Nova Scotia Prospect Profile Offshore 2010

NOVA SCOTIA
Department of Energy

Information as of January 2010

1 mile	**=**	**1.6093 km**
1 square mile	**=**	**2.5898 sq km**
1 cubic foot	**=**	**0.0283 cubic metres**
1 million cubic feet	**=**	**28,317 cubic metres**
1 trillion cubic feet	**=**	**28.317 x 109 cubic metres**

With a competitive fiscal regime, proximity to North American markets and strong potential for additional commercial reserves, Nova Scotia offers a competitive advantage in offshore exploration and development.

Add to that our commitment to continue to streamline our regulatory processes and a business community that is gaining a worldwide reputation for excellence in engineering, fabrication and supply and services; it's easy to see why Nova Scotia continues to attract attention.

The Nova Scotia Prospect Profile Offshore 2010 provides you with a glimpse of the opportunities and potential in Nova Scotia's offshore.

The Nova Scotia Department of Energy

The Department of Energy promotes, supports and coordinates, administers and sets policy on the development of a prosperous, clean, efficient, and sustainable energy industry in Nova Scotia. Our mission is to help Nova Scotians build a better future by ensuring responsible resource management of Nova Scotia's energy resources, and by maximizing the financial, economic, industrial, and employment benefits that flow from our energy resources.

The Department creates the policy, legislation, and regulations for the exploration and development of Nova Scotia's offshore and onshore petroleum resources. In the onshore, the Department administers the granting of petroleum rights and coordinates the regulation of exploration activity. The Canada-Nova Scotia Offshore Petroleum Board regulates day-to-day offshore petroleum activity while the Department promotes Nova Scotia's onshore and offshore petroleum potential.

Visit our web site at **www.gov.ns.ca/energy** for additional information.

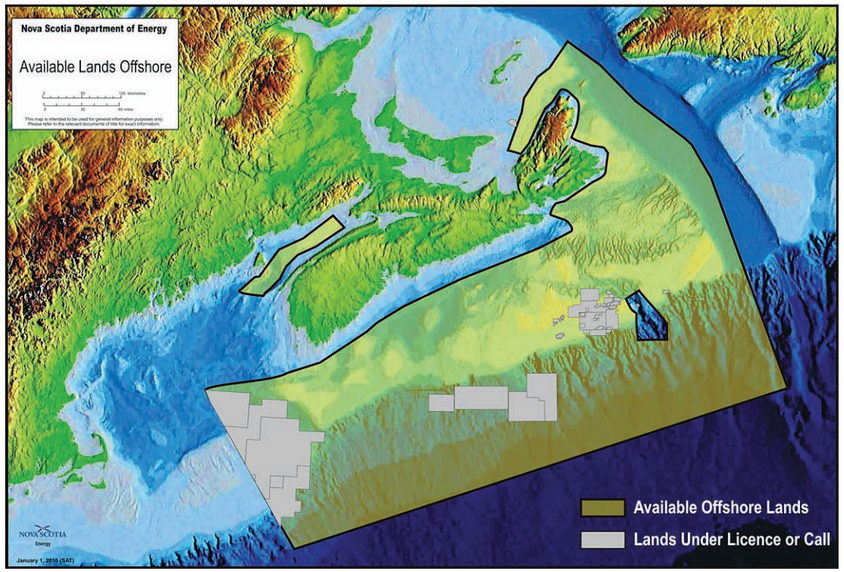
The Canada-Nova Scotia Offshore Petroleum Board

The Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) regulates petroleum activities offshore Nova Scotia in an efficient, fair and competent manner. The Board is the independent joint agency of the Governments of Canada and Nova Scotia established pursuant to the federal **Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation Act** and the provincial **Canada-Nova Scotia Offshore Petroleum Resources Accord Implementation (Nova Scotia) Act**.

The Board's responsibilities include:

- ensuring the safe conduct of offshore operations
- protecting the environment during offshore petroleum activities
- managing offshore oil and gas resources
- reviewing industrial benefits and employment opportunities
- issuing licences for offshore exploration and development
- collecting, evaluating and distributing resource data.

Visit them at **www.cnsopb.ns.ca** for additional information.



- Crown Reserve Lands
- Call for Nominations
- Call for Bids/Public Consultation
- Exploration Licence
- Significant Discovery Licence
- Production Licence

PETROLEUM RIGHTS offshore Nova Scotia are managed by the CNSOPB and are based on the *Canadian Petroleum Resources Act* model. The main components include:

Crown Reserve Lands
These are lands over which no interest has been issued. Interests in Crown Reserve lands are issued through a competitive bidding process. Details of the rights issuance process are described in the Board publication, **"Guidelines On the Issuance Of Exploration Licences."**

Call for Nominations
The Board relies on industry to nominate lands. Nominations can be submitted at anytime; however, the Board has established a semi-annual cycle for a June and December Call for Bids. The closing dates to nominate lands for consideration in the June and December Call for Bids are March 31st and September 30th, respectively.

Call for Bids/Public Consultation
Once the land has been nominated, the Board will start the process to issue a Call for Bids and request for public comments. The Call for Bids specifies;

- the type of interest to be issued (Exploration Licence (EL), Significant Discovery Licence (SDL) or Production Licence (PL);
- the terms and conditions of the interest:
- the form and manner in which the bid is to be submitted;
- a closing date (120 days from issuance); and
- the sole criterion that the Board will apply in assessing bids submitted in response to the Call.

