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The Playbook

A supplement to *Oil and Gas Investor, E&P,* and *Midstream Business*

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Winter lasts a long time at shale drilling sites in northern British Columbia. *(Photo courtesy of Encana Corp.)*

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Winter comes early and cold to operators working the shales of the Horn River Basin of northeastern British Columbia. *(Photo courtesy of Apache Corp.)*

O Canada!

Its turbulent geological history has turned the Western Canada Sedimentary Basin into a complex exploration province.

By Steve Thornhill
Contributing Editor

When viewing the Western Canada Sedimentary Basin (WCSB), with the majestic Canadian Rockies bounding the basin to the west and the Precambrian igneous and metamorphic rock of the Canadian Shield bounding the basin to the east, it is easy to take a simplistic basin view. That view is further reinforced when one views sediment thickness maps, revealing a westward sediment thickening to a depth of over 7,010 m (23,000 ft) towards the obvious apparent sediment source, the Canadian Rockies. Don't be deceived by this simplistic view; today's Canadian Rockies have only been there since the Middle to Late Jurassic, a mere 170 million to 150 million years. Going back to Early Mississippian times and earlier, everything west of Saskatchewan was under water.

(Source: USGS)

A map of Canada from 550 million years ago, during the Late Precambrian when viewed from west to east, reveals first the plains and next the mountains of the Precambrian Canadian Shield to the east. By studying erosional rates and sedimentation, geologists estimate that the mountainous area constituting the early Canadian Shield reached elevations in excess of 12,000 m (39,000 ft). This soaring continental landmass stretched westward across Canada through the eastern half of British Columbia. Everything further west was under water. In addition, the Canadian Shield, also known as the continent of Laurentia, was located just south of the equator and was rotated 180o from its current position.

During the following Cambrian period, far to the south of the Canadian Shield, a huge landmass known as supercontinent Gondwana began to break apart with several sections moving northward and ultimately colliding with the Canadian Shield, forming a small supercontinent called Euramerica, as well as the northern Appalachian Mountains.

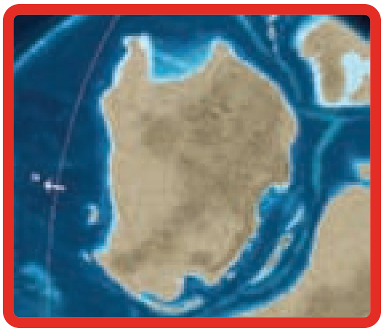
Fast forward 165 million years to the Middle Devonian period 385 million years ago, when the Duvernay Formation was being deposited, and just before deposition of the Bakken/Exshaw Formations in the Late Devonian, and it's apparent that eastern British Columbia and nearly all of western Alberta had begun to subside under water, while sedimentary fill poured in from the mountainous Canadian Shield region to the east. During this period, British Columbia and Alberta were both under water, part of a broad shallow prograding continental shelf. While this subsidence and deposition was going on, the entire Canadian Shield landmass was slowly rotating in a clockwise direction, while moving northwards over the equator. During the Devonian, Gondwana began migrating towards Euramerica, while later during the Carboniferous, Australia, India, and Antarctica migrated down to the south pole and were heavily glaciated, globally dropping the sea level and helping to cause the emergence and subsequent erosion of earlier sediments deposited in Alberta.

By the Middle Triassic, 230 million years ago when the Montney Formation was being deposited, subsidence and subsequent sedimentation had extended across most of Alberta, leaving the western third of western Alberta still submerged, along with nearly all of British Columbia. In addition, the South America Plate had broken off from supercontinent Gondwana and migrated northward, colliding with the Canadian Shield and forming the southern Appalachian Mountains and the North American Plate. Because the world's oceans were blocked north to south by the resulting huge supercontinent Pangaea landmass, much of the ocean currents we have today didn't exist. Middle Triassic Canada was mostly desert, and much of the sedimentation on the adjoining continental shelf was aeolian (windblown) in nature.

During the Middle to Late Jurassic, approximately 170 million to 150 million years ago, the oceanic plate adjoining the North American Plate to the west began to be subducted under the North American Plate. Shallow sedimentary wedges were planed off the subducted plate and piled up against the western edge of the North American Plate, forming the Canadian Rockies.

During the Late Cretaceous, approximately 85 million years ago, when the Cardium Formation was being deposited, formation of the WCSB as we know it today finally began. The Kula Oceanic Plate, located to the west of Northern California, Oregon, Washington, and British Columbia, began to be subducted under the North American Plate. As the Kula Plate was subducted, shallower parts of the plate were planed off and became emergent, with sections stacking up on one another, creating the mountain chains that today are Canada's far western Coast Mountains, the Columbian Mountains further inland, and lastly, the Canadian Rockies, formed earlier during the Middle to Late Jurassic. Eventually, a second oceanic plate, the Farallon Plate, adjoining the Kula Plate to the south, began pushing the Kula Plate north, while it was still being subducted under the North American Plate. Ultimately, the entire Kula Plate was subducted, with the exception of today's Vancouver Island, which was sheared off the subducted Kula Plate and left behind. Accordingly, Kula is Tlingit for "all gone."

While the western mountain building was occurring, the area to the east in front of the Canadian Rockies was subsiding, possibly from the weight of the sediments pushed up onto the North American Plate, from erosional sediment loading, or simply because of regional tilting of the Canadian Shield. The subsidence may have been the result of all three factors working in conjunction. The result was a long generally north-south subsidence band along



Late Precambrian Canada

Middle Devonian Western Canada

Middle Triassic Western Canada

Late Cretaceous Western Canada

(© Ron Blakey, Colorado Plateau Geosystems, used with permission)

the eastern mountain edge causing the formation of a long shallow seaway, known as the Western Interior Seaway. The Western Interior Seaway was nearly as wide as Alberta and Saskatchewan combined and reached all the way from the Arctic Ocean south to the Gulf of Mexico. The resulting seaway covered up nearly the entire province of Alberta and most of Saskatchewan with a shallow sea.

By the Late Cretaceous, the supercontinent Gondwana had separated into many of the landmasses we know today, leaving the much smaller continent of Antarctica at the South Pole. Like Gondwana, the supercontinent Pangaea had also broken up, creating more of today's landmasses, including all of North and South America and Greenland.

In conjunction with the formation of the Western Interior Seaway, there were numerous localized areas along the seaway's length that were subject to tectonic uplift, as well as other areas subject to greater than normal subsidence; for instance, the Sweetgrass Arch, which runs northeast to southwest through the south end of the Alberta Province into Saskatchewan. The Sweetgrass Arch, along with further subsidence south of the arch, divided the WCSB, causing the southern part of the WCSB to become the separate Williston Basin, located predominately in the US. The Peace River Arch, running in a general west to east direction where the Peace River crosses the Alberta/British Columbia border, divided the WCSB into two separate sub-basins, with the Peace River Arch becoming a periodic erosional zone, and thus a localized unconformity on the stratigraphic column, creating a much more complicated geological picture than one would expect viewing the WCSB as a whole.

During this nutshell time travel, the Devonian, Triassic, and Late Cretaceous were specifically focused on, because it was during those times that the sediments making up the source rocks and reservoir rocks discussed further on in this report were deposited.

This report will discuss several current unconventional oil plays being pursued in Canada. Normally, when discussing a list of several different oil plays, it's a good idea to put them in order based on their geological age. For this report the following unconventional oil plays will be discussed:

