FINAL FIELD DEVELOPMENT PLAN

THYLACINE AND GEOGRAPHE FIELDS

OFFSHORE OTWAY BASIN

OCTOBER 2003

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Otway Gas Project: Final Field Development Plan

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KEY TO ABBREVIATIONS

bar	barometric pressure
bbl	barrel
bbl/d	barrels per day
Bcf	Billion cubic feet
Bm3	Billion cubic metres
Btu/scf	British thermal units per standard cubic feet
CGR	Condensate Gas Ratio
CIIP	Condensate Initially in Place
CRA	Corrosion Resistant Alloy
DCQ	Daily Contract Quantity
DN	Diameter Nominal
DPI	Department of Primary Industries
DST	Drill Stem Test
EES	Environment Effects Statement
EIS	Environmental Impact Statement
EMV	Expected Monetary Value
FBHP	Flowing Bottom Hole Pressure
FMI	Formation Micro Imager
FMS	Formation Micro Scanner
FTHP	Flowing Tubing Head Pressure
FVF	Formation Volume Factor
FWL	Free Water Level
GIIP	Gas Initially in Place
GRV	Gross Rock Volume
GWC	Gas Water Contact
HDD	Horizontal Directionally Drilled
HFPT	Hydrocarbon Field Planning Tool
HKG	Highest Known Gas
HPV	Hydrocarbon Pore Volume
HSE	Health Safety & Environment
JV	Joint Venture
JVPs	Joint Venture Participants
Kh	Horizontal permeability
Kv	Vertical permeability
kJ/m3	kilojoules per cubic metre
kPa	Kilopascal
LAT	Lowest Astronomical Tide
LKG	Lowest Known Gas
LPG	Liquefied Petroleum Gas
Ma	Million years
MEG	mono ethylene glycol
mD	milliDarcy
MDQ	Maximum Daily Quantity
MDT	Multiple Dynamics Tester
ML	Most Likely

MMm3	Million cubic metres
MMscf	Million standard cubic feet
MMstb	Million stock tank barrels
MSCT	Mechanical Sidewall Coring Tool
mRT	metres below Rotary Table
mss	metres below subsea
m/s	metres per second
mTVDSS	metres True Vertical Depth subsea
N/G	Net to Gross
NPV	Net Present Value
NWBM	Non Water Based Mud
OPREP	Opportunity Realisation Process
PDHG	Permanent Down-Hole Pressure Gauges
PLT	Production Logging Test
POS	Probability of Success
ppm	parts per million
PSDM	Pre-Stack Depth Migration
P(SL)A	Petroleum (Submerged Lands) Act
psi	pounds per square inch
PJ/annum	Petajoules per annum
PU	Porosity Units
PVT	Pressure Volume Temperature
RCA	Routine Core Analysis
RE	Recovery Efficiency
RF	Recovery Factor
RFSU	Ready For Start Up
RFT	Repeat Formation Tester
ROP	Rate of Penetration
SCAL	Special Core Analysis
s.d.	standard deviation
SEM	Scanning Electron Microscope
SFR	Scope For Recovery
SGR	Shale Gouge Ratio
s.g.	specific gravity
ST	Side Track
Sw	Water saturation
TD	Total Depth
THP	Tubing Head Pressure
TJ/d	Terajoules per day
twt	two way time
UR	Ultimate Recovery
VOI	Value Of Information
WB	Water Bottom

1. EXECUTIVE SUMMARY

This is a submission to the Joint Authorities of the Finalised Field Development Plan for the Thylacine and Geographe Fields, offshore Otway Basin, South East Australia. The Field Development Plan is required for the application of Production Licences over graticular blocks 2795 and 2796 of Map Sheet SJ 54 within the Tasmanian exploration permit T/30P, and blocks 2723 and 2724 of Map Sheet SJ 54 within the Victorian exploration permit Vic/P43. The T/30P and Vic/P43 Joint Venture wishes to proceed with the commercial development of these fields by 2006.

The two separate fields, Thylacine and Geographe, are together expected to contain over 51 Bm3 (1800 Bcf) of gas in place. Both accumulations contain gas columns of around 300m. Reservoir quality is expected to be variable (poor to excellent) in both fields. The lower reservoir units communicate with a regional aquifer, but structural considerations and faulting mean that the main recovery mechanisms are depletion drive.

The subsurface development plan has been designed to optimise recovery from the gas in place in the two fields. Extensive use is made of horizontal wells to mitigate against the key subsurface risks, connectivity and permeability, by connecting up potentially separate fault blocks and increasing well inflow potential. Production wells of 1200 - 1600m horizontal length (five in Thylacine and three in Geographe) are expected to produce at a plateau rate of around 4.95 MMm3/d (175 MMscf/d) for eight years, within a total project life of 25 - 30 years. Technical ultimate recovery of over 27 Bm3 (964 Bcf) of gas is expected from the two fields.

Both static and dynamic simulation modelling has been used in the design of this development plan and in order to test the plan's robustness against the reservoir uncertainties. The models will be maintained and updated with production and reservoir surveillance data through the life of the project to ensure continuing optimisation of recovery.

The chosen development concept is for an un-manned wellhead platform at Thylacine with subsequent subsea tie-backs of Geographe and an additional Thylacine well. Wet gas will be exported through a 70km 20" offshore pipeline to a new onshore gas plant in south-western Victoria. Onshore processing will produce dry gas to pipeline spec, LPG (propane & autogas) and condensate. Produced water is to be recharged to the Iona aquifer.

It is proposed to develop the fields in 2 phases, Thylacine first (platform) in mid 2006, followed by Geographe (subsea) 3 years later. The design basis also has the flexibility to allow for future infill drilling or tie-in of nearby discoveries and fields that are commercially viable.

2. PERMIT HISTORY & STATUS

2.1. Location

The Thylacine and Geographe fields are two separate gas condensate accumulations located in the offshore Otway Basin, 55 - 70km South of Port Campbell (Figure 1). The fields lie in Permits Vic/P43 and T/30P respectively. The Thylacine and Geographe fields were discovered in 2001 by the drilling of the Thylacine-1 and Geographe-1 exploration wells.

2.2. Permit History

Exploration Permit T/30P is located in the Tasmanian sector of the offshore Otway Basin, approximately 70km south of Port Campbell, and contains 101 graticular blocks covering an area of 6309 km². The permit was awarded on 10 July 1997 to Benaris International NV. Origin Energy Resources Ltd farmed into the Permit on 6 July 1999. Woodside farmed into Origin's interest in December 1999 (farm-in agreement executed 26 June 2000). Woodside assumed operatorship on 17 February 2002. Participating interest at the time of discovery and appraisal was:

- Woodside Energy Ltd (Operator) 50%
- Origin Energy Resources Ltd 30%
- Benaris International NV 20%

T/30P is within year 6 and is in good standing with respect to work programme commitments.

Exploration Permit Vic/P43 is located in the Victorian sector of the offshore Otway Basin, approximately 50km south of Port Campbell, and contains 54 graticular blocks covering an area of 2960 km². The permit was awarded on 11 August 1999 to Woodside Energy Ltd (50%), Origin Energy Resources Ltd (Operator, 25%) & CalEnergy Gas (Australia) Ltd (25%). Woodside and Origin both farmed in to 5% each of CalEnergy Gas (UK) Ltd's original equity in the permit, prior to drilling Geographe-1 in June 2001. Woodside Energy Limited took over from Origin Energy Resources Ltd as Operator of VIC/P43 on 1 January 2002. Participating interest at the time of discovery was:

- Woodside Energy Ltd. (Operator) 55%
- Origin Energy Resources Ltd 30%
- CalEnergy Gas (Australia) Ltd 15%

Vic/P43 is within year 4 and is in good standing with respect to work programme commitments.

The Joint Venture Participants in T/30P and VIC/P43 negotiated a re-alignment of equities between the two permits at the end of 2002 with the following interests presently held across the two permits;

- Woodside Energy Ltd. 51.55%
- Origin Energy Resources Limited 29.75%
- Benaris International N.V. 12.7%
- CalEnergy Gas (Australia) Limited 6%

2.3. Discovery and Appraisal

2.3.1. Thylacine-1

Thylacine-1 was spudded on 5th May 2001 in 101m of water, reaching a total depth of 2710 mRT. An estimated 274m gross gas column was penetrated in Late Cretaceous sands of the Sherbrook Group at a depth of 2074 mRT. A core was taken over the interval 2165-2201 mRT with 99.5% recovery. Conventional wireline logs were run and confirmed the presence of gas in variable quality sandstone reservoir. A standard VSP was taken.

Petrophysical analyses of the conventional wireline dataset confirm the net porosity and gas saturation of this interval to be 16.8% and 62.6% respectively. Pressure tests acquired with the MDT tool confirm a single gas gradient. Gas samples were obtained using the MDT tool and returned to surface for analysis. In addition, a water sample was obtained from 2344.5 mRT for analysis at surface.

The Thylacine-1 well was suspended as a gas discovery and the rig was released on 28th May 2001.

2.3.2. Thylacine-2

Thylacine-2 was spudded on 28th August 2001 in a water depth of 101 m to appraise the western extent of the gas discovery made in Thylacine-1. Thylacine-2 reached a total depth of 2525 mRT. An estimated 211m gross gas column was penetrated in Late Cretaceous sands of the Sherbrook Group at a depth of 2143 mRT. Cores were taken over the following intervals:

- Core#1: 2150-2203.5 mRT (93% recovery)
- Core#2: 2203.5-2258.5 mRT (98% recovery)
- Core#3: 2258.5-2316 mRT (97% recovery)

Conventional wireline logs were run and confirmed the presence of gas in poor to good quality sandstone reservoirs. Petrophysical analyses of the conventional wireline dataset confirm the net porosity and gas saturation of this interval to be 15.2% and 43% respectively. Pressure tests, acquired with the MDT tool confirmed the presence of a number of independent gas gradients. Gas samples were obtained using the MDT tool and returned to surface for analysis.

Two drill stem tests were performed at Thylacine-2. DST#1 resulted in a maximum flow rate of 7.1 MMscf/d (0.2MMm3/d) @ 580 psi (3999 kPa) FTHP on 3/4" (1.9cm) choke from poorer quality reservoir over the perforated interval 2176 - 2226 mRT. DST#2 resulted in a co-mingled flow of 28 MMscf/d (0.79MMm3/d) @735 psi (5068 kPa) FHTP on 1.5" (3.8 cm) choke from both the above interval as well as a deeper perforated interval between 2296 - 2302 mRT, which comprised a high porosity Unit 4 sand.

The Thylacine-2 well was plugged and abandoned and the rig was released on 28th September 2001.

2.3.3. Geographe-1

Geographe -1 was spudded on 30th May 2001 in a water depth of 85m, reaching a total depth of 2430 mRT. An estimated 241m gross gas column was penetrated in Late Cretaceous sands of the Sherbrook Group at a depth of 1816 mRT. Cores were taken over the interval 1814 - 1850 mRT and from 1907 - 1915mRT. Conventional wireline logs were run and confirmed the presence of gas in good quality sandstone reservoir. A standard VSP was taken.

Petrophysical analyses of the conventional wireline dataset confirm the net porosity and gas saturation of this interval to be 17.4% and 74% respectively. Pressure tests, acquired with the MDT tool identified a single gas gradient. Gas samples were obtained from using the MDT tool and returned to surface for analysis.

The Geographe-1 well was suspended as a gas discovery and the rig was released on 29th June 2001.

2.3.4. Geographe North-1

Geographe North-1 was spudded on 29th September 2001 in a water depth of 82m to explore a structural closure to the north west of the Geographe gas discovery. Geographe North-1 reached a total depth of 2156 mRT. No gas column was penetrated. Minor gas shows were encountered. Conventional wireline logs were run and confirmed the absence of gas.

3. SUMMARY OF PROPOSED DEVELOPMENT

3.1. Background

3.1.1. Purpose of this Document

This document brings together the sub-surface evaluation, concept selection studies and field development planning carried out up to the end of August 2003. This work has focused on a preferred concept market scenario producing an MDQ (Maximum Daily Quantity) of approximately 205 TJ/d of sales gas through a dedicated export pipeline to an onshore plant in South-west Victoria.

The format of the document is based on the Field Development Plan guidelines issued by the Department of Industry, Science and Resources (now the Department of Industry, Tourism and Resources), Australia.

3.2. Field Development Plan

The objective of the proposed development concept is to establish a competitive long-term gas supply from the Thylacine (T/30P) & Geographe (Vic/P43) gas discoveries that:

- Ensures customer requirements of product specification, first gas, long term supply and reliability of supply are achieved

- Economic recovery from the fields is maximised through an optimum initial development, flexibility to handle uncertainty and appropriate reservoir monitoring and management to identify and optimise subsequent phases of development.

3.2.1. Summary of Proposed Plan

The major components of the proposed Field Development Plan are as follows:

- A market requiring a MDQ (Maximum Daily Quantity) of 205 TJ/d of energy equivalent to 6.23 MMm3/d (220 MMscf/d) of raw gas production or 5.24 MMm3/d (185 MMscf/d) dry gas export. Swing factors and down time reduce the annual average gas sales to 164 TJ/d equivalent to 60 PJ/annum, circa 4.95 MMm3/d (175 MMscf/d) raw gas production.

- The fields will be developed with a total 8 to 10 wells. Four wells will initially be drilled from an unmanned wellhead platform (with no processing facilities) located on Thylacine Field in +/- 100m water depth. Geographe will subsequently be developed via a subsea tie back (3 wells) with a second phase of development drilling at Thylacine.

- Wet gas export through a 70km, 20inch offshore pipeline to a new gas plant in south-western Victoria.

- On-shore processing of gas to produce dry gas, LPG (propane and autogas) and condensate.

- Discharge of condensed and produced water into the Waarre reservoir of the Iona Field.

Reservoir monitoring will be conducted to confirm the degree of reservoir connectivity. This data will be used to optimise the number and location of development wells to ensure effective depletion and to maximise economic recovery.

3.2.2. Project Schedule

Schedule dates are summarised below:

- Start Basis of Design May 2003
- Final Investment Decision April 2004
- On-shore plant construction commences 4Q 2004
- Off-shore pipeline installation commences December 2005
- Off-shore wellhead platform installation and well construction commences 4Q 2005
- First gas mid - 2006
- Field Abandonment Approx. 2031

4. PRODUCTION OVERVIEW

Gas sales in the preferred concept market scenario build up to a maximum plateau demand of 164 TJ/d equivalent to 4.95 MMm3/d (175 MMscf/d) of raw gas production. The productivity of each of the initial Thylacine platform wells (completed with 5.5" to 7" tubing) is expected to be between 1.42 to 5.66 MMm3/d (50 to 200 MMscf/d). The productivity of the initial Geographe subsea wells (completed with 4.5" to 5" tubing) is expected to be between 1.42 to 3.11 MMm3/d (50 to 110 MMscf/d). Initially there is surplus capacity with the 4 wells drilled from the Thylacine platform, but additional wells are required as the reservoir pressure depletes and well productivity declines.

The development will not require compression initially and will run with a plant inlet pressure at 5000-7000 kPa (50-70 bar), giving offshore flowing tubing head pressures (FTHP) around 9000-10,000 kPa (90-100 bar). Onshore compression will be required to maintain plateau rates in about year 6, and compressor inlet pressure will be reduced to 3500 kPa (35 bar) at this stage while maintaining plant pressures; FTHP will reduce to 5000 kPa (50 bar). As FTHP continues to reduce, plateau will eventually not be met when using maximum compressor power and rate will decline until economics dictate field shut-in.

4.1. Estimated Annual Production Rates

TABLE 1 shows the raw gas production as well as sales gas, condensate and water production rates. Sales volumes are calculated based on:

- 93.9% and 90.9% shrinkages for Geographe and Thylacine raw gas respectively due to partial removal of C3+ components and inerts
- 3% of raw gas required for onshore fuel (average)
- 1% of raw gas required for onshore compressor when installed (average)

A small amount of inerts, (nitrogen and CO_2) remain in the sales gas. The Thylacine gas stream has an HHV of 38410 kJ/m3 (1031 Btu/scf) whilst that from Geographe has an HHV of 43253 kJ/m3 (1161 Btu/scf). The shrinkage, fuel and sales-gas heating values are process dependent and liable to slight changes as the facility engineering and process modelling are matured.

The MDQ is likely to be 125% (swing factor) of the DCQ (Daily Contract Quantity) for this preferred concept market scenario.

TABLE 1 PRODUCTION AND SALES FORECAST

	Production				Sales					
Year	Raw Gas (MMscf/d)	Raw Gas (MMm3/d)	Water (Bbl/d)	Water (m3/d)	Sales Gas (TJ/yr)	Sales Gas (TJ/d)	Cond (Bbl/d)	Cond (m3/d)	Propane (kt/yr)	Autogas (kt/yr)
2006	88	2.5	502	80	30,259	83	1,121	178	26	24
2007	176	5.0	502	80	60,009	164	2,179	346	52	47
2008	176	5.0	502	80	60,177	165	2,144	341	52	47
2009	175	4.9	513	82	60,118	165	2,338	372	58	51
2010	172	4.9	514	82	59,949	164	2,603	414	68	57
2011	172	4.9	515	82	59,772	164	2,446	389	65	56
2012	173	4.9	522	83	59,873	164	2,359	375	64	55
2013	177	5.0	534	85	60,586	166	2,318	369	63	55
2014	177	5.0	604	96	60,459	166	2,264	360	62	54
2015	161	4.6	653	104	54,967	151	2,035	324	56	49
2016	140	4.0	694	110	47,553	130	1,748	278	48	42
2017	120	3.4	723	115	40,762	112	1,492	237	41	36
2018	105	3.0	747	119	35,406	97	1,293	206	36	31
2019	95	2.7	785	125	32,029	88	1,169	186	33	28
2020	82	2.3	826	131	27,596	76	1,009	160	28	25
2021	77	2.2	775	123	25,975	71	949	151	26	23
2022	74	2.1	804	128	24,936	68	911	145	25	22
2023	63	1.8	830	132	21,152	58	778	124	22	19
2024	54	1.5	844	134	17,869	49	662	105	19	16
2025	39	1.1	798	127	12,856	35	482	77	13	12
2026	38	1.1	948	151	12,537	34	469	75	13	11
2027	28	0.8	888	141	9,083	25	347	55	10	8
2028	29	0.8	947	151	9,164	25	352	56	10	9
2029	24	0.7	991	158	7,411	20	285	45	8	7
2030	26	0.7	828	132	8,172	22	323	51	9	8
	Bcf	Bm3	MMbbl	MMm3	PJ	PJ	MMbbl	MMm3	kt	kt
TOTAL	**964.0**	**27.3**	**6.9**	**1.1**	**899.0**	**899.0**	**12.4**	**2.0**	**907.1**	**791.3**

5. GEOLOGY AND RESERVOIR INFORMATION

5.1. History of Discovery and Appraisal

Woodside (50%) together with Origin Energy (30%) and Benaris International (20%) discovered the Thylacine gas field some 70km off Port Campbell in exploration permit T/30P in May/June 2001 with the drilling of exploration hole Thylacine-1. This was immediately followed by a similar discovery in the Geographe field 15km closer to the coast in exploration permit VIC/P43 (well Geographe-1). The participants in the latter were Woodside (55%), Origin (30%) and CalEnergy Gas Australia (15%). The Thylacine and Geographe fields are located 70 & 50 km South of Port Campbell respectively (Figure 1).

The Thylacine field is covered by five graticular blocks - 2794, 2795, 2796, 2867 & 2868 (Figures 2 & 3 and Enclosures 1 & 2)) whilst the Geographe field is covered by two graticular blocks - 2723 & 2724 both of Map Sheet SJ54 (Figures 4 & 5 and Enclosures 3 & 4).

Early appraisal drilling of the Thylacine field was carried out with the drilling of Thylacine-2 in August 2001. The objectives of the well were to demonstrate the presence of reservoir in a separate structural culmination to Thylacine-1 and to prove up additional gas volumes. The reservoir section was cored extensively and two production tests were carried out.

Following on from the successful appraisal of Thylacine an additional exploration well was drilled on a prospect to the north of Geographe (well Geographe North-1). The well was plugged and abandoned with minor gas shows having demonstrated the absence of the main reservoir intervals present in Geographe (Units 1 and 2).

Since discovery, the two joint ventures, covering Geographe in VIC/P43 and Thylacine in T/30P, have been aligned to form one joint venture, thereby enabling the joint development and sharing of infrastructure for both fields. Woodside continues to operate both permits. Equity interests in the permits are:

Companies	**Pre-agreement (%)**		**Post-agreement (%)**
	VIC/P43	**T/30P**	**VIC/P43 and T/30P**
Woodside Energy Ltd.	55	50	51.55
Origin Energy Resources Limited	30	30	29.75
Benaris International N.V.	0	20	12.7
CalEnergy Gas (Australia) Limited	15	0	6

The fields contain combined recoverable expectation reserves of some 26.5 MMm3 (964 Bcf) raw gas and 2 MMm3 (12.4 MMbbls) condensate.

5.2. Reservoir Data

The following tables (TABLES 2 & 3) summarise the data available for the fields. The following sub-sections describe the data and interpretations in further detail.

TABLE 2 RESERVOIR DATA

	Geographe	Thylacine
Seismic coverage (reservoir)	3D seismic reprocessed with PreSDM	3D seismic reprocessed with PreSDM
Wells intersecting Reservoir	One	Two
Basic log data (Gamma Ray, Density, Neutron, Resistivity, Sonic)	Yes	All wells
Advanced log data (Shear Sonic, Image Logs).	Shear sonic for entire well, FMI over reservoir section in Geographe-1 only	For both wells acquired shear sonic for entire well, FMI over reservoir section
MDT Samples	Geographe - 10 samples	Thylacine-1 - 11 MDT samples Thylacine-2 - 4 samples
Gas density	By integration of PVT & high mobility pressure points 0.1599 g/cc	By integration of PVT & high mobility pressure points 0.167 g/cc
Drill stem tests	None	Two in one well
Core of reservoir	38m Geographe -1	35.56m in Thylacine-1, 164m Thylacine-2
Core images, gamma scans, Mini-permeametry	All core	All core
Routine Core Analyses	114 plugs, 1 MCST plug	Thylacine-1, 11 MCST's & 88 plugs Thylacine-2, 247 plugs
Special Core Analyses	Geographe-1, 14 plugs	Thylacine-1, 13 plugs Thylacine-2, 22 plugs
Palynology	Geographe-1, 83 age and facies determinations Geographe-N, 29 age and facies determinations	Thylacine-1, 61 age and facies determinations Thylacine-2, 46 age and facies determinations
Petrology (thin section, XRD, SEM, EM)	26 thin section analyses	55 thin section analyses

TABLE 3 RESERVOIR DATA CONTINUED

	Geographe	Thylacine
Reservoir Unit	Flaxman & Belfast FM's	Waarre, Flaxman & Belfast FM's
Reservoir age	L. Turonian to E. Santonian	L. Cenomanian - E. Santonian
Dinoflagellate zones	P. infusorioides - I. cretaceum	P. infusorioides - I. cretaceum
Reservoir Lithology	Litharenite - Quartz arenite	Litharenite - Quartz arenite
Depositional setting	Lower delta plain - gravity flow deposits	Fluvial - shelfal marine - gravity flow deposits
Trap type	Faulted anticline	Faulted horst block
Areal closure	15 Sq Km	31 Sq Km
Vertical Closure	Circa 300m	Circa 300m
Gross Reservoir Thickness	125m	90 - 150m
Average Porosity	17.5%	15 - 17%
Average Gas Saturation	75%	55 - 70%
Reservoir Temperature	95.5^{o} C @ 1832 mss	109.2^{o} C @ 2119 mss
Salinity of Formation Water	17000 ppm (log derived)	11860 ppm (sample)
Maximum recorded flow rate	No test conducted	28 MMscf/d tubing constrained
Initial Reservoir Pressure	19822 kPa (2875 psi) @ 1832 mss	22518 kPa (3266 psi) @ 2119 mss
Gas Expansion Factor	178 surf. vol/res. vol	194 surf. vol/res. vol
GIIP (p90 p50 p10) Bcm (Bcf)	10.1-13.4-17.0 (357-473-600)	28.0-38.1-49.3 (988-1345-1740)
Dry Gas UR (p90 p50 p10) PJ	160-252-361	412-641-886
Condensate UR (p90 p50 p10)MMm3(MMstb)	0.44-0.70-0.98 (2.7-4.4-6.2)	0.83-1.29-1.78 (5.2-8.1-11.2)
Average CGR (m3/MMm3)	118.8 (18.9 stb/MMscf)	76.1 (12.1 stb/MMscf)
Carbon Dioxide	4.3%	9.3%
H_2S	N/A	N/A
Dry Gas Higher Heating Value (incl. inerts) kJ/m3 (Btu/scf)	43253 (1161)	38410 (1031)
Distance to Shore Crossing	55 Km	70 Km
Water Depth	80m	100m

5.3. Regional Geology

The Otway Basin is one of a series of Late Jurassic - Tertiary basins that developed along the southern margin of Australia in response to the break-up of Eastern Gondwana (Ref. 1). It is a composite basin consisting of an early, non-marine, intra-cratonic rift basin of Late Jurassic – Early Cretaceous age, overlain in part by a marginal marine rift basin of Late Cretaceous age, which is in turn succeeded by a fully-marine basin of Tertiary age.

The first rift event began with the Callovian (c.159 - 165 Ma) rifting in the western Bight Basin. During the Tithonian (c.142 - 146 Ma), rifting extended eastwards into the Otway and Gippsland Basins. In the Otway basin rifting extended into the Barremian (c.115 - 123 Ma) resulting in a series of half-grabens which were in filled with Casterton Formation and Crayfish Subgroup. In the early Aptian the Otway basin underwent a period of regional sag during which the Eumeralla Formation was deposited. This event lasted up to the end of the Albian.

The second rift event began during the Cenomanian (c.92 - 97.5 Ma) with uplift in eastern Australia, stress reorganisation and divergence of basin development. The Otway, Sorrell and Great South Basins formed in a transtensional regime resulting in trap generation through faulting, local inversion and wrenching. During the Santonian, oceanic spreading began in the southern Tasman Sea (c. 85 Ma). Slow extension caused thinning of the continental crust in the Bight and Otway Basins and subsidence into deeper water. Ocean crust formed south of the Bight Basin in the Early Campanian (c. 83 Ma) and also started extending along the eastern Australian coast. During this time period the Thylacine and Geographe reservoir units of the Waarre, Flaxman and Belfast formations were deposited in a deltaic to marginal marine to shelfal setting in response to marine encroachment from the west as Australia and Antarctica moved apart.

The final stage of development commenced in the Eocene and was caused by an increase in spreading rate in the Southern Ocean (c. 44 Ma), final separation of Australia and Antarctica and cessation of Tasman Sea spreading. These events caused collapse of continental margins and widespread marine transgression. This created a starved margin culminating in the deposition of the carbonate rich Nirranda and Heytesbury Groups. At the end of the Late Miocene (c. 12 Ma) the Otway Basin underwent another period of compression resulting in significant folding, uplift and erosion both onshore and offshore.

Figure 6 is adapted from Norvick and Smith (Ref.1) and includes plate reconstructions from the Turonian (early phase second rift event) and early Campanian (late phase second rift event) illustrating the main geological elements described above, that ultimately controlled the distribution of reservoir, source and seal and impacted on trap formation.

5.4. Geophysics

5.4.1. Seismic Data Acquisition and Processing

The Geographe and Thylacine fields are covered by the Investigator 3D seismic survey, which was acquired by Western Geophysical in 1999/2000 (Figure 1). The survey covers an area of 986 km^2 providing fully migrated coverage of both fields. The acquisition geometry initially consisted of eight 4600 m streamers however the number of cables deployed was reduced to six early in the survey due to operational conditions. The CMP line shot and group intervals were 25 m and 12.5 m respectively giving nominal 92 fold data. Final processed bin sizes were 12.5 m in both in-line and cross-line direction. Full details are outlined in the Investigator 3D Marine Seismic Survey Acquisition Report submitted to government.

Initial processing of the seismic data was contracted to Veritas DGC Asia Pacific Ltd in their Singapore processing centre. Processing commenced on 1st April 2000, and was completed on 26th September 2000. The details of the processing are documented in the Investigator 3D Marine Seismic Survey Data Processing Report submitted to government.

Following discovery of the Thylacine and Geographe Fields, the seismic data were reprocessed in-house using iterative 3D pre-stack depth migration. The objective of the PreSDM processing was to improve imaging below complex overburden and to improve the amplitude fidelity as a basis for quantitative interpretation and seismically constrained reservoir modelling. The PreSDM processing was completed in May 2002.

5.4.2. Time to depth conversion

Four velocity datasets were investigated for depth conversion of the interpreted seismic horizons. These included velocities derived from the well velocity surveys, seismic imaging velocities from the initial time domain processing, and both sparse and detailed velocity models used for PreSDM seismic processing.

In addition, to the separate velocity data investigated, various workflows were investigated for time to depth conversion and calibration at well intersections. Procedures investigated included smoothing of overburden interval velocities after decompaction, map migration through overburden layers, various methods of kriging misties at wells etc. In the final analysis the differences in methodology did not produce significant differences in the resultant top-reservoir depth map.

Interval velocity maps were quality checked for geological relevance and consistency with well data. The interval maps were generally consistent with structure.

The four velocity datasets resulted in a variation in the GRV computed at the intersection of the top reservoir depth surface and the most likely fluid contacts. The Geographe field showed a larger degree of sensitivity to the velocity model because it is an anticlinal structure with the hydrocarbon reservoirs dipping through the fluid contact. Conversely, the Thylacine structure is a relatively flat fault-bounded structure and is therefore less sensitive to velocity variation.

The preferred concept velocity model for deterministic reservoir modelling and probabilistic volumetric calculations was an average of the three seismic-derived velocity datasets. The well velocity model was considered too optimistic to apply because it does not account for lateral velocity variation. The standard deviation of the three seismic-derived velocity maps at top reservoir horizon was approximately 40 m/s, which is consistent with the depth prediction error experienced during the exploration drilling. This value is consistent with the sill value determined from the variographic analysis of the velocity data, which in turn influenced the parameters applied for probabilistic volumetric GRV calculations.

Most likely depth and amplitude maps for the fields are shown in Figures 2 – 5.

5.4.3. Structural Interpretation

The fields are characterised by complex structuration, due to the influence of several overprinted phases of tectonic deformation. The first stage of rifting occurred in the Early Cretaceous, which resulted in dominantly east-west extensional faulting. The early rift structures were subsequently overprinted by Late Cretaceous extension under a transtensional regime. This resulted in trap formation through faulting, inversion and wrenching of the pre-existing rift structures. The fields are located in an area of intense structuration due to their close proximity to the Sorrel Transfer zone, a north-trending discontinuity in the Early Cretaceous, which has concentrated transtensional deformation during the Late Cretaceous. This reactivation has created the accommodation for sedimentary deposition of the Late Cretaceous Shipwreck Trough (Figures 6 & 7).

Major faults interpreted from the seismic data were correlated in three dimensions and incorporated into three-dimensional structural models. However a significant number of minor faults were also mappable from the seismic data. Significantly, the improved imaging achieved from the PreSDM seismic data allowed a greater number of minor faults to be interpreted. Additional post-processing of the seismic data assisted the mapping of subtle faults. Length and throw statistics for all faults was analysed using SGT (Shell proprietary structural geology software). This analysis (fault frequency versus throw) follows a 'power law distribution' and showed that minor faults with an average throw of 20 m or more were fully sampled by the seismic interpretation and that a large proportion of faults with average throw of 10-20 m was sampled.

Given that some of the reservoirs in the field are low net to gross (less than 30% in some areas), it is important to include the minor faults in the reservoir model, as they have a significant impact on transmissibility. Minor faults (<15 m throw) were interpreted as centrelines in map view representations of the seismic data. These faults are very subtle to detect on vertical reflectivity sections. Generally they do not show detectable offset of reflections and can only be confirmed by subtle amplitude dimming. This is consistent with forward-modelling experiments published in the literature. Semblance processing of the seismic data has assisted the detection and interpretation of the minor faults. Semblance data is a representation of the correlation between neighbouring seismic traces, and is calculated using the mathematical technique of cross-correlation. In addition to the standard semblance algorithm, a Shell proprietary algorithm was applied which accounts for the structural dip of the reflectors. This is called structurally oriented semblance.

Another technique used to interpret the minor faults was an automated technique, which uses the auto-tracked horizons. This technique looks for inflections of the horizon, and extracts faults based on user specified thresholds. The user can then quality-check the displacement profiles of the extracted faults, and calculates length and throw statistics of the extracted fault population. The faults extracted by this method were quality-checked against those that could be interpreted directly from semblance data. Automatically detected faults which did not show a response on the semblance data were not included in the final interpretation.

The final interpreted fault population was loaded into SGT (Structural Geological Toolkit) to calculate the throws. In addition to providing quality control of the faults, this also allowed the generation of throw maps, and therefore a means of filtering the fault population by fault throw. This allowed the testing of sensitivities of different fault seal scenarios in the dynamic simulator (see section 4.4.6).

5.4.4. Reflection picking and Horizons

Reservoir units in each field have been correlated regionally, using biostratigraphic control. Five seismic horizons (see Figure's 8 & 9 and TABLE 4) were interpreted over each field.

The top Unit 1 pick for both fields is a strong reflection corresponding to top porosity. This horizon shows strong amplitude vs. offset response above the gas water contact. The Unit 1 package shows inclined internal stratification in both fields, consistent with progradational deposition. This is clearly seen near Thylacine-1 and on the eastern flank of the Geographe Field. The progradational deposition of the Unit 1 reservoir is supported by the log data, which show a number of coarsening upward parasequences. These can be correlated to the inclined foresets observed on the seismic data. The direction of progradation is from east to west. Consequently, the sand development is poorer in the Thylacine-2 area. This well intersected only one coarsening upward parasequence.

On the western flank of the Geographe field, the top Unit 1 pick is ambiguous. It is not clear if the strong reflection at approximately 1500 ms represents the top of the Unit 1 or an internal progradational cycle. To address this uncertainty, both scenarios were interpreted to test the volumetric impact. Since the GRV difference was very low (approximately 2%), the alternative scenarios were not carried forward into discrete modelling scenarios. The GRV uncertainty associated with the alternative interpretation scenarios is captured by the uncertainty range of the probabilistic GRV modelling.

TABLE 4 INTERPRETED HORIZONS FOR THYLACINE & GEOGRAPHE

Thylacine		
Horizon	Polarity	Comment
Top Unit 1	Strong peak	High confidence
Top Unit 2	peak	Moderate-low confidence
Top Unit 4a	trough	Angular unconformity
Base incised valley	trough	
Top Unit 5	Weak trough	Relatively low confidence
Geographe		
Horizon	Polarity	Comment
Top Unit 1	Strong peak	High confidence
Top Unit 2	Weak peak	Relatively low confidence
Top Unit 3	trough	Thickness constrained by seismic resolution
Top Unit 4a	Zero crossing above peak	Angular unconformity
Top Unit 4d	Strong peak	Low confidence outside gas zone

For the South Block of Thylacine an alternative higher pick was mapped for the top Unit 1. This higher alternative pick correlated to the top of high amplitude progradational package interpreted to the east of the field. However, acoustic impedance data suggest that this package does not contain sandstone facies in the Thylacine South area. Therefore the higher pick has been rejected for volumetric calculations.

The top Unit 2 is a weak to strong peak, showing amplitude vs. offset response above the gas water contact in both fields. The synthetic seismogram tie in Geographe-1 shows that the top Unit 2 is a relatively low confidence tie. However the confidence is much higher in the Thylacine wells. Unit 2, mass-flow sandstone, is interpreted to have been deposited in palaeo-bathymetric lows. Accordingly the thickness of this reservoir is variable. Although the mass flow facies has been intersected by Geographe-1 and both Thylacine wells, it is possible that these intersections could be separate mass-flow sandstones. The correlation of Unit 2 between Thylacine-1 and Thylacine 2 is particularly ambiguous. It shows a significantly thicker Unit 2 section in Thylacine 2, which thins and is then faulted down to a thinner package that is tied to Thylacine-1. An alternative explanation of the observed geometry is that the Unit 2 section observed in Thylacine-2 is a separate mass flow deposit to the one intersected in Thylacine-1.

Despite the ambiguity of the geological correlation, the lateral prediction of the Unit 2 reservoir facies is relatively straightforward within the Thylacine Field, due to the distinctive seismic response. It is more difficult at Geographe due to the lower confidence seismic correlation to the top of the unit. The unit is characterised by homogeneous sandstone, and is represented as low acoustic impedance on inverted seismic data.

In the Geographe field, the Unit 1 and 2 reservoirs thin towards the Geographe North structure. This structure appears to have been a palaeo high at the time these reservoirs were deposited. There is a thin shale drape, which is interpreted from palynology data to be time equivalent to the Unit 1 reservoir, but there are no sandstone facies present.

The Unit 3 shale represents a regional flooding event, and is intersected in all wells. It is only 3 m thick in the Thylacine wells, and therefore not resolvable by the seismic data. In Geographe, the Unit 3 shale is approximately 30 m thick, and ties to a trough one cycle below the top Unit 2. Although the marker has been interpreted across the Geographe field, the lateral prediction of the thickness of the unit is of low confidence due to the resolution limit of the seismic data.

The top Unit 4a is an angular unconformity that separates the relatively unfaulted lower Belfast reservoirs from the deeper Flaxman and Waarre reservoirs which still show significant influence of Late Cretaceous rifting. Specifically, the deeper section is characterised by planar extensional faults with rotated beds that are truncated by the unconformity.

In the Thylacine-1 area, Unit 4a facies is an incised valley fill (IVF). Since the rock properties of the IVF are very similar to the overlying Unit 2 sandstone, there is very little acoustic contrast at the top Unit 4a in this area. Consequently there is no reliable reflection event to map in this area. The top IVF has been interpreted in this area by maintaining a geologically reasonable thickness of the overlying Unit 2 sandstone. The base of the incised valley is represented by a trough, and can be mapped with reasonable confidence.

In the Geographe Field, the top Unit 4d sandstone has been mapped. This reservoir is blocky, channelised sandstone in the well, and corresponds with a strong peak. However, due to the channelised nature of the reservoir, the lateral extent of the strong reflection is limited and the unit becomes very difficult to interpret away from the field. This problem is emphasised by the strong faulting of the Unit 4 stratigraphy.
The top Unit 5b horizon has been interpreted in the Thylacine field only. This horizon corresponds to a relatively weak trough. This event can be interpreted with reasonable confidence in the Thylacine main block, however confidence decreases in more structurally complex parts of the field such as the Thylacine-2 area.

5.4.5. Attribute Analysis and Quantitative Interpretation

A number of seismic attributes were investigated in order to interpret rock properties and fluid-fill of the separate reservoirs. The far-offset seismic volume showed increased amplitude response above the known gas water contacts for the top and base of all reservoirs. In addition to instantaneous extractions, windowed averages were also calculated in order to achieve the most reliable result. The benefit of the far-offset seismic data for quantitative analysis is that it does not assume any layer interpretation or rock property model. The disadvantage is that it responds to interface conditions rather than the in-situ properties of the reservoir. For example, the amplitude response is equally effected by the properties of the shale overlying a given gas reservoir as the reservoir itself.

The far-offset data was cross-plotted against depth to interpret the fluid contacts in the non-penetrated fault blocks. The response in the outlying blocks was benchmarked against the response at the known fluid contacts penetrated by the wells. In general the cross plots show an abrupt decrease below the gas water contact. However, in some blocks the transition is more gradational, making the fluid contact interpretation more ambiguous.

Quantitative inversion of the seismic data was also undertaken. A number of different methods were used, including inversion of the full-stack data to acoustic impedance, and AVO inversion of the sub-stacks to P-wave impedance and VP/VS ratio. In particular, the full-stack acoustic inversion and the P-wave impedance volume from the AVO inversion provided excellent discrimination of hydrocarbon charged reservoir sandstones.

The VP/VS volume created from the AVO inversion is in theory a representation of lithology without the overprinted effect of fluid fill. In practise, this volume was of limited value because of the poor signal to noise ratio and resolution of the far-angle seismic data required to invert for shear impedance.

5.4.6. Reservoir Compartmentalisation Potential

Given the high density of faulting interpreted from the PreSDM seismic data, the issue of reservoir compartmentalisation was investigated in detail. In particular the quantification of cross-fault fluid flow is significant for the number, type and placement of development wells.

The impact of faulted interfaces upon dynamic behaviour was modelled by applying transmissibility reduction factors to the upscaled geological model in the dynamic simulation model. The transmissibility factor is defined as the ratio of faulted flow versus un-faulted flow over a given interface. The faulted flow is primarily related to fault zone thickness and permeability, which can be estimated from empirical relationships of fault throw versus fault zone thickness and fault zone permeability versus shale gouge ratio. Since these empirical relationships have a large uncertainty, a probabilistic approach was used, where the scatter of published data around the most likely empirical relationships were accommodated with uncertainty distributions.

Given that the Thylacine and Geographe Fields contain a mixture of low and high net-to-gross reservoirs, and both low and high permeability reservoirs, the fault transmissibility multipliers vary significantly for each given fault. For example the Unit 1 reservoir in Thylacine has a low net-to-gross and consequently a high shale gouge ratio and low fault zone permeability. Accordingly, faults with small throw (10m) can significantly inhibit flow. Conversely, the Unit 2 reservoir has very high net-to-gross and low matrix permeability, and therefore transmissibility is not significantly inhibited by minor faults (Figure 10).

To accommodate the varying transmissibility multipliers for different reservoir units, a look-up TABLE was applied in the reservoir simulator, where the reduction factor was applied for each grid cell interface based on the reservoir unit and fault throw. Fault throws of the upscaled simulation model were quality-checked against the input geological model to ensure that appropriate transmissibility reduction factors were being applied.

5.5. Stratigraphic Framework

The stratigraphy of the region is summarised in Figure 11. The oldest sediments encountered are middle Cretaceous clastics of the Eumeralla Formation (in Thylacine-1). The Late Cretaceous Sherbrook Group is the main interval of interest as it includes the reservoir units of the Waarre (reservoir Unit 5), Flaxman (reservoir Unit 4) and Belfast Formations (Reservoir Units 1 to 3). A discussion of the relevant Formations and their relationship to the Reservoir Units is presented in section 4.6.

5.6. Reservoir Geology

Sedimentological and sequence stratigraphic models were developed from core, biostratigraphic, petrographic and wireline data. A most likely depositional model was developed along with low and high case 3-D depositional models. These were generated by varying sand / shale ratios and sand-body correlatability and geometries. Geometry data from field, outcrop and modern depositional analogues (Shell proprietary database) were used to constrain the geostatistical population of depositional facies in the 3-D models.

Sedimentologists and stratigraphers from Baker Atlas Geoscience, Core Laboratories and Woodside described and interpreted over 237 m of core and combined this work with quantitative micropal, petrography, wireline and image (FMI) logs. A stratigraphic correlation framework was developed (Figures 12 & 13). Four major reservoir intervals were identified and constrained with the 3D seismic data and correlated between wells; these are Units 1, 2, 4 and 5 (Figure 14). In addition a regionally significant shale interval (non-reservoir interval) Unit 3 was identified. These reservoir units were further subdivided into sub-units at or below seismic resolution using wire-line logs. A table (TABLE 5) of relevant tops is provided below.

TABLE 5 RESERVOIR UNIT / SUB-UNIT TOPS

			Zone Top MD (m)		
Reservoir Unit	Sub-Units		Thy-1	Thy-2	Geo-1
Unit 1			2048.71	2143.50	1816.40
	1a		2048.71	Absent	1816.40
	1b		2065.11	Absent	1828.04
	1c		2076.24	Absent	1843.80
	1d		2091.63	2143.50	1860.10
Unit 2			2132.78	2176.10	1876.50
	2a		2132.78	2176.10	1876.50
	2b		2141.37	2204.41	1888.20
Unit 3			2158.84	2232.50	1916.30
Unit 4			2160.82	2237.20	1962.40
	4a		2160.82	2237.20	1962.40
		Top IVF	2160.82	Absent	Absent
		Base IVF	2196.63	Absent	Absent
	4b		2208.82	2274.23	Lumped with 4a
	4c		2227.17	2285.96	1999.34
	4d		2235.80	2296.02	2015.19
	4e		2251.04	2310.04	2045.50
	4f		2262.77	2323.61	Not Picked
	4g		2268.11	2334.80	Not Picked
Unit 5			2273.59	2354.85	Not Picked
	5a		2273.59	2354.85	Not Picked
	5b		2310.17	2383.35	Not Picked

The sedimentology and sequence stratigraphy of the base - case model is summarised below.

5.6.1. Waarre Formation - Reservoir Unit 5

The Waarre Formation is interpreted to have accumulated in a fluvial to shallow marine environment. Two distinct sequences are recognised separated by a regionally significant sequence boundary (marked by the top of the *Basal P. infusorioides (mid)* biozone). The lower sequence consists of poorly developed volcanilithic sandstones, mudstones and minor coal. Petrological studies show the volcanilithic sandstones are similar in composition to the underlying Eumeralla Formation. The sequence is predominantly transgressive and marine in nature.

The upper Waarre sequence includes reservoir Unit 5. The sequence forms a low-stand systems tract and consists of fluvial to marginal marine facies. The dominant reservoir facies are interpreted to be coarse-grained fluvial sandstones based on core data within this unit from Minerva-1 and Minerva-2A and quantitative palynology.

Petrological studies demonstrate that a granitic/metamorphic provenance provides an important input into the sediments of the upper Waarre sequence. These sandstones are quartzarenitic and have superior reservoir quality compared to the volcanilithic provenance derived sandstones.

5.6.2. Flaxman Formation - Reservoir Unit 4

The Flaxman Formation accumulated in a marine shelfal environment and is Late Turonian in age. The Flaxman Formation represents reservoir Unit 4 which is dominantly transgressive in nature.

The boundary between the underlying Waarre Formation and the Flaxman Formation is characterised by a rapid change from fluvial sandstones to a marine succession dominated by siltstones and minor very fine to fine grained bioturbated to finely laminated sandstones. Two pulses of coarse to very coarse grained cross-bedded sandstones have been intersected (reservoir Units 4d and 4a). The lower of the two (Unit 4d) is interpreted to represent fluvially dominated distributary channels whilst the upper (Unit 4a) is interpreted as an Incised Valley Fill complex consisting of estuarine channels, tidal bars and sand flats in Thylacine-1 and interpreted fluvial sandstones in Geographe-1 to the north.

The coarse clastic pulses are interpreted to represent 'local' sequence boundaries driven by a fall in relative sea level 'forcing' progradation of the shoreline from the 'north'. Both events were subsequently drowned by rising sea level.

The Upper boundary of the Flaxman Formation is marked by the *C. striatoconus* sequence boundary, which locally forms a significant angular unconformity as demonstrated by seismic, dip-meter & core data in Thylacine-2 (Figure 15).

5.6.3. Belfast Formation Reservoir Units 1 - 2 and Non Reservoir Unit 3

The Belfast Formation accumulated in a shelfal marine environment and is Coniacian to Late Santonian in age. The basal Belfast Formation is represented by reservoir Unit 3 dominated by massive, glauconitic, silty claystone. The contact between these claystones and the underlying silty sandstones is an angular unconformity (Figure 15). This interval is thin (<5 m) over Thylacine but significantly thicker (circa 46 m) in Geographe-1. The contact is interpreted to represent a major flooding event.

The sharp nature of the flooding surface at the base of the interval suggests it formed in response to a rapid rise in sea level. As demonstrated by the angular unconformity seen at Thylacine-2 this rise appears to have formed in response to tectonic movement which has also had a control on thickness distribution. The timing of this flooding event is constrained to the *Basal O. porifera* bio-zone.

Reservoir Unit 2 overlies Unit 3. Unit2 consists of a multi-story stack of very fine to fine grained, massive to faintly laminated sandstones locally interrupted by thin, bioturbated layers of argillaceous siltstone and thin beds of claystone pebbles. The base of the interval is sharp and scoured as demonstrated by core (Thylacine-2) and logs from all wells. The sandstones are interpreted to represent gravity flow deposits whose thickness distribution is controlled by the preceding tectonic.

Reservoir Unit 1 overlies Unit 2. In Thylacine the interval is dominated by coarsening upward cycles as demonstrated by GR logs, core and rotary sidewall cores. The cycles typically coarsen upwards from intensely bioturbated sandy, argillaceous siltstones to fine grained sandstones. The cycles are interpreted to represent shoreline progradation.

In Geographe, Unit 1 core demonstrates a more proximal reservoir facies. The overall interval is a mud dominated sandy succession with an ichnofaunal association typical of brackish water conditions. It is interpreted as an inter-distributary bay fill succession that has been tidally influenced.

5.7. Reservoir Quality

Petrological studies were carried out on eighty-one samples. Analytical techniques used were thin-section analysis, quantitative bulk rock/clay fraction, X-ray diffraction analysis and scanning electron microscopy.

Studies have demonstrated the presence of two petrographically distinct sandstones represented by and restricted to reservoir Units 1 & 2 and Units 4 & 5 respectively. These units lie above and below the sequence boundary and regional flooding surface represented by Unit 3.

The sandstones of reservoir Units 1 & 2 are moderately-well to well sorted, very fine to fine grained, lithic rich sublitharenites and litharenites in which framework grains are mainly quartz and also include K-feldspar, metamorphic rock fragments, sedimentary rock fragments, mica, reworked glauconite, organics and accessory heavy minerals.
These sandstones contain little or no detrital clay. However, authigenic clay ranges up to 26.3% and is mainly kaolinite that occurs where labile grains have altered. Clay minerals detected by XRD are dominantly kaolinite and minor illite.

The main diagenetic effects besides authigenic clay formation are ductile/authigenic clay compaction, grain contact dissolution, cementation by quartz overgrowth and cementation/replacement by siderite, ankerite and calcite.

Porosity reduction is mainly the result of authigenic clay formation, clay compaction, quartz overgrowth, grain contact dissolution and localised calcite cementation.

Reservoir quality is controlled by grain size and authigenic kaolinite plus metamorphic rock fragment content. Permeability increases with increasing grainsize.

The sandstones of reservoir Units 4 & 5 sandstones are dominantly sublitharenites and quartzarenites in which framework grains are mainly quartz and minor K-feldspar, metamorphic rock fragments, mica, organics and accessory heavy minerals. Compositional maturity generally increases with depth, with quartz increasing downward (Unit 4 to Unit 5) at the expense of clay, rock fragments, feldspar and siderite.

Sandstones are fine to coarse grained and moderately-well to well sorted. Below this interval, sorting and grain-size fluctuate widely. Sandstones are derived from a continental provenance dominated by low grade metasedimentary and granitic rocks.

Minor detrital clay is concentrated along thin laminae and forms patchy matrix. Most sandstones lack detrital clay. Authigenic clay content is generally less than 10% but can range up to 20%. It is predominantly kaolinite and occurs where micaceous/argillaceous grains have completely altered.

The main diagenetic effects besides authigenic clay formation are grain contact dissolution, labile grain (mainly K-feldspar) dissolution, ductile grain/authigenic clay compaction, cementation by quartz overgrowths, and cementation/replacement by ferroan carbonate and rare calcite.

Porosity reduction is mainly the result of authigenic clay formation, ductile grain/clay compaction, and grain contact dissolution/microstylolitisation and quartz overgrowth cementation. Visible porosity ranges up to 18.6% and generally decreases with increasing clay plus metamorphic rock fragment content.

Reservoir quality is also controlled by grain size, the content of clay (mostly authigenic kaolinite) and, of less importance, metamorphic rock fragments.

Figure 16 illustrates the clear relationship between clay and rock fragment content versus permeability whilst Figure 17 illustrates the relationship between composition and depth and the clear distinction between Units 1 & 2 compared to Units 4 & 5 for Thylacine-1. A similar relationship is observed in Geographe-1.

5.8. Depositional Uncertainty

Depositional uncertainty in terms of sand/shale ratios, sand body geometry and sand body distribution forms one of the major sub-surface uncertainties identified and has a fundamental impact on sand-body connectivity. These uncertainties are reflected in the low and high case 3-D depositional models.

5.9. 3-D Static Reservoir Modelling

For Thylacine Field the low and high case models were generated by varying sand-body correlatability, sand-body geometry and sand/shale ratio in the respective reservoir units. In the most likely model, well sand-bodies within Units 1 and 4 are modelled as laterally extensive lower to mid shore-face sheet sands or amalgamated channel complexes (Unit 4d). In the low and high case models the well sand bodies are modelled as relatively discontinuous distributary mouth-bars in Units 1 and 4 and 'isolated' distributary channels (Unit 4d). Inter-well probabilistic bodies were then modelled. The number of inter-well bodies was constrained by varying the sand / shale ratio for the low and high case models (circa. 20% & 40%) to allow for an assessment of the impact on connectivity, GIIP and recovery.

In the most likely model the incised valley geometry (Unit 4a) is constrained by seismic mapping. The low and high case models use modern day analogues to constrain the geometry.

In all scenarios Unit 2 is constrained by seismic mapping.

Finally, in reservoir Unit 5 the sand / shale ratio is varied between the respective scenarios.

Figure 18 summarises the above approach for assessing the uncertainty in and impact of sand body geometry and net to gross for the respective reservoir units.

A similar approach was adopted for the Geographe Field where the focus is on Reservoir Units 1 & 2.

5.10. Petrophysics

A petrophysical review of the Thylacine and Geographe gas Fields has been carried out (Ref. 2). Routine and special core analysis data from the cores recovered from Thylacine-1 & 2 and Geographe-1 was used to calibrate and constrain the petrophysical evaluations. Figures 19 - 22 are log evaluation summaries for Thylacine 1 & 2, Geographe 1 & Geographe North.

5.10.1. Porosity & Water Saturation

Porosity and water saturation (Sw) were calculated using density porosity/Waxman Smits saturation approach. This method results in an excellent match to core porosity data and saturation estimation, particularly in the shaly reservoirs of Units 1 and 2.

A series of field and Reservoir unit specific saturation height functions were developed using a regression technique which relates saturation to permeability and height above free water level (FWL). These functions honour the SCAL capillary pressure data particularly in transition zones. The saturations derived using these functions are generally in good agreement with those derived from resistivity logs.

TABLE’s 6 & 7 summarise the log derived average porosity and water saturation by Reservoir unit for the respective wells.

TABLE 6 AVERAGE POROSITY BY RESERVOIR UNIT

Porosity					
Reservoir Unit	**Thylacine-1**	**Thylacine-2**	**Thylacine ML 3D Model**	**Geographe-1**	**Geographe ML 3D Model**
Unit-1	0.180	0.143	0.159	0.164	0.16
Unit-2	0.154	0.151	0.149	0.18	0.18
Unit 4 IV	0.176	Absent	0.159	N/A	N/A
Unit 4a - g	0.169	0.156	0.129	0.177	0.16
Unit 5	0.180	0.158	0.160	N/A	N/A

TABLE 7 AVERAGE WATER SATURATION BY RESERVOIR UNIT

Water Saturation					
Reservoir Unit	**Thylacine-1**	**Thylacine-2**	**Thylacine ML 3D Model**	**Geographe-1**	**Geographe ML 3D Model**
Unit-1	0.398	0.564	0.421	0.313	0.43
Unit-2	0.426	0.662	0.455	0.227	0.44
Unit 4 IV	0.292	Absent	0.285	N/A	N/A
Unit 4a - g	0.378	0.414	0.476	0.246	0.32
Unit 5	0.359	N/A	0.356	N/A	N/A

5.10.2. Net / Gross

Net Reservoir is defined on the basis of a minimum permeability threshold of 0.01 mD. This threshold was identified on the basis of sensitivity analysis of calculated hydrocarbon pore volume (HPV) to incremental changes in permeability cut-off.

The HPV of the sub - 0.01mD fraction was not considered as log interpretations are ascribed low confidence in such poor quality rock. In addition, the Thylacine - Geographe saturation-height functions are unstable at permeabilities below 0.01mD.

The 0.01mD cut-off is low compared with the more common 0.1mD value, but facilitates the evaluation of the potential pressure support and connectivity contributions of low permeability reservoir elements. Increasing the cut-off from 0.01mD to 0.1mD results in significant reductions in HPV (see Figure 23 for comparisons).

TABLE 8 below summarises the log derived net / gross by Reservoir unit for the respective wells.

TABLE 8 AVERAGE NET TO GROSS BY RESERVOIR UNIT

Net / Gross					
Reservoir Unit	**Thylacine-1**	**Thylacine-2**	**Thylacine ML 3D Model**	**Geographe-1**	**Geographe ML 3D Model**
Unit-1	0.3825	0.271	0.326	0.617	0.61
Unit-2	0.913	0.913	1	0.954	1
Unit 4 IV	0.664	N/A	0.73	N/A	N/A
Unit 4a - g	0.351	0.24	0.341	0.52	0.39
Unit 5	0.788	0.679	0.688	N/A	N/A

5.10.3. Porosity - Permeability Transforms

Available routine core analysis (RCA) data for the Thylacine-1, Thylacine-2 and Geographe-1 wells has been used to derive unit-specific porosity-permeability transforms. Where appropriate, units with similar porosity-permeability relations have been grouped and are represented by common transforms. The transforms derived are considered to be of excellent quality with correlation coefficients greater than 0.8 for all reservoir units.

For each unit or group of units, five transforms have been estimated and are presented in Figures 24 - 28:

- best-fit (mean) transform
- plus 1 standard deviation (s.d) transform
- minus 1 s.d. transform
- plus 2 s.d. transform
- minus 2 s.d. transform

The +/- 2SD transforms have been used for high and low case volumetric calculations and high and low case reservoir permeability models.

5.10.4. Kv / Kh Transforms

Available RCA data for the Thylacine-1, Thylacine-2 and Geographe-1 wells has been used to evaluate Kv / Kh relations. The RCA data set includes Kv and Kh measurements for twin / neighbouring plugs.

Kv / Kh relations are very consistent in the Thylacine-1, Thylacine-2 and Geographe-1 wells, and can be represented by common transforms (Figure 29).

5.11. Free Water Levels (FWL's) of the Thylacine & Geographe Fields

The interpreted FWL's are largely based on the integration of PVT-derived gas density data with MDT pressure data. Only points with a mobility greater than 10 mD/cp have been used to fit gas and water lines.

The uncertainty associated with the interpreted FWL's was calculated on the basis of the repeatability of the MDT tool (± 2.1 kPa (0.3 psi); this equates to a depth uncertainty of ± 0.52m) and the accuracy of Schlumberger's depth recording equipment (± 1ft in 5000 ft; this equates to a depth uncertainty of ± 0.41 - 0.46 m at the interpreted FWL for Geographe and Thylacine respectively).

5.11.1. Geographe

In Geographe-1 a single gas system is interpreted with a FWL at 2031.1 ± 0.9mTVDSS (2056.5mRT) (see Figure 30).

5.11.2. Thylacine

The gas column of Thylacine-1 is relatively simple with a single gas system currently interpreted. In contrast the gas column of Thylacine-2 is relatively complex with a series of stacked systems interpreted.

The gas-bearing sections of Thylacine 1 and 2 appear to overlie a common regional aquifer; thus high mobility MDT data from both wells was used to define a common water line used in the FWL interpretations for each well.

5.11.2.1. Thylacine-1

In Thylacine-1 a single gas system is interpreted with a FWL at 2297.6 +/-1.0mTVDSS (2323.2mRT) (see Figure 31).

5.11.2.2. Thylacine-2

In Thylacine-2 a series of five stacked gas systems is currently interpreted (Figures 32 – 34). The FWL's of the Thylacine-2 gas systems were originally interpreted on the basis of the intersections of MDT and PVT - derived gas gradients with the Thylacine regional aquifer / common water line (Figure 32). However, there is significant evidence to suggest that the shallower gas systems in Thylacine-2 (Units 1 & 2) are associated with a perched aquifer, and thus have much shallower FWL's than those interpreted using the Thylacine regional aquifer / common water line. This evidence includes:

- The interpretation of five stacked gas systems indicates significant vertical compartmentalisation in the vicinity of Thylacine-2.

- In the shallower gas systems of Thylacine-2, capillary pressure derived water saturation estimates, grounded on FWL's interpreted from the intersection of gas gradients with the regional aquifer / common water line, are much lower than resistivity-derived water saturation estimates (Figure 34). This suggests that the FWL's of these systems are shallower than those interpreted assuming a common regional aquifer. This evidence of shallower FWL's is particularly pronounced in Unit 2 (Figure 33).

- Trends in resistivity-derived water saturations in the Unit 2 interval of Thylacine-2 are suggestive of a transition zone (i.e. water saturations show a marked increase down-section, despite relatively uniform permeabilities). Transitional saturations in this interval would indicate that Unit 2 has a much shallower FWL than that interpreted assuming a common regional aquifer.

- Pre-SDM seismic data indicates a significant increase in acoustic impedance and dimming of amplitudes in the Unit 2 interval a short distance down-dip from Thylacine-2 (Figure 35). This seismic character is consistent with a change in fluid content from gas to water at approximately 2250mTVDSS (~50m shallower than the FWL interpreted for Unit 2 assuming a common regional aquifer).

An alternative method of FWL interpretation involves the inversion of saturation-height functions: that is using saturation-height functions, together with log derived saturation and permeability estimates, to solve for FWL. FWL estimates determined using this method are documented in TABLE 9. The most likely FWL for Unit 2 is currently considered to be that derived using this approach.

On the basis of the foregoing, the gas systems of Thylacine-2 are inferred to connect to at least two distinct aquifers. Gas systems 3, 4 & 5 (Unit4a & Unit 4b to g) is connected to the regional aquifer seen in the water legs of the Thylacine-1 and 2, while gas systems 1 & 2 (Unit 2) are believed to be connected to a shallower 'perched' aquifer that has not been intersected in the wells (Figure 36).

TABLE 9 THYLACINE-2 BLOCK - FWL'S BY RESERVOIR UNIT

The gas systems of Thylacine-2

Gas System	Strat. Unit	HKG (mRT)	HKG (mTVDSS)	LKG (mRT)	LKG (mTVDSS)	MDT FWL (mRT)	MDT FWL (mTVDSS)	Pc FWL (mRT)	Pc FWL (mTVDSS)	ML FWL (mRT)	ML FWL (mTVDSS)
1	Unit 1	2143.4	2118.2	2152	2126.8	2284.4	2259.1	2164.1	2138.9	2191.3	2166.1
2	Unit 2	2176.1	2150.9	2228	2202.8	2322.8	2297.6	2228.3	2203.1	2228.3	2203.1
3	Unit 4A	2237.7	2212.5	2241.6	2216.4	2348.9	2323.6	2270.1	2244.8	2348.9	2323.6
4	Unit 4A	2247.6	2222.4	2264.3	2239.0	2363.6	2338.3	2321.2	2295.9	2363.6	2338.3
5	Unit 4B-G	2275	2249.7	2334.7	2309.4	2370.6	2345.3	2371.2	2345.9	2370.6	2345.3

HKG = highest known gas
LKG = lowest known gas
MDT FWL = FWL interpreted from MDT data assuming connection to the Thylacine regional aquifer / common water line
Pc FWL = FWL interpreted through inversion of saturation height functions
ML FWL = most likely FWL

5.11.3. Unpenetrated Fault Blocks

A number of unpenetrated potentially isolated fault blocks are present in both fields. In Thylacine the two most significant unpenetrated fault blocks are Thylacine North & South (Figure 37) whilst in Geographe it is the North block (Figure 38). A range of FWL's has been derived for these unpenetrated blocks principally by examining amplitude versus depth plots for the respective blocks and comparing and calibrating these to the penetrated blocks. The ranges have been used to assess the impact of uncertainty in the FWL on the GIIP in the unpenetrated blocks.

