FROM FRONTIER BASINS TO FUTURE SUPER BASINS BY SOURCE ROCK DE-RISKING

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RESUMEN

El término Super Basin (Súper Cuenca en español) fue creado en 2016 por Bob Fryklund y Pete Stark. La cuenca Guyana-Surinam se perfila a ser la adición más reciente a la lista de este tipo de cuencas, con más de 10 BBOE descubiertos desde 2015. Una de las mayores lecciones de esta cuenca es el éxito del exhaustivo trabajo técnico que se llevó a cabo para mitigar el riesgo del sistema petrolero y revelar una roca madre de clase mundial.

La disminución del riesgo asociado a la roca madre en cualquier tipo de cuenca puede lograrse por medio de varias herramientas sísmicas tales como anomalías AVO (Amplitude vs Offset por sus siglas en inglés) Tipo IV asociadas con el techo de una roca madre, presencia de IDHs (Indicadores Directos de Hidrocarburos) tales como anomalías de amplitud y respuesta AVO relacionada con posibles acumulaciones de hidrocarburos y datos indirectos como indicadores de fuga de hidrocarburos y filtraciones de petróleo identificadas en la superficie del mar por imágenes satelitales. La disminución del riesgo asociado a la presencia de la roca madre representa aproximadamente el 90% del trabajo de exploración en cuencas de frontera. El trabajo realizado en la Cuenca de Malvinas es una buena ilustración del detalle requerido para lograr la reducción del riesgo en la roca madre.

Las súper cuencas futuras se pueden hallar en cuencas de frontera donde la roca madre ha sido evaluada por un trabajo geocientífico exhaustivo. Un excelente ejemplo de este tipo de cuenca, recientemente perforada, es la Cuenca de Orange, costa afuera de Namibia y la cuenca conjugada, aún sin explorar, de Pelotas, costa afuera de Brasil.

Una condición necesaria para lograr la comercialidad de descubrimientos en aguas profundas es la aceleración de la puesta en producción (en Guyana pasaron sólo 4 años entre el descubrimiento y la primera producción de petróleo), lo cual requiere de grandes descubrimientos. A través de trabajos realizados en las cuencas mencionadas anteriormente, se concluye que los mayores prospectos a perforar se encuentran en aguas profundas y que el camino para encontrar una nueva súper cuenca, comienza con la mitigación del riesgo de la roca madre.

INTRODUCTION

The term Super Basin was coined in 2016 by Bob Fryklund and Pete Stark (as cited in Sternbach 2020). According to the original paper published in IHS Markit, a basin must contain at least 5 BBOE produced and the same volume of recoverable remaining reserves; two or more petroleum systems or source rocks; stacked reservoirs; existing infrastructure and oil field services; and good access to markets. The Guyana-Suriname Basin is on track to being the most recent addition to the super basins list with over 10 BBOE discovered since 2015. One of the biggest lessons from this basin is the success of the thorough technical work which was undertaken to de-risk and reveal a world class source rock.

In order to de-risk the source rock existence in any basin there are various key seismic indications, such as AVO Type IV associated with the top of a thick (>20 m) and high TOC (Total Organic Content) source rock, presence of DHIs (Direct Hydrocarbon Indicators) such as amplitude anomalies and AVO response related to possible hydrocarbon accumulations, and indirect indications such as hydrocarbon leakage indicators and oil seeps on the sea surface identified by satellite images. De-risking source presence is about 90% of the frontier exploration job. Next is to find that source rock under sediment accumulations thick enough to be generative and mature.

Exploration in frontier basins can also be encouraged in the conjugate margin of significant discoveries, such as the Malvinas Basin, Argentina, where reprocessed seismic data has helped to de-risk source rock presence, distribution and quality. Further support comes from the southern South African Brulpadda and Luiperd discoveries made in the conjugate margin and estimated to contain over 1 BBOE.

Alternatively, exploration can be stimulated in new frontier basins where the source can be de-risked by relevant geoscientific methodologies. Examples of frontier basins where source rock de-risking has played a main role include the Orange Basin, offshore Namibia, where the Venus-1 well recently drilled by TotalEnergies is estimated to contain over 13 BBOE and the conjugate Pelotas Basin, (offshore Brazil) which remains undrilled.

METHODOLOGY

Frontier basin exploration requires a detailed petroleum systems evaluation to de-risk firstly and foremost the main critical elements, source rock presence and maturity to then address the other three key elements, reservoir, trap and seal.

Source rock de-risking methodologies which have been used for this study include plate tectonic reconstruction and tectonostratigraphic evolution to identify suitable environments for source rock deposition, integration of conjugate margin evidence, well evidence, geochemical seabed sampling results and coring, and sea surface naturally occurring oil seeps.

