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PETROLEUM SYSTEMS AND SOURCE ROCK CHARACTERIZATION IN CEDUNA SUB-BASIN, AUSTRALIA.

TESINA

QUE PARA OPTAR POR EL GRADO DE:

ESPECIALISTA EN EXPLORACIÓN PETROLERA Y CARACTERIZACIÓN DE YACIMIENTOS

PRESENTA:

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To Ross, *in memoriam*, for her entire presence in every step of my life, who continues teaching me even in absence, I hold you in my heart.

Gaby

Abstract

This thesis presents the analysis of petroleum systems and the characterization of the source rock in the Ceduna sub-basin in Australia, making use of two workflows. The establishment of a petroleum system is essential to form oil and gas fields. The petroleum system is a unifying concept that encompasses all the disparate geological or geochemical elements and processes of petroleum geology. Oil and gas fields will not be formed if any of the elements or processes of the petroleum system is missing.

The Ceduna sub-basin is one of the sub-basins in south Australia with the highest probability to contain hydrocarbon accumulations, but to date exploratory wells drilled have not been successful; hence the importance of carrying out this type of analysis since it is intended to reduce risk during drilling, and in the production chain, then increase the probability of success. The models carried out resulted from a combination of seismic information, and geological information to model the evolution of a sedimentary basin for predicting the likelihood, quality, and quantity of technically and economically recoverable oil and gas is at the core of successful exploration and appraisal strategies.

The analysis of the Petroleum System and characterization of the elements was developed with the help of two workflows Petroleum System Modeling and Petroleum System Quick Look. The results show the best scenario to find hydrocarbon accumulations, as well as the synchrony of the other elements that make up the petroleum system.

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RESEARCH OVERVIEW

CHAPTER 1 Introduction and Objective

1. *Introduction*

A petroleum system encompasses a pod of active source rock and all genetically related oil and gas accumulations. It includes all the geologic elements and processes that are essential for a hydrocarbon accumulation to exist (Magoon & Dow, 1994). A petroleum system consists of four essential rock elements comprising source, reservoir, seal, and overburden. The processes are expulsion, migration, accumulation, trap formation and preservation. This work focuses on a 1D petroleum system modeling (1D PSM) to identify the petroleum systems and source rock characterization in Ceduna sub-Basin, one of the main depocenters of Bight Basin in Australia.

The formation of the Bight Basin was initiated during a period of Middle-Late Jurassic to Early Cretaceous upper crustal extension. (Totterdell and Bradshaw, 2004). Classified as a mainly offshore basin, that extends along the southern Australia margin which resulted from the separation of Australia and Antarctica (Veevers, 1986; Teasdale et al., 2003). The eastside area of Bight Basin is considered one of Australia's most prospective frontier hydrocarbon exploration regions (Totterdell et al., 2008). This is characterized to contain five main depocenters: the Ceduna, Duntroon, Eyre, Bremer and Recherche sub-basins (Totterdell et al., 2004). The most prospective petroleum systems are believed to be associated with thick Mid to Late Cretaceous deltaic and marine sediments, which provide reservoirs, seals and potential oil-prone source rocks at several stratigraphic levels, together with a wide range of structural and stratigraphic plays (Blevin et al., 2000).

The Bight Basin has experienced several phases of petroleum exploration since the 1970s, but to date drilling results have been disappointing. The exploration phase has been focusing on the inner basin margins. From the 1970s up to the mid-1990s nine petroleum exploration wells were drilled, six of these are in the Duntroon Sub-basin (Totterdell et al., 2008). The Ceduna sub-basin contains a sedimentary section more than 15,000m thick being one of the most prospective deepwater frontier basins in offshore Australia; and which hydrocarbon potential remains largely untested.

The drilling of Gnarlyknots-1/1A well in Ceduna sub-basin at 1316 m water depth in 2003, despite being dry, provided more information about the petroleum systems complexity, reinforcing the results obtained during the geological sampling in Bight basin in 2007, public articles and revisions by the government of Australia about the petroleum system through the Bight Basin and specifically in Ceduna sub-basin.

2. Objectives of the Study

2.1. Overall Objective:

- Characterize the sequences of source rocks in the Ceduna sub-basin, as a key element of its petroleum systems. Integrating each of its geochemical aspects and processes, for a better understanding and evaluation of effectiveness.

2.2. Specific objectives:

- Evaluate the quality and maturity parameters of the different source rocks in the area, to determine which is the most effective.
- Perform a burial history analysis of Ceduna Basin, characterizing its key elements with the assistance of petroleum systems 1D modeling and quick look workflows.
- Postmortem well analysis: wells previously drilled will be analyzed to determine which elements or processes were absent or not favorable to reach hydrocarbon accumulations.

CHAPTER 2 Delimitation of the study area

3. Location

The Bight Basin extends from the south of Cape Leeuwin in the west, to just south of Kangaroo Island in the east, where it adjoins the Otway Basin. This work is focused on the petroleum systems characterization in Ceduna sub-basin (Figure 1).

The Ceduna Sub-basin is one of the main depocenters of the Mesozoic to Cenozoic Bight Basin. Ceduna has an area of approximately 90,000 km^2 and contains a sedimentary thickness more than 15 km of syn and post rift Mesozic sediments. The study is based on the petroleum analysis using interpretation of 2D seismic survey covering the Ceduna sub-basin, Petroleum System Analysis modeling (PSM 1-D) and a Petroleum System Quick Look (PSQL).

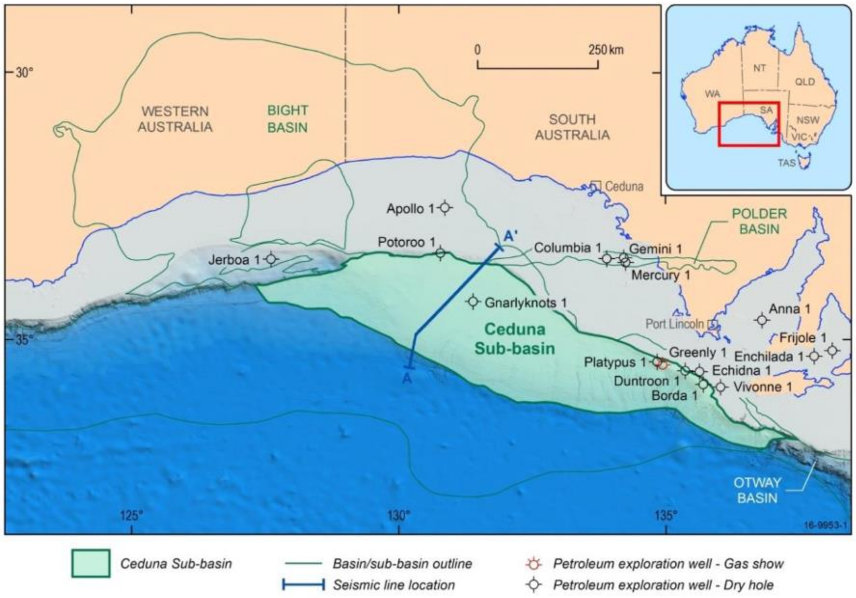


Fig. 1. Location of the Bight Basin along the southern Australian margin, with component sub-basins (modified Totterdel, 2008).

In the deep-water Ceduna sub-basin two wells have been drilled to test the hydrocarbon potential Gnarlyknots-1total depth 1824m and Gnarlyknots-1A total depth 4736m (Woodside, 2003). None of these wells encountered significant hydrocarbons. The most recent is Gnarlyknots-1A drilled in 2003, although both wells failed to recover hydrocarbons, several encouraging signs of the presence of hydrocarbons were observed, that information will be of vital importance in this work.

CHAPTER 3 Workflow

4. Evaluation of Petroleum Systems

In order to know the principal features and behavior of Ceduna sub-basin, two different workflows were used. The first one refers to the modeling 1D Petroleum System Modeling (1D PSM, Figure 2) in which the properties of the petroleum system are examined over time in a specific location; This PSM has become a critical component in the worldwide exploration programs of many national and international oil companies for both conventional and unconventional resources (Peters et al., 2017). And the second refers to a Petroleum System Quick Look (PSQL) (Figure 3) which allows rapid evaluation of the key exploration risk elements – trap, reservoir, charge, and seal and enables uncertainty evaluation in exploration environments characterized by low data density.

4.1. 1D Petroleum System Modeling

The PSM is a quantitative tool to test and refine models of petroleum generation, migration, and accumulation for conventional resources. This tool combines well and geological information to model the evolution of a basin over time. The results of 1D PSM are analyzed to determine the timing, the synergy of the elements of the petroleum system and understand the results of the specific location. The workflow to create the PSM is explained below.

First, a location needs to be analyzed where the timing of petroleum systems elements will be evaluated, all the different lithologies that will be used are identified and created, to later produce the facies (denotes a range of petrophysical properties and reservoir or source characteristics assigned to the different strata of the model) with their age and element of the corresponding petroleum system. The source rock properties are included here (kinetics, TOC, and HI), with these elements it is possible to build a chronostratigraphic column.

Next step is to create Boundary Conditions - Time Trends which are the conditions of the basin through the time, they are three: Paleo Water Depth (PWD), Sediment Water interface Temperature (SWIT), and Heat Flow (HF). All these data were taken from the research of the area already published.

- **Paleo Water Depth (PWD)**: The water depth of the basin during deposition of sediments through geologic time. Positive numbers indicate subaqueous sedimentation; negative numbers are for uplifted erosion-sensitive areas.

- **Sediment Water interface Temperature (SWIT)**: The temperature of the interface between sediment and water (derived from PWD) through time. It is the upper temperature condition.
- **Heat Flow (HF)**: The amount of the heat through the basin in mW/m^2

When all the lithologies, facies, source rock properties and boundary conditions are created it is time to run the 1D petroleum system simulation. In this step all the information required before is integrated. The mechanical compaction is an important factor during simulation of the basin over time, the results obtained during this simulation include some maturity parameters of the source rock, such as: a) Transformation Ratio (TR) identifying the critical moment for source rocks, b) vitrinite reflectance (Ro); c) Capillary Entry Pressure for the seal rock; and d) bulk history.

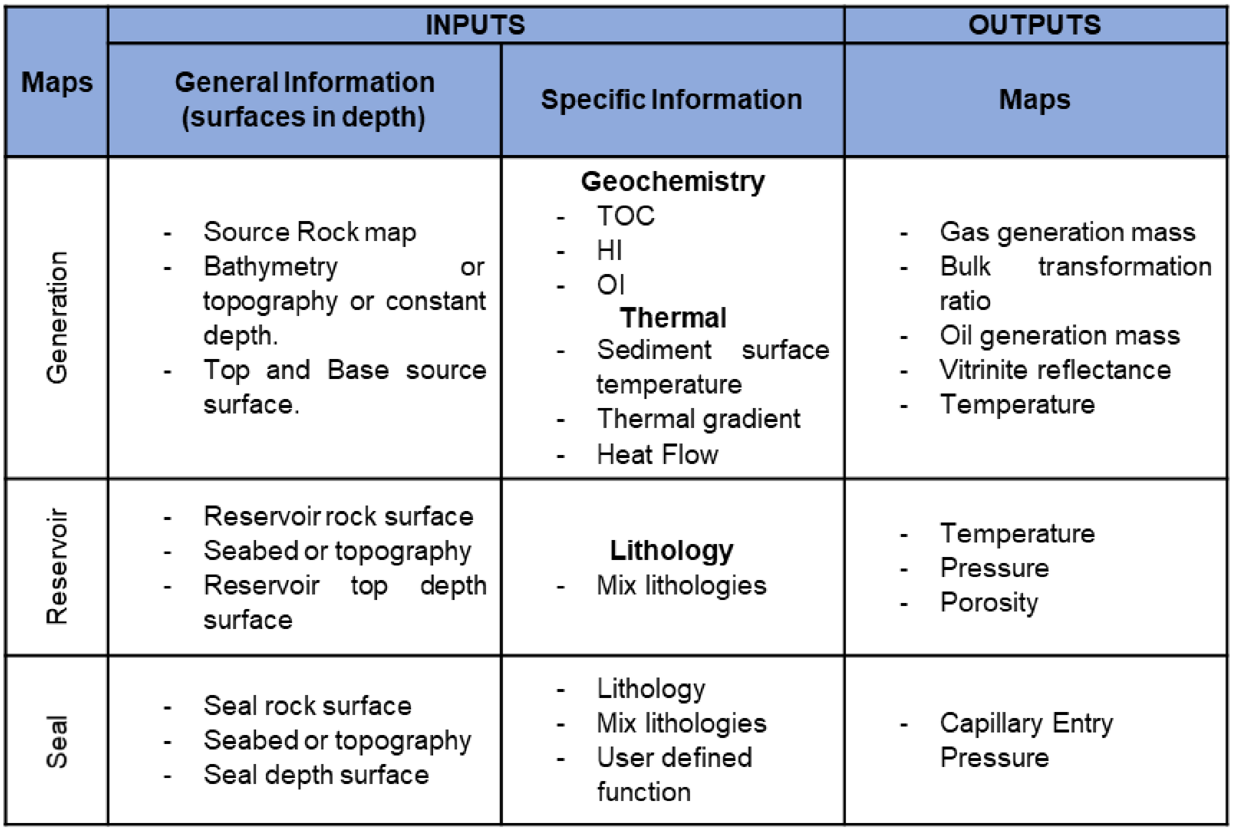
Next step is to analyze the outputs, which are: burial history adding maturity parameters (Ro, Tr) and describe the source rocks with oil or gas generating potential. The graphs of capillary entry pressure will be used to determine the effectiveness of seal rock and determine at what age they reached that potential.

The final stage is to create an event chart using all data and ages collected during the previous step. An event chart indicates when the essential elements and processes took place from a petroleum system, the critical moment, and the preservation time.

4.2. Petroleum System Quick Look

Due to the limited available information, it was necessary to perform a PSQL (Figure 3), which is designed based on maps and properties of source, reservoir, and seal rock. The outcome are maps of potential areas, which lead us to better understand the petroleum system simulating different scenarios for generation, reservoir, seal and charge. The creation of output maps requires some general input data, such as depth maps, top and base maps; most of the information required in this step has already been obtained in the PSM modeling. Also, some specific information must be added depending on the bedrock to be analyzed (source, reservoir, and seal rock). Table 1 shows the necessary input data (general and specific information) for the generation of each surface with the required properties. The final step during this workflow is to join the data previously obtained to perform a charge modeling whose outputs are accumulation and drainage areas maps.

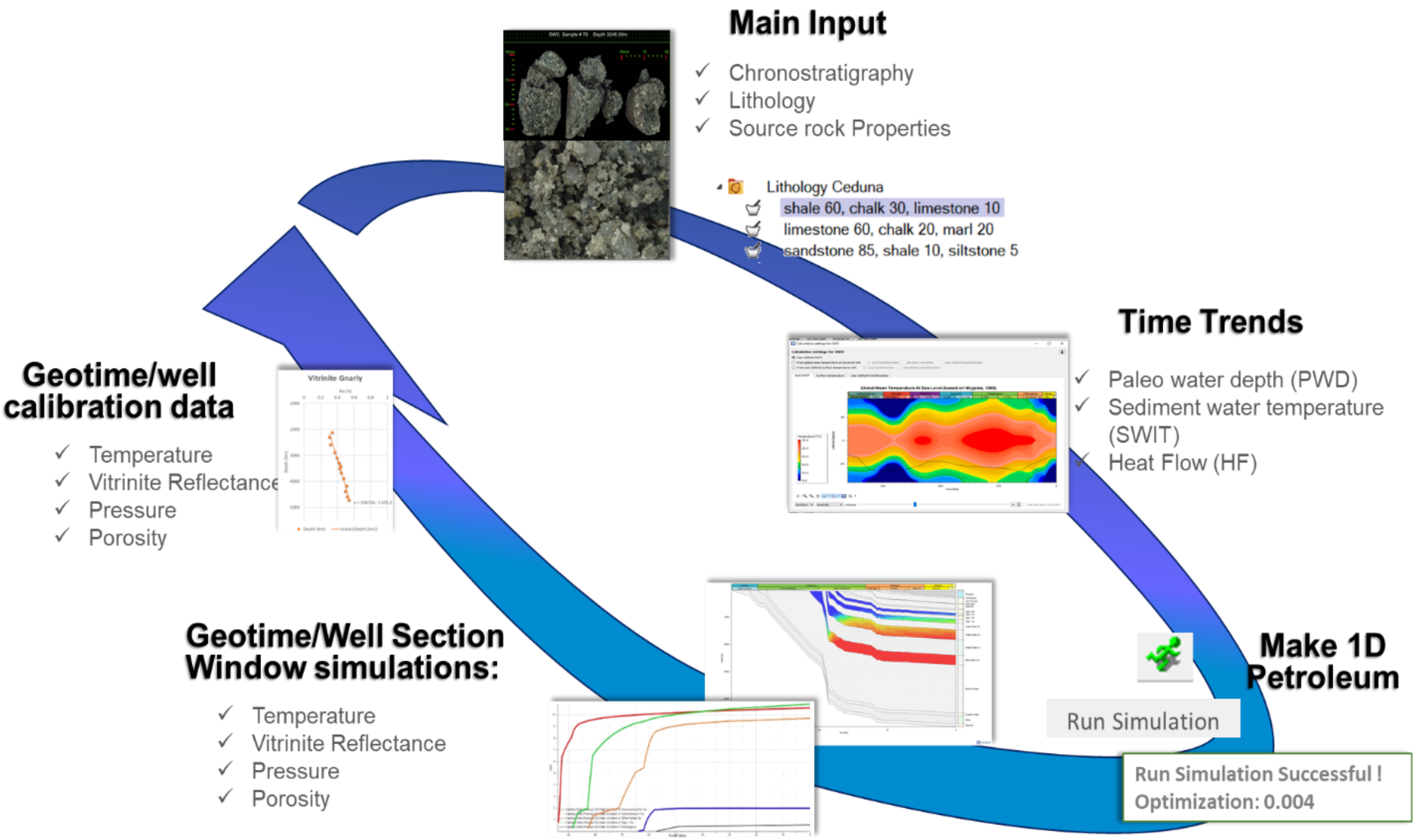
A PSQL has clear limitations to the accuracy of the results that are usually static using present day geometries and conditions and seldom calibrates results to hard data. However, it produces rapid evaluation when a short time frame is required, and it has been used for this work due the lack of information and low data density.



