Natural Gas Resource Assessment of the Jeanne d'Arc Basin

Phase II 2026



Newfoundland & Labrador
CANADA


V-8020C

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Executive Summary



Newfoundland and Labrador is Canada's easternmost province and a significant contributor to both renewable and non-renewable energy development. The Province possesses a diverse and globally competitive energy endowment, including offshore oil and natural gas, hydroelectricity, wind, and emerging clean energy opportunities. Within this portfolio, offshore natural gas represents one of the Province's largest undeveloped strategic opportunities, offering compelling investment potential.

Newfoundland and Labrador's offshore area spans 1.8 million square kilometres with oil and gas reserves that are recognized for their comparatively low emissions intensity among offshore producing regions.

The Province is actively advancing policies and initiatives to support natural gas development. Newfoundland and Labrador has committed to further technical and economic studies on the feasibility of various development options, with results expected in 2027. In parallel, the Province has announced $90 million for an Offshore Exploration Fund to encourage new oil and gas exploration activities.



A dedicated natural gas royalty regime, scheduled for release in 2026, has been designed with international expert input to ensure competitiveness while delivering fair returns to the public. Any natural gas development will occur within a stable, well-established regulatory system jointly managed with the Government of Canada through the Canada–Newfoundland and Labrador Offshore Energy Regulator (C-NLOER), which administers land tenure, exploration rights, and safety oversight.

Newfoundland and Labrador offers a mature regulatory environment, a world-class offshore supply and service sector, a skilled workforce, and global expertise in harsh-environment operations. The province has a strong environmental, social, and governance (ESG) track record and is well positioned to support responsible offshore natural gas development that complements the global energy transition.

The Province holds significant, largely undeveloped offshore natural gas resources, offering compelling investment potential. Resource assessments completed by Beicip-Franlab between 2011 and 2021 estimate 133.3 billion barrels (bbls) of oil and 329.1 trillion cubic feet (Tcf) of natural gas in-place potential within less than 20 per cent of the offshore area. Much of this gas potential is concentrated in the shallow-water Jeanne d'Arc Basin, a mature producing region with established infrastructure, the focus of this Report.

In 2025, the Government of Newfoundland and Labrador released A Natural Gas Resource Assessment of the Jeanne d'Arc Basin, providing the most comprehensive and scientifically grounded evaluation of the basin's offshore natural gas resources ever undertaken. Building on this work, Phase II of the assessment expanded the scope beyond the producing fields and licensed lands assessed in Phase I to include adjacent areas and gas prone zones, culminating in a basin-wide evaluation of 39 prospective areas.

Phases I and II of the assessment provide a basin-wide evaluation of natural gas resources in the Jeanne d'Arc Basin. Phase I identified recoverable resources of 8.1 to 11.3 Tcf (P50: 9.7 Tcf) within existing licences. This includes 5.2 - 7.8 Tcf of recoverable natural gas from Significant Discovery Licences (SDLs) plus 2.2 - 4.1 Tcf of recoverable natural gas from current Production Licences (PLs). Phase II identified an additional 10.2 to 25.5 Tcf (P50: 16 Tcf) in adjacent and unlicensed areas. Combined, the assessment estimates total probabilistic recoverable natural gas resources of 19.8 to 35.4 Tcf, with a P50 estimate of 27.6 Tcf.

Importantly, a large portion of this natural gas is located outside existing licenses and is available for future investors through the scheduled land tenure system. This assessment materially improves the visibility, confidence, and commercial understanding of natural gas opportunities offshore Newfoundland and Labrador.

During Phase II, three areas stood out as having potential to support a stand-alone development - Ballicatters; Northeastern Jeanne d'Arc; and Northern Jeanne d'Arc.

With confirmed resource scale, modern infrastructure, supportive policy frameworks, and open Crown Lands available for investment, Newfoundland and Labrador is open for business and positioned to play a meaningful role in Canada's future natural gas development.

A Comprehensive Natural Gas Resource Assessment of the Jeanne d'Arc Basin

Newfoundland and Labrador's Oil and Gas Sector

Newfoundland and Labrador is Canada's only offshore oil producer, accounting for about five percent of Canada's total oil output. There are currently four offshore oil-producing projects, all located in the Jeanne d'Arc Basin: Hibernia and Hebron, each utilizing a Gravity-Based Structure (GBS), along with Terra Nova and White Rose, which both employ Floating Production, Storage, and Offloading (FPSO) vessels. The West White Rose CGS supports production from the West Rose FPSO. The upcoming Bay du Nord development, situated in the deep waters of the Flemish Pass, will be Newfoundland and Labrador's fifth oil project.



West White Rose CGS on the Grand Banks
Credit: Department of Energy and Mines

Advancing the Development of Natural Gas in Newfoundland and Labrador

Incentivizing Natural Gas Exploration

Newfoundland and Labrador is investing in additional technical work to support natural gas development, including assessing the feasibility of various development options. Results are expected in early 2027. Additionally, the Province has announced $90 million for an Offshore Exploration Fund to encourage and incentivize oil and gas exploration in offshore Newfoundland and Labrador.

Globally Competitive Royalty Regime

Alongside investing in assessments of its natural gas resources, Newfoundland and Labrador has developed a natural gas royalty regime, scheduled for industry consultation and release in 2026. Developed with input from international experts, the regime aims to be globally competitive and appealing to industry while ensuring the Province receives a fair economic return on its natural gas resources. A clearly defined natural gas royalty regime will enhance transparency and regulatory certainty for exploration and development proponents, enabling informed assessment of resource opportunities and investment decisions in the Newfoundland and Labrador offshore.

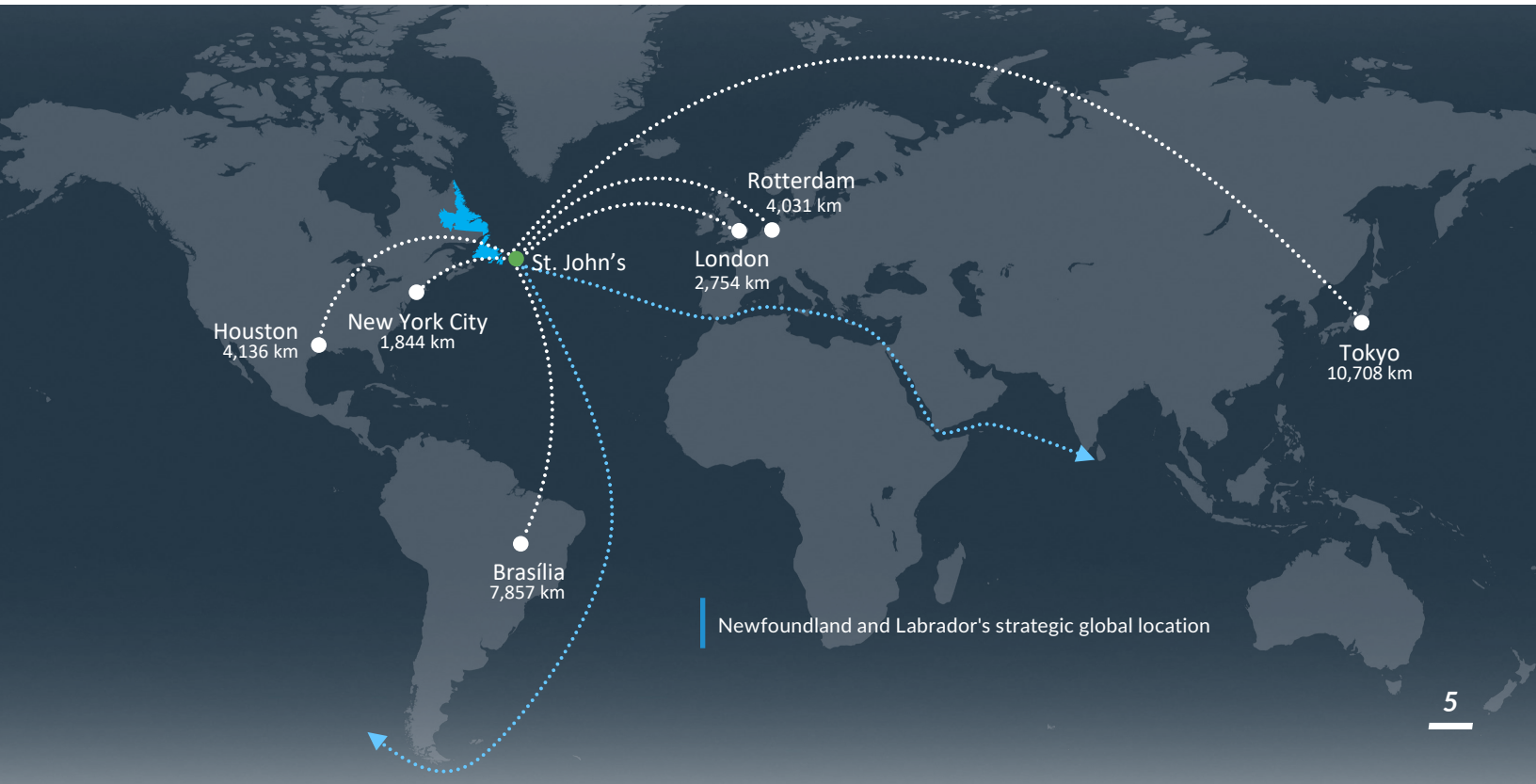
Established Regulatory Framework

Newfoundland and Labrador boasts a strong regulatory framework and a comprehensive occupational health and safety system.

The oil and gas sector in Newfoundland and Labrador is jointly regulated by the Government of Newfoundland and Labrador and the Government of Canada through the Canada–Newfoundland and Labrador Offshore Energy Regulator (C-NLOER).

The C-NLOER administers the issuance of offshore petroleum rights on behalf of both governments and oversees the scheduled land tenure system, including the Call for Nominations, Call for Bids, and Sector Identification processes. Exploration rights are issued as time-limited exploration licences within a predictable and transparent tenure framework.

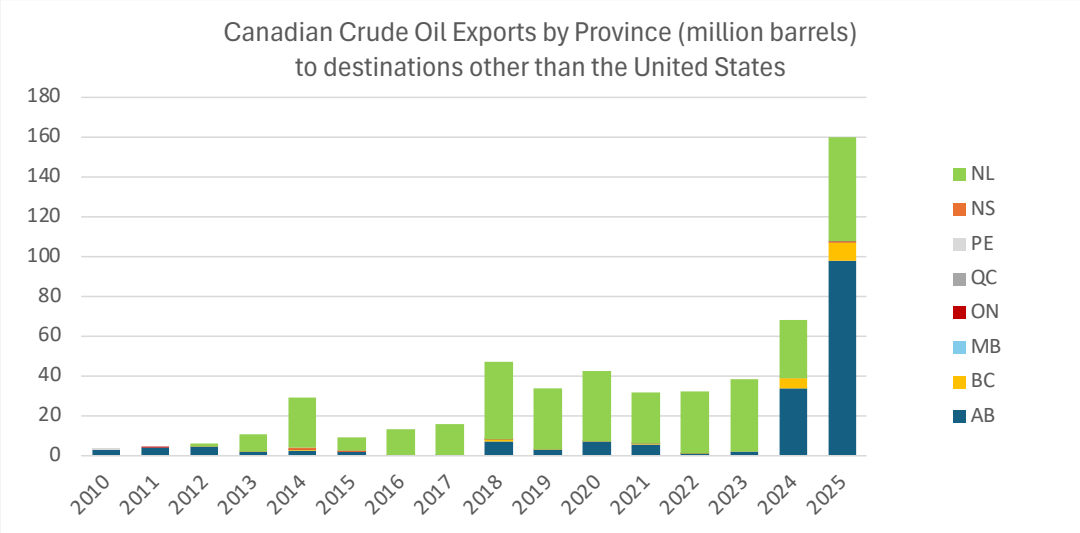
Interested parties are encouraged to contact the C-NLOER directly or visit www.cnloer.ca/exploration for further information on the offshore land tenure system.

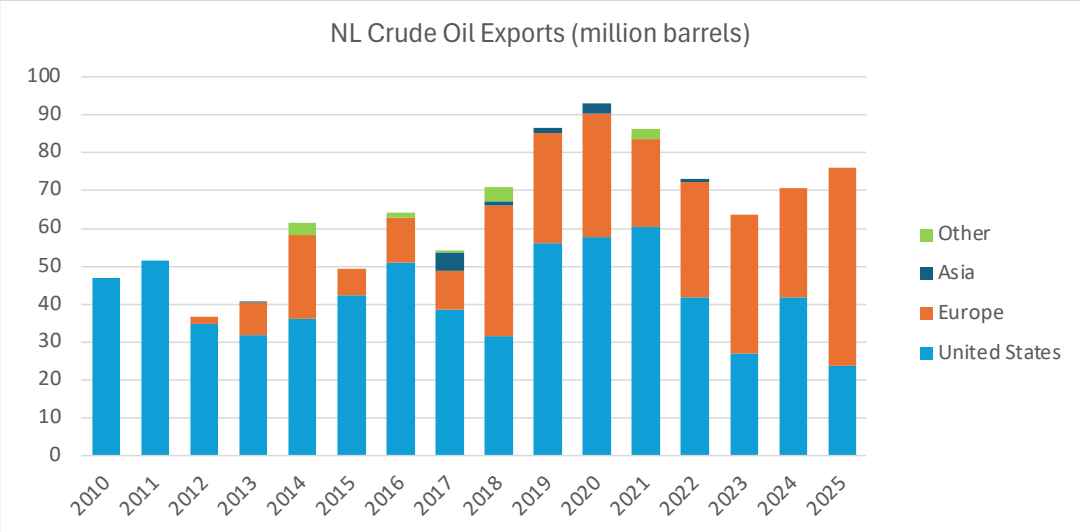


Newfoundland and Labrador's strategic global location

Newfoundland and Labrador's Competitive Advantages

Newfoundland and Labrador offers several advantages for the energy sector as an investment location. First and foremost, the Province has tremendous resource prospectivity to support future oil and natural gas developments, and its oil and gas are produced in tidal waters, providing direct access to global markets. Newfoundland and Labrador is one of the largest provincial exporters of Canadian oil to non-U.S. markets with approximately 69% of its total provincial oil exports going to Europe in 2025. Our prospectivity has attracted major international oil and gas companies, including ExxonMobil, Chevron, Equinor, BP, Cenovus and Suncor as operators or partners in ventures offshore Newfoundland and Labrador.





Source: Department of Energy and Mines, 2026

Complementing these natural competitive advantages, Newfoundland and Labrador has developed robust support systems, infrastructure, and governance models, establishing the Province as a mature jurisdiction for both conventional and renewable energy.



National Research Council of Canada - Model testing in the ice tank

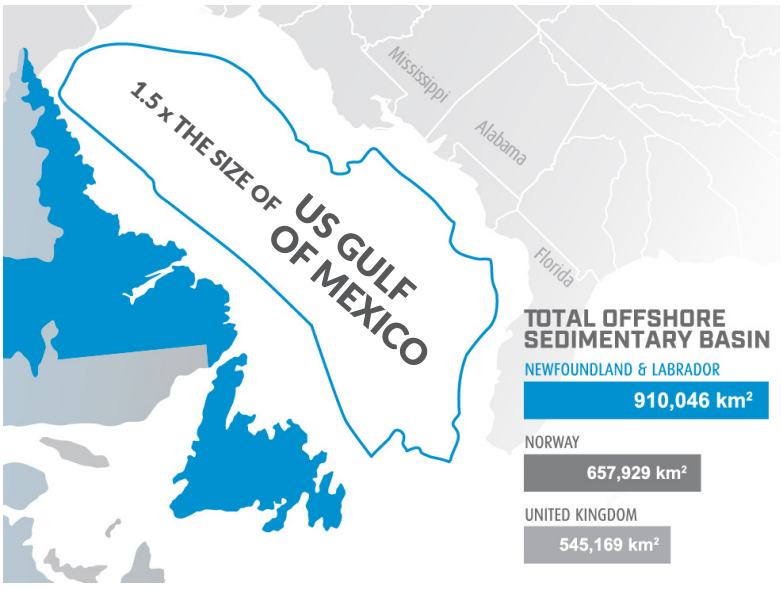
The Province has a well-established supply and service sector offering engineering, fabrication, subsea work, logistics, and marine support. This world-class supply chain attracts international investment and supports highly specialized local companies.

Newfoundland and Labrador is home to numerous public and private institutions with global expertise in operations in harsh environments, deep-water exploration, ice management, environmental and remote monitoring, and enhanced oil recovery. Additionally, we have a skilled workforce in fabrication, specialized engineering, and oil and gas operations.

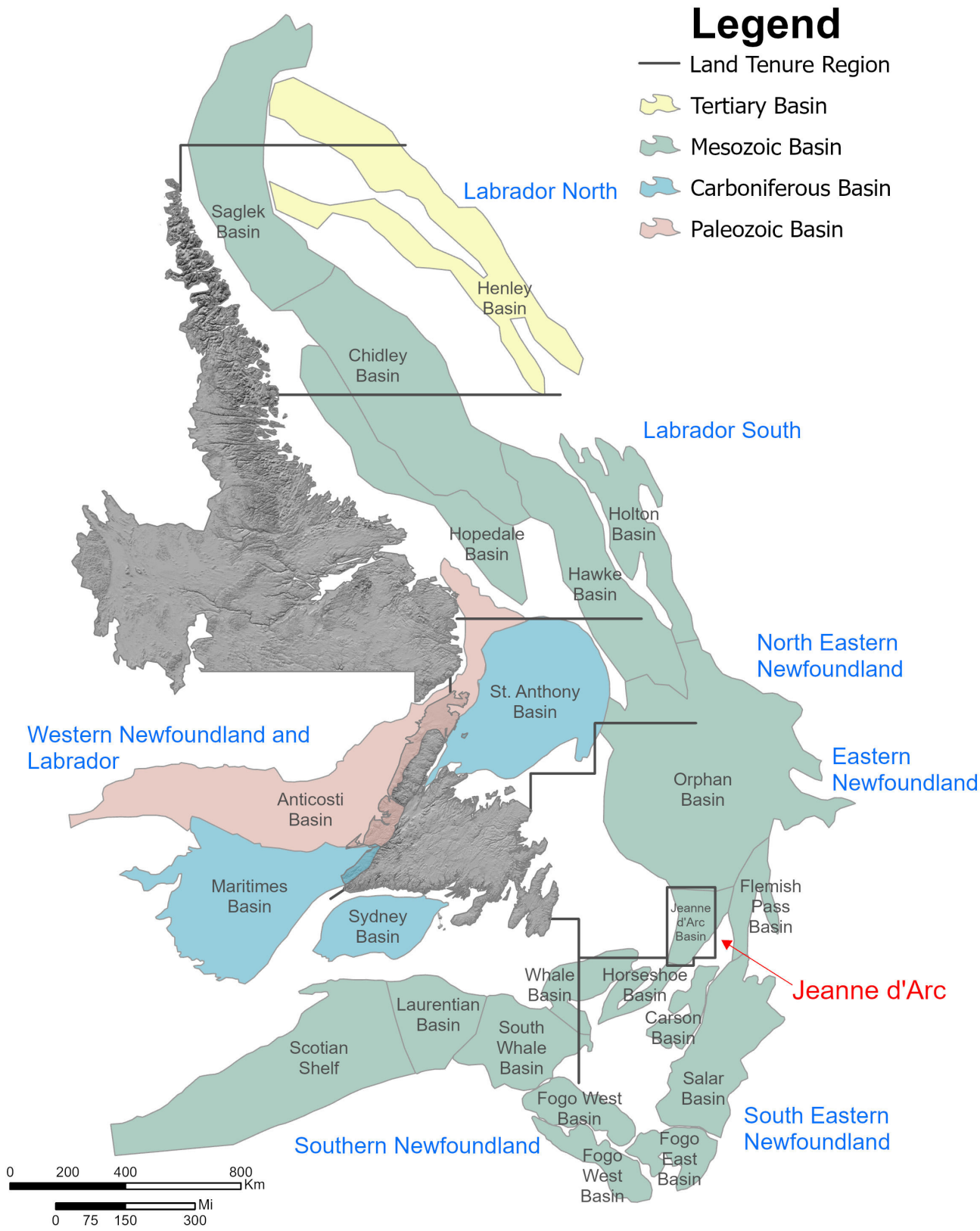
This critical mass that has supported the development of Newfoundland and Labrador's oil projects can also support the development of natural gas projects in the future. With a strong ESG record, the Newfoundland and Labrador oil and gas industry and our energy sector are well-positioned to become key players in the energy transition.

Newfoundland and Labrador's Untapped Natural Gas Resource Potential

The Province possesses significant yet largely undeveloped offshore natural gas resources, positioning Newfoundland and Labrador as a highly attractive investment destination. Between 2011 and 2021, 10 independent resource assessments conducted by Beicip-Franlab on behalf of the Oil and Gas Corporation of Newfoundland and Labrador identified an estimated 133.3 billion bbls of oil and 329.1 Tcf of natural in-place gas potential within less than 20 per cent of the province's offshore area. The assessments can be found at: oilconl.com/exploration-reports/resource-assessments/.



Total offshore area. Source: Oil and Gas Corporation of Newfoundland and Labrador



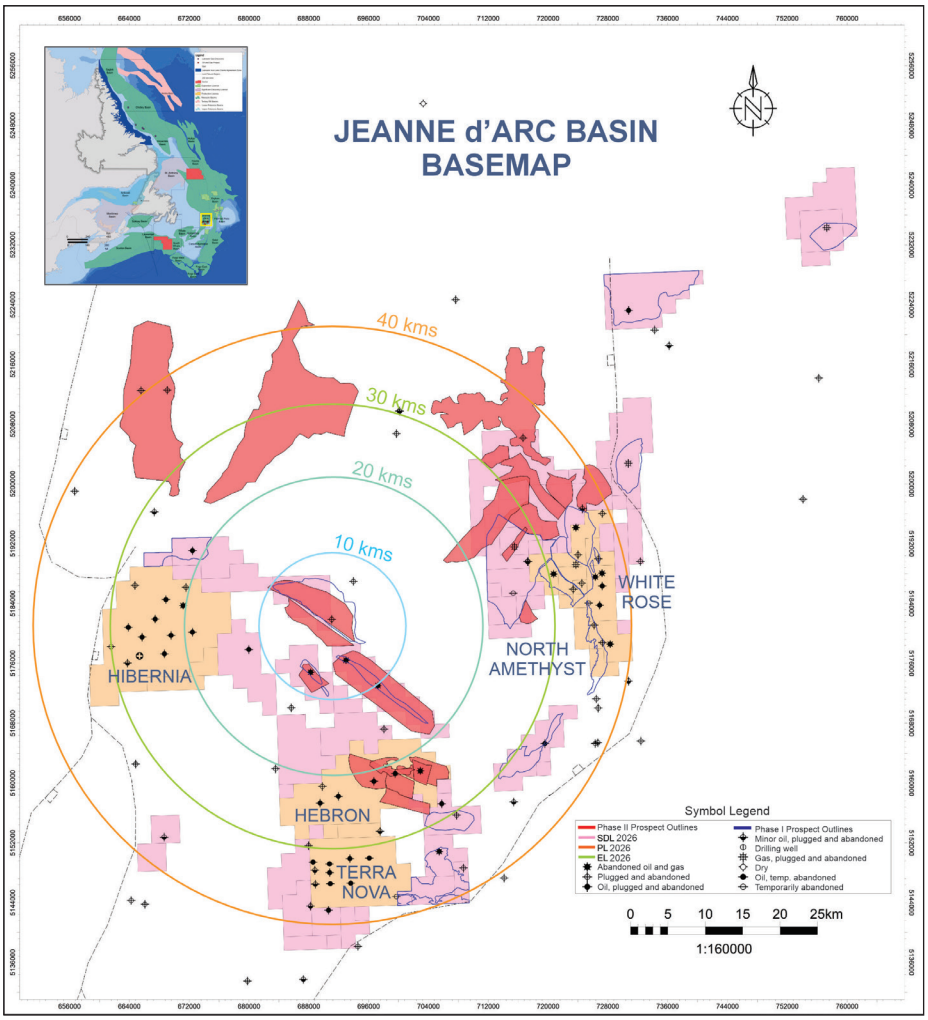
NL Offshore Basins. Source: Department of Energy and Mines, 2026

The Jeanne d'Arc Basin

Much of Newfoundland and Labrador's natural gas resources are in the shallow waters of the Jeanne d'Arc Basin. This basin has been an active oil-producing region since 1997. It is home to all major oil-producing projects in the Newfoundland and Labrador offshore: Hibernia, Hebron, White Rose, North Amethyst, and Terra Nova. It features waters less than 130 metres deep and is located approximately 350 kilometres east of the provincial capital, St. John's, which serves as a well-established hub for supply and service industries in Newfoundland and Labrador.

The Jeanne d'Arc Basin has had several significant natural gas discoveries, and all prospects lie within a 50 kilometre radius of each other and of existing infrastructure, creating potential tieback opportunities.

To date, natural gas has been used only as fuel for offshore oil production facilities and to improve oil recovery. While not the focus of this assessment, it is also worth noting that there is significant natural gas potential offshore Labrador. The Hopedale Basin is particularly noteworthy with 4 Tcf of recoverable gas discovered and held under SDLs.



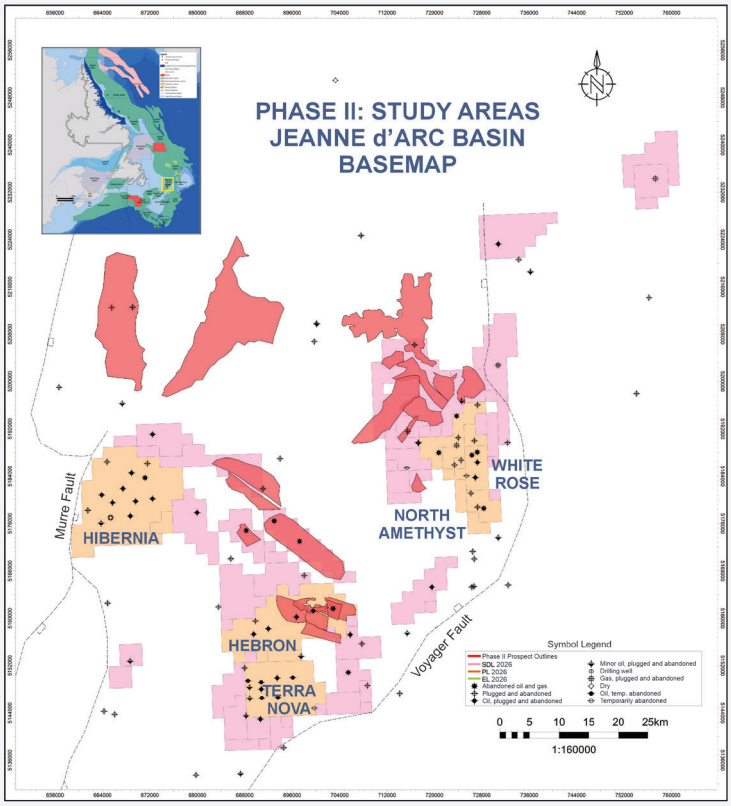
Source: Department of Energy and Mines, 2026

Natural Gas Resource Assessment in Jeanne d'Arc Basin – Phase II

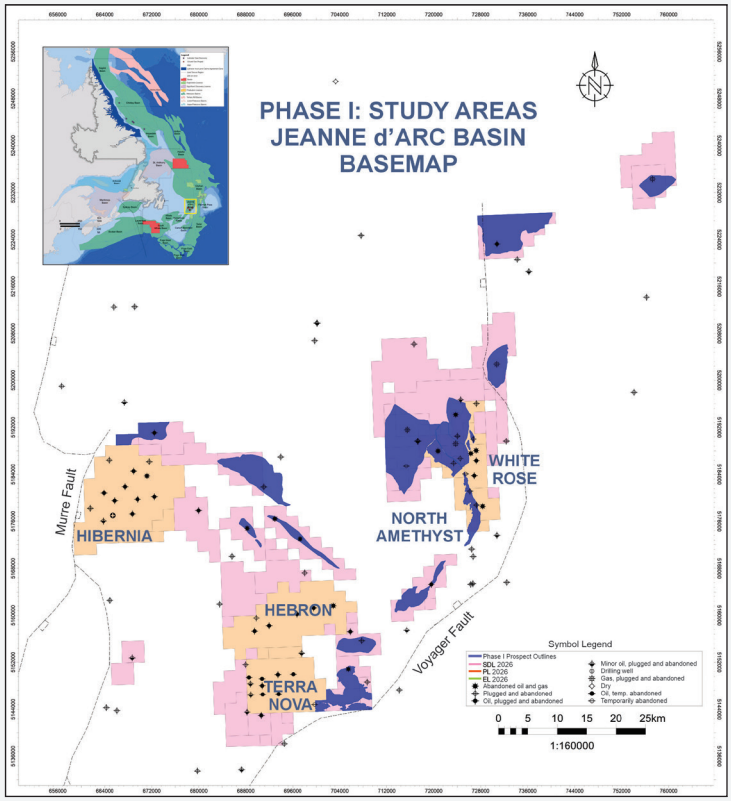
Phase II of the Natural Gas Resource Assessment was a ground-up assessment that used the same data-driven scientific approach as Phase I, integrating geoscience datasets, including seismic data, well logs, core samples, and other geological reports, to quantify the probabilistic ranges of gas-in-place and recoverable gas volumes in the Jeanne d'Arc Basin.

The Phase I assessment evaluated 18 areas with proven discoveries within SDLs or PLs in the currently producing fields in the basin. Phase II evaluated an additional 21 areas, focusing on tested gas bearing formations on the SDLs not included in Phase I, as well as exploration prospects on adjacent open Crown Lands within the northern gas prone area of the basin. The objective was to evaluate the upside natural gas volumes. An assessment of these incremental resources had not been conducted previously.

All 39 assessed areas are in shallow waters less than 130 metres deep, within 20 kilometres of existing infrastructure, and supported by high-resolution 3D seismic mapping. Most of the land areas that form the basis of both the Phase I and Phase II assessments have relevant discovery wells that have been flow-tested, helping to quantify the range of discovered gas in place more accurately.



Land map of the Jeanne d'Arc Basin showing the Phase II Study Areas 19-39 (red) with SDLs (pink) and PLs (orange).
Source: Department of Energy and Mines, 2026



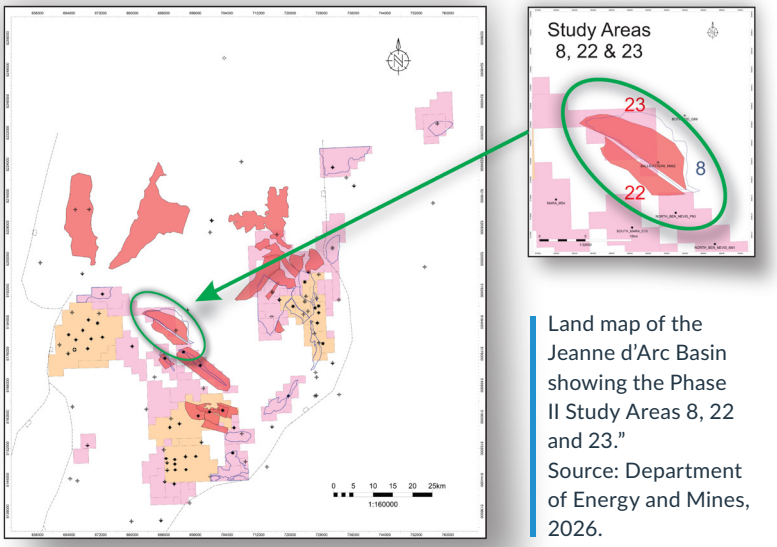
Land map of the Jeanne d'Arc Basin showing the Phase I Study Areas 1-18 (blue) with SDLs (pink) and PLs (orange).
Source: Department of Energy and Mines, 2026

Summary of Select Study Areas

The 39 mapped study areas in the integrated Natural Gas Resource Assessment show favourable petroleum system elements for hydrocarbon accumulation. Three areas in particular stand out as having significant potential for the development of stand-alone natural gas developments.

Study Areas 8, 22 and 23 – Ballicatters

Located in approximately 101 metres water depth, approximately 21 kilometres east of the Hibernia Field GBS, areas 8 and 23 have been drilled (Ballicatters M-96/z) and have proven gas with a drill stem test. Based on well results, a Significant Discovery Declaration (SDD) was awarded in 2013. As mapped, study area 22 is likely in communication with the adjacent hydrocarbon accumulation in study area 8.



Land map of the Jeanne d'Arc Basin showing the Phase II Study Areas 8, 22 and 23."
Source: Department of Energy and Mines, 2026.

Study areas 8, 22, and 23 represent a hydrocarbon accumulation that spans SDL 1051 and open Crown Lands. In January 2026, a portion of the SDD was relinquished to the Crown; as a result, the open Crown Lands portion could be subject to the scheduled land tenure system. These study areas are attractive due to a large a real extent with seismic evidence of reservoir continuity and proven gas discovery. Area 22 would require a well to validate volumes.

The un-risked volume range for study area 8 is estimated to be 1061–2776 bcf oil gas in place (OGIP) and 649-1850 bcf recoverable.

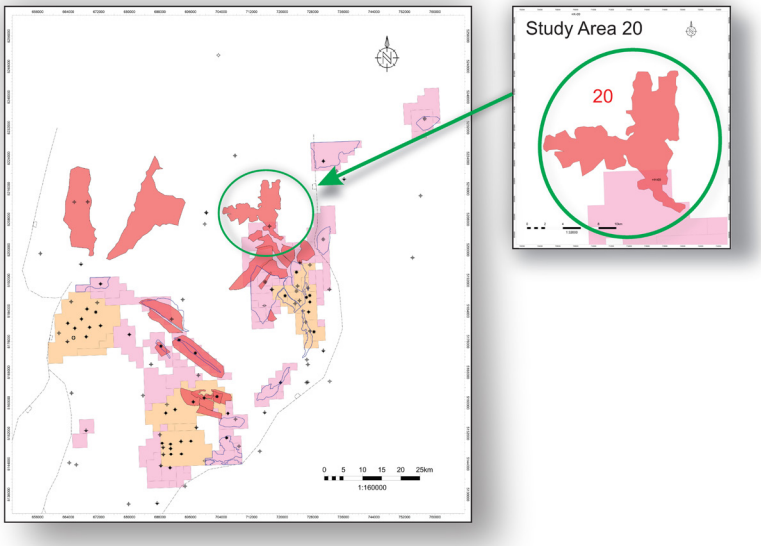
The un-risked volume range for study area 23 is estimated to be 182–1318 bcf OGIP and 136-991 bcf recoverable.

