INFORMATION AND OPPORTUNITIES

PETROLEUM EXPLORATION IN SOUTH AFRICA

PETROLEUM AGENCY SA

Vision, Mission, Strategic Thrust, Value Statement, Roles, Permits & Rights

OUR VISION

To grow a diverse upstream petroleum industry contributing to energy security and sustainable economic development

OUR MISSION

To promote, facilitate and regulate exploration, production and sustainable development of the upstream oil and gas industry

STRATEGIC THRUST

To increase exploration and production of oil and gas in the country by engaging and managing stakeholders to improve the efficiency and effectiveness of our legislative and regulatory mechanisms and building capacity in emerging technologies to develop a competitive upstream oil and gas industry in a financially sustainable way

VALUES STATEMENT

Petroleum Agency SA aspires to be a world class organisation, committed to:

Professional Excellence
Integrity
Direct, Open Consultative Communication
Transparency
Respect
Teamwork
Active Regard for the natural environment
Corporate Social Responsibility
Empowering, vibrant workplace
We are proud to be South African

ROLES

Petroleum Agency SA
Promotion of open acreage
Data management
Reconnaissance surveys
Contract negotiations
Evaluation of work programmes
Evaluation of development programmes
Monitoring of operations
Recommendations for granting of rights
Issuing of permits
Administration of Upstream Training Trust
Department of Mineral Resources
Policy and regulations
Liaison with other State Departments
Health and safety
Approval of Exploration and Production Rights

PERMITS AND RIGHTS

Reconnaisance Permit
The right to collect new data, eg. a non-exclusive seismic survey
Technical Co-operation Permit
12-month study of data in the national archive with option to apply for an exploration right
Exploration Right
Multiphase programme of exploration work with acreage relinquishment at end of each phase
Production Right
The right to produce oil and gas

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Recent local and regional discoveries spark renewed interest in South Africa's upstream potential

Petroleum Agency SA is responsible for promoting and regulating oil and gas exploration in South Africa, archiving all data related to oil and gas exploration, and developing the local upstream industry for the benefit of all South Africans.

One of the Agency's roles is to counsel government on issues related to oil and gas, and we have recently played a leadership role in the Task Team process investigating shale gas exploration and the controversial technique of hydraulic fracturing.

South Africa is on the brink of major developments in the upstream industry and the next few years will be key in determining South Africa's future energy profile. The recent Brulpadda and Luiperd discoveries off South Africa's south coast offshore and the major exploration success seen in the southern Namibian sector of the deep-water Orange Basin predict a bright future for further offshore exploration. Basin analysis studies of the onshore Karoo Basin have indicated potential for both unconventional and even conventional resources.

In the Orange Basin, TotalEnergies have taken up three large exploration areas where they share risk with Sezigyn and Qatar Petroleum, Impact Africa and Qatar petroleum and Shell together with PetroSA, respectively. Sunbird and PetroSA continue their efforts to monetise the Ibhubesi gas field while other explorers concentrate on the mid-basin.

Tosaco have taken up acreage on the shelf in the northern sector while Shell and OK Energy concentrate efforts on the deep-water northern sector. Petroleum Agency SA is pleased to have attracted exploration companies of such high calibre, who have a record of successful exploration. We are of the opinion that there is immense potential for both gas and oil reserves in this basin.

The south coast has seen on-going exploration in Block 9 by PetroSA, where they have concentrated on finding further assets close to existing infrastructure.

Other activity off the south coast includes ongoing negotiations regarding the commercialisation of the Paddavissie play discoveries at Brulpadda and Luiperd. BG International and Impact Africa are exploring acreage off the coast directly south of Coega while TotalEnergies has recently been granted an exploration right over a large deep-water area to the south and west of their recent discoveries.

Off our east coast, Impact Africa and BG International are currently working on the prospectivity of a large area covering the shelf and slope.

Onshore, the major interest remains in unconventional resources. These are of three types, namely: Coal bed methane, biogenic gas, and shale gas.

Coal bed methane exploration is concentrated around the coal bearing basins in the north-eastern parts of the country. Operators have already carried out successful drilling in terms of their work programs.

To the south Renergen continues with development of the first production right granted onshore. This small project marks the first economic production of gas onshore.

Many will be aware of the EIA's estimate of 370 Tcf of gas as a shale gas resource figure for the Karoo. Our own estimate of the resource is far smaller, yet still represents a particularly valuable resource. At the time of writing, the Minister has yet to lift the moratorium through a notice in the Government Gazette, and it is this announcement that will guide and inform the process in future.

The above summary presents some of the exciting developments underway, and a little of what we expect in South Africa's upstream industry over the next few years. Petroleum Agency SA welcomes our new operators to our country and wishes them all success in their endeavours. It is our hope that indigenous oil and gas may soon play a significant role in our country's energy supply.

Chief People Officer (CPO)

The office of the CPO is responsible for leading the human resources function of the organization, for creating and implementing HR strategies that support the organization's goals and objectives, and fostering a culture of excellence, inclusiveness, and innovation across the organization.
Our expertise in the oil and gas industry allows us to provide valuable insights and recommendations to the government on matters related to exploration and production. Additionally, our involvement in special projects directed by the Minister enables us to address specific challenges and opportunities in this sector. Human Resources & Admin are two divisions led and reporting to the CPO.

Human Resource Management

The division is responsible for the overall human resources function for the Agency, who is responsible for managing the employee life cycle (i.e., recruiting, hiring, onboarding, training, and firing employees) and administering employee benefits.
These disciplines help HR professionals understand the behavior and motivations of employees, effectively manage teams, analyze data to make informed decisions, and study the impact of social factors on workplace dynamics. This holistic approach aligns with organizational goals and fosters a positive work environment, ensuring a more effective management of personnel.

Administration

The administrative division plays a crucial role in coordinating and implementing policies and procedures to ensure smooth operations across different departments. This division collaborate with other divisions to streamline processes, allocate resources effectively, and promote a safe and productive work environment. Moreover, the division is responsible for managing budgets, monitoring expenses, and ensuring compliance with regulatory requirements to support the organization's overall goals and objectives.

Comms & Stakeholder Relations Division

The Comms & Stakeholder division ensures that PASA's messages and initiatives are effectively communicated to both internal and external stakeholders. This division works closely with internal and external stakeholders to ensure consistent messaging and alignment with PASA's mission and values. By actively engaging with stakeholders, the Comms & Stakeholder division helps to foster trust, enhance transparency, and promote a positive image of the organization within the industry.

Office of the Chief Executive Officer (CEO)

The office of the CEO is responsible for performing duties as the highest-ranking executive within a corporation to guide company practices and procedures. Their duties include overseeing company operations, communicating between board members and other company executives and making important decisions that impact the company's brand identity and financial health.

Office of Company Secretary (COSEC)

The Company Secretary also plays a crucial role in maintaining accurate and up-to-date records of the company's activities, including minutes of board meetings and shareholder communications. Additionally, they oversee the proper dissemination of information to shareholders and ensure compliance with reporting obligations to regulatory authorities.

Office of Chief Operating Officer (COO)

The office of the COO plays a crucial role in resource allocation and optimizing operational efficiency. They are responsible for identifying and implementing process improvements, cost-saving measures, and technology advancements to drive growth and profitability. Additionally, the COO is often involved in talent management, ensuring the right people are in the right positions to support the company's objectives.

Resource Evaluation , Environmental & Technical Compliance are three departments led and reporting to the COO.

Resource Evaluation Department

The division collaborates with international partners and stakeholders to promote South Africa as a favorable destination for oil and gas investment. Furthermore, they conduct thorough assessments and analysis to accurately estimate the potential reserves of oil and gas in the country.

Our team is highly skilled in analyzing seismic data, well logs, and geological maps to assess the potential of different regions in South Africa. We also collaborate with government agencies and industry experts to stay updated on the latest regulations and technological advancements in the oil and gas sector. This allows us to provide accurate assessments and recommendations to interested investors, ultimately contributing to the growth of South Africa's energy industry.

The division is responsible for evaluating and attempting to quantify the potential of the offshore, including areas beyond the reach of current exploration technology, as well as that of the onshore Karoo Basin where little exploration has taken place to date and existing data is old, so that the basin's potential is still poorly understood. The Resource Evaluation Department is concerned with the conventional as well as future sources of hydrocarbon resource such as gas hydrates offshore and coal bed methane and shale gas onshore.

The division is task with determining the area's exploration potential and assisting new explorers as they enter the South African upstream industry. This inventory includes detailed geological and geophysical data, as well as analysis of potential reserves and production rates. The division also works closely with government agencies and industry stakeholders to ensure responsible and sustainable development of South Africa's oil and gas resources.

In addition, the division is in charge of assessing and estimating the potential of offshore areas around South Africa that can be exploited using current exploration and production technologies.

Environmental Compliance Department

The division oversees, enforces, monitors, and evaluates holders' compliance and implementation with environmental legislation as well as the terms and conditions of the MPRDA's right or permit. As custodians of the environment, this division works relentlessly to preserve the fine line between development and preservation.

Additionally, the division collaborates with stakeholders such as local communities, indigenous groups, and environmental organizations to gather input and address concerns regarding resource extraction activities. This inclusive approach helps to ensure that decision-making processes are transparent and considerate of the diverse perspectives and interests involved.

To maintain compliance with environmental rules, the division collaborates with other regulatory agencies and stakeholders to develop and implement strategies for improving environmental compliance. They also provide guidance and support to businesses and individuals to help them understand and meet environmental regulations, promoting a culture of proactive compliance.

They also work closely with government agencies and other regulatory bodies to develop and enforce environmental policies and regulations. Additionally, the division conducts regular inspections and audits to ensure that businesses and individuals are adhering to these regulations and taking appropriate measures to protect the environment.

Technical Compliance Department

In today's rapidly changing world, the need for responsible and sustainable energy practices has become paramount. The division in question plays a crucial role in assessing and monitoring various technical studies and work programs related to energy exploration and production. By combining engineering expertise with environmental considerations, the division aims to foster the development of projects that not only meet energy demands but also minimize environmental impact and contribute to the transition towards a low-carbon economy.

Office of Chief Information Officer (CIO)

The CIO's office is responsible for designing, implementing, and evolving platforms capable of supporting the company's strategy and adapting flexibly to changing demand. They work closely with the IT team to implement robust security measures, conduct regular audits, and stay updated on the latest cybersecurity threats. Additionally, the office collaborates with other departments to align technology initiatives with business goals and drive innovation throughout the organization.

Information Services & Management & Information Technology (IT) are two divisions led and reporting to the CIO.

Information Management (IM) Division

The continental shelf of the Republic of South Africa covers some 1 000 000 km^2, and the country has a coastline of approximately 3 000 km in length. Petroleum Agency SA is responsible for the archiving and management of the national exploration database and has catalogued all the data and reports resulting from the drilling of some 300 boreholes and the acquisition of 227 000 line km of 2-D and 9700 km of 3-D seismic data. All hydrocarbon exploration data belongs to the state. Licensees that carry out exploration activities are required to supply all new and reprocessed data on relinquishment to the Agency for incorporation into the National Database.

A new block naming system has been in use since 1994. For convenience of reference to existing data, the old (1965) licence blocks are also used since borehole and seismic line designations refer to them. The latest degree licence block system definitions are also defined as an overlay on our maps.

The data catalogues provide information on the geological characteristics, such as rock types and structures, within these basins. This includes information gathered through seismic surveys, which use sound waves to create images of the subsurface. Seismic data helps in identifying potential oil and gas reservoirs by mapping the subsurface structures and identifying areas with high hydrocarbon potential.

Although data catalogues can be generated for any offshore geographical defined area, including listings of all the data available that is relevant to the assessment of each area, the data is conveniently organised into geological basins and features below:

Summary of wells by basin
Summary of seismic by basin
Generalised location maps

The Data Room is an essential resource for interested parties to gain access to all available data related to ongoing projects and operations. It provides a comprehensive collection of selected reports, seismic data, and associated results, allowing individuals to thoroughly review and analyse the information. To ensure a smooth and efficient process, interested parties are advised to make bookings for the Data Room by contacting our offices in advance.

The Information Services department is also responsible for IT by providing the operating parameters for individuals and supporting use of the IT systems, networks, and architecture. This includes responsibility for conventional IT security and data assurance.

Information Technology (IT) Division

The IT Division ensures the proper functioning of an IT system by providing necessary infrastructure, including operational networks, circuits, and equipment. It is responsible for developing and implementing the ICT strategy and Digital Transformation plan, as well as managing the deployment and maintenance of ICT infrastructure and applications through continuous improvement.

Office of Chief Financial Officer (CFO)

The CFO's office manages the company's financial risk by implementing effective risk management practices and ensuring compliance with industry standards. CFO works closely with other departments to analyse financial data, identify areas for improvement, and make informed decisions to optimize the company's financial performance.

Finance and Supply Chain Management are two divisions led and reporting to the CFO.

Finance Division

The Finance division is responsible for conducting financial analysis and forecasting to support strategic decision-making within the agency. Additionally, they collaborate with external auditors to ensure compliance with financial regulations and maintain transparency in financial reporting.

Supply Chain Management Division

The Supply Chain Management division continuously evaluates market trends and industry best practices to ensure that the Preferred Supplier agreements remain competitive and aligned with the company's strategic objectives. By regularly reviewing and updating the database of suppliers, Petroleum Agency SA can effectively identify potential cost-saving opportunities and streamline its procurement processes.

SCM plays a crucial role in ensuring transparency and fairness in the procurement process, by following strict guidelines and regulations. The division also collaborates with various stakeholders to develop strategies that promote local economic development and job creation through the inclusion of BEE vendors in the supply chain.

The division collaborates with various departments to understand procurement needs, conducts market research, and negotiates contracts with potential suppliers. They regularly review supplier performance to ensure quality and cost-effectiveness in the procurement process, ensuring alignment with the organization's goals and objectives.

Licensing, Legal Compliance & Regulation

Petroleum Agency SA is mandated to regulate the exploration and production of oil and gas in South Africa in a sustainable manner. Regulation is managed by 3 departments: Licensing & Legal Compliance; Technical Compliance and Environmental Compliance.

The Licensing & Legal Compliance Department ensures compliance by the holders of rights and permits and the Agency with the terms and conditions of rights and permits and evaluates and monitors compliance with the social and labour plan. The Technical Compliance Department assesses the technical ability of the applicant and ensures compliance by the holders and the Agency with the terms and conditions of the right and the permit in terms of the MPRDA.

The Environmental Compliance Department manages, enforces, monitors, and evaluates implementation of environmental requirements by holders with environmental legislation and terms and conditions of the right or permit under the MPRDA.

RIGHTS AND PERMITS IN TERMS OF THE MPRDA

There are two types of permits and two types of right which may be issued or granted under the MPRDA:

Technical Cooperation Permit

A Technical Cooperation Permit (TCP) is a permit issued to applicant in terms of section 77(1) of MPRDA which allows the applicant to carry out desktop studies, acquire existing seismic and other data from other sources including the Agency but does not include any prospecting or exploration activities.

Reconnaissance Permit

A Reconnaissance Permit is issued to the applicant in terms of section 75(1) of MPRDA to carry out any operation for or in connection with the search for a mineral or petroleum by geological, geophysical or photogeological surveys and includes any remote sensing techniques but does not include and prospecting or exploration operation. This permit accommodates those wishing to acquire speculative surveys.

Exploration Right

An Exploration Right is granted to the applicant in terms of section 80 of MPRDA to enable reprocessing of existing seismic data, acquisition and processing of new seismic data or any other related activity to define a trap to be tested by drilling, logging, and testing, including extended well testing of a well with the intention of locating discovery.

Production Right

A Production Right is granted to the applicant in terms of section 84 of MPRDA to enable the applicant to conduct any operation, activity or matter that relates to the exploration, appraisal, development, and production of petroleum.

South African Oil & Gas Fiscal Terms

The key provisions are:
An annual exploration fee, royalty and income tax, state participation, BEE participation in production and an annual contribution to the Upstream Training Trust.

Annual Exploration Fee

Onshore rights - starts at R1/hectare with a minimum of R 1000 and escalates in 50c/hectare increments each year. Offshore right - starts at R 200 000/ sq degree pro rata with a minimum of R 50 000 and escalates annually in line with the South African Consumer Price Index (CPI).

Royalty

Royalty is payable in terms of the Mineral and Petroleum Resources Royalty Act. The rate is variable based on profitability with a minimum rate of 0.5% and a maximum of 5% per annum.

Income Tax is payable

Income tax is payable in terms of the Income Tax Act, Schedule 10 of which contains additional provisions applicable only to the upstream petroleum sector and will not exceed 28%. All expenditure and losses incurred will be allowed as deductions. In addition, a further 100% of all capital expenditure incurred for exploration and 50% in production is allowed as a deduction for the purposes of calculating income tax liability. This amounts to 200% of capital expenditure for exploration and 150% for production. All allowable costs (both operational and capital) may be immediately expensed for income tax purposes.

Guarantees

Both the Income Tax Act and the Royalty Act make provision for the Minister of Finance to enter into a contract guaranteeing that for the duration of the right (including any production right flowing from an exploration right but excluding renewal of a production right) the terms of the Tenth Schedule and Royalty Act will be no more stringent than at date of signature.

Customs Duties and Exchange Control

The Customs and Excise Act makes provision for the full rebate of customs duties on imported goods and equipment for use in the upstream sector. Oil and gas companies are also exempt from the normal restrictions on operating Customer Foreign Currency Accounts.

State Participation and BEE Participation Interest

State participation of 10% at the production stage, carried through exploration, will be through PetroSA. A further 10% interest will be made available on commercial terms for participation by BEE companies (Black Economic Empowerment companies). This may be taken up by PetroSA in the absence of any BEE participants.

Annual Upstream Training Trust Donation

Onshore rights: -
R1/ hectare with a minimum of R 1 000.

Offshore rights: -
R 200 000/ sq degree pro rata with a minimum of R 50 000.

ABOUT SOUTH AFRICA

In any economic analysis, South Africa stands out as the most developed nation in Africa as well as one of the richest. For example, whereas South Africa comprises only 4% of the area (Figure 1) and has 6% of the population of Africa, it consumes more than 50% of the continent's electrical power. The economy is based on free market principles and the country is one of the world's major trading nations.

Population and GDP (Gross Domestic Product)

Population and GDP South Africa's population is estimated at >50 million. Estimates of purchasing power parity Gross Domestic Product (2022) are around US$ 806.77 billion (World Bank) showing a steady post-Covid recovery. The most important contributors to the GDP were services (65.5%), industry (31.3%) and agriculture (3.2%).

Figure 1. South Africa in relation to Africa

Energy

South Africa's energy interests are administered by the Department of Minerals and Energy. The South African Agency for Promotion of Petroleum Exploration and Exploitation (Petroleum Agency SA) is a subsidiary of CEF (Pty) Ltd, a government owned company concerned with the search for energy solutions for South Africa and SADC countries. Petroleum Agency SA is responsible for promoting, licensing, monitoring and data archiving of South Africa's petroleum exploration and production industry and is the designated agency in terms of the Mineral and Petroleum Resources Development Act (2002).