The range in FWL's for the unpenetrated fault blocks used in the probabilistic calculations in Thylacine & Geographe is shown in TABLE 10.

TABLE 10 RANGE OF FWL'S APPLIED BY RESERVOIR UNIT AND BLOCK

Fluid contact ranges used in Xtrap			
	FWL Depth (mss)		Comments
	Min	Max	
Thylacine Main	2295	2304	RFT gradient intersection
Thylacine Central	2295	2304	Inference is this block is connected to Main block
Thylacine Thy2			
Unit 1	2127	2263	RFT gradient intersection, Min - GDT from Thy-2
Unit 2	2195	2250	ML – communicates with Main_Thy1 block (some support from RFTs), Min – GDT from Thy-2
Unit 4_5	2320	2350	ML – RFT gradient interpretation, Min & Max from RFT scatter
Thylacine North	2200	2350	ML – far amplitude vs. depth cut-off, Min – communicates with Main_Thy2, Max – as Main_Thy1
Thylacine South	2295	2400	Min – communicates with Main_Thy1, Max – deeper amplitude cut-off
Geographe Main	2026	2036	RFT gradient intersection
Geographe East	2026	2090	Min – communicates with Main block, Max – deeper amplitude cut-off
Geographe North	2020	2050	Min – communicates with Main block, Max – deeper amplitude cut-off
Geographe Far North	1980	2035	Min – communicates with Main block, Max – communicates with Main block
Geographe South	1980	2035	Amplitude vs. depth cut-off
Geographe Far South	1980	2035	Amplitude vs. depth cut-off

5.12. Reservoir Fluid Parameters

5.12.1. Fluid Sampling Summary

An extensive data-set of samples have been collected and analysed from Thylacine-1 & 2 and Geographe-1. No Drill Stem Tests (DST) were conducted on Thylacine-1. However, 11 Modular Dynamic Formation Tester (MDT) samples were collected. Two DSTs were carried out in Thylacine-2 and an additional 4 MDT samples were collected. No DSTs were conducted on Geographe-1 but 10 MDT samples were collected.

5.12.2. Hydrocarbon Composition

A summary of representative fluid compositions for the respective fields is included in TABLE 11.

Compositional variations/differences between wells (Thylacine1 and Thylacine-2) and reservoir Units (1 & 2 vs. 4 & 5) are insignificant and are summarised in Figure 39.

TABLE 11 GAS COMPOSITIONS FOR THYLACINE AND GEOGRAPHE

Mole %		
Component	**Geographe**	**Thylacine**
Hydrogen Sulphide	0.00	0.00
Carbon Dioxide	4.31	9.29
Nitrogen	1.70	1.38
Methane	80.92	81.13
Ethane	7.13	4.88
Propane	2.95	1.61
iso-Butane	0.50	0.29
n-Butane	0.73	0.39
iso-Pentane	0.26	0.15
n-Pentane	0.21	0.11
Hexanes	0.25	0.14
Heptanes	0.41	0.23
Octanes	0.31	0.21
Nonanes	0.11	0.06
Decanes	0.06	0.03
Undecanes	0.04	0.02
Dodecanes plus	0.11	0.08

The compositions are used to calculate theoretical CGRs (Bbl/MMscf) and LPGs (ton/MMscf). In general, Geographe is richer in liquids than Thylacine (see TABLES 11 & 12 and Figure 40).

TABLE 12 THEORETICAL CGR'S & EXPANSION FACTOR'S

	Geographe	**Thylacine**
CGR m3/MMsm3 (Bbl/MMscf)	118.8 (18.9)	76.1 (12.1)
Expansion factor (sv/rv)	178	194

5.13. Hydrocarbons in Place

TABLE 13 summarises the current probabilistic evaluation of in-place volumes for the Thylacine and Geographe fields.

TABLE 13 PROBABILISTIC RAW GAS INITIALLY IN PLACE (GIIP)

Raw Gas Initially in Place				
Thylacine	**P90**	**P50**	**P10**	**Expectation**
GIIP Bm3 (Bcf)	27.98 (988)	37.26(1316)	49.27 (1740)	38.09 (1345)
CIIP (C5+) MMm3 (MMstb)	1.9 (12.0)	2.5 (16.0)	3.4 (21.1)	2.6 (16.3)
Geographe	**P90**	**P50**	**P10**	**Expectation**
GIIP Bm3 (Bcf)	10.11 (357)	13.17 (465)	16.99 (600)	13.39 (473)
CIIP (C5+) MMm3 (MMstb)	1.1 (6.7)	1.4 (8.8)	1.8 (11.3)	1.4 (8.9)

The hydrocarbon volumetrics estimation was undertaken using probabilistic (Monte Carlo simulation) methods utilising Crystal Ball Pro and XTRAP (Shell proprietary software). XTRAP was used to assess GRV uncertainty due to time, velocity and fluid contact uncertainty. This involves statistically generating multiple equally likely structural interpretations from the most-likely time and velocity maps, time and velocity uncertainty maps and geostatistical correlations. The resulting GRV distributions were combined with rock property distributions to derive the GIIP distributions presented above. Figures 41 & 42 are a summary of Probabilistic GIIP by block and formation for the Thylacine and Geographe fields respectively.

Figure 43 are Tornado charts that quantify the impact of the key uncertainties (GRV and net / gross) on the GIIP for Thylacine & Geographe respectively. In addition Figure 44 quantifies the relative impact of the time, velocity and GWC uncertainty on the GRV for Thylacine & Geographe respectively.

5.14. Reserves

Recoverable volumes for the Thylacine and Geographe Fields have been evaluated probabilistically using recovery factor distributions discussed in section 5.16. The results are summarised below in TABLE 14:

TABLE 14 PROBABILISTIC RAW GAS ULTIMATE RECOVERY (UR)

Ultimate Recovery				
Thylacine	**P90**	**P50**	**P10**	**Expectation**
Raw gas Bm3 (Bcf)	10.9 (448)	19.1 (678)	29.9 (957)	19.9 (693)
Condensate MMm3 (MMstb)	0.76 (4.8)	1.17 (7.38)	1.68 (10.55)	1.2 (7.57)
Geographe	**P90**	**P50**	**P10**	**Expectation**
Raw Gas Bm3 (Bcf)	3.8 (169)	7.1 (266)	11.4 (378)	7.4 (271)
Condensate MMm3 (MMstb)	0.41 (2.58)	0.66 (4.19)	0.96 (6.04)	0.677 (4.26)

Reserves distributions have been generated using a final FTHP of 1500 kPa (15 bar) and total field production of 0.57 MMm3/d (20 MMscf/d). Figures 45 & 46, and TABLE's 15 & 16 are a summary of Probabilistic GIIP and UR by block and formation for the Thylacine and Geographe fields respectively (Ref. 3).

5.15. Scope for Recovery

The Geographe field carries 0.71 Bm3 (25 Bcf) of gas scope for recovery based on a possible South block well. The poor amplitude support in this block means that there is a high likelihood of poor gas saturation and/or poor reservoir quality and hence the area has been excluded from the FDP. With only GIIP 1.78 Bm3 (63 Bcf) of GIIP within the South and Far South blocks, it is unlikely any well would be economic hence the area is considered scope for recovery. The South Geographe blocks will be re-evaluated once the development wells have been drilled to see if any upside potential can be exploited.

2.46 Bm3 (87 Bcf) of scope for recovery also exists in the Thylacine West area around Thylacine-2. There is significant uncertainty in the gas-water contacts in this block however and with the poor reservoir quality and excessive compartmentalisation seen in Thylacine-2 it is not included in the field development plan. Commercialisation would likely require additional appraisal and a successful definition of a deep gas-water contact in Unit 2, where the majority of the in-place volume would reside. Further delineation of this block should wait until additional gas is required and then should be ranked alongside exploration potential in the area.

Additional scope exists by appraisal of deeper gas-water contacts in the Thylacine North and South blocks during the phase-1 drilling. In the South block, this would allow an extra well to be drilled in a down dip fault terrace, which could develop an additional 1.7 Bm3 (60 Bcf) of reserves. Additionally, the South block pilot well will appraise a deeper amplitude supported prospect in Unit 5, which carries a GIIP of 2.55 Bm3 (90 Bcf), and a POS of 30%. No scope volumes are booked against these volumes.

TABLE 15a Thylacine Field GIIP Results

Block	Units	GIIP P90 Bm3	**GIIP P90 Bcf**	GIIP P50 Bm3	**GIIP P50 Bcf**	GIIP P10 Bm3	**GIIP P10 Bcf**	GIIP Mean Bm3	**GIIP Mean Bcf**
Central	1 & 2	2.2	78	3.5	123	5.1	181	3.6	127
	4 & 5	1.1	39	2.3	82	3.9	138	2.4	86
	Block Total	4.3	**151**	5.9	**209**	7.9	**279**	6.0	**212**
Main	1 & 2	5.2	183.8	7.2	256	9.3	328	7.2	256
	4 & 5	5.8	207	8.8	311	12.5	442	9.0	319
	Block Total	13.5	**476**	16.2	**571**	19.2	**678**	16.3	**575**
Central & Main	1 & 2	7.4	261	10.7	379	14.4	509	10.8	382
	4 & 5	7.0	245.7	11.1	392.7	16.4	580.1	11.5	405.1
	Block Total	17.8	**627**	22.1	**780**	27.1	**957**	22.3	**788**
Thy2	1 & 2	0.9	32	2.3	80	4.2	149	2.4	86
	4 & 5	1.6	57.0	2.9	103.2	5.0	176.3	3.1	111.0
	Block Total	3.0	**105**	5.3	**187**	8.6	**303**	5.6	**197**
North	1 & 2	1.8	65	4.7	167	8.4	298	5.0	175
	4 & 5	0.2	6	1.1	37	3.6	126	1.5	54
	Block Total	2.4	**85**	6.2	**218**	11.0	**389**	6.5	**229**
South	1 & 2	1.2	42	2.9	101	5.9	208	3.3	115
	4 & 5	0.1	3	0.3	12	1.0	35	0.5	16
	Block Total	1.4	**50**	3.3	**116**	6.7	**235**	3.7	**132**
Field Total	1 & 2	13.6	481	20.9	739	30.1	1063	21.5	759
	4 & 5	10.4	368	16.0	565	23.5	832	16.6	586
	All units	28.0	**988**	37.3	**1316**	49.3	**1740**	38.1	**1345**

TABLE 15b Thylacine Field UR (Raw Gas) Results

Block	Units	UR P90 Bm3	**UR P90 Bcf**	UR P50 Bm3	**UR P50 Bcf**	UR P10 Bm3	**UR P10 Bcf**	UR Mean Bm3	**UR Mean Bcf**
Central	1 & 2	1	28	2	69	3	123	2	73
	4 & 5	0.7	26	1.9	65	3.4	119	2.0	70
	Block Total	2.4	**84**	3.9	**139**	5.8	**206**	4.0	**142**
Main	1 & 2	1.9	69	4.1	145	6.4	226	4.2	148
	4 & 5	3.8	134	7.0	247	10.5	372	7.1	252
	Block Total	8.2	**290**	11.3	**398**	14.5	**514**	11.3	**400**
Central & Main	1 & 2	2.7	96	6.1	214	9.9	349	6.3	221
	4 & 5	4.5	160	8.8	312	13.9	491	9.1	322
	Block Total	10.6	**373**	15.2	**537**	20.4	**720**	15.4	**543**
Thy2	1 & 2	SFR	SFR	SFR	SFR	SFR	SFR	SFR	SFR
	4 & 5	SFR	SFR	SFR	SFR	SFR	SFR	SFR	SFR
	Block Total	SFR	SFR	SFR	SFR	SFR	SFR	SFR	SFR
North	1 & 2	0.4	14	1.5	54	3.6	129	1.8	64
	4 & 5	0.1	4	0.6	21	1.9	67	0.8	30
	Block Total	0.6	**23**	2.4	**85**	5.0	**177**	2.7	**94**
South	1 & 2	0.5	17	1.3	46	3.2	112	1.6	57
	4 & 5	0.0	0	0.0	0	0.0	1	0.0	0
	Block Total	0.5	**18**	1.4	**48**	3.1	**110**	1.6	**57**
Field Total	1 & 2	4.2	149	9.1	323	15.7	555	9.7	342
	4 & 5	5.1	180	9.7	342	15.0	528	10.0	352
	All units	12.7	**448**	19.2	**678**	27.1	**957**	19.6	**693**

TABLE 16a Geographe Field GIIP Results

Blocks	**Units**	GIIP P90 Bm3	**GIIP P90 Bcf**	GIIP P50 Bm3	**GIIP P50 Bcf**	GIIP P10 Bm3	**GIIP P10 Bcf**	GIIP Mean Bm3	**GIIP Mean Bcf**
Main	1 & 2	4.7	164	5.8	205	7.3	256	5.9	208
	4	1.0	35	1.6	57	2.5	87	1.7	59
	Block Total	6.2	**218**	7.6	**267**	9.3	**328**	7.6	**270**
East	1 & 2	0.6	20	1.0	36	1.5	54	1.0	37
	4	0.0	1	0.1	4	0.3	11	0.1	5
	Block Total	0.6	**23**	1.1	**40**	1.8	**63**	1.2	**42**
Central (Main & East)	1 & 2	5.2	185	6.8	241	8.8	310	6.9	245
	4	1.0	36	1.7	60	2.8	98	1.8	64
	Block Total	6.8	**241**	8.7	**307**	11.1	**391**	8.8	**312**
North	1 & 2	1.0	34	1.8	64	3.0	107	1.9	68
Far North	1 & 2	0.2	7	0.7	25	1.5	54	0.8	28
North Blocks	1 & 2	1.2	**41**	2.5	**89**	4.5	**160**	2.7	**96**
South	1 & 2	0.4	14	1.0	36	2.0	71	1.1	40
Far South	1 & 2	0.2	7	0.6	22	1.4	48	0.7	25
South Blocks	1 & 2	0.6	**21**	1.6	**58**	3.4	**119**	1.8	**65**
Field Total	1 & 2	8.1	287	11.2	396	15.3	539	11.5	406
	4	1.1	38	1.7	61	2.7	96	1.8	64
	All units	10.1	**357**	13.2	**465**	17.0	**600**	13.4	**473**

TABLE 16b Geographe Field UR (Raw Gas) Results

Blocks	Units	UR P90 Bm3	**UR P90 Bcf**	UR P50 Bm3	**UR P50 Bcf**	UR P10 Bm3	**UR P10 Bcf**	UR Mean Bm3	**UR Mean Bcf**
Main	1 & 2	2.6	92.0	4.1	144.4	5.6	198.3	4.1	145.4
	4	0.3	12	0.7	25	1.3	46	0.8	27
	Block Total	3.2	**114**	4.9	**173**	6.6	**234**	4.9	**174**
East	1 & 2	0.3	10.9	0.7	25.0	1.2	43.3	0.7	26.3
	4	0.0	0	0.0	2	0.2	6	0.1	2
	Block Total	0.3	**12**	0.8	**27**	1.4	**48**	0.8	**29**
Central (West & East)	1 & 2	2.9	102.9	4.8	169.4	6.8	241.7	4.9	171.7
	4	0.3	12.2	0.7	26.1	1.5	51.7	0.8	29.7
	Block Total	3.6	**126.3**	5.7	**200.7**	8.0	**282.7**	5.8	**203.4**
North	1 & 2	0.4	16	1.3	44	2.3	82	1.3	47
Far North	1 & 2	0.1	4	0.5	17	1.2	41	0.6	20
North Blocks	1 & 2	0.5	**19**	1.7	**61**	3.5	**123**	1.9	**67**
South	1 & 2	SFR	SFR	SFR	SFR	SFR	SFR	SFR	SFR
Far South	1 & 2	SFR	SFR	SFR	SFR	SFR	SFR	SFR	SFR
South Blocks	1 & 2	SFR	SFR	SFR	SFR	SFR	SFR	SFR	SFR
Field Total	1 & 2	4.0	142	6.6	233	9.7	342	6.8	239
	4	0.4	13	0.7	26	1.5	51	0.8	30
	All units	4.8	**169**	7.5	**266**	10.7	**378**	7.7	**271**

5.16. Dynamic Simulation Modelling

Full-field simulation models have been developed for both fields to accurately predict reservoir performance and to quantify the impact of key uncertainties. These models were up-scaled from geo-cellular depositional/structural models built using GEOCAP (Shell proprietary software). The work built on earlier sector simulation work carried out on both fields.

The Thylacine full field simulation model contains 37 layers with 200 x 200m areal grid blocks. The Geographe full field simulation model contains 43 layers with 100 x 100m areal grid blocks. Infinite edge and bottom water aquifers have been attached to both models.

A deterministic base case ('Most Likely' model) has been used to identify the sub-surface development and to determine the impact of uncertainties. A suite of models capturing the key uncertainties has also been used to confirm the robustness of the development across a range of sub-surface realisations, and for derivation of the recovery factor distributions used in the reserves determinations.

The drive mechanism is predominantly depletion with the faulting interpreted from the seismic significantly limiting the effect of the aquifer.

Well creaming curves have been used to demonstrate the value of each well and to confirm that no extra wells are justified. The work shows the optimum number of well completions for each of the main fault blocks, as documented in Ref. 4.

The development has been designed with mainly long horizontal wells in the poorer quality upper reservoir units 1 and 2. These wells provide good areal drainage, production rates and recovery. The planned wells for Thylacine are shown in Figures 47a - 47e and for Geographe in Figures 48a – 48c.

Initial well potential is between 1.4 and 7.1 MMm3/d (50 and 250 MMscf/d). Wells completed in the upper low permeability Units (1 & 2) decline rapidly as the pressure around the wells depletes, and a relatively long production period (25 years) is required to drain the reserves. The development will be phased to maintain deliverability and contracted gas sales, with the first platform drilling campaign installing TA-1, TA-2, TA-3 and TA-4. The second campaign, expected to be some three years later will provide a subsea tie-back for TN-1 and install the Geographe development. The expectation gas production profile is shown in Figure 49 with the comparison to the P90 and P10 production profiles shown in Figure 50.

A network model has been created in HFPT (Hydrocarbon Field Planning Tool – Shell proprietary software) to allow the individual field simulation models to be coupled together and integrated with a surface network which models the pipeline pressure drops. This allows integrated forecasts to be made for the whole of the Otway development by accurately modelling the interaction between the fields with the network running to meet sales gas contract and compression constraints.

Recovery is sensitive to the abandonment pressure and compressor suction pressure is expected to be reduced as field rates decline. A minimum compressor suction pressure of 500-700 kPa (5-7 bar) has been estimated at abandonment conditions. The corresponding platform FTHP is around 1200-1500 kPa (12-15 bar), depending upon total liquids production through the pipeline. Simulation modelling for reserves purposes has used the conservative 1500 kPa FTHP abandonment assumption.

TABLE 17: OTWAY RESERVES VS ABANDONMENT COMPRESSOR PRESSURE

Compressor pressure kPa	3000	1500	700	500
Reserves Bm3	23.65	26.34	27.30	27.36
Reserves Bcf	835	930	964	966

Condensate forecasts take account of liquid dropout in the reservoir as a function of bottom hole pressure (Figures 51 & 52).

5.17. Recovery Factor Uncertainties and Range

Multiple sub-surface realisations built around the key uncertainties have been used to generate recovery factor (RF) distributions that have been used for ultimate recovery analysis. Recovery factor distributions were generated by fault block and in the case of the Thylacine-1 fault block, two distributions were created representing the combined Units 1 & 2 and the combined Units 4 & 5. Figures 53 & 54 summarise the RF distributions by fault block & reservoir unit for Thylacine and Geographe respectively.

Sector reservoir modelling followed by full field reservoir modelling identified GIIP, reservoir permeability-thickness and potential compartmentalisation as the key dynamic uncertainties.

The final FTHP also effects ultimate recovery whilst well type (slant vs. horizontal) and well length can also impact ultimate recovery. However, these are design parameters not uncertainties.

The key uncertainties affecting recovery factor and ultimate recovery are shown in the dynamic uncertainty tree in Figure 55. Uncertainty in each of these parameters has been estimated and their impact simulated using the full field simulation models (see Figure 56 for the recovery factor tornado's per field). Probabilities of occurrence have been assigned to each outcome in order to derive RF distributions. The effect of each of these parameters on recovery is discussed below:

5.17.1. Depositional Uncertainty including Sand / Shale

Most-likely, high and low case depositional models have been generated using object based geo-cellular modelling (GEOCAP); see section 4.9 for a description of the models.

This uncertainty has a significant impact on production as both the GIIP, and in the case of Units 1, 4 & 5, reservoir connectivity are affected. In the low case depositional model where reservoir connectivity is poor due to sand-body geometry and the reduced sand / shale ratio, recovery factor is also impacted. In the high case depositional model, which models sand body geometry in the same manner as in the low case model but increases the sand / shale ratio, the recovery factor isn't impacted.

5.17.2. Fault Transmissibility Reduction

Shale gouge (SGR) is the most likely mechanism that will reduce transmissibility across faults where there is sand to sand juxtaposition. Early fault interpretation for the respective fields was based on interpretation of the time migrated 3D seismic data set. The interpretation highlighted the high fault density across both fields (Figure 57) but the lack of a significant number of fault compartments due to the 'open' network of the interpreted faults.

Re-interpretation of the seismic data after Pre Stack Depth Migration (PSDM) led to an update of the fault interpretation resulting in a higher fault density and highlighted a significant increase in fault compartments (Figure 57). As a result a probabilistic approach for estimating fault transmissibility reduction as a function of throw for each reservoir unit was adopted (see section 4.4.6). Four fault sealing scenarios were modelled. These are summarised below. Fault transmissibility reduction factors were set to zero for fault throws greater than 50m for all scenarios.

- Most optimistic fault transmissibility multiplier scenario assumed a P10 value based on shale gouge ratios generated for Thylacine-1 (Figure. 10)
- Most likely fault transmissibility multiplier scenario assumed a P50 value based on shale gouge ratios generated for Thylacine-1 (Figure. 10)
- Low fault transmissibility multiplier scenario assumed a P90 value based on shale gouge ratios generated for Thylacine-2 (Figure. 10)
- A most pessimistic fault transmissibility scenario in which fault transmissibility reduction factors were set to zero where Unit 1 and Unit 4 were offset against themselves.

Setting all the faults as sealing, results in a very low recovery factor due to the large number of fault block compartments. The possibility of this occurring is given zero probability based on field analogues and the probabilistic studies conducted on fault transmissibility reduction factors section 4.4.6).

5.17.3. Permeability Model

Uncertainty in the poro-perm correlation is incorporated in the reserves evaluation. Porosity-permeability uncertainty (+/- 2 standard deviations) has been simulated and shown to be significant. Reservoir quality will be assessed by open hole logs during development drilling.

5.18. Key Subsurface Development Uncertainties

The planned development is economically robust over a wide range of reservoir realisations. The phased drilling will allow a degree of development optimisation as the 'true' realisation becomes apparent. Key uncertainties affecting field development are listed below in order of priority:

- Compartmentalisation; affects volume of GIIP connected to development wells, hence sustainable plateau length, well productivity decline rate, drilling and compression schedules.
- Depositional Uncertainty including sand / shale ratio; affects GIIP and connectivity and hence affects sustainable plateau length, rate of depletion hence drilling and compression timing.
- Water Production; interpreted to be manageable in all realisations.
- Gas Composition / Reservoir Fluids; good coverage of data provides confidence in gas and fluid composition / properties. However, gas inerts content & CGR variation in the un-drilled fault blocks carries some uncertainty, which is not expected to be large.

5.19. Reservoir Development and Management

The key uncertainties that could impact the development that need to be identified during development drilling and early production are,

- Significantly higher or lower in-place volumes largely dictated by reservoir quality (sand / shale ratios) and gas-water contacts in un-drilled fault blocks
- Reservoir quality
- Potential fault block &/or stratigraphic compartmentalisation
- Poor initial well productivity due to 'low case' permeability outcome
- Significant &/or early water influx

The impact of the subsurface uncertainties can be seen by comparing the P90, expectation and P10 production profiles in Figure 50. In addition to the ultimate recovery (section 4.14), these parameters impact on the length of the production plateau and the timing of the phase 2 development and compression requirements. The phase 2 development of the Geographe field could be required between 1.7 and 5 years from production start-up, depending upon Thylacine results.

The uncertainties discussed above will be managed through data collection, specifically to reduce uncertainty in the following key parameters:

5.19.1. GIIP distribution and reservoir quality

Open hole logging (conventional or while drilling) will provide structural, stratigraphic and reservoir quality data. The 3D static reservoir models will be updated after each drilling campaign to re-evaluate in-place volumes, field performance and development opportunities.

FWL uncertainty will be addressed by extending development wells to intersect and appraise unpenetrated blocks.

5.19.2. Reservoir Connectivity

Logging the pressure profile in wells will identify vertical connectivity and potential compartmentalisation issues. Improved vertical communication reduces pressure differences between reservoir units. Improved transmissibility across faults increases production in all Units, particularly Units 1 & 4.

History matching of updated models after production start-up will aim to differentiate between different sub-surface realisations, for example low GIIP improved transmissibility across faults versus ML GIIP with reduced fault transmissibility scenarios. Future studies will also attempt to confirm the degree of vertical connectivity and compartmentalisation.

Preliminary studies have demonstrated the feasibility of using 4D seismic (repeat 3D seismic surveys) to monitor pressure changes and to identify 'bypassed gas' due to compartmentalisation. Further work is required to determine across the range of geological outcomes the ability to acquire 4D seismic far enough ahead of future development wells in order to be able to influence their optimisation (location and numbers).

5.19.3. Initial Well Performance

New wells will be tested prior to the drilling rig departing. Drilling damage can be determined and remedial work considered.

5.19.4. Water Production

Water production is predicted to occur in only a few development wells across the range of scenarios modelled. The main water production intervals, requiring zonal isolation capability in selected development wells, are in the good quality lower reservoir units (Unit 5 in Thylacine and Unit 4 in Geographe).

A Smart completion subsea well is planned at Geographe to manage potential Unit 4 water production (G-2). In Thylacine, TA-1 and TA-2 may cut water in the lower intervals, and where practical the completions will be designed to allow zonal isolation via wireline from the platform.

Simulation modelling has shown that the potential water producing intervals are not rate sensitive, and that reserves are relatively insensitive to the water rate used for zonal shut-off. Zonal shut-off water rates of 32 m3/d (200 bbl/d) per interval are planned for these wells. This is discussed in more detail in Ref. 5.
The plant facilities have been designed for the total expected water production rate of 160 m3/d (1000 bbl/d), but can be relatively easily upgraded to twice this capacity. Key components, such as the offshore MEG line have been sized to handle 800 m3/d (5000 bbl/d) of water, which is far in excess of any prediction and provides capacity to handle unforeseen uncertainty in reservoir behaviour.

5.20. Data Acquisition

5.20.1. Open Hole Data

Basic open hole logs will be acquired to provide geological reservoir data. These will be obtained while drilling.

Pressure profiles will be determined in the initial development wells and post start-up development wells to better understand reservoir connectivity.

5.20.2. Well Monitoring and Testing

For subsea wells (Geographe & Thylacine TN-1) the development philosophy is based on a “No planned well intervention”. As such, reservoir monitoring will be performed using permanent down-hole pressure gauges (PDHG) to provide continuous pressure and temperature data. Well tubing head pressures and temperatures will be measured continuously. Wet gas venturi meters will be installed on each flow line (ahead of the manifold) and Multi Phase Flow Meters will be installed between the manifold and pipeline in order to detect water.

During the early stage of the field life, focus will be given to establishing good correlations between THP and BHP to enable use of THP to predict BHP in the event of PDHG failure.

For the platform wells a number of options in addition to those outlined above are under consideration, including PLT’s or fibre optic cables to determine inflow profiles. However, the benefits and use of flow profile data is yet to be demonstrated. Direct vertical communication between reservoir Units and between individual sands within reservoir Units (eg. Units 1 & 4) are likely to be limited. Numerous intra reservoir faults juxtapose the various Units / Sands against each other. As a result any flow profile data obtained from wells could be history matched any number of ways.

Options are being explored to assess the connectivity within Unit1 by using one of the initial development wells, TA-1, targeted at the deeper reservoir units as an observation well for that unit. Dedicated pressure monitoring of Unit 1 in TA-1 would indicate whether the sands were in pressure communication with other Unit 1 producers see Figure 58. Any completion that allows monitoring of Unit 1 will have to be balanced against the future productivity of Unit 1 and the reliability of PDHG to obtain data.
Attempts will be made to incorporate new data into dynamic reservoir models, which will be updated/modified as required to optimise depletion policy, to update reserves and to determine further data acquisition and drilling activities.

5.20.3. Well Intervention

For subsea wells the development philosophy is based on a “No planned well intervention”. Well performance will be routinely monitored and intervention considered if a well starts to produce sub-optimally. So long as there is surplus well deliverability, the work-over could be postponed until the next drilling campaign. Alternatively, the next drilling campaign could be brought forward. If no further drilling campaigns are planned intervention (i.e. Rig mobilisation) would have to be justified economically.

For the platform wells, other drivers for intervention include setting of zonal isolation plugs &/or straddles for water shut-off and running of PLTs.

5.21. Development Drilling

5.21.1. Well Numbers & Locations

The number and phasing of wells required to deliver/maintain peak gas requirement varies due to reservoir uncertainty. The most likely geological model and preferred development concept scenario assumes 8 wells (5 wells on Thylacine & 3 wells on Geographe). This development is economically robust against most reservoir realisations.

The development concept is based on drilling 4 wells from an offshore wellhead platform and a single subsea well (TN-1) tied back at Thylacine and 3 subsea wells at Geographe. Development drilling will be phased initially drilling the 4 'platform' wells at Thylacine prior to drilling the subsea wells in 1 or 2 subsequent phases.

The well locations, for both fields, are shown in Figures 59 & 60 respectively. Future well locations (subsequent drilling phases) will be reviewed based on understanding at the time.

5.21.2. Inclusion of the Thylacine-1 and Geographe-1 Discovery Wells

Thylacine 1:

The Thylacine-1 subsea well is not compatible with the Thylacine wellhead platform, and the reserves around Thylacine-1 will be drained by the TA-1 well drilled to a nearby location. The TA-1 well is a big bore well designed to maximize productivity and extend field plateau. The key features of the TA-1 well are 9-5/8” production tubing, 9-5/8” liner through the reservoir and wireline access for zonal isolation. In comparison the Thylacine -1 well would restrict productivity with 7” tubing and 7” liner and would require the installation of a SMART completion to allow zonal isolation. There are also concerns about corrosion of the Thylacine 1 carbon steel 7” liner.

Geographe 1:

The Geographe Field will be developed using horizontal wells to mitigate the risk of reservoir compartmentalization. The G-2 horizontal well will drain the reserves around the Geographe 1 well, but in addition will access a number of blocks. If the Geographe-1 well was used instead the reserves in these other blocks could be left behind.

Thylacine 1 and Geographe 1 as additional wells

The proposed development wells could be drilled as planned but in addition the Thylacine -1 and Geographe-1 wells could be completed and tied back to provide extra capacity. This has been modelled using reservoir simulation and it has minimal impact on the production profile and plateau length.

In addition, tying back the Thylacine-1 and Geographe-1 wells has limited cost savings over drilling and completing a new well, particularly when the installation of flowlines and control umbilicals are included.

Thylacine 1 and Geographe 1 as monitoring wells
The intention is to install pressure monitoring in the new development wells, including the TA-1 and G-2 wells. This will provide the same data as if the gauges were installed in the Thylacine-1 and Geographe-1 wells.

Installing gauges in the new wells is the most cost effective method for reservoir pressure monitoring. The costs to complete the Thylacine 1 and Geographe 1 wells with downhole gauges would be prohibitive.

Thylacine 1 and Geographe 1 as back up wells
A significant risk for the Thylacine and Geographe development is the reliance on the TA-1 well. If this well was unavailable for production it is likely to cause a short fall in the contracted gas rate. A large jack up rig would be required to work over TA-1 and this could cause delays and would be expensive.

Instead the Thylacine-1 well could be tied back to the Thylacine platform and used to meet the contracted gas rate. It would be accessing the same reserves as TA-1 and as it would be completed in Units 4 and 5 would be high rate. Using Thylacine-1 as back up has the advantage of being able to use the more available semi-submersible rigs to minimize delay and is the most cost effective option to replace TM1 capacity. The Thylacine-1 well should therefore be kept as a back up well for TA-1.

Geographe-1 could be used as back up well, particularly for the G-2 well. This does not have the same impact as using Thylacine-1 to back up TA-1, as G-2 can be accessed with a semi-submersible. It is therefore more likely G-2 would be worked over and Geographe-1 would only be a back up if G-2 could not be returned to production.

Recommendations
Thylacine-1 and Geographe-1 will not be used as primary or additional wells in the development of the Thylacine and Geographe Fields.

The Thylacine-1 and Geographe-1 wells will be kept suspended to act as back up wells and for use in potential future development.

Thylacine-1 and Geographe-1 will be plugged and abandoned when they are no longer needed as back up wells and it has been determined they have no future use.

5.21.3. Development Well Completion Design

The ability to prevent and manage sand production is a key consideration in the selection of the preferred offshore gathering system (Ref. 6). Sand production is a major risk due to the inability of corrosion inhibitor to protect the carbon steel pipeline in the presence of sand. Effective corrosion management will require sand to be excluded from entering the pipeline.

Thylacine and Geographe sand strength work has been carried out to aid prediction of whether a reservoir unit is in the safe, transient or catastrophic sand production region. The sand production region combined with the development concept determines whether downhole sand control is installed, as can be seen by the decision logic summarised in TABLE 18.

The safe sand region only produces a limited amount of clean up sand and downhole sand control is not required. The transient sand region produces some sand. In a subsea case the sand enters the flowline and downhole sand control is required. In the platform with sand hydrocyclone case the sand is knocked out at surface and downhole sand control is not required. In the catastrophic sand region downhole sand control is required as sand is a threat to the well.

Development Concept	**Safe Clean Up Sand Only**	**Transient**	**Catastrophic**
Subsea	No downhole sand control	Install downhole sand control	Install downhole sand control
Platform with Sand Hydrocyclone	No downhole sand control	No downhole sand control	Install downhole sand control

TABLE 18: SAND PRODUCTION REGION COMBINED WITH CONCEPT

Applying the decision logic to the sand prediction results gives the following sand control requirements in TABLE 19.

Reservoir Unit	Subsea	Platform with Sand Hydrocyclone
Geographe 1 Unit 1	**Safe** **No sand control**	Safe No sand control
Geographe 1 Unit 2	**Safe** **No sand control**	Safe No sand control
Geographe 1 Unit 4	**Safe** **No sand control**	Safe No sand control
Thylacine 1 Unit 1	Transient Sand control	**Transient** **No sand control**
Thylacine 1 Unit 2	Transient Sand control	**Transient** **No sand control**
Thylacine 1 Unit 4A	Catastrophic Sand control	**Catastrophic** **Sand control**
Thylacine 1 Unit 4	Catastrophic (?) Sand control	**Catastrophic (?)** **Sand control**
Thylacine 1 Unit 5	Catastrophic (?) Sand control	**Catastrophic (?)** **Sand control**

TABLE 19: SAND PRODUCTION UNIT COMBINED WITH CONCEPT

The highlighted outcomes are for the proposed development concept of a Thylacine platform and Geographe subsea development.

The transient sand production for Thylacine Units 1 and 2 has been a key driver to install the platform at Thylacine to remove downhole sand control.

Due to a lack of data there is uncertainty over the sand production region for Thylacine Unit 4 and Unit 5 and on a risk basis sand control installation is warranted. In the catastrophic sand region downhole sand control is required as sand is a threat to the well.

In addition to sand control, wells completed in Units 4 and 5 will also require the capability to shut-off produced water. This requirement applies to two Thylacine wells and one Geographe well. For platform wells (Thylacine) this will be achieved by installing plugs run on wireline. Due to the costs and time associated with subsea well interventions SMART technology in conjunction with Internal Gravel Packs (IGP) will be installed for subsea wells. Reverse permeability testing will be undertaken to ensure formation damage due to drilling is minimised and the wells can be effectively cleaned up.

The 'upper' completion designs specified for the Otway development are designed to maximise well potential, reliability and to minimise the requirement for future well interventions. The majority of the wells will be completed with 5 1/2" 13Cr L80 tubing with one well on Thylacine being completed with 9 5/8" tubing to maximise potential production rates. 13Cr or higher tubulars are stipulated to combat CO_2 corrosion (10% CO_2 predicted).

A tubing retrievable safety valve will be run in all wells to maximise the through-bore ID of the completion and eliminate the requirement for regular well interventions to change out an insert safety valve. Down-hole gauges are stipulated in each design to assist reservoir management. A standard hydraulic set permanent production packer made up directly to the tubing is proposed for each well, to minimise the number of leak paths in the tubing string. See Figures 61 to 64 for schematic diagrams of proposed development wells.

5.21.4. Multi-Lateral Wells

Multi-lateral wells were considered for the Thylacine and Geographe development, but were eliminated in preference for long horizontal wells.

The well design objective is to access as many blocks in the possibly compartmentalised reservoir as possible to maximise reserves. For Thylacine this has led to the selection of the TA-1, TA-2, TA-3 and TA-4 wells with a centrally located platform. Reservoir modelling indicates the long horizontal wells are optimal for reservoir drainage and extra reservoir penetrations do not increase reserves.

Multi-lateral wells would add value by combining two wells into one well, however the well trajectories are not suitable for multi-lateral application as they are radiating away from the platform in different directions. Multi-lateral wells would be applicable if there was a requirement for multiple drainage points in a localised area; this is not the case for Thylacine.

There are also technical issues related to multi-lateral wells. The multi-lateral junction would be located in the Belfast shale. The shale will remain at a high pressure as the reservoir depletes, for a number of junction types where the shale is left exposed to the well bore this will lead to shale / junction collapse and loss of the well.

The shale has to be sealed behind the multi-lateral junction. This can be achieved with a level 6 multi-lateral. However the current level 6 junctions do not have the collapse rating required for when the reservoir depletes (there would be depleted reservoir pressure inside the junction and initial formation pressure outside the junction).

The horizontal wells will be easier to access and carry out monitoring and remedial work than a multi-lateral well, where some legs may not be accessible. Multi-lateral wells increase installation and operation risk compared to the simple horizontal wells.

Multi-lateral wells are not recommended for the Thylacine and Geographe fields because:

- Multi-lateral wells do not add significant reserves.
- Current multi-lateral technology is not feasible for the Thylacine and Geographe fields, primarily due to junction stability in depletion drive reservoirs
- Multi-laterals increase installation and operational risk

5.22. Future Exploration

Future exploration activity is expected to focus on the area covered by the Investigator 3D seismic survey and adjacent areas to the south and east. Further to the east, structural closures identified on 2D seismic data within VIC/P43 are generally small, although several large leads have been mapped in T/30P. However, absence of seal, as at Prawn-1, is considered a major risk in the eastern half of both T/30P and VIC/P43.

Numerous fault-dependent prospects and leads have been identified within the area of the Investigator 3D seismic survey, particularly the VIC/P43 portion. Of these the small Artisan prospect has been matured as a possible drilling candidate. Current exploration activity is focused on improving the Probability of Success (POS) for several potentially attractive leads north-west of Geographe that lack conventional amplitude support. These include Fagus, the Glenaire complex and Hercules. The recent Investigator North PreSDM and RockTrace (AvO) inversion projects have provided key data for this ongoing activity. Early results of this work are encouraging.

In the longer term, additional 2D seismic is planned to evaluate the Razorback/Saddleback area south of Thylacine and several leads beneath the shelf edge to the south-east. Additional 3D seismic will be acquired over hi-graded leads. Further exploration drilling will probably be contingent on identifying prospects with larger volumes and higher POS than are available in the current portfolio, either from additional seismic or by enhancing the POS of existing leads. Figures 65 & 66 summarise the location of the prospects and leads in Vic/P43 & T/30P with respect to the two discoveries. Presently no development wells are planned within the area around Thylacine-2 due to FWL uncertainty. Future studies will focus on identifying an appropriate strategy to reduce the FWL uncertainty and to mature future development options for the area.

6. DRILLING, PRODUCTION & PROCESS FACILITIES

6.1. Well Construction

The proposed development requires five wells at Thylacine and three wells at Geographe, consisting of 7 horizontal wells and 1 slanted well. Horizontal reservoir sections of 1200 to 2000m are required and the maximum step-out to total depth (TD) is 5km for the platform case (Thylacine). The wells will be completed with 5-1/2" tubing except for the slant well which requires 9 5/8" tubing (Figures 61 - 64).

Four Thylacine wells will be drilled over a platform using a Giant Jack-up in the initial drilling phase. In the second drilling phase, three subsea wells will be drilled at Geographe from a central subsea manifold and the remaining Thylacine well will be drilled as a subsea satellite well tied back to the Thylacine platform.

6.2. Offset Well Review

A total of four vertical exploration/appraisal wells were drilled in the Otway Basin by WEL in 2001. Two of the wells were suspended and two wells were plugged and abandoned.

Several areas of risk have been identified which form part of the Risk Register for detailed well planning.

6.2.1. Weather

Weather downtime in the Otway basin is a large uncertainty that will have significant impact on well construction cost. During the 2001 Otway drilling campaign, an average of 10% weather downtime was experienced during the period May to October using the Ocean Bounty semi-submersible. Weather allowance has been included in the cost estimates based on historic met-ocean and downtime data.

6.2.2. Borehole Stability

Instances of hole cavings causing hole fill and overpull were reported on offset wells in the Belfast formation. In all cases water based mud (WBM) was used and hole stability was sensitive to increases in mud weight. Studies (Ref. 7) show the development wells are drillable provided the following recommendations are taken:

- Drill out 17.5" hole sections with 1.25 sg weighting up to a maximum of 1.4 sg
- Use minimum mudweight 1.3 - 1.35 sg in all horizontal reservoir sections (minimum of 1.25 sg) depending on perceived impact of overbalance on formation damage.
- Avoid drilling along obvious faults
- Maximise angle of attack through the unconformity at the base of the Belfast Shale.
- Try to avoid re-entering the Belfast mudstone in the horizontal sections.

- Learning's of each development well need to be quickly digested and used to optimise the design of the next.
- Given the most likely stress tensor, TA-3 (TM-10) should be drilled last in order to maximise learning's from the wells prior to drilling TM-10.
- Use Non-Water Based (NWB) mud / minimise ECD variations (swab vs. surge)

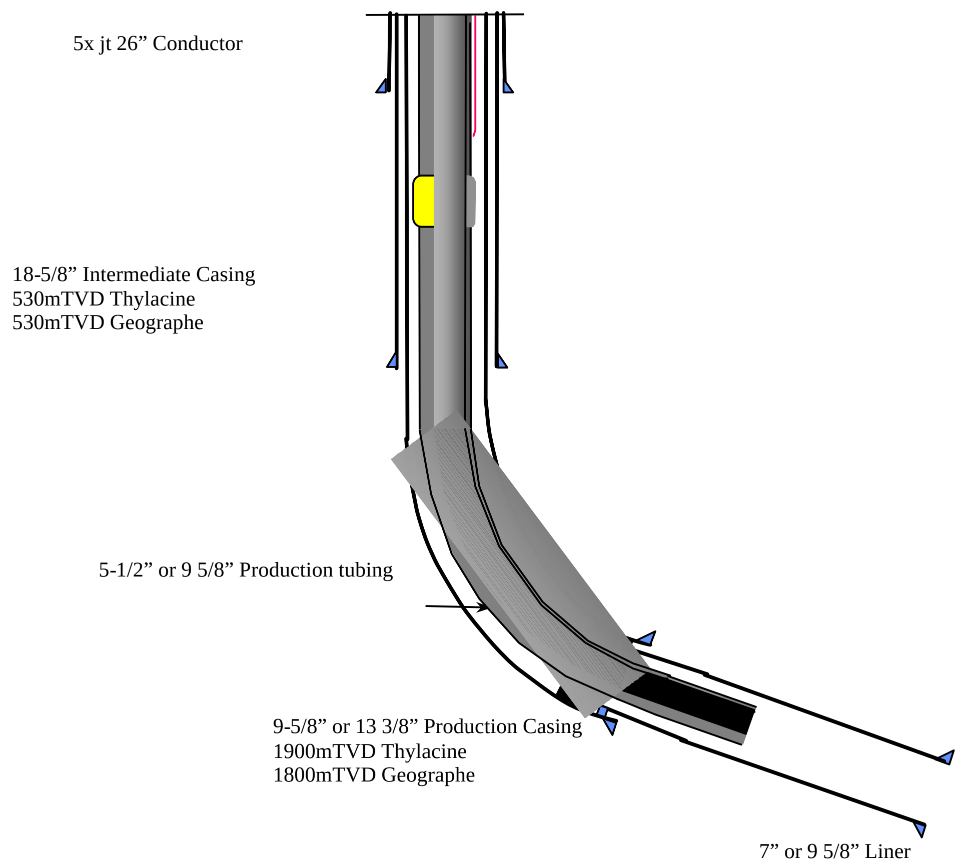
6.2.3. Toxic Gas

Concentrations of up to 5ppm of H_2S were seen in the Thylacine-2 well test while the existence of H_2S at Geographe is unknown, but is expected to be low, based on PVT samples. It is likely that the actual H_2S concentrations at Thylacine would have been higher than 5ppm if the well test had continued. The13Cr completion tubulars specified for CO2 corrosion are suitable for 15ppm H_2S and Super 13Cr is suitable for up to 150ppm H_2S.

6.3. Basis of Well Design

6.3.1. Casing Programme

The currently planned casing program for a typical horizontal well is shown below:



6.3.2. Well Trajectories

Typical bottom-hole locations have been selected for the eight wells in the current preferred concept. The platform template locations in each field have been chosen to minimise well length and complexity.

6.3.3. Drilling Fluids

Drilling fluids will be selected to meet the well objectives and to comply with environmental regulations. It is likely that Non-Water Based mud (NWBM) will be required to minimise borehole instability in the overburden formations and the long geo-steered horizontal reservoir sections.

6.3.4. Drilling Facilities

Platform wells will be drilled using a Giant/Ultra Harsh Environment jack-up cantilevered over the platform. Cost comparisons incorporating both platform and well costs show jack-up drilling to be the most economic and robust platform drilling option. Other platform drilling options such as tender assisted semi submersible drilling, modular platform drilling and pre-drilling and tying wells back to the platform have been eliminated on a cost basis.

Subsea wells will be drilled with a semi-submersible drilling rig. It is feasible for the Giant/Ultra Harsh Environment jack-up to drill subsea wells if required, although this is not anticipated.

6.3.5. Well Construction Duration

The first phase platform drilling campaign is currently estimated to take approximately 194 days, followed by the second phase which is estimated to be in the order of 205 days duration.

6.4. Facilities Description

The Geographe and Thylacine fields will be developed via:

- An offshore gathering system at each field;
- An offshore wet gas pipeline linking the Thylacine and Geographe gathering systems to shore near Port Campbell.
- A buried wet gas pipeline from shore to the onshore gas plant.
- An onshore processing facility at which raw gas will be treated and separated into sales quality domestic gas, LPG (propane and auto-gas) and condensate.

The preferred concept for the offshore gathering system consists of an unmanned (normally) wellhead platform at Thylacine and subsea cluster manifold wells at Geographe. The preferred concept field layout schematic is shown in Figure 67.

Two alternative offshore gathering systems where considered. A full subsea development with subsea wellheads in a clustered manifold arrangement at both

Geographe and Thylacine locations, controlled from shore via an umbilical piggybacked to the gas export pipeline (Figure 68). The second alternative consisted of unmanned wellhead platforms at both Geographe and Thylacine locations, Figure 69.

This section describes the key features of the preferred development concept, with eliminated alternatives described in Section .9.

6.5. Offshore Gathering System

The preferred concept will develop Thylacine by an unmanned minimal facilities tripod platform. The platform will be controlled from shore via a remote communication system. The minimal facilities topside will provide de-sanding, chemical injection, pigging facilities, telemetry to shore, and heli-deck. A Giant jack-up will be used to drill the first phase of development wells.

Geographe will be developed approximately three to four years later via clustered subsea wells drilled with a semi submersible rig. The subsea wells will be controlled via an umbilical from the Thylacine platform and will be tied into the gas export pipeline to shore at the Geographe location. Additional Thylacine well(s) will be developed via subsea satellite, cluster or daisy chain wells tied back to the Thylacine wellhead platform.

6.5.1. Metering

Accuracy and reliability of metering was another key consideration in the selection of the preferred development concept. The metering provides for the following requirements:

- Government reporting - gas rates and composition per well for monthly reporting;
- Reservoir monitoring - gas & liquid rates per well to update reservoir models and set well priorities/limits; and
- Operational requirements - water detection to control hydrate inhibitor injection.

A three part metering strategy has been developed to address gas rates, composition and water monitoring and reporting requirements.

- Gas – A wet gas venturi meter will be provided at each well for continuous gas rate determination. This will provide an instantaneous accuracy of +/-10% and will be reconciled monthly with onshore fiscal meters to provide +/- 5% accuracy.
- Composition – Initial well compositions will be determined through sampling during well clean up. Modelling will then be used to predict composition change with time (small changes due to pressure decline). Subsequent samples will be collected as required to confirm models.
- Water – A high sensitivity water cut meter will be provided per field to determine the field water rate. Well trend data and the wet gas venturi meter will be used to identify which well is breaking through water.

The use of wet gas venturi meters and sampling per well is proven technology with low risk. The high sensitivity water cut meter proposed has been laboratory tested, however no field experience is available at this stage. Operational experience of the water cut meter will become available and laboratory testing under expected Otway conditions will be conducted during the design phase. An alternative design based on flow splitting will be adopted if these design phase activities conclude that the proposed meter is inadequate. The following additional contingency measures will be adopted:

- Use of field proven components;
- Duplication of transmitters and electronics; and
- In the event of meter failure, well modelling (virtual metering) and onshore water meter feedback will be used.

6.6. Raw Gas Pipeline Offshore

A DN 500 (20 inch) pipeline will export raw gas 14kms from Thylacine to Geographe and 56kms from Geographe to shore.

The pipeline design pressure of 20000 kPa (200 bar) is based on maximum shut in tubing head pressures (SITHP). SITHP modelling has taken into consideration deeper gas water contacts in un-appraised blocks and is based on initial reservoir pressure.

The worst case is the Southern block deepest contact of 2400 mTVDss resulting in SITHP of 19900 kPa (199 bar) The majority of wells are in the central block, the gas water contact is 2298 mTVDss resulting in SITHP of 19200 kPa (192 bar).

The modelling work is conservative and lower SITHP would be expected as indicated from the two Thylacine-2 well tests which gave SITHP of 18164 kPa (181.6 bar) and 18888 kPa (188.8 bar).

The pipeline design pressure of 20000 kPa (200 bar) is above expected maximum SITHP. It should also be noted the reservoir pressure depletes rapidly, therefore the exposure time at these high SITHP's is limited.

The majority of this pipeline will be API grade 5LX-65 carbon steel in accordance with design requirements in DNV OS F101 (Submarine Pipeline Systems, Det Norske Veritas 2000). The pipeline wall thickness is estimated to be 19mm, including a 5mm corrosion allowance (see section 5.6.1). Internal corrosion will be managed through a combination of CRA cooling sections, continuous injection of corrosion inhibitor blended with MEG and periodic maintenance pigging. Performance of these measures will be continuously monitored using a pipeline corrosion monitoring system and through periodic intelligent pigging. External corrosion protection will be provided by an external coating of three-layer polypropylene and a sacrificial bracelet anode cathodic protection system.

CRA cooling sections (316 stainless steel lined carbon steel) will be installed downstream of each manifold or wellhead platform. These sections will cool the raw gas to below 60^{o}C to reduce the corrosion rate and control the rate of condensation.

Pipeline stability will be achieved through concrete weight coating and the selective use of secondary stabilisation such as rock bolts or gravity anchors. The thickness of concrete coating will range from 146 mm in shallower water to 40mm in deeper water at Thylacine.

A wellhead platform based pig launcher will be located at Thylacine allowing periodic maintenance and intelligent pigging of the pipeline.

Wet gas pipeline operation will require continuous hydrate and corrosion inhibition. This will be provided from shore via a DN100mm (4 inch) carbon steel (grade 5LX65) pipeline with external coating, piggybacked to the main wet gas export pipeline.

6.6.1. Corrosion Mechanisms and Factors

6.6.1.1. CO_2 Corrosion

Flow induced localised corrosion in CO_2 corrosion systems starts from corrosion pits, welds or other surface discontinuities where localised turbulence may be created. The localised turbulence, in addition with stresses contained within the growing scales, may result in the destruction of existing scales, and prevent the reformation of further protective scales. This type of corrosion is typically observed as parallel grooves extending in the flow direction. Flow induced localised corrosion may occur in systems with relatively high flowing velocities. Selection of corrosion inhibitors with good performance at high shear stresses will minimise the impact of flow induced localised corrosion (Ref. 8).

6.6.1.2. Temperature Effect

The temperature of the produced fluids plays a major role on the corrosion rates and corrosion processes expected within the production pipeline. There is a critical temperature where the rate of corrosion is too high for effective corrosion mitigation to control the corrosion processes enough to ensure economical and technical protection by corrosion inhibitors. In addition to increased corrosion rates with temperature, at the higher temperatures the rate of cooling of the produced fluids is great enough that water may condense at the top of line resulting in excessive TOL corrosion. However, operating and laboratory experience has shown that when the rate of condensation is decreased to low levels (< 0.25 g/m^2.s), the rate of corrosion is stifled to below 0.1 mm/yr. Therefore, if the rate of condensation is controlled, then effective control of TOL corrosion is possible.

6.6.1.3. Microbially Influenced Corrosion

There are low levels of H_2S predicted in the reservoir fluids, and without seawater injection or souring of the reservoir, MIC attack is unlikely.

6.6.1.4. Sand Erosion/Corrosion

There is a risk of solids being present in the produced fluids where processing of the gas to remove the solids does not, or cannot occur. Any solids in the produced fluids may pose a risk on the corrosion integrity of the pipeline. Solids present in sufficient quantities and velocity may result in erosion and/or erosion corrosion of the carbon steel or CRA. Erosional velocity limits have been calculated and as the maximum velocities in the main pipeline are only 1 to 2 m/s, sand erosion is not considered a problem.

Solids in the produced fluids may also remove the protective inhibitor films on the pipe walls, or settle out on the bottom of the pipe during normal or low flow conditions, acting as a barrier to the inhibitor films. In either of these situations, the effectiveness of the corrosion inhibitor may be compromised. Studies performed by BP have indicated that correct selection and application rates of corrosion inhibitors can reduce corrosion to manageable levels.

6.6.1.5. Corrosion Allowance

Corrosion allowances provided below assume that the control of sand production is such that any solids produced into the pipeline are managed, and do not impact on the efficiency of the corrosion inhibition programme. Data provided to date suggests that while there is a risk of sand production, there are adequate methods and controls available to mitigate the effect of sand production. For each of the modelled cases, the CRA requirements to achieve a 5mm lifecycle corrosion allowance for the 35 year design life case was calculated. The results of the corrosion modelling are presented below in TABLE 20.

TABLE 20: CRA REQUIREMENTS PER FIELD

Field	Spool	Flowline	Comments
Thylacine	70 m duplex stainless steel, 40 mm concrete weight coating.	0 m (0 Joints)	The first joint of the pipeline to incorporate corrosion monitoring spool.
Geographe	120 m duplex stainless steel, 40 mm concrete weight coating.	134.2 m (11 Joints)	An additional 25m of uncoated CRA between the wellhead and manifold has been modelled. CRA length based on TOL corrosion control to allow maximum uniform condensation rate to be lower than 0.25 $g/m^2.s$.
Prospect ‘X Future Tie-In 1	Not Applicable. All pre-installed pipe work to be CRA (solid duplex stainless steel).	12.2 m (1 Joint)	1 Joint of CRA downstream of CRA Hot Tap Tee. Future Tie-Ins shall ensure that condensation rates shall be less than 0.25 $g/(m^2.s)$ after the first joint immediately downstream of the Tee.(1)
Prospect ‘Y’ Future Tie-In 2	Not Applicable All pre-installed pipe work to be CRA (solid duplex stainless steel).	12.2 m (1 Joint)	1 Joint of CRA downstream of CRA Hot Tap Tee. Future Tie-Ins shall ensure that condensation rates shall be less than 0.25 $g/(m^2.s)$ after the first joint immediately downstream of the Tee.(1)

Through correct corrosion mitigation system design and operation, use of CRA sections to control cooling and TOL corrosion, a corrosion allowance of 5 mm for the carbon steel sections of the pipeline will be possible for the 35 year design case.

6.6.2. Shore Crossing

The raw gas pipeline is anticipated to cross the Victorian coast at the Rifle Range site, to the West of Port Campbell. The gas export pipeline, service pipeline (and umbilical in the full subsea development option) will be installed in horizontal directionally drilled (HDD) holes under the coastal cliffs emerging beyond the surf zone. The estimated length of the shore crossing is 1000m. One hole will be drilled for the wet gas pipeline and one hole will be drilled to house both the umbilical and service pipeline.

6.6.3. Raw Gas Pipeline Onshore

The onshore section of the raw gas pipeline will extend approximately 11.5km in a north-easterly direction to the gas plant site. The pipeline will be DN 500 (20inch) carbon steel (grade X65) with an 19mm wall thickness which includes a 3mm corrosion allowance and will be coated with either a high-density polyethylene or fusion bonded epoxy. The pipeline will be buried with a minimum cover of 900 mm and will be cathodically protected along its entire length.

The hydrate and corrosion inhibition service line will be DN 100 (4inch) and similarly coated. The service line will be buried together with the main export pipeline.

6.7. Onshore Gas Plant

The onshore gas plant is planned to be adjacent to the TXU facility near Port Campbell. The plant will be designed for 205 TJ/d peak gas export rate and will cater for 100% Geographe, 100% Thylacine or combined production of the two fields. The plant will process gas, condensate and LPG to meet sales quality specifications. Produced and condensed water will be removed from the raw gas and will be treated before being re-charged into the onshore Iona field Waarre reservoir. CO_2 will also be removed from the gas to meet the maximum inerts specification for sales gas.

The plant will consist of primary inlet separation (slug catcher), CO_2 removal, condensate stabilisation, dehydration, LPG recovery, and export metering and export compression. LPG recovery will consist of turbo expander based NGL extraction and LPG fractionation. Additional facilities include hydrate inhibitor regeneration, corrosion inhibitor injection, condensate and LPG storage, water treatment facilities and general utilities. Sales gas will be delivered to customers at the gas plant boundary before being transported via pipeline for distribution to the south-east Australian market. Condensate and autogas will be delivered via road tanker or pipeline. Propane and autogas will be delivered via road tanker (see Figures 70 & 71 - a simplified plant diagram and aerial view of proposed plant site).

6.7.1. Future Compression

Future installation of inlet compression is proposed to extend plateau production rates and maximise reservoir recovery by effectively reducing the plant inlet pressure from approximately 7000 to 3500 kPa (70 to 35 bar). Timing of inlet compression will be optimised along with well phasing.

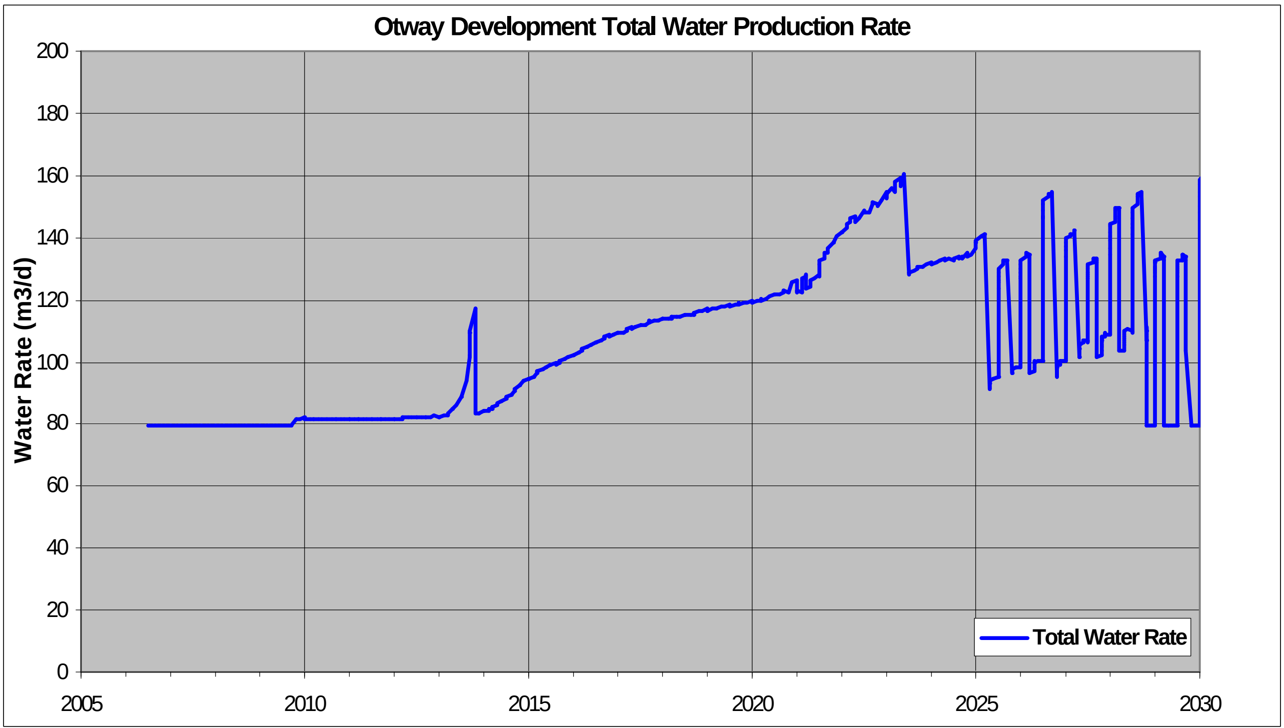
6.7.2. Facilities Capacity

The facilities capacities are listed below:

- 60 PJ/a annual contract quantity sales gas (164 TJ/d).
- Maximum contract quantity (MCQ) and plant design capacity of 125% of the annual contract quantity (ACQ) (205 TJ/day).
- Maximum sales gas export pressure of 15000 kPa (150 bar).
- Sales gas to Victorian / National specification.
- 150 - 350 tonnes per day of LPG (propane and autogas) to commercial specification.
- 159 - 397 m3/d (1000 - 2500 bbl/d) condensate to 69 kPa (10 psi) RVP maximum.
- Up to 160 m3/d (1000 bbl/d) produced and condensed water (upgradeable).
- CO_2 removal for Thylacine production, catering for up to 10.3% in the raw gas.

6.7.2.1. Water Capacity

Reservoir modelling and production forecasts indicate a maximum total water production of 160 m3/d (1000 bbl/d) (see Figure below). This comprises a constant 64-80 m3/d (400-500 bbl/d) of condensed water, and produced water which is only expected after the installation of export compression. The water processing facilities will be provided in a phased manner up to the expected maximum production rate of 160 m3/d (1000 bbl/d). Consequently, systems which are relatively easy to expand such as the MEG regeneration facilities have been designed for 160 m3/d, with potential expansion to 320 m3/d (2000 bbl/d) should it be required. Systems which are not easily expanded such as the MEG piggy back line, slug catcher and condensate flash drum are designed for 320 m3/d (2000 bbl/d). Note that due to mechanical strength requirements, the MEG piggy back line can in fact cater for up to 800 m3/d (5000 bbl/d) water production, and the plant could be similarly upgraded if required.