For the most recent Call information, please visit www.cnsopb.ns.ca

All bids for Exploration Licenses (EL's) are evaluated on the basis of total work expenditures or the amount of money to be committed on exploration on the subject lands during Period I (see Exploration License (EL) below) of the term. In addition, the Board invites written public comment, and after reviewing both the comments and bids, will determine whether or not to issue an EL. This is not an automatic decision.

Where Significant Discovery Licenses (SDL) or Production Licenses (PL) are posted, the Board may specify that cash bidding will be used as the sole criterion. Work Expenditure bids of less than $1 million CDN are not considered.

Within 15 days of being notified the bid has been accepted, the successful bidder must provide a work deposit equal to 25 per cent of the work expenditure bid. The deposit is refunded annually in proportion to the amount of the work expenditure bid that is expended in that year as determined in accordance with the allowable expenditures included. Any work deposit balance remaining at the end of the specified period is forfeited.

Exploration License (EL)
This license is issued to an explorer for a term up to nine years on lands that do not contain significant discoveries or, in effect, wildcat acreage. The Exploration License specifies the owner must start drilling a well before the first period expires (generally 5 years). If this is not done, the EL terminates at the end of the first period. There are no rentals paid in Period I. Period II (generally 4 years) rentals are refundable against allowable expenditures. The EL confers the following:

- the right to explore the subject lands;
- the exclusive right to drill and test for petroleum on those lands; and
- the exclusive right to obtain a Production License.

Significant Discovery License (SDL)
The SDL is an intermediate interest intended to maintain an explorer's rights during the period between the first discovery and eventual production. After a discovery has been made, the explorer may apply to have it declared a Significant Discovery (SD) defined by the first well on a geological feature that demonstrates by flow testing the existence of hydrocarbons and suggests that the accumulation of hydrocarbons has potential for sustained production.

Once a SD has been declared, the holder of the EL may then apply for an SDL for all portions of the significant discovery area located on the EL. An SDL confers the same rights as an EL but has an indefinite term.

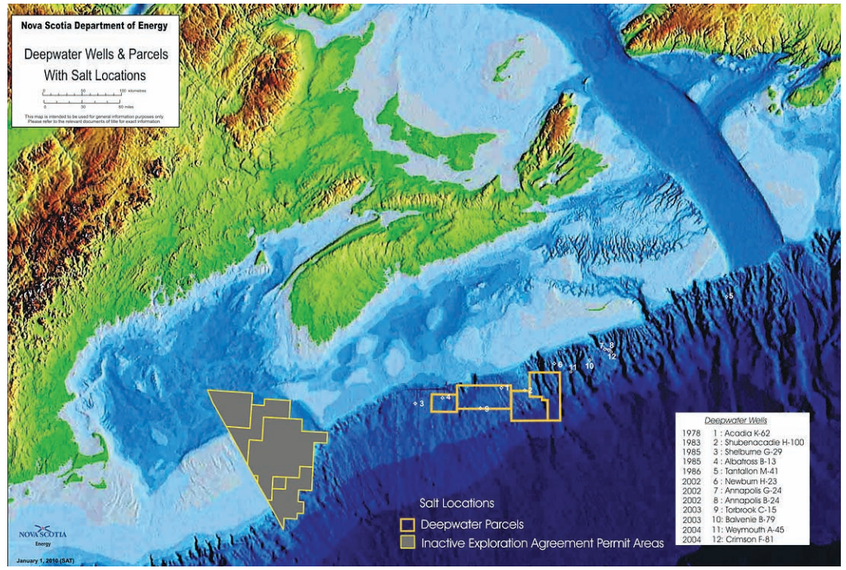
When a declaration of SD extends to Crown Reserve Lands, these lands may be posted for bid and an SDL may be issued to the winning bidder.

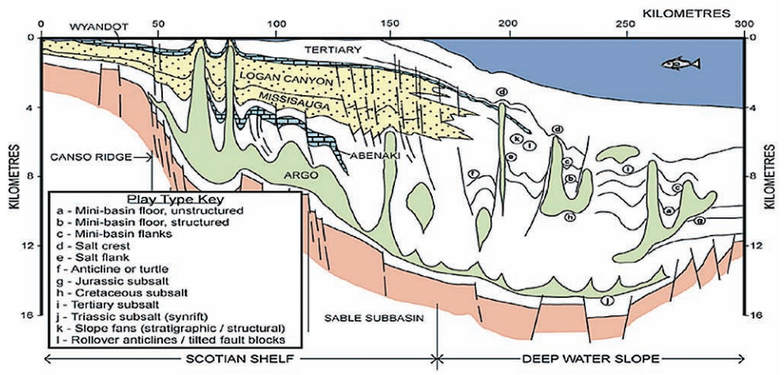
Production Licence (PL)
Production rights are conferred by the issuance of a Production License (PL), which may be issued in respect of any portion of the offshore area subject to a commercial discovery. A commercial discovery is one that has demonstrated it contains reserves that will justify the investment of capital and effort to bring the discovery to production. No PL may be held by any person other than a corporation incorporated in Canada.
A PL has a term of 25 years but may be extended if commercial production is continuing or is likely to recommence.

To help stimulate exploration activity, the governments of Nova Scotia and Newfoundland and Labrador and the CNSOPB have met with industry to find ways to encourage wells to be drilled rather than lands reverting to the Crown without drilling.

One incentive to industry is consolidation of EL's. Consolidation allows the combination of work obligations from two or more blocks. This means the financial commitment made under the work can be applied to a drilling commitment on another block. The Companies can apply their original work obligation or apply excess credits from work done to another parcel of land, whether they are an interest holder or not. The CNSOPB is open to consider any creative combination that will result in additional exploration drilling. Such flexibility may include the surrender of a portion of the combined lands. Any such consolidation request must be submitted by industry for approval by the CNSOPB.