PetroSA is South Africa's national oil company and is separate from Petroleum Agency SA. It is also a subsidiary of CEF (Pty) Ltd., and owns, operates and manages the South African Government's commercial assets in the petroleum industry, including exploration and production off the southern coast of South Africa, participation in international upstream petroleum ventures and responsibility for the GTL plant at Mossel Bay.

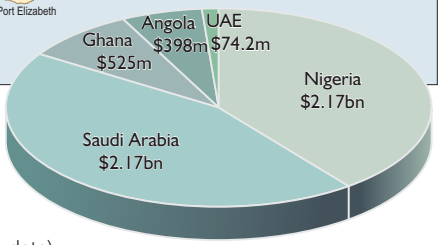
The national electricity utility, Eskom, has a total installed capacity of approximately 44 000 MW. Despite plans to almost double this capacity by 2026, Eskom has struggled to meet demand and the country has been subject to major power shortages Coal provides the source for 90% of Eskom's capacity. The remainder comes from nuclear and hydro-electric power stations and gas turbines. Electricity sales have increased significantly in recent years: utilisation demand is beyond capacity and is expected to continue to increase strongly. This provides an excellent environment for the introduction of gas as a primary fuel source for electricity generation.

The primary energy resource in South Africa is coal. Due to large coal deposits, which can be exploited at extremely favourable costs, a large coal-mining industry has developed. South Africa has proven reserves of 30 billion tonnes - the seventh largest in the world. It is also the world's sixth largest coal producer and the second largest exporter of steam coal. Annual production exceeds 250 million tonnes.

Most of the coal consumed locally is utilised not as a final energy product but as feedstock, primarily for electricity and synthetic fuel production; coal supplies about 77% of the total primary energy market in South Africa. There is currently active interest in exploring for Coal Bed Methane in parts of the Karoo Basin.

South Africa also has 14% of the western world's uranium resources. These resources are scattered with most of the current production as a by-product of gold mining. Whereas South Africa's coal and uranium reserves are clearly sufficient for many years to come it is certain that energy demand will also increase rapidly. It is government's stated objective to diversify the energy mix and environmental pressures suggest that at least part of this demand be met by a 'clean' source such as natural gas.

Figure 2. Infrastructure - Inset-Figure 3. South Africa's oil supply in 2021 (estimated from a variety of sources)



Imports Only (OEC World) 2021

Oil imports, local oil production, & consumption

South Africa imports its crude oil requirements (Figure 3), mainly from Nigeria, Saudi Arabia, Ghana, Angola and the UAE). Current domestic consumption is approximately 513 000 bbl/d (ceicdata). The balance between imports and consumption is made up by the production of liquid fuels from coal using Sasol's synthol process. Sasol's synfuel production capacity is around 150 000 bbl/d (crude oil equivalent) with products including petrol, diesel, paraffin and LPG (SAPIA, 2017). A modified form of the Fischer-Tropsch process has been used since 1992 by PetroSA at its Mossel Bay GTL plant to convert gas and condensate to liquid fuels. The maximum capacity of this plant is 45 000 bbl/d (crude oil equivalent), is currently not producing.

Natural Gas

Domestic natural gas wasproduced from the F-A and E-M gas fields and satellites from 1992 and was utilized but the plant GTL feedstock. Natural gas has been imported from the Pande and Temane fields in Mozambique since 2004 and is distributed to approximately 550 industrial and commercial customers in Gauteng, the Free State, Mpumalanga and KwaZuluNatal. Current imports are around 4 Mcf a month (ceicdata).

Refining

South Africa has a total crude oil refining capacity of 508 000 bbl/d from the following refineries: Sapref and Enref (Durban), Astron (Cape Town) and Natref (Sasolburg). The total synthetic fuel refining capacity is 150 000 bbl/d from Sasol (Sapia).

Transport

In addition to well-developed air and rail links, South Africa has 750 000 km of roads and over 12 million registered vehicles. South Africa thus represents an important world market for petroleum products and this market is currently expanding rapidly. Since most current demand is met by imported crude there is a ready local market for any indigenous hydrocarbons that are discovered in South Africa. South Africa has six major ports, namely Saldanha, Cape Town, Port Elizabeth, East London, Durban and Richards Bay (Figure 2). Smaller facilities exist at Mossel Bay and Port Nolloth, and a new deep-water harbour at Coega near Port Elizabeth.

THE OFFSHORE ENVIRONMENT

South Africa is a large country. Its land area is more than 1.2 million sq km and its coastline has a total length of nearly 3000 km. The west coast, from the Orange River to Cape Point, is almost 900 km long and the remainder, from Cape Point to the Mozambique border, is more than 2000 km long.

The continental shelf is 70-270 km wide off the west coast, 50-250 km wide off the south coast, but rarely up to 50 km wide on the east coast, except along the Durban Basin. Similarly, the continental slope is wide on the west and south coasts but narrow to the east (Figure 4).

The coastline is swept by two major surface ocean currents: -

- The Agulhas Current is a warm south-westerly flowing current that skirts the east and south coasts as far as Cape Point. It reaches its maximum strength close to the shelf break and over the continental slope.
- The Benguela Current, on the other hand, is cold and flows northwards from the Antarctic up the west coast of Africa as far as Angola.
- In addition to the surface currents, a number of large water masses are present along the coast in the form of thermohaline bottom currents. These are the Antarctic Bottom Water, North Atlantic Deep Water, and Antarctic Intermediate water.

Figure 4. Structural elements and sedimentary basins of South Africa.

REGIONAL GEOLOGICAL SETTING

Stratigraphic nomenclature

Soekor (now PetroSA), the state oil company founded in 1965, developed a stratigraphic nomenclature for the sedimentary successions encountered offshore. During initial stages of exploration, various structural elements such as basins, sub-basins, structural highs, and major faults were identified and named.

Current stratigraphic nomenclature reflects a committed sequence stratigraphic approach based on the seismic recognition of multiple unconformities within the drift successions. Sequences initially defined by significant unconformities, as recognised on seismic sections, were assigned numbers (1 to 22) (Brown et al., 1995). Third and higher order sequences, composite sequences and sequence sets recognised subsequently were designated by letters (A, B, C etc.). Unconformities are designated by the sequence overlying them (e.g. 1A, 4B etc) and by their nature (Type 1 = t1 etc.), as illustrated in the chronostratigraphic charts of the Orange Basin and Bredasdorp Basin (Figure 6).

Structural elements

South Africa's offshore basins can be divided into three distinct tectonostratigraphic zones. The western offshore comprises a broad passive margin basin related to the opening of the South Atlantic in the Early Cretaceous. This is known as the Orange Basin which is the largest offshore basin (Figures 4 and 5).

The eastern offshore is a narrow passive margin that was formed as a result of the breakup of Africa, Madagascar, and Antarctica in the Jurassic.

Limited deposition has occurred here and only the Durban and Zululand Basins contain an appreciable sedimentary section. The southern offshore region, known as the Outeniqua Basin, shows a history of strong strike slip movement during the Late Jurassic - Early Cretaceous breakup and separation of Gondwana.

The Outeniqua Basin consists of a series of en-echelon sub-basins (the Bredasdorp, Pletmos, Gamtoos and Algoa basins) each of which comprises a complex of rift half-graben overlain by variable thicknesses of drift sediments. The deepwater extensions of these basins (excluding the Algoa Basin) merge into the Southern Outeniqua Basin.

Upper Palaeozoic

Subduction on the southwest margin of Gondwana in the Late Carboniferous - Early Permian led to the transformation of an old passive margin into a oreland basin (the Great Karoo Basin), Figure 7. Further convergence in the Permo-Triassic led to the development of the Cape Fold Belt which extends from Australia through Antarctica and South Africa to South America.

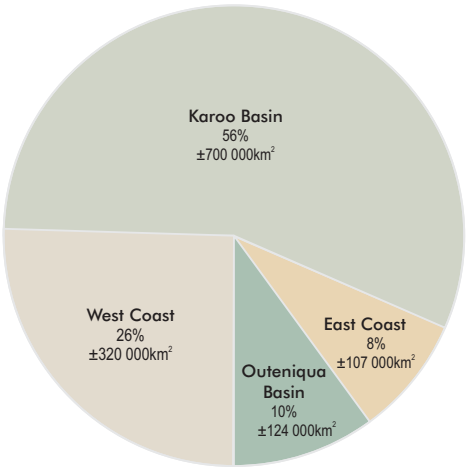
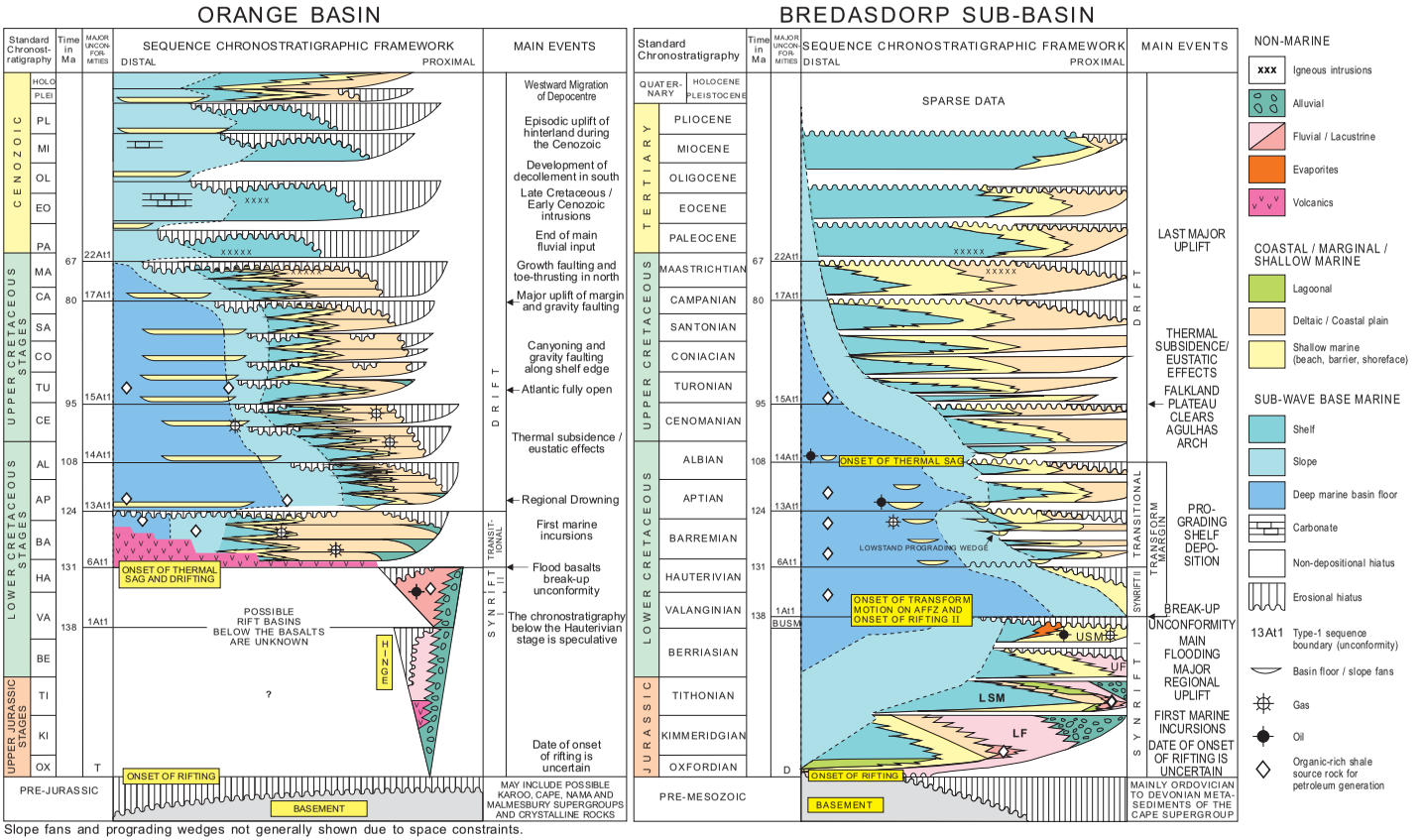


Figure 5. Comparative size of South Africa's major basins.



Slope fans and prograding wedges not generally shown due to space constraints.

Figure 6. Generalised chronostratigraphy of the Orange and Bredasdorp basins, with ages subject to revision by International Commission on Stratigraphy (2012).

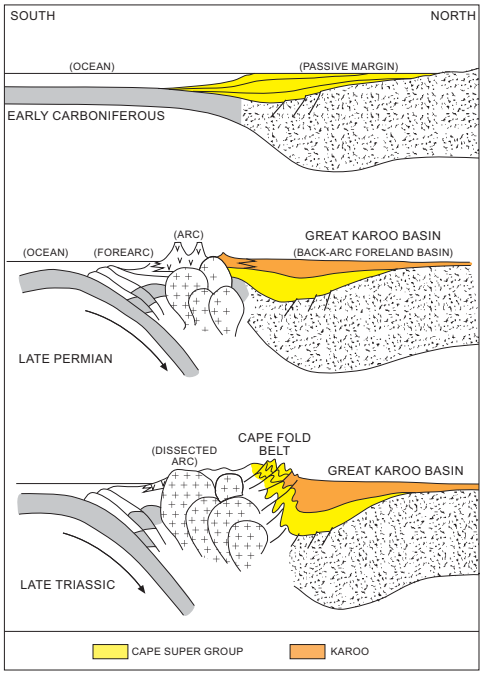


Figure 7. Evolution of Cape Fold Belt and Great Karoo Basin.

Mesozoic and Cenozoic

Following erosion and peneplanation there was a phase of widespread volcanism in the Early to Middle Jurassic in southern Africa, the Falklands and Antarctica. This provides the first evidence of the impending breakup of Gondwana (Figure 8).

At this time, the Falkland Islands lay off the south or southeast coast of South Africa (Figure 9). Breakup started on the eastern margin of Africa with Madagascar and Antarctica beginning to move away in the Middle Jurassic. This initiated the formation of the Durban and Zululand basins.

During the Early to Mid-Cretaceous a complex series of microplates including the Falkland Plateau gradually moved west south-westwards past the southern coast of Africa creating important dextral shearing of the South African margin. This created the Outeniqua sub-basins as a series of oblique rift half-grabens which may be regarded as failed rifts, the oldest in the east and youngest in the west.

The rift phase on the south coast ended in the Lower Valanginian (drift-onset unconformity, 1At1) (Figure 6)

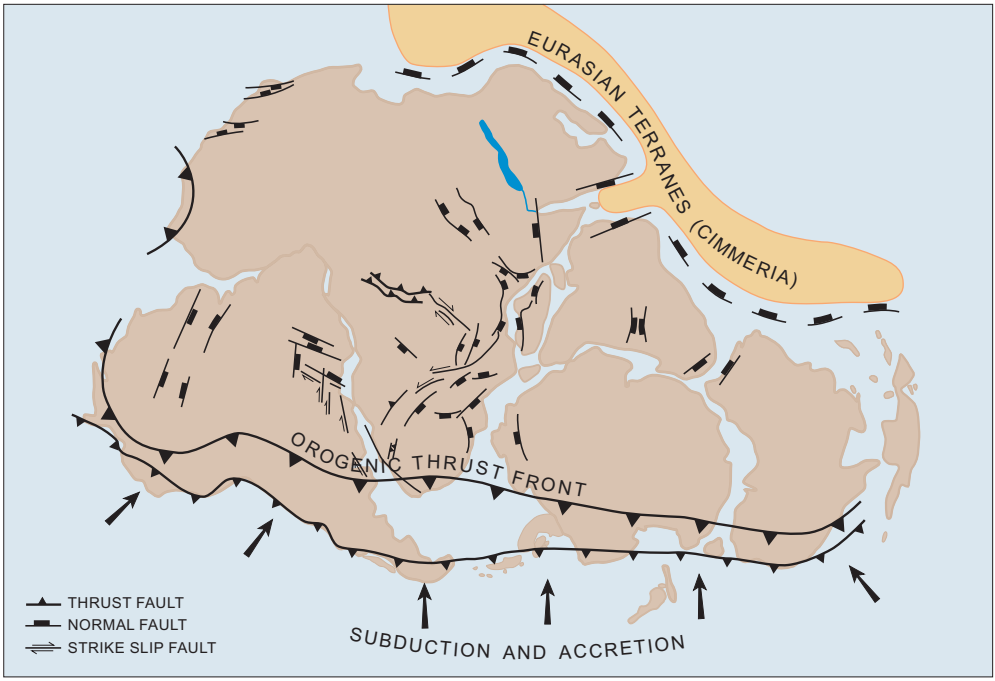


Figure 8. Gondwana in the Late Paleozoic to Early Mesozoic (from de Wit and Ransome, 1992).

but was followed by at least three phases of inversion related to continued dextral shearing. This ended in the mid-Albian (14At1) with the final separation of the Falkland Plateau from Africa. This transitional rift-drift phase was followed by development of a true passive margin. The Lower Valanginian drift-onset unconformity on the south coast is contemporaneous with the earliest oceanic crust in the South Atlantic.

The Orange Basin was initiated as a series of isolated and linked north-south trending grabens during the Lower Cretaceous. The drift-onset unconformity here is dated as Hauterivian (6At1), younger than in the Outeniqua Basin. A rift-drift transitional phase in the Orange Basin occurred until the Early Aptian (13At1). Later Cretaceous and Cenozoic sedimentation took place in a marine passive margin setting.

Figure 9. Pre-break-up distribution of rift basins within southwest Gondwana (after Jungslager,1999).

HISTORY OF EXPLORATION AND PRODUCTION

The first organised search for hydrocarbons in South Africa was undertaken by the Geological Survey of South Africa in the 1940's. In 1965 Soekor (Pty) Ltd was formed by the government and began its search in the onshore areas of the Karoo, Algoa and Zululand Basins.

In 1967 a new Mining Rights Act was passed, and offshore concessions were granted to several international companies including Total, Gulf Oil, Esso, Shell, ARCO, CFP and Superior. This led to the first offshore well being drilled in 1969 and the discovery by Superior of gas and condensate in the Ga-A1 well situated in the Pletmos Basin.

In 1970, Soekor (together with Rand Mines) extended its efforts to the offshore but, despite further encouraging discoveries, international companies gradually withdrew. This was largely as a result of political sanctions against South Africa. Thus, from the mid 1970's to the late 1980's Soekor, the State-owned oil and gas exploration company, was the sole explorer operating the entire offshore area of South Africa. The offshore areas were opened to international investors via a Licensing Round held in 1994.

