ESTIMATE OF THE UNRISKED DISCOVERED AND UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE (PIIP) FOR THE ETINDE PERMIT AREA DOUALA BASIN, CAMEROON, WEST AFRICA

(As of September 30, 2012)

FOR

BOWLEVEN PLC

Worldwide Petroleum Consultants

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Introduction

This report was prepared by Sproule International Limited ("Sproule") at the request of Mr. Ed Willett, Exploration Director, Bowleven plc. Bowleven plc is hereinafter referred to as "the Company". The effective date of this report is September 30, 2012.

The report consists of an estimate of unrisked discovered and undiscovered petroleum initially-in-place (PIIP) only and did not include estimation of the recoverable contingent and prospective resources associated with the Company's interests in the Etinde Permit, Block MLHP-5, Douala Basin, offshore Cameroon, West Africa. This report was prepared between June 2012 and September 2012 for the Company's corporate purposes.

This report consists of a single volume comprising an Introduction, Summary, Discussion, Tables, Figures and Appendices. The Introduction describes the evaluation standards and procedures and includes pertinent author certificates, the Summary includes high-level summaries of the evaluation, and the Discussion includes general commentaries pertaining to the evaluation of the resource potential for the Etinde Block MLHP-5. Separate overview summaries tables are included for the unrisked discovered petroleum initially-in-place (Table S-1) and unrisked undiscovered petroleum initially-in-place (Table S-2). Tables detailing the estimates by individual entity are provided in the Discussion section (Tables D-1A, D-1B, D-2A, D-2B). The Figures section pertains to the Discussion. Reserve definitions, abbreviations, units and conversion factors are included in the Appendices.

Field Operations

In the preparation of this report, a field inspection of the properties was not performed. The relevant data was made available by the Company or obtained from public sources and non-confidential files at Sproule. No material information regarding the estimate of the unrisked petroleum initially-in-place would have been obtained by an on-site visit.

Historical Data, Interests and Burdens

1. All historical production, well data, revenue and expense data, product prices actually received, and other data that were obtained from the Company or from public sources were accepted as represented, without any further investigation by Sproule.

2. Property descriptions and details of interests held, as supplied by the Company, were accepted as represented. No investigation was made into either the legal titles held or any operating agreements in place relating to the subject properties.

3. Lessor and overriding royalties and other burdens were obtained from the Company. No further investigation was undertaken by Sproule.

Evaluation Standards

This report has been prepared by Sproule using current geological and engineering knowledge, techniques and computer software. It has been prepared within the Code of Ethics of the Association of Professional Engineers and Geoscientists of Alberta (APEGA). This report adheres in all material aspects to the Society of Petroleum Engineers (SPE) 2007 Petroleum Resources Management System (PRMS).

Evaluation Procedures

1. The Company provided Sproule with geological, geophysical and engineering data that were used to evaluate the resource potential of the area.

2. There were no economic forecasts or infrastructure development plans included as part of this resource assessment.

Evaluation Results

The accuracy of resource estimates is in part, a function of the quality and quantity of available data and of engineering and geological interpretation and judgment. Given the data provided at the time this report was prepared, the estimates presented herein were considered reasonable. However, they should be accepted with the understanding that reservoir and financial performance subsequent to the date of the estimates may necessitate revision. These revisions may be material.

BOE Cautionary Statement

BOEs (or McfGEs or other applicable units of equivalency) may be misleading, particularly if used in isolation. A BOE conversion ratio of 6 Mcf:1 bbl (or an McfGE conversion ratio of

1 bbl:6 Mcf) is based on an energy equivalency conversion method primarily applicable at the burner tip and does not represent a value equivalency at the wellhead.

Forward-Looking Statements

This report may contain forward-looking statements including expectations of future production revenues and capital expenditures. Information concerning reserves may also be deemed to be forward-looking as estimates involve the implied assessment that the reserves described can be profitably produced in the future. These statements were based on current expectations that involve a number of risks and uncertainties, which could cause actual results to differ from those anticipated. These risks include, but were not limited to: the underlying risks of the oil and gas industry (i.e., corporate commitment, regulatory approval, operational risks in development, exploration and production; potential delays or changes in plans with respect to exploration or development projects or capital expenditures; the uncertainty of reserves estimations; the uncertainty of estimates and projections relating to production; costs and expenses, and health, safety and environmental factors), commodity price and exchange rate fluctuation.

Exclusivity

This report has been prepared for the exclusive use of Bowleven plc. It may not be reproduced, distributed, or made available to any other company or person, regulatory body, or organization without the knowledge and written consent of Sproule, and without the complete contents of the report being made available to that party.

Certification

Report Preparation

The report entitled "Estimate of the Unrisked Discovered and Undiscovered Petroleum Initially-In-Place (PIIP) of the Etinde Permit Area, Douala Basin, Cameroon, West Africa (As of September 30, 2012) for Bowleven plc" was prepared by the following Sproule personnel:

Original Signed by Barrie F. Jose, P.Geoph.

Barrie F. Jose, P.Geoph.
Project Leader;
Vice-President, Geoscience,
International and Partner
02 / 11 /2012 dd/mm/yr

Original Signed by Suryanarayana Karri, P.Geoph.

Suryanarayana Karri, P.Geoph.
Senior Petrophysicist;
Supervisor, Geoscience and Partner
02 / 11 /2012 dd/mm/yr

Original Signed by Byron Cowley, P.Geol.

Byron Cowley, P.Geol.
Senior Geoscience Advisor and Associate
02 / 11 /2012 dd/mm/yr

Original Signed by Phil Pantella, P.Eng.

Phil Pantella, P.Eng.
Manager, Engineering and Partner
02 / 11 /2012 dd/mm/yr

Sproule Executive Endorsement

This report has been reviewed and endorsed by the following Executive of Sproule:

Original Signed by Douglas J. Carsted, P.Geol.

Douglas J. Carsted, P.Geol.
Vice-President, Geoscience and Director
02 / 11 /2012 dd/mm/yr

Permit to Practice

Sproule International Limited is a member of the Association of Professional Engineers and Geoscientists of Alberta and our permit number is P6151.

Certificate

Barrie F. Jose, M.Sc., P.Geoph.

I, Barrie F. Jose, Vice-President, Geosciences and Partner of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degrees:
   a. M.Sc. Geophysics (1979) University of British Columbia, Vancouver, B.C., Canada
   b. B.Sc. (Honours) Geological Science with Physics (1977) Queens University, Kingston, ON, Canada

2. I am a registered professional:
   a. Professional Geophysicist (P.Geoph.) Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Canadian Society of Exploration Geophysicists (CSEG)
   c. Society of Exploration Geophysicists (SEG)
   d. Canadian Society of Petroleum Geologists (CSPG)
   e. American Association of Petroleum Geologists (AAPG)
   f. Petroleum Exploration Society of Great Britain (PESGB)
   g. European Association of Geoscientists and Engineers (EAGE)
   h. Indonesian Petroleum Association, Professional Division (IPA)

4. I am a qualified reserves evaluator and reserves auditor as defined in National Instrument 51-101.

5. My contribution to the report entitled "Estimate of the Unrisked Discovered and Undiscovered Petroleum Initially-In-Place (PIIP) of the Etinde Permit Area, Douala Basin, Cameroon, West Africa (As of September 30, 2012) for Bowleven plc" is based on my geophysical knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Bowleven plc.

Original Signed by Barrie F. Jose, P.Geoph.

Barrie F. Jose, P.Geoph.

Certificate

Suryanarayana Karri, M.Sc., P.Geoph.

I, Suryanarayana Karri, Supervisor, Geoscience, Senior Petrophysicist and Partner of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degrees:
   a. M.Sc. Engineering Physics and Instrumentation (1983), Osmania University, Hyderabad, India

2. I am a registered professional:
   a. Professional Geophysicist (P.Geoph.), Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Society of Petroleum Engineers (SPE)
   c. The Society of Petrophysicists and Well Log Analysts (SPWLA)
   d. Canadian Well Logging Society (CWLS)

4. My contribution to the report entitled "Estimate of the Unrisked Discovered and Undiscovered Petroleum Initially-In-Place (PIIP) of the Etinde Permit Area, Douala Basin, Cameroon, West Africa (As of September 30, 2012) for Bowleven plc" is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

5. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Bowleven plc.

Original Signed by Suryanarayana Karri, P.Geoph.

Suryanarayana Karri, P.Geoph.

Certificate

Byron A. Cowley, B.Sc., B.Comm., P.Geol.

I, Byron A. Cowley, Senior Geoscience Advisor and Associate of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degrees:
   a. B.Sc. Geological Sciences (1986), University of British Columbia
   b. B.Comm. Accounting (1993), University of Calgary, Alberta

2. I am a registered professional:
   a. Professional Geologist (P.Geol.) Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Canadian Society of Petroleum Geologists (CSPG)
   c. American Association of Petroleum Geologists (AAPG)

4. I am a qualified reserves evaluator and reserves auditor as defined in National Instrument 51-101.

5 My contribution to the report entitled "Estimate of the Unrisked Discovered and Undiscovered Petroleum Initially-In-Place (PIIP) of the Etinde Permit Area, Douala Basin, Cameroon, West Africa (As of September 30, 2012) for Bowleven plc" is based on my geological knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Bowleven plc.

Original Signed by Byron A. Cowley, P.Geol.

Byron A. Cowley, P.Geol.

Certificate

Philip W. Pantella, B.Sc., P.Eng.

I, Philip W. Pantella, Manager, Engineering and Partner, of Sproule, 900, 140 Fourth Ave SW, Calgary, Alberta, declare the following:

1. I hold the following degree:
   a. B.Sc. Chemical Engineering (1972), University of Saskatchewan, Saskatoon, Saskatchewan

2. I am a registered professional:
   a. Professional Engineer (P.Eng.), Province of Alberta, Canada

3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Society of Petroleum Engineers (SPE)

4. I am a qualified reserves evaluator as defined in National Instrument 51-101.

5. My contribution to the report entitled "Estimate of the Unrisked Discovered and Undiscovered Petroleum Initially-In-Place (PIIP) of the Etinde Permit Area, Douala Basin, Cameroon, West Africa (As of September 30, 2012) for Bowleven plc" is based on my engineering knowledge and the data provided to me by the Company, from public sources, and from the non-confidential files of Sproule. I did not undertake a field inspection of the properties.

6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Bowleven plc.

Original Signed by Philip W. Pantella, P.Eng.

Philip W. Pantella, P.Eng.

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Douglas J. Carsted, B.Sc., P.Geol.

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1. I hold the following degrees:
   a. B.Sc. (Honours) Geology (1982) University of Manitoba, Winnipeg MB, Canada
   b. B.Sc. Chemistry (1979) University of Winnipeg, Winnipeg MB, Canada

2. I am a registered professional:
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3. I am a member of the following professional organizations:
   a. Association of Professional Engineers and Geoscientists of Alberta (APEGA)
   b. Ordre des géologues du Québec (OGQ)
   c. Canadian Society of Petroleum Geologists (CSPG)
   d. American Association of Petroleum Geologists (AAPG)
   e. Society of Petroleum Engineers (SPE)
   f. Canadian Well Logging Society (CWLS)
   g. Indonesian Petroleum Association, Professional Division (IPA)

4. I am a qualified reserves evaluator and reserves auditor as defined in National Instrument 51-101.

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6. I have no interest, direct or indirect, nor do I expect to receive any interest, direct or indirect, in the properties described in the above-named report or in the securities of Bowleven plc.

Original Signed by Douglas J. Carsted, P.Geol.

Douglas J. Carsted, P.Geol.

Executive Summary

This report is based on interpretations of technical data including seismic, geological maps, well logs, well tests and cross-sections, engineering and test data and other information supplied by the Company, obtained from published information or based on our personal knowledge of this general area of Cameroon.

A map highlighting the location of the Etinde Block MLHP-5 is included as Figure 1. The Company holds a 75-percent interest and is operator of the offshore Etinde permit which comprises blocks MLHP-5, MLHP-6, and MLHP-7 within the Douala Basin in offshore Cameroon. Vitol's wholly owned subsidiary, CamOp, holds the remaining 25-percent interest. The Deep Omicron play fairway covers MLHP-5 and the southeast portion of MLHP-6 (Figure 2). The areas of the concessions and play fairway are sizeable.

Region	Area (km2)
MLHP- 5	867
MLHP-6	1286
Deep Omicron Play Fairway	1300

The Company has a 75-percent working interest in the permit areas and is the operator of the property. As of September 30, 2012, there is no production from the six wells in Block MLHP-5 in the Etinde permit area.

The Douala Basin lies at the north end of the Aptian salt basin of the West-Central Coastal Province. The Aptian salt basin formed during the late Jurassic to early Cretaceous as the result of the tectonic rifting of the North America and South America from Africa.

Sproule was asked to conduct an independent assessment of the unrisked discovered and undiscovered petroleum initially-in-place (PIIP) of the Deep Omicron sandstone reservoir fairway in the Oligocene to Miocene aged members of the Souellaba formation. Determination of recovery factors, and thus estimates of the recoverable contingent and prospective resources, was beyond the scope of the project defined by the Company. No proved, probable or possible reserves have been assigned to these lands at this time.

These clastic fluvial and deltaic sediments deposited on the continental margin would have been destabilized and redistributed into the basin during large-scale storm or flooding events. The turbidite sand deposits settled in the channels or as over-bank deposits and submarine fans on the continental slope and were subsequently buried by clays and silts during periods of normal sedimentation.

Traps occur in the Omicron and Deep Omicron sandstone reservoirs in the Oligocene to Miocene aged members of the Souellaba formation. Trapping mechanisms in the offshore are limited to stratigraphic pinchouts, however, in the onshore region of the basin structural fault blocks and roll-over anticlines associated with graben development are also present. This resource assessment addresses only the Deep Omicron interval. The main fairway for this play lies on MLHP-5 with a portion extending onto the southern half of the MLHP-6 block (Figure 2).

Four wells have been drilled by the Company into the Deep Omicron interval within MLHP-5. The Sapele-1, Sapele 1-ST, and Sapele-2 wells were drilled on the southeast side of a major regional seismic marker, (the "X-Cut"), between February and August 2011. On the northwest side of the X-Cut, the Sapele-3 well was drilled in October 2011. All four wells encountered hydrocarbons. An earlier well (SNA-1X) on the southern margin of MLHP-5 also encountered hydrocarbons in the Deep Omicron interval.

The Company provided Sproule with three varieties of a very large 3D seismic volume (~96 gigabytes each); VSP data; digital well log data for the four Sapele wells (-1, -1ST, -2, and 3, SNA-1X) and the Souellaba-1, -2, -3, -4 wells; DST and MDT data; fluid and PVT studies; and mud log data. Three-dimensional voxel visualization and opacity rendering of the various 3D seismic volumes yielded amplitude anomalies that appeared to be of stratigraphic origin and were captured as geobodies.

Unrisked discovered petroleum initially-in-place has been assigned to zones identified within these four wells on the basis of DSTs and MDT data to be hydrocarbon-bearing. Seven hydrocarbon-bearing zones were identified within the three wells on the southeastern side of the X-Cut. Two hydrocarbon-bearing zones were identified within the Sapele-3 well on the northwest side of the X-Cut. These zones were tied to amplitude geobodies within the 3D seismic volumes and the areal extent of these sands was estimated. The unrisked discovered petroleum initially-in-place estimates were based upon the petrophysical parameters of these hydrocarbon zones and the areal extent of the 3D seismic amplitude geobodies and have been evaluated probabilistically.

Table S-1 summarizes our estimate of the Company's estimated gross and net unrisked petroleum initially-in-place within these discovered hydrocarbon-bearing zones in the Etinde Permit area, considering their 75-percent working interest in MLHP-5 and MLHP-6. The effective date of our estimate is September 30, 2012. Determining the recoverable contingent and prospective resources associated with these in-place estimates was beyond the scope defined by the Company.

For similar geobody anomalies which have not been drilled, the unrisked undiscovered petroleum initially-in-place has been estimated (Table S-2). These tables show both the gross in-place estimates as well as the net Company share at their seventy-five percent working interest.

In addition to the geobodies associated with the known hydrocarbon zones within the four Sapele wells, other geobodies of interest outside of the current well control were also identified in Sproule's independent seismic analysis. Unrisked undiscovered petroleum initially-in-place has been assigned to these leads. Thirteen leads were identified on the northwest side of the X-Cut, while seven leads were identified on the southeast side of the X-Cut. The gross and net (75-percent working interest) unrisked undiscovered petroleum initially-in-place associated with these leads in the Etinde blocks are summarized in Table S-2.

The guidelines used in estimating these unrisked in-place numbers were based upon those prepared by the Society of Petroleum Engineers (SPE) and sponsored by the World Petroleum Council (WPC), the American Association of Petroleum Geologists (AAPG) and the Society of Petroleum Evaluation Engineers (SPEE) as set out in the 2007 Petroleum Resources Management System (PRMS). The scope of the project defined by the Company was to determine only in-place estimates and did not include estimation of recoverable contingent and prospective resources.

Table S-1

Summary of Unrisked Discovered Petroleum Initially-In-Place (PIIP), Deep Omicron Formation,[1]

MLHP 5 and 6 (Etinde) Block, Douala Basin, Offshore Cameroon,

Estimated by Sproule International Limited, As of September 30, 2012

Prospect	Oil (MMbbl)[2]								Associated Gas (BCF)[2]								Total Resources (MMBOE)[2]							
	Gross[3]				Net[4]				Gross[3]				Net[4]				Gross[3]				Net[4]			
	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean
SE Total[5]	43.9	68.9	116.9	76.2	32.9	51.7	87.7	57.2	178.4	285.4	502.1	318.9	133.8	214.1	376.6	239.2	73.7	116.7	202.6	130.2	55.3	87.5	152.0	97.7
NW Total[5]	0.8	1.3	2.2	1.4	0.6	1.0	1.7	1.1	3.1	5.5	9.5	6.0	2.3	4.1	7.1	4.5	1.3	2.3	3.8	2.4	1.0	1.7	2.8	1.8
Grand Total[5]				77.6				58.2				324.9				243.6				132.6				99.5

Notes:

1. These are the unrisked discovered petroleum in-place estimates associated with hydrocarbon zones identified within the four wells (Sapele-1, -1ST, -2, -3). Discovered petroleum initially-in-place (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of the discovered initally-in-place includes production, reserves, and contingent resources; the remainder is unrecoverable.

2. "MMbbl" is millions of barrels, "BCF" is billion cubic feet, “MMboe” is millions of barrels of oil equivalent.

3. These are gross estimates independent of working interest before consideration of royalties or other encumbrances.

4. These are net estimates for the Company's 75% working interest, before consideration of royalties or other encumbrances.

5. The total volumes reported are statistically aggregated and may not necessarily add up arithmatically.

Table S-2

Summary of Unrisked Undiscovered Petroleum Initially-In-Place (PIIP), Deep Omicron Formation,[1]

MLHP 5 and 6 (Etinde) Block, Douala Basin, Offshore Cameroon,

Estimated by Sproule International Limited, As of September 30, 2012

Prospect	Oil (MMbbl)[2]								Associated Gas (BCF)[2]								Total Resources (MMBOE)[2]							
	Gross[3]				Net[4]				Gross[3]				Net[4]				Gross[3]				Net[4]			
	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean
SE Area Total[5]	160.9	201.8	253.5	205.0	120.7	151.4	190.1	153.8	657.3	839.6	1086.2	858.9	493.0	629.7	814.7	644.2	272.3	343.2	433.1	348.9	204.2	257.4	324.8	261.7
NW Area Total[5]	308.3	412.2	564.2	426.0	231.2	309.2	423.2	319.5	1257.8	1710.2	2424.7	1788.0	943.4	1282.7	1818.5	1341.0	522.3	701.3	964.1	725.9	391.7	526.0	723.1	544.4
Grand Total[5]				631.0				473.3				2646.9				1985.2				1074.8				806.1

Notes:

1. Undiscovered petroleum initially-in-place (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in accumulations yet to be discovered. These estimates are based upon seismic anomalies identified outside of the known well control at the Sapele-1, -1ST, -2, -3 wells. The recoverable portion of the undiscovered initally-in-place is refered to "prospective resources", the remainder as "unrecoverable".

2. "MMbbl" is millions of barrels, "BCF" is billion cubic feet, "MMboe" is millions of barrels of oil equivalent.

3. These are gross estimates independent of working interest before consideration of royalties or other encumbrances.

4. These are net estimates for the Company's 75% working interest, before consideration of royalties or other encumbrances.

5. The total volumes reported are statistically aggregated and may not necessarily add up arithmatically.

Sproule

Discussion

1.0 General

Figures 1, 2, and 3 show the regional setting of the Company's Etinde permits offshore Cameroon. Sproule was asked to conduct a resource assessment of the Deep Omicron sandstone reservoirs in the Oligocene to Miocene aged members of the Souellaba formation. The play fairway covers MLHP-5 and a portion of MLHP-6 in the Company's offshore Etinde concession.

2.0 Regional Background

2.1 Geological Setting

The Douala Basin is located offshore Cameroon, as indicated in the inset map (Figures 1 and 2) at the north end of the Aptian salt basin of the West-Central Coastal Province of Africa. The Aptian salt basin formed during the late Jurassic to early Cretaceous as the result of the tectonic rifting of North and South America from Africa. The West-Central Coastal Province consists of eight basins that are bracketed to the south by the Walvis Ridge and to the north by the Cameroon Fracture zone (Figure 3). The Douala Basin shares a similar genetic and structural history with the other West Africa basins, except that it is shallower (Figure 4). Early Cretaceous sediments are therefore confined to the deepest southernmost parts of the basin. Aptian salt deposits are also less prominent in the Douala Basin and limited to the southeastern parts of it where Late Cretaceous sediments unconformably overlie basement rocks across the rest of the basin.

There were three major stages of basin development defined as the pre-rift, syn-rift and post-rift stages. The pre-rift stage consists of a thick succession of continental sediments deposited in an interior sub-basin that lasted through the Late Jurassic. The early Cretaceous syn-rift stage resulted in a series of horst and graben basins with the deposition of thick fluvial and lacustrine sequences that were deposited in the developing rift basins. The post-rift phase represents the initial opening of the Atlantic Ocean with the deposition of continental, fluvial and lagoonal sediments followed by an extensive period of evaporite deposition that is limited to the southeast part of the Douala Basin.

The pre-rift basement rocks in the basin are Precambrian aged sandstones and conglomerates that are not reservoir quality. The initial rift phase created a series of horst and graben sub-basins that formed parallel to the NW-SE strike of the Jurassic to Early

Cretaceous continental margin. The emerging basin was filled with thick sequences of fluvial and lacustrine sediments eroded from the craton and deposited during the Early Cretaceous syn-rift phase of basin development. The syn-rift clastics and shales sit unconformably on the Precambrian basement. The post-rift development of the Douala passive margin is characterized by late Aptian organic-rich shales and sandstones of lacustrine origin followed by transgressive deltaic shelf clastics and carbonate muds.

The Douala Basin is partially separated from Rio del Ray basin to the north by the Cameroon Volcanic Fracture zone and from the Campo basin to the south by the Campo fault zone (Figures 4 and 5). The initial rifting phase started in the Early Jurassic with widespread volcanism of the Early Cretaceous indicative of active continental separation. The Douala Basin developed during break-up and was subsequently buried and in-filled with fluvial and deltaic sediments deposited along the passive continental margin during the Late Cretaceous and Tertiary.

The Omicron Deep reservoir displays a strong linear seismic character that trends NE to SW into the basin and perpendicular to the existing continental margin as indicated in the depositional model in Figure 6. The sandstones are interpreted to be associated with shoreface sands, marine bars and submarine channel systems that distributed sediments eroded from the craton into basin (Figure 7). Clastic fluvial and deltaic sediments deposited on the continental margin would have been destabilized and redistributed into the basin during large-scale storm or flooding events. The turbidite sand deposits settled in the channels, or as over-bank deposits and submarine fans on the continental shelf and slope and were subsequently buried by clays and silts during periods of normal sedimentation. Biostratigraphy studies conducted by the Company of the Deep Omicron interval suggest a shelfal (inner to outer neritic) depositional environment.

There is a strong correlation in the biostratigraphic and chemostratigraphic data provided for the Sapele wells that indicates that the Omicron and Omicron Deep rocks were derived from similar source rocks and deposited into the basin during the equivalent Eocene to Oligocene time. It is plausible to correlate the Omicron sand units between the Sapele-1, Sapele-1ST and Sapele-2 wells as indicated in the stratigraphic cross-section shown in Figure 8. The three easternmost wells are in close proximity to each other and are aligned along the NE–SW trend apparent in the geophysical interpretation. It is difficult to definitively correlate the hydrocarbon-bearing Omicron sand units between the southeastern cluster of wells (Sapele-1, Sapele-1ST, and Sapele-2) to the more westerly Sapele-3 well on the other side of regional X-Cut seismic marker. The stratigraphic amplitude geobody trends seen in the seismic interpretation also suggest that the Sapele-3 well would be on a separate depositional trend from the other three wells. The two prominent seismic features appear to be separate depositional systems but could be part of a continuous stratigraphic sequence that consists of siltier sediments that extend between the Sapele-1 and Sapele-2 wells across the basin to the Sapele-3 well. It would require several more exploration wells to delineate the presence of reservoir quality rock between the two seismic events.

Basin Architecture

The stylized architecture of the Douala Basin is shown below in Figure 4 with the Cameroon Volcanic fracture zone separating the Rio del Rey and Douala Basins (Figures 3 and 5). The basin extends over 8,335 square miles and covers 5.33 million acres in area and is up to 3,280 feet (1,000 metres) deep at the offshore western limit.

Source

Hydrocarbon source rocks occur in the Paleocene to Eocene lacustrine and marine sediments of the N'Kapa formation and Early Oligocene lacustrine sediments of the Souellaba formation (Figure 9). Other known source rocks present in the Douala Basin are the Upper Cretaceous Mungo and Logbadjeck formations. These source rocks generally contain Type II and Type III kerogens with TOC contents of 1 to 3 percent throughout the section with values as high as 6 percent.

Generation and Migration

Petroleum generation has been active from the late Cretaceous through to the present in the sedimentary depocentres of the basin. Chemical analysis from well samples and oil seeps indicates that hydrocarbon migration occurred from lacustrine, lagoonal and marine source rocks. Migration has likely occurred along simple migration paths along bedding planes and graben associated fault lines.

Traps

Traps occur in the Omicron and Deep Omicron sandstone reservoirs in the Eocene to Oligocene aged members of the Souellaba formation. Seismic interpretation of the data indicates a variety of potential reservoir rocks, including deep-water sandstone units deposited as submarine fans, fan-deltas, and turbidites in the Paleocene Epsilon complex. In the offshore, trapping mechanisms are limited to stratigraphic pinchouts. This resource assessment addresses only the Deep Omicron interval.

Seals

Thick interbedded marine shale and tight carbonate sequences are the primary seals for Souellaba reservoirs.

Preservation

The presence of hydrocarbons in the Sapele-1ST and Sapele-2 well drill stem tests is conclusive evidence that an active petroleum system, with trap and seal preservation, occurs in the basin.

2.2 Exploration History

Petroleum exploration in Cameroon began in 1947. Initial drilling to test onshore oil and gas seeps near the town of Douala resulted in the discovery of the Logbaba gas field in 1955. The lack of a market for natural gas in the area has limited exploration in the basin. The first significant gas and condensate discovery was at Sanaga Sud in 1980. Exploration drilling moved north to the Rio del Rey Basin but continued in the Douala Basin through the 1990s with significant gas discoveries in the Kribi area offshore Cameroon. The Company entered the region in 2005 when its subsidiary, EurOil, acquired a 100-percent interest in the Etinde Permit. Several discoveries on the northern MLHP-7 block have led to exploration on the MLHP-5 block and have resulted in hydrocarbon discoveries in the four Sapele wells drilled to date.

2.3 Well Summary

Bowleven Well Summary: Etinde Block MLHP-5

Sapele-1: Drilled in January 2011 to a total depth of 15,529 ft (4,733 m) measured depth. The well was drilled to evaluate targets in the Miocene Upper and Lower Omicron, Paleogene Deep Omicron and Cretaceous Epsilon complex. A full suite of logs was acquired from surface to 14,778 ft before tool failures occurred due to excessive downhole temperatures. The well encountered a severe gas kick at 15,529 ft and was plugged back to 3,840 ft to secure the well. No drill stem tests could be conducted. Log analysis indicates that there is 133 feet (41 m) of net hydrocarbon pay in the Upper Omicron, Lower Omicron, Omicron Deep, X-Cut Sand and Epsilon Complex formations.

Sapele-1ST: Drilled in April 2011 to a total depth of 14,745 ft (4,494 m) measured depth and logged to TD. The well was drilled as a deviated side track wellbore to evaluate a seismic amplitude response in relation to the hydrocarbon shows encountered in the Sapele-

1 well. Two DSTs were completed in the Lower and Upper sections of the Deep Omicron. DST#1 recovered 40° API oil and flowed at a maximum rate of 700 bbl of fluid per day. DST #2 also produced 40° API oil and flowed at a maximum rate of 2,000 bbl of fluid per day. Log analysis indicates that there is 97 ft (30 m) of combined net hydrocarbon pay in the Upper Omicron, Lower Omicron, Omicron Deep and X-Cut Sand formations.

Sapele-2: Drilled in April 2011 to a total measured depth of 12,300 ft (3,749 m) and logged to TD. Three DSTs were conducted. DST #1 flowed oil and gas at a final rate of 144 bbl/d. DST #2a had a final flow rate of 677 bbl/d of oil with 2.8 MMcf/d. DST #2b flowed at 481 bbl/d of oil with 2.2 MMcf/d. DST #3 was reported to produce gas at 1-2.5 MMcf/d with 81-117 Bbl/MMcf of condensate. Log analysis indicates that there is 89 ft (27 m) of combined net hydrocarbon pay in the Upper Omicron, Lower Omicron and Omicron Deep formations.

Sapele-3: Drilled in November 2011 to a total measured depth of 14,698 ft (4,480 m) and logged to TD. No drill stem tests were run on the Sapele-3 well, but MDT tests indicate the presence of hydrocarbons in the Omicron Deep. Log analysis indicates that there is 34 ft (10 m) of net hydrocarbon pay in the Omicron Deep and Epsilon formations.

3.0 Geological Evaluation

3.1 Petrophysics

3.1.1 Methodology

Sproule conducted an independent petrophysical analysis of the Deep Omicron formation using PRIZM module in Geographix software. The objective of the analysis was to estimate the effective porosity and water saturation to estimate the original gas in place. The analysis was carried out on wells Sapele-1, Sapele-1-ST1, Sapele-2, Sapele-3 and SNA-1X.

In the analysis, the volume of shale was computed as the minimum of two indicators: gamma ray and neutron-density combination. The effective porosity (PHIE) was calculated by correcting the apparent porosity from logs for the estimated volume of shale within the formation. The water saturation was calculated using the modified Simandoux equation.

The volume of shale from the GR log was estimated using the following equation:

$$Vsh_{GR} = 0 < \frac{(GR - GR_{clean})}{(GR_{shl} - GR_{clean})} < 1$$

Where Vsh_{GR} is the volume of shale from the gamma ray log, *GR* is the gamma ray value of the formation in API units, GR_{clean} is the clean matrix gamma ray value and GR_{shl} is the gamma ray value in shale.

Similarly, the volume of shale from the neutron-density logs was estimated using the following equation:

$$Vsh_{ND} = 0.0 < \frac{\rho_b - \rho_{ma} + \phi_n(\rho_{ma} - \rho_{fl})}{\rho_{sh} - \rho_{ma} + HI_{sh}(\rho_{ma} - \rho_{fl})} < 1$$

Where ρ_b is the bulk density, ρ_{ma} is the matrix density, ρ_{fl} is the fluid density, ρ_{sh} is the shale density, ϕ_n is the neutron porosity and HI_{sh} is the neutron porosity values for shale.

The volume of shale was computed as the minimum of two indicators, gamma ray and neutron-density combination, as

$$Vsh = \min(Vsh_{ND}, Vsh_{GR})$$

Where *Vsh* is the volume of shale, taking the minimum value of either the Vsh_{ND}, the volume of shale from the neutron-density log or Vsh_{GR}, the volume of shale from the normalized gamma ray log. The shale volume was then used in the calculation of effective porosity and water saturation.

The density porosity was calculated using the bulk density log, assuming a matrix density of 2.68 gm/cc and a fluid density of 1.0 gm/cc. The equation used in the analysis is as follows:

$$\phi_D = \frac{(\rho_{ma} - \rho_b)}{(\rho_{ma} - \rho_{fl})}$$

Where ϕ_D is the density porosity, ρ_b is the measured bulk density in gm/cc, ρ_{ma} is the matrix density in gm/cc and ρ_{fl} is the fluid density in gm/cc.

The apparent porosity was calculated by taking the average of the density and neutron porosity values, using the equation

$$\phi_A = \frac{(\phi_D + \phi_{NSS})}{2}$$

Where ϕ_A is the apparent porosity, ϕ_D is the density porosity and ϕ_{NSS} is the neutron porosity in sandstone units.

The effective porosity (PHIE) was calculated by correcting for the estimated volume of shale within the formation, using the equation

$$\phi_e = \phi_A(1 - V_{sh})$$

Where ϕ_e is the effective porosity, ϕ_A is the apparent porosity and V_{sh} is the volume of shale. The water saturation was calculated using the modified Simandoux equation, which is better suited to evaluate formations with high shale content. The equation is as follows:

$$Sw_{MS} = \left[\frac{\left(\sqrt{\left(\frac{V_{sh}}{R_{sh}}\right)^2 + \frac{4\phi_e^{\ m}}{aR_w(1-V_{sh})R_t}} - \frac{V_{sh}}{R_{sh}} \right)}{\frac{2\phi_e^{\ m}}{aR_w(1-V_{sh})}} \right]^{1/n}$$

Where Sw_{MS} is the water saturation, ϕ_e is the effective porosity, *Rt* is the true formation resistivity in ohm, V_{sh} is the volume of shale, "a" is the Archie constant, "m" is the cementation factor, "n" is the saturation exponent, Rw is the formation water resistivity and Rsh is the resistivity of shale.

Values of a, m and n used in the analysis were set to 1, 2 and 2, respectively. A value of 0.25 ohm-m at 75° F was used for formation water resistivity (Rw).

The net pay was computed using the effective porosity cut-off of 10 percent, a water saturation cut-off of 60 percent and volume of shale cut-off of 50 percent. Figures 10 to 18 show the petrophysical analysis results.

A histogram analysis was carried out on the thickness, effective porosity and water saturation from the five wells. The gross thickness of deep Omicron section has a range of 1,200 to 1,600 feet. The pay intervals are discreet and thin, having a range of 22 to

160 feet. The net to gross ratio is between 0.01 and 0.08. The effective porosity has a range between 12 percent and 23 percent, with a most likely value of 17 percent. The water saturation varies from 35 percent to 58 percent, with a most likely value of 48 percent. The histogram plots are shown in Figures 19 to 21. These parameter ranges were used in probabilistic volumetric evaluation.

3.1.2 Summary of Derived Reservoir Parameters

A summary of the petrophysical analysis for the Sapele-1, Sapele-1ST, Sapele-2, Sapele-3 and SNA-1X wells is provided in Figure 22. Probabilistic volumetrics have been estimated only for the Deep Omicron interval in this report.

3.2 Biostratigraphy

The biostratigraphic assemblages identified in the four Sapele wells (1, 1-ST, 2 and 3) display a strong age correlation for the Lower Eocene to Lower Miocene aged Omicron Deep to Upper Omicron formations. This data indicates that the Omicron to Omicron Deep sections in all of the Sapele wells are approximately time equivalent and were deposited during the same time period.

3.3 Chemostratigraphy

Chemostratigraphic analysis for the Sapele-1, S-2 and S-3 wells indicates that the Omicron to Omicron Deep sequence was derived from a similar source provenance. Minor differences in chemical composition with slightly higher sulphur content in the S-3 well could indicate that the Sapele 1 and 2 wells may have a different source than the Omicron section in the Sapele 3 well. In spite of the differences in seismic facies character of the Deep Omicron interval on either side of the prominent X-Cut seismic marker, the chemostratigraphic data (Figure 23) would support the Deep Omicron interval in the Sapele-3 well to be chronostratigraphically equivalent to the other three Sapele wells on the southeast side of the X-Cut.

3.4 Geophysics

3.4.1 Data Control

The Deep Omicron play fairway, which covers MLHP-5 and the southeast half of MLHP-6 (green shaded area in Figure 2, lower image), is a subset of a larger 3D seismic volume. The Sapele-1, -1ST, -2 and -3 wells all lie within MLHP-5.

Initially, an 8-bit version of the final merged SEGY stacked data was received from the Company, over the play fairway area. These data were loaded into *Petrel* and were found to be very limited in bandwidth, with very faint seismic reflectivity. Interesting amplitude anomalies that appeared to be stratigraphic in nature were still observed on this poorly scaled data, so the Company decided to provide the near-, mid- and far-stack data on an additional USB drive. When these new 8-bit truncated volumes were loaded into the *Petrel* model, they had even more limited bandwidth than the final migrated stack. A decision was made to provide the original processed 32-bit versions to Sproule. These were each about 96 gigabytes in size, and considerable effort was expended to load and re-scale these into truncated 8-bit versions over the area of interest. The area of the optimally scaled 8-bit near-, mid- and far-stack datasets utilized in this project is illustrated in Figure 24 along with the wells within MLHP-5, the block boundaries, and areas interpreted on either side of the X-Cut. The 32-bit version of the final migrated stack lacked coverage immediately north of the Sapele-1 well, and the original poorly scaled version of this particular 3D volume was still utilized to fill in the interpretation north of that well when dealing with that 3D volume. The size of the volumes proved cumbersome and time-consuming in the later visualization phases.

3.4.2 Seismic-to-Well Calibration

Using the well tops from the chemostratigraphy and biostratigraphy studies (Figure 22), the top and base Deep Omicron events were annotated on 3D inline 1780 which traverses past the Sapele-3 well on the northwest side of the X-Cut and Sapele-2 on the southeast side (Figure 24). The checkshot corrected top and base of the Deep Omicron package are shown by the square symbols along the well paths. Also shown are the interpreted top and base of the Deep Omicron stratigraphic package.

A prominent feature referred to as the X-Cut separates the Sapele-3 well to the northwest from the Sapele-1, Sapele-1ST and Sapele-2 wells to the southeast. There are different opinions regarding this features origin, with proposed interpretations ranging from a very low-angle regional glide plane to a major regional unconformity.

In the shallower section of Figure 25, there are amplitude anomalies and changes in reflection character and dip on either side of the X-Cut. The top and base of the Deep Omicron zones identified in the wells on the basis of the biostratigraphy and chemostratigraphy are shown in the red and blue squares. Within this deeper section, the seismic character changes even more dramatically across the X-Cut. Terminations may be seen against this feature, and there are marked amplitude differences on either side. At Sapele-3 in the northwest, the Deep Omicron package (yellow to green markers) has a relatively high amplitude with weak amplitude packages above and below. The Deep

Omicron exhibits a very wedge-shaped character, thickening to the northwest with clinoforms downlapping to the southeast towards the X-Cut.

Above and beneath the Deep Omicron seismic package are relatively characterless low-amplitude packages. In contrast, the Deep Omicron interval on the southeast side of the X-Cut (red to magenta markers) is characterized by fairly low amplitude with a high-amplitude reflection seismic facies above. The chemostratigraphy and biostratigraphy correlations (Figure 23) provided a fairly compelling argument that, in spite of the differences in seismic character, these two intervals were chronostratigraphically equivalent. The Company suggests any movement along the X-Cut may be out of the plane of this inline section and may help to explain this discrepancy.

3.4.3 Horizon and Fault Interpretation

Figure 26 shows a 3D seismic fence diagram between the Sapele-3 well to the northwest of the X-Cut and the Sapele-2, Sapele-1 and Sapele-1ST wells on the southeast side of the X-Cut. The base Deep Omicron surface is displayed in this 3D perspective view so that the overlying Deep Omicron package may be observed. In this original version of the final migrated stack, the amplitudes of the Deep Omicron interval covered a very narrow range of the 8-bit spectrum. This low resolution and limited dynamic range of this 3D volume made it difficult to visualize and extract anomalous amplitude geobodies. Figure 27 shows the same 3D perspective fence diagram with a properly scaled migrated volume. Note that a portion of the data was missing from the higher resolution original processed 32-bit volumes from which the refined seismic was extracted. The geobodies north of Sapele-1 were extended based upon the lower resolution 3D seismic volume.

Similarly, re-scaled near-stack and far-stack volumes were created from the original 32-bit volumes to replace the low resolution volumes initially received (Figures 28 and 29). These optimally scaled 3D migrated, near-stack and far-stack 3D volumes enabled better correlation of the top and base of the Deep Omicron, formation sculpting of that interval, and 3D voxel filtering and visualization of that stratigraphic package to identify anomalous amplitudes related to the unrisked discovered hydrocarbon-bearing zones within the wells and also the identification of unrisked undiscovered leads that as yet are undrilled.

Using the well tops from the chemostratigraphy and biostratigraphy studies (Figure 23), the top and base of the Deep Omicron event were correlated throughout the study area as shown in the 2D map views of Figures 30–31, and in the 3D perspective views from the south in Figures 32–33.

Figure 34 shows a 3D perspective view from the southwest of both the top and base Deep Omicron time picks on either side of the X-Cut surface (white listric surface). The bounding Deep Omicron horizon surfaces are shown in a similar view (Figure 35).

Figures 36 and 37 show some additional 3D perspective views from the south of the final time and depth structure surfaces.

3.4.4 3D Formation Sculpting and Voxel Visualization

The final top and base of the Deep Omicron surfaces with the four intersecting wellbores is shown in Figure 35. With these surfaces interpreted on both sides of the X-Cut, Sproule was able to use formation sculpting to isolate the 3D voxels (seismic samples at each bin location) between these surfaces and then apply opacity filtering to different amplitude ranges of each of the various 3D volumes to identify stratigraphic features of interest within the Deep Omicron interval. An example is provided for the near-stack 3D volumes on the SE side of the X-Cut covering the Sapele-1, Sapele-1ST, and Sapele-2 wells (Figure 38). This image shows the formation sculpted 8-bit near-stack 3D volume after amplitude re-scaling by Sproule. If the troughs and weakest of the peaks is filtered out, leaving just the highest amplitude value peaks within this 3D volume, some interesting stratigraphic trends are revealed (Figure 39). These can be further colour enhanced (Figure 40). The troughs may also be visualized for each of the four enhanced 3D volumes. The trend of these features is generally NE–SW in orientation on both sides of the X-Cut, and, while in the same overall chemostratigraphic and biostratigraphic package, the anomalies on either side of the X-Cut do not appear to be connected by the same amplitude anomalies. While these 3D voxel visualization techniques showed some very encouraging amplitude trends suggesting a stratigraphic origin, the overall thickness of the Deep Omicron package made it challenging to identify and map particular geobodies associated with a particular hydrocarbon zone within such a thick package.

Similarly, Figure 41 shows the strongest voxel-filtered peaks form the merged final AGC stack 3D seismic volume over the Deep Omicron package northwest of the X-Cut. Some of the identified amplitude anomalies are very sharp, discrete features, as shown in Figures 41–44. In the upper portion of the Deep Omicron on other 3D seismic volumes, such as the near-stack, some fan-shaped lobes are identified (Figures 46 and 47).

3.4.5 Discrete Geobody Calibration to DST/MDT Events for Unrisked Discovered Petroleum Initially-in-Place

A focused approach was taken to better isolate individual anomalies tied to the well DST and MDT tests. All available DST and MDT test data were entered as well tops into the *Petrel* model (Figure 47). This facilitated easier identification of whether a peak or trough on each of the final migrated stack, near stack, mid stack or far stack best tied to the hydrocarbon show within these wells. The two areas, the northwest (Sapele-3) and southeast (Sapele-1, -1ST and -2) areas were examined in isolation. When zoomed in on one of the re-scaled 8-bit enhanced 3D seismic volumes, it could be decided whether the peak or trough best represented the zone where the hydrocarbon show occurred. Three-dimensional visualization and geobody detection methods were then utilized to pick the extent of that feature. The extent of the hydrocarbon show was mapped on each of the various 3D seismic data volumes. Figures 49–55 show the horizons and polygons picked on near-stack events chosen to represent the DST/MDT events identified with the well bores (Figure 48). Figures 56–61 show the horizons and polygons picked on far-stack events chosen to best represent other DST/MDT events identified with the well bores (Figure 48). Similarly, Figures 62–67 show the horizons and polygons picked on events from the final merged AGC volume chosen to best represent other DST/MDT events identified with the well bores (Figure 48). These picked horizons, interpreted on either the final migrated AGC, near-stack or far-stack, whichever best represented the hydrocarbon zone, were used in the analysis of the unrisked discovered petroleum initially-in-place (Figure 68).

Seven geobody anomalies were mapped in the southeast associated with the known hydrocarbon zones identified in the Sapele-1, Sapele-1ST and Sapele-2 wells. Two geobody anomalies were identified in the Sapele-3 well in the northwest.

3.4.6 Discrete Geobody Calibration to Undrilled Leads for Unrisked Undiscovered Petroleum Initially-in-Place

A similar approach was taken to identify prospective leads away from the well control with the exception of being able to calibrate to known hydrocarbon zones in the wells. The strongest amplitude geobodies were identified on the near-stack 3D volume (Figures 70–76), the far-stack 3D volume (Figures 77–82), and the final migrated AGC stack (Figures 83–86). The areas from the leads identified on these three volumes constitute the basis for the unrisked undiscovered petroleum initially-in-place (Figures 86–87).

Nine geobody anomalies associated with the undrilled undiscovered leads identified in the southeast area away from the Sapele-1, Sapele-1ST, and Sapele-2 well penetrations were mapped. In the northwest, thirteen geobody anomalies associated with the undrilled undiscovered leads identified in the northwest area away from the Sapele-3 well penetration were mapped.

4.0 Reservoir Engineering

4.1 Well Test Interpretation

The Sapele-1 well experienced well control problems as a result of a gas kick. As a consequence, the main well bore was subsequently cemented off, and the sidetrack Sapele-1ST was drilled. No DSTs were conducted in the Sapele-1 well.

Two DSTs have been conducted by the Company in sidetrack Sapele-1ST. The Company then drilled the Sapele-2 well, in which a total of four DSTs were conducted.

The pressure transient responses from all six DSTs in the S-1ST and S-2 wells have been analyzed by ERC-Equipoise Limited (ERC). The conclusion was that the reservoir is generally tight, with permeability ranging from 0.2 mD to 1 mD for most of the tested intervals (DST1 in well Sapele-1ST and DST1, DST2B and DST3 in Sapele-2). ERC also suggested that there can be pockets of better quality reservoir with permeability ranging from 6 to 38 mD, but they are of very limited extent (DST 2 in Sapele-1ST and DST 2A in Sapele-2). The presence of multiple no-flow boundaries near the wells has also been interpreted by ERC.

Sproule reviewed ERC's interpretation and found it generally reasonable, although in some instances, lower permeability values would be interpreted by Sproule. Additionally, non-reservoir or composite reservoir effects were found to be an alternative, and in many cases a potentially more likely interpretation than the ERC interpretation of multiple no-flow boundaries very close to a well.

A summary of ERC's well test interpretation is presented below.

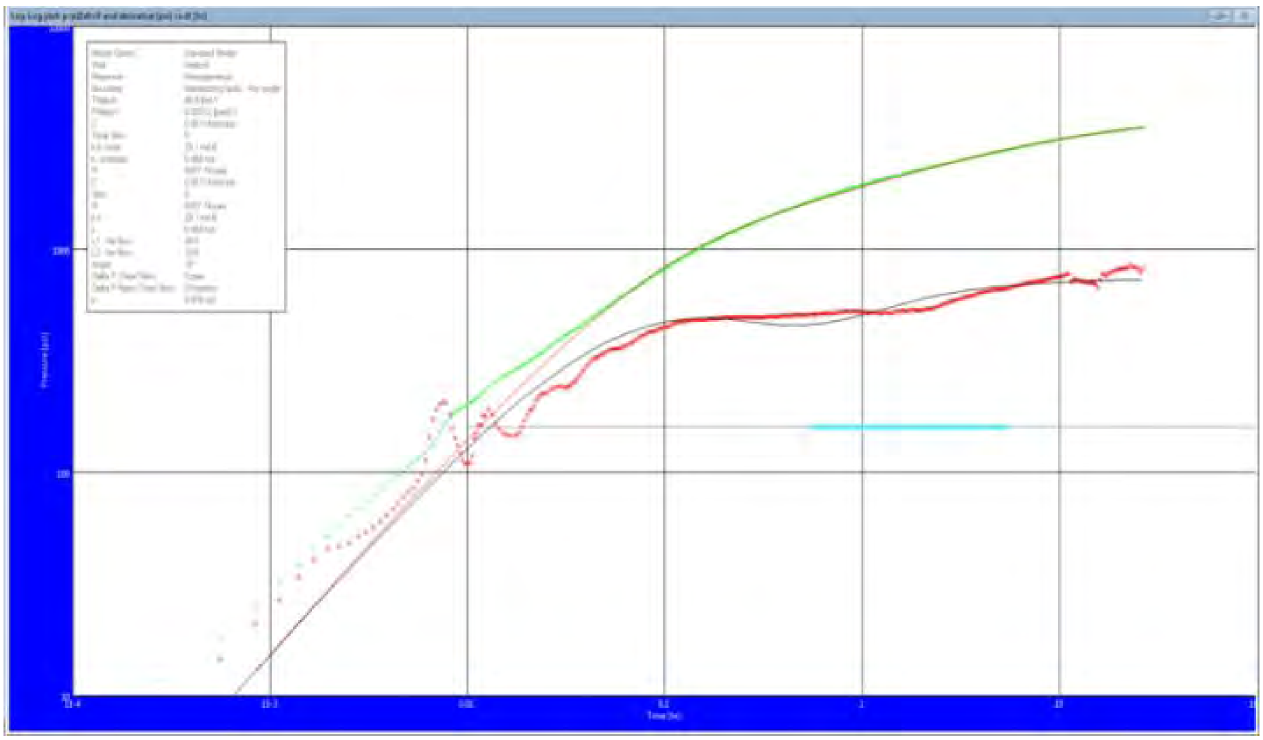
<u>Well Sapele-1 ST, DST #1 (Deep Omicron Formation)</u>

The Deep Omicron Formation was tested over the interval 14,266–14,476 ft measured depth (MD) with a cleanup flow followed by a six-hour buildup; then a 13.5-hour flow period followed by a 27.5-hour buildup period. The well flowed oil at a rate that fluctuated between 0 and 700 bopd. The final flow rate was estimated to be 150 bopd, flowing sand face pressure varied between 7,763 and 4,223 psia, and the final drawdown on the well was estimated to be 49 percent.

ERC modelled the pressure response using permeability of 0.64 mD and skin of zero. The increase in the slope of the derivative was matched by incorporating two no-flow boundaries located 10 and 36 feet away from the wellbore. A reservoir pressure of 8,208 psia was estimated.

Sproule has reviewed the ERC interpretation and found it reasonable but also concluded that the boundaries specified in the model were not apparent in the geophysical interpretation of the extent of the geobody. A composite reservoir model (decreasing permeability-thickness [kh] away from the wellbore) is a possible alternative interpretation of the pressure transient response.

Well Sapele-1, DST #1. PTA results (as interpreted by ERC Equipoise)



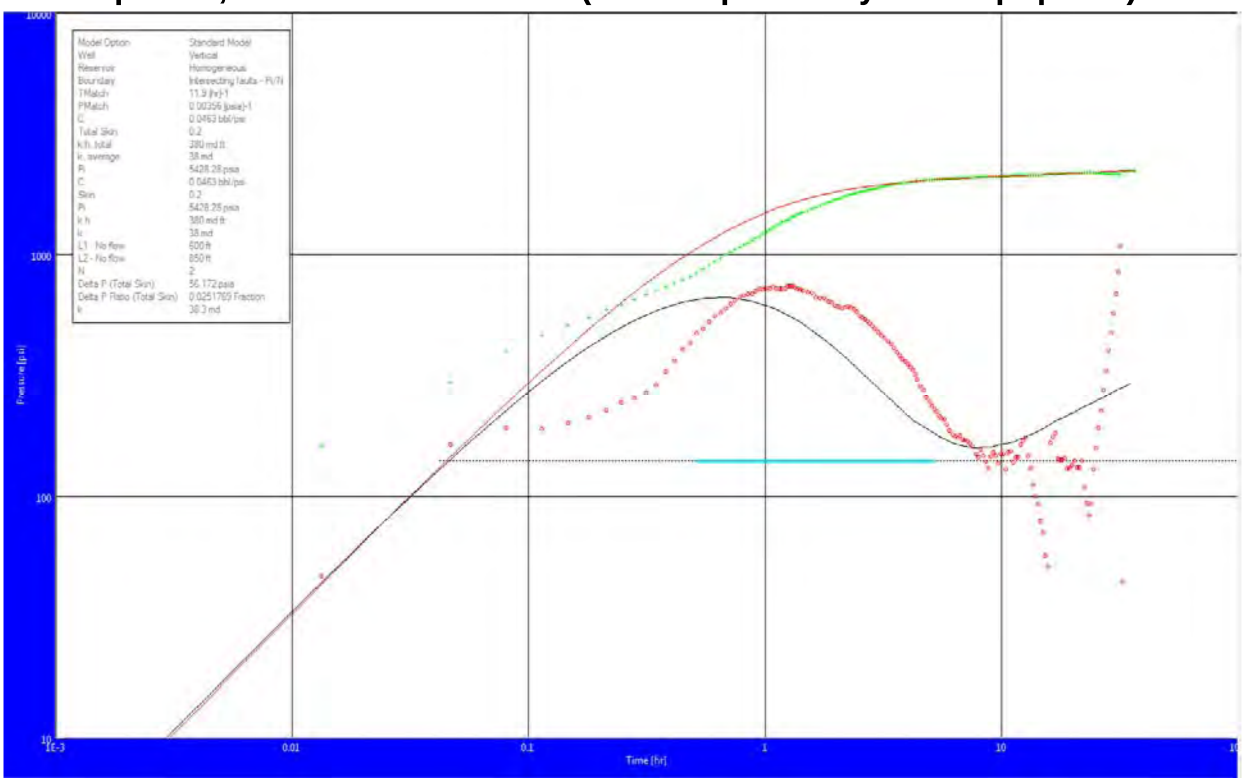
Sapele-1 ST, DST #2 (Deep Omicron Formation)

The Deep Omicron Formation was tested over the interval 12,856-13,090 ft MD with an initial flow period of 12.5 hours that resulted in a final rate of 5,846 bopd and a wellhead flowing pressure of 2079 psia. This reported rate was viewed as an anomaly by ERC because it was not compatible with the pressure profile and was not included in ERC's analysis. This was followed by an unplanned three-hour buildup due to surface equipment handling issues. The well was flowed again for 10.5 hours followed by a 37-hour buildup. The reported final flow rates were 1,620 bopd with a final flowing sand face pressure of 3,035 psia. The final drawdown on the well was estimated to be 44 percent.