For further assistance, contact the Manager of Resources & Rights at the Board (902.422.5588) or
www.cnsopb.ns.ca





- **15 – 40 Tcf**
- **31,000 mi²**
- **Multiple untested play types**
- **100's of features**

NOVA SCOTIA'S offshore oil and gas sector has undergone a major resurgence since the late 1990's. Exploration success in the deep water passive margins around the world has resulted in companies bringing that experience to offshore Nova Scotia to begin the process of evaluating the potential. The last few rounds of lands awarded have been over acreage that lies in water depths greater than 3000 ft.

Salt Study
The Canada-Nova Scotia Offshore Petroleum Board has prepared a report on deep water plays associated with salt features. Nova Scotia has seismic and geological attributes similar to other Atlantic-facing, look-alike deep water basins in the Gulf of Mexico, offshore Brazil and offshore West Central Africa. The study is a geological basin evaluation and numerical assessment of the hydrocarbon potential of the deep water region. This slope region comprises some 31,000 square miles and extends some 530 miles from the boundary with Newfoundland and Labrador south to the Canada-United States border.

Some 18,650 miles of regional 2D seismic were used to correlate wells on the Scotian Shelf and with older crustal seismic data. The focus of mapping was the mobile Jurassic Argo salt member. Some 12 play types were identified and mapped and included supra-salt minibasins, salt flank plays where the salt diapirs intersect Cretaceous and Tertiary aged sediments, and sub-salt features. Geochemical models examined known and inferred source rocks. Probability distributions were developed for oil, gas, solution gas and natural gas liquids for each of the 12 play types. Since there were no significant discoveries to validate the petroleum systems in deep water at the time of the study, geological risk was assigned.

Resource Estimates
Resource estimates range from 15 - 40 Tcf and 2 - 5 billion barrels of oil. The oil potential is very significant and conforms to the high oil-to-gas ratios encountered in other deep water basins of the circum-Atlantic region. If the estimated ultimate recovery (EUR) per unit area for the Scotian Slope is calculated, it appears to be in line with other Canadian frontier regions such as the MacKenzie-Beaufort basin, the Labrador Shelf and the Sverdrup Basin of the Arctic Islands. If some or all of the 12 plays defined in the assessment are eventually proven, the slope region could have a much higher ranking and approach that of offshore Brazil in hydrocarbon richness per unit area.

The impact of these numbers, on a risked basis, is to basically double the gas potential of offshore Nova Scotia while adding significant oil potential. Previous resource assessments showing 18 Tcf were made by the Geological Survey of Canada and did not include the slope area. This study suggests the slope acreage could contribute an additional 15 Tcf of gas and 2 billion barrels of oil.

Deep Water Slope – Update
During 2002 to 2004 there were six exploration wells drilled in the deepwater offshore Nova Scotia. Of those six wells, five were drilled along the upper slope in front of the Sable paleo-delta targeting Cretaceous sands and one (Torbrook C-15) was drilled on the upper slope further west targeting the Tertiary submarine fan play. The exploration targets of the six public domain wells were turbidite sands in submarine fans and although gas was encountered at Annapolis G-24, the overall success rate was low. The problem was lack of reservoir sands in the structures.

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DEEP WATER

In mid-2002 the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) released their assessment report on the hydrocarbon potential of the deepwater slope. The results were an undiscovered potential of 15 - 40 Tcf of gas and 2 - 5 BBL of oil (see previous section). Once this recent round of drilling was completed, the CNSOPB assessed the new data and in 2006 revised the undiscovered potential to 12 - 39 Tcf of gas and 1.3 - 4.5 BBL of oil. The recent drilling, except for Torbrook C-15, took place along a narrow band of the present day upper slope in front of the Sable area, hence only a very small portion of the deepwater was tested. The drilled anomalies in front of the Sable paleo-delta all attempted to assess a similar play concept. This play required deposition of turbidite sands into a low which was subsequently transformed into a closed high, as a result of salt movement.

The undiscovered hydrocarbon potential assessment results mentioned above represents a wide range of possible outcomes which, intrinsically, embraces degrees of success and failure. Even, at this immature stage of exploration the assessment continues to remain rather robust. While recent drilling results prove the existence of an active petroleum system (Annapolis G-24) there is some degree of negativity attached to the dry holes but given the areal restriction of the wells, the overall impact on the assessment is rather small. The well results do indicate that there is not a well developed understanding of the depositional systems and overall petroleum systems in Nova Scotia's deep water.

Deep Water Petroleum Systems Risk Assessment
Phase I petroleum systems study was funded by the Nova Scotia Department of Energy and completed in May 2006. This study involved compiling data on the 11 deepwater wells for use in 1-D numerical modeling. 2-D petroleum systems modeling was performed on 5 seismic lines from the most recent TGS NOPEC survey acquired over the deepwater Scotian Slope. Conclusions were made about the source rock potential, hydrocarbon charge, salt movement and general areas were identified where prospective plays may exist. This contract was awarded to Halifax-based Global Geoenergy Research Ltd., a geochemical and petroleum systems modeling consulting company. Dr. P.K. Mukhopadhyay (Muki) was the lead scientist during the study with much assistance provided by the N.S. Dept. of Energy and the Canada-Nova Scotia Offshore Petroleum Board staff. The final report entitled **"Evaluation of the Petroleum Systems by One and Two Dimensional Numerical Modeling and Geochemical Analysis in the Area of Most Recent Exploration Wells on the Deepwater Scotian Slope, Offshore Nova Scotia"** is now available on our website.