In 1999 Petroleum Agency SA was established and in 2001 a new State oil company, PetroSA, was formed by the merger of Soekor and Mossgas. The Mineral and Petroleum Resources Development Act was passed in 2002 and became operational on 1 May 2004.

In the entire offshore area, there are now over 300 exploration wells including appraisal and production wells. In addition, 227 000 line km of 2-D and 9700 km of 3-D seismic data have been acquired since exploration began offshore.

Exploration drilling was most active from 1981 to 1991 during which period some 181 exploration wells were drilled. The Bredasdorp Basin has been the focus of most seismic and drilling activity since 1980.

The results of this exploration are the discovery of several small oil and gas fields, and the commercial production of oil and gas from the Bredasdorp Basin (Figures 10 and 11). In the Pletmos Basin there are two undeveloped gas fields and a further six gas discoveries. One oil and several gas discoveries have been made in the South African part of the Orange Basin. One of these discoveries is currently being appraised and developed as the Ibhubesi gas field by Sunbird Energy.

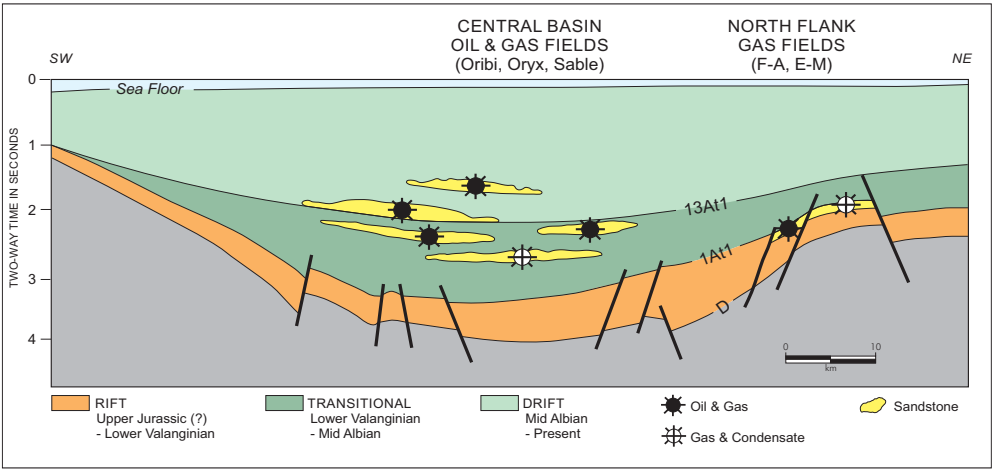


Figure 10. Schematic geological cross-section showing Bredasdorp Basin discoveries.

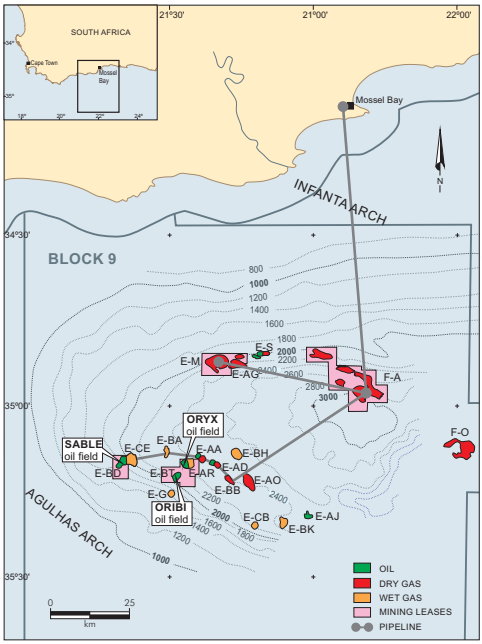


Figure 11. Oil and gas discoveries of Bredasdorp Basin - depth contours on horizon 14At1 (mid-Albian).

Offshore Production History

The F-A/E-M and satellite gas fields, situated 90 km offshore, are owned and were operated by PetroSA at the time (Figure 11). Production began in 1992 and gas and condensate was piped ashore to the PetroSA GTL plant at Mossel Bay where it was converted to petrol, diesel, paraffin, and petrochemicals. During 2006 average daily production from these fields was approximately 160 MMscfg/d (million standard cubic feet of gas per day) and 3900 BOPD (barrels of oil per day).

South Africa's first oil production began in 1997 when the Oribi oil field began flowing at an initial rate of 25 000 bbl/d. A floating production facility (the Orca) was used to fill a shuttle tanker, which supplied crude oil to a refinery in Cape Town. In May 2000, the adjacent Oryx oil field was also brought on stream utilising the same facilities. A third field, Sable, commenced production in August 2003. During 2006 average daily production from Sable was 9700 BOPD. Production from South Africa's offshore oil and gas fields is now halted, making exploration for further domestic reserves imperative.

Database

A substantial database has been accumulated during 40 years of offshore exploration (Figures 12 and 13). This comprises well, seismic, gravity, magnetic, geochemical, geological, biostratigraphic and other data together with a large volume of interpretation reports and related studies. Most of this data is held by Petroleum Agency SA on behalf of the State and is well organised and accessible.

The quality of this database varies considerably from area to area. Seismic data coverage for example, varies in quantity and vintage from one basin to another. Drilling activity shows a similar pattern with a heavy concentration in the Bredasdorp Basin.

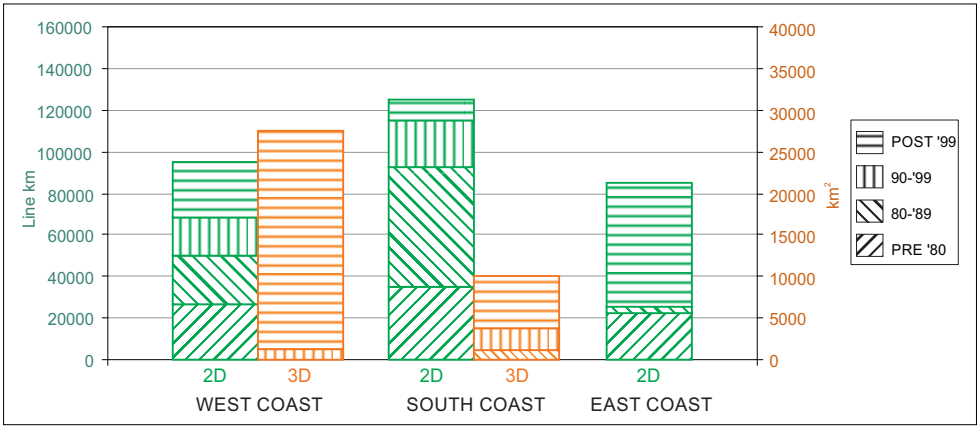


Figure 12. 2D and 3D seismic acquisition by region.

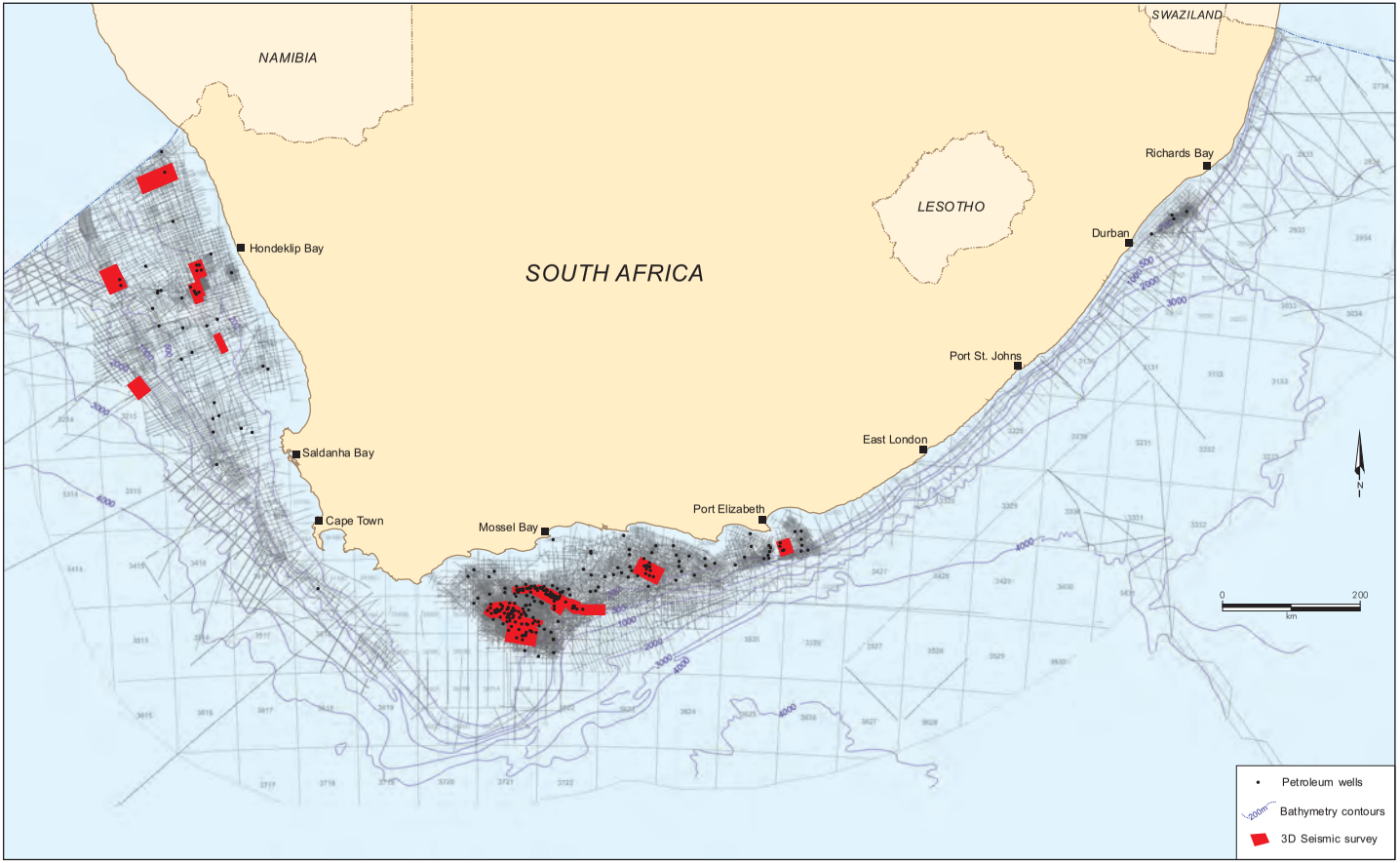


Figure 13. Extent of offshore seismic data.

THE ORANGE BASIN

The Orange Basin is areally and volumetrically the largest shared basin between South Africa and Namibia, with the South African portion reaching about 320 000km^2 in extent. It is largely underexplored with most wells located on the shelf. Several petroleum systems (oil and gas) are known to be present in the basin. The earliest hydrocarbon/petroleum discovery within the basin is the Kudu gas field. It was discovered by Chevron in 1974 and is located roughly 170km off the Namibian coast. The Kudu gas field is estimated to contain 1C-2C-3C Contingent Resource range within the main reservoir ("K3") of 755-1330-2308 Bscf respectively [1].

The Ibhubesi gas field discovered in 1981 is situated approximately 105km off the coast of South Africa and lies within water depths of 200 to 250 meters [2]. The field is estimated to have roughly 540 Bcf of gas and about 4.81 Mmbbl of oil. Production is planned to start in 2025 and will peak in 2040.

A light oil discovery made by the then-state-owned company Soekor in 1988, flowed 191 barrels per day of 36°API oil from a 10-m sandstone interval located at approximately 3250 m. In the most recent drilling campaigns in 2021 and 2022, Shell and its partners, as well as TotalEnergies and their partners have made several play-opening light oil discoveries in the Namibian part of the Orange Basin. This has stimulated renewed interest in the deep water Orange Basin. The Graff-1 discovery in 2022 in Namibia by Shell and its partners purportedly contains up to 1500mmbo recoverable oil (Upstream online, 2022; Africa oil+gas report, 2022). The Graff-1 well was drilled in approximately 2000 m water depth to a total depth of 5376 m and likely encountered a 60 m Santonian to Cenomanian age hydrocarbon-bearing interval (Geoexpro, 2022). It was the first of a four-well program to date by the partners with the recent Lesedi-1X well in July 2023 also encountering significant light oil hydrocarbons [3].

The Venus-1X light oil discovery in Namibia was drilled by TotalEnergies and its partners in February 2022. It holds an estimated 3000 Mmbl of oil and associated gas and was drilled to a depth of 6296 m in roughly 3000 m water depth. The reservoir is an Aptian basin-floor fan found on a counter-regional dip slope. It onlaps the Outer High landward creating the trap. The oil comes from a mature Aptian source rock residing over the oceanic crust with a net oil pay of 84 m (Heins, 2022; Hedley et al.,2022). In June 2023, the partners drilled the Nara-1X well [4] approximately 13km away following the Venus discovery and are in the process of conducting flow tests of the Venus discovery. These discoveries hold considerable promise for the future exploration and development of Namibia's hydrocarbon resources.

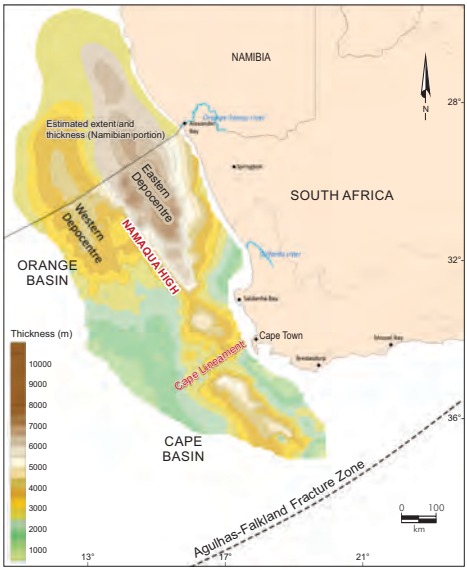


Figure 14. Sediment thickness of the Orange Basin.

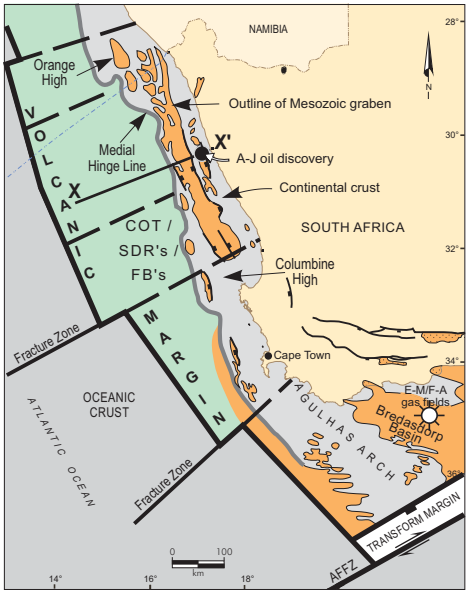


Figure 15. Major tectonic elements and crustal segments of the rifted volcanic margin (after Jungslager, 1999).

Structure and stratigraphy

The Orange Basin is outlined by the isopach map of the post-rift sedimentary succession (Figure 14). It is the southernmost West African basin and was fed mainly by a major river system with a delta rivaling those of rivers further to the north in Africa. The underlying synrift succession comprises of isolated, truncated remnants of half-graben to the east of the medial hinge (Figure 15). Sedimentary fill may be as old as Jurassic but the oldest dated sediments are Hauterivian, found mainly within these Synrift grabens. All the penetrated sediments are continental, with igneous lithologies in places. To the west of the hinge seismic seaward-dipping reflectors are interpreted as subaerial flood-basalts thought to have poured rapidly onto the attenuated continental crust at the close of the active rifting phase (6At1 or 117.5 Ma, see Figure 6).

The basalts are coeval and partially interbedded with continental to shallow marine sediments, primarily of the Barremian "transitional" age. True oceanic crust is located to the west of the seaward-dipping reflectors beyond the prominent marginal ridge, referred to as the Namaqua High. The western margin is thus of the divergent volcanic type and is segmented into several crustal segments, with the southern segment of the margin related to early rifting.

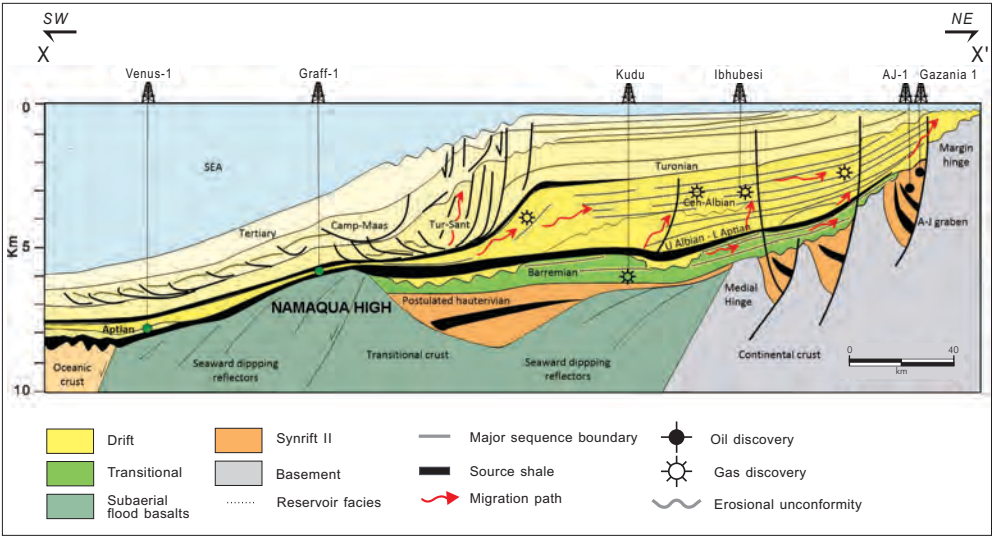


Figure 16. Schematic geological profile across the central Orange Basin (after Jungslager, 1999).

A significant inundation of the shelf edge marks the conclusion of the initial period in the basin's history and marks the commencement of the characteristic extensive sediment accumulation in a wedge shape, featuring highly advancing sequences intermittently interrupted by eroded sequence boundaries (refer to Figures 6 and 16). The Cretaceous sediments are siliciclastic ranging from continental in the east to deep-marine in the west.

The thick wedge of drift sediments underwent repeated deformation of the palaeo-shelf edges and palaeo- slopes due to sediment loading and slope instability, especially in the Upper Cretaceous. These sedimentary tectonic features are found in the northern and southern parts of the basin and are deep water fold and thrust belts typically comprising of extensional gravity faults and folds up-dip, a detachment glide plane in mobile/overpressured shales, and compressional toe-thrust faults and folds down-dip.