However, some of the most game changing insights have been derived from different types of seismic datasets selected from a large global dataset (Fig. 1) consisting of newly acquired, reprocessed and rectified seismic data. Seismic data has provided the most valuable tools to de-risk source rock presence, quality and maturity. Using the selected seismic datasets, different methodologies were employed to identify potential source rocks. These included a detailed seismic facies analysis in the Malvinas Basin and, for the Southern Atlantic, the identification of regionally extensive high amplitude events associated with a decrease in acoustic impedance and AVO Type IV anomalies (Davison *et al.* 2018). Both methodologies were complemented by the identification of DHIs, fluid escape and seabed features as well as BSRs (Bottom Simulating Reflectors), all of which will be described in more detail below.

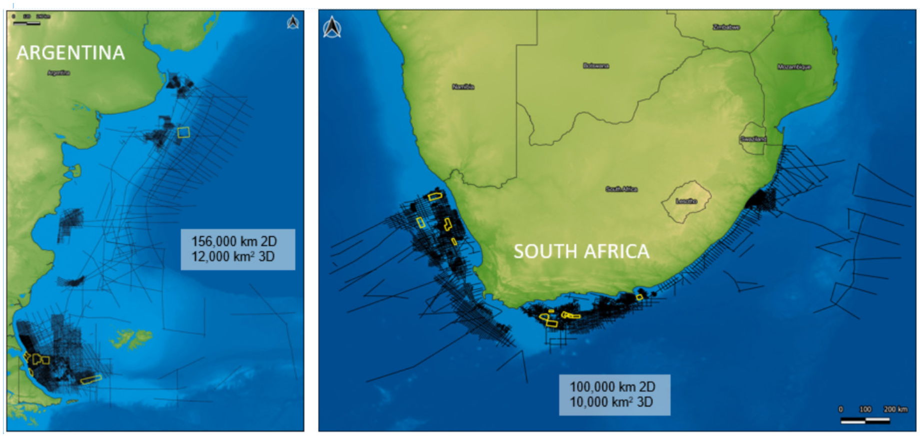

Figure 1. Offshore seismic dataset available for this study.

SOURCE ROCK DE-RISKING EXAMPLE FROM THE MALVINAS BASIN

Source rock presence, distribution and quality have been considered primary concerns for exploration in the Malvinas Basin. The Malvinas Basin is underexplored with most of the exploration in Argentinian waters concentrated to the west, in the Austral-Magallanes Basin, where all the economic scale hydrocarbon accumulations have been discovered thus far. However, in the Malvinas Basin itself, there have been discoveries at Calamar.x-1, Salmón.x-1 and Salmón.x-2 and oil shows encountered at several other wells (Fig. 3).

The conjugate margins of southern South Africa and southern Argentina were part of the same intracratonic Upper Jurassic rift that finally split Gondwana apart in the Early Cretaceous. The Upper Jurassic rifts are characterized by lacustrine environments where organic rich material could be deposited and preserved. As rifting progressed, marine waters flooded these rift basins creating initially restricted lacustrine basins, perfect for preservation of organic material. Once Atlantic drifting commenced, along the Agulhas fracture zone, the margins stopped sharing their common history except for one element, the source rock. The Falklands Plateau allowed for restricted conditions to be maintained on both sides of the margin throughout the Early Cretaceous (Fig. 2) which, together with global oceanic anoxia events which took place during this time, enhanced the conditions for source rock deposition.

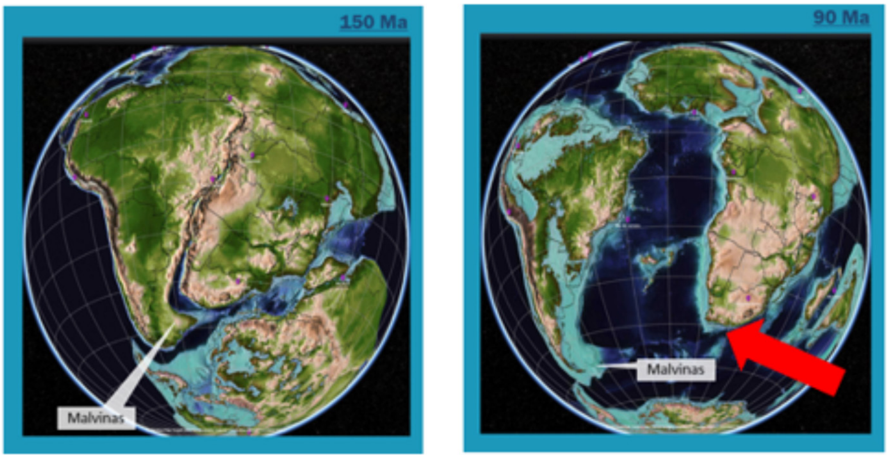

Figure 2. Tectonic evolution from 150 Ma to 90 Ma showing the presence of the Falklands Plateau which allowed for restricted conditions to be maintained on both sides of the margin throughout the Early Cretaceous.