The un-risked volume range for study area 22 is estimated to be 101-731 bcf OGIP and 65-478 bcf recoverable. Once proven, this could be developed as a stand-alone or a tie-back to a hub. However, agreements need to be reached among current landholders regarding the SDL.

Study Area 20 - Northeastern Jeanne d'Arc Basin

Located mainly on open Crown Lands in approximately 115 metres water depth, approximately 18 kilometres northwest of the White Rose asset, this study area is attractive due to its large areal extent supported by strong seismic amplitudes. The study area includes the well Glenwood H 69. The well did not reach the main reservoir, but it recorded a gas kick, confirming the presence of gas. This untested study area requires a well to validate the volumes.

The un-risked volume range is estimated to be 2803–12482 bcf OGIP and 2067–9343 bcf recoverable. Once proven, this could be developed as a stand-alone or tied back to a hub.



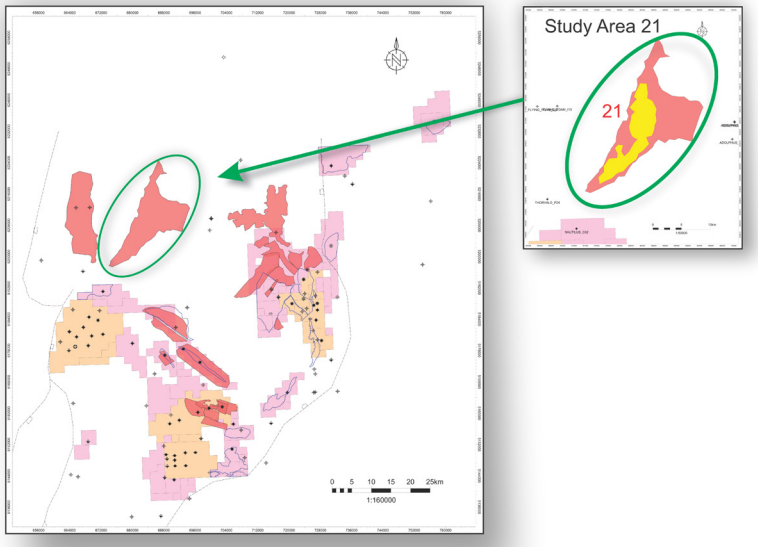
Study Area 20 – Northeastern Jeanne d'Arc Basin.
Source: Department of Energy and Mines, 2026.

Study Area 21 - Northern Jeanne d'Arc Basin

Located entirely on open Crown Lands in approximately 130 metres water depth, approximately 20 kilometres northeast of the Hibernia Field GBS, this undrilled study area is attractive due to its large areal extent with seismic evidence of reservoir continuity, and nearby wells show encouraging gas indications. This untested study area requires a well to validate the volumes.

The un-risked volume range is estimated to be 1554–20640 bcf OGIP and 995–13601 bcf recoverable. Once proven, this could be developed as a stand-alone or tied back to a hub.

Further details on all 39 prospects identified in the comprehensive assessment are provided in the attached report.



Study Area 21 – Northern Jeanne d'Arc Basin.
Source: Department of Energy and Mines, 2026

Comprehensive Assessment of Jeanne d'Arc Basin

Together, Phase I and Phase II represent a comprehensive natural gas assessment of the Jeanne d'Arc Basin, integrating decades of exploration data, modern seismic interpretation, and probabilistic resource methodologies to quantify both discovered and potential natural gas volumes to inform future development pathways.

The combined probabilistic recoverable natural gas identified in both Phase I and Phase II ranges from 19.8 to 35.4 Tcf, with a P50 estimate of 27.6 Tcf. Much of this natural gas is not associated with existing licenses and remains available for investors to develop. The integrated information and analysis for the 39 prospects provided in this report will assist potential developers in better understanding the business case for developing natural gas offshore Newfoundland and Labrador.

Phase I: Probabilistic Natural Gas Volumes

Volumes	P90	P50	P10
Prospect OGIP (BCF)	8279	9905	11892
Prospect REC (BCF)	5291	6438	7843

Phase II: Probabilistic Natural Gas Volumes

Volumes	P90	P50	P10
Prospect OGIP (BCF)	14939	23371	37351
Prospect REC (BCF)	10221	16013	25519

Phase I and II: Probabilistic Natural Gas Volumes (NO PLs)

Volumes	P90	P50	P10
Prospect OGIP (BCF)	24908	36228	47598
Prospect REC (BCF)	16681	24426	32151

Phase I and II: Probabilistic *Recoverable* Natural Gas Volumes (ALL PLs, SDLs and Adjacent Lands)

Volumes	P90	P50	P10
Prospect REC (BCF)	19810	27590	35396

* These are probabilistic statistical volumes. P50s (or P90s or P10s) cannot be added together to calculate an overall total.

Source: Department of Energy and Mines, 2026

Canada and Newfoundland and Labrador are Open for Business

Newfoundland and Labrador is open for business as we pursue promising opportunities in natural gas development. Our Natural Gas Resource Assessment report highlights the value of our natural gas resource in the Jeanne d'Arc Basin, and we continue to expand our understanding of this resource and its development potential.

The investment climate for oil and gas development in Canada has improved, and the federal government has established a Major Projects Office to support large-scale projects and expedite federal regulatory approvals. Canada is accelerating natural gas development efforts, aiming to establish itself as a major global leader in LNG supply.

Newfoundland and Labrador can be an important contributor to Canada's ambitious natural gas development plans. Ground-level efforts to assess the potential of natural gas resources are essential to development.

Like our approach to oil, Newfoundland and Labrador will develop our natural gas resources responsibly. Our industry is recognized for strong ESG performance. We will preserve that reputation while promoting natural gas development as an essential low-emissions energy source that supports the world's transition to a lower-carbon economy.

Investors and developers interested in exploring oil and/or natural gas development are encouraged to contact the Department of Energy and Mines, Government of Newfoundland and Labrador, to discuss how we can work together to advance opportunities for offshore development in Newfoundland and Labrador.

Annex A

Natural Gas Resource Assessment of the Jeanne d'Arc Basin Offshore Newfoundland and Labrador



Source: TGS Geophysical Company



OFFSHORE NATURAL GAS RESOURCE ASSESSMENT 2025-2026

THE NATURAL GAS RESOURCE ASSESSMENT

- This study aims to quantify the probabilistic range of discovered and prospective gas volumes and natural gas liquid yields within the offshore Jeanne d'Arc Basin.
- While exploration for offshore oil has been ongoing for over 50+ years, no focused effort has yet been undertaken to find and develop natural gas. The current natural gas volumetric estimates, as noted by the Canadian Newfoundland and Labrador Offshore Energy Regulator (C-NLOER$_1$), is approximately 10.9 tcf / 309 $10^9 m^3$ of recoverable resources across the entire East Coast offshore (C-NLOER$_1$).
- The natural gas discoveries are primarily free gas, capping an oil column, found as a result of oil exploration drilling. Most discoveries currently reside on Significant Discovery Licenses (SDLs) or Production Licenses (PLs) of the current oil fields; Hibernia, Hebron, White Rose, North Amethyst and Terra Nova (Figure 1).
- Recent focus on natural gas as a preferred source of energy, emphasis on energy security on a global scale and the clear need to develop in jurisdictions like Newfoundland and Labrador offshore with upstream low emissions, has brought natural gas to the forefront of stakeholders minds.

TECHNICAL OVERVIEW SUMMARY

- A natural gas scientific data driven analysis was undertaken to understand the range of discovered gas in-place, recoverable gas volumes and natural gas liquid yields held within the Jeanne d'Arc Basin (Figure 1).
- Probabilistic range of original gas in-place (OGIP), recoverable gas (REC) and recoverable NGLs on SDLs and PLs were calculated using all available modern data at the time of this study. The combined probabilistic total for prospects included in this analysis is shown in Table 1.
- All volumes noted in this document are unrisked. Geological chance of success, mechanical chance of success or development risks have not been applied to these volumes.

Total Probabilistic Volumes in Jeanne d'Arc Basin (Study Area)	P90	P50	P10
OGIP - NO PLs (bcf)	24908	36228	47598
RECOVERABLE - NO PLs (bcf)	16681	24426	32151
PL REC ASSOC GAS (bcf)	2208	3169	4129
REC NGL SDLs + PLs (mmbbls)	258	372	488
TOTAL REC STUDY AREAS + PLs (bcf)	**19810**	**27590**	**35396**

Table 1. Probabilistic estimates of combined total volumes of OGIP and REC in the Jeanne d'Arc Basin. Statistical volumes cannot be added together for an overall summed total.

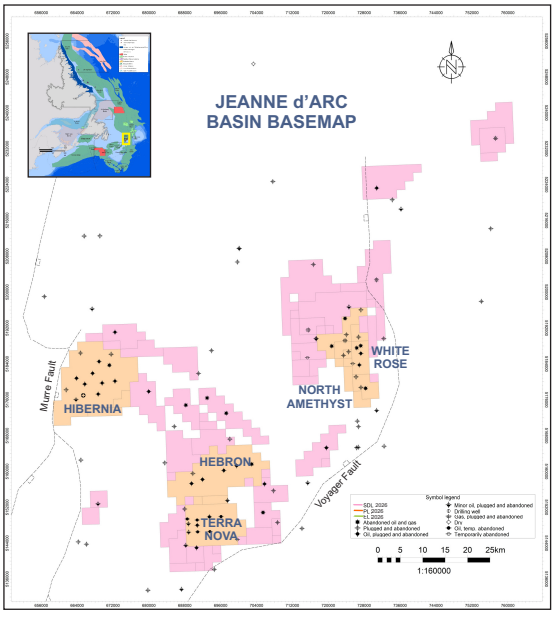
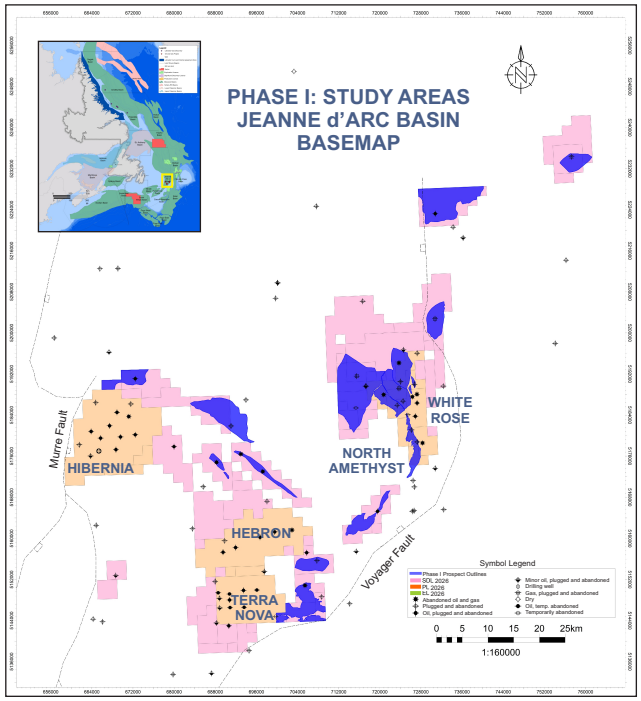


Figure 1. Land map of the Jeanne d'Arc Basin showing the study area. Basin bounding faults defined by grey dashed lines (Department of Energy and Mines 2026).

PROBABILISTIC NATURAL GAS VOLUME SUMMARY

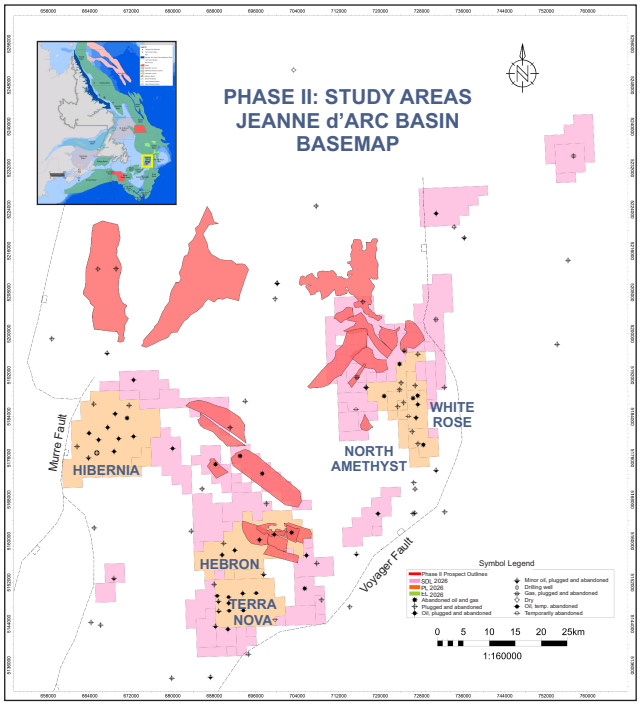
- The Phase I objective aimed to calculate the range of discovered OGIP and REC volumes in the main gas bearing formation, often the one used to award the SDL (Figure 2). The combined probabilistic volumes of the first 18 areas for this assessment are shown in Table 2.
- The Phase II objective evaluated the upside natural gas volumes encountered in other formations in the wellbores, adjacent lands and open Crown Lands (Figure 3). The combined probabilistic volumes of the last 20 areas for this assessment are shown in Table 3.



Phase I: Probabilistic Natural Gas Volumes	P90	P50	P10
Combined Study Areas 1-18 OGIP (bcf)	**8279**	**9905**	**11892**
Combined Study Areas1-18 REC (bcf)	**5291**	**6438**	**7843**

Table 2. Probabilistic estimates of combined total volumes of unrisked OGIP and REC of the Phase I gas prospects in the Jeanne d'Arc Basin (excluding PL's). Statistical volumes cannot be added together for an overall summed total.

Figure 2. Land map of the Jeanne d'Arc Basin showing the Phase I study areas 1-18 (blue) with SDLs (pink) and PLs (orange). Basin bounding faults defined by grey dashed lines (Department of Energy and Mines 2026).



Phase II: Probabilistic Natural Gas Volumes	P90	P50	P10
Combined Study Areas 19-39 OGIP (bcf)	**14939**	**23371**	**37351**
Combined Study Areas 19-39 REC (bcf)	**10221**	**16013**	**25519**

Table 3. Probabilistic estimates of combined total volumes of unrisked OGIP and REC of the Phase II gas prospects in the Jeanne d'Arc Basin. Statistical volumes cannot be added together for an overall summed total.

Figure 3. Land map of the Jeanne d'Arc Basin showing the Phase II study areas 19-39 (red) with SDLs (pink) and PLs (orange). Basin bounding faults defined by grey dashed lines (Department of Energy and Mines 2026).

Phase I & II: Probabilistic Natural Gas Volumes (No PLs)	P90	P50	P10
Combined Study Area OGIP (bcf)	**24908**	**36228**	**47598**
Combined Study Area REC (bcf)	**16681**	**24426**	**32151**
Phase I & II: Probabilistic Natural Gas Volumes (ALL PLs, SDLs and Adjacent Lands)	P90	P50	P10
Combined REC Study Area (bcf)	**19810**	**27590**	**35396**

Table 4. Combined total probabilistic unrisked volumes of Phase I & II gas prospects in the Jeanne d'Arc Basin. Statistical volumes cannot be added together for an overall summed total.

STUDY AREA AND METHODOLOGY

- Each of the SDL land areas have relevant discovery wells with flow tested volumes of natural gas in their respective wellbores. The phase one objective aimed to calculate the range of discovered OGIP and REC volumes in the main gas bearing formation, often the one used to award the SDL (Figure 2). The phase two objective evaluated the upside natural gas volumes encountered in other formations in the wellbores, adjacent lands and open Crown Lands (Figure 3).
- The Geoscience Petroleum Division utilized multiple time and depth seismic datasets over the study area. A workflow was developed to integrate interpreted time horizons, well tops, well ties, sonic and density logs to generate velocity models and convert time seismic datasets to the depth domain.
- Detailed interpretations were mapped on high resolution 3D seismic surveys to evaluate the structural - stratigraphic traps used to calculate the bulk rock volume (BRV) for this assessment.
- Analyzed curves for volume of shale, porosity and water saturation were generated by a third party petrophysical consultant (SLB) in order to define appropriate ranges for the assessment.
- @risk software was utilized to generate the stochastic original gas in place and recoverable ranges.

CURRENT OIL AND GAS INDUSTRY

- The Province of Newfoundland and Labrador, located on the east coast of North America, is Canada's leading offshore oil producing region. Since the discovery of oil in the Jeanne d'Arc Basin in 1979 with the exploration well Hibernia P-15, five oil fields have started production in the Jeanne d'Arc Basin: Hibernia, Terra Nova, White Rose, North Amethyst, and Hebron (Figure 1).

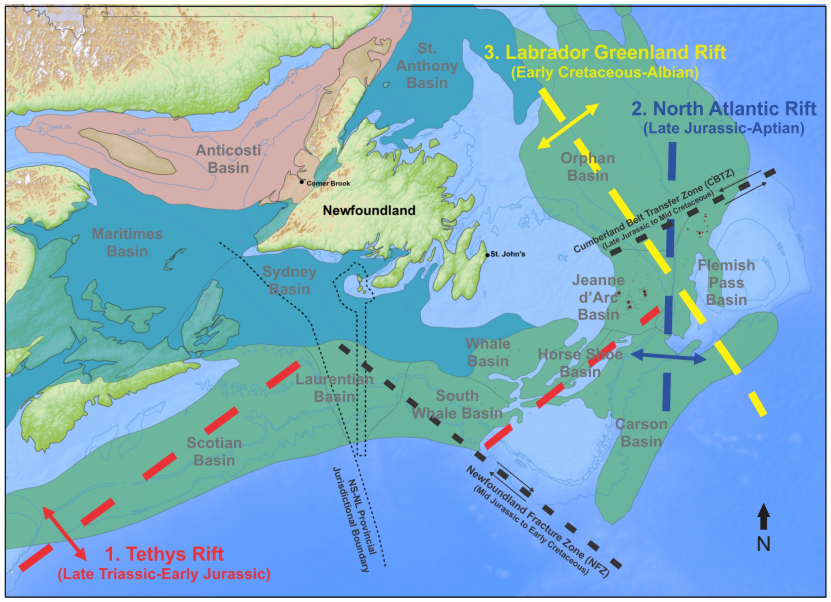


Figure 4. Regional geology of the Canadian Atlantic Margin showing main structural elements that define the basins including three phases of rift extension and transfer zones. Modified from Enachescu (2020).

- To date, oil production is in excess of 2.4 billion barrels of oil with remaining recoverable reserves/resources totaling 3.0 Bbbls, 10.97 Tcf of natural gas and 267 million barrels natural gas liquids in East Coast Newfoundland and Labrador offshore (noted by C-NLOER$_1$ as of February 2026).

REGIONAL GEOLOGY OF THE ATLANTIC MARGIN

- In eastern Canada, a series of interconnected sedimentary Mesozoic rift basins developed (green areas on map; Figure 4).
- This network of basins stretch from offshore Nova Scotia to Newfoundland and Labrador. The Scotian Basin extends between Cape Breton Island and Southern Newfoundland. The offshore Newfoundland area contains; Laurentian, South Whale, Whale, Horse Shoe, Jeanne d'Arc, Flemish Pass and Orphan basins (green areas on map; Figure 4).
- The Mesozoic extensional Jeanne d'Arc Basin (9000 km^2) formed over hyper-stretched Precambrian and Paleozoic basement on the Canadian Atlantic Margin.

JEANNE d'ARC BASIN GEOLOGY

- Jeanne d'Arc Basin is host to most of the significant petroleum discoveries in the Newfoundland and Labrador offshore area. This basin forms an elongate NE-SW trending large half-graben structure, hinged on the East side by the Voyager Fault, the Murre Fault to the West, the Egret Fault to the South and the Cumberland Belt Transfer Zone (CBTZ) delineating the basin to the North (Figure 1 and 4).
- Three main extensional rift phases influenced the final structural shapes of the basins expressed today (Figure 4):
    1. Tethys Phase (Red), during Late Triassic-Early Jurassic opening in the Northwest-Southeast direction
    2. North Atlantic Phase (Blue), during Late Jurassic-Early Cretaceous opening in the East-West direction
    3. Labrador Phase (Yellow), during late Early Cretaceous opening the basin further in the Southwest to Northwest orientation

JEANNE d'ARC BASIN GEOLOGY (continued)

- The rift phases propagated a series of extensional faults in the crust to form the Jeanne d'Arc basin region which subsequently created a deep depression in which to capture the northeast thickening wedge of clastic sediments (Figure 4 and 5).
- The four petroleum system elements: source, reservoir, trap and seal exist to create the optimal conditions for hydrocarbon accumulations in the Jeanne d'Arc Basin (Figure 5)
    - Jurassic source rocks of the Egret Formation consists of organic-rich deep marine silts and muds
    - Late Jurassic, Cretaceous and Tertiary reservoir rocks contain porous permeable siliciclastic sandstones
    - Numerous structural-stratigraphic traps
    - Prevalent lateral and top seals
- The 50 m to 500 m Late Jurassic Tithonian and Kimmeridgian organic rich shales of the Rankin Formation is the predominant source rock underlying the fields in the Jeanne d'Arc Basin. The Kimmeridgian Egret Member is a Type II, oil prone source rock with up to 9% TOC and the average hydrogen index (HI) ranging from 560 mg HC/g TOC to 410 mg HC/g TOC.
- Expulsion of the kerogen and migration of oil started in the Early Cretaceous and continue to present day with the oil phase transitioning to gas phase in the deeper northern basin areas in the Late Cretaceous Aptian/Albian time (Figure 6).

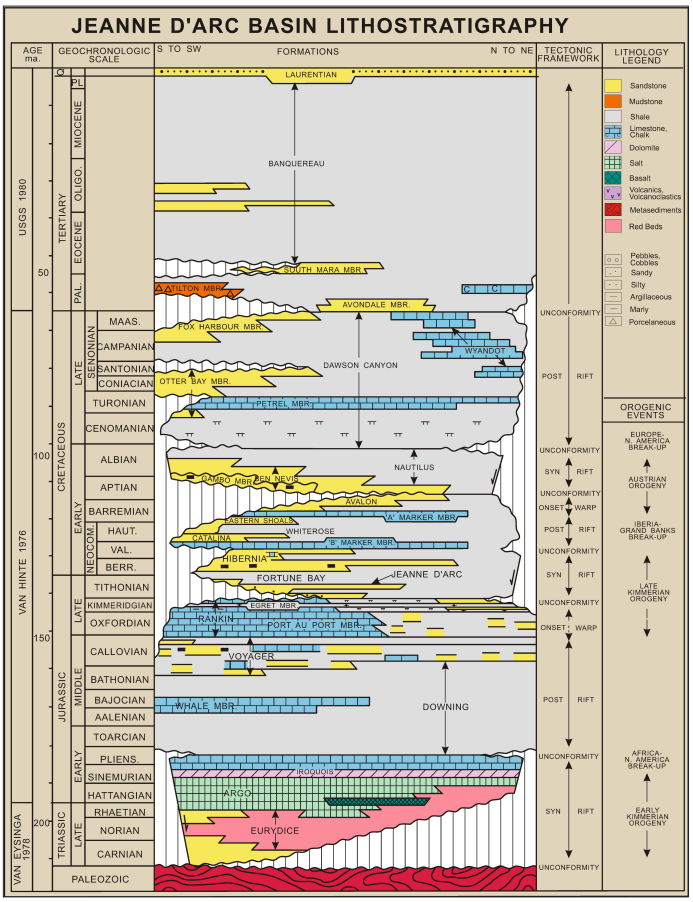


Figure 5. Jeanne d'Arc Basin stratigraphic chart illustrating deposition of sediment during the synrift and post rift phases. Modified after Sinclair (1992).

- The basin exhibits numerous stacked siliciclastic sandstone intervals from the Late Jurassic to the Tertiary age and are proven to be high reservoir quality with porosities ranging from 10-30% in the sandstones.
- Regional flooding events resulted in deep marine muds deposited over the reservoirs sandstones providing the impermeable seal necessary to trap the hydrocarbons in place.

NOMENCLATURE

- **Gross Thickness:** Total thickness from top reservoir to base reservoir or contact
- **Net Thickness:** Gross Interval that passes a volume of clay (Vcl) cut off
- **Reservoir Thickness:** Net Interval that passes a Vcl and porosity cut off (i.e. net sand)
- **Pay** Thickness: Reservoir Interval that passes a Vcl, porosity and water saturation cut off (i.e. net pay)
- **Reservoir:Gross** ($N:G_{res}$): reservoir interval / gross interval
- **Pay:Gross**: ($N:G_{pay}$) pay / gross
- **Average Porosity:** ($Avg\ Phi_{res}$): average phi over the Reservoir
- **Gas Saturation** (Sg): average gas saturation over the Pay
- **Formation volume Factor** (1/Bg)
- **Bulk Rock Volume** (BRV)
- **Net to Gross** (N:G)
- **Repeat Formation Sampler** (RFS)
- **Drill Stem Test** (DST)
- **Original Gas In Place** (OGIP**;** bcf)
- **Recoverable Gas** (REC; bcf)
- **Natural Gas Liquid Yield** (NGL; bbls/mmscf)

HYDROCARBON CONTACTS

- **Gas-Oil Contact** (GOC)
- **Gas-Water Contact** (GWC)
- **Gas Down To Contact** (GDT)
- **Oil Up To Contact** (OUT)
- **Water Up To Contact** (WUT)

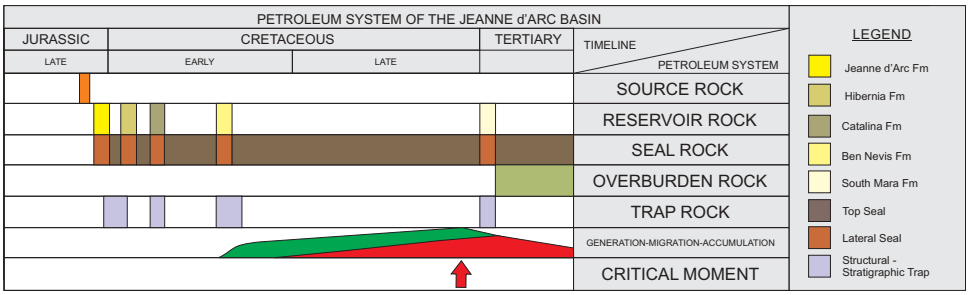


Figure 6. Petroleum system event chart summarizing the timing of each petroleum element for the Jeanne d'Arc Basin.

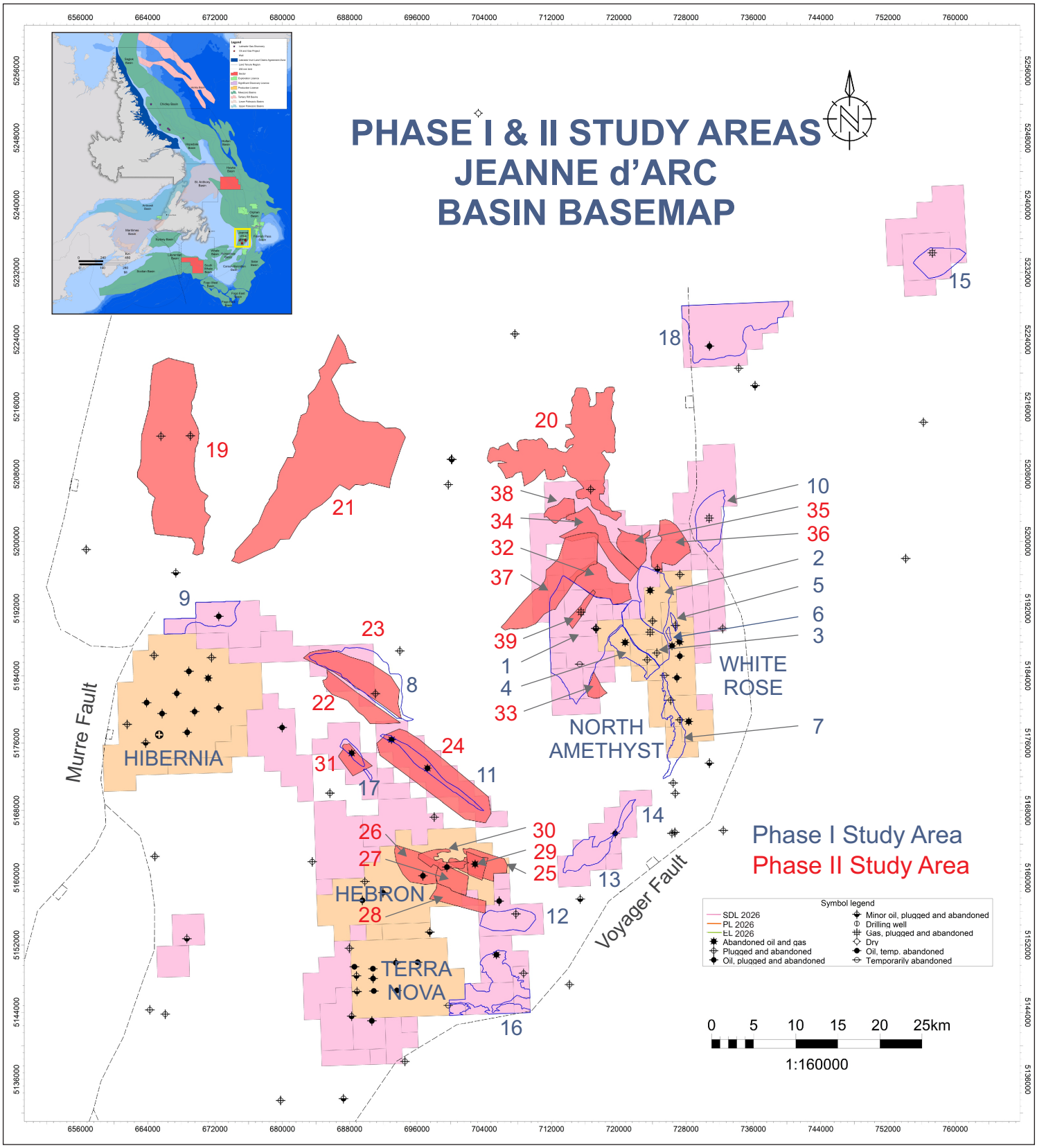


Figure 7. Basemap illustrating the location of the study areas for Phase I (1-18 outlined in blue) and Phase II (19-39 filled with red). Volumes for the phases are referenced in Tables 1 through 6.

PHASE I: JEANNE d'ARC BASIN SDL GAS RESOURCE (P50) SUMMARY

Table 5: An @risk statistical assessment of the P50 unrisked gas resource summaries for the main gas bearing formations on the SDLs and select PLs, with the applicable NGL yields. Statistical volumes cannot be added together for an overall summed total (Blue outline polygon Study Areas in Figure 7).

Study Area	Significant Discovery	Formation	SDL (PL)	OGIP P50 (bcf)	REC P50 (bcf)	NGL Yields (bbls/mmscf)	NGL (MMbbls)
1	White Rose (H-70 Area)	BNA	1019, 1020, 1023, 1025, 1026, 1027, 1028, 1054, (1014)	2243	1436	37	123.4
2	White Rose (N-22 Area)	Ben Nevis	1028, (1013 & 1014)	1469	947		
3	White Rose (C-30 Area)	Ben Nevis	1028 & 1025; (1006, 1009, 1010, 1014)	1045	673		
4	White Rose (J-49 Area)	Ben Nevis	1007,1009, 1010 1014	416	268		
5	White Rose (H-20)	Ben Nevis	(1013)	10	7		
6	White Rose (B-19z)	Ben Nevis	(1006 & 1013)	8	5		
7	North Amethyst (K-15 Area)	Ben Nevis	(1006,1007 & 1008)	53	34	37	1.3
8	Ballicatters (M-96/z)	BNA	1051	1718	1109	22	24.4
9	Nautilus (C-92)	Catalina	1001, 1041	796	511	48	24.5
10	Trave (E-87)	Hibernia	1031	591	382	24	9.2
11	North Ben Nevis(P-93/M-61)	Ben Nevis	1008	299	192	32	6.1
12	West Bonne Bay (F-12/z)	Upper Hibernia	1040	276	178	24	4.3
13	South Fortune (G-57)	Basal Hibernia	1011, 1012	139	90	23	2.6
14	North Fortune (G-57)	Basal Hibernia	1011, 1012	36	24		
15	North Dana (I-43)	Tempest	200A, 200B, 200C	119	77	23	1.8
16	Springdale (M-29)	South Mara	1013, 1014, 1015, 1016, 1017	111	71	36	2.6
17	South Mara (C-13)	Ben Nevis	1003	55	36	47	1.7
18	South Tempest (G-88)	Tempest	197	20	13	23	0.3

- Natural Gas Liquids (NGLs) are a mixture of light hydrocarbons that exist in the gaseous phase in the reservoir and are recovered as liquids in gas processing plants. NGLs differ from condensate in two principal respects:

  1. NGLs are extracted and recovered in gas plants rather than lease separators or other lease facilities, and

  2. NGLs include very light hydrocarbons (ethane, propane, or butanes) as well as the pentanes-plus that are the main constituents of condensates (Source from SPE).

- Natural Gas Liquids on the SDLs are derived from formation flow tests (Table 5).
- Statistical mathematical volumes for P50's (or P90's or P10's) cannot be added together to calculate an overall total.

