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East Canada stays the course in navigating offshore development

While most portions of North America have seen E&P activity shrink to levels that are a fraction of what they were two years ago, work in Newfoundland and Labrador, and Nova Scotia, continues to move forward, due, in part, to long lead times and very promising geology.

KURT ABRAHAM, Editor

As a new day dawns along Canada's eastern maritime coastline, the sun rises above the horizon, and sunlight streams through the narrow neck of the channel leading to the harbor at St. John's, Newfoundland, flooding the area with a golden glow, Fig. 1. Following the golden path into the harbor is a large workboat returning from ferrying equipment and supplies to one of several major offshore installations. Yet another workboat is about to edge away from the docks, ready to bring more supplies to sustain oil and gas production in one of the industry's more challenging environments.

A sunny day is to be cherished in St. John's, which is notorious for being the foggiest (124 days), windiest (15.1-mph average speed), and cloudiest (only 1,497 hr of sunshine in 365 days) location among all of Canada's major cities. But this is part of the charm of what is the hub of Canadian offshore operations. In Part 1 of this new article series, we take a wide look at the history, achievements and future promise of E&P, offshore East Canada.

NEWFOUNDLAND/LABRADOR

Since first oil went onstream 19 years ago, the province's four fields in the Jeanne d'Arc basin (Hibernia, Terra Nova, White Rose and North Amethyst, Fig. 2) have produced roughly 1.6 Bbbl of oil. "Our four fields are producing approximately 25% of Canada's light oil," noted Keith Hynes, director of petroleum engineering at the NL Department of Natural Resources.

As estimated by the Canada-Newfoundland Offshore Petroleum Board (C-NLOPB), discovered, cumulative reserves/resources now total 3.9 Bbbl of oil and 12.6 Tcf of natural gas. "In addition to that, a new resource assessment, conducted by international oil and gas consultant Beicep Franlab of France, for Nalcor Energy (the provincial energy crown corporation) shows an in-place resource potential of 12 Bbbl of oil and 113 Tcf of gas, in the 2015 licensing area (Fig. 2) offshore Newfoundland and Labrador," said Hynes.

What's more, the total Newfoundland and Labrador area available for exploration is huge, and, compared to some regions, is underexplored. "We've got about 50% more jurisdiction, in terms of total offshore basin area, than the Gulf of

Fig. 1. As the sun comes up on another day, one workboat servicing Grand Banks installations is about to enter the channel to the Port of St. John's, while another workboat at the A. Harvey docks takes on equipment and supplies, preparatory to making another run to Newfoundland's producing facilities. Photo by the author.

Fig. 2. In this map of Newfoundland's discovered assets, the producing fields are visible in the lower-left portion, while Statoil's more recent finds are in the right-center area. Most of the tracts offered in November's licensing round are tracts that surround Statoil's finds. Map: Statoil.

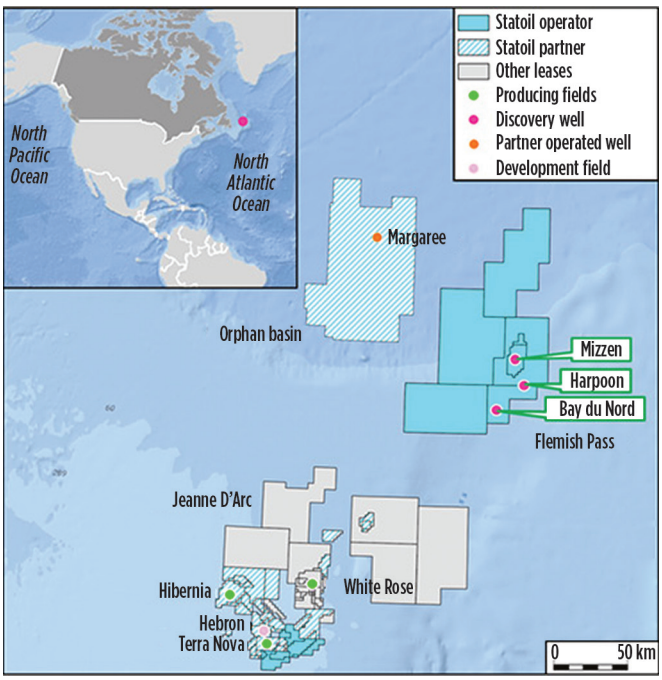

Fig. 3. In a view typical of the region's notorious weather, the Hibernia platform is partially obscured in fog. Photo: Suncor Energy.