The Malvinas Basin was initiated with Jurassic (Bathonian to Tithonian) rifting, followed by thermal subsidence from the Tithonian to Maastrichtian. The syn-rift sediments contain Jurassic tuffs, lacustrine shales and sandstones of the Tobífera Formation (Cohen *et al.* 2013). The main source rocks are considered to be shales of the Lower Inoceramus Formation, while the Middle-Upper Inoceramus Formation serves as a seal. As described in the previous paragraph, potential source rocks may also be found within the shales of the Springhill, Tobífera and Margas Verdes formations although these are less well understood.

Seismic data reprocessed by Searcher showing significant uplift (Fig. 3) was used to help de-risk the presence, distribution and quality of syn-rift source rocks in the Malvinas Basin.

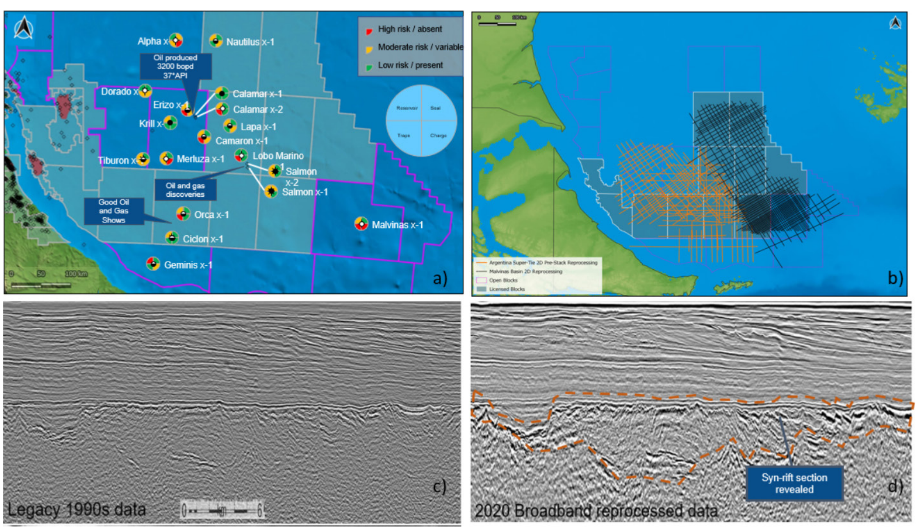

Figure 3. a) Map showing wells in the Malvinas Basin with a post-drill risk interpretation of the elements of the petroleum system. b) Reprocessed 2D seismic data used in this study. Comparison of legacy c) and reprocessed seismic d) illustrating the resulting significant uplift observed in the broadband reprocessed seismic data. Seismic display is SEG normal polarity (peak is black representing an increase in acoustic impedance)

Shallow gas indicators occur throughout the Malvinas Basin (Fig. 4). The distribution of shallow gas indicators was mapped across the reprocessed 2D seismic data within the Malvinas Basin, using both traditional methods such as manual identification of hydrocarbon indicators like bright spots, flat spots and phase reversals, as well as application of a Machine Learning process to assist in identifying all gas anomalies within the datasets. The results of the Machine Learning Algorithm were encouraging, and accuracy is expected to improve with increased data labelling.

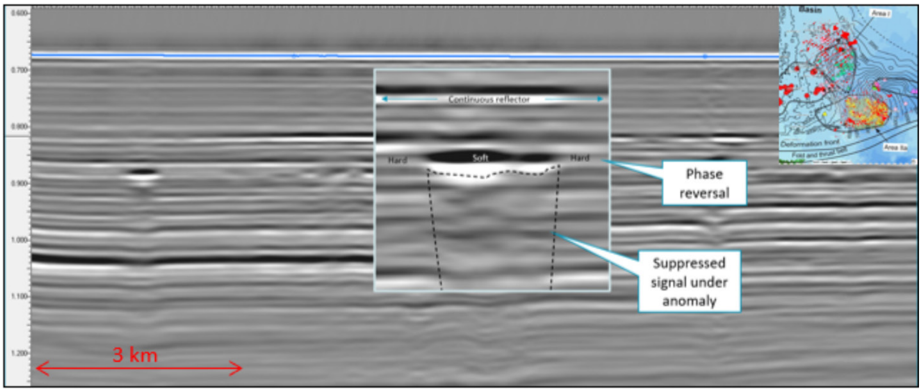

Figure 4. Example of a shallow gas indicator mapped from the Malvinas 2D Reprocessed Dataset. Data displayed in Two Way Time (sec). Reverse SEG polarity where black is a peak representing a decrease in acoustic impedance. Inset map shows location of shallow gas indicators in green and yellow mapped by Baristeas *et al*. (2012) and in red mapped as part of this study.