PHASE II: JEANNE d'ARC BASIN GAS RESOURCE (P50) SUMMARY

Table 6: A @risk statistical assessment of the P50 unrisked gas resource summaries in the upside natural gas volumes encountered in wellbore, adjacent lands and open Crown Lands (red polygon study areas in Figure 7). Statistical volumes cannot be added together for an overall summed total.

Study Area	Formation	Lands	OGIP P50 (bcf)	REC P50 (bcf)
19	Catalina	Crown Land	574	369
20	Albian	Crown Land / SDL 1061	6505	4895
21	Upper Cretaceous	Crown Land	7787	4942
22	Middle Avalon	Crown Land / SDL 1051	353	299
23	Middle Avalon	Crown Land / SDL 1051	617	462
24	Lower Hibernia	SDL 1008	813	609
25	A-Marker	PL 1012	164	106
26	Upper Hibernia	PL 1012	490	317
27	Upper Hibernia	PL 1012	165	107
28	Upper Hibernia	PL 1012	503	326
29	Basal Hibernia	PL 1012	38	24
30	Ben Nevis	PL 1012	40	26
31	Jeanne d'Arc	SDL 1003	4	3
32	BNA	SDL 1027 / 1028	492	317
33	BNA	Crown Land / SDL 1020	26	17
34	Ben Nevis	SDL 1028 / 1061	392	252
35	Ben Nevis	SDL 1028 / 1029	264	171
36	Ben Nevis	SDL 1028 / 1029 / 1061	351	228
37	Lower Hibernia	Crown Land / SDL 1026 / 1028 / 1054 / 1061	1789	1159
38	Lower Hibernia	SDL 1061	185	120
39	Eastern Shoals	SDL 1026 / 1027	14	9

• Statistical mathematical volumes for P50's cannot be added together to calculate an overall total.

PRODUCTION FIELDS IN THE JEANNE d'ARC BASIN: CONTINGENT RESOURCES

- For the production fields, the associated solution gas that is not consumed in operations (CiO) during oil production is reinjected into the reservoir to enhance oil recovery and/or for conservation.
- A conservative approach has been applied which assumes gas development or gas cap 'blowdown' occurs at the end of the field life (EOFL), with CiO projections accounted for up to that point.
- To estimate the solution gas available at EOFL, the range of oil Estimated Ultimate Recovery (EUR) published by the C-NLOER is used, multiplied by the initial gas-oil ratio (GOR), with adjustments made to exclude CiO (fuel and flare gas). The same recovery factor distribution for gas fields is applied, when a gas cap is present.
- The NGL yield estimates are derived from formation flow tests, typically Drill Stem Test (DST) results. These estimates provide a data-driven assessment of recoverable liquids, ensuring a comprehensive evaluation of the resource potential.

Field	P90 Gas (bcf)	P50 Gas (bcf)	P10 Gas (bcf)	P90 NGL (mmbbl)	P50 NGL (mmbbl)	P10 NGL (mmbbl)
Hibernia	1154	1615	2122	77	100	123
Hebron	77	161	330	2	2	3
Terra Nova	59	98	139	0	0	0
White Rose	873	1163	1460	31	41	50
North Amethyst	45	62	78	2	2	2
TOTAL	**2208**	**3169**	**4129**	**112**	**145**	**178**

Table 7: Associated recoverable gas resources for the fields on production for all formations. Shrinkage was accounted for in the recovery factor. Statistical volumes cannot be added together for an overall summed total.

STUDY AREA 1: SDLs and PL 1014 H-70 REGION

- SDLs 1019, 1020, 1023, 1025, 1026, 1027, 1028, 1054, PL 1014
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 8019 ha

Key Well: White Rose H-70
Interval: Ben Nevis Siltstone to A-Marker

- Gross : 585m
- Gas Pay: 33.5m
- GOC: -3642m TVDss
- Sg: 66%
- N:G_{res}: 11%
- N:G_{pay}: 6%
- Avg Phi_{res}: 12%

- White Rose H-70 prospect uses range of contacts supported by gas pressures, samples and DST in H-70/z, A-78 and L-61.
- P90 BRV was determined from mapping the Ben Nevis Siltstone top to A-Marker (both flexed to well tops to account for depth error) with GDT of -3584m TVDss yellow polygon on Figure A and yellow interval on Figure B).
- P50 BRV was determined from same methodology as P90 and most likely GOC of -3642m TVDss based on pressures (yellow and orange polygons on Figure 5 and yellow interval on Figure B).
- P10 BRV was determined from same methodology as P90 to OUT 3661m TVDss (yellow,orange and red polygons on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to A-Marker interval; offset wells were used (Figure C and Table A).
- Reservoir pressure is approximately 37000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

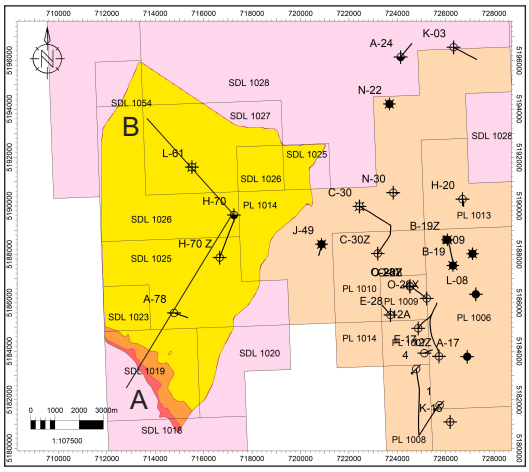


Figure A. Basemap illustrating the outline for White Rose A-78/H-70/H-70z prospect; yellow, orange, red polygons used as input to determine the P90, P50 and P10 BRV. A-B line depicting location of schematic cross section.

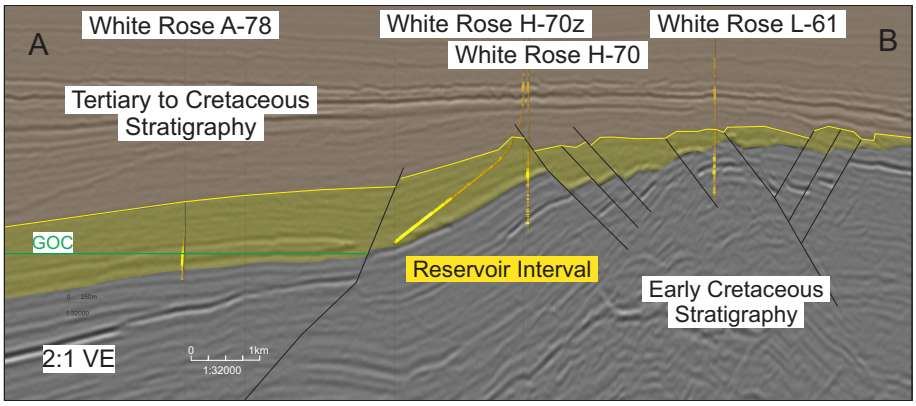


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the southwest to northeast extent across the White Rose A-78/H-70/z prospect. Target reservoir interval from Ben Nevis Formation to A-Marker (highlighted in yellow).

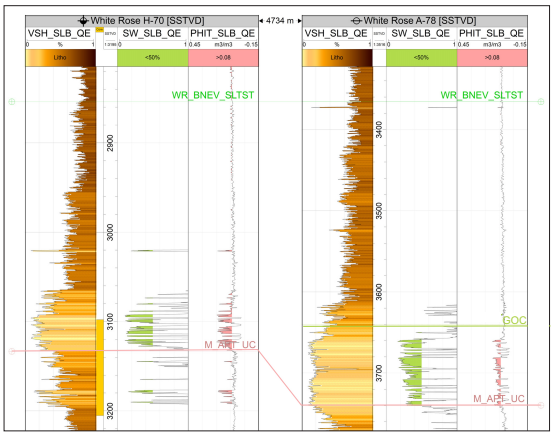


Figure C. White Rose H-70/A-78 well section over the reservoir interval from Ben Nevis Siltstone Formation to A-Marker including the assumed GOC.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	23243	7	10	60	239	1227	763
P50	25358	12	12	66	265	2243	1436
P10	27473	19	14	72	284	3698	2465

Table A. Input values compiled from Ben Nevis Siltstone Formation to A-Marker within the White Rose H-70 prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 2: SDL 1028 and PL 1013, 1014 N-22 REGION

- SDL 1028, PL 1013, 1014
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 2642 ha

Key Well: White Rose N-22
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

- Gross : 77m
- Gas Pay: 10.3m
- GOC: -3014m TVDss
- Sg: 65%
- $N:G_{res}$: 55%
- $N:G_{pay}$: 19%
- Avg Phi_{res}: 14%

- White Rose N-22 prospect uses the GOC of -3014m TVDss from the White Rose N-30 well; supported by pressure data.
- P50 BRV was determined from mapping the Ben Nevis Siltstone top to Mid-Aptian Unconformity (both flexed to well tops to account for depth error) down to the GOC within the fault bounded block (yellow polygon on Figure A and yellow interval on Figure B).
- P1 BRV was determined from same methodology as P50 but includes the red area to the west (yellow and red polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure C and Table A).
- Reservoir pressure is approximately 37000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

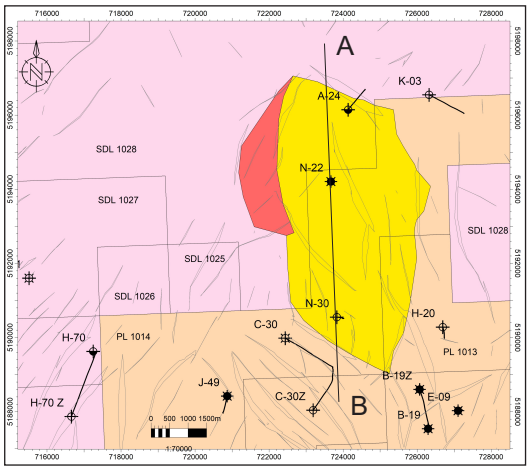


Figure A. Basemap illustrating the outline for White Rose N-22 prospect; yellow and red polygons used as input to determine the P50 and P1 BRV. A-B line depicting location of schematic cross section.

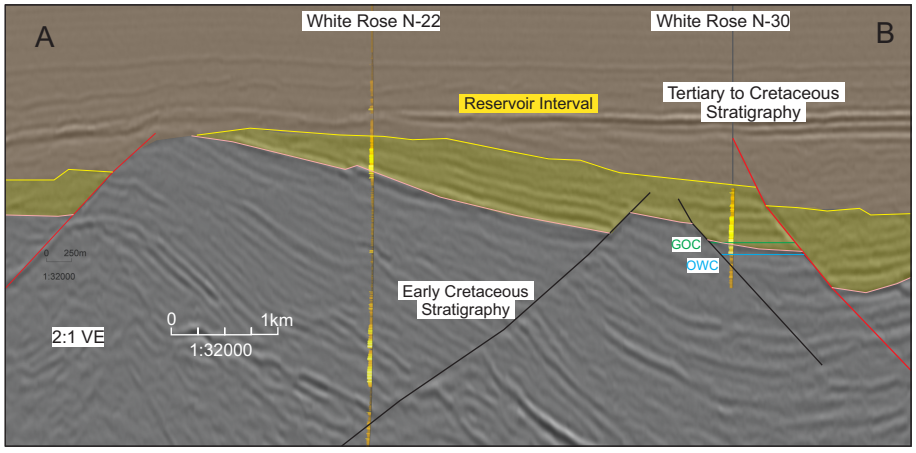


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the north to south extent across the White N-22 prospect. Target reservoir interval from Ben Nevis Formation to Mid-Aptian Unconformity, highlighted in yellow between the two red faults.

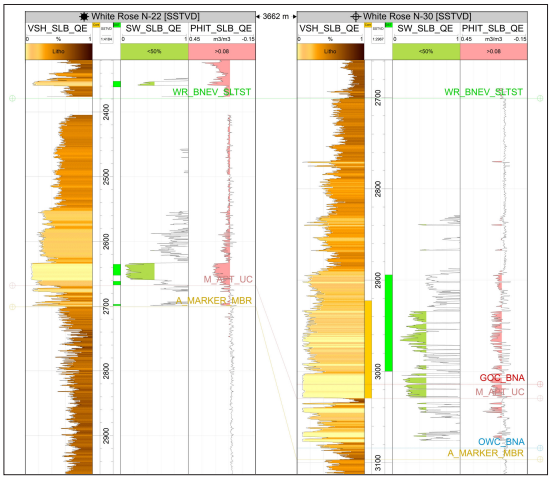


Figure C. White Rose N-22 to N-30 well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity including the GOC.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	4557	33	12	62	239	1198	709
P50	4811	38	13	66	265	1469	947
P10	5065	46	14	71	284	1811	1258

Table A. Input values compiled from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity within the White Rose N-22 prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 3: SDLs and PLs C-30 REGION

- SDL 1028 and 1025; PL 1006, 1009, 1010, 1014
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 2012 ha

Key Well: White Rose C-30z
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

- Gross : 377m
- Gas Pay: 15m
- GOC: -3085m TVDss
- Sg: 59%
- N:G_{res}: 40%
- N:G_{pay}: 4%
- Avg Phi_{res}: 13%

- White Rose C-30/z prospect uses the GOC of -3085m TVDss observed in White Rose C-30z; supported by gas samples and DST.
- P50 BRV was determined from mapping the Ben Nevis Siltstone top to Mid-Aptian Unconformity (both flexed to well tops to account for depth error) down to the GOC within the fault bounded block (yellow polygon on Figure A and yellow interval on Figure B).
- P1 BRV was determined from same methodology as P50 but includes the red area to the North (yellow and red polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure C and Table A).
- Reservoir pressure is approximately 35000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

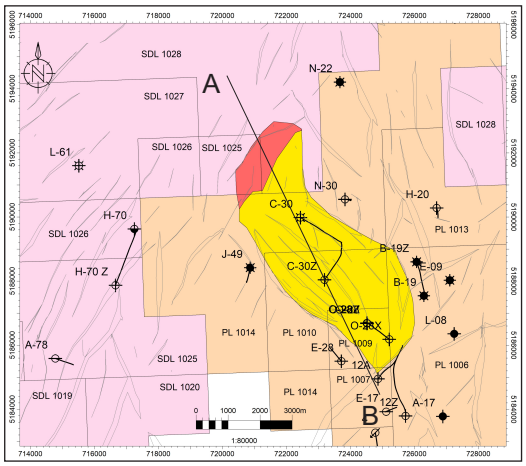


Figure A. Basemap illustrating the outline for White C-30/z prospect; yellow and red polygons used as input to determine the P50 and P1 BRV. A-B line depicting location of schematic cross section.

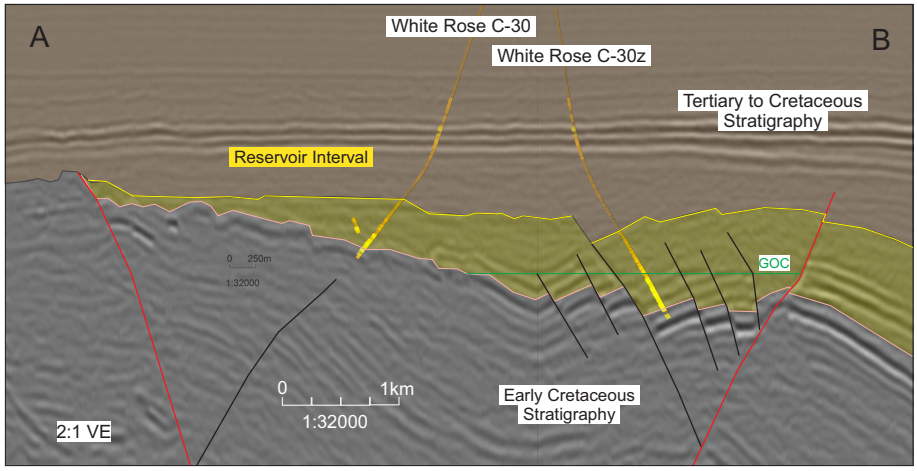


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across the White Rose C-30/C-30z prospect. Target reservoir interval from Ben Nevis Formation to Mid-Aptian Unconformity, highlighted in yellow between the two red faults.

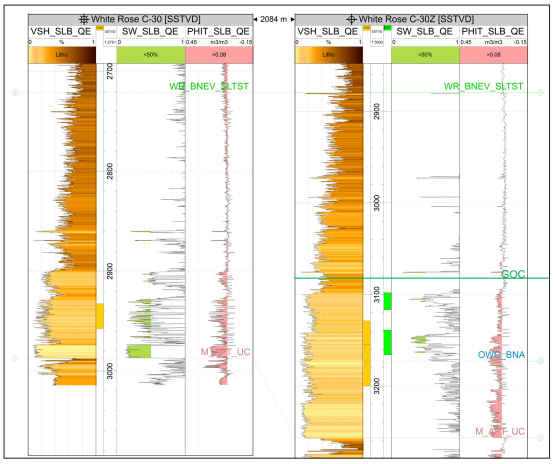


Figure C. White Rose C-30/C30z well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity including the GOC.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	2905	29	12	61	239	682	414
P50	2997	43	13	67	265	1045	673
P10	3089	63	14	73	284	1548	1046

Table A. Input values compiled from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity within the White Rose C-30/z prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 4: PLs J-49 REGION

- PL 1007,1009, 1010 1014
- Effective Date: November 19, 2007
- License Representative: Cenovus Energy Inc
- Prospect Area: 1276 ha

Key Well: White Rose J-49
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

- Gross : 343m
- Gas Pay: 28m
- GOC: -3070m TVDss
- Sg: 71%
- N:G_{res}: 17%
- N:G_{pay}: 8%
- Avg Phi_{res}: 11%

- White Rose J-49 prospect uses the GOC of -3070m TVDss; supported by gas samples and DST.
- P50 BRV was determined from mapping the Ben Nevis Siltstone to Mid-Aptian Unconformity (both flexed to well tops to account for depth error) down to the GOC within the fault bounded block (yellow interval on Figure B).
- P1 BRV was determined from mapping the Ben Nevis Siltstone top to A-Marker down to GOC (red polygon on Figure and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure C and Table A).
- Reservoir pressure is approximately 31000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

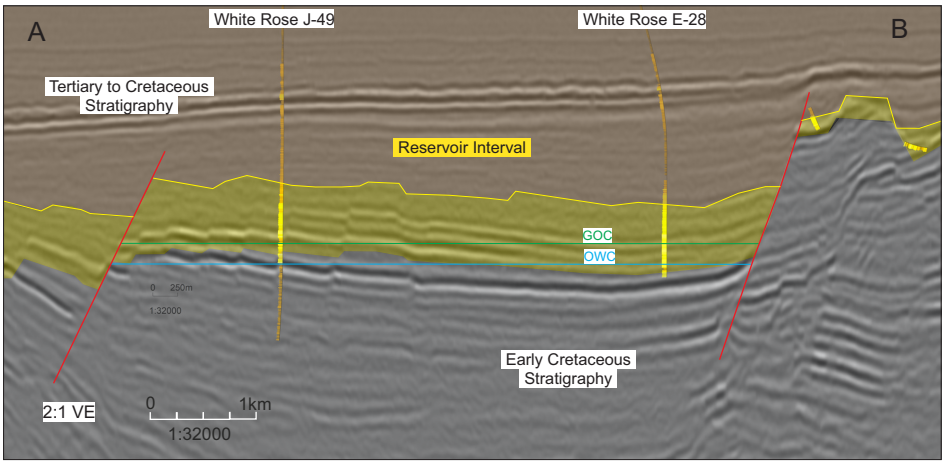


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across the White Rose J-49 prospect. Target reservoir interval from Ben Nevis Formation to Mid-Aptian Unconformity, highlighted in yellow between the two red faults.

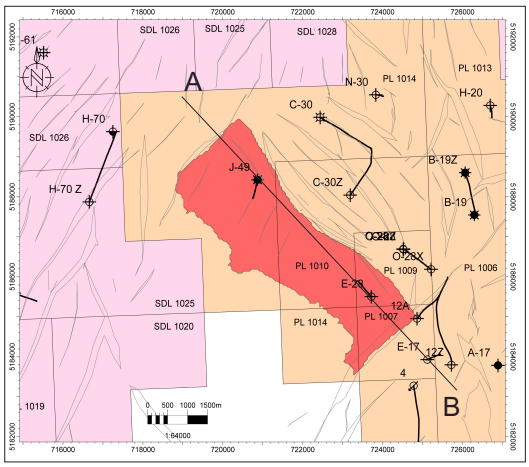


Figure A. Basemap illustrating the outline for White Rose J-49 prospect; red polygon used as input to determine the P1 BRV. A-B line depicting location of schematic cross section.

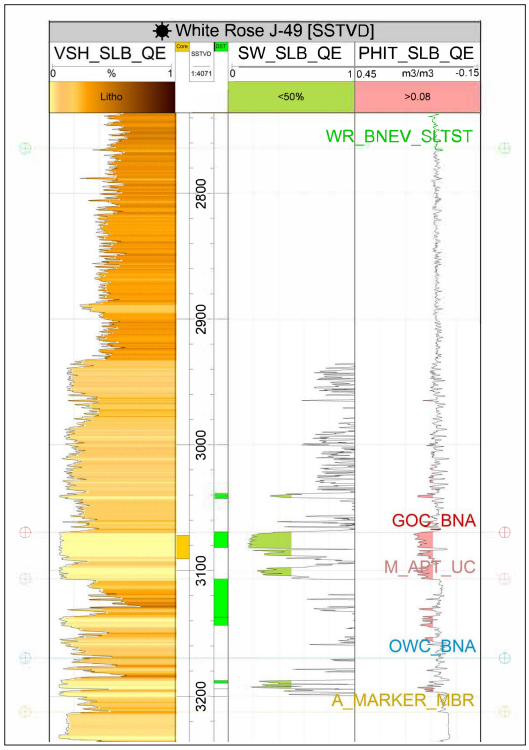


Figure C. White Rose J-49 well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity including the GOC.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	2107	12	12	61	239	213	132
P50	2203	24	13	67	265	416	268
P10	2299	46	14	73	284	819	546

Table A. Input values compiled from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity within the White Rose J-49 prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 5: PL 1013 H-20 REGION

- PL 1013
- Effective Date: December 19, 2025
- License Representative: Cenovus Energy Inc.
- Prospect Area: 83 ha

Key Well: White Rose H-20
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

• Gross :	437m	• Sg:	52%
• Gas Pay:	1.0m	• N:G_{res}:	66%
• GOC:	-2872m TVDss	• N:G_{pay}:	0.2%
		• Avg Phi_{res}:	12%

- White Rose H-20 well contains a gas oil contact (GOC) at -2872m TVDss as noted in the End of Well Report.
- P50 BRV was determined from mapping the Ben Nevis Siltstone top (flexed to well tops to account for depth error) down to the GOC (red polygon on Figure A and yellow on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure C and Table A).
- Reservoir pressure is approximately 32000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

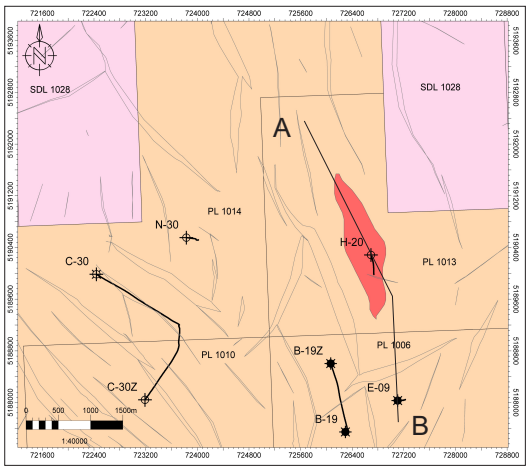


Figure A. Basemap illustrating the outline for White Rose H-20 prospect; red polygon used to dertermine the P50 BRV. A-B line depicting location of schematic cross section.

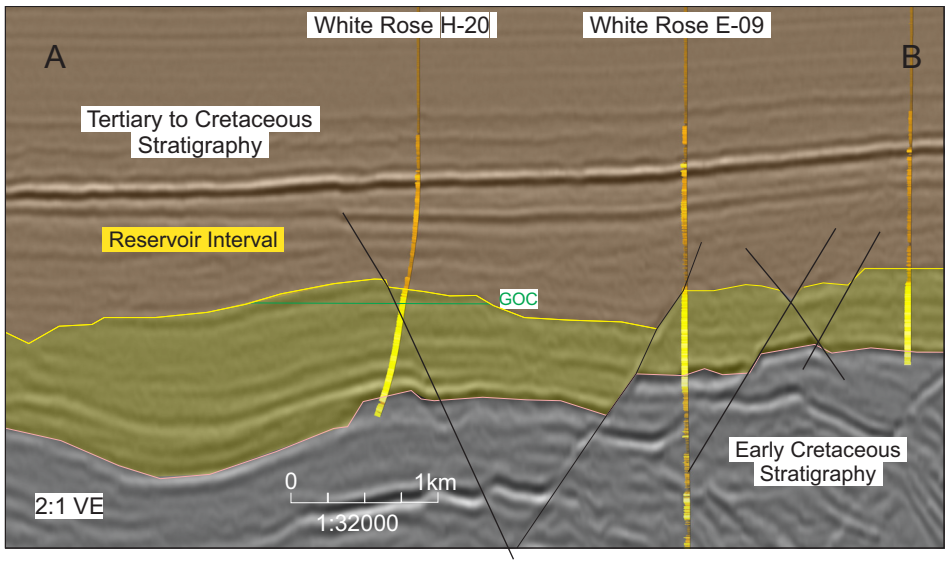


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the north to south extent across the White Rose H-20 prospect. Target reservoir interval from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity, highlighted in yellow.

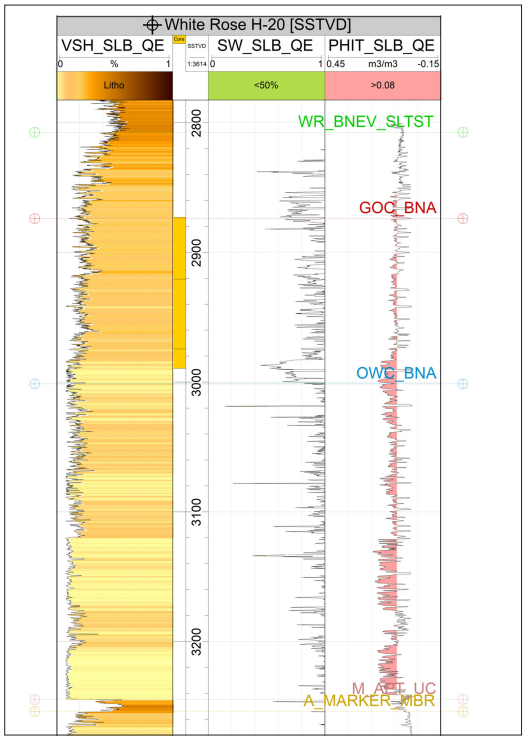


Figure C. White Rose H-20 well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity including the GOC.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	43	32	9	54	239	8	5
P50	49	37	10	60	265	10	7
P10	55	44	11	66	284	13	9

Table A. Input values compiled from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity within the White Rose H-20 prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 6: PL 1006 & 1013 WHITE ROSE B-19z BEN NEVIS FM

- PL 1006 and 1013
- Effective Date: August 10, 2025
- License Representative: Cenovus Energy Inc.
- Prospect Area: 50 ha

Key Well: White Rose B-19z
Interval: Ben Nevis Siltstone to Mid-Aptian Unconformity

• Gross :	315m	• Sg:	62%
• Gas Pay:	34m	• N:G_{res}:	89%
• GOC:	-2893m TVDss	• N:G_{pay}:	11%
		• Avg Phi_{res}:	15%

- White Rose B-19z well contains a gas oil contact at -2893m TVDss as noted in the Development Plan Amendment report.
- P50 BRV was determined from mapping the Ben Nevis Siltstone (flexed to well tops to account for depth error) down to the GOC (red polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone to Mid-Aptian Unconformity interval; offset wells were used (Figure C and Table A).
- Reservoir pressure is approximately 36000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

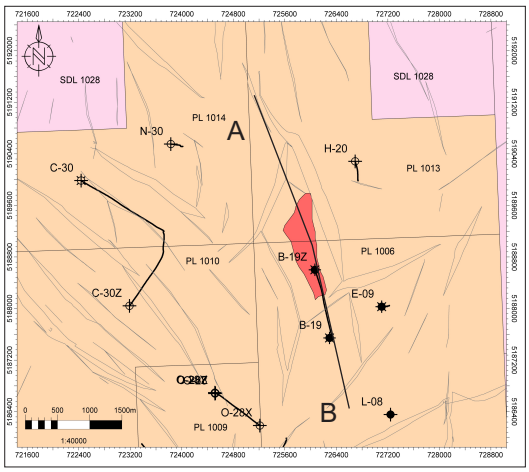


Figure A. Basemap illustrating the outline for White Rose B-19z prospect; red polygon used as input to determine the BRV. A-B line depicting location of schematic cross section.

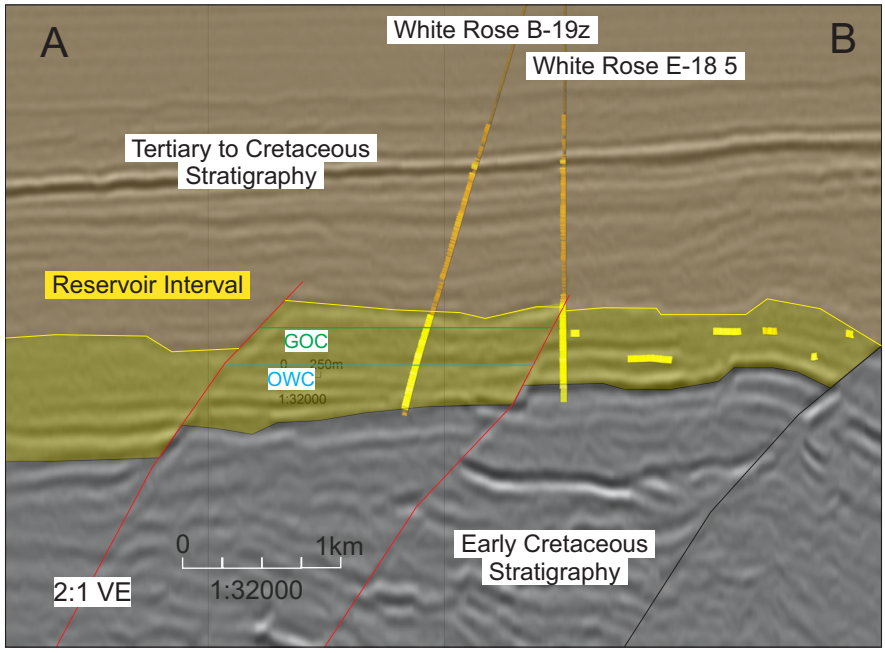


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the north to south extent across the White Rose B-19z prospect. Target reservoir interval from Ben Nevis Formation to Mid-Aptian Unconformity, highlighted in yellow between the two red faults.

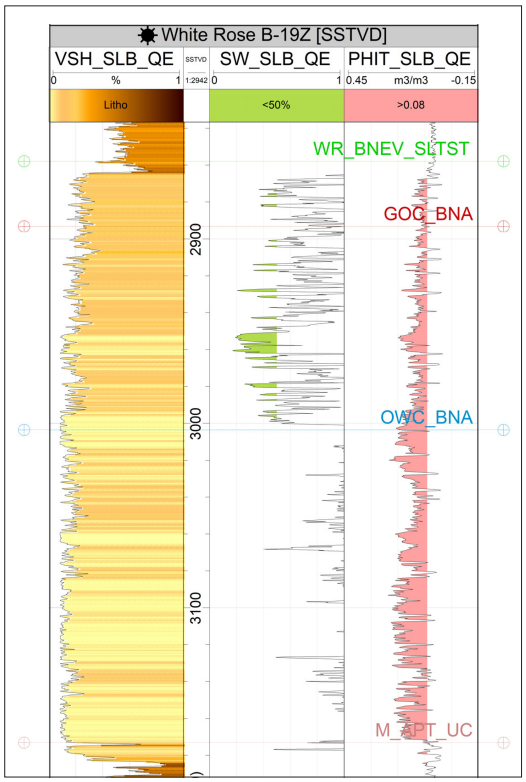


Figure C. White Rose B-19z well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity including the GOC.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	16	45	11	64	239	6	4
P50	20	55	12	70	265	8	5
P10	24	65	13	76	284	11	8

Table A. Input values compiled from Ben Nevis Siltstone Formation to Mid-Aptian Unconformity within the White Rose B-19z prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 7: PLs 1007 and 1008 NORTH AMETHYST

- PLs 1006, 1007 and 1008
- Effective Date: August 10, 2025
- License Representative: Cenovus Energy Inc.
- Prospect Area: 1275 ha

Key Well: North Amethyst K-15
Interval: Ben Nevis Siltstone Fm to Gas-Oil-Contact

- Gross : 74m
- Gas Pay: 67m
- GOC: -2334m TVDss
- Sg: 73%
- N:G_{res}: 91%
- N:G_{pay}: 91%
- Avg Phi_{res}: 17%

- North Amethyst K-15 well contains a gas response in well logs, supported by pressures and recovered gas samples in the Ben Nevis Fm.
- P50 BRV was determined from Ben Nevis Fm (flexed to well tops) to the GOC (yellow polygon on Figure A and yellow on Figure B).
- P10 BRV was determined from Ben Nevis Siltstone Fm top (flexed to well tops) to the GOC (yellow and red polygons on Figure A and yellow on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis Siltstone Fm to gas-oil-contact interval; four offset wells were used (Figure C and Table A).
- Reservoir pressure is approximately 23700 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

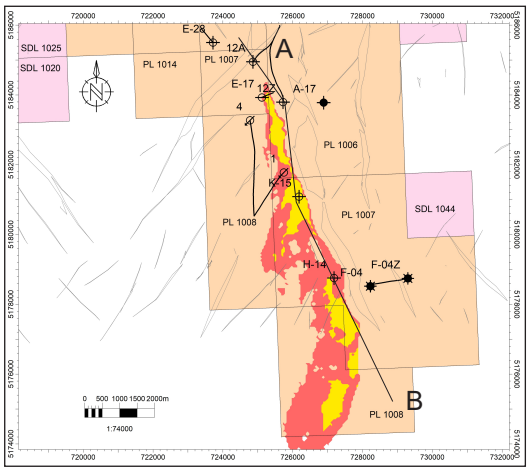


Figure A. Basemap illustrating North Amethyst prospect outline yellow and red polygons gas accumulations used as input to determine the P50 and P10 BRV. A-B line depicting location of schematic cross section.