Maps	**INPUTS**		**OUTPUTS**
	General Information (surfaces in depth)	**Specific Information**	**Maps**
Generation	- Source Rock map - Bathymetry or topography or constant depth. - Top and Base source surface.	**Geochemistry** - TOC - HI - OI **Thermal** - Sediment surface temperature - Thermal gradient - Heat Flow	- Gas generation mass - Bulk transformation ratio - Oil generation mass - Vitrinite reflectance - Temperature
Reservoir	- Reservoir rock surface - Seabed or topography - Reservoir top depth surface	**Lithology** - Mix lithologies	- Temperature - Pressure - Porosity
Seal	- Seal rock surface - Seabed or topography - Seal depth surface	- Lithology - Mix lithologies - User defined function	- Capillary Entry Pressure

Table 1 . Input information required to create a PSQL and the surface outputs obtained through the modelling

1D PSM



Main Input

- ✓ Chronostratigraphy
- ✓ Lithology
- ✓ Source rock Properties

Lithology Ceduna
- shale 60, chalk 30, limestone 10
- limestone 60, chalk 20, marl 20
- sandstone 85, shale 10, siltstone 5

Time Trends

- ✓ Paleo water depth (PWD)
- ✓ Sediment water temperature (SWIT)
- ✓ Heat Flow (HF)

Make 1D Petroleum

Run Simulation

Run Simulation Successful !
Optimization: 0.004

Geotime/Well Section Window simulations:

- ✓ Temperature
- ✓ Vitrinite Reflectance
- ✓ Pressure
- ✓ Porosity

Geotime/well calibration data

- ✓ Temperature
- ✓ Vitrinite Reflectance
- ✓ Pressure
- ✓ Porosity

Fig. 2. Petroleum System modeling 1D Workflow. The Petroleum System is composed of various sub-elements in this work each one was analyzed. For the reservoir rock we are interested in the type of rock, thickness, continuity, porosity, and permeability; regarding the source rock, the type of rock (quality), quantity and maturity. The Petroleum Systems modeling is a digital data model where the entire petroleum system is understood, and all processes are interrelated.

PSQL

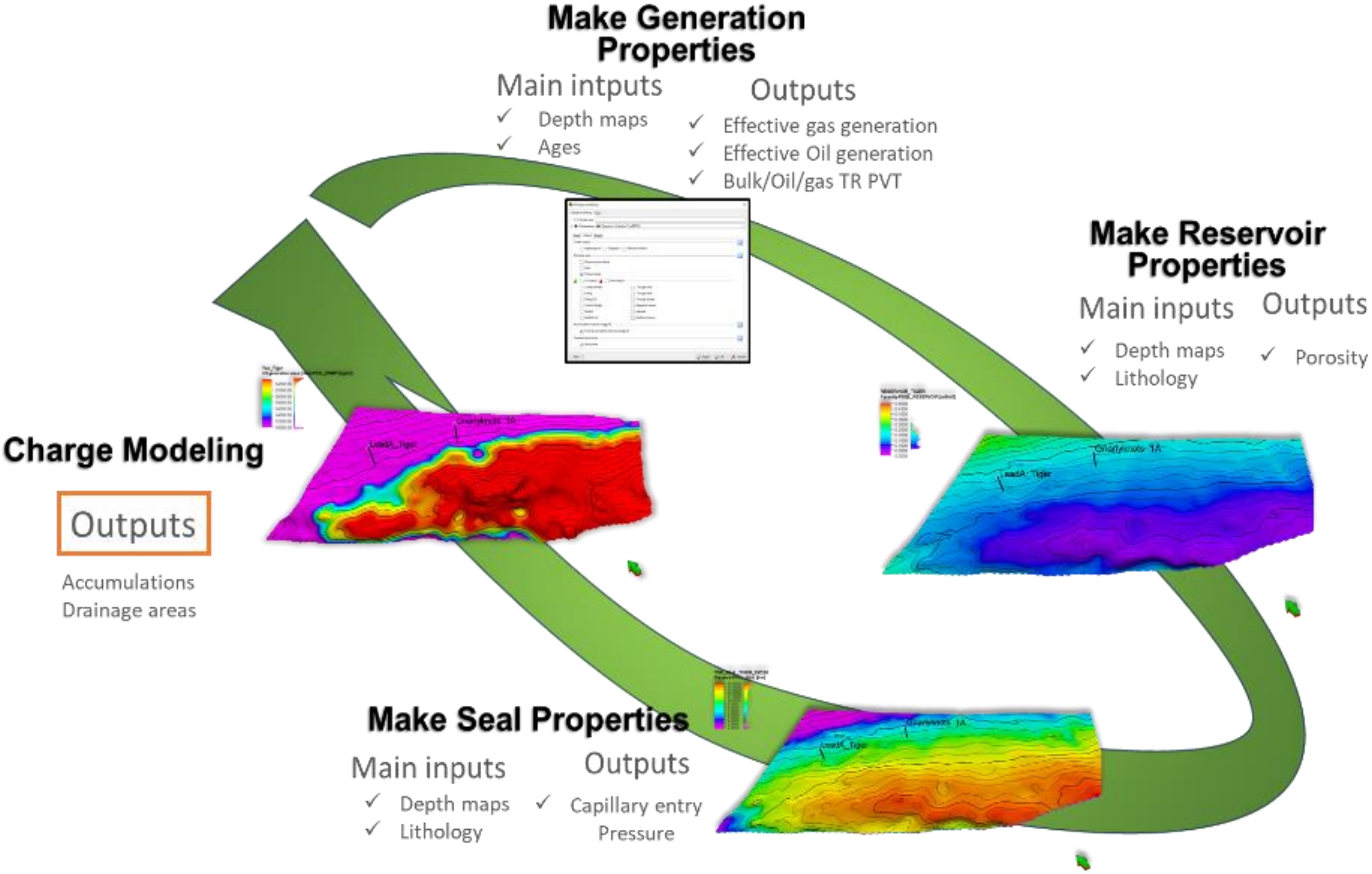


Fig. 3. PSQL workflow, it is necessary to create maps with properties, with which some output maps are obtained, for example maps of porosity, capillary pressure, drainage areas; among other. Which are simulated under current conditions.

GEOLOGICAL BACKGROUND

CHAPTER 4 Petroleum Geology of The Bight Basin

5. Bight Basin Stratigraphic and Sedimentological Framework

The Ceduna Sub-basin covers an area of more than 125,000 km^2 and contains at least 15,000m of rift and post-rift Middle Jurassic–Upper Cretaceous sediments. The accumulation of sediments and the rapid subsidence rate in the Ceduna Sub-basin are the cause of the prominent bathymetric feature.

The sediments accumulated in the basin as it evolved from an intracontinental rift between the still connected Australian and Antarctic continents (about 165 Ma), to a passive margin basin following sea-floor spreading between the continents (about 84 Ma) and Australia's subsequent drift northward. Figure 4 is a seismic cross-section from the northern Ceduna Sub-basin and shows the typical geology of the basin. The colored horizons differentiate the ten super-sequences (SS) identified by (Totterdell et al., 2003).

The earliest sediments were deposited in lakes and rivers in a series of rift valleys. As the earth's crust continued to stretch and subside with the opening of the proto-Southern Ocean, sedimentation became more widespread and eventually marine conditions began to dominate. By about 100 Ma, a narrow seaway, closed off at its eastern end, existed between Australia and Antarctica. Thick marine shales (the Blue Whale SS shown near the base of the cross-section in Figure 4) accumulated in this seaway. From about 98-65Ma, massive delta systems fed sediments into the basin (White Pointer, Tiger and Hammerhead SS). While the rivers that formed these deltas no longer exist, the presence of large delta systems in the Great Australian Bight during the Cretaceous is indicated by the sedimentology of rocks intersected in wells such as Potoroo 1 and Gnarlyknots 1A, and the architecture of the sedimentary packages revealed by seismic data. A regional crustal uplift at the end of the Cretaceous resulted in the basin being cut-off from sediment input. Deposition from that time on was dominated by cool-water carbonate sedimentation; these carbonate rocks are seen in the cliffs at the head of the Great Australian Bight. (Totterdell et al., 2003).

A total of ten super-sequences were defined: Dungong, Wobbegong, Hammerhead, Tiger, White Pointer, Blue Whale, Bronze Whales, Southern Right, Minke and Sea Lion. For this work, the use of the term super-sequences was preferable since these refer to units of the stratigraphy of sequences, that are related to sea level cycles. The deposit history of each SS is described in Figure 6. Each super-sequence is associated with one or more elements of the petroleum system. Because this work is focused on the rocks deposited during third and fourth basin phases, we will focus mainly on the super-sequences Hammerhead, Tiger, White Pointer and Blue Whale. (Geoscience Australia, 2016).

6. *Bight Basin Tectonostratigraphic framework*

The Bight Basin tectonic evolution is formed by a depocenters series initiated during a period of Middle-Late Jurassic to Early Cretaceous upper crustal extension, along Australia's southern margin within a tectonic framework dominated by the break-up of eastern Gondwana. (Fraser & Tilbury 1979; Bein & Taylor 1981; Willcox & Stagg 1990; Stagg et al. 1990; Hill 1995; Totterdell et al. 2000; Norvick & Smith 2001; Teasdale et al. 2003; Totterdell & Bradshaw 2004). The basin evolved through repeated episodes of extension and thermal subsidence leading up to, and following, the commencement of seafloor spreading between Australia and Antarctica (Totterdell & Bradshaw, 2004).

The northern margin of Ceduna Sub-basin is characterized by a series of fault-bounded half graben; these contain a Middle Jurassic – Early Cretaceous syn-rift fill (Sea Lion and Minke SS) overlain by Early-Late Cretaceous post rift deposits (Southern Right to Hammerhead SS). Syn-rift sediments from the Sea Lion and Minke SS thicken across east to east-northeast-striking normal faults at the northern margin of each half graben, and thin to the southeast across rotated basement tilt blocks. The half graben is also bound by a series of relatively long (230 km), discontinuous, southwest-dipping faults on their landward flanks and northeast-dipping faults on their basinward flanks. Farther southeast, the inboard Ceduna Sub-basin boundary is defined by the southeast-striking Bettong and Wopilkara Fault Systems. (Totterdell et al., 2003)

The oldest and most significant set of gravity-driven structures in the Ceduna Sub-basin is the Early Cretaceous Mulgara Fault Family (Figure 4 and 5.). This comprises a series of listric normal growth faults that formed as a result of gravity sliding and gravity spreading processes during deposition of a major delta (the White Pointer SS). A younger series of grow faults, the Kowari Fault Family, comprises gravity-slide structures that formed during collapse of the gravitationally unstable paleo shelf-margin in the Campanian-Maastrichtian. (Totterdell et al., 2003). The formation periods of fault families Mulgara and Kowari were generated and reactivated during the deposition of the Tiger and Hammerhead SS, which is why the risk of no accumulation of hydrocarbons is possible.

Following synopsis taken from various work by Geoscience Australia, the tectonostratigraphic development of the Bight Basin can be defined in terms of four phases that reflect those different tectonic drivers. Figure 7 shows a summary of each phase, this include the age, structural elements, sedimentation, and super-sequence deposited.

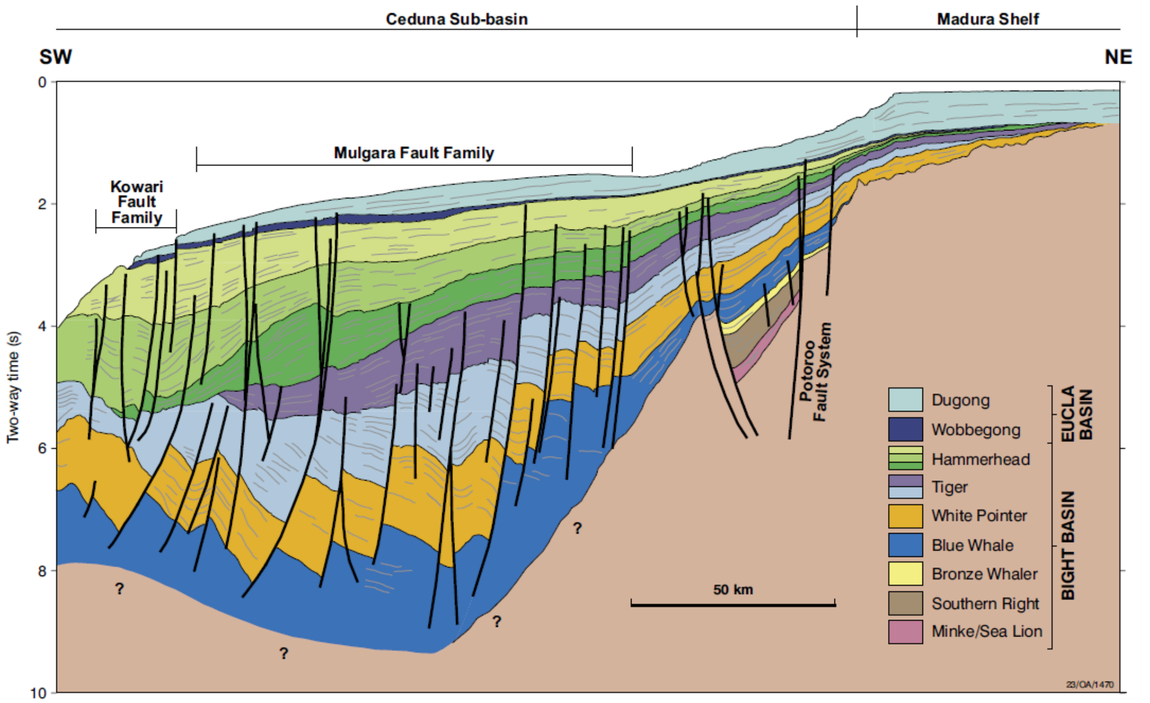


Fig. 4: Cross-section through the Madura Shelf and the Ceduna Sub-basin. Showing in different colors the super-sequences presents in Ceduna sub basin and the Kowari and Mulgara Fault families. (Totterdell, et al., 2003)