The base case water production profile above shows:

- 80 m3/d (500 bbl/d) constant condensed water
- No formation water production predicted until 2013 (post installation of onshore compression).
- Peak of Geographe water produced at that time (zone shut-in).
- Lower interval (Unit 5) of Thylacine TM-1 shut-in in 2023
- Low rates of formation water from other wells from 2013 to end of field life.
- Maximum formation water production rate of 80 m3/d (500 bbl/d).

Should high water rates occur early in production it is expected that this will be from a single well. A work over of the well should enable the water producing region(s) to be isolated and the water rate decreased. Early water production should be able to be curtailed by closing in the offending well until either the water zone is isolated or the water handling facilities are upgraded.

Once operating the produced water rate can be monitored and a better understanding of the wells obtained. Any increases in the expected produced water rates later in field life can be more accurately predicted and the necessary expansion to handle increased water rates can be carried out when required.

6.8. Provision for Future Tie-ins and Expansion

The planned Otway Facilities have considered not only the requirements for planned tie-ins as required in phase II but also included an allowance for future tie-ins. The philosophy adopted was to review existing fields and potential exploration prospects and to make allowance in the proposed facilities for the ability to tie-in existing or future discoveries if economically viable. TABLE 21 outlines the provision for future tie-ins to the development.

The timing of future tie-ins will likely be dictated by the requirement to maintain plateau production rates into the gas plant. Depending upon the size and reservoir quality of the prospect, tie-in could be targeted either pre, or post implementation of compression. Good quality sands would provide useful swing capacity and could be accelerated, while poorer reservoir quality would most likely benefit from the reduced FTHP post compression.

At present, the possible prospects in the area are all relatively small in size, and any deferral of production from the Thylacine and Geographe fields due to inequalities in FTHP would be quickly dissipated as the additional field was produced. This is illustrated in Figure 49, where the Thylacine production is initially partly deferred as the higher pressure and better liquids production Geographe wells come on stream; Thylacine production is required shortly after due to the relatively low Geographe volumes being quickly depleted however. Larger reservoirs could be incorporated by using manifold chokes to equalize pressures, increase overall off take rates by de-bottlenecking of the plant or by accepting some deferral of the existing fields if it proved economically more attractive.

TABLE 21: PROVISIONS FOR FUTURE TIE-INS

Wells	Location	Facilities	Product	Throughput	P50 Reserves	Temp.	Pressure	Chemical Req's
1 x S/S well	25m-2km from Geo	Spare slot on Geo manifold – product, MEG. The Geo umbilical from Thy will be sized to support 3 future subsea wells.	As per other Geo wells	As per other Geo wells	As per other Geo wells	As per other Geo wells	As per other Geo wells	As per other Geo wells
1 x S/S well	Prospect X (up to 25km away from Geo)	DN 300 Hot tap tee in DN500, DN 100 MEG, tee, controls from Geo	As per other Geo wells	50 MMscfd	Up to 50 bcf	As per other Geo wells	As per other Geo wells	As per other Geo wells
1 x S/S well	Prospect Y (up to 25km away from Geo)	DN 300 Hot tap tee in DN500, DN 100 MEG tee, controls from Geo	As per other Geo wells	50 MMscfd	Up to 50 bcf	As per other Geo wells	As per other Geo wells	As per other Geo wells
1-3 S/S wells	Thylacine north and west prospects (up to 5km away)	Spare capacity in DN 200 TN1 riser, and spare J-Tube, space for piping on Thylacine	As per other Thy wells	100 MMscfd	Up to 150 bcf	As per other Thy wells	As per other Thy wells	As per other Thy wells
3-4 S/S wells	Other southern prospects (up to 50km away)	Spare 5th conductor slot that could be riser, spare J-Tube	As per other Geo wells	As per Geographe, cluster manifold	As per other Geo wells	As per other Geo wells	As per other Geo wells	As per other Geo wells

(1) Allowance for system expansion is to be limited to these prospects. No additional financial pre-investment will be targeted.

The facilities design does not specifically allow for expansion for La Bella. However, several provisions have been made for future expansion which could come from a number of sources, including La Bella or other fields.

The platform has been provided with a spare drilling slot, spare riser capacity and spare B tubes. The platform HPU (hydraulic pressure unit) has been sized for a potential 8 subsea wells.

Additional tie-in points to the main pipeline have been allowed at two locations. Provision for additional wells has also been made at the Thylacine and Geographe fields via subsea tiebacks. Additional tiebacks could also be executed in future with a more complex hot-tap.

In case of expansion, the pipeline has capacity for up to 400 TJ/d (depending on inlet pressure) and is therefore not expected to be a capacity constraint in the future. In case of significant additional discoveries offshore, the development plan could be revised to include offshore compression.

The onshore plant is being designed with minimal pre-investment for future expansion as this would affect economic viability. However, allowance has been made for potential future tie-in of additional units as follows:

- Additional slug catcher capacity
- Additional gas treatment
- Additional fractionation
- Additional gas export compression

In addition, based on historical results, debottlenecking of the gas plant by 10-20% may be achievable with relatively minor work.

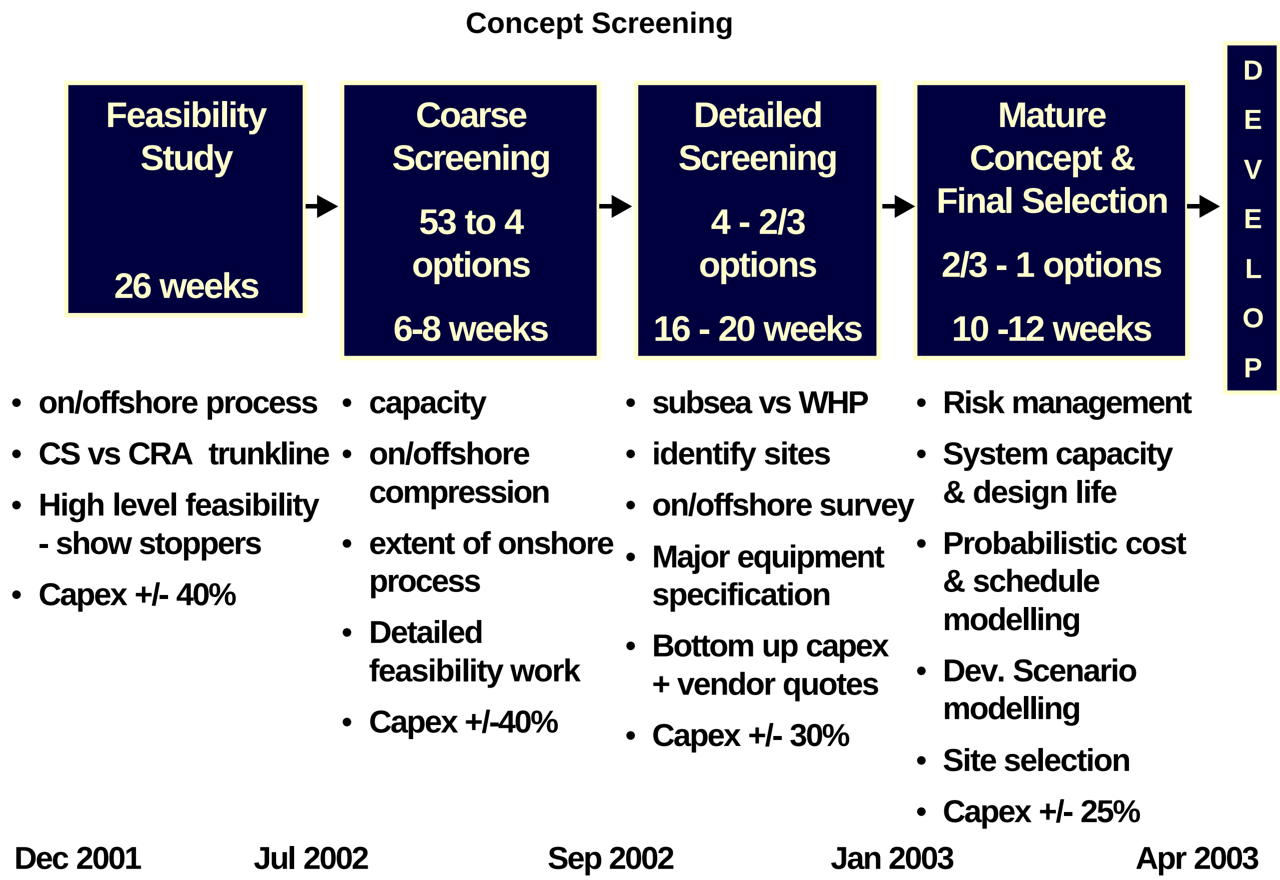
It should be noted that La Bella has about 16% inerts, compared to the Otway design basis of 11.6%, based on the worst case Thylacine sample. La Bella could be accommodated by either blending (e.g. with Geographe) or by de-bottlenecking the CO_2 extraction unit.

It should be noted that additional gas developments can be developed as either expansion in capacity, or as extension on the relatively short plateau gas production rate. In this case, no expansion of facilities is required. The life of the offshore pipeline has been specified as 35 years.

6.9. Facilities Alternatives Considered

The diagram below describes the process adopted to select the optimum development concept. Feasibility and coarse screening evaluation considered the full range of development options, parameters and costs to establish feasible and attractive options for further investigation. The key outcome of this analysis was a clear preference for onshore gas processing and compression over offshore processing options.

Selection of the short-list of preferred development options for detailed screening was based on lifecycle cost estimates including both capital and operating expenditure. Safety, environmental and technical risk assessments were also included as key screening criteria.



Detailed screening narrowed the offshore gathering system development options carried forward into final concept selection to the following:

- Preferred concept - An unmanned wellhead platform development at the Thylacine location controlling a subsea cluster manifold development at the Geographe location via umbilical Figure 67.

- Option 1 - Full subsea development with subsea cluster manifolds located at each of Geographe and Thylacine locations, controlled from shore via an umbilical. Refer to Figure 68. Subsea facilities would be developed in a cluster arrangement with manifolds located in approximately 85m of water at Geographe and 100m of water at Thylacine. Provision would be made to accommodate future satellite wells if required. Control and monitoring of the subsea wells would be from shore via a steel tube electro-hydraulic umbilical piggybacked to the gas export pipeline.

- Option 2 – Unmanned, minimal facilities, Giant Jack-up drilled wellhead platform developments at both Geographe and Thylacine locations. The three and four legged Geographe and Thylacine substructures would be located in 85m and 100m of water depth respectively. The Thylacine platform would be controlled from shore via telemetry. The minimal facilities topsides would provide for desanding, chemical injection, pigging facilities, telemetry to shore, and helideck. Refer to Figure 69.

A series of workshops and numerous peer reviews were held with a view to carrying forward the option which provided the highest value and suitability. The options screening process that was utilised considered NPV between options and concept suitability. The NPV values considered full lifecycle cost impacts areas including:

- Project economics.
- Project Schedule.
- Potential Loss of Life.
- Availability.
- Reservoir monitoring impacts.

The Suitability Index considered a variety of risk areas to complete a qualitative ranking of each option. Areas that were assessed for the coarse screening included:

- Health and Safety Risk.
- Environmental Risk.
- Implementation Risk (Cost & Schedule).
- Project Technical Risk.
- Operations / Availability Risk.

Final review of options determined that the Thylacine wellhead platform, with second campaign TN-1 subsea tie-back, and Phase 2 Geographe subsea development (Preferred Option), provided the best combination of overall value and suitability (Ref 9).

The major differentiators versus a 2 wellhead platform option were:

- Better overall project value.
- Better overall suitability.
- 2 platform option reliance on GJU drilling and platform installation for all campaigns, resulting in higher risk.

6.10. Key Technical Issues

The key technical issues are summarised in TABLE 22 below:

Area	Issue	Mitigation
Sand Production	The potential for transient sand production is a major risk due to the high uninhibited corrosion rate and inability to adequately protect the carbon steel export pipeline in the presence of sand. Effective corrosion management will require sand to be excluded from entering the pipeline.	– Platform scenarios include topside cyclonic separation de-sanding. – Subsea wells include cased and perforated completions and / or gravel packs for down-hole sand control. – Sand monitoring will be provided in all wells to determine sand production. – Maintenance pigging will be performed to further protect against sand build-up in main pipeline.
Water Production	The design basis for water production is 1000 bpd based on current subsurface modelling. Actual water production will remain uncertain until the fields are produced.	– A 'Smart' completion will be provided in the Geographe subsea well considered most likely to produce water to allow interval shut-off. – The two Thylacine wells most likely to produce water have completions which allow zonal isolation if this occurs. – A wet gas venturi meter per well and high sensitivity water cut meter per field will allow early water detection. – Hydrate and corrosion inhibition service line will be capable of increasing dose rates to address higher water production. – Onshore MEG regeneration can be expanded if necessary.
Managing Pipeline Corrosion	Raw gas will be highly corrosive to the carbon steel pipeline at temperatures above 60 deg C.	– CRA cooling sections will be provided at Thylacine and Geographe to control the temperature in the downstream CS pipeline. – A continuous, high reliability inhibition system will be used.

Table 22 KEY TECHNICAL ISSUES FOR PREFERRED DEVELOPMENT OPTION

6.11. Decommissioning

6.11.1. Wells

Well decommissioning is anticipated to involve removal of wellheads and tubing. The wells will be sealed and the conductor and casing strings cut off at about three metres below the seabed. All conductor and casing strings above that point will be removed. Subsea equipment decommissioning is anticipated to involve removal of equipment, such as the manifold, with transportation to shore for recycling.

6.11.2. Platform

Platform decommissioning is anticipated to involve removal of material above the seabed, transportation to shore for dismantling and recycling or re-use as scrap.

6.11.3. Pipeline

It is expected that decommissioning of the pipeline would entail it being thoroughly cleaned and disconnected. The offshore pipeline will then be flooded and left open-ended on the seabed. However, Woodside recognises that in some circumstances there can be a desire to leave some structures in the seabed if marine life has colonised the area. This will therefore be reviewed with the regulator of the day to determine a fit for purpose decommissioning strategy.

Decommissioning of the onshore pipeline will follow practices for pipelines set in Victoria. At present, this involves filling the pipeline with water containing a long-term corrosion inhibitor, sealing the pipeline and maintaining inspection and cathodic protection.

6.11.4. Gas Plant

It is expected that upon decommissioning the plant components will be removed and the plant site rehabilitated to at least the current condition of the site. At the end of the development's economic life all facilities will be decommissioned. Exact details of decommissioning will be established in consultation with the regulatory authorities at that time.

7. PROJECT PLANNING & MANAGEMENT

The Otway Gas Project is managed following Woodside's Opportunity Realisation Process' (OPREP) a process adopted to ensure that opportunities are progressed in the optimum manner by improving decision quality. The process involves breaking the project up into 5 distinct phases with milestone decision points and deliverables at the end of each phase. Assurance checks are required at the end of each phase before moving to the next. The phases are:

- Assess : Determine Potential Value and Business Strategy
- Select : Generate and Select the Preferred Development - Concept Selection
- Develop : Finalise Design, Cost, Schedule - Basis of Design, Front End Engineering
- Execute : Produce the Operating Assets - Engineer, Construct and Commission
- Operate and Evaluate : Maximise performance and value of asset

7.1. Schedules Defining Key Events

The updated Level 1 Schedule is presented in Enclosure 5.

7.2. Statutory and Other Approvals Schedule

The development of the Thylacine and Geographe gas fields, offshore and onshore pipeline and the onshore gas processing plant are subject to a range of planning, environmental and development approvals under Commonwealth, Tasmanian and Victorian State legislation and regulations.

The environmental impact assessment process for the Otway Gas Project is being undertaken under the provisions of:

- the Victorian Environment Effects Act 1978 (EE Act); and
- The Commonwealth Environment Protection and Biodiversity Conservation Act 1999 (EPBC Act).

The Victorian and Commonwealth governments have agreed to a co-ordinated environmental impact assessment process and preparation of a single Environment Effects Statement (EES) / Environmental Impact Statement (EIS).

The joint Victorian and Commonwealth environmental impact assessment process is being used to provide information to decision makers for the resource development, pipeline and gas plant construction and operation, land use planning, safety and environmental approvals. A number of project ‘start up’ approvals are being sought concurrently with the impact assessment process. These approvals include:

- an Amendment to the Corangamite Planning Scheme for the gas processing plant under the *Planning and Environment Act 1987* (Victoria);

- a Works Approval for the construction and operation of the gas processing plant under the *Environment Protection Act 1970* (Victoria); and

- A permit to own and use a gas pipeline under the *Pipelines Act 1967* (Victoria).

Once the Victorian Minister for Planning and Commonwealth Minister for Environment and Heritage have assessed and approved the EES/EIS, there are a number of other subsequent approvals, permits and licences that will need to be obtained for the project to meet land acquisition, safety and environmental obligations.

The steps for the joint environmental impact assessment process are summarised in the flow chart below with the required approvals; permits and licences for establishment and/or operation of the onshore and offshore components shown in TABLE 23.

A detailed schedule of the Project approvals is provided as Enclosure 6. This is only a preliminary schedule and is yet to be tabled with the appropriate government agencies for endorsement to ensure coverage of the necessary approvals. Appropriate allowances for time have been allocated to achieve all the approvals.

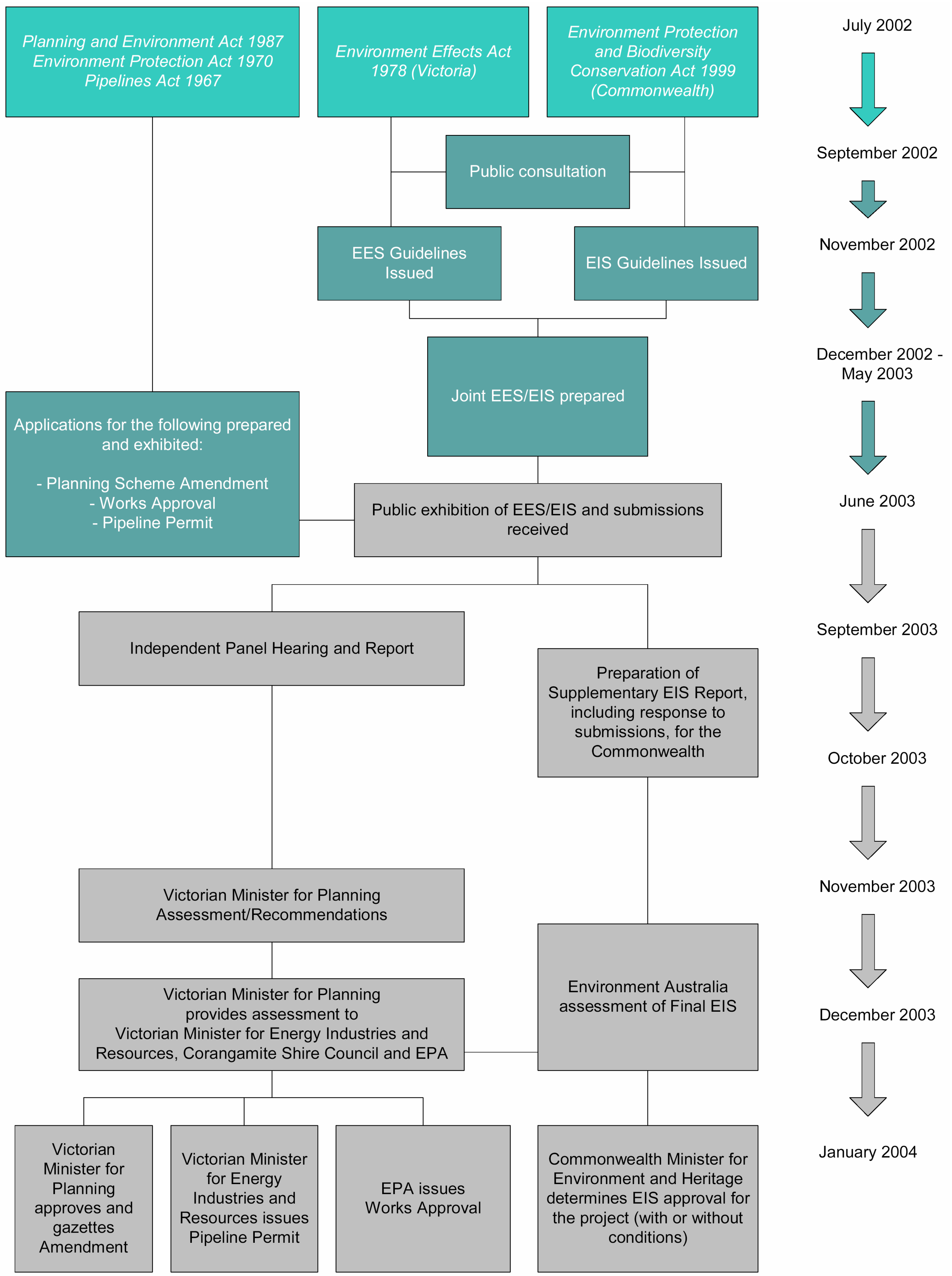


TABLE 23: KEY PROJECT REGULATIONS AND APPROVALS

Project Element	Act	Regulations	Approval	Administering Agency
Gas Plant	Planning and Environment Act 1987 (Victoria)		Planning Permit	Local Shire Council/s /Minister for Planning
	Occupational Health and Safety (Major Hazard Facilities) Regulations 2000 (Victoria)	Safety Case Acceptance	WorkSafe (Victorian WorkCover Authority)	
	Environment Protection Act 1970 ( )		Works Approval	Environment Protection Authority (EPA)
	Pipelines Act 1967 (Victoria)	Pipelines Regulations 2000	Pipeline Permit	Department of Sustainability and Environment (DSE)
	Gas Safety Act 1997 (Victoria)	Gas Safety (Safety Case) Regulations 1999	Safety Case Acceptance	Victorian Office of Gas Safety
Onshore pipeline	Pipelines Act 1967 (Victoria)	Pipelines Regulations 2000	Pipeline Permit	DSE
			Pipeline Licence	DSE
		Gas Safety (Safety Case) Regulations 1999	Safety Case Acceptance	Office of Gas Safety (via DSE)
Shore Crossing	Coastal Management Act 1995	None	Use or development on coastal Crown land	DSE
Offshore Pipeline	Petroleum (Submerged Lands) Act (Commonwealth) 1967	P(SL) (Pipelines) Regulations 2001	Pipeline Licence	DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities
			Consent to construct a pipeline Consent to use a pipeline	DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities
		P(SL) (Management of Environment) Regulations 1999	Environment Plan	DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities
	Petroleum (Submerged Lands) Act (Victoria) 1982	Petroleum (Submerged Lands) Regulations 2001	Pipeline Licence – Conditions attached to the Licence will reflect Commonwealth P(SL) Regulations	DSE
Offshore Facilities/ Subsea Production System	Petroleum (Submerged Lands) Act (Cwth) 1967		Production Licence	DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities
		P(SL) (Management of Safety on Offshore Facilities) Regulations 1996		DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities
		P(SL) (Management of Environment) Regulations 1999	Environment Plan	DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities
		P(SL) Occupational Health and Safety Regulations		DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities

Project Element	Act	Regulations	Approval	Administering Agency
Well Drilling	Petroleum (Submerged Lands) Act (Cwth) 1967	P(SL) (Management of Safety on Offshore Facilities) Regulations 1996	Approval to drill	DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities
		P(SL) (Management of Environment) Regulations 1999		DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities
		P(SL) Act Schedule Specific Requirements as to Offshore Petroleum Exploration and Production		DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities
		P(SL) Occupational Health and Safety Regulations		DSE (Victoria) and Minerals and Resources Tasmania (MRT) as the designated authorities

7.3. Health, Safety and Environment

It is Woodside's policy to integrate Health, Safety, Environment and Risk Management into every aspect of its business activities. Woodside have developed and issued Corporate Environmental Standards and Aspirations (W1000AH139319) as well as corporate guidelines for HSE Planning and HSE Strategic Objectives that are titled respectively: *Guidelines for HSE Planning (Document No. HSE 21)* and *HSE Strategic Objectives (Document No. HSE-22).*

To this end the Project will act positively to prevent injury or ill health to personnel or damage to facilities and the environment. At all times the Project will comply with all safety, fire, health and environmental laws and regulations without regard to the degree of enforcement.

The Otway Development Project is progressively integrating the following general principles of effective HSER management in all aspects of its activities through:

- Preparation of HSE Management Plans which will facilitate implementation of WEL's Health and Safety & Environmental policies.
- Setting and monitoring of meaningful HSER goals and objectives
- The acceptance of responsibility at and from WEL management, exercised through a clear chain of command throughout the project organisation, including contractors. A conviction that the highest standards are achievable through proper management.
- Ensure that Contractors understand and adhere to WEL's Health, Safety and Environmental policies and standards.

- Application of relevant standards, good engineering practice and principles of risk management consistent with ALARP principals.

- The development of, and operation in line with, the requirements of appropriate safety cases for the facilities involved. The safety cases being a demonstration that risks have been identified and analysed, and that appropriate controls and contingency measures are in place for the proposed development.

- Every member of the Project team has a duty to ensure that WEL's policies and principles are adhered to and to take all steps to prevent unsafe features being incorporated into the design and to reduce risks to personnel and facilities.

- Continued review and improvement processes being put in place to allow immediate rectification of any areas where deficiencies exist.

8. FIELD LIFE

Field life has been forecast using a combined Thylacine & Geographe minimum economic production rate of 0.6 MMm3/d (20 MMscf/d) raw gas production.

The resulting field life is circa 25 years in the Expectation sub-surface realisation. Production declines below the plateau rate during the initial third of field life.

It is assumed that gas sales contracts can be extended and managed through the decline phase of the fields by bringing on further discoveries to back-fill the decline in Thylacine and Geographe.

The offshore facilities have been designed for a life of 30 years and the offshore pipeline has been designed for 35 years. Decommissioning of the facilities at the end of field life will be undertaken in line with prevailing legislation.

9. REFERENCES

1. Norvick, M.S, and Smith, M.A., 2001, Mapping the Plate Tectonic Reconstruction of the Southern and South Eastern Australia and Implications for Petroleum Systems. APPEA Journal, pages 15 – 35.
2. Select Phase Petrophysical Review of the Thylacine & Geographe Gas Fields, DRIMS # 179500, December 2002
3. Otway Development – Volumetrics and Reserves Report (Post AC3 Update), DRIMS # 254 439, May 2003
4. Creaming Curves Note for File, DRIMS # 339 292, September 2003
5. Otway Development – Water Production Note for File, DRIMS # 377 477, September 2003
6. Thylacine and Geographe Sand Prediction Study, DRIMS # 190 921, January 2003
7. Thylacine/Geographe Borehole Stability Report, DRIMS # 371 764, Sept. 2003
8. Pipeline Corrosion Potential and Mitigation, DRIMS # 267 814, June 2003
9. Concept Selection Report, DRIMS # 242 761, April 2003

Thylacine & Geographe Location

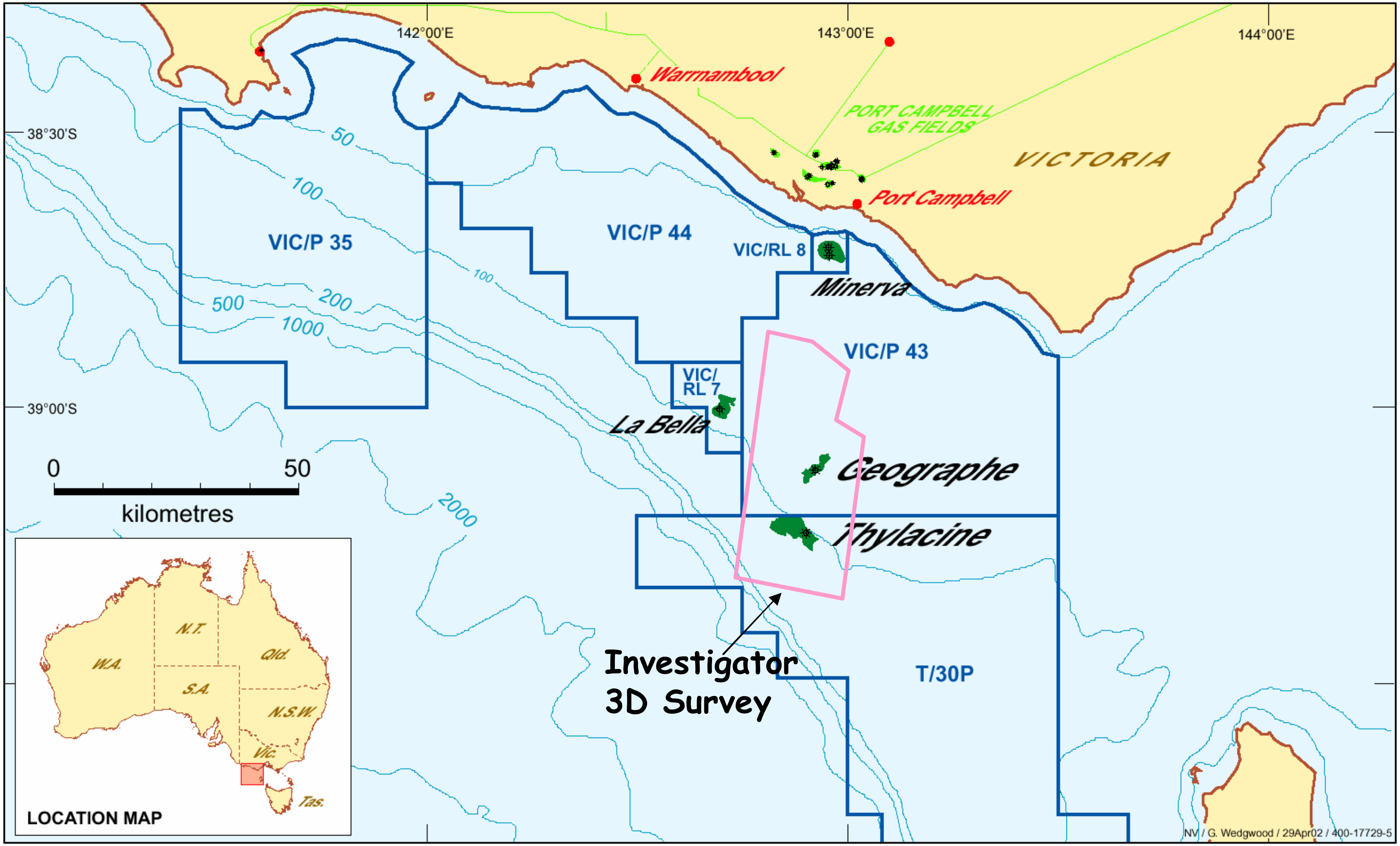


Figure 1

Thylacine Field - Top Porosity (Unit 1) Depth Structure

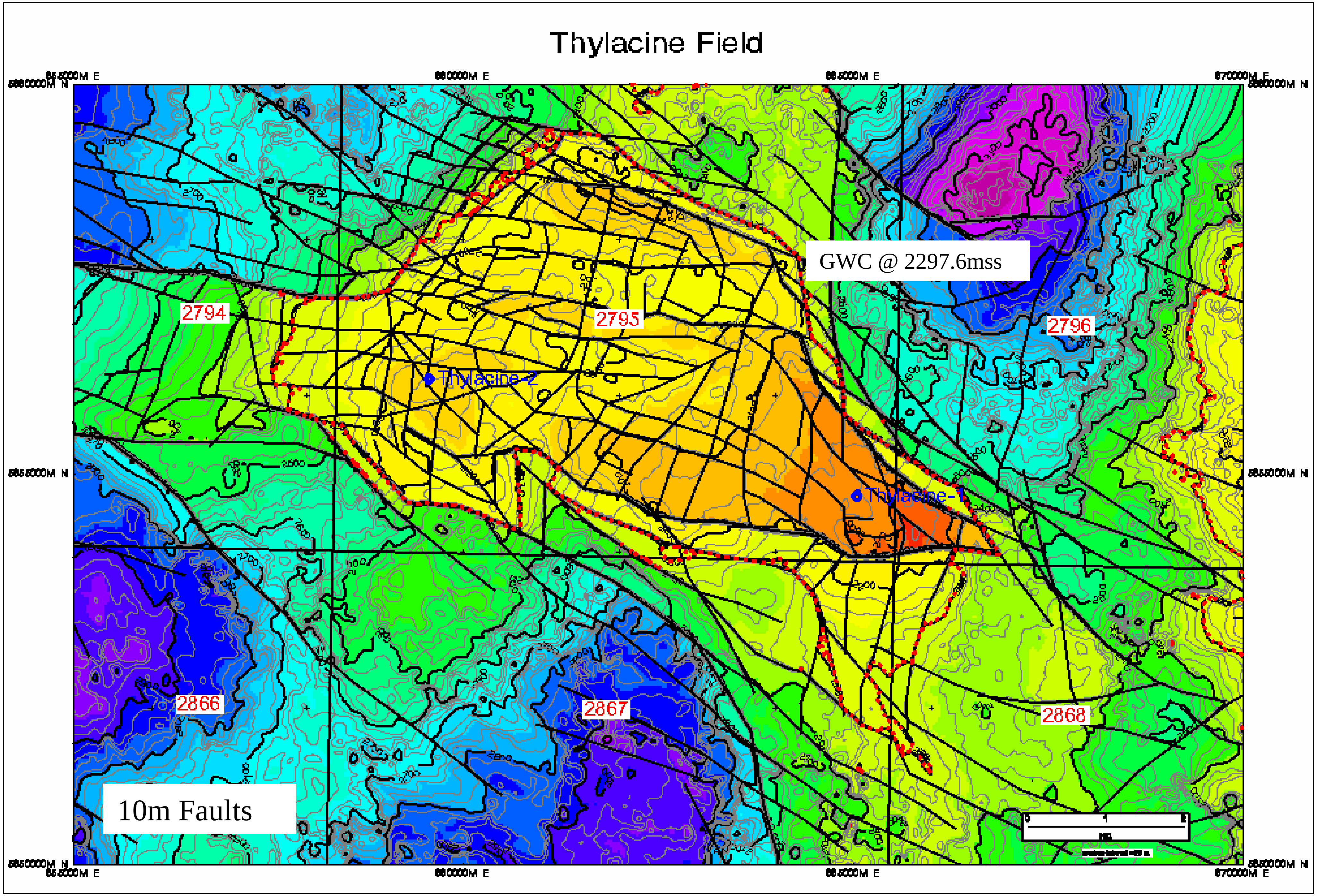


Figure 2

Thylacine Field - Far Offset Amplitudes (Unit 1)

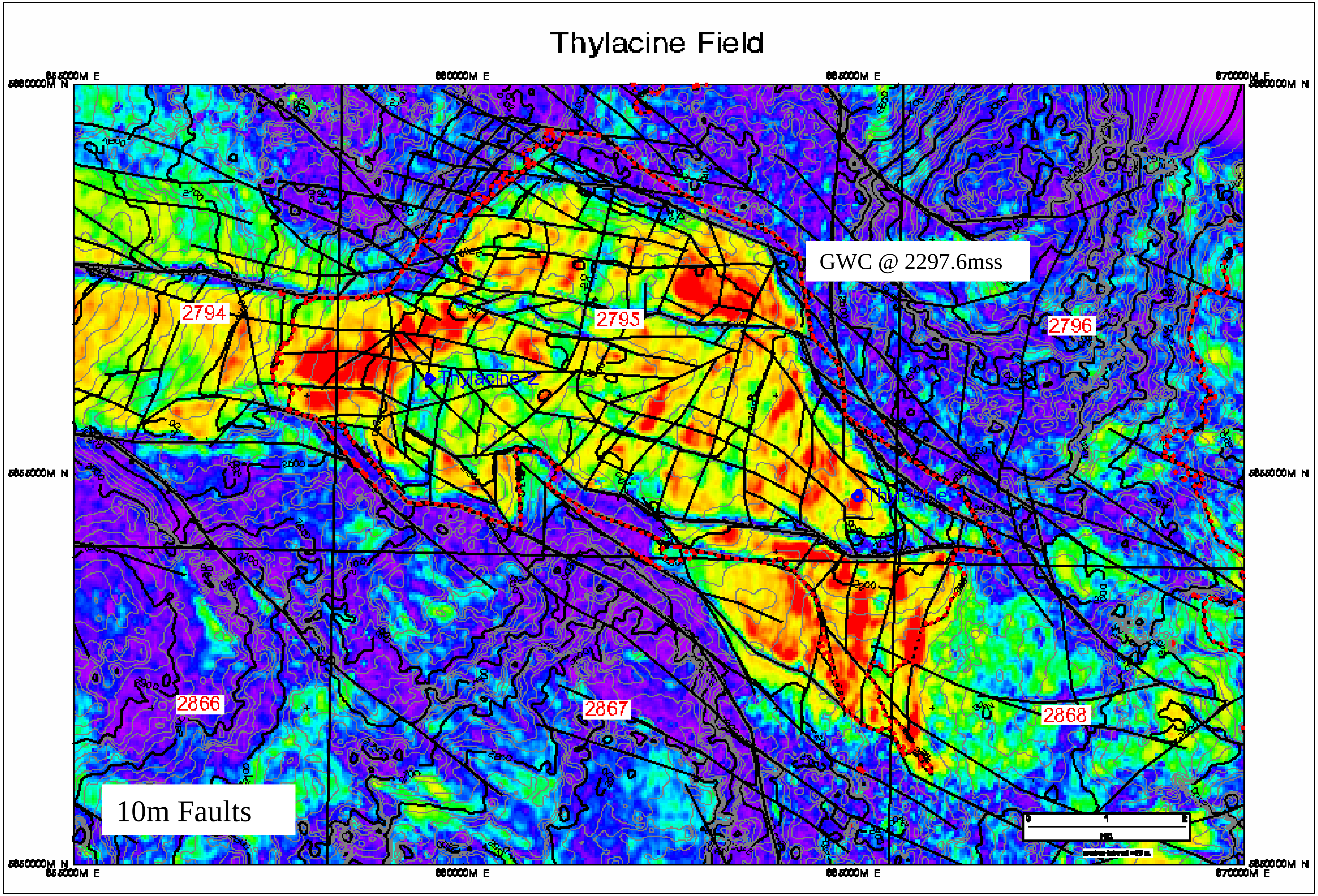


Figure 3

Geographe Field - Top Porosity (Unit 1) Depth Structure

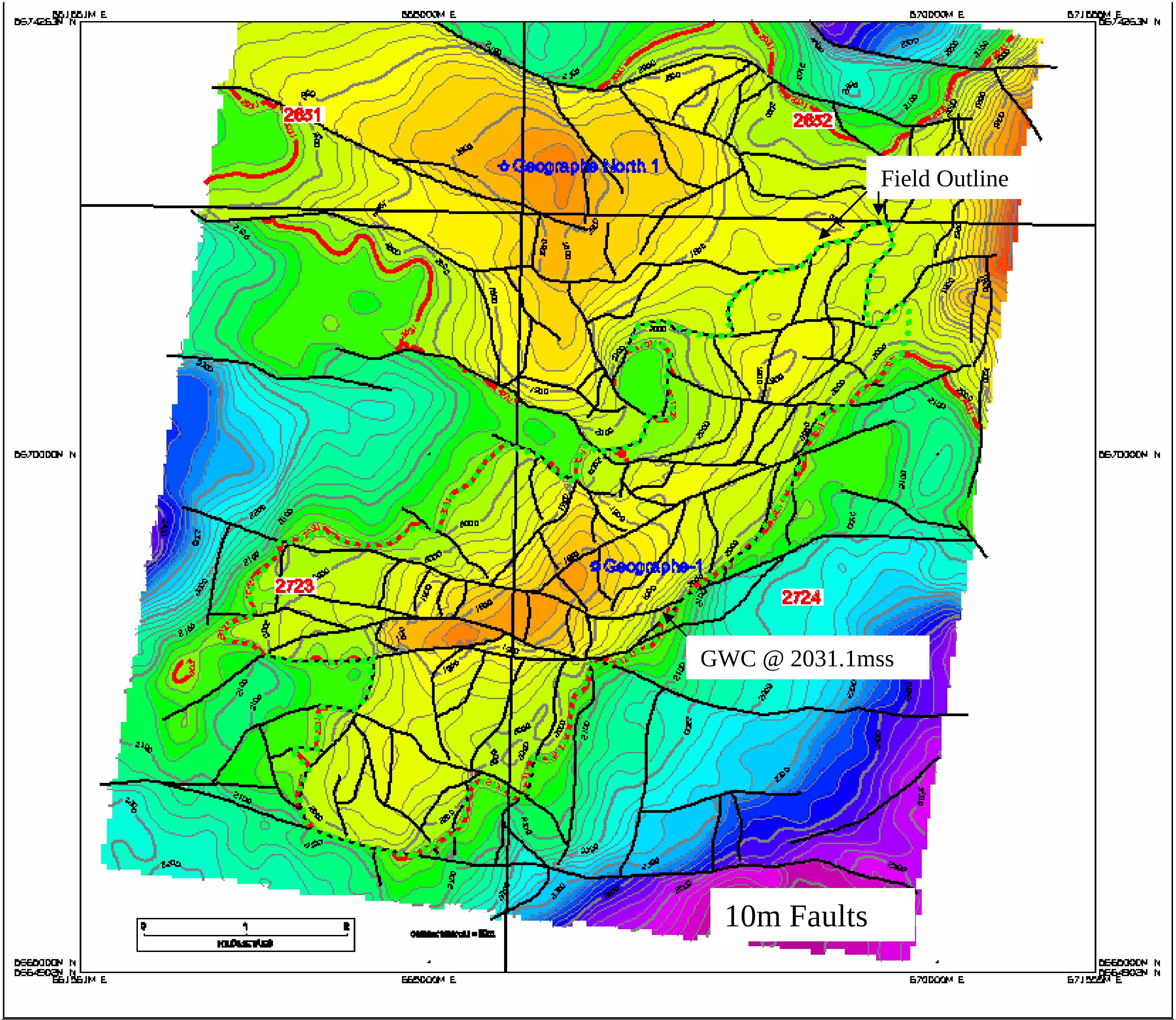


Figure 4

Geographe Field - Far Offset Amplitudes (Unit 1)

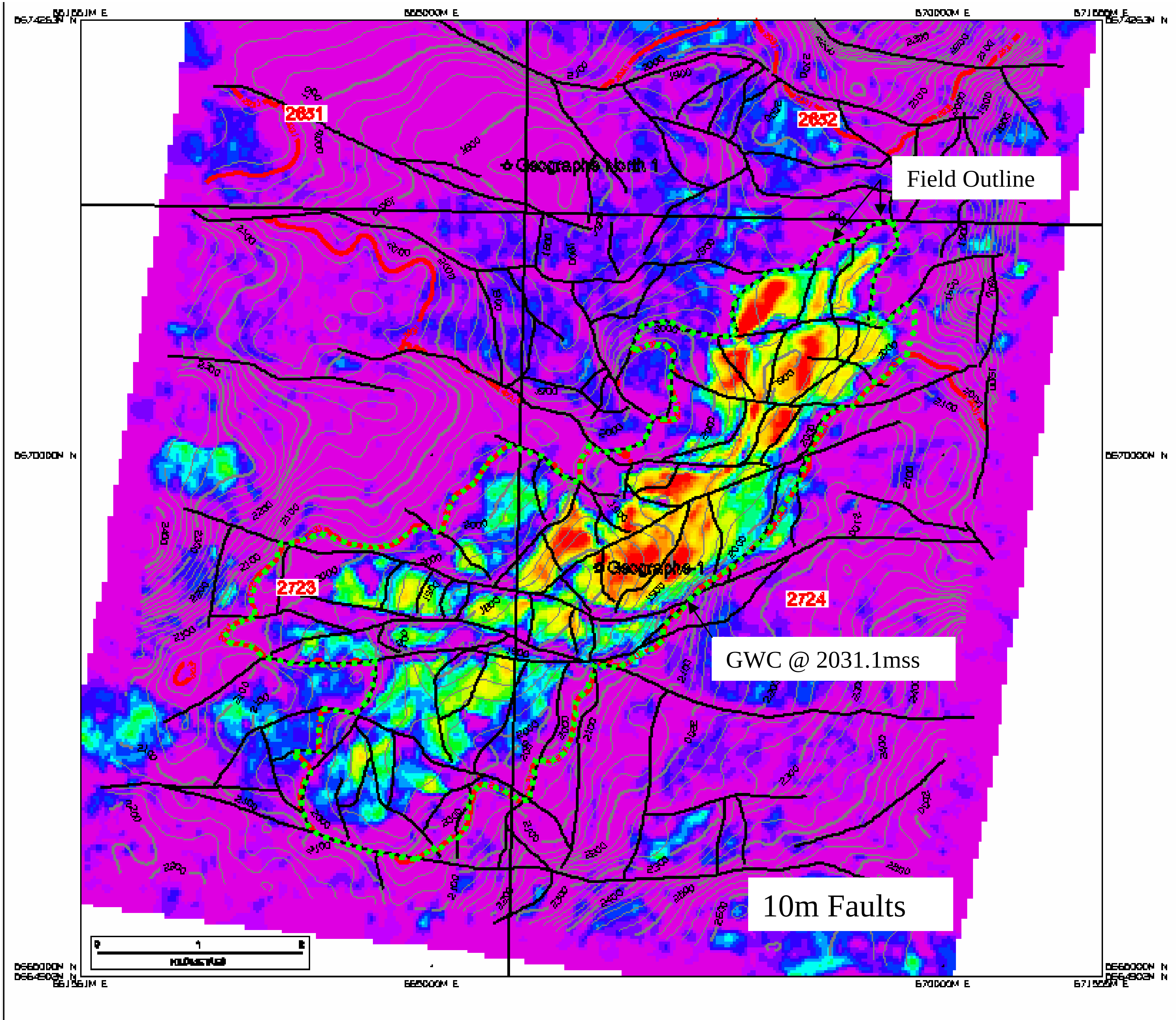


Figure 5

Southern Australia Plate Reconstructions from the Late Cretaceous

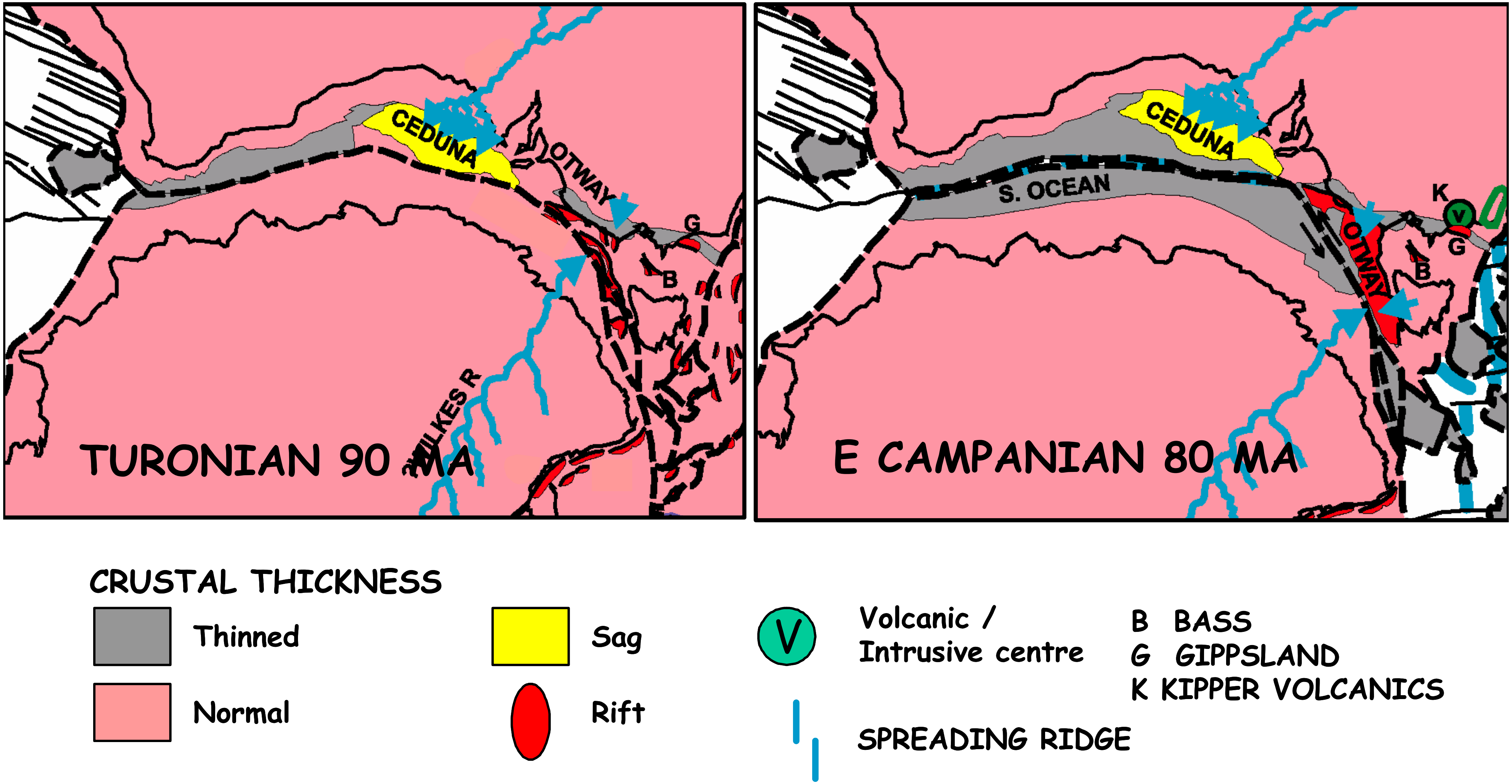


Figure 6

Structural Elements, Otway Basin

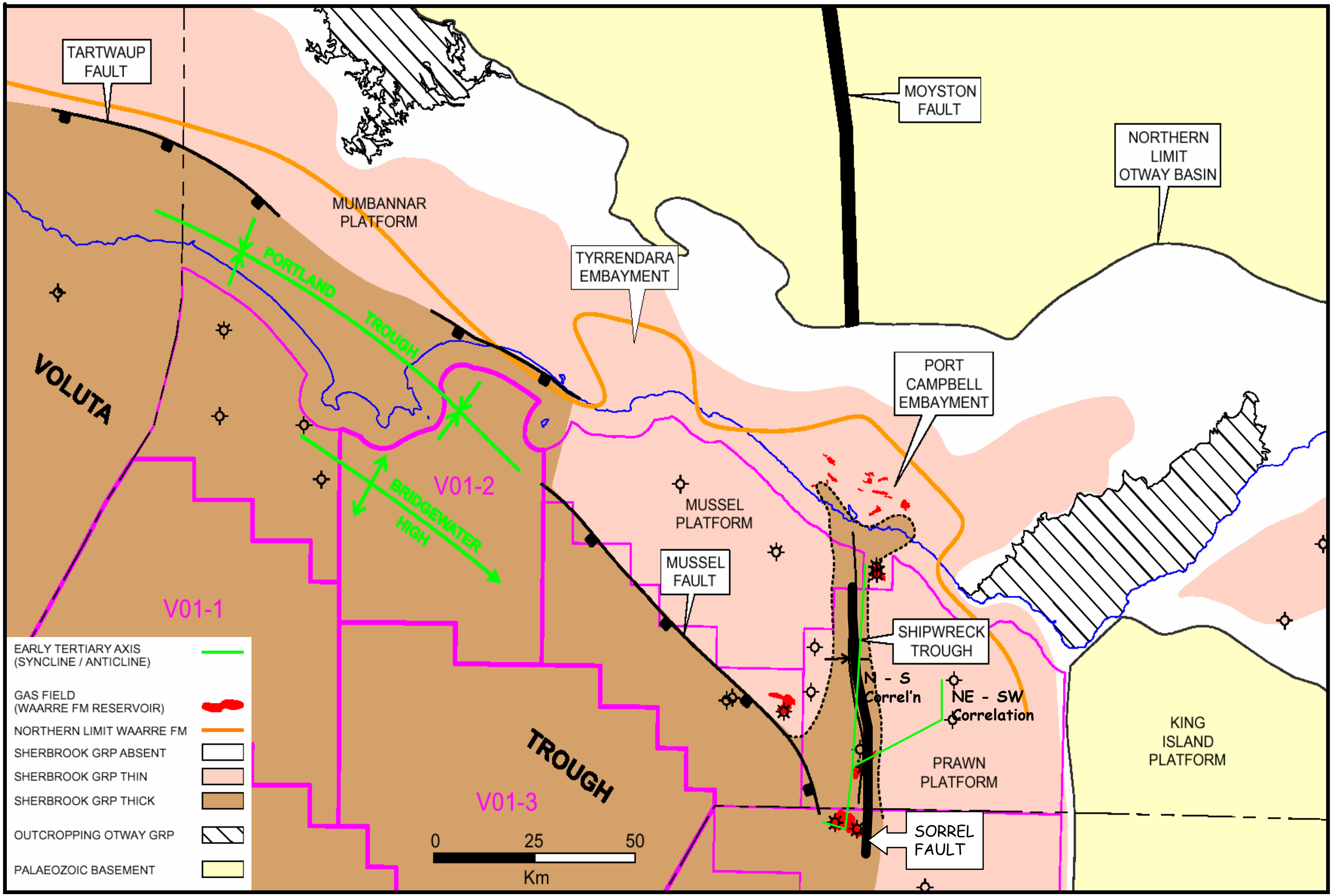


Figure 7

Thylacine-2 to Thylacine-1 Seismic Line

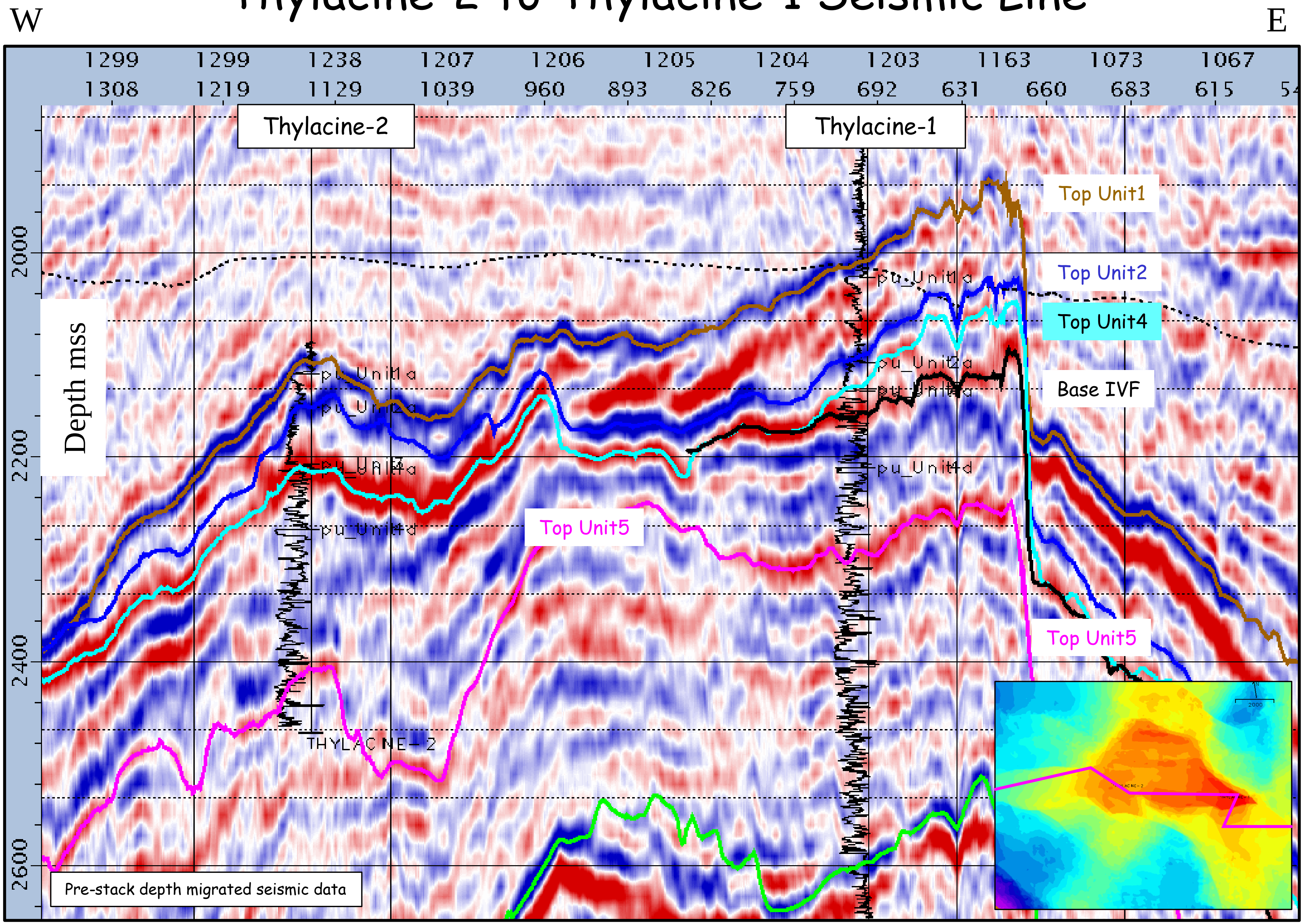


Figure 8

Geographe-1 to Geographe North-1 Seismic Line

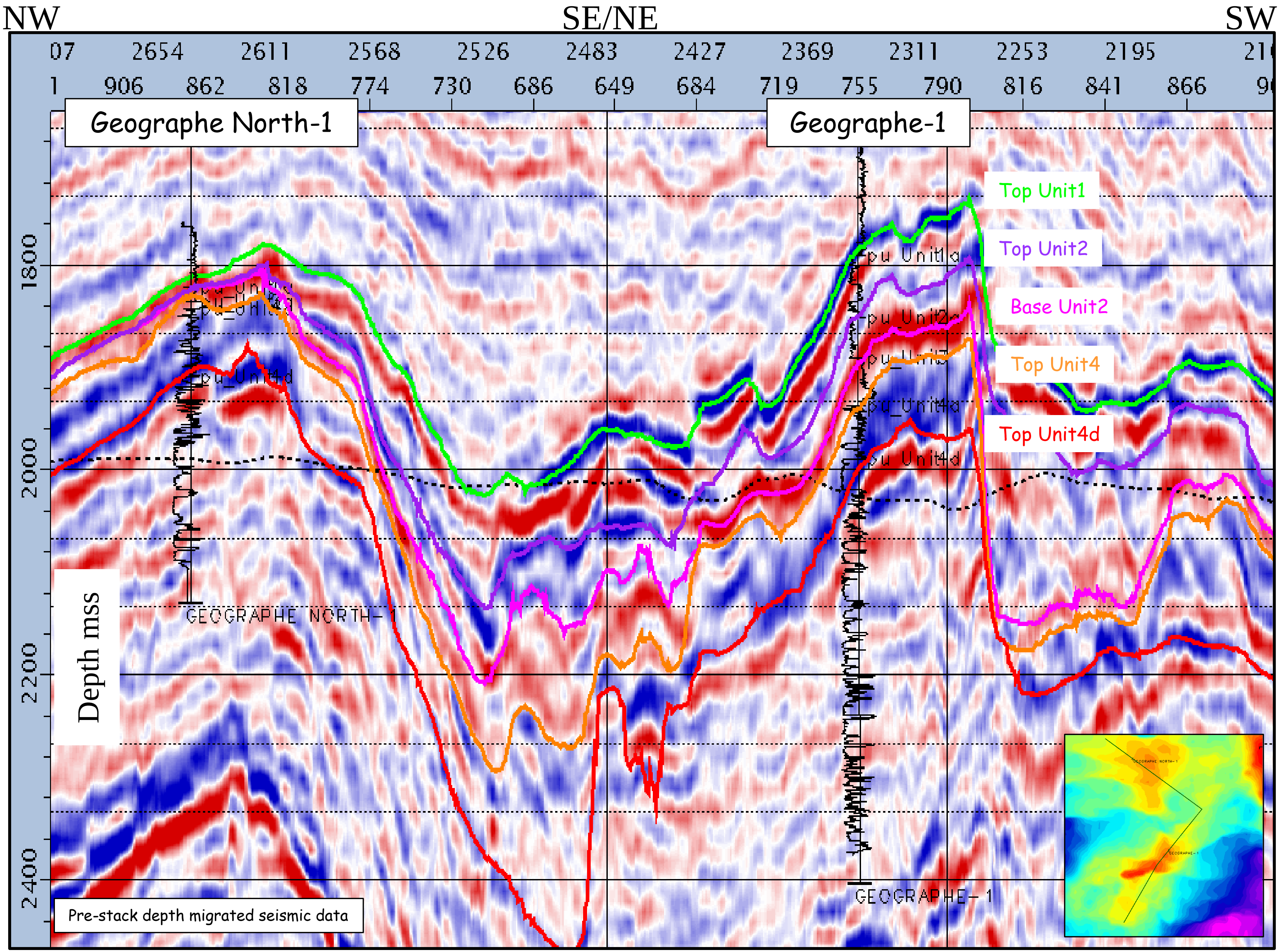


Figure 9

Fault Handling - Probabilistic transmissibility reduction factors applied to faults