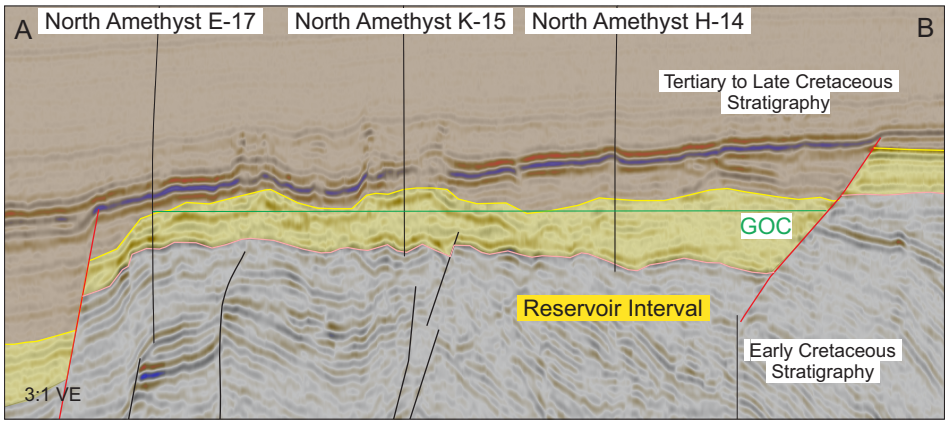


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent of the North Amethyst prospect. Target reservoir interval from Ben Nevis Formation to GOC, highlighted in yellow between the two red faults.

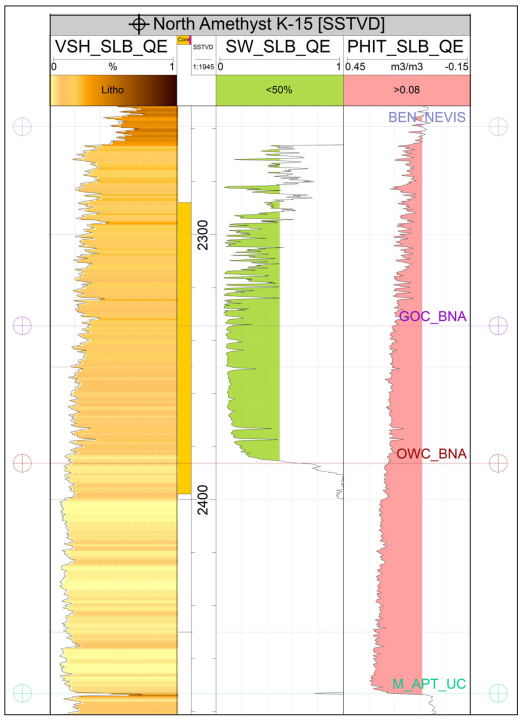


Figure C. North Amethyst K-15 well section over the reservoir interval from Ben Nevis Formation to the GOC.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	43	27	12	72	204	16	10
P50	116	50	17	76	217	53	34
P10	320	73	22	80	230	166	108

Table A. Input values compiled from top Ben Nevis Siltstone Formation to GOC within the North Amethyst prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 8: SDL 1051 and CROWN LAND BALLICATTERS

- SDL 1051 and Crown Land
- Effective Date: September 24, 2013
- License Representative: Suncor Energy Inc.
- Prospect Area: 4292 ha

Key Wells: Ballicatters M-96/M-96z
Interval: Ben Nevis Fm to Upper Avalon base seismic marker

- Gross : 232m
- Gas Pay: 54m
- GWC: -3680m TVDss
- Sg: 63%
- $N:G_{res}$: 34%
- $N:G_{pay}$: 23%
- Avg Phi_{res}: 11%

- Ballicatters observed a most likely gas-water contact of -3680m TVDss in the Ben Nevis Formation based on logs, pressures and is supported by DSTs.
- P50 BRV was determined by mapping the top of the Ben Nevis (flexed to the well tops) to the gas-water contact (red on figure A and yellow on figure B).
- P90 and P10 BRV were calculated by adjusting the top structure plus or minus 15m to account for seismic interpretation uncertainty.
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the well averages for the Ben Nevis – Upper Avalon base seismic marker interval; five offset wells were used (Figure C and Table A).
- Reservoir pressure tested at 46000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

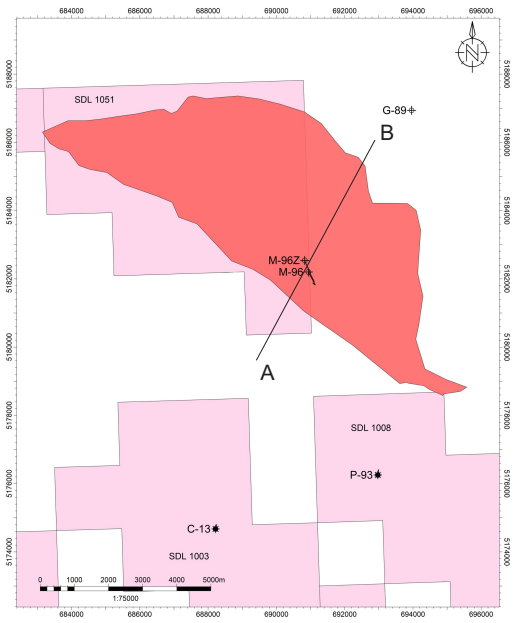


Figure A. Basemap illustrating SDL outline; P50 (red polygon) gas accumulation used as input to determine the BRV. A-B line depicting location of schematic cross section.

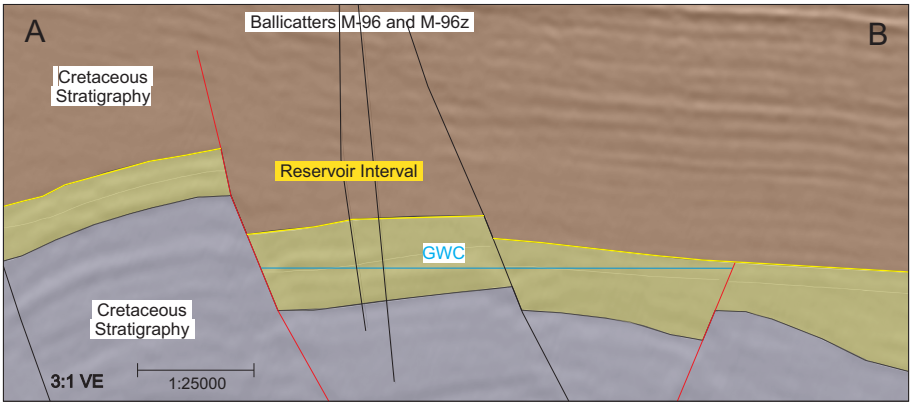


Figure B. Schematic cross-section from CA-3001062-GOA-JDA SOUTH* depth survey illustrating the Ben Nevis - Upper Avalon Formation in the fault blocks, highlighted by yellow between the two red faults.

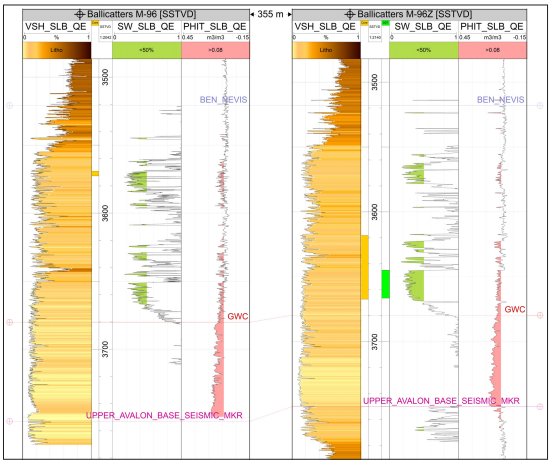


Figure C. Ballicatters well section over the reservoir interval from Ben Nevis Fm to Upper Avalon base seismic marker illustrating the GWC.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	(1/Bg)	OGIP (bcf)	REC (bcf)
P90	3092	40	9	74	237	1061	649
P50	3397	56	13	80	256	1718	1109
P10	3731	72	18	86	275	2776	1850

Table A. Input values compiled from top Ben Nevis to Upper Avalon base seismic marker over mapped interval within the Ballicatters SDL 1051 boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 9: SDLs 1001 and 1041 NAUTILUS

- SDLs 1001 and 1041
- Effective Date: February 16, 1990
- License Representative: ExxonMobil Canada and Chevron Canada
- Prospect Area: 1862 ha

Key Well: Nautilus C-92
Interval: Catalina Fm to B-Marker

- Gross : 305m
- Gas Pay: 70m
- GDT: -4136m TVDss
- Sg: 80%
- N:G_{res}: 23%
- N:G_{pay}: 23%
- Avg Phi_{res}: 12%

- Nautilus C-92 observed a most likely gas-down-to contact of -4136m TVDss in the Catalina Formation based on well logs and supported by pressures and DSTs.
- P90 BRV was determined by mapping the top of the Catalina Fm to the gas-down-to contact (Figure A and yellow on Figure B).
- P10 BRV was determined by mapping the top of the Catalina Fm to down to the B-Marker (yellow on Figure B).
- Nautilus C-92 well is assumed to represent the distal end of the depositional environment.
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Catalina interval; offset wells were used (Figure C and Table A).
- Reservoir pressure tested at approximately 75000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

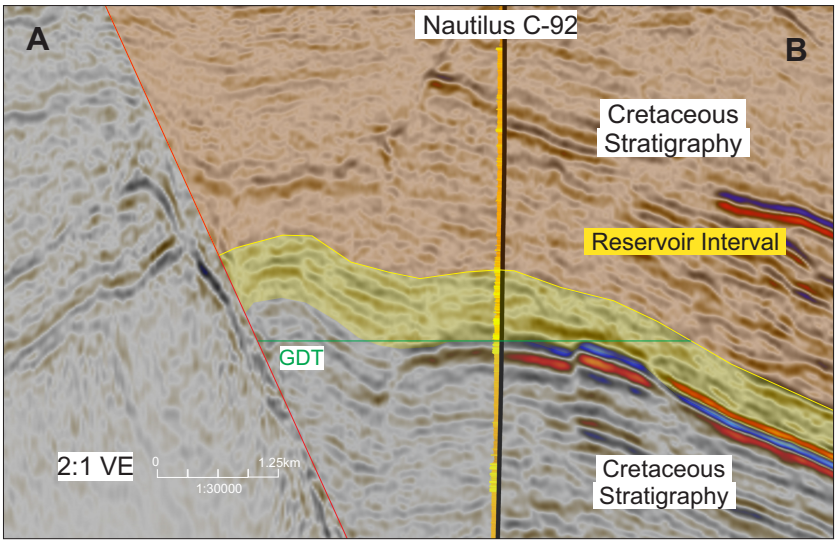


Figure B. Schematic cross-section from CA-3001011_2015 Hibernia IsoMetrix 4D M1 Survey illustrating the reservoir interval from the Catalina Formation to the B-Marker, highlighted by yellow south of the red fault.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	3707	10	10	74	225	311	196
P50	3772	27	12	80	238	796	511
P10	3838	48	15	86	251	1516	995

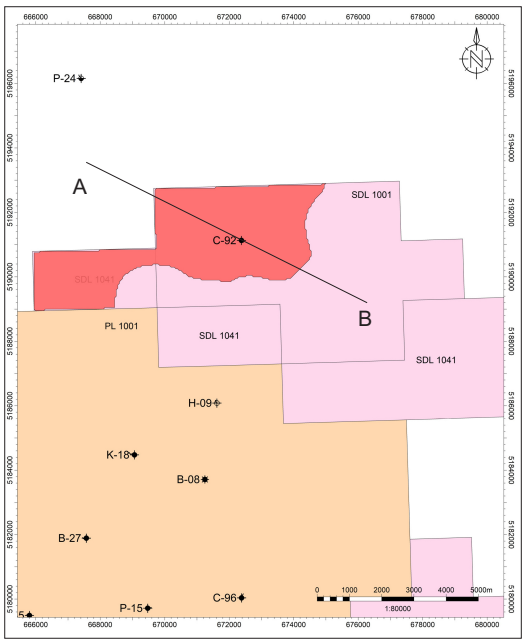


Figure A. Nautilus basemap illustrating study area in red polygon used as input to determine the BRV. A-B line depicting location of schematic cross section.

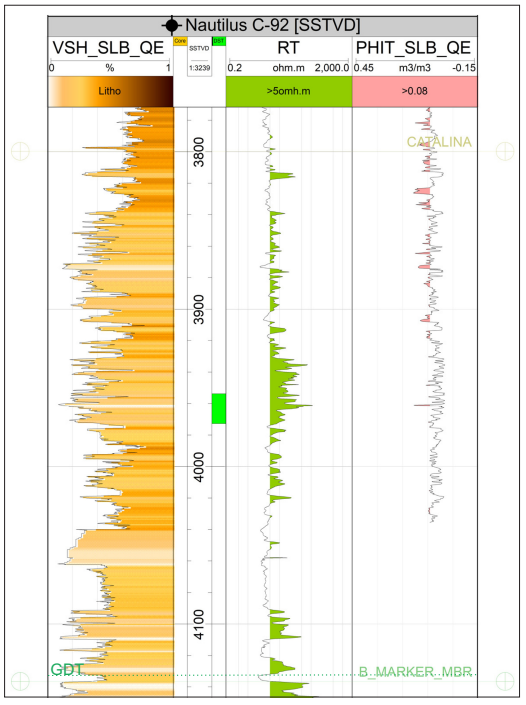


Figure C. Nautilus C-92 well section over the reservoir interval from the Catalina Formation to B-Marker Member.

Table A. Input values compiled from Catalina Formation to B-Marker Member within the SDL's 1001 &1041 boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 10: SDL 1031 TRAVE

- SDL 1031
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 1827 ha

Key Well: Trave E-87
Interval: Hibernia Fm to Fortune Bay Fm

• Gross :	379m	• Sg:	54%
• Gas Pay:	1.9m	• N:G_{res}:	57%
• GWC:	-2250m TVDss	• N:G_{pay}:	0.5%
		• Avg Phi_{res}:	12%

- Trave E-87 well tested and recovered gas from DST's in the Hibernia Fm; the GWC is confirmed by pressures.
- P50 BRV was determined by mapping from the preserved Upper Hibernia Fm (bulk shifted -64m to account for velocity error) to the GWC (red polygon on Figure A and yellow polygon on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Hibernia Fm interval; offset wells were used (Figure C and Table A).
- Reservoir pressure tested at approximately 24000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

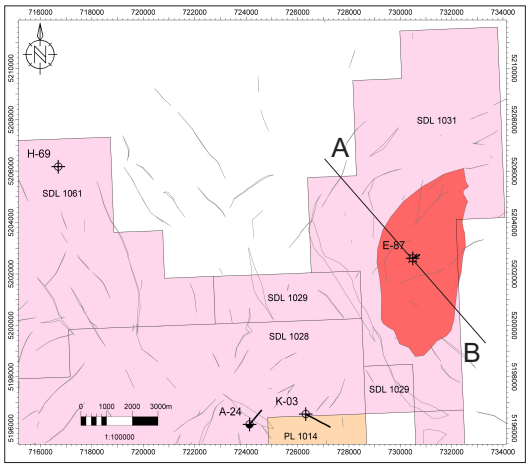


Figure A. Basemap illustrating the outline for Trave prospect; red used as input to determine the P50 BRV. A-B line depicting location of schematic cross section.

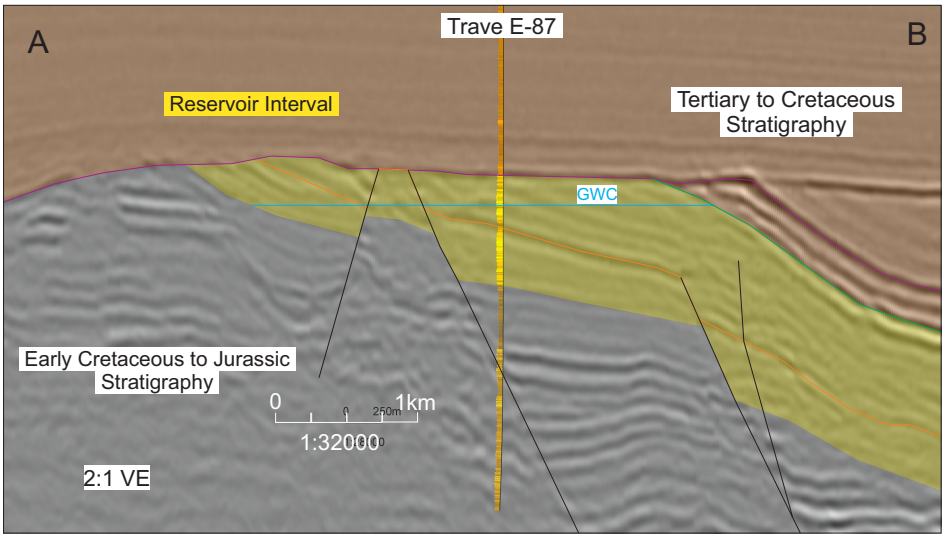


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across the Trave prospect. Target reservoir interval is the Hibernia Formation to Fortune Bay, highlighted in yellow.

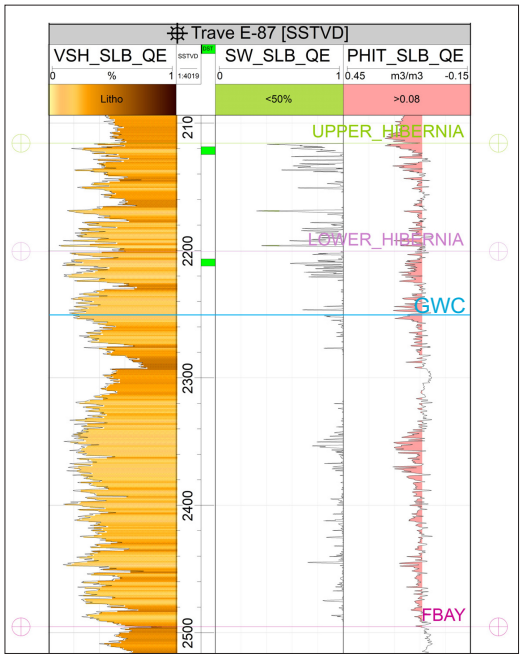


Figure C. Trave E-87 well section over the reservoir interval from the preserved upper Hibernia Fm showing the GWC.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	1939	42	10	52	196	408	247
P50	2122	55	12	58	204	591	382
P10	2322	68	15	71	212	845	570

Table A. Input values compiled from Hibernia Formation interval; using @risk to determine probabilistic unrisked OGIP and REC within the Trave prospect boundary.

STUDY AREA 11: SDL 1008 NORTH BEN NEVIS

- SDL 1008
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 1028 ha

Key Wells: North Ben Nevis P-93 and M-61
Interval: Ben Nevis Fm to Upper Avalon base seismic marker

• Gross :	175m	• Sg:	63%
• Gas Pay:	35m	• N:G_{res}:	57%
• GOC:	-3043m TVDss	• N:G_{pay}:	20%
		• Avg Phi_{res}:	16%

- North Ben Nevis observed a most likely gas-oil contact of -3043m TVDss in the Ben Nevis Formation based on logs, pressures and supported by DSTs.
- P50 BRV was determined by mapping the top of the Ben Nevis (bulk shifted 12m to account for velocity error) to the gas-oil contact (red in Figure A and yellow in Figure B).
- P90 and P10 BRV were calculated by adjusting the top of the structure plus or minus 15m to account for seismic interpretation uncertainty (Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis - Upper Avalon interval; five offset wells were used (Figure C and Table A).
- Reservoir pressure tested at approximately 40000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

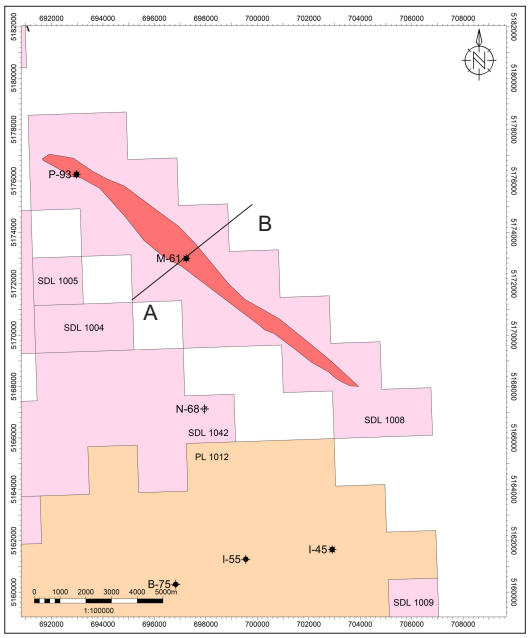


Figure A. Basemap illustrating SDL outline and study area in red for the gas accumulation used as input to determine the P50 BRV. A-B line depicting location of schematic seismic cross sections.

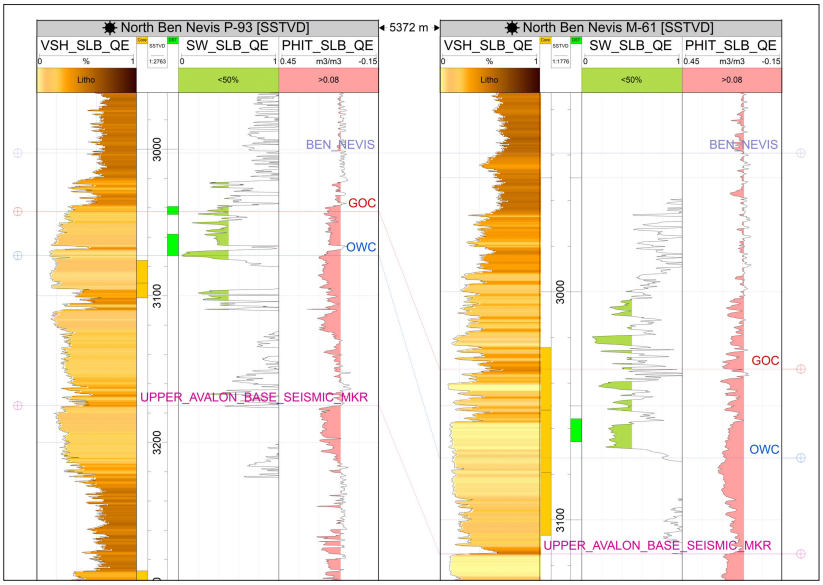


Figure C. North Ben Nevis well section over the reservoir interval from Ben Nevis Fm to Upper Avalon base seismic marker illustrating the GOC and OWC.

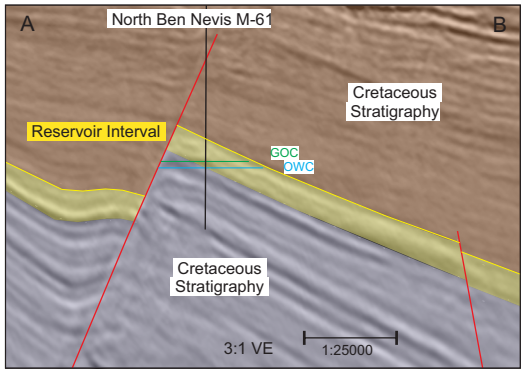


Figure B. Two schematic cross-sections from CA-3001062-GOA-JDA SOUTH* depth survey through North Ben Nevis P-93 and North Ben Nevis M-61 illustrating the BNA resource interval as outlined by the highlighted bounding red faults.

	BRV(e^6m^3)	N:G_{res}	Phi_{res}	Sg	(1/Bg)	OGIP (bcf)	REC (bcf)
P90	599	43	11	57	199	186	115
P50	699	56	16	65	212	299	192
P10	815	69	21	73	225	451	304

Table A. Input values compiled from top Ben Nevis to Upper Avalon base seismic marker interval within the North Ben Nevis SDL 1008 boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 12: SDL 1040 WEST BONNE BAY F-12/F-12z

- SDL 1040
- Effective Date: January 8, 2001
- License Representative: Cenovus Energy Inc.
- Prospect Area: 1386 ha

Key Well: West Bonne Bay F-12/F-12z
Interval: Upper Hibernia Member to Lower Hibernia Member

- Gross : 272m
- Gas Pay: 49m
- GDT: -3620m TVDss
- Sg: 60%
- $N:G_{res}$: 36%
- $N:G_{pay}$: 18%
- Avg Phi_{res}: 11%

- West Bonne Bay F-12/z prospect uses range of contacts supported by gas samples and pressures.
- P99 was determined from mapping the Upper Hibernia (flexed to well tops to account for depth error) to GDT of -3620m TVDss (Figure A and yellow interval on Figure B).
- P1 BRV was determined from same methodology as P99 to OUT -3682m TVDss (Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Hibernia interval; offset wells were used (Figure C and Table A).
- Reservoir pressure tested at 36000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

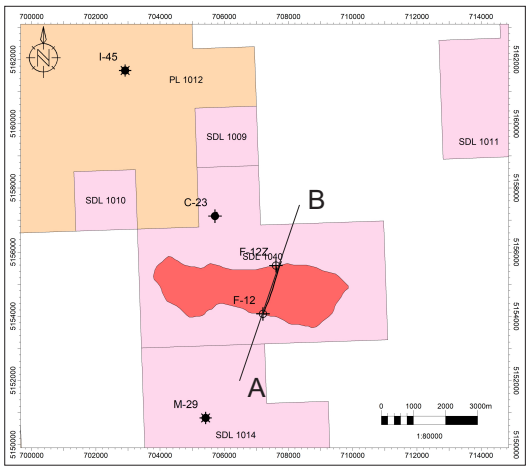


Figure A. West Bonne Bay F-12 basemap illustrating the outline for the prospect area (red) that was used as input to determine the BRV. A-B line depicting location of schematic cross section.

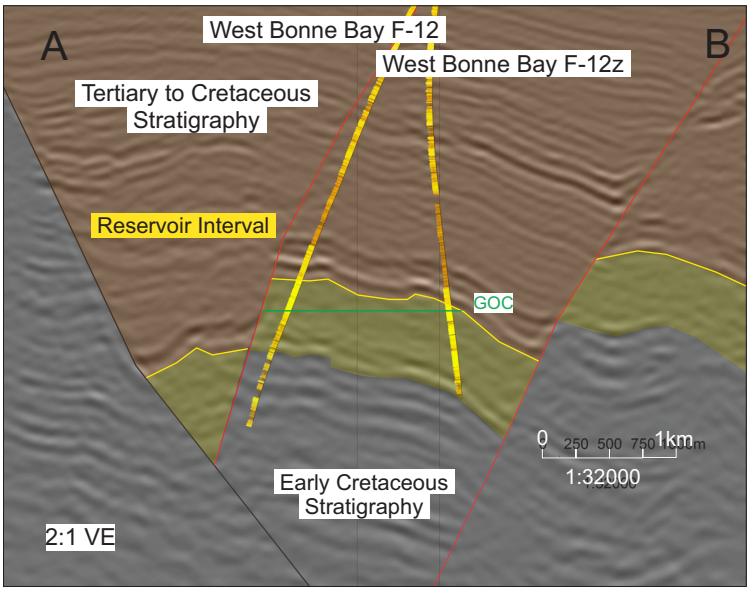


Figure B. Schematic cross-section from CA-3000695 2006 Husky Fortune 3D survey (converted to depth) illustrating south to north extent across the West Bonne Bay F-12/z prospect. Target reservoir interval from Upper Hibernia to Lower Hibernia, highlighted in yellow between the two red faults.

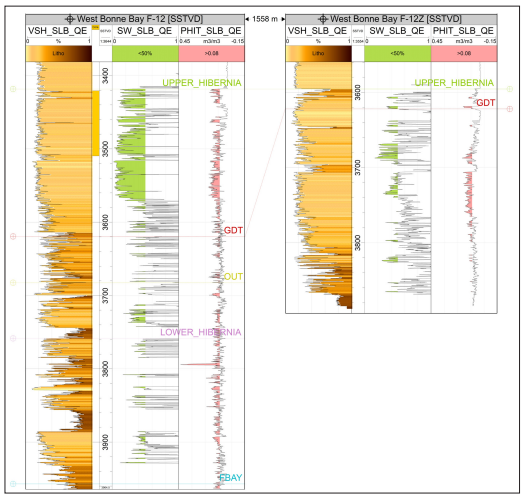


Figure C. West Bonne F-12/F-12z well section over the reservoir interval from Upper Hibernia to Lower Hibernia including the GDT and OUT.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	924	30	9	63	204	175	107
P50	1089	42	12	69	217	276	178
P10	1254	55	15	75	230	422	281

Table A. Input values compiled from Upper Hibernia to Lower Hibernia within the West Bonne Bay F-12/F-12z prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 13: SDLs 1011 and 1012 FORTUNE SOUTH

- SDLs 1011 and 1012
- Effective Date: March 28, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 1317 ha

Key Well: Fortune G-57
Interval: Basal Hibernia Member to Fortune Bay Fm

• Gross :	77m	• Sg:	65%
• Gas Pay:	5.4m	• N:G_{res}:	55%
• GOC:	-3870m TVDss	• N:G_{pay}:	7%
		• Avg Phi_{res}:	15%

- Fortune G-57 well crossed a fault in the reservoir interval of the Basal Hibernia. The true thickness is not representative. The surrounding wells were a key factor to determining gross and pay intervals.
- The oil tested in Fortune G-57 well is an OUT scenario and is represented by the red polygon in the Figure A.
- P50 BRV was determined from Basal Hibernia Member top to the GOC at -3870m TVDss (inferred from industry standard of applying 1/3 gas cap shown as yellow polygon in South Fortune in Figure A and A-B seismic section in Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Basal Hibernia Member interval; offset wells were used (Figure C and Table A).
- Reservoir pressure tested at 39190 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

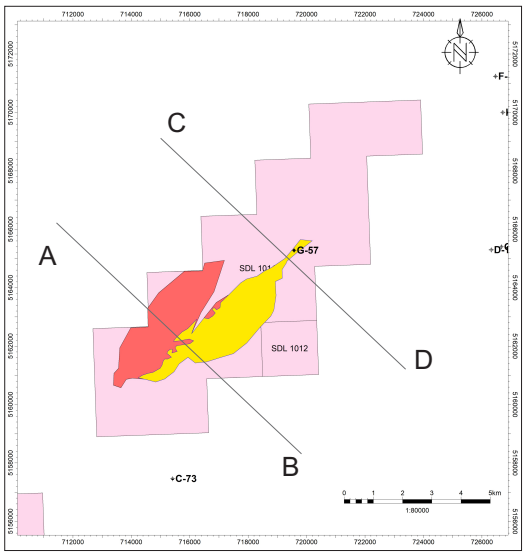


Figure A. Basemap illustrating the South Fortune prospect showing possible 1/3 gas cap in yellow; input to determine the P50 BRV. Two lines A-B and C-D depict the location of two schematic cross sections.

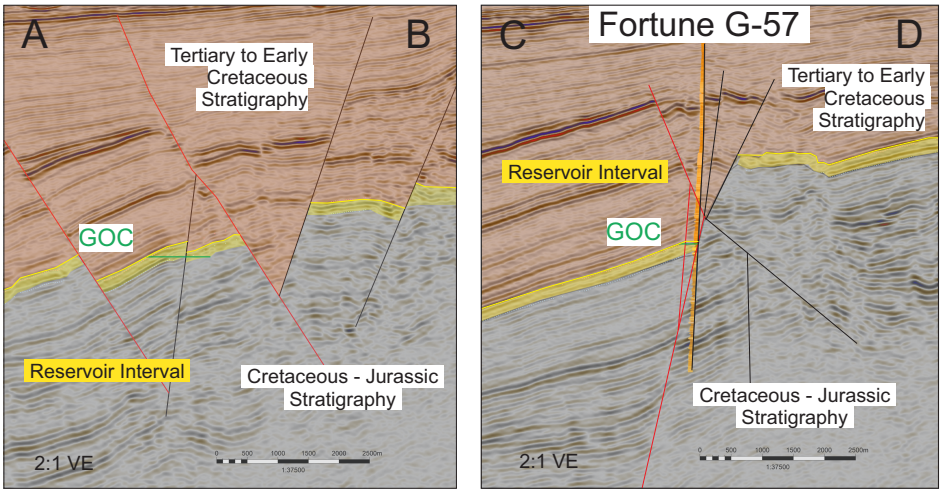


Figure B. Two schematic cross-sections from CA-3000695 2006 Husky Fortune 3D survey (converted to depth) illustrating the northwest to southeast extent across the South Fortune prospect. Target reservoir interval from Basal Hibernia Member to Fortune Bay, highlighted in yellow between the two red faults.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	355	51	12	54	201	109	65
P50	414	55	14	60	207	139	90
P10	583	60	16	66	212	177	122

Table A. Input values compiled from top Basal Hibernia Member to Fortune Bay within the Fortune prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

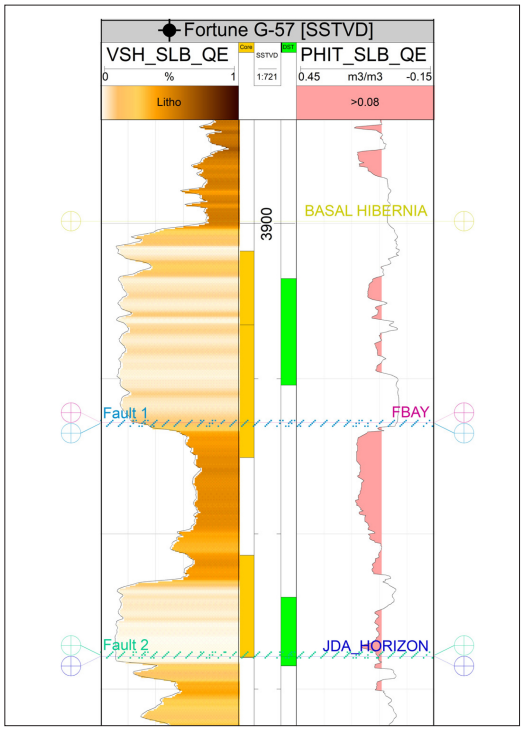


Figure C. Fortune G-57 well section over the reservoir interval from Basal Hibernia Mbr to the fault. This is not a complete section of this Member as the well path crossed a fault.