The spatial distribution of the shallow gas features identified across the dataset shows that there are many gas anomalies in the Malvinas Basin pointing strongly to a working charge system. The shallow gas features have good seismic indications pointing to hydrocarbon accumulations and therefore provide strong suggestions of a working charge system.

When compared to the distribution of the shallow gas indicators mapped on the vintage 2D dataset in Baristeas *et al.* (2012), a variation in the spatial distribution was observed, with this work showing greater indications of shallow gas anomalies in the northern part of the Malvinas Basin area, which can be attributed to a potential Jurassic syn-rift charge origin identified by seismic facies mapping.

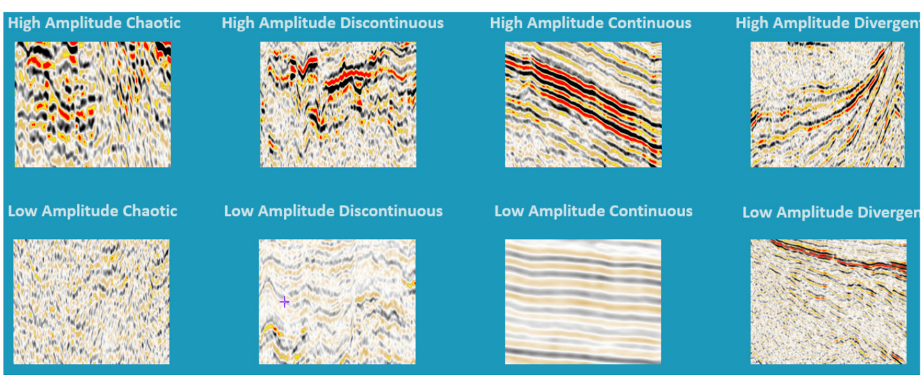

Figure 5. Seismic facies analysis using a modified Ramsayer Method was undertaken across the Malvinas 2D reprocessed dataset. Dominant facies types mapped are indicated in this image. Reverse SEG polarity where black is a peak representing a decrease in acoustic impedance.

To further depict the understanding of the hydrocarbon systems of the area, seismic facies mapping and analysis were undertaken. The seismic facies mapping utilised a modified Ramsayer (1979) method with dominant facies types mapped as shown in Fig. 5.

Using the results of the seismic facies mapping analysis and a regional understanding gained from previous regional studies (Discover Geoscience 2017), a paleogeographic reconstruction of the Upper Jurassic syn-rift section was compiled (Fig. 6) The reconstruction shows the existence of high amplitude chaotic and discontinuous facies (Discover Geoscience 2017) in the north which are interpreted as volcanics and volcaniclastic conglomerates. Deep graben depocentres are mapped and interpreted to contain interbedded tuffaceous sands and claystones in an anoxic environment conducive to the preservation of organic facies.

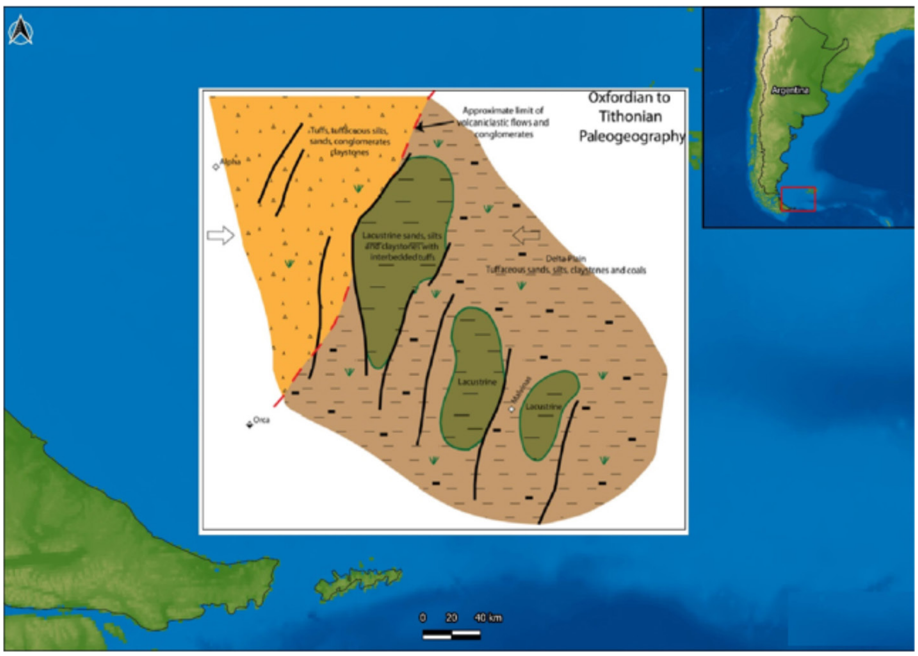

Figure 6. Upper Jurassic syn-rift section paleogeographic map based on seismic facies mapping results and regional knowledge of the area.