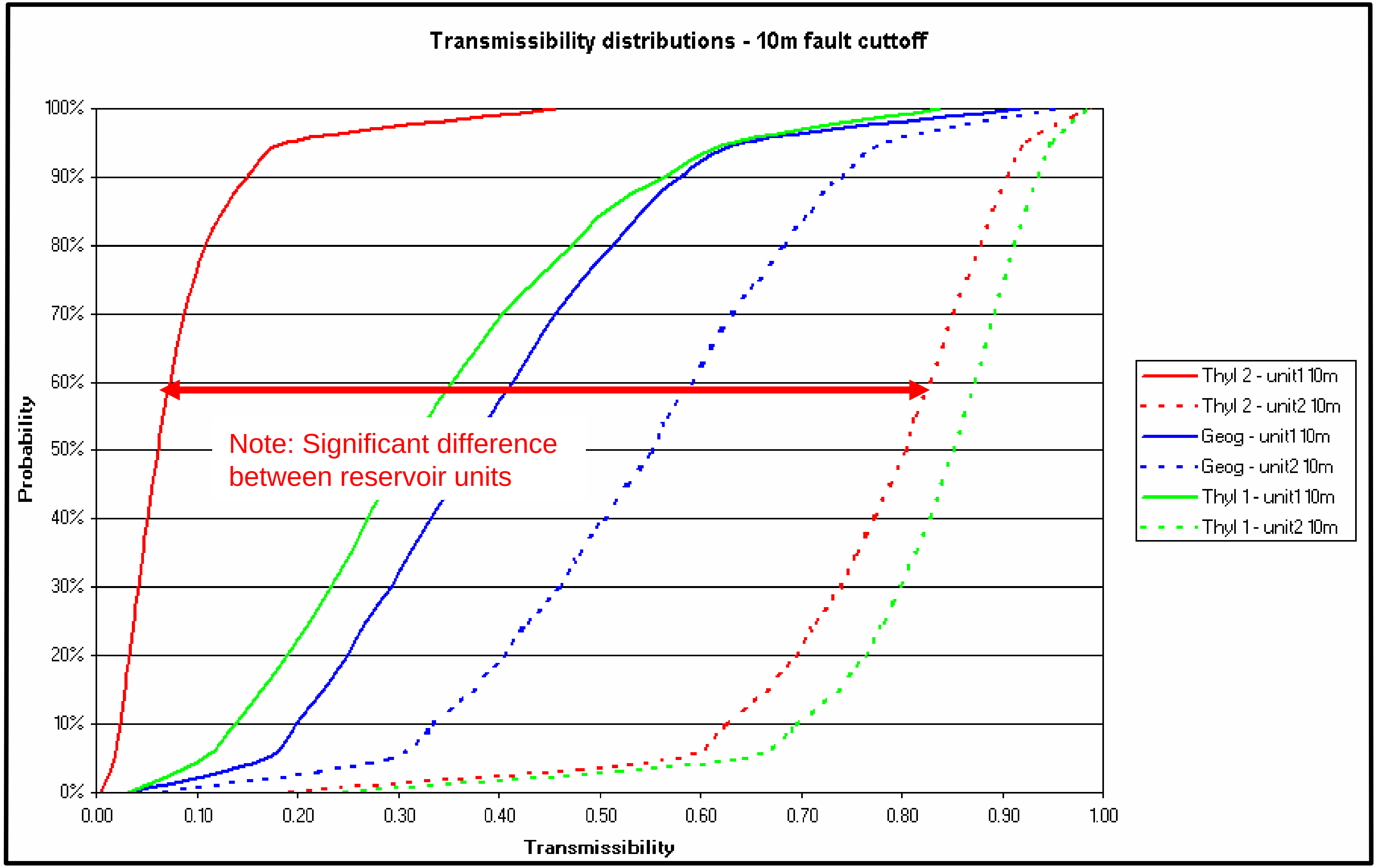


Figure 10

Otway Basin Late Cretaceous Lithostratigraphy/Biostratigraphy

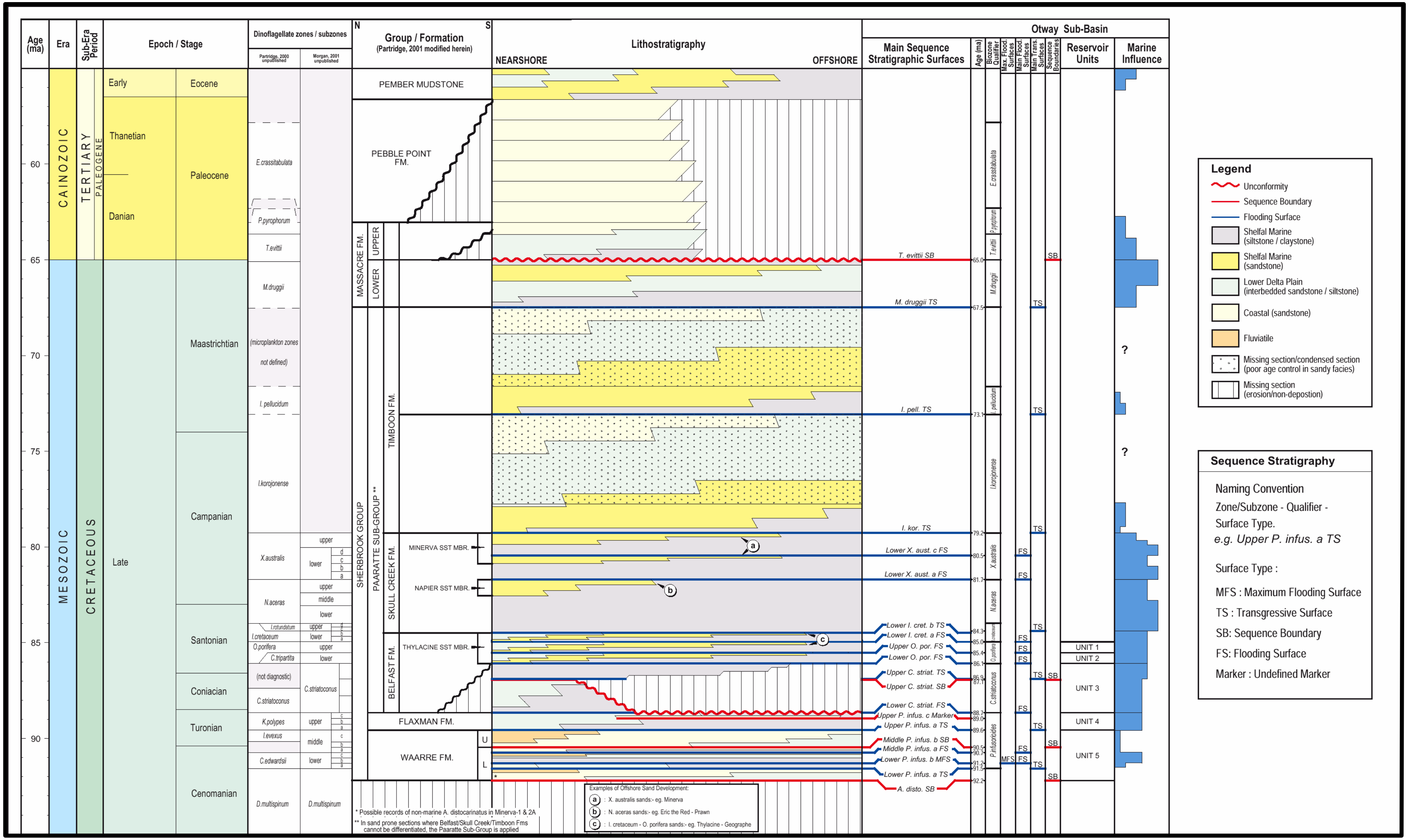


Figure 11

North to South Biostratigraphic Correlation

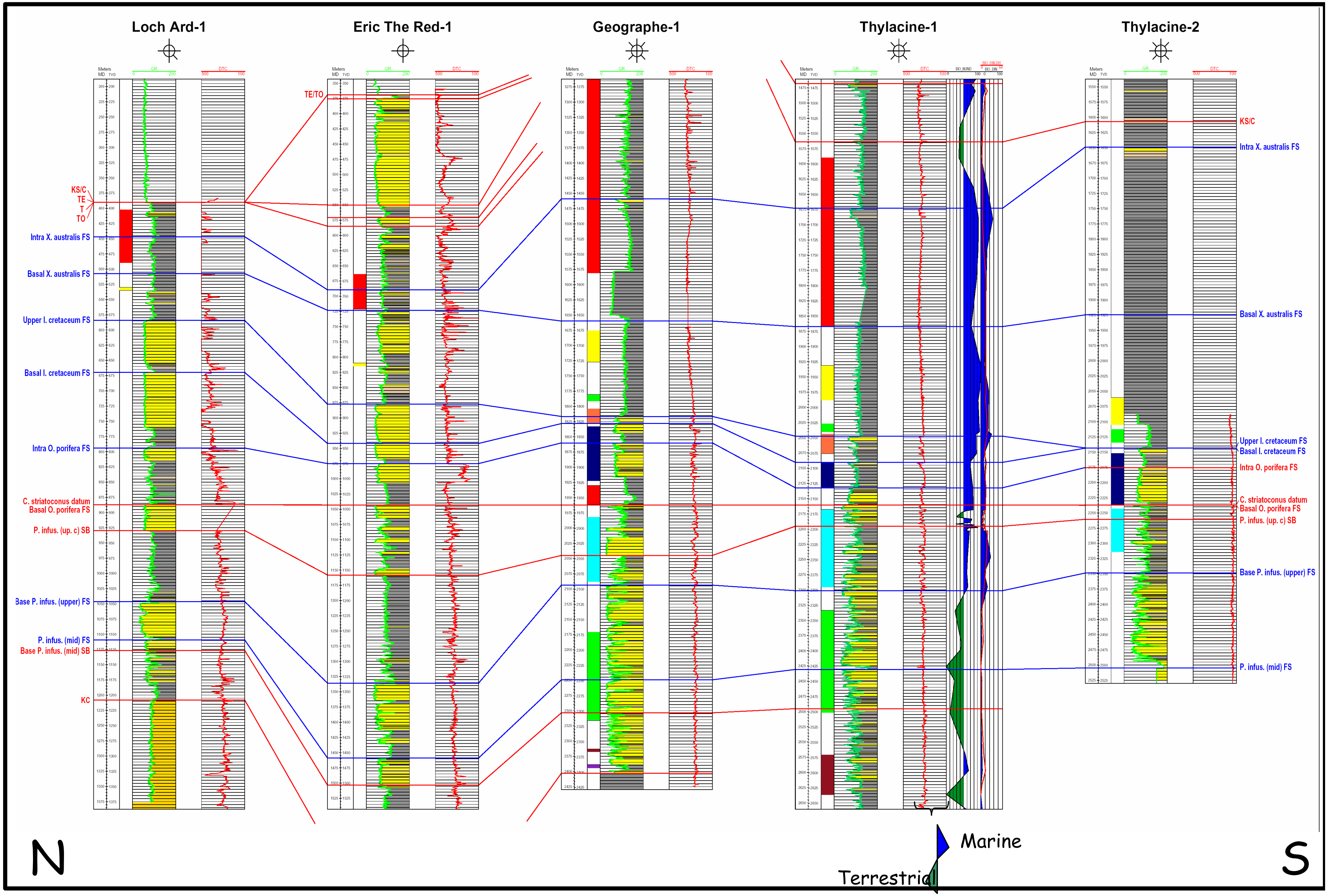


Figure 12

NE to SW Biostratigraphic Correlation

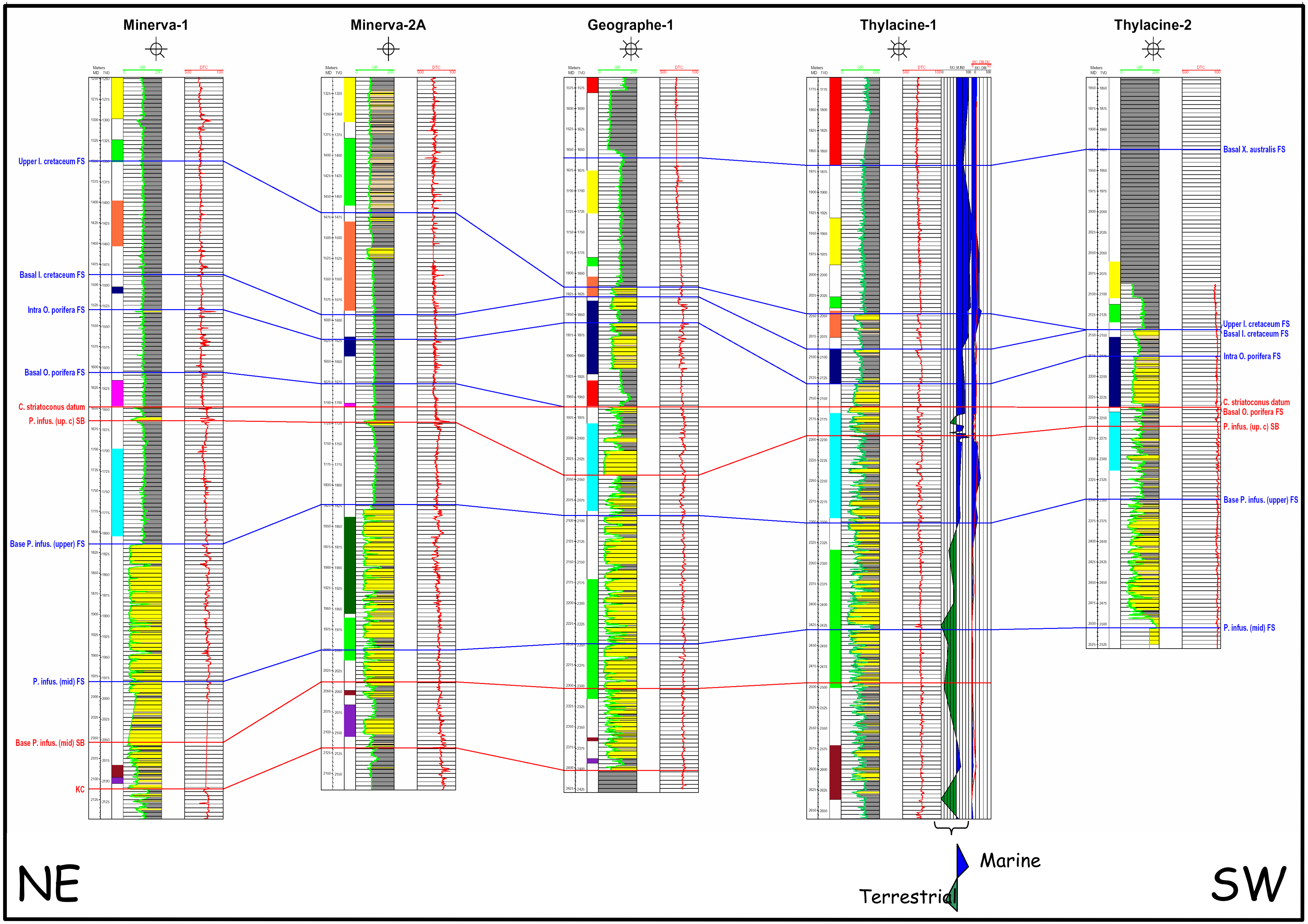


Figure 13

Correlation of Main Reservoir Units

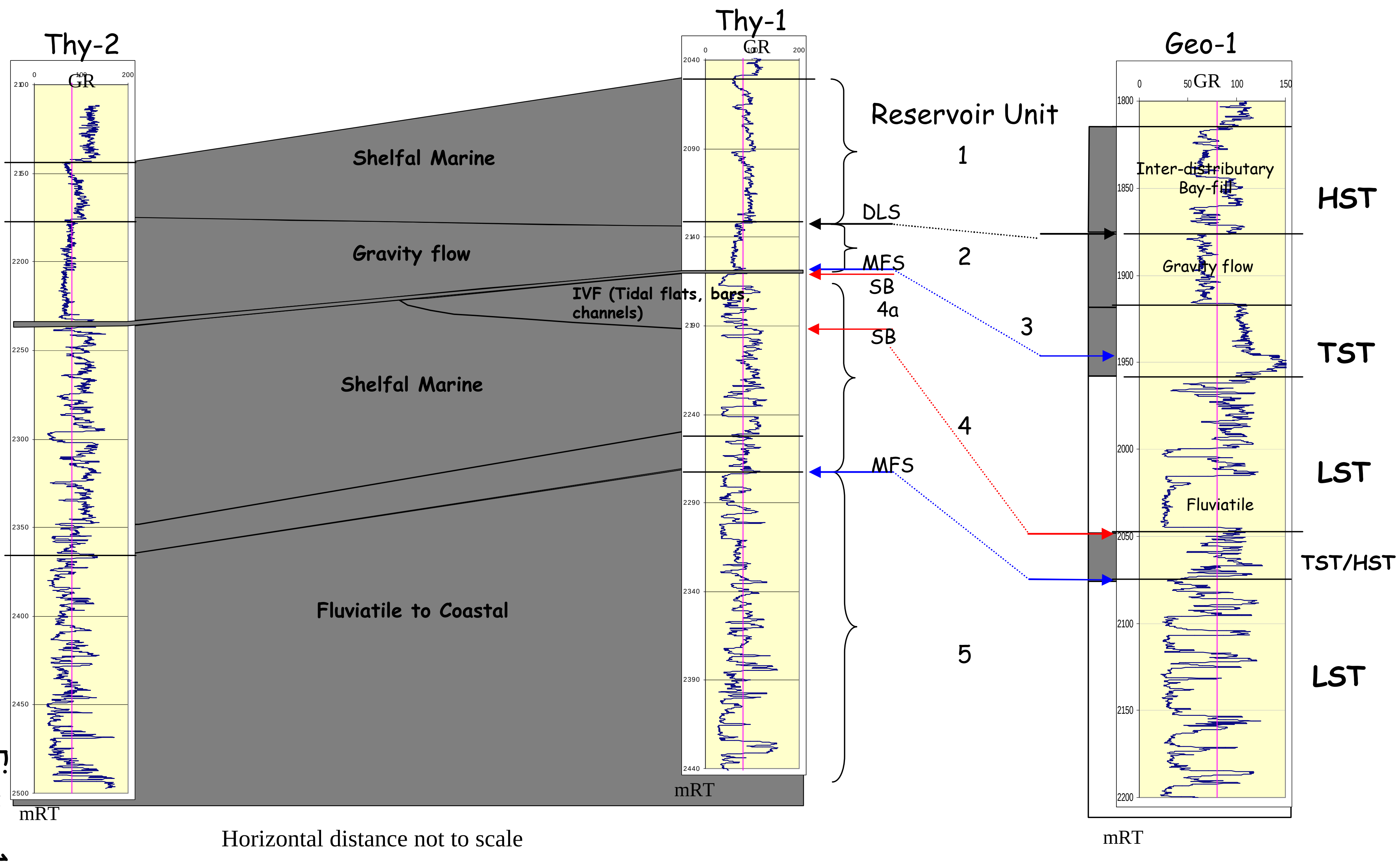


Figure 14

Sequence Boundary between Units 3 & 4

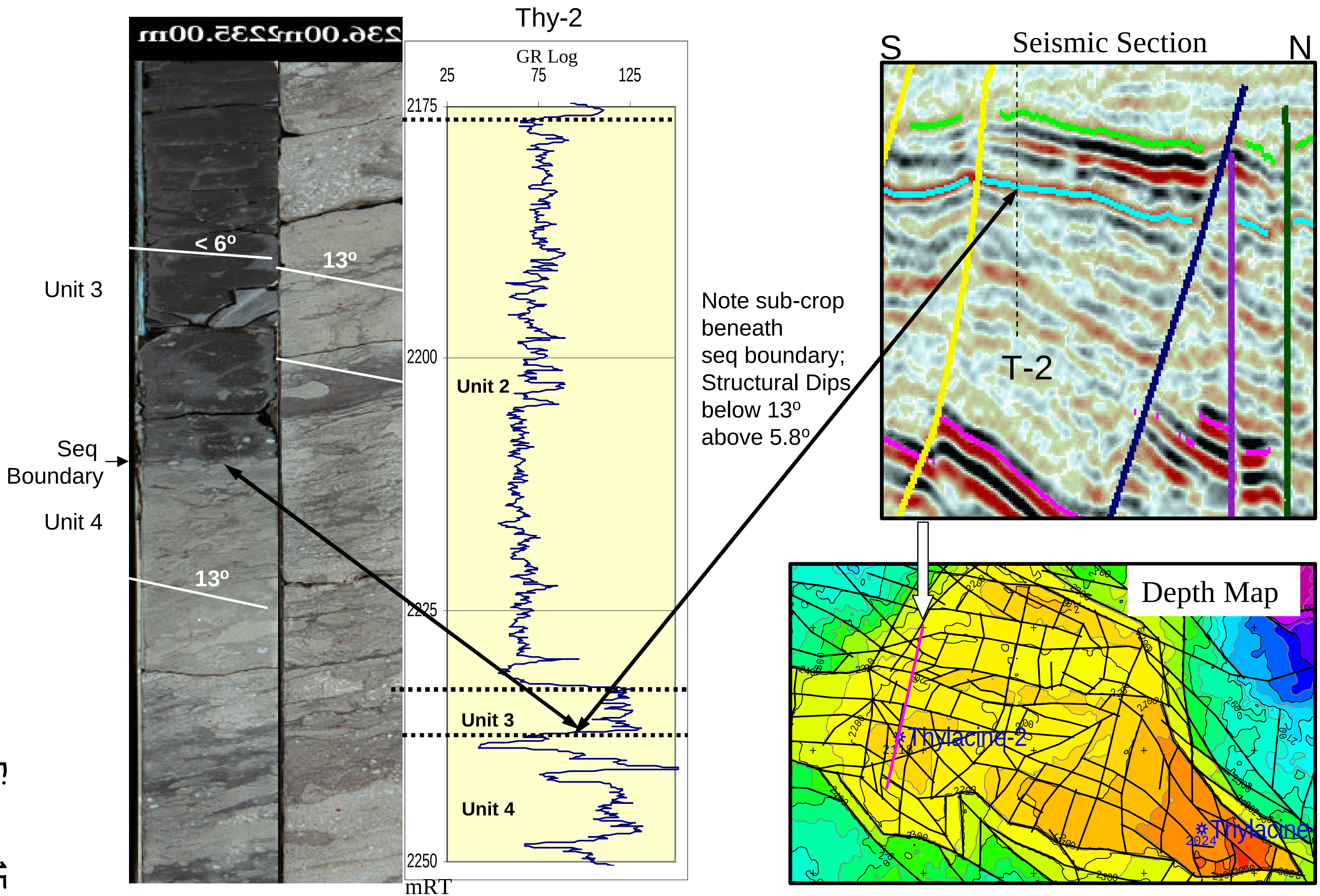
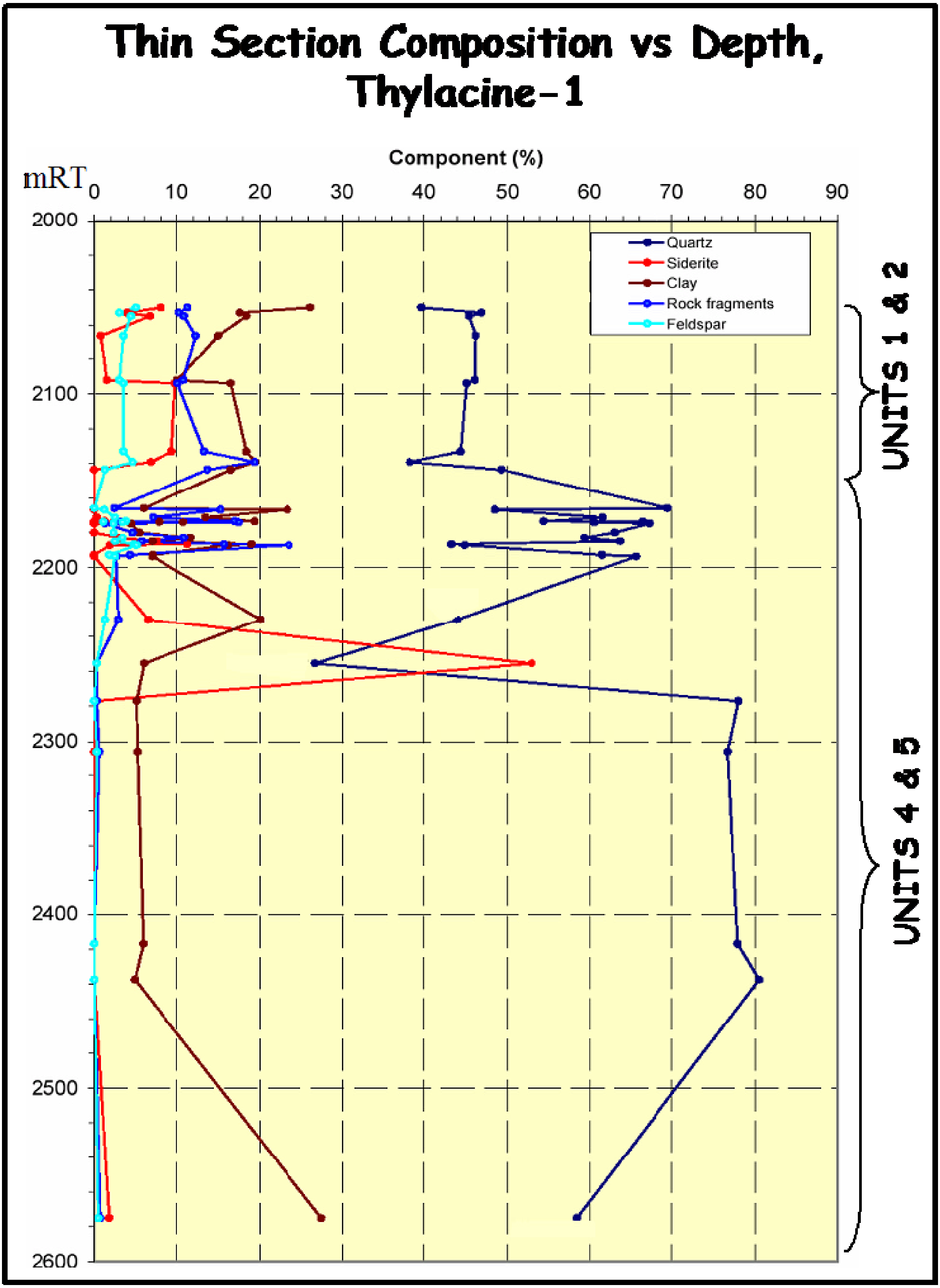


Figure 15



Thin Section Composition vs Depth, Thylacine-1
Component (%)
mRT
0
10
20
30
40
50
60
70
80
90
2000
2100
2200
2300
2400
2500
2600
Quartz
Siderite
Clay
Rock fragments
Feldspar
UNITS 1 & 2
UNITS 4 & 5

Figure 16

Clay & Metamorphic Rock Fragments vs Permeability, Thylacine-1

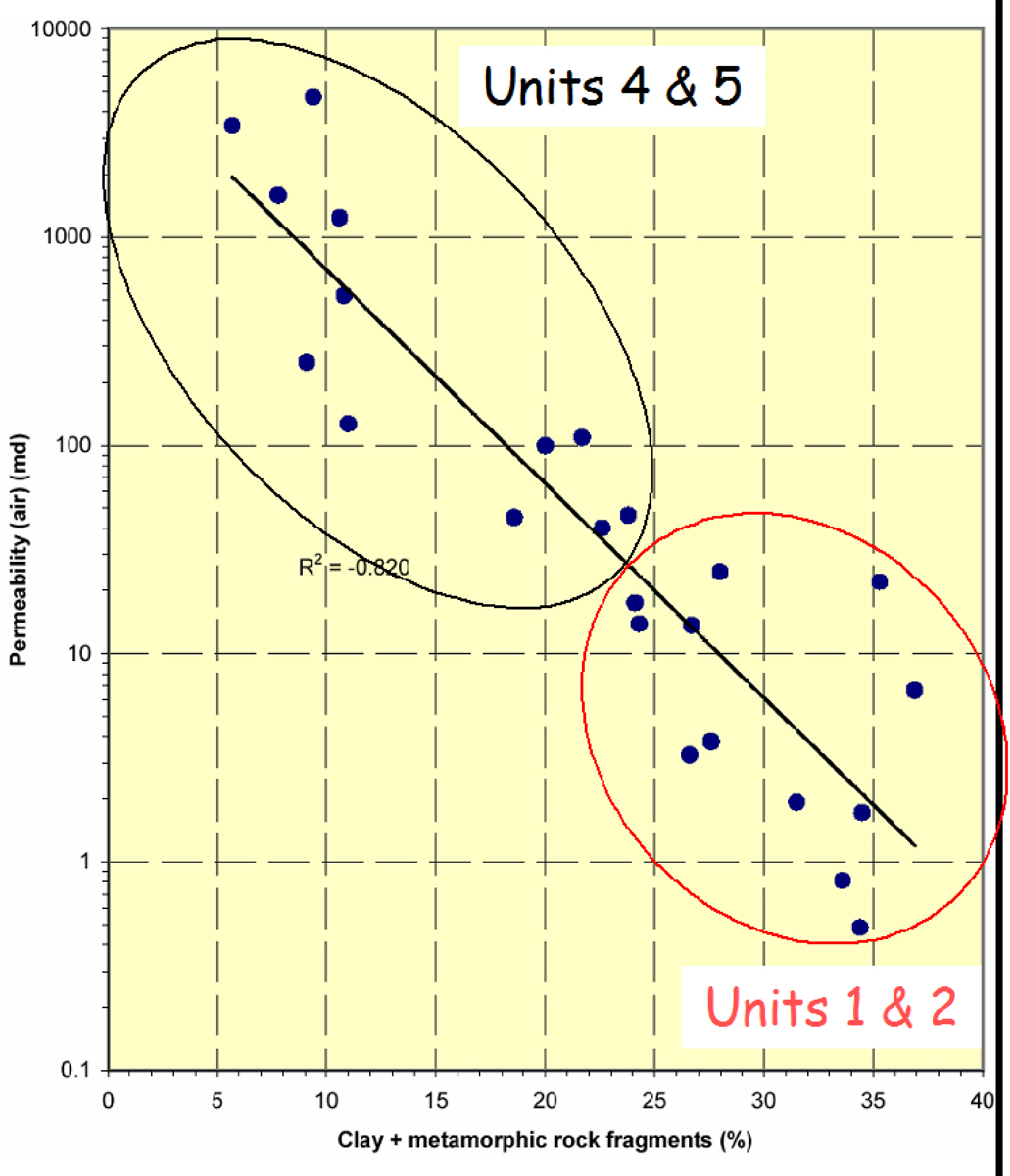
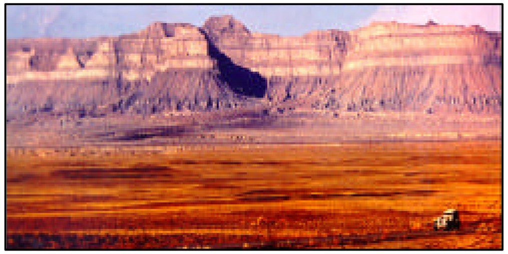
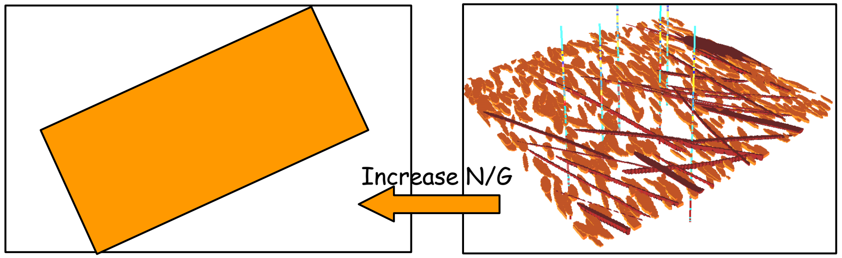


Figure 17

Scenario Matrix - Sand Body Geometry and Net to Gross by Reservoir Unit

	Unit 1 & 4	Unit 2
Correlatability / Geometry	 	Seismic constraint for all models
Sand / Shale Ratio	 ML model - no variation in sand / shale ratio as all well sand bodies modelled as sheets L & H case models. Model well sand bodies as bars and probabilistically infill limiting number of bodies using sand / shale ratio	Fixed at one - (impact on GIIP assessed probabilistically)

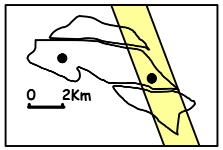
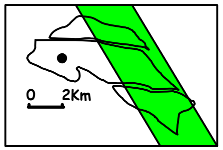
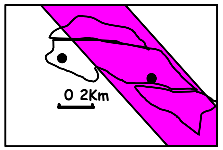
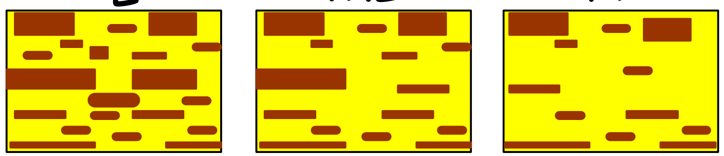
	Unit 4a	Unit 5
Correlatability / Geometry	 L - analogue database  ML - Seismic constraint  H - analogue database	Well bodies modelled as channels in a 'shale background' lithology
Sand / Shale Ratio	Fixed (impact on GIIP assessed probabilistically)	L ML H 

Figure 18

Thylacine-1 Well
Evaluation Summary

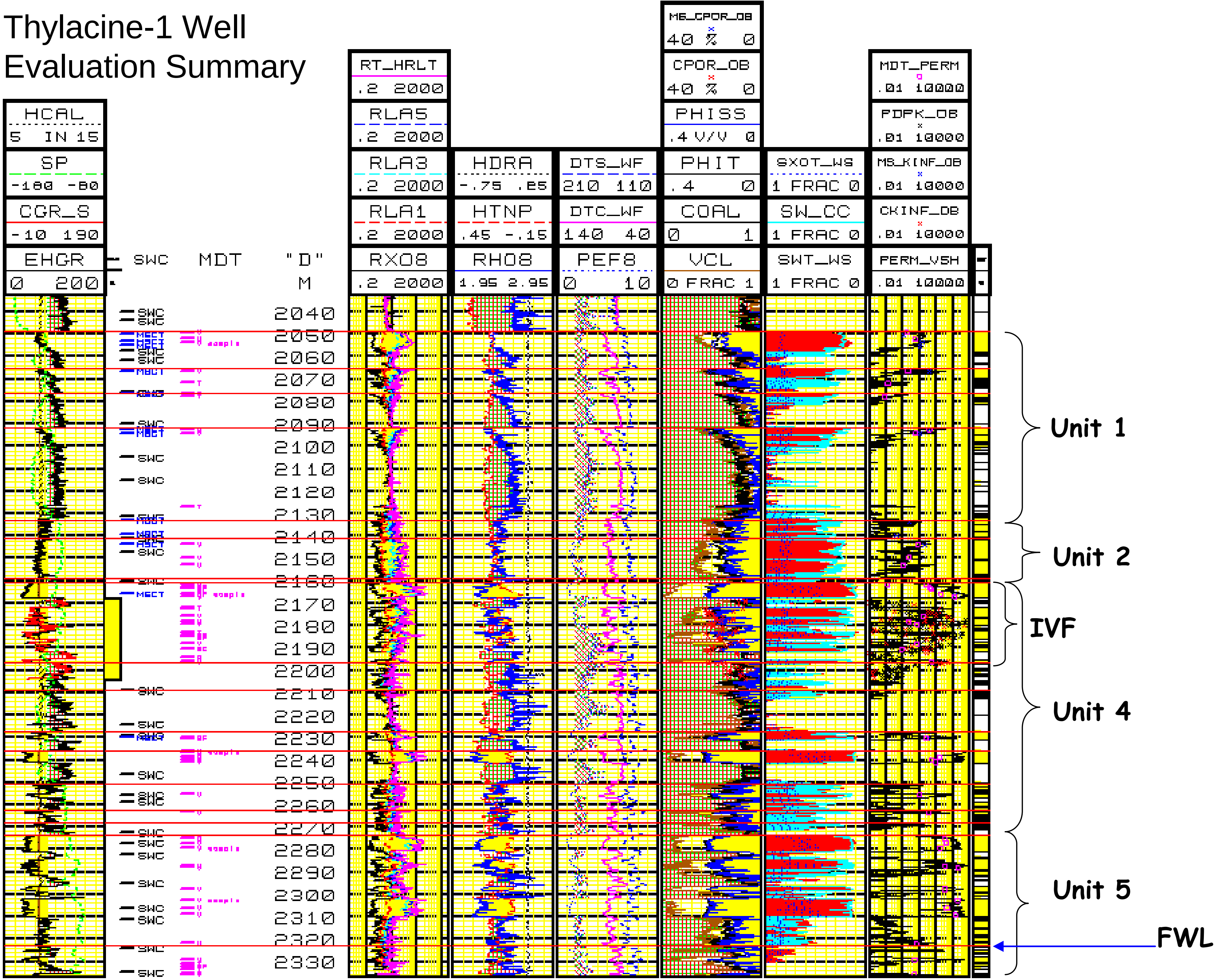


Figure 19

Thylacine-2 Well Evaluation Summary

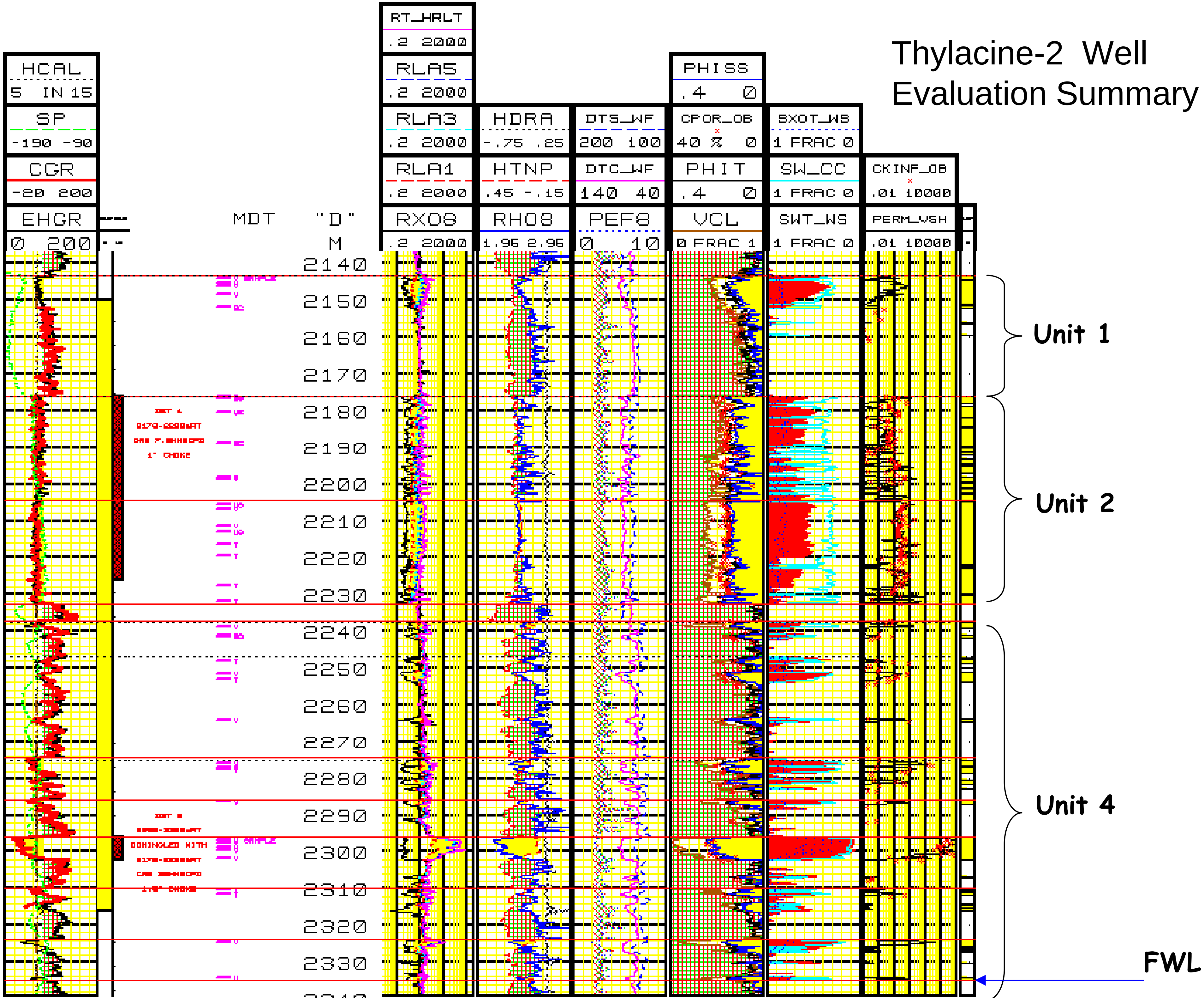


Figure 20

Geographe-1 Well Evaluation Summary

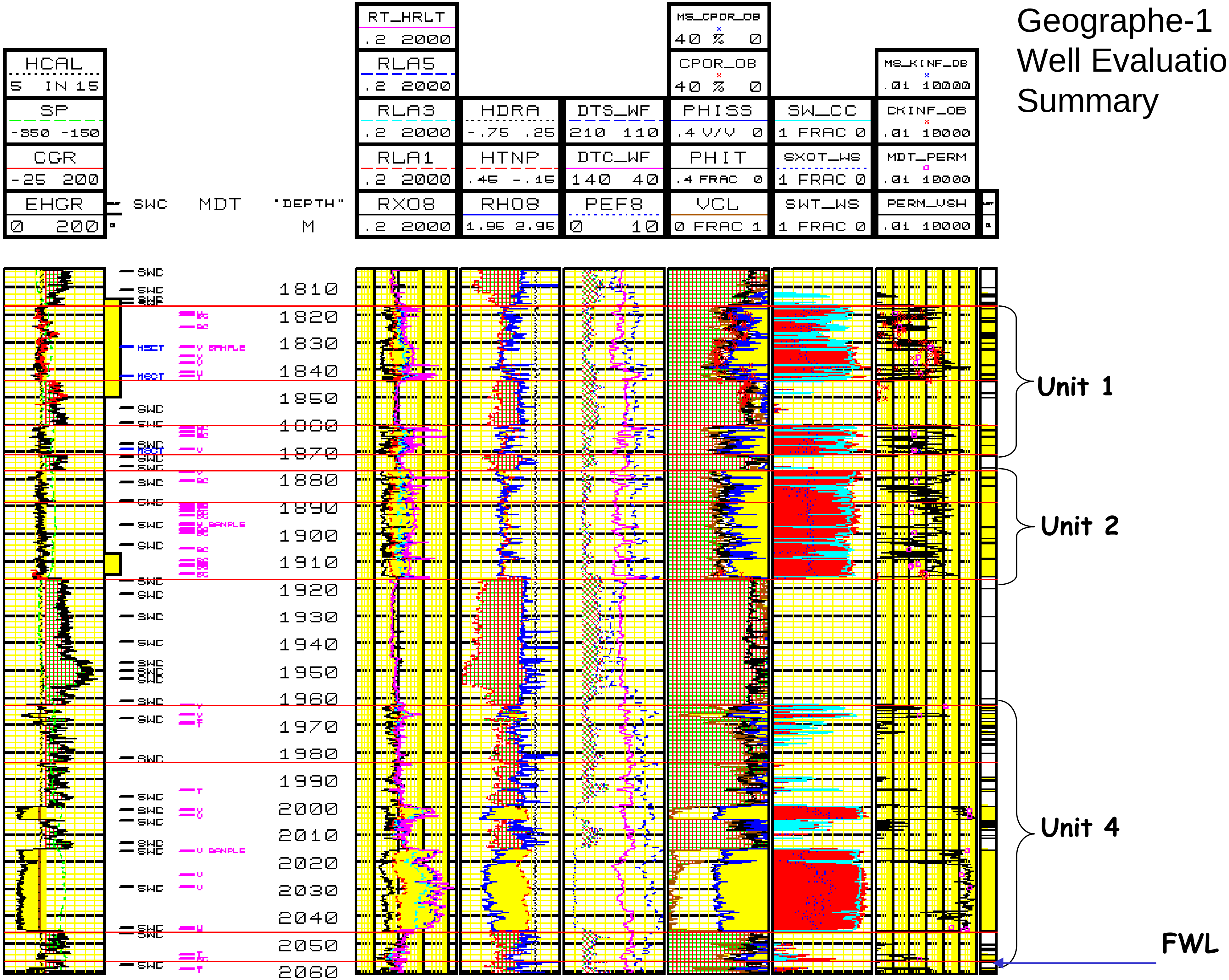


Figure 21

Geographe - North Well Evaluation Summary

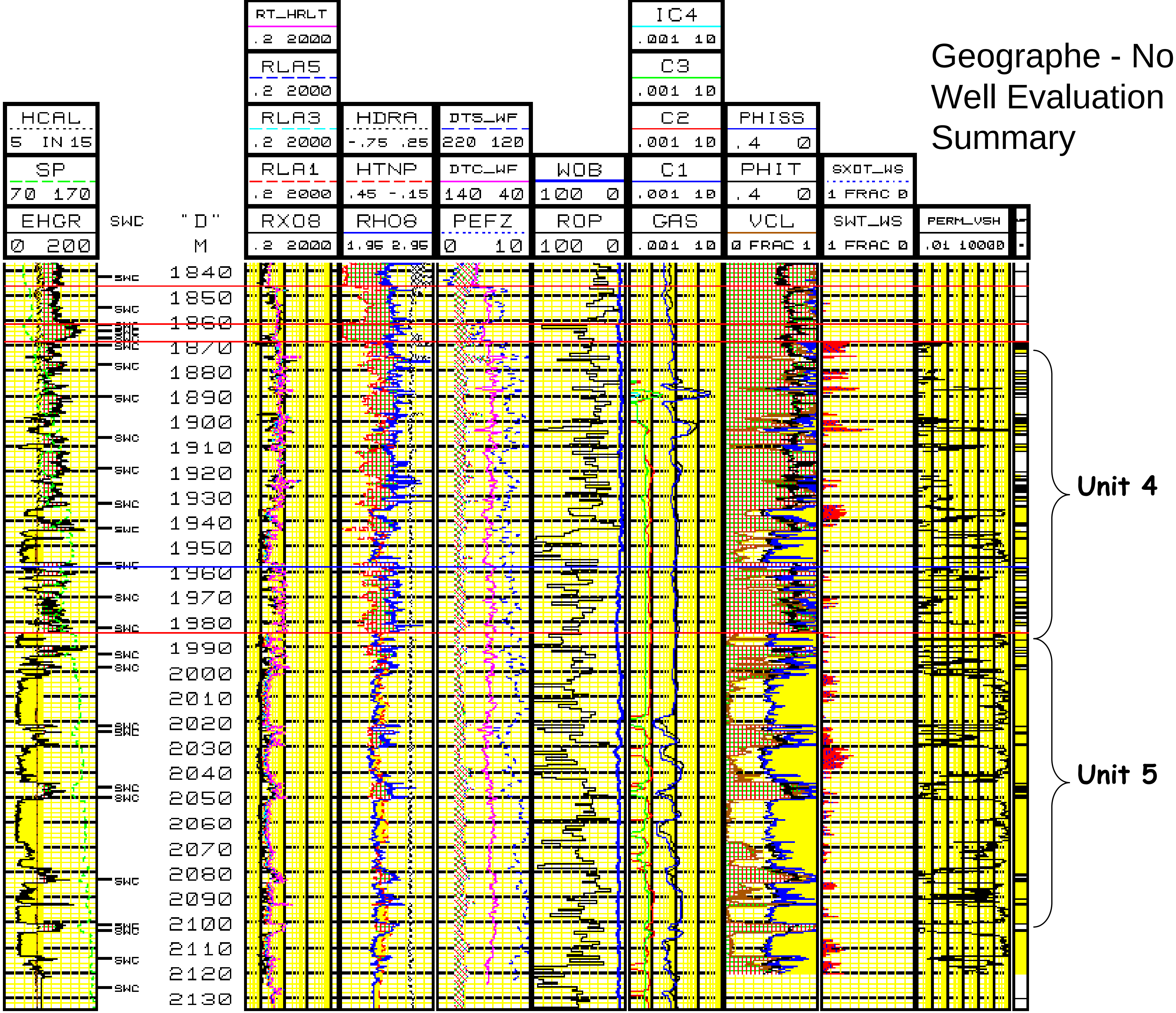
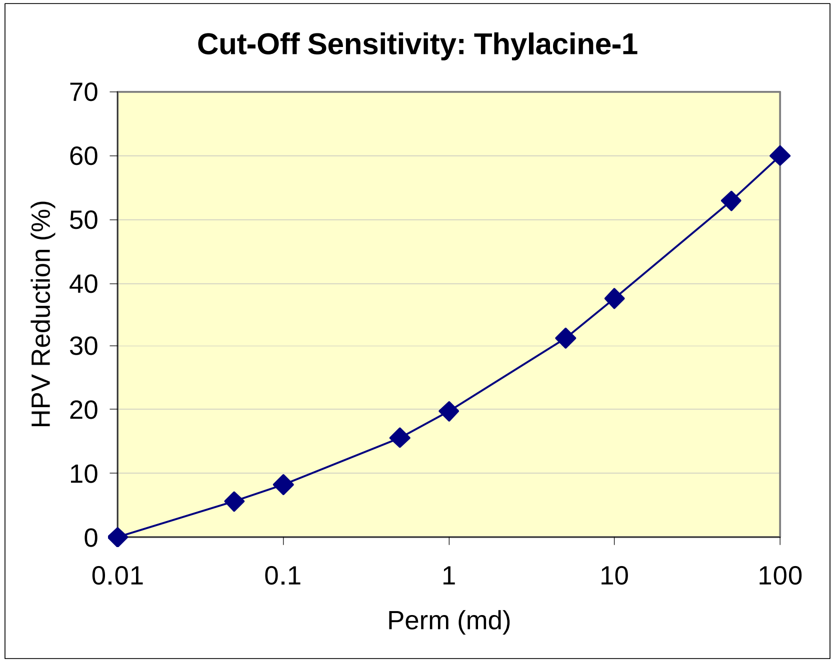
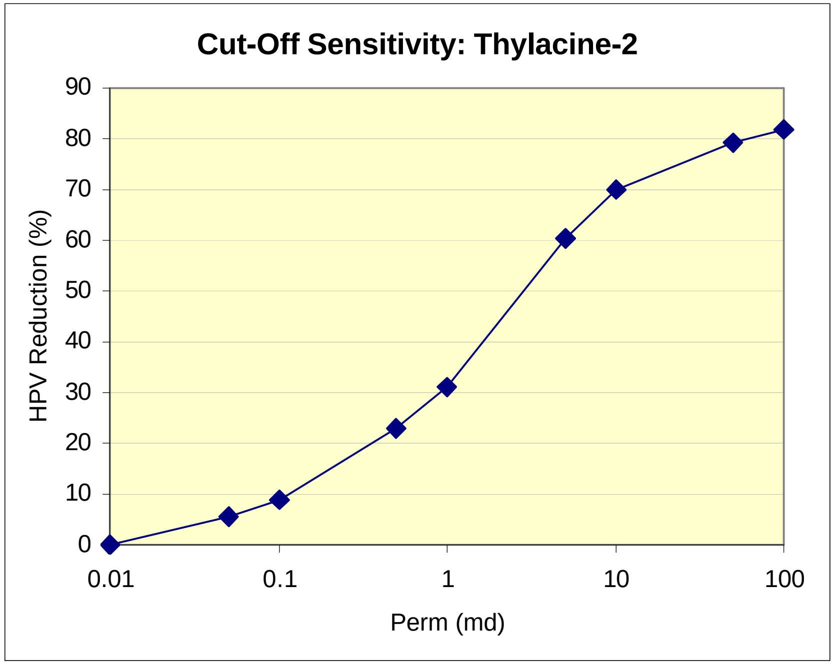
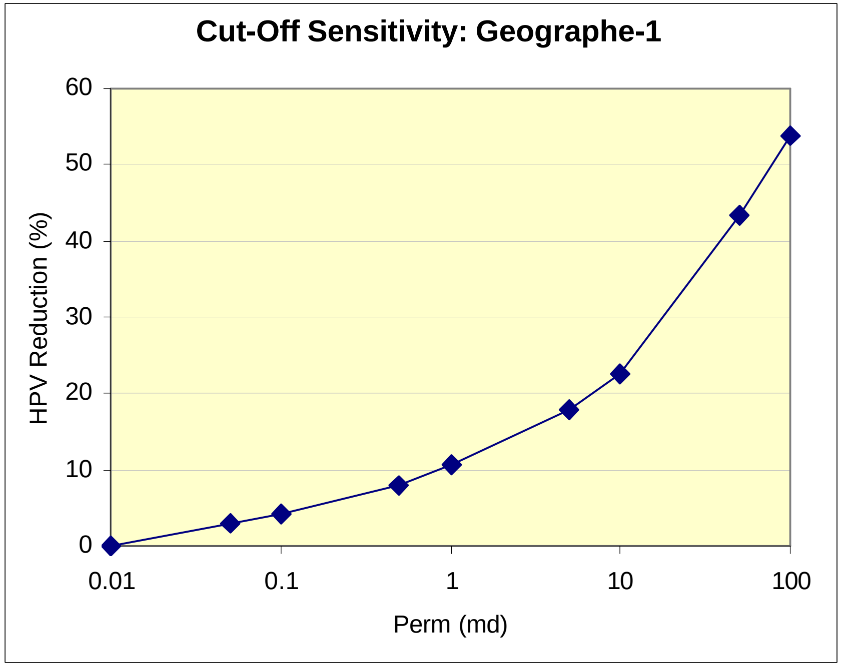


Figure 22

Sensitivity of hydrocarbon pore volume (HPV) to changes in permeability threshold







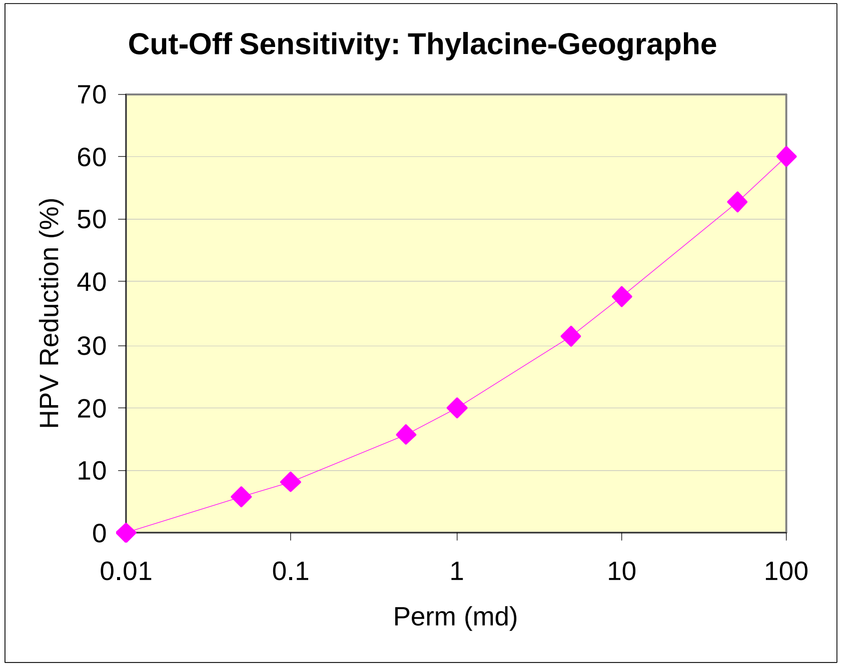
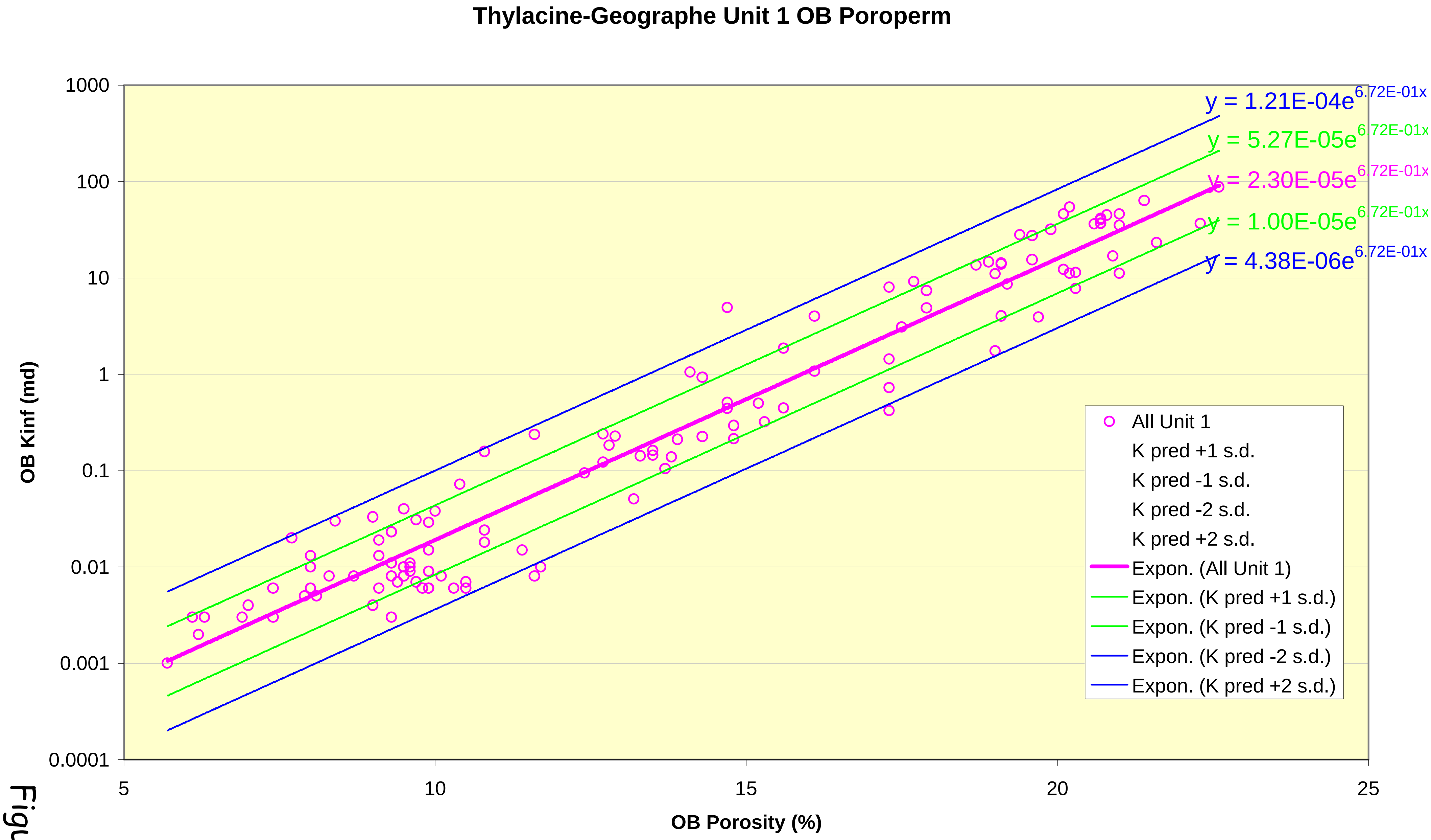
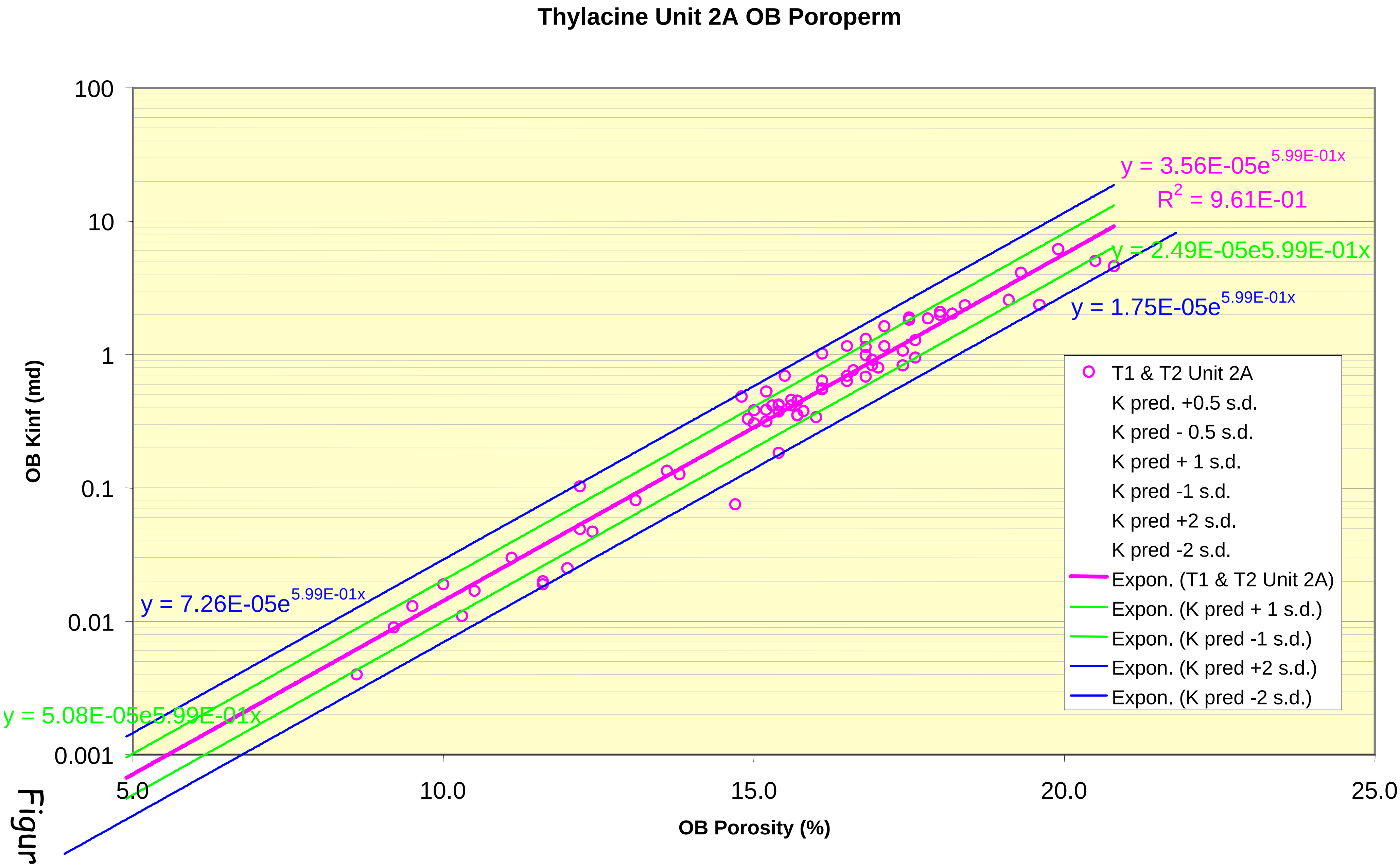


Figure 23



Thylacine-Geographe Unit 1 OB Poroperm
OB Kinf (md)
OB Porosity (%)
1000
100
10
1
0.1
0.01
0.001
0.0001
5
10
15
20
25
y = 1.21E-04e6.72E-01x
y = 5.27E-05e6.72E-01x
y = 2.30E-05e6.72E-01x
y = 1.00E-05e6.72E-01x
y = 4.38E-06e6.72E-01x
All Unit 1
K pred +1 s.d.
K pred -1 s.d.
K pred -2 s.d.
K pred +2 s.d.
Expon. (All Unit 1)
Expon. (K pred +1 s.d.)
Expon. (K pred -1 s.d.)
Expon. (K pred -2 s.d.)
Expon. (K pred +2 s.d.)

Figure 24



Thylacine Unit 2A OB Poroperm
OB Kinf (md)
100
10
1
0.1
0.01
0.001
5.0
10.0
15.0
20.0
25.0
OB Porosity (%)
y = 3.56E-05e5.99E-01x
R2 = 9.61E-01
y = 2.49E-05e5.99E-01x
y = 1.75E-05e5.99E-01x
y = 7.26E-05e5.99E-01x
y = 5.08E-05e5.99E-01x
T1 & T2 Unit 2A
K pred. +0.5 s.d.
K pred - 0.5 s.d.
K pred + 1 s.d.
K pred -1 s.d.
K pred +2 s.d.
K pred -2 s.d.
Expon. (T1 & T2 Unit 2A)
Expon. (K pred + 1 s.d.)
Expon. (K pred -1 s.d.)
Expon. (K pred +2 s.d.)
Expon. (K pred -2 s.d.)