STUDY AREA 14: SDLs 1011 and 1012 FORTUNE NORTH

- SDLs 1011 and 1012
- Effective Date: March 28, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 252 ha

Key Well: Fortune G-57
Interval: Basal Hibernia Member to Fortune Bay Fm

- Gross : 77m
- Gas Pay: 5.4m
- GOC: -3689m TVDss
- Sg: 65%
- N:G_{res}: 55%
- N:G_{pay}: 7%
- Avg Phi_{res}: 15%

- Fortune G-57 well crossed a fault in the reservoir interval of the Basal Hibernia. The true thickness is not representative. The surrounding wells were a key factor to determining gross and pay intervals.
- The oil tested in Fortune G-57 well is an OUT scenario and is represented by the red polygon in the Figure A.
- P50 BRV was determined from Basal Hibernia Member top to the GOC (inferred from industry standard of applying 1/3 gas cap shown as yellow polygon in North Fortune in Figure A and C-D seismic section in Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Basal Hibernia Member interval; six offset wells were used (Figure C and Table A).
- Reservoir pressure tested at 39190 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

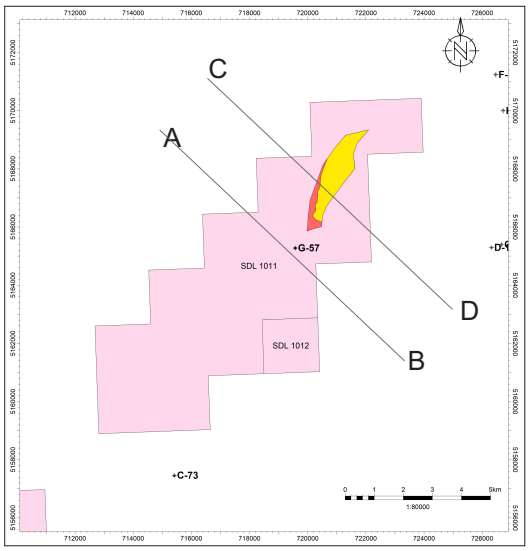


Figure A. Basemap illustrating the outline for North Fortune prospects; showing possible 1/3 gas cap in yellow; input to determine the P50 BRV. Two lines A-B and C-D depict the location of two schematic cross sections.

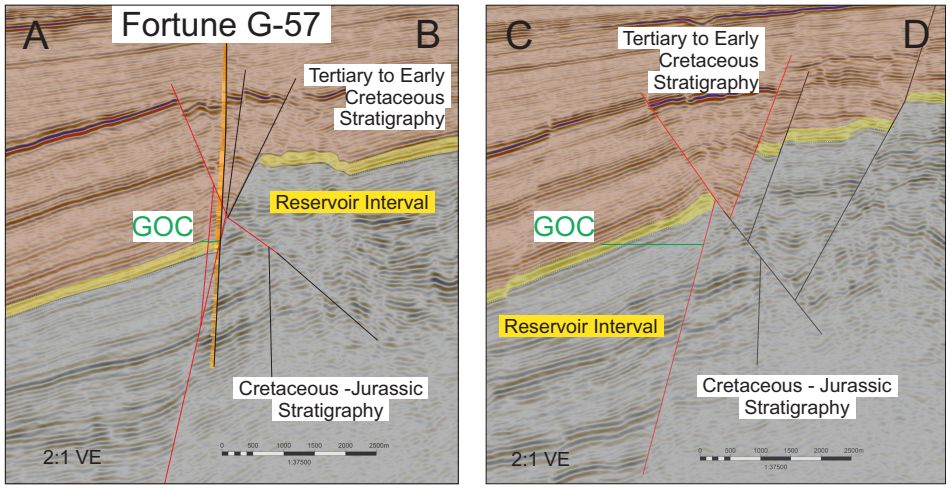


Figure B. Two schematic cross-sections from CA-3000695 2006 Husky Fortune 3D survey (converted to depth) illustrating the northwest to southeast extent across the North Fortune prospect. Target reservoir interval from Basal Hibernia Member to Fortune Bay, highlighted in yellow.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	103	51	12	54	201	30	17
P50	109	55	14	60	206	36	24
P10	115	60	16	66	212	45	31

Table A. Input values compiled from top Basal Hibernia Member to Fortune Bay within the Fortune prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

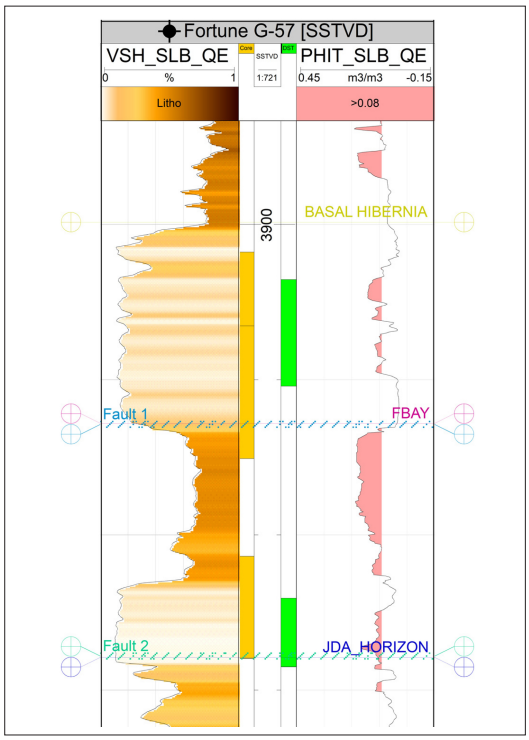


Figure C. Fortune G-57 well section over the reservoir interval from Basal Hibernia Mbr to the Fault. This is not a complete section of this Member as the well path crossed a fault.

STUDY AREA 15: SDL 200A, 200B, 200C NORTH DANA

- SDL 200A, 200B, 200C
- Effective Date: April 4, 1987
- License Representative: ExxonMobil Canada Properties
- Prospect Area: 1430 ha

Key Well: North Dana I-43
Interval: Tempest Member to Egret Member (Rankin Formation)

- Gross : 171m
- Gas Pay: 8.5m
- GDT: -4512 m TVDss
- Sg: 65%
- $N:G_{res}$: 13%
- $N:G_{pay}$: 5%
- Avg Phi_{res}: 9%

- North Dana I-43 well recovered gas from the DSTs in the Tempest Member of the Rankin Formation.
- Tempest Member stratigraphy is interpreted as a series of stacked sand channels which shows as a package of strong trough and peak response in the seismic data.
- P50 BRV was determined from Tempest Member top to the GDT within the brightest anomaly from the North Dana I-43 well up to the bound updip red fault (yellow area on Figure A and B).
- P1 BRV was determined by mapped down to the saddle of the structure (yellow and red area on Figure A and yellow on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Tempest Member interval; four offset wells were used (Figure C and Table A).
- Reservoir pressure tested at 73983 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

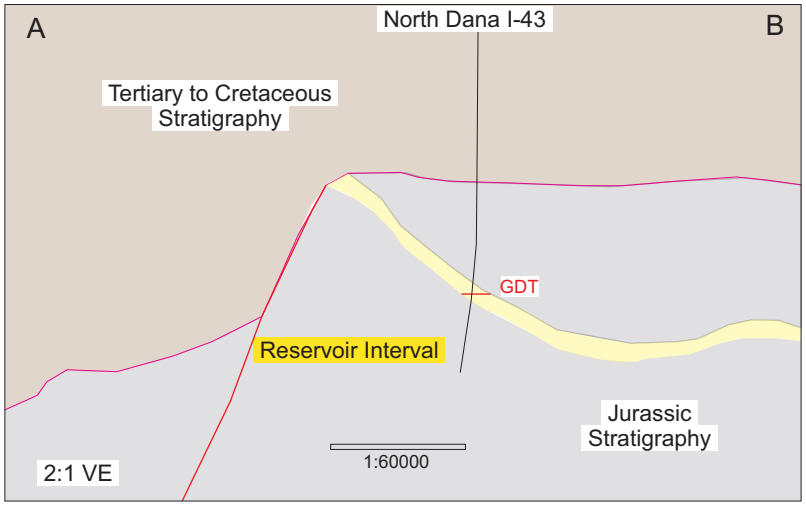


Figure B. Schematic cross-section illustrating the southwest-northeast extent of the North Dana prospect based on proprietary seismic data. Target reservoir interval from Tempest Member to the Egret Member, highlighted in yellow.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	652	6	8	56	357	49	30
P50	1020	13	11	65	370	119	77
P10	1595	20	15	74	383	249	165

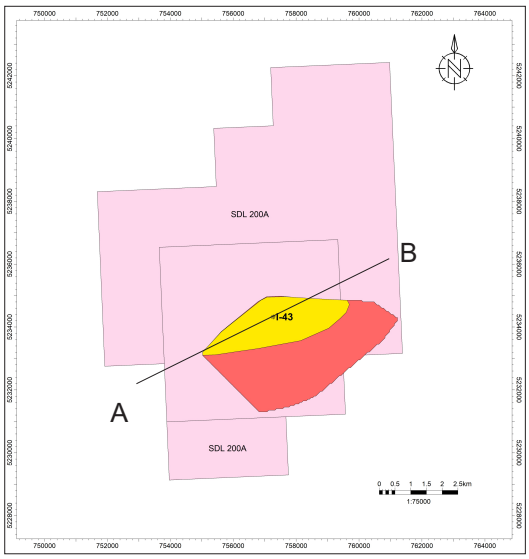


Figure A. North Dana basemap illustrating SDL outline; P1 (yellow and red) and P50 (yellow) gas accumulations used as input to determine the BRV. A-B line depicting location of schematic cross section.

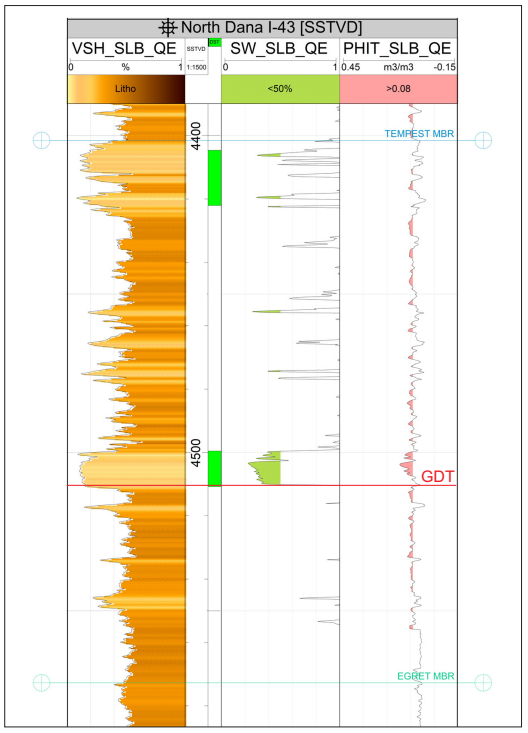


Figure C. North Dana I-43 well section over the reservoir interval from South Tempest Member to the Egret Member.

Table A. Input values compiled from top Tempest Member to Egret Member of the Rankin Fm within the SDL 200B boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 16: SDLs 1013 - 1017 SPRINGDALE

- SDLs 1013, 1014, 1015, 1016 and 1017
- Effective Date: March 28, 1990
- License Representative: Esso Resources; 1017 - Cenovus Energy Inc.
- Prospect Area: 3367 ha

Key Well: Springdale M-29
Interval: South Mara Fm top to Base Tertiary Unc (BTU)

- Gross : 146m
- Gas Pay: 4.6m
- GOC: -1294.5m TVDss
- Sg: 65%
- $N:G_{res}$: 39%
- $N:G_{pay}$: 3%
- Avg Phi_{res}: 31%

- Springdale M-29 and North Trinity H-71 wells contain a gas response in well logs and recovered gas from the DSTs in the South Mara Fm.
- South Mara Formation illustrates a strong trough over peak amplitude response in the seismic data. This response is indicative of reservoir and is a possible hydrocarbon indicator.
- P99 BRV was determined from South Mara top (flexed to well tops) to the GOC within the brightest anomaly around the Springdale M-29 well (yellow area on Figure A and B).
- P1 BRV was determined by lateral continuity of the trough-peak signature within the South Mara to BTU reservoir interval in the SDL boundary (yellow and red area on Figure A and yellow on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 27%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the South Mara to BTU interval; four offset wells were used (Figure C and Table A).
- Reservoir pressure tested at 13268 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

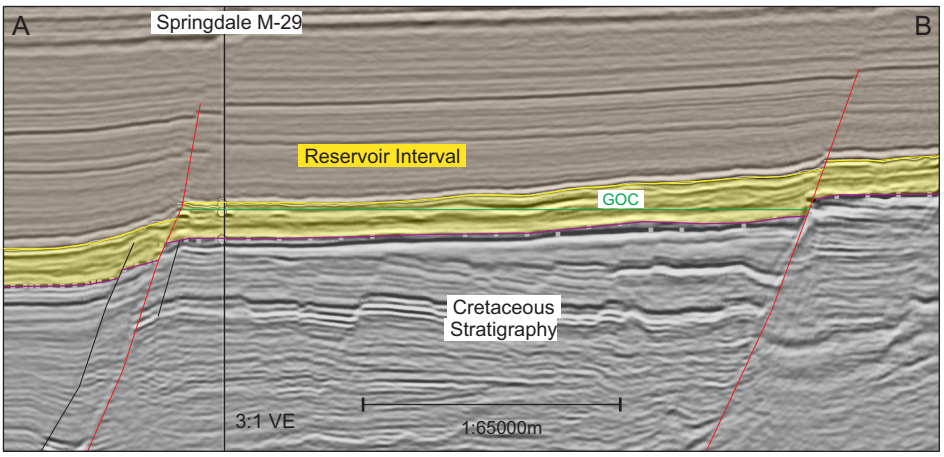


Figure B. Schematic cross-section from CA-3000718 GOA time (converted to depth) survey illustrating the north-south extent of the Springdale prospect. Target reservoir interval from South Mara Formation top to BTU, highlighted in yellow between the two red faults.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	141	22	22	56	108	32	21
P50	430	36	30	65	111	111	71
P10	1282	47	38	76	114	367	239

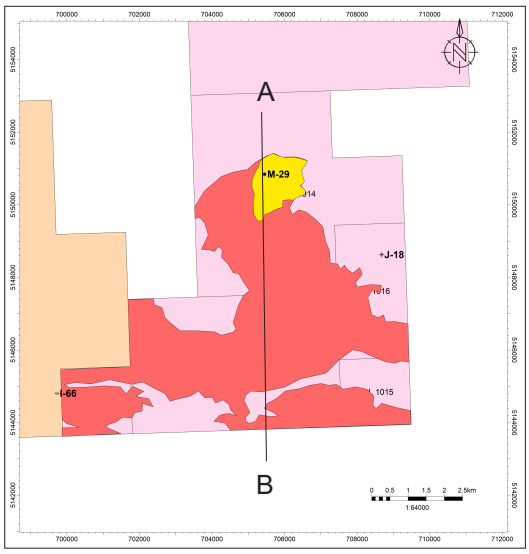


Figure A. Basemap illustrating SDL outline; P1 (yellow and red) and P99 (yellow) gas accumulations used as input to determine the BRV. A-B line depicting location of schematic cross section.

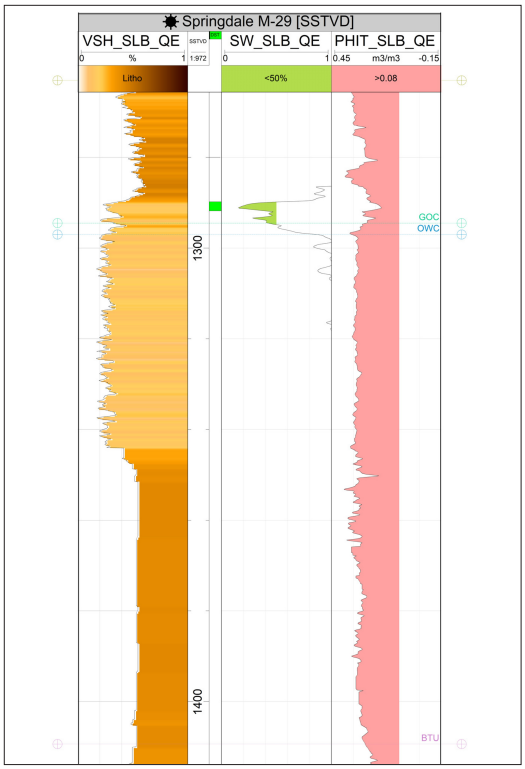


Figure C. Springdale M-29 well section over the reservoir interval from South Mara Formation top to BTU illustrating the GOC.

Table A. Input values compiled from top South Mara to BTU within the Springdale SDL boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 17: SDLs 1003 SOUTH MARA

- SDLs 1003
- Effective Date: February 16, 1990
- License Representative: Mobile Oil
- Prospect Area: 421 ha

Key Well: South Mara C-13
Interval: Ben Nevis Fm to Upper Avalon seismic base marker

- Gross : 32m
- Gas Pay: 26m
- GOC: -2917m TVDss
- Sg: 87%
- $N:G_{res}$: 84%
- $N:G_{pay}$: 81%
- Avg Phi_{res}: 17%

- South Mara C-13 observed a most likely gas-oil contact of -2917m TVDss in the Ben Nevis Formation based on neutron-density well log crossover and supported by pressures and DSTs.
- P50 BRV was determined by mapping the top of the Ben Nevis (flexed to the well tops) to the gas-oil contact within the SDL 1003 -1005 boundary (red on Figure A and yellow on Figure B).
- P90 and P10 BRV were calculated by plus or minus 10% to account for seismic interpretation and velocity model uncertainties.
- South Mara C-13 well is assumed to represent the high side reservoir properties based on depositional environment.
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Ben Nevis - Upper Avalon seismic base marker; five offset wells were used (Figure C and Table A).
- Reservoir pressure tested at 33000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

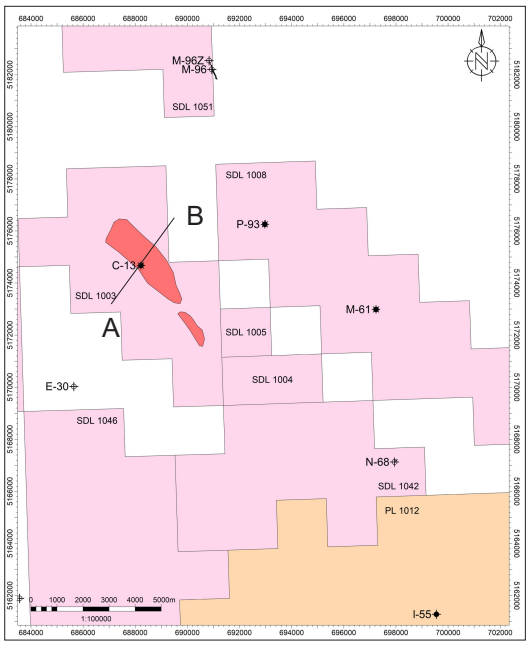


Figure A. Basemap illustrating SDL outline; P50 (red) gas accumulation used as input to determine the BRV. A-B line depicting location of schematic cross section.

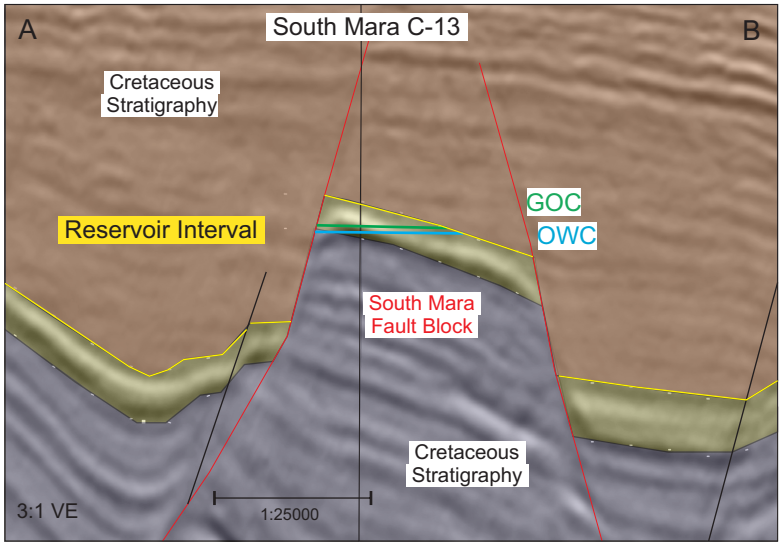


Figure B. Schematic cross-section from CA-3001062-GOA-JDA SOUTH* depth survey illustrating the reservoir interval from the Ben Nevis - Upper Avalon seismic base marker in the fault block, highlighted in yellow between the two red bounding faults.

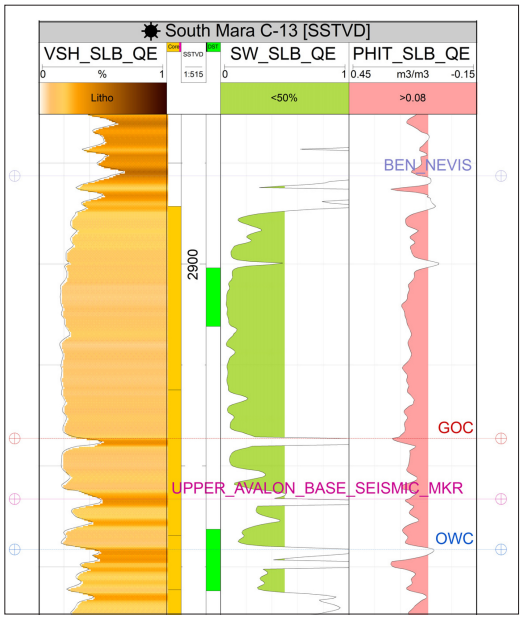


Figure C. South Mara C-13 well section over the reservoir interval from Ben Nevis Fm to Upper Avalon base seismic marker illustrating the GOC.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	80	49	12	75	201	36	22
P50	86	65	17	80	212	55	36
P10	92	81	22	85	224	81	55

Table A. Input values compiled from top Ben Nevis to Upper Avalon seismic base marker over mapped interval within the South Mara SDLs 1003-1005 boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 18: SDL 197 SOUTH TEMPEST

- SDL 197
- Effective Date: April 4, 1987
- License Representative: ExxonMobil Canada
- Prospect Area: 2164 ha

Key Well: SouthTempest G-88
Interval: Tempest Member to Egret Member (Rankin Formation)

- Gross : 721m
- Gas Pay: 29m
- GDT: -4275m TVDss
- Sg: 65%
- $N:G_{res}$: 20%
- $N:G_{pay}$: 4%
- Avg Phi_{res}: 10%

- South Tempest G-88 well recovered gas from the DSTs in the Tempest Member of the Rankin Formation.
- Tempest Member is a series of stacked sand channels which shows as a package of strong trough and peak responses in the seismic data.
- P50 BRV was determined by an updip fault and a gas-down-to contact (-4275m TVDss) to create a closure within the Tempest Member Interval (yellow area on Figure A and yellow on Figure B).
- P10 BRV was determined by an updip fault and down dip to the SDL boundary to create a closure within the Tempest Member Interval (yellow and red area on Figure A and yellow on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Tempest Member interval; four offset wells were used (Figure C and Table A).
- Reservoir pressure tested at 74000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

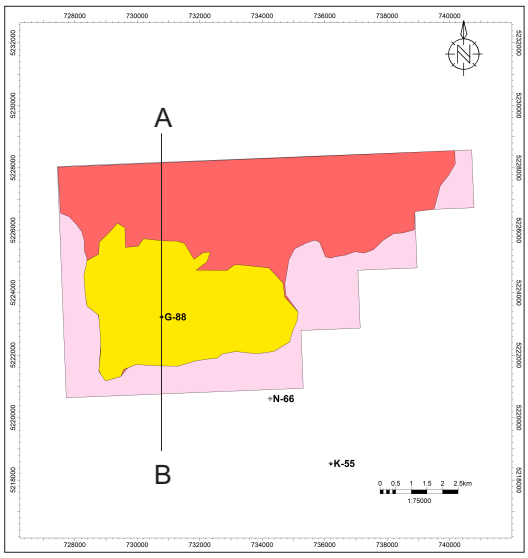


Figure A. South Tempest basemap illustrating SDL outline; P10 (yellow and red) and P50 (yellow) gas accumulations used as input to determine the BRV. A-B line depicting location of schematic cross section.

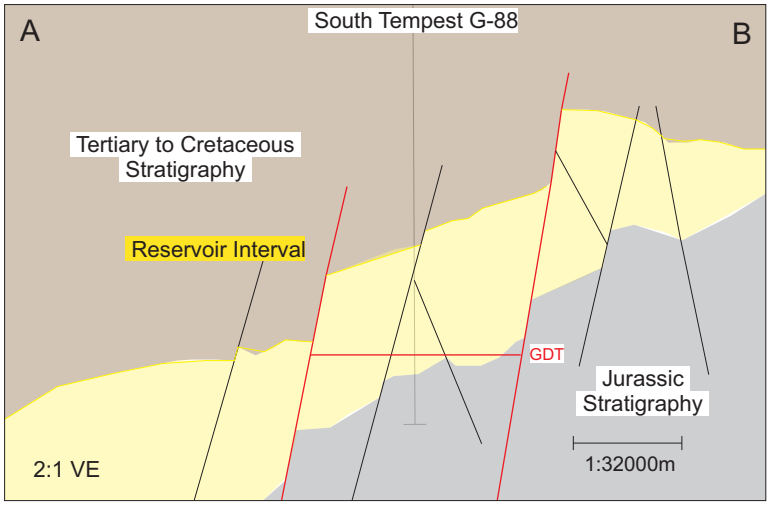


Figure B. Schematic cross-section illustrating the north-south extent of the South Tempest prospect based on proprietary seismic data. Target reservoir interval from Tempest Member to the Egret Member, highlighted in yellow between the red bounding faults.

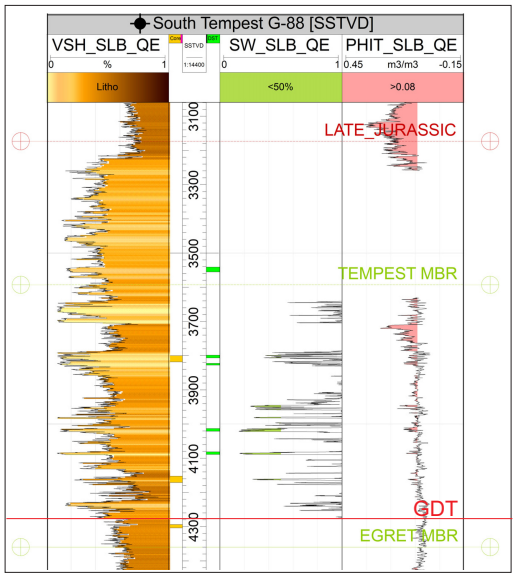


Figure C. South Tempest G-88 well section over the reservoir interval from Tempest Member to the Egret Members.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	42	8	8	59	357	5	3
P50	115	21	10	65	370	20	13
P10	319	40	14	71	383	72	47

Table A. Input values compiled from top Tempest Member to the Egret Member within the SDL 197 boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 19: CROWN LAND FLYING FOAM I-13 CATALINA FM

- Open Crown Lands
- Effective Date: N/A
- License Representative: N/A
- Prospect Area: 12804 ha

Key Well: Flying Foam I-13
Interval: Catalina Formation to the B-Marker Member

- Gross : 263m
- Gas Pay: 14m
- Sg: 64%
- N:G_{res}: 22%
- N:G_{pay}: 6%
- Avg Phi_{res}: 12%

- Flying Foam I-13 and Nautilus C-92 wells show a potential gas response within the Catalina formation interval.
- P50 BRV was determined from mapping the Catalina Formation to the B-Marker Member down to the GOC at -3106m TVDss (inferred from industry standard of applying 1/3 gas cap, shown as yellow polygon) (yellow on Figure A and yellow interval on Figure B).
- P1 BRV was determined from mapping the Catalina Formation to the B-Marker Member and applying BRV to the full column height (red and yellow in Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure in offset well Nautilus C-92 tested approximately 75000 kpa in the Catalina Formation.
- Recovery factor analysis from analogues using industry trends and standards.

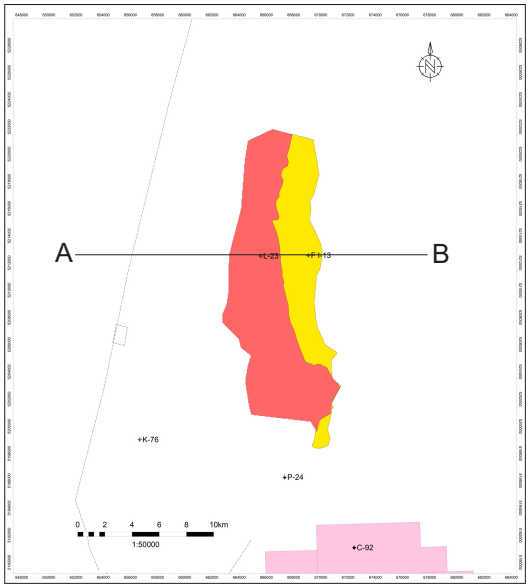


Figure A. Basemap illustrating the outline of Flying Foam I-13 prospect and respective P50 (yellow) and P1 (yellow and red) BRV. A-B line depicting location of seismic cross section.

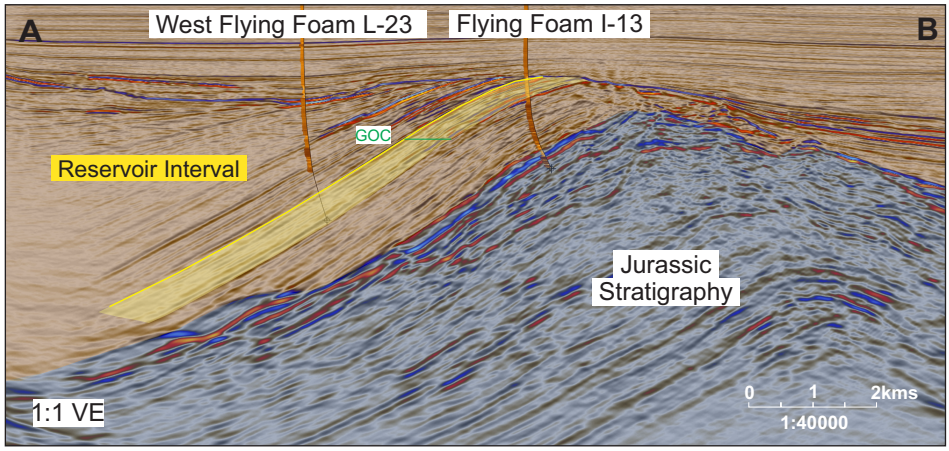


Figure B. Schematic seismic cross-section from CA-3001053-1062 GOA-JDAR NORTH* 3D survey (converted to depth) illustrating the extent across the Flying Foam prospect. Target reservoir interval highlighted in yellow; green line highlighting 1/3 crest depth.