Fig. 4. For 14 years, the *Terra Nova* FPSO has received and stored oil produced at its namesake field. Photo: Suncor Energy.

Mexico," said Bob Cadigan, president and CEO of the Newfoundland and Labrador Oil & Gas Industries Association (NOIA). "And we have 45% more than Norway. When you look at it from that perspective, and look at the variety of leads and play types, we believe we are in the early days, rather than the late days, of our industry."

History/background. Prior to 1973, the Canadian federal government was fairly passive, with respect to oil and gas E&P regulation. Growth was the main goal. But in response to the Arab Oil Embargo of 1973, Canadian officials decided to gain better control of domestic resources and protect the country from high oil prices.

Accordingly, the first new policy step was to establish a state-owned oil company, Petro-Canada, in 1974. It was intended to give the federal government direct involvement in, and influence over, E&P development in ways that it never could before. Then, in 1980, prompted by the second global oil crisis (the 1979 overthrow of the Shah of Iran, and the subsequent drop-off in Iranian oil production), officials in Ottawa established the National Energy Program (NEP). The ambitious NEP effort had, as its goals, making the country self-sufficient in oil production by 1990, gaining 50% ownership of energy resources by the government, and directing a greater share of oil and gas revenues into the federal treasury.

However, the NEP's lifetime was limited. Within several years, anxiety over high oil prices and limited supplies had diminished, and government interest in the NEP's agenda lapsed. Pressure began to build from both Canadian and U.S. firms within the industry to dismantle the NEP. In 1984, upon election of a Progressive-Conservative regime led by new Prime Minister Brian Mulroney, the NEP was replaced with market-based strategies for managing oil and gas resources. In this environment, the modern chapter of Newfoundland and Labrador's offshore industry emerged.

Early exploration. The C-NLOPB-regulated offshore area covers in excess of 1.8 million km^2. Over 20 offshore sedimentary basins have been identified. Although the first exploration wells were drilled off the coast of Newfoundland and Labrador (NL) in the 1960s, they were few and far between. For instance, just two wells were drilled in 1966, and no further drilling took place until 1971, when six wells were spudded.

This was due partly to the fact that worldwide, there were plenty of oil fields that were cheaper and easier to develop. Thus, operators had little incentive to explore offshore Newfoundland and Labrador. However, when oil prices rose significantly in 1973, interest in NL exploration increased. That year, 17 wells were drilled, followed by another 10 in 1974.

A somewhat fallow period followed, from 1976 through 1978, with just six wells drilled over three years. However, in 1979, drilling picked up with the discovery of Hibernia oil field, which proved the commercial potential of the NL offshore sector. "Actually, Newfoundland kept up pace with Norway on exploration, surveying until about 1984," noted Richard Wright, exploration manager at Nalcor Energy. "But then it flat-lined, especially after 1986, and didn't uptick until the 2000s."

The success at Hibernia did make the province realize that it had to implement the offshore regulations that it had instituted in 1977. But this put NL officials into conflict with the federal government, which viewed Hibernia's potential development as part of its NEP strategy. In fact, federal officials believed that oil was too important a commodity to be kept under provincial control. This prompted a six-year dispute over jurisdiction.

In 1985, the legal battle ended, when the Atlantic Accord was signed, establishing a joint management system between the federal and provincial governments, and creating the C-NOPB, the predecessor to C-NLOPB. Thus, development of NL's resources could, theoretically, finally begin at Hibernia.