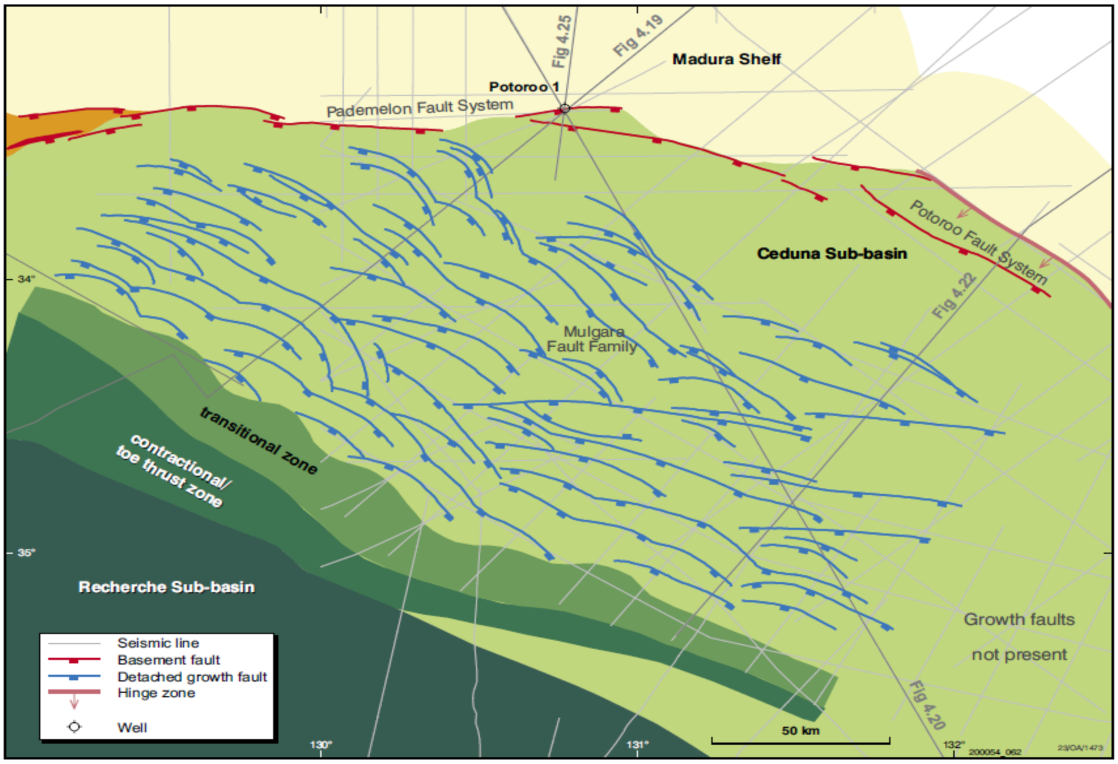
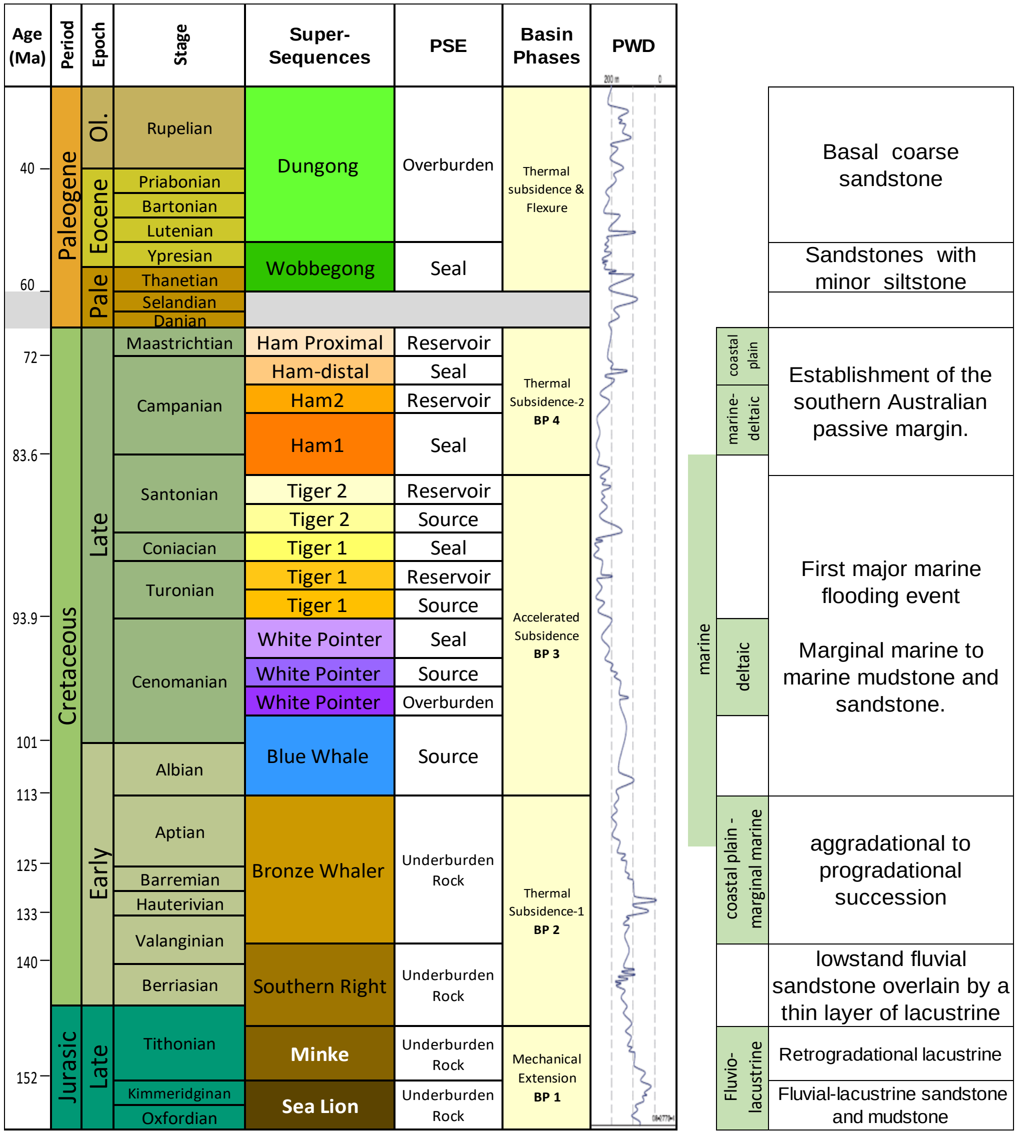


Fig. 5 Structural elements map for the central Ceduna Sub-basin showing growth faults (Mulgara Fault Family) and associated contractional toe-thrust zone from the Late Cretaceous White Pointer Super-sequence. Also shown are basement faults (Pademelon and Potoroo Fault Systems) and the basement hinge zone. (Totterdell et al., 2003).

Stratigraphic and Sedimentological Framework



Late Paleocene to present: the largely cool-water carbonates of the Eucla Basin accumulated on a sediment-starved passive margin. In the Middle Eocene (around 45 Ma) there was a dramatic increase in the rate of spreading (Tikku & Cande 1999), which resulted in widespread subsidence of the margin.

End of the Cretaceous: Dramatic reduction in sediment supply, abandonment of deltaic deposition. Regional uplift resulted in the erosion of the Hammerhead Supersequence, and much of the underlying Tiger Supersequence, from the Eyre Sub-basin, and the progressive erosion of the Cretaceous section across the Madura Shelf.

Latest Santonian—Maastrichtian: The commencement of ultra-slow to very slow sea floor spreading followed by a period of thermal subsidence and the establishment of the southern Australian passive margin (BP4). This phase is represented by the latest Santonian–Maastrichtian Hammerhead Supersequence, a sand-rich deltaic system characterised by strongly prograding stratal geometries. Because of the slow rate of sea floor spreading, the seaway into which the deltas prograded would have been relatively narrow.

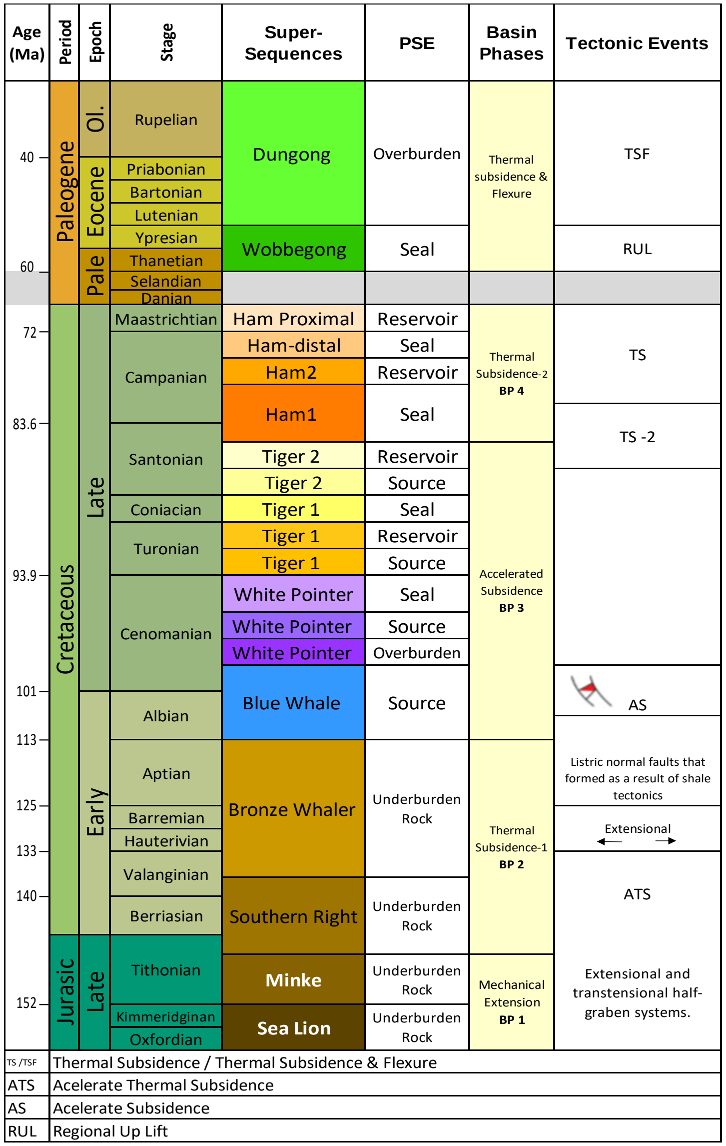
Cenomanian: Progradation of deltaic sediments into a narrow seaway (White Pointer Supersequence). Rapid deposition resulted in a short-lived period of shale mobilisation and growth faulting throughout the northern half of the Ceduna

Mid Albian: An abrupt increase in subsidence rate signalled the start of the third basin phase (BP3). This period of accelerate subsidence, which continued until the commencement of sea-floor spreading between Australia and Antarctica in the Late Santonian, coincided with a period of rising global sea level. This combination of factors resulted in a high rate of creation of accommodation, the first major marine flooding event in the basin and the widespread deposition of marine silts and shales of the Albian–Cenomanian Blue Whale Supersequence.

Mid-Late Jurassic to Early Cretaceous upper crustal extention. The rocks deposited during this phase and the subsequent period of thermal subsidence (BP2) were largely non-marine, with some marine influence becoming evident late in BP2 during the Late Aptian.

Fig. 6 Summary of stratigraphic and sedimentological framework (Modified from Totterdel et al. 2000); these include principal stage of the basin, age, sea level curve, sedimentation and super-sequences deposited.

Tectonic Framework – Structural



Age (Ma)	Period	Epoch	Stage	Super-Sequences	PSE	Basin Phases	Tectonic Events
	Paleogene	Ol.	Rupelian	Dungong	Overburden	Thermal subsidence & Flexure	TSF
40		Eocene	Priabonian				
			Bartonian				
			Lutenian				
			Ypresian	Wobbegong	Seal		RUL
60		Pale	Thanetian				
			Selandian				
			Danian				
	Cretaceous	Late	Maastrichtian	Ham Proximal	Reservoir	Thermal Subsidence-2 **BP 4**	TS
72			Campanian	Ham-distal	Seal		
				Ham2	Reservoir		
				Ham1	Seal		TS -2
83.6			Santonian	Tiger 2	Reservoir	Accelerated Subsidence **BP 3**	
				Tiger 2	Source		
			Coniacian	Tiger 1	Seal		
			Turonian	Tiger 1	Reservoir		
				Tiger 1	Source		
93.9			Cenomanian	White Pointer	Seal		
				White Pointer	Source		
				White Pointer	Overburden		
101		Early	Albian	Blue Whale	Source		AS
113			Aptian	Bronze Whaler	Underburden Rock	Thermal Subsidence-1 **BP 2**	Listric normal faults that formed as a result of shale tectonics
125			Barremian				Extensional ← →
			Hauterivian				
133			Valanginian				ATS
140			Berriasian	Southern Right	Underburden Rock		
	Jurassic	Late	Tithonian	**Minke**	Underburden Rock	Mechanical Extension **BP 1**	Extensional and transtensional half-graben systems.
152			Kimmeridginan	**Sea Lion**	Underburden Rock		
			Oxfordian				

TS /TSF	Thermal Subsidence / Thermal Subsidence & Flexure
ATS	Acelerate Thermal Subsidence
AS	Acelerate Subsidence
RUL	Regional Up Lift

Period of thermal subsidence. A short phase of magmatism in the middle Eocene, affected the central Ceduna Sub-basin

Accelerated subsidence, which continued until the commencement of seafloor spreading between Australia and Antartica in the Late santonian.

Slow thermal subsidence that lasted throughout most of the Early Cretaceous

Initiation of sedimentation. Upper Crustal Extension.

Middle Eocene: magmatic phase characterised by extrusive volcanism (volcanoes, flows, volcanic build-ups) and the intrusion of sills, dykes and deeper igneous bodies (Schofield & Totterdell, 2008).

End of the Cretaceous: regional uplift

Late Santonian: Continental break-up followed by a period of thermal subsidence and the establishment of the southern Australian passive margin (BP4)

Mid Albian: Abrupt increase in subsidence rate This period of accelerated subsidence, which continued until the commencement of seafloor spreading between Australia and Antarctica in the late Santonian,

Early Cretaceous: period of slow thermal subsidence In the Eyre Sub-basin, the extent of deposition of BP2 is generally constrained by the half-graben bounding faults, but the succession does not thicken appreciably into the faults, indicating that little or no actual upper crustal extension occurred at this time. Overall, the succession has an onlapping, sag-fill geometry which indicates that accommodation was created largely by thermal subsidence and compaction, with deposition concentrated over the earlier half graben.

Mid-Late Jurassic to Early Cretaceous: phase of NW–SE to NNW–SSE intracontinental extension. This resulted in the formation of a series of oblique extensional and transtensional half graben in the Bremer, Eyre and Duntroon sub-basins, and along the northern and eastern margins of the Ceduna Sub-basin

Fig. 7 Summary of tectonostratigraphic framework described in four phases (Modified from Totterdel et al. 2000); these include principal stage of the basin, age, structural elements, sedimentation and super sequences deposited

7. Petroleum Systems Description in the Ceduna sub-basin, Australia

The data presented below are the result of a compilation of biostratigraphic, sedimentological and geochemical studies previously published by various authors. These studies were carried out in the Ceduna sub-basin and its margins. The most current study was conducted In February – March 2007, Geoscience Australia undertook a marine sampling survey in the Great Australian Bight Basin and testing by dredging a number of samples from rocks outcropping on the seafloor. The survey successfully recovered a suite of mid-basin to distal rocks of Cenomanian – Maastrichtian age, including several samples with excellent source potential.

The definition of the elements of the petroleum systems was carried out considering several sedimentological studies such as: lithology, depositional environment, sequence stratigraphic models and others. Likewise, a compilation of geochemical analyzes was carried out for the source rocks. The source, reservoir, and seal rocks are described below.

7.1. Potential Source Rock

Source rocks result from a convergence of physical, biochemical, and geologic processes that culminate in the formation of fine-grained sedimentary rocks containing carbon- and hydrogen-rich organic matter. The amount and type of organic material incorporated into a source rock are controlled, in part, by environmental and depositional conditions (McCarthy, et al., (2011).

Source rocks form where environmental conditions support biologic activities that produce large quantities of organic matter, where depositional conditions concentrate this matter and where post depositional conditions permit its preservation. Organic content is controlled largely by biologic productivity, sediment mineralogy and oxygenation of the water column and sediment. Biologic contributions to organic content range from hydrogen-poor woody fragments to hydrogen-rich algal or bacterial components. From these, a variety of organic compounds may be created (McCarthy et al., (2011).

- Hydrocarbon Generation

Thermal transformation of organic matter is what makes a rock produce oil or natural gas. The mechanisms by which oil and gas are generated vary from basin to basin; these mechanisms depend on the sedimentation facies, their burial history, tectonics, and other geological processes. As sediments with high organic content are deposited, microbial processes convert part of the organic matter into biogenic gas. As new deposits accumulate and the overburden rocks act on them, the depth increases, and the temperature also increases according to the thermal gradient of the basin, causing the heat to gradually convert the organic matter into kerogen.

This transformation of the kerogen continues as the temperature increases, thus converting the kerogen into bitumen and oil (enriched in hydrogen and carbon). As it releases oil, the kerogen becomes poorer in hydrogen content. Increasing maturity also causes petroleum compounds to undergo a process of structural simplification, generally starting as petroleum, then with wet gas, and ending with dry gas. The conditions of pressure, temperature, and time in which the generation of hydrocarbons occurs is called the hydrocarbon generation window, which is at a temperature of 60°C to 120°C, and between about 1500 to 3500 meters deep.

- Oil Window

The source rock matures with increasing heat, and it undergoes catagenesis. During this stage, petroleum is generated as temperature increases to between 50°C and 150°C (122°F and 302°F), causing chemical bonds to break down within the kerogen. Within this oil window, Type I and II kerogens produce both oil and gas, while Type III kerogens produce mainly hydrocarbon gas. Further increases in burial depth, temperature and pressure force the source rock into the upper part of the gas window, where secondary cracking of the oil molecules produces wet gas containing methane, ethane, propane and heavier hydrocarbons.

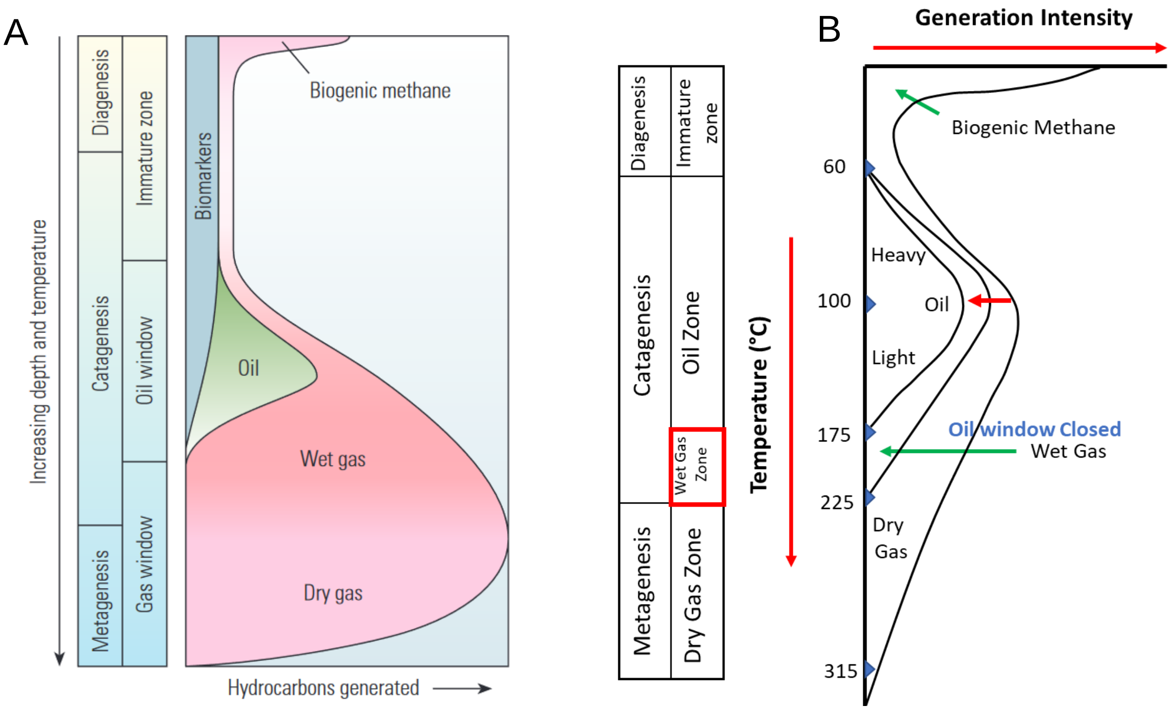


Fig. 8 A. Thermal transformation of kerogen. The generation of hydrocarbons in source rocks is controlled primarily by temperature as the kerogen content evolves from reactive carbon to dead carbon. Gas is given off during early diagenesis, primarily through biologic activity. B. Catagenesis takes place with further burial, during which oil and gas are given off. With increasing depth and temperature, any remaining oil is cracked during metagenesis, initially giving off gas, followed by simpler forms of dry gas. The process varies somewhat from one kerogen type to another. (Modified from Tissot et al.,1974).