Figure 25a

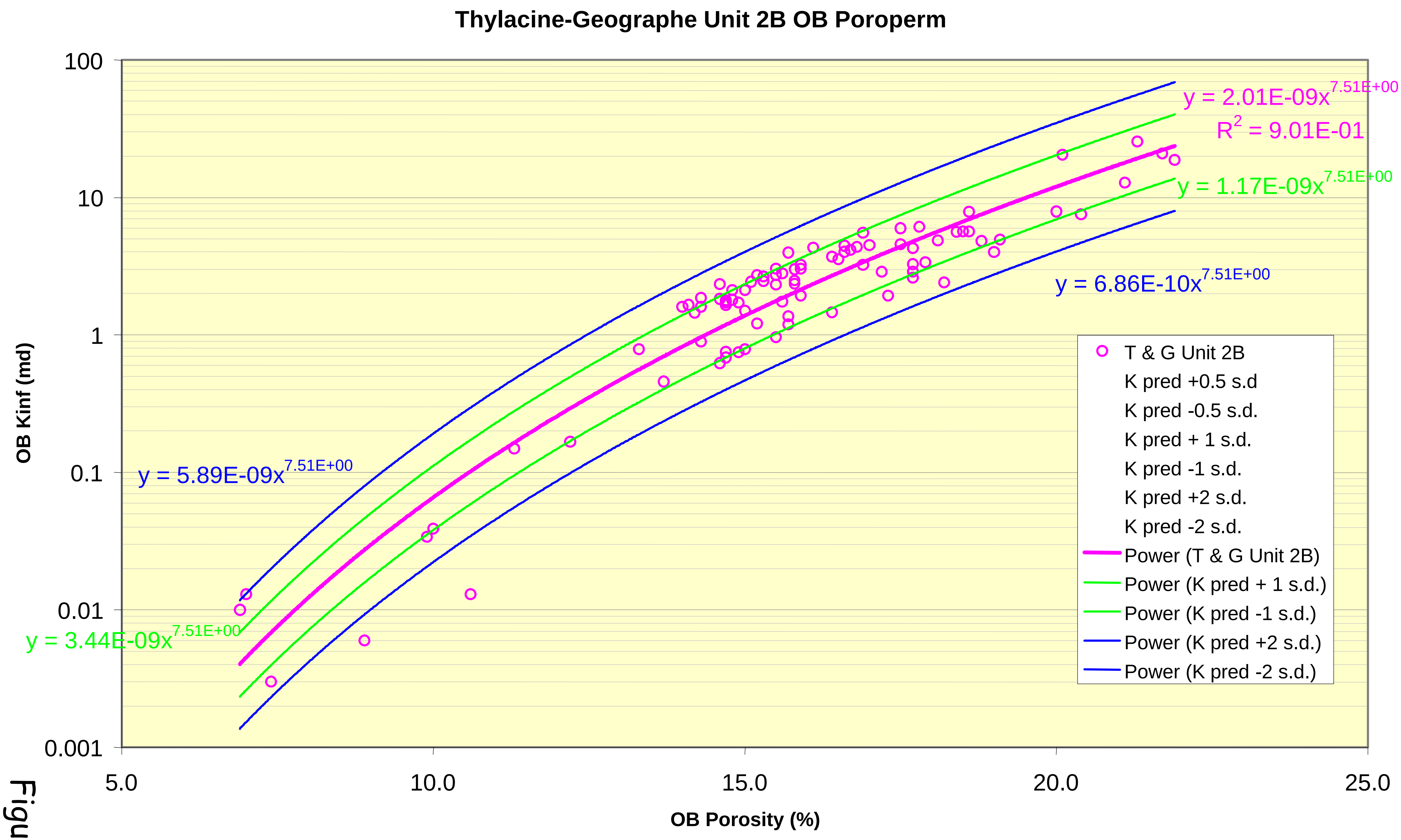
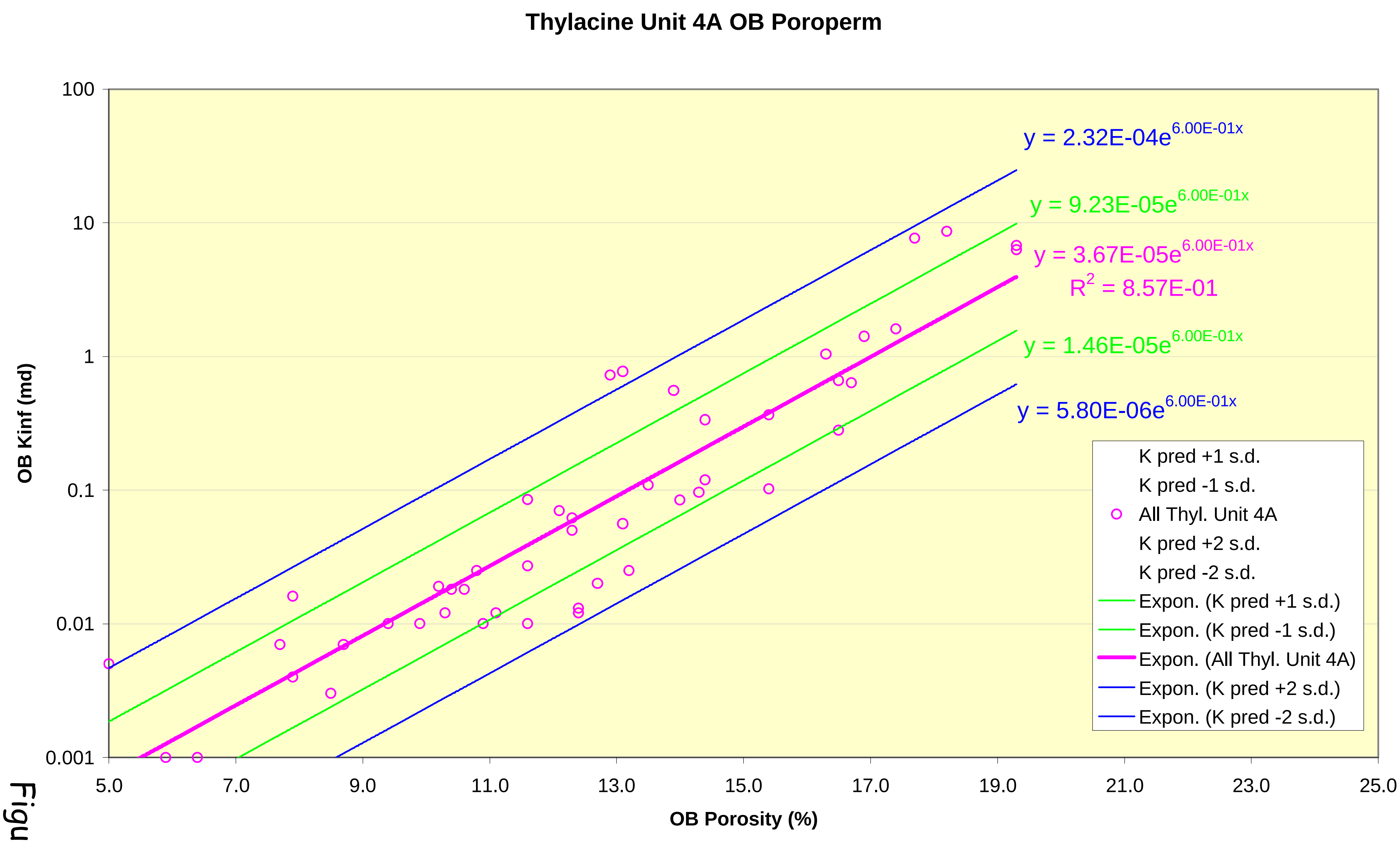

Thylacine-Geographe Unit 2B OB Poroperm
OB Kinf (md)
OB Porosity (%)
100
10
1
0.1
0.01
0.001
5.0
10.0
15.0
20.0
25.0
y = 2.01E-09x^7.51E+00
R^2 = 9.01E-01
y = 1.17E-09x^7.51E+00
y = 6.86E-10x^7.51E+00
y = 5.89E-09x^7.51E+00
y = 3.44E-09x^7.51E+00
T & G Unit 2B
K pred +0.5 s.d
K pred -0.5 s.d.
K pred + 1 s.d.
K pred -1 s.d.
K pred +2 s.d.
K pred -2 s.d.
Power (T & G Unit 2B)
Power (K pred + 1 s.d.)
Power (K pred -1 s.d.)
Power (K pred +2 s.d.)
Power (K pred -2 s.d.)

Figure 25b



Thylacine Unit 4A OB Poroperm
y = 2.32E-04e^6.00E-01x
y = 9.23E-05e^6.00E-01x
y = 3.67E-05e^6.00E-01x
R^2 = 8.57E-01
y = 1.46E-05e^6.00E-01x
y = 5.80E-06e^6.00E-01x
K pred +1 s.d.
K pred -1 s.d.
All Thyl. Unit 4A
K pred +2 s.d.
K pred -2 s.d.
Expon. (K pred +1 s.d.)
Expon. (K pred -1 s.d.)
Expon. (All Thyl. Unit 4A)
Expon. (K pred +2 s.d.)
Expon. (K pred -2 s.d.)
100
10
1
0.1
0.01
0.001
OB Kinf (md)
5.0
7.0
9.0
11.0
13.0
15.0
17.0
19.0
21.0
23.0
25.0
OB Porosity (%)

Figure 26

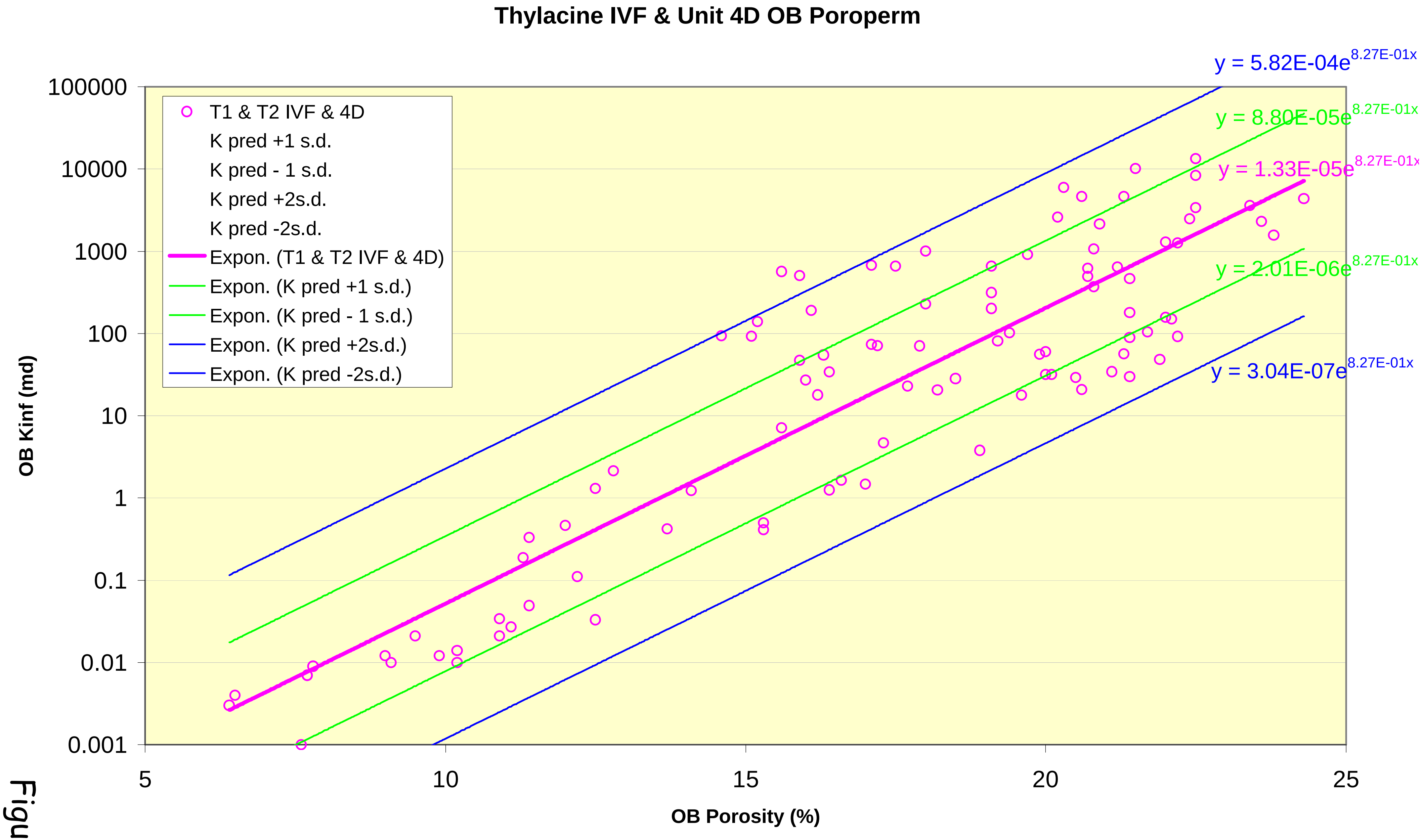

Thylacine IVF & Unit 4D OB Poroperm
y = 5.82E-04e^8.27E-01x
y = 8.80E-05e^8.27E-01x
y = 1.33E-05e^8.27E-01x
y = 2.01E-06e^8.27E-01x
y = 3.04E-07e^8.27E-01x
T1 & T2 IVF & 4D
K pred +1 s.d.
K pred - 1 s.d.
K pred +2s.d.
K pred -2s.d.
Expon. (T1 & T2 IVF & 4D)
Expon. (K pred +1 s.d.)
Expon. (K pred - 1 s.d.)
Expon. (K pred +2s.d.)
Expon. (K pred -2s.d.)
OB Kinf (md)
100000
10000
1000
100
10
1
0.1
0.01
0.001
5
10
15
20
25
OB Porosity (%)

Figure 27

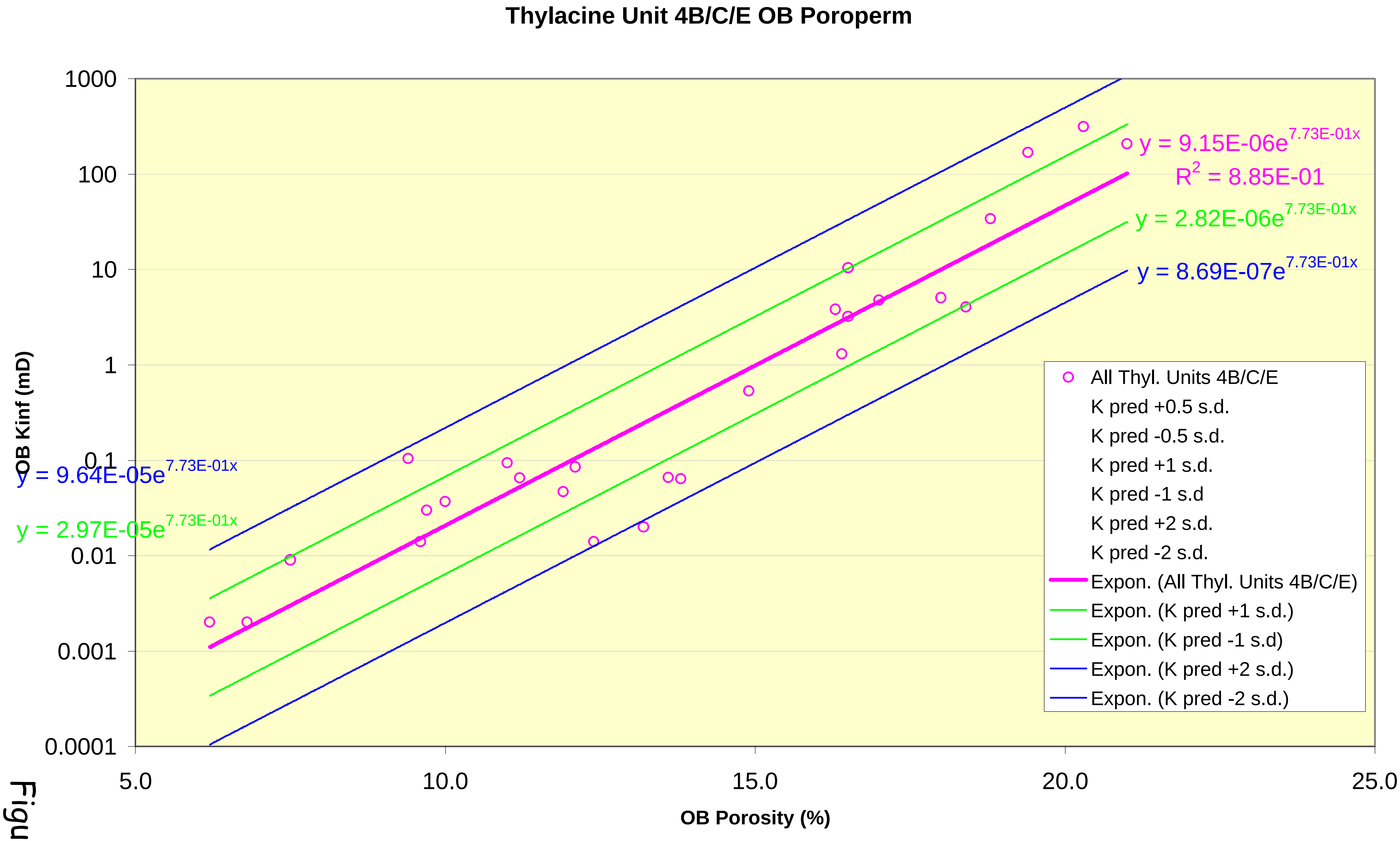

Thylacine Unit 4B/C/E OB Poroperm
OB Kinf (mD)
OB Porosity (%)
1000
100
10
1
0.1
0.01
0.001
0.0001
5.0
10.0
15.0
20.0
25.0
y = 9.15E-06e^7.73E-01x
R^2 = 8.85E-01
y = 2.82E-06e^7.73E-01x
y = 8.69E-07e^7.73E-01x
y = 9.64E-05e^7.73E-01x
y = 2.97E-05e^7.73E-01x
All Thyl. Units 4B/C/E
K pred +0.5 s.d.
K pred -0.5 s.d.
K pred +1 s.d.
K pred -1 s.d
K pred +2 s.d.
K pred -2 s.d.
Expon. (All Thyl. Units 4B/C/E)
Expon. (K pred +1 s.d.)
Expon. (K pred -1 s.d)
Expon. (K pred +2 s.d.)
Expon. (K pred -2 s.d.)

Figure 28

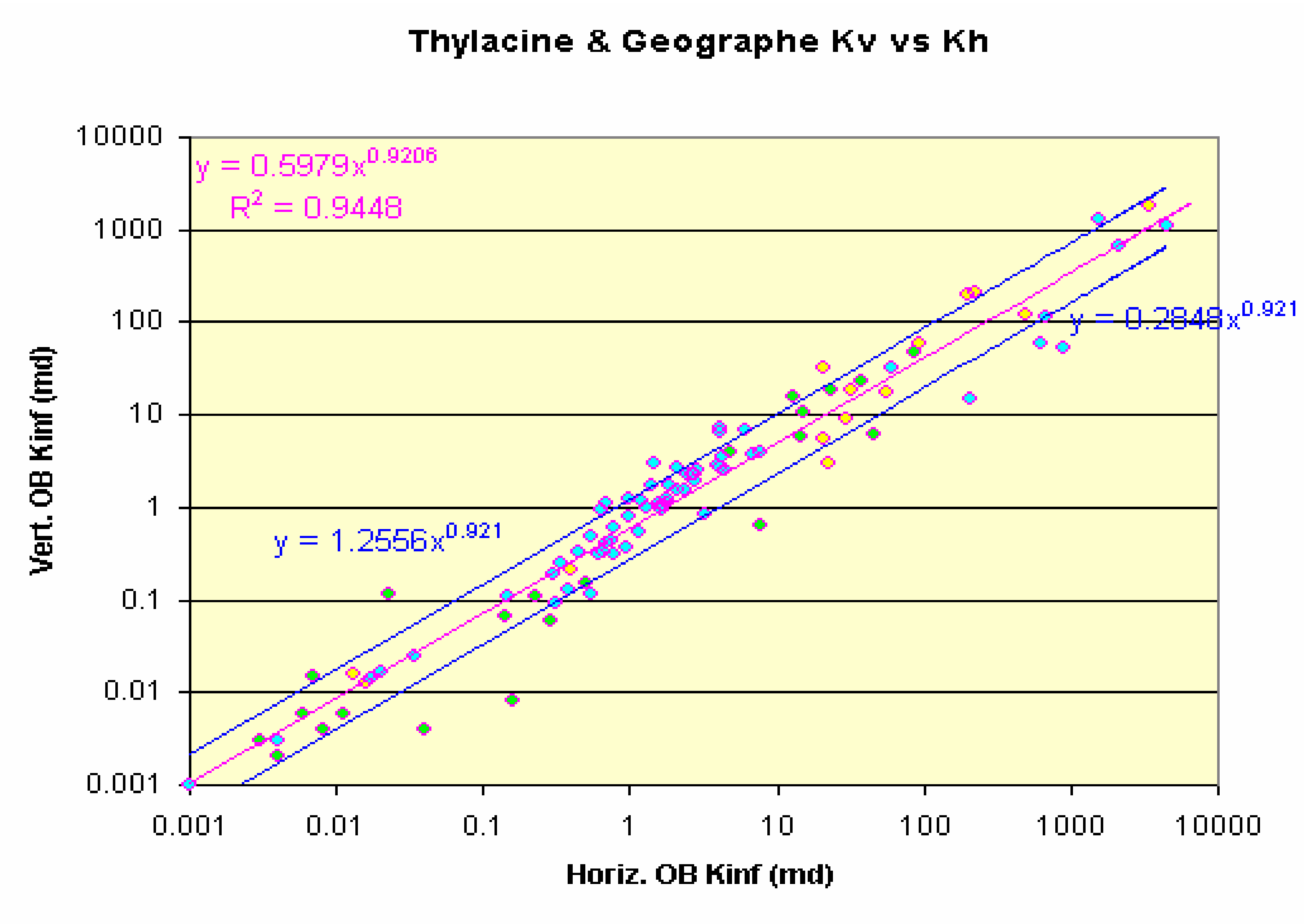

Thylacine & Geographe Kv vs Kh
y = 0.5979x^0.9206
R^2 = 0.9448
y = 0.2848x^0.921
y = 1.2556x^0.921
Vert. OB Kinf (md)
Horiz. OB Kinf (md)
10000
1000
100
10
1
0.1
0.01
0.001
0.001
0.01
0.1
1
10
100
1000
10000

Figure 29

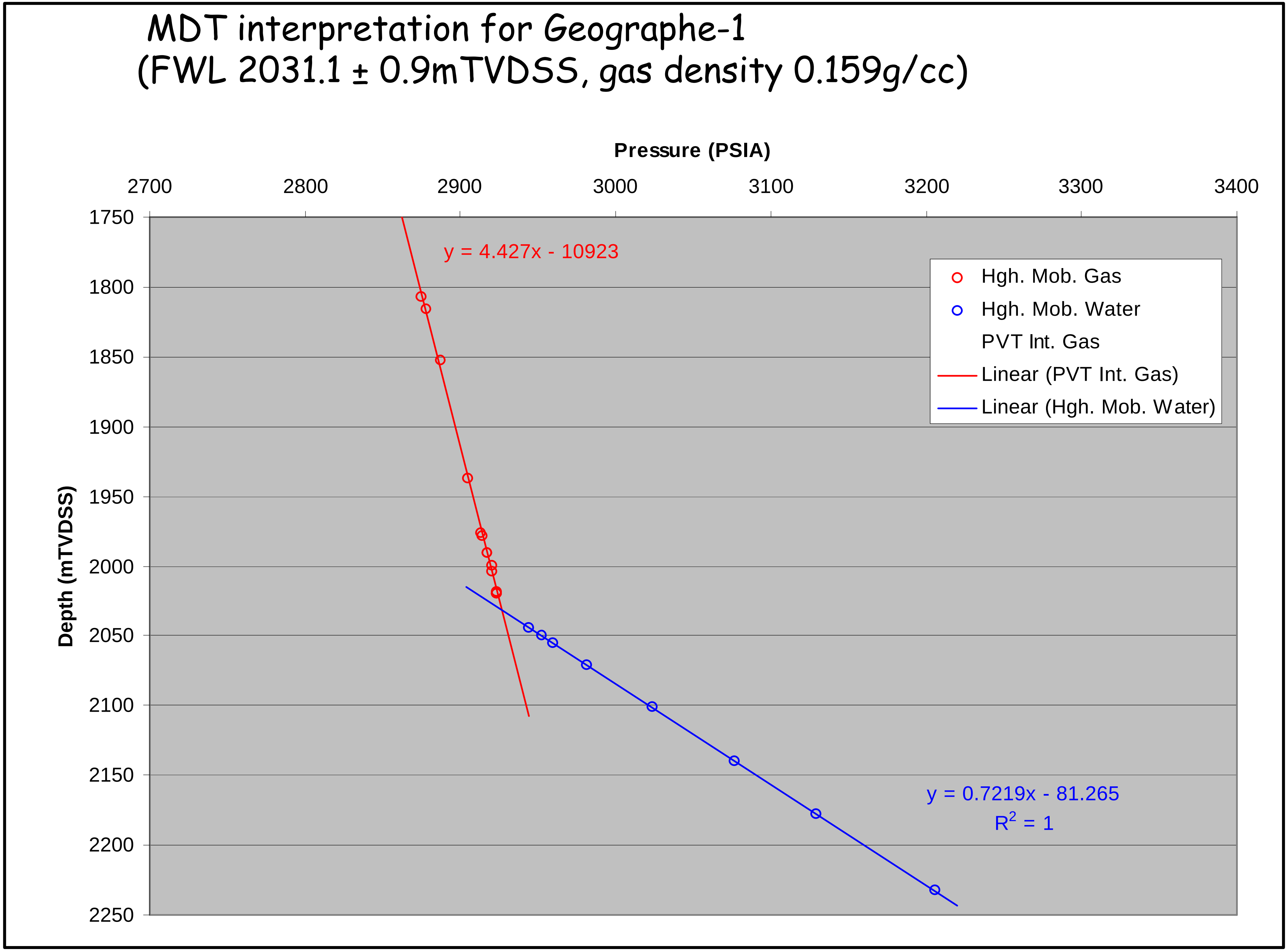
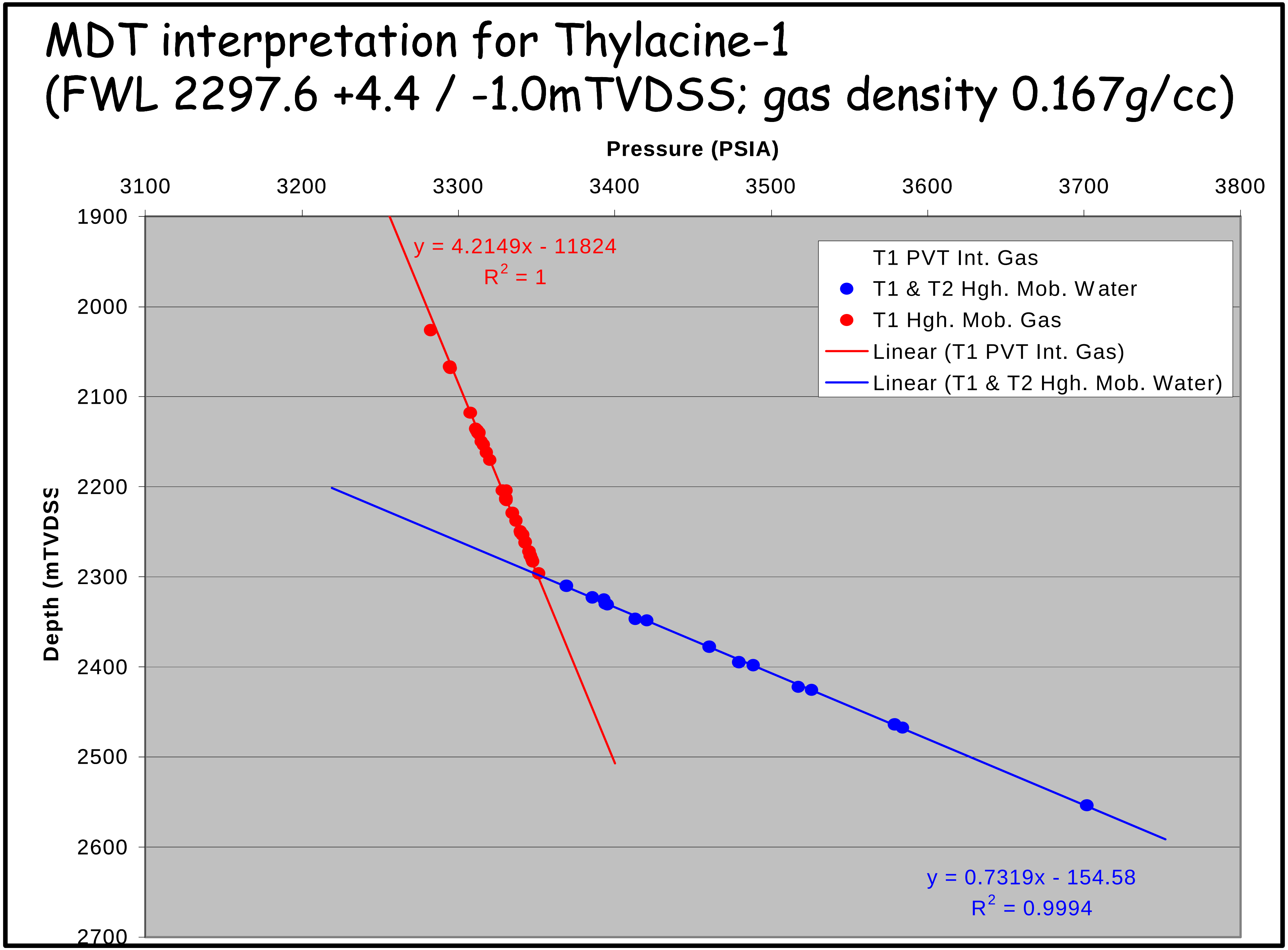
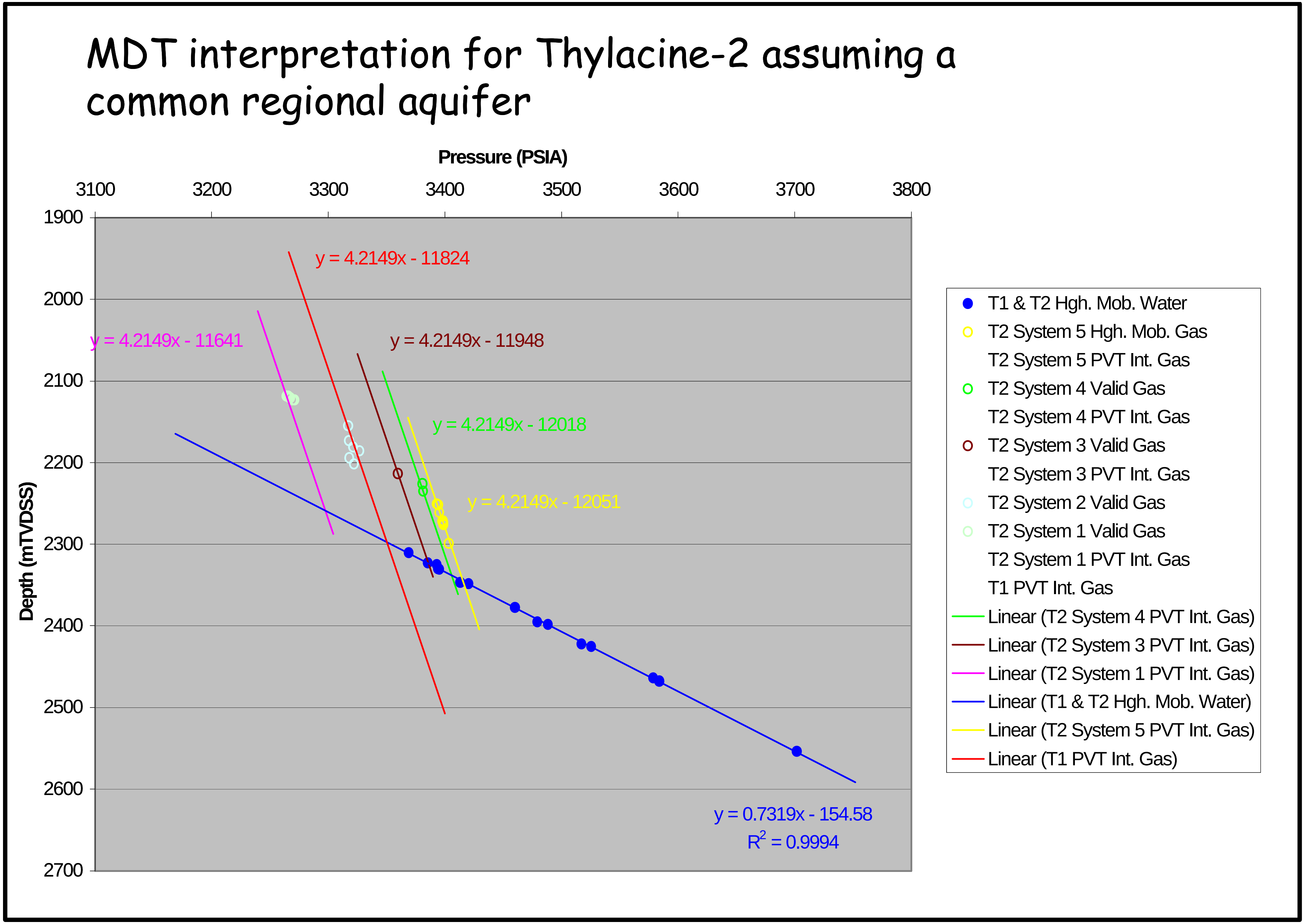

MDT interpretation for Geographe-1
(FWL 2031.1 ± 0.9mTVDSS, gas density 0.159g/cc)
Pressure (PSIA)
2700
2800
2900
3000
3100
3200
3300
3400
Depth (mTVDSS)
1750
1800
1850
1900
1950
2000
2050
2100
2150
2200
2250
y = 4.427x - 10923
Hgh. Mob. Gas
Hgh. Mob. Water
PVT Int. Gas
Linear (PVT Int. Gas)
Linear (Hgh. Mob. Water)
y = 0.7219x - 81.265
R2 = 1

Figure 30



MDT interpretation for Thylacine-1
(FWL 2297.6 +4.4 / -1.0mTVDSS; gas density 0.167g/cc)
Pressure (PSIA)
3100
3200
3300
3400
3500
3600
3700
3800
Depth (mTVDSS)
1900
2000
2100
2200
2300
2400
2500
2600
2700
y = 4.2149x - 11824
R2 = 1
T1 PVT Int. Gas
T1 & T2 Hgh. Mob. Water
T1 Hgh. Mob. Gas
Linear (T1 PVT Int. Gas)
Linear (T1 & T2 Hgh. Mob. Water)
y = 0.7319x - 154.58
R2 = 0.9994

Figure 31



MDT interpretation for Thylacine-2 assuming a common regional aquifer
Pressure (PSIA)
3100
3200
3300
3400
3500
3600
3700
3800
Depth (mTVDSS)
1900
2000
2100
2200
2300
2400
2500
2600
2700
y = 4.2149x - 11824
y = 4.2149x - 11641
y = 4.2149x - 11948
y = 4.2149x - 12018
y = 4.2149x - 12051
y = 0.7319x - 154.58
R2 = 0.9994
T1 & T2 Hgh. Mob. Water
T2 System 5 Hgh. Mob. Gas
T2 System 5 PVT Int. Gas
T2 System 4 Valid Gas
T2 System 4 PVT Int. Gas
T2 System 3 Valid Gas
T2 System 3 PVT Int. Gas
T2 System 2 Valid Gas
T2 System 1 Valid Gas
T2 System 1 PVT Int. Gas
T1 PVT Int. Gas
Linear (T2 System 4 PVT Int. Gas)
Linear (T2 System 3 PVT Int. Gas)
Linear (T2 System 1 PVT Int. Gas)
Linear (T1 & T2 Hgh. Mob. Water)
Linear (T2 System 5 PVT Int. Gas)
Linear (T1 PVT Int. Gas)

Figure 32

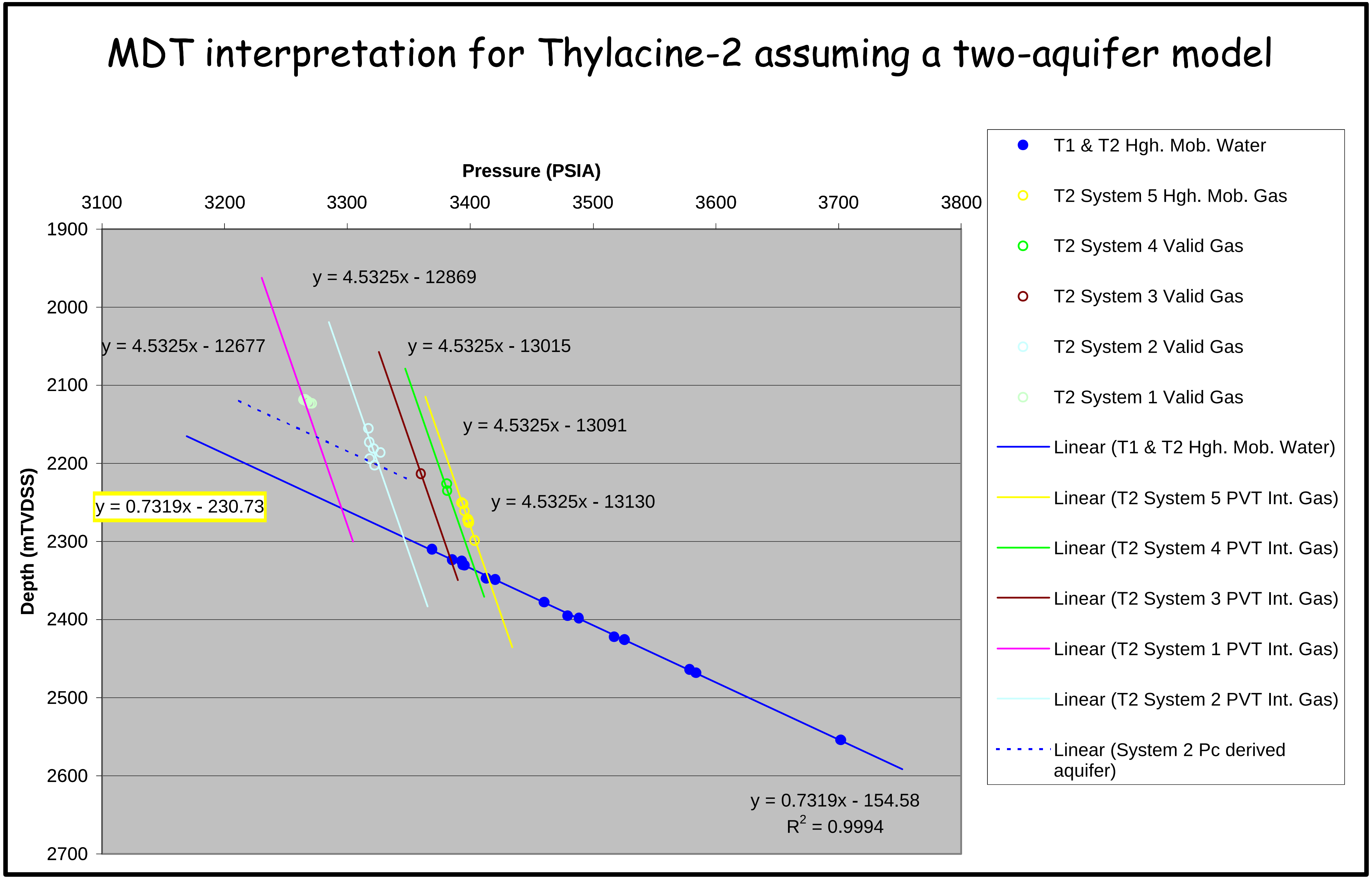

MDT interpretation for Thylacine-2 assuming a two-aquifer model
Pressure (PSIA)
3100
3200
3300
3400
3500
3600
3700
3800
Depth (mTVDSS)
1900
2000
2100
2200
2300
2400
2500
2600
2700
y = 4.5325x - 12869
y = 4.5325x - 12677
y = 4.5325x - 13015
y = 4.5325x - 13091
y = 4.5325x - 13130
y = 0.7319x - 230.73
y = 0.7319x - 154.58
R2 = 0.9994
T1 & T2 Hgh. Mob. Water
T2 System 5 Hgh. Mob. Gas
T2 System 4 Valid Gas
T2 System 3 Valid Gas
T2 System 2 Valid Gas
T2 System 1 Valid Gas
Linear (T1 & T2 Hgh. Mob. Water)
Linear (T2 System 5 PVT Int. Gas)
Linear (T2 System 4 PVT Int. Gas)
Linear (T2 System 3 PVT Int. Gas)
Linear (T2 System 1 PVT Int. Gas)
Linear (T2 System 2 PVT Int. Gas)
Linear (System 2 Pc derived aquifer)

Figure 33

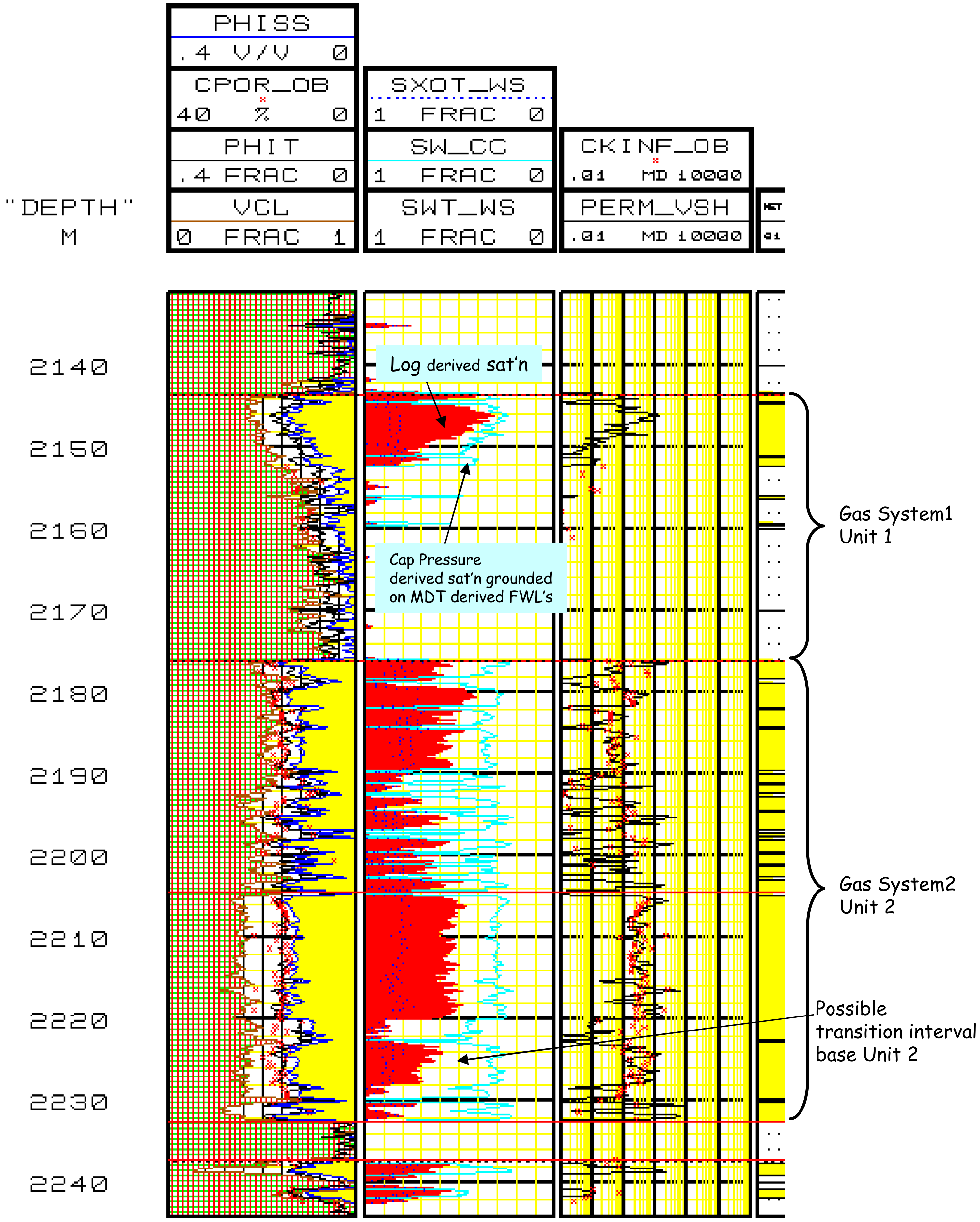


Figure 34: Thylacine-2 gas systems 1 & 2: Comparison of resistivity derived Sw's (SWT_WS) with saturation-height derived Sw estimates (SW_CC) grounded on FWL's interpreted assuming a common regional aquifer

Seismic Evidence for 'FWL' in Thylacine-2 Block

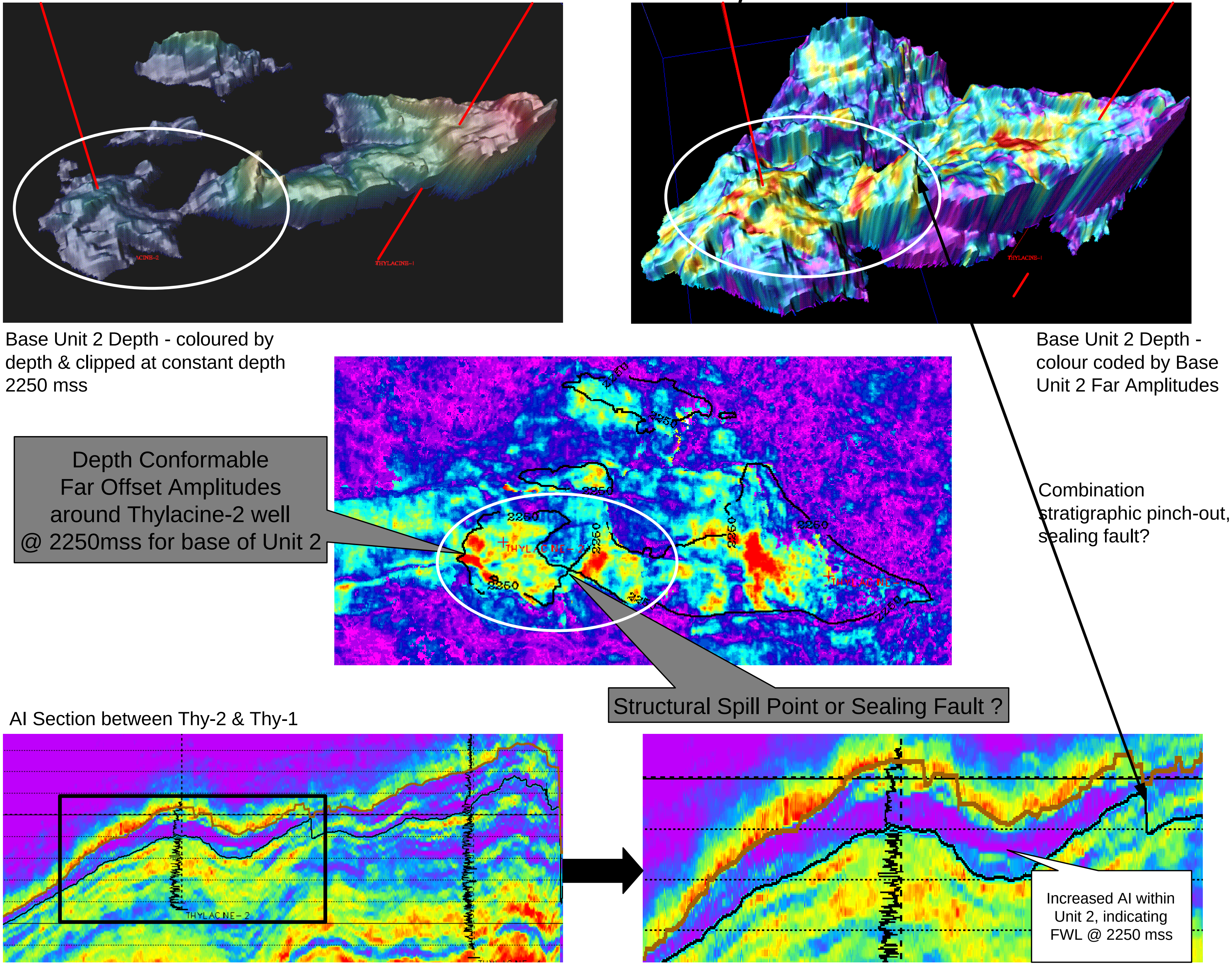


Figure 35

Schematic Cross Section of Gas Systems in Thylacine-2

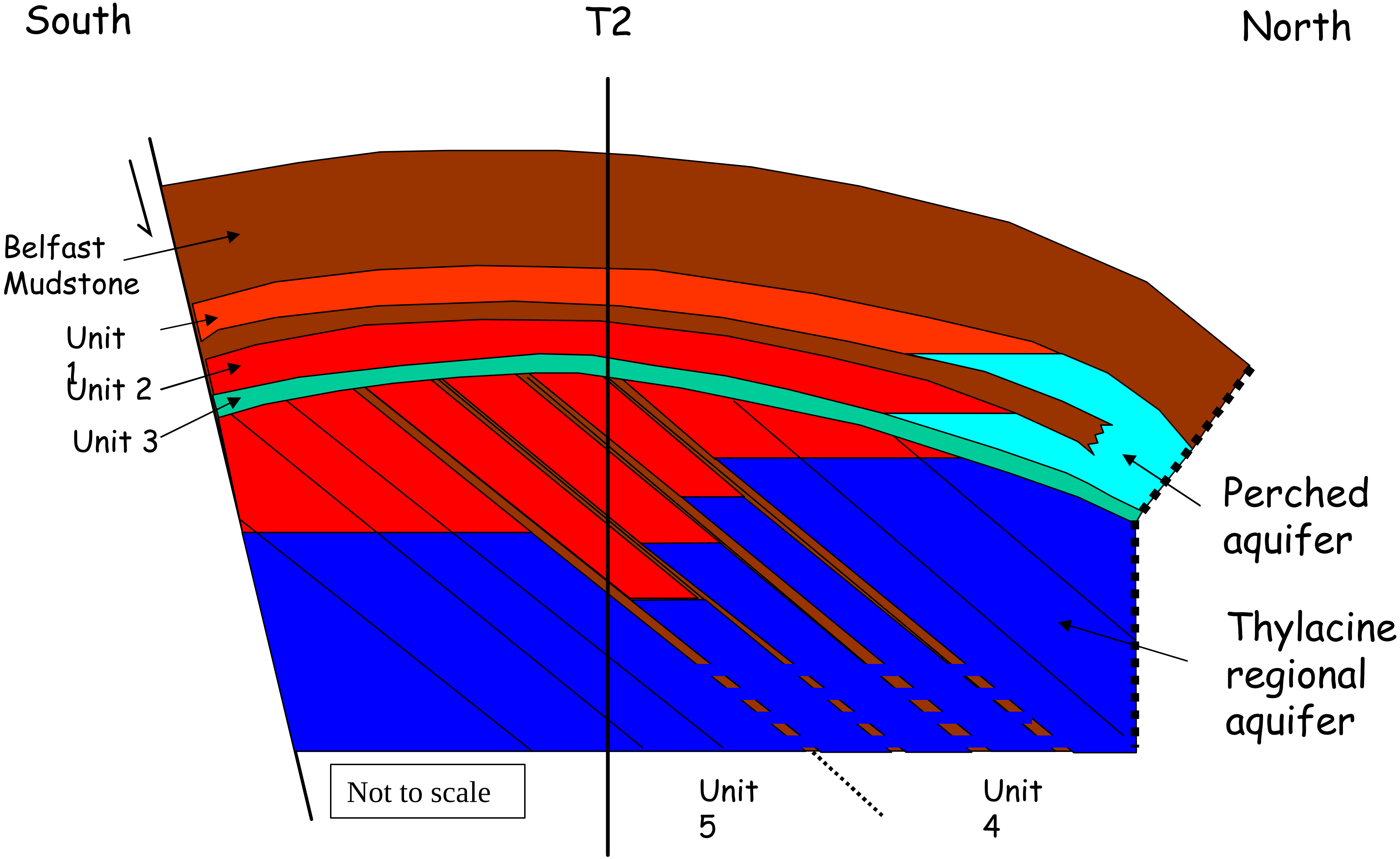


Figure 36

Blocks defined in the Thylacine Field

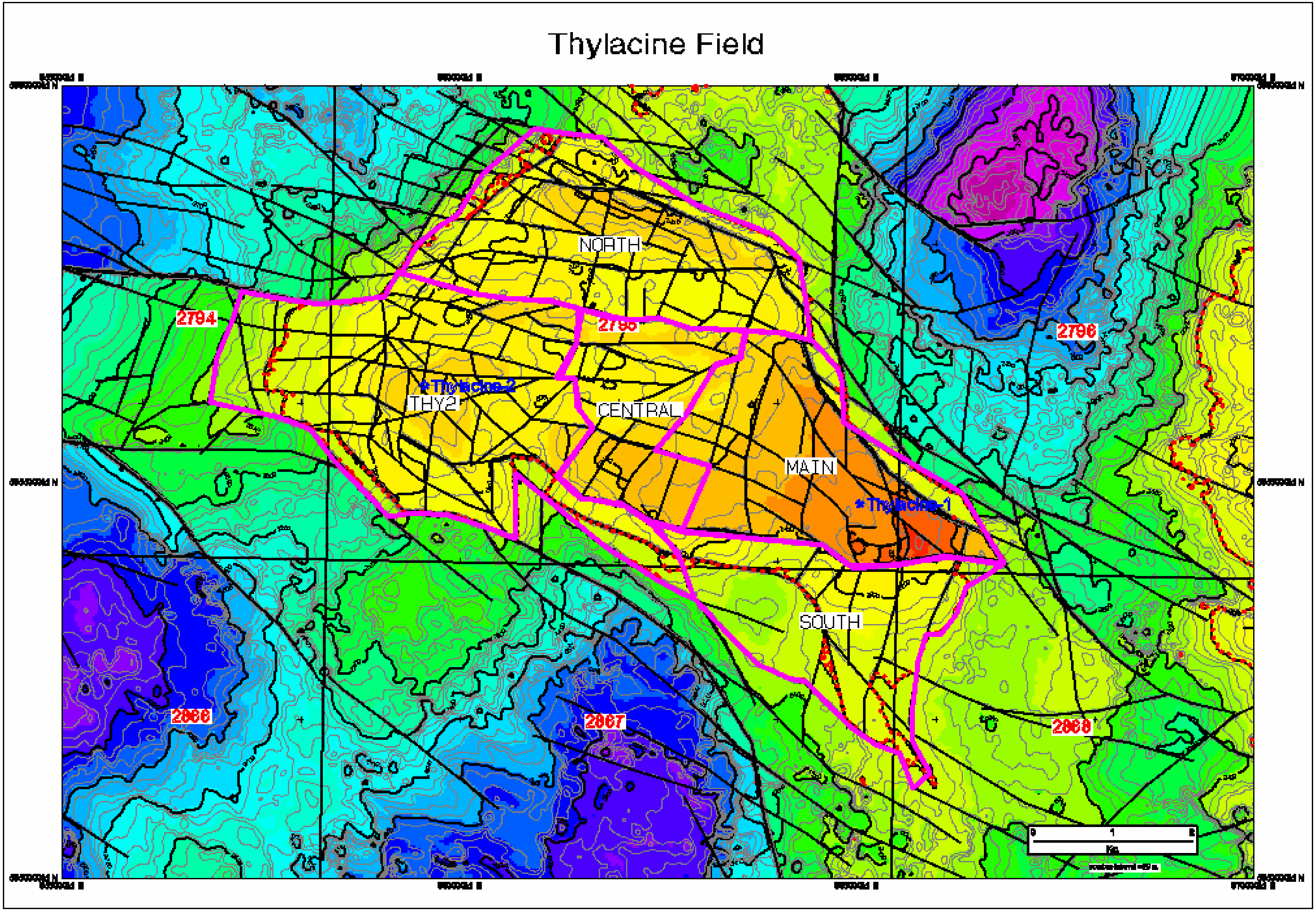


Figure 37

Blocks defined in the Geographe Field

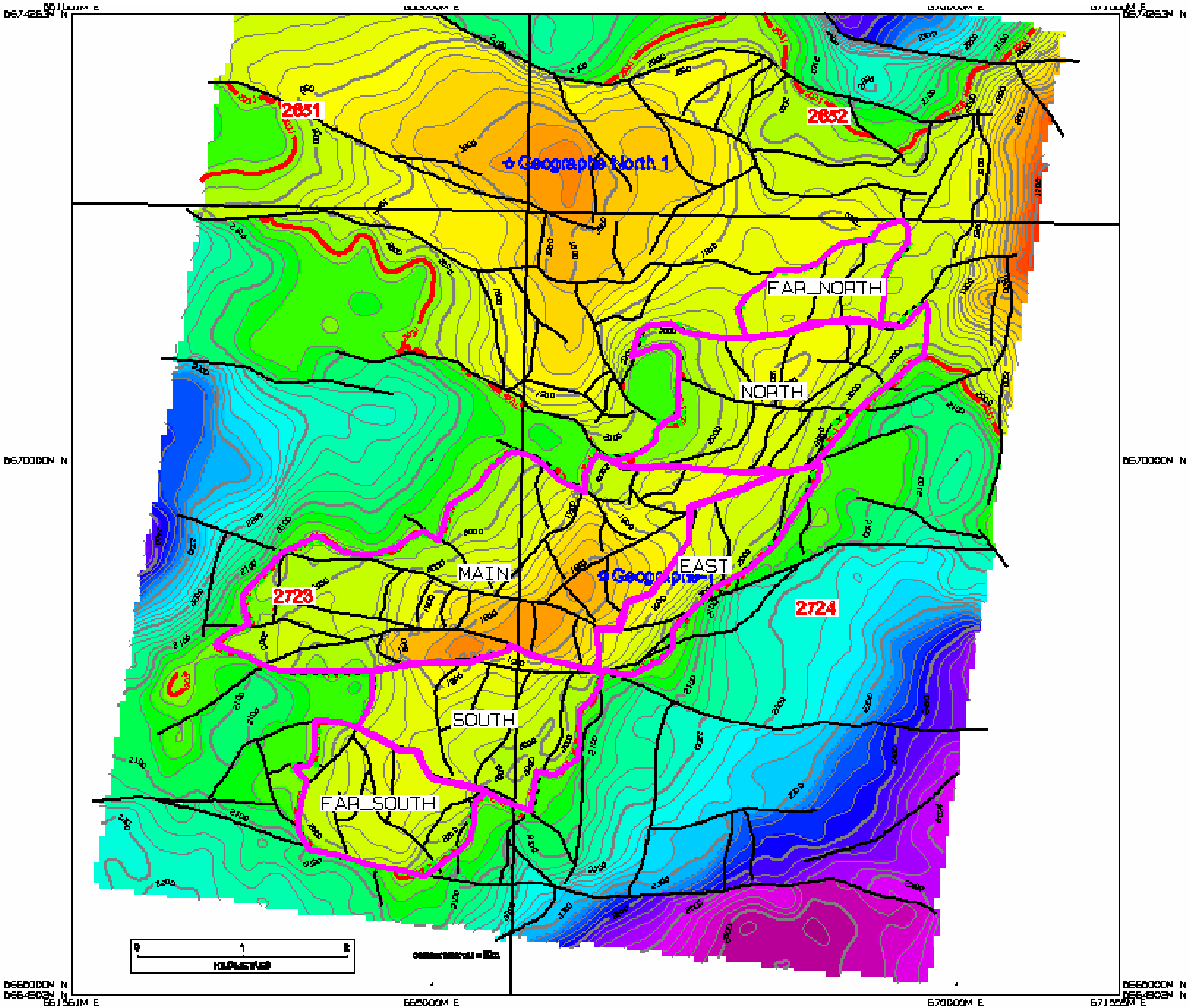
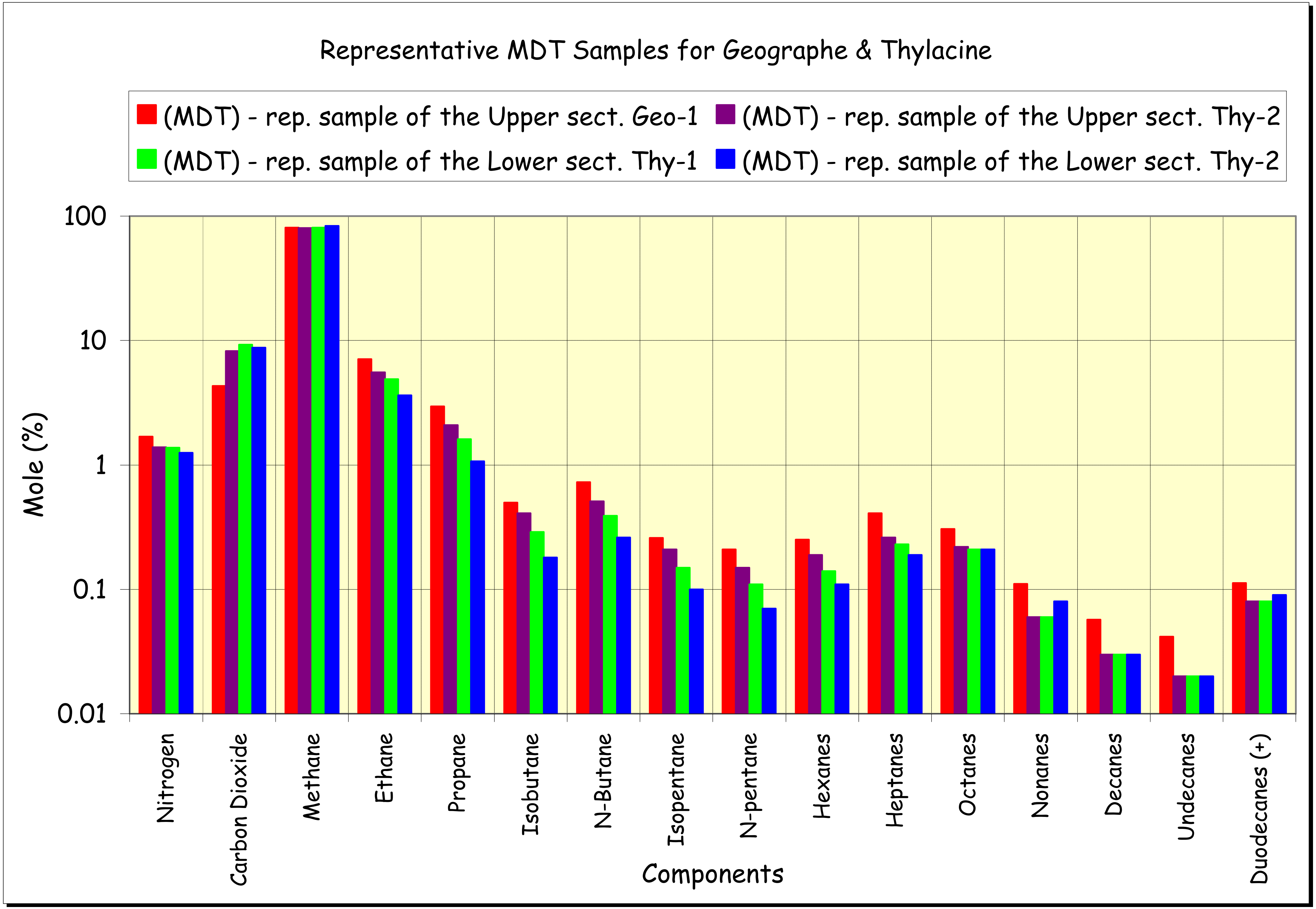


Figure 38



Representative MDT Samples for Geographe & Thylacine
(MDT) - rep. sample of the Upper sect. Geo-1
(MDT) - rep. sample of the Upper sect. Thy-2
(MDT) - rep. sample of the Lower sect. Thy-1
(MDT) - rep. sample of the Lower sect. Thy-2
Mole (%)
100
10
1
0.1
0.01
Nitrogen
Carbon Dioxide
Methane
Ethane
Propane
Isobutane
N-Butane
Isopentane
N-pentane
Hexanes
Heptanes
Octanes
Nonanes
Decanes
Undecanes
Duodecanes (+)
Components