"To this day, one of the biggest challenges that we have here is getting more of the 'prescriptive' Canadian regulations to fit better with the industry, and make them more goal-oriented," said Paul Barnes, manager, Atlantic Canada, for the Canadian Association of Petroleum Producers (CAPP). "With all the industry innovation, the operators are trying to be efficient and see what's the best fit and works well. So, in this low-price environment, we're always looking to make these regulations more cost-efficient and less burdensome."

Development/production—Hibernia. Situated on the northeastern Grand Banks, approximately 315 km southeast of St. John's, Newfoundland, Hibernia field lies in an 80-m

Fig. 5. The *SeaRose* FPSO receives oil produced from White Rose and North Amethyst fields, as well as three subsea tie-backs. A shuttle tanker can be seen in the background. Photo: Husky Energy.

Fig. 6. Under construction at the Bull Arm fabrication facility, the Hebron GBS is designed to withstand sea ice, icebergs, and other meteorological and oceanographic conditions. It will be able to store 1.2 MMbbl of oil. Photo: Exxon Mobil.

water depth, **Fig. 3.** Hibernia was discovered in 1979 by the Chevron, et al, Hibernia P-15 well. Between 1979 and 1984, Mobil, as operator for the participants, drilled nine additional wells to delineate the field. A Significant Discovery Area for Hibernia was officially declared on Oct. 2, 1985.

When initially proposed for development, the field's area was about 223 km^2. Mobil estimated that it contained 520 MMbbl of recoverable oil in two separate reservoirs, named Hibernia and Avalon. Unfortunately, in early 1986, global oil prices took a deep dive. Mobil said that it would need at least $22/bbl to proceed with Hibernia's development and did not expect a rise in prices to that level anytime soon. However, eager provincial officials offered the project a number of incentives. Finally, in 1990, an agreement was hammered out between the provincial government, and Mobil and its partners.

A $5.8-billion development project then ensued, including a concrete, gravity base structure (GBS), on which the topsides would be mounted. The Hibernia partners agreed to build the GBS in NL, providing the province with some much-needed jobs. The field finally began oil production on Nov. 17, 1997.

The Petroleum Board approved an amendment to the Hibernia Development Plan in 2009, which covered part of the Hibernia South extension area. The province also negotiated an increased royalty in this area, and a 10% equity share in the remaining area. The C-NLOPB now estimates cumulative resources at Hibernia to be 1.644 Bbbl. Cumulative production, as of February 2016, was 959 MMbbl.

Development/production—Terra Nova. On the northeastern Grand Banks, Terra Nova is approximately 350 km southeast of St. John's, in a water depth of about 90 to 100 m. The field was discovered in 1984 by the Petro-Canada, et al, Terra Nova K-08 well. Following the initial discovery, eight wells were drilled to define the field's structure. A Significant Discovery Area for Terra Nova field was declared on Oct. 2, 1985.

When initially proposed for development, the field had an area of about 128 km^2, and the operator estimated that it contained 400 MMbbl of recoverable oil. The field began oil production from the *Terra Nova* FPSO (**Fig. 4**) on Jan. 20, 2002. The C-NLOPB now estimates Terra Nova's cumulative reserves at 505 MMbbl of oil. Cumulative production, as of February 2016, was 381 MMbbl.

Development/production—White Rose/North Amethyst. White Rose field is on the northeastern Grand Banks, 350 km east of St. John's, in a water depth of about 120 m. The field was discovered in 1984 by the drilling and testing of the Husky, et al, Whiterose N-22 exploratory well. Following the initial discovery, eight additional wells were drilled to define the structure. The C-NLOPB issued a Significant Discovery License for the field on Jan. 15, 2004, including both oil and gas accumulations.

The White Rose Development has focused on the South Avalon pool. At the time that it was initially proposed for development, the field had an area of about 40 km^2, and the operator, Husky Energy, estimated that it contained 230 MMbbl of recoverable oil. A $2.3-billion development project proceeded.