Using the seismic facies mapping and analysis of results for the Lower Cretaceous sag phase, a paleogeographic reconstruction was undertaken (Fig. 7). The reconstruction indicates active deposition in the inner to middle neritic marine environment in the north and a transition to outer neritic to upper bathyal hemi-pelagic and pelagic deposition in the south. There is a low amplitude chaotic seismic response in the south which is interpreted as signal loss due to effects of a post depositional fold and thrust belt occurrence (Discover Geoscience 2017).

Combining depth of burial, hydrocarbon maturities, gas indications and source rock facies allows an understanding of the hydrocarbon history in the area. The analysis indicates that in Area I (Fig. 8) shallow gas anomalies are coincident with the mature and best quality inferred source rock facies of the Jurassic and that in Area IIa shallow gas anomalies are coincident with the most

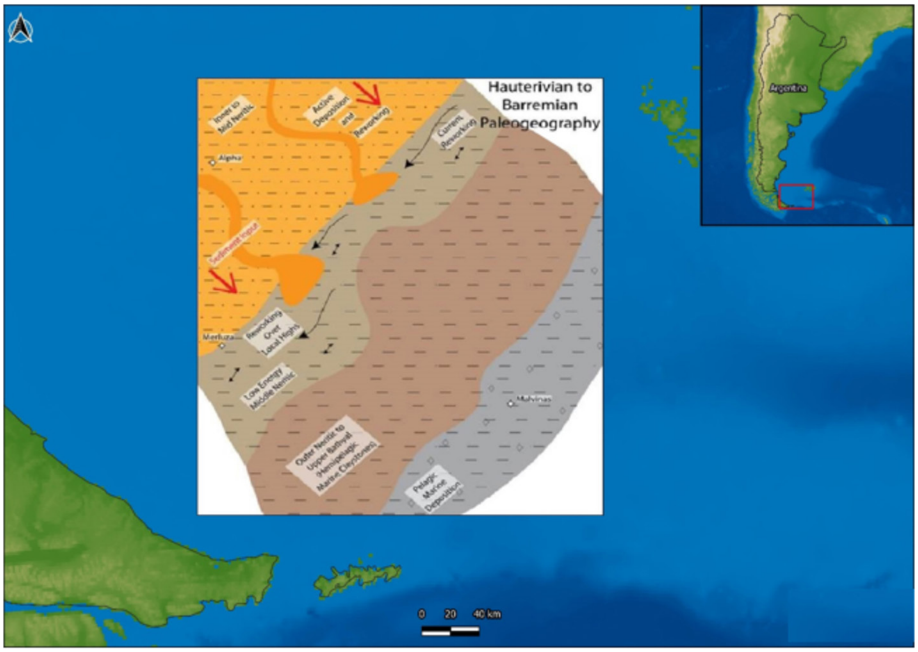

Figure 7. Paleogeographic reconstruction of the Lower Cretaceous paleogeography early sag phase based on seismic facies analysis mapping and regional understanding of the area.

favourable facies and mature of the Cretaceous source rocks. Based on this, a simple charge model for the Malvinas Basin is proposed where Area I is charged by lacustrine Mid to Late Jurassic source rocks and Area IIa is charged by the Cretaceous source rocks. The bulk of the migration would be semi-vertical with a small amount of lateral migration out of the main source generative kitchens.