Catagenesis is the main oil formation zone; and gas formation zone, where wet gas, with an increasing proportion of methane, is generated in quantities through decay.

At 60°C the main generation of liquid hydrocarbons begins, which are heavy and rich in nitrogen, sulfur, and oxygen. Increase in temperature the oils become successively lighter: at 100°C the maximum generation occurs. Above 100°C, hydrocarbon generation decreases, and condensed hydrocarbons and gases are formed. The liquid hydrocarbon generation window closes at 175°C (Figure 8).

- Determining source rock potential

Some petroleum compounds within source rock are released at temperatures lower than those needed to break down the kerogen. By monitoring the compounds released during a steady increase in temperature, geochemists can determine the amount of generated petroleum relative to a rock's total potential. In addition, the temperature corresponding to the maximum evolution of gas gives an indication of source rock maturity. Geoscientists employ a variety of techniques (Rock-Eval pyrolysis, Macerals Petrography, fluorescence, etc.) to evaluate the hydrocarbon-generating capacity of source rocks. Geochemical testing of outcrop samples, formation cuttings, sidewall cores and conventional cores can help determine the amount, type, and thermal maturity of organic matter present in the rock. The results help geoscientists ascertain whether, how much, when and what kind of petroleum might have been generated as well as determine what secondary processes may have occurred following the expulsion of hydrocarbons from the source rock (McCarthy, et al., 2011).

The Rock Eval (RE) pyrolysis method consists of a programmed temperature heating (in a pyrolysis oven) in an inert atmosphere (helium) of a small sample (~100 mg) to quantitatively and selectively determine: the free hydrocarbons contained in the sample and the hydrocarbon and oxygen containing compounds (CO2) that are volatilized during the cracking of the unextractable organic matter in the sample (kerogen). The four basic parameters obtained by pyrolysis are:

S_1: represents how many milligrams of free hydrocarbons can be thermally distilled out of one gram of the sample. If S_1 >1 mg/g, it may be indicative of an oil show. S_1 normally increases with depth. Contamination of samples by drilling fluids and mud can give an abnormally high value for S_1.

S_2: represents milligrams of residual hydrocarbons in one gram of rock, thus indicating the potential amount of hydrocarbons that the source rock might still produce if thermal maturation continues. This reading can have important implications for the evaluation of oil shales. S_2 is an indication of the quantity of hydrocarbons that the rock has the potential of producing should burial and maturation continue.

S_3: the amount of CO_2 (in milligrams CO_2 per gram of rock) produced during pyrolysis of kerogen. S_3 is an indication of the amount of oxygen in the kerogen and is used to calculate the oxygen index (see below). Contamination of the samples should be suspected if abnormally high S_3 values are obtained. High concentrations of carbonates that break down at lower temperatures than 390°C will also cause higher S_3 values than expected.

Tmax = the temperature at which the maximum release of hydrocarbons from cracking of kerogen occurs during pyrolysis (top of S_2 peak). Tmax is an indication of the stage of maturation of the organic matter.

Carbon is an essential element of any organic compound, and one way to assess the organic richness of a rock is to measure its carbon content. Because the oil or gas potential of a formation is related to its carbon content, the Total Organic Carbon (TOC) measurement is a priority in source rock assessment. This initial carbon assessment is followed by other screening procedures such as pyrolysis and vitrinite reflectance analysis.

The TOC measurement is the first screen for quantifying organic richness. TOC values provide only a semiquantitative scale of petroleum-generating potential. TOC indicates the quantity, but not the quality, of the organic matter. If this initial screening test demonstrates sufficient organic content, the rock should undergo additional tests to ascertain organic matter quality and maturity (McCarthy, et al., 2011).

Vitrinite reflectance is a key diagnostic tool for assessing maturation. Vitrinite, a maceral formed through thermal alteration of lignin and cellulose in plant cell walls, is found in many kerogens. As temperature increases, vitrinite undergoes complex, irreversible aromatization reactions that increase reflectance. This technique is used to evaluate kerogen maturity over temperatures corresponding to early diagenesis through metamorphism a range spanning the sequence of petroleum generation, preservation and destruction in rocks (McCarthy, et al., 2011).

As indicators of thermal maturity, Ro values vary with the type of organic matter. And because the temperature range of the gas window extends beyond that of oil, Ro values for gas will show a corresponding increase over those of oil. Thus, high maturation values (Ro > 1.5%) generally indicate the presence of predominantly dry gas; intermediate maturation values (1.1%<Ro<1.5%) indicate gas with a tendency toward oil generation at the lower end of the range. Wet gas can be found still lower in the range (0.8% < Ro < 1.1%). Lower reflectivity values (0.6% < Ro < 0.8%) indicate predominantly oil, while Ro < 0.6% points to immature kerogen (McCarthy, et al., 2011).

This work emphases three special characteristics that a good source rock should have to be considered; these are:

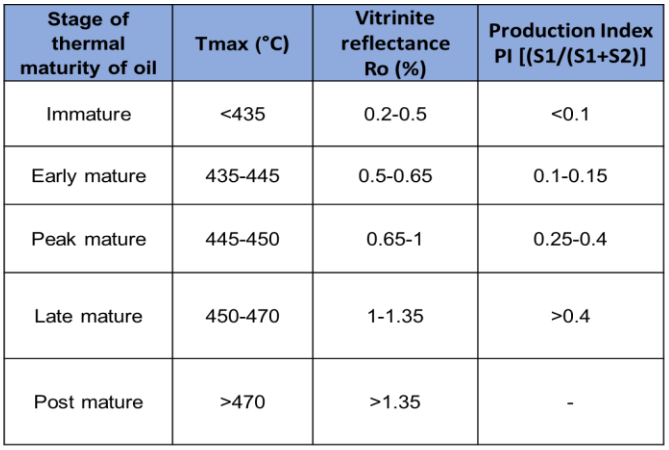
- Quality (Kerogen type I-II and III, Rock Eval, (Pr/Ph) ratio, HI (Original mgHC/gTOC, chromatogram).
- Quantity (TOC, HI, S2 (mgHc/g rock)).
- Maturity (Ro, Tmax, Biomarkers, Macerals Petrography).

The first two components are products of the depositional setting. The third is a function of the structural and tectonic history of the province. Table 2 shows a general interpretation scheme for some maturity parameters for the main stages of hydrocarbon generation.

The key to the petroleum prospectivity of the Ceduna Sub-basin is the distribution of Upper Cretaceous marine and deltaic sediments. Potential source rocks are interpreted to be present throughout this succession, including oil-prone marine shales (Blue Whale and Tiger super-sequences respectively), deltaic and shallow marine shale and coal (White Pointer super-sequence), and pro delta shales (Hammerhead super-sequence; Figure 6). Table 3 shows some parameters from four source rocks with potential to be considered as source rocks. Annexed1 shows the different analysis made in marine samples taken by Geoscience Australia, sampling survey in the Great Australian Bight Basin.

The 1st order transgressive–regressive cycle (Fig. 6) reached its transgressive maximum in the mid-Cretaceous just prior to the commencement of seafloor spreading in the central Bight Basin. Therefore, an increasing marine influence from the Aptian to the eustatic sea-level peak in the late Albian–mid-Turonian, was likely to have led to a basin ward improvement in source rock quality for the uppermost Bronze Whaler, Blue Whale, White Pointer and Tiger super-sequences. Source rock quality may also have been enhanced by the paleogeography of the margin. By the mid-Cretaceous, open ocean lay to the west and a narrow, possibly restricted, seaway would have existed along the southern margin, at least as far east as the western Otway Basin. Accelerated subsidence prior to the commencement of seafloor spreading led to increased marine accommodation in the Bight Basin, with an enhanced potential for the deposition and accumulation of organic-rich rocks. (Totterdell et al., 2008)

Another factor potentially influencing source rock quality was that deposition during the mid–Late Cretaceous coincided with several global marine organic carbon burial events or Oceanic Anoxic Events (OAE) (Schlanger and Jenkyns 1976; Jenkyns 1980; Schlanger et al., 1987; Arthur et al., 1987). Elevated primary productivity during these periods is generally credited with causing an increased flux of planktonic material to the seafloor and creating oxygen-poor conditions in bottom waters, both factors favouring the preservation of organic matter (Kuypers et al., 2002). The most significant Oceanic Anoxic Event occurred during the late Cenomanian–early Turonian (OAE 2; Schlanger et al., 1987). Evidence for oceanic anoxic events in the Jurassic and Cretaceous is recorded in deep and shallow marine carbonates, marine organic matter, and terrestrial organic matter and further, each event has been successfully correlated between globally distributed and facies-independent sections. Pelagic intervals deposited during these events are characterized by a range of factors, notably the presence of elevated organic-carbon levels (black-shale deposits; e.g. Jenkyns and Clayton 1986), and facies changes suggestive of eustatic sea-level rise (e.g. Hallam 1981, 1992; Haq et al., 1988; Hesselbo and Jenkyns 1998).



Stage of thermal maturity of oil	Tmax (°C)	Vitrinite reflectance Ro (%)	Production Index PI [(S1/(S1+S2)]
Immature	<435	0.2-0.5	<0.1
Early mature	435-445	0.5-0.65	0.1-0.15
Peak mature	445-450	0.65-1	0.25-0.4
Late mature	450-470	1-1.35	>0.4
Post mature	>470	>1.35	-

Table 2 Geochemical parameters describing the level of thermal maturity (Peters, 1986 and Peters and Cassa, 1994).

The thick sedimentary succession in the Ceduna sub-basin contains four source intervals of marine and none-marine carbonaceous shale, coal and oil shale. They were deposited in a variety of lacustrine (lake), deltaic and marine environments that have the potential to form good to excellent quality source rocks capable of generating hydrocarbons.

- Tiger Super-sequence

The Turonian–Santonian Tiger SS comprises marine shales. While historic well data suggested the sequence had overall poor to fair source potential (Totterdell et al., 2009, 2010), deposition was at a time of high global sea levels, and potentially coincident with the Bonarelli Event (or Ocean Anoxia Event, OAE 2) at the Cenomanian–Turonian boundary (Arthur et al., 1990). Totterdell et al. (2000) and Struckmeyer et al (2001) postulated that this unit in the Bight Basin could contain good quality marine source rocks. This was tested by dredging a number of samples from rocks outcropping on the seafloor (Totterdell et al., 2008; Totterdell and Mitchell, 2009) and those dated as latest-Cenomanian-to-Turonian (11 samples) had high amounts of extractable organic matter that was deposited in a marine environment under reducing conditions. These rocks have good to excellent generative potential for oil and is mature for oil and gas across the greater part of the depocentre and immature along the basin margins (Totterdell et al., 2008).

- White Pointer Super-sequence

The Cenomanian White Pointer SS comprises deltaic to shallow marine shales, with considerable proportion of organic matter being coal comprising Type III kerogen (Struckmeyer et al., 2001). TOC values from shales and siltstones are consistently above 1% and mostly above 2% and contain Type II/III kerogen. The succession has good to excellent source potential for both oil and gas (Totterdell et al., 2009, 2010). The lower part of this thick succession is typically gas mature hroughout the basin, except for the basin margins. The upper White Pointer SS lies within the oil window and wet gas window in the greater part of the basin (Totterdell et al., 2008).

- Blue Whale Super-sequence

The Albian–Cenomanian Blue Whale SS comprises marine shales. The proximal end members of the Blue Whale super-sequence have been sampled in several wells and organic matter content is high (Struckmeyer et al., 2001), with TOC values ranging from 0.5% to 62%, typically comprising Type II/III kerogen. Rock-Eval and TOC data show that, overall, the Blue Whale super-sequence has good potential for the generation of both oil and gas (Totterdell et al., 2009, 2010). The depositional framework suggests that the super-sequence was deposited in more open marine conditions further basin ward, indicating source potential is likely to increase in more distal facies.

Super Sequence (SS)	TOC (%)	Facies	Kerogen (Quality)	HI (mgHC/gTOC)
Tiger-2	2%	Marine	II	500
Tiger-1	6%	Marine	II	500
White Pointer	3%	Deltaic	III	500
Blue Whale	4%	Marine	II	500

Table 3 Potential source rocks located in the Ceduna sub-basin, and some characteristics such as TOC, Facies, and Kerogen Quality. Taken

7.2. Potential Reservoir Rock

A reservoir rock is defined as a subsurface body of rock having sufficient porosity and permeability to store and transmit fluids. Sedimentary rocks are the most common reservoir rocks because they have more porosity than most igneous and metamorphic rocks and form under temperature conditions at which hydrocarbons can be preserved. A reservoir is a critical component of a complete petroleum system. A potential reservoir rock must have 3 main characteristics, which are:

- Be porous
- Be permeable
- Have lateral and vertical continuity

Certain intervals of reservoir rock are proposed in Figure 6, some of them, due to the age and type of lithology, appear to be better than others.

In this work a possible scenario with the reservoir rock of the Tiger 1 super-sequence is presented. The lithological analysis from Tiger 1 reservoir shows compositions of 70% sand and 30% shale. Another reservoir rock that could probably be considered as a prospect is the sequence consisting of 80% sands, 17% siltstone, and 3% silty coal; belonging to the super-sequence Hammerhead 2 Reservoir. In chapter 5 a modelling analysis is carried out from the possible Tiger reservoir.

Other analyzes carried out to determine the possible reservoir rock were the review of seismic data in the Ceduna sub-basin, in which a clear impedance contrast was verified at the stratigraphic level of Tiger 1 reservoir, supporting the possible presence of hydrocarbons.

7.3. Potential Seal Rock

Seal Rock is defined as a relatively impermeable rock, that forms a barrier or cap above and around reservoir rock such that fluids cannot migrate beyond the reservoir. A seal is a critical component of a complete petroleum system. The thickness of the seal rock is variable, it can be of very low thickness, if they have excellent quality or of medium or thick thickness, if it is of medium or poor quality.

- ➢ Effective Seals for Hydrocarbon Accumulation and Exploration

We can define an effective seal as for oil equal to or greater than 0.5 MPa and for gas we would expect to see slightly higher capillary pressures of 0.8 MPa.

- ➢ Lithology
  - Sandy shales
  - Clay-mineral-rich shale, silty shales, and dense mudstones.
  - Evaporites and kerogen-rich shale are most effective seals for containing oil.

On Figure 6 five rocks are proposed as seal rocks; they belong from different super sequences

Regional seals

Middle Eocene to Holocene Wobbegong distal super-sequence marls
Turonian–Santonian Tiger super-sequence marine shales
Cenomanian White Pointer super-sequence, deltaic facies include a broad band of coaly sediments
Albian–lower Cenomanian Blue Whale super-sequence marine shales

Intraformational seals

Upper Santonian to Maastrichtian Hammerhead super-sequence marine shales

All the seal rocks proposed will be analyzed in Chapter 5 to verify their effectiveness.

COMPUTATIONAL MODELING AND SIMULATIONS

CHAPTER 5 1D PSM

The simulation models of the basin in 1D on Ceduna sub-basin were carried out with the use of the Petrel and PetroMod softwares. Results of petroleum system modelling include burial, thermal, reservoir and seal rocks properties, and basin evolution history. The PSQL was carried out with the use of the Petrel software some maps obtained during this modelling are timing, maturity, and generation of hydrocarbon, reservoir and seal rocks properties, and charge maps.

7. Basin analysis, 1D Petroleum Systems Modeling

1D PSM describes the evolution of the rocks, kerogen, and generated petroleum throughout geologic history. One dimensional (1D) PSM reconstructs the geo-history at one location, commonly at the position of a well. It is based on burial histories constructed using formation tops from wells, seismic sections, out-crops. Table 5 shows the input data used during the modelling.

7.1. Building the basin and petroleum systems modeling

The input database used for the creation of the 1D model is a compilation of public information, age of sequences was taken from public articles, thickness and depths of the sequences were established with the aid of seismic and well information. Lithology used for each sequence was created manually and customized for each sequence. Some super-sequences were divided in different Petroleum System Elements (PSE). Due to the different lithology by which they were made they were classified as Overburden, Seal, Reservoir, Source and Underburden rock. An example of this is the SS Tiger that was divided in different PSE, two of them have potential characteristics to be a source rock.

The accurate construction of Table 5 was key for the development of the modeling to be precise. The stratigraphy column showed on Figure 9 is the result of the first part of the modeling, it shows in three different colors (purple, brown, and gray) the source, reservoir and seal rocks proposed for the PS.

7.2. Kinetics models

Nowadays basin analysis uses kinetics models to predict the extent of oil generation within potential source rocks. The global kinetic model used in this work was the one proposed by “Pepper & Corvi (1995)” Which assigns kinetic parameters based on gross depositional environment and stratigraphic age; this is useful in areas of low geochemical knowledge.

Pepper and Corvi (1995), describes an organofacies as a collection of kerogens derived from common organic precursors, deposited under similar environmental conditions, and exposed to similar early diagenetic histories. As the organofacies concept combines kerogen type, depositional environment, and generation kinetics, it makes the kerogen kinetic classification based on the organofacies concept very useful for modelling hydrocarbon generation.

Five different organofacies have been defined (Table 5) by Pepper and Corvi (1995) these are A, B, C, D/E and F. The organofacies can be related to the three kerogen types.