First oil production was achieved on the *SeaRose* FPSO (**Fig. 5**) on Nov. 12, 2005, making White Rose the province's third actively producing offshore oil development.

According to C-NLOPB, White Rose's reserves are now estimated at 404 MMbbl. As of February 2016, cumulative production was 214 MMbbl.

In 2003 and 2006, exploration drilling in and around White Rose led to the discovery of a new field, North Amethyst, and the increase in understanding of two oil pools that are part of the existing project: West White Rose and the South White Rose Expansion.

North Amethyst is the first White Rose satellite expansion, originally estimated by C-NLOPB to hold 68 MMbbl of oil. Located approximately 6 km southwest of the *SeaRose* FPSO, North Amethyst is also the first near-field tieback offshore Canada. This $1.8-billion satellite development achieved first oil on May 31, 2010.

The C-NLOPB estimates cumulative reserves at North Amethyst to be 74.6 MMbbl of oil. Cumulative production, as of February 2016, was 43.6 MMbbl.

Development—Hebron. Discovered in 1981, the Exxon Mobil-operated Hebron field project consists of three fields: Hebron, West Ben Nevis and Ben Nevis. The Hebron project, in the Jeanne d'Arc basin, has been estimated, by C-NLOPB, to contain 707 MMbbl of oil. An additional 36 MMbbl and 252 MMbbl are

Fig. 7. Statoil's Bay du Nord and Harpoon discoveries were drilled by the *West Hercules* semisubmersible rig. Photo: Statoil.

estimated at West Ben Nevis and Ben Nevis, respectively. According to the project description filed with the Petroleum Board, Hebron should produce its first oil before the end of 2017, using a GBS platform that is under construction at Bull Arm, **Fig. 6.**

Nalcor's formation and mission. In 2007, the NL government formed Nalcor Energy, an arms-length crown corporation that is involved in development of provincial energy resources. Nalcor's oil and gas division manages the province's equity interest in offshore resources, and is focused on the continued growth and long-term sustainability of oil and gas.

Nalcor also holds and manages the province's equity share in offshore projects. In the mid-2000s, NL negotiated a larger share of offshore resources, meaning that the province can acquire up to 10% equity in projects requiring development plan approvals. Per the equity ownership agreement, Nalcor pays a negotiated pro rata share of exploration and pre-development costs incurred by operators and their partners—on a go-forward basis, the crown corporation contributes its equity share of development and operational costs.

In the last couple of years, Nalcor has produced up to 2,800 bopd from its 10% stake in the Hibernia South Extension and a 5% stake in the White Rose Growth Project, which also includes North Amethyst and West White Rose fields, and the South White Rose Extension. The crown corporation also has acquired a 4.9% working interest in the Hebron field development project. Nalcor estimates that its production share will skyrocket to between 10,000 and 14,000 bopd, when the Hibernia South Extension and Hebron field go onstream.

Recent, ongoing exploration. In addition to its equity positions, Nalcor, along with industry consultants, has undertaken an ambitious geological assessment of NL's offshore hydrocarbon resources. This will help to reduce geological risk in offshore activity and support future Calls for Bids. This effort includes extensive new multi-client seismic data, a regional rock physics study, a seabed core analysis study and the satellite imaging of hydrocarbon seeps emanating from the sea floor.

As of 2010, roughly 85% of NL's historical seismic database was more than 15 years old. New advancements in seismic acquisition and processing technologies have enhanced the ability of explorers to image new plays and structures in basins around the world.

Accordingly, in the 2011–2014 period, Nalcor invested $15 million for an investment stake in 47,000 km of new broadband, long offest, 2D, multi-client seismic data acquired in a JV between TGS-NOPEC Geophysical Company ASA (TGS) and Petroleum Geo-Services ASA (PGS). In 2015, over 27,400 km of 2D data were acquired offshore NL. By the end of 2015, over 110,000 km of seismic data had been acquired. The program is expected to continue throughout 2016.