Petroleum systems, exploration plays, and prospects

Ongoing exploration endeavors have confirmed the existence of multiple petroleum systems from recognized source rocks within the Orange Basin. Research by van der Spuy (2003) showed evidence supporting the presence of Aptian source rocks, and there are indications of an active Cenomanian/Turonian source rock as well (Aldrich et al, 2003). These petroleum systems encompass both oil and gas reserves, offering diverse

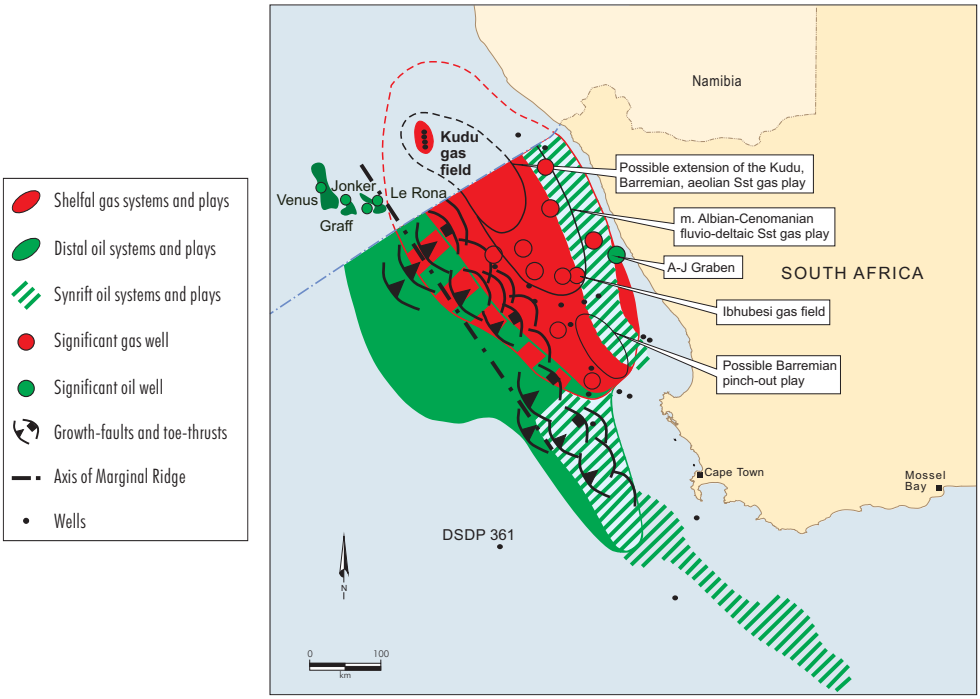


Figure 17. Main known and predicted petroleum systems and complementary exploration plays (after Jungslager, 1999).

exploration prospects that are currently being actively pursued. The Kabeljou-1 and Moosehead-1 wells in Namibia proved the existence of both the Aptian and Cenomanian-Turonian source rocks in the deep water in the Orange Basin. These wells, together with the Wingat-1 well in the Walvis Basin demonstrated the Aptian source rock is thick, widespread, and oil-mature. The Windgat-1 well drilled in 2013 was the first well to recover oil from a mature Aptian source in deeper waters (Hodgson and Intawong, 2013). The venus-1X well proved that the Aptian source rock is also oil mature over oceanic crust.

Despite being quite extensive, a mere 41 wells have been drilled to date of which 39 are Oil and Gas exploration wells, as well as 5 research wells (DSDP, ODP) (Figure 20). Key aspects of these exploration initiatives are visually depicted in Figure 17. Amongst these, from the shallow inner shelfal area, are the Synrift Graben Oil Play, the Albian Gas Play, the Upper Cretaceous Shallow Gas Play, the Barremian Deep Gas Play, and the Albian Deep Gas Play. Towards the west of the inner shelf are the Upper Cretaceous Deep Water Slope Turbidite Oil/Gas Play, the Upper Cretaceous Deep Water Turbidite Oil Play and the southern Cape Basin Deep Water Fan Oil Play. Recent discoveries in the ultra-deep water within the Namibian portion of the Orange Basin have confirmed an oil play west of the Namaqua High marginal ridge (figure 14) with encouraging evidence of its southern extension into the South African portion of the Orange Basin marked by numerous analogous leads identified within the deep water.

The most well-documented petroleum system discovered in South Africa to date is the Albian Gas Play, referred to as the Ibhubesi gas field, sourced from the lower Aptian and Barremian source shales located in the eastern depocentre of the Orange Basin (Figures 14, 16). The reservoirs are stratigraphically trapped fluvial channel-fill sandstones, which yielded 68 MMscfg/d and 340 bbl of condensate per day during the testing of the A-K1 discovery well by Soekor in 1987.

A further 8 wells have been subsequently drilled during subsequent appraisal of the field and combined tests yielded 221 MMscf/d. Bright spots and seismic gas chimneys are common occurrences in the play fairway. The Barremian Deep Gas Play has yielded the Kudu gas field in the Orange Basin off southern Namibia. The reservoirs are stratigraphically trapped aeolian sandstones with good gas deliverability. Both the Ibhubesi and Kudu plays are regarded as having the potential for multi-TCF reserves of natural gas.

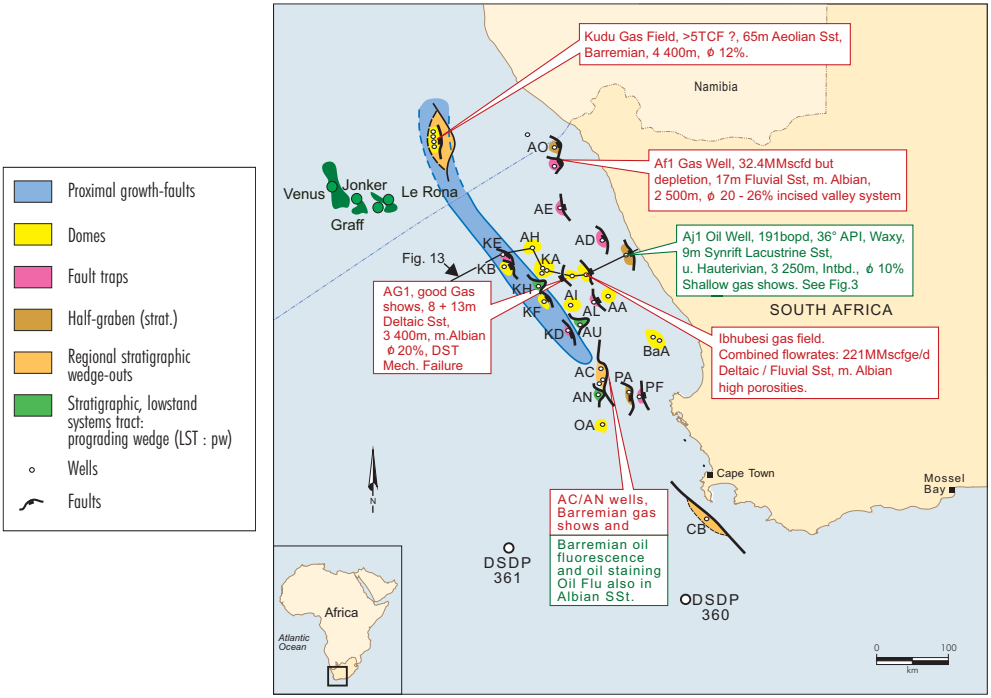


Figure 18. The main petroleum discoveries and shows in the Orange Basin (after Jungslager, 1999).

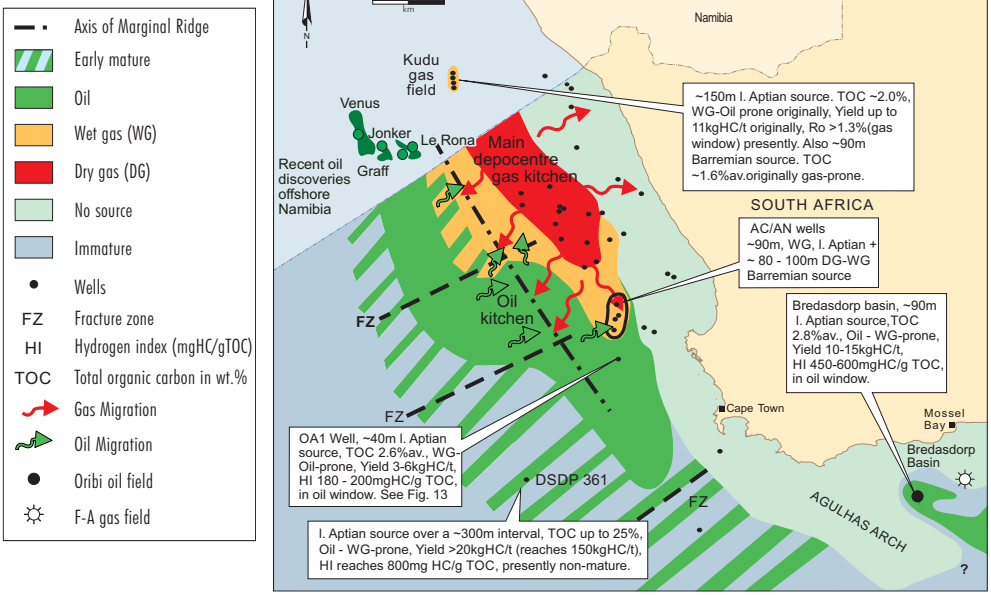


Figure 19. The active marine source rock kitchen at the lower Aptian level (after Jungslager, 1999).

Within the synrift succession, the only oil system confirmed to date occurs in the isolated A-J half-graben (Figures 15, 16 and 18). The oil is sourced from typically rich Hauterivian lacustrine shales within the half-graben and is trapped stratigraphically within lake shore-line sandstones interbedded with the source shales. The maximum flow rate reached whilst testing is about 200 barrels per day of viscous oil. A second well, Gazania-1, was drilled in 2022 to a depth of 2330m and encounters light oil with gas throughout the main target, however not deemed commercial, it does confirm an active petroleum system.

This geological success has shown the potential of the Synrift Oil Play. Several speculative petroleum systems and plays are also prognosed in the mostly undrilled parts of the basin, notably in the deep water areas (Figures 16-18). Seismic gas chimneys, seismic wipe-out zones, seafloor gas escape features (mounds, craters, mud volcanoes), bottom simulating reflectors (gas hydrates), discrete bright spots, flat spots as well as gravity slide systems identified along the west coast indicate the likelihood of an active petroleum system in deep water

Initially, the Aptian-Barremian source rocks were postulated to be increasingly oil-prone westward on the basis of evidence from the more distal wells, the DSDP 361 borehole, and the nearby Bredasdorp Basin (Figure 19 and Van der Spuy, 2003).

A Turonian oil source rock was envisaged as a possibility based on intersections in the distal part of the Bredasdorp Basin, in Namibia's Walvis Basin, evidence of a wet-gas source shale in some of the Orange Basin wells, seismic character and possible organically rich, climatically-driven upwelling zones in the Late Cretaceous (Aldrich et al., 2003).

During the Late Cretaceous, shelfal sand supply was ample and several canyons have been identified whereby sand could be supplied to the slope and basinal domains providing reservoirs for vertically migrating hydrocarbons. Potential reservoirs are ponded and channelized turbidite sandstones structurally and stratigraphically trapped and are encased in mass transport deposits. These deep water plays remain high risk but are believed to be attractive targets for exploration.

In summary, the Orange Basin is a large under-explored area with a very sizeable potential for both oil and gas. The oil potential may be greatest beyond the present day shelf, whereas the gas potential may be greatest on the shelf.

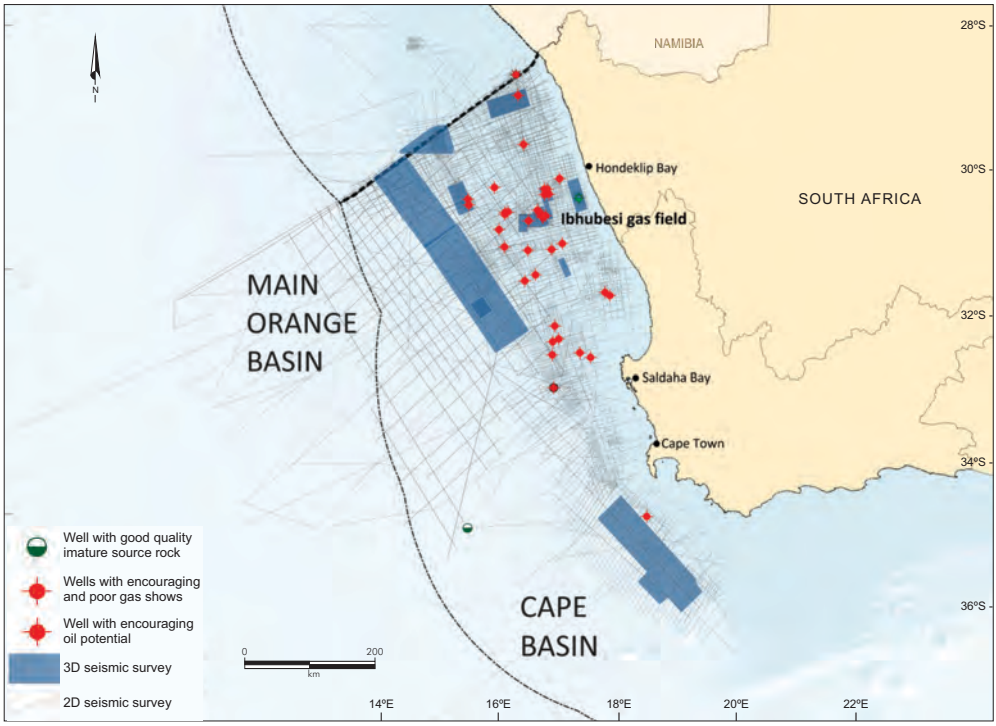


Figure 20. Seismic line and well status map of the Orange Basin.

THE OUTENIQUA BASIN

Structure and stratigraphy

Structure and stratigraphy maps and cross-sections of the Outeniqua Basin (Figures 21, 22) clearly illustrate the half-graben geometry of the synrift sediments and the variable thickness of the later drift sediments. The size of the sub-basins increases systematically from east to west and the initial trends of the half-graben bounding faults were strongly influenced by the pre-existing fabric of the Cape Fold Belt. The deepwater extension of these sub-basins comprises the Southern Outeniqua Basin.

Source rocks and maturity

Rich, wet gas and oil-prone marine source rocks of Kimmeridgian to Berriasian age have been intersected in the Gamtoos and Algoa sub-basins. An oil-prone Lower Cretaceous lacustrine source rock is present in the onshore Algoa sub-basin. Several deep marine oil and gas source rocks are known in the transitional rift-drift sequence (Lower Valanginian to mid-Aptian; 1A to 13A sequences). These are best developed in the Bredasdorp Basin where the 13A (mid-Aptian) source is probably the main source for the oil fields and a minor source for the gas condensate fields. These source rocks are also postulated to be thick and rich in the Southern Outeniqua Basin. All the synrift source rocks are mature over large parts of the area. The younger source intervals are mature in the west and south (Bredasdorp and Southern Outeniqua basins).

Reservoirs, seals, and traps

Sandstone reservoirs are present in both the synrift and drift sections. The synrift reservoirs are shallow marine to fluvial whereas drift sandstones are deep marine turbidite deposits. The trapping mechanisms within the synrift are mainly structural as well as truncational. Drift marine shales provide the main seals but potential synrift seals also exist. Traps within the synrift section are mostly tilted fault blocks. In the drift section a wide variety of low relief closures is developed. These include compactional drape anticlines, stratigraphic pinch-out traps, and inversion-related closures.

Oil and gas fields

The Oribi and Oryx oil fields, now suspended, (Figure 11) produced a light oil (42-degree API gravity) from Lower Cretaceous (mid-Albian) age sandstone reservoirs which were deposited in a deep-water fan channel complex in the axial part of the Bredasdorp Basin. The reservoir of the Sable field, a similar Albian age basin floor fan complex, produces oil, condensate, and gas. The F-A / E-M gas fields produced from Lower Cretaceous (Late Valanginian) sandstones which were deposited as shallow marine shelf deposits along the northern flank of the basin.

Prospectivity

The prospectivity of the Outeniqua's sub-basins is shown in Figure 23. Bredasdorp and Pletmos basins. The hydrocarbon prospectivity is rated high in these basins which contain almost all of South Africa's proven hydrocarbons. Numerous small oil and gas accumulations have been discovered in the Bredasdorp Basin and some are currently under appraisal. Further exploration in these basins is expected to yield continued success.

Southern Outeniqua Basin

Until recently, the only control was provided by a wide grid of old seismic lines. 2D seismic data acquired by Canadian Natural Resources (formerly Ranger Oil) in 2001 and 2005 confirmed the presence of major structures in this deep-water frontier area. Domally closed synrift structures are generally within the oil window and expected to contain gas. Seismic interpretation of this new data indicated a gigantic basin floor fan complex (named "Paddavissie") with an upside potential of billions of barrels of oil equivalent, now confirmed by the drilling of the Brulpadda and Luiperd wells. Drilling of the first prospect (Brulpadda) by Total and partners confirmed a large accumulation of gas condensate and oil. This was followed by a significant condensate discovery at Luiperd. The Southern Outeniqua Basin is highly rated for oil in the central and southern extent of the basin, and more gas-prone towards the northern periphery with its thicker overburden. Regional studies suggest the presence of multiple source rocks, shallow marine and turbidite sandstones and large structural and stratigraphic traps.

Active petroleum systems have been confirmed in both these sub-basins. The Algoa Basin has Kimmeridgian age good quality oil prone source rocks, encouraging oil shows, good reservoirs and traps and hosts a large wet-gas shallow water seep anomaly. The Gamtoos Basin is more gas-prone, although basin floor fan sandstones in the drift succession may contain oil sourced from an underlying Hauterivian source.

Algoa and Gamtoos basins

Active petroleum systems have been confirmed in both these sub-basins. The Algoa Basin has Kimmeridgian age good quality oil prone source rocks, encouraging oil shows, good reservoirs and traps and hosts a large wet-gas shallow water seep anomaly. The Gamtoos Basin is more gas-prone, although basin floor fan sandstones in the drift succession may contain oil sourced from an underlying Hauterivian source.