Organofacies	*Descriptor*	*Principal biomass*	*Sulphur incorporation*	*Environmental/age association*	*Possible IFT classification*
A	Aquatic, marine, siliceous or carbonate/evaporite	Marine algae bacteria	High	Marine, upwelling zones, clastic-starved basins (any ages)	Type II'S'
B	Aquatic, marine, siliciclastic	Marine algae, bacteria	Moderate	Marine, clastic basins (any age)	Type II
C	Aquatic, non-marine, lacustrine	Freshwater algae, bacteria	Low	'Tectonic non-marine basins; minor on coastal plains (Phanerozoic)'	Type I
D	Terrigenous, non-marine-waxy	Higher plant cuticle, resin, ligning; bacteria	Low	Some (Mesozoic and younger) 'Ever -wet' coastal plains	Type III'H'
E		Higher plant cuticle, ligning; bacteria			
F	Terrigenous, non marine, wax-poor	Ligning	Low	Coastal plains (Late Paleozoic and younger)	Type III/IV

Table 4 **Summary of data sets used in optimization of kinetic parameters for the five organofacies. Pepper and Corvi (1995)**

7.3. Boundary Conditions

PSM requires thermal boundary conditions at the top and base of the sedimentary column. The top boundary condition is a temperature, which varies with latitude and water depth through geologic time. These temperatures can be related to geologic age and mean surface paleotemperature based on plate tectonic reconstructions. Based on plate reconstruction, the paleolatitudes can be reconstructed and used to estimate paleosurface temperature. Together with the paleowater depth, the sediment surface temperature can be estimated. (Peters et al., 2017).

- PWD trend used in this modeling consisted of the digitization of the curve (PWD) located in Figure 6; which was previously created and modified by Totterdell et al. 2008; Haq et al. 1988; Gradstein et al 2004. Fig. 10 A

- SWIT is calculated from the global mean temperature at sea level matrix, and it is a function of the varying latitude of the area of interest at the time of deposition. In these simulations, this global mean surface temperature profile was then recalculated for paleo-water columns along the 1D model. Fig. 10 B

Basin type is important in PSM because it influences basal heat flow and the magnitude, timing, and distribution of temperature with depth (geothermal gradient). Understanding basin type allows the interpreter to narrow the range of possible heat flow scenarios

(Peters et al., 2017). The Figure 11 shows a simplified classification summarizes typical heat flow associated with extensional, compressional, and strike slip sedimentary basins.

- Since Heat Flow is one of the most difficult data to find due to limited information, we use a specific data. The sub-basin Ceduna is characterized to developed on an extensive passive margin, knowing this we can make use of the parameters proposed by P.A. & Allen, J.R. (2005**)** Figure 12. And Figure. 10 C

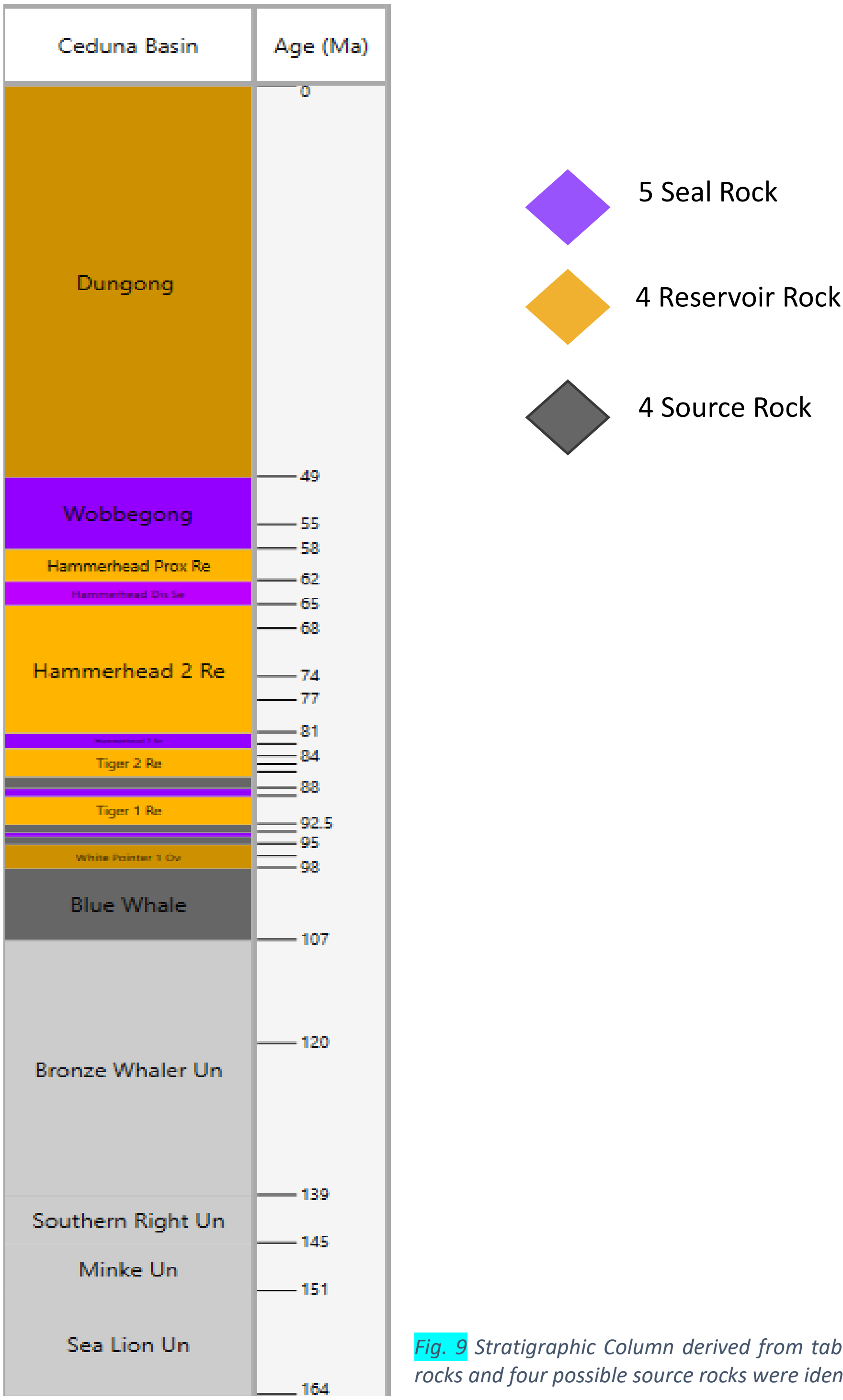


Fig. 9 Stratigraphic Column derived from table 4. Five seal rocks, four reservoir rocks and four possible source rocks were identified.

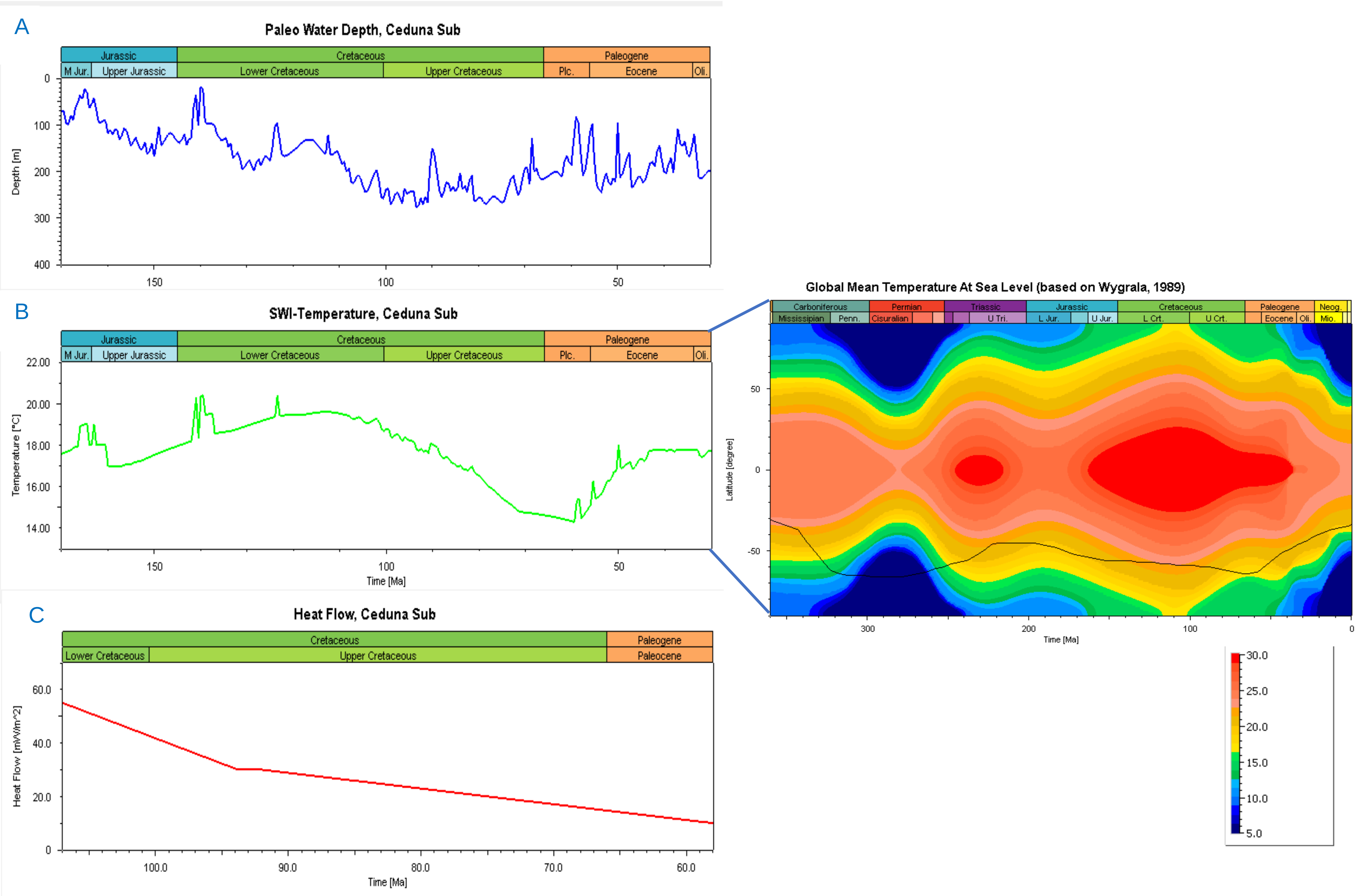


Fig. 10 At left boundary Conditions. A. Paleo Water Depth; B. SWIT; C. Heat Flow. At right SWIT, the software provides an automated estimate of the sediment surface temperature based on a plot of surface temperatures vs latitude vs geological time.

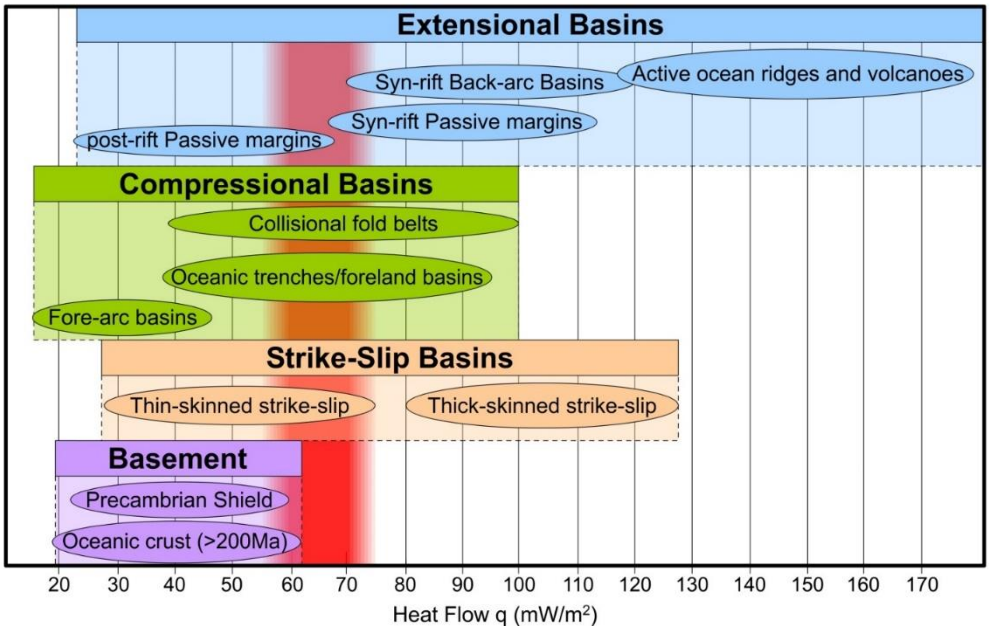


Fig. 11 Typical ranges of heat-flow values for extensional, compressional, strike-slip basins and basement rock. The Global average heat flow ~ 60-70 mW/m2. After Allen, P.A & Allen, J.R. (2005),

Age (ma)	Depth (m)	Super Sequence (SS)	Lithology	Petroleum System Element	Kinetics Group	Kinetics	TOC	HI (mgHC/ gTOC)
0-49	1341	Dungong	Lim 60, chalk 20, marl 20	Overburden				
49-58	1380	Wob-Dung distal	Sh 60, chalk 30, lim 10	Seal				
58-62	1593	Ham Proximal	Ss 85, Sh 10, slt 5	Reservoir				
62-65	2561	Ham-distal	Sh 80, Slt 20	Seal				
65-81	2661	Ham2	Ss 80, Slt 18, Silty coal 2	Reservoir				
81-83	3516	Ham1	Sh 80, Slt 20	Seal				
83-86.5	3574	Tiger 2.1	Ss 70, Slt 27, Silty coal 3	Reservoir				
86.5-88	3735	Tiger 2	Sh 80, Slt 15, Ss 5	Source	Kerogen-oil-gas	Pepper&Corvi(1995) _TII-S(A)	2	500
88-89	3574	Tiger 1.2	Sh 80, Slt 15, Ss 5	Seal				
89-92.5	3735	Tiger 1.1	Ss 70, Sh 30	Reservoir				
92.5-93.5	4304	Tiger 1	Sh 80, Slt 15, Ss 5	Source	Kerogen-oil-gas	Pepper&Corvi(1995) _TII-S(A)	6	500
93.5-94	6174	White Pointer 3	Sh 50, Slt 30, Ss 10,	Seal				
94-95	7320	White Pointer 2	Sh 50, Slt 30, Ss 10,	Source	Kerogen-oil-gas	Pepper&Corvi(1995) _TIIIH(DE)	3	500
95-98	9160	White Pointer 1	Slt 40, Ss 40, Sh 20	Overburden				
98-107	12000	Blue Whale	Sh 60, Slt 40	Source	Kerogen-oil-gas	Pepper&Corvi(1995) _TIIH(DE)	4	500
107-139	13780	Bronze Whaler	Sh 70, Slt 18, Ss 10, coal 2	Underburden				
139-145	22600	Southern Right	Ss 70, Sh 15, Slt 12, coal 3	Underburden				
145-151	23150	Minke	Slt 40, Sh 40, Ss 20	Underburden				
151-164	24550	Sea Lion	Ss 50, Slt 30, Sh 20	Underburden				

Table 5 Input for a 1D PSM, this include Super Sequences their age, lithology, petroleum System Element, for the source rocks the kinetics group used, TOC and HI.

7.4. Forward modeling simulation

The final phase of the PSM is the forward modeling that performs calculations on the model to simulate the burial history, pressure, and temperature variations. One of the most important steps during the modeling run is to verify that you have a correct optimization value. Once this information is verified, graphs and models are obtained, which later will be analyzed.

8. 1D PSM results.

8.1. Source Rock 1D PSM

The following results were plotted on the burial history, which gives an indication of the depth of burial of the source rock through time.

Four major source rock units were modeled in 1D PSM:

- Marine shales in the Albian to Cenomanian Blue Whale SS
- Two different units from the marine shales in the Turonian to Santonian Tiger SS,
- Deltaic coaly shales in the Cenomanian upper White Pointer SS.

➢ Maturity

The Maturity overlay (VR zones defined by Sweeney & Burnham (1990). Helps to identify the main oil and gas windows.

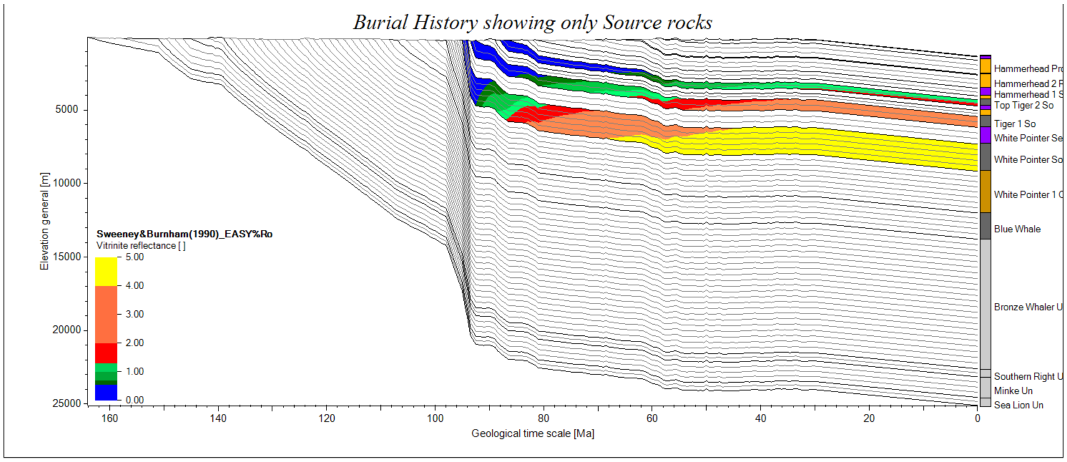


Fig. 12 Burial History showing only source rocks, overlaying %Ro

Predicted present-day maturity plotted on burial history is showed in Figure 12. Vitrinite reflectance indicates the maximum source rock maturity state reached during the basin's history and provides maturity windows for oil, condensate, or gas. In green colors scale 0.5% to 1.3% Ro representing a maturity stage and the main oil generation phase. For the modelled source rock units illustrate the distribution of oil and gas mature source kitchens in the basin. It is expected that the source rock reaches the top of the oil window (the zone where petroleum is generated) deeper than 6000m as indicated by vitrinite reflectance of approximately 0.6% Ro.