In addition, Nalcor, in partnership with TGS and PGS, is carrying out the first multiclient 3D seismic data acquisition offshore NL in advance of a scheduled license round. In 2015, 4,600 km^2 of 3D seismic in the Orphan basin were acquired and are now in the processing stage. "In 2015, we ran four programs," said Nalcor's Wright. "We acquired 27,000 line-km of 2D with two vessels, gained 4,600 km^2 of 3D, and conducted the slicks/seabed coring study and the satellite slick mapping. We are conducting evaluations of all Newfoundland and Labrador basins to find and quantify our oil and gas resource potential and open new frontier areas for exploration."

In December 2013, the C-NLOPB implemented a new, Scheduled Land Tenure System. This system divides the offshore into eight regions and categorizes them, based on the level of historical exploration activity. Scheduled licensing rounds will be held in each region, on either a one-, two- or four-year cycle.

In the results of the 2015 licensing round, announced last Nov. 12, seven winning bids were awarded, totaling $1.2 billion. In 2015, approximately 9% of the NL offshore was covered by either a license, call for bids or sector. However, by 2017, officials said that up to 20% of the offshore area could be covered by licenses, calls for bids and sectors.

"It's been good having mega-projects for our industry to live on, but the reason why we're excited to have this offering is that the groundwork is being laid to show consistent prospectivity," said NOIA's Cadigan. "This puts us, potentially, in a position similar to where Norway was at in the 1970s. Hopefully, this will tighten the gaps between development projects."

The heightened seismic and geological research effort has generated some healthy oil **discoveries** by Statoil in the Flemish Pass area, including Mizzen (100 MMbbl to 200 MMbbl) in 2009, and Harpoon (still under evaluation) and Bay du Nord (300 MMbbl to 600 MMbbl) in 2013. Last fall, on behalf of Statoil, the *West Hercules* semisubmersible rig (**Fig. 7**) continued with appraisal work at Bay du Nord, although results have not been made public. In March 2016, the Bay de Loup well was spud in EL-1112 to further assess the potential of this area. The *West Hercules* drilled the Cupids A-33 wildcat to TD, again with no results disclosed. In February 2016, the rig completed the Bay d'Espoir B-09 wildcat, but no data were released. Finally, in March 2016, the Baccalieu F-89 well was spud on EL-1143, which was issued to Statoil on Jan. 15, 2016.

Service/supply sector. NL is home to major infrastructure facilities, providing broad capabilities and high standards of work. The more-than-600 member companies of the Newfoundland and Labrador Oil & Gas Industries Association (NOIA), along with facilities at Memorial University, College of the North Atlantic and the Marine Institute, to name some of the bigger academic institutes, have provided skilled labor,

research, engineering, geophysical work, fabrication, construction, management and marine support, as well as other supplies and services. They have provided unique solutions to the many challenges of operating in harsh environments, including metocean forecasting, ice engineering and detection (as in icebergs), and construction and fabrication.

At the Port of St. John's, virtually all of the offshore E&P servicing work is handled through the facilities of marine stevedoring firm A. Harvey. "Business is pretty good here," said A. Harvey's director of offshore operations, Geoff Cunningham. "Overall, while there's a short-term drop for us, which was planned, there will be an uptick soon, especially with the Hebron project about to pile on top of that. So, we're putting in two additional berths along the waterfront. Statoil's ongoing exploration and potential development work gives us more certainty of our operations. We wouldn't be investing in the extra dock space, without the growth potential provided by Statoil."

Likewise, Rob Crosbie, chairman of St. John's-based Crosbie Group Limited, is upbeat about the East Canada market. "Our business is doing well, as our focus is on the operators with the three existing assets, although our customers are renegotiating some contracts," observed Crosbie. "But our existing business is fairly busy and consistent. We've been successful in picking up new work. Our basket of services—coatings, insulation, industrial cleaning, exterior maintenance, helidecks—is a fairly broad spectrum. We're the second- or third-largest employer on Hibernia. We're running close to 300 employees offshore, compared to the full-time equivalent for us, which is a little over 400."