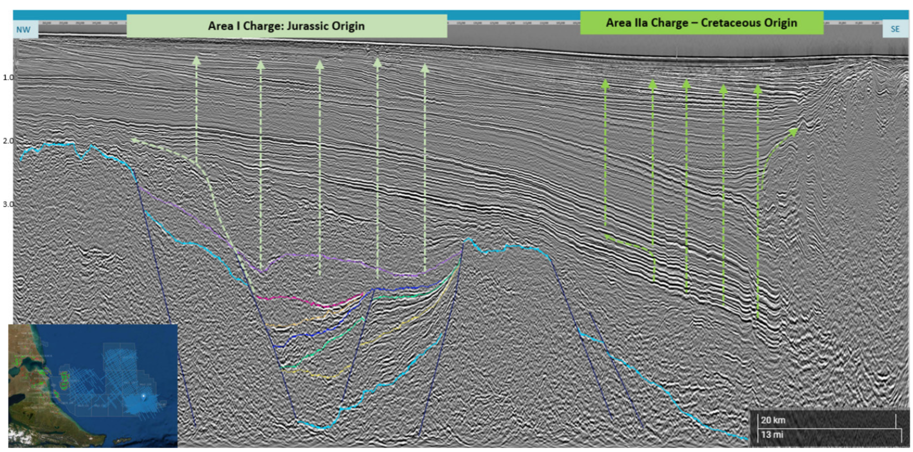

Figure 8. Example seismic line in Two Way Time (s), showing the simplified charge model of the Malvinas Basin. Seismic display is SEG reverse polarity (black is a peak representing a decrease in acoustic impedance). The blue horizon is the basement pick. The younger events interpreted above basement indicate that over 8km of total sediment accumulated within the graben, with individual sigmoids inferring that the basin depth at any one time may have been up to 2km deep. That means this graben would have been as deep as any rift lake on the planet today, allowing for substantial lateral facies change away from the drilled highs and into the deep grabens. With such depths must surely have been accumulating fine grained sediments and organic matter in an anoxic lacustrine environment, ideal for the formation of hydrocarbon source rocks. White dot on inset map shows approximate line location. Area I and Area IIa are shown in inset map in Fig. 4.

SOURCE ROCK DE-RISKING IN THE DEEP-WATER SOUTHERN ATLANTIC MARGIN

Plate tectonic reconstructions show that until the Latest Aptian the southern Atlantic remained a restricted seaway (Fig. 2) which, together with the global anoxic event during this period (Schlanger and Jenkyns 1976; Jenkyns 2010), created the ideal conditions for widespread source rock deposition.

Presence of Aptian source rock had, until recently, only been proven in the conjugate margin, in DSDP well 361 in South Africa (Bray *et al.* 1998). In Namibia, mature Aptian source rock was reported from the relatively recent HRT wells Wingat-1, Moosehead-1 and Morombe-1 (Petrorio 2015a; Petrorio 2015b and Petrorio 2015c), with light oil recovered from the Wingat-1 well.

Seismic data along the southern Atlantic margin shows strong indications of an Aptian age source rock interval, deposited above oceanic crust, with an observed consistent low frequency, semi-transparent low amplitude character, interpreted to be associated with source rock presence. Additionally, source rock characterization studies (Eastwell *et al.* 2018; Davison *et al.* 2018) show a strong amplitude anomaly with an expected decrease in acoustic impedance, due to the velocity and density decrease associated with kerogen presence; as well as an AVO Type IV anomaly with the amplitude dimming with angle due to the strong anisotropy generated by the horizontally aligned clay minerals. This character has been observed on original legacy data in the Pelotas Basin (Fig. 8) and may be mapped regionally to demonstrate the sedimentologic and loading controls on richness and maturity.

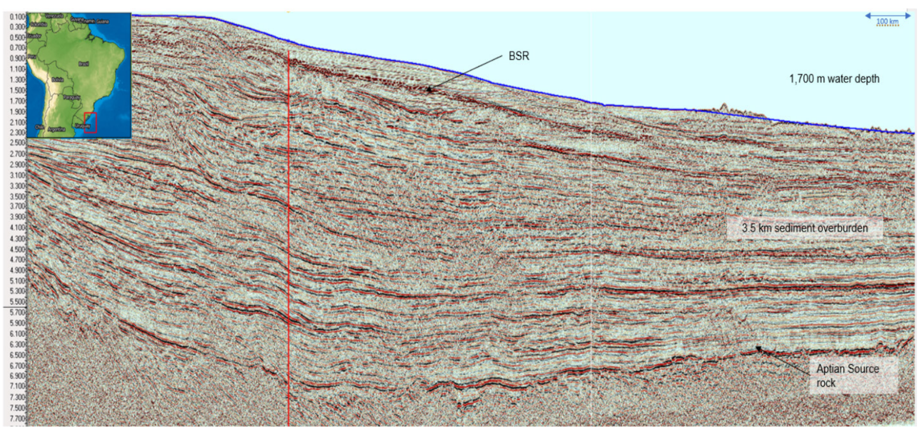

Figure 9. Original legacy dip line, in time but water depth compensated, in the Pelotas Basin, showing the typical Aptian source rock character observed along the southern Atlantic margin as well as a clear BSR (Bottom Simulating Reflector). Seismic display is SEG normal polarity (peak is black representing an increase in acoustic impedance). Inset map shows approximate line location.

