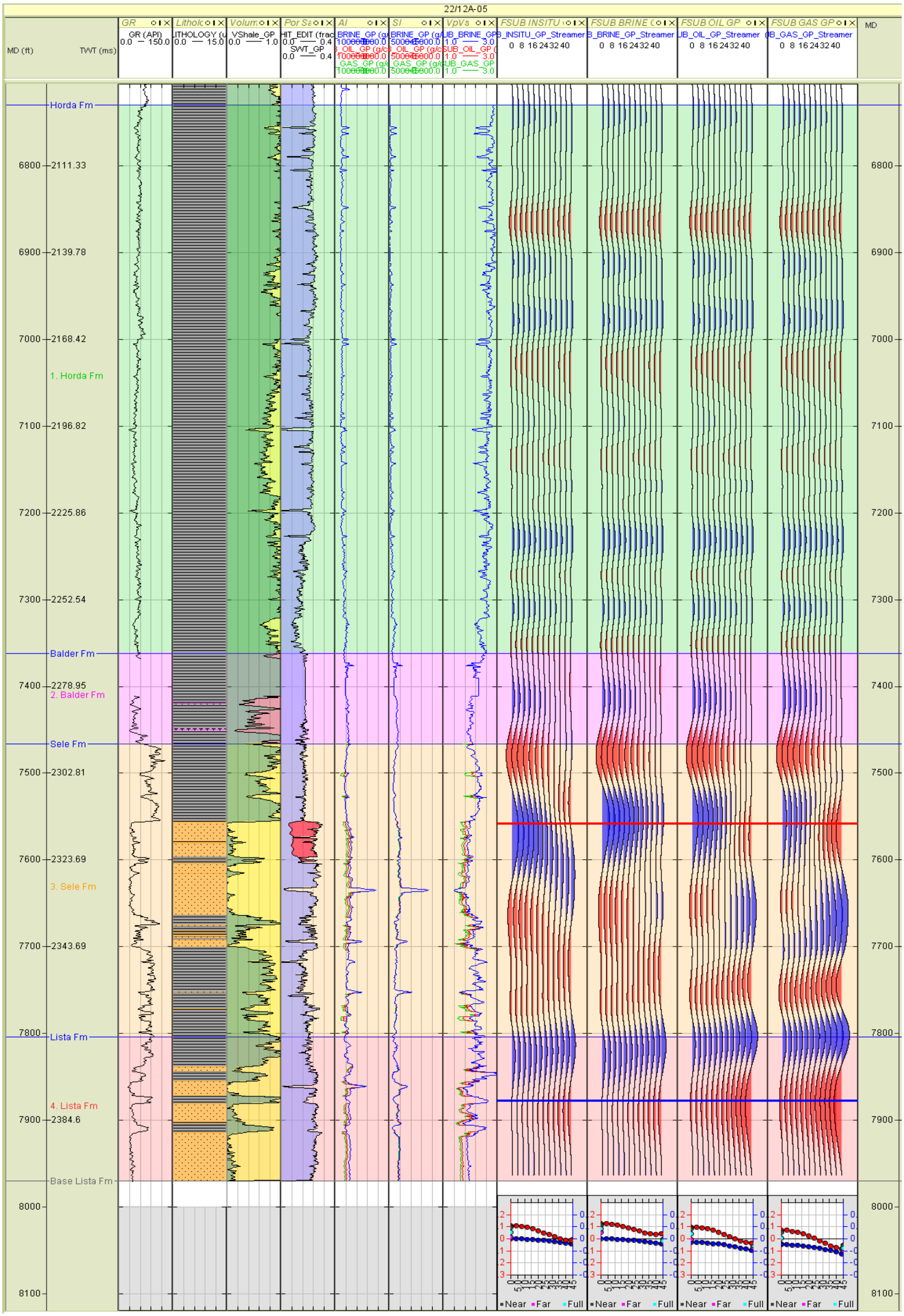


Figure 3.9.7 - Well Panel: Tertiary reservoirs for well 22/12A-05. Wavelet: Streamer

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a number of stacked clean blocky sands separated by thin shale intervals, net reservoir is approximately 150 feet. The uppermost reservoir sand is overlain by a shale interval approximately 90 feet thick and tuffaceous shale of the Balder Formation.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil, and a modelled class IIp response for the 90% gas case. Within the synthetic gathers, the seismic event correlating to top reservoir has a consistent class I AVO response. However, it is apparent that wavelet interference of the reservoir sands in the underburden plays some role in this response, this is particularly evident by comparing the FSUB_INSITU_GP and FSUB_OIL_GP synthetic gathers.
- Elastic Contrast Analysis shows contrasts are generally positive in the 100% brine case. Although many elastic contrasts remain relatively constant with the addition of hydrocarbons, Lambda and LambdaRho show the most sensitivity to fluid effects.

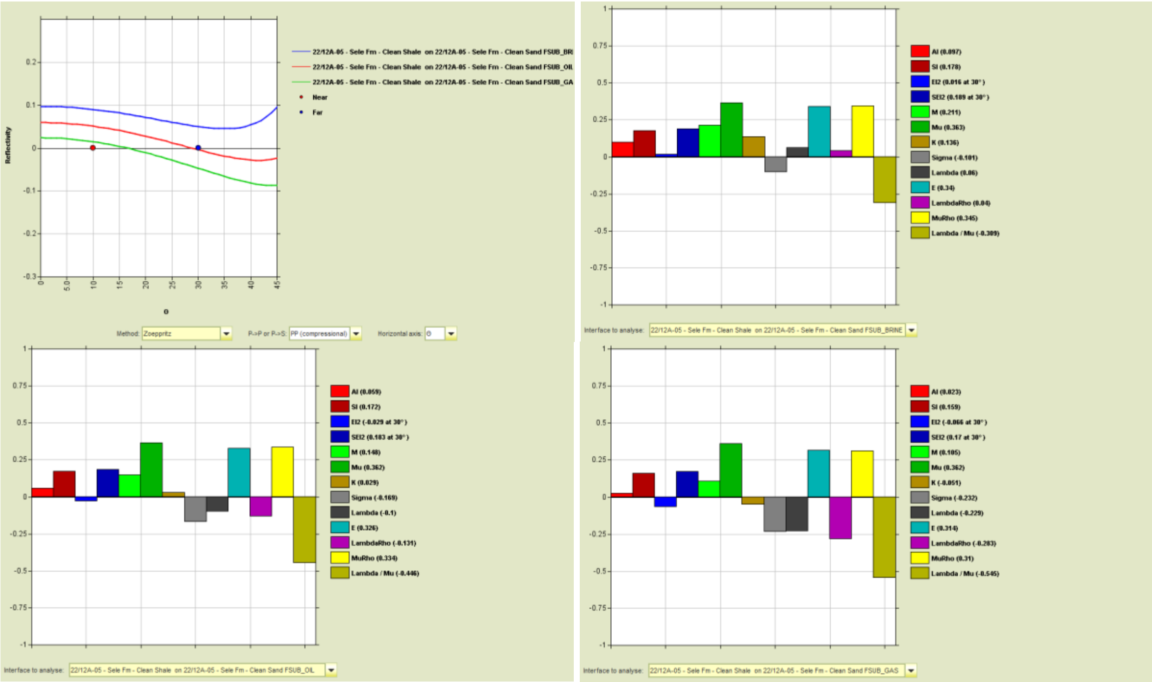


Figure 3.9.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/12A-05.

Lista Formation

- Reservoir formed within this interval by a number of clean blocky stacked sands separated by shale intervals. The reservoir is overlain by a silty interval which extends in to the Sele Formation. The well terminates at the base of Lista Formation, so no information on the underlying stratigraphy exists. Net reservoir is approximately 103 feet with porosities of around 25%.
- Blocky AVO shows a modelled class I response for the 100% brine case, a class IIp response for the 80% oil case, and a marginal class II/III response for the 90% gas case. Synthetic gathers created at the well location show a class II AVO response for the 100% brine case, and class III response for the hydrocarbon fluid fill cases. It is likely that the observed difference in AVO response is due to wavelet interference caused by the stacked nature of the reservoir sands.
- Elastic Contrast Analysis shows contrasts are mainly moderate and positive in the 100% brine case, trending towards strong negative contrasts with the addition of hydrocarbons. Lambda and LambdaRho show the most sensitivity to fluid effects, whereas Mu and MuRho show the least sensitivity to fluid effects.

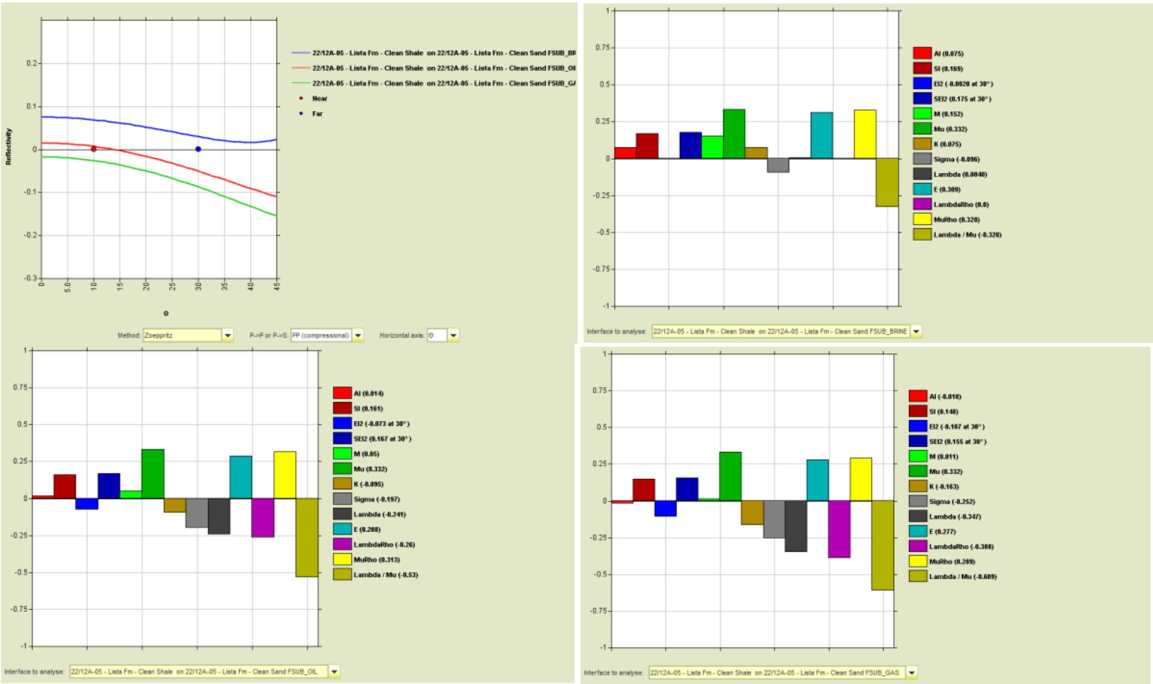


Figure 3.9.9 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/12A-05.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/02A-06 is provided below;

There is no Cretaceous section at this well.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/12A-05 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/12A-05	Overburden	Shale	7219		2.25
22/12A-05	Underburden				

Table 3.9.8 - Overburden and underburden properties at Well 22/12A-05.

Well: 22/15-02

General

Well Information
Total operated exploration well spudded, completed in 1987 and abandoned in 1988. The well encountered oil shows in the Upper Jurassic and Triassic.

Objectives
The well was drilled on the western flank of the Jaeren High, with a primary objective of evaluating Palaeocene sands which are hydrocarbon bearing (gas condensate/gas) to the northwest. The secondary objective was to test the Upper Jurassic-Triassic sandstone sequence. The Palaeocene Sele Formation (Forties Member), Lista Formation (Andrew Member) and Upper Cretaceous Chalk Group were present but wet. Resistivity indicated oil may be present within the Sele Formation, but the reservoir is too tight to flow. Oil shows were encountered within Upper Jurassic-Triassic sands.

Log conditioning overview
Negligible log conditioning was required within this well due to the good quality of measured log data. Spikes of anomalously low velocity are removed from the Vp log within the Horda Formation.

Invasion correction
Invasion correction of the density log performed over all intervals with measured density log coverage (Sele, Lista, Maureen and Ekofisk Formations) due to use of oil based drilling mud.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda Formation for Vp. Modelled log data was also used to extend the density log over the Horda, Balder, Sele, Tor and Hod Formations. A complete Vs log is modelled in the absence of measured shear log data.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 22/15-02 is displayed in the figures below;

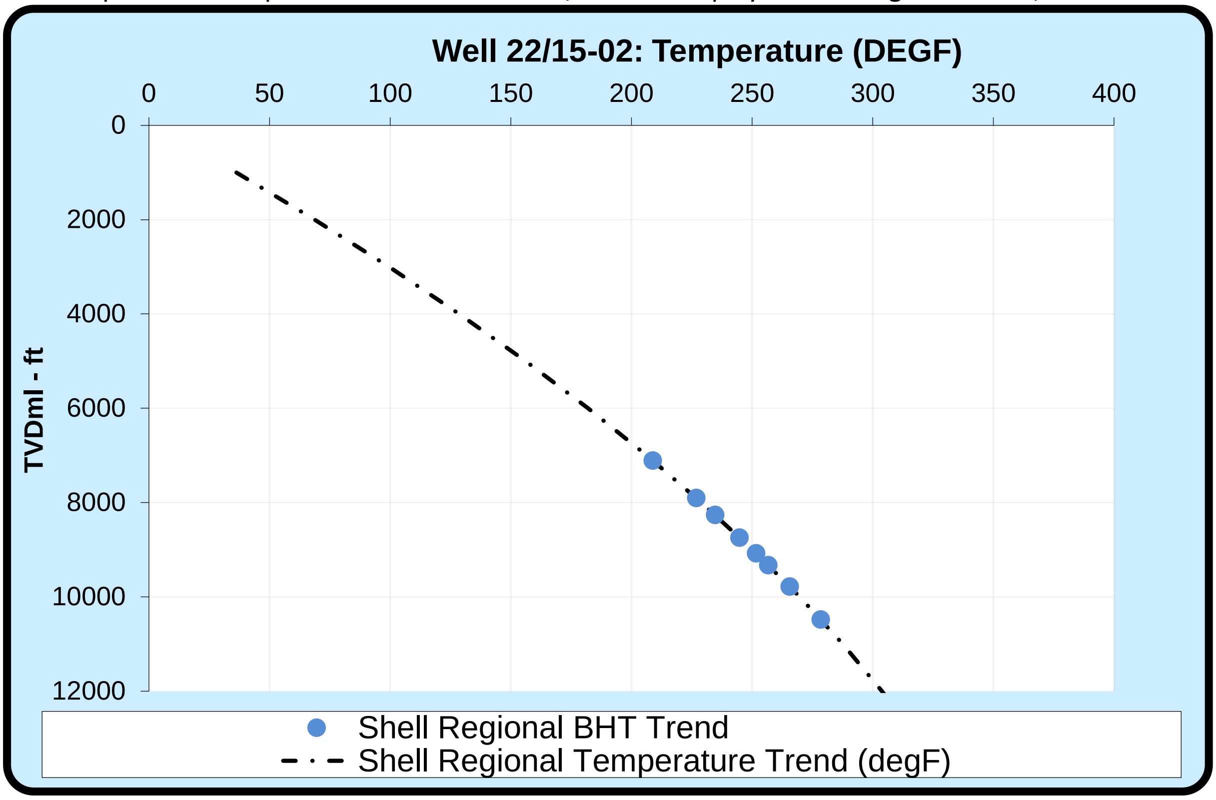


Figure 3.10.1 - Temperature data at Well 22/15-02

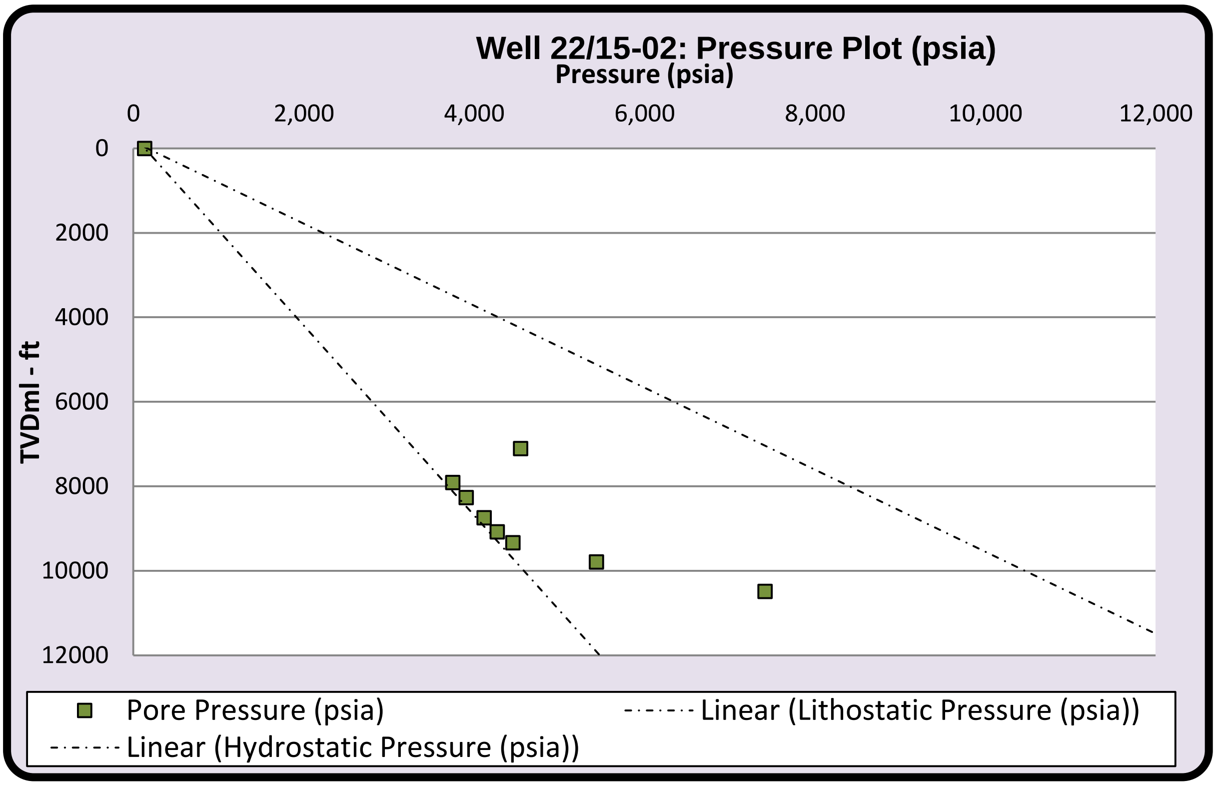


Figure 3.10.2 - Pressure data at Well 22/15-02

The temperature and pressure data for the formation mid-points in Well 22/15-02 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/15-02	Sea Bed	383.9	298.6	0.0	39.2	132.9	132.9	132.86	0.00
22/15-02	Horda	7492.3	7407.0	7108.4	208.9	3296.1	4546.1	7241.25	2695.16
22/15-02	Balder	8290.5	8205.2	7906.6	227.0	3651.3	3751.3	8039.50	4288.19
22/15-02	Sele	8645.0	8559.7	8261.1	234.7	3809.1	3909.1	8394.00	4484.93
22/15-02	Lista	9126.5	9041.2	8742.6	244.9	4023.3	4119.3	8875.50	4756.17
22/15-02	Maureen	9463.5	9378.2	9079.6	251.8	4173.3	4271.3	9212.50	4941.20
22/15-02	Ekofisk	9716.0	9630.7	9332.1	256.8	4285.7	4455.7	9465.00	5009.34
22/15-02	Tor	10169.0	10083.7	9785.1	265.6	4487.2	5437.2	9918.00	4480.75
22/15-02	Hod	10869.0	10783.7	10485.1	278.6	4798.7	7418.2	10618.00	3199.75

Table 3.10.1 - Summary of mid-point temperature and pressure data at Well 22/15-02

Fluid data

A summary of the fluid set parameters at Well 22/15-02 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/25-02	Horda	72000	730	39.0	0.71	0.71
22/25-02	Balder	72000	730	39.9	0.71	0.71
22/25-02	Sele	72000	730	40.3	0.71	0.71
22/25-02	Lista	72000	730	40.8	0.71	0.71
22/25-02	Maureen	72000	730	41.2	0.71	0.71
22/25-02	Ekofisk	94000	730	41.4	0.71	0.71
22/25-02	Tor	94000	730	41.9	0.71	0.71
22/25-02	Hod	94000	730	42.7	0.71	0.71

Table 3.10.2 - Summary of fluid parameter data at Well 22/15-02

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
22/25-02	Horda	16380	55.1	0.8
22/25-02	Balder	16380	55.8	0.8
22/25-02	Sele	16380	56.1	0.8
22/25-02	Lista	16380	56.5	0.8
22/25-02	Maureen	16380	56.8	0.8
22/25-02	Ekofisk	16380	57.0	0.8
22/25-02	Tor	16380	57.4	0.8
22/25-02	Hod	16380	58.0	0.8

Table 3.10.3 - Summary of additional parameter data at Well 22/15-02

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.10.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	14.76	8.09	2.472	10,546	5,934

Table 3.10.5 - Tuff properties used at Well 22/15-02

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/15-02	Horda	PAY	1427.500	0.000	0.000	0.000	0.000	0.000	0.000
22/15-02	Horda	RES	1427.500	0.500	0.000	0.108	0.216	1.000	0.377
22/15-02	Balder	PAY	169.000	0.000	0.000	0.000	0.000	0.000	0.000
22/15-02	Balder	RES	169.000	5.250	0.031	1.095	0.209	0.943	0.342
22/15-02	Sele	PAY	540.000	0.000	0.000	0.000	0.000	0.000	0.000
22/15-02	Sele	RES	540.000	102.000	0.189	17.330	0.170	0.974	0.161
22/15-02	Lista	PAY	423.000	0.000	0.000	0.000	0.000	0.000	0.000
22/15-02	Lista	RES	423.000	233.750	0.553	40.753	0.174	0.966	0.168
22/15-02	Maureen	PAY	251.000	0.000	0.000	0.000	0.000	0.000	0.000
22/15-02	Maureen	RES	251.000	151.250	0.603	25.578	0.169	0.944	0.109
22/15-02	Ekofisk	PAY	254.000	0.000	0.000	0.000	0.000	0.000	0.000
22/15-02	Ekofisk	RES	254.000	150.250	0.592	14.295	0.095	0.963	0.113
22/15-02	Tor	PAY	652.000	0.000	0.000	0.000	0.000	0.000	0.000
22/15-02	Tor	RES	652.000	532.750	0.817	38.804	0.073	0.988	0.009
22/15-02	Hod	PAY	748.000	0.000	0.000	0.000	0.000	0.000	0.000
22/15-02	Hod	RES	748.000	705.000	0.943	37.108	0.053	0.886	0.044

Table 3.10.6 - Petrophysical parameters used at Well 22/15-02

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

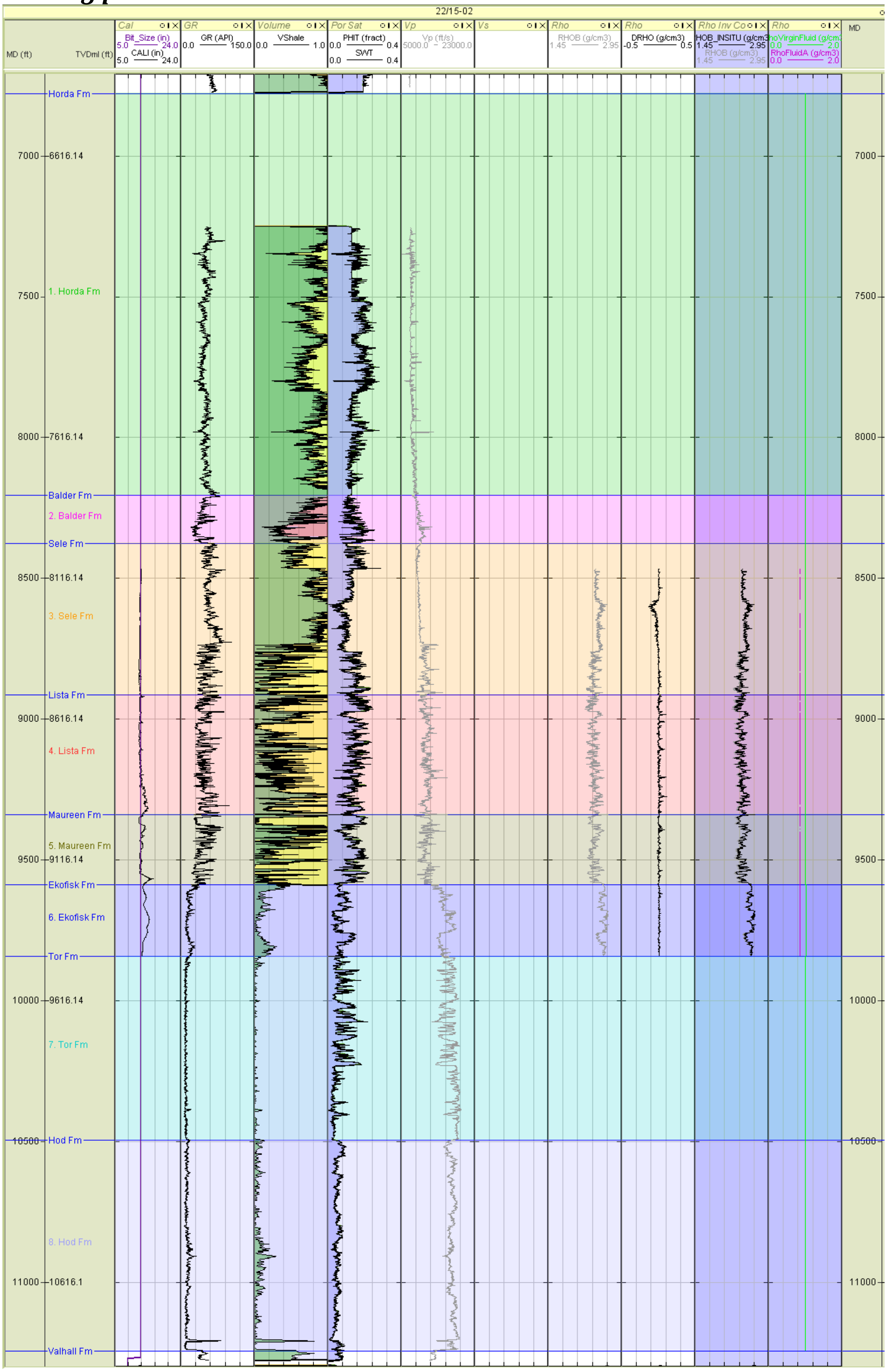


Figure 3.10.3 - Well Panel: Measured data and invasion correction for well 22/15-02.

Well log panel – log editing and audit

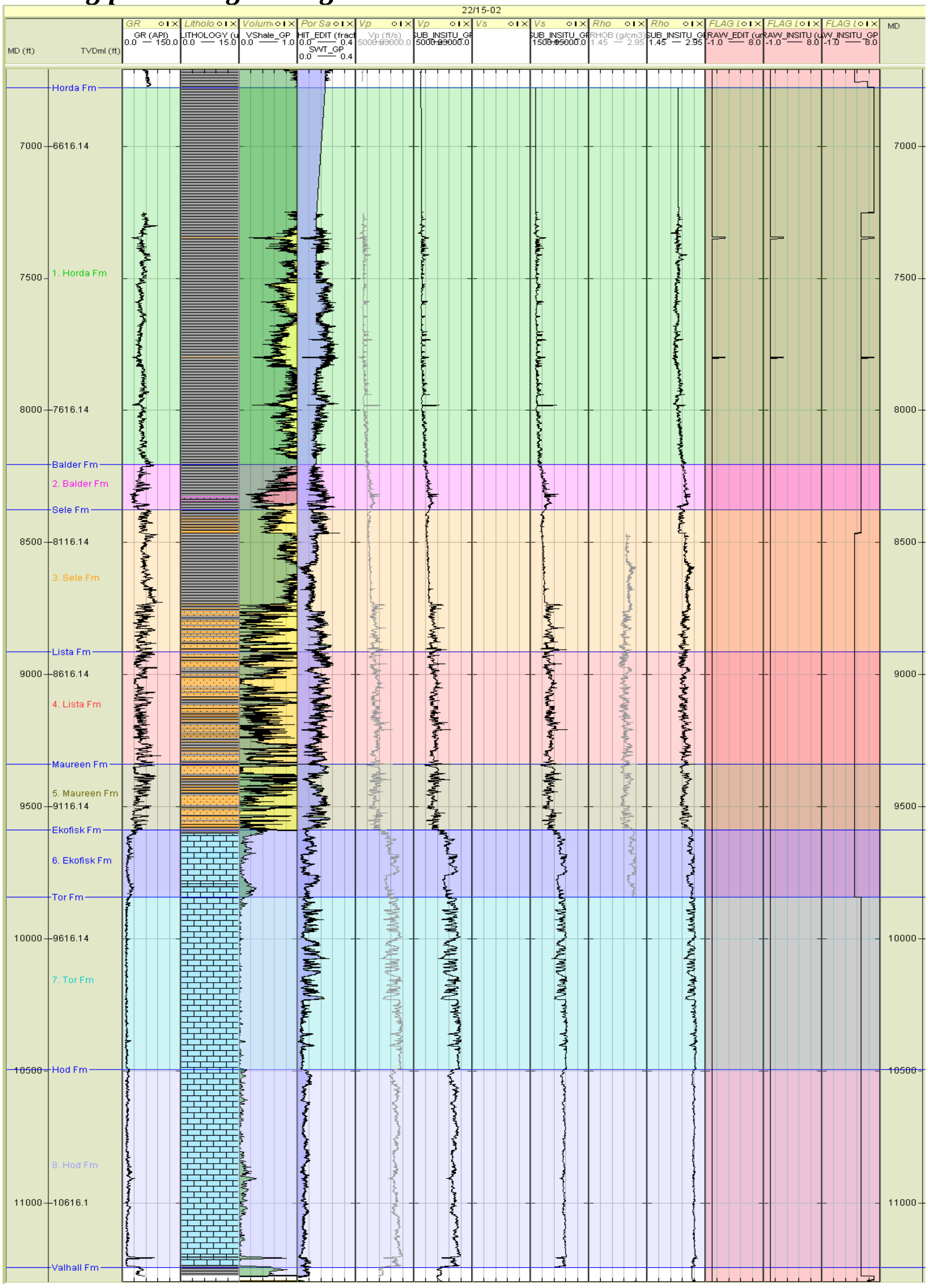


Figure 3.10.4 - Well Panel: Log edits for well 22/15-02.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

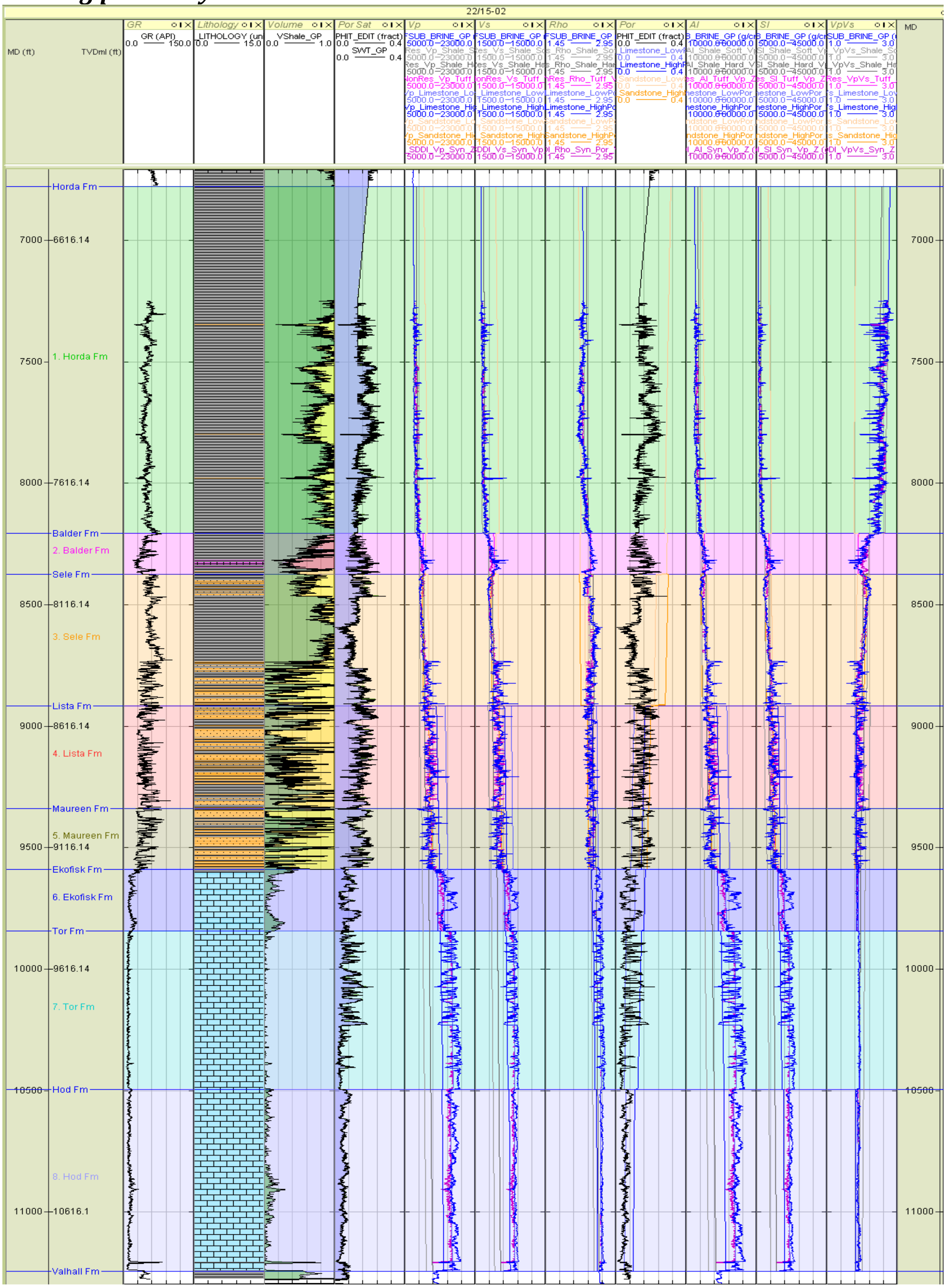


Figure 3.10.5 - Well Panel: End-member and synthetic logs for well 22/15-02.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

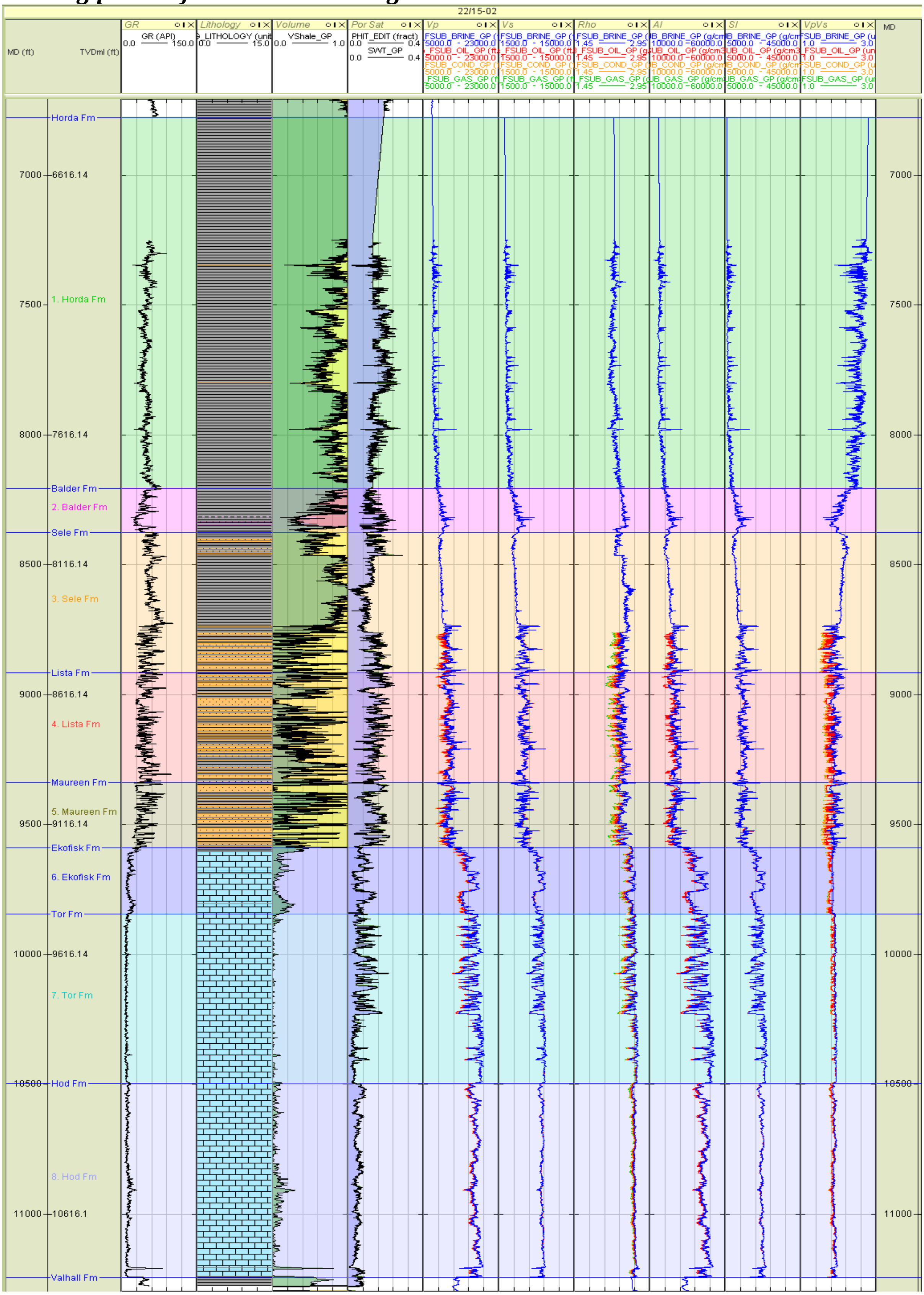


Figure 3.10.6 - Well Panel: Fluid substituted and elastic logs for well 22/15-02.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/15-02 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/15-02	Horda	7428	2829	2.25
22/15-02	Balder	8889	4173	2.40
22/15-02	Sele	9372	4516	2.45
22/15-02	Lista	10554	5321	2.45
22/15-02	Maureen	10224	5097	2.46

Table 3.10.7 - Clean shale properties at Well 22/15-02

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/15-02	Horda	100% Brine			
22/15-02	Balder	100% Brine			
22/15-02	Sele	100% Brine	10783	5759	2.36
22/15-02	Lista	100% Brine	11514	6196	2.36
22/15-02	Maureen	100% Brine	11631	6318	2.38
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/15-02	Horda	80% Oil			
22/15-02	Balder	80% Oil			
22/15-02	Sele	80% Oil	10055	5801	2.33
22/15-02	Lista	80% Oil	10757	6260	2.31
22/15-02	Maureen	80% Oil	10838	6379	2.33
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/15-02	Horda	90% Gas			
22/15-02	Balder	90% Gas			
22/15-02	Sele	90% Gas	9862	5873	2.27
22/15-02	Lista	90% Gas	10628	6365	2.24
22/15-02	Maureen	90% Gas	10688	6447	2.26
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/15-02	Horda	80% Cond			
22/15-02	Balder	80% Cond			
22/15-02	Sele	80% Cond	9844	5851	2.29
22/15-02	Lista	80% Cond	10592	6333	2.26
22/15-02	Maureen	80% Cond	10658	6447	2.28

Table 3.10.8 - Clean sand properties at Well 22/15-02 for each fluid case

Tertiary reservoirs – Well panel

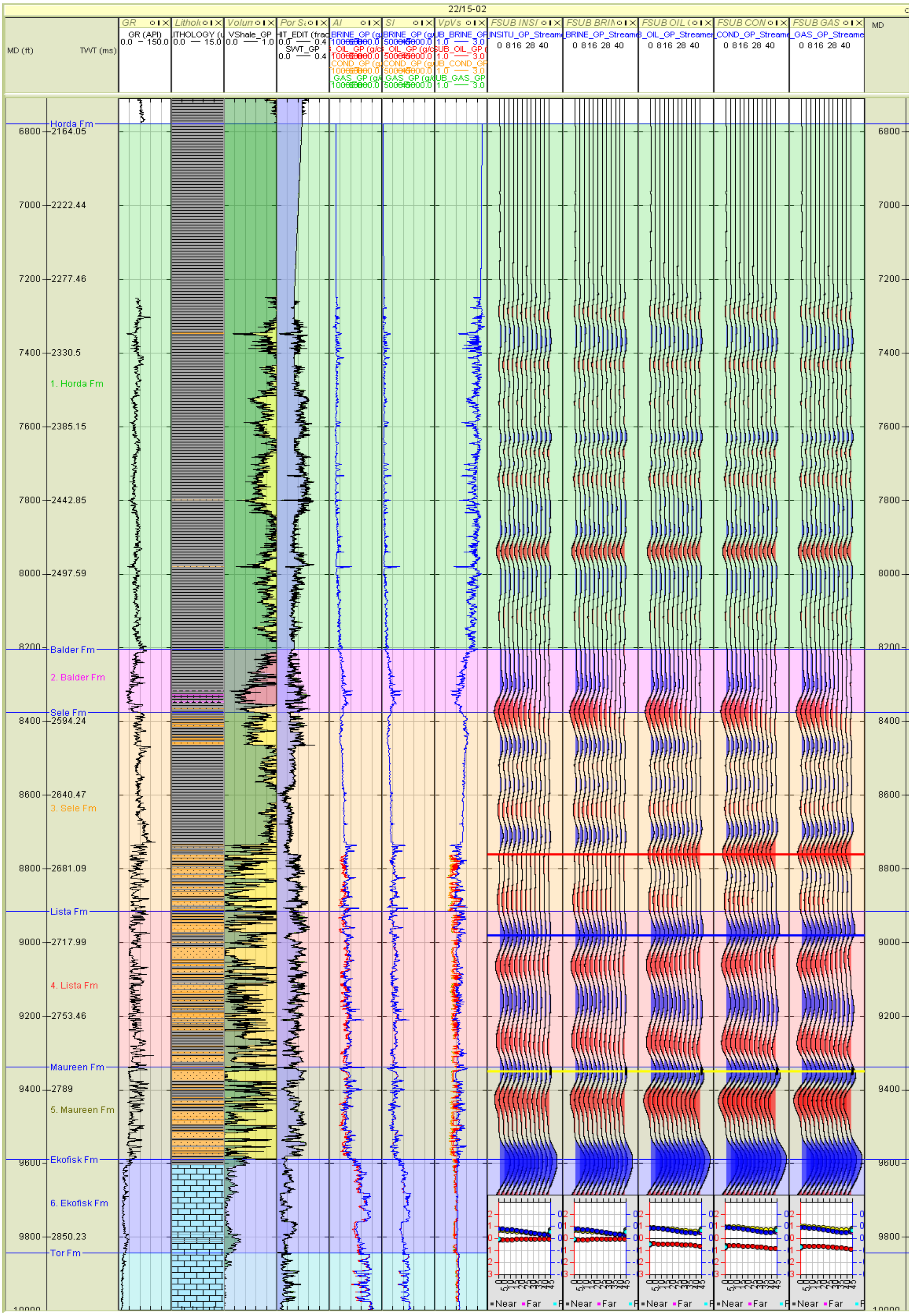


Figure 3.10.7 - Well Panel: Tertiary reservoirs for well 22/15-02. Wavelet: Streamer

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir within the formation comprises of a number of thin (approximately 3-20 feet thick) sands separated by shale beds towards the base of the interval. Directly above the uppermost reservoir lies a number of thin low porosity and high velocity streaks, these may be representative of cemented sand or calcite stringers. Net reservoir is approximately 102 feet containing porosities of 15-23%.
- Blocky AVO shows a modelled class I response for the 100% brine case, a class IIp response for the 80% oil case, with the 80% gas condensate and 90% gas cases showing modelled class II responses. Within the synthetic gathers, the 100% case gives no defined seismic response, whereas each of the hydrocarbon bearing cases gives a class III AVO response. It is apparent that interference is playing some role in the observed response. This is likely due to a combination the layered nature of the reservoir sands, in addition to the overlying high velocities events observed, masking the seismic signature of the sand where the increased elastic contrast created by the presence of hydrocarbons is not present.
- Elastic Contrast Analysis shows contrasts are often positive in the 100% brine case. It is apparent that many of the elastic contrasts show strong fluid effects, with Lambda and LambdaRho showing the greatest sensitivity. Mu and MuRho show the least sensitivity to fluid effects.

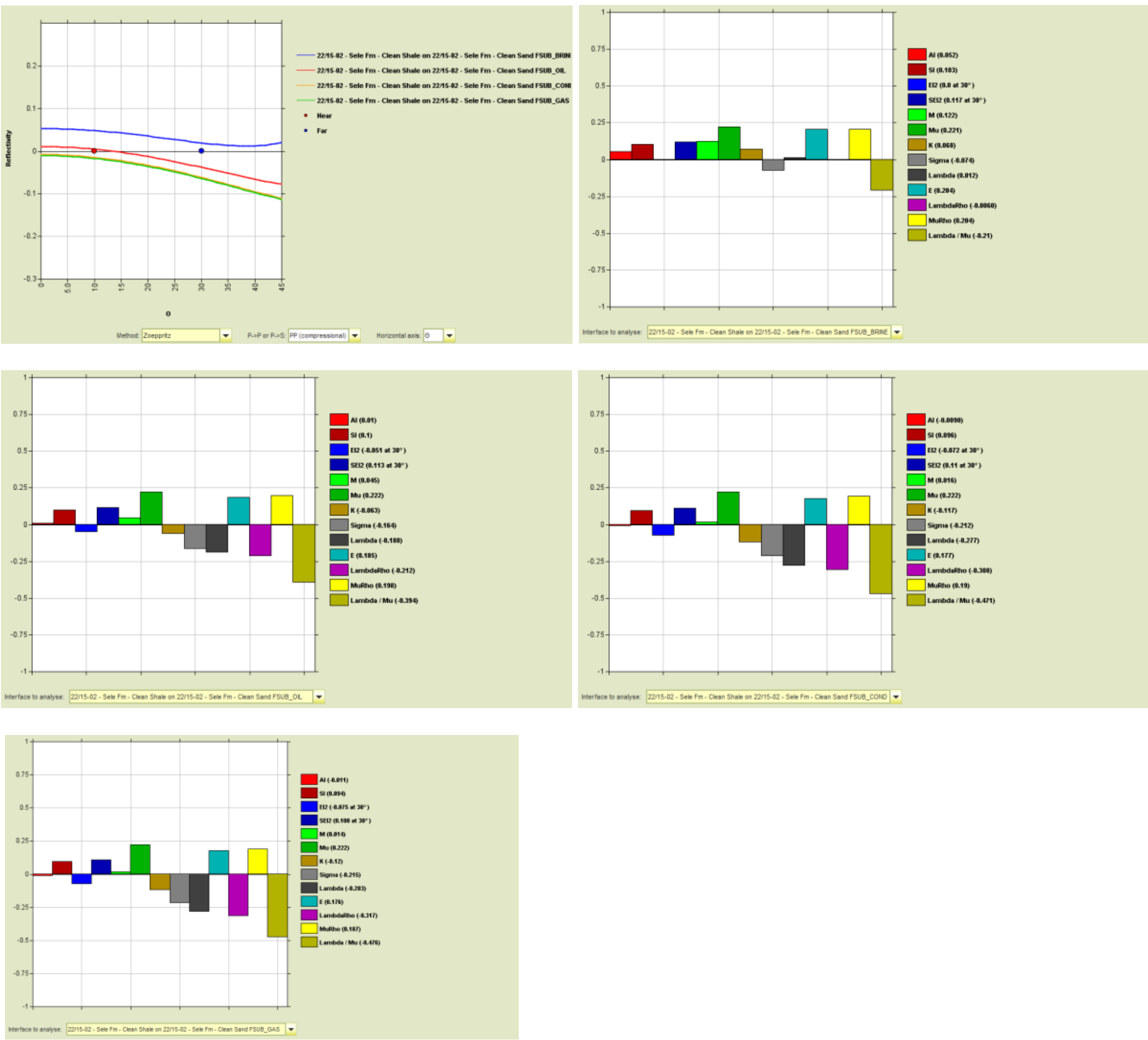


Figure 3.10.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/15-02.

Lista Formation

- Reservoir within the formation is formed by a number of thin (approximately 2-32 feet thick) sands running throughout the interval separated by shale beds. The formation is directly overlain by the reservoir forming part of the Sele Formation, which is comparable in its character. Net reservoir is approximately 234 feet with an average porosity of 17%.
- Blocky AVO shows a modelled class I response for the 100% brine case, the 80% oil case shows a marginal class II/III response, while the 80% gas condensate and 90% gas cases are modelled with a class III response. Synthetic gathers show a number of internal reflectors associated with the Lista Formation, as would be expected given the stacked nature of the reservoir sands. The uppermost reflector gives a constant class I AVO response in all fluid cases, which is consistent with a modelled Sele Formation sand on Lista Formation sand contact, although it is apparent there will be some effects of wavelet interference present.
- Elastic Contrast Analysis shows contrasts are mainly weak and positive in the 100% brine case. Many of the elastic contrasts show strong fluid effects, with Lambda and LambdaRho showing the greatest sensitivity. Mu shows the least sensitivity to fluid effects.

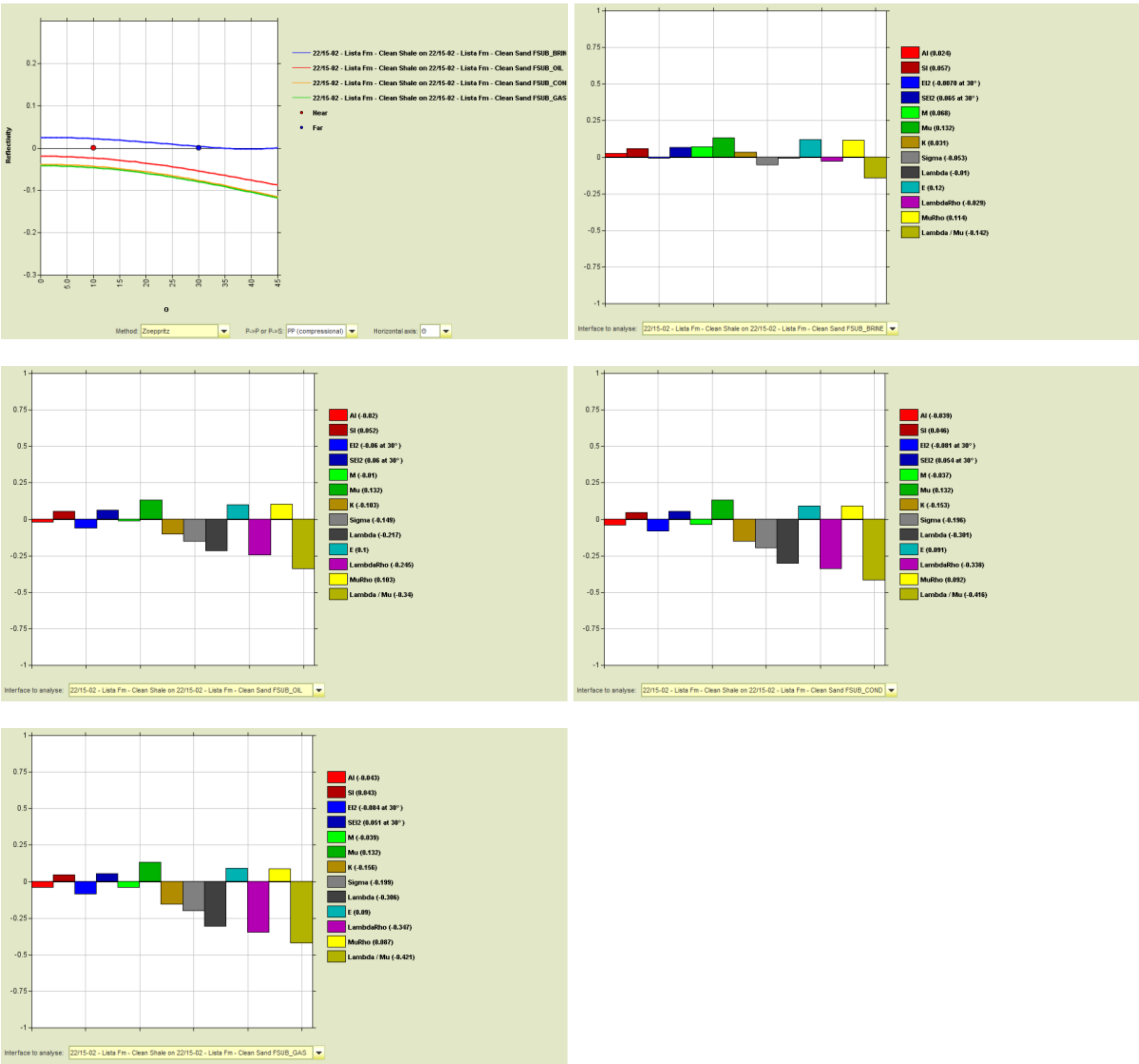


Figure 3.10.9 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/15-02.

Maureen Formation

- Reservoir within the formation comprises of a number of stacked sand bodies running throughout the interval separated by shale beds. Net reservoir is approximately 151 feet containing porosities of around 15-22%. The formation is directly overlaid by the Lista Formation which is comparable in character, and overlies massive chalks of the Ekofisk Formation.
- Blocky AVO shows a modelled class I response for the 100% brine case, the 80% oil shows a class II response, the 80% gas condensate and 90% gas cases show a marginal class II/III response. As for the Lista Formation, synthetic gathers show a number of internal reflectors associated with the Maureen Formation, with high probabilities of wavelet interferences contributing to the observed response. An AVO response of class I represents the uppermost reflector in all fluid cases.
- Elastic Contrast Analysis shows contrasts are mainly positive in the 100% brine case, and have a tendency to become increasingly negative with the introduction of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda and LambdaRho shows the most sensitivity to fluid effects.

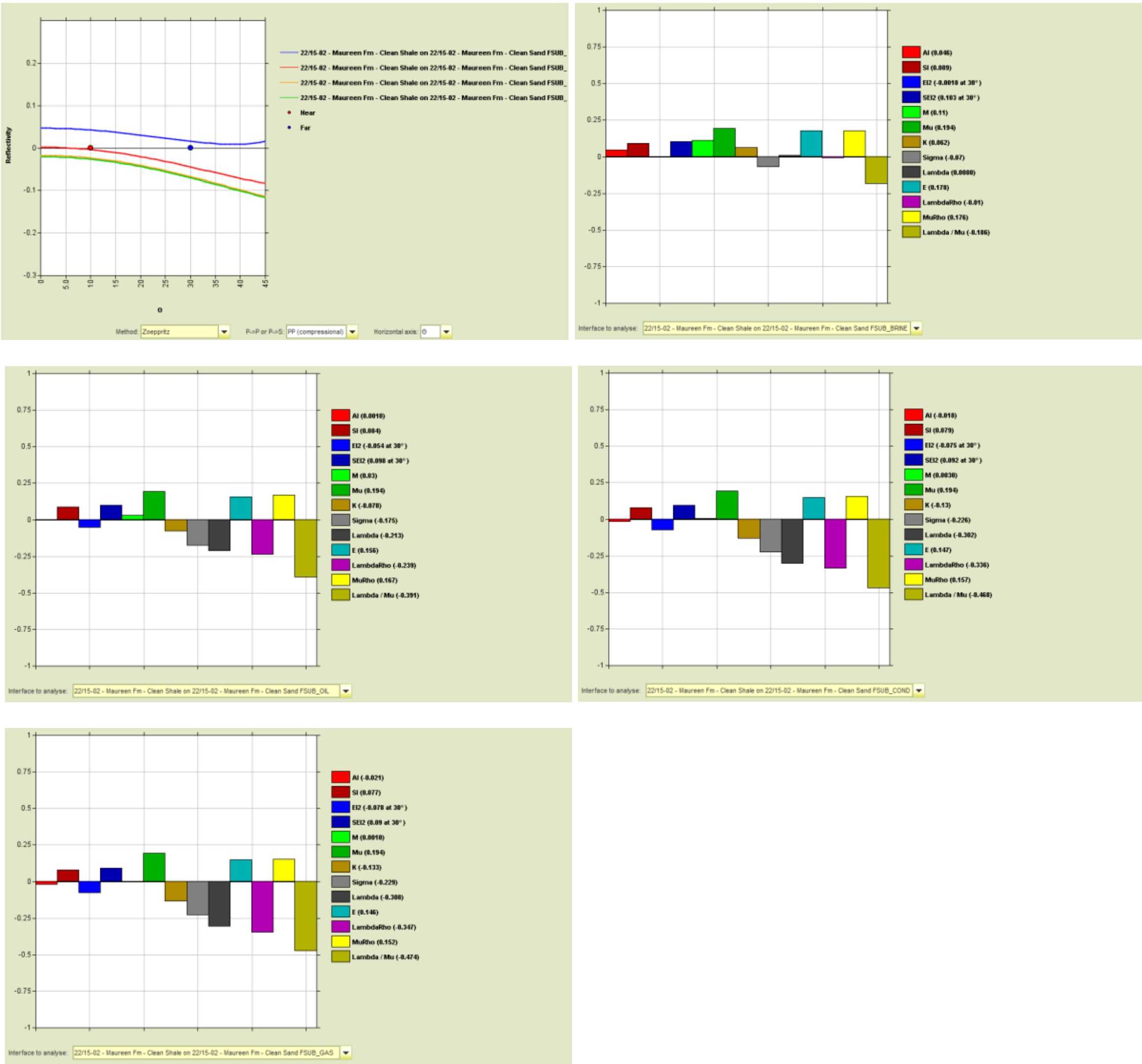


Figure 3.10.10 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/15-02.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/15-02 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/15-02	Ekofisk	100% Brine	16291	8811	2.58
22/15-02	Tor	100% Brine	17340	9045	2.63
22/15-02	Hod	100% Brine	17501	9234	2.65
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/15-02	Ekofisk	80% Oil	15991	8840	2.56
22/15-02	Tor	80% Oil	17154	9073	2.61
22/15-02	Hod	80% Oil	17339	9259	2.63
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/15-02	Ekofisk	90% Gas	15959	8883	2.53
22/15-02	Tor	90% Gas	17157	9114	2.59
22/15-02	Hod	90% Gas	17329	9294	2.61
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/15-02	Ekofisk	80% Cond	15943	8870	2.54
22/15-02	Tor	80% Cond	17139	9101	2.59
22/15-02	Hod	80% Cond	17315	9283	2.62

Table 3.10.9 - Clean limestone properties at Well 22/15-02 for each fluid case

Cretaceous reservoirs

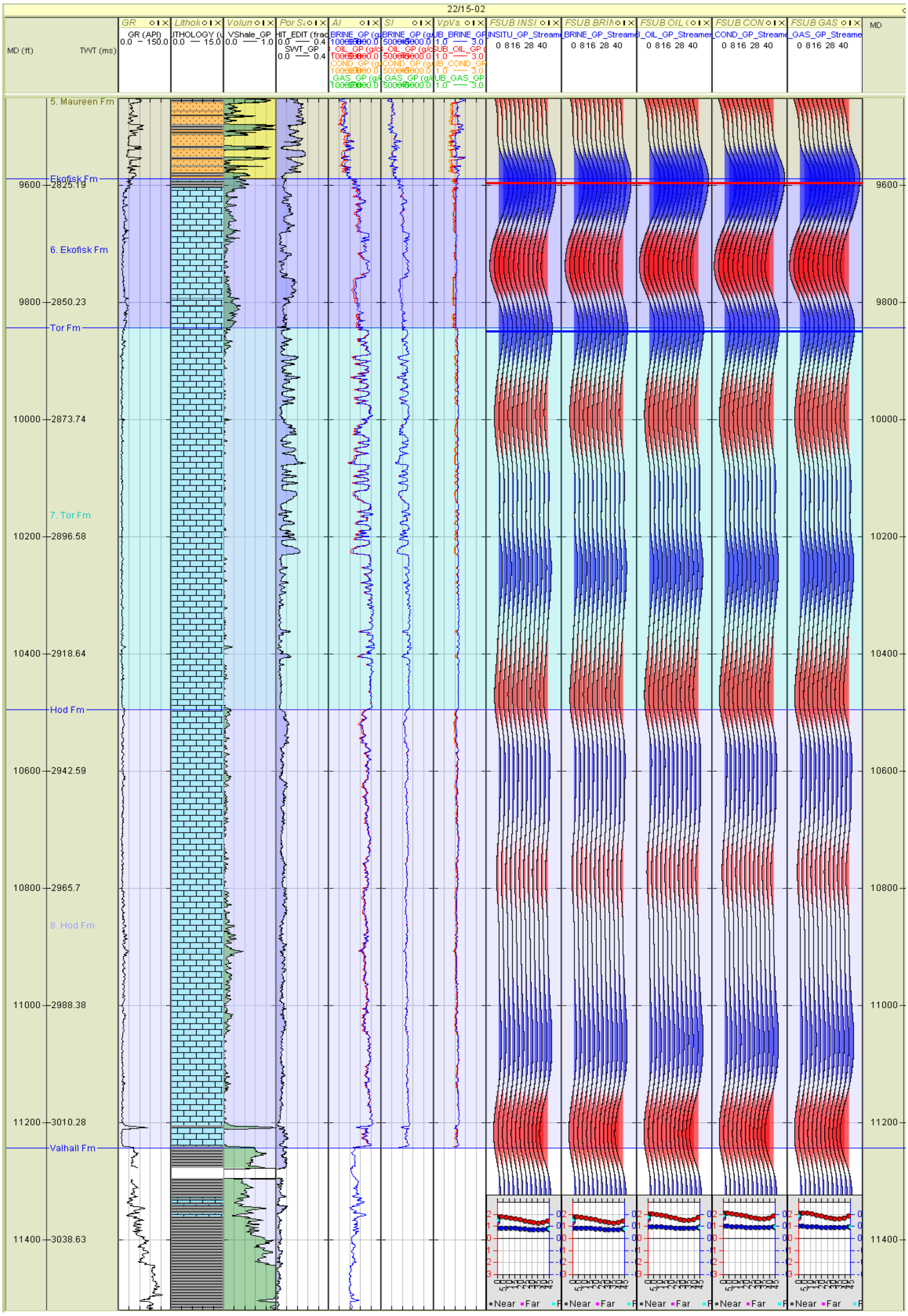


Figure 3.10.11 - Well Panel: Cretaceous reservoirs for well 22/15-02. Wavelet: Streamer

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir is formed by patchy zones of higher porosity focused within two zones towards the top and base of the interval. Porosities within these zones are approximately 8-16%. The interval is overlain by laminated sand and shale of the Maureen Formation. Net reservoir is approximately 150 feet.
- Blocky AVO modelling shows a class I response predicted in each fluid case, where reflectivity decreases moving from brine to hydrocarbons bearing cases. Within the synthetic gathers, a corresponding class I AVO response is observed in each fluid case, although reflectivity increases with the introduction of hydrocarbons. This is likely due to wavelet interference caused by the multiple internal reflectors within the Maureen Formation, and porosity changes throughout the Ekofisk Formation.
- Elastic Contrast Analysis shows contrasts are often strong and positive in the 100% brine case, showing little sensitivity to the introduction of hydrocarbons. Lambda/Mu shows the most sensitivity to fluid effects.

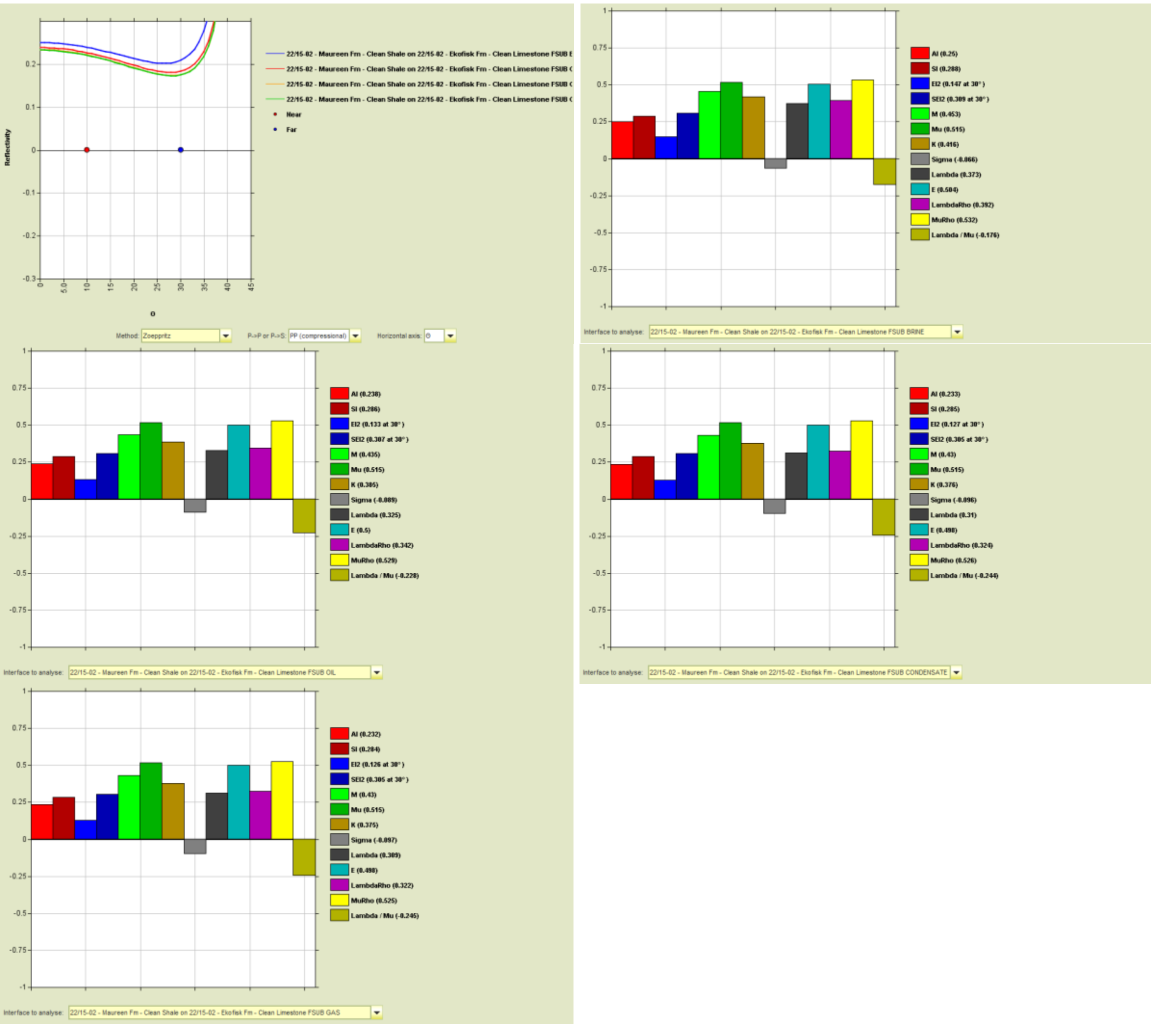


Figure 3.10.12 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/15-02.

Tor Formation

- Reservoir is formed by a number of patchy zones of higher porosity (approximately 6-22%) found mostly within the top half of the formation. The interval is bounded by the relatively silty chalks of the Ekofisk and Hod Formations. Net reservoir is approximately 533 feet.
- Blocky AVO modelling shows a class I response predicted in all fluid cases, where reflectivity is insensitive to incidence angle and fluid effects. Within the synthetic gathers, comparative AVO responses are observed in each fluid case.
- Elastic Contrast Analysis shows contrasts are weak and positive in the 100% brine case, with little change occurring with the inclusion of hydrocarbon fluid fill. Lambda/Mu shows the most sensitivity to fluid effects.

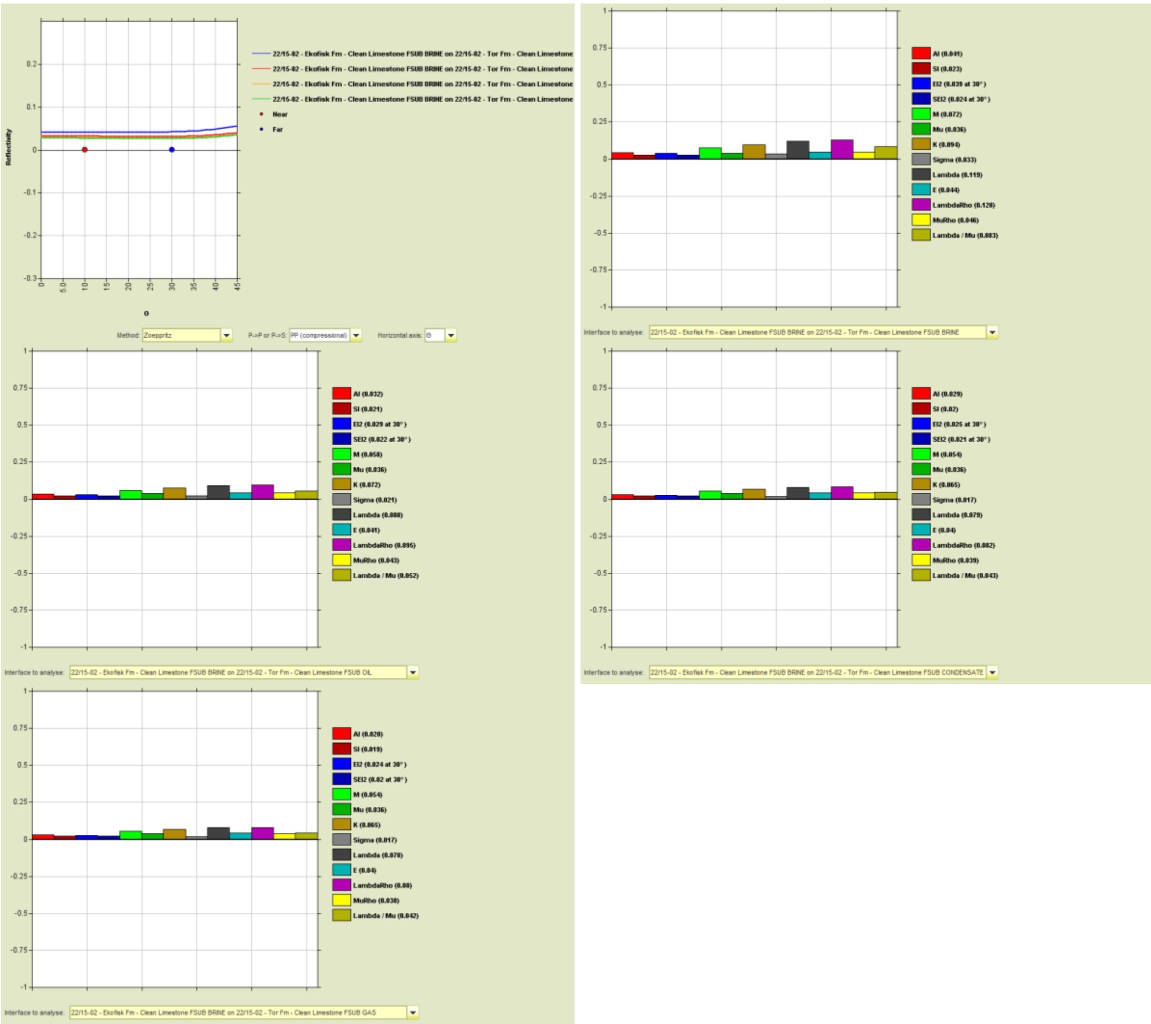


Figure 3.10.13 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/15-02.

Hod Formation

- Reservoir formed by a massive silty chalk containing an average porosity of 5%. The interval is overlain by relatively low porosity chalk of the Tor Formation and underlain by calcareous shale of the Valhall Formation. Net reservoir is approximately 705 feet.
- Blocky AVO modelling shows little sensitivity to fluid fill, with no AVO signature observed in each fluid case modelled. Within the synthetic gathers, top reservoir would arguably be picked on a negative reflection event, which gives a low gradient class III response in all fluid cases.
- Elastic Contrast Analysis shows contrasts are negligible in the 100% brine case. LambdaRho shows the most sensitivity to fluid effects, but contrasts on the whole remain relative insensitive to changes in pore fill.

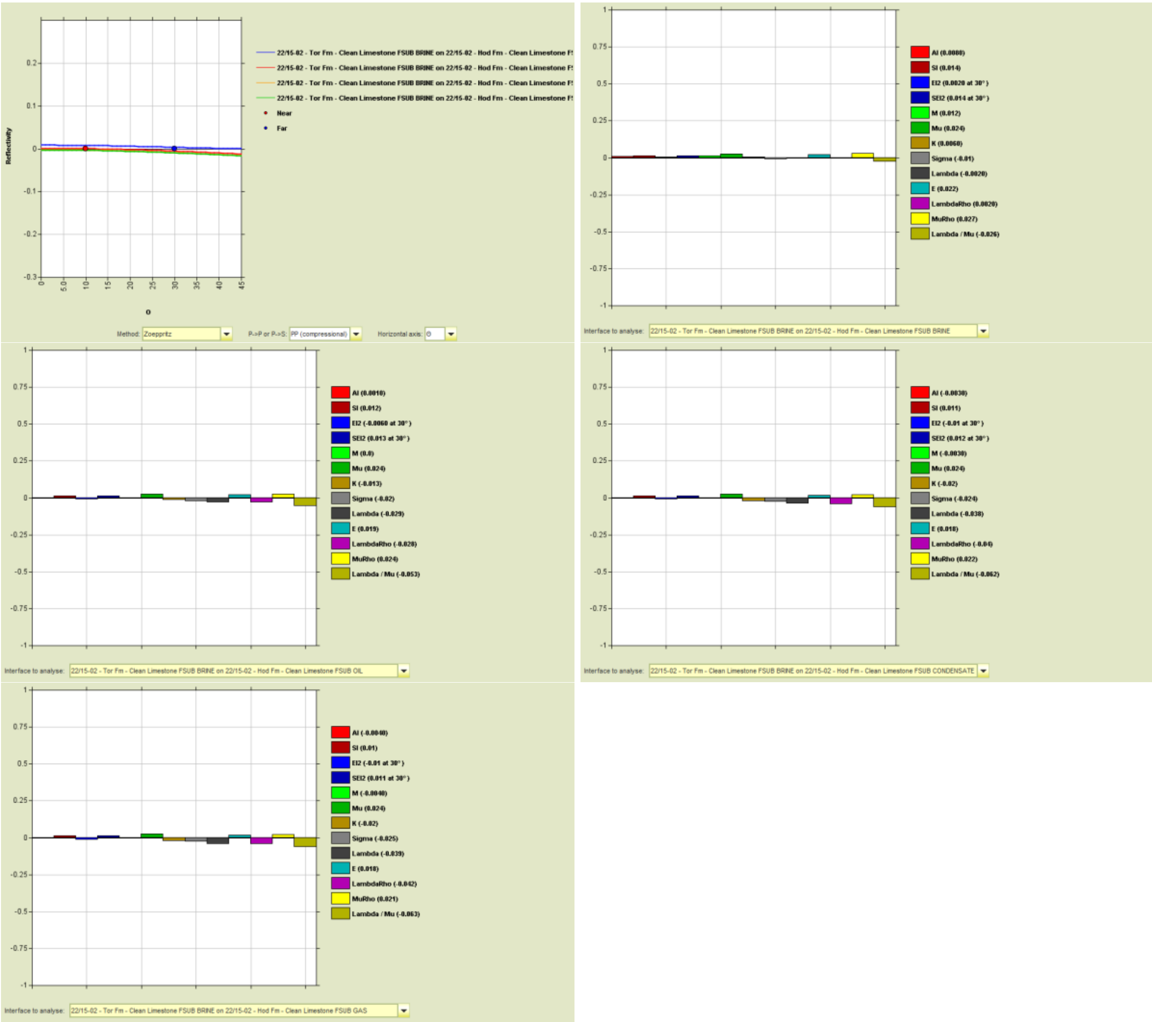


Figure 3.10.14 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/15-02.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/15-02 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/15-02	Overburden	Shale	7076		
22/15-02	Underburden	Limestone/Shale	12637		2.67

Table 3.10.10 - Overburden and underburden properties at Well 22/15-02.

Well: 22/19-01

General

Well Information
Occidental operated exploration well spudded, completed and abandoned in 1984. The well encountered gas condensate in the Sele Formation (Forties Member).

Objectives
The well was drilled on the Fiddich structure to evaluate Palaeocene sands and Upper Cretaceous Chalk Group. The Sele Formation was present and encountered gas condensate. The Lista Formation (Andrew Member) and Upper Cretaceous Chalk Group were also present but wet.

Log conditioning overview
A number of log conditioning steps were undertaken within this well. Vp and density logs have been clipped at the start of logging runs two and three in the Horda Formation, associated with borehole washout as indicated by the caliper log. Density spikes are removed within the Sele Formation, again due to borehole washout. Anomalous data within the Vp log was removed over the Lista and Maureen Formations due to tool failure.

Invasion correction
The drilling mud used within this well was water based, with invasion correction of the density log being required within the gas condensate bearing Sele Formation.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log. The only exception is a minor gap within the Rho log over a hydrocarbon zone in the Sele Formation and the methodology for filling this gap is documented within the Rock Physics Part 2 PowerPoints.

Log modelling was performed to fill gaps within the Horda, Lista and Maureen Formations for Vp. Modelled density data was also used to fill gaps and extend the density coverage over the Horda, Sele, Lista, Maureen, Ekofisk, Tor and Hod Formations. In the absence of measured shear log data, a complete Vs log is modelled using Modified Gassmann methodology due to the presence of hydrocarbons within this well.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 22/19-01 is displayed in the figures below;

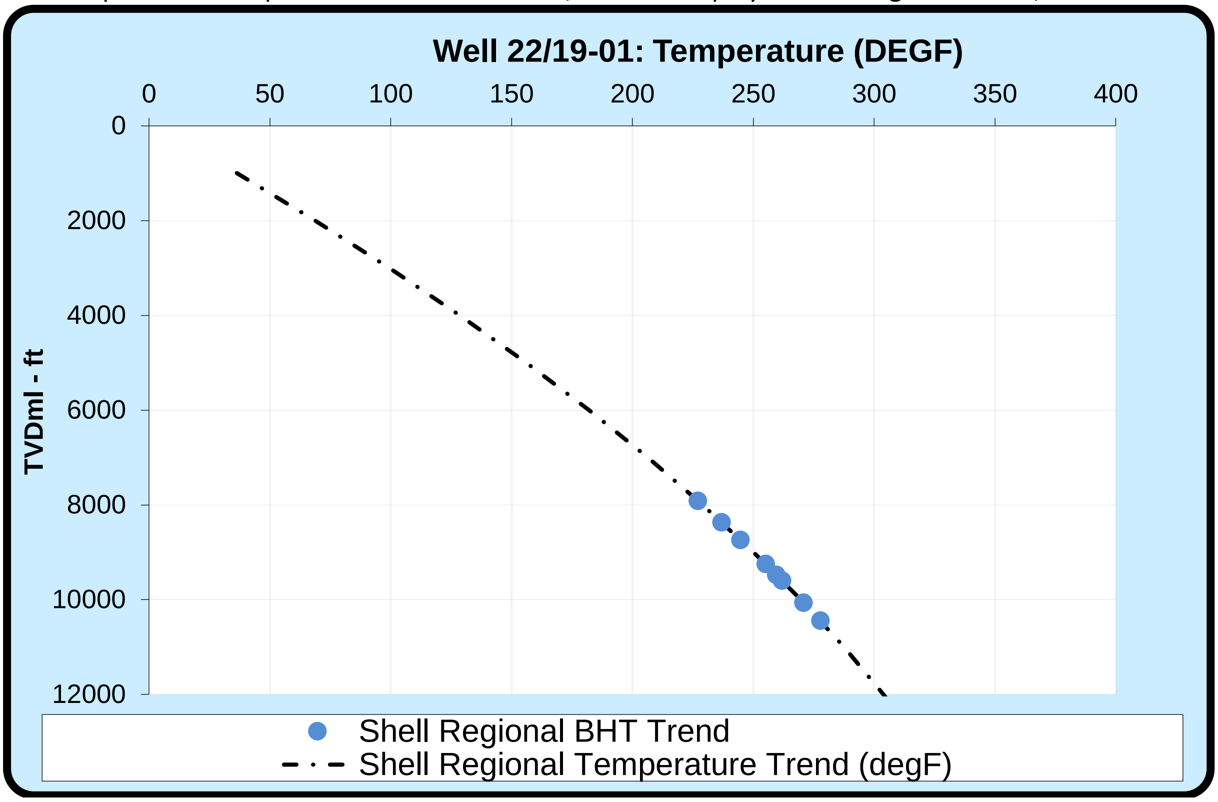


Figure 3.11.1 - Temperature data at Well 22/19-01

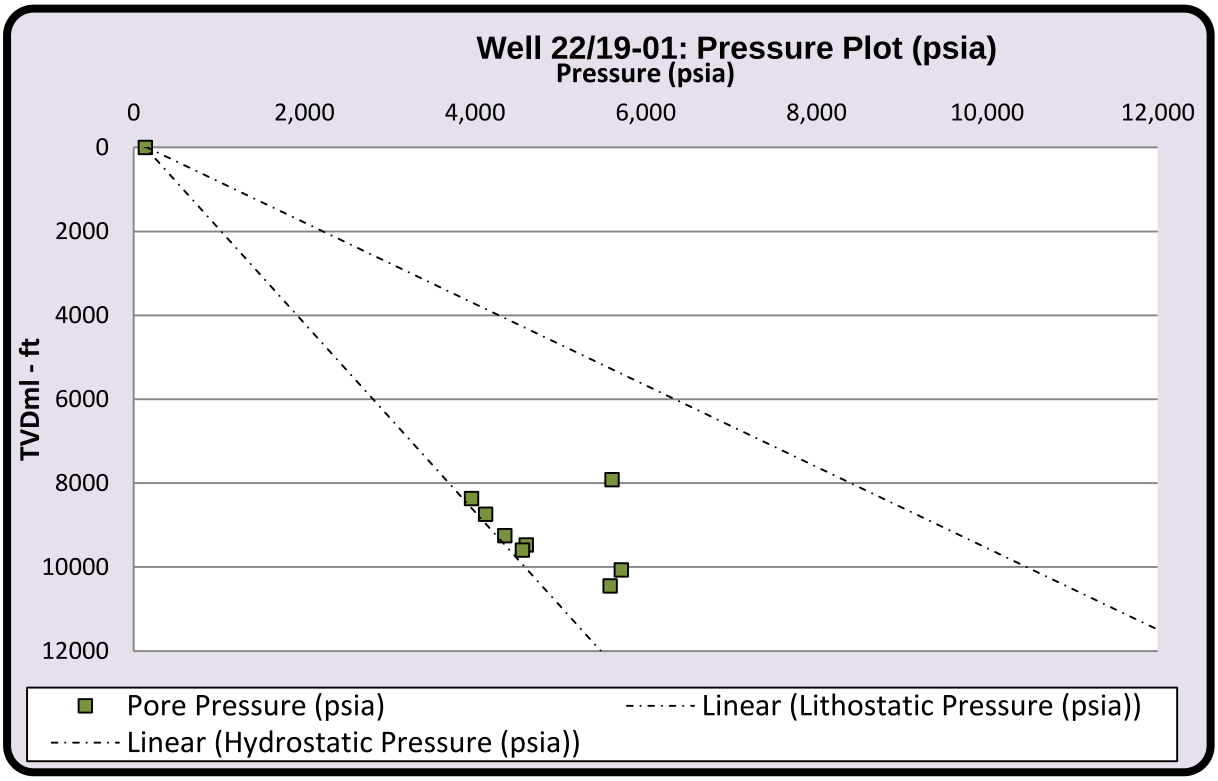


Figure 3.11.2 - Pressure data at Well 22/19-01

The temperature and pressure data for the formation mid-points in Well 22/19-01 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/19-01	Sea Bed	392.0	307.0	0.0	39.2	136.6	136.6	136.62	0.00
22/19-01	Horda	8307.1	8220.7	7913.7	227.2	3658.2	5608.2	8050.28	2442.08
22/19-01	Balder	8760.5	8674.0	8367.0	237.0	3859.9	3959.9	8503.63	4543.70
22/19-01	Sele	9130.5	9044.0	8737.0	244.8	4024.6	4124.6	8873.57	4749.01
22/19-01	Lista	9642.0	9555.4	9248.4	255.2	4252.1	4352.1	9384.98	5032.84
22/19-01	Maureen	9867.0	9780.3	9473.3	259.6	4352.2	4602.2	9609.92	5007.69
22/19-01	Ekofisk	9989.0	9902.3	9595.3	262.0	4406.5	4556.5	9731.89	5175.38
22/19-01	Tor	10460.0	10373.2	10066.2	270.9	4616.1	5716.1	10202.80	4486.74
22/19-01	Hod	11031.5	10751.7	10444.7	277.8	4784.5	5584.5	10581.29	4996.80

Table 3.11.1 - Summary of mid-point temperature and pressure data at Well 22/19-01

Fluid data

A summary of the fluid set parameters at Well 22/19-01 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/19-01	Horda	90000	730	39.9	0.71	0.71
22/19-01	Balder	90000	730	40.4	0.71	0.71
22/19-01	Sele	90000	730	40.8	0.71	0.71
22/19-01	Lista	90000	730	41.4	0.71	0.71
22/19-01	Maureen	90000	730	41.6	0.71	0.71
22/19-01	Ekofisk	200000	730	41.7	0.71	0.71
22/19-01	Tor	200000	730	42.2	0.71	0.71
22/19-01	Hod	200000	730	42.6	0.71	0.71

Table 3.11.2 - Summary of fluid parameter data at Well 22/19-01

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
22/19-01	Horda	16380	55.8	0.8
22/19-01	Balder	16380	56.2	0.8
22/19-01	Sele	16380	56.5	0.8
22/19-01	Lista	16380	56.9	0.8
22/19-01	Maureen	16380	57.1	0.8
22/19-01	Ekofisk	16380	57.2	0.8
22/19-01	Tor	16380	57.6	0.8
22/19-01	Hod	16380	58.0	0.8

Table 3.11.3 - Summary of additional parameter data at Well 22/19-01

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.11.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	14.54	7.97	2.45	1,0545	5,933

Table 3.11.5 - Tuff properties used at Well 22/19-01

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/19-01	Horda	PAY	821.830	0.000	0.000	0.000	0.000	0.000	0.000
22/19-01	Horda	RES	821.830	0.000	0.000	0.000	0.000	0.000	0.000
22/19-01	Balder	PAY	85.000	0.000	0.000	0.000	0.000	0.000	0.000
22/19-01	Balder	RES	85.000	0.000	0.000	0.000	0.000	0.000	0.000
22/19-01	Sele	PAY	655.000	11.000	0.017	2.445	0.222	0.409	0.089
22/19-01	Sele	RES	655.000	527.500	0.805	106.405	0.202	0.921	0.155
22/19-01	Lista	PAY	368.000	0.000	0.000	0.000	0.000	0.000	0.000
22/19-01	Lista	RES	368.000	84.750	0.230	15.299	0.181	0.998	0.233
22/19-01	Maureen	PAY	82.000	0.000	0.000	0.000	0.000	0.000	0.000
22/19-01	Maureen	RES	82.000	30.250	0.369	4.599	0.152	0.978	0.299
22/19-01	Ekofisk	PAY	162.000	0.000	0.000	0.000	0.000	0.000	0.000
22/19-01	Ekofisk	RES	162.000	134.250	0.829	12.142	0.090	0.841	0.199
22/19-01	Tor	PAY	780.000	0.000	0.000	0.000	0.000	0.000	0.000
22/19-01	Tor	RES	780.000	533.500	0.684	32.482	0.061	0.978	0.045
22/19-01	Hod	PAY	450.000	0.000	0.000	0.000	0.000	0.000	0.000
22/19-01	Hod	RES	450.000	367.500	0.817	19.772	0.054	0.988	0.237

Table 3.11.6 - Petrophysical parameters used at Well 22/19-01

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

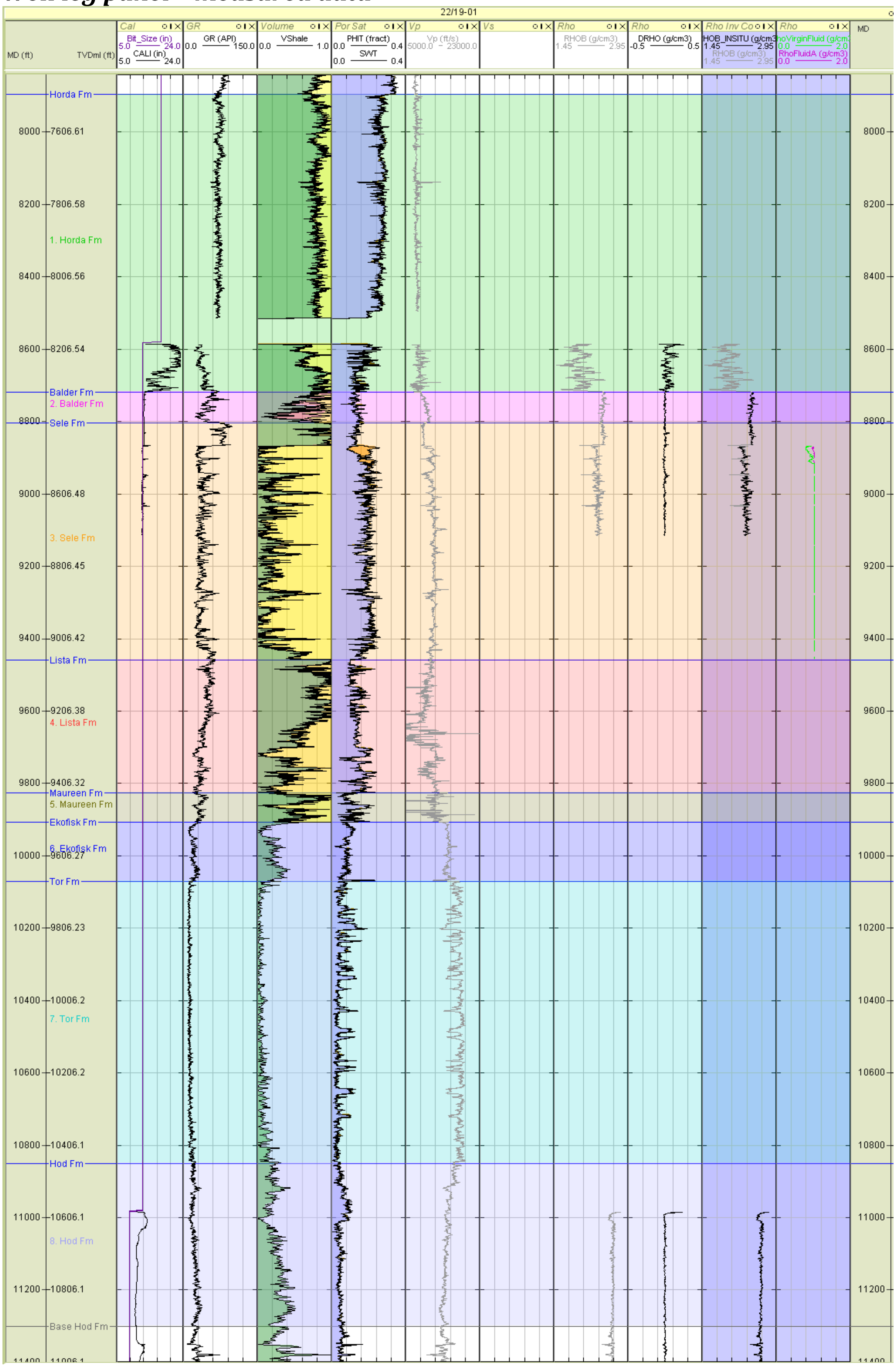


Figure 3.11.3 - Well Panel: Measured data and invasion correction for well 22/19-01.

Well log panel – log editing and audit

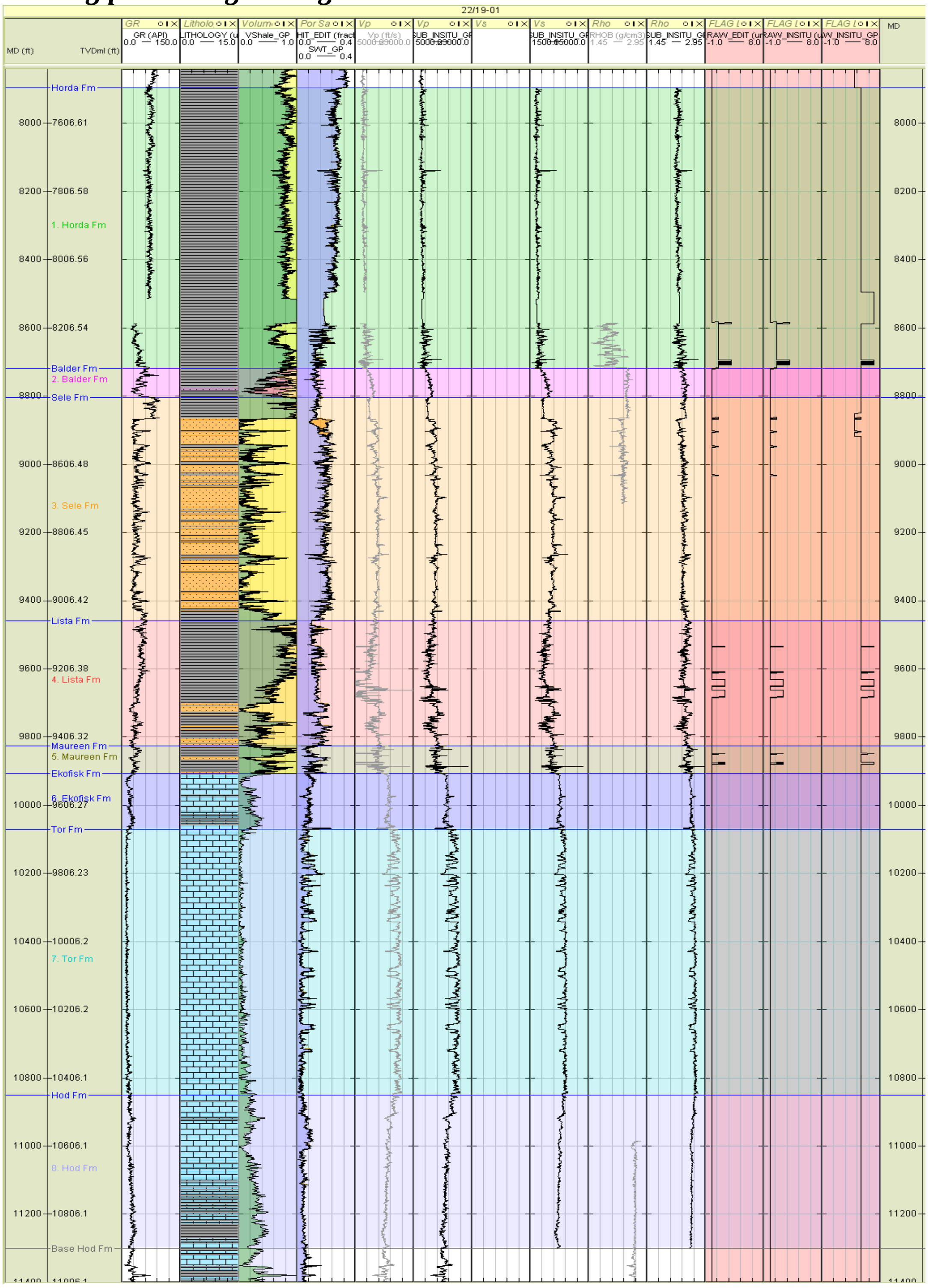


Figure 3.11.4 - Well Panel: Log edits for well 22/19-01.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

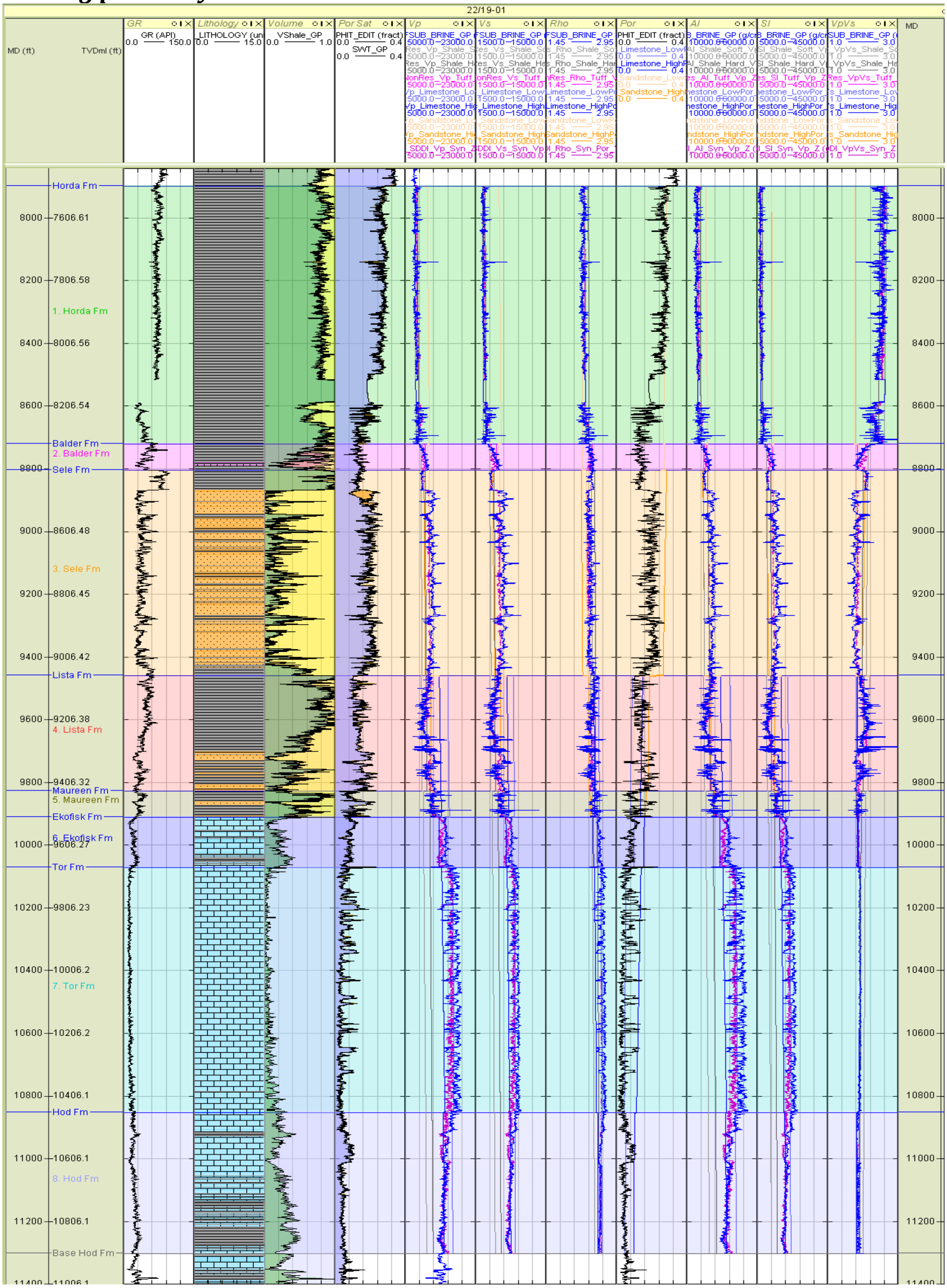


Figure 3.11.5 - Well Panel: End-member and synthetic logs for well 22/19-01.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

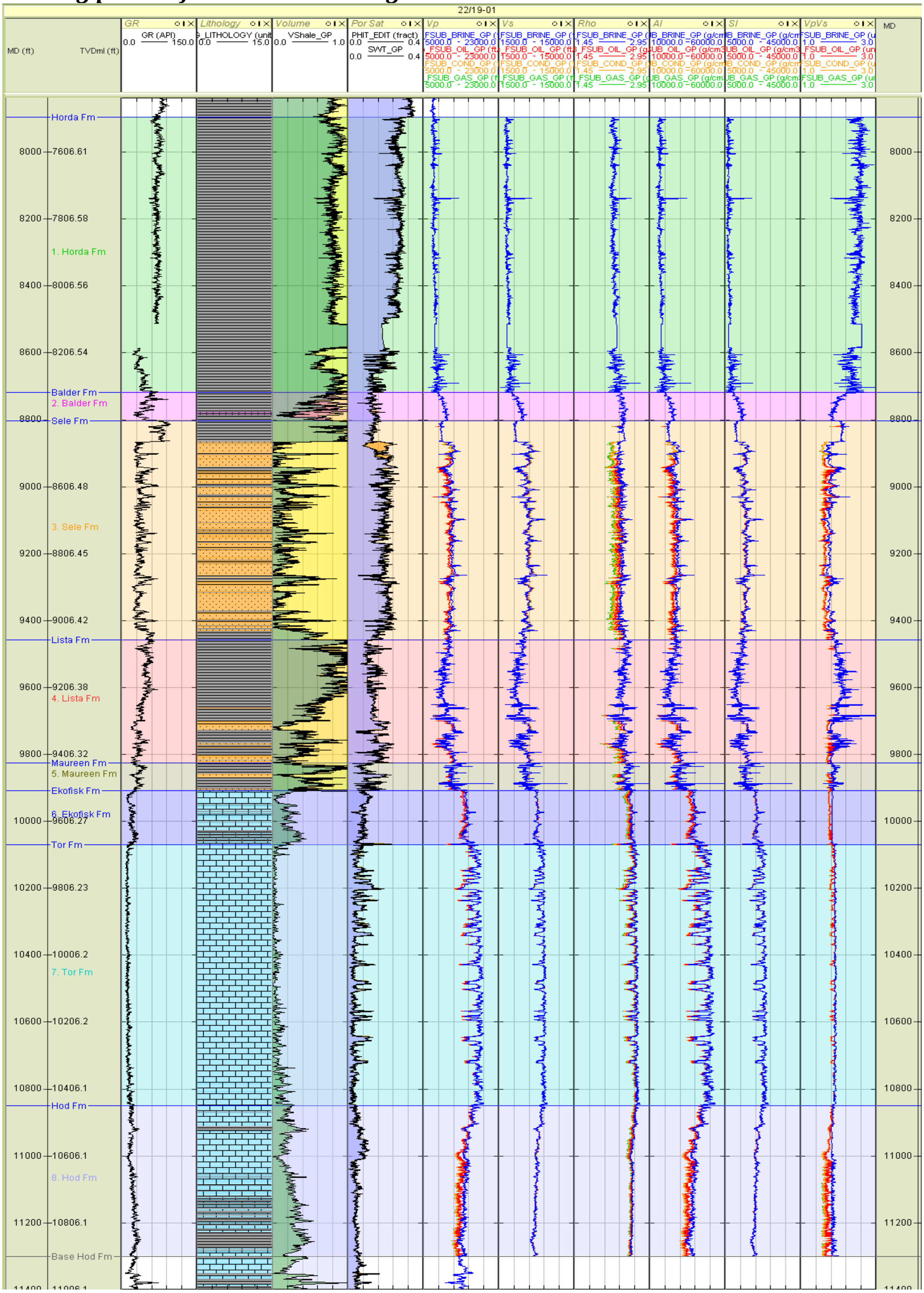


Figure 3.11.6 - Well Panel: Fluid substituted and elastic logs for well 22/19-01.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/19-01 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/19-01	Horda	7677	3083	2.25
22/19-01	Balder	9124	4408	2.40
22/19-01	Sele	9512	4642	2.43
22/19-01	Lista	10026	4920	2.44
22/19-01	Maureen	11465	5969	2.52

Table 3.11.7 - Clean shale properties at Well 22/19-01

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/19-01	Horda	100% Brine			
22/19-01	Balder	100% Brine			
22/19-01	Sele	100% Brine	11816	6741	2.37
22/19-01	Lista	100% Brine	11902	6516	2.42
22/19-01	Maureen	100% Brine	12250	6676	2.43
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/19-01	Horda	80% Oil			
22/19-01	Balder	80% Oil			
22/19-01	Sele	80% Oil	11242	6817	2.32
22/19-01	Lista	80% Oil	11365	6586	2.37
22/19-01	Maureen	80% Oil	11828	6743	2.38
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/19-01	Horda	90% Gas			
22/19-01	Balder	90% Gas			
22/19-01	Sele	90% Gas	11145	6962	2.22
22/19-01	Lista	90% Gas	11348	6699	2.29
22/19-01	Maureen	90% Gas	11799	6815	2
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/19-01	Horda	80% Cond			
22/19-01	Balder	80% Cond			
22/19-01	Sele	80% Cond	11092	6921	2.25
22/19-01	Lista	80% Cond	11302	6664	2.31
22/19-01	Maureen	80% Cond	11843	6848	2.31

Table 3.11.8 - Clean sand properties at Well 22/19-01 for each fluid case

Tertiary reservoirs – Well panel

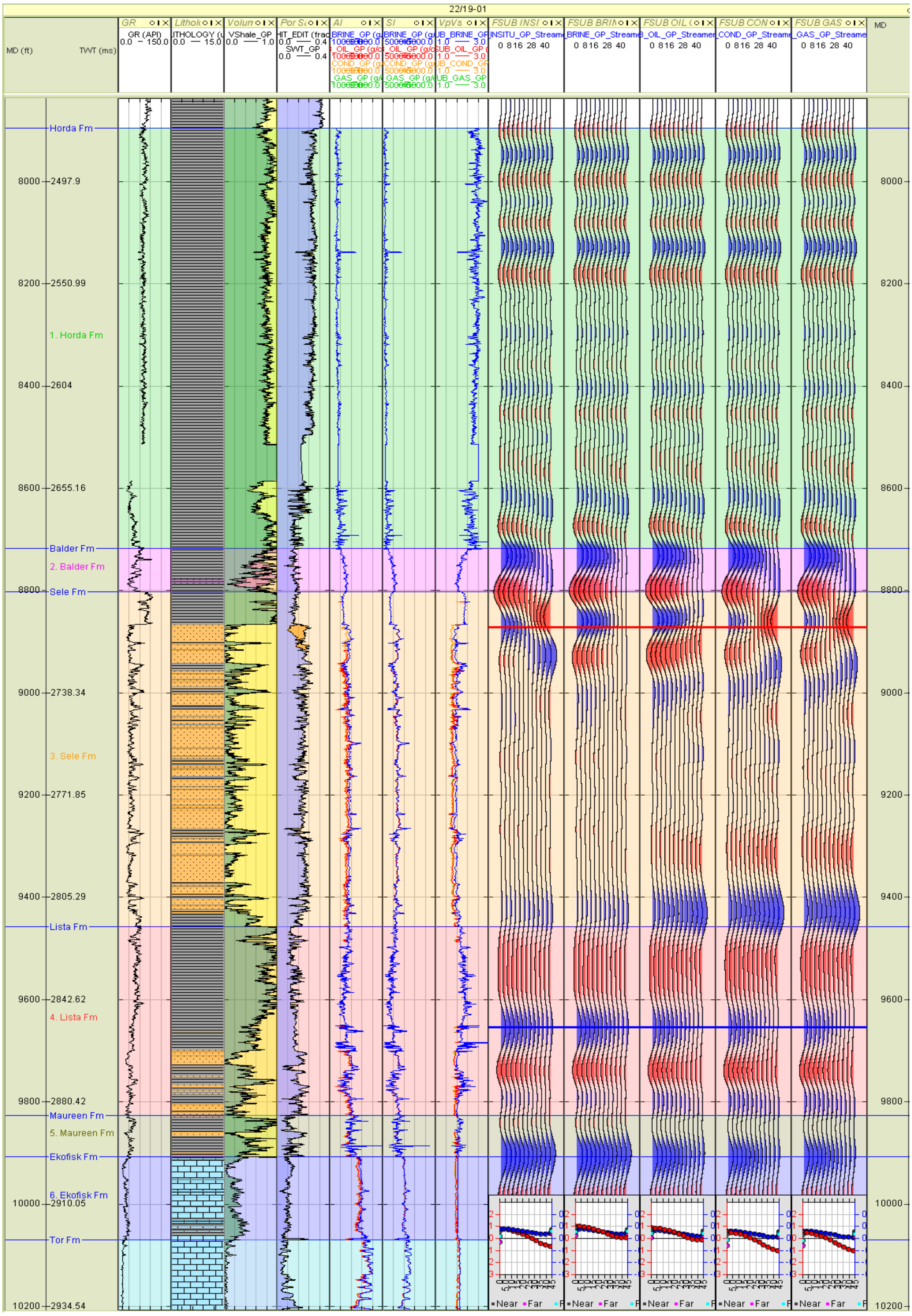


Figure 3.11.7 - Well Panel: Tertiary reservoirs for well 22/19-01. Wavelet: Streamer

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir within the formation comprises a blocky sandstone overlain a shale interval approximately 62 feet thick and a tuffaceous interval of the Balder Formation. The net reservoir is approximately 527 feet with porosities of around 20%.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil, and a marginal class I/IIp response for the 80% gas condensate and 90% gas cases. A phase reversal occurs with the addition of hydrocarbons. Corresponding AVO signatures are seen within the synthetic gathers in all fluid cases, although the 80% oil case gives a response more consistent with both the modelled and synthetic 100% brine case response, showing no phase reversal at far offsets. It is likely that the seismic signature is affected by wavelet interference, particularly using a lower frequency streamer wavelet, given the limited vertical extend of the overlying shale and intra-reservoir reflectors present.
- Elastic Contrast Analysis shows contrasts are mainly moderate and positive in the 100% brine case, showing minor effects with the addition of hydrocarbons. Mu and MuRho show the least sensitivity to fluid changes, whilst Lambda and LambdaRho show the most sensitivity to fluid effects.

Figure 3.11.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/19-01.

Lista Formation

- Reservoir comprises a number of sand bodies distributed throughout the formation separated by intra-formational shales. Individual reservoir bodies range in thickness from approximately 3-28 feet, giving a total net reservoir of approximately 85 feet. Uppermost sands of the formation lie within 20 feet of the overlying Sele Formation reservoir.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases, while the 80% gas condensate and 90% gas cases show a margin class I/IIp response. A phase reversal occurs in the presence of hydrocarbon fluid fill. Synthetic gathers show the presence of no defining seismic events over the Lista Formation, which is likely due to in part to the limited vertical extent of reservoir sands and low porosities limiting the potential for fluid effects, and wavelet interference caused by thin overburden and intra-formational shales.
- Elastic Contrast Analysis shows contrasts generally positive in the 100% brine case, showing variable responses to the addition of hydrocarbons. Lambda and LambdaRho shows the most sensitivity to fluid effects.

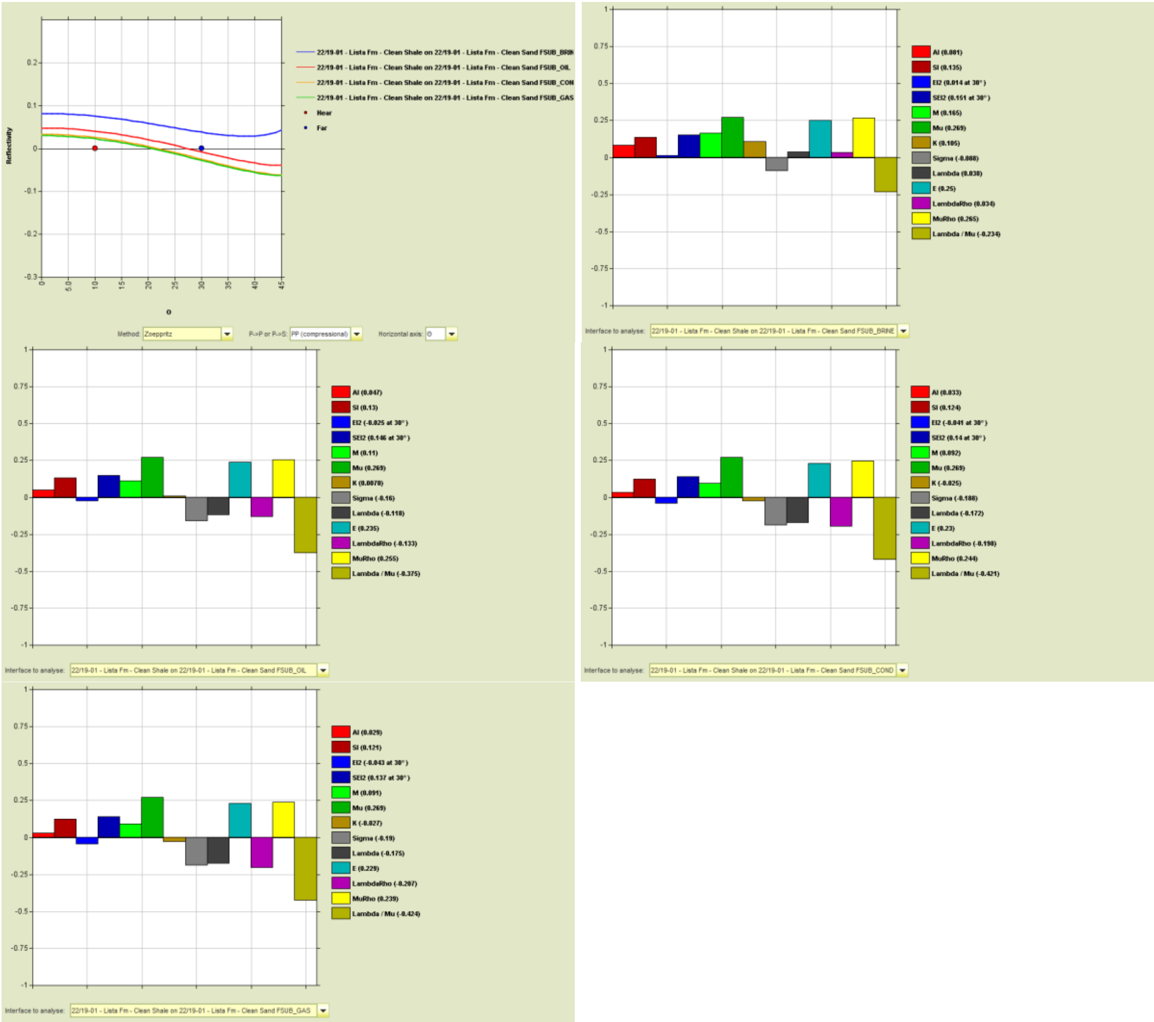


Figure 3.11.9 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/19-01.

Maureen Formation

- Reservoir is formed by predominantly formed by a thin (approximately 12 feet) blocky sandstone at the centre of the interval with porosities of 18-22%. The vertical extend of the complete Maureen Formation is approximately 82 feet, and is overlain by sandstone of the Lista Formation and overlies chalk of the Ekofisk Formation.
- Blocky AVO shows a modelled class I response for the 100% brine case, class II response for the 80% oil case, and class III response for the 80% gas condensate and 90% gas cases. The response varies to that observed within the synthetic gathers, where no defining AVO responses are observed. This variance is likely due to wavelet interference caused by the limited vertical extent of the reservoirs/ formation and strong reflection events at the top and base contacts of the formation.
- Elastic Contrast Analysis shows contrasts are negligible in the 100% brine case, often becoming weakly negative with the addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda and LambdaRho show the most sensitivity to fluid effects.

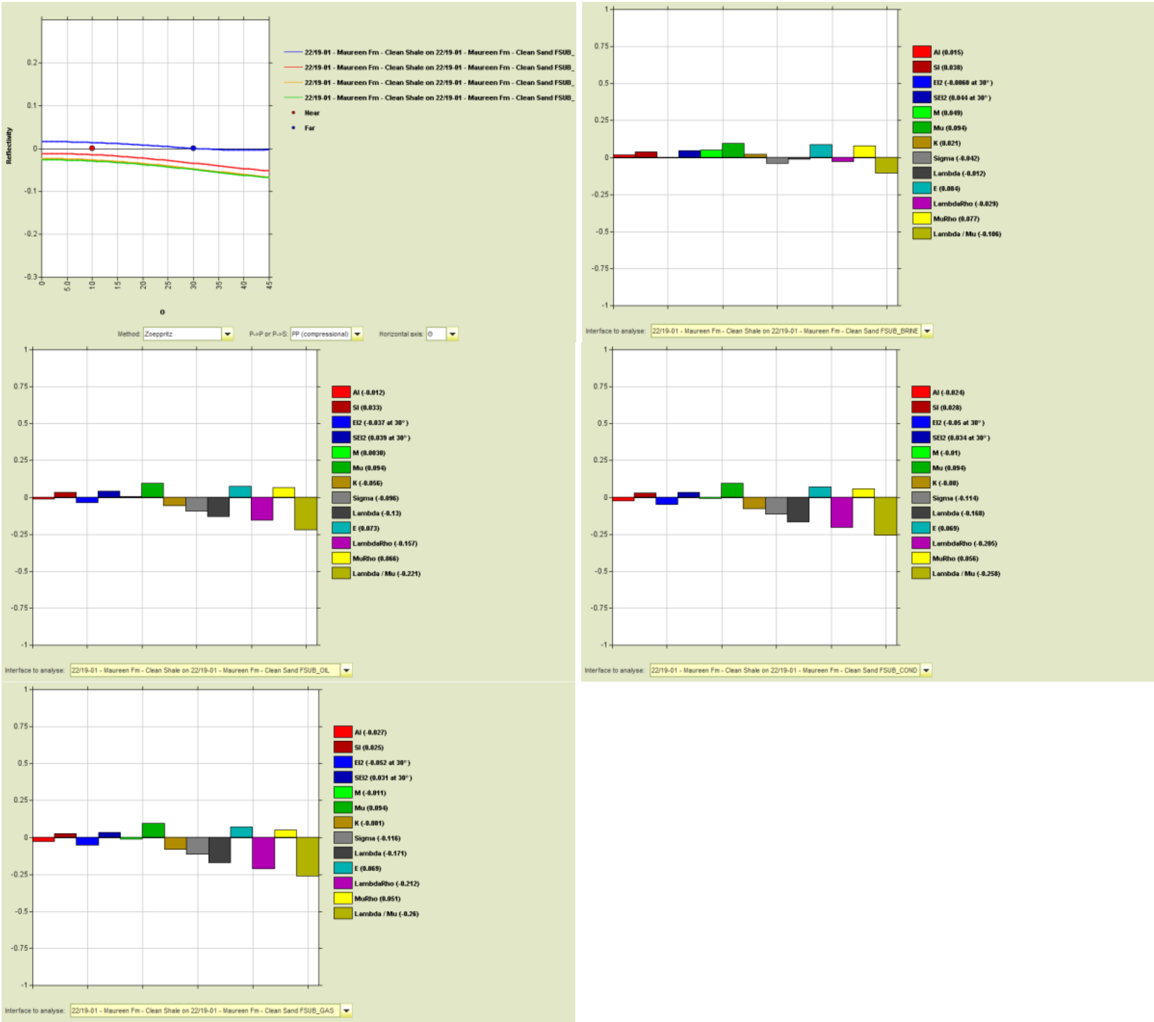


Figure 3.11.10 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/19-01.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/19-01 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/19-01	Ekofisk	100% Brine	15237	8280	2.55
22/19-01	Tor	100% Brine	17573	9198	2.65
22/19-01	Hod	100% Brine	15261	8308	2.58
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/19-01	Ekofisk	80% Oil	14235	8350	2.55
22/19-01	Tor	80% Oil	17404	9224	2.63
22/19-01	Hod	80% Oil	14235	8350	2.55
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/19-01	Ekofisk	90% Gas	14539	8421	2.46
22/19-01	Tor	90% Gas	17407	9258	2.61
22/19-01	Hod	90% Gas	13973	8405	2.52
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/19-01	Ekofisk	80% Cond	14508	8396	2.48
22/19-01	Tor	80% Cond	17392	9247	2.62
22/19-01	Hod	80% Cond	13972	8387	2.53

Table 3.11.9 - Clean limestone properties at Well 22/19-01 for each fluid case

Cretaceous reservoirs

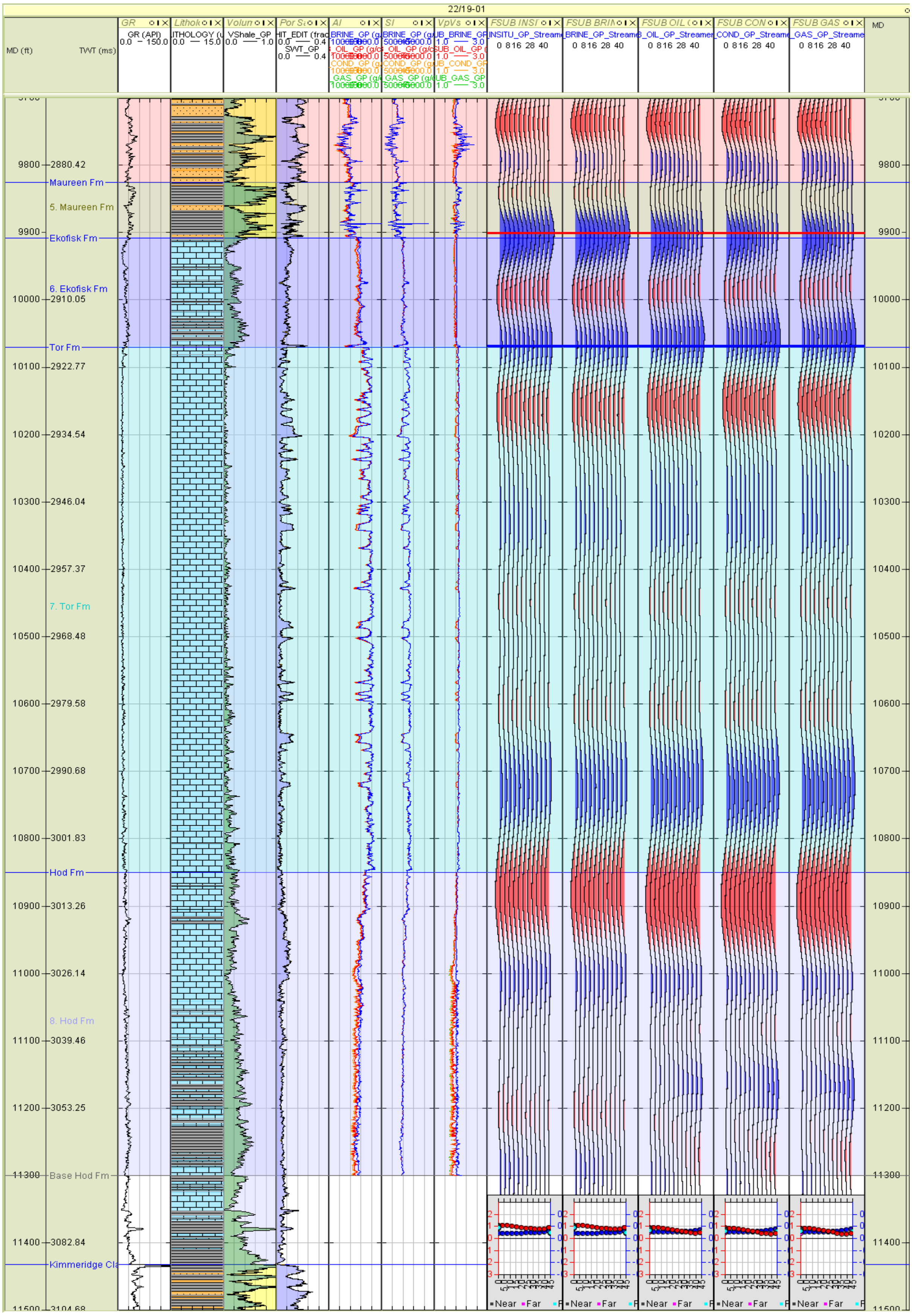


Figure 3.11.11 - Well Panel: Cretaceous reservoirs for well 22/19-01. Wavelet: Streamer

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir is formed by massive chalk becomingly increasingly silty and reducing in porosity with depth, containing an average porosity of 8. The reservoir is overlain by silty sands of the Maureen Formation and overlies clean relatively low porosity chalk of the Tor Formation. Net reservoir is approximately 134 feet.
- Blocky AVO modelling shows in the 100% brine, 80% oil, 80% gas condensate and 90% gas cases, a class I response is predicted. Corresponding class I AVO responses are seen within the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are generally positive and moderate in the 100% brine case. Many of the constants show little variation in the 80% oil, 80% gas condensate and 90% gas cases. Lambda, LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

Figure 3.11.12 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/19-01.

Tor Formation

- Reservoir occurs as patchy zones of higher porosity (approximately 5-19%) throughout the interval. The formation is bordered by the relatively silty chalks of the Ekofisk and Hod Formations. Net reservoir is approximately 534 feet.
- Blocky AVO modelling shows a predicted class I response in all fluid cases, where reflectivity decreases with pore fluid density. Within the synthetic gathers, equivalent class I AVO responses are seen in all fluid cases.
- Elastic Contrast Analysis shows contrasts are positive and weak in each of the fluid cases. The majority of constants show little variation with the addition of hydrocarbons, although Lambda/Mu shows the most sensitivity to fluid effects.

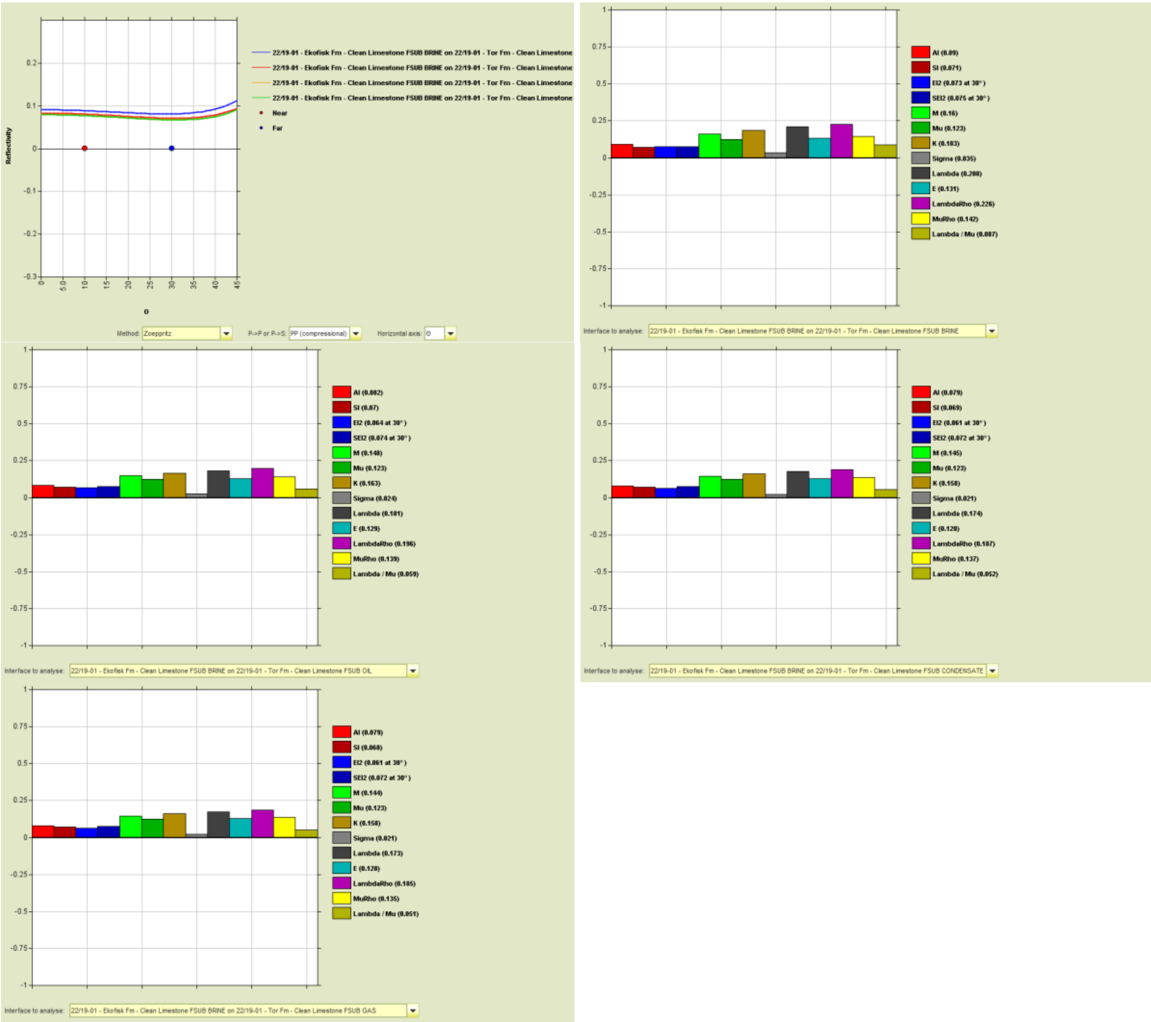


Figure 3.11.13 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/19-01.

Hod Formation

- Reservoir is formed by a zone of higher porosity (approximately 6-11%) towards the top of the reservoir. The formation is overlain by chalk of the Tor Formation, which contains relatively lower porosity and is similar is character. Net reservoir is approximately 368 feet.
- Blocky AVO modelling shows a class VI response predicted in each of the modelled fluid cases. Comparable AVO responses are seen within the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are negative in all fluid cases, becoming increasingly negative in many cases with addition of hydrocarbons. Mu and MuRho show the least sensitivity to fluid effects, while LambdaRho shows the most sensitivity to fluid effects.

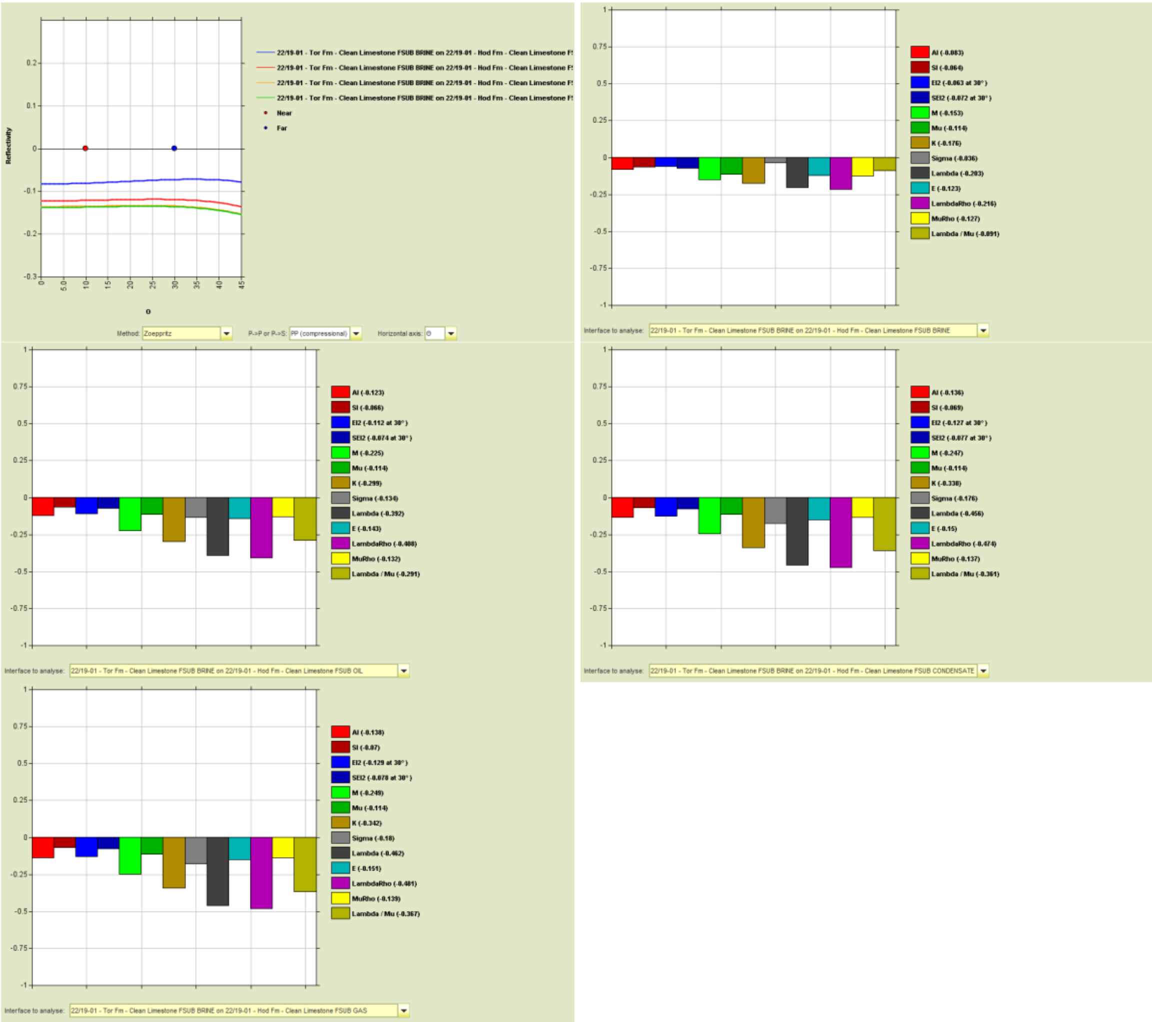


Figure 3.11.14 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/19-01.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/19-01 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/19-01	Overburden	Shale	7435		
22/19-01	Underburden	Limestone/Sand	12054		2.49

Table 3.11.10. - Overburden and underburden properties at Well 22/19-01.

Well: 22/21-D7

General

Well Information
Shell operated exploration well spudded, completed and suspended in 1987. The well encountered oil in the Horda (Tay Member), Balder (Odin Member), Sele (Gannet Member) and Lista (Andrew Member) Formations. The well was re-entered and completed in 2001 as an oil producer for the Gannet D field.

Objectives
The well was drilled on the crest of a dip closed trap, with the primary objective of evaluating Horda (Tay Member) and Sele Formation (Forties Member) sands north of the Gannet East accumulation. A number of Paleocene reservoirs were present encountering oil. The Forties Member was absent.

Log conditioning overview
Log quality within the well is generally of good quality as indicated by the caliper and density correction logs. Thin calcite stringers in the Horda and Lista Formation below the resolution of the Vp and Vs log are removed from all logs. A Vs spike over the hydrocarbon zone in Balder Formation is removed. Finally, the density has been clipped at the start of the second logging run where borehole washout is occurring in the Lista Formation shale.

Invasion correction
Both oil and water based drilling muds were used within this well, requiring invasion correction of the density log to be performed in all formations present.

Log modelling
In this well, with the exception of a gap within the Vp log filled using a spline fit, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z). All gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda and Lista Formations for Vp and density. Additionally, gaps are filled in the Horda, Balder and Lista Formations for Vs.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 22/21-D7 is displayed in the figures below;

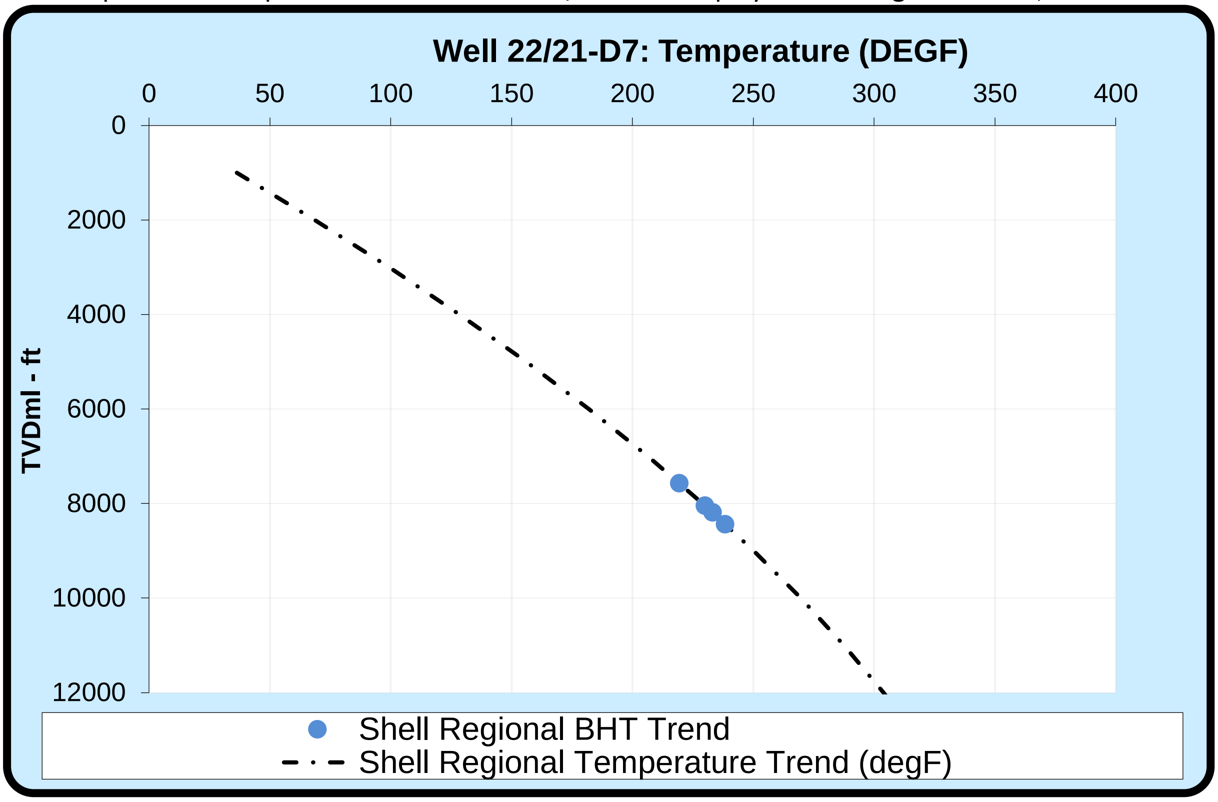


Figure 3.12.1 - Temperature data at Well 22/21-D7

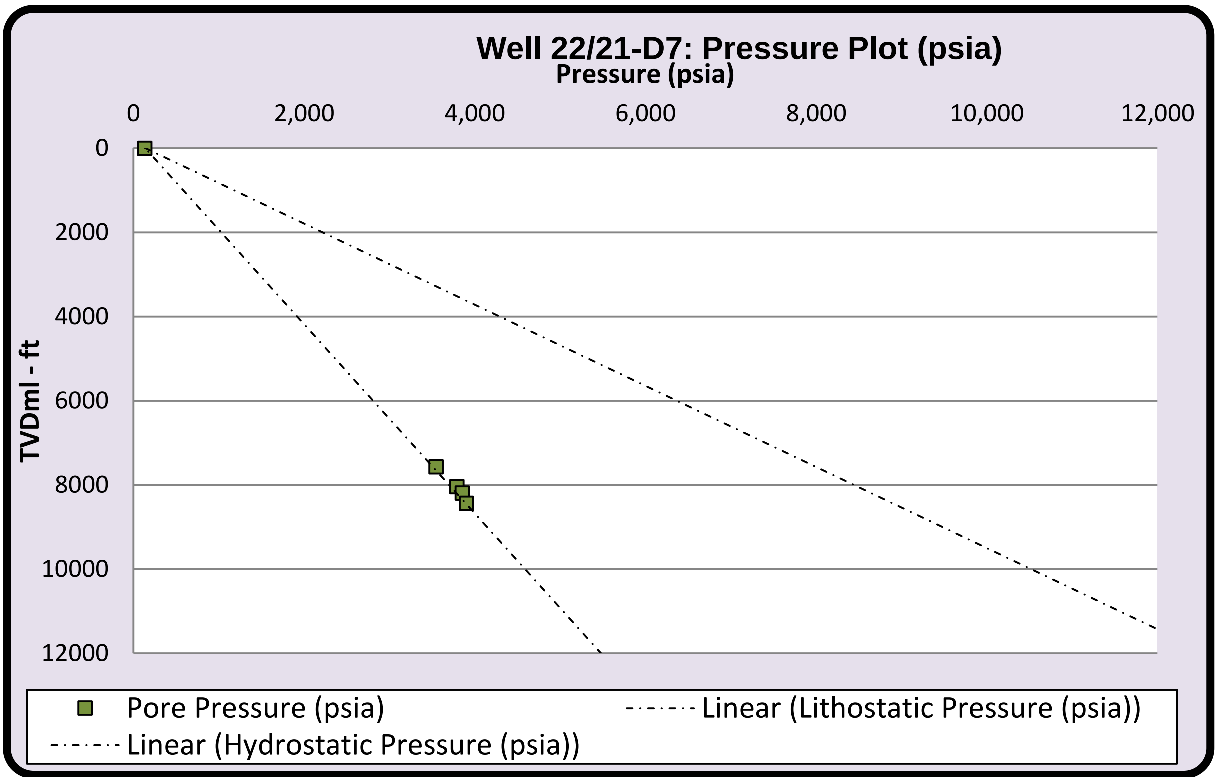


Figure 3.12.2 - Pressure data at Well 22/21-D7

The temperature and pressure data for the formation mid-points in Well 22/21-D7 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/21-D7	Sea Bed	391.0	306.0	0.0	39.2	136.2	136.2	136.17	0.00
22/21-D7	Horda	8191.3	7876.4	7570.4	219.5	3505.0	3549.0	7706.54	4157.55
22/21-D7	Balder	8668.3	8350.3	8044.3	230.0	3715.9	3790.9	8180.49	4389.60
22/21-D7	Sele	8814.5	8495.7	8189.7	233.2	3780.6	3855.6	8325.86	4470.28
22/21-D7	Lista	9061.5	8741.1	8435.1	238.4	3889.8	3903.8	8571.30	4667.50

Table 3.12.1 - Summary of mid-point temperature and pressure data at Well 22/21-D7

Fluid data

A summary of the fluid set parameters at Well 22/21-D7is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/21-D7	Horda	90000	800	43.7	0.897	0.897
22/21-D7	Balder	90000	730	40.1	0.71	0.71
22/21-D7	Sele	90000	730	40.2	0.71	0.71
22/21-D7	Lista	82000	1000	44.0	0.815	0.815

Table 3.12.2 - Summary of fluid parameter data at Well 22/21-D7

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.12.3 - Constant mineral properties used in this project

There is no Tuff present in this well.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/21-D7	Horda	PAY	846.540	10.000	0.012	2.708	0.271	0.361	0.083
22/21-D7	Horda	RES	846.540	36.000	0.043	7.789	0.216	0.716	0.265
22/21-D7	Balder	PAY	107.460	2.500	0.023	0.825	0.330	0.455	0.033
22/21-D7	Balder	RES	107.460	68.250	0.635	19.026	0.279	0.855	0.097
22/21-D7	Sele	PAY	185.000	0.000	0.000	0.000	0.000	0.000	0.000
22/21-D7	Sele	RES	185.000	94.750	0.512	25.092	0.265	0.929	0.122
22/21-D7	Lista	PAY	309.000	49.500	0.160	11.818	0.239	0.233	0.046
22/21-D7	Lista	RES	309.000	60.000	0.194	14.300	0.238	0.271	0.074

Table 3.12.4 - Petrophysical parameters used at Well 22/21-D7

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

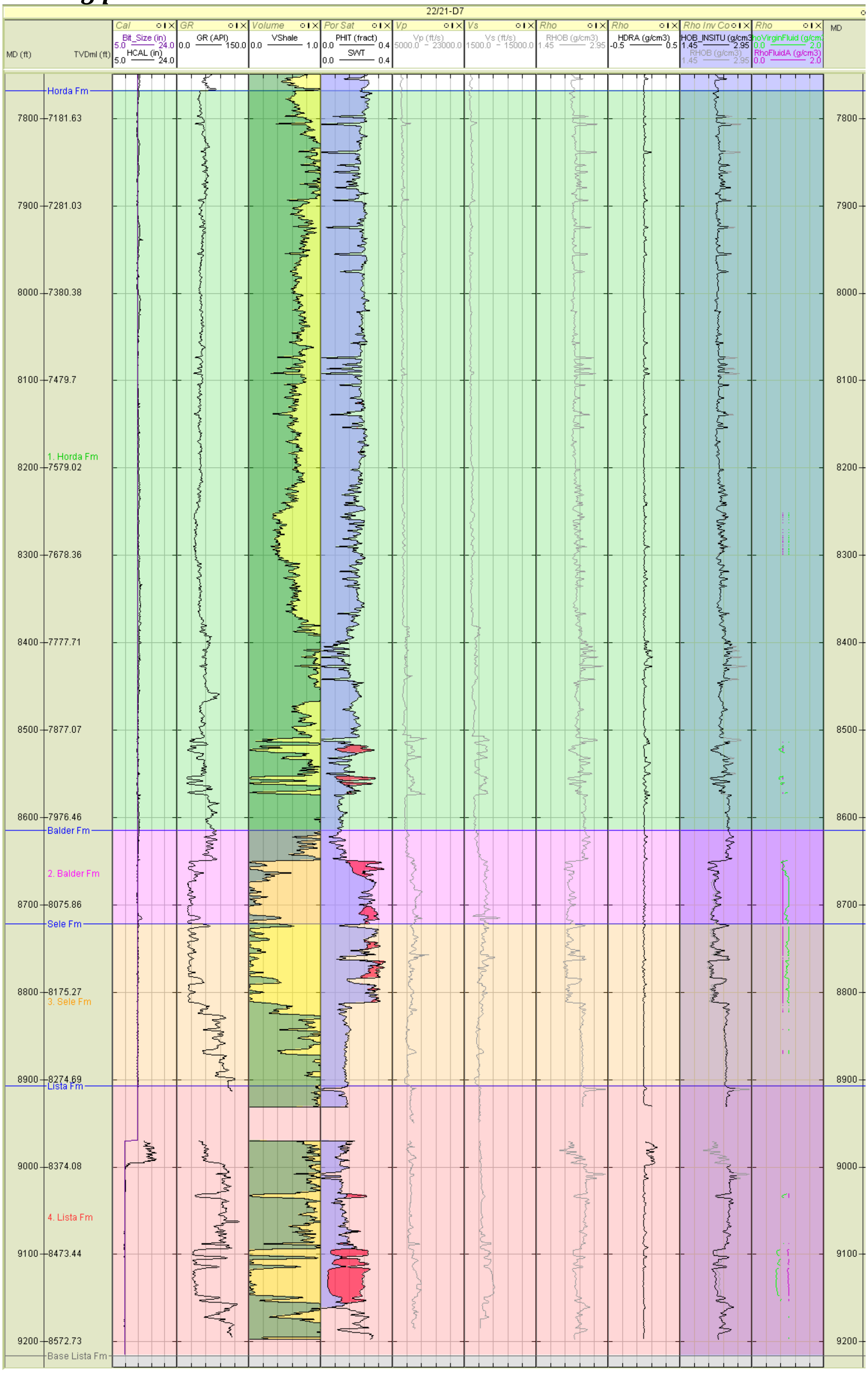


Figure 3.12.3 - Well Panel: Measured data and invasion correction for well 22/21-D7.

Well log panel – log editing and audit

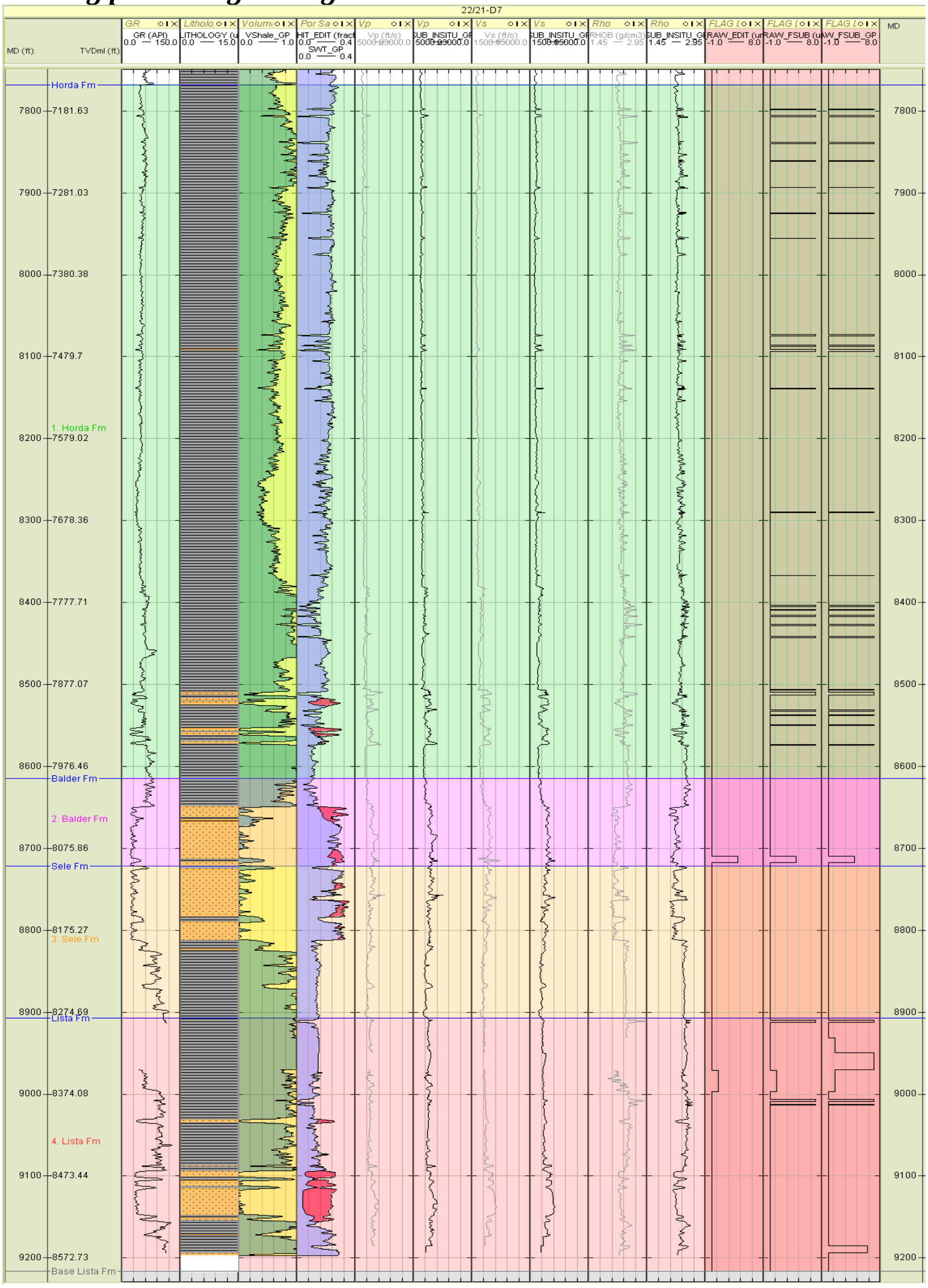


Figure 3.12.4 - Well Panel: Log edits for well 22/21-D7.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

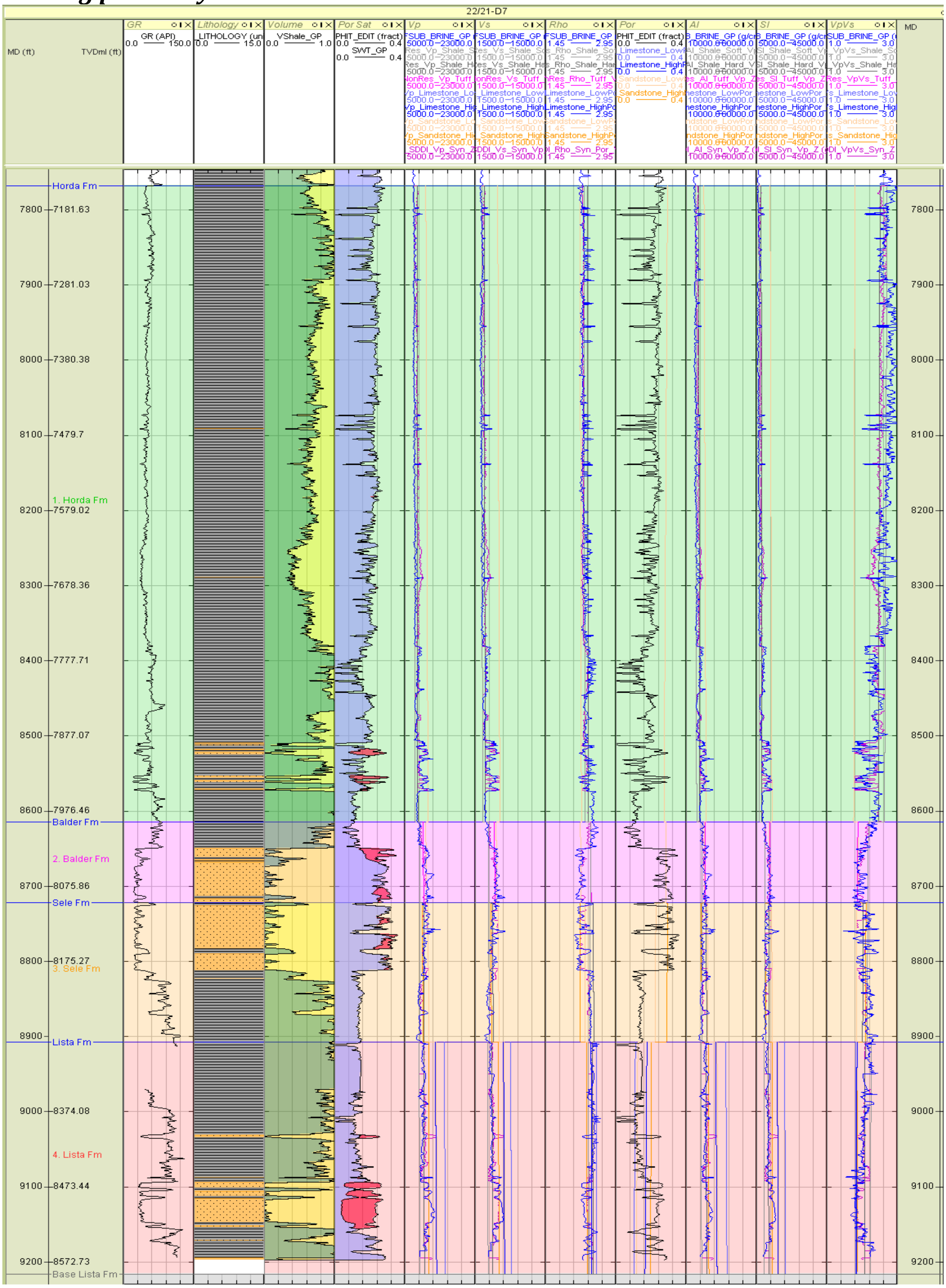


Figure 3.12.5 - Well Panel: End-member and synthetic logs for well 22/21-D7.

Curves: Blue/Black = Measured, Purple = Synthetic,

End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

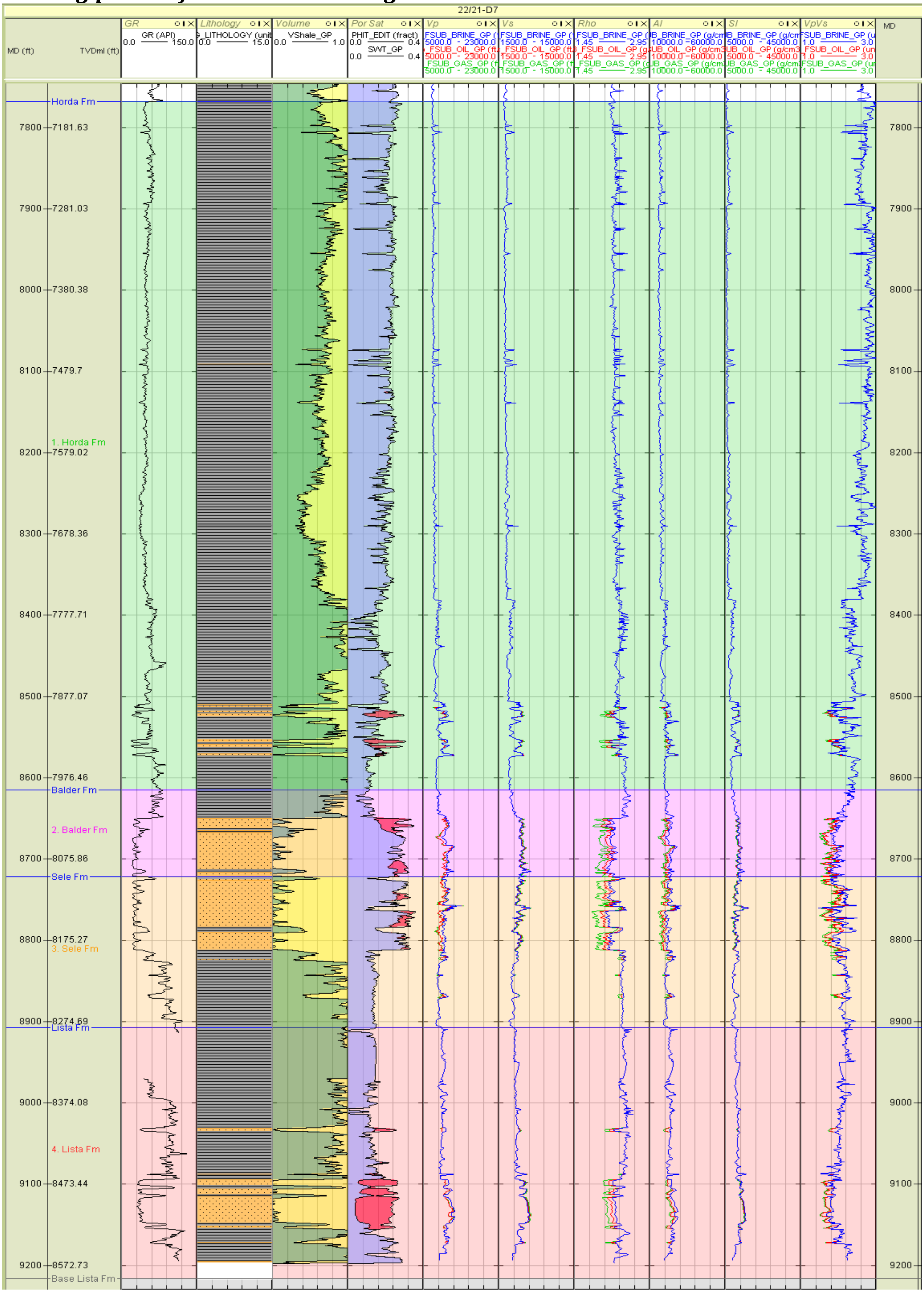


Figure 3.12.6 - Well Panel: Fluid substituted and elastic logs for well 22/21-D7.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/21-D7 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/21-D7	Horda	7724	3058	2.31
22/21-D7	Balder	8779	3970	2.46
22/21-D7	Sele	8606	3946	2.40
22/21-D7	Lista	9538	4628	2.45
22/21-D7	Maureen			

Table 3.12.5 - Clean shale properties at Well 22/21-D7

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/21-D7	Horda	100% Brine	10634	5339	2.26
22/21-D7	Balder	100% Brine	10398	5513	2.19
22/21-D7	Sele	100% Brine	10265	5041	2.19
22/21-D7	Lista	100% Brine	11482	6294	2.26
22/21-D7	Maureen	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/21-D7	Horda	80% Oil	10170	5411	2.20
22/21-D7	Balder	80% Oil	10019	5617	2.11
22/21-D7	Sele	80% Oil	9528	5135	2.11
22/21-D7	Lista	80% Oil	10807	6404	2.19
22/21-D7	Maureen	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/21-D7	Horda	90% Gas	10192	5512	2.13
22/21-D7	Balder	90% Gas	10034	5793	1.99
22/21-D7	Sele	90% Gas	9509	5295	1.99
22/21-D7	Lista	90% Gas	10862	6547	2.09
22/21-D7	Maureen	90% Gas			

Table 3.12.6 - Clean sand properties at Well 22/21-D7 for each fluid case

Tertiary reservoirs – Well panel

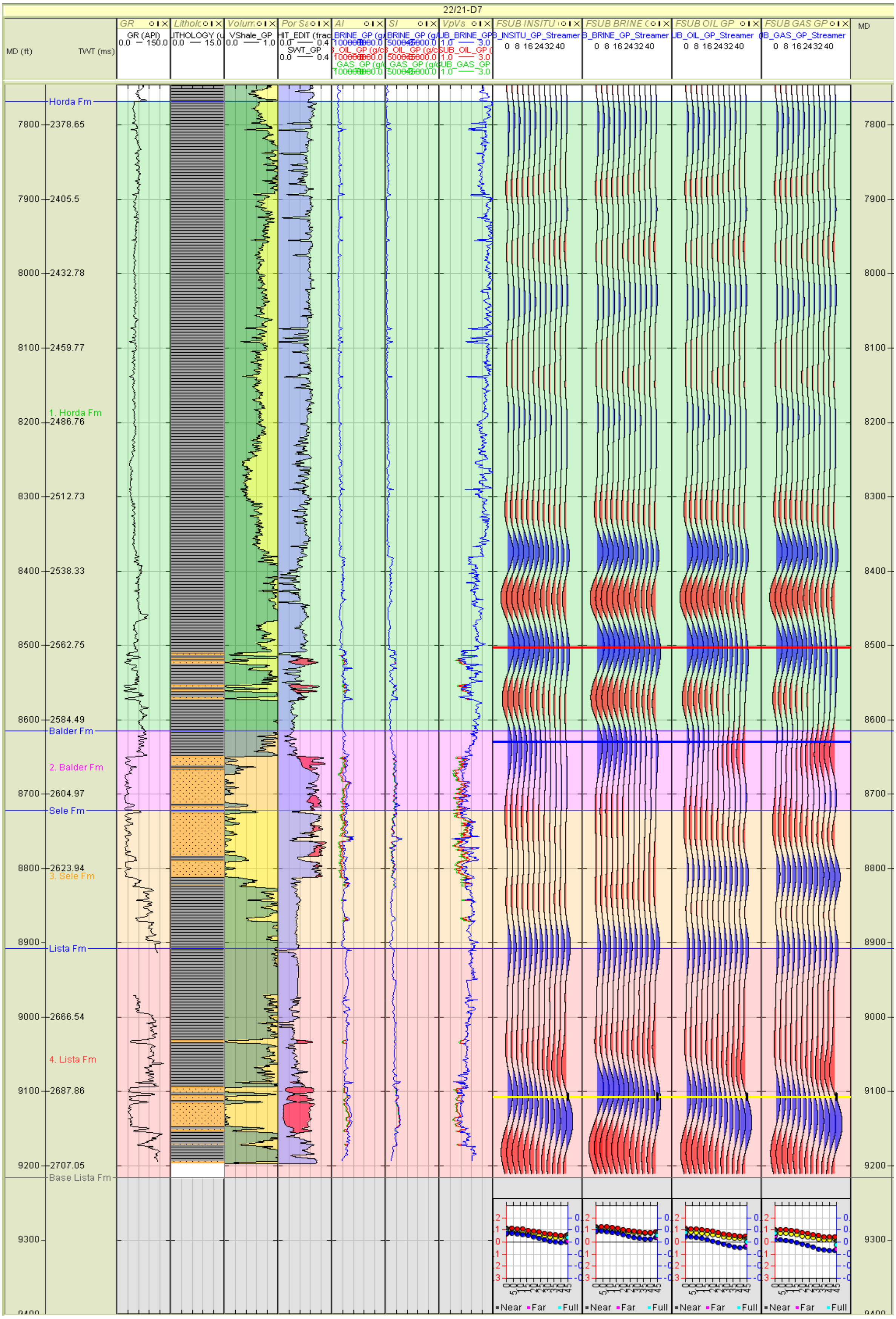


Figure 3.12.7 - Well Panel: Tertiary reservoirs for well 22/21-D7. Wavelet: Streamer

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir within the formation comprises of a number of thin (approximately 4-9 feet thick) sands encased within shale at the base of the interval. Directly above the uppermost reservoir is a very thin low porosity streak, which is likely representative of a calcite stringer. Net reservoir is approximately 36 feet with porosities of 18-30%.
- Blocky AVO shows a modelled class I response for the 100% brine, 80% oil and 90% gas case, with reflectivity decreasing with the addition of hydrocarbons. Within the synthetic gathers, the seismic event correlating to top reservoir has a consistent AVO signature. However, it is apparent that interference is playing some role in this response, likely in combination of interference caused by the layered reservoir sands and the overlying low porosity event dominating the seismic signature.
- Elastic Contrast Analysis shows contrasts are generally positive in the 100% brine case. Although many elastic contrasts remain relatively constant with the addition of hydrocarbons, Lambda, LambdaRho and Lambda/Mu all show sensitivity to fluid effects.

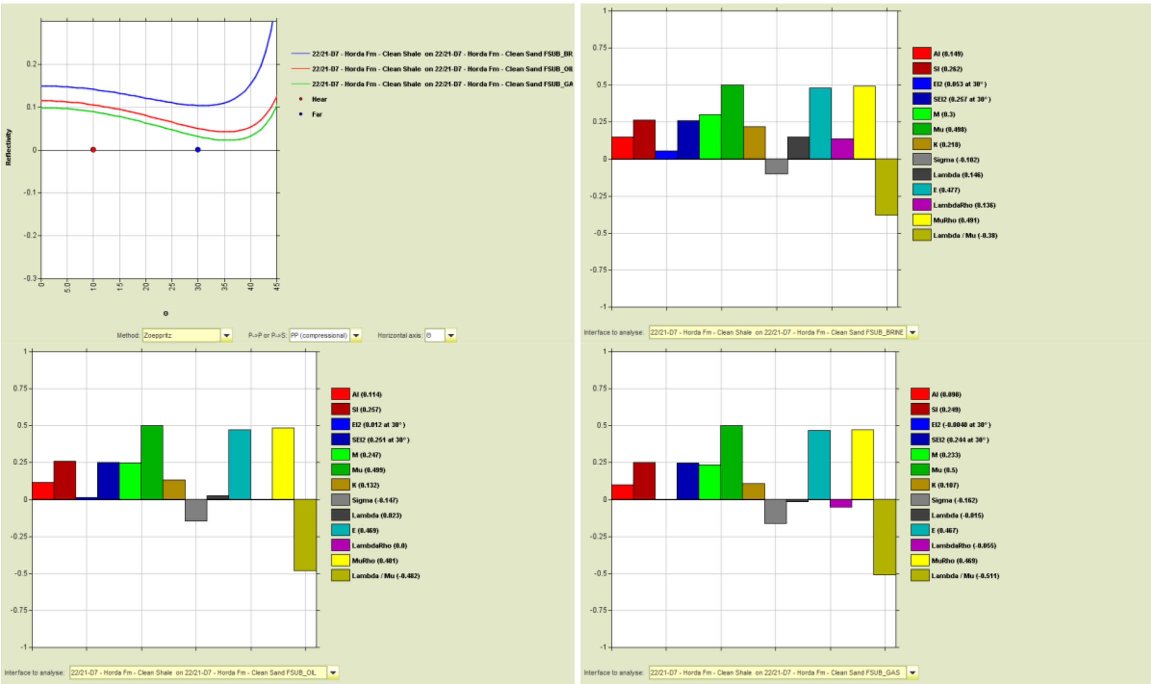


Figure 3.12.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 22/21-D7.

Balder Formation

- Reservoir is formed by a relatively blocky clean sandstone overlain by a thick continuous shale interval. The reservoir extends below in to the underlying Sele Formation (Forties Member) separated by a thin shale. Net reservoir within the Balder Formation is approximately 68 feet and contains porosities of 24-35%.
- Blocky AVO shows a class I response predicted for the 100% brine case, a class II response for the 80% oil case and class III for the 90% gas case. Within the synthetic gathers, the 100% brine case shows a class I AVO response, the 80% oil case shows a class IIp response, while the 90% gas case gives a class II response. In comparing the response of the streamer and broadband wavelet, wavelet interference issues are confirmed, as when using the higher frequency broadband wavelet synthetic gather responses match those of the Blocky AVO Modelling.
- Elastic Contrast Analysis shows some variation in the 100% brine case, with the addition of hydrocarbons the constant have a tendency to become more negative. SEI and Mu show the least sensitivity to fluid effect, whilst Lambda and LambdaRho show the greatest sensitivity to fluid effects.

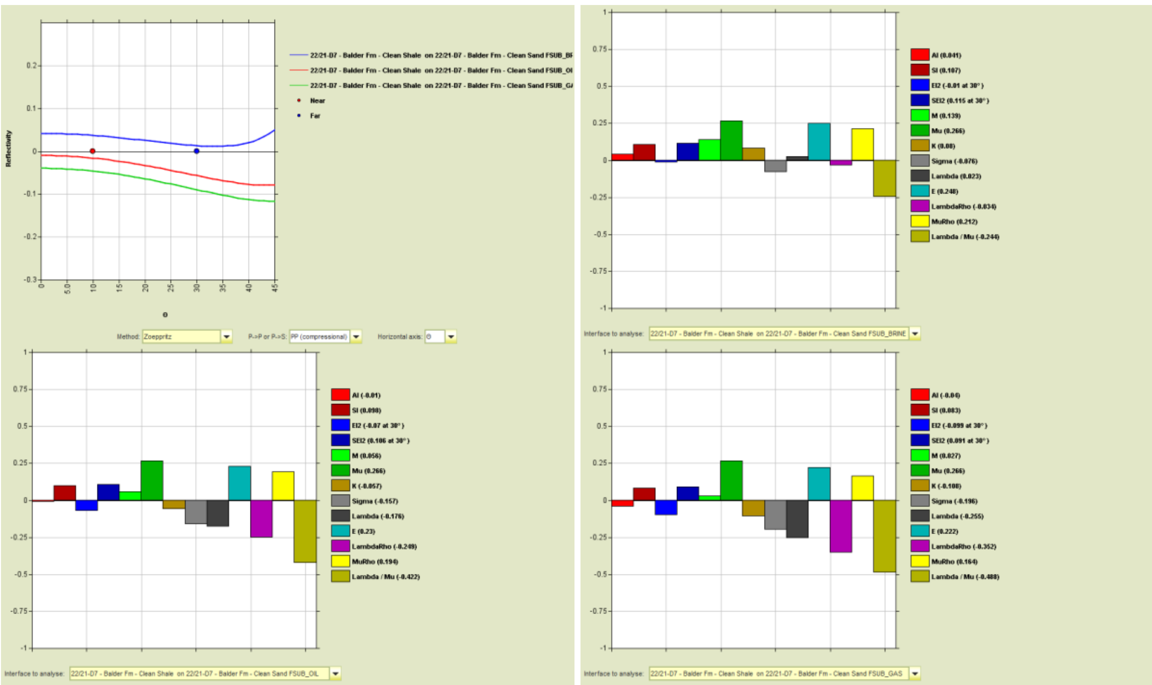


Figure 3.12.9 - Blocky AVO Model and Elastic Contrast Analysis for the Balder Formation in well 22/21-D7.

Sele Formation

- Reservoir is a continuation of the blocky clean sandstone present within the Balder Formation, with the presence of a thin shale marking the transition from the Balder to Sele. Net reservoir within the Sele Formation is approximately 95 feet with porosities of 14-36%.
- Blocky AVO shows a class I response predicted for the 100% brine case, a class II response for the 80% oil case and class III response for the 90% gas case. Within the synthetic gathers, the 100% brine, 80% oil and 90% cases show a class IV AVO response, with reflectivity increasing with the addition of hydrocarbons, matching the responses given by Blocky AVO modelling of a Balder Formation sand on Sele Formation sand contact.
- Elastic Contrast Analysis shows contrasts are generally positive in the 100% brine case. With the addition of hydrocarbons, contrasts generally become increasingly negative. Mu shows the least sensitivity to fluid changes, whilst LambdaRho and Lambda/Mu show the most sensitivity to fluid effects.

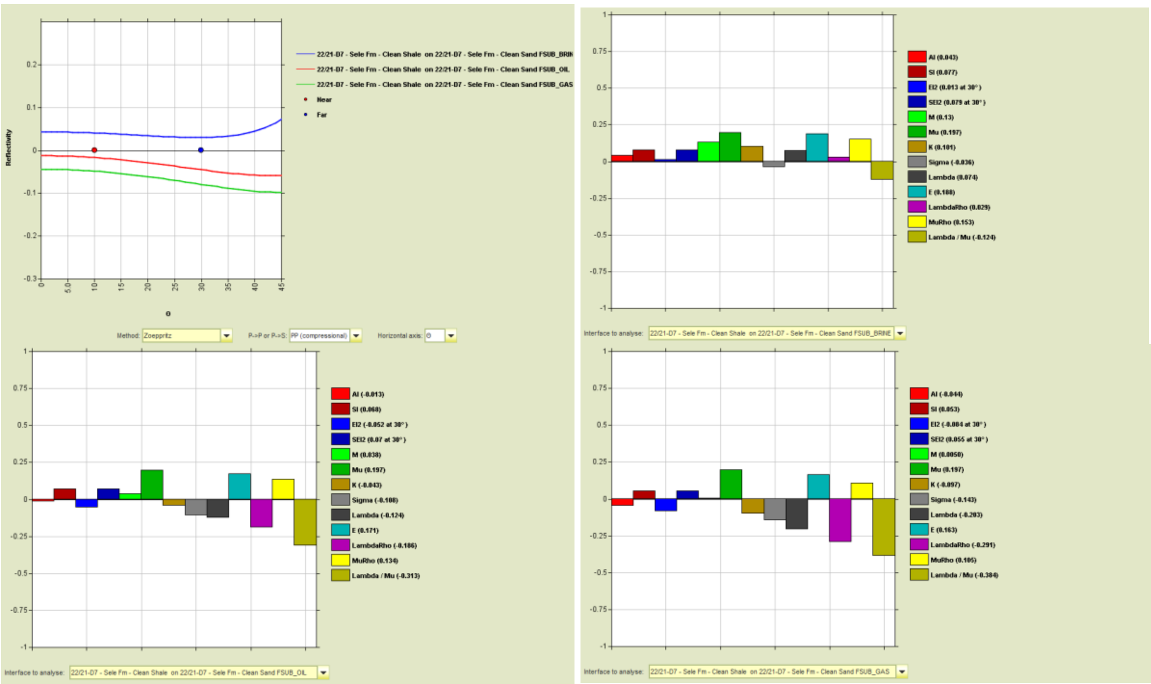


Figure 3.12.10 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/21-D7.

Lista Formation

- Reservoir is formed by a relatively thin sandstone in the centre of the interval and stacked blocky clean sandstones towards the base of the interval. Individual reservoir zones are both separated and overlain by clean shale intervals. The well terminates within the Lista Formation. Net reservoir is approximately 60 feet, containing porosities of 17-28%.
- Blocky AVO shows a class I response predicted for the 100% Blocky AVO, and a class II response for both the 80% oil and 90% gas cases. Within the synthetic gathers, a class I AVO response is seen in each fluid case. This variation is likely due to wavelet interference effects caused by intra-formational shales.
- Elastic Contrast Analysis shows contrasts are typically weak and positive in the 100% brine case, often becoming more negative with the introduction of hydrocarbons. LambdaRho and Lambda/Mu show the most sensitivity to fluid effects, while Mu shows the least sensitivity to fluid effects.

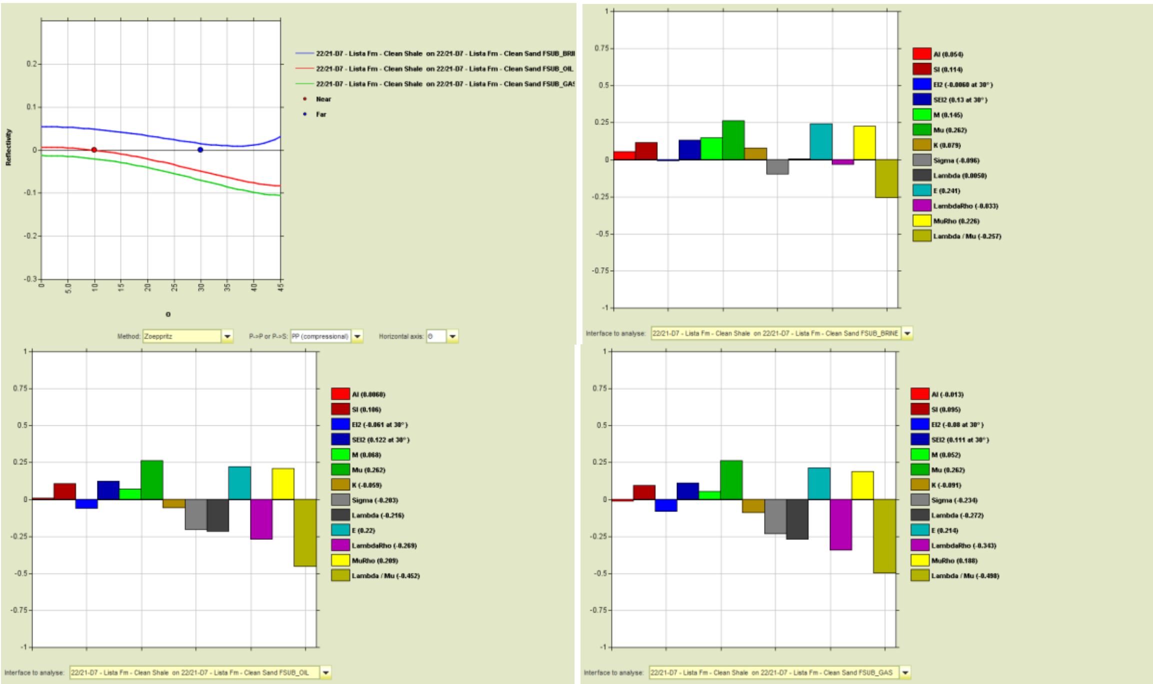


Figure 3.12.11 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/21-D7.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/02A-06 is provided below;

There is no Cretaceous section at this well.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/21-D7 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/21-D7	Overburden	Shale	7600	2896	2.29
22/21-D7	Underburden				

Table 3.12.7 - Overburden and underburden properties at Well 22/21-D7.

Well: 22/24B-07

General

Well Information
Well 22/24B-07 was drilled in early 1986 to investigate the Triassic Skagerrak Formation.

Objectives
The well's objective was to establish the presence of hydrocarbons in the Triassic Sandstones in a satellite structure to the south-west of BP's Marnock gas/condensate discovery. The well confirmed the Triassic Sands be oil-bearing (flowed 40API crude oil) and in vertical pressure communication.

Log conditioning overview
Two thin calcite stringers are seen by the density log but not the sonic log and these points are removed from both the Vp and density logs. All log edits in the Rock Physics part of the project detailed in Single Well Part 1 - Rock Physics PowerPoint's.
All edits applied to the Vp_EDIT and Vs_EDIT logs in the initial Rock Physics QC plots will also be applied to the P-Sonic and S-Sonic EDIT logs.

Invasion correction

Well 22/24B-07 was drilled with oil-based mud. Invasion correction has been performed within all formations containing reservoir intervals. The Horda and Balder Formations do not contain any reservoir intervals.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda and Hod Formation for Vp and within the Horda Formation for density. A complete Vs log is modelled since a measured Vs log is not available at this well.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 22/24B-07 is displayed in the figures below;

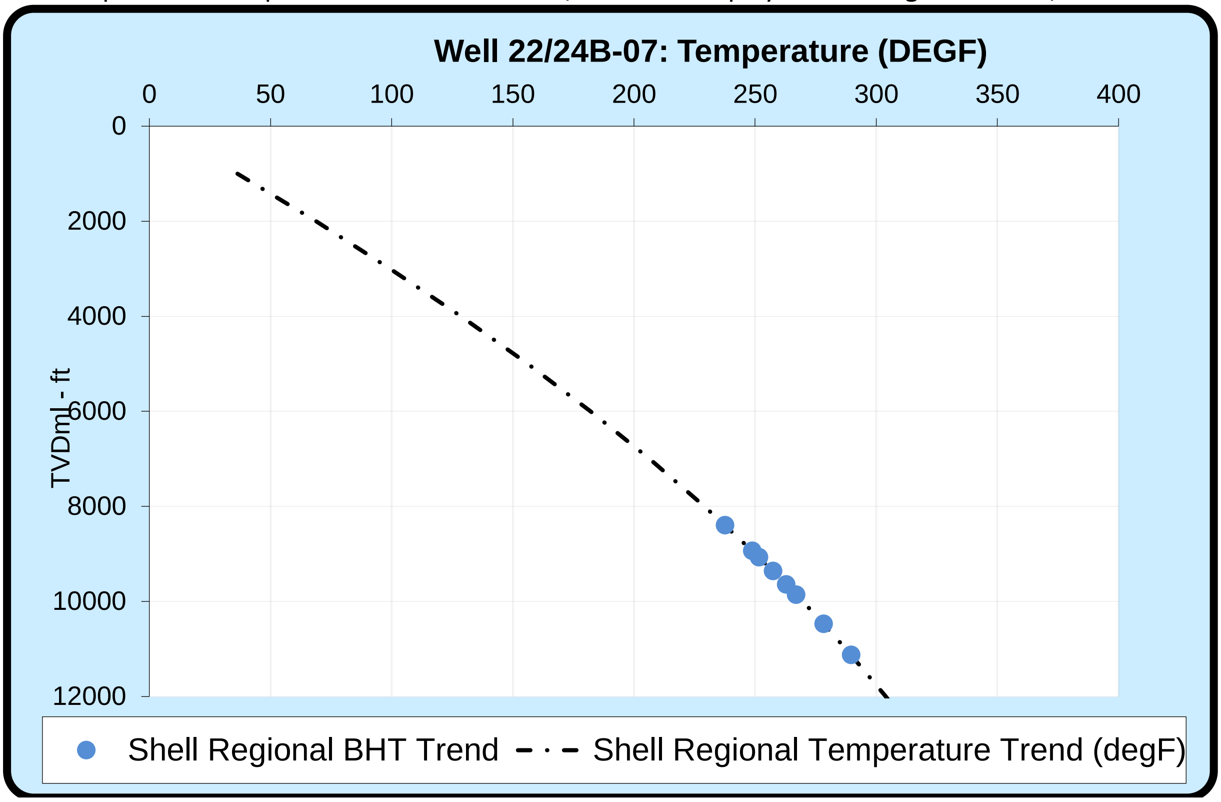


Figure 3.13.1 - Temperature data at Well 22/24B-07.

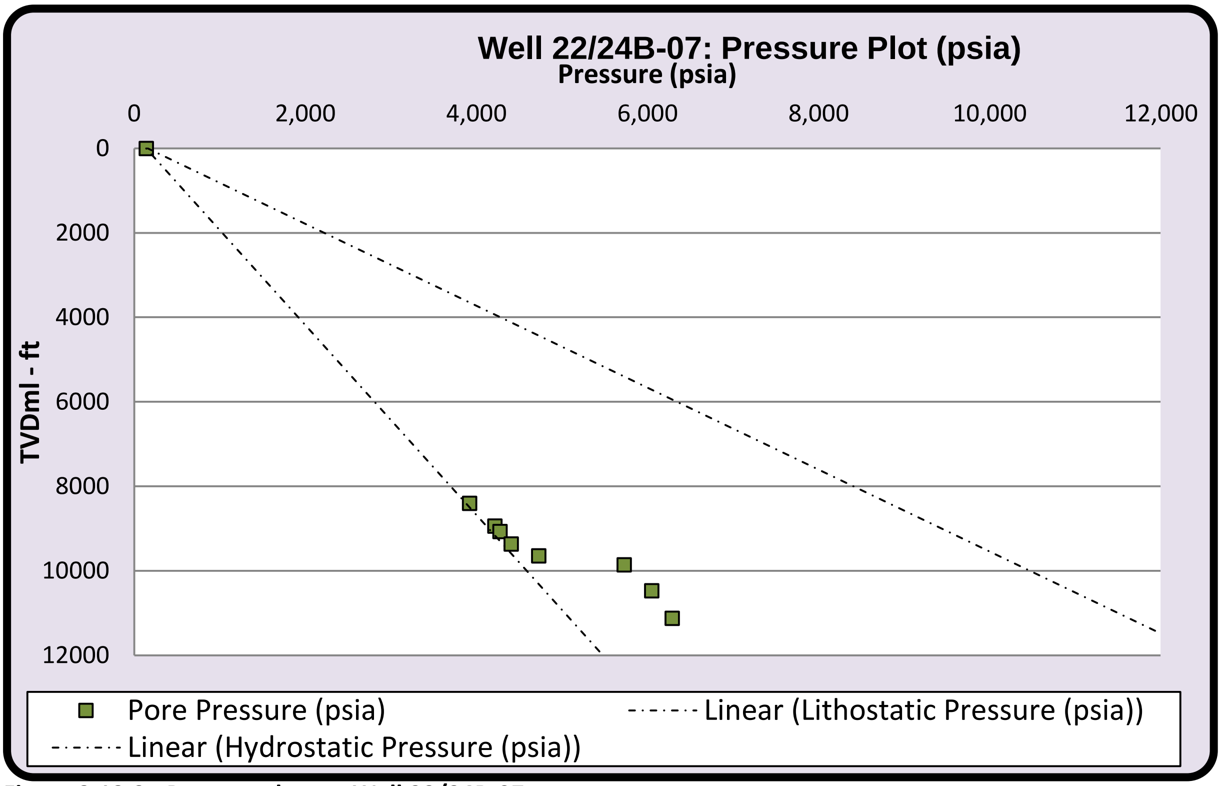


Figure 3.13.2 - Pressure data at Well 22/24B-07.

The temperature and pressure data for the formation mid-points in Well 22/24B-07 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/24B-07	Sea Bed	389.0	319.0	0.0	39.2	142.0	142.0	142.0	0.0
22/24B-07	Horda	8788.0	8717.6	8398.6	237.7	3879.3	3922.3	8540.5	4618.2
22/24B-07	Balder	9326.5	9256.0	8937.0	248.9	4118.9	4218.9	9078.9	4860.0
22/24B-07	Sele	9460.5	9390.0	9071.0	251.6	4178.5	4278.5	9212.9	4934.4
22/24B-07	Lista	9753.3	9682.6	9363.6	257.5	4308.8	4408.8	9505.6	5096.8
22/24B-07	Maureen	10030.8	9960.1	9641.1	262.9	4432.2	4732.2	9783.0	5050.8
22/24B-07	Ekofisk	10248.5	10177.7	9858.7	267.0	4529.1	5729.1	10000.7	4271.6
22/24B-07	Tor	10864.0	10793.0	10474.0	278.4	4802.9	6052.9	10615.9	4563.1
22/24B-07	Hod	11517.0	11445.7	11126.7	289.7	5093.3	6293.3	11268.7	4975.3

Table 3.13.1 - Summary of mid-point temperature and pressure data at Well 22/24B-07.

Fluid data

A summary of the fluid set parameters at Well 22/24B-07is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/24B-07	Horda	78000	730	40.4	0.71	0.71
22/24B-07	Balder	78000	730	41.0	0.71	0.71
22/24B-07	Sele	78000	730	41.2	0.71	0.71
22/24B-07	Lista	78000	730	41.5	0.71	0.71
22/24B-07	Maureen	130000	730	41.8	0.71	0.71
22/24B-07	Ekofisk	130000	730	42.0	0.71	0.71
22/24B-07	Tor	130000	730	42.7	0.71	0.71
22/24B-07	Hod	130000	730	43.4	0.71	0.71

Table 3.13.2 - Summary of fluid parameter data at Well 22/24B-07.

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
29/09C-04	Horda	16380	56.2	0.8
29/09C-04	Balder	16380	56.7	0.8
29/09C-04	Sele	16380	56.8	0.8
29/09C-04	Lista	16380	57.0	0.8
29/09C-04	Maureen	16380	57.3	0.8
29/09C-04	Ekofisk	16380	57.5	0.8
29/09C-04	Tor	16380	58.0	0.8
29/09C-04	Hod	16380	58.5	0.8

Table 3.13.3 - Summary of additional parameter data at Well 22/24B-07.

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.13.4 - Constant mineral properties used in this project.

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	14.56	7.9	2.45	10,492	5,886

Table 3.13.5 - Tuff properties used at Well 22/24B-07.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/24B-07	Horda	PAY	1028.000	0.000	0.000	0.000	0.000	0.000	0.000
22/24B-07	Horda	RES	1028.000	4.000	0.004	0.693	0.173	1.000	0.233
22/24B-07	Balder	PAY	49.000	0.000	0.000	0.000	0.000	0.000	0.000
22/24B-07	Balder	RES	49.000	0.000	0.000	0.000	0.000	0.000	0.000
22/24B-07	Sele	PAY	219.000	0.000	0.000	0.000	0.000	0.000	0.000
22/24B-07	Sele	RES	219.000	112.250	0.513	21.667	0.193	0.970	0.133
22/24B-07	Lista	PAY	366.520	0.000	0.000	0.000	0.000	0.000	0.000
22/24B-07	Lista	RES	366.520	143.750	0.392	26.363	0.183	0.960	0.169
22/24B-07	Maureen	PAY	188.480	0.000	0.000	0.000	0.000	0.000	0.000
22/24B-07	Maureen	RES	188.480	95.750	0.508	16.908	0.177	0.975	0.131
22/24B-07	Ekofisk	PAY	247.000	0.000	0.000	0.000	0.000	0.000	0.000
22/24B-07	Ekofisk	RES	247.000	189.250	0.766	18.062	0.095	0.964	0.148
22/24B-07	Tor	PAY	984.000	0.000	0.000	0.000	0.000	0.000	0.000
22/24B-07	Tor	RES	984.000	470.500	0.478	25.220	0.054	0.999	0.021
22/24B-07	Hod	PAY	322.000	0.000	0.000	0.000	0.000	0.000	0.000
22/24B-07	Hod	RES	322.000	259.500	0.806	15.530	0.060	1.000	0.248

Table 3.13.6 - Petrophysical parameters used at Well 22/24B-07

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

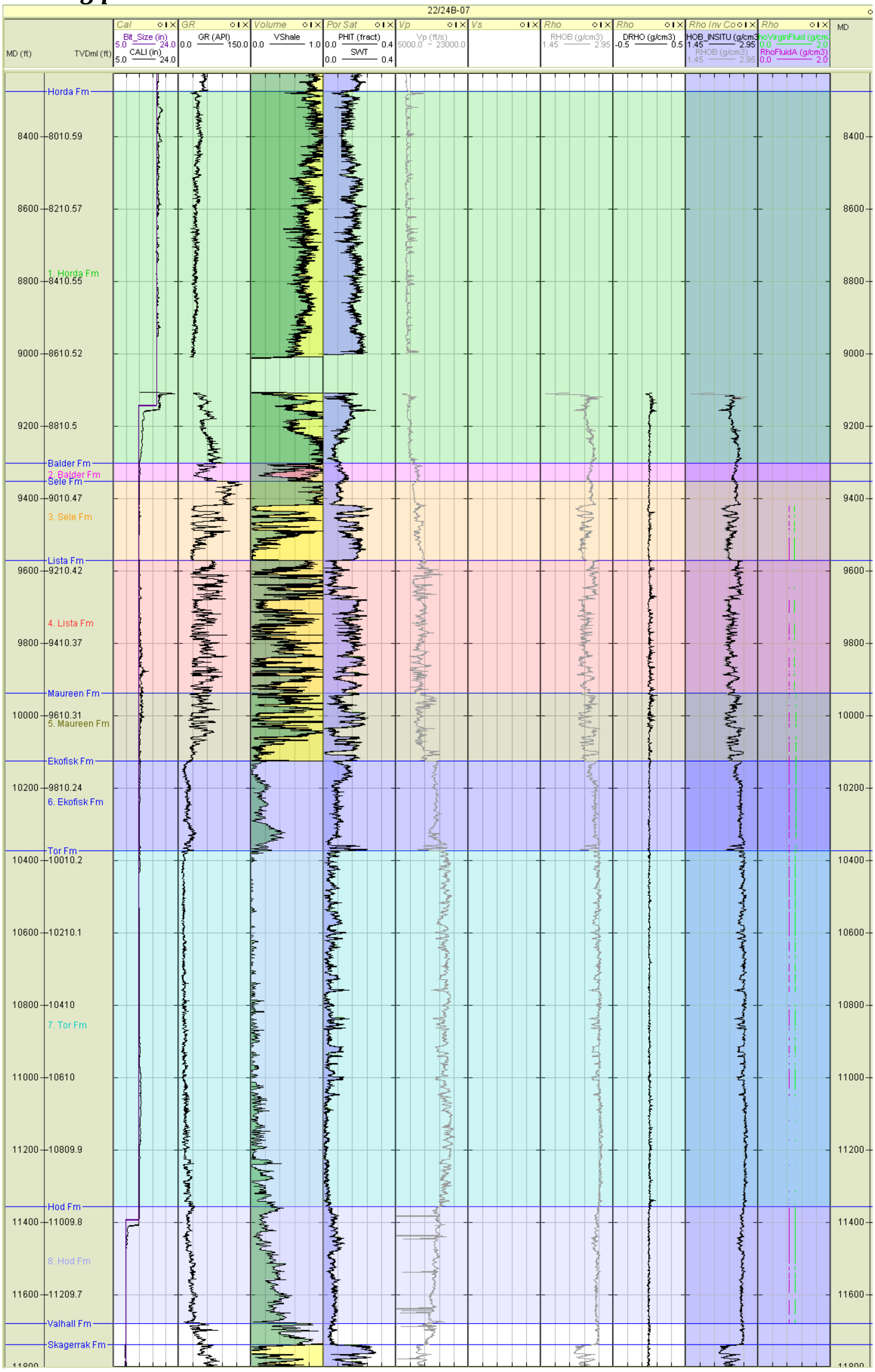


Figure 3.13.3 - Well Panel: Measured data and invasion correction for well 22/24B-07.