"In terms of servicing a steady state of production, things are normal," added NOIA's Cadigan. "But the pressure is on producers to lower costs, and suppliers to lower prices. Any time the oil or gas price drops, oil companies react by trying to cut costs, and part of that is reducing the expenses for supplies and services. So, the pressure remains on suppliers."

NOVA SCOTIA

Nova Scotia (NS) has two producing natural gas projects—the Sable Offshore Energy Project and Deep Panuke. Together, these projects produce about 350 MMcfgd, representing 2.0% of Canada's natural gas production. Sable was the first offshore gas development in Canadian history. Deep Panuke commenced production in 2013.

Fig. 8. The central Thebaud complex handles gas production from five fields at the Sable Offshore Energy Project. Photo: Exxon Mobil.

The NS government estimates the province's offshore resource potential at more than 8 Bbbl of oil and 120 Tcf of gas. Significant exploration programs are also underway by Shell Canada and BP, offshore Nova Scotia (NS).

Historical background/early exploration. The first NS offshore well was drilled in 1967. One year later, the first offshore discovery was made south of Sable Island. To date, about 127 exploration wells have been drilled offshore NS, yielding 24 significant discoveries. Another 80 or so development wells were drilled through 2009, when a drilling hiatus began.

"The Nova Scotia offshore is relatively unexplored," said Stuart Pinks, CEO of the Canada-Nova Scotia Offshore Petroleum Board (CNSOPB). "We've had maybe 170 exploration wells—over 200 including production wells—drilled in our offshore history."

Development/production—Cohasset/Panuke project. This project operated from 1992 to 1999, producing 44.5 MMbbl of oil. It was Canada's first offshore oil project, beating Newfoundland's Hibernia field by about five years, when it went onstream in 1992. The project was developed by LASMO Nova Scotia Limited, in partnership with Nova Scotia Resources (Ventures) Limited. PanCanadian Petroleum (EnCana) acquired LASMO's 50% ownership in January 1996 and became operator. The project was decommissioned in 2009.

Development/production—Sable Island. Producing natural gas and liquids since 1999, the Sable Offshore Energy Project (Fig. 8) is Canada's first offshore gas project, operated by Exxon Mobil. The Sable Project dates back to the issuing of exploration licenses in the late 1950s, early offshore drilling in the 1960s, with most discoveries made in the 1970s and 1980s.

In the mid-1990s, the JV that would develop Sable was formed, and the regulatory process began leading in 1998 to approval of this development project, as well as construction of the Maritimes & Northeast Pipeline. That line would carry Sable's gas to markets in Nova Scotia, New Brunswick and the U.S. Northeast.

Sable includes seven offshore platforms in five different fields, with 21 wells and 340 km of subsea pipeline. The fields are Thebaud, North Triumph, Venture, Alma and South Venture. A sixth field, Glenelg, is not active. The development is spread over 200 km^2. The seven platforms are in shallow water, with depths between 22 and 76 m.

Interfield pipelines connect satellite fields to the central Thebaud complex, which includes a processing facility and accommodations unit, a wellhead platform and a compression deck. The project was built in phases, with first gas achieved on Dec. 31, 1999, and ongoing output of natural gas and NGLs since that time.

The Thebaud complex is connected by a 200-km subsea pipeline to a gas plant at Goldboro, Guysborough County. There, liquids are removed and sent by pipeline to the Point Tupper Fractionation Plant for additional processing. Market-ready gas is transported from Goldboro to customers via the Maritimes & Northeast Pipeline.

"Clearly, we have Sable in decline, and Deep Panuke has had recent water-related issues," noted Ray Ritcey, CEO of The Maritimes Energy Association. "However, Sable was up 20% last year, and we're hoping that the end days will be in 2019 or later."

Development/production—Deep Panuke. Encana's Deep Panuke Offshore Gas Development Project (Fig. 9) produces

natural gas from an offshore field about 250 km southeast of Halifax and transports that gas via subsea pipeline to shore, for relay to markets in Canada and the U.S.