Figure 39

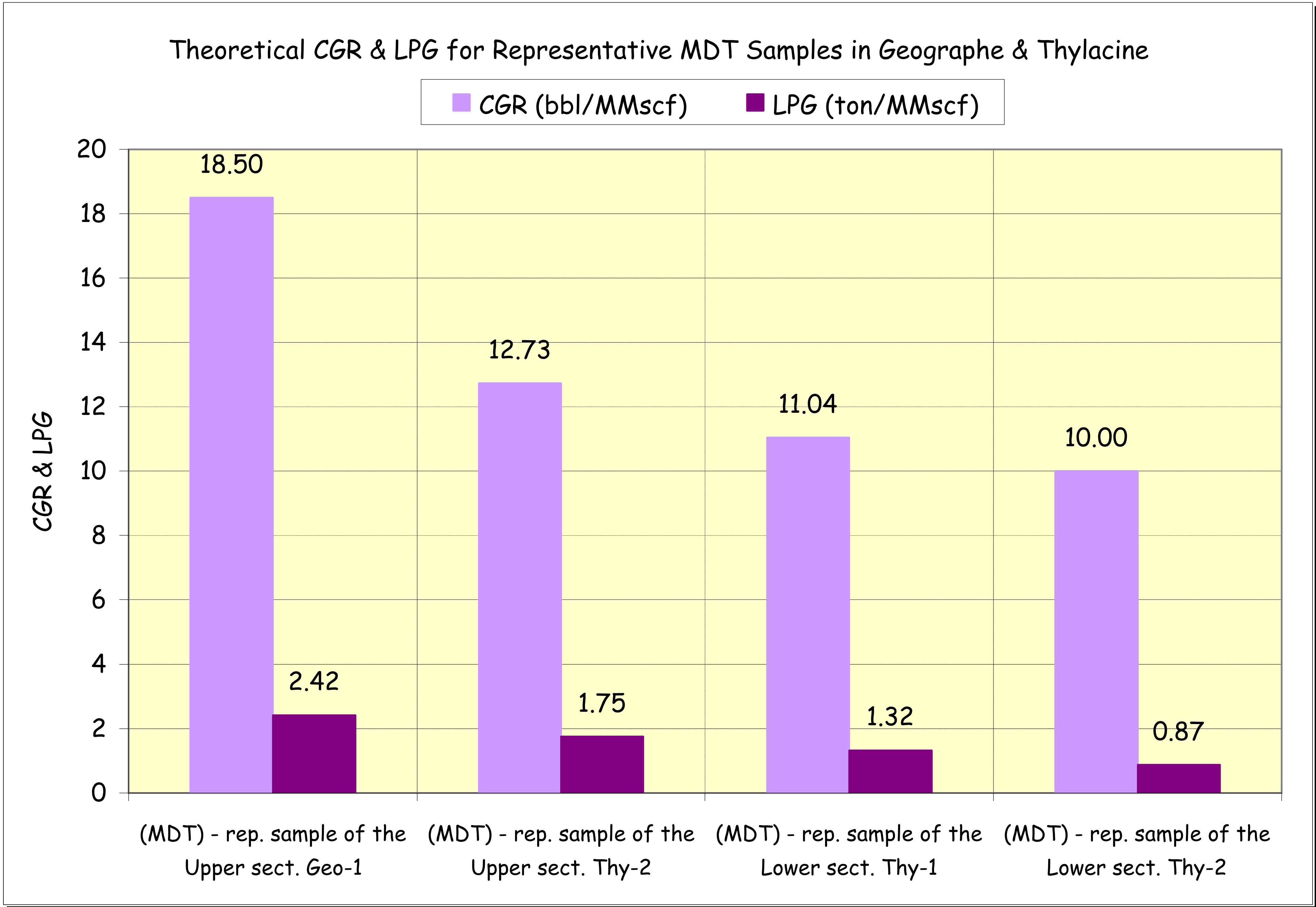
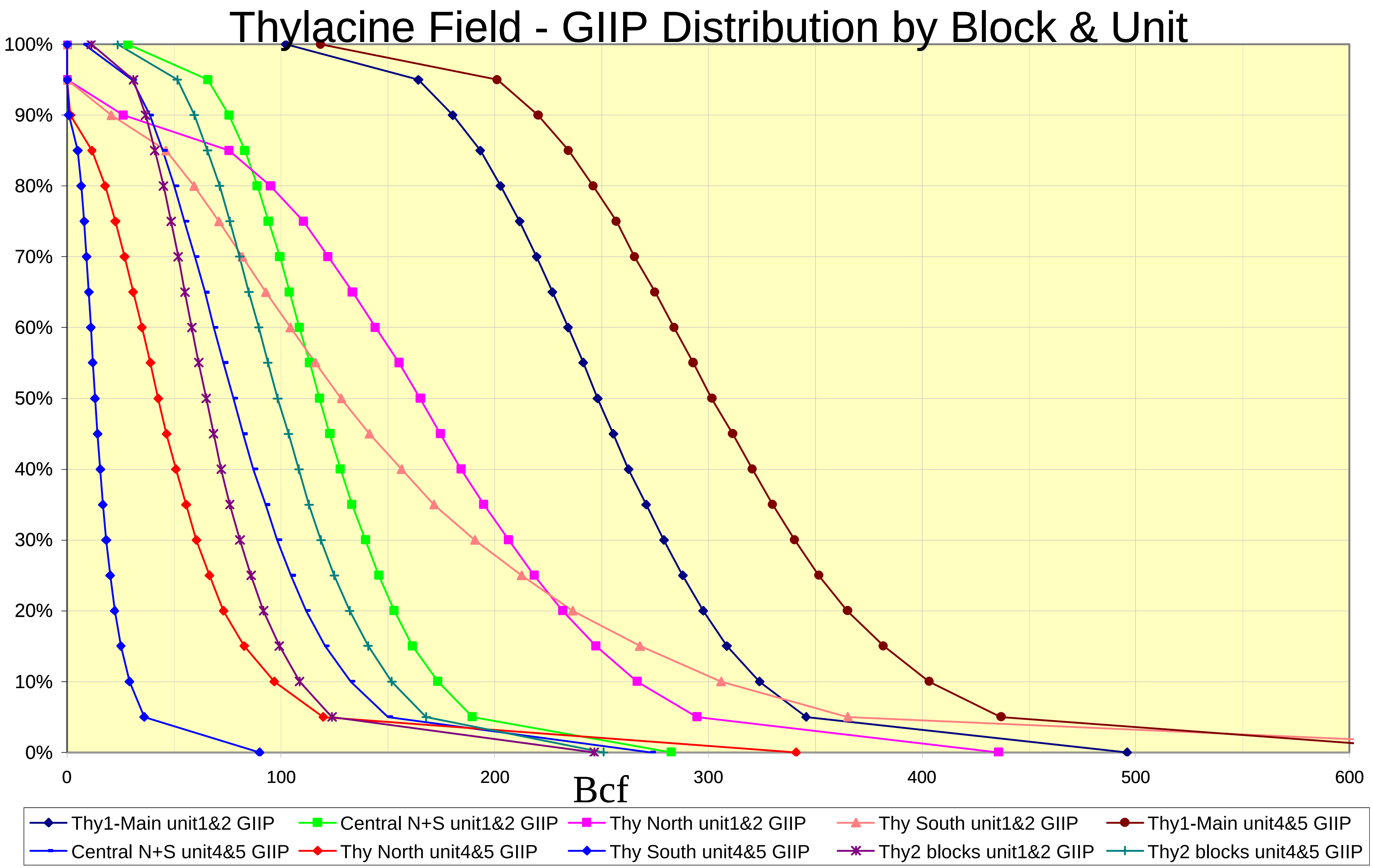
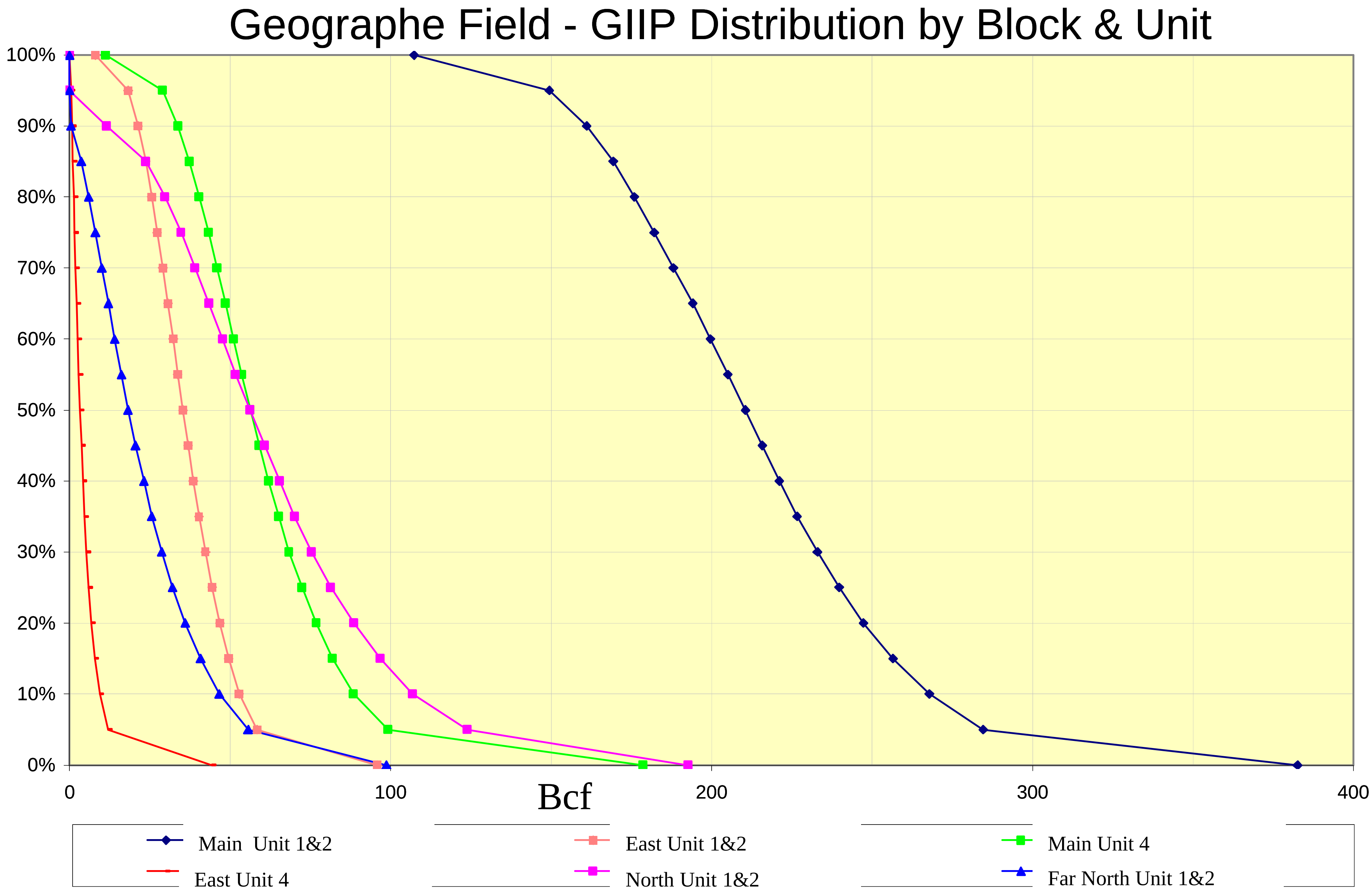

Theoretical CGR & LPG for Representative MDT Samples in Geographe & Thylacine
CGR (bbl/MMscf)
LPG (ton/MMscf)
CGR & LPG
0
2
4
6
8
10
12
14
16
18
20
18.50
2.42
12.73
1.75
11.04
1.32
10.00
0.87
(MDT) - rep. sample of the Upper sect. Geo-1
(MDT) - rep. sample of the Upper sect. Thy-2
(MDT) - rep. sample of the Lower sect. Thy-1
(MDT) - rep. sample of the Lower sect. Thy-2

Figure 40



Thylacine Field - GIIP Distribution by Block & Unit
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
100
200
300
400
500
600
Bcf
Thy1-Main unit1&2 GIIP
Central N+S unit1&2 GIIP
Thy North unit1&2 GIIP
Thy South unit1&2 GIIP
Thy1-Main unit4&5 GIIP
Central N+S unit4&5 GIIP
Thy North unit4&5 GIIP
Thy South unit4&5 GIIP
Thy2 blocks unit1&2 GIIP
Thy2 blocks unit4&5 GIIP

Figure 41



Geographe Field - GIIP Distribution by Block & Unit
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
100
200
300
400
Bcf
Main Unit 1&2
East Unit 1&2
Main Unit 4
East Unit 4
North Unit 1&2
Far North Unit 1&2

Figure 42

Key Uncertainties and their Impact (P90/P10) on P50 GIIP

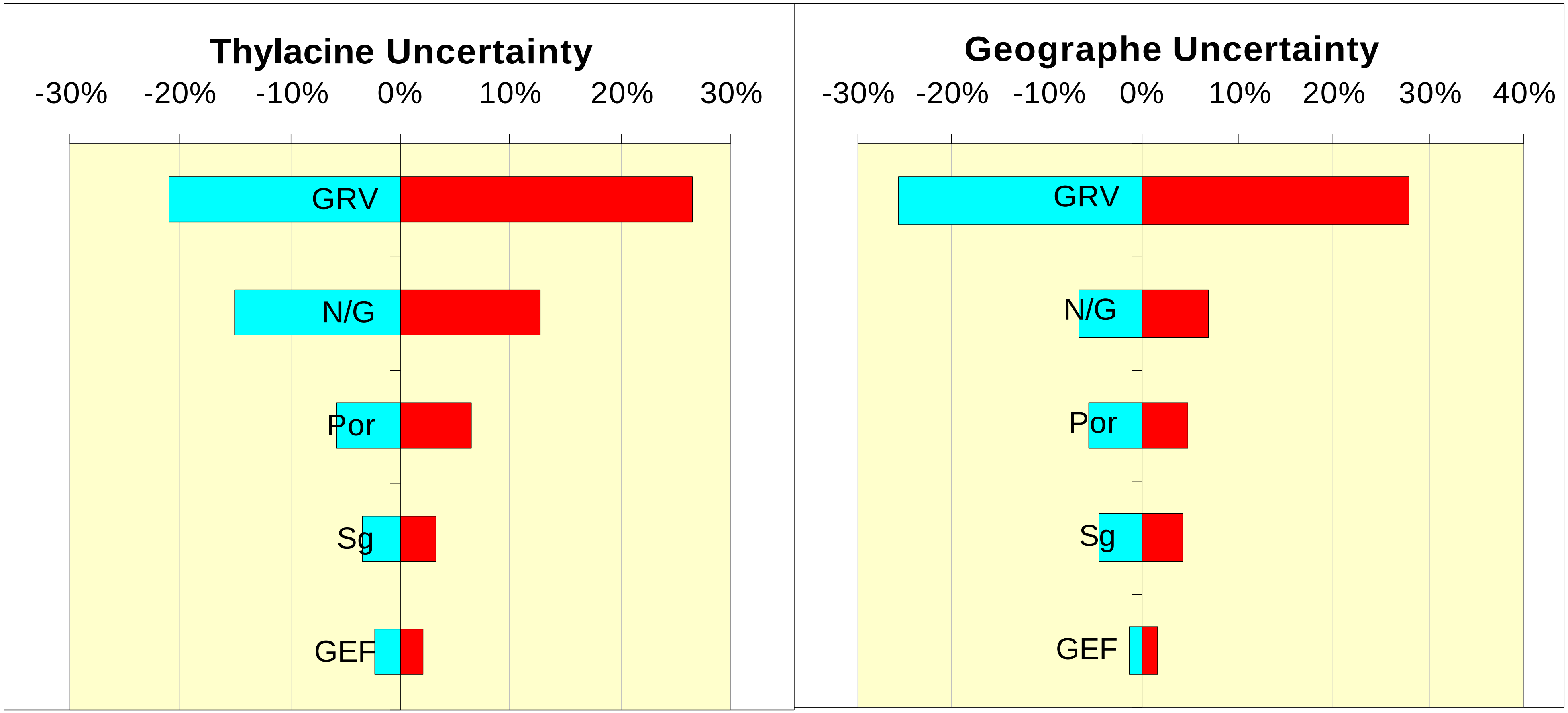
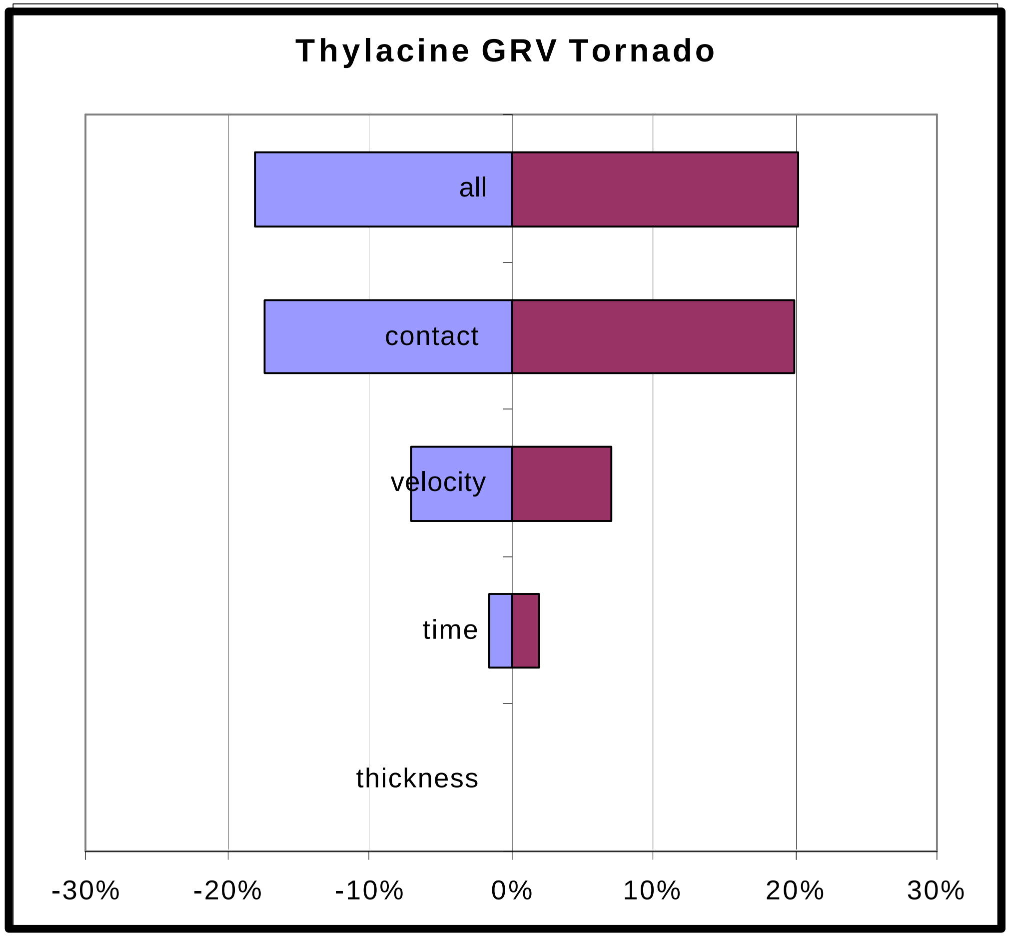


Figure 43

Thylacine & Geographe GRV Tornado's



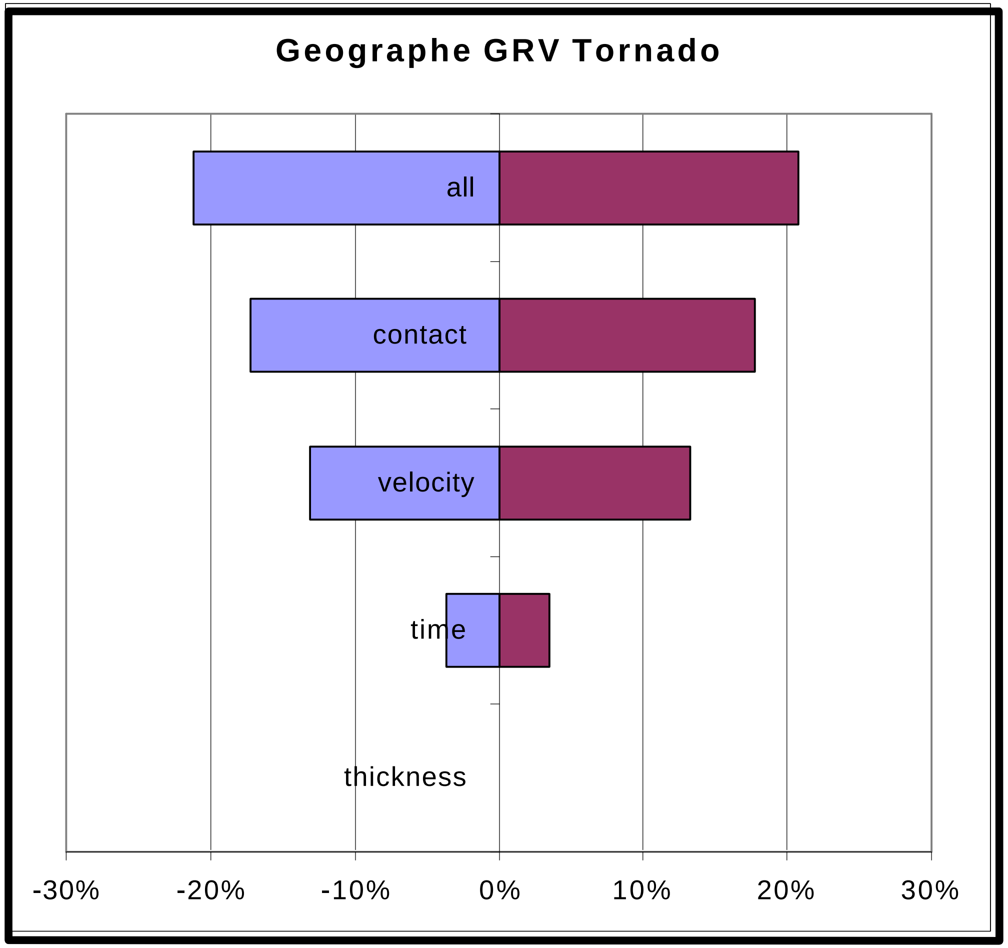


Figure 44

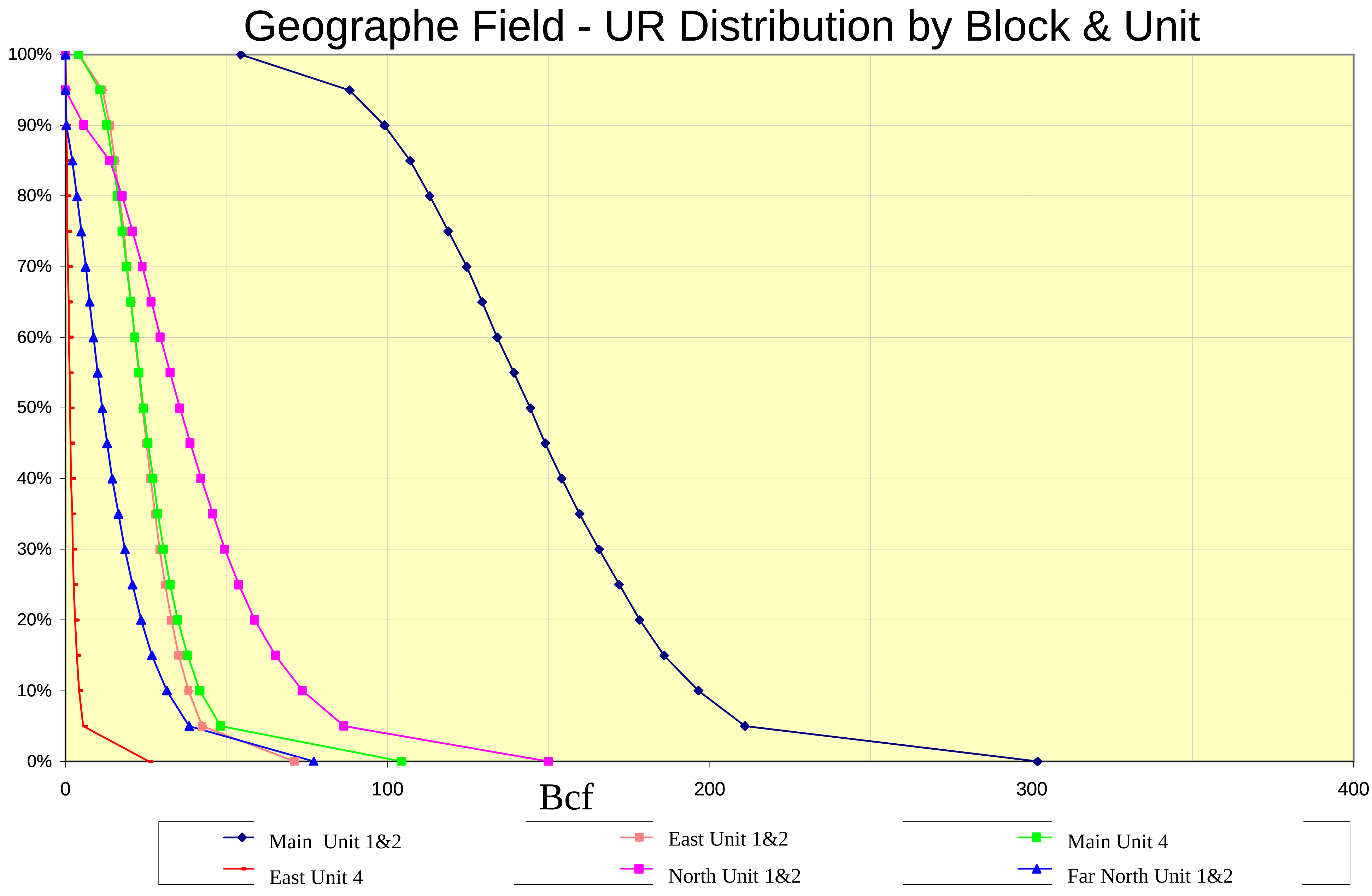

Geographe Field - UR Distribution by Block & Unit
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
100
200
300
400
Bcf
Main Unit 1&2
East Unit 4
East Unit 1&2
North Unit 1&2
Main Unit 4
Far North Unit 1&2

Figure 45

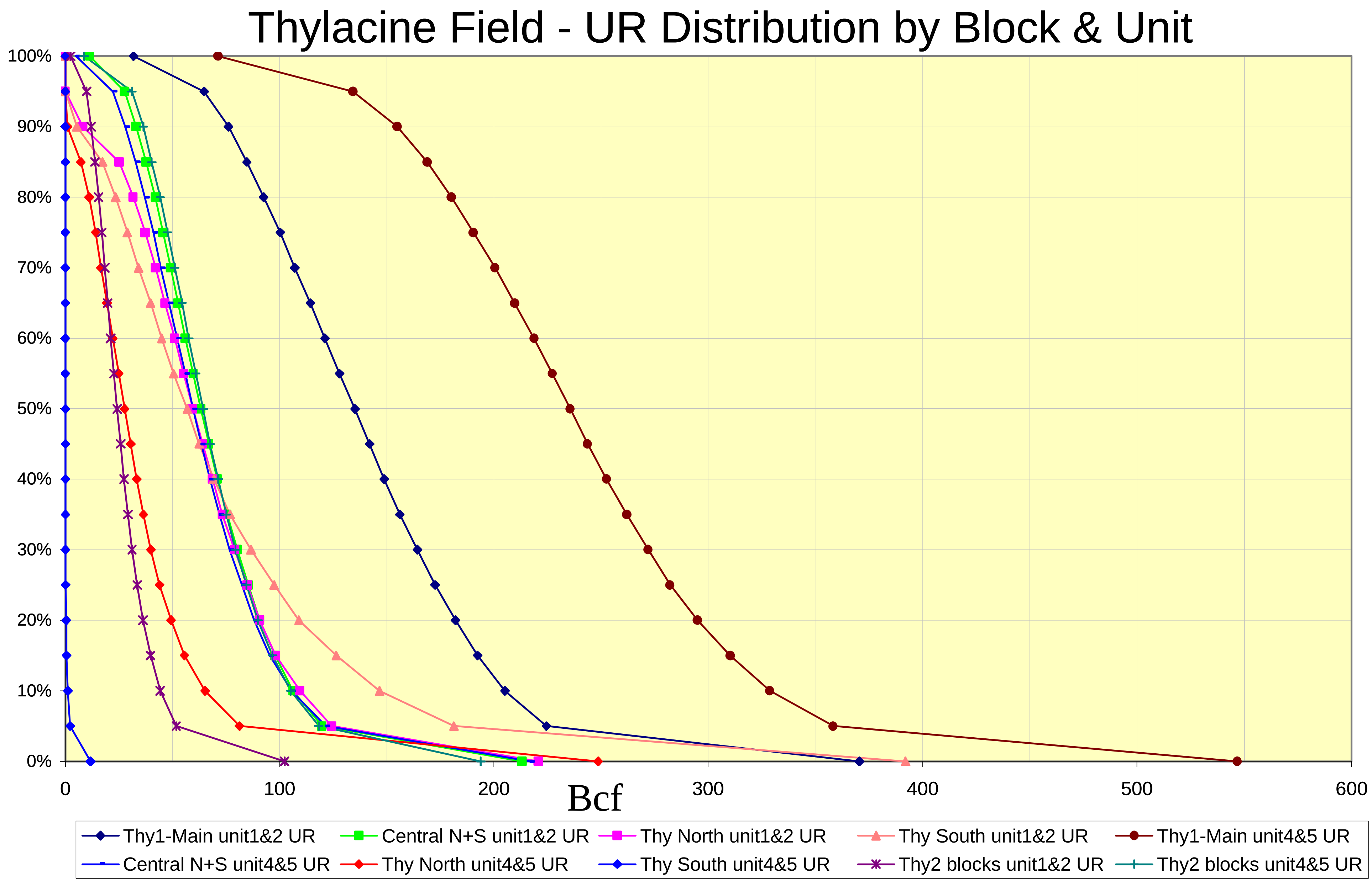

Thylacine Field - UR Distribution by Block & Unit
100%
90%
80%
70%
60%
50%
40%
30%
20%
10%
0%
0
100
200
300
400
500
600
Bcf
Thy1-Main unit1&2 UR
Central N+S unit1&2 UR
Thy North unit1&2 UR
Thy South unit1&2 UR
Thy1-Main unit4&5 UR
Central N+S unit4&5 UR
Thy North unit4&5 UR
Thy South unit4&5 UR
Thy2 blocks unit1&2 UR
Thy2 blocks unit4&5 UR

Figure 46

TA-1: Thylacine Development Well Section

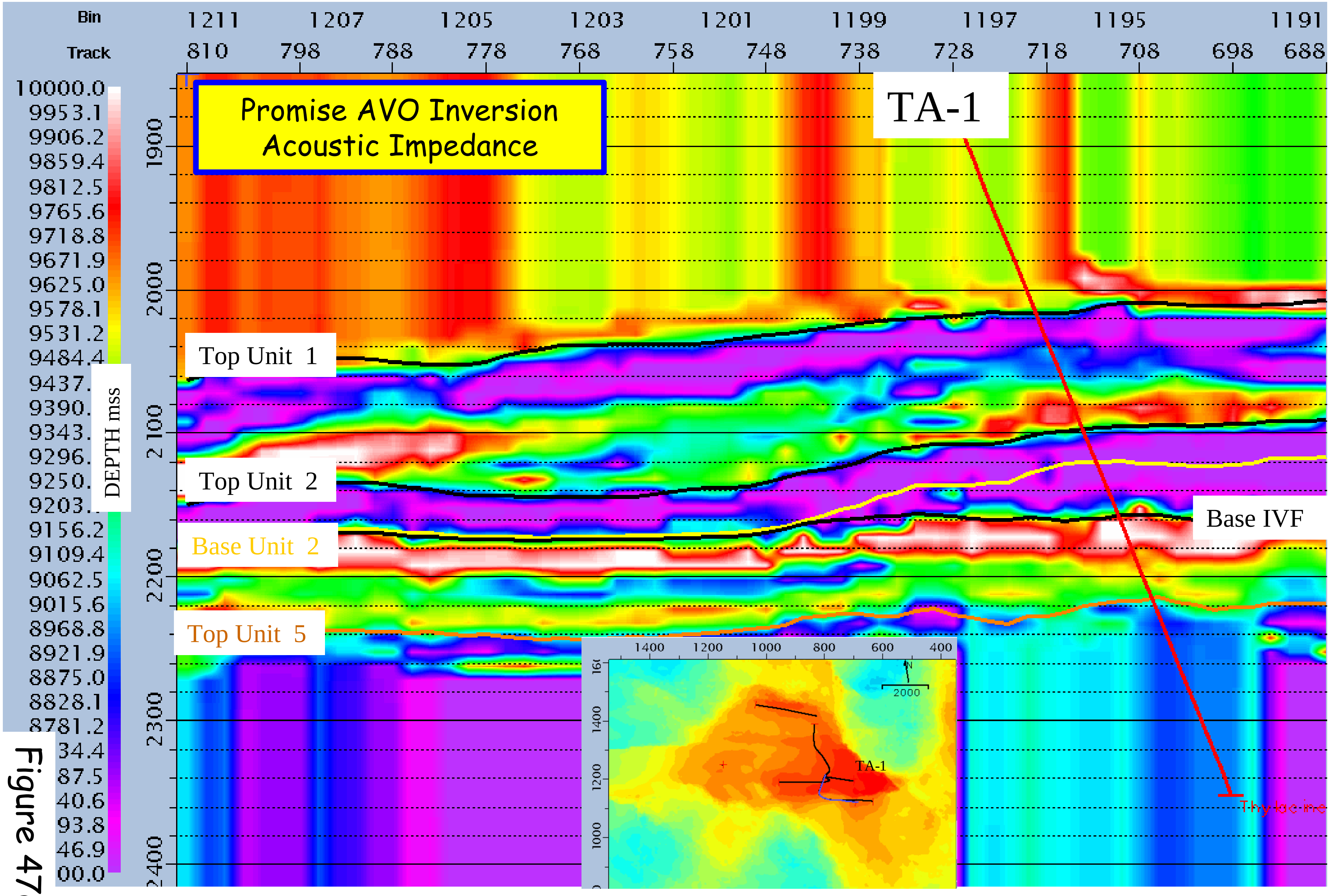


Figure 47a

TA-2: Thylacine Development Well Section

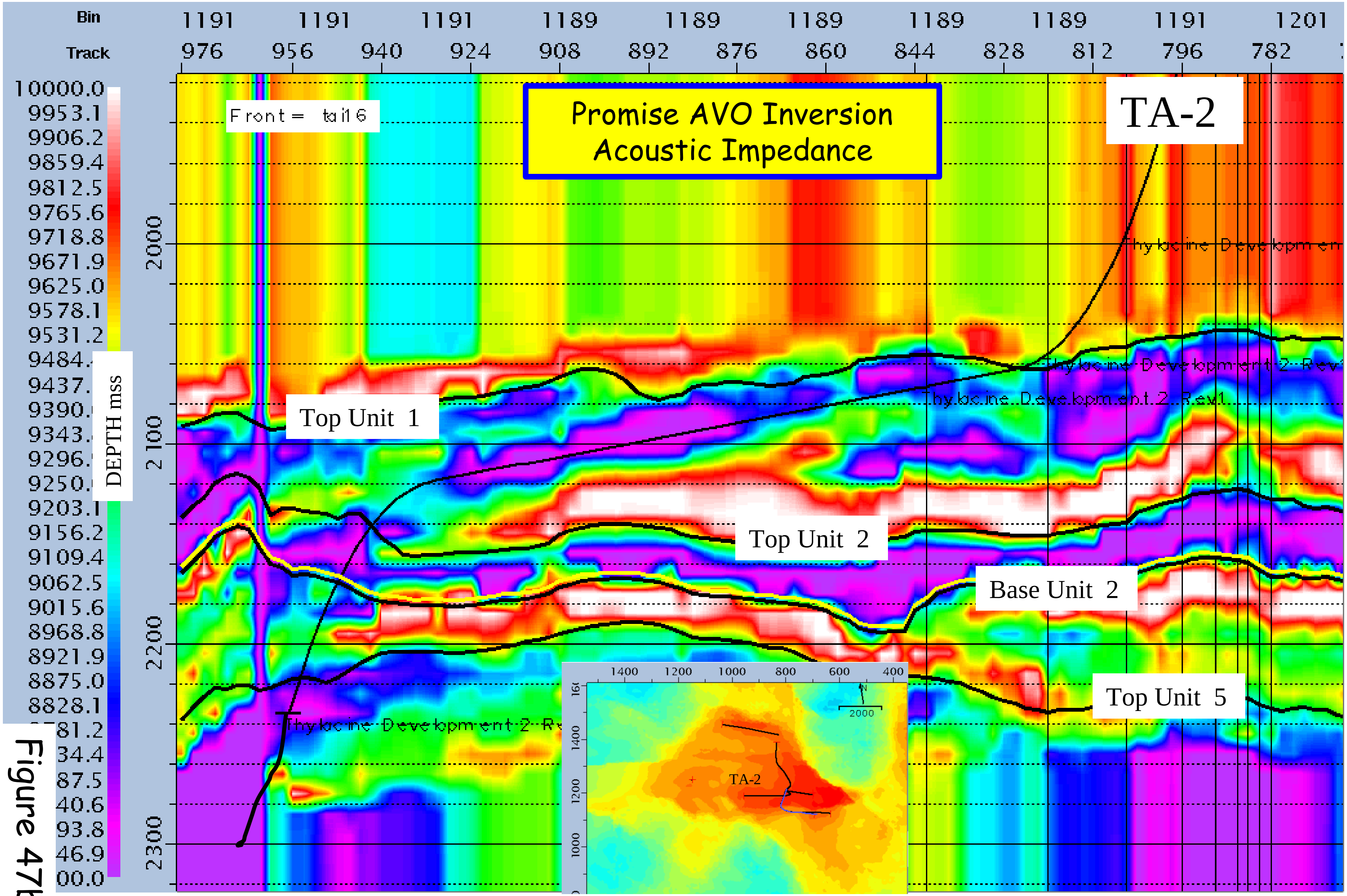


Figure 47b

TA-3: Thylacine Development Well Section

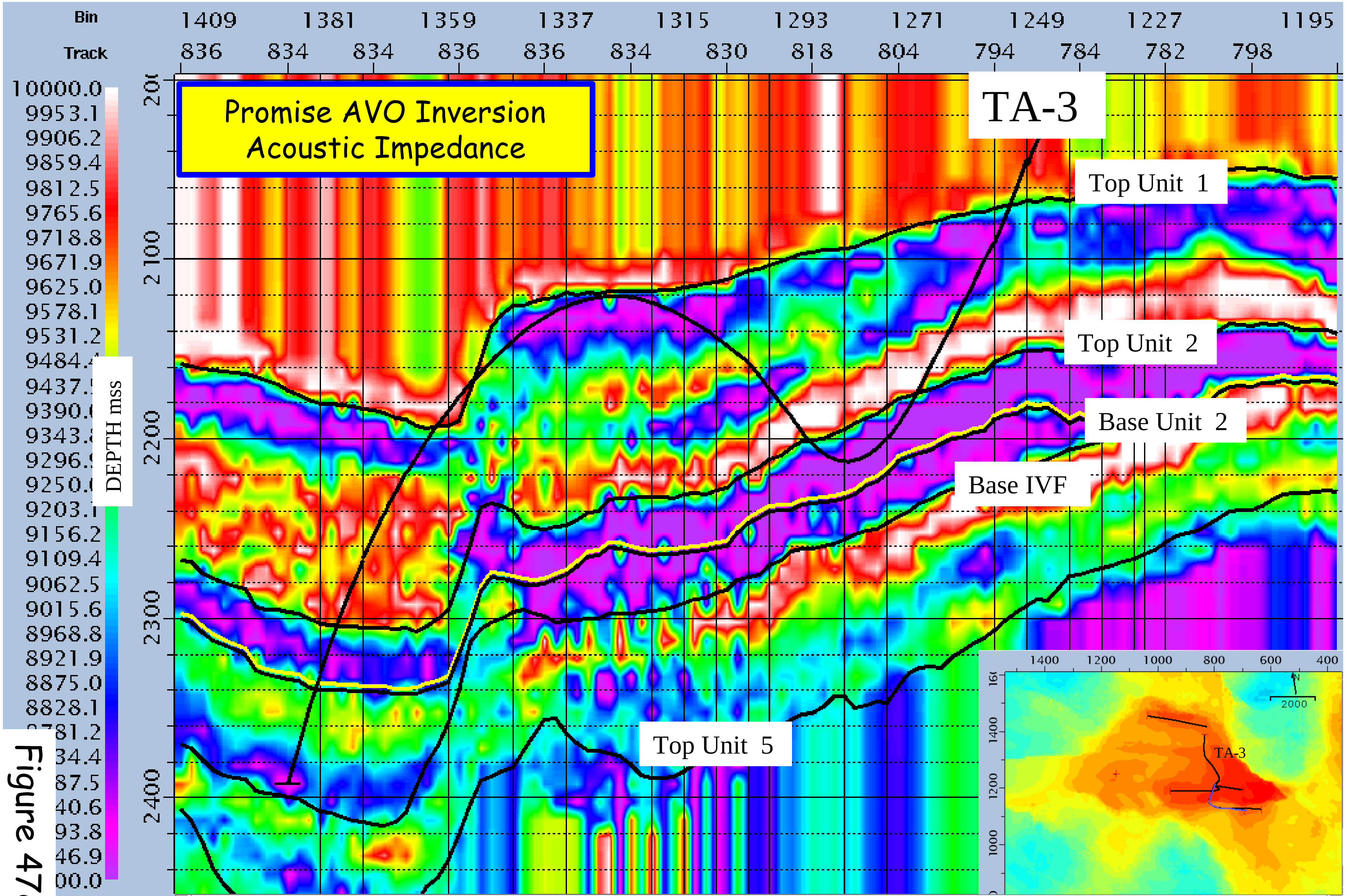


Figure 47c

TA-4: Thylacine South Appraisal & Development Well Section

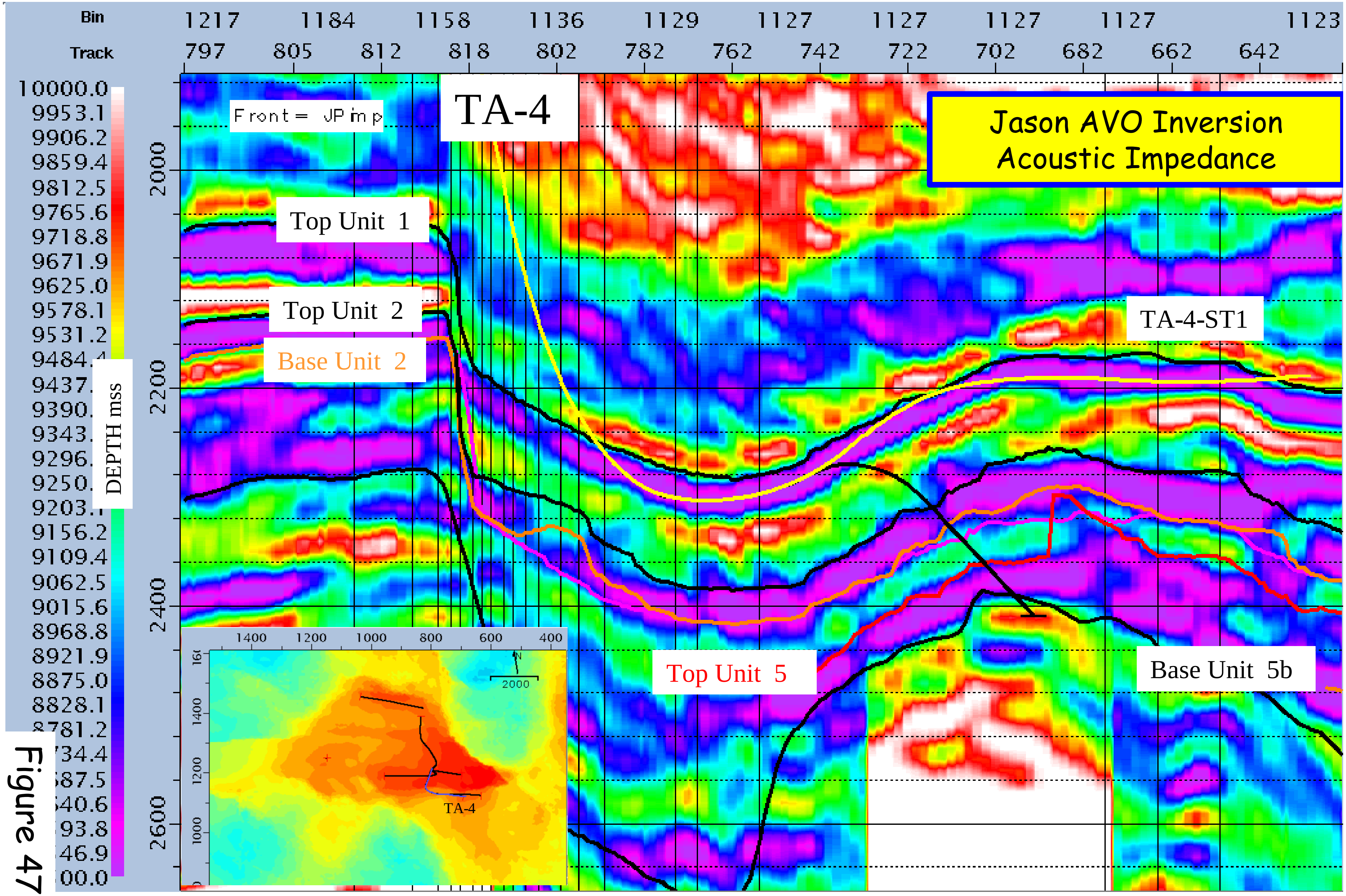


Figure 47d

TN-1: Thylacine North Development Well Section

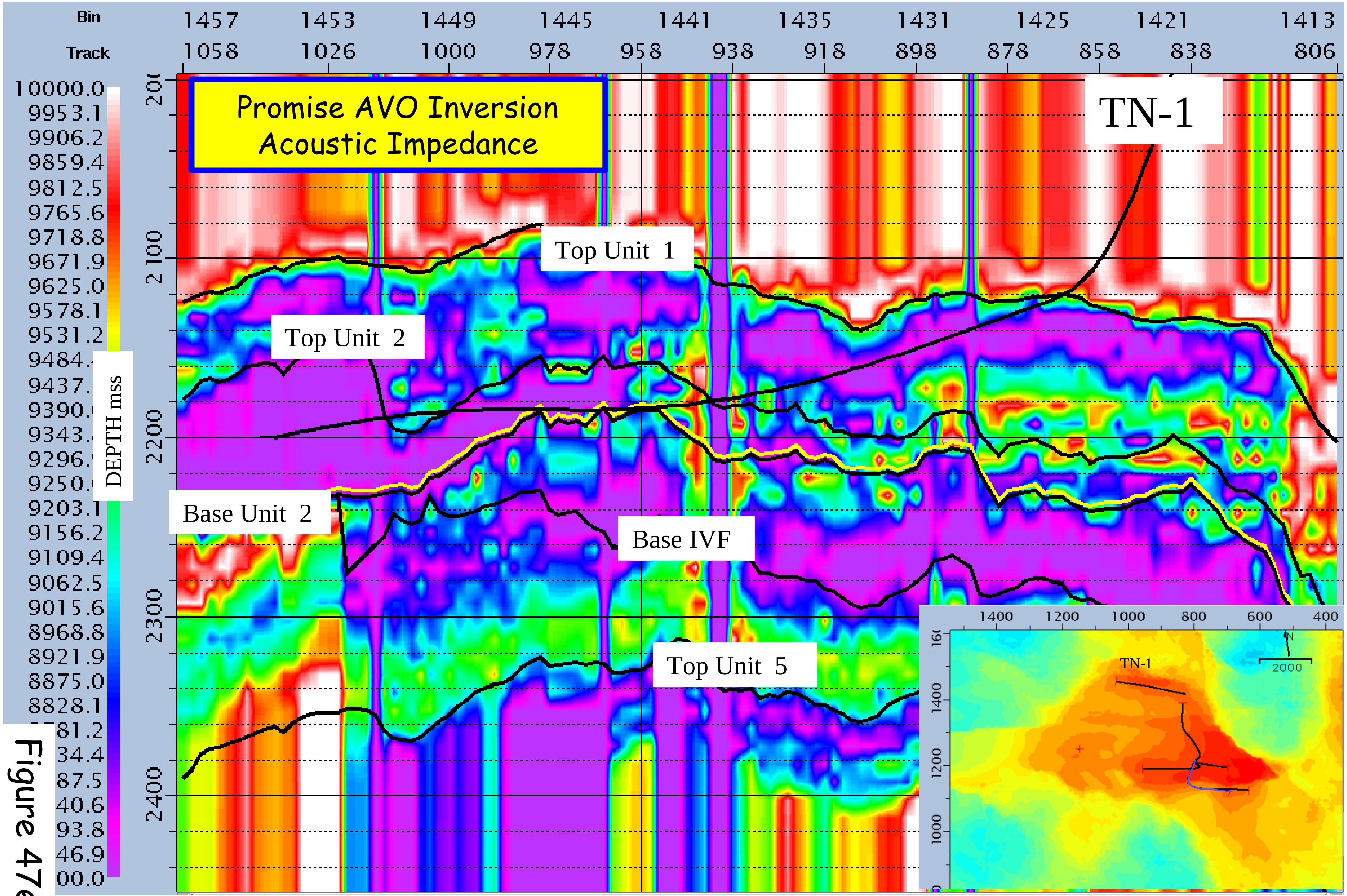


Figure 47e

G-2: Geographe Development Well Section

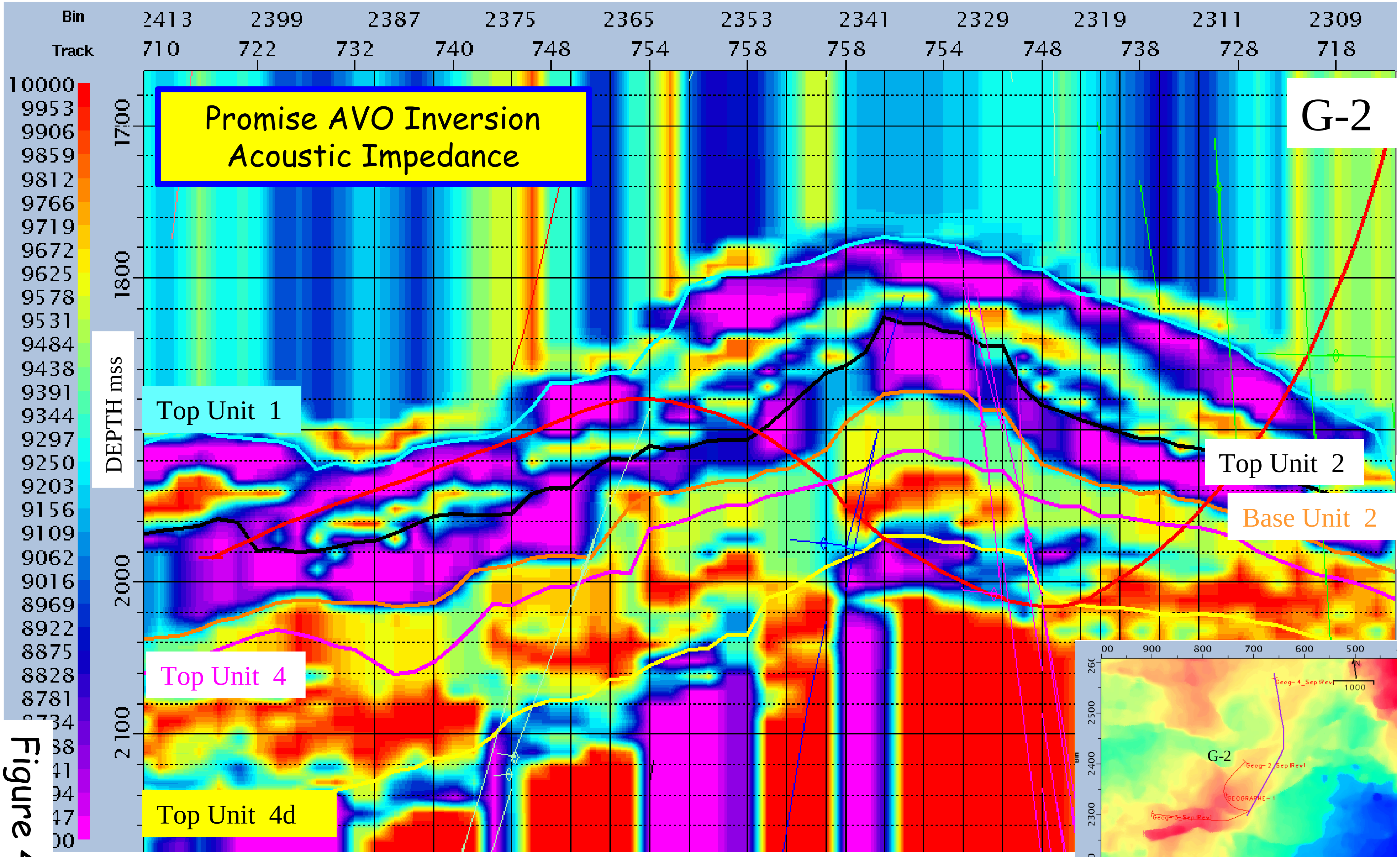


Figure 48a

G-3: Geographe Development Well Section

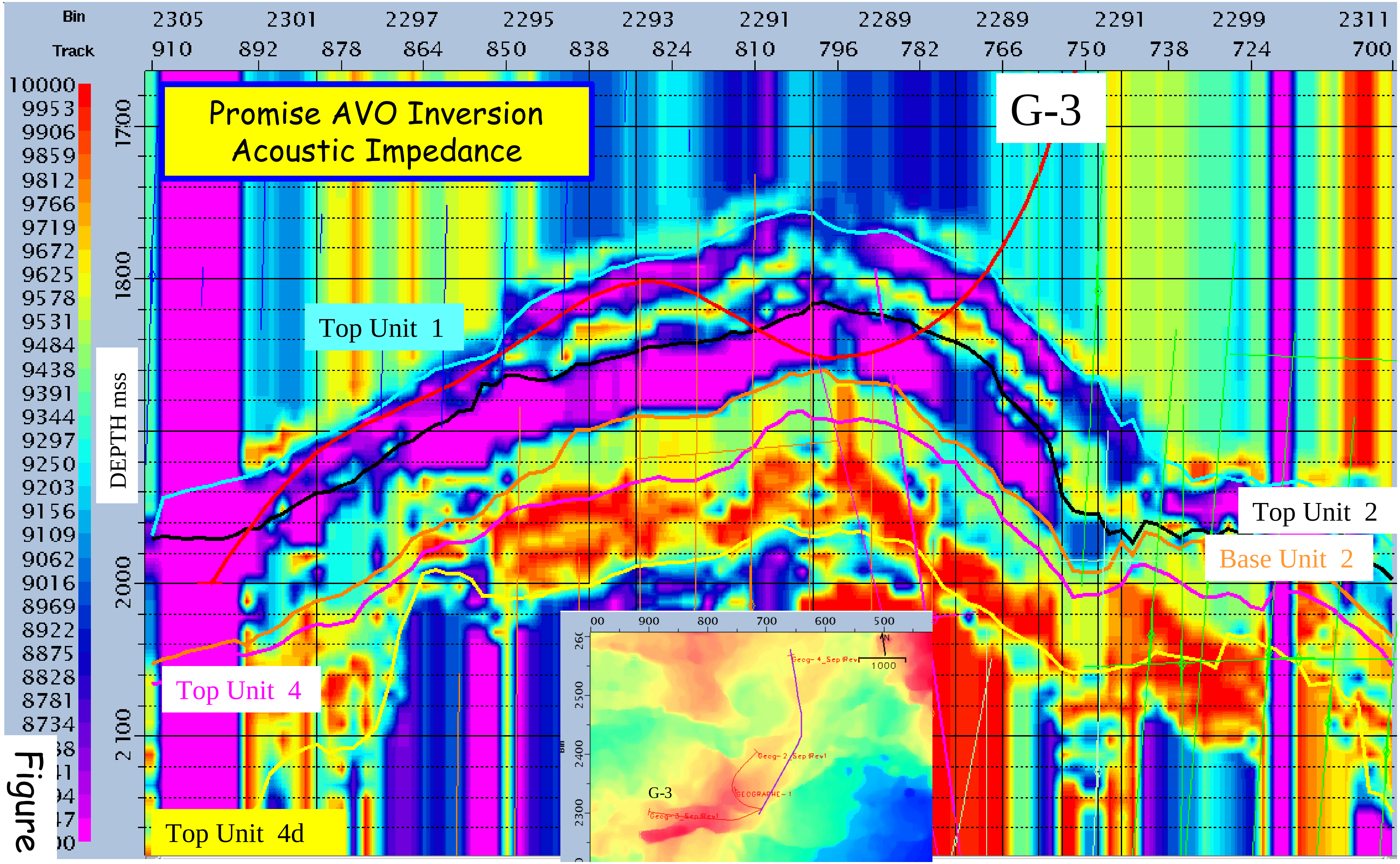


Figure 48b

G-4: Geographe Development Well Section

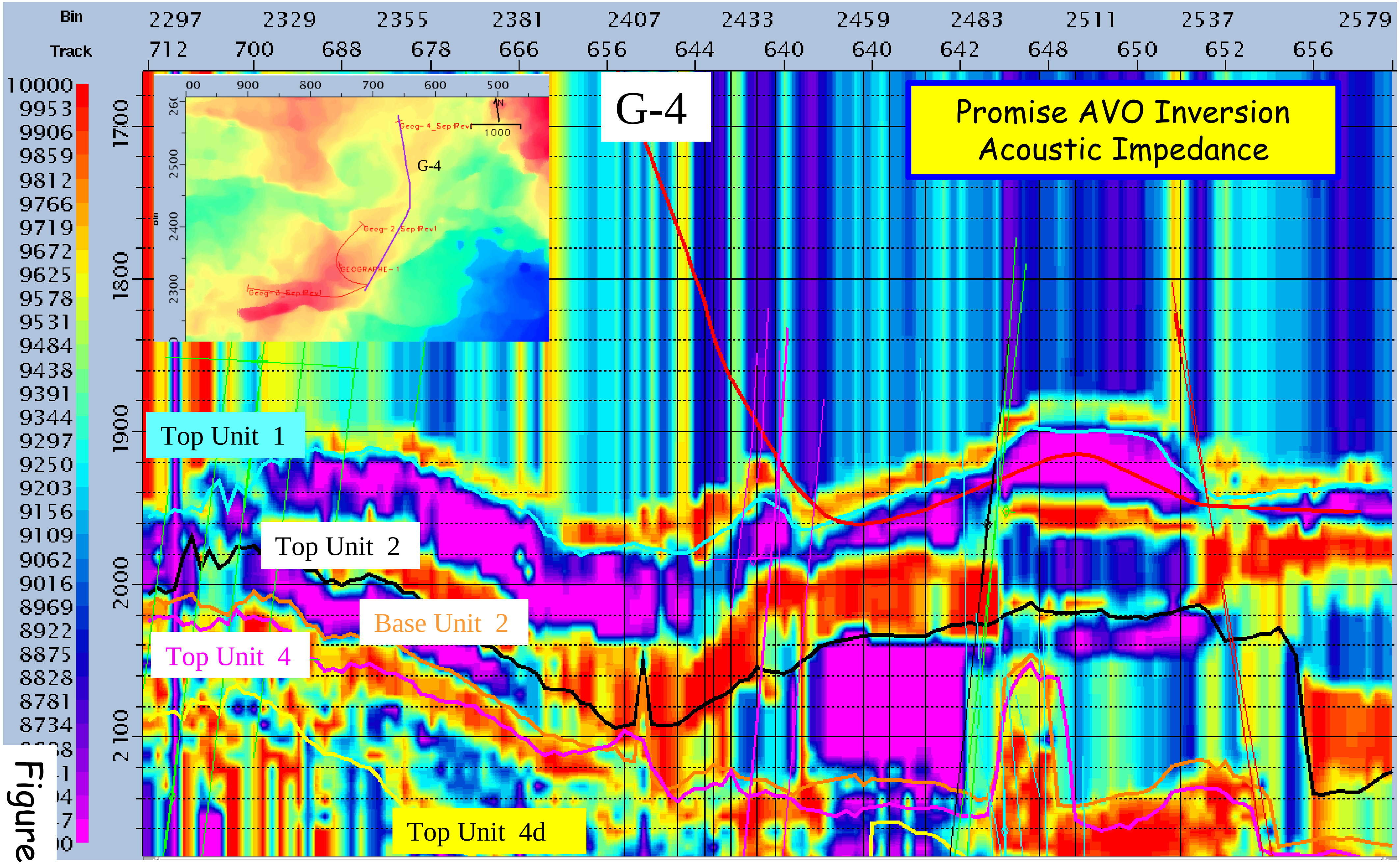
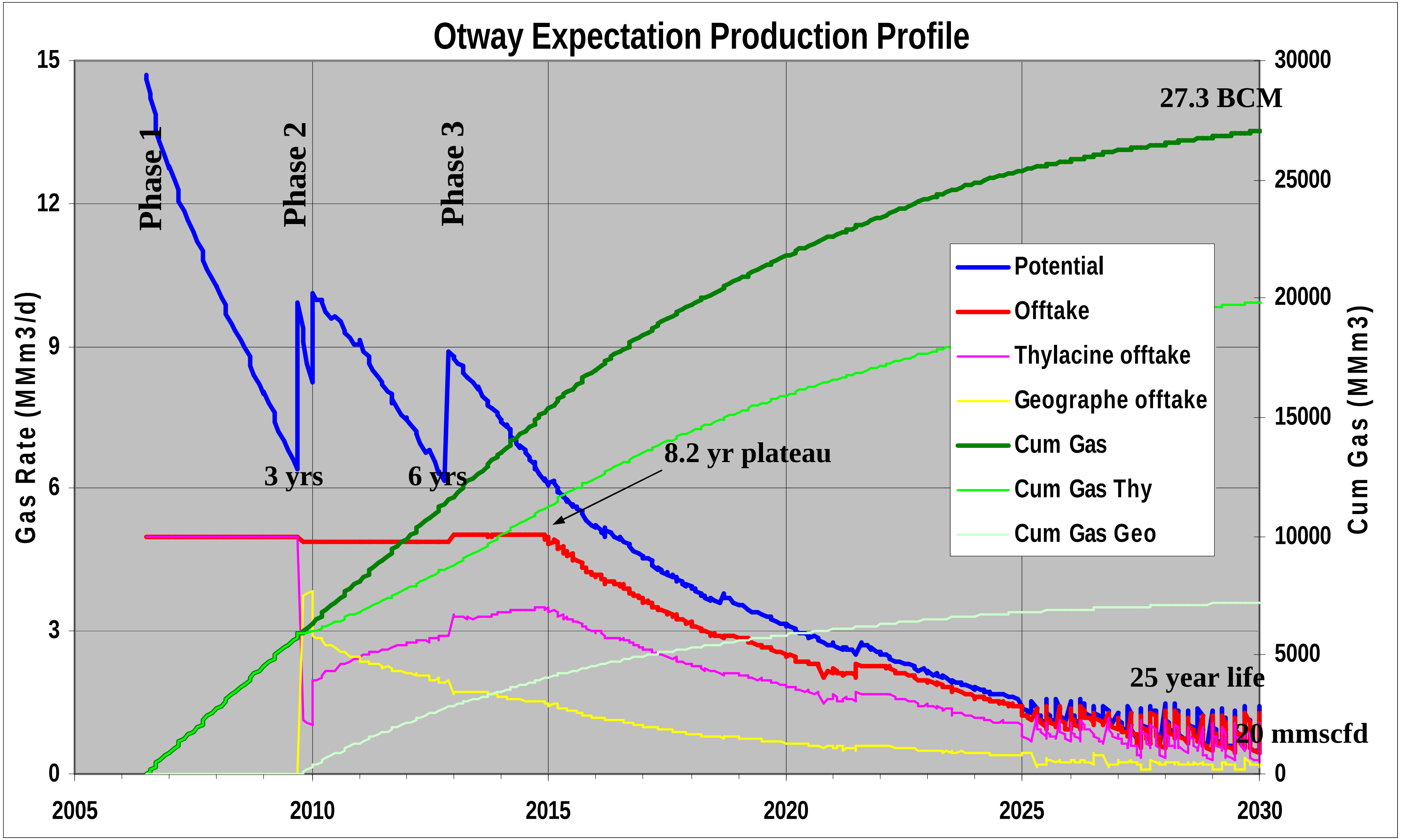
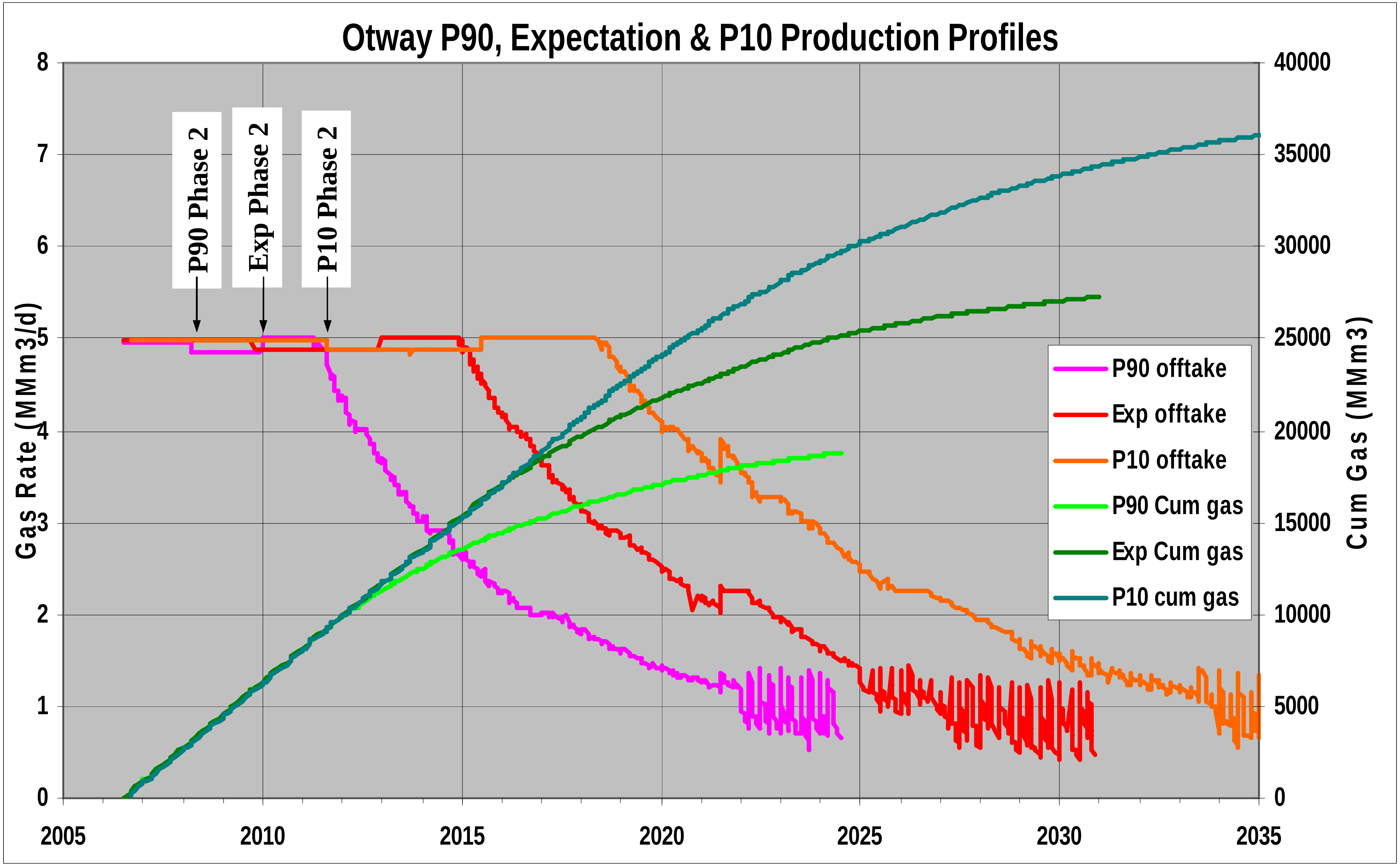