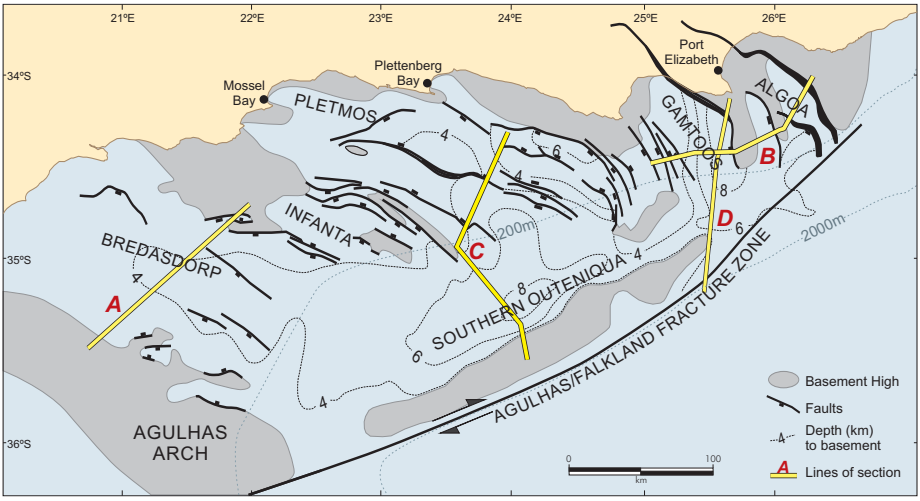


Figure 21. Major tectonic elements in the Outeniqua Basin

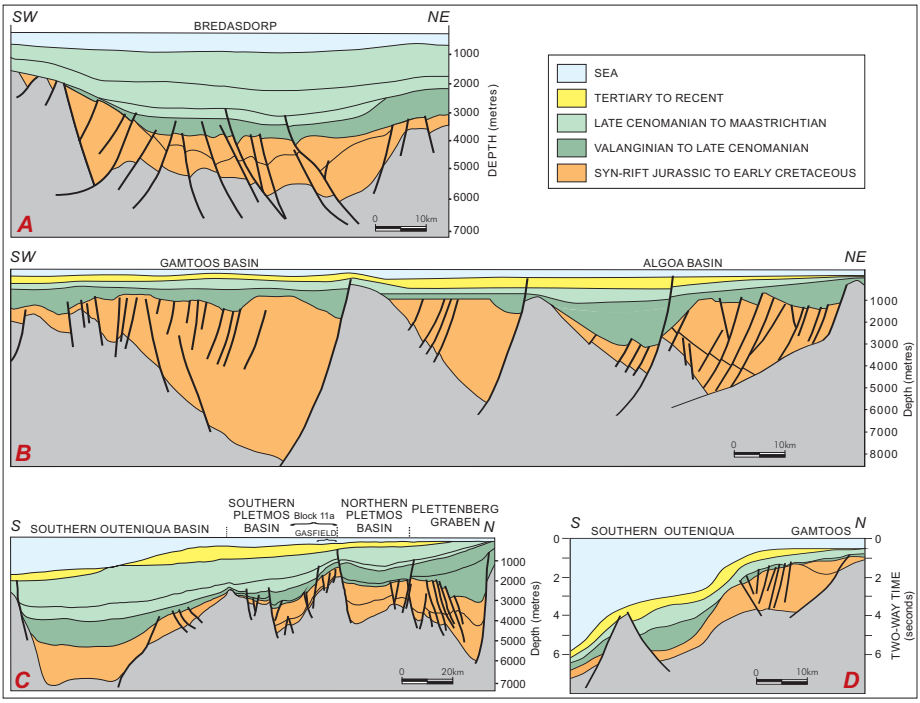


Figure 22. Cross-sections of the Outeniqua Basin

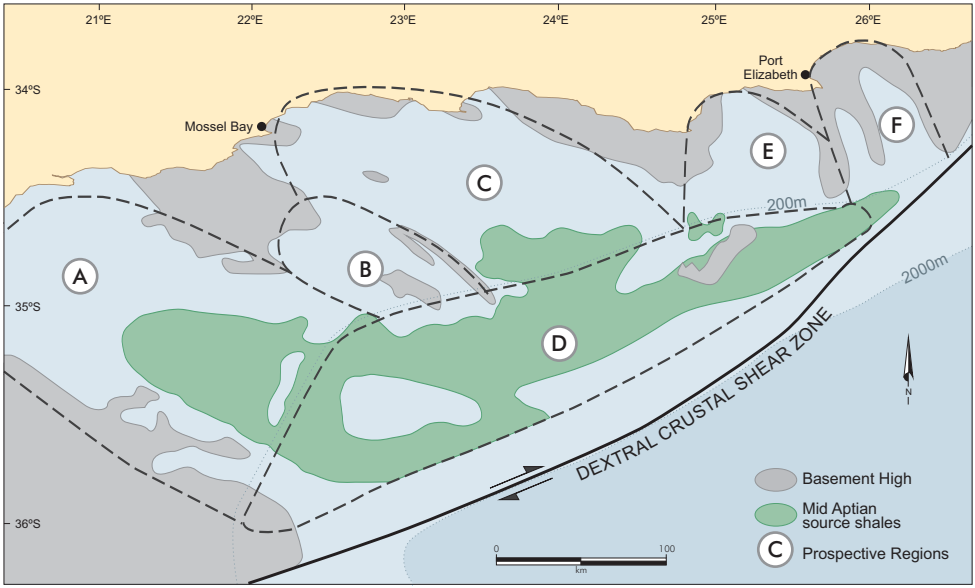


Figure 23. Ranking of areas of the Outeniqua Basin.

	PROSPECTIVE REGIONS				
A Bredasdorp	B Infanta Embayment	C Pletmos	D Southern Outeniqua	E Gamtoos	F Algoa
KITCHEN AREA					
Large	Small	Moderate	Large	Small	Small
MIGRATION DISTANCES					
Short	Long	Short	Short	Long	Short
TRAPS					
Abundant	Limited	Abundant	Abundant	Limited	Limited
EFFECTIVE SEALS					
Widespread	Limited	Widespread	Widespread	Limited	Limited
OIL AND GAS FINDS					
Proven oil and gas potential. Undrilled to East	Little potential to North. Undrilled in South	Proven gas potential to North Undrilled in South	Undrilled	Gas shows	Oil shows Undrilled To South
HYDROCARBON POTENTIAL					
Excellent	Poor	Good	Excellent	Good for gas	Excellent

THE EAST COAST

The eastern offshore extends from the Port Alfred Arch (near East London) in the south to the Mozambique border in the north. It is divided into the Transkei Swell, the Durban Basin, and the Zululand Basin. This large area has seen extremely limited exploration. Seismic lines are mostly old and widely spaced (typically a 25km grid) and only four offshore wells have been drilled. Two new 3D seismic data sets have offered new insights into the deeper synrift structure and prospectivity of the basin (Figure 24). The continental shelf is very narrow along the Transkei Swell, broadening northwards in the Durban and Zululand basins.

Transkei Swell

The Transkei Swell stretches from the Port Alfred Arch to just south of Durban. It has a narrow continental shelf and a steep continental slope both of which contain a veneer of mainly Tertiary sediments resting on basement. Locally, however, some structurally controlled Jurassic - Cretaceous basins are developed but are poorly defined on old seismic data.

Durban Basin

The Durban Basin is bounded to the south by the Port Shepstone Arch and merges northwards into the Zululand Basin which represents the southern tip of the large Mozambique Basin which hosts the Pande and Temane gas fields. It covers an area of some 4000 sq km between the coast and the 1500 m isobath. The continental shelf is approximately 35km wide between Durban and Richards Bay. The shelf and slope areas contain thick Tertiary successions and lesser thicknesses of Early Cretaceous sediments that rest on Jurassic to Palaeozoic basement. A north-south oriented graben is thought to contain substantial thicknesses of synrift sediment, and several large structural traps have been defined in water depths between 400 m and 600 m.

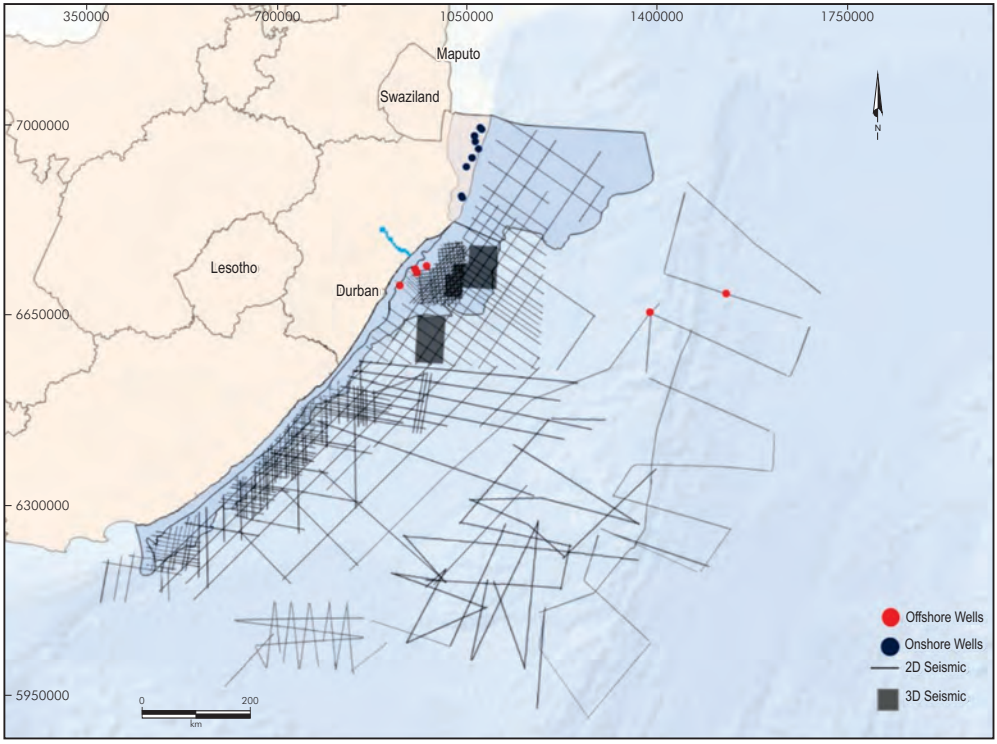


Figure 24. Regional seismic data and well locations along the east coast of South Africa.

Zululand Basin (onshore and offshore)

The offshore Zululand Basin covers an area of approximately 13,500 sq km out to the 1500 m isobath although most of this lies in water depths of more than 200 m. The offshore is undrilled, however 10 onshore wells where drilled during 1960's / 70's. Late Cretaceous source rocks and porous Cretaceous sandstones were demonstrated, but no shows were encountered. The scant offshore seismic data shows evidence of asymmetrical grabens that are interpreted to contain oil prone Cretaceous sediments. Extrapolation from wells drilled in Mozambique suggests that Late Cretaceous source rocks (the Domo Shales) could be widely developed in the offshore Zululand Basin and may be gas prone.

Basin evolution

The Durban and Zululand basins initially developed during the early Jurassic to early Cretaceous break-up of the Gondwana super-continent. Plate tectonic reconstructions suggest that early divergent plate movements between East and West Gondwana resulted in transtentional stress, which resulted in the development of rift basins along the break-up margin. Right lateral strike-slip faulting dominates segments of the Durban Basin break-up margin. Both divergent and transtentional movements served to extend the continental crust and formed horst and graben structures. The early Cretaceous was characterised by the movement of the Maurice Ewing Bank (Falklands microplate) from its original position adjacent to the Durban Basin. This occurred as part of a late north-south orientated extensional event.

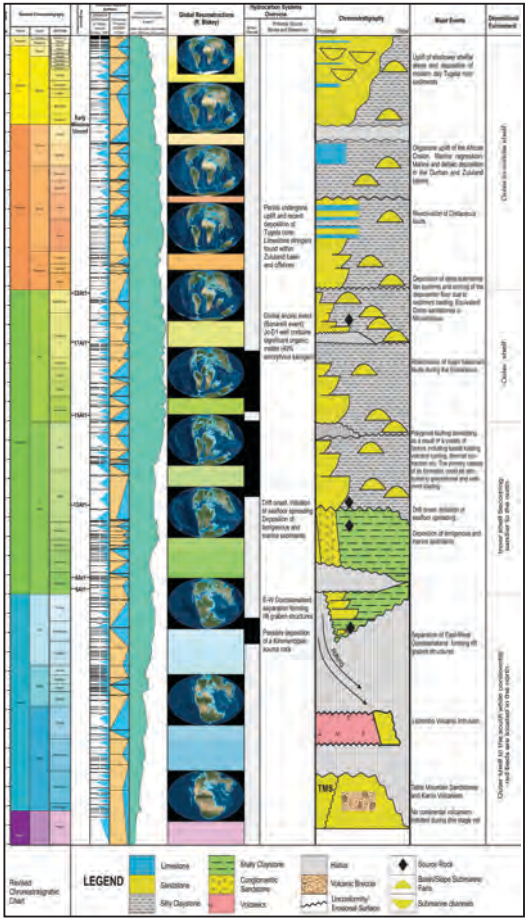


Figure 25. Chronostratigraphy of the Durban and Zululand basins.

Chronostratigraphy

Using regional seismic data and limited well control, the stratigraphy has been correlated from the modern shelf into the deepwater areas of the basins. Figure 25 provides a summary of the main geological events that influenced the development of the Durban and Zululand basins.

The Tugela Delta

The Tugela River system has played a significant role in shaping the landscape of the eastern offshore. In the Late Cretaceous to Tertiary, the Tugela River was a major source of sediment and built up the extensive sediment pile of the Tugela Cone.

This cone comprises a large constructional delta that extends out across the shelf margin and a distal fan which extends to water depths of 2000 meters and beyond. Two sediment growth phases are present, one related to synrift and early drift sediment supply, the other to a renewal of progradation during the Early Tertiary. The resultant Tugela Fan, associated with prolonged sediment input from the palaeo-Tugela River, dominates the mid-Cretaceous geology of the Durban Basin. The Tugela Fan has not been explored for hydrocarbons, but recent seismic mapping reveals extensive systems of basin floor fan complexes extending into deeper water.

Northwest trending seismic dip lines show prograding Tertiary reflectors with oblique seismic signatures. Well Jc-A1 intersected prodelta shales comprising upward-coarsening regressive cycles. The deltaic signature is particularly well displayed in the Tertiary succession.

Petroleum elements of the Durban and Zululand basins

The hydrocarbon potential of the Durban Basin has been tested by only four wells, all of which were non-commercial but two of which had showns. Jc-D1 (drilled by Phillips in 2000) provides evidence for oil and gas petroleum systems (Figure 26).

Source rocks

- Possible source rocks within the Durban and Zululand basins are as follows:
- A Jurassic source within graben sediments of the basins as indicated by extract analysis from Jc-D1.
- An early to mid-Cretaceous source as intersected within the Durban Basin and the Mozambique Basin.
- Cenomanian-Turonian and Barremian-Aptian source rocks as intersected by wells in the Durban Basin.
- Possibly the Domo Shale equivalent in the deep synrift sections, as seen in the Mozambique Basin to the north.

Evidence supporting the presence of source rocks and active petroleum systems is

- DSDP wells 330 and 511, located on the Maurice Ewing Bank, intersected thick oil prone source rocks of Kimmeridgian to Aptian age. Similar age source rocks are postulated to occur within the Durban Basin in the rift and early drift succession that underlies the Tugela Cone.
- Jc-B1 exhibited a minor gas show, and the associated shale has total organic carbon values, ranging from 2.75 to 5%.
- Jc-D1 mud gas values indicate a trend of increasing wetness with depth. In addition, fluid inclusion studies of Jc-D1 samples provide evidence for seeping light hydrocarbons and an extract sample yielded slightly biodegraded oil. Fluorescence was also observed in this interval and in the basal section of the well in association with bitumen staining. An extract from the latter yielded evidence for a light oil derived from a marine claystone of Cretaceous to Jurassic age.
- Gas escape features, sea floor craters and mounds have been identified in the Durban and Zululand basins (Figures 26, 27 and 28).

Reservoirs

With the existing wells positioned on shelf-margin highs, none encountered any sandstone of significant thickness. Seismic evidence suggests that reservoir rocks are present in deeper water and are associated with basin floor fans, turbidites and channel systems. Well Jc-B1 intersected a 17 m thick marine sandstone, which represents the last sand associated with retrograde deposition.

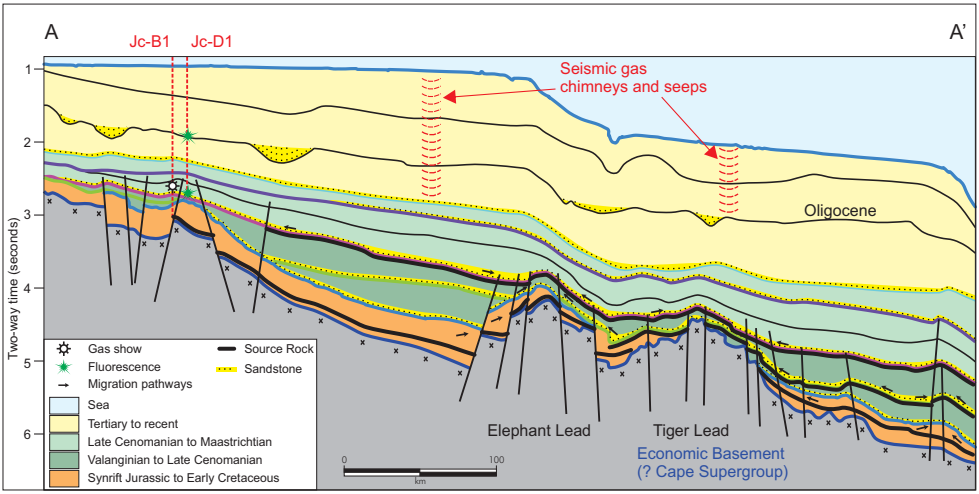


Figure 26. Geo-seismic cross section across the Durban Basin. Shelf width exaggerated due to oblique line of section. (see Figure 27 for location of cross-section).

In the onshore Zululand Basin, a borehole located on the Bumbeni Ridge, encountered early Cretaceous sandstones with porosities ranging from 15 to 21%. Channel and basin floor fan systems are evident within the offshore Zululand Basin.

Play types

Tilted fault blocks, faulted anticlines, stratigraphic traps, basin floor fans and channel sands constitute the principal exploration targets of the Durban and Zululand basins (Figure 27, black open polygons). The acquisition of new 2D and 3D seismic datasets has opened new play opportunities in the area. This is highlighted in Figure 27; the black polygons are a combination of the existing play types while the new play types include the graben plays in the deepwater Durban basin (red polygons) and basin floor fans on oceanic crust along the Transkei basin/ Natal valley (green polygons).

Petroleum potential

Existing wells and sparse seismic data are inadequate for effective evaluation of the petroleum potential of this large area. However, there is sufficient encouragement in the presence of reservoirs, traps, source rocks and active petroleum systems to justify further exploration. The acquisition of modern seismic data, particularly in the extensive deep-water areas is regarded as essential for further exploration.