This report includes information concerning organic facies, source rock potential and maturation. Thermal and pressure properties were also derived from 1-D modeling and results of the 2-D petroleum systems modeling. Upon completion of this work, personnel from the department of Energy and the contracted consultant finalized the study through a series of one-on-one meetings with explorers that were interested in the results of the study. A Halifax based geoscience workshop was also held to showcase the results and discuss future work.

Offshore Energy Technical Research Association

The OETR (Offshore Energy Technical Research Association) was established in March 2006 with $2.6 million in government funding to foster research and development related to offshore petroleum geoscience and the diffusion of that knowledge. This research builds geoscience knowledge about Nova Scotia's offshore oil and gas potential as well as reducing the technical and engineering barriers to the development of discovered reserves and, where consistent with these goals, to encourage building research capacity in Nova Scotia. Current membership includes Dalhousie University, Saint Mary's University, and the Nova Scotia Department of Energy.

Its research priorities include:

(i) To support studies to look at geoscience issues;
(ii) Hold workshops to bring together world experts;
(iii) To acquire strategic geoscience information; and
(iv) Other studies consistent with the general objectives.

One of the main purposes of funding research projects will be to provide study results to offshore oil and gas explorers. Therefore, the OETR Association requires project reports to be placed freely in the public domain. Where confidential data belonging to a third party is used for study purposes, proposals must adequately demonstrate how they will balance OETR Association's requirement to place meaningful study results in the public domain with the proprietary nature of data required for the study.

Research Funded

1. *Analysis of petroleum systems on the Scotia shelf using thermal & seismic techniques.* Funded to Dalhousie University for a project that will lead to a better understanding of the nature of basement and salt structures and their effect on petroleum maturation.

2. *River sources & the transfer of sands to the deepwater Lower Cretaceous Scotia Basin.* Funded to Saint Mary's University for a study that will define the distribution systems for sand and help industry explorers refine their exploration targets and better understand the quality of underground petroleum reservoirs.

3. *Reservoir distribution & characterization: Shelf to slope linked depositional systems.* Funded to Dalhousie University for a project that will investigate reservoir distribution within the petroleum system. It will provide industry with the groundwork for a better understanding of petroleum reservoirs.

4. *Archiving & reprocessing of seismic reflection datasets in offshore Nova Scotia.* Funded to Kelman Technologies Inc. for a study that will be made available to the public and interpreted so as to obtain a better understanding of the geology and of potential new plays and prospects.

In spring 2009, the OETR Association initiated an industry standard play fairway analysis and geoscience data package program for offshore Nova Scotia. This program will work to fill geoscience knowledge gaps and encourage industry exploration of Nova Scotia's remaining offshore resources.

Petroleum Research Atlantic Canada

Petroleum Research Atlantic Canada (PRAC) is a not-for-profit organization that funds and facilitates collaborative research and development (R&D) to support the safe and environmentally-sound development of Atlantic Canada's petroleum resources.

Governed by a nine-member Board of Directors (the majority of whom are from industry), PRAC's members include: upstream producers and explorers, universities and colleges involved in petroleum research, and federal and provincial government departments and agencies.

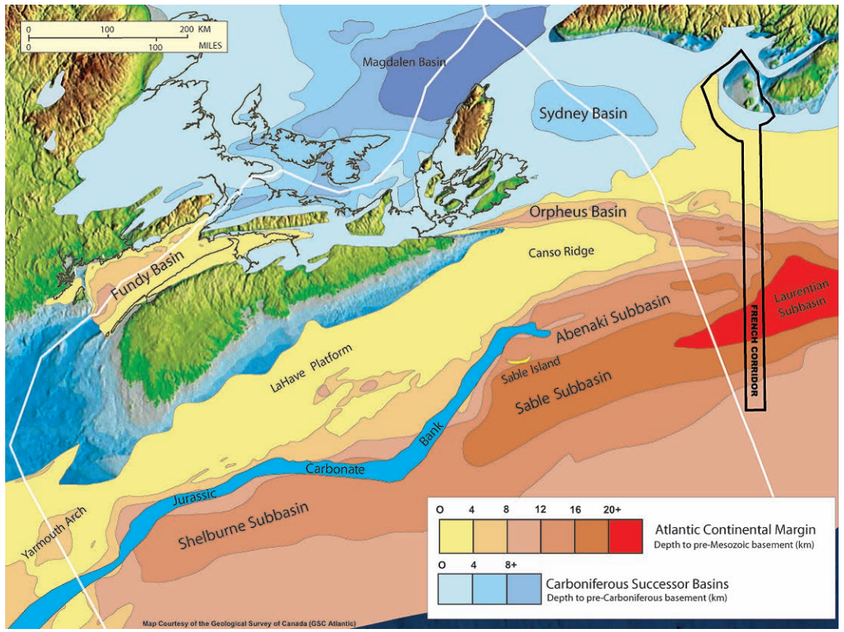
PRAC issues Calls for Proposals in focused areas as directed by our Research Advisory Committee, and provides research funding to successful applicants. We provide Transfer-to-Usability (TTU) grants to help bridge the gap between applied research and commercialization, and facilitate multi-partner Joint Industry Projects to address specific member needs.