The CNSOPB approved, with conditions, the Deep Panuke Canada Nova Scotia Benefits Plan and Development Plan on Sept. 10, 2007. The project utilizes a jackup-type offshore platform as its Production Field Center (PFC), tied back to production wells with subsea flowlines and umbilicals.

Production began in 2013, and is expected to continue for a mean life of 8 years. Reserves for the project were recalculated due to earlier-than-expected water production. They were estimated to be about 80 Bcf at the end of 2014. "Thank goodness, Encana went ahead with the project when it did," said Ritcey. "The water issue has caused them to move to seasonal production, to optimize the value of production, as pricing is based on pipeline-constrained markets in New England."

Renewed exploration/drilling. The NS Department of Energy (DOE), the Offshore Energy Research Association, and the CNSOPB have instituted geoscience analysis programs to help reduce offshore geological risk, and support future Calls for Bids. In 2009, the NS DOE commissioned a $15-million petroleum Play Fairway Analysis, examining previous drilling results and seismic research in the offshore. From this, the aforementioned estimate of 8 Bbbl of oil and 120 Tcf of gas potential was identified.

Fig. 9. The Deep Panuke gas field has been onstream since 2013 and now produces seasonally. Photo: Encana.

Fig. 10. The *Stena IceMax* drillship has been drilling Shell's first deepwater wildcat offshore Nova Scotia, the Cheshire well, since late last year. Photo: Stena Drilling Limited.

Last June, the NS DOE conducted a two-week research expedition in the Shelburne basin off the southeastern coast. The goal was to extract core samples from the ocean floor, about 2,600 m beneath the surface. "At least two of the core samples show good evidence of petrogenic hydrocarbons," said Sandy MacMullin, executive director of the Petroleum Branch in the NS DOE. "This supports the suggestion that we happen to be in an area that's oil dominant as opposed to gas dominant," explained MacMullin.

Meanwhile, Shell and BP in recent years have poured fresh investment into renewed exploration. Shell Canada was awarded four deepwater parcels for a combined work expenditure of $970 million. In 2012, BP was awarded four deepwater tracts for a total work commitment of $1.05 billion. Additionally, Shell Canada was awarded two deepwater and two shelf tracts for a commitment of $32 million. In total, the $2.05 billion committed represents the highest amount attained in Atlantic Canada, on both a per-bidding round and per-block basis. In November 2015, Statoil was the successful bidder on two deepwater parcels, for a combined work expenditure of $82 million.

"With low oil prices, Shell and BP have cancelled projects in other parts of the world, so sticking with us is a great sign of confidence, including our regulatory regime," said NS Minister of Energy Michel Samson. "Ideally, we would like to see Shell and BP have successful drilling programs and move on to development. Hopefully, that would cause other companies to take a second look at Nova Scotia."

Last October, Shell received CNSOPB approval to drill the first of two deepwater exploratory wells offshore NS, and drilling began shortly thereafter on the Cheshire wildcat. In early 2016, Shell submitted an application to drill a second well, Monterey Jack. The Cheshire well was planned to reach a 7,532 m, MD, over an 11-to-12-month period. By March 5, workers on the *Stena IceMAX* drillship had drilled the well down to 6,700 m, MD, about 225 km southeast of Halifax.

However, also on March 5, as the crew of the *Stena IceMAX* was disconnecting the rig from the well, in preparation for bad weather approaching, high waves and heave caused the riser tensioner system to release, causing the riser and lower marine riser package to fall to the seabed. Given that the water depth at the wellsite is about 2,000 m, the riser is about that same length.

Shell and the CNSOPB suspended operations at the Cheshire wellsite, pending completion of an investigation into the incident. Shell was determining whether the riser on the ocean floor would be retrieved. The operator won't know the cost of the recovery, or the duration of the delay, until the investigation is complete. WO

EDITOR'S NOTE: Part 2 of this East Canada series will examine, in greater depth, the expanded exploration efforts by the NL and NS governments, including multi-faceted geoscientific initiatives.