Well log panel – log editing and audit

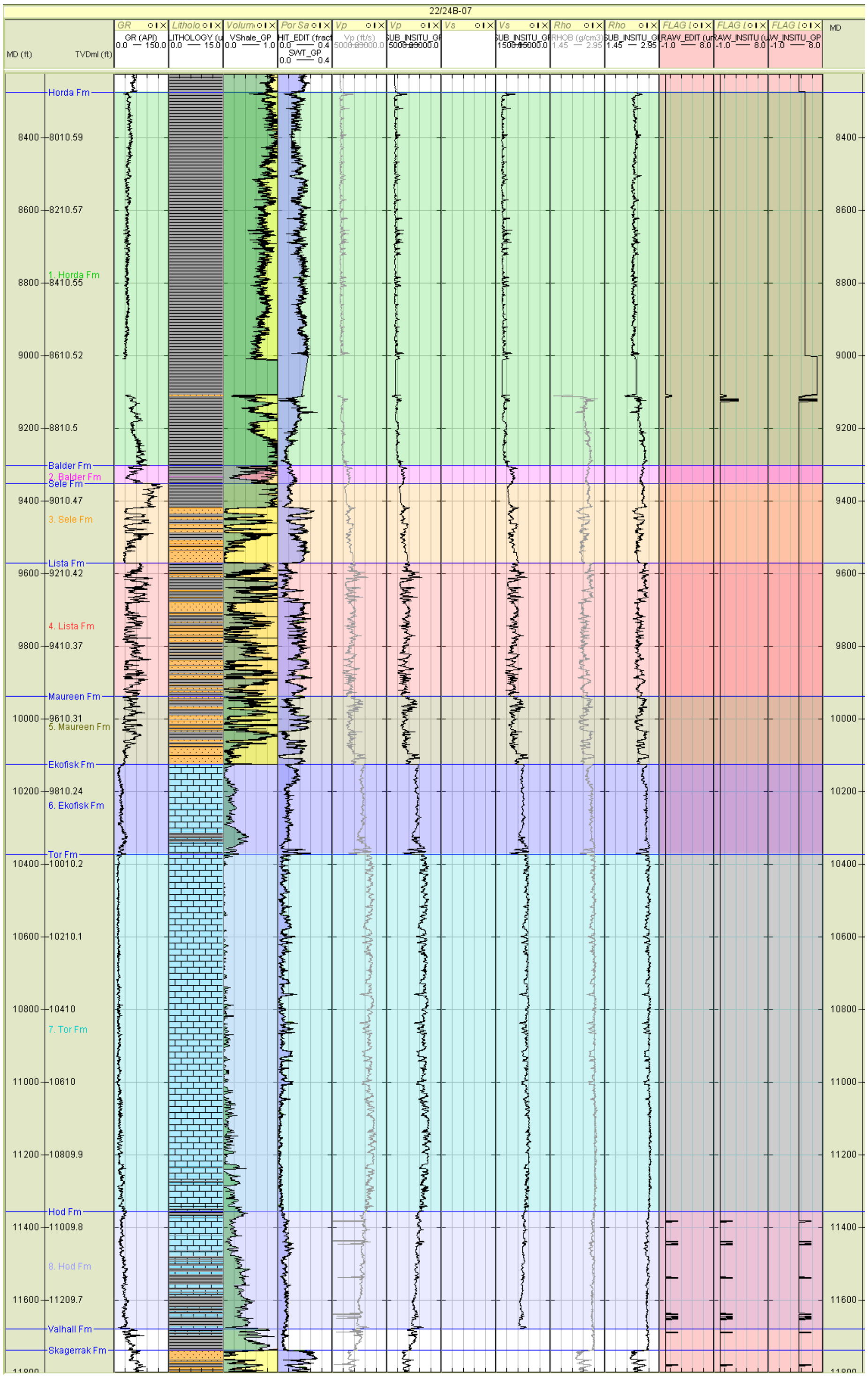


Figure 3.13.4 - Well Panel: Log edits for well 22/24B-07.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

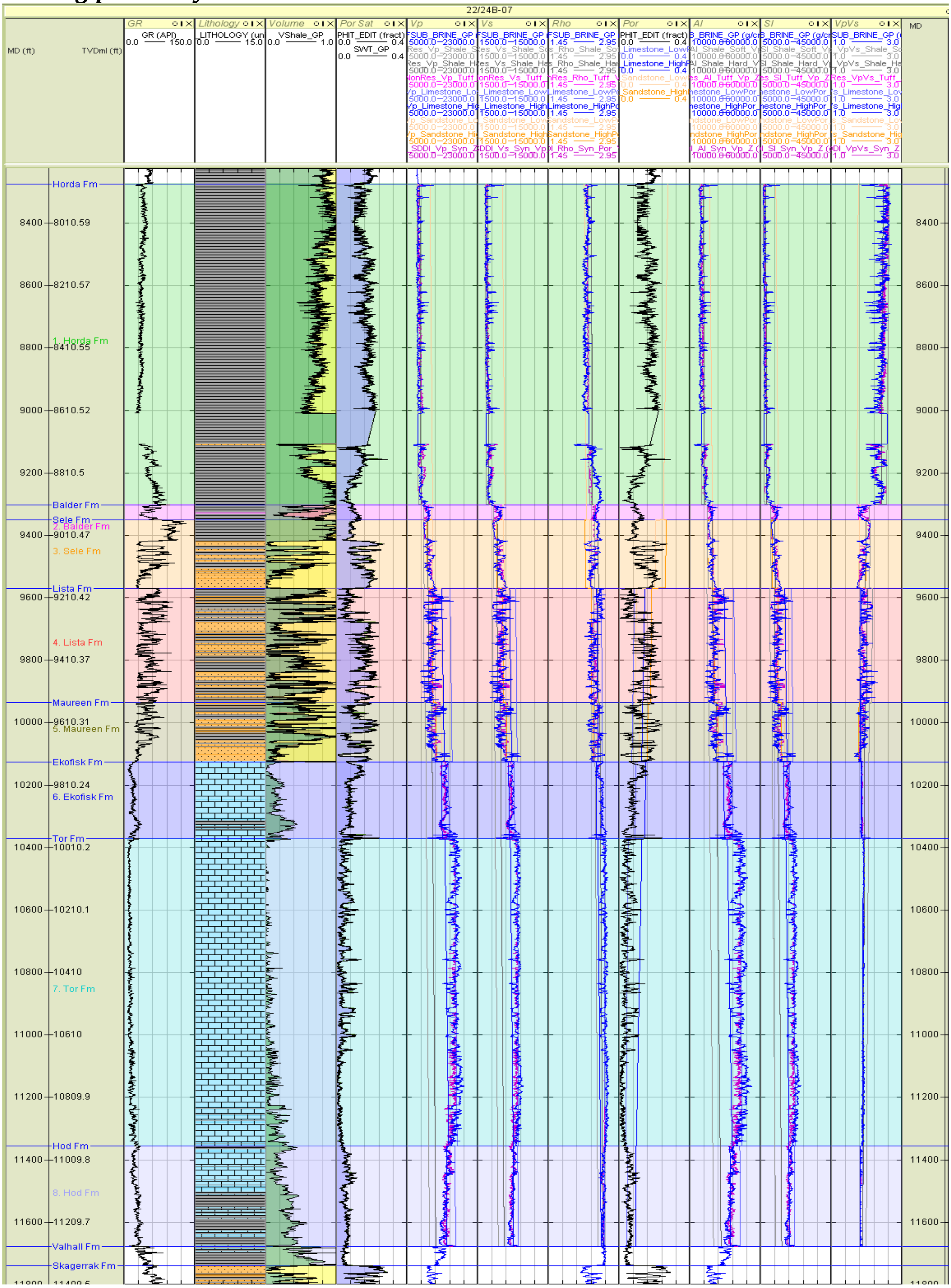


Figure 3.13.5 - Well Panel: End-member and synthetic logs for well 22/24B-07.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

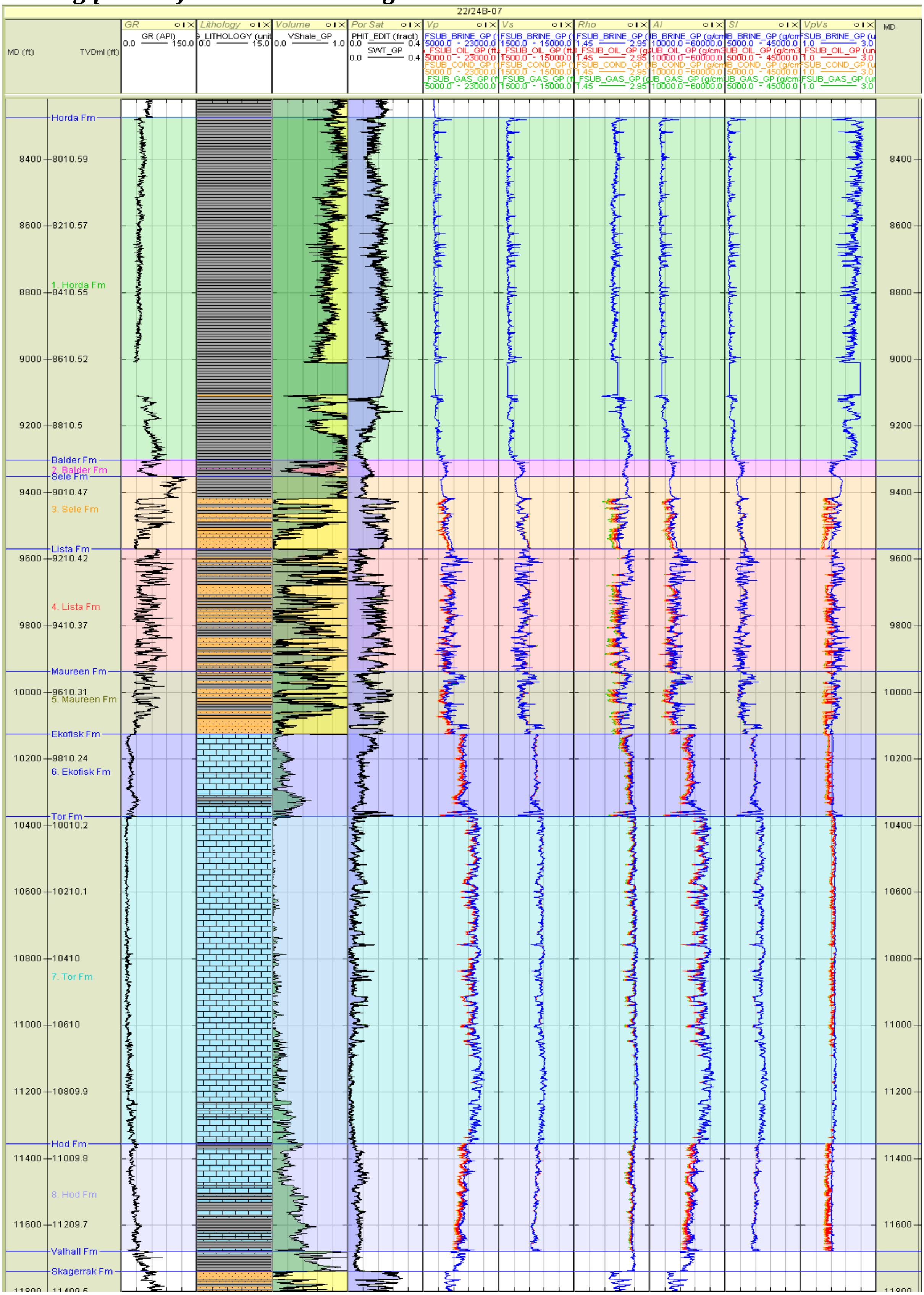


Figure 3.13.6 - Well Panel: Fluid substituted and elastic logs for well 22/24B-07.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/24B-07is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/24B-07	Horda	7880	3214	2.30
22/24B-07	Balder	9794	5003	2.48
22/24B-07	Sele	9624	4723	2.50
22/24B-07	Lista	10299	5128	2.50
22/24B-07	Maureen	10771	5483	2.50

Table 3.13.7 - Clean shale properties at Well 22/24B-07

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/24B-07	Horda	100% Brine			
22/24B-07	Balder	100% Brine			
22/24B-07	Sele	100% Brine	11101	6074	2.32
22/24B-07	Lista	100% Brine	11881	6467	2.37
22/24B-07	Maureen	100% Brine	11770	6431	2.39
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/24B-07	Horda	80% Oil			
22/24B-07	Balder	80% Oil			
22/24B-07	Sele	80% Oil	10195	6148	2.27
22/24B-07	Lista	80% Oil	11265	6531	2.32
22/24B-07	Maureen	80% Oil	10946	6495	2.34
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/24B-07	Horda	90% Gas			
22/24B-07	Balder	90% Gas			
22/24B-07	Sele	90% Gas	10040	6268	2.18
22/24B-07	Lista	90% Gas	11206	6636	2.25
22/24B-07	Maureen	90% Gas	10809	6589	2.27
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/24B-07	Horda	80% Cond			
22/24B-07	Balder	80% Cond			
22/24B-07	Sele	80% Cond	100003	6231	2.21
22/24B-07	Lista	80% Cond	11167	6604	2.27
22/24B-07	Maureen	80% Cond	10781	6560	2.29

Table 3.13.8 - Clean sand properties at Well 22/24B-07 for each fluid case

Tertiary reservoirs – Well panel

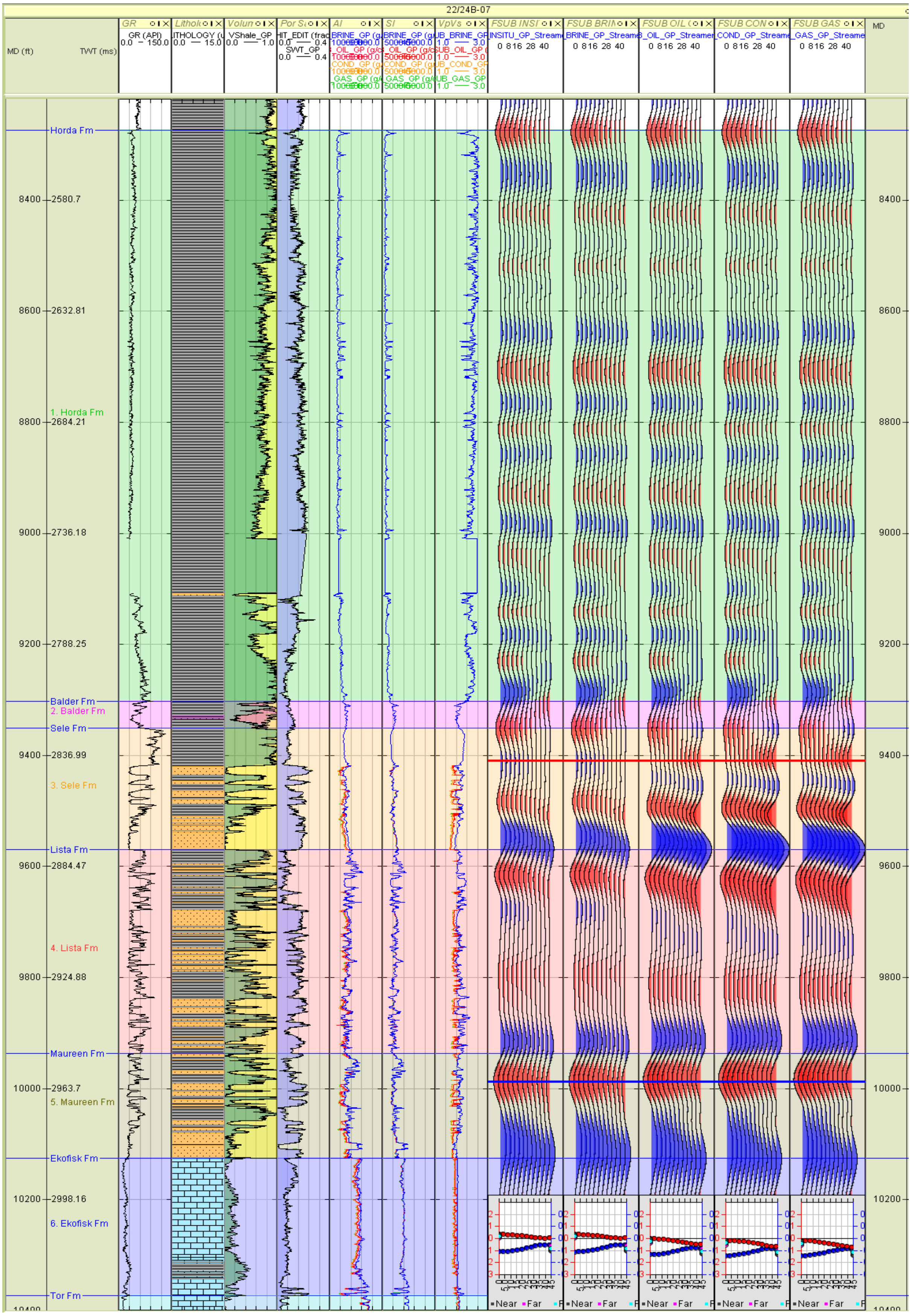


Figure 3.13.7 - Well Panel: Tertiary reservoirs for well 22/24B-07. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by inter-bedded sand and shale packages with a maximum porosity of 26%. The top reservoir sand is overlain directly by overburden shale in the upper section of the Sele Fm.
- Blocky AVO shows a modelled class I response for the 100% brine and a modelled class III response for the 80% oil, 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

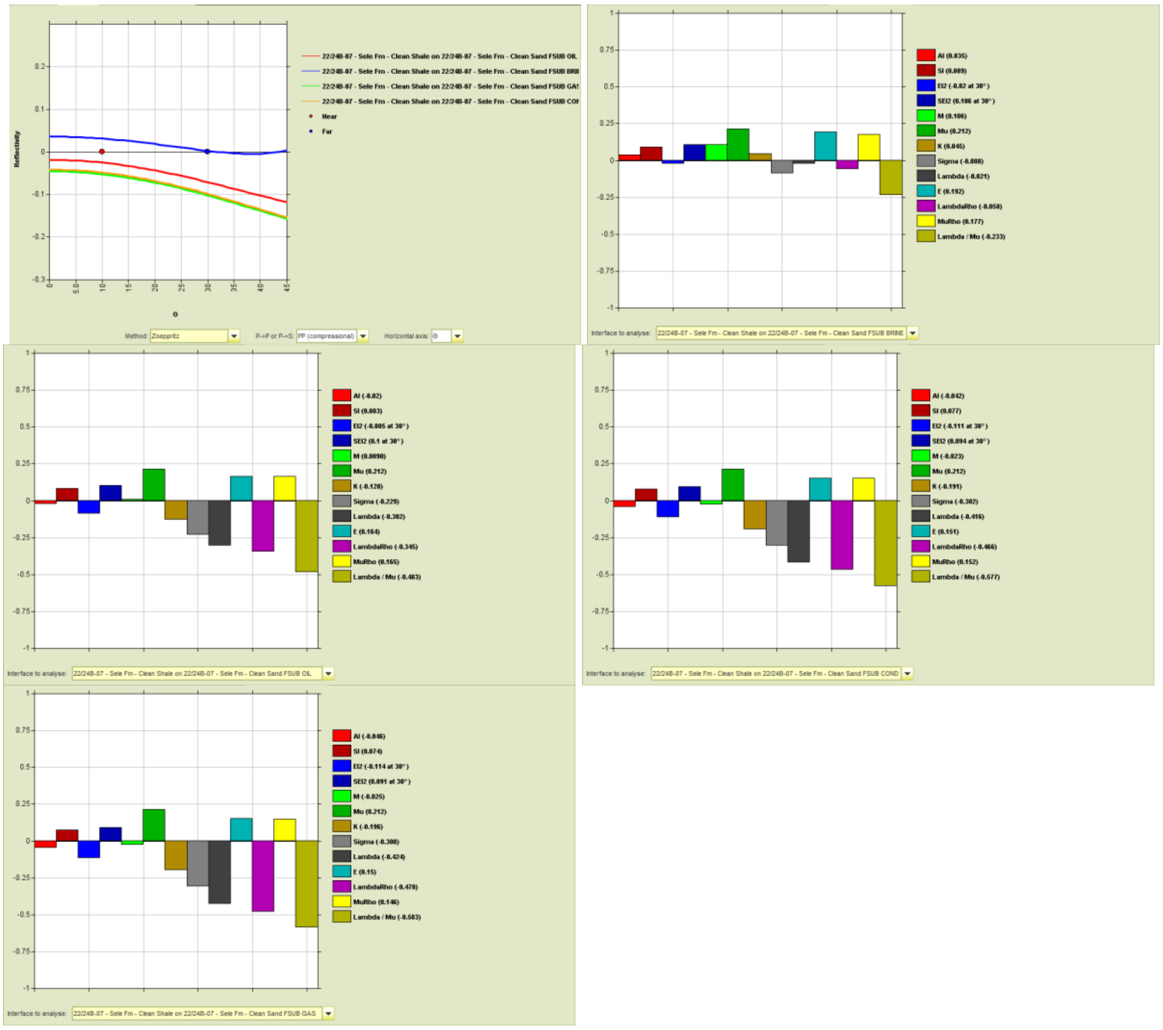


Figure 3.13.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/24B-07.

Lista Formation

- Reservoir formed by inter-bedded sand and shale packages. The maximum net reservoir is approximately 28 feet and contains porosities of around 19-24%.
- Blocky AVO shows a modelled class I response for the 100% brine, a modelled class IIp response for the 80% oil and a modelled class II response for 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

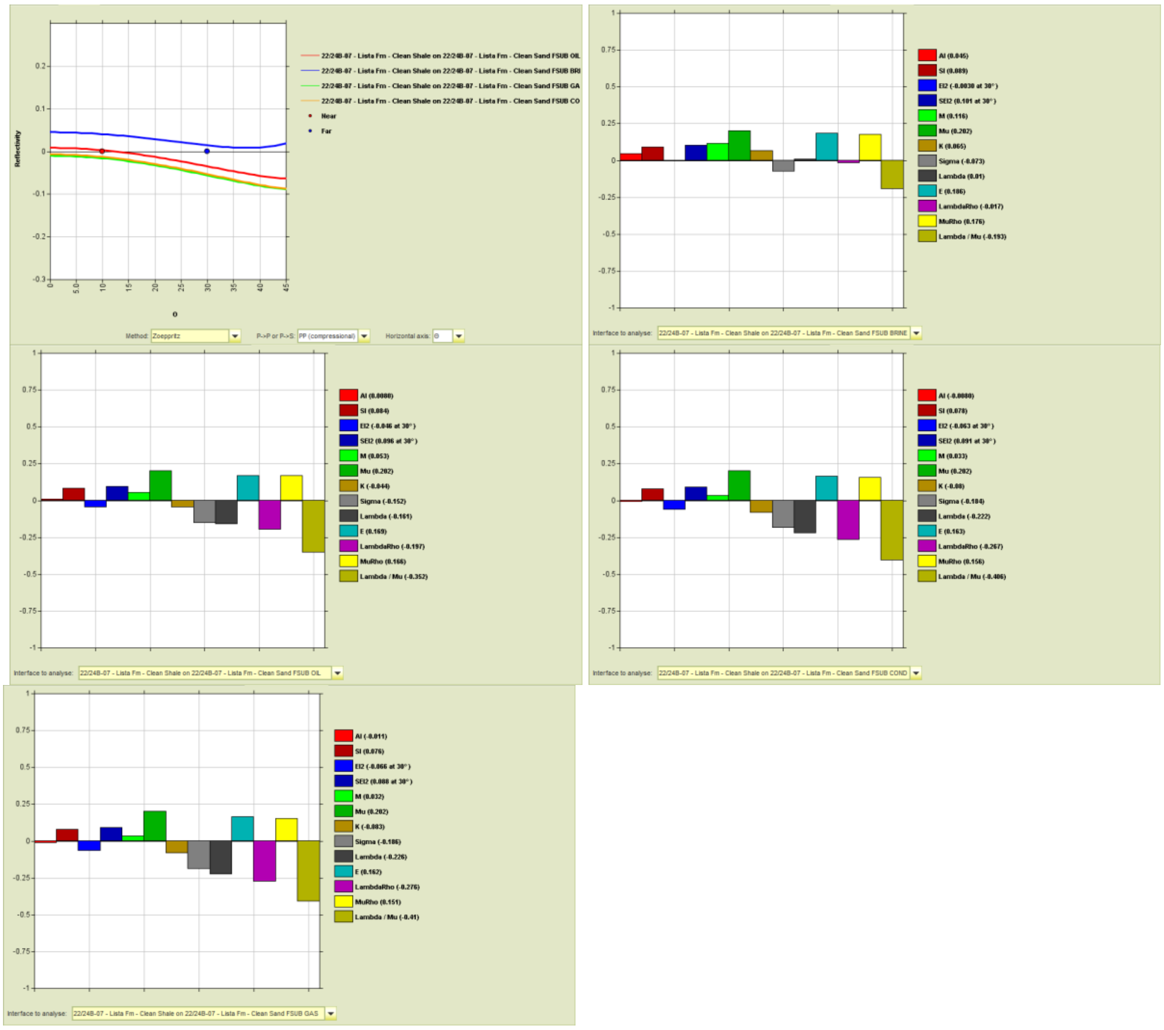


Figure 3.13.9 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/24B-07.

Maureen Formation

- Reservoir formed by inter-bedded sand and shale packages. The maximum net reservoir is approximately 20 feet and contains porosities of around 19-23%.
- Blocky AVO shows a modelled class I response for the 100% brine and a modelled class III response for the 80% oil, 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

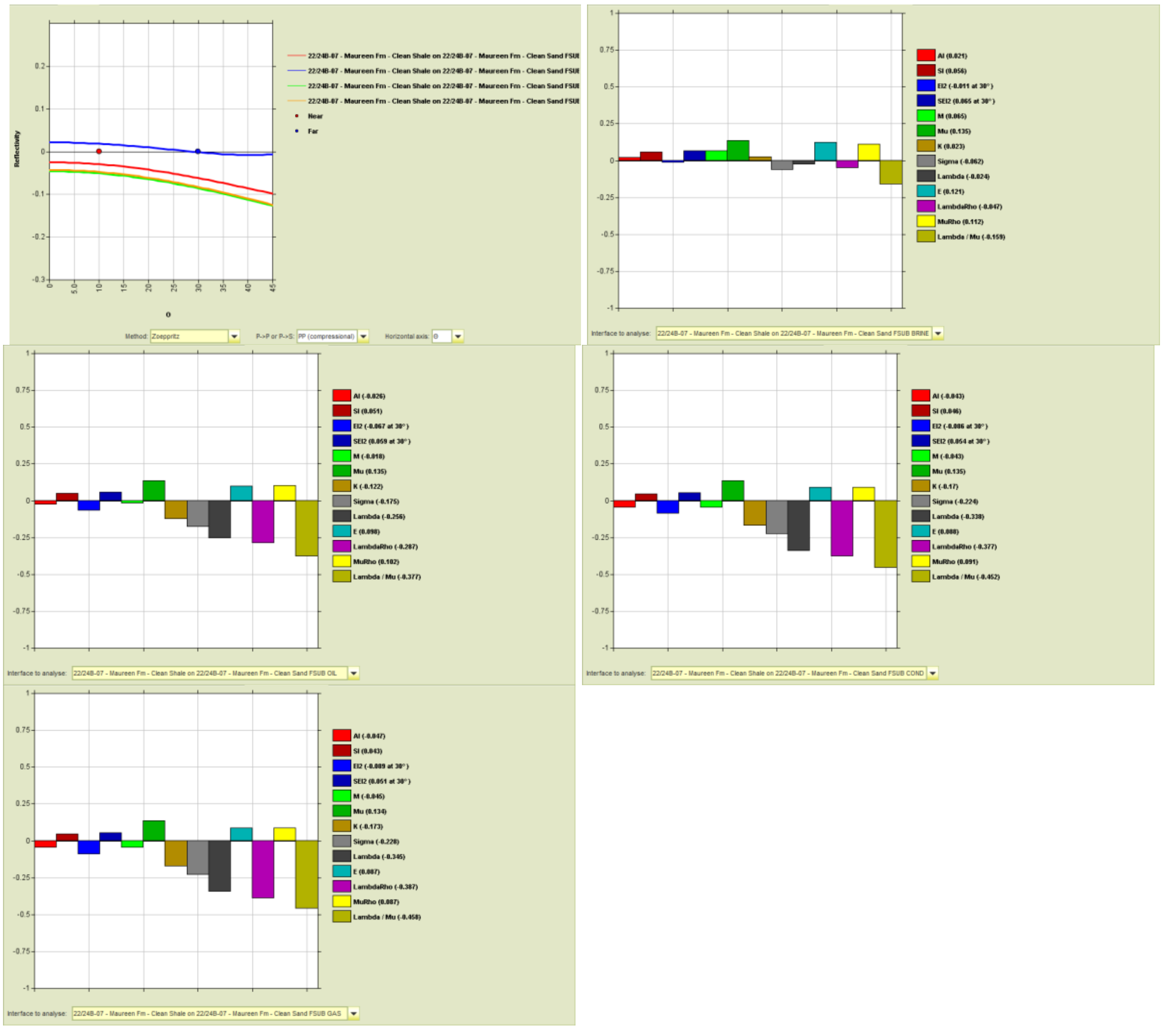


Figure 3.13.10 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/24B-07.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/24B-07 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/24B-07	Ekofisk	100% Brine	15094	8180	2.53
22/24B-07	Tor	100% Brine	17326	9085	2.64
22/24B-07	Hod	100% Brine	15755	8559	2.59
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/24B-07	Ekofisk	80% Oil	14498	8229	2.50
22/24B-07	Tor	80% Oil	17067	9100	2.64
22/24B-07	Hod	80% Oil	15048	8594	2.57
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/24B-07	Ekofisk	90% Gas	14396	8299	2.46
22/24B-07	Tor	90% Gas	17010	9121	2.62
22/24B-07	Hod	90% Gas	14878	8642	2.54
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/24B-07	Ekofisk	80% Cond	14376	8277	2.47
22/24B-07	Tor	80% Cond	17006	9115	2.63
22/24B-07	Hod	80% Cond	14874	8627	2.55

Table 3.13.9 - Clean limestone properties at Well 22/24B-07 for each fluid case

Cretaceous reservoirs

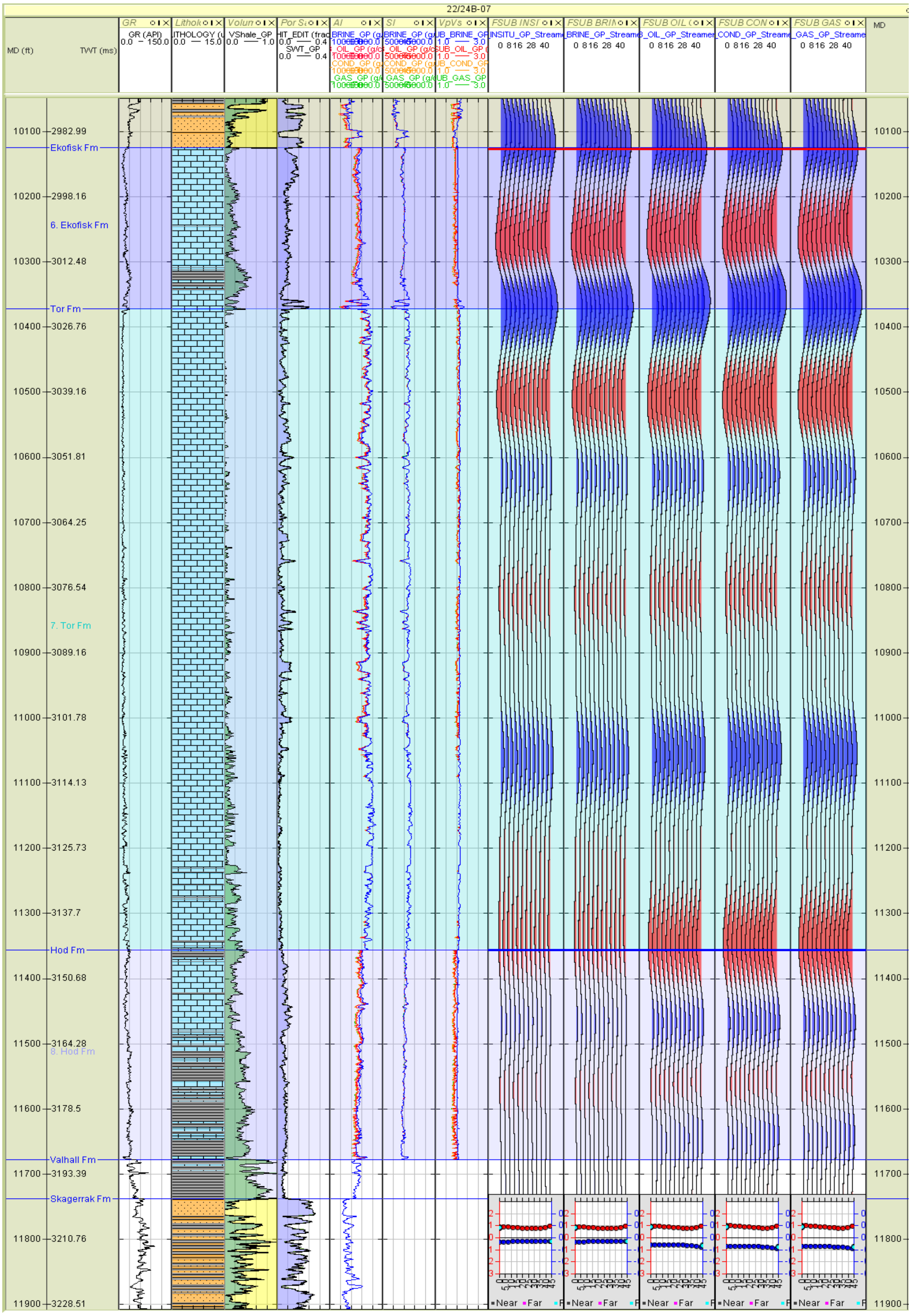


Figure 3.13.11 - Well Panel: Cretaceous reservoirs for well 22/24B-07. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the top section of the Ekofisk Fm and the porosity in this section is approximately 16%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons. This AVO response can't be compared to the synthetic gathers since the overburden section of the Maureen Fm is sand at this well.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude for all the fluid cases. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

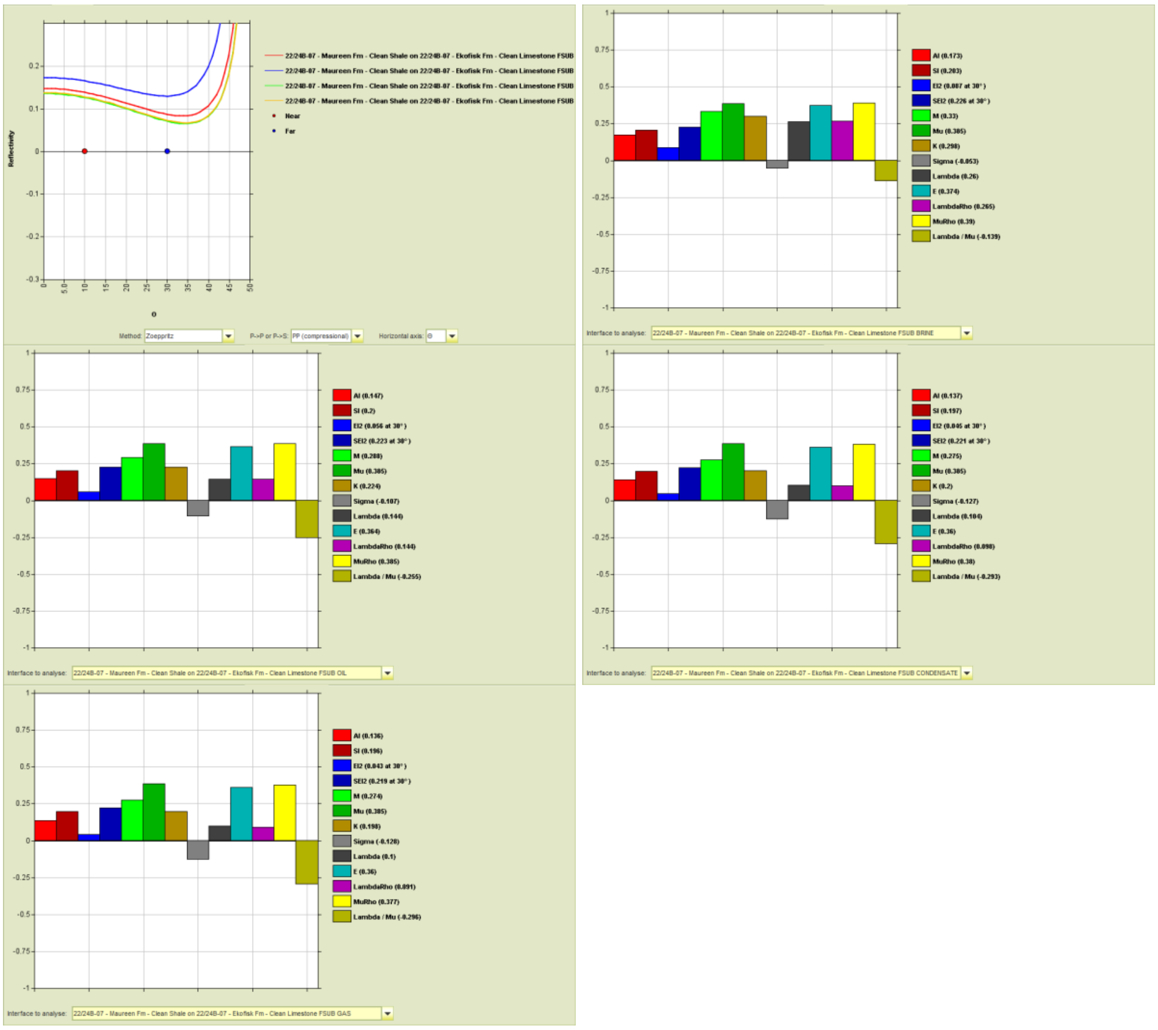


Figure 3.13.12 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/24B-07.

Tor Formation

- Reservoir formed by a clean limestone formation. The highest porosity reservoir is found in the top section of the Tor Fm as patchy zones of higher porosity (approximately 10%). These high porosity layers are found throughout the Tor Fm and could be representative of re-worked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are all positive and of low amplitude for all fluid cases. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

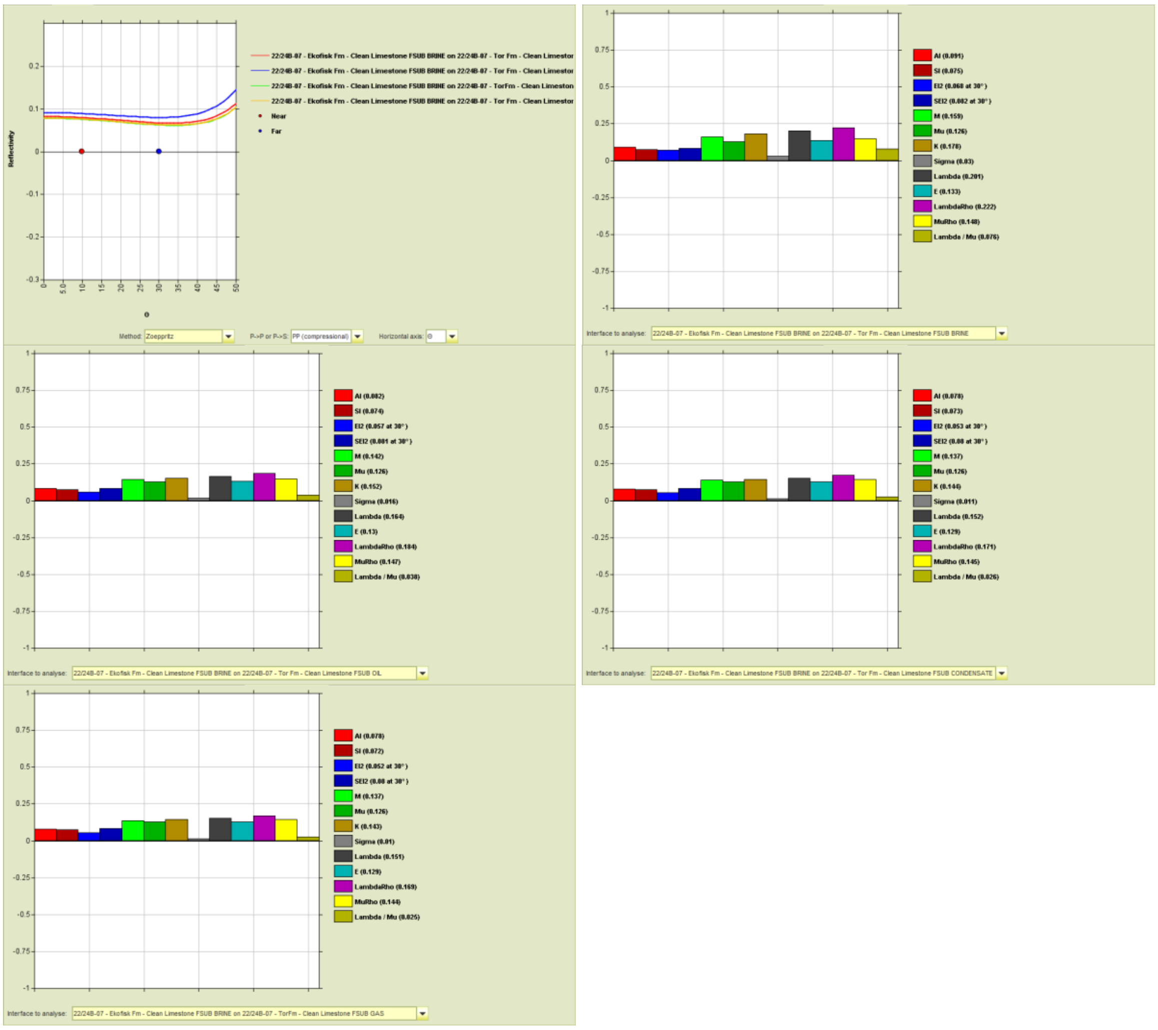


Figure 3.13.13 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/24B-07.

Hod Formation

- Reservoir formed by a limestone in the top section of the Hod Fm and an increasing component of shale is observed from 11500ft. The maximum porosity is observed to be 9% in the upper section decreasing to a more constant 7% porosity in the lower portion of the promotion.
- Blocky AVO shows a modelled class III response for all the fluid cases but with a flat gradient. The softness of the limestone in relation to the overburden brine-saturated limestone increases with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are all negative and of low amplitude in the brine case, but that the contrasts increase in amplitude to become negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic resp onse for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

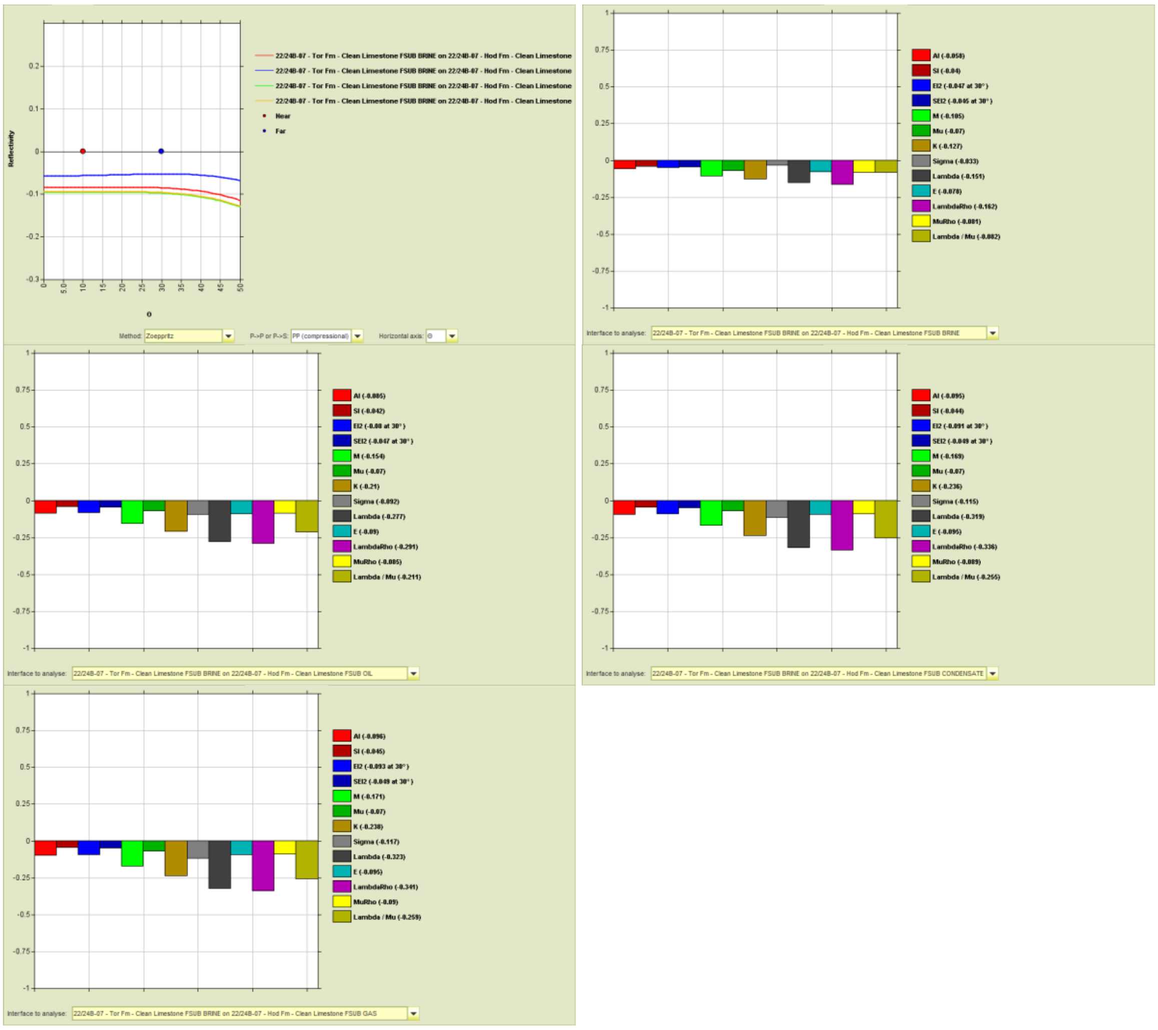


Figure 3.13.14 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/24B-07.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/24B-07is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/24B-07	Overburden	Shale	7658		
22/24B-07	Underburden	Shale/Anhydrite	11801		2.41

Table 3.13.10 - Overburden and underburden properties at Well 22/24B-07

Well: 22/26A-01

General

Well Information
Shell operated exploration well spudded, completed and abandoned in 1981. The well was drilled in the Gannet F field but did not encounter any hydrocarbons.

Objectives
Well 22/26a-1 was drilled to test the Tay formation. Both the Tay and underlying Forties sands were encountered and found to be water bearing.

Log conditioning overview
Only minor log conditioning required due to good log data quality within this well. The calliper log demonstrates that the bore hole is in good condition across any of the working intervals. Small sections of the Vp log were removed from the Balder and Sele Formations at approximately 7820ft and 7972ft respectively.

Invasion correction

Well 22/26A-01 was drilled with oil-based drilling muds. Invasion correction has been performed within all formations containing reservoir intervals with exception of the non-reservoir bearing Balder Fm.

Log modelling
In this well, with the exception of a gap within the Vp log filled using a spline fit, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Sele and Ekofisk Formations for Vp. No gaps were present in the density log. A complete Vs log is modelled since a measured Vs log is not available at this well.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 22/26A-01 is displayed in the figures below;

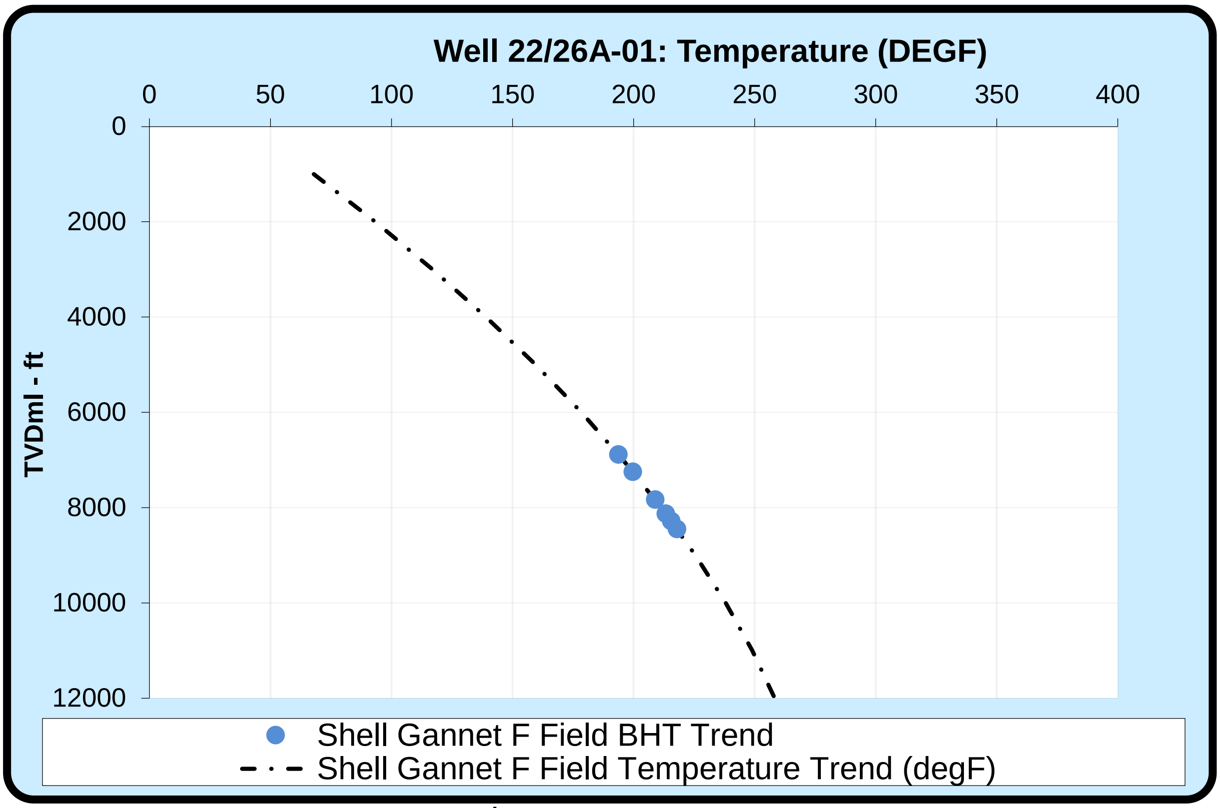


Figure 3.14.1 - Temperature data at Well 22/26A-01

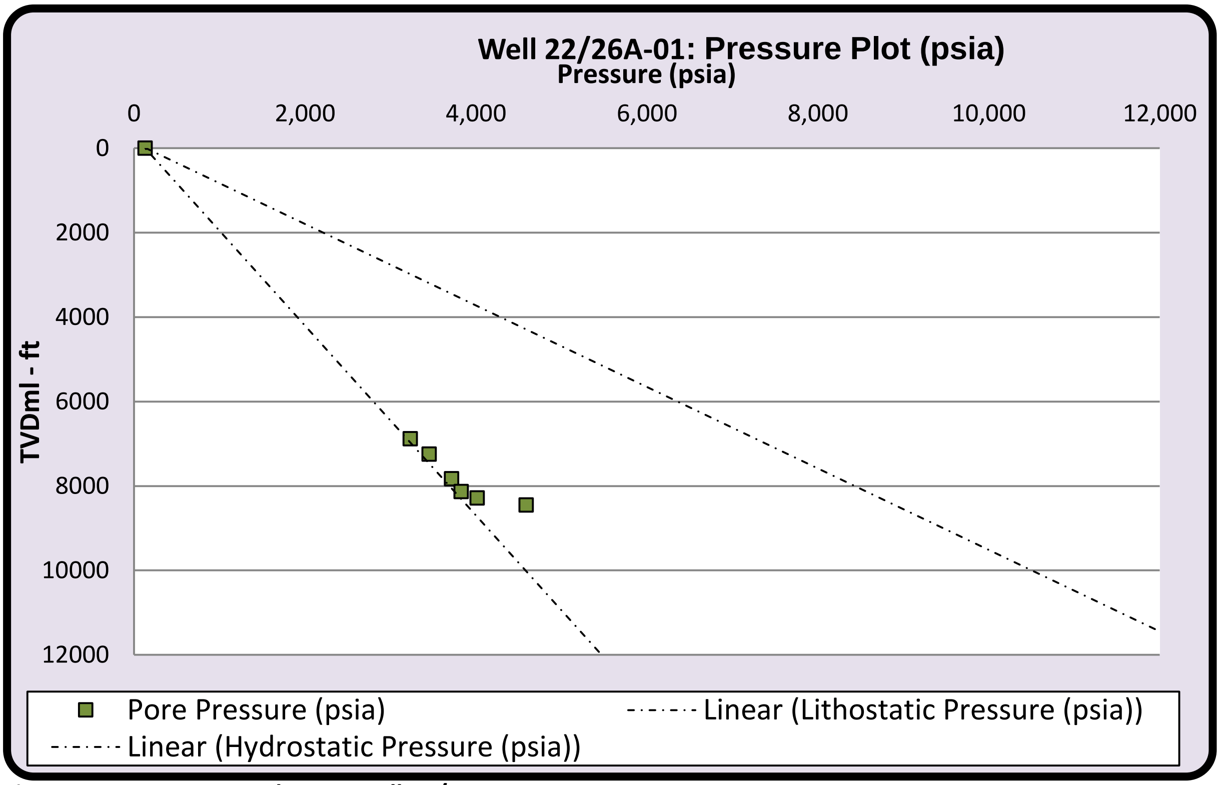


Figure 3.14.2 - Pressure data at Well 22/26A-01

The temperature and pressure data for the formation mid-points in Well 22/26A-01 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/26A-01	Sea Bed	374.0	294.0	0.0	39.2	130.8	130.8	130.8	0.0
22/26A-01	Horda	7529.0	7448.6	7154.6	210.0	3314.6	3354.6	7285.4	3930.8
22/26A-01	Balder	7888.5	7808.0	7514.0	218.2	3474.6	3574.6	7644.9	4070.3
22/26A-01	Sele	8206.5	8126.0	7832.0	225.4	3616.1	3716.1	7962.8	4246.7
22/26A-01	Lista	8504.0	8423.4	8129.4	231.9	3748.4	3828.4	8260.2	4431.8
22/26A-01	Maureen	8658.5	8577.9	8283.9	235.2	3817.2	4017.2	8414.7	4397.5
22/26A-01	Ekofisk	8823.5	8742.8	8448.8	238.7	3890.6	4590.6	8579.7	3989.1
22/26A-01	Tor	374.0	294.0	0.0	39.2	130.8	130.8	130.8	0.0
22/26A-01	Hod	7529.0	7448.6	7154.6	210.0	3314.6	3354.6	7285.4	3930.8

Table 3.14.1 - Summary of mid-point temperature and pressure data at Well 22/26A-01

Fluid data

A summary of the fluid set parameters at Well 22/26A-01 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/26A-01	Horda	75000	730	38.8	0.71	0.71
22/26A-01	Balder	75000	730	39.2	0.71	0.71
22/26A-01	Sele	75000	440	36.5	0.8	0.8
22/26A-01	Lista	75000	730	40.1	0.71	0.71
22/26A-01	Maureen	75000	730	40.3	0.71	0.71
22/26A-01	Ekofisk	75000	730	40.5	0.71	0.71

Table 3.14.2 - Summary of fluid parameter data at Well 22/26A-01

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.14.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	12.16	4.27	2.46	8,902	4,355

Table 3.14.4 - Tuff properties used at Well 29/27-09

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/26A-01	Horda	PAY	596.000	0.000	0.000	0.000	0.000	0.000	0.000
22/26A-01	Horda	RES	596.000	190.000	0.319	54.742	0.288	0.975	0.125
22/26A-01	Balder	PAY	123.000	0.000	0.000	0.000	0.000	0.000	0.000
22/26A-01	Balder	RES	123.000	1.750	0.014	0.317	0.181	1.000	0.218
22/26A-01	Sele	PAY	513.000	0.000	0.000	0.000	0.000	0.000	0.000
22/26A-01	Sele	RES	513.000	338.750	0.660	79.608	0.235	0.993	0.220
22/26A-01	Lista	PAY	82.000	0.000	0.000	0.000	0.000	0.000	0.000
22/26A-01	Lista	RES	82.000	16.000	0.195	3.526	0.220	0.984	0.137
22/26A-01	Maureen	PAY	227.000	0.000	0.000	0.000	0.000	0.000	0.000
22/26A-01	Maureen	RES	227.000	92.500	0.407	16.866	0.182	0.987	0.226
22/26A-01	Ekofisk	PAY	103.000	0.000	0.000	0.000	0.000	0.000	0.000
22/26A-01	Ekofisk	RES	103.000	90.000	0.874	9.274	0.130	0.980	0.170

Table 3.14.5 - Petrophysical parameters used at Well 22/26A-01

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

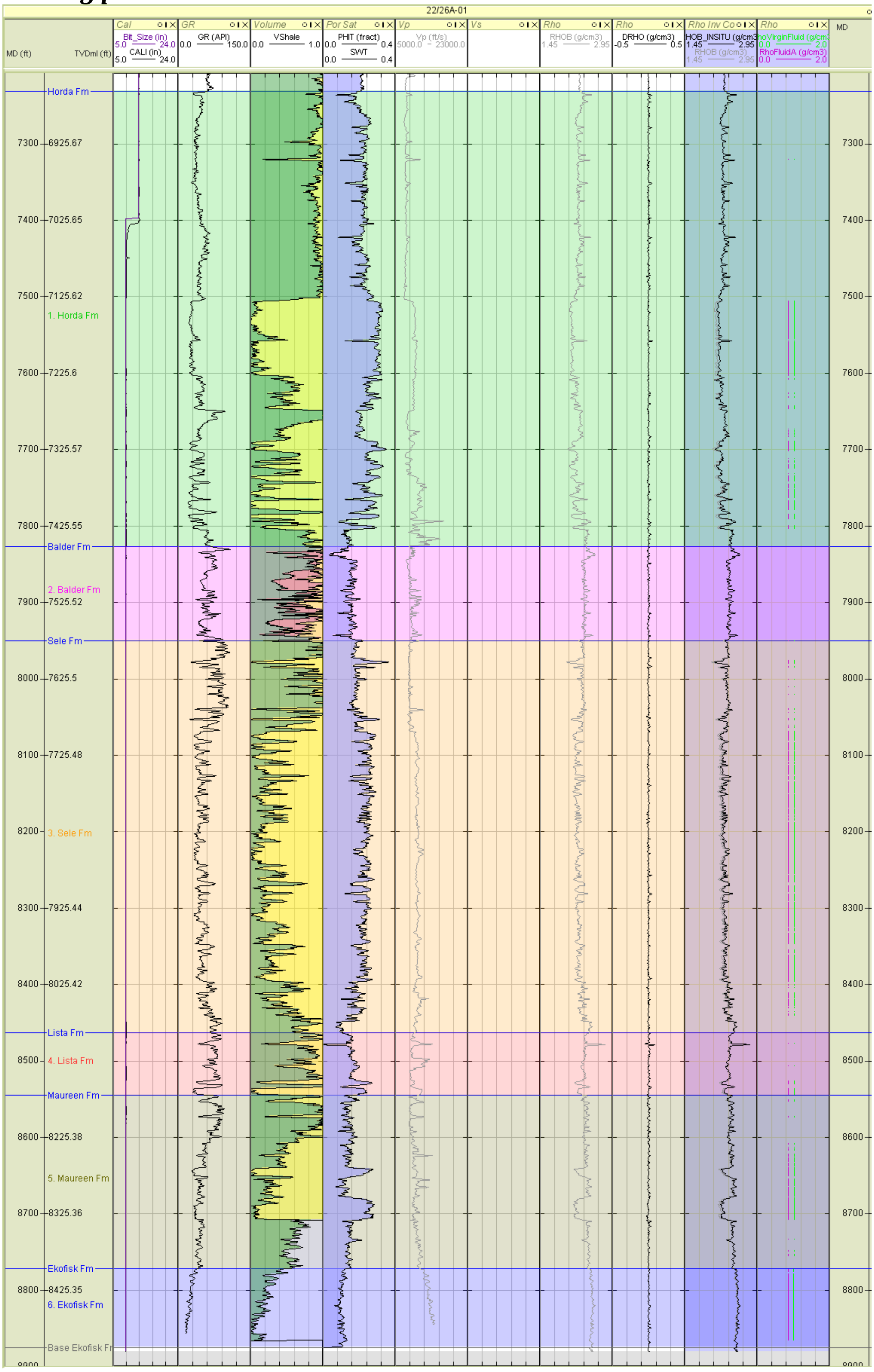


Figure 3.14.3 - Well Panel: Measured data and invasion correction for well 22/26A-01.

Well log panel – log editing and audit

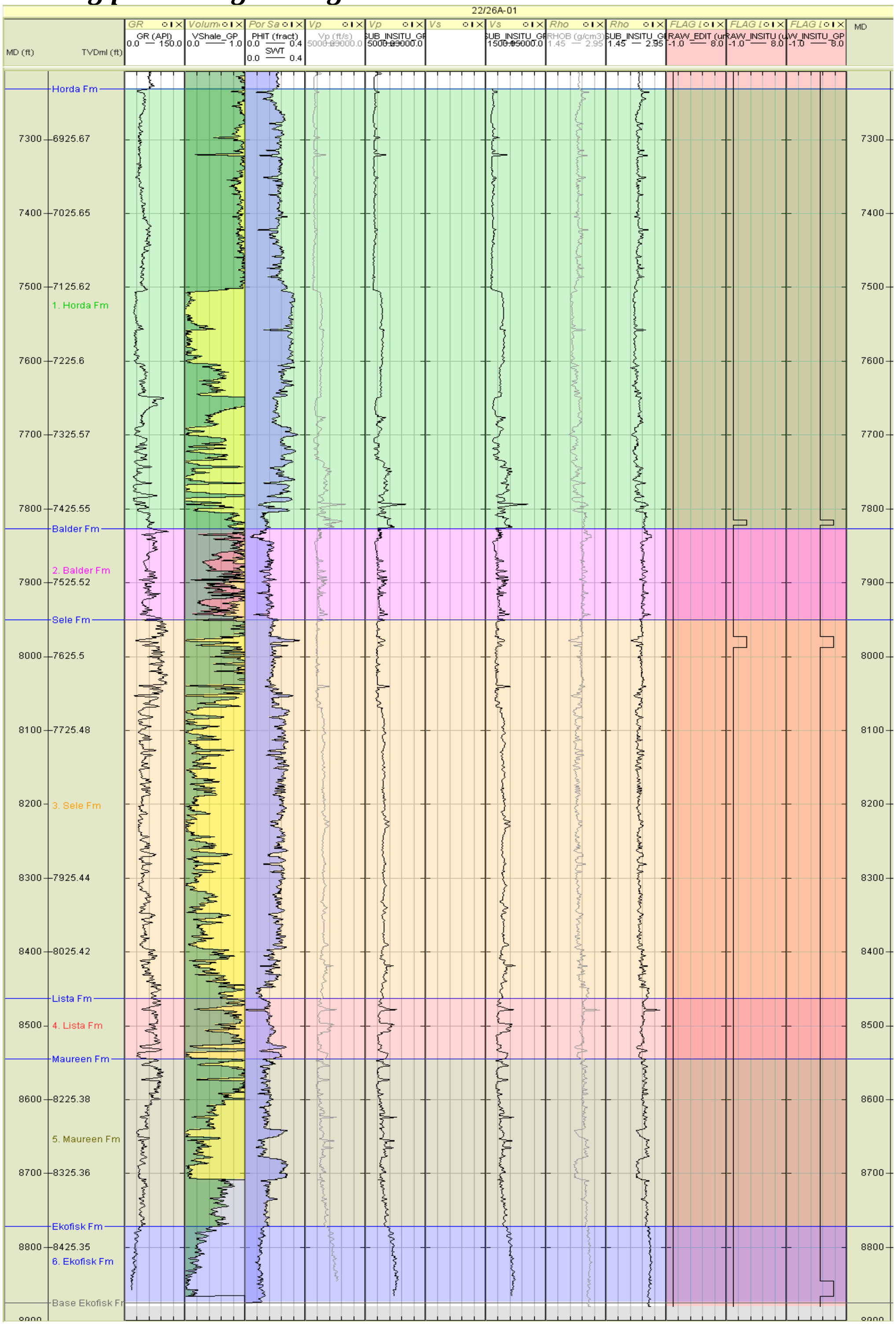


Figure 3.14.4 - Well Panel: Log edits for well 22/26A-01.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

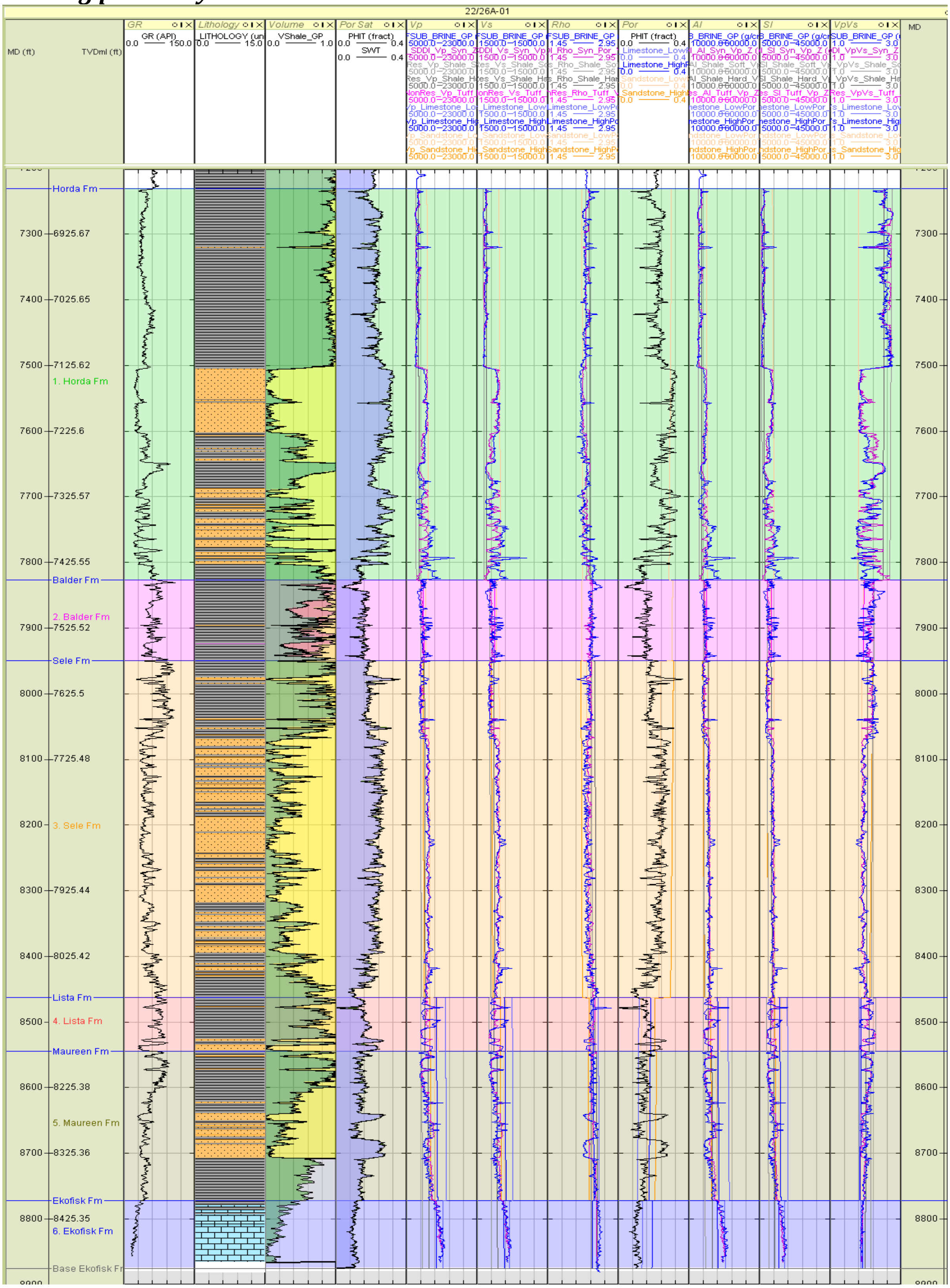


Figure 3.14.5 - Well Panel: End-member and synthetic logs for well 22/26A-01.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

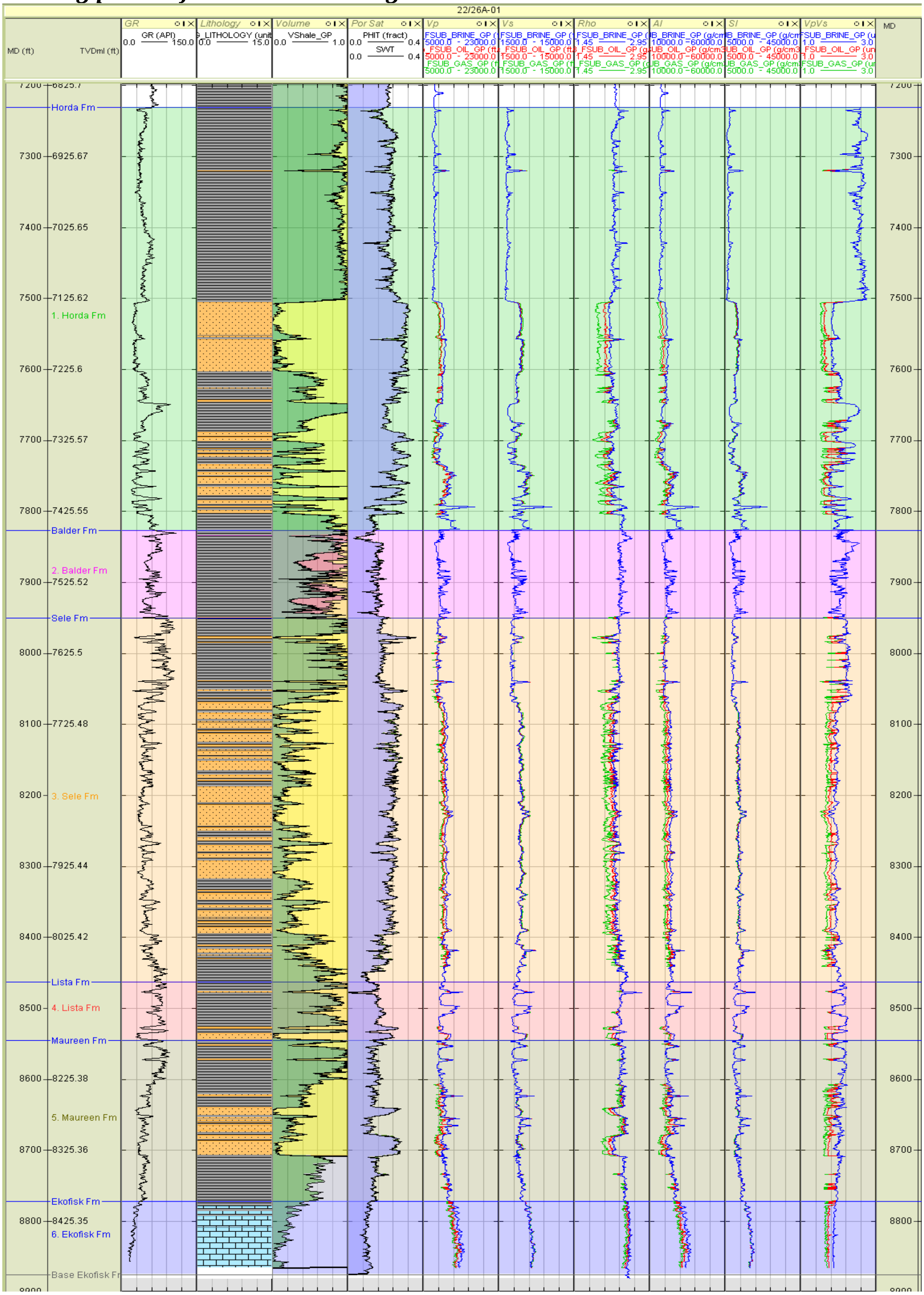


Figure 3.14.6 - Well Panel: Fluid substituted and elastic logs for well 22/26A-01.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/26A-01 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/26A-01	Horda	7933	3197	2.27
22/26A-01	Balder	8758	4056	2.39
22/26A-01	Sele	8723	4017	2.34
22/26A-01	Lista	9369	4432	2.37
22/26A-01	Maureen	9011	4243	2.40

Table 3.14.6 - Clean shale properties at Well 22/26A-01

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/26A-01	Horda	100% Brine	10098	5506	2.18
22/26A-01	Balder	100% Brine			
22/26A-01	Sele	100% Brine	10509	5498	2.25
22/26A-01	Lista	100% Brine	11098	5925	2.30
22/26A-01	Maureen	100% Brine	10454	5317	2.32
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/26A-01	Horda	80% Oil	9204	5611	2.09
22/26A-01	Balder	80% Oil			
22/26A-01	Sele	80% Oil	9809	5567	2.20
22/26A-01	Lista	80% Oil	10345	6004	2.24
22/26A-01	Maureen	80% Oil	9411	5381	2.27
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/26A-01	Horda	90% Gas	9065	5800	1.96
22/26A-01	Balder	90% Gas			
22/26A-01	Sele	90% Gas	9561	5725	2.08
22/26A-01	Lista	90% Gas	10217	6136	2.14
22/26A-01	Maureen	90% Gas	9095	5488	2.18

Table 3.14.7 - Clean sand properties at Well 22/26A-01 for each fluid case

Tertiary reservoirs – Well panel

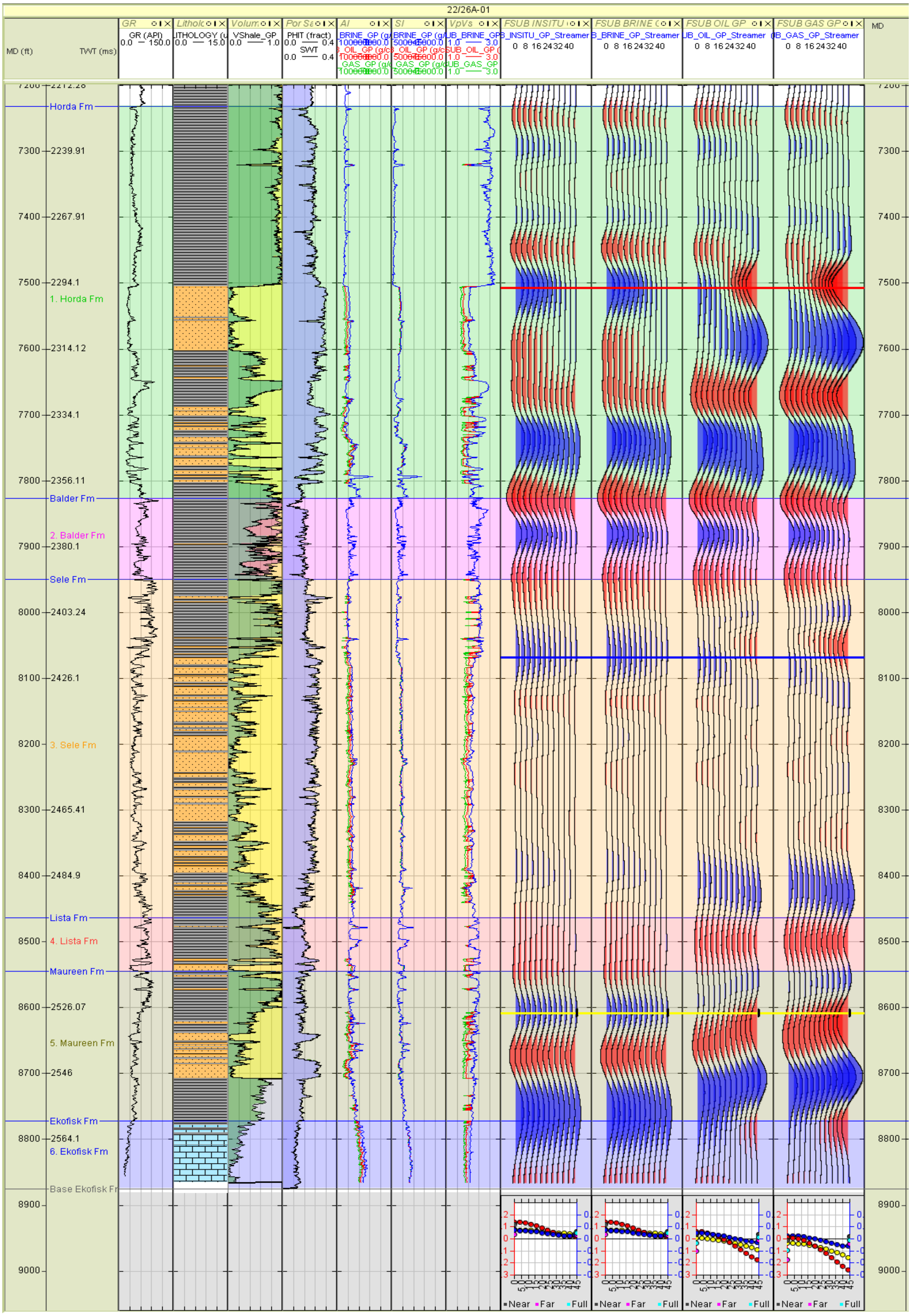


Figure 3.14.7 - Well Panel: Tertiary reservoirs for well 22/26A-01. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Horda Formation

- The main reservoir within the formation is clean blocky sandstone, approximately 100 feet thick with an associated porosity of 31%. This reservoir occurs in the centre of the interval, overlain by a silty interval containing thin shales. An inter-bedded sand / shale sequence is seen at the base of the interval where the net reservoir is approximately 20 feet and the associated porosity's range from 23-35%.
- Blocky AVO shows a modelled class I response for the 100% brine, a modelled class IIp response for the 80% oil cases and a modelled class II response for the 90% gas case. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts generally become more negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

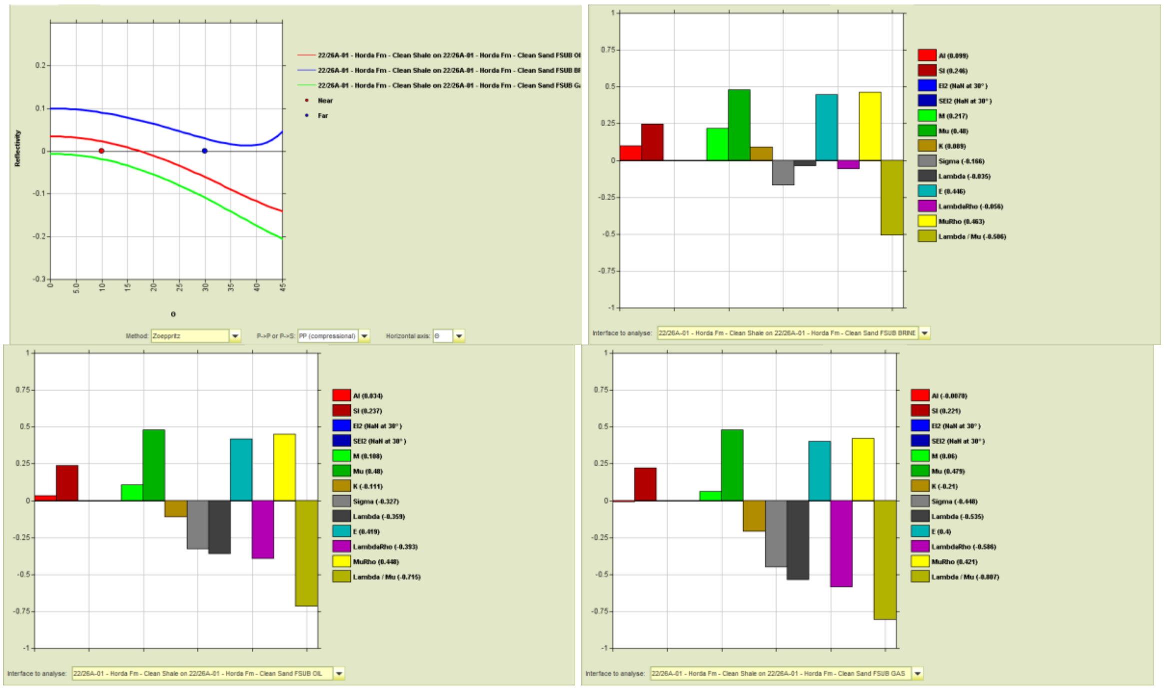


Figure 3.14.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 22/26A-01.

Sele Formation

- Reservoir is formed by a number of thin sands (approximately 3-30 feet thick). The reservoir is overlain by thick clean shale. Porosity varies throughout the reservoir ranging from 19-29%.
- Blocky AVO shows a modelled class I response for the 100% brine, a modelled class IIp response for the 80% oil cases and a modelled class II response for the 90% gas case. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are often moderate and positive in the 100% brine case, and become increasingly negative in the 80% oil and 90% gas cases. Mu shows the least sensitivity to fluid changes, while Lambda/LambdaRho show the most sensitivity to fluid effects.

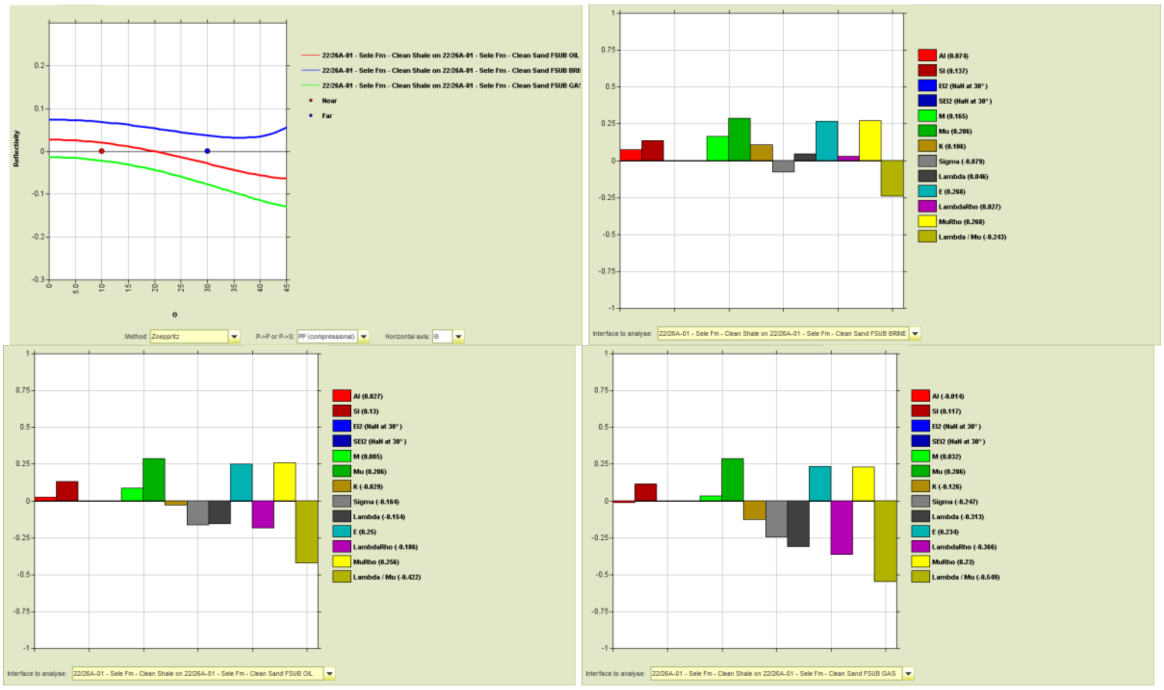


Figure 3.14.9 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/26A-01.

Lista Formation

- Reservoir is formed by two thin sand packages approximately 4 ft and 12 ft thick respectively, overlain by thick clean shale. The associated porosity ranges from 24-27%.
- Blocky AVO shows a modelled class I response for the 100% brine, a modelled class IIp response for the 80% oil cases and a modelled class II response for the 90% gas case. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are often moderate and positive in the 100% brine case, and become increasingly negative in the 80% oil and 90% gas cases. Mu shows the least sensitivity to fluid changes, while Lambda/LambdaRho show the most sensitivity to fluid effects.

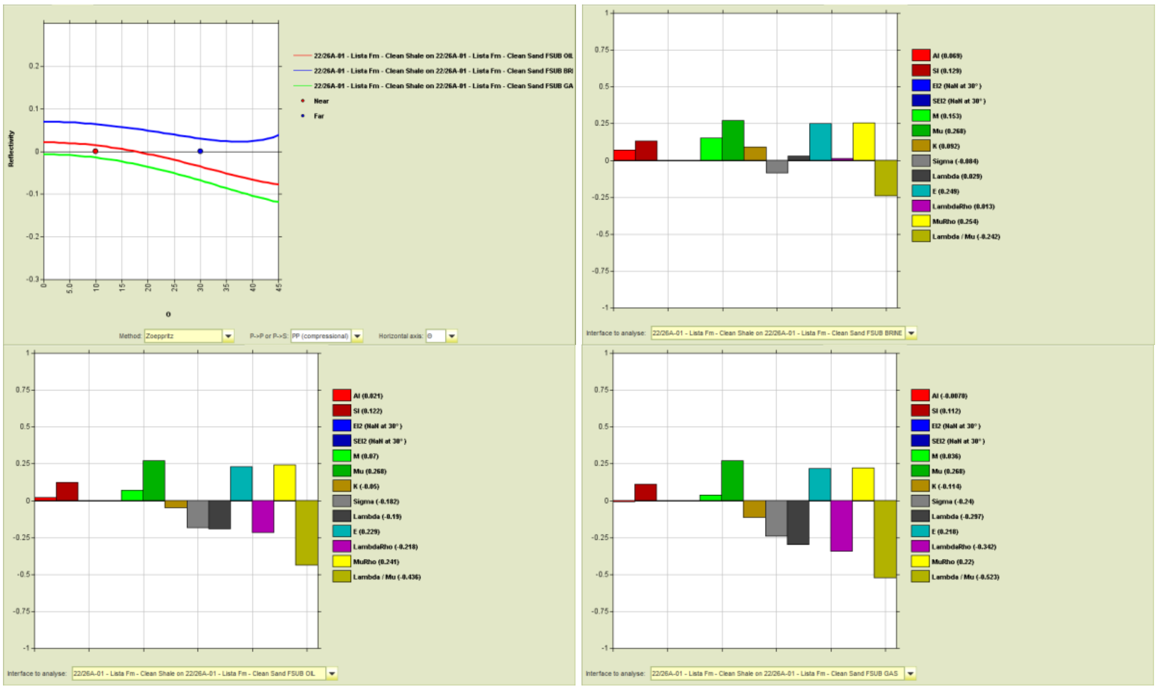


Figure 3.14.10 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/26A-01.

Maureen Formation

- Reservoir formed by a discrete sand package of varying porosity. Two zones of high porosity, very clean sand are evident. The first high porosity zone occurs at 8637ft MD and is approximately 12 ft thick with an associated maximum porosity of 26%; the second is 30ft thick with a maximum porosity of 28%. A shalier sand interval separates the two zones and the entire sand package is overlain by thick clean shale.
- Blocky AVO shows a modelled class I response for the 100% brine, a modelled class II response for the 80% oil cases and a modelled class III response for the 90% gas case. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

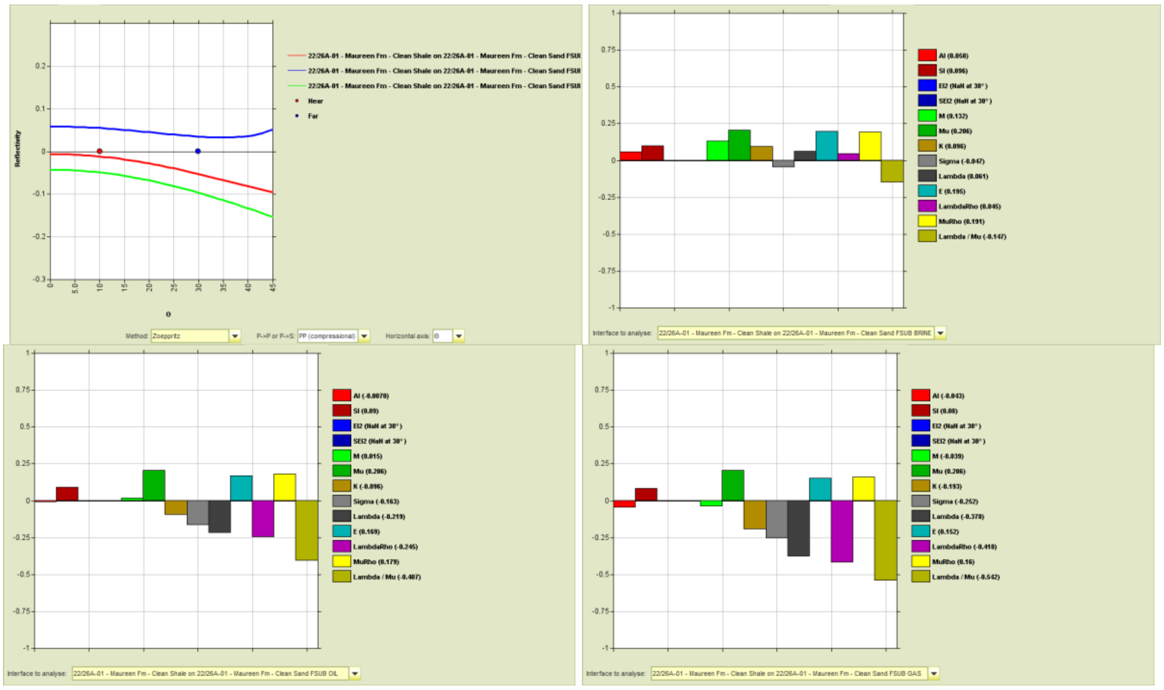


Figure 3.14.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/26A-01.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/26A-01 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/26A-01	Ekofisk	100% Brine	14151	7618	2.53
22/26A-01	Tor	100% Brine			
22/26A-01	Hod	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/26A-01	Ekofisk	80% Oil	13204	7661	2.51
22/26A-01	Tor	80% Oil			
22/26A-01	Hod	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/26A-01	Ekofisk	90% Gas	12876	7729	2.46
22/26A-01	Tor	90% Gas			
22/26A-01	Hod	90% Gas			

Table 3.14.8 - Clean limestone properties at Well 22/26A-01 for each fluid case

Cretaceous reservoirs

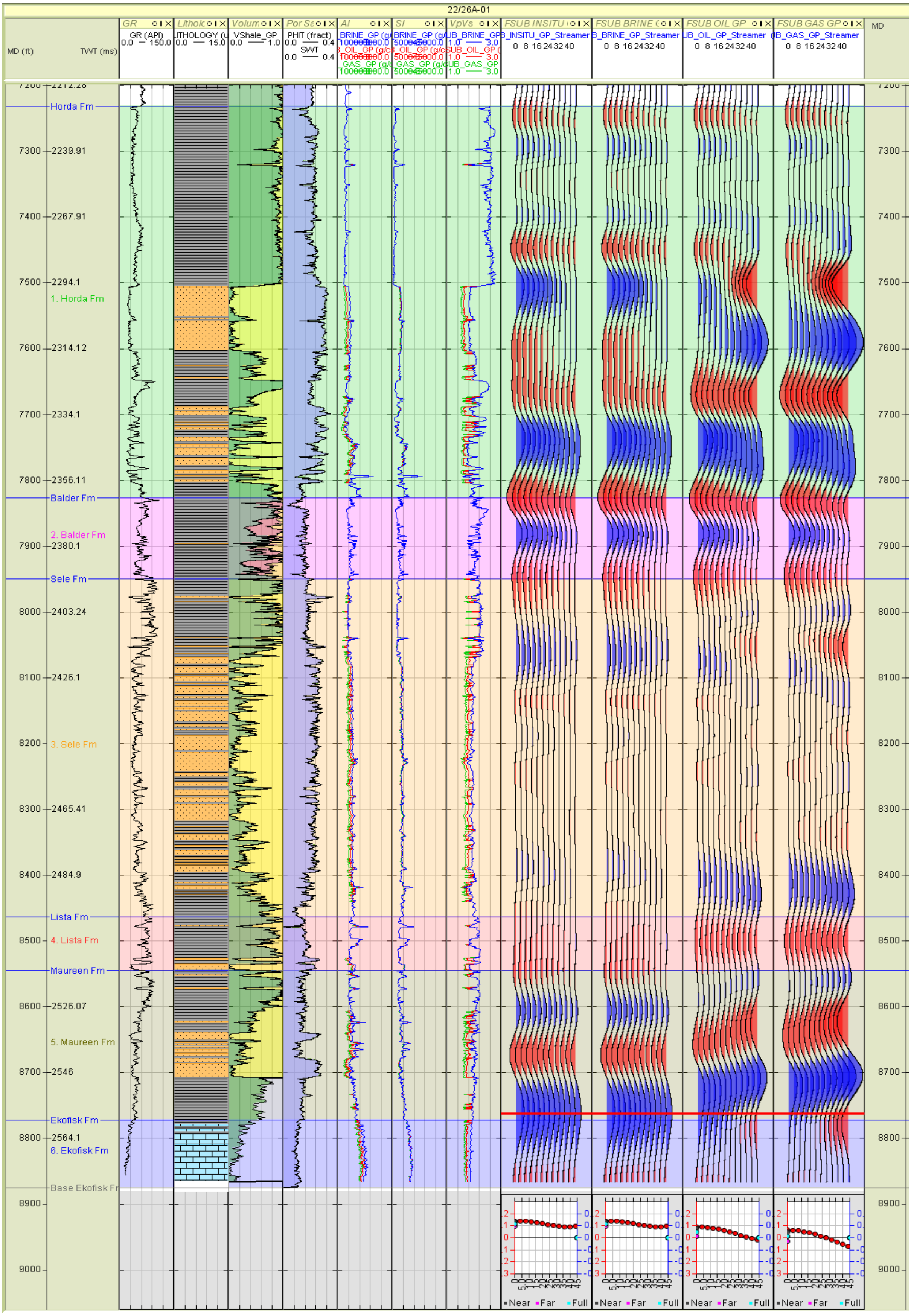


Figure 3.14.12 - Well Panel: Cretaceous reservoirs for well 22/26A-01. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The shale component decreases with depth. The porosity is fairly constant and is approximately 12%. It is unclear what lies beneath the reservoir as the well terminates just before the apparent reservoir base.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons. This AVO response can't be compared to the synthetic gathers since the overburden section of the Maureen Fm is sand at this well.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

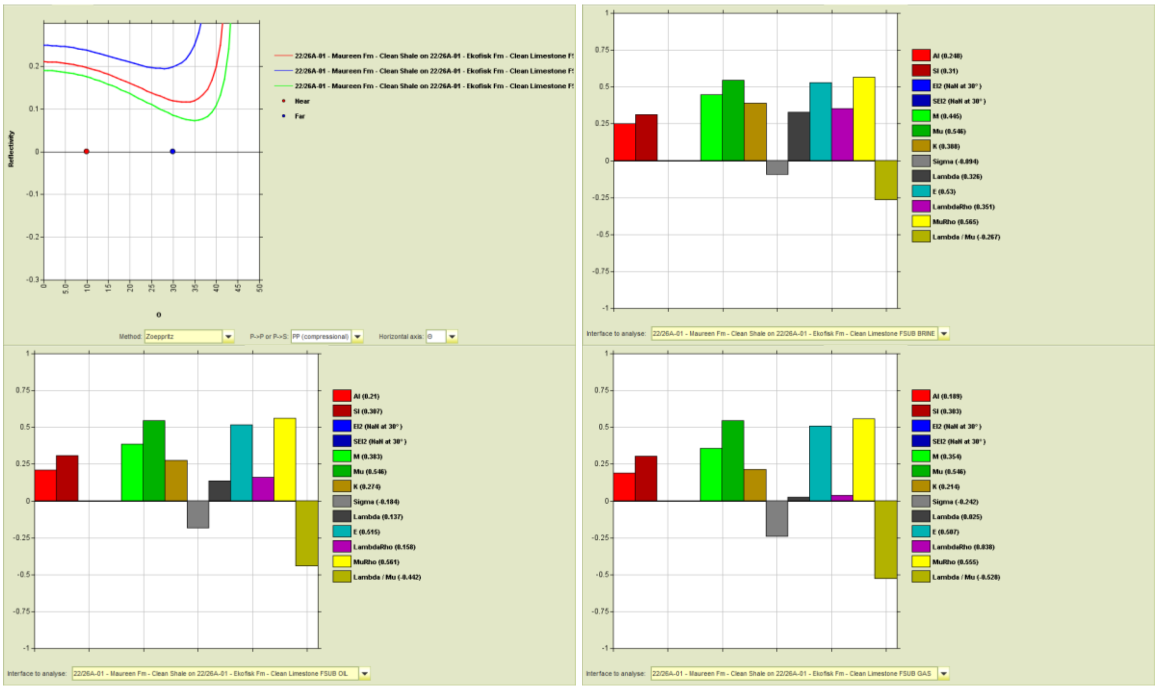


Figure 3.14.13 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/26A-01.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/26A-01 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/26A-01	Overburden	Shale	7928		2.27
22/26A-01	Underburden				

Table 3.14.9 - Overburden and underburden properties at Well 22/26A-01

Well: 22/27A-01

General

Well Information
Ranger exploration well spudded, completed and abandoned in 1984.

Objectives
Well 22/27A-1 was drilled to test structural prospects at both Upper Jurassic and Rotliegend.

Log conditioning overview
No log conditioning was required in this well.

Invasion correction

Well 22/27A-01 was drilled with oil-based drilling mud. Invasion correction has been performed within all formations containing reservoir intervals with exception of non-reservoir Horda Fm.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

No gaps were present in the Vp or density log. A complete Vs log is modelled since a measured Vs log is not available at this well. A gap was also filled above the interval of interest in the Vp log using a spline function.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 22/27A-01 is displayed in the figures below;

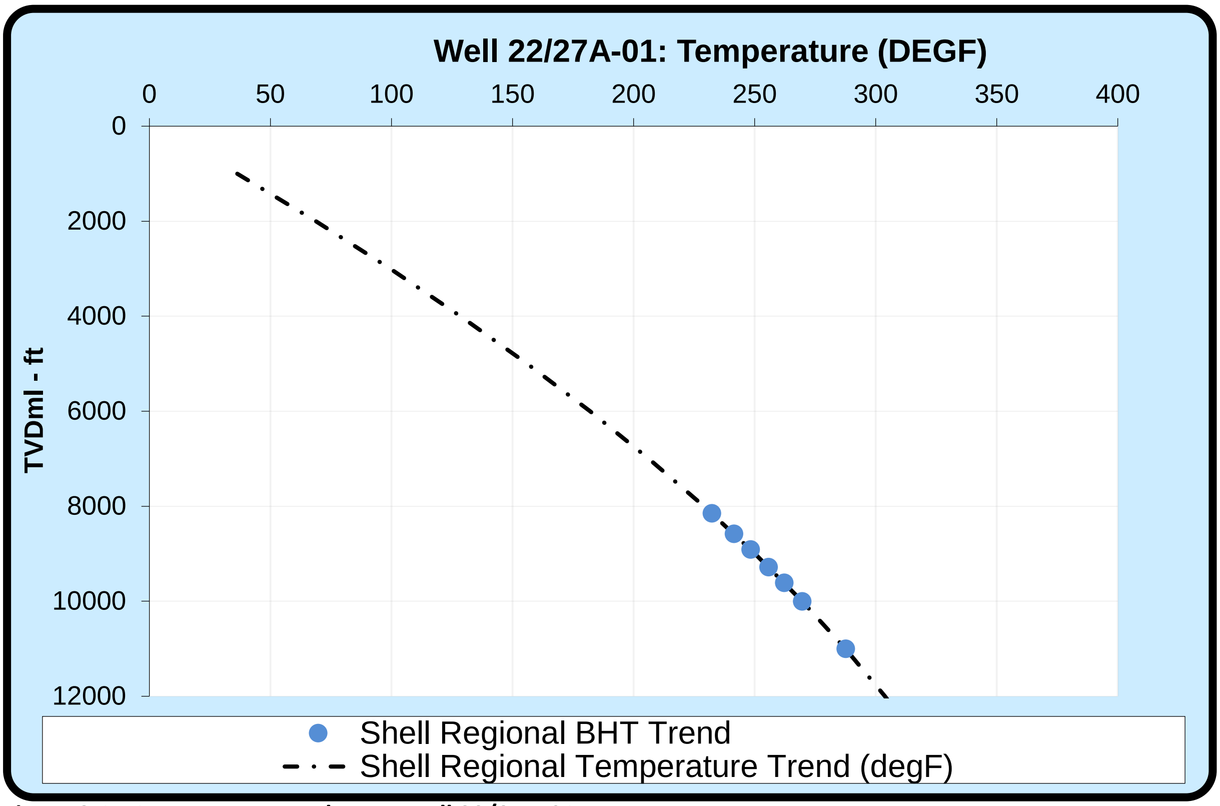


Figure 3.15.1 - Temperature data at Well 22/27A-01

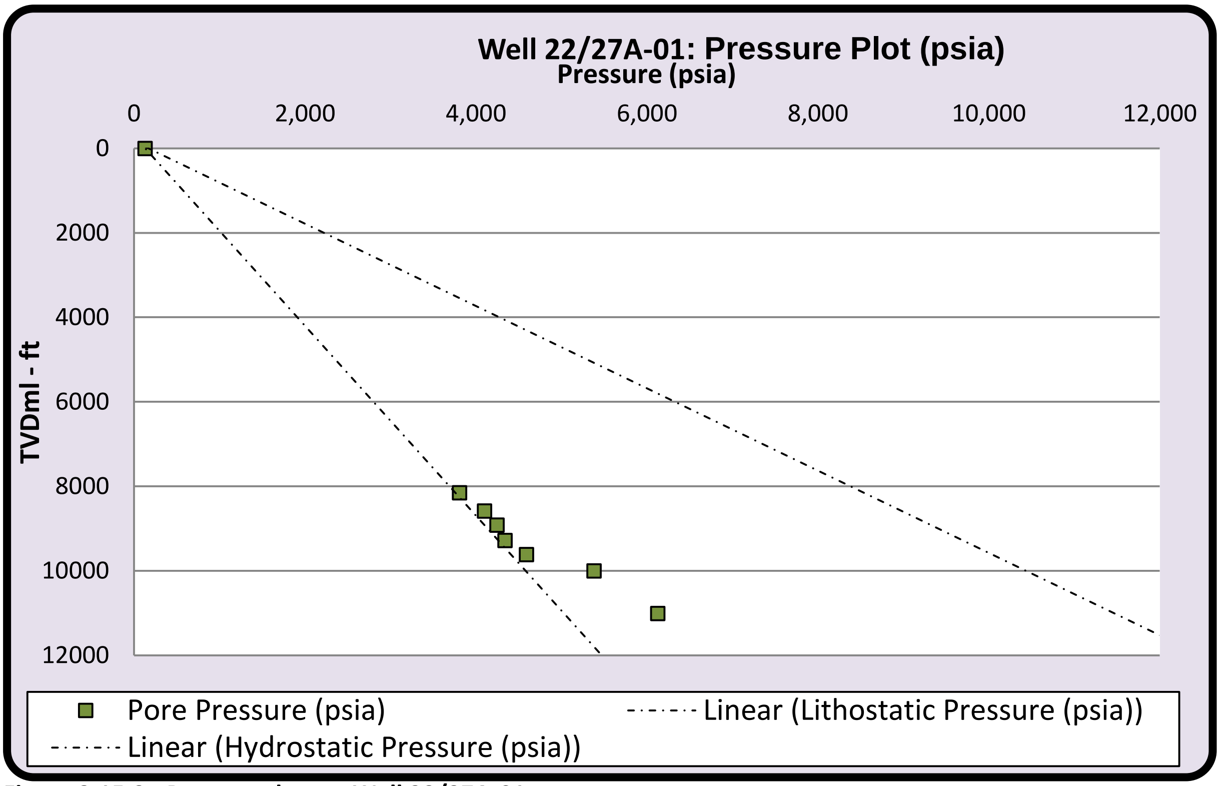


Figure 3.15.2 - Pressure data at Well 22/27A-01

The temperature and pressure data for the formation mid-points in Well 22/27A-01 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/27A-01	Sea Bed	382.0	297.0	0.0	39.2	132.2	132.2	132.2	0.0
22/27A-01	Horda	8538.5	8450.3	8153.3	232.4	3760.4	3810.4	8285.4	4475.1
22/27A-01	Balder	8967.0	8878.4	8581.4	241.5	3950.9	4100.9	8713.6	4612.7
22/27A-01	Sele	9302.5	9213.6	8916.6	248.5	4100.1	4250.1	9048.8	4798.7
22/27A-01	Lista	9669.6	9580.4	9283.4	255.9	4263.3	4343.3	9415.6	5072.3
22/27A-01	Maureen	10002.1	9912.7	9615.7	262.4	4411.2	4595.2	9747.9	5152.7
22/27A-01	Ekofisk	10389.8	10300.3	10003.3	269.7	4583.6	5383.6	10135.5	4751.9
22/27A-01	Tor	11393.3	11303.6	11006.6	287.7	5030.1	6130.1	11138.7	5008.7
22/27A-01	Hod	12714.5	12624.3	12327.3	308.9	5617.8	8917.8	12459.5	3541.7

Table 3.15.1 - Summary of mid-point temperature and pressure data at Well 22/27A-01

Fluid data

A summary of the fluid set parameters at Well 22/27A-01 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/27A-01	Horda	94000	730	40.2	0.71	0.71
22/27A-01	Balder	94000	730	40.6	0.71	0.71
22/27A-01	Sele	94000	730	41.0	0.71	0.71
22/27A-01	Lista	94000	730	41.4	0.71	0.71
22/27A-01	Maureen	94000	730	41.7	0.71	0.71
22/27A-01	Ekofisk	94000	730	42.2	0.71	0.71
22/27A-01	Tor	94000	730	43.3	0.71	0.71
22/27A-01	Hod	94000	730	44.7	0.71	0.71

Table 3.15.2 - Summary of fluid parameter data at Well 22/27A-01

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.15.3 - Constant mineral properties used in this project

There is no Tuff present in this well.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/27A-01	Horda	PAY	747.000	0.000	0.000	0.000	0.000	0.000	0.000
22/27A-01	Horda	RES	747.000	6.000	0.008	1.048	0.175	0.956	0.350
22/27A-01	Balder	PAY	110.000	0.000	0.000	0.000	0.000	0.000	0.000
22/27A-01	Balder	RES	110.000	42.500	0.386	7.717	0.182	0.977	0.179
22/27A-01	Sele	PAY	561.000	0.000	0.000	0.000	0.000	0.000	0.000
22/27A-01	Sele	RES	561.000	284.250	0.507	50.940	0.179	0.974	0.231
22/27A-01	Lista	PAY	173.130	0.000	0.000	0.000	0.000	0.000	0.000
22/27A-01	Lista	RES	173.130	79.250	0.458	12.463	0.157	0.973	0.157
22/27A-01	Maureen	PAY	491.870	0.000	0.000	0.000	0.000	0.000	0.000
22/27A-01	Maureen	RES	491.870	233.500	0.475	36.373	0.156	0.992	0.150
22/27A-01	Ekofisk	PAY	283.610	0.000	0.000	0.000	0.000	0.000	0.000
22/27A-01	Ekofisk	RES	283.610	108.500	0.383	10.271	0.095	0.975	0.085
22/27A-01	Tor	PAY	1723.390	4.000	0.002	0.441	0.110	0.467	0.000
22/27A-01	Tor	RES	1723.390	559.000	0.324	29.653	0.053	0.949	0.014
22/27A-01	Hod	PAY	919.000	0.000	0.000	0.000	0.000	0.000	0.000
22/27A-01	Hod	RES	919.000	604.750	0.658	25.246	0.042	0.992	0.183

Table 3.15.4 - Petrophysical parameters used at Well 22/27A-01

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

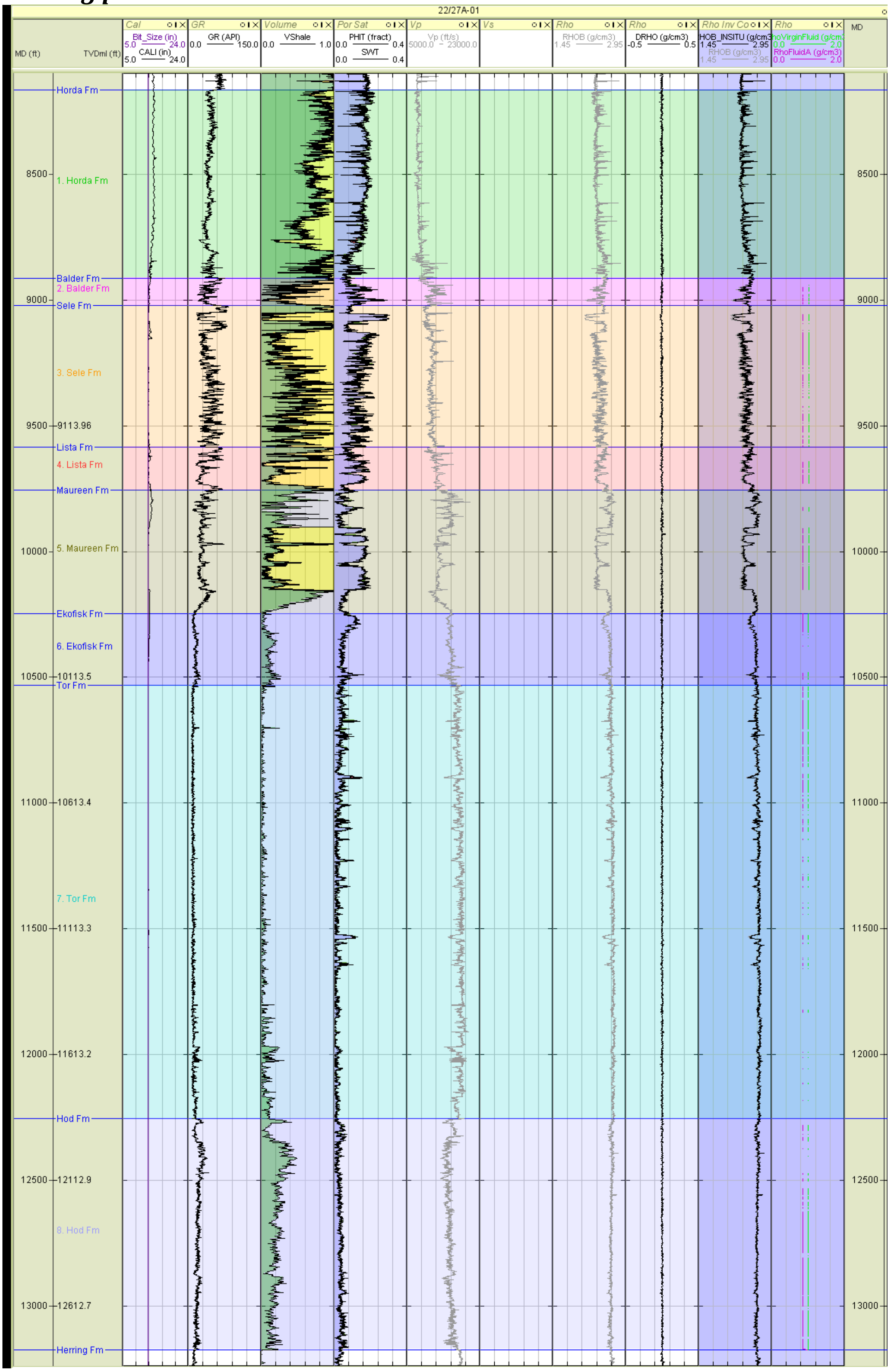


Figure 3.15.3 - Well Panel: Measured data and invasion correction for well 22/27A-01.

Well log panel – log editing and audit

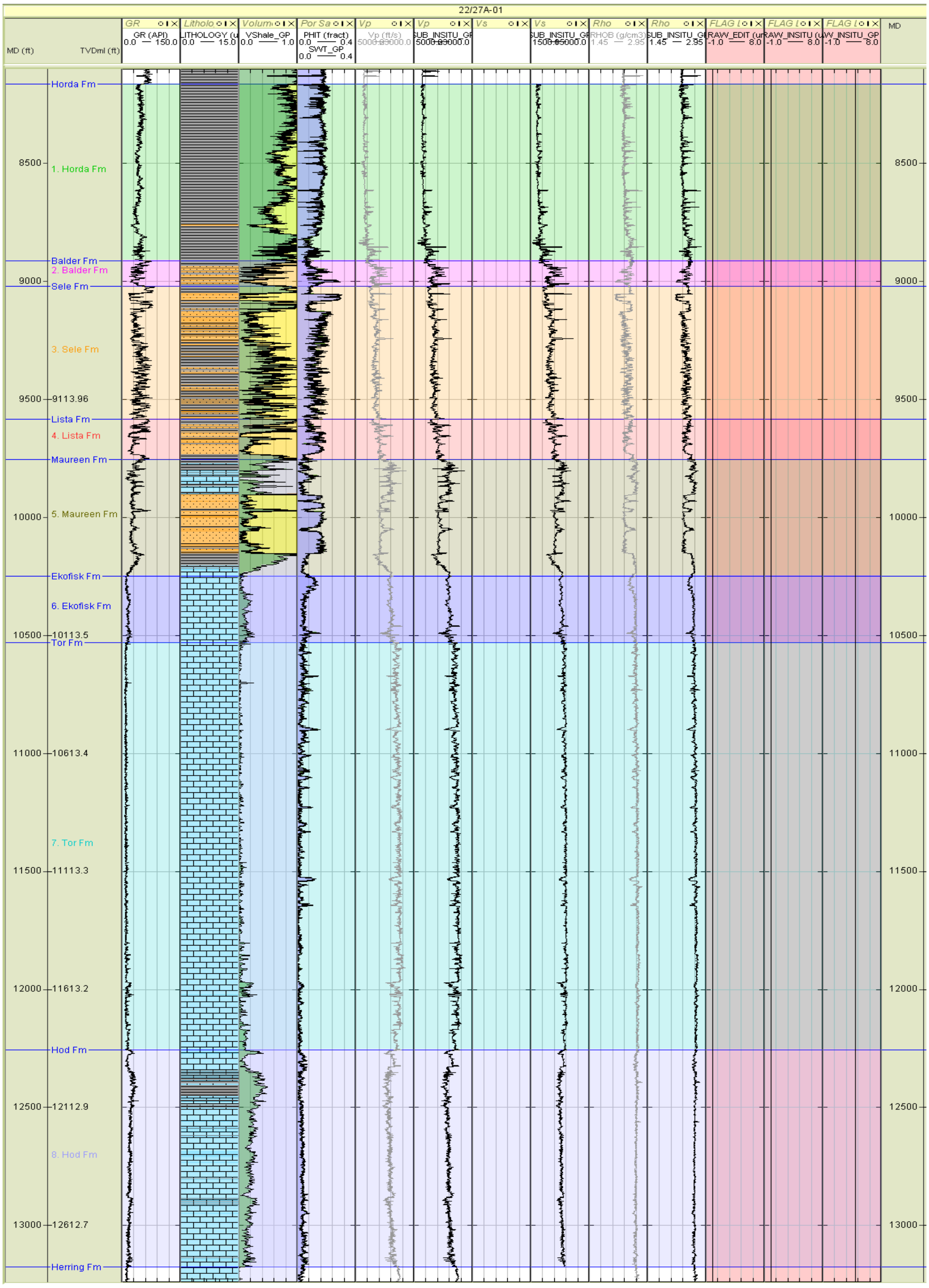


Figure 3.15.4 - Well Panel: Log edits for well 22/27A-01.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**

Flag = 3 Edit in Rho and Vs	Flag = 7 Edit in Vp, Vs and Rho

Well log panel – synthetic curves

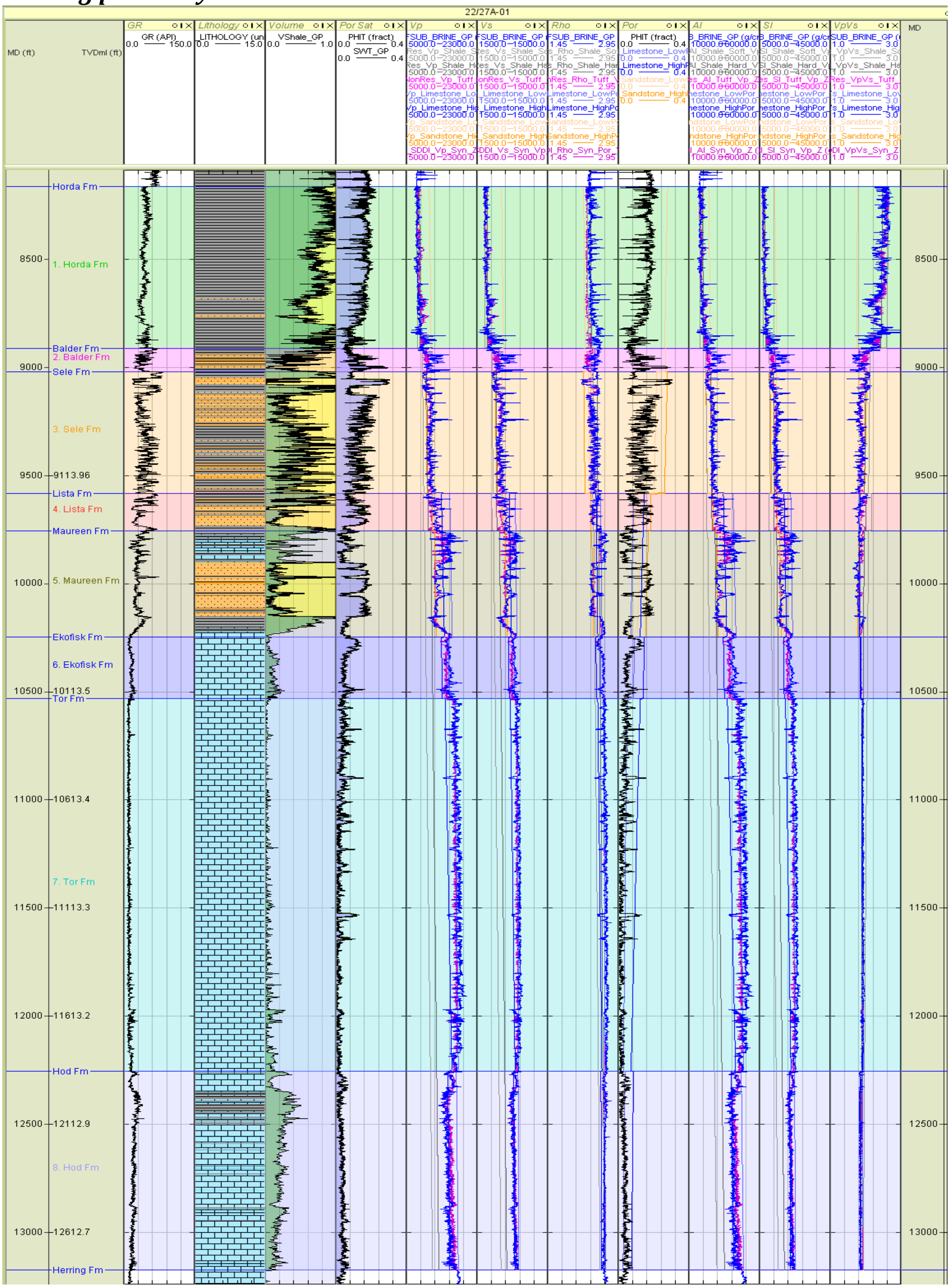


Figure 3.15.5 - Well Panel: End-member and synthetic logs for well 22/27A-01.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

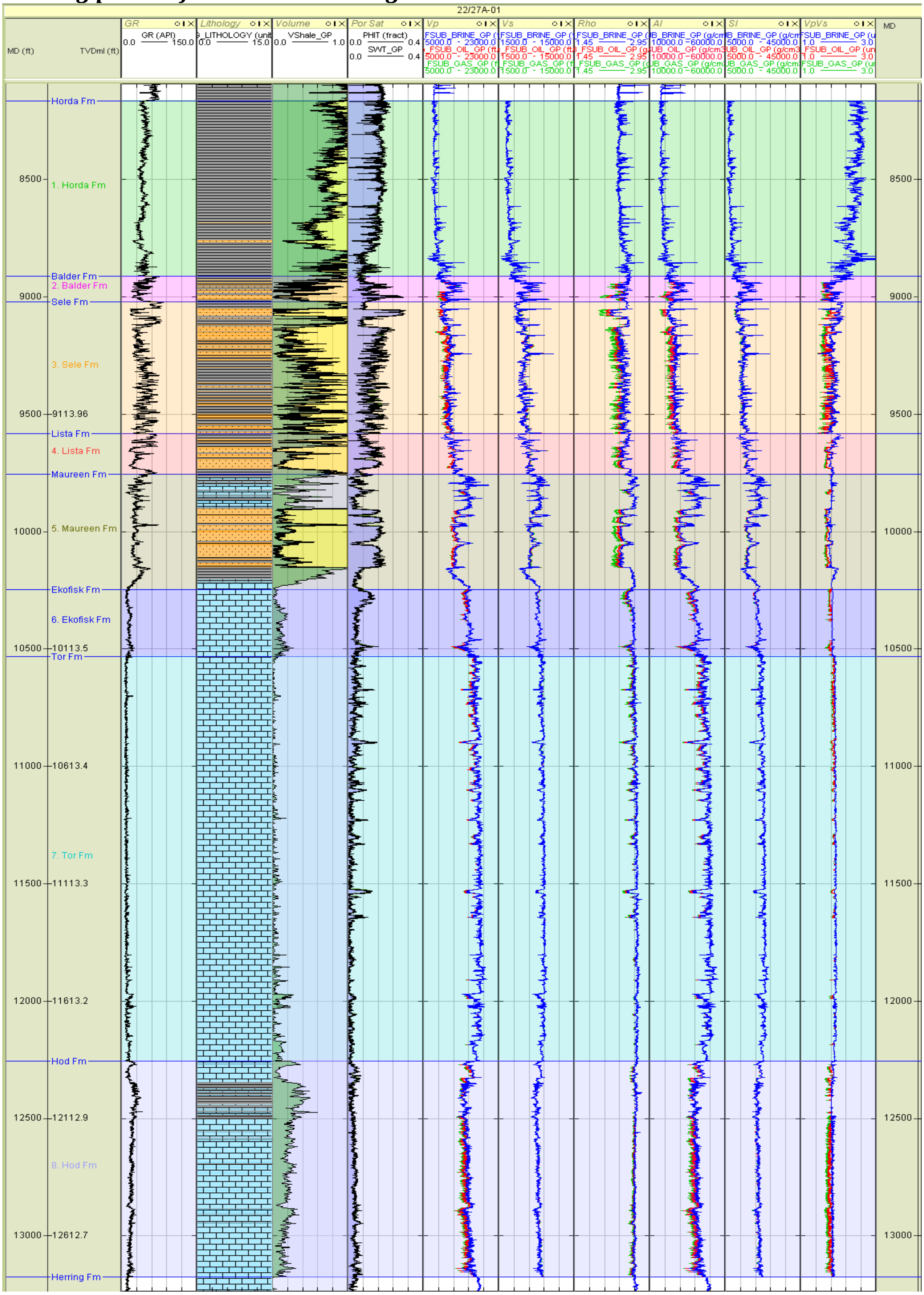


Figure 3.15.6 - Well Panel: Fluid substituted and elastic logs for well 22/27A-01.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/27A-01 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/27A-01	Horda	7820	3149	2.37
22/27A-01	Balder	9677	4876	2.51
22/27A-01	Sele	10139	5133	2.51
22/27A-01	Lista	11394	5942	2.52
22/27A-01	Maureen	12214	6467	2.58

Table 3.15.5 - Clean shale properties at Well 22/27A-01

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/27A-01	Horda	100% Brine			
22/27A-01	Balder	100% Brine	11771	6615	2.36
22/27A-01	Sele	100% Brine	11442	6375	2.35
22/27A-01	Lista	100% Brine	12669	7082	2.41
22/27A-01	Maureen	100% Brine	13102	7430	2.40
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/27A-01	Horda	80% Oil			
22/27A-01	Balder	80% Oil	11097	6675	2.32
22/27A-01	Sele	80% Oil	10627	6445	2.29
22/27A-01	Lista	80% Oil	12197	7139	2.37
22/27A-01	Maureen	80% Oil	12697	7493	2.36
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/27A-01	Horda	90% Gas			
22/27A-01	Balder	90% Gas	10975	6772	2.25
22/27A-01	Sele	90% Gas	10492	6556	2.21
22/27A-01	Lista	90% Gas	12159	7227	2.32
22/27A-01	Maureen	90% Gas	12676	7599	2.29

Table 3.15.6 - Clean sand properties at Well 22/27A-01 for each fluid case

Tertiary reservoirs – Well panel

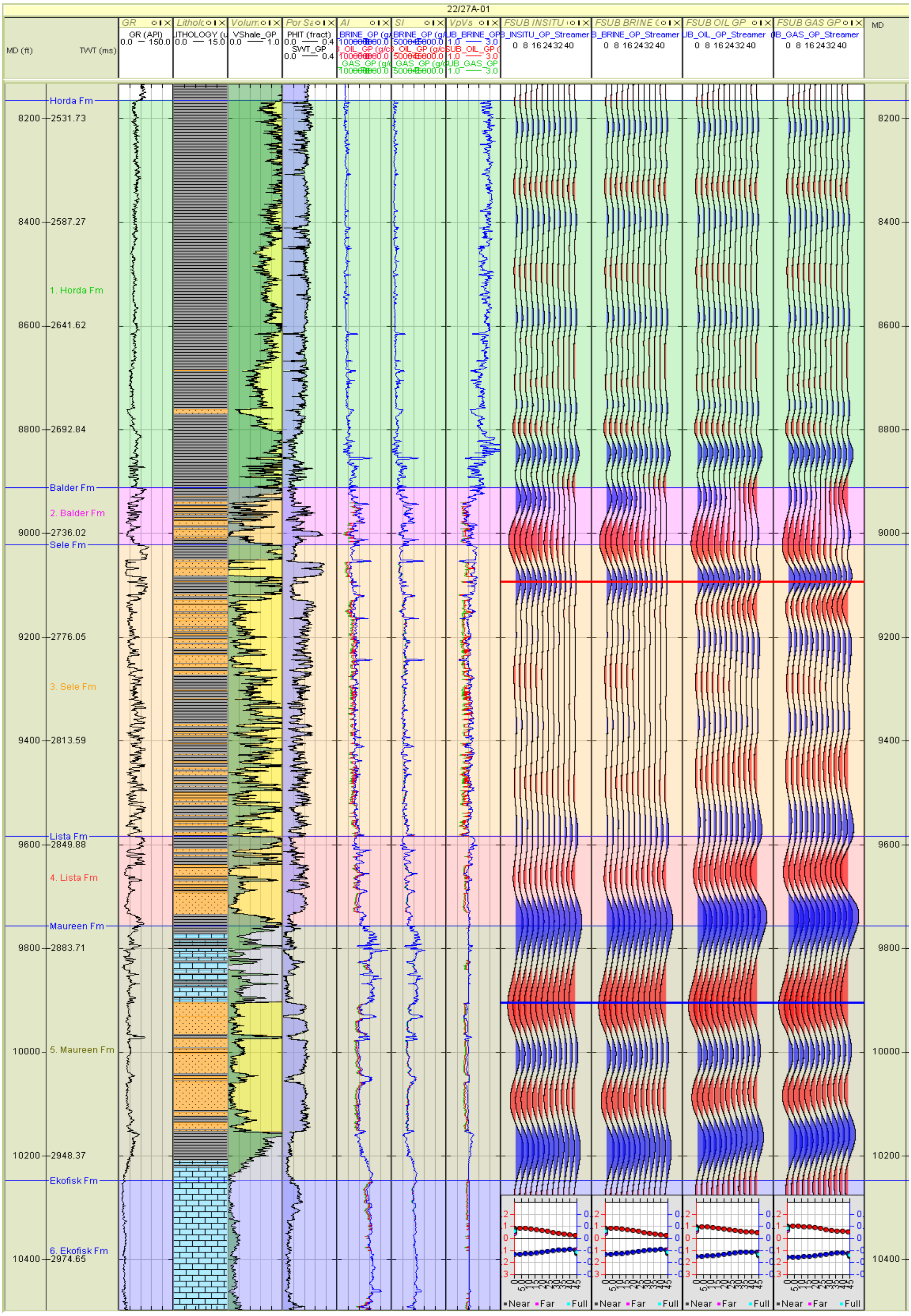


Figure 3.15.7 - Well Panel: Tertiary reservoirs for well 22/27A-01. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Balder Formation

- Reservoir is formed by a number of thin sands with inter-bedded shales. The highest porosity sand is associated with a thin bed, 14 feet thick, where the porosity is approximately 27%.
- Blocky AVO shows a modelled class I response for the 100% brine, a modelled class IIp response for the 80% oil case and a modelled class II response for the 90% gas case. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

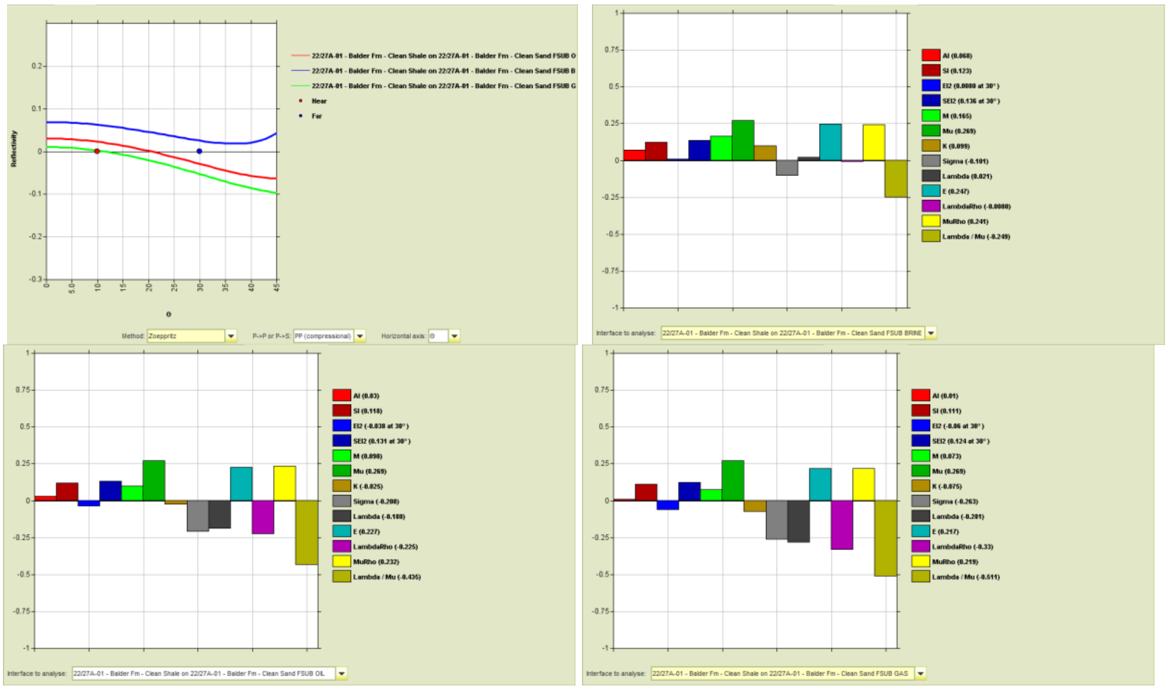


Figure 3.15.8 - Blocky AVO Model and Elastic Contrast Analysis for the Balder Formation in well 22/27A-01.

Sele Formation

- Reservoir is formed by a number of thin sands with inter-bedded shales. A high porosity sand package, approximately 28 feet thick, is present at the top of the interval. The porosity associated with these sands is approximately 30%. The porosity in the lower sections of the reservoir ranges from 10-23%.
- Blocky AVO shows a modelled class I response for the 100% brine and a modelled class III response for the 80% oil and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are low in amplitude in the brine case, but that the contrasts generally become stronger and negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

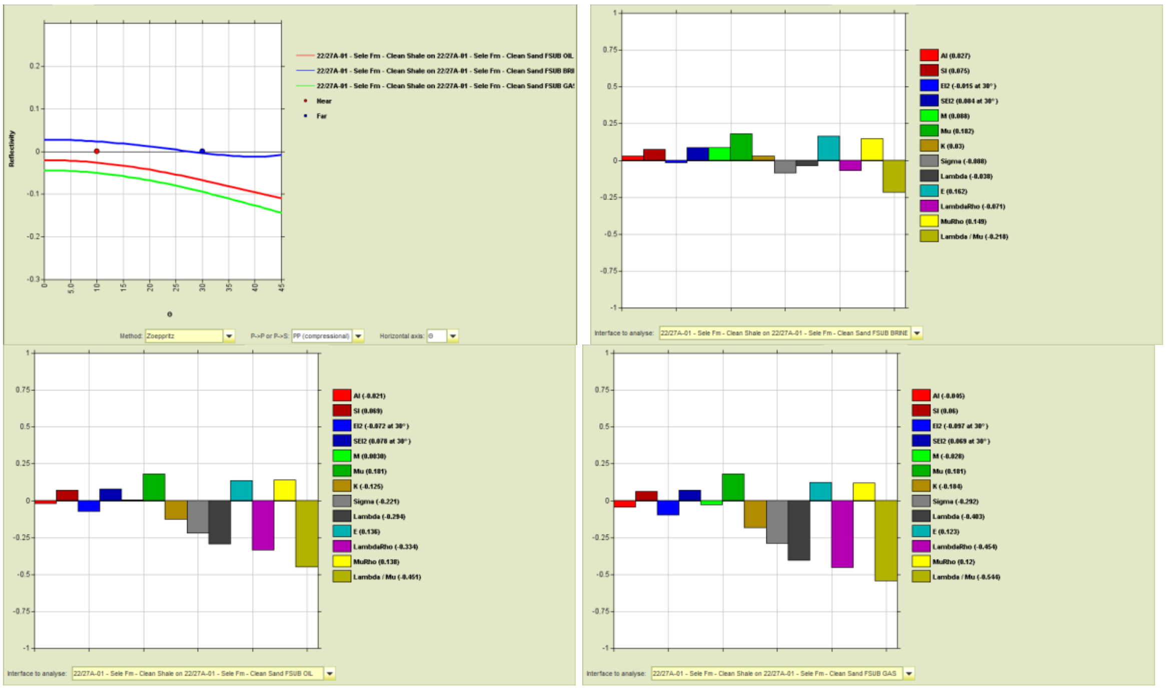


Figure 3.15.9 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/27A-01.

Lista Formation

- A thicker sand package is evident in Lista formation, but inter-bedded shale is still evident. The porosity associated with these sands is 12-18%.
- Blocky AVO shows a modelled class I response for the 100% brine and a modelled class II response for the 80% oil and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

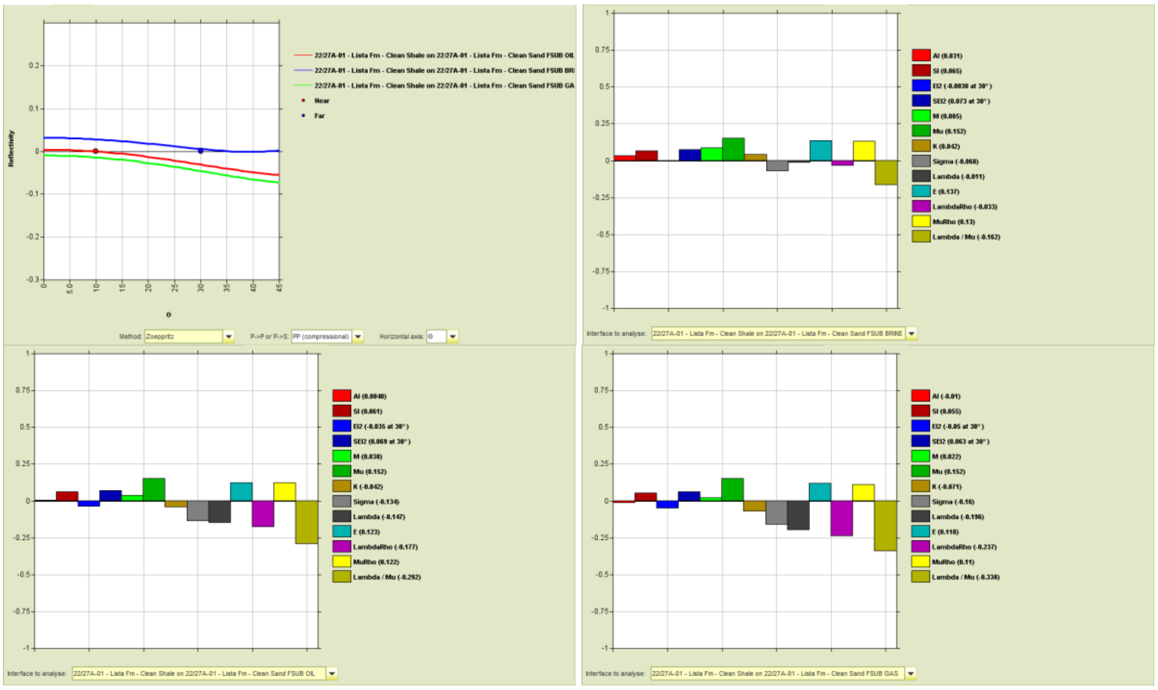


Figure 3.15.10 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/27A-01.

Maureen Formation

- Reservoir formed by a discrete sand package with a maximum porosity of 19% and net reservoir is approximately 95 feet. The reservoir sand is overlain directly by limestone in the upper section of the Maureen Fm.
- Blocky AVO shows a modelled class II response for the 100% brine case and a modelled class III response for the 80% oil and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

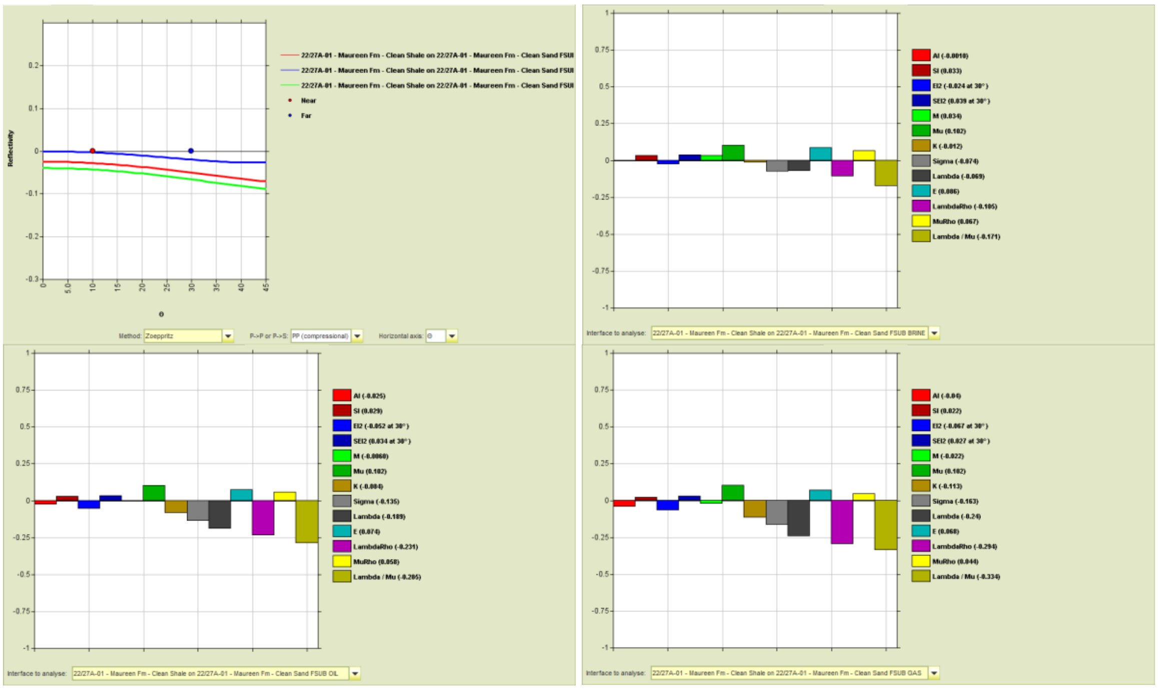


Figure 3.15.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/27A-01.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/27A-01 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/27A-01	Ekofisk	100% Brine	15889	8631	2.58
22/27A-01	Tor	100% Brine	17992	9381	2.67
22/27A-01	Hod	100% Brine	16821	9010	2.64
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/27A-01	Ekofisk	80% Oil	15575	8659	2.56
22/27A-01	Tor	80% Oil	17899	9389	2.66
22/27A-01	Hod	80% Oil	16449	9028	2.63
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/27A-01	Ekofisk	90% Gas	15532	8700	2.54
22/27A-01	Tor	90% Gas	17885	9400	2.66
22/27A-01	Hod	90% Gas	16327	9055	2.61

Table 3.15.7 - Clean limestone properties at Well 22/27A-01 for each fluid case

Cretaceous reservoirs

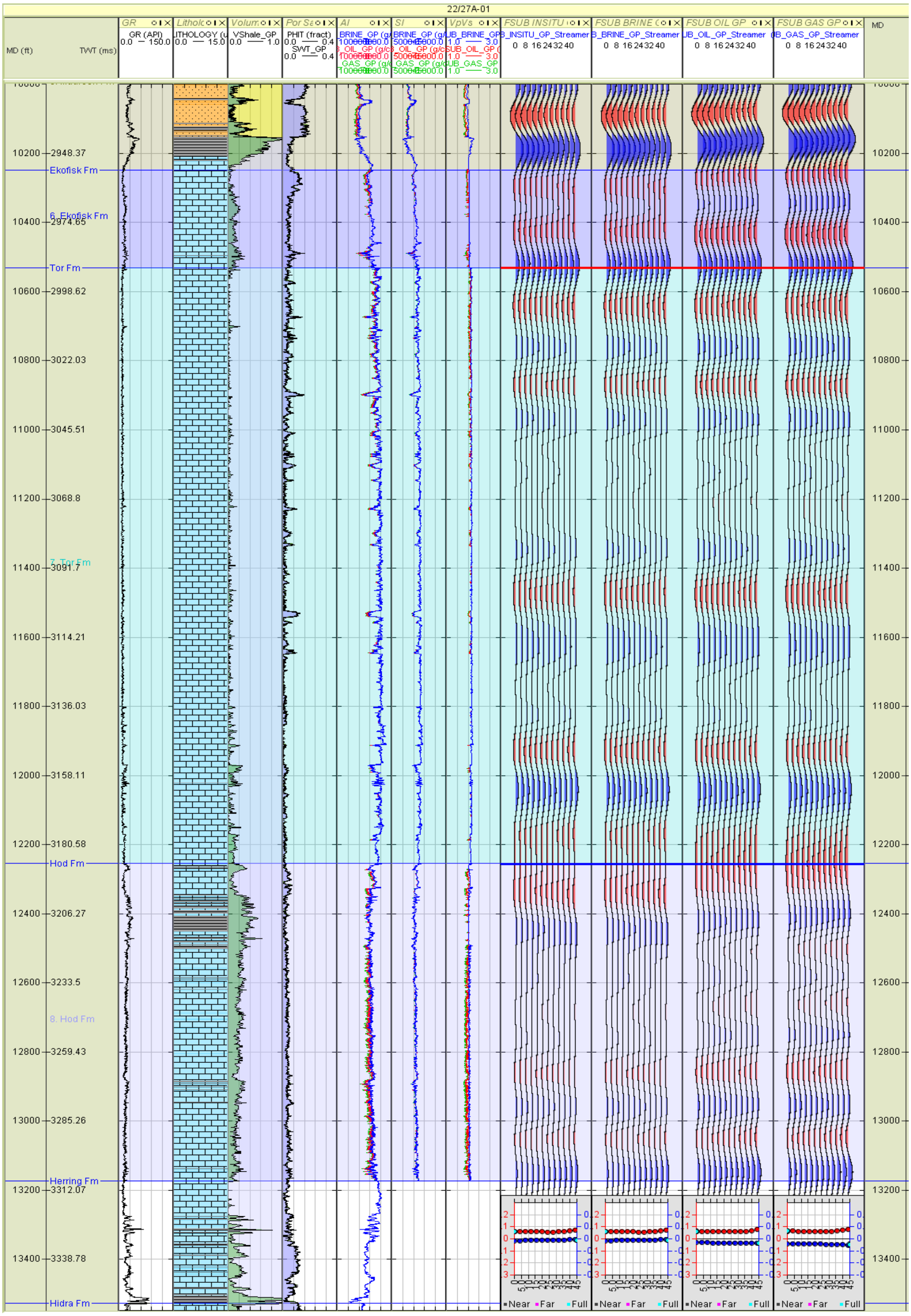


Figure 3.15.12 - Well Panel: Cretaceous reservoirs for well 22/27A-01. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the top section of the Ekofisk Fm and the porosity in this section is approximately 12%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons. This AVO response can't be compared to the synthetic gathers since the overburden section of the Maureen Fm is sand at this well.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine and oil cases, but a number of attributes turn negative and decrease in amplitude with the addition of gas. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

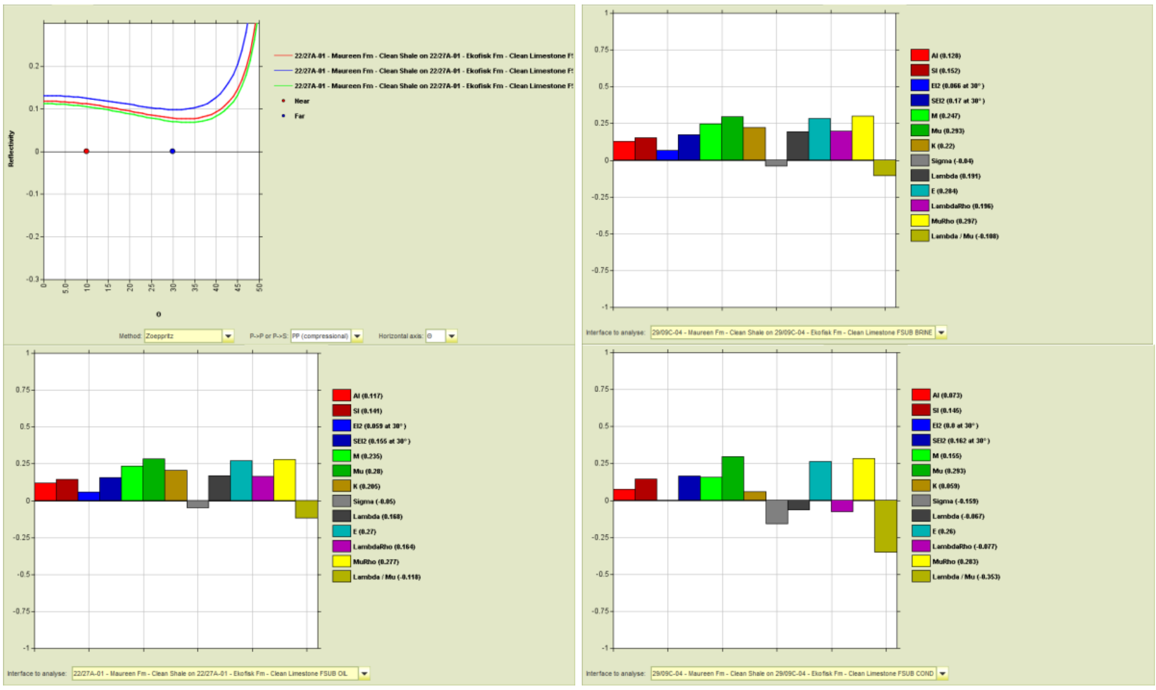


Figure 3.15.13 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/27A-01.

Tor Formation

- Reservoir formed by a clean limestone formation. The highest porosity reservoir is found in the top section of the Tor Fm, where porosities range from 10-14%, decreasing to 1-5% at the base of the formation. Thin beds of high porosity chalk are found throughout the Tor Fm and could be representative of reworked chalk zones. The maximum porosity observed in such layers is 15%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in all the fluid cases. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

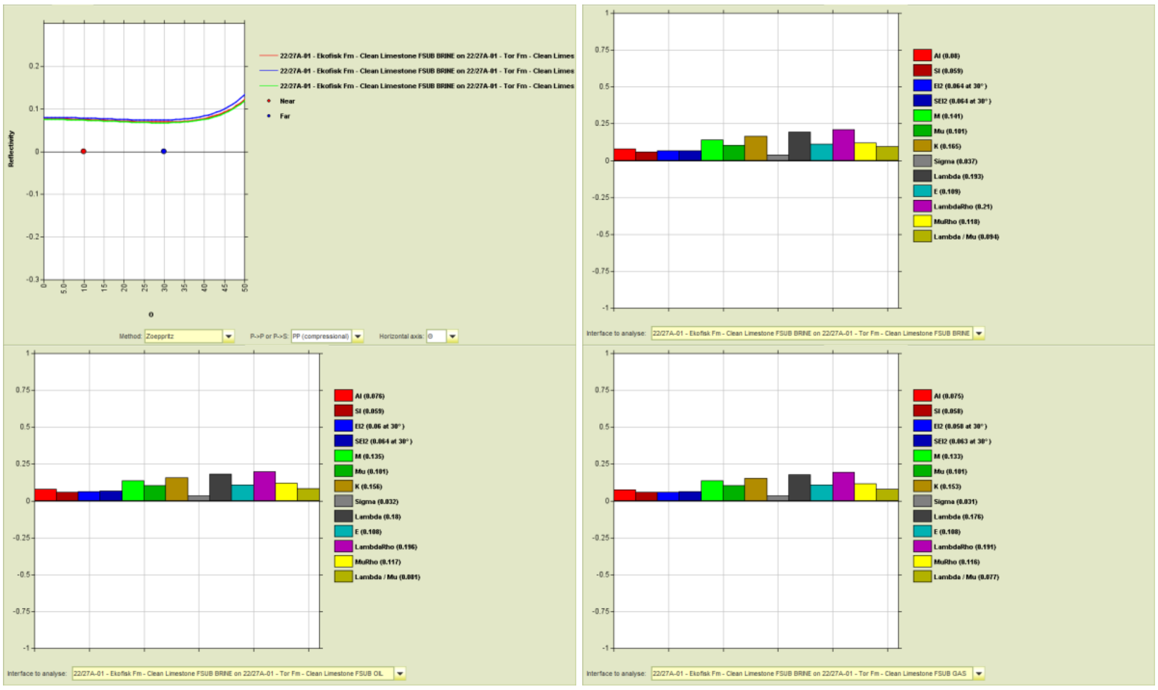


Figure 3.15.14 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/27A-01.

Hod Formation

- Reservoir formed by a limestone formation with a greater component of shale. The reservoir is low porosity throughout, approximately 3-6%.
- Blocky AVO shows a modelled class III response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are all negative and very low in amplitude in all of the fluid cases, but a number of attributes increase in amplitude with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

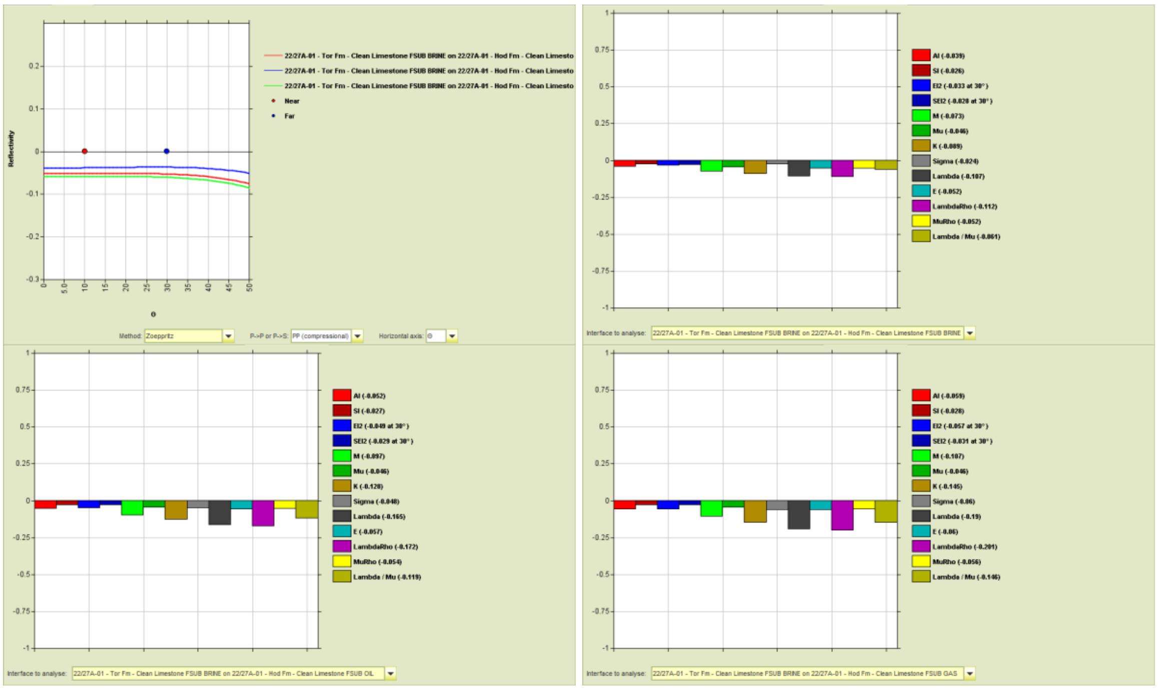


Figure 3.15.15 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/27A-01.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/27A-01 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/27A-01	Overburden	Shale	7741		2.35
22/27A-01	Underburden	Limestone	16293		2.60

Table 3.15.8 - Overburden and underburden properties at Well 22/27A-01.

Well: 22/28A-01

General

Well Information
Phillips exploration well, completed and abandoned in 1988.

Objectives
The primary objective of the well 22/28A-01 was to test the hydrocarbon potential of the Fulmar and Skagerrak intervals. Further objectives were anticipated in the Palaeocene sands and Upper Cretaceous chalk. No shows were encountered in either of the primary objectives. The Palaeocene sands had no shows while drilling. Gas shows were detected in the Chalk.

Log conditioning overview
Two small sections of poor Vp data were removed in the Horda Fm at 9110ft MD and 9120ft MD. A further small section of Vp data was edited out of the Balder Fm at 9290ft MD.

Invasion correction

Well 22/28A-01 was drilled with oil-based drilling mud. Invasion correction has been performed within all formations containing reservoir intervals.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log. The only exception is a minor gap within the Vp log over a hydrocarbon zone in the Hod Formation and the methodology for filling this gap is documented within the Rock Physics Part 2 PowerPoints.

Log modelling was performed to fill gaps within the Horda, Balder, Lista, Tor and Hod Formations for Vp and within the Horda Formation for density. A complete Vs log is modelled since a measured Vs log is not available at this well. A gap was also filled above the interval of interest in the Vp log using a spline function.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 22/28A-01 is displayed in the figures below;

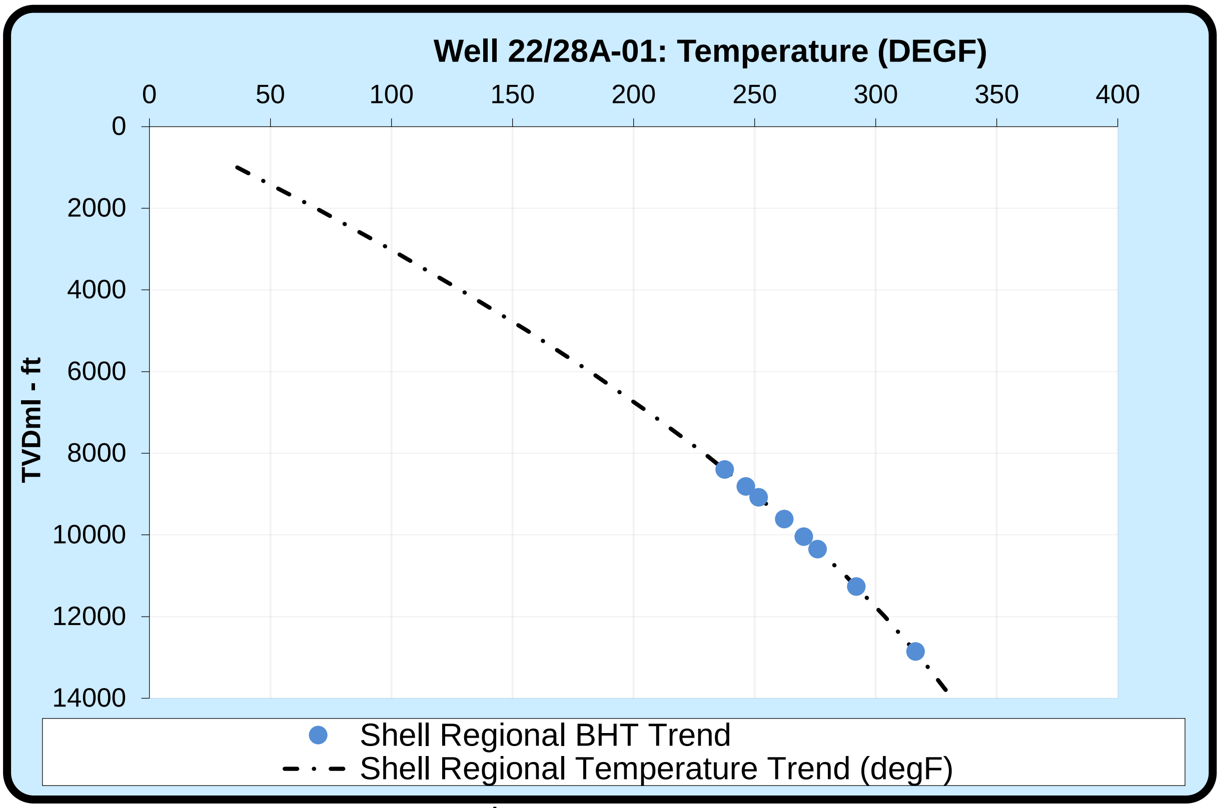


Figure 3.16.1 - Temperature data at Well 22/28A-01

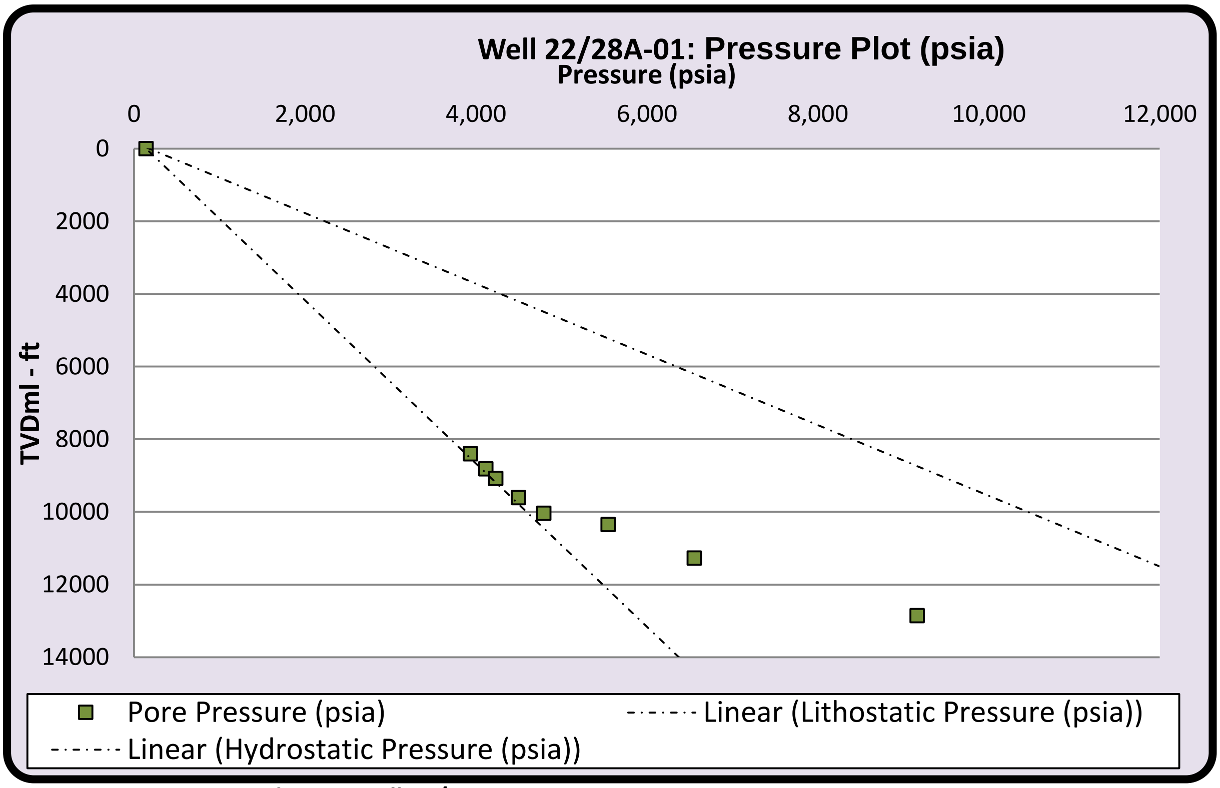


Figure 3.16.2 - Pressure data at Well 22/28A-01

The temperature and pressure data for the formation mid-points in Well 22/28A-01 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydrostatic Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/28A-01	Sea Bed	450.0	320.0	0.0	39.2	142.4	142.4	142.4	0.0
22/28A-01	Horda	8853.0	8723.0	8403.0	237.8	3881.7	3936.7	8545.4	4608.7
22/28A-01	Balder	9269.5	9139.5	8819.5	246.5	4067.1	4119.1	8961.9	4842.8
22/28A-01	Sele	9530.0	9400.0	9080.0	251.8	4183.0	4235.0	9222.4	4987.4
22/28A-01	Lista	10062.2	9932.2	9612.2	262.3	4419.8	4499.8	9754.6	5254.8
22/28A-01	Maureen	10492.2	10362.2	10042.2	270.5	4611.2	4795.2	10184.6	5389.4
22/28A-01	Ekofisk	10797.5	10667.5	10347.5	276.1	4747.0	5547.0	10489.9	4942.9
22/28A-01	Tor	11720.0	11590.0	11270.0	292.1	5157.6	6557.6	11412.4	4854.9
22/28A-01	Hod	13310.0	13180.0	12860.0	316.6	5865.1	9165.1	13002.4	3837.3

Table 3.16.1 - Summary of mid-point temperature and pressure data at Well 22/28A-01

Fluid data

A summary of the fluid set parameters at Well 22/28A-01 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/28A-01	Horda	74000	730	40.4	0.71	0.71
22/28A-01	Balder	74000	730	40.9	0.71	0.71
22/28A-01	Sele	74000	730	41.2	0.71	0.71
22/28A-01	Lista	74000	730	41.7	0.71	0.71
22/28A-01	Maureen	74000	730	42.2	0.71	0.71
22/28A-01	Ekofisk	74000	730	42.5	0.71	0.71
22/28A-01	Tor	74000	730	43.5	0.71	0.71
22/28A-01	Hod	74000	730	45.3	0.71	0.71

Table 3.16.2 - Summary of fluid parameter data at Well 22/28A-01

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.16.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	14.56	7.88	2.41	5,937	10,590

Table 3.16.4 - Tuff properties used at Well 22/28A-01

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/28A-01	Horda	PAY	782.020	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-01	Horda	RES	782.020	43.500	0.056	9.936	0.228	0.882	0.178
22/28A-01	Balder	PAY	50.980	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-01	Balder	RES	50.980	9.000	0.177	1.791	0.199	0.814	0.060
22/28A-01	Sele	PAY	470.000	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-01	Sele	RES	470.000	324.000	0.689	62.942	0.194	0.969	0.147
22/28A-01	Lista	PAY	594.420	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-01	Lista	RES	594.420	153.670	0.259	21.899	0.143	0.972	0.163
22/28A-01	Maureen	PAY	265.600	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-01	Maureen	RES	265.600	133.830	0.504	13.463	0.101	0.943	0.203
22/28A-01	Ekofisk	PAY	345.000	0.500	0.001	0.046	0.093	0.499	0.105
22/28A-01	Ekofisk	RES	345.000	278.000	0.806	26.305	0.095	0.923	0.129
22/28A-01	Tor	PAY	1500.000	18.000	0.012	1.780	0.099	0.432	0.010
22/28A-01	Tor	RES	1500.000	1015.01	0.677	64.790	0.064	0.959	0.020
22/28A-01	Hod	PAY	1680.000	50.500	0.030	6.952	0.138	0.389	0.095
22/28A-01	Hod	RES	1680.000	1426.22	0.849	123.643	0.087	0.906	0.256

Table 3.16.5 - Petrophysical parameters used at Well 22/28A-01

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

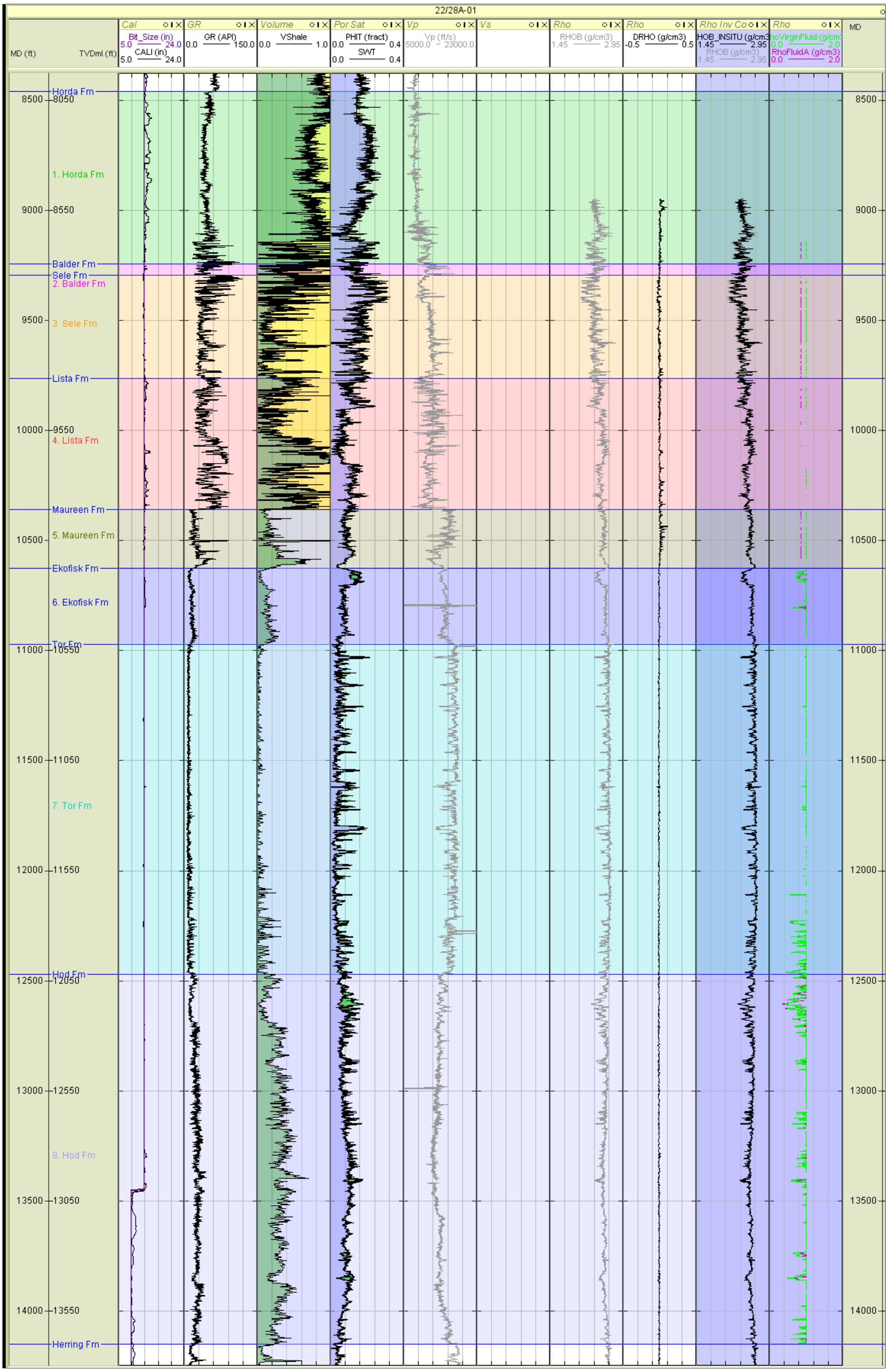


Figure 3.16.3 - Well Panel: Measured data and invasion correction for well 22/28A-01.

Well log panel – log editing and audit

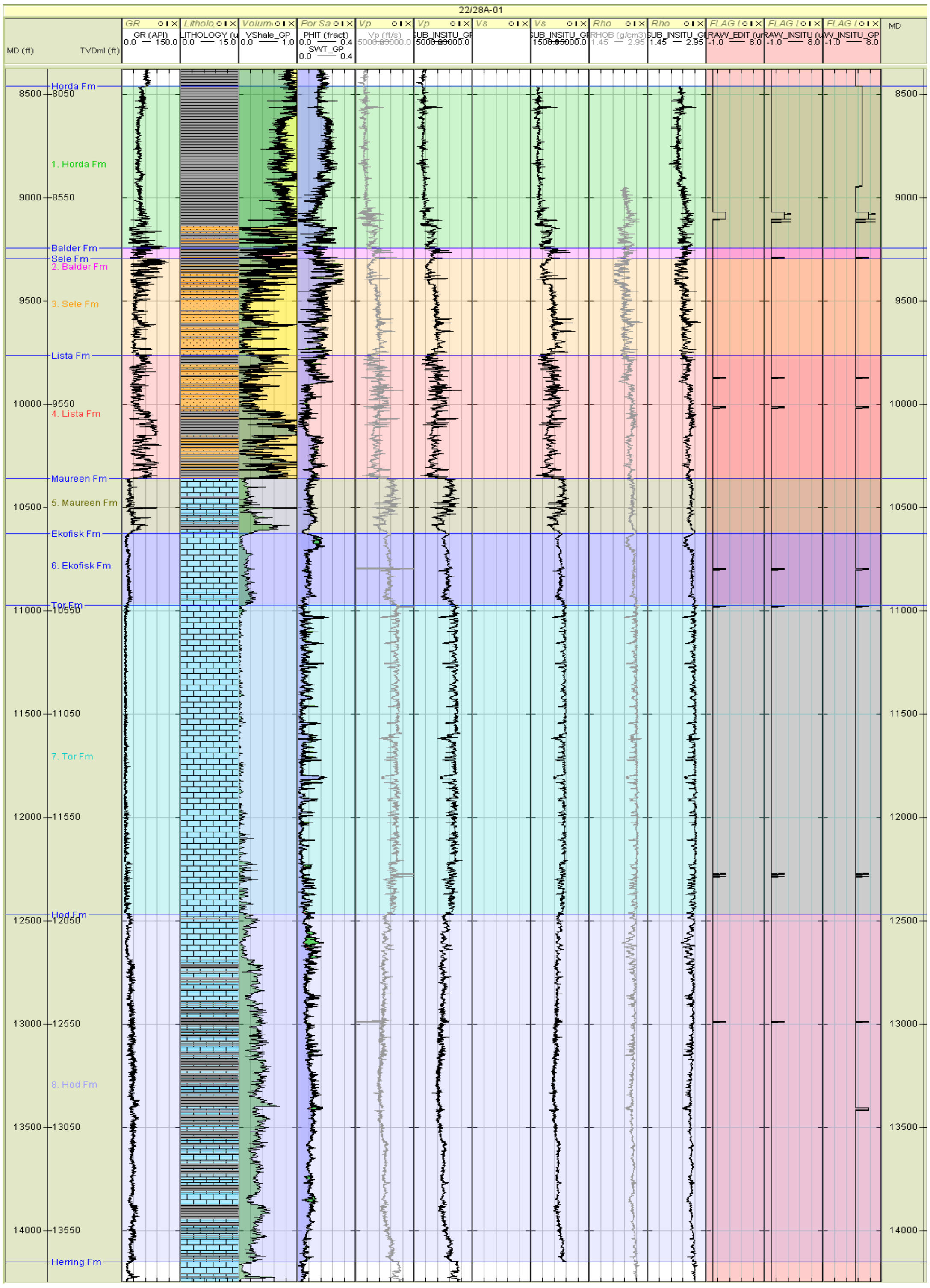


Figure 3.16.4 - Well Panel: Log edits for well 22/28A-01.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**

Flag = 3 Edit in Rho and Vs	Flag = 7 Edit in Vp, Vs and Rho

Well log panel – synthetic curves

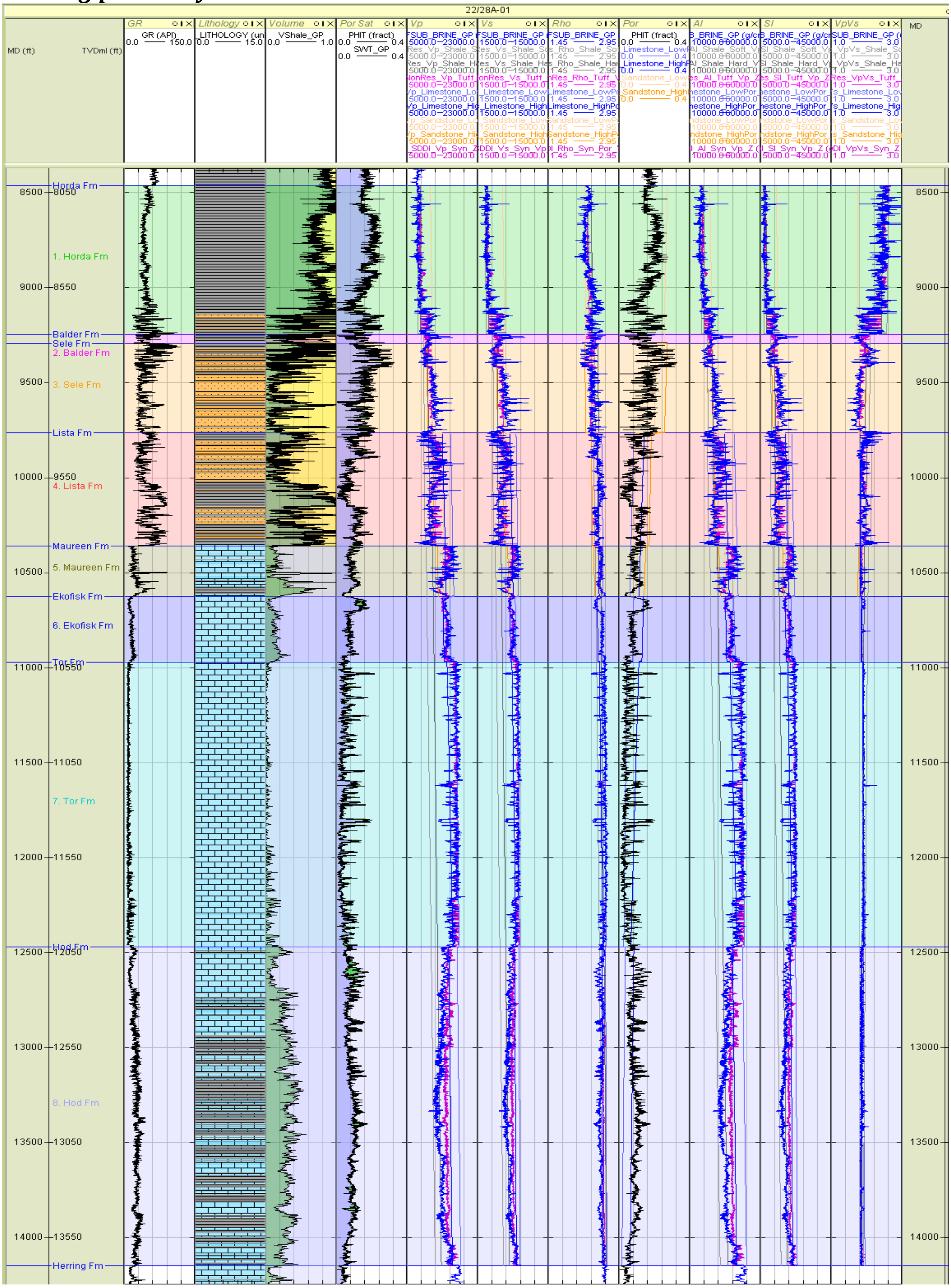


Figure 3.16.5 - Well Panel: End-member and synthetic logs for well 22/28A-01.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

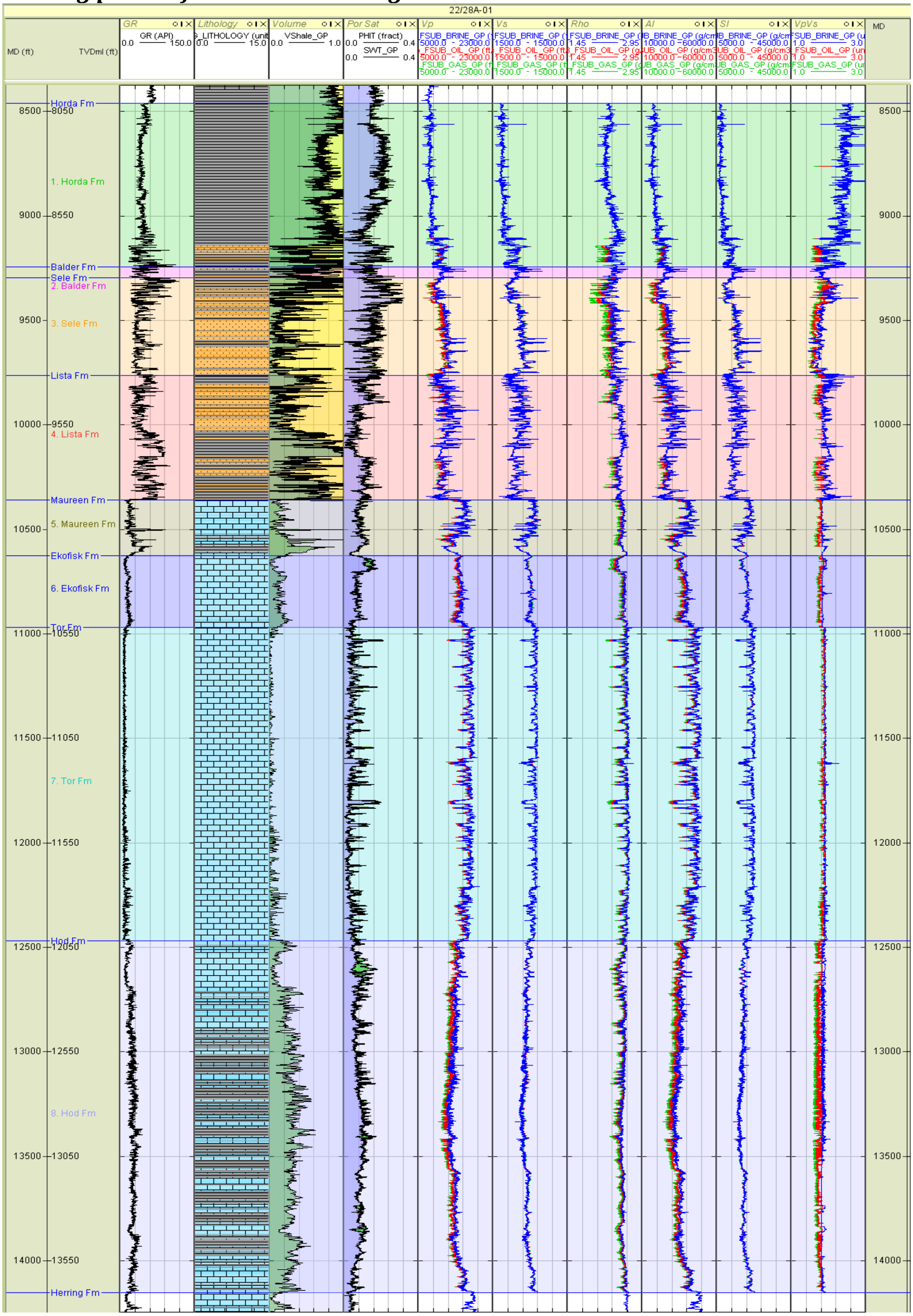


Figure 3.16.6 - Well Panel: Fluid substituted and elastic logs for well 22/28A-01.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/28A-01 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-01	Horda	8106	3351	2.33
22/28A-01	Balder	10352	5503	2.49
22/28A-01	Sele	10066	5077	2.43
22/28A-01	Lista	10480	5265	2.52
22/28A-01	Maureen	11304	5826	2.50

Table 3.16.6 - Clean shale properties at Well 22/28A-01

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-01	Horda	100% Brine	11242	6329	2.26
22/28A-01	Balder	100% Brine			
22/28A-01	Sele	100% Brine	11611	6546	2.34
22/28A-01	Lista	100% Brine	12683	6850	2.47
22/28A-01	Maureen	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-01	Horda	80% Oil	10516	6424	2.20
22/28A-01	Balder	80% Oil			
22/28A-01	Sele	80% Oil	10851	6613	2.29
22/28A-01	Lista	80% Oil	12274	6879	2.45
22/28A-01	Maureen	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-01	Horda	90% Gas	10466	6584	2.09
22/28A-01	Balder	90% Gas			
22/28A-01	Sele	90% Gas	10735	6723	2.22
22/28A-01	Lista	90% Gas	12195	6926	2.42
22/28A-01	Maureen	90% Gas			

Table 3.16.7 - Clean sand properties at Well 22/28A-01 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-01	Maureen	100% Brine	15,552	8,526	2.56
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/28A-01	Maureen	80% Oil	15,287	8,552	2.55
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/28A-01	Maureen	90% Gas	15,257	8,591	2.52

Table 3.16.8 - Clean limestone properties at Well 22/28A-01 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

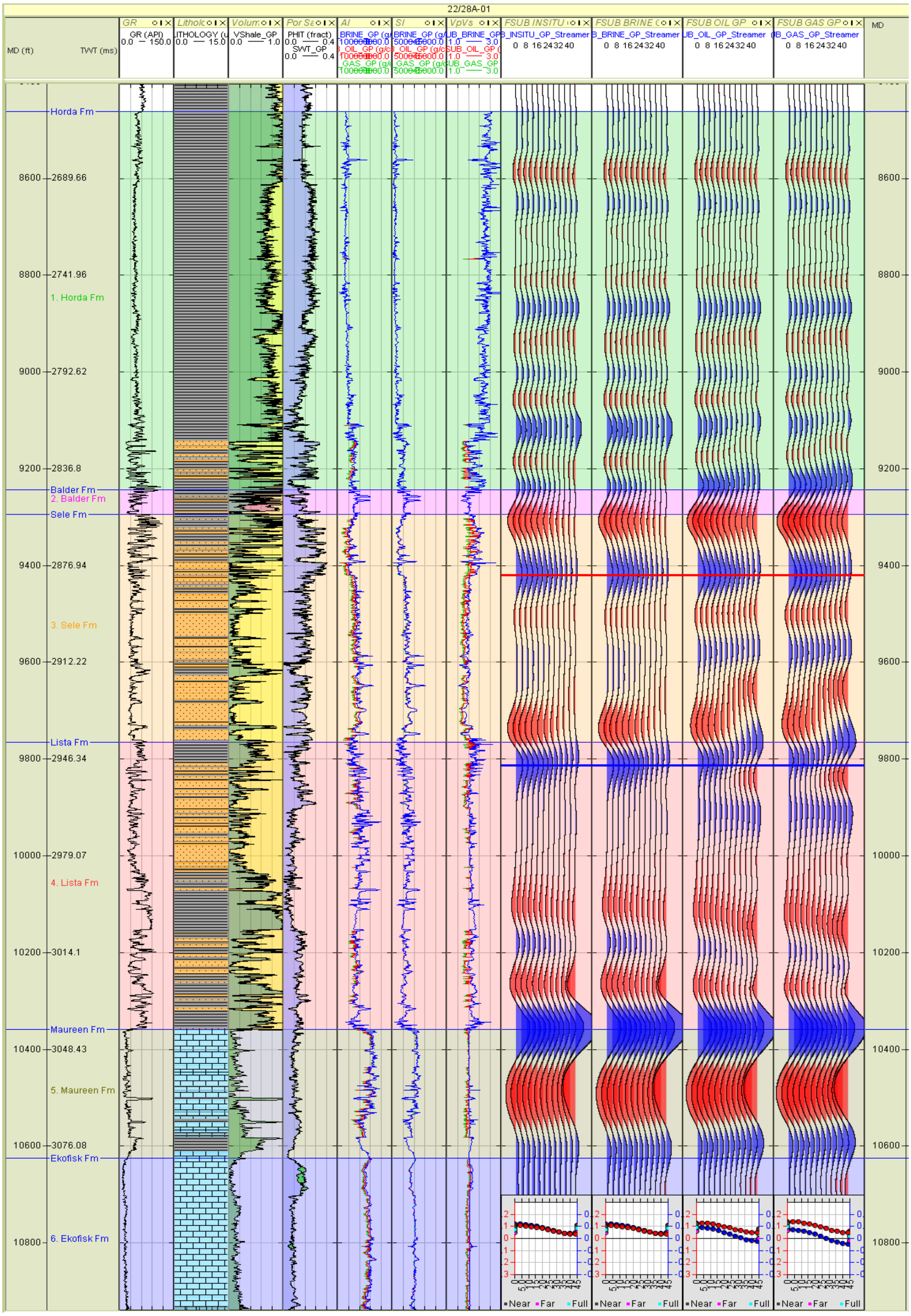


Figure 3.16.7 - Well Panel: Tertiary reservoirs for well 22/28A-01. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir formed by discrete sand packages encased in shale. The first of these sand packages is approximately 10 foot with an associated maximum porosity of 27%. The reservoir sand is overlain directly by overburden shale in the upper section of the Horda formation.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases and a modelled class IIp response for the 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and of medium amplitude in all the fluid cases, but several attributes turn negative with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

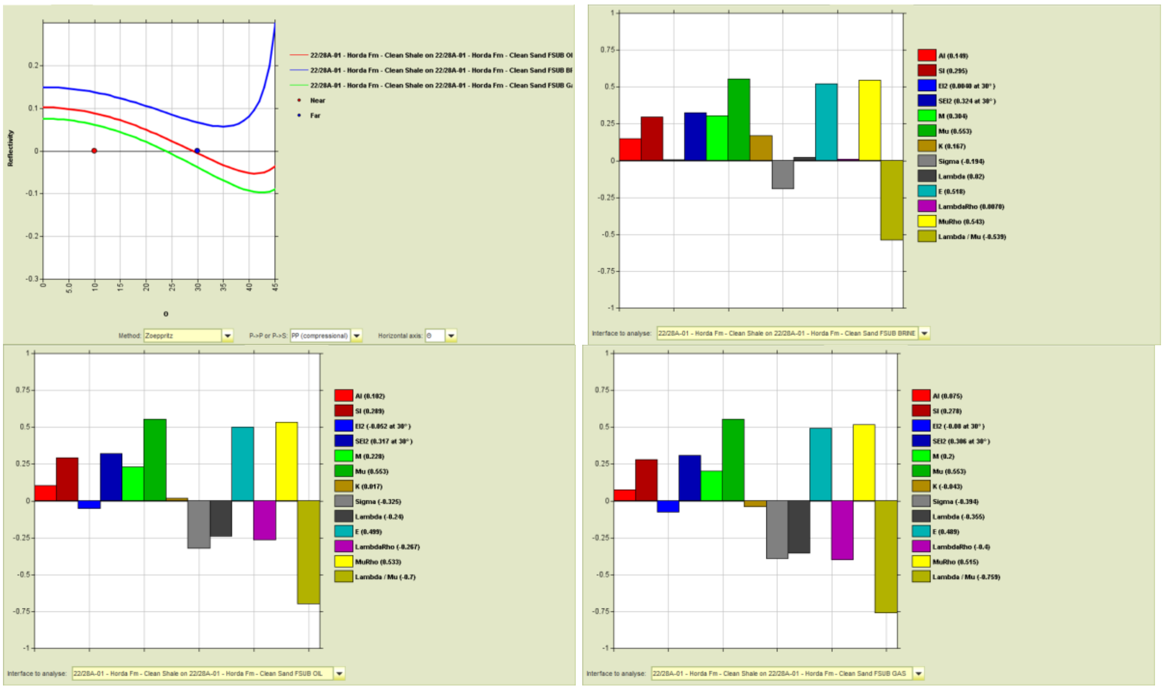


Figure 3.16.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 22/28A-01.

Sele Formation

- Inter-bedded sand and shales are observed at the top of the formation however, more discrete sand packages encased in shale are observed towards the base of the interval. Porosities of 32% are associated with the inter-bedded sands, and slightly lower porosities of 18-25% are observed in the lower sections of the formation.
- Blocky AVO shows a modelled class I response for the 100% brine case and a modelled class II response for the 80% oil and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

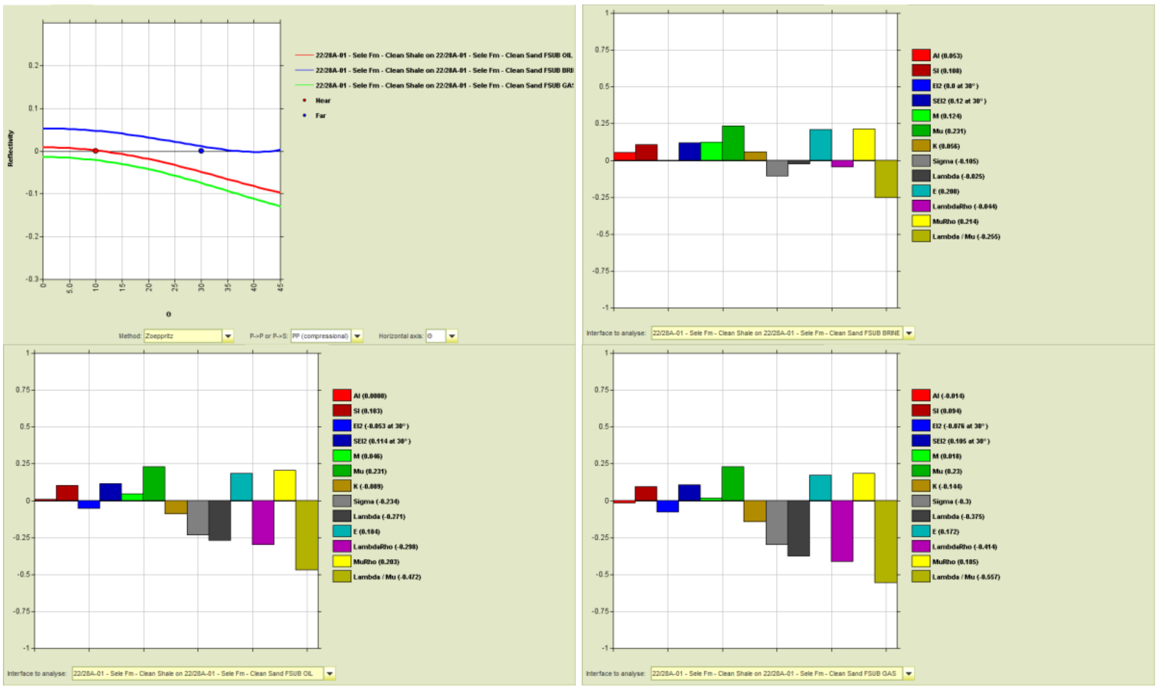


Figure 3.16.9 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/28A-01.

Lista Formation

- Reservoir formed by discrete sand packages encased in shale. The highest porosities of 20-25% are associated with the thicker packages of sands in the upper portion of the formation. Net reservoir sands 21 foot.
- Blocky AVO shows a modelled class I response for all fluid cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine and oil cases, but that the contrasts generally become negative for most attributes with addition of gas. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

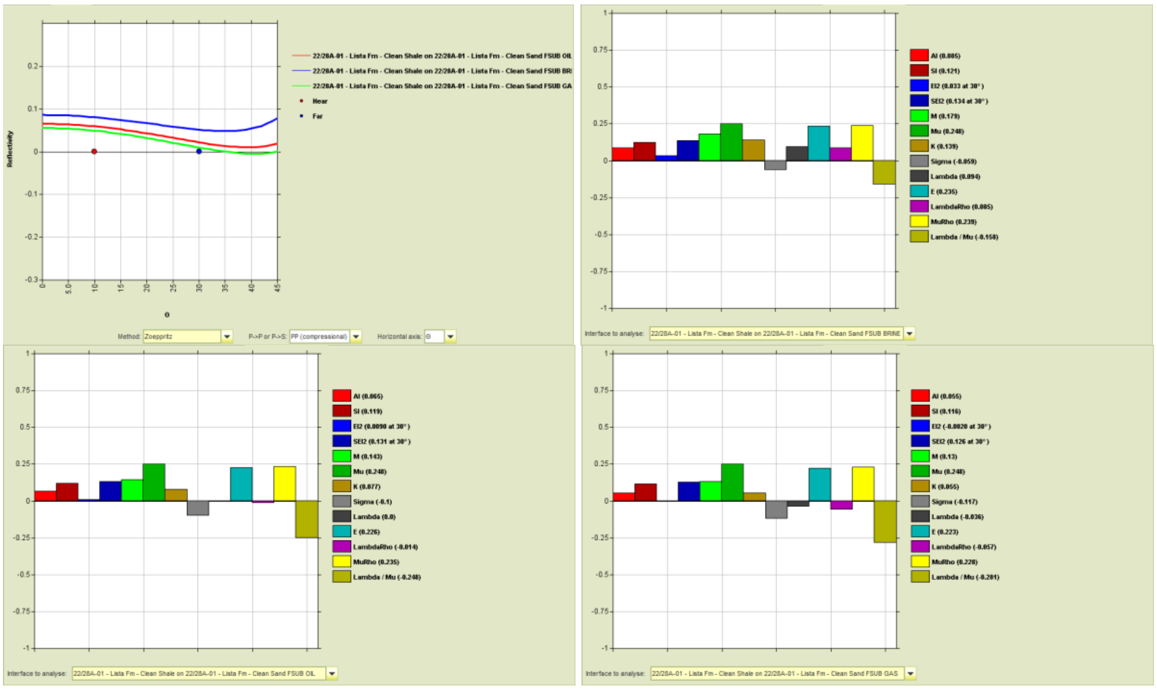


Figure 3.16.10 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/28A-01.

Maureen Formation

- Reservoir formed by a limestone section in the upper section of the interval, net reservoir is approximately 134 feet. This limestone section has high velocities and densities in comparison with the overburden sands/shale in the Lista Fm and gives a strong positive impedance contrast on the synthetic gathers.
- Blocky AVO shows a strong modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, and that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

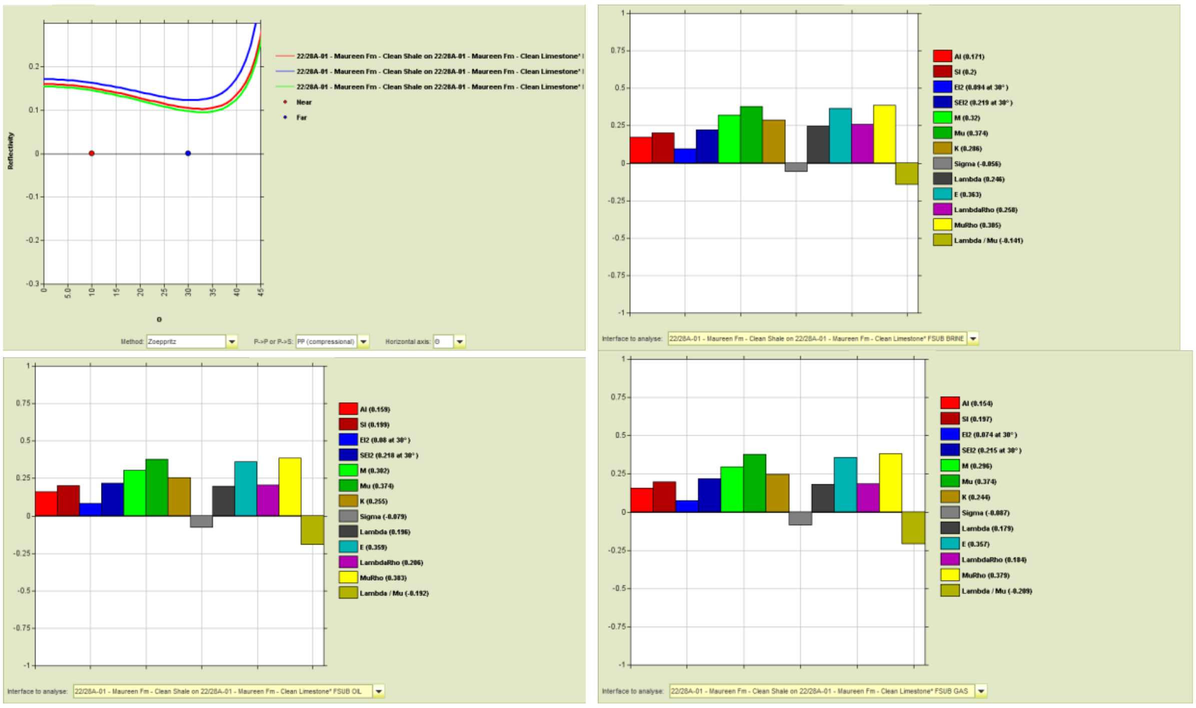


Figure 3.16.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/28A-01.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/28A-01 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-01	Ekofisk	100% Brine	15108	8033	2.50
22/28A-01	Tor	100% Brine	17089	8951	2.62
22/28A-01	Hod	100% Brine	14791	7833	2.51
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/28A-01	Ekofisk	80% Oil	14716	8085	2.47
22/28A-01	Tor	80% Oil	16871	8971	2.61
22/28A-01	Hod	80% Oil	14276	7880	2.48
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/28A-01	Ekofisk	90% Gas	14708	8164	2.42
22/28A-01	Tor	90% Gas	16842	9001	2.59
22/28A-01	Hod	90% Gas	14169	7947	2.44

Table 3.16.9 - Clean limestone properties at Well 22/28A-01 for each fluid case

Cretaceous reservoirs

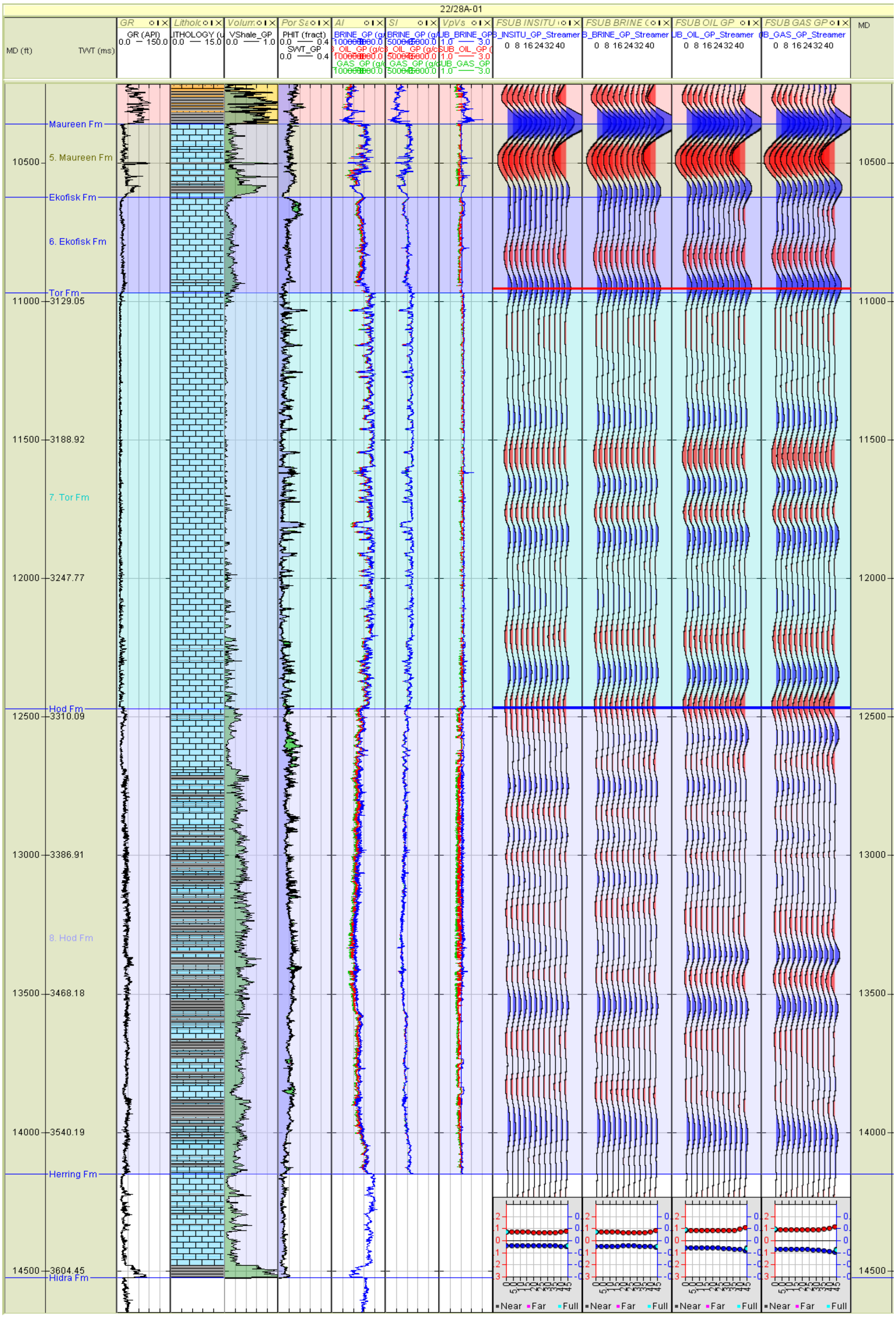


Figure 3.16.12 - Well Panel: Cretaceous reservoirs for well 22/28A-01. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the top section of the Ekofisk Fm where the maximum porosity in this section is approximately 18%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons. This AVO response can't be compared to the synthetic gathers since the overburden section of the Maureen Fm is sand at this well.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude for all the fluid cases, but the contrasts decrease in amplitude slightly with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

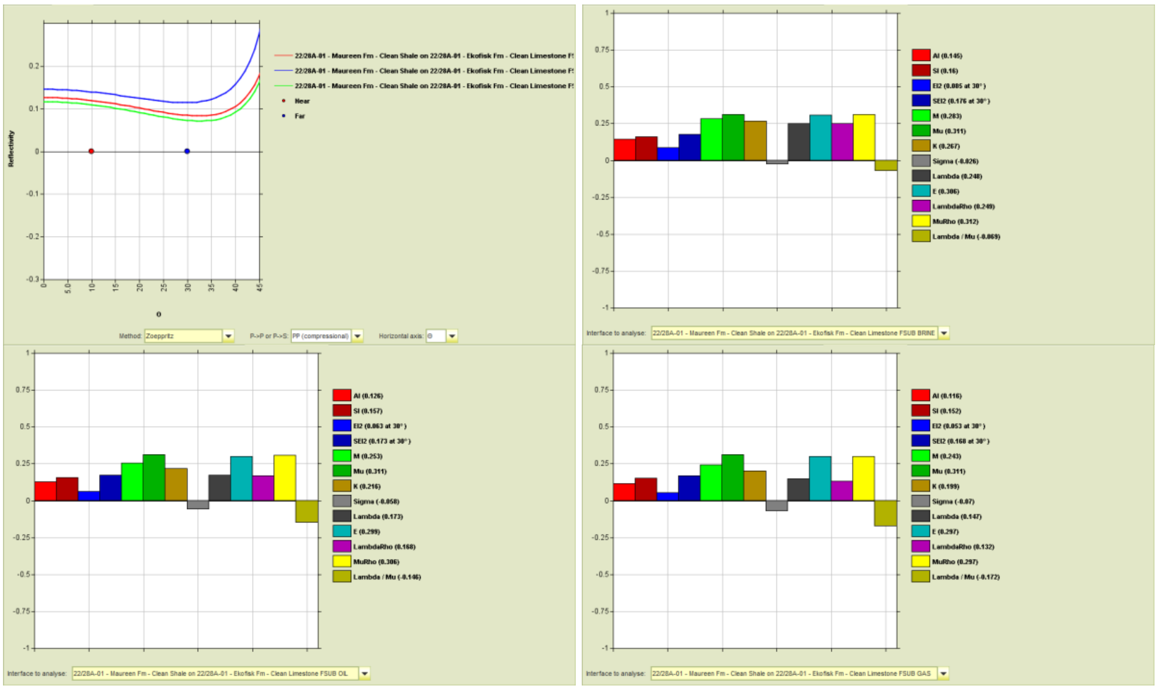


Figure 3.16.13 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/28A-01.