ERC matched the pressure response with a bounded homogeneous reservoir model having two boundaries 600 and 850 feet away. A permeability of 38 mD, a skin of 0.2 and a reservoir pressure of 5,428 psia were estimated from the test.

Sproule has reviewed the interpretation and concluded that the interpretation results are of considerable uncertainty because of the pressure data reliability. The late-time pressure behavior was clearly not a reservoir-related phenomenon. Radial flow was not developed prior to the onset of these perceived wellbore effects and accordingly, the estimates of permeability and skin are highly uncertain. Comparison of the subsequent buildup trend suggests depletion may have occurred as a result of test production.

Well Sapele-1, DST #2. PTA results (as interpreted by ERC-equipoise)



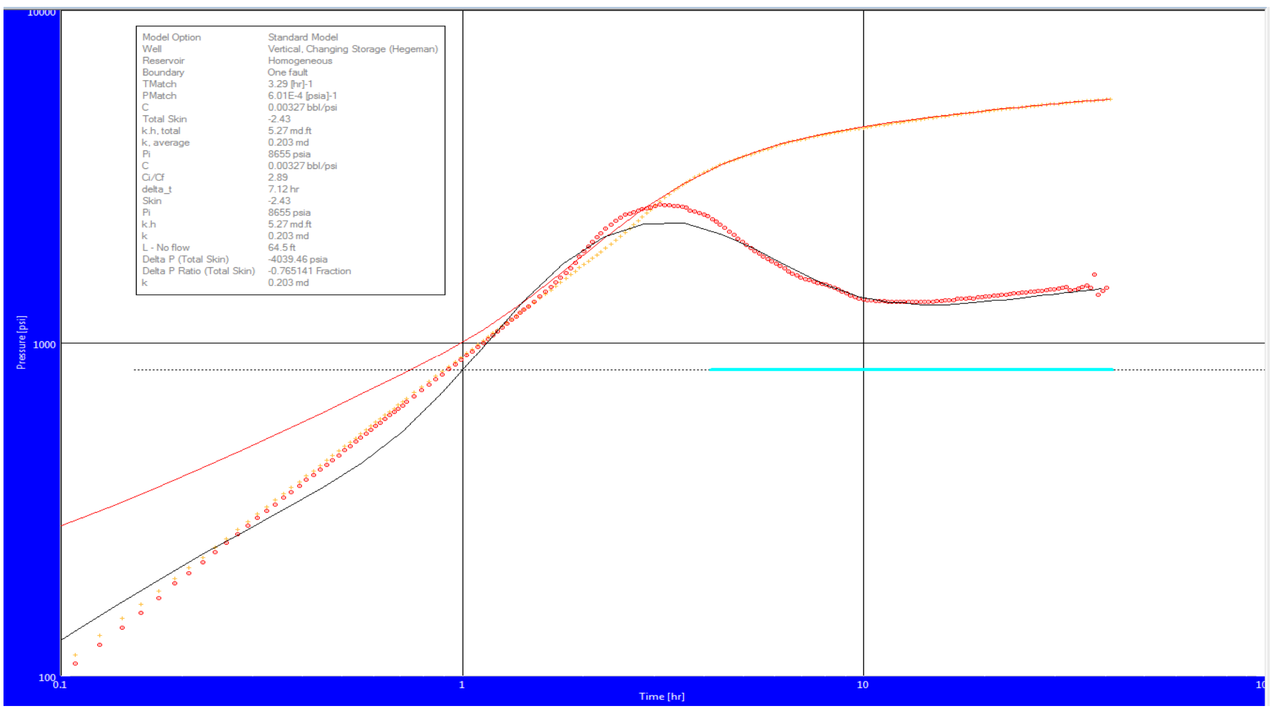
Sapele-2, DST #1 (Deep Omicron Formation)

The Deep Omicron Formation was tested over the interval 11,867–12,061 ft MD with an initial flow and clean up of 13 hours, followed by an extended flow period of 14 hours that resulted in a final average rate of 144 bopd and a final flowing sand face pressure of 2552 psia. The final drawdown on the well was estimated to be 71 percent.

ERC matched the pressure response with a bounded homogeneous reservoir model having a single boundary 65 feet away. A permeability of 0.3 mD, a skin of -2.0 and a reservoir pressure of 8,655 psia were estimated from the test.

Sproule reviewed the interpretation and concluded that the estimate of permeability may be optimistic. The permeability should have been estimated from a point approximately a quarter of a log cycle higher than where it was picked on the derivative plot. Sproule also considers the subtlety of the increase in the slope of the derivative to be more indicative of a decrease in kh away from the wellbore rather than a nearby boundary. Thus, a composite reservoir model (decreasing kh away from the wellbore) could be an alternative interpretation for the pressure transient response.

Well Sapele-2, DST #1. PTA results (as interpreted by ERC-equipoise)



Sapele-2, DST #2A (Deep Omicron Formation)

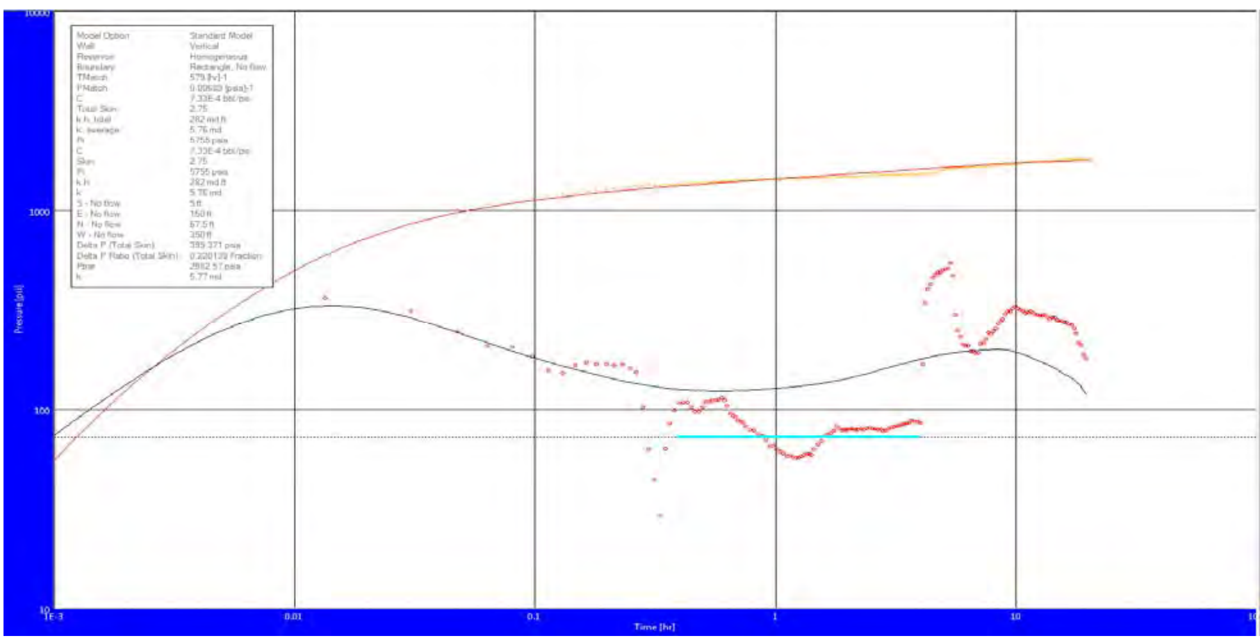
The Deep Omicron Formation was tested over the interval 11,070–11,277 ft MD, and three flows and buildups were performed. The first flow was a short cleanup. The second was a 12-hour flow followed by a 24-hour buildup, and the third was a final 6-hour flow and 21-hour buildup. Flow rates of 1,000 to 2,000 bopd with a final extended rate of 896 bopd at a final flowing sand face pressure of 992 psia were reported. The final drawdown on the well was estimated to be 83 percent.

The pressure response was modelled by ERC with a bounded homogeneous reservoir model having four boundaries between 5 and 530 feet away. A permeability of 5.8 mD, a skin of 2.8 and a reservoir pressure of 5,755 psia were estimated from the test.

A comparison of each subsequent buildup trends suggests depletion. Although the second buildup was the longest, the pressure response, after about one hour of shut-in, was adversely affected by wellbore effects and was not considered. Wellbore effects also affected the final buildup period after about five hours of shut-in.

Sproule believes the analysis to be reasonable given the limitations of the data.

Well Sapele-2, DST #2A. PTA results (as interpreted by ERC-equipoise)



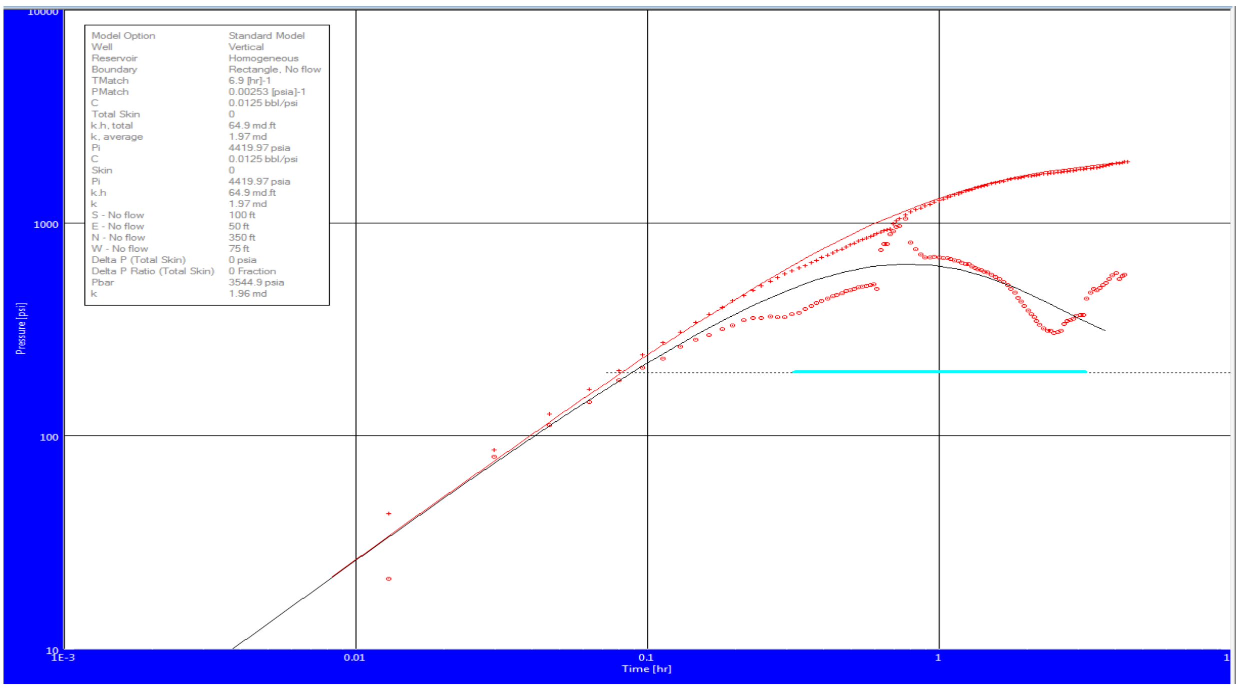
Sapele-2, DST #2B (Deep Omicron Formation)

The Deep Omicron Formation was tested over an extended interval from 11,070 to 11,438 ft MD, which included the DST#2A interval (11,070–11,277 ft MD). Two flow and buildups were performed. The first buildup showed depletion arising from the previously tested DST#2A. The second was a very short flow followed by a 4.5-hour buildup used for interpretation. Rates varied from 500 to 2,000 bopd, and we concur that there are obvious signs of depletion. The final flowing sand-face pressure was 982 psia, and the final drawdown on the well was estimated to be 78 percent.

ERC concluded that there had been crossflow between the new interval being tested and the depleted DST#2A interval. A match of the pressure response was obtained by ERC with a bounded homogeneous reservoir model having its nearest reservoir boundary 50 feet away. A permeability of 2.0 mD, a skin of 0 and reservoir pressure of 4,420 psia were estimated from the test.

Sproule concurs with ERC that the test is not particularly useful due to crossflow into the depleted interval from DST#2A.

Well Sapele-2, DST #2B. PTA results (as interpreted by ERC-equipoise)



Sapele-2, DST #3 (Deep Omicron Formation)

The Deep Omicron Formation was tested over the interval 9,725–9,768 ft MD which flowed gas condensate at a ratio of 81 to 117 bbl/MMscf and at condensate rates between 100 and 250 bcpd. The final flow from the well was near AOF.

ERC matched the pressure response with a bounded homogeneous reservoir model having a single no-flow boundary 1,010 feet away. A permeability of 0.4 mD, a skin of 0 and a reservoir pressure of 5,701 psia were estimated from the test.

Although the quality of the match was complicated by data limitations, Sproule believes the interpretation is reasonable.

Well Sapele-2, DST #3. PTA results (as interpreted by ERC-equipoise)

Summary of ERC-equipoise's Well Test Analyses

Test	Description	Deliverability	Pressure Transient Analysis (as interpreted by ERC-equipoise)	Sproule's Comments
Sapele 1 ST DST#1 14,266-14,476 feet	Homogeneous, 2 boundaries 10 & 36 feet	700 - 150 bopd (175 - 150 bopd avg final rate used)	Pi = 8,207 psia k = 0.64 mD Skin = 0 kh = 29 mD.ft	Sproule has reviewed the interpretation and found it reasonable but also concluded that the boundaries used in the model are not apparent in geophysical interpretations of the geobody extent and a composite reservoir model (decreasing kh away from the wellbore) could be an alternative interpretation of the pressure. transient response.
Sapele 1 ST DST#2 12,856-13,090 feet	Homogeneous, 2 boundaries 600 & 850 feet	2,000 – 1,500 bopd (1,620 bopd avg final rate used)	Pi = 5,428 psia k = 38 mD Skin = 0.2 kh = 380 mD.ft	Sproule has reviewed the interpretation and concluded the interpretation results to be of considerable uncertainty because of the quality of the pressure data. Comparison of sequential buildup trends suggests depletion may have occurred as a result of test production.

Test	Description	Deliverability	Pressure Transient Analysis (as interpreted by ERC-equipoise)	Sproule's Comments
Sapele 2 DST#1 11,867-12,061 feet	Homogeneous, 1 boundary 42 feet	200 - 140 bopd (144 bopd avg final rate used, some BS&W ~ 10%)	Pi = 8,655 psia k = 0.3 mD Skin = -2.0 kh= 7 mD.ft	Sproule has reviewed the interpretation and concluded that the estimate of permeability may be optimistic. Sproule also considers the subtleness of the increase in the slope of the derivative to be more indicative of a decrease in kh away from the wellbore rather than a nearby boundary. Thus a composite reservoir model (decreasing kh away from the wellbore) could be an alternative interpretation of the pressure transient response.
Sapele 2 DST#2A 11,071-11,277 feet	Homogeneous, 4 boundaries 5 to 350 feet	2,000 – 1,000 bopd (896 bopd avg final rate used) and 2.8 MMCFPD	Pi = 5,755 psia k = 5.8 mD Skin = 2.8 kh = 282 mD.ft	A comparison of each subsequent buildup trend suggests depletion. The pressure response was adversely impacted by wellbore effects; Sproule believes the analysis to be reasonable given the limitations of the data.
Sapele 2 DST#2B 11,070-11,438 feet	Homogeneous, 4 boundaries 50 - 350 feet	2,000 - 500 bopd (628 bopd avg final rate used) and 2.8 MMCFPD	Pi = 4,420 psia k = 2 mD Skin = 0 kh = 65 mD.ft	Sproule concurs with ERC that the test is not particularly useful due to crossflow into the depleted interval from DST #2A.
Sapele 2 DST#3 9,725-9,768 feet	Homogenous, 1 boundary 1,010 feet	Average rate of 1,842 bopd from gas condensate rates of 1-2.5 MMCFPD	Pi = 4,701 psia k = 0.4 mD Skin = 0 kh = 12.2 mD.ft	Sproule believes the analysis to be reasonable given the limitations of the data.

4.2 Fluid Properties

The combination of lab single-stage flash and multistage separator tests have been conducted on four MDT oil samples from the Sapele-1 well in the Expro Fluid Analysis

Centre. The results of the MDT sampling bear a high amount of uncertainty due to the inherently small volume of the MDT samples and also the mud contamination.

In addition to MDT sample lab tests, the oil PVT parameters have been estimated using the results from DSTs in wells Sapele-1ST and Sapele-2 and Standing's black oil correlation.

Stock tank oil gravity measurements averaged 40° API, indicating very light oil.

The initial formation volume factor was estimated to vary between 2.25 rb/stb and 3.07 rb/stb.

The PVT properties, based on reported MDT sample analyses and estimated from Standing's black oil correlation, are as follows:

Well	Sapele-1	Sapele-1	Sapele-1	Sapele-1	Sapele-1ST DST1	Sapele-1ST DST2	Sapele-2 DST 1	Sapele-2 DST 2
Type of sampling	MDT	MDT	MDT	MDT	Surface	Surface	Surface	Surface
Type of analysis	Lab Test				Standing's Black Oil Correlation			
Depth	11,511	10,771	10,818	10,879	14,265-14,475	12,854-13,091	11,867-12,060	11,070-11,276
Initial reservoir pressure(psig)	6,149		5,995	6,149	8,207	5,428	8,655	5,755
Reservoir temperature (deg F)	314	289	292	293	322	286	326	311
API(degrees)	35	40	41	37	40	40	40	40
Initial formation volume factor(rb/stb)	-	-	2.71	2.25	2.95	2.25	3.07	2.28
Oil viscosity at initial reservoir conditions(cp)	-	-	0.12	0.13	0.23	0.15	0.26	0.13
Saturation pressure(psig)	-	1,765	4,400	4,165	At reservoir pressure			
Initial solution gas oil ratio(scf/bbl)	2,654	843	2,722	1,999	-	3,286	5,244	3,600-4,000
Mud contamination (weight %)	-	45	5	10	-	-	-	-

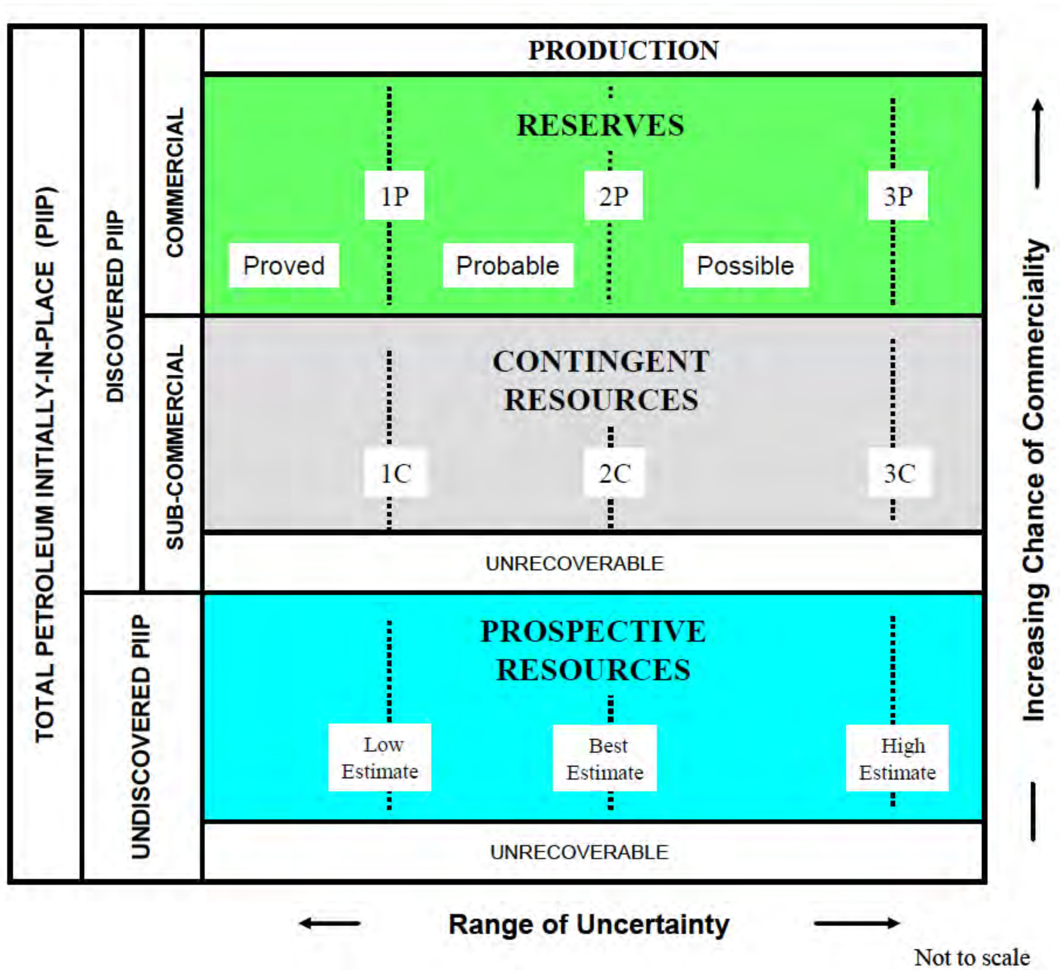
4.3 Recovery Factor Estimates

The scope of the project defined by the Company was to estimate only the unrisked discovered and undiscovered petroleum initially-in-place and not to estimate recovery factors associated with any potential contingent or prospective resource volumes.

5.0 Summary of Unrisked Discovered and Undiscovered Petroleum Initially-in-Place

5.1 General Categorization

No proved, probable, or possible reserves have been assigned at this time. A development plan is not in place, nor are there regulatory approvals or infrastructure. As noted previously, no contingent or prospective resources have been assigned.



Resource Classification Framework (SPE - PRMS)

Unrisked discovered petroleum initially-in-place (discovered PIIP) has been assigned to hydrocarbon-bearing zones mapped in the Sapele-1, Sapele-1ST, Sapele-2 and Sapele-3 wells.

Unrisked undiscovered petroleum initially-in-place (undiscovered PIIP) has been assigned to additional leads mapped seismically as amplitude geobodies outside of the well control.

5.2 Unrisked Discovered Petroleum Initially-In-Place

Hydrocarbons have been discovered within the four Sapele wells drilled within MLHP-5. The areas identified for unrisked discovered PIIP were mapped seismically from hydrocarbon-bearing zones identified within the four wells (Figures 68–69).

Unrisked discovered petroleum initially-in-place (Discovered PIIP) has been assigned to seven prospects to the southeast of the X-cut fault and two areas in northwest of X-cut fault identified on the current 3D seismic, based on geobodies identified in the seismic interpretation. These leads have been assessed using probabilistic models developed in *GeoX*. The ranges of input parameters are summarized in Figure 89.

Table D-1A												
Summary of Gross Unrisked Discovered Petroleum Initially-In-Place (PIIP), Deep Omicron Formation,[1,2]												
MLHP 5 and 6 (Etinde) Block, Douala Basin, Offshore Cameroon,												
Estimated by Sproule International Limited, As of September 30, 2012												
Prospect	Oil (MMbbl)[3]				Associated Gas (BCF)[3]				Total Resources (MMBOE)[3]			
	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean
SE Area (Sapele 1, 1ST, 2)												
SE-1	11.4	30.7	77.3	39.6	45.9	125.3	331.2	166.1	20.0	53.3	136.1	69.2
SE-2	0.8	2.9	7.5	3.7	3.3	11.7	31.8	15.3	1.4	5.0	13.1	6.4
SE-3	0.6	1.0	1.6	1.1	2.4	4.1	7.0	4.5	1.1	1.7	2.8	1.9
SE-4	3.6	8.4	16.4	9.4	14.1	34.2	69.9	39.2	6.1	14.5	28.8	16.3
SE-5	1.4	3.7	7.6	4.2	5.6	15.1	32.5	17.6	2.4	6.4	13.4	7.3
SE-6	4.2	11.4	26.9	14.0	17.2	46.3	115.2	58.6	7.4	19.7	47.2	24.4
SE-7	2.5	4.5	7.8	4.9	9.8	18.7	33.9	20.6	4.3	7.9	13.8	8.6
SE Total[4]	**43.9**	**68.9**	**116.9**	**76.2**	**178.4**	**285.4**	**502.1**	**318.9**	**73.7**	**116.7**	**202.6**	**130.2**
NW Area (Sapele 3)												
NW-8	0.4	0.8	1.4	0.8	1.5	3.2	6.0	3.5	0.7	1.3	2.5	1.5
NW-9	0.2	0.5	1.1	0.6	0.7	2.0	4.8	2.4	0.3	0.8	2.0	1.0
NW Total[4]	**0.8**	**1.3**	**2.2**	**1.4**	**3.1**	**5.5**	**9.5**	**6.0**	**1.3**	**2.3**	**3.8**	**2.4**
Grand Total[4]				**77.6**				**324.9**				**132.6**

Notes:

1. These are gross estimates independent of working interest before consideration of royalties or other encumbrances.

2. These are the gross unrisked discovered petroleum in-place estimates associated with hydrocarbon zones identified within the four wells (Sapele-1, -1ST, -2, -3). Discovered petroleum initially-in-place (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of the discovered initially-in-place includes production, reserves, and contingent resources; the remainder is unrecoverable.

3. "MMbbl" is millions of barrels, "BCF" is billion cubic feet, "MMboe" is millions of barrels of oil equivalent.

4. The total volumes reported are statistically aggregated and may not necessarily add up arithmetically.

The unrisked discovered PIIP for these mapped zones is summarized in Tables D-1A (gross) and Table D-1B (net at the Company's 75-percent working interest). Incorporation of recovery factors and shrinkage and estimation of the recoverable portion were beyond the scope defined by the Company. Economics were also not part of the sanctioned scope of this project.

Table D-1B												
Summary of Net Unrisked Discovered Petroleum Initially-In-Place (PIIP), Deep Omicron Formation,[1,2]												
MLHP 5 and 6 (Etinde) Block, Douala Basin, Offshore Cameroon,												
Estimated by Sproule International Limited, As of September 30, 2012												
Prospect	Oil (MMbbl)[3]				Associated Gas (BCF)[3]				Total Resources (MMBOE)[3]			
	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean
SE Area (Sapele 1, 1ST, 2)												
SE-1	8.6	23.0	58.0	29.7	34.4	94.0	248.4	124.6	15.0	40.0	102.1	51.9
SE-2	0.6	2.1	5.6	2.7	2.5	8.8	23.9	11.5	1.1	3.7	9.8	4.8
SE-3	0.5	0.7	1.2	0.8	1.8	3.1	5.2	3.3	0.8	1.3	2.1	1.4
SE-4	2.7	6.3	12.3	7.0	10.6	25.7	52.4	29.4	4.6	10.9	21.6	12.2
SE-5	1.1	2.8	5.7	3.2	4.2	11.3	24.4	13.2	1.8	4.8	10.1	5.5
SE-6	3.2	8.6	20.2	10.5	12.9	34.7	86.4	44.0	5.5	14.8	35.4	18.3
SE-7	1.9	3.4	5.9	3.7	7.4	14.0	25.4	15.5	3.2	5.9	10.4	6.4
SE Total[4]	**32.9**	**51.7**	**87.7**	**57.2**	**133.8**	**214.1**	**376.6**	**239.2**	**55.3**	**87.5**	**152.0**	**97.7**
NW Area (Sapele 3)												
NW-8	0.3	0.6	1.1	0.6	1.1	2.4	4.5	2.6	0.5	1.0	1.8	1.1
NW-9	0.1	0.4	0.8	0.4	0.5	1.5	3.6	1.8	0.2	0.6	1.5	0.8
NW Total[4]	**0.6**	**1.0**	**1.7**	**1.1**	**2.3**	**4.1**	**7.1**	**4.5**	**1.0**	**1.7**	**2.8**	**1.8**
Grand Total[4]				**58.2**				**243.6**				**99.5**

Notes:

1. These are net estimates for the Company's 75% working interest, before consideration of royalties or other encumbrances.

2. These are the gross unrisked discovered petroleum in-place estimates associated with hydrocarbon zones identified within the four wells (Sapele-1, -1ST, -2, -3). Discovered petroleum initially-in-place (equivalent to discovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production. The recoverable portion of the discovered initially-in-place includes production, reserves, and contingent resources; the remainder is unrecoverable.

3. "MMbbl" is millions of barrels, "BCF" is billion cubic feet, "MMboe" is millions of barrels of oil equivalent.

4. The total volumes reported are statistically aggregated and may not necessarily add up arithmetically.

Input distributions for the area were developed from the seismic interpretation. The geobodies identified by the seismic are tied to the sands that either flowed oil on DST or oil samples were collected using the MDT sampling method. The ranges for the reservoir parameters such as net pay thickness, porosity and water saturation for each of these prospects were obtained from the petrophysical interpretation of the reservoir sands that flowed oil on DST or the reservoir sands with MDT sampling.

5.3 Unrisked Undiscovered Petroleum Initially-in-Place

Unrisked undiscovered PIIP leads were identified using the various 3D seismic volumes. The areas identified for unrisked undiscovered PIIP were mapped seismically from amplitude geobodies identified outside of the current well control on various 3D seismic volumes (Figures 87 and 88).

Table D-2A

Summary of Gross Unrisked Undiscovered Petroleum Initially-In-Place (PIIP), Deep Omicron Formation,[1,2]

MLHP 5 and 6 (Etinde) Block, Douala Basin, Offshore Cameroon

Estimated by Sproule International Limited, As of September 30, 2012

Prospect	Oil (MMbbl)				Associated Gas (BCF)				Total Resources (MMBOE)			
	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean
SE Area (Sapele 1, 1ST, 2)												
SE Near-Far-Peak-14	16.1	30.6	55.4	33.7	63.7	125.4	237.8	141.5	27.0	51.6	94.5	57.3
SE-Near Peak-15	10.2	18.6	32.3	20.2	40.2	76.7	140.3	84.8	17.1	31.5	55.2	34.4
SE-Near-Peak-16	12.0	21.7	37.6	23.6	47.1	89.8	163.1	98.9	20.1	36.8	64.2	40.1
SE-Near-Peak-17	6.1	11.0	19.1	12.0	23.9	45.6	82.8	50.2	10.2	18.7	32.6	20.3
SE-Near-Peak-18	5.8	10.4	18.0	11.3	22.6	43.0	78.2	47.4	9.6	17.6	30.8	19.2
SE-Near-Trough-19	10.6	19.2	33.3	20.9	41.8	79.6	144.7	87.7	17.8	32.6	57.0	35.5
SE-Near-Trough-21	6.7	12.0	20.8	13.1	26.1	49.8	90.5	54.8	11.1	20.4	35.6	22.2
SE-Far-Trough-22	31.7	57.3	99.2	62.3	124.4	237.1	430.9	261.1	53.0	97.2	169.7	105.8
65 feet upside	4.7	7.7	12.5	8.2	18.3	31.9	54.2	34.5	7.9	13.1	21.3	14.0
SE Area Total[4]	**160.9**	**201.8**	**253.5**	**205.0**	**657.3**	**839.6**	**1086.2**	**858.9**	**272.3**	**343.2**	**433.1**	**348.9**
NW Area (Sapele 3)												
NW Near Peak Far Trough 1	39.2	73.6	130.6	80.6	155.4	302.0	561.5	337.9	66.0	124.4	223.2	136.9
NW Near Peak Far Peak 2	3.0	5.6	9.8	6.1	11.9	22.9	42.2	25.5	5.1	9.4	16.7	10.3
NW Near Peak 3	0.9	1.6	2.7	1.7	3.4	6.5	11.9	7.2	1.5	2.7	4.7	2.9
NW Near Peak 4	3.8	6.9	12.0	7.5	14.9	28.5	52.1	31.5	6.4	11.7	20.5	12.8
NW Near Peak 5	15.5	28.1	48.8	30.6	60.7	115.9	212.0	128.2	25.9	47.6	83.4	51.9
NW Near Peak 6	106.7	194.0	336.8	211.1	419.3	800.0	1463.6	885.0	178.9	328.3	575.5	358.6
NW Near Peak 7	3.8	7.0	12.1	7.6	15.0	28.7	52.5	31.7	6.4	11.8	20.6	12.9
NW Near Peak 8	0.9	1.6	2.7	1.7	3.4	6.5	11.9	7.2	1.5	2.7	4.7	2.9
NW Near Trough 9	4.5	8.2	14.2	8.9	17.7	33.8	61.9	37.4	7.6	13.9	24.3	15.2
NW Near Trough 10	11.3	20.6	35.8	22.4	44.6	85.0	155.5	94.0	19.0	34.9	61.2	38.1
NW Far Peak 11	11.9	21.6	37.5	23.5	46.7	89.0	162.9	98.5	19.9	36.5	64.0	39.9
NW Far Peak 12	7.0	12.8	22.2	13.9	27.6	52.7	96.4	58.3	11.8	21.6	37.9	23.6
NW Final Stack 13	6.1	11.0	19.1	12.0	23.8	45.3	83.0	50.2	10.1	18.6	32.6	20.3
NW Area Total[4]	**308.3**	**412.2**	**564.2**	**426.0**	**1257.8**	**1710.2**	**2424.7**	**1788.0**	**522.3**	**701.3**	**964.1**	**725.9**
Grand Total[4]				**631.0**				**2646.9**				**1074.8**

Notes:

1. These are gross estimates independent of working interest before consideration of royalties or other encumbrances.

2. Undiscovered petroleum initially-in-place (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in accumulations yet to be discovered. These estimates are based upon seismic anomalies identified outside of the known well control at the Sapele-1, -1ST, -2, -3 wells. The recoverable portion of the undiscovered initially-in-place is referred to "prospective resources", the remainder as "unrecoverable".

3. "MMbbl" is millions of barrels, "BCF" is billion cubic feet, "MMboe" is millions of barrels of oil equivalent.

4. The total volumes reported are statistically aggregated and may not necessarily add up arithmetically.

The unrisked undiscovered PIIP for these mapped zones is summarized in Tables D-2A (gross) and Table D-2B (net at the Company's 75-percent working interest). Incorporation of recovery factors and shrinkage and estimation of the recoverable portion were beyond the scope defined by the Company. Economics were also not part of the sanctioned scope of this project.

Table D-2B
Summary of Net Unrisked Undiscovered Petroleum Initially-In-Place (PIIP), Deep Omicron Formation,[1,2]
MLHP 5 and 6 (Etinde) Block, Douala Basin, Offshore Cameroon
Estimated by Sproule International Limited, As of September 30, 2012

Prospect	Oil (MMbbl)				Associated Gas (BCF)				Total Resources (MMBOE)			
	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean	Low (P90)	Best (P50)	High (P10)	Mean
SE Area (Sapele 1, 1ST, 2)												
SE Near-Far-Peak-14	12.1	23.0	41.6	25.3	47.8	94.1	178.4	106.1	20.3	38.7	70.9	43.0
SE-Near Peak-15	7.7	14.0	24.2	15.2	30.2	57.5	105.2	63.6	12.8	23.6	41.4	25.8
SE-Near-Peak-16	9.0	16.3	28.2	17.7	35.3	67.4	122.3	74.2	15.1	27.6	48.2	30.1
SE-Near-Peak-17	4.6	8.3	14.3	9.0	17.9	34.2	62.1	37.7	7.7	14.0	24.5	15.2
SE-Near-Peak-18	4.3	7.8	13.5	8.5	17.0	32.3	58.7	35.6	7.2	13.2	23.1	14.4
SE-Near-Trough-19	8.0	14.4	25.0	15.7	31.4	59.7	108.5	65.8	13.4	24.5	42.8	26.6
SE-Near-Trough-21	5.0	9.0	15.6	9.8	19.6	37.4	67.9	41.1	8.3	15.3	26.7	16.7
SE-Far-Trough-22	23.8	43.0	74.4	46.7	93.3	177.8	323.2	195.8	39.8	72.9	127.3	79.4
65 feet upside	3.5	5.8	9.4	6.2	13.7	23.9	40.7	25.9	5.9	9.8	16.0	10.5
SE Area Total[4]	**120.7**	**151.4**	**190.1**	**153.8**	**493.0**	**629.7**	**814.7**	**644.2**	**204.2**	**257.4**	**324.8**	**261.7**
NW Area (Sapele 3)												
NW Near Peak Far Trough 1	29.4	55.2	98.0	60.5	116.6	226.5	421.1	253.4	49.5	93.3	167.4	102.7
NW Near Peak Far Peak 2	2.3	4.2	7.3	4.6	8.9	17.2	31.7	19.1	3.8	7.1	12.5	7.7
NW Near Peak 3	0.7	1.2	2.0	1.3	2.6	4.9	8.9	5.4	1.1	2.0	3.5	2.2
NW Near Peak 4	2.9	5.2	9.0	5.6	11.2	21.4	39.1	23.6	4.8	8.8	15.4	9.6
NW Near Peak 5	11.6	21.1	36.6	23.0	45.5	86.9	159.0	96.2	19.4	35.7	62.6	38.9
NW Near Peak 6	80.0	145.5	252.6	158.3	314.5	600.0	1097.7	663.8	134.2	246.2	431.6	269.0
NW Near Peak 7	2.9	5.2	9.1	5.7	11.3	21.5	39.4	23.8	4.8	8.9	15.5	9.7
NW Near Peak 8	0.7	1.2	2.0	1.3	2.6	4.9	8.9	5.4	1.1	2.0	3.5	2.2
NW Near Trough 9	3.4	6.2	10.7	6.7	13.3	25.4	46.4	28.1	5.7	10.4	18.2	11.4
NW Near Trough 10	8.5	15.5	26.9	16.8	33.5	63.8	116.6	70.5	14.3	26.2	45.9	28.6
NW Far Peak 11	8.9	16.2	28.1	17.6	35.0	66.8	122.2	73.9	14.9	27.4	48.0	29.9
NW Far Peak 12	5.3	9.6	16.7	10.4	20.7	39.5	72.3	43.7	8.9	16.2	28.4	17.7
NW Final Stack 13	4.5	8.3	14.3	9.0	17.9	34.0	62.3	37.7	7.6	14.0	24.5	15.2
NW Area Total[4]	**231.2**	**309.2**	**423.2**	**319.5**	**943.4**	**1282.7**	**1818.5**	**1341.0**	**391.7**	**526.0**	**723.1**	**544.4**
Grand Total[4]				**473.3**				**1985.2**				**806.1**

Notes:

1. These are net estimates for the Company's 75% working interest, before consideration of royalties or other encumbrances.

2. Undiscovered petroleum initially-in-place (equivalent to undiscovered resources) is that quantity of petroleum that is estimated, as of a given date, to be contained in accumulations yet to be discovered. These estimates are based upon seismic anomalies identified outside of the known well control at the Sapele-1, -1ST, -2, -3 wells. The recoverable portion of the undiscovered initially-in-place is referred to "prospective resources", the remainder as "unrecoverable".

3. "MMbbl" is millions of barrels, "BCF" is billion cubic feet, "MMboe" is millions of barrels of oil equivalent.

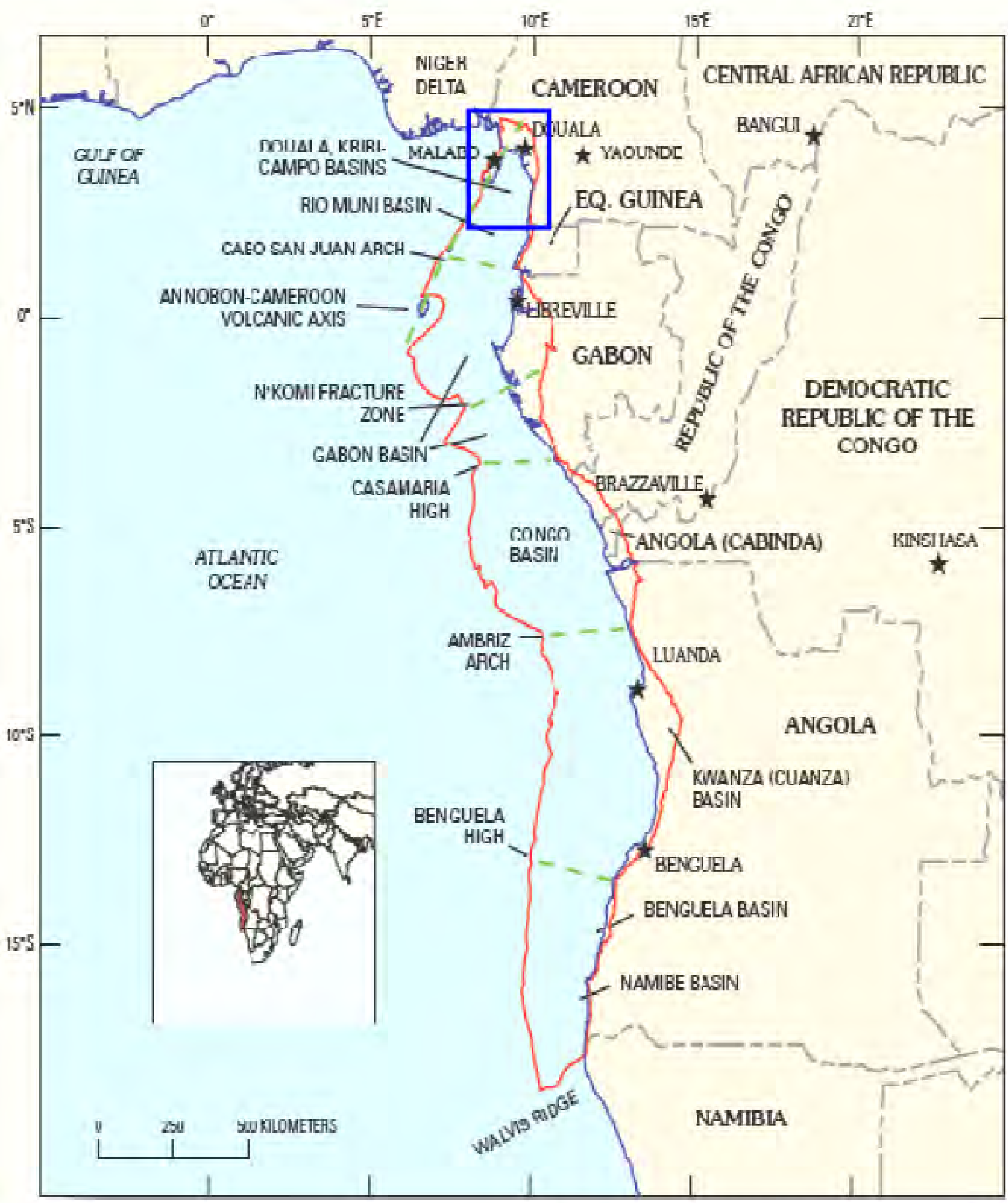
4. The total volumes reported are statistically aggregated and may not necessarily add up arithmetically.

Unrisked undiscovered petroleum initially-in-place (Undiscovered PIIP) has been estimated for 9 undrilled prospects in the SE area and 13 prospects in the northwest area identified on the current 3D seismic, based on geobodies identified in the seismic interpretation through 3D voxel visualization. These leads have been assessed using probabilistic models developed in *GeoX*. The ranges of input parameters are summarized in Figure 90.

Input distributions for the area were developed from the seismic interpretation; net pay thickness, porosity and water saturation ranges for each of the prospects were estimated from well logs. For all leads, reservoir parameters have been taken from the four Sapele-1, -1ST, -2 and -3 wells.

All of the prospects are expected to be oil-prone and have been modelled as containing oil with associated gas. The solution gas volumes are calculated and then reported in barrels of oil equivalent.

The prospects have been assessed using probabilistic models developed in *GeoX*. The ranges of input parameters are summarized in Figure 89.

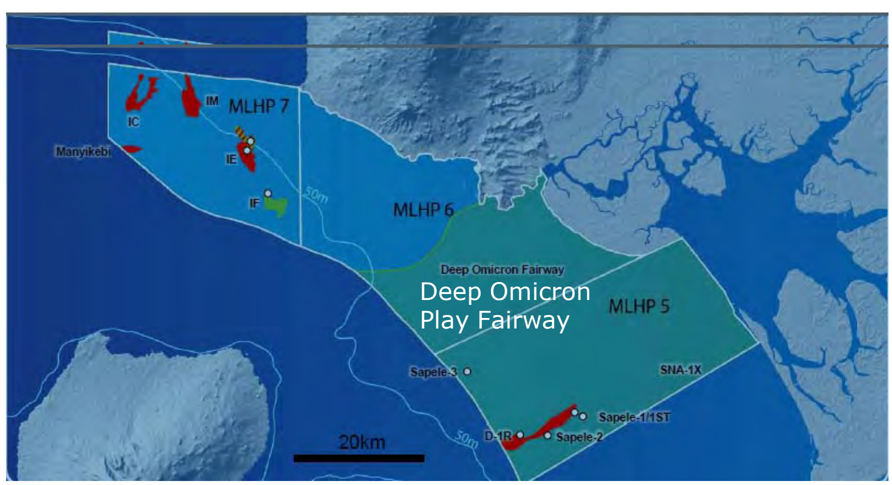


(from Company Presentation after USGS Bulletin 2207-B)

Location Map For West Africa

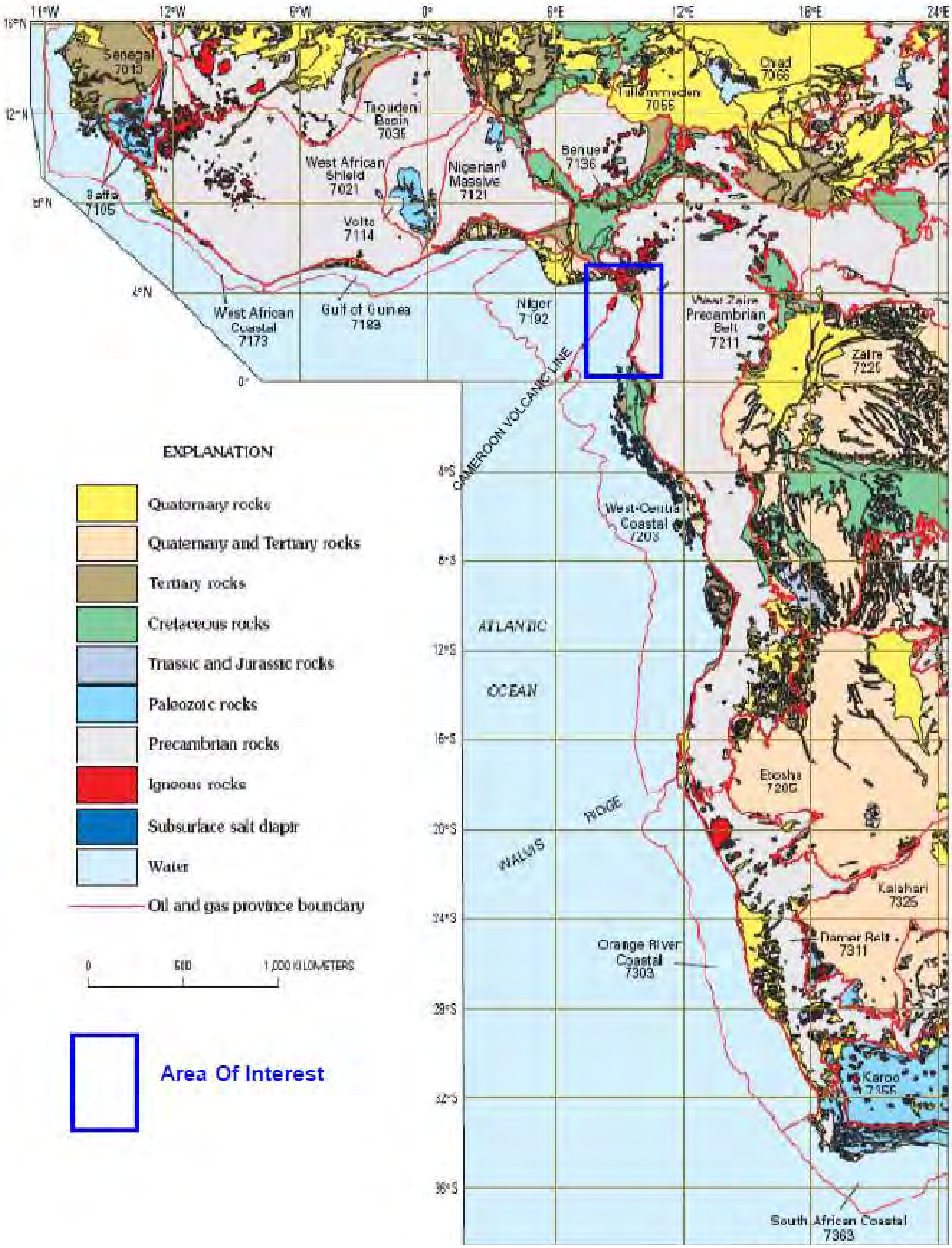
Figure 2

from GoogleEarth



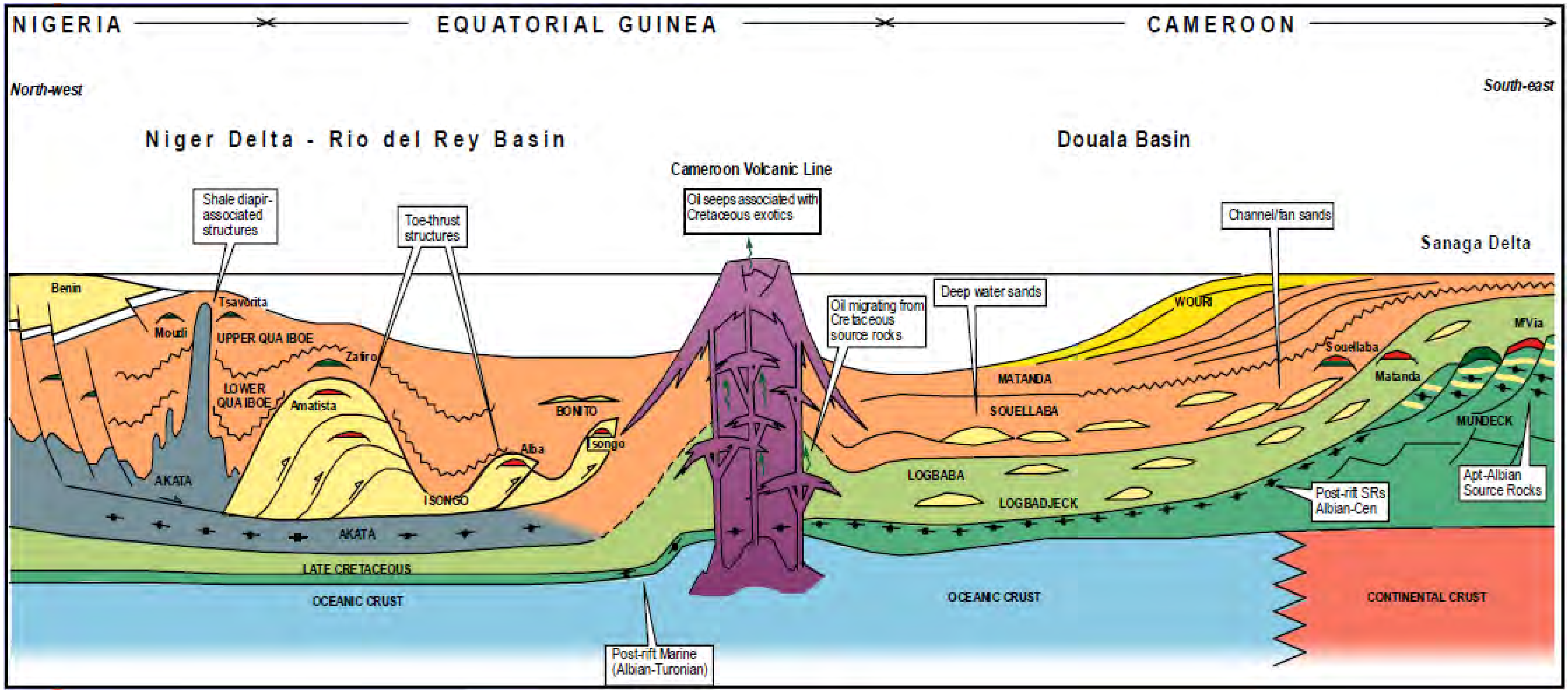
from Commonwealth Secretariat, Bowleven plc.

Block MLHP-5 and MLHP-6 Concessions, Deep Omicron Play Fairway



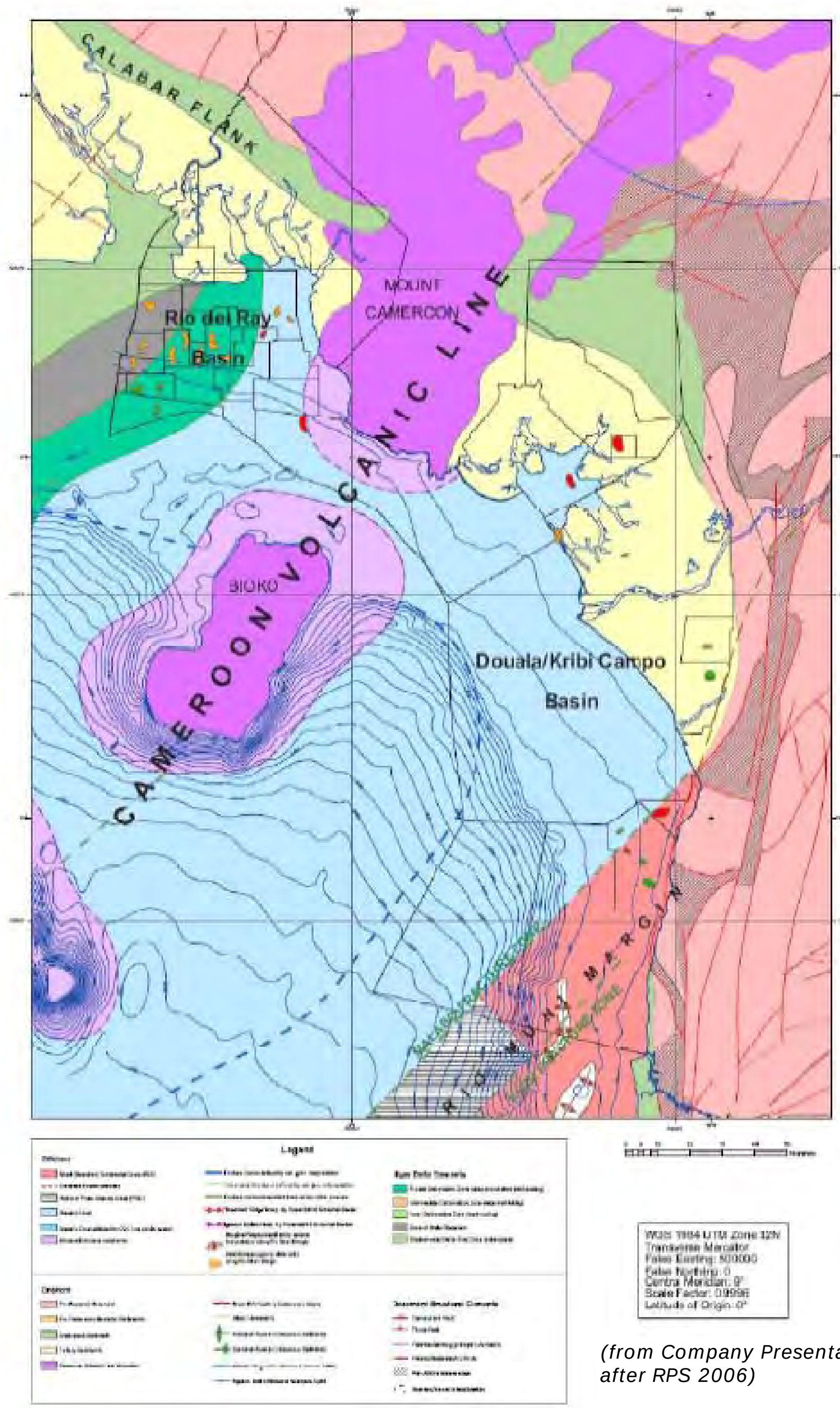
(from Company Presentation after USGS Bulletin 2207-B)

Geological Map of West Africa



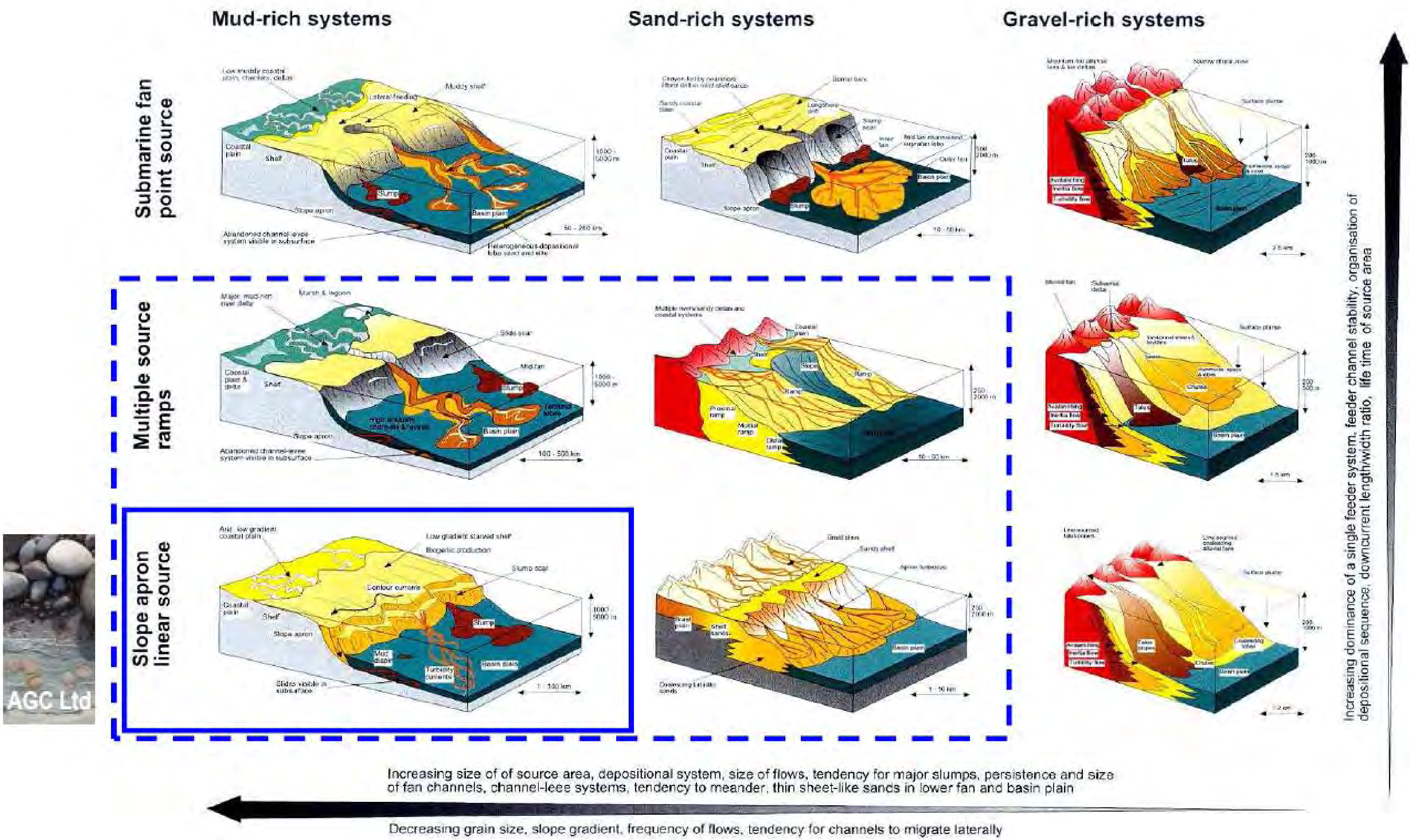
from Company presentation

Schematic Architecture of the Douala Basin



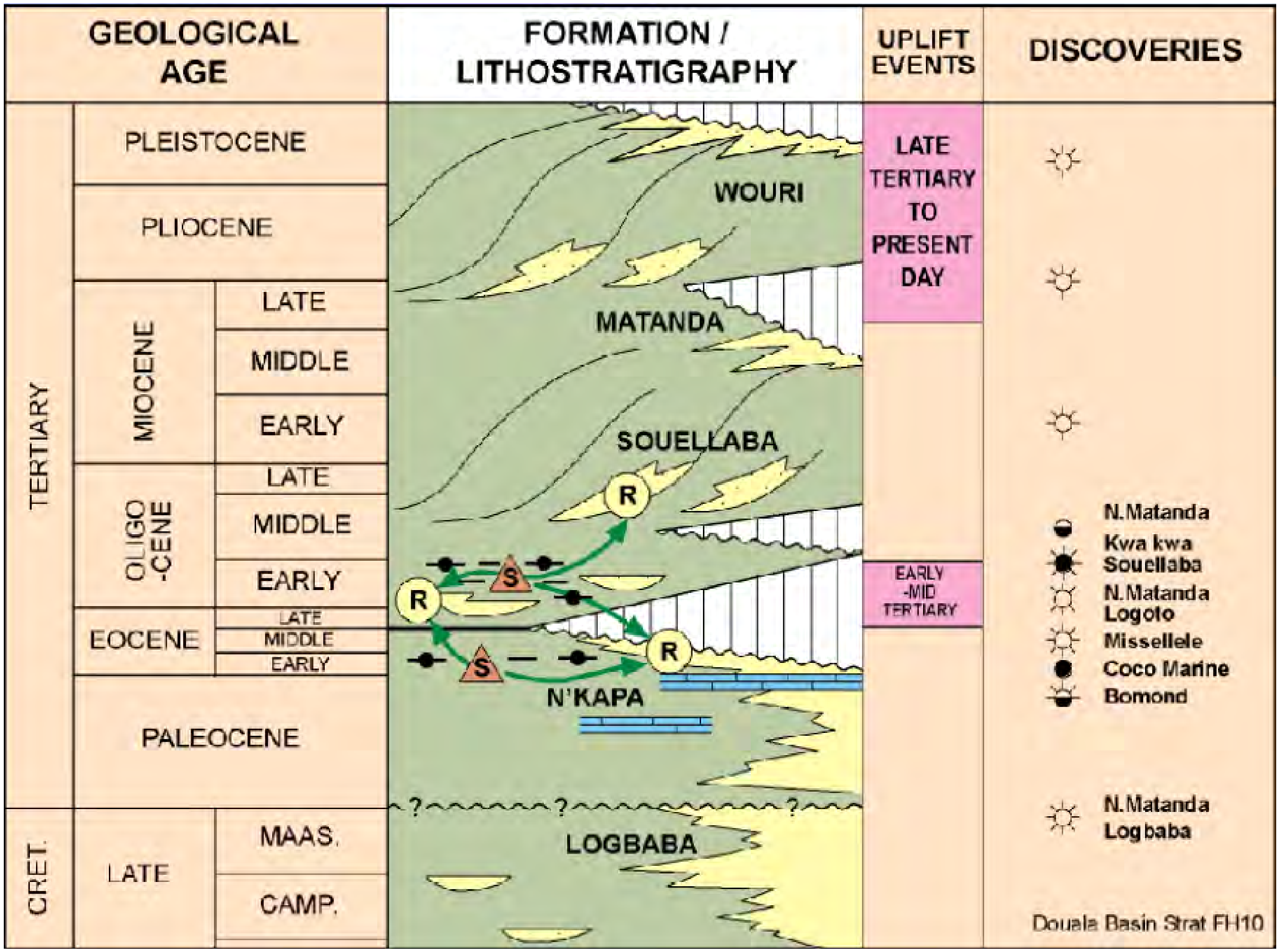
(from Company Presentation after RPS 2006)

Regional Geological Setting of the Douala and Kribi-Campo Basins



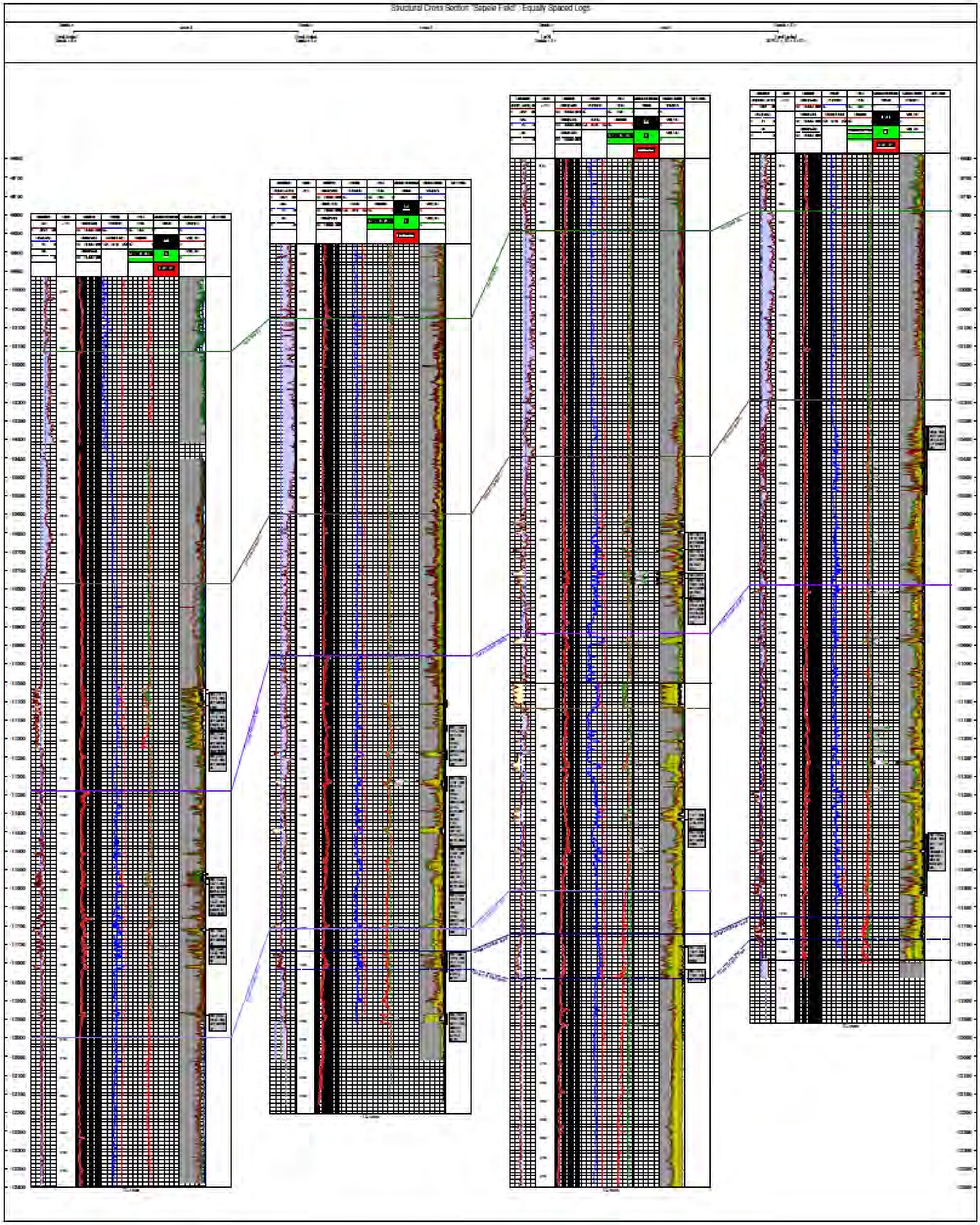
from figure provided by Company; (from AGC Ltd modified after Reading & Richards 1994, Fig 16, Idealized continental slope, ramp, and fan systems highlighting probable systems for Cameroon)

Proposed depositional model for Etinde Block MLHP-5

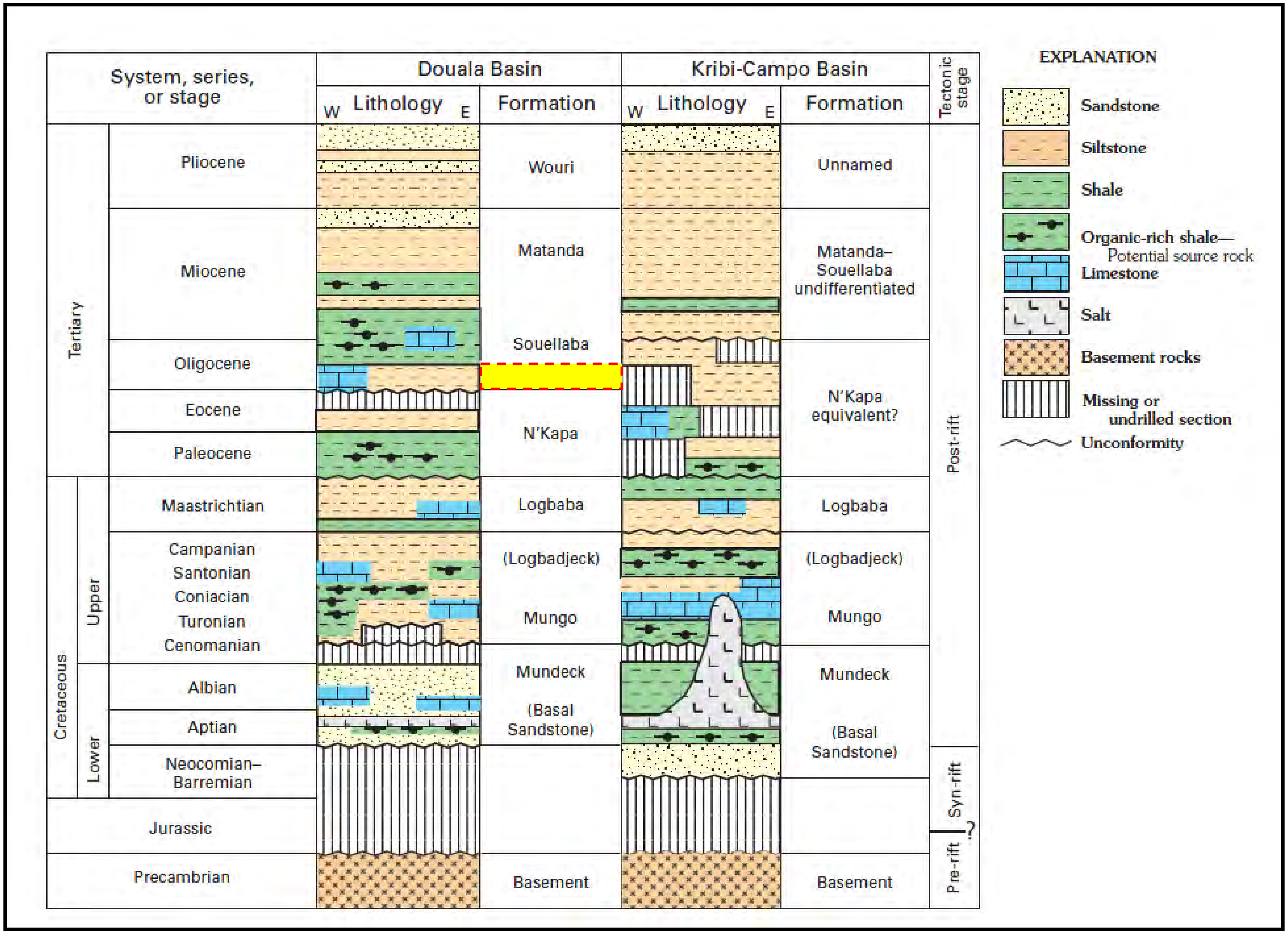


from ECL 2001

Stratigraphic Chart of the Douala Basin



Stratigraphic Correlation of the Omicron and Omicron Deep Formations in the Sapele wells

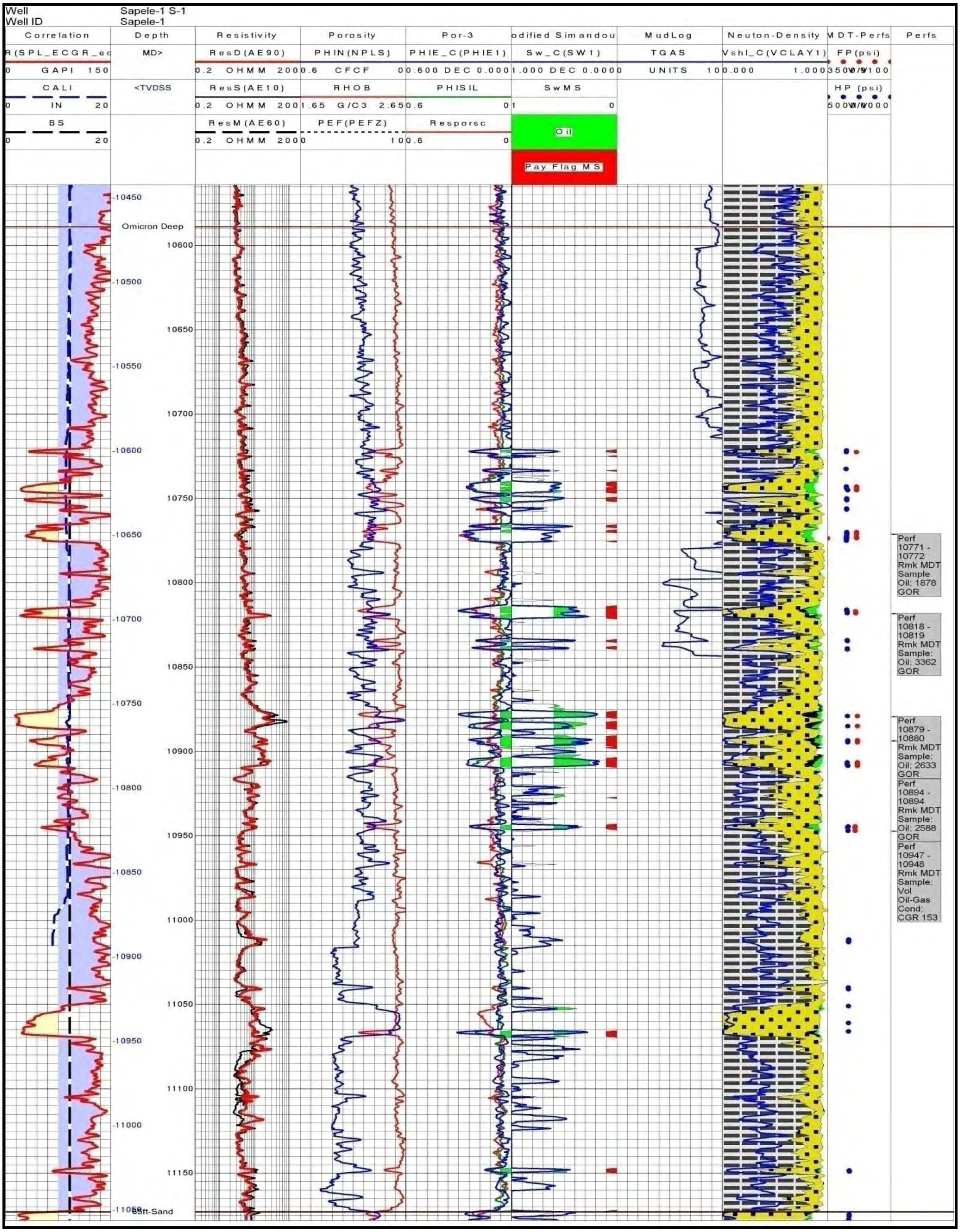


from image supplied by the Company odified from Nguene and others (1992), Tamfu and others (1995), and Oba (2001).

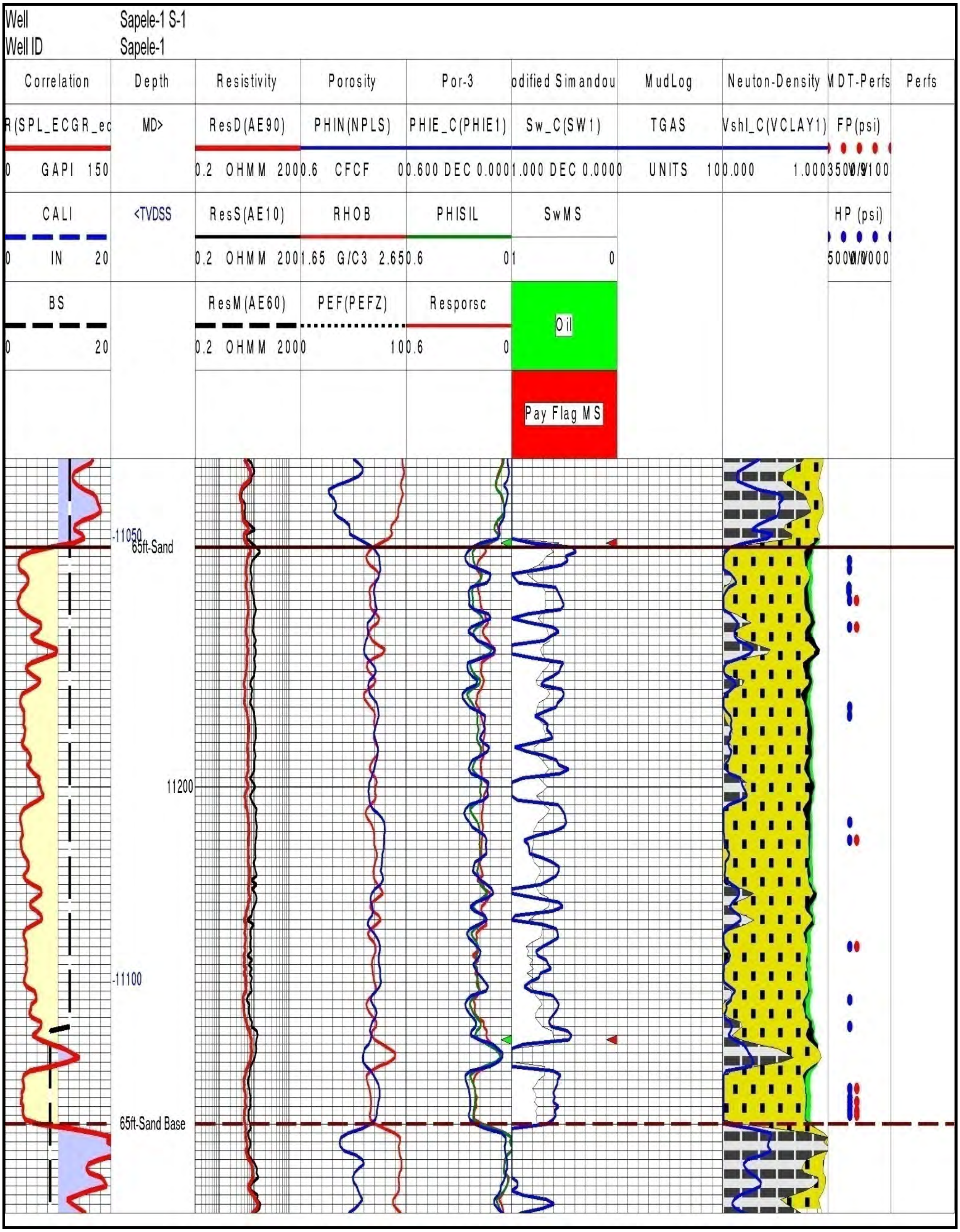
Generalized Stratigraphic Columns, Showing Ages, Formation Names, Lithology, Probable Source Rocks, and Tectonic Stages of the Douala and Kribi-Campo Aptian Salt Basins, Cameroon, Equatorial West Africa

Figure 9

Figure 10

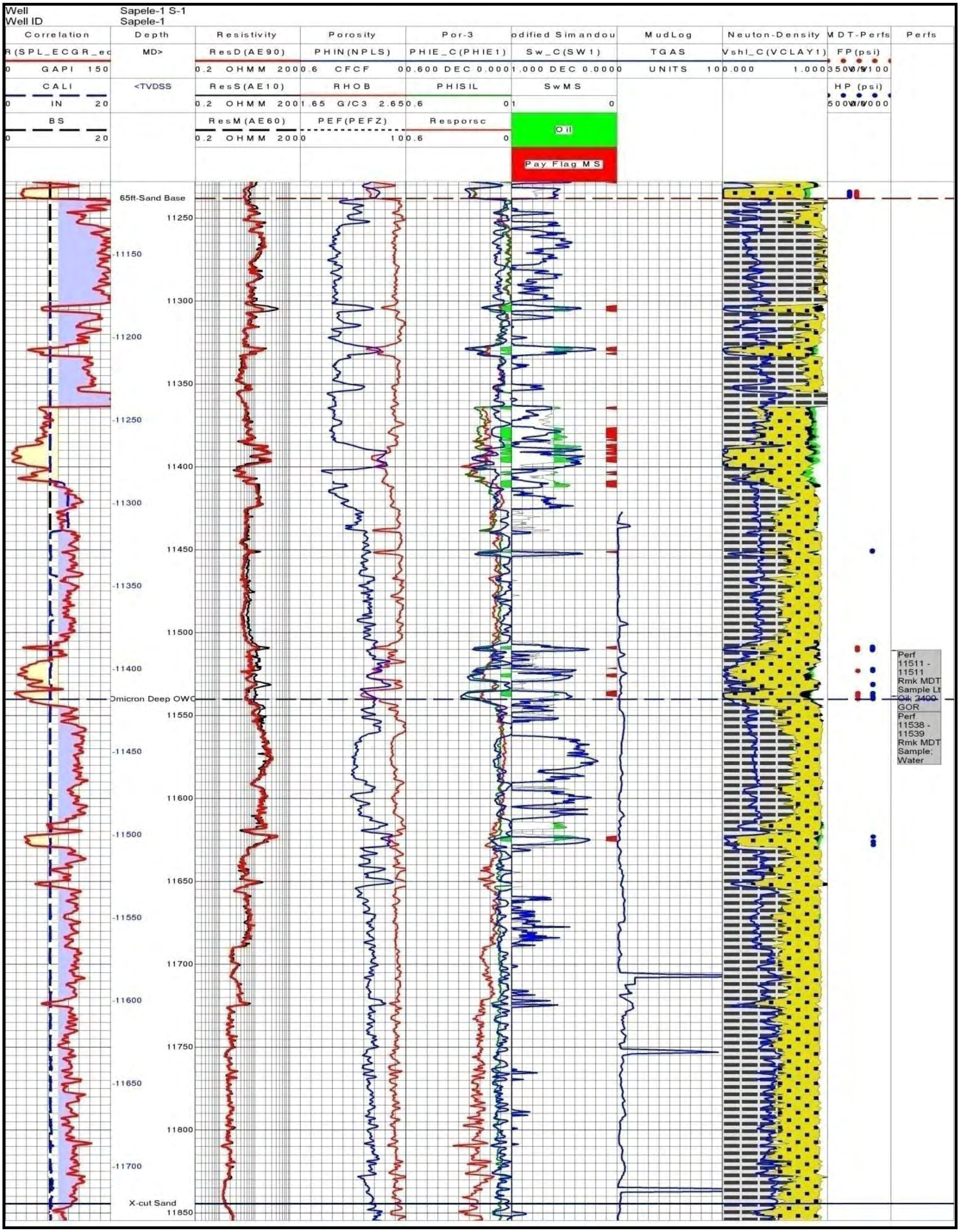


Sapele-1 Deep Omicron above 65' Sand Petrophysics Results

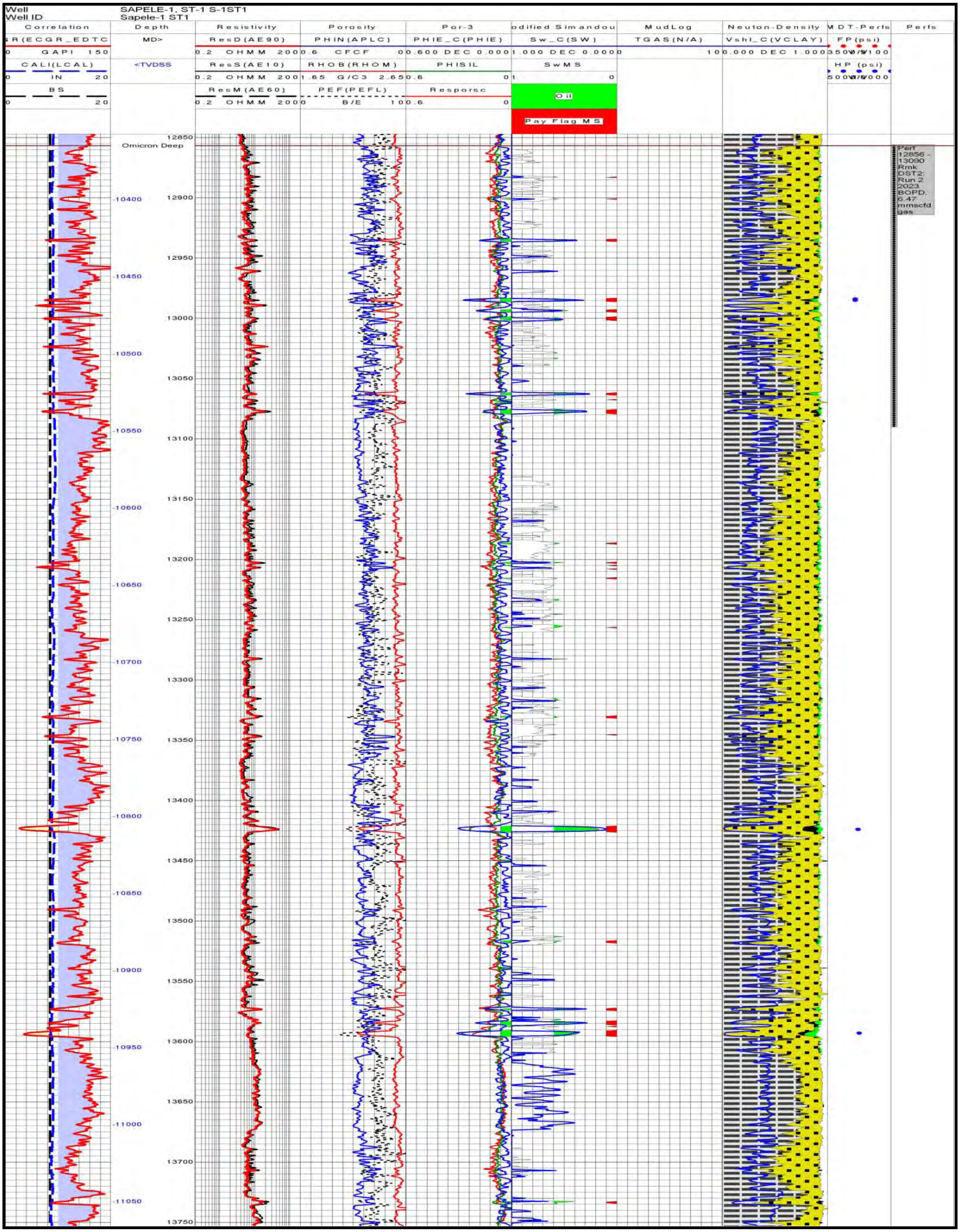


Sapele-1 65’ Sand Petrophysics Results

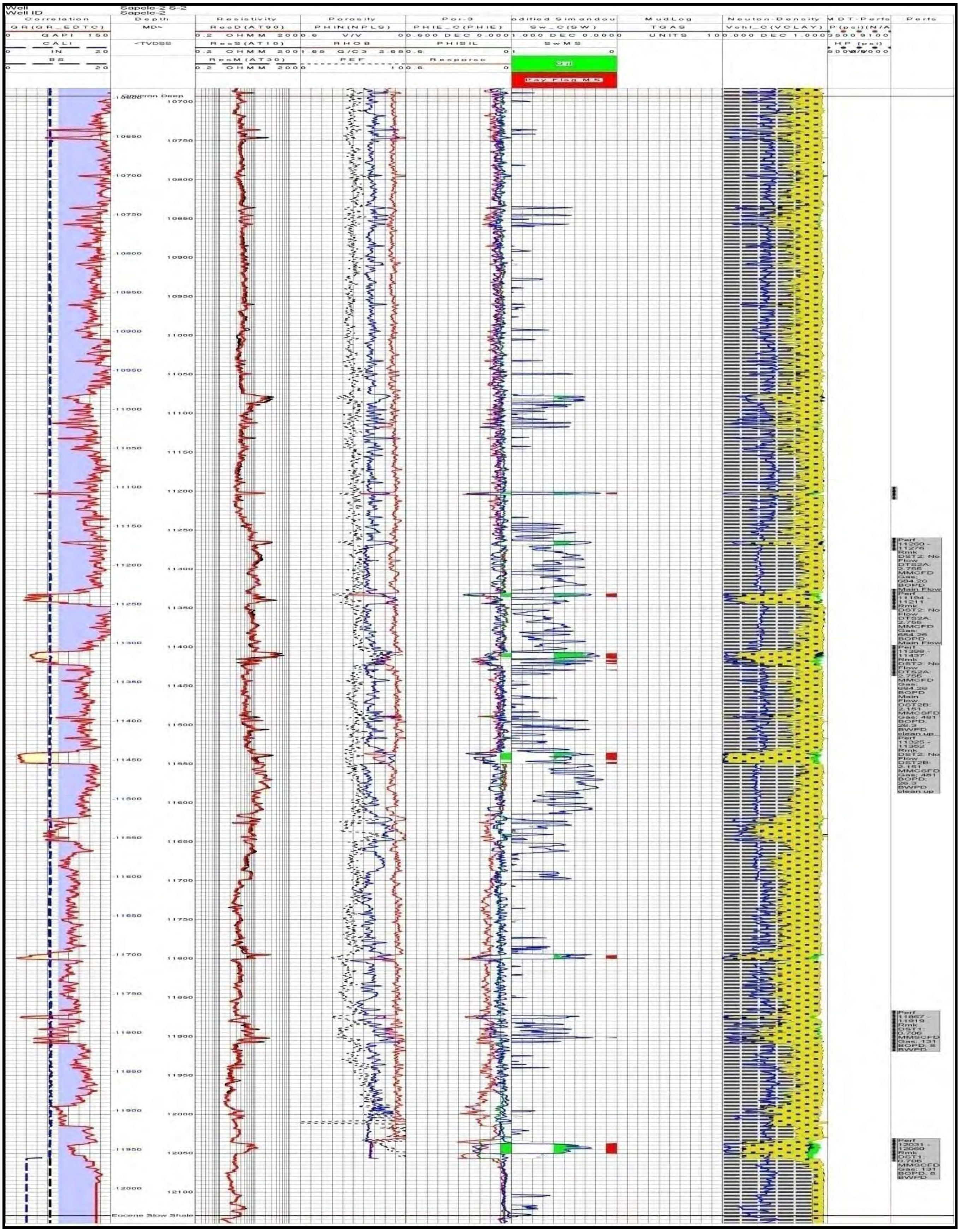
Sproule



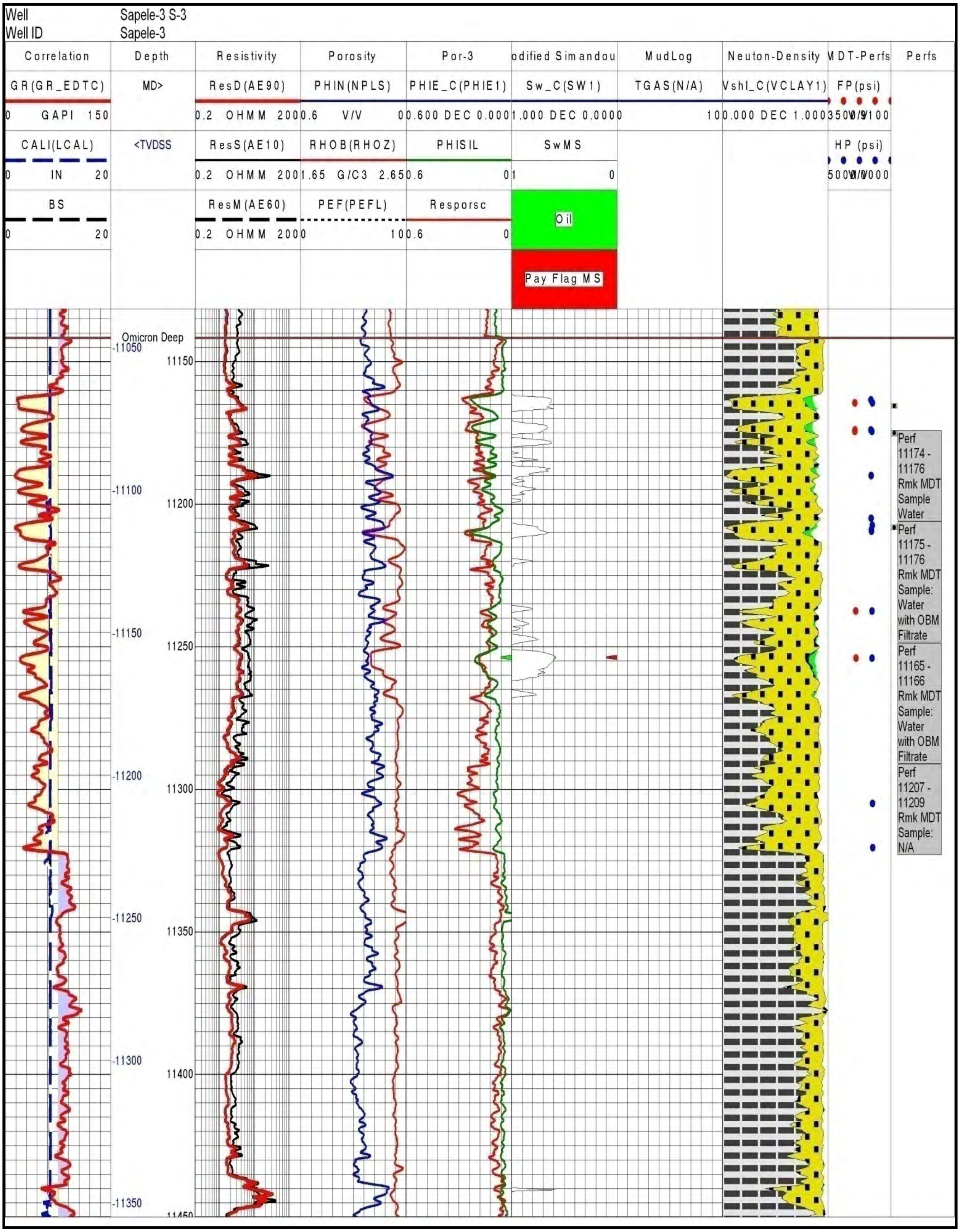
Sapele-1 Deep Omicron Below 65' Sand Petrophysics Results



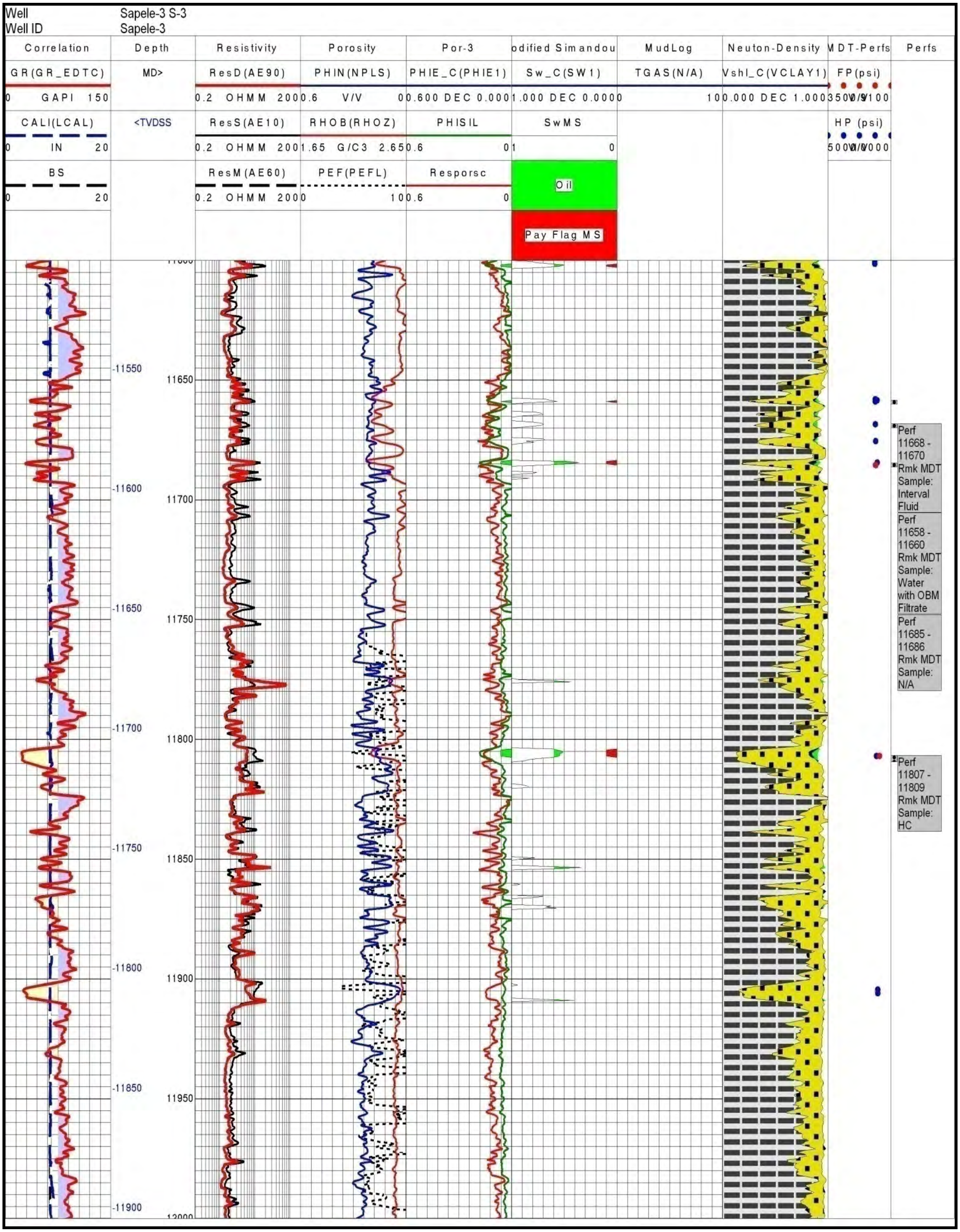
Sapele-1-ST1 Deep Omicron Sand Petrophysics Results



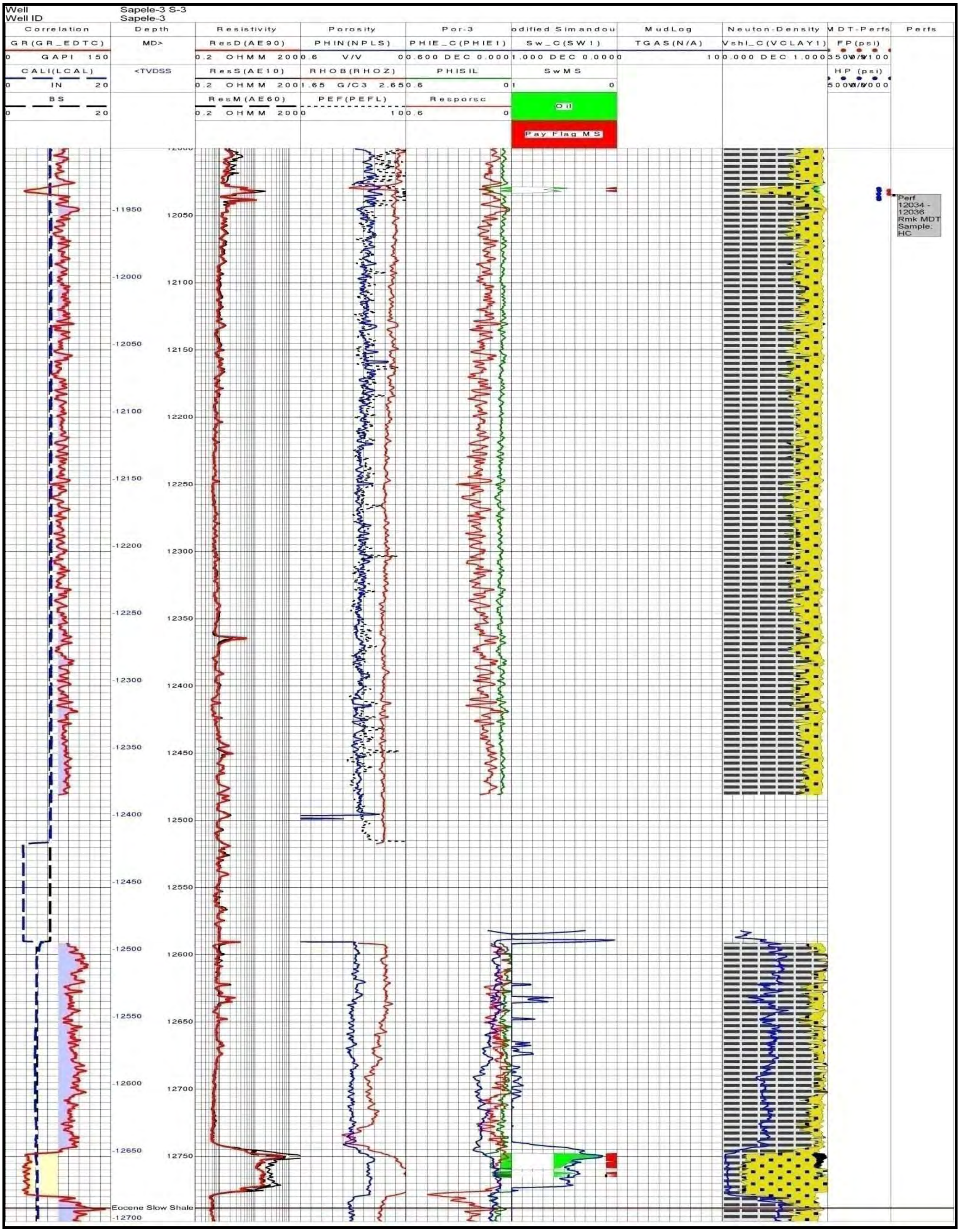
Sapele-2 Deep Omicron Sand Petrophysics Results



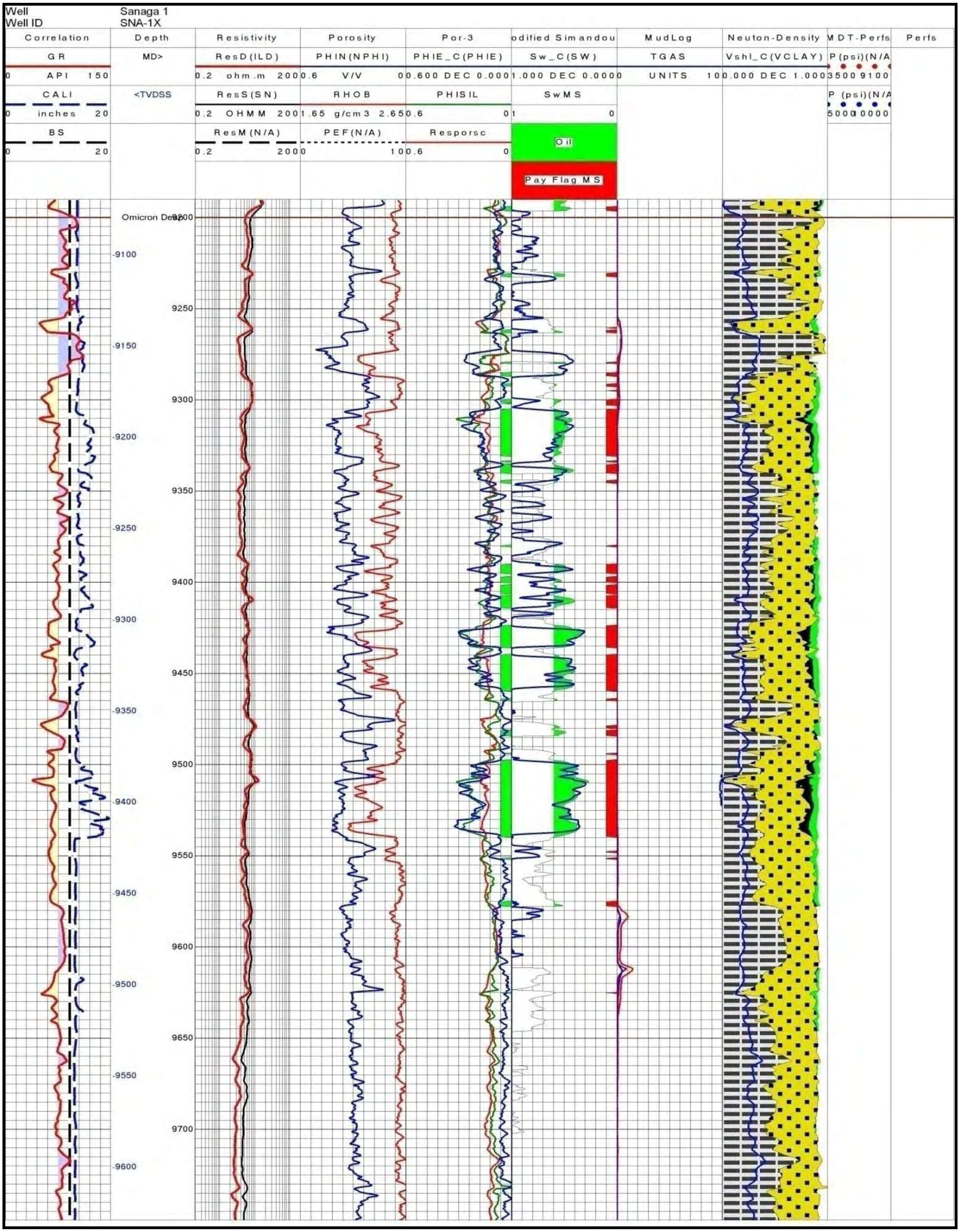
Sapele-3 Deep Omicron sand Petrophysics Results



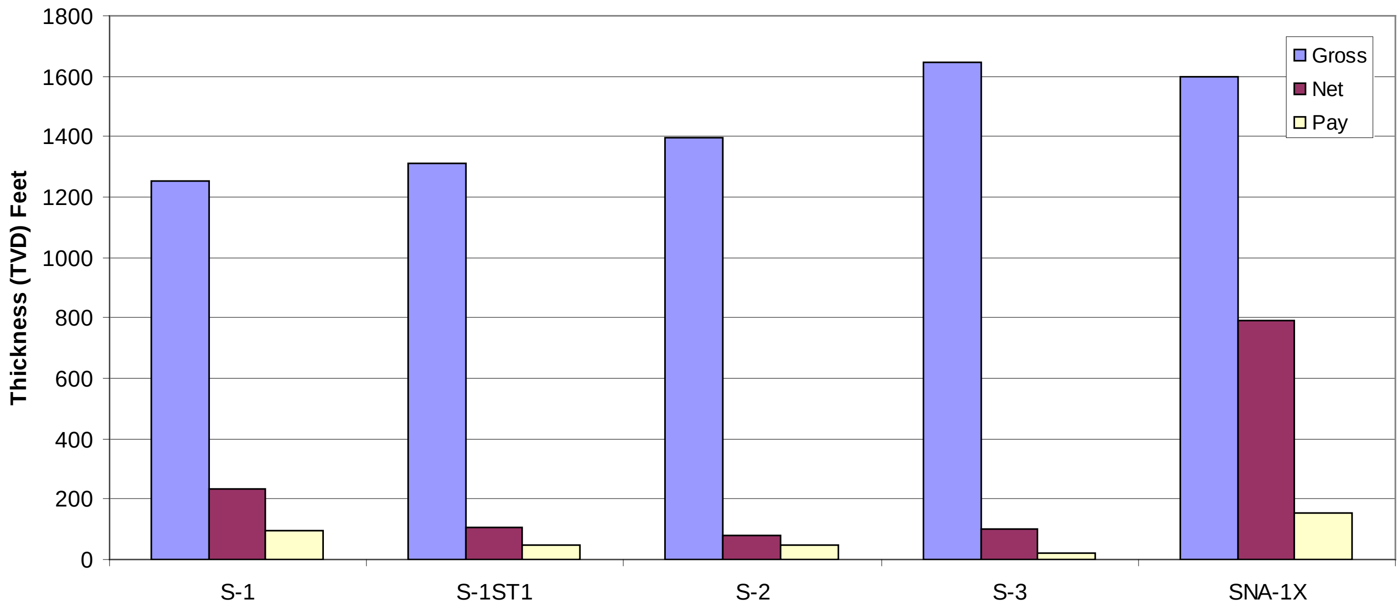
Sapele-3 Deep Omicron Sand Petrophysics Results



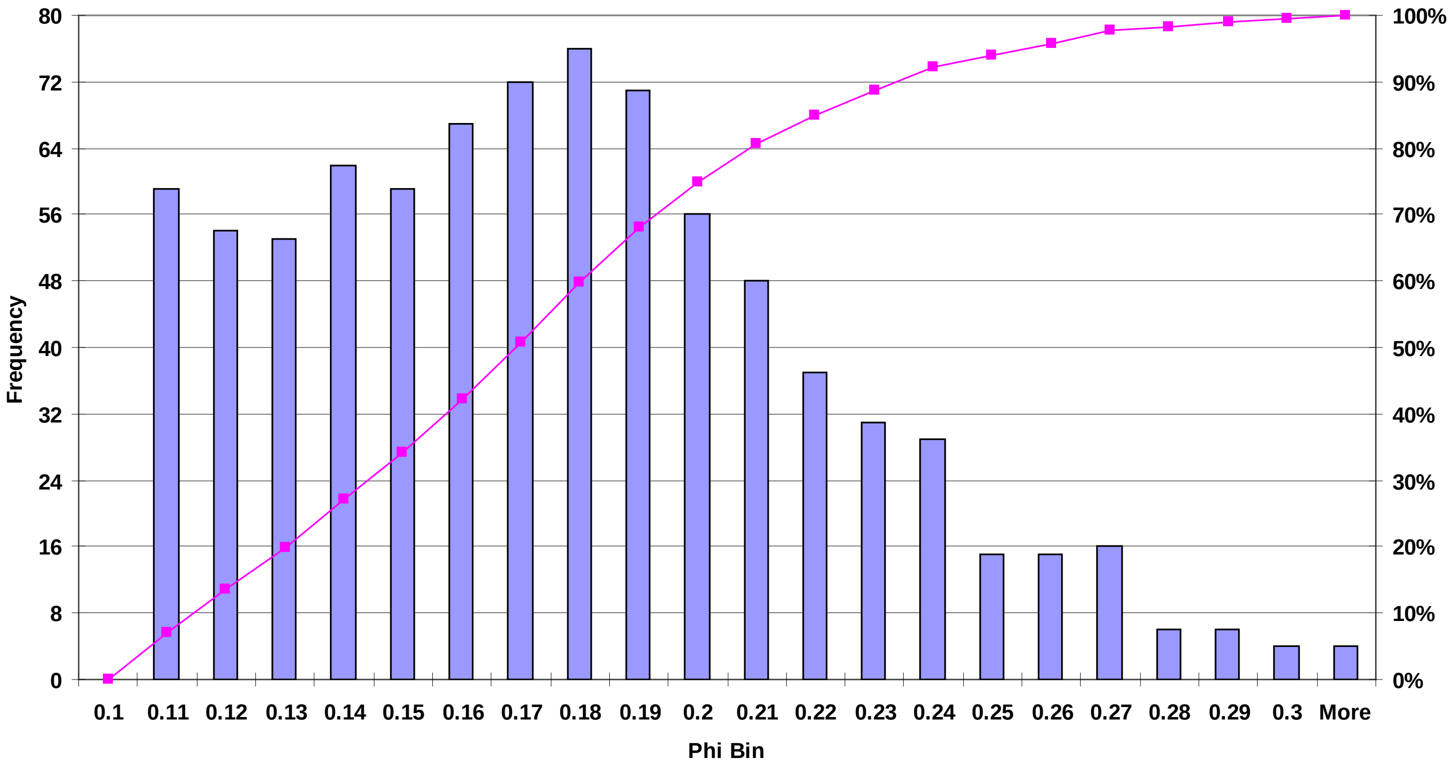
Sapele-3 Deep Omicron Sand Petrophysics Results



SNX-1A Deep Omicron Sand Petrophysics Results



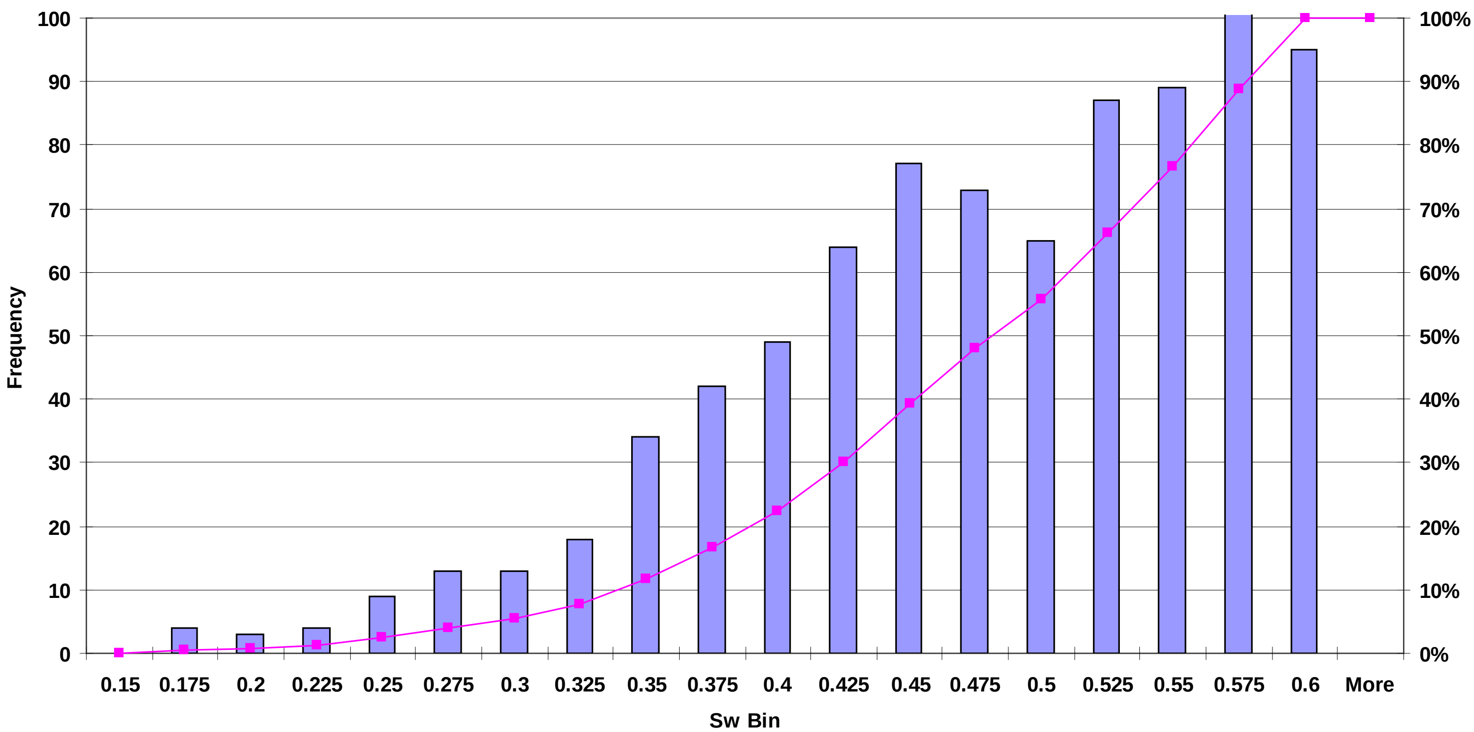
Deep Omicron Sand Thickness Comparison for the Five Wells



	P99	P90	P50	P10	P1	Dist
Phi-Pay	0.1	0.12	0.17	0.23	0.3	Ln

Effective Porosity Histogram for the Deep Omicron Sand Pay Intervals in the Five Wells

Sproule

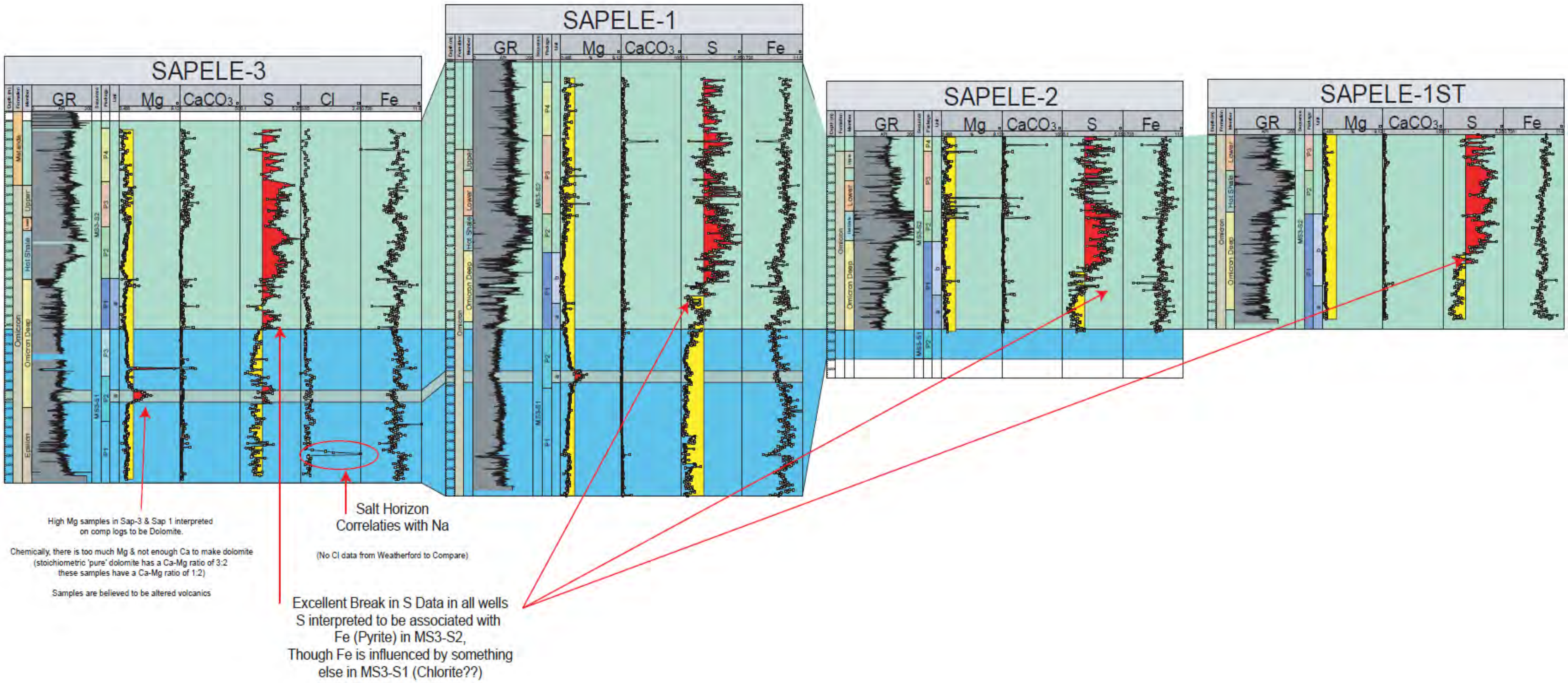


	P99	P90	P50	P10	P1	Dist
Sw	0.15	0.35	0.475	0.575	0.6	Str Beta
So	0.85	0.65	0.525	0.425	0.4	Ln

Water Saturation Histogram for the Deep Omicron Sand Pay Intervals in the Five Wells

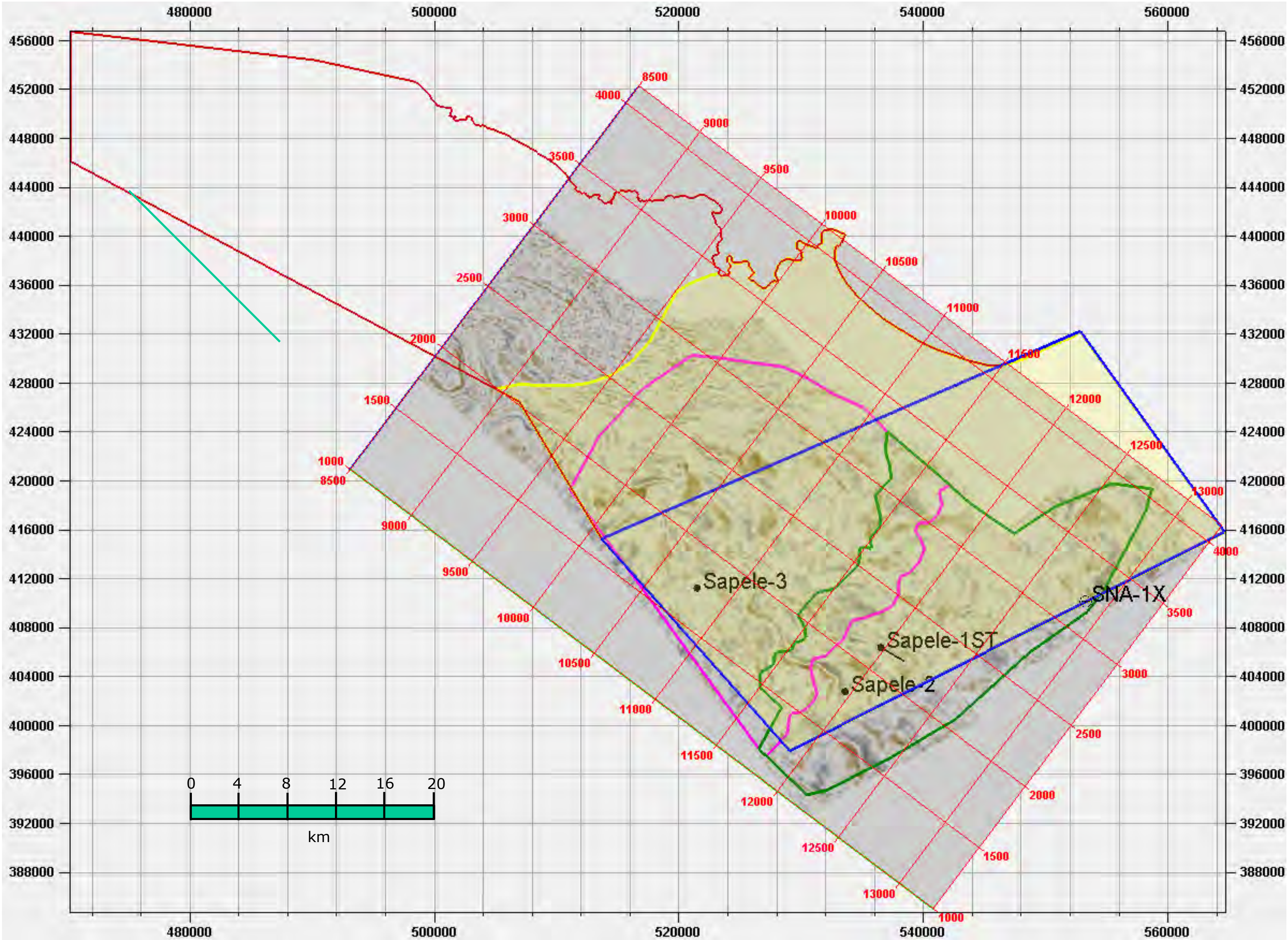
Summary of Petrophysical Parameters for Sapele 1, ST-1, 2, 3 and SNA-1X Wells															
Well	**Zone**	**Top**	**Base**	**Gross**		**NET**					**Pay (Modified Simandoux)**				
		Feet	**Feet**	**Feet**	**SS-Feet**	**Phi**	**Sw**	**Feet**	**SS-Feet**	**Vshl**	**Phi**	**Sw**	**Feet**	**SS-Feet**	**Vshl**
S-1	Upper Omicron	8,798.0	9,443.5	646.0	645.9	0.1	0.7	3.5	3.5	0.2	0.1	0.5	2.5	2.5	0.2
S-1	Lower Omicron	9,443.5	9,967.0	524.5	524.5	0.2	0.5	22.5	22.5	0.2	0.2	0.4	20.5	20.5	0.2
S-1	Omicron Deep	10,589.0	11,844.5	1,256.0	1,255.6	0.2	0.7	233.5	233.4	0.2	0.2	0.5	98.0	98.0	0.2
S-1	X-Cut Sands	11,844.5	11,964.0	120.0	119.9	0.1	0.9	45.0	45.0	0.2	0.2	0.5	1.5	1.5	0.1
S-1	Epsilon Complex	13,550.0	14,240.0	690.0	689.8	0.1	0.4	12.0	12.0	0.1	0.1	0.3	11.0	11.0	0.0
S-1ST1	Upper Omicron	10,690.5	11,394.0	703.5	506.6	0.2	0.7	103.0	72.2	0.1	0.2	0.5	20.5	14.3	0.2
S-1ST1	Lower Omicron	11,394.0	12,119.5	725.5	564.1	0.1	0.5	45.5	35.4	0.3	0.1	0.4	44.5	34.6	0.3
S-1ST1	Omicron Deep	12,857.0	14,580.5	1,723.5	1,311.8	0.1	0.8	142.0	107.5	0.3	0.2	0.4	60.5	46.9	0.2
S-1ST1	X-cut Sand	14,580.5	14,753.0	172.5	117.7	0.1	0.9	47.0	32.1	0.1	0.1	0.5	2.0	1.4	0.1
S-2	Upper Omicron	9,120.5	9,630.5	510.0	510.0	0.1	0.9	19.0	19.0	0.3	0.1	0.5	4.0	4.0	0.4
S-2	Lower Omicron	9,630.5	10,172.0	541.5	541.5	0.1	0.6	41.5	41.5	0.3	0.1	0.4	39.5	39.5	0.3
S-2	Omicron Deep	10,692.5	12,091.5	1,399.0	1,399.0	0.1	0.7	78.5	78.5	0.2	0.2	0.5	45.5	45.5	0.2
S-3	Upper Omicron	9,557.0	9,872.0	315.0	315.0	0.2	1.0	8.0	8.0	0.4			0.0	0.0	
S-3	Lower Omicron	9,872.0	10,540.5	668.5	668.5	0.2	1.0	81.0	81.0	0.4			0.0	0.0	
S-3	Omicron Deep	11,141.5	12,785.0	1,643.5	1,643.5	0.1	0.8	102.5	102.5	0.2	0.1	0.4	22.0	22.0	0.2
S-3	Epsilon Complex	13,806.0	14,350.5	544.5	544.5	0.1	0.8	25.5	25.5	0.2	0.1	0.5	12.0	12.0	0.2
SNA-1X	Omicron Deep	9,199.9	10,800.1	1,600.6	1,599.7	0.1	0.9	789.9	789.5	0.4	0.2	0.5	156.3	156.2	0.3

Summary of Petrophysical Parameters for Sapele-1, -1ST, -2, -3 and SNA-1X Wells



Chemostratigraphic Correlations between the Sapele wells

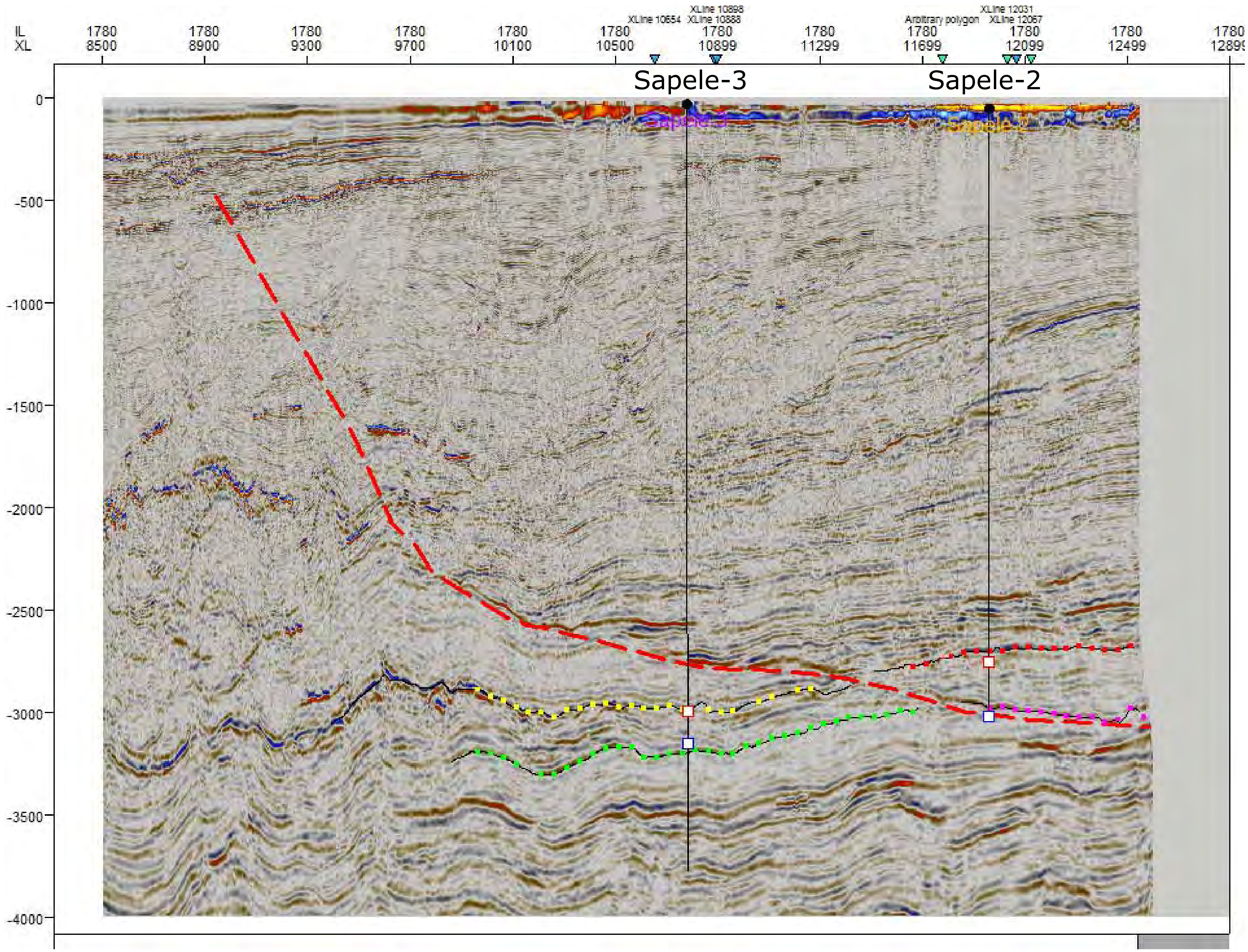
Figure 23



3D Seismic Basemap with Well Control and Timeslice Showing Mapped Extent on Either Side of X-Cut

Figure 24

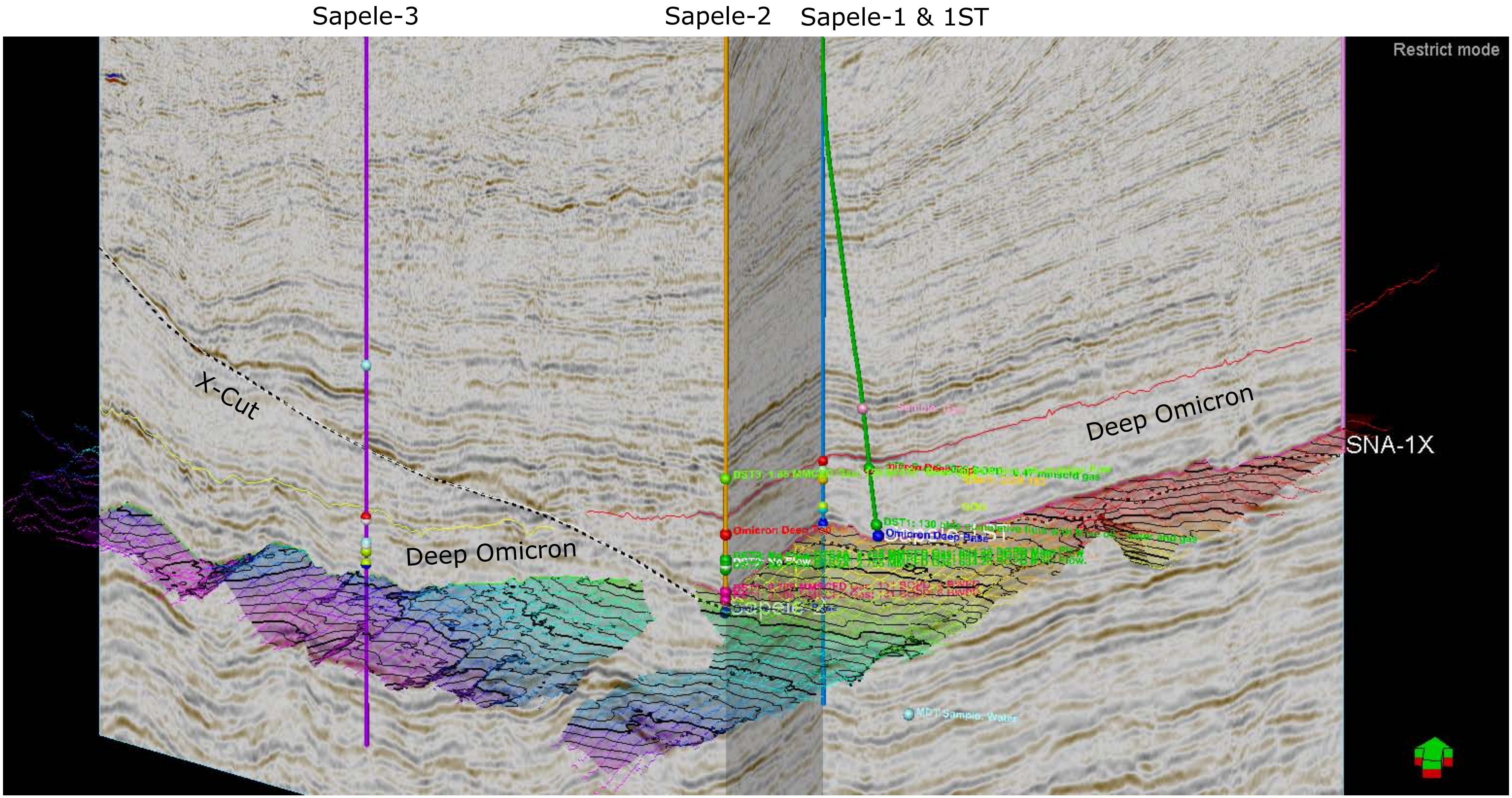
Sproule



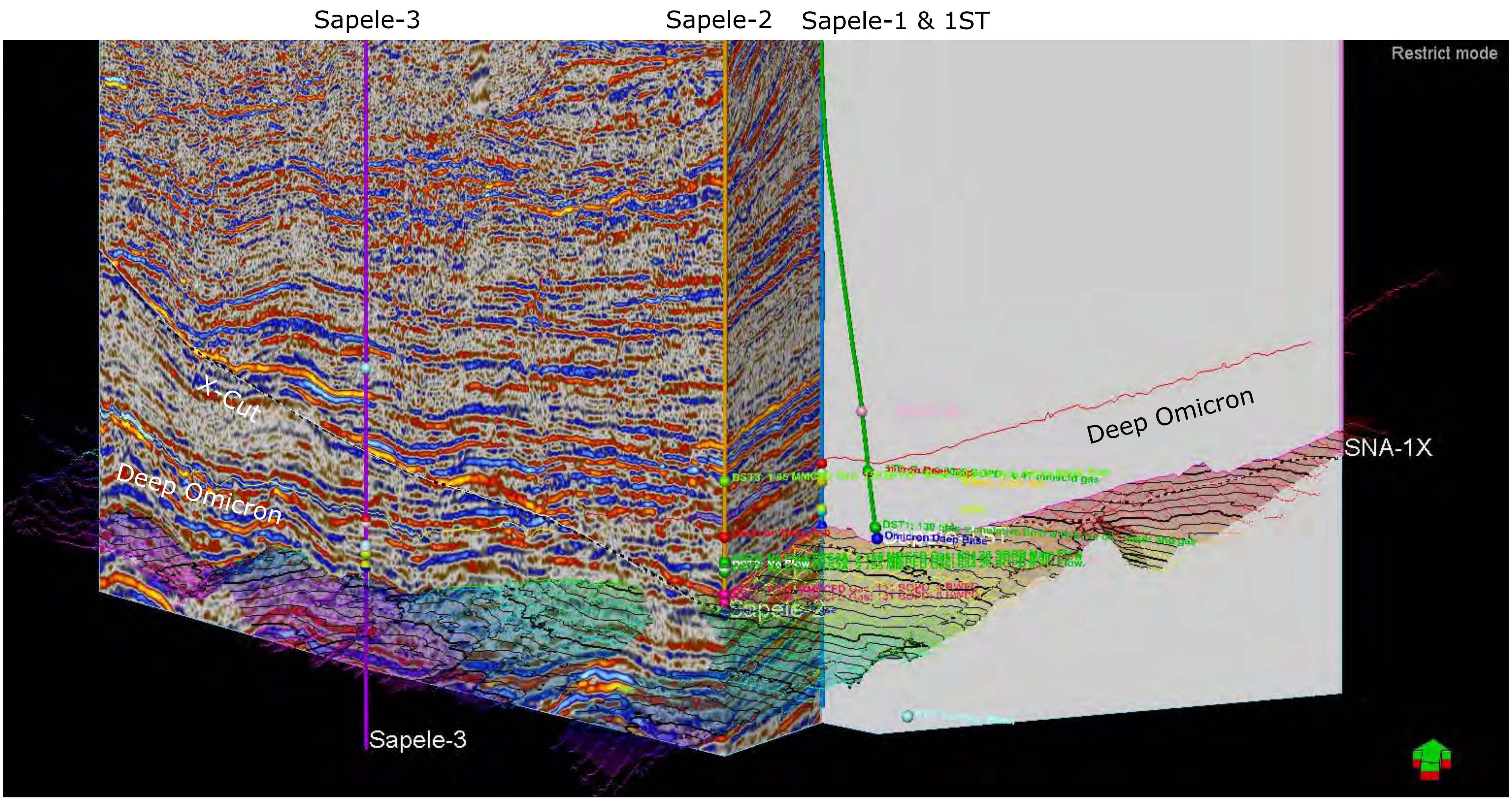
Deep Omicron

X-Cut Feature Shown on Inline 1780 of Original Merged Final Stack with Sapele-3 and Sapele-2

Figure 25



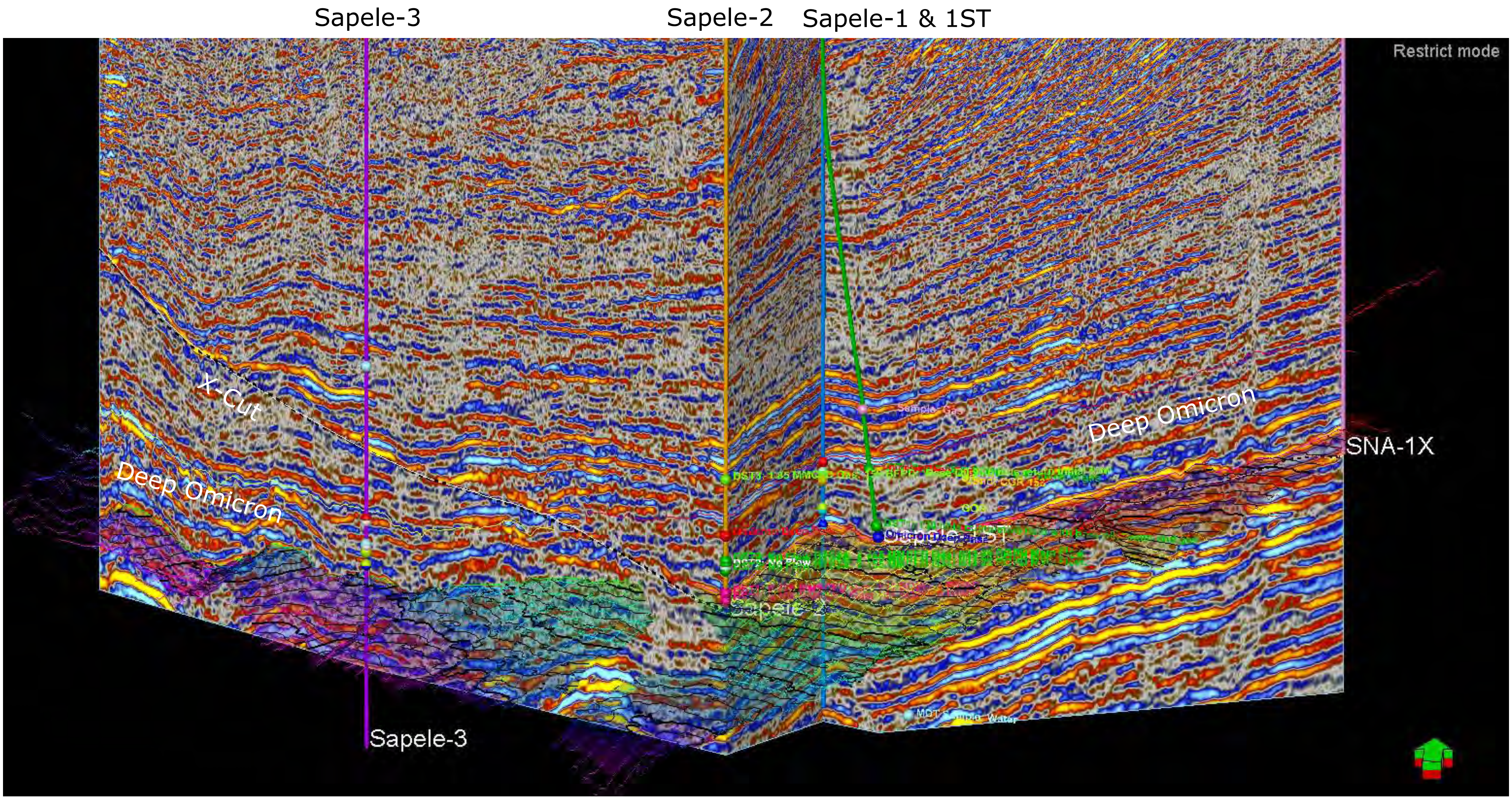
3D Seismic Fence of <u>Original Migrated Final Stack</u> Volume Through Wells Showing X-Cut, Base Deep Omicron Surface and Picks, Top Deep Omicron (thin line), Top (Red) & Base (Blue) Deep Omicron Tops along with Hydrocarbon DST / MDT Locations



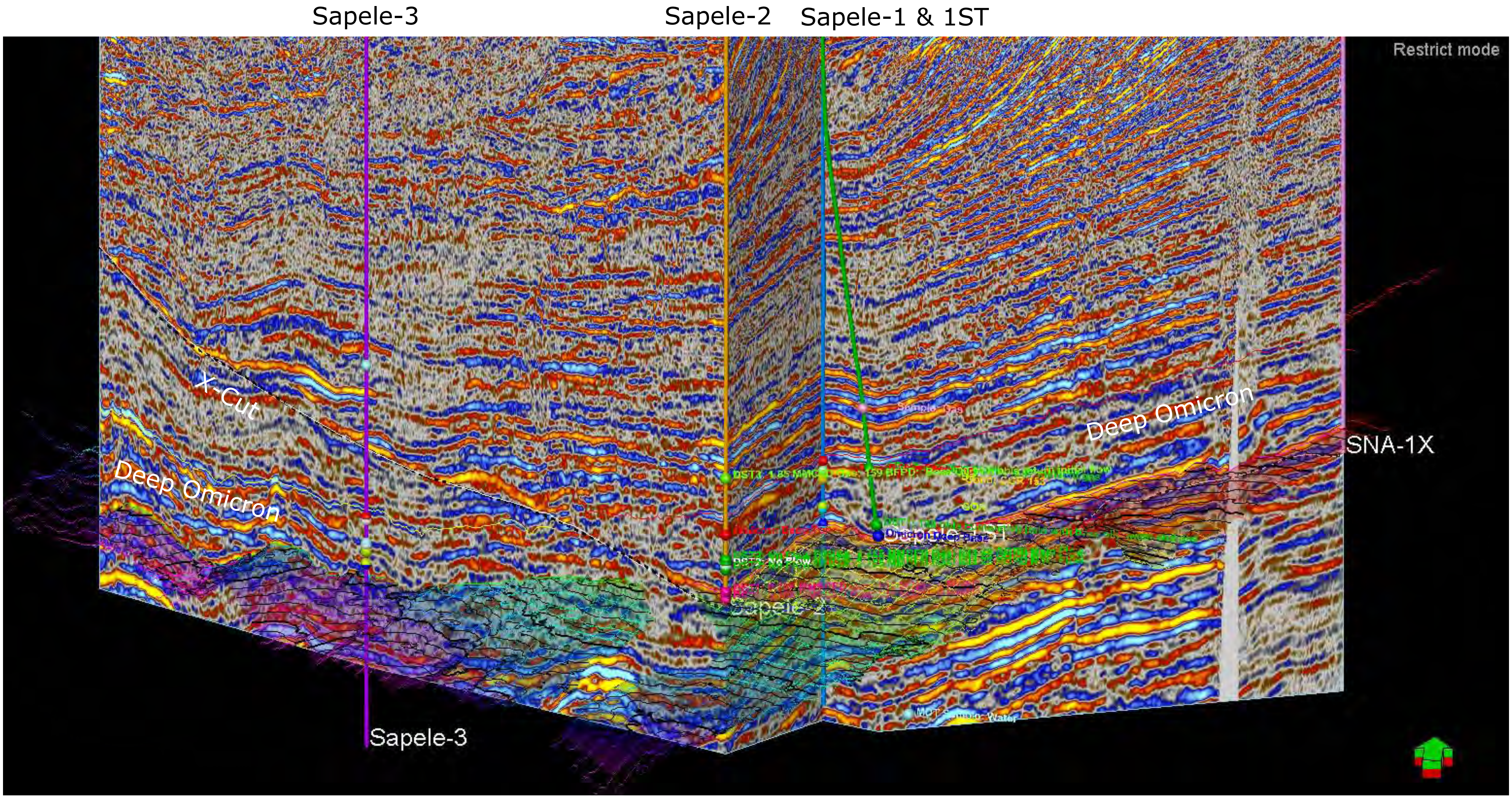
3D Seismic Fence of Re-Scaled Migrated Final Stack Volume Through Wells Showing X-Cut, Base Deep Omicron Surface and Picks, Top Deep Omicron (thin line), Top (Red) & Base (Blue) Deep Omicron Tops along with Hydrocarbon DST / MDT Locations

70701

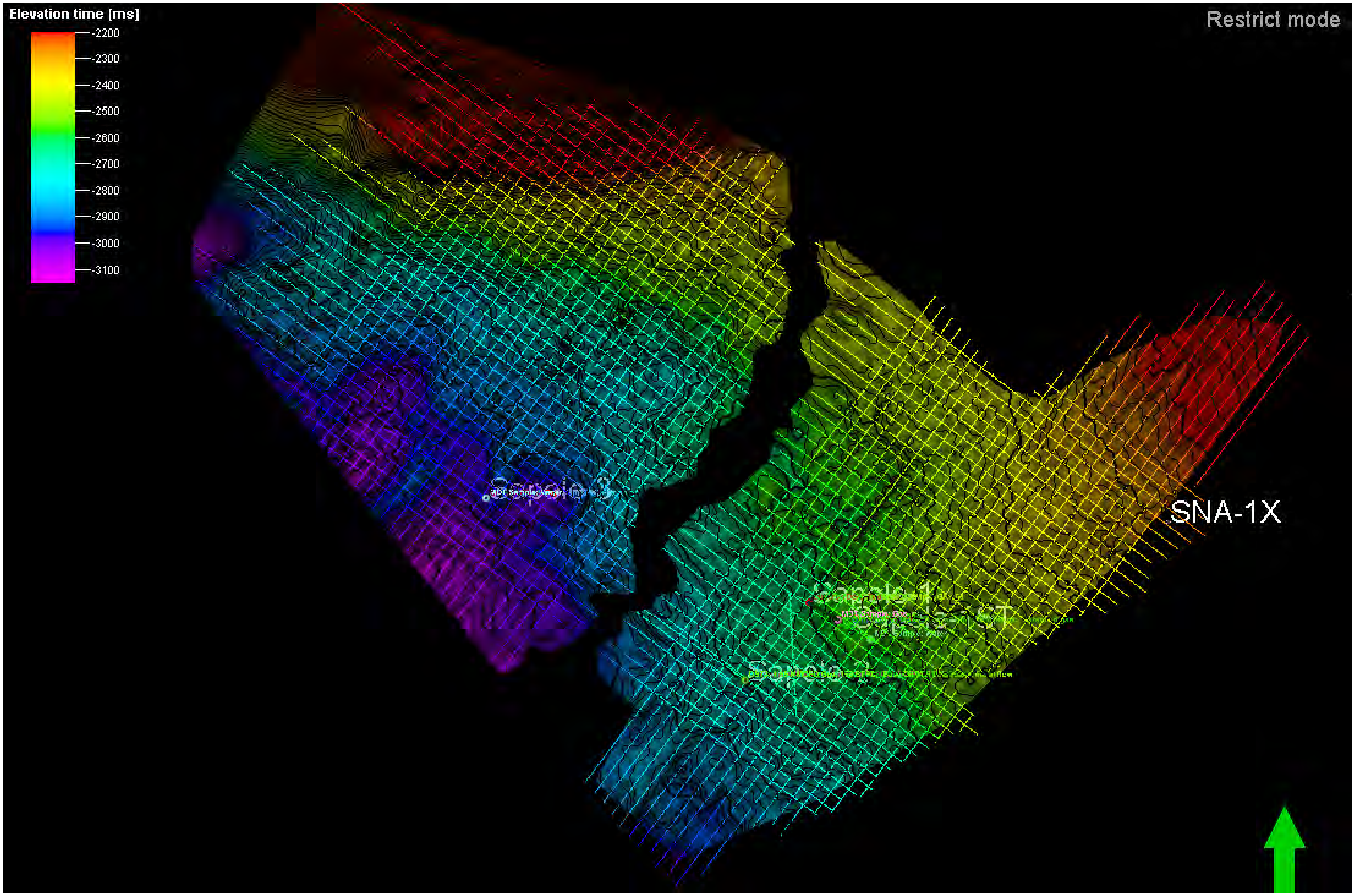
Sproule



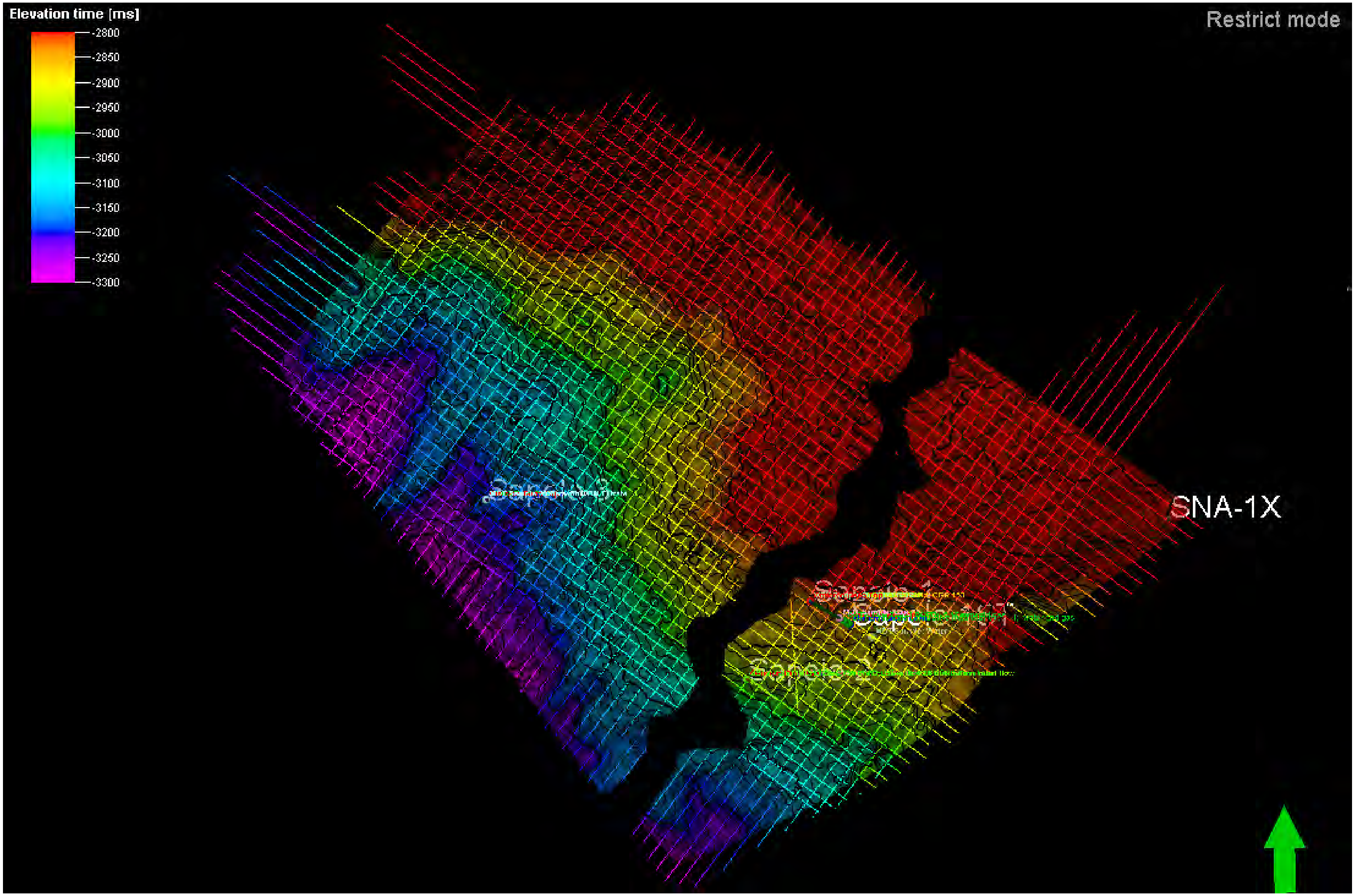
3D Seismic Fence of <u>Re-Scaled Near-Stack</u> Volume Through Wells Showing X-Cut, Base Deep Omicron Surface and Picks, Top Deep Omicron (thin line), Top (Red) & Base (Blue) Deep Omicron Tops along with Hydrocarbon DST / MDT Locations



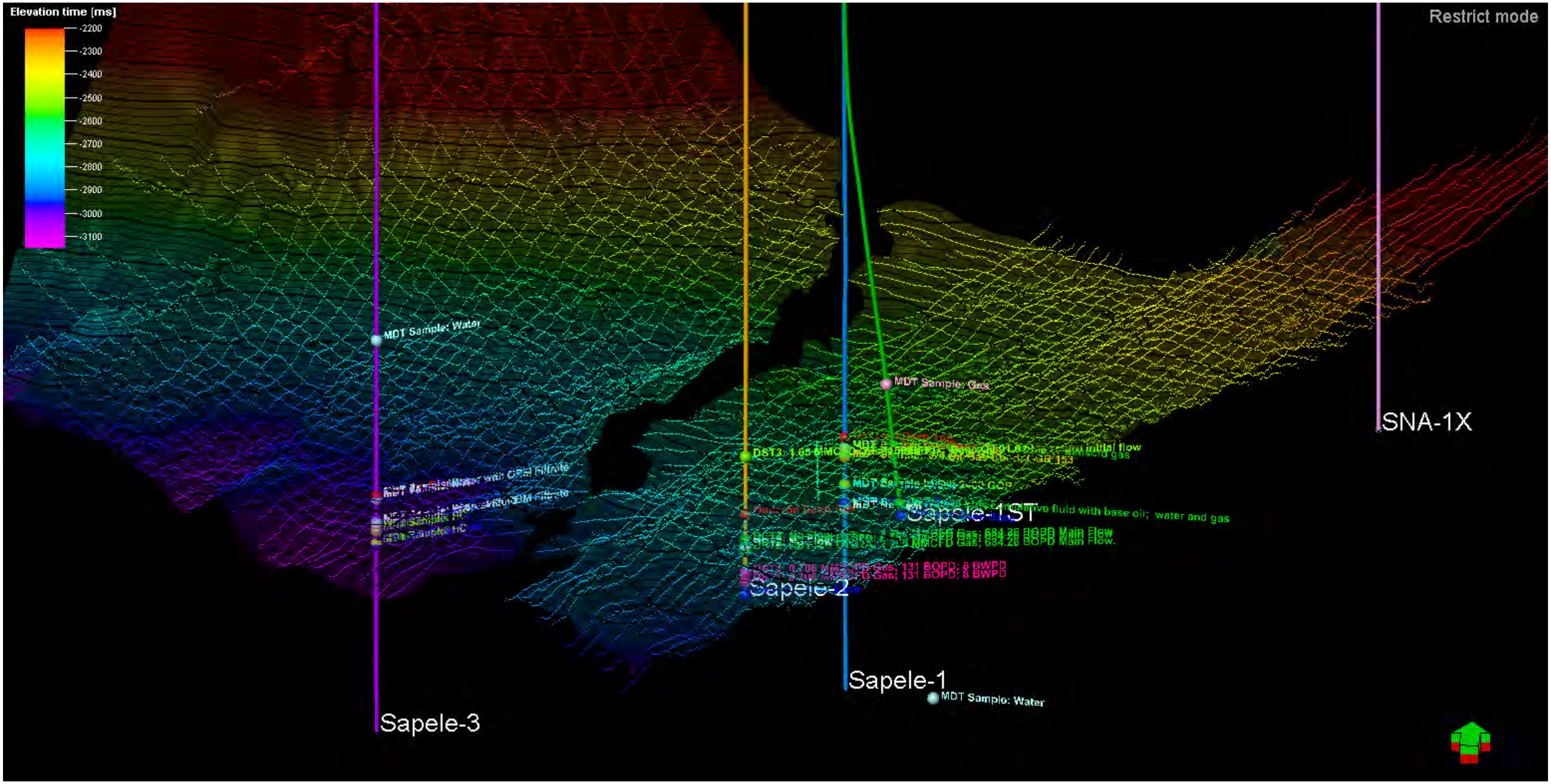
3D Seismic Fence of <u>Re-Scaled Mid-Stack</u> Volume Through Wells Showing X-Cut, Base Deep Omicron Surface and Picks, Top Deep Omicron (thin line), Top (Red) & Base (Blue) Deep Omicron Tops along with Hydrocarbon DST / MDT Locations



Map View of Top Deep Omicron Time Picks and Surface With Well Penetrations



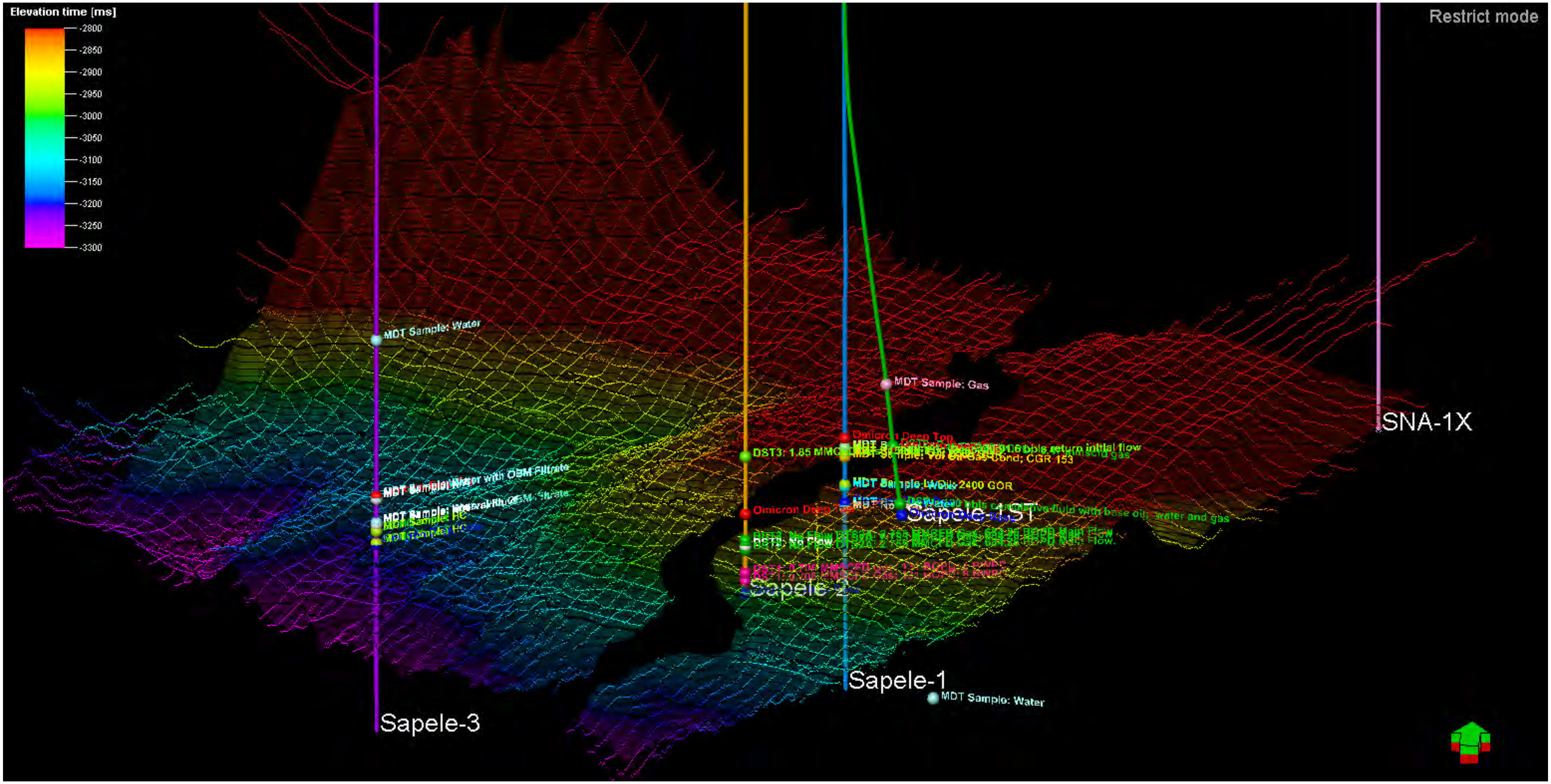
Map View of Base Deep Omicron Time Picks and Surface With Well Penetrations



3D Perspective View From South of Top Deep Omicron Picks and Surface With Well Penetrations, Tops, and DST / MDT Shows

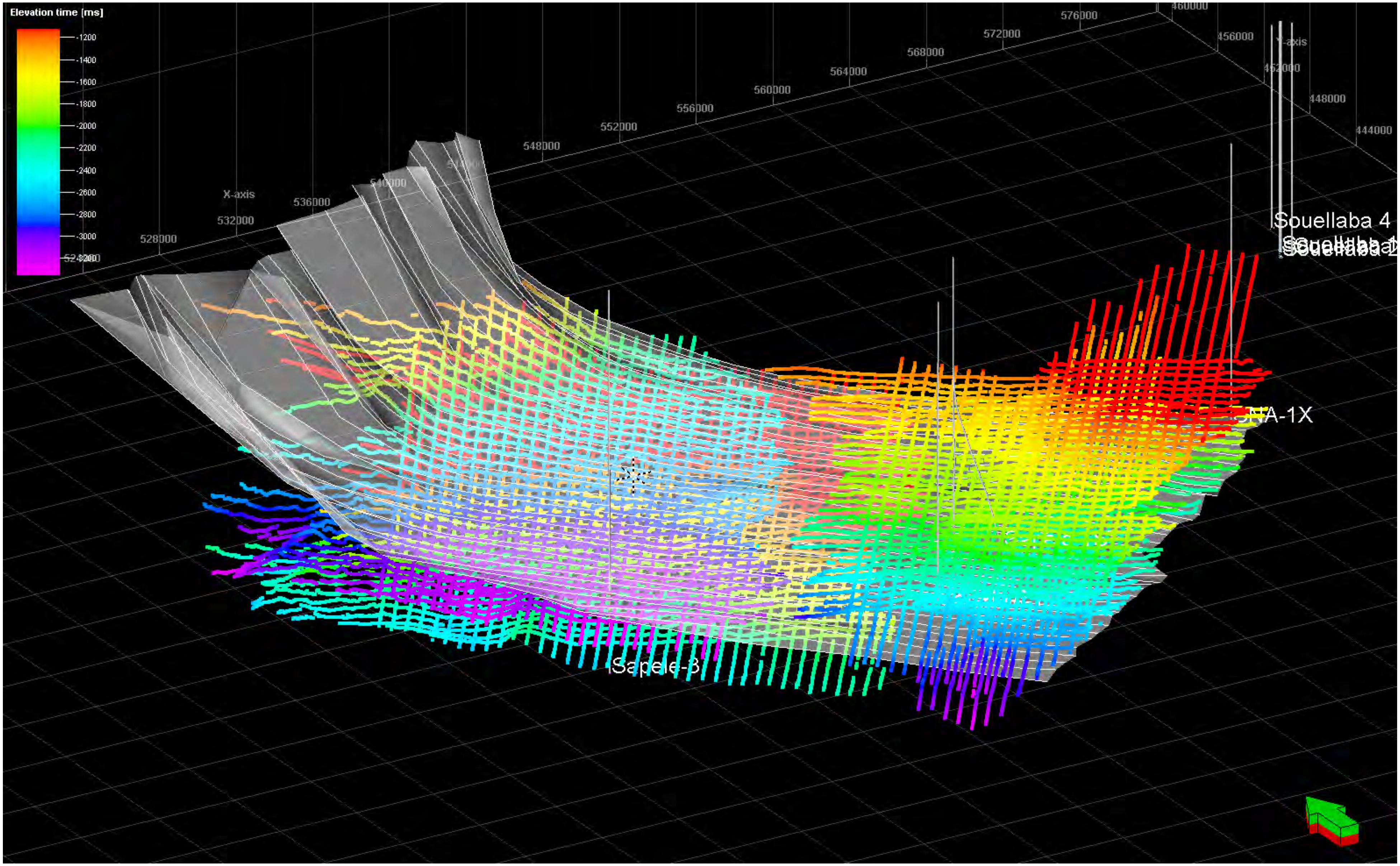
Figure 32

70701

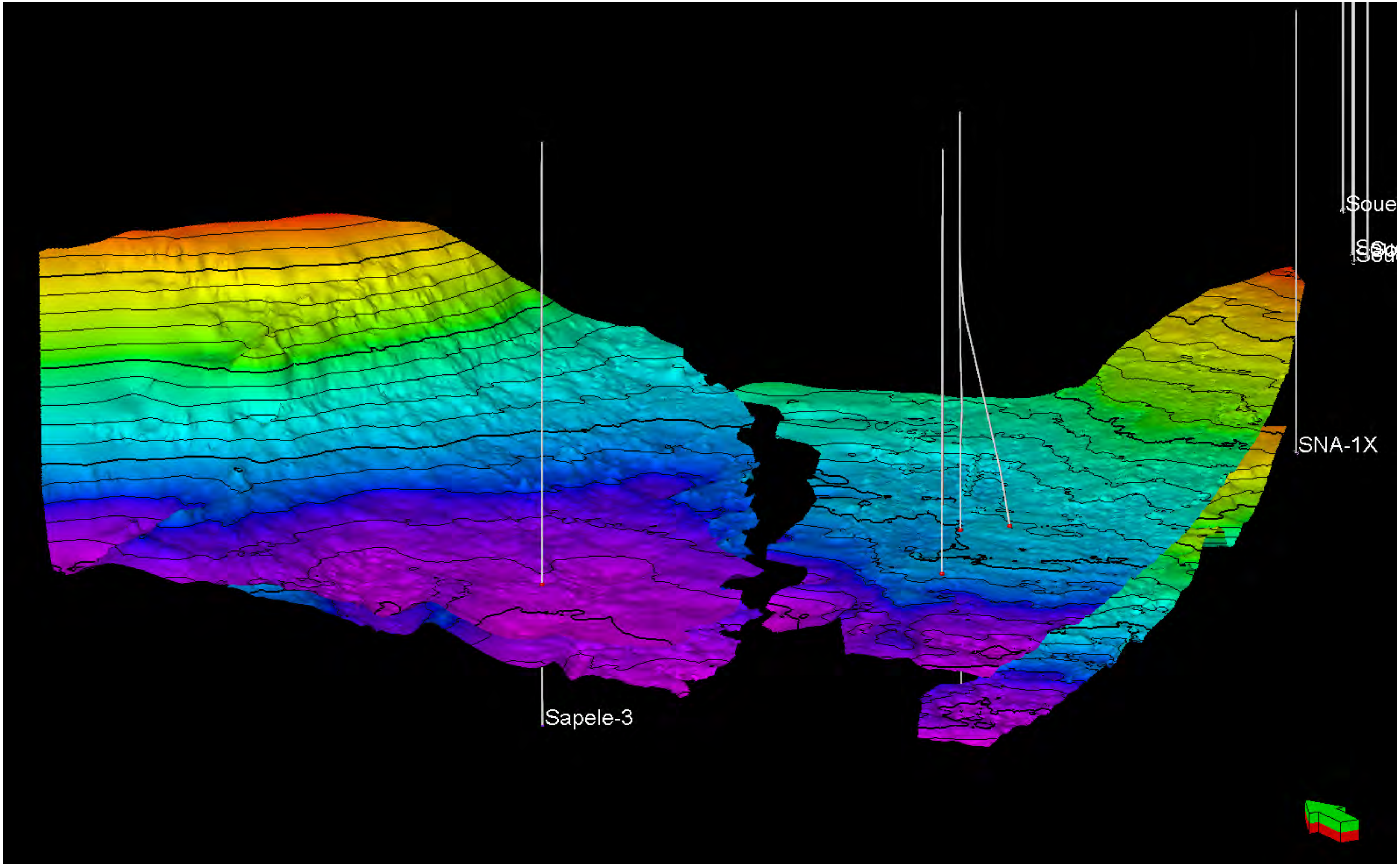


3D Perspective View From South of Base Deep Omicron Picks and Surface With Well Penetrations, Tops, and DST / MDT Shows

Figure 33

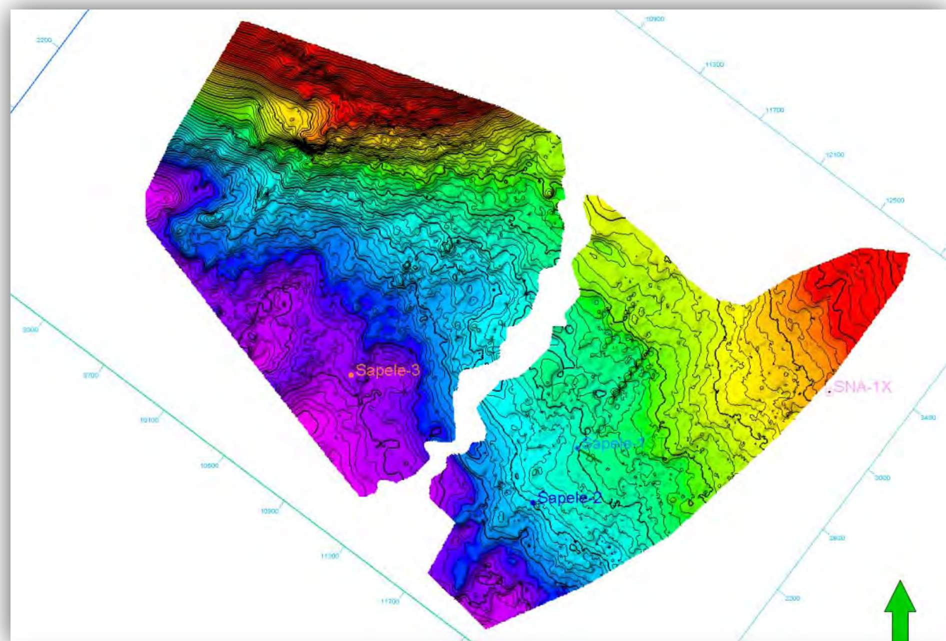


Top and Base Deep Omicron Picks on Either Side of X-Cut Feature

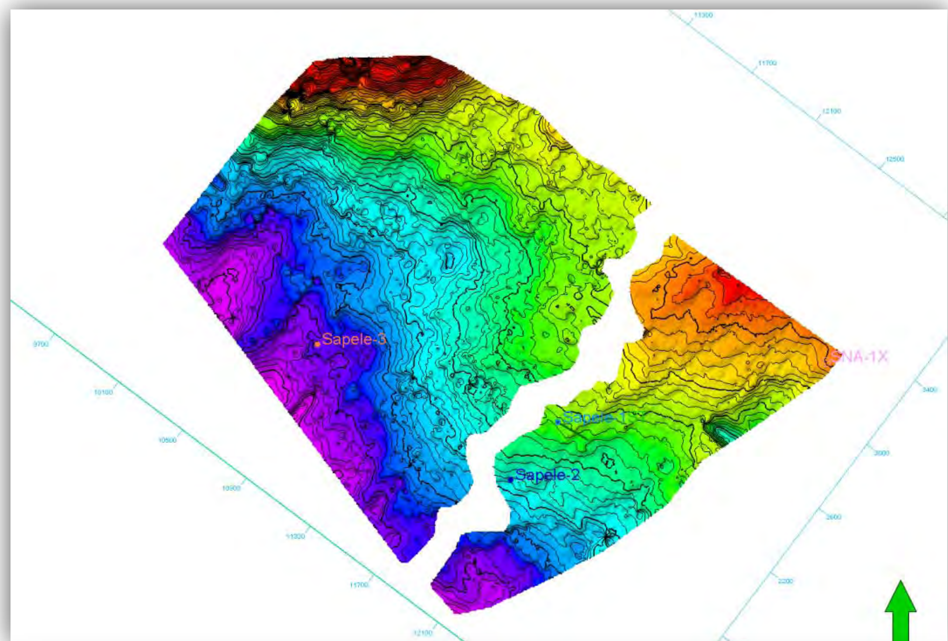


Top and Base Deep Omicron Picks on Either Side of X-Cut Feature

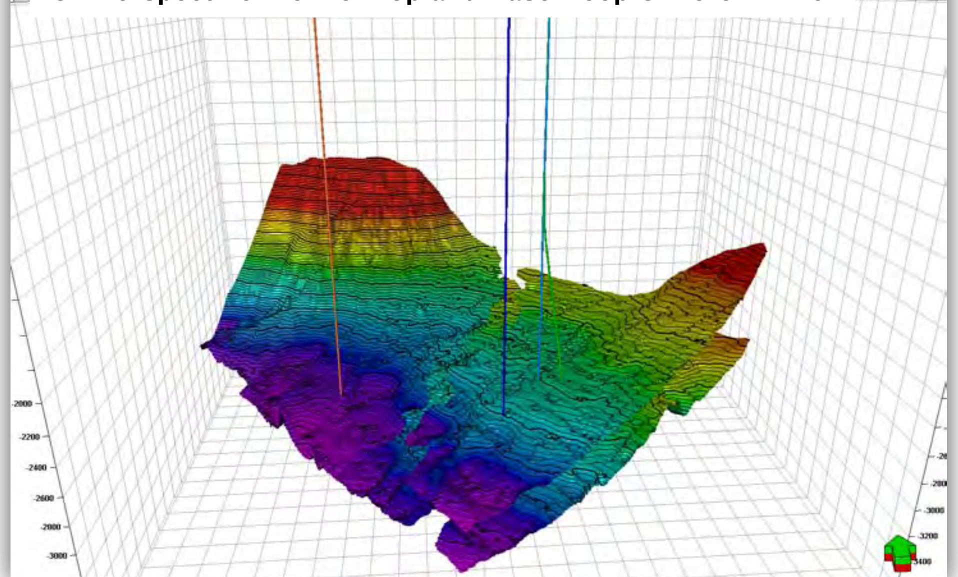
Deep Omicron Top Time Structure Map



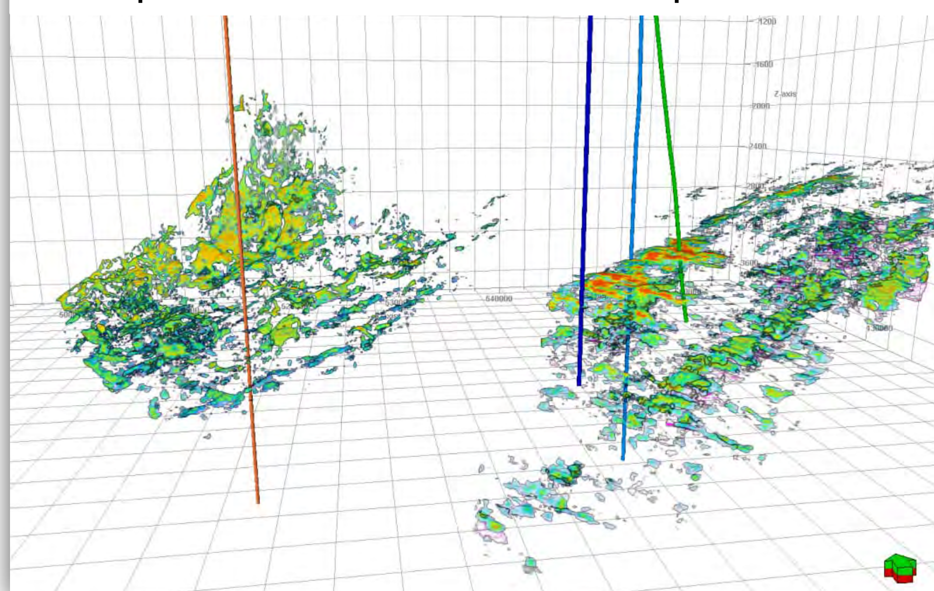
Deep Omicron Base Time Structure Map



3D Perspective View of Top and Base Deep Omicron Time



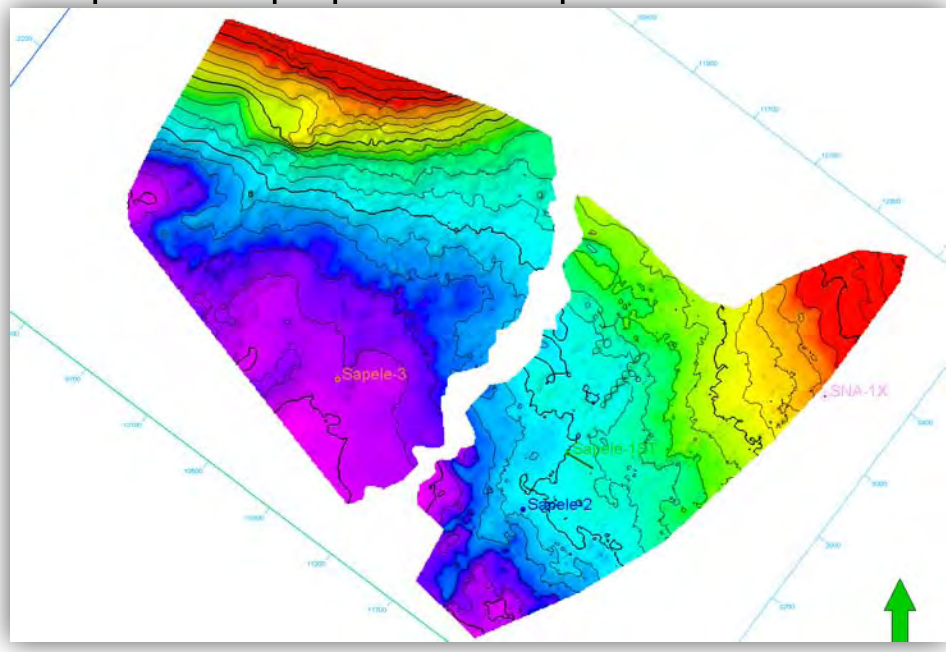
3D Perspective view of Far Stack - Horizon Sculptured Geobodies



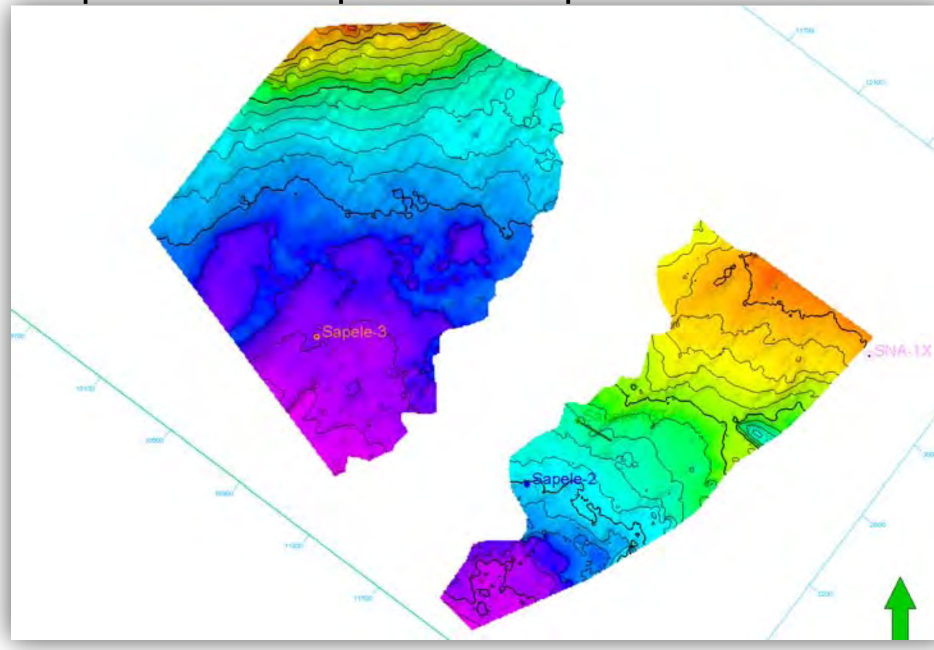
Deep Omicron Time Structure Maps

Figure 36

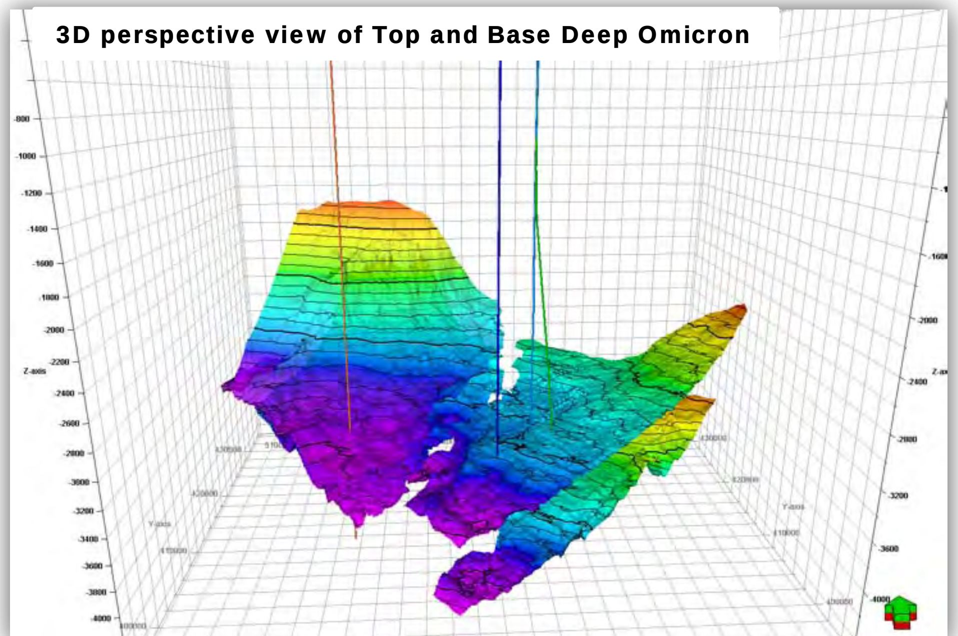
Deep Omicron Top Depth Structure Map



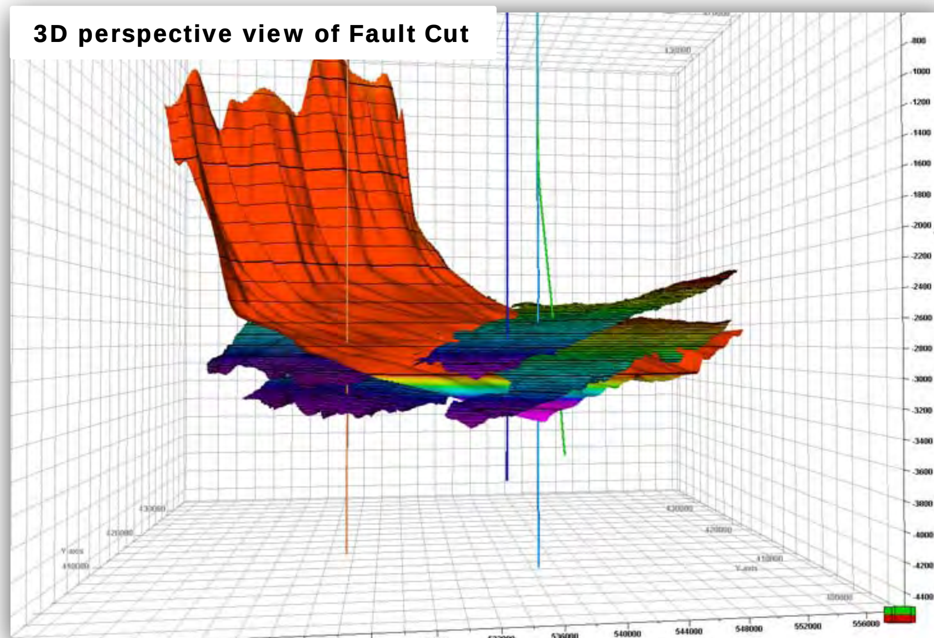
Deep Omicron Base Depth Structure Map



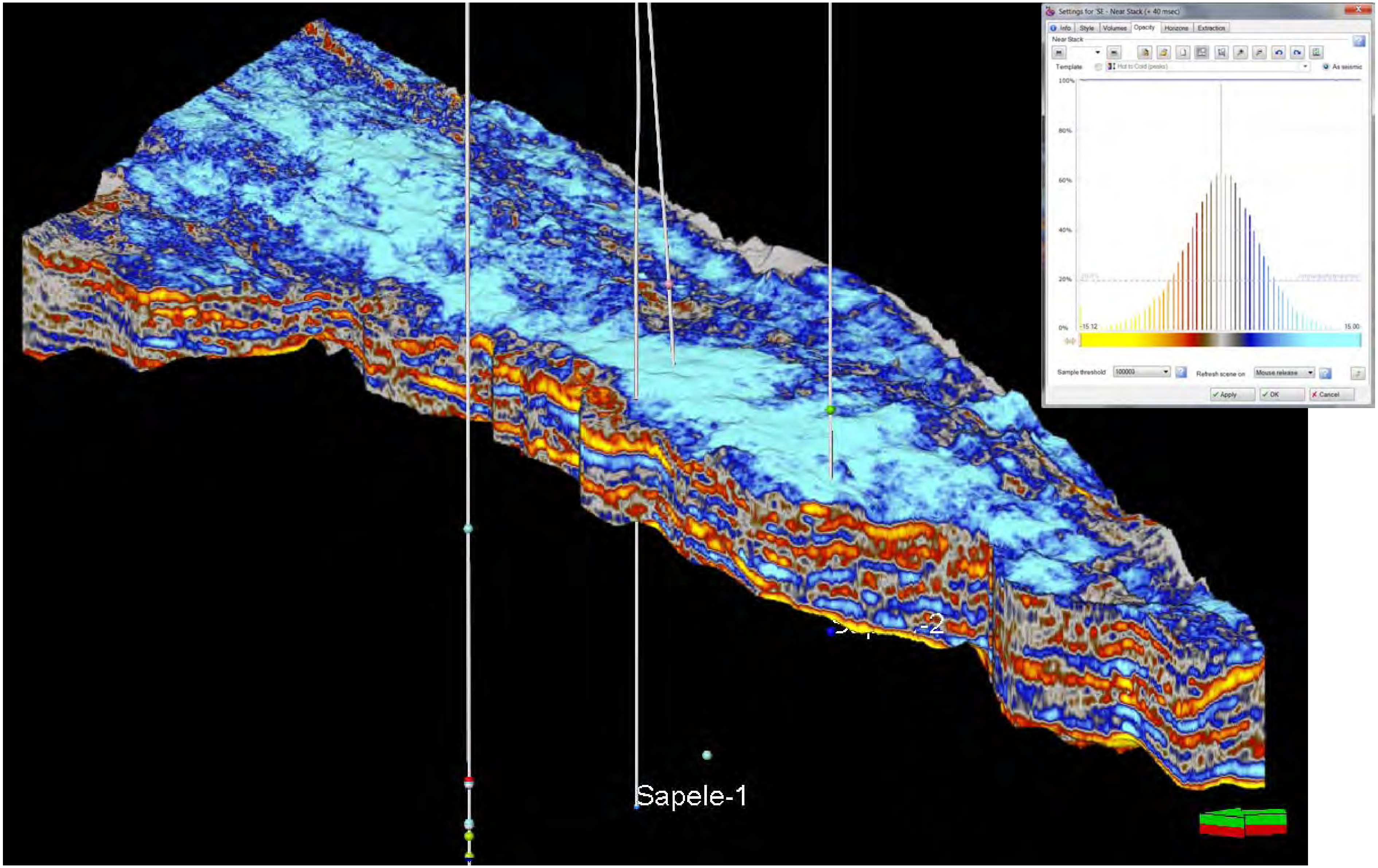
3D perspective view of Top and Base Deep Omicron



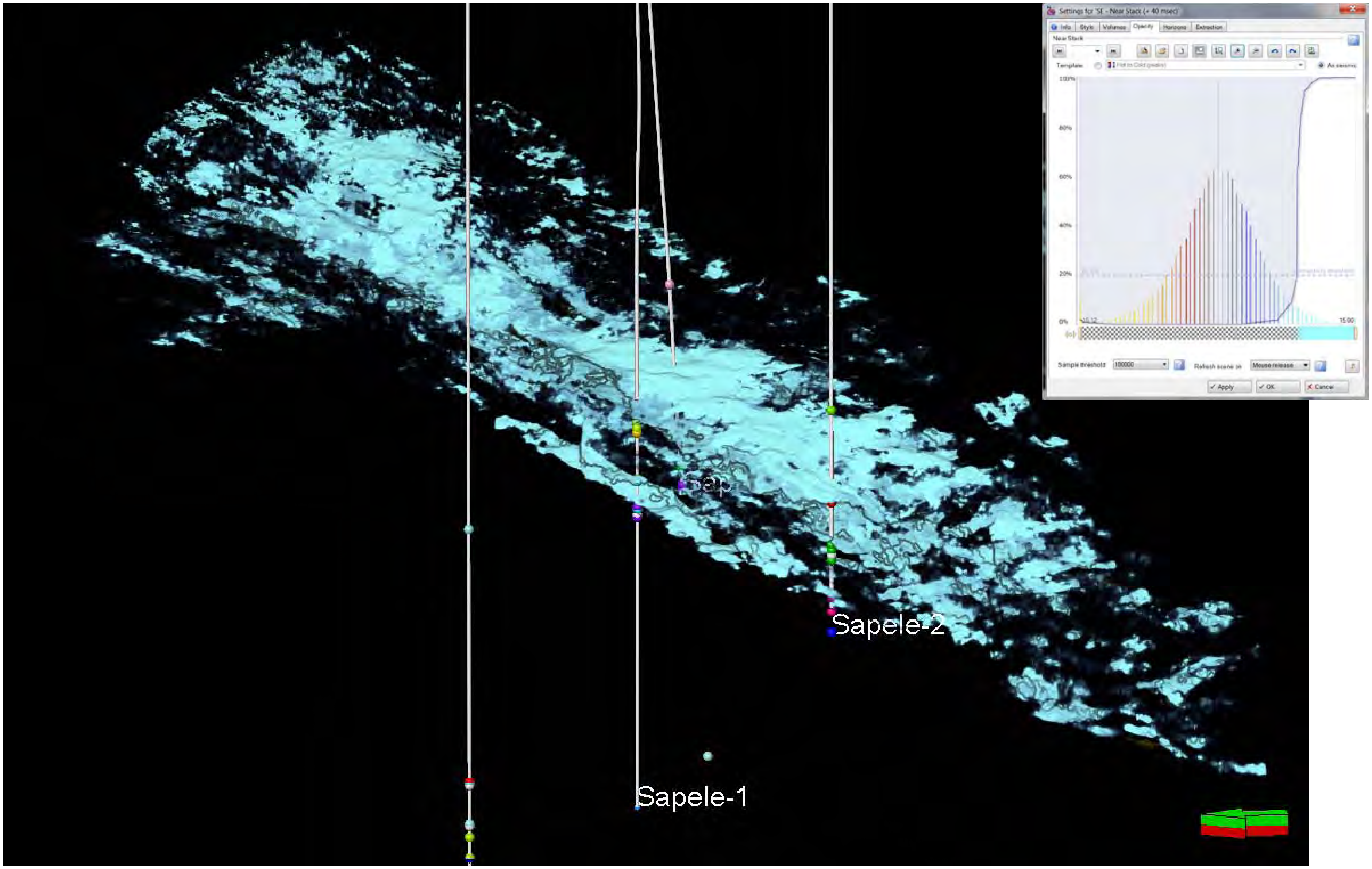
3D perspective view of Fault Cut



Deep Omicron Depth Structure Maps



3D Perspective View from West of Formation Sculpted Volume Between Top and Base of Deep Omicron for Near Stack Seismic Attribute Volume for the Southeast Area

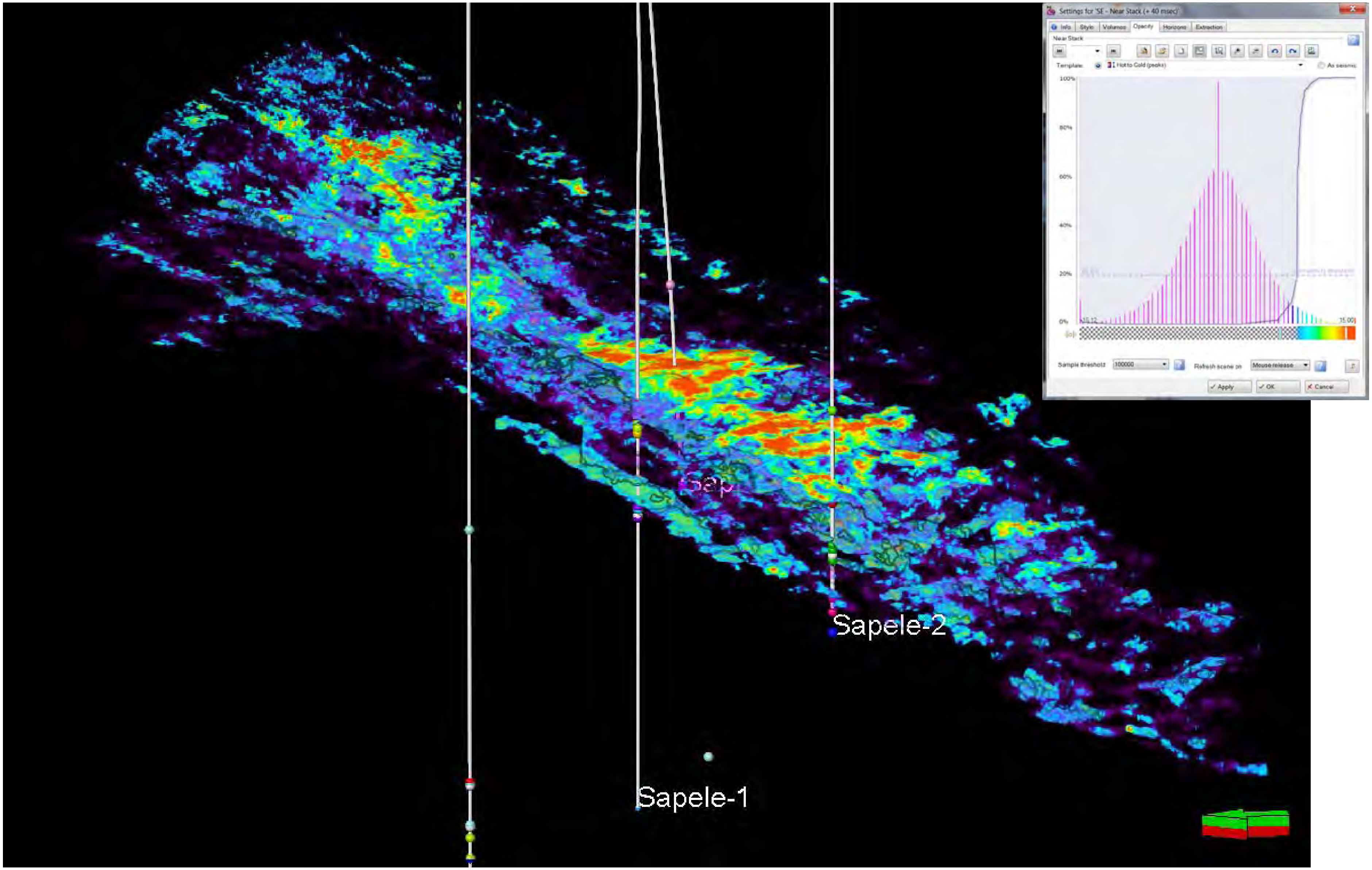


3D Perspective View from West of Opacity Filtered to Identify Strongest Peaks of Previous Figure Formation Sculpted Volume Between Top and Base of Deep Omicron for <u>Near Stack</u> Seismic Attribute Volume

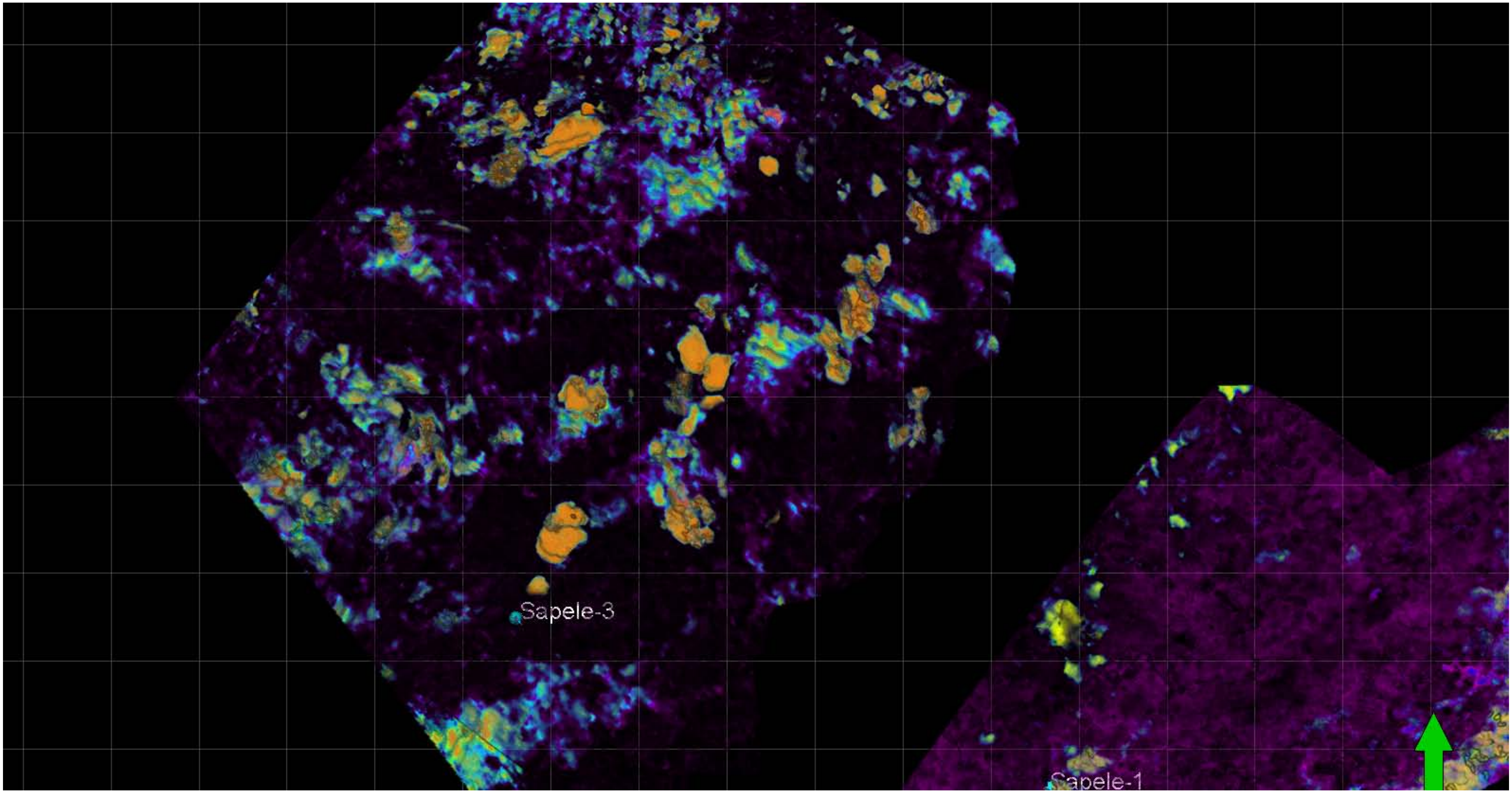
70701

Sproule

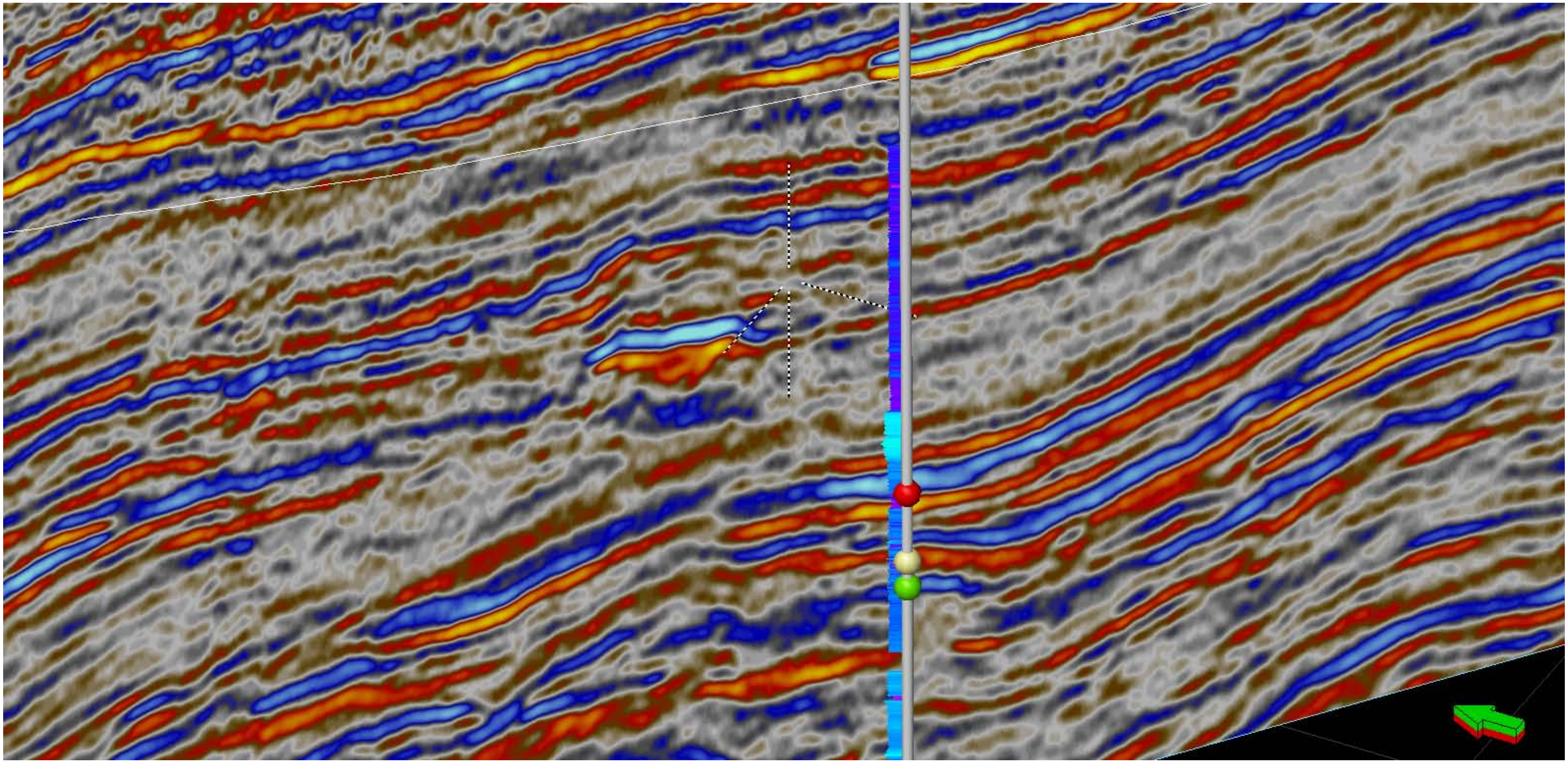
Figure 39



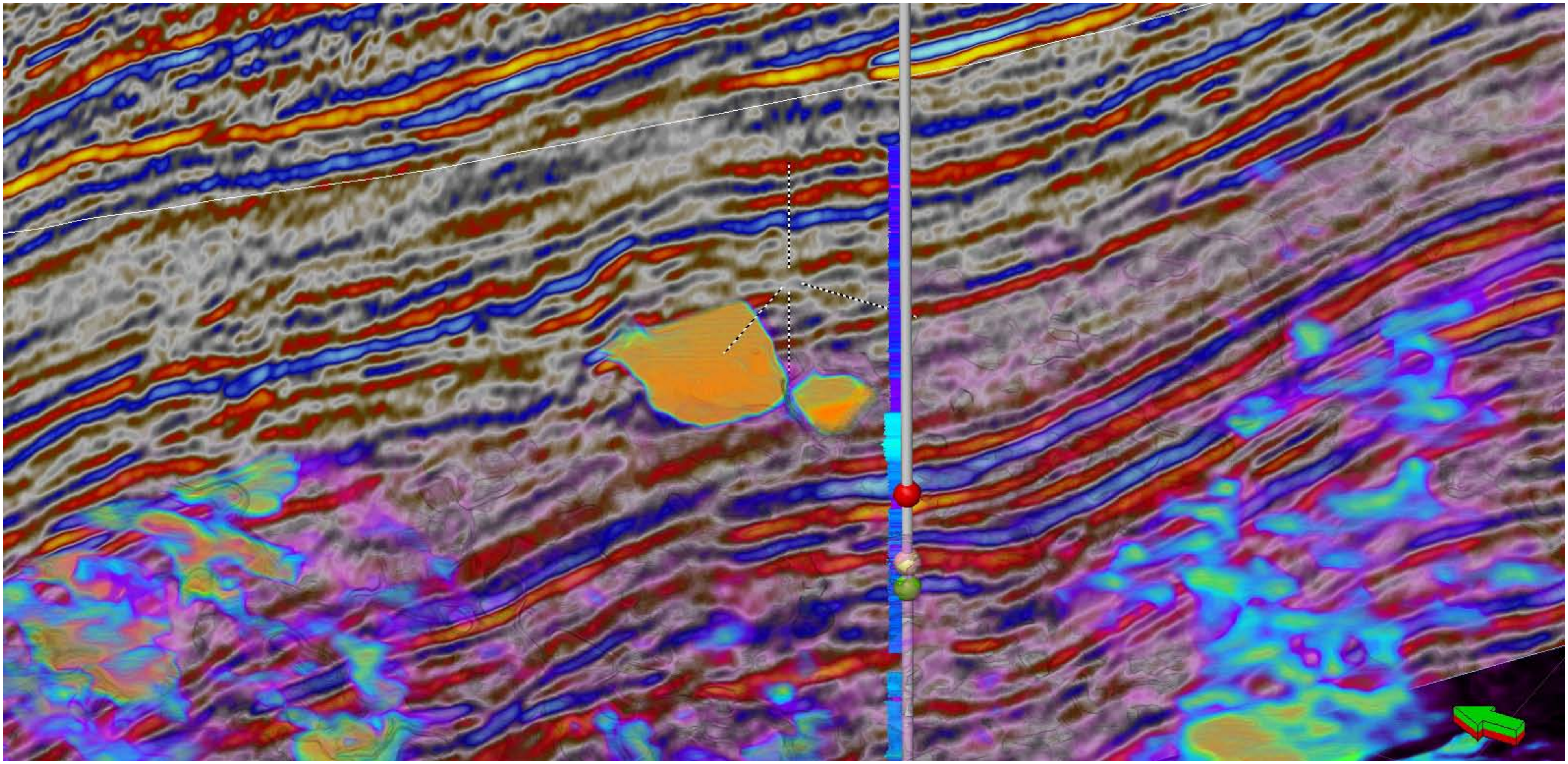
3D Perspective View from West of Opacity Filtered and Colour Enhanced to Identify Strongest Peaks of Previous Figure Formation Sculpted Volume Between Top and Base of Deep Omicron for Near Stack Seismic Attribute Volume



3D Voxel Visualization of Peaks from the Merged Final Stack with AGC Seismic Attribute Volume Over the Northwest Area



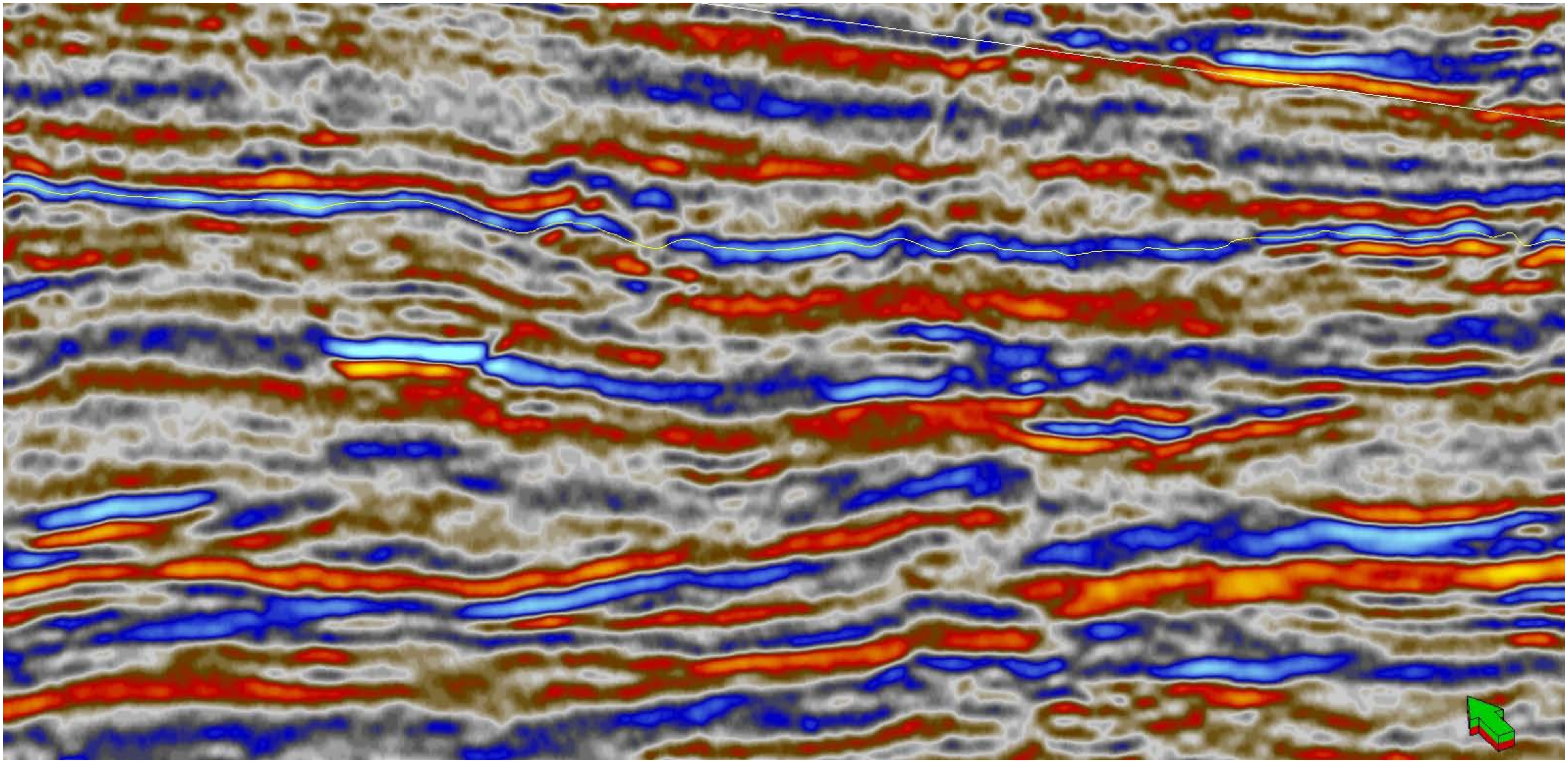
3D Perspective View from SE of Merged Final Stack with AGC Seismic Attribute Volume Near Sapele-3



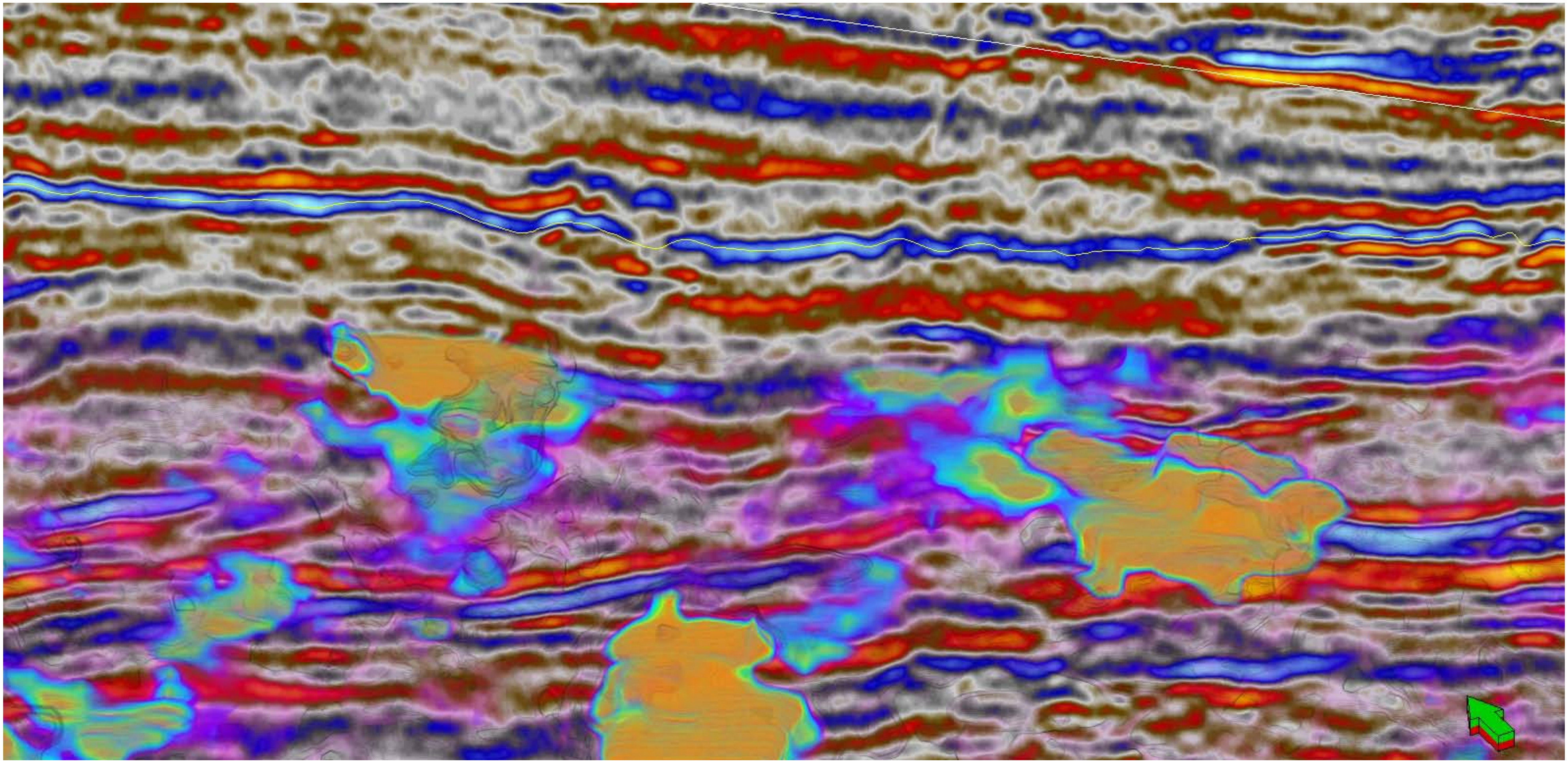
3D Perspective View from SE of Peaks from Voxel Visualization of Merged Final Stack with AGC Seismic Attribute Volume Near Sapele-3

Figure 43

Sproule



IL 2240 of <u>Merged Final Stack with AGC</u>

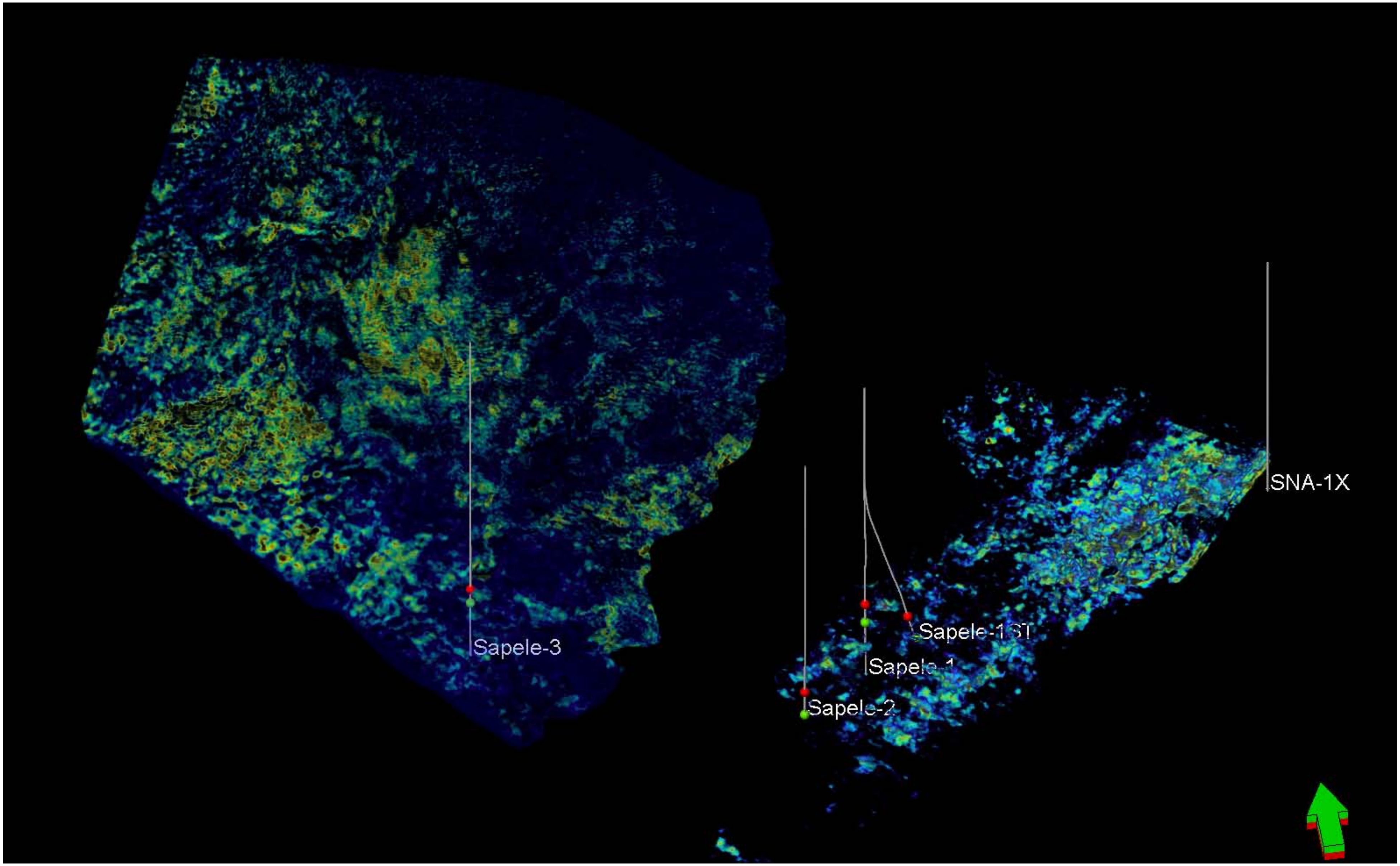


3D Perspective View from SE of Peaks from Merged Final Stack with AGC Voxel Visualization Seismic Attribute Volume Near Sapele-3

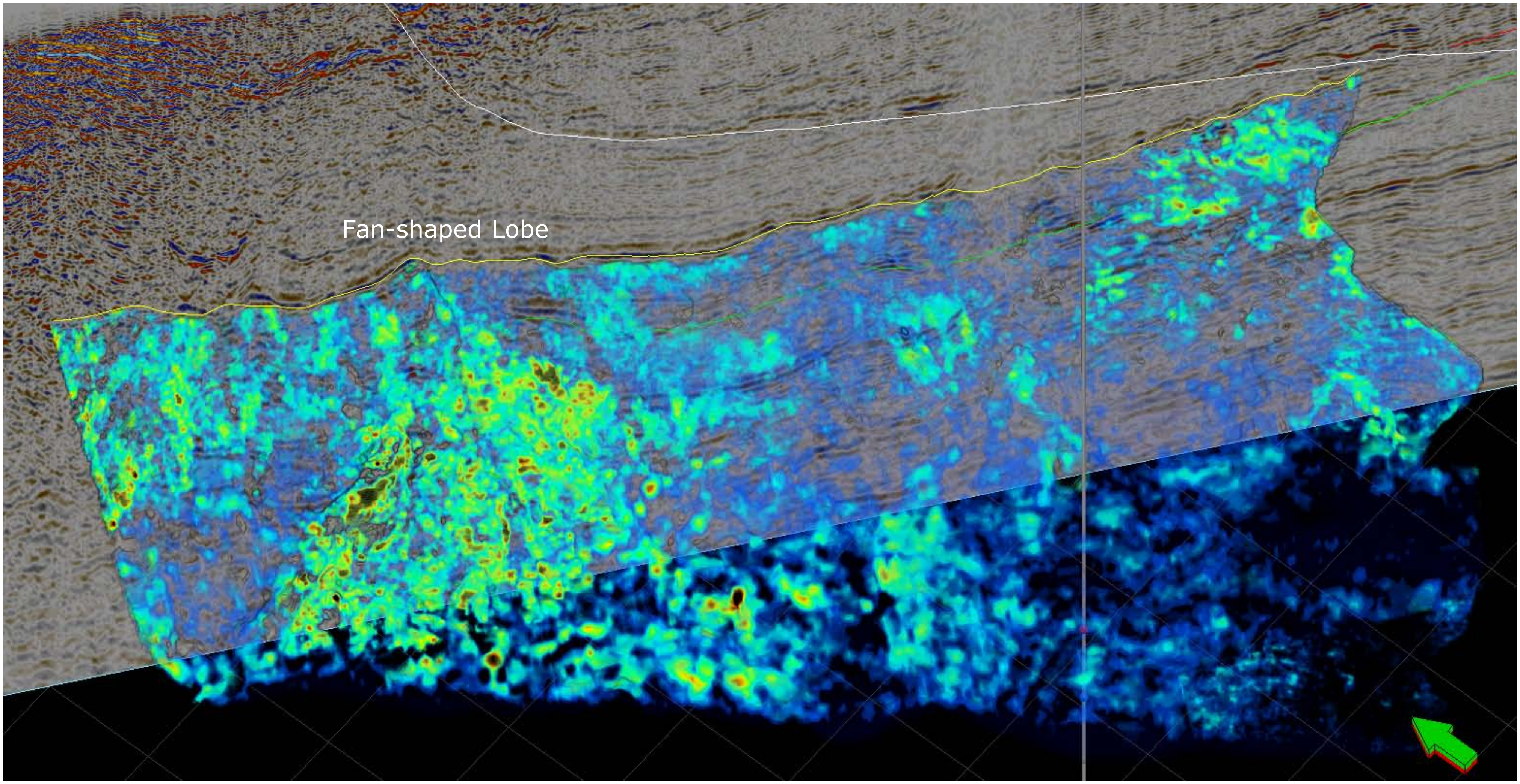
70701

Sproule

Figure 45



3D Voxel Visualization of Near-EHF-ss Seismic Attribute Volume



3D Perspective View of Voxel Visualization of Near-EHF-ss Seismic Attribute Volume for the SE Area
Inline 2274

Figure 47

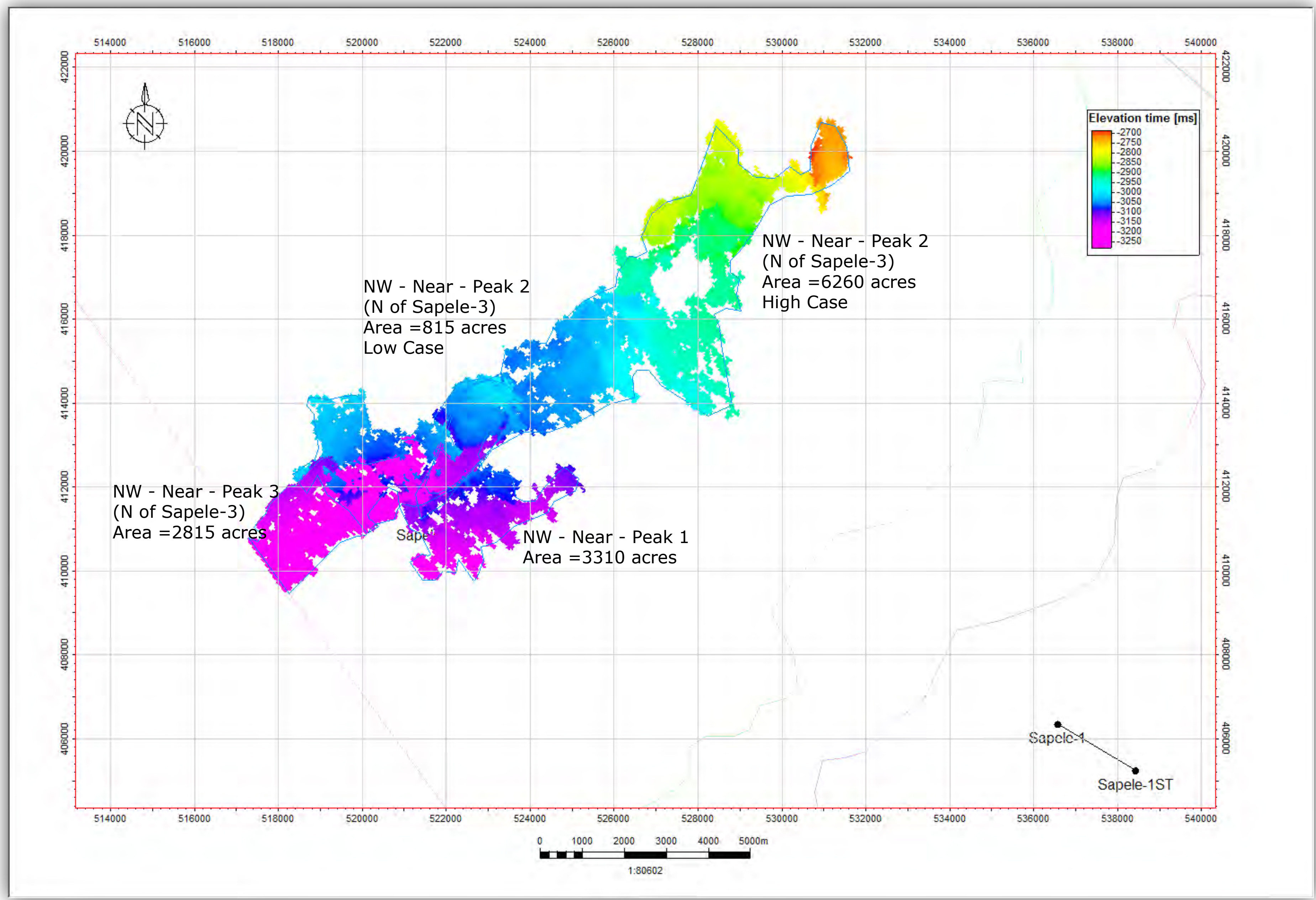
3D Perspective View from West with Well DST and MDT Results

DISCOVERED PETROLEUM INITIALLY-IN-PLACE (PIIP)

NEAR STACK VOLUME

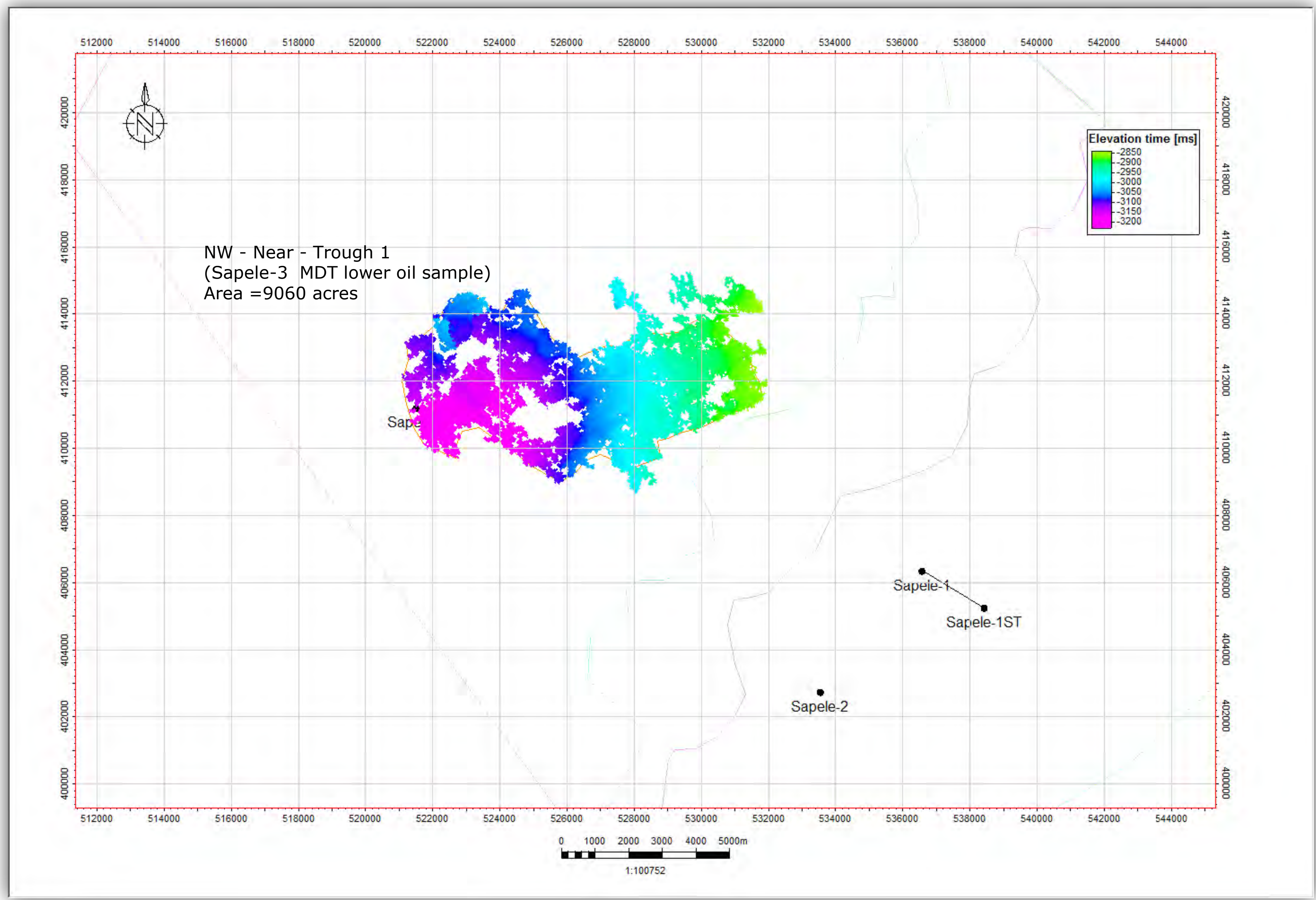
NW AREA – PEAK & TROUGH

SE AREA – PEAK & TROUGH



Near Stack – NW - Peak

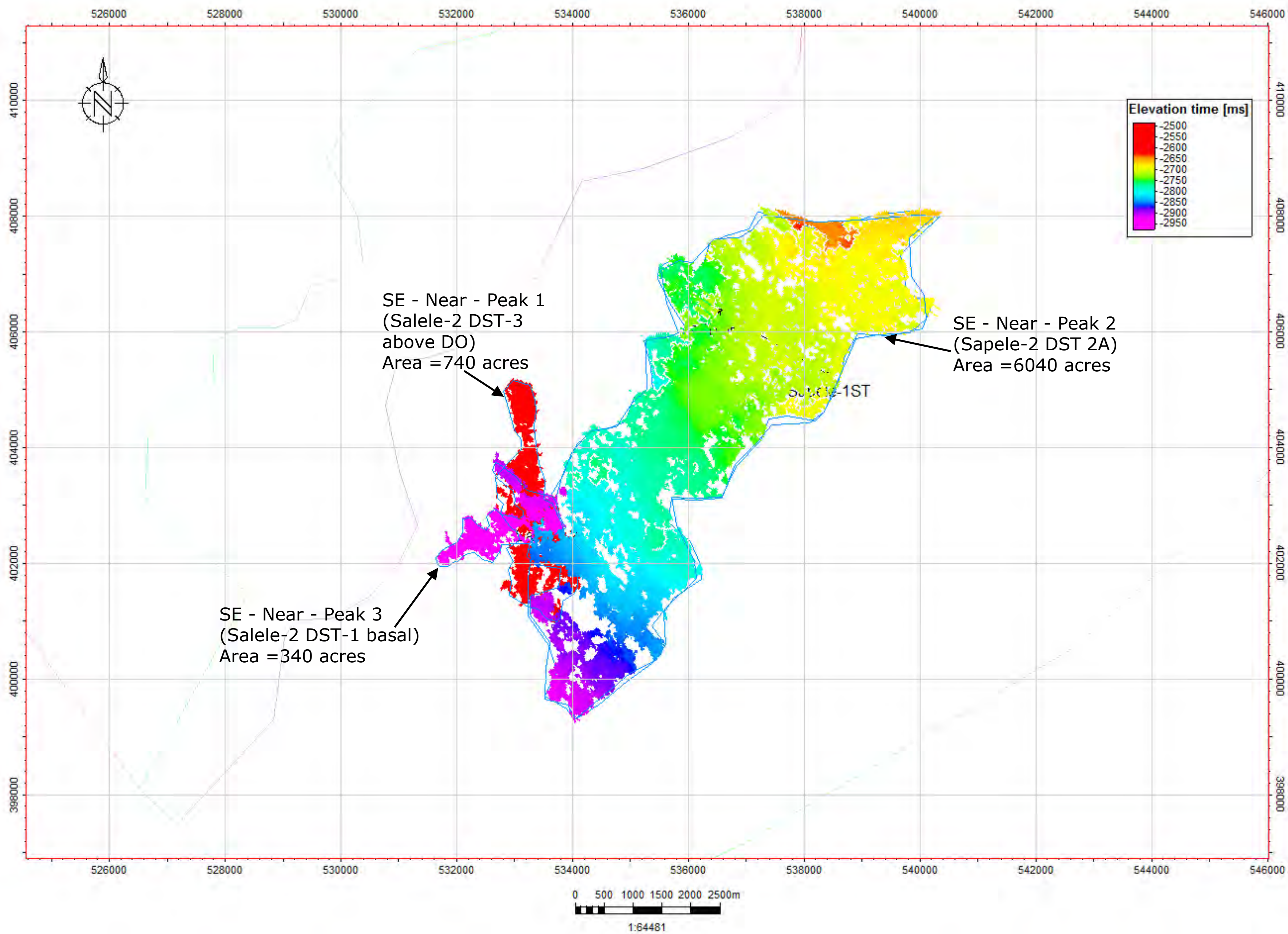
Figure 50



70701

Near Stack – NW - Trough

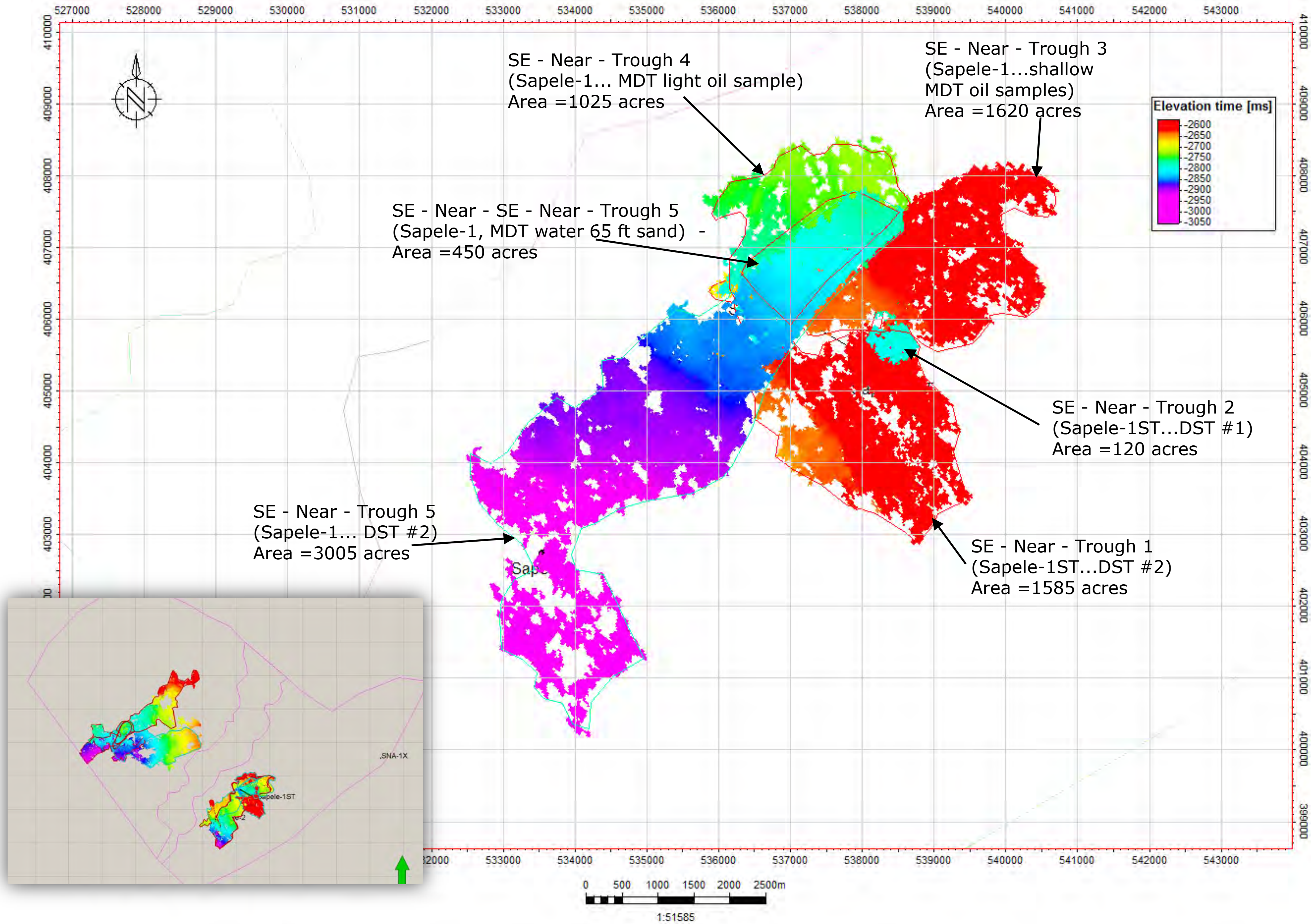
Figure 51



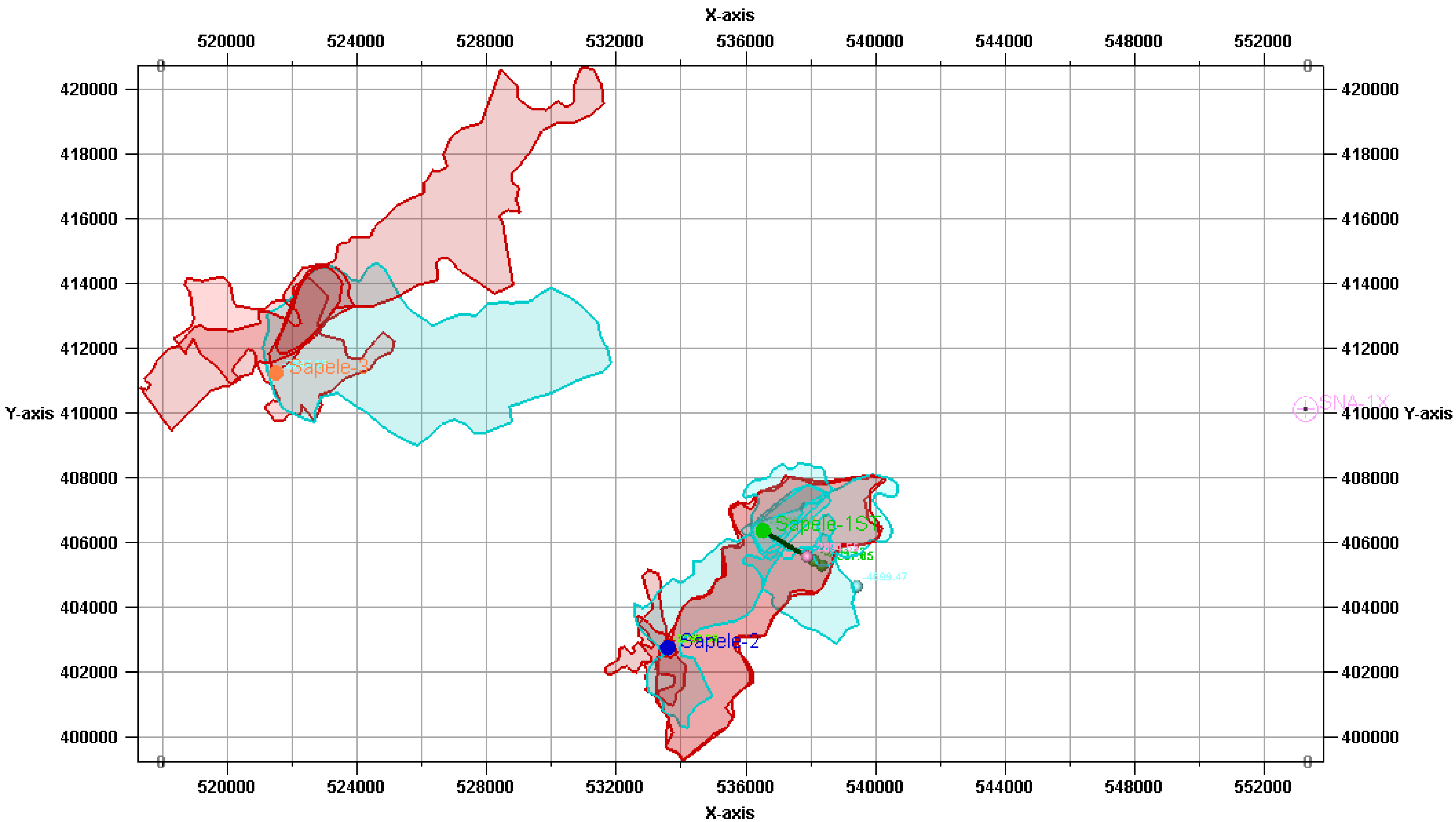
Near Stack – SE - Peak

Sproule

Figure 52



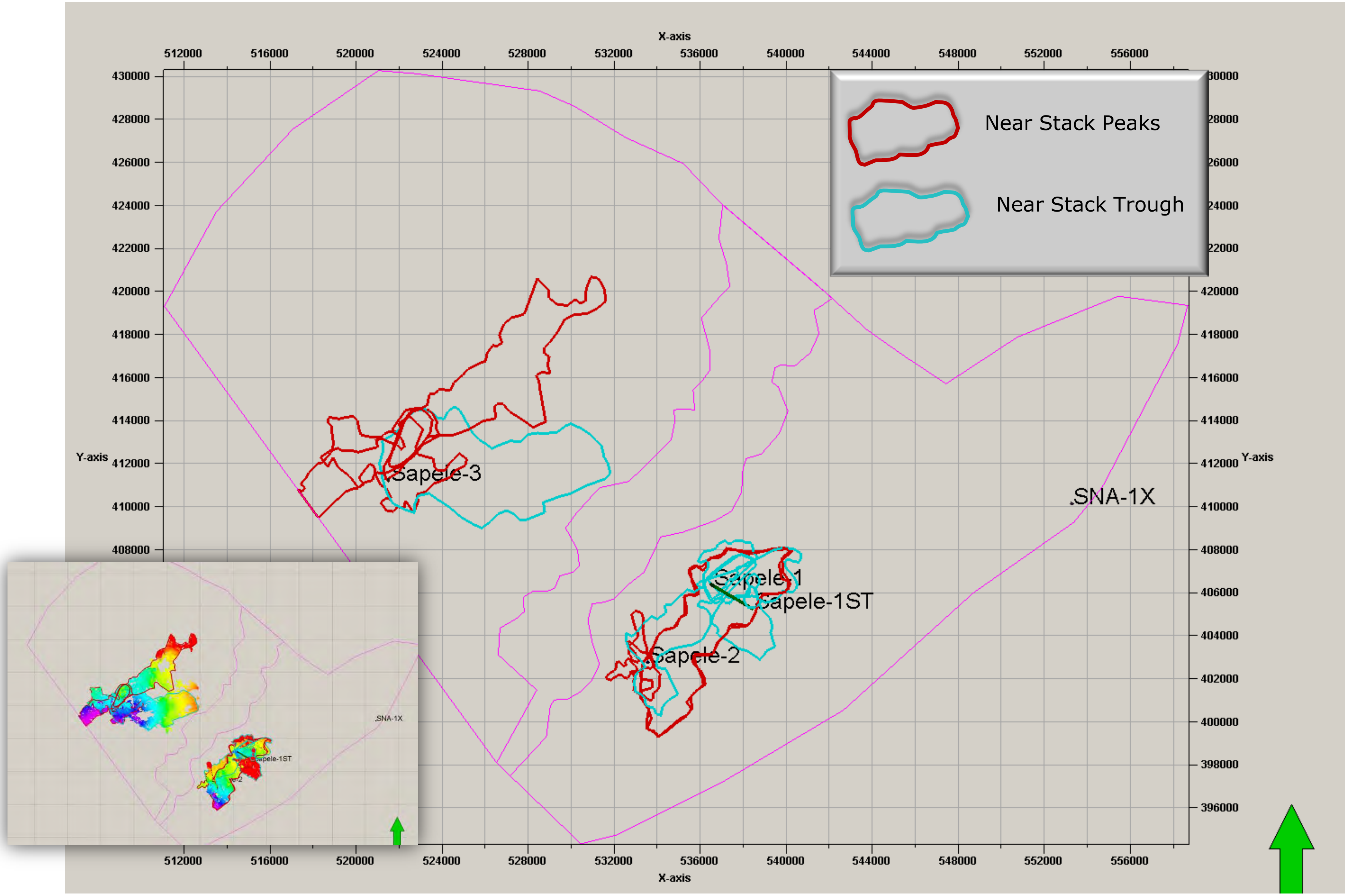
Near Stack – SE - Trough



70701

Near Stack Prospect Area Polygons (Peak and Trough)

Figure 54

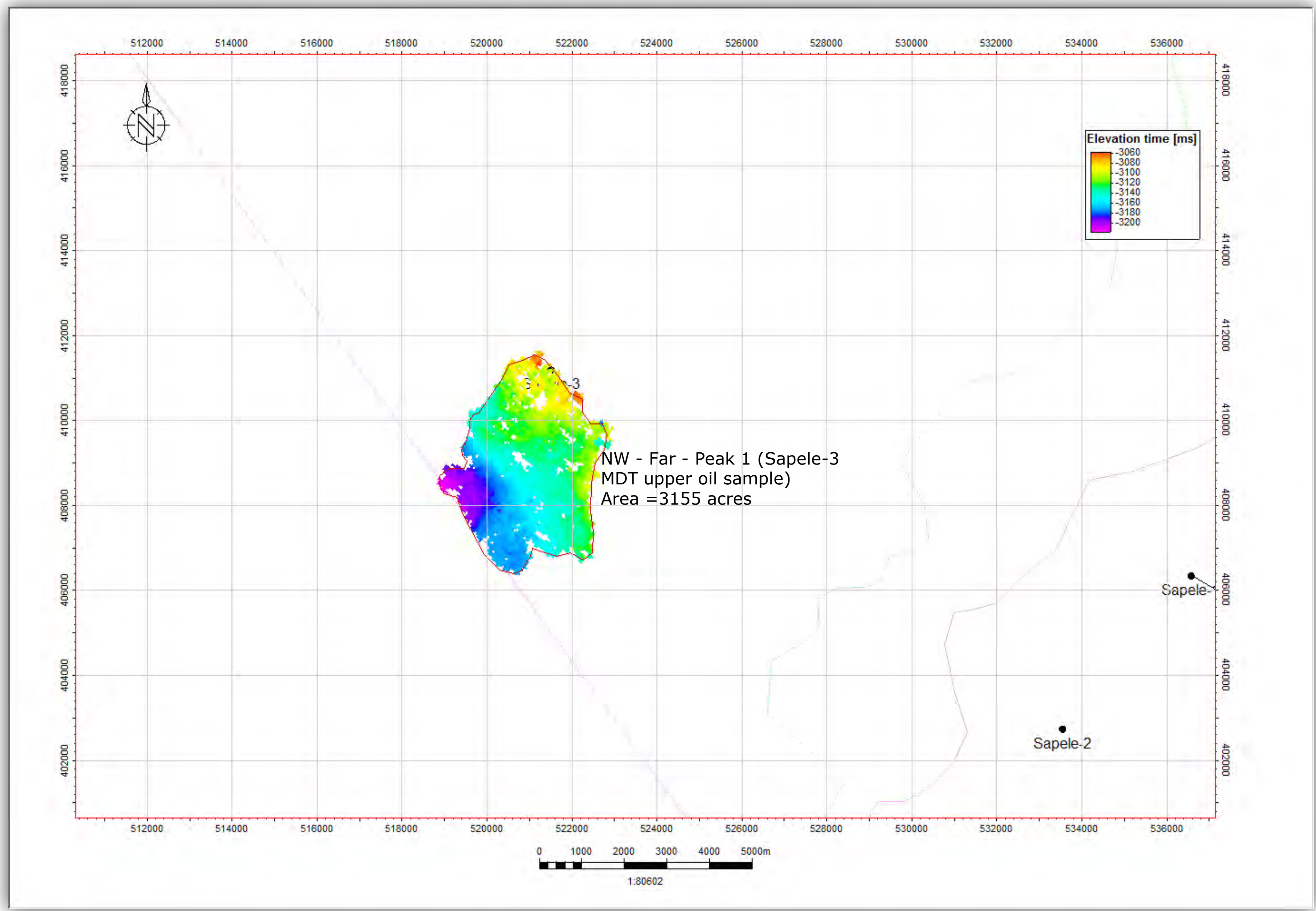


Near Stack Prospect Area Polygons (Peak and Trough)

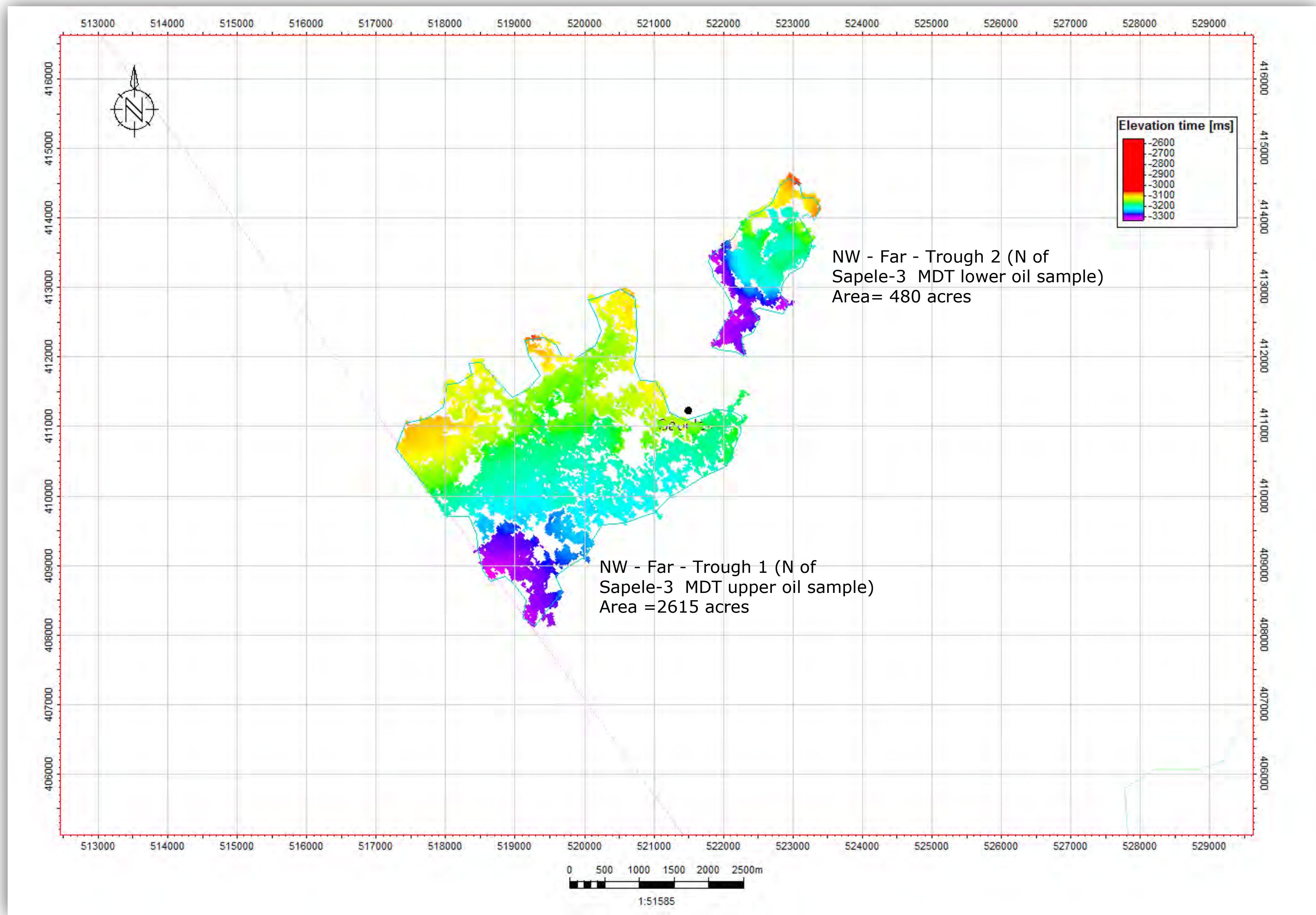
FAR STACK VOLUME

NW AREA – PEAK & TROUGH

SE AREA – PEAK & TROUGH



Far Stack – NW - Peak

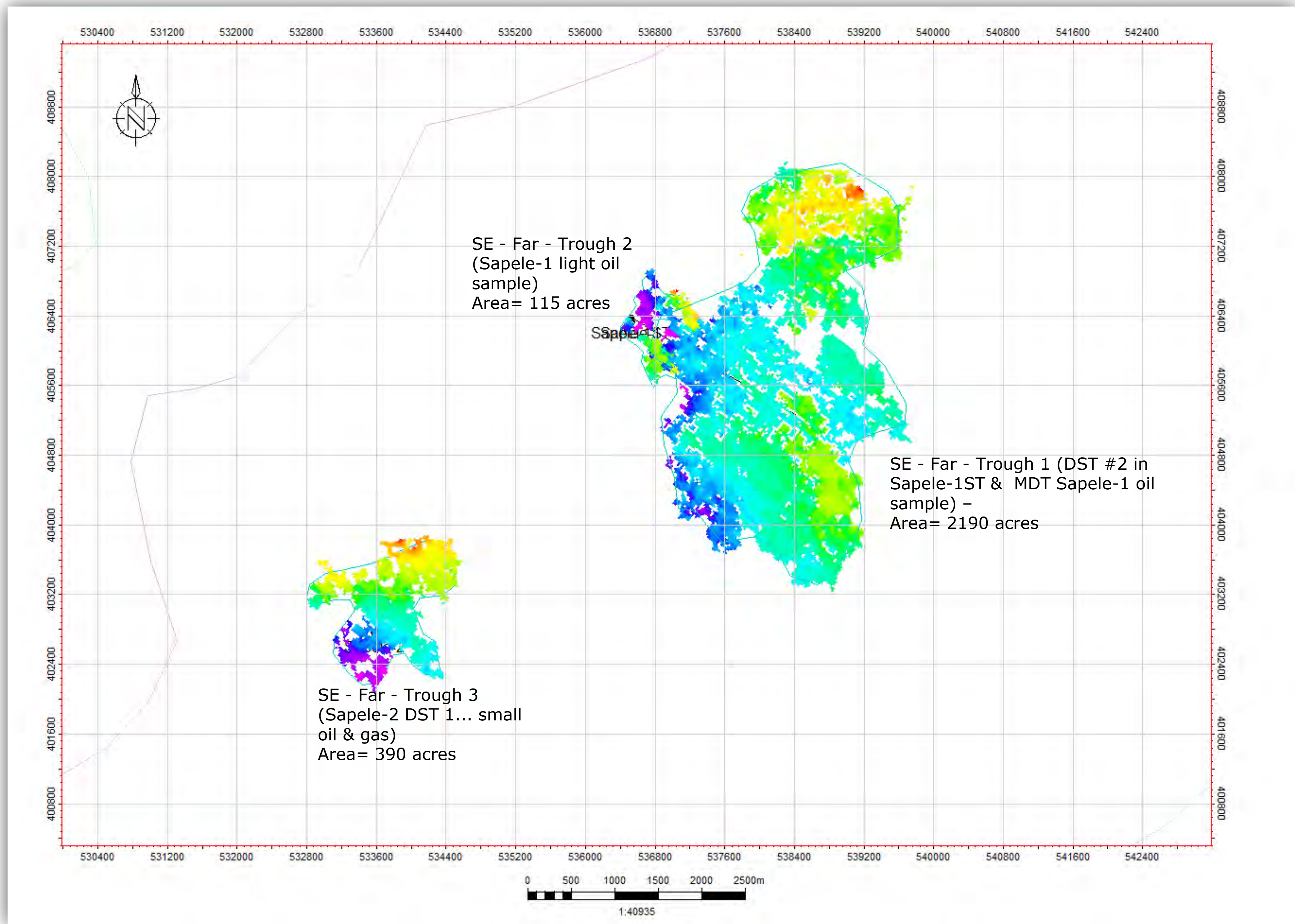


Far Stack – NW - Trough

70701

Sproule

Figure 58



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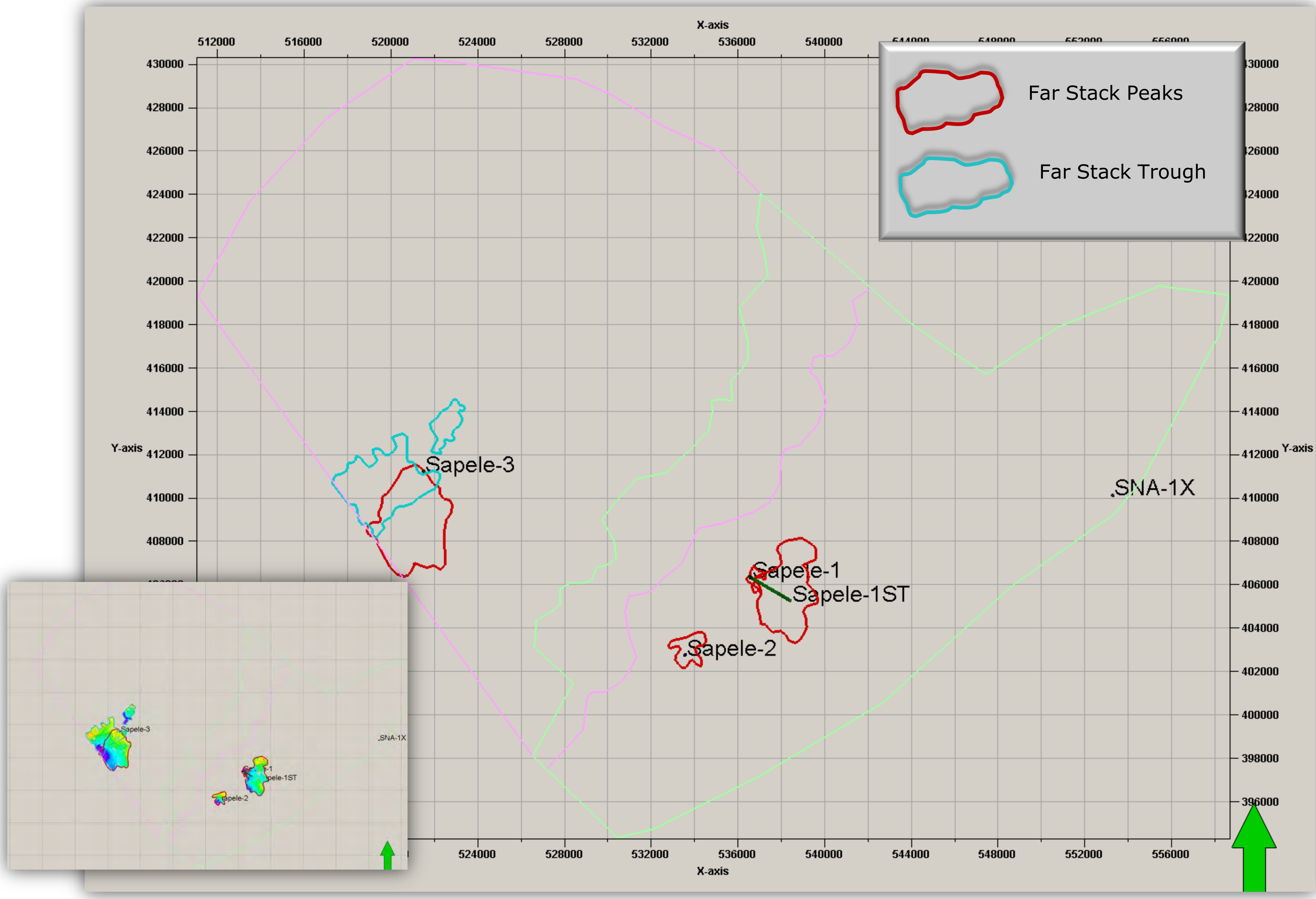
Far Stack – SE - Trough

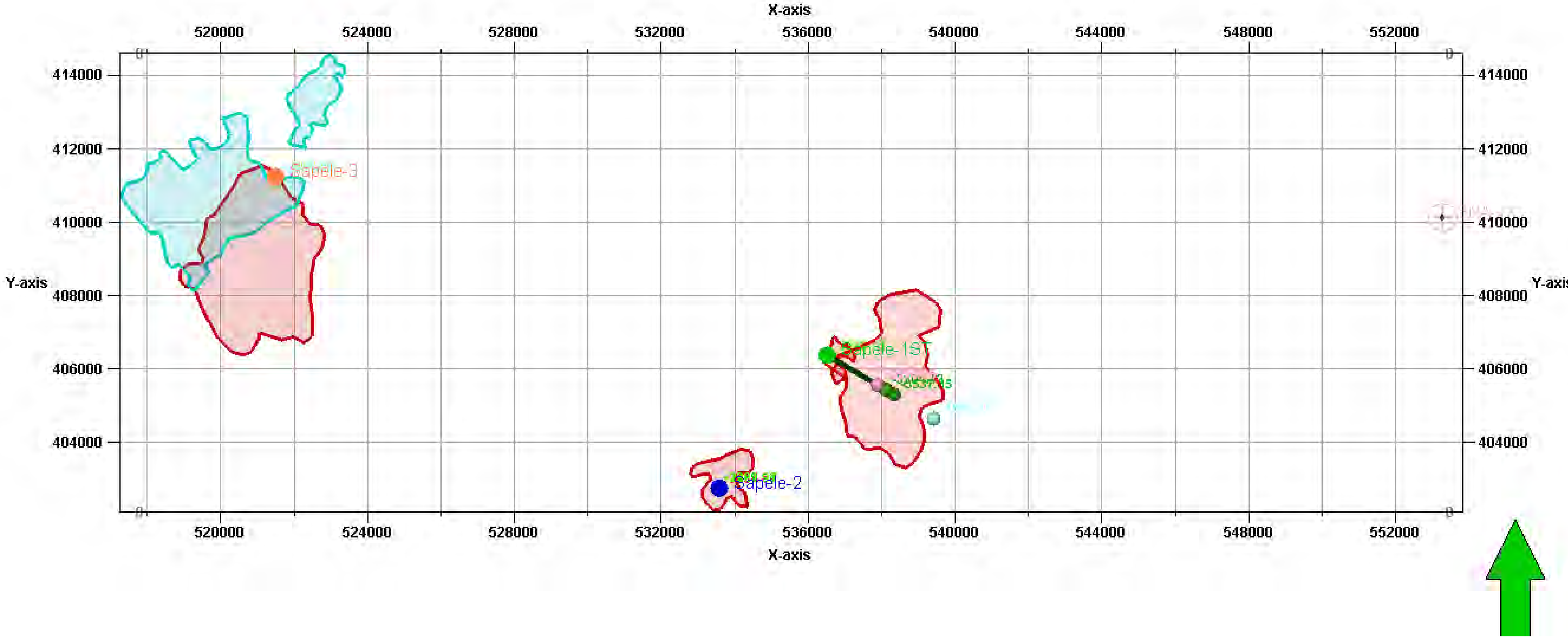
Figure 59



Far Stack Prospect Area Polygons (Peak and Trough)

Figure 60

Sproule

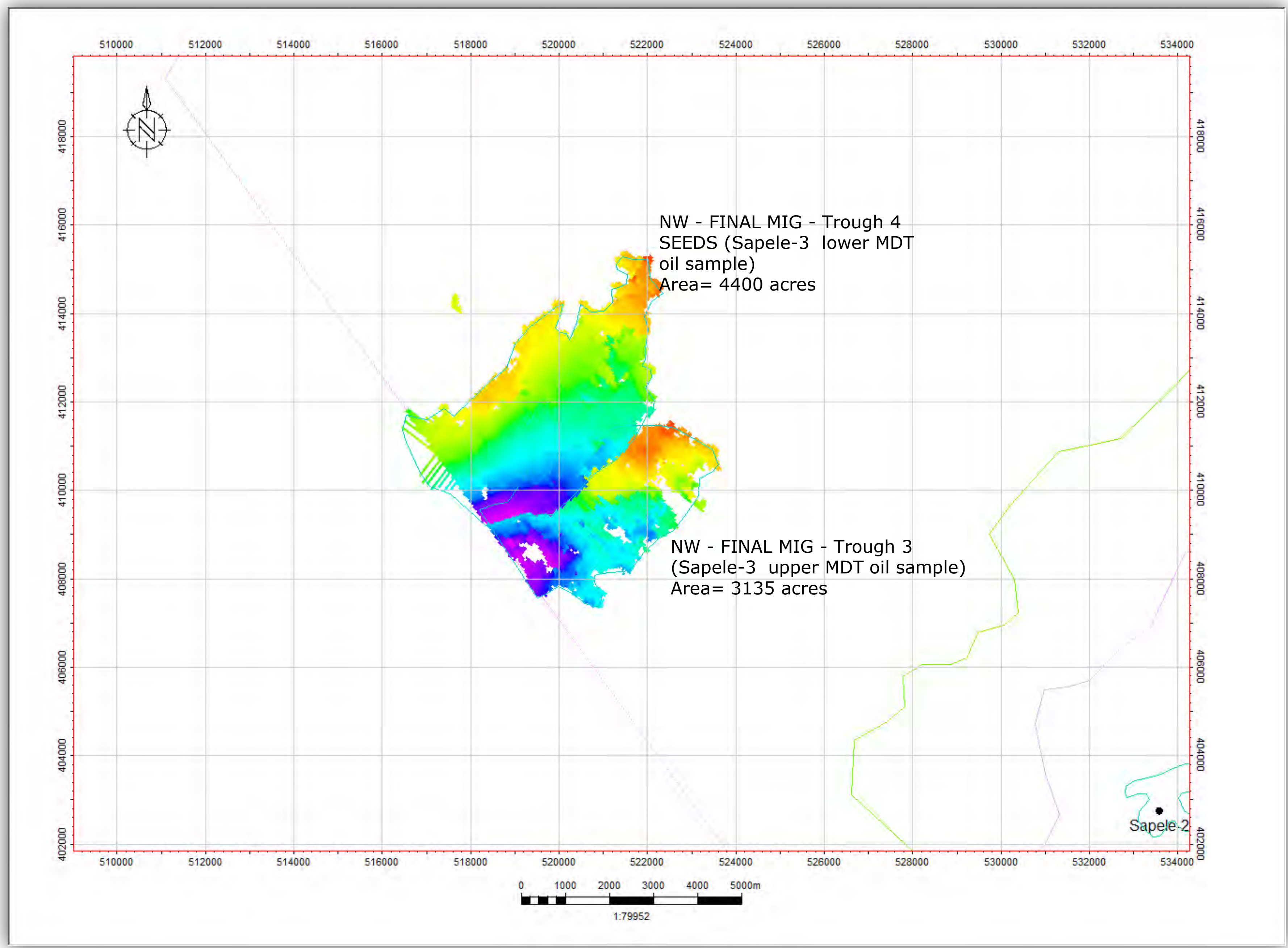


Far Stack Prospect Area Polygons (Peak and Trough)

FINAL STACK VOLUME

NW AREA –TROUGH

SE AREA – PEAK & TROUGH



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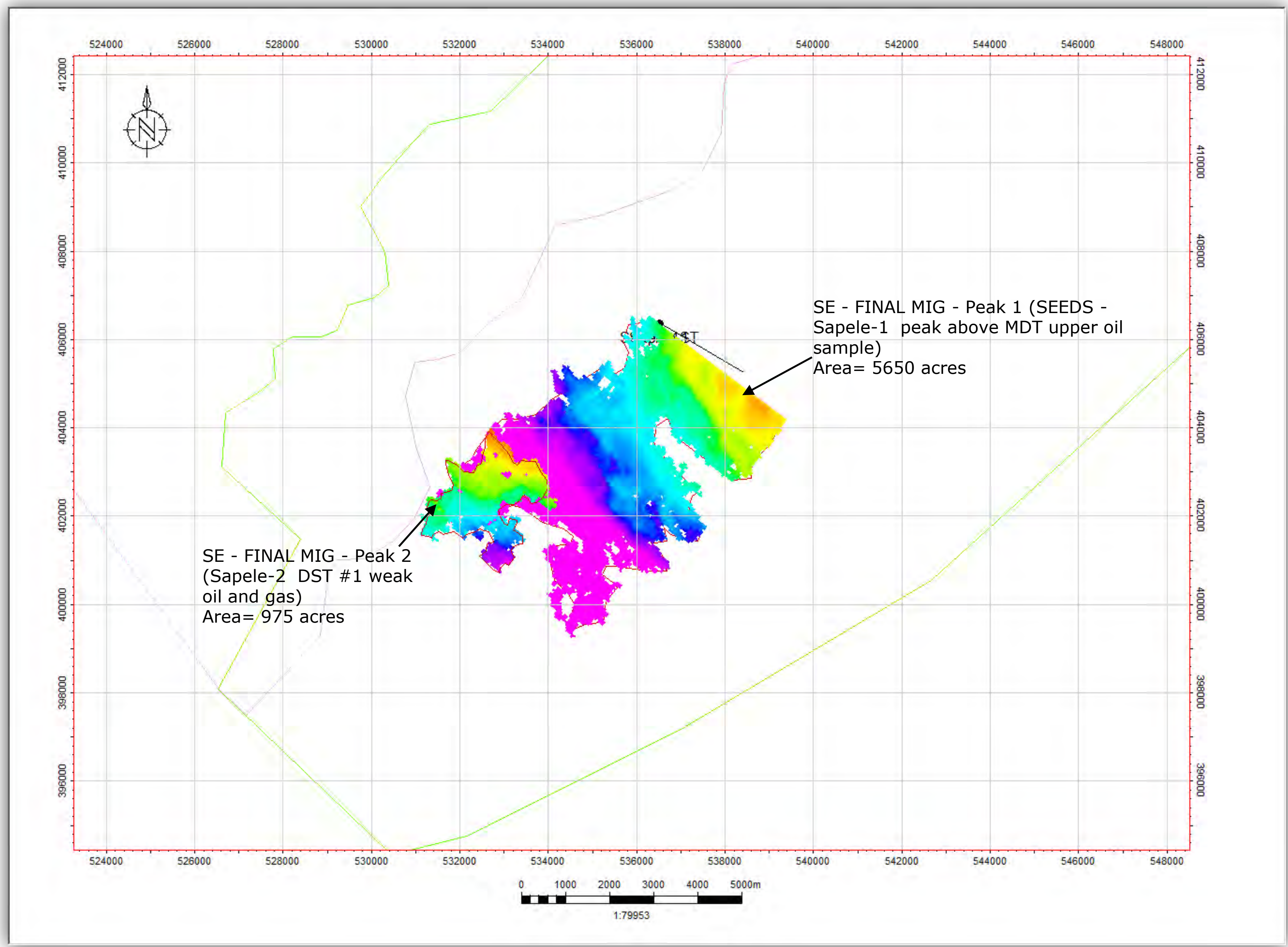
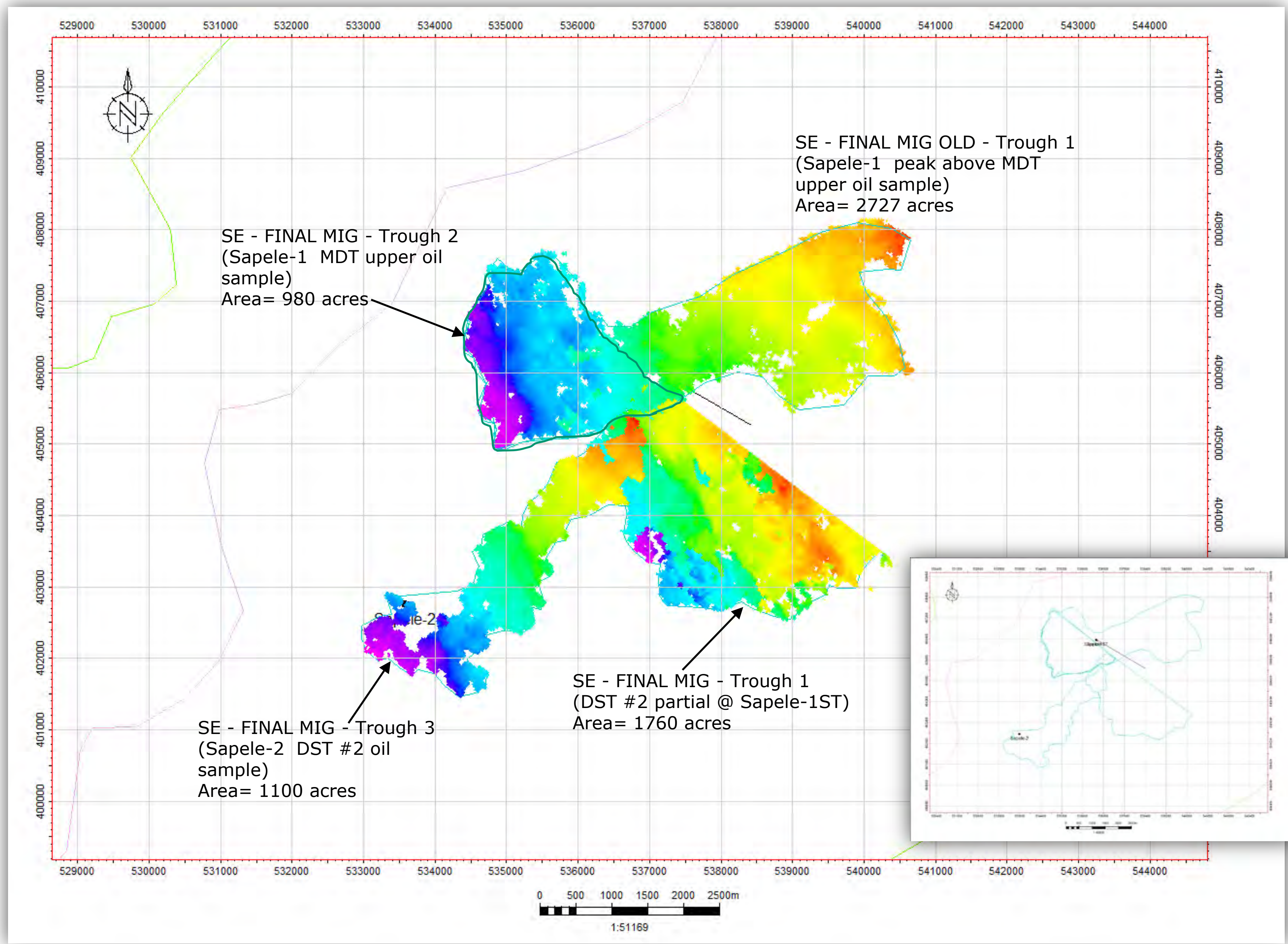
Final Stack – NW - Trough

Figure 63



Final Stack – SE- Peaks

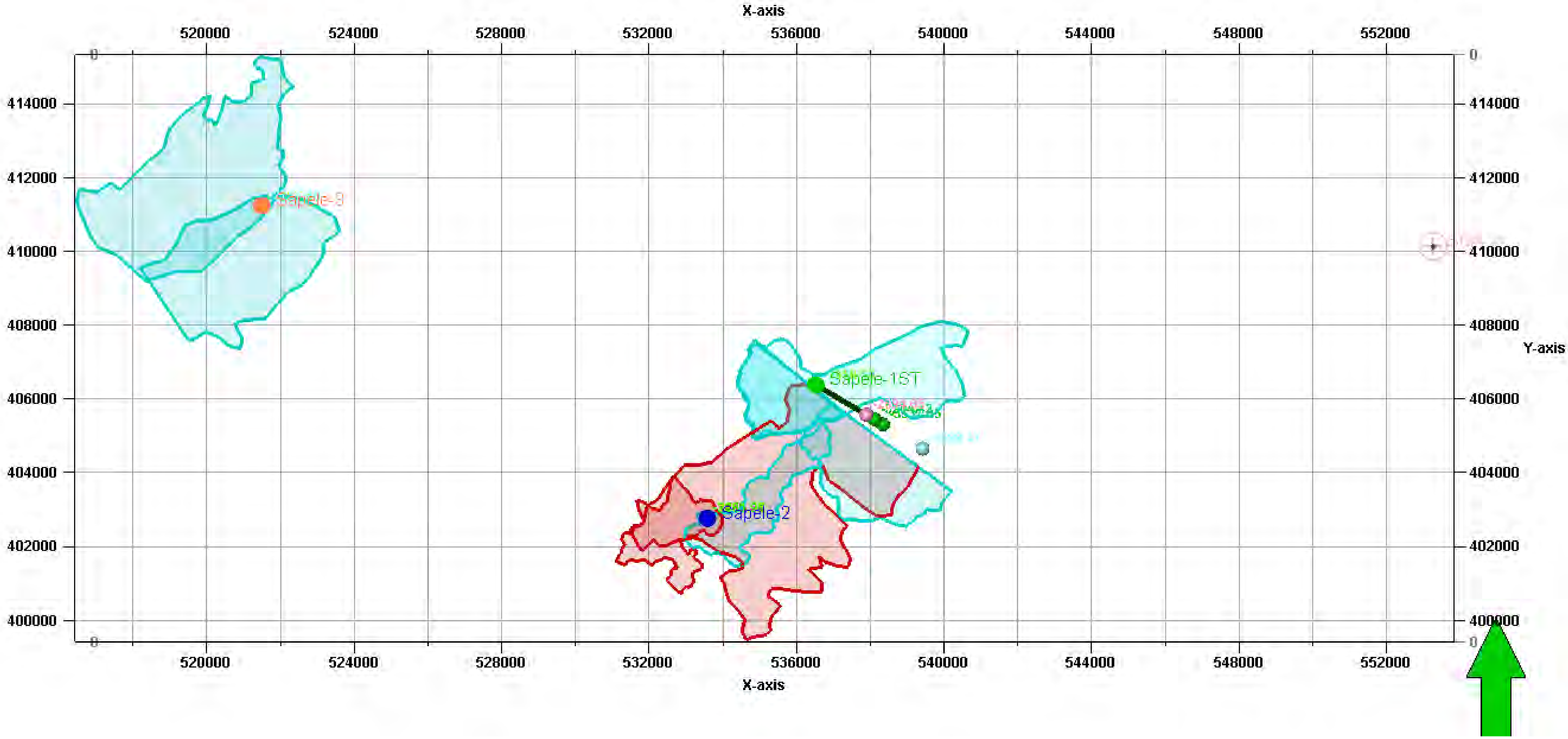


Final Stack – SE- Trough

Figure 65

Sproule

Final Stack Prospect Area Polygons (Peak and Trough)



Final Stack Prospect Area Polygons (Peak and Trough)

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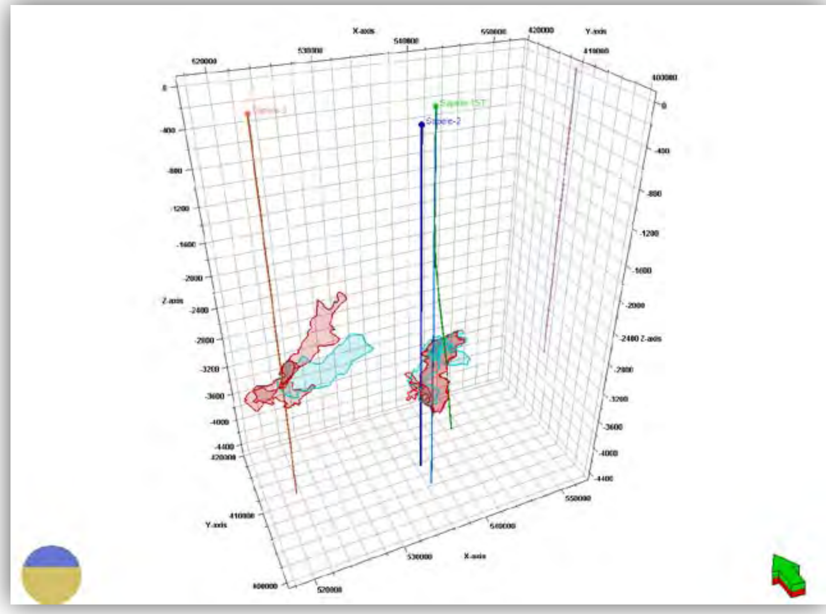
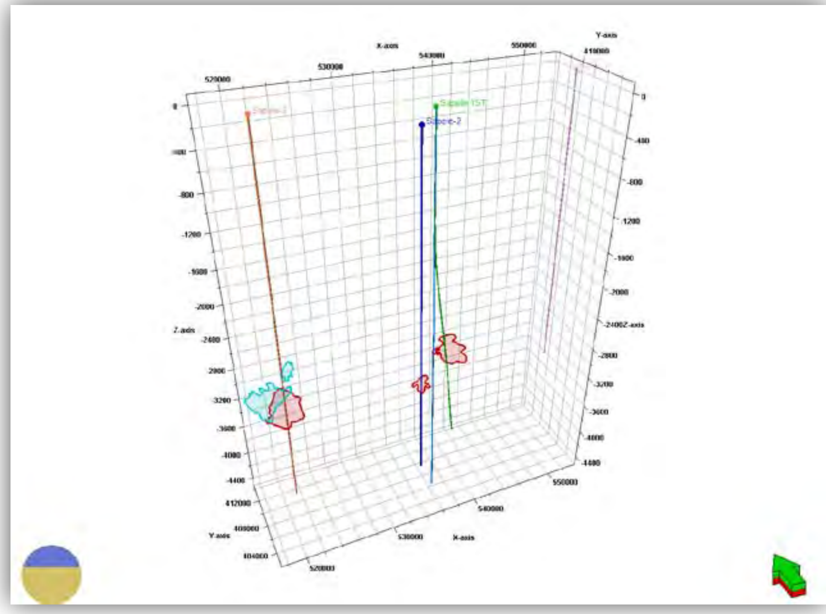
Figure 67

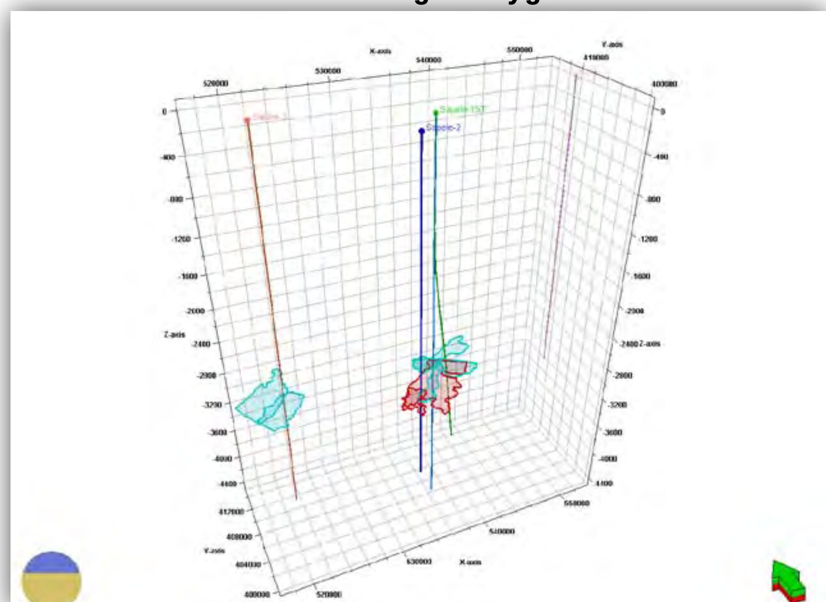
Near Stack – Peak & Trough Polygons



Far Stack – Peak & Trough Polygons

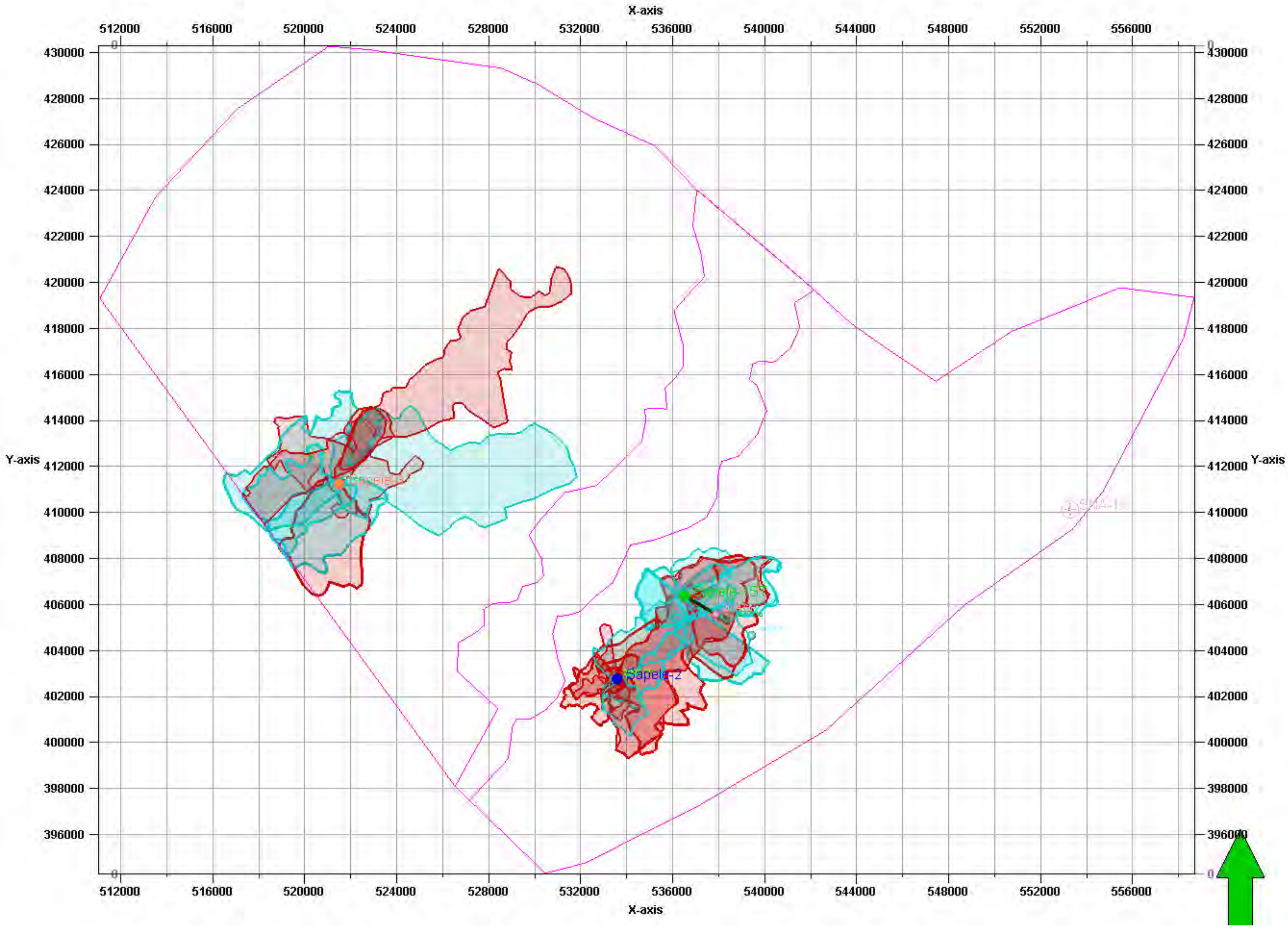


Final Stack – Peak & Trough Polygons



3D View of the Discovered PIIP Polygons – Peak & Troughs

Figure 68



Discovered PIIP - Near, Far, and Final Stack Polygon Stacked

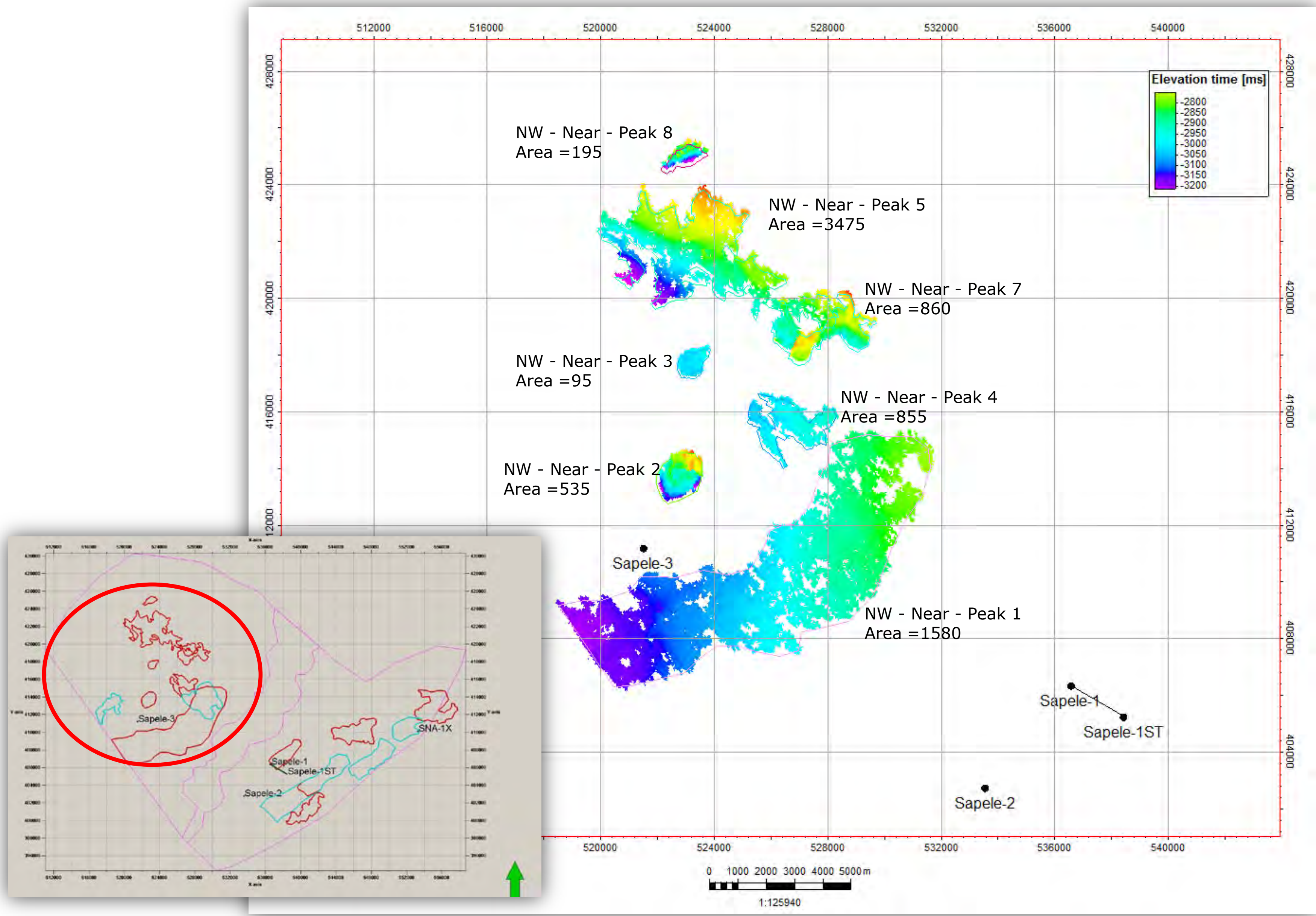
Figure 69

UNDISCOVERED PETROLEUM INITIALLY-IN-PLACE (PIIP)

NEAR STACK VOLUME

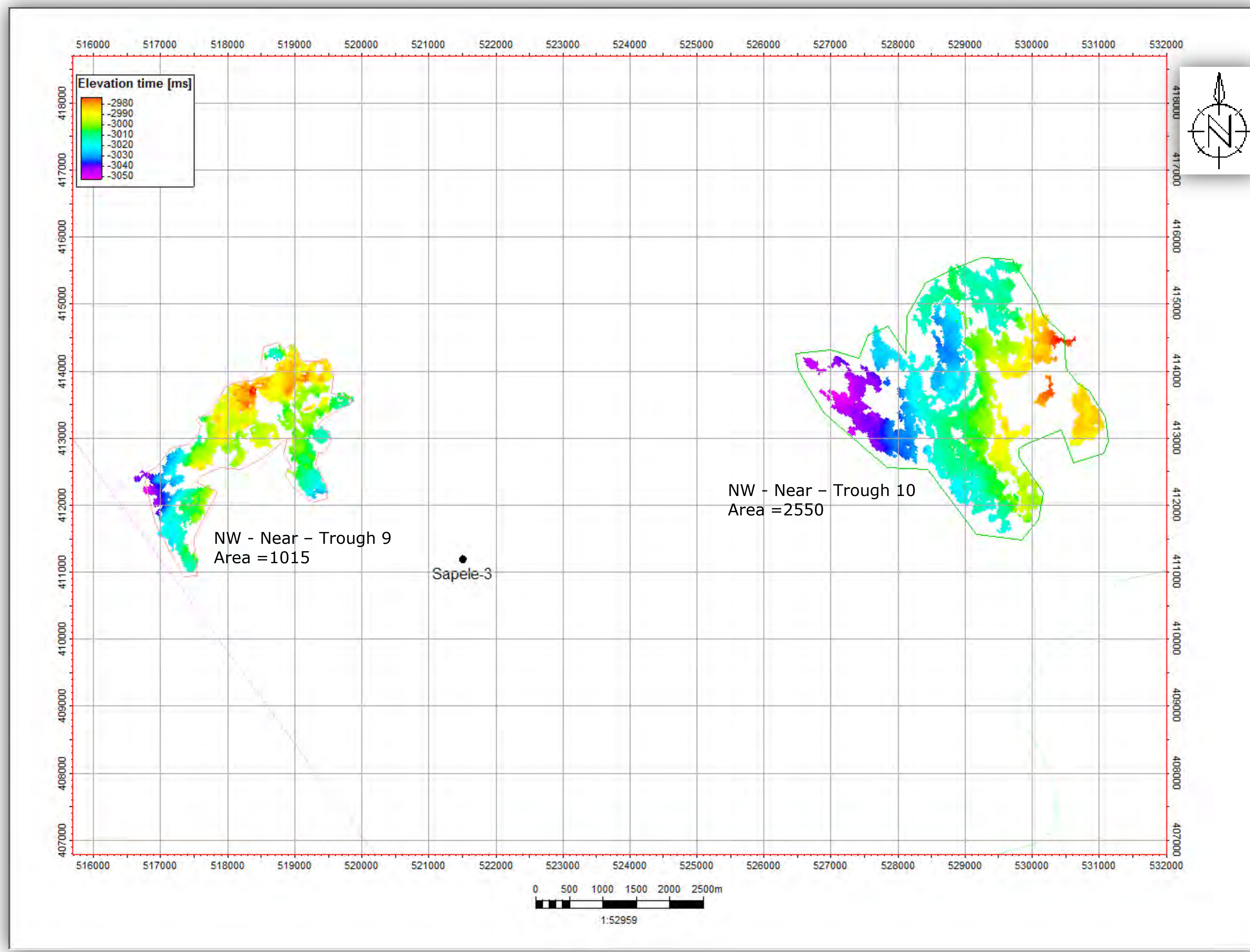
NW AREA – PEAK & TROUGH

SE AREA – PEAK & TROUGH

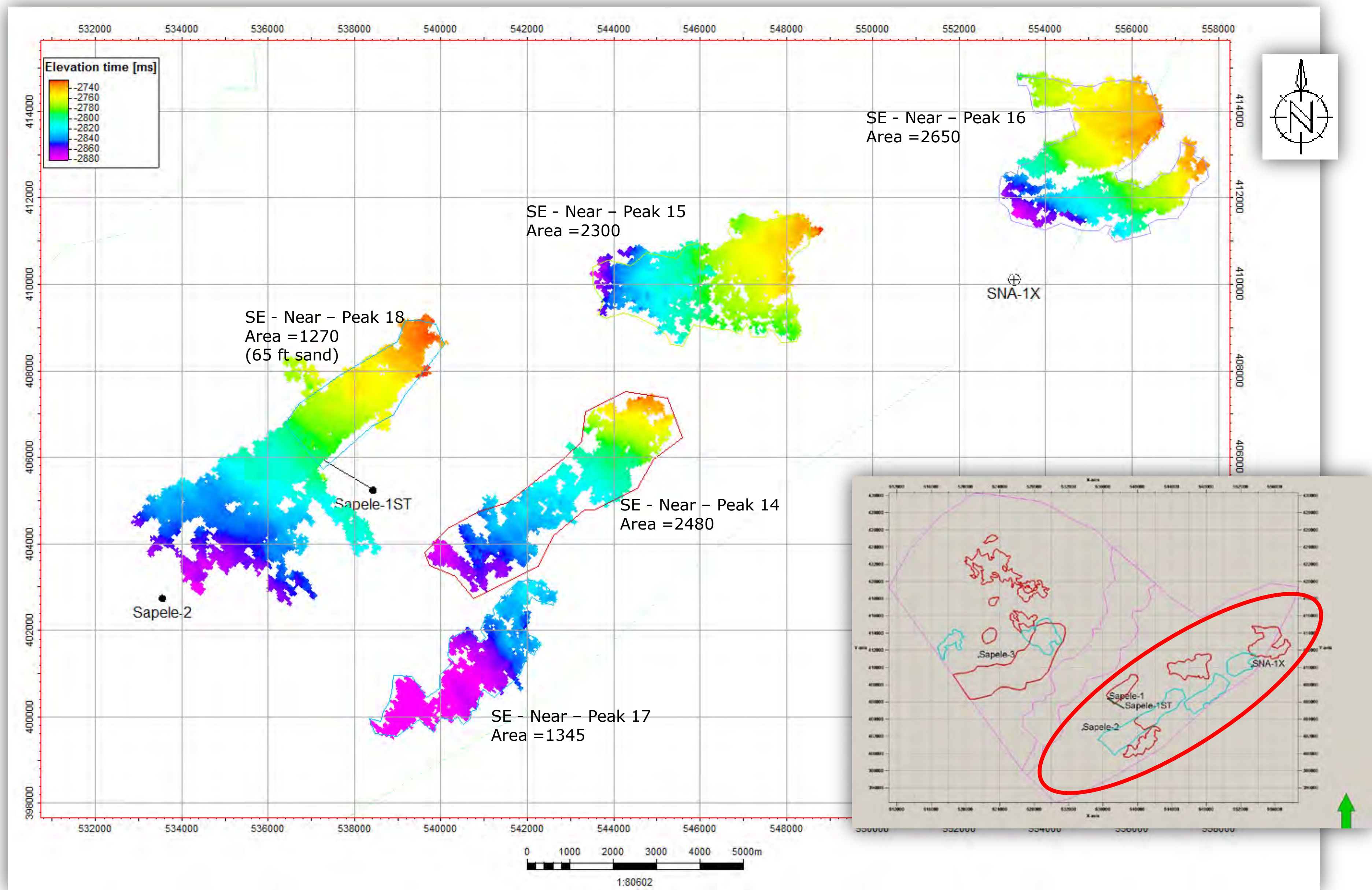


Near Stack – NW - Peak

Figure 71



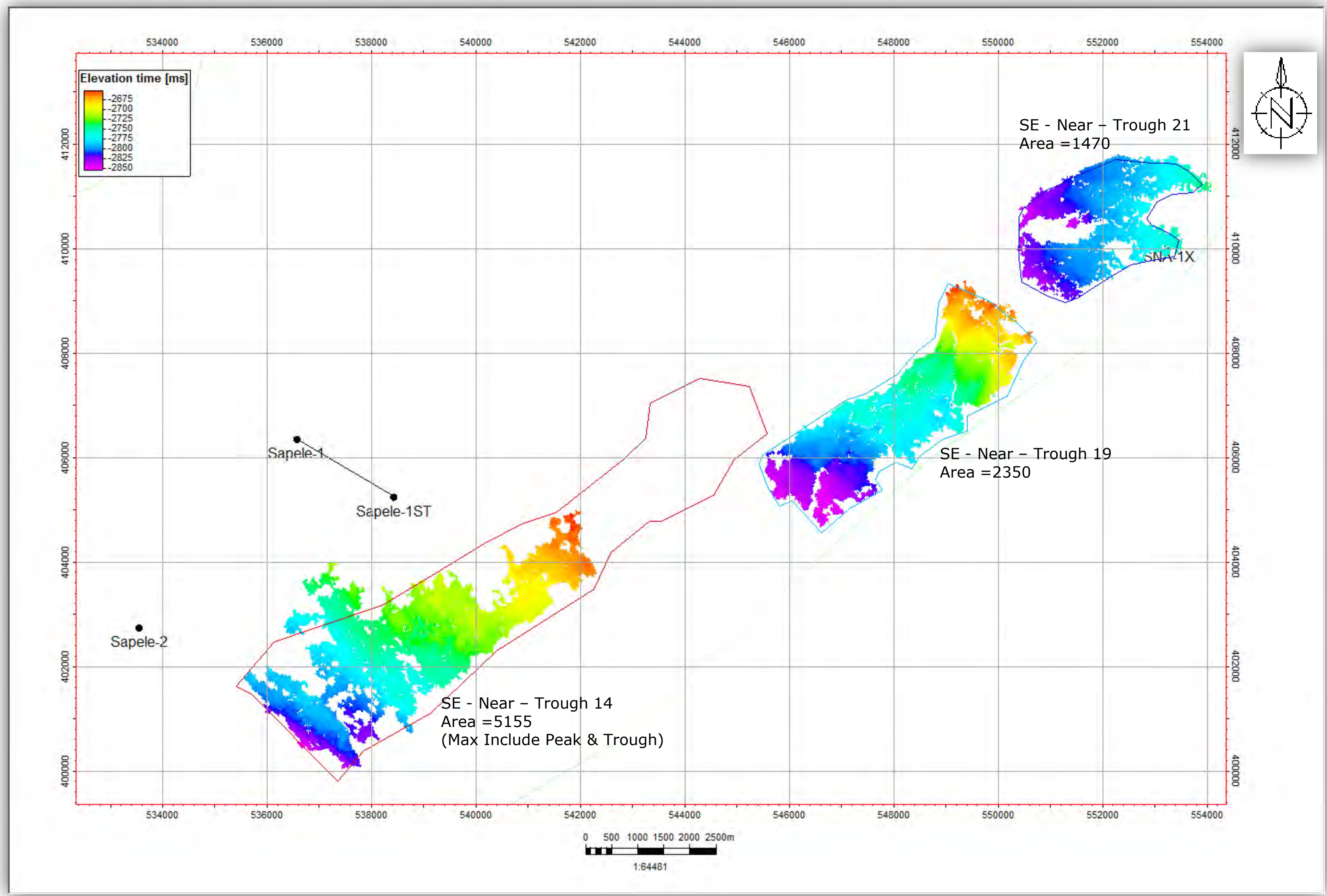
Near Stack – NW - Trough



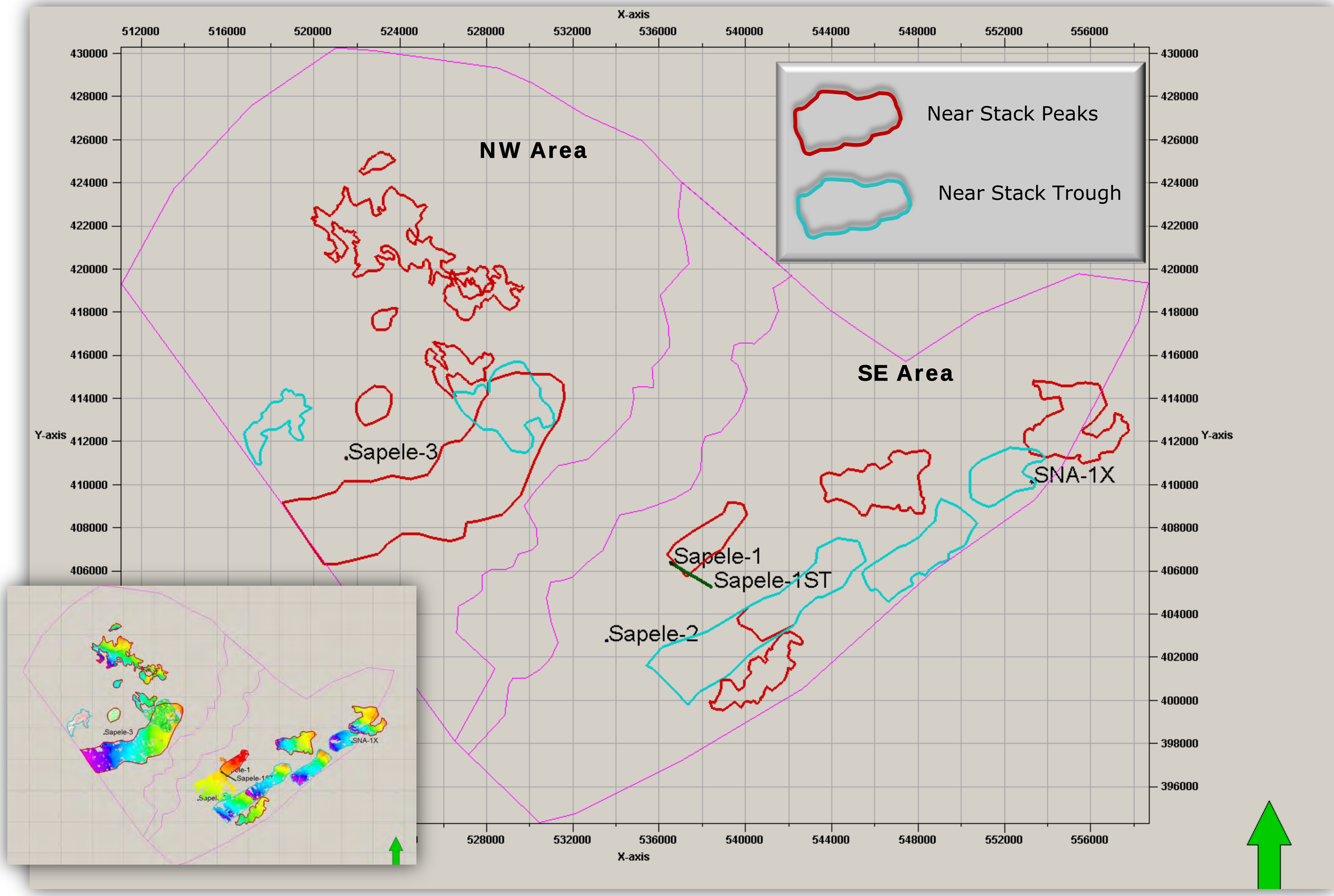
Near Stack – SE- Peak

Figure 73

Sproule



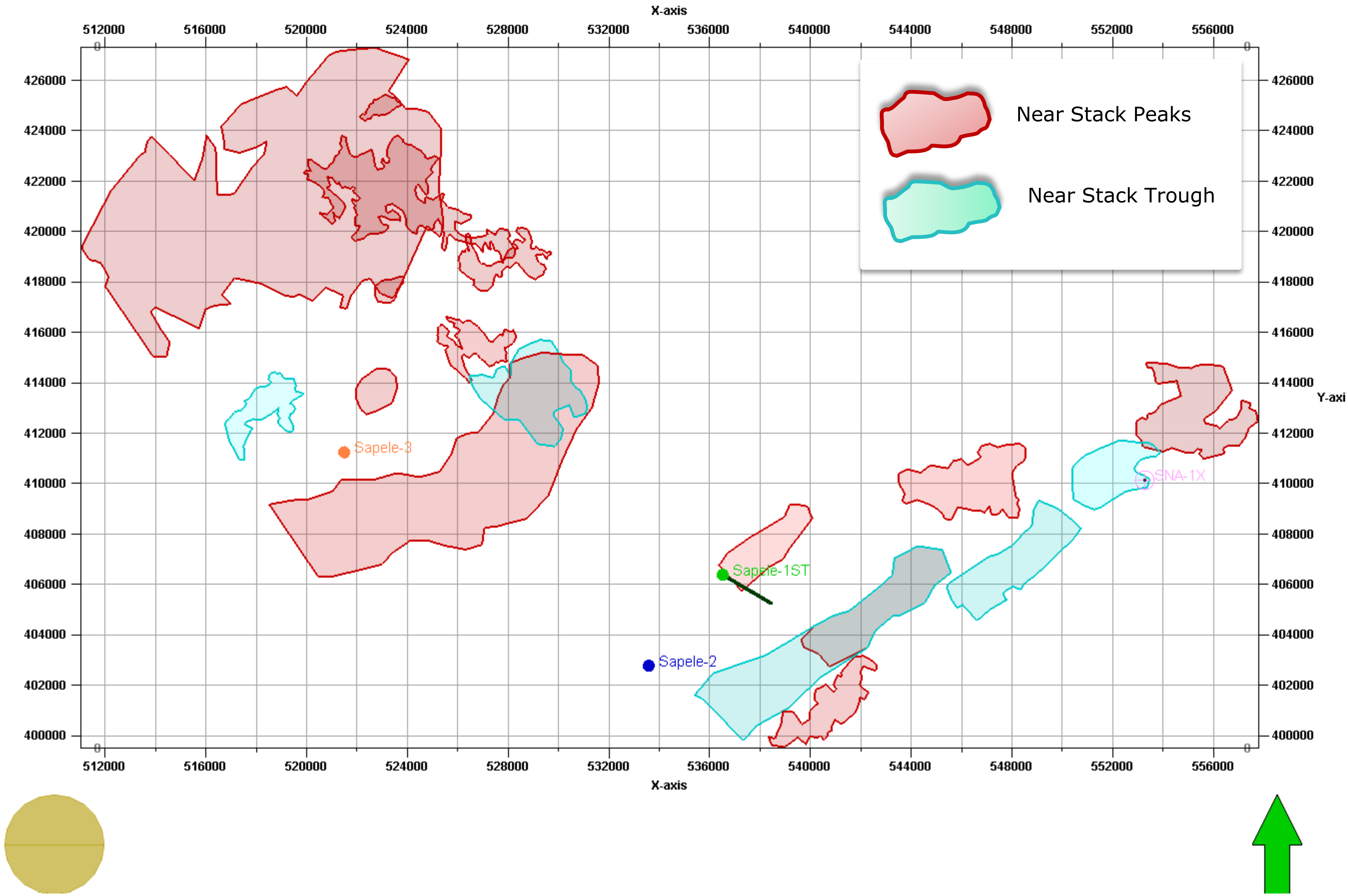
Near Stack – SE- Trough



Near Stack Prospect Area Polygons (Peak and Trough)

Sproule

Figure 75



Near Stack Prospect Area Polygons (Peak and Trough)

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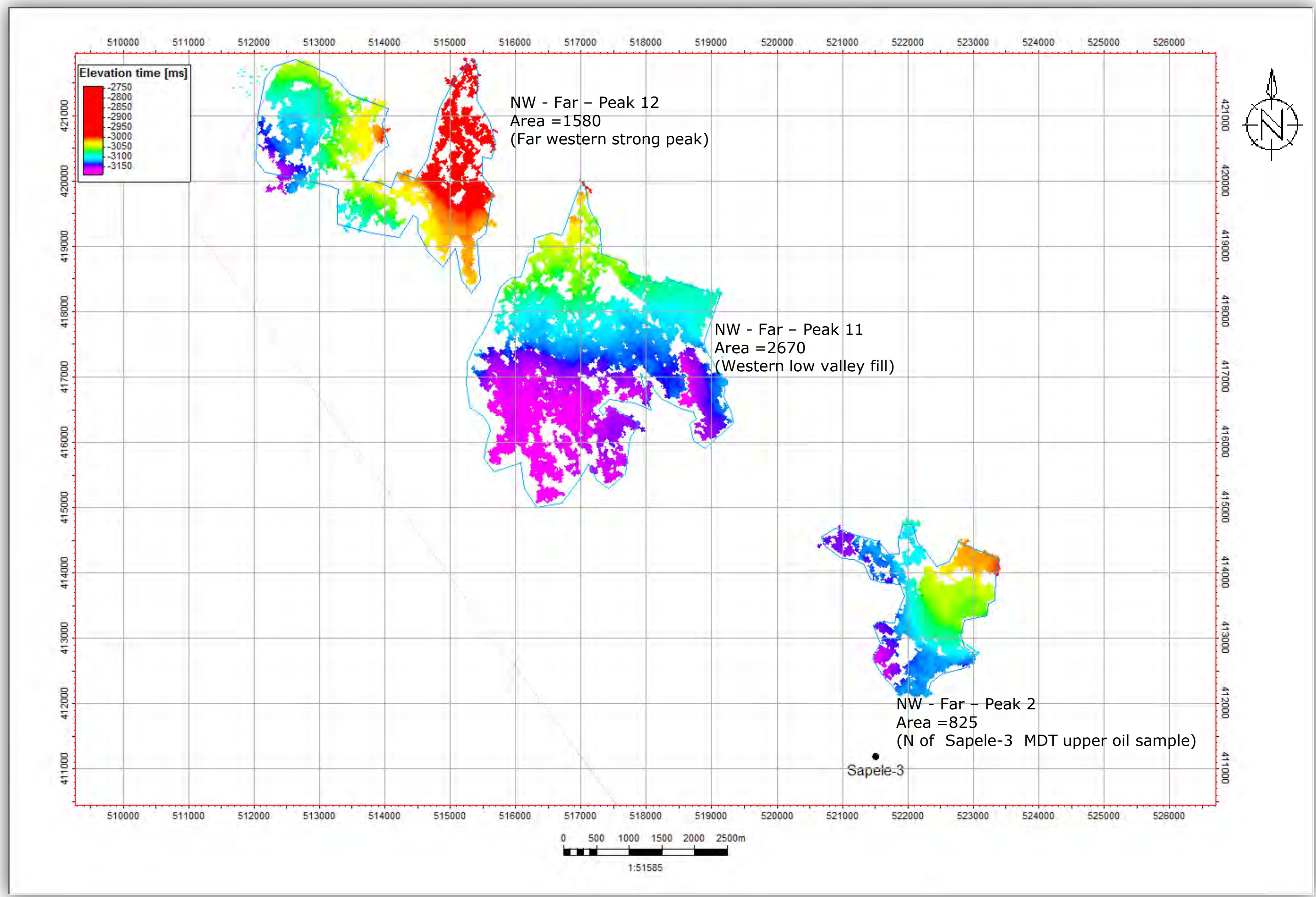
Sproule

Figure 76

FAR STACK VOLUME

NW AREA – PEAK & TROUGH

SE AREA –TROUGH



Far Stack – NW - Peak

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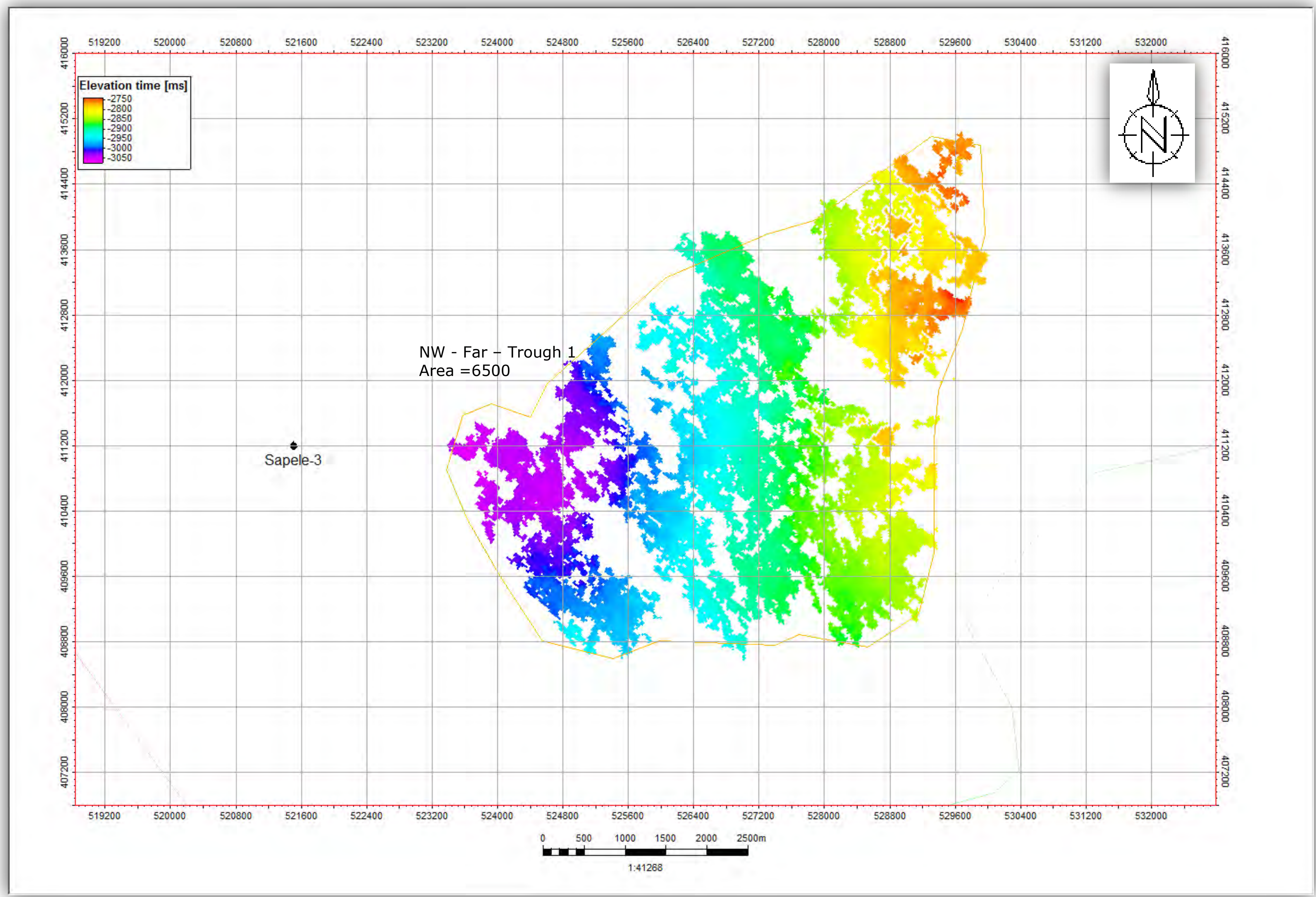
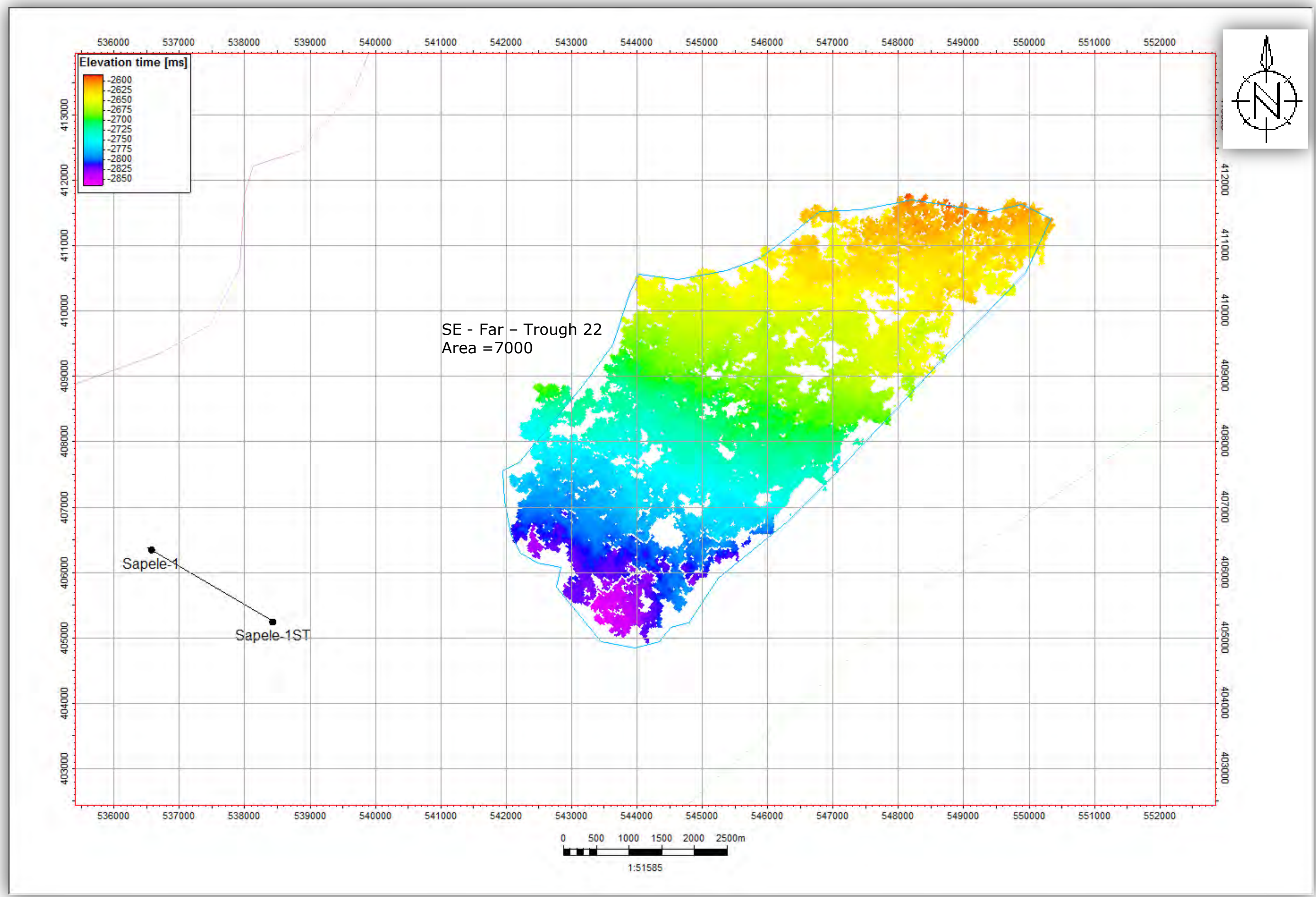
Sproule

Figure 78



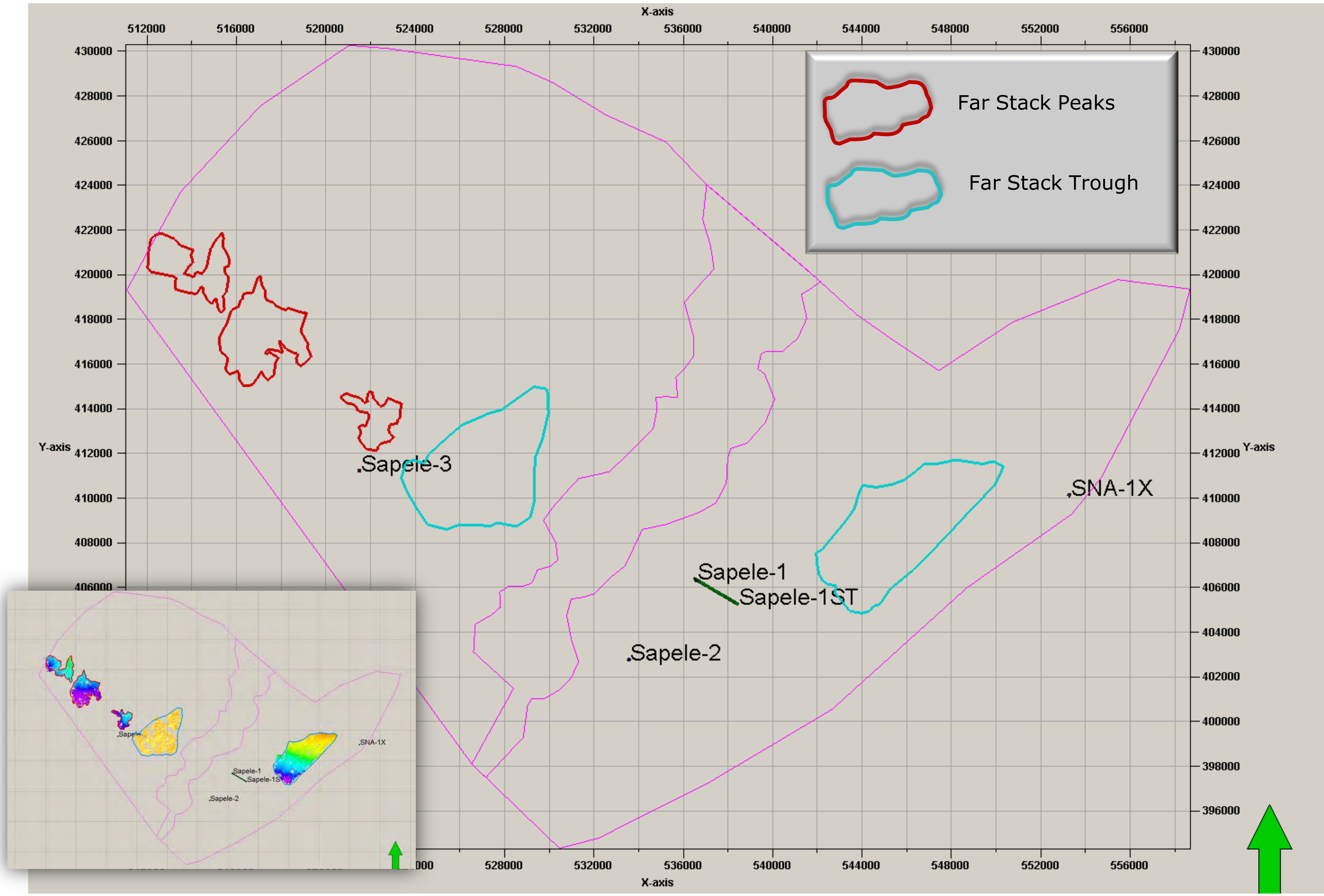
Far Stack – NW - Trough



Far Stack – SE - Trough

Figure 80

Sproule



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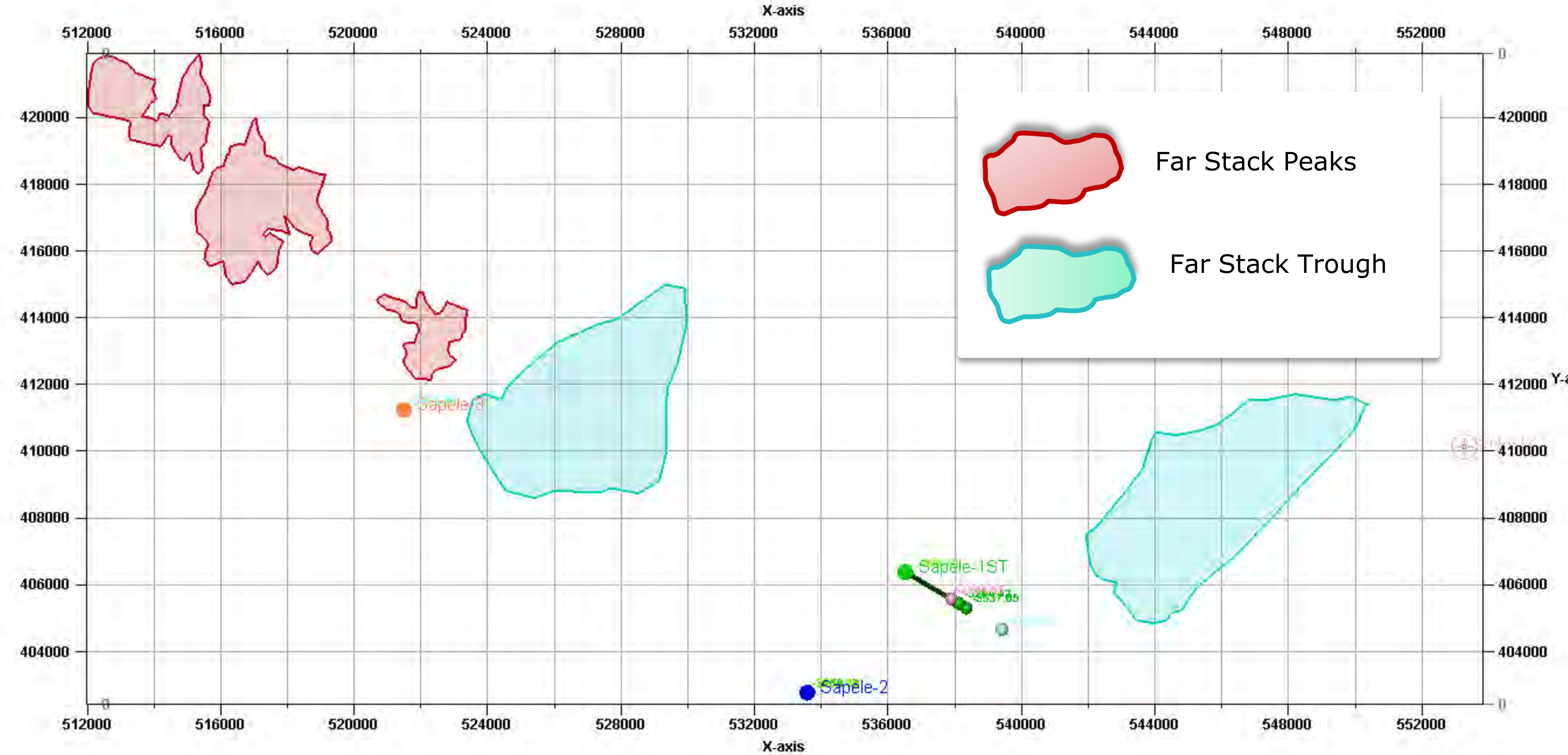
Far Stack Prospect Area Polygons (Peak and Trough)

Sproule

Figure 81



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Far Stack Prospect Area Polygons (Peak and Trough)

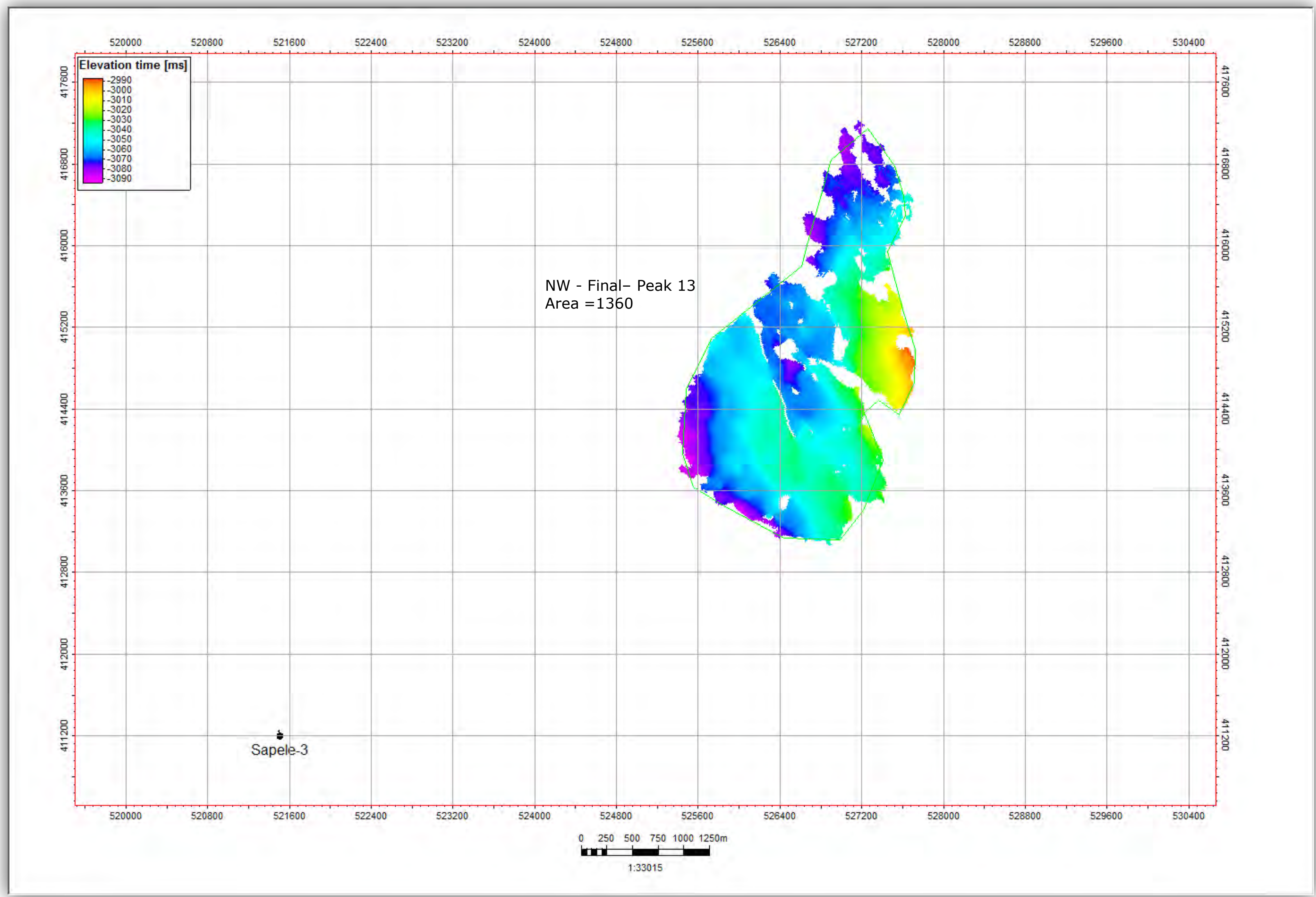
Sproule

Figure 82

FINAL STACK VOLUME

NW AREA – PEAK & TROUGH

SE AREA – PEAK & TROUGH



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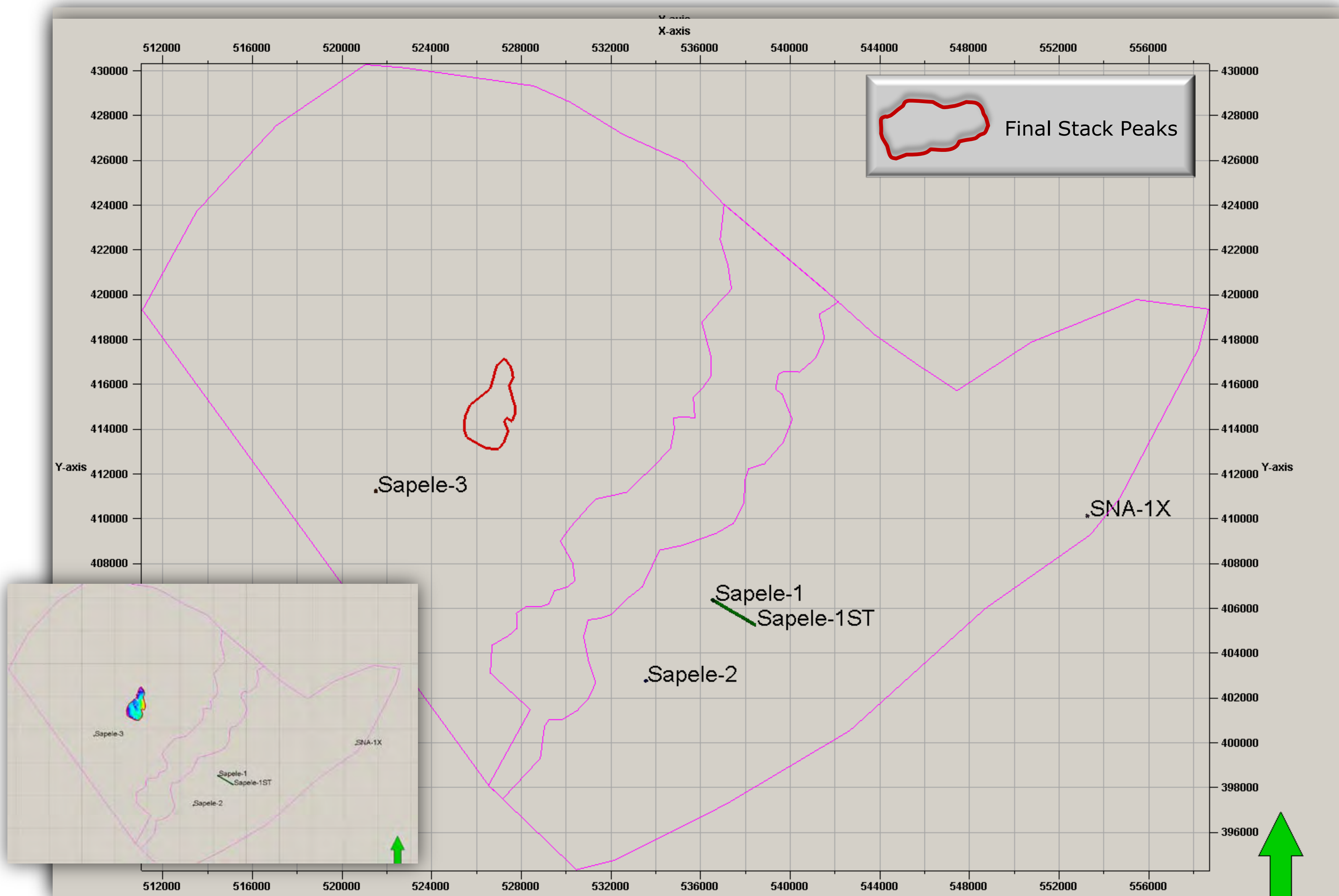
Final Stack – NW - Peak

Figure 84



Final Stack Prospect Area Polygons (Peak and Trough)

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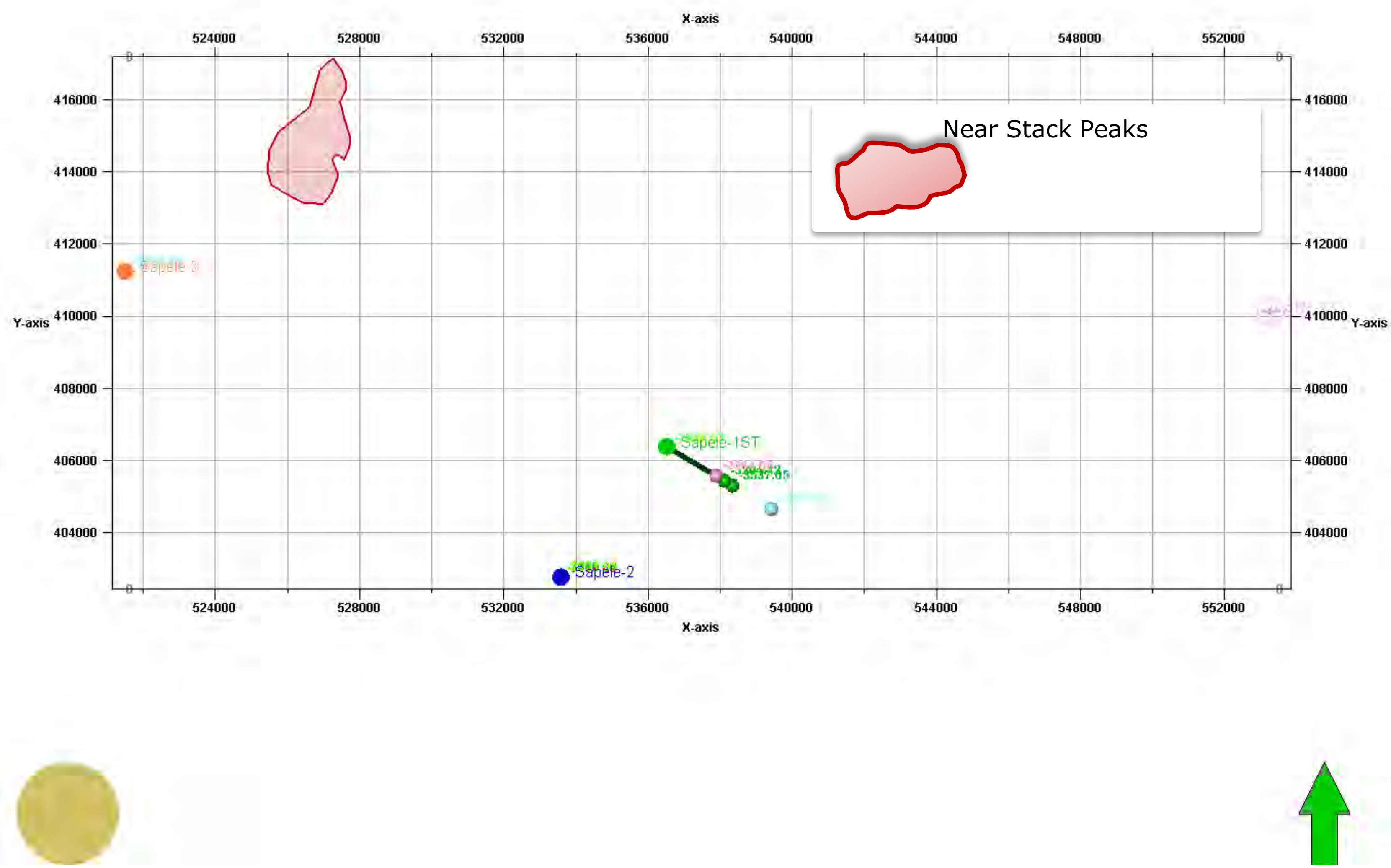
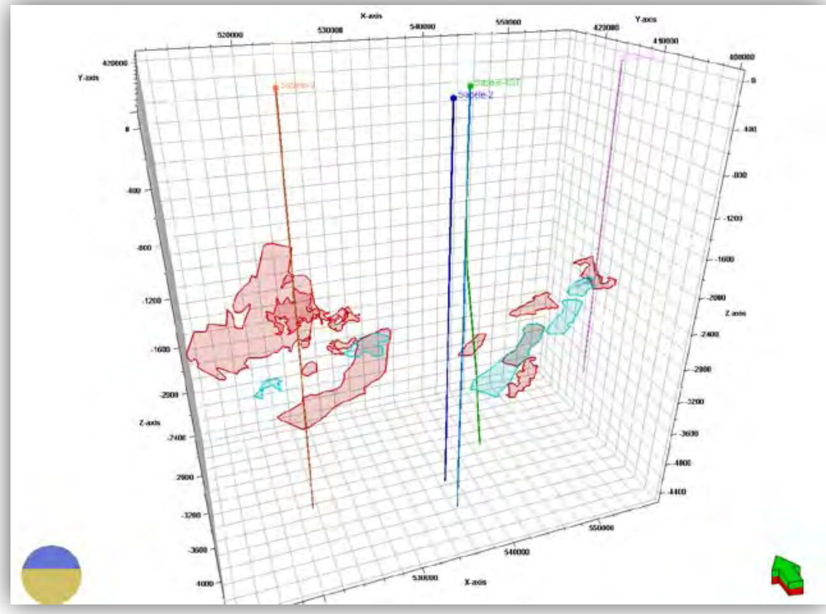
Figure 85

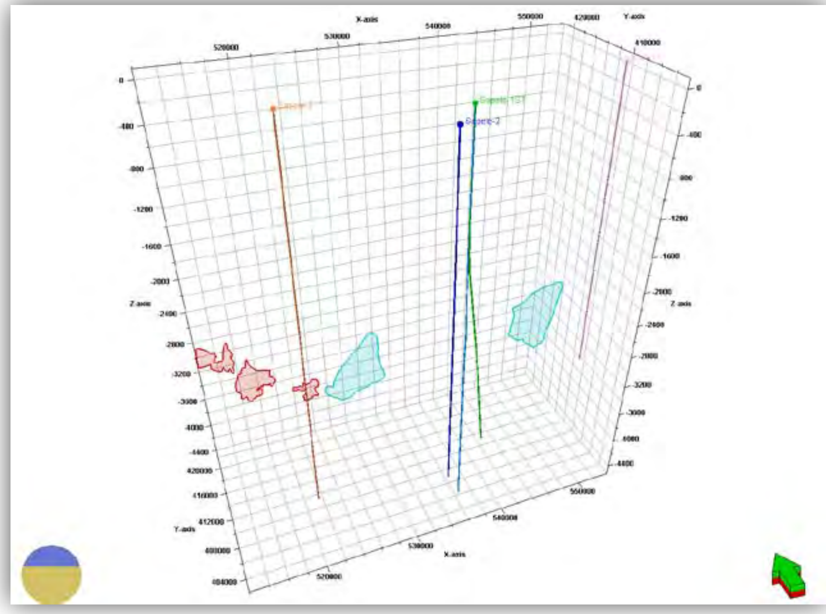


Final Stack Prospect Area Polygons (Peak and Trough)

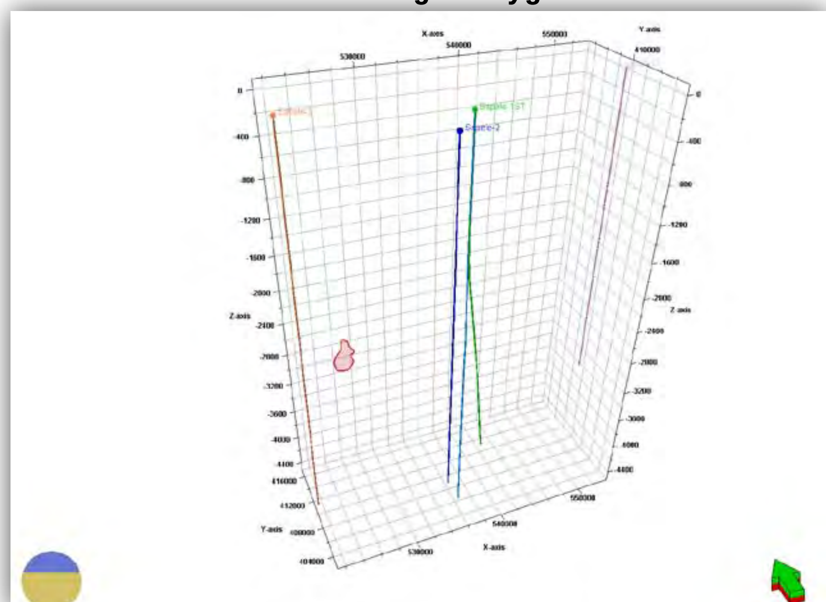
Near Stack – Peak & Trough Polygons



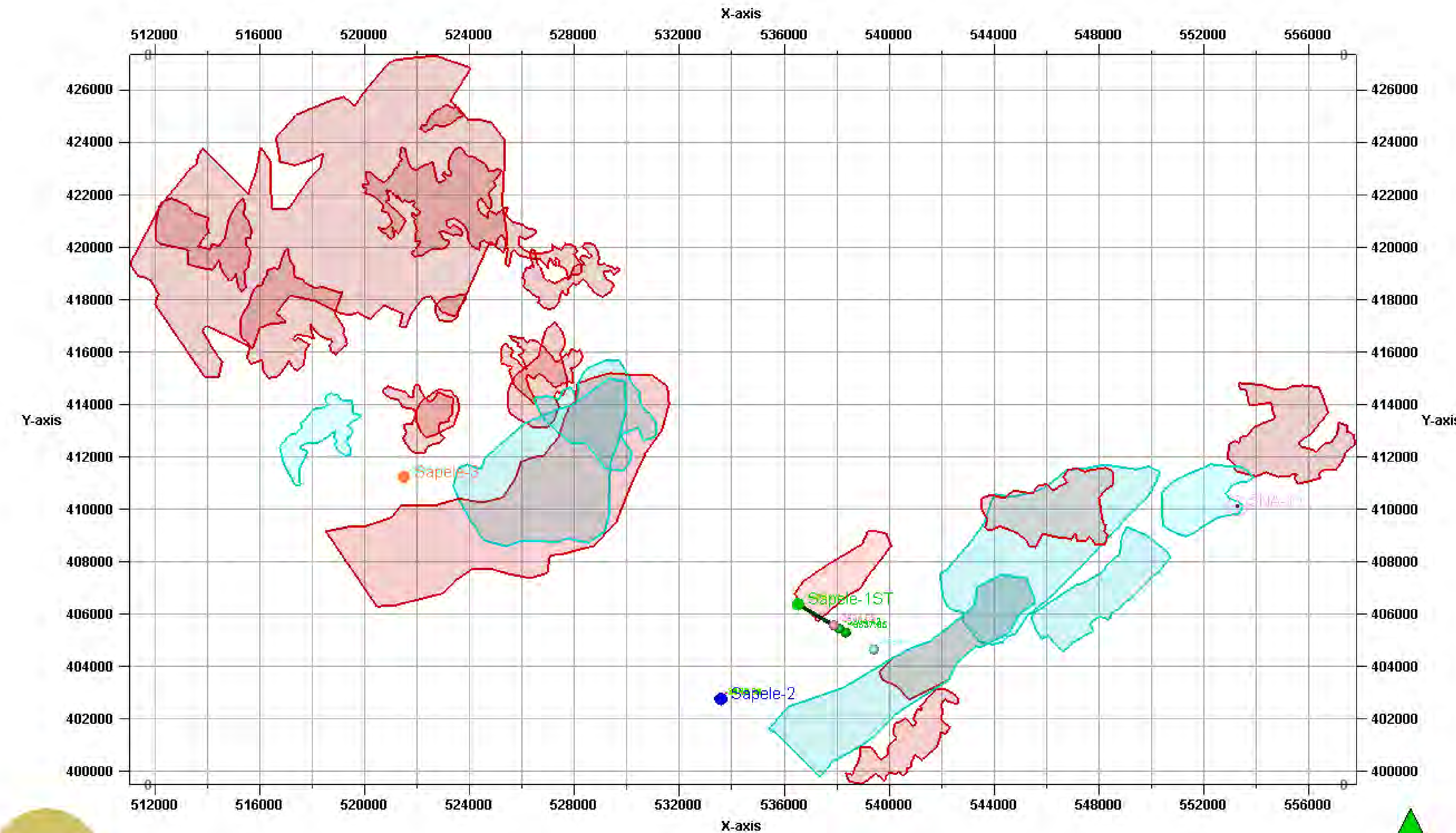
Far Stack – Peak & Trough Polygons



Final Stack – Peak & Trough Polygons



3D View of the Undiscovered PIIP Polygons – Peak & Troughs



Undiscovered PIIP - Near, Far, and Final Stack Polygon Stacked

Figure 88

Sproule

Reservoir Parameters for Probabilistic Unrisked Discovered Petroleum Initially-In-Place (PIIP) Estimation																									
Prospect	Area (km^2)				Net Pay (m)				Porosity				Hydrocarbon Saturation				Bo (bbl/STB)				GOR (scf/STB)				GRV (m^3 x 10^6)
	Dist	P90	P50	P10	Dist	P90	P50	P10	Dist	P90	P50	P10	Dist	P90	P50	P10	Dist	P90	P50	P10	Dist	P90	P50	P10	Mean
SE Area (Sapele 1, 1ST, 2)																									
SE-1	Ln	3.64	8.17	18.33	Norm	12.19	16.76	21.34	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	166
SE-2	Ln	0.78	1.59	3.08	Norm	3.41	8.47	13.78	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	15
SE-3	Norm	0.45	0.49	0.53	Norm	7.62	9.14	10.67	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	4
SE-4	Ln	4.90	6.31	8.05	Norm	3.05	6.10	9.14	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	39
SE-5	Ln	1.76	2.49	3.41	Norm	3.14	6.89	10.70	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	18
SE-6	Ln	3.67	8.34	17.64	Norm	4.57	6.10	7.62	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	59
SE-7	Norm	2.95	2.99	3.04	Norm	4.57	6.86	9.14	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	21
NW Area (Sapele 3)																									
NW-8	Norm	3.24	3.30	3.36	Norm	0.61	1.07	1.52	Ln	11	12	14	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	4
NW-9	Norm	0.62	1.13	1.96	Norm	0.91	1.98	3.05	Ln	11	12	14	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	2

Reservoir Parameters for Probabilistic Unrisked Discovered Petroleum Initially-In-Place (PIIP) Estimation

Reservoir Parameters for Probabilistic Unrisked Undiscovered Petroleum Initially-In-Place (PIIP) Estimation																									
Prospect	Area (km^2)				Net Pay (m)				Porosity				Hydrocarbon Saturation				Bo (bbl/STB)				GOR (scf/STB)				GRV ($m^3 \times 10^6$)
	Dist	P90	P50	P10	Dist	P90	P50	P10	Dist	P90	P50	P10	Dist	P90	P50	P10	Dist	P90	P50	P10	Dist	P90	P50	P10	Mean
SE Area (Sapele 1, 1ST, 2)																									
SE Near-Far-Peak-14	Ln	11.98	15.26	19.47	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	142
SE-Near Peak-15	Ln	8.38	9.31	10.24	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	85
SE-Near-Peak-16	Ln	10.12	10.85	11.57	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	99
SE-Near-Peak-17	Ln	5.14	5.50	5.87	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	50
SE-Near-Peak-18	Ln	4.86	5.18	5.54	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	48
SE-Near-Trough-19	Ln	8.98	9.59	10.28	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	88
SE-Near-Trough-21	Ln	5.63	5.99	6.43	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	55
SE-Far-Trough-22	Ln	26.75	28.61	30.59	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	262
65 feet upside	Ln	1.78	1.82	1.86	Norm	15.24	19.05	22.86	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	35
NW Area (Sapele 3)																									
NW Near Peak Far Trough 1	Ln	30.23	36.66	44.52	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	339
NW Near Peak Far Peak 2	Ln	2.40	2.78	3.21	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	26
NW Near Peak 3	Ln	0.71	0.79	0.87	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	7
NW Near Peak 4	Ln	3.11	3.46	3.80	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	32
NW Near Peak 5	Ln	12.67	14.08	15.46	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	129
NW Near Peak 6	Ln	87.41	97.12	106.84	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	889
NW Near Peak 7	Ln	3.13	3.48	3.83	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	32
NW Near Peak 8	Ln	0.71	0.79	0.87	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	7
NW Near Trough 9	Ln	3.69	4.13	4.53	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	38
NW Near Trough 10	Ln	9.31	10.32	11.37	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	94
NW Far Peak 11	Ln	9.71	11.09	12.42	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	99
NW Far Peak 12	Ln	5.75	6.39	7.04	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	59
NW Final Stack 13	Ln	4.94	5.50	6.07	Norm	6.10	9.14	12.19	Ln	12	18	25	Ln	44	53	68	Norm	2.25	2.66	3.07	Norm	3200	4200	5200	50

Reservoir Parameters for Probabilistic Unrisked Undiscovered Petroleum Initially-In-Place (PIIP) Estimation

Appendix A — Resource Definitions

This discussion has been excerpted from Sections 5.2 and 5.3 of the Canadian Oil and Gas Evaluation Handbook, Second Edition, September 1, 2007.

The following definitions relate to the subdivisions in the SPE-PRMS resources classification framework and use the primary nomenclature and concepts contained in the 2007 SPE-PRMS, with direct excerpts shown in italics.

Total Petroleum Initially-In-Place (PIIP) *is that quantity of petroleum that is estimated to exist originally in naturally occurring accumulations. It includes that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations, prior to production, plus those estimated quantities in accumulations yet to be discovered (equivalent to "total resources").*

Discovered Petroleum Initially-In-Place (equivalent to discovered resources) *is that quantity of petroleum that is estimated, as of a given date, to be contained in known accumulations prior to production.* The recoverable portion of discovered petroleum initially in place includes production, reserves, and contingent resources; the remainder is unrecoverable.

> ***Production*** *is the cumulative quantity of petroleum that has been recovered at a given date.*
>
> **Reserves** are estimated remaining quantities of oil and natural gas and related substances anticipated to be recoverable from known accumulations, as of a given date, based on the analysis of drilling, geological, geophysical, and engineering data; the use of established technology; and specified economic conditions, which are generally accepted as being reasonable. Reserves are further classified according to the level of certainty associated with the estimates and may be subclassified based on development and production status.
>
> ***Contingent Resources*** *are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from known accumulations* using established technology or technology under development, but which are not currently considered to be commercially recoverable due to one or more

contingencies. Contingencies may include factors such as economic, legal, environmental, political, and regulatory matters, or a lack of markets. It is also appropriate to classify as contingent resources the estimated discovered recoverable quantities associated with a project in the early evaluation stage. *Contingent Resources are further classified in accordance with the level of certainty associated with the estimates and may be subclassified based on project maturity and/or characterized by their economic status.*

Unrecoverable *is that portion of Discovered or Undiscovered PIIP quantities which is estimated, as of a given date, not to be recoverable by future development projects. A portion of these quantities may become recoverable in the future as commercial circumstances change or technological developments occur; the remaining portion may never be recovered due to the physical/chemical constraints represented by subsurface interaction of fluids and reservoir rocks.*

Undiscovered Petroleum Initially-In-Place (equivalent to undiscovered resources) *is that quantity of petroleum that is estimated, on a given date, to be contained in accumulations yet to be discovered.* The recoverable portion of undiscovered petroleum initially in place is referred to as "prospective resources," the remainder as "unrecoverable."

Prospective Resources *are those quantities of petroleum estimated, as of a given date, to be potentially recoverable from undiscovered accumulations by application of future development projects. Prospective resources have both an associated chance of discovery and a chance of development. Prospective Resources are further subdivided in accordance with the level of certainty associated with recoverable estimates assuming their discovery and development and may be subclassified based on project maturity.*

Resource Categories

Due to the high uncertainty in estimating resources, evaluations of these assets require some type of probabilistic methodology. When evaluating resources, in particular, contingent and prospective resources, the following mutually exclusive categories are recommended:

- Low Estimate: This is considered to be a conservative estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P_{90} confidence level.

- Best Estimate: This is considered to be the best estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term is a measure of central tendency of the uncertainty distribution (most likely/mode, P_{50}/median, or arithmetic average/mean).

- High Estimate: This is considered to be an optimistic estimate of the quantity that will actually be recovered from the accumulation. If probabilistic methods are used, this term reflects a P_{10} confidence level.

For Contingent Resources, the general cumulative terms low/best/high estimates are denoted as 1C/2C/3C respectively. For Prospective Resources, the general cumulative terms low/best/high estimates still apply. No specific terms are defined for incremental quantities within Contingent and Prospective Resources.

Company Gross Contingent Resources are the Company's working interest share of the contingent resources, before deduction of any royalties.

Company Net Contingent Resources are the gross contingent resources of the properties in which the Company has an interest, less all royalties and interests owned by others.

Fair Market Value is defined as the price at which a purchaser seeking an economic and commercial return on investment would be willing to buy, and a vendor would be willing to sell, where neither is under compulsion to buy or sell and both are competent and have reasonable knowledge of the facts.

Appendix B — Abbreviations, Units and Conversion Factors

This appendix contains a list of abbreviations found in Sproule reports, a table comparing Imperial and Metric units, and conversion tables used to prepare this report.

Abbreviations

AFE	authority for expenditure
AOF	absolute open flow
APO	after pay out
B_g	gas formation volume factor
B_o	oil formation volume factor
bopd	barrels of oil per day
bfpd	barrels of fluid per day
BPO	before pay out
BS&W	basic sediment and water
BTU	British thermal unit
bwpd	barrels of water per day
CF	casing flange
CGR	condensate gas ratio
D&A	dry and abandoned
DCQ	daily contract quantity
DSU	drilling spacing unit
DST	drill stem test
EOR	enhanced oil recovery
EPSA	exploration and production sharing agreement
FVF	formation volume factor
GOR	gas-oil ratio
GORR	gross overriding royalty
GWC	gas-water-contact
HCPV	hydrocarbon pore volume
ID	inside diameter
IOR	improved oil recovery
IPR	inflow performance relationship
IRR	internal rate of return
k	permeability
KB	kelly bushing
LKH	lowest known hydrocarbons
LNG	liquefied natural gas

LPG	liquefied petroleum gas
md	millidarcies
MDT	modular formation dynamics tester
MPR	maximum permissive rate
MRL	maximum rate limitation
NGL	natural gas liquids
NORR	net overriding royalty
NPI	net profits interest
NPV	net present value
OD	outside diameter
OGIP	original gas in place
OOIP	original oil in place
ORRI	overriding royalty interest
OWC	oil-water-contact
P1	proved
P2	probable
P3	possible
P&NG	petroleum and natural gas
PI	productivity index
ppm	parts per million
PSU	production spacing unit
PSA	production sharing agreement
PSC	production sharing contract
PVT	pressure-volume-temperature
RFT	repeat formation tester
RT	rotary table
SCAL	special core analysis
SS	subsea
TVD	true vertical depth
WGR	water gas ratio
WI	working interest
WOR	water oil ratio
2D	two-dimensional
3D	three-dimensional
4D	four-dimensional
1P	proved
2P	proved plus probable
3P	proved plus probable plus possible
^{o}API	degrees API (American Petroleum Institute)

Imperial and Metric Units

Imperial Units			Metric Units	
M (10^3)	one thousand	**Prefixes**	k (10^3)	one thousand
MM (10^6)	Million		M (10^6)	million
B (10^9)	one billion		T (10^{12})	one billion
T (10^{12})	one trillion		E (10^{18})	one trillion
			G (10^9)	one milliard
in.	Inches	**Length**	cm	centimetres
ft	Feet		m	metres
mi	Mile		km	kilometres
ft^2	square feet	**Area**	m^2	square metres
ac	Acres		ha	hectares
cf or ft^3	cubic feet	**Volume**	m^3	cubic metres
scf	Standard cubic feet			
gal	Gallons		L	litres
Mcf	Thousand cubic feet			
Mcfpd	Thousand cubic feet per day			
MMcf	million cubic feet			
MMcfpd	million cubic feet per day			
Bcf	billion cubic feet (10^9)			
bbl	Barrels		m^3	cubic metre
Mbbl	Thousand barrels			
stb	stock tank barrel		stm^3	stock tank cubic metres
bbl/d	barrels per day		m^3/d	cubic metre per day
bbl/mo	barrels per month			
Btu	British thermal units	**Energy**	J	joules
			MJ/m^3	megajoules per cubic metre (10^6)
			TJ/d	terajoule per day (10^{12})
oz	ounce	**Mass**	g	gram
lb	pounds		kg	kilograms
ton	ton		t	tonne
lt	long tons			
Mlt	thousand long tons			
psi	pounds per square inch	**Pressure**	Pa	pascals
			kPa	kilopascals (10^3)
psia	pounds per square inch absolute			
psig	pounds per square inch gauge			
°F	degrees Fahrenheit	**Temperature**	°C	degrees Celsius
°R	degrees Rankine		K	Kelvin
M$	thousand dollars	**Dollars**	k$	thousand dollars

Imperial and Metric Units (Cont'd)

Imperial Units			Metric Units	
sec	second	**Time**	s	second
min	minute		min	minute
hr	hour		h	hour
day	day		d	day
wk	week			week
mo	month			month
yr	year		a	annum

Conversion Tables

Conversion Factors — Metric to Imperial

cubic metres (m^3) (@ 15°C)	x 6.29010	= barrels (bbl) (@ 60°F), water
m^3 (@ 15°C)	x 6.3300	= bbl (@ 60°F), Ethane
m^3 (@ 15°C)	x 6.30001	= bbl (@ 60°F), Propane
m^3 (@ 15°C)	x 6.29683	= bbl (@ 60°F), Butanes
m^3 (@ 15°C)	x 6.29287	= bbl (@ 60°F), oil, Pentanes Plus
m^3 (@ 101.325 kPaa, 15°C)	x 0.0354937	= thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)
1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)	x 35.49373	= Mcf (@ 14.65 psia, 60°F)
hectares (ha)	x 2.4710541	= acres
1,000 square metres (10^3m^2)	x 0.2471054	= acres
10,000 cubic metres (ha·m)	x 8.107133	= acre feet (ac-ft)
$m^3/10^3m^3$ (@ 101.325 kPaa, 15° C)	x 0.0437809	= Mcf/Ac.ft. (@ 14.65 psia, 60°F)
joules (j)	x 0.000948213	= Btu
megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)	x 26.714952	= British thermal units per standard cubic foot (Btu/scf) (@ 14.65 psia, 60°F)
dollars per gigajoule ($/GJ)	x 1.054615	= $/Mcf (1,000 Btu gas)
metres (m)	x 3.28084	= feet (ft)
kilometres (km)	x 0.6213712	= miles (mi)
dollars per 1,000 cubic metres ($\$/10^3m^3$)	x 0.0288951	= dollars per thousand cubic feet ($/Mcf) (@ 15.025 psia) B.C.
($\$/10^3m^3$)	x 0.02817399	= $/Mcf (@ 14.65 psia) Alta.
dollars per cubic metre ($\$/m^3$)	x 0.158910	= dollars per barrel ($/bbl)
gas/oil ratio (GOR) (m^3/m^3)	x 5.640309	= GOR (scf/bbl)
kilowatts (kW)	x 1.341022	= horsepower
kilopascals (kPa)	x 0.145038	= psi
tonnes (t)	x 0.9842064	= long tons (LT)
kilograms (kg)	x 2.204624	= pounds (lb)
litres (L)	x 0.2199692	= gallons (Imperial)
litres (L)	x 0.264172	= gallons (U.S.)
cubic metres per million cubic metres ($m^3/10^6m^3$) (C_3)	x 0.177496	= barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia)
$m^3/10^6m^3$ (C_4)	x 0.1774069	= bbl/MMcf (@ 14.65 psia)
$m^3/10^6m^3$ (C_{5+})	x 0.1772953	= bbl/MMcf (@ 14.65 psia)
tonnes per million cubic metres ($t/10^6m^3$) (sulphur)	x 0.0277290	= LT/MMcf (@ 14.65 psia)
millilitres per cubic meter (mL/m^3) (C_{5+})	x 0.0061974	= gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf)
(mL/m^3) (C_{5+})	x 0.0074428	= gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf)
Kelvin (K)	x 1.8	= degrees Rankine (°R)
millipascal seconds (mPa·s)	x 1.0	= centipoise

Conversion Tables (Cont'd)

Conversion Factors — Imperial to Metric		
barrels (bbl) (@ 60°F)	x 0.15898	= cubic metres (m^3) (@ 15°C), water
bbl (@ 60°F)	x 0.15798	= m^3 (@ 15°C), Ethane
bbl (@ 60°F)	x 0.15873	= m^3 (@ 15°C), Propane
bbl (@ 60°F)	x 0.15881	= m^3 (@ 15°C), Butanes
bbl (@ 60°F)	x 0.15891	= m^3 (@ 15°C), oil, Pentanes Plus
thousands of cubic feet (Mcf) (@ 14.65 psia, 60°F)	x 28.17399	= m^3 (@ 101.325 kPaa, 15°C)
Mcf (@ 14.65 psia, 60°F)	x .02817399	= 1,000 cubic metres (10^3m^3) (@ 101.325 kPaa, 15°C)
acres	x 0.4046856	= hectares (ha)
acres	x 4.046856	= 1,000 square metres (10^3m^2)
acre feet (ac-ft)	x 0.123348	= 10,000 cubic metres (10^4m^3) (ha·m)
Mcf/ac-ft (@ 14.65 psia, 60°F)	x 22.841028	= $10^3m^3/m^3$ (@ 101.325 kPaa, 15°C)
Btu	x 1054.615	= joules (J)
British thermal units per standard cubic foot (Btu/Scf) (@ 14.65 psia, 60°F)	x .03743222	= megajoules per cubic metre (MJ/m^3) (@ 101.325 kPaa, 15°C)
$/Mcf (1,000 Btu gas)	x 0.9482133	= dollars per gigajoule ($/GJ)
$/Mcf (@ 14.65 psia, 60°F) Alta.	x 35.49373	= $\$/10^3m^3$ (@ 101.325 kPaa, 15°C)
$/Mcf (@ 15.025 psia, 60°F), B.C.	x 34.607860	= $\$/10^3m^3$ (@ 101.325 kPaa, 15°C)
feet (ft)	x 0.3048	= metres (m)
miles (mi)	x 1.609344	= kilometres (km)
$/bbl	x 6.29287	= $\$/m^3$ (average for 30°-50° API)
GOR (scf/bbl)	x 0.177295	= gas/oil ratio (GOR) (m^3/m^3)
horsepower	x 0.7456999	= kilowatts (kW)
psi	x 6.894757	= kilopascals (kPa)
long tons (LT)	x 1.016047	= tonnes (t)
pounds (lb)	x 0.453592	= kilograms (kg)
gallons (Imperial)	x 4.54609	= litres (L) (.001 m^3)
gallons (U.S.)	x 3.785412	= litres (L) (.001 m^3)
barrels per million cubic feet (bbl/MMcf) (@ 14.65 psia) (C_3)	x 5.6339198	= cubic metres per million cubic metres ($m^3/10^6m^3$)
bbl/MMcf (C_4)	x 5.6367593	= ($m^3/10^6m^3$)
bbl/MMcf (C_{5+})	x 5.6403087	= ($m^3/10^6m^3$)
LT/MMcf (sulphur)	x 36.063298	= tonnes per million cubic metres ($t/10^6m^3$)
gallons (Imperial) per thousand cubic feet (gal (Imp)/Mcf) (C_{5+})	x 161.3577	= millilitres per cubic meter (mL/m^3)
gallons (U.S.) per thousand cubic feet (gal (U.S.)/Mcf) (C_{5+})	x 134.3584	= (mL/m^3)
degrees Rankine (°R)	x 0.555556	= Kelvin (K)
centipoises	x 1.0	= millipascal seconds (mPa·s)