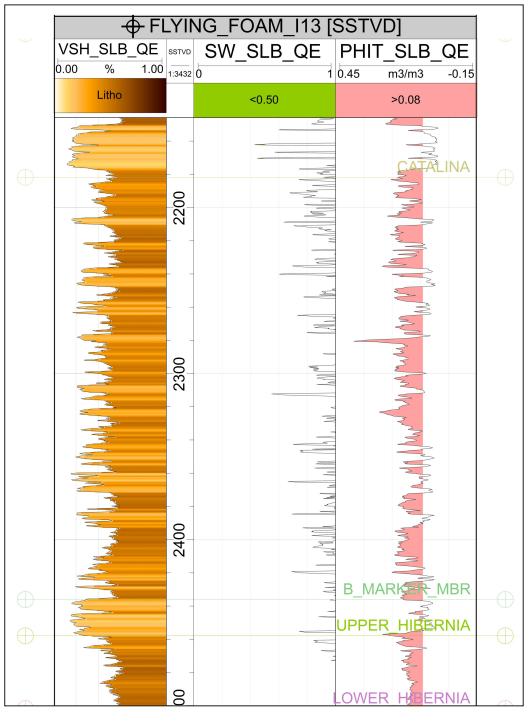


Figure C. Flying Foam I-13 well section over the reservoir interval from the Catalina Formation to top of B-Marker Member.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	4142	8	10	51	225	208	132
P50	10884	11	11	53	237	574	369
P10	26040	14	12	56	250	1447	944

Table A. Input values compiled from analogous fields worldwide and applied to Flying Foam prospect using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 20: CROWN LAND / SDL 1061 GLENWOOD H-69 ALBIAN

- Open Crown Land and SDL 1061
- Effective Date: January 12, 2026
- License Representative: Cenovus Energy Inc.
- Prospect Area: 9453 ha

Key Well: Glenwood H-69
Interval: Albian-Aptian Interval

- Gross : 92m
- Sg: 70%
- N:G_{res}: 50%
- Avg Phi_{res}: 21%

- Glenwood H-69 prospect assumes the structure filled with overpressured gas as observed in last LWD pressure reading in the well.
- P90 BRV was determined from mapping the high amplitude anomaly and applying a series of weighted bulk shifts to account for varying fan thickness; modal thickness 50m (Figure A and yellow interval on Figure B).
- P50 BRV was determined from mapping the high amplitude anomaly and applying a series of weighted bulk shifts to account for varying fan thickness; modal thickness 100m (red polygon on Figure A and yellow interval on Figure B).
- P10 BRV was determined from mapping the high amplitude anomaly and applying a series of weighted bulk shifts to account for varying fan thickness; modal thickness 200m (Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure at time of kick is calculated at approximately 75000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

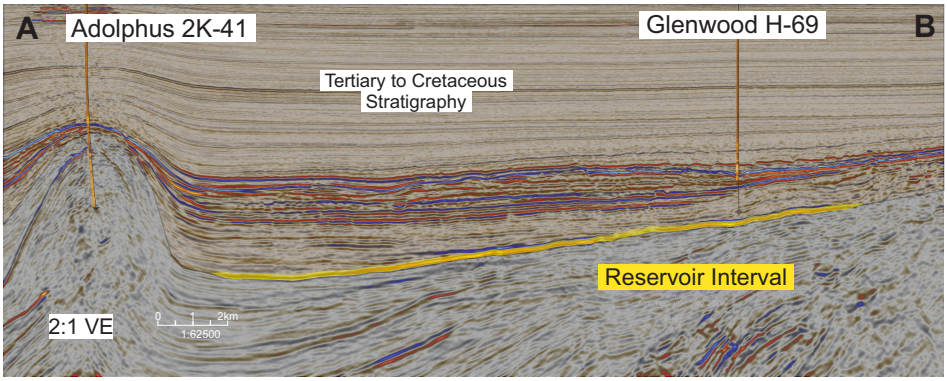


Figure B. Schematic seismic cross-section from CA-3001062-GOA-JDAR NORTH* 3D survey (converted to depth) illustrating the extent across the Glenwood H-69 prospect. Target reservoir interval has high amplitude response, highlighted in yellow.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	4307	30	15	60	344	2803	2067
P50	7699	50	21	70	357	6505	4895
P10	11105	70	27	80	370	12482	9343

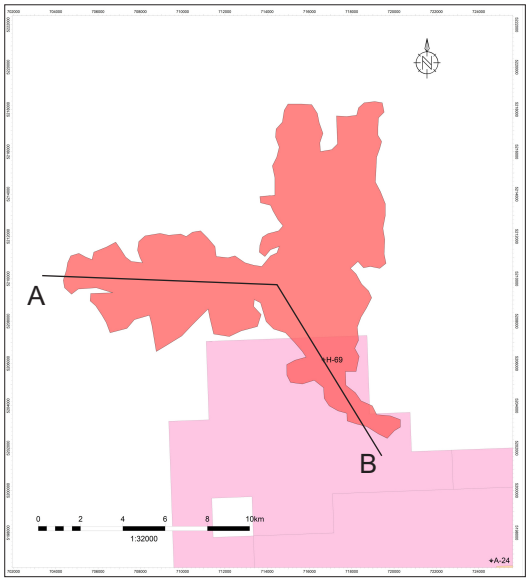


Figure A. Basemap illustrating the outline of Glenwood H-69 prospect. A-B line depicting location of seismic cross section.

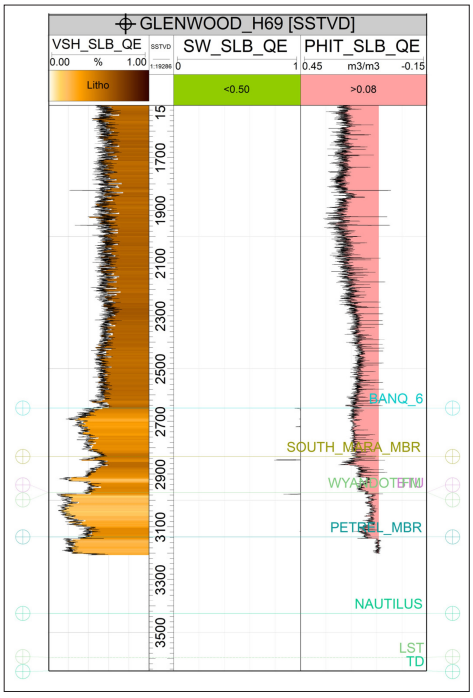


Figure C. Glenwood H-69 well section does not penetrate the full reservoir interval but tagged the top before taking an over pressured kick.

Table A. Input values compiled from analogous fields worldwide and applied to Glenwood prospect using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 21: CROWN LAND ALBIAN

- Open Crown Land
- Effective Date: N/A
- License Representative: N/A
- Prospect Area: 17216 ha

Key Well: Global Well Analogues
Interval: Albian-Aptian Interval

- Gross $_{Avg}$: 119m
- Sg: 70%
- N:G$_{res}$: 50%
- Avg Phi$_{res}$: 21%

- This prospect has no well penetration and assumes ranges based on analogue reservoirs in the industry.
- P50 BRV was determined from mapping the maximum negative amplitude within the fan down to the base of the prospect (yellow area in Figure A and red line to base fan interval in Figure B).
- P10 BRV was determined from mapping the top and base anomaly (red and yellow area on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Table A).
- Reservoir pressure is assumed to be normally pressured and similar to those in the Jeanne d'Arc Basin.
- Recovery factor analysis from analogues using industry trends and standards.

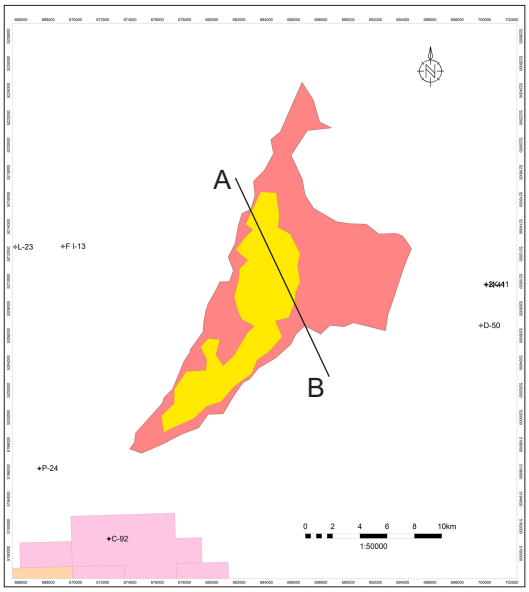


Figure A. Basemap illustrating the outline of the prospect with respective P50 area (yellow) and P10 area (red and yellow polygons). A-B line depicting location of seismic cross section.

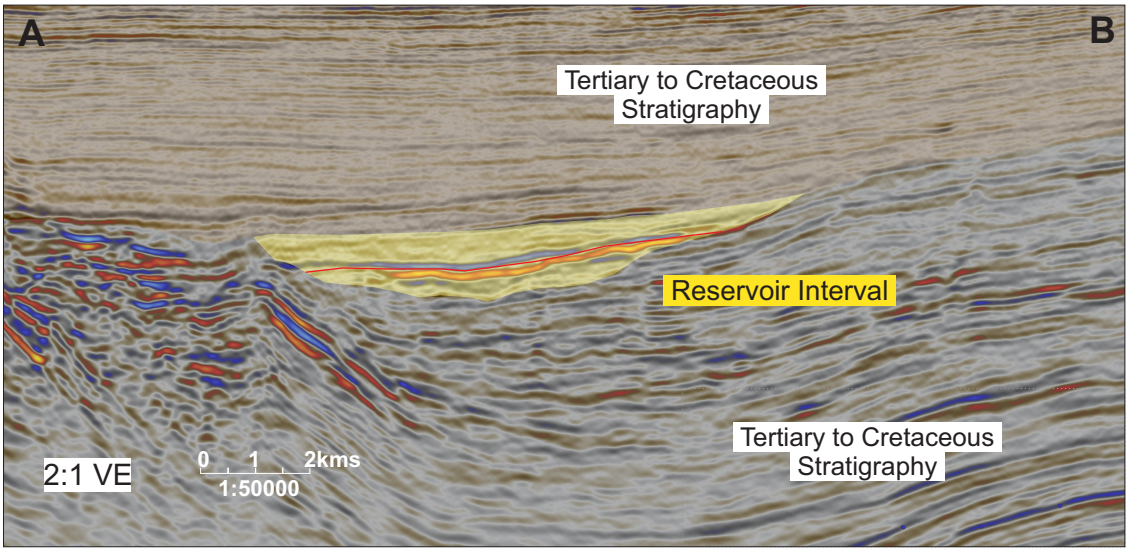


Figure B. Schematic seismic cross-section from CA-3001062 GOA JDAR NORTH* 3D survey (converted to depth) illustrating the extent across the prospect. Target reservoir interval highlighted in yellow; red line highlighting the maximum negative amplitude of the P50 volumes.

	BRV (e^6m^3)	N:G$_{res}$	Phi$_{res}$	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	4007	30	15	60	175	1554	995
P50	18060	50	21	70	188	7787	4942
P10	38445	70	27	80	201	20640	13601

Table A. Input values compiled from analogous fields worldwide and applied to the prospect using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 22: CROWN LAND / SDL 1051 BALLICATTERS M-96/Z MID-AVALON MBR

- Open Crown Land and SDL1051
- Effective Date: September 24, 2013
- License Representative: Suncor Canada Inc.
- Prospect Area: 1651 ha

Key Well: Ballicatters M-96/z
Interval: Mid-Avalon Member

- Gross : 28m
- Sg: 55%
- GWC: -3680m TVDss
- N:G_{res}: 24%
- Avg Phi_{res}: 15%

- Ballicatters South prospect assumes reservoir connectivity with Ballicatters M-96z Ben Nevis Avalon Fm utilizing a common GWC -3680m TVDss (orange in Figure B).
- P50 BRV was determined from mapping Mid-Avalon Member to the GWC (red area on Figure A and yellow interval down to GWC blue line on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure in Ballicatters M-96z tested at approximately 46000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

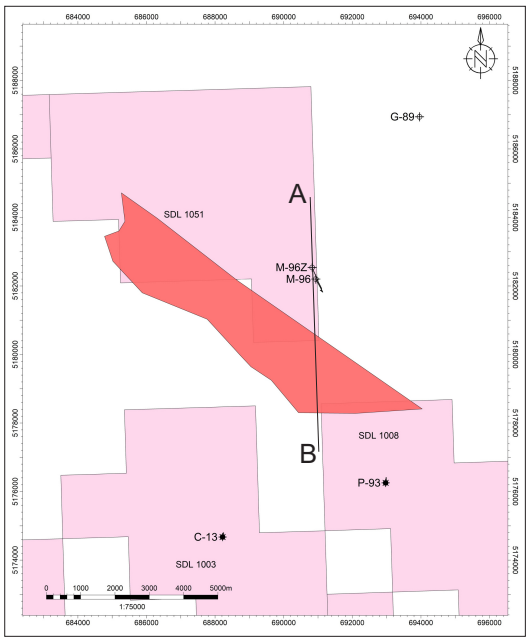


Figure A. Basemap illustrating the outline of the Ballicatters South prospect. A-B line depicting location of seismic cross section.

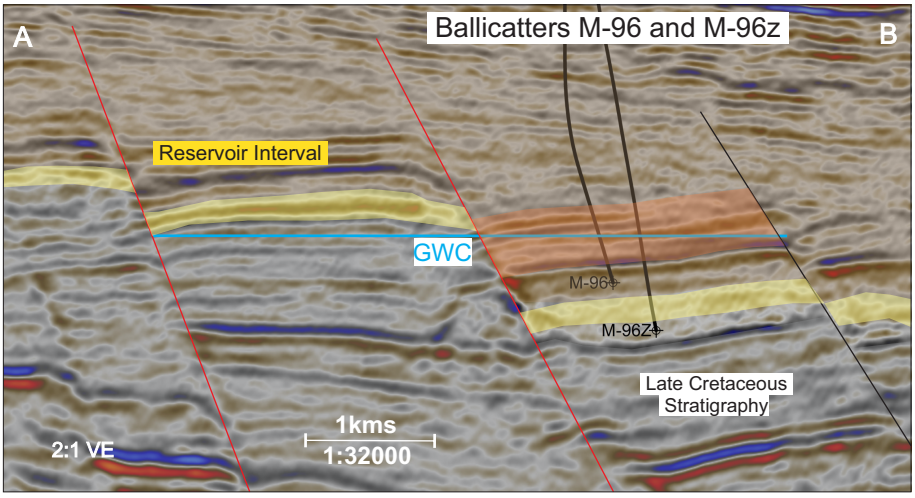


Figure B. Schematic cross-section from CA-3001062-GOA-JDA SOUTH* depth survey illustrating the Middle Avalon interval in the fault block, highlighted in yellow between two red faults.

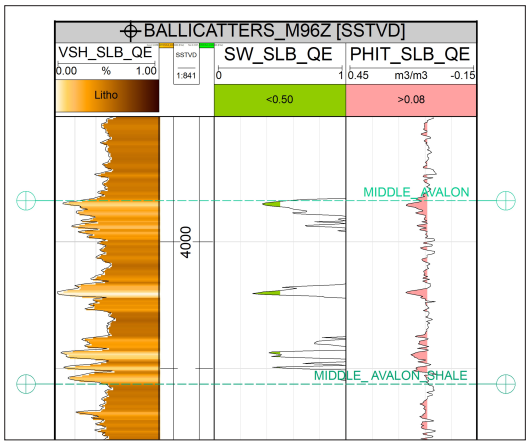


Figure C. Ballicatters well section over the reservoir interval from Middle Avalon Member to the Middle Avalon shale.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	1277	8	12	60	248	101	65
P50	1465	26	15	70	256	353	229
P10	1653	51	18	80	264	731	478

Table A. Input values compiled from Middle Avalon Member to the Middle Avalon shale over mapped interval, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 23: SDL 1051 / CROWN LAND BALLICATTERS M-96/Z MID-AVALON MBR

- Open Crown Lands and SDL1051
- Effective Date: September 24, 2013
- License Representative: Suncor Energy Inc.
- Prospect Size: 3358 ha

Key Wells: Ballicatters M-96z
Interval: Middle Avalon Member

- Gross : 28m
- Sg: 55%
- GDT: -4028m TVDss
- N:G_{res}: 24%
- Avg Phi_{res}: 15%

- Ballicatters M-96z observed a most likely gas-down-to contact of -4028m TVDss based on logs and pressures.
- P50 BRV was determined by mapping the top of the Middle Avalon Member to the GDT contact (red polygon on Figure A and yellow interval on Figure B).
- MDT samples and pressure from the Middle Avalon reservoir is calculated at approximately 75000 kpa.
- At reservoir conditions Middle Avalon is considered to be gas; however MDT samples also yielded high liquid condensate at surface.
- Recovery factor analysis from analogues using industry trends and standards.
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the well averages (Figure C and Table A).

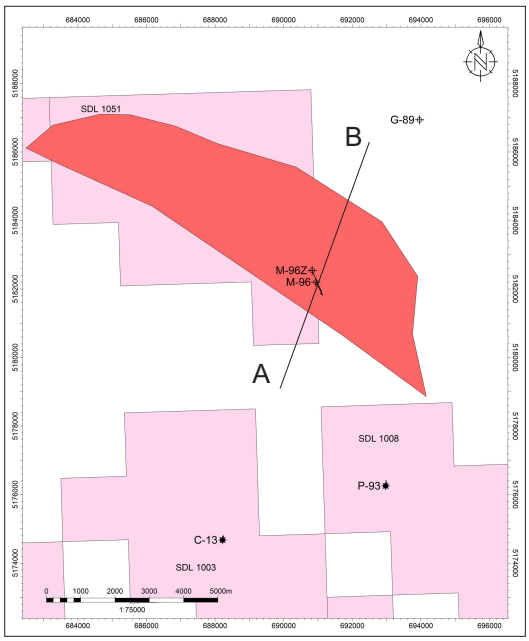


Figure A. Basemap illustrating SDL outline; P50 (red) gas accumulation used as input to determine the BRV. A-B line depicting location of schematic cross section.

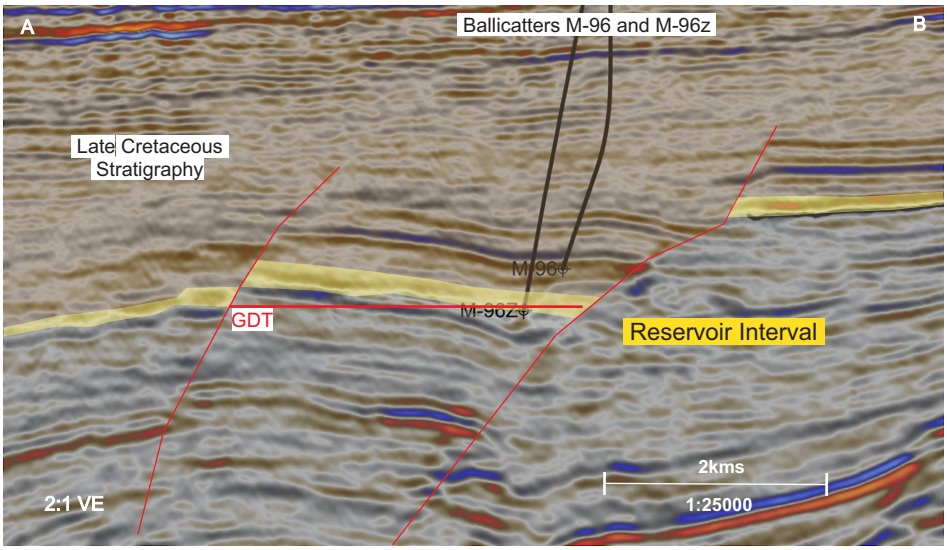


Figure B. Schematic cross-section from CA-3001062-GOA-JDA SOUTH* depth survey illustrating the Middle Avalon Member to the Middle Avalon shale in the fault blocks, highlighted in yellow between two red faults.

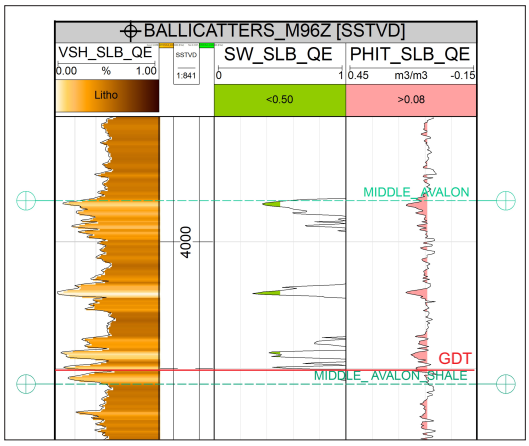


Figure C. Ballicatters well section over the reservoir interval from Middle Avalon Member to the Middle Avalon shale.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	(1/Bg)	OGIP (bcf)	REC (bcf)
P90	2028	8	10	60	315	182	136
P50	2325	26	13	70	323	617	462
P10	2622	51	17	80	330	1318	991

Table A. Input values compiled from Middle Avalon Member to the Middle Avalon shale over mapped interval, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 24: SDL 1008 NORTH BEN NEVIS P-93 HIBERNIA FM

- SDL 1008
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 6029 ha

Key Well: North Ben Nevis P-93
Interval: Lower Hibernia Member to the Fortune Bay Formation

- Gross : 419m
- Sg: 65%
- GDT: -5148m TVDss
- N:G_{res}: 6%
- Avg Phi_{res}: 10%

- P50 BRV was determined from mapping top of Lower Hibernia Member to GDT contact at -5148m TVDss (red polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- RFS sampled gas in the Lower Hibernia Member at -5134m TVDss (seen in Figure C).
- Recovery factor analysis from analogues using industry trends and standards.

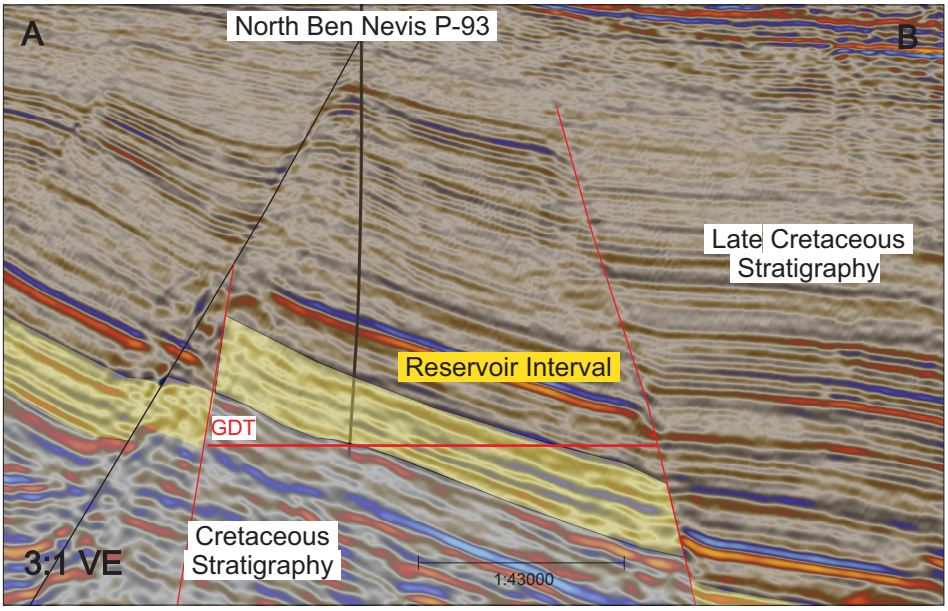


Figure B. Schematic seismic cross-section from CA-3001062-GOA-JDA SOUTH* 3D survey (converted to depth) illustrating the extent across the North Ben Nevis P-93 Hibernia prospect. Target reservoir interval highlighted in yellow between the two red faults.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	17661	2	9	60	322	316	234
P50	18943	5	12	65	335	813	609
P10	20224	12	16	70	345	2094	1572

Table A. Input values compiled from Hibernia Formation to the Fortune Bay Formation using @risk to determine probabilistic unrisked OGIP and REC.

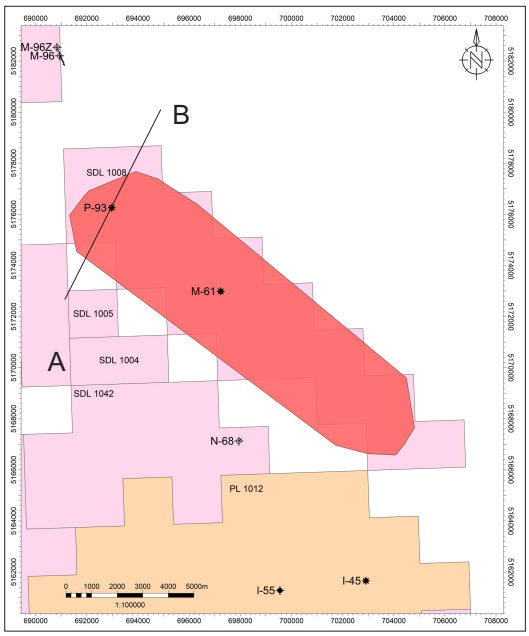


Figure A. Basemap illustrating the outline of North Ben Nevis P93 prospect. A-B line depicting location of seismic cross section.

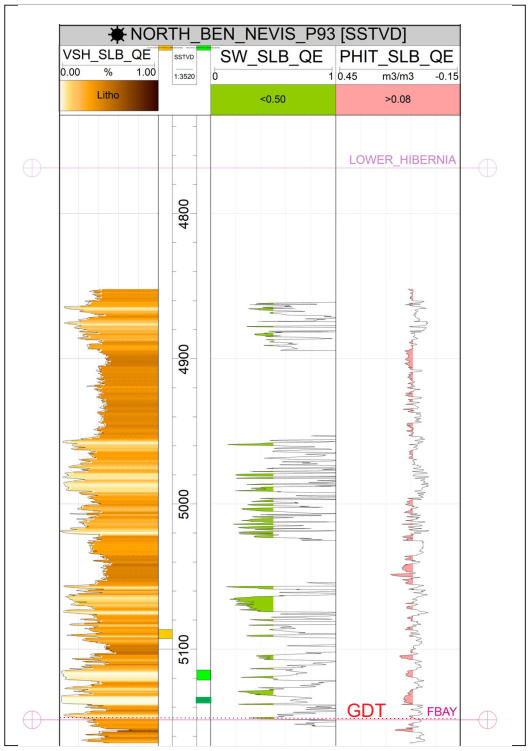


Figure C. North Ben Nevis P-93 well section over the reservoir interval from the Hibernia Formation to the Fortune Bay Formation / GDT.

• STUDY AREA 25: PL 1012 BEN NEVIS I-45 A-MARKER MBR

- PL 1012
- Effective Date: April 18, 2017
- License Representative: ExxonMobil Canada
- Prospect Area: 1512 ha

Key Well: Ben Nevis I-45
Interval: A-Marker to Whiterose Shale Member

- Gross : 385m
- Sg: 53%
- WUT: -2930m TVDss
- N:G_{res}: 88%
- Avg Phi_{res}: 16%

- P99 BRV was determined from mapping the top of the A-Marker to base of the DST at -2867m TVDss.
- P10 BRV was determined from mapping the A-Marker to WUT -2930m TVDss (red polygon in Figure A and yellow interval in Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure tested at approximately 29500 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

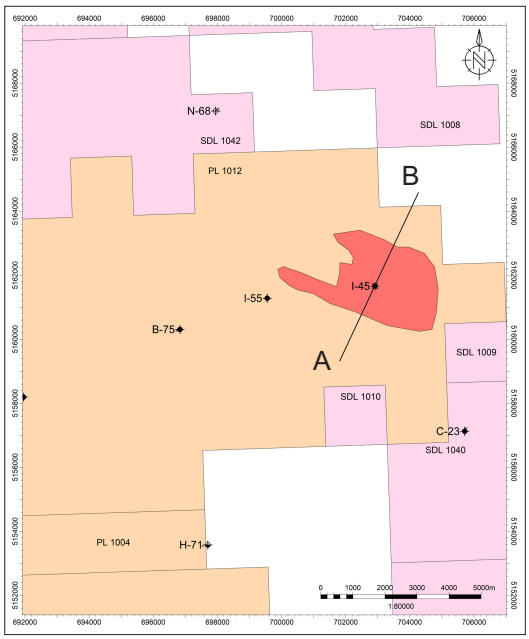


Figure A. Basemap illustrating the outline of Ben Nevis I-45 prospect. A-B line depicting location of seismic cross section.

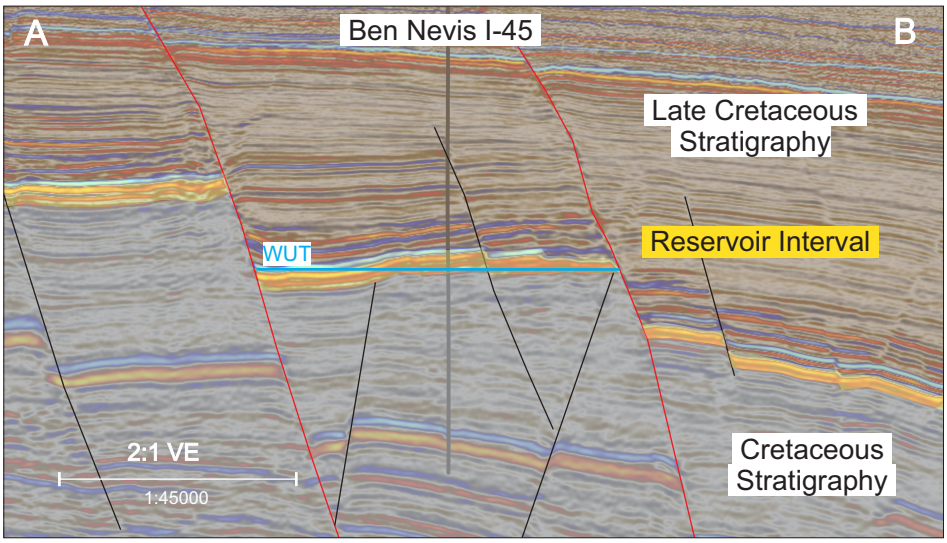


Figure B. Schematic cross-section from CA-3000960 depth survey illustrating the A-Marker interval in the fault blocks, highlighted in yellow between the two red faults.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	200	54	14	56	175	81	52
P50	391	64	16	63	188	164	106
P10	583	77	18	70	201	267	175

Table A. Input values compiled from the A-Marker interval within the Ben Nevis I-45 prospect, using @risk to determine probabilistic unrisked OGIP and REC.

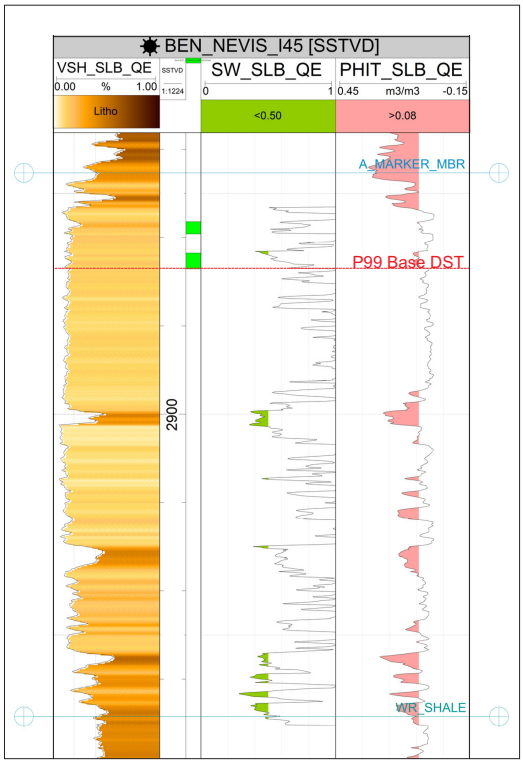


Figure C. Ben Nevis I-45 well section over the reservoir interval from the A-Marker to the Whiterose Shale.

STUDY AREA 26: PL 1012 WEST BEN NEVIS B-75 UPPER HIBERNIA MBR

- PL 1012
- Effective Date: April 18, 2017
- License Representative: ExxonMobil Canada
- Prospect Area: 1628 ha

Key Well: West Ben Nevis B-75
Interval: Upper Hibernia Member

- Gross : 416m
- Sg: 54%
- GDT: -3555m TVDss
- N:G_{res}: 31%
- Avg Phi_{res}: 10%

- RFS sampled gas in the Upper Hibernia Member at -3555m TVDss (seen in Figure C).
- P50 BRV was determined from mapping the top and base of Upper Hibernia Fm and GDT -3555m TVDss (red polygon in Figure A and yellow interval in Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure tested at approximately 40000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

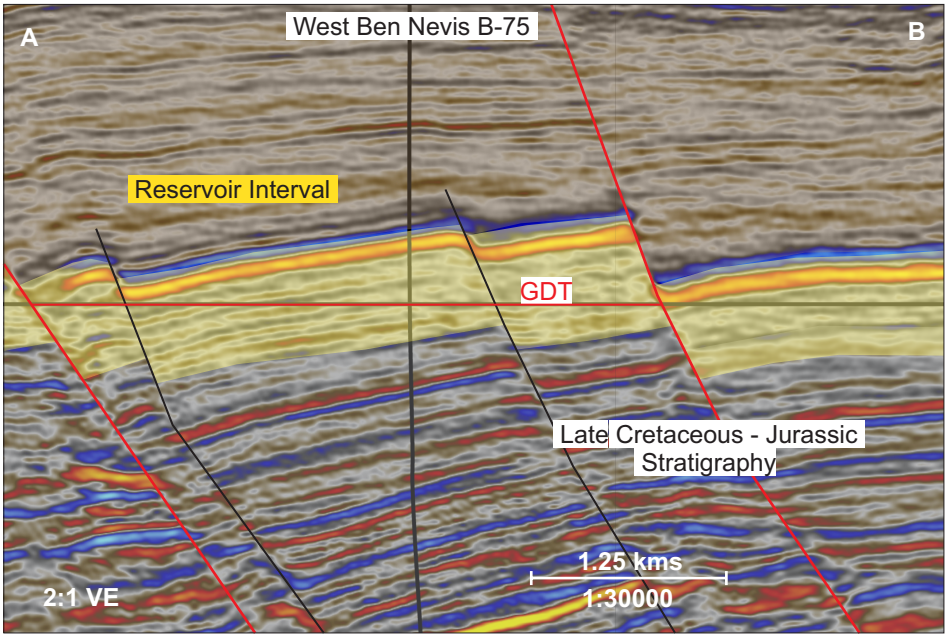


Figure B. Schematic cross-section from CA-3000960 depth survey illustrating the Upper Hibernia to the GDT depth in the fault blocks highlighted in yellow between the two red faults.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	2505	23	10	55	195	311	196
P50	2633	32	13	61	208	490	317
P10	2761	45	17	67	221	761	502

Table A. Input values compiled from the Upper Hibernia Member to the Lower Hibernia Member over mapped interval, using @risk to determine probabilistic unrisked OGIP and REC.

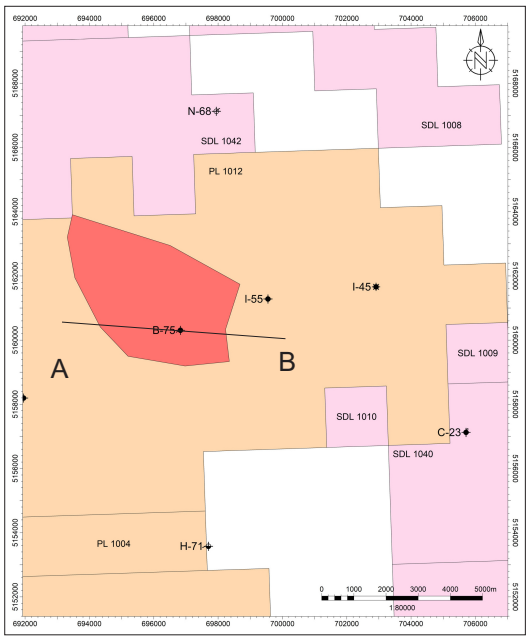


Figure A. Basemap illustrating the outline of West Ben Nevis B-75 Upper Hibernia Block 1 prospect. A-B line depicting location of seismic cross section.