Tor Formation

- Reservoir formed by a clean limestone formation. High porosity layers are found throughout the Tor Fm and could be representative of reworked chalk zones. The porosity of these layers is approximately 16-18% porosity.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude for all the fluid cases. A slight decrease in the contrasts amplitudes is observed with the addition of hydrocarbons.

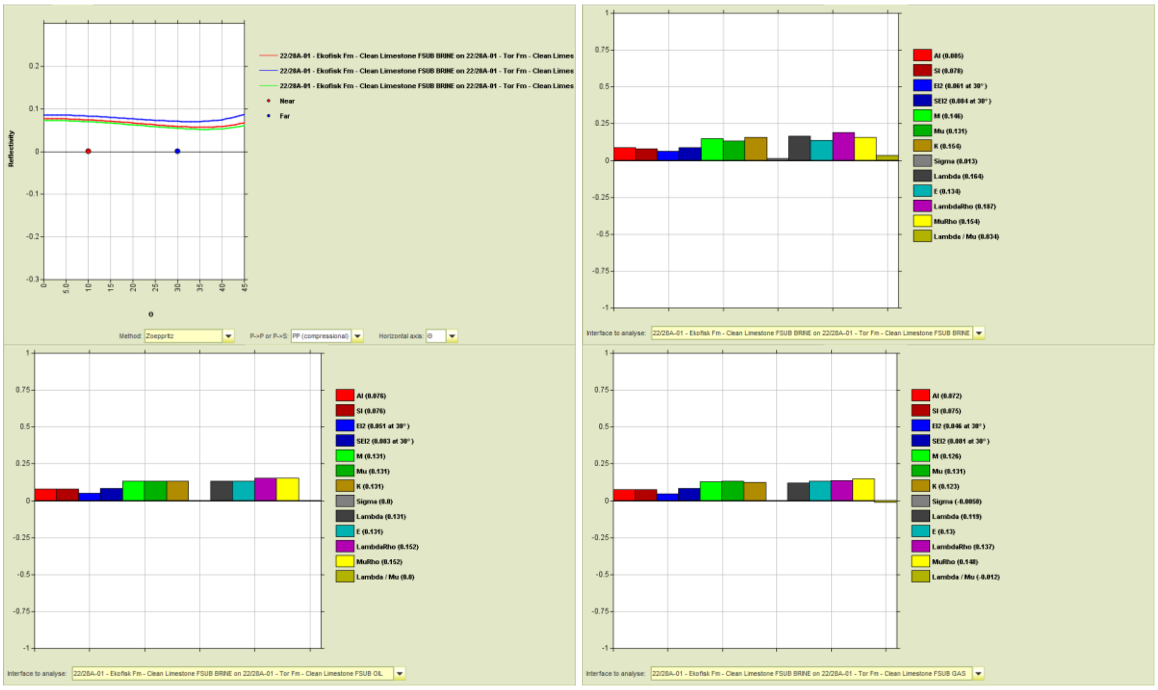


Figure 3.16.14 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/28A-01.

Hod Formation

- Reservoir formed by a limestone formation with a greater component of shale. The maximum porosity of these inter-bedded limestone reservoirs is observed to be 17%.
- Blocky AVO shows a modelled class IV response for all the fluid cases.
- Elastic Contrast Analysis shows contrasts are low amplitude and negative for all fluid cases, but the contrasts increase in amplitude slightly with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

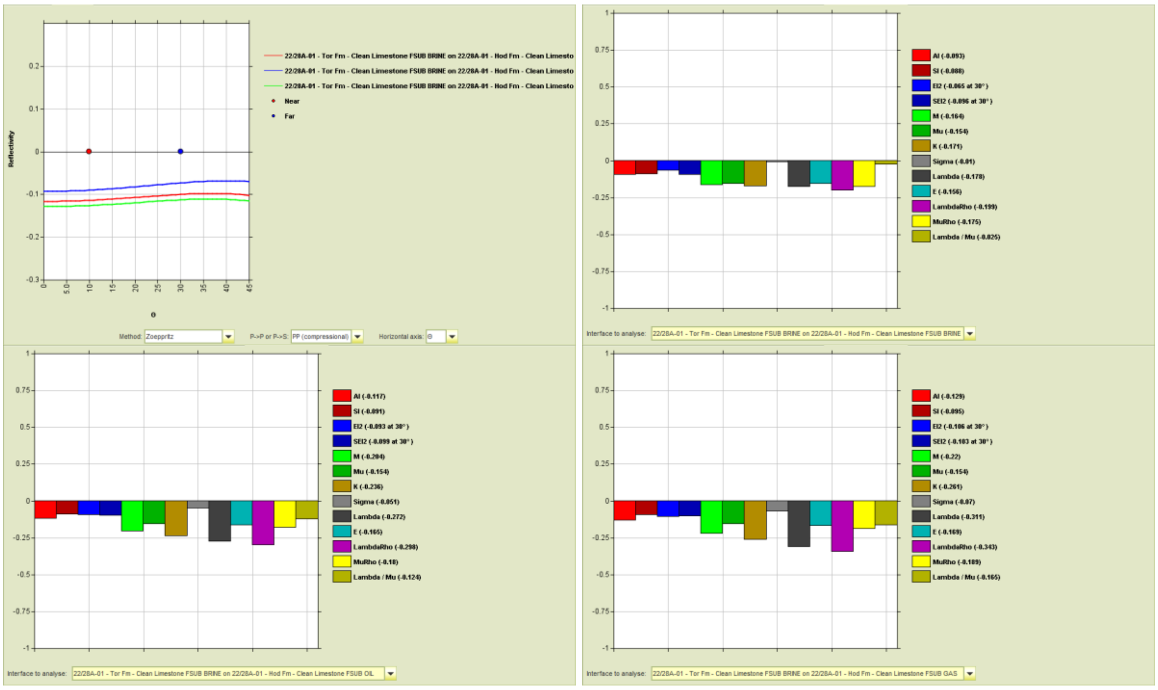


Figure 3.16.15 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/28A-01.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/28A-01 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-01	Overburden	Shale	7393		
22/28A-01	Underburden	Limestone	17252		2.64

Table 3.16.10 - Overburden and underburden properties at Well 22/28A-01.

Well: 22/28A-04

General

Well Information

Drilled by BP as an appraisal well for the Madoes field; completed and suspended in 1998.

Objectives

The objectives for well 22/28a-4 were to prove and test oil in the Fulmar and Skagerrak sands and also to confirm the presence of oil bearing sands in the Tay Formation.

Log conditioning overview

The calliper log is only present in the Horda, Balder and Sele Formations. The calliper log shows good hole conditions in these intervals though. Poor Vs data was removed from a small section at the top of Horda Fm and thin calcite stringers were removed from the Vp, Vs and density logs from within the same interval. A section of the measured Vp log was also edited out of the Hod Fm from 13750ft to 13950ft.

All log edits in the Rock Physics part of the project detailed in Single Well Part 1 - Rock Physics PowerPoint’s.

Invasion correction

Well 22/28A-04 was drilled with oil-based drilling mud. Invasion correction has been performed within the oil-bearing Horda Fm and brine-bearing Balder and Sele Fm’s. There was no density log coverage over any of the other formations.

Log modelling

In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda and Hod Formations for the Vp log, within the Horda, Balder and Hod Formations for the Vs log and within the Horda, Sele, Lista, Maureen, Ekofisk, Tor and Hod Formations for the density log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoint's.

P&T data

The temperature and pressure data for Well 22/28A-04 is displayed in the figures below;

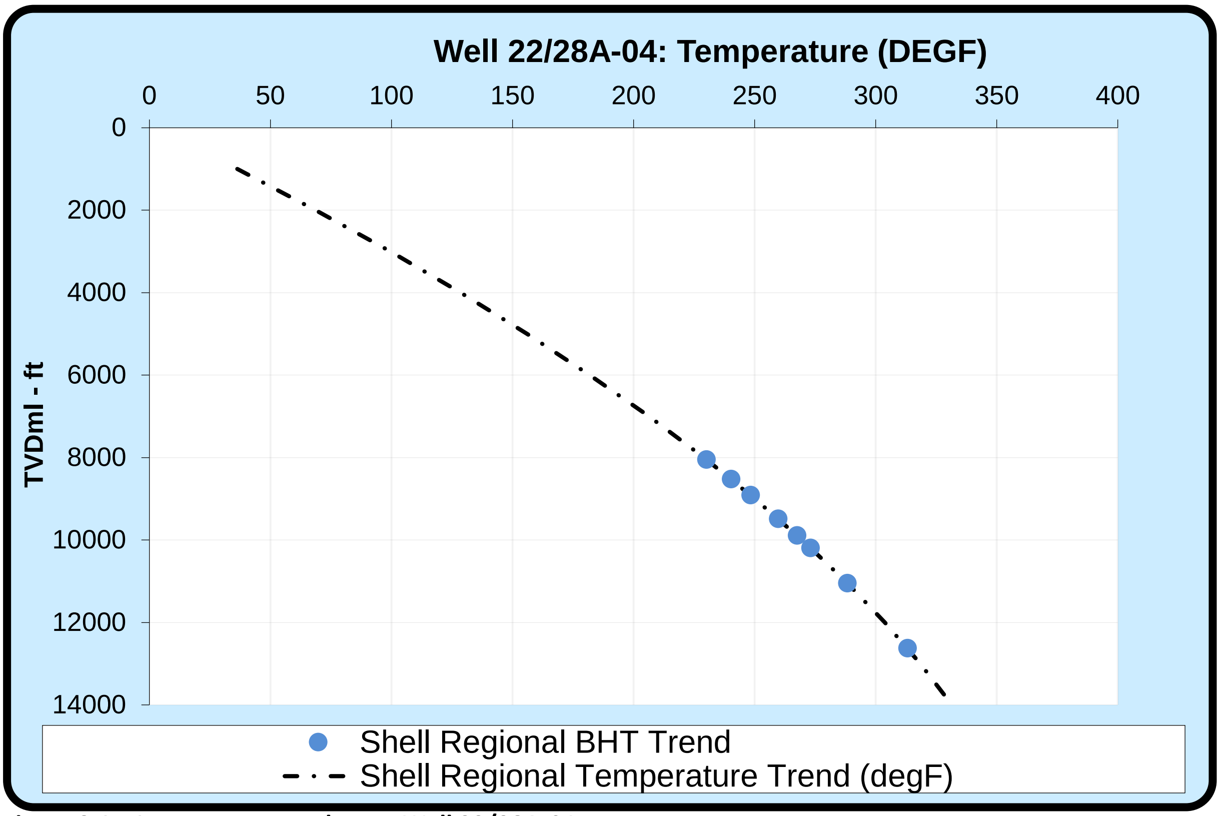


Figure 3.17.1 - Temperature data at Well 22/28A-04

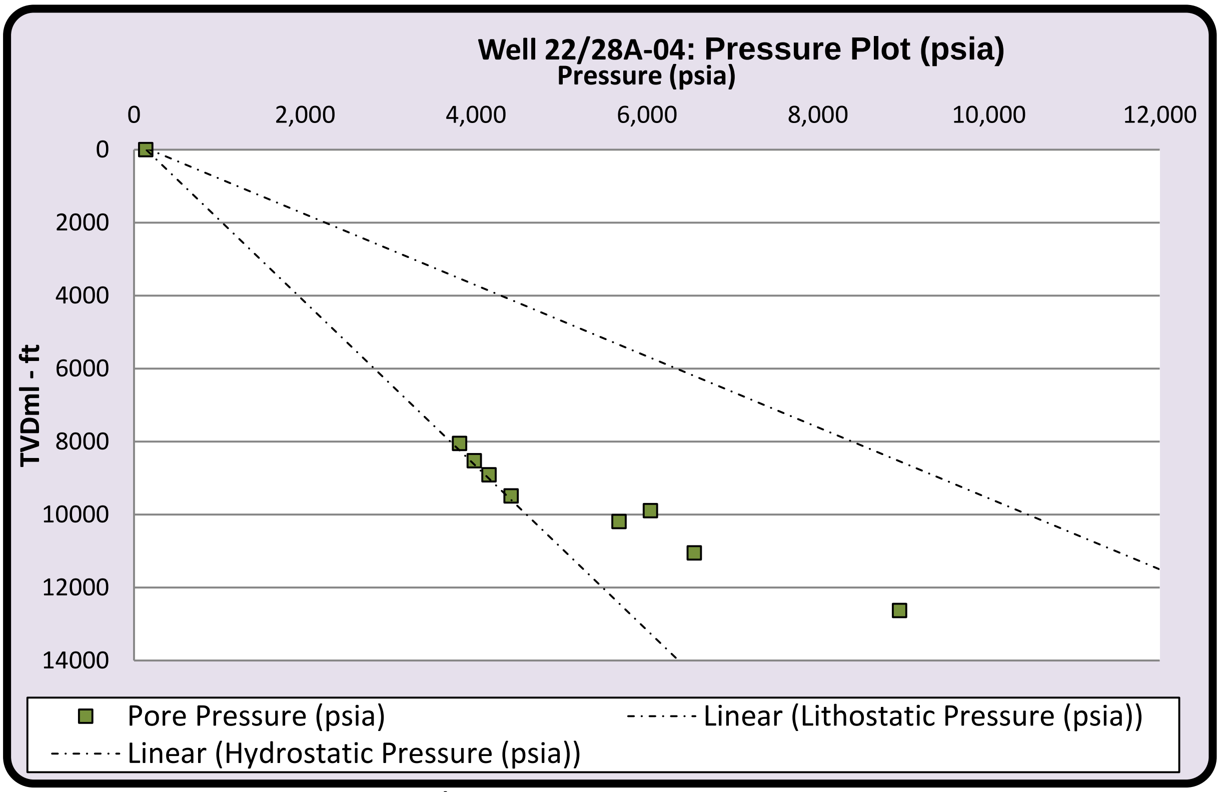


Figure 3.17.2 - Pressure data at Well 22/28A-04

The temperature and pressure data for the formation mid-points in Well 22/28A-04 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/28A-04	Sea Bed	452.0	316.0	0.0	39.2	140.6	140.6	140.6	0.0
22/28A-04	Horda	8505.3	8369.2	8053.2	230.2	3724.3	3809.3	8193.8	4384.5
22/28A-04	Balder	8977.2	8841.1	8525.1	240.4	3934.3	3984.3	8665.8	4681.4
22/28A-04	Sele	9365.3	9229.1	8913.1	248.4	4107.0	4157.0	9053.8	4896.8
22/28A-04	Lista	9938.5	9802.4	9486.4	259.9	4362.1	4412.1	9627.0	5214.9
22/28A-04	Maureen	10344.1	10208.0	9892.0	267.7	4542.5	6042.5	10032.6	3990.0
22/28A-04	Ekofisk	10644.5	10508.4	10192.4	273.2	4676.2	5676.2	10333.0	4656.8
22/28A-04	Tor	11500.0	11363.8	11047.8	288.4	5056.9	6556.9	11188.4	4631.5
22/28A-04	Hod	13078.6	12942.3	12626.3	313.3	5759.3	8959.3	12766.9	3807.6

Table 3.17.1 - Summary of mid-point temperature and pressure data at Well 22/28A-04

Fluid data

A summary of the fluid set parameters at Well 22/28A-04 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/28A-04	Horda	74000	910	42.7	1.3	1.3
22/28A-04	Balder	74000	730	40.6	0.71	0.71
22/28A-04	Sele	74000	730	41.0	0.71	0.71
22/28A-04	Lista	74000	730	41.6	0.71	0.71
22/28A-04	Maureen	74000	730	42.0	0.71	0.71
22/28A-04	Ekofisk	74000	730	42.4	0.71	0.71
22/28A-04	Tor	74000	730	43.3	0.71	0.71
22/28A-04	Hod	74000	730	45.0	0.71	0.71

Table 3.17.2 - Summary of fluid parameter data at Well 22/28A-04

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table3.17.3 - Constant mineral properties used in this project

There is no Tuff present in this well.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/28A-04	Horda	PAY	806.520	32.000	0.040	9.177	0.287	0.253	0.021
22/28A-04	Horda	RES	806.520	221.500	0.275	57.631	0.260	0.860	0.089
22/28A-04	Balder	PAY	137.420	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-04	Balder	RES	137.420	94.000	0.684	22.695	0.241	0.949	0.171
22/28A-04	Sele	PAY	638.650	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-04	Sele	RES	638.650	442.810	0.693	101.121	0.228	0.953	0.169
22/28A-04	Lista	PAY	507.860	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-04	Lista	RES	507.860	196.500	0.387	38.120	0.194	0.817	0.153
22/28A-04	Maureen	PAY	303.390	1.000	0.003	0.184	0.184	0.339	0.111
22/28A-04	Maureen	RES	303.390	36.590	0.121	3.687	0.101	0.888	0.139
22/28A-04	Ekofisk	PAY	297.400	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-04	Ekofisk	RES	297.400	263.410	0.886	23.749	0.090	0.950	0.144
22/28A-04	Tor	PAY	1413.530	0.000	0.000	0.000	0.000	0.000	0.000
22/28A-04	Tor	RES	1413.530	995.010	0.704	48.058	0.048	0.963	0.025
22/28A-04	Hod	PAY	1743.710	15.000	0.009	0.819	0.055	0.330	0.003
22/28A-04	Hod	RES	1743.710	982.480	0.563	64.380	0.066	0.957	0.188

Table 3.17.4 - Petrophysical parameters used at Well 22/28A-04

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

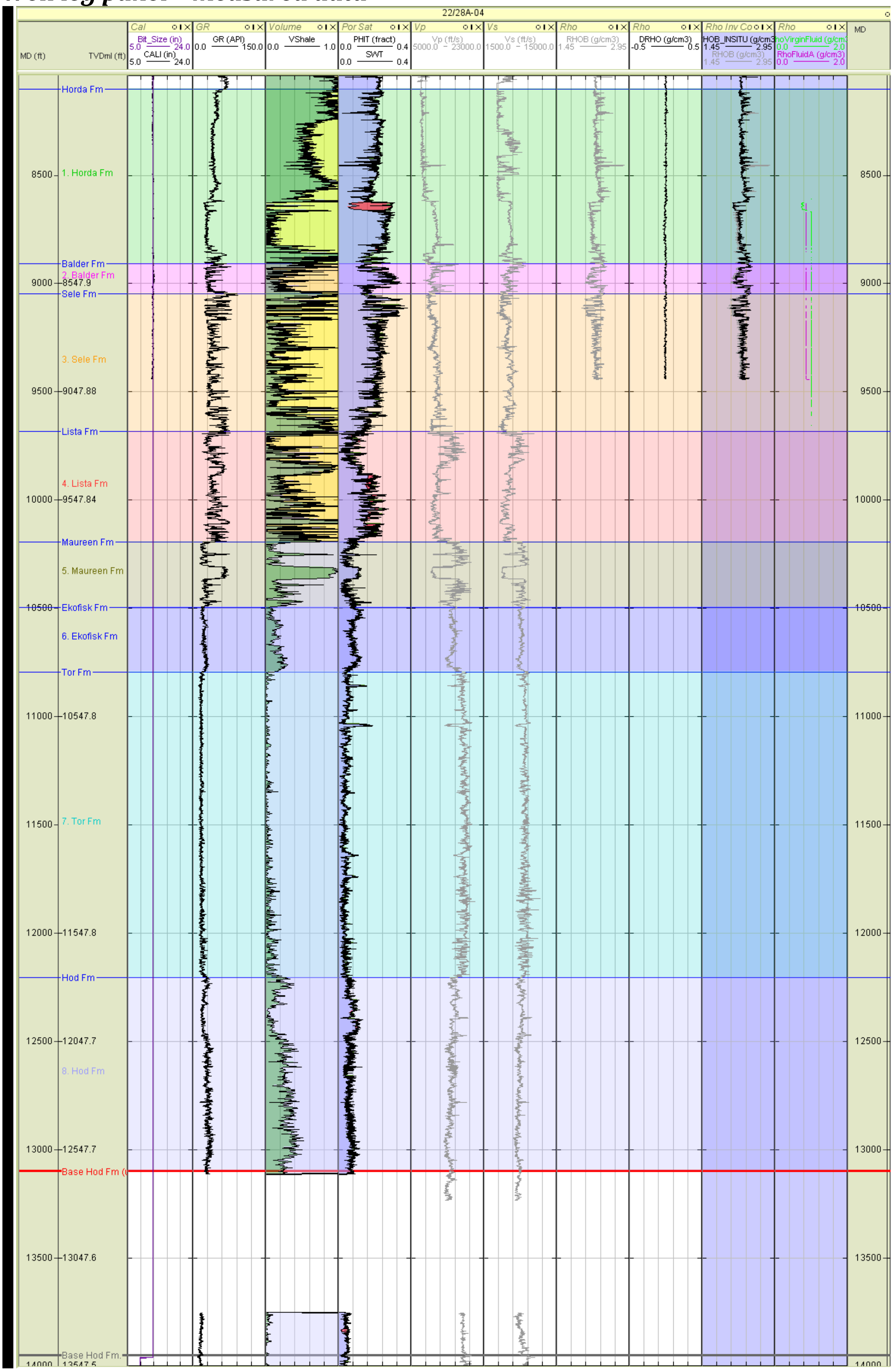


Figure 3.17.3 - Well Panel: Measured data and invasion correction for well 22/28A-04.

Well log panel – log editing and audit

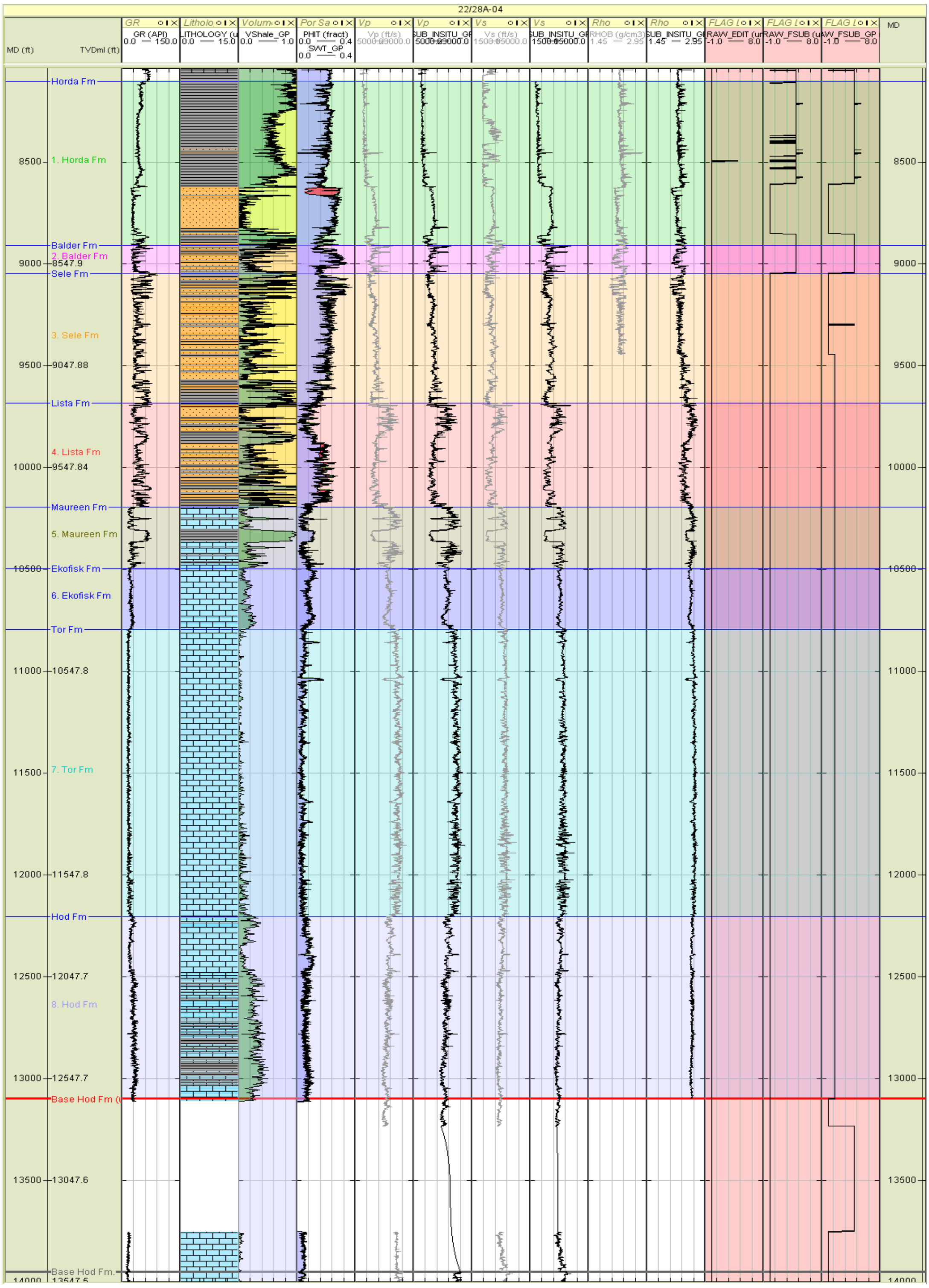


Figure 3.17.4 -Well Panel: Log edits for well 22/28A-04.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

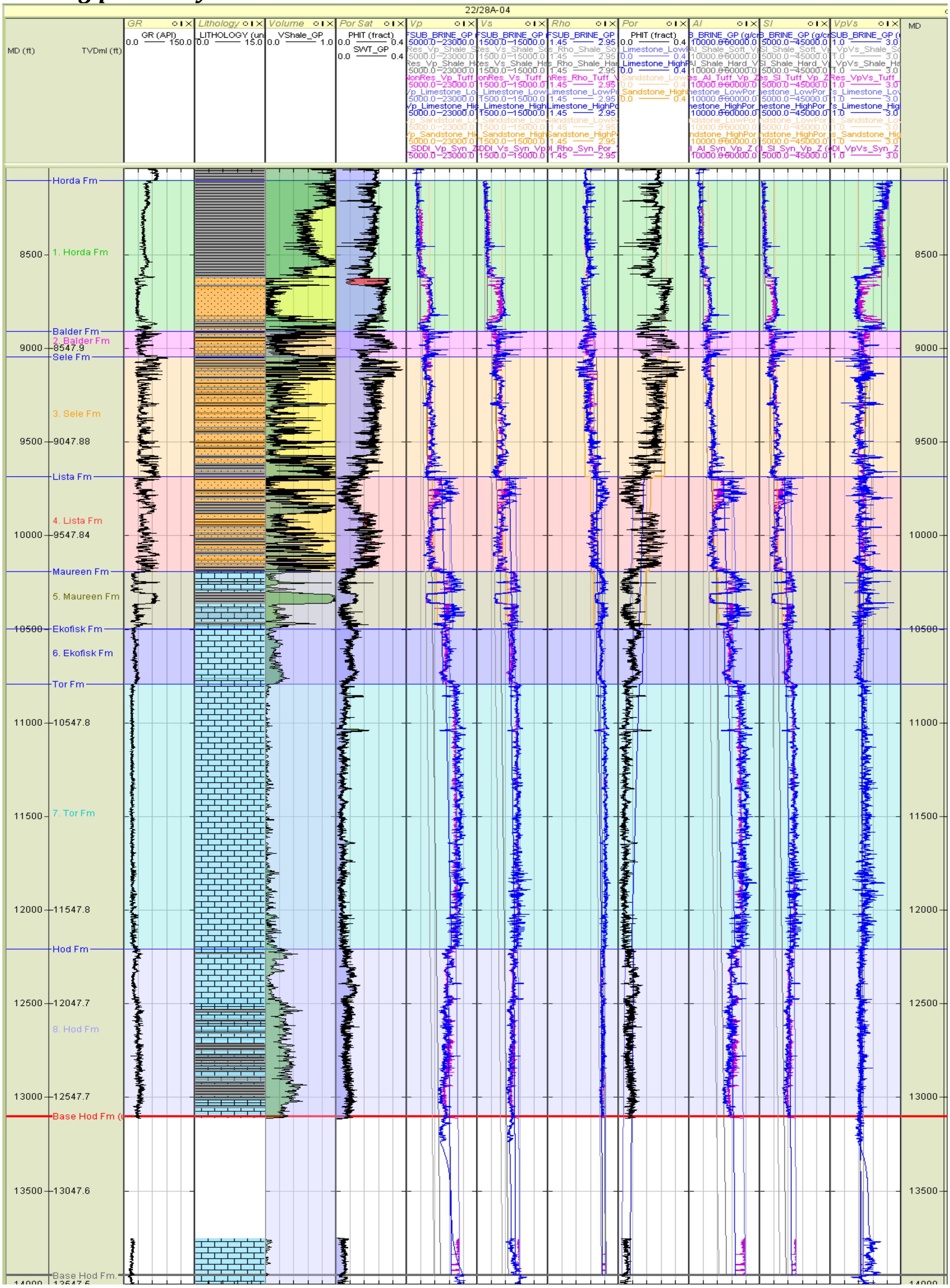


Figure 3.17.5 - Well Panel: End-member and synthetic logs for well 22/28A-04.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

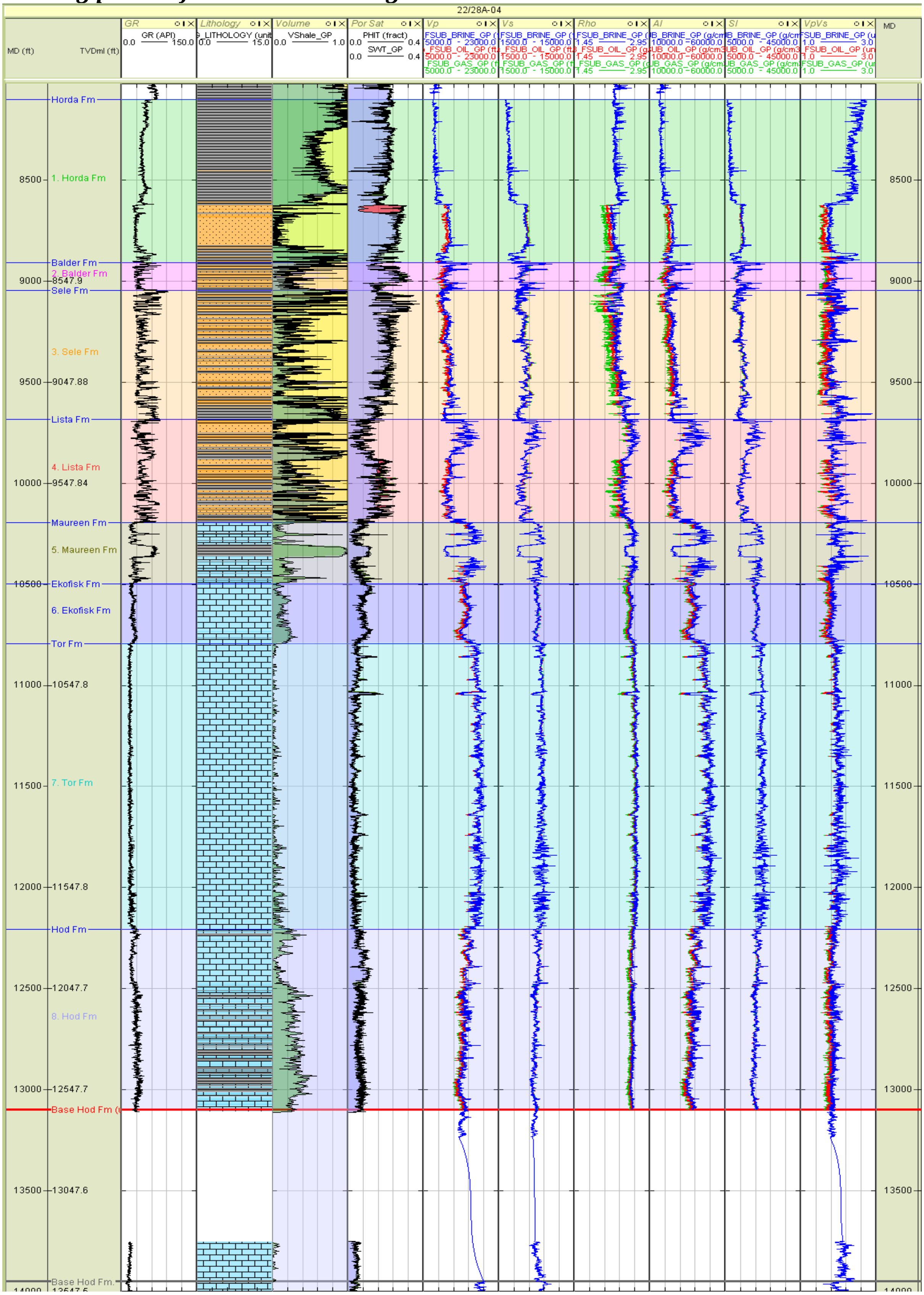


Figure 3.17.6 - Well Panel: Fluid substituted and elastic logs for well 22/28A-04.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/28A-04 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-04	Horda	8019	3322	2.30
22/28A-04	Balder	10249	5396	2.38
22/28A-04	Sele	10134	5182	2.43
22/28A-04	Lista	11052	5591	2.51
22/28A-04	Maureen	10743	5204	2.49

Table 3.17.5 - Clean shale properties at Well 22/28A-04

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-04	Horda	100% Brine	11172	6314	2.22
22/28A-04	Balder	100% Brine	10871	5942	2.24
22/28A-04	Sele	100% Brine	11124	6128	2.28
22/28A-04	Lista	100% Brine	13031	6919	2.48
22/28A-04	Maureen	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-04	Horda	80% Oil	10445	6419	2.15
22/28A-04	Balder	80% Oil	10125	6033	2.17
22/28A-04	Sele	80% Oil	10407	6217	2.22
22/28A-04	Lista	80% Oil	12655	6969	2.44
22/28A-04	Maureen	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-04	Horda	90% Gas	10468	6534	2.08
22/28A-04	Balder	90% Gas	10072	6188	2.06
22/28A-04	Sele	90% Gas	10368	6365	2.12
22/28A-04	Lista	90% Gas	12467	7049	2.38
22/28A-04	Maureen	90% Gas			

Table 3.17.6 - Clean sand properties at Well 22/28A-04 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-04	Maureen	100% Brine	16,544	8,676	2.61
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/28A-04	Maureen	80% Oil	16,443	8,683	2.61
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/28A-04	Maureen	90% Gas	16,422	8,694	2.60

Table 3.17.7 - Clean limestone properties at Well 22/28A-04 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

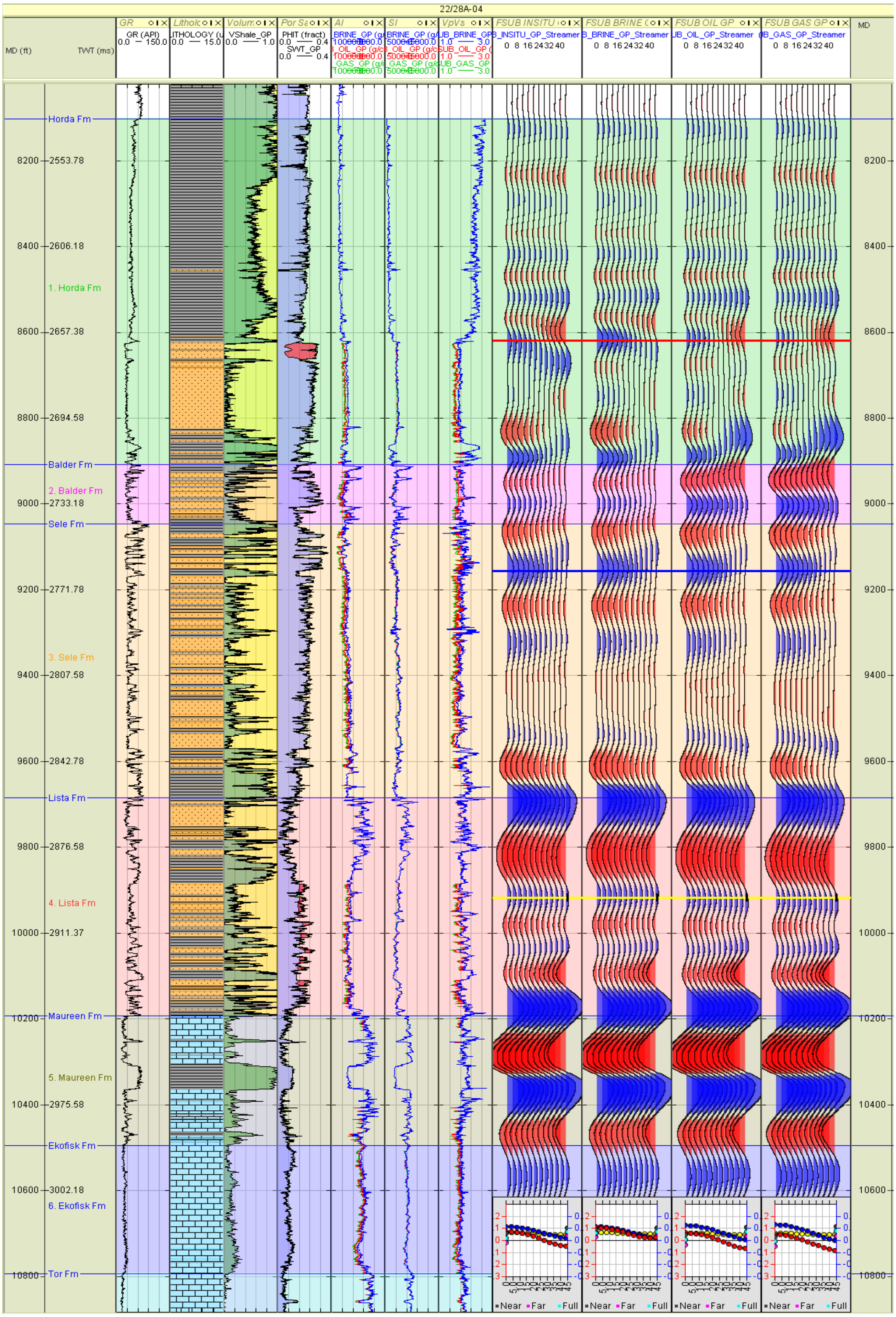


Figure 3.17.7 - Well Panel: Tertiary reservoirs for well 22/28A-04. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir consists of a discrete sand package in the lower section of the Horda formation. The average porosity is approximately 27% and net reservoir is approximately 200 feet. The reservoir sand is overlain directly by overburden shale that contains 50% sand content in parts.
- Blocky AVO shows a modelled class I response for all fluid cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

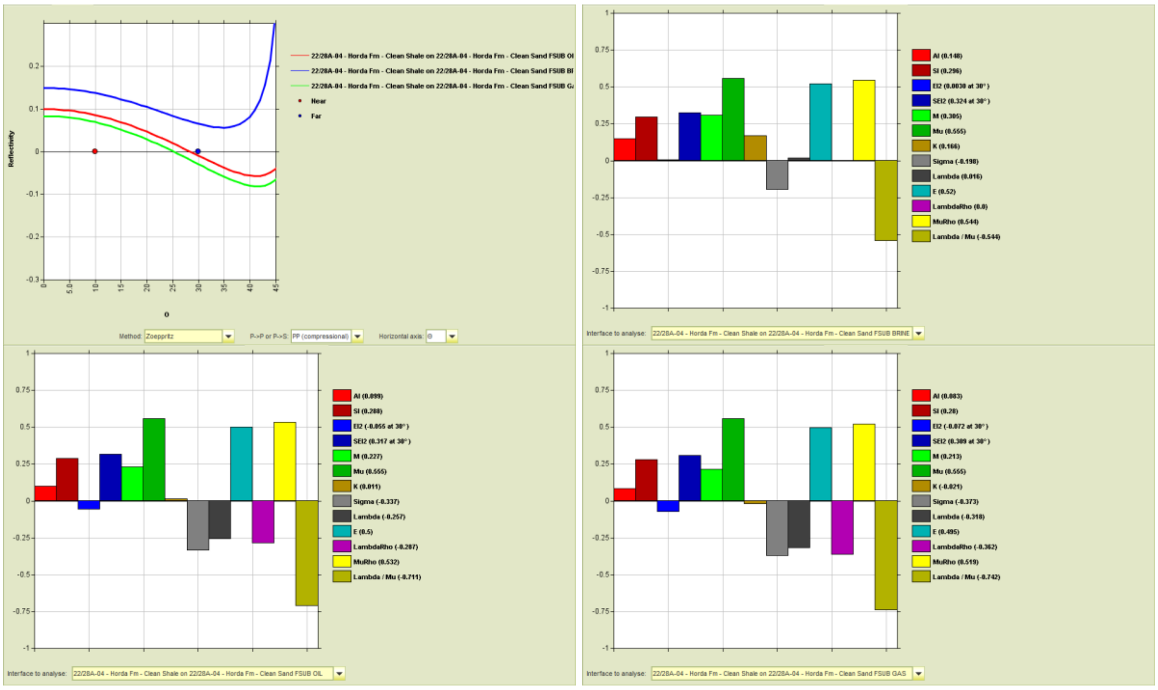


Figure 3.17.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 22/28A-04.

Balder Formation

- Reservoir formed by inter-bedded sand and shale. The greatest sand accumulation is approximately 16ft and has a maximum porosity of 36%.
- Blocky AVO shows a very weak modelled class II response for the 100% brine case and a modelled class III response for the 80% oil and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are very low amplitude in the brine case, but the amplitude of the contrasts greatly increases with the addition of hydrocarbons, with most attributes turning negative. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

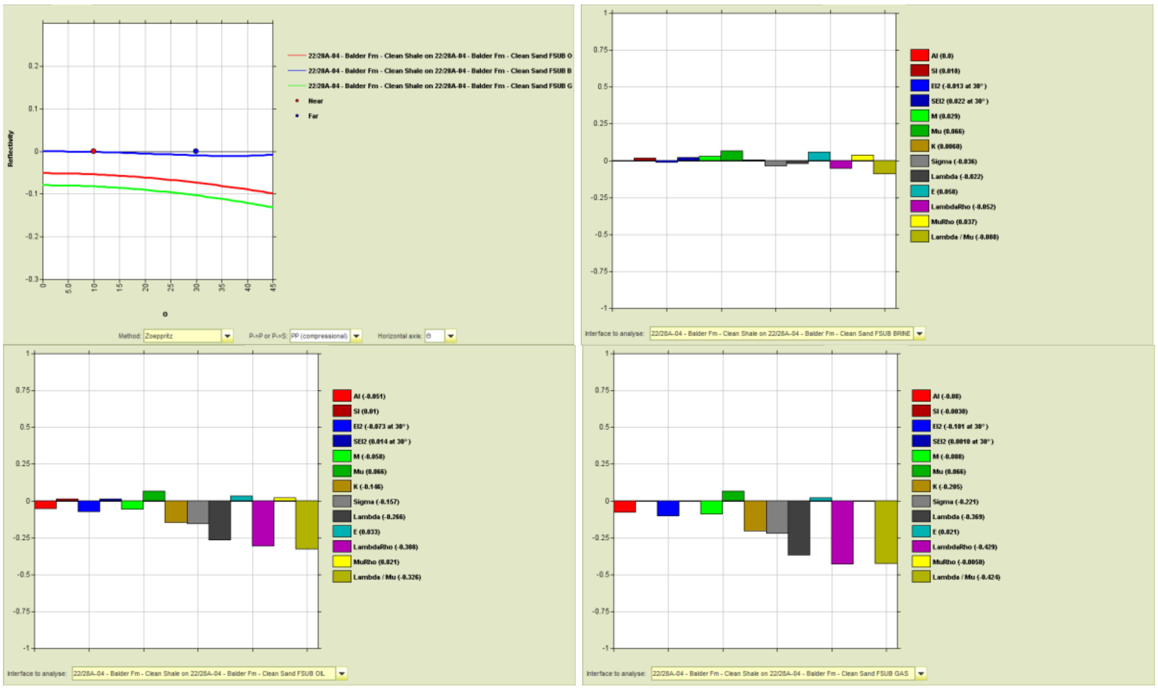


Figure 3.17.9 - Blocky AVO Model and Elastic Contrast Analysis for the Balder Formation in well 22/28A-04.

Sele Formation

- Reservoir formed by inter-bedded sand and shale with the greatest porosities seen at the top of the formation where the maximum porosity is 37%.
- Blocky AVO shows a modelled class II response for the 100% brine and modelled class III response for the 80% oil and gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are very low amplitude in the brine case, but the amplitude of the contrasts greatly increases with the addition of hydrocarbons, with most attributes turning negative. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

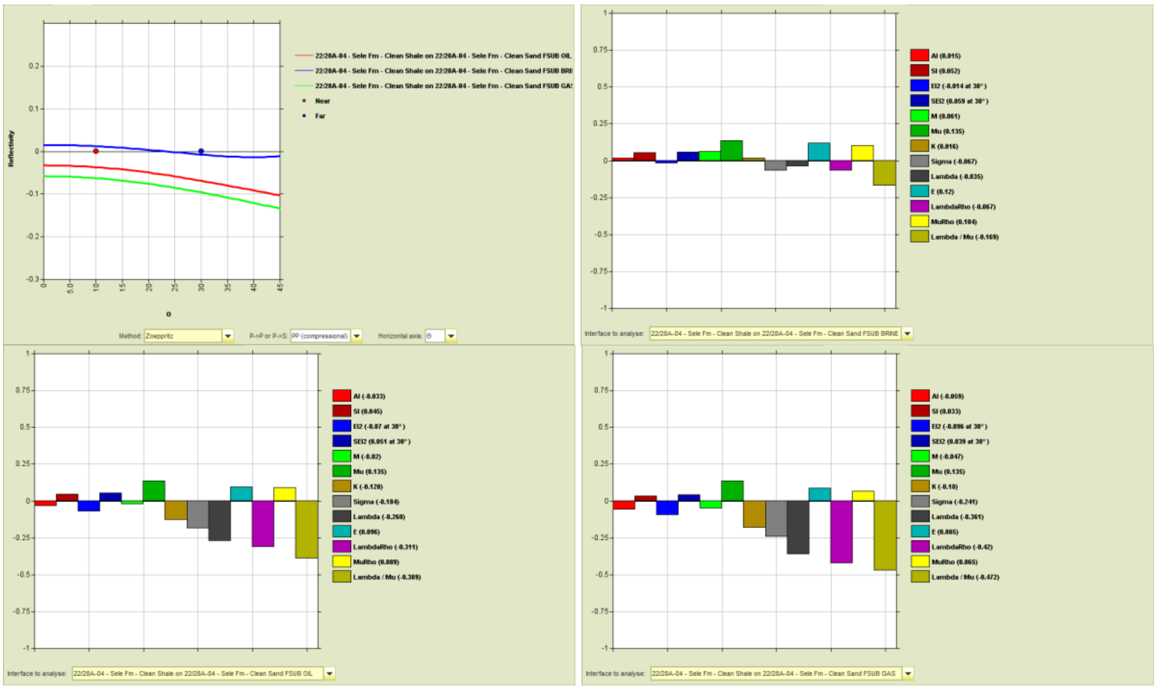


Figure 3.17.10 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/28A-04.

Lista Formation

- Reservoir formed by inter-bedded sand and shale with the greatest porosities seen in the lower sections of the formation where the maximum porosity reaches 27%.
- Blocky AVO shows a modelled class I response for all fluid cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally reduce in amplitude yet further with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

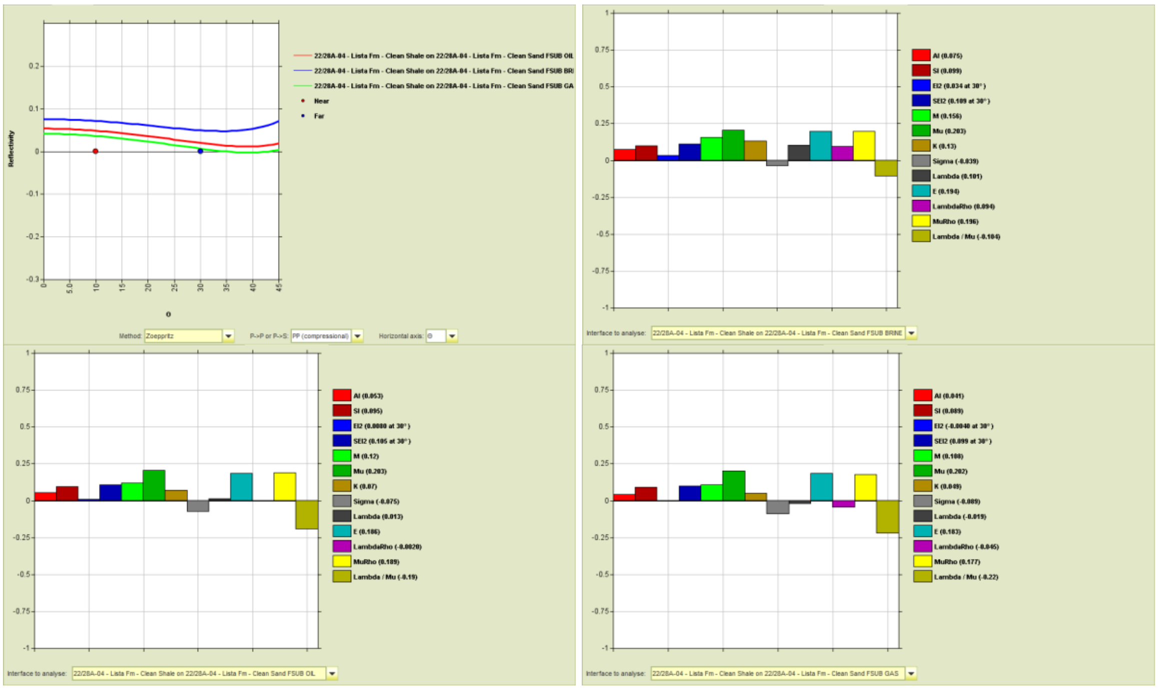


Figure 3.17.11 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/28A-04.

Maureen Formation

- Reservoir formed by two limestone sections that are separated by a 60ft shale layer in the middle section of the interval, gross reservoir is approximately 303ft but net reservoir is only approximately 37 feet due to the low porosities seen in this formation. This limestone section has high velocities and densities in comparison with the overburden sands/shale in the Lista Fm and gives a strong positive impedance contrast on the synthetic gathers.
- Blocky AVO shows a strong modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, and that the contrasts slightly decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

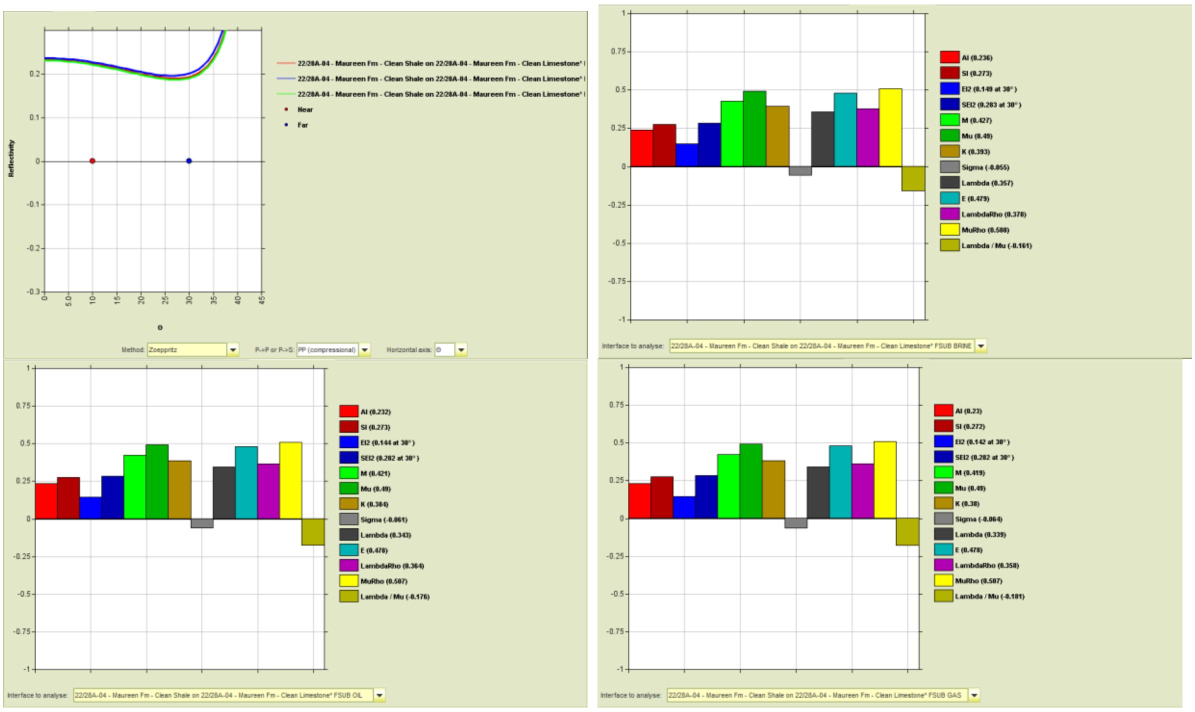


Figure 3.17.12 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/28A-04.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/28A-04 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-04	Ekofisk	100% Brine	15434	8417	2.56
22/28A-04	Tor	100% Brine	18058	9142	2.66
22/28A-04	Hod	100% Brine	15870	8684	2.60
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/28A-04	Ekofisk	80% Oil	14953	8461	2.53
22/28A-04	Tor	80% Oil	17995	9158	2.66
22/28A-04	Hod	80% Oil	15475	8722	2.58
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/28A-04	Ekofisk	90% Gas	14885	8528	2.49
22/28A-04	Tor	90% Gas	18011	9182	2.64
22/28A-04	Hod	90% Gas	15379	8776	2.55

Table 3.17.8 - Clean limestone properties at Well 22/28A-04 for each fluid case

Cretaceous reservoirs

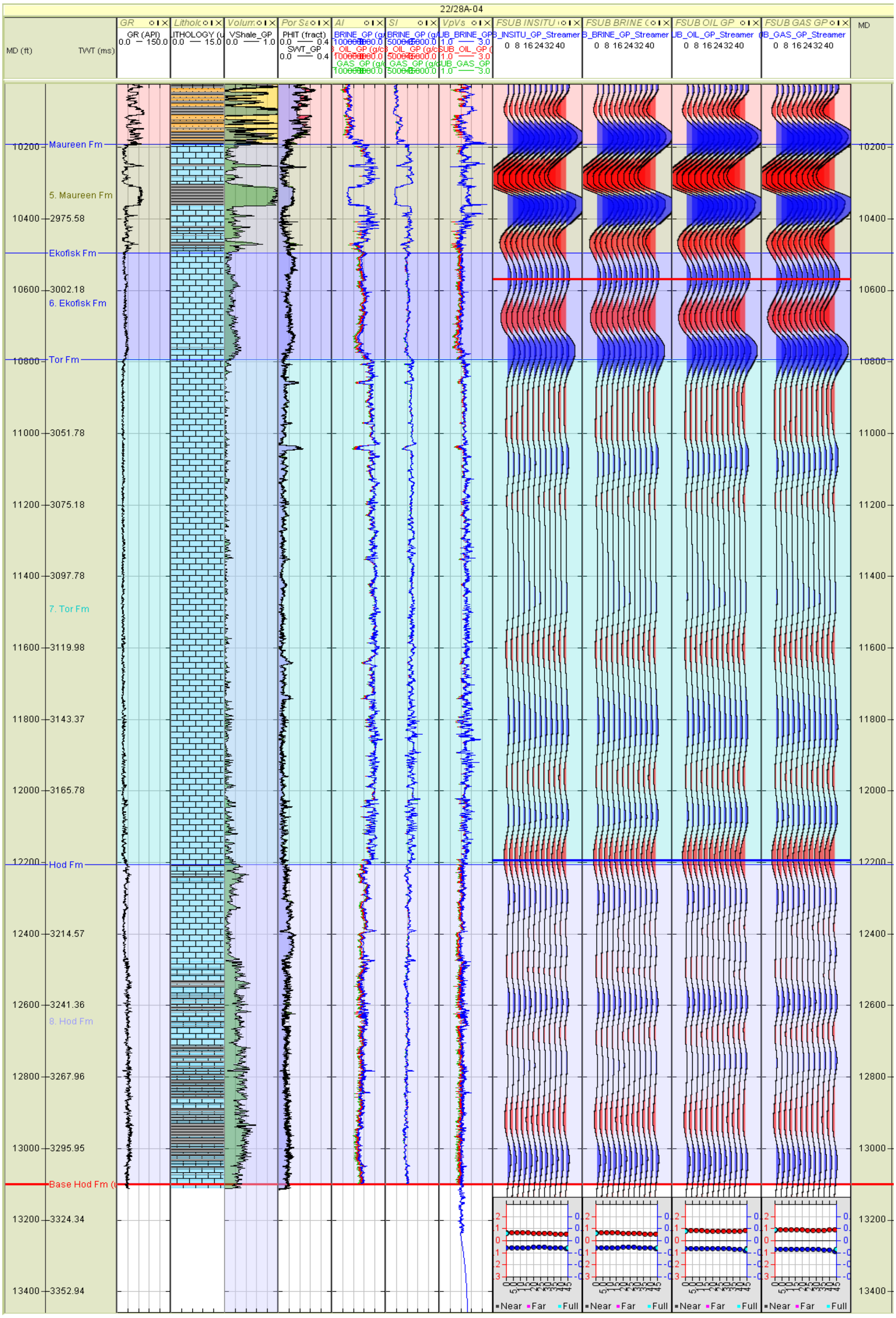


Figure 3.17.13 - Well Panel: Cretaceous reservoirs for well 22/28A-04. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the top and base sections of the Ekofisk Fm where porosity reaches 12-14% versus 7-9% porosity in the middle section of the formation.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons. This AVO response can't be compared to the synthetic gathers since the overburden section of the Maureen Fm is sand at this well.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts increase in amplitude for most attributes with addition of oil but reduce to negative in the presence of gas. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

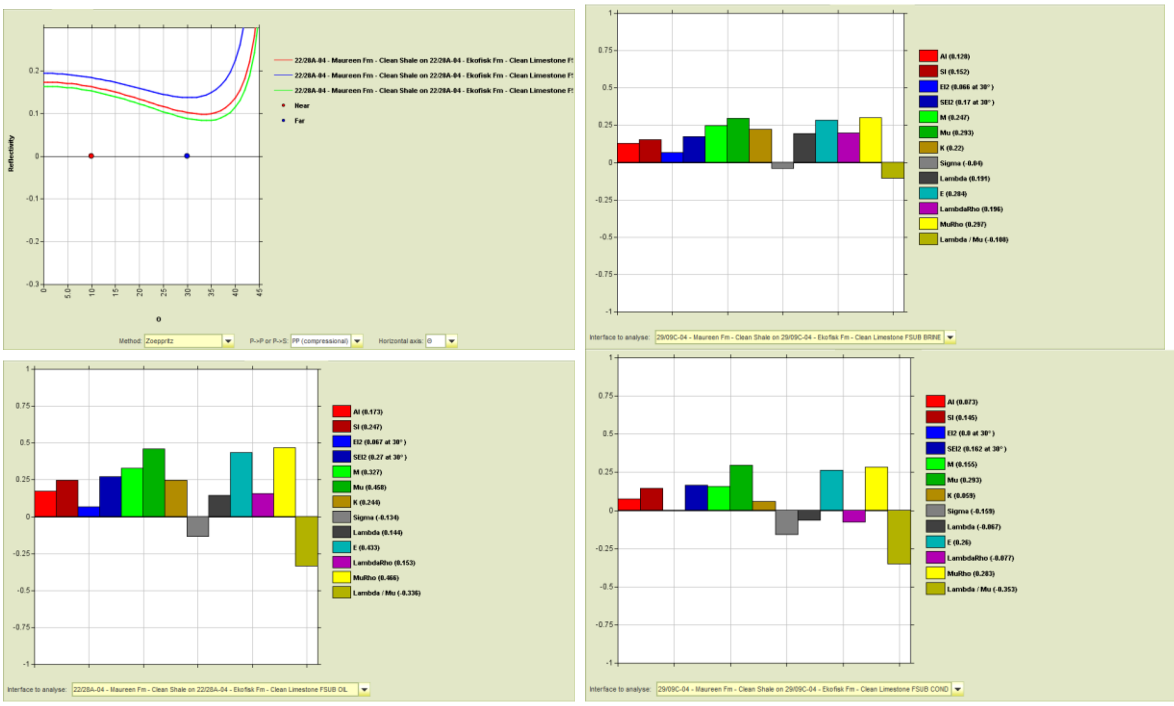


Figure 3.17.14 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/28A-04.

Tor Formation

- Reservoir formed by a very clean limestone formation. High porosity layers are found throughout the Tor Fm and could be representative of reworked chalk zones. The maximum inferred porosity is 16%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are all positive and of low amplitude in the brine case, with the contrasts decreasing in amplitude slightly with the addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

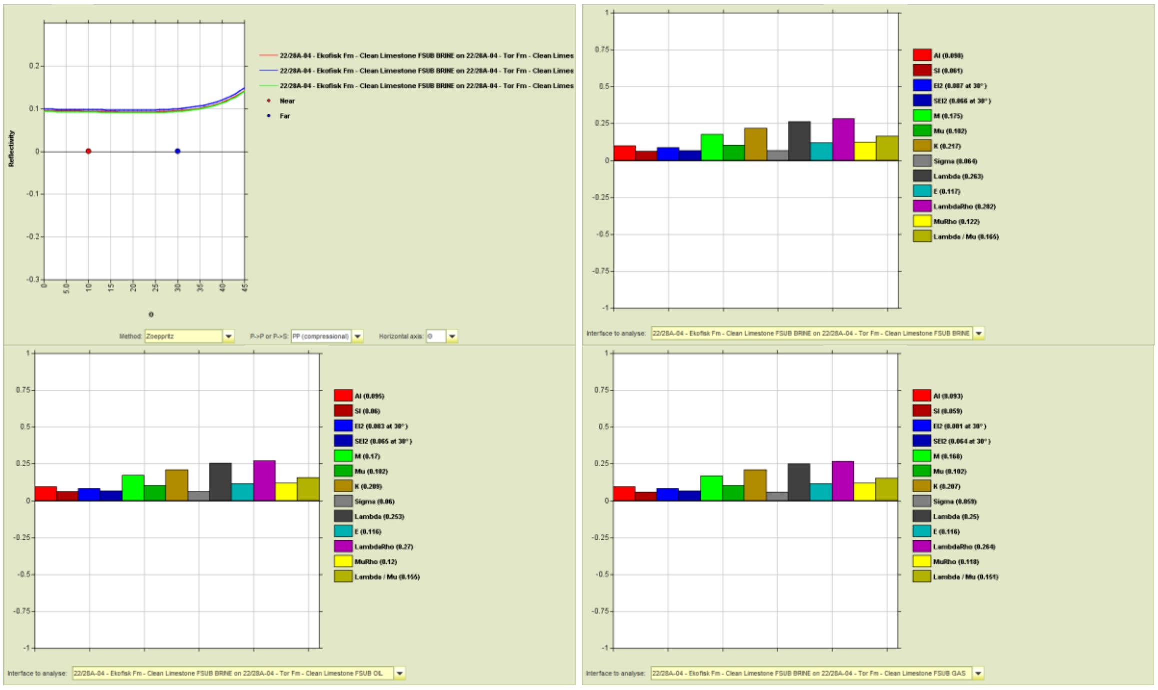


Figure 3.17.15 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/28A-04.

Hod Formation

- Reservoir formed by a limestone formation with an increasing component of shale. The maximum inferred porosity at the top of the reservoir is 11% in the cleanest section, dropping down to 6-9% porosity towards the base of this interval.
- Blocky AVO shows a modelled class II response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are all negative and of low amplitude in the brine case, with the contrasts increasing in amplitude slightly with the addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

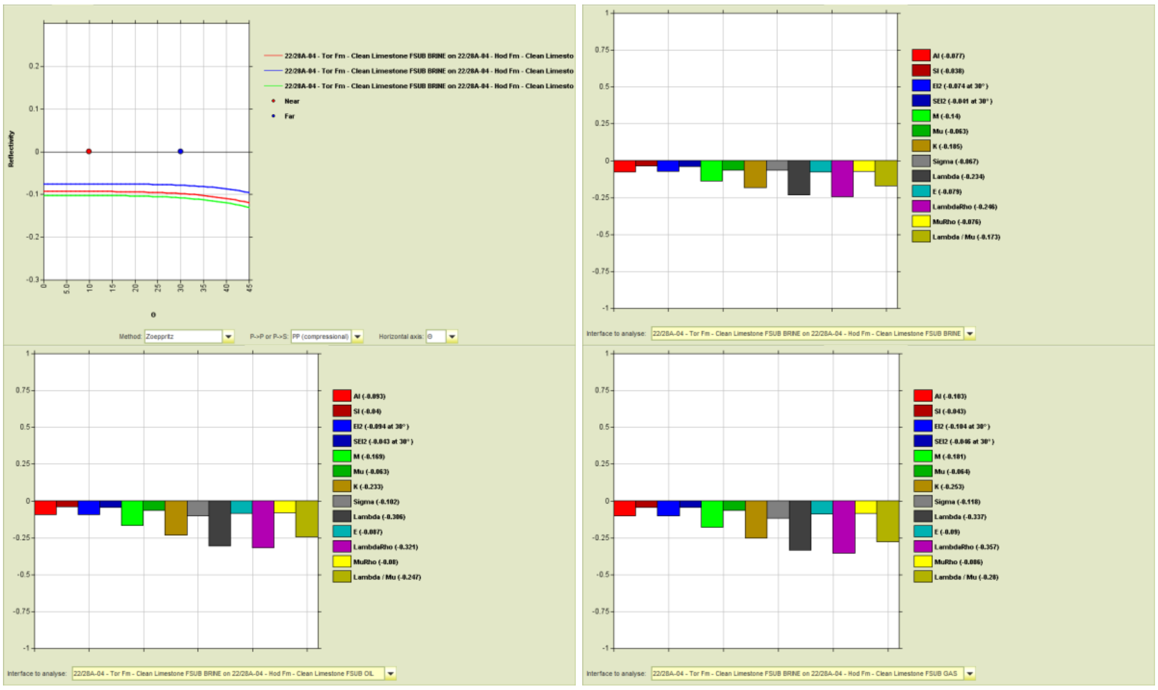


Figure 3.17.16 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/28A-04.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/28A-04 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/28A-04	Overburden	Shale	7644		2.27
22/28A-04	Underburden	Limestone	16524	8588	

Table 3.17.9 - Overburden and underburden properties at Well 22/28A-04.

Well: 22/29-05

General

Well Information
Shell operated appraisal well for the Heron field. Suspended in 1994.

Objectives
The well 22/29-5 was designed to evaluate the Skagerrak reservoir in the upper part of the Heron field.

Log conditioning overview
Poor Vp and Vs data was edited out from 11150ft to 11169ft MD in the Maureen Fm.

Invasion correction

Well 22/29-05 was drilled with oil-based drilling muds. Invasion correction has been performed within all formations except for the non-reservoir Balder Fm.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Sele and Maureen Formations for the Vp log, within the Horda, Balder, Sele, Lista and Maureen Formations for the Vs log and within the Sele and Hod Formations for the density log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoint's.

P&T data

The temperature and pressure data for Well 22/29-05 is displayed in the figures below;

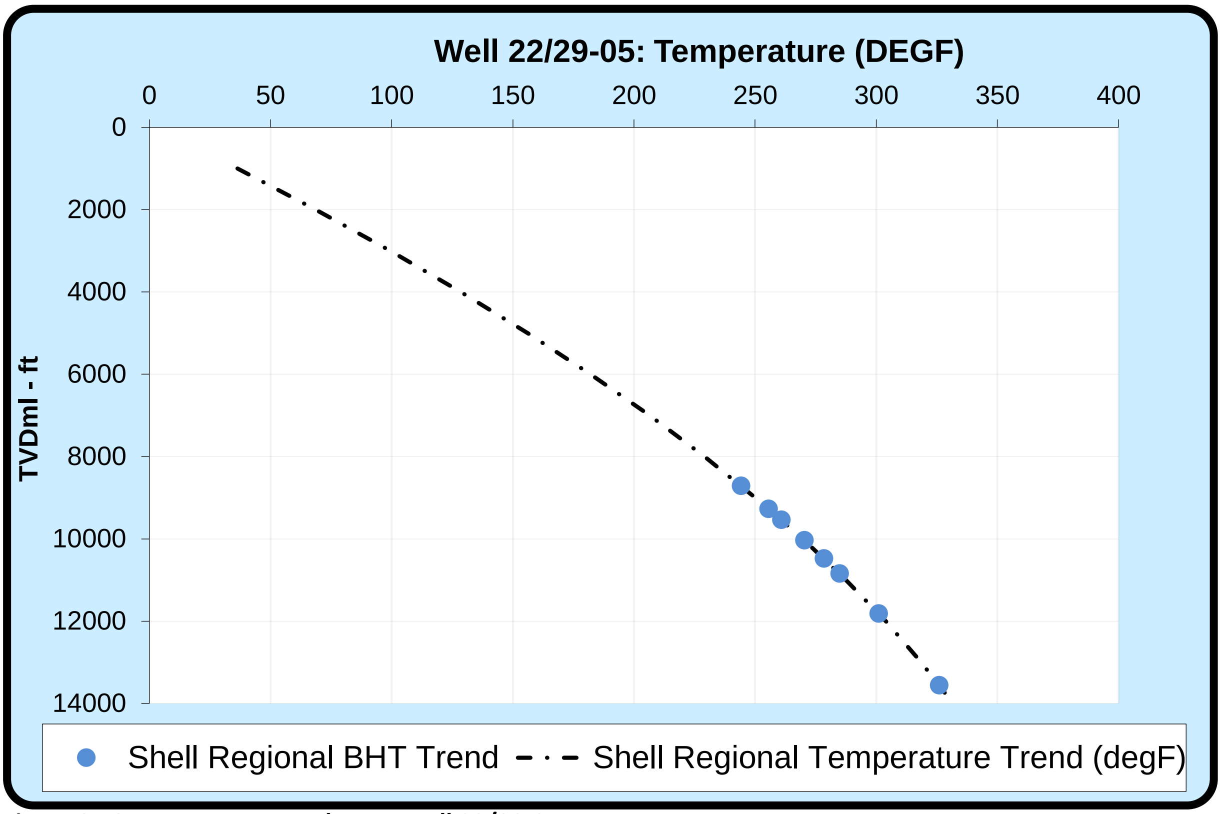


Figure 3.18.1 - Temperature data at Well 22/29-05

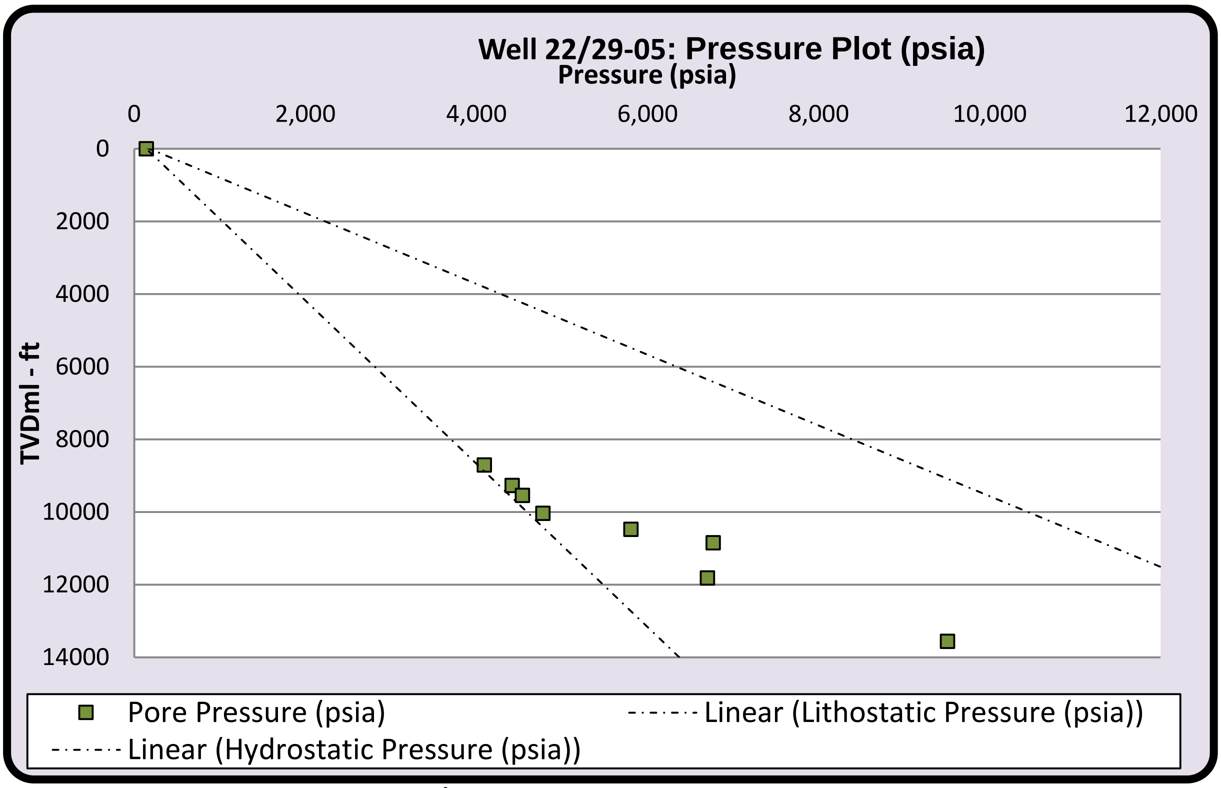


Figure 3.18.2 - Pressure data at Well 22/29-05

The temperature and pressure data for the formation mid-points in Well 22/29-05 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydrostatic Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/29-05	Sea Bed	386.0	304.0	0.0	39.2	135.3	135.3	135.3	0.0
22/29-05	Horda	9288.5	8950.7	8646.7	242.9	3983.1	4063.1	8782.0	4718.9
22/29-05	Balder	9968.5	9584.0	9280.0	255.8	4264.9	4364.9	9415.3	5050.4
22/29-05	Sele	10374.5	9967.9	9663.9	263.3	4435.7	4535.7	9799.2	5263.5
22/29-05	Lista	10926.0	10488.7	10184.7	273.1	4667.5	4817.5	10320.0	5502.5
22/29-05	Maureen	11245.0	10788.8	10484.8	278.6	4801.0	5801.0	10620.1	4819.1
22/29-05	Ekofisk	11531.5	11058.8	10754.8	283.3	4921.2	6421.2	10890.1	4468.9
22/29-05	Tor	12501.0	11965.1	11661.1	298.5	5324.5	6724.5	11796.3	5071.9
22/29-05	Hod	13974.0	13231.4	12927.4	317.6	5888.0	9220.0	13062.7	3842.7

Table 3.18.1 - Summary of mid-point temperature and pressure data at Well 22/29-05

Fluid data

A summary of the fluid set parameters at Well 22/29-05 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/29-05	Horda	75500	730	40.7	0.78	0.78
22/29-05	Balder	75500	730	41.4	0.78	0.78
22/29-05	Sele	75500	730	41.8	0.78	0.78
22/29-05	Lista	75500	730	42.4	0.78	0.78
22/29-05	Maureen	75500	730	42.7	0.78	0.78
22/29-05	Ekofisk	75500	730	43.0	0.78	0.78
22/29-05	Tor	75500	730	44.0	0.78	0.78
22/29-05	Hod	75500	730	45.3	0.78	0.78

Table 3.18.2 - Summary of fluid parameter data at Well 22/29-05

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
22/29-05	Horda	16380	56.4	0.8
22/29-05	Balder	16380	57.0	0.8
22/29-05	Sele	16380	57.3	0.8
22/29-05	Lista	16380	57.7	0.8
22/29-05	Maureen	16380	58.0	0.8
22/29-05	Ekofisk	16380	58.2	0.8
22/29-05	Tor	16380	59.0	0.8
22/29-05	Hod	16380	60.1	0.8

Table 3.18.3 - Summary of additional parameter data at Well 22/29-05

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.18.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	16.83	9.53	2.51	11,265	6,398

Table 3.18.5 - Tuff properties used at Well 22/29-05

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/29-05	Horda	PAY	1301.000	2.000	0.002	0.619	0.309	0.480	0.000
22/29-05	Horda	RES	1301.000	16.000	0.012	3.645	0.228	0.742	0.192
22/29-05	Balder	PAY	59.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-05	Balder	RES	59.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-05	Sele	PAY	753.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-05	Sele	RES	753.000	489.500	0.650	92.206	0.188	0.983	0.185
22/29-05	Lista	PAY	350.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-05	Lista	RES	350.000	164.000	0.469	26.589	0.162	0.905	0.211
22/29-05	Maureen	PAY	288.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-05	Maureen	RES	288.000	47.250	0.164	5.007	0.106	0.959	0.199
22/29-05	Ekofisk	PAY	285.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-05	Ekofisk	RES	285.000	234.750	0.824	20.844	0.089	0.964	0.150
22/29-05	Tor	PAY	1654.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-05	Tor	RES	1654.000	1380.50	0.835	73.213	0.053	0.964	0.021
22/29-05	Hod	PAY	1292.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-05	Hod	RES	1292.000	1097.75	0.850	61.757	0.056	0.996	0.244

Table 3.18.6 - Petrophysical parameters used at Well 22/29-05

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

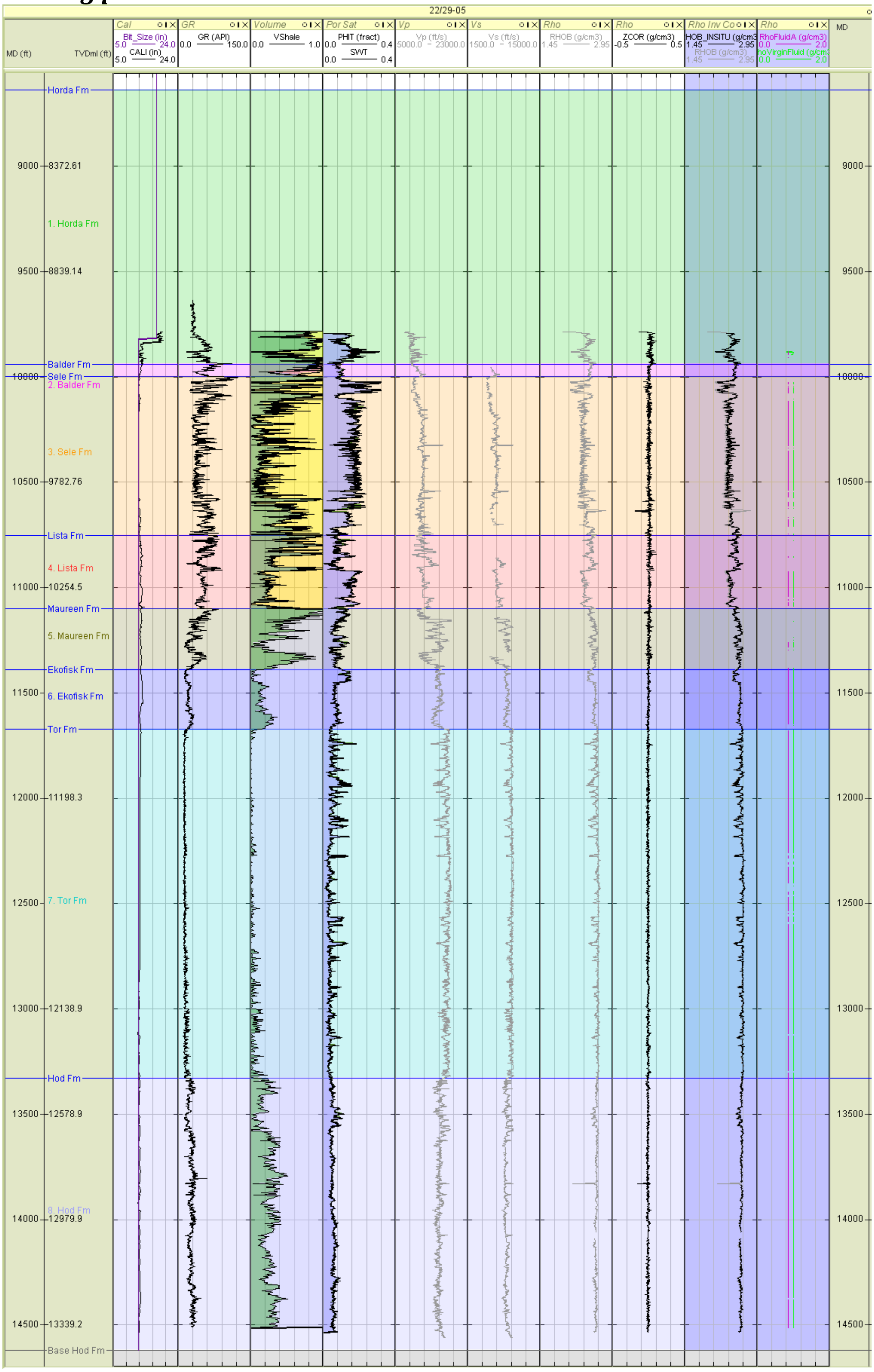


Figure 3.18.3 - Well Panel: Measured data and invasion correction for well 22/29-05.

Well log panel – log editing and audit

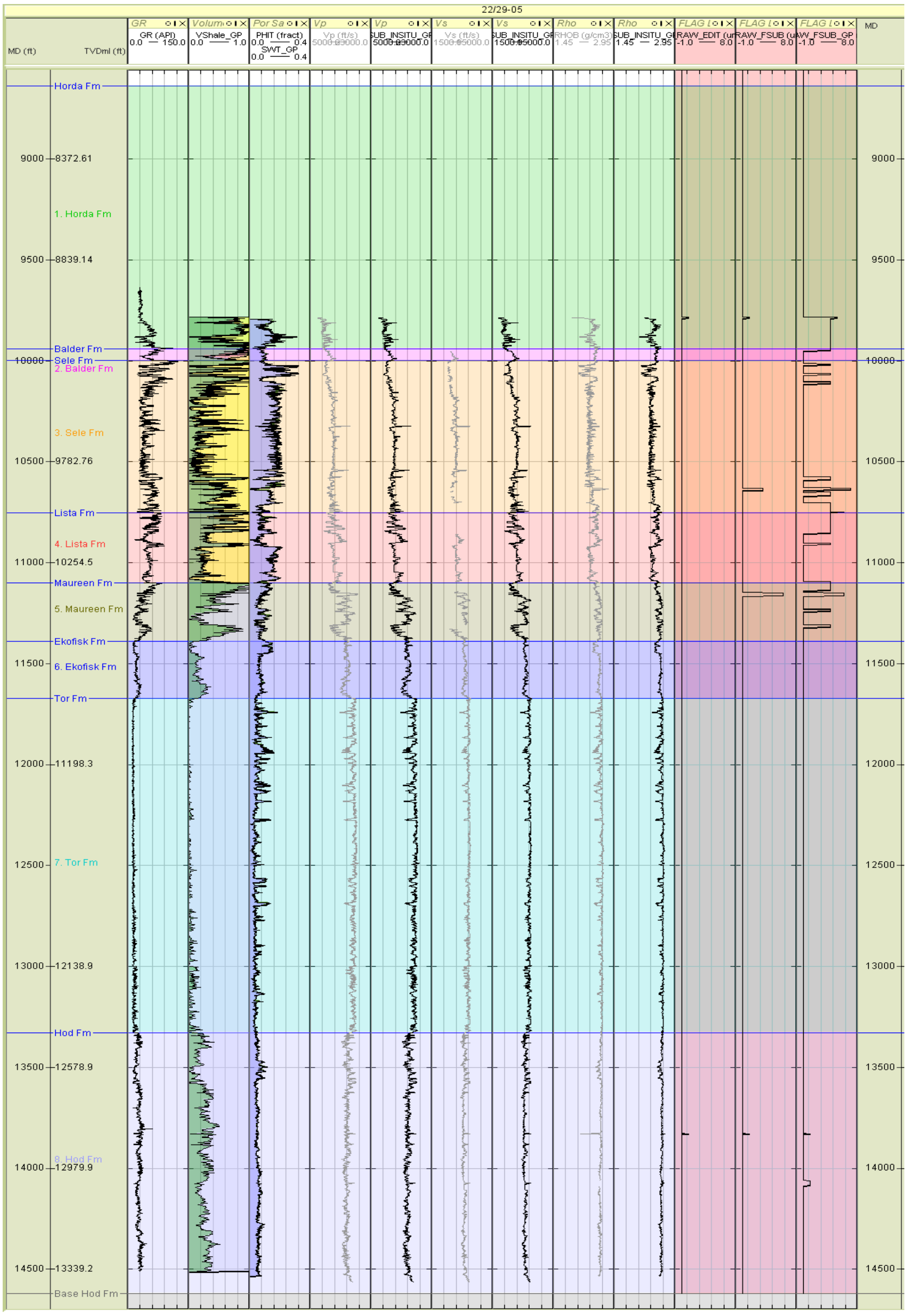


Figure 3.18.4 - Well Panel: Log edits for well 22/29-05.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

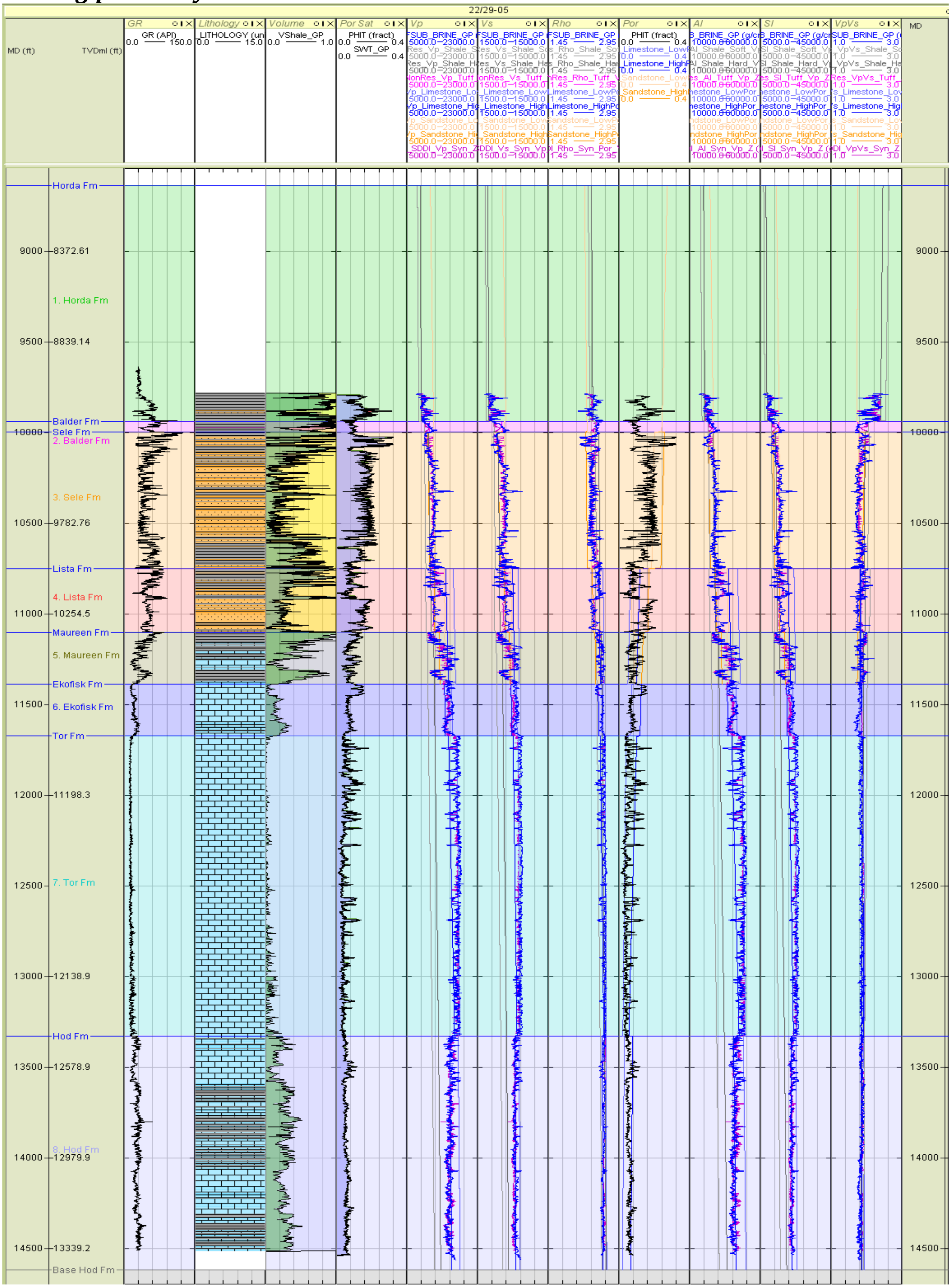


Figure 3.18.5 - Well Panel: End-member and synthetic logs for well 22/29-05.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

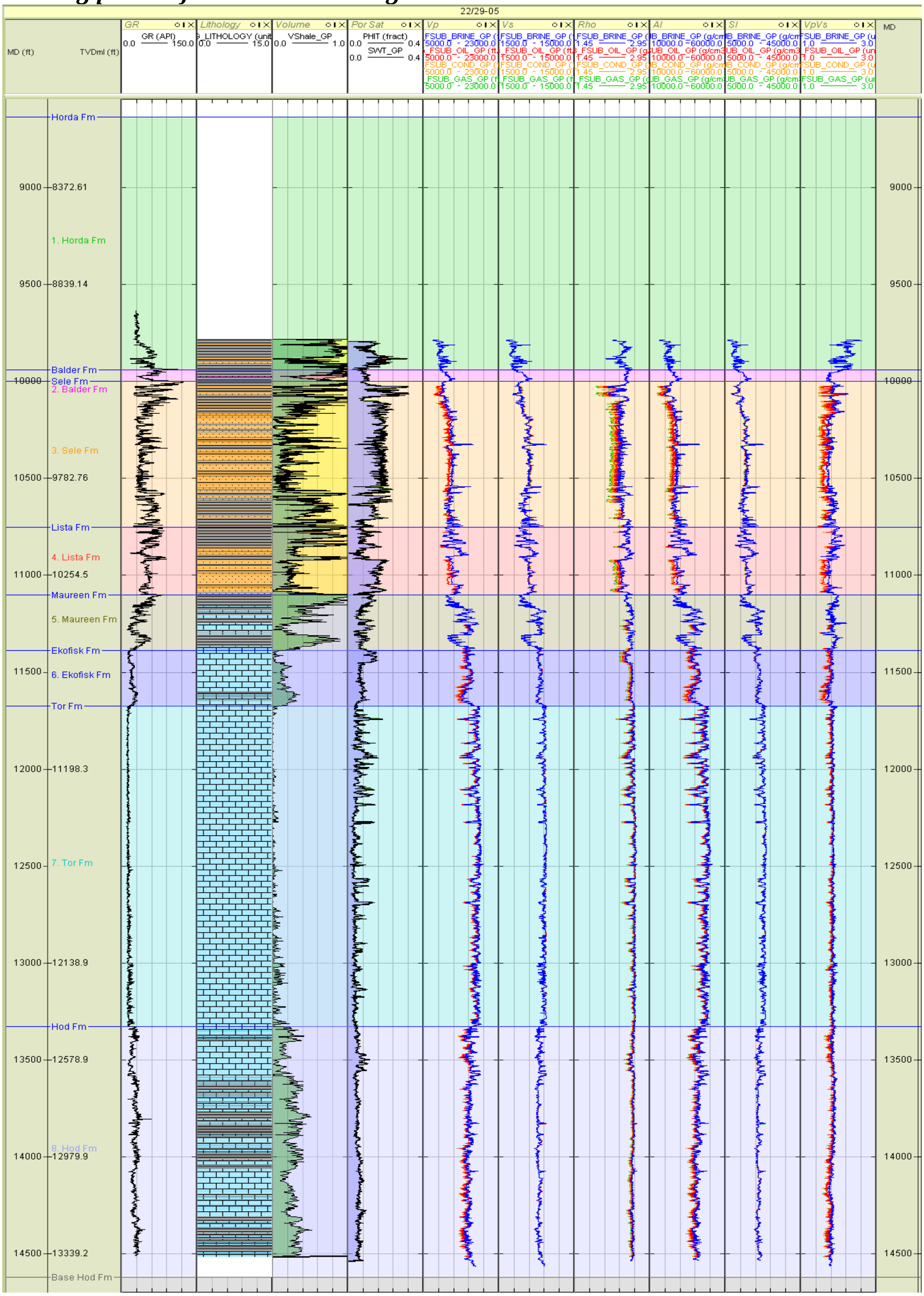


Figure 3.18.6 - Well Panel: Fluid substituted and elastic logs for well 22/29-05.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/29-05 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Horda	8965	3957	2.43
22/29-05	Balder	10086	5373	2.50
22/29-05	Sele	10315	5477	2.47
22/29-05	Lista	10830	5564	2.49
22/29-05	Maureen	11328	5883	2.50

Table 3.18.7 - Clean shale properties at Well 22/29-05

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Horda	100% Brine			
22/29-05	Balder	100% Brine			
22/29-05	Sele	100% Brine	11708	6696	2.34
22/29-05	Lista	100% Brine	12453	7061	2.41
22/29-05	Maureen	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Horda	80% Oil			
22/29-05	Balder	80% Oil			
22/29-05	Sele	80% Oil	10968	6771	2.28
22/29-05	Lista	80% Oil	11908	7114	2.37
22/29-05	Maureen	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Horda	90% Gas			
22/29-05	Balder	90% Gas			
22/29-05	Sele	90% Gas	10854	6895	2.20
22/29-05	Lista	90% Gas	11839	7199	2.32
22/29-05	Maureen	90% Gas			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Horda	80% Cond			
22/29-05	Balder	80% Cond			
22/29-05	Sele	80% Cond	10843	6854	2.28
22/29-05	Lista	80% Cond	11812	7173	2.34
22/29-05	Maureen	80% Cond			

Table 3.18.8 - Clean sand properties at Well 22/29-05 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Maureen	100% Brine	16,044	8,802	2.58
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-05	Maureen	80% Oil	15,926	8,823	2.57
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-05	Maureen	90% Gas	15,932	8,853	2.55
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-05	Maureen	80% Cond	15,919	8,844	2.55

Table 3.18.9 - Clean limestone properties at Well 22/29-05 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

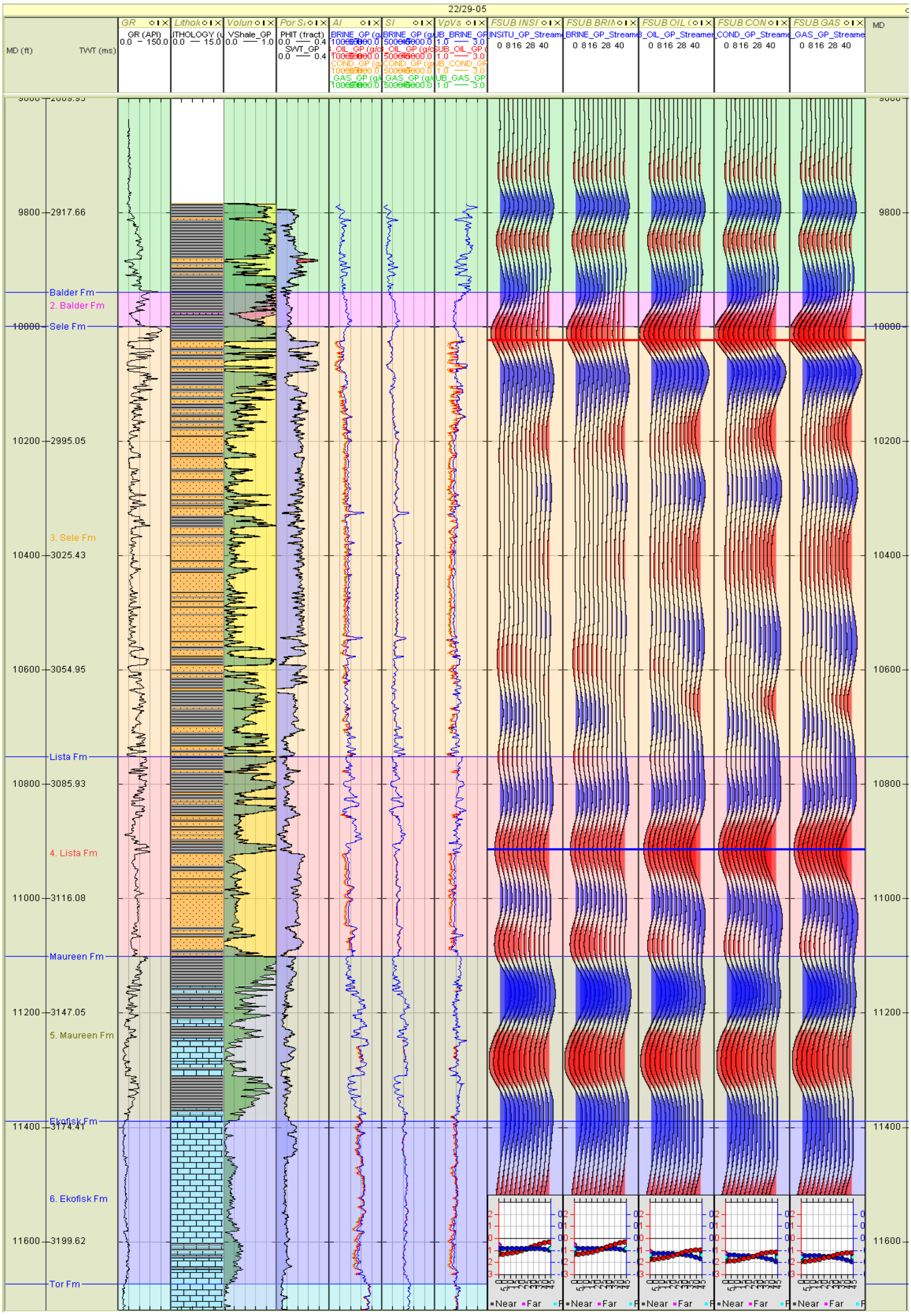


Figure 3.18.7 - Well Panel: Tertiary reservoirs for well 22/29-05. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by inter-bedded sand and shales. The highest porosity sands are found at the top of the formation where the net reservoir is approximately 15 feet and the associated porosity reaches 32%.
- Blocky AVO shows a modelled class I response for the 100% brine; a modelled class II response for the 80% oil cases and a modelled class III for the 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative and increase in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

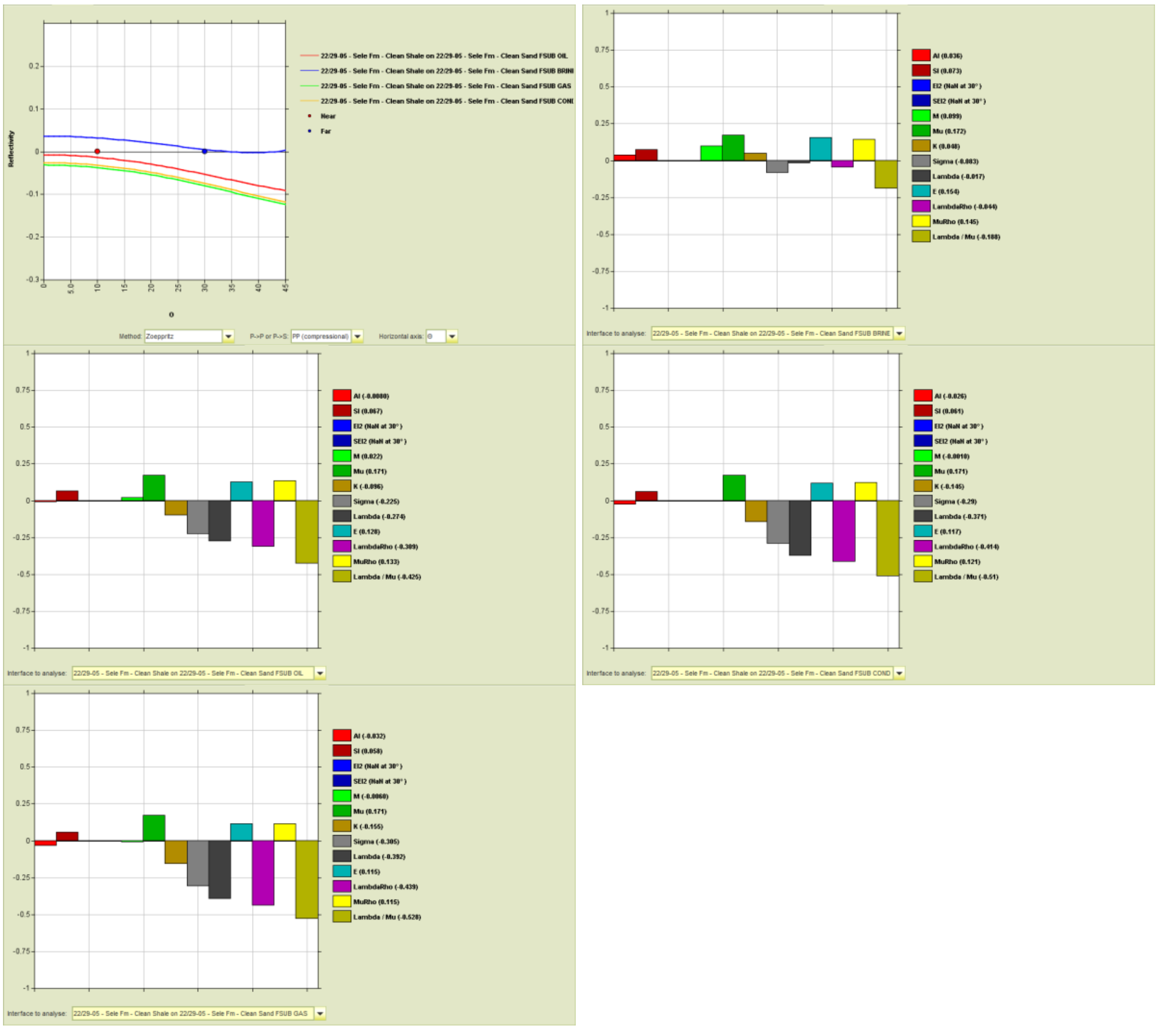


Figure 3.18.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/29-05.

Lista Formation

- Inter-bedded sand and shales, present at the top of the formation, become blockier, high porosity sand packages towards the base of the interval and where the maximum associated porosity is 21%.
- Blocky AVO shows a modelled class I response for the 100% brine case and a modelled class IIp response for the 80% oil, 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative and increase in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

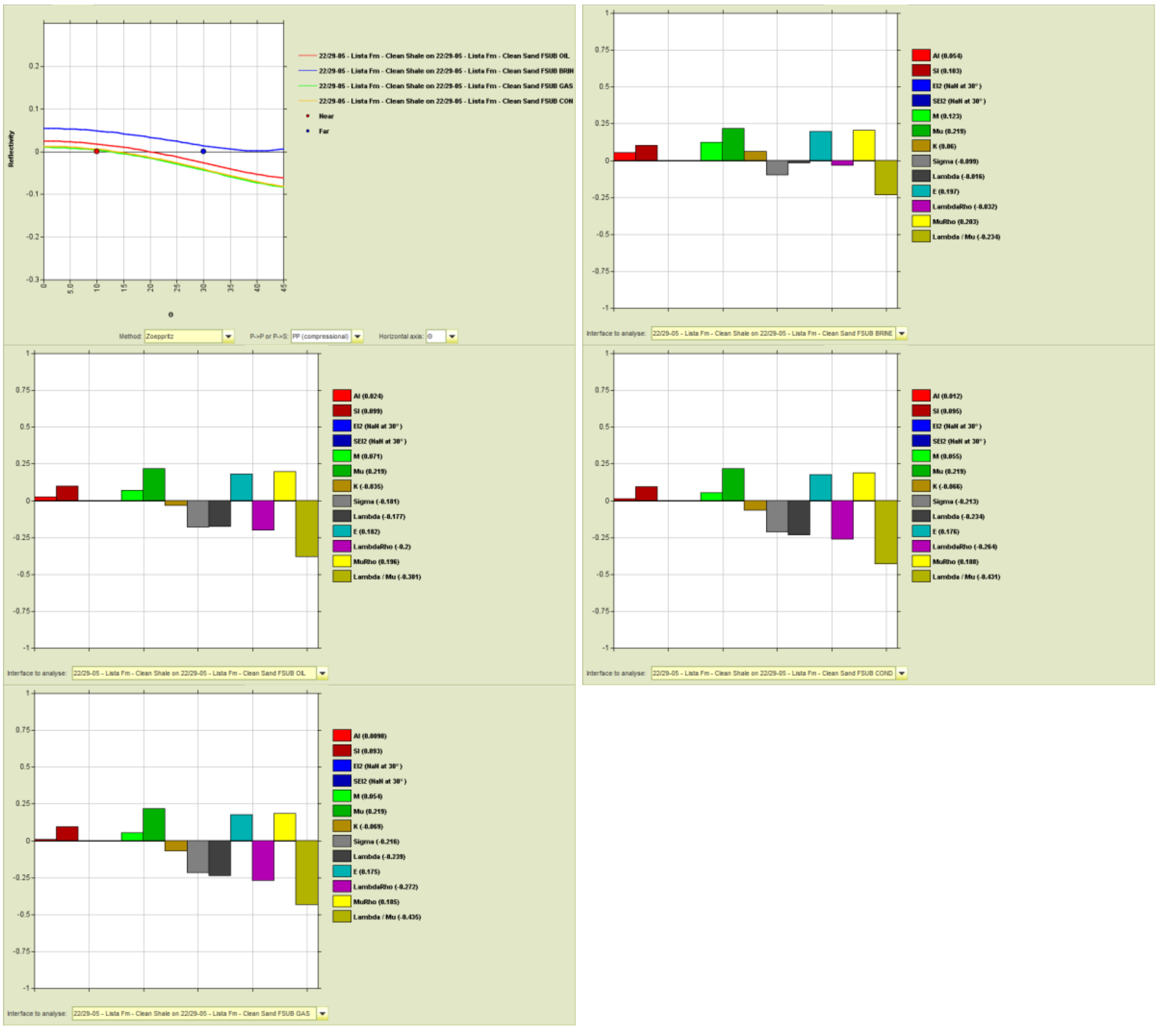


Figure 3.18.9 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/29-05.

Maureen Formation

- Reservoir formed by a set of limestone sections inter-bedded with shale, gross reservoir is approximately 288 feet but net reservoir is only approximately 47 feet due to the low porosities seen in this formation. This limestone section has high velocities and densities in comparison with the overburden sands/shale in the Lista Fm and gives a strong positive impedance contrast on the synthetic gathers.
- Blocky AVO shows a strong modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

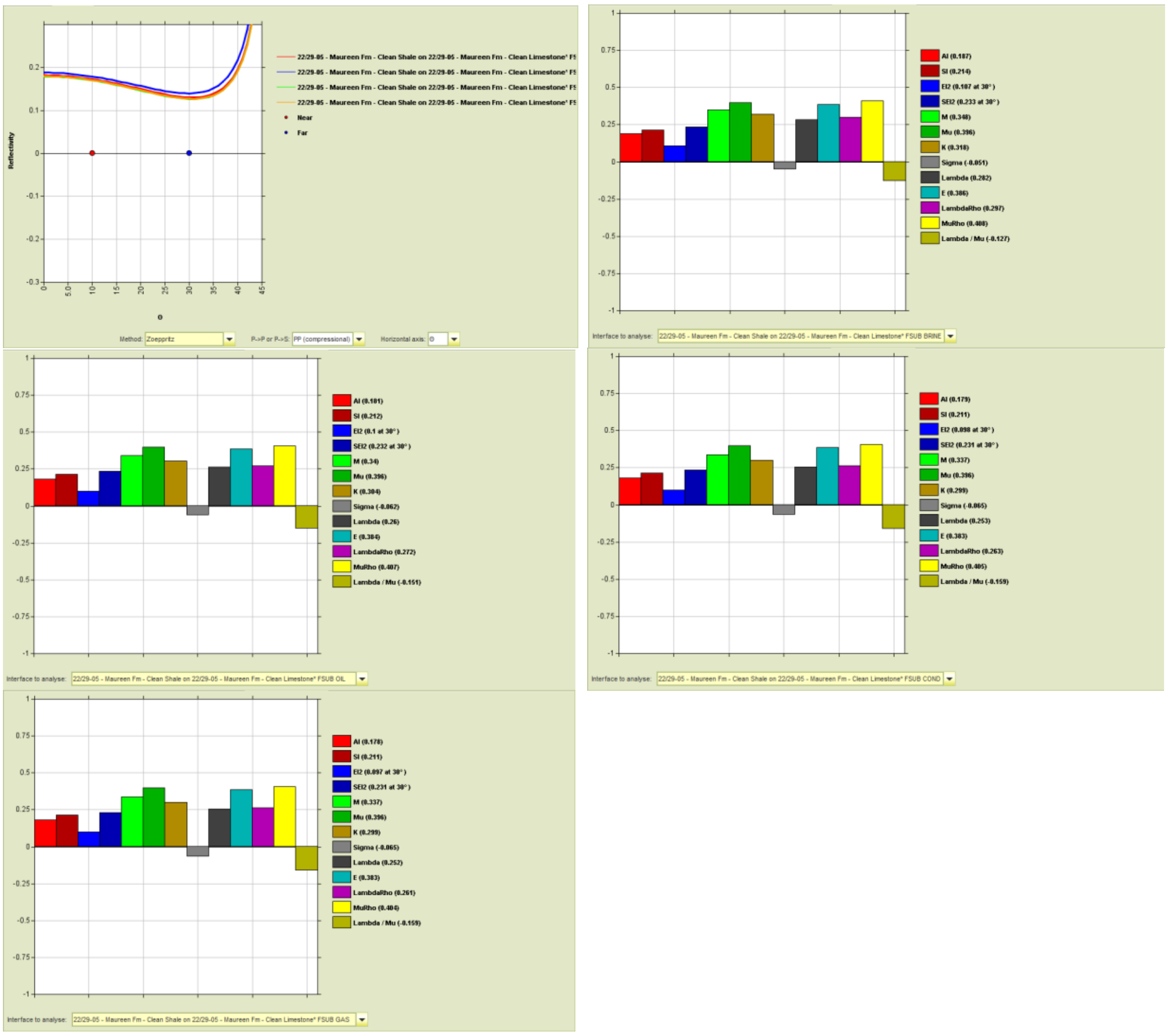


Figure 3.18.10 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/29-05.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/29-05 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Ekofisk	100% Brine	15841	8745	2.51
22/29-05	Tor	100% Brine	17731	9601	2.62
22/29-05	Hod	100% Brine	16853	9105	2.60
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Ekofisk	80% Oil	15485	8798	2.48
22/29-05	Tor	80% Oil	17531	9623	2.61
22/29-05	Hod	80% Oil	16546	9133	2.59
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Ekofisk	90% Gas	15479	8879	2.44
22/29-05	Tor	90% Gas	17513	9655	2.59
22/29-05	Hod	90% Gas	16481	9175	2.56
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Ekofisk	80% Cond	15448	8854	2.45
22/29-05	Tor	80% Cond	17502	9645	2.60
22/29-05	Hod	80% Cond	16473	9162	2.57

Table 3.18.10 - Clean limestone properties at Well 22/29-05 for each fluid case

Cretaceous reservoirs

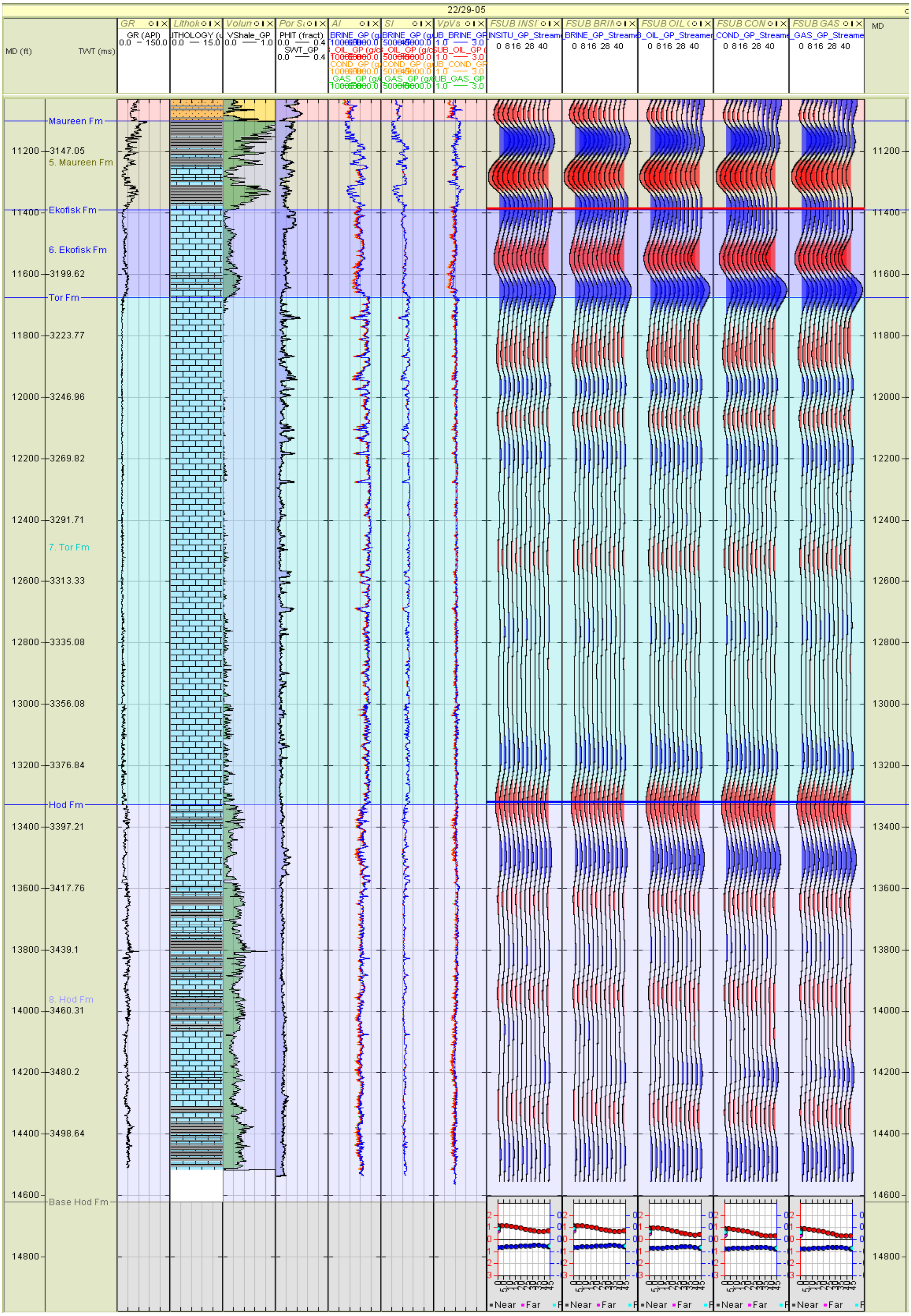


Figure 3.18.11 - Well Panel: Cretaceous reservoirs for well 22/29-05. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the top section of the Ekofisk Fm and the porosity in this section is approximately 16%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

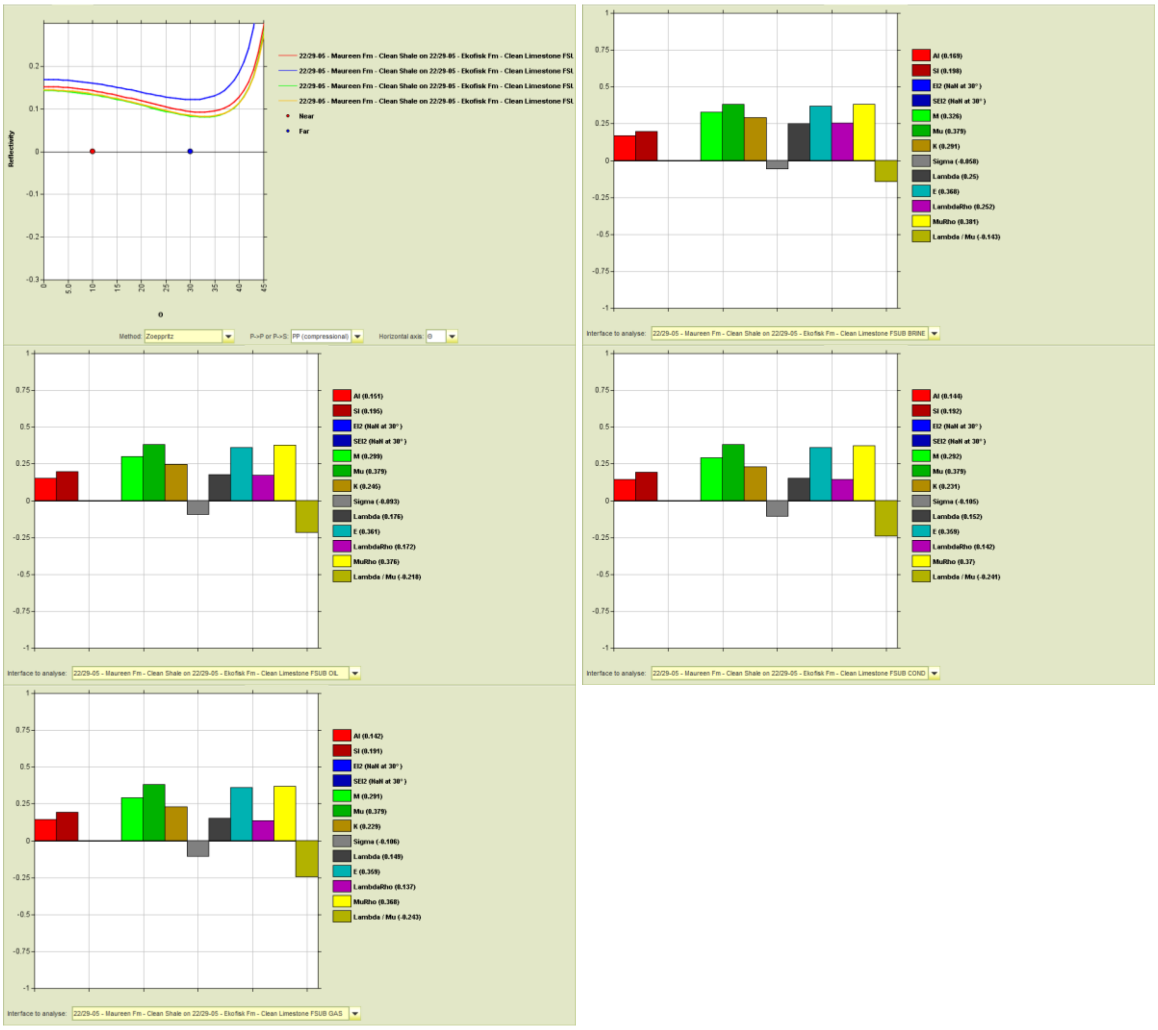


Figure 3.18.12 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/29-05.

Tor Formation

- Reservoir formed by a clean limestone formation. High porosity layers are found throughout the Tor Fm and could be representative of reworked chalk zones. The maximum porosity associated with these layers is 18%.
- Blocky AVO shows a modelled class I response for all the fluid cases.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

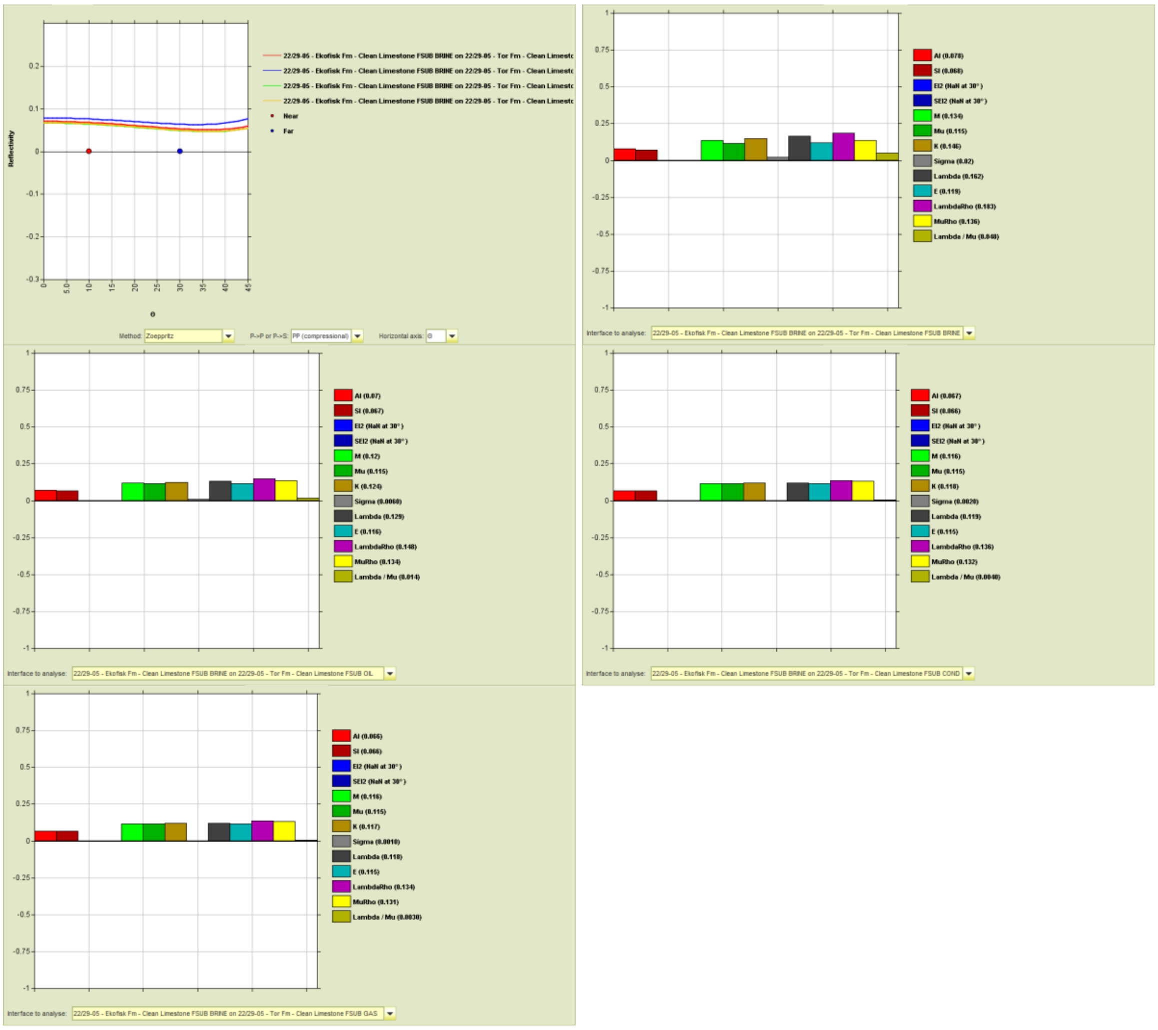


Figure 3.18.13 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/29-05.

Hod Formation

- Reservoir formed by a limestone formation inter-bedded with shale. The highest porosity reservoir is found in the top section of the Hod Fm and the porosity in this section is approximately 1%.
- Blocky AVO shows a modelled class IV response for all the fluid cases.
- Elastic Contrast Analysis shows contrasts are all negative and of low amplitude in the brine case, but that the contrasts decrease in amplitude to become more negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

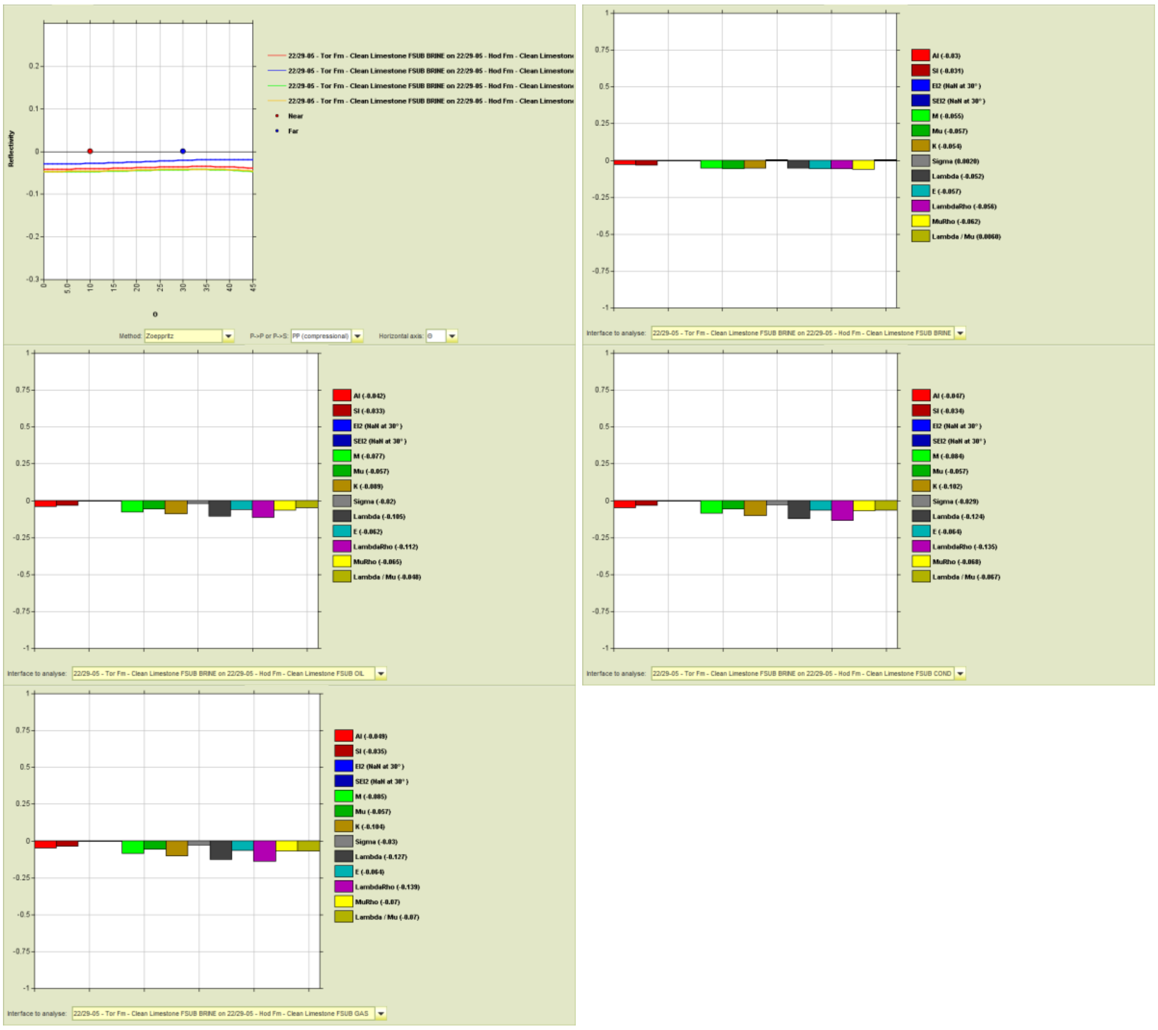


Figure 3.18.14 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/29-05.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/29-05 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

In this well, there were no logs present in the underburden and overburden sections.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-05	Overburden				
22/29-05	Underburden				

Table 3.18.11 - Overburden and underburden properties at Well 22/29-05.

Well: 22/29-06S2

General

Well Information
A Shell exploration well drilled into an unassigned field location. Completed and abandoned in 1996.

Objectives
The primary objective of well 22/29-06S2 was the Fulmar formation. The secondary objectives were the Pentland and Skagerrak formations.

Log conditioning overview
Minor edits to remove bad Vs data in the Horda and Balder Fm's. Thin calcite stringers in the Horda Fm are not captured by the sonic logs so Vp, Vs and density log data have all been edited at these points. Poor data was also removed from Vs log at 9890ft MD in the Sele Fm and a small section of bad data removed from Vp log at 10296ft MD in the Lista Fm.

Invasion correction

Well 22/29-06S2 was drilled with oil-based drilling mud. Invasion correction performed within all formations except for the non-reservoir Balder Fm.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda and Ekofisk Formations for the Vp log, within the Horda, Balder, Sele, Ekofisk, Tor and Hod Formations for the Vs log and within the Horda, Ekofisk and Hod Formations for the density log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoint's.

P&T data

The temperature and pressure data for Well 22/29-06S2 is displayed in the figures below;

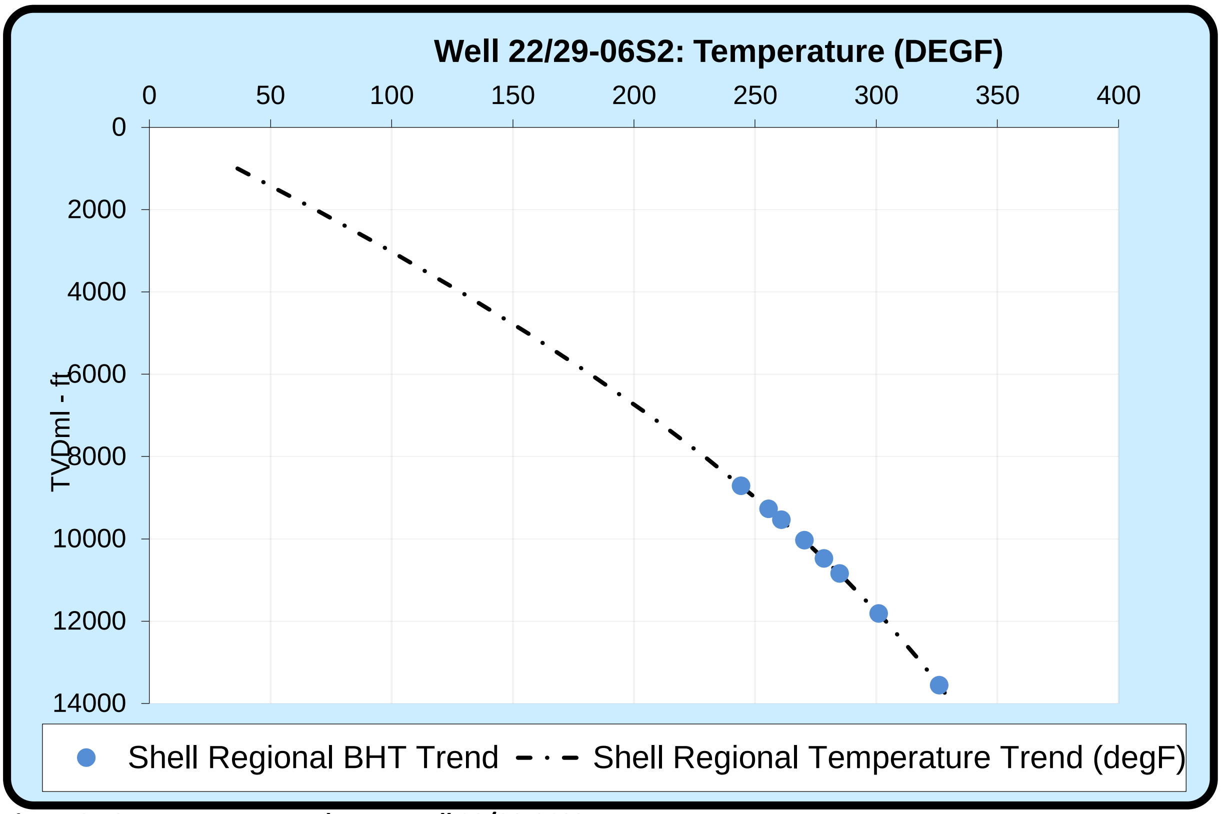


Figure 3.19.1 - Temperature data at Well 22/29-06S2

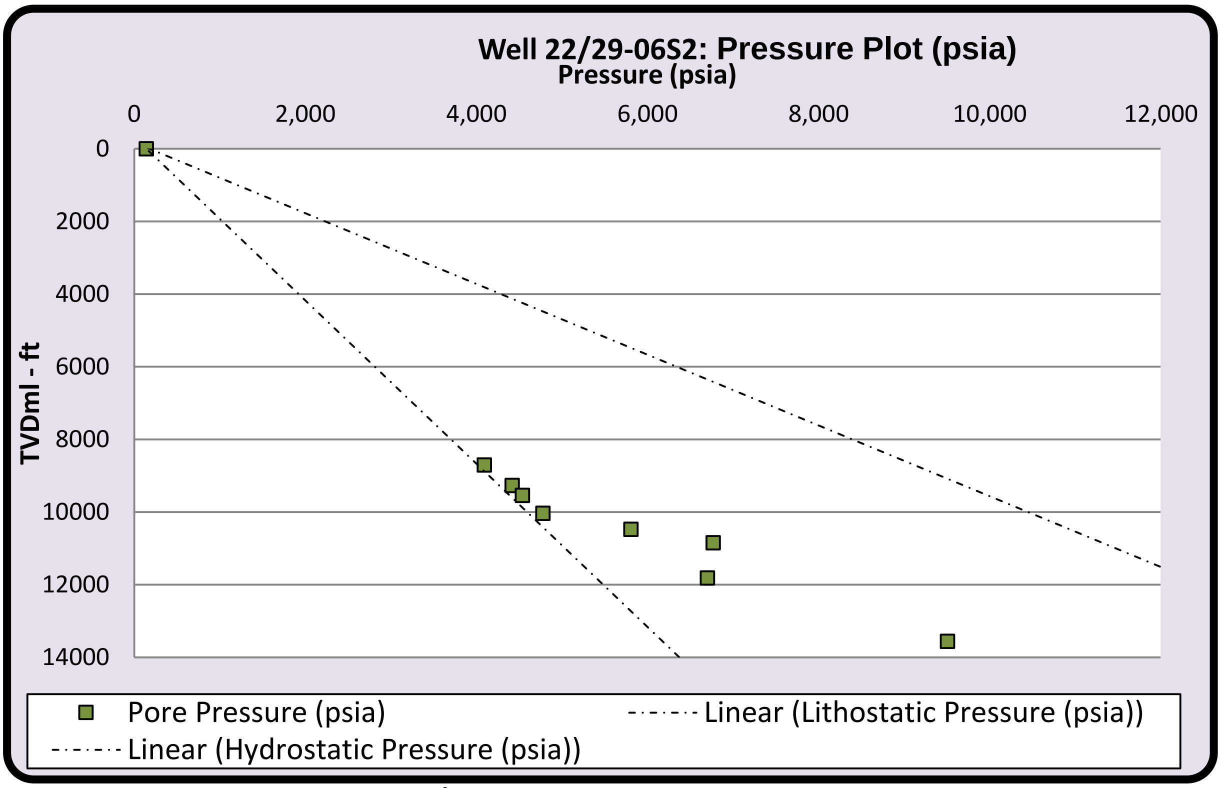


Figure 3.19.2 - Pressure data at Well 22/29-06S2

The temperature and pressure data for the formation mid-points in Well 22/29-06S2 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/29-06S2	Sea Bed	394.0	325.0	0.0	39.2	144.6	144.6	144.6	0.0
22/29-06S2	Horda	9216.0	9034.5	8709.5	244.2	4020.4	4093.4	8854.1	4760.8
22/29-06S2	Balder	9781.0	9599.1	9274.1	255.7	4271.6	4421.6	9418.7	4997.1
22/29-06S2	Sele	10047.0	9864.9	9539.9	260.9	4389.9	4539.9	9684.6	5144.7
22/29-06S2	Lista	10544.5	10362.3	10037.3	270.4	4611.2	4781.2	10181.9	5400.7
22/29-06S2	Maureen	10986.0	10803.7	10478.7	278.4	4807.6	5807.6	10623.3	4815.7
22/29-06S2	Ekofisk	11354.5	11172.2	10847.2	284.9	4971.6	6771.6	10991.8	4220.2
22/29-06S2	Tor	12328.0	12144.4	11819.4	301.1	5404.3	6704.3	11964.0	5259.8
22/29-06S2	Hod	14070.0	13883.6	13558.6	326.1	6178.2	9510.2	13703.3	4193.0

Table 3.19.1 - Summary of mid-point temperature and pressure data at Well 22/29-06S2

Fluid data

A summary of the fluid set parameters at Well 22/29-06S2 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/29-06S2	Horda	125000	730	40.8	0.78	0.78
22/29-06S2	Balder	125000	730	41.4	0.78	0.78
22/29-06S2	Sele	125000	730	41.7	0.78	0.78
22/29-06S2	Lista	125000	730	42.2	0.78	0.78
22/29-06S2	Maureen	125000	730	42.7	0.78	0.78
22/29-06S2	Ekofisk	125000	730	43.1	0.78	0.78
22/29-06S2	Tor	125000	730	44.1	0.78	0.78
22/29-06S2	Hod	125000	730	46.0	0.78	0.78

Table 3.19.2 - Summary of fluid parameter data at Well 22/29-06S2

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
22/29-06S2	Horda	16380	56.5	0.8
22/29-06S2	Balder	16380	57.0	0.8
22/29-06S2	Sele	16380	57.2	0.8
22/29-06S2	Lista	16380	57.6	0.8
22/29-06S2	Maureen	16380	58.0	0.8
22/29-06S2	Ekofisk	16380	58.3	0.8
22/29-06S2	Tor	16380	59.1	0.8
22/29-06S2	Hod	16380	60.6	0.8

Table 3.19.3 - Summary of additional parameter data at Well 22/29-06S2

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.19.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	16.26	11.16	2.53	11,501	6,885

Table 3.19.5 - Tuff properties used at Well 22/29-06S2

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/29-06S2	Horda	PAY	1052.000	1.000	0.001	0.246	0.246	0.490	0.000
22/29-06S2	Horda	RES	1052.000	186.000	0.177	40.227	0.216	0.958	0.128
22/29-06S2	Balder	PAY	78.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-06S2	Balder	RES	78.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-06S2	Sele	PAY	454.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-06S2	Sele	RES	454.000	277.500	0.611	46.767	0.169	0.972	0.215
22/29-06S2	Lista	PAY	541.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-06S2	Lista	RES	541.000	59.000	0.109	8.438	0.143	0.916	0.220
22/29-06S2	Maureen	PAY	342.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-06S2	Maureen	RES	342.000	26.000	0.076	2.489	0.096	0.841	0.158
22/29-06S2	Ekofisk	PAY	395.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-06S2	Ekofisk	RES	395.000	107.000	0.271	12.092	0.113	0.964	0.117
22/29-06S2	Tor	PAY	1552.000	0.000	0.000	0.000	0.000	0.000	0.000
22/29-06S2	Tor	RES	1552.000	417.250	0.269	24.066	0.058	0.983	0.013
22/29-06S2	Hod	PAY	1932.000	20.500	0.011	1.463	0.071	0.441	0.227
22/29-06S2	Hod	RES	1932.000	1139.75	0.590	57.893	0.051	0.942	0.244

Table 3.19.6 - Petrophysical parameters used at Well 22/29-06S2

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

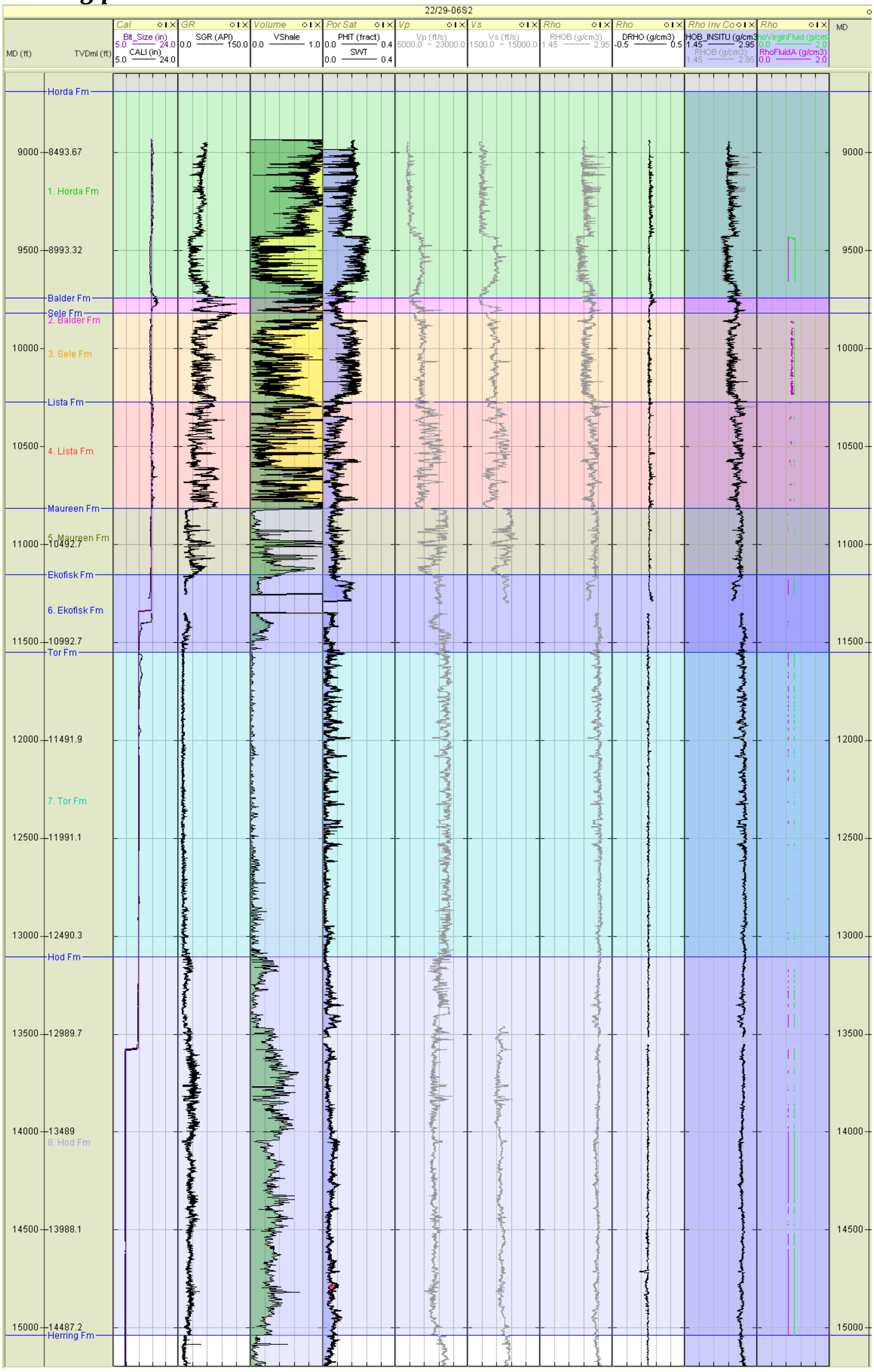


Figure 3.19.3 - Well Panel: Measured data and invasion correction for well 22/29-06S2.

Well log panel – log editing and audit

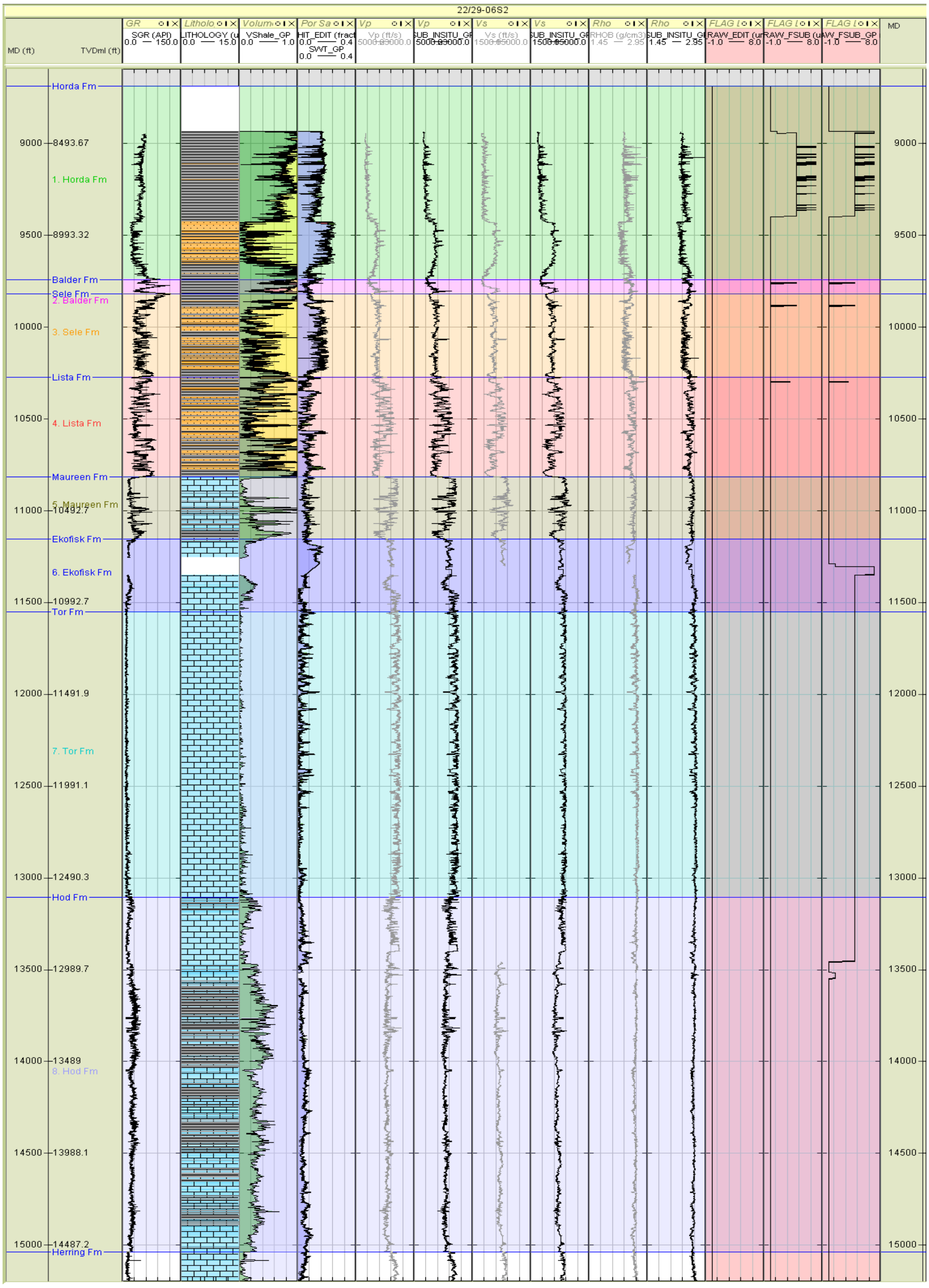


Figure 3.19.4 - Well Panel: Log edits for well 22/29-06S2.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

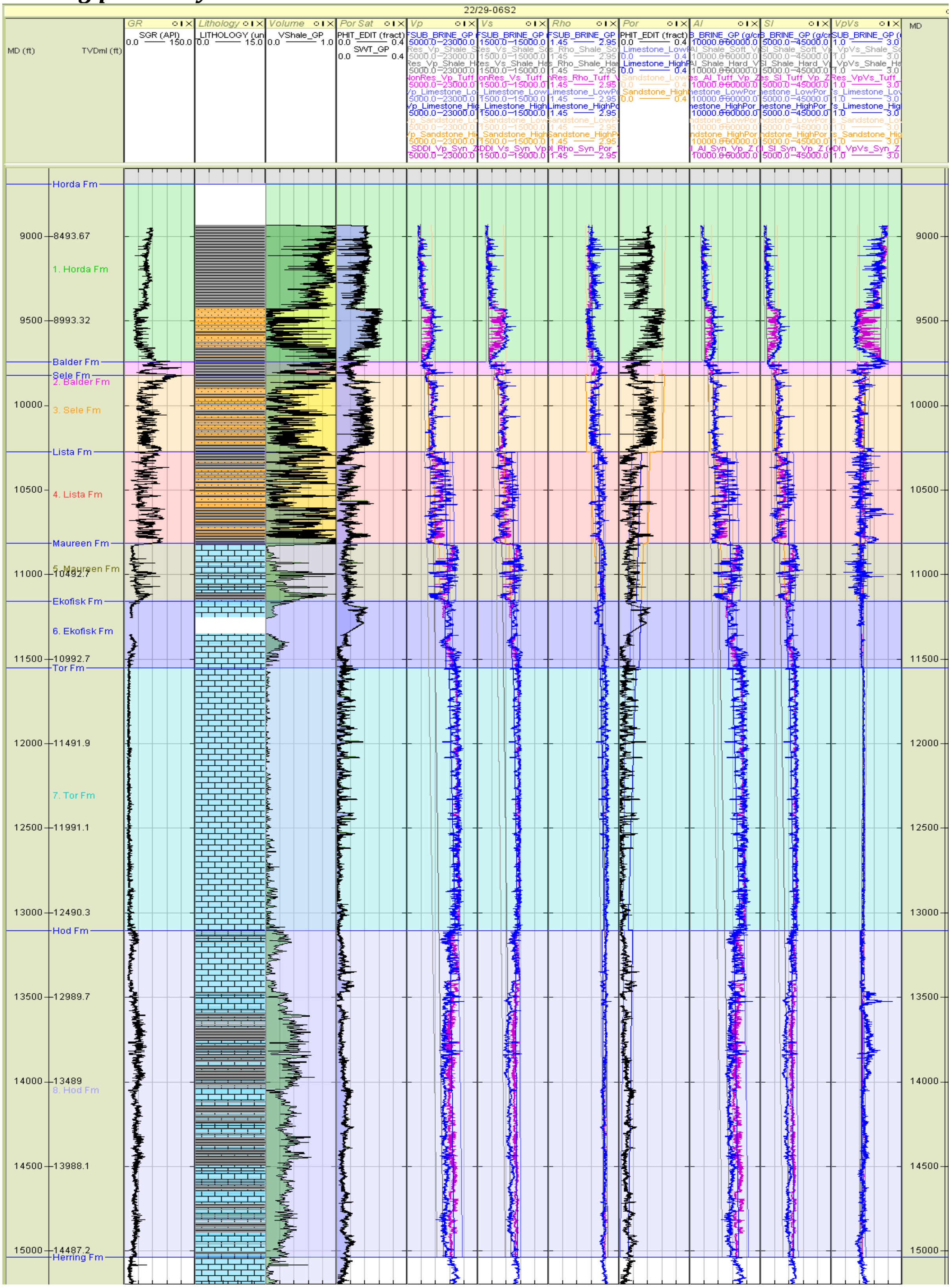


Figure 3.19.5 - Well Panel: End-member and synthetic logs for well 22/29-06S2.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

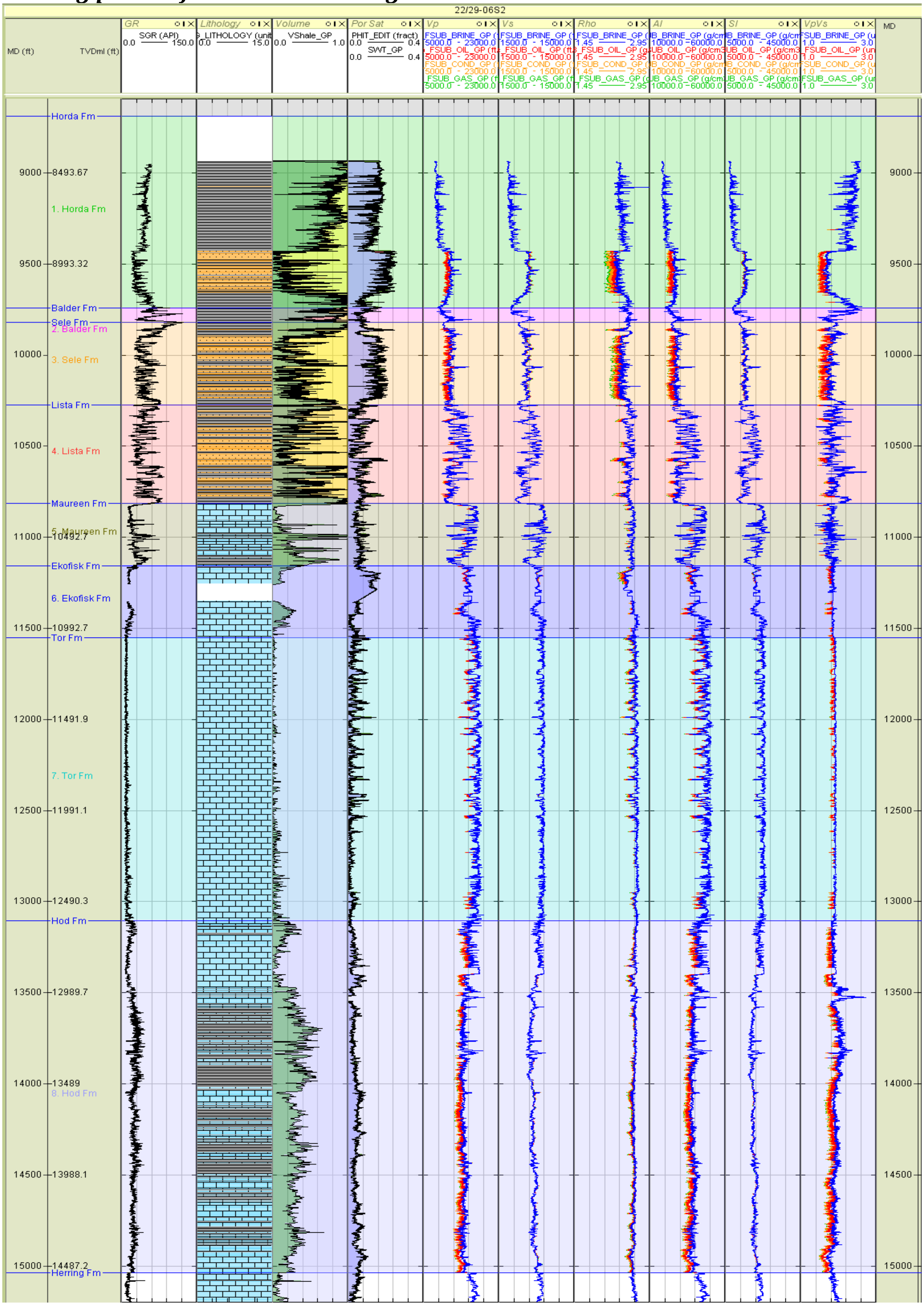


Figure 3.19.6 - Well Panel: Fluid substituted and elastic logs for well 22/29-06S2.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/09C-04 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-06S2	Horda	8,612	3,751	2.39
22/29-06S2	Balder	9,602	4,529	2.50
22/29-06S2	Sele	10,490	5,500	2.53
22/29-06S2	Lista	10,832	5,543	2.54
22/29-06S2	Maureen	12,056	6,681	2.54

Table 3.19.7 - Clean shale properties at Well 22/29-06S2

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-06S2	Horda	100% Brine	11632	6794	2.30
22/29-06S2	Balder	100% Brine			
22/29-06S2	Sele	100% Brine	11833	6666	2.37
22/29-06S2	Lista	100% Brine	14226	7728	2.56
22/29-06S2	Maureen	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-06S2	Horda	80% Oil	10820	6889	2.24
22/29-06S2	Balder	80% Oil			
22/29-06S2	Sele	80% Oil	10993	6741	2.31
22/29-06S2	Lista	80% Oil	14071	7739	2.55
22/29-06S2	Maureen	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-06S2	Horda	90% Gas	10738	7035	2.15
22/29-06S2	Balder	90% Gas			
22/29-06S2	Sele	90% Gas	10877	6852	2.24
22/29-06S2	Lista	90% Gas	14042	7755	2.54
22/29-06S2	Maureen	90% Gas			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-06S2	Horda	80% Cond	10687	6990	2.18
22/29-06S2	Balder	80% Cond			
22/29-06S2	Sele	80% Cond	10842	6818	2.26
22/29-06S2	Lista	80% Cond	14038	7750	2.54
22/29-06S2	Maureen	80% Cond			

Table 3.19.8 - Clean sand properties at Well 22/29-06S2 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-06S2	Maureen	100% Brine	16,260	9,039	2.61
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-06S2	Maureen	80% Oil	16,212	9,043	2.61
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-06S2	Maureen	90% Gas	16,206	9,050	2.60
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-06S2	Maureen	80% Cond	16,204	9,048	2.60

Table 3.19.9 - Clean limestone properties at Well 22/29-06S2 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

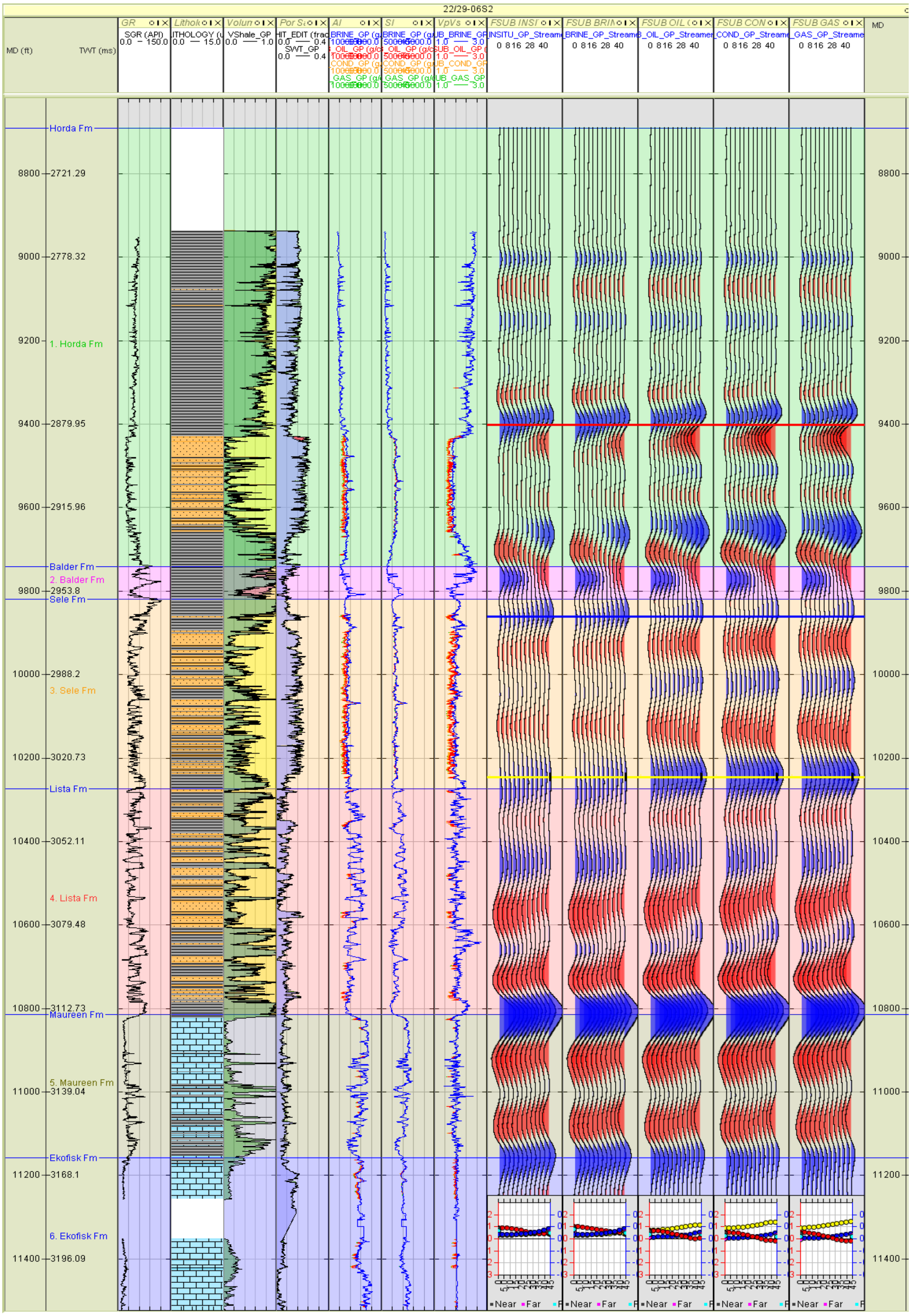


Figure 3.19.7 - Well Panel: Tertiary reservoirs for well 22/29-06S2. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir formed by inter-bedded sand and shales with a maximum porosity of 26%. The thickness of the discrete sand packages reduces with depth and the reservoir sand is over-lain directly by clean shale in the upper section of the Horda Fm.
- Blocky AVO shows a modelled class I response for the 100% brine sand and a modelled class IIp response for the 80% oil, 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, with the greatest change evident in LambdaRho with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case.

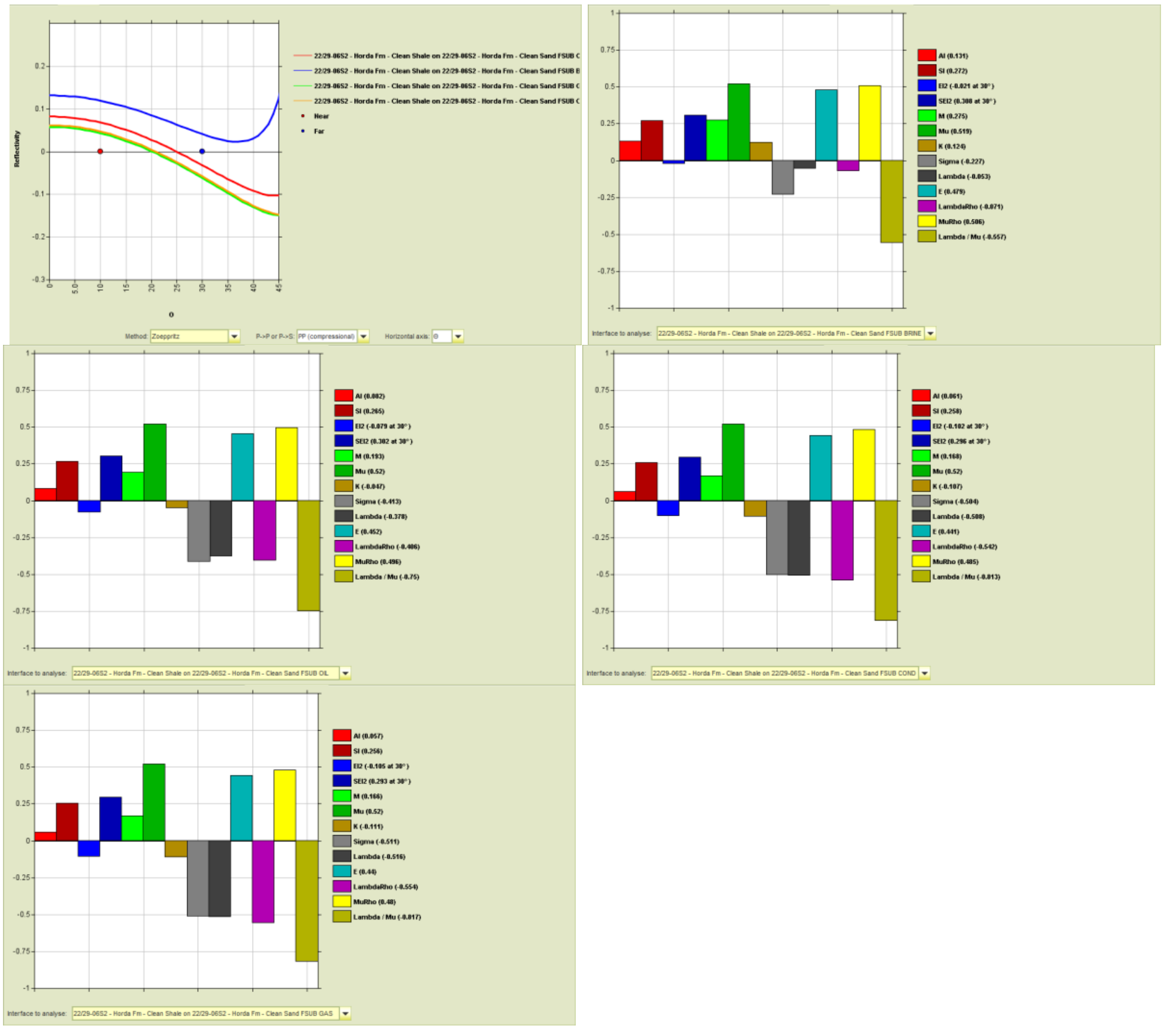


Figure 3.19.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 22/29-06S2.

Sele Formation

- Reservoir formed by inter-bedded sand and shales. A thin, 6 foot, bed of sand has a maximum porosity of 25% at the top of the formation but below this thin bed the maximum porosity is 20-22%. The thickness of the discrete sand packages reduces with depth and the reservoir sand is overlain directly by clean shale in the upper section of the Sele Fm.
- Blocky AVO shows a modelled class I response for the 100% brine case and a modelled class III response for the 80% oil, 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

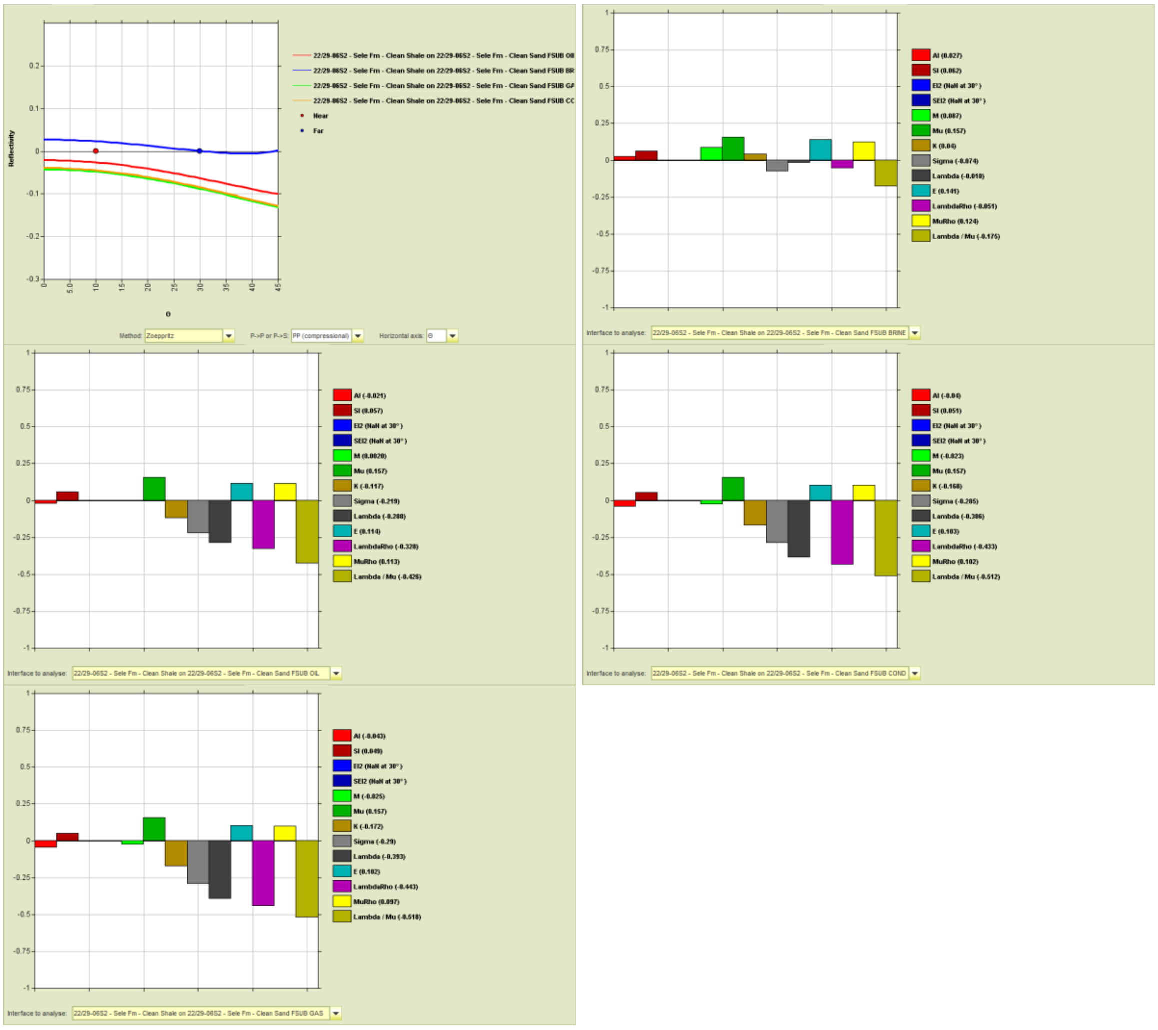


Figure 3.19.9 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/29-06S2.

Lista Formation

- Reservoir formed by inter-bedded sand and shales with a maximum porosity of 21%
- Blocky AVO shows a modelled class I response for all fluid cases.
- Elastic Contrast Analysis shows contrasts are mainly positive and of medium amplitude in the brine case, but there is no contrast between the different fluid cases with addition of hydrocarbons.

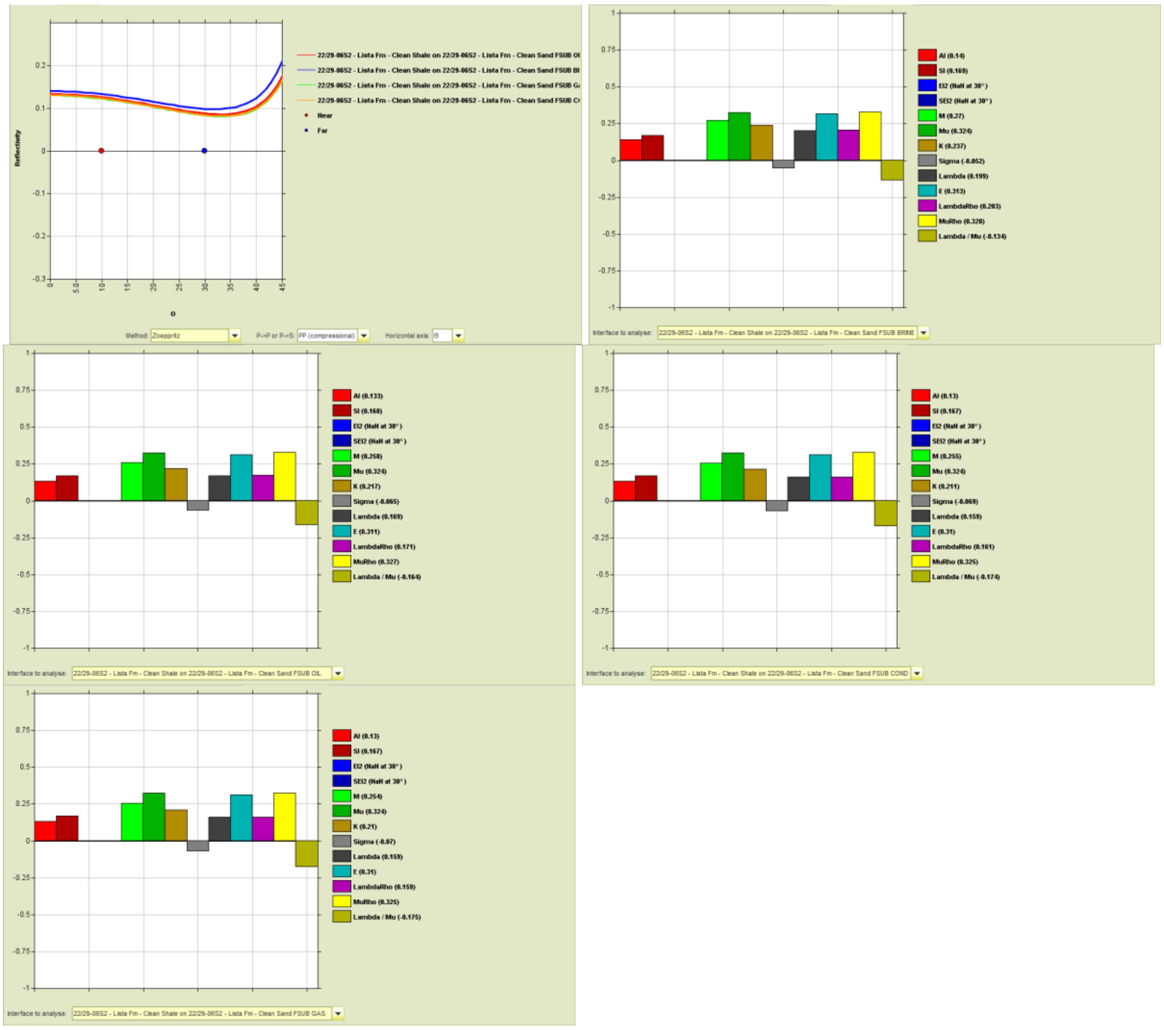


Figure 3.19.10 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/29-06S2.

Maureen Formation

- Reservoir formed by a set of limestone sections inter-bedded with shale, gross reservoir is approximately 342 feet but net reservoir is only approximately 26 feet due to the low porosities seen in this formation. This limestone section has high velocities and densities in comparison with the overburden sands/shale in the Lista Fm and gives a strong positive impedance contrast on the synthetic gathers.
- Blocky AVO shows a strong modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, and that the contrasts very slightly decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

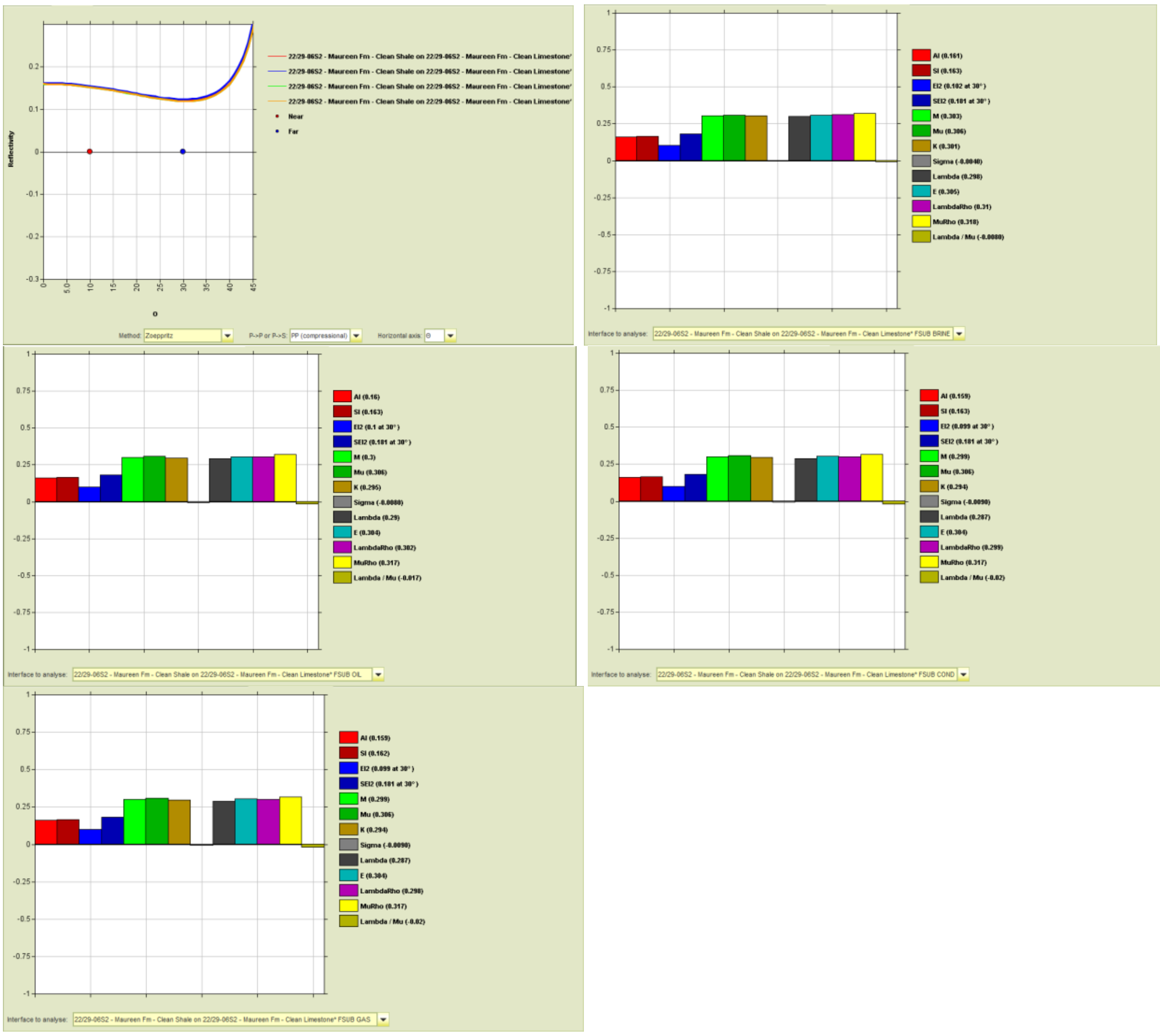


Figure 3.19.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/29-06S2.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/09C-04 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-06S2	Ekofisk	100% Brine	16735	9043	2.61
22/29-06S2	Tor	100% Brine	17655	9234	2.67
22/29-06S2	Hod	100% Brine	16702	8809	2.64
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-06S2	Ekofisk	80% Oil	16617	9061	2.60
22/29-06S2	Tor	80% Oil	17526	9242	2.66
22/29-06S2	Hod	80% Oil	16283	8823	2.63
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-06S2	Ekofisk	90% Gas	16615	9087	2.59
22/29-06S2	Tor	90% Gas	17502	9253	2.66
22/29-06S2	Hod	90% Gas	16134	8842	2.62
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/29-06S2	Ekofisk	80% Cond	16605	9079	2.59
22/29-06S2	Tor	80% Cond	17499	9250	2.66
22/29-06S2	Hod	80% Cond	16145	8836	2.63

Table 3.19.10 - Clean limestone properties at Well 22/29-06S2 for each fluid case

Cretaceous reservoirs

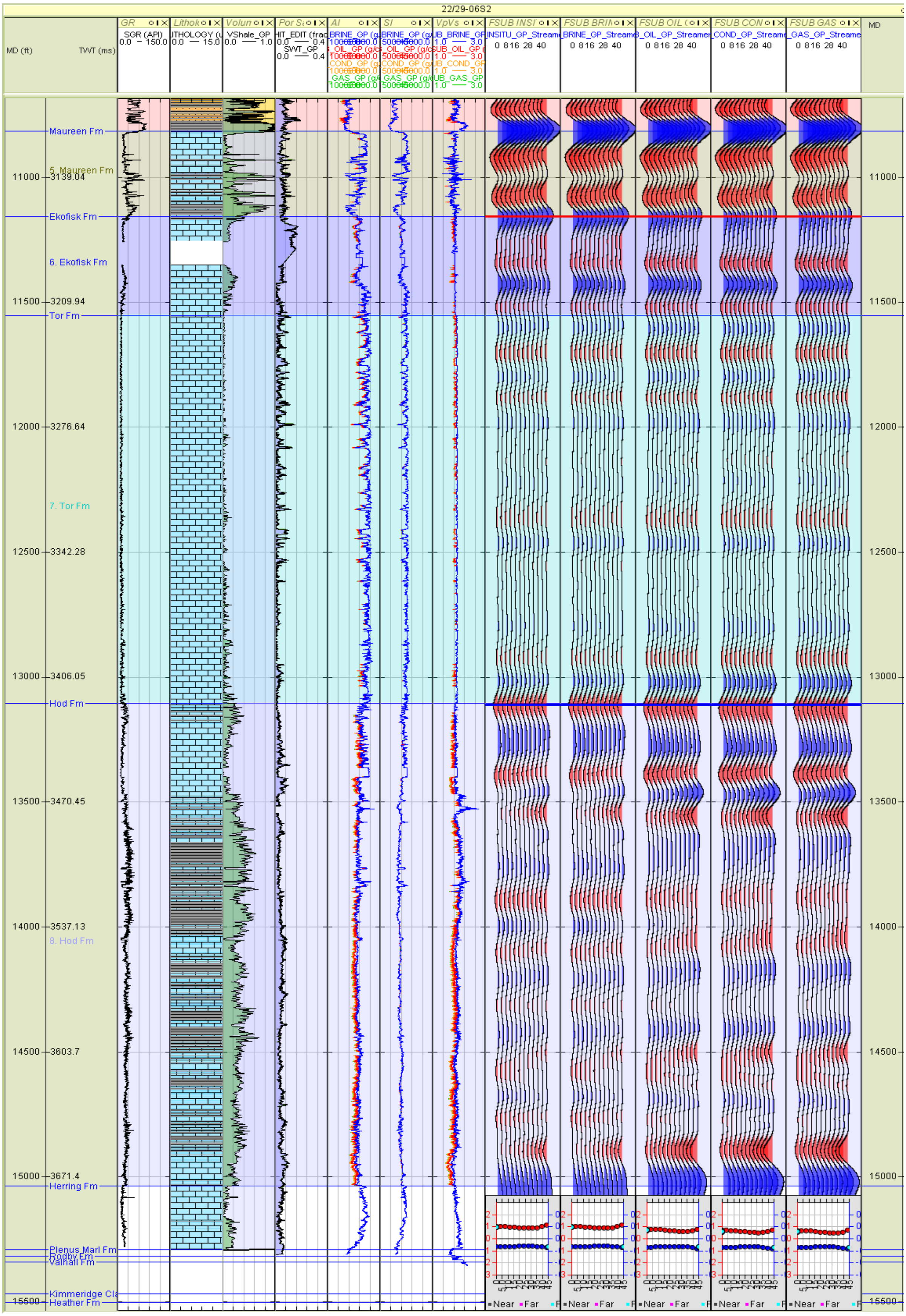


Figure 3.19.12 - Well Panel: Cretaceous reservoirs for well 22/29-06S2. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. A casing change has occurred within the middle of this interval, however, the highest porosity reservoir is found in the top section of the Ekofisk Fm and the maximum porosity in this section is approximately 17%.
- Blocky AVO shows a modelled class I response for all the fluid cases.
- Elastic Contrast Analysis shows contrasts are mainly positive and of medium amplitude in the brine case, but there is no contrast between the different fluid cases with addition of hydrocarbons.

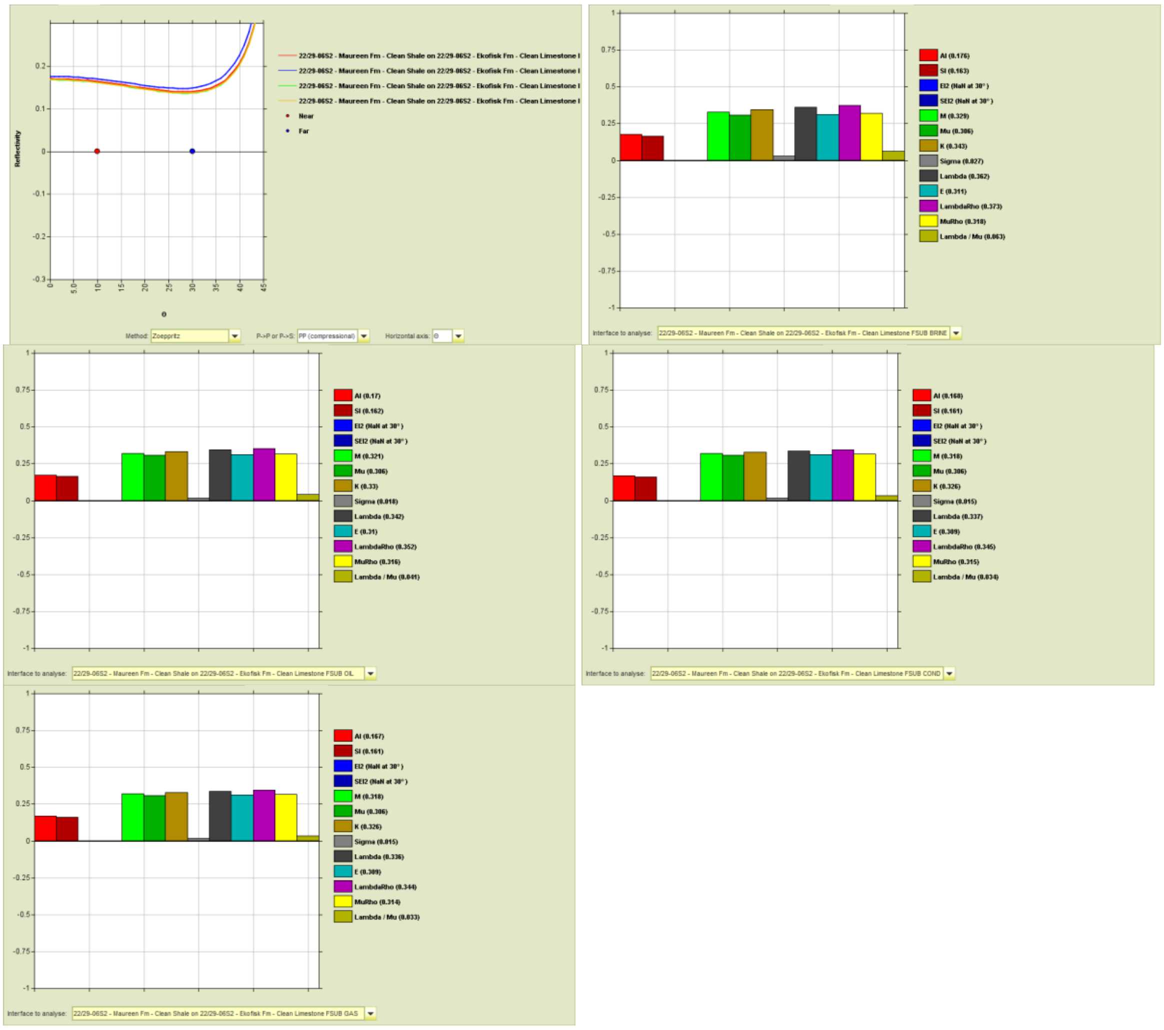


Figure 3.19.13 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/29-06S2.

Tor Formation

- Reservoir formed by a clean limestone formation. High porosity layers are found throughout the Tor Fm and could be representative of reworked chalk zones. The maximum porosity of such layers is 10-15%.
- Blocky AVO shows a modelled class I response for all the fluid cases but with a flat gradient and the amplitude does not vary with angle.
- Elastic Contrast Analysis shows contrasts are mainly positive and of very low amplitude in the brine case, but there is no contrast between the different fluid cases with addition of hydrocarbons.

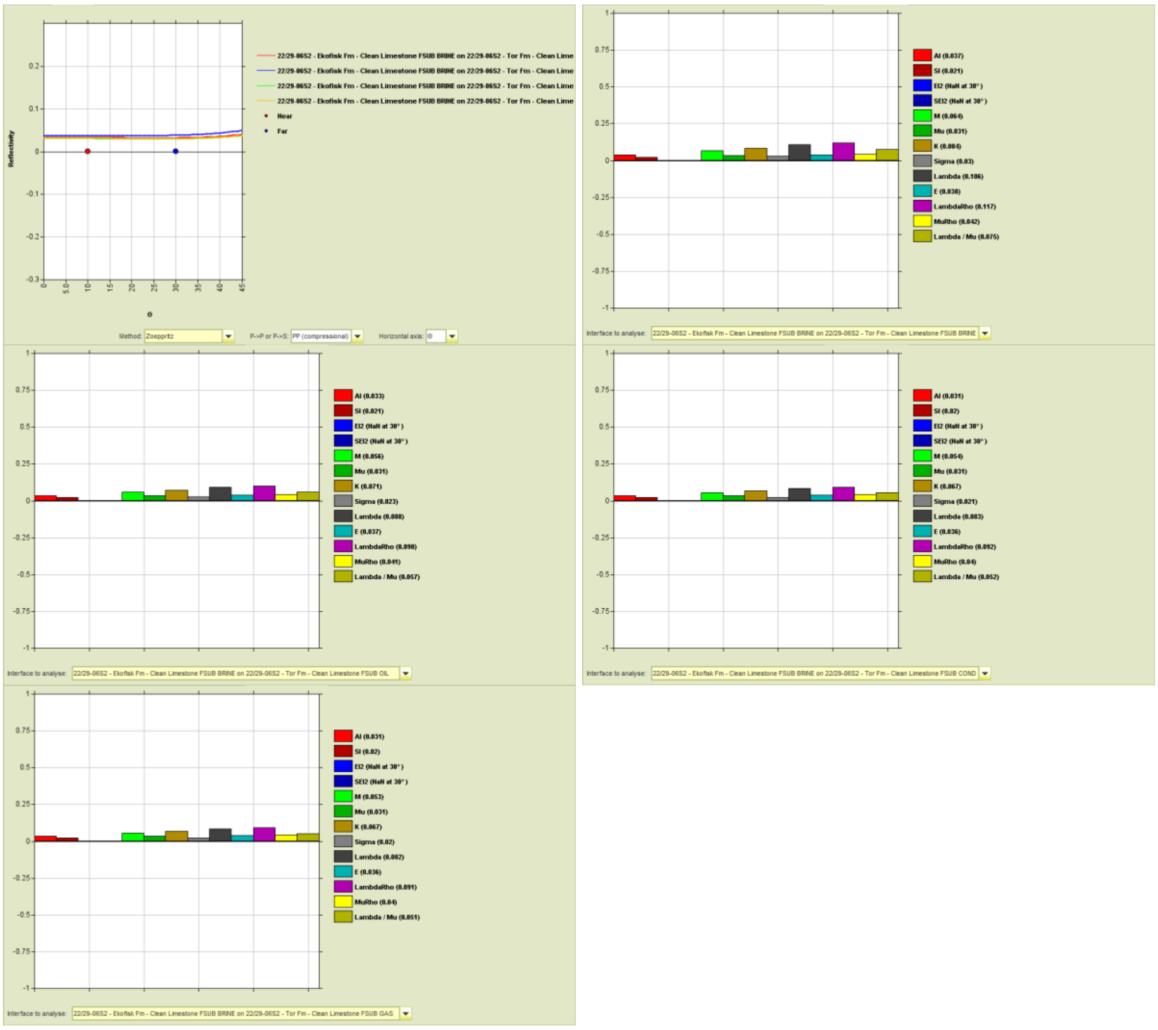


Figure 3.19.14 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/29-06S2.

Hod Formation

- Reservoir formed by a limestone formation with inter-bedded shale. The maximum observed porosities range from 8-10%.
- Blocky AVO shows a weak modelled class III response for all the fluid cases but with a flat gradient and the amplitude does not vary with angle.
- Elastic Contrast Analysis shows contrasts are all null or negative and of low amplitude in the brine case, increasing in amplitude to become negative with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

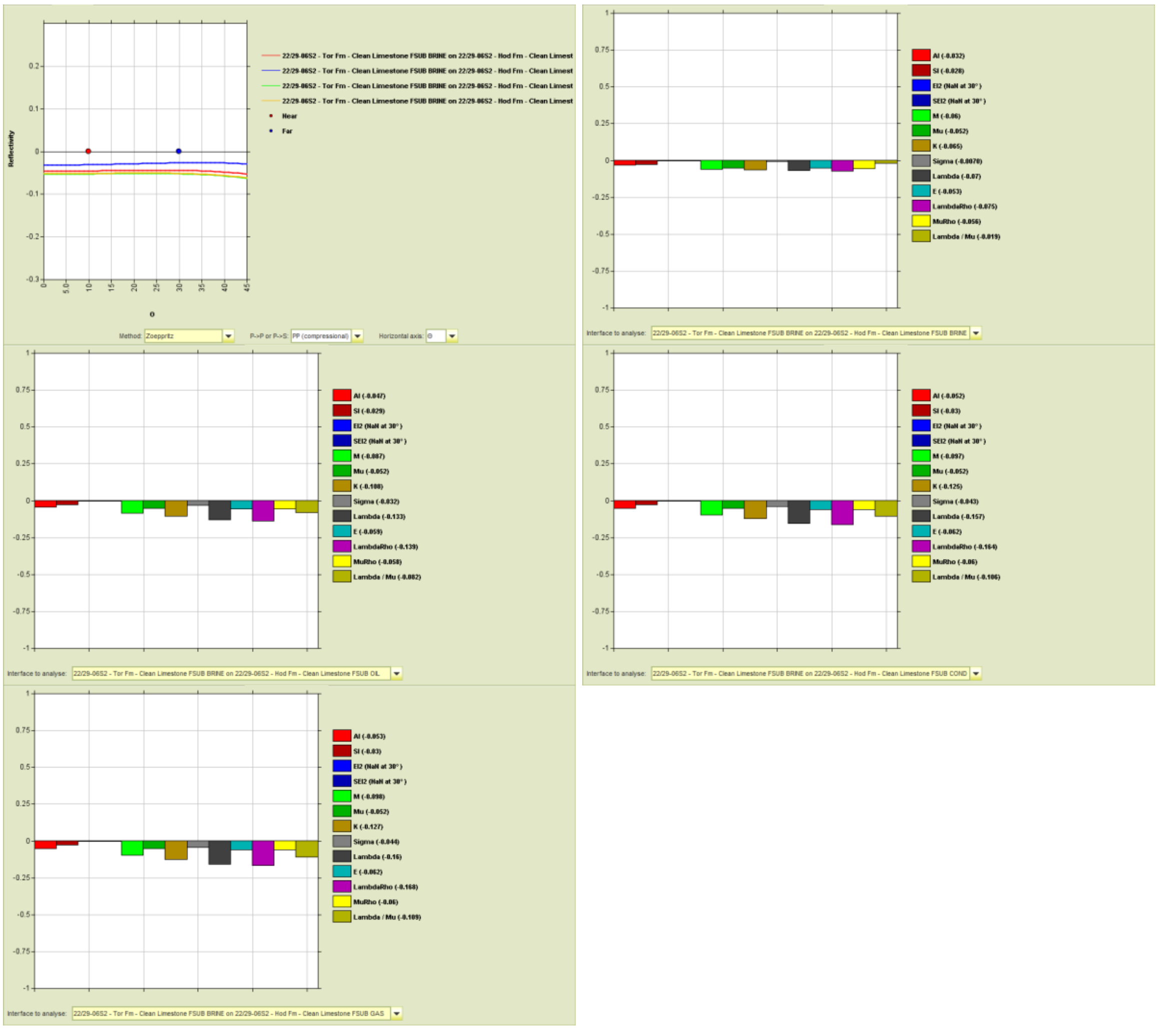


Figure 3.19.15 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/29-06S2.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/29-06S2 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/29-06S2	Overburden	Shale			
22/29-06S2	Underburden	Shale/Anhydrite	16,175	8,434	2.63

Table 3.19.11 - Overburden and underburden properties at Well 22/29-06S2.

Well: 22/30A-16

General

Well Information
A Shell exploration well, drilled into the Scooter field. Completed and suspended in 1997.

Objectives
The main objective of well 22/30A-16 was the Fulmar formation. The Pentland and Skagerrak sandstones were secondary objectives.

Log conditioning overview
Poor Vp and Vs data was edited out from 10,144 to 10,154 foot MD in the Balder Fm and from between 10,782 to 10,789 foot MD in the Sele Fm. Thin calcite stringers in the Horda Fm are not being seen by the sonic logs so Vp, Vs and density log data was all removed at these points.

Invasion correction

Well 22/30A-16 was drilled oil-based drilling mud. Invasion correction performed within all formations except for the non-reservoir Balder Fm.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Balder and Sele Formations for the Vp log, within the Horda, Balder and Sele Formations for the Vs log and within the Horda, Balder and Ekofisk Formations for the density log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoint's.