Figure 48c



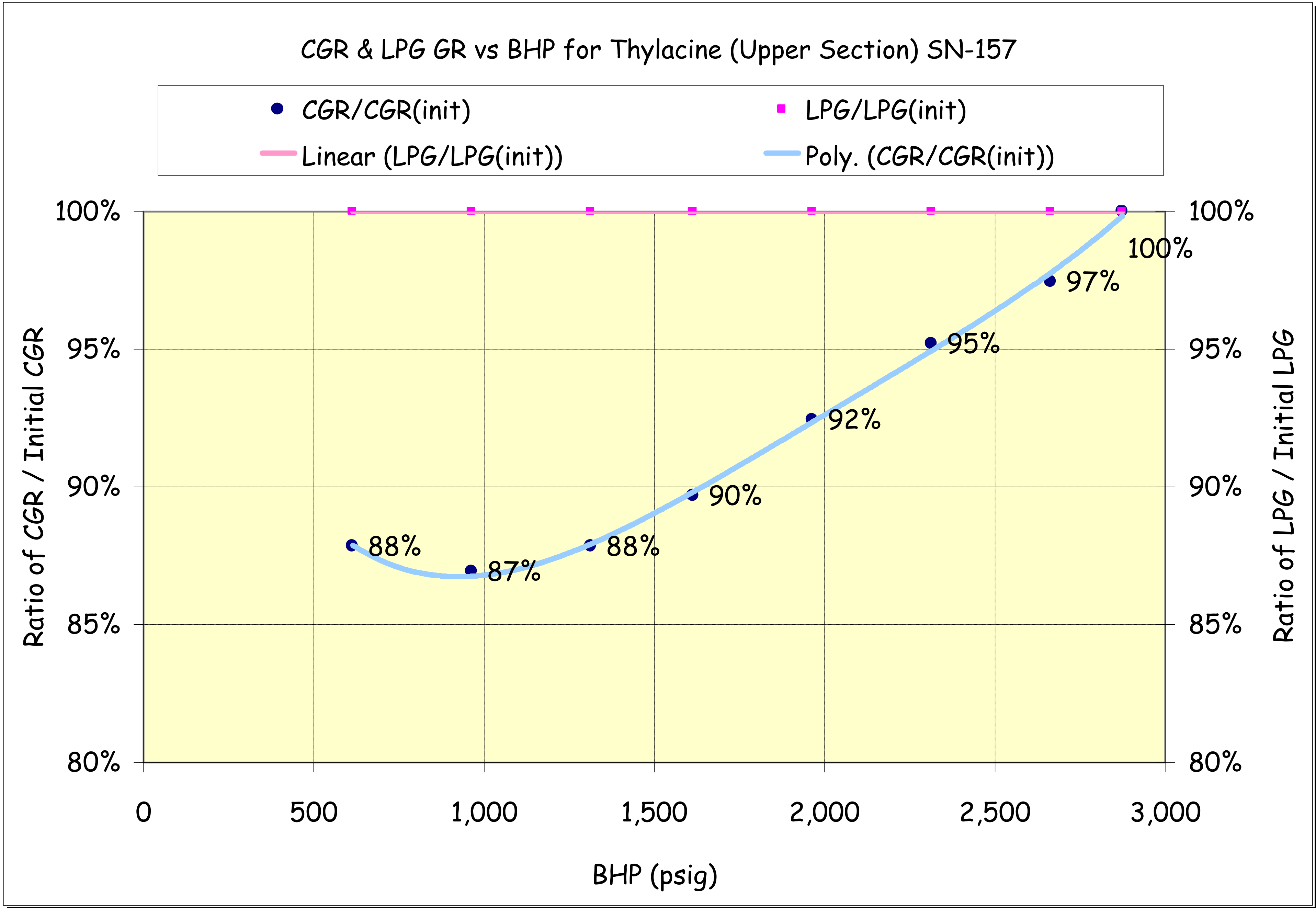
- Phase 1 = TA1, TA2, TA3, TA4 platform drilling
- Phase 2 = Geographe development (G-2, G-3 & G-4), TN1 subsea
- Phase 3 = Onshore compression

Figure 49



- Phase 1 = TA1, TA2, TA3, TA4 platform drilling
- Phase 2 = Geographe development (G-2, G-3 & G-4), TN1 subsea
- Phase 3 = Onshore compression

Figure 50



CGR & LPG GR vs BHP for Thylacine (Upper Section) SN-157
CGR/CGR(init)
LPG/LPG(init)
Linear (LPG/LPG(init))
Poly. (CGR/CGR(init))
Ratio of CGR / Initial CGR
Ratio of LPG / Initial LPG
100%
95%
90%
85%
80%
88%
87%
88%
90%
92%
95%
97%
100%
0
500
1,000
1,500
2,000
2,500
3,000
BHP (psig)

Figure 51

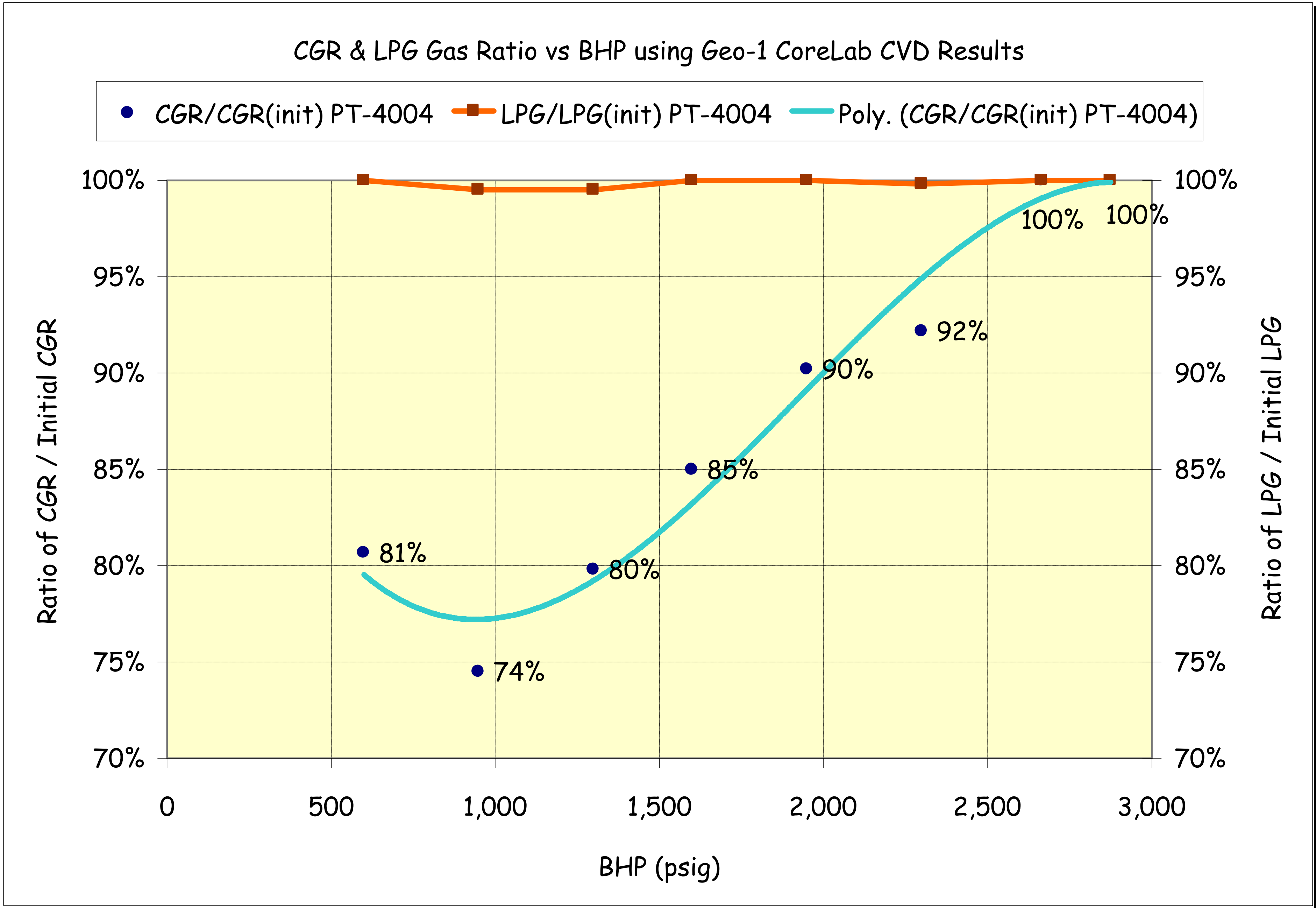
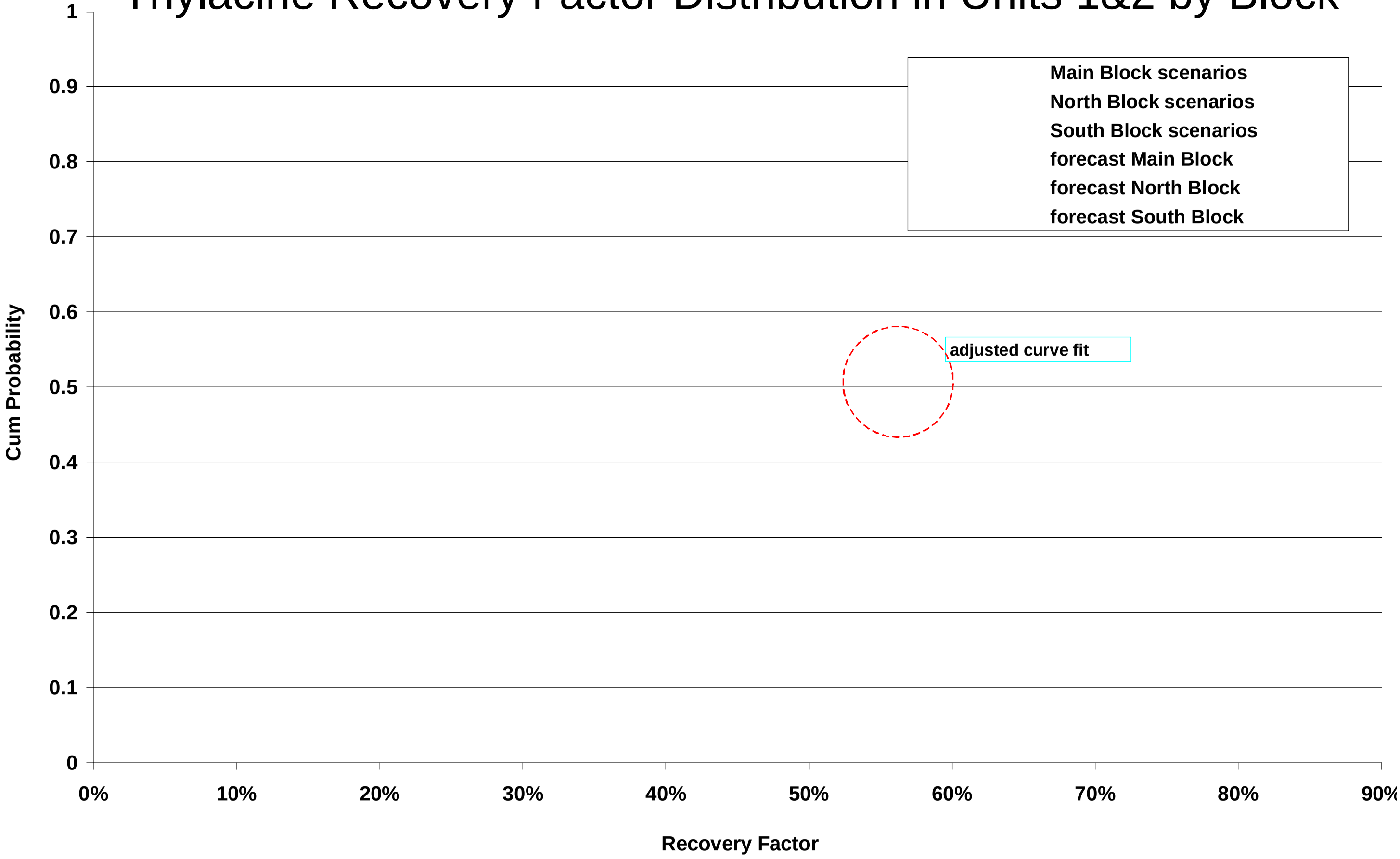

CGR & LPG Gas Ratio vs BHP using Geo-1 CoreLab CVD Results
CGR/CGR(init) PT-4004
LPG/LPG(init) PT-4004
Poly. (CGR/CGR(init) PT-4004)
Ratio of CGR / Initial CGR
Ratio of LPG / Initial LPG
100%
95%
90%
85%
80%
75%
70%
0
500
1,000
1,500
2,000
2,500
3,000
BHP (psig)
81%
74%
80%
85%
90%
92%
100%
100%

Figure 52

Thylacine Recovery Factor Distribution in Units 1&2 by Block



Thylacine Recovery Factor Distribution in Units 4A, 4BH & 5 by Block

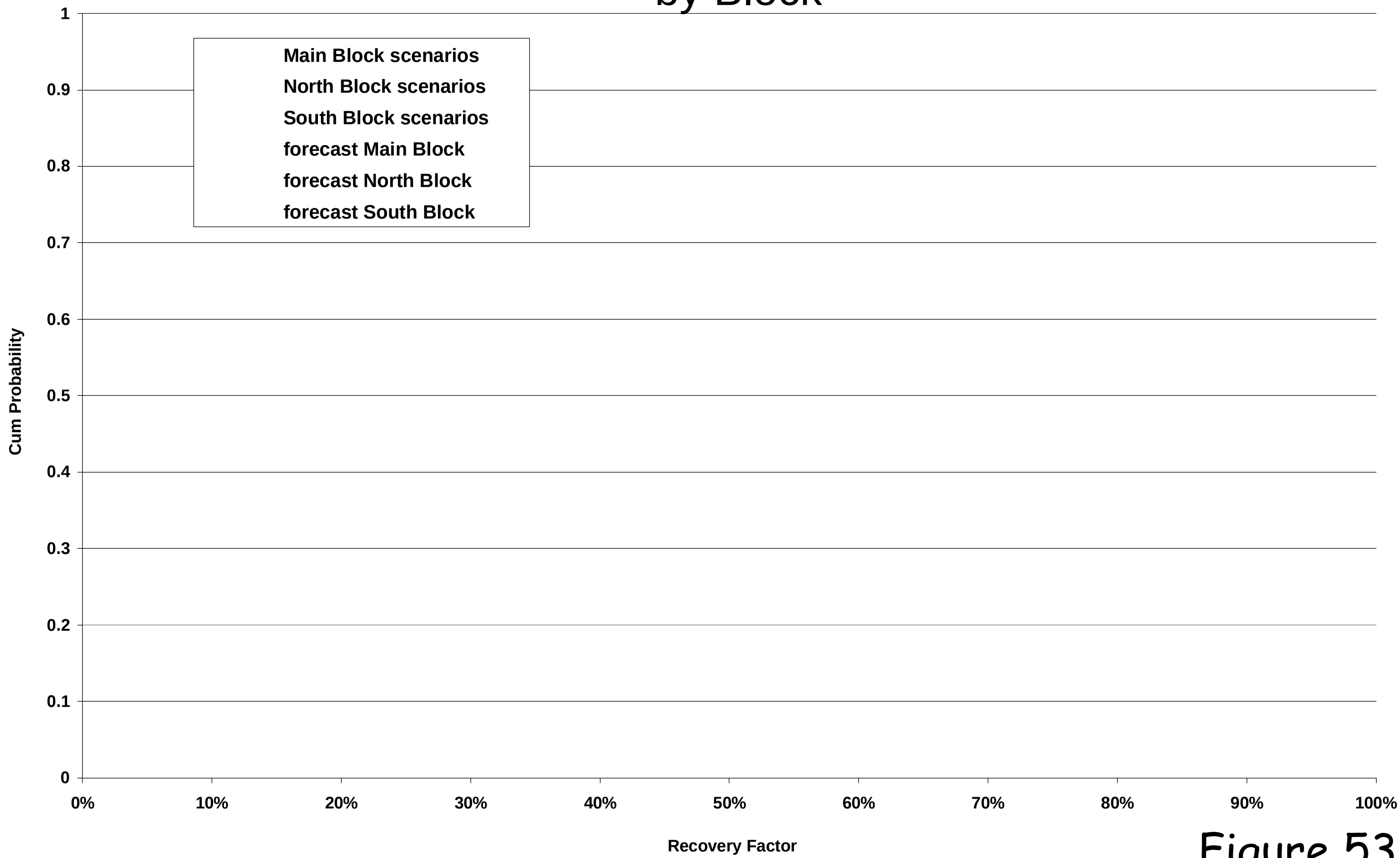
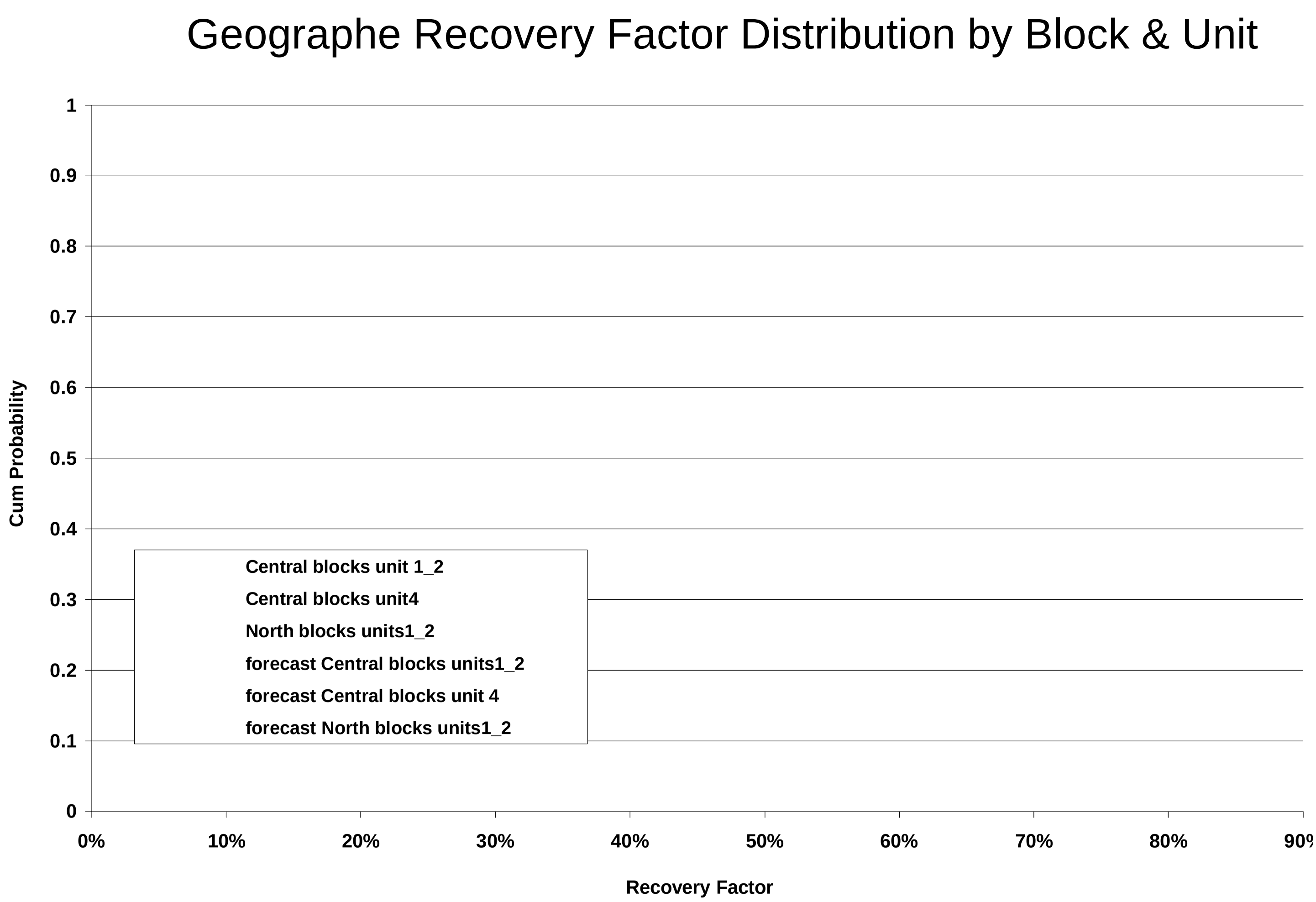


Figure 53


Geographe Recovery Factor Distribution by Block & Unit
Cum Probability
1
0.9
0.8
0.7
0.6
0.5
0.4
0.3
0.2
0.1
0
0%
10%
20%
30%
40%
50%
60%
70%
80%
90%
Recovery Factor
Central blocks unit 1_2
Central blocks unit4
North blocks units1_2
forecast Central blocks units1_2
forecast Central blocks unit 4
forecast North blocks units1_2

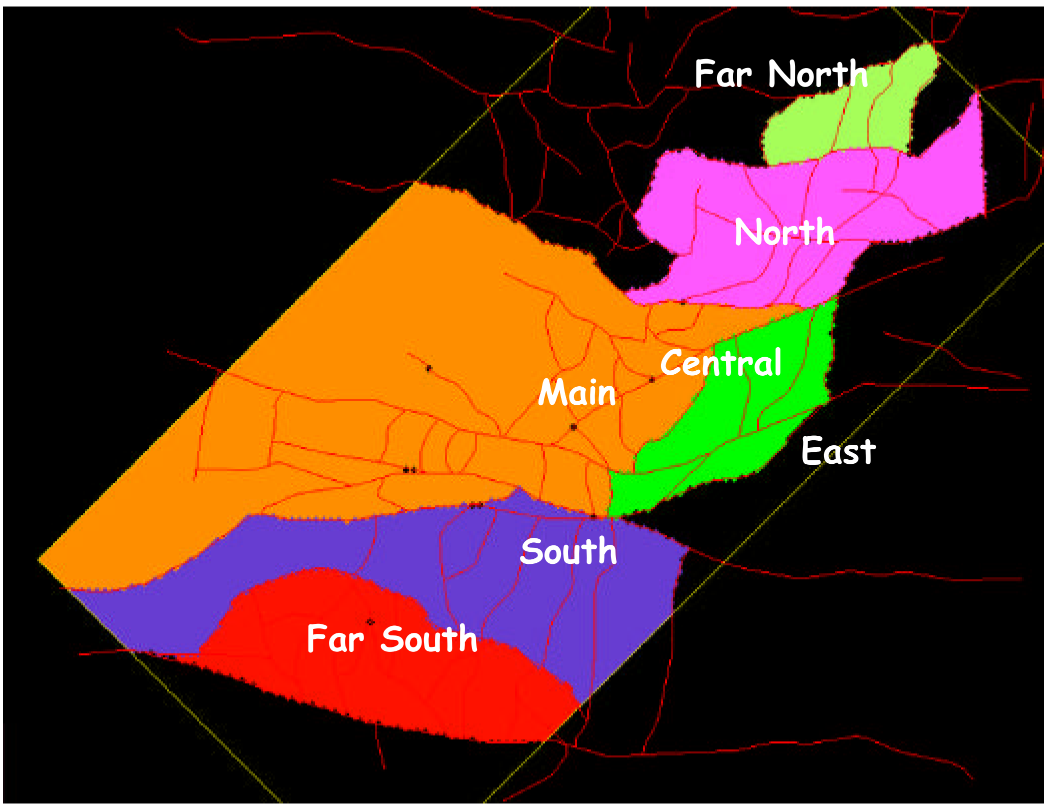

Far North
North
Central
Main
East
South
Far South

Figure 54

Dynamic Uncertainty Scenarios & Probability of Occurrence

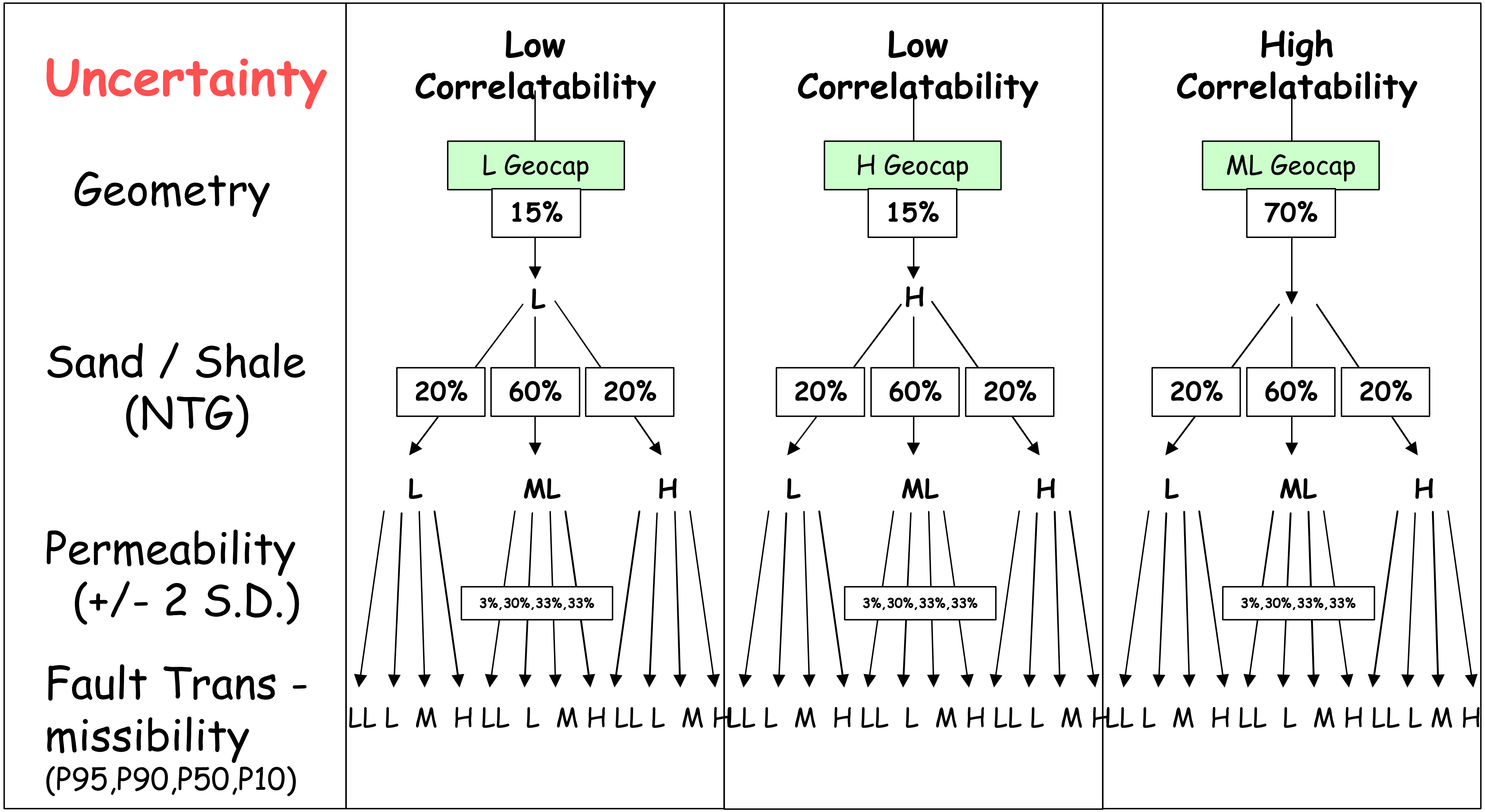
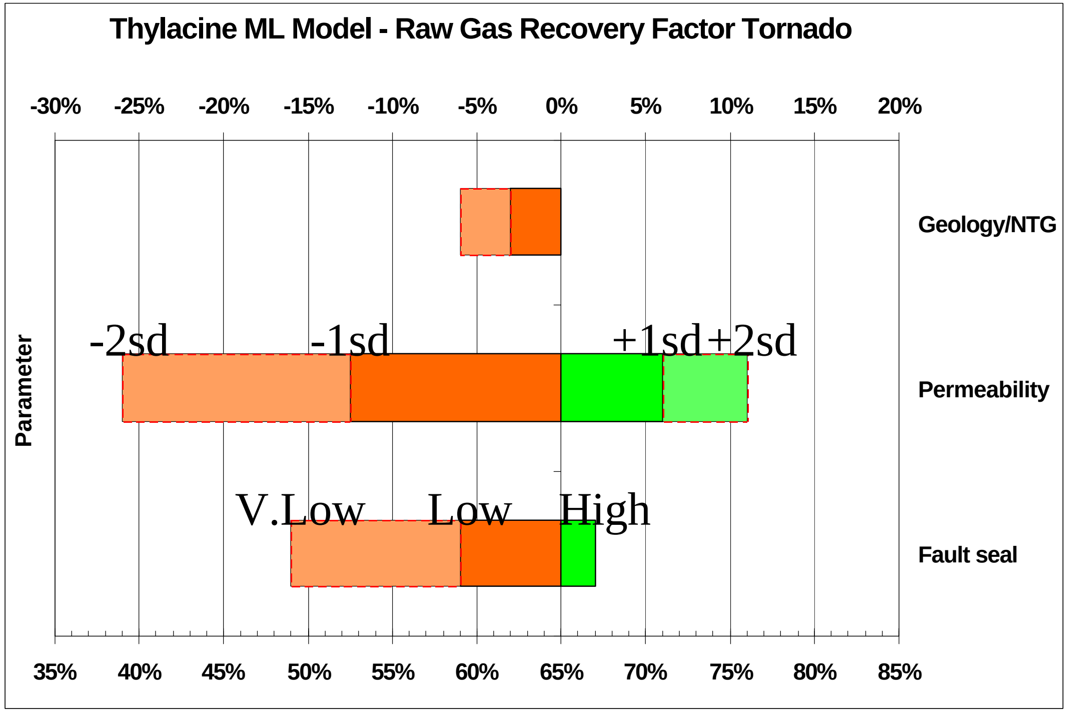


Figure 55

Recovery Factor Tornado Diagrams



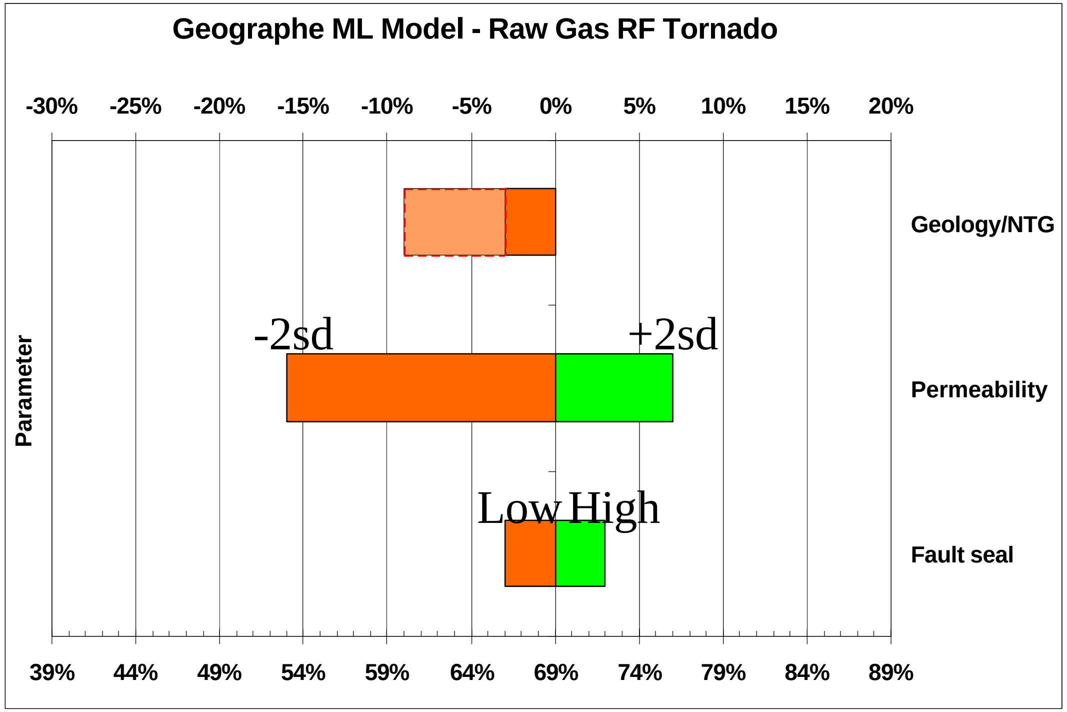


Figure 56

Fault Interpretation: Time migration vs PSDM

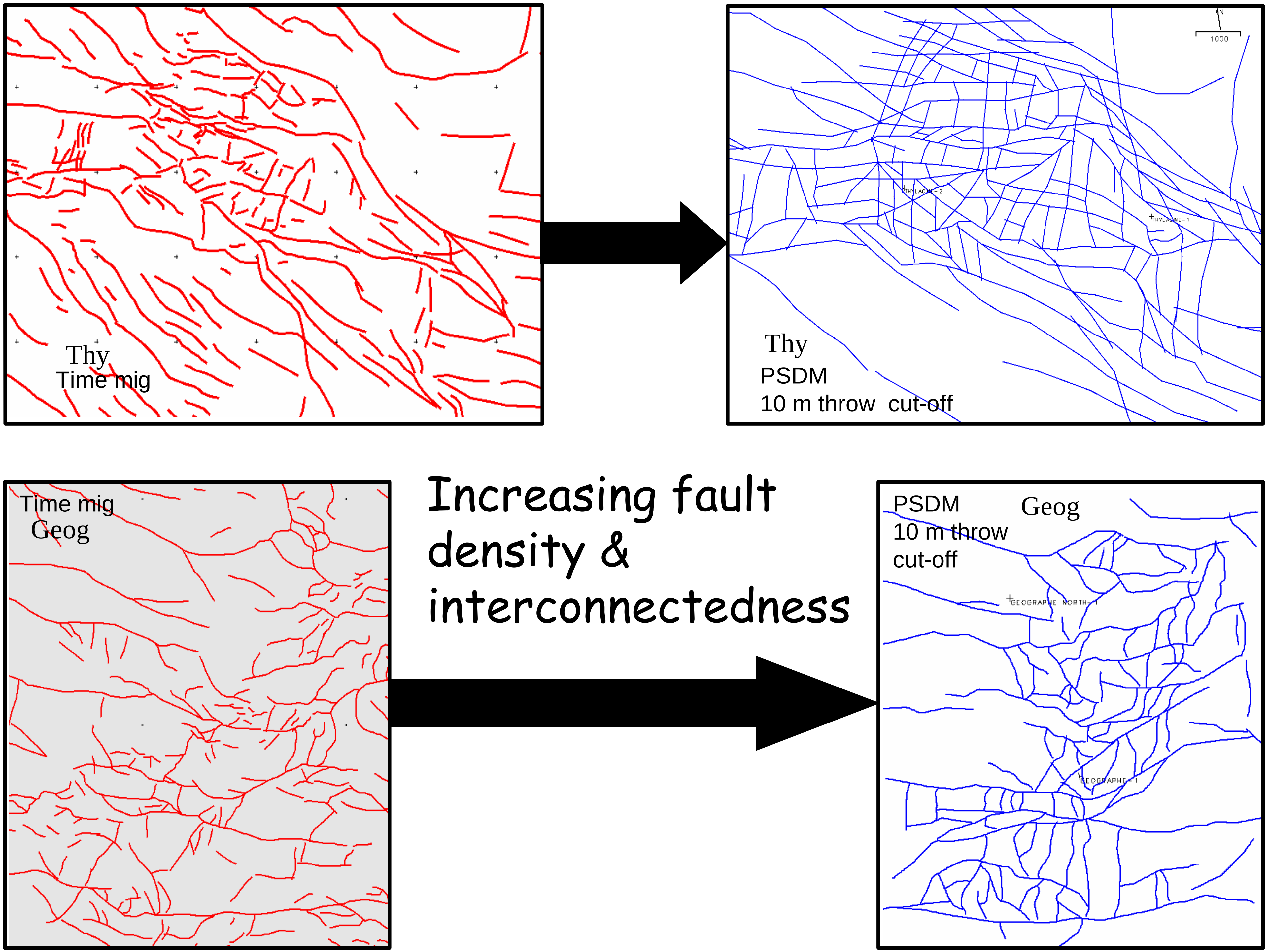


Figure 57

Reservoir monitoring to determine reservoir connectivity

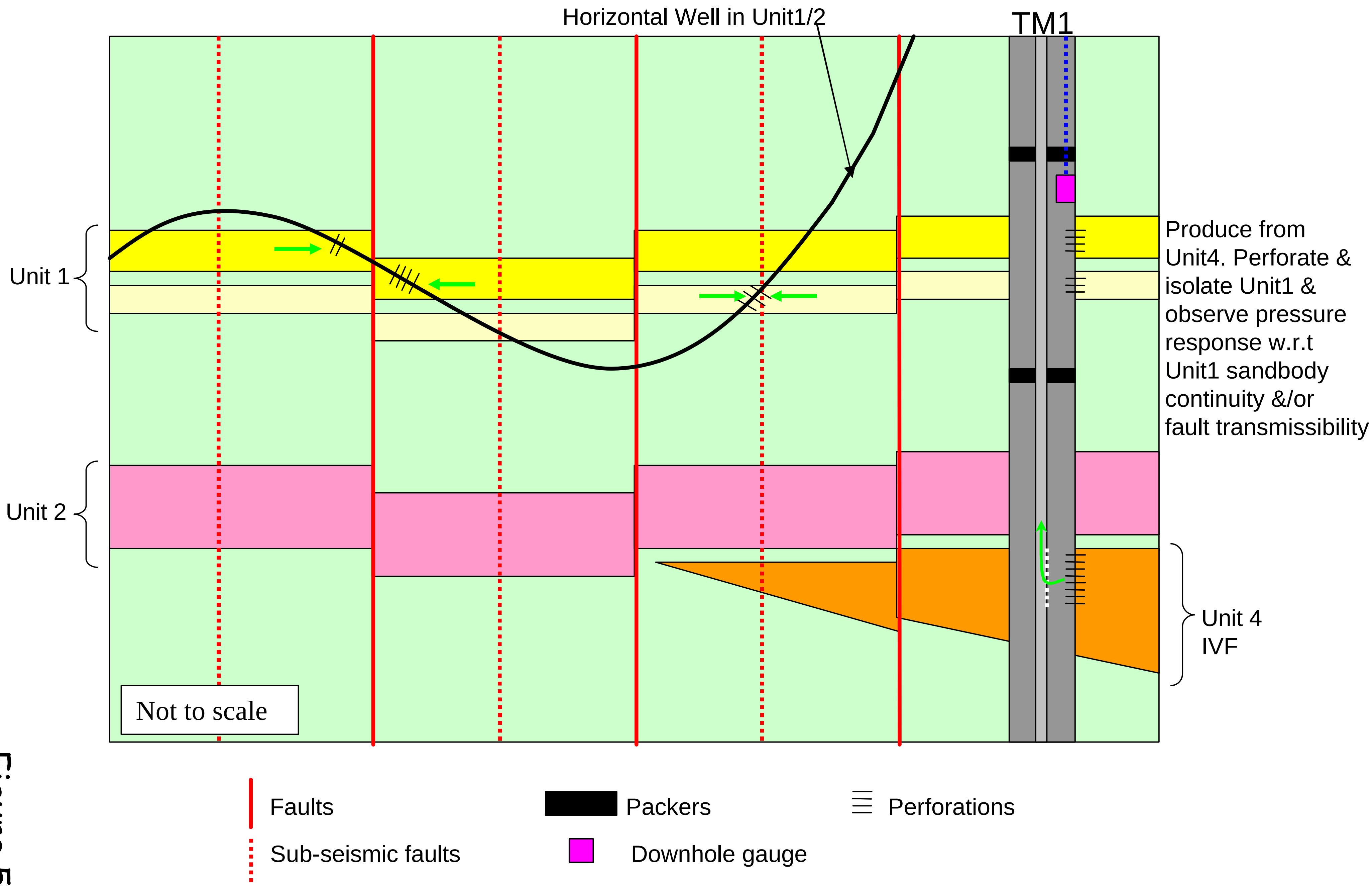


Figure 58

Thylacine - Location of Development Wells on Amplitude Map (Unit 1)

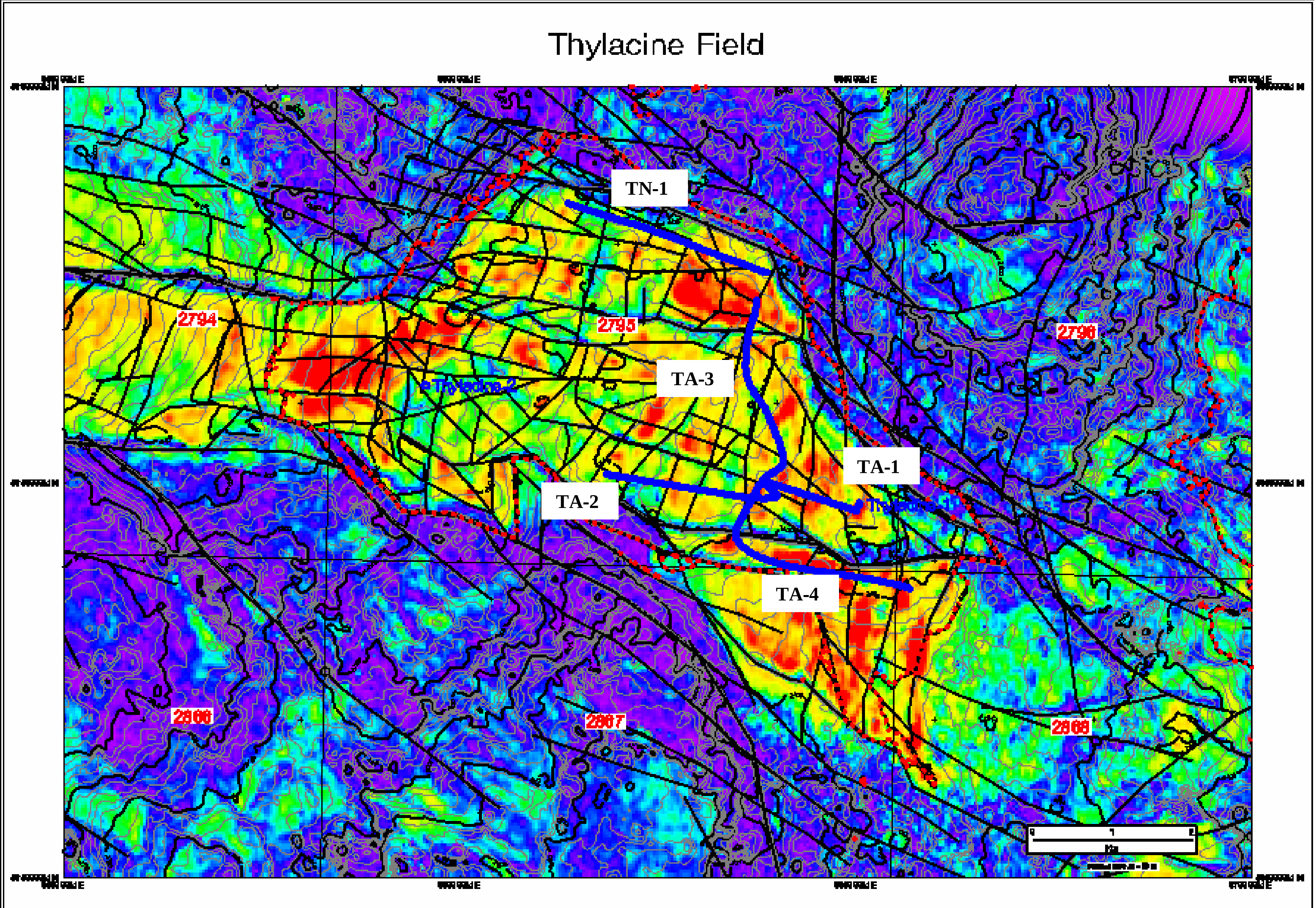


Figure 59

Geographe - Location of Development Wells on Amplitude Map (Unit 1)

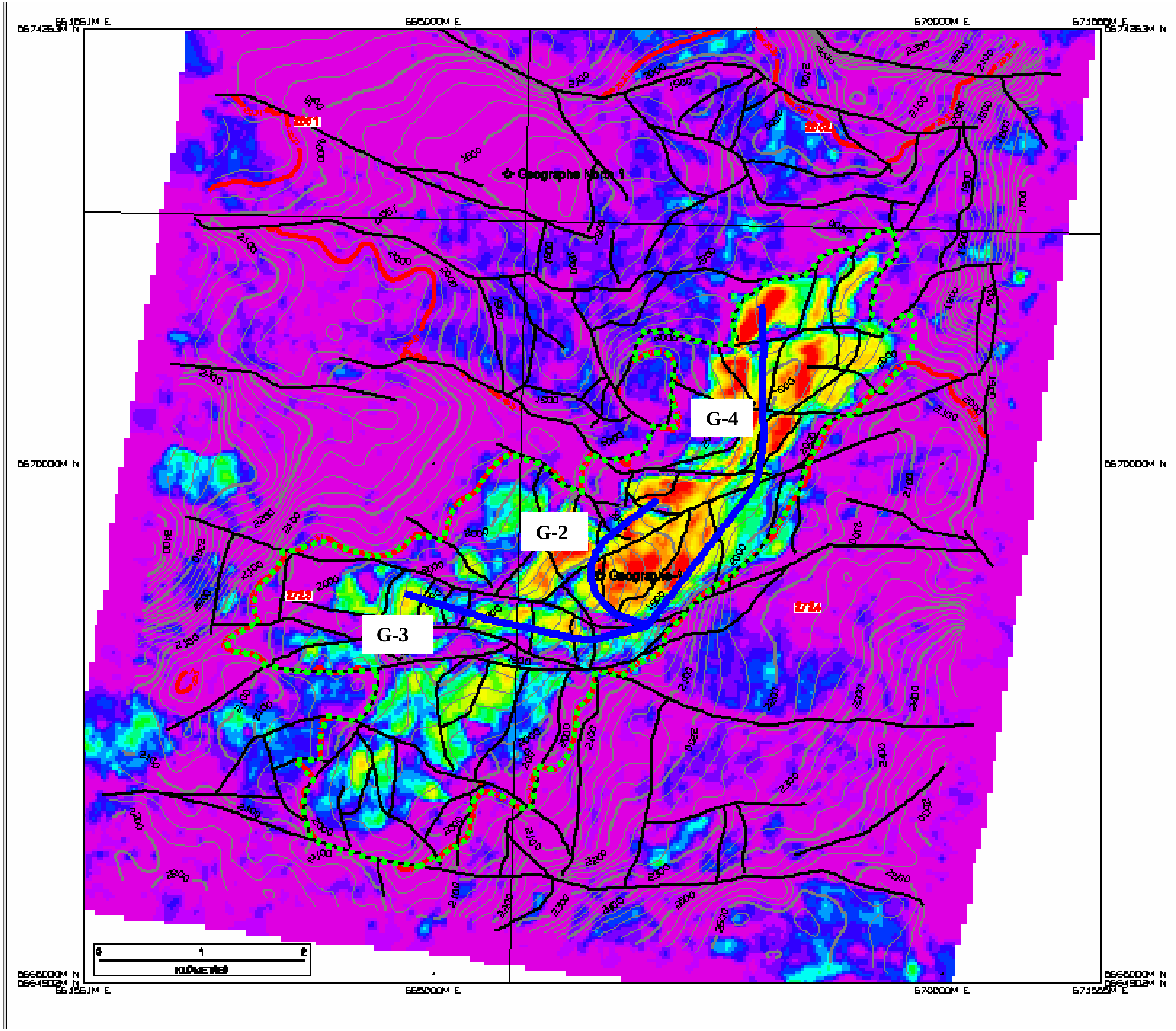
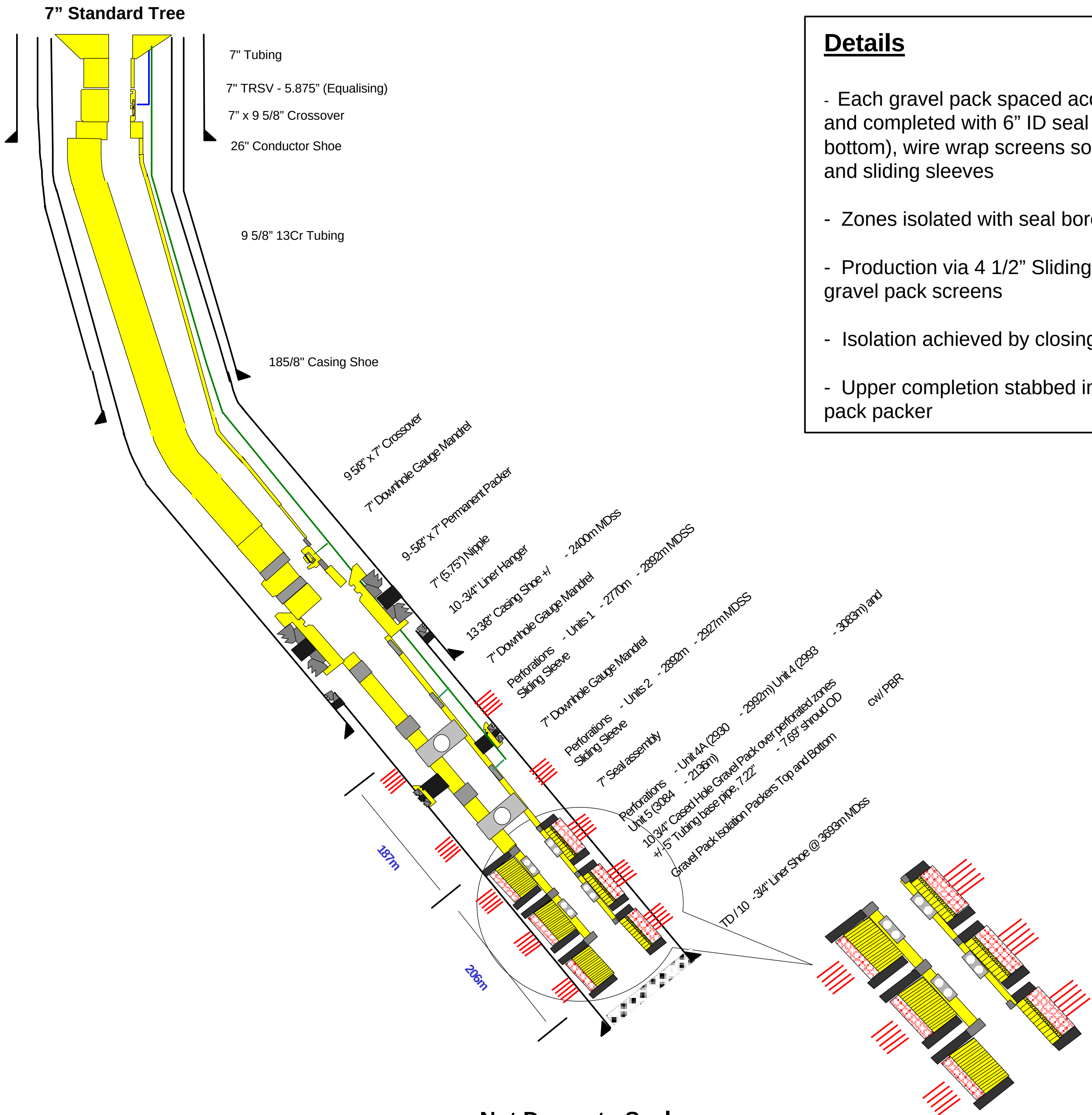


Figure 60

Thylacine TA-1 Conceptual 'Big Bore' Platform Well Schematic

No Sand Control in Units 1 & 2 + Internal Gravel Packs in Units 4A, 4 & 5 + Selective Production from Units 1 & 2



Not Drawn to Scale

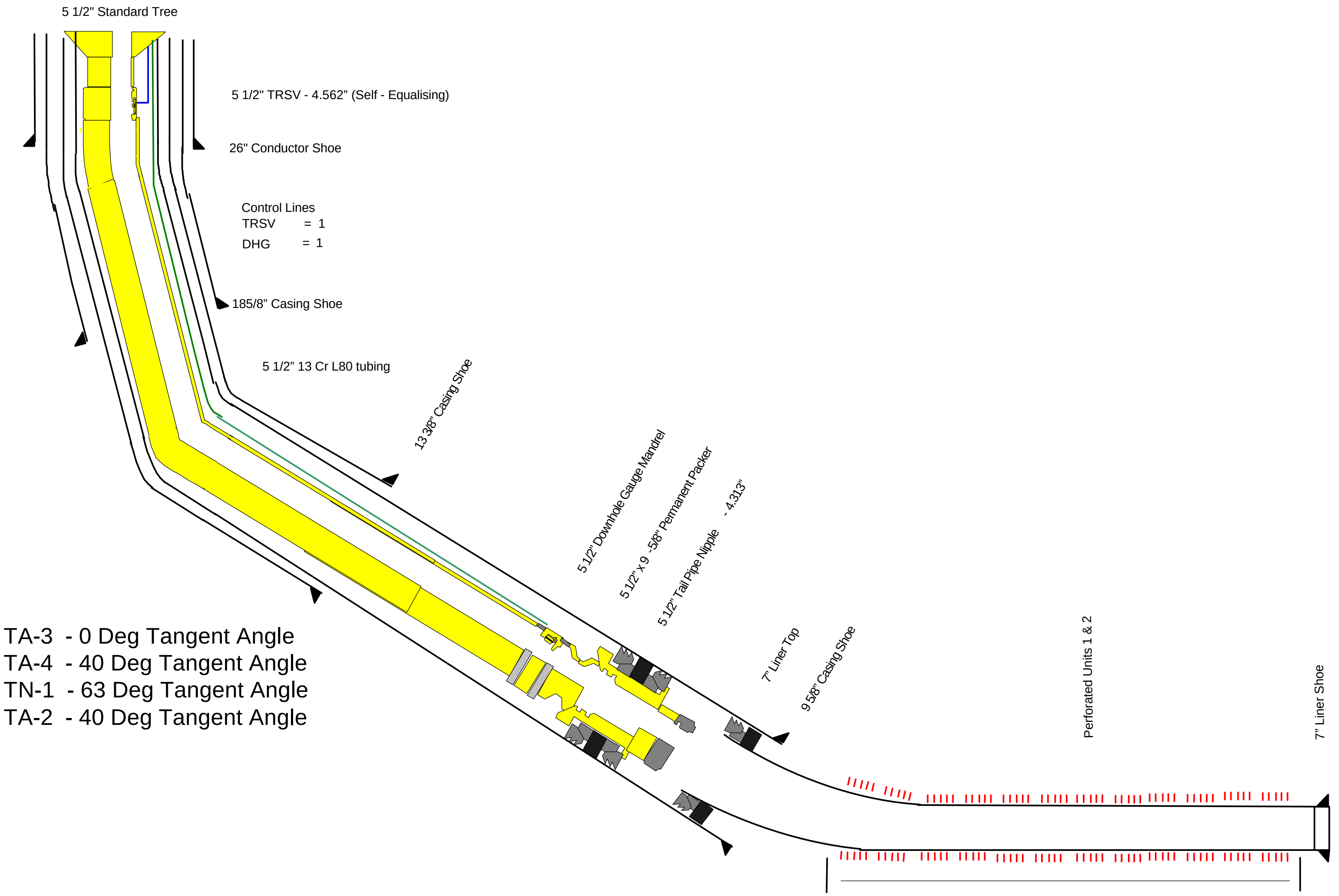
Details

- Each gravel pack spaced according to perforated zones and completed with 6" ID seal bore packers (top and bottom), wire wrap screens solid base pipe (+/- 5" Tubing) and sliding sleeves
- Zones isolated with seal bore packers
- Production via 4 1/2" Sliding Sleeves, installed with gravel pack screens
- Isolation achieved by closing Sliding Sleeve
- Upper completion stabbed into top seal bore gravel pack packer

Figure 61

Thylacine TA-2, TA-3, TA-4 & TN-1 Conceptual Platform Wells Schematic

No Sand Control in Units 1 & 2



TA3 - Total Reservoir interval = +/- 1470m
TA4 - Total Reservoir interval = +/- 1900m
TN1 - Total Reservoir interval = +/- 2200m
TA2 - Total Reservoir interval = +/- 1164m

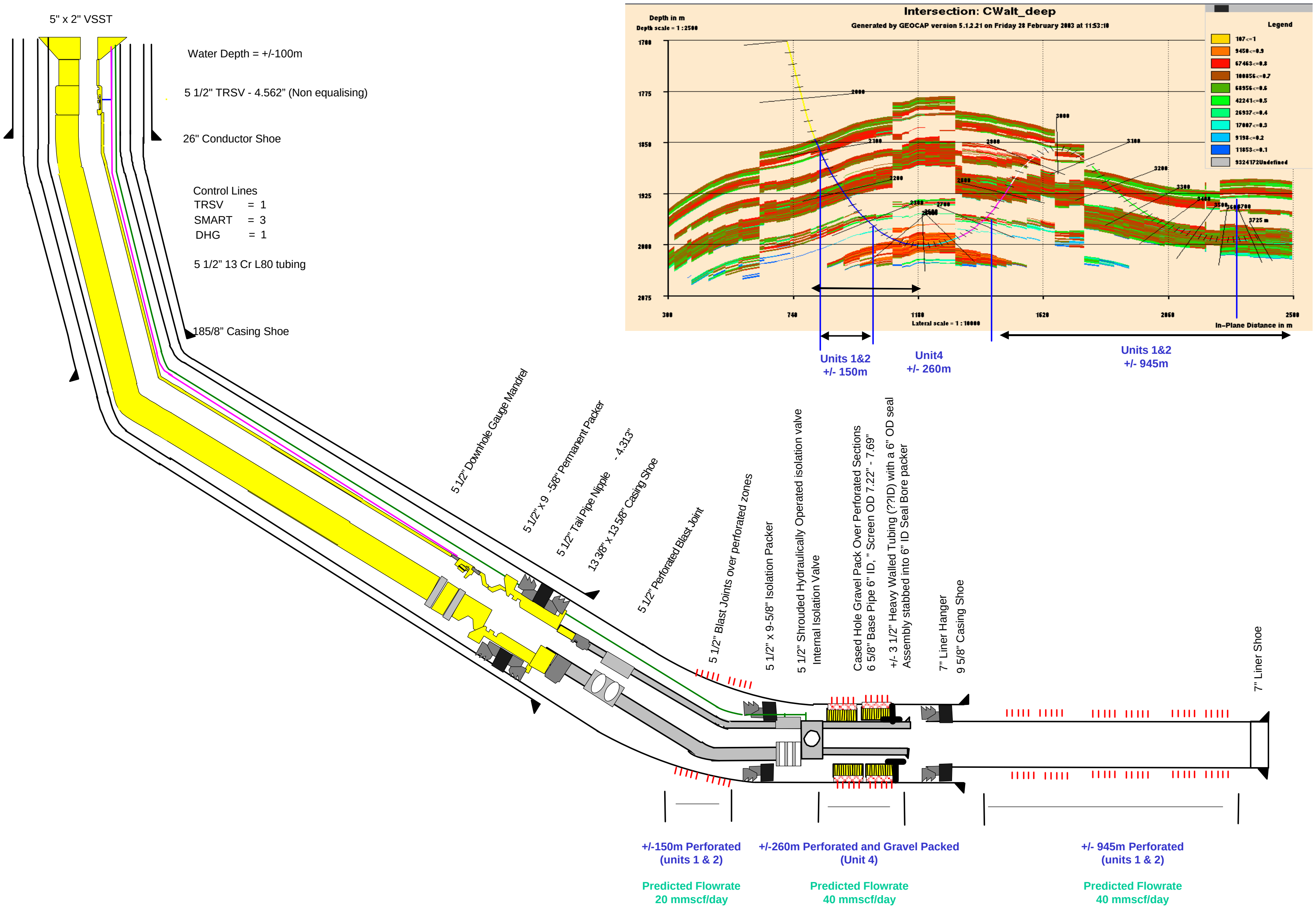
Note: Perforations required from top to bottom with spacer sections over shales