➢ Transformation ratio (TR)

The transformation ratio (TR) as defined by Tissot and Welte (1984) is the ratio of the petroleum (oil and gas) formed by the kerogen to the total amount of petroleum that the kerogen can generate. And it depends on the origin of the organic material (kerogen type) and the maturation history associated to the geological history of a basin. As such is a parameter that quantifies the progress of hydrocarbons generation.

TR means how much of the kerogen has been converted to hydrocarbon; when the TR is greater than 0, hydrocarbon is already generated, but it is considered that an expulsion occurs when TR values of 15 to 20% are reached. The most important value of TR is 50% that is considered as the critical moment of the source rock; and it characterizes the migration peak. The figure 13 shows present-day kerogen transformation of the Blue Whale to Tiger SS.

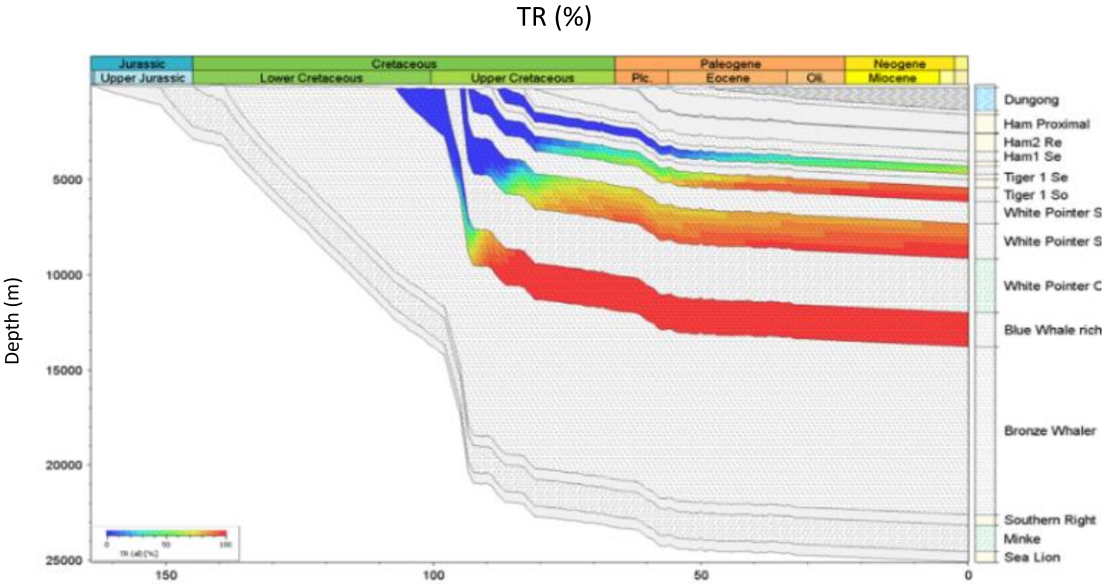


Fig. 13 Computed Transformation Ratio on reconstructed burial history for Blue whale, White Pointer showed, Tiger 1, and Tiger 2 super-sequences. Gnarlyknots-1

➢ Timing of Generation & Expulsion

The transformation ratios increase with increasing maturity and were used to predict the timing of petroleum generation and expulsion. Expulsion modeled to commence at a transformation ratio (TR) of 10%. Expelled early oil, peak oil and late oil windows are defined at TRs ranging from 10 to 25%, 25 to 50% and 50 to 80% respectively. Results from the 1D models indicated that generation and expulsion from the four source rocks proposed occurred only in three of them from the Turonian onwards. Figure 14 and Table 6 exposed the different stage at which source rocks reach a TR higher than 50%.

Timing of generation & Expulsion

- ✗ Tiger (sup).
- ✓ Tiger (base Tiger source) → Mid-Campanian to Recent
- ✓ White Pointer (Cenomanian) → Early Turonian to Recent
- ✓ Blue Whale (Albian) → Cenomanian to Recent

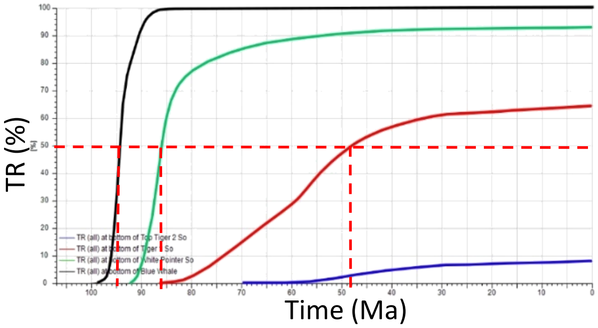


Fig. 14 Predicted Transformation Ratio % (TR %) for four source rocks. Tiger 2 line blue, was the only one that did not reach a TR of 15 to 50% and was therefore discarded as possible source rock of the PS.

	Source Rock	TR > 0%	TR > 15-20 %	TR > 50%
Time (Ma)	Tiger Sup	60	-	-
	Tiger Inf	85	71	48.5
	White P.	92	89	86
	B. Whale	99	96.5	94.9

Table 6 Transformation Ratio values for the source rocks proposed, only Tiger 2 does not have the potential to be considered part of the petroleum system because it did not reach a TR value greater than or equal to 50%.

8.2. Seal Rock 1D PSM

Three of the five possible seals rocks suggested are effective (table 7).

Effective Seal Rock (Figure 15 ant table 7)

- ✓ Hammerhead 1 (Santonian-Campanian) → Early Campanian
- ✓ Tiger 1 (Turonian) → Late Santonian
- ✓ White Pointer (Late Cenomanian) → Late Turonian
- ✗ Wob-Dung Distal
- ✗ Hammerhead Distal

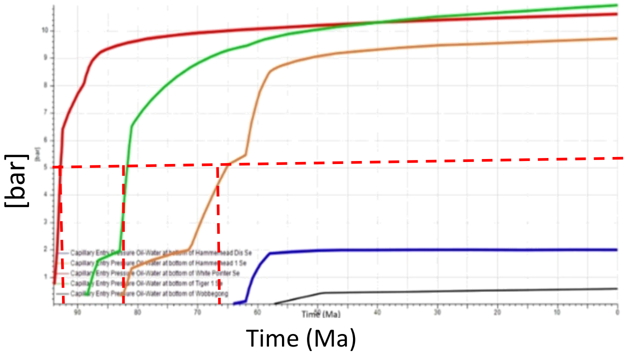


Fig. 15 Seal effective analysis, three of the five seal proposed reach a capillary entry pressure higher than 5 bar, at different age.

	Seal	CEP > 5 bar
Time (Ma)	Wob-Dung distal	-
	Hammerhead Dis	-
	Hammerhead 1	65
	Tiger 1 Se	82
	White Pointer	93

Table 7 Effectiveness of seal rocks, and age at which they began to be effective.

CHAPTER 6 PSQL

9. *Petroleum System Quick Look (PSQL)*

Petroleum System Quick Look provides a way to rapidly evaluate key exploration risk, trap/reservoir, and charge. In exploration environments characterized by low data density PSQL enables uncertainty evaluation. It is important to be aware of the accuracy limitations of the results. PSQL is not a model that provides sufficient detail; its role is to prioritize workflows, rule out or discover potential prospects, and compare geological scenarios for hydrocarbon formation.

Expectations to evaluate the chance of success of a play must be carried out geologically. In this stage, PSQL allows to quickly simulate and compare geological scenarios, it is possible to visualize source rock maturation maps. To generate these properties, the input data of the PS1D model, the Ceduna structural model were required. The PSQL model considers four aspects: expulsion mass maps, migration pathways, potential accumulations, maps of effectiveness of the seal rock. By combining the reservoir quality maps with the effectiveness of the seal, analyzing trap and the charge, an evaluation of the play could be obtained. Therefore, we obtain a map of opportunity for success of the play, which is of great help when looking for and establishing a lead, to reduce the exploratory risk.

The following scenarios were run during the PSQL modeling process:

Generation of process properties, in this stage It is verified:
- ✓ The effectiveness of the kitchens at present day.
- ✓ The TR values of the source rocks at present day.
- ✓ What hydrocarbon phase can be expected from the source socks: oil, gas, or both.

The mapping process of the possible reservoir rocks, shows specific values that helps to determine:
- ✓ Areas that have the best quality reservoir
- ✓ Controlling factors on reservoir quality

Maps of seal rock and their properties helps to answer the following question:
- ✓ How good is the seal across the whole basin or area of interest?

The final step during this modelling, is a vital piece of the PSQL and corresponds to the charge modelling process:

- ✓ Predictions of areas with hydrocarbons accumulations.

Although the software used throughout this modelling allows the use of seismic attributes to make the distribution of the properties obtained in 3D facies maps, it was not done in this work because of the absence of a seismic cube in the Ceduna sub-basin. The maps showed below were obtained based on the spatial distribution and lithology of the SS.

In this stage of work, a Lead is proposed “Lead A”. Which was identified in addition to the PSM/PSQL, with the help of Petrophysical Model (Zapata Miranda, 2021) and Seismic Interpretation (León Lazcano, 2021).

With the help of the Petrophysical Model, Zapata Miranda (2021). The results obtained from RT, RW, Salinity and SW values in different intervals of the Gnarlyknots well, the analysis of formation evaluation, petrophysical parameters were calculated using Crossplot Techniques, Dual Water method and Cut-off values for the three wells. A well correlation was made within the ceduna sub-basin, correlating three wells: Jerboa 1, Apollo 1 and Gnarlyknots 1A. Which helped highlight the SS and formations associated with these. The evaluation of Seal and reservoir as well as the quality was made in this step. The shallowest reservoir was analyzed, this has a salinity of 70 ppm and a SW equal to 87%. The lithology that conforms the interval has 70% sand and 30% lutite, while the seal that underlies it is composed of 80% lutite, 15% limonite and 5% sand.

The seismic interpretation of 132 seismic lines for 6 horizons analyzed at Eric Lazcano work’s titled “Estimación volumétrica, riesgo exploratorio e incertidumbre en Prospectos Petroleros de la Subcuenca Ceduna, Australia (2021)”. The analysis of seismic lines, bright spots, changes of phase and polarity, sags, the use of some seismic attributes, and the analysis of faults in the basin helped to identify the main stratigraphic and structural features of the selected horizons. The seismic attributes used were Chaos, RMS amplitudes, Relative Acustic Impedance and Tecva. Additionally, the structural model was created, delimiting the area of study, delimiting the depth of the prospects and the closeness of these to the kitchens, and the analysis of the possible migration routes.

9.1. PSQL Results.

The results shown below correspond to a source rock (Tiger Inferior super-sequence), a reservoir rock (base of Tiger super-sequence), and a seal rock (Tiger 1 super-sequence), which are potentially considered within a functional petroleum system.

The data collected before on PSM was necessary in this step to investigate hydrocarbon generation properties and use the outputs to determine changes in source rock charge. Hydrocarbon generation estimation is based on a burial history that was created form simplified results.

Depth maps or constant values are required for several inputs, Figure 16 shows several types of data input tabs (Input, output, and expert) and corresponding subtabs required during the generation properties modeling generation.

Subtabs corresponding from Input → Depth/age (Figure 16 A); helps to determine the depositional age, thickness of the source rock, and the burial depth they are:

- Bathymetry or topography or constant depth
- Top source rock surface
- Base source rock surface
- Age

Subtabs corresponding from Input → Geochemistry (Figure 16 B); are:

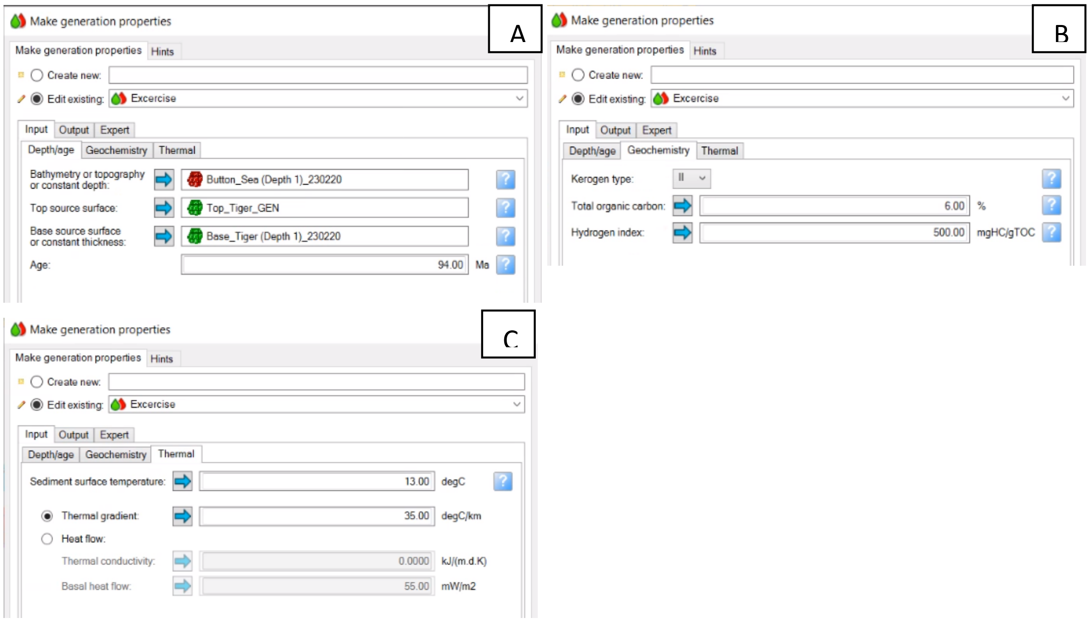
- Kerogen type
- TOC
- HI

They are necessary to stablish the initial source rock geochemical properties which are assumed to be constant through geological time.

The subtabs corresponding from Input →Thermal Properties (Figure 16 C) are:

- Sediment surface temperature
- Thermal gradient or heat flow

Thermal subtabs determine the thermal conditions in which the source rock was buried. These conditions are assumed to be constant in space and time. The temperature calculation requires two thermal boundary conditions. Sediment surface temperature is needed to define the upper thermal boundary. It is coupled with thermal gradient or heat flow inputs for the lower thermal boundary.



A)

○ Create new:
● Edit existing: Excercise

Bathymetry or topography or constant depth: Button_Sea (Depth 1)_230220
Top source surface: Top_Tiger_GEN
Base source surface or constant thickness: Base_Tiger (Depth 1)_230220
Age: 94.00 Ma

B)

○ Create new:
● Edit existing: Excercise

Kerogen type: II
Total organic carbon: 6.00 %
Hydrogen index: 500.00 mgHC/gTOC

C)

○ Create new:
● Edit existing: Excercise

Sediment surface temperature: 13.00 degC
● Thermal gradient: 35.00 degC/km
○ Heat flow:
Thermal conductivity: 0.0000 kJ/(m.d.K)
Basal heat flow: 55.00 mW/m2

Fig. 16 Input tab and subtabs values used on the Make generation Properties window. A) Depth/age subtab, B) Geochemistry subtab and C) Thermal subtab

9.2. Source Rock PSQL

Results from this process, including oil and gas generation surface attributes are used in the Charge modeling process.

Maturity map of potential source rocks Tiger 1 SS, Turonian age; Figure 17. Where, yellow color (%Ro 5.0–4.0) indicates the over mature window, brownish orange color (%Ro 4.0–2.0) indicates the dry gas window, red color (%Ro 2.0–1.3) indicates the wet gas window, light to dark green color (%Ro 1.3–0.5) indicates the oil window and blue color (%Ro 0.5–0) indicates the immature window.

Based on all the information collected in this chapter, a lead (Lead_A) is proposed, which is suggested would have oil accumulations in the lower Tiger store rock. Figure 18 is an oil generation mass map corresponding to the lower Tiger source rock, the warm colors correspond to areas where there is more mass generation, in colder colors there is less mass generation. Due to the type of structure, the thermal conditions that were added to the model, more mass generation was obtained at the center of the map where the color red to green range from 24000 to 20000 kg/m^2; these areas are called as kitchen zones. The color scale shown on this map corresponds to values of km/m^2, these data cannot be taken as the definitive ones, it only shows us and gives an idea where our possible kitchens may be.