P&T data

The temperature and pressure data for Well 22/30A-16 is displayed in the figures below;

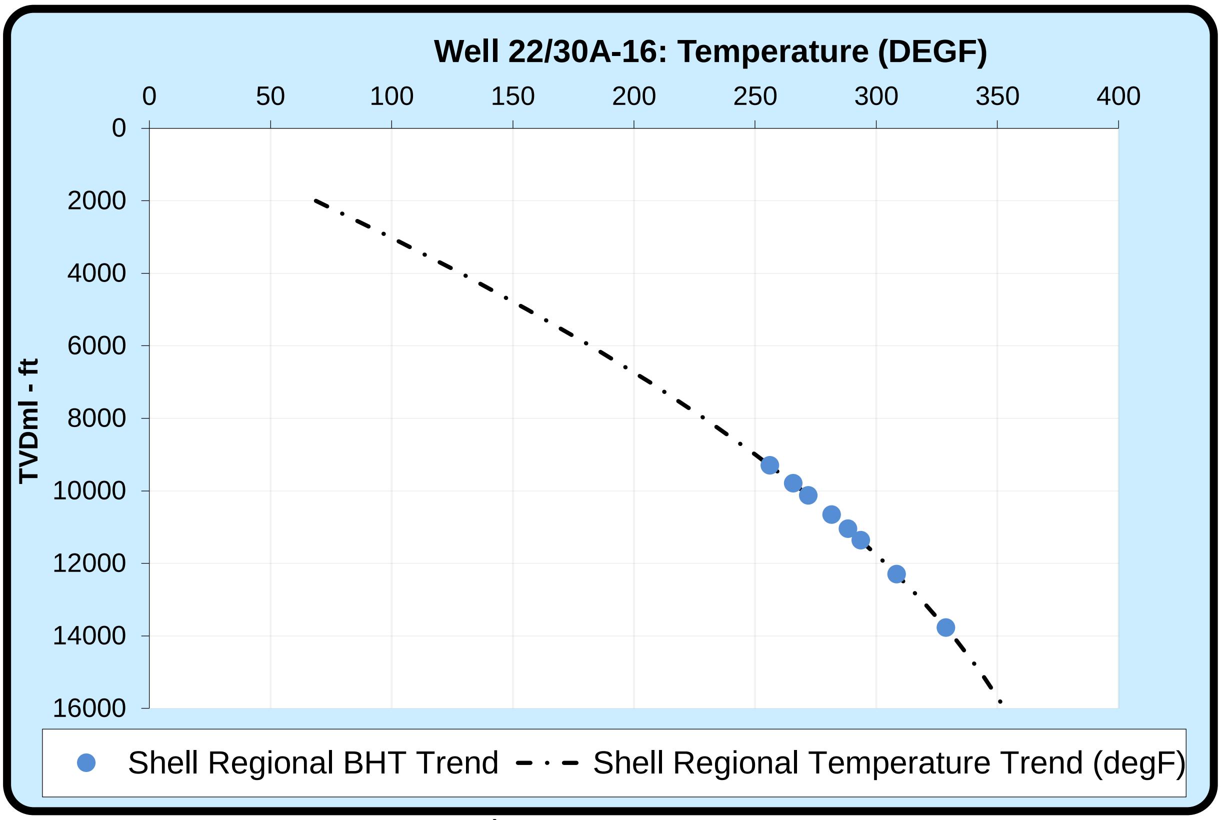


Figure 3.20.1 - Temperature data at Well 22/30A-16

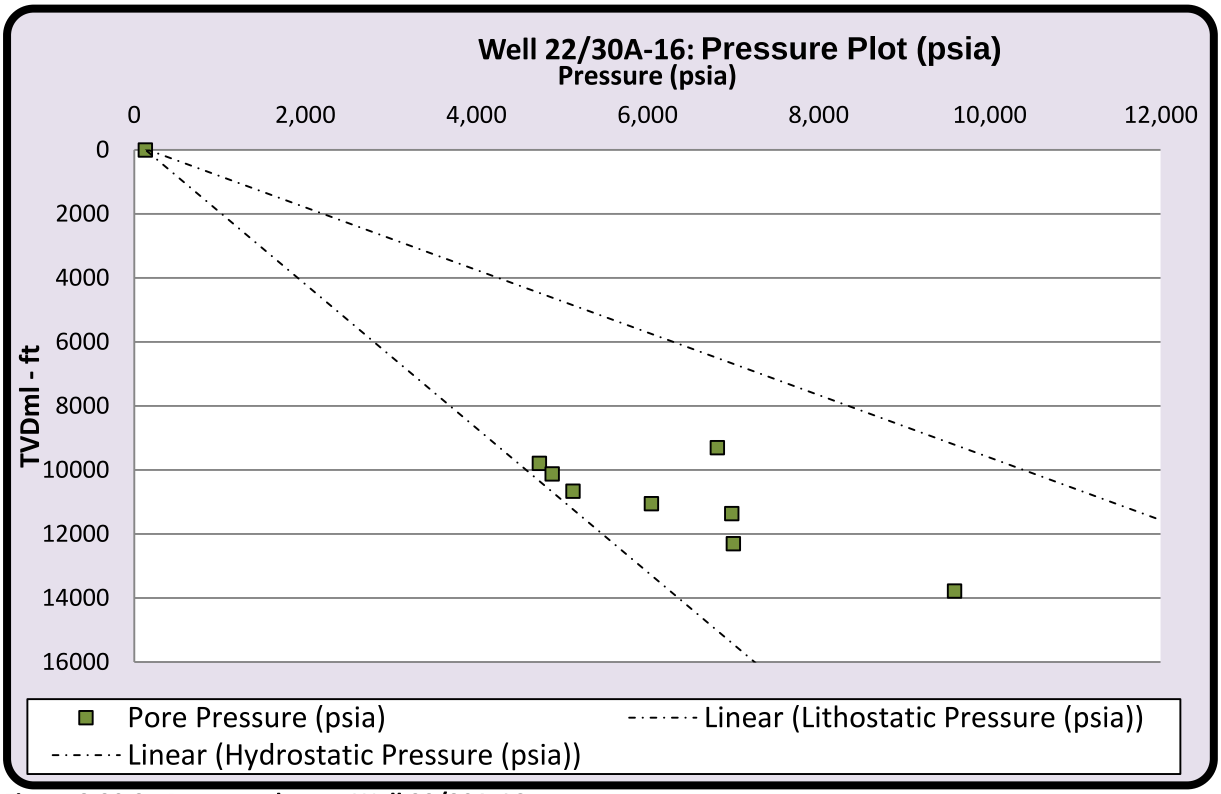


Figure 3.20.2 - Pressure data at Well 22/30A-16

The temperature and pressure data for the formation mid-points in Well 22/30A-16 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/30A-16	Sea Bed	365.0	296.0	0.0	39.2	131.7	131.7	131.7	0.0
22/30A-16	Horda	9667.2	9596.6	9300.6	256.2	4270.5	6820.5	9432.3	2611.8
22/30A-16	Balder	10160.5	10089.8	9793.8	265.8	4490.0	4740.0	9925.5	5185.6
22/30A-16	Sele	10491.5	10420.8	10124.8	272.0	4637.2	4887.2	10256.5	5369.3
22/30A-16	Lista	11027.0	10956.2	10660.2	281.7	4875.5	5131.5	10791.9	5660.4
22/30A-16	Maureen	11412.5	11341.7	11045.7	288.4	5047.1	6047.1	11177.4	5130.4
22/30A-16	Ekofisk	11728.0	11657.2	11361.2	293.7	5187.4	6987.4	11492.9	4505.4
22/30A-16	Tor	12667.0	12596.1	12300.1	308.5	5605.3	7005.3	12431.8	5426.6
22/30A-16	Hod	14142.0	14071.1	13775.1	328.8	6261.6	9593.6	13906.8	4313.2

Table 3.20.1 - Summary of mid-point temperature and pressure data at Well 22/30A-16

Fluid data

A summary of the fluid set parameters at Well 22/30A-16 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/30A-16	Horda	84000	730	41.4	0.78	0.78
22/30A-16	Balder	84000	730	41.9	0.78	0.78
22/30A-16	Sele	84000	730	42.3	0.78	0.78
22/30A-16	Lista	84000	730	42.9	0.78	0.78
22/30A-16	Maureen	84000	730	43.3	0.78	0.78
22/30A-16	Ekofisk	84000	730	43.6	0.78	0.78
22/30A-16	Tor	84000	730	44.6	0.78	0.78
22/30A-16	Hod	84000	730	46.2	0.78	0.78

Table 3.20.2 - Summary of fluid parameter data at Well 22/30A-16

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
22/30A-16	Horda	16380	57.0	0.8
22/30A-16	Balder	16380	57.4	0.8
22/30A-16	Sele	16380	57.7	0.8
22/30A-16	Lista	16380	58.1	0.8
22/30A-16	Maureen	16380	58.5	0.8
22/30A-16	Ekofisk	16380	58.7	0.8
22/30A-16	Tor	16380	59.5	0.8
22/30A-16	Hod	16380	60.8	0.8

Table 3.20.3 - Summary of additional parameter data at Well 22/30A-16

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.20.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	14.72	10.99	2.52	11,210	6,856

Table 3.20.5 - Tuff properties used at Well 22/30A-16

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/30A-16	Horda	PAY	937.510	0.000	0.000	0.000	0.000	0.000	0.000
22/30A-16	Horda	RES	937.510	4.500	0.005	0.749	0.166	0.997	0.287
22/30A-16	Balder	PAY	49.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30A-16	Balder	RES	49.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30A-16	Sele	PAY	613.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30A-16	Sele	RES	613.000	424.000	0.692	73.955	0.174	0.953	0.149
22/30A-16	Lista	PAY	458.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30A-16	Lista	RES	458.000	10.500	0.023	1.201	0.114	0.973	0.204
22/30A-16	Maureen	PAY	313.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30A-16	Maureen	RES	313.000	127.000	0.406	13.205	0.104	0.918	0.163
22/30A-16	Ekofisk	PAY	318.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30A-16	Ekofisk	RES	318.000	159.000	0.502	14.000	0.088	0.971	0.116
22/30A-16	Tor	PAY	1560.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30A-16	Tor	RES	1560.000	491.000	0.315	28.797	0.059	0.958	0.023
22/30A-16	Hod	PAY	1390.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30A-16	Hod	RES	1390.000	944.750	0.680	42.323	0.045	0.970	0.244

Table 3.20.6 - Petrophysical parameters used at Well 22/30A-16

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

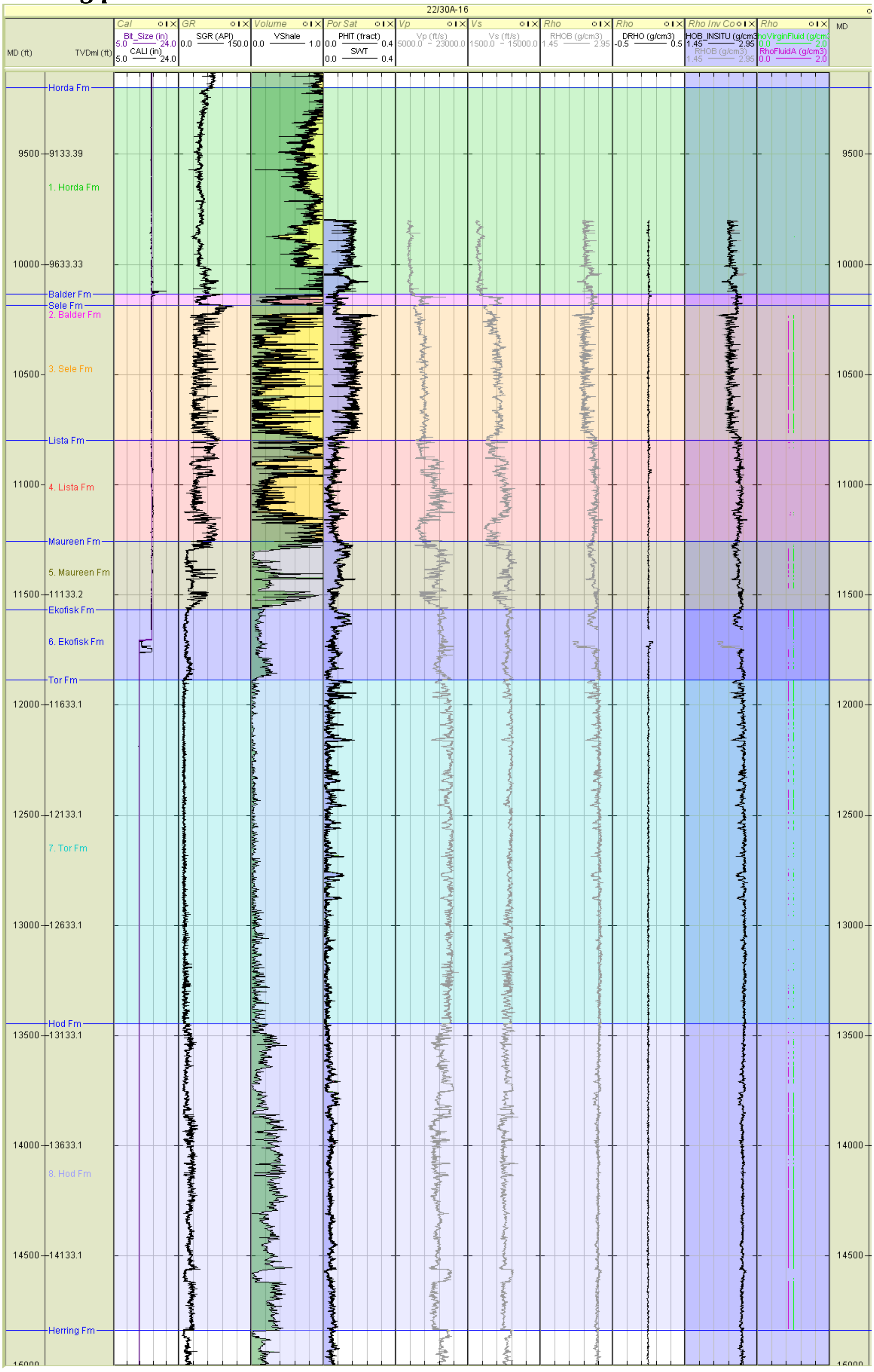


Figure 3.20.3 - Well Panel: Measured data and invasion correction for well 22/30A-16.

Well log panel – log editing and audit

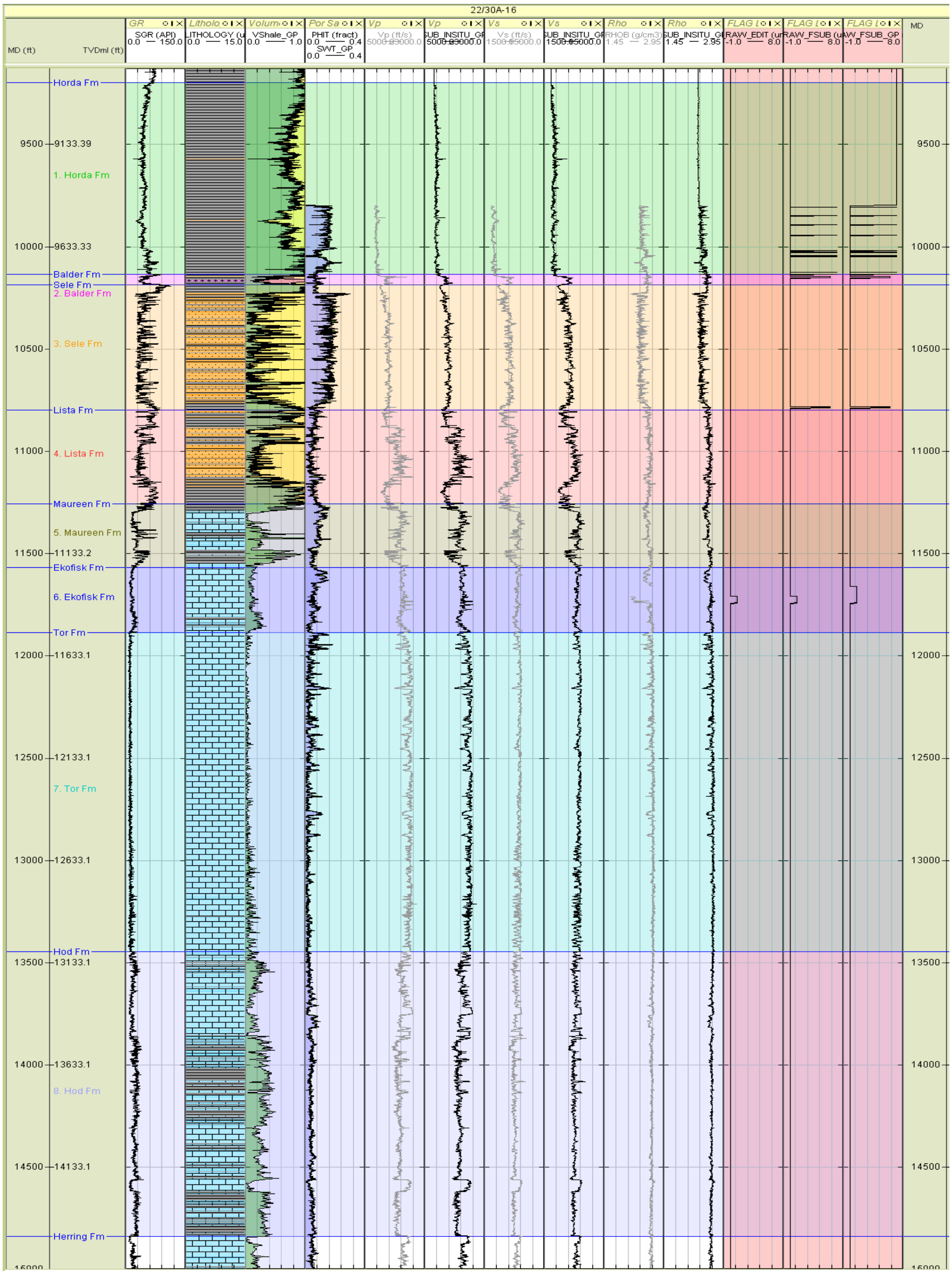


Figure 3.20.4 - Well Panel: Log edits for well 22/30A-16.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

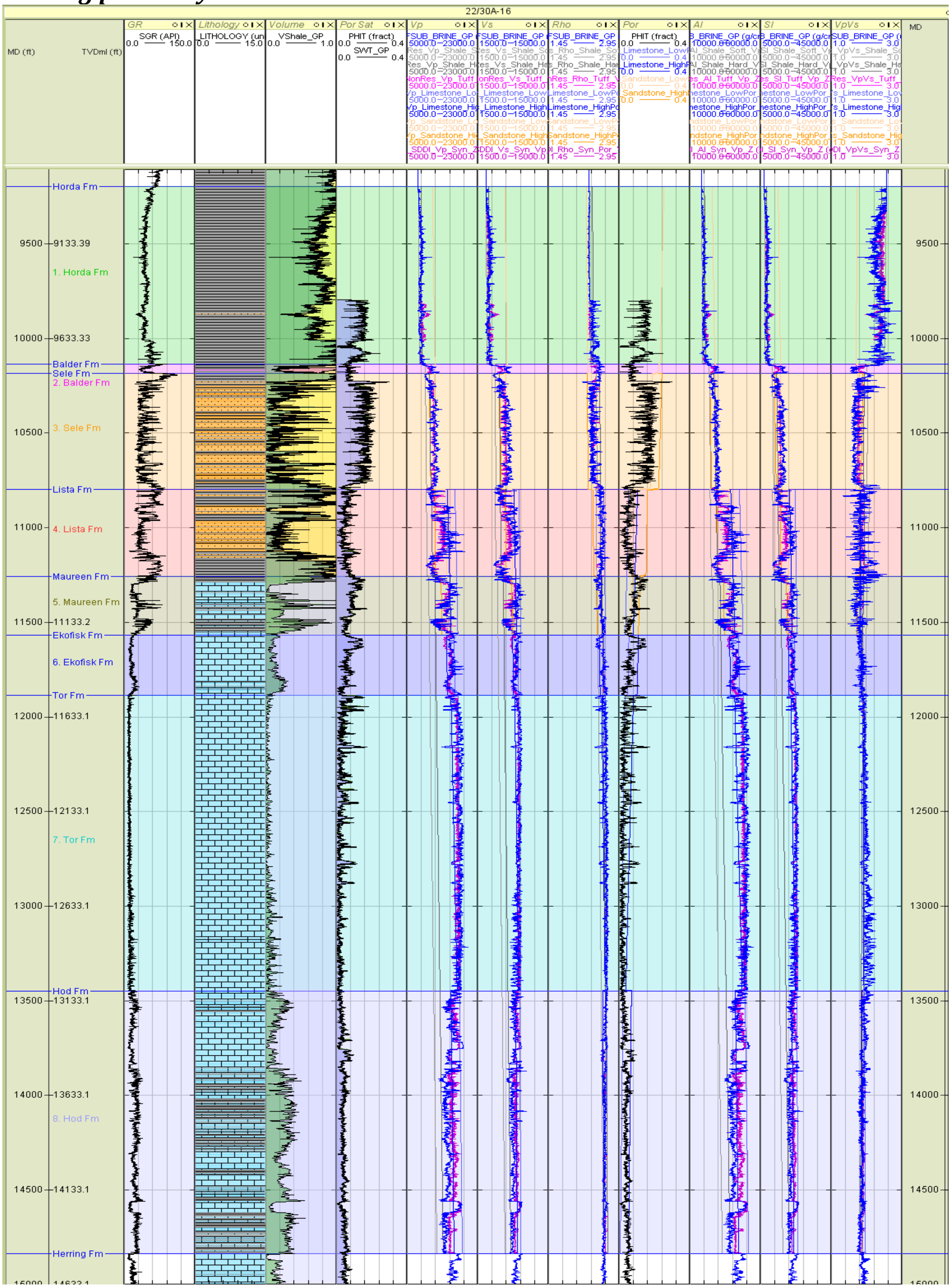


Figure 3.20.5 - Well Panel: End-member and synthetic logs for well 22/30A-16.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

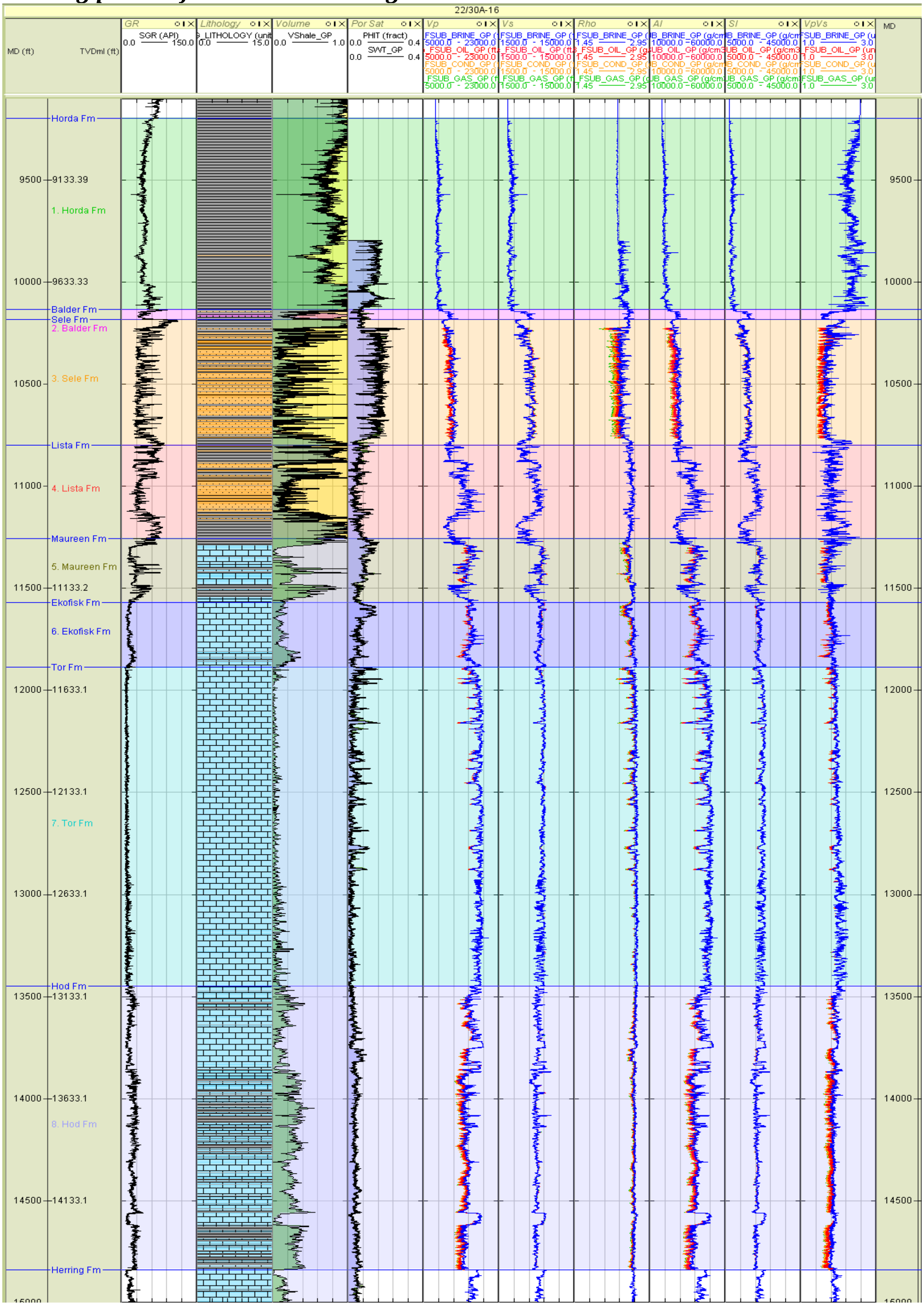


Figure 3.20.6 - Well Panel: Fluid substituted and elastic logs for well 22/30A-16.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/30A-16 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30A-16	Horda	8,281	3,467	2.34
22/30A-16	Balder	9,506	4,316	2.53
22/30A-16	Sele	10,649	5,692	2.52
22/30A-16	Lista	11,143	5,859	2.55
22/30A-16	Maureen	11,934	6,727	2.53

Table 3.20.7 - Clean shale properties at Well 22/30A-16

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30A-16	Horda	100% Brine			
22/30A-16	Balder	100% Brine			
22/30A-16	Sele	100% Brine	12,157	7,249	2.36
22/30A-16	Lista	100% Brine			
22/30A-16	Maureen	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30A-16	Horda	80% Oil			
22/30A-16	Balder	80% Oil			
22/30A-16	Sele	80% Oil	11,363	7,327	2.31
22/30A-16	Lista	80% Oil			
22/30A-16	Maureen	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30A-16	Horda	90% Gas			
22/30A-16	Balder	90% Gas			
22/30A-16	Sele	90% Gas	11,265	7,446	2.23
22/30A-16	Lista	90% Gas			
22/30A-16	Maureen	90% Gas			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30A-16	Horda	80% Cond			
22/30A-16	Balder	80% Cond			
22/30A-16	Sele	80% Cond	11,226	7,410	2.26
22/30A-16	Lista	80% Cond			
22/30A-16	Maureen	80% Cond			

Table 3.20.8 - Clean sand properties at Well 22/30A-16 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30A-16	Maureen	100% Brine	15,902	8,987	2.56
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/30A-16	Maureen	80% Oil	15,650	9,016	2.55
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/30A-16	Maureen	90% Gas	15,628	9,061	2.52
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/30A-16	Maureen	80% Cond	15,613	9,047	2.53

Table 3.20.9 - Clean limestone properties at Well 22/30A-16 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

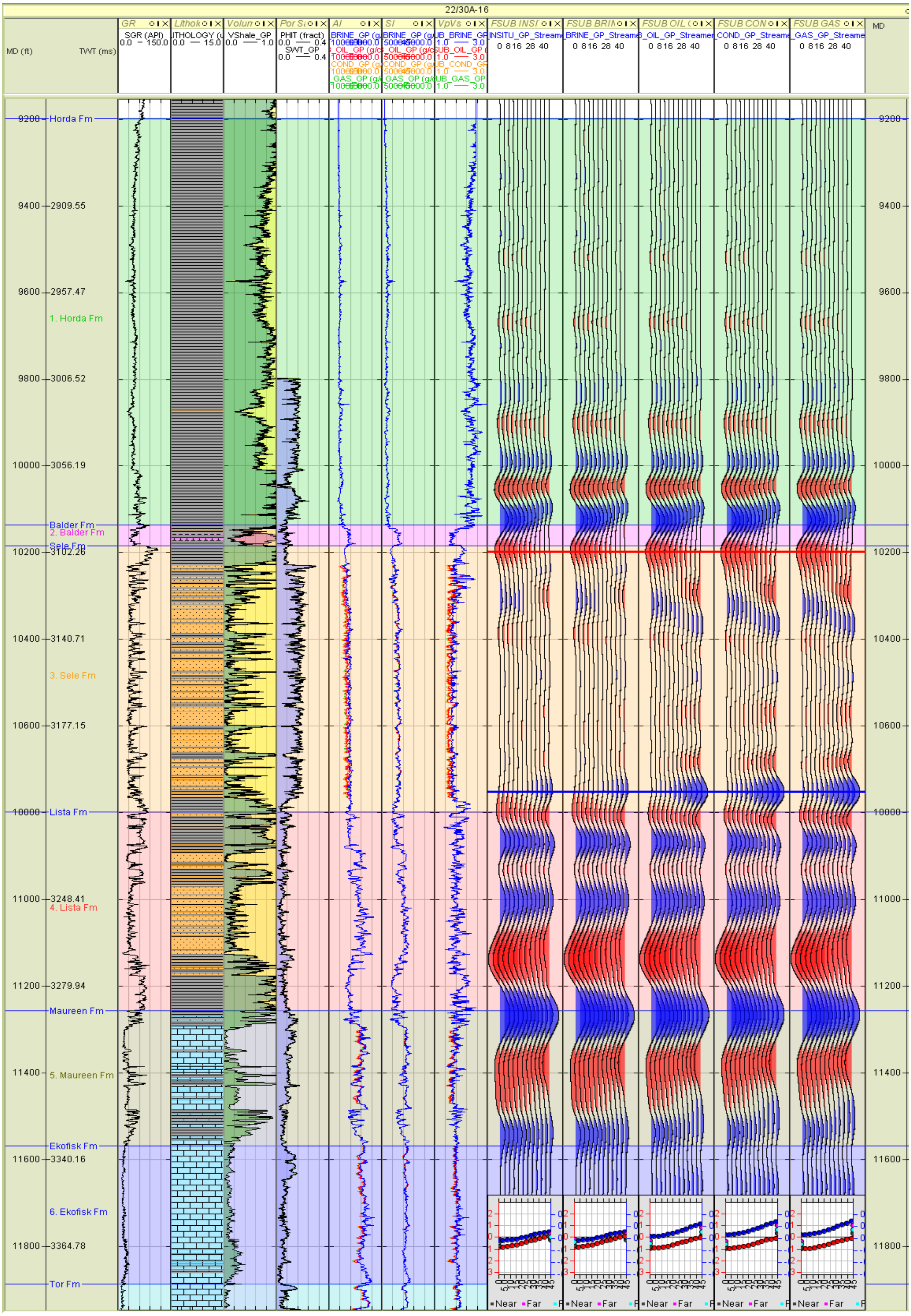


Figure 3.20.7 - Well Panel: Tertiary reservoirs for well 22/30A-16. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a discrete sand package with a maximum porosity of 26% and net reservoir is approximately 25 feet. The reservoir sand is overlain directly by overburden shale in the upper section of the Sele Fm.
- Blocky AVO shows a modelled class I response for the 100% brine case; a modelled class II response for the 80% oil case and a modelled class III response for the 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are a mixture of positive and negative low amplitudes in the brine case, but that the contrasts generally become significantly greater negative amplitudes for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

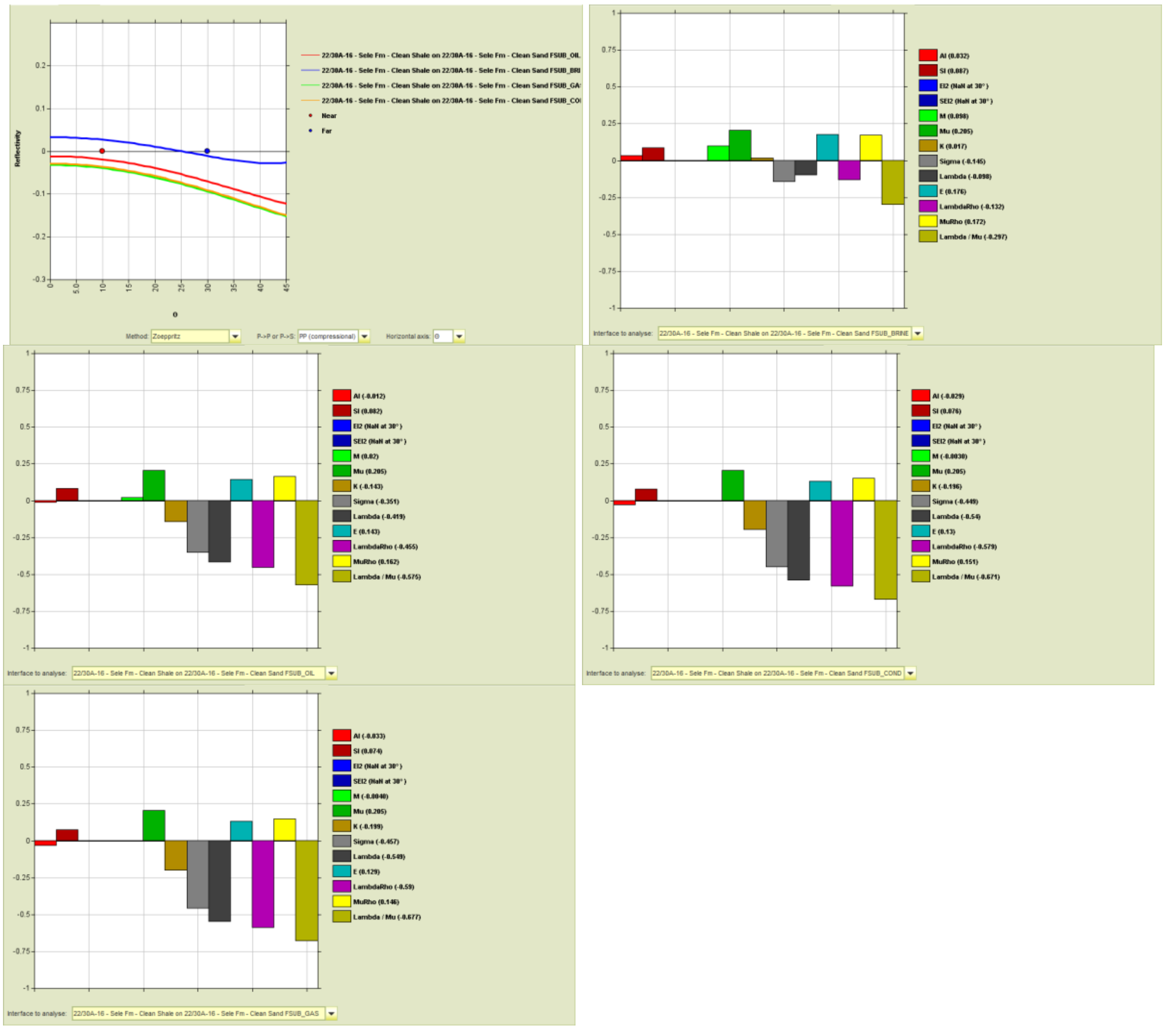


Figure 3.20.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/30A-16.

Maureen Formation

- Reservoir formed by a set of limestone sections inter-bedded with shale, net reservoir is approximately 127 feet in this formation. This limestone section has high velocities and densities in comparison with the overburden shale in the Lista Fm and gives a strong positive impedance contrast on the synthetic gathers.
- Blocky AVO shows a strong modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, and that the contrasts slightly decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

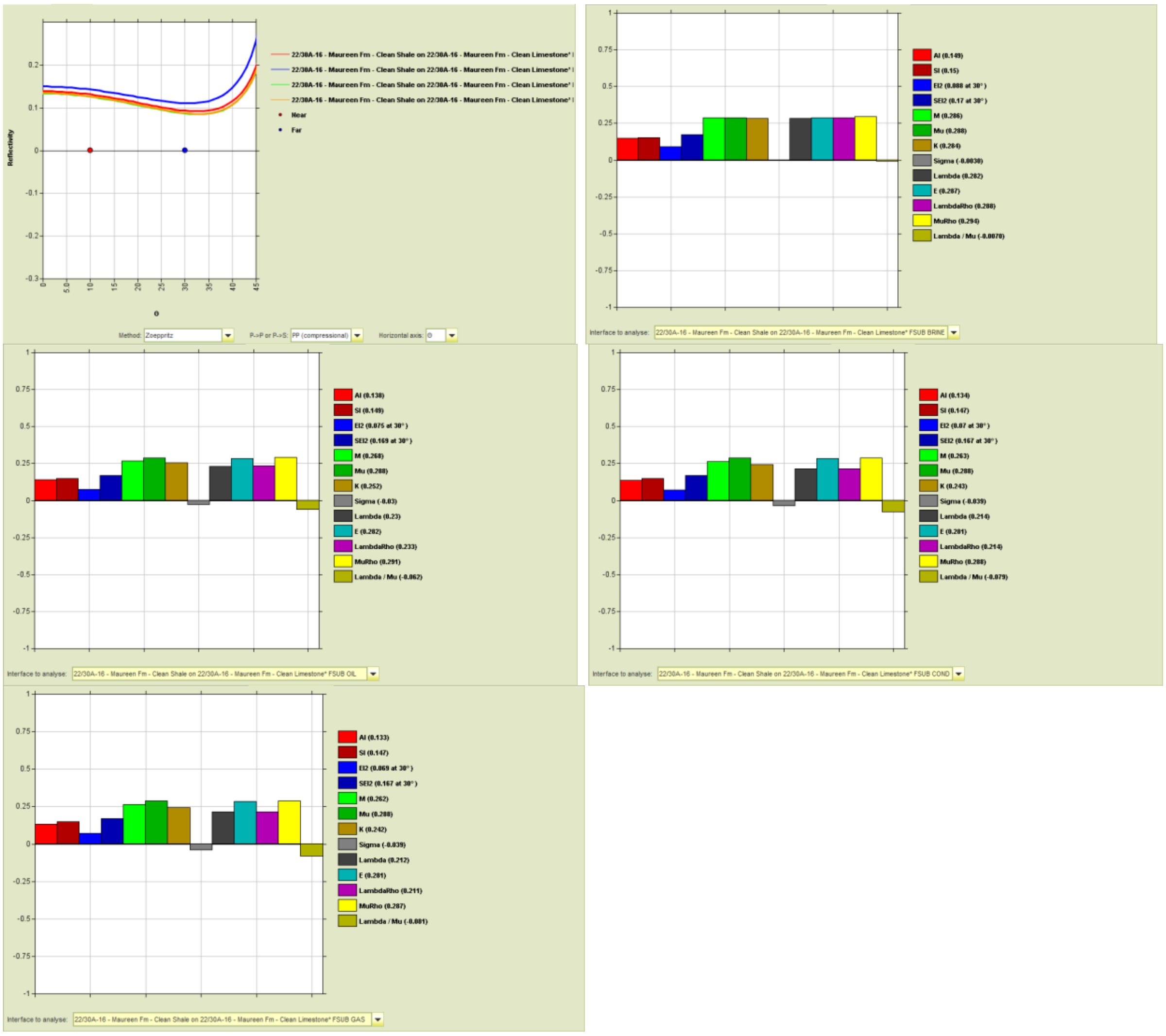


Figure 3.20.9 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/30A-16.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/30A-16 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30A-16	Ekofisk	100% Brine	16634	8990	2.58
22/30A-16	Tor	100% Brine	18203	9269	2.66
22/30A-16	Hod	100% Brine	17858	9283	2.65
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/30A-16	Ekofisk	80% Oil	16430	9020	2.57
22/30A-16	Tor	80% Oil	18145	9279	2.65
22/30A-16	Hod	80% Oil	17749	9292	2.65
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/30A-16	Ekofisk	90% Gas	16423	9065	2.54
22/30A-16	Tor	90% Gas	18148	9293	2.64
22/30A-16	Hod	90% Gas	17724	9305	2.64
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/30A-16	Ekofisk	80% Cond	16407	9051	2.55
22/30A-16	Tor	80% Cond	18142	9288	2.65
22/30A-16	Hod	80% Cond	17722	9301	2.64

Table 3.20.10 - Clean limestone properties at Well 22/30A-16 for each fluid case

Cretaceous reservoirs

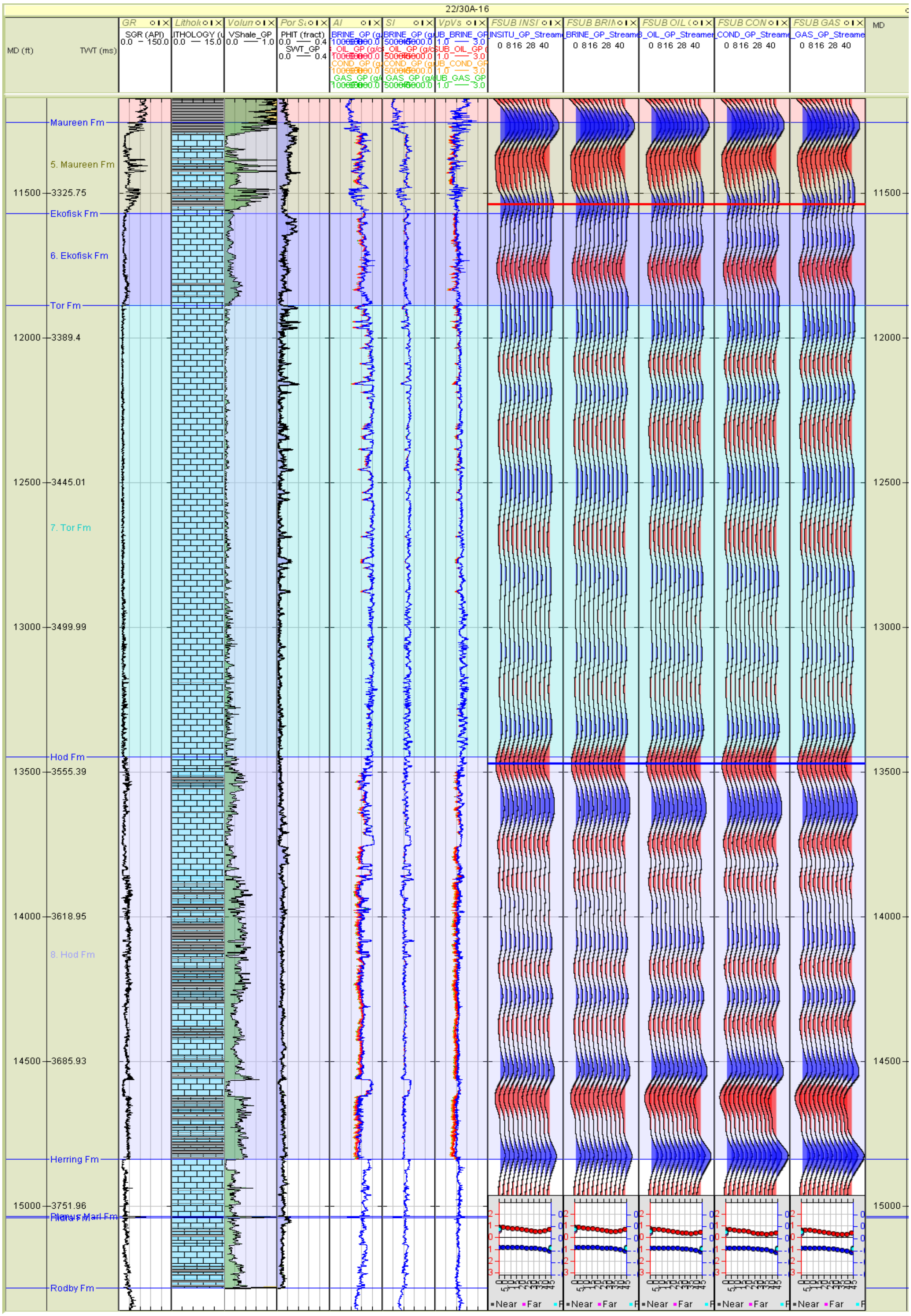


Figure 3.20.10 - Well Panel: Cretaceous reservoirs for well 22/30A-16. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with some very thin shale beds. The highest porosity reservoir is found in the top section of the Ekofisk Fm and the porosity in this section is approximately 15%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts decreases slightly in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

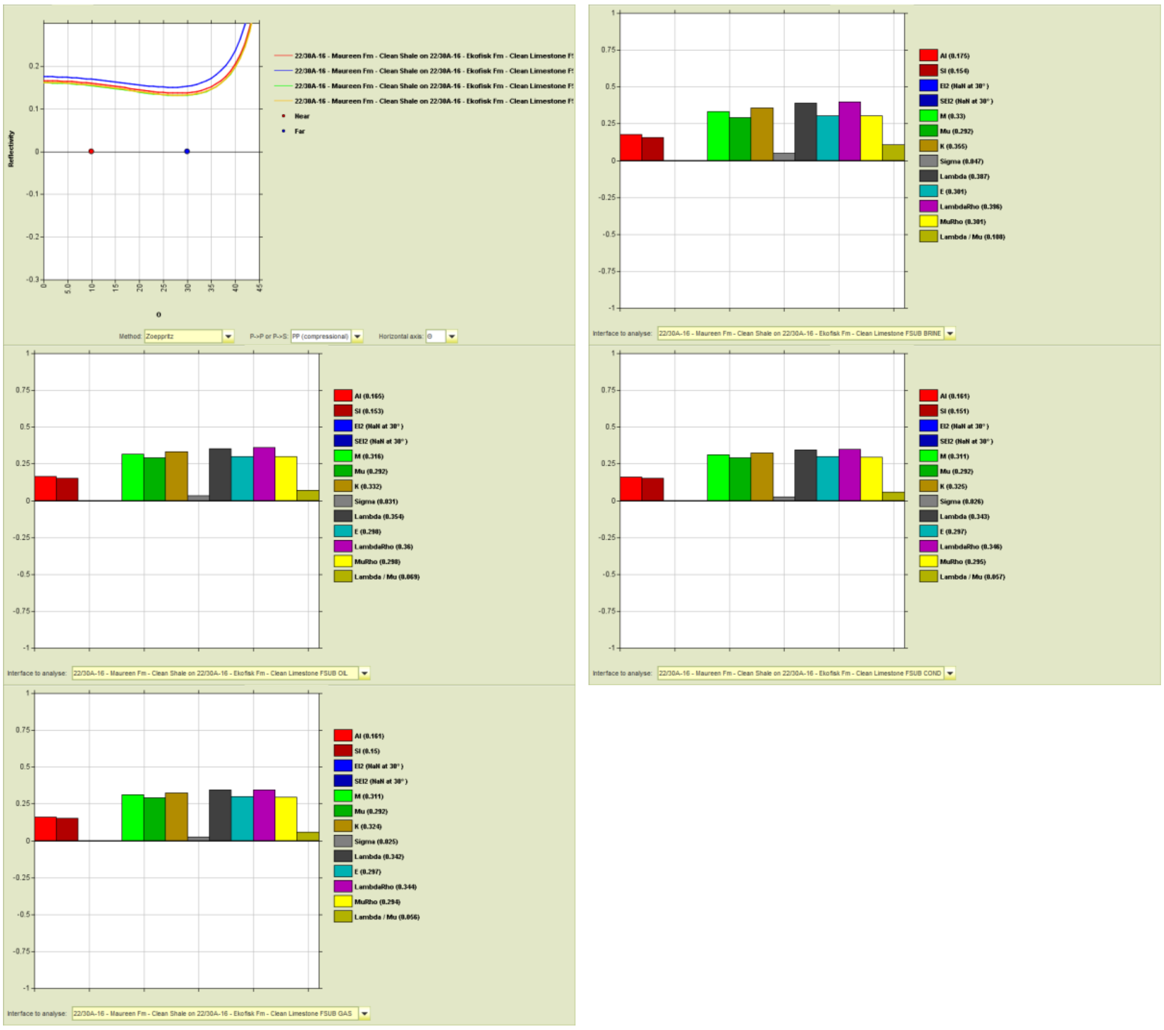


Figure 3.20.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/30A-16.

Tor Formation

- Reservoir formed by a clean limestone formation. High porosity layers ranging from 9-15% are found throughout the Tor Fm and could be representative of reworked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, but with a flat gradient and the amplitude does not vary with angle.
- Elastic Contrast Analysis shows contrasts are mainly positive and of low amplitude in the brine case, but there is no contrast between the different fluid cases with addition of hydro-carbons.

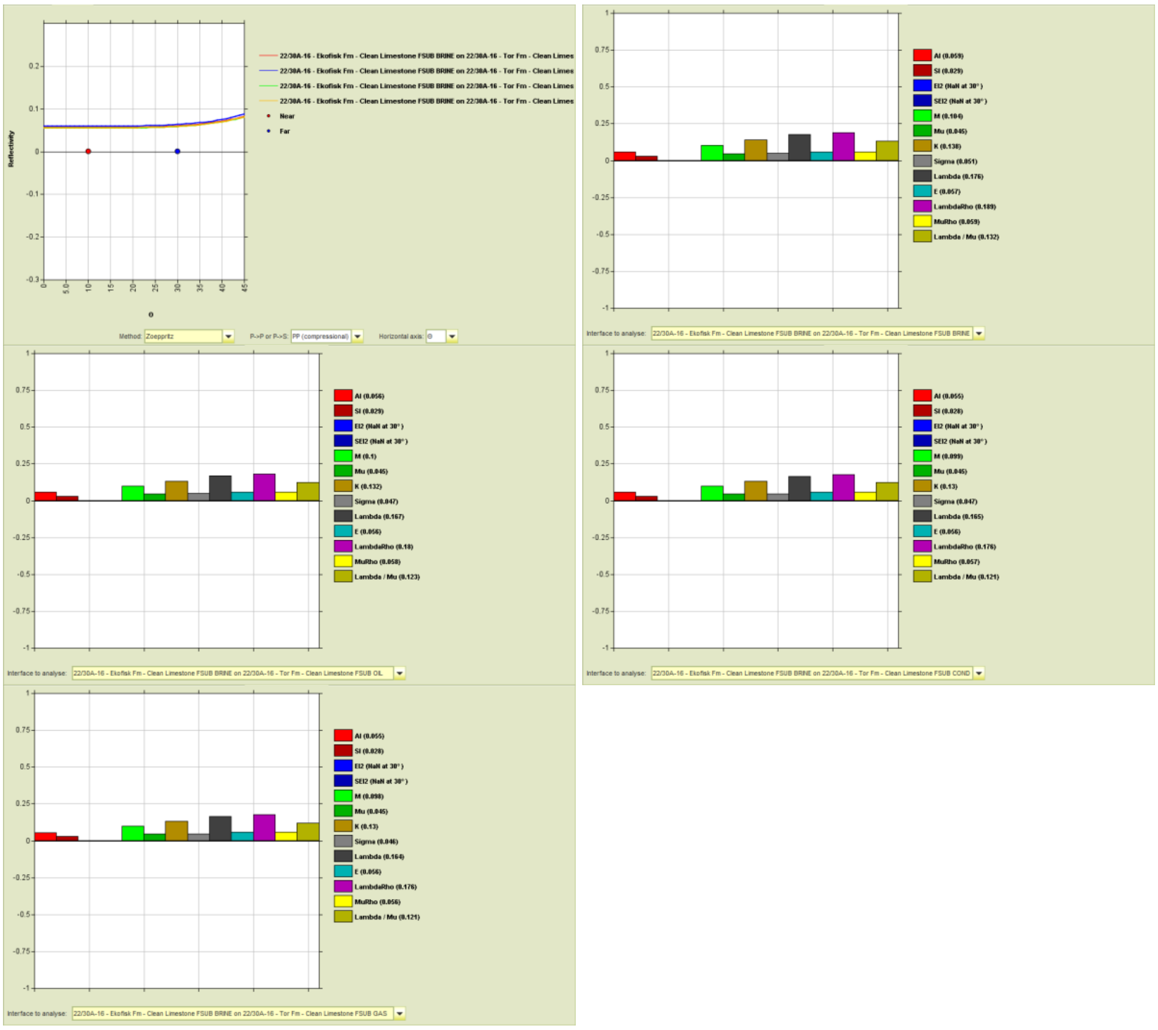


Figure 3.20.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/30A-16.

Hod Formation

- Reservoir formed by a limestone formation with inter-bedded shale. The maximum porosity observed in this formation is 9%.
- Blocky AVO shows a weak modelled class II response for all the fluid cases but with a flat gradient and the amplitude does not vary with angle.
- Elastic Contrast Analysis shows contrasts are all null or negative and of very low amplitude in the brine case, increasing in amplitude to become slightly more negative with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

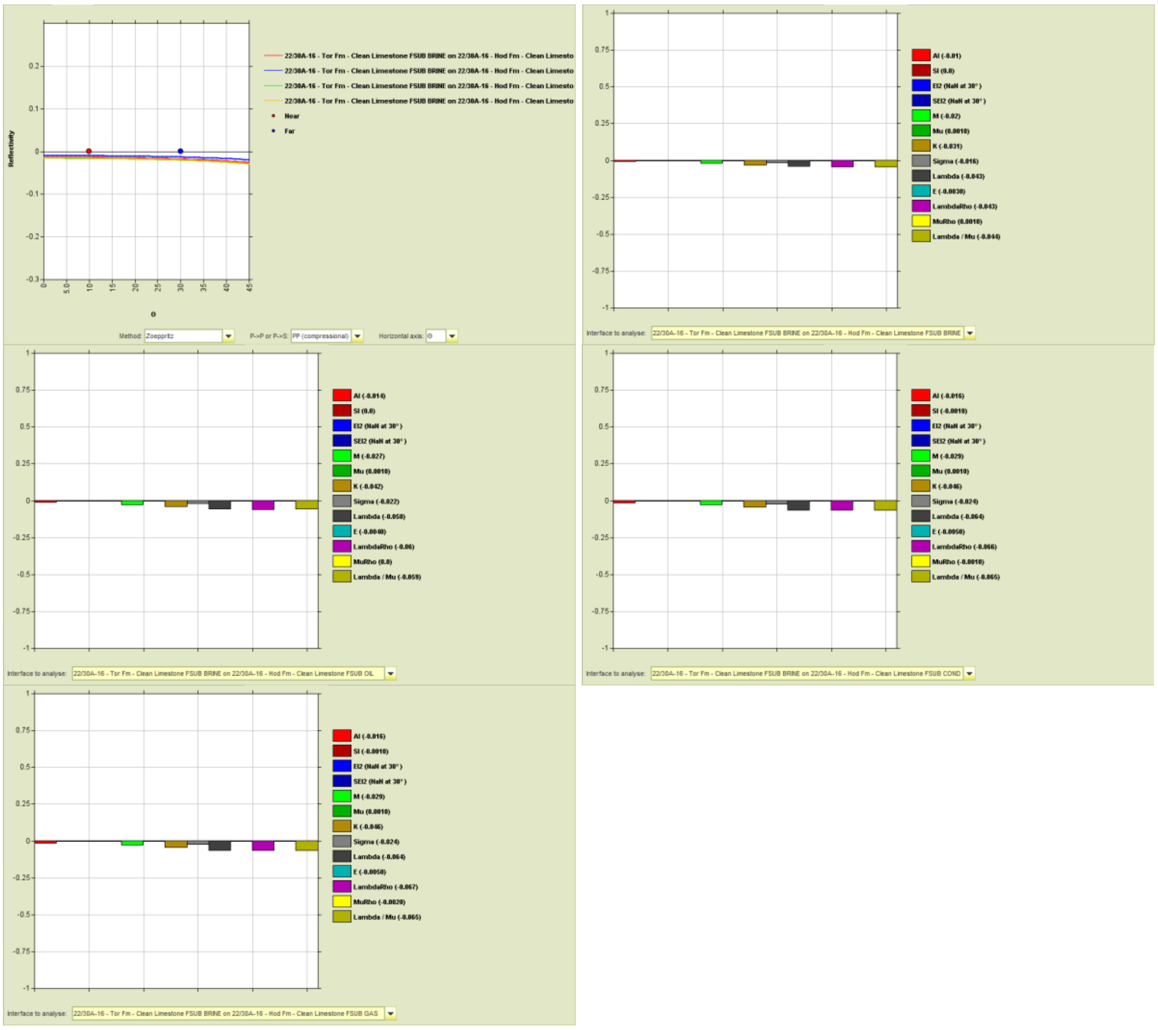


Figure 3.20.13 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/30A-16.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/30A-16 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30A-16	Overburden	Shale			
22/30A-16	Underburden	Shale/Anhydrite	16,330	8,643	2.62

Table 3.20.11 - Overburden and underburden properties at Well 22/30A-16.

Well: 22/30B-11

General

Well Information
A Shell appraisal well drilled in the Shearwater field, a HTHP field in the Central North Sea. Well 22/30B-11 was completed and abandoned in 1994.

Objectives
Objective of well 22/30B-11 was to appraise the Upper Jurassic Fulmar formation.

Log conditioning overview
Thin calcite stringers in the Horda Fm are not being seen by the sonic logs so Vp, Vs and density log data was all removed at these points.

Invasion correction

Well 22/30B-11 was drilled with oil-based drilling mud. Invasion correction performed within all formations except for the non-reservoir Balder Fm.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Maureen and Ekofisk Formations for Vp and within the Horda and Ekofisk Formations for density. A complete Vs log is modelled since a measured Vs log is not available at this well. A gap was also filled above the interval of interest in the Vp log using a spline function.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoint's.

P&T data

The temperature and pressure data for Well 22/30B-11 is displayed in the figures below;

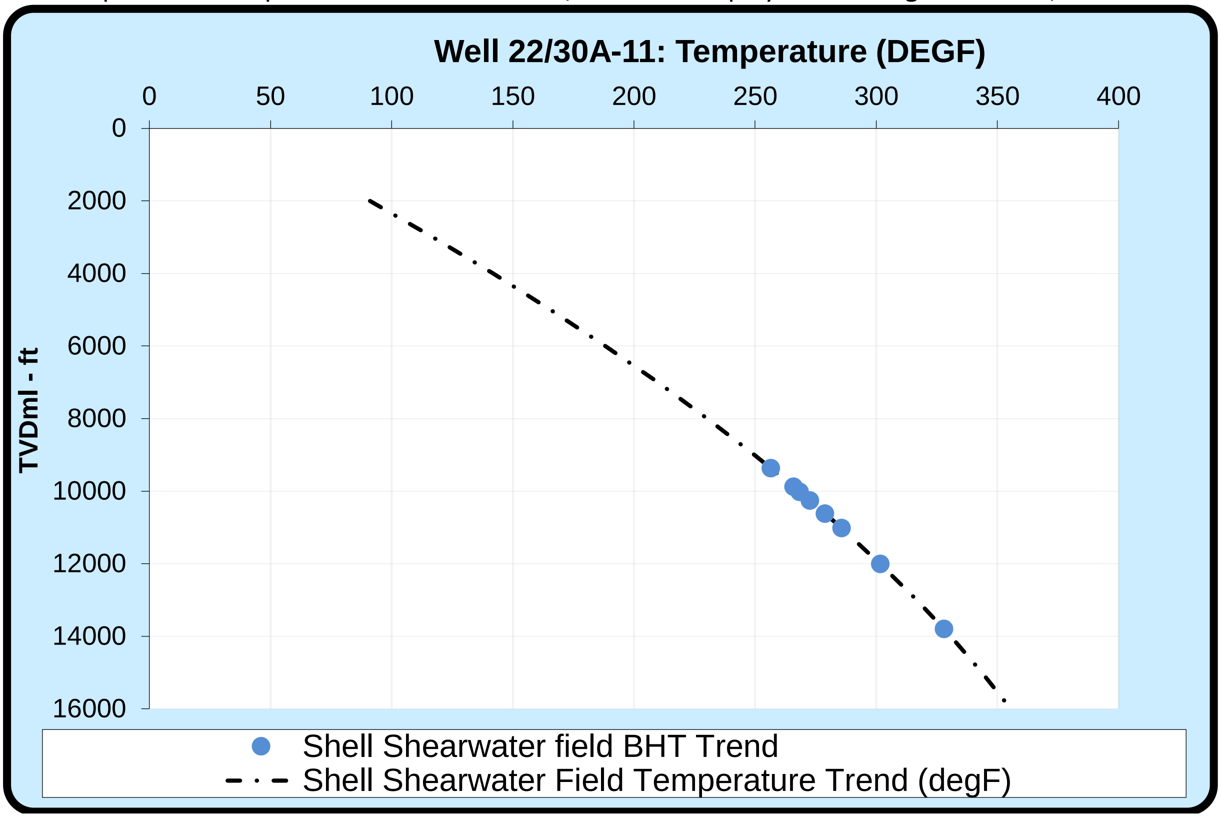


Figure 3.21.1 - Temperature data at Well 22/30B-11

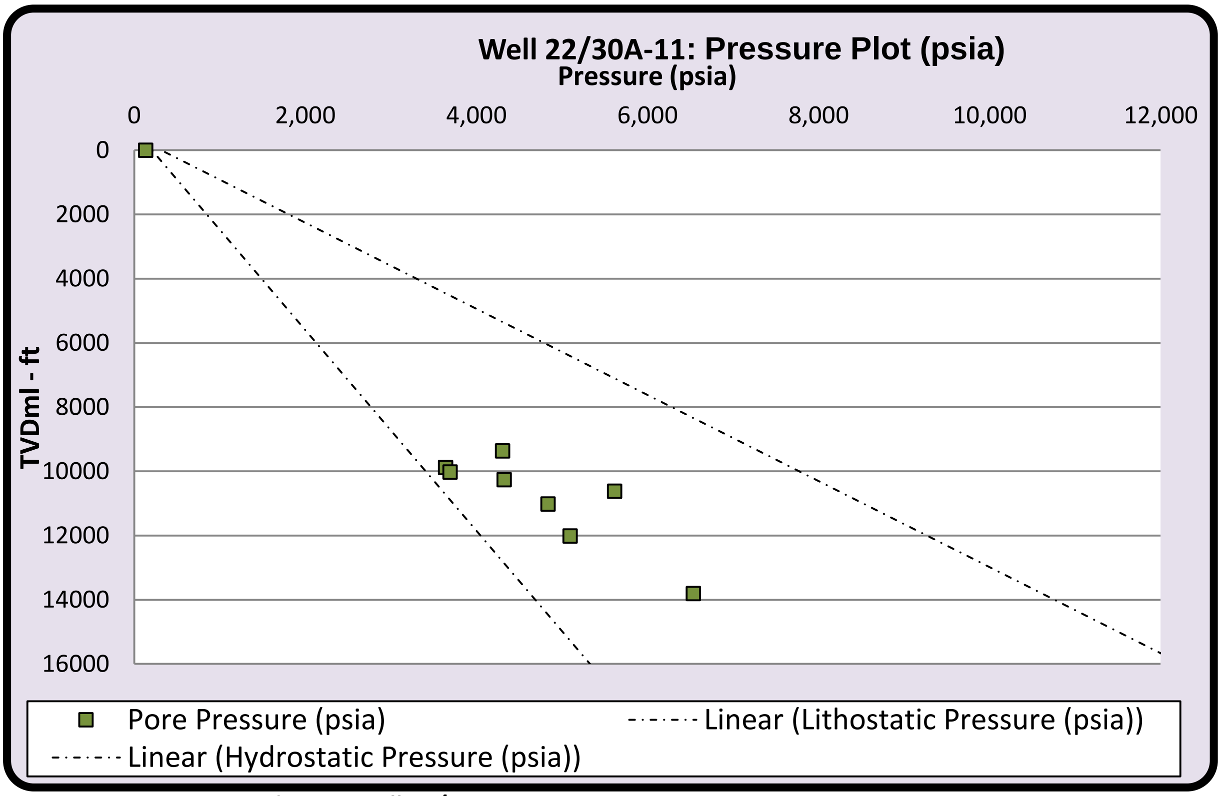


Figure 3.21.2 - Pressure data at Well 22/30B-11

The temperature and pressure data for the formation mid-points in Well 22/30B-11is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
22/30B-11	Sea Bed	378.0	296.0	0.0	39.2	131.7	131.7	131.7	0.0
22/30B-11	Horda	9744.0	9661.5	9365.5	257.5	4299.4	6899.4	9497.3	2597.9
22/30B-11	Balder	10259.5	10177.0	9881.0	267.4	4528.8	4828.8	10012.7	5184.0
22/30B-11	Sele	10400.5	10318.0	10022.0	270.1	4591.5	4891.5	10153.7	5262.2
22/30B-11	Lista	10635.4	10552.8	10256.8	274.4	4696.0	5196.0	10388.5	5192.5
22/30B-11	Maureen	10995.4	10912.7	10616.7	280.9	4856.2	8306.2	10748.5	2442.3
22/30B-11	Ekofisk	11397.7	11315.0	11019.0	287.9	5035.2	6835.2	11150.8	4315.6
22/30B-11	Tor	12384.7	12301.9	12005.9	304.0	5474.4	7074.4	12137.6	5063.3
22/30B-11	Hod	14180.2	14096.8	13800.8	329.2	6273.1	9605.1	13932.5	4327.5

Table 3.21.1 - Summary of mid-point temperature and pressure data at Well 22/30B-11

Fluid data

A summary of the fluid set parameters at Well 22/30B-11is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
22/30B-11	Horda	60000	730	41.5	0.78	0.78
22/30B-11	Balder	60000	730	42.0	0.78	0.78
22/30B-11	Sele	60000	730	42.2	0.78	0.78
22/30B-11	Lista	60000	730	42.4	0.78	0.78
22/30B-11	Maureen	60000	730	42.8	0.78	0.78
22/30B-11	Ekofisk	60000	730	43.3	0.78	0.78
22/30B-11	Tor	60000	730	44.3	0.78	0.78
22/30B-11	Hod	60000	730	46.3	0.78	0.78

Table 3.21.2 - Summary of fluid parameter data at Well 22/30B-11

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
22/30B-11	Horda	16380	57.0	0.8
22/30B-11	Balder	16380	57.5	0.8
22/30B-11	Sele	16380	57.6	0.8
22/30B-11	Lista	16380	57.8	0.8
22/30B-11	Maureen	16380	58.1	0.8
22/30B-11	Ekofisk	16380	58.4	0.8
22/30B-11	Tor	16380	59.3	0.8
22/30B-11	Hod	16380	60.8	0.8

Table 3.21.3 - Summary of additional parameter data at Well 22/30B-11

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.21.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	16.2	10.2	2.54	11,229	6,567

Table 3.21.5 - Tuff properties used at Well 22/30B-11

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
22/30B-11	Horda	PAY	964.000	2.000	0.002	0.474	0.237	0.487	0.015
22/30B-11	Horda	RES	964.000	9.000	0.009	1870.00	0.208	0.712	0.163
22/30B-11	Balder	PAY	67.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30B-11	Balder	RES	67.000	0.500	0.007	0.069	0.138	0.996	0.110
22/30B-11	Sele	PAY	215.000	0.000	0.000	0.000	0.000	0.000	0.000
22/30B-11	Sele	RES	215.000	75.250	0.350	12.404	0.165	0.948	0.197
22/30B-11	Lista	PAY	254.700	0.000	0.000	0.000	0.000	0.000	0.000
22/30B-11	Lista	RES	254.700	22.000	0.086	3.044	0.138	0.940	0.220
22/30B-11	Maureen	PAY	465.300	0.000	0.000	0.000	0.000	0.000	0.000
22/30B-11	Maureen	RES	465.300	80.500	0.173	8.847	0.110	0.958	0.187
22/30B-11	Ekofisk	PAY	339.410	0.000	0.000	0.000	0.000	0.000	0.000
22/30B-11	Ekofisk	RES	339.410	204.660	0.603	16.034	0.078	0.974	0.132
22/30B-11	Tor	PAY	1634.590	16.000	0.010	1.166	0.073	0.452	0.000
22/30B-11	Tor	RES	1634.590	1502.59	0.919	80.174	0.053	0.945	0.028
22/30B-11	Hod	PAY	1956.420	36.500	0.019	3.610	0.099	0.380	0.025
22/30B-11	Hod	RES	1956.420	1951.42	0.997	147.396	0.076	0.950	0.168

Table 3.21.6 - Petrophysical parameters used at Well 22/30B-11

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

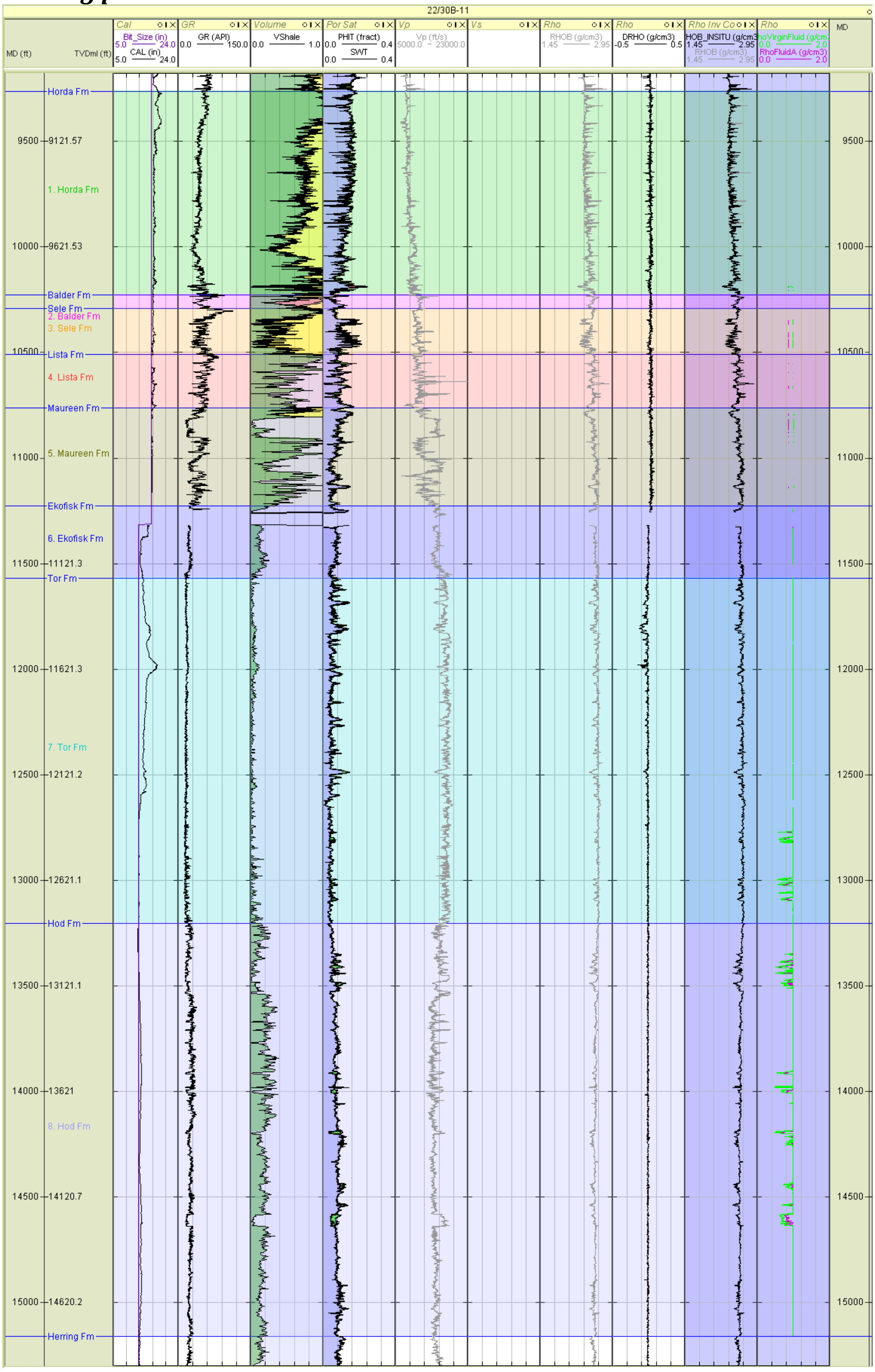


Figure 3.21.3 - Well Panel: Measured data and invasion correction for well 22/30B-11.

Well log panel – log editing and audit

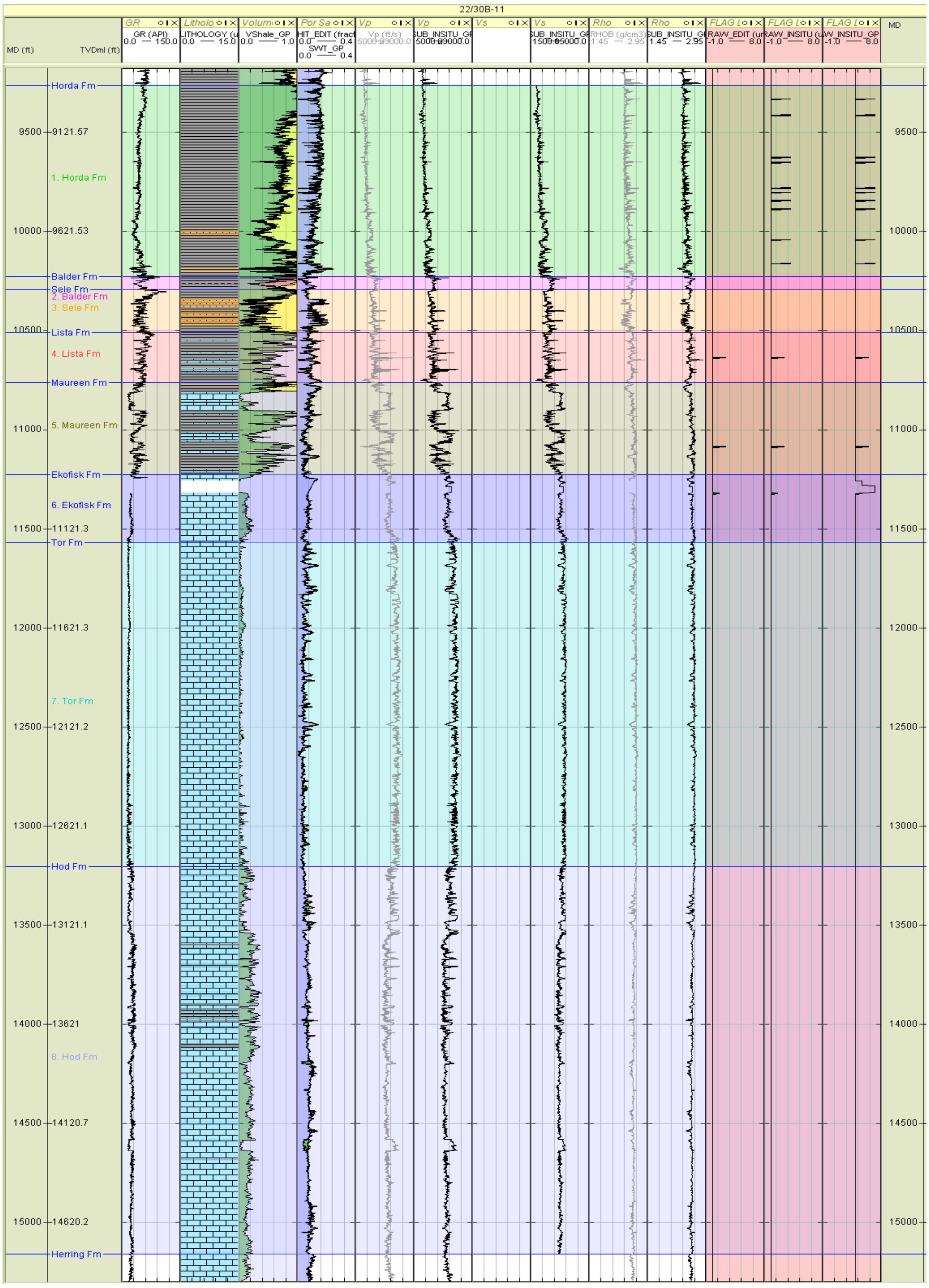


Figure 3.21.4 - Well Panel: Log edits for well 22/30B-11.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

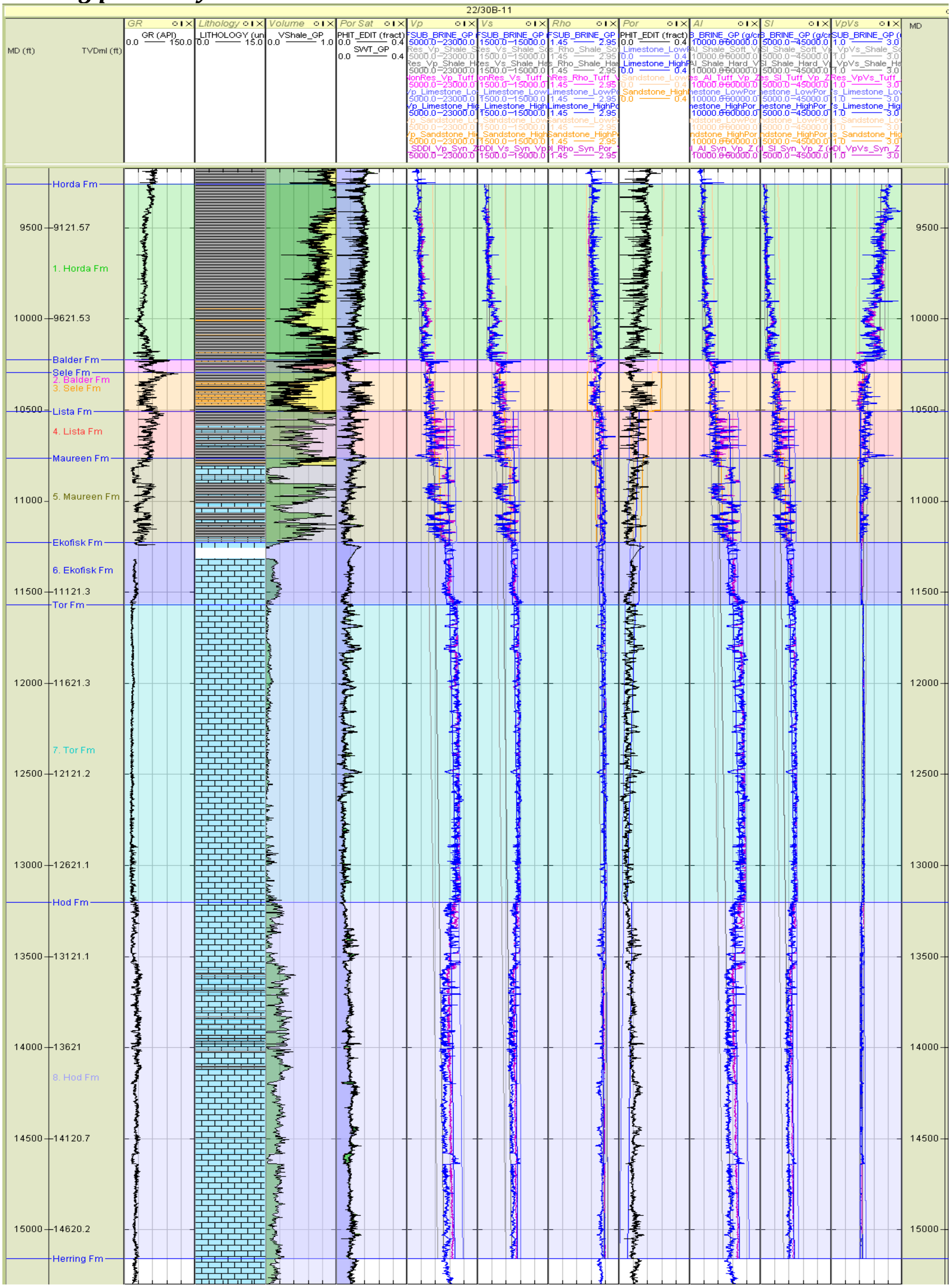


Figure 3.21.5 - Well Panel: End-member and synthetic logs for well 22/30B-11.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

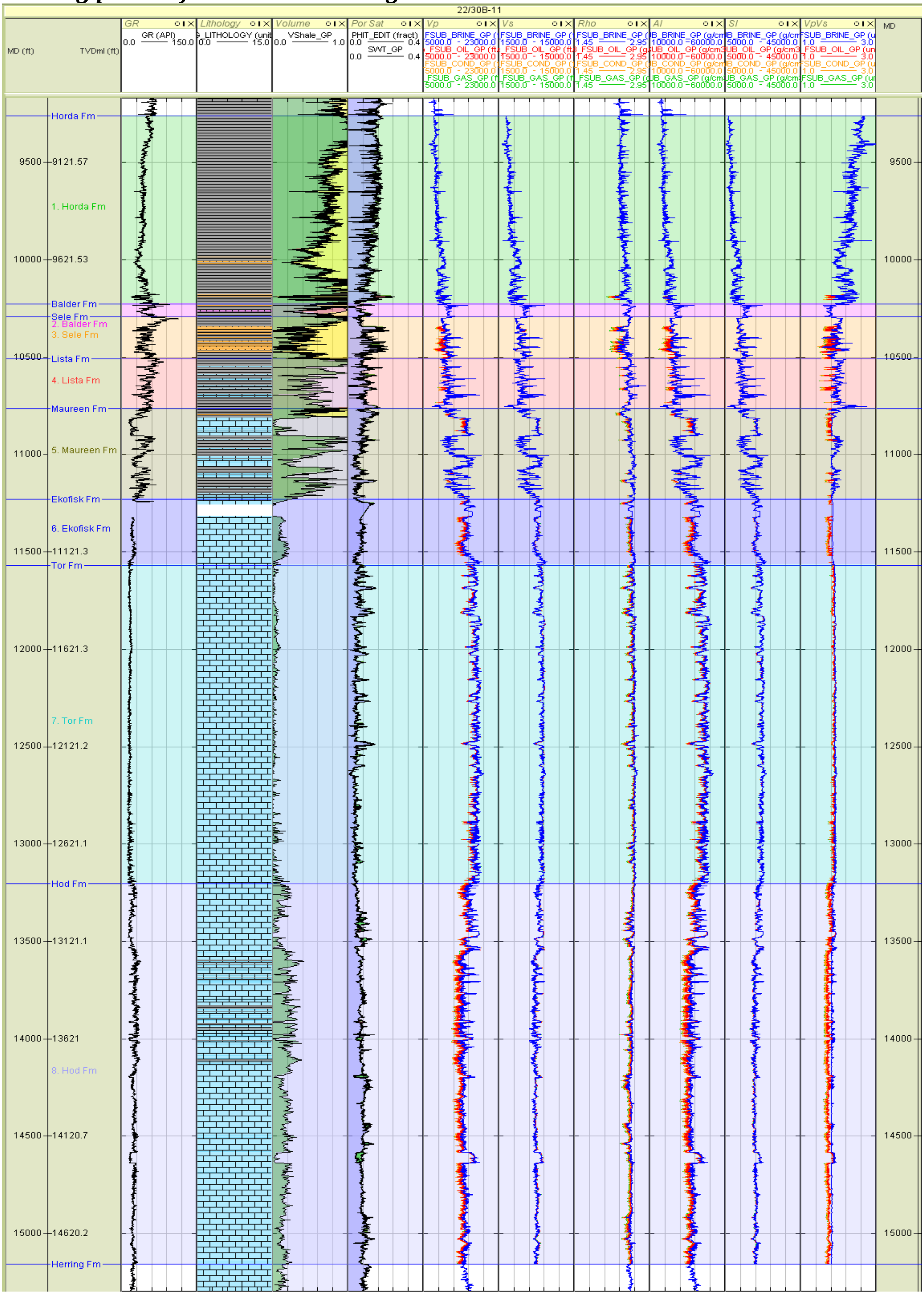


Figure 3.21.6 - Well Panel: Fluid substituted and elastic logs for well 22/30B-11.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 22/30B-11 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Horda	8,089	3,350	2.40
22/30B-11	Balder	10,289	5,442	2.56
22/30B-11	Sele	9,818	4,879	2.53
22/30B-11	Lista	10,051	4,920	2.55
22/30B-11	Maureen	10,751	5,453	2.55

Table 3.21.7 - Clean shale properties at Well 22/30B-11

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Horda	100% Brine	10,415	5,521	2.40
22/30B-11	Balder	100% Brine			
22/30B-11	Sele	100% Brine	10,859	5,792	2.40
22/30B-11	Lista	100% Brine			
22/30B-11	Maureen	100% Brine	12,363	6,851	2.44
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Horda	80% Oil	10,202	5543	2.38
22/30B-11	Balder	80% Oil			
22/30B-11	Sele	80% Oil	9,997	5,834	2.36
22/30B-11	Lista	80% Oil			
22/30B-11	Maureen	80% Oil	11,964	6,886	2.42
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Horda	90% Gas	10,152	5,577	2.35
22/30B-11	Balder	90% Gas			
22/30B-11	Sele	90% Gas	9,772	5,902	2.30
22/30B-11	Lista	90% Gas			
22/30B-11	Maureen	90% Gas	11,847	6,941	2.38
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Horda	80% Cond	10,142	5,566	2.36
22/30B-11	Balder	80% Cond			
22/30B-11	Sele	80% Cond	9,764	5,882	2.32
22/30B-11	Lista	80% Cond			
22/30B-11	Maureen	80% Cond	11,836	6,924	2.39

Table 3.21.8 - Clean sand properties at Well 22/30B-11for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Lista	100% Brine	12,876	6,912	2.58
22/30B-11	Maureen	100% Brine	15,279	8,393	2.59
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/30B-11	Lista	80% Oil	12,299	6,931	2.56
22/30B-11	Maureen	80% Oil	15,077	6,931	2.58
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/30B-11	Lista	90% Gas	12,123	6,961	2.54
22/30B-11	Maureen	90% Gas	15,010	8,426	2.57
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
22/30B-11	Lista	80% Cond	12,122	6,952	2.55
22/30B-11	Maureen	80% Cond	15,004	8,420	2.57

Table 3.21.9 - Clean limestone properties at Well 22/30B-11 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

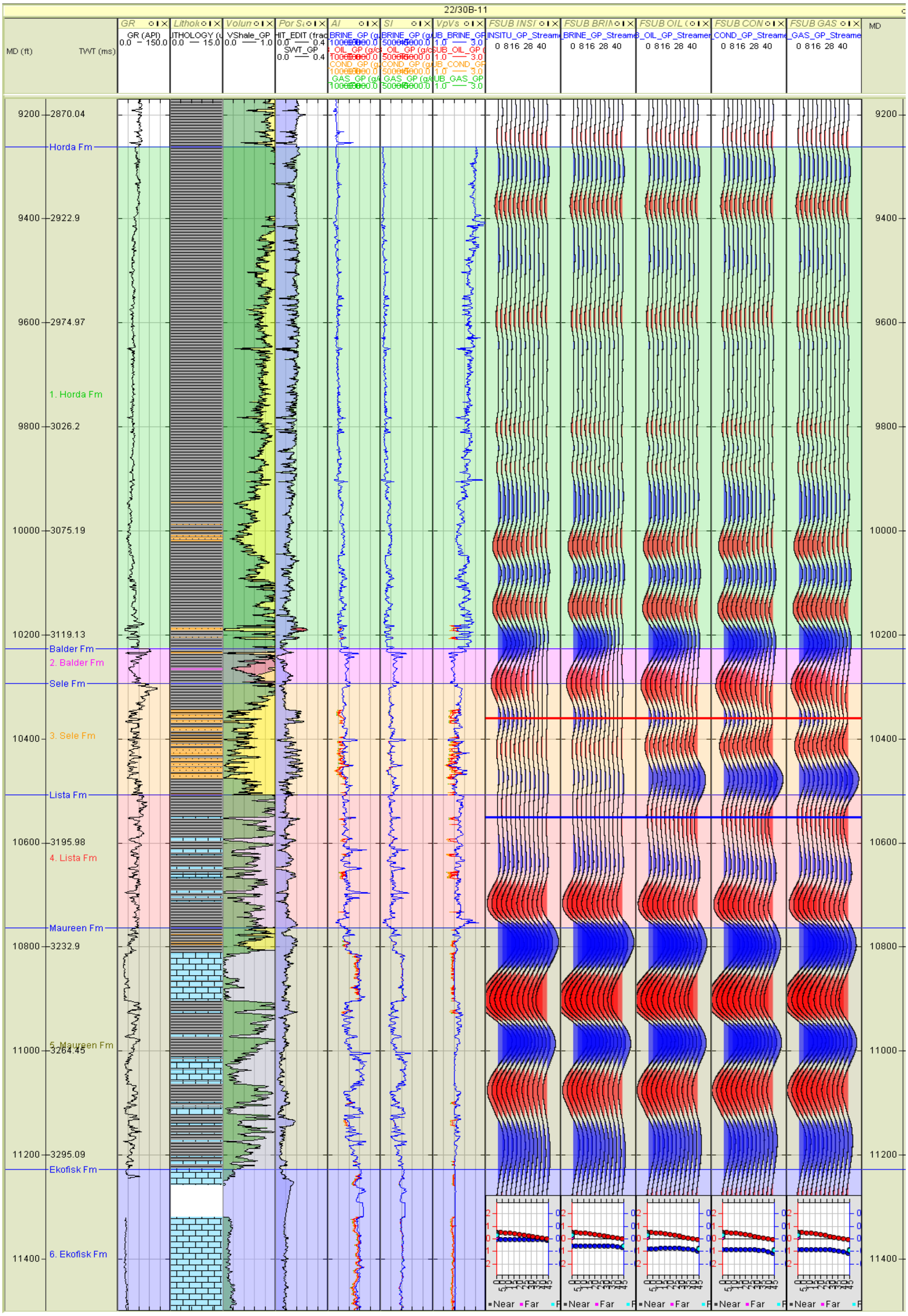


Figure 3.21.7 - Well Panel: Tertiary reservoirs for well 22/30B-11. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Horda Formation

- Reservoir formed by very thin sand packages with a maximum porosity of 24% and net reservoir is approximately 7 foot. The majority of the reservoir is shale.
- Blocky AVO shows a modelled class I response all fluid cases, with the softness of the sand in relation to the overburden shale increasing slightly with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and of medium amplitude in the brine case, but there is very little change in any of the attributes with addition of hydrocarbons. Lambda/LambdaRho shows the most sensitivity to fluid effects.

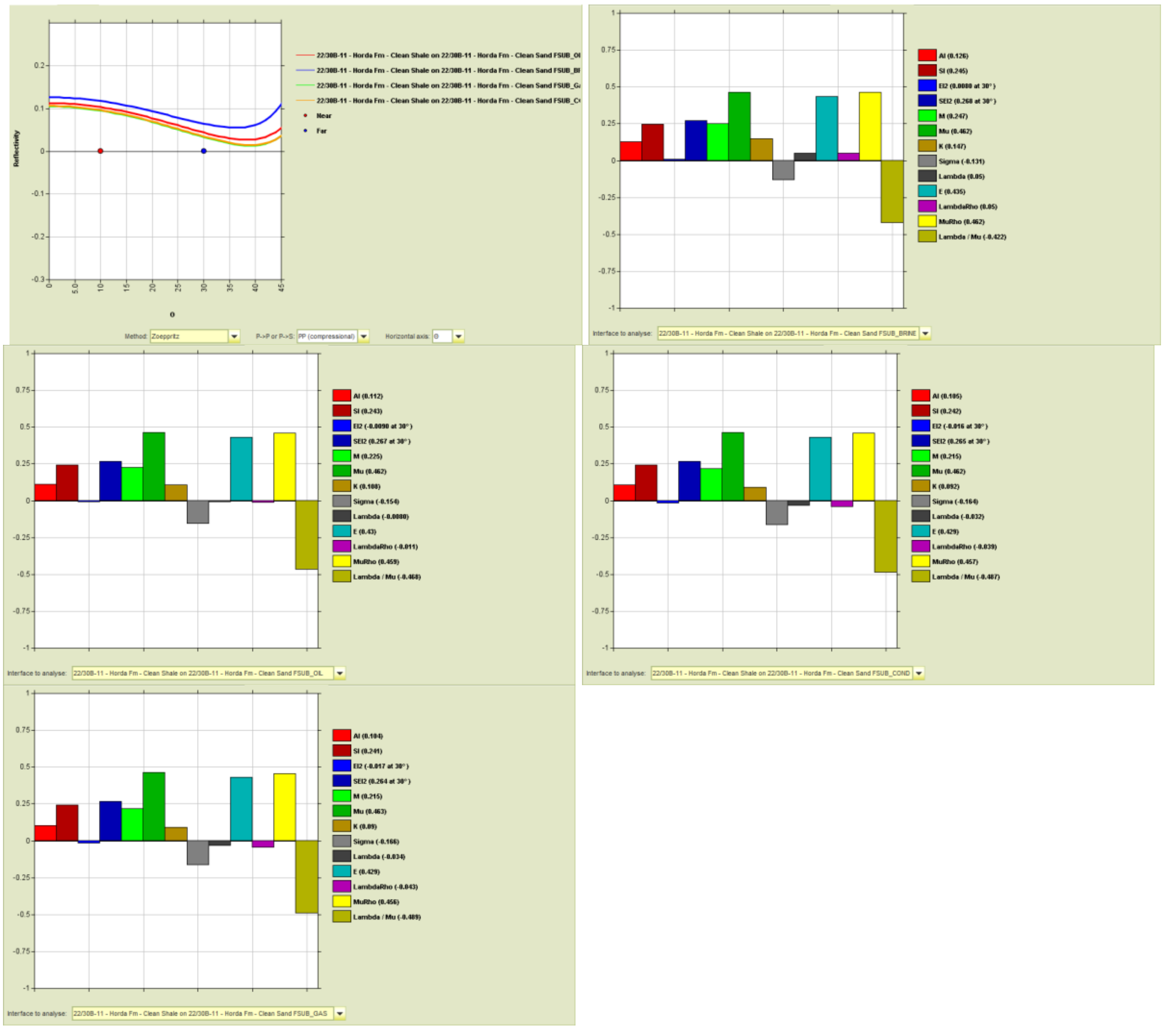


Figure 3.21.8 - Blocky AVO Model and Elastic Contrast Analysis for the Horda Formation in well 22/30B-11

Sele Formation

- Reservoir formed by inter-bedded sand and shales with a maximum porosity of 22%. The reservoir sand is overlain directly by overburden shale in the upper section of the Sele Fm.
- Blocky AVO shows a modelled class I response for the 100% brine case and a modelled class III response for the 80% oil, condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

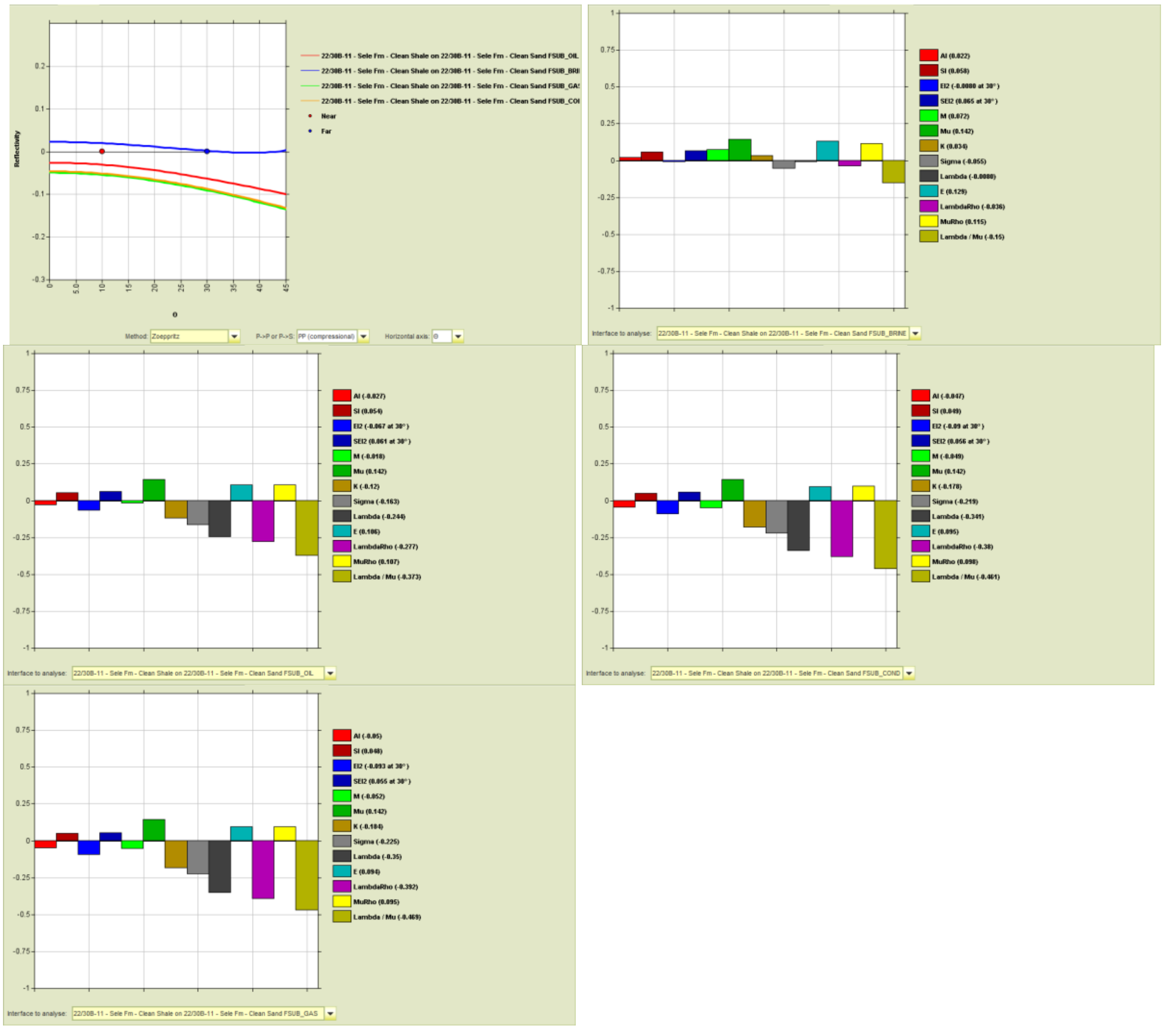


Figure 3.21.9 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 22/30B-11.

Lista Formation

- Reservoir formed by a thin section of limestone inter-bedded with shale, net reservoir is approximately 22 feet in this formation.
- Blocky AVO shows a strong modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, and that the contrasts slightly decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

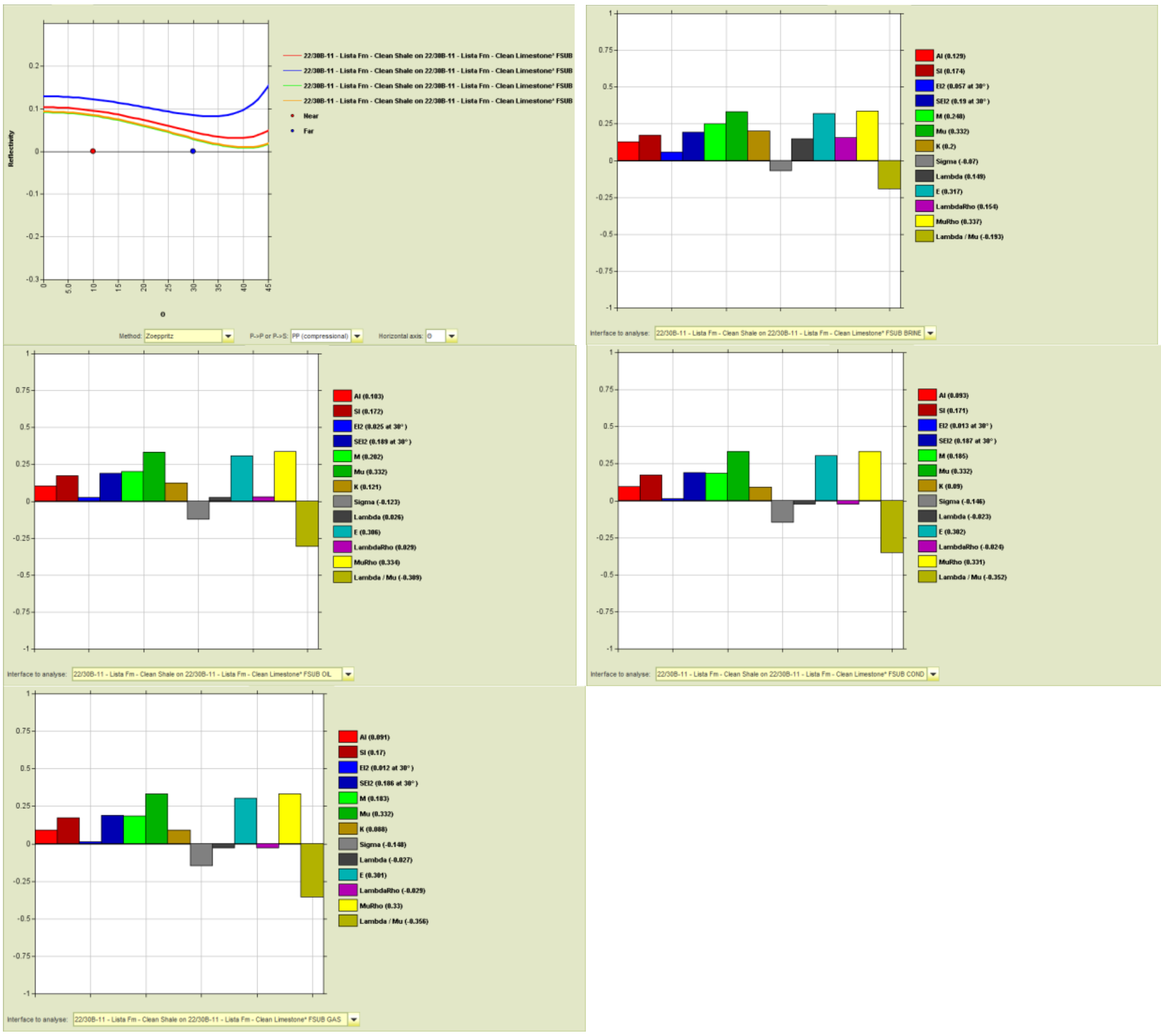


Figure 3.21.10 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 22/30B-11.

Maureen Formation (Sandstone)

- Reservoir formed very thin sand packages of maximum porosity 17% and net reservoir of approximately 3 foot. These thin sand beds are observed in the very top potion of the Maureen Fm only.
- Blocky AVO shows a modelled class I response for the 100% brine case and a modelled class IIp response for the 80% oil, condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

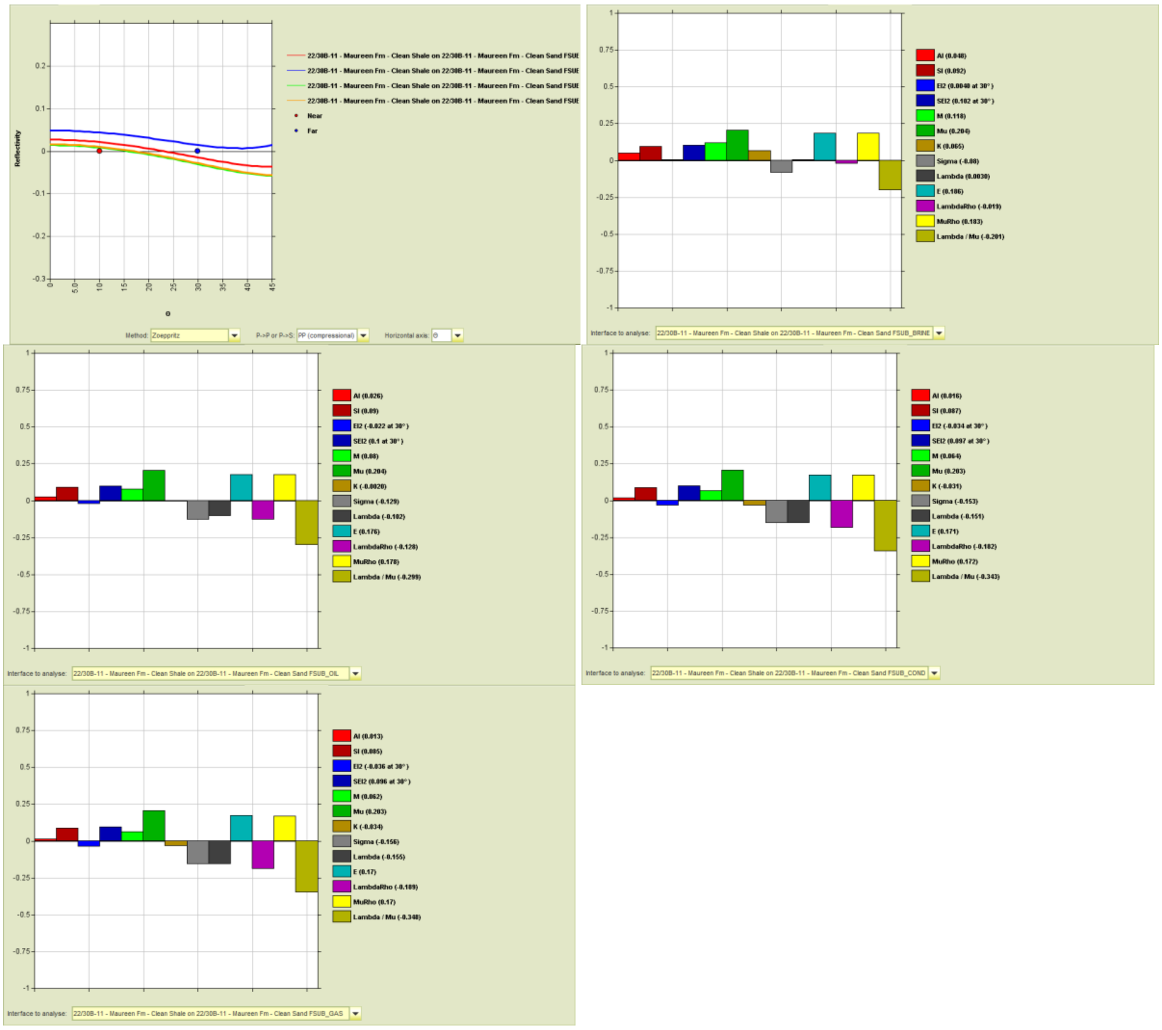


Figure 3.21.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/30B-11 (Sandstone).

Maureen Formation (Limestone)

- Reservoir formed by a series of limestone sections inter-bedded with shale, net reservoir is approximately 81 feet in this formation.
- Blocky AVO shows a strong modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, and that the contrasts slightly decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

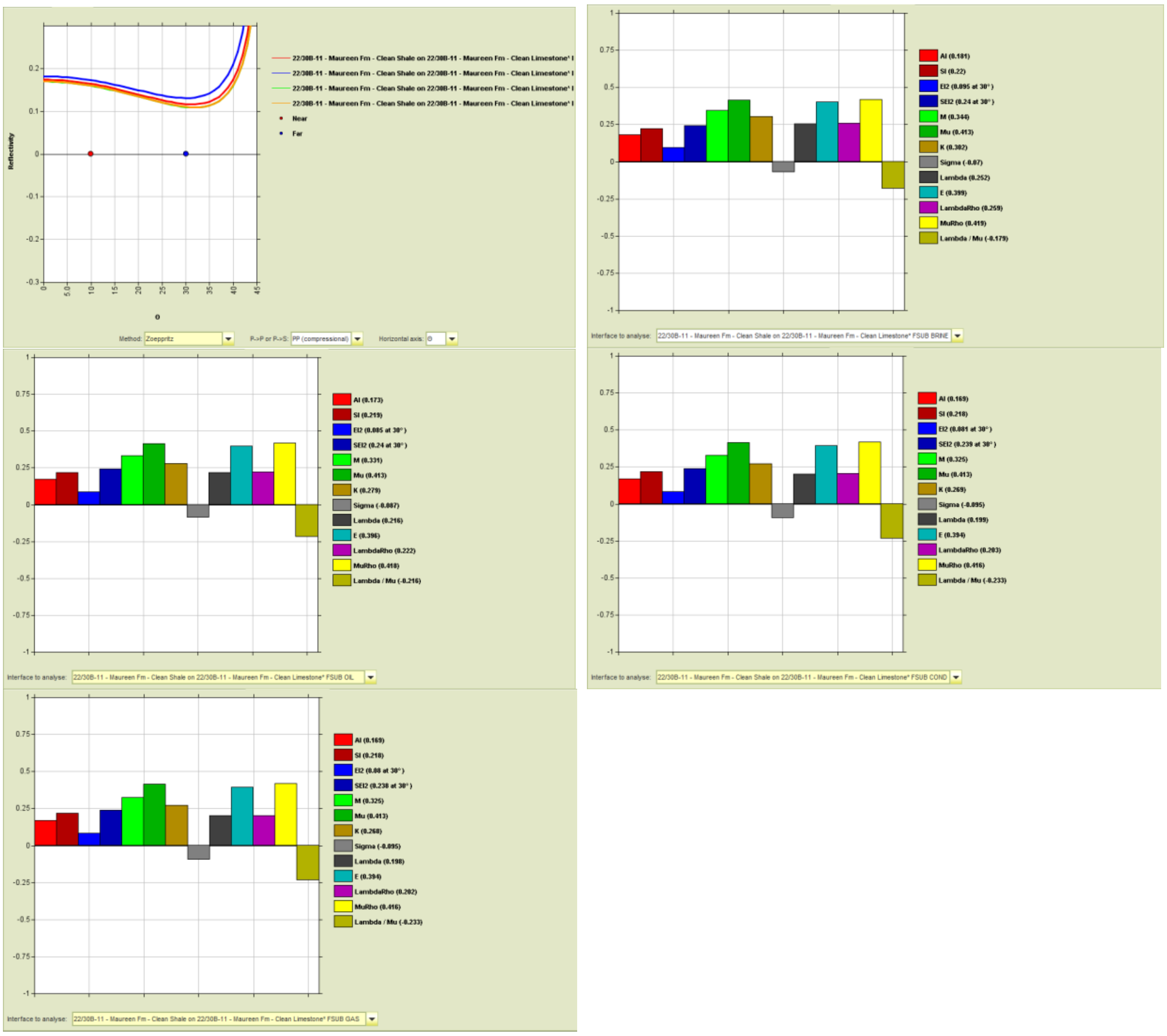


Figure 3.21.12 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 22/30B-11 (Limestone).

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 22/30B-11 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Ekofisk	100% Brine	16454	8911	2.61
22/30B-11	Tor	100% Brine	17479	9159	2.62
22/30B-11	Hod	100% Brine	16488	8817	2.58
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Ekofisk	80% Oil	16154	8931	2.60
22/30B-11	Tor	80% Oil	17314	9182	2.61
22/30B-11	Hod	80% Oil	16173	8849	2.56
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Ekofisk	90% Gas	16080	8960	2.58
22/30B-11	Tor	90% Gas	17308	9215	2.59
22/30B-11	Hod	90% Gas	16114	8896	2.53
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Ekofisk	80% Cond	16066	8951	2.58
22/30B-11	Tor	80% Cond	17301	9203	2.60
22/30B-11	Hod	80% Cond	16101	8882	2.54

Table 3.21.10 - Clean limestone properties at Well 22/30B-11for each fluid case

Cretaceous reservoirs

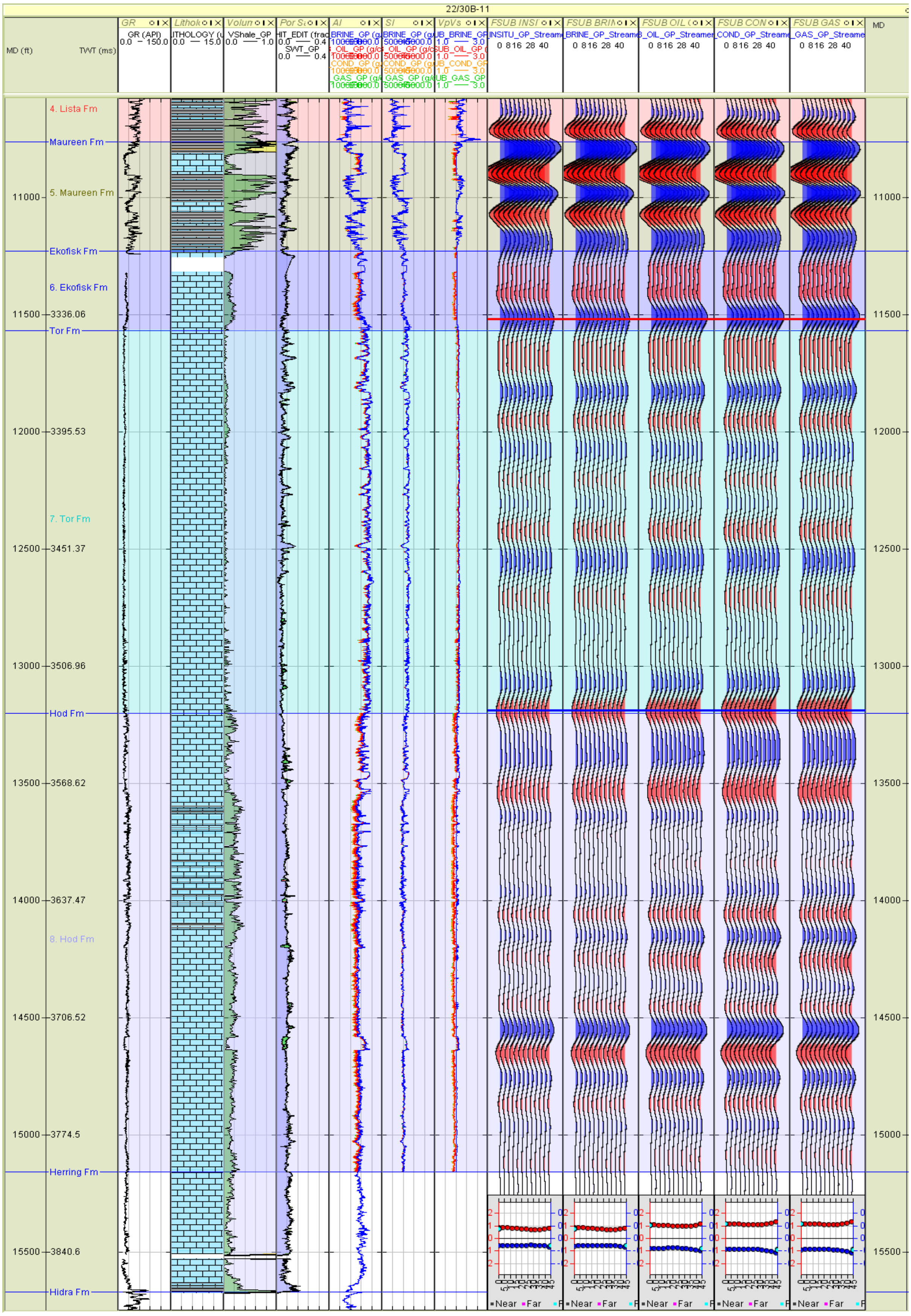


Figure 3.21.13 - Well Panel: Cretaceous reservoirs for well 22/30B-11. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. A casing change occurs near the top of the Ekofisk Fm and where the highest porosity reservoir, 14% porosity, is also observed.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but there is very little change with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

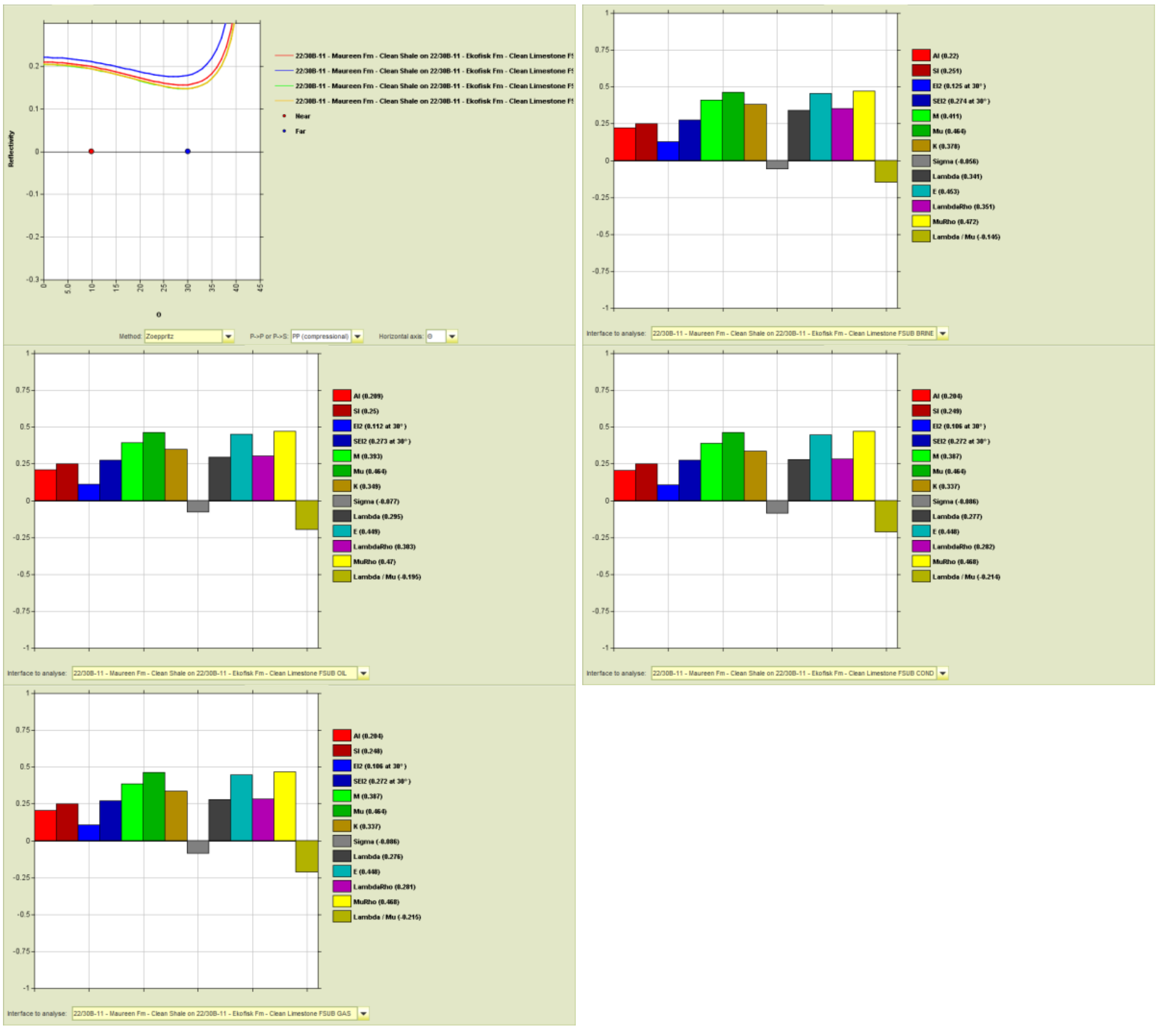


Figure 3.21.14 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 22/30B-11.

Tor Formation

- Reservoir formed by a clean limestone formation. High porosity layers ranging from 10-12-15% are found throughout the Tor Fm and could be representative of reworked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, but with a flat gradient and the amplitude does not vary with angle.
- Elastic Contrast Analysis shows contrasts are all positive and of very low amplitude in the brine case, but there is very little change with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

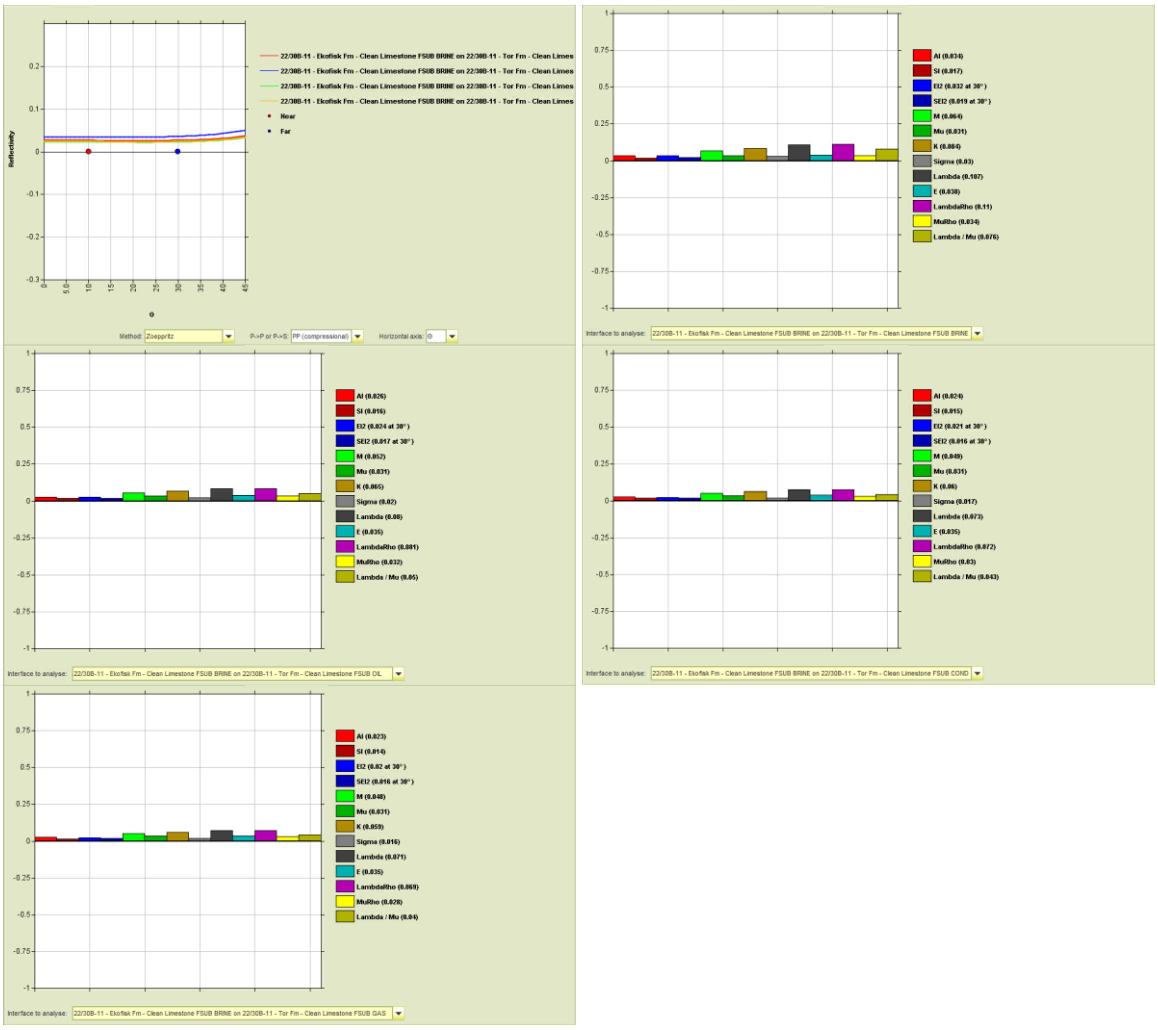


Figure 3.21.15 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 22/30B-11.

Hod Formation

- Reservoir formed by a limestone formation with some very thin shale beds. The maximum porosity observed in this formation is 12%.
- Blocky AVO shows a weak modelled class III response for all the fluid cases but with a flat gradient and the amplitude does not vary with angle.
- Elastic Contrast Analysis shows contrasts are all null or negative and of very low amplitude in the brine case, increasing in amplitude to become slightly more negative with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

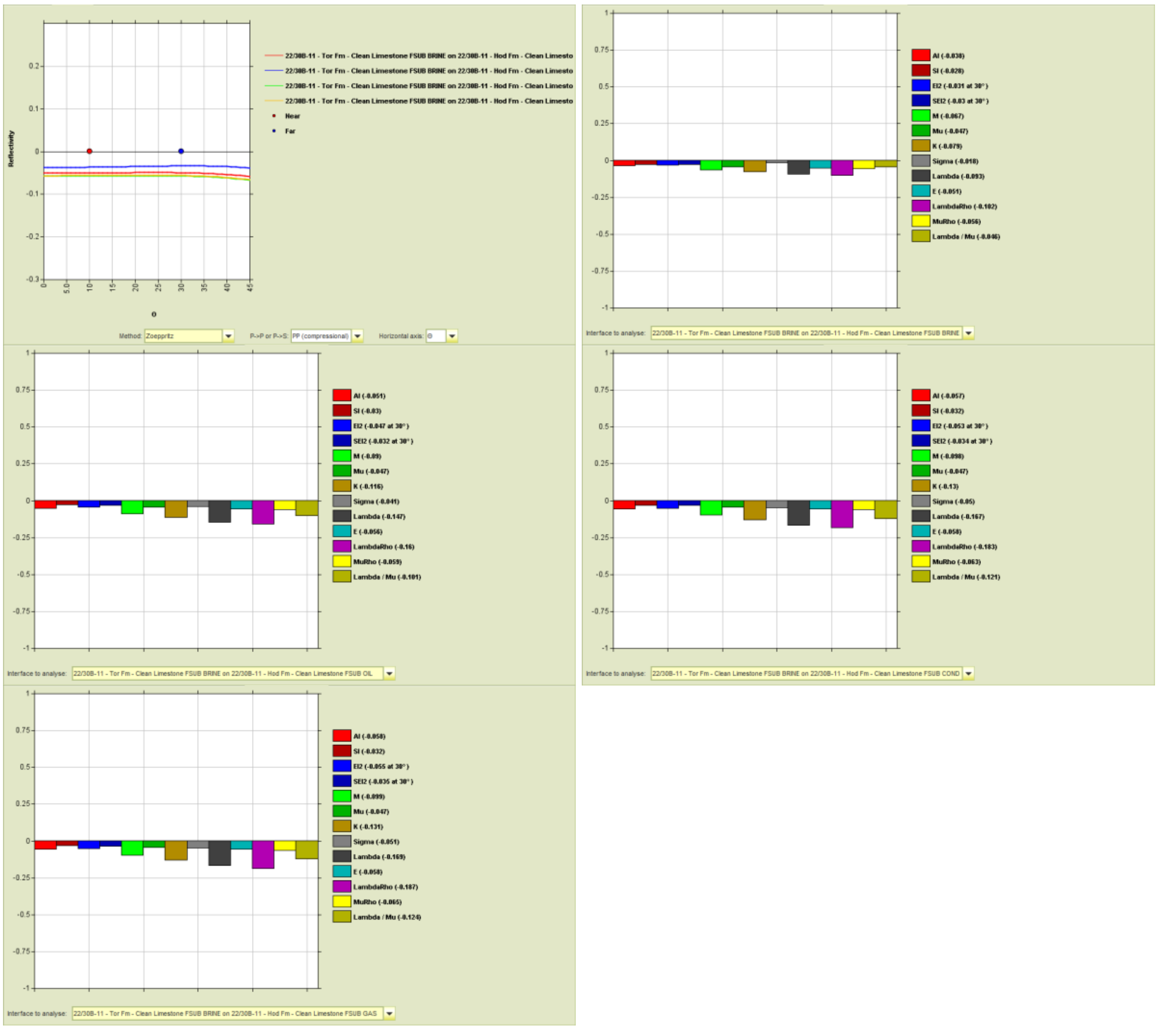


Figure 3.21.16 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 22/30B-11.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 22/30B-11 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
22/30B-11	Overburden	Shale	7702		2.37
22/30B-11	Underburden	Shale/Anhydrite	15556		2.55

Table 3.21.11 - Overburden and underburden properties at Well 22/30B-11.

Well: 23/26B-14

General

Well Information
Drilled by Texaco as an appraisal well for the Erskine formation. Completed and suspended in 1990.

Objectives
The main objectives of well 23/26b-14 were to confirm the presence of commercial hydrocarbons in the Fulmar Sandstone and Pentland formation.

Log conditioning overview
Thin calcite stringers in the Horda Fm are not being seen by the sonic log so Vp and density log data is removed at these points.

Invasion correction

Well 23/26B-14 was drilled with oil-based drilling mud. Invasion correction has been performed within all formations except for the non-reservoir Balder Fm.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Sele, Lista, Maureen and Hod Formations for Vp and within the Horda Formation for density. A complete Vs log is modelled since a measured Vs log is not available at this well. Small gaps was also filled above and below the interval of interest in the Vp log using a spline function.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoint's.

P&T data

The temperature and pressure data for Well 23/26B-14 is displayed in the figures below;

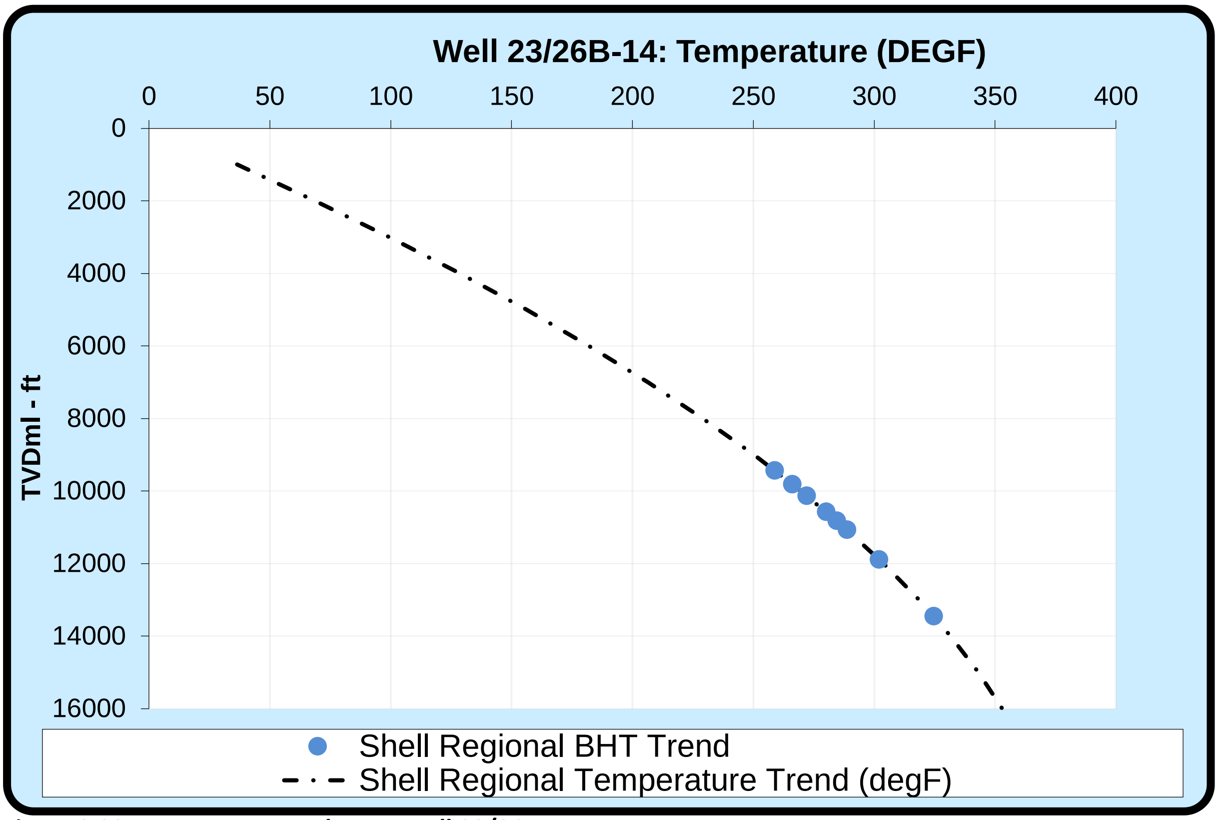


Figure 3.22.1 - Temperature data at Well 23/26B-14

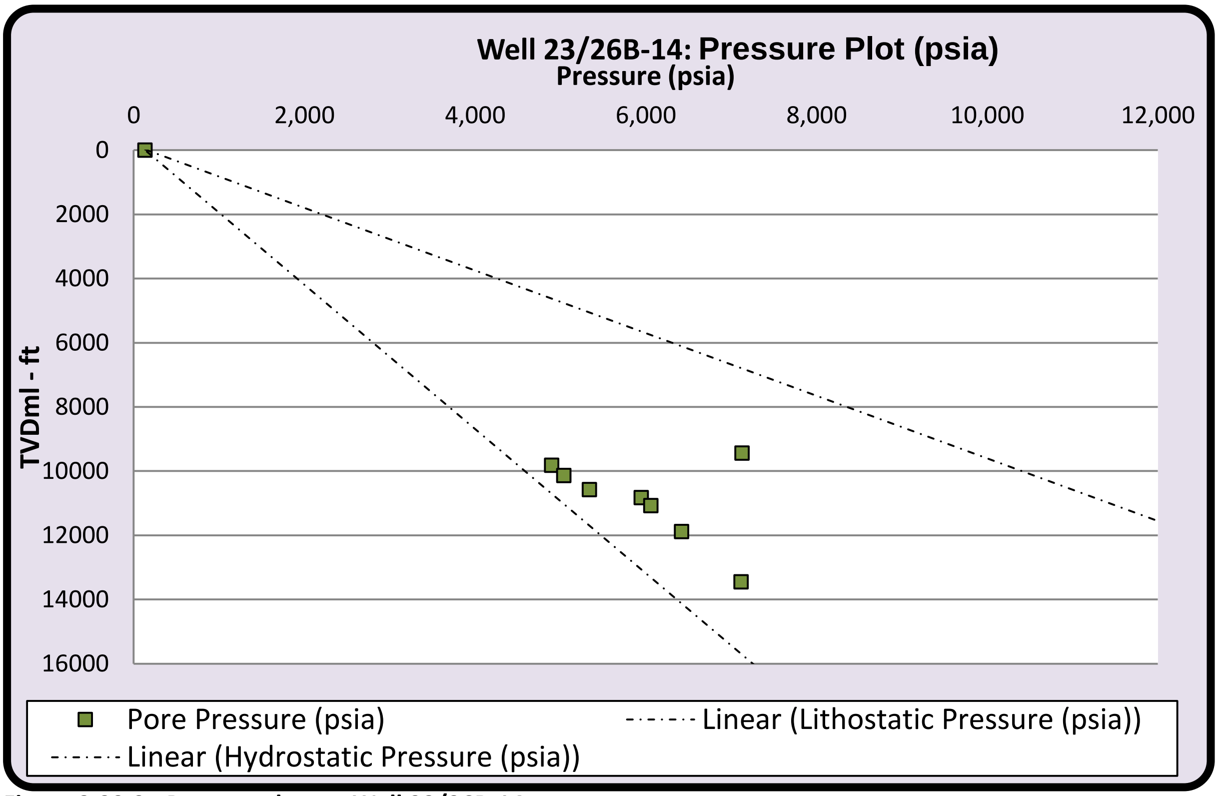


Figure 3.22.2 - Pressure data at Well 23/26B-14

The temperature and pressure data for the formation mid-points in Well 23/26B-14 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
23/26B-14	Sea Bed	372.0	299.0	0.0	39.2	133.1	133.1	133.1	0.0
23/26B-14	Horda	9807.5	9733.0	9434.0	258.8	4331.2	7131.2	9567.1	2435.9
23/26B-14	Balder	10185.0	10110.2	9811.2	266.1	4499.1	4899.1	9944.3	5045.2
23/26B-14	Sele	10505.0	10430.1	10131.1	272.1	4641.4	5041.4	10264.1	5222.7
23/26B-14	Lista	10951.0	10875.8	10576.8	280.2	4839.7	5339.7	10709.9	5370.1
23/26B-14	Maureen	11197.5	11122.2	10823.2	284.5	4949.4	5949.4	10956.3	5006.9
23/26B-14	Ekofisk	11445.5	11370.1	11071.1	288.8	5059.7	6059.7	11204.2	5144.5
23/26B-14	Tor	12258.5	12183.0	11884.0	302.1	5421.4	6421.4	12017.1	5595.6
23/26B-14	Hod	13828.0	13752.4	13453.4	324.7	6119.8	7119.8	13586.5	6466.6

Table 3.22.1 - Summary of mid-point temperature and pressure data at Well 23/26B-14

Fluid data

A summary of the fluid set parameters at Well 23/26B-14 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
23/26B-14	Horda	87000	730	41.6	0.78	0.78
23/26B-14	Balder	87000	730	42.0	0.78	0.78
23/26B-14	Sele	87000	730	42.3	0.78	0.78
23/26B-14	Lista	87000	730	42.8	0.78	0.78
23/26B-14	Maureen	87000	730	43.1	0.78	0.78
23/26B-14	Ekofisk	68000	730	43.3	0.78	0.78
23/26B-14	Tor	55000	730	44.2	0.78	0.78
23/26B-14	Hod	55000	730	45.9	0.78	0.78

Table 3.22.2 - Summary of fluid parameter data at Well 23/26B-14

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.22.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	14.9	8.6	2.45	10,773	6,144

Table 3.22.4 - Tuff properties used at Well 23/26B-14

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Num-	Formation	Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM

ber									
23/26B-14	Horda	PAY	705.000	0.000	0.000	0.000	0.000	0.000	0.000
23/26B-14	Horda	RES	705.000	15.000	0.021	2.469	0.165	1.000	0.330
23/26B-14	Balder	PAY	50.000	0.000	0.000	0.000	0.000	0.000	0.000
23/26B-14	Balder	RES	50.000	0.000	0.000	0.000	0.000	0.000	0.000
23/26B-14	Sele	PAY	590.000	0.000	0.000	0.000	0.000	0.000	0.000
23/26B-14	Sele	RES	590.000	391.25	0.663	69.084	0.177	0.932	0.173
23/26B-14	Lista	PAY	302.000	0.000	0.000	0.000	0.000	0.000	0.000
23/26B-14	Lista	RES	302.000	6.750	0.022	1.189	0.176	0.952	0.259
23/26B-14	Maureen	PAY	191.000	0.000	0.000	0.000	0.000	0.000	0.000
23/26B-14	Maureen	RES	191.000	26.500	0.139	2.763	0.104	0.998	0.273
23/26B-14	Ekofisk	PAY	305.000	0.000	0.000	0.000	0.000	0.000	0.000
23/26B-14	Ekofisk	RES	305.000	212.50	0.697	23.346	0.110	0.989	0.117
23/26B-14	Tor	PAY	1321.000	0.500	0.000	0.071	0.142	0.492	0.004
23/26B-14	Tor	RES	1321.000	938.75	0.711	60.538	0.064	0.924	0.022
23/26B-14	Hod	PAY	1818.000	18.000	0.010	1.408	0.078	0.417	0.029
23/26B-14	Hod	RES	1818.000	1469.25	0.808	82.214	0.056	0.946	0.204

Table 3.22.5 - Petrophysical parameters used at Well 23/26B-14

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

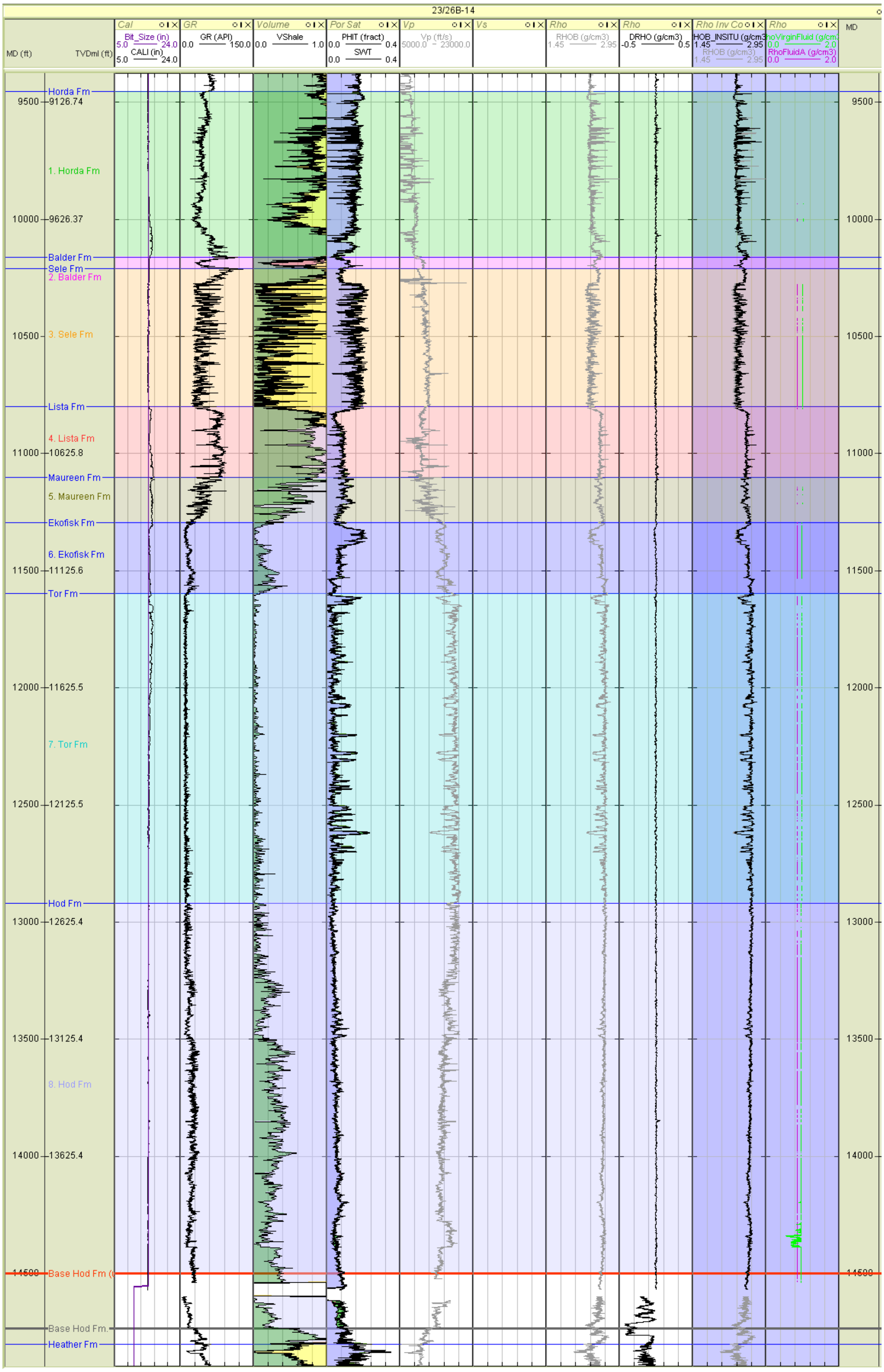


Figure 3.22.3 - Well Panel: Measured data and invasion correction for well 23/26B-14.

Well log panel – log editing and audit

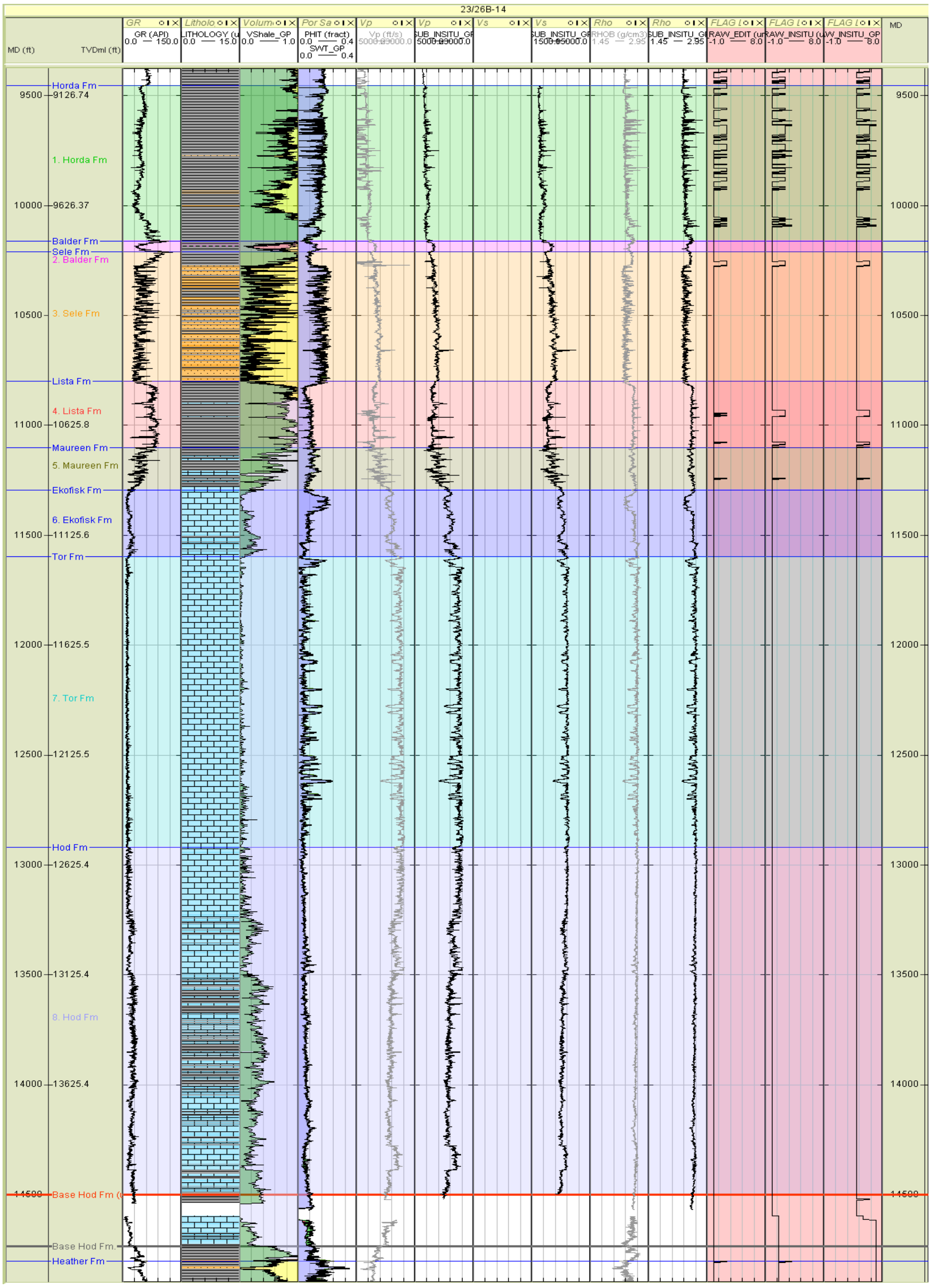


Figure 3.22.4 - Well Panel: Log edits for well 23/26B-14.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**

Flag = 3	Edit in Rho and Vs	Flag = 7	Edit in Vp, Vs and Rho

Well log panel – synthetic curves

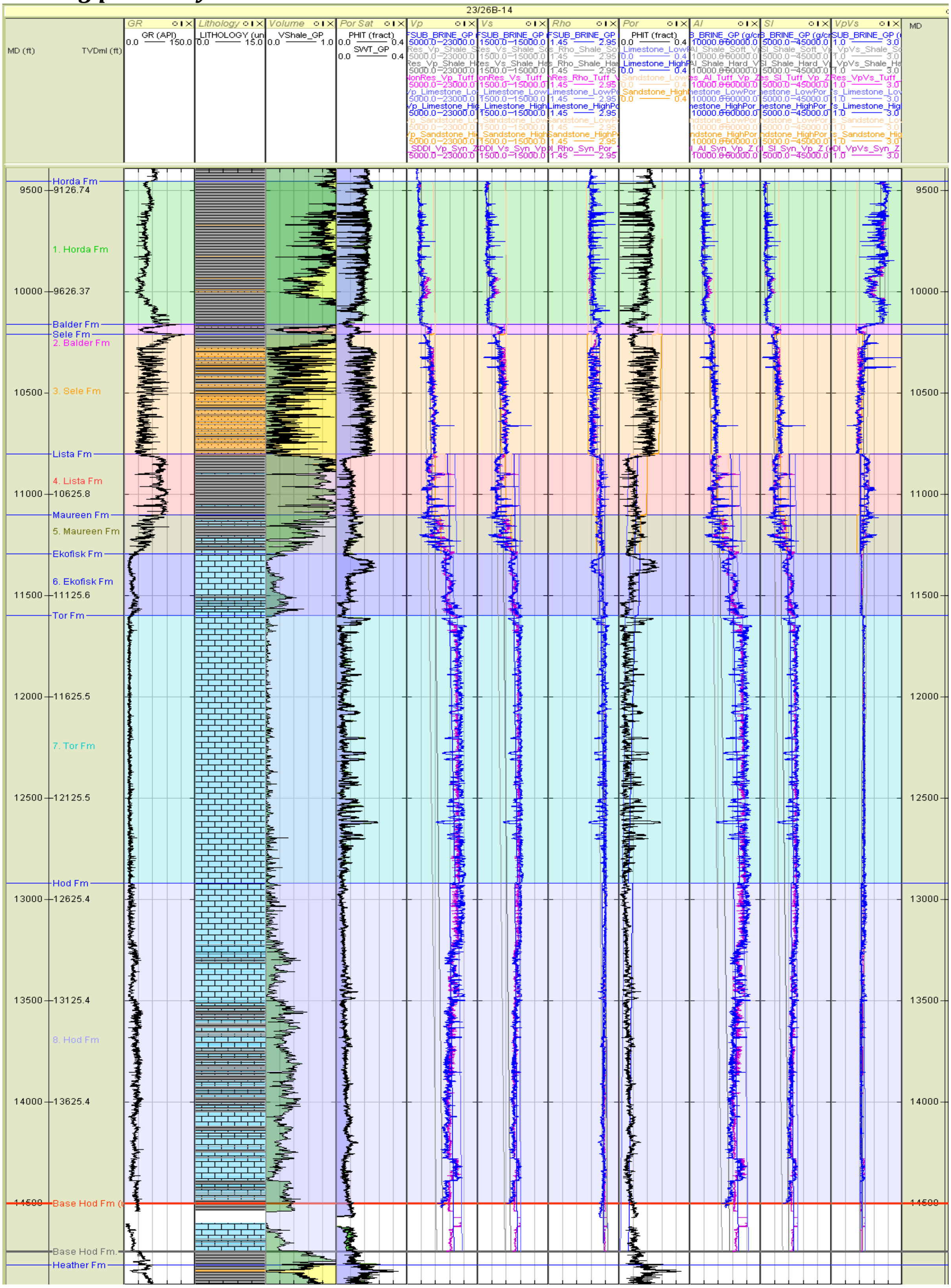


Figure 3.22.5 - Well Panel: End-member and synthetic logs for well 23/26B-14.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

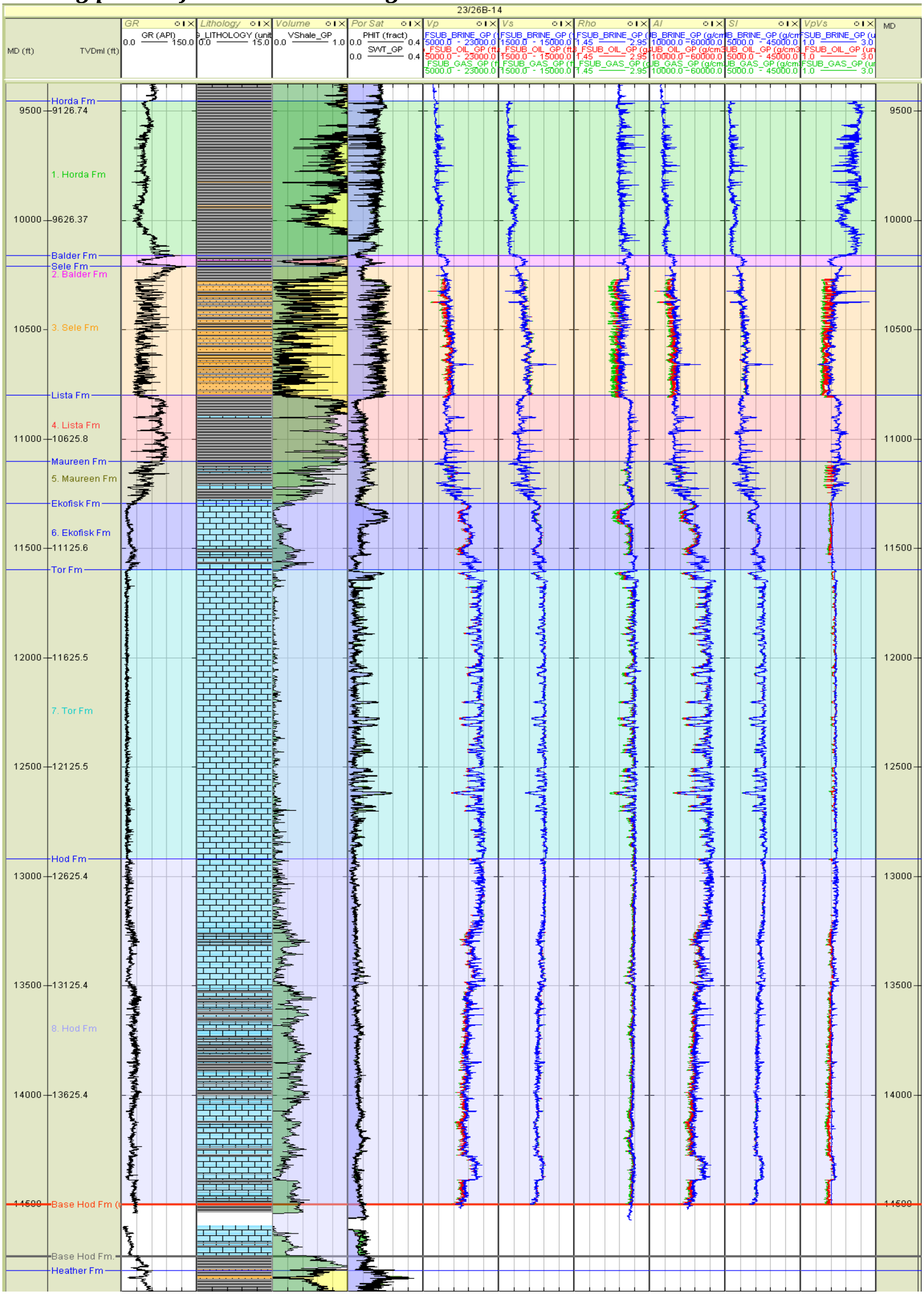


Figure 3.22.6 - Well Panel: Fluid substituted and elastic logs for well 23/26B-14.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 23/26B-14 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/26B-14	Horda	8,124	3,329	2.38
23/26B-14	Balder	9,673	4,881	2.52
23/26B-14	Sele	10,333	5,285	2.49
23/26B-14	Lista	10,328	5,135	2.55
23/26B-14	Maureen	10,113	5,000	2.51

Table 3.22.6 - Clean shale properties at Well 23/26B-14

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/26B-14	Horda	100% Brine			
23/26B-14	Balder	100% Brine			
23/26B-14	Sele	100% Brine	11,635	6,563	2.35
23/26B-14	Lista	100% Brine	11,057	5,906	2.35
23/26B-14	Maureen	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/26B-14	Horda	80% Oil			
23/26B-14	Balder	80% Oil			
23/26B-14	Sele	80% Oil	10,816	6,634	2.30
23/26B-14	Lista	80% Oil	10,173	5,971	2.30
23/26B-14	Maureen	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/26B-14	Horda	90% Gas			
23/26B-14	Balder	90% Gas			
23/26B-14	Sele	90% Gas	10,670	6,745	2.23
23/26B-14	Lista	90% Gas	10,019	6,070	2.23
23/26B-14	Maureen	90% Gas			

Table 3.22.7 - Clean sand properties at Well 23/26B-14 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/26B-14	Maureen	100% Brine	14,357	7,835	2.58
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/26B-14	Maureen	80% Oil	14,093	7,848	2.57
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/26B-14	Maureen	90% Gas	14,026	7,866	2.56

Table 3.22.8 - Clean limestone properties at Well 23/26B-14 for each fluid case (Tertiary)

Tertiary reservoirs

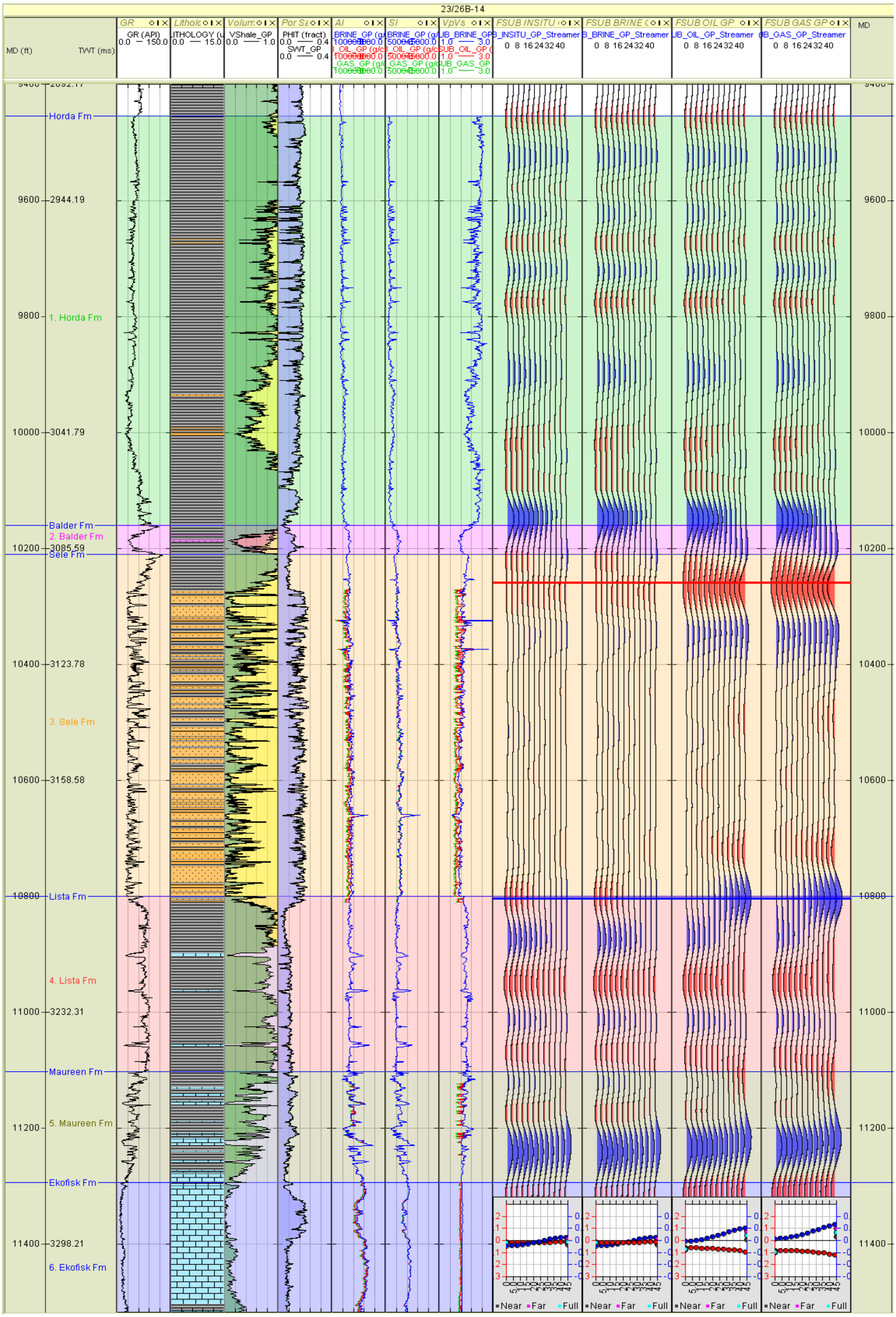


Figure 3.22.7 - Well Panel: Tertiary reservoirs for well 23/26B-14. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by inter-bedded sand and shale, overlain by approximately 70 foot of clean shale. The observed porosities in the clean sands are fairly constant, around 21%.
- Blocky AVO shows a modelled class I response for the 100% brine case; a modelled class II response for the 80% oil and a modelled class III response for the 90% gas case. Where the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

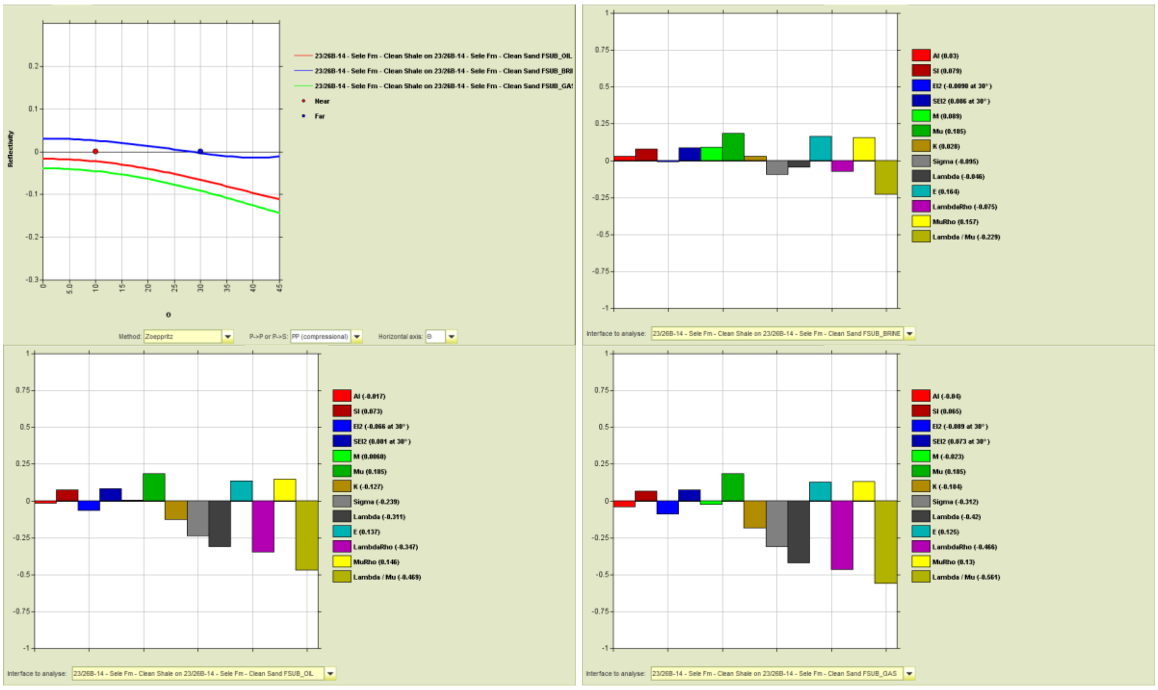


Figure 3.22.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 23/26B-14.

Maureen Formation

- Reservoir formed by a set of limestone sections inter-bedded with shale, net reservoir is approximately 27 feet in this formation. A higher proportion of limestone is found at the bottom of the interval.
- Blocky AVO shows a strong modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, and that the contrasts slightly decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

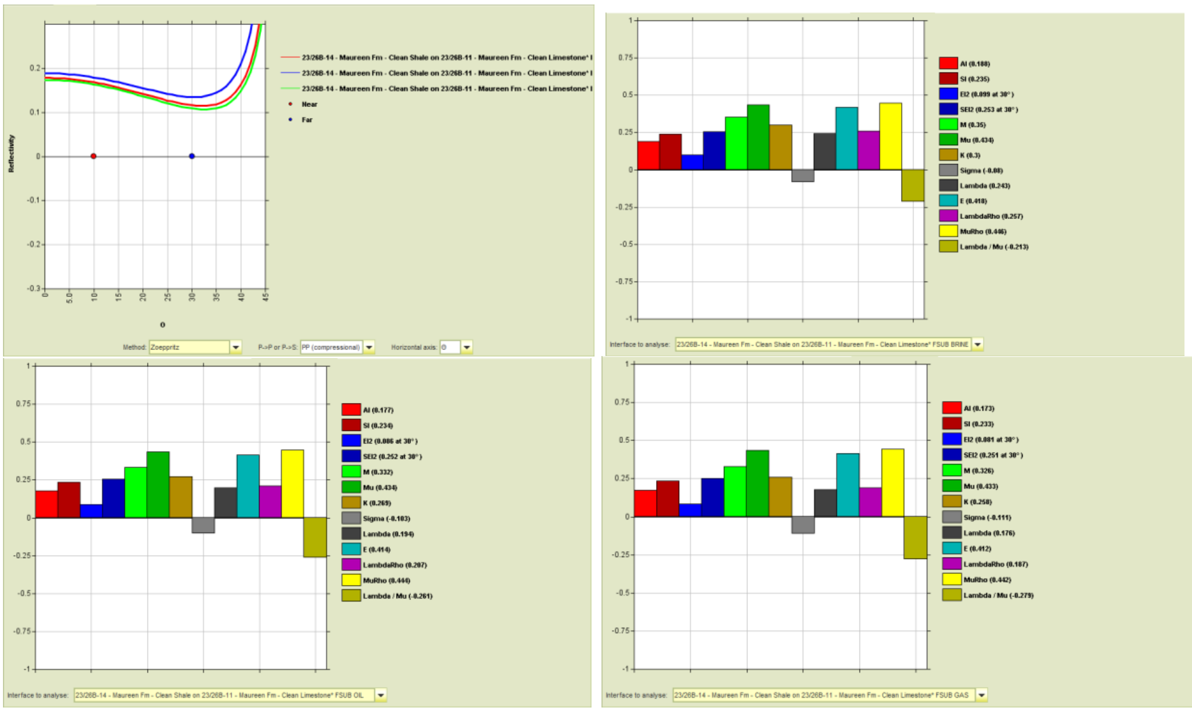


Figure 3.22.9 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 23/26B-14.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 23/26B-14 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/26B-14	Ekofisk	100% Brine	15439	8363	2.48
23/26B-14	Tor	100% Brine	18030	9379	2.62
23/26B-14	Hod	100% Brine	18389	9519	2.63
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/26B-14	Ekofisk	80% Oil	15104	8420	2.45
23/26B-14	Tor	80% Oil	17956	9401	2.60
23/26B-14	Hod	80% Oil	18351	9537	2.62
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/26B-14	Ekofisk	90% Gas	15127	8508	2.40
23/26B-14	Tor	90% Gas	17985	9434	2.59
23/26B-14	Hod	90% Gas	18381	9564	2.61

Table 3.22.9 - Clean limestone properties at Well 23/26B-14 for each fluid case

Cretaceous reservoirs

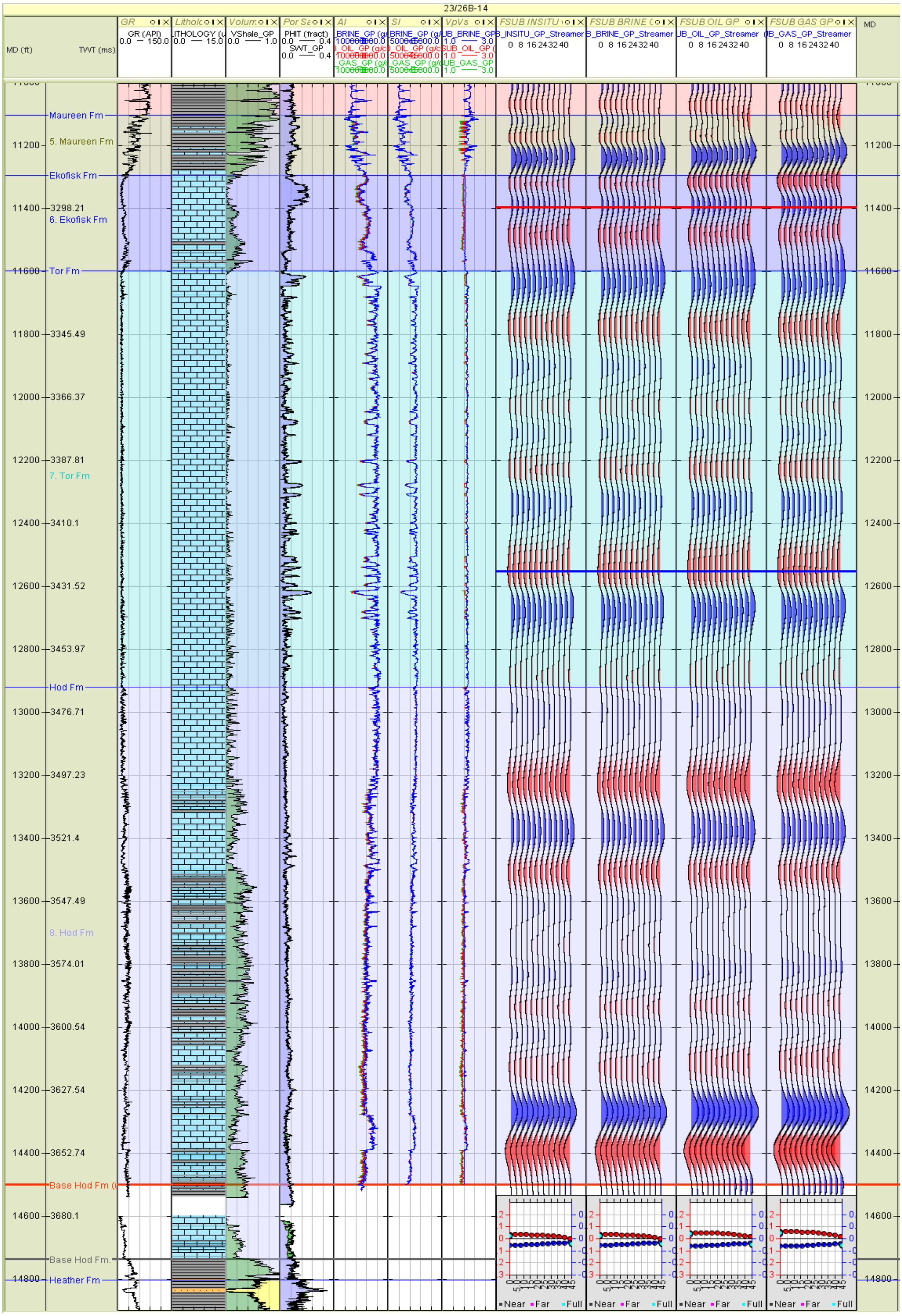


Figure 3.22.10 - Well Panel: Cretaceous reservoirs for well 23/26B-14. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the top section of the Ekofisk Fm and the porosity in this section is approximately 20%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, with little change across most attributes with addition of hydrocarbons. Lambda/LambdaRho shows the most sensitivity to fluid effects.

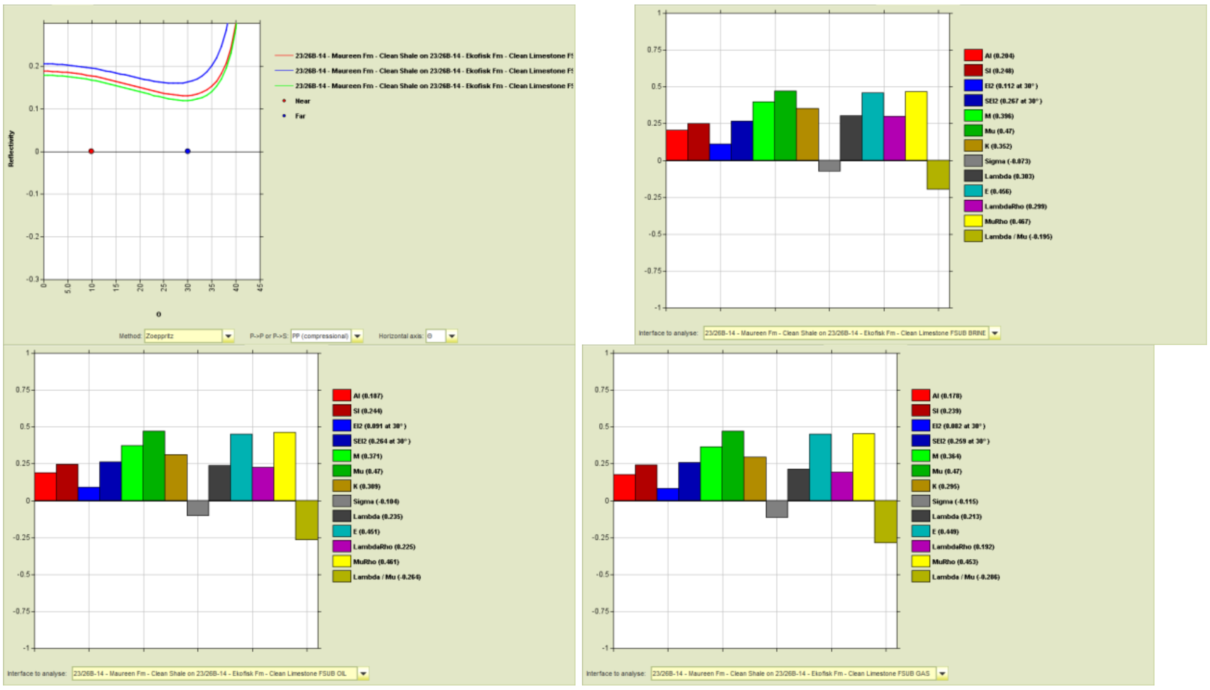


Figure 3.22.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 23/26B-14.

Tor Formation

- Reservoir formed by a clean limestone formation. High porosity layers are found throughout the Tor Fm and could be representative of reworked chalk zones. The maximum porosity observed in such layers is 17 and 23%
- Blocky AVO shows a modelled class I response for all the fluid cases but with a flat gradient. The Elastic Contrast Analysis shows no change between the different fluid cases.

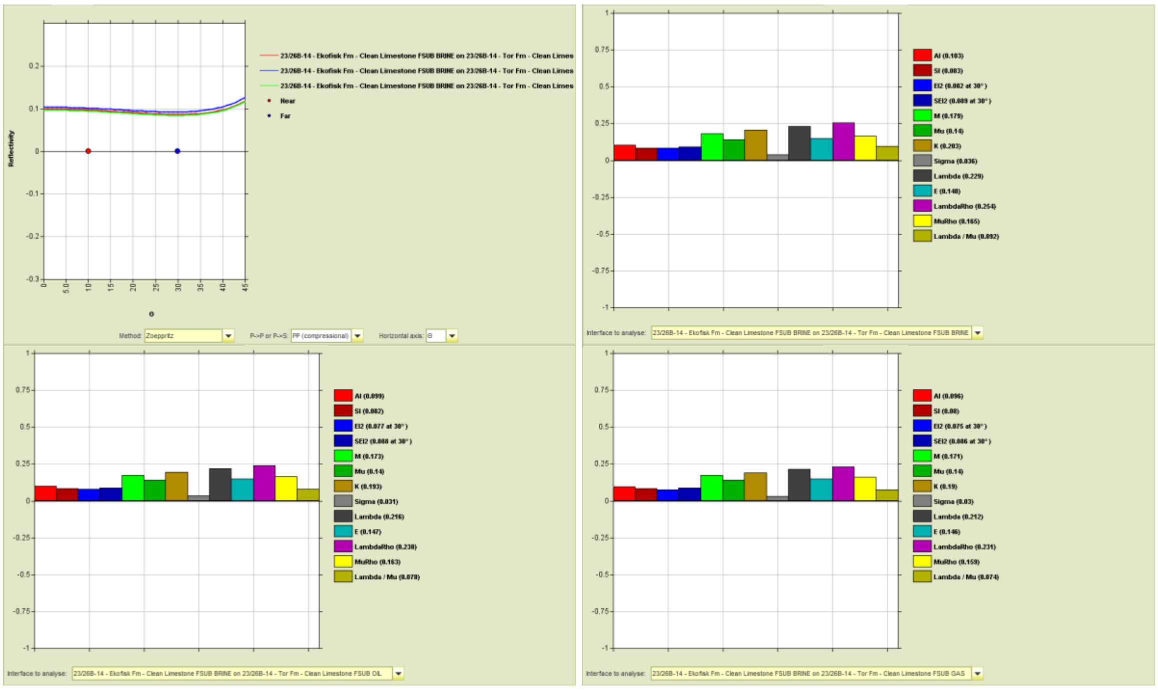


Figure 3.22.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 23/26B-14.

Hod Formation

- Reservoir formed by a limestone formation with the component of shale generally increasing with depth.
- Blocky AVO shows a modelled class I response for all the fluid cases but with a flat gradient and no variation in amplitude with angle. The Elastic Contrast Analysis shows no change between the different fluid cases.

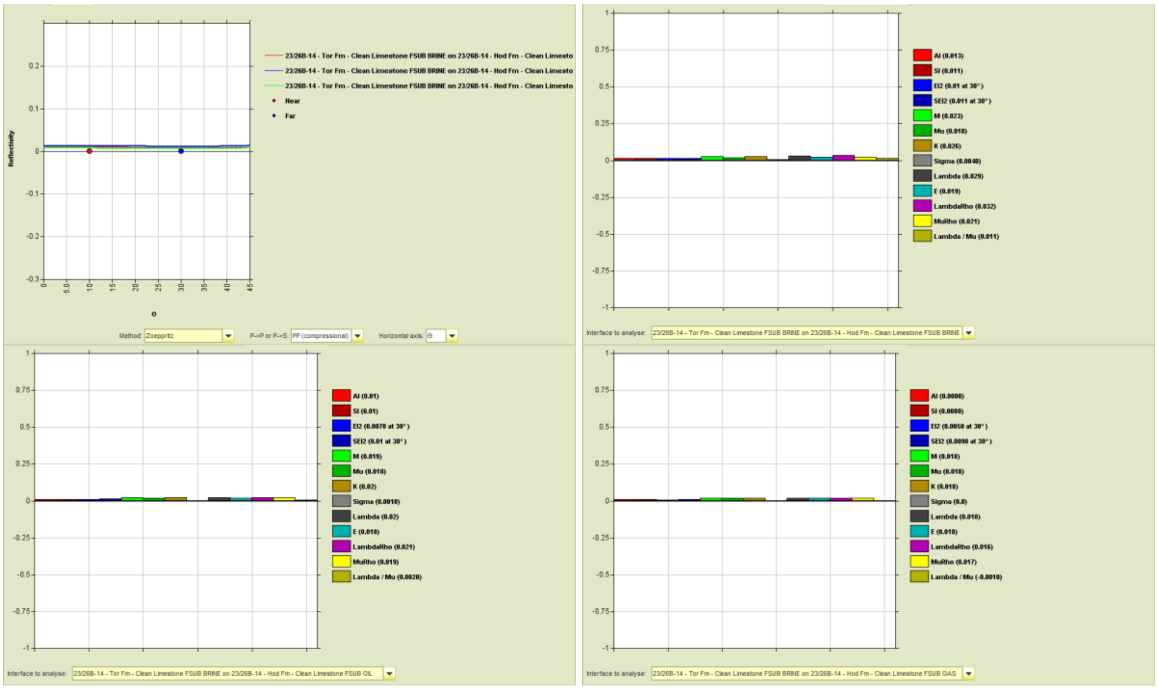


Figure 3.22.13 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 23/26B-14.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 23/26B-14 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/26B-14	Overburden	Shale	7577		2.34
23/26B-14	Underburden	Sand/Shale	10085		

Table 3.22.10 - Overburden and underburden properties at Well 23/26B-14.

Well: 23/27-09

General

Well Information
Well 23/27-09 was drilled to investigate the lateral extension, quality, distribution and producibility of the Upper Palaeocene sands which had tested oil at low rates in adjacent wells.

Objectives
This well is located up dip of 23/27-04 to test the same fault compartment on the northern flank of a Zechstein salt diapir. Studies are now underway on potential development options. After testing oil and gas in the Forties and Ekofisk Formations the well was suspended as a future oil and gas producer.

Log conditioning overview
No log conditioning was required in this well.

Invasion correction

Well 23/27-09 was drilled with a combination of water-based and oil-based drilling muds. Invasion correction has been performed within all formations containing reservoir intervals. The Horda, Balder and Lista Formations do not contain any reservoir intervals.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log. The only exception is a minor gap within the Rho log over a hydrocarbon zone in the Tor Formation and the methodology for filling this gap is documented within the Rock Physics Part 2 PowerPoints.

No gaps were found for the Vp log. A gap was filled within the Tor Formation for density. A complete Vs log is modelled since a measured Vs log is not available at this well. A gap was also filled above the interval of interest in the Vp log using a spline function.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 23/27-09 is displayed in the figures below;

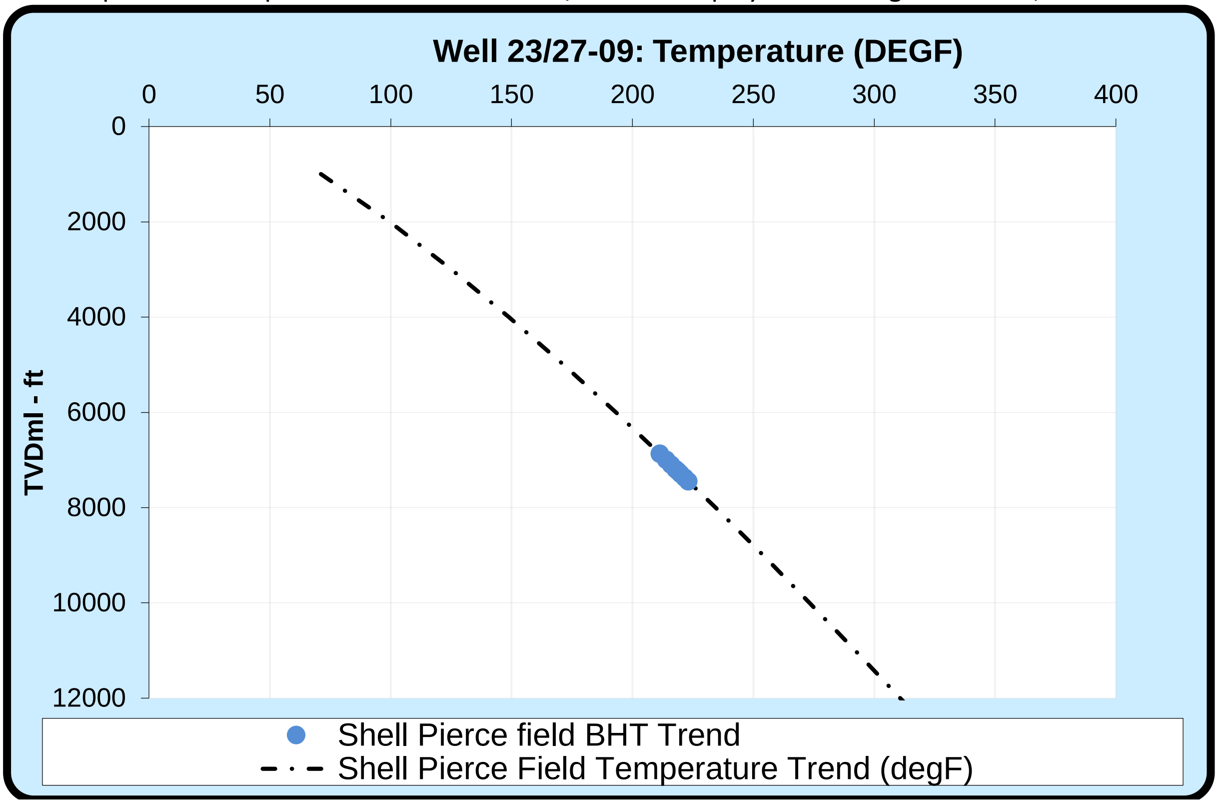


Figure 3.23.1 - Temperature data at Well 23/27-09

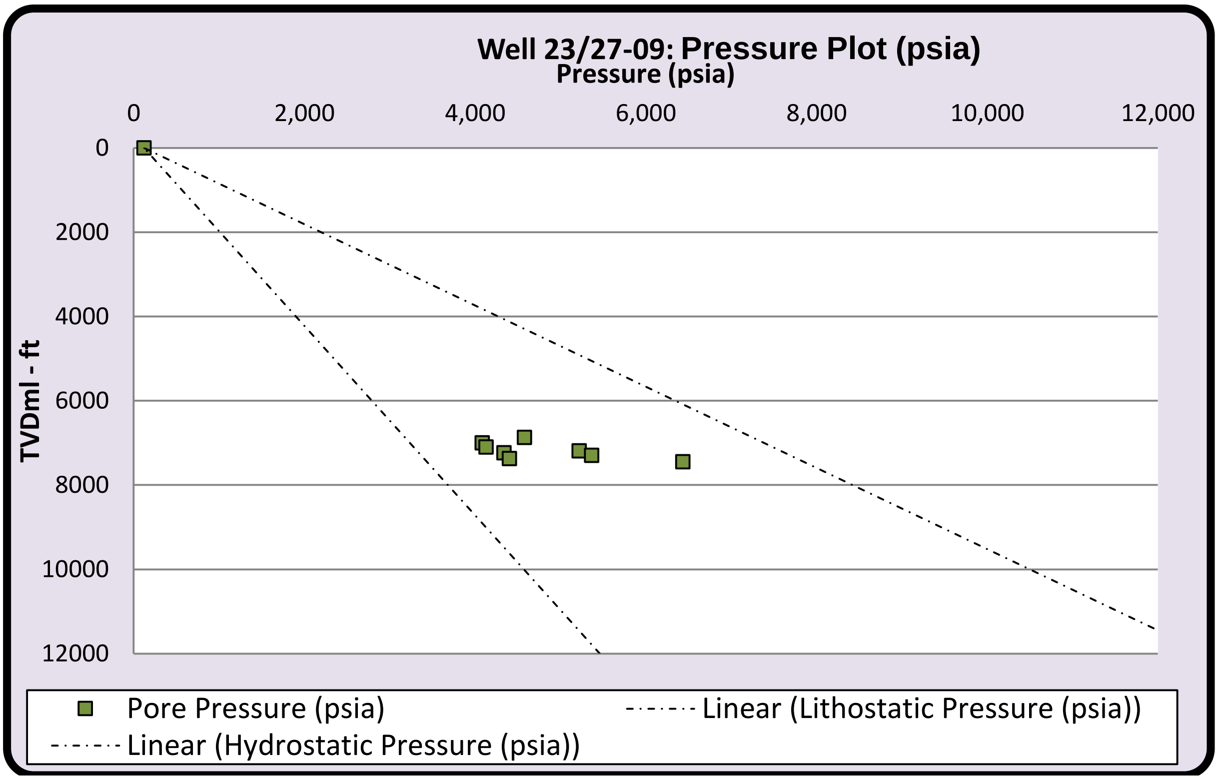


Figure 3.23.2 - Pressure data at Well 23/27-09

The temperature and pressure data for the formation mid-points in Well 23/27-09 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
23/27-09	Sea Bed	422.0	273.0	0.0	39.2	121.5	121.5	121.5	0.0
23/27-09	Horda	7758.0	7145.4	6872.4	203.3	3179.7	4579.7	6993.9	2414.2
23/27-09	Balder	7928.5	7273.1	7000.1	206.4	3236.5	4086.5	7121.6	3035.1
23/27-09	Sele	8062.5	7370.7	7097.7	208.6	3279.9	4129.9	7219.1	3089.2
23/27-09	Lista	8191.5	7464.0	7191.0	210.8	3321.5	5221.5	7312.5	2091.0
23/27-09	Maureen	8252.0	7507.0	7234.0	211.8	3340.6	4340.6	7355.5	3014.9
23/27-09	Ekofisk	8338.0	7568.1	7295.1	213.2	3367.8	5367.8	7416.6	2048.8
23/27-09	Tor	8449.5	7647.2	7374.2	215.0	3403.0	4403.0	7495.7	3092.7
23/27-09	Hod	8557.0	7723.3	7450.3	216.8	3436.9	6436.9	7571.8	1134.9

Table 3.23.1 - Summary of mid-point temperature and pressure data at Well 23/27-09

Fluid data

A summary of the fluid set parameters at Well 23/27-09 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
23/27-09	Horda	55000	730	38.8	0.78	0.78
23/27-09	Balder	55000	730	38.9	0.78	0.78
23/27-09	Sele	55000	1193	37.6	0.819	0.819
23/27-09	Lista	55000	730	39.1	0.78	0.78
23/27-09	Maureen	55000	730	39.2	0.78	0.78
23/27-09	Ekofisk	55000	1147	36.9	0.816	0.816
23/27-09	Tor	55000	730	39.3	0.78	0.78
23/27-09	Hod	55000	730	39.4	0.78	0.78

Table 3.23.2 - Summary of fluid parameter data at Well 23/27-09

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.23.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	13.6	6.5	2.419	9,944	5,368

Table3.23.4. - Tuff properties used at Well 23/27-09

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
23/27-09	Horda	PAY	300.000	0.000	0.000	0.000	0.000	0.000	0.000
23/27-09	Horda	RES	300.000	0.000	0.000	0.000	0.000	0.000	0.000
23/27-09	Balder	PAY	41.000	0.000	0.000	0.000	0.000	0.000	0.000
23/27-09	Balder	RES	41.000	0.000	0.000	0.000	0.000	0.000	0.000
23/27-09	Sele	PAY	227.000	64.500	0.284	12.062	0.187	0.373	0.212
23/27-09	Sele	RES	227.000	105.000	0.463	18.685	0.178	0.484	0.269
23/27-09	Lista	PAY	31.000	0.000	0.000	0.000	0.000	0.000	0.000
23/27-09	Lista	RES	31.000	2.000	0.065	0.308	0.154	0.952	0.369
23/27-09	Maureen	PAY	90.000	0.250	0.003	0.038	0.153	0.149	0.177
23/27-09	Maureen	RES	90.000	26.250	0.292	3.462	0.132	0.849	0.217
23/27-09	Ekofisk	PAY	82.000	34.250	0.418	6.098	0.178	0.411	0.056
23/27-09	Ekofisk	RES	82.000	79.500	0.970	11.233	0.141	0.543	0.113
23/27-09	Tor	PAY	141.000	71.500	0.507	9.843	0.138	0.303	0.007
23/27-09	Tor	RES	141.000	119.750	0.849	12.979	0.108	0.396	0.035
23/27-09	Hod	PAY	74.000	9.000	0.122	1.168	0.130	0.419	0.107
23/27-09	Hod	RES	74.000	64.750	0.875	5.541	0.086	0.820	0.219

Table 3.23.5 - Petrophysical parameters used at Well 23/27-09

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

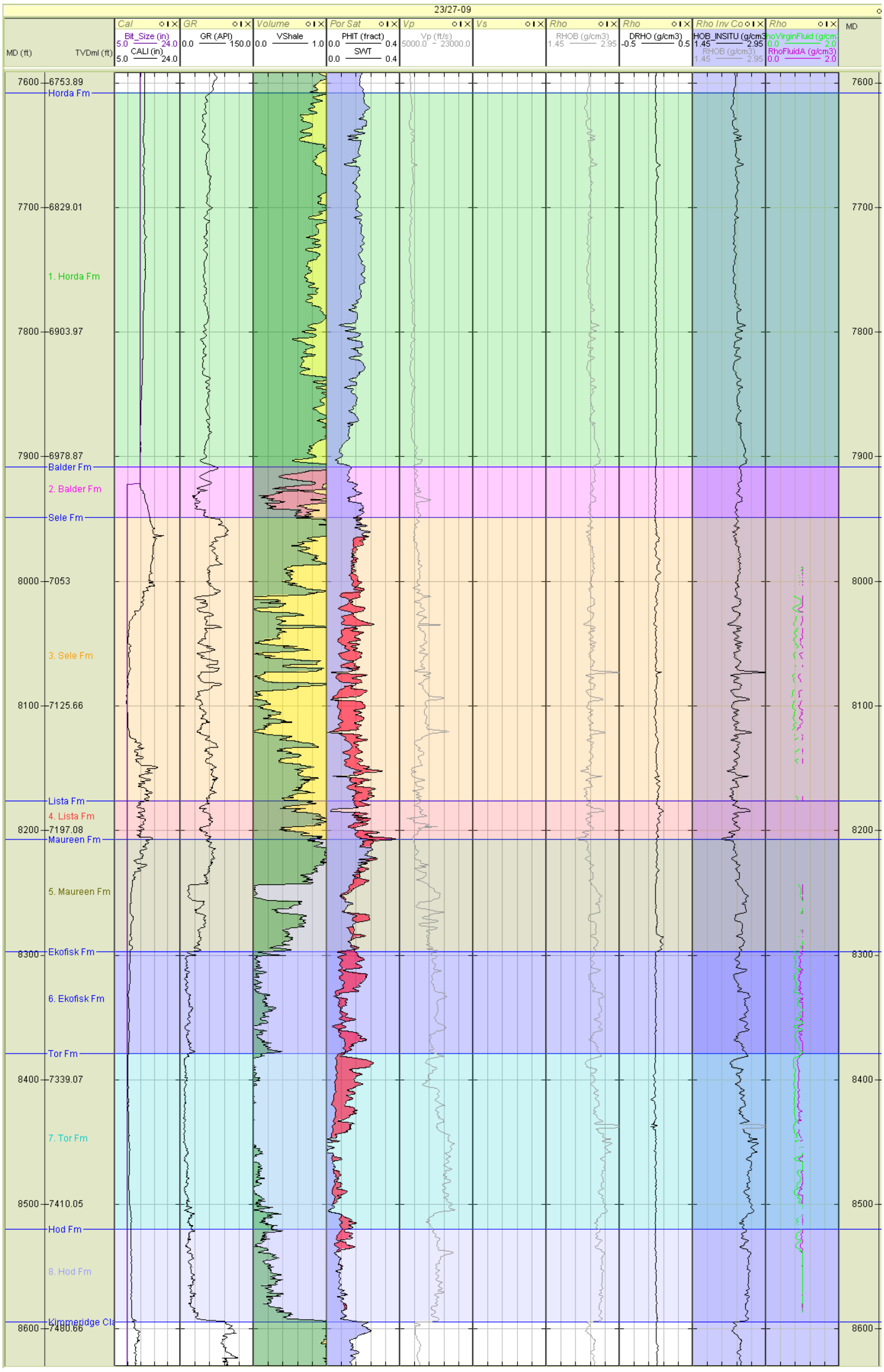


Figure 3.23.3 - Well Panel: Measured data and invasion correction for well 23/27-09.