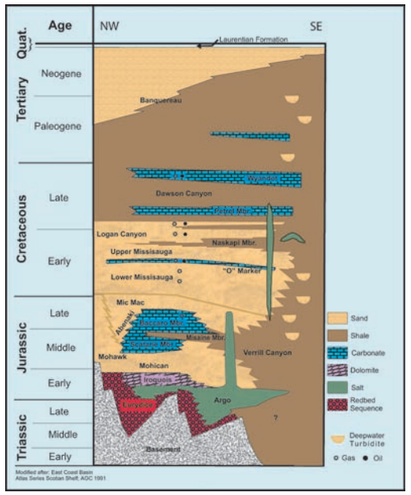
Since 1999, PRAC has awarded over $4.2M in direct funding to projects with a total value exceeding $20M. Additionally, PRAC undertakes a broad range of communications and outreach activities to assist with research identification, planning and dissemination of research project results.

In 2007, PRAC was contracted by the Nova Scotia Department of Energy to manage a study to investigate the feasibility of using controlled source electromagnetic imaging (CSEMI) as a means of exploring for hydrocarbons offshore. CSEMI can detect the presence of resistive features (such as oil or gas-bearing zones) beneath the seafloor, however certain conditions must exist for the technology to be utilized. The study will provide information about hydrocarbon prospects which may fit the CSEMI criteria and may lead to a full-scale survey offshore.

PRAC also assisted the province by managing a Call for Proposals for the Offshore Energy Technical Research (OETR) Association. The Call resulted in the issuance of three grants worth $900,000 to geoscience research projects which leveraged an additional $2 million from other sources. This research will provide valuable insight in thermal, mineral and depositional characteristics of offshore geology.

Several other geoscience studies funded by PRAC in 2006 or earlier are making significant progress, or have been completed. Project reports and more information about PRAC are available on its website at **www.pr-ac.ca**.





- **Sable and Abenaki Subbasins**
- **Deep Water Slope**
- **Jurassic Carbonate Bank**
- **Shelburne Subbasin**
- **Orpheus Basin**

THE CURRENT exploration cycle has resulted in a significant amount of prospective offshore land being returned to the Crown. These Crown lands lie in the Sable, Abenaki and the Shelburne Subbasins, the deep water slope region, with prospective Crown lands also available in the Orpheus Basin. Two other basins, the Fundy (late Triassic-early Jurassic syn-rift) and the Sydney (late Carboniferous sag) Basins contain petroleum opportunities but are less understood and therefore riskier than other offshore basins (only two wells in each). Further work has been completed on the Sydney Basin to help better understand the basin architecture and geologic history in an effort to unravel its petroleum potential.

The Scotian Basin comprises a series of connected depocentres initially formed during the rifting stage that preceded the breakup of the supercontinent of Pangea starting in the middle Triassic. The basins' histories record the entire sequence of Atlantic-style rifting and formation on the wide offshore margins with maximum sedimentation during the late Jurassic and Cretaceous.

This entire basin is still at a relatively immature stage of exploration. Exploration activity has been conducted in the Sable & Abenaki Subbasins, Upper Jurassic carbonate bank and the deep water slope resulting in some success. On the shallow shelf, PanCanadian (now EnCana) discovered the Deep Panuke field in 1999 situated on the Abenaki carbonate bank. The discovery was followed by five successful delineation wells which all tested in excess of 50 MMcf/d on DSTs with net pay values ranging from 100 to 328 ft. Deep Panuke has received regulatory approval for this project. On the deep water slope, an undelineated Upper Cretaceous gas discovery was made by Marathon in 2002 with its Annapolis G-24 well in 6035 ft of water.

The acquisition of new seismic datasets, particularly 3-D and regional programs, and the latest well information from recently released wells together provide new insights on the region's geology and petroleum systems. This new data and the Canada-Nova Scotia Offshore Petroleum Board's current large archival holdings of well and seismic data provide an excellent information database with which to assess exploration opportunities. In the fall of 2007 the CNSOPB opened a new Data Management Center. This allows for even easier access to the technical information. With only 130 exploration wells drilled and 24 oil and gas discoveries made, it is clear that much potential exists for successes in current and future hydrocarbon play types, many of which have not been tested.

The following details the petroleum potential for four areas in the Scotian Basin where large tracts of Crown lands are available for nomination.

Sable and Abenaki Subbasins

In the Sable Island area during late Jurassic to early Cretaceous time, an extensive delta system developed at the mouth of the paleo-St. Lawrence River. The Sable Delta was a complex series of prograding delta wedges dominated by both wave and tidal forces. Tremendous volumes of mature sediments were sourced from the adjacent Upper Paleozoic age Maritimes Basin (Gulf of St. Lawrence) and the resultant fluvial, deltaic, strandline and marine sedimentation dominated much of the eastern and central Scotian Shelf area (Mic Mac and Mississauga Formations respectively). From about middle Jurassic time, the delta first rapidly filled the eastern Laurentian Subbasin. Then, in the late Jurassic and early Cretaceous, it shifted its locus of deposition steadily southwestward to the Abenaki and Sable Subbasins. It eventually overwhelmed the coeval Abenaki carbonate bank complex in the Sable Island area. The accumulation of Mesozoic and Cenozoic age sediments in these latter two basins reaches thicknesses in excess of 13.5 mi without major unconformities.

The Sable and Abenaki Subbasins have been the focus of much of the petroleum exploration over the past forty years. To date, 24 gas and oil discoveries have been made in the offshore Nova Scotia

region, mainly in the Sable and Abenaki Subbasins near Sable Island. Most of these discoveries involve rollover anticlinal structures associated with down-to-basin growth faults. Reservoirs are deep and overpressured in structures situated in proximity of Sable Island, and shallower and normally pressured reservoirs south of Sable Island along the delta's distal margins.