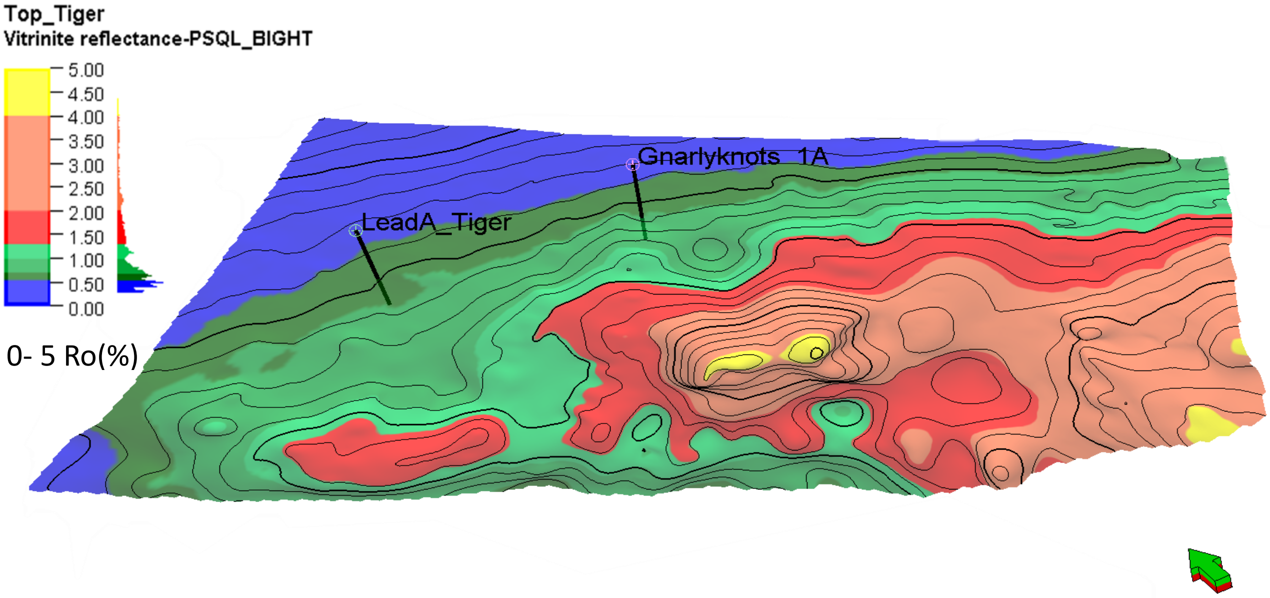


Fig. 17 Maturity map for Turonian marine shale at the base of the Tiger super-sequence showing mature source rocks throughout most of the basin depocenter. The well Gnarlyknots 1A previously drilled it's on a mature stage (oil window), also the ***Lead A proposed*** *on this work is the oil window stage. This is the predicted present-day maturity at the top of the White Pointer Super-sequence.*

9.3. Reservoir Rock PSQL

The make reservoir properties process generates a porosity map using the reservoir burial depth and a lithology-base mechanical compaction trend. A simple mechanical compaction curve is used to define the porosity based on the lithology and the burial depth of the input surface. The input data for the generation of the porosity map are surfaces in depth: seabed, bathymetry, reservoir surface and its lithology (Fig. 19). Due to the limited information available and that only one well had been drilled in the area, it was not possible to calibrate the reservoir map data with real data. Therefore, the porosity map in figure 20 is considered as a map of rapid evaluation at present day conditions.

The porosity of the reservoir surface is calculated as a function of burial depth and the defined lithology mechanical compaction trend. PSQL uses Athny's law to infer porosity at a depth. Athy's Law provides that a theorical curve of porosity and burial depth is an assumption of hydrostatic pressures and deposition of the charge column to sediment layer, with the same lithotype.

Reservoir rock potential of each unit are summarized in Figure 6. However, since all the elements of the oil system must be in synchrony, only the porosity map analysis (Figure 20) of the proposed lead "lead A" was carried out, which has an excellent quality reservoir rock; and corresponds to marine sandstones of the Tiger SS. The calculate porosity values shown in Figure 18 seen high; the porosity proposed for the Lead A corresponds to 20%. But this value is not what we should expect, it is important to calibrate the map to the available well data. Other possible with a high-quality reservoir rock, are delta sandstones of the Hammerhead SS some samples with porosities up to 30% have been encountered.

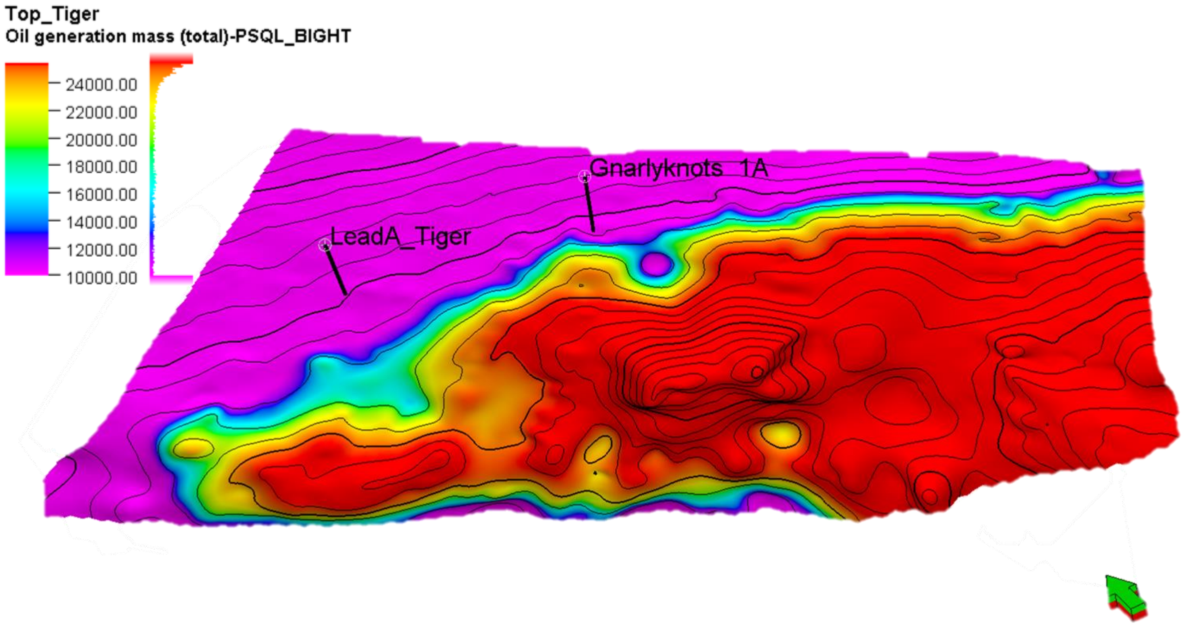
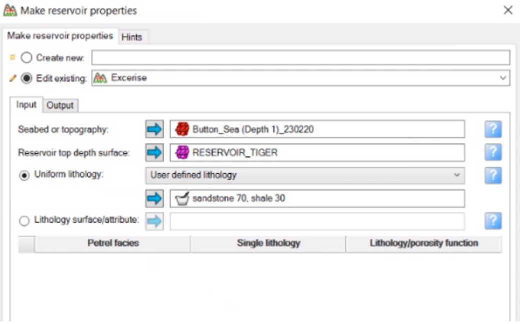


Fig. 18 Map of oil generation mass, for the source rock Tiger 1 source. warm colors correspond to areas where there is more mass generation, in colder colors there is less mass generation.



○ Create new:
● Edit existing: Excerise

Seabed or topography: Button_Sea (Depth 1)_230220
Reservoir top depth surface: RESERVOIR_TIGER
● Uniform lithology: User defined lithology
sandstone 70, shale 30
○ Lithology surface/attribute:

Fig. 19 Input tabs to define reservoir properties, this tabs (seabed or topography, reservoir top depth surface, lithology type or map) helps refine the porosity calculation.

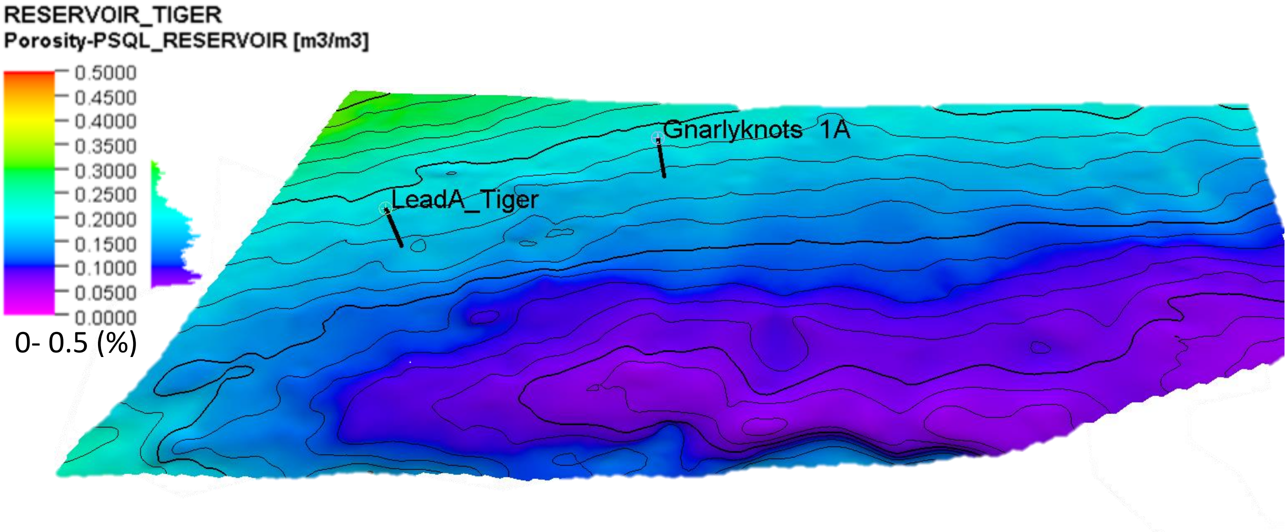
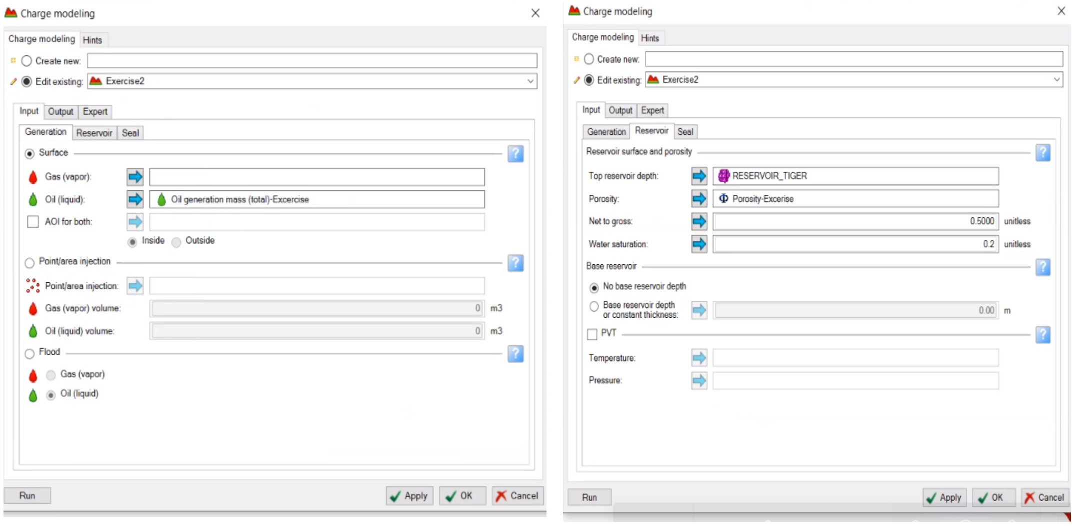


Fig. 20 Porosity map of Santonian Sand at the base of Tiger SS, showing on violet and blue values of 0.1 to 0.2 of porosity. Calculations are based on hydrostatic pressures.

- Migration and accumulation

The charge modeling are important to determine if there may be the presence and accumulation of significant hydrocarbons. Although the charge model in PSQL is performed quickly it is a very helpful tool to delimit possible prospects, provides valuable information for the volumetric calculation such as possible accumulations, type of hydrocarbon expected, critical moments and maturity of the source rock, porosity of the reservoir rocks, effectiveness of seal rocks and spatial distribution accumulations on the charge map is not only in a single locations, but along the reservoir rock. The charge modeling process performs initial investigations into the structural aspects of the top reservoir and their influences on hydrocarbon migration and accumulation. The process collects input for generation, reservoir, and seal (Figure 21), it outputs several types of information: drainage areas, migration flow lines, accumulation bodies.



○ Create new:
● Edit existing: Exercise2

● Surface
Gas (vapor):
Oil (liquid): Oil generation mass (total)-Excercise
☐ AOI for both:
● Inside ○ Outside
○ Point/area injection
Point/area injection:
Gas (vapor) volume: 0 m3
Oil (liquid) volume: 0 m3
○ Flood
○ Gas (vapor)
● Oil (liquid)

○ Create new:
● Edit existing: Exercise2

Reservoir surface and porosity
Top reservoir depth: RESERVOIR_TIGER
Porosity: Φ Porosity-Excerise
Net to gross: 0.5000 unitless
Water saturation: 0.2 unitless
Base reservoir
● No base reservoir depth
○ Base reservoir depth or constant thickness: 0.00 m
☐ PVT
Temperature:
Pressure:

Fig. 21 Input tabs to generate charge map; this input tabs are different from generation, reservoir, and seal.

At this stage it is important to keep in mind and know the following concepts:

- Hydrocarbon generation: is the transformation of the reactive kerogen within the source rock to hydrocarbon molecules (oil and gas).
- Hydrocarbon expulsion is the movement of the hydrocarbon molecules out of the source rock into another rock (hopefully, a rock that will serve as a conduit to a trap).
- Hydrocarbon migration is the process, whereby hydrocarbons move from source rocks to traps.

At present day conditions, the PSQL, is a quick evaluation tool, at present day conditions. This simulates the flow path by vertical migrating upwards from the generation mass source rock surface, a point/polygon set, or flooding the reservoir. The vertical form of migration is not necessarily like this and that is why 3D analyzes are carried out since in these it is possible to add another type of flow path, it can be using Darcy's law, invasion percolation, etc.; these will depend on the type of deposit.

With the conditions that occurred from the beginning of the load modeling, in figure 22 it can be seen where some possible potential oil accumulations could exist, black lines represent drainage areas.

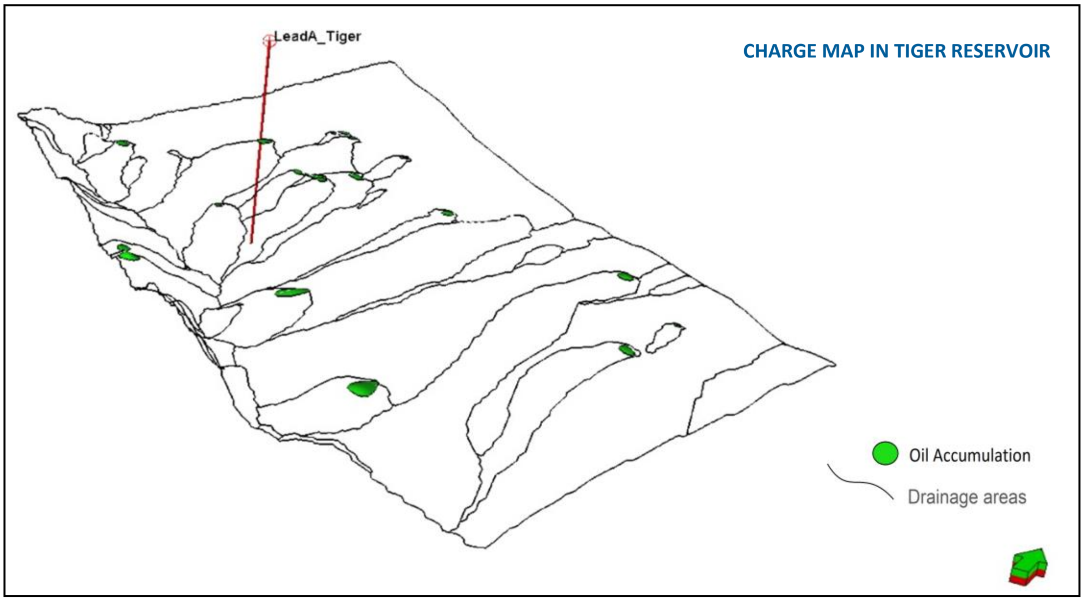


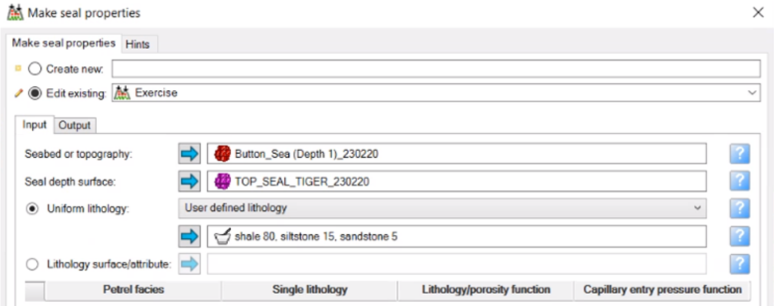
Fig. 22 Charge map of Santonian-Tiger reservoir. In green some oil accumulations, black lines represent the drainage areas, the "Lead A" proposed on this work appears to be on an oil accumulation. With this the change of success increases.

9.4. Seal Rock PSQL

The make seal properties process generates attributes for the top seal capillary entry pressure, which seals the reservoir. The top seal capillary entry pressure is based on the top seal depth surface and lithology-based mechanical compaction trend. This process uses two calculations. The first is a transformation of a lithology-based mechanical compaction function with burial depth to produce porosity (Athy's law). The second is a transformation of the porosity into capillary entry pressure (equations).

The input tabs required to make seal properties are three (Figure 23): seabed or topography, seal depth surface and lithology type or attribute. Three assumptions have to be considered at the moment to run the model a) calculations are based on hydrostatic pressures, b) porosity map values are calculating using only depth porosity functions, c) capillary entry pressure is calculated based on this porosity.

Potential intraformational seals are present in the Upper Cretaceous deltaic successions, and regional seals could be provided by Upper Cretaceous marine shales. The seal rock modelling results shows that three of them have the special characteristic to be considered as an effective seal.