Well log panel – log editing and audit

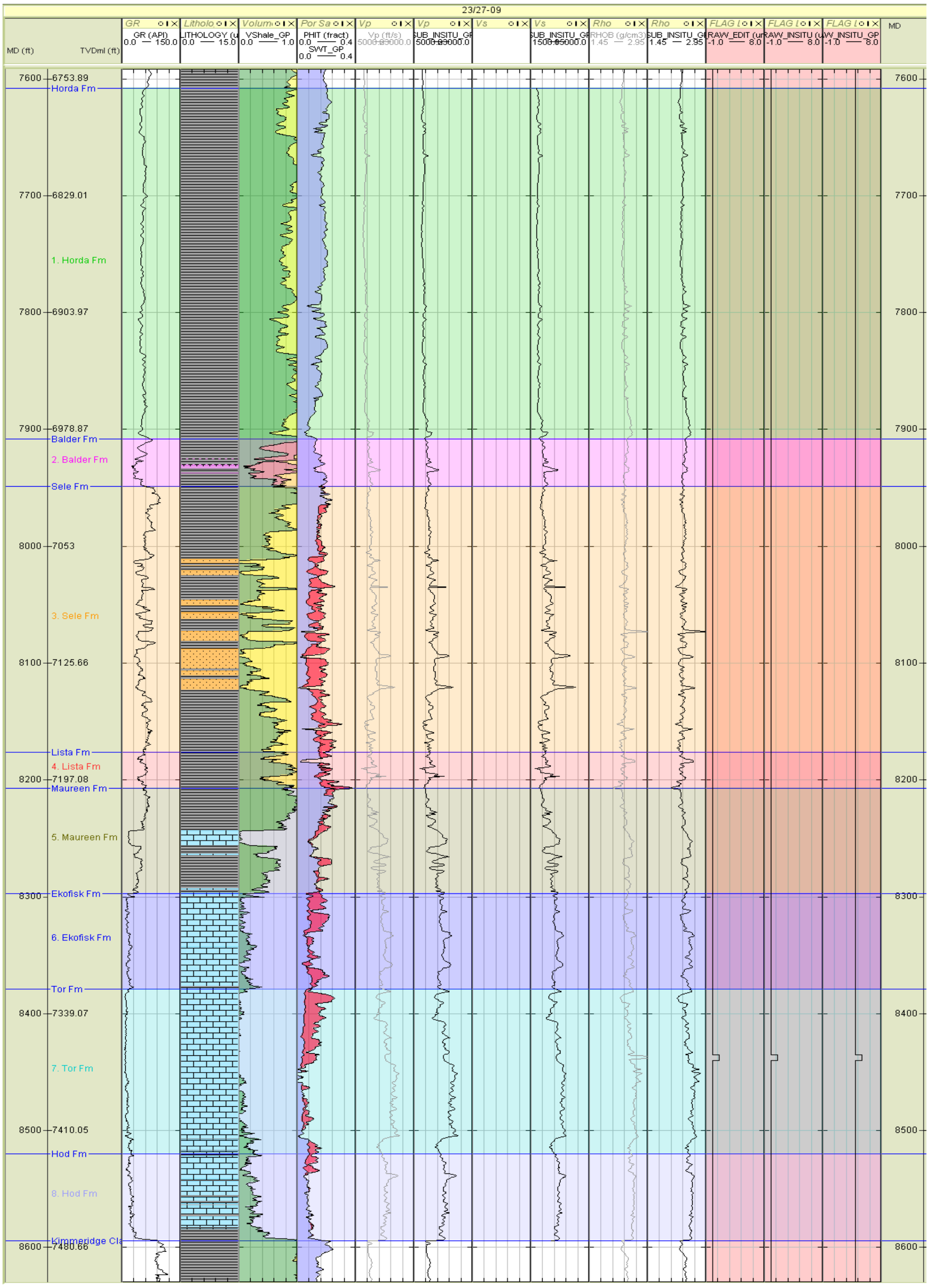


Figure 3.23.4 - Well Panel: Log edits for well 23/27-09.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**

Flag = 3 Edit in Rho and Vs	Flag = 7 Edit in Vp, Vs and Rho

Well log panel – synthetic curves

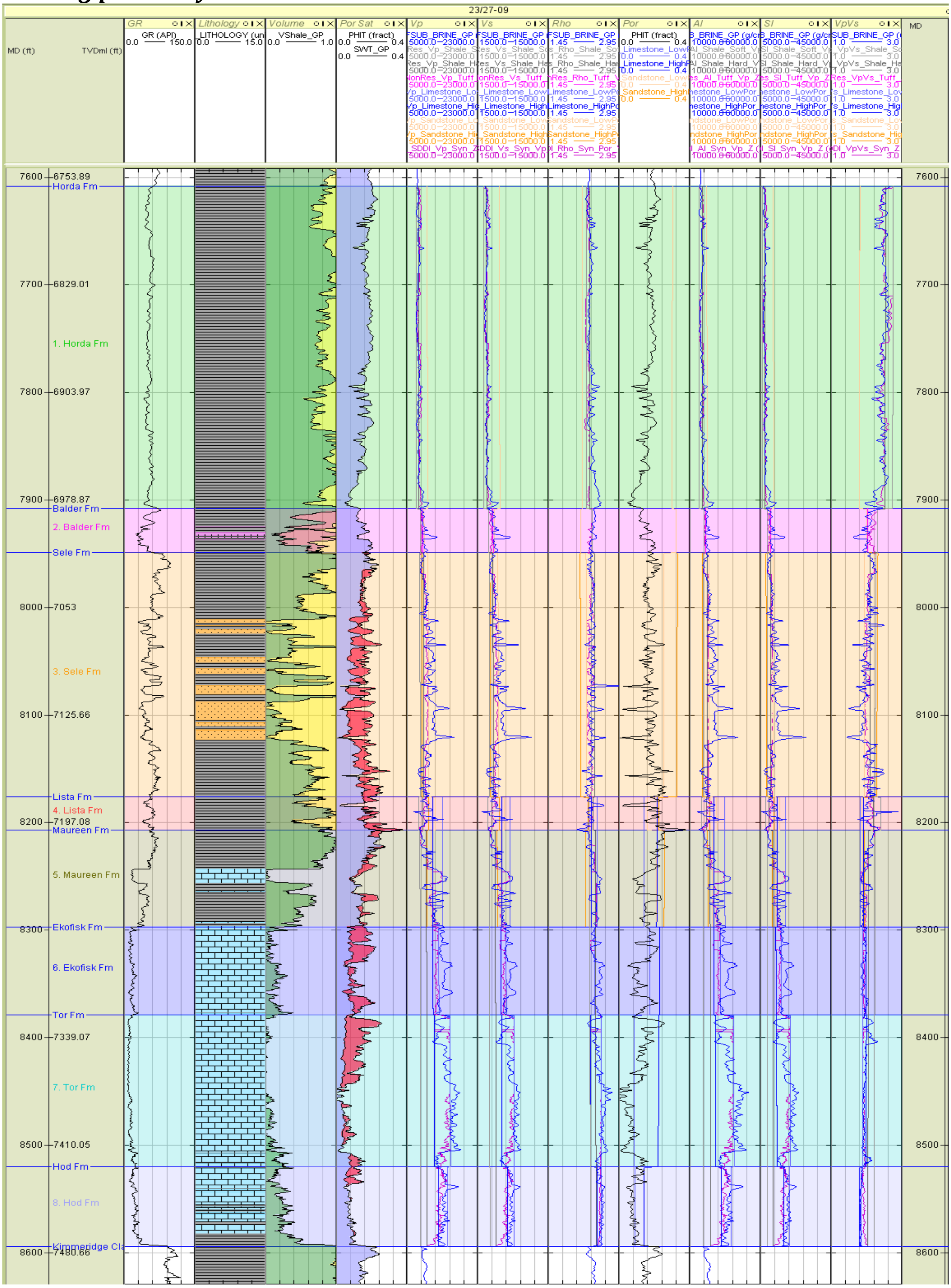


Figure 3.23.5 - Well Panel: End-member and synthetic logs for well 23/27-09.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

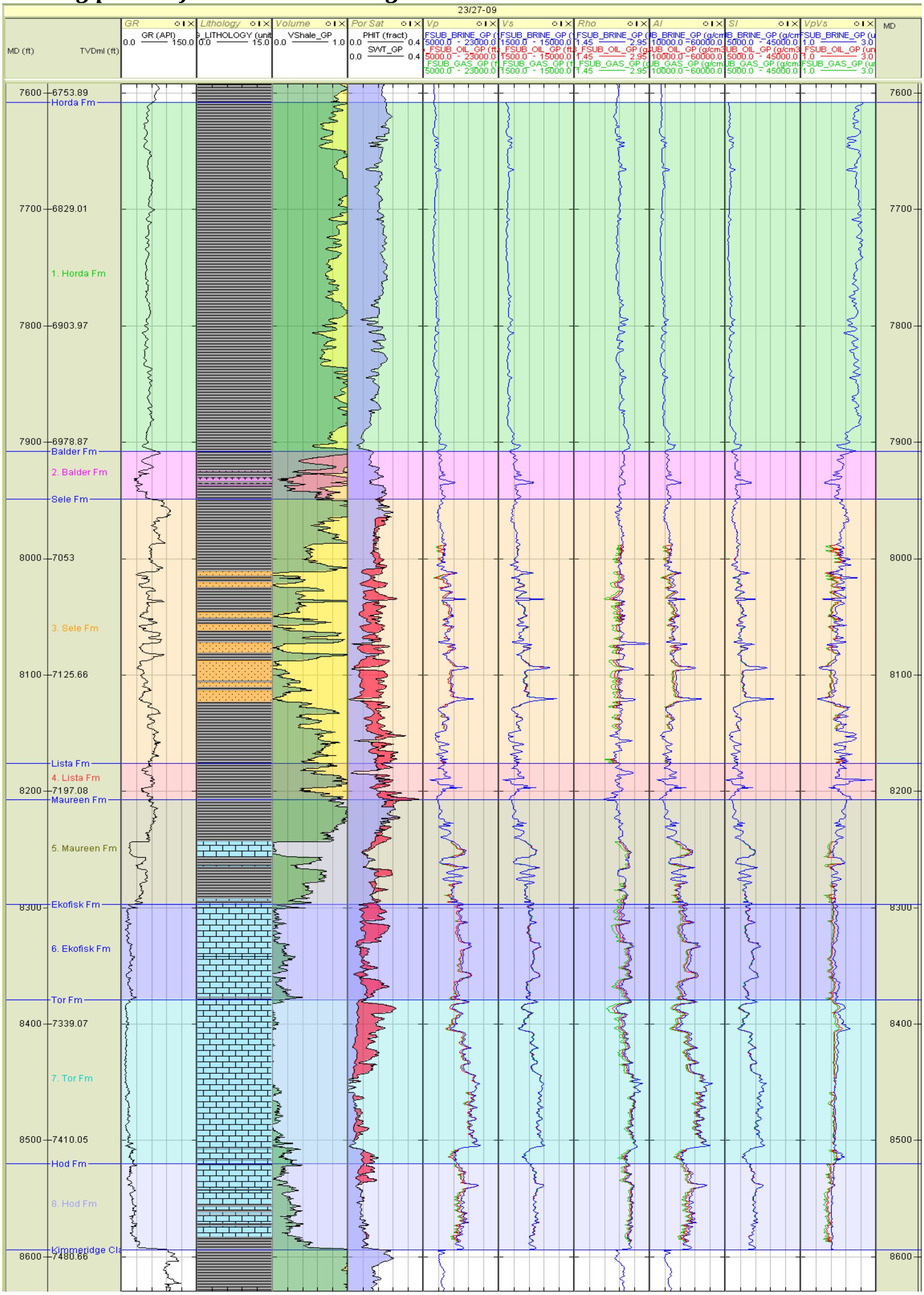


Figure 3.23.6 - Well Panel: Fluid substituted and elastic logs for well 23/27-09.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/09C-04 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/27-09	Horda	7,907	3,211	2.354
23/27-09	Balder	8,946	4,215	2.406
23/27-09	Sele	9,290	4,453	2.367
23/27-09	Lista	9,497	4,532	2.301
23/27-09	Maureen	9,793	4,772	2.331

Table 3.23.6 - Clean shale properties at Well 23/27-09

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/27-09	Horda	100% Brine			
23/27-09	Balder	100% Brine			
23/27-09	Sele	100% Brine	12,099	6,550	2.384
23/27-09	Lista	100% Brine			
23/27-09	Maureen	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/27-09	Horda	80% Oil			
23/27-09	Balder	80% Oil			
23/27-09	Sele	80% Oil	11,630	6,613	2.337
23/27-09	Lista	80% Oil			
23/27-09	Maureen	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/27-09	Horda	90% Gas			
23/27-09	Balder	90% Gas			
23/27-09	Sele	90% Gas	11,617	6,698	2.276
23/27-09	Lista	90% Gas			
23/27-09	Maureen	90% Gas			

Table 3.23.7 - Clean sand properties at Well 23/27-09 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/27-09	Maureen	100% Brine	13,814	7,345	2.49
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/27-09	Maureen	80% Oil	13,144	7,393	2.46
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/27-09	Maureen	90% Gas	12,962	7,474	2.41

Table 3.23.8 - Clean limestone properties at Well 23/27-09 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

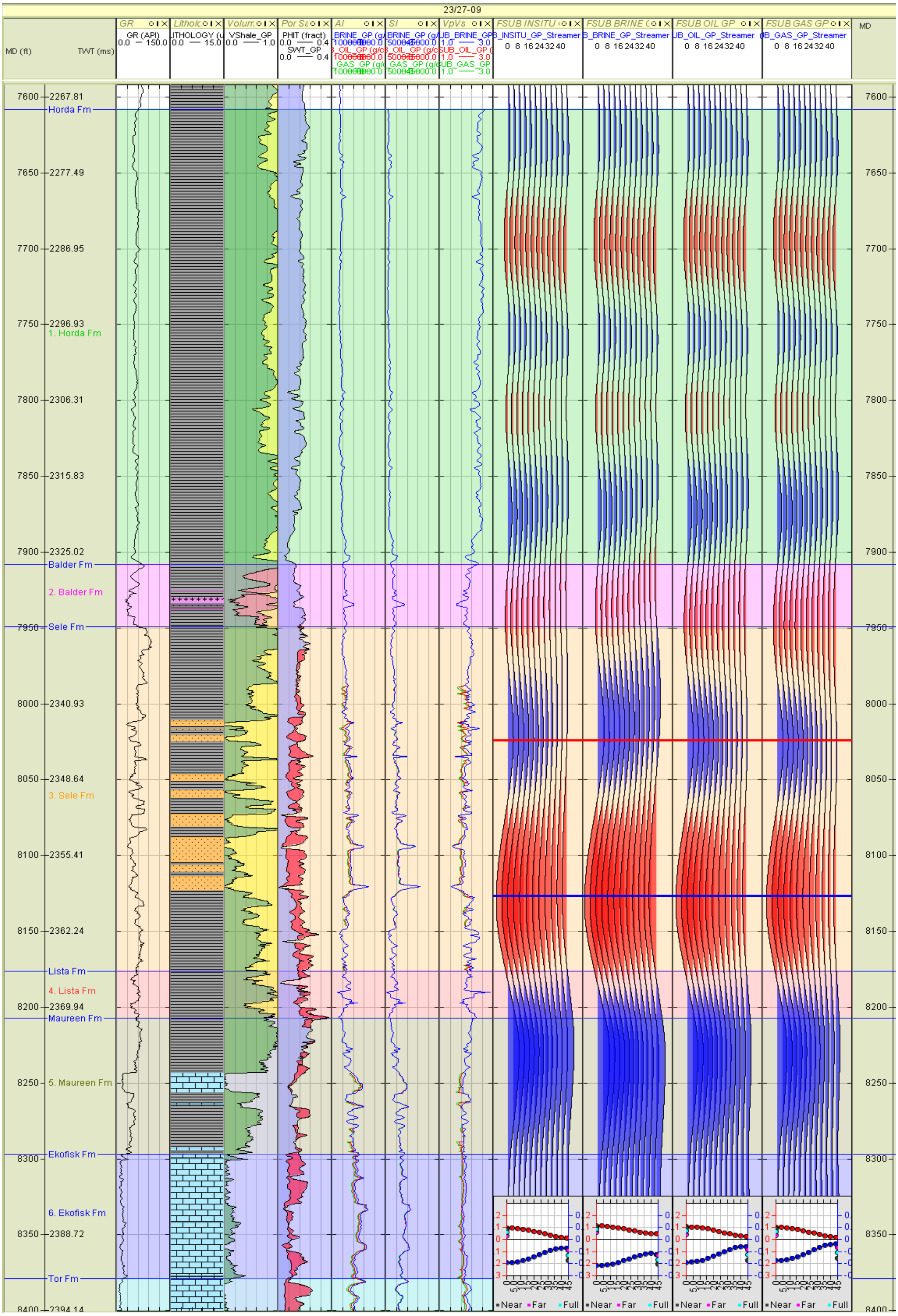


Figure 3.23.7 - Well Panel: Tertiary reservoirs for well 23/27-09. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a discrete sand package with a maximum porosity of 21%. The reservoir sand is encased by shale at the top and base of the formation.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts generally reduce in amplitude with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

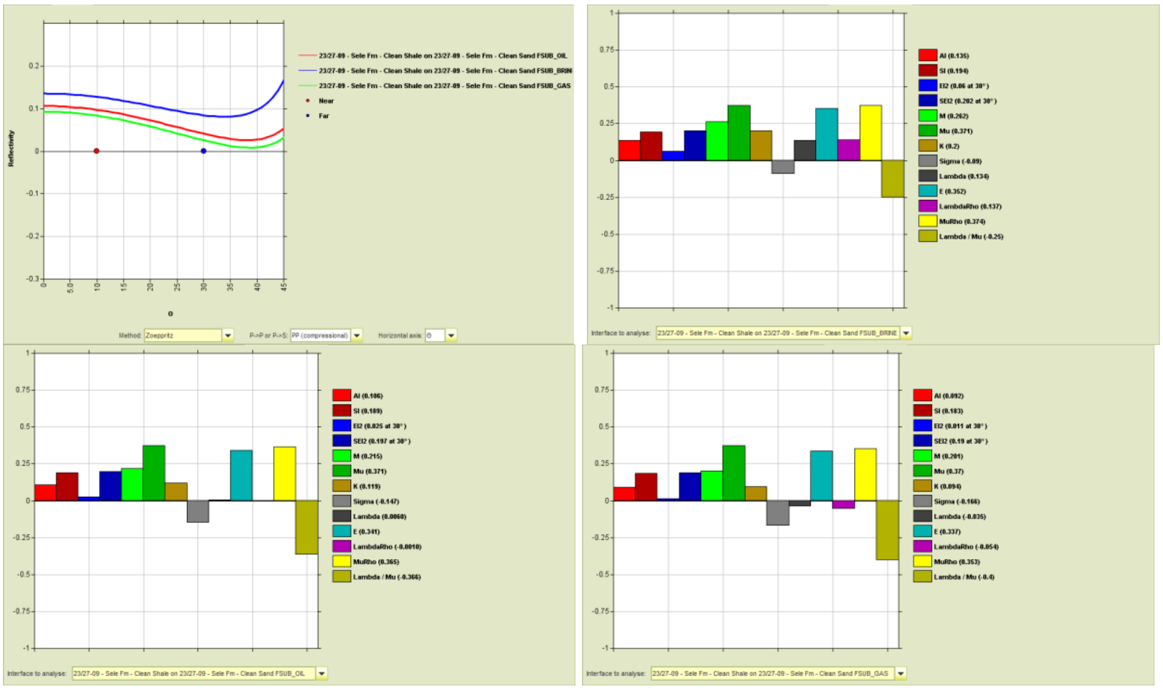


Figure 3.23.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 23/27-09.

Maureen Formation

- Reservoir formed by a thin limestone section in the middle of the interval, net reservoir is approximately 26 feet in this formation. A higher proportion of limestone is found at the bottom of the interval.
- Blocky AVO shows a strong modelled class I response for all fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, and that the contrasts slightly decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

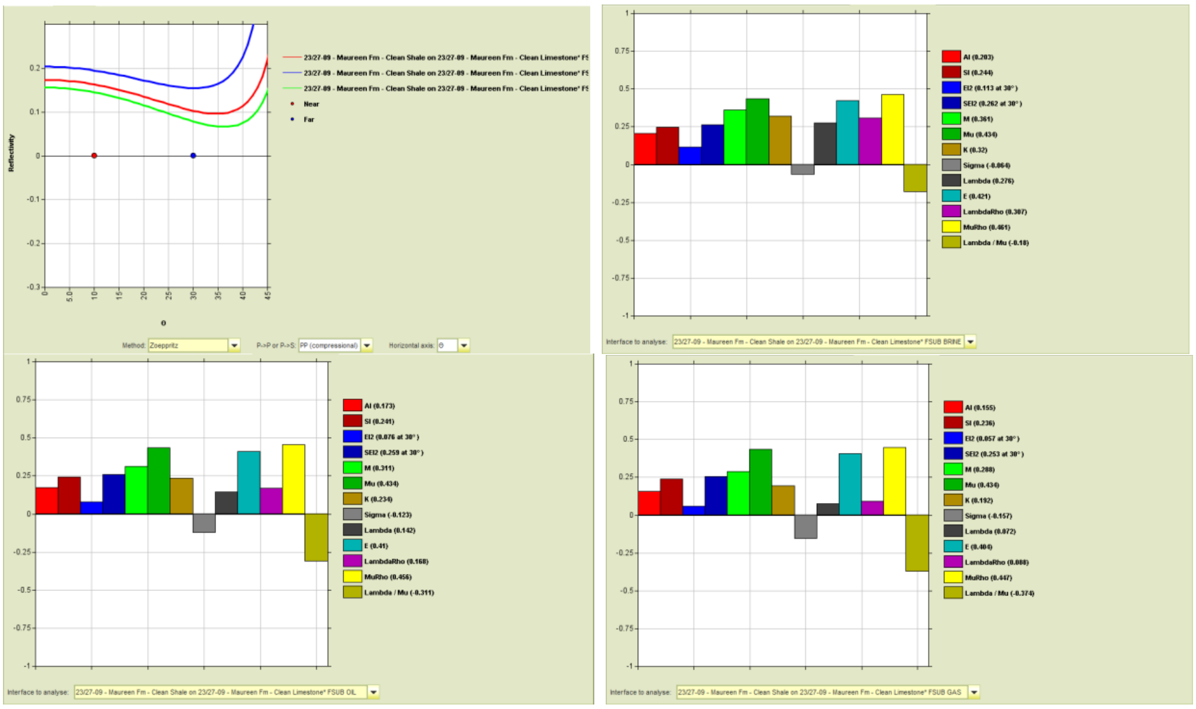


Figure 3.23.9 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 23/27-09.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/09C-04 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/27-09	Ekofisk	100% Brine	14068	7225	2.43
23/27-09	Tor	100% Brine	15348	7820	2.54
23/27-09	Hod	100% Brine	15393	8213	2.54
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/27-09	Ekofisk	80% Oil	13568	7295	2.39
23/27-09	Tor	80% Oil	14943	7859	2.51
23/27-09	Hod	80% Oil	14928	8255	2.51
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
23/27-09	Ekofisk	90% Gas	13546	7387	2.33
23/27-09	Tor	90% Gas	14872	7926	2.47
23/27-09	Hod	90% Gas	14768	8321	2.47

Table 3.23.9 - Clean limestone properties at Well 23/27-09 for each fluid case

Cretaceous reservoirs

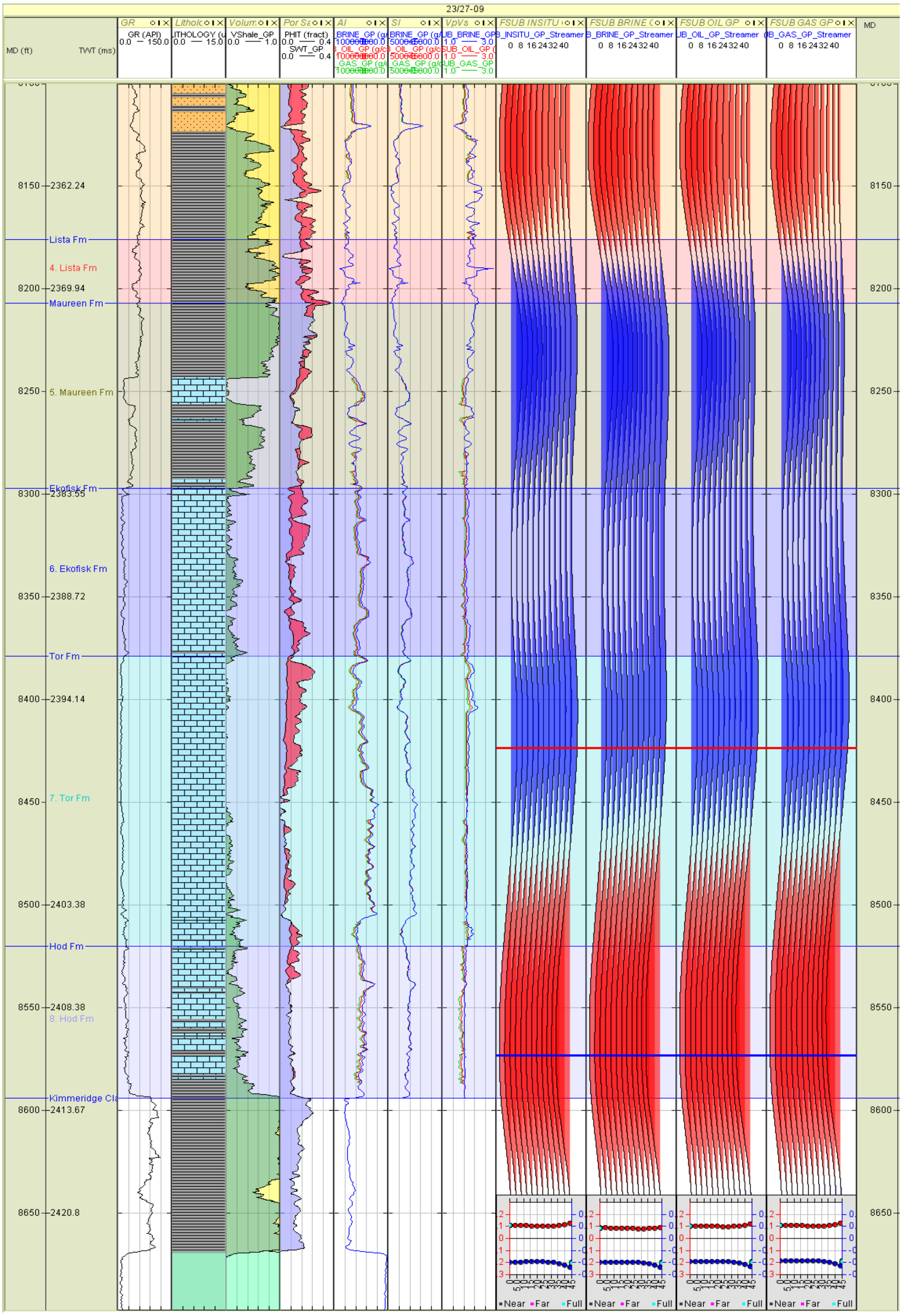


Figure 3.23.10 Well Panel: Cretaceous reservoirs for well 23/27-09. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The maximum reservoir porosity is 22%, dropping off in areas of higher shale content.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but there is a slight decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

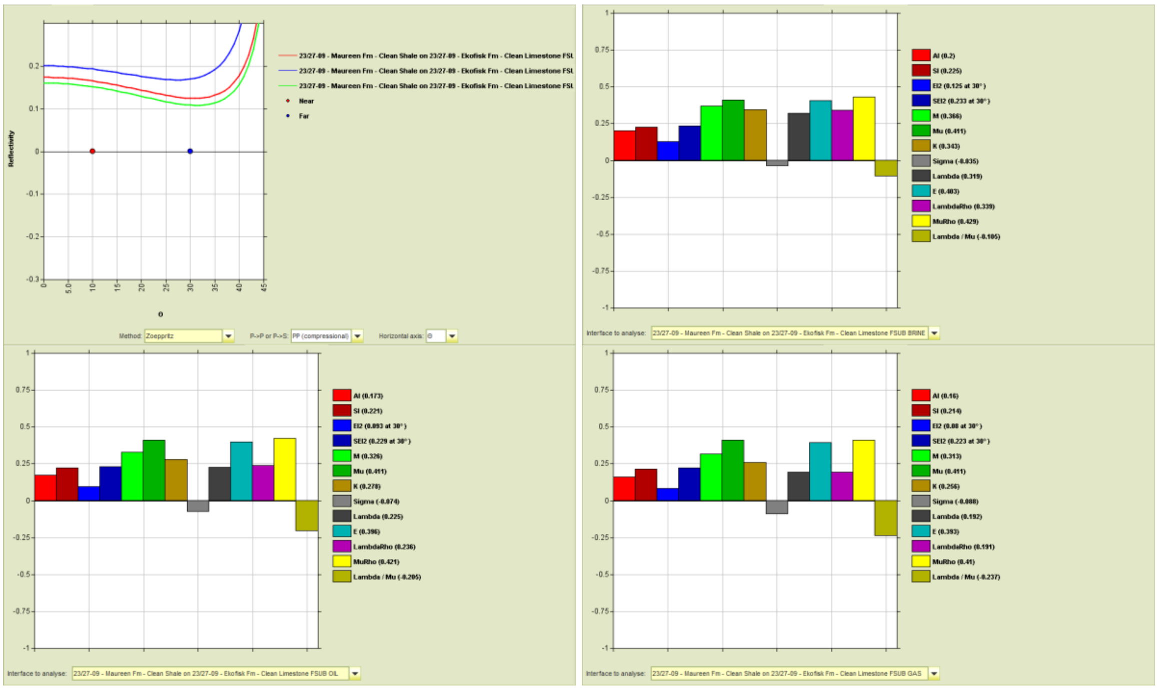


Figure 3.23.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 23/27-09.

Tor Formation

- Reservoir formed by a clean limestone formation. The highest porosity reservoir is found in the top section of the Tor Fm and the porosity in this section is approximately 25%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are positive and low in amplitude for the brine case, decreasing slightly with the addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

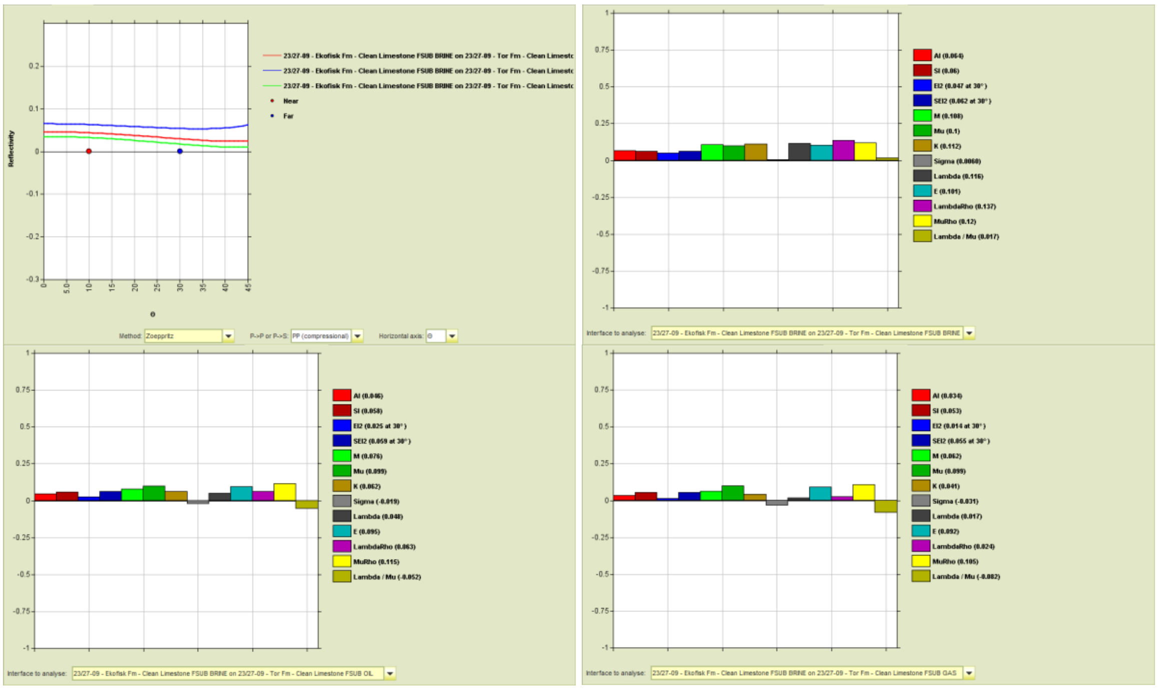


Figure 3.23.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 23/27-09.

Hod Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the top section of the Hod Fm and the porosity in this section is approximately 15%. Below this section of high porosity the reservoir has a relatively constant porosity of closer to 8%.
- Blocky AVO shows a modelled class II response for the 100% brine and 80% oil cases and a modelled class III response for the 90% gas case, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly negative and very low in amplitude in the brine case; the addition of hydrocarbons increases the amplitude of the contrasts. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

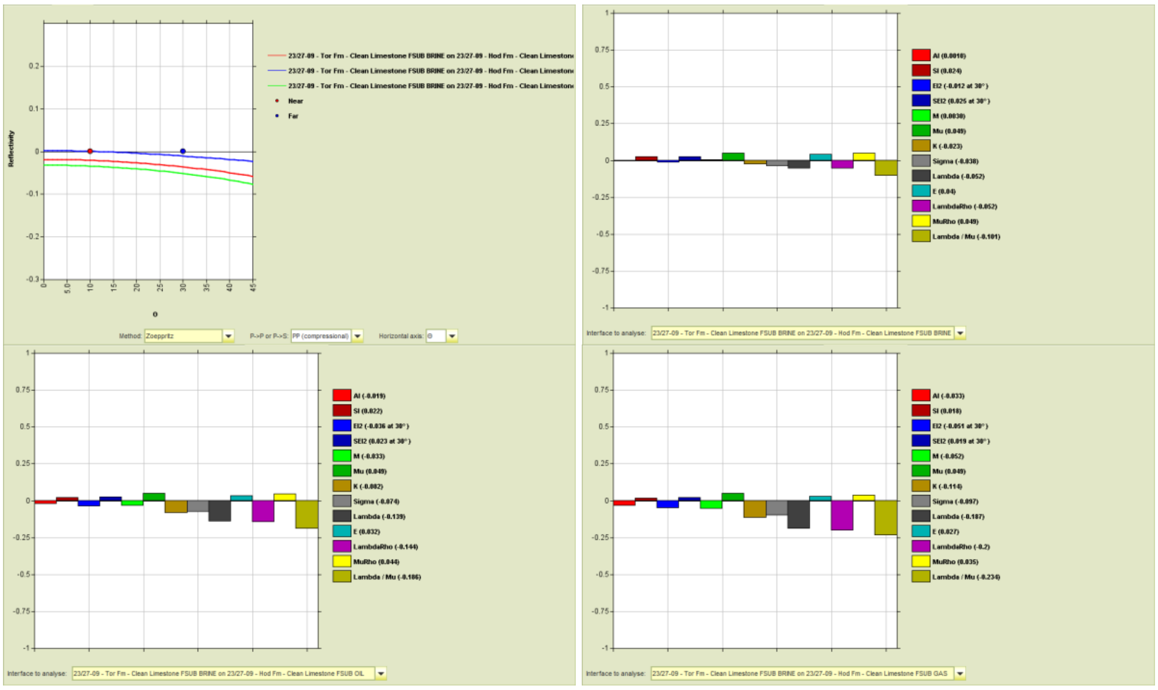


Figure 3.23.13 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 23/27-09.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 23/27-09 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
23/27-09	Overburden	Shale	7548		2.30
23/27-09	Underburden	Shale/Anhydrite	13515		2.65

Table 3.23.10 - Overburden and underburden properties at Well 23/27-09.

Well: 29/02A-06

General

Well Information

This well is a Ranger operated exploration well which was spudded, drilled and abandoned in 1991. The well encountered oil in the Tertiary sands and Cretaceous chalk section, and it is part of the Banff field.

Objectives

This well was drilled to test the Tertiary sands draped against a Zechstein salt diapir straddling 22/27a and 29/2a boundary. The diapir is controlled by reactivation of deep seated faults within the western arm of the Central Graben. A mechanical sidetrack was drilled because of a stuck pipe. The well tested oil and gas.

Log conditioning overview

Only minor log conditioning was required due to good log data quality within this well. Calliper logs show washout within the Horda Formation, as is common due to its unconsolidated nature. Thin calcite stringers in the Horda Formation seen on the density log were not apparent on the Vp log, with data relating to these intervals was consequentially removed.

Invasion correction

Invasion correction was not performed on the density log at this well. The reservoir fluids in this well are oil and drilling mud used within this well was oil-based so negligible invasion will occur at this well.

Log modelling

In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log. The only exception is a minor gap within the Vp log over a hydrocarbon zone in the Tor Formation and the methodology for filling this gap is documented within the Rock Physics Part 2 PowerPoints.

Log modelling was performed to fill gaps within the Sele and Tor Formations for Vp and within the Sele Formation for density. A complete Vs log is modelled since a measured Vs log is not present at this well. A gap was also filled above the interval of interest in the Vp log using a spline function.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 29/02A-06 is displayed in the figures below;

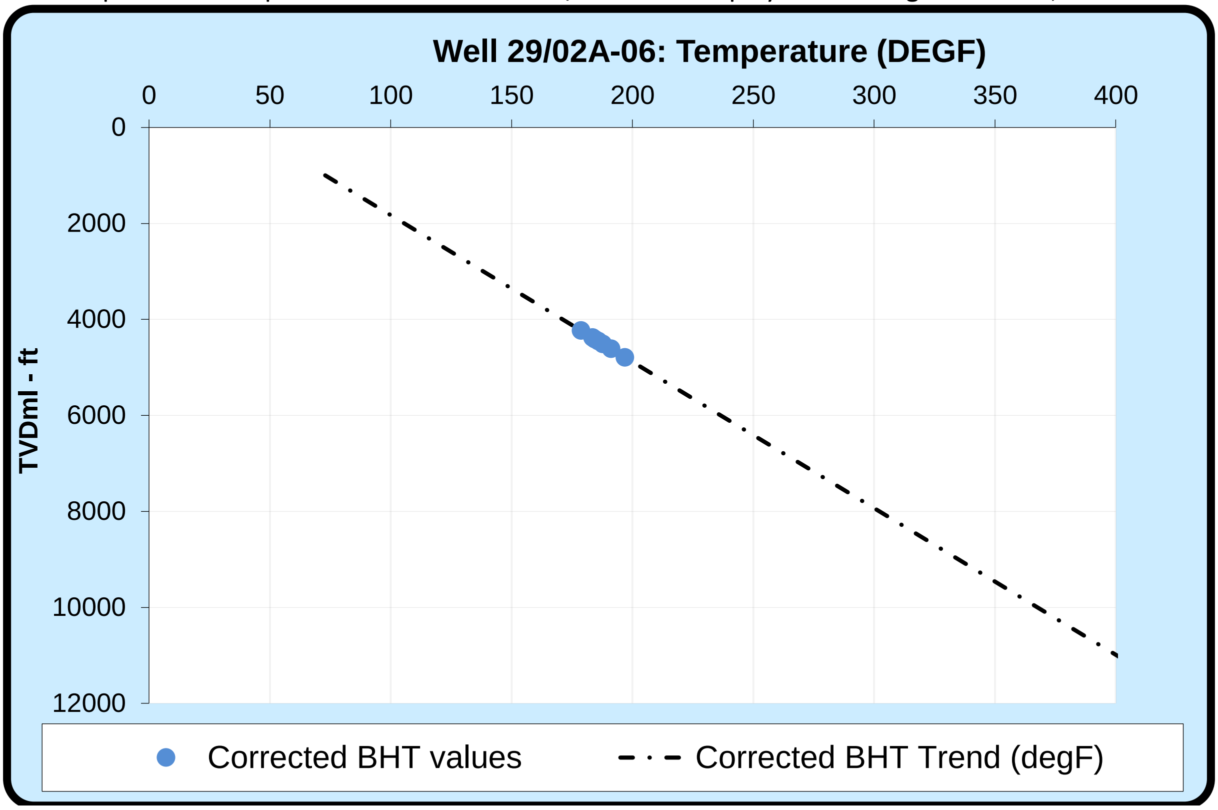


Figure 3.24.1 - Temperature data at Well 29/02A-06

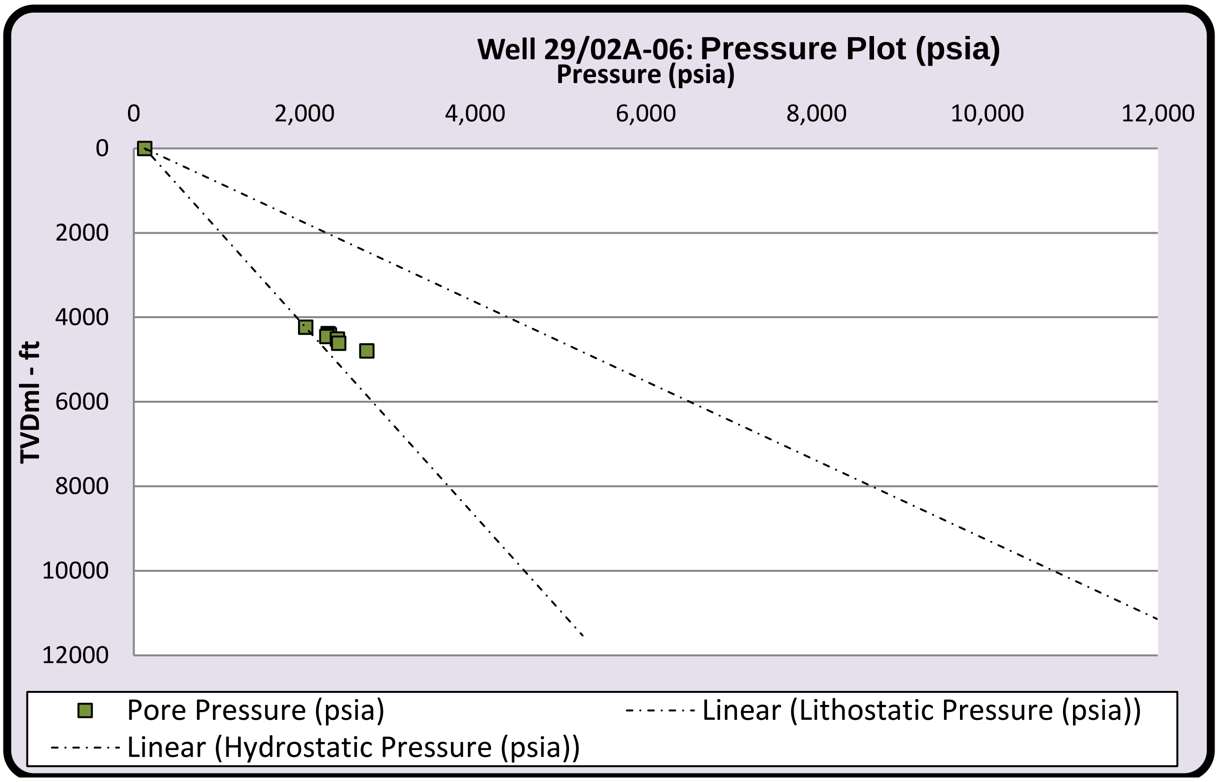


Figure 3.24.2 - Pressure data at Well 29/02A-06

The temperature and pressure data for the formation mid-points in Well 29/02A-06 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Corrected BHT values (deg F)	Hydrostatic Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
29/02A-06	Sea Bed	375.0	293.0	0.0	39.2	130.4	130.4	130.39	0.00
29/02A-06	Horda	4609.0	4525.4	4232.4	178.7	2013.8	2013.8	4232.44	2218.62
29/02A-06	Balder	4757.5	4672.7	4379.7	183.5	2079.4	2279.4	4379.70	2100.35
29/02A-06	Sele	4788.0	4702.7	4409.7	184.5	2092.7	2292.7	4409.65	2116.97
29/02A-06	Lista	4833.5	4747.2	4454.2	186.0	2112.5	2262.5	4454.22	2191.71
29/02A-06	Maureen	4889.5	4801.9	4508.9	187.8	2136.9	2386.9	4508.93	2122.07
29/02A-06	Ekofisk	4996.0	4905.6	4612.6	191.2	2183.0	2401.0	4612.63	2211.63
29/02A-06	Tor	5178.0	5082.4	4789.4	197.0	2261.7	2731.7	4789.38	2057.72

Table 3.24.1 - Summary of mid-point temperature and pressure data at Well 29/02A-06

Fluid data

A summary of the fluid set parameters at Well 29/02A-06 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	**Formation**	**Salinity (ppm)**	**GOR (scf/stb)**	**Oil API (API)**	**Gas Gravity (air=1)**	**Gas Gravity (air=1)**
29/02A-06	Horda	55000	730	35.9	0.78	0.78
29/02A-06	Balder	55000	730	36.1	0.78	0.78
29/02A-06	Sele	55000	730	36.1	0.78	0.78
29/02A-06	Lista	55000	730	36.2	0.78	0.78
29/02A-06	Maureen	55000	730	36.2	0.78	0.78
29/02A-06	Ekofisk	55000	730	36.3	0.78	0.78
29/02A-06	Tor	55000	620.5	42.3	0.788	0.788

Table 3.24.2 - Summary of fluid parameter data at Well 29/02A-06

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.24.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	9.88	2.24	2.304	7,753	3,238

Table 3.24.4 - Tuff properties used at Well 29/02A-06

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
29/02A-06	Horda	PAY	276.050	0.000	0.000	0.000	0.000	0.000	0.000
29/02A-06	Horda	RES	276.050	4.500	0.016	1.195	0.266	1.000	0.346
29/02A-06	Balder	PAY	21.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02A-06	Balder	RES	21.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02A-06	Sele	PAY	40.000	6.500	0.163	1.559	0.240	0.407	0.126
29/02A-06	Sele	RES	40.000	11.000	0.275	2.360	0.215	0.517	0.190
29/02A-06	Lista	PAY	51.000	7.000	0.137	1.548	0.221	0.458	0.163
29/02A-06	Lista	RES	51.000	20.000	0.392	4.216	0.211	0.610	0.243
29/02A-06	Maureen	PAY	61.000	22.250	0.365	5.638	0.253	0.390	0.059
29/02A-06	Maureen	RES	61.000	59.500	0.975	12.900	0.217	0.545	0.130
29/02A-06	Ekofisk	PAY	152.000	18.750	0.123	4.977	0.265	0.434	0.036
29/02A-06	Ekofisk	RES	152.000	151.500	0.997	32.775	0.216	0.629	0.123
29/02A-06	Tor	PAY	212.000	174.000	0.821	32.263	0.185	0.283	0.010
29/02A-06	Tor	RES	212.000	200.250	0.945	35.448	0.177	0.311	0.017

Table 3.24.5 - Petrophysical parameters used at Well 29/02A-06

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

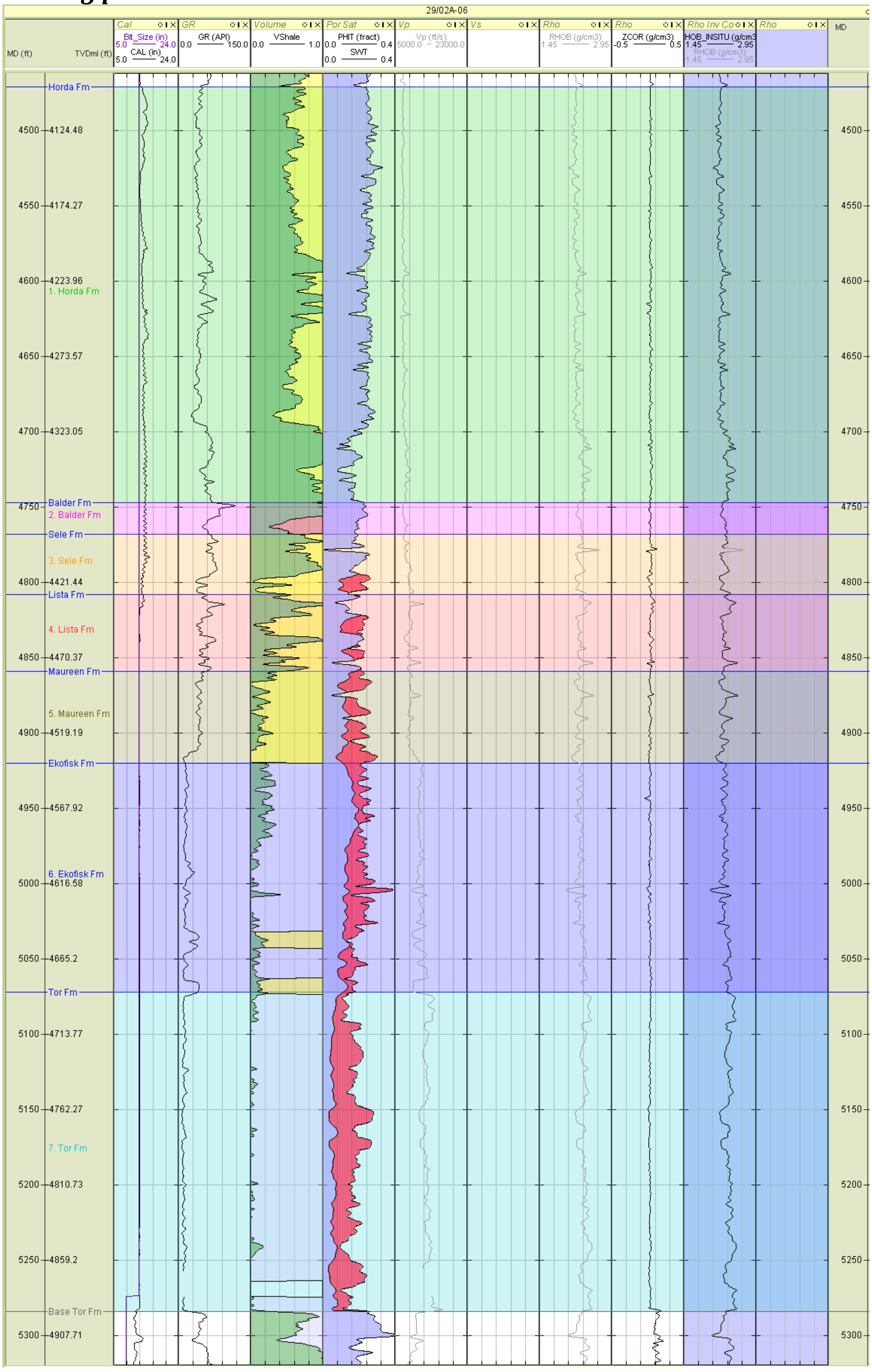


Figure 3.24.3 - Well Panel: Measured data and invasion correction for well 29/02A-06.

Well log panel – log editing and audit

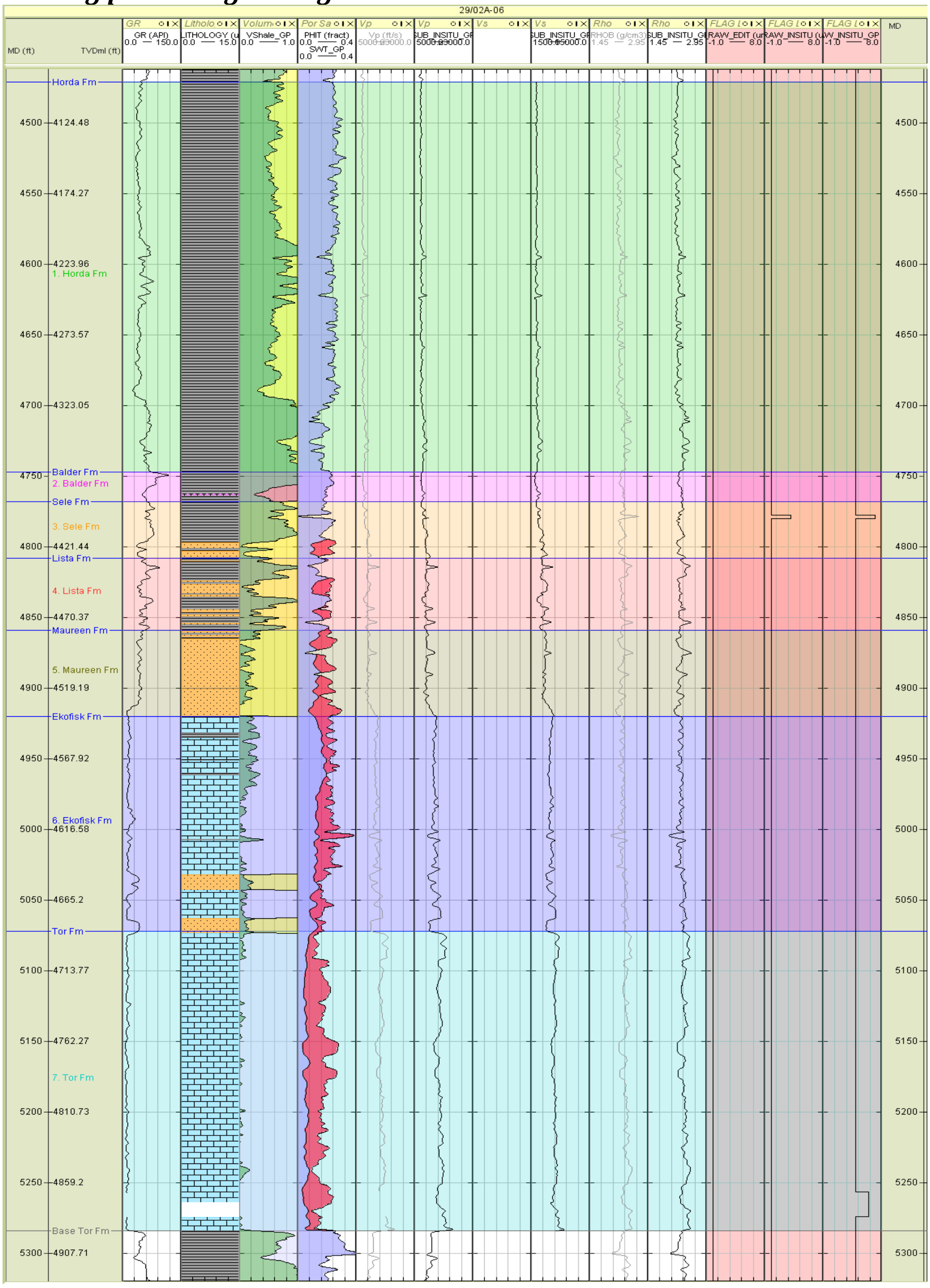


Figure 3.24.4 - Well Panel: Log edits for well 29/02A-06.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

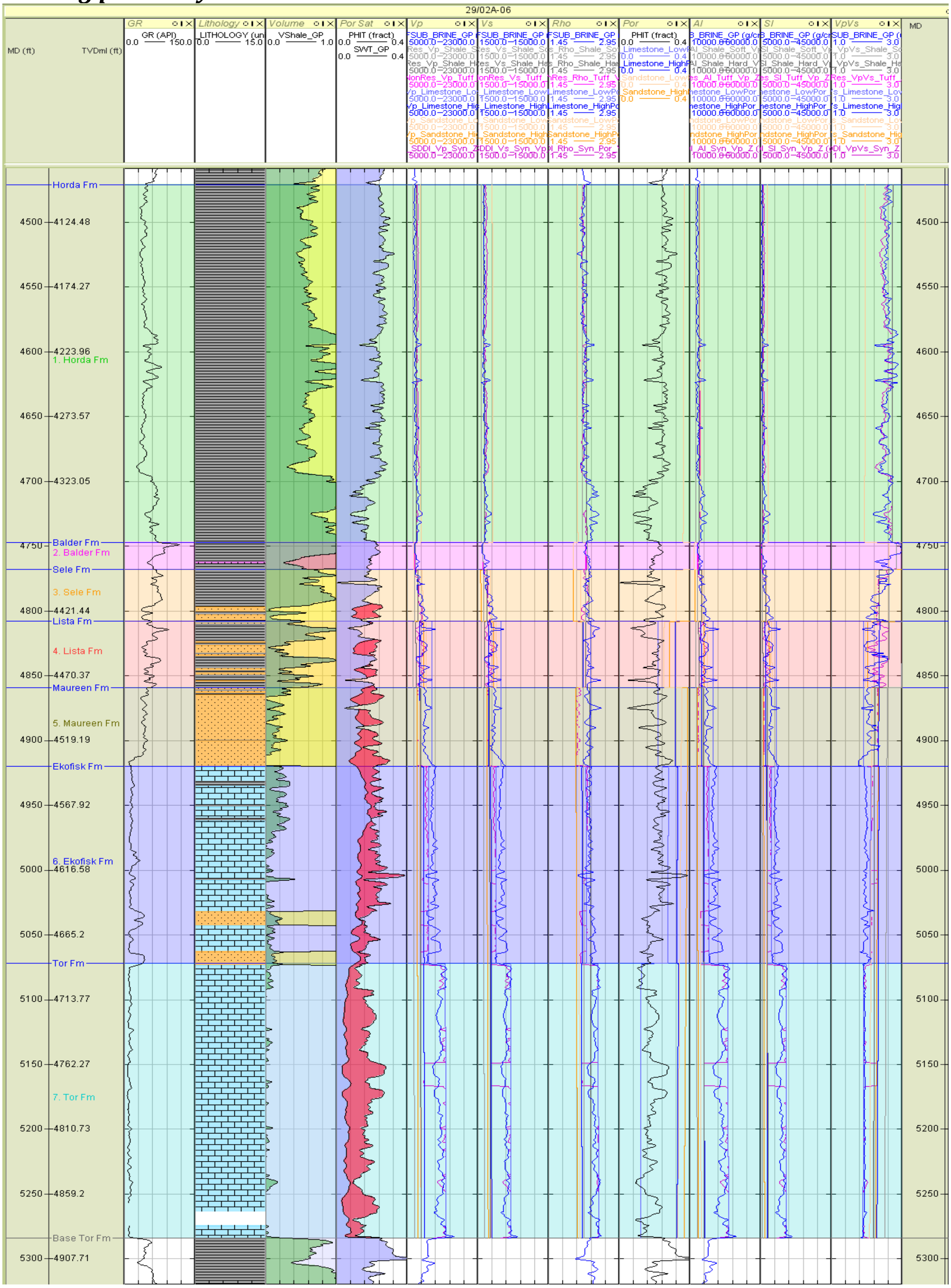


Figure 3.24.5 - Well Panel: End-member and synthetic logs for well 29/02A-06.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

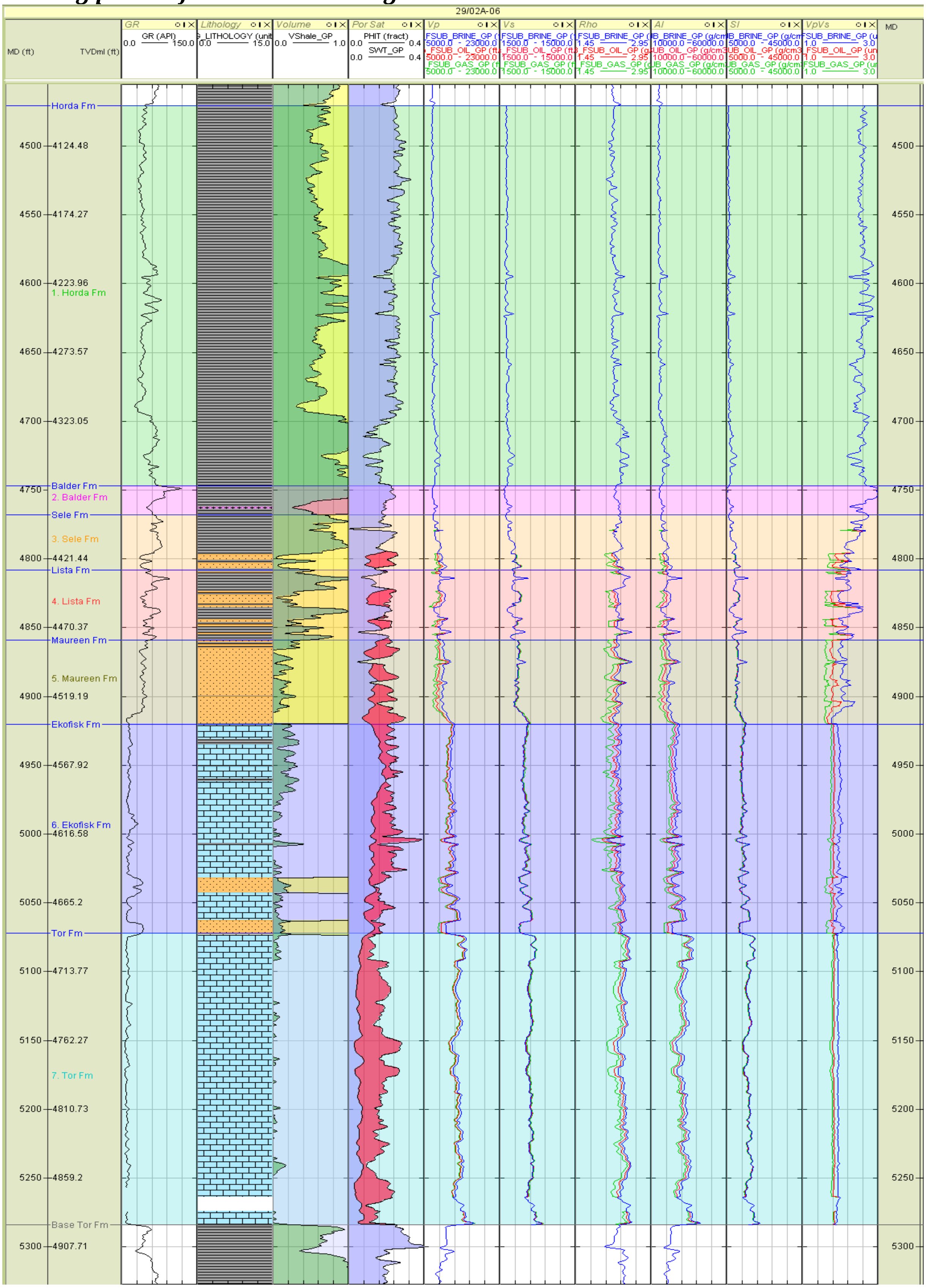


Figure 3.24.6 - Well Panel: Fluid substituted and elastic logs for well 29/02A-06.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/02A-06 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02A-06	Horda	7350	2795	2.28
29/02A-06	Balder	6980	2385	2.24
29/02A-06	Sele	7918	3343	2.30
29/02A-06	Lista	8496	3781	2.34
29/02A-06	Maureen			

Table 3.24.6 - Clean shale properties at Well 29/02A-06

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02A-06	Horda	100% Brine			
29/02A-06	Balder	100% Brine			
29/02A-06	Sele	100% Brine	9531	4495	2.29
29/02A-06	Lista	100% Brine	9558	4663	2.31
29/02A-06	Maureen	100% Brine	9742	4811	2.30
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02A-06	Horda	80% Oil			
29/02A-06	Balder	80% Oil			
29/02A-06	Sele	80% Oil	8516	4552	2.23
29/02A-06	Lista	80% Oil	8531	4716	2.26
29/02A-06	Maureen	80% Oil	8687	4870	2.25
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02A-06	Horda	90% Gas			
29/02A-06	Balder	90% Gas			
29/02A-06	Sele	90% Gas	7960	4676	2.11
29/02A-06	Lista	90% Gas	7932	4832	2.15
29/02A-06	Maureen	90% Gas	8103	4993	2.14

Table 3.24.7 - Clean sand properties at Well 29/02A-06 for each fluid case

Tertiary reservoirs – Well panel

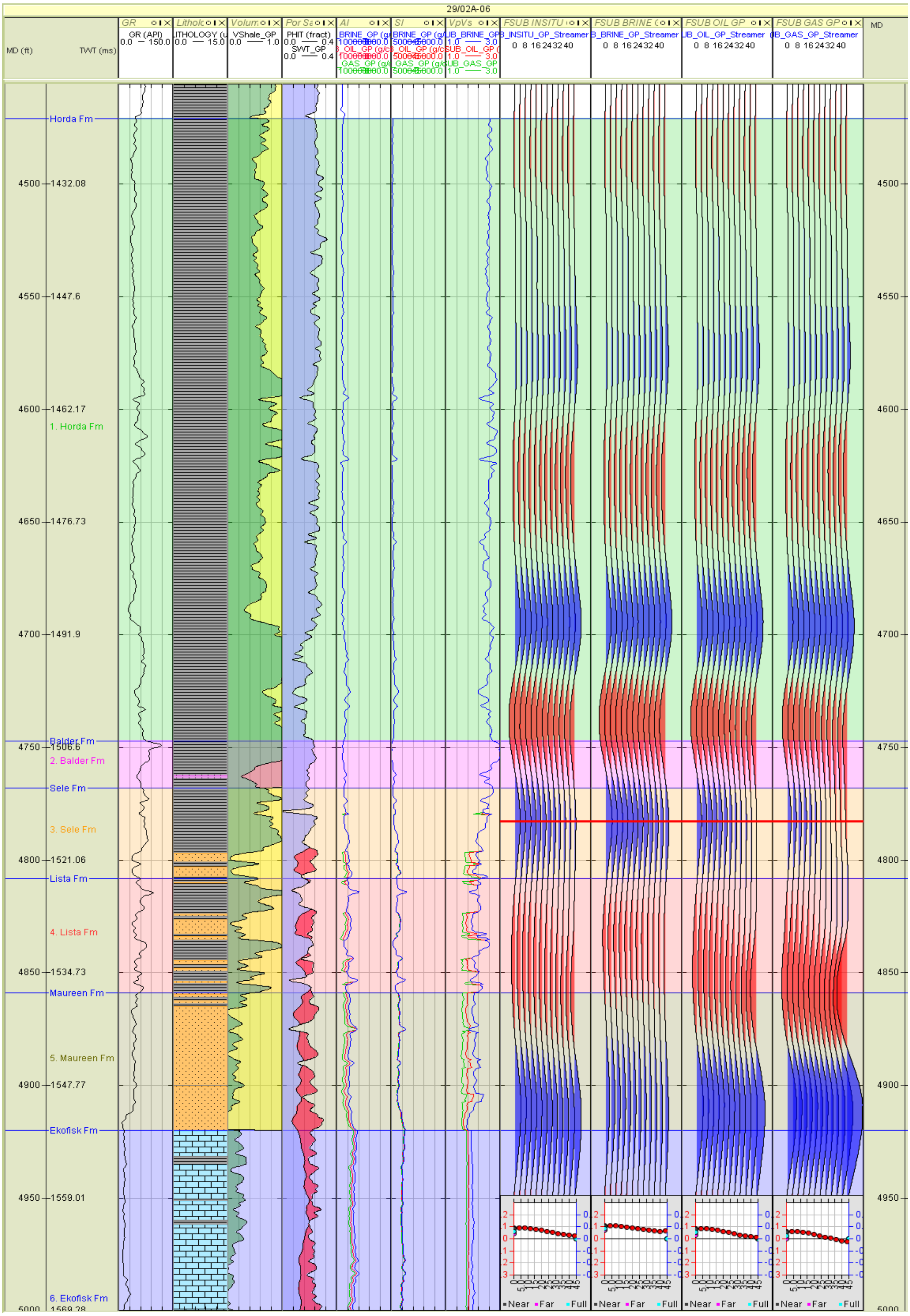


Figure 3.24.7 - Well Panel: Tertiary reservoirs for well 29/02A-06. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a very thin sand towards the base of the interval with approximately 30ft of shale as the overburden, net reservoir is approximately 11 feet.
- Blocky AVO shows a modelled class I response for the 100% brine case, a modelled class IIp response for the 80% oil case and a modelled class III response for the 90% gas cases in turn, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is less pronounced on the synthetic gathers where the introduction of hydrocarbons results in class I responses for all fluid cases and this is likely to be due to interference effects affecting the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive in the brine case, but that the contrasts generally become strongly negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

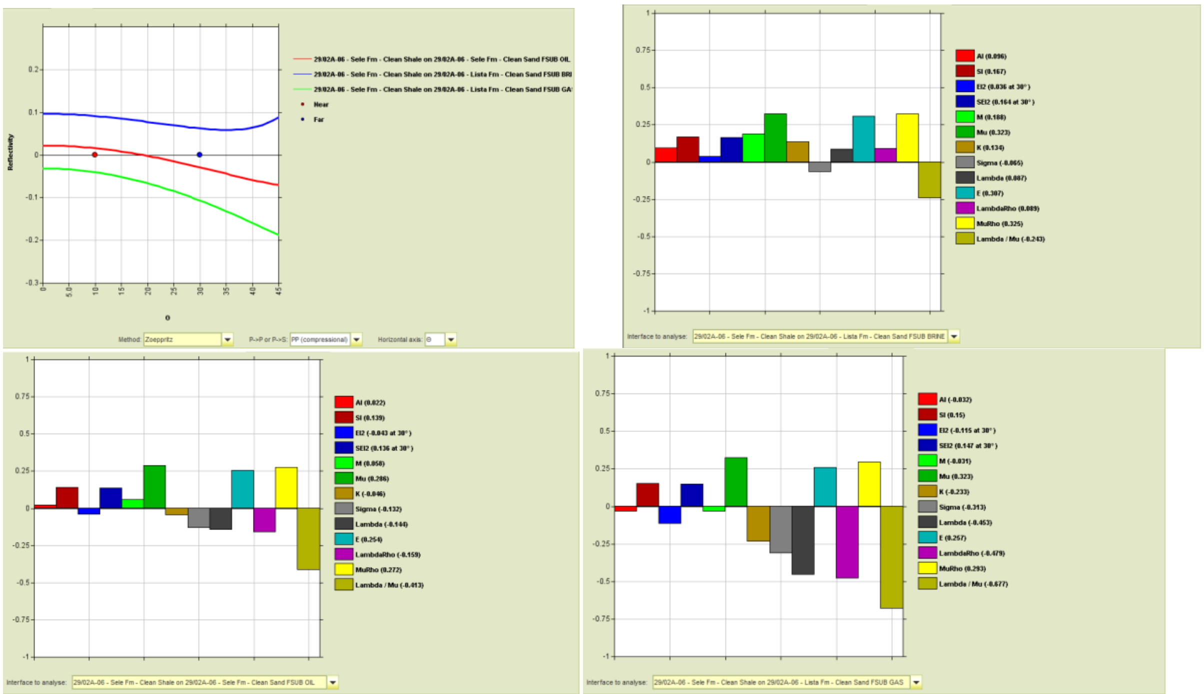


Figure 3.24.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in 29/02A-06.

Lista Formation

- Reservoir comprises a more continuous sand package with a few isolated shale intervals, net reservoir is approximately 20 feet. The Maureen Fm sitting below this reservoir is a continuous sand body with minimal shale. We are unable to analyse the Maureen Fm for blocky AVO since there are no clean shale points within the interval
- Blocky AVO shows a modelled class I response for the 100% brine case, a modelled class II response for the 80% oil case and a modelled class III response for the 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. No obvious top reservoir pick is present on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive in the brine case, but that the contrasts generally become strongly negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

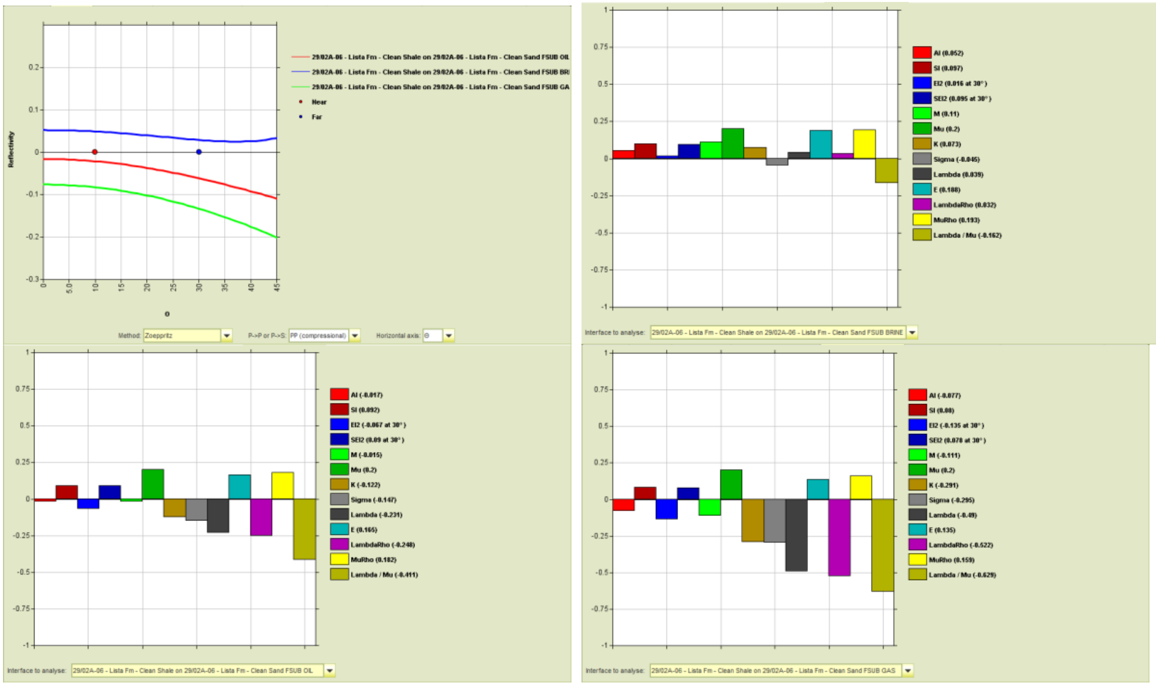


Figure 3.24.9 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 29/02A-06.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/02A-06 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02A-06	Ekofisk	100% Brine	11854	6034	2.32
29/02A-06	Tor	100% Brine	13378	6921	2.42
29/02A-06	Hod	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/02A-06	Ekofisk	80% Oil	11156	6113	2.26
29/02A-06	Tor	80% Oil	12813	6990	2.38
29/02A-06	Hod	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/02A-06	Ekofisk	90% Gas	10971	6277	2.14
29/02A-06	Tor	90% Gas	12689	7117	2.29
29/02A-06	Hod	90% Gas			

Table 3.24.8 - Clean limestone properties at Well 29/02A-06 for each fluid case.

Cretaceous reservoirs

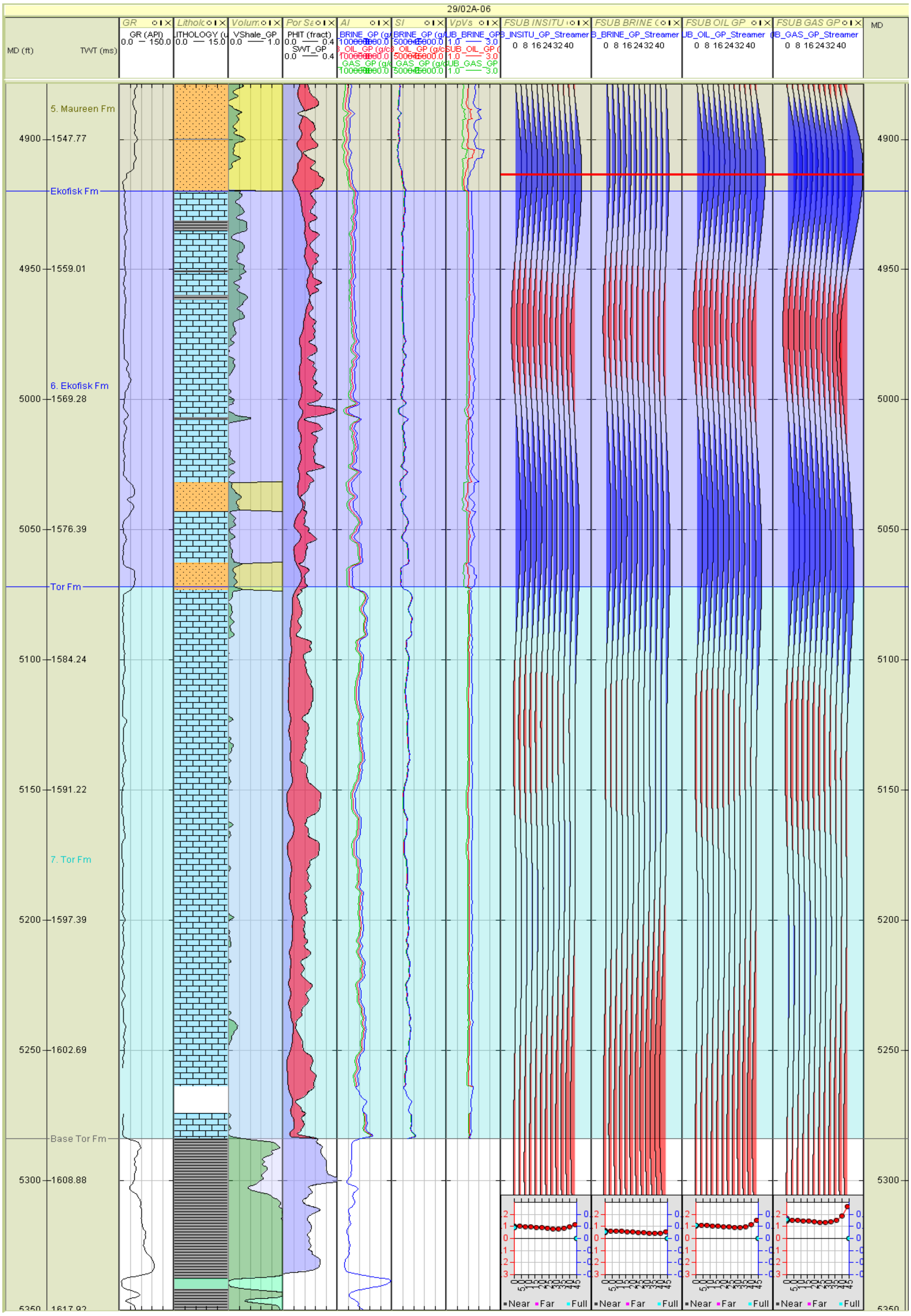


Figure 3.24.10 - Well Panel: Cretaceous reservoirs for well 29/02A-06. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Tor Formation

- Reservoir formed by a clean limestone formation. The highest porosity reservoir is found in the middle section of the Tor Fm and the porosity in this section is approximately 28%. High porosity layers are found throughout the Tor Fm and could be representative of reworked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts decrease in amplitude and become negative for some attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

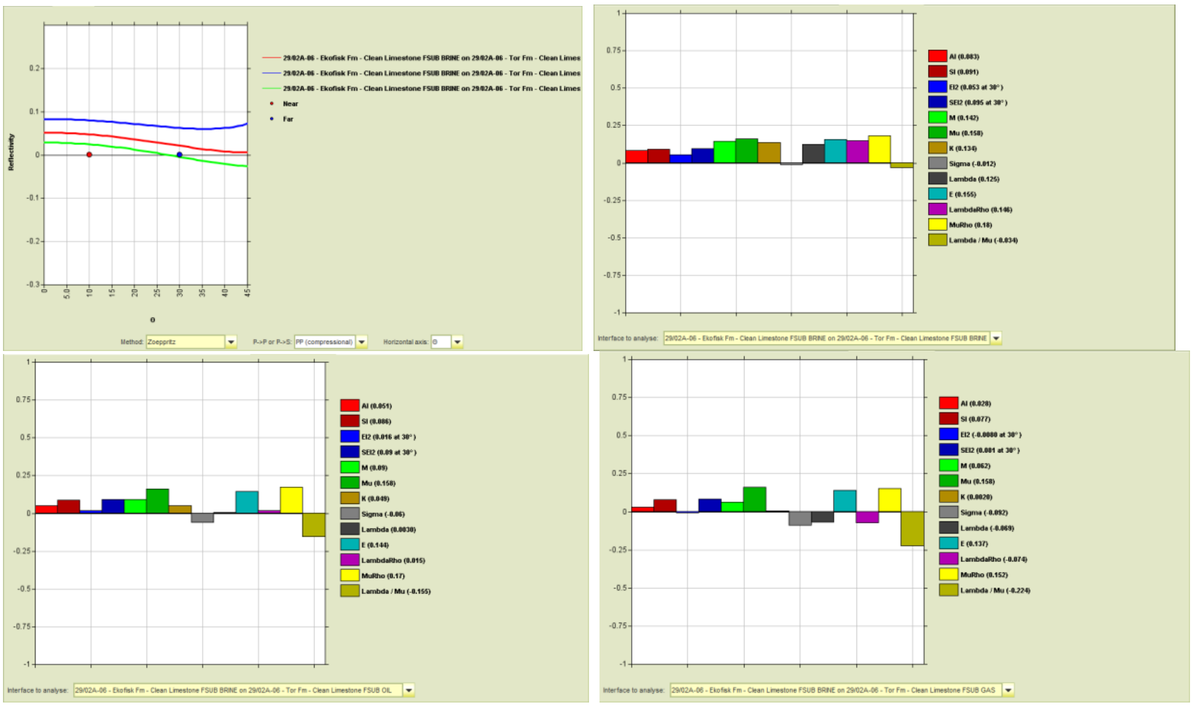


Figure 3.24.11 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 29/02A-06.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 29/02A-06 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02A-06	Overburden	Shale	6827		2.18
29/02A-06	Underburden	Shale/Anhydrite	16605		2.80

Table 3.24.9 - Overburden and underburden properties at Well 29/02A-06.

Well: 29/02C-09

General

Well Information
This well is a Mobil operated exploration well which was spudded in 1993, drilled and then abandoned in 1994. The well did not encounter hydrocarbons.

Objectives
This well probed the deeper flanks of the diapir structure discovered by #8 and #8Z. A disappointing result from this well as a successful outcome would have upgraded reserves for the prospect.

Log conditioning overview
Only minor log conditioning was required due to good log data quality within this well. Calliper logs showed minor washout towards the top of the Horda Formation, as is common due to its unconsolidated nature. More significant washouts were seen in the Maureen Fm at depths of 9,325ft and 9,373ft MD, these corresponded with spikes on the Vp and density logs and the data relating to these intervals was consequentially removed.

Invasion correction

Invasion correction was not performed on the density log at this well. The reservoir fluids in this well are brine and drilling mud used within this well was a brine-based so negligible invasion will occur at this well.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Maureen Formation for Vp and density. A complete Vs log is modelled since a measured Vs log is not available at this well . A gap was also filled above the interval of interest in the Vp log using a spline function.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 29/02C-09 is displayed in the figures below;

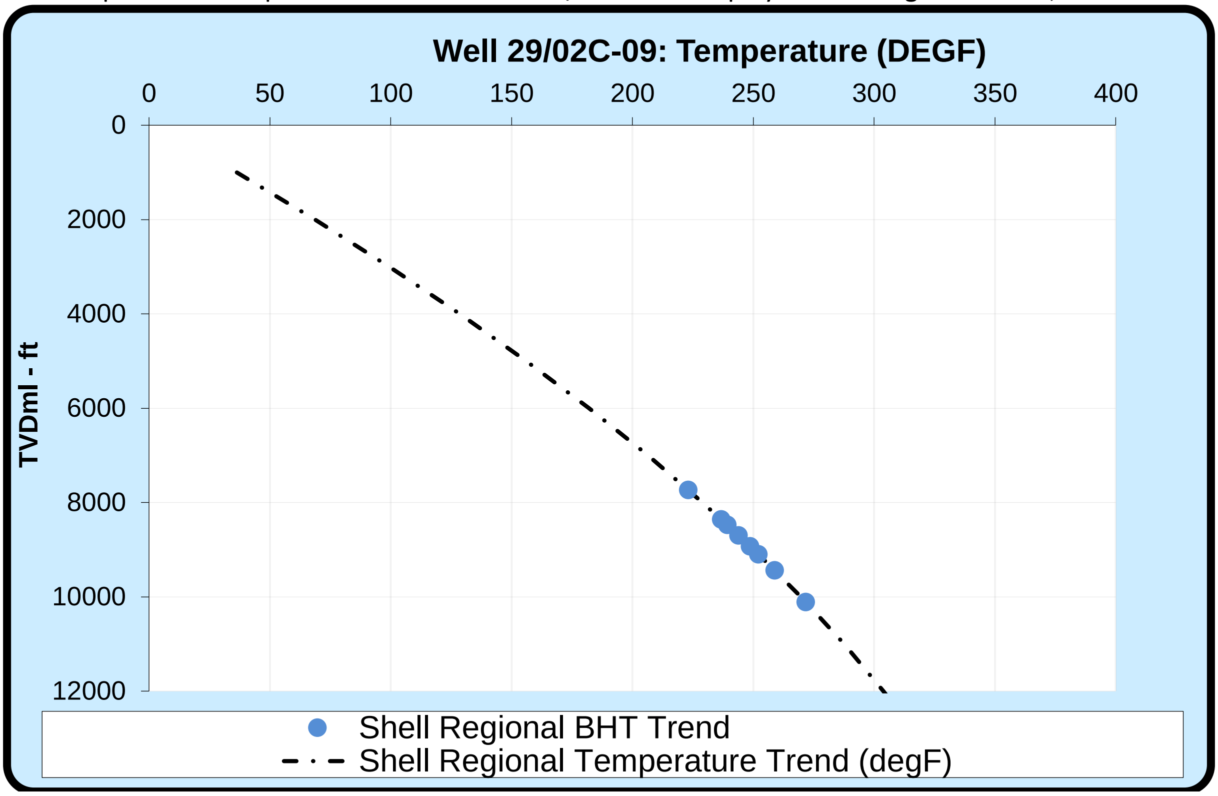


Figure 3.25.1 - Temperature data at Well 29/02C-09

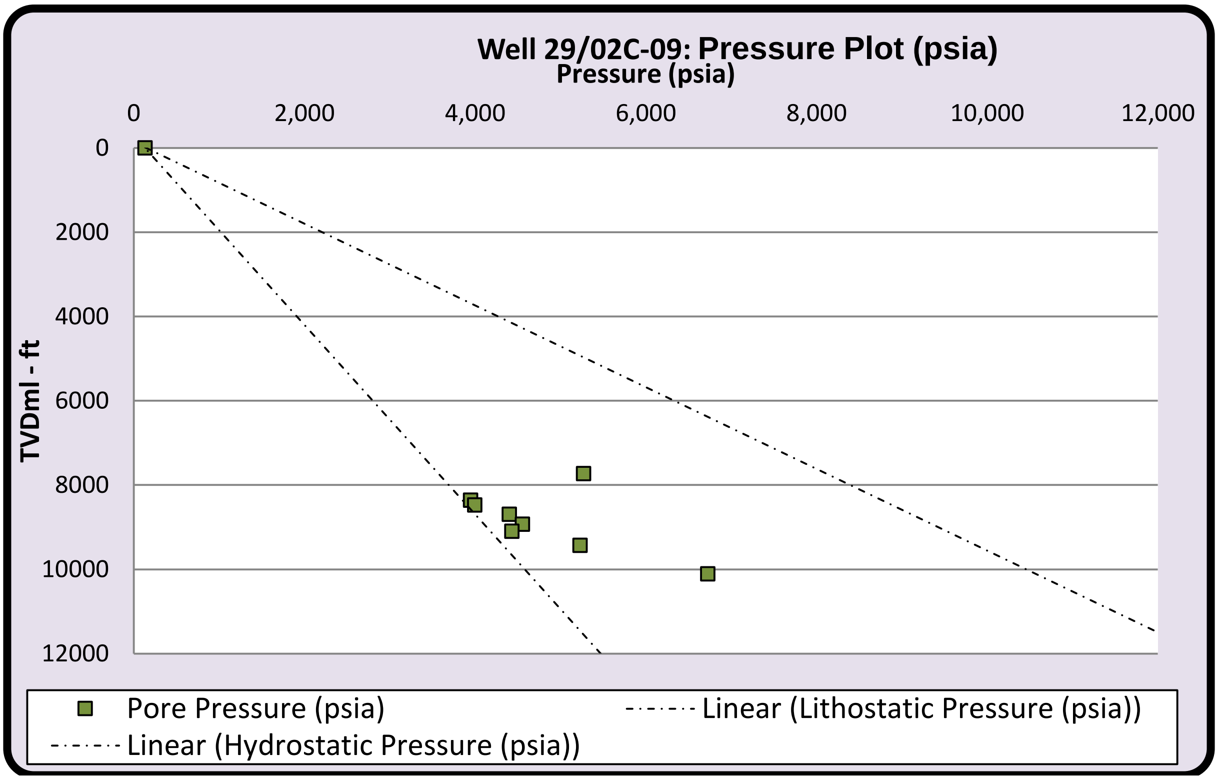


Figure 3.25.2 - Pressure data at Well 29/02C-09

The temperature and pressure data for the formation mid-points in Well 29/02C-09 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
29/02C-09	Sea Bed	380.0	295.0	0.0	39.2	131.3	131.3	131.28	0.00
29/02C-09	Horda	8111.5	8025.0	7732.0	223.1	3571.1	5271.1	7732.03	2460.89
29/02C-09	Balder	8740.0	8652.5	8359.5	236.8	3850.4	3945.4	8359.49	4414.13
29/02C-09	Sele	8854.0	8766.2	8473.2	239.3	3901.0	3996.0	8473.19	4477.24
29/02C-09	Lista	9079.5	8991.1	8698.1	244.0	4001.0	4401.0	8698.12	4297.07
29/02C-09	Maureen	9312.0	9223.0	8930.0	248.8	4104.2	4554.2	8930.01	4375.77
29/02C-09	Ekofisk	9481.0	9391.5	9098.5	252.2	4179.2	4429.2	9098.54	4669.31
29/02C-09	Tor	9820.0	9729.8	9436.8	258.9	4329.8	5229.8	9436.79	4207.03
29/02C-09	Hod	10495.0	10403.6	10110.6	271.7	4629.6	6724.9	10110.59	3385.71

Table 3.25.1 - Summary of mid-point temperature and pressure data at Well 29/02C-09

Fluid data

A summary of the fluid set parameters at Well 29/02C-09 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
29/02C-09	Horda	74000	730	39.7	0.78	0.78
29/02C-09	Balder	74000	730	40.4	0.78	0.78
29/02C-09	Sele	74000	616	38.0	0.772	0.772
29/02C-09	Lista	74000	730	40.8	0.78	0.78
29/02C-09	Maureen	74000	730	41.0	0.78	0.78
29/02C-09	Ekofisk	74000	730	41.2	0.78	0.78
29/02C-09	Tor	74000	730	41.6	0.78	0.78
29/02C-09	Hod	74000	730	42.3	0.78	0.78

Table 3.25.2 - Summary of fluid parameter data at Well 29/02C-09

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.25.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	14.52	7.26	2.481	10,246	5,612

Table 3.25.4 - Tuff properties used at Well 29/02C-09

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
29/02C-09	Horda	PAY	1153.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02C-09	Horda	RES	1153.000	4.500	0.004	1.010	0.224	0.995	0.366
29/02C-09	Balder	PAY	104.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02C-09	Balder	RES	104.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02C-09	Sele	PAY	124.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02C-09	Sele	RES	124.000	39.500	0.319	7.002	0.177	0.951	0.300
29/02C-09	Lista	PAY	327.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02C-09	Lista	RES	327.000	9.500	0.290	1.525	0.161	0.951	0.313
29/02C-09	Maureen	PAY	138.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02C-09	Maureen	RES	138.000	75.500	0.547	16.834	0.223	0.959	0.100
29/02C-09	Ekofisk	PAY	200.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02C-09	Ekofisk	RES	200.000	160.000	0.800	16.063	0.100	0.955	0.139
29/02C-09	Tor	PAY	478.000	0.000	0.000	0.000	0.000	0.000	0.000
29/02C-09	Tor	RES	478.000	424.750	0.889	26.417	0.062	0.987	0.011
29/02C-09	Hod	PAY	872.000	0.500	0.001	0.052	0.104	0.485	0.000
29/02C-09	Hod	RES	872.000	705.750	0.809	46.276	0.066	0.921	0.133

Table 3.25.5 - Petrophysical parameters used at Well 29/02C-09

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

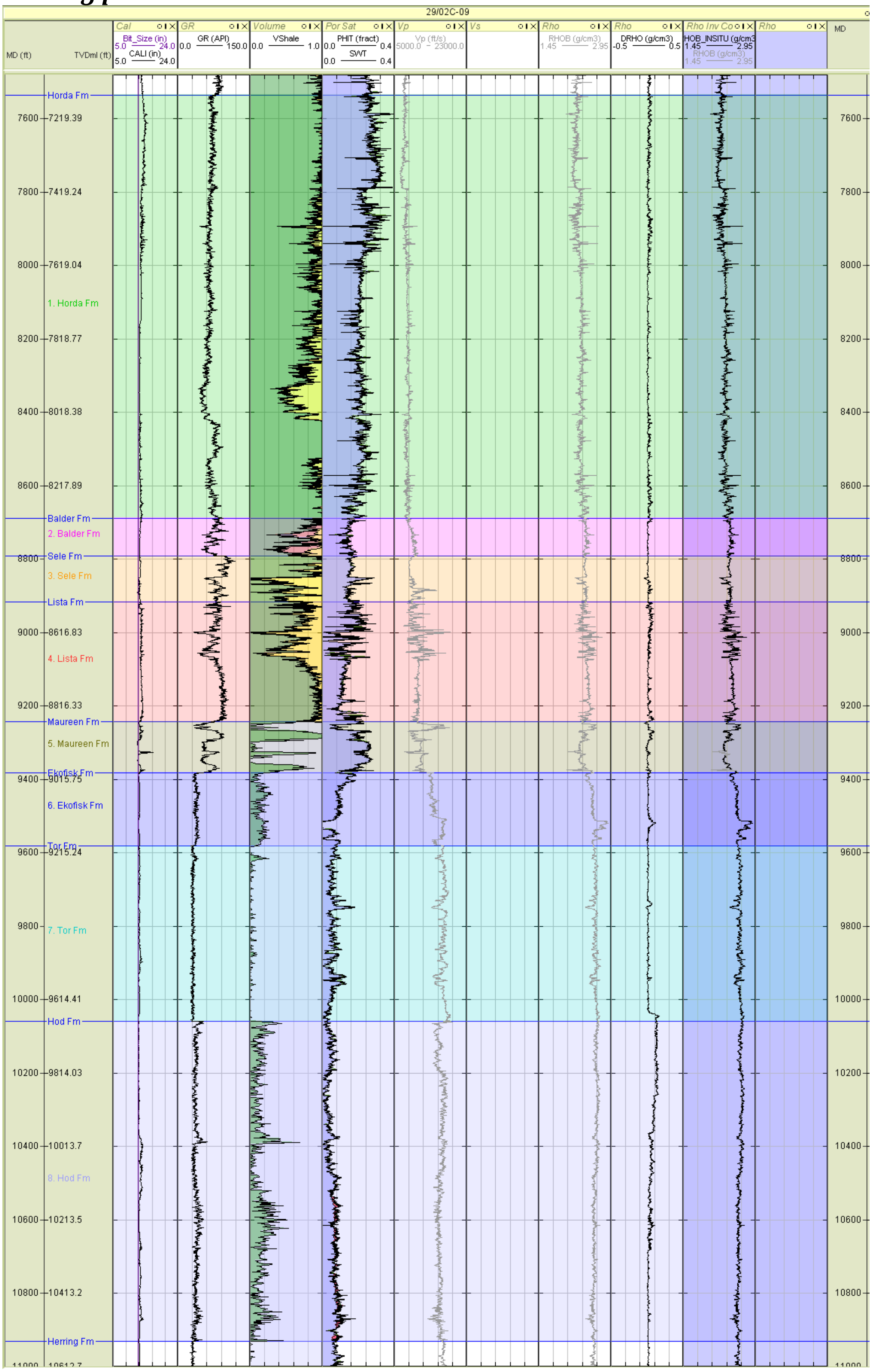


Figure 3.25.3 - Well Panel: Measured data and invasion correction for well 29/02C-09.

Well log panel – log editing and audit

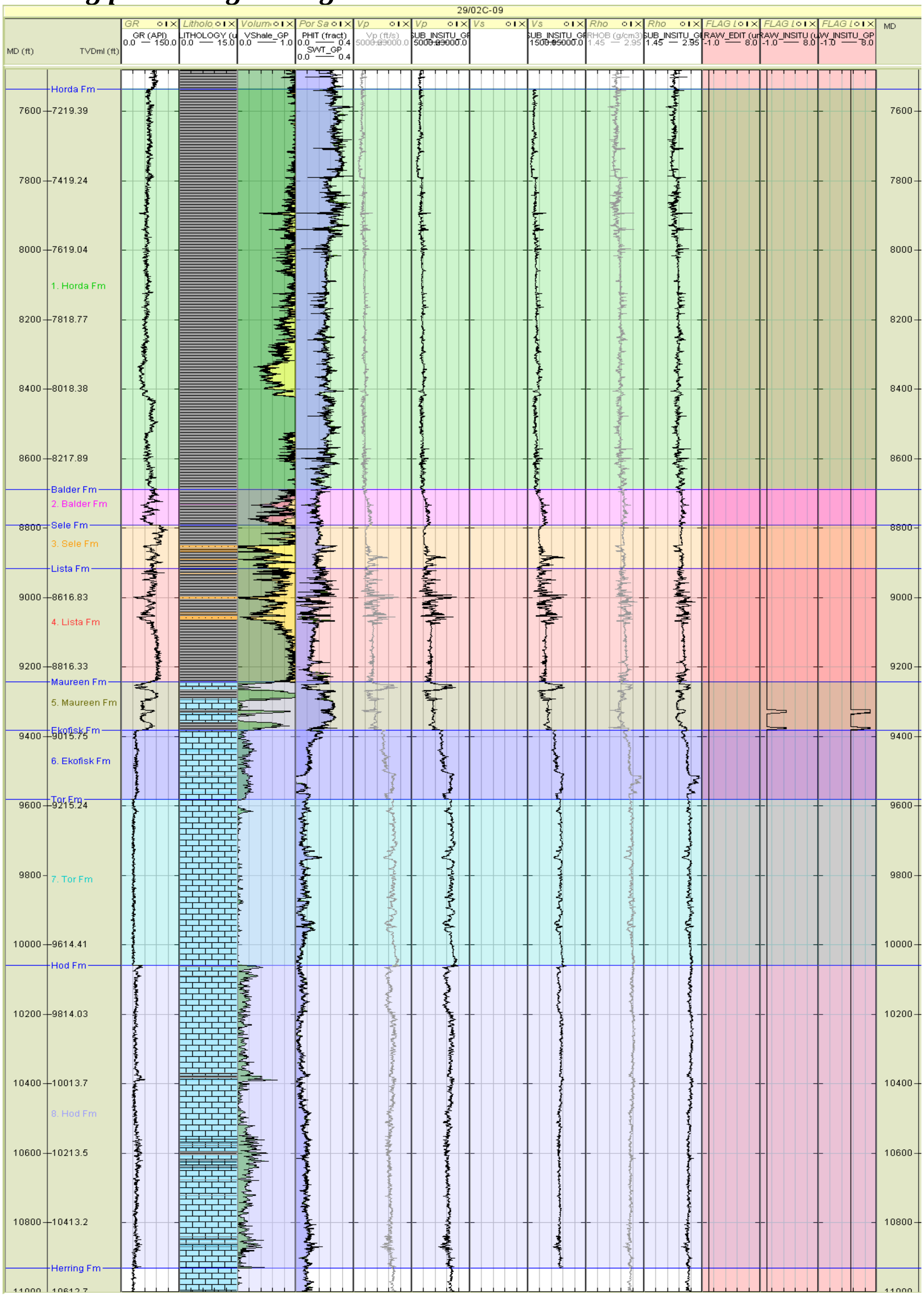


Figure 3.25.4 - Well Panel: Log edits for well 29/02C-09.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

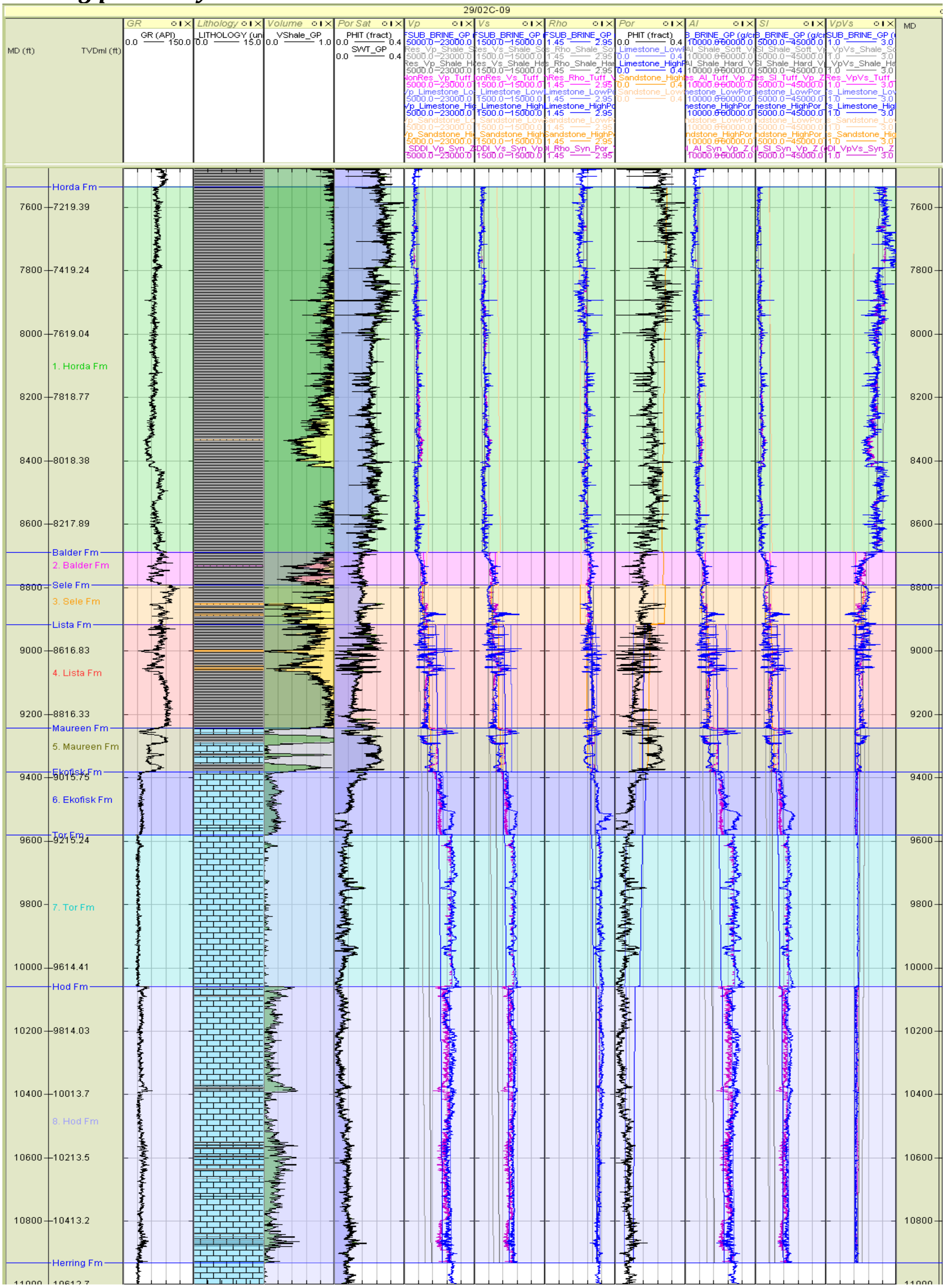


Figure 3.25.5 - Well Panel: End-member and synthetic logs for well 29/02C-09.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

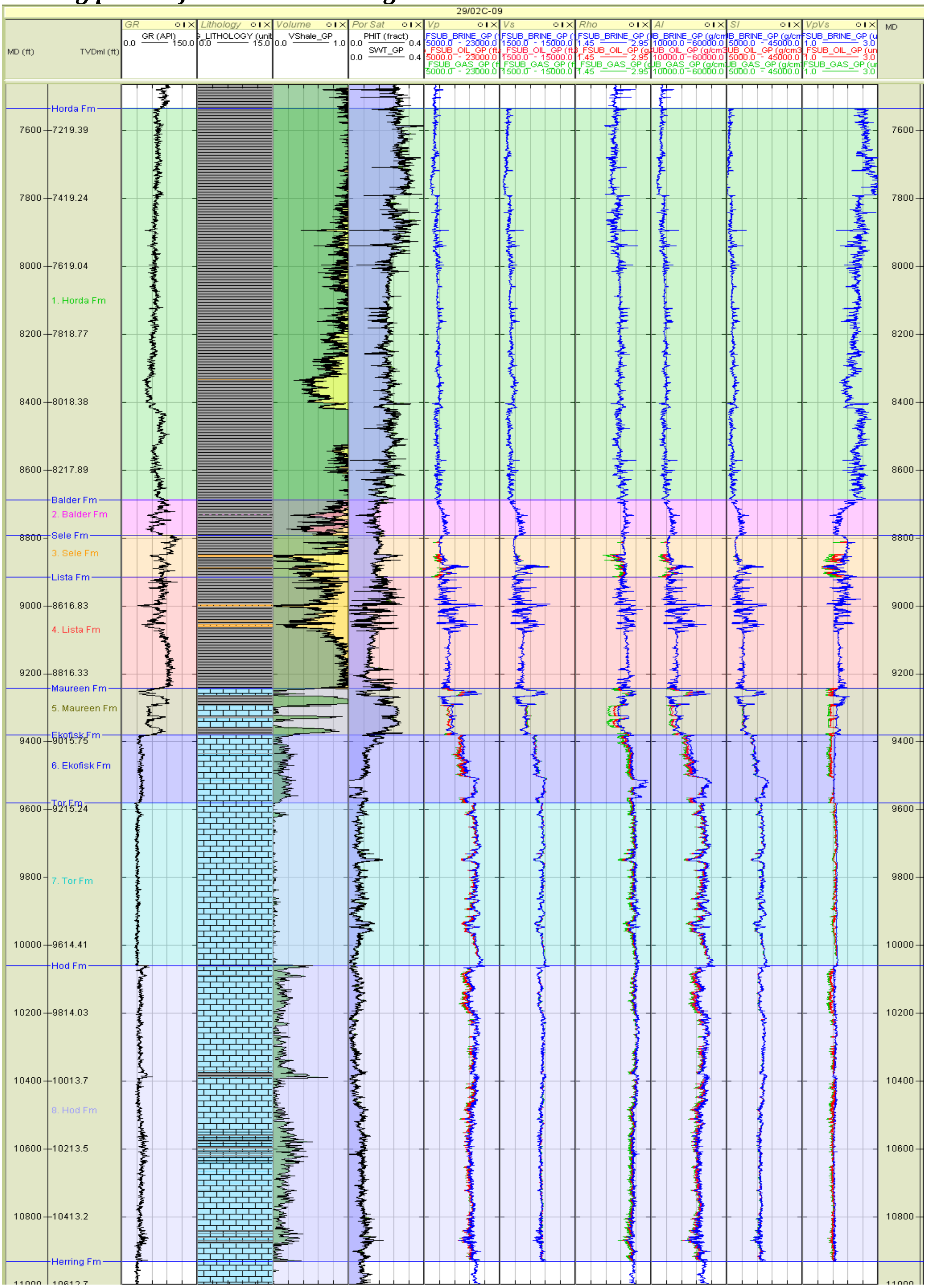


Figure 3.25.6 - Well Panel: Fluid substituted and elastic logs for well 29/02C-09.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/02C-09 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02C-09	Horda	7904	3159	2.29
29/02C-09	Balder	9058	4327	2.42
29/02C-09	Sele	8919	4173	2.41
29/02C-09	Lista	10275	5110	2.43
29/02C-09	Maureen	10107	4995	2.40

Table 3.25.6 - Clean shale properties at Well 29/02C-09

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02C-09	Horda	100% Brine			
29/02C-09	Balder	100% Brine			
29/02C-09	Sele	100% Brine	10341	5289	2.32
29/02C-09	Lista	100% Brine			
29/02C-09	Maureen	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/02C-09	Horda	80% Oil			
29/02C-09	Balder	80% Oil			
29/02C-09	Sele	80% Oil	9306	5351	2.28
29/02C-09	Lista	80% Oil			
29/02C-09	Maureen	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/02C-09	Horda	90% Gas			
29/02C-09	Balder	90% Gas			
29/02C-09	Sele	90% Gas	8962	5464	2.18
29/02C-09	Lista	90% Gas			
29/02C-09	Maureen	90% Gas			

Table 3.25.7 - Clean sand properties at Well 29/02C-09 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02C-09	Maureen	100% Brine	12,484	6,638	2.37
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/02C-09	Maureen	80% Oil	11,776	6,721	2.31
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/02C-09	Maureen	90% Gas	11,712	6,850	2.22

Table 3.25.8 - Clean limestone properties at Well 29/02C-09 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

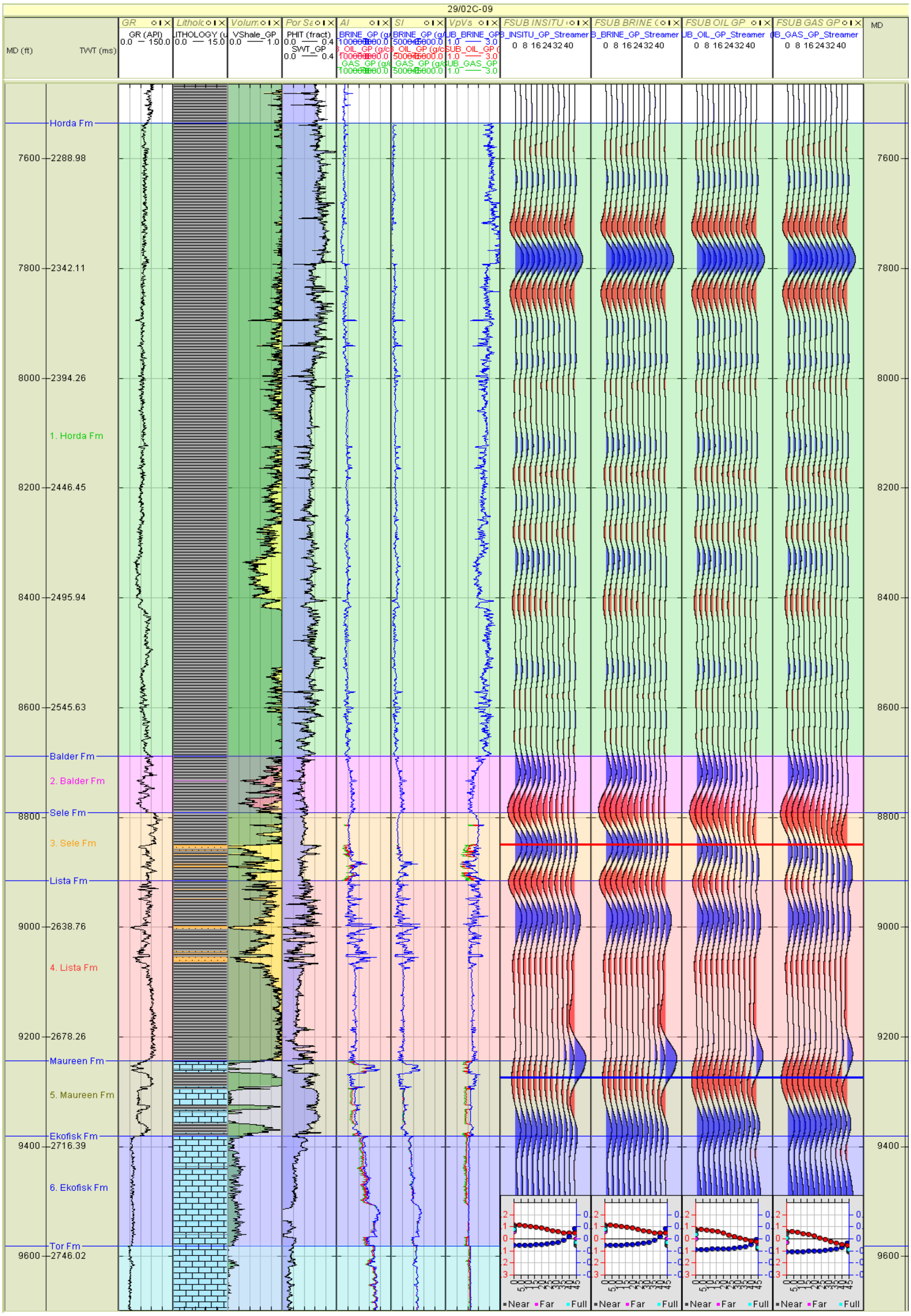


Figure 3.25.7 - Well Panel: Tertiary reservoirs for well 29/02C-09. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a sand package in the lower half of the interval with the upper half of the interval comprised exclusively of shale overburden, net reservoir is approximately 40 feet. The sand package in the lower half of the interval has variable porosity and shale content but contains two thin high porosity streaks and the porosity value in these streaks is approximately 30%.
- Blocky AVO shows a modelled class I response for the 100% brine case, a modelled class II response for the 80% oil case and a modelled class III response for the 90% gas case, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is less pronounced on the synthetic gathers where the introduction of hydrocarbons results in class I responses for all fluid cases and this is likely to be due to interference effects affecting the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

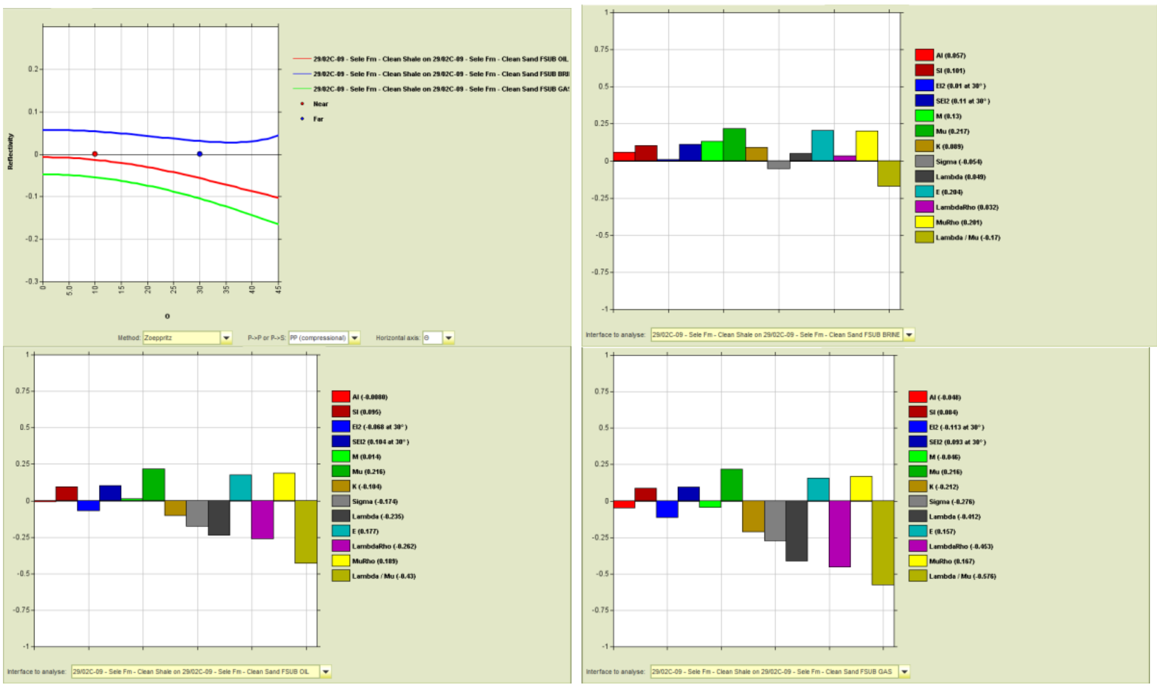


Figure 3.25.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 29/02C-09.

Maureen Formation

- Reservoir formed by three limestone sections inter-bedded with shale, net reservoir is approximately 76 feet. The uppermost of the limestone sections has a low porosity leading to a high Vp and density log values and a hard response on the seismic.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil fluid cases and a modelled class IIp response for the 90% gas case, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

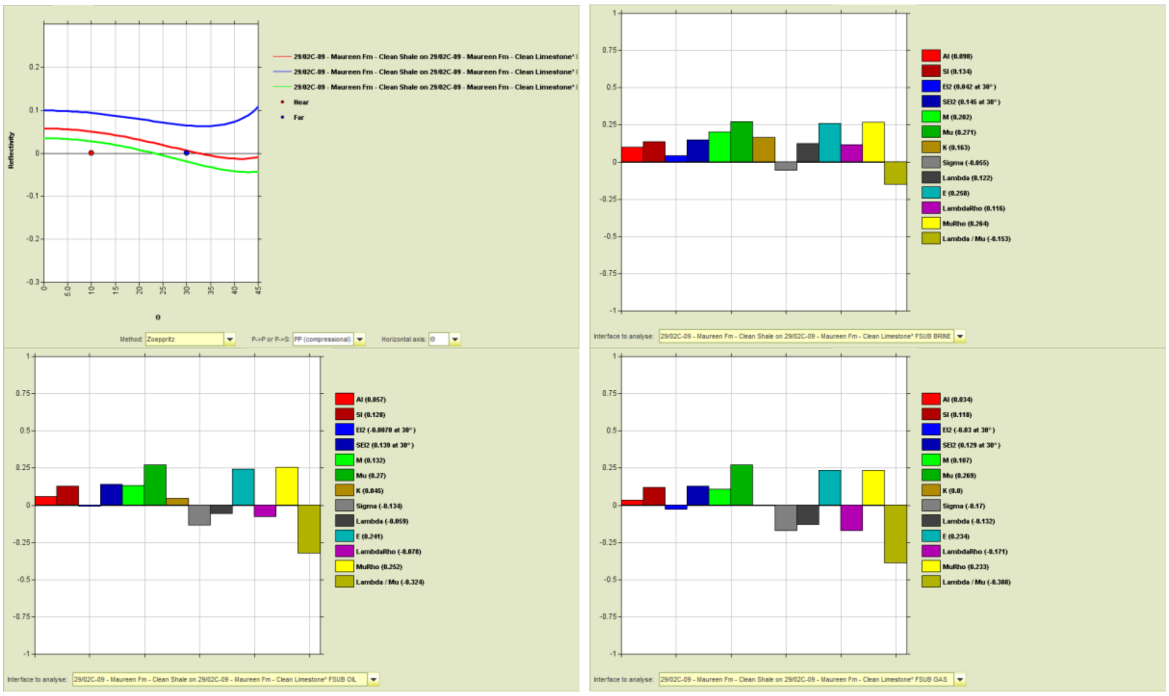


Figure 3.25.9 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 29/02C-09.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/02C-09 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02C-09	Ekofisk	100% Brine	14682	7944	2.53
29/02C-09	Tor	100% Brine	17114	8982	2.62
29/02C-09	Hod	100% Brine	16734	8963	2.63
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/02C-09	Ekofisk	80% Oil	14010	7995	2.50
29/02C-09	Tor	80% Oil	16854	9009	2.60
29/02C-09	Hod	80% Oil	16402	8985	2.61
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/02C-09	Ekofisk	90% Gas	13888	8073	2.45
29/02C-09	Tor	90% Gas	16821	9049	2.58
29/02C-09	Hod	90% Gas	16310	9019	2.59

Table 3.25.9 - Clean limestone properties at Well 29/02C-09 for each fluid case

Cretaceous reservoirs

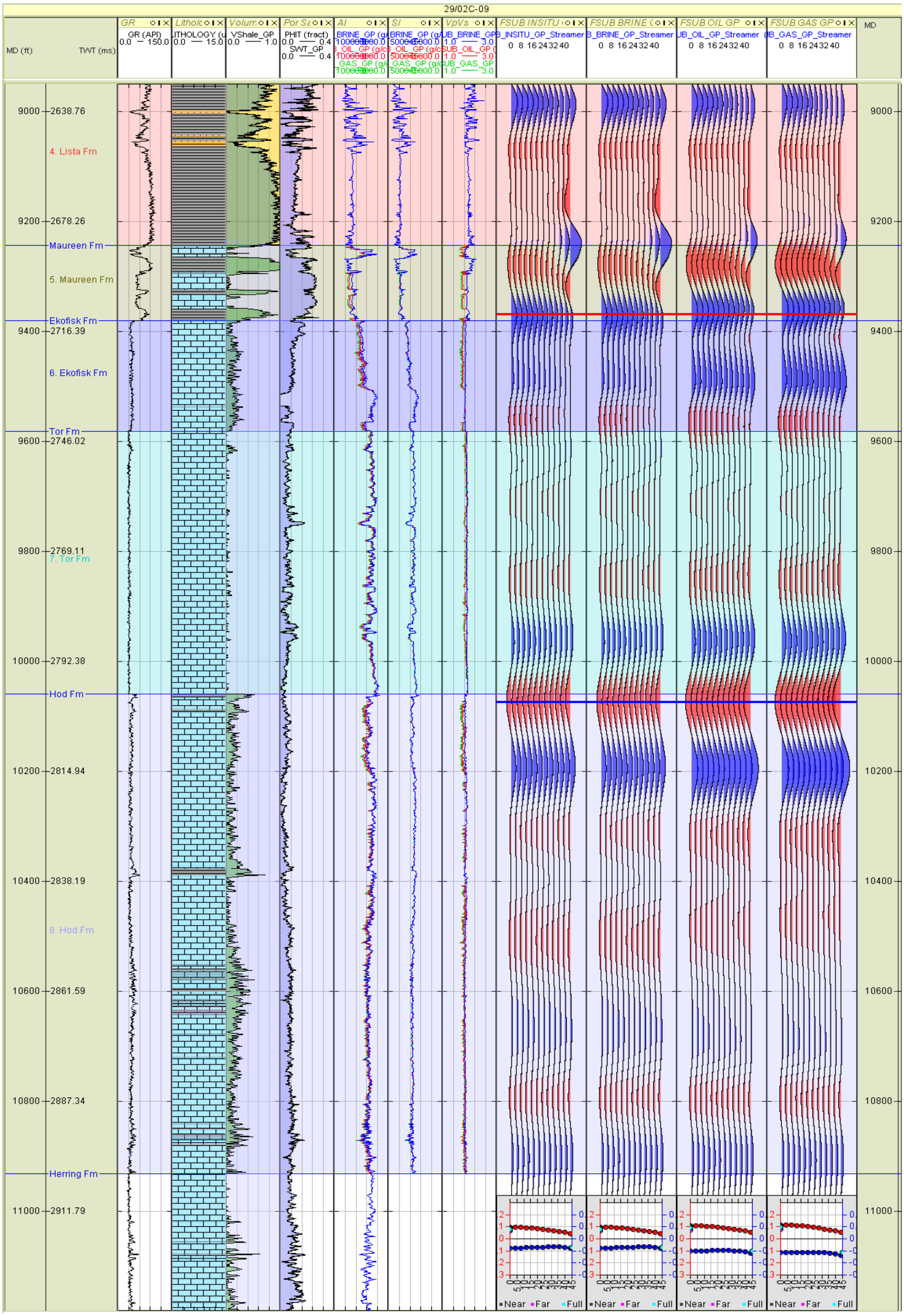


Figure 3.25.10 - Well Panel: Cretaceous reservoirs for well 29/02C-09. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the top section of the Ekofisk Fm and the porosity decreases towards the base of the reservoir. A small section of zero porosity is found at a depth of 9510ft MD and this corresponds to high velocity and density values on the logs.
- Blocky AVO shows a strong modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, and that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

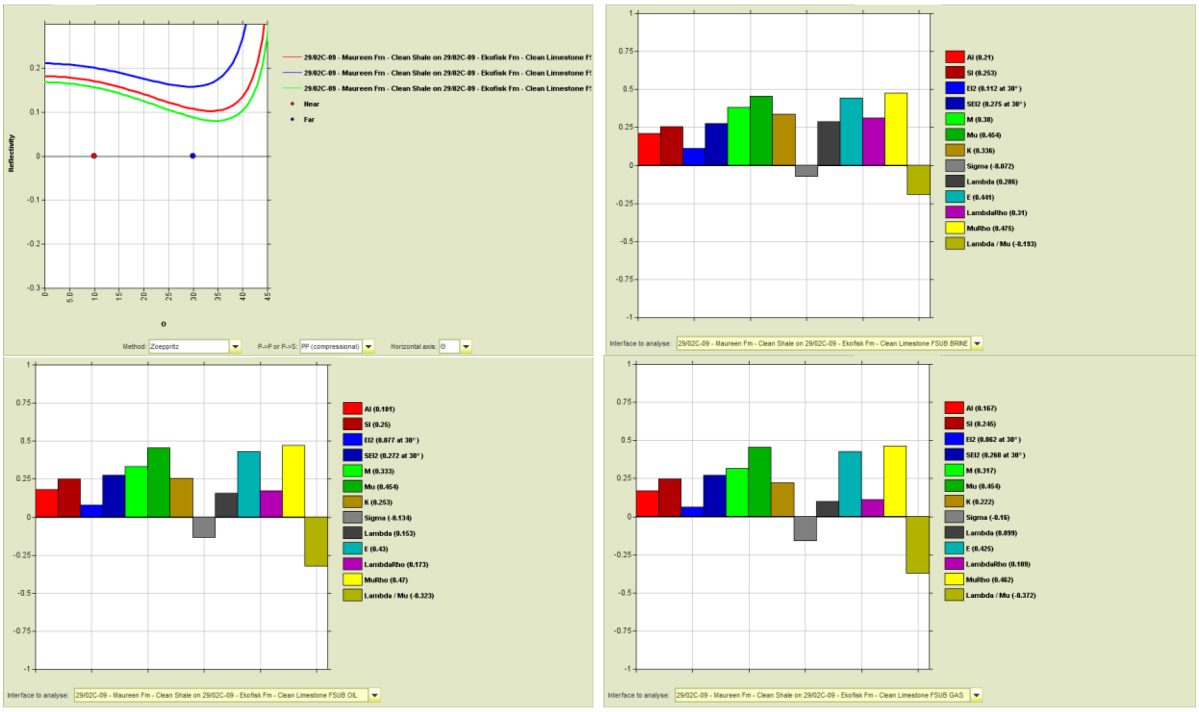


Figure 3.25.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 29/02C-09.

Tor Formation

- Reservoir formed by a clean limestone formation. This reservoir is generally a low porosity reservoir with an average porosity of approximately 6% and consequently fluid effects are minimal in this interval.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are all positive and medium amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

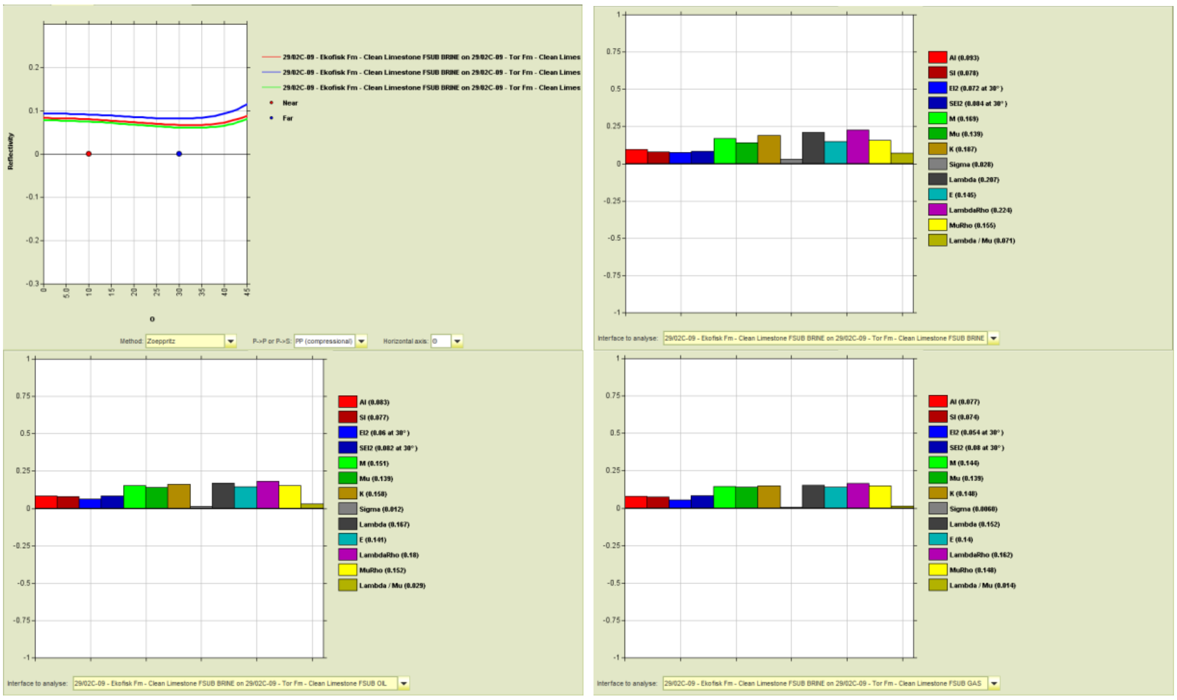


Figure 3.25.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 29/02C-09.

Hod Formation

- Reservoir formed by a limestone formation with a minor component of shale. The reservoir has a relatively constant porosity of approximately 7%.
- Blocky AVO shows a modelled class II response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are negative and low amplitude in the brine case, and that the contrasts become more negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

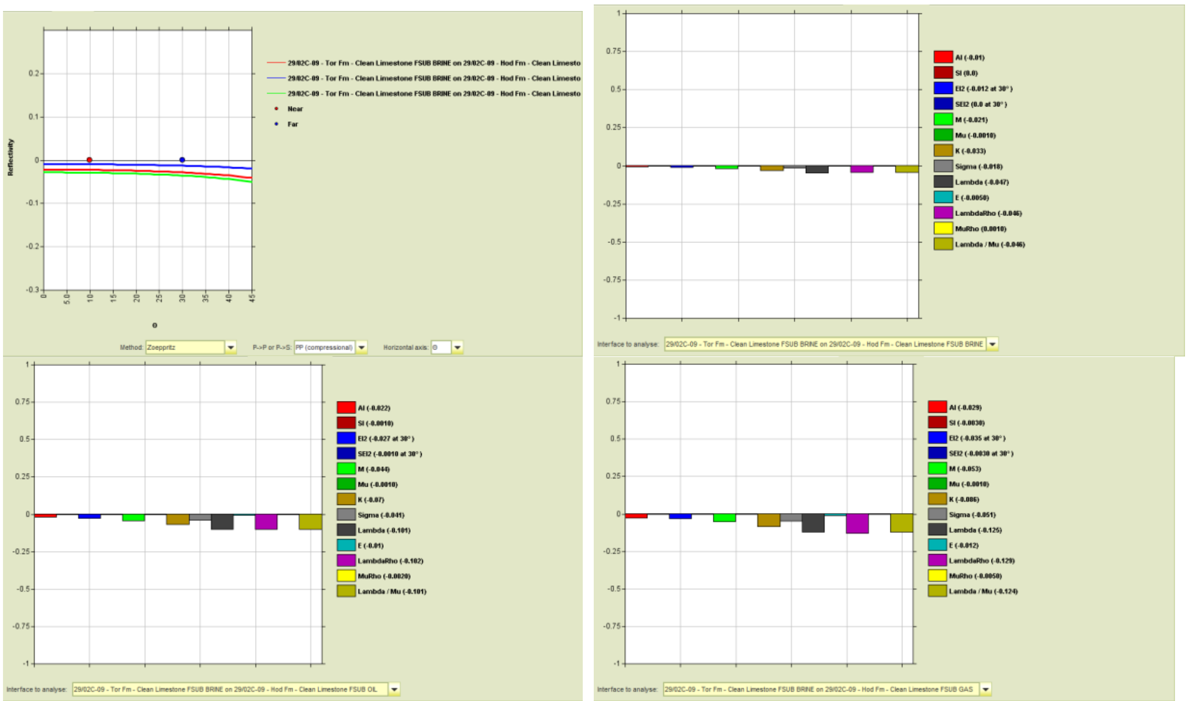


Figure 3.25.13 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 29/02C-09.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 29/02C-09 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/02C-09	Overburden	Shale	7794		2.27
29/02C-09	Underburden	Limestone	15931		2.55

Table 3.25.10 - Overburden and underburden properties at Well 29/02C-09.

Well: 29/03A-06

General

Well Information
This well is a Shell operated exploration well which was spudded, drilled and then abandoned in 1999. The well encountered condensate within the Sele Fm, and it is part of the Fram field.

Objectives
This well was drilled to investigate the Fram prospect and targeted the hydrocarbon potential of the Palaeocene sands of the Forties Sandstone Member in a salt flank trap. The well was tested after encountering gas condensate.

Log conditioning overview
Only minor log conditioning was required due to good log data quality within this well. Thin calcite stringers in the Horda and Sele Formation were seen on the density log but were not apparent on the Vp log, and data relating to these intervals was consequentially removed.

Invasion correction
Invasion correction has been performed on the density log within all formations with the exception of the non-reservoir forming Balder and Lista Formations. The drilling mud used within this well was oil-based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Sele, Lista and Maureen Formations for the Vp log, within the Horda, Sele, Lista and Maureen Formations for the Vs log and within the Horda and Sele Formations for the density log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 29/03A-06 is displayed in the figures below;

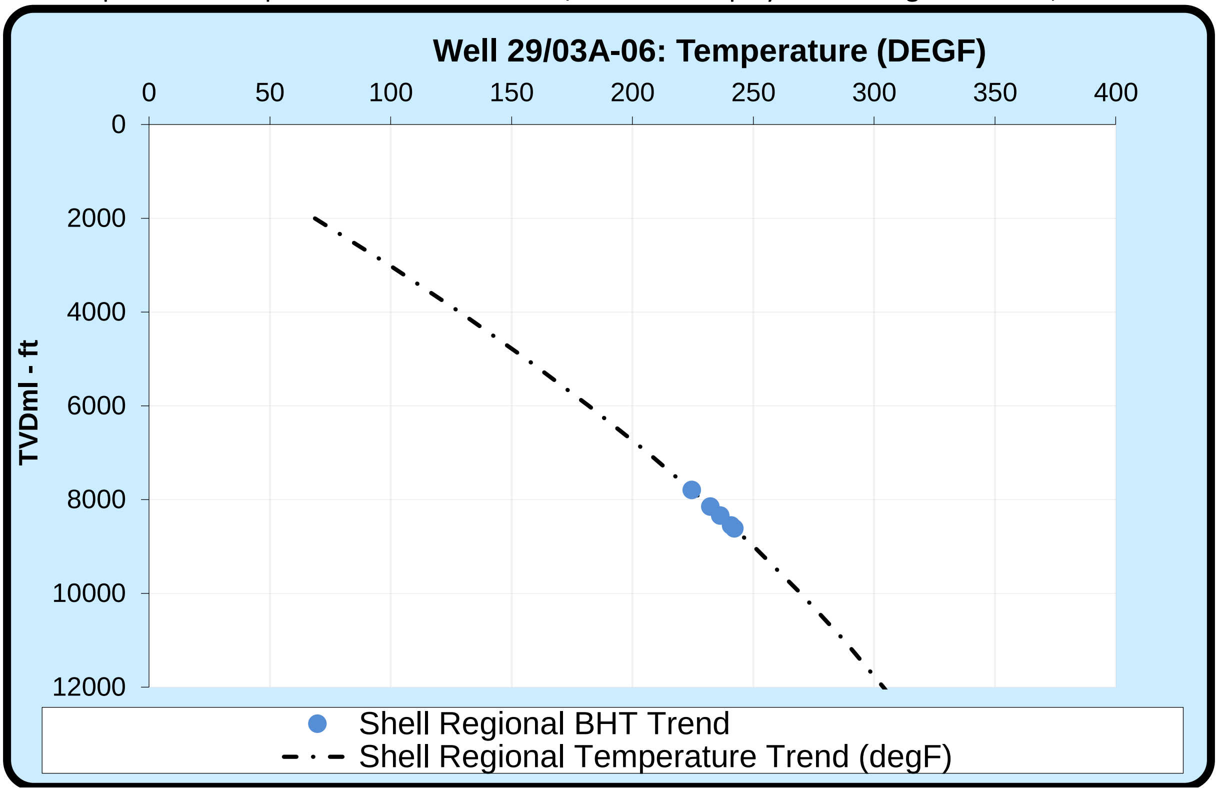


Figure 3.26.1 - Temperature data at Well 29/03A-06

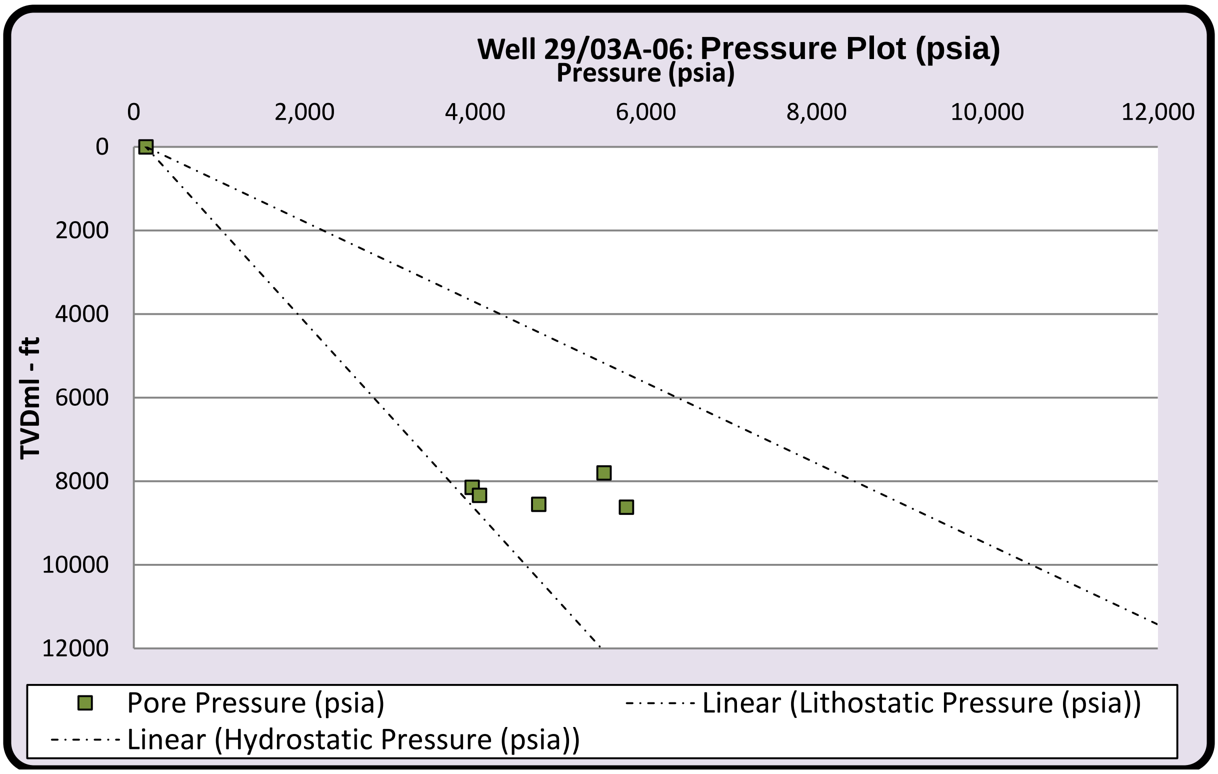


Figure 3.26.2 - Pressure data at Well 29/03A-06

The temperature and pressure data for the formation mid-points in Well 29/03A-06 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
29/03A-06	Sea Bed	402.0	319.0	0.0	39.2	142.0	142.0	141.95	0.00
29/03A-06	Horda	8197.5	8113.9	7794.9	224.5	3610.7	5510.7	7794.94	2284.24
29/03A-06	Balder	8550.0	8466.3	8147.3	232.3	3767.5	3967.5	8147.28	4179.78
29/03A-06	Sele	8741.0	8657.2	8338.2	236.4	3852.5	4052.5	8338.22	4285.75
29/03A-06	Lista	8951.5	8867.6	8548.6	240.8	3946.1	4746.1	8548.65	3802.54
29/03A-06	Maureen	9018.0	8934.1	8615.1	242.2	3975.7	5775.7	8615.12	2839.44

Table 3.26.1 - Summary of mid-point temperature and pressure data at Well 29/03A-06

Fluid data

A summary of the fluid set parameters at Well 29/03A-06 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
29/03A-06	Horda	72000	730	39.8	0.78	0.78
29/03A-06	Balder	72000	730	40.2	0.78	0.78
29/03A-06	Sele	72000	730	40.4	0.78	0.78
29/03A-06	Lista	72000	730	40.6	0.78	0.78
29/03A-06	Maureen	72000	730	40.7	0.78	0.78

Table 3.26.2 - Summary of fluid parameter data at Well 29/03A-06

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
29/03A-06	Horda	16380	55.7	0.8
29/03A-06	Balder	16380	56.0	0.8
29/03A-06	Sele	15649.5	56.3	0.8
29/03A-06	Lista	16380	56.3	0.8
29/03A-06	Maureen	16380	56.4	0.8

Table 3.26.3 - Summary of additional parameter data at Well 29/03A-06

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.26.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	16.15	6.23	2.462	10,341	5,220

Table 3.26.5 - Tuff properties used at Well 29/03A-06

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
29/03A-06	Horda	PAY	639.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-06	Horda	RES	639.000	68.500	0.107	12.984	0.190	1.000	0.342
29/03A-06	Balder	PAY	66.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-06	Balder	RES	66.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-06	Sele	PAY	316.000	10.500	0.033	2.443	0.233	0.390	0.024
29/03A-06	Sele	RES	316.000	145.000	0.459	28.143	0.194	0.806	0.221
29/03A-06	Lista	PAY	105.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-06	Lista	RES	105.000	9.000	0.086	1.369	0.152	0.990	0.182
29/03A-06	Maureen	PAY	28.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-06	Maureen	RES	28.000	0.000	0.000	0.000	0.000	0.000	0.000

Table 3.26.6 - Petrophysical parameters used at Well 29/03A-06

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

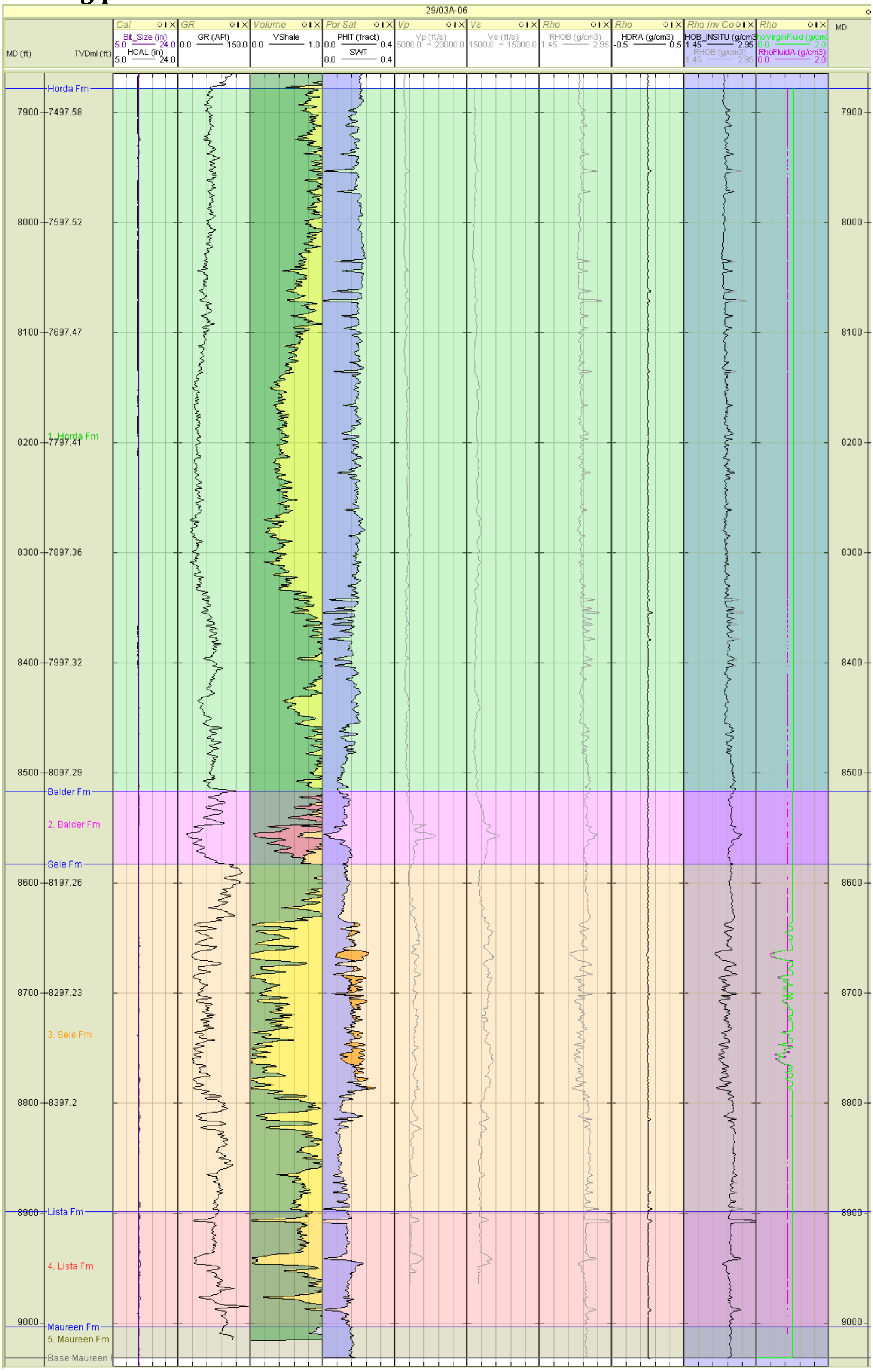


Figure 3.26.3 - Well Panel: Measured data and invasion correction for well 29/03A-06.

Well log panel – log editing and audit

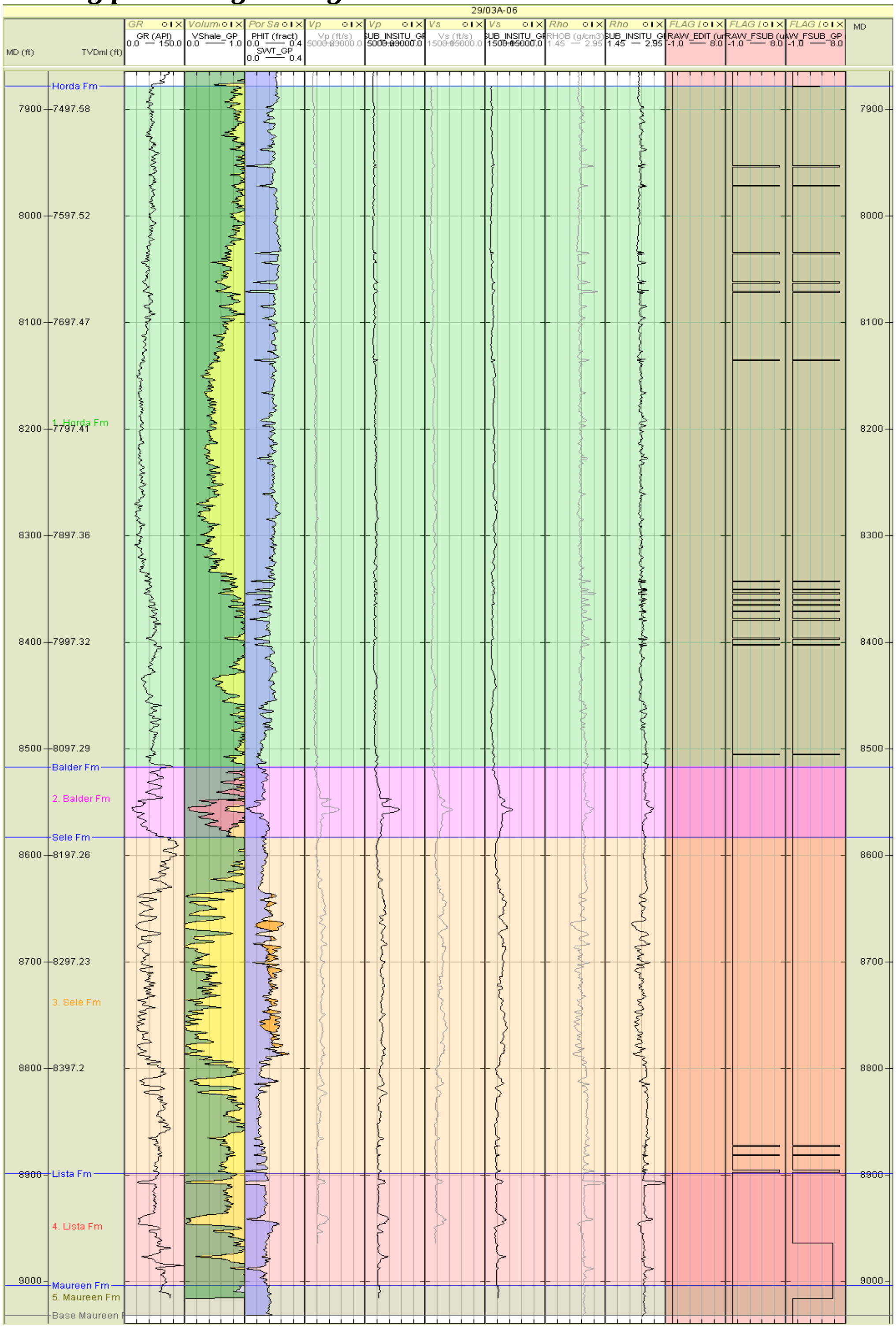


Figure 3.26.4 - Well Panel: Log edits for well 29/03A-06.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

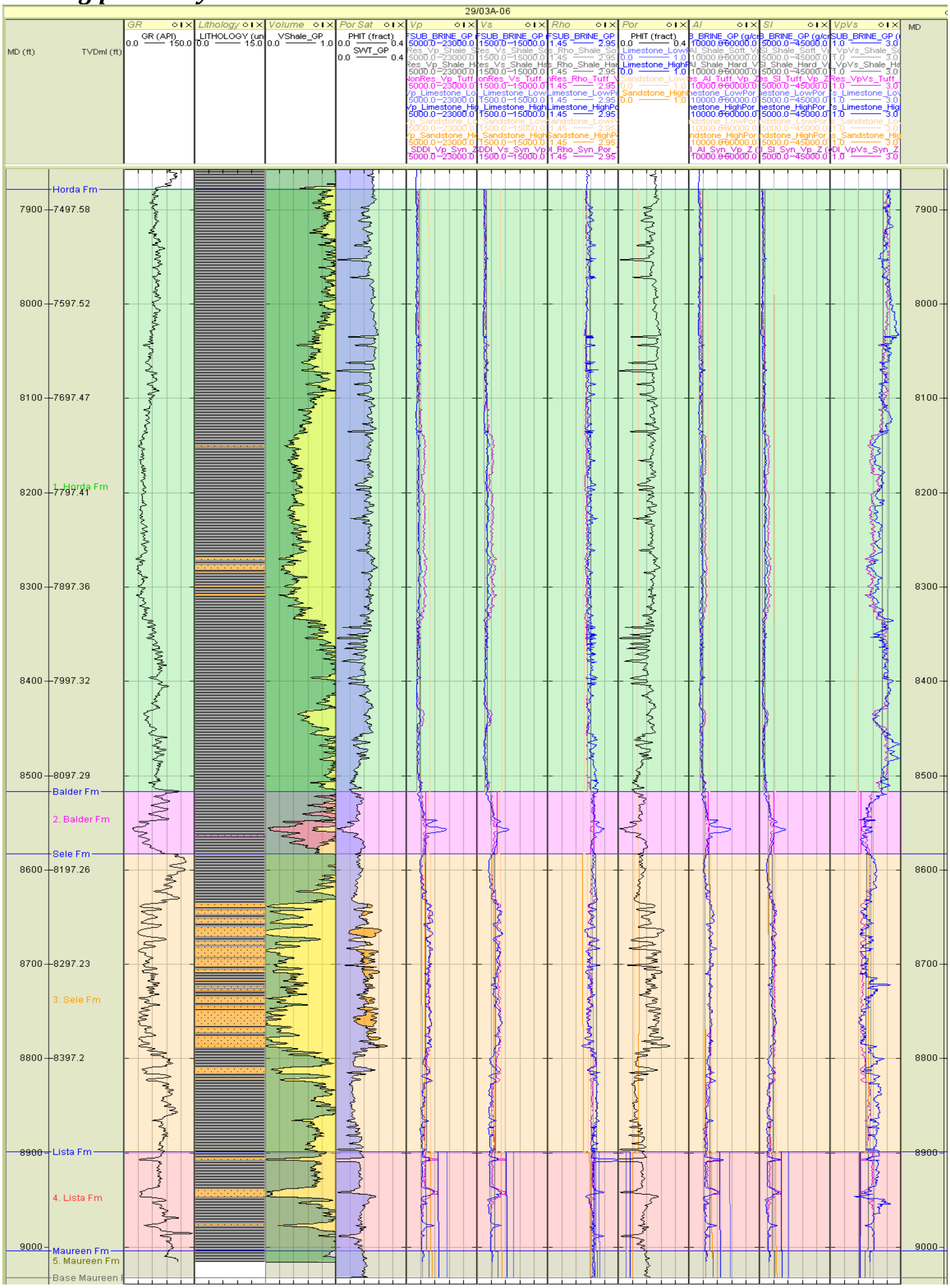


Figure 3.26.5 - Well Panel: End-member and synthetic logs for well 29/03A-06.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

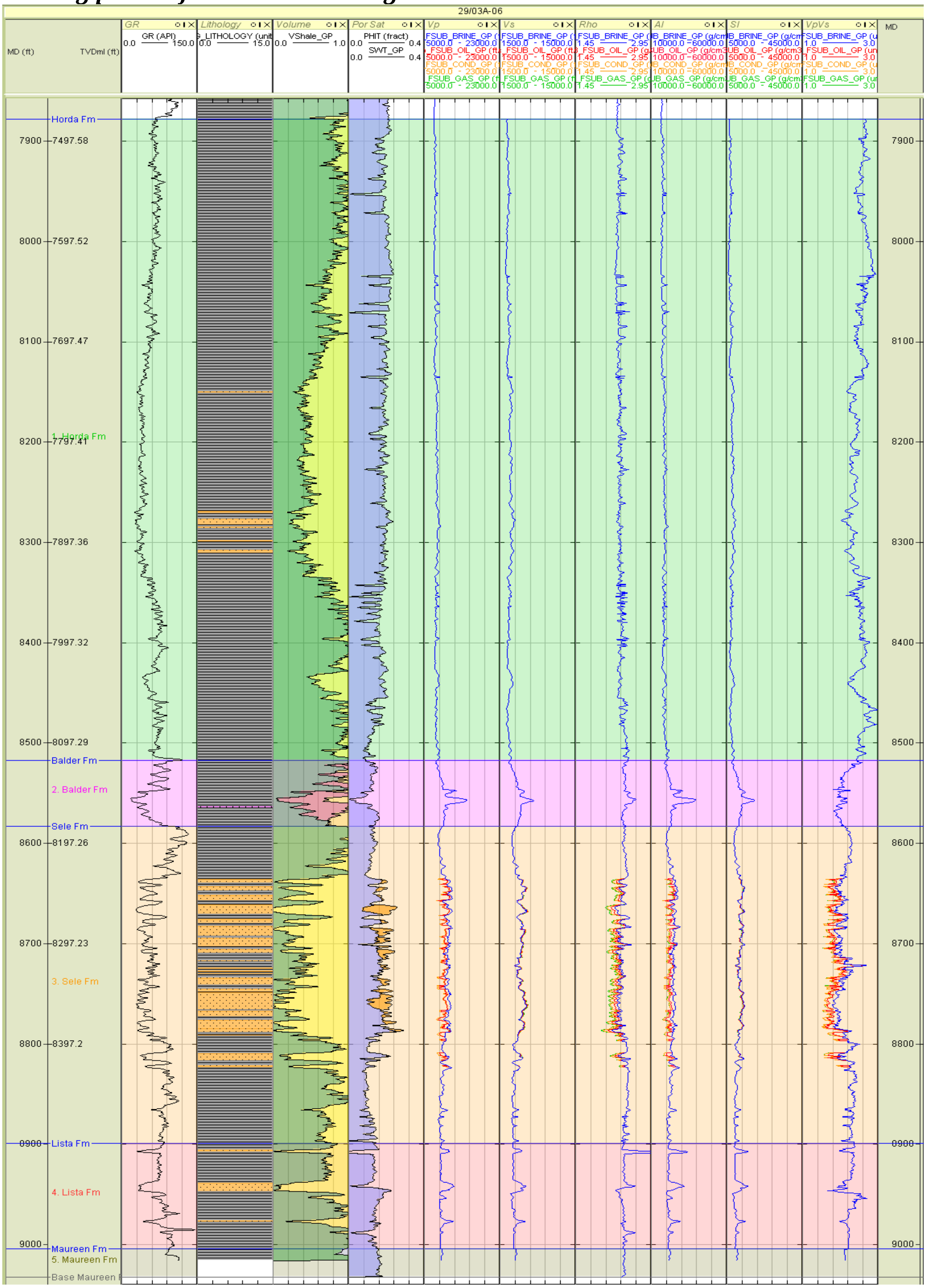


Figure 3.26.6 - Well Panel: Fluid substituted and elastic logs for well 29/03A-06.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/03A-06 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-06	Horda	7642	2944	2.34
29/03A-06	Balder	8841	4134	2.42
29/03A-06	Sele	8973	3946	2.45
29/03A-06	Lista	8835	3765	2.39
29/03A-06	Maureen	9202	4360	2.42

Table 3.26.7 - Clean shale properties at Well 29/03A-06

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-06	Horda	100% Brine			
29/03A-06	Balder	100% Brine			
29/03A-06	Sele	100% Brine	10878	5483	2.32
29/03A-06	Lista	100% Brine			
29/03A-06	Maureen	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-06	Horda	80% Oil			
29/03A-06	Balder	80% Oil			
29/03A-06	Sele	80% Oil	10160	5549	2.27
29/03A-06	Lista	80% Oil			
29/03A-06	Maureen	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-06	Horda	90% Gas			
29/03A-06	Balder	90% Gas			
29/03A-06	Sele	90% Gas	10051	5658	2.19
29/03A-06	Lista	90% Gas			
29/03A-06	Maureen	90% Gas			

Table 3.26.8 - Clean sand properties at Well 29/03A-06 for each fluid case

Tertiary reservoirs – Well panel

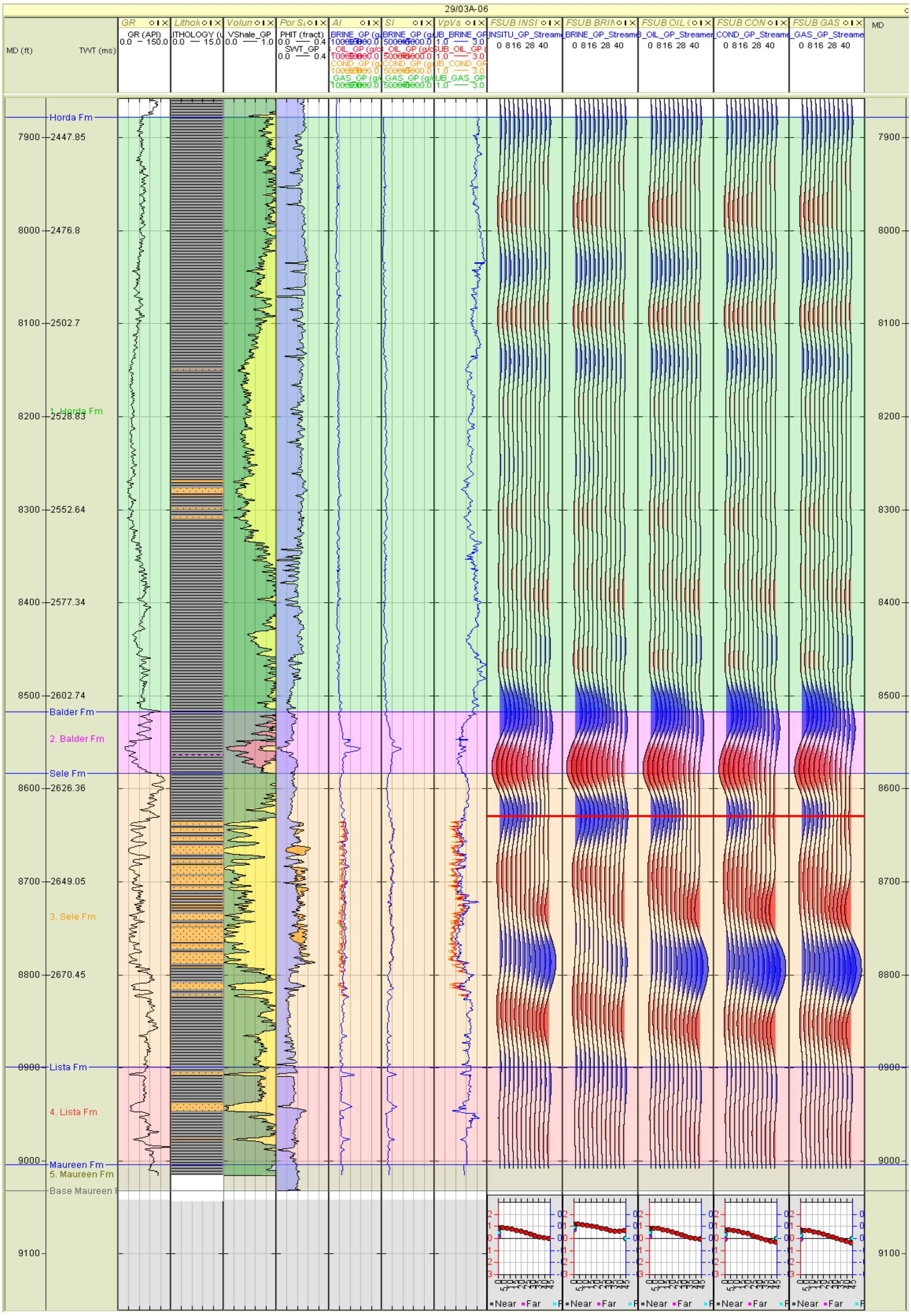


Figure 3.26.7 - Well Panel: Tertiary reservoirs for well 29/03A-06. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a thick clean sand in the middle of the interval and net reservoir is approximately 145 feet. The reservoir sand is overlain directly by overburden shale and tuffaceous shale in the Balder Fm.
- Blocky AVO shows a modelled class I response for the 100% brine case and a modelled class IIp response for the 80% oil, 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is also seen on the synthetic gathers with the addition of hydrocarbons leading to class IIp responses for the 90% gas and 80% condensate fluid cases.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

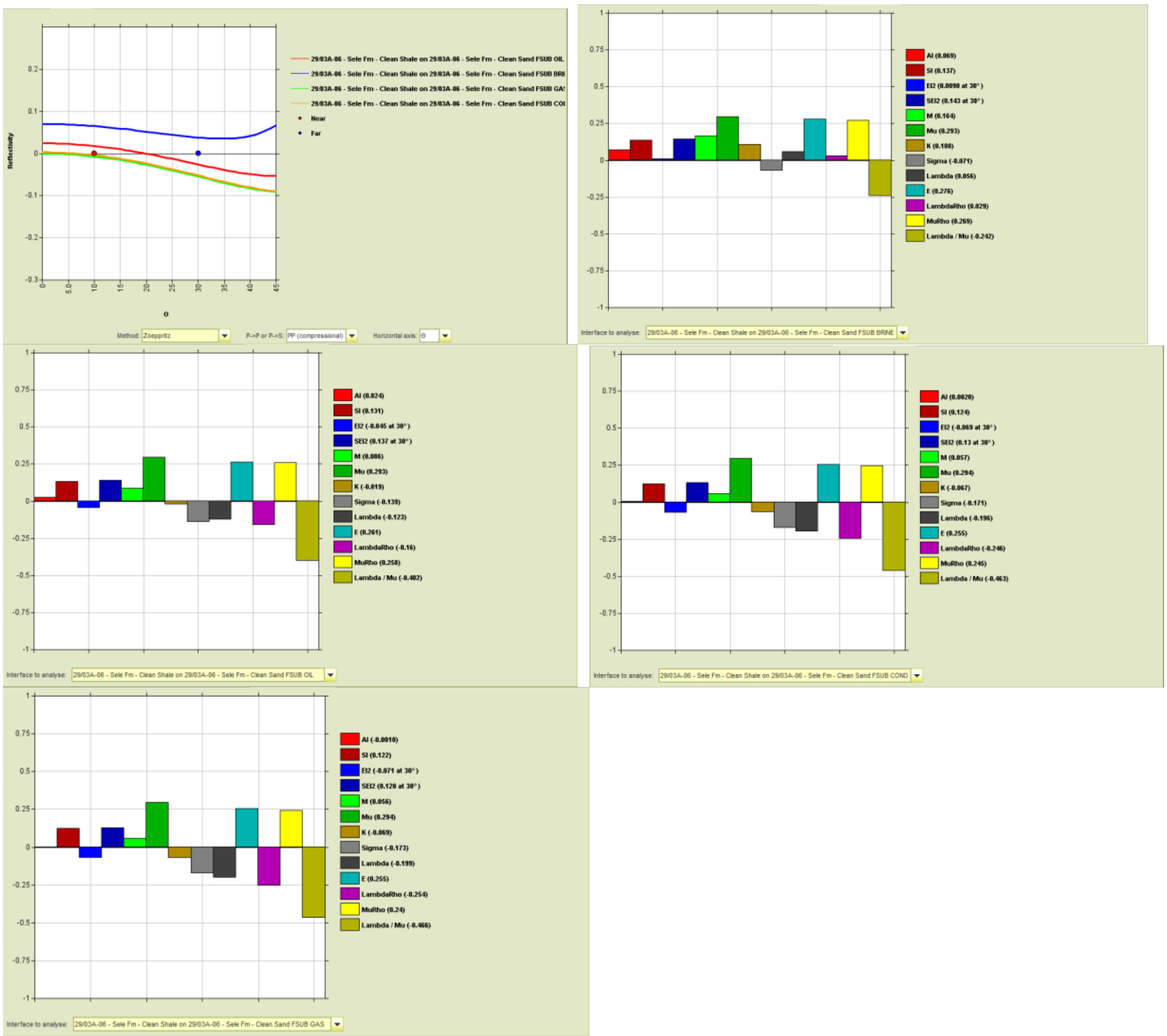


Figure 3.26.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 29/03A-06.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/02A-06 is provided below;

There is no Cretaceous section at this well.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 29/03A-06 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-06	Overburden	Shale	7436		2.30
29/03A-06	Underburden				

Table 3.26.9 - Overburden and underburden properties at Well 29/03A-06.

Well: 29/03A-07

General

Well Information
This well is a Shell operated appraisal well which was spudded, completed and abandoned in 2003. The well encountered condensate and oil within the Sele Fm, and it is part of the Starling field.

Objectives
The primary objective of the well was to appraise the Forties sandstone member in the Sele Fm with a secondary objective of the Maureen Sandstone. The well encountered gas condensate within the Forties sandstone member but the Maureen Sandstone was found to be water bearing. Gas condensate reserves were thus proved in the Starling structure.

Log conditioning overview
The Vs log was deemed to be of poor quality over the Horda Fm and Balder Fm and the data was removed from these sections after multi-well analysis had taken place. The Vs log data in the Horda Fm and Balder Fm was noticed to be poor quality during the multi-well analysis and thus the data was not included in any trends derived in the multi-well analysis. Vp and Vs data was also removed between a depth of 9,020-9,030ft MD in the Lista Fm in part 1 of the rock physics.

Invasion correction
Invasion correction has been performed on the density log within all formations with the exception of the non-reservoir forming Horda and Balder Formations. The drilling mud used within this well was oil-based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Lista and Maureen Formations for the Vp log, within the Horda, Balder, Lista and Maureen Formations for the Vs log and within the Horda, Balder and Sele Formations for the density log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 29/03A-07 is displayed in the figures below;

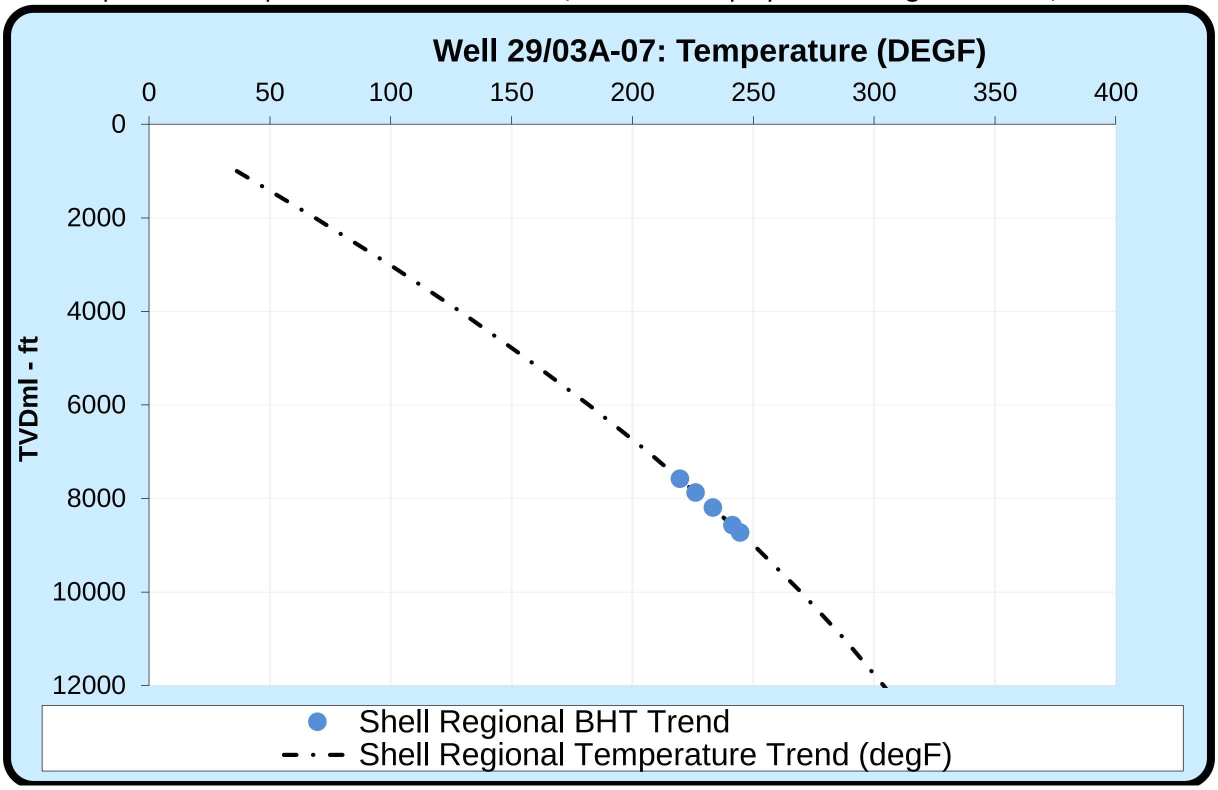


Figure 3.27.1 - Temperature data at Well 29/03A-07

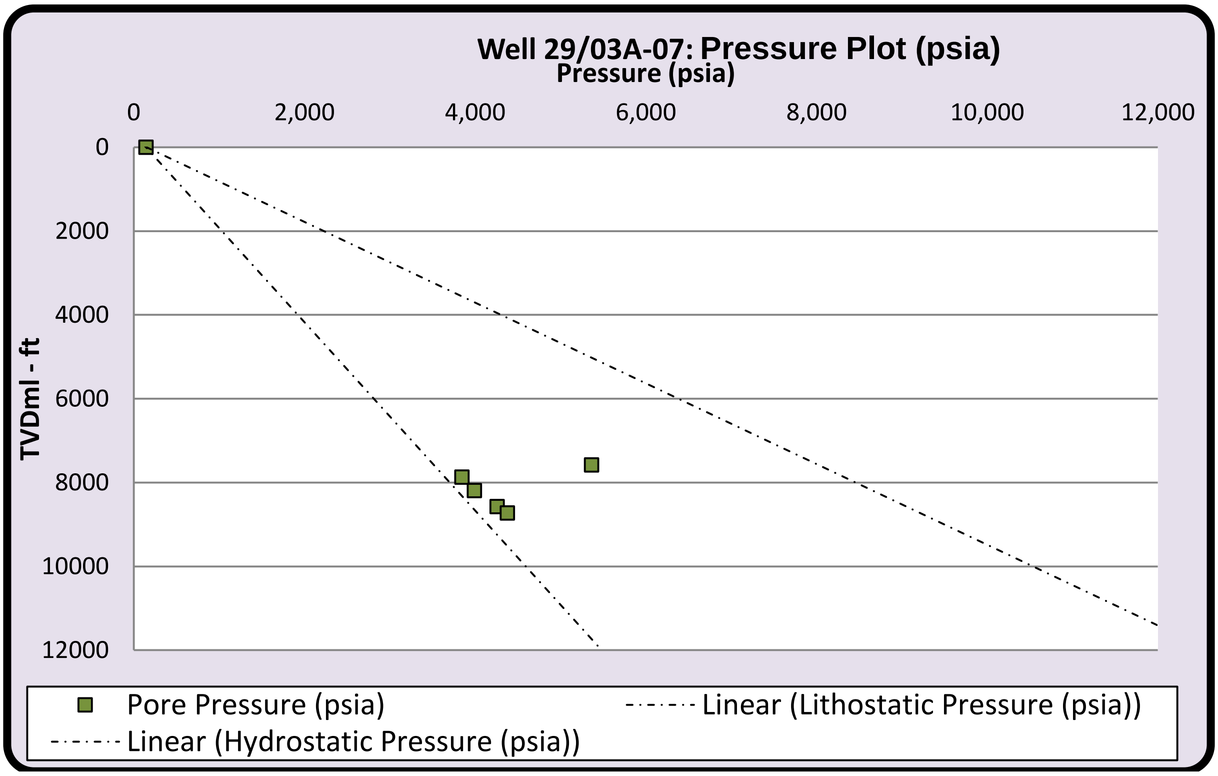


Figure 3.27.2 - Pressure data at Well 29/03A-07

The temperature and pressure data for the formation mid-points in Well 29/03A-07 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
29/03A-07	Sea Bed	412.5	322.5	0.0	39.2	143.5	143.5	143.51	0.00
29/03A-07	Horda	7992.5	7901.6	7579.1	219.7	3516.2	5366.2	7579.08	2212.88
29/03A-07	Balder	8285.5	8194.3	7871.8	226.2	3646.5	3846.5	7871.78	4025.33
29/03A-07	Sele	8609.5	8517.8	8195.3	233.3	3790.4	3990.4	8195.30	4204.88
29/03A-07	Lista	8989.5	8897.2	8574.7	241.4	3959.2	4259.2	8574.66	4315.43
29/03A-07	Maureen	9141.5	9048.8	8726.3	244.6	4026.7	4376.7	8726.29	4349.58

Table 3.27.1 - Summary of mid-point temperature and pressure data at Well 29/03A-07

Fluid data

A summary of the fluid set parameters at Well 29/03A-07 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
29/03A-07	Horda	71000	730	39.6	0.78	0.78
29/03A-07	Balder	71000	730	39.9	0.78	0.78
29/03A-07	Sele	71000	730	40.2	0.78	0.78
29/03A-07	Lista	71000	730	40.6	0.78	0.78
29/03A-07	Maureen	98000	730	40.8	0.78	0.78

Table 3.27.2 - Summary of fluid parameter data at Well 29/03A-07

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
29/03A-07	Horda	16380	55.5	0.8
29/03A-07	Balder	16380	55.5	0.8
29/03A-07	Sele	15260	55.0	0.67
29/03A-07	Lista	16380	56.4	0.8
29/03A-07	Maureen	16380	56.5	0.8

Table 3.27.3 - Summary of additional parameter data at Well 29/03A-07

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.27.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	13.17	5.39	2.41	9,529	4,904

Table 3.27.5 - Tuff properties used at Well 29/03A-07

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
29/03A-07	Horda	PAY	517.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-07	Horda	RES	517.000	10.500	0.020	3.163	0.301	-	0.355
29/03A-07	Balder	PAY	69.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-07	Balder	RES	69.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-07	Sele	PAY	579.000	233.000	0.402	50.098	0.215	0.304	0.138
29/03A-07	Sele	RES	579.000	341.250	0.589	68.509	0.201	0.389	0.206
29/03A-07	Lista	PAY	181.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-07	Lista	RES	181.000	53.000	0.293	9.198	0.174	0.971	0.163
29/03A-07	Maureen	PAY	123.000	0.000	0.000	0.000	0.000	0.000	0.000
29/03A-07	Maureen	RES	123.000	92.000	0.748	19.553	0.213	0.971	0.111

Table 3.27.6 - Petrophysical parameters used at Well 29/03A-07

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

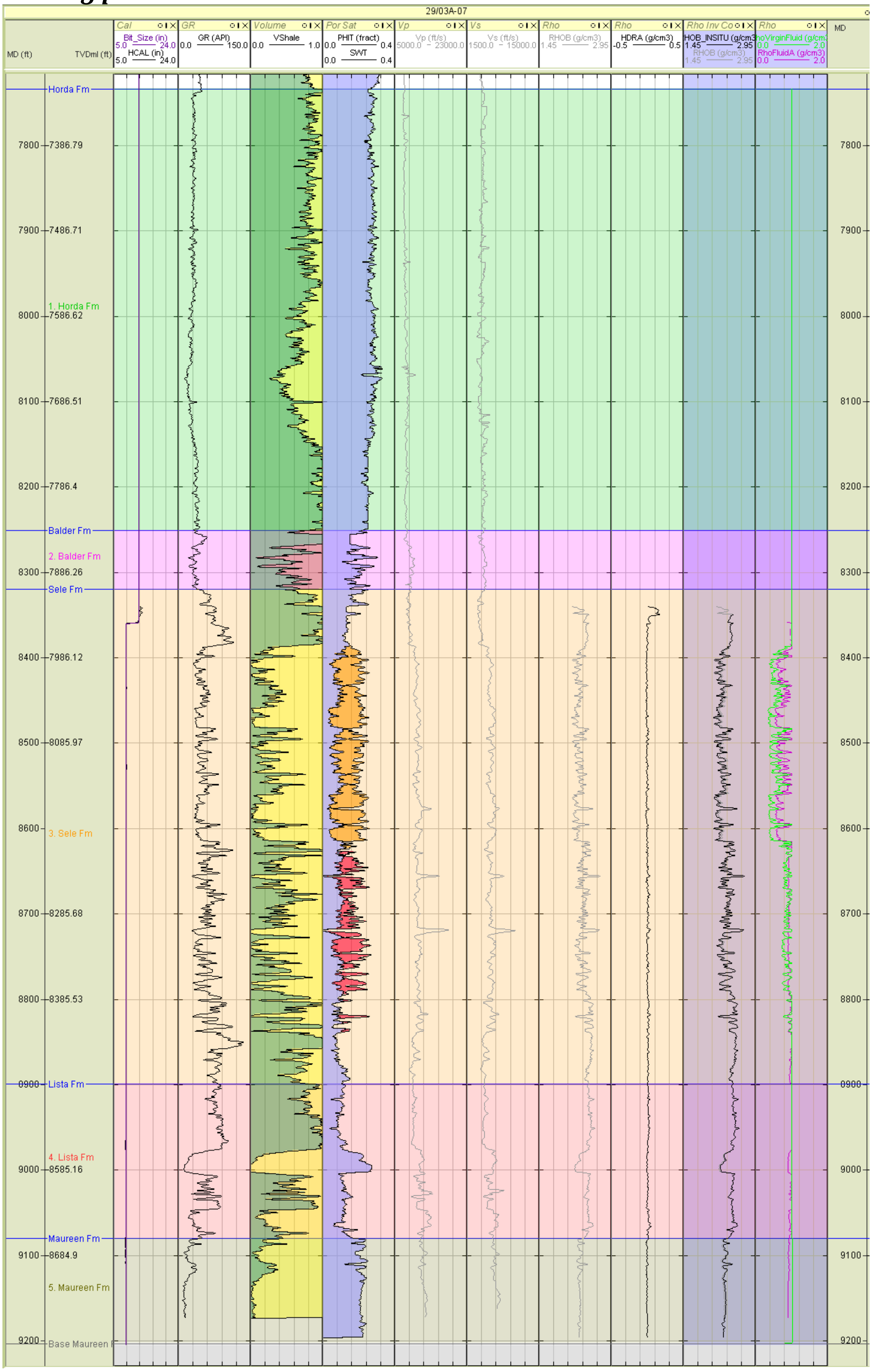


Figure 3.27.3 - Well Panel: Measured data and invasion correction for well 29/03A-07.

Well log panel – log editing and audit

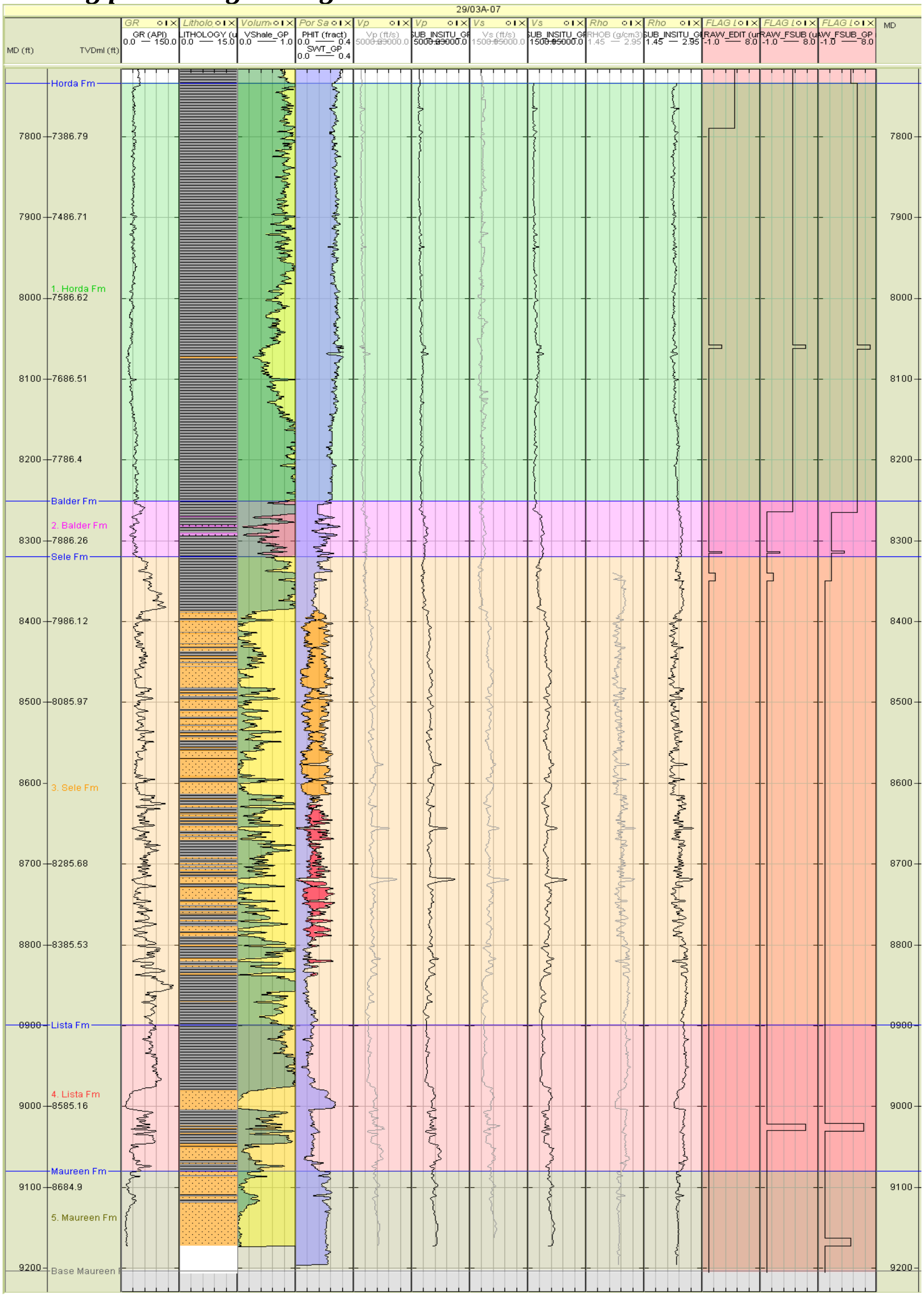


Figure 3.27.4 - Well Panel: Log edits for well 29/03A-07.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

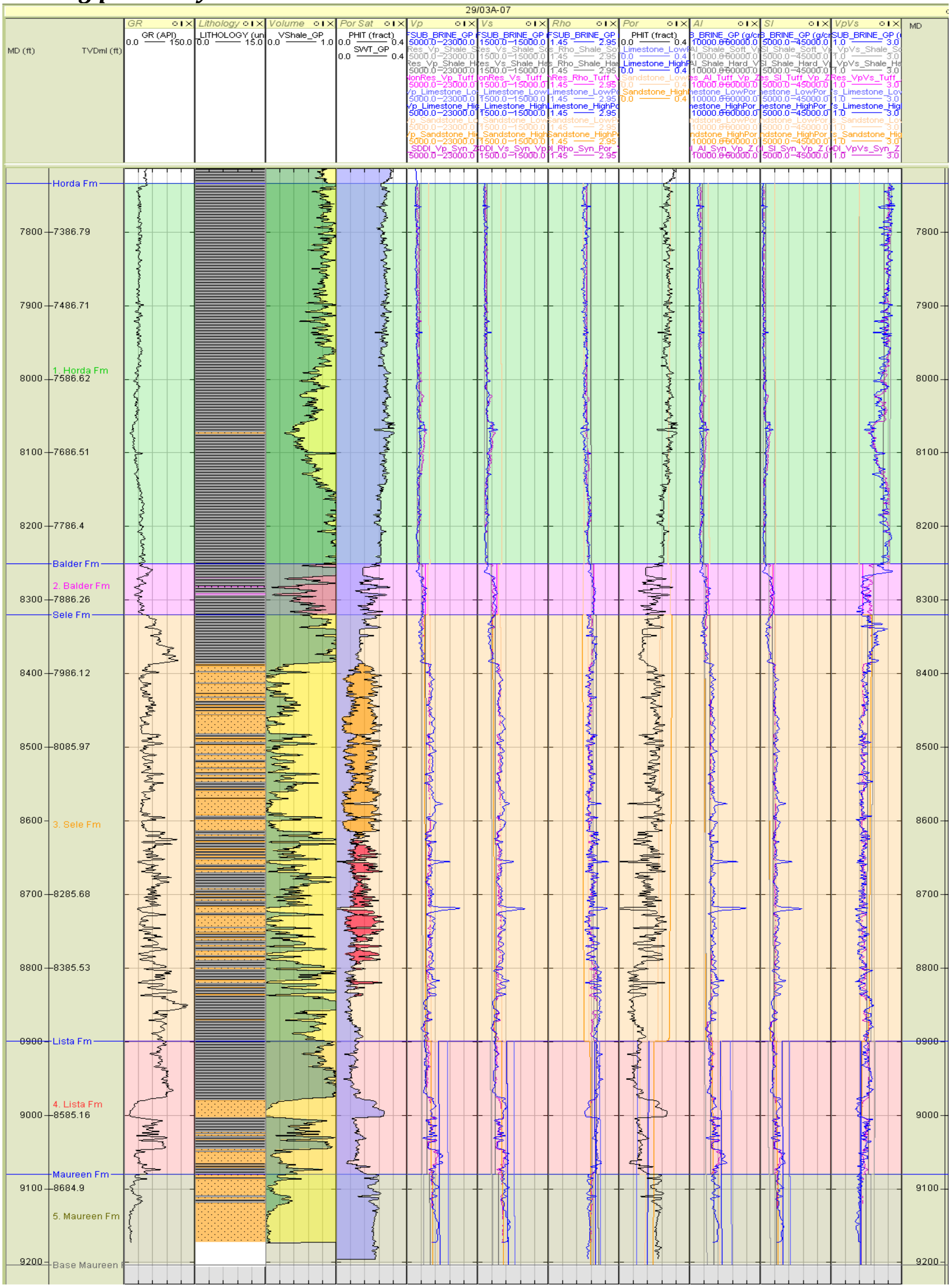


Figure 3.27.5 - Well Panel: End-member and synthetic logs for well 29/03A-07.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

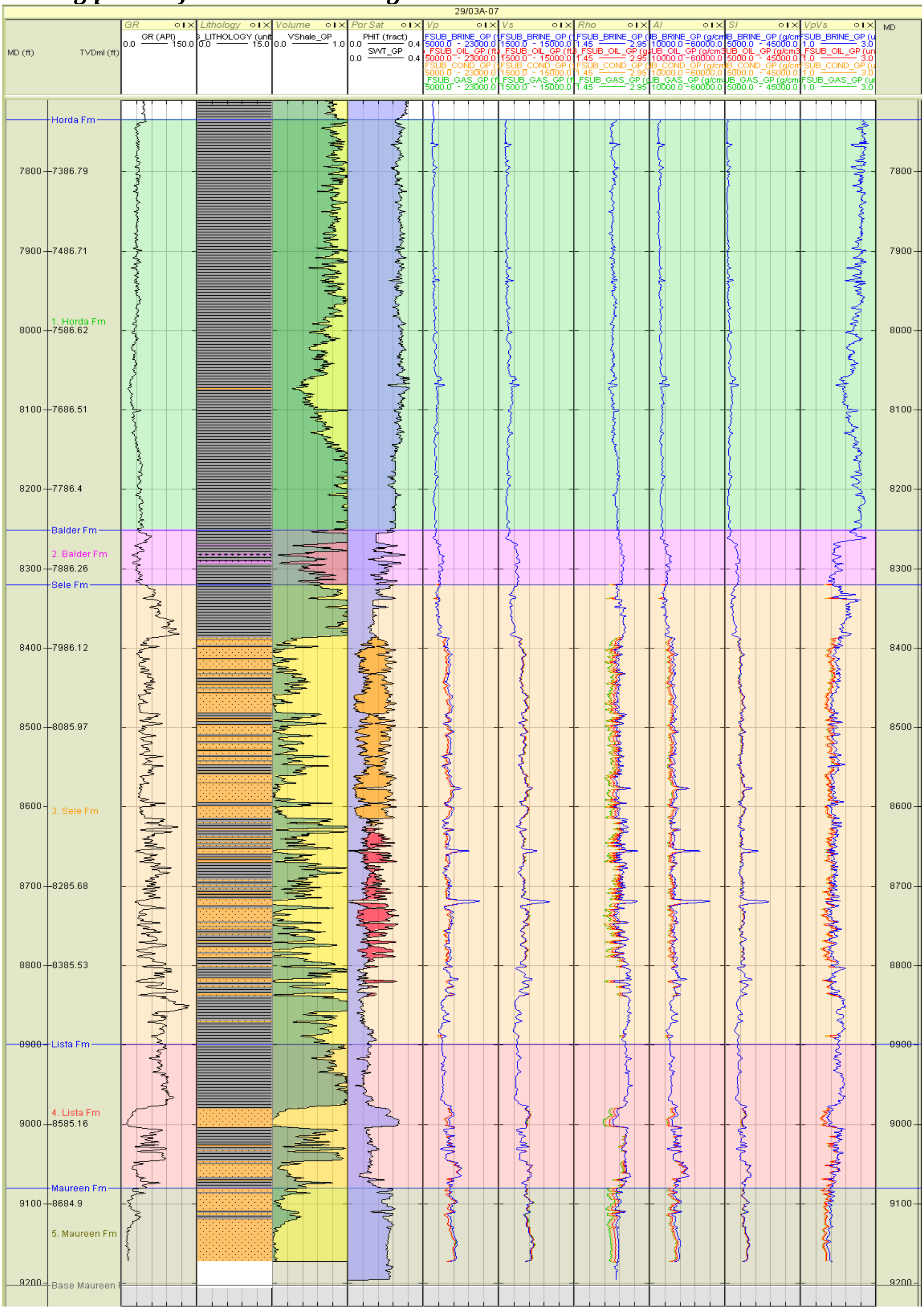


Figure 3.27.6 - Well Panel: Fluid substituted and elastic logs for well 29/03A-07.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/03A-07 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-07	Horda	7526	2946	2.25
29/03A-07	Balder	8243	3799	2.36
29/03A-07	Sele	9339	4545	2.46
29/03A-07	Lista	9771	4824	2.49
29/03A-07	Maureen			

Table 3.27.7 - Clean shale properties at Well 29/03A-07

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-07	Horda	100% Brine			
29/03A-07	Balder	100% Brine			
29/03A-07	Sele	100% Brine	11622	6161	2.32
29/03A-07	Lista	100% Brine	12380	6714	2.38
29/03A-07	Maureen	100% Brine	12149	6878	2.31
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-07	Horda	80% Oil			
29/03A-07	Balder	80% Oil			
29/03A-07	Sele	80% Oil	11064	6236	2.27
29/03A-07	Lista	80% Oil	11955	6780	2.34
29/03A-07	Maureen	80% Oil	11612	6973	2.25
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-07	Horda	90% Gas			
29/03A-07	Balder	90% Gas			
29/03A-07	Sele	90% Gas	11042	6363	2.18
29/03A-07	Lista	90% Gas	11952	6888	2.27
29/03A-07	Maureen	90% Gas	11634	7122	2.16

Table 3.27.8 - Clean sand properties at Well 29/03A-07 for each fluid case

Tertiary reservoirs – Well panel

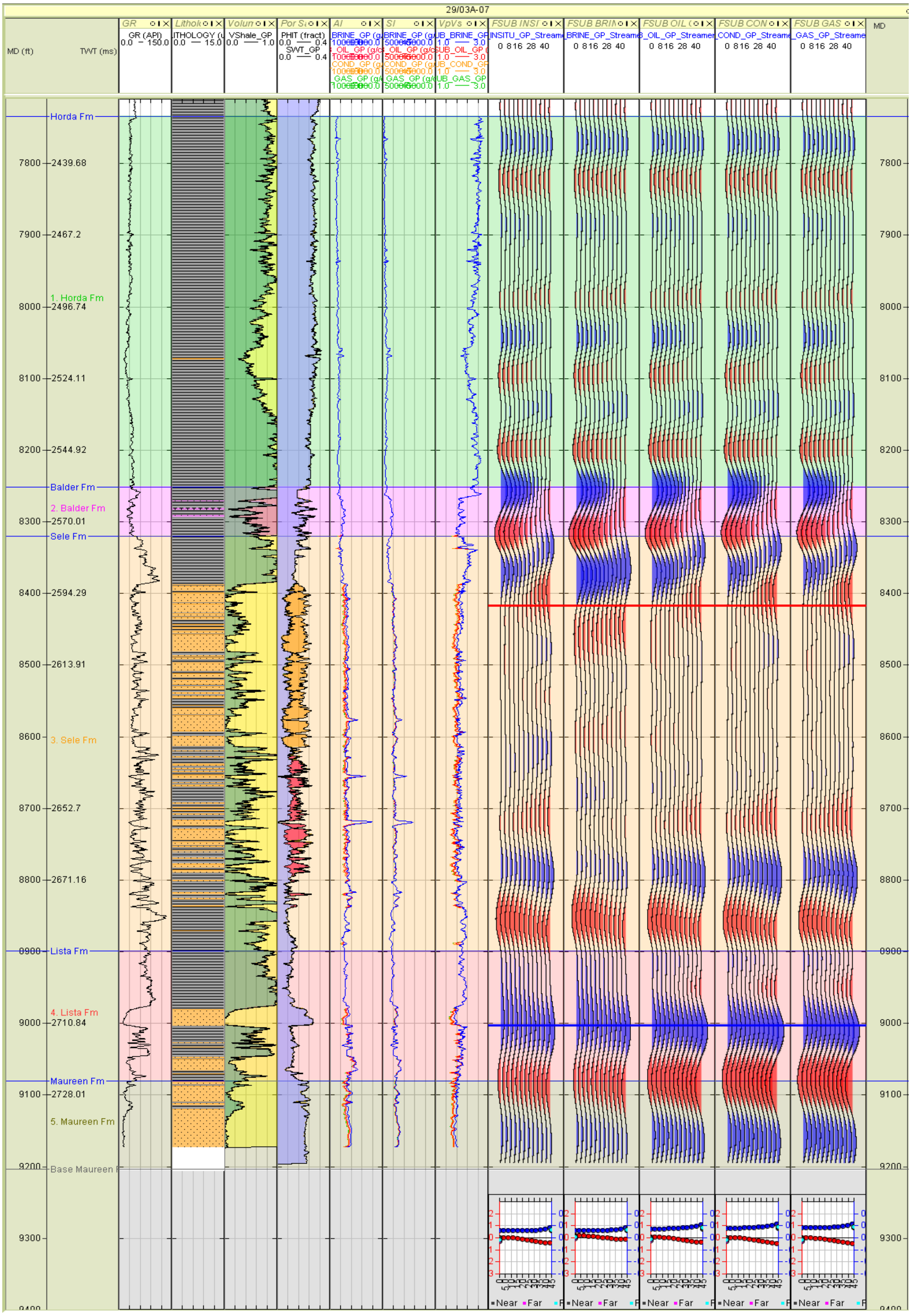


Figure 3.27.7 - Well Panel: Tertiary reservoirs for well 29/03A-07. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a thick sand interspersed with thin shale layers, located in the middle of the interval and net reservoir is approximately 340 feet. The reservoir sand is overlain directly by overburden shale and tuffaceous shale in the Balder Fm.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil fluid cases and a modelled class IIp response for the 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. A change in AVO is also seen on the synthetic gathers with the hydrocarbon cases causing a decrease in amplitude of the synthetic reflectivity and a class IIp AVO response is seen for all fluid cases.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for some attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

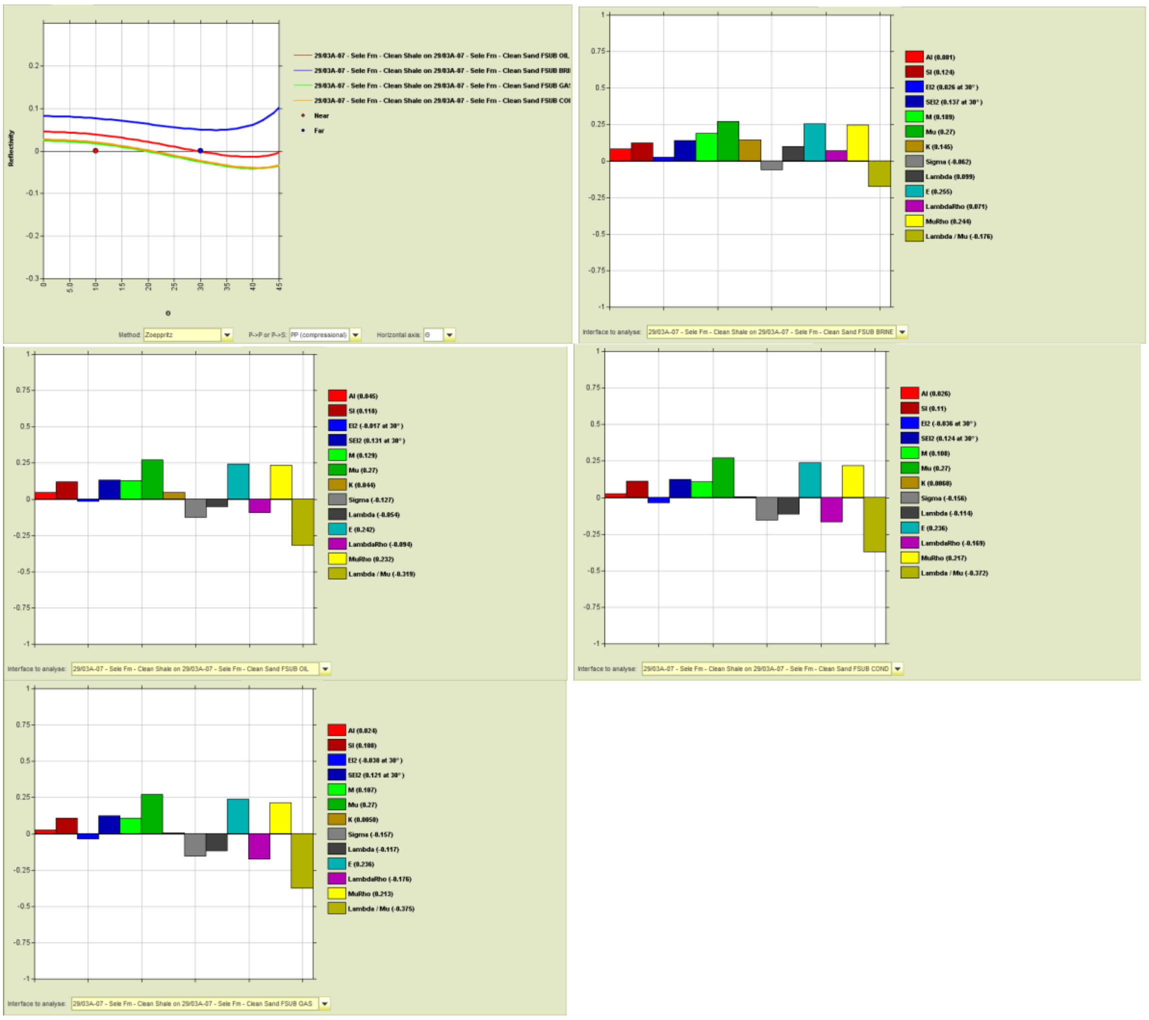


Figure 3.27.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 29/03A-07.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/02A-06 is provided below;

There is no Cretaceous section at this well.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 29/03A-07 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/03A-07	Overburden	Shale	7417		
29/03A-07	Underburden				

Table 3.27.9 - Overburden and underburden properties at Well 29/03A-07.

Well: 29/07-01

General

Well Information
This well is a Shell operated exploration well which was spudded, drilled and then abandoned in 1977. The well did not encounter any hydrocarbons within the study interval, and it is part of the Curlew A complex.

Objectives
The well objectives were the Triassic, Upper Jurassic and Palaeocene sands. The Triassic was absent and the Upper Jurassic section was found to be water wet.

Log conditioning overview
Only minor log conditioning was required due to good log data quality within this well. Calliper logs showed washout within the Horda and Balder Formations, as is fairly common due to their unconsolidated nature. A low value spike in the Vp log was seen at 8,998ft MD in the Tor Fm and this corresponded to a casing change so the spike was removed from the Vp log.