Not Drawn to Scale

Figure 62

Geographe G-2 Sub Sea Conceptual Well Schematic

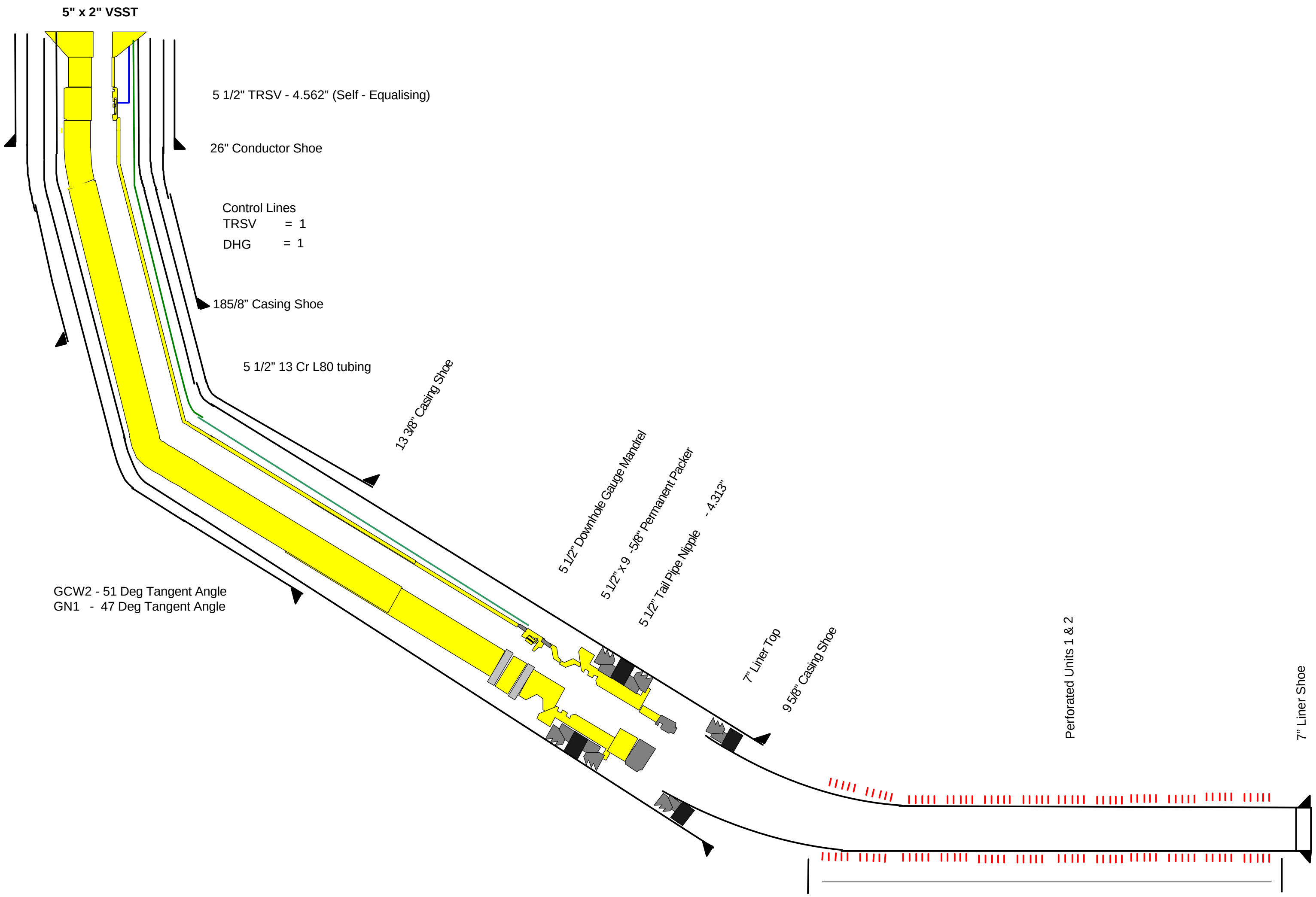
2 Zone Isolation + 1 Zone Gravel Pack



Not Drawn to Scale

Figure 63

Geographe G-3 & G-4 Conceptual Subsea Wells Schematic



G-3 - Total Reservoir interval = +/- 1637m
G-4 - Total Reservoir interval = +/- 1247m

Note: Perforations required from top to bottom with spacer sections over shales

Not Drawn to Scale

Figure 64

Otway - T/30P 2D Leads

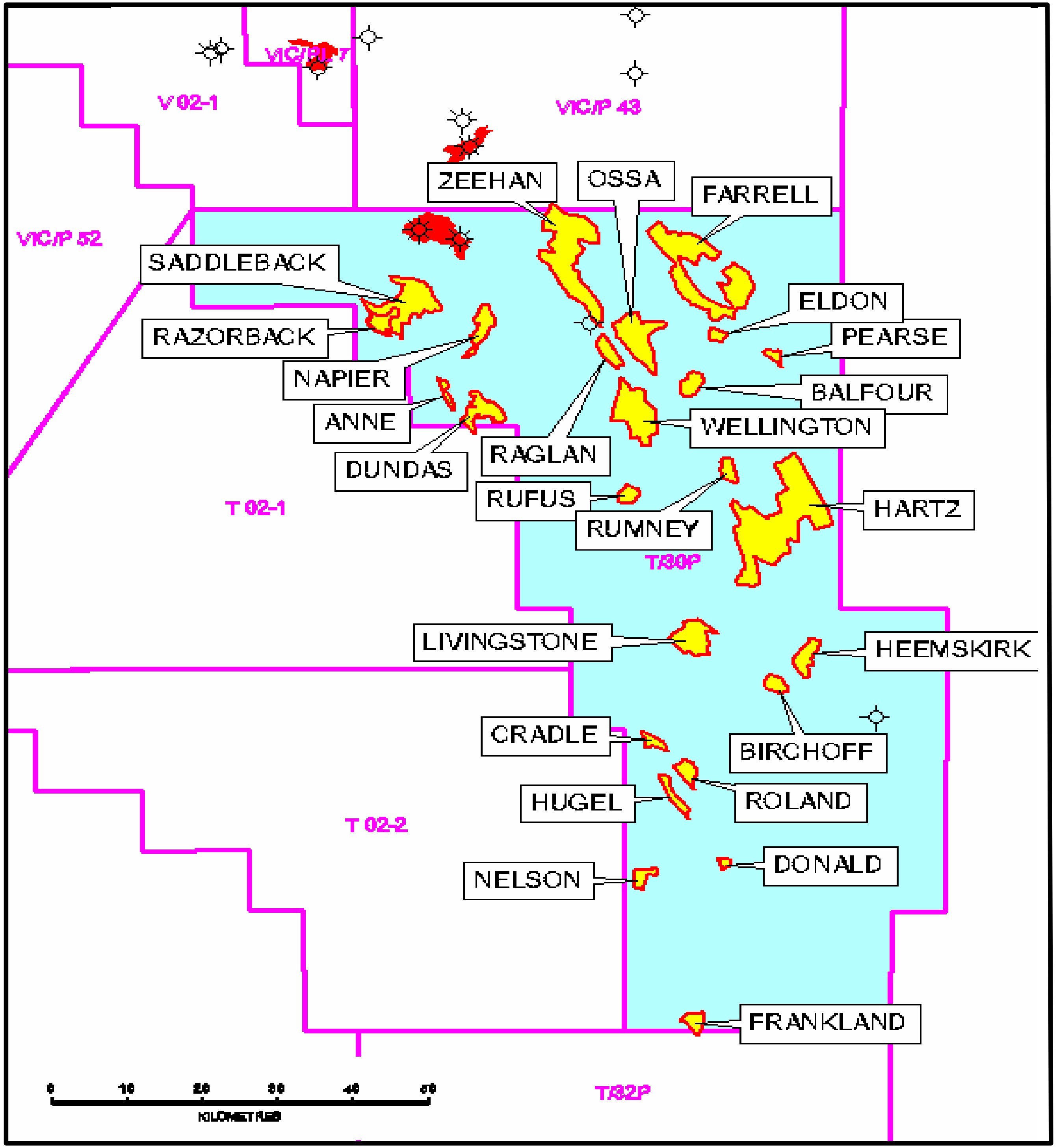


Figure 65a

Otway - T/30P 3D Prospects and Leads

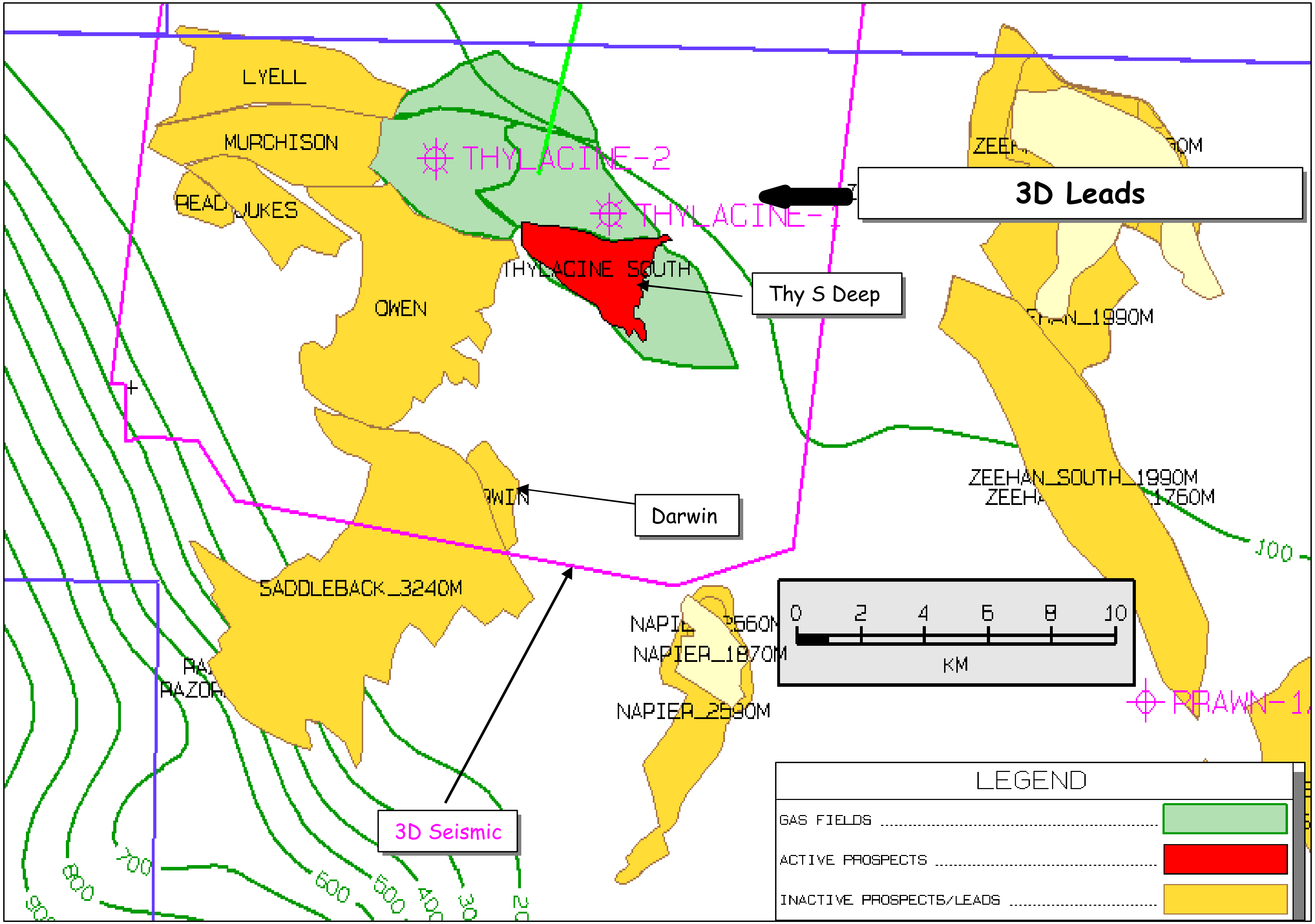


Figure 65b

OTWAY - Prospects and Leads VIC/P43

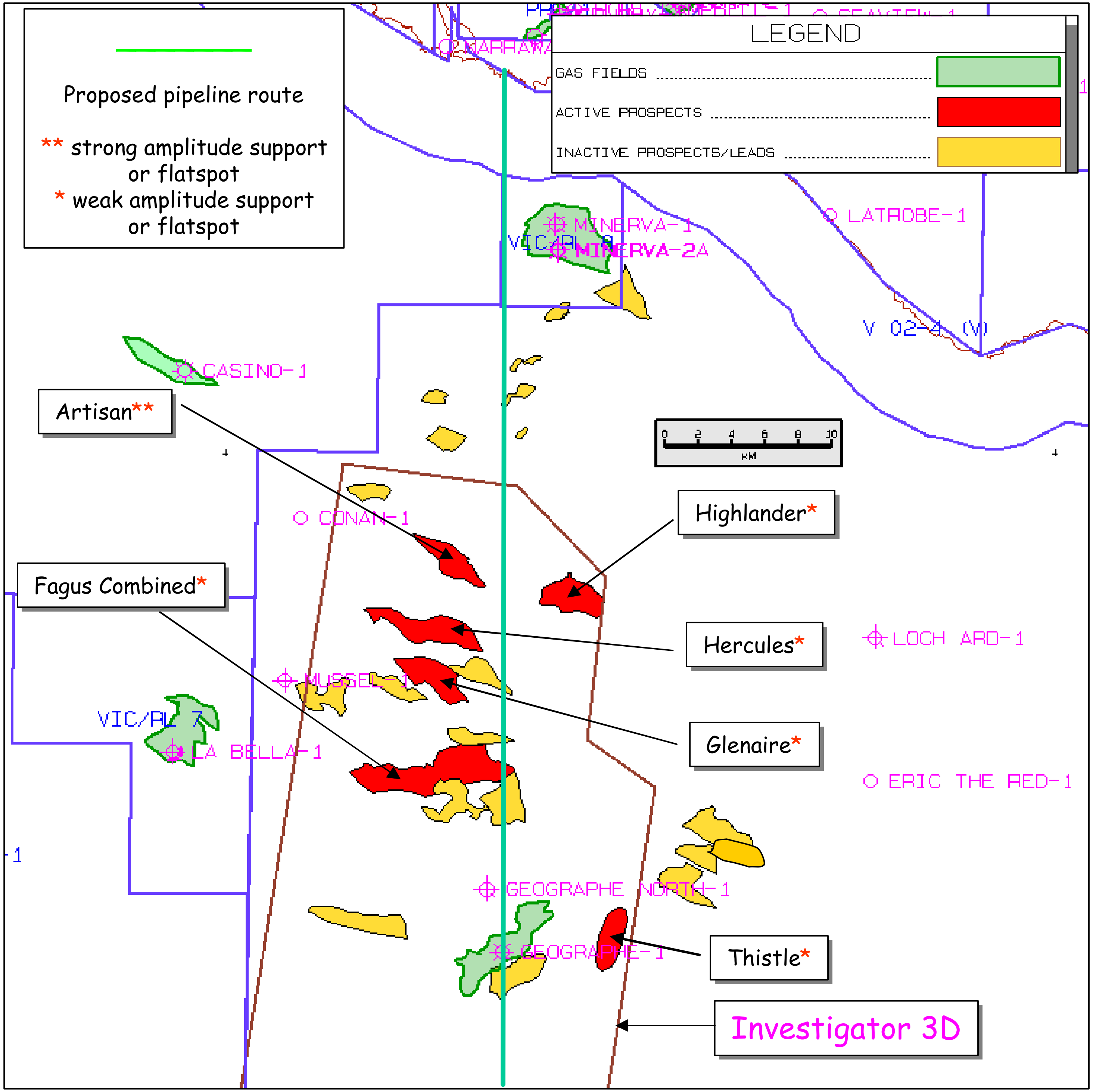


Figure 66

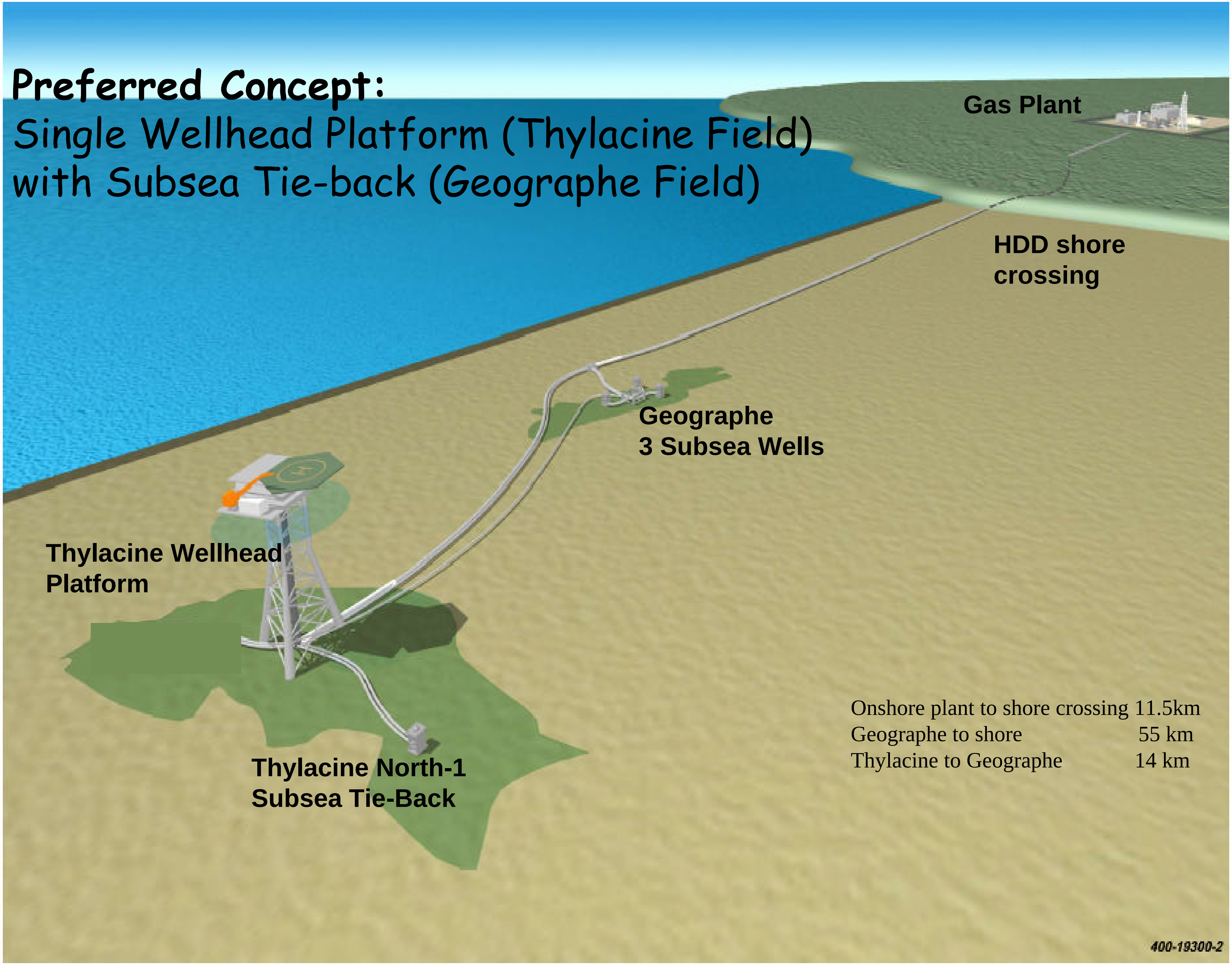

Preferred Concept:
Single Wellhead Platform (Thylacine Field)
with Subsea Tie-back (Geographe Field)
Gas Plant
HDD shore
crossing
Geographe
3 Subsea Wells
Thylacine Wellhead
Platform
Thylacine North-1
Subsea Tie-Back
Onshore plant to shore crossing 11.5km
Geographe to shore 55 km
Thylacine to Geographe 14 km
400-19300-2

Figure 67


Full Subsea Development Option
Gas processing plant at Waarre
Buried onshore raw gas pipeline
Shore crossing
Seabed raw gas pipeline
Geographe subsea production manifold
Geographe subsea production manifold
Onshore plant to shore crossing 11.5km
Geographe to shore 55 km
Thylacine to Geographe 14 km

Figure 68

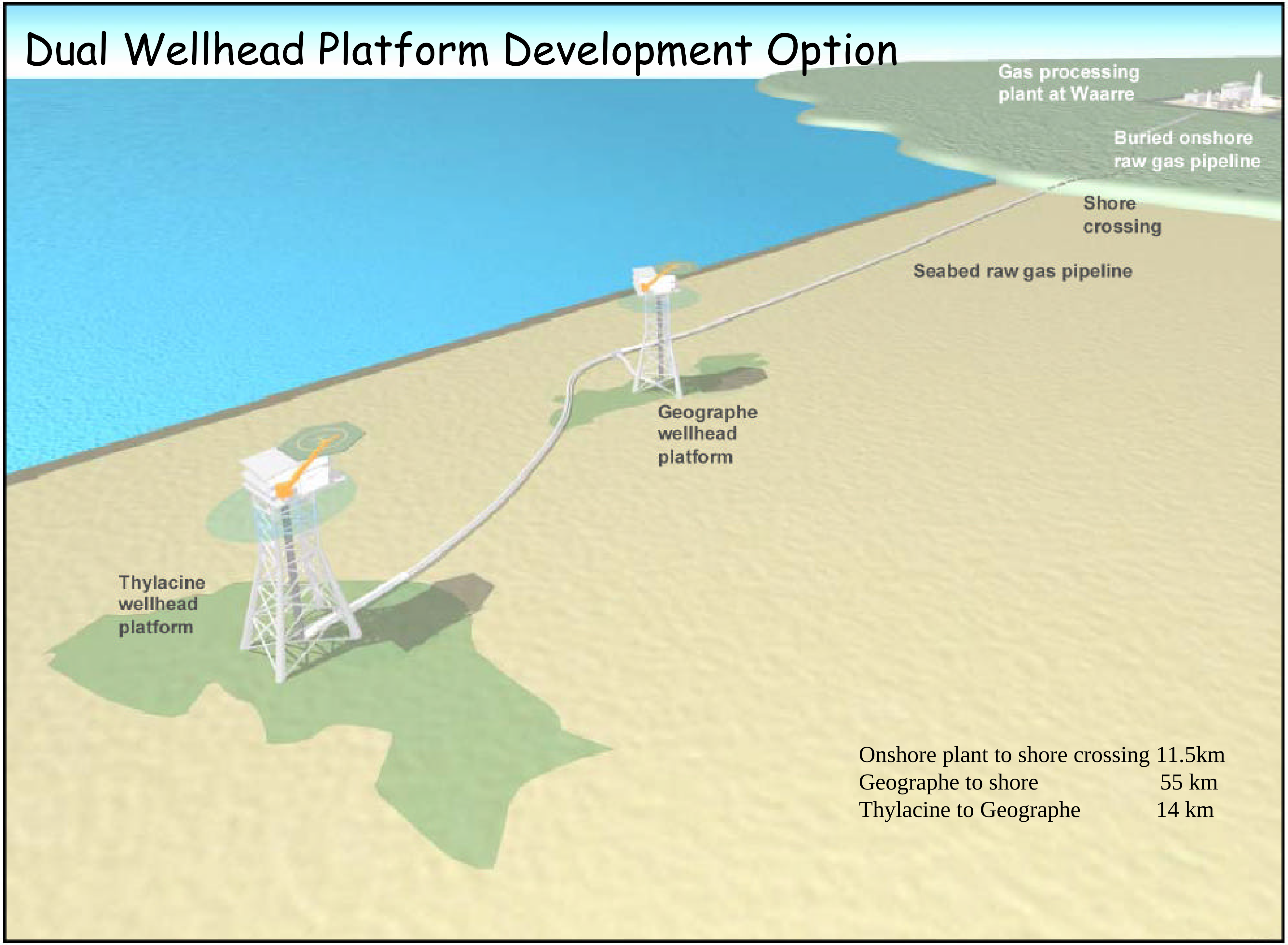

Dual Wellhead Platform Development Option
Gas processing plant at Waarre
Buried onshore raw gas pipeline
Shore crossing
Seabed raw gas pipeline
Geographe wellhead platform
Thylacine wellhead platform
Onshore plant to shore crossing 11.5km
Geographe to shore 55 km
Thylacine to Geographe 14 km

Figure 69

Onshore Plant Simplified Process Block Diagram

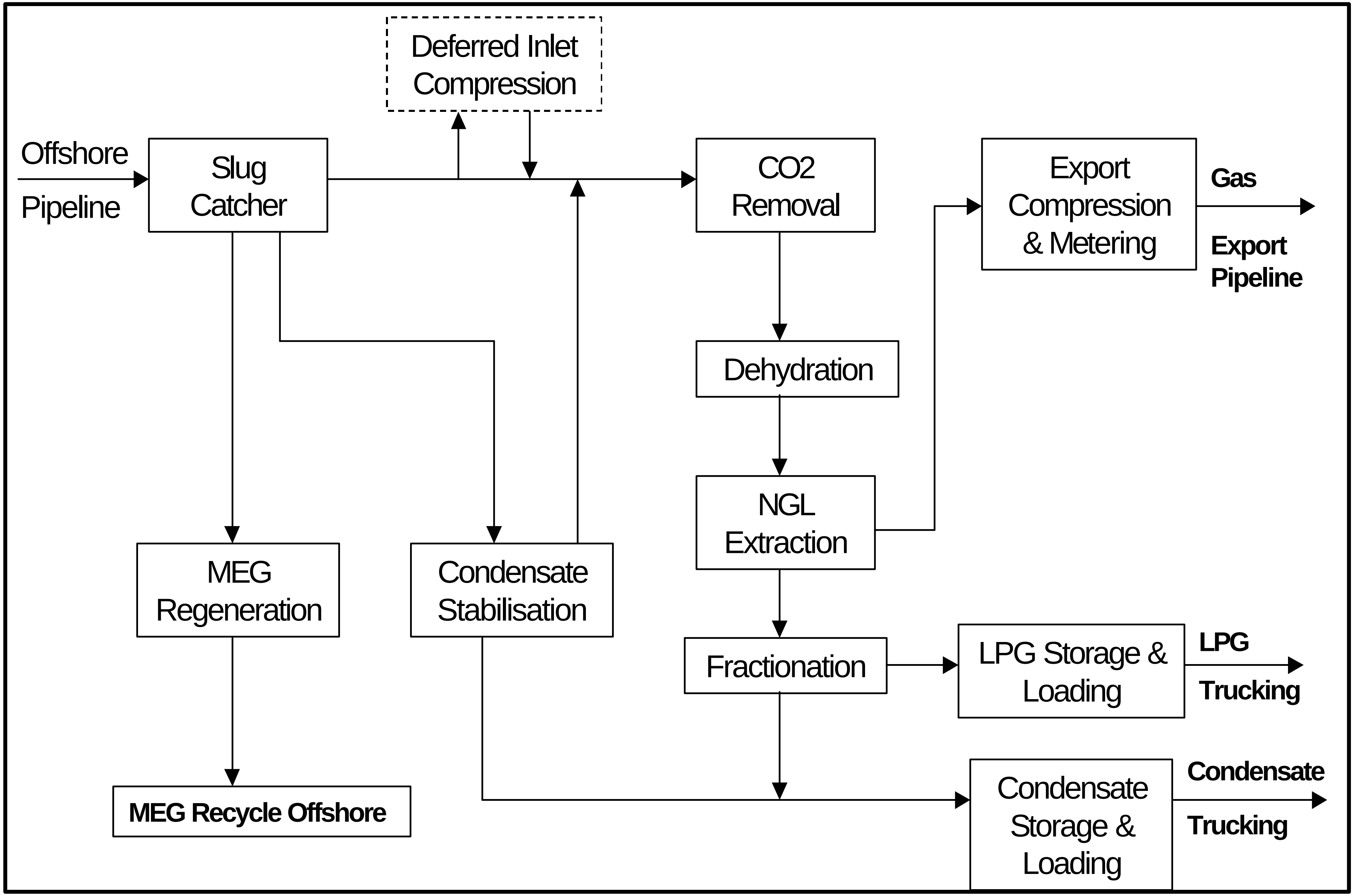


Figure 70

Aerial View of Proposed Plant Site

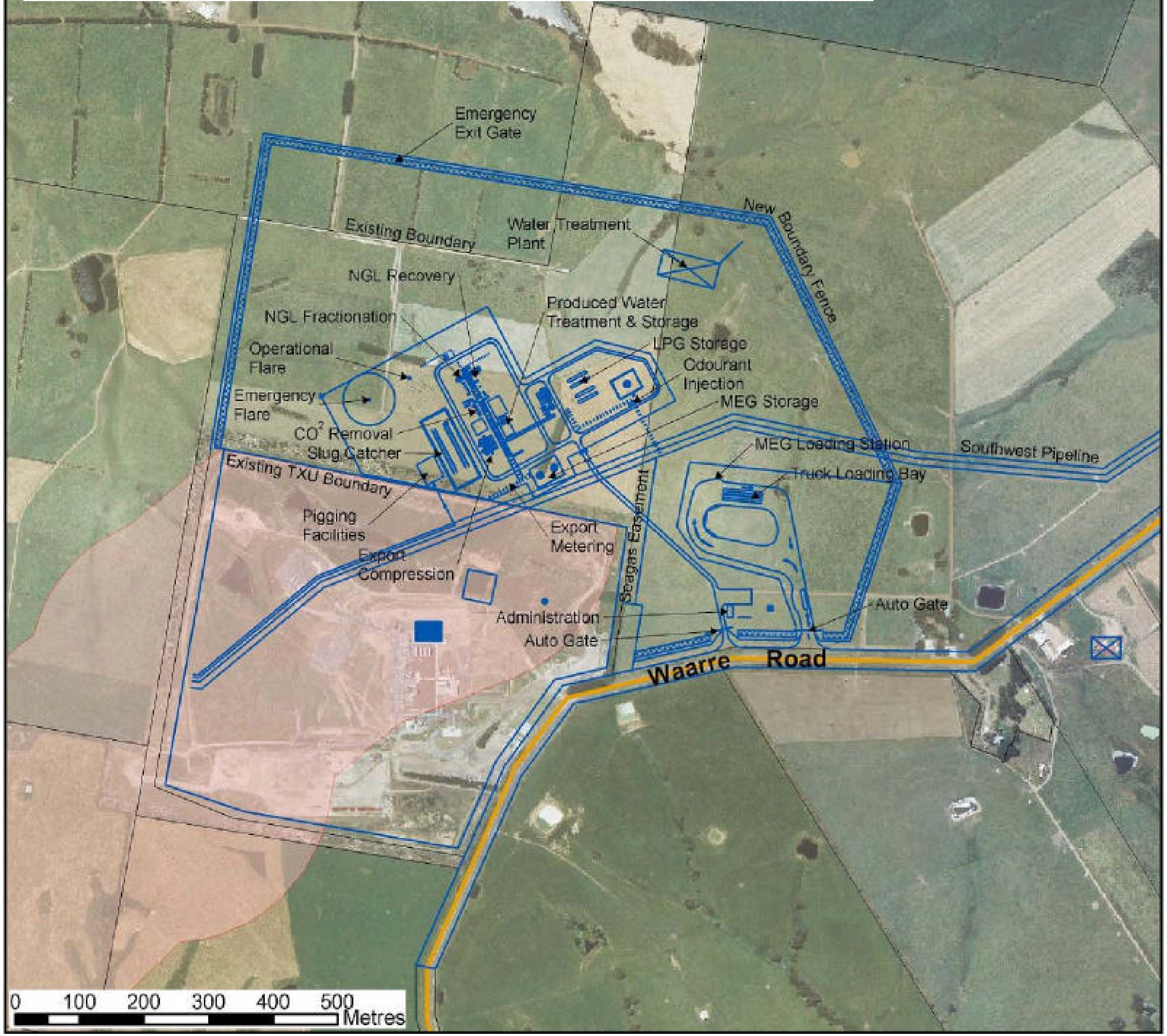
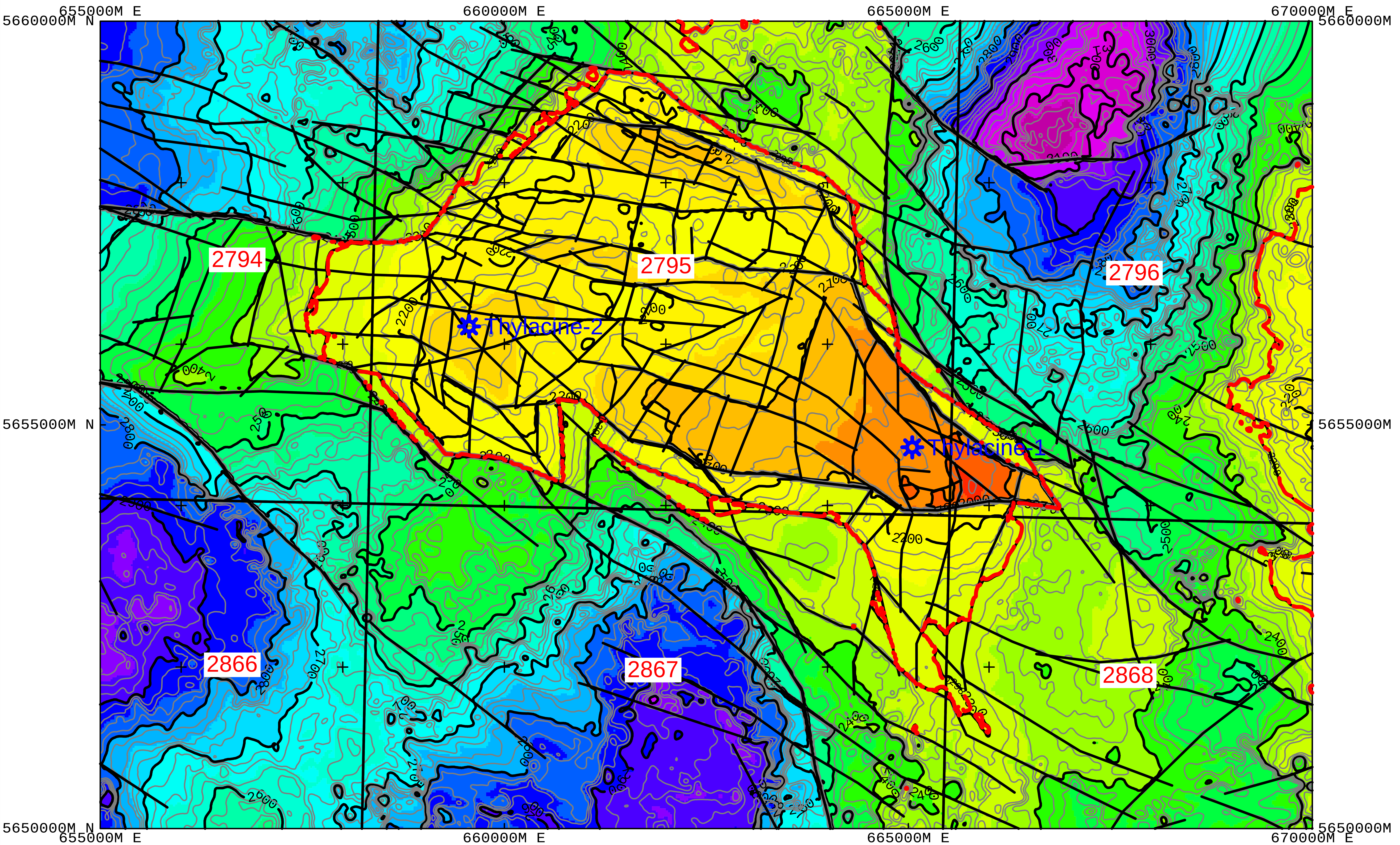


Figure 71

Thylacine Field



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0 1 2

KILOMETRES

UNIVERSAL TRANSVERSE MERCATOR PROJECTION
AUSTRALIAN NATIONAL SPHEROID
CENTRAL MERIDIAN 141 00 00 E
Mapsheet datum: "Unknown"

Woodside Energy Ltd.
A.C.N. 005 482 986

Upstream New Ventures and Exploration

T/30P

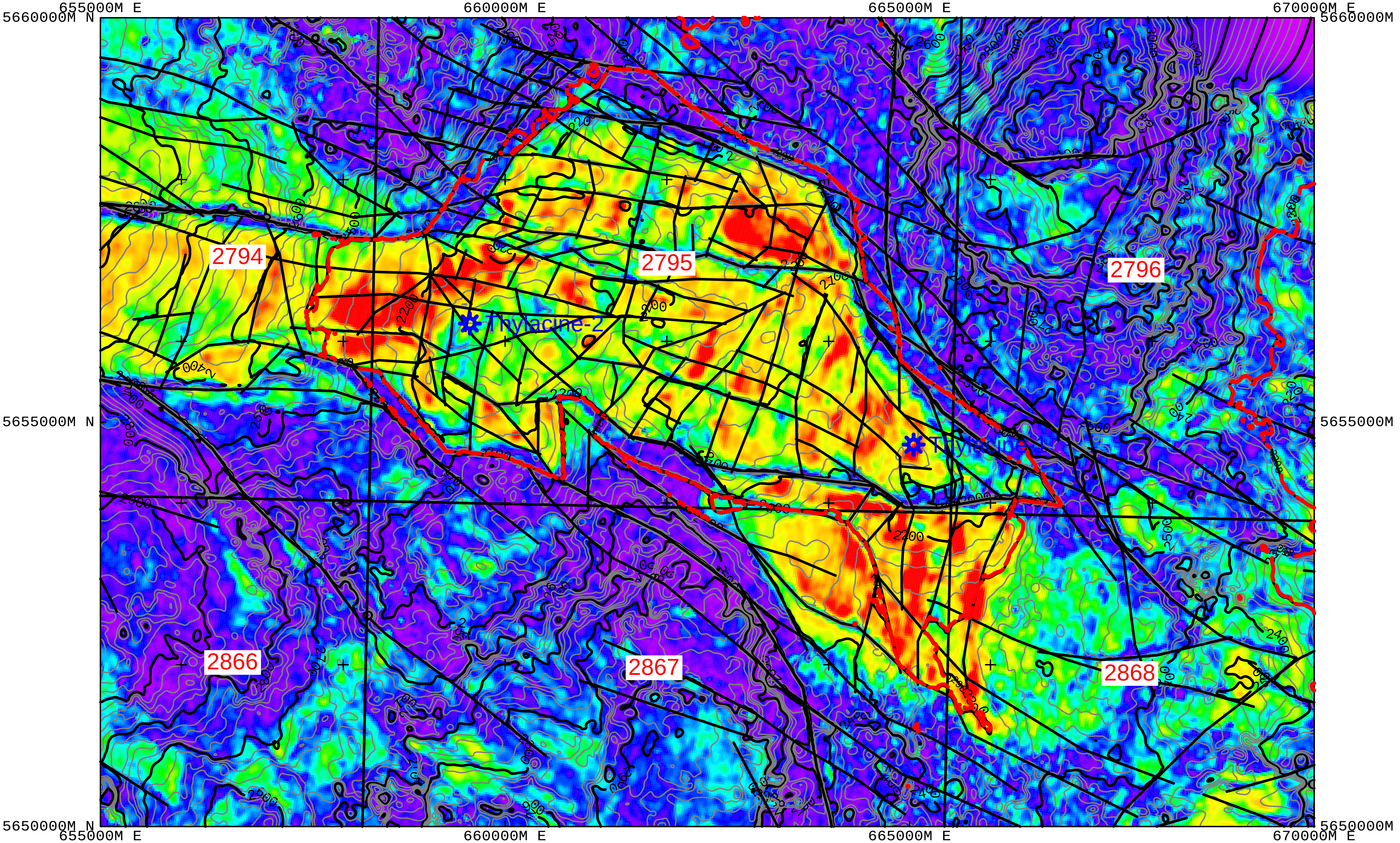
THYLACINE FIELD
Top Porosity (Unit 1) Depth Structure

c.i. 20m

Author : S. Winters	Mapsheet : SW_THYLACINE FIELD_25K_FDP	
Drafted By : wopb5b	Scale : 1:25000	Zone : 54
Date : 15-OCT-2003 11:06:26	Contour Interval : 20m	
Map File :	Project : /nfs/dsvi1/data/petrosys/Geographe	

ENCLOSURE 1

Thylacine Field



1:25000

0 1 2

KILOMETRES

UNIVERSAL TRANSVERSE MERCATOR PROJECTION
AUSTRALIAN NATIONAL SPHEROID
CENTRAL MERIDIAN 141 00 00 E
Mapsheet datum: "Unknown"

Woodside Energy Ltd.
A.C.N. 005 482 986

Upstream New Ventures and Exploration

T/30P

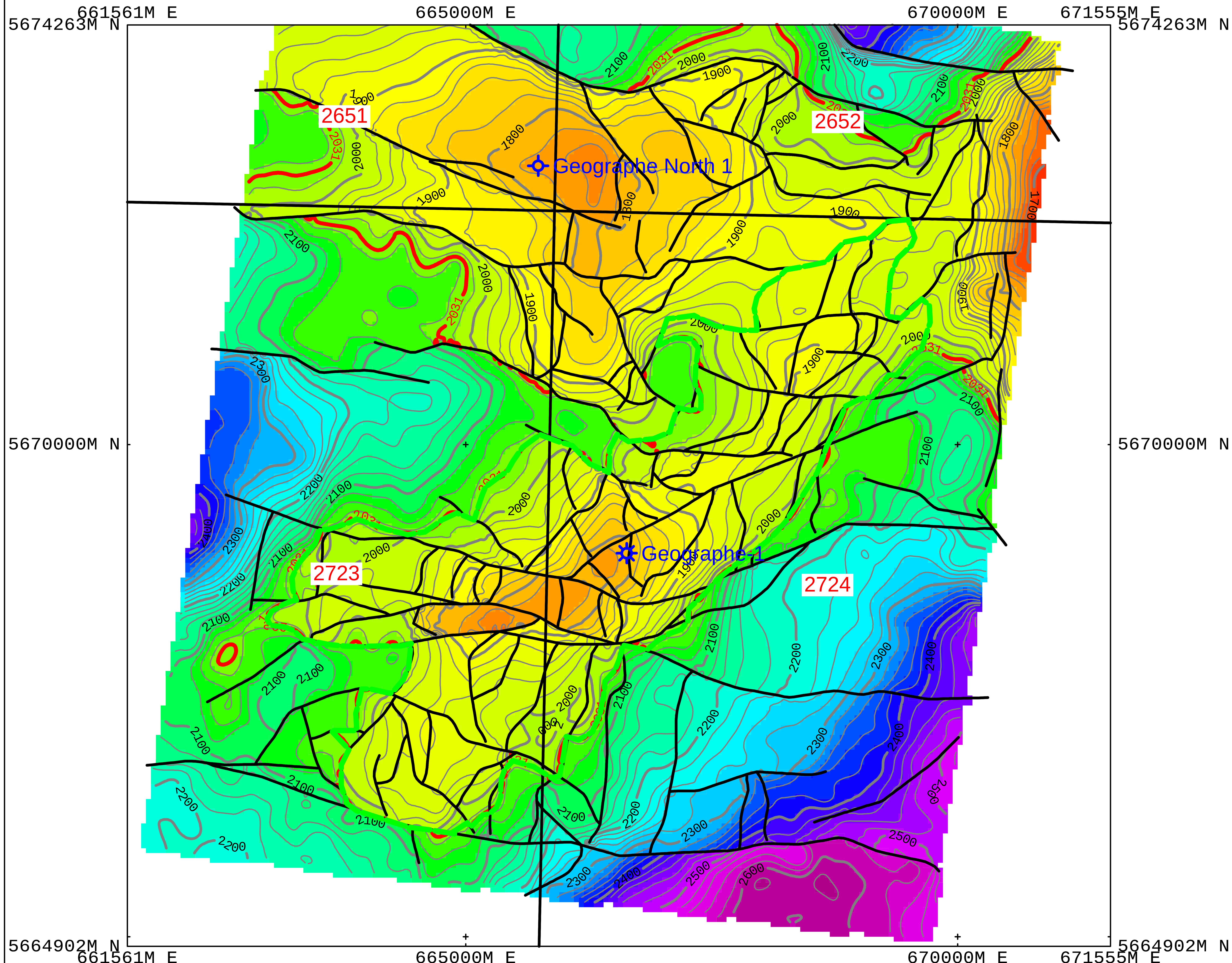
THYLACINE FIELD
Top Porosity (Unit 1) Depth Structure

c.i. 20m

Author : S. Winters	Mapsheet : SW_THYLACINE FIELD_25K_FDP	
Drafted By : wopb5b	Scale : 1:25000	Zone : 54
Date : 15-OCT-2003 11:10:08	Contour Interval : 20m	
Map File :	Project : /nfs/dsvi1/data/petrosys/Geographe	

ENCLOSURE 2

Geographe Field



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KILOMETRES

UNIVERSAL TRANSVERSE MERCATOR PROJECTION
AUSTRALIAN NATIONAL SPHEROID
CENTRAL MERIDIAN 141 00 00 E
Mapsheet datum: "Unknown"

Woodside Energy Ltd.
A.C.N. 005 482 986

Upstream New Ventures and Exploration

VIC/P43

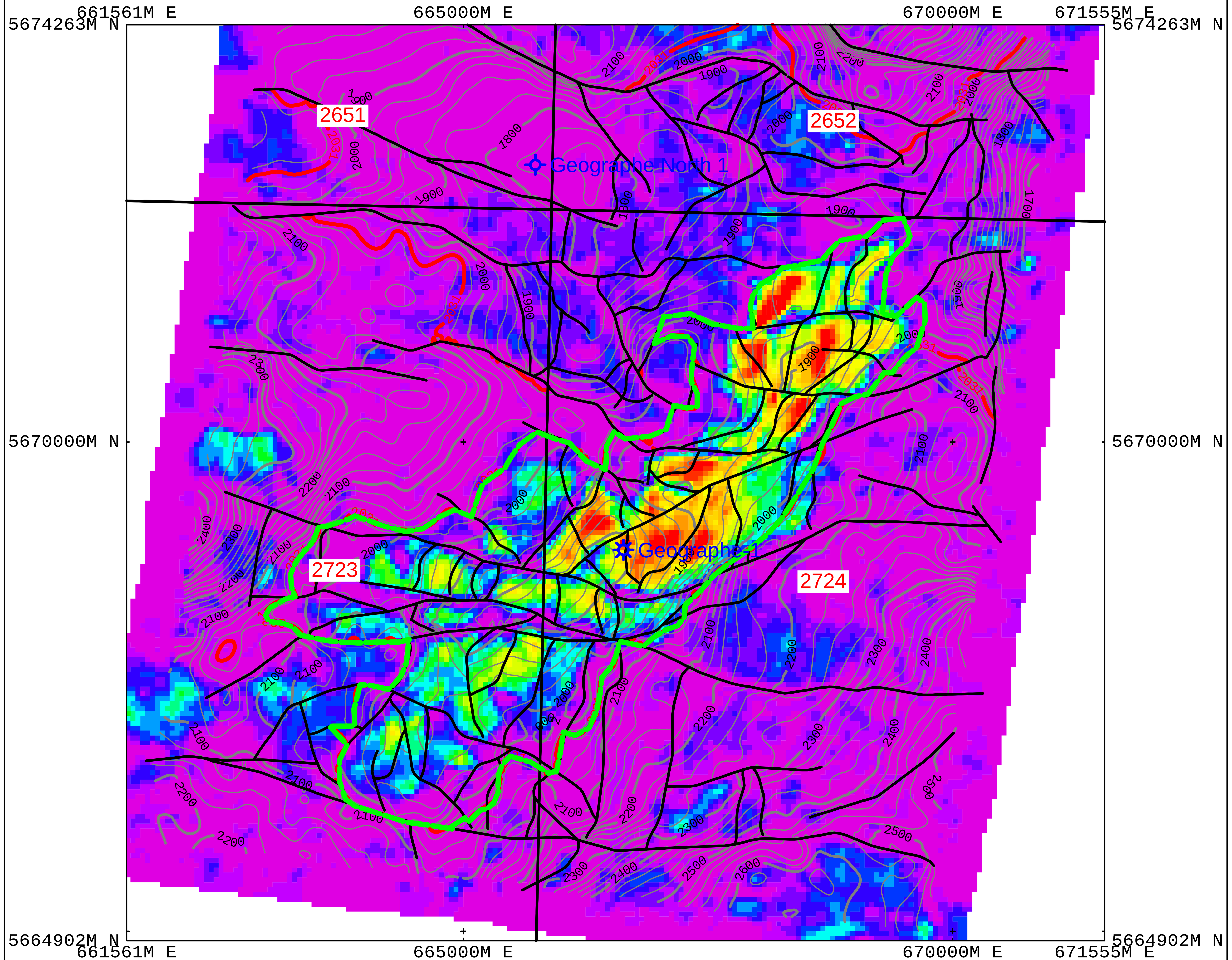
GEOGRAPHE FIELD
Top Porosity (Unit 1) Depth Structure

c.i. 20m

Author : S. Winters	Mapsheet : SW_GEOGRAPHE_25K_FDP
Drafted By : wopb5b	Scale : 1:25000 / Zone : 54
Date : 15-OCT-2003 11:03:53	Contour Interval : 20m
Map File :	Project : /nfs/dsvi1/data/petrosys/Geographe

ENCLOSURE 3

Geographe Field



1:25000
0 1 2
KILOMETRES
UNIVERSAL TRANSVERSE MERCATOR PROJECTION
AUSTRALIAN NATIONAL SPHEROID
CENTRAL MERIDIAN 141 00 00 E
Mapsheet datum: "Unknown"

Woodside Energy Ltd.
A.C.N. 005 482 986

Upstream New Ventures and Exploration

VIC/P43

GEOGRAPHE FIELD
Far Offset Amplitudes (Unit 1)

c.i. 20m

Author : S. Winters	Mapsheet : SW_GEOGRAPHE_25K_FDP
Drafted By : wopb5b	Scale : 1:25000 Zone : 54
Date : 15-OCT-2003 11:03:19	Contour Interval : 20m
Map File :	Project : /nfs/dsvi1/data/petrosys/Geographe

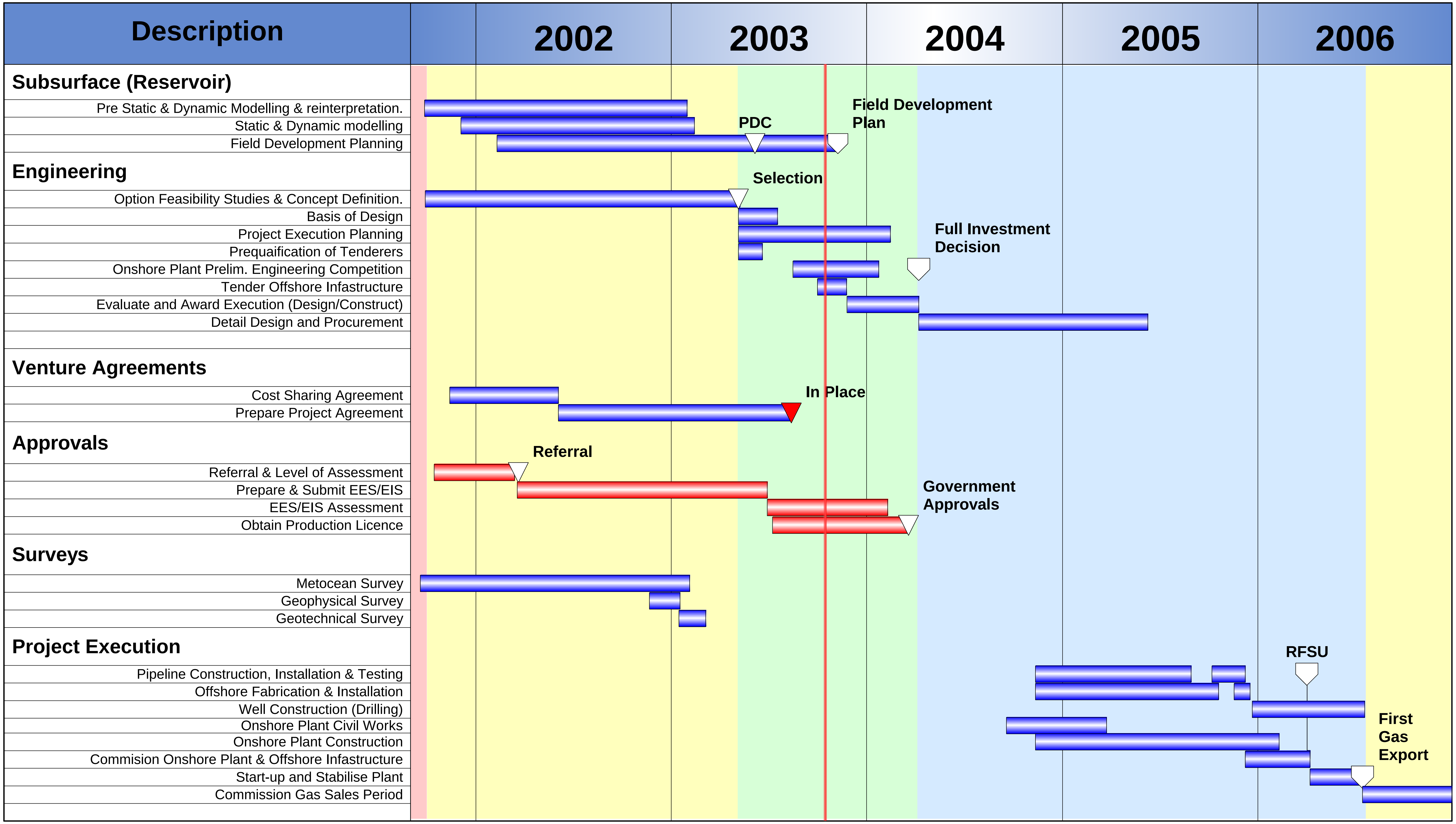
ENCLOSURE 4

OTWAY Development

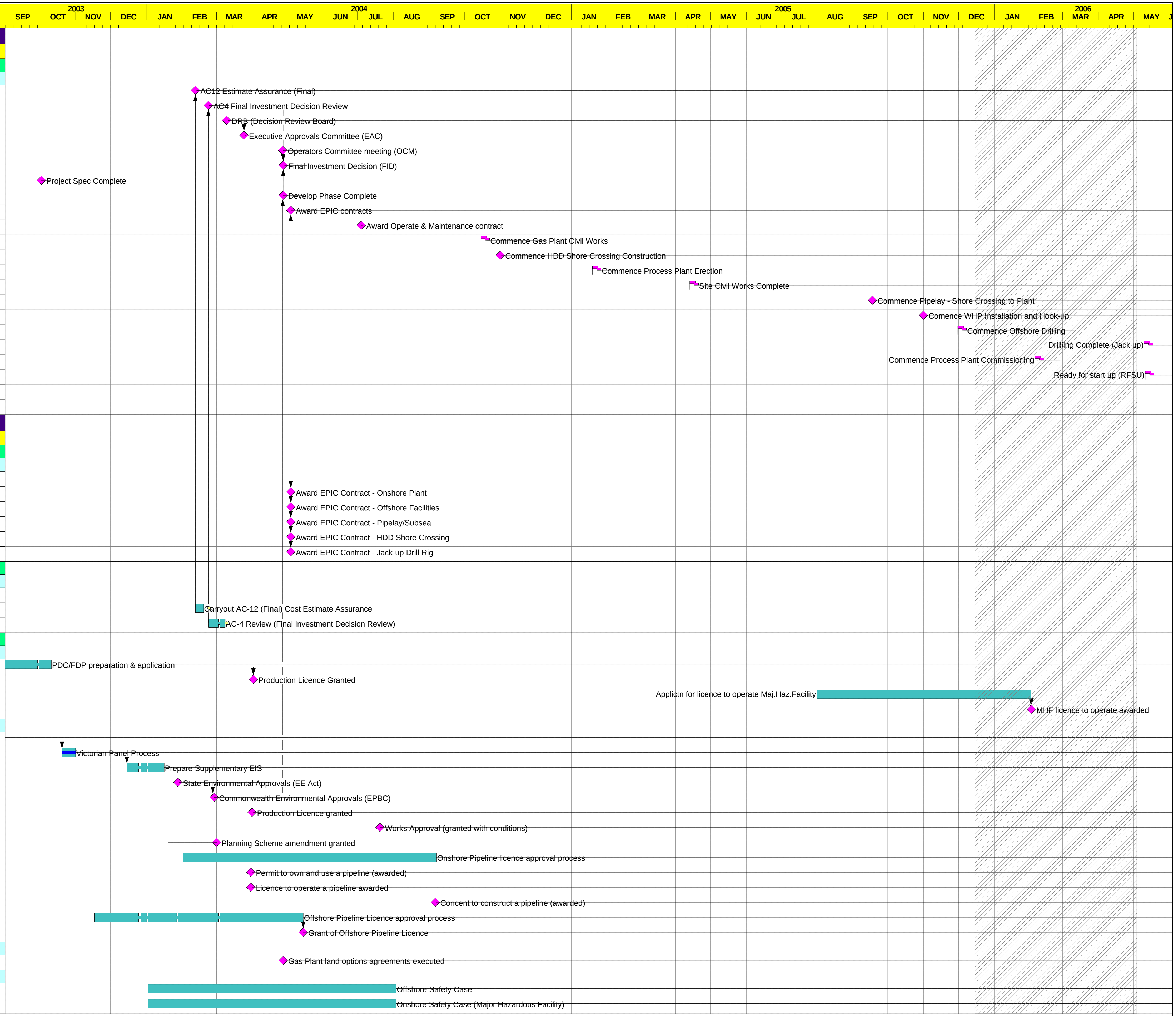
High Level Schedule

Rev 6 - 25/7/03 - D Roberts

14/10/03



Activity ID	Activity Description
Project Milestones	
DM130	AC12 Estimate Assurance (Final)
DM140	AC4 Final Investment Decision Review
DM240	DRB (Decision Review Board)
DM210	Executive Approvals Committee (EAC)
DM230	Operators Committee meeting (OCM)
DM150	Final Investment Decision (FID)
DM120	Project Spec Complete
DM145	Develop Phase Complete
DM225	Award EPIC contracts
DM155	Award Operate & Maintenance contract
DM160	Commence Gas Plant Civil Works
DM235	Commence HDD Shore Crossing Construction
DM165	Commence Process Plant Erection
DM170	Site Civil Works Complete
DM215	Commence Pipelay - Shore Crossing to Plant
DM180	Comence WHP Installation and Hook-up
DM182	Commence Offshore Drilling
DM190	Driilling Complete (Jack up)
DM185	Commence Process Plant Commissioning
DM187	Ready for start up (RFSU)
DM195	First Gas Export Date
DM200	Contract Gas Date
General Project Area	
General	
Project Mgmt & Services (Develop Ph)	
Contract Services	
DM24	Award & Issue Design Competition Package
DM26	Award EPIC Contract - Onshore Plant
DM028	Award EPIC Contract - Offshore Facilities
DM028B	Award EPIC Contract - Pipelay/Subsea
DM30	Award EPIC Contract - HDD Shore Crossing
DM34	Award EPIC Contract - Jack-up Drill Rig
HSE/Assurance - Develop Phase	
Assurance	
DH001-1	AC-8 HSE Audit Closeout actions
DH001-4	Carryout AC-12 (Final) Cost Estimate Assurance
DH001-8	AC-4 Review (Final Investment Decision Review)
External Affairs/Approvals	
Approvals	
DE002-5	PDC/FDP preparation & application
DE002-35	Production Licence Granted
DE098	Applictn for licence to operate Maj.Haz.Facility
DE108	MHF licence to operate awarded
Environmental	
DE015-3	Public Exhibition EES/EIS
DE015-6	Victorian Panel Process
DE015-9	Prepare Supplementary EIS
DM52	State Environmental Approvals (EE Act)
DM54	Commonwealth Environmental Approvals (EPBC)
DE002-15	Production Licence granted
DM50	Works Approval (granted with conditions)
DM55	Planning Scheme amendment granted
DE050	Onshore Pipeline licence approval process
DE040-2	Permit to own and use a pipeline (awarded)
DE040-3	Licence to operate a pipeline awarded
DM57	Concent to construct a pipeline (awarded)
DE042-1	Offshore Pipeline Licence approval process
DE042-11	Grant of Offshore Pipeline Licence
Land Aquisition	
DE068	Gas Plant land options agreements executed
Safety Case	
DE078	Offshore Safety Case
DE088	Onshore Safety Case (Major Hazardous Facility)



ENCLOSURE 6

Start Date	01MAY03
Finish Date	20FEB07
Data Date	01JUL03
Run Date	14OCT03 14:21

Early Bar
Float Bar
Progress Bar
Critical Activity

WS18
01JUL03
A3 Critical Path
14OCT03 14:21

Sheet 1 of 1

OTWAY DEVELOPMENT

LEVEL 3 -Preliminary Approvals Schedule
S20000AG144290

Comments Box

Date	Revision	Checked	Approved
23JUL03	Rev B - Progress and Shedule update	D Roberts	
21APR03	Rev A - Develop Phase Added	D Roberts	
21MAR03	AC12 Submission	D Roberts	

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Otway Gas Project

FINAL FIELD DEVELOPMENT PLAN

THYLACINE AND GEOGRAPHE FIELDS
OFFSHORE OTWAY BASIN

Doc. No: S4000AU148861
Revision: 0
October 2003

WOODSIDE AUSTRALIAN ENERGY

Otway Gas Project
FINAL FIELD DEVELOPMENT PLAN
THYLACINE AND GEOGRAPHE FIELDS
OFFSHORE OTWAY BASIN
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