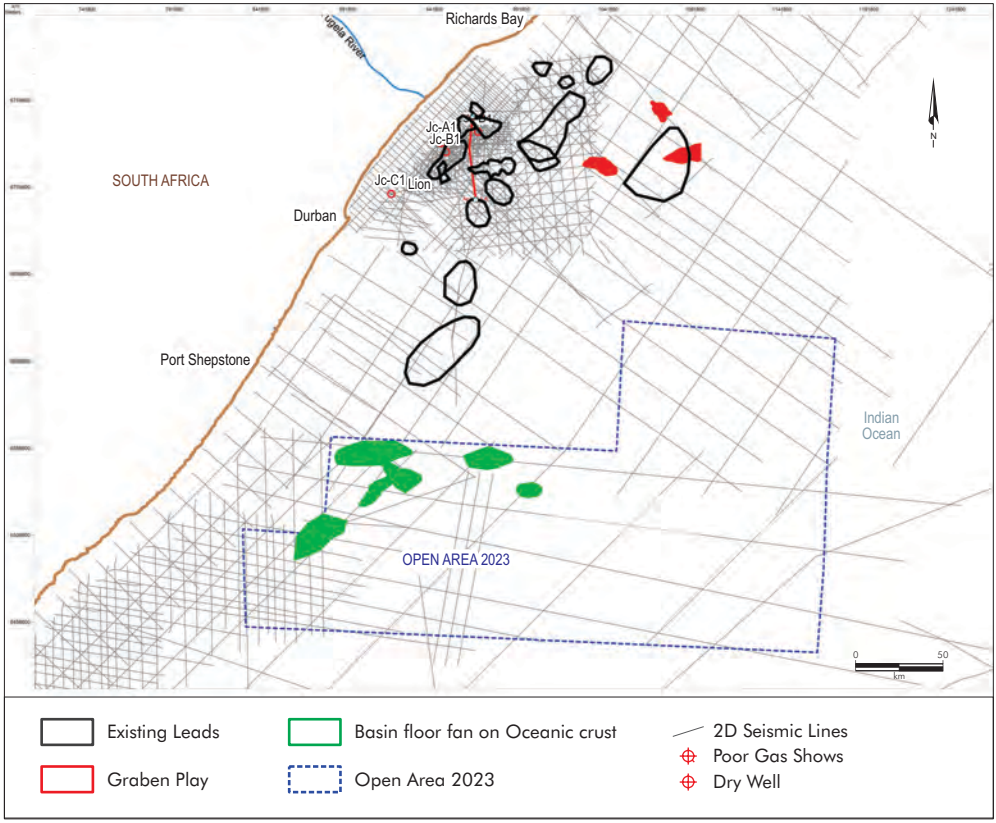


Figure 27. Seismic line and lead location map of the Durban Basin.

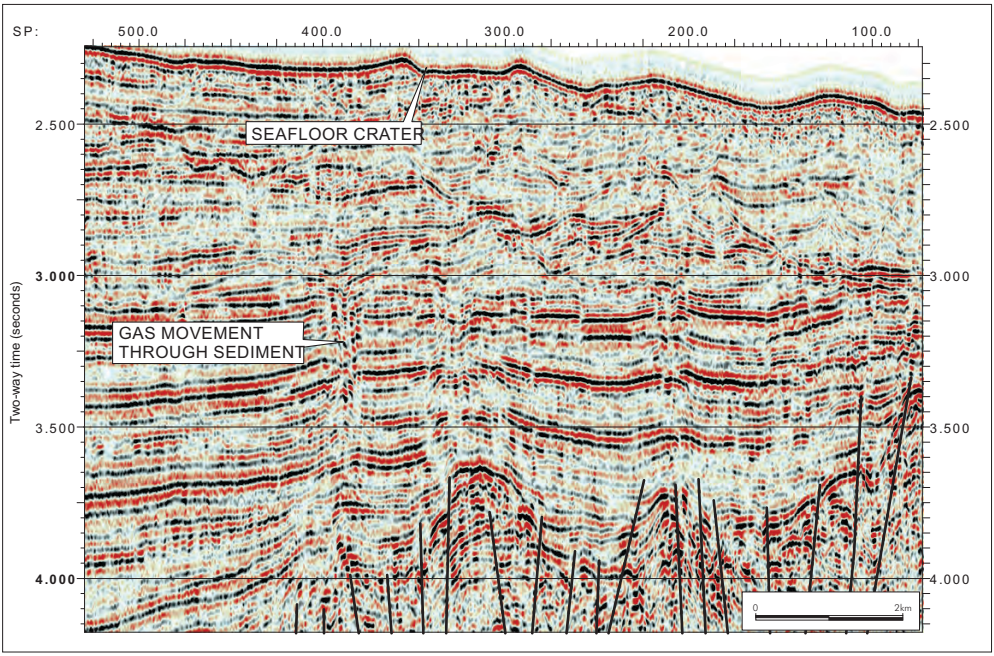


Figure 28. Possible gas escape features.

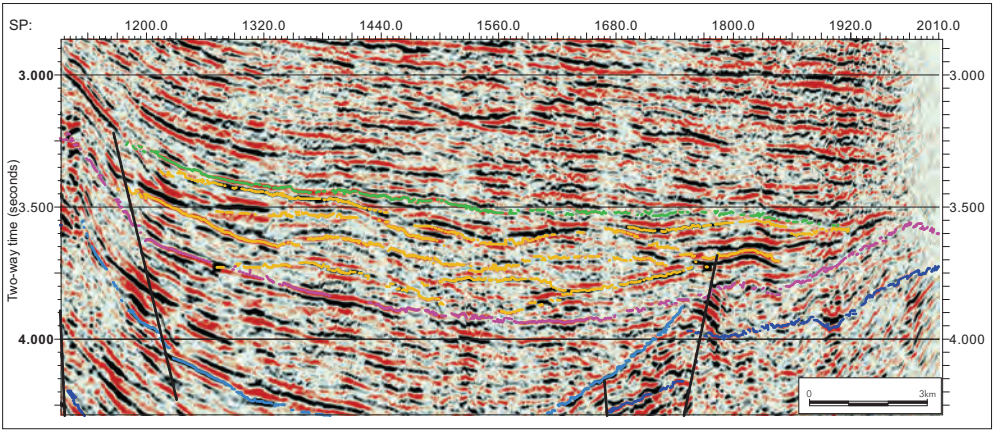


Figure 29. Basin floor fan systems in the Durban Basin: The Lion Prospect.

THE ONSHORE ENVIRONMENT

The Main (or Great) Karoo Basin and subsidiary basins occupy more than half of South Africa's land surface (~700,000 km; Figure 30). Although early exploration efforts by former national oil company SOEKOR for conventional oil resources during the 1960s and 1970s did not meet with commercial success, the Karoo basins nevertheless constitute a petroleum province with significant potential, as evidenced by numerous oil and gas shows being noted in scientific publications since the 19th Century.

Today, the onshore Karoo basins are the focus of a renewed international exploration effort, with unconventional gas being the principal exploration target. Coal bed methane, microbial gas and shale gas are considered to be the most promising play types at present.

REGIONAL GEOLOGICAL SETTING

Tectonic setting

The deposition of Karoo sediments took place between the Late Carboniferous and the Early Jurassic (~300-180 Ma) in the heartland of the supercontinent Gondwana. Northern, subsidiary Karoo basins in South Africa are primarily fault controlled, although tectonic models for the evolution of the Main Karoo Basin (Figure 31) remain controversial. The Main Basin is traditionally described as a retro-arc foreland basin (e.g. Johnson et al., 2006) formed on the continental side of a fold-thrust belt (the Cape Fold Belt), possibly with a strike-slip structural component (Tankard et al., 2009).

However, seismic data yields evidence of southward-dipping décollements and blind Palaeozoic thrusts within the southern Main Karoo Basin, but no significant foredeep thickening or deep suture zone, suggesting that southward subduction occurred to the south of the Cape Fold Belt, and not beneath the Main Karoo Basin (Lindeque et al., 2011). Other possible influences on basin evolution include isostatic crustal depression by Carboniferous ice sheets during the Dwyka glaciation, crustal flexure due to tectonic loading and unloading, and plume-induced uplift in the Triassic prior to volcanism and Gondwana rifting in the Jurassic.

Stratigraphy and thermal history

Karoo sedimentation occurred in a wide range of depositional environments. Sedimentary units include the glacial diamictites of the basal Dwyka Group, the epeiric marine/lacustrine black shales, turbidites, deltaic sediments and coals of the overlying Ecca Group, and the fluvial deposits, coals and aeolianites of the Beaufort Group and upper Karoo formations (e.g. Catuneanu et al., 2005).

During the Permian-Triassic Cape Orogeny, the extreme southwest margin of the Main Karoo Basin experienced lower greenschist facies metamorphism. Later regional magmatism in the Early Jurassic (Karoo Large Igneous Province; ~183 Ma) resulted in the basin-wide intrusion of Karoo dolerites. Zircon fission track data (Brown et al., 1994) from the southwest Main Karoo Basin indicates palaeo-temperatures of at least 250 ± 50 °C at this time. It has been suggested that intrusion of the Karoo dolerites may have been responsible for the explosive formation of hydrothermal vents and breccia pipes following the heating of sediments rich in organic matter (Aarnes et al., 2011). According to apatite fission track thermochronology studies (e.g., Tinker et al., 2008), major exhumation of the Karoo Basin occurred in the middle and late Cretaceous (~140- 80 Ma) with low rates of denudation since that time.

Karoo Basin petroleum potential

Due to the generally low porosity and permeability of potential conventional reservoirs as well as the thermal effects of Karoo dolerite intrusion and prolonged deep burial, mid-20th Century exploration efforts for conventional oil resources in the Karoo Basin were unsuccessful (Rowsell and de Swardt, 1976; Rowsell and Conan, 1979). However, a large number of applications have been received for petroleum exploration rights in the Karoo since 2004, when the Mineral and Petroleum Resources Development Act of 2002 became effective.

Petroleum potential in the Karoo basins varies from north to south with increasing thermal maturity. The northern Main Karoo Basin and subsidiary basins are characterised by having oil and coalbed methane potential, with shale gas being the principal exploration target in the south-western Main Karoo Basin. In addition, Karoo strata that overly the Archean metasediments of the Witwatersrand Supergroup have been shown to be of commercial interest for the production of microbial gas.

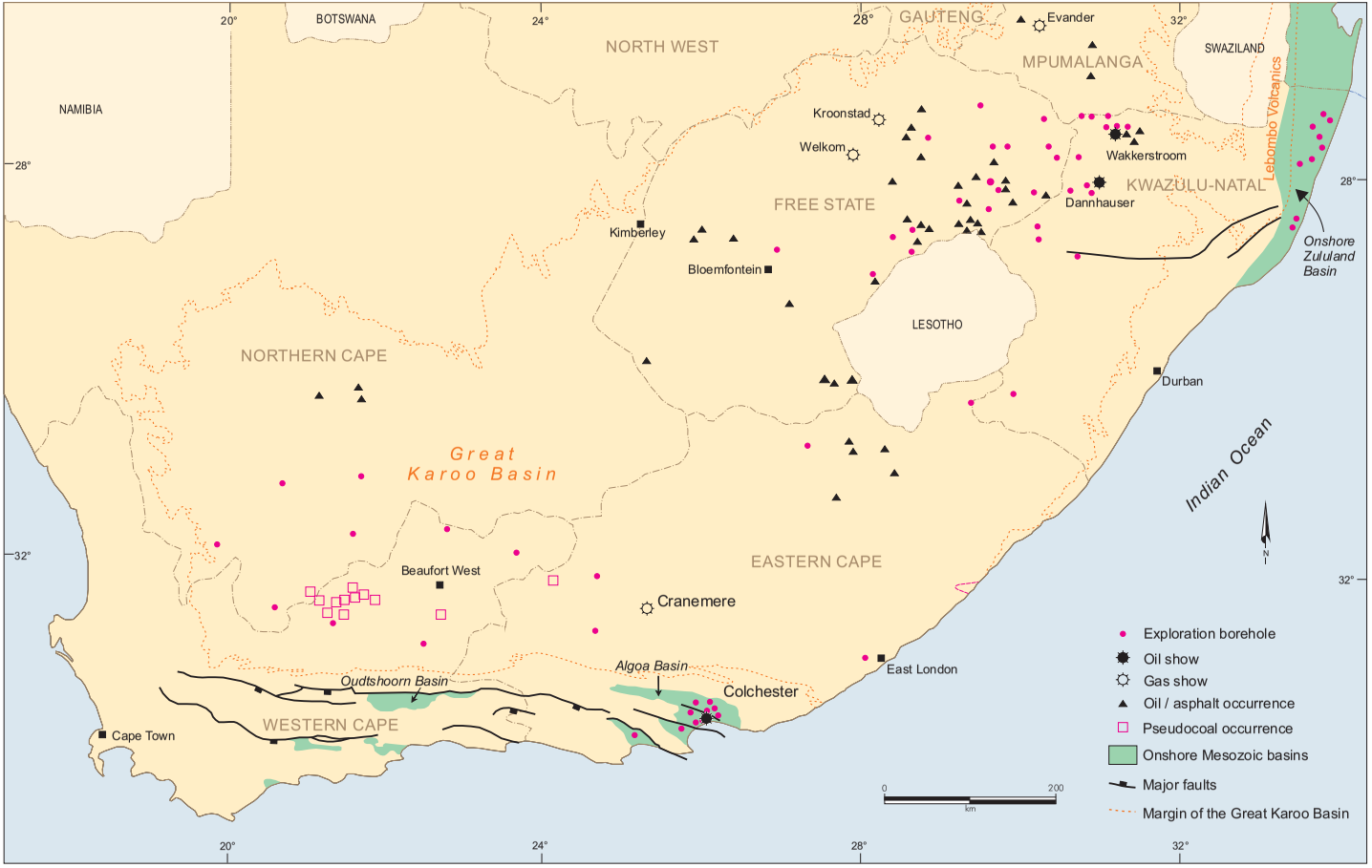
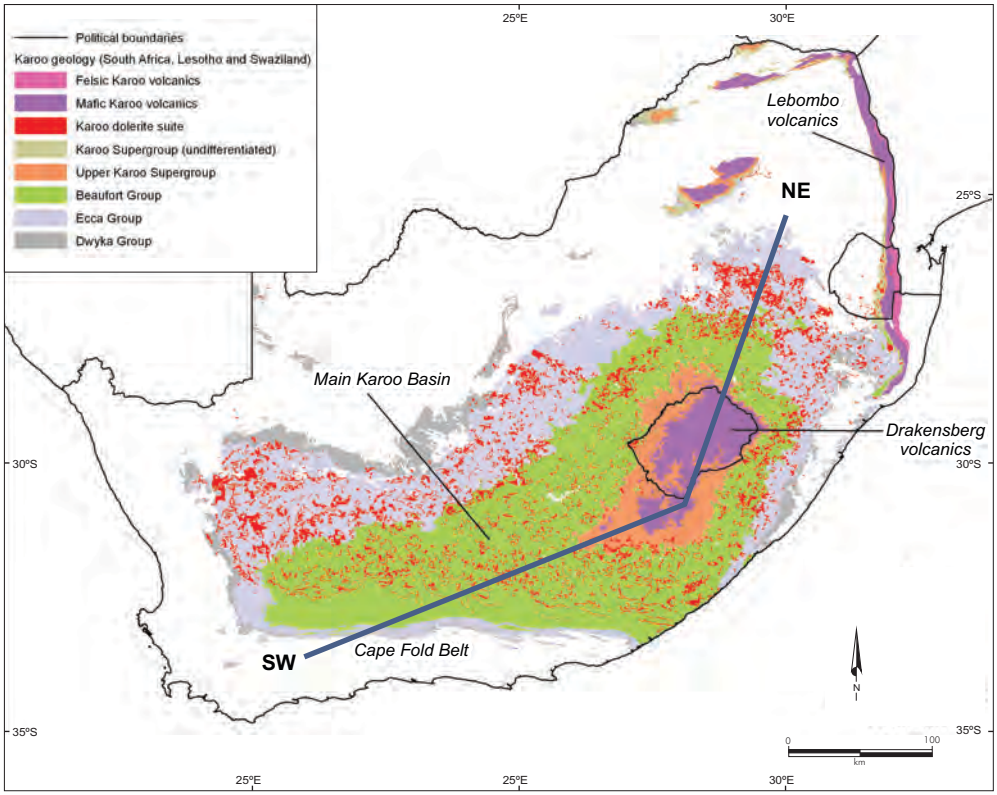


Figure 30. Exploration boreholes and oil shows of the Karoo and other onshore basins (after van Vuuren, et al., 1998).



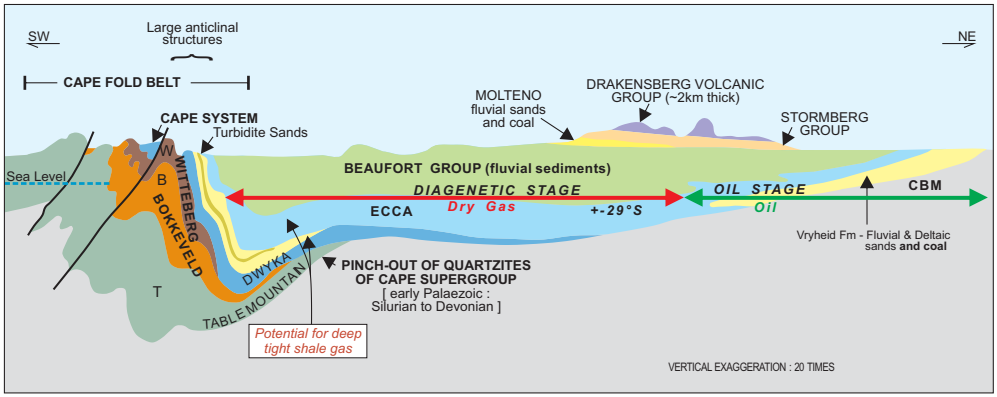


Figure 31. Geological map of the Karoo Basins of South Africa (top), and schematic SW-NE cross-section of the Main Karoo Basin (bottom).

COALBED METHANE

Coalbed methane (CBM) is sourced from coal seams and has become an important unconventional source of natural gas globally. Historically, in South Africa's coal mining operations, methane gas discharge from coal has been a safety hazard and the primary cause of underground mine explosions. There is therefore potential to create a synergistic relationship between exploration for coal and exploitation of CBM. The development of the resource is strategically important and if proven to be economically feasible provides an energy source that will address South Africa's growing energy demand. In addition, by comparison to coal and oil, methane is a cleaner form of energy as it emits less CO2 per unit of energy released.

Coal Occurrence

Coal seams are hosted in Early to Late Permian and Triassic-aged rocks of the Karoo Supergroup (Cairncross, 2001). Overall, South Africa's coal deposits occur in 19 coalfields distributed across the Main Karoo Basin and extensional rift-related sub-basins namely, Springbok Flats, Lephalale, Tshipise, and Tuli basins (Figure 32). Coals are predominantly high to medium volatile bituminous rank, and there is a general trend of increasing rank from west to east, across South African coalfields (Cairncross, 2001).