Invasion correction
Invasion correction was not performed on the density log at this well. The reservoir fluids in this well are brine and drilling mud used within this well was a brine-based so negligible invasion will occur at this well.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Tor Formation for Vp and within the Horda and Tor Formations for density. A complete Vs log is modelled since a measured Vs log is not available at this well.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 29/07-01 is displayed in the figures below;

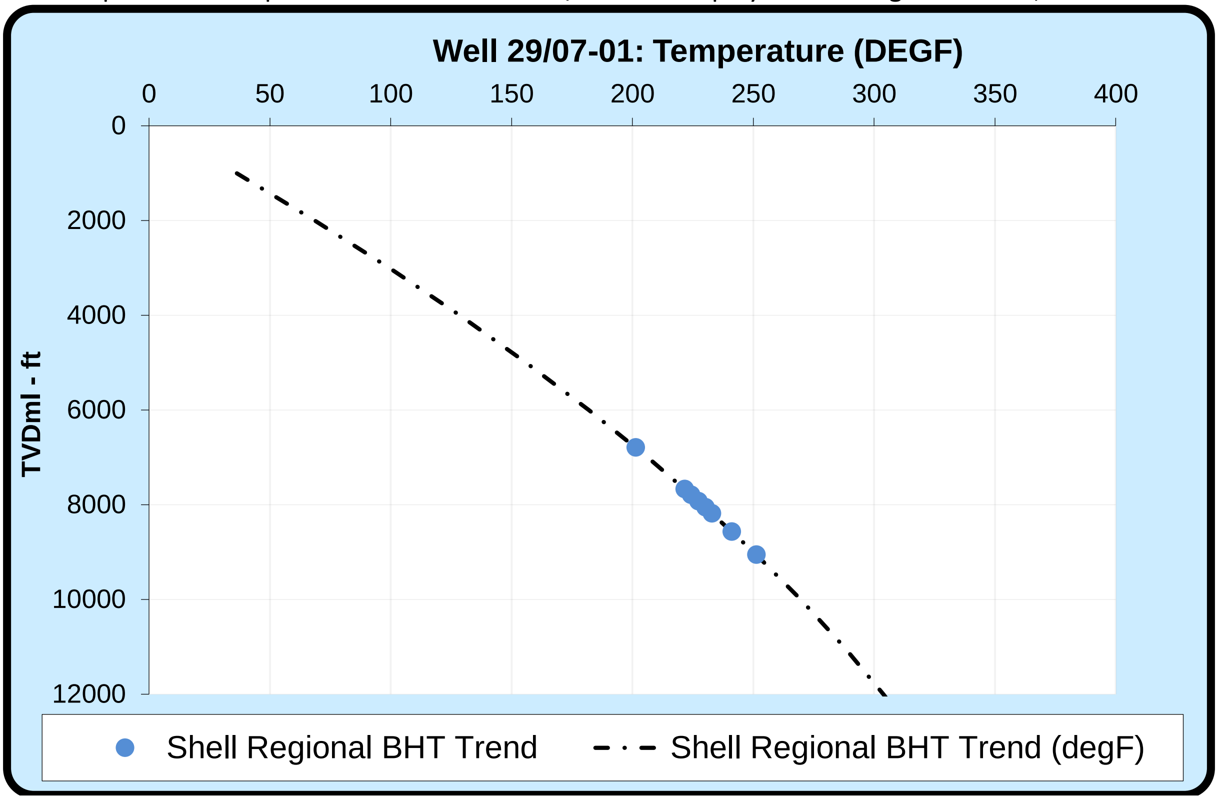


Figure 3.28.1 - Temperature data at Well 29/07-01

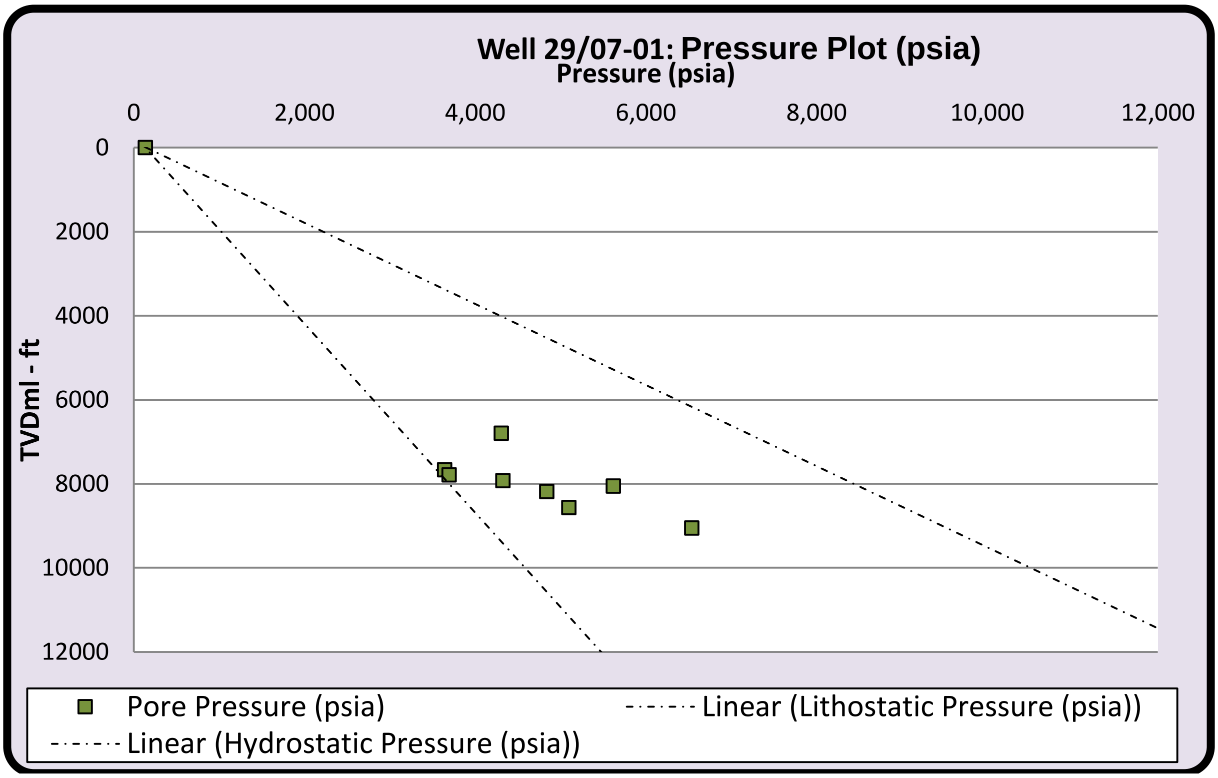


Figure 3.28.2 - Pressure data at Well 29/07-01

The temperature and pressure data for the formation mid-points in Well 29/07-01 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Corrected BHT values (deg F)	Hydrostatic Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
29/07-01	Sea Bed	390.0	305.0	0.0	39.2	135.7	135.7	135.73	0.00
29/07-01	Horda	7183.0	7098.0	6793.0	201.5	3158.6	4308.6	6793.00	2484.39
29/07-01	Balder	8058.0	7973.0	7668.0	221.7	3548.0	3643.0	7668.00	4025.02
29/07-01	Sele	8177.0	8092.0	7787.0	224.4	3600.9	3695.9	7787.00	4091.06
29/07-01	Lista	8315.0	8230.0	7925.0	227.4	3662.4	4327.4	7925.00	3597.65
29/07-01	Maureen	8444.0	8359.0	8054.0	230.2	3719.8	5619.8	8054.00	2434.25
29/07-01	Ekofisk	8569.0	8484.0	8179.0	233.0	3775.4	4838.4	8179.00	3340.62
29/07-01	Tor	8956.0	8871.0	8566.0	241.2	3947.6	5097.6	8566.00	3468.41
29/07-01	Hod	9445.0	9360.0	9055.0	251.3	4165.2	6539.7	9055.00	2515.31

Table 3.28.1 - Summary of mid-point temperature and pressure data at Well 29/07-01

Fluid data

A summary of the fluid set parameters at Well 29/07-01 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	**Formation**	**Salinity (ppm)**	**GOR (scf/stb)**	**Oil API (API)**	**Gas Gravity (air=1)**	**Gas Gravity (air=1)**
29/07-01	Horda	70000	730	38.7	0.78	0.78
29/07-01	Balder	120000	730	39.6	0.78	0.78
29/07-01	Sele	120000	900	36.0	0.7	0.7
29/07-01	Lista	120000	730	39.9	0.78	0.78
29/07-01	Maureen	120000	730	40.1	0.78	0.78
29/07-01	Ekofisk	120000	730	40.2	0.78	0.78
29/07-01	Tor	120000	730	40.6	0.78	0.78
29/07-01	Hod	120000	730	41.1	0.78	0.78

Table 3.28.2 - Summary of fluid parameter data at Well 29/07-01

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.28.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	12.68	5.02	2.38	9,357	4,672

Table 3.28.4 - Tuff properties used at Well 29/07-01

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
29/07-01	Horda	PAY	1634.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-01	Horda	RES	1634.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-01	Balder	PAY	116.000	2.500	0.022	0.678	0.271	0.461	0.033
29/07-01	Balder	RES	116.000	7.500	0.065	1.873	0.250	0.546	0.156
29/07-01	Sele	PAY	122.000	10.000	0.082	2.740	0.274	0.370	0.050
29/07-01	Sele	RES	122.000	31.000	0.254	6.619	0.214	0.601	0.268
29/07-01	Lista	PAY	154.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-01	Lista	RES	154.000	8.500	0.055	1.452	0.171	0.924	0.023
29/07-01	Maureen	PAY	104.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-01	Maureen	RES	104.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-01	Ekofisk	PAY	146.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-01	Ekofisk	RES	146.000	143.500	0.983	17.186	0.120	0.898	0.134
29/07-01	Tor	PAY	628.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-01	Tor	RES	628.000	609.500	0.971	43.449	0.071	0.949	0.050
29/07-01	Hod	PAY	350.000	6.000	0.014	0.658	0.110	0.476	0.123
29/07-01	Hod	RES	350.000	337.000	0.963	28.655	0.085	0.884	0.195

Table 3.28.5 - Petrophysical parameters used at Well 29/07-01

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

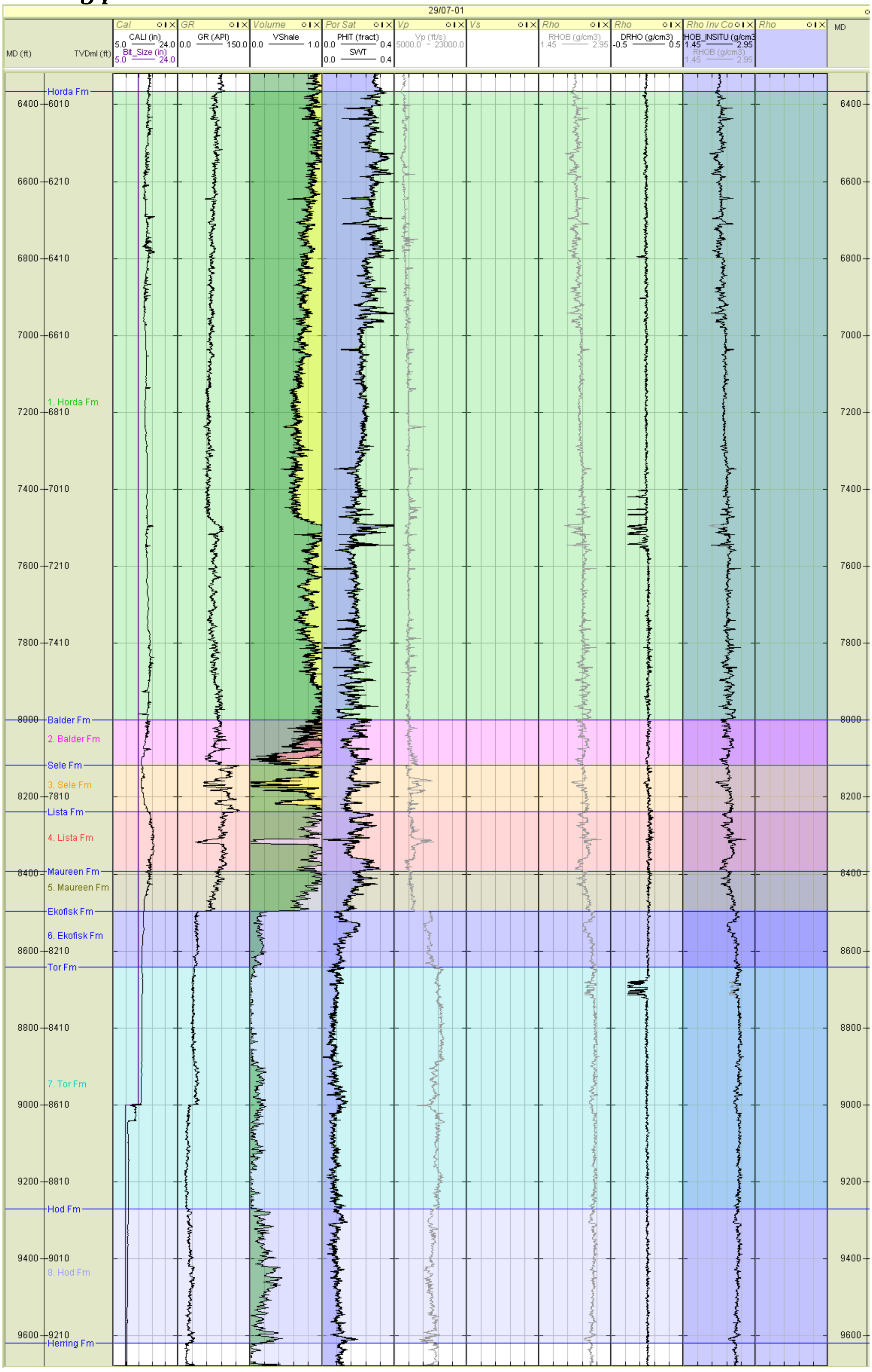


Figure 3.28.3 - Well Panel: Measured data and invasion correction for well 29/07-01.

Well log panel – log editing and audit

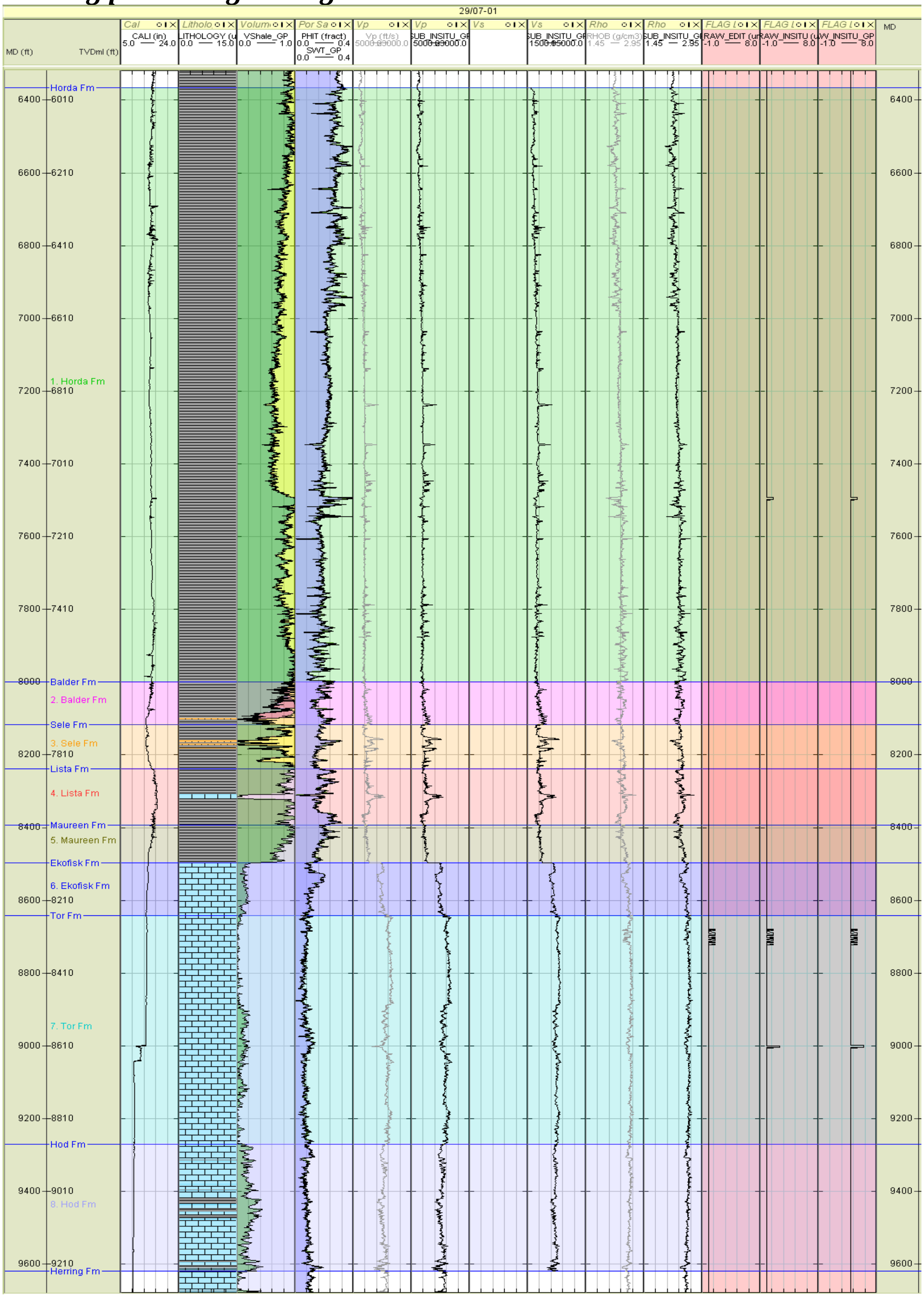


Figure 3.28.4 - Well Panel: Log edits for well 29/07-01.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

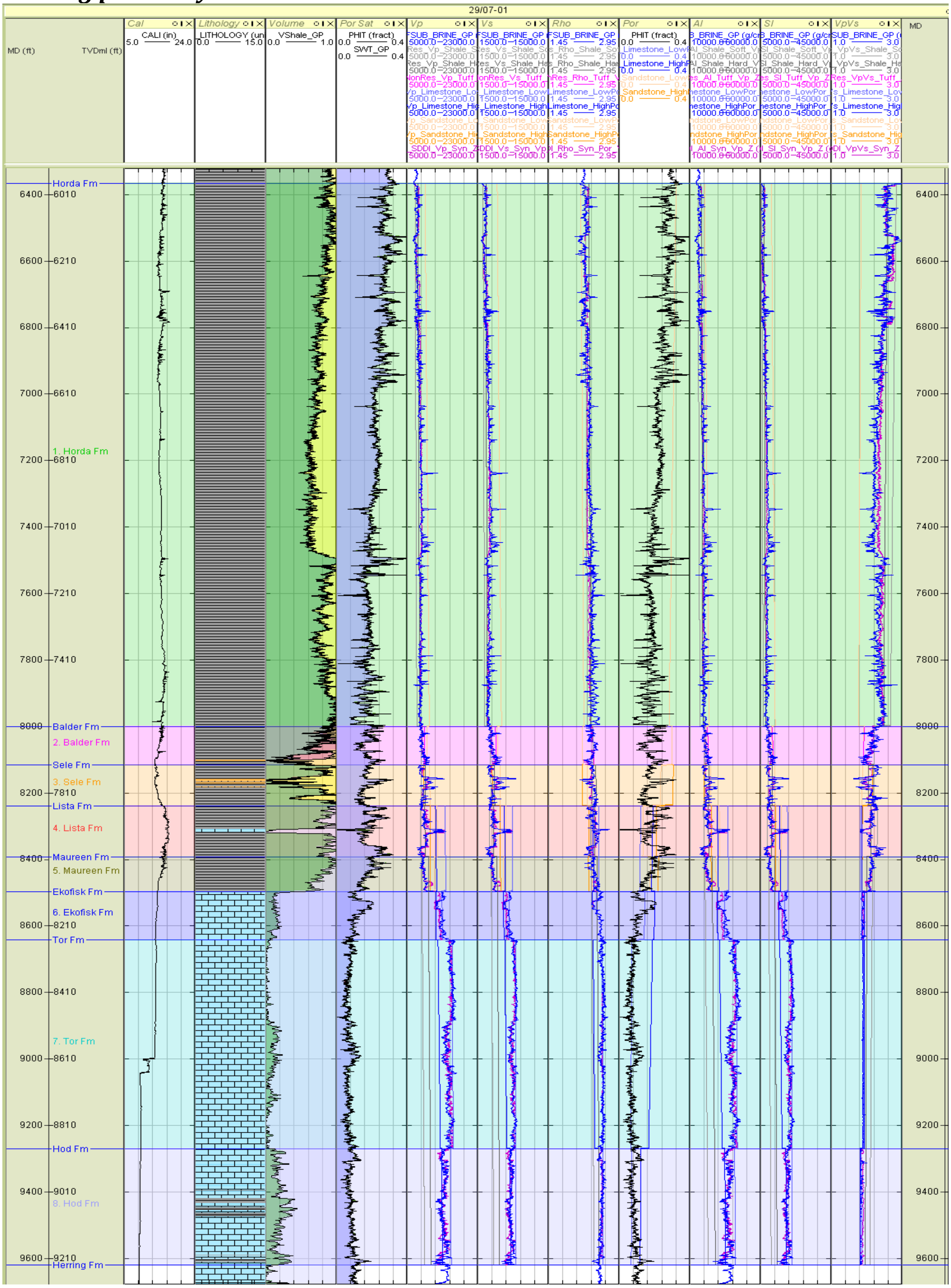


Figure 3.28.5 - Well Panel: End-member and synthetic logs for well 29/07-01.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

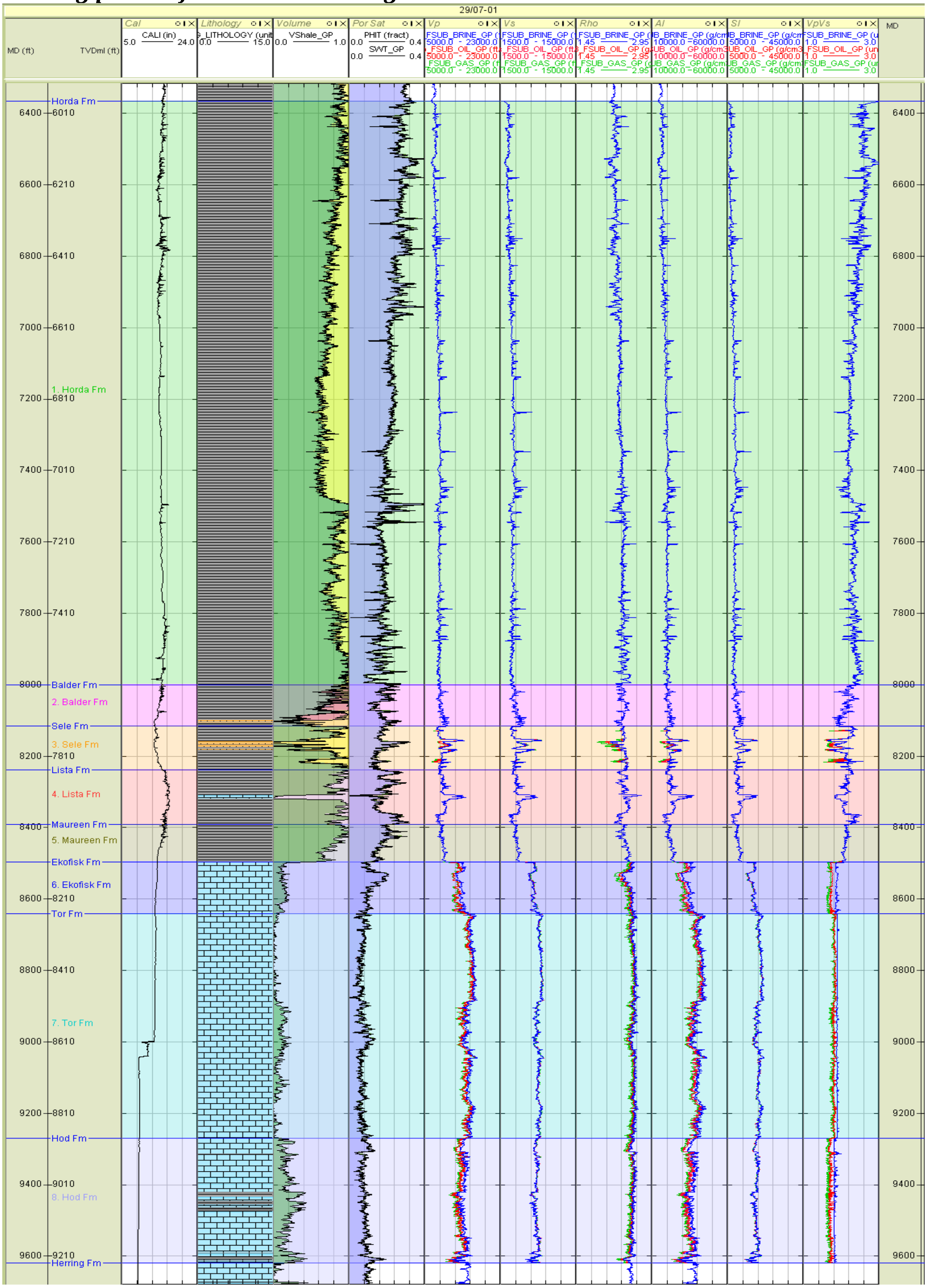


Figure 3.28.6 - Well Panel: Fluid substituted and elastic logs for well 29/07-01.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/07-01 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/07-01	Horda	8004	3305	2.30
29/07-01	Balder	8560	3876	2.36
29/07-01	Sele	8753	4033	2.41
29/07-01	Lista	9210	4279	2.39
29/07-01	Maureen	9101	4287	2.40

Table 3.28.6 - Clean shale properties at Well 29/07-01

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/07-01	Horda	100% Brine			
29/07-01	Balder	100% Brine			
29/07-01	Sele	100% Brine	10474	5458	2.24
29/07-01	Lista	100% Brine			
29/07-01	Maureen	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/07-01	Horda	80% Oil			
29/07-01	Balder	80% Oil			
29/07-01	Sele	80% Oil	9565	5556	2.16
29/07-01	Lista	80% Oil			
29/07-01	Maureen	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/07-01	Horda	90% Gas			
29/07-01	Balder	90% Gas			
29/07-01	Sele	90% Gas	9474	5718	2.03
29/07-01	Lista	90% Gas			
29/07-01	Maureen	90% Gas			

Table 3.28.7 - Clean sand properties at Well 29/07-01 for each fluid case

Tertiary reservoirs – Well panel

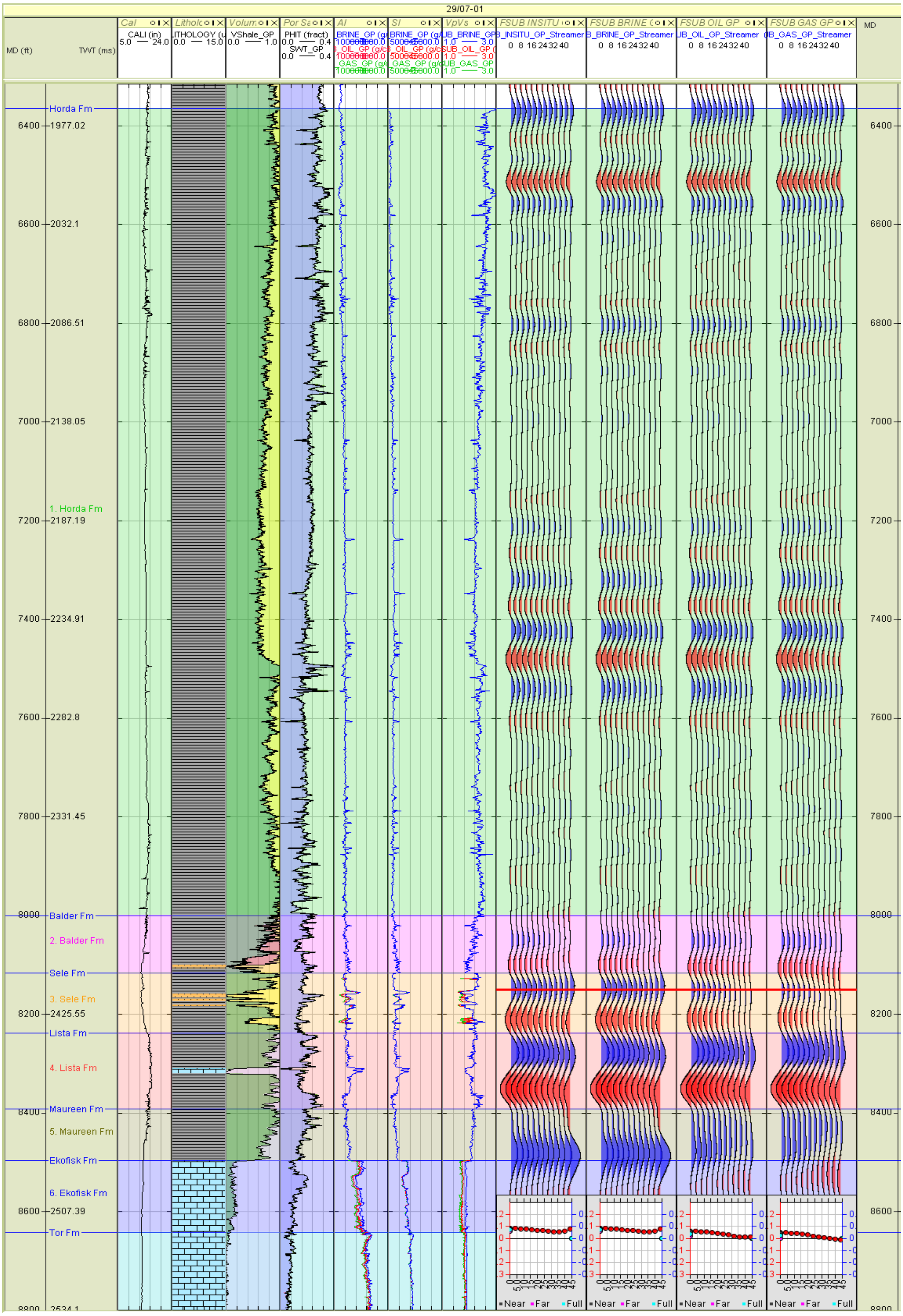


Figure 3.28.7 - Well Panel: Tertiary reservoirs for well 29/07-01. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a set of thin sand packages which thicken and increase porosity upwards to a depth of 8,160ft MD and net reservoir is approximately 31 feet. The reservoir sand is overlain directly by overburden shale and tuffaceous shale in the Balder Fm.
- Blocky AVO shows a modelled class I response for the 100% brine case, a modelled class II response for the 80% oil case and a modelled class III response for the 90% gas case, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is less pronounced on the synthetic gathers where the introduction of hydrocarbons results in class I responses and this is likely to be due to interference effects affecting the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for some attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

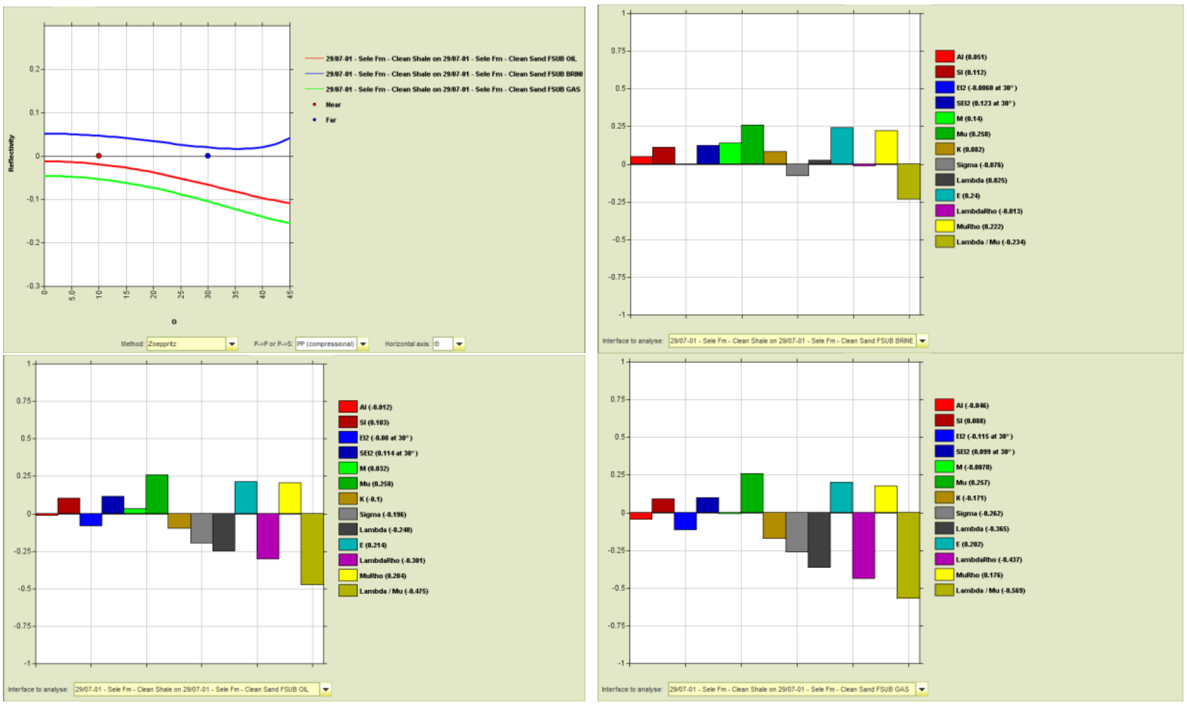


Figure 3.28.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 29/07-01.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/07-01 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/07-01	Ekofisk	100% Brine	14142	7601	2.51
29/07-01	Tor	100% Brine	16003	8456	2.60
29/07-01	Hod	100% Brine	14897	8175	2.56
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/07-01	Ekofisk	80% Oil	13294	7656	2.47
29/07-01	Tor	80% Oil	15461	8488	2.58
29/07-01	Hod	80% Oil	14126	8213	2.53
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/07-01	Ekofisk	90% Gas	13073	7737	2.42
29/07-01	Tor	90% Gas	15323	8534	2.55
29/07-01	Hod	90% Gas	13881	8271	2.50

Table 3.28.8 - Clean limestone properties at Well 29/07-01 for each fluid case

Cretaceous reservoirs

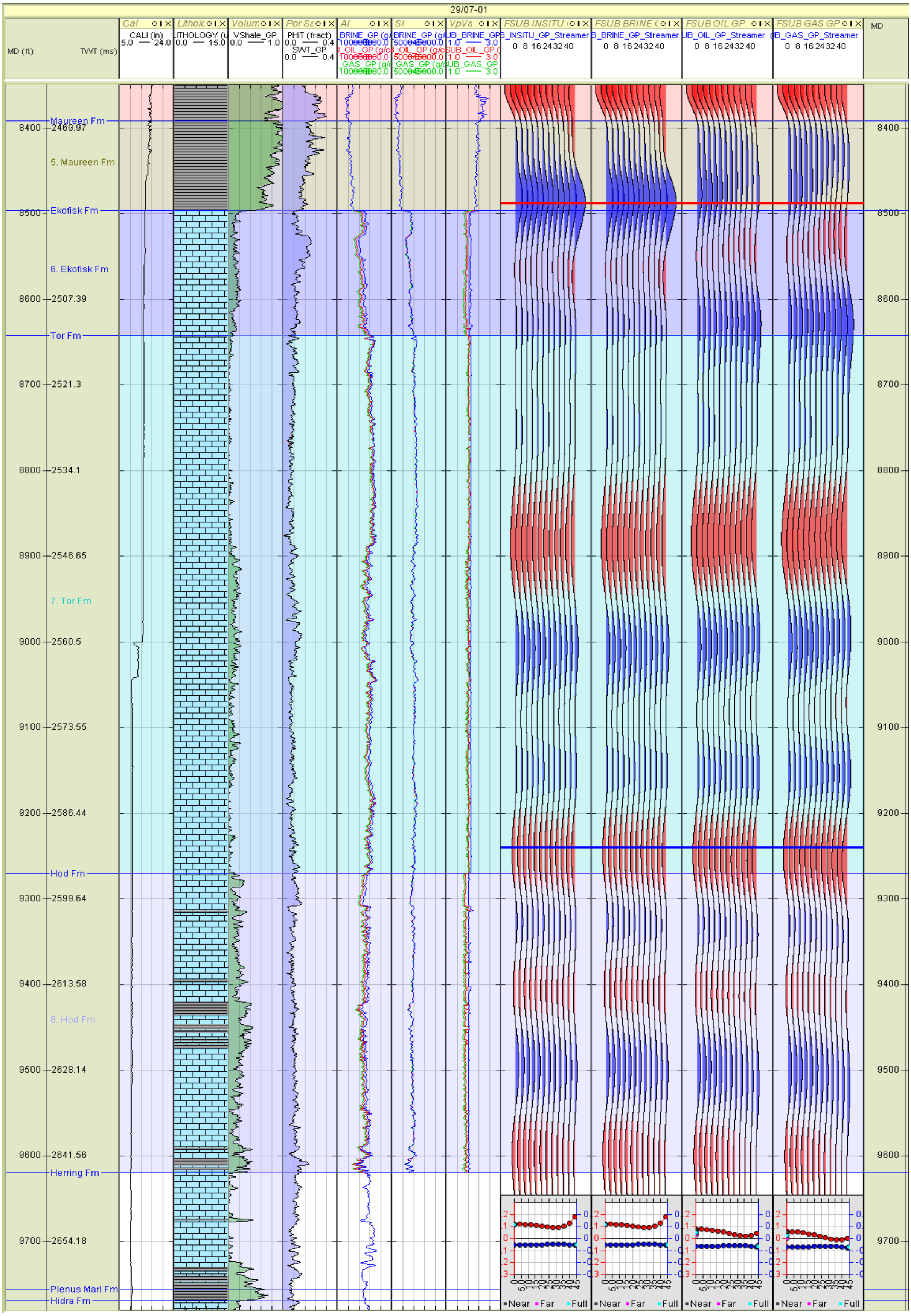


Figure 3.28.9 - Well Panel: Cretaceous reservoirs for well 29/07-01. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the upper section of the Ekofisk Fm and the porosity in this section is approximately 20%. The porosity decreases with depth towards the base of the Ekofisk Fm.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and strong amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

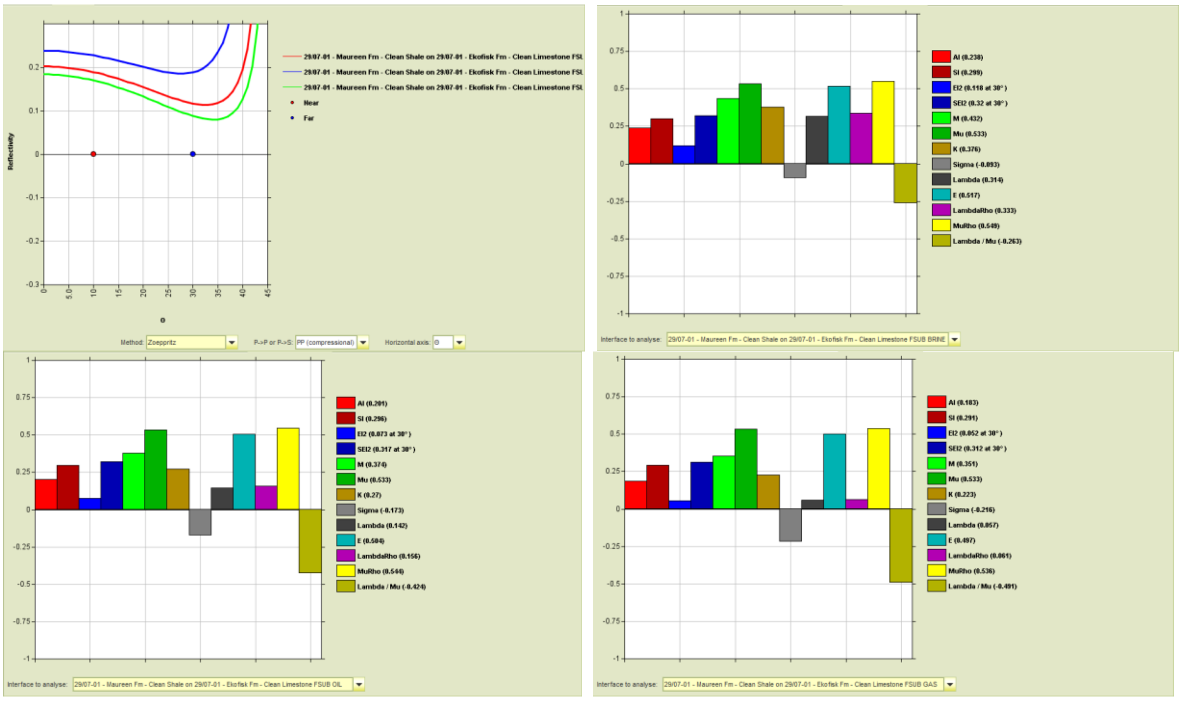


Figure 3.28.10 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 29/07-01.

Tor Formation

- Reservoir formed by a clean limestone formation. The reservoir has a relatively constant porosity of approximately 7%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are positive in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

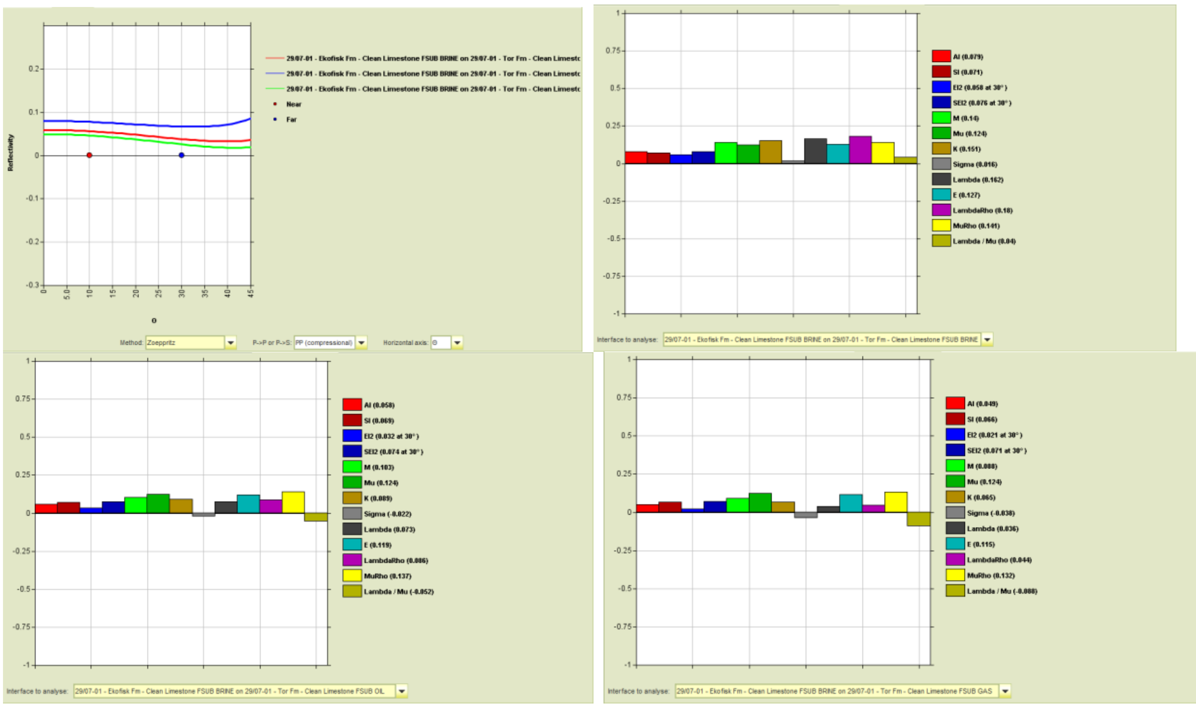


Figure 3.28.11 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 29/07-01.

Hod Formation

- Reservoir formed by a limestone formation with a minor component of shale. The reservoir has a relatively constant porosity of approximately 8%.
- Blocky AVO shows a modelled class III response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are negative amplitude in the brine case, and that the contrasts become more negative for all attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

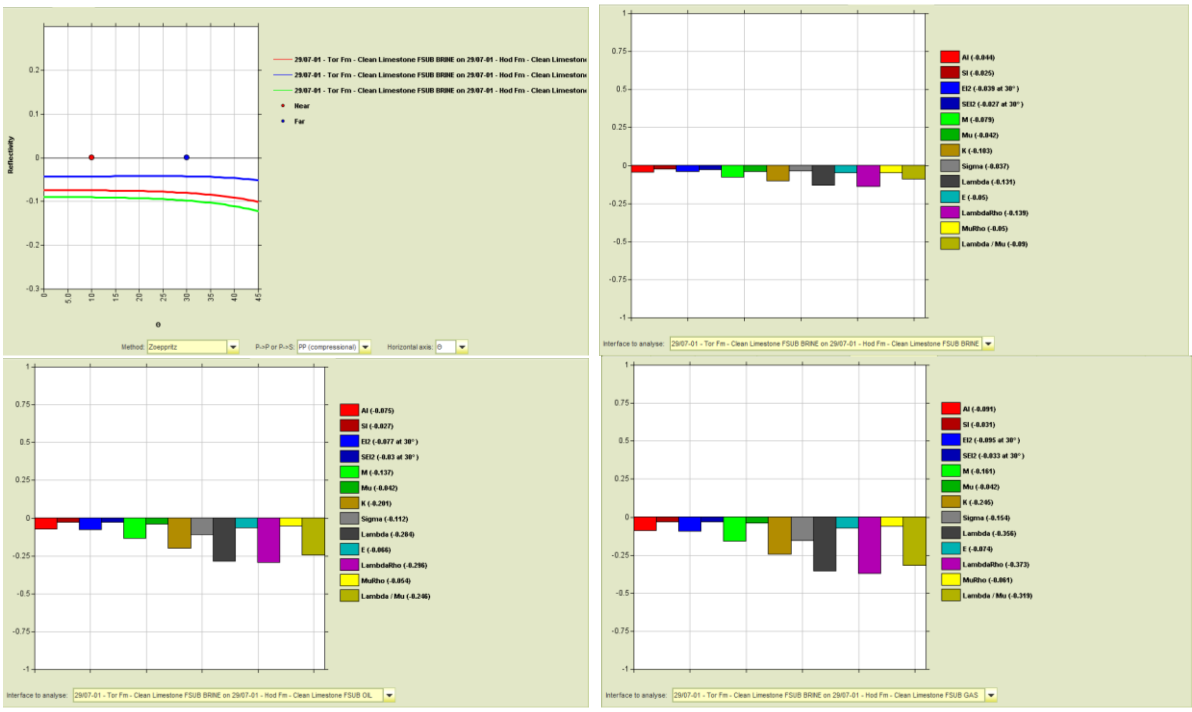


Figure 3.28.12 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 29/07-01.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 29/07-01 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/07-01	Overburden	Shale	7534		2.22
29/07-01	Underburden	Limestone	13918		2.57

Table 3.28.9 - Overburden and underburden properties at Well 29/07-01.

Well: 29/07-05

General

Well Information
This well is a Shell operated exploration well which was spudded, drilled and then abandoned in 1993. The well encountered oil within the Ekofisk and Tor Formations, and it is part of the Curlew C field.

Objectives
This well was drilled to test the hydrocarbon potential of the Upper Jurassic Fulmar Formation sandstones in a fault bounded dip closure at base Cretaceous and Upper Jurassic shale levels. The prospect is a salt induced structure between Curlew and Acorn. It is a dip closure bounded to the north-west by a major fault associated with salt withdrawal from the area to the north-west of the prospect. Despite the Chalk not being considered a target at the start of drilling the Tor Formation was oil-bearing and was subsequently formation tested. Both the Fulmar and Pentland Formations were water-bearing.

Log conditioning overview
Only minor log conditioning was required due to good log data quality within this well. Thin calcite stringers in the Horda Formation seen on the density log were not apparent on the Vp log, with data relating to these intervals was consequentially removed. Two high value spikes in the density log were seen at 8,725ft MD in the Tor Fm and 9,037ft MD in the Hod Fm and these spikes were removed from the density log.

Invasion correction

Invasion correction has been performed on the density log within the oil bearing Ekofisk and Tor Formations. The drilling mud used within this well was brine-based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda and Lista Formations for the Vp log, within the Horda, Balder, Sele, Lista and Maureen Formations for the Vs log and within the Horda, Lista, Tor and Hod Formations for the density log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 29/07-05 is displayed in the figures below;

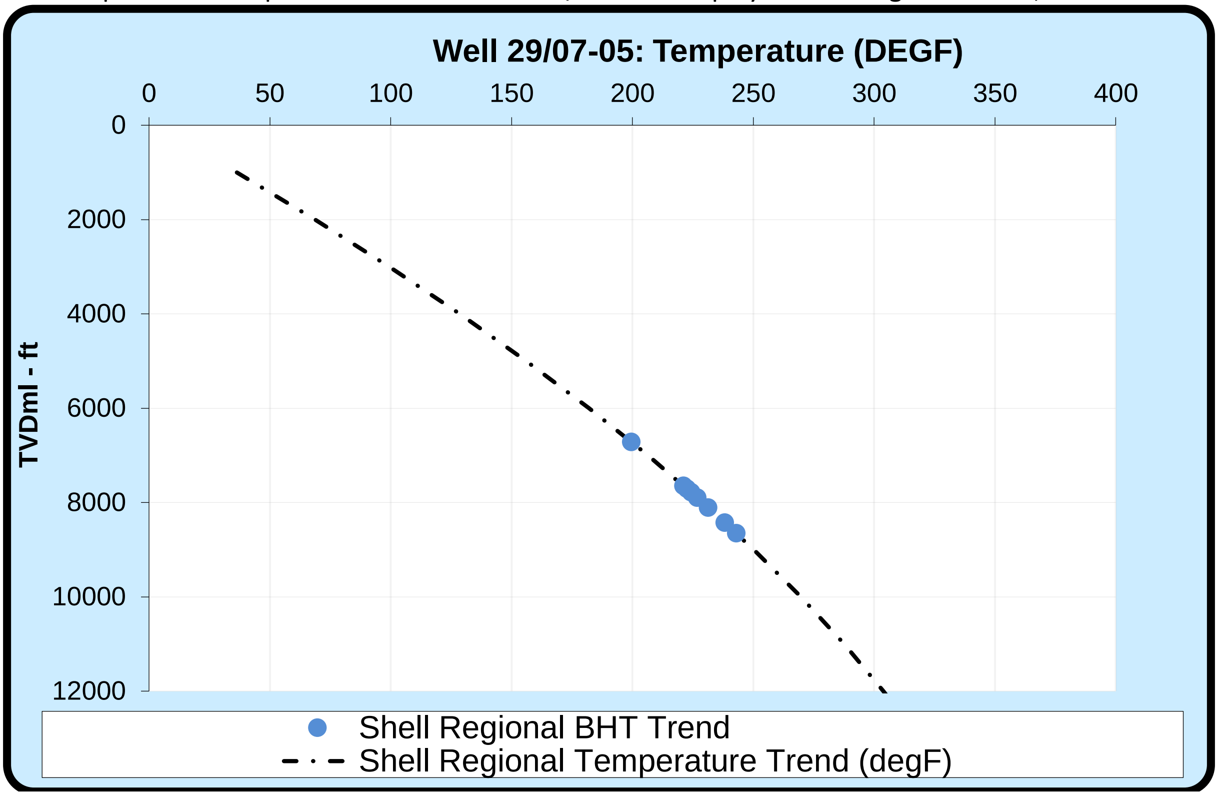


Figure 3.29.1 - Temperature data at Well 29/07-05

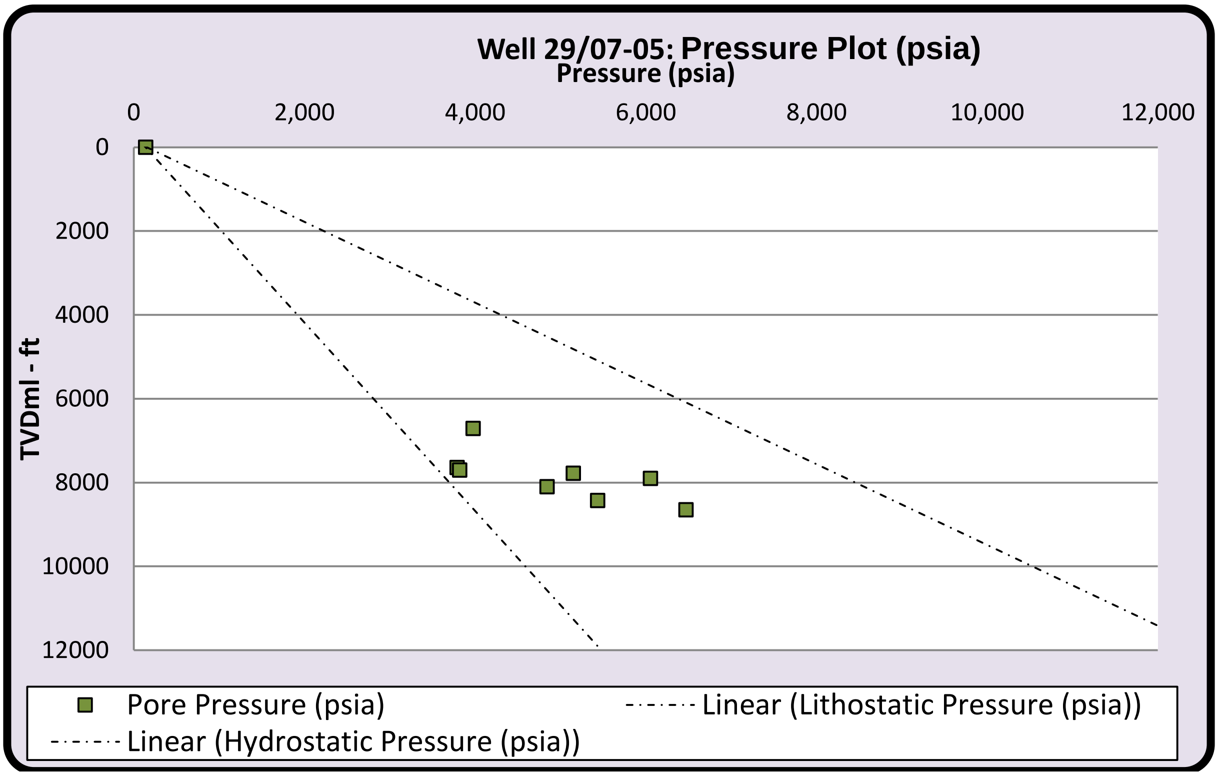


Figure 3.29.2 - Pressure data at Well 29/07-05

The temperature and pressure data for the formation mid-points in Well 29/07-05 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
29/07-05	Sea Bed	398.0	312.0	0.0	39.2	138.8	138.8	138.84	0.00
29/07-05	Horda	7111.0	7024.6	6712.6	199.5	3125.9	3975.9	6712.59	2736.65
29/07-05	Balder	8043.0	7956.4	7644.4	221.2	3540.6	3790.6	7644.36	3853.78
29/07-05	Sele	8105.5	8018.8	7706.8	222.6	3568.4	3818.4	7706.81	3888.44
29/07-05	Lista	8182.5	8095.8	7783.8	224.3	3602.6	5152.6	7783.77	2631.15
29/07-05	Maureen	8298.5	8211.7	7899.7	226.9	3654.2	6054.2	7899.70	1845.49
29/07-05	Ekofisk	8503.5	8416.6	8104.6	231.4	3745.4	4845.4	8104.61	3259.22
29/07-05	Tor	8827.0	8740.0	8428.0	238.3	3889.3	5437.3	8428.00	2990.70
29/07-05	Hod	9051.5	8964.4	8652.4	243.0	3989.2	6470.0	8652.43	2182.43

Table 3.29.1 - Summary of mid-point temperature and pressure data at Well 29/07-05

Fluid data

A summary of the fluid set parameters at Well 29/07-05 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
29/07-05	Horda	92000	730	38.6	0.78	0.78
29/07-05	Balder	92000	730	39.6	0.78	0.78
29/07-05	Sele	92000	730	39.7	0.78	0.78
29/07-05	Lista	92000	730	39.8	0.78	0.78
29/07-05	Maureen	92000	730	39.9	0.78	0.78
29/07-05	Ekofisk	92000	547	41.0	0.784	0.784
29/07-05	Tor	92000	945	39.0	0.936	0.936
29/07-05	Hod	92000	730	40.7	0.78	0.78

Table 3.29.2 - Summary of fluid parameter data at Well 29/07-05

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.29.3 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	12.50	4.83	2.39	9,237	4,664

Table 3.29.4 - Tuff properties used at Well 29/07-05

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
29/07-05	Horda	PAY	1790.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-05	Horda	RES	1790.000	6.000	0.003	1.308	0.218	0.928	0.374
29/07-05	Balder	PAY	74.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-05	Balder	RES	74.000	6.000	0.003	1.308	0.218	0.928	0.374
29/07-05	Sele	PAY	51.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-05	Sele	RES	51.000	2.000	0.039	0.348	0.174	1.000	0.453
29/07-05	Lista	PAY	103.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-05	Lista	RES	103.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-05	Maureen	PAY	129.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-05	Maureen	RES	129.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-05	Ekofisk	PAY	281.000	42.000	0.149	10.354	0.247	0.428	0.120
29/07-05	Ekofisk	RES	281.000	255.750	0.910	41.613	0.163	0.754	0.206
29/07-05	Tor	PAY	366.000	77.500	0.212	13.604	0.176	0.358	0.029
29/07-05	Tor	RES	366.000	365.250	0.998	47.651	0.130	0.731	0.042
29/07-05	Hod	PAY	83.000	0.000	0.000	0.000	0.000	0.000	0.000
29/07-05	Hod	RES	83.000	67.250	0.810	8.701	0.129	0.991	0.296

Table 3.29.5 - Petrophysical parameters used at Well 29/07-05

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

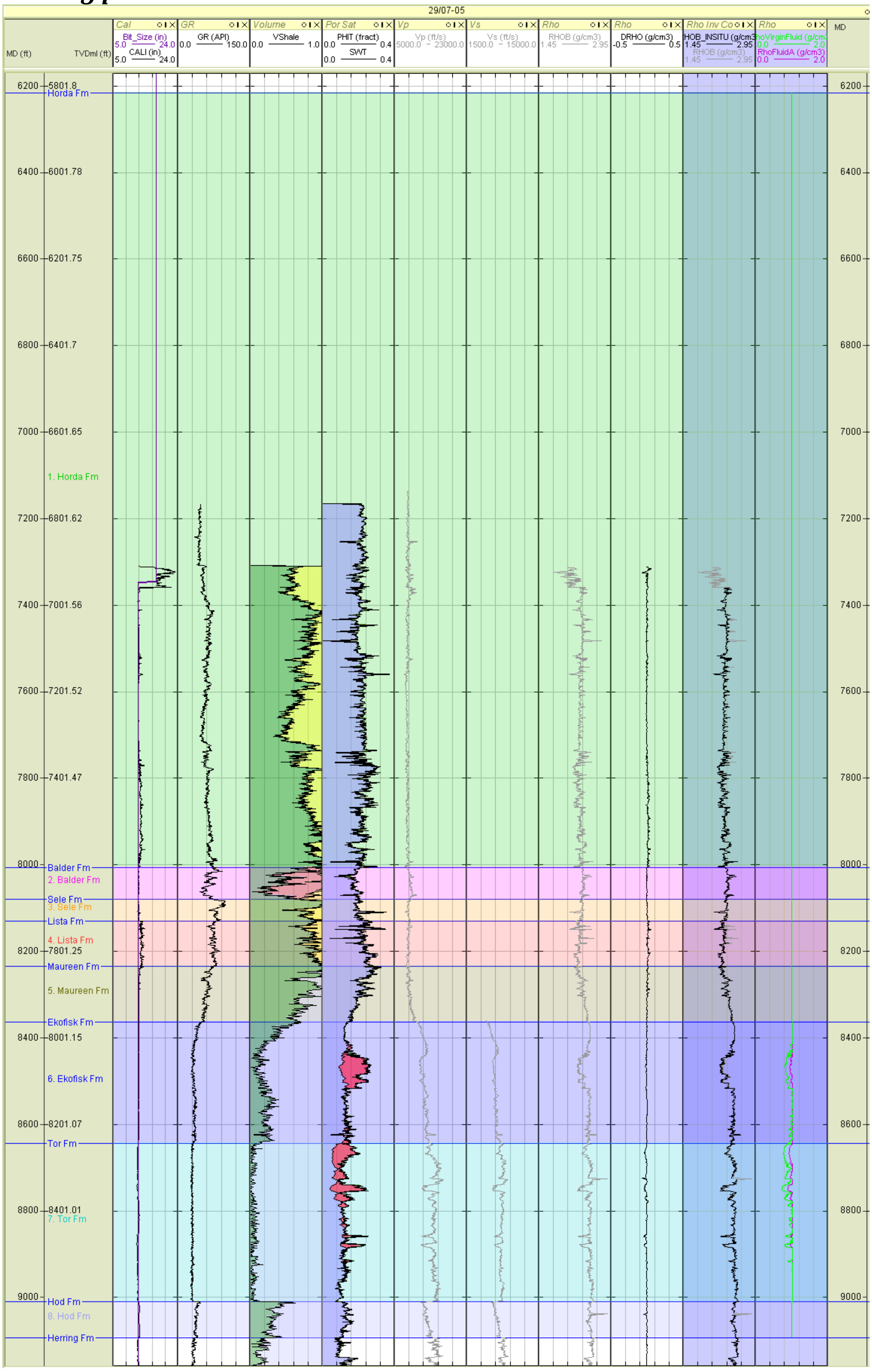


Figure 3.29.3 - Well Panel: Measured data and invasion correction for well 29/07-05.

Well log panel – log editing and audit

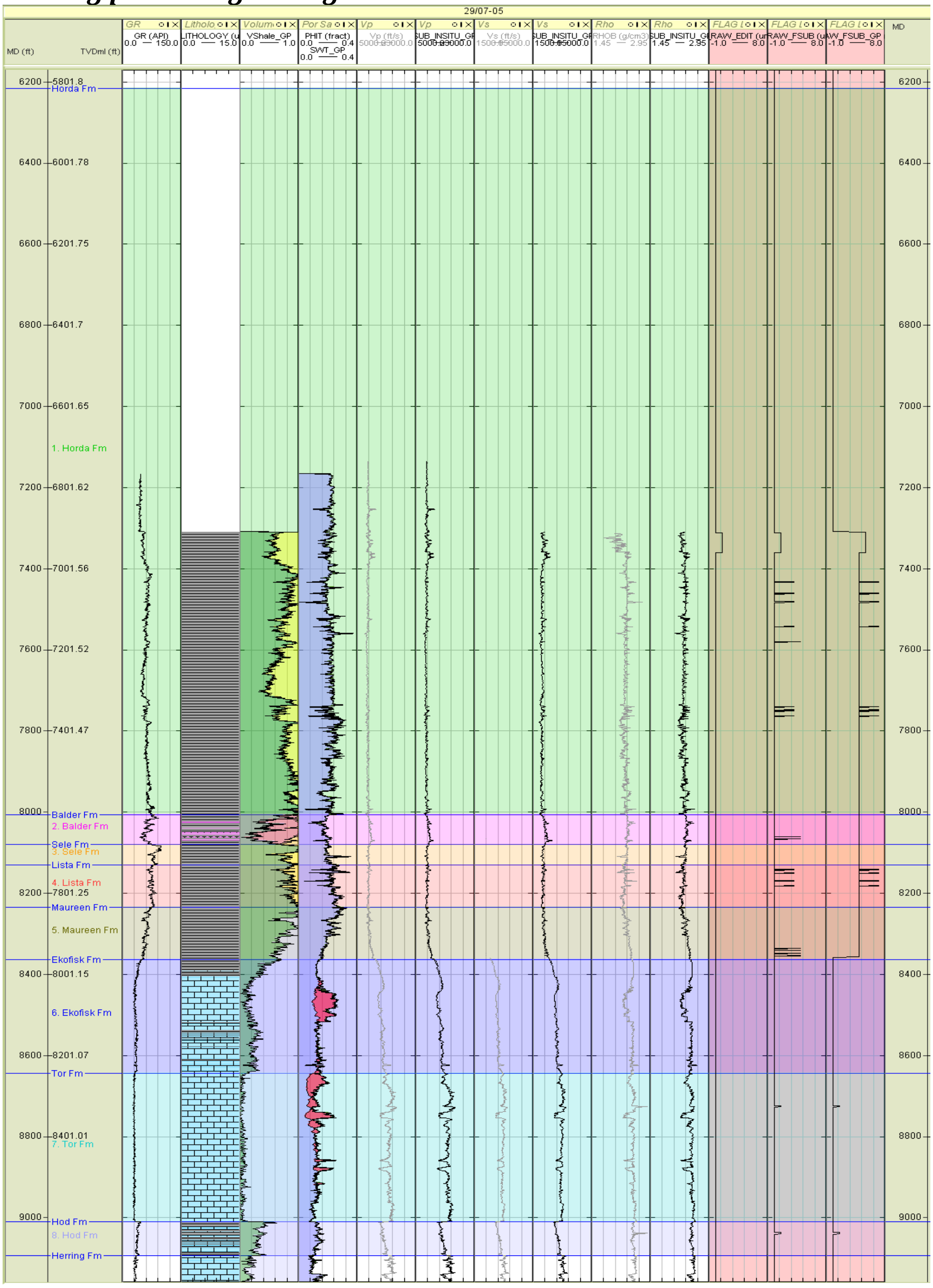


Figure 3.29.4 - Well Panel: Log edits for well 29/07-05.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

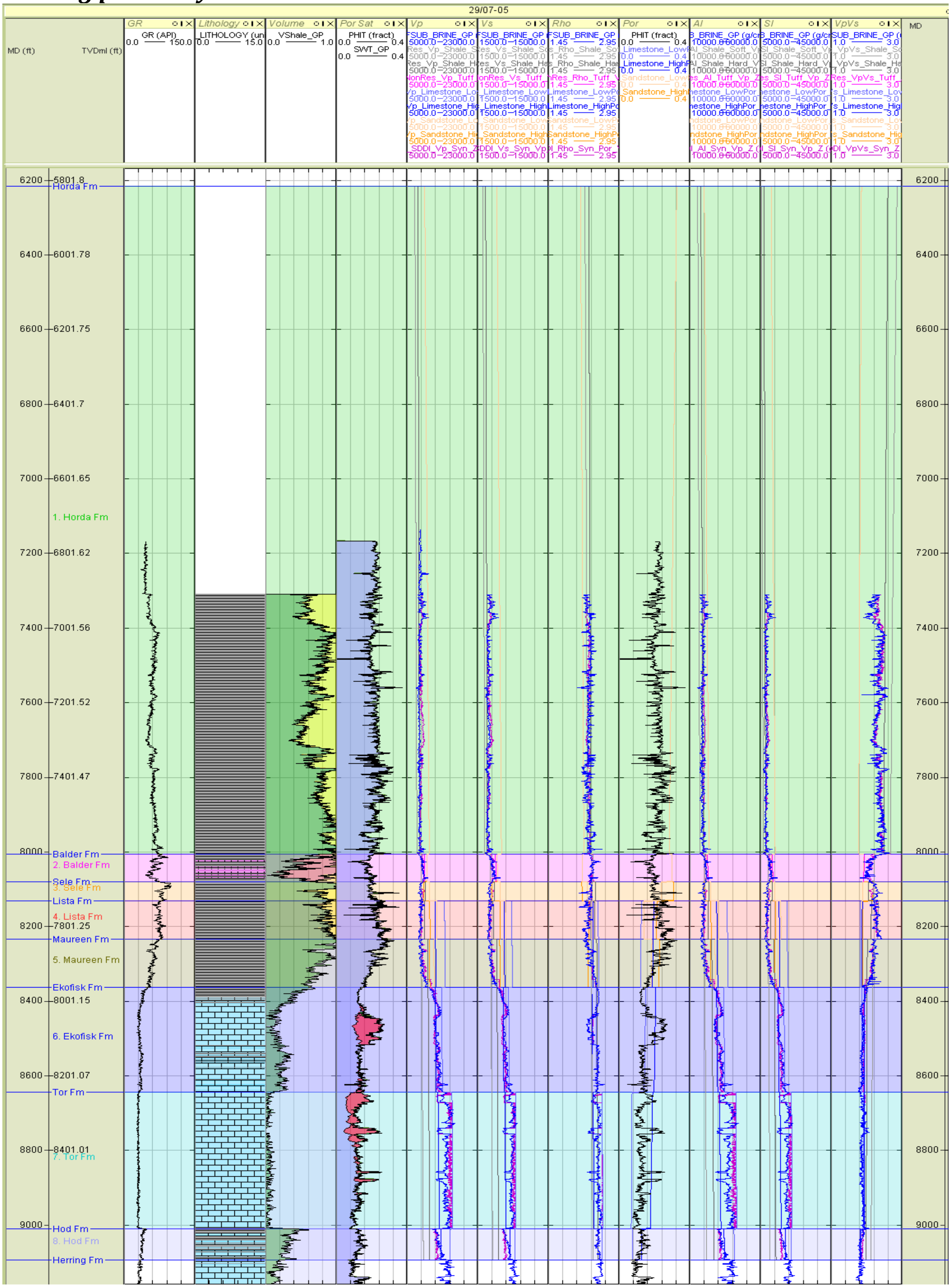


Figure 3.29.5 - Well Panel: End-member and synthetic logs for well 29/07-05.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

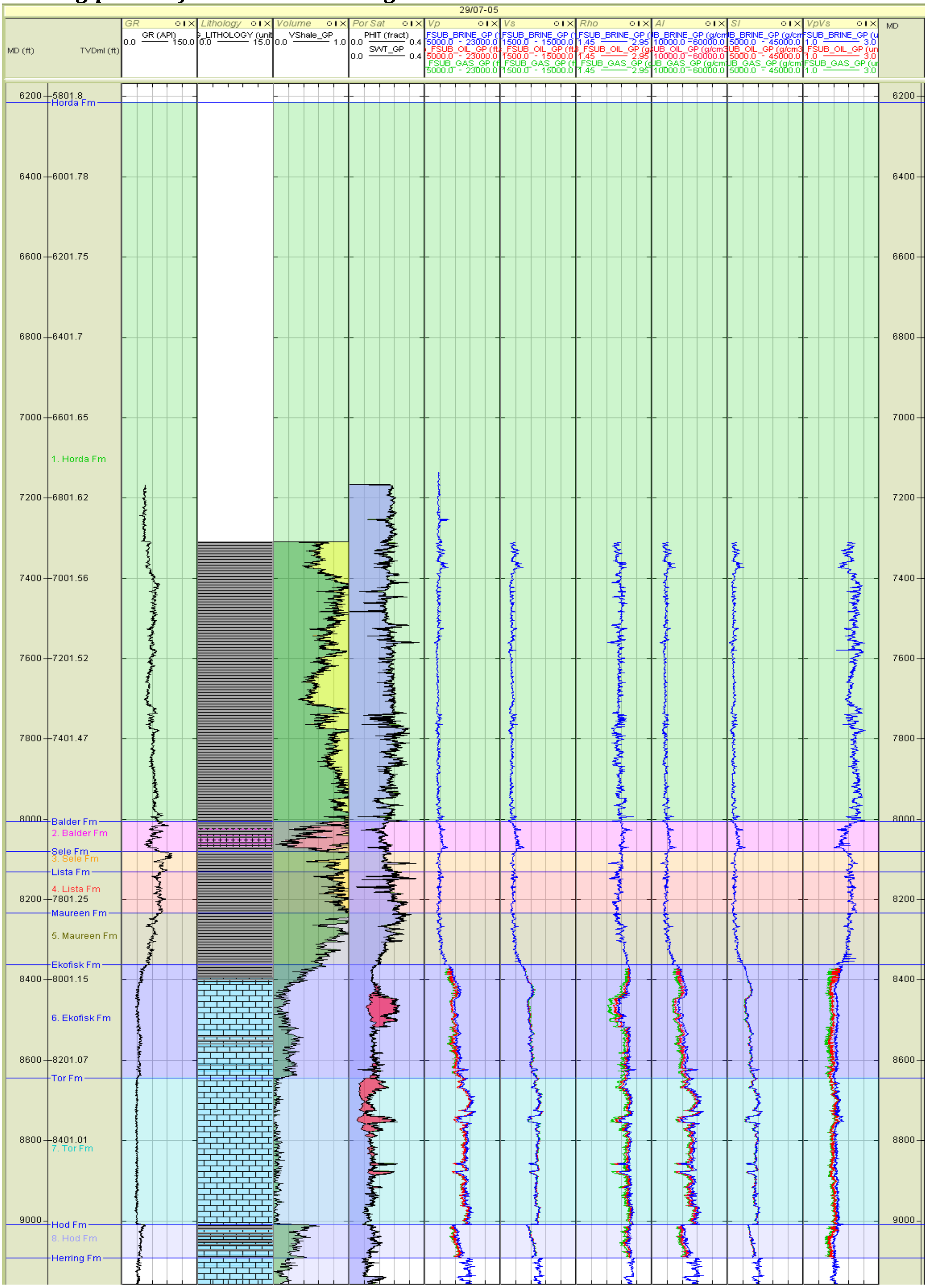


Figure 3.29.6 - Well Panel: Fluid substituted and elastic logs for well 29/07-05.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/07-05 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/07-05	Horda	8152	3406	2.31
29/07-05	Balder	8493	3827	2.36
29/07-05	Sele	8413	3764	2.33
29/07-05	Lista	8372	3672	2.27
29/07-05	Maureen	8591	3926	2.33

Table 3.29.6 - Clean shale properties at Well 29/07-05

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;
No viable sand reservoirs are found in Tertiary intervals in this well.

Tertiary reservoirs

No Tertiary reservoirs are present at this well.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/07-05 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm³)
29/07-05	Ekofisk	100% Brine	12759	6786	2.36
29/07-05	Tor	100% Brine	14919	7916	2.49
29/07-05	Hod	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm³)
29/07-05	Ekofisk	80% Oil	12121	6867	2.30
29/07-05	Tor	80% Oil	14409	7976	2.45
29/07-05	Hod	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm³)
29/07-05	Ekofisk	90% Gas	12022	7009	2.21
29/07-05	Tor	90% Gas	14365	8052	2.41
29/07-05	Hod	90% Gas			

Table 3.29.7 - Clean limestone properties at Well 29/07-05 for each fluid case

Cretaceous reservoirs

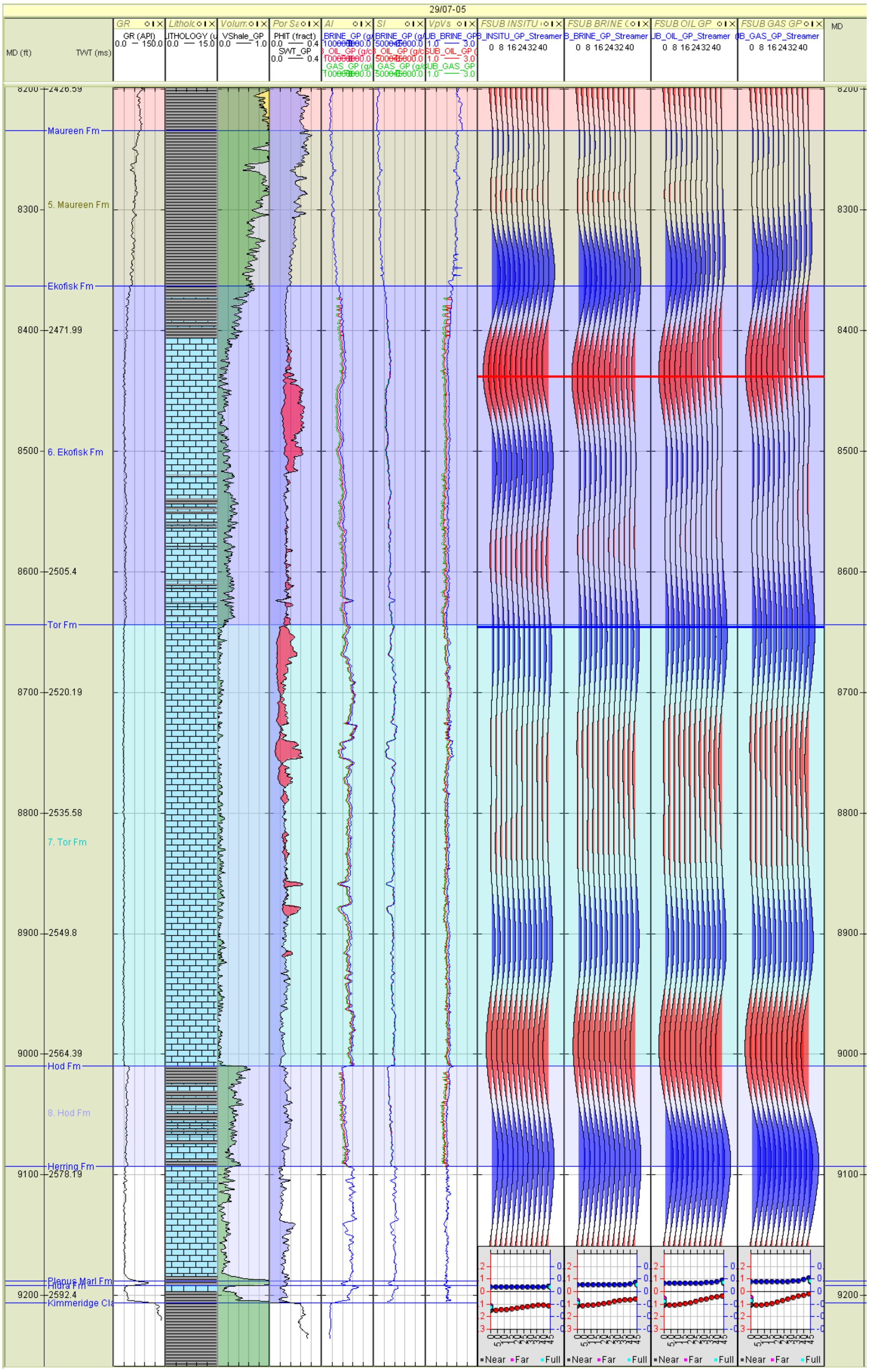


Figure 3.29.7 - Well Panel: Cretaceous reservoirs for well 29/07-05. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a component of shale. The highest porosity reservoir is found in the middle section of the Ekofisk Fm, the porosity in this section is approximately 26% and this formation is oil-bearing. The porosity is relatively constant outside the oil-bearing reservoir zone. The higher porosity layers found in the Ekofisk Fm could be representative of reworked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and strong amplitude in the brine case, but that the contrasts broadly decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

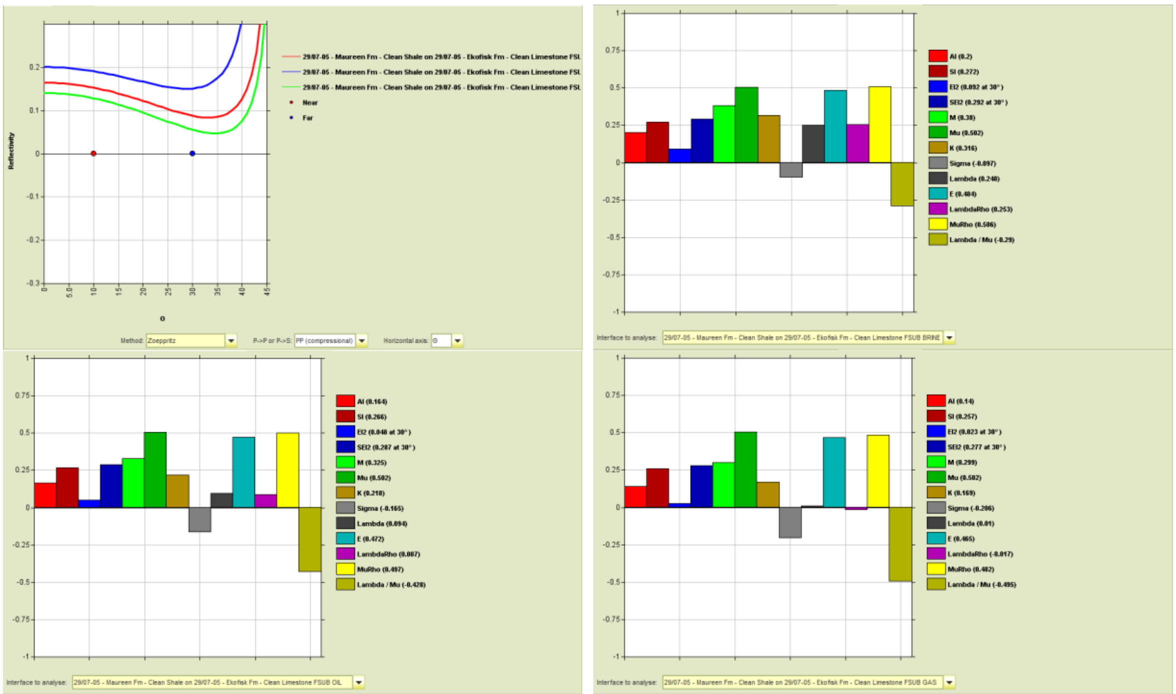


Figure 3.29.8 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 29/07-05.

Tor Formation

- Reservoir formed by a clean limestone formation. The reservoir has a relatively constant porosity but contains several high porosity streaks. The higher porosity layers found in the Tor Fm could be representative of reworked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

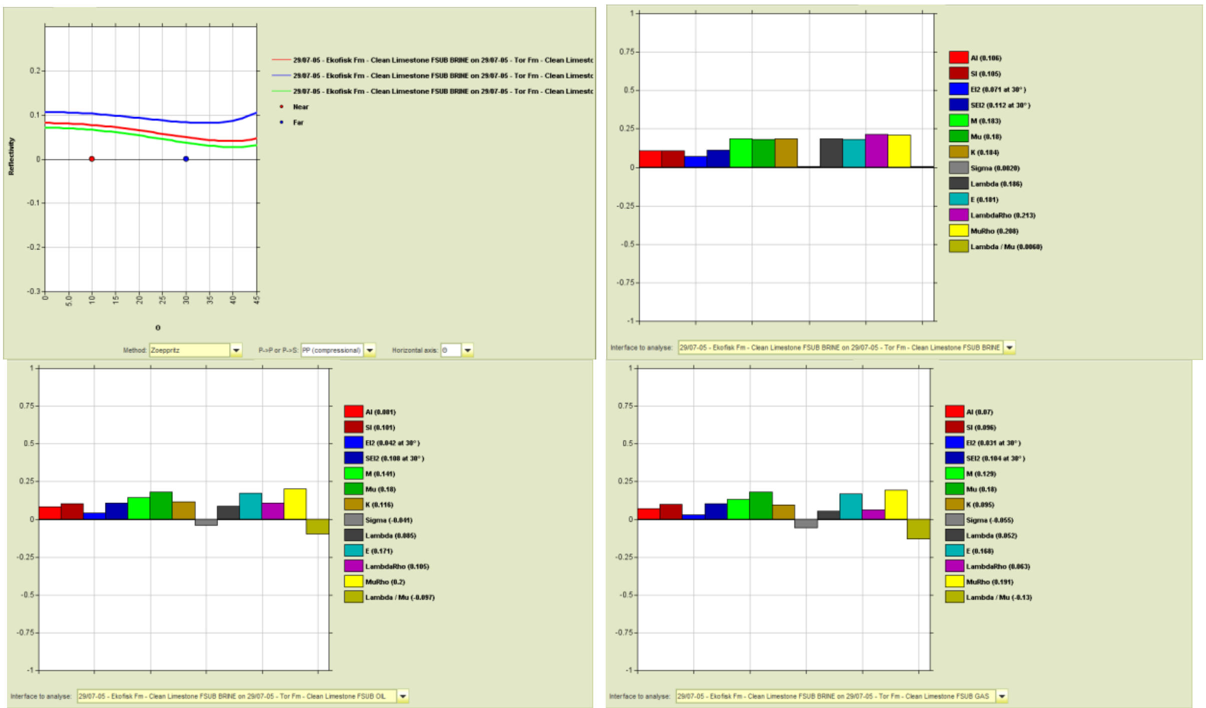


Figure 3.28.9 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 29/07-05.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 29/07-05 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/07-05	Overburden				
29/07-05	Underburden	Limestone	14921	8221	2.49

Table 3.29.8 - Overburden and underburden properties at Well 29/07-05.

Well: 29/09C-04

General

Well Information
This well is a Tenneco operated exploration well spudded, completed and abandoned in 1987. The well did not encounter any significant hydrocarbons within the study interval, and is not associated with any oil field complex.

Objectives
The objective of this well was the dip and fault defined closure in the Upper Jurassic Fulmar and Middle Jurassic sands. The secondary targets were the Maureen, Forties and Eocene sands. The Jurassic targets were absent although some oil shows were seen in the Early Jurassic (Liassic). The well was not formation tested.

Log conditioning overview
Only minor log conditioning required due to good log data quality within this well. A low value spike in the density log was seen at 8,879ft MD (the start of the logging run) in the Horda Fm and the spike was removed from the density log. A section of poor quality data was seen on the Vp log at 9,639ft MD in the Lista Fm and this data was removed from the Vp log.

Invasion correction
Invasion correction has been performed on the density log within all formations with the exception of the non-reservoir forming Horda, Balder and Sele Formations. The drilling mud used within this well was oil-based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Lista Formation for the Vp log and within the Horda Formation for the density log. A complete Vs log is modelled since a measured Vs log is not present at this well.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 29/09C-04 is displayed in the figures below;

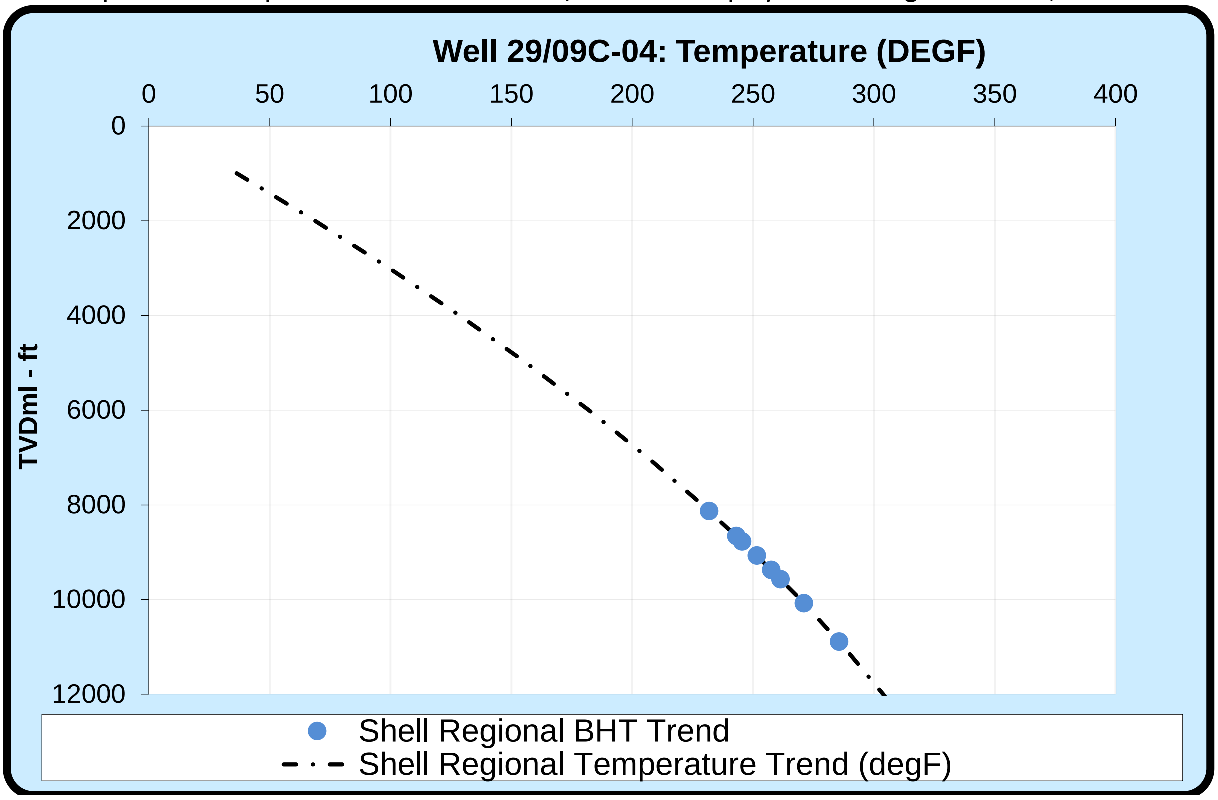


Figure 3.30.1 - Temperature data at Well 29/09C-04

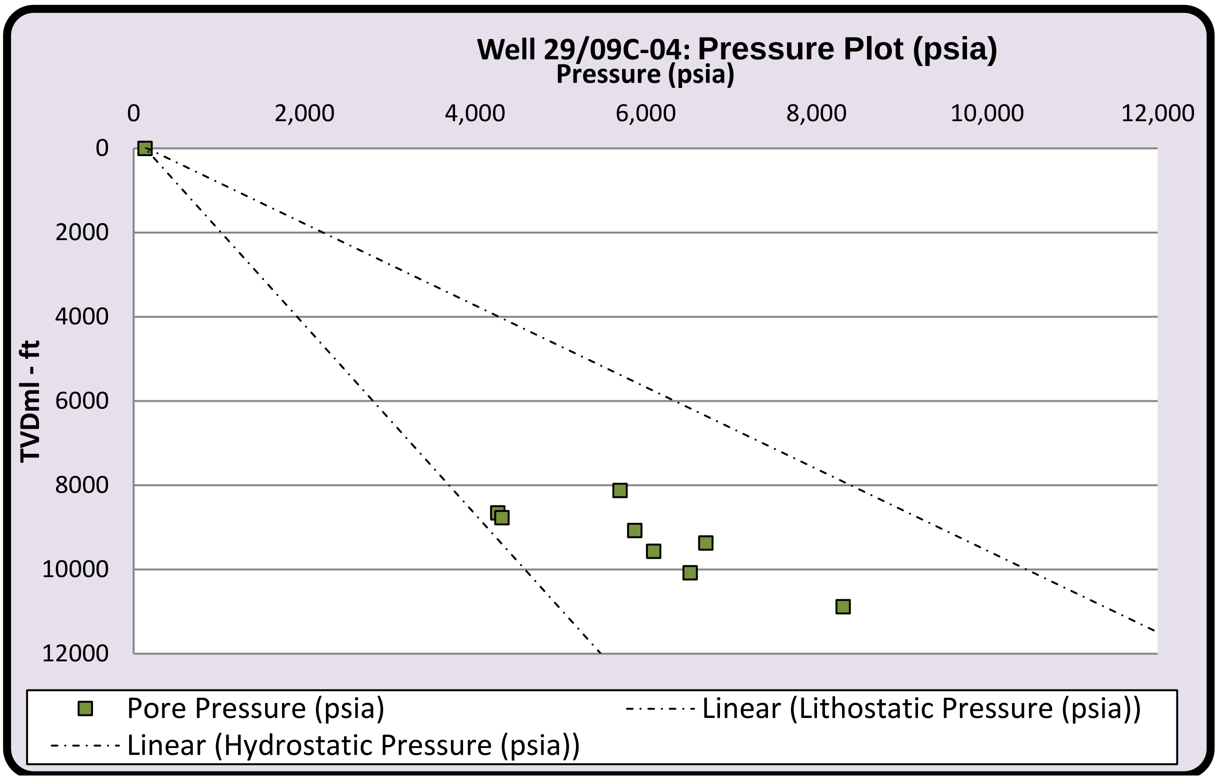


Figure 3.30.2 - Pressure data at Well 29/09C-04

The temperature and pressure data for the formation mid-points in Well 29/09-04C is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
29/09C-04	Sea Bed	422.1	305.1	0.0	39.2	135.8	135.8	135.78	0.00
29/09C-04	Horda	8552.0	8433.1	8128.0	231.9	3752.8	5702.8	8128.03	2425.28
29/09C-04	Balder	9084.5	8965.5	8660.4	243.2	3989.7	4269.7	8660.40	4390.74
29/09C-04	Sele	9195.5	9076.5	8771.4	245.5	4039.0	4319.0	8771.38	4452.34
29/09C-04	Lista	9496.5	9377.4	9072.3	251.6	4173.0	5873.0	9072.32	3199.36
29/09C-04	Maureen	9797.0	9677.9	9372.8	257.6	4306.7	6706.7	9372.77	2666.11
29/09C-04	Ekofisk	9993.5	9874.4	9569.3	261.5	4394.1	6094.1	9569.25	3475.16
29/09C-04	Tor	10504.5	10385.3	10080.2	271.2	4621.5	6521.5	10080.22	3558.74
29/09C-04	Hod	11311.0	11191.8	10886.7	285.6	4980.4	8316.7	10886.68	2570.03

Table 3.30.1 - Summary of mid-point temperature and pressure data at Well 29/09C-04

Fluid data

A summary of the fluid set parameters at Well 29/09C-04 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
29/09C-04	Horda	68000	730	40.1	0.78	0.78
29/09C-04	Balder	68000	730	40.7	0.78	0.78
29/09C-04	Sele	68000	730	40.8	0.78	0.78
29/09C-04	Lista	68000	730	41.2	0.78	0.78
29/09C-04	Maureen	68000	730	41.5	0.78	0.78
29/09C-04	Ekofisk	68000	730	41.7	0.78	0.78
29/09C-04	Tor	68000	730	42.3	0.78	0.78
29/09C-04	Hod	68000	730	43.1	0.78	0.78

Table 3.30.2 - Summary of fluid parameter data at Well 29/09C-04

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
29/09C-04	Horda	16380	56.0	0.8
29/09C-04	Balder	16380	56.4	0.8
29/09C-04	Sele	16380	56.5	0.8
29/09C-04	Lista	16380	56.8	0.8
29/09C-04	Maureen	16380	57.0	0.8
29/09C-04	Ekofisk	16380	57.2	0.8
29/09C-04	Tor	16380	57.6	0.8
29/09C-04	Hod	16380	58.3	0.8

Table 3.30.3 - Summary of additional parameter data at Well 29/09C-04

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.30.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	11.83	4.31	2.351	8,969	4,440

Table 3.30.5 - Tuff properties used at Well 29/09C-04

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
29/09C-04	Horda	PAY	1004.000	0.000	0.000	0.000	0.000	0.000	0.000
29/09C-04	Horda	RES	1004.000	1.500	0.001	0.311	0.207	0.984	0.376
29/09C-04	Balder	PAY	61.000	0.000	0.000	0.000	0.000	0.000	0.000
29/09C-04	Balder	RES	61.000	0.000	0.000	0.000	0.000	0.000	0.000
29/09C-04	Sele	PAY	161.000	0.000	0.000	0.000	0.000	0.000	0.000
29/09C-04	Sele	RES	161.000	11.000	0.068	1.694	0.154	1.000	0.413
29/09C-04	Lista	PAY	441.000	0.000	0.000	0.000	0.000	0.000	0.000
29/09C-04	Lista	RES	441.000	25.500	0.058	5.418	0.212	0.933	0.131
29/09C-04	Maureen	PAY	160.000	1.000	0.006	0.231	0.231	0.488	0.219
29/09C-04	Maureen	RES	160.000	73.750	0.461	7.905	0.107	0.900	0.183
29/09C-04	Ekofisk	PAY	233.000	0.000	0.000	0.000	0.000	0.000	0.000
29/09C-04	Ekofisk	RES	233.000	233.000	1.000	26.283	0.113	0.984	0.123
29/09C-04	Tor	PAY	789.000	0.000	0.000	0.000	0.000	0.000	0.000
29/09C-04	Tor	RES	789.000	755.000	0.957	78.763	0.104	0.984	0.016
29/09C-04	Hod	PAY	824.000	0.000	0.000	0.000	0.000	0.000	0.000
29/09C-04	Hod	RES	824.000	818.500	0.933	55.277	0.068	0.995	0.158

Table 3.30.6 - Petrophysical parameters used at Well 29/09C-04

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

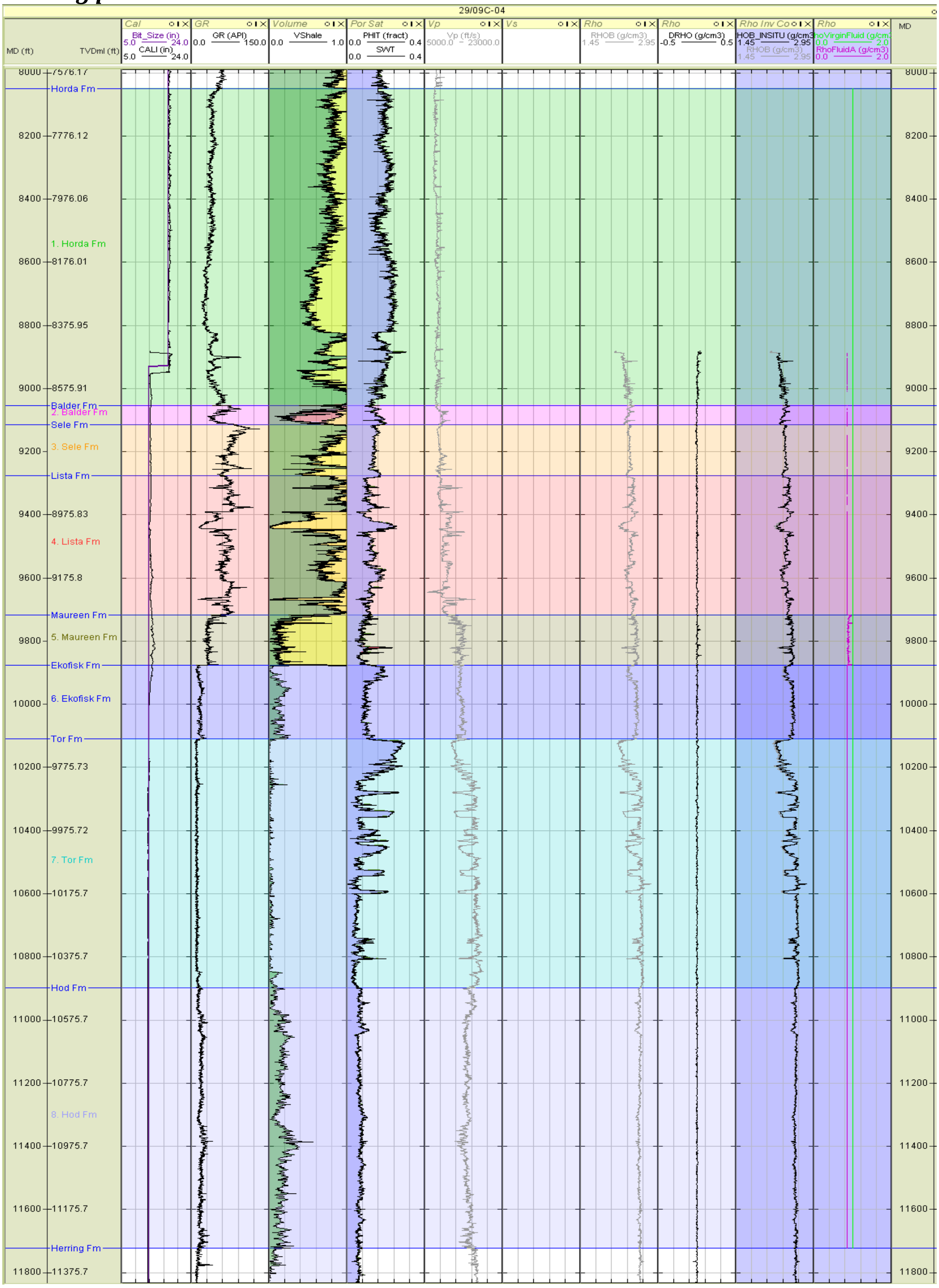


Figure 3.30.3 - Well Panel: Measured data and invasion correction for well 29/09C-04.

Well log panel – log editing and audit

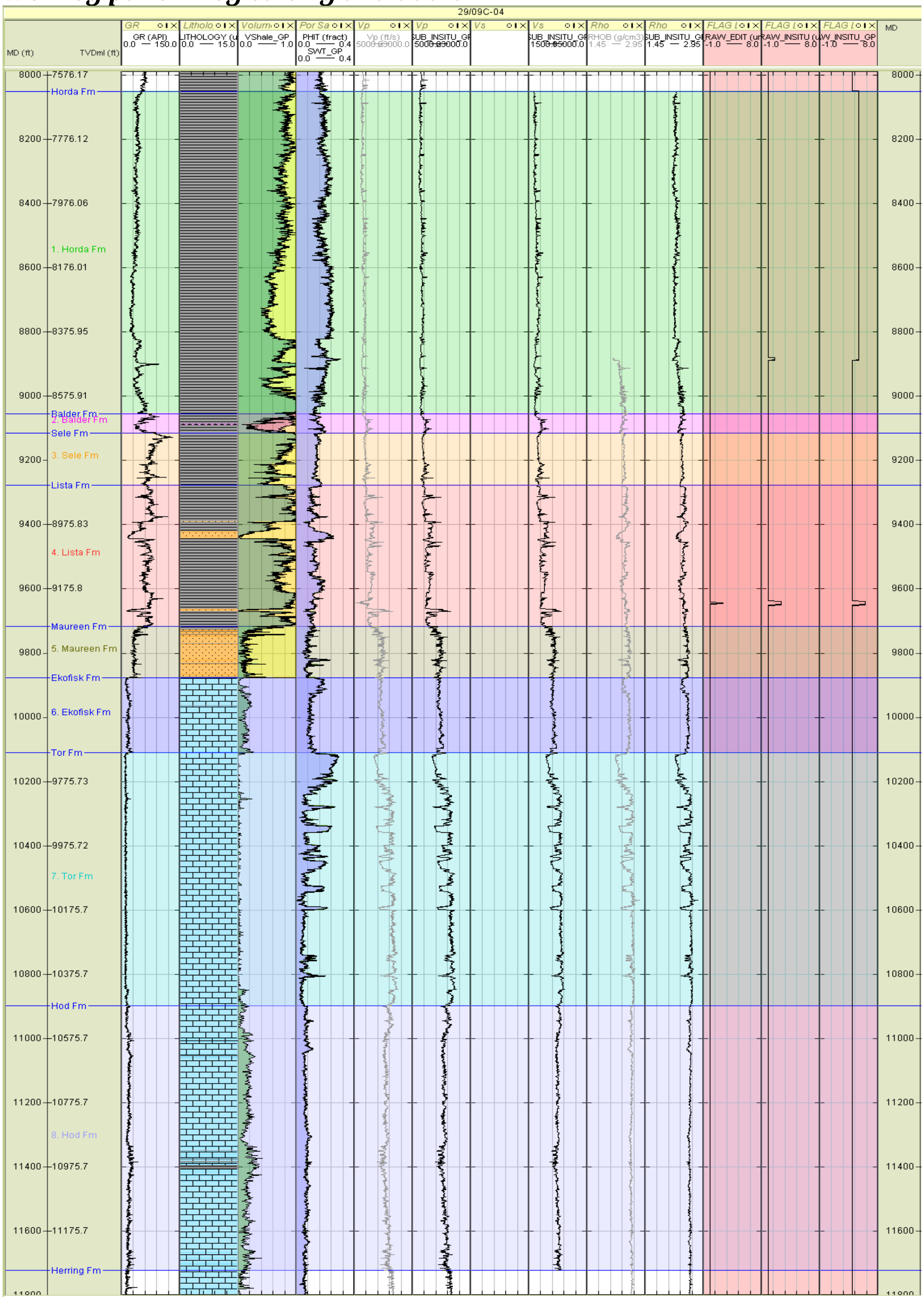


Figure 3.30.4 - Well Panel: Log edits for well 29/09C-04.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

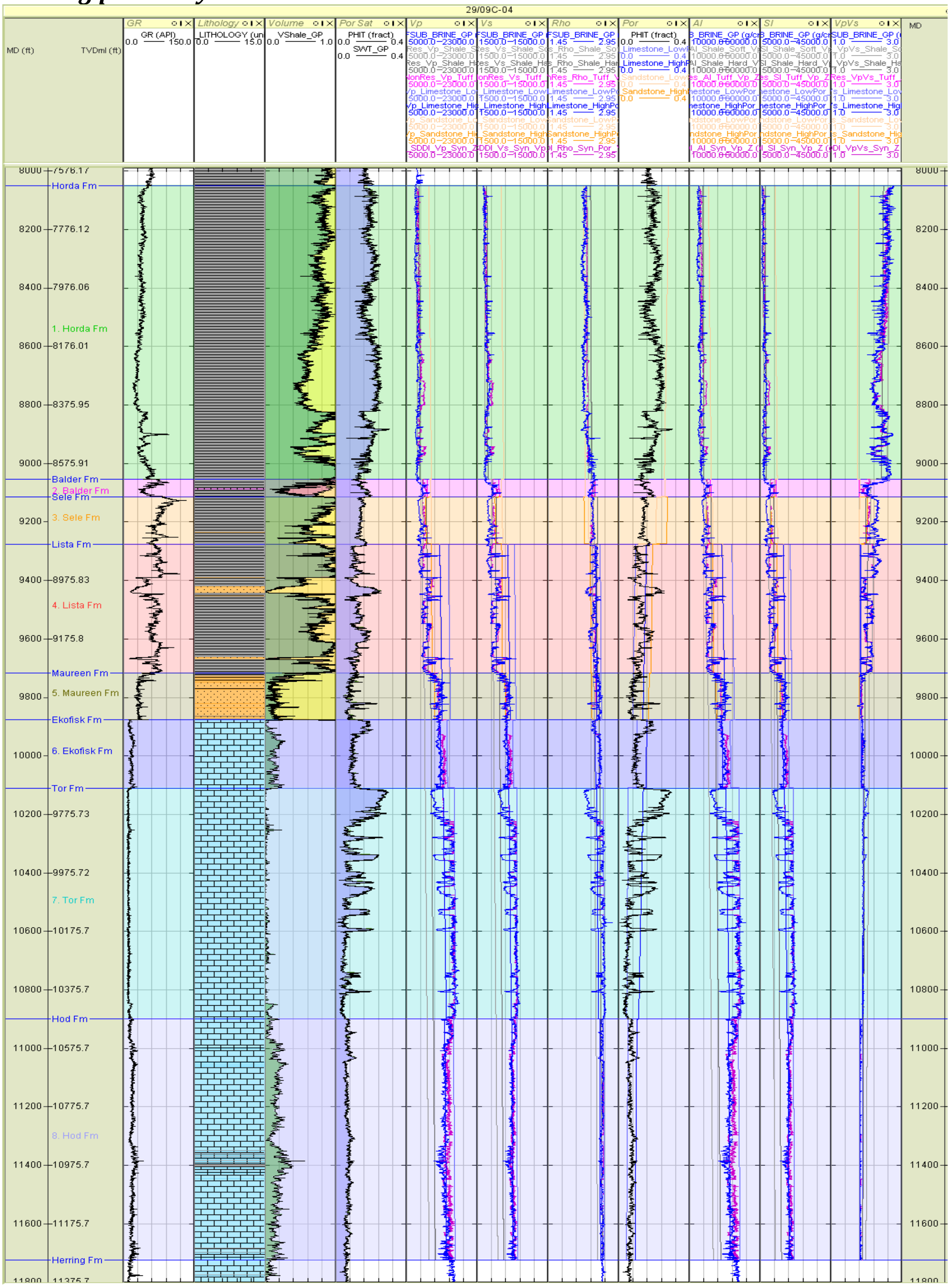


Figure 3.30.5 - Well Panel: End-member and synthetic logs for well 29/09C-04.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

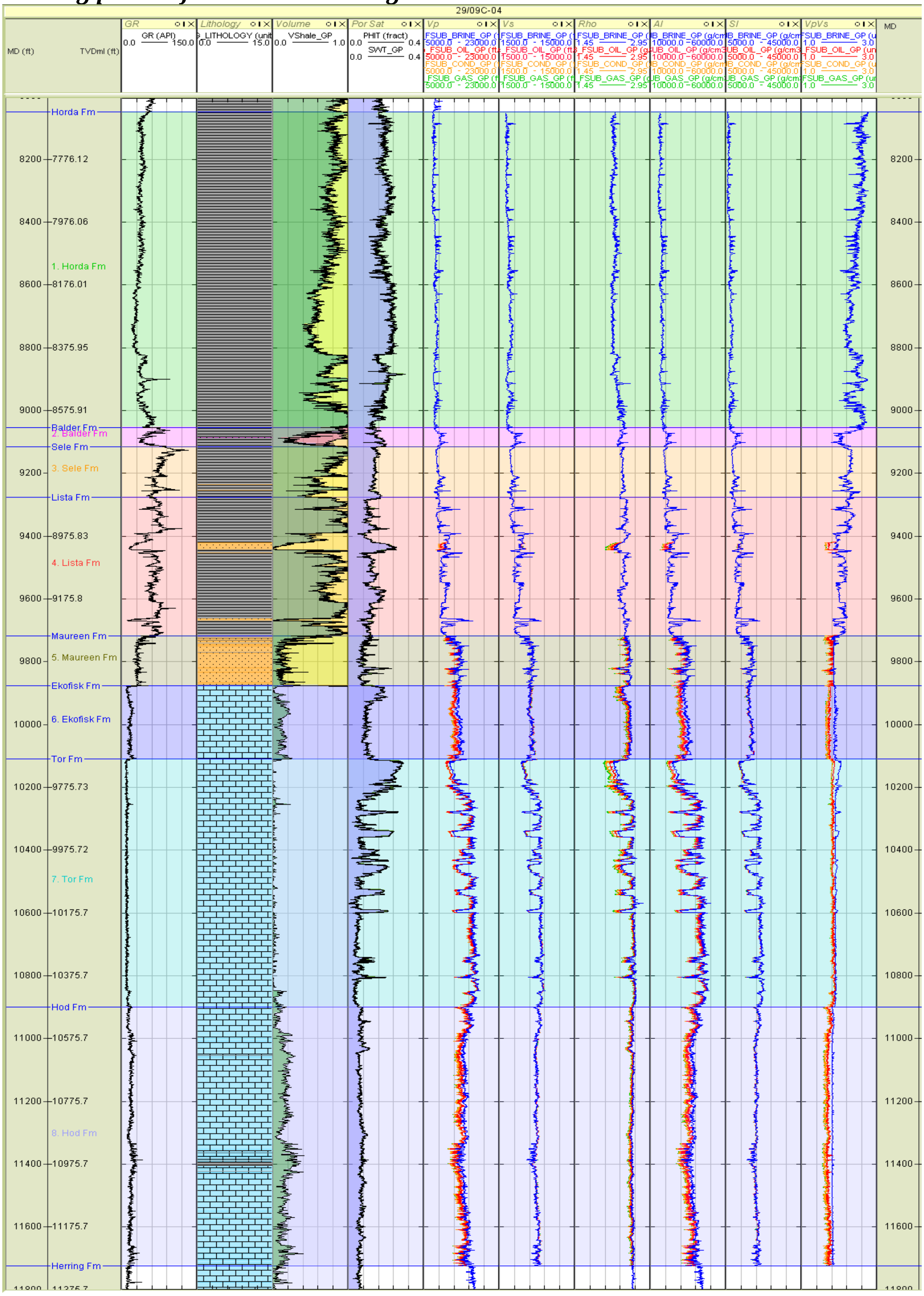


Figure 3.30.6 - Well Panel: Fluid substituted and elastic logs for well 29/09C-04.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/09C-04 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/09C-04	Horda	7536	2971	2.25
29/09C-04	Balder	8063	3409	2.38
29/09C-04	Sele	8217	3608	2.39
29/09C-04	Lista	9199	4299	2.43
29/09C-04	Maureen	10622	5397	2.45

Table 3.30.7 - Clean shale properties at Well 29/09C-04

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/09C-04	Horda	100% Brine			
29/09C-04	Balder	100% Brine			
29/09C-04	Sele	100% Brine			
29/09C-04	Lista	100% Brine	11526	6094	2.36
29/09C-04	Maureen	100% Brine	13311	7212	2.52
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/09C-04	Horda	80% Oil			
29/09C-04	Balder	80% Oil			
29/09C-04	Sele	80% Oil			
29/09C-04	Lista	80% Oil	10858	6143	2.32
29/09C-04	Maureen	80% Oil	13064	7230	2.51
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/09C-04	Horda	90% Gas			
29/09C-04	Balder	90% Gas			
29/09C-04	Sele	90% Gas			
29/09C-04	Lista	90% Gas	10678	6222	2.26
29/09C-04	Maureen	90% Gas	12983	7258	2.49
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/09C-04	Horda	80% Cond			
29/09C-04	Balder	80% Cond			
29/09C-04	Sele	80% Cond			
29/09C-04	Lista	80% Cond	10661	6197	2.28
29/09C-04	Maureen	80% Cond	12979	7249	2.49

Table 3.30.8 - Clean sand properties at Well 29/09C-04 for each fluid case

Tertiary reservoirs – Well panel

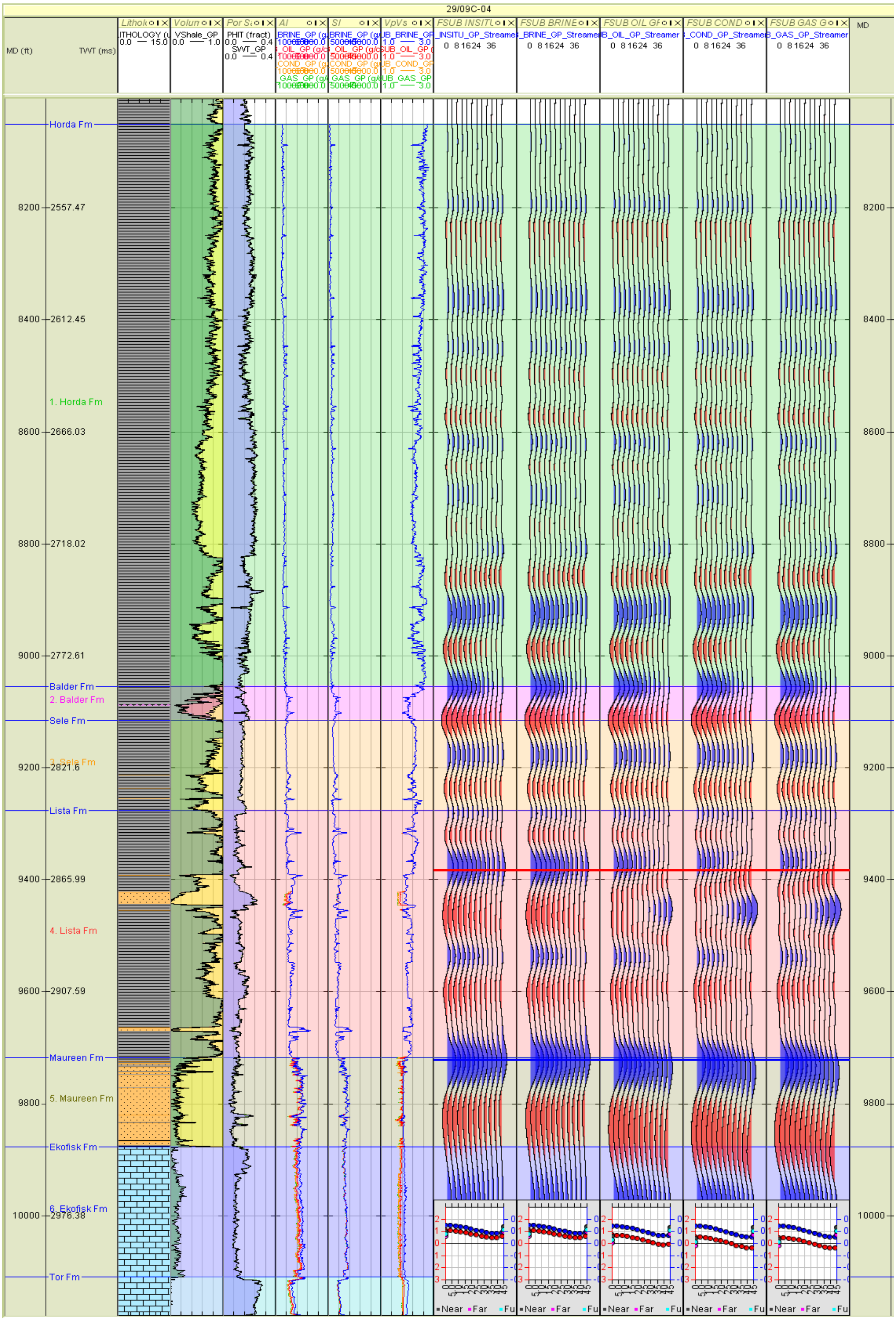


Figure 3.30.7 - Well Panel: Tertiary reservoirs for well 29/09C-04. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Lista Formation

- Reservoir formed by a discrete sand package with a maximum porosity of 26% and net reservoir is approximately 25 feet. The reservoir sand is overlain directly by overburden shale in the upper section of the Lista Fm.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases and a modelled class IIp response for the 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts generally become negative for some attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

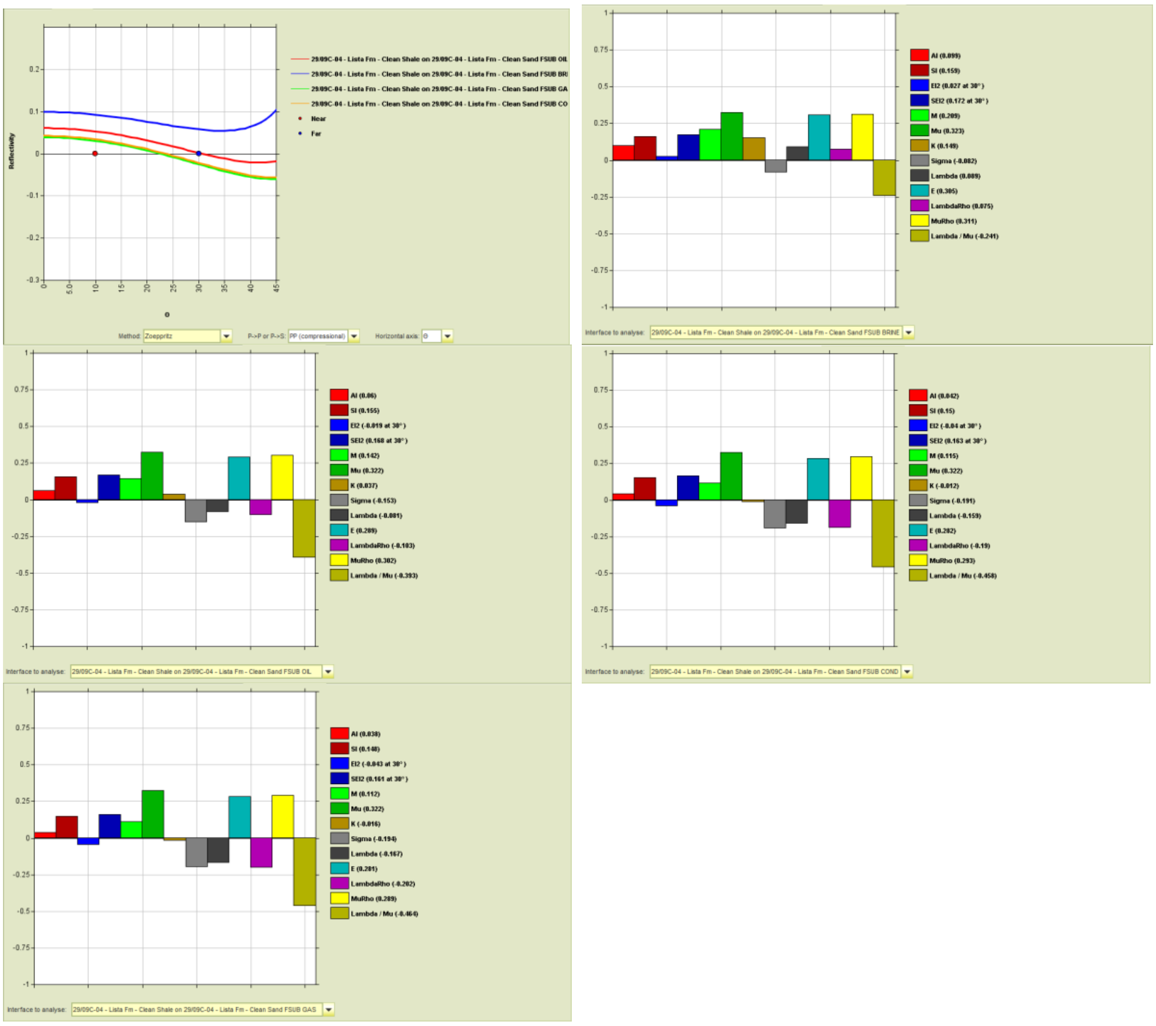


Figure 3.30.8 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 29/09C-04.

Maureen Formation

- Reservoir formed by a thick low porosity sand package and net reservoir is approximately 75 feet. The Maureen reservoir sand is overlain directly by overburden shale in the lower section of the Lista Fm.
- Blocky AVO shows a modelled class I response for all fluid cases, with the softness of the sand in relation to the overburden shale very slightly increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and moderate amplitude in the brine case. These contrasts stay positive in amplitude for most attributes even with addition of hydrocarbons. The addition of hydrocarbons does slightly decrease the amplitude of the positive elastic contrasts. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

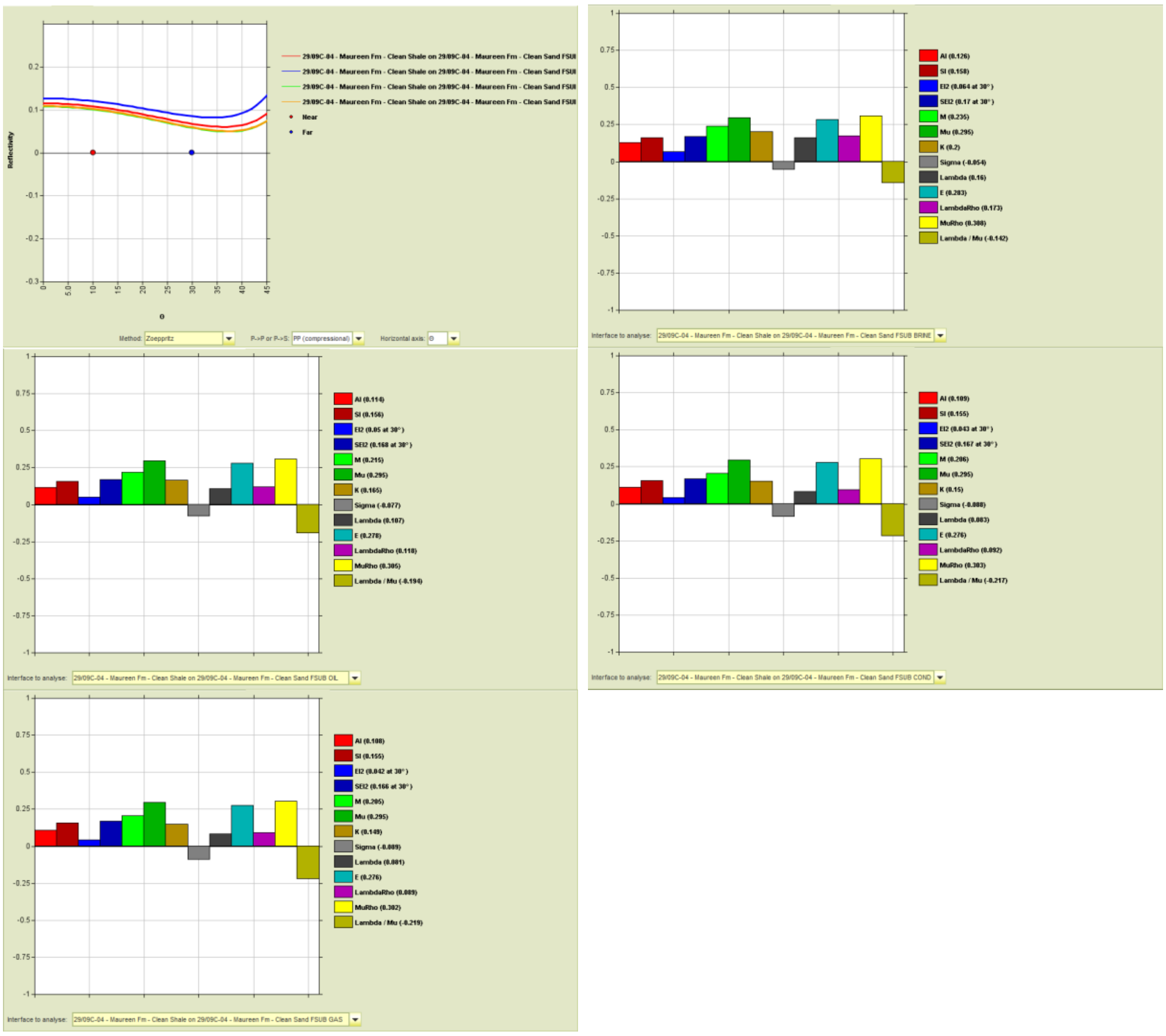


Figure 3.30.9 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 29/09C-04.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/09C-04 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/09C-04	Ekofisk	100% Brine	13596	7258	2.48
29/09C-04	Tor	100% Brine	15558	8148	2.54
29/09C-04	Hod	100% Brine	15641	8523	2.59
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/09C-04	Ekofisk	80% Oil	12775	7312	2.44
29/09C-04	Tor	80% Oil	15104	8188	2.51
29/09C-04	Hod	80% Oil	15015	8554	2.57
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/09C-04	Ekofisk	90% Gas	12559	7396	2.39
29/09C-04	Tor	90% Gas	15018	8251	2.47
29/09C-04	Hod	90% Gas	14788	8599	2.54
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/09C-04	Ekofisk	80% Cond	12542	7369	2.40
29/09C-04	Tor	80% Cond	15000	8231	2.48
29/09C-04	Hod	80% Cond	14794	8585	2.55

Table 3.30.9 - Clean limestone properties at Well 29/09C-04 for each fluid case

Cretaceous reservoirs

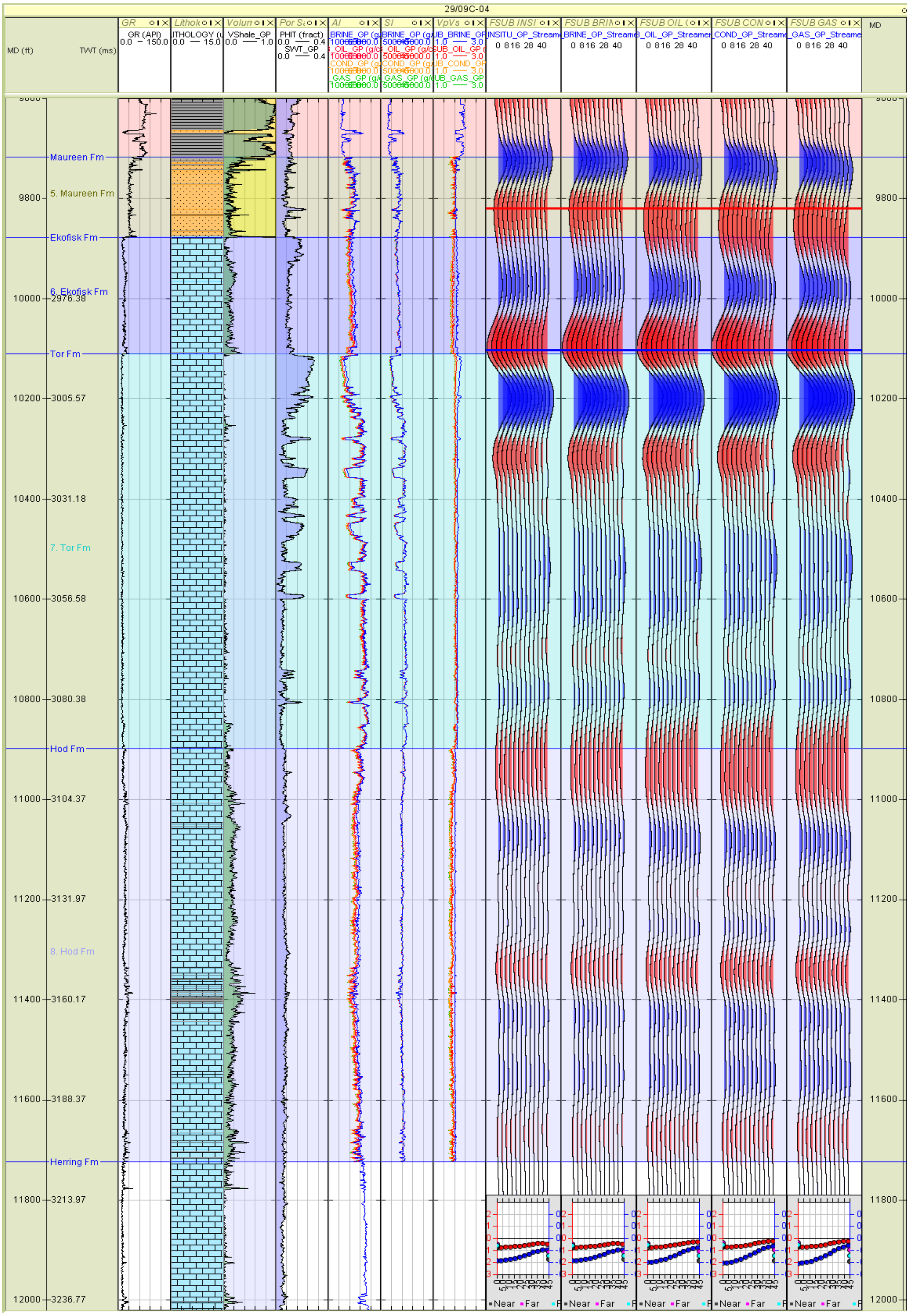


Figure 3.30.10 - Well Panel: Cretaceous reservoirs for well 29/09C-04. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the top section of the Ekofisk Fm and the porosity in this section is approximately 20%.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons. This AVO response can't be compared to the synthetic gathers since the overburden section of the Maureen Fm is sand at this well.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

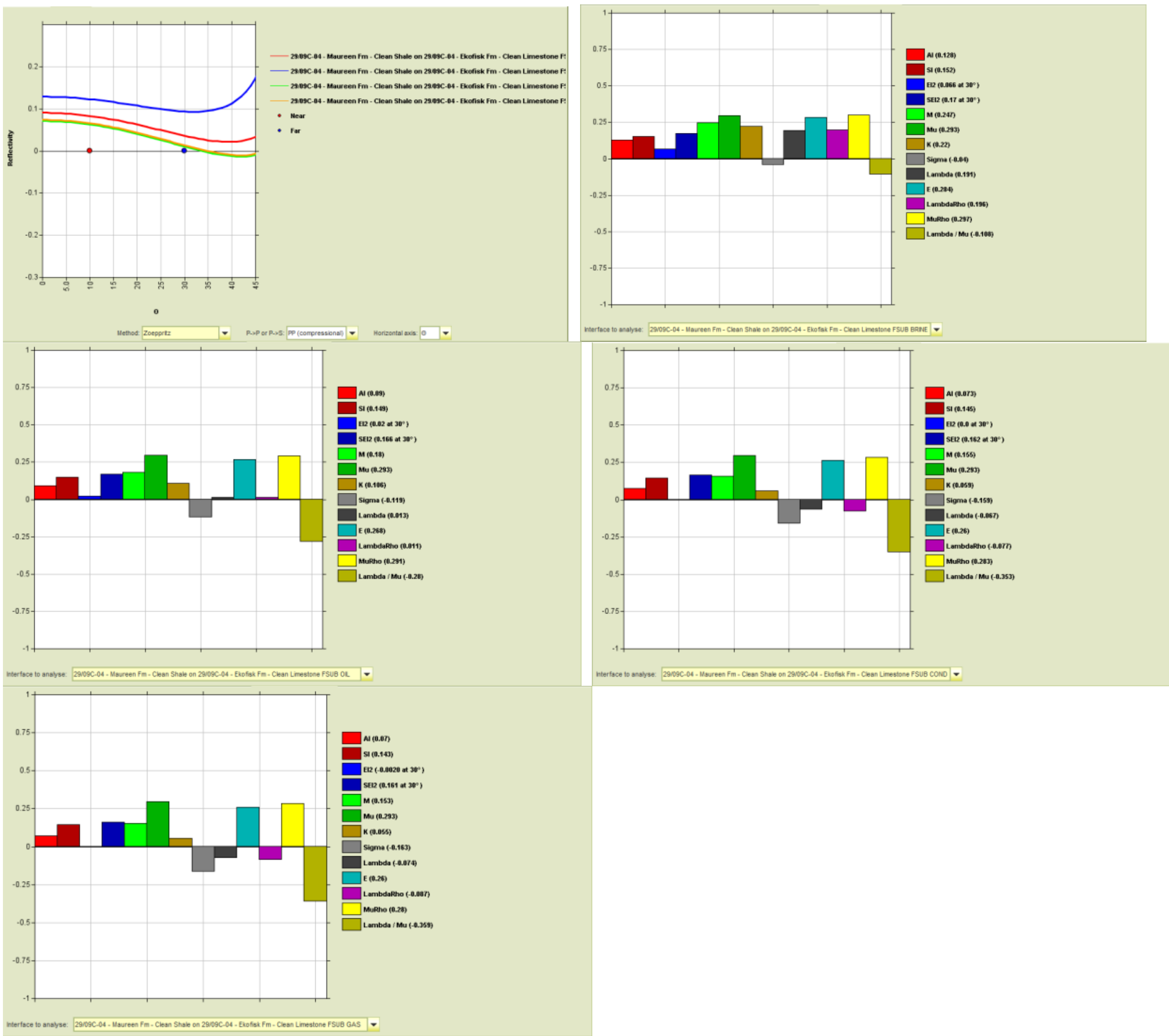


Figure 3.30.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 29/09C-04.

Tor Formation

- Reservoir formed by a clean limestone formation. The highest porosity reservoir is found in the top section of the Tor Fm and the porosity in this section is approximately 25%. High porosity layers are found throughout the Tor Fm and could be representative of reworked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are all positive and medium amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

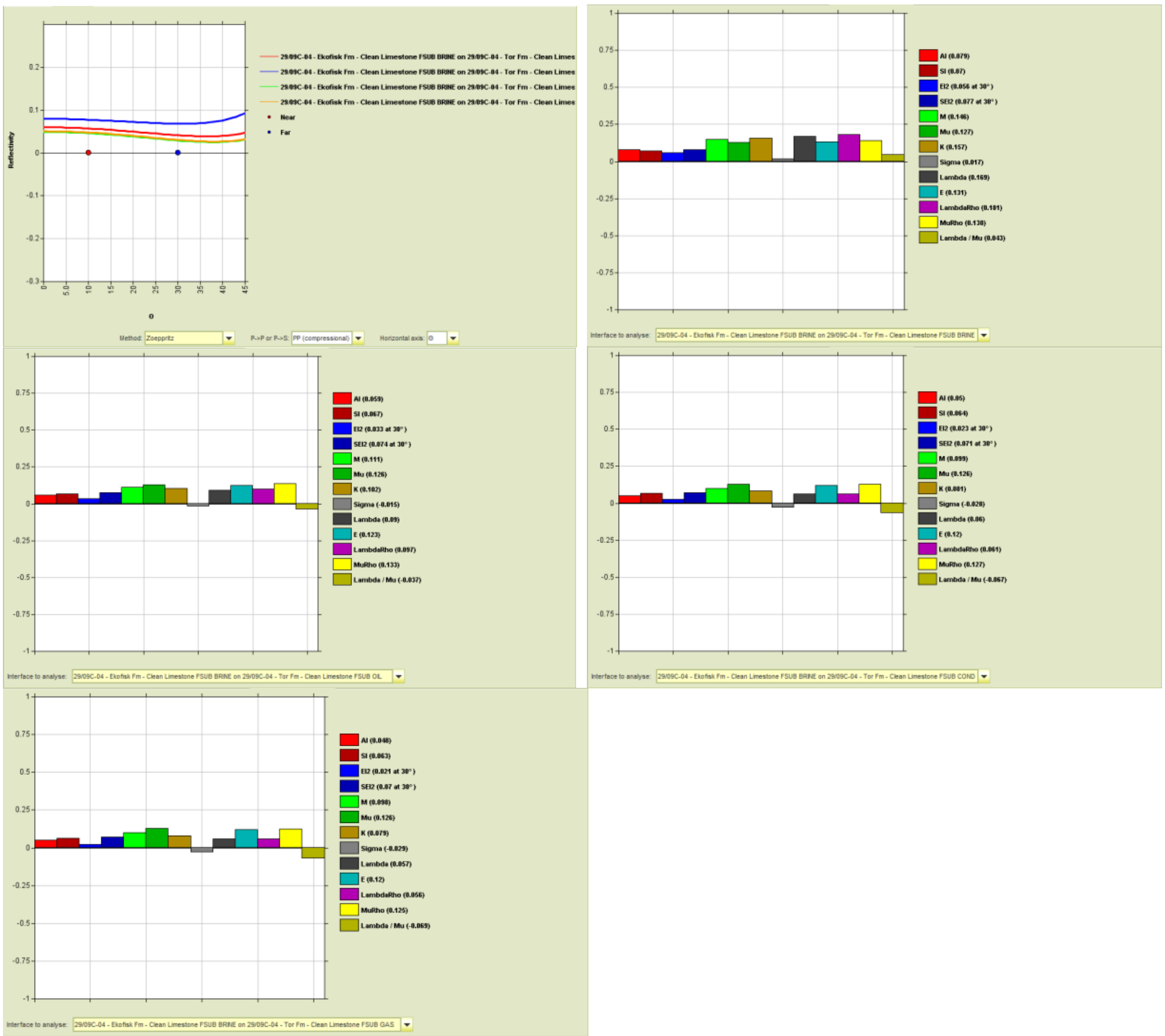


Figure 3.30.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 29/09C-04.

Hod Formation

- Reservoir formed by a limestone formation with a minor component of shale. The reservoir has a relatively constant porosity of approximately 7%.
- Blocky AVO shows a modelled class II response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are low amplitude in the brine case, and that the contrasts become negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

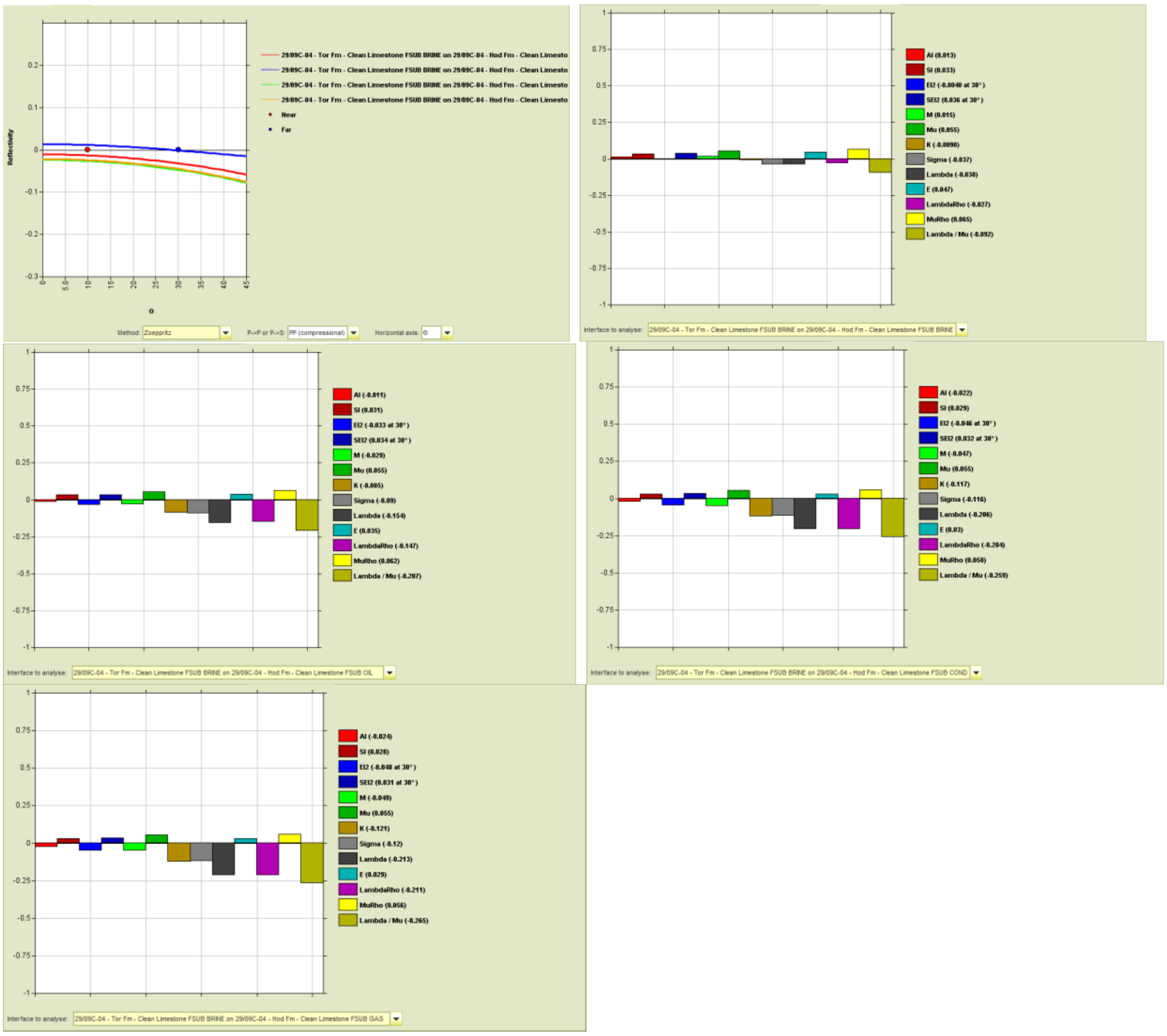


Figure 3.30.13 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 29/09C-04.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 29/09C-04 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/09C-04	Overburden	Shale	7247		
29/09C-04	Underburden	Limestone	17115		2.61

Table 3.30.10 - Overburden and underburden properties at Well 29/09C-04.

Well: 29/10-02

General

Well Information
This well is a Shell operated exploration well spudded, drilled and abandoned in 1983. The well encountered oil in the Lista Fm and Hod Fm within the study interval, and it is part of the Puffin field.

Objectives
The objective of this well was to target a high relief dip closure at three prospective levels. The primary objective was the upper/middle Jurassic sands, the secondary objective was the Tor and Ekofisk Formations (following on from the Joanne discovery) and the tertiary objective was the Maureen Formation (following on from some success in well 29/10-01).

Log conditioning overview
Only minor log conditioning was required due to good log data quality within this well. Calliper logs show minor washout towards the top of the Horda Formation, as is common due to its unconsolidated nature. Thin calcite stringers in the Horda Formation seen on the density log were not apparent on the Vp log, with data relating to these intervals was consequentially removed. A high value spike in the Vp log was seen at 8,569ft MD in the Sele Fm and this spike was removed from the Vp log.

Invasion correction
Invasion correction has been performed on the density log within all formations with the exception of the non-reservoir forming Balder and Sele Formations. The drilling mud used within this well was oil-based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Balder and Lista Formations for the Vp log and within the Horda Formation for the density log. A complete Vs log is modelled since measured Vs data is not available at this well. Gaps were also filled above and below the interval of interest in the Vp log using a spline function.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 29/10-02 is displayed in the figures below;

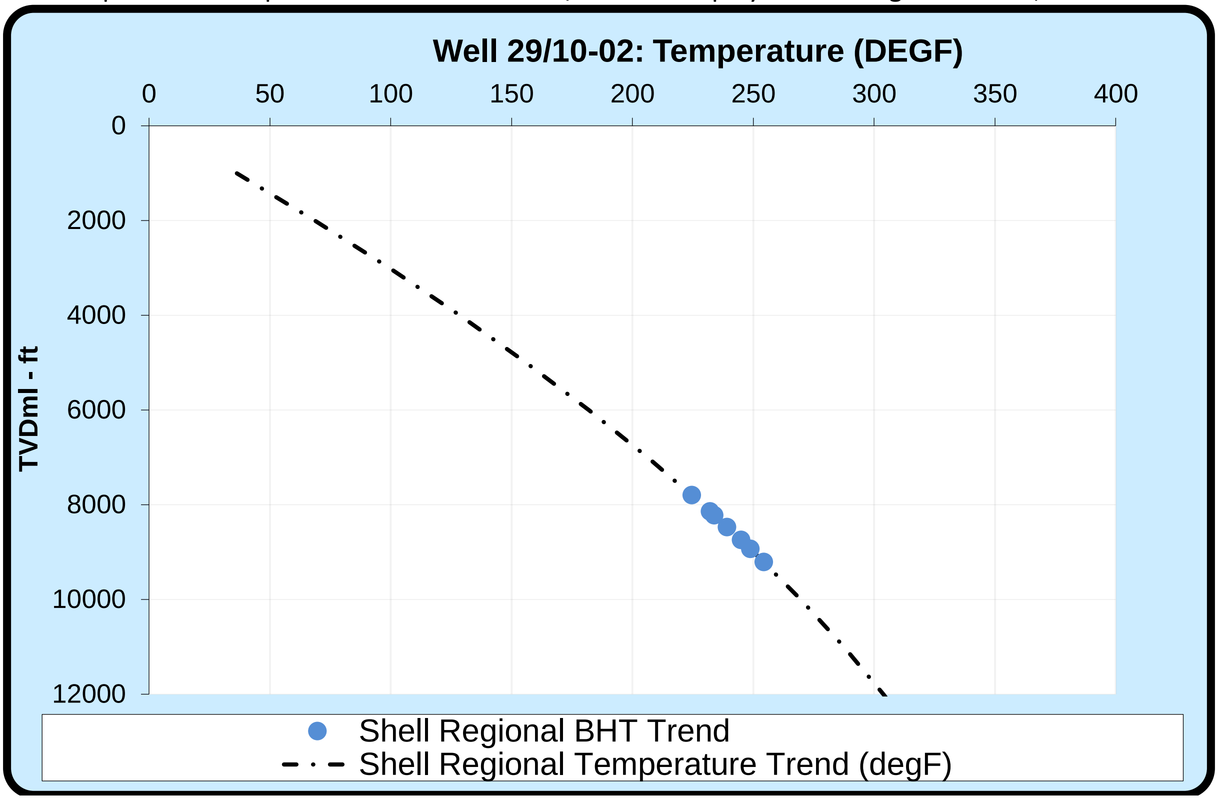


Figure 3.31.1 - Temperature data at Well 29/10-02

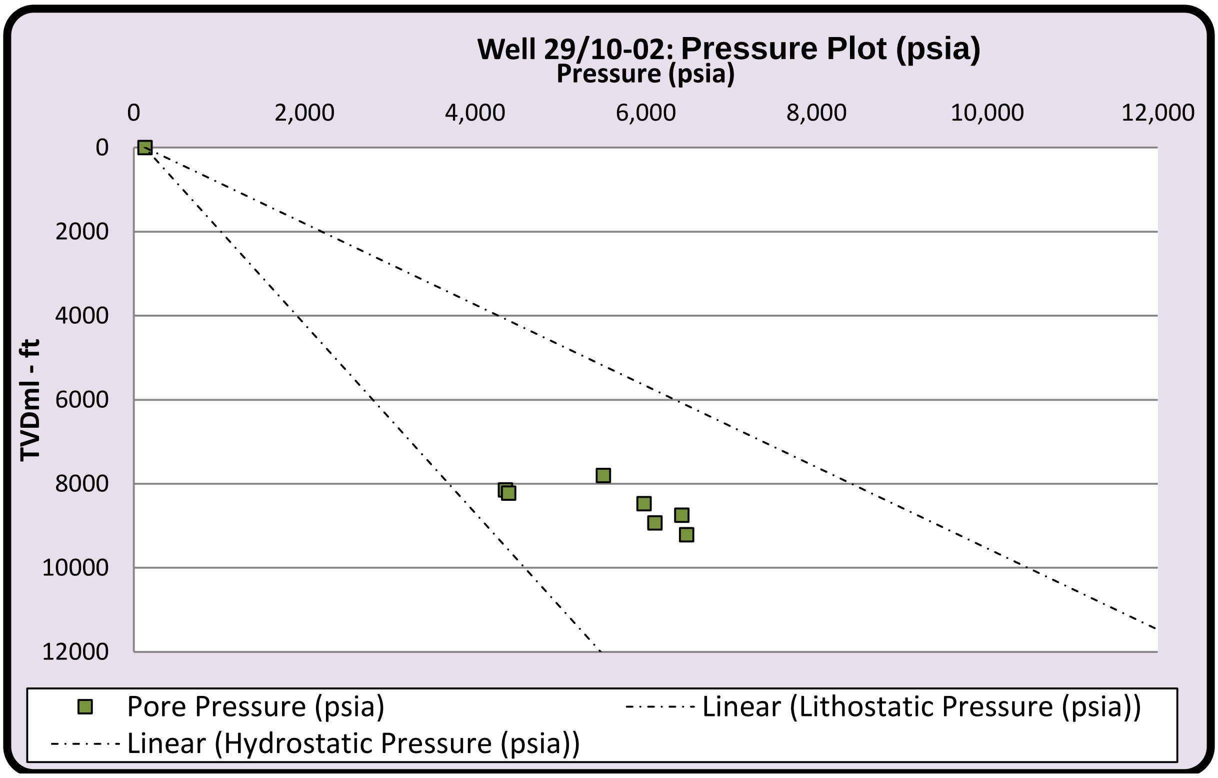


Figure 3.31.2 - Pressure data at Well 29/10-02

The temperature and pressure data for the formation mid-points in Well 29/10-02 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydrostatic Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
29/10-02	Sea Bed	368.0	298.0	0.0	39.2	132.6	132.6	132.61	0.00
29/10-02	Horda	8168.0	8097.9	7799.9	224.6	3603.5	5503.5	7799.86	2296.31
29/10-02	Balder	8511.5	8441.3	8143.3	232.2	3756.4	4356.4	8143.33	3786.94
29/10-02	Sele	8591.0	8520.8	8222.8	233.9	3791.8	4391.8	8222.82	3831.06
29/10-02	Lista	8837.1	8766.9	8468.9	239.2	3901.3	5981.3	8468.87	2487.61
29/10-02	Maureen	9113.6	9043.3	8745.3	245.0	4024.3	6424.3	8745.35	2321.06
29/10-02	Ekofisk	9300.5	9230.3	8932.3	248.8	4107.5	6107.5	8932.26	2824.80
29/10-02	Tor	9577.0	9506.7	9208.7	254.4	4230.5	6480.5	9208.73	2728.24
29/10-02	Hod	10076.0	10005.6	9707.6	264.1	4452.5	7268.5	9707.64	2439.13

Table 3.31.1 - Summary of mid-point temperature and pressure data at Well 29/10-02

Fluid data

A summary of the fluid set parameters at Well 29/10-02 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
29/10-02	Horda	168000	730	39.8	0.78	0.78
29/10-02	Balder	168000	730	40.2	0.78	0.78
29/10-02	Sele	168000	730	40.2	0.78	0.78
29/10-02	Lista	168000	730	40.5	0.78	0.78
29/10-02	Maureen	168000	730	40.8	0.78	0.78
29/10-02	Ekofisk	168000	730	41.0	0.78	0.78
29/10-02	Tor	168000	730	41.3	0.78	0.78
29/10-02	Hod	168000	730	41.8	0.78	0.78

Table 3.31.2 - Summary of fluid parameter data at Well 29/10-02

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
29/10-02	Horda	16380	55.7	0.8
29/10-02	Balder	16380	56.0	0.8
29/10-02	Sele	16380	56.1	0.8
29/10-02	Lista	16380	56.3	0.8
29/10-02	Maureen	16380	56.5	0.8
29/10-02	Ekofisk	16380	56.7	0.8
29/10-02	Tor	16380	56.9	0.8
29/10-02	Hod	16380	57.3	0.8

Table 3.31.3 - Summary of additional parameter data at Well 29/10-02

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.31.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	13.91	6.58	2.45	9,975	5,372

Table 3.31.5 - Tuff properties used at Well 29/10-02

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
29/10-02	Horda	PAY	630.000	0.000	0.000	0.000	0.000	0.000	0.000
29/10-02	Horda	RES	630.000	15.500	0.025	3.675	0.237	0.840	0.345
29/10-02	Balder	PAY	57.000	0.000	0.000	0.000	0.000	0.000	0.000
29/10-02	Balder	RES	57.000	0.500	0.009	0.068	0.137	1.000	0.306
29/10-02	Sele	PAY	102.000	0.000	0.000	0.000	0.000	0.000	0.000
29/10-02	Sele	RES	102.000	2.000	0.020	0.355	0.178	1.000	0.470
29/10-02	Lista	PAY	390.130	19.500	0.050	5.138	0.263	0.378	0.146
29/10-02	Lista	RES	390.130	80.500	0.206	17.978	0.223	0.646	0.157
29/10-02	Maureen	PAY	162.870	0.000	0.000	0.000	0.000	0.000	0.000
29/10-02	Maureen	RES	162.870	127.500	0.783	14.800	0.116	0.961	0.117
29/10-02	Ekofisk	PAY	211.000	0.000	0.000	0.000	0.000	0.000	0.000
29/10-02	Ekofisk	RES	211.000	206.000	0.976	28.835	0.140	0.987	0.160
29/10-02	Tor	PAY	342.000	0.000	0.000	0.000	0.000	0.000	0.000
29/10-02	Tor	RES	342.000	341.750	0.999	37.524	0.110	0.991	0.031
29/10-02	Hod	PAY	656.000	12.000	0.018	2.240	0.187	0.412	0.098
29/10-02	Hod	RES	656.000	656.000	1.000	75.717	0.115	0.940	0.179

Table 3.31.6 - Petrophysical parameters used at Well 29/10-02

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

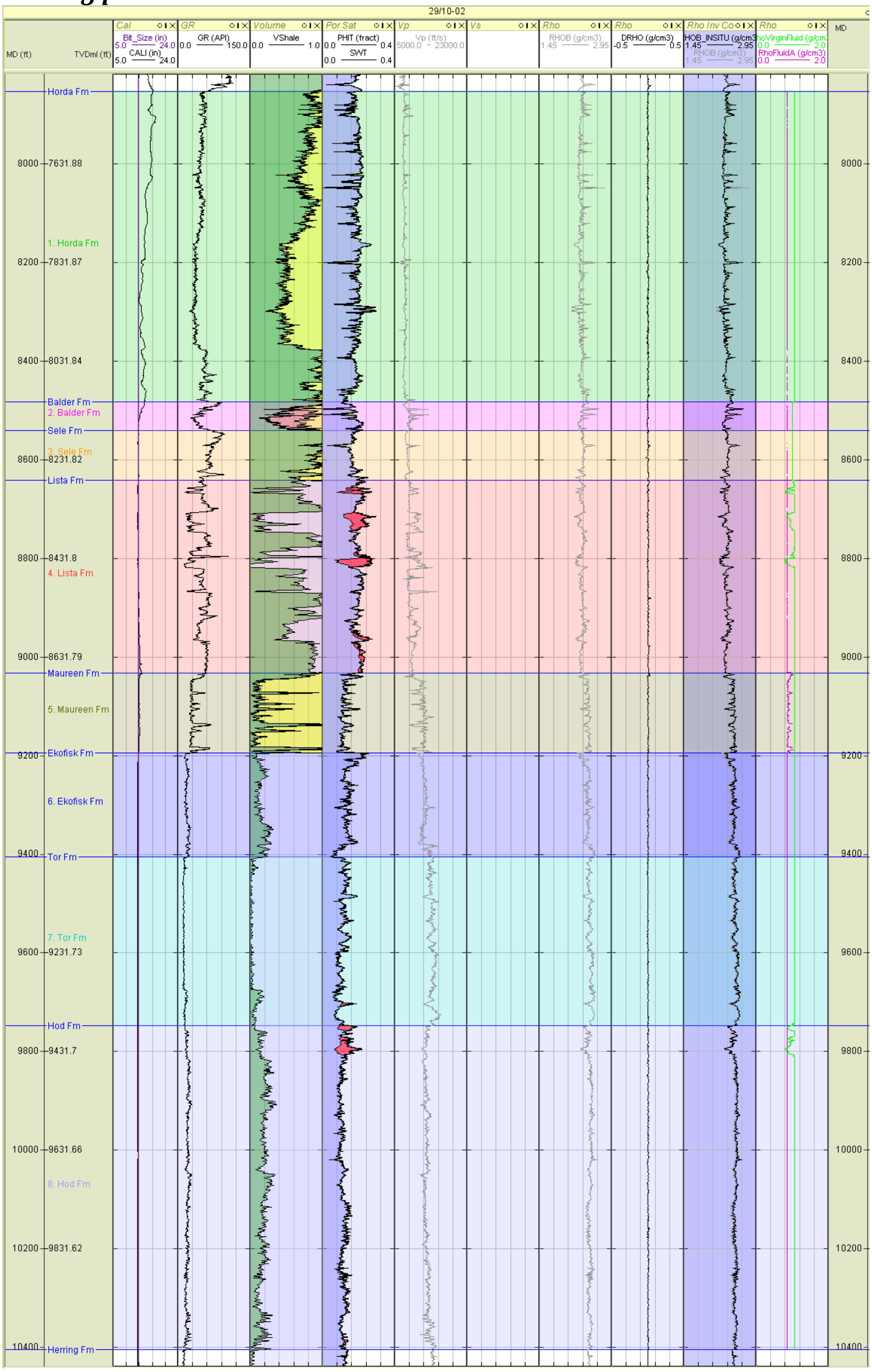


Figure 3.31.3 - Well Panel: Measured data and invasion correction for well 29/10-02.

Well log panel – log editing and audit

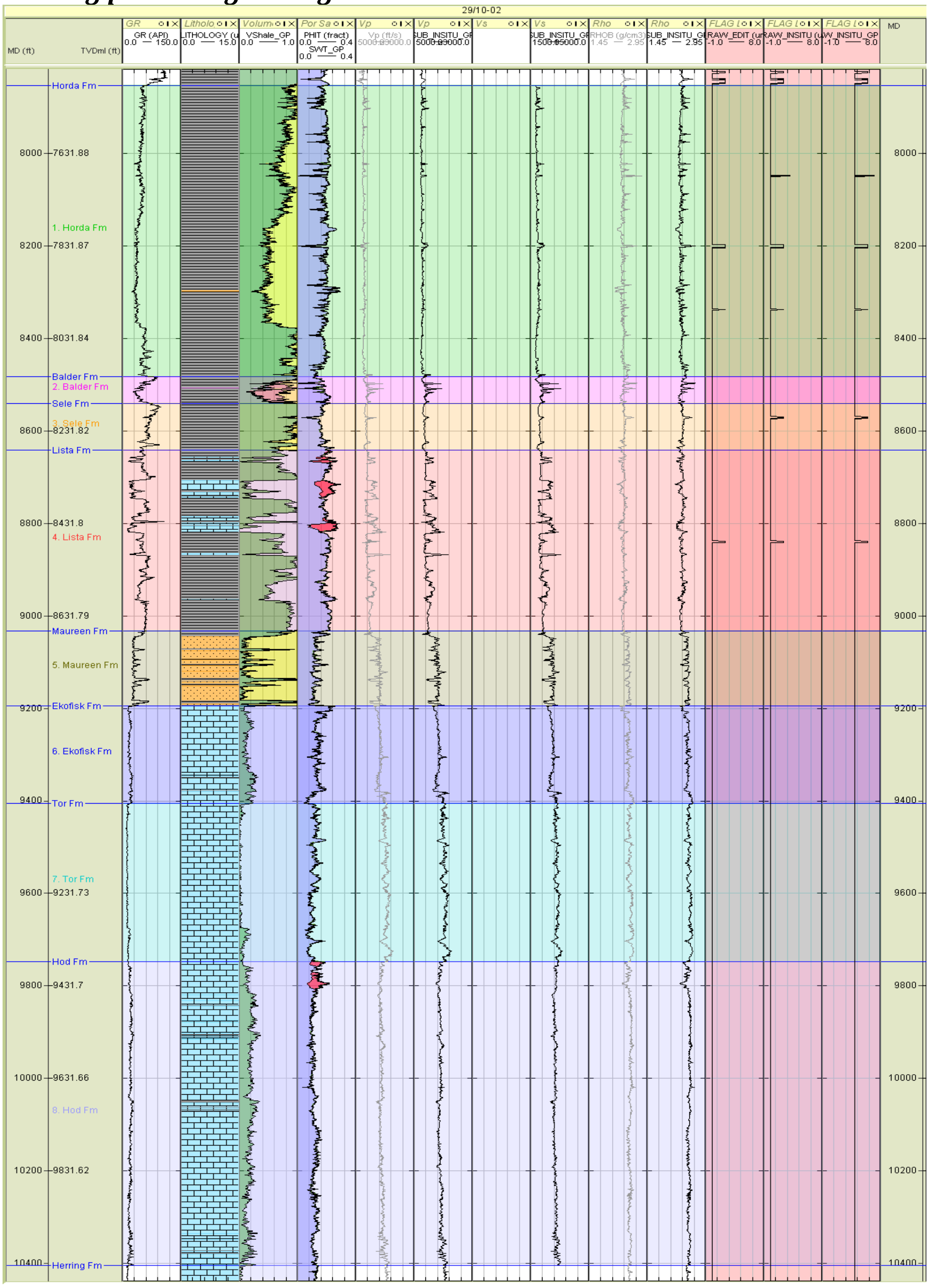


Figure 3.31.4 - Well Panel: Log edits for well 29/10-02.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

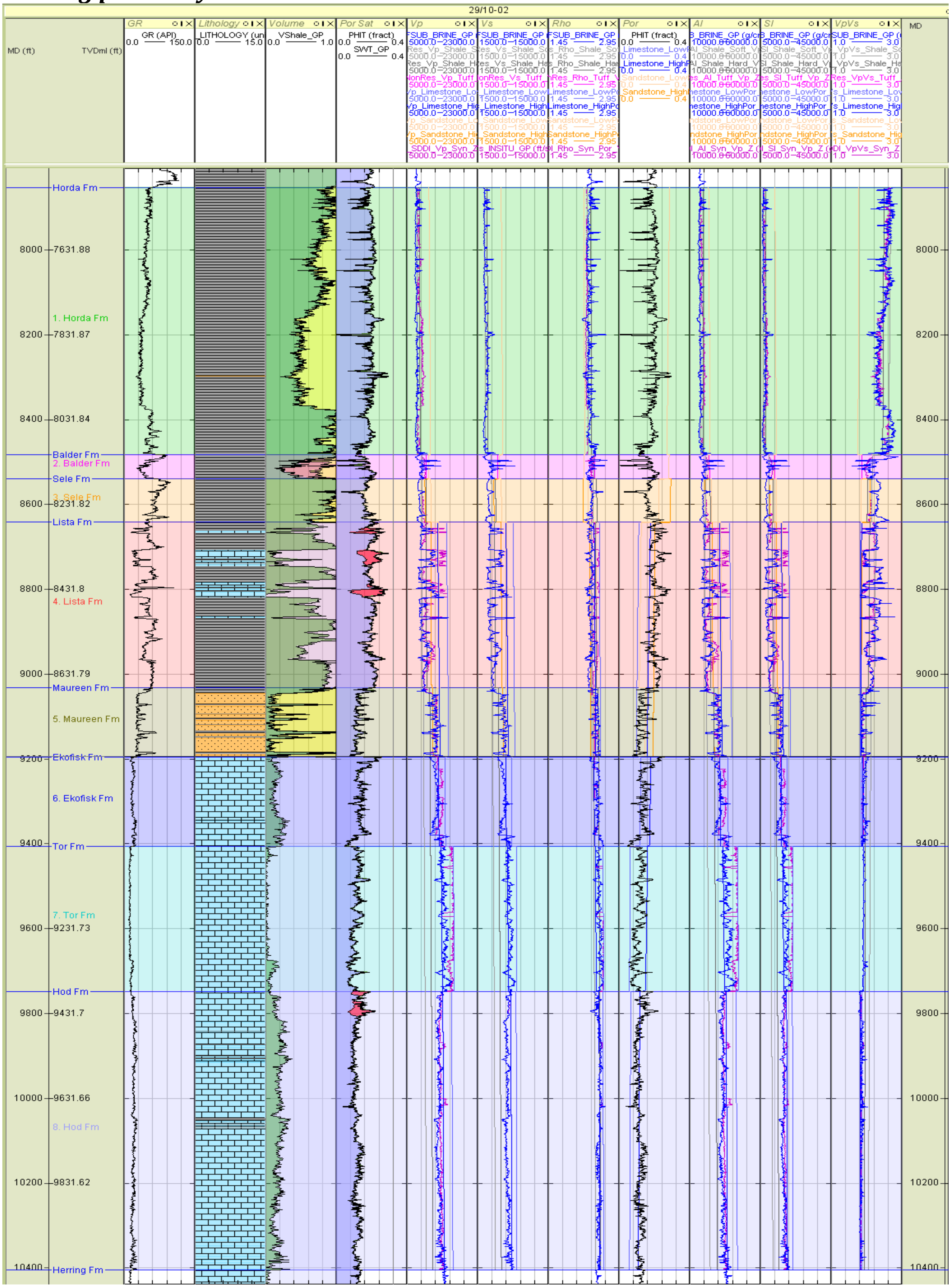


Figure 3.31.5 - Well Panel: End-member and synthetic logs for well 29/10-02.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

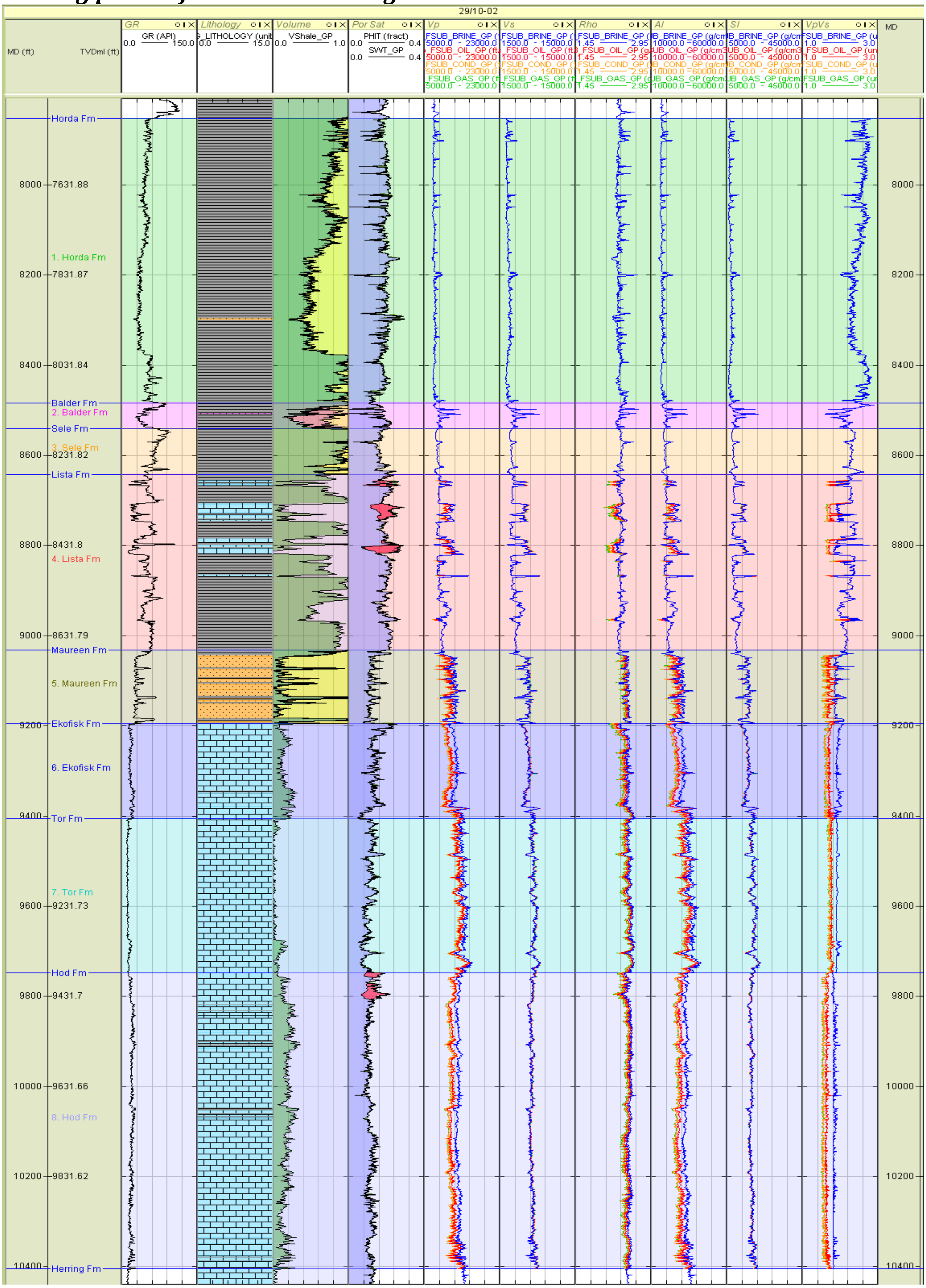


Figure 3.31.6 - Well Panel: Fluid substituted and elastic logs for well 29/10-02.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/10-02 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm³)
29/10-02	Horda	7329	2809	2.32
29/10-02	Balder	7579	2939	2.39
29/10-02	Sele	8053	3504	2.36
29/10-02	Lista	8746	3924	2.33
29/10-02	Maureen	9499	4584	2.38

Table 3.31.7 - Clean shale properties at Well 29/10-02

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm³)
29/10-02	Horda	100% Brine			
29/10-02	Balder	100% Brine			
29/10-02	Sele	100% Brine			
29/10-02	Lista	100% Brine			
29/10-02	Maureen	100% Brine	12174	6489	2.49
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm³)**
29/10-02	Horda	80% Oil			
29/10-02	Balder	80% Oil			
29/10-02	Sele	80% Oil			
29/10-02	Lista	80% Oil			
29/10-02	Maureen	80% Oil	11114	6535	2.46
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm³)**
29/10-02	Horda	90% Gas			
29/10-02	Balder	90% Gas			
29/10-02	Sele	90% Gas			
29/10-02	Lista	90% Gas			
29/10-02	Maureen	90% Gas	10701	6596	2.41
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm³)**
29/10-02	Horda	80% Cond			
29/10-02	Balder	80% Cond			
29/10-02	Sele	80% Cond			
29/10-02	Lista	80% Cond			
29/10-02	Maureen	80% Cond	10712	6576	2.43

Table 3.31.8 - Clean sand properties at Well 29/10-02 for each fluid case

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-02	Lista	100% Brine	11,572	5,955	2.34
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/10-02	Lista	80% Oil	10,494	6,046	2.27
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/10-02	Lista	90% Gas	10,254	6,173	2.18
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/10-02	Lista	80% Cond	10,219	6,131	2.21

Table 3.31.9 - Clean limestone properties at Well 29/10-02 for each fluid case (Tertiary)

Tertiary reservoirs – Well panel

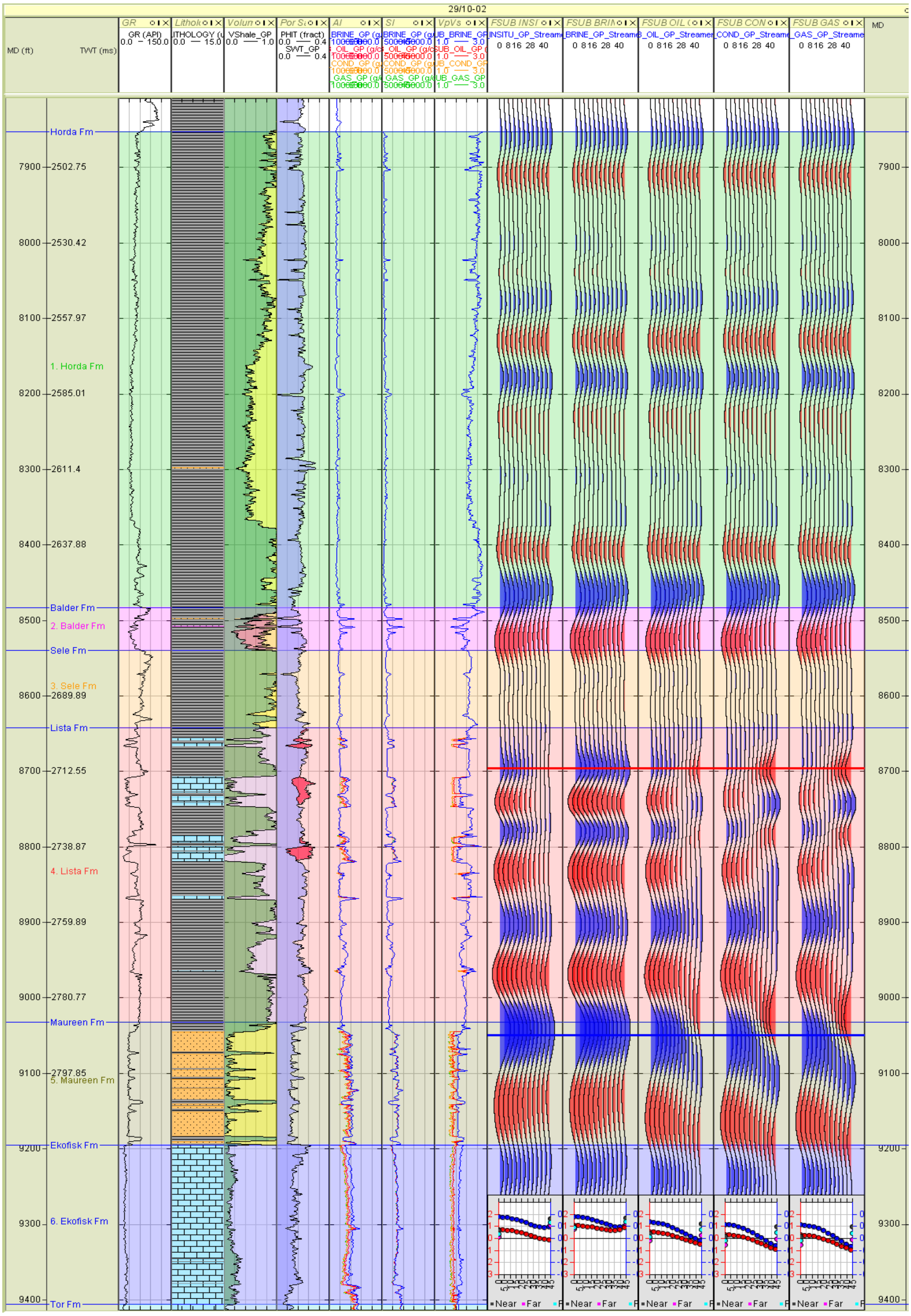


Figure 3.31.7 - Well Panel: Tertiary reservoirs for well 29/10-02. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Lista Formation

- Reservoir formed by a set of limestone sections inter-bedded with shale, net reservoir is approximately 80 feet and contains oil in some of the sections.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases and a modelled class IIp response for the 80% condensate and 90% gas cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

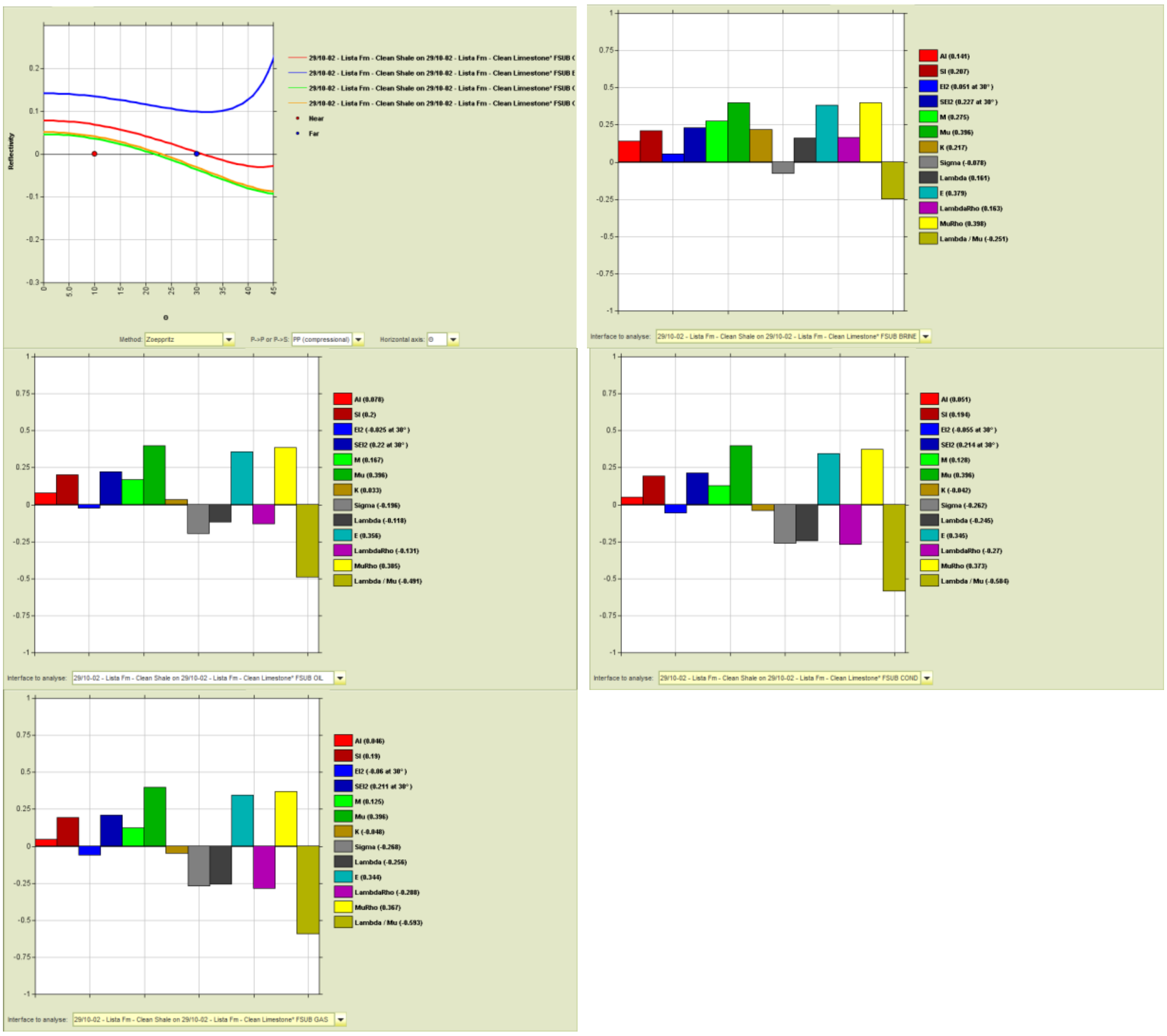


Figure 3.31.8 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 29/10-02.

Maureen Formation

- Reservoir formed by a thick low porosity sand package and net reservoir is approximately 128 feet. The Maureen reservoir sand is overlain directly by overburden shale in the lower section of the Lista Fm.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases and a modelled class IIp response for the 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The change in AVO type is the same on the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts generally become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

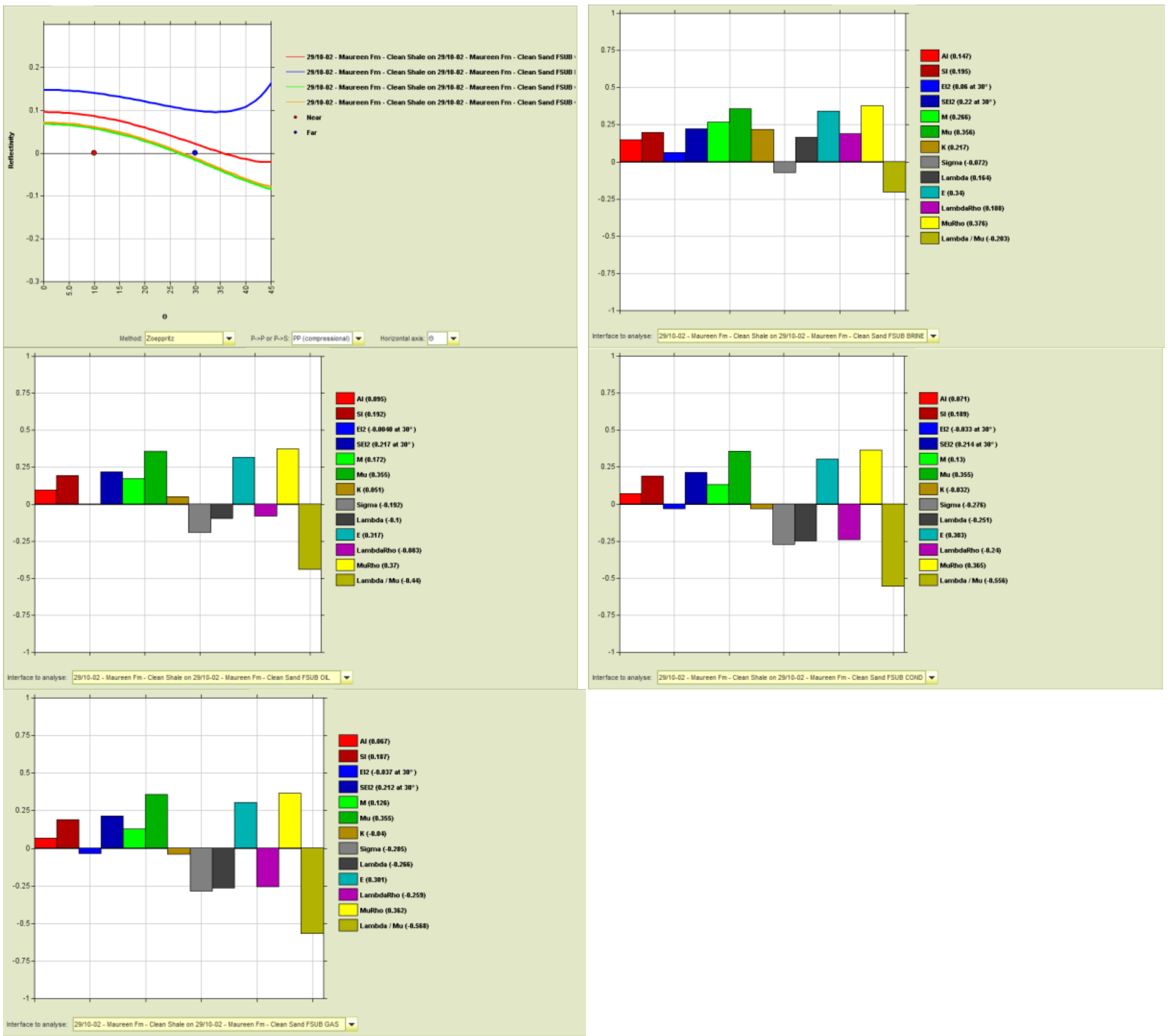


Figure 3.31.9 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 29/10-02.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/10-02 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-02	Ekofisk	100% Brine	12463	6471	2.43
29/10-02	Tor	100% Brine	14305	7516	2.53
29/10-02	Hod	100% Brine	13685	7581	2.48
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/10-02	Ekofisk	80% Oil	11297	6540	2.38
29/10-02	Tor	80% Oil	13346	7567	2.49
29/10-02	Hod	80% Oil	12639	7646	2.44
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/10-02	Ekofisk	90% Gas	10984	6634	2.31
29/10-02	Tor	90% Gas	13077	7636	2.45
29/10-02	Hod	90% Gas	12341	7732	2.39
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/10-02	Ekofisk	80% Cond	10970	6603	2.34
29/10-02	Tor	80% Cond	13071	7614	2.46
29/10-02	Hod	80% Cond	12335	7704	2.41

Table 3.31.10 - Clean limestone properties at Well 29/10-02 for each fluid case

Cretaceous reservoirs

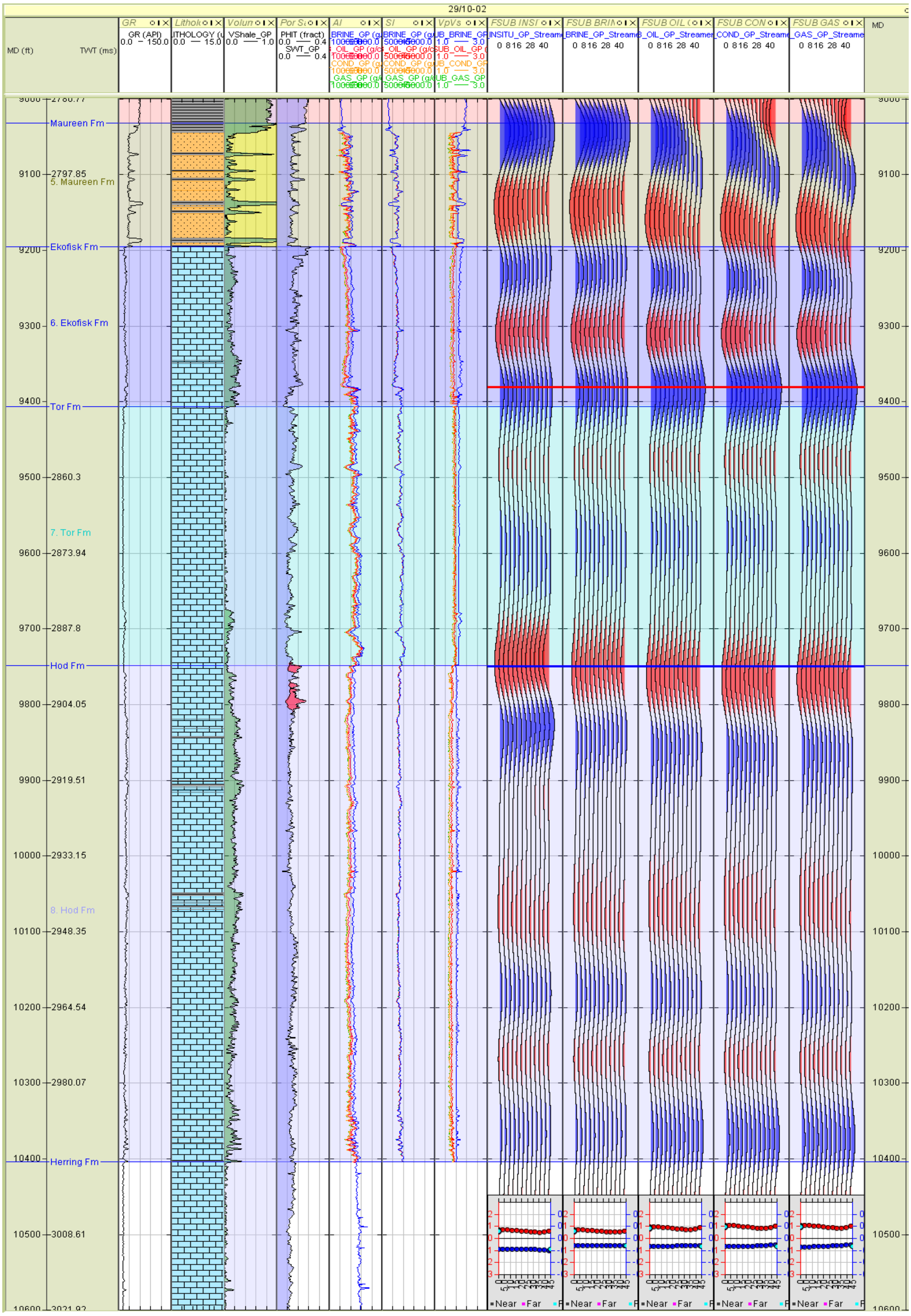


Figure 3.31.10 - Well Panel: Cretaceous reservoirs for well 29/10-02. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The reservoir consists of chalk with a continually varying porosity from 6-22%.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases and a modelled class IIp response for the 80% condensate and 90% gas cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

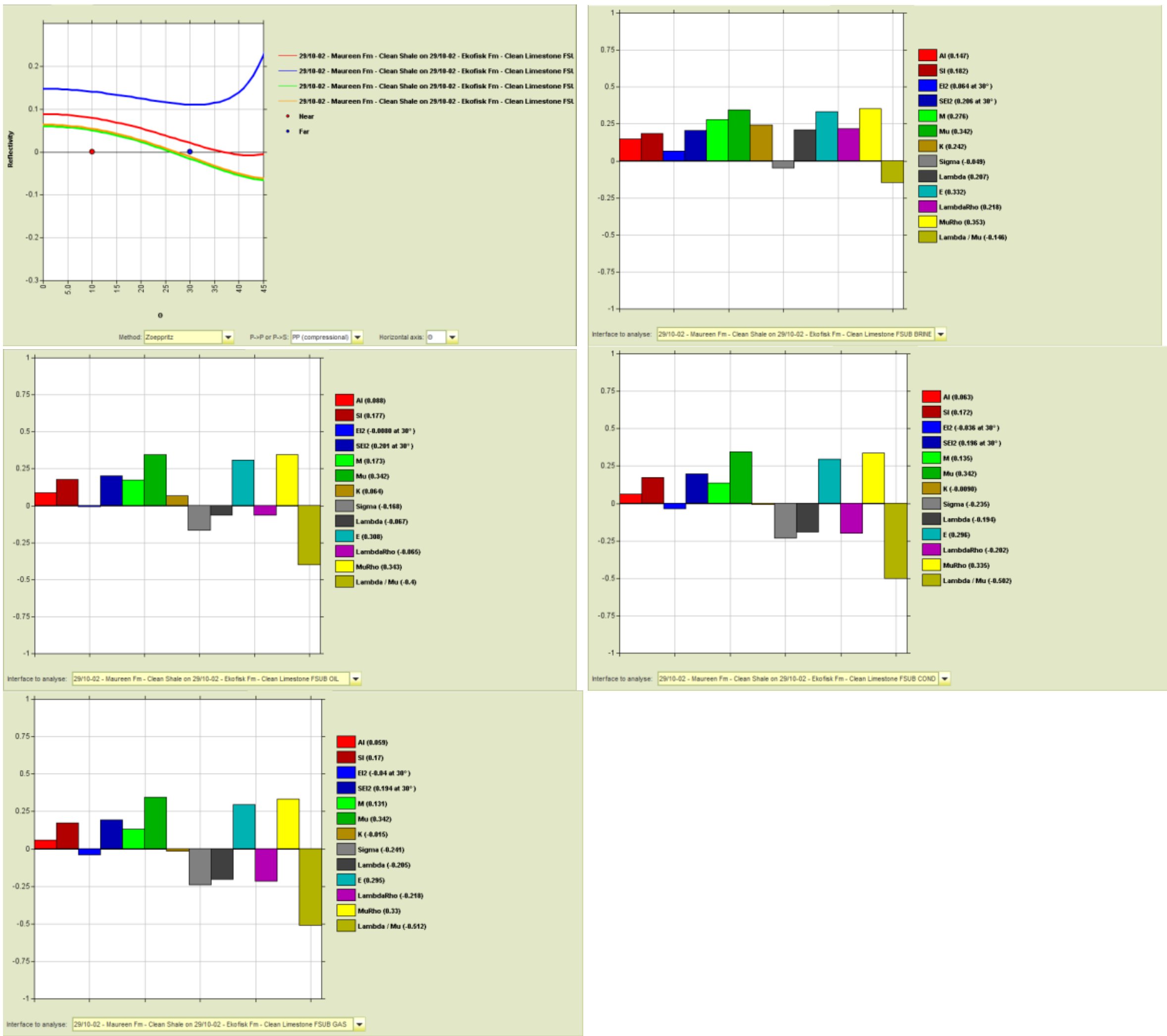


Figure 3.31.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 29/10-02.

Tor Formation

- Reservoir formed by a clean limestone formation. The reservoir consists of chalk with a low-medium porosity from 6-18%.
- Blocky AVO shows a modelled class I response for the 100% brine and 80% oil cases and a modelled class IIp response for the 80% condensate and 90% gas cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

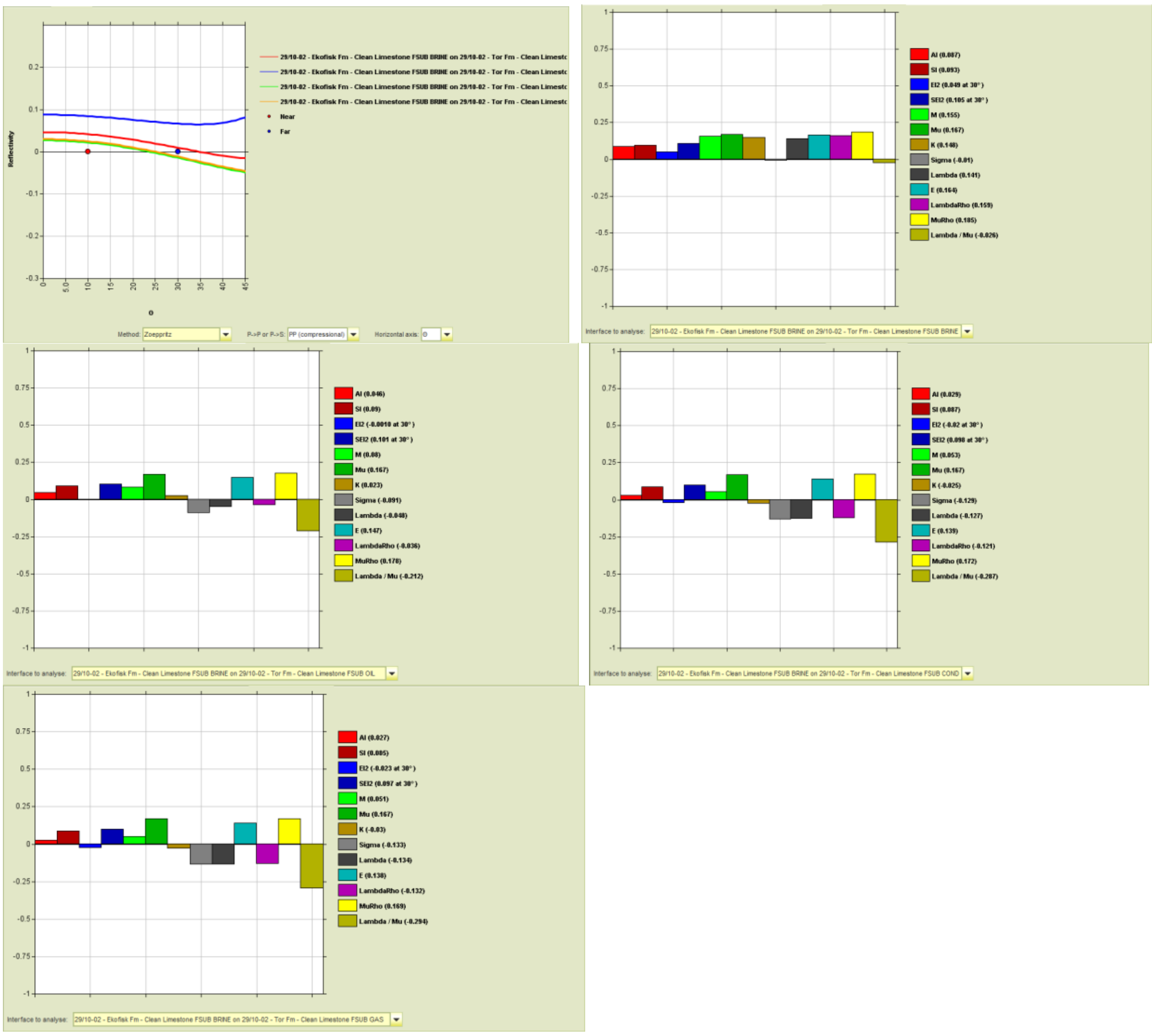


Figure 3.31.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 29/10-02.

Hod Formation

- Reservoir formed by a limestone formation with a minor component of shale. The reservoir consists of chalk with a continually varying porosity from 11-22%. The highest porosity zone is found at the top of the Hod Fm and contains some oil-bearing reservoir.
- Blocky AVO shows a modelled class III response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are negative amplitude in the brine case, and that the contrasts become more negative for all attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

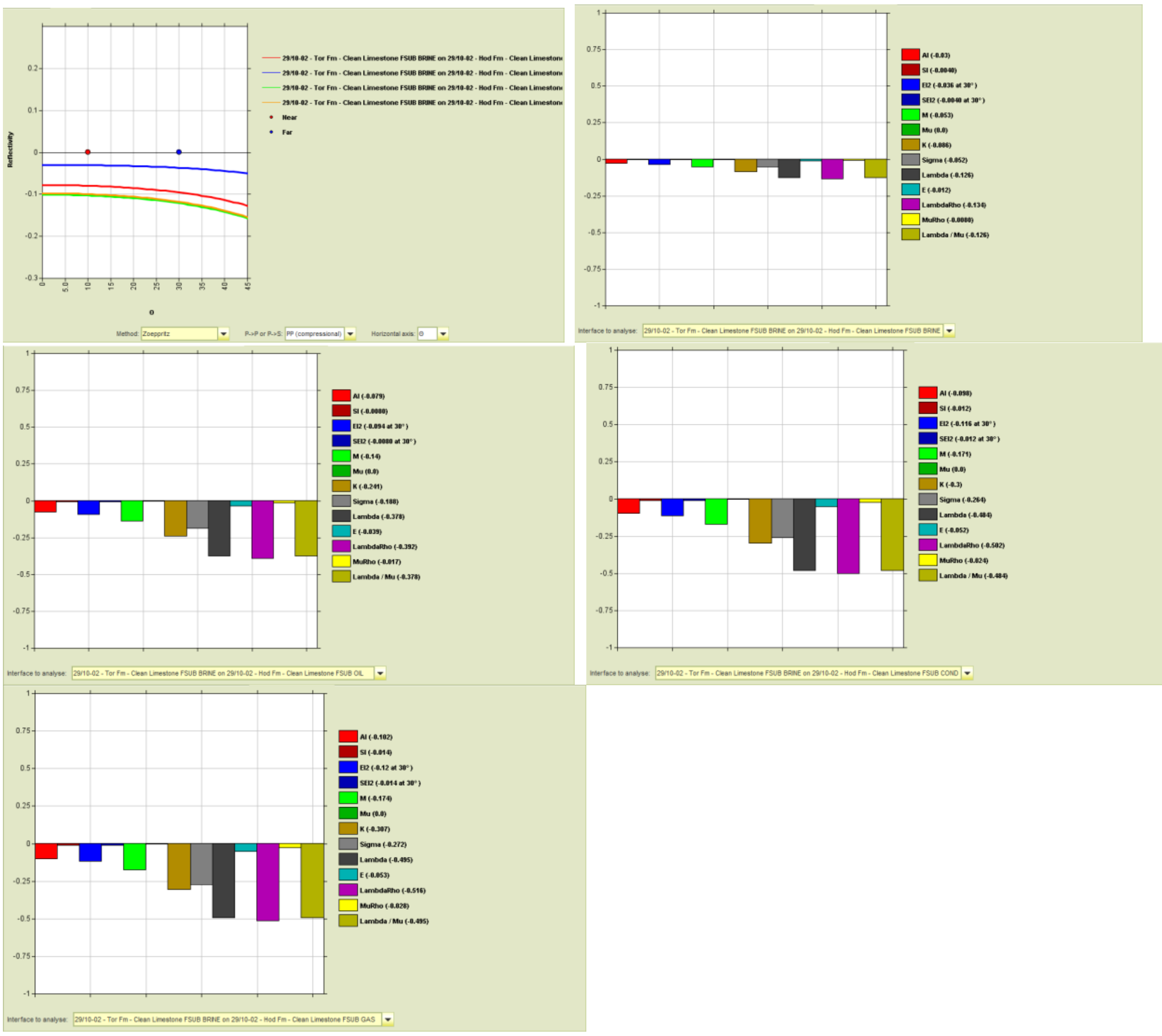


Figure 3.31.13 - Blocky AVO Model and Elastic Contrast Analysis for the Tor Limestone/Hod Limestone interface in well 29/10-02.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 29/10-02 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-02	Overburden	Shale	7241		2.29
29/10-02	Underburden	Limestone	15045		2.52

Table 3.31.11 - Overburden and underburden properties at Well 29/10-02.