○ Create new:
● Edit existing: Exercise

Seabed or topography: Button_Sea (Depth 1)_230220

Seal depth surface: TOP_SEAL_TIGER_230220

● Uniform lithology: User defined lithology

shale 80, siltstone 15, sandstone 5

○ Lithology surface/attribute:

Fig. 23 Input tabs to define seal properties

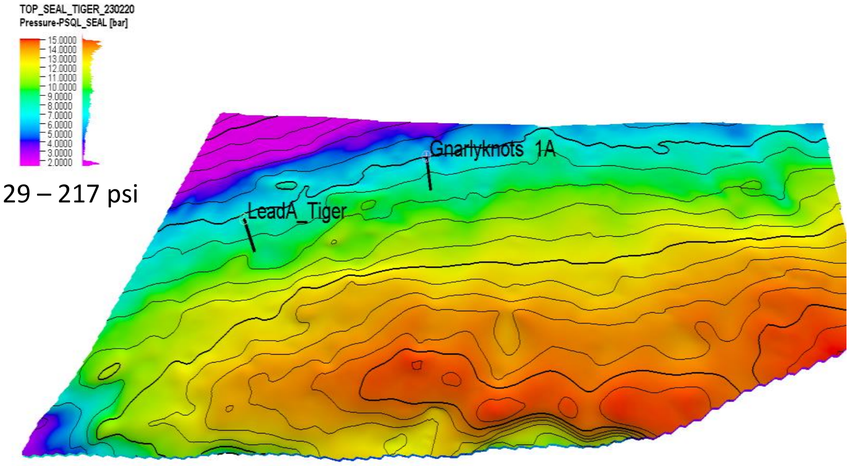


Fig. 24 Capillary entry pressure for Lead A, values in blue to green correspond to 7-10 bars.

At the center of the map, the warm colors correspond to values of 15 bars, as the colors begin to get colder, the capillary pressure drops until reaching purple colors at the limit of the map with values of 2 bars. The position suggested for LeadA_Tiger cross the seal Tiger (Figure 24) with values of capillary entry pressure above 5 and 10 bars blue, and green colors. The seal Tiger 1 started to be effective at the Late Santonian age.

RESULTS AND CONCLUSION

10. Event Chart and d Postmortem Analysis.

A Petroleum Systems Events (PSE) Chart is a display of all Petroleum systems elements and processes. All events and processes can be analyzed in a timing perspective.

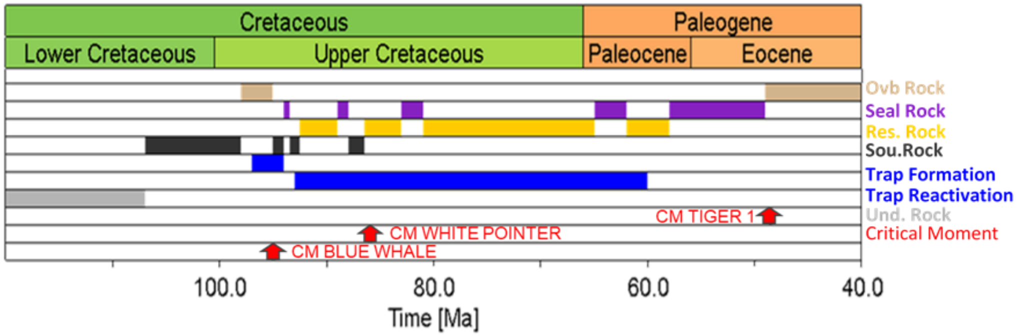


Fig. 25 Local Petroleum event Chart, for Ceduna sub-basin showing the relationship between essential elements and geological processes as well as preservation time for the Upper Jurassic/Lower Cretaceous-Lower Cretaceous petroleum system. It also shows the preservation time and the critical moment for the system.

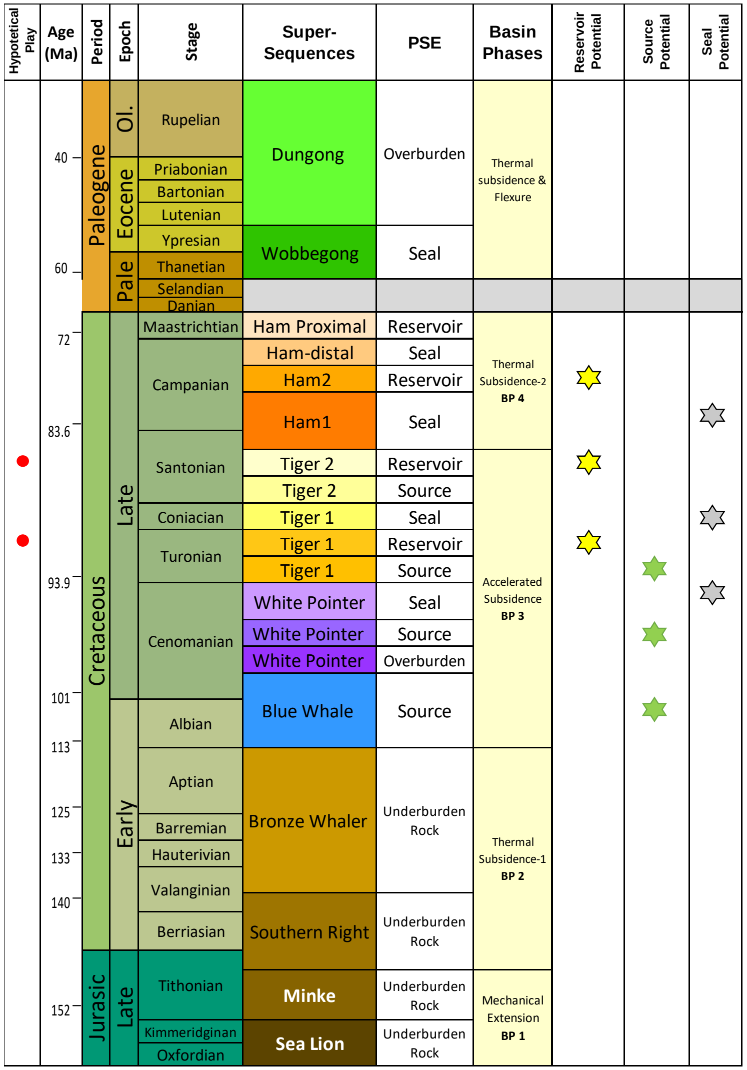
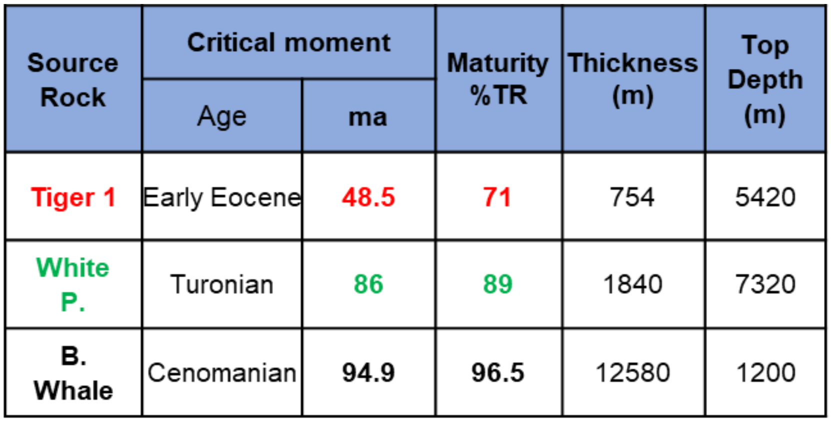


Fig. 26 Stratigraphic column with the main source, reservoir and seal rocks with potential to be part of the petroleum system.

The event chart in Figure 25, shows the different elements that could be part of a petroleum system. For the source rocks there are only three critical moments due to only three of them (Tiger Inf, White P., and B. Whale SS) reach a TR>50%. Below table 8 is an exemplified summary of the source rock properties. The critical moment for the source rock Blue Whale occurred in the early Upper Cretaceous, the thickness and depth of this super-sequence and the results showed on of Ro, and TR suggested that the Blue Whale source rock is overmature. The critical moment for the White Pointer source rock occurred at the Turonian stage, the results showed about the maturity parameters, the thickness and depth of deposit also influence in the quality of the source rock, that is estimated on a stage of maturity. The Tiger 1 can be defined as the best source rock, due to some values of TOC, Ro, and TR are the best parameters of the three proposed rocks, Tiger is in a maturity stage, and along with Hammerhead source rock would be possible that both sequences have not been affected by the movement and generation of the faults, and a possible scenario of timing could exists.



Source Rock	Critical moment		Maturity %TR	Thickness (m)	Top Depth (m)
	Age	ma			
Tiger 1	Early Eocene	**48.5**	**71**	754	5420
White P.	Turonian	**86**	**89**	1840	7320
B. Whale	Cenomanian	**94.9**	**96.5**	12580	1200

Table 8 Summary of source rock characteristics in Ceduna sub-basin

The four reservoir rocks correspond to Late Cretaceous age, two of them are from the Tiger SS and the other two to Hammerhead SS. The results from seal rocks analysis showed that only three of the seal proposed will be effective that is why on Figure 25 only three seal rocks are showed; this correspond to Cenomanian White Pointer SS, Canocian Tiger SS, Santonian-Campanian Hammerhead seals.

The most complex element throughout the construction history of the Bight basin and especially the Ceduna sub-basin is the continuous subsidence and what led to the creation of faults at the beginning of the Upper Cretaceous and the reactivation of these from Upper Cretaceous to the middle of the Paleocene. The failures and their continuous reactivation were considered a trap element, although a possible leak through these faults is not completely ruled out.

In this work a possible lead was proposed, all the results during the basin modeling were of great help, but it was also decided to choose it with the help of some studies of petrophysics and seismic images making use of seismic attributes (RAI, RMS and Chaos). All these elements together were of great help when choosing the possible lead. It is suspected that on the Turonian Tiger 1 reservoir could exists some oil accumulations, if this scenario is analyzed making use of the event chart it is a scenario where the elements of the petroleum system are in timing, therefore there are high expectations of a possible accumulation.

Woodside Energy Ltd and its joint venture partners drilled Gnarlyknots 1, 1A in April 2003. Gnarlyknots 1 was abandoned at 1,824 mRT due to mechanical difficulties and Gnarlyknots 1A was spudded approximately 50 m to the southwest. The well was designed to test the petroleum systems within the more distal Upper Cretaceous depositional systems of the Ceduna Sub-basin where oil-prone, marine source rocks are more likely (Tapley et al, 2005). The well was drilled to test as much of the prospective basin stratigraphy as possible by penetrating four stratigraphic horizons with fault dependent closure within a tilted fault block, targeting reservoir-seal pairs predicted in the intra-Santonian and top-Coniacian units (Woodside, 2004). However, due to adverse sea and weather conditions, the well was abandoned at 4,736 mRT near the top of the Tiger Super-sequence, some 1,500 m above the predicted total depth, and several key targets remained untested. Although Gnarlyknots 1A failed to recover hydrocarbons, several encouraging indications were observed.

Since the wells with geochemical data located in other sub-basins were very far away from Ceduna, it was not possible to establish a correlation of information between them. It is only possible to carry out the post-mortem analysis of the Gnarlyknots because this was the only one well drilled in Ceduna sub-basin. It is determined that various elements did not work (Trap and Seal). It is possible that the trap did not work and the faulting result as a migration route; the missing process on Gnarlyknots is the absence of charge in the reservoir rock. The abandonment of the Gnarlyknots well was reportedly because of the bad weather and due to this, it was not possible to reach the proposed goal.

11. Conclusion.

The results of the 1D PSM and PSQL modeling were used to verify the existence and behavior of the petroleum systems. The table of events reflects that the synchronicity of the elements could be affected by the reactivation of the Mulgara faults, compromising the accumulation of hydrocarbons in the storage rocks. The uncertainty of knowing if these accumulations really exist is due to the lack of data and the absence of more wells with petrophysical and geochemical information in the Ceduna sub-basin.

Regarding the source rocks, they are prioritized as follows: Lower source Tiger as the best followed by Hammerhead source and finally Blue Whale. Blue Whale ss showed very high maturity parameters, that is why it is classified as over mature. The source rock of the lower Tiger super-sequence was shown to be even within the hydrocarbon generation window and is therefore considered the best of the three.

Due to the limited information available during this work, it was possible to determine only one possible Lead, which is in the reservoir rocks of the Tiger super-sequence. It is necessary to obtain more information to be able to propose more leads within the Ceduma sub-basin. The Gnarlyknots 1A well drilled in 2003 did not reach the objectives proposed for Lead_A, and certain elements such as the trap and the source rock of which we now have more details but not enough did not work for Gnarlyknots.

The models presented in this work and the petrophysical analysis are the key for the subsequent volumetric calculation analysis. Since there were no analogous wells within the Ceduna sub-basin, the petrophysical and geochemical results for the reservoir rocks were interpolated to obtain porosity, water saturation, NTG and the type of hydrocarbon expected. PSQL models, despite being performed very quickly, help us to discriminate be able to discriminate the data and obtain more information in a concise way. These results need to be always considered at the perspective of preliminar results because for:

1. Generation maps. Simplified overburden, geochemistry and thermal inputs
2. Porosity maps. Simplified by calculating at hydrostatic levels using a Porosity-Depth relationship.
3. Charge. Flow path, and it only take into account two components (Oil & Gas).

The risk assessment of a lead or given segment is initially consisting of estimating the probability of geological success, considering random factors of all elements of the oil system. Table 9 shows the possibility of success estimated for the lead proposed, the effective quantification and the management of risks and uncertainties of exploration remains a key challenge for the O & G. industry. The values in table 9 were estimated by own creterion, the analysis of values shows a 28% of probability proposed for this lead. Some recommendations will be given later.

Table 9 Proposed values to determine the Objective Lead success opportunity.

Lead Chance									
Rate	0-10%	10-25%	25-50%	50%	50-75%	75-90%	90-100%	Notes	
Class	Non existent	Unfavorable	Questionable	Neutral	Encouraging	Favorable	Certain		
Local Source									
Depositional Model						X		Close to the Kitchen	
Organic Content (TOC/HI)						X			
Maturity					X				
Thickness					X				
Lateral continuity				X				Possibility of hydrocarbon compartment	
Expulsion evidence (seismics)			X						
Remarks								Source Chance	0.64
Local Reservoir									
Depositional Model						X			
Porosity					X				
Permeability					X				
Preservation of fractures				X					
Thickness					X				
Lateral continuity					X			Limited by geological faults.	
Local Seal								Reservoir Chance	0.55
Depositional Model						X			
Thickness					X				
Lateral continuity						X			
Seal Integrity						X			
Remarks								Seal Chance	0.80
								Lead Chance 0.28	

12. Recommendations

The uncertainty of some of the models that were carried out in this work is in some cases high, due to the lack of sufficient information along the Ceduna sub-basin. The deficiency of chemical and seismic data is listed below, with which having them will help to reduce and, in some cases, eliminate uncertainty.

Information deficiency of geochemical:

- Lack of wells near the Ceduna sub-basin with geochemical analyzes for the sequences of the White Pointer, Tiger, Hammerhead, and Blue Whale source rocks.
- Know the correct heat flow to model hydrocarbon generation more accurately. The heat flow curves used were not the most appropriate during the modeling, so it requires more information to verify it and calibrate them.
- Have access to information from samples taken during seafloor sampling by Geoscience Australia and corroborate geochemical data.
- Perform complete geochemistry analyzes including the data obtained during Rock eval analysis (Tmax, pristene/phytane ratio, S1, S2, S3, HI, OI etc.), since in the literature it was only possible to know TOC and HI data.
- Have facies maps, so a 3D cube of the Ceduna sub-basin is required; since the maps that were perform during the PSQL used constant values for the entire layer of reservoir, and seal rocks.
- The 1D modeling of the petroleum system can be improved by fitting a special kinetic formula for modeling the source rocks and not use a general formula for all the source rocks in Ceduna.

Information deficiency of seismic data:

- Access to seismic information such as a 3D seismic cube will be of great help in generating 3D basin models, as well as facies map details instead of maps with a single lithological property along the entire length, using seismic attributes and collating them with well data
- Conduct more exploration campaigns to access more well information. Geochemical values for other wells in other sub-basins within the Bight basin are not helpful as they are too far away for geochemical correlation.
- Having a 3D seismic cube would greatly improve the basin modeling and the resulting PSQL maps, especially for the reservoir rock where the complexity of it can be more analyzed in detail.
- Calibrated data for a better adjustment of the models (Ro, and Temperature)

Annexed 1

SAMPLE No	TOC	Tmax	Tmax_ker	S1	S2	S3	PI	HI	HI_ker	OI
	%	°C		mg HC/g rock		mg CO2/g rock		mg HC/g TOC		mg CO2/g TOC
1935199	2.25	426	411	0.1	2.81	2.14	0.03	125	76	95
1935202	2.29	431	420	0.04	3.37	1.19	0.01	147	71	52
1935204	2.1	427	414	0.06	2.45	0.86	0.02	117	102	41
1935218	2.26	424	422	0.03	0.72	2.31	0.04	32	40	102
1935219	2.46	423	429	0.04	0.84	1.56	0.05	34	27	64
1935017	2.93	422	413	0.06	9.24	0.85	0.01	315	323	29
1935034	2.34	423	411	0.1	6.42	1.28	0.01	274	368	55
1935035	3.17	418	409	0.11	9.38	0.63	0.01	296	355	20
1935036	6.2	412	396	0.31	29.68	0.5	0.01	479	380	8
1935037	6.02	419	409	0.29	28.21	1.17	0.01	468	384	19
1935038	5.9	417	410	0.22	24.92	1.34	0.01	423	381	23
1935098	2.66	422	413	0.11	3.98	0.48	0.03	150	192	18
1935256	4.64	416	409	0.19	17.46	1.33	0.01	376	359	29
1936847	2.33	426	409	0.06	5.76	1.18	0.01	247	485	50
1951405	5.86	412	405	0.33	22.37	1.34	0.01	382	507	23
1951406	6.91	409	403	0.4	29.47	1.6	0.01	426	530	23
1951409	6.09	419	396	0.22	23.17	2.16	0.01	380	515	35

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