CBM Resource Potential

Exploration for coal during the past 30 years and more has significantly increased the knowledge base and understanding of the distribution of coal in South Africa. This knowledge base together with more recent exploration results for CBM has confirmed the presence of potentially economic volumes of methane in South African coals. The results of exploration efforts at the time by Anglo American Thermal Coal, Badimo Gas in partnership with Kinetiko Energy and Umbono Capital in partnership with Sunbird Energy, suggests that the most prospective areas for CBM development at present occur in the Waterberg coalfield in the Lephalale Basin, Ermelo coalfield in the Main Karoo Basin, and Mopane coalfield in the Tshipise Basin. In addition, access to over 2000 coal exploration core holes and analysis data has aided with the evaluation of the CBM resource potential for the Springbok Flats Basin. The following section provides an overview of the CBM resource potential of the prospective basins described above.

CBM Prospectivity

Lephalale

The Lephalale Basin containing the Waterberg coalfields is the most promising area for CBM production. This region hosts 40 % of South Africa's remaining coal resources. The coals, which have high vitrinite content, are up to 70 m thick (net coal) and buried to depths greater than 250 m. Over 80 exploration core holes have been drilled and this includes a 5-spot pilot production well array. Total gas-in-place resources of 3.5 Tcf and contingent (2C) resources of 1.5 Tcf are reported for the Lephalale CBM project.

Ermelo Coalfield

The Majuba coal colliery near Amersfoort was intended to supply the Majuba Power Station; however underground mine explosions associated with high concentrations of methane gas in the coal resulted in closure of the colliery in 1993. Average depths to the most significant coal seams range from 315 to 385m and coal thicknesses range from less than 1m to 16m. The coals vary in rank from high volatile bituminous to medium bituminous. Best estimate gas-in-place resources of 6.9 Tcf and contingent (2C) resources of 4.5 Tcf are reported for the Amersfoort CBM project.

Springbok Flats

There is currently no mining activity in the Springbok Flats coalfields and the basin is largely untested, but it appears to have good CBM potential. The coal seams, which are 3m to 9m thick, with a net thickness of up to 18m in places (Roberts, 1992), are buried to a depth of more than 600m and have high vitrinite content. Prospective gas-in-place resources of 5 Tcf has been assessed for the basin.

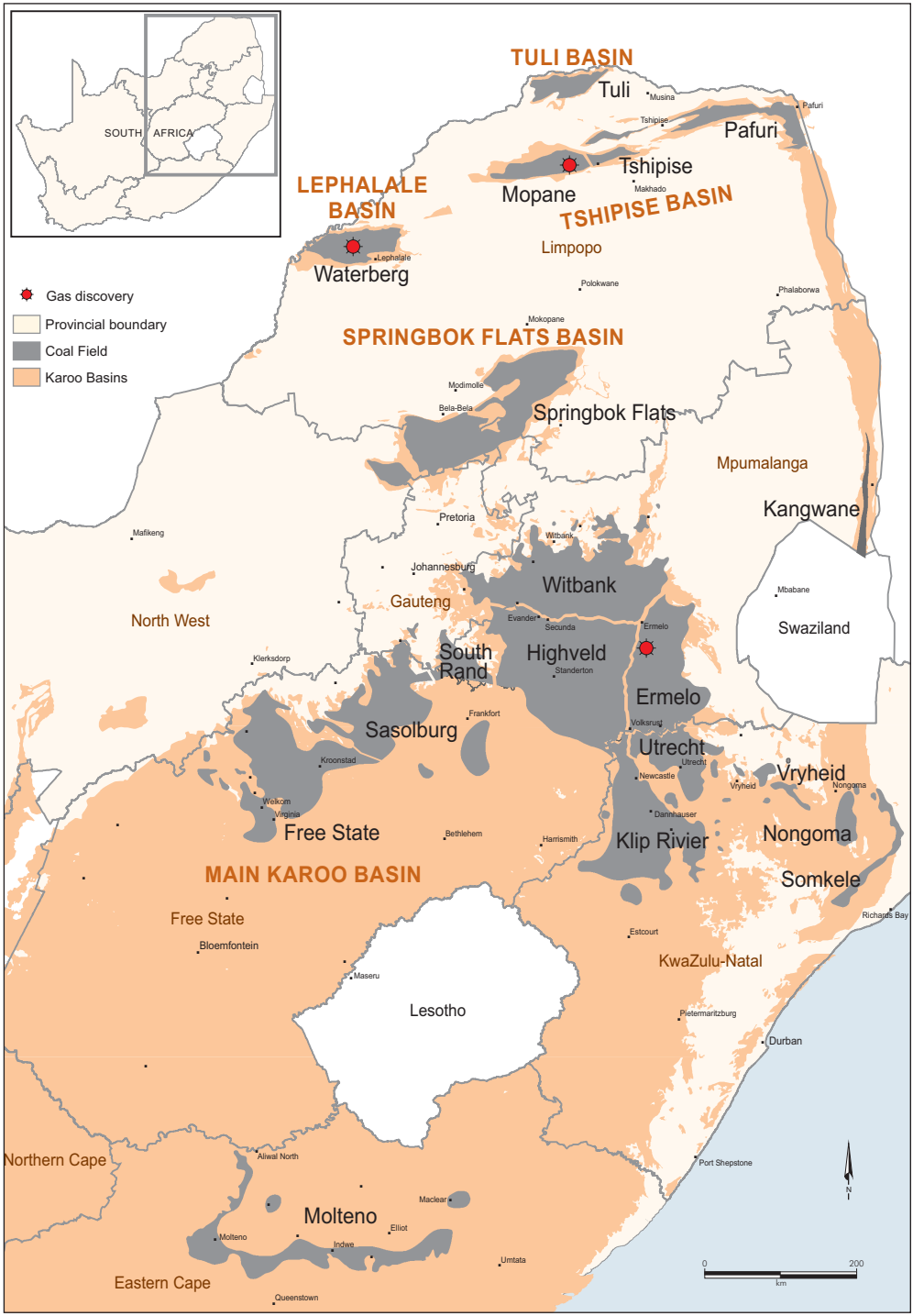


Figure 32. Distribution of coal fields in the Karoo-aged basins in South Africa (digital geological data sourced from Council for Geoscience)

DEEP BIOGENIC (MICROBIAL) GAS

The methane encountered in underground gold mining of the Archean Witwatersrand Basin in the Free State and Evander goldfields (Figure 33) was regarded only as a mine explosion hazard and flared in large quantities. Local gas shows at surface have also been known to burn for years without showing any evidence of depletion.

Substantial quantities of hydrocarbon gases have been observed within the Witwatersrand Basin during both coal and gold exploration activities (Hugo, 1963). The gas is composed predominantly of methane, and other gases including helium. Gas encountered is not generally contained in traps but rather is being continually generated at depth and migrating to surface along natural fracture systems, faults and dykes. A number of published analyses (Ward et al., 2004; Sherwood-Lollar et al., 2006; 2008) indicate that much of the produced gas is of microbial origin, generated by primitive bacteria that inhabit deep water-bearing fissures.

It is thought that additional gas may be generated within the shale or coal-bearing Karoo strata. However, despite recent advances, knowledge about microbially mediated processes in the subsurface is still in its infancy. The source and migration pathway of the gas are unusual and present significant challenges to fully define the ultimate potential of the resources as no known analogues exist for this type of gas production.

Play types

The presence of hydrocarbons is, to a large extent, controlled by the geologic formations in which the gases are found. Possible traps or play types have been suggested to account for hydrocarbon gas to migrate up through faults/joints and become trapped within these fractures or sealed by Karoo Supergroup. The following plays are evident and supported by existing well data:

- Primary Play - comprises natural fractures (joint/faults) associated with major faults/folds in the Archean Witwatersrand Basin.
- Secondary Play - found within the Karoo Supergroup mainly Karoo sandstones sealed by claystone/siltstone and volcanics.

Hydrocarbon shows / production are associated with:

- Karoo Ecca / Dwyka Group
- Ventersdorp Supergroup
- Witwatersrand Supergroup

The Free State and Evander goldfields are structurally complex, with crustal fracture zones bounded by major faults. The abundance of semi-vertical cross-cutting dykes, kimberlite fissures and fractures throughout the Witwatersrand Basin suggest the potential for gas migration and transport along these structures.

Resource Potential

The only gas production right onshore South Africa has been granted over the Virginia Gas Project in the Free State. The source of natural gas is primarily microbial and originates from deep within the Witwatersrand Supergroup, via groundwater circulating through large faults and contacting bacteria deep within the earth's crust.

The methane is biogenic and a continuing renewable resource. The natural gas contains one of the richest helium concentrations recorded globally. Proven methane gas reserves (1P) of 215 Bcf and 7 Bcf of Helium are reported for the project.

Local gas shows at surface (courtesy of Molopo Energy Ltd)

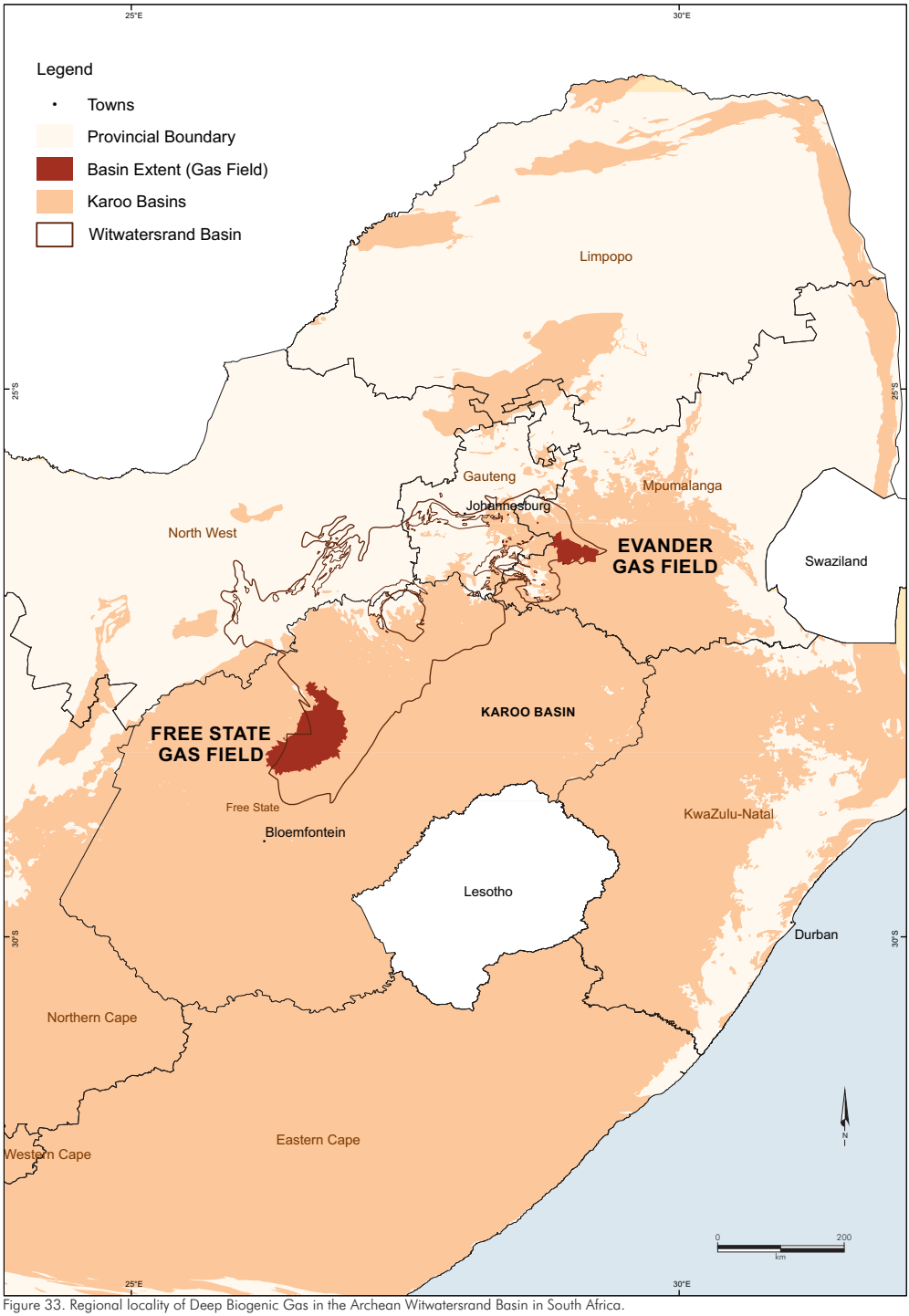


Figure 33. Regional locality of Deep Biogenic Gas in the Archean Witwatersrand Basin in South Africa.

SHALE GAS

Resource potential

There is significant international interest in the Main Karoo Basin's shale gas potential at present. A report commissioned by the U.S. Energy Information Administration (Kuuskraa et al., 2013) proposed that the Karoo hosts a technically recoverable shale gas resource of 370 Tcf. Petroleum Agency SA's own ongoing research suggests that a smaller but nevertheless significant recoverable resource of the order of tens of Tcf is more probable. However, shale gas exploration in the Karoo remains at a very early stage, making any resource estimate necessarily speculative. The only production test of any significance in the region dates from 1968, when Soekor well CR1/68 near Pearston yielded a gas flow rate of 1.83 mmscf/day for 23 hours from natural fractures in the Fort Brown Formation shale. The Fort Brown was considered to be self-sourcing at the time but may also have been charged by the underlying Whitehill Formation.

Prospectivity indicators

The Permian-aged lower Ecca Group in the southern Main Karoo Basin is comprised of several fine-grained formations of variable prospectivity. Of these, the Whitehill Formation is considered the most prospective for shale gas.

The Whitehill Formation's depositional environment is a subject of some debate, with contrasting epeiric marine and brackish lacustrine models being proposed (Faure and Cole, 1999). However, the formation is characterised by high total organic carbon content (up to 14%; average 4.5 %), high thermal maturity (Ro = 1-4 %), high quartz content (50 % average with carbonate-rich intervals) and sufficient thickness for commercial development (35 m average). Legacy exploration data demonstrates that it is regionally continuous over some 200,000 km^2 and buried to depths of up to 4 km in the extreme south of the basin.

Additional positive indicators include numerous gas shows in the lower Ecca Group and underlying Dwyka Group in the southern Karoo Basin and the occurrence of pyrobitumen (pseudo-coal) in fissures, indicating the existence of an originally oil-prone source rock.

Risk and uncertainty

Intrusions of the Karoo dolerite suite outcrop across much of the Main Karoo Basin, with the exception the deep southern marginal zone. While their subsurface geometry and distribution is not well understood at present, it is possible that intrusion of the dolerite magma may have resulted in the fracturing, contact metamorphism and degassing of shales in places, resulting in reservoir compartmentalization. However, Karoo dolerites have also been reported to serve as cap rocks for conventional traps, and even serve as hydrocarbon reservoirs where fracture porosity exists (e.g., Hall, 1929).

High maturities along the basin's southern margin (the Cape Fold Belt) indicate graphite-facies metamorphism of the Whitehill Formation (e.g., Branch et al. 2007), with maturities decreasing northwards. The effect of high maturity on the gas content of the Whitehill remains to be determined, with no gas content measurements of fresh deep core currently available.

Comparisons with analogue shale plays suggests that the Whitehill Formation may be the most prospective in areas of distal deposition, where stratigraphic thicknesses greater than 30 m are buried to depths greater than 1.5 km but not subjected to maturities greater than 3.5 % Ro, and where sub-surface dolerite intrusions are minor or absent (Figure 34).

Outlook

The long-term market for gas in South Africa is likely to be strong, as the country's economy develops and the demand for energy grows. However, a significant investment in exploration and infrastructure will be required in the sparsely populated, ecologically sensitive and economically disadvantaged Karoo region if sustainable shale gas development is to become a reality.

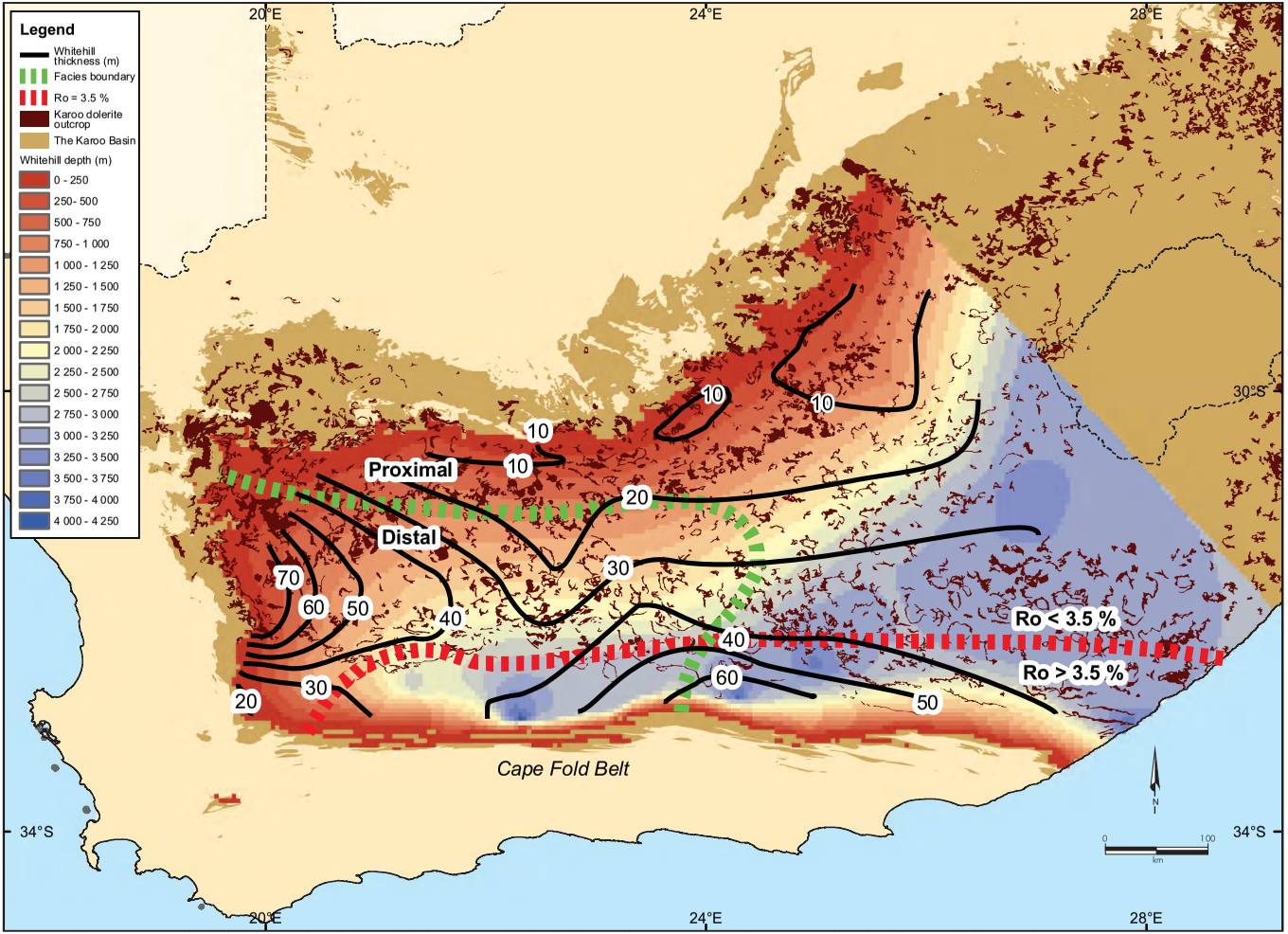


Figure 34. The prospective Whitehill shale gas play. Thickness (black contours), depth (shading) and maturity (red stipples) contours based on legacy well data are shown. Also indicated is the surface distribution of Karoo dolerite and the approximate boundary between proximal and distal facies (green stipples) (after Visser, 1992).