Well: 29/10-04Z

General

Well Information
This well is a Shell operated exploration well spudded, drilled and abandoned in 1995. The well encountered oil in the Sele and Lista Fm within the study interval.

Objectives
Well 29/10-04 was drilled as an exploration well in order to determine the hydrocarbon content of the Eocene Rogland Sandstone. The Rogland is a channel sand which lies in a stratigraphic trap, sealed by the Balder, Sele, and Lisa Formations. All of which comprise a sequence of Eocene submarine fans. The primary objective of well 29/10-04 was to test the hydrocarbon potential of the Rogland sands. The well was drilled into the Ekofisk Chalk in order to allow logging of the Lower Tertiary stratigraphy as well as the primary objective. Well 29/10-04Z is an up-dip sidetrack targeting the Rogland Sandstone. The sands were found to be 76 feet thick with a well defined OWC giving 40 feet of net oil sands. There were also two Andrew Formation sand intervals with hydrocarbons.

Log conditioning overview
Thin calcite stringers in the Horda Formation seen on the density log were not apparent on the Vp log, with data relating to these intervals was consequentially removed. Vs data points that did not show correlative measurements were removed from the log data in the Horda, Balder and Sele Formations. A high value spike in the Vp log was seen between 10,083-10,104ft MD in the Lista Fm and this spike was removed from the Vp log. A high value spike in the Vs log was seen between 10,064-10,104ft MD in the Lista Fm and this spike was removed from the Vs log. The density log was edited to remove a section of washed-out data in the Maureen Fm.

Invasion correction
Invasion correction has been performed on the density log within all of the five formations with reservoir present. The drilling mud used within this well was oil-based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Lista and Ekofisk Formations for the Vp log, within the Horda, Balder, Sele, Lista and Ekofisk Formations for the Vs log and within the Horda, Lista and Maureen Formations for the density log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 29/10-04Z is displayed in the figures below;

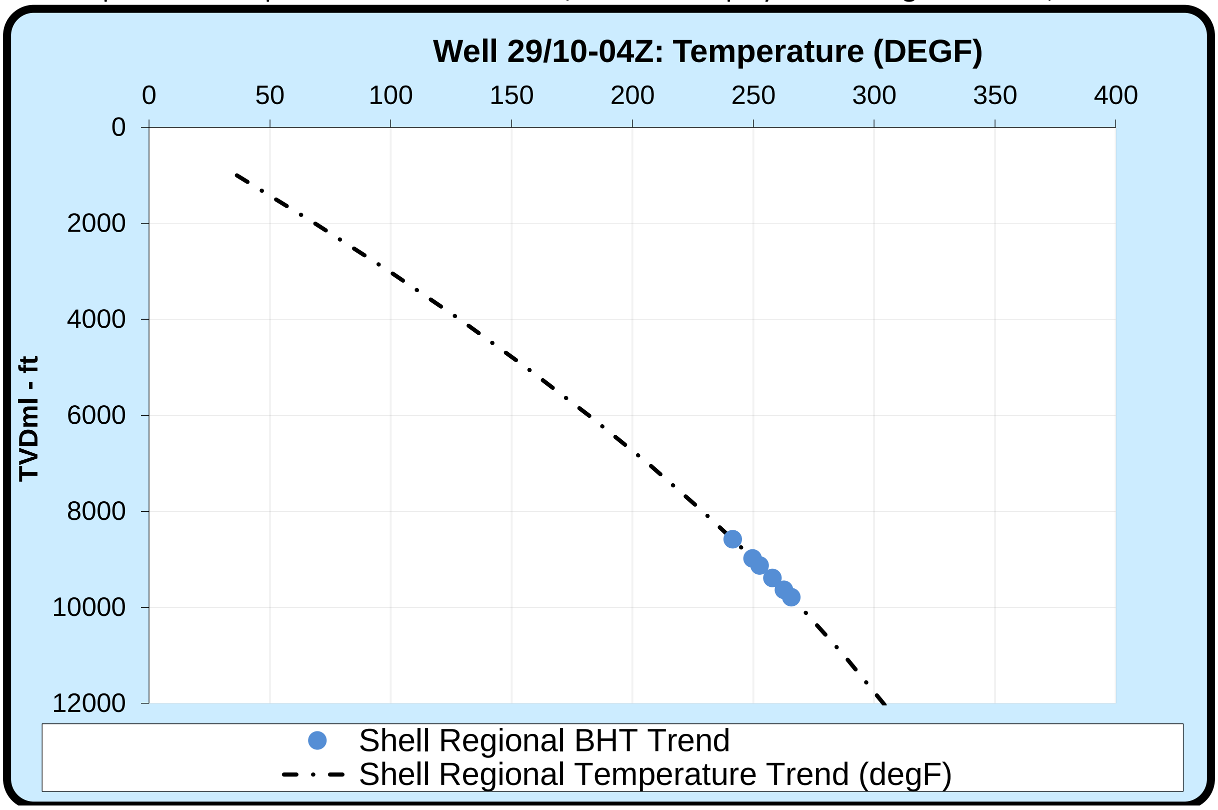


Figure 3.32.1 - Temperature data at Well 29/10-04Z

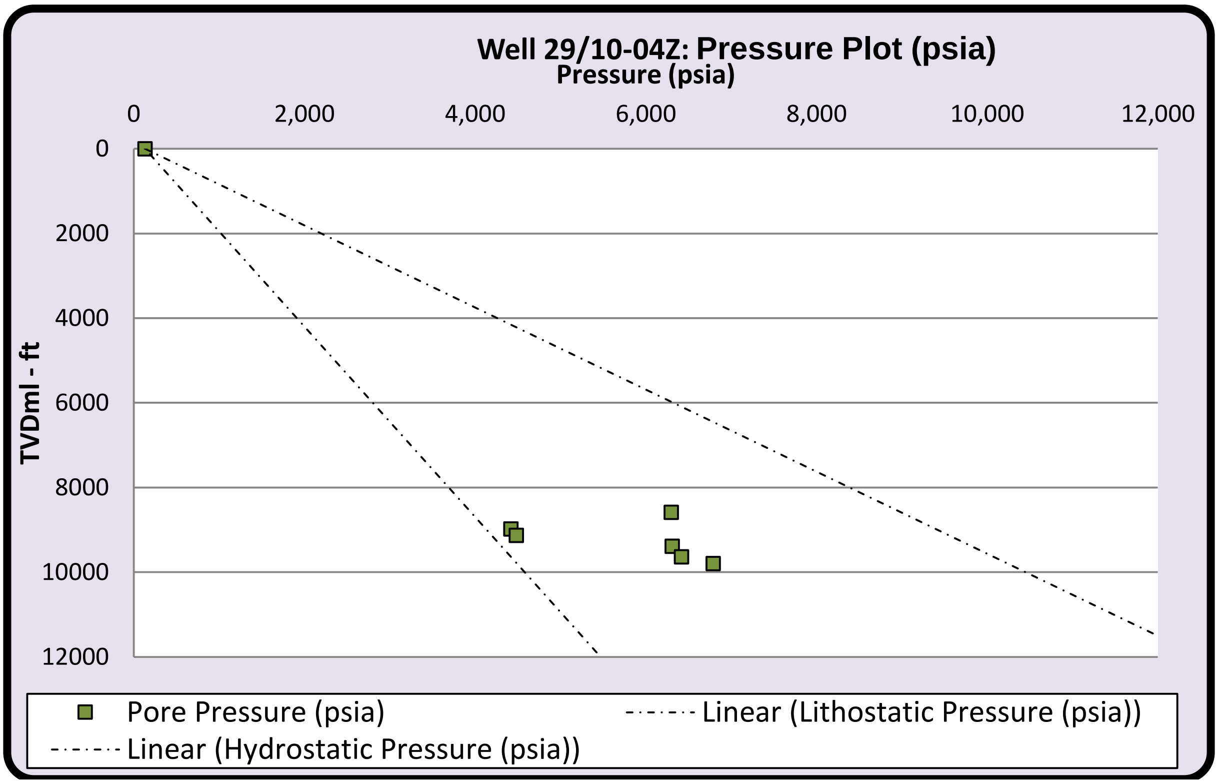


Figure 3.32.2 - Pressure data at Well 29/10-04Z

The temperature and pressure data for the formation mid-points in Well 29/10-04Z is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
29/10-04Z	Sea Bed	445.0	297.0	0.0	39.2	132.2	132.2	132.17	0.00
29/10-04Z	Horda	9185.3	8877.7	8580.7	241.5	3950.6	6300.6	8580.69	2280.12
29/10-04Z	Balder	9599.2	9276.3	8979.3	249.8	4128.0	4418.0	8979.35	4561.37
29/10-04Z	Sele	9749.4	9422.8	9125.8	252.7	4193.1	4483.1	9125.81	4642.66
29/10-04Z	Lista	10016.7	9683.8	9386.8	257.9	4309.3	6309.3	9386.82	3077.52
29/10-04Z	Maureen	10268.8	9930.4	9633.4	262.7	4419.0	6419.0	9633.40	3214.37
29/10-04Z	Ekofisk	10429.3	10087.6	9790.6	265.7	4489.0	6789.0	9790.61	3001.63

Table 3.32.1 - Summary of mid-point temperature and pressure data at Well 29/10-04Z

Fluid data

A summary of the fluid set parameters at Well 29/10-04Z is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
29/10-04Z	Horda	60000	730	40.6	0.78	0.78
29/10-04Z	Balder	60000	730	41.1	0.78	0.78
29/10-04Z	Sele	60000	2501	40.8	0.7783	0.7783
29/10-04Z	Lista	60000	1350	42.1	0.7882	0.7882
29/10-04Z	Maureen	60000	730	41.8	0.78	0.78
29/10-04Z	Ekofisk	110000	730	41.9	0.78	0.78

Table 3.32.2 - Summary of fluid parameter data at Well 29/10-04Z

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
29/10-04Z	Horda	16380	56.4	0.8
29/10-04Z	Balder	16380	56.7	0.8
29/10-04Z	Sele	16380	56.8	0.8
29/10-04Z	Lista	16380	57.1	0.8
29/10-04Z	Maureen	16380	57.3	0.8
29/10-04Z	Ekofisk	16380	57.4	0.8

Table 3.32.3 - Summary of additional parameter data at Well 29/10-04Z

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.32.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	12.42	7.35	2.401	9,981	5,739

Table 3.32.5 - Tuff properties used at Well 29/10-04Z

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Num-ber	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
29/10-04Z	Horda	PAY	757.290	0.000	0.000	0.000	0.000	0.000	0.000
29/10-04Z	Horda	RES	757.290	20.000	0.026	3.765	0.188	0.987	0.350
29/10-04Z	Balder	PAY	70.590	0.000	0.000	0.000	0.000	0.000	0.000
29/10-04Z	Balder	RES	70.590	0.000	0.000	0.000	0.000	0.000	0.000
29/10-04Z	Sele	PAY	229.860	32.500	0.141	10.832	0.333	0.329	0.088
29/10-04Z	Sele	RES	229.860	63.500	0.276	19.939	0.314	0.557	0.108
29/10-04Z	Lista	PAY	304.640	5.500	0.018	1.276	0.232	0.439	0.007
29/10-04Z	Lista	RES	304.640	95.250	0.313	16.776	0.176	0.836	0.143
29/10-04Z	Maureen	PAY	199.500	0.000	0.000	0.000	0.000	0.000	0.000
29/10-04Z	Maureen	RES	199.500	112.000	0.561	26.026	0.232	0.992	0.033
29/10-04Z	Ekofisk	PAY	122.110	0.000	0.000	0.000	0.000	0.000	0.000
29/10-04Z	Ekofisk	RES	122.110	95.000	0.778	13.762	0.145	0.997	0.082

Table 3.32.6 - Petrophysical parameters used at Well 29/10-04Z

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

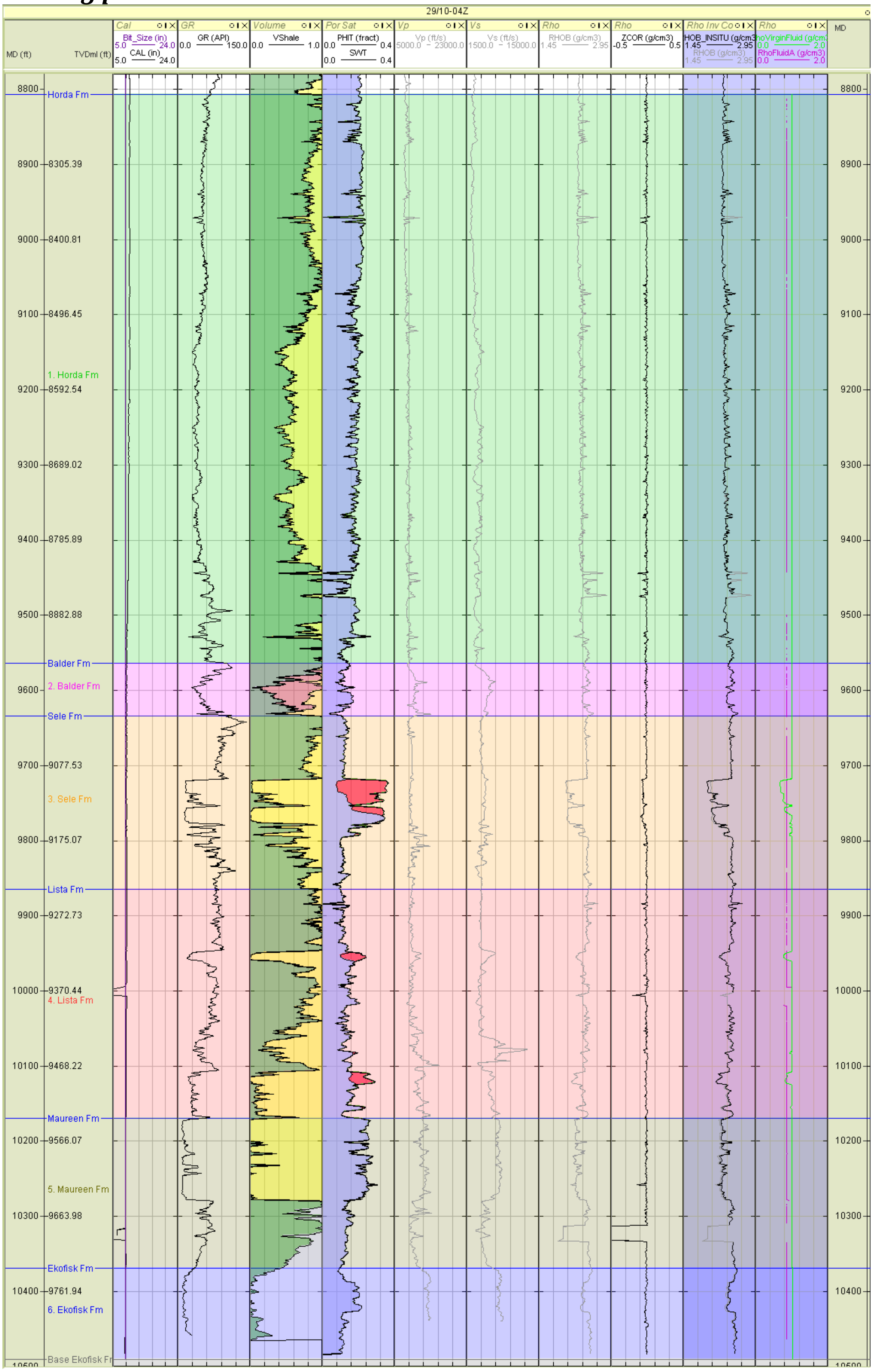


Figure 3.32.3 - Well Panel: Measured data and invasion correction for well 29/10-04Z.

Well log panel – log editing and audit

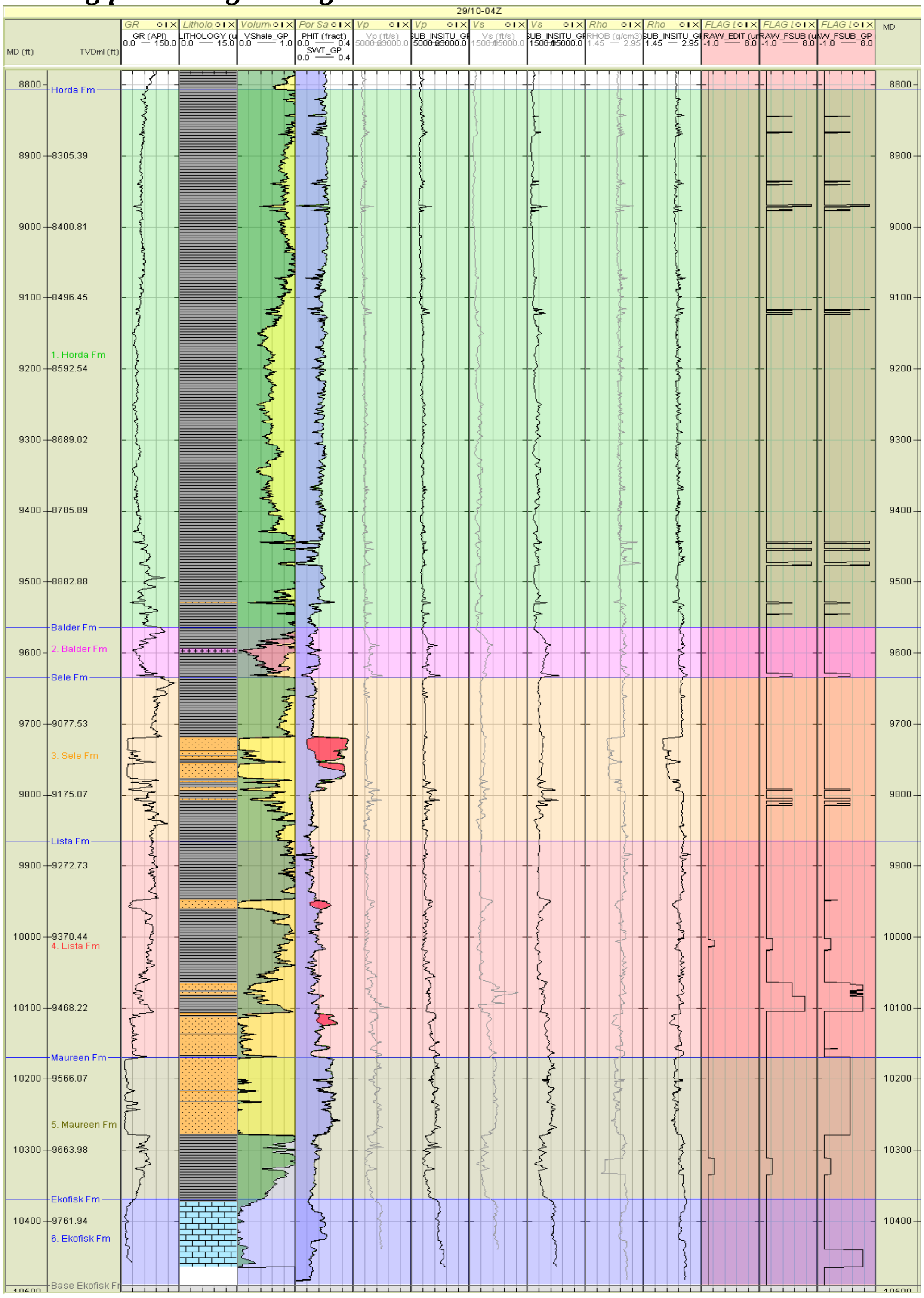


Figure 3.32.4 - Well Panel: Log edits for well 29/10-04Z.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

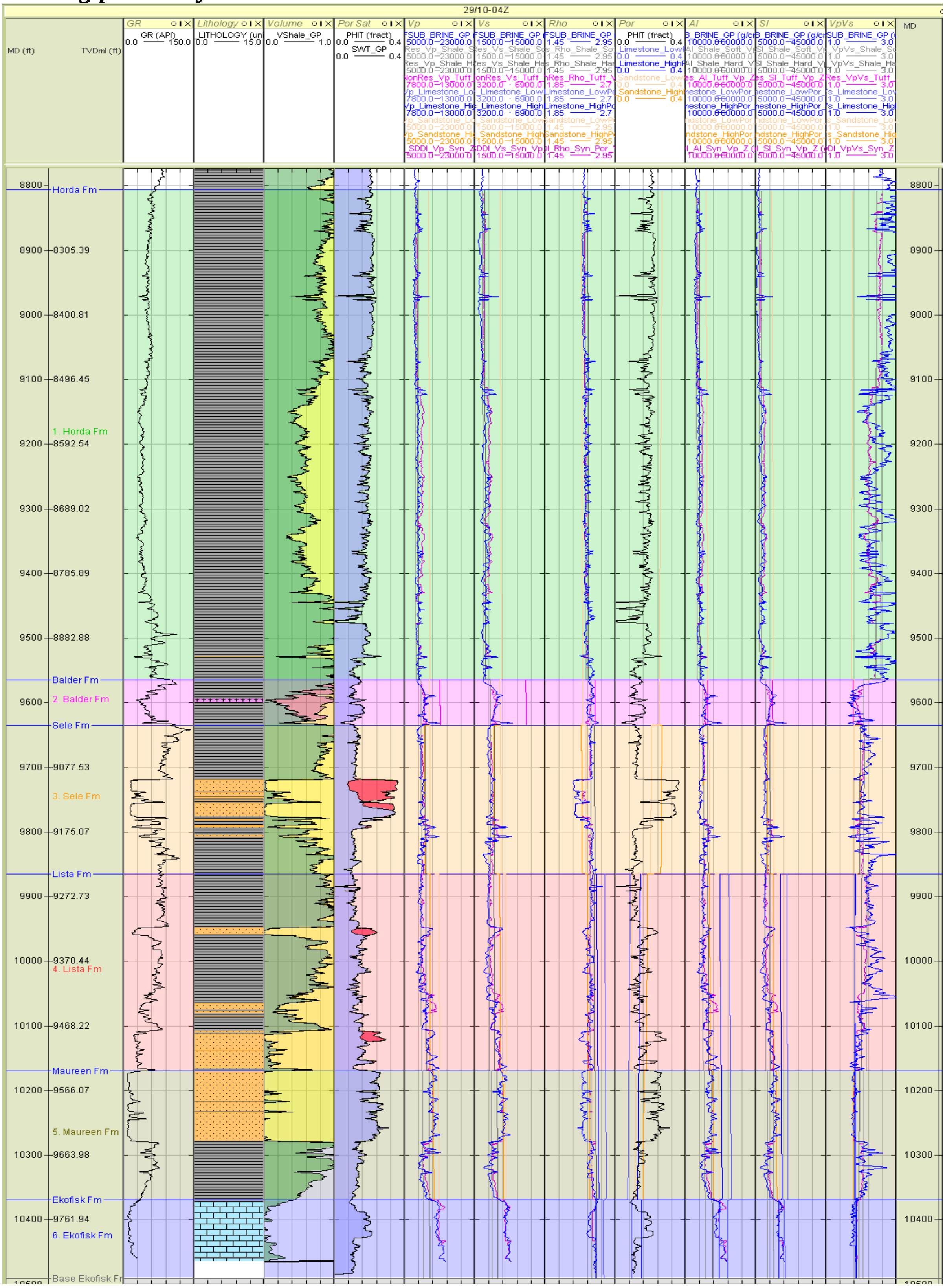


Figure 3.32.5 - Well Panel: End-member and synthetic logs for well 29/10-04Z.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

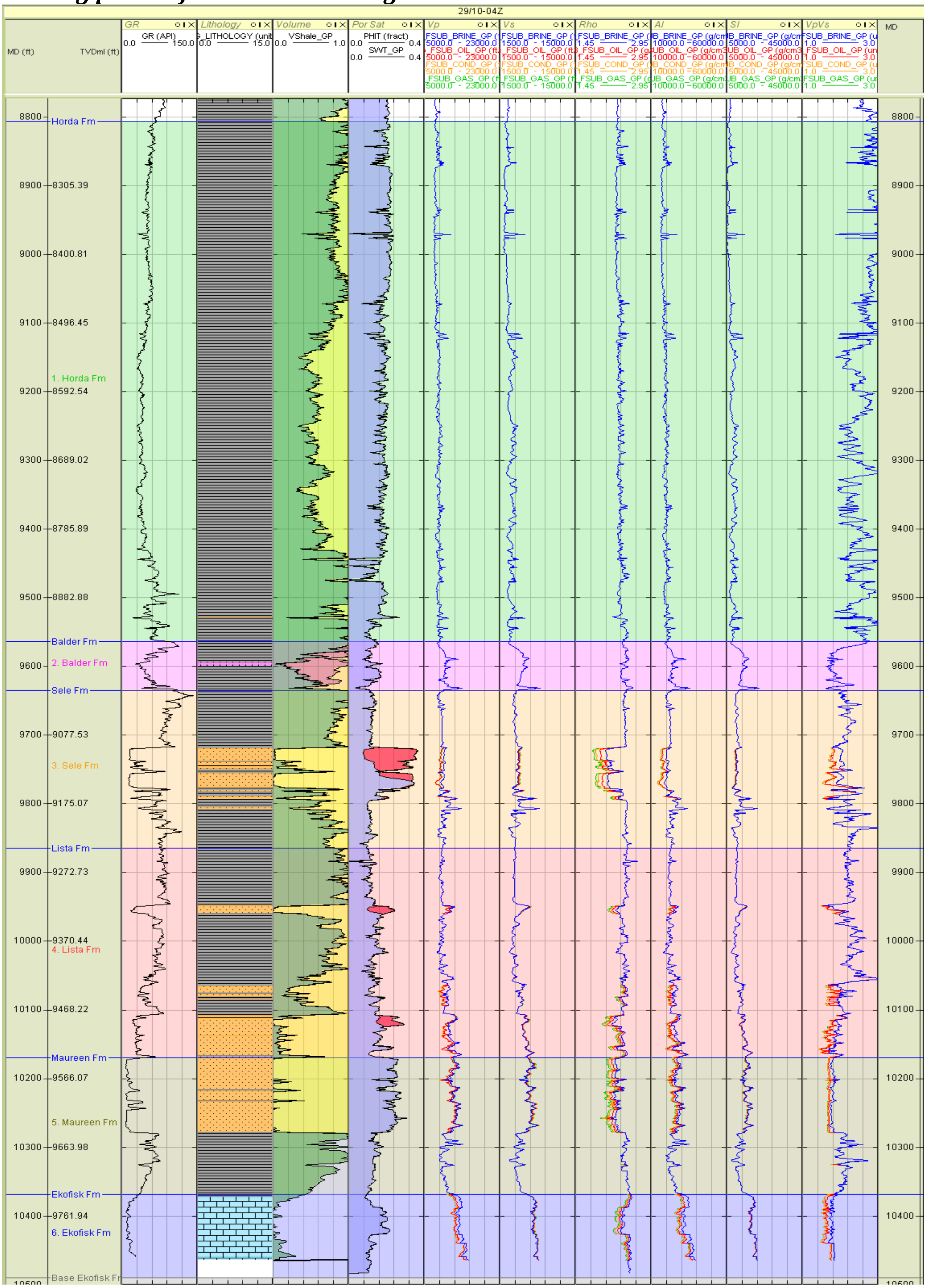


Figure 3.32.6 - Well Panel: Fluid substituted and elastic logs for well 29/10-04Z.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 29/10-04Z is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-04Z	Horda	7948	2874	2.31
29/10-04Z	Balder	8980	4189	2.43
29/10-04Z	Sele	9068	4168	2.43
29/10-04Z	Lista	9148	4038	2.44
29/10-04Z	Maureen	9708	4494	2.44

Table 3.32.7 - Clean shale properties at Well 29/10-04Z

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-04Z	Horda	100% Brine			
29/10-04Z	Balder	100% Brine			
29/10-04Z	Sele	100% Brine	9921	4968	2.13
29/10-04Z	Lista	100% Brine	11399	5922	2.36
29/10-04Z	Maureen	100% Brine	12189	6821	2.27
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-04Z	Horda	80% Oil			
29/10-04Z	Balder	80% Oil			
29/10-04Z	Sele	80% Oil	9119	5088	2.03
29/10-04Z	Lista	80% Oil	10561	5995	2.30
29/10-04Z	Maureen	80% Oil	11764	6916	2.21
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-04Z	Horda	90% Gas			
29/10-04Z	Balder	90% Gas			
29/10-04Z	Sele	90% Gas	9193	5237	1.92
29/10-04Z	Lista	90% Gas	10465	6077	2.24
29/10-04Z	Maureen	90% Gas	11794	7068	2.11
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-04Z	Horda	80% Cond			
29/10-04Z	Balder	80% Cond			
29/10-04Z	Sele	80% Cond	9119	5184	1.96
29/10-04Z	Lista	80% Cond	10444	6047	2.26
29/10-04Z	Maureen	80% Cond	11732	7020	2.14

Table 3.32.8 - Clean sand properties at Well 29/10-04Z for each fluid case

Tertiary reservoirs – Well panel

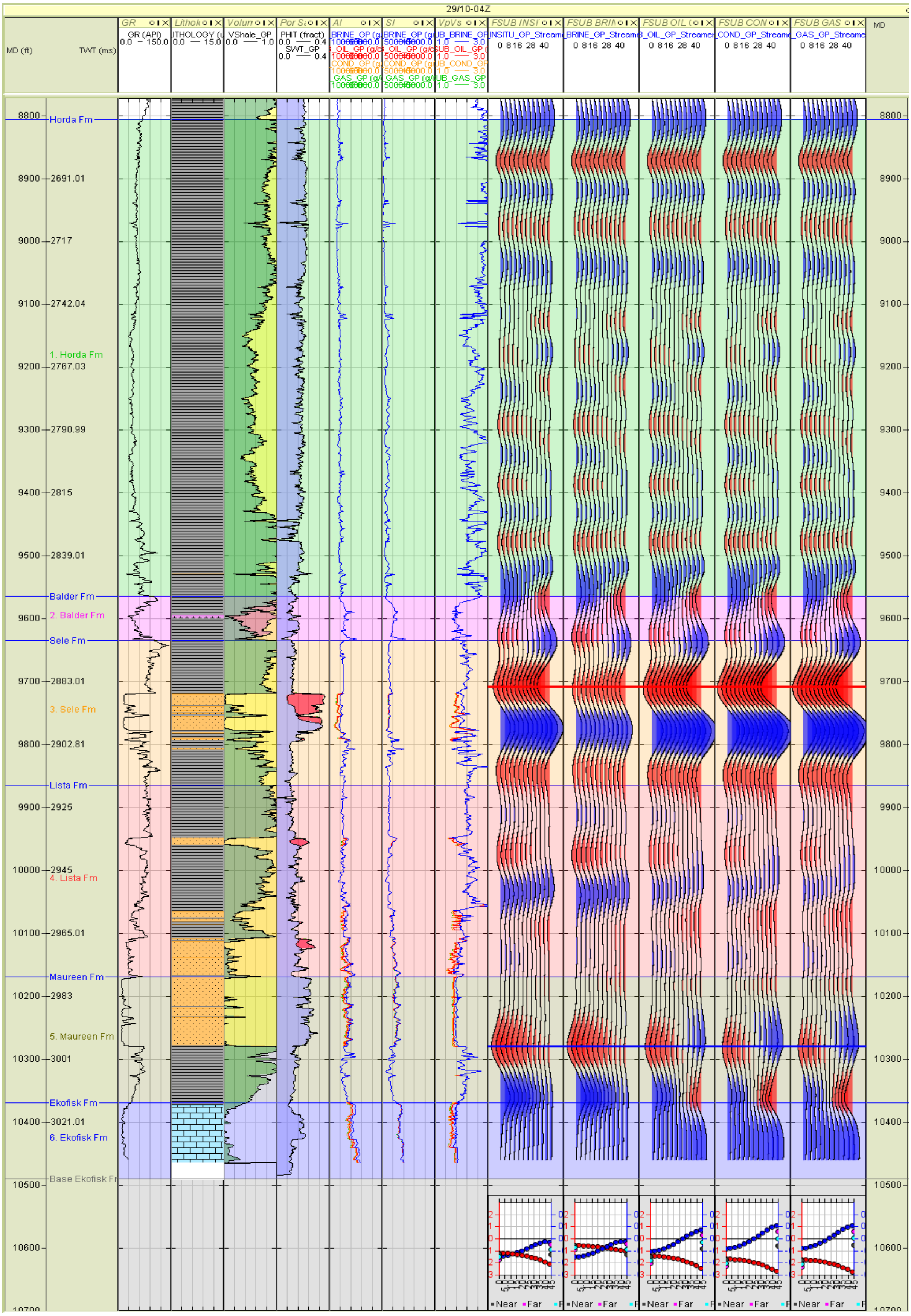


Figure 3.32.7 - Well Panel: Tertiary reservoirs for well 29/10-04Z. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a blocky high porosity sand package and net reservoir is approximately 60 feet. The Sele reservoir sand is overlain directly by the overburden shale of the upper section of the Sele Fm.
- Blocky AVO shows a modelled class II response for the 100% brine case and a modelled class III response for the 80% oil, 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. This change in AVO type is similar to the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly negative and low amplitude in the brine case, but that the contrasts generally become more negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

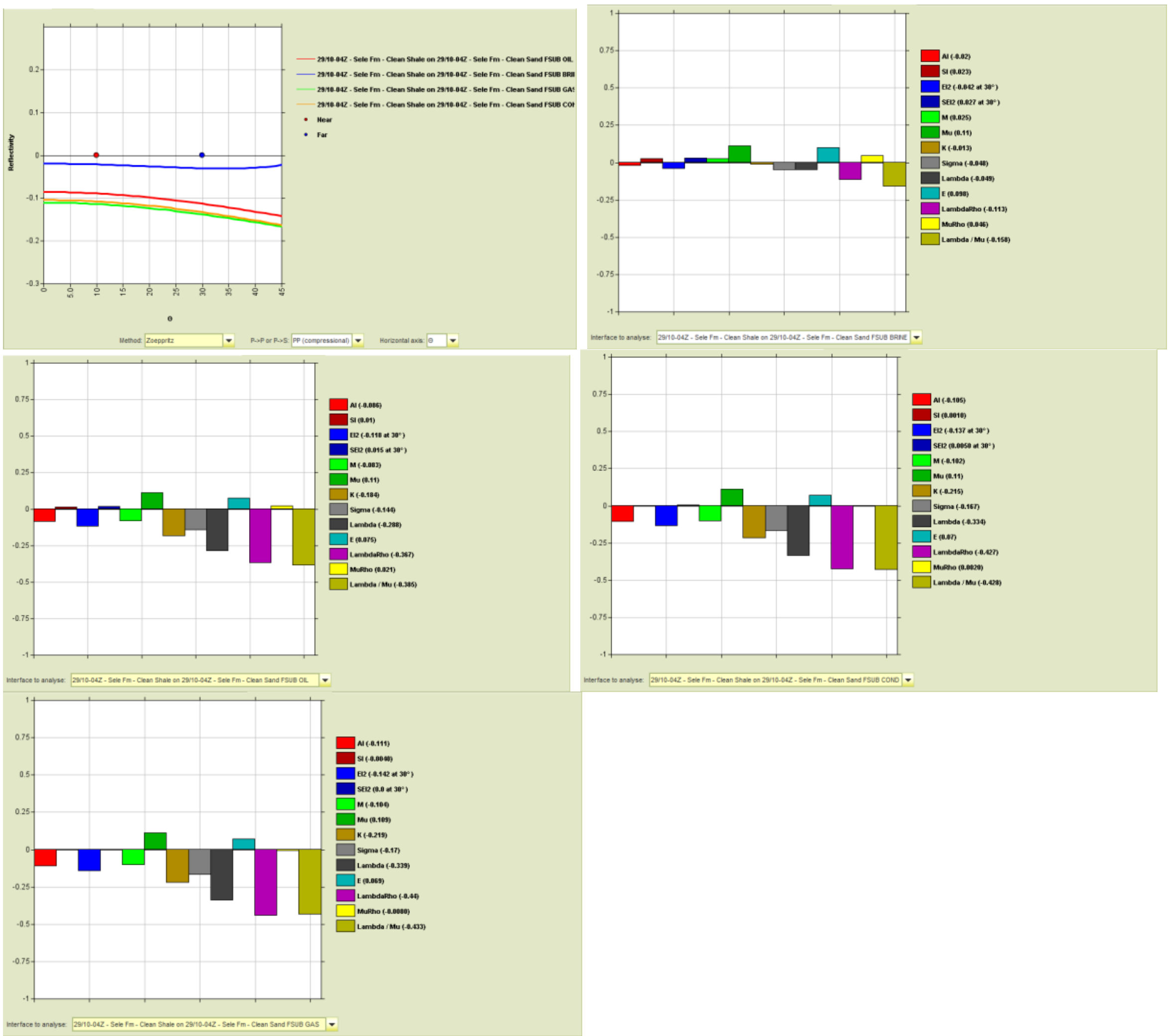


Figure 3.32.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 29/10-04Z.

Lista Formation

- Reservoir formed by a fining upwards sand package towards the base of the interval and a thin high porosity sand with a hard impedance response at 9945ft MD. Net reservoir is approximately 95 feet in this interval.
- Blocky AVO shows a modelled class I response for the 100% brine case and a modelled class IIp response for the 80% oil, 80% condensate and 90% gas fluid cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The synthetic gathers show very weak reflectivity at this interface and this may be due to the gradational nature of the Lista sand towards the base of the interval.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts mainly become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

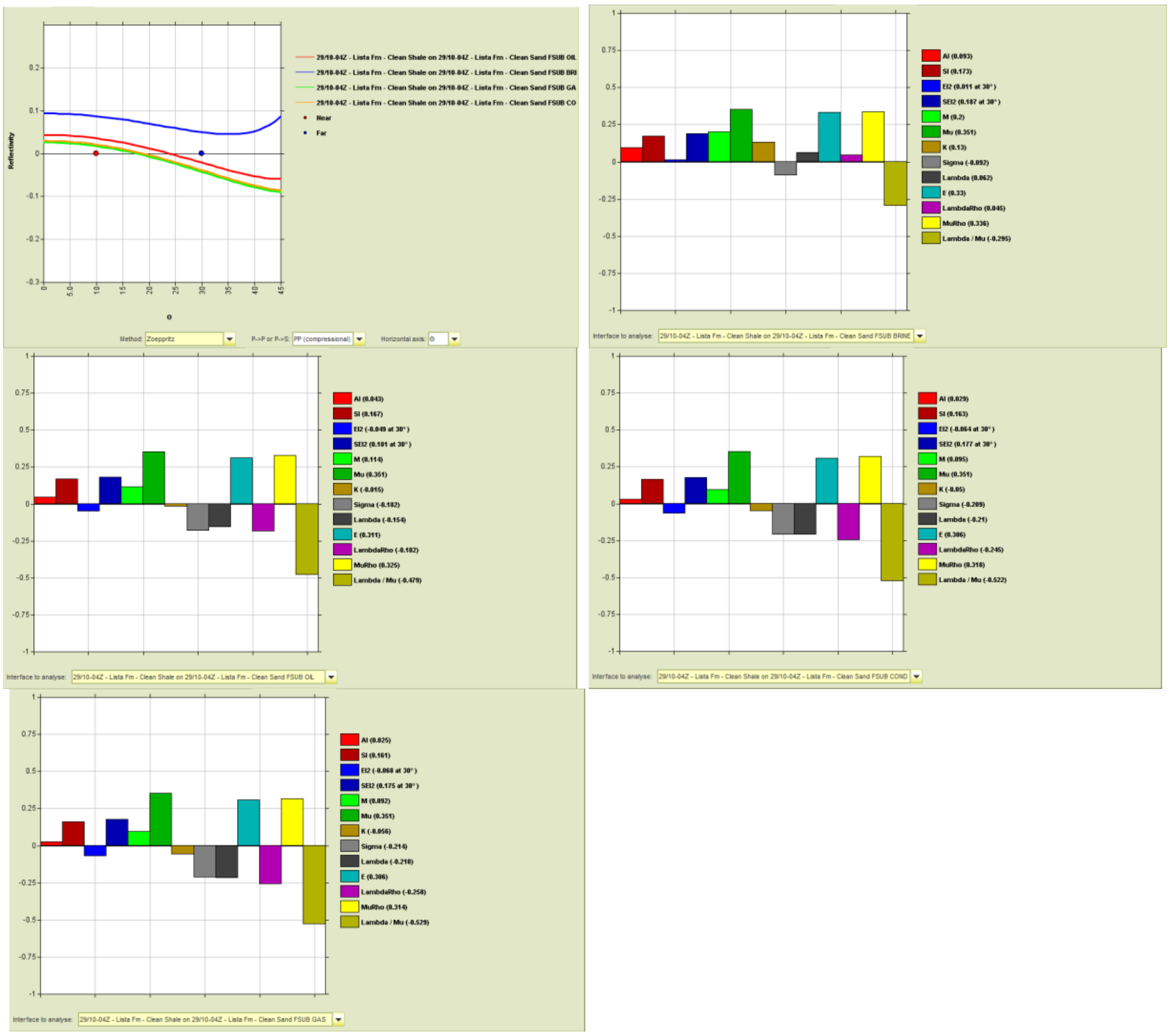


Figure 3.32.9 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 29/10-04Z.

Maureen Formation

- Reservoir formed by a clean, constant porosity sand package in the top half of the Maureen Fm interval. Net reservoir is 112 feet in this interval and the reservoir overlies a marl section of limestone and shale to produce a sand/shale interface.
- Blocky AVO shows a modelled class I response for the 100% brine case and a modelled class IIp response for the 80% oil, 80% condensate and 90% gas fluid cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The synthetic gathers show a base reservoir response and this is the reverse of the modelled top reservoir blocky AVO response.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts mainly become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

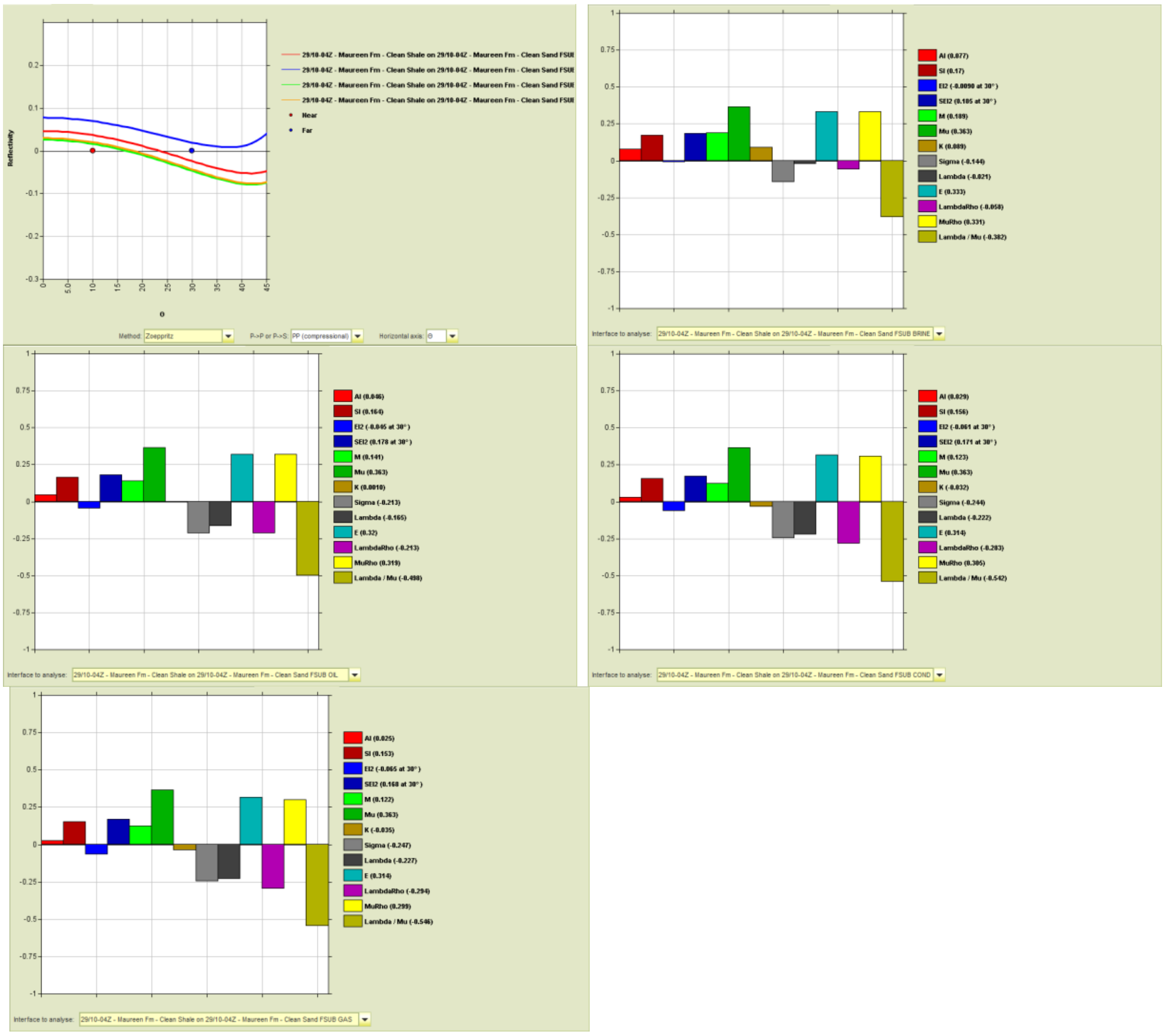


Figure 3.32.10 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 29/10-04Z.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 29/10-04Z is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-04Z	Ekofisk	100% Brine	13648	7660	2.44
29/10-04Z	Tor	100% Brine			
29/10-04Z	Hod	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/10-04Z	Ekofisk	80% Oil	12808	7733	2.39
29/10-04Z	Tor	80% Oil			
29/10-04Z	Hod	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/10-04Z	Ekofisk	90% Gas	12621	7840	2.33
29/10-04Z	Tor	90% Gas			
29/10-04Z	Hod	90% Gas			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
29/10-04Z	Ekofisk	80% Cond	12597	7806	2.35
29/10-04Z	Tor	80% Cond			
29/10-04Z	Hod	80% Cond			

Table 3.32.9 - Clean limestone properties at Well 29/10-04Z for each fluid case

Cretaceous reservoirs

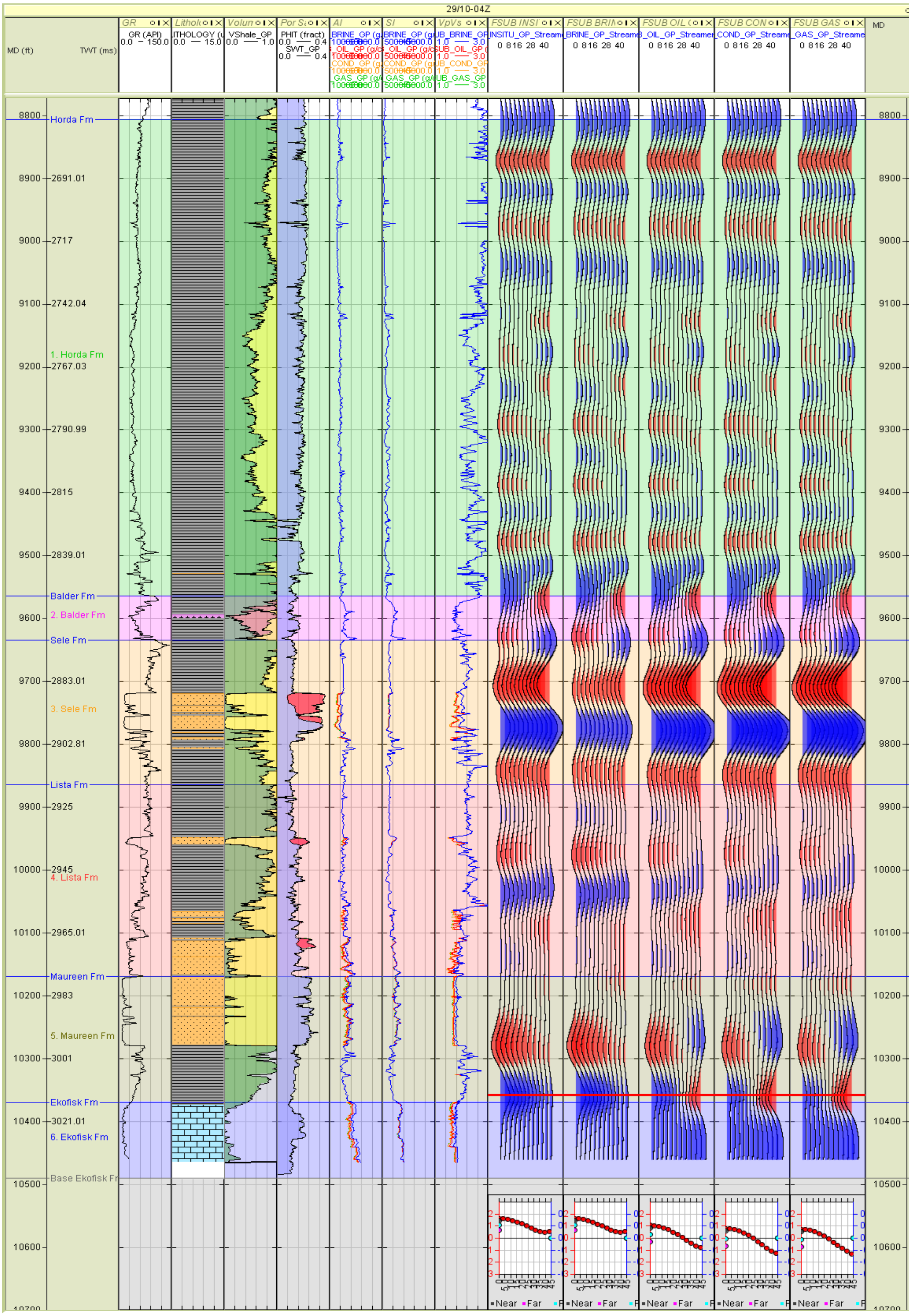


Figure 3.32.11 - Well Panel: Cretaceous reservoir for well 29/10-04Z. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the upper section of the Ekofisk Fm and the porosity becomes lower towards the base of the reservoir. The well reaches its total depth in this reservoir.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

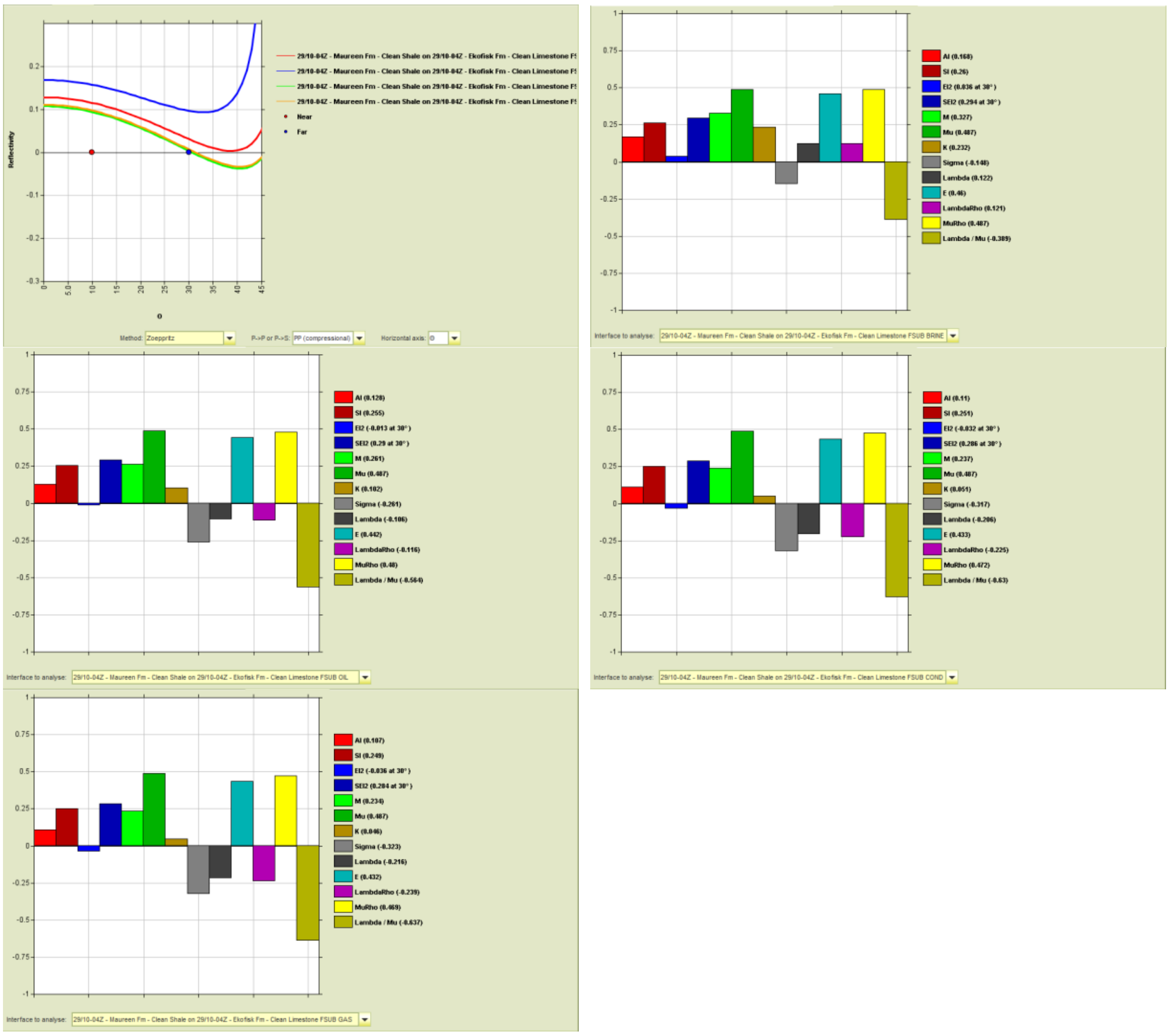


Figure 3.32.12 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 29/10-04Z.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 29/10-04Z is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
29/10-04Z	Overburden	Shale	7724	2988	2.29
29/10-04Z	Underburden				

Table 3.32.10 - Overburden and underburden properties at Well 29/10-04Z.

Well: 30/03A-01

General

Well Information
This well is a BP operated exploration well spudded, drilled and suspended in 1989. The well encountered oil shows in the Sele and Maureen Fm within the study interval.

Objectives
The well was spudded by the semisubmersible rig Santa Fe 140 to test for the presence of hydrocarbons in Palaeocene sandstone and Ekofisk and Tor chalk. The well was suspended with oil shows.

Log conditioning overview
No log editing was required at this well.

Invasion correction
Invasion correction has been performed on the density log within the oil bearing Sele and Maureen Formations. The drilling mud used within this well was water-based. There was no need to perform invasion correction in the Ekofisk Fm since the reservoir fluid was brine-bearing and the difference in density with the drilling mud would be negligible.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log. The only exception is a minor gap within the Rho log over a hydrocarbon zone in the Maureen Formation and the methodology for filling this gap is documented within the Rock Physics Part 2 PowerPoints.

Log modelling was performed to fill gaps within the Sele, Lista and Maureen Formations for the density log. A complete Vs log is modelled at this well. Data was removed above the interval of interest in the Vp log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 30/03A-01 is displayed in the figures below;

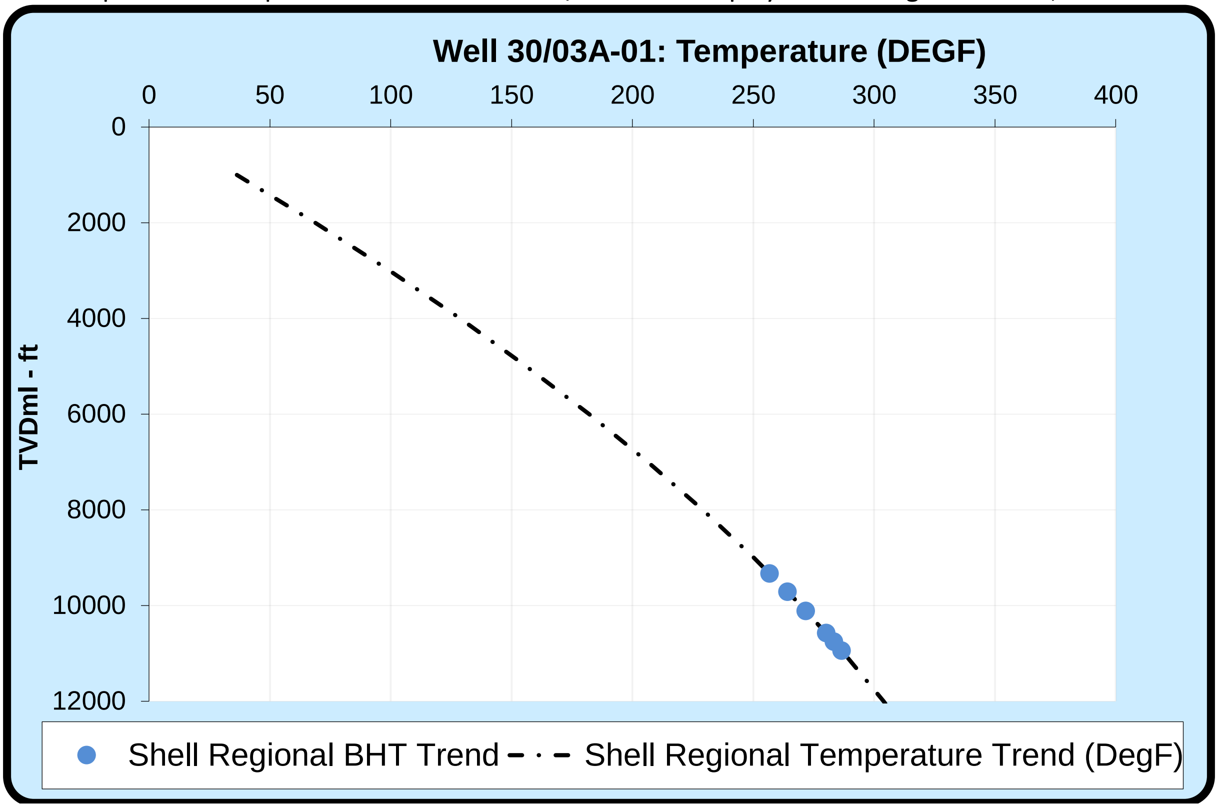


Figure 3.33.1 - Temperature data at Well 30/03A-01

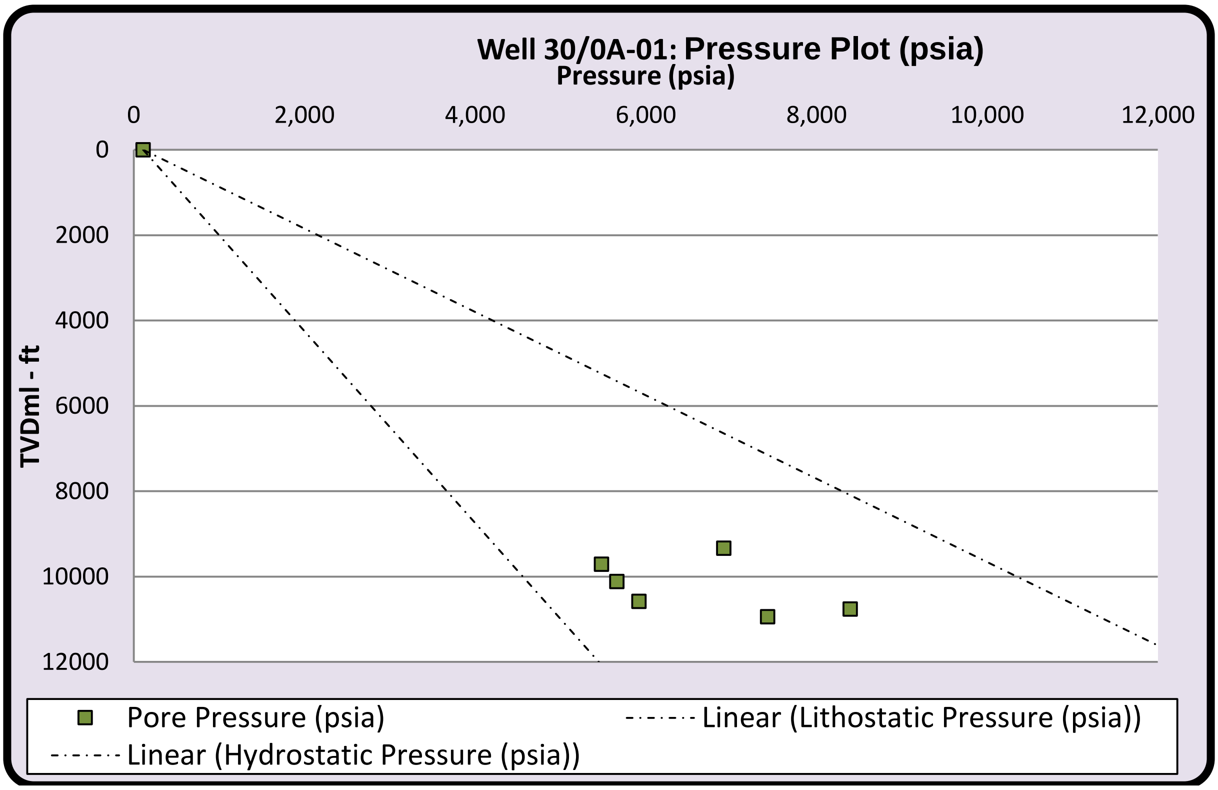


Figure 3.33.2 - Pressure data at Well 30/03A-01

The temperature and pressure data for the formation mid-points in Well 30/03A-01 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
30/03A-01	Sea Bed	334.0	249.0	0.0	39.2	110.8	110.8	110.81	0.00
30/03A-01	Horda	9669.7	9578.7	9329.6	256.8	4262.5	6912.5	9329.65	2417.14
30/03A-01	Balder	10052.7	9960.5	9711.4	264.2	4432.4	5482.4	9711.44	4229.03
30/03A-01	Sele	10455.0	10361.7	10112.7	271.8	4611.0	5661.0	10112.69	4451.73
30/03A-01	Lista	10922.5	10828.0	10579.0	280.2	4818.5	5918.5	10579.00	4660.53
30/03A-01	Maureen	11100.0	11005.2	10756.2	283.4	4897.3	8397.3	10756.21	2358.88
30/03A-01	Ekofisk	11285.0	11190.0	10940.9	286.6	4979.5	7429.5	10940.94	3511.41

Table 3.33.1 - Summary of mid-point temperature and pressure data at Well 30/03A-01

Fluid data

A summary of the fluid set parameters at Well 30/03A-01is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
30/03A-01	Sele	78000	428	58.0	1.029	1.029
30/03A-01	Lista	78000	730	42.8	0.78	0.78
30/03A-01	Maureen	78000	730	43.0	0.78	0.78
30/03A-01	Ekofisk	51000	730	43.3	0.78	0.78

Table 3.33.2 - Summary of fluid parameter data at Well 30/03A-01

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
30/03A-01	Sele	16380	57.7	0.8
30/03A-01	Lista	16380	58.1	0.8
30/03A-01	Maureen	16380	58.2	0.8
30/03A-01	Ekofisk	16380	58.5	0.8

Table 3.33.3 - Summary of additional parameter data at Well 30/03A-01

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.33.4 - Constant mineral properties used in this project

There is no Tuff present in this well.

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
30/03A-01	Sele	PAY	760.000	54.500	0.072	10.579	0.194	0.446	0.098
30/03A-01	Sele	RES	760.000	414.770	0.546	77.625	0.187	0.757	0.216
30/03A-01	Lista	PAY	175.000	1.000	0.006	0.191	0.191	0.474	0.000
30/03A-01	Lista	RES	175.000	9.500	0.054	1.810	0.191	0.684	0.148
30/03A-01	Maureen	PAY	180.000	0.000	0.000	0.000	0.000	0.000	0.000
30/03A-01	Maureen	RES	180.000	87.500	0.486	10.454	0.119	0.904	0.221
30/03A-01	Ekofisk	PAY	194.480	0.000	0.000	0.000	0.000	0.000	0.000
30/03A-01	Ekofisk	RES	194.480	165.730	0.852	23.498	0.142	0.962	0.079

Table 3.33.5 - Petrophysical parameters used at Well 30/03A-01

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

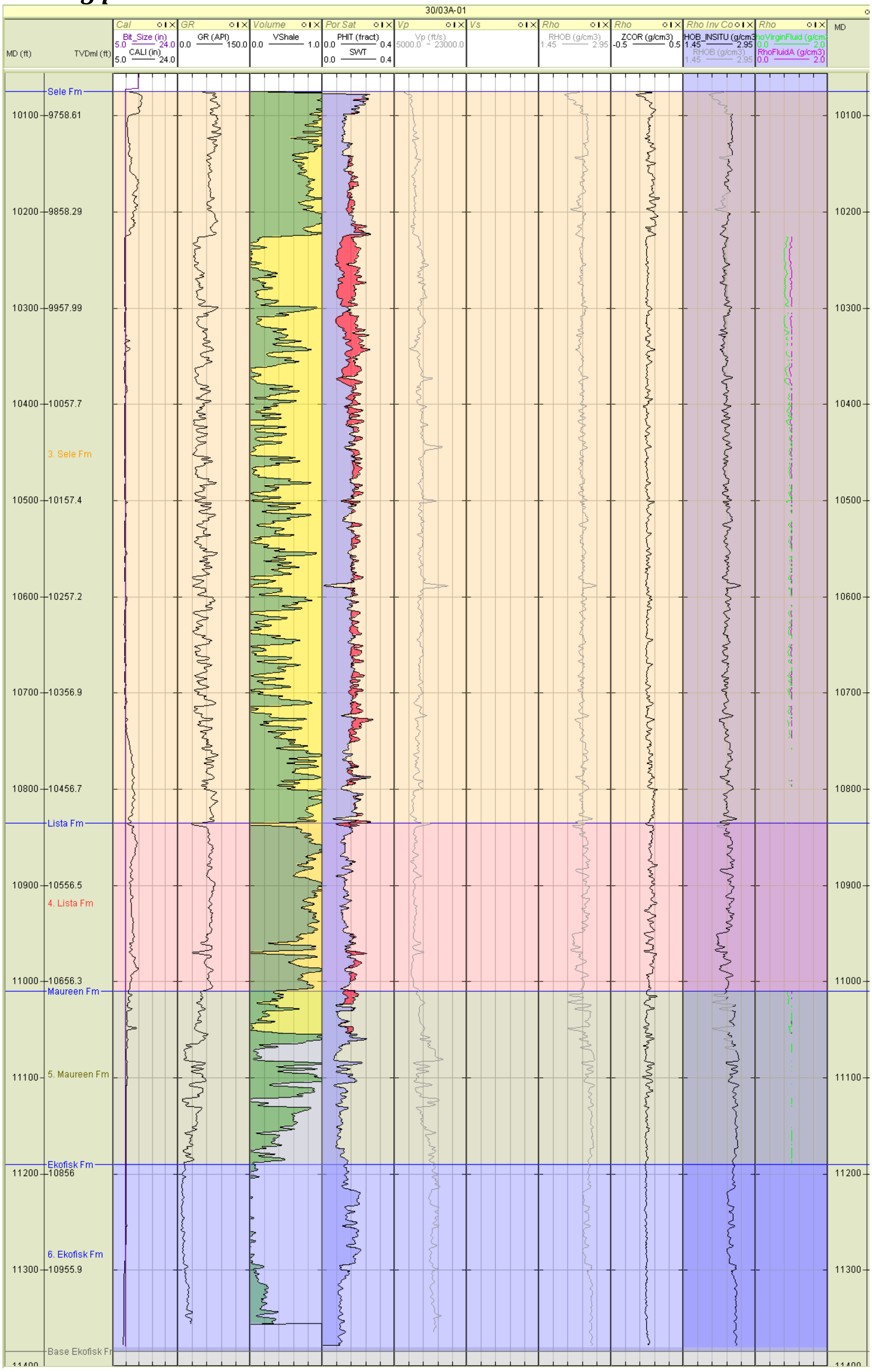


Figure 3.33.3 - Well Panel: Measured data and invasion correction for well 30/03A-01.

Well log panel – log editing and audit

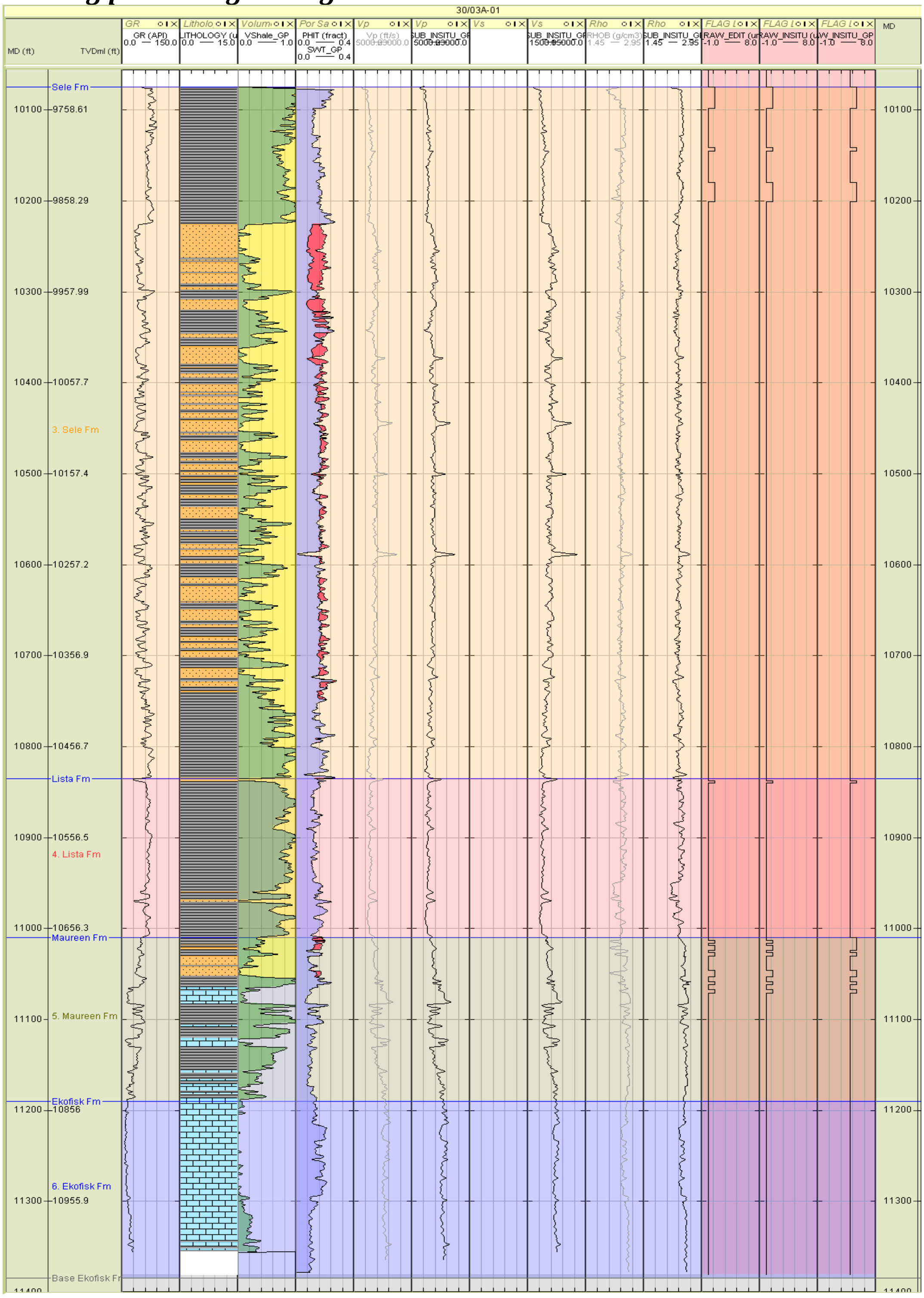


Figure 3.33.4 - Well Panel: Log edits for well 30/03A-01.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

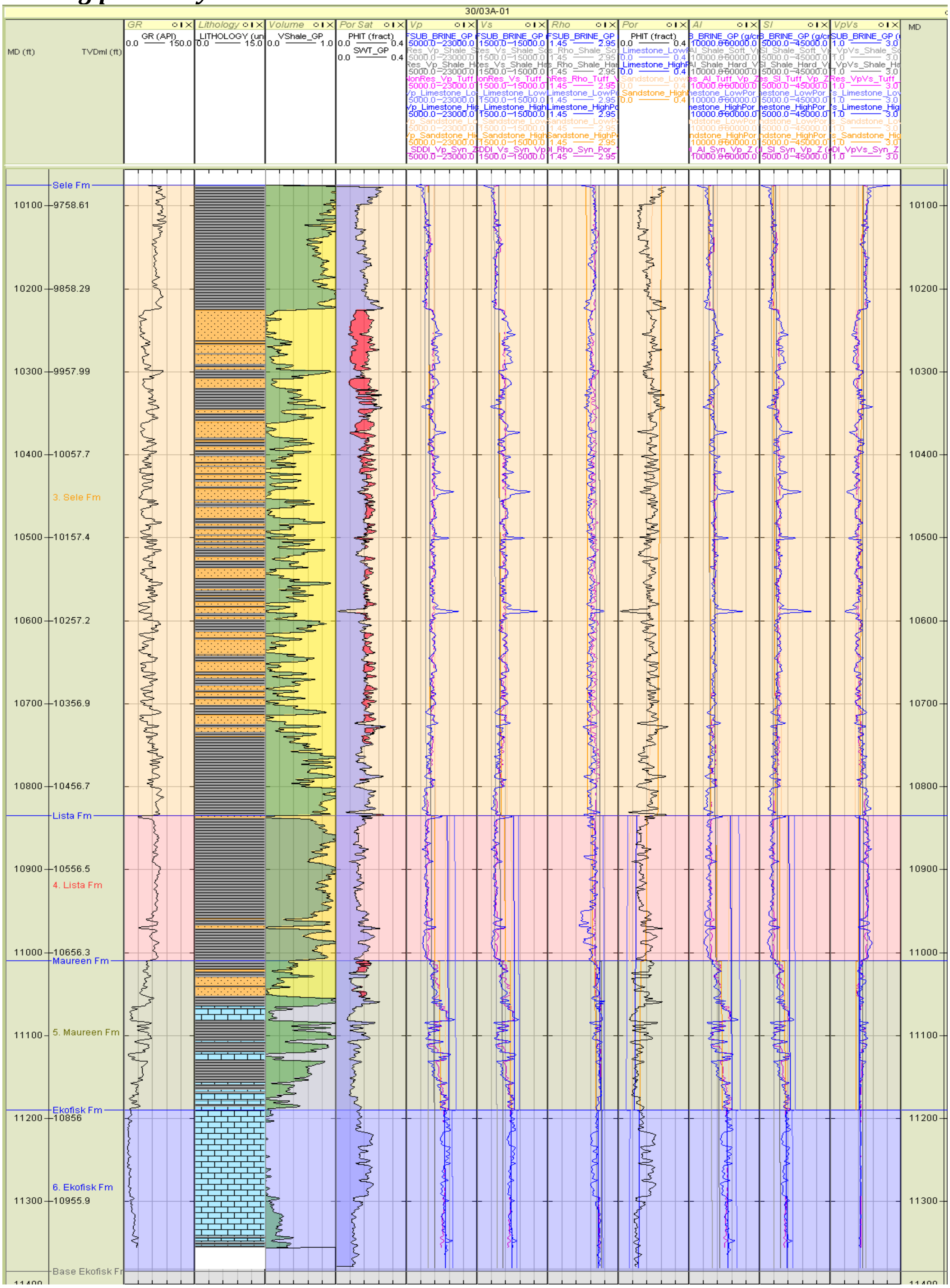


Figure 3.33.5 - Well Panel: End-member and synthetic logs for well 30/03A-01.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

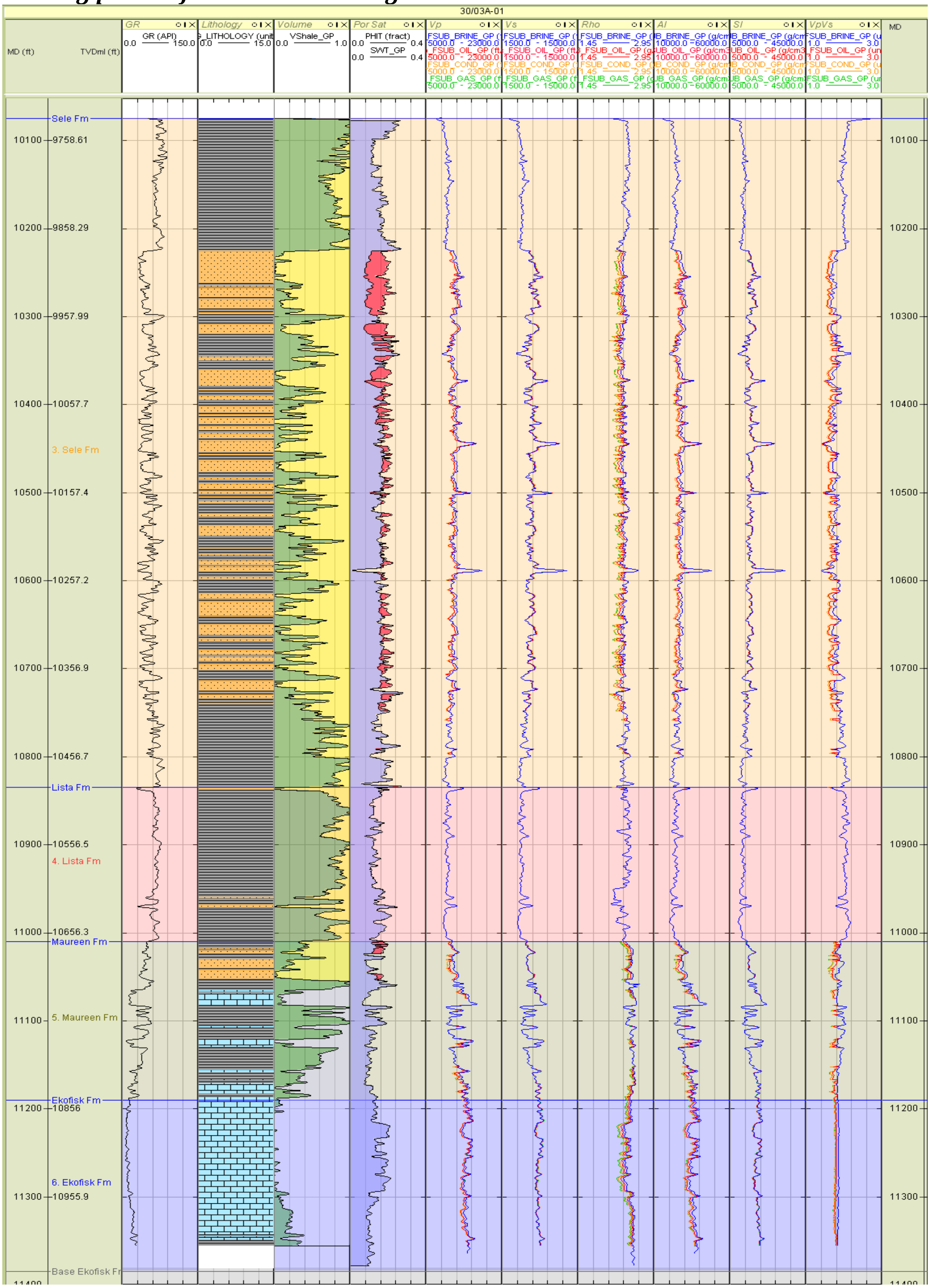


Figure 3.33.6 - Well Panel: Fluid substituted and elastic logs for well 30/03A-01.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 30/03A-01 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Horda			
30/03A-01	Balder			
30/03A-01	Sele	9951	4982	2.39
30/03A-01	Lista	9882	4823	2.39
30/03A-01	Maureen	11161	5731	2.47

Table 3.33.6 - Clean shale properties at Well 30/03A-01

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Horda	100% Brine			
30/03A-01	Balder	100% Brine			
30/03A-01	Sele	100% Brine	12382	7267	2.34
30/03A-01	Lista	100% Brine			
30/03A-01	Maureen	100% Brine	12026	6472	2.51
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Horda	80% Oil			
30/03A-01	Balder	80% Oil			
30/03A-01	Sele	80% Oil	11792	7349	2.29
30/03A-01	Lista	80% Oil			
30/03A-01	Maureen	80% Oil	11283	6513	2.48
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Horda	90% Gas			
30/03A-01	Balder	90% Gas			
30/03A-01	Sele	90% Gas	11745	7448	2.23
30/03A-01	Lista	90% Gas			
30/03A-01	Maureen	90% Gas	10980	6574	2.43
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Horda	80% Cond			
30/03A-01	Balder	80% Cond			
30/03A-01	Sele	80% Cond	11719	7433	2.23
30/03A-01	Lista	80% Cond			
30/03A-01	Maureen	80% Cond	10991	6555	2.45

Table 3.33.7 - Clean sand properties at Well 30/03A-01 for each fluid case

Tertiary reservoirs – Well panel

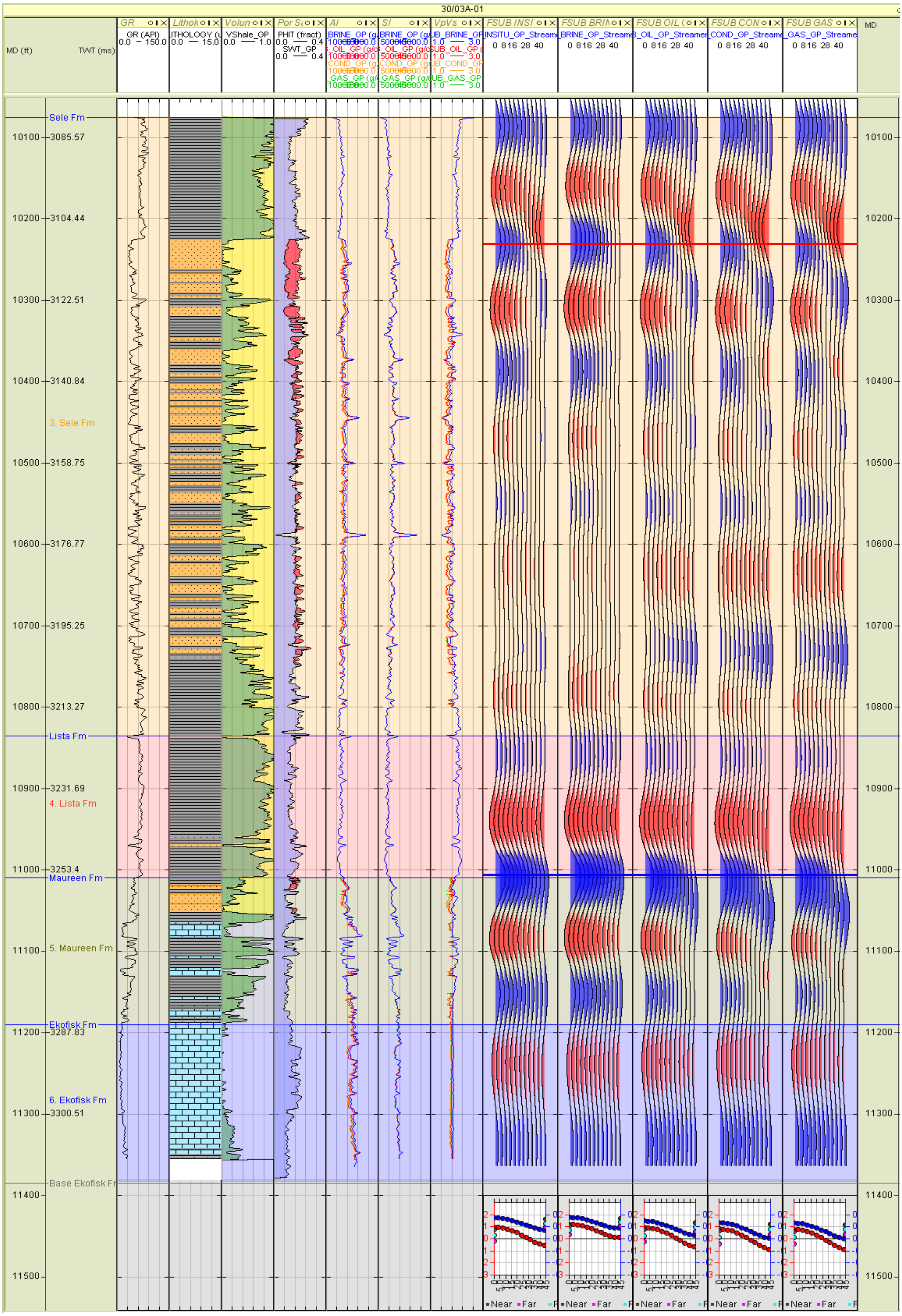


Figure 3.33.7 - Well Panel: Tertiary reservoirs for well 30/03A-01. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Sele Formation

- Reservoir formed by a thick inter-bedded sand package and net reservoir is approximately 415 feet. The Sele reservoir sand is overlain directly by the overburden shale of the upper section of the Sele Fm.
- Blocky AVO shows a modelled class I response for the 100% brine fluid case and a modelled class IIp response for the 80% oil, 80% condensate and 90% gas fluid cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. This change in AVO type is similar to the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

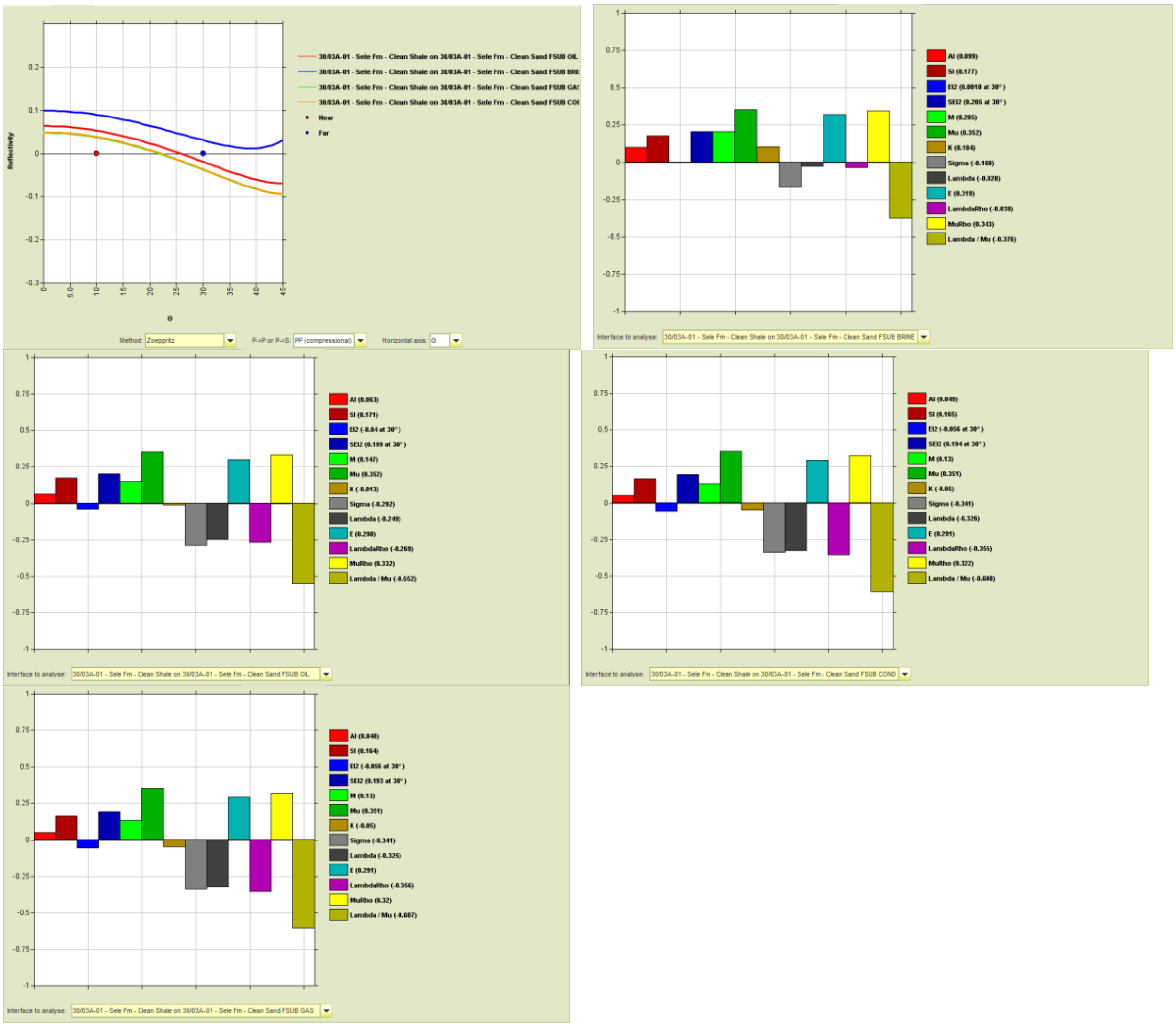


Figure 3.33.8 - Blocky AVO Model and Elastic Contrast Analysis for the Sele Formation in well 30/03A-01.

Maureen Formation

- Reservoir formed by a thin (~40ft) sand package in the top third of the Maureen Fm interval. The sand reservoir overlies a marl section of limestone and shale to produce a sand/shale interface for base reservoir.
- Blocky AVO shows a modelled class I response for the 100% brine case, a modelled class IIp response for the 80% oil case and a modelled class II response for the 80% condensate and 90% gas fluid cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The synthetic gathers show the reflection at top reservoir and this is most influenced by the overlaying Lista Fm shale rather than the underlying Maureen Fm shale section.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

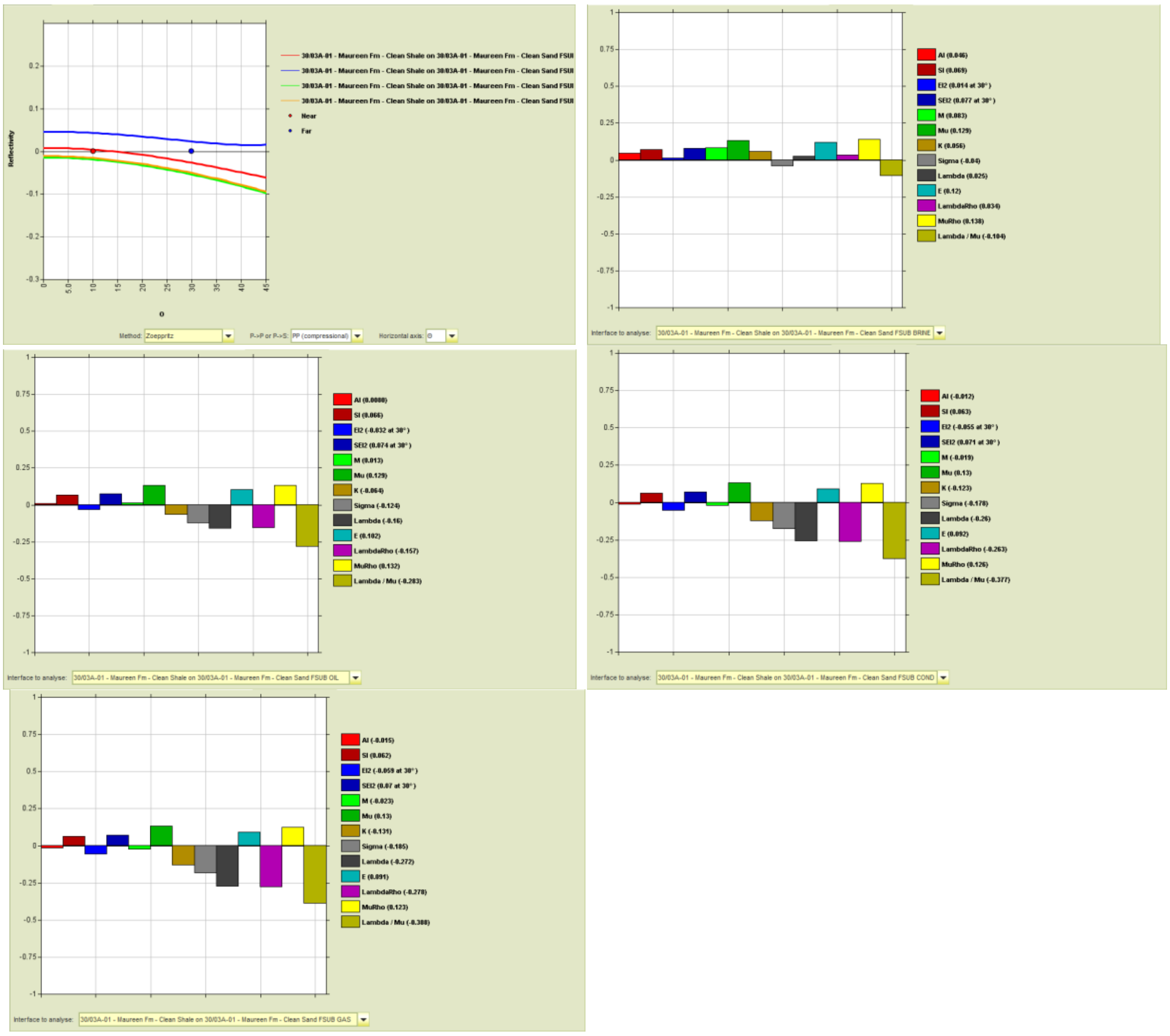


Figure 3.33.9 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 30/03A-01.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 30/03A-01 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Ekofisk	100% Brine	14712	7954	2.44
30/03A-01	Tor	100% Brine			
30/03A-01	Hod	100% Brine			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Ekofisk	80% Oil	14305	8021	2.40
30/03A-01	Tor	80% Oil			
30/03A-01	Hod	80% Oil			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Ekofisk	90% Gas	14298	8126	2.34
30/03A-01	Tor	90% Gas			
30/03A-01	Hod	90% Gas			
Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Ekofisk	80% Cond	14259	8093	2.35
30/03A-01	Tor	80% Cond			
30/03A-01	Hod	80% Cond			

Table 3.33.8 - Clean limestone properties at Well 30/03A-01 for each fluid case

Cretaceous reservoirs

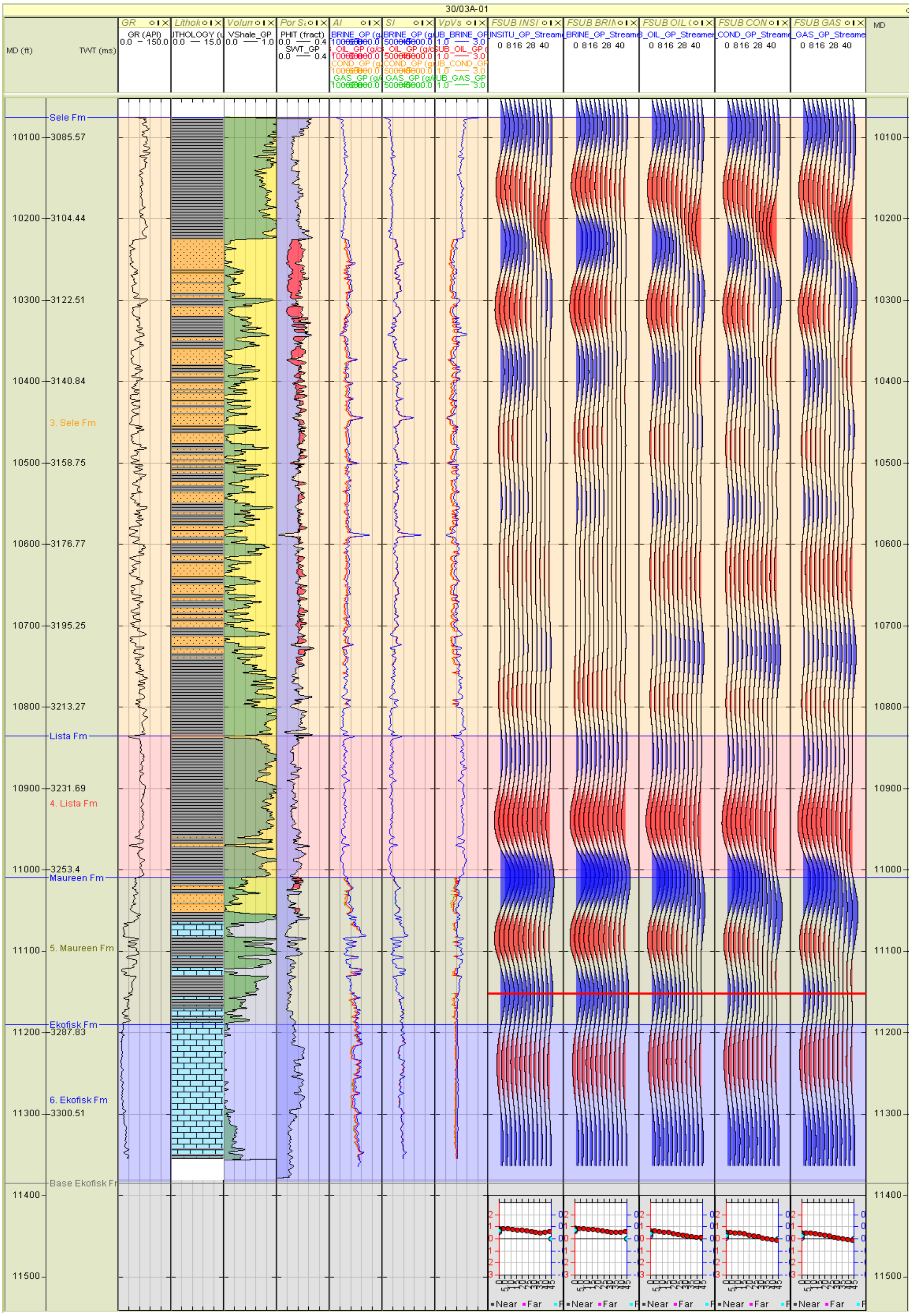


Figure 3.33.10 - Well Panel: Cretaceous reservoir for well 30/03A-01. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the upper section of the Ekofisk Fm and the porosity becomes lower towards the base of the reservoir. The well reaches its total depth in this reservoir.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

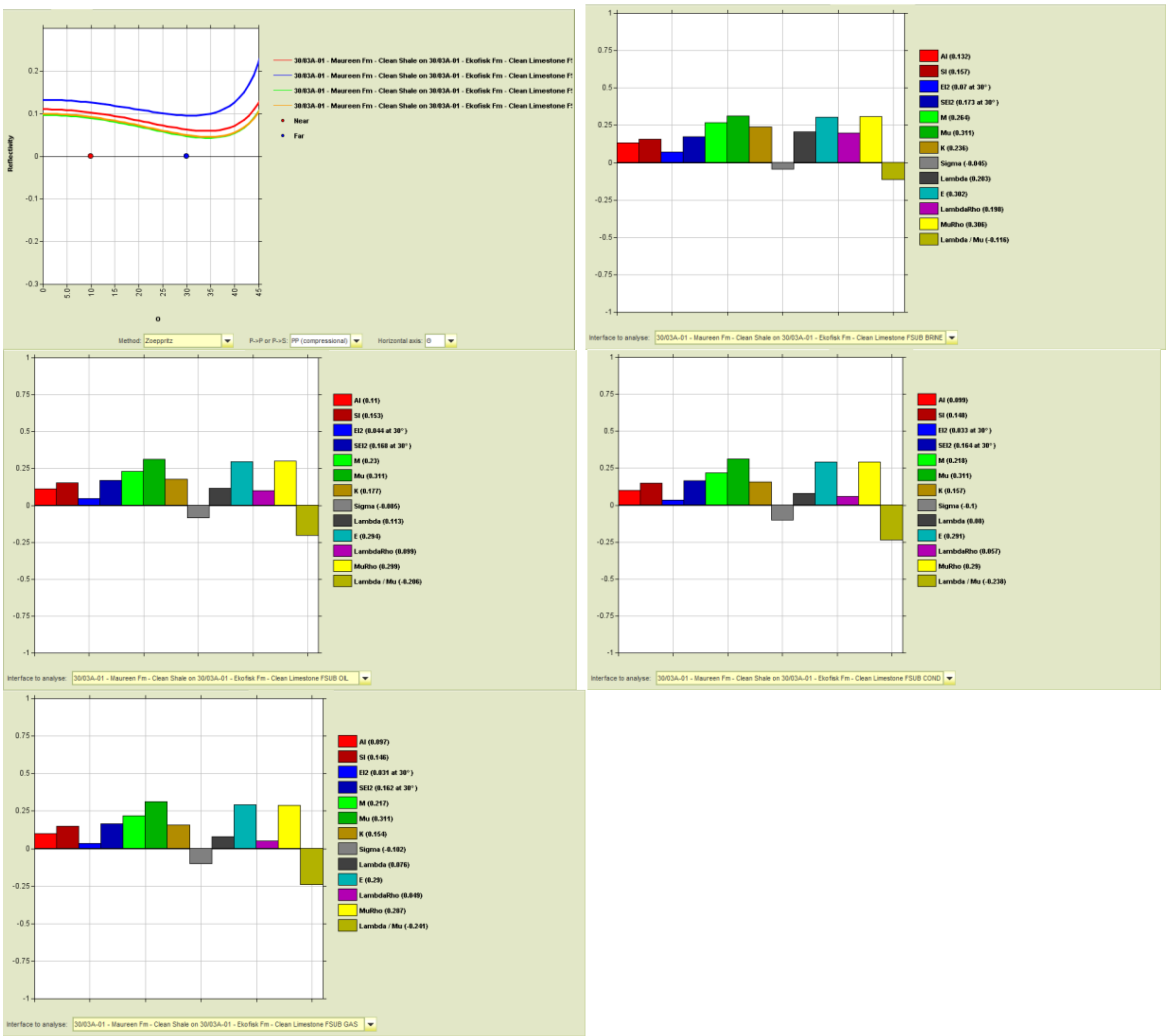


Figure 3.33.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 30/03A-01.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 30/03A-01 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

In this well, there were no logs present in the underburden and overburden sections.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/03A-01	Overburden				
30/03A-01	Underburden				

Table 3.33.9 - Overburden and underburden properties at Well 30/03A-01

Well: 30/06-04

General

Well Information
This well is a Maersk operated exploration well which was spudded, drilled and then abandoned in 2003. The well encountered condensate within the Lista, Maureen, Ekofisk and Tor Formations, and it is part of the Harrier Shallow field.

Objectives
This well has been drilled on the Harrier shallow prospect. The well was designed to drill into the Tor Formation then be sidetracked to test the prospect. The primary objective was to evaluate the Ekofisk chalk for hydrocarbons. Secondary objectives were to check the reservoir quality stratigraphy and hydrocarbon potential in overlying sandstones and the underlying Tor formation. The Danian and Maastrichtian chalks were found with 60% to 70% hydrocarbon saturation.

Log conditioning overview
Only minor log conditioning was required due to good log data quality within this well. Thin calcite stringers in the Horda and Sele Formation were seen on the density log but were not apparent on the Vp log, and data relating to these intervals was consequentially removed. A section of poor quality data was seen on the density log at 9,605-9,9665ft MD in the Lista Fm and this data was removed from the density log.

Invasion correction
No invasion correction was required on the density log at this well. This is because the density log is MWD data and therefore representative of the INSITU conditions in the wellbore.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda Formation for the Vp log, within the Horda Formation for the Vs log and within the Horda, Lista and Tor Formations for the density log.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 30/06-04 is displayed in the figures below;

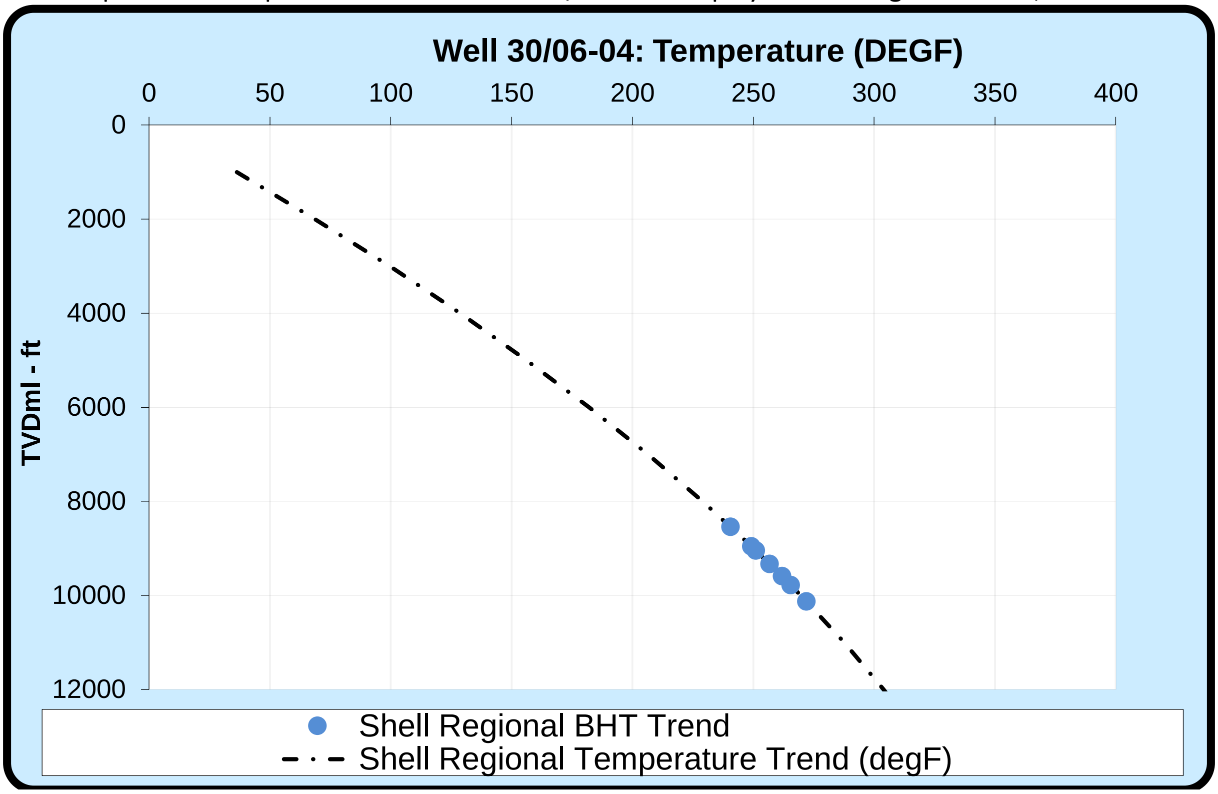


Figure 3.34.1 - Temperature data at Well 30/06-04

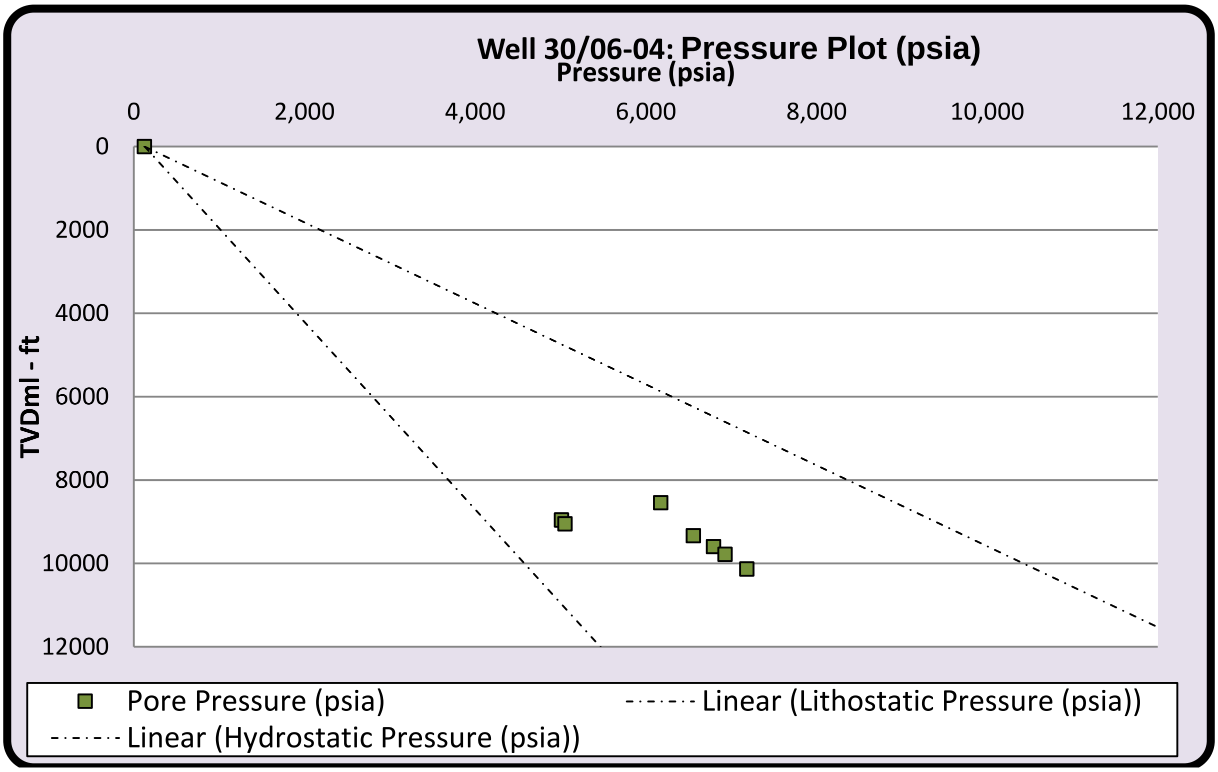


Figure 3.34.2 - Pressure data at Well 30/06-04

The temperature and pressure data for the formation mid-points in Well 30/06-04 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydrostatic Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
30/06-04	Sea Bed	366.0	284.0	0.0	39.2	126.4	126.4	126.38	0.00
30/06-04	Horda	8908.5	8825.1	8541.1	240.7	3927.2	6177.2	8541.08	2363.92
30/06-04	Balder	9323.0	9239.5	8955.5	249.3	4111.6	5011.6	8955.54	3943.95
30/06-04	Sele	9414.5	9331.0	9047.0	251.1	4152.3	5052.3	9047.04	3994.72
30/06-04	Lista	9700.0	9616.5	9332.5	256.8	4279.4	6559.4	9332.52	2773.17
30/06-04	Maureen	9960.5	9877.0	9593.0	261.9	4395.3	6795.3	9593.01	2797.74
30/06-04	Ekofisk	10146.5	10063.0	9779.0	265.5	4478.0	6928.0	9778.97	2850.95
30/06-04	Tor	10496.0	10412.4	10128.4	272.1	4633.5	7183.5	10128.38	2944.87

Table 3.34.1 - Summary of mid-point temperature and pressure data at Well 30/06-04

Fluid data

A summary of the fluid set parameters at Well 30/06-04 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
30/06-04	Horda	60000	730	40.6	0.78	0.78
30/06-04	Balder	60000	730	41.0	0.78	0.78
30/06-04	Sele	60000	730	41.1	0.78	0.78
30/06-04	Lista	60000	730	41.4	0.78	0.78
30/06-04	Maureen	60000	730	41.7	0.78	0.78
30/06-04	Ekofisk	55000	730	41.9	0.78	0.78
30/06-04	Tor	60000	730	42.3	0.78	0.78

Table 3.34.2 - Summary of fluid parameter data at Well 30/06-04

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
30/06-04	Horda	16380	56.3	0.8
30/06-04	Balder	16380	56.7	0.8
30/06-04	Sele	16380	56.8	0.8
30/06-04	Lista	16380	57.0	0.8
30/06-04	Maureen	74708.4	50.4	0.674
30/06-04	Ekofisk	16380	57.4	0.8
30/06-04	Tor	16380	57.7	0.8

Table 3.34.3 - Summary of additional parameter data at Well 30/06-04

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.34.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm³)	Vp (ft/sec)	Vs (ft/sec)
Tuff	13.15	5.66	2.378	9,678	5,060

Table 3.34.5 - Tuff properties used at Well 30/06-04

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
30/06-04	Horda	PAY	777.000	0.000	0.000	0.000	0.000	0.000	0.000
30/06-04	Horda	RES	777.000	10.000	0.013	2.793	0.279	0.947	0.351
30/06-04	Balder	PAY	52.000	0.000	0.000	0.000	0.000	0.000	0.000
30/06-04	Balder	RES	52.000	4.500	0.087	1.238	0.275	0.822	0.209
30/06-04	Sele	PAY	131.020	0.000	0.000	0.000	0.000	0.000	0.000
30/06-04	Sele	RES	131.020	0.000	0.000	0.000	0.000	0.000	0.000
30/06-04	Lista	PAY	439.990	38.760	0.088	8.696	0.224	0.345	0.130
30/06-04	Lista	RES	439.990	213.760	0.486	39.450	0.185	0.734	0.199
30/06-04	Maureen	PAY	80.990	14.740	0.182	3.536	0.240	0.342	0.206
30/06-04	Maureen	RES	80.990	21.990	0.272	5.218	0.237	0.418	0.270
30/06-04	Ekofisk	PAY	291.000	50.000	0.172	12.843	0.257	0.329	0.011
30/06-04	Ekofisk	RES	291.000	285.000	0.979	49.065	0.172	0.669	0.038
30/06-04	Tor	PAY	435.000	36.000	0.083	7.773	0.216	0.259	0.036
30/06-04	Tor	RES	435.000	290.750	0.668	39.988	0.138	0.753	0.019

Table 3.34.6 - Petrophysical parameters used at Well 30/06-04

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

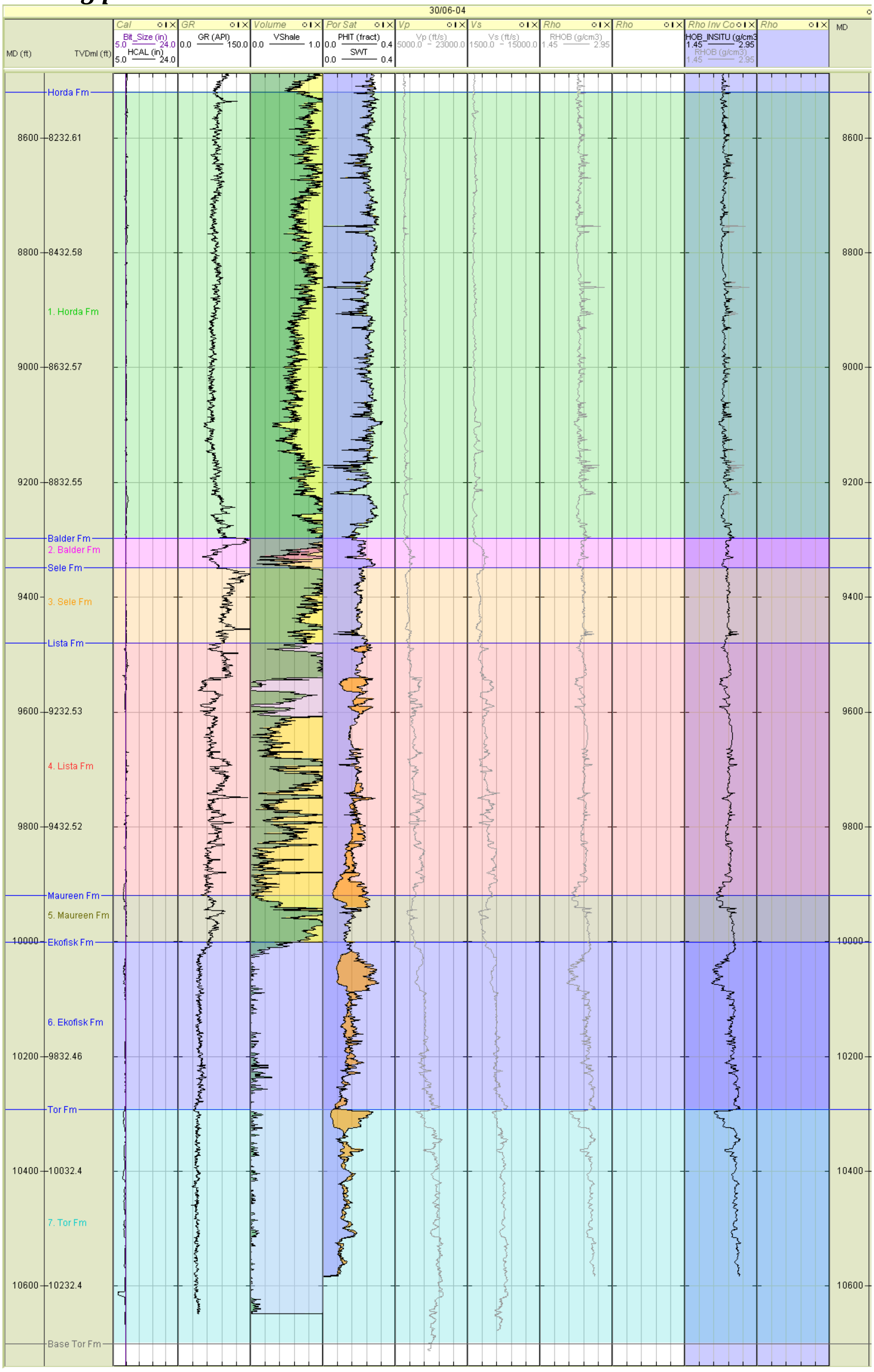


Figure 3.34.3 - Well Panel: Measured data and invasion correction for well 30/06-04.

Well log panel – log editing and audit

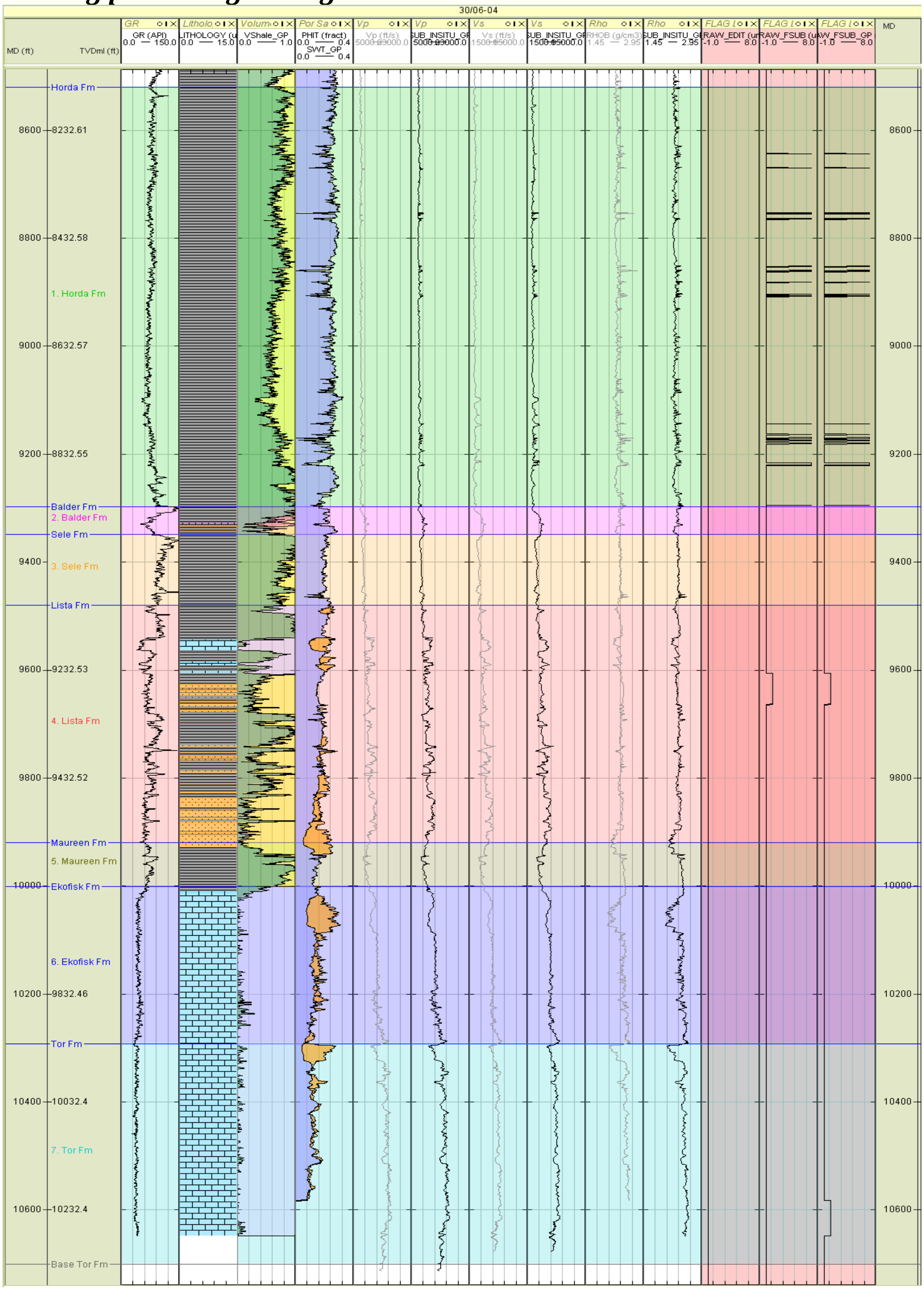


Figure 3.34.4 - Well Panel: Log edits for well 30/06-04.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

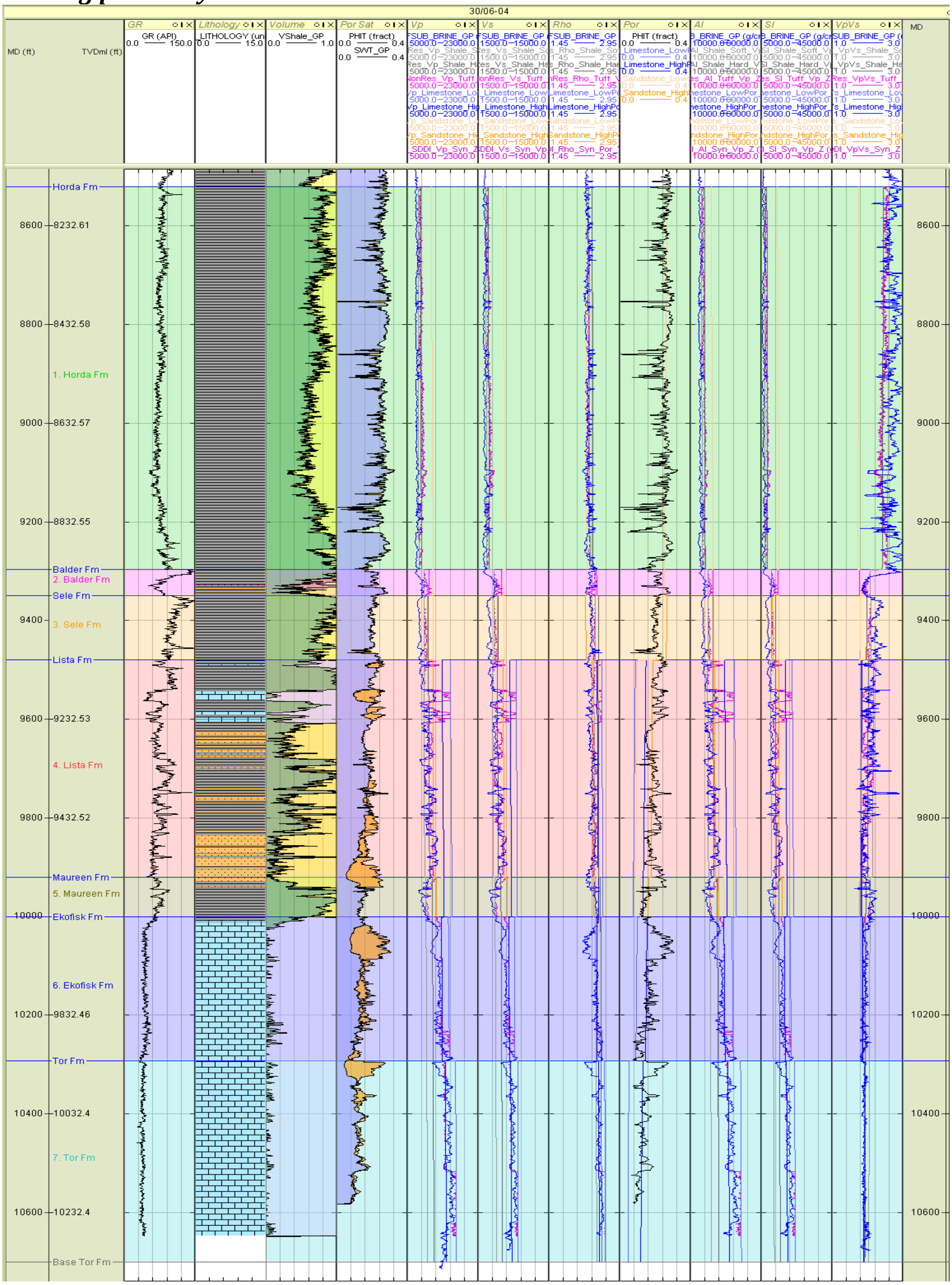


Figure 3.34.5 - Well Panel: End-member and synthetic logs for well 30/06-04.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

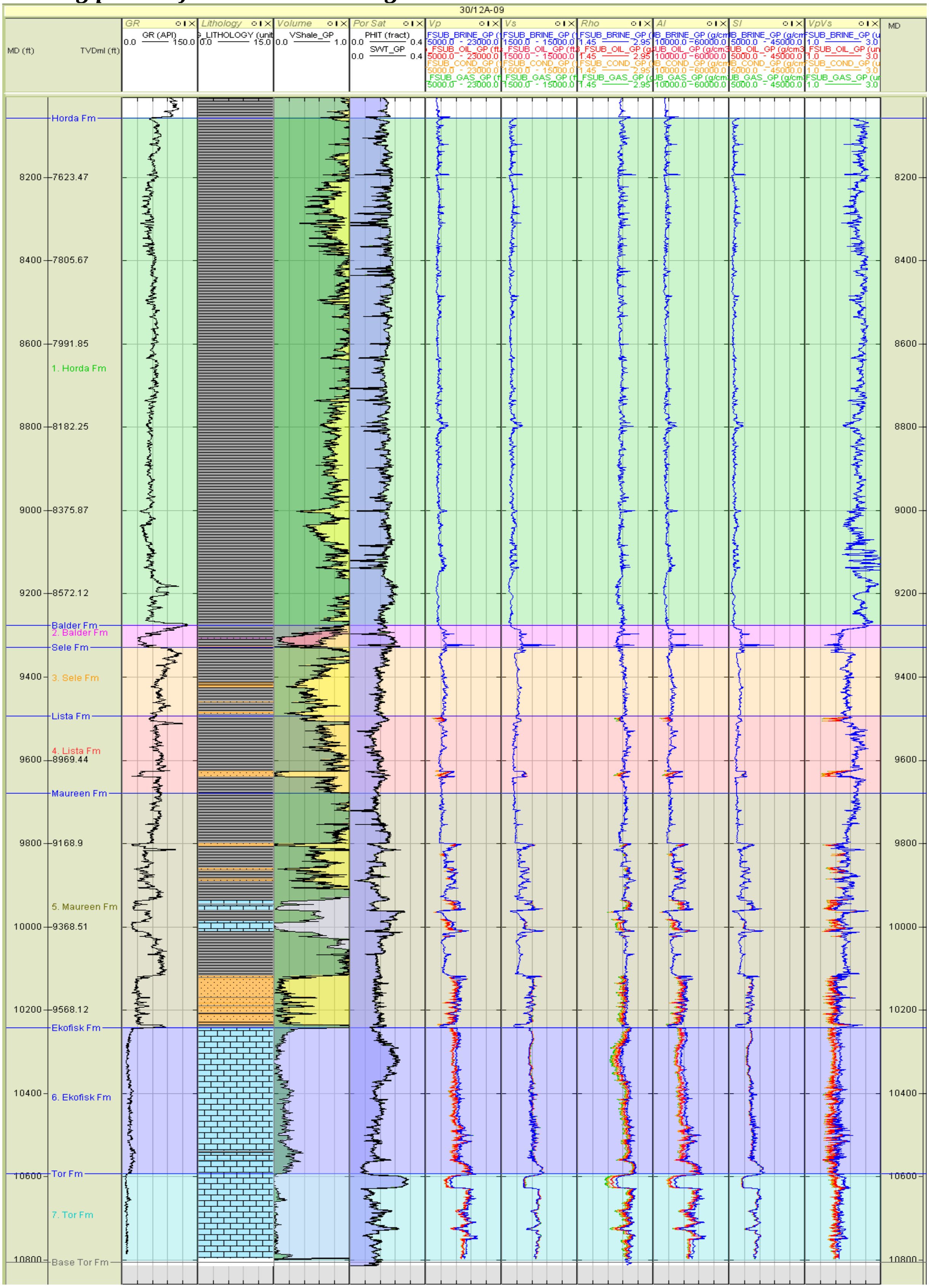


Figure 3.34.6 - Well Panel: Fluid substituted and elastic logs for well 30/06-04.

Key: Blue = Brine, Red = Oil, Green = Gas and Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 30/06-04 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/06-04	Horda	7257	2695	2.27
30/06-04	Balder	7605	3272	2.33
30/06-04	Sele	7694	3565	2.34
30/06-04	Lista	8963	4274	2.36
30/06-04	Maureen	8838	4194	2.44

Table 3.34.7 - Clean shale properties at Well 30/06-04

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/06-04	Horda	100% Brine			
30/06-04	Balder	100% Brine			
30/06-04	Sele	100% Brine			
30/06-04	Lista	100% Brine	11367	5485	2.37
30/06-04	Maureen	100% Brine	10392	5277	2.26
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/06-04	Horda	80% Oil			
30/06-04	Balder	80% Oil			
30/06-04	Sele	80% Oil			
30/06-04	Lista	80% Oil	10666	5902	2.33
30/06-04	Maureen	80% Oil	9638	5350	2.20
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/06-04	Horda	90% Gas			
30/06-04	Balder	90% Gas			
30/06-04	Sele	90% Gas			
30/06-04	Lista	90% Gas	10465	5992	2.26
30/06-04	Maureen	90% Gas	9476	5468	2.10
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/06-04	Horda	80% Cond			
30/06-04	Balder	80% Cond			
30/06-04	Sele	80% Cond			
30/06-04	Lista	80% Cond	10446	5964	2.28
30/06-04	Maureen	80% Cond	9446	5439	2.13

Table 3.34.8 - Clean sand properties at Well 30/06-04 for each fluid case

Tertiary reservoirs – Well panel

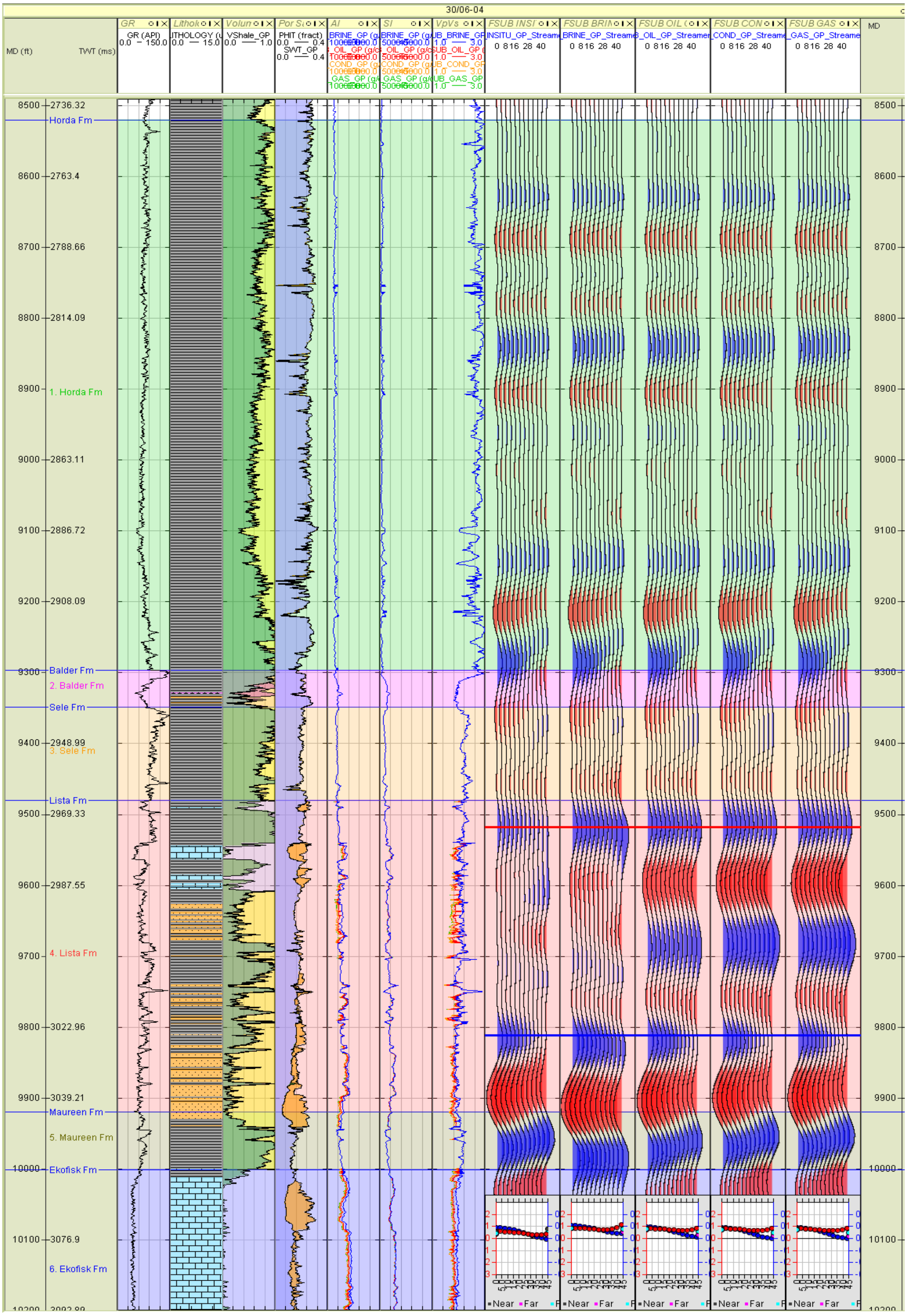


Figure 3.34.7 - Well Panel: Tertiary reservoirs for well 30/06-04. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Lista Formation

- Reservoir contains both sandstone and limestone lithologies. The sand reservoir is formed by an inter-bedded sand package in the lower section of the interval and net reservoir is approximately 215 feet. The Lista reservoir sand is overlain directly by a marl section of limestone and shale in the upper part of the Lista Fm.
- Blocky AVO shows a modelled class I response for all fluid cases, with the softness of the sand in relation to the shale increasing with the addition of hydrocarbons. This change in AVO type is not seen on the synthetic gathers since the top reservoir on the synthetic gathers is a limestone layer overlaying the reservoir sand rather than a shale/sand interface.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, but that the contrasts become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

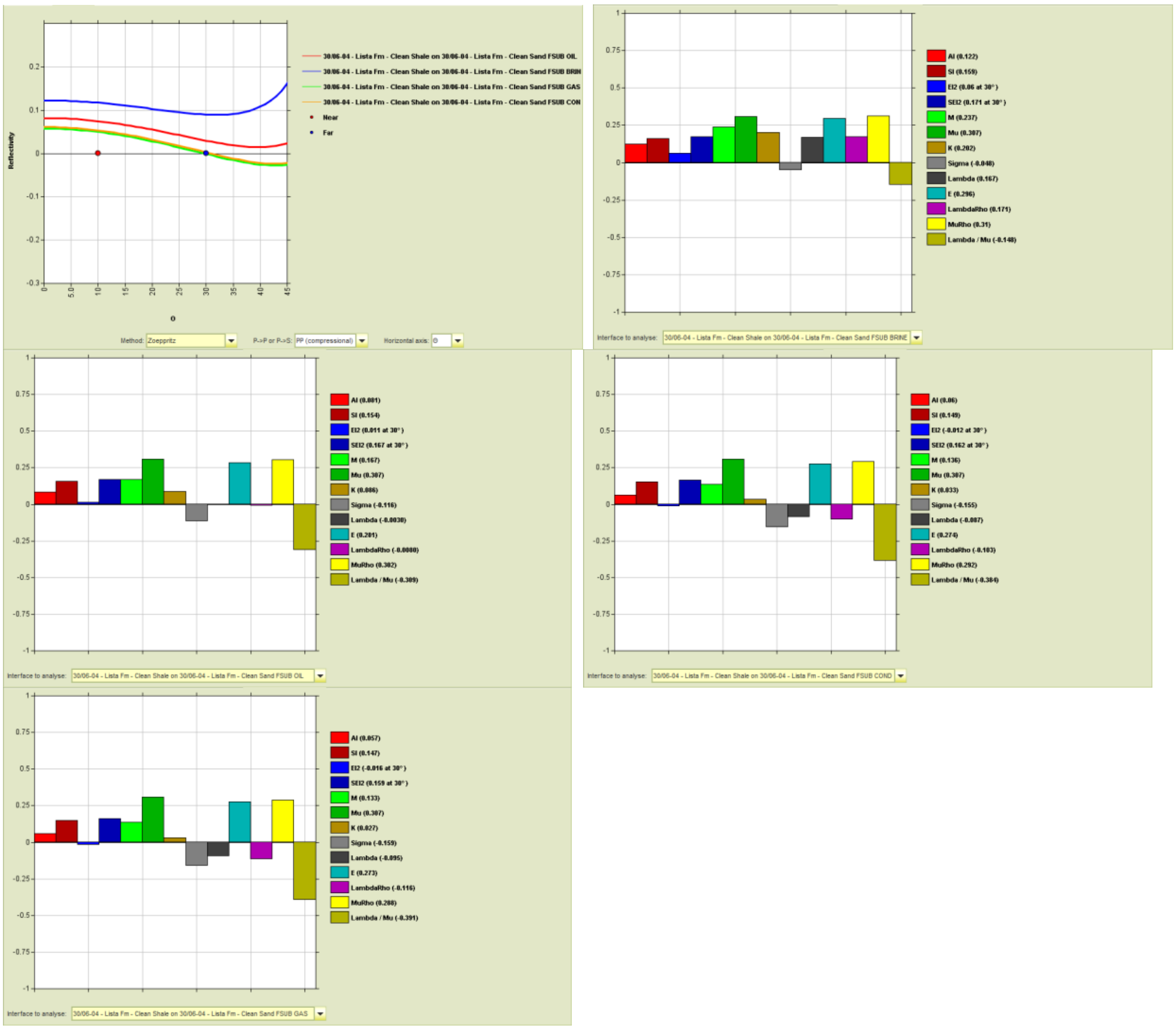


Figure 3.34.8 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 30/06-04.

Maureen Formation

- Reservoir formed by the lowermost section of the Lista Fm sand package and this comprises of the top third of the Maureen Fm interval. The sand reservoir overlies a section of shale to produce a sand/shale interface for base reservoir.
- Blocky AVO shows a modelled class I response for the 100% brine case, a modelled class II response for the 80% oil case, and a modelled class III response for the 80% condensate and 90% gas cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The synthetic gathers show the prominent reflection at base reservoir and can't be compared with the blocky AVO response for top reservoir.
- Elastic Contrast Analysis shows contrasts are mainly positive and low amplitude in the brine case, but that the contrasts become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

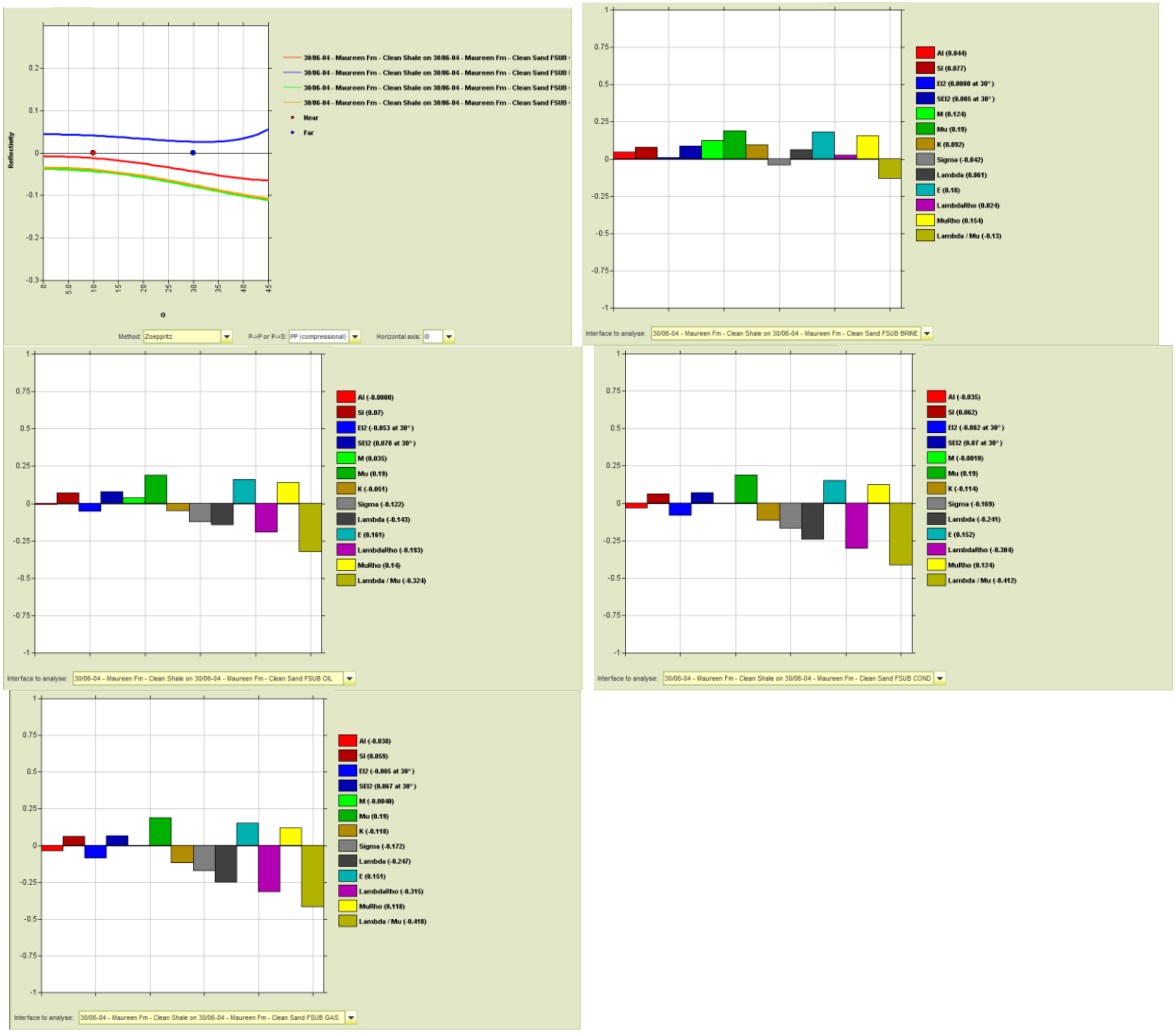


Figure 3.34.9 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 30/06-04.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 30/06-04 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/06-04	Ekofisk	100% Brine	12943	6752	2.42
30/06-04	Tor	100% Brine	15290	8030	2.50
30/06-04	Hod	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/06-04	Ekofisk	80% Oil	12177	6814	2.38
30/06-04	Tor	80% Oil	14994	8076	2.47
30/06-04	Hod	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/06-04	Ekofisk	90% Gas	11989	6913	2.31
30/06-04	Tor	90% Gas	14975	8147	2.43
30/06-04	Hod	90% Gas			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/06-04	Ekofisk	80% Cond	11966	6882	2.33
30/06-04	Tor	80% Cond	14948	8125	2.44
30/06-04	Hod	80% Cond			

Table 3.34.9 - Clean limestone properties at Well 30/06-04 for each fluid case

Cretaceous reservoirs

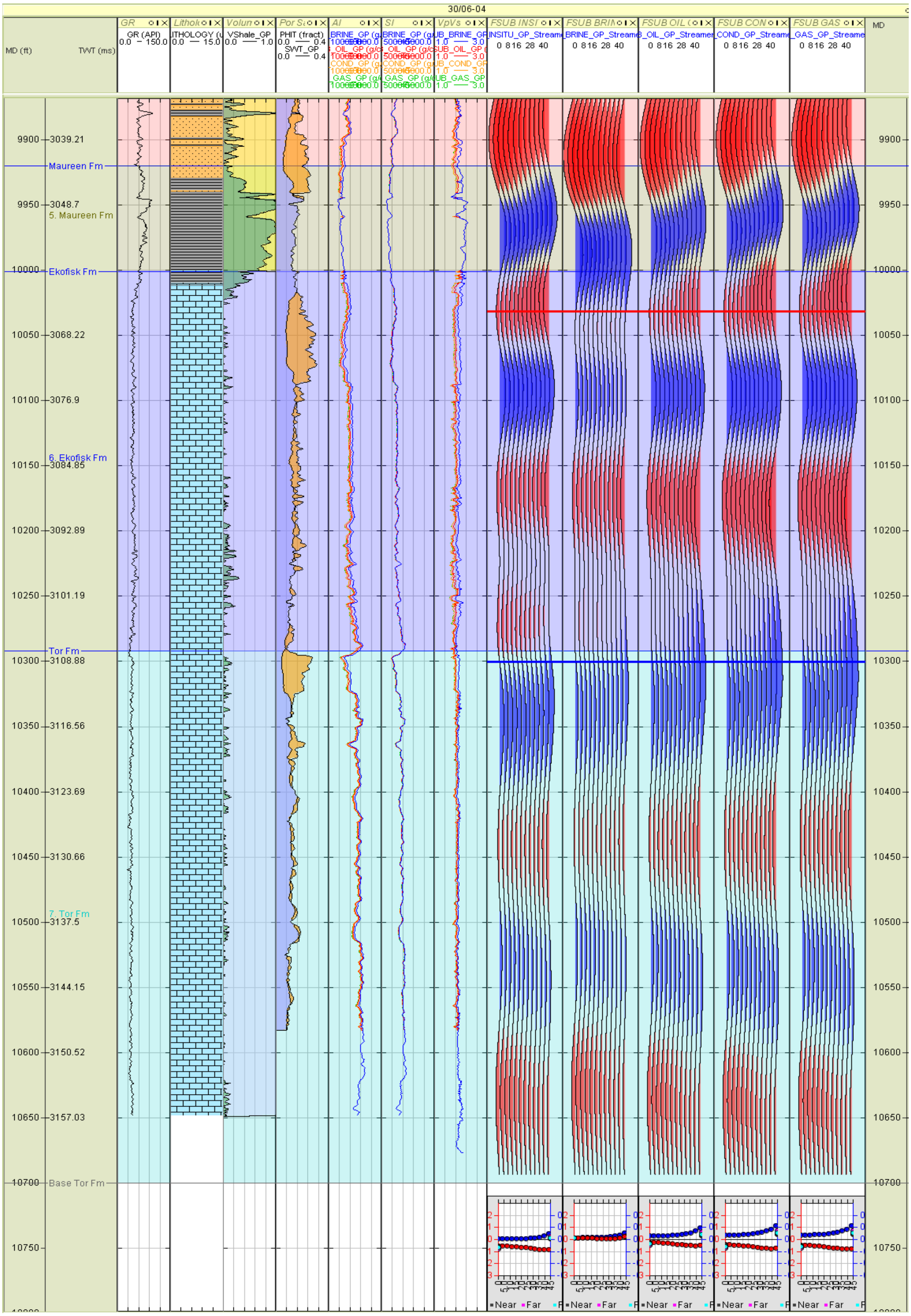


Figure 3.34.10 - Well Panel: Cretaceous reservoirs for well 30/06-04. Wavelet: Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the upper section of the Ekofisk Fm, the porosity in this section is approximately 28% and this formation is condensate-bearing. The porosity is lower outside the main condensate-bearing reservoir zone. The higher porosity layers found in the Ekofisk Fm could be representative of reworked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and strong amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

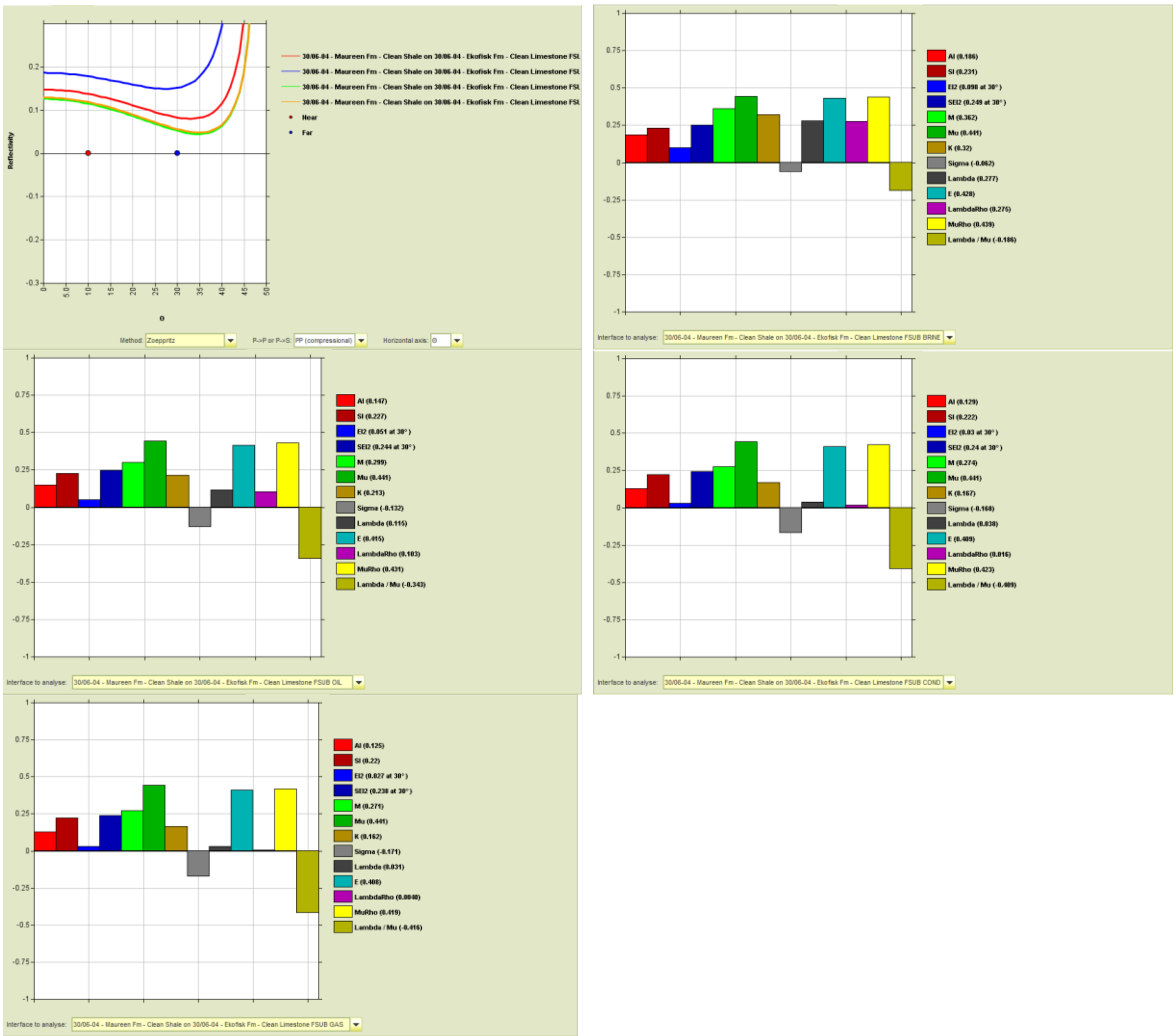


Figure 3.34.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 30/06-04.

Tor Formation

- Reservoir formed by a clean limestone formation. The highest porosity reservoir is found in the upper section of the Tor Fm, the porosity in this section is approximately 26% and this formation is condensate-bearing. The porosity is lower outside the main condensate-bearing reservoir zone. The higher porosity layers found in the Tor Fm could be representative of reworked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

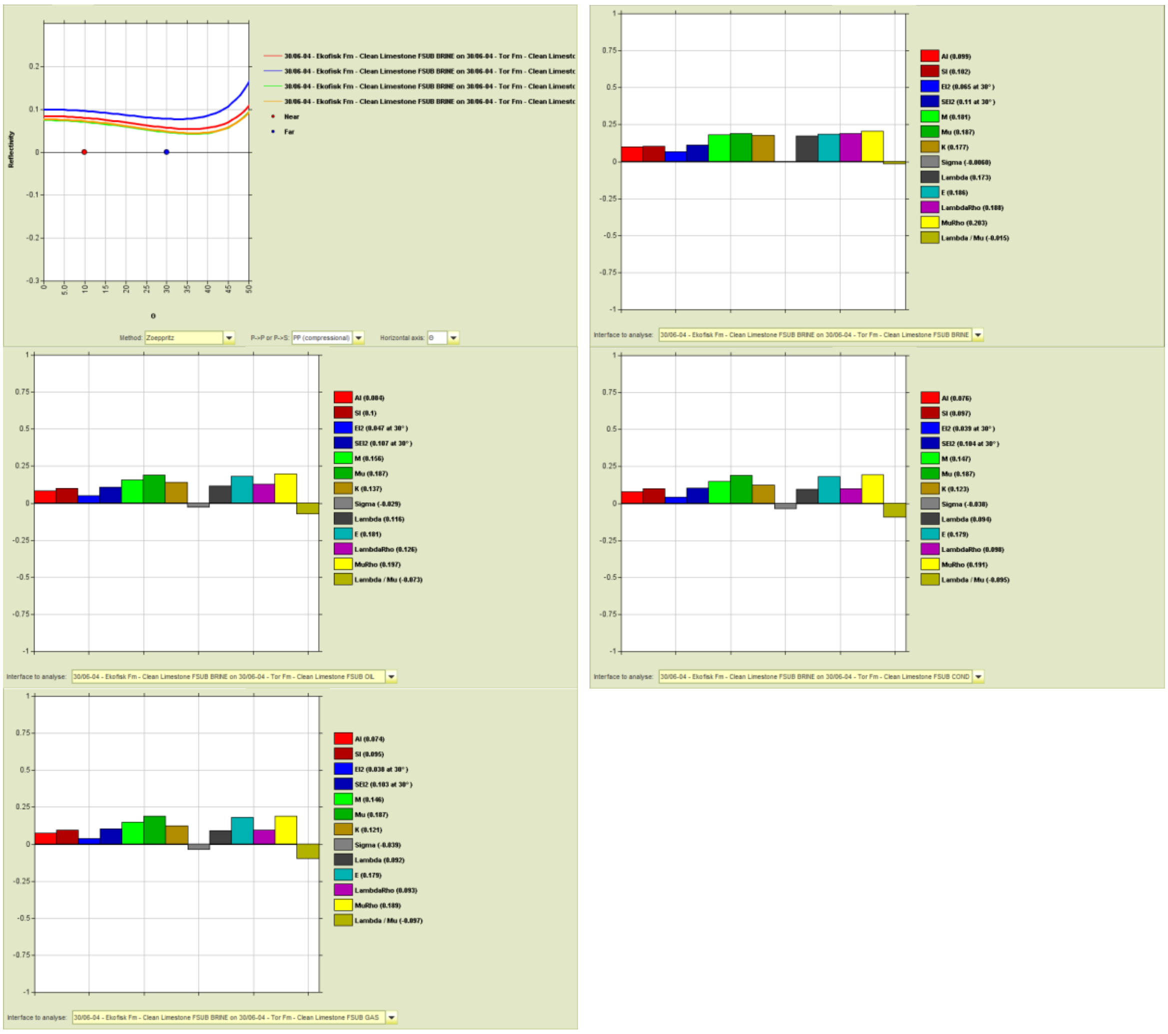


Figure 3.34.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 30/06-04.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 30/06-04 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/06-04	Overburden	Shale	7261	2832	2.26
30/06-04	Underburden				

Table 3.34.10 - Overburden and underburden properties at Well 30/06-04.

Well: 30/12A-09

General

Well Information
This well is a Phillips operated exploration well which was spudded, drilled and completed in 2001. The well did not encounter hydrocarbons.

Objectives
This well was drilled to investigate the Jane prospect to the south of Joanne. This is the second well to be drilled on the Jane prospect the previous being a dry hole (30/12A-5) drilled in 1993. The well encountered the prognosed geology at the expected depths. Whilst drilling there was no indication of hydrocarbons at any point on the well. However post well analysis did prove hydrocarbons but in lower saturations than the rig equipment could monitor.

Log conditioning overview
Only minor log conditioning was required due to good log data quality within this well. Thin calcite stringers in the Horda and Sele Formations were seen on the density log but were not apparent on the Vp log, and data relating to these intervals was consequentially removed. A section of poor quality data was seen on the Vs log at 9,320-9,328ft MD in the Balder Formation and this data was removed from the Vs log. Two small sections of poor quality data were seen on the Vs log at 9,960ft and 10,120ft MD in the Maureen Formation and this data was removed from the Vs log.

Invasion correction
Invasion correction has been performed on the density log in all formations. The drilling mud used within this well was oil-based.

Log modelling
In this well, all gaps in the Vp log were filled using the synthetic regional trend log (Vp_Trend_SDDI_Syn_Z) and all gaps in the Vs and Rho logs were filled using modelled Vs and Rho logs directly from the gap-filled Vp log.

Log modelling was performed to fill gaps within the Horda, Maureen and Tor Formations for the Vp log, within the Horda, Balder, Maureen and Tor Formations for the Vs log and within the Horda and Maureen Formations for the density log. A gap was also filled above the interval of interest in the Vp log using a spline function.

Note: For more detailed explanations of well specific log conditioning, invasion correction and log modelling, please refer to the Rock Physics Part 1 and 2 PowerPoints.

P&T data

The temperature and pressure data for Well 30/12A-09 is displayed in the figures below;

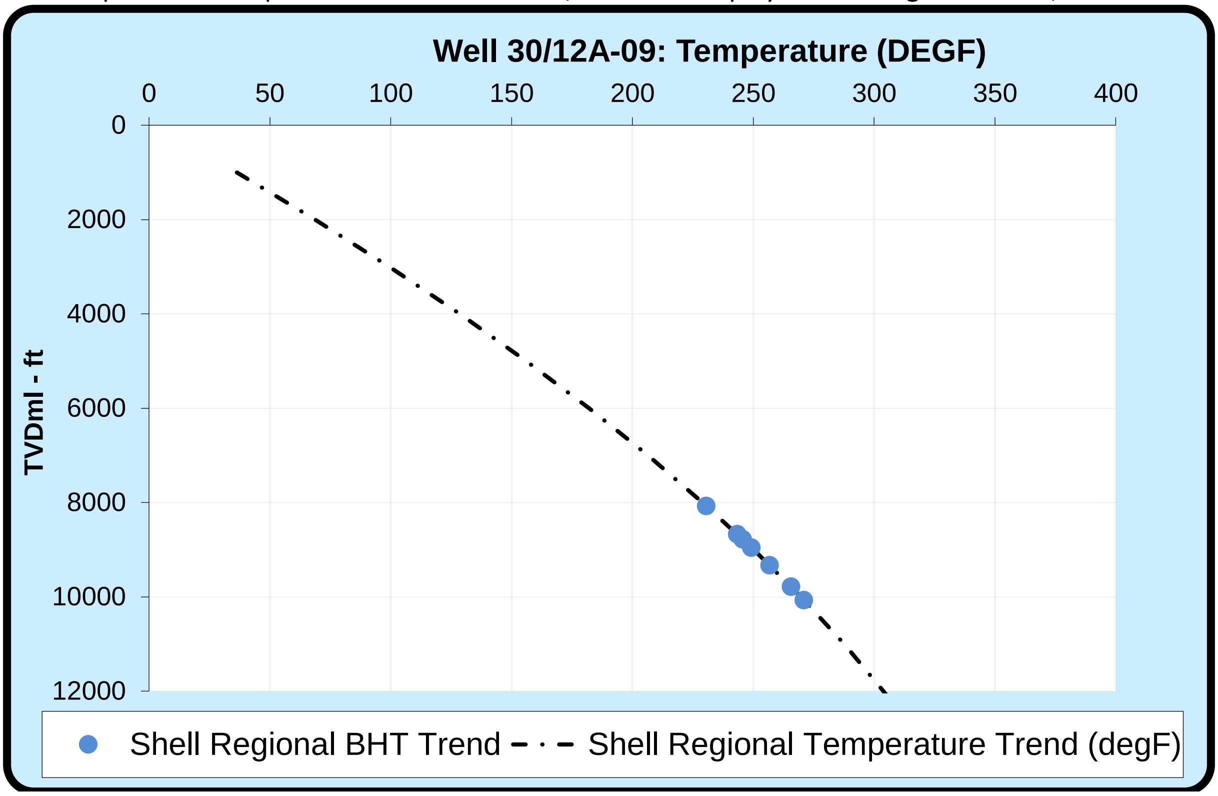


Figure 3.35.1 - Temperature data at Well 30/12A-09

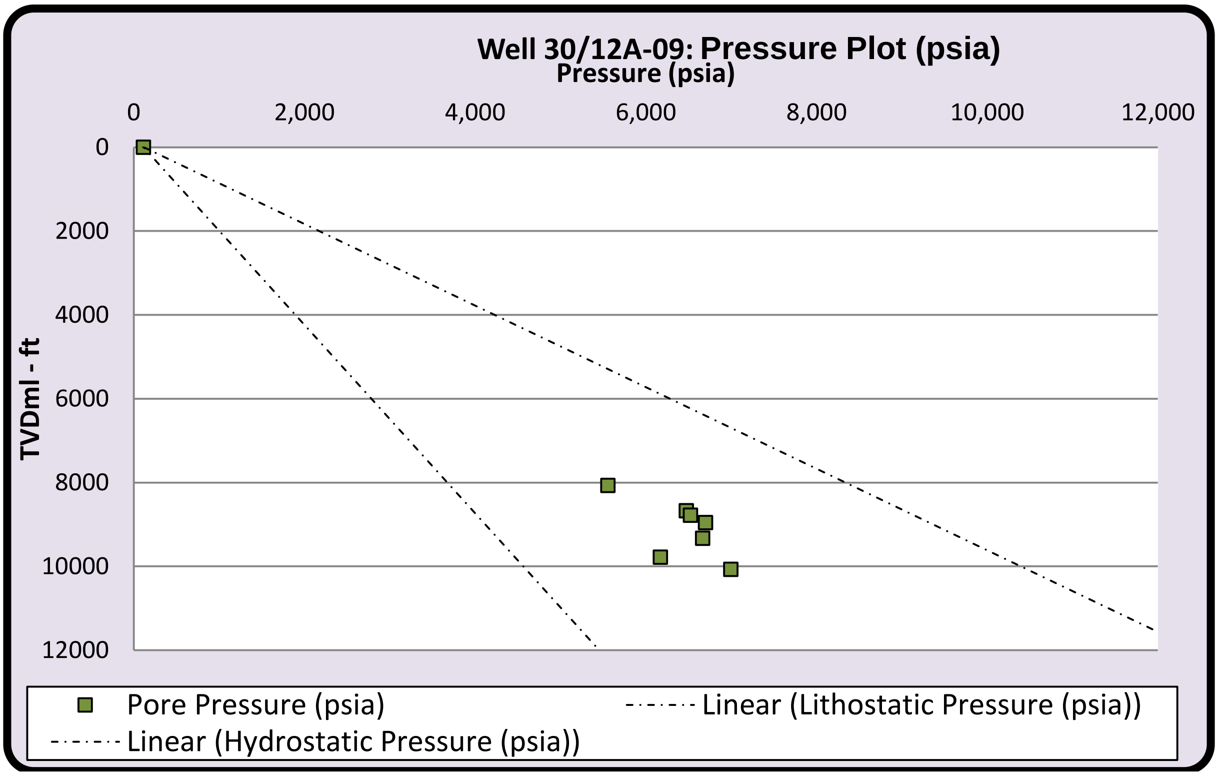


Figure 3.35.2 - Pressure data at Well 30/12A-09

The temperature and pressure data for the formation mid-points in Well 30/12A-09 is displayed in the table below;

Well Number	Interval	Mid-Point; MD (ft)	Mid-Point; TVDss (ft)	Mid-Point; TVDml (ft)	Shell Regional BHT Trend (deg F)	Hydro-static Pressure (Psia)	Pore Pressure (Psia)	Lithostatic Pressure (Psia)	Effective Pressure (Psia)
30/12A-09	Sea Bed	344.5	259.2	0.0	39.2	115.3	115.3	115.34	0.00
30/12A-09	Horda	8666.0	8329.6	8070.4	230.6	3706.7	5556.7	8070.41	2513.74
30/12A-09	Balder	9301.5	8931.8	8672.6	243.4	3974.7	6474.7	8672.62	2197.97
30/12A-09	Sele	9410.5	9040.1	8780.9	245.7	4022.8	6522.8	8780.91	2258.06
30/12A-09	Lista	9586.0	9214.7	8955.5	249.3	4100.6	6700.6	8955.55	2254.99
30/12A-09	Maureen	9960.5	9588.3	9329.1	256.8	4266.8	6666.8	9329.12	2662.32
30/12A-09	Ekofisk	10417.5	10044.4	9785.2	265.6	4469.8	6169.8	9785.21	3615.45
30/12A-09	Tor	10703.5	10329.8	10070.6	271.0	4596.8	6996.8	10070.62	3073.86

Table 3.35.1 - Summary of mid-point temperature and pressure data at Well 30/12A-09

Fluid data

A summary of the fluid set parameters at Well 30/12A-09 is provided below;

		Brine	Oil	Oil	Oil	Dry Gas
Well	Formation	Salinity (ppm)	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)	Gas Gravity (air=1)
30/12A-09	Horda	120000	730	40.1	0.78	0.78
30/12A-09	Balder	120000	730	40.7	0.78	0.78
30/12A-09	Sele	120000	730	40.8	0.78	0.78
30/12A-09	Lista	120000	730	41.0	0.78	0.78
30/12A-09	Maureen	120000	730	41.4	0.78	0.78
30/12A-09	Ekofisk	120000	730	41.9	0.78	0.78
30/12A-09	Tor	200000	730	42.2	0.78	0.78

Table 3.35.2 - Summary of fluid parameter data at Well 30/12A-09

In this well, there are additional properties for the condensate case and these are also provided below;

		Condensate	Condensate	Condensate
Well	Formation	GOR (scf/stb)	Oil API (API)	Gas Gravity (air=1)
30/12A-09	Horda	16380	55.9	0.8
30/12A-09	Balder	16380	56.5	0.8
30/12A-09	Sele	16380	56.5	0.8
30/12A-09	Lista	16380	56.7	0.8
30/12A-09	Maureen	16380	57.0	0.8
30/12A-09	Ekofisk	16380	57.4	0.8
30/12A-09	Tor	16380	57.6	0.8

Table 3.35.3 - Summary of additional parameter data at Well 30/12A-09

Mineral data

The mineral set at this well comprises of the following constant values used in this project

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Quartz	38.9	35.3	2.635	18,740	12,008
Calcite	60	25	2.71	19,253	9,965
Dry Clay	25	10	2.72	12,317	6,291

Table 3.35.4 - Constant mineral properties used in this project

The mineral set at this well also consists of derived Tuff properties and these are shown below;

Mineral	Ko (GPa)	Mu (GPa)	Rho (g/cm^3)	Vp (ft/sec)	Vs (ft/sec)
Tuff	12.06	5.16	2.303	9,409	4,913

Table 3.35.5 - Tuff properties used at Well 30/12A-09

Petrophysical data

A summary of the Petrophysical parameters is provided below;

Well Number	Formation		Gross (ft)	Net (ft)	N:G	PHITH	PHIT_AV	SWT_AV	VSH_AM
30/12A-09	Horda	PAY	1218.000	0.000	0.000	0.000	0.000	0.000	0.000
30/12A-09	Horda	RES	1218.000	2.000	0.002	0.343	0.172	0.987	0.354
30/12A-09	Balder	PAY	53.000	0.000	0.000	0.000	0.000	0.000	0.000
30/12A-09	Balder	RES	53.000	0.250	0.005	0.051	0.204	1.000	0.000
30/12A-09	Sele	PAY	165.000	0.000	0.000	0.000	0.000	0.000	0.000
30/12A-09	Sele	RES	165.000	67.750	0.411	10.915	0.161	1.000	0.369
30/12A-09	Lista	PAY	186.000	0.000	0.000	0.000	0.000	0.000	0.000
30/12A-09	Lista	RES	186.000	16.500	0.089	2.754	0.167	0.985	0.124
30/12A-09	Maureen	PAY	563.000	0.000	0.000	0.000	0.000	0.000	0.000
30/12A-09	Maureen	RES	563.000	187.000	0.332	27.436	0.147	0.973	0.149
30/12A-09	Ekofisk	PAY	351.000	4.500	0.013	0.519	0.115	0.451	0.291
30/12A-09	Ekofisk	RES	351.000	347.250	0.989	55.095	0.159	0.861	0.144
30/12A-09	Tor	PAY	222.000	0.000	0.000	0.000	0.000	0.000	0.000
30/12A-09	Tor	RES	222.000	200.250	0.902	31.470	0.157	0.988	0.030

Table 3.35.6 - Petrophysical parameters used at Well 30/12A-09

Additional details of the parameters used in the Petrophysics can be found in the accompanying Petrophysics reports and the Master Spreadsheet.

Well panels

Well log panel – measured data

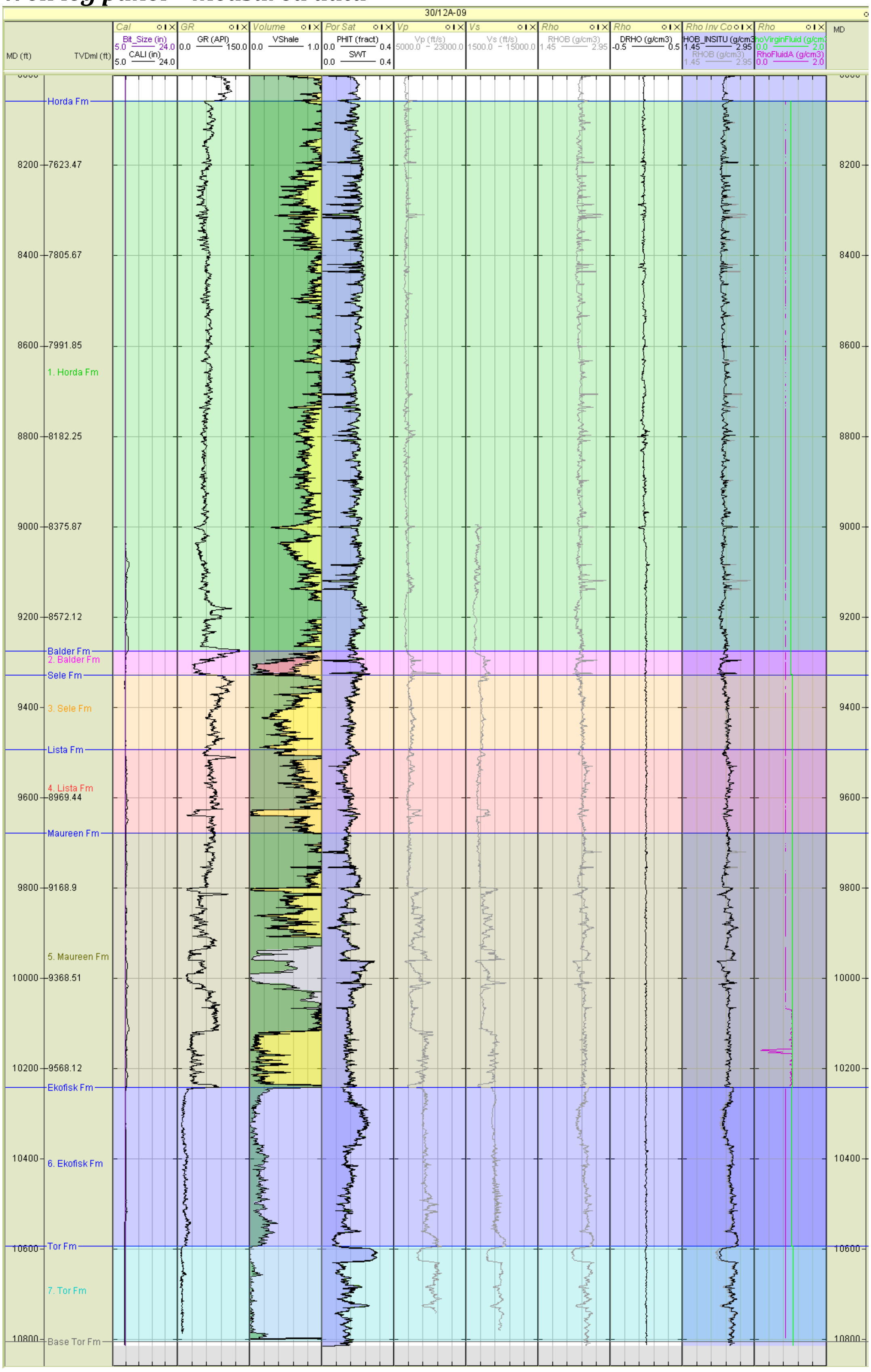


Figure 3.35.3 - Well Panel: Measured data and invasion correction for well 30/12A-09.

Well log panel – log editing and audit

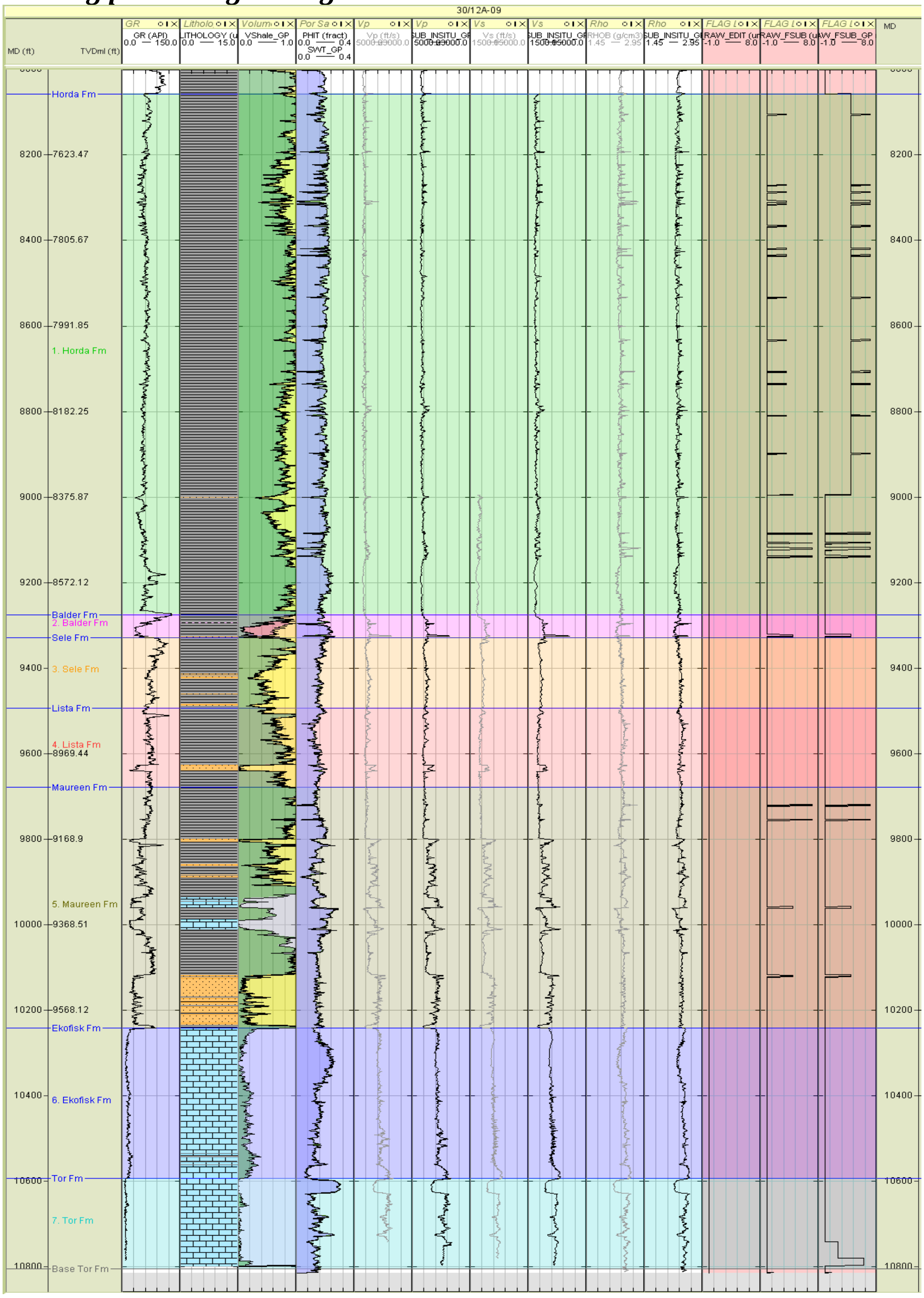


Figure 3.35.4 - Well Panel: Log edits for well 30/12A-09.

Legend

Flag = 0	**No edits**	**Flag = 4**	**Edit in Vp**
Flag = 1	**Edit in Rho**	**Flag = 5**	**Edit in Vp and Rho**
Flag = 2	**Edit in Vs**	**Flag = 6**	**Edit in Vp and Vs**
Flag = 3	**Edit in Rho and Vs**	**Flag = 7**	**Edit in Vp, Vs and Rho**

Well log panel – synthetic curves

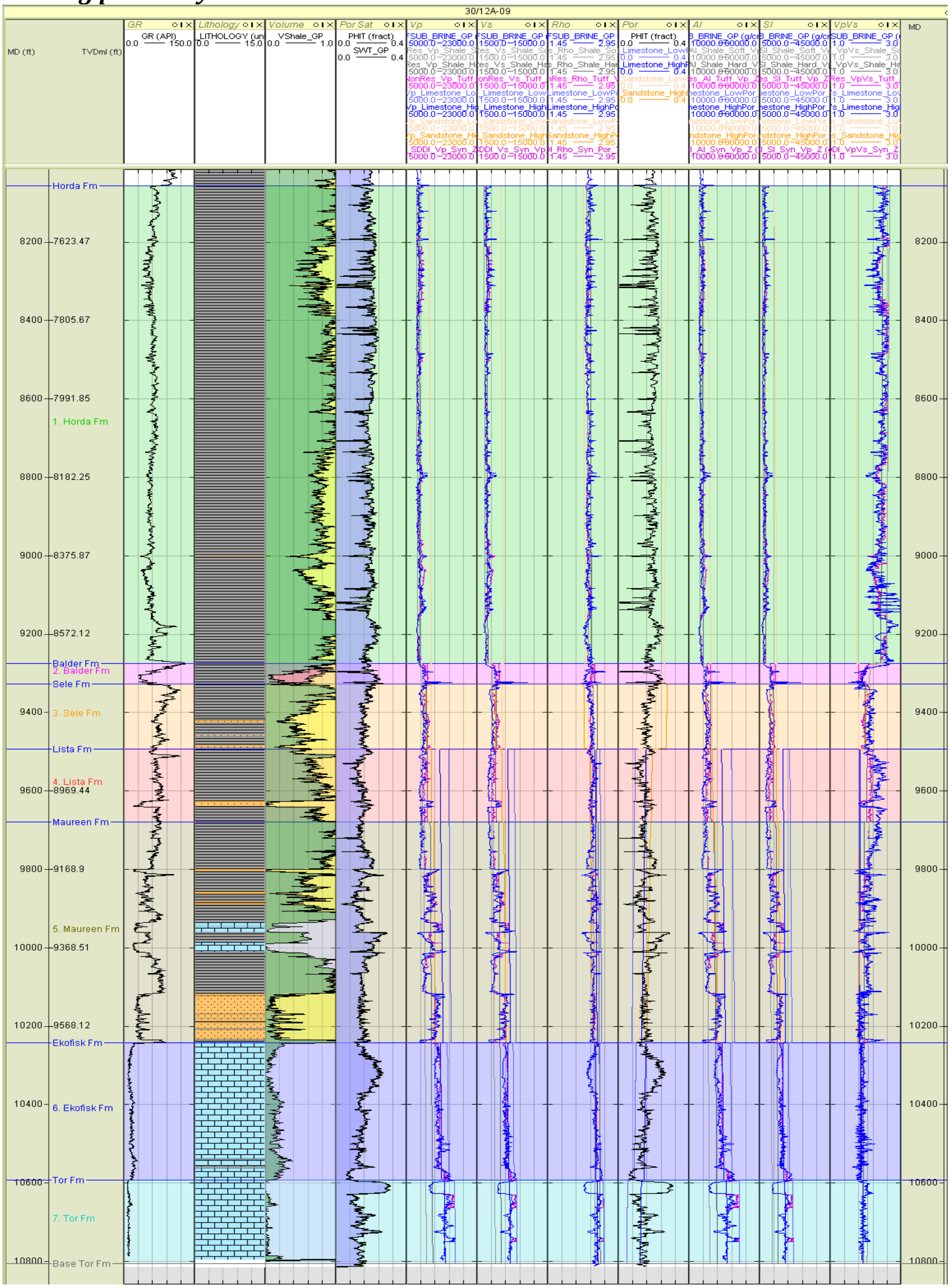


Figure 3.35.5 - Well Panel: End-member and synthetic logs for well 30/12A-09.

Curves: Blue/Black = Measured, Purple = Synthetic,
End member : Grey = Shl, Yellow = Sst, Violet = Limestone, Pink = Tuff (Balder)

Well log panel – fluid substituted logs

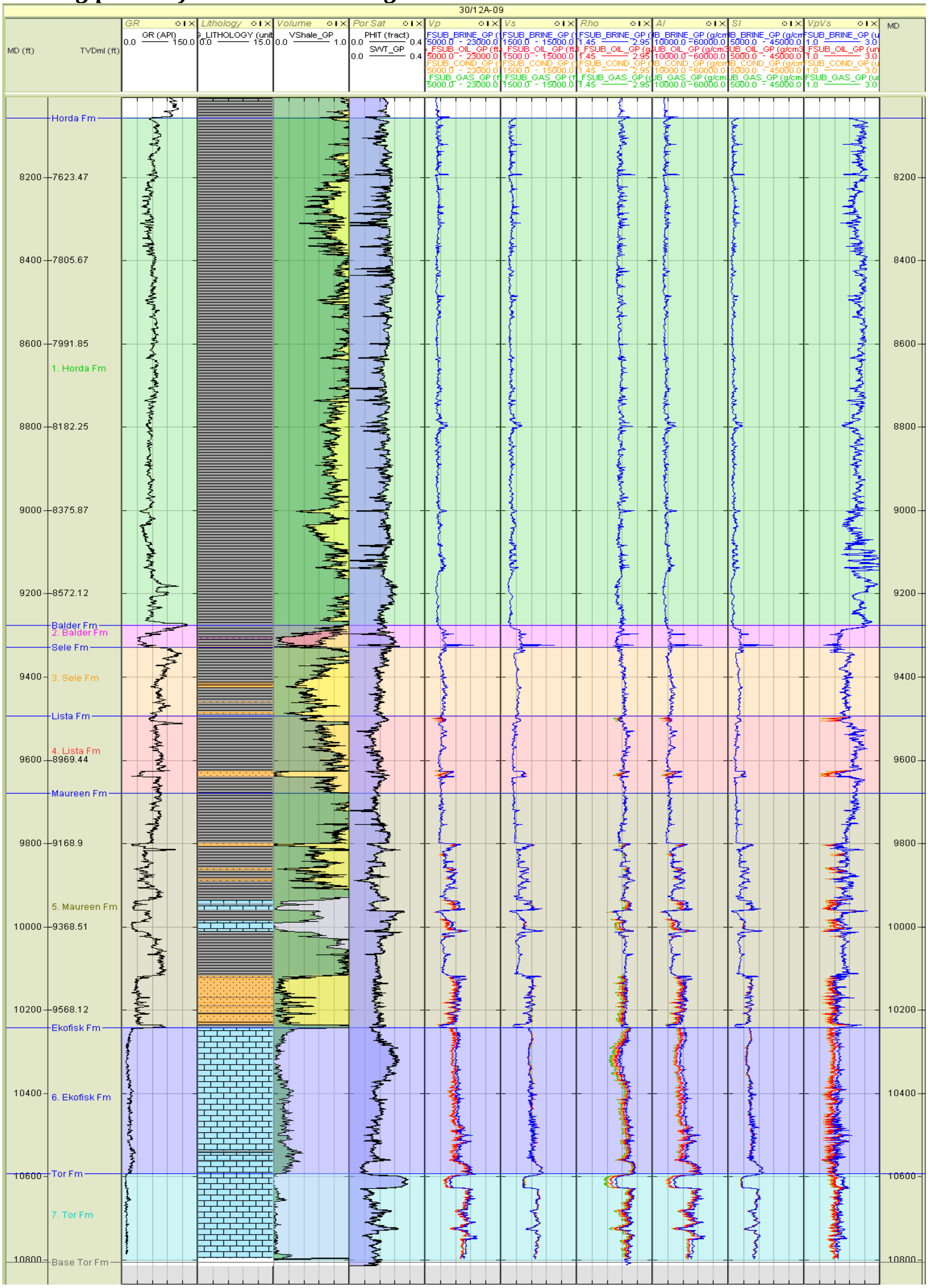


Figure 3.35.6 - Well Panel: Fluid substituted and elastic logs for well 30/12A-09.

Curves: Blue = Brine, Red = Oil, Green = Gas, Orange = Condensate (not present at every well)

Average Vp, Vs and Rho values - Tertiary

A summary of the average Vp, Vs and Rho values found in the Tertiary section at Well 30/12A-09 is provided below;

Clean Shale values

A shale volume cut-off of VSh>0.7 is used to find these average values;

Well	Formation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/12A-09	Horda	8144	3270	2.31
30/12A-09	Balder	8726	3739	2.34
30/12A-09	Sele	8824	4285	2.24
30/12A-09	Lista	8632	3682	2.38
30/12A-09	Maureen	9180	4282	2.38

Table 3.35.7 - Clean shale properties at Well 30/12A-09

Clean Sand values

Clean sand values are only derived in formations containing viable sand reservoir according to the reservoir interval cut-offs.

A sand volume cut-off of Vol_Sand>0.7 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/12A-09	Horda	100% Brine			
30/12A-09	Balder	100% Brine			
30/12A-09	Sele	100% Brine			
30/12A-09	Lista	100% Brine	10753	5424	2.40
30/12A-09	Maureen	100% Brine	12458	6724	2.42
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/12A-09	Horda	80% Oil			
30/12A-09	Balder	80% Oil			
30/12A-09	Sele	80% Oil			
30/12A-09	Lista	80% Oil	9577	5472	2.36
30/12A-09	Maureen	80% Oil	11979	6781	2.38
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/12A-09	Horda	90% Gas			
30/12A-09	Balder	90% Gas			
30/12A-09	Sele	90% Gas			
30/12A-09	Lista	90% Gas	9354	5525	2.31
30/12A-09	Maureen	90% Gas	11851	6863	2.33
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/12A-09	Horda	80% Cond			
30/12A-09	Balder	80% Cond			
30/12A-09	Sele	80% Cond			
30/12A-09	Lista	80% Cond	9201	5514	2.32
30/12A-09	Maureen	80% Cond	11829	6837	2.34

Table 3.35.8 - Clean sand properties at Well 30/12A-09 for each fluid case

Tertiary reservoirs – Well panel

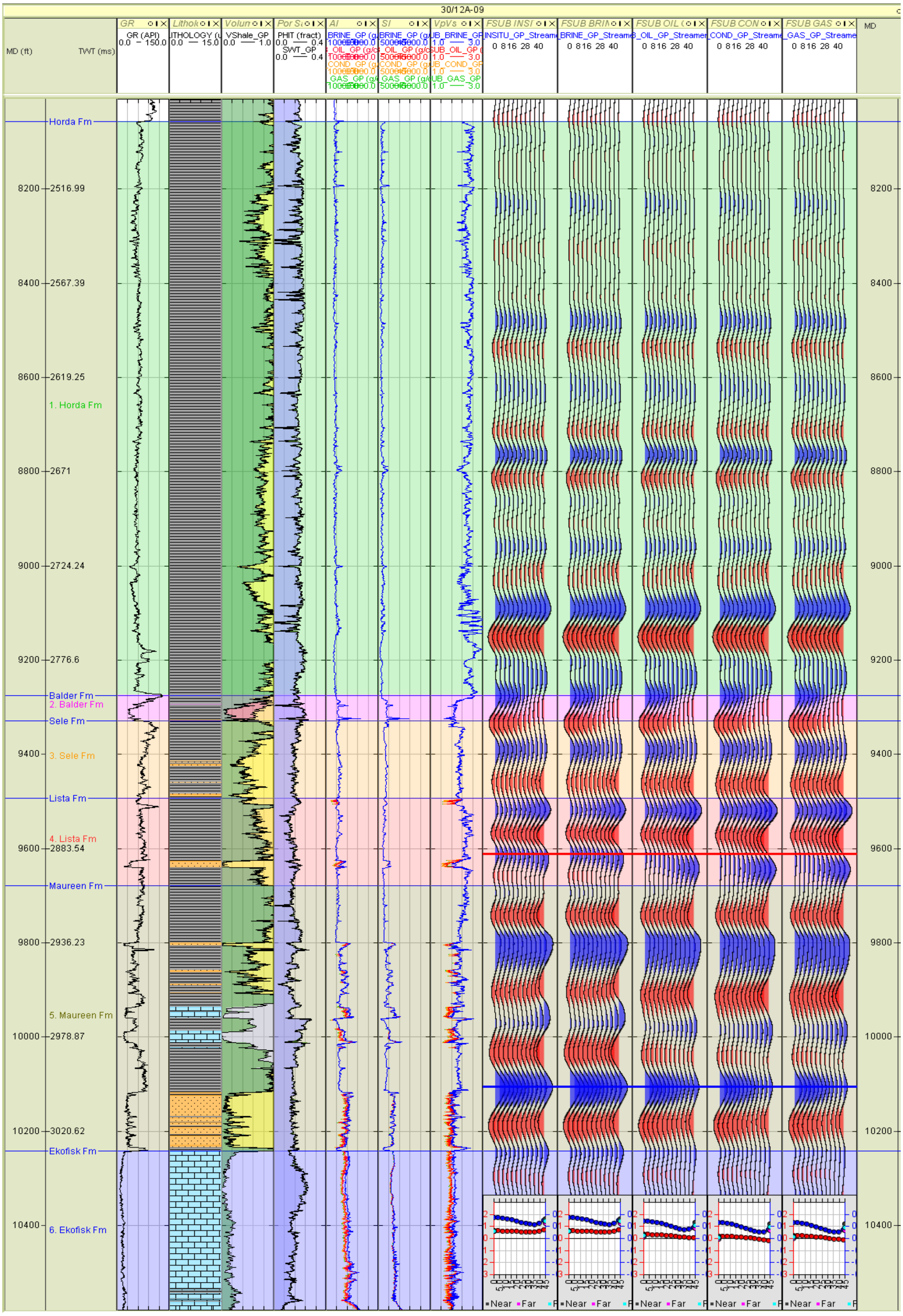


Figure 3.35.7 - Well Panel: Tertiary reservoirs for well 30/12A-09. Wavelet : Streamer.

Formation description - Tertiary reservoirs

Lista Formation

- Reservoir formed by a thin hard sand package within shale and net reservoir is approximately 17 feet. The Lista reservoir sand is overlain directly by the overburden shale of the upper section of the Lista Fm.
- Blocky AVO shows a modelled class I response for the 100% brine case and a modelled class IIp response for the 80% oil, 80% condensate and 90% gas fluid cases, with the softness of the sand in relation to the shale increasing with the addition of hydrocarbons. This change in AVO type is similar to the synthetic gathers.
- Elastic Contrast Analysis shows contrasts are mainly positive and medium amplitude in the brine case, and that the contrasts become negative for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

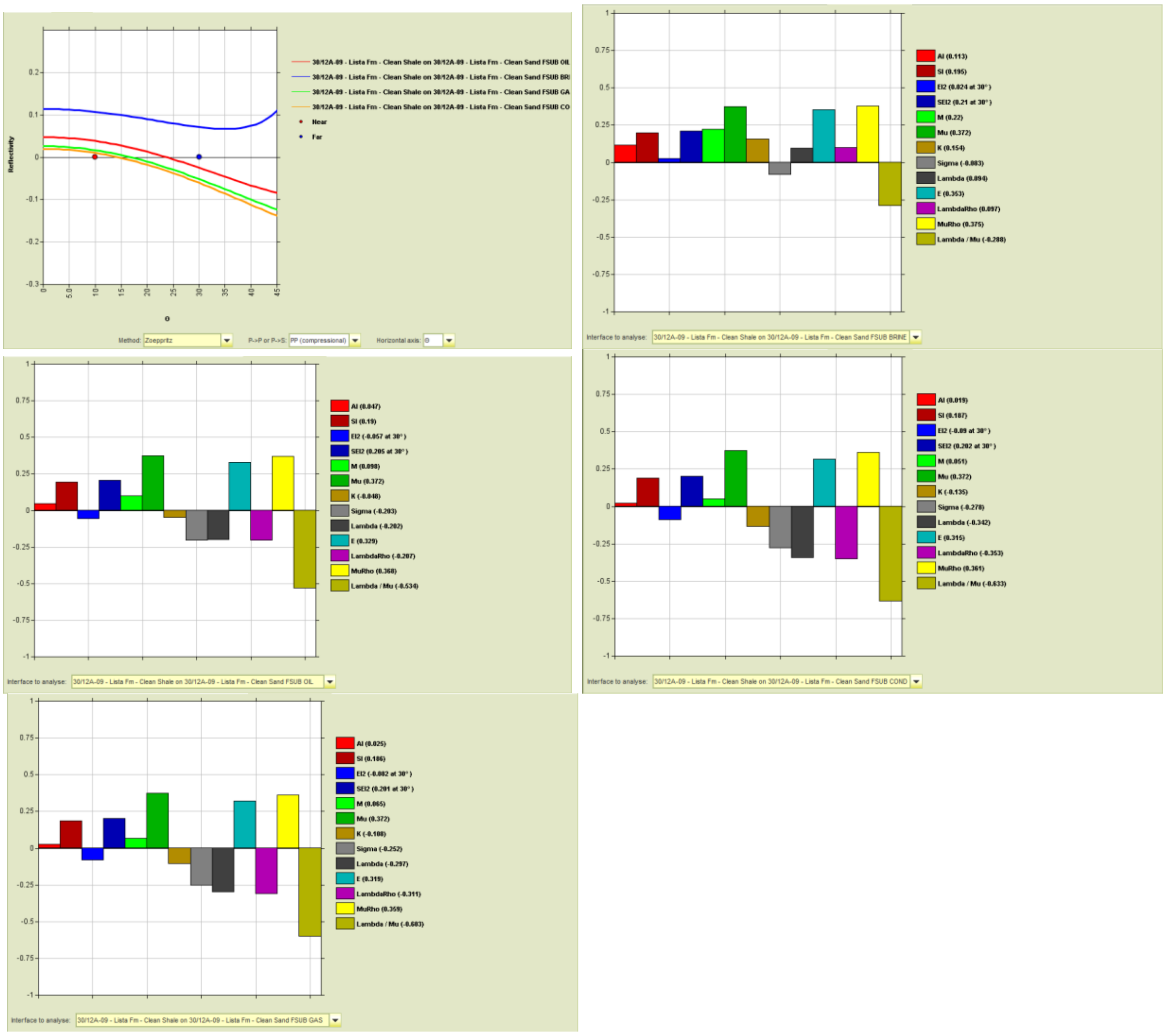


Figure 3.35.8 - Blocky AVO Model and Elastic Contrast Analysis for the Lista Formation in well 30/12A-09.