The overpressured reservoirs occur in sandstones of the Upper Jurassic Mic Mac and Lower Cretaceous Mississauga Formations. More than 375 feet of net gas pay within 15 reservoirs have been recorded in one well in the Venture field – the largest discovery to date. Gas in the normally pressured sandstones is situated in the upper member of the Mississauga Formation. Gas also occurs in several additional reservoirs, including the Upper Cretaceous Wyandot (chalk) and Dawson Canyon (deltaic) Formations, and Middle Cretaceous Logan Canyon (deltaic) Formation indicating further potential in many different play trends. Please refer to Summary Section on offshore development projects for more details on the SOEP project.

A report released by the Canadian Gas Potential Committee in 2001 shows 8.9 Tcf of discovered gas in place in the Sable Subbasin while 8.1 Tcf of gas remains undiscovered in this Subbasin. An undiscovered gas potential of 7.1 Tcf was also assigned to the Abenaki Subbasin. These numbers were generated using the CNSOPB's 1997 evaluation.

A large endowment of potential gas, condensate and oil resources has been predicted for the offshore Nova Scotia shelf region and the slope down to the ~5000 foot isobath. The last detailed gas resource evaluation was done by the Geological Survey of Canada in 1983 and predicted a mean probability of 18.1 Tcf of gas, 370 MMbbls of associated condensate and 710 MMbbls of oil. Analysis indicates that many attractive exploration targets remain in these subbasins and on the Shelf, particularly for gas pools in the range 200 Bcf to 1 Tcf.

Deep Water Slope

Since the late 1990s, Nova Scotia has seen a resurgence of exploration in water depths greater than 3200 feet along the Scotian Slope. The Slope region covers an area of about 31,000 square miles extending about 530 miles along the entire breadth of offshore Nova Scotia. Successes in other deep water passive margins around the world including the Gulf of Mexico, offshore Brazil and West Central Africa have spurred this exploration. Industry has recognized that the Nova Scotia slope shares the same geological attributes as other successful exploration and producing Atlantic Margin deep water regions. These attributes include production in the adjacent up-dip, shallow water region (Scotian Shelf SOEP Project), a large, ancient, sand-rich delta system (Sable Delta), and a mobile salt substrate (Argo Fm.)

The Canada-Nova Scotia Offshore Petroleum Board prepared and released a detailed assessment report in October, 2002 for the deep water potential and defined 12 play types associated with salt features. Prior to the report, Marathon Oil Company spudded a well in 5500 feet of water to test their Annapolis prospect. The B-24 well experienced a well control incident caused by an influx of gas believed to be from the shallow late Cretaceous Wyandot chalk. The well was abandoned and immediately repositioned. The Annapolis G-24 well was drilled to planned TD and encountered approximately 100 ft of net gas pay over several zones. This first discovery in the deep water provides confidence that this portion of the Slope region contains an active petroleum system. However, further evaluation is required to determine the commerciality of this discovery. A third exploration well, Crimson F-81, drilled by Marathon basinward six miles from the Annapolis discovery to test the Crimson Prospect was unsuccessful.

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OPPORTUNITIES

Four more modern deep water wells were drilled by three different operators to the west of the Annapolis discovery but with little success. Given the availability of modern 3-D seismic coverage, the fact that there are many prospects and leads interpreted from the new datasets, and that multiple play types remain untested, there are numerous exploration opportunities present in the deep water for the aggressive explorer.

Jurassic Carbonate Bank

From the Middle Jurassic to Early Cretaceous, an extensive carbonate bank margin was formed along the North Atlantic margins. In the Scotian Basin offshore Nova Scotia, the carbonate platform extends 420 miles from the Canada-US border in the southwest to the Sable Island Area on the Scotian Shelf. It continues intermittently along the northeastern Shelf over to the southern Grand Banks of Newfoundland.

The Abenaki carbonate bank developed along the ancient rift margin hinge-line in the Middle Jurassic. The bank displays several margin profiles types ranging from steep escarpment to ramp-like. These attributes were used to divide it into three segments: Panuke, Acadia and Shelburne. Beyond Sable Island to the northeast, the carbonate shelf changes into a gently dipping ramp margin. In the region west of Sable Island, a total of 20 exploration wells have been drilled from 1970 to 2004; nine on the bank edge, nine on the landward interior platform and two on the foreslope. Seven play types have been identified across the Abenaki platform and margin and several have been tested, though in some cases by a single well. The CNSOPB has completed a study of the carbonate bank that was released to the public in June 2005.

The Panuke Segment is the best understood of the three and is where a commercial oil project (the Cohasset Project) and the Deep Panuke offshore gas development project (see summary of offshore development projects for more details) are located. This region is relatively undisturbed by erosion and faulting and is juxtaposed against the prolific Sable Delta, which contains all but two of the 24 discoveries to date, and is the site of the current offshore gas production.

The Abenaki bank margin was first drilled in 1973. The target was structural closure at depth and although the Abenaki carbonates were wet, an up-hole oil discovery was made in overlying draped sands of the Cretaceous Logan Canyon Formation. This discovery became the Cohasset/Panuke oil project that produced 44 million barrels of light gravity 55° API crude from 1992-1999. These types of low-relief simple closure fields are very attractive due to the high productivity of the sandstones, location in shallow water and in moderate metocean conditions. Similar shallow oil accumulations should be found in other areas of the extensive carbonate bank and a large scale 3-D seismic dataset will certainly allow better imaging of these subtle traps.

Subsequently, a further eight wells were drilled in the 1970s along the bank margin until PanCanadian (EnCana) drilled from the existing Panuke oil production platform and discovered the Deep Panuke gas field in 1999. The main gas reservoir is a dolomitized and leached limestone reef margin facies near the top of the thick Baccaro Member. The reservoir has impressive properties: porosities of 3 to 40 per cent, permeabilities of 1 md to several darcies and net pay values from 100 to 328 feet. Flow rates for the six wells including the discovery well have ranged from 50 to 63 MMcfd. Traces of H_2S were also encountered at concentrations of about 0.18 per cent (about 1800 ppm).