Special Project

UNCLOS 1982 and the Extended Continental Shelf Claim Project

UNCLOS 82 is a remarkable international agreement intended to ensure responsible management of the world's oceans. Under maritime law a coastal state has sovereign right to a number of maritime zones including the Territorial Sea (up to 22kms from shore), the Contiguous zone (44 kilometres from shore) and the Exclusive Economic Zone (370 kilometres from shore). Article 76 of the Convention makes provision for states to claim an additional zone called the Extended Continental Shelf. This is intended to include the submarine plateaus and ridges that extend from the continental margins of coastal states beyond their exclusive economic zone limits. Each coastal state is responsible for the management of these zones according to the provisions of international law, with the remaining unclaimed areas being managed by the United Nations International Seabed Authority in trust for humanity.

The area under cover of South Africa's submissions, jointly amount to approximately 1.87 million square kilometers, if endorsed by the United Nations, will more than double South Africa's maritime territory (see figure 35).

The potential of this opportunity was initially recognized as being of national importance during the 1980s. The SA Navy Hydrographic Office with the assistance of the Institute for Maritime Technology carried out the initial investigations and lobbied for the establishment of a dedicated national project. This successfully resulted in a Cabinet decision to allocate responsibility to the Minister of the then Department of Minerals and Energy, who directed the Petroleum Agency to manage the project. The project officially started in April 2003 and the technical study took 6 years to complete. Initial phases included the search for and acquisition of existing and new data.

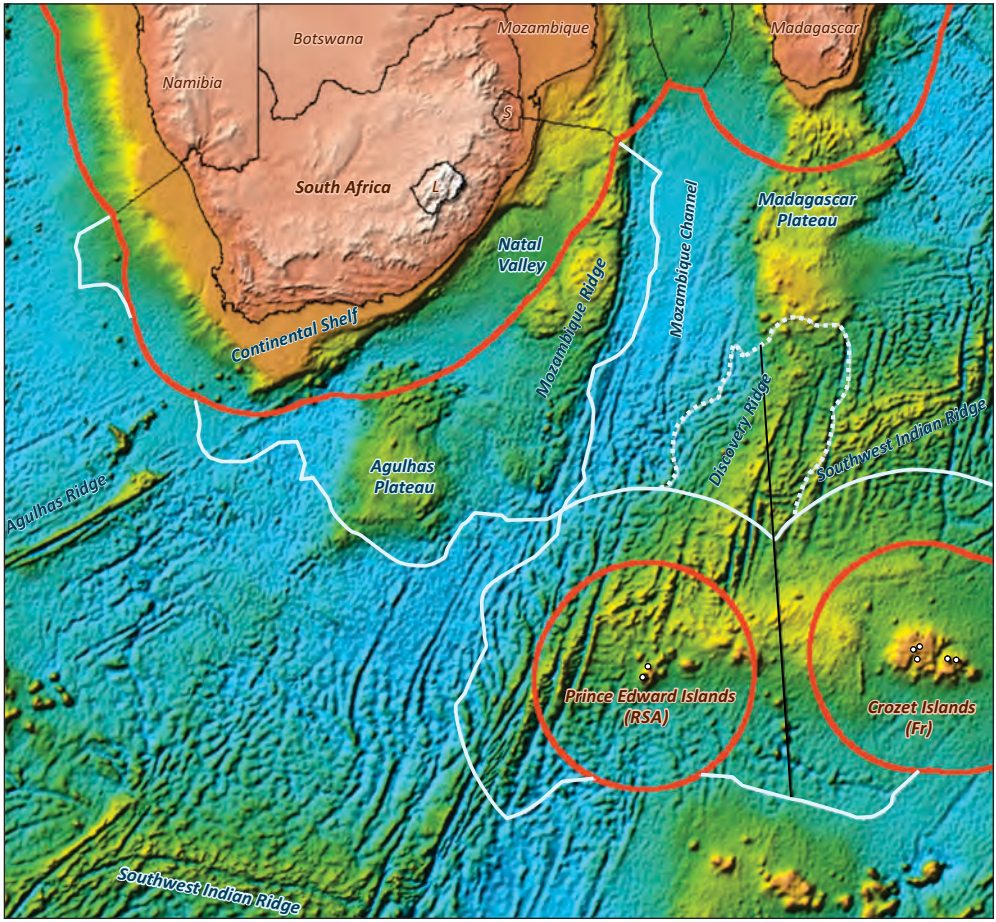
This was followed by the application of the scientific and legal principles prescribed by Article 76 of UNCLOS and the compilation of the submission documents and appendices. Finally, these were lodged with the United Nations in May 2009.

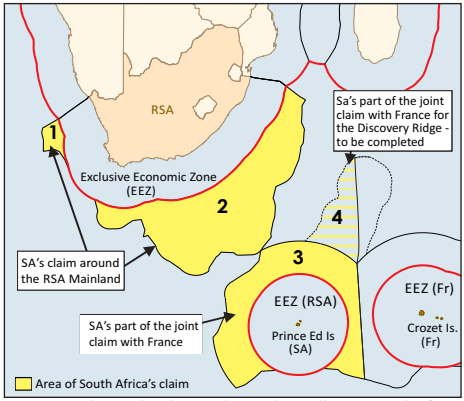
Benefits for the Nation

Many benefits beyond the acquisition of the extra territory were realized during this process. These included, inter alia, the identification and accessing of vast tracts of existing geophysical and hydrological data for the benefit of the State; the acquisition of new survey data; the building of international contacts and the close cooperation with France which led to the agreement to lodge a joint claim around the South African Prince Edward and French Crozet Islands.

It is important to remember that the rights to an Extended Continental Shelf zone are limited to mineral and living resources on and under the sea floor and that conventional fish stocks are not included. The benefits of the acquisition of the new territory is however still numerous. These include the potential for mineral resources including oil and gas, manganese nodules and crusts possibly enriched with precious metals. And, in the vicinity of the Prince Edward Islands, the possibility exists of discovering gold-bearing hydrothermal deposits and of exploiting the pharmaceutical and medical benefits of microbes associated with the inhospitable ultra-deep ocean floor and toxic hot water geysers. Many of these benefits are not immediately quantifiable or exploitable with current knowledge and technology, but through this project future access to these has been assured for coming generations of South Africans.

The successful completion of this part of the project represents an historic event for South Africa. If endorsed, South Africa will control one of the largest maritime territories in the world. With this, should come not only a renewed sense of national pride but also the realization of South Africa's huge obligation to contribute to the responsible management of the world's oceans in order to ensure that their productivity and ecological balance is maintained for future generations.





SOUTH AFRICA'S EXISTING TERRITORY	Area (sq kms)
Land - RSA Mainland	1,220,000
Sea - EEZ of RSA Mainland & Prince Edward Islands	1,540,000
NEW EXTENDED CONTINENTAL SHELF	
1. West Coast	45,000
2. East and South Coast	1,075,000
3. Prince Edward Islands	560,000
4. Discovery Ridge (to be submitted) - SA's part (50%)	~190,000
Total Area of Claim	**1,870,000**

Figure 35. White outlined areas shown above, illustrate South Africa's Extended Continental Shelf Claim.

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USEFUL WEBSITES

Petroleum Agency SA (PASA)
www.petroleumagencysa.com

Department of Mineral Resources Department of Energy (DMRE)
www.dmre.gov.za

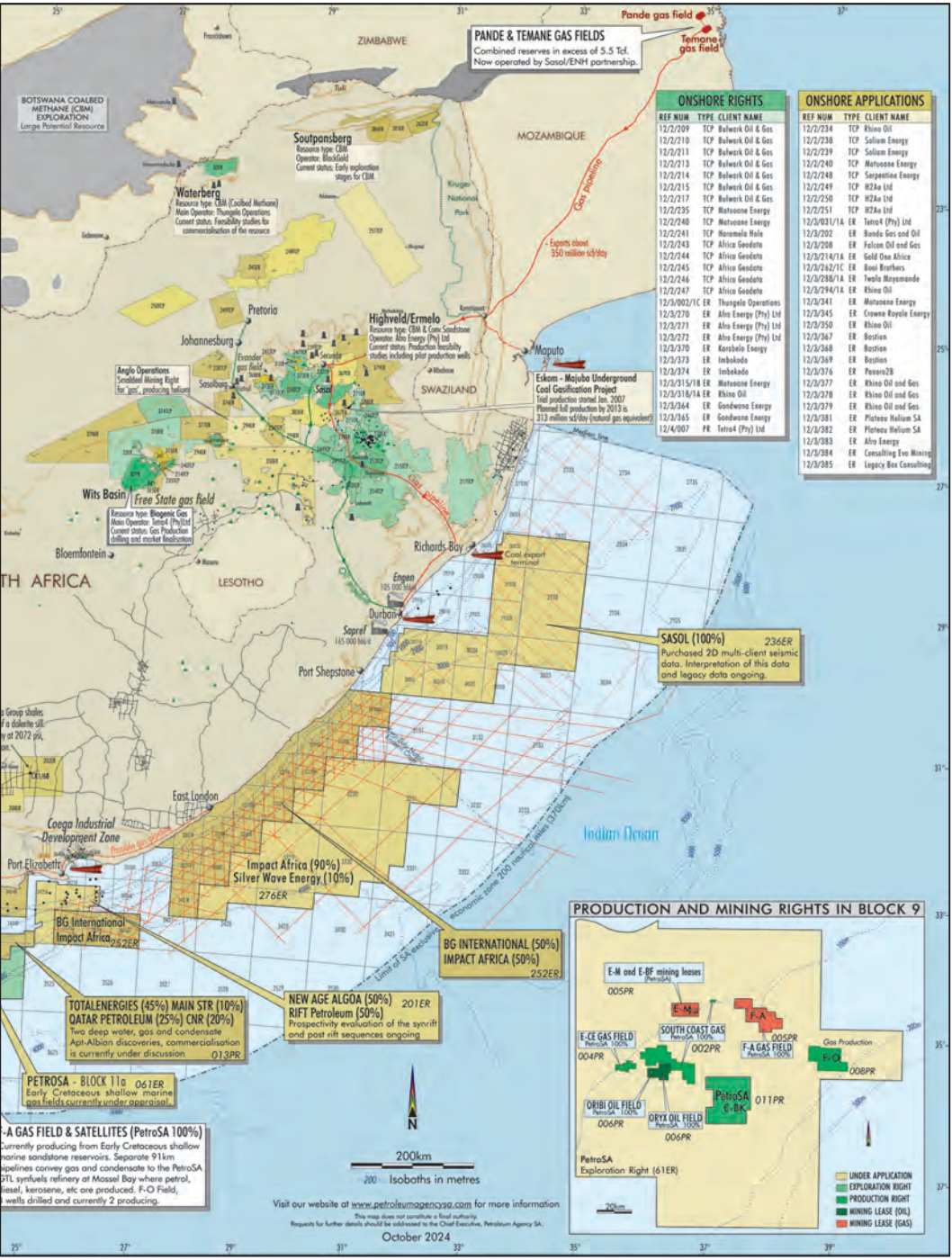
CEF Group of Companies (CEF)
www.cef.org.za

National Energy Regulator of South Africa (NERSA)
www.nersa.org.za

PetroSA
www.petrosa.co.za

Strategic Fuel Fund (SFF)
www.strategicfuelfund.co.za

PETROLEUM EXPLORATION AND PRODUCTION ACTIVITIES IN SOUTH AFRICA


PANDE & TEMANE GAS FIELDS
Combined reserves in excess of 5.5 Tcf.
Now operated by Sasol/ENH partnership.
Pande gas field
Temane gas field
ONSHORE RIGHTS
REF NUM TYPE CLIENT NAME
12/2/209 TCP Bulwark Oil & Gas
12/2/210 TCP Bulwark Oil & Gas
12/2/211 TCP Bulwark Oil & Gas
12/2/213 TCP Bulwark Oil & Gas
12/2/214 TCP Bulwark Oil & Gas
12/2/215 TCP Bulwark Oil & Gas
12/2/217 TCP Bulwark Oil & Gas
12/2/235 TCP Matoome Energy
12/2/240 TCP Matoome Energy
12/2/241 TCP Horomelo Hole
12/2/243 TCP Africa Geodata
12/2/244 TCP Africa Geodata
12/2/245 TCP Africa Geodata
12/2/246 TCP Africa Geodata
12/2/247 TCP Africa Geodata
12/3/002/1C ER Thungela Operations
12/3/270 ER Afro Energy (Pty) Ltd
12/3/271 ER Afro Energy (Pty) Ltd
12/3/272 ER Afro Energy (Pty) Ltd
12/3/370 ER Karabela Energy
12/3/373 ER Imbokodo
12/3/374 ER Imbokodo
12/3/315/18 ER Matoome Energy
12/3/318/1A ER Rhino Oil
12/3/364 ER Gondwana Energy
12/3/365 ER Gondwana Energy
12/4/007 PR Tetra4 (Pty) Ltd
ONSHORE APPLICATIONS
REF NUM TYPE CLIENT NAME
12/2/234 TCP Rhino Oil
12/2/238 TCP Soliam Energy
12/2/239 TCP Soliam Energy
12/2/240 TCP Matoome Energy
12/2/248 TCP Serpentine Energy
12/2/249 TCP H2Au Ltd
12/2/250 TCP H2Au Ltd
12/2/251 TCP H2Au Ltd
12/3/031/1A ER Tetra4 (Pty) Ltd
12/3/202 ER Bundu Gas and Oil
12/3/208 ER Falcon Oil and Gas
12/3/214/1A ER Gold One Africa
12/3/262/1C ER Booi Brothers
12/3/288/1A ER Twala Moyamande
12/3/294/1A ER Rhino Oil
12/3/341 ER Matoome Energy
12/3/345 ER Crowne Royale Energy
12/3/350 ER Rhino Oil
12/3/367 ER Bostion
12/3/368 ER Bostion
12/3/369 ER Bostion
12/3/376 ER Panoro28
12/3/377 ER Rhino Oil and Gas
12/3/378 ER Rhino Oil and Gas
12/3/379 ER Rhino Oil and Gas
12/3/381 ER Plateau Helium SA
12/3/382 ER Plateau Helium SA
12/3/383 ER Afro Energy
12/3/384 ER Consulting Evo Mining
12/3/385 ER Legacy Box Consulting
BOTSWANA COALBED METHANE (CBM) EXPLORATION
Large Potential Resource
Soutpansberg
Resource type: CBM
Operator: BlackGold
Current status: Early exploration stages for CBM
Waterberg
Resource type: CBM (Coalbed Methane)
Main Operator: Thungela Operations
Current status: Feasibility studies for commercialisation of the resource
Highveld/Ermelo
Resource type: CBM & Coal-Sandstone
Operator: Afro Energy (Pty) Ltd
Current status: Production feasibility studies including pilot production wells
Anglo Operations
Sasolburg Mining Right for 'gas', producing helium
Wits Basin
Free State gas field
Resource type: Biogenic Gas
Main Operator: Tetra4 (Pty)Ltd
Current status: Gas Production drilling and market finalisation
Eskom - Majuba Underground Coal Gasification Project
Trial production started Jan. 2007
Planned full production by 2013 is 313 million scf/day (natural gas equivalent)
Gas pipeline
- Exports about 350 million scf/day
Coal export terminal
Enpen
105 000 bbl/d
Sapref
165 000 bbl/d
SASOL (100%) 236ER
Purchased 2D multi-client seismic data. Interpretation of this data and legacy data ongoing.
Impact Africa (90%)
Silver Wave Energy (10%)
276ER
BG International
Impact Africa 252ER
BG INTERNATIONAL (50%)
IMPACT AFRICA (50%)
252ER
TOTALENERGIES (45%) MAIN STR (10%)
QATAR PETROLEUM (25%) CNR (20%)
Two deep water, gas and condensate Apt-Albian discoveries, commercialisation is currently under discussion 013PR
NEW AGE ALGOA (50%)
RIFT Petroleum (50%) 201ER
Prospectivity evaluation of the synrift and post rift sequences ongoing
PETROSA - BLOCK 11a 061ER
Early Cretaceous shallow marine gas fields currently under appraisal.
-A GAS FIELD & SATELLITES (PetroSA 100%)
Currently producing from Early Cretaceous shallow marine sandstone reservoirs. Separate 91km pipelines convey gas and condensate to the PetroSA GTL synfuels refinery at Mossel Bay where petrol, diesel, kerosene, etc are produced. F-O Field, wells drilled and currently 2 producing.
PRODUCTION AND MINING RIGHTS IN BLOCK 9
E-M and E-BF mining leases
005PR
E-M
F-A
SOUTH COAST GAS
002PR
005PR
E-CE GAS FIELD
004PR
F-A GAS FIELD
Gas Production
F-O
008PR
ORIBI OIL FIELD
006PR
ORYX OIL FIELD
006PR
PetroSA E-BK
011PR
PetroSA
Exploration Right (61ER)
UNDER APPLICATION
EXPLORATION RIGHT
PRODUCTION RIGHT
MINING LEASE (OIL)
MINING LEASE (GAS)
ZIMBABWE
MOZAMBIQUE
SWAZILAND
LESOTHO
TH AFRICA
Pretoria
Johannesburg
Maputo
Richards Bay
Durban
Port Shepstone
East London
Port Elizabeth
Bloemfontein
Coega Industrial Development Zone
Indian Ocean
Kruger National Park
Gas Pipeline
Limit of SA exclusive economic zone 200 nautical miles (370km)
N
200km
200 Isobaths in metres
Visit our website at www.petroleumagencysa.com for more information
This map does not constitute a final authority.
Requests for further details should be addressed to the Chief Executive, Petroleum Agency SA.
October 2024

DATA PACKAGES

A variety of information and data packages are available from the Agency. These packages contain well and seismic data together with short reports describing the petroleum potential. Interested investors are welcome to visit the Agency's data room in Cape Town to view data and to obtain further information on exploration opportunities.

MORE INFORMATION

Interested parties are invited to contact the Agency for further information concerning technical, legal and contractual details or for any other queries regarding participation in exploration and production in South Africa.

October 2024

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