Maureen Formation

- Reservoir contains both sandstone and limestone lithologies. The sand reservoir is formed by a clean blocky sand package in the base section of the interval and net reservoir is approximately 187 feet. The Lista reservoir sand is overlain directly by a section of shale.
- Blocky AVO shows a modelled class I response for all fluid cases, with the softness of the sand in relation to the overburden shale increasing with the addition of hydrocarbons. The synthetic gathers also show a class I response for all fluid cases.
- Elastic Contrast Analysis shows contrasts are mainly positive and high amplitude in the brine case, and that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

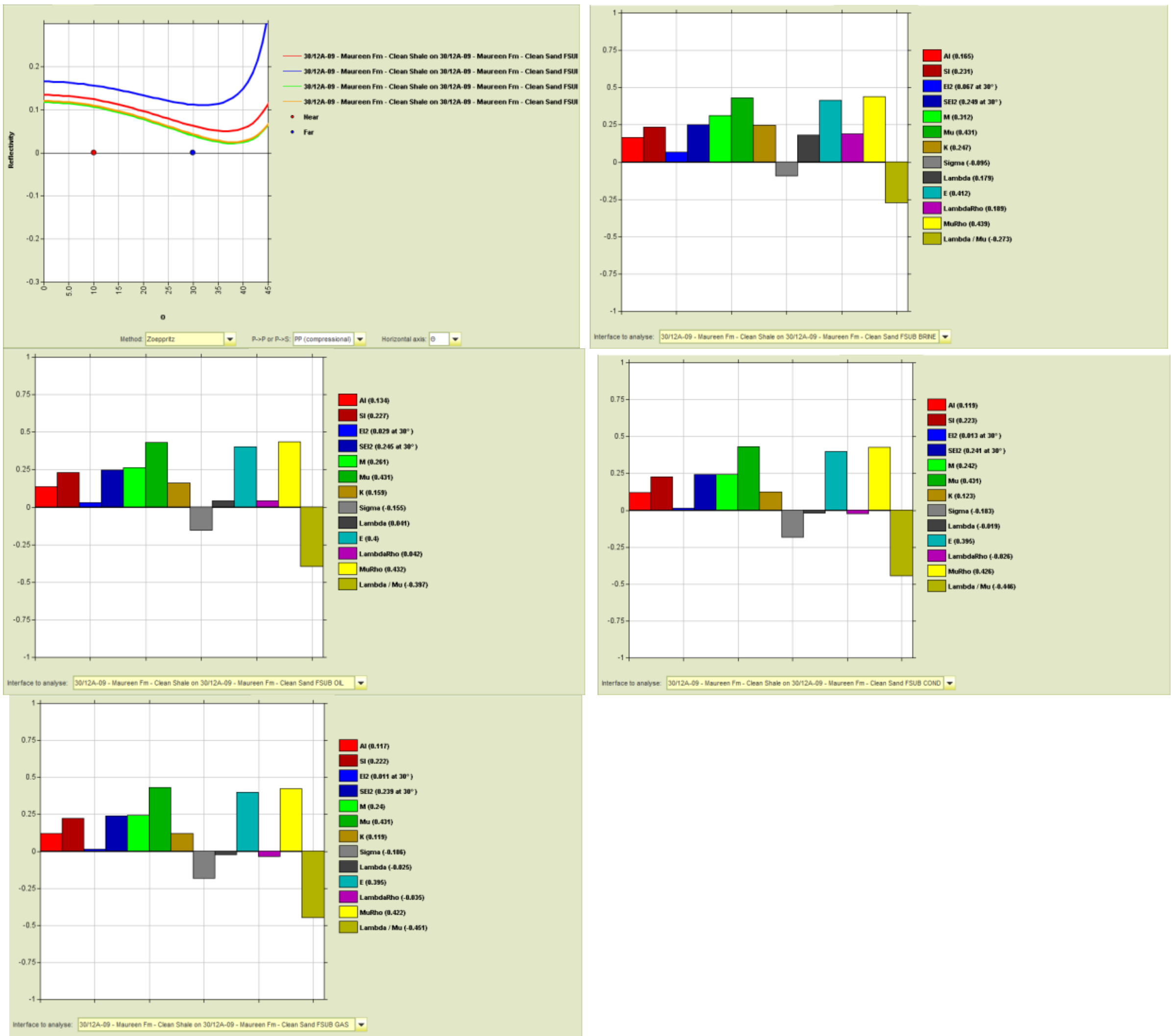


Figure 3.35.9 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Formation in well 30/12A-09.

Average Vp, Vs and Rho values - Cretaceous

A summary of the average Vp, Vs and Rho values found in the Cretaceous section at Well 30/12A-09 is provided below;

Clean Shale values

No clean shale values are available in the Cretaceous section of this well.

Clean Limestone values

Clean limestone values are only derived in formations containing viable limestone reservoir according to the reservoir interval cut-offs.

A limestone volume cut-off of Vol_Lime>0.9 is used to find these average values for each fluid case;

Well	Formation	Saturation	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/12A-09	Ekofisk	100% Brine	12722	6646	2.36
30/12A-09	Tor	100% Brine	14353	7434	2.45
30/12A-09	Hod	100% Brine			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/12A-09	Ekofisk	80% Oil	11973	6732	2.30
30/12A-09	Tor	80% Oil	13726	7511	2.40
30/12A-09	Hod	80% Oil			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/12A-09	Ekofisk	90% Gas	11892	6856	2.22
30/12A-09	Tor	90% Gas	13664	7609	2.33
30/12A-09	Hod	90% Gas			
Well	**Formation**	**Saturation**	**Vp (ft/sec)**	**Vs (ft/sec)**	**Rho (g/cm^3)**
30/12A-09	Ekofisk	80% Cond	11846	6816	2.25
30/12A-09	Tor	80% Cond	13627	7577	2.36
30/12A-09	Hod	80% Cond			

Table 3.35.9 - Clean limestone properties at Well 30/12A-09 for each fluid case

Cretaceous reservoirs

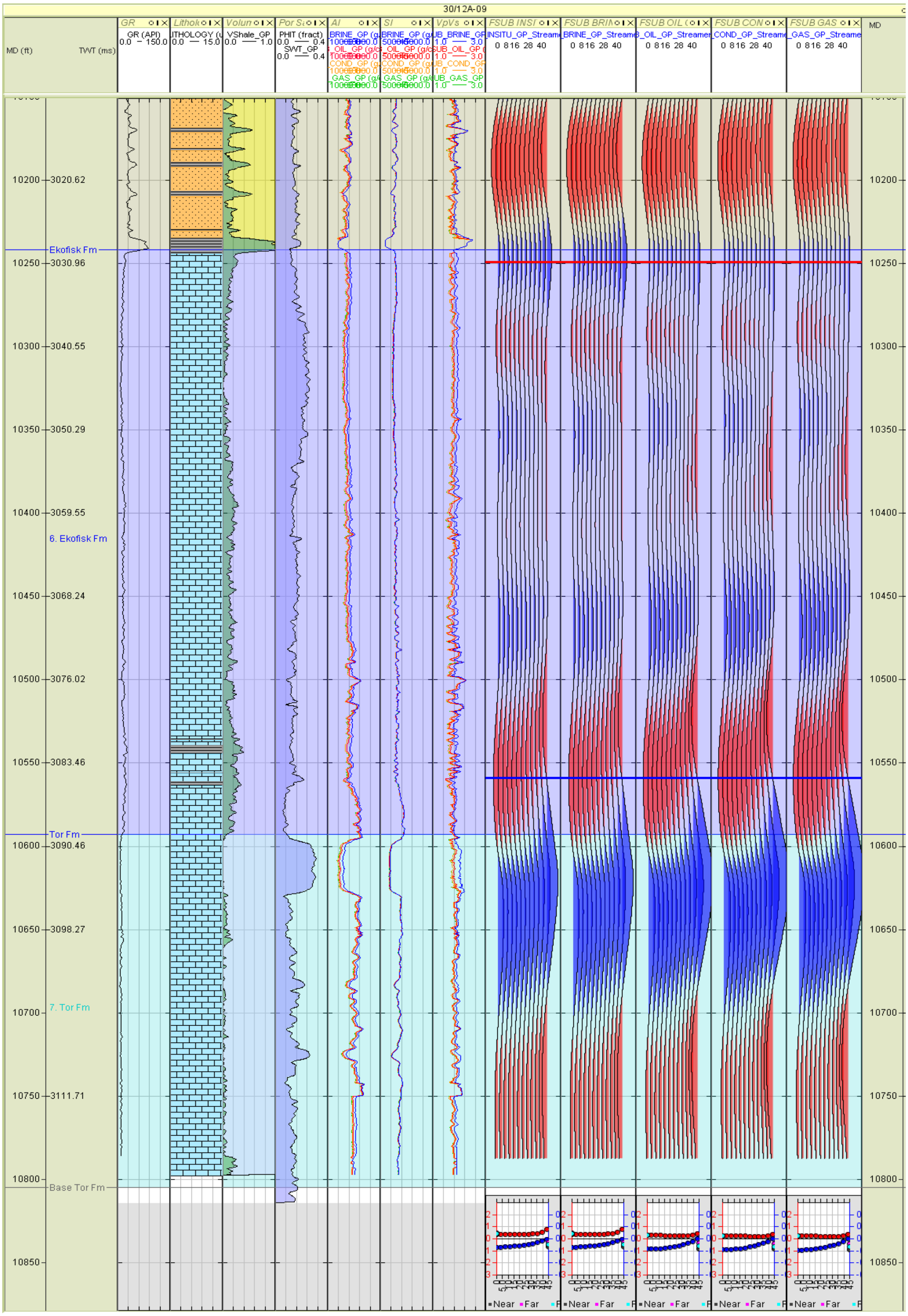


Figure 3.35.10 - Well Panel: Cretaceous reservoirs for well 30/12A-09. Wavelet : Streamer.

Formation description - Cretaceous reservoirs

Ekofisk Formation

- Reservoir formed by a limestone formation with a minor component of shale. The highest porosity reservoir is found in the upper section of the Ekofisk Fm, the porosity in this section is approximately 24% and this formation is brine-bearing. The higher porosity layers found in the Ekofisk Fm could be representative of reworked chalk zones.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden shale increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are mainly positive and strong amplitude in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

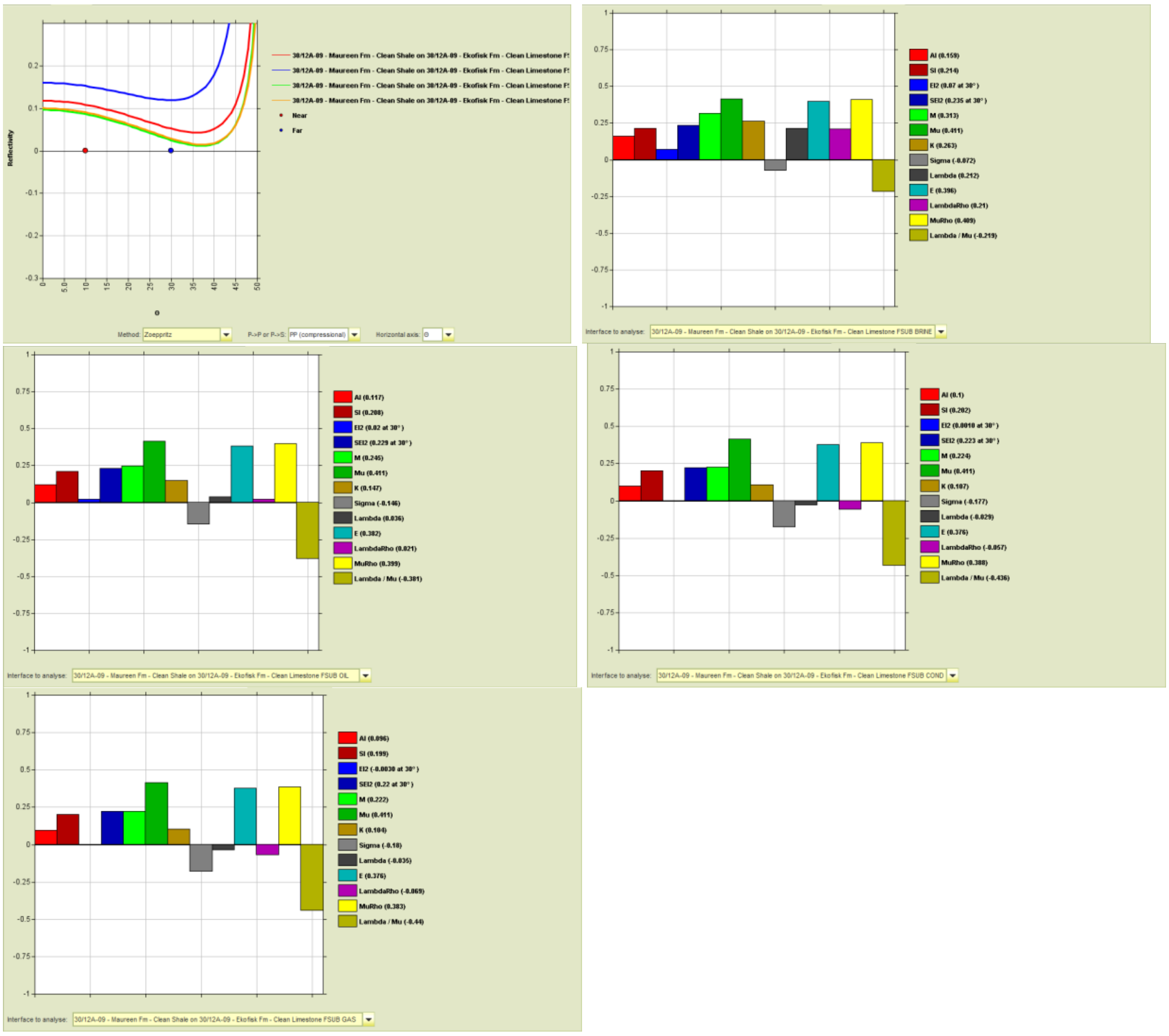


Figure 3.35.11 - Blocky AVO Model and Elastic Contrast Analysis for the Maureen Shale/Ekofisk Limestone interface in well 30/12A-09.

Tor Formation

- Reservoir formed by a clean limestone formation. The highest porosity reservoir is found in the upper section of the Tor Fm, the porosity in this section is approximately 31% and this section of the reservoir has a significantly higher porosity than all other sections of the well. This high porosity layer found in the Tor Fm could be representative of a reworked chalk zone.
- Blocky AVO shows a modelled class I response for all the fluid cases, with the softness of the limestone in relation to the overburden brine-saturated limestone increasing with the addition of hydrocarbons.
- Elastic Contrast Analysis shows contrasts are positive in the brine case, but that the contrasts decrease in amplitude for most attributes with addition of hydrocarbons. The elastic response for the 80% condensate fluid case is very similar to the elastic response for the 90% gas fluid case. Mu shows the least sensitivity to fluid changes, whilst Lambda/LambdaRho show the most sensitivity to fluid effects.

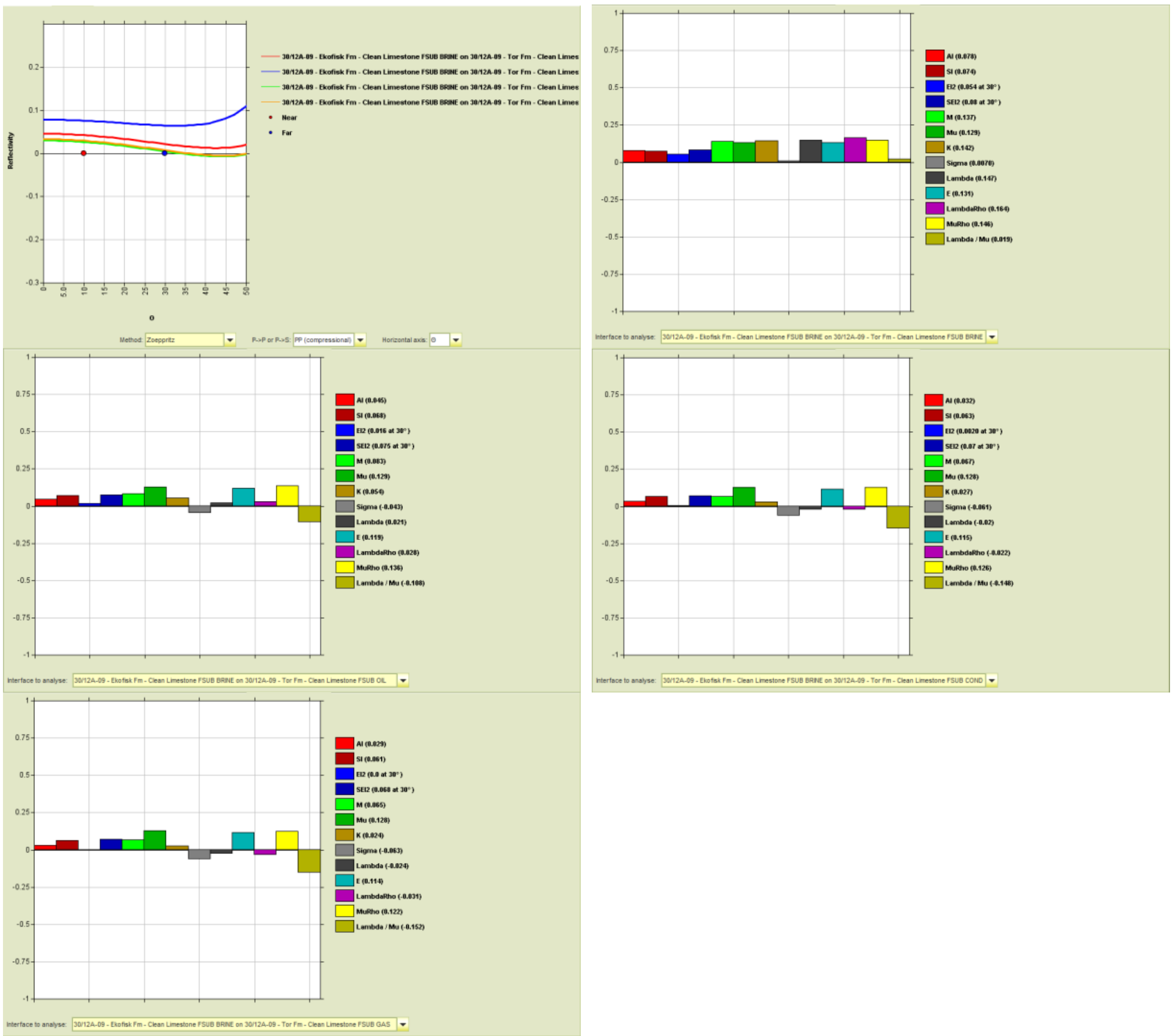


Figure 3.35.12 - Blocky AVO Model and Elastic Contrast Analysis for the Ekofisk Limestone/Tor Limestone interface in well 30/12A-09.

Average Vp, Vs and Rho values - Underburden/Overburden sections

A summary of the average Vp, Vs and Rho values found in the underburden and overburden sections at Well 30/12A-09 is provided below;

These average values were derived from measured INSITU log data. The averages were derived using log data 300ft above the Horda Fm for the overburden section and log data 300ft below the Hod Fm for the underburden section.

No cut-offs were applied to the average values and they provide an estimate of the rock physics properties above and below the study interval in this well.

Well	Formation	Lithology	Vp (ft/sec)	Vs (ft/sec)	Rho (g/cm^3)
30/12A-09	Overburden	Shale	7790		2.31
30/12A-09	Underburden				

Table 3.35.10 - Overburden and underburden properties at Well 30/12A-09.

Appendix G – User Programmer Scripts

G.1 – Invasion Correction

```
// RokDoc User Programmer Custom Script:
// Invasion Correction

// Input - RHOB
// Output - RHOB_Corrected, RhoFluidA, RhoVirginFluid
// Description - Invasion correction of the Density log

// 1. Define the input logs used within the script

$RhoBMeasured = Rho ;

$VShale = Volume ;
$VLime = Volume ;
$VQtz = Volume ;
$VTuff = Volume ;

$Por = Por ;
$Sw = Sat ;
$SOil = Sat ;
$SGas = Sat ;

// 2. Define the global variables
// nb: Values for study wells contained within report/ ppts/ petrophysical reports
//     If Gas Condensate present, substitute values/saturation log for another hydrocarbon phase

// Grain Density
$RhoQtz = 2.65 ;
$RhoLime = 2.71 ;
$RhoTuff = 2.65 ;
```

```
// Perform Invasion Correction? 0.0 = Don't Perform and 1.0 = Perform
$Apply_Horda = 0.0 ;
$Apply_Balder = 0.0 ;
$Apply_Sele = 0.0 ;
$Apply_Lista = 0.0 ;
$Apply_Maureen = 0.0 ;
$Apply_Ekofisk = 0.0 ;
$Apply_Tor = 0.0 ;
$Apply_Hod = 0.0 ;

// Filtrate Density
$RhoFiltrate_Horda = 0.85 ;
$RhoFiltrate_Balder = 0.85 ;
$RhoFiltrate_Sele = 0.85 ;
$RhoFiltrate_Lista = 0.85 ;
$RhoFiltrate_Maureen = 0.85 ;
$RhoFiltrate_Ekofisk = 0.85 ;
$RhoFiltrate_Tor = 0.85 ;
$RhoFiltrate_Hod = 0.85 ;

// Reservoir Fluid Density
$RhoWater_Horda = 1.000 ;
$RhoOil_Horda = 0.700 ;
$RhoGas_Horda = 0.200 ;
$RhoWater_Balder = 1.000 ;
$RhoOil_Balder = 0.700 ;
$RhoGas_Balder = 0.200 ;
$RhoWater_Sele = 1.000 ;
$RhoOil_Sele = 0.700 ;
$RhoGas_Sele = 0.200 ;
$RhoWater_Lista = 1.000 ;
$RhoOil_Lista = 0.700 ;
$RhoGas_Lista = 0.200 ;
$RhoWater_Maureen = 1.000 ;
$RhoOil_Maureen = 0.700 ;
$RhoGas_Maureen = 0.200 ;
```

$RhoWater_Ekofisk = 1.000 ;

$RhoOil_Ekofisk = 0.700 ;

$RhoGas_Ekofisk = 0.200 ;

$RhoWater_Tor = 1.000 ;

$RhoOil_Tor = 0.700 ;

$RhoGas_Tor = 0.200 ;

$RhoWater_Hod = 1.000 ;

$RhoOil_Hod = 0.700 ;

$RhoGas_Hod = 0.200 ;

//
//////////////////////////////// DO NOT EDIT BELOW /////////////////////////////////
//

// 3. Definition of reservoir cut-offs

// nb: To apply no cut-off, set $<variable> = 1.0

$VShaleCutOff_Horda = 0.40 ;

$PorCutOff_Horda = 0.15 ;

$VShaleCutOff_Balder = 0.60 ;

$PorCutOff_Balder = 0.12 ;

$VShaleCutOff_Sele = 0.50 ;

$PorCutOff_Sele = 0.12 ;

$VShaleCutOff_Lista = 0.40 ;

$PorCutOff_Lista = 0.10 ;

$VShaleCutOff_Maureen = 0.45 ;

$PorCutOff_Maureen = 0.08 ;

$VShaleCutOff_Ekofisk = 0.40 ;

$PorCutOff_Ekofisk = 0.06 ;

$VShaleCutOff_Tor = 0.20 ;

$PorCutOff_Tor = 0.03 ;

$VShaleCutOff_Hod = 0.40 ;

$PorCutOff_Hod = 0.03 ;

//

// 4. Removes null values and normalises the volume/saturation logs to create a continuous volume/saturation set

```
if ($VShale = null)
  $VShale_Min = 0;
else
  if ($VShale > 1)
    $VShale_Min = 1;
  else
    if ($VShale < 0)
      $VShale_Min = 0;
    else
      $VShale_Min = $VShale;
    endif;
  endif;
endif;

if ($VLime = null)
  $VLime_Min = 0;
else
  if ($VLime > 1)
    $VLime_Min = 1;
  else
    if ($VLime < 0)
      $VLime_Min = 0;
    else
      $VLime_Min = $VLime;
    endif;
  endif;
endif;

if ($VQtz = null)
  $VQtz_Min = 0;
else
  if ($VQtz > 1)
    $VQtz_Min = 1;
```

```
  else
    if ($VQtz < 0)
      $VQtz_Min = 0;
    else
      $VQtz_Min = $VQtz;
    endif;
  endif;
endif;

if ($VTuff = null)
  $VTuff_Min = 0;
else
  if ($VTuff > 1)
    $VTuff_Min = 1;
  else
    if ($VTuff < 0)
      $VTuff_Min = 0;
    else
      $VTuff_Min = $VTuff;
    endif;
  endif;
endif;

$Volume_Sum = $VShale_Min + $VLime_Min + $VQtz_Min + $VTuff_Min ;

$VShale = $VShale_Min / $Volume_Sum ;
$VLime = $VLime_Min / $Volume_Sum ;
$VQtz = $VQtz_Min / $Volume_Sum ;
$VTuff = $VTuff_Min / $Volume_Sum ;

if ( $Sw = null )
		$Sw = 0.0 ;
endif ;
if ( $SOil = null )
		$SOil = 0.0 ;
endif ;
```

```
if ( $SGas = null )
        $SGas = 0.0 ;
endif ;

$Sx = $Sw ; // unless otherwise calculated

if ( $VQtz > 0.0 )
        $RhoShale = $RhoQtz ;
endif ;
if ( $VLime > 0.0 )
        $RhoShale = $RhoLime ;
endif;

////////////////////////////////////////////////////////////////////////////////////

// 5. Performs invasion correction of the Density log through comparison of the measured/ predicted fluid density

if ( 1. Horda Fm )

// Density of matrix
        $RhoMatrix_Horda = ( $VShale * $RhoShale ) + ( $VLime * $RhoLime ) + ( $VQtz * $RhoQtz ) + ( $VTuff * $RhoTuff ) ;

// Density of virgin fluid
        $RhoVirginFluid = ( $Sw * $RhoWater_Horda ) + ( $SOil * $RhoOil_Horda ) + ( $SGas * $RhoGas_Horda ) ;

// Density of apparent fluid
        $RhoFluidA = $RhoMatrix_Horda - ( ( $RhoMatrix_Horda - $RhoBMeasured ) / $Por );

// Density of apparent fluid density overwritten if outside following criteria
        if ( $RhoFluidA > $RhoWater_Horda )
                $RhoFluidA = $RhoWater_Horda ;
        endif ;
        if ( $RhoFluidA < $RhoVirginFluid AND $RhoFiltrate_Horda >= $RhoWater_Horda )
                $RhoFluidA = $RhoVirginFluid ;
```

```
        endif ;

// Density corrected to virgin zone saturation
        $RhoCorr = $RhoBMeasured + ( ( $Por * $RhoVirginFluid ) - ( $Por * $RhoFluidA ) ) ;

        if ( $Apply_Horda = 1.0 AND $VShale < $VShaleCutOff_Horda AND $Por > $PorCutOff_Horda )
                $ApplyCorrection = 1.0 ;
        else
                $ApplyCorrection = 0.0 ;
        endif ;

endif ;

if ( 2. Balder Fm )

        $RhoMatrix_Balder = ( $VShale * $RhoShale ) + ( $VLime * $RhoLime ) + ( $VQtz * $RhoQtz ) + ( $VTuff * $RhoTuff ) ;
        $RhoVirginFluid = ( $Sw * $RhoWater_Balder ) + ( $SOil * $RhoOil_Balder ) + ( $SGas * $RhoGas_Balder ) ;
        $RhoFluidA = $RhoMatrix_Balder - ( ( $RhoMatrix_Balder - $RhoBMeasured ) / $Por );

        if ( $RhoFluidA > $RhoWater_Balder )
                $RhoFluidA = $RhoWater_Balder ;
        endif ;
        if ( $RhoFluidA < $RhoVirginFluid AND $RhoFiltrate_Balder >= $RhoWater_Balder )
                $RhoFluidA = $RhoVirginFluid ;
        endif ;

        $RhoCorr = $RhoBMeasured + ( ( $Por * $RhoVirginFluid ) - ( $Por * $RhoFluidA ) ) ;

        if ( $Apply_Balder = 1.0 AND $VShale < $VShaleCutOff_Balder AND $Por > $PorCutOff_Balder )
                $ApplyCorrection = 1.0 ;
        else
                $ApplyCorrection = 0.0 ;
        endif ;
```

```
endif ;

if ( 3. Sele Fm )

    $RhoMatrix_Sele = ( $VShale * $RhoShale ) + ( $VLime * $RhoLime ) + ( $VQtz * $RhoQtz ) + (
$VTuff * $RhoTuff ) ;
    $RhoVirginFluid = ( $Sw * $RhoWater_Sele ) + ( $SOil * $RhoOil_Sele ) + ( $SGas * $Rho-
Gas_Sele ) ;
    $RhoFluidA = $RhoMatrix_Sele - ( ( $RhoMatrix_Sele - $RhoBMeasured ) / $Por );

    if ( $RhoFluidA > $RhoWater_Sele )
        $RhoFluidA = $RhoWater_Sele ;
    endif ;
     if ( $RhoFluidA < $RhoVirginFluid AND $RhoFiltrate_Sele >= $RhoWater_Sele )
        $RhoFluidA = $RhoVirginFluid ;
    endif ;

    $RhoCorr =  $RhoBMeasured + ( ( $Por * $RhoVirginFluid ) - ( $Por * $RhoFluidA ) ) ;

    if ( $Apply_Sele = 1.0 AND $VShale < $VShaleCutOff_Sele AND $Por > $PorCutOff_Sele )
        $ApplyCorrection = 1.0 ;
    else
        $ApplyCorrection = 0.0 ;
    endif ;

endif ;

if ( 4. Lista Fm )

    $RhoMatrix_Lista = ( $VShale * $RhoShale ) + ( $VLime * $RhoLime ) + ( $VQtz * $RhoQtz ) +
( $VTuff * $RhoTuff ) ;
    $RhoVirginFluid = ( $Sw * $RhoWater_Lista ) + ( $SOil * $RhoOil_Lista ) + ( $SGas * $Rho-
Gas_Lista ) ;
    $RhoFluidA = $RhoMatrix_Lista - ( ( $RhoMatrix_Lista - $RhoBMeasured ) / $Por );

    if ( $RhoFluidA > $RhoWater_Lista )
```

```
            $RhoFluidA = $RhoWater_Lista ;
        endif ;
        if ( $RhoFluidA < $RhoVirginFluid AND $RhoFiltrate_Lista >= $RhoWater_Lista )
            $RhoFluidA = $RhoVirginFluid ;
        endif ;

        $RhoCorr = $RhoBMeasured + ( ( $Por * $RhoVirginFluid ) - ( $Por * $RhoFluidA ) ) ;

        if ( $Apply_Lista = 1.0 AND $VShale < $VShaleCutOff_Lista AND $Por > $PorCutOff_Lista )
            $ApplyCorrection = 1.0 ;
        else
            $ApplyCorrection = 0.0 ;
        endif ;

endif ;

if ( 5. Maureen Fm )

        $RhoMatrix_Maureen = ( $VShale * $RhoShale ) + ( $VLime * $RhoLime ) + ( $VQtz * 
$RhoQtz ) + ( $VTuff * $RhoTuff ) ;
        $RhoVirginFluid = ( $Sw * $RhoWater_Maureen ) + ( $SOil * $RhoOil_Maureen ) + ( $SGas * 
$RhoGas_Maureen ) ;
        $RhoFluidA = $RhoMatrix_Maureen - ( ( $RhoMatrix_Maureen - $RhoBMeasured ) / $Por );

        if ( $RhoFluidA > $RhoWater_Maureen )
            $RhoFluidA = $RhoWater_Maureen ;
        endif ;
        if ( $RhoFluidA < $RhoVirginFluid AND $RhoFiltrate_Maureen >= $RhoWater_Maureen )
            $RhoFluidA = $RhoVirginFluid ;
        endif ;

        $RhoCorr = $RhoBMeasured + ( ( $Por * $RhoVirginFluid ) - ( $Por * $RhoFluidA ) ) ;

        if ( $Apply_Maureen = 1.0 AND $VShale < $VShaleCutOff_Maureen AND $Por > 
$PorCutOff_Maureen )
            $ApplyCorrection = 1.0 ;
        else
```

```
        $ApplyCorrection = 0.0 ;
    endif ;

endif ;

if ( 6. Ekofisk Fm )

    $RhoMatrix_Ekofisk = ( $VShale * $RhoShale ) + ( $VLime * $RhoLime ) + ( $VQtz * $RhoQtz ) + ( $VTuff * $RhoTuff ) ;
    $RhoVirginFluid = ( $Sw * $RhoWater_Ekofisk ) + ( $SOil * $RhoOil_Ekofisk ) + ( $SGas * $RhoGas_Ekofisk ) ;
    $RhoFluidA = $RhoMatrix_Ekofisk - ( ( $RhoMatrix_Ekofisk - $RhoBMeasured ) / $Por );

    if ( $RhoFluidA > $RhoWater_Ekofisk )
        $RhoFluidA = $RhoWater_Ekofisk ;
    endif ;
    if ( $RhoFluidA < $RhoVirginFluid AND $RhoFiltrate_Ekofisk >= $RhoWater_Ekofisk )
        $RhoFluidA = $RhoVirginFluid ;
    endif ;

    $RhoCorr = $RhoBMeasured + ( ( $Por * $RhoVirginFluid ) - ( $Por * $RhoFluidA ) ) ;

    if ( $Apply_Ekofisk = 1.0 AND $VShale < $VShaleCutOff_Ekofisk AND $Por > $PorCutOff_Ekofisk )
        $ApplyCorrection = 1.0 ;
    else
        $ApplyCorrection = 0.0 ;
    endif ;

endif ;

if ( 7. Tor Fm )

    $RhoMatrix_Tor = ( $VShale * $RhoShale ) + ( $VLime * $RhoLime ) + ( $VQtz * $RhoQtz ) + ( $VTuff * $RhoTuff ) ;
    $RhoVirginFluid = ( $Sw * $RhoWater_Tor ) + ( $SOil * $RhoOil_Tor ) + ( $SGas * $Rho-Gas_Tor ) ;
```

```
        $RhoFluidA = $RhoMatrix_Tor - ( ( $RhoMatrix_Tor - $RhoBMeasured ) / $Por );

        if ( $RhoFluidA > $RhoWater_Tor )
                $RhoFluidA = $RhoWater_Tor ;
        endif ;
         if ( $RhoFluidA < $RhoVirginFluid AND $RhoFiltrate_Tor >= $RhoWater_Tor )
                $RhoFluidA = $RhoVirginFluid ;
        endif ;

        $RhoCorr = $RhoBMeasured + ( ( $Por * $RhoVirginFluid ) - ( $Por * $RhoFluidA ) ) ;

        if ( $Apply_Tor = 1.0 AND $VShale < $VShaleCutOff_Tor AND $Por > $PorCutOff_Tor )
                $ApplyCorrection = 1.0 ;
        else
                $ApplyCorrection = 0.0 ;
        endif ;

endif ;

if ( 8. Hod Fm )

        $RhoMatrix_Hod = ( $VShale * $RhoShale ) + ( $VLime * $RhoLime ) + ( $VQtz * $RhoQtz ) + (
$VTuff * $RhoTuff ) ;
        $RhoVirginFluid = ( $Sw * $RhoWater_Hod ) + ( $SOil * $RhoOil_Hod ) + ( $SGas * $Rho-
Gas_Hod ) ;
        $RhoFluidA = $RhoMatrix_Hod - ( ( $RhoMatrix_Hod - $RhoBMeasured ) / $Por );

        if ( $RhoFluidA > $RhoWater_Hod )
                $RhoFluidA = $RhoWater_Hod ;
        endif ;
         if ( $RhoFluidA < $RhoVirginFluid AND $RhoFiltrate_Hod >= $RhoWater_Hod )
                $RhoFluidA = $RhoVirginFluid ;
        endif ;

        $RhoCorr = $RhoBMeasured + ( ( $Por * $RhoVirginFluid ) - ( $Por * $RhoFluidA ) ) ;
```

```
        if ( $Apply_Hod = 1.0 AND $VShale < $VShaleCutOff_Hod AND $Por > $PorCutOff_Hod )
                $ApplyCorrection = 1.0 ;
        else
                $ApplyCorrection = 0.0 ;
        endif ;

endif ;

/////////////////////////////////////////////////////////////////////////////////////////

// 6. Applies the invasion correction Density log where criteria met

if ( $ApplyCorrection = 1.0 )
        $RHOB_Corrected = $RhoCorr ;
else
        $RHOB_Corrected = $RhoBMeasured ;
endif ;

/////////////////////////////////////////////////////////////////////////////////////////

// 7. Define which logs are output by the script

save ( $RhoFluidA ) ;
save ( $RhoVirginFluid ) ;
save ( $RHOB_Corrected ) ;
```

G.2 – End-Member and Synthetic Logs

```
// RokDoc User Programmer Custom Script:
// End-Member and Synthetic Logs

// Input - Volume Logs (one required for each lithology, create null logs where necessary)
// Output - End-Member and Synthetic Logs (Vp, Vs, Rho, Por, AI, SI, VpVs)
// Description -

// 1. Define the input logs used within the script

$Depth = Depth ;

$Volume_Shale = Volume ;
$Volume_Sandstone = Volume ;
$Volume_Limestone = Volume ;
$Volume_Tuff = Volume ;

$Use_Shale = FLAG_End_Member ;
$Use_Sandstone = FLAG_End_Member ;
$Use_Limestone = FLAG_End_Member ;

// 2. Define the multi-well rock physics templates
// nb: It is important to use the same trend types used within the project
//     See report/ multi-well ppts for further details

///////////////////////////////////////////////////////////////////////////////////
///////// Define RPM in the form y=(m)x+(c), y=(m2)x^2+(m1)x+(c), y=(m)x^(n) /////////
///////////////////////////////////////////////////////////////////////////////////

// nb: Rock physics templates are sorted on a working interval then lithology basis
//     Where a lithology is not present, this is shown by $<lithology> = 0.0

// Horda Formation - contains no limestone or tuff
if ( 1. Horda Fm )
```

```
// Non-Reservoir Relationships
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.2922942 ;
$Vp_Z_Shale_Soft_c = 5233.447 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.2571209 ;
$Vp_Z_Shale_Hard_c = 6198.616 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.7057037 ;
$Vs_Vp_Shale_c = -2465.212 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1066255 ;
$Rho_Vp_Shale_n = 0.3432433 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_LowPor_m = 0.660582 ;
$Vp_Z_Sandstone_LowPor_c = 5583.154 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_LowPor_m = -0.00003584127 ;
$Por_Z_Sandstone_LowPor_c = 0.5508362 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_LowPor_m2 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m1 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_c = 0.0 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 0.660582 ;
```

```
$Vp_Z_Sandstone_HighPor_c = 5583.154 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_HighPor_m = -0.00003584127 ;
$Por_Z_Sandstone_HighPor_c = 0.5508362 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_HighPor_m = 0.7596545 ;
$Vs_Vp_Sandstone_HighPor_c = -2064.222 ;
// Shared Trends
// Rho (from Rho-Vp)
$Rho_Vp_Sandstone_m = 0.1698896 ;
$Rho_Vp_Sandstone_n = 0.2765268 ;
// Rho (from Rho-Por)
$Rho_Por_Sandstone_m = -1.611234 ;
$Rho_Por_Sandstone_c = 2.65 ;
// Por (from Vp-Por)
$Por_Vp_Sandstone_m2 = 0.0000000002163757 ;
$Por_Vp_Sandstone_m1 = -0.00004096828 ;
$Por_Vp_Sandstone_c = 0.6917572 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 0.0 ;

else
// Balder Formation - contains no limestone
if ( 2. Balder Fm )

// Non-Reservoir Relationships
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.4515433 ;
$Vp_Z_Shale_Soft_c = 5153.091 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.4515433 ;
$Vp_Z_Shale_Hard_c = 5153.091 ;
// Shared Trends
// Vs (from Vs-Vp)
```

```
$Vs_Vp_Shale_m = 0.9232975 ;
$Vs_Vp_Shale_c = -4065.238 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.2392956 ;
$Rho_Vp_Shale_n = 0.2539949 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 1.0 ;
// Vp (from Vp-Depth)
$Vp_Z_Tuff_m = 0.7812615 ;
$Vp_Z_Tuff_c = 3411.229 ;
// Vs (from Vs-Vp)
$Vs_Vp_Tuff_m = 0.9711005 ;
$Vs_Vp_Tuff_c = -4225.107 ;
// Rho (from Rho-Vp)
$Rho_Vp_Tuff_m = 0.52428 ;
$Rho_Vp_Tuff_c = -2.39628 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_LowPor_m = 1.023924 ;
$Vp_Z_Sandstone_LowPor_c = 2127.82 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_LowPor_m = -0.00003770699 ;
$Por_Z_Sandstone_LowPor_c = 0.58089 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_LowPor_m2 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m1 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_c = 0.0 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 1.023924 ;
$Vp_Z_Sandstone_HighPor_c = 2127.82 ;
// Por (from Por-Depth)
```

```
$Por_Z_Sandstone_HighPor_m = -0.00003770699 ;
$Por_Z_Sandstone_HighPor_c = 0.58089 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_HighPor_m = 0.80416 ;
$Vs_Vp_Sandstone_HighPor_c = -2808.005 ;
// Shared Trends
// Rho (from Rho-Vp)
$Rho_Vp_Sandstone_m = 0.2609613 ;
$Rho_Vp_Sandstone_n = 0.2305883 ;
// Rho (from Rho-Por)
$Rho_Por_Sandstone_m = -1.607725 ;
$Rho_Por_Sandstone_c = 2.65 ;
// Por (from Vp-Por)
$Por_Vp_Sandstone_m2 = 0.0000000001726589 ;
$Por_Vp_Sandstone_m1 = -0.00003894957 ;
$Por_Vp_Sandstone_c = 0.6692793 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 0.0 ;

else
// Sele Formation - contains no limestone or tuff
if ( 3. Sele Fm )

// Non-Reservoir Relationships
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5072923 ;
$Vp_Z_Shale_Soft_c = 4640.669 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.5420831 ;
$Vp_Z_Shale_Hard_c = 5362.252 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.7655861 ;
$Vs_Vp_Shale_c = -2640.943 ;
```

// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1832278 ;
$Rho_Vp_Shale_n = 0.2830127 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_LowPor_m = 0.5542149 ;
$Vp_Z_Sandstone_LowPor_c = 6430.183 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_LowPor_m = -0.00002654017 ;
$Por_Z_Sandstone_LowPor_c = 0.4426344 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_LowPor_m2 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m1 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_c = 0.0 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 0.6740104 ;
$Vp_Z_Sandstone_HighPor_c = 3979.824 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_HighPor_m = -0.00003721717 ;
$Por_Z_Sandstone_HighPor_c = 0.6085076 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_HighPor_m = 0.9720799 ;
$Vs_Vp_Sandstone_HighPor_c = -4702.516 ;
// Shared Trends
// Rho (from Rho-Vp)
$Rho_Vp_Sandstone_m = 0.12631 ;
$Rho_Vp_Sandstone_n = 0.3115259 ;
// Rho (from Rho-Por)
$Rho_Por_Sandstone_m = -1.608423 ;

```
$Rho_Por_Sandstone_c = 2.65 ;
// Por (from Vp-Por)
$Por_Vp_Sandstone_m2 = 0.000000001773932 ;
$Por_Vp_Sandstone_m1 = -0.00008149762 ;
$Por_Vp_Sandstone_c = 0.904825 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 0.0 ;

else
// Lista Formation - contains no tuff
if ( 4. Lista Fm )

// Non-Reservoir Relationships
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5780684 ;
$Vp_Z_Shale_Soft_c = 3817.599 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.6624602 ;
$Vp_Z_Shale_Hard_c = 4252.494 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.758194 ;
$Vs_Vp_Shale_c = -2709.194 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1700515 ;
$Rho_Vp_Shale_n = 0.2902445 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
```

```
$Vp_Z_Sandstone_LowPor_m = 0.8167227 ;
$Vp_Z_Sandstone_LowPor_c = 6191.856 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_LowPor_m = -0.0000318877 ;
$Por_Z_Sandstone_LowPor_c = 0.3770017 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_LowPor_m2 = -0.0000173188832737427 ;
$Vs_Vp_Sandstone_LowPor_m1 = 1.02637492252863 ;
$Vs_Vp_Sandstone_LowPor_c = -3384.8165155481 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 0.4780259 ;
$Vp_Z_Sandstone_HighPor_c = 7035.789 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_HighPor_m = -0.00003110392 ;
$Por_Z_Sandstone_HighPor_c = 0.4798181 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_HighPor_m = 0.7639454 ;
$Vs_Vp_Sandstone_HighPor_c = -2484.919 ;
// Shared Trends
// Rho (from Rho-Vp)
$Rho_Vp_Sandstone_m = 0.1235797 ;
$Rho_Vp_Sandstone_n = 0.3157153 ;
// Rho (from Rho-Por)
$Rho_Por_Sandstone_m = -1.622425 ;
$Rho_Por_Sandstone_c = 2.65 ;
// Por (from Vp-Por)
$Por_Vp_Sandstone_m2 = 0.000000001529275 ;
$Por_Vp_Sandstone_m1 = -0.00007601945 ;
$Por_Vp_Sandstone_c = 0.8522162 ;

// Brine-Bearing Reservoir Relationships (Limestone) (from Maureen Fm)
$Limestone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_LowPor_m = 0.9858379 ;
```

```
$Vp_Z_Limestone_LowPor_c = 6847.396 ;
// Por (from Por-Depth)
$Por_Z_Limestone_LowPor_m = -0.00001937362 ;
$Por_Z_Limestone_LowPor_c = 0.2537034 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_HighPor_m = 1.17964 ;
$Vp_Z_Limestone_HighPor_c = 2948.817 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.00002767867 ;
$Por_Z_Limestone_HighPor_c = 0.397615 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.00002212974 ;
$Vs_Vp_Limestone_m1 = 1.21382 ;
$Vs_Vp_Limestone_c = -4983.408 ;
// Rho (from Rho-Vp)
$Rho_Vp_Limestone_m = 0.594 ;
$Rho_Vp_Limestone_c = -3.18998 ;
// Rho (from Rho-Por)
$Rho_Por_Limestone_m = -1.673549 ;
$Rho_Por_Limestone_c = 2.71 ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.0000000004114573 ;
$Por_Vp_Limestone_m1 = -0.00004001338 ;
$Por_Vp_Limestone_c = 0.6178595 ;

else
// Maureen Formation - contains no tuff
if ( 5. Maureen Fm )

// Non-Reservoir Relationships
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5966925 ;
$Vp_Z_Shale_Soft_c = 3923.665 ;
```

```
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.588856 ;
$Vp_Z_Shale_Hard_c = 5630.318 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.693495 ;
$Vs_Vp_Shale_c = -2017.296 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1857183 ;
$Rho_Vp_Shale_n = 0.280225 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone) (from Maureen Fm)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_LowPor_m = 1.096406 ;
$Vp_Z_Sandstone_LowPor_c = 3131.354 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_LowPor_m = -0.00005003434 ;
$Por_Z_Sandstone_LowPor_c = 0.5447623 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_LowPor_m2 = -0.0000173188832737427 ;
$Vs_Vp_Sandstone_LowPor_m1 = 1.02637492252863 ;
$Vs_Vp_Sandstone_LowPor_c = -3384.8165155481 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 0.9648193 ;
$Vp_Z_Sandstone_HighPor_c = 3085.523 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_HighPor_m = -0.00005051964 ;
$Por_Z_Sandstone_HighPor_c = 0.6525103 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_HighPor_m = 0.7639454 ;
```

$Vs_Vp_Sandstone_HighPor_c = -2484.919 ;
// Shared Trends
// Rho (from Rho-Vp)
$Rho_Vp_Sandstone_m = 0.1222036 ;
$Rho_Vp_Sandstone_n = 0.3158323 ;
// Rho (from Rho-Por)
$Rho_Por_Sandstone_m = -1.608069 ;
$Rho_Por_Sandstone_c = 2.65 ;
// Por (from Vp-Por)
$Por_Vp_Sandstone_m2 = 0.000000001845871 ;
$Por_Vp_Sandstone_m1 = -0.0000824894 ;
$Por_Vp_Sandstone_c = 0.8976042 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_LowPor_m = 0.9858379 ;
$Vp_Z_Limestone_LowPor_c = 6847.396 ;
// Por (from Por-Depth)
$Por_Z_Limestone_LowPor_m = -0.00001937362 ;
$Por_Z_Limestone_LowPor_c = 0.2537034 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_HighPor_m = 1.17964 ;
$Vp_Z_Limestone_HighPor_c = 2948.817 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.00002767867 ;
$Por_Z_Limestone_HighPor_c = 0.397615 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.00002212974 ;
$Vs_Vp_Limestone_m1 = 1.21382 ;
$Vs_Vp_Limestone_c = -4983.408 ;
// Rho (from Rho-Vp)
$Rho_Vp_Limestone_m = 0.594 ;

```
$Rho_Vp_Limestone_c = -3.18998 ;
// Rho (from Rho-Por)
$Rho_Por_Limestone_m = -1.673549 ;
$Rho_Por_Limestone_c = 2.71 ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.0000000004114573 ;
$Por_Vp_Limestone_m1 = -0.00004001338 ;
$Por_Vp_Limestone_c = 0.6178595 ;

else
// Ekofisk Formation - contains no tuff
if ( 6. Ekofisk Fm )

// Trend used within synthetic generation - 0.0 = Soft and 1.0 = Hard
$Use_Shale = 1.0 ;

// Non-Reservoir Relationships (from Maureen Fm)
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5966925 ;
$Vp_Z_Shale_Soft_c = 3923.665 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.588856 ;
$Vp_Z_Shale_Hard_c = 5630.318 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.693495 ;
$Vs_Vp_Shale_c = -2017.296 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1857183 ;
$Rho_Vp_Shale_n = 0.280225 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
```

```
$Sandstone = 0.0 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_LowPor_m = 0.982537 ;
$Vp_Z_Limestone_LowPor_c = 5881.333 ;
// Por (from Por-Depth)
$Por_Z_Limestone_LowPor_m = -0.00001848521 ;
$Por_Z_Limestone_LowPor_c = 0.2637967 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_HighPor_m = 0.8729134 ;
$Vp_Z_Limestone_HighPor_c = 5203.576 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.00002017612 ;
$Por_Z_Limestone_HighPor_c = 0.3555333 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.00002553698 ;
$Vs_Vp_Limestone_m1 = 1.342143 ;
$Vs_Vp_Limestone_c = -6253.14 ;
// Rho (from Rho-Vp)
$Rho_Vp_Limestone_m = 0.74272 ;
$Rho_Vp_Limestone_c = -4.61654 ;
// Rho (from Rho-Por)
$Rho_Por_Limestone_m = -1.677809 ;
$Rho_Por_Limestone_c = 2.71    ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.00000000126444 ;
$Por_Vp_Limestone_m1 = -0.00006871545 ;
$Por_Vp_Limestone_c = 0.8542784 ;

else
// Tor Formation - contains no sandstone or tuff
```

```
if ( 7. Tor Fm )

// Trend used within synthetic generation - 0.0 = Soft and 1.0 = Hard
$Use_Shale = 1.0 ;

// Non-Reservoir Relationships (from Maureen Fm)
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5966925 ;
$Vp_Z_Shale_Soft_c = 3923.665 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.588856 ;
$Vp_Z_Shale_Hard_c = 5630.318 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.693495 ;
$Vs_Vp_Shale_c = -2017.296 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1857183 ;
$Rho_Vp_Shale_n = 0.280225 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 0.0 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_LowPor_m = 0.4740226 ;
$Vp_Z_Limestone_LowPor_c = 12488.51 ;
// Por (from Por-Depth)
$Por_Z_Limestone_LowPor_m = -0.000009372 ;
$Por_Z_Limestone_LowPor_c = 0.1406966 ;
```

```
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_HighPor_m = 1.011436 ;
$Vp_Z_Limestone_HighPor_c = 4483.004 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.0000252572 ;
$Por_Z_Limestone_HighPor_c = 0.3942969 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.000022813668 ;
$Vs_Vp_Limestone_m1 = 1.238671 ;
$Vs_Vp_Limestone_c = -5526.247 ;
// Rho (from Rho-Vp)
$Rho_Vp_Limestone_m = 0.74353 ;
$Rho_Vp_Limestone_c = -4.62711 ;
// Rho (from Rho-Por)
$Rho_Por_Limestone_m = -1.681826 ;
$Rho_Por_Limestone_c = 2.71 ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.000000001139213 ;
$Por_Vp_Limestone_m1 = -0.0000658779 ;
$Por_Vp_Limestone_c = 0.846066 ;

else
// Hod Formation - contains no sandstone or tuff
if ( 8. Hod Fm )

// Trend used within synthetic generation - 0.0 = Soft and 1.0 = Hard
$Use_Shale = 1.0 ;

// Non-Reservoir Relationships (from Maureen Fm)
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5966925 ;
$Vp_Z_Shale_Soft_c = 3923.665 ;
// Hard Trends
```

```
$Vp_Z_Shale_Hard_m = 0.588856 ;
$Vp_Z_Shale_Hard_c = 5630.318 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.693495 ;
$Vs_Vp_Shale_c = -2017.296 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1857183 ;
$Rho_Vp_Shale_n = 0.280225 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 0.0 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_LowPor_m = 0.537352 ;
$Vp_Z_Limestone_LowPor_c = 11248.14 ;
// Por (from Por-Depth)
$Por_Z_Limestone_LowPor_m = -0.000009445337 ;
$Por_Z_Limestone_LowPor_c = 0.157783 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_HighPor_m = 0.56478 ;
$Vp_Z_Limestone_HighPor_c = 8753.391 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.00001273299 ;
$Por_Z_Limestone_HighPor_c = 0.2384544 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.000023837095 ;
$Vs_Vp_Limestone_m1 = 1.171225 ;
```

```
$Vs_Vp_Limestone_c = -3974.697 ;
// Rho (from Rho-Vp)
$Rho_Vp_Limestone_m = 0.51197 ;
$Rho_Vp_Limestone_c = -2.36269 ;
// Rho (from Rho-Por)
$Rho_Por_Limestone_m = -1.645595 ;
$Rho_Por_Limestone_c = 2.71 ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.0000000001198912 ;
$Por_Vp_Limestone_m1 = -0.00002624041 ;
$Por_Vp_Limestone_c = 0.4607655 ;

endif;
endif;
endif;
endif;
endif;
endif;
endif;
endif;

/////////////////////////////////////////////////////////////////////////////////////
//////////////////////////////// DO NOT EDIT BELOW /////////////////////////////////
/////////////////////////////////////////////////////////////////////////////////////

// 3. Removes null values and normalises the volume logs to create a continuous volume set

if ($Volume_Shale = null)
  $Volume_Shale_Min = 0;
else
  if ($Volume_Shale > 1)
    $Volume_Shale_Min = 1;
  else
    if ($Volume_Shale < 0)
      $Volume_Shale_Min = 0;
    else
```

```
      $Volume_Shale_Min = $Volume_Shale;
    endif;
  endif;
endif;

if ($Volume_Sandstone = null)
  $Volume_Sandstone_Min = 0;
else
  if ($Volume_Sandstone > 1)
    $Volume_Sandstone_Min = 1;
  else
    if ($Volume_Sandstone < 0)
      $Volume_Sandstone_Min = 0;
    else
      $Volume_Sandstone_Min = $Volume_Sandstone;
    endif;
  endif;
endif;

if ($Volume_Limestone = null)
  $Volume_Limestone_Min = 0;
else
  if ($Volume_Limestone > 1)
    $Volume_Limestone_Min = 1;
  else
    if ($Volume_Limestone < 0)
      $Volume_Limestone_Min = 0;
    else
      $Volume_Limestone_Min = $Volume_Limestone;
    endif;
  endif;
endif;

if ($Volume_Tuff = null)
  $Volume_Tuff_Min = 0;
else
```

```
  if ($Volume_Tuff > 1)
    $Volume_Tuff_Min = 1;
  else
    if ($Volume_Tuff < 0)
      $Volume_Tuff_Min = 0;
    else
      $Volume_Tuff_Min = $Volume_Tuff;
    endif;
  endif;
endif;

$Summed = $Volume_Shale_Min + $Volume_Sandstone_Min + $Volume_Limestone_Min + $Volume_Tuff_Min ;

$Volume_Shale_Norm = $Volume_Shale_Min / $Summed;
$Volume_Sandstone_Norm = $Volume_Sandstone_Min / $Summed;
$Volume_Limestone_Norm = $Volume_Limestone_Min / $Summed;
$Volume_Tuff_Norm = $Volume_Tuff_Min / $Summed;

/////////////////////////////////////////////////////////////////////////////////////////

// 4. Where lithology defined as 'not present', null rock physics templates are set-up automatically

if ( $Tuff = 0.0 )
$Vp_Z_Tuff_m = 0.0 ;
$Vp_Z_Tuff_c = 0.0 ;
$Vs_Vp_Tuff_m = 0.0 ;
$Vs_Vp_Tuff_c = 0.0 ;
$Rho_Vp_Tuff_m = 0.0 ;
$Rho_Vp_Tuff_c = 0.0 ;
endif;
if ( $Sandstone = 0.0 )
$Vp_Z_Sandstone_LowPor_m = 0.0 ;
$Vp_Z_Sandstone_LowPor_c = 0.0 ;
$Vp_Z_Sandstone_HighPor_m = 0.0 ;
$Vp_Z_Sandstone_HighPor_c = 0.0 ;
```

```
$Por_Z_Sandstone_LowPor_m = 0.0 ;
$Por_Z_Sandstone_LowPor_c = 0.0 ;
$Por_Z_Sandstone_HighPor_m = 0.0 ;
$Por_Z_Sandstone_HighPor_c = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m2 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m1 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_c = 0.0 ;
$Vs_Vp_Sandstone_HighPor_m = 0.0 ;
$Vs_Vp_Sandstone_HighPor_c = 0.0 ;
$Rho_Vp_Sandstone_m = 0.0 ;
$Rho_Vp_Sandstone_n = 1.0 ;
$Rho_Por_Sandstone_m = 0.0 ;
$Rho_Por_Sandstone_c = 0.0 ;
$Por_Vp_Sandstone_m2 = 0.0 ;
$Por_Vp_Sandstone_m1 = 0.0 ;
$Por_Vp_Sandstone_c = 0.0 ;
endif;
if ( $Limestone = 0.0 )
$Vp_Z_Limestone_LowPor_m = 0.0 ;
$Vp_Z_Limestone_LowPor_c = 0.0 ;
$Vp_Z_Limestone_HighPor_m = 0.0 ;
$Vp_Z_Limestone_HighPor_c = 0.0 ;
$Por_Z_Limestone_LowPor_m = 0.0 ;
$Por_Z_Limestone_LowPor_c = 0.0 ;
$Por_Z_Limestone_HighPor_m = 0.0 ;
$Por_Z_Limestone_HighPor_c = 0.0 ;
$Vs_Vp_Limestone_m2 = 0.0 ;
$Vs_Vp_Limestone_m1 = 0.0 ;
$Vs_Vp_Limestone_c = 0.0 ;
$Rho_Vp_Limestone_m = 0.0 ;
$Rho_Vp_Limestone_c = 1.0 ;
$Rho_Por_Limestone_m = 0.0 ;
$Rho_Por_Limestone_c = 0.0 ;
$Por_Vp_Limestone_m2 = 0.0 ;
$Por_Vp_Limestone_m1 = 0.0 ;
$Por_Vp_Limestone_c = 0.0 ;
```

```
endif;

////////////////////////////////////////////////////////////////////////////////

// 5. Depth curve and rock physics templates used to create end-member curves using various models
// nb: See report/ Rock Physics Part 2 ppts for further details

//m0 - NonRes
$Calc_Vp_Shale_Soft_Z = ( $Depth * $Vp_Z_Shale_Soft_m ) + $Vp_Z_Shale_Soft_c ;
$Calc_Vs_Shale_Soft_Vp = ($Calc_Vp_Shale_Soft_Z * $Vs_Vp_Shale_m ) + $Vs_Vp_Shale_c ;
$Calc_Rho_Shale_Soft_Vp = $Rho_Vp_Shale_m * ( $Calc_Vp_Shale_Soft_Z ^ $Rho_Vp_Shale_n ) ;
$Calc_AI_Shale_Soft_Vp_Z = ( $Calc_Vp_Shale_Soft_Z * $Calc_Rho_Shale_Soft_Vp ) ;
$Calc_SI_Shale_Soft_Vp_Z = ( $Calc_Vs_Shale_Soft_Vp * $Calc_Rho_Shale_Soft_Vp ) ;
$Calc_lnAI_Shale_Soft_Vp_Z = ln( $Calc_AI_Shale_Soft_Vp_Z / 1000 ) ;
$Calc_lnSI_Shale_Soft_Vp_Z = ln( $Calc_SI_Shale_Soft_Vp_Z / 1000 ) ;
$Calc_VpVs_Shale_Soft_Z = $Calc_Vp_Shale_Soft_Z / $Calc_Vs_Shale_Soft_Vp ;

$Calc_Vp_Shale_Hard_Z = ( $Depth * $Vp_Z_Shale_Hard_m ) + $Vp_Z_Shale_Hard_c ;
$Calc_Vs_Shale_Hard_Vp = ($Calc_Vp_Shale_Hard_Z * $Vs_Vp_Shale_m ) + $Vs_Vp_Shale_c ;
$Calc_Rho_Shale_Hard_Vp = $Rho_Vp_Shale_m * ( $Calc_Vp_Shale_Hard_Z ^ $Rho_Vp_Shale_n ) ;
$Calc_AI_Shale_Hard_Vp_Z = ( $Calc_Vp_Shale_Hard_Z * $Calc_Rho_Shale_Hard_Vp ) ;
$Calc_SI_Shale_Hard_Vp_Z = ( $Calc_Vs_Shale_Hard_Vp * $Calc_Rho_Shale_Hard_Vp ) ;
$Calc_lnAI_Shale_Hard_Vp_Z = ln( $Calc_AI_Shale_Hard_Vp_Z / 1000 ) ;
$Calc_lnSI_Shale_Hard_Vp_Z = ln( $Calc_SI_Shale_Hard_Vp_Z / 1000 ) ;
$Calc_VpVs_Shale_Hard_Z = $Calc_Vp_Shale_Hard_Z / $Calc_Vs_Shale_Hard_Vp ;

$Calc_Vp_Tuff_Z = ( $Depth * $Vp_Z_Tuff_m ) + $Vp_Z_Tuff_c ;
$Calc_Vs_Tuff_Vp = ( $Calc_Vp_Tuff_Z * $Vs_Vp_Tuff_m ) + $Vs_Vp_Tuff_c ;
        if ( 2. Balder Fm )
$Calc_Rho_Tuff_Vp = ( $Rho_Vp_Tuff_m * ln ( $Calc_Vp_Tuff_Z )) + $Rho_Vp_Tuff_c ;
        else
$Calc_Rho_Tuff_Vp = 0.0 ;
        endif;
$Calc_AI_Tuff_Vp_Z = ( $Calc_Vp_Tuff_Z * $Calc_Rho_Tuff_Vp ) ;
$Calc_SI_Tuff_Vp_Z = ( $Calc_Vs_Tuff_Vp * $Calc_Rho_Tuff_Vp ) ;
```

$Calc_lnAI_Tuff_Vp_Z = ln($Calc_AI_Tuff_Vp_Z / 1000) ;

$Calc_lnSI_Tuff_Vp_Z = ln($Calc_SI_Tuff_Vp_Z / 1000) ;

$Calc_VpVs_Tuff_Z = $Calc_Vp_Tuff_Z / $Calc_Vs_Tuff_Vp ;

//m1 - SDDI

$Calc_Vp_Sandstone_LowPor_Z = ($Depth * $Vp_Z_Sandstone_LowPor_m) + $Vp_Z_Sandstone_LowPor_c ;

$Calc_Por_Sandstone_LowPor_Vp_Z = (($Calc_Vp_Sandstone_LowPor_Z ^ 2) * $Por_Vp_Sandstone_m2) + ($Calc_Vp_Sandstone_LowPor_Z * $Por_Vp_Sandstone_m1) + $Por_Vp_Sandstone_c ;

$Calc_Rho_Sandstone_LowPor_Por_Vp = ($Calc_Por_Sandstone_LowPor_Vp_Z * $Rho_Por_Sandstone_m) + $Rho_Por_Sandstone_c ;

if (1. Horda Fm OR 2. Balder Fm OR 3. Sele Fm)

$Calc_Vs_Sandstone_LowPor_Vp_Z = ($Calc_Vp_Sandstone_LowPor_Z * $Vs_Vp_Sandstone_HighPor_m) + $Vs_Vp_Sandstone_HighPor_c ;

else

$Calc_Vs_Sandstone_LowPor_Vp_Z = (($Calc_Vp_Sandstone_LowPor_Z ^ 2) * $Vs_Vp_Sandstone_LowPor_m2) + ($Calc_Vp_Sandstone_LowPor_Z * $Vs_Vp_Sandstone_LowPor_m1) + $Vs_Vp_Sandstone_LowPor_c ;

endif;

$Calc_AI_Sandstone_LowPor_Vp_Z = ($Calc_Vp_Sandstone_LowPor_Z * $Calc_Rho_Sandstone_LowPor_Por_Vp) ;

$Calc_SI_Sandstone_LowPor_Vp_Z = ($Calc_Vs_Sandstone_LowPor_Vp_Z * $Calc_Rho_Sandstone_LowPor_Por_Vp) ;

$Calc_lnAI_Sandstone_LowPor_Vp_Z = ln($Calc_AI_Sandstone_LowPor_Vp_Z / 1000) ;

$Calc_lnSI_Sandstone_LowPor_Vp_Z = ln($Calc_SI_Sandstone_LowPor_Vp_Z / 1000) ;

$Calc_VpVs_Sandstone_LowPor_Z = $Calc_Vp_Sandstone_LowPor_Z / $Calc_Vs_Sandstone_LowPor_Vp_Z ;

$Calc_Vp_Sandstone_HighPor_Z = ($Depth * $Vp_Z_Sandstone_HighPor_m) + $Vp_Z_Sandstone_HighPor_c ;

$Calc_Por_Sandstone_HighPor_Vp_Z = (($Calc_Vp_Sandstone_HighPor_Z ^ 2) * $Por_Vp_Sandstone_m2) + ($Calc_Vp_Sandstone_HighPor_Z * $Por_Vp_Sandstone_m1) + $Por_Vp_Sandstone_c ;

$Calc_Rho_Sandstone_HighPor_Por_Vp = ($Calc_Por_Sandstone_HighPor_Vp_Z * $Rho_Por_Sandstone_m) + $Rho_Por_Sandstone_c ;

$Calc_Vs_Sandstone_HighPor_Vp_Z = ($Calc_Vp_Sandstone_HighPor_Z * $Vs_Vp_Sandstone_HighPor_m) + $Vs_Vp_Sandstone_HighPor_c ;

$Calc_AI_Sandstone_HighPor_Vp_Z = ($Calc_Vp_Sandstone_HighPor_Z * $Calc_Rho_Sandstone_HighPor_Por_Vp) ;

$Calc_SI_Sandstone_HighPor_Vp_Z = ($Calc_Vs_Sandstone_HighPor_Vp_Z * $Calc_Rho_Sandstone_HighPor_Por_Vp) ;

$Calc_lnAI_Sandstone_HighPor_Vp_Z = ln($Calc_AI_Sandstone_HighPor_Vp_Z / 1000) ;

$Calc_lnSI_Sandstone_HighPor_Vp_Z = ln($Calc_SI_Sandstone_HighPor_Vp_Z / 1000) ;

$Calc_VpVs_Sandstone_HighPor_Z = $Calc_Vp_Sandstone_HighPor_Z / $Calc_Vs_Sandstone_HighPor_Vp_Z ;

$Calc_Vp_Limestone_LowPor_Z = ($Depth * $Vp_Z_Limestone_LowPor_m) + $Vp_Z_Limestone_LowPor_c ;

$Calc_Por_Limestone_LowPor_Vp_Z = (($Calc_Vp_Limestone_LowPor_Z ^ 2) * $Por_Vp_Limestone_m2) + ($Calc_Vp_Limestone_LowPor_Z * $Por_Vp_Limestone_m1) + $Por_Vp_Limestone_c ;

$Calc_Rho_Limestone_LowPor_Por_Vp = ($Calc_Por_Limestone_LowPor_Vp_Z * $Rho_Por_Limestone_m) + $Rho_Por_Limestone_c ;

$Calc_Vs_Limestone_LowPor_Vp_Z = (($Calc_Vp_Limestone_LowPor_Z ^ 2) * $Vs_Vp_Limestone_m2) + ($Calc_Vp_Limestone_LowPor_Z * $Vs_Vp_Limestone_m1) + $Vs_Vp_Limestone_c ;

$Calc_AI_Limestone_LowPor_Vp_Z = ($Calc_Vp_Limestone_LowPor_Z * $Calc_Rho_Limestone_LowPor_Por_Vp) ;

$Calc_SI_Limestone_LowPor_Vp_Z = ($Calc_Vs_Limestone_LowPor_Vp_Z * $Calc_Rho_Limestone_LowPor_Por_Vp) ;

$Calc_lnAI_Limestone_LowPor_Vp_Z = ln($Calc_AI_Limestone_LowPor_Vp_Z / 1000) ;

$Calc_lnSI_Limestone_LowPor_Vp_Z = ln($Calc_SI_Limestone_LowPor_Vp_Z / 1000) ;

$Calc_VpVs_Limestone_LowPor_Z = $Calc_Vp_Limestone_LowPor_Z / $Calc_Vs_Limestone_LowPor_Vp_Z ;

$Calc_Vp_Limestone_HighPor_Z = ($Depth * $Vp_Z_Limestone_HighPor_m) + $Vp_Z_Limestone_HighPor_c ;

$Calc_Por_Limestone_HighPor_Vp_Z = (($Calc_Vp_Limestone_HighPor_Z ^ 2) * $Por_Vp_Limestone_m2) + ($Calc_Vp_Limestone_HighPor_Z * $Por_Vp_Limestone_m1) + $Por_Vp_Limestone_c ;

$Calc_Rho_Limestone_HighPor_Por_Vp = ($Calc_Por_Limestone_HighPor_Vp_Z * $Rho_Por_Limestone_m) + $Rho_Por_Limestone_c ;

$Calc_Vs_Limestone_HighPor_Vp_Z = (($Calc_Vp_Limestone_HighPor_Z ^ 2) * $Vs_Vp_Limestone_m2) + ($Calc_Vp_Limestone_HighPor_Z * $Vs_Vp_Limestone_m1) + $Vs_Vp_Limestone_c ;

$Calc_AI_Limestone_HighPor_Vp_Z = ($Calc_Vp_Limestone_HighPor_Z * $Calc_Rho_Limestone_HighPor_Por_Vp) ;

$Calc_SI_Limestone_HighPor_Vp_Z = ($Calc_Vs_Limestone_HighPor_Vp_Z * $Calc_Rho_Limestone_HighPor_Por_Vp) ;

$Calc_lnAI_Limestone_HighPor_Vp_Z = ln($Calc_AI_Limestone_HighPor_Vp_Z / 1000) ;

$Calc_lnSI_Limestone_HighPor_Vp_Z = ln($Calc_SI_Limestone_HighPor_Vp_Z / 1000) ;

$Calc_VpVs_Limestone_HighPor_Z = $Calc_Vp_Limestone_HighPor_Z / $Calc_Vs_Limestone_HighPor_Vp_Z ;

//m2 - Rck3D

$Calc_Por_Sandstone_LowPor_Z = ($Depth * $Por_Z_Sandstone_LowPor_m) + $Por_Z_Sandstone_LowPor_c ;

$Calc_Rho_Sandstone_LowPor_Por_Z = ($Calc_Por_Sandstone_LowPor_Z * $Rho_Por_Sandstone_m) + $Rho_Por_Sandstone_c ;

$Calc_Vp_Sandstone_LowPor_Rho = e ^ ((ln($Calc_Rho_Sandstone_LowPor_Por_Z) - ln($Rho_Vp_Sandstone_m)) / $Rho_Vp_Sandstone_n) ;

if (1. Horda Fm OR 2. Balder Fm OR 3. Sele Fm)

$Calc_Vs_Sandstone_LowPor_Vp_Rho = ($Calc_Vp_Sandstone_LowPor_Rho * $Vs_Vp_Sandstone_HighPor_m) + $Vs_Vp_Sandstone_HighPor_c ;

else

$Calc_Vs_Sandstone_LowPor_Vp_Rho = (($Calc_Vp_Sandstone_LowPor_Rho ^ 2) * $Vs_Vp_Sandstone_LowPor_m2) + ($Calc_Vp_Sandstone_LowPor_Rho * $Vs_Vp_Sandstone_LowPor_m1) + $Vs_Vp_Sandstone_LowPor_c ;

endif;

$Calc_AI_Sandstone_LowPor_Vp_Rho = ($Calc_Vp_Sandstone_LowPor_Rho * $Calc_Rho_Sandstone_LowPor_Por_Z) ;

$Calc_SI_Sandstone_LowPor_Vp_Rho = ($Calc_Vs_Sandstone_LowPor_Vp_Rho * $Calc_Rho_Sandstone_LowPor_Por_Z) ;

$Calc_lnAI_Sandstone_LowPor_Vp_Rho = ln($Calc_AI_Sandstone_LowPor_Vp_Rho / 1000) ;

$Calc_lnSI_Sandstone_LowPor_Vp_Rho = ln($Calc_SI_Sandstone_LowPor_Vp_Rho / 1000) ;

$Calc_VpVs_Sandstone_LowPor_Rho = $Calc_Vp_Sandstone_LowPor_Rho / $Calc_Vs_Sandstone_LowPor_Vp_Rho ;

$Calc_Por_Sandstone_HighPor_Z = ($Depth * $Por_Z_Sandstone_HighPor_m) + $Por_Z_Sandstone_HighPor_c ;

$Calc_Rho_Sandstone_HighPor_Por_Z = ($Calc_Por_Sandstone_HighPor_Z * $Rho_Por_Sandstone_m) + $Rho_Por_Sandstone_c ;

$Calc_Vp_Sandstone_HighPor_Rho = e ^ ((ln($Calc_Rho_Sandstone_HighPor_Por_Z) - ln($Rho_Vp_Sandstone_m)) / $Rho_Vp_Sandstone_n) ;

$Calc_Vs_Sandstone_HighPor_Vp_Rho = ($Calc_Vp_Sandstone_HighPor_Rho * $Vs_Vp_Sandstone_HighPor_m) + $Vs_Vp_Sandstone_HighPor_c ;

$Calc_AI_Sandstone_HighPor_Vp_Rho = ($Calc_Vp_Sandstone_HighPor_Rho * $Calc_Rho_Sandstone_HighPor_Por_Z) ;

$Calc_SI_Sandstone_HighPor_Vp_Rho = ($Calc_Vs_Sandstone_HighPor_Vp_Rho * $Calc_Rho_Sandstone_HighPor_Por_Z) ;

$Calc_lnAI_Sandstone_HighPor_Vp_Rho = ln($Calc_AI_Sandstone_HighPor_Vp_Rho / 1000) ;

$Calc_lnSI_Sandstone_HighPor_Vp_Rho = ln($Calc_SI_Sandstone_HighPor_Vp_Rho / 1000) ;

$Calc_VpVs_Sandstone_HighPor_Rho = $Calc_Vp_Sandstone_HighPor_Rho / $Calc_Vs_Sandstone_HighPor_Vp_Rho ;

$Calc_Por_Limestone_LowPor_Z = ($Depth * $Por_Z_Limestone_LowPor_m) + $Por_Z_Limestone_LowPor_c ;

$Calc_Rho_Limestone_LowPor_Por_Z = ($Calc_Por_Limestone_LowPor_Z * $Rho_Por_Limestone_m) + $Rho_Por_Limestone_c ;

$Calc_Vp_Limestone_LowPor_Rho = e ^ (($Calc_Rho_Limestone_LowPor_Por_Z - $Rho_Vp_Limestone_c) / $Rho_Vp_Limestone_m) ;

$Calc_Vs_Limestone_LowPor_Vp_Rho = (($Calc_Vp_Limestone_LowPor_Rho ^ 2) * $Vs_Vp_Limestone_m2) + ($Calc_Vp_Limestone_LowPor_Rho * $Vs_Vp_Limestone_m1) + $Vs_Vp_Limestone_c ;

$Calc_AI_Limestone_LowPor_Vp_Rho = ($Calc_Vp_Limestone_LowPor_Rho * $Calc_Rho_Limestone_LowPor_Por_Z) ;

$Calc_SI_Limestone_LowPor_Vp_Rho = ($Calc_Vs_Limestone_LowPor_Vp_Rho * $Calc_Rho_Limestone_LowPor_Por_Z) ;

$Calc_lnAI_Limestone_LowPor_Vp_Rho = ln($Calc_AI_Limestone_LowPor_Vp_Rho / 1000) ;

$Calc_lnSI_Limestone_LowPor_Vp_Rho = ln($Calc_SI_Limestone_LowPor_Vp_Rho / 1000) ;

$Calc_VpVs_Limestone_LowPor_Rho = $Calc_Vp_Limestone_LowPor_Rho / $Calc_Vs_Limestone_LowPor_Vp_Rho ;

$Calc_Por_Limestone_HighPor_Z = ($Depth * $Por_Z_Limestone_HighPor_m) + $Por_Z_Limestone_HighPor_c ;

$Calc_Rho_Limestone_HighPor_Por_Z = ($Calc_Por_Limestone_HighPor_Z * $Rho_Por_Limestone_m) + $Rho_Por_Limestone_c ;

$Calc_Vp_Limestone_HighPor_Rho = e ^ (($Calc_Rho_Limestone_HighPor_Por_Z - $Rho_Vp_Limestone_c) / $Rho_Vp_Limestone_m) ;

$Calc_Vs_Limestone_HighPor_Vp_Rho = (($Calc_Vp_Limestone_HighPor_Rho ^ 2) * $Vs_Vp_Limestone_m2) + ($Calc_Vp_Limestone_HighPor_Rho * $Vs_Vp_Limestone_m1) + $Vs_Vp_Limestone_c ;

$Calc_AI_Limestone_HighPor_Vp_Rho = ($Calc_Vp_Limestone_HighPor_Rho * $Calc_Rho_Limestone_HighPor_Por_Z) ;

$Calc_SI_Limestone_HighPor_Vp_Rho = ($Calc_Vs_Limestone_HighPor_Vp_Rho * $Calc_Rho_Limestone_HighPor_Por_Z) ;

$Calc_lnAI_Limestone_HighPor_Vp_Rho = ln($Calc_AI_Limestone_HighPor_Vp_Rho / 1000) ;

$Calc_lnSI_Limestone_HighPor_Vp_Rho = ln($Calc_SI_Limestone_HighPor_Vp_Rho / 1000) ;

$Calc_VpVs_Limestone_HighPor_Rho = $Calc_Vp_Limestone_HighPor_Rho / $Calc_Vs_Limestone_HighPor_Vp_Rho ;

//

```
// 5. Mixing of end-member curves with volume logs to produce synthetic logs for both models
// nb: Combined end-member curves are used to allow switching between soft/hard shale and low/high porosity reservoir
//     See report/ Rock Physics Part 2 ppts for further details

if ( $Use_Shale = 1.0 )
        $Calc_Vp_Shale_Z = $Calc_Vp_Shale_Hard_Z ;
        $Calc_Vs_Shale_Vp = $Calc_Vs_Shale_Hard_Vp ;
        $Calc_Rho_Shale_Vp = $Calc_Rho_Shale_Hard_Vp ;
else
        $Calc_Vp_Shale_Z = $Calc_Vp_Shale_Soft_Z ;
        $Calc_Vs_Shale_Vp = $Calc_Vs_Shale_Soft_Vp ;
        $Calc_Rho_Shale_Vp = $Calc_Rho_Shale_Soft_Vp ;
endif;
if ( $Use_Sandstone = 1.0 )
        $Calc_Vp_Sandstone_Z = $Calc_Vp_Sandstone_HighPor_Z ;
        $Calc_Vs_Sandstone_Vp_Z = $Calc_Vs_Sandstone_HighPor_Vp_Z ;
        $Calc_Rho_Sandstone_Por_Vp = $Calc_Rho_Sandstone_HighPor_Por_Vp ;
        $Calc_Vp_Sandstone_Rho = $Calc_Vp_Sandstone_HighPor_Rho ;
        $Calc_Vs_Sandstone_Vp_Rho = $Calc_Vs_Sandstone_HighPor_Vp_Rho ;
        $Calc_Rho_Sandstone_Por_Z = $Calc_Rho_Sandstone_HighPor_Por_Z ;
else
        $Calc_Vp_Sandstone_Z = $Calc_Vp_Sandstone_LowPor_Z ;
        $Calc_Vs_Sandstone_Vp_Z = $Calc_Vs_Sandstone_LowPor_Vp_Z ;
        $Calc_Rho_Sandstone_Por_Vp = $Calc_Rho_Sandstone_LowPor_Por_Vp ;
        $Calc_Vp_Sandstone_Rho = $Calc_Vp_Sandstone_LowPor_Rho ;
        $Calc_Vs_Sandstone_Vp_Rho = $Calc_Vs_Sandstone_LowPor_Vp_Rho ;
        $Calc_Rho_Sandstone_Por_Z = $Calc_Rho_Sandstone_LowPor_Por_Z ;
endif;
if ( $Use_Limestone = 1.0 )
        $Calc_Vp_Limestone_Z = $Calc_Vp_Limestone_HighPor_Z ;
        $Calc_Vs_Limestone_Vp_Z = $Calc_Vs_Limestone_HighPor_Vp_Z ;
        $Calc_Rho_Limestone_Por_Vp = $Calc_Rho_Limestone_HighPor_Por_Vp ;
        $Calc_Vp_Limestone_Rho = $Calc_Vp_Limestone_HighPor_Rho ;
        $Calc_Vs_Limestone_Vp_Rho = $Calc_Vs_Limestone_HighPor_Vp_Rho ;
```

```
        $Calc_Rho_Limestone_Por_Z = $Calc_Rho_Limestone_HighPor_Por_Z ;
else
        $Calc_Vp_Limestone_Z = $Calc_Vp_Limestone_LowPor_Z ;
        $Calc_Vs_Limestone_Vp_Z = $Calc_Vs_Limestone_LowPor_Vp_Z ;
        $Calc_Rho_Limestone_Por_Vp = $Calc_Rho_Limestone_LowPor_Por_Vp ;
        $Calc_Vp_Limestone_Rho = $Calc_Vp_Limestone_LowPor_Rho ;
        $Calc_Vs_Limestone_Vp_Rho = $Calc_Vs_Limestone_LowPor_Vp_Rho ;
        $Calc_Rho_Limestone_Por_Z = $Calc_Rho_Limestone_LowPor_Por_Z ;
endif;

// nb: Density log created using arithmetic averaging

$Trend_SDDI_Rho_Syn_Por_Vp = ( $Volume_Sandstone_Norm * $Calc_Rho_Sandstone_Por_Vp ) + ( $Volume_Tuff_Norm * $Calc_Rho_Tuff_Vp ) + ( $Volume_Limestone_Norm * $Calc_Rho_Limestone_Por_Vp ) + ( $Volume_Shale_Norm * $Calc_Rho_Shale_Vp ) ;
$Trend_Rck3D_Rho_Syn_Por_Z = ( $Volume_Sandstone_Norm * $Calc_Rho_Sandstone_Por_Z ) + ( $Volume_Tuff_Norm * $Calc_Rho_Tuff_Vp ) + ( $Volume_Limestone_Norm * $Calc_Rho_Limestone_Por_Z ) + ( $Volume_Shale_Norm * $Calc_Rho_Shale_Vp ) ;

// nb: Vp/Vs logs created using Backus averging

if ( $Sandstone = 0.0 )
        $Vp_Syn_Z_MinCalc1 = 1.0 ;
        $Vp_Syn_Rho_MinCalc1 = 1.0 ;
        $Vs_Syn_Vp_Z_MinCalc1 = 1.0 ;
        $Vs_Syn_Vp_Rho_MinCalc1 = 1.0 ;
else
        $Vp_Syn_Z_MinCalc1 = $Calc_Rho_Sandstone_Por_Vp * ( $Calc_Vp_Sandstone_Z ^2 ) ;
        $Vp_Syn_Rho_MinCalc1 = $Calc_Rho_Sandstone_Por_Z * ( $Calc_Vp_Sandstone_Rho ^2 ) ;
        $Vs_Syn_Vp_Z_MinCalc1 = $Calc_Rho_Sandstone_Por_Vp * ( $Calc_Vs_Sandstone_Vp_Z ^2 ) ;
        $Vs_Syn_Vp_Rho_MinCalc1 = $Calc_Rho_Sandstone_Por_Z * ( $Calc_Vs_Sandstone_Vp_Rho ^2 ) ;
endif;
if ( $Tuff = 0.0 )
        $Vp_Syn_Z_MinCalc2 = 1.0 ;
        $Vs_Syn_Vp_Z_MinCalc2 = 1.0 ;
```

```
else
        $Vp_Syn_Z_MinCalc2 = $Calc_Rho_Tuff_Vp * ( $Calc_Vp_Tuff_Z ^2 ) ;
        $Vs_Syn_Vp_Z_MinCalc2 = $Calc_Rho_Tuff_Vp * ( $Calc_Vs_Tuff_Vp ^2 ) ;
endif;
if ( $Limestone = 0.0 )
        $Vp_Syn_Z_MinCalc3 = 1.0 ;
        $Vp_Syn_Rho_MinCalc3 = 1.0 ;
        $Vs_Syn_Vp_Z_MinCalc3 = 1.0 ;
        $Vs_Syn_Vp_Rho_MinCalc3 = 1.0 ;
else
        $Vp_Syn_Z_MinCalc3 = $Calc_Rho_Limestone_Por_Vp * ( $Calc_Vp_Limestone_Z ^2 ) ;
        $Vp_Syn_Rho_MinCalc3 = $Calc_Rho_Limestone_Por_Z * ( $Calc_Vp_Limestone_Rho ^2 ) ;
        $Vs_Syn_Vp_Z_MinCalc3 = $Calc_Rho_Limestone_Por_Vp * ( $Calc_Vs_Limestone_Vp_Z ^2 ) ;
        $Vs_Syn_Vp_Rho_MinCalc3 = $Calc_Rho_Limestone_Por_Z * ( $Calc_Vs_Limestone_Vp_Rho ^2 ) ;
endif;
        $Vp_Syn_Z_MinCalc4 = $Calc_Rho_Shale_Vp * ( $Calc_Vp_Shale_Z ^2 ) ;
        $Vs_Syn_Vp_Z_MinCalc4 = $Calc_Rho_Shale_Vp * ( $Calc_Vs_Shale_Vp ^2 ) ;


$Vp_Syn_Z_SumCalc1 = 1 / (( $Volume_Sandstone_Norm / $Vp_Syn_Z_MinCalc1 ) + ( $Volume_Tuff_Norm / $Vp_Syn_Z_MinCalc2 ) + ( $Volume_Limestone_Norm / $Vp_Syn_Z_MinCalc3 ) + ( $Volume_Shale_Norm / $Vp_Syn_Z_MinCalc4 )) ;

$Vp_Syn_Rho_SumCalc1 = 1 / (( $Volume_Sandstone_Norm / $Vp_Syn_Rho_MinCalc1 ) + ( $Volume_Tuff_Norm / $Vp_Syn_Z_MinCalc2 ) + ( $Volume_Limestone_Norm / $Vp_Syn_Rho_MinCalc3 ) + ( $Volume_Shale_Norm / $Vp_Syn_Z_MinCalc4 )) ;

$Vs_Syn_Vp_Z_SumCalc1 = 1 / (( $Volume_Sandstone_Norm / $Vs_Syn_Vp_Z_MinCalc1 ) + ( $Volume_Tuff_Norm / $Vs_Syn_Vp_Z_MinCalc2 ) + ( $Volume_Limestone_Norm / $Vs_Syn_Vp_Z_MinCalc3 ) + ( $Volume_Shale_Norm / $Vs_Syn_Vp_Z_MinCalc4 )) ;

$Vs_Syn_Vp_Rho_SumCalc1 = 1 / (( $Volume_Sandstone_Norm / $Vs_Syn_Vp_Rho_MinCalc1 ) + ( $Volume_Tuff_Norm / $Vs_Syn_Vp_Z_MinCalc2 ) + ( $Volume_Limestone_Norm / $Vs_Syn_Vp_Rho_MinCalc3 ) + ( $Volume_Shale_Norm / $Vs_Syn_Vp_Z_MinCalc4 )) ;

$Trend_SDDI_Vp_Syn_Z = sqrt( $Vp_Syn_Z_SumCalc1 / $Trend_SDDI_Rho_Syn_Por_Vp ) ;

$Trend_Rck3D_Vp_Syn_Rho = sqrt( $Vp_Syn_Rho_SumCalc1 / $Trend_Rck3D_Rho_Syn_Por_Z ) ;

$Trend_SDDI_Vs_Syn_Vp_Z = sqrt( $Vs_Syn_Vp_Z_SumCalc1 / $Trend_SDDI_Rho_Syn_Por_Vp ) ;

$Trend_Rck3D_Vs_Syn_Vp_Rho = sqrt( $Vs_Syn_Vp_Rho_SumCalc1 / $Trend_Rck3D_Rho_Syn_Por_Z ) ;


// nb: Elastic logs created using synthetic Vp/Vs/Density logs
```

```
$Trend_SDDI_AI_Syn_Vp_Z = $Trend_SDDI_Rho_Syn_Por_Vp * $Trend_SDDI_Vp_Syn_Z ;
$Trend_Rck3D_AI_Syn_Vp_Rho = $Trend_Rck3D_Rho_Syn_Por_Z * $Trend_Rck3D_Vp_Syn_Rho ;
$Trend_SDDI_SI_Syn_Vp_Z = $Trend_SDDI_Rho_Syn_Por_Vp * $Trend_SDDI_Vs_Syn_Vp_Z ;
$Trend_Rck3D_SI_Syn_Vp_Rho = $Trend_Rck3D_Rho_Syn_Por_Z * $Trend_Rck3D_Vs_Syn_Vp_Rho ;
$Trend_SDDI_VpVs_Syn_Z = $Trend_SDDI_Vp_Syn_Z / $Trend_SDDI_Vs_Syn_Vp_Z ;
$Trend_Rck3D_VpVs_Syn_Rho = $Trend_Rck3D_Vp_Syn_Rho / $Trend_Rck3D_Vs_Syn_Vp_Rho ;

////////////////////////////////////////////////////////////////////////////////

// 6. Zero values within end-member and synthetic logs replace with 'null' value

if ( $Calc_Vp_Shale_Soft_Z = 0.0 )
        $Trend_NonRes_Vp_Shale_Soft_Z = null ;
        else
        $Trend_NonRes_Vp_Shale_Soft_Z = $Calc_Vp_Shale_Soft_Z ;
endif;
if ( $Calc_Vs_Shale_Soft_Vp = 0.0 )
        $Trend_NonRes_Vs_Shale_Soft_Vp = null ;
        else
        $Trend_NonRes_Vs_Shale_Soft_Vp = $Calc_Vs_Shale_Soft_Vp ;
endif;
if ( $Calc_Rho_Shale_Soft_Vp = 0.0 )
        $Trend_NonRes_Rho_Shale_Soft_Vp = null ;
        else
        $Trend_NonRes_Rho_Shale_Soft_Vp = $Calc_Rho_Shale_Soft_Vp ;
endif;
if ( $Calc_AI_Shale_Soft_Vp_Z = 0.0 )
        $Trend_NonRes_AI_Shale_Soft_Vp_Z = null ;
        else
        $Trend_NonRes_AI_Shale_Soft_Vp_Z = $Calc_AI_Shale_Soft_Vp_Z ;
endif;
if ( $Calc_SI_Shale_Soft_Vp_Z = 0.0 )
        $Trend_NonRes_SI_Shale_Soft_Vp_Z = null ;
        else
        $Trend_NonRes_SI_Shale_Soft_Vp_Z = $Calc_SI_Shale_Soft_Vp_Z ;
```

```
endif;
if ( $Calc_lnAI_Shale_Soft_Vp_Z = 0.0 )
        $Trend_NonRes_lnAI_Shale_Soft_Vp_Z = null ;
        else
        $Trend_NonRes_lnAI_Shale_Soft_Vp_Z = $Calc_lnAI_Shale_Soft_Vp_Z ;
endif;
if ( $Calc_lnSI_Shale_Soft_Vp_Z = 0.0 )
        $Trend_NonRes_lnSI_Shale_Soft_Vp_Z = null ;
        else
        $Trend_NonRes_lnSI_Shale_Soft_Vp_Z = $Calc_lnSI_Shale_Soft_Vp_Z ;
endif;
if ( $Calc_VpVs_Shale_Soft_Z = 0.0 )
        $Trend_NonRes_VpVs_Shale_Soft_Z = null ;
        else
        $Trend_NonRes_VpVs_Shale_Soft_Z = $Calc_VpVs_Shale_Soft_Z ;
endif;

if ( $Calc_Vp_Shale_Hard_Z = 0.0 )
        $Trend_NonRes_Vp_Shale_Hard_Z = null ;
        else
        $Trend_NonRes_Vp_Shale_Hard_Z = $Calc_Vp_Shale_Hard_Z ;
endif;
if ( $Calc_Vs_Shale_Hard_Vp = 0.0 )
        $Trend_NonRes_Vs_Shale_Hard_Vp = null ;
        else
        $Trend_NonRes_Vs_Shale_Hard_Vp = $Calc_Vs_Shale_Hard_Vp ;
endif;
if ( $Calc_Rho_Shale_Hard_Vp = 0.0 )
        $Trend_NonRes_Rho_Shale_Hard_Vp = null ;
        else
        $Trend_NonRes_Rho_Shale_Hard_Vp = $Calc_Rho_Shale_Hard_Vp ;
endif;
if ( $Calc_AI_Shale_Hard_Vp_Z = 0.0 )
        $Trend_NonRes_AI_Shale_Hard_Vp_Z = null ;
        else
        $Trend_NonRes_AI_Shale_Hard_Vp_Z = $Calc_AI_Shale_Hard_Vp_Z ;
```

```
endif;
if ( $Calc_SI_Shale_Hard_Vp_Z = 0.0 )
        $Trend_NonRes_SI_Shale_Hard_Vp_Z = null ;
        else
        $Trend_NonRes_SI_Shale_Hard_Vp_Z = $Calc_SI_Shale_Hard_Vp_Z ;
endif;
if ( $Calc_lnAI_Shale_Hard_Vp_Z = 0.0 )
        $Trend_NonRes_lnAI_Shale_Hard_Vp_Z = null ;
        else
        $Trend_NonRes_lnAI_Shale_Hard_Vp_Z = $Calc_lnAI_Shale_Hard_Vp_Z ;
endif;
if ( $Calc_lnSI_Shale_Hard_Vp_Z = 0.0 )
        $Trend_NonRes_lnSI_Shale_Hard_Vp_Z = null ;
        else
        $Trend_NonRes_lnSI_Shale_Hard_Vp_Z = $Calc_lnSI_Shale_Hard_Vp_Z ;
endif;
if ( $Calc_VpVs_Shale_Hard_Z = 0.0 )
        $Trend_NonRes_VpVs_Shale_Hard_Z = null ;
        else
        $Trend_NonRes_VpVs_Shale_Hard_Z = $Calc_VpVs_Shale_Hard_Z ;
endif;

if ( 2. Balder Fm )
        $Trend_NonRes_Vp_Tuff_Z = $Calc_Vp_Tuff_Z ;
        $Trend_NonRes_Vs_Tuff_Vp = $Calc_Vs_Tuff_Vp ;
        $Trend_NonRes_Rho_Tuff_Vp = $Calc_Rho_Tuff_Vp ;
        $Trend_NonRes_AI_Tuff_Vp_Z = $Calc_AI_Tuff_Vp_Z ;
        $Trend_NonRes_SI_Tuff_Vp_Z = $Calc_SI_Tuff_Vp_Z ;
        $Trend_NonRes_lnAI_Tuff_Vp_Z = $Calc_lnAI_Tuff_Vp_Z ;
        $Trend_NonRes_lnSI_Tuff_Vp_Z = $Calc_lnSI_Tuff_Vp_Z ;
        $Trend_NonRes_VpVs_Tuff_Z = $Calc_VpVs_Tuff_Z ;
        else
        $Trend_NonRes_Vp_Tuff_Z = null ;
        $Trend_NonRes_Vs_Tuff_Vp = null ;
        $Trend_NonRes_Rho_Tuff_Vp = null ;
        $Trend_NonRes_AI_Tuff_Vp_Z = null ;
```

```
        $Trend_NonRes_SI_Tuff_Vp_Z = null ;
        $Trend_NonRes_lnAI_Tuff_Vp_Z = null ;
        $Trend_NonRes_lnSI_Tuff_Vp_Z = null ;
        $Trend_NonRes_VpVs_Tuff_Z = null ;
endif;

if ( $Calc_Vp_Sandstone_LowPor_Z = 0.0 )
        $Trend_SDDI_Vp_Sandstone_LowPor_Z = null ;
        else
        $Trend_SDDI_Vp_Sandstone_LowPor_Z = $Calc_Vp_Sandstone_LowPor_Z ;
endif;
if ( $Calc_Por_Sandstone_LowPor_Vp_Z = 0.0 )
        $Trend_SDDI_Por_Sandstone_LowPor_Vp_Z = null ;
        else
        $Trend_SDDI_Por_Sandstone_LowPor_Vp_Z = $Calc_Por_Sandstone_LowPor_Vp_Z ;
endif;
if ( $Calc_Rho_Sandstone_LowPor_Por_Vp = 0.0 )
        $Trend_SDDI_Rho_Sandstone_LowPor_Por_Vp = null ;
        else
        $Trend_SDDI_Rho_Sandstone_LowPor_Por_Vp = $Calc_Rho_Sandstone_LowPor_Por_Vp ;
endif;
if ( $Calc_Vs_Sandstone_LowPor_Vp_Z = 0.0 )
        $Trend_SDDI_Vs_Sandstone_LowPor_Vp_Z = null ;
        else
        $Trend_SDDI_Vs_Sandstone_LowPor_Vp_Z = $Calc_Vs_Sandstone_LowPor_Vp_Z ;
endif;
if ( $Calc_AI_Sandstone_LowPor_Vp_Z = 0.0 )
        $Trend_SDDI_AI_Sandstone_LowPor_Vp_Z = null ;
        else
        $Trend_SDDI_AI_Sandstone_LowPor_Vp_Z = $Calc_AI_Sandstone_LowPor_Vp_Z ;
endif;
if ( $Calc_SI_Sandstone_LowPor_Vp_Z = 0.0 )
        $Trend_SDDI_SI_Sandstone_LowPor_Vp_Z = null ;
        else
        $Trend_SDDI_SI_Sandstone_LowPor_Vp_Z = $Calc_SI_Sandstone_LowPor_Vp_Z ;
endif;
```

```
if ( $Calc_lnAI_Sandstone_LowPor_Vp_Z = 0.0 )
	$Trend_SDDI_lnAI_Sandstone_LowPor_Vp_Z = null ;
	else
	$Trend_SDDI_lnAI_Sandstone_LowPor_Vp_Z = $Calc_lnAI_Sandstone_LowPor_Vp_Z ;
endif;
if ( $Calc_lnSI_Sandstone_LowPor_Vp_Z = 0.0 )
	$Trend_SDDI_lnSI_Sandstone_LowPor_Vp_Z = null ;
	else
	$Trend_SDDI_lnSI_Sandstone_LowPor_Vp_Z = $Calc_lnSI_Sandstone_LowPor_Vp_Z ;
endif;
if ( $Calc_VpVs_Sandstone_LowPor_Z = 0.0 )
	$Trend_SDDI_VpVs_Sandstone_LowPor_Z = null ;
	else
	$Trend_SDDI_VpVs_Sandstone_LowPor_Z = $Calc_VpVs_Sandstone_LowPor_Z ;
endif;
if ( $Calc_Vp_Sandstone_HighPor_Z = 0.0 )
	$Trend_SDDI_Vp_Sandstone_HighPor_Z = null ;
	else
	$Trend_SDDI_Vp_Sandstone_HighPor_Z = $Calc_Vp_Sandstone_HighPor_Z ;
endif;
if ( $Calc_Por_Sandstone_HighPor_Vp_Z = 0.0 )
	$Trend_SDDI_Por_Sandstone_HighPor_Vp_Z = null ;
	else
	$Trend_SDDI_Por_Sandstone_HighPor_Vp_Z = $Calc_Por_Sandstone_HighPor_Vp_Z ;
endif;
if ( $Calc_Rho_Sandstone_HighPor_Por_Vp = 0.0 )
	$Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp = null ;
	else
	$Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp = $Calc_Rho_Sandstone_HighPor_Por_Vp ;
endif;
if ( $Calc_Vs_Sandstone_HighPor_Vp_Z = 0.0 )
	$Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z = null ;
	else
	$Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z = $Calc_Vs_Sandstone_HighPor_Vp_Z ;
endif;
if ( $Calc_AI_Sandstone_HighPor_Vp_Z = 0.0 )
```

```
        $Trend_SDDI_AI_Sandstone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_AI_Sandstone_HighPor_Vp_Z = $Calc_AI_Sandstone_HighPor_Vp_Z ;
endif;
if ( $Calc_SI_Sandstone_HighPor_Vp_Z = 0.0 )
        $Trend_SDDI_SI_Sandstone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_SI_Sandstone_HighPor_Vp_Z = $Calc_SI_Sandstone_HighPor_Vp_Z ;
endif;
if ( $Calc_lnAI_Sandstone_HighPor_Vp_Z = 0.0 )
        $Trend_SDDI_lnAI_Sandstone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_lnAI_Sandstone_HighPor_Vp_Z = $Calc_lnAI_Sandstone_HighPor_Vp_Z ;
endif;
if ( $Calc_lnSI_Sandstone_HighPor_Vp_Z = 0.0 )
        $Trend_SDDI_lnSI_Sandstone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_lnSI_Sandstone_HighPor_Vp_Z = $Calc_lnSI_Sandstone_HighPor_Vp_Z ;
endif;
if ( $Calc_VpVs_Sandstone_HighPor_Z = 0.0 )
        $Trend_SDDI_VpVs_Sandstone_HighPor_Z = null ;
        else
        $Trend_SDDI_VpVs_Sandstone_HighPor_Z = $Calc_VpVs_Sandstone_HighPor_Z ;
endif;
if ( $Calc_Vp_Limestone_LowPor_Z = 0.0 )
        $Trend_SDDI_Vp_Limestone_LowPor_Z = null ;
        else
        $Trend_SDDI_Vp_Limestone_LowPor_Z = $Calc_Vp_Limestone_LowPor_Z ;
endif;
if ( $Calc_Por_Limestone_LowPor_Vp_Z = 0.0 )
        $Trend_SDDI_Por_Limestone_LowPor_Vp_Z = null ;
        else
        $Trend_SDDI_Por_Limestone_LowPor_Vp_Z = $Calc_Por_Limestone_LowPor_Vp_Z ;
endif;
if ( $Calc_Rho_Limestone_LowPor_Por_Vp = 0.0 )
        $Trend_SDDI_Rho_Limestone_LowPor_Por_Vp = null ;
```

```
	else
	$Trend_SDDI_Rho_Limestone_LowPor_Por_Vp = $Calc_Rho_Limestone_LowPor_Por_Vp ;
endif;
if ( $Calc_Vs_Limestone_LowPor_Vp_Z = 0.0 )
	$Trend_SDDI_Vs_Limestone_LowPor_Vp_Z = null ;
	else
	$Trend_SDDI_Vs_Limestone_LowPor_Vp_Z = $Calc_Vs_Limestone_LowPor_Vp_Z ;
endif;
if ( $Calc_AI_Limestone_LowPor_Vp_Z = 0.0 )
	$Trend_SDDI_AI_Limestone_LowPor_Vp_Z = null ;
	else
	$Trend_SDDI_AI_Limestone_LowPor_Vp_Z = $Calc_AI_Limestone_LowPor_Vp_Z ;
endif;
if ( $Calc_SI_Limestone_LowPor_Vp_Z = 0.0 )
	$Trend_SDDI_SI_Limestone_LowPor_Vp_Z = null ;
	else
	$Trend_SDDI_SI_Limestone_LowPor_Vp_Z = $Calc_SI_Limestone_LowPor_Vp_Z ;
endif;
if ( $Calc_lnAI_Limestone_LowPor_Vp_Z = 0.0 )
	$Trend_SDDI_lnAI_Limestone_LowPor_Vp_Z = null ;
	else
	$Trend_SDDI_lnAI_Limestone_LowPor_Vp_Z = $Calc_lnAI_Limestone_LowPor_Vp_Z ;
endif;
if ( $Calc_lnSI_Limestone_LowPor_Vp_Z = 0.0 )
	$Trend_SDDI_lnSI_Limestone_LowPor_Vp_Z = null ;
	else
	$Trend_SDDI_lnSI_Limestone_LowPor_Vp_Z = $Calc_lnSI_Limestone_LowPor_Vp_Z ;
endif;
if ( $Calc_VpVs_Limestone_LowPor_Z = 0.0 )
	$Trend_SDDI_VpVs_Limestone_LowPor_Z = null ;
	else
	$Trend_SDDI_VpVs_Limestone_LowPor_Z = $Calc_VpVs_Limestone_LowPor_Z ;
endif;
if ( $Calc_Vp_Limestone_HighPor_Z = 0.0 )
	$Trend_SDDI_Vp_Limestone_HighPor_Z = null ;
	else
```

```
        $Trend_SDDI_Vp_Limestone_HighPor_Z = $Calc_Vp_Limestone_HighPor_Z ;
endif;
if ( $Calc_Por_Limestone_HighPor_Vp_Z = 0.0 )
        $Trend_SDDI_Por_Limestone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_Por_Limestone_HighPor_Vp_Z = $Calc_Por_Limestone_HighPor_Vp_Z ;
endif;
if ( $Calc_Rho_Limestone_HighPor_Por_Vp = 0.0 )
        $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp = null ;
        else
        $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp = $Calc_Rho_Limestone_HighPor_Por_Vp ;
endif;
if ( $Calc_Vs_Limestone_HighPor_Vp_Z = 0.0 )
        $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z = $Calc_Vs_Limestone_HighPor_Vp_Z ;
endif;
if ( $Calc_AI_Limestone_HighPor_Vp_Z = 0.0 )
        $Trend_SDDI_AI_Limestone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_AI_Limestone_HighPor_Vp_Z = $Calc_AI_Limestone_HighPor_Vp_Z ;
endif;
if ( $Calc_SI_Limestone_HighPor_Vp_Z = 0.0 )
        $Trend_SDDI_SI_Limestone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_SI_Limestone_HighPor_Vp_Z = $Calc_SI_Limestone_HighPor_Vp_Z ;
endif;
if ( $Calc_lnAI_Limestone_HighPor_Vp_Z = 0.0 )
        $Trend_SDDI_lnAI_Limestone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_lnAI_Limestone_HighPor_Vp_Z = $Calc_lnAI_Limestone_HighPor_Vp_Z ;
endif;
if ( $Calc_lnSI_Limestone_HighPor_Vp_Z = 0.0 )
        $Trend_SDDI_lnSI_Limestone_HighPor_Vp_Z = null ;
        else
        $Trend_SDDI_lnSI_Limestone_HighPor_Vp_Z = $Calc_lnSI_Limestone_HighPor_Vp_Z ;
```

```
endif;
if ( $Calc_VpVs_Limestone_HighPor_Z = 0.0 )
        $Trend_SDDI_VpVs_Limestone_HighPor_Z = null ;
        else
        $Trend_SDDI_VpVs_Limestone_HighPor_Z = $Calc_VpVs_Limestone_HighPor_Z ;
endif;

if ( $Calc_Por_Sandstone_LowPor_Z = 0.0 )
        $Trend_Rck3D_Por_Sandstone_LowPor_Z = null ;
        else
        $Trend_Rck3D_Por_Sandstone_LowPor_Z = $Calc_Por_Sandstone_LowPor_Z ;
endif;
if ( $Calc_Rho_Sandstone_LowPor_Por_Z = 0.0 )
        $Trend_Rck3D_Rho_Sandstone_LowPor_Por_Z = null ;
        else
        $Trend_Rck3D_Rho_Sandstone_LowPor_Por_Z = $Calc_Rho_Sandstone_LowPor_Por_Z ;
endif;
if ( $Calc_Vp_Sandstone_LowPor_Rho = 0.0 )
        $Trend_Rck3D_Vp_Sandstone_LowPor_Rho = null ;
        else
        $Trend_Rck3D_Vp_Sandstone_LowPor_Rho = $Calc_Vp_Sandstone_LowPor_Rho ;
endif;
if ( $Calc_Vs_Sandstone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_Vs_Sandstone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_Vs_Sandstone_LowPor_Vp_Rho = $Calc_Vs_Sandstone_LowPor_Vp_Rho ;
endif;
if ( $Calc_AI_Sandstone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_AI_Sandstone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_AI_Sandstone_LowPor_Vp_Rho = $Calc_AI_Sandstone_LowPor_Vp_Rho ;
endif;
if ( $Calc_SI_Sandstone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_SI_Sandstone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_SI_Sandstone_LowPor_Vp_Rho = $Calc_SI_Sandstone_LowPor_Vp_Rho ;
```

```
endif;
if ( $Calc_lnAI_Sandstone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_lnAI_Sandstone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_lnAI_Sandstone_LowPor_Vp_Rho = $Calc_lnAI_Sandstone_LowPor_Vp_Rho ;
endif;
if ( $Calc_lnSI_Sandstone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_lnSI_Sandstone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_lnSI_Sandstone_LowPor_Vp_Rho = $Calc_lnSI_Sandstone_LowPor_Vp_Rho ;
endif;
if ( $Calc_VpVs_Sandstone_LowPor_Rho = 0.0 )
        $Trend_Rck3D_VpVs_Sandstone_LowPor_Rho = null ;
        else
        $Trend_Rck3D_VpVs_Sandstone_LowPor_Rho = $Calc_VpVs_Sandstone_LowPor_Rho ;
endif;
if ( $Calc_Por_Sandstone_HighPor_Z = 0.0 )
        $Trend_Rck3D_Por_Sandstone_HighPor_Z = null ;
        else
        $Trend_Rck3D_Por_Sandstone_HighPor_Z = $Calc_Por_Sandstone_HighPor_Z ;
endif;
if ( $Calc_Rho_Sandstone_HighPor_Por_Z = 0.0 )
        $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z = null ;
        else
        $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z = $Calc_Rho_Sandstone_HighPor_Por_Z ;
endif;
if ( $Calc_Vp_Sandstone_HighPor_Rho = 0.0 )
        $Trend_Rck3D_Vp_Sandstone_HighPor_Rho = null ;
        else
        $Trend_Rck3D_Vp_Sandstone_HighPor_Rho = $Calc_Vp_Sandstone_HighPor_Rho ;
endif;
if ( $Calc_Vs_Sandstone_HighPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho = $Calc_Vs_Sandstone_HighPor_Vp_Rho ;
endif;
```

```
if ( $Calc_AI_Sandstone_HighPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_AI_Sandstone_HighPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_AI_Sandstone_HighPor_Vp_Rho = $Calc_AI_Sandstone_HighPor_Vp_Rho ;
endif;
if ( $Calc_SI_Sandstone_HighPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_SI_Sandstone_HighPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_SI_Sandstone_HighPor_Vp_Rho = $Calc_SI_Sandstone_HighPor_Vp_Rho ;
endif;
if ( $Calc_lnAI_Sandstone_HighPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_lnAI_Sandstone_HighPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_lnAI_Sandstone_HighPor_Vp_Rho = $Calc_lnAI_Sandstone_HighPor_Vp_Rho
;
endif;
if ( $Calc_lnSI_Sandstone_HighPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_lnSI_Sandstone_HighPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_lnSI_Sandstone_HighPor_Vp_Rho = $Calc_lnSI_Sandstone_HighPor_Vp_Rho
;
endif;
if ( $Calc_VpVs_Sandstone_HighPor_Rho = 0.0 )
        $Trend_Rck3D_VpVs_Sandstone_HighPor_Rho = null ;
        else
        $Trend_Rck3D_VpVs_Sandstone_HighPor_Rho = $Calc_VpVs_Sandstone_HighPor_Rho ;
endif;
if ( $Calc_Por_Limestone_LowPor_Z = 0.0 )
        $Trend_Rck3D_Por_Limestone_LowPor_Z = null ;
        else
        $Trend_Rck3D_Por_Limestone_LowPor_Z = $Calc_Por_Limestone_LowPor_Z ;
endif;
if ( $Calc_Rho_Limestone_LowPor_Por_Z = 0.0 )
        $Trend_Rck3D_Rho_Limestone_LowPor_Por_Z = null ;
        else
        $Trend_Rck3D_Rho_Limestone_LowPor_Por_Z = $Calc_Rho_Limestone_LowPor_Por_Z ;
```

```
endif;
if ( $Calc_Vp_Limestone_LowPor_Rho = 0.0 )
        $Trend_Rck3D_Vp_Limestone_LowPor_Rho = null ;
        else
        $Trend_Rck3D_Vp_Limestone_LowPor_Rho = $Calc_Vp_Limestone_LowPor_Rho ;
endif;
if ( $Calc_Vs_Limestone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_Vs_Limestone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_Vs_Limestone_LowPor_Vp_Rho = $Calc_Vs_Limestone_LowPor_Vp_Rho ;
endif;
if ( $Calc_AI_Limestone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_AI_Limestone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_AI_Limestone_LowPor_Vp_Rho = $Calc_AI_Limestone_LowPor_Vp_Rho ;
endif;
if ( $Calc_SI_Limestone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_SI_Limestone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_SI_Limestone_LowPor_Vp_Rho = $Calc_SI_Limestone_LowPor_Vp_Rho ;
endif;
if ( $Calc_lnAI_Limestone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_lnAI_Limestone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_lnAI_Limestone_LowPor_Vp_Rho = $Calc_lnAI_Limestone_LowPor_Vp_Rho ;
endif;
if ( $Calc_lnSI_Limestone_LowPor_Vp_Rho = 0.0 )
        $Trend_Rck3D_lnSI_Limestone_LowPor_Vp_Rho = null ;
        else
        $Trend_Rck3D_lnSI_Limestone_LowPor_Vp_Rho = $Calc_lnSI_Limestone_LowPor_Vp_Rho ;
endif;
if ( $Calc_VpVs_Limestone_LowPor_Rho = 0.0 )
        $Trend_Rck3D_VpVs_Limestone_LowPor_Rho = null ;
        else
        $Trend_Rck3D_VpVs_Limestone_LowPor_Rho = $Calc_VpVs_Limestone_LowPor_Rho ;
endif;
```

```
if ( $Calc_Por_Limestone_HighPor_Z = 0.0 )
	$Trend_Rck3D_Por_Limestone_HighPor_Z = null ;
	else
	$Trend_Rck3D_Por_Limestone_HighPor_Z = $Calc_Por_Limestone_HighPor_Z ;
endif;
if ( $Calc_Rho_Limestone_HighPor_Por_Z = 0.0 )
	$Trend_Rck3D_Rho_Limestone_HighPor_Por_Z = null ;
	else
	$Trend_Rck3D_Rho_Limestone_HighPor_Por_Z = $Calc_Rho_Limestone_HighPor_Por_Z ;
endif;
if ( $Calc_Vp_Limestone_HighPor_Rho = 0.0 )
	$Trend_Rck3D_Vp_Limestone_HighPor_Rho = null ;
	else
	$Trend_Rck3D_Vp_Limestone_HighPor_Rho = $Calc_Vp_Limestone_HighPor_Rho ;
endif;
if ( $Calc_Vs_Limestone_HighPor_Vp_Rho = 0.0 )
	$Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho = null ;
	else
	$Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho = $Calc_Vs_Limestone_HighPor_Vp_Rho ;
endif;
if ( $Calc_AI_Limestone_HighPor_Vp_Rho = 0.0 )
	$Trend_Rck3D_AI_Limestone_HighPor_Vp_Rho = null ;
	else
	$Trend_Rck3D_AI_Limestone_HighPor_Vp_Rho = $Calc_AI_Limestone_HighPor_Vp_Rho ;
endif;
if ( $Calc_SI_Limestone_HighPor_Vp_Rho = 0.0 )
	$Trend_Rck3D_SI_Limestone_HighPor_Vp_Rho = null ;
	else
	$Trend_Rck3D_SI_Limestone_HighPor_Vp_Rho = $Calc_SI_Limestone_HighPor_Vp_Rho ;
endif;
if ( $Calc_lnAI_Limestone_HighPor_Vp_Rho = 0.0 )
	$Trend_Rck3D_lnAI_Limestone_HighPor_Vp_Rho = null ;
	else
	$Trend_Rck3D_lnAI_Limestone_HighPor_Vp_Rho = $Calc_lnAI_Limestone_HighPor_Vp_Rho
;
endif;
```

```
if ( $Calc_lnSI_Limestone_HighPor_Vp_Rho = 0.0 )
	$Trend_Rck3D_lnSI_Limestone_HighPor_Vp_Rho = null ;
	else
	$Trend_Rck3D_lnSI_Limestone_HighPor_Vp_Rho = $Calc_lnSI_Limestone_HighPor_Vp_Rho
;
endif;
if ( $Calc_VpVs_Limestone_HighPor_Rho = 0.0 )
	$Trend_Rck3D_VpVs_Limestone_HighPor_Rho = null ;
	else
	$Trend_Rck3D_VpVs_Limestone_HighPor_Rho = $Calc_VpVs_Limestone_HighPor_Rho ;
endif;

////////////////////////////////////////////////////////////////////////////////////

// 7. Define which logs are output by the script

save ($Trend_NonRes_Vp_Shale_Soft_Z) ;
save ($Trend_NonRes_Vs_Shale_Soft_Vp ) ;
save ($Trend_NonRes_Rho_Shale_Soft_Vp) ;
save ($Trend_NonRes_AI_Shale_Soft_Vp_Z) ;
save ($Trend_NonRes_SI_Shale_Soft_Vp_Z) ;
save ($Trend_NonRes_lnAI_Shale_Soft_Vp_Z) ;
save ($Trend_NonRes_lnSI_Shale_Soft_Vp_Z) ;
save ($Trend_NonRes_VpVs_Shale_Soft_Z) ;
save ($Trend_NonRes_Vp_Shale_Hard_Z) ;
save ($Trend_NonRes_Vs_Shale_Hard_Vp ) ;
save ($Trend_NonRes_Rho_Shale_Hard_Vp) ;
save ($Trend_NonRes_AI_Shale_Hard_Vp_Z) ;
save ($Trend_NonRes_SI_Shale_Hard_Vp_Z) ;
save ($Trend_NonRes_lnAI_Shale_Hard_Vp_Z) ;
save ($Trend_NonRes_lnSI_Shale_Hard_Vp_Z) ;
save ($Trend_NonRes_VpVs_Shale_Hard_Z) ;
save ($Trend_NonRes_Vp_Tuff_Z) ;
save ($Trend_NonRes_Vs_Tuff_Vp) ;
save ($Trend_NonRes_Rho_Tuff_Vp) ;
save ($Trend_NonRes_AI_Tuff_Vp_Z) ;
```

```
save ($Trend_NonRes_SI_Tuff_Vp_Z) ;
save ($Trend_NonRes_lnAI_Tuff_Vp_Z) ;
save ($Trend_NonRes_lnSI_Tuff_Vp_Z) ;
save ($Trend_NonRes_VpVs_Tuff_Z) ;

save ($Trend_SDDI_Vp_Sandstone_LowPor_Z) ;
save ($Trend_SDDI_Por_Sandstone_LowPor_Vp_Z) ;
save ($Trend_SDDI_Rho_Sandstone_LowPor_Por_Vp) ;
save ($Trend_SDDI_Vs_Sandstone_LowPor_Vp_Z) ;
save ($Trend_SDDI_AI_Sandstone_LowPor_Vp_Z) ;
save ($Trend_SDDI_SI_Sandstone_LowPor_Vp_Z) ;
save ($Trend_SDDI_lnAI_Sandstone_LowPor_Vp_Z) ;
save ($Trend_SDDI_lnSI_Sandstone_LowPor_Vp_Z) ;
save ($Trend_SDDI_VpVs_Sandstone_LowPor_Z) ;
save ($Trend_SDDI_Vp_Sandstone_HighPor_Z) ;
save ($Trend_SDDI_Por_Sandstone_HighPor_Vp_Z) ;
save ($Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp) ;
save ($Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z) ;
save ($Trend_SDDI_AI_Sandstone_HighPor_Vp_Z) ;
save ($Trend_SDDI_SI_Sandstone_HighPor_Vp_Z) ;
save ($Trend_SDDI_lnAI_Sandstone_HighPor_Vp_Z) ;
save ($Trend_SDDI_lnSI_Sandstone_HighPor_Vp_Z) ;
save ($Trend_SDDI_VpVs_Sandstone_HighPor_Z) ;
save ($Trend_SDDI_Vp_Limestone_LowPor_Z) ;
save ($Trend_SDDI_Por_Limestone_LowPor_Vp_Z) ;
save ($Trend_SDDI_Rho_Limestone_LowPor_Por_Vp) ;
save ($Trend_SDDI_Vs_Limestone_LowPor_Vp_Z) ;
save ($Trend_SDDI_AI_Limestone_LowPor_Vp_Z) ;
save ($Trend_SDDI_SI_Limestone_LowPor_Vp_Z) ;
save ($Trend_SDDI_lnAI_Limestone_LowPor_Vp_Z) ;
save ($Trend_SDDI_lnSI_Limestone_LowPor_Vp_Z) ;
save ($Trend_SDDI_VpVs_Limestone_LowPor_Z) ;
save ($Trend_SDDI_Vp_Limestone_HighPor_Z) ;
save ($Trend_SDDI_Por_Limestone_HighPor_Vp_Z) ;
save ($Trend_SDDI_Rho_Limestone_HighPor_Por_Vp) ;
save ($Trend_SDDI_Vs_Limestone_HighPor_Vp_Z) ;
```

```
save ($Trend_SDDI_AI_Limestone_HighPor_Vp_Z) ;
save ($Trend_SDDI_SI_Limestone_HighPor_Vp_Z) ;
save ($Trend_SDDI_lnAI_Limestone_HighPor_Vp_Z) ;
save ($Trend_SDDI_lnSI_Limestone_HighPor_Vp_Z) ;
save ($Trend_SDDI_VpVs_Limestone_HighPor_Z) ;

save ($Trend_Rck3D_Por_Sandstone_LowPor_Z) ;
save ($Trend_Rck3D_Rho_Sandstone_LowPor_Por_Z) ;
save ($Trend_Rck3D_Vp_Sandstone_LowPor_Rho) ;
save ($Trend_Rck3D_Vs_Sandstone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_AI_Sandstone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_SI_Sandstone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_lnAI_Sandstone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_lnSI_Sandstone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_VpVs_Sandstone_LowPor_Rho) ;
save ($Trend_Rck3D_Por_Sandstone_HighPor_Z) ;
save ($Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z) ;
save ($Trend_Rck3D_Vp_Sandstone_HighPor_Rho) ;
save ($Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_AI_Sandstone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_SI_Sandstone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_lnAI_Sandstone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_lnSI_Sandstone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_VpVs_Sandstone_HighPor_Rho) ;
save ($Trend_Rck3D_Por_Limestone_LowPor_Z) ;
save ($Trend_Rck3D_Rho_Limestone_LowPor_Por_Z) ;
save ($Trend_Rck3D_Vp_Limestone_LowPor_Rho) ;
save ($Trend_Rck3D_Vs_Limestone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_AI_Limestone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_SI_Limestone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_lnAI_Limestone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_lnSI_Limestone_LowPor_Vp_Rho) ;
save ($Trend_Rck3D_VpVs_Limestone_LowPor_Rho) ;
save ($Trend_Rck3D_Por_Limestone_HighPor_Z) ;
save ($Trend_Rck3D_Rho_Limestone_HighPor_Por_Z) ;
save ($Trend_Rck3D_Vp_Limestone_HighPor_Rho) ;
```

```
save ($Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_AI_Limestone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_SI_Limestone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_lnAI_Limestone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_lnSI_Limestone_HighPor_Vp_Rho) ;
save ($Trend_Rck3D_VpVs_Limestone_HighPor_Rho) ;

save ($Trend_SDDI_Vp_Syn_Z) ;
save ($Trend_Rck3D_Vp_Syn_Rho) ;
save ($Trend_SDDI_Vs_Syn_Vp_Z) ;
save ($Trend_Rck3D_Vs_Syn_Vp_Rho) ;
save ($Trend_SDDI_Rho_Syn_Por_Vp) ;
save ($Trend_Rck3D_Rho_Syn_Por_Z) ;
save ($Trend_SDDI_AI_Syn_Vp_Z) ;
save ($Trend_Rck3D_AI_Syn_Vp_Rho) ;
save ($Trend_SDDI_SI_Syn_Vp_Z) ;
save ($Trend_Rck3D_SI_Syn_Vp_Rho) ;
save ($Trend_SDDI_VpVs_Syn_Z) ;
save ($Trend_Rck3D_VpVs_Syn_Rho) ;
```

G.3 – End-Member Gassmann Fluid Substitution

```
// RokDoc User Programmer Custom Script:
// End-Member Gassmann Fluid Substitution

// IMPORTANT - project units for Vp and Vs must be in m/s before use

// Input - End-Member Logs (Vp, Vs, Rho, Por)
// Output - End-Member Logs Oil80 / Gas90 (Vp, Vs, Rho, AI, SI, VpVs)
// Description - Performs Gassmann fluid substitution using averages

// 1. Select the end-member logs output by the 'End-Member and Synthetic Logs' script

$Trend_SDDI_Vp_Sandstone_HighPor_Z = Vp ;
$Trend_SDDI_Vp_Limestone_HighPor_Z = Vp ;
$Trend_Rck3D_Vp_Sandstone_HighPor_Rho = Vp ;
$Trend_Rck3D_Vp_Limestone_HighPor_Rho = Vp ;

$Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z = Vs ;
$Trend_SDDI_Vs_Limestone_HighPor_Vp_Z = Vs ;
$Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho = Vs ;
$Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho = Vs ;

$Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp = Rho ;
$Trend_SDDI_Rho_Limestone_HighPor_Por_Vp = Rho ;
$Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z = Rho ;
$Trend_Rck3D_Rho_Limestone_HighPor_Por_Z = Rho ;

$Trend_SDDI_Por_Sandstone_HighPor_Vp_Z = Por ;
$Trend_SDDI_Por_Limestone_HighPor_Vp_Z = Por ;
$Trend_Rck3D_Por_Sandstone_HighPor_Z = Por ;
$Trend_Rck3D_Por_Limestone_HighPor_Z = Por ;

// 2. Define fluid properties
// nb: Fluid properties are well specific
```

```
//     See report/ xls/ multi-well ppts for fluid properties of study wells

////////////////////////////////////////////////////////////////////////////////
////////////// Define Fluid Propeties from Fluid Sets (Well Specific) //////////////
////////////////////////////////////////////////////////////////////////////////

// nb: Fluid property templates are sorted on a working interval then fluid basis
//     Where working interval is not present, set each contained $<variable> = 0.0
//       If Gas Condensate present, use 'End-Member Gassmann Fluid Substitution inc. Condensate' script

// Horda Formation
if ( 1. Horda Fm )

$K_Fluid_Brine = 0.0 ;
$Rho_Fluid_Brine = 0.0 ;
$K_Fluid_Oil = 0.0 ;
$Rho_Fluid_Oil = 0.0 ;
$K_Fluid_Gas = 0.0 ;
$Rho_Fluid_Gas = 0.0 ;

else
// Balder Formation
if ( 2. Balder Fm )

$K_Fluid_Brine = 0.0 ;
$Rho_Fluid_Brine = 0.0 ;
$K_Fluid_Oil = 0.0 ;
$Rho_Fluid_Oil = 0.0 ;
$K_Fluid_Gas = 0.0 ;
$Rho_Fluid_Gas = 0.0 ;

else
// Sele Formation
if ( 3. Sele Fm )
```

```
$K_Fluid_Brine = 0.0 ;
$Rho_Fluid_Brine = 0.0 ;
$K_Fluid_Oil = 0.0 ;
$Rho_Fluid_Oil = 0.0 ;
$K_Fluid_Gas = 0.0 ;
$Rho_Fluid_Gas = 0.0 ;

else
// Lista Formation
if ( 4. Lista Fm )

$K_Fluid_Brine = 0.0 ;
$Rho_Fluid_Brine = 0.0 ;
$K_Fluid_Oil = 0.0 ;
$Rho_Fluid_Oil = 0.0 ;
$K_Fluid_Gas = 0.0 ;
$Rho_Fluid_Gas = 0.0 ;

else
// Maureen Formation
if ( 5. Maureen Fm )

$K_Fluid_Brine = 0.0 ;
$Rho_Fluid_Brine = 0.0 ;
$K_Fluid_Oil = 0.0 ;
$Rho_Fluid_Oil = 0.0 ;
$K_Fluid_Gas = 0.0 ;
$Rho_Fluid_Gas = 0.0 ;

else
// Ekofisk Formation
if ( 6. Ekofisk Fm )

$K_Fluid_Brine = 0.0 ;
$Rho_Fluid_Brine = 0.0 ;
$K_Fluid_Oil = 0.0 ;
```

```
$Rho_Fluid_Oil = 0.0 ;
$K_Fluid_Gas = 0.0 ;
$Rho_Fluid_Gas = 0.0 ;

else
// Tor Formation
if ( 7. Tor Fm )

$K_Fluid_Brine = 0.0 ;
$Rho_Fluid_Brine = 0.0 ;
$K_Fluid_Oil = 0.0 ;
$Rho_Fluid_Oil = 0.0 ;
$K_Fluid_Gas = 0.0 ;
$Rho_Fluid_Gas = 0.0 ;

else
// Hod Formation
if ( 8. Hod Fm )

$K_Fluid_Brine = 0.0 ;
$Rho_Fluid_Brine = 0.0 ;
$K_Fluid_Oil = 0.0 ;
$Rho_Fluid_Oil = 0.0 ;
$K_Fluid_Gas = 0.0 ;
$Rho_Fluid_Gas = 0.0 ;

endif;
endif;
endif;
endif;
endif;
endif;
endif;
endif;

// 3. Define saturations and mineral properties
```

```
// nb: Set to project defaults

///////////////////////////////////////////////////////////////////////////////////
//////////////////// Define Saturations and Mineral Properties /////////////////////
///////////////////////////////////////////////////////////////////////////////////

// Oil Saturation
$Oil_Sat = 0.8 ;
// Gas Saturation
$Gas_Sat = 0.9 ;

// Bulk Modulus (Sandstone)
$K_Sst_Matrix = 38.9 ;
// Density (Sandstone)
$Rho_Sst_Matrix = 2.635 ;
// Bulk Modulus (Limestone)
$K_Lst_Matrix = 60.0 ;
// Density (Limestone)
$Rho_Lst_Matrix = 2.71 ;

///////////////////////////////////////////////////////////////////////////////////
//////////////////////////////// DO NOT EDIT BELOW /////////////////////////////////
///////////////////////////////////////////////////////////////////////////////////

// 4. Calculates bulk modulus and density of oil and gas at defined saturations

$Volume_0 = 0.0 ;

$K_Fluid_Brine100 = $K_Fluid_Brine ;
$Calc_K_Fluid_Oil80 = ( $Oil_Sat / $K_Fluid_Oil ) + (( 1 - $Oil_Sat ) / $K_Fluid_Brine ) ;
$K_Fluid_Oil80 = ( 1 / $Calc_K_Fluid_Oil80 ) ;
$Calc_K_Fluid_Gas90 = ( $Gas_Sat / $K_Fluid_Gas ) + (( 1 - $Gas_Sat ) / $K_Fluid_Brine ) ;
$K_Fluid_Gas90 = ( 1 / $Calc_K_Fluid_Gas90 ) ;

$Rho_Fluid_Brine100 = $Rho_Fluid_Brine ;
$Rho_Fluid_Oil80 = ( $Oil_Sat * $Rho_Fluid_Oil ) + (( 1 - $Oil_Sat ) * $Rho_Fluid_Brine ) ;
```

$Rho_Fluid_Gas90 = ($Gas_Sat * $Rho_Fluid_Gas) + ((1 - $Gas_Sat) * $Rho_Fluid_Brine) ;

//

// 4. Performs Gassmann fluid substitution after Gassmann

// Sandstone Vp_Z (SDDI) to Dry

$KSat_Init_Sandstone_SDDI_Pa = $Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp * (($Trend_SDDI_Vp_Sandstone_HighPor_Z ^ 2) - ((4 / 3) * ($Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z ^ 2))) ;

$KSat_Init_Sandstone_SDDI_GPa = $KSat_Init_Sandstone_SDDI_Pa * (10 ^ -6) ;

$MuSat_Init_Sandstone_SDDI_Pa = $Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp * ($Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z ^ 2) ;

$MuSat_Init_Sandstone_SDDI_GPa = $MuSat_Init_Sandstone_SDDI_Pa * (10 ^ -6) ;

$KDry_Sandstone_SDDI_Num = ($KSat_Init_Sandstone_SDDI_GPa * ((($Trend_SDDI_Por_Sandstone_HighPor_Vp_Z * $K_Sst_Matrix) / $K_Fluid_Brine100) + 1 - $Trend_SDDI_Por_Sandstone_HighPor_Vp_Z)) - $K_Sst_Matrix ;

$KDry_Sandstone_SDDI_Den = (($Trend_SDDI_Por_Sandstone_HighPor_Vp_Z * $K_Sst_Matrix) / $K_Fluid_Brine100) + ($KSat_Init_Sandstone_SDDI_GPa / $K_Sst_Matrix) - 1 - $Trend_SDDI_Por_Sandstone_HighPor_Vp_Z ;

$KDry_Sandstone_SDDI_GPa = $KDry_Sandstone_SDDI_Num / $KDry_Sandstone_SDDI_Den ;

// Sandstone Vp_Z (SDDI) Dry to Oil80

$KSat_Final_Sandstone_SDDI_Oil80_Num = (1 - ($KDry_Sandstone_SDDI_GPa / $K_Sst_Matrix)) ^ 2 ;

$KSat_Final_Sandstone_SDDI_Oil80_Den = ($Trend_SDDI_Por_Sandstone_HighPor_Vp_Z / $K_Fluid_Oil80) + ((1 - $Trend_SDDI_Por_Sandstone_HighPor_Vp_Z) / $K_Sst_Matrix) - ($KDry_Sandstone_SDDI_GPa / ($K_Sst_Matrix ^ 2)) ;

$KSat_Final_Sandstone_SDDI_Oil80_GPa = $KDry_Sandstone_SDDI_GPa + ($KSat_Final_Sandstone_SDDI_Oil80_Num / $KSat_Final_Sandstone_SDDI_Oil80_Den) ;

$Calc_Rho_Sandstone_Por_Vp_Oil80 = ($Trend_SDDI_Por_Sandstone_HighPor_Vp_Z * $Rho_Fluid_Oil80) + ((1 - $Trend_SDDI_Por_Sandstone_HighPor_Vp_Z) * $Rho_Sst_Matrix) ;

$Calc_Vp_Sandstone_Z_Oil80 = (sqrt (($KSat_Final_Sandstone_SDDI_Oil80_GPa + ((4 / 3) * $MuSat_Init_Sandstone_SDDI_GPa)) / $Calc_Rho_Sandstone_Por_Vp_Oil80)) * (10 ^ 3) ;

$Calc_Vs_Sandstone_Vp_Z_Oil80 = (sqrt ($MuSat_Init_Sandstone_SDDI_GPa / $Calc_Rho_Sandstone_Por_Vp_Oil80)) * (10 ^ 3) ;

// Sandstone Vp_Z (SDDI) Dry to Gas90

$KSat_Final_Sandstone_SDDI_Gas90_Num = (1 - ($KDry_Sandstone_SDDI_GPa / $K_Sst_Matrix)) ^ 2 ;

$KSat_Final_Sandstone_SDDI_Gas90_Den = ($Trend_SDDI_Por_Sandstone_HighPor_Vp_Z / $K_Fluid_Gas90) + ((1 - $Trend_SDDI_Por_Sandstone_HighPor_Vp_Z) / $K_Sst_Matrix) - ($KDry_Sandstone_SDDI_GPa / ($K_Sst_Matrix ^ 2)) ;

$KSat_Final_Sandstone_SDDI_Gas90_GPa = $KDry_Sandstone_SDDI_GPa + ($KSat_Final_Sandstone_SDDI_Gas90_Num / $KSat_Final_Sandstone_SDDI_Gas90_Den) ;

$Calc_Rho_Sandstone_Por_Vp_Gas90 = ($Trend_SDDI_Por_Sandstone_HighPor_Vp_Z * $Rho_Fluid_Gas90) + ((1 - $Trend_SDDI_Por_Sandstone_HighPor_Vp_Z) * $Rho_Sst_Matrix) ;

$Calc_Vp_Sandstone_Z_Gas90 = (sqrt (($KSat_Final_Sandstone_SDDI_Gas90_GPa + ((4 / 3) * $MuSat_Init_Sandstone_SDDI_GPa)) / $Calc_Rho_Sandstone_Por_Vp_Gas90)) * (10 ^ 3) ;

$Calc_Vs_Sandstone_Vp_Z_Gas90 = (sqrt ($MuSat_Init_Sandstone_SDDI_GPa / $Calc_Rho_Sandstone_Por_Vp_Gas90)) * (10 ^ 3) ;

// Limestone Vp_Z (SDDI) to Dry

$KSat_Init_Limestone_SDDI_Pa = $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp * (($Trend_SDDI_Vp_Limestone_HighPor_Z ^ 2) - ((4 / 3) * ($Trend_SDDI_Vs_Limestone_HighPor_Vp_Z ^ 2))) ;

$KSat_Init_Limestone_SDDI_GPa = $KSat_Init_Limestone_SDDI_Pa * (10 ^ -6) ;

$MuSat_Init_Limestone_SDDI_Pa = $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp * ($Trend_SDDI_Vs_Limestone_HighPor_Vp_Z ^ 2) ;

$MuSat_Init_Limestone_SDDI_GPa = $MuSat_Init_Limestone_SDDI_Pa * (10 ^ -6) ;

$KDry_Limestone_SDDI_Num = ($KSat_Init_Limestone_SDDI_GPa * ((($Trend_SDDI_Por_Limestone_HighPor_Vp_Z * $K_Lst_Matrix) / $K_Fluid_Brine100) + 1 - $Trend_SDDI_Por_Limestone_HighPor_Vp_Z)) - $K_Lst_Matrix ;

$KDry_Limestone_SDDI_Den = (($Trend_SDDI_Por_Limestone_HighPor_Vp_Z * $K_Lst_Matrix) / $K_Fluid_Brine100) + ($KSat_Init_Limestone_SDDI_GPa / $K_Lst_Matrix) - 1 - $Trend_SDDI_Por_Limestone_HighPor_Vp_Z ;

$KDry_Limestone_SDDI_GPa = $KDry_Limestone_SDDI_Num / $KDry_Limestone_SDDI_Den ;

// Limestone Vp_Z (SDDI) Dry to Oil80

$KSat_Final_Limestone_SDDI_Oil80_Num = (1 - ($KDry_Limestone_SDDI_GPa / $K_Lst_Matrix)) ^ 2 ;

$KSat_Final_Limestone_SDDI_Oil80_Den = ($Trend_SDDI_Por_Limestone_HighPor_Vp_Z / $K_Fluid_Oil80) + ((1 - $Trend_SDDI_Por_Limestone_HighPor_Vp_Z) / $K_Lst_Matrix) - ($KDry_Limestone_SDDI_GPa / ($K_Lst_Matrix ^ 2)) ;

$KSat_Final_Limestone_SDDI_Oil80_GPa = $KDry_Limestone_SDDI_GPa + ($KSat_Final_Limestone_SDDI_Oil80_Num / $KSat_Final_Limestone_SDDI_Oil80_Den) ;

$Calc_Rho_Limestone_Por_Vp_Oil80 = ($Trend_SDDI_Por_Limestone_HighPor_Vp_Z * $Rho_Fluid_Oil80) + ((1 - $Trend_SDDI_Por_Limestone_HighPor_Vp_Z) * $Rho_Lst_Matrix) ;

$Calc_Vp_Limestone_Z_Oil80 = (sqrt (($KSat_Final_Limestone_SDDI_Oil80_GPa + ((4 / 3) * $MuSat_Init_Limestone_SDDI_GPa)) / $Calc_Rho_Limestone_Por_Vp_Oil80)) * (10 ^ 3) ;

$Calc_Vs_Limestone_Vp_Z_Oil80 = (sqrt ($MuSat_Init_Limestone_SDDI_GPa / $Calc_Rho_Limestone_Por_Vp_Oil80)) * (10 ^ 3) ;

```
// Limestone Vp_Z (SDDI) Dry to Gas90

$KSat_Final_Limestone_SDDI_Gas90_Num = ( 1 - ( $KDry_Limestone_SDDI_GPa / $K_Lst_Matrix )) ^ 2 ;

$KSat_Final_Limestone_SDDI_Gas90_Den = ( $Trend_SDDI_Por_Limestone_HighPor_Vp_Z / $K_Fluid_Gas90 ) + (( 1 - $Trend_SDDI_Por_Limestone_HighPor_Vp_Z ) / $K_Lst_Matrix ) - ( $KDry_Limestone_SDDI_GPa / ( $K_Lst_Matrix ^ 2 )) ;

$KSat_Final_Limestone_SDDI_Gas90_GPa = $KDry_Limestone_SDDI_GPa + ( $KSat_Final_Limestone_SDDI_Gas90_Num / $KSat_Final_Limestone_SDDI_Gas90_Den ) ;

$Calc_Rho_Limestone_Por_Vp_Gas90 = ( $Trend_SDDI_Por_Limestone_HighPor_Vp_Z * $Rho_Fluid_Gas90 ) + (( 1 - $Trend_SDDI_Por_Limestone_HighPor_Vp_Z ) * $Rho_Lst_Matrix ) ;

$Calc_Vp_Limestone_Z_Gas90 = ( sqrt (( $KSat_Final_Limestone_SDDI_Gas90_GPa + (( 4 / 3 ) * $MuSat_Init_Limestone_SDDI_GPa )) / $Calc_Rho_Limestone_Por_Vp_Gas90 )) * ( 10 ^ 3 ) ;

$Calc_Vs_Limestone_Vp_Z_Gas90 = ( sqrt ( $MuSat_Init_Limestone_SDDI_GPa / $Calc_Rho_Limestone_Por_Vp_Gas90 )) * ( 10 ^ 3 ) ;


// Sandstone Vp_Rho (Rck3D) to Dry

$KSat_Init_Sandstone_Rck3D_Pa = $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z * (( $Trend_Rck3D_Vp_Sandstone_HighPor_Rho ^ 2 ) - (( 4 / 3 ) * ( $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho ^ 2 ))) ;

$KSat_Init_Sandstone_Rck3D_GPa = $KSat_Init_Sandstone_Rck3D_Pa * ( 10 ^ -6 ) ;

$MuSat_Init_Sandstone_Rck3D_Pa = $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z * ( $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho ^ 2 ) ;

$MuSat_Init_Sandstone_Rck3D_GPa = $MuSat_Init_Sandstone_Rck3D_Pa * ( 10 ^ -6 ) ;

$KDry_Sandstone_Rck3D_Num = ( $KSat_Init_Sandstone_Rck3D_GPa * ((( $Trend_SDDI_Por_Sandstone_HighPor_Vp_Z * $K_Sst_Matrix ) / $K_Fluid_Brine100 ) + 1 - $Trend_Rck3D_Por_Sandstone_HighPor_Z )) - $K_Sst_Matrix ;

$KDry_Sandstone_Rck3D_Den = (( $Trend_Rck3D_Por_Sandstone_HighPor_Z * $K_Sst_Matrix ) / $K_Fluid_Brine100 ) + ( $KSat_Init_Sandstone_Rck3D_GPa / $K_Sst_Matrix ) - 1 - $Trend_Rck3D_Por_Sandstone_HighPor_Z ;

$KDry_Sandstone_Rck3D_GPa = $KDry_Sandstone_Rck3D_Num / $KDry_Sandstone_Rck3D_Den ;


// Sandstone Vp_Rho (Rck3D) to Oil80

$KSat_Final_Sandstone_Rck3D_Oil80_Num = ( 1 - ( $KDry_Sandstone_Rck3D_GPa / $K_Sst_Matrix )) ^ 2 ;

$KSat_Final_Sandstone_Rck3D_Oil80_Den = ( $Trend_Rck3D_Por_Sandstone_HighPor_Z / $K_Fluid_Oil80 ) + (( 1 - $Trend_Rck3D_Por_Sandstone_HighPor_Z ) / $K_Sst_Matrix ) - ( $KDry_Sandstone_Rck3D_GPa / ( $K_Sst_Matrix ^ 2 )) ;

$KSat_Final_Sandstone_Rck3D_Oil80_GPa = $KDry_Sandstone_Rck3D_GPa + ( $KSat_Final_Sandstone_Rck3D_Oil80_Num / $KSat_Final_Sandstone_Rck3D_Oil80_Den ) ;
```

$Calc_Rho_Sandstone_Por_Z_Oil80 = ($Trend_Rck3D_Por_Sandstone_HighPor_Z * $Rho_Fluid_Oil80) + ((1 - $Trend_Rck3D_Por_Sandstone_HighPor_Z) * $Rho_Sst_Matrix) ;

$Calc_Vp_Sandstone_Rho_Oil80 = (sqrt (($KSat_Final_Sandstone_Rck3D_Oil80_GPa + ((4 / 3) * $MuSat_Init_Sandstone_Rck3D_GPa)) / $Calc_Rho_Sandstone_Por_Z_Oil80)) * (10 ^ 3) ;

$Calc_Vs_Sandstone_Vp_Rho_Oil80 = (sqrt ($MuSat_Init_Sandstone_Rck3D_GPa / $Calc_Rho_Sandstone_Por_Z_Oil80)) * (10 ^ 3) ;

// Sandstone Vp_Rho (Rck3D) to Gas90

$KSat_Final_Sandstone_Rck3D_Gas90_Num = (1 - ($KDry_Sandstone_Rck3D_GPa / $K_Sst_Matrix)) ^ 2 ;

$KSat_Final_Sandstone_Rck3D_Gas90_Den = ($Trend_Rck3D_Por_Sandstone_HighPor_Z / $K_Fluid_Gas90) + ((1 - $Trend_Rck3D_Por_Sandstone_HighPor_Z) / $K_Sst_Matrix) - ($KDry_Sandstone_Rck3D_GPa / ($K_Sst_Matrix ^ 2)) ;

$KSat_Final_Sandstone_Rck3D_Gas90_GPa = $KDry_Sandstone_Rck3D_GPa + ($KSat_Final_Sandstone_Rck3D_Gas90_Num / $KSat_Final_Sandstone_Rck3D_Gas90_Den) ;

$Calc_Rho_Sandstone_Por_Z_Gas90 = ($Trend_Rck3D_Por_Sandstone_HighPor_Z * $Rho_Fluid_Gas90) + ((1 - $Trend_Rck3D_Por_Sandstone_HighPor_Z) * $Rho_Sst_Matrix) ;

$Calc_Vp_Sandstone_Rho_Gas90 = (sqrt (($KSat_Final_Sandstone_Rck3D_Gas90_GPa + ((4 / 3) * $MuSat_Init_Sandstone_Rck3D_GPa)) / $Calc_Rho_Sandstone_Por_Z_Gas90)) * (10 ^ 3) ;

$Calc_Vs_Sandstone_Vp_Rho_Gas90 = (sqrt ($MuSat_Init_Sandstone_Rck3D_GPa / $Calc_Rho_Sandstone_Por_Z_Gas90)) * (10 ^ 3) ;

// Limestone Vp_Rho (Rck3D) to Dry

$KSat_Init_Limestone_Rck3D_Pa = $Trend_Rck3D_Rho_Limestone_HighPor_Por_Z * (($Trend_Rck3D_Vp_Limestone_HighPor_Rho ^ 2) - ((4 / 3) * ($Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho ^ 2))) ;

$KSat_Init_Limestone_Rck3D_GPa = $KSat_Init_Limestone_Rck3D_Pa * (10 ^ -6) ;

$MuSat_Init_Limestone_Rck3D_Pa = $Trend_Rck3D_Rho_Limestone_HighPor_Por_Z * ($Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho ^ 2) ;

$MuSat_Init_Limestone_Rck3D_GPa = $MuSat_Init_Limestone_Rck3D_Pa * (10 ^ -6) ;

$KDry_Limestone_Rck3D_Num = ($KSat_Init_Limestone_Rck3D_GPa * ((($Trend_Rck3D_Por_Limestone_HighPor_Z * $K_Lst_Matrix) / $K_Fluid_Brine100) + 1 - $Trend_Rck3D_Por_Limestone_HighPor_Z)) - $K_Lst_Matrix ;

$KDry_Limestone_Rck3D_Den = (($Trend_Rck3D_Por_Limestone_HighPor_Z * $K_Lst_Matrix) / $K_Fluid_Brine100) + ($KSat_Init_Limestone_Rck3D_GPa / $K_Lst_Matrix) - 1 - $Trend_Rck3D_Por_Limestone_HighPor_Z ;

$KDry_Limestone_Rck3D_GPa = $KDry_Limestone_Rck3D_Num / $KDry_Limestone_Rck3D_Den ;

// Limestone Vp_Rho (Rck3D) to Oil80

$KSat_Final_Limestone_Rck3D_Oil80_Num = (1 - ($KDry_Limestone_Rck3D_GPa / $K_Lst_Matrix)) ^ 2 ;

$KSat_Final_Limestone_Rck3D_Oil80_Den = ($Trend_Rck3D_Por_Limestone_HighPor_Z / $K_Fluid_Oil80) + ((1 - $Trend_Rck3D_Por_Limestone_HighPor_Z) / $K_Lst_Matrix) - ($KDry_Limestone_Rck3D_GPa / ($K_Lst_Matrix ^ 2)) ;

$KSat_Final_Limestone_Rck3D_Oil80_GPa = $KDry_Limestone_Rck3D_GPa + ($KSat_Final_Limestone_Rck3D_Oil80_Num / $KSat_Final_Limestone_Rck3D_Oil80_Den) ;

$Calc_Rho_Limestone_Por_Z_Oil80 = ($Trend_Rck3D_Por_Limestone_HighPor_Z * $Rho_Fluid_Oil80) + ((1 - $Trend_Rck3D_Por_Limestone_HighPor_Z) * $Rho_Lst_Matrix) ;

$Calc_Vp_Limestone_Rho_Oil80 = (sqrt (($KSat_Final_Limestone_Rck3D_Oil80_GPa + ((4 / 3) * $MuSat_Init_Limestone_Rck3D_GPa)) / $Calc_Rho_Limestone_Por_Z_Oil80)) * (10 ^ 3) ;

$Calc_Vs_Limestone_Vp_Rho_Oil80 = (sqrt ($MuSat_Init_Limestone_Rck3D_GPa / $Calc_Rho_Limestone_Por_Z_Oil80)) * (10 ^ 3) ;

// Limestone Vp_Rho (Rck3D) to Gas90

$KSat_Final_Limestone_Rck3D_Gas90_Num = (1 - ($KDry_Limestone_Rck3D_GPa / $K_Lst_Matrix)) ^ 2 ;

$KSat_Final_Limestone_Rck3D_Gas90_Den = ($Trend_Rck3D_Por_Limestone_HighPor_Z / $K_Fluid_Gas90) + ((1 - $Trend_Rck3D_Por_Limestone_HighPor_Z) / $K_Lst_Matrix) - ($KDry_Limestone_Rck3D_GPa / ($K_Lst_Matrix ^ 2)) ;

$KSat_Final_Limestone_Rck3D_Gas90_GPa = $KDry_Limestone_Rck3D_GPa + ($KSat_Final_Limestone_Rck3D_Gas90_Num / $KSat_Final_Limestone_Rck3D_Gas90_Den) ;

$Calc_Rho_Limestone_Por_Z_Gas90 = ($Trend_Rck3D_Por_Limestone_HighPor_Z * $Rho_Fluid_Gas90) + ((1 - $Trend_Rck3D_Por_Limestone_HighPor_Z) * $Rho_Lst_Matrix) ;

$Calc_Vp_Limestone_Rho_Gas90 = (sqrt (($KSat_Final_Limestone_Rck3D_Gas90_GPa + ((4 / 3) * $MuSat_Init_Limestone_Rck3D_GPa)) / $Calc_Rho_Limestone_Por_Z_Gas90)) * (10 ^ 3) ;

$Calc_Vs_Limestone_Vp_Rho_Gas90 = (sqrt ($MuSat_Init_Limestone_Rck3D_GPa / $Calc_Rho_Limestone_Por_Z_Gas90)) * (10 ^ 3) ;

//

// 5. Fluid substituted sandstone log selected over Horda Fm to Lista Fm

//   Fluid substituted limestone log selected over Maureen Fm to Hod Fm

//   Zero values within end-member and synthetic logs replace with 'null' value

if (1. Horda Fm OR 2. Balder Fm OR 3. Sele Fm OR 4. Lista Fm)

if ($Calc_Rho_Sandstone_Por_Vp_Oil80 = 0.0)

    $Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Oil80 = null ;

    else

    $Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Oil80 = $Calc_Rho_Sandstone_Por_Vp_Oil80 ;

```
endif;
if ( $Calc_Vp_Sandstone_Z_Oil80 = 0.0 )
        $Trend_SDDI_Vp_Sandstone_HighPor_Z_Oil80 = null ;
        else
        $Trend_SDDI_Vp_Sandstone_HighPor_Z_Oil80 = $Calc_Vp_Sandstone_Z_Oil80 ;
endif;
if ( $Calc_Vs_Sandstone_Vp_Z_Oil80 = 0.0 )
        $Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Oil80 = null ;
        else
        $Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Oil80 = $Calc_Vs_Sandstone_Vp_Z_Oil80 ;
endif;

if ( $Calc_Rho_Sandstone_Por_Vp_Gas90 = 0.0 )
        $Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Gas90 = null ;
        else
        $Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Gas90                    =
$Calc_Rho_Sandstone_Por_Vp_Gas90 ;
endif;
if ( $Calc_Vp_Sandstone_Z_Gas90 = 0.0 )
        $Trend_SDDI_Vp_Sandstone_HighPor_Z_Gas90 = null ;
        else
        $Trend_SDDI_Vp_Sandstone_HighPor_Z_Gas90 = $Calc_Vp_Sandstone_Z_Gas90 ;
endif;
if ( $Calc_Vs_Sandstone_Vp_Z_Gas90 = 0.0 )
        $Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Gas90 = null ;
        else
        $Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Gas90 = $Calc_Vs_Sandstone_Vp_Z_Gas90 ;
endif;

if ( $Calc_Rho_Sandstone_Por_Z_Oil80 = 0.0 )
        $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Oil80 = null ;
        else
        $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Oil80 = $Calc_Rho_Sandstone_Por_Z_Oil80
;
endif;
if ( $Calc_Vp_Sandstone_Rho_Oil80 = 0.0 )
```

```
        $Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Oil80 = null ;
        else
        $Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Oil80 = $Calc_Vp_Sandstone_Rho_Oil80 ;
endif;
if ( $Calc_Vs_Sandstone_Vp_Rho_Oil80 = 0.0 )
        $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Oil80 = null ;
        else
        $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Oil80 =
$Calc_Vs_Sandstone_Vp_Rho_Oil80 ;
endif;

if ( $Calc_Rho_Sandstone_Por_Z_Gas90 = 0.0 )
        $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Gas90 = null ;
        else
        $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Gas90 =
$Calc_Rho_Sandstone_Por_Z_Gas90 ;
endif;
if ( $Calc_Vp_Sandstone_Rho_Gas90 = 0.0 )
        $Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Gas90 = null ;
        else
        $Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Gas90 = $Calc_Vp_Sandstone_Rho_Gas90 ;
endif;
if ( $Calc_Vs_Sandstone_Vp_Rho_Gas90 = 0.0 )
        $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Gas90 = null ;
        else
        $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Gas90 =
$Calc_Vs_Sandstone_Vp_Rho_Gas90 ;
endif;
endif;

if ( 5. Maureen Fm OR 6. Ekofisk Fm OR 7. Tor Fm OR 8. Hod Fm )

if ( $Calc_Rho_Limestone_Por_Vp_Oil80 = 0.0 )
        $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Oil80 = null ;
        else
        $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Oil80 =
$Calc_Rho_Limestone_Por_Vp_Oil80 ;
```

```
endif;
if ( $Calc_Vp_Limestone_Z_Oil80 = 0.0 )
        $Trend_SDDI_Vp_Limestone_HighPor_Z_Oil80 = null ;
        else
        $Trend_SDDI_Vp_Limestone_HighPor_Z_Oil80 = $Calc_Vp_Limestone_Z_Oil80 ;
endif;
if ( $Calc_Vs_Limestone_Vp_Z_Oil80 = 0.0 )
        $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Oil80 = null ;
        else
        $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Oil80 = $Calc_Vs_Limestone_Vp_Z_Oil80 ;
endif;

if ( $Calc_Rho_Limestone_Por_Vp_Gas90 = 0.0 )
        $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Gas90 = null ;
        else
        $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Gas90                                   =
$Calc_Rho_Limestone_Por_Vp_Gas90 ;
endif;
if ( $Calc_Vp_Limestone_Z_Gas90 = 0.0 )
        $Trend_SDDI_Vp_Limestone_HighPor_Z_Gas90 = null ;
        else
        $Trend_SDDI_Vp_Limestone_HighPor_Z_Gas90 = $Calc_Vp_Limestone_Z_Gas90 ;
endif;
if ( $Calc_Vs_Limestone_Vp_Z_Gas90 = 0.0 )
        $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Gas90 = null ;
        else
        $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Gas90 = $Calc_Vs_Limestone_Vp_Z_Gas90 ;
endif;

if ( $Calc_Rho_Limestone_Por_Z_Oil80 = 0.0 )
        $Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Oil80 = null ;
        else
        $Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Oil80  =  $Calc_Rho_Limestone_Por_Z_Oil80
;
endif;
if ( $Calc_Vp_Limestone_Rho_Oil80 = 0.0 )
```

```
        $Trend_Rck3D_Vp_Limestone_HighPor_Rho_Oil80 = null ;
        else
        $Trend_Rck3D_Vp_Limestone_HighPor_Rho_Oil80 = $Calc_Vp_Limestone_Rho_Oil80 ;
endif;
if ( $Calc_Vs_Limestone_Vp_Rho_Oil80 = 0.0 )
        $Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Oil80 = null ;
        else
        $Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Oil80 =
$Calc_Vs_Limestone_Vp_Rho_Oil80 ;
endif;

if ( $Calc_Rho_Limestone_Por_Z_Gas90 = 0.0 )
        $Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Gas90 = null ;
        else
        $Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Gas90 =
$Calc_Rho_Limestone_Por_Z_Gas90 ;
endif;
if ( $Calc_Vp_Limestone_Rho_Gas90 = 0.0 )
        $Trend_Rck3D_Vp_Limestone_HighPor_Rho_Gas90 = null ;
        else
        $Trend_Rck3D_Vp_Limestone_HighPor_Rho_Gas90 = $Calc_Vp_Limestone_Rho_Gas90 ;
endif;
if ( $Calc_Vs_Limestone_Vp_Rho_Gas90 = 0.0 )
        $Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Gas90 = null ;
        else
        $Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Gas90 =
$Calc_Vs_Limestone_Vp_Rho_Gas90 ;
endif;
endif;

/////////////////////////////////////////////////////////////////////////////////

$Trend_SDDI_AI_Sandstone_HighPor_Vp_Z_Oil80 = $Trend_SDDI_Vp_Sandstone_HighPor_Z_Oil80
* $Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Oil80 ;

$Trend_SDDI_SI_Sandstone_HighPor_Vp_Z_Oil80 =
$Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Oil80 *
$Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Oil80 ;
```

$Trend_SDDI_VpVs_Sandstone_HighPor_Z_Oil80 = $Trend_SDDI_Vp_Sandstone_HighPor_Z_Oil80 / $Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Oil80 ;

$Trend_SDDI_AI_Sandstone_HighPor_Vp_Z_Gas90 = $Trend_SDDI_Vp_Sandstone_HighPor_Z_Gas90 * $Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Gas90 ;

$Trend_SDDI_SI_Sandstone_HighPor_Vp_Z_Gas90 = $Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Gas90 * $Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Gas90 ;

$Trend_SDDI_VpVs_Sandstone_HighPor_Z_Gas90 = $Trend_SDDI_Vp_Sandstone_HighPor_Z_Gas90 / $Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Gas90 ;

$Trend_SDDI_AI_Limestone_HighPor_Vp_Z_Oil80 = $Trend_SDDI_Vp_Limestone_HighPor_Z_Oil80 * $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Oil80 ;

$Trend_SDDI_SI_Limestone_HighPor_Vp_Z_Oil80 = $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Oil80 * $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Oil80 ;

$Trend_SDDI_VpVs_Limestone_HighPor_Z_Oil80 = $Trend_SDDI_Vp_Limestone_HighPor_Z_Oil80 / $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Oil80 ;

$Trend_SDDI_AI_Limestone_HighPor_Vp_Z_Gas90 = $Trend_SDDI_Vp_Limestone_HighPor_Z_Gas90 * $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Gas90 ;

$Trend_SDDI_SI_Limestone_HighPor_Vp_Z_Gas90 = $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Gas90 * $Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Gas90 ;

$Trend_SDDI_VpVs_Limestone_HighPor_Z_Gas90 = $Trend_SDDI_Vp_Limestone_HighPor_Z_Gas90 / $Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Gas90 ;

$Trend_Rck3D_AI_Sandstone_HighPor_Vp_Rho_Oil80 = $Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Oil80 * $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Oil80 ;

$Trend_Rck3D_SI_Sandstone_HighPor_Vp_Rho_Oil80 = $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Oil80 * $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Oil80 ;

$Trend_Rck3D_VpVs_Sandstone_HighPor_Rho_Oil80 = $Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Oil80 / $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Oil80 ;

$Trend_Rck3D_AI_Sandstone_HighPor_Vp_Rho_Gas90 = $Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Gas90 * $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Gas90 ;

$Trend_Rck3D_SI_Sandstone_HighPor_Vp_Rho_Gas90 = $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Gas90 * $Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Gas90 ;

$Trend_Rck3D_VpVs_Sandstone_HighPor_Rho_Gas90 = $Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Gas90 / $Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Gas90 ;

```
$Trend_Rck3D_AI_Limestone_HighPor_Vp_Rho_Oil80                              =
$Trend_Rck3D_Vp_Limestone_HighPor_Rho_Oil80                                 *
$Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Oil80 ;

$Trend_Rck3D_SI_Limestone_HighPor_Vp_Rho_Oil80                              =
$Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Oil80                              *
$Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Oil80 ;

$Trend_Rck3D_VpVs_Limestone_HighPor_Rho_Oil80                               =
$Trend_Rck3D_Vp_Limestone_HighPor_Rho_Oil80                                 /
$Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Oil80 ;

$Trend_Rck3D_AI_Limestone_HighPor_Vp_Rho_Gas90                              =
$Trend_Rck3D_Vp_Limestone_HighPor_Rho_Gas90                                 *
$Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Gas90 ;

$Trend_Rck3D_SI_Limestone_HighPor_Vp_Rho_Gas90                              =
$Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Gas90                              *
$Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Gas90 ;

$Trend_Rck3D_VpVs_Limestone_HighPor_Rho_Gas90                               =
$Trend_Rck3D_Vp_Limestone_HighPor_Rho_Gas90                                 /
$Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Gas90 ;

/////////////////////////////////////////////////////////////////////////////////

// 6. Defines which logs are output by the script

save ($Trend_SDDI_Vp_Sandstone_HighPor_Z_Oil80) ;
save ($Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Oil80) ;
save ($Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Oil80) ;
save ($Trend_SDDI_AI_Sandstone_HighPor_Vp_Z_Oil80) ;
save ($Trend_SDDI_SI_Sandstone_HighPor_Vp_Z_Oil80) ;
save ($Trend_SDDI_VpVs_Sandstone_HighPor_Z_Oil80) ;
save ($Trend_SDDI_Vp_Sandstone_HighPor_Z_Gas90) ;
save ($Trend_SDDI_Vs_Sandstone_HighPor_Vp_Z_Gas90) ;
save ($Trend_SDDI_Rho_Sandstone_HighPor_Por_Vp_Gas90) ;
save ($Trend_SDDI_AI_Sandstone_HighPor_Vp_Z_Gas90) ;
save ($Trend_SDDI_SI_Sandstone_HighPor_Vp_Z_Gas90) ;
save ($Trend_SDDI_VpVs_Sandstone_HighPor_Z_Gas90) ;

save ($Trend_SDDI_Vp_Limestone_HighPor_Z_Oil80) ;
save ($Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Oil80) ;
```

save ($Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Oil80) ;
save ($Trend_SDDI_AI_Limestone_HighPor_Vp_Z_Oil80) ;
save ($Trend_SDDI_SI_Limestone_HighPor_Vp_Z_Oil80) ;
save ($Trend_SDDI_VpVs_Limestone_HighPor_Z_Oil80) ;
save ($Trend_SDDI_Vp_Limestone_HighPor_Z_Gas90) ;
save ($Trend_SDDI_Vs_Limestone_HighPor_Vp_Z_Gas90) ;
save ($Trend_SDDI_Rho_Limestone_HighPor_Por_Vp_Gas90) ;
save ($Trend_SDDI_AI_Limestone_HighPor_Vp_Z_Gas90) ;
save ($Trend_SDDI_SI_Limestone_HighPor_Vp_Z_Gas90) ;
save ($Trend_SDDI_VpVs_Limestone_HighPor_Z_Gas90) ;

save ($Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Oil80) ;
save ($Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Oil80) ;
save ($Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Oil80) ;
save ($Trend_Rck3D_AI_Sandstone_HighPor_Vp_Rho_Oil80) ;
save ($Trend_Rck3D_SI_Sandstone_HighPor_Vp_Rho_Oil80) ;
save ($Trend_Rck3D_VpVs_Sandstone_HighPor_Rho_Oil80) ;
save ($Trend_Rck3D_Vp_Sandstone_HighPor_Rho_Gas90) ;
save ($Trend_Rck3D_Vs_Sandstone_HighPor_Vp_Rho_Gas90) ;
save ($Trend_Rck3D_Rho_Sandstone_HighPor_Por_Z_Gas90) ;
save ($Trend_Rck3D_AI_Sandstone_HighPor_Vp_Rho_Gas90) ;
save ($Trend_Rck3D_SI_Sandstone_HighPor_Vp_Rho_Gas90) ;
save ($Trend_Rck3D_VpVs_Sandstone_HighPor_Rho_Gas90) ;

save ($Trend_Rck3D_Vp_Limestone_HighPor_Rho_Oil80) ;
save ($Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Oil80) ;
save ($Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Oil80) ;
save ($Trend_Rck3D_AI_Limestone_HighPor_Vp_Rho_Oil80) ;
save ($Trend_Rck3D_SI_Limestone_HighPor_Vp_Rho_Oil80) ;
save ($Trend_Rck3D_VpVs_Limestone_HighPor_Rho_Oil80) ;
save ($Trend_Rck3D_Vp_Limestone_HighPor_Rho_Gas90) ;
save ($Trend_Rck3D_Vs_Limestone_HighPor_Vp_Rho_Gas90) ;
save ($Trend_Rck3D_Rho_Limestone_HighPor_Por_Z_Gas90) ;
save ($Trend_Rck3D_AI_Limestone_HighPor_Vp_Rho_Gas90) ;
save ($Trend_Rck3D_SI_Limestone_HighPor_Vp_Rho_Gas90) ;
save ($Trend_Rck3D_VpVs_Limestone_HighPor_Rho_Gas90) ;

G.4 – Modelled Vs and RHOB (from Vp_FSUB_BRINE_GP)

```
// RokDoc User Programmer Custom Script:
// Modelled Vs and RHOB (from Vp_FSUB_BRINE_GP)

// Input - Vp_FSUB_BRINE_GP
// Output - Vs_FSUB_BRINE_MODELLED_GC, RHOB_FSUB_BRINE_MODELLED
// Description - Uses GC/Backus averaging to model Vs and Rho for use in log conditioning

// 1. Define the input logs used within the script

$Vp = Vp ;
$Depth = Depth ;
$Volume_Shale = Volume ;
$Volume_Sandstone = Volume ;
$Volume_Limestone = Volume ;
$Volume_Tuff = Volume ;

$Use_Sandstone = FLAG_End_Member ;

// 2. Define the multi-well rock physics templates
// nb: It is important to use the same trend types used within the project
//     See report/ multi-well ppts for further details

/////////////////////////////////////////////////////////////////////////////////////
////////////////////////// Define RPM in the form y=mx+c ///////////////////////////
/////////////////////////////////////////////////////////////////////////////////////

// nb: Rock physics templates are sorted on a working interval then lithology basis
//     Where a lithology is not present, this is shown by $<lithology> = 0.0

// Horda Formation - contains no limestone or tuff
if ( 1. Horda Fm )

// Non-Reservoir Relationships
```

```
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.2922942 ;
$Vp_Z_Shale_Soft_c = 5233.447 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.2571209 ;
$Vp_Z_Shale_Hard_c = 6198.616 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.7057037 ;
$Vs_Vp_Shale_c = -2465.212 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1066255 ;
$Rho_Vp_Shale_n = 0.3432433 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_LowPor_m = 0.660582 ;
$Vp_Z_Sandstone_LowPor_c = 5583.154 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_LowPor_m = -0.00003584127 ;
$Por_Z_Sandstone_LowPor_c = 0.5508362 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_LowPor_m2 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m1 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_c = 0.0 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 0.660582 ;
$Vp_Z_Sandstone_HighPor_c = 5583.154 ;
// Por (from Por-Depth)
```

```
$Por_Z_Sandstone_HighPor_m = -0.00003584127 ;
$Por_Z_Sandstone_HighPor_c = 0.5508362 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_HighPor_m = 0.7596545 ;
$Vs_Vp_Sandstone_HighPor_c = -2064.222 ;
// Shared Trends
// Rho (from Rho-Vp)
$Rho_Vp_Sandstone_m = 0.1698896 ;
$Rho_Vp_Sandstone_n = 0.2765268 ;
// Rho (from Rho-Por)
$Rho_Por_Sandstone_m = -1.611234 ;
$Rho_Por_Sandstone_c = 2.65 ;
// Por (from Vp-Por)
$Por_Vp_Sandstone_m2 = 0.0000000002163757 ;
$Por_Vp_Sandstone_m1 = -0.00004096828 ;
$Por_Vp_Sandstone_c = 0.6917572 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 0.0 ;

else
// Balder Formation - contains no limestone
if ( 2. Balder Fm )

// Non-Reservoir Relationships
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.4515433 ;
$Vp_Z_Shale_Soft_c = 5153.091 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.4515433 ;
$Vp_Z_Shale_Hard_c = 5153.091 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.9232975 ;
$Vs_Vp_Shale_c = -4065.238 ;
```

```
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.2392956 ;
$Rho_Vp_Shale_n = 0.2539949 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 1.0 ;
// Vp (from Vp-Depth)
$Vp_Z_Tuff_m = 0.7812615 ;
$Vp_Z_Tuff_c = 3411.229 ;
// Vs (from Vs-Vp)
$Vs_Vp_Tuff_m = 0.9711005 ;
$Vs_Vp_Tuff_c = -4225.107 ;
// Rho (from Rho-Vp)
$Rho_Vp_Tuff_m = 0.52428 ;
$Rho_Vp_Tuff_c = -2.39628 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_LowPor_m = 1.023924 ;
$Vp_Z_Sandstone_LowPor_c = 2127.82 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_LowPor_m = -0.00003770699 ;
$Por_Z_Sandstone_LowPor_c = 0.58089 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_LowPor_m2 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m1 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_c = 0.0 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 1.023924 ;
$Vp_Z_Sandstone_HighPor_c = 2127.82 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_HighPor_m = -0.00003770699 ;
$Por_Z_Sandstone_HighPor_c = 0.58089 ;
```

// Vs (from Vs-Vp)

$Vs_Vp_Sandstone_HighPor_m = 0.80416 ;

$Vs_Vp_Sandstone_HighPor_c = -2808.005 ;

// Shared Trends

// Rho (from Rho-Vp)

$Rho_Vp_Sandstone_m = 0.2609613 ;

$Rho_Vp_Sandstone_n = 0.2305883 ;

// Rho (from Rho-Por)

$Rho_Por_Sandstone_m = -1.607725 ;

$Rho_Por_Sandstone_c = 2.65 ;

// Por (from Vp-Por)

$Por_Vp_Sandstone_m2 = 0.0000000001726589 ;

$Por_Vp_Sandstone_m1 = -0.00003894957 ;

$Por_Vp_Sandstone_c = 0.6692793 ;

// Brine-Bearing Reservoir Relationships (Limestone)

$Limestone = 0.0 ;

else

// Sele Formation - contains no limestone or tuff

if (3. Sele Fm)

// Non-Reservoir Relationships

// Vp (from Vp-Depth)

// Soft Trends

$Vp_Z_Shale_Soft_m = 0.5072923 ;

$Vp_Z_Shale_Soft_c = 4640.669 ;

// Hard Trends

$Vp_Z_Shale_Hard_m = 0.5420831 ;

$Vp_Z_Shale_Hard_c = 5362.252 ;

// Shared Trends

// Vs (from Vs-Vp)

$Vs_Vp_Shale_m = 0.7655861 ;

$Vs_Vp_Shale_c = -2640.943 ;

// Rho (from Rho-Vp)

$Rho_Vp_Shale_m = 0.1832278 ;

```
$Rho_Vp_Shale_n = 0.2830127 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_LowPor_m = 0.5542149 ;
$Vp_Z_Sandstone_LowPor_c = 6430.183 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_LowPor_m = -0.00002654017 ;
$Por_Z_Sandstone_LowPor_c = 0.4426344 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_LowPor_m2 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m1 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_c = 0.0 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 0.6740104 ;
$Vp_Z_Sandstone_HighPor_c = 3979.824 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_HighPor_m = -0.00003721717 ;
$Por_Z_Sandstone_HighPor_c = 0.6085076 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_HighPor_m = 0.9720799 ;
$Vs_Vp_Sandstone_HighPor_c = -4702.516 ;
// Shared Trends
// Rho (from Rho-Vp)
$Rho_Vp_Sandstone_m = 0.12631 ;
$Rho_Vp_Sandstone_n = 0.3115259 ;
// Rho (from Rho-Por)
$Rho_Por_Sandstone_m = -1.608423 ;
$Rho_Por_Sandstone_c = 2.65 ;
// Por (from Vp-Por)
```

```
$Por_Vp_Sandstone_m2 = 0.000000001773932 ;
$Por_Vp_Sandstone_m1 = -0.00008149762 ;
$Por_Vp_Sandstone_c = 0.904825 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 0.0 ;

else
// Lista Formation - contains no tuff
if ( 4. Lista Fm )

// Non-Reservoir Relationships
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5780684 ;
$Vp_Z_Shale_Soft_c = 3817.599 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.6624602 ;
$Vp_Z_Shale_Hard_c = 4252.494 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.758194 ;
$Vs_Vp_Shale_c = -2709.194 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1700515 ;
$Rho_Vp_Shale_n = 0.2902445 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_LowPor_m = 0.8167227 ;
$Vp_Z_Sandstone_LowPor_c = 6191.856 ;
```

// Por (from Por-Depth)

$Por_Z_Sandstone_LowPor_m = -0.0000318877 ;

$Por_Z_Sandstone_LowPor_c = 0.3770017 ;

// Vs (from Vs-Vp)

$Vs_Vp_Sandstone_LowPor_m2 = -0.0000173188832737427 ;

$Vs_Vp_Sandstone_LowPor_m1 = 1.02637492252863 ;

$Vs_Vp_Sandstone_LowPor_c = -3384.8165155481 ;

// High Porosity Trends

// Vp (from Vp-Depth)

$Vp_Z_Sandstone_HighPor_m = 0.4780259 ;

$Vp_Z_Sandstone_HighPor_c = 7035.789 ;

// Por (from Por-Depth)

$Por_Z_Sandstone_HighPor_m = -0.00003110392 ;

$Por_Z_Sandstone_HighPor_c = 0.4798181 ;

// Vs (from Vs-Vp)

$Vs_Vp_Sandstone_HighPor_m = 0.7639454 ;

$Vs_Vp_Sandstone_HighPor_c = -2484.919 ;

// Shared Trends

// Rho (from Rho-Vp)

$Rho_Vp_Sandstone_m = 0.1235797 ;

$Rho_Vp_Sandstone_n = 0.3157153 ;

// Rho (from Rho-Por)

$Rho_Por_Sandstone_m = -1.622425 ;

$Rho_Por_Sandstone_c = 2.65 ;

// Por (from Vp-Por)

$Por_Vp_Sandstone_m2 = 0.000000001529275 ;

$Por_Vp_Sandstone_m1 = -0.00007601945 ;

$Por_Vp_Sandstone_c = 0.8522162 ;

// Brine-Bearing Reservoir Relationships (Limestone) (from Maureen Fm)

$Limestone = 1.0 ;

// Low Porosity Trends

// Vp (from Vp-Depth)

$Vp_Z_Limestone_LowPor_m = 0.9858379 ;

$Vp_Z_Limestone_LowPor_c = 6847.396 ;

// Por (from Por-Depth)

```
$Por_Z_Limestone_LowPor_m = -0.00001937362 ;
$Por_Z_Limestone_LowPor_c = 0.2537034 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_HighPor_m = 1.17964 ;
$Vp_Z_Limestone_HighPor_c = 2948.817 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.00002767867 ;
$Por_Z_Limestone_HighPor_c = 0.397615 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.00002212974 ;
$Vs_Vp_Limestone_m1 = 1.21382 ;
$Vs_Vp_Limestone_c = -4983.408 ;
// Rho (from Rho-Vp)
$Rho_Vp_Limestone_m = 0.594 ;
$Rho_Vp_Limestone_c = -3.18998 ;
// Rho (from Rho-Por)
$Rho_Por_Limestone_m = -1.673549 ;
$Rho_Por_Limestone_c = 2.71 ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.0000000004114573 ;
$Por_Vp_Limestone_m1 = -0.00004001338 ;
$Por_Vp_Limestone_c = 0.6178595 ;

else
// Maureen Formation - contains no tuff
if ( 5. Maureen Fm )

// Non-Reservoir Relationships
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5966925 ;
$Vp_Z_Shale_Soft_c = 3923.665 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.588856 ;
```

$Vp_Z_Shale_Hard_c = 5630.318 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.693495 ;
$Vs_Vp_Shale_c = -2017.296 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1857183 ;
$Rho_Vp_Shale_n = 0.280225 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone) (from Maureen Fm)
$Sandstone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_LowPor_m = 1.096406 ;
$Vp_Z_Sandstone_LowPor_c = 3131.354 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_LowPor_m = -0.00005003434 ;
$Por_Z_Sandstone_LowPor_c = 0.5447623 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_LowPor_m2 = -0.0000173188832737427 ;
$Vs_Vp_Sandstone_LowPor_m1 = 1.02637492252863 ;
$Vs_Vp_Sandstone_LowPor_c = -3384.8165155481 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Sandstone_HighPor_m = 0.9648193 ;
$Vp_Z_Sandstone_HighPor_c = 3085.523 ;
// Por (from Por-Depth)
$Por_Z_Sandstone_HighPor_m = -0.00005051964 ;
$Por_Z_Sandstone_HighPor_c = 0.6525103 ;
// Vs (from Vs-Vp)
$Vs_Vp_Sandstone_HighPor_m = 0.7639454 ;
$Vs_Vp_Sandstone_HighPor_c = -2484.919 ;
// Shared Trends

```
// Rho (from Rho-Vp)
$Rho_Vp_Sandstone_m = 0.1222036 ;
$Rho_Vp_Sandstone_n = 0.3158323 ;
// Rho (from Rho-Por)
$Rho_Por_Sandstone_m = -1.608069 ;
$Rho_Por_Sandstone_c = 2.65 ;
// Por (from Vp-Por)
$Por_Vp_Sandstone_m2 = 0.000000001845871 ;
$Por_Vp_Sandstone_m1 = -0.0000824894 ;
$Por_Vp_Sandstone_c = 0.8976042 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_LowPor_m = 0.9858379 ;
$Vp_Z_Limestone_LowPor_c = 6847.396 ;
// Por (from Por-Depth)
$Por_Z_Limestone_LowPor_m = -0.00001937362 ;
$Por_Z_Limestone_LowPor_c = 0.2537034 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_HighPor_m = 1.17964 ;
$Vp_Z_Limestone_HighPor_c = 2948.817 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.00002767867 ;
$Por_Z_Limestone_HighPor_c = 0.397615 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.00002212974 ;
$Vs_Vp_Limestone_m1 = 1.21382 ;
$Vs_Vp_Limestone_c = -4983.408 ;
// Rho (from Rho-Vp)
$Rho_Vp_Limestone_m = 0.594 ;
$Rho_Vp_Limestone_c = -3.18998 ;
// Rho (from Rho-Por)
```

```
$Rho_Por_Limestone_m = -1.673549 ;
$Rho_Por_Limestone_c = 2.71 ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.0000000004114573 ;
$Por_Vp_Limestone_m1 = -0.00004001338 ;
$Por_Vp_Limestone_c = 0.6178595 ;

else
// Ekofisk Formation - contains no tuff
if ( 6. Ekofisk Fm )

// Trend used within synthetic generation - 0.0 = Soft and 1.0 = Hard
$Use_Shale = 1.0 ;

// Non-Reservoir Relationships (from Maureen Fm)
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5966925 ;
$Vp_Z_Shale_Soft_c = 3923.665 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.588856 ;
$Vp_Z_Shale_Hard_c = 5630.318 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.693495 ;
$Vs_Vp_Shale_c = -2017.296 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1857183 ;
$Rho_Vp_Shale_n = 0.280225 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 0.0 ;
```

```
// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_LowPor_m = 0.982537 ;
$Vp_Z_Limestone_LowPor_c = 5881.333 ;
// Por (from Por-Depth)
$Por_Z_Limestone_LowPor_m = -0.00001848521 ;
$Por_Z_Limestone_LowPor_c = 0.2637967 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_HighPor_m = 0.8729134 ;
$Vp_Z_Limestone_HighPor_c = 5203.576 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.00002017612 ;
$Por_Z_Limestone_HighPor_c = 0.3555333 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.00002553698 ;
$Vs_Vp_Limestone_m1 = 1.342143 ;
$Vs_Vp_Limestone_c = -6253.14 ;
// Rho (from Rho-Vp)
$Rho_Vp_Limestone_m = 0.74272 ;
$Rho_Vp_Limestone_c = -4.61654 ;
// Rho (from Rho-Por)
$Rho_Por_Limestone_m = -1.677809 ;
$Rho_Por_Limestone_c = 2.71    ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.00000000126444 ;
$Por_Vp_Limestone_m1 = -0.00006871545 ;
$Por_Vp_Limestone_c = 0.8542784 ;

else
// Tor Formation - contains no sandstone or tuff
if ( 7. Tor Fm )
```

// Trend used within synthetic generation - 0.0 = Soft and 1.0 = Hard

$Use_Shale = 1.0 ;

// Non-Reservoir Relationships (from Maureen Fm)

// Vp (from Vp-Depth)

// Soft Trends

$Vp_Z_Shale_Soft_m = 0.5966925 ;

$Vp_Z_Shale_Soft_c = 3923.665 ;

// Hard Trends

$Vp_Z_Shale_Hard_m = 0.588856 ;

$Vp_Z_Shale_Hard_c = 5630.318 ;

// Shared Trends

// Vs (from Vs-Vp)

$Vs_Vp_Shale_m = 0.693495 ;

$Vs_Vp_Shale_c = -2017.296 ;

// Rho (from Rho-Vp)

$Rho_Vp_Shale_m = 0.1857183 ;

$Rho_Vp_Shale_n = 0.280225 ;

// Non-Reservoir Relationships (Tuff)

$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)

$Sandstone = 0.0 ;

// Brine-Bearing Reservoir Relationships (Limestone)

$Limestone = 1.0 ;

// Low Porosity Trends

// Vp (from Vp-Depth)

$Vp_Z_Limestone_LowPor_m = 0.4740226 ;

$Vp_Z_Limestone_LowPor_c = 12488.51 ;

// Por (from Por-Depth)

$Por_Z_Limestone_LowPor_m = -0.000009372 ;

$Por_Z_Limestone_LowPor_c = 0.1406966 ;

// High Porosity Trends

// Vp (from Vp-Depth)

```
$Vp_Z_Limestone_HighPor_m = 1.011436 ;
$Vp_Z_Limestone_HighPor_c = 4483.004 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.0000252572 ;
$Por_Z_Limestone_HighPor_c = 0.3942969 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.000022813668 ;
$Vs_Vp_Limestone_m1 = 1.238671 ;
$Vs_Vp_Limestone_c = -5526.247 ;
// Rho (from Rho-Vp)
$Rho_Vp_Limestone_m = 0.74353 ;
$Rho_Vp_Limestone_c = -4.62711 ;
// Rho (from Rho-Por)
$Rho_Por_Limestone_m = -1.681826 ;
$Rho_Por_Limestone_c = 2.71 ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.000000001139213 ;
$Por_Vp_Limestone_m1 = -0.0000658779 ;
$Por_Vp_Limestone_c = 0.846066 ;

else
// Hod Formation - contains no sandstone or tuff
if ( 8. Hod Fm )

// Trend used within synthetic generation - 0.0 = Soft and 1.0 = Hard
$Use_Shale = 1.0 ;

// Non-Reservoir Relationships (from Maureen Fm)
// Vp (from Vp-Depth)
// Soft Trends
$Vp_Z_Shale_Soft_m = 0.5966925 ;
$Vp_Z_Shale_Soft_c = 3923.665 ;
// Hard Trends
$Vp_Z_Shale_Hard_m = 0.588856 ;
$Vp_Z_Shale_Hard_c = 5630.318 ;
```

```
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Shale_m = 0.693495 ;
$Vs_Vp_Shale_c = -2017.296 ;
// Rho (from Rho-Vp)
$Rho_Vp_Shale_m = 0.1857183 ;
$Rho_Vp_Shale_n = 0.280225 ;

// Non-Reservoir Relationships (Tuff)
$Tuff = 0.0 ;

// Brine-Bearing Reservoir Relationships (Sandstone)
$Sandstone = 0.0 ;

// Brine-Bearing Reservoir Relationships (Limestone)
$Limestone = 1.0 ;
// Low Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_LowPor_m = 0.537352 ;
$Vp_Z_Limestone_LowPor_c = 11248.14 ;
// Por (from Por-Depth)
$Por_Z_Limestone_LowPor_m = -0.000009445337 ;
$Por_Z_Limestone_LowPor_c = 0.157783 ;
// High Porosity Trends
// Vp (from Vp-Depth)
$Vp_Z_Limestone_HighPor_m = 0.56478 ;
$Vp_Z_Limestone_HighPor_c = 8753.391 ;
// Por (from Por-Depth)
$Por_Z_Limestone_HighPor_m = -0.00001273299 ;
$Por_Z_Limestone_HighPor_c = 0.2384544 ;
// Shared Trends
// Vs (from Vs-Vp)
$Vs_Vp_Limestone_m2 = -0.000023837095 ;
$Vs_Vp_Limestone_m1 = 1.171225 ;
$Vs_Vp_Limestone_c = -3974.697 ;
// Rho (from Rho-Vp)
```

```
$Rho_Vp_Limestone_m = 0.51197 ;
$Rho_Vp_Limestone_c = -2.36269 ;
// Rho (from Rho-Por)
$Rho_Por_Limestone_m = -1.645595 ;
$Rho_Por_Limestone_c = 2.71 ;
// Por (from Vp-Por)
$Por_Vp_Limestone_m2 = 0.0000000001198912 ;
$Por_Vp_Limestone_m1 = -0.00002624041 ;
$Por_Vp_Limestone_c = 0.4607655 ;

endif;
endif;
endif;
endif;
endif;
endif;
endif;
endif;

/////////////////////////////////////////////////////////////////////////////////////
//////////////////////////////// DO NOT EDIT BELOW //////////////////////////////////
/////////////////////////////////////////////////////////////////////////////////////

// 3. Where lithology defined as 'not present', null rock physics templates are set-up automatically

if ( $Tuff = 0.0 )
$Vs_Vp_Tuff_m = 0.0 ;
$Vs_Vp_Tuff_c = 0.0 ;
$Rho_Vp_Tuff_m = 0.0 ;
$Rho_Vp_Tuff_n = 0.0 ;
endif;
if ( $Sandstone = 0.0 )
$Vs_Vp_Sandstone_LowPor_m2 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m1 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_c = 0.0 ;
$Vs_Vp_Sandstone_HighPor_m = 0.0 ;
```

```
$Vs_Vp_Sandstone_HighPor_c = 0.0 ;
$Rho_Vp_Sandstone_m = 0.0 ;
$Rho_Vp_Sandstone_n = 0.0 ;
endif;
if ( $Limestone = 0.0 )
$Vs_Vp_Limestone_m2 = 0.0 ;
$Vs_Vp_Limestone_m1 = 0.0 ;
$Vs_Vp_Limestone_c = 0.0 ;
$Rho_Vp_Limestone_m = 0.0 ;
$Rho_Vp_Limestone_n = 0.0 ;
endif;

////////////////////////////////////////////////////////////////////////////////////

// 4. Removes null values and normalises the volume logs to create a continuous volume set

if ($Volume_Shale = null)
 $Volume_Shale_Min = 0;
else
 if ($Volume_Shale > 1)
  $Volume_Shale_Min = 1;
 else
  if ($Volume_Shale < 0)
   $Volume_Shale_Min = 0;
  else
   $Volume_Shale_Min = $Volume_Shale;
  endif;
 endif;
endif;

if ($Volume_Sandstone = null)
 $Volume_Sandstone_Min = 0;
else
 if ($Volume_Sandstone > 1)
  $Volume_Sandstone_Min = 1;
 else
```

```
    if ($Volume_Sandstone < 0)
      $Volume_Sandstone_Min = 0;
    else
      $Volume_Sandstone_Min = $Volume_Sandstone;
    endif;
  endif;
endif;

if ($Volume_Limestone = null)
  $Volume_Limestone_Min = 0;
else
  if ($Volume_Limestone > 1)
    $Volume_Limestone_Min = 1;
  else
    if ($Volume_Limestone < 0)
      $Volume_Limestone_Min = 0;
    else
      $Volume_Limestone_Min = $Volume_Limestone;
    endif;
  endif;
endif;

if ($Volume_Tuff = null)
  $Volume_Tuff_Min = 0;
else
  if ($Volume_Tuff > 1)
    $Volume_Tuff_Min = 1;
  else
    if ($Volume_Tuff < 0)
      $Volume_Tuff_Min = 0;
    else
      $Volume_Tuff_Min = $Volume_Tuff;
    endif;
  endif;
endif;
```

```
$Summed = $Volume_Shale_Min + $Volume_Sandstone_Min + $Volume_Limestone_Min + $Vol-
ume_Tuff_Min ;

$Volume_Shale_Norm = $Volume_Shale_Min / $Summed;
$Volume_Sandstone_Norm = $Volume_Sandstone_Min / $Summed;
$Volume_Limestone_Norm = $Volume_Limestone_Min / $Summed;
$Volume_Tuff_Norm = $Volume_Tuff_Min / $Summed;

////////////////////////////////////////////////////////////////////////////////////

// 5. Modelling of Density and Vs logs

// nb: Density log created using arithmetic averaging

$RhosumCalc1 = 0.0 ;

if ( $Limestone = 0.0 )
$Rho_Vp_Limestone_m = 0.0 ;
$Rho_Vp_Limestone_c = 1.0 ;
endif;
if ( $Tuff = 0.0 )
$Rho_Vp_Tuff_m = 0.0 ;
$Rho_Vp_Tuff_c = 1.0 ;
endif;

$RhoMin1_Calc = $Rho_Vp_Shale_m * ( $Vp ^ $Rho_Vp_Shale_n ) ;
$RhosumCalc1 = $RhosumCalc1 + $RhoMin1_Calc * $Volume_Shale_Norm ;

$RhoMin2_Calc = $Rho_Vp_Sandstone_m * ( $Vp ^ $Rho_Vp_Sandstone_n ) ;
$RhosumCalc1 = $RhosumCalc1 + $RhoMin2_Calc * $Volume_Sandstone_Norm ;

$RhoMin3_Calc = ( $Rho_Vp_Limestone_m * ln ( $Vp )) + $Rho_Vp_Limestone_c ;
$RhosumCalc1 = $RhosumCalc1 + $RhoMin3_Calc * $Volume_Limestone_Norm ;

$RhoMin4_Calc = ( $Rho_Vp_Tuff_m * ln ( $Vp )) + $Rho_Vp_Tuff_c ;
$RhosumCalc1 = $RhosumCalc1 + $RhoMin4_Calc * $Volume_Tuff_Norm ;
```

```
// nb: Zero values within modelled Rho log replace with 'null' value

if ( $RhosumCalc1 = 0 )
  $RHOB_FSUB_BRINE_MODELLED = null ;
else
  $RHOB_FSUB_BRINE_MODELLED = $RhosumCalc1 ;
endif;

////////////////////////////////////////////////////////////////////////////////////

// nb: Vs log created using Backus averging

// nb: End-member sandstone curve is used to allow switching between low/high porosity sandstone
//     See report/ Rock Physics Part 2 ppts for further details

$VssumCalc1 = 0;
$VssumCalc2 = 0;

if ( $Sandstone = 0.0 )
$Vs_Vp_Sandstone_LowPor_m2 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_m1 = 0.0 ;
$Vs_Vp_Sandstone_LowPor_c = 1.0 ;
$Vs_Vp_Sandstone_HighPor_m = 0.0 ;
$Vs_Vp_Sandstone_HighPor_c = 1.0 ;
endif;
if ( $Limestone = 0.0 )
$Vs_Vp_Limestone_m2 = 0.0 ;
$Vs_Vp_Limestone_m1 = 0.0 ;
$Vs_Vp_Limestone_c = 1.0 ;
endif;
if ( $Tuff = 0.0 )
$Vs_Vp_Tuff_m = 0.0 ;
$Vs_Vp_Tuff_c = 1.0 ;
endif;
```

```
$VsMin1_Calc = ( $Vp * $Vs_Vp_Shale_m ) + $Vs_Vp_Shale_c ;
$VssumCalc1 = $VssumCalc1 + $VsMin1_Calc * $Volume_Shale_Norm ;
$VssumCalc2 = $VssumCalc2 + $Volume_Shale_Norm / $VsMin1_Calc ;

        if ( $Use_Sandstone = 1.0 )
$VsMin2_Calc = ( $Vp * $Vs_Vp_Sandstone_HighPor_m ) + $Vs_Vp_Sandstone_HighPor_c ;
        else
                if ( 1. Horda Fm OR 2. Balder Fm OR 3. Sele Fm )
$VsMin2_Calc = ( $Vp * $Vs_Vp_Sandstone_HighPor_m ) + $Vs_Vp_Sandstone_HighPor_c ;
                else
$VsMin2_Calc = (( $Vp ^ 2 ) * $Vs_Vp_Sandstone_LowPor_m2 ) + ( $Vp * $Vs_Vp_Sandstone_LowPor_m1 ) + $Vs_Vp_Sandstone_LowPor_c ;
                endif;
        endif;
$VssumCalc1 = $VssumCalc1 + $VsMin2_Calc * $Volume_Sandstone_Norm ;
$VssumCalc2 = $VssumCalc2 + $Volume_Sandstone_Norm / $VsMin2_Calc ;

$VsMin3_Calc = (( $Vp ^ 2 ) * $Vs_Vp_Limestone_m2 ) + ( $Vp * $Vs_Vp_Limestone_m1 ) + $Vs_Vp_Limestone_c ;
$VssumCalc1 = $VssumCalc1 + $VsMin3_Calc * $Volume_Limestone_Norm ;
$VssumCalc2 = $VssumCalc2 + $Volume_Limestone_Norm / $VsMin3_Calc ;

$VsMin4_Calc = ( $Vp * $Vs_Vp_Tuff_m ) + $Vs_Vp_Tuff_c ;
$VssumCalc1 = $VssumCalc1 + $VsMin4_Calc * $Volume_Tuff_Norm ;
$VssumCalc2 = $VssumCalc2 + $Volume_Tuff_Norm / $VsMin4_Calc ;

// nb: Zero values within modelled Vs log replace with 'null' value

if ($VssumCalc1 = 0 or $VssumCalc2 = 0)
  $Vs_FSUB_BRINE_MODELLED_GC = null ;
else
  $Vs_FSUB_BRINE_MODELLED_GC = ( $VssumCalc1 + 1.0 / $VssumCalc2 ) / 2.0 ;
endif;

////////////////////////////////////////////////////////////////////////////////
```

```
// 6. Sonic logs created of script Vp input and Vs output

$DT_FSUB_BRINE_GP = 1000000 / $Vp ;
$DTSM_FSUB_BRINE_MODELLED_GC = 1000000 / $Vs_FSUB_BRINE_MODELLED_GC ;

////////////////////////////////////////////////////////////////////////////////////

// 7. Define which logs are output by the script

save ($Vs_FSUB_BRINE_MODELLED_GC) ;
save ($RHOB_FSUB_BRINE_MODELLED) ;
save ($DT_FSUB_BRINE_GP ) ;
save ($DTSM_FSUB_BRINE_MODELLED_GC) ;
```

Appendix H – Annexes

H.1 – Petrophysics reports

See separate ZIP archive with evaluation reports and well panel plots per well

H.2 – Rock Physics Analysis Audit trail QC PPTs

See separate ZIP archives with QC PPTs for three steps in rock physics analysis per well

H.2.1 – QC PPT for Single Well Rock Physics Analysis - Part 1

See also chapter 2, section 2.1 (p. 29)

H.2.2 – QC PPT for Multi Well Rock Physics Analysis

See also chapter 2, section 2.2 (p.43)

H.2.3 – QC PPT for Single Well Rock Physics Analysis - Part 2

See also chapter 2, section 2.3 (p.91)

H.3 – Master spreadsheet

See separate ZIP archive with collection of all relevant data (also as embedded object below) and fluid data per well.

Shell_CNS_Study_Master.xlsx

H.4 – Single well reports

See separate ZIP archive with collection of all single well reports per well

See also Appendix F (p. 224)

H.5 – User programs

See separate ZIP archive with collection of user scripts for Invasion correction, end-member flag & synthetic curves, end member Gassmann substitution scripts generic & per well and modelling of Vs & RhoB curves.

H.6 – RokDoc project file

See separate RokDoc project file on dedicated RokDoc project disks:

GID : \\nlamvfsep045\rokdoc01\cns\Q-3054_RoknowledgeCNS_2012\RokDoc

Linux : /glb/eu/epe/data/rokdoc01/cns/Q-3054_RoknowledgeCNS_2012\RokDoc