This reservoir information shows that the Deep Panuke type of carbonate reservoir can be an excellent producer despite high variability in reservoir characteristics. Because the play is based on seismic attributes, they are also difficult to find. With the Deep Panuke discovery, the existence of other fields along the Panuke Segment and/or extension of the current discovery is considerably enhanced. Please refer to Summary Section for more details on the Deep Panuke Project.

The Acadia Segment was penetrated by three wells drilled between 1970 and 1980. This region displays a more complex geological history than the Panuke segment, involving faulting, erosion and salt disruption. The positive aspect of this segment is that all three wells drilled in this area (Bonnet, Albatross and Acadia) encountered degrees of lost circulation indicating potential porosity zones, but incomplete mud gas logs and few drill stem tests make it impossible to evaluate the potential and significance of these zones. A continuous grid of 3-D seismic is required over the Acadia Segment bank margin to fully evaluate the reef potential in this area.

The Shelburne Segment of the Abenaki bank margin is discussed in the Shelburne Subbasin section that follows below.

Shelburne Subbasin
The Shelburne Subbasin was a major center of deposition in the southwestern portion of the Scotian Basin. The Subbasin saw rapid deposition throughout the Jurassic and lesser infill during the Cretaceous and Tertiary, resulting in a cumulative thicknesses of 7.5 mi.

The Shelburne Subbasin contains carbonate bank opportunities in both the Acadia and Shelburne segments. A discussion of the Acadia Segment is included in the Jurassic Carbonate Bank section.

The Abenaki carbonate of the Shelburne Segment has been unexplored with only some older regional seismic coverage but no wells. Seismic in this area shows a faulted rimmed carbonate platform with a steeply dipping foreslope. To the north-east, seismic shows the carbonate margin buried by a thick Cretaceous section with listric down-to-basin faults very close to the bank edge and fore slope. These structures offer exploration opportunities in the bank complex although new seismic data is required to better define the margin itself and related structures.

Thick salts are also present in the deep water portion of this subbasin. The 12 plays identified by the CNSOPB's 2002 Deep Water Scotian Slope Resource Assessment are associated with the salt and provide many opportunities to the explorer. A continuous 3-D seismic dataset will be necessary to fully evaluate these opportunities prior to drilling a well.

Orpheus Basin
The Orpheus Basin forms a structural trough on the northern Scotian Shelf, widening and plunging eastward from nearshore to the Laurentian Subbasin. Interpretations of industry seismic and magnetic data indicate that the northern margin of the Orpheus Basin coincides with the boundary between the Appalachian Avalon and Meguma terrains. The northern margin of the basin is bounded by the eastern extension of the Cobequid-Chedabucto fault with approximately 5 miles of vertical displacement. The southern margin consists of a series of discontinuous faults antithetic to the Cobequid-Chedabucto fault. Thick sedimentation into this basin was received during pre-breakup time and was filled by Middle Jurassic time.

The rift-fill sequence of the Orpheus Basin was comprised of mostly Triassic to Jurassic Mesozoic sediments which were deposited unconformably on a basement comprised of various lithologies and age including metasedimentary, metavolcanic, igneous intrusive, siliciclastic, carbonate and evaporate rocks. Seven exploratory wells were drilled in this basin in the 1970s primarily on structures at the basin margins or on poorly defined salt structures.

The Eurydice Formation overlying basement is the deepest target in the Orpheus Basin and is designated as Late Triassic redbeds. No wells have been drilled through the entire basin-fill sequence predicted to be approximately 6 miles thick. The type section for the formation is the Eurydice P-36 well which penetrated only the upper 200 ft of the formation, leaving approximately 6600 ft of the formation untested. This lower section of the Eurydice Formation in the Orpheus Basin could comprise the same coarse, presumably alluvial facies that has been drilled in the lower part of the Eurydice Formation in the Emerald Basin on the Scotian Shelf.

This basin has not been adequately explored and the petroleum potential is not well understood. The basin holds the potential for shallower, salt-related and deeper play opportunities especially in the lower portion of the Eurydice Formation. Additional close grid seismic needs to be acquired to better detail these plays particularly beneath the thick salt prior to drilling a well.

A report released by the Canadian Gas Potential Committee in 2001 attributes 1.3 Tcf of risked undiscovered gas potential to the Orpheus Basin.

Sydney Basin
The Sydney Basin is visible in outcrop sections onshore in eastern Cape Breton and is believed to extend offshore as far as southwestern Newfoundland. The offshore portion of the basin consists of at least four major half-graben extensional subbasins bounded by a series of north-east trending and southeast dipping faults. These subbasins are primarily filled with early Mississippian Horton Group alluvial fan deposits of red bed conglomerate, sandstone and shales. Three wells have been drilled in the basin in the 1970s; North Sydney P-05 and North Sydney F-24 were drilled offshore and Birch Grove No.1 onshore. The offshore wells were drilled on the prominent North Sydney anticlinal structure. Both wells encountered gas shows but generally have porosities less than 10 per cent and low permeability. Subsequent source rock evaluations from the P-05 well have shown a mature section that is gas prone at depth and may be prospective for light oil in the shallow section.