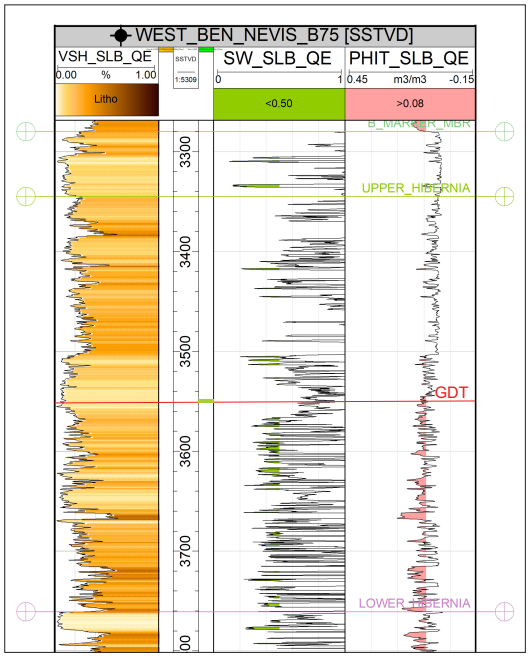


Figure C. West Ben Nevis B-75 well section over the reservoir interval from the Upper Hibernia Member to the Lower Hibernia Member.

STUDY AREA 27: PL 1012 WEST BEN NEVIS B-75 UPPER HIBERNIA MBR

- PL 1012
- Effective Date: April 18, 2017
- License Representative: ExxonMobil Canada
- Prospect Area: 920 ha

Key Well: West Ben Nevis B-75
Interval: Upper Hibernia Member

- Gross : 416m
- Sg: 54%
- GDT: -3555m TVDss
- N:G_{res}: 31%
- Avg Phi_{res}: 10%

- RFS sampled gas in the Upper Hibernia Member at -3555m TVDss (seen in Figure C).
- P50 BRV was determined from mapping the top and base of Upper Hibernia Fm and GDT -3555m TVDss (red polygon in Figure A and yellow interval in Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure tested at approximately 40000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

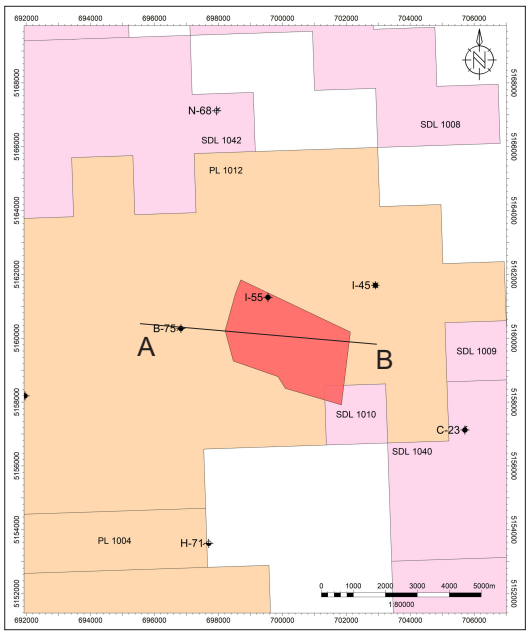


Figure A. Basemap illustrating the outline of West Ben Nevis B-75 Upper Hibernia prospect. A-B line depicting location of seismic cross section.

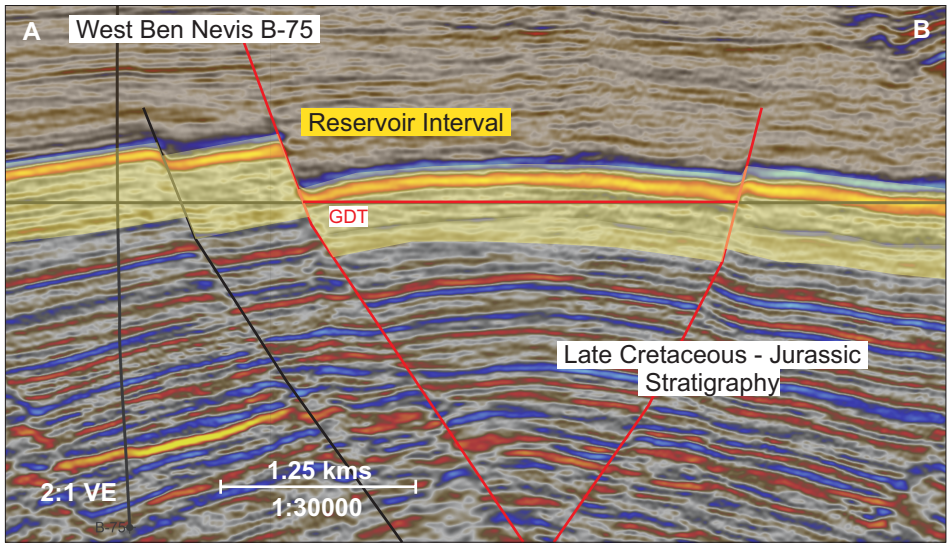


Figure B. Schematic cross-section from CA-3000960 depth survey illustrating the Upper Hibernia to the GDT depth in the fault block highlighted in yellow between the two red faults.

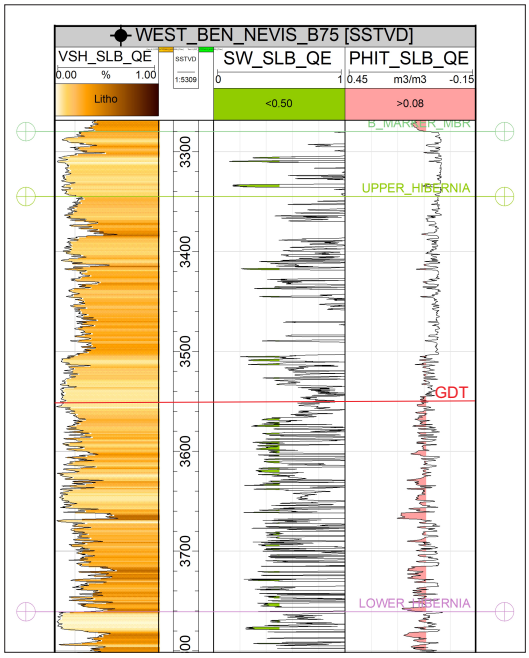


Figure C. West Ben Nevis B-75 well section over the reservoir interval from the Upper Hibernia member to the Lower Hibernia Member.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	826	23	10	55	195	104	67
P50	890	32	13	61	208	165	107
P10	954	45	17	67	221	260	171

Table A. Input values compiled from the Upper Hibernia Member to the Lower Hibernia Member over mapped interval, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 28: PL 1012 WEST BEN NEVIS B-75 UPPER HIBERNIA MBR

- PL 1012
- Effective Date: April 18, 2017
- License Representative: ExxonMobil Canada
- Prospect Area: 1023 ha

Key Well: West Ben Nevis B-75
Interval: Upper Hibernia Member

- Gross : 416m
- Sg: 54%
- GDT: -3555m TVDss
- N:G_{res}: 31%
- Avg Phi_{res}: 10%

- RFS sampled gas in the Upper Hibernia Member at -3555m TVDss (seen in Figure C).
- P50 BRV was determined from mapping the top and base of Upper Hibernia Fm and GDT -3555m TVDss (red polygon in Figure A and yellow interval in Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure tested at approximately 40000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

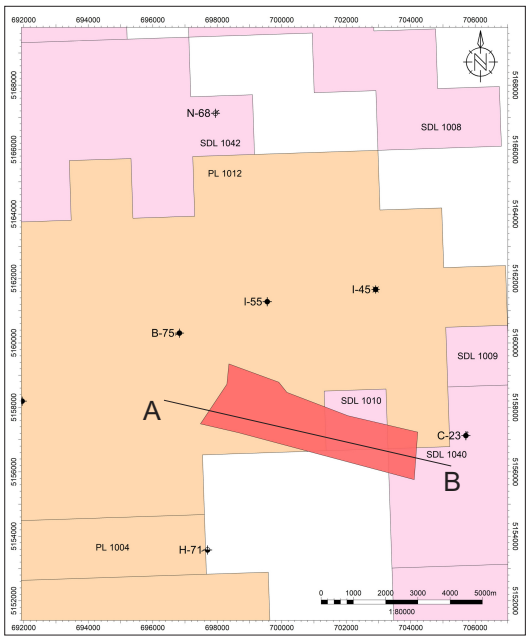


Figure A. Basemap illustrating the outline of West Ben Nevis B-75 Upper Hibernia prospect. A-B line depicting location of seismic cross section.

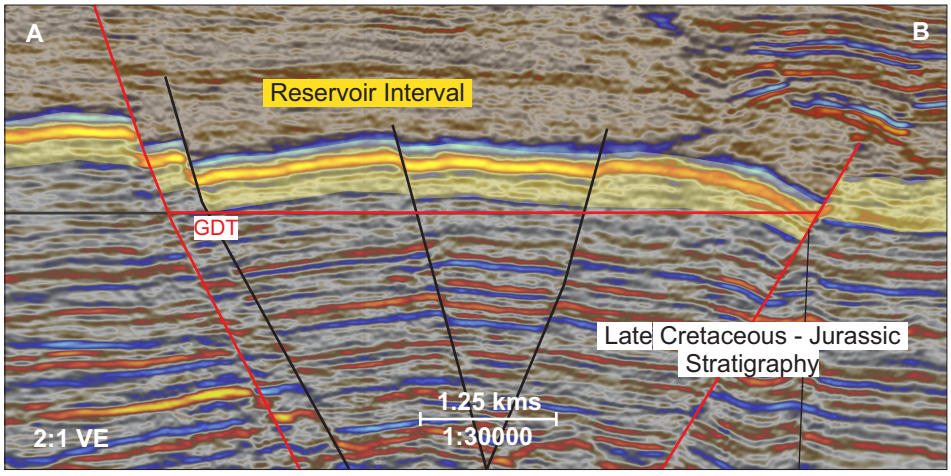


Figure B. Schematic cross-section from CA-3000960 depth survey illustrating the Upper Hibernia to the GDT depth in the fault blocks highlighted in yellow between the two red faults.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	2575	23	10	55	195	318	204
P50	2703	32	13	61	208	503	326
P10	2831	45	17	67	221	782	514

Table A. Input values compiled from the Upper Hibernia member to the Lower Hibernia Member over mapped interval, using @risk to determine probabilistic unrisked OGIP and REC.

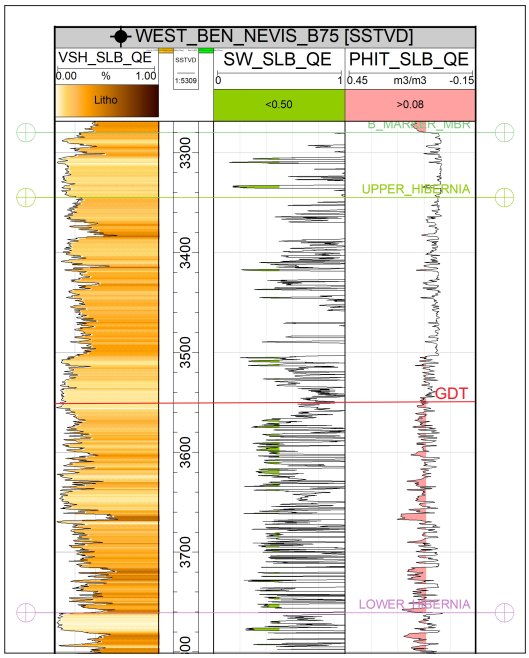


Figure C. West Ben Nevis B-75 well section over the reservoir interval from the Upper Hibernia Member to the Lower Hibernia Member.

STUDY AREA 29: PL 1012 BEN NEVIS I-45 BASAL HIBERNIA MBR

- PL 1012
- Effective Date: April 18, 2017
- License Representative: ExxonMobil Canada
- Prospect Area: 566 ha

Key Well: Ben Nevis I-45
Interval: Basal Hibernia Member to the Fortune Bay Formation

- Gross : 71m
- Sg: 70%
- GDT -4546m TVDss
- N:G_{res}: 46%
- Avg Phi_{res}: 10%

- Ben Nevis I-45 DST tested gas in the Basal Hibernia Member.
- P50 BRV was determined from mapping the top and base of the Basal Hibernia Member to GDT contact of -4546m TVDss (red polygon in Figure A and yellow interval in Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure is tested at approximately 75000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

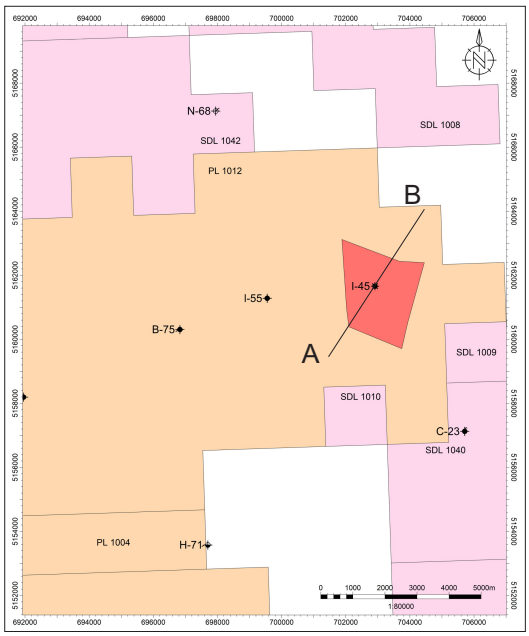


Figure A. Basemap illustrating the outline of Ben Nevis I-45 Basal Hibernia prospect. A-B line depicting location of seismic cross section.

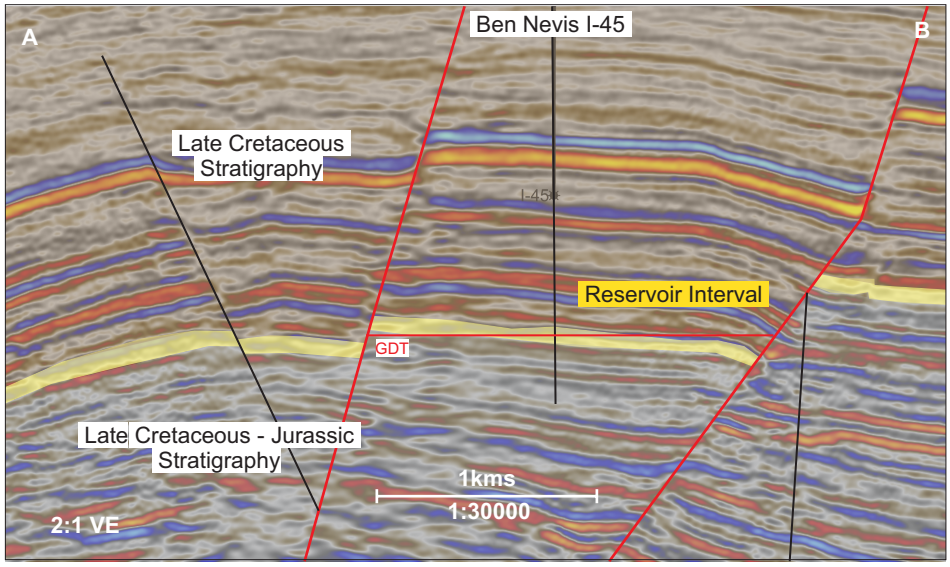


Figure B. Schematic cross-section from CA-3000960 depth survey illustrating the Basal Hibernia Member to the Fortune Bay Formation in the fault block highlighted in yellow between two red faults.

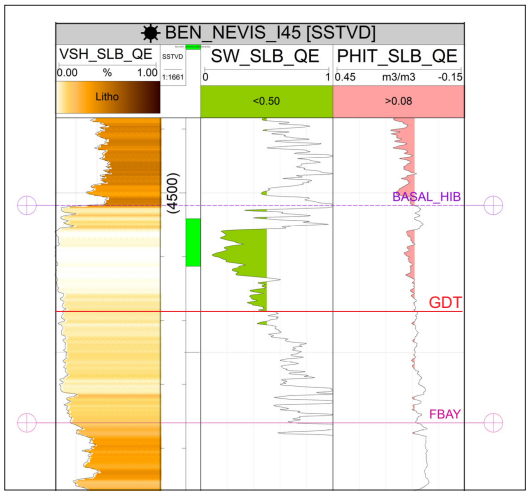


Figure C. Ben Nevis I-45 well section over the reservoir interval from the Basal Hibernia top to the Fortune Bay Formation.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	134	35	9	64	195	27	17
P50	147	45	11	70	208	38	24
P10	160	58	14	76	221	53	35

Table A. Input values compiled from top Basal Hibernia Formation to the Fortune Bay Formation over mapped interval, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 30: PL 1012 BEN NEVIS L-55 BEN NEVIS FM

- PL 1012
- Effective Date: April 18, 2017
- License Representative: ExxonMobil Canada
- Prospect Area: 666 ha

Key Well: Ben Nevis L-55
Interval: Ben Nevis Formation to Mid-Aptian Unconformity

- Gross : 316m
- Sg: 56%
- GOC: -2317m TVDss
- N:G_{res}: 71%
- Avg Phi_{res}: 15%

- Ben Nevis L-55 Ben Nevis formation assumes GOC -2317m TVDss from observed pressure data
- P50 BRV was determined from mapping the Ben Nevis interval to the GOC (red polygon in Figure A and yellow interval in Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure tested at approximately 24000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

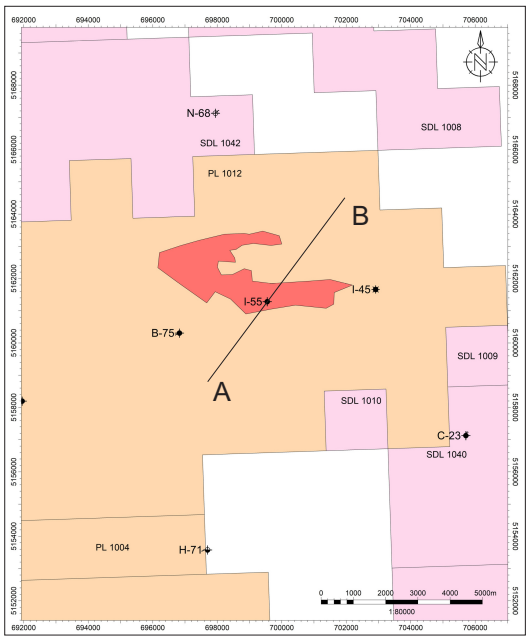


Figure A. Basemap illustrating the outline of Ben Nevis L-55 prospect. A-B line depicting location of seismic cross section.

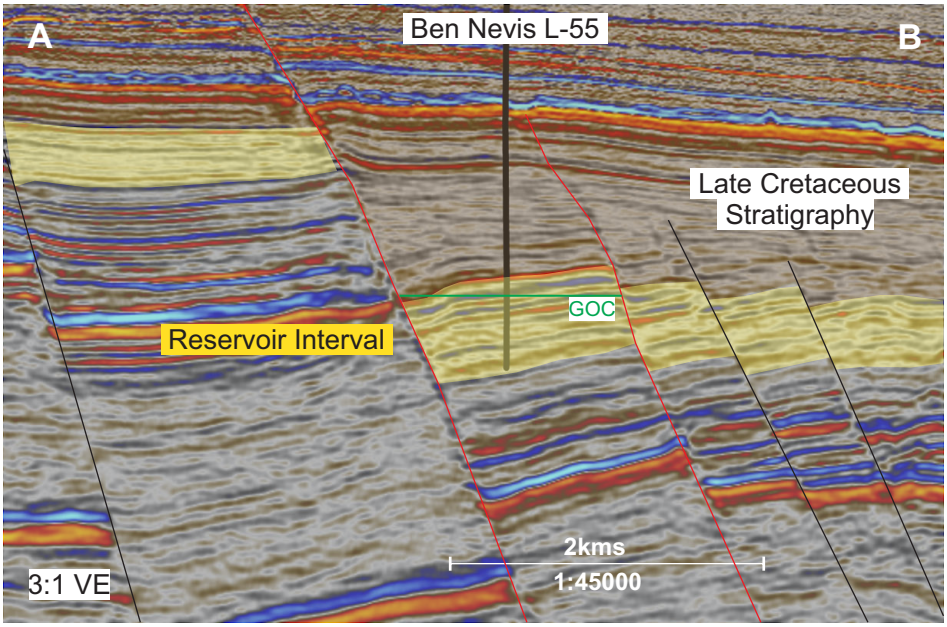


Figure B. Schematic seismic cross-section from CA-3000960 (converted to depth) illustrating the extent across the Ben Nevis L-55 prospect. Target reservoir interval highlighted in yellow situated between the red faults.

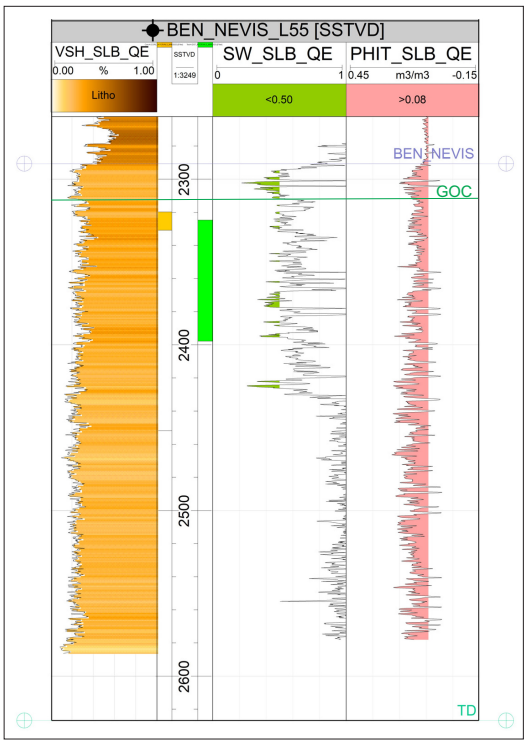


Figure C. Ben Nevis L-55 well section over the Ben Nevis interval. Well logs do not cover entire Ben Nevis Formation Interval.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	92	61	12	53	175	31	19
P50	98	71	15	58	188	40	26
P10	104	81	18	65	201	52	35

Table A. Input values compiled from Ben Nevis interval, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 31: SDL 1003 SOUTH MARA C-13 JEANNE d'ARC FM

- SDL 1003
- Effective Date: February 16, 1990
- License Representative: ExxonMobil Canada
- Prospect Area: 754 ha

Key Well: South Mara C-13
Interval: Jeanne d'Arc Formation

- Gross : 245m
- Sg: 68%
- GDT: -4985m TVDss
- N:G_{res}: 4%
- Avg Phi_{res}: 13%

- South Mara C-13 Jeanne d'Arc Formation prospect assumes a GDT -4985m TVDss.
- P50 BRV was determined from mapping the top of the Jeanne d'Arc Formation to GDT -4985m TVDss near the base of the well (red area on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- RFS sampled gas in the Jeanne d'Arc Formation at -4956m TVDss.
- Recovery factor analysis from analogues using industry trends and standards.

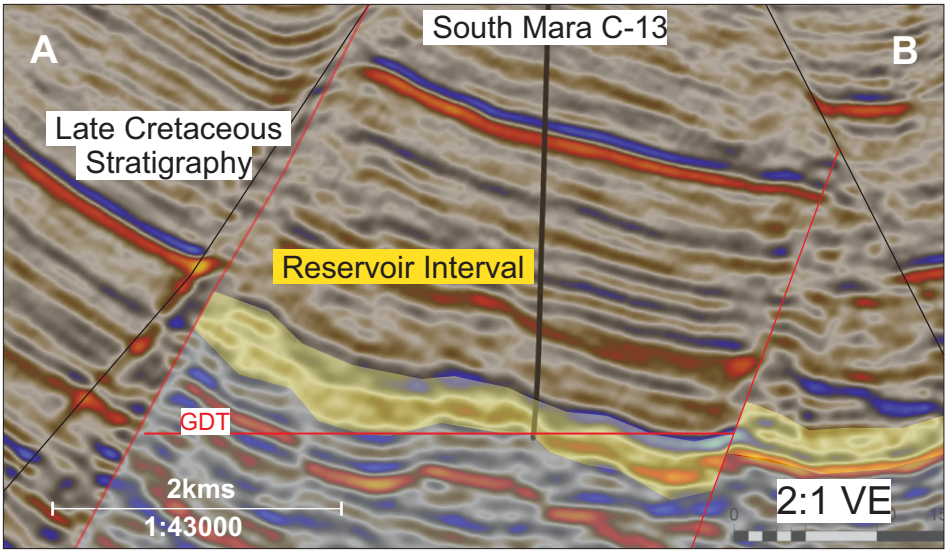


Figure B. Schematic seismic cross-section from CA-3001062-GOA-JDA SOUTH* (converted to depth) illustrating the extent across the South Mara C-13 Jeanne d'Arc Formation prospect. Target reservoir interval highlighted in yellow between the two red faults.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	176	2	9	62	225	2	1
P50	189	4	10	68	238	4	3
P10	202	7	11	74	251	7	5

Table A. Input values compiled from Jeanne d'Arc Formation using @risk to determine probabilistic unrisked OGIP and REC.

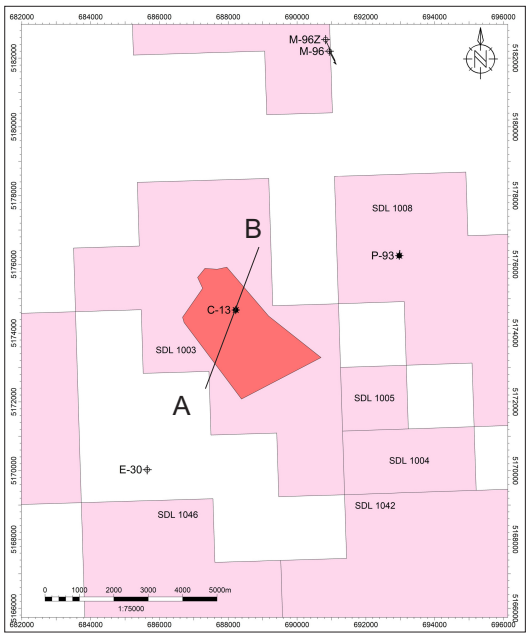


Figure A. Basemap illustrating the outline of South Mara C-13 Jeanne d'Arc Formation prospect. A-B line depicting location of seismic cross section.

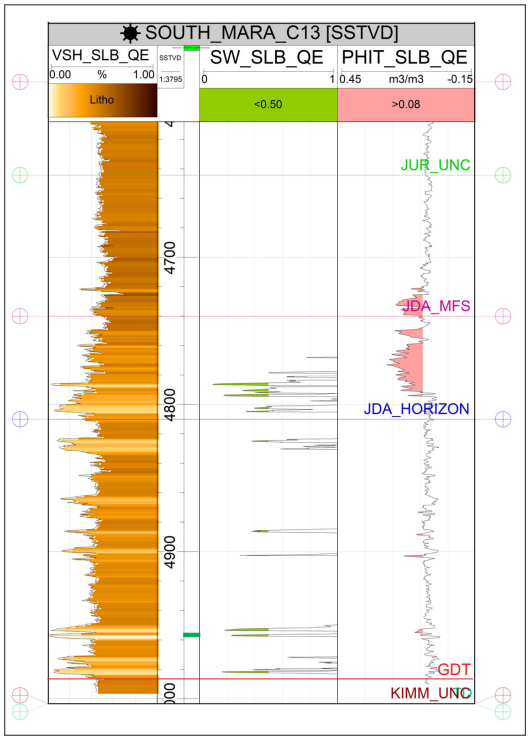


Figure C. South Mara C-13 well section over the Jeanne d'Arc Formation.

STUDY AREA 32: SDL 1027/1028 - WHITE ROSE BEN NEVIS FM

- SDL 1027and1028
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc
- Prospect Area: 1903 ha

Key Well: White Rose H-70
Interval: Ben Nevis Siltstone top to Mid Aptian Unconformity top

• Gross :	131m	• Sg:	68%
• Gas Pay:	27m	• N:G_{res}:	34%
• GOC:	-3642m TVDss	• Avg Phi_{res}:	13%

- This prospect is assumed to share a GOC contact with White Rose H-70 supported by gas pressures, samples and DST in H-70/z, A-78 and L-61.
- P50 BRV was determined from mapping the Ben Nevis Siltstone top to Mid Aptian Unconformity to the most likely GOC of -3642m TVDss (red polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure is approximately 37000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

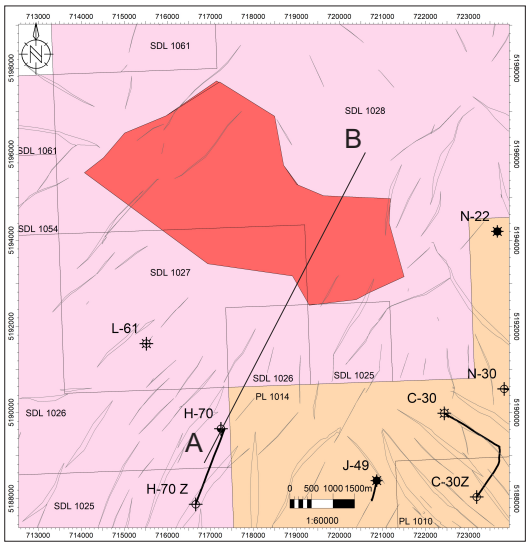


Figure A. Basemap illustrating the outline for the prospect; red used as input to determine the BRV. A-B line depicting location of schematic cross section.

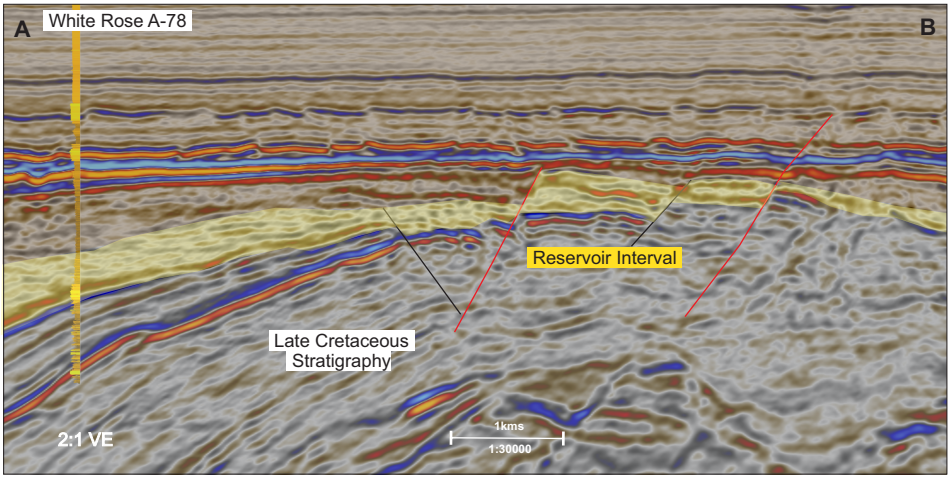


Figure B. Schematic cross-section from CA-3001062-GOA-JDA SOUTH* 3D survey (converted to depth) illustrating the southwest to northeast extent across the prospect. Target reservoir interval from Ben Nevis Formation to Mid Aptian Unconformity highlighted in yellow between two red faults.

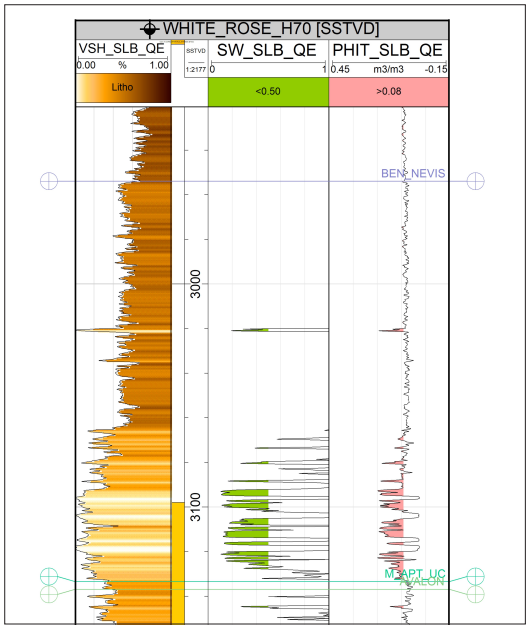


Figure C. White Rose H-70 well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid Aptian Unconformity.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	1926	18	11	60	239	261	166
P50	1990	33	12	68	265	492	317
P10	2054	48	13	76	284	747	493

Table A. Input values compiled from Ben Nevis Siltstone Formation top to Mid Aptian Unconformity within the prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 33: SDL 1020 / CROWN LAND WHITE ROSE BEN NEVIS FM

- SDL 1020 / Open Crown Land
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc
- Prospect Area: 348 ha

Key Well: White Rose A-78
Interval: Ben Nevis Siltstone to Mid Aptian Unconformity

- Gross : 162m
- Sg: 70%
- GOC: -3642m TVDss
- N:G_{res}: 35%
- Avg Phi_{res}: 10%

- This prospect is controlled by juxtaposition to White Rose A-78 fault block and its GOC of -3642m TVDss.
- P10 BRV was determined from mapping the Mid Aptian Unconformity and isopaching up 150m for reservoir top and constrained by closing contour -3520mTVDss and allowing for seismic uncertainty (red and yellow polygons on Figure A and yellow interval on Figure B).
- P99 BRV was determined by applying 1/3 crest (-3400m TVDss) of the trap (yellow polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure is approximately 37000 kpa from offset White Rose H-70 well.
- Recovery factor analysis from analogues using industry trends and standards.

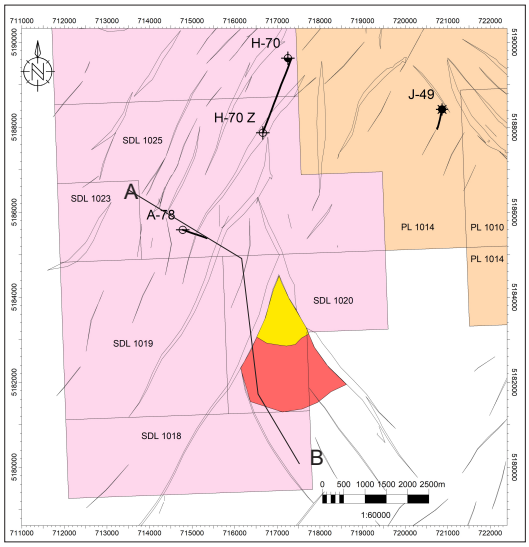


Figure A. Basemap illustrating the outline for this prospect; red and yellow polygons are used as input to determine the BRV. A-B line depicting location of schematic cross section.