Determining the geothermal gradient in undrilled regions remains one of the largest areas of uncertainty in frontier basin exploration. Bottom Simulating Reflectors (BSR's) occur at the base of shallow gas hydrate layers in many of the world's deep-water basins and by calculating the geothermal gradient from the sea floor to the base of the hydrate, quantitative and qualitative inference of the deeper heat flow can be made.

In the Pelotas Basin the clear and extensive observed BSR (Fig. 9), has been used to apply a methodology developed to calculate the temperature at the base of the gas hydrate, which is then used as a proxy for shallow geothermal gradient. The methodology involves mapping the seabed and base hydrate at the BSR's (Fig. 10) and calculating the temperature at the BSR from the Pressure-Temperature phase stability for gas hydrates in a saline medium (Vohat *et al.* 2003; Hodgson and Intawong 2013). With an estimate of the sea floor temperature one can derive the geothermal gradient in the shallow section (Kvenvolden and Claypool 1988).

Once the geothermal gradient is obtained, a structural map of potential source rocks is generated in depth and using the temperature grid obtained from the geothermal gradient, a maturity map is produced in the area covered by the BSR. In the area where a BSR can be confidently picked, the hydrate geothermal gradient for the Pelotas Basin is seen to vary between 28 to 32°C/km (Fig. 11), with a relatively small variation in the dip direction and a slightly greater variation along strike. This is a surprising observation as the crustal architecture is observed to change in the dip direction, whilst the geothermal gradient remains relatively constant.

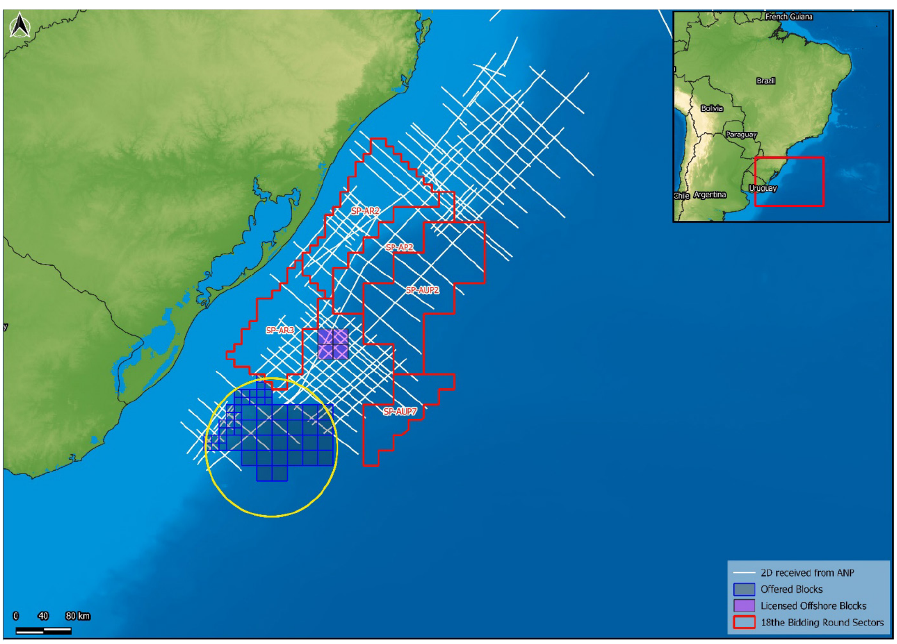

Figure 10. Map showing seismic dataset available in the Pelotas Basin. The yellow polygon outlines the main area of interest for this study. Blocks offered in the permanent round are shown as reference.

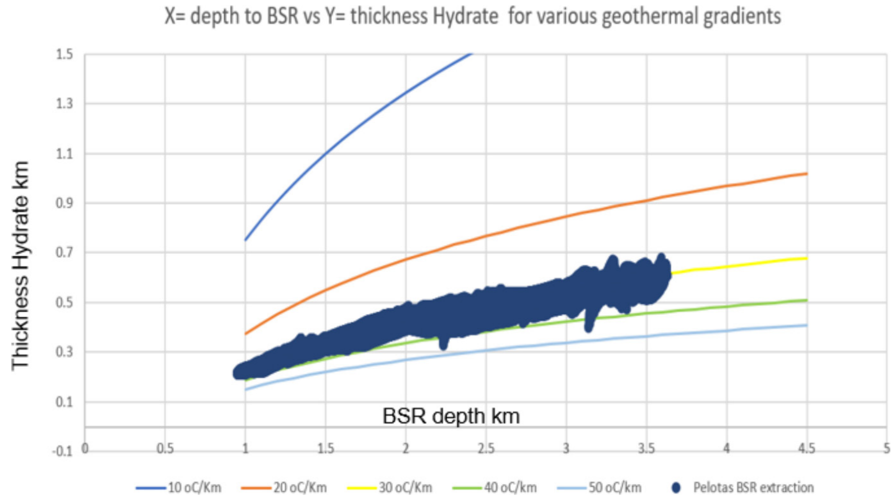

Figure 11. Depth to BSR vs thickness of hydrate layer, where the lines are geothermal gradients in °C/km. The lines have been derived from the Pressure Temperature Phase Diagram in Vohat *et al*. 2003. 288K data points were extracted from a 2D mapped 20,000 sqkm BSR in the Pelotas Basin.