For the past 30 years there have been no real attempts by the oil and gas industry to explore in this area. In 1998, Hunt Oil of Canada Inc. acquired two blocks in the Sydney Basin. A prohibition order was in effect for three years of their licensing agreement and therefore their work expenditures were on hold. Work by Hunt Oil Canada has once again commenced on the offshore blocks with an extensive 2D seismic program acquired in the late fall and early winter of 2005. Approximately 1800 km of 2D industry seismic from 1981 and 1983 have been reprocessed by the Department of Energy in an attempt to understand better the offshore portion of the Sydney Basin, the prospective plays and their potential for containing hydrocarbons. A cooperative study between the Nova Scotia Department of Energy and the Canada-Nova Scotia Offshore Petroleum Board has resulted in a re-interpretation of this reprocessed seismic data and the wells. This recent work has re-confirmed the potential of the deeper, thicker and basinward Horton and overlying marine Windsor Group which remain untested throughout the basin.

Summary – Offshore Development Projects

Cohasset Project (1992-1999)
The Cohasset Project began production in 1992. It reached its economic limit and production terminated on December 17, 1999. The project produced a total of 44.5 million barrels of 55° API oil over its seven-year life.

The oil was produced from sands in the Cretaceous Logan Canyon Formation contained within simple structural closures formed by drape over the Jurassic carbonate bank. The project achieved high production rates up to 40,000 bbls/day.

This offshore oil production project was located about 41 kilometres southwest of Sable Island, Nova Scotia. It was operated by PanCanadian (which later became EnCana) on behalf of itself and Nova Scotia Resources (Ventures) Limited, a Nova Scotia Crown corporation which held a 50% interest in the project.

The project comprised two separate fields, called Cohasset and Panuke, which are about eight kilometres apart. A platform was located at each field. A number of wells were drilled through jackets at each of these platforms using the jack-up drilling rig, Rowan Gorilla III, which also served as the production facility. Production flowed between the fields through a subsea line. It was processed through facilities and equipment located on the rig that alternated between both fields as appropriate.

Following processing, the oil was stored in a specially adapted tanker called the Nordic Apollo, which was moored to a nearby buoy. Processed oil was periodically transferred from the storage tanker to a shuttle tanker called the Nordic Challenger, which delivered the oil to markets.

Sable Offshore Energy Project (1999-2015*)
An economic joint venture known as the Sable Offshore Energy Project led by ExxonMobil Canada Properties Ltd. that includes Shell Canada Limited, Imperial Oil Resources, Pengrowth Energy Trust and Mosbacher Operating Ltd. began gas production on December 31, 1999. SOEP is a $3 billion project and is divided into two tiers. Tier 1 was completed in December, 1999 and involved the development of the Thebaud, North Triumph and Venture gas fields through three platforms, a subsea pipeline, a gas plant at Goldboro, a natural gas liquids pipeline and a fractionation plant at Point Tupper. Tier 2 commenced with the Alma field being on stream in late 2003 while production from the South Venture field began in late 2004. A total of 21 production wells have been drilled to extract the 1.6 Tcf of gas reserves. Recently the project had just produced over the 1 Tcf mark.

These five fields involve rollover anticlinal structures associated with down-to-basin growth faults. Reservoirs in the Thebaud, Venture and South Venture fields are deep and overpressured situated in the Mic Mac and Mississauga Formations while the North Triumph and Alma fields contain reservoirs in the Mississauga Formation.

A compression unit was installed on a jacket adjacent to the project's central processing Thebaud platform and was operational in mid-November, 2006. This $700 million compression unit is expected to boost output by 25% and significantly increase overall project deliverability until 2015.

Nova Scotia is strategically located adjacent to the major energy markets of northeastern North America. Producing between 400 and 500 MMcfd, SOEP production is going to markets in eastern Canada and the U.S. Northeast. The SOEP fields are also producing natural gas liquids in the range of 20,000 bbls/day. These are processed at a liquids handling facility in Point Tupper.
In the short term, several of the gas discoveries that have been made in the vicinity of the SOEP project are being examined to help maintain future production levels as they are very attractive to be produced through the current infrastructure.

Deep Panuke Offshore Gas Development Project (2010*-2023*)
Recent exploration in the drilling of the Dominion J-14 & J-14A wells to delineate the Deep Panuke gas pool to the north-east were unsuccessful and no reservoir was penetrated in these wellbores.

On November 9, 2006 EnCana Corporation filed applications with the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB) and the National Energy Board (NEB) for its Deep Panuke Offshore Gas Development Project. Both the CNSOPB and the NEB coordinated a public review leading up to the public hearings. This coordinated approach made the review process easier and streamlined. The project was sanctioned late 2007. The pipeline installation was completed in 2009. First gas could be produced from the Project in 2010.

Encana holds a majority working interest in and is the operator of Deep Panuke. The project design consists of a jackup MOPU (Mobile Offshore Production Unit) in a water depth of 145 ft. Production wells will include completing four previously drilled wells and drilling two new wells, one production and one acid gas injection well. Another three additional subsea production wells could be drilled at least after one full year of production, if required. All wells will have horizontal trees and will be tied back individually to the MOPU with subsea flowlines and control umbilicals.

The export system will consist of a single subsea pipeline delivering sales gas to either an interconnection with M&NP at Goldboro or a a subsea pipeline at a close point on the SOEP pipeline route. The gas processing system will include inlet compression, separation, sweetening, dehydration, export compression and measurement. Deep Panuke is considered a sour gas reservoir (0.18% H_2S) and sweetening equipment is required.

The Deep Panuke pool will produce natural gas from a porous and permeable carbonate reservoir located about 11,500 ft. below the seafloor discovered in 1999 below the decommissioned Cohasset Project. The production sales gas for the project is 300 MMcfd and the mean life of the project will be 13 years.

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