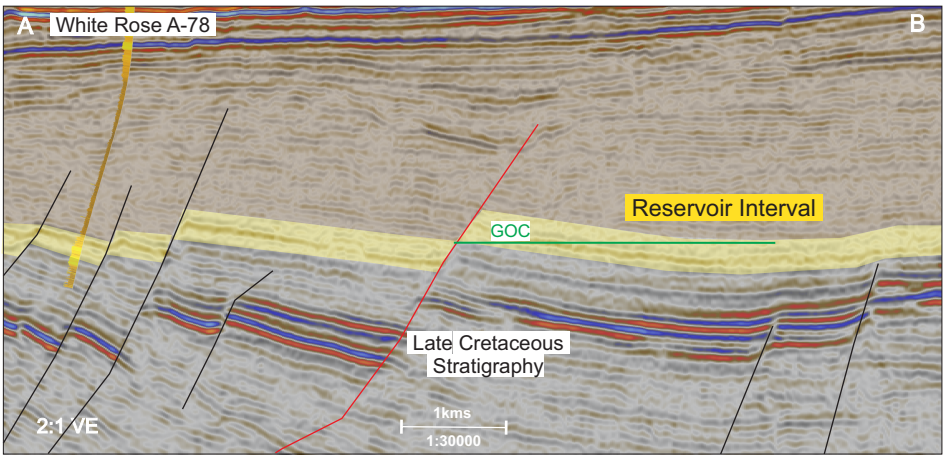


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across this prospect. Target reservoir interval from top Ben Nevis Siltstone Formation to Mid Aptian Unconformity highlighted in yellow east of the red fault.

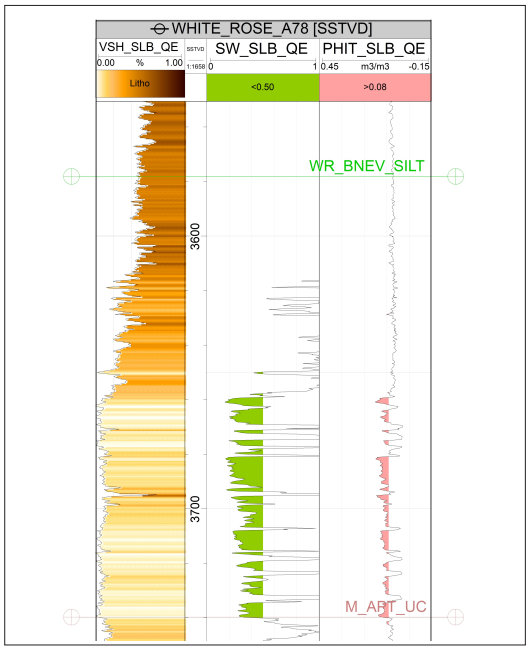


Figure C. White Rose A-78 well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid Aptian Unconformity.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	61	18	10	62	239	10	6
P50	119	33	11	70	265	26	17
P10	178	48	12	78	284	49	32

Table A. Input values compiled from Ben Nevis Siltstone Formation to Mid Aptian Unconformity, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 34: SDL 1028/1061 WHITE ROSE BEN NEVIS FM

- SDL 1028 and 1061
- Effective Date: February 16, 1990 / January 12, 2026
- License Representative: Cenovus Energy Inc.
- Prospect Area: 2133 ha

Key Well: White Rose H-70
Interval: Ben Nevis Siltstone to Mid Aptian Unconformity

- Gross : 131m
- Sg: 68%
- GOC -3540m TVDss
- N:G_{res}: 34%
- Avg Phi_{res}: 13%

- This prospect applies a most likely GOC of -3540m TVDss based on offset well pressures.
- P50 BRV was determined from mapping the Ben Nevis Siltstone to Mid Aptian Unconformity to the most likely GOC (red polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure is approximately 37000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

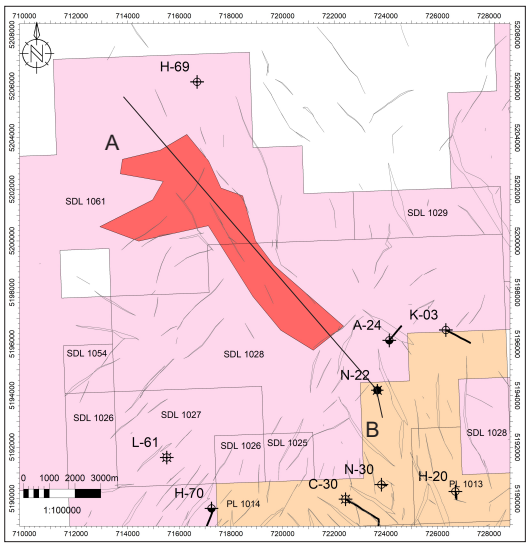


Figure A. Basemap illustrating the outline for this prospect; red polygon used as input to determine the BRV. A-B line depicting location of schematic cross section.

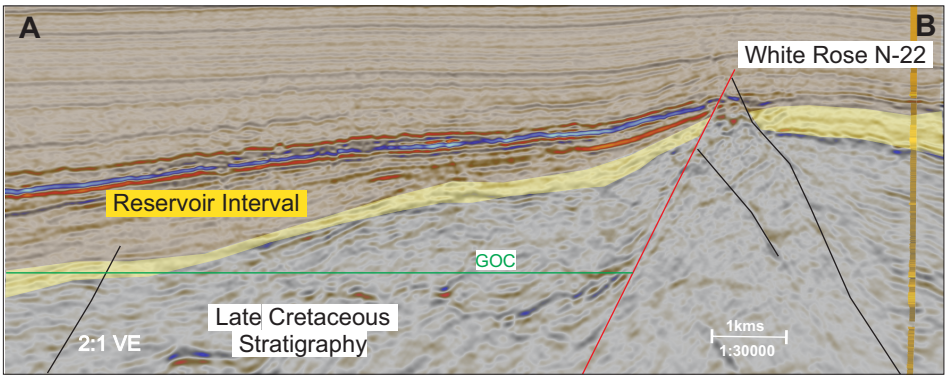


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across the prospect. Target reservoir interval from Ben Nevis Formation to Mid Aptian Unconformity highlighted in yellow northwest of the red fault.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	1854	18	11	60	204	208	132
P50	1918	33	12	68	217	392	252
P10	1982	48	13	76	230	593	392

Table A. Input values compiled from Ben Nevis Siltstone Formation to Mid Aptian Unconformity within the prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

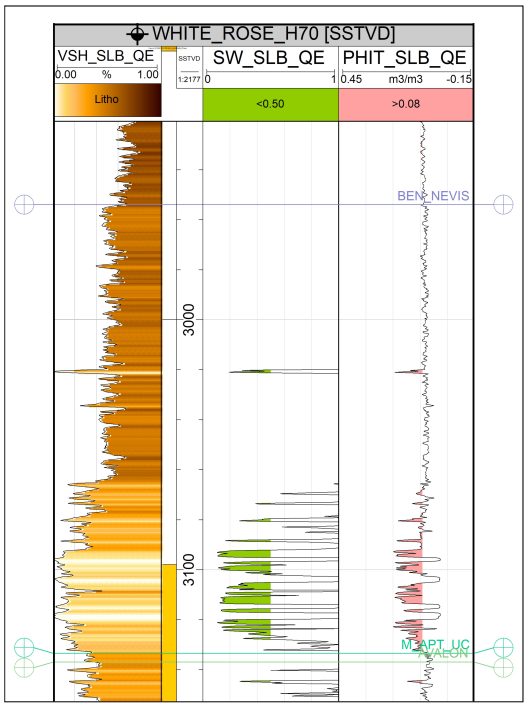


Figure C. White Rose H-70 well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid Aptian Unconformity.

• STUDY AREA 35: SDL 1028 and 1029 WHITE ROSE BEN NEVIS FM

- SDL 1028 and 1029
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 1708 ha

Key Well: White Rose N-22
Interval: Ben Nevis Siltstone to Mid Aptian Unconformity

- $Gross_{map}$: 114m
- Sg: 85%
- $N:G_{res}$: 36%
- Avg Phi_{res}: 13%

- This prospect assumes a filled to spill scenario in the gas phase.
- P1 BRV was determined from mapping the Ben Nevis Siltstone top to Mid Aptian Unconformity (red polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure is approximately 37000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

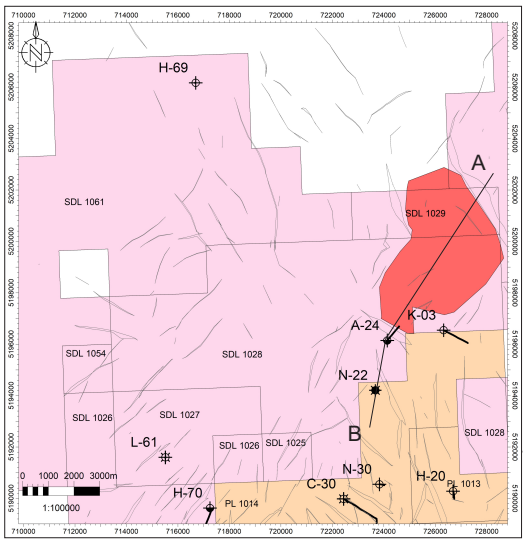


Figure A. Basemap illustrating the outline for this prospect; red polygon used as input to determine the BRV. A-B line depicting location of schematic cross section.

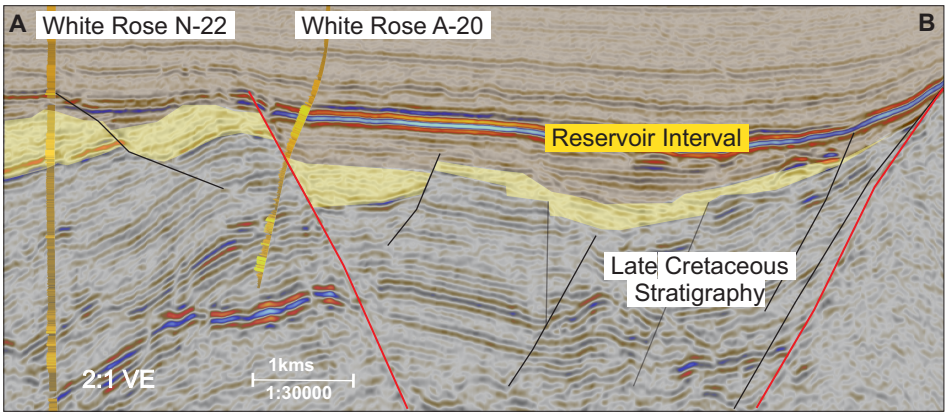


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northeast to southwest extent across this prospect. Target reservoir interval from Ben Nevis Formation to Mid Aptian Unconformity highlighted in yellow between the two red faults.

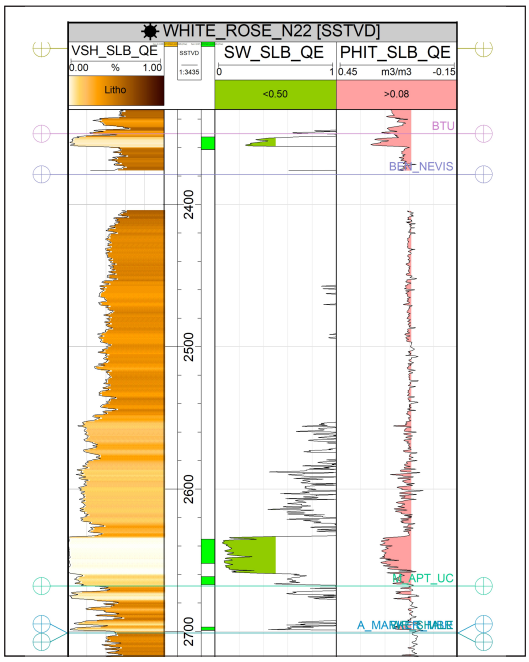


Figure C. White Rose N-22 well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid Aptian Unconformity.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	732	30	12	67	204	181	115
P50	990	36	13	75	217	264	171
P10	1436	42	14	83	230	403	267

Table A. Input values compiled from Ben Nevis Siltstone Formation to Mid Aptian Unconformity within this prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 36: SDL 1028, 1029, 1061 WHITE ROSE BEN NEVIS FM

- SDL 1028, 1029 and 1061
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 1114 ha

Key Well: White Rose N-22
Interval: Ben Nevis Siltstone to Mid Aptian Unconformity

- $Gross_{map}$: 114m
- Sg: 85%
- $N:G_{res}$: 36%
- Avg Phi_{res}: 13%

- This prospect assumes a filled to spill scenario with a closing contour at -3350m TVDss in the gas phase.
- P1 BRV was determined from mapping the Ben Nevis Siltstone to Mid Aptian Unconformity (red polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure is approximately 37000 kpa.
- Recovery factor analysis from analogues using industry trends and standards.

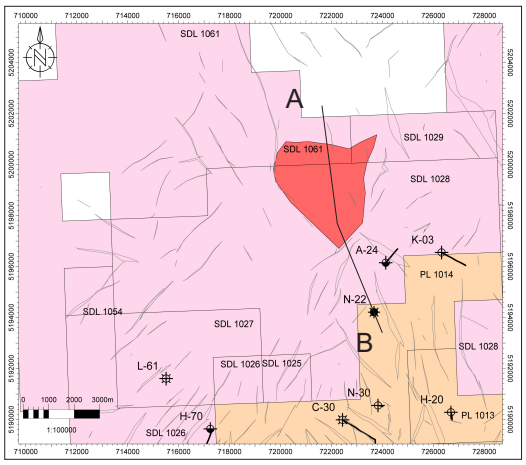


Figure A. Basemap illustrating the outline for this prospect; red polygon used as input to determine the BRV. A-B line depicting location of schematic cross section.

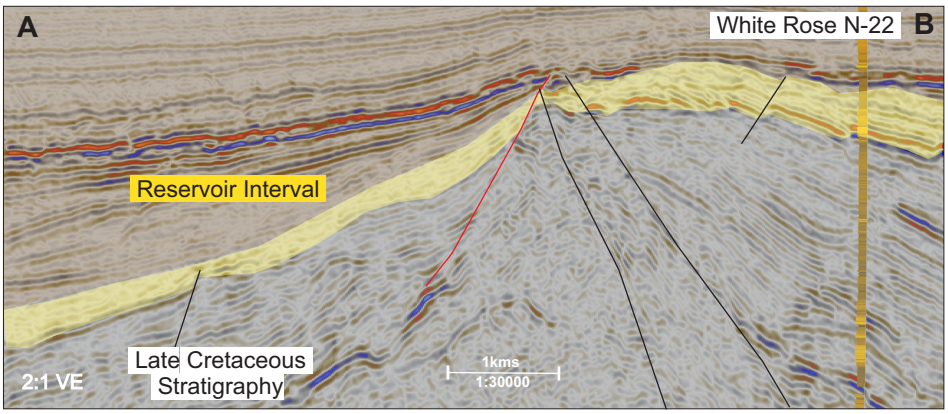


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across this prospect. Target reservoir interval from Ben Nevis Formation to Mid Aptian Unconformity highlighted in yellow, north of the red fault.

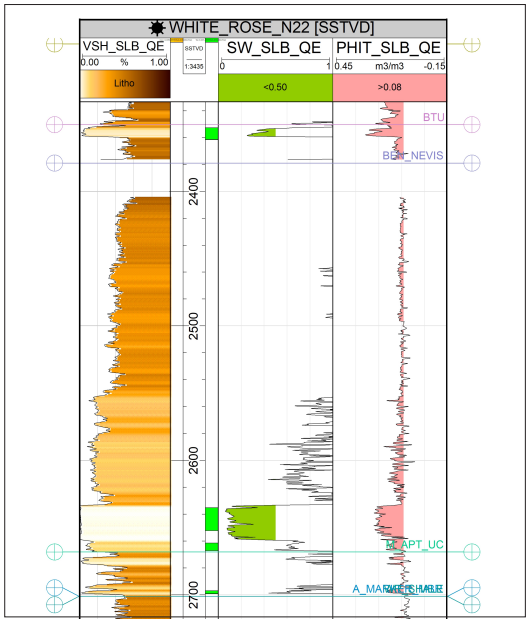


Figure C. White Rose N-22 well section over the reservoir interval from Ben Nevis Siltstone Formation to Mid Aptian Unconformity.

	BRV (e^6m^3)	$N:G_{res}$	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	1257	30	12	67	204	275	174
P50	1320	36	13	75	217	351	228
P10	1383	42	14	83	230	439	292

Table A. Input values compiled from Ben Nevis Siltstone Formation top to Mid Aptian Unconformity within the prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 37: CROWN/ SDL 1026/1028/1054/1061 WHITE ROSE LOWER HIBERNIA MBR

- SDL 1026, 1028, 1054, 1061
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 4654 ha

Key Well: White Rose N-22
Interval: Lower Hibernia Fm to Fortune Bay Fm

- Gross : 426m
- Sg: 63%
- N:G_{res}: 22%
- Avg Phi_{res}: 10%

- Lower Hibernia Member prospect assumes filled to spill in the gas phase.
- P1 BRV was determined from mapping the Lower Hibernia Fm to the top of the Fortune Bay Fm and filled to spill (red and yellow polygon on Figure A and yellow interval on Figure B).
- P50 BRV was determined from same methodology and applying 1/3 crest (-4518m TVDss) of the trap (yellow polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Lower Hibernia Fm to Fortune Bay Fm (Figure C and Table A).
- Reservoir pressure is approximated from fields and offset wells of similar depth.
- Recovery factor analysis from analogues using industry trends and standards.

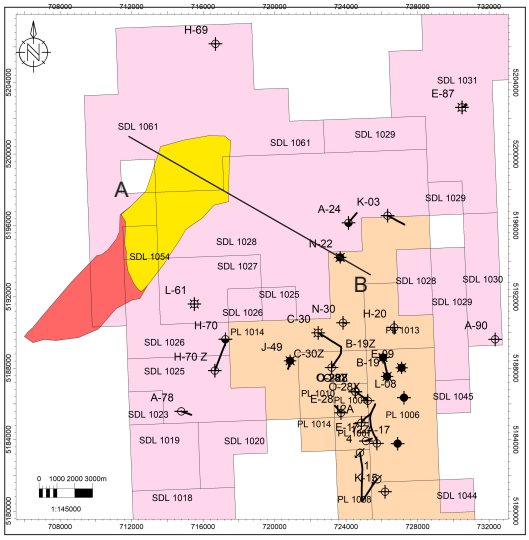


Figure A. Basemap illustrating the outline for this prospect; red and yellow polygons used as input to determine the BRV. A-B line depicting location of schematic cross section.

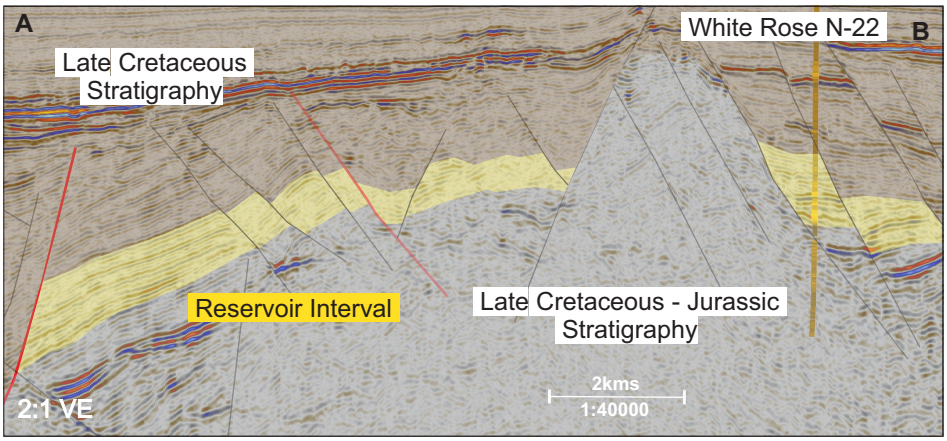


Figure B. Schematic cross-section from CA-3000696 2008 Husky JDA-Whiterose 3D survey (converted to depth) illustrating the northwest to southeast extent across this prospect. Target reservoir interval from Lower Hibernia Member to the Fortune Bay Formation highlighted in yellow between the two red faults.

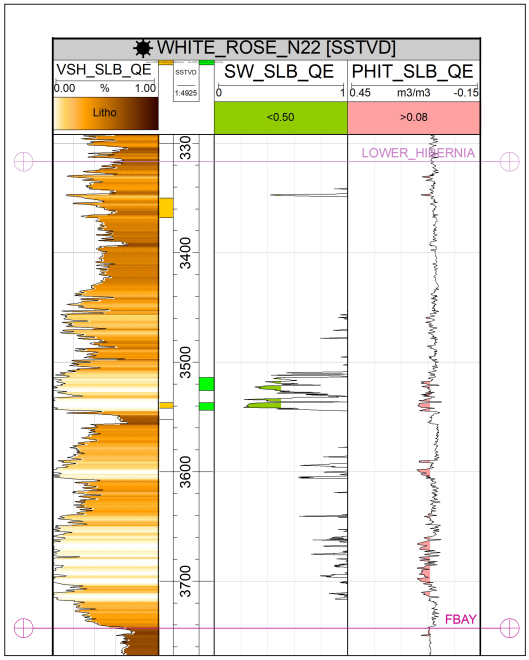


Figure C. White Rose N-22 well section over the reservoir interval from Lower Hibernia Member to the Fortune Bay Formation.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	5096	22	11	59	191	802	512
P50	10781	30	12	67	204	1789	1159
P10	16595	38	13	75	217	3096	2034

Table A. Input values compiled from the Lower Hibernia Member within this prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

• STUDY AREA 38: SDL 1061 WHITE ROSE LWR HIBERNIA MBR

- SDL 1061
- Effective Date: January 12, 2026
- License Representative: Cenovus Energy Inc.
- Prospect Area: 651 ha

Key Well: White Rose N-22
Interval: Lower Hibernia Member to Fortune Bay Formation

- Gross : 426m
- Sg: 63%
- N:G_{res}: 22%
- Avg Phi_{res}: 10%

- Lower Hibernia Member prospect assumes filled to spill in the gas phase.
- P1 BRV was determined from mapping the Lower Hibernia Fm to the top of the Fortune Bay Fm and filled to spill (red and yellow polygon on Figure A and yellow interval on Figure B).
- P50 BRV was determined from same methodology and applying 1/3 crest (-5162m TVDss) of the trap (yellow polygon on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages for the Lower Hibernia Fm to Fortune Bay Fm (Figure C and Table A).
- Reservoir pressure is approximated from fields and offset wells of similar depth.
- Recovery factor analysis from analogues using industry trends and standards.

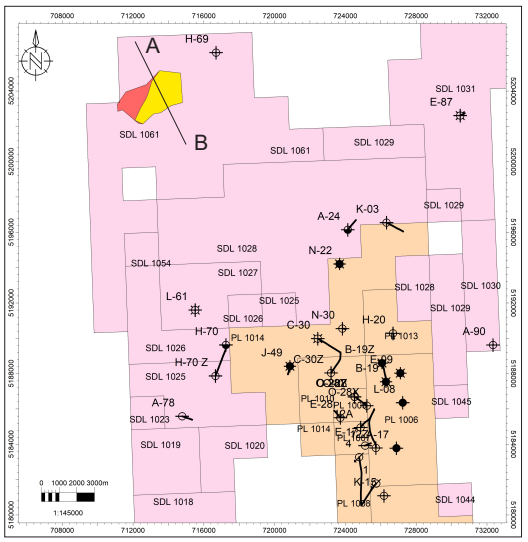


Figure A. Basemap illustrating the outline for this prospect; red and yellow polygons used as input to determine the BRV. A-B line depicting location of schematic cross section.

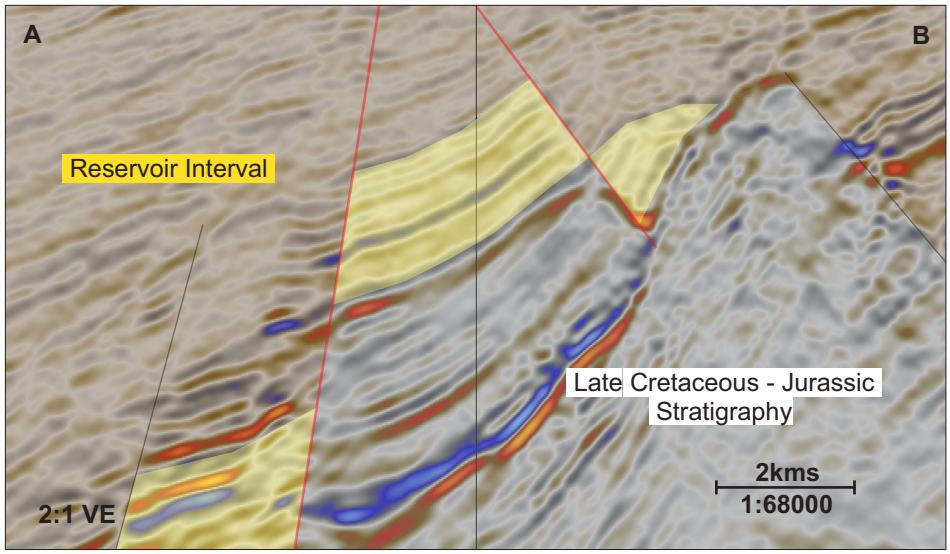


Figure B. Schematic cross-section from CA-3001062-GOA-JDA NORTH* 3D survey (converted to depth) illustrating the northwest to southeast extent across this prospect. Target reservoir interval from Lower Hibernia Member to the Fortune Bay Formation highlighted in yellow between the two red faults.

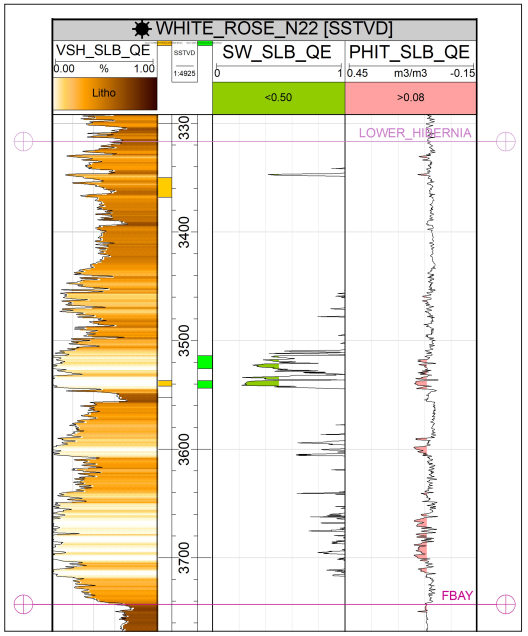


Figure C. White Rose N-22 well section over the reservoir interval from Lower Hibernia Member to the Fortune Bay Fm.

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	260	22	11	59	191	42	27
P50	1123	30	12	67	204	185	120
P10	2329	38	13	75	217	419	274

Table A. Input values compiled from the Lower Hibernia Member within this prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

STUDY AREA 39: SDL 1026 and 1027 - WHITE ROSE L-61 EASTERN SHOALS FM

- SDL 1026 and 1027
- Effective Date: February 16, 1990
- License Representative: Cenovus Energy Inc.
- Prospect Area: 390 ha

Key Well: White Rose L-61
Interval: Eastern Shoals Formation

- Gross : 52m
- Sg: 54%
- GDT -3235.7m TVDss
- N:G_{res}: 8%
- Avg Phi_{res}: 11%

- White Rose L-61 acquired RFS gas samples in the Eastern Shoals at -3235.7m TVDss.
- P90 BRV was determined from mapping the top and bottom of the Eastern Shoals Fm with GDT of -3235.7m TVDss (yellow polygon on Figure A and yellow interval on Figure B).
- P10 BRV was determined from same methodology and filled to spill with seismic uncertainty (red and yellow polygons on Figure A and yellow interval on Figure B).
- SLB petrophysical curves for Vcl, Phi and Sw with cutoffs Vcl < 30%; Phi > 8%; Sw < 50% provide the reservoir input well averages (Figure C and Table A).
- Reservoir pressure is approximated from fields and offset wells of similar depth.
- Recovery factor analysis from analogues using industry trends and standards.

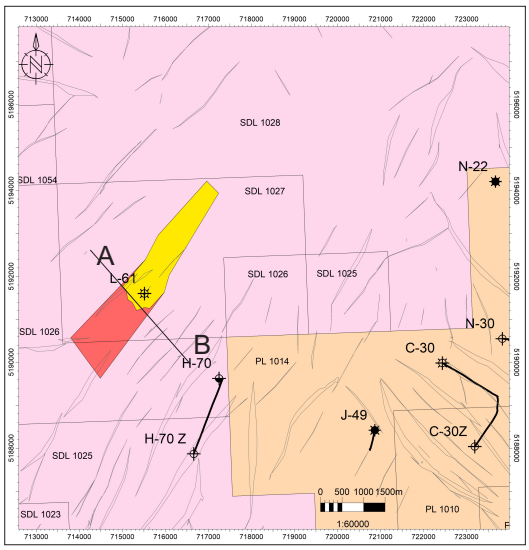


Figure A. Basemap illustrating the outline for this prospect; red and yellow polygons used as input to determine the BRV. A-B line depicting location of schematic cross section.

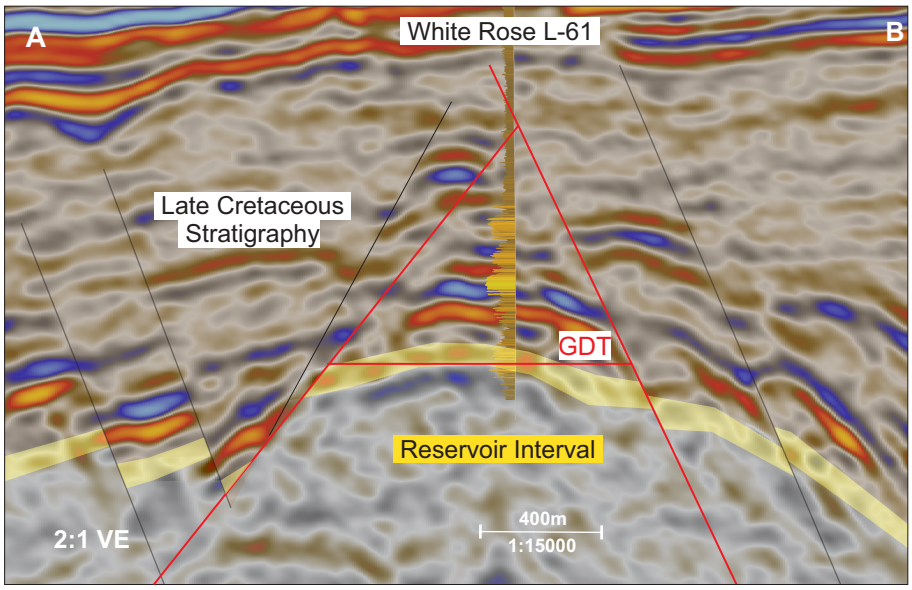


Figure B. Schematic cross-section from CA-3001062-GOA-JDA SOUTH* 3D survey (converted to depth) illustrating the northeast to southwest extent across this prospect. Target reservoir interval from Eastern Shoals Fm highlighted in yellow between the two red faults.

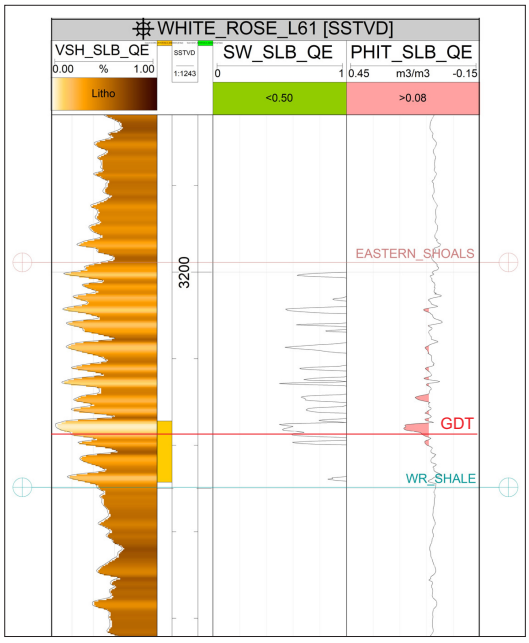


Figure C. White Rose L-61 well section over the reservoir interval from Eastern Shoals Fm

	BRV (e^6m^3)	N:G_{res}	Phi_{res}	Sg	1/Bg	OGIP (bcf)	REC (bcf)
P90	105	11	10	51	250	8	5
P50	162	15	11	56	263	14	9
P10	219	20	12	63	276	22	14

Table A. Input values compiled from Eastern Shoals Fm within the White Rose L-61 prospect boundary, using @risk to determine probabilistic unrisked OGIP and REC.

ADDITIONAL INFORMATION AND CONTACTS

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C-NLOER$_1$ (February 4, 2026) Petroleum Estimated Ultimate Recovery and Contingent Resources Newfoundland Offshore Area. https://www.cnloer.ca/resource/information/

CA-3001062-GOA-JDA SOUTH 3D and CA-3001062-GOA-JDA NORTH 3D survey seismic data provided by TGS Geophysical Company*, Operational Headquarters, 10451 Clay Road, Houston, Texas 77041, USA

*Permission granted to use seismic images seen in this document

All remaining seismic data used provided by C-NLOER (public data)

In-house Natural Gas Resource Assessment completed by the Petroleum Geoscience and Petroleum Engineering Divisions of the Department of Energy and Mines.

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Reviewed by: J. Petrovic and D.Corkey, Directors of Petroleum Geoscience & Engineering in the Department of Energy and Mines

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