Using the hydrate geothermal gradient as an indicator of geothermal gradient, it was calculated that under the thickest part of the Pelotas delta the Aptian source rock is likely to be gas and condensate generative. However, as the sedimentary column thins radially around the cone, the Aptian source rock is modelled to be in the oil window in the area of a large interpreted Cretaceous basin floor fan (BFF) play in the Pelotas Basin.

Recent discoveries offshore Namibia have proven not only the presence and maturity of an Aptian source, but also its ability to generate sufficient hydrocarbons to charge very significant prospects. This has opened-up both slope and basin floor plays in the Orange Basin and its conjugate margin.

When the South Atlantic margin in Aptian times was ca 150 km wide, the first marine transgression created a shallow, restricted marine anoxic basin, where subsequently several hundred meters of organic rich mudstones where deposited. The Aptian source rock is present not only in the Namibian Orange Basin but also extends into both South Africa and the conjugate margin – the Pelotas Basin (Fig. 12). The South Atlantic was as much as 350 km wide by the end of the Aptian by which time coarse clastics were pouring into the basin from either margin. Plate

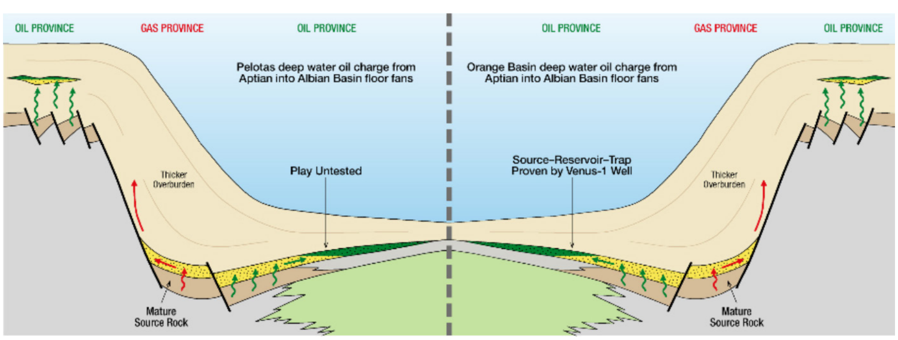

Figure 12. Southern Atlantic Conjugate Margin Source Rock and Basin Floor Fan Model updated after Venus-1 discovery offshore Namibia.

development and dynamic topography have shaped the organization of the clastic sequences on either margin differently, the same plays (BFF counter regional dip pinch out, slope mixed systems) proven in Namibia will be present in South Brazil, Uruguay, North Argentina (where it remains untested), and South Africa.

In common with the basins of southern Argentina, bringing together new elements of analysis through the use of improved seismic data, is widening the areas previously thought to be prospective and paving the way for more effective and de-risked opening up of super basins in the near future.

CONCLUSIONS

Using regional datasets from both the Malvinas Basin and South African conjugate margin, source rock evaluation enables an understanding of the lateral distribution of lacustrine shales within syn-rift grabens, which is key to unlocking the charge history. Progress has been made by reprocessing legacy seismic datasets which now allow a detailed interpretation below the Base Cretaceous unconformity. Shallow gas indicators occur throughout the Malvinas Basin providing further evidence of a working petroleum system. The distribution of shallow hydrocarbon indicators has been mapped within the Malvinas Basin using both traditional methods and a Machine Learning process. A variation in the spatial distribution was observed, showing greater indications of shallow anomalies in the northern part of the Malvinas Basin, which can be attributed to a potential Jurassic syn-rift charge origin.

In the southern Atlantic region, a world class Aptian source rock has been proven by the recent Venus and Graff discoveries offshore Namibia. In the conjugate Brazilian southern Pelotas Basin, the same diagnostic seismic character for the Aptian source rock is observed. This largely supports the extension of the proven source rock into the Pelotas Basin where further de-risking of source rock maturity and hydrocarbon phase were enabled by estimating a BSR-derived geothermal gradient.

Frontier basin exploration begins by de-risking the source rock. Seismic provides a powerful tool which integrated with all other methodologies to de-risk the source rock, open the pathway for the Malvinas and Pelotas frontier basins to become future super basins, such as the multibillion-barrel discoveries in the Orange Basin offshore Namibia nicely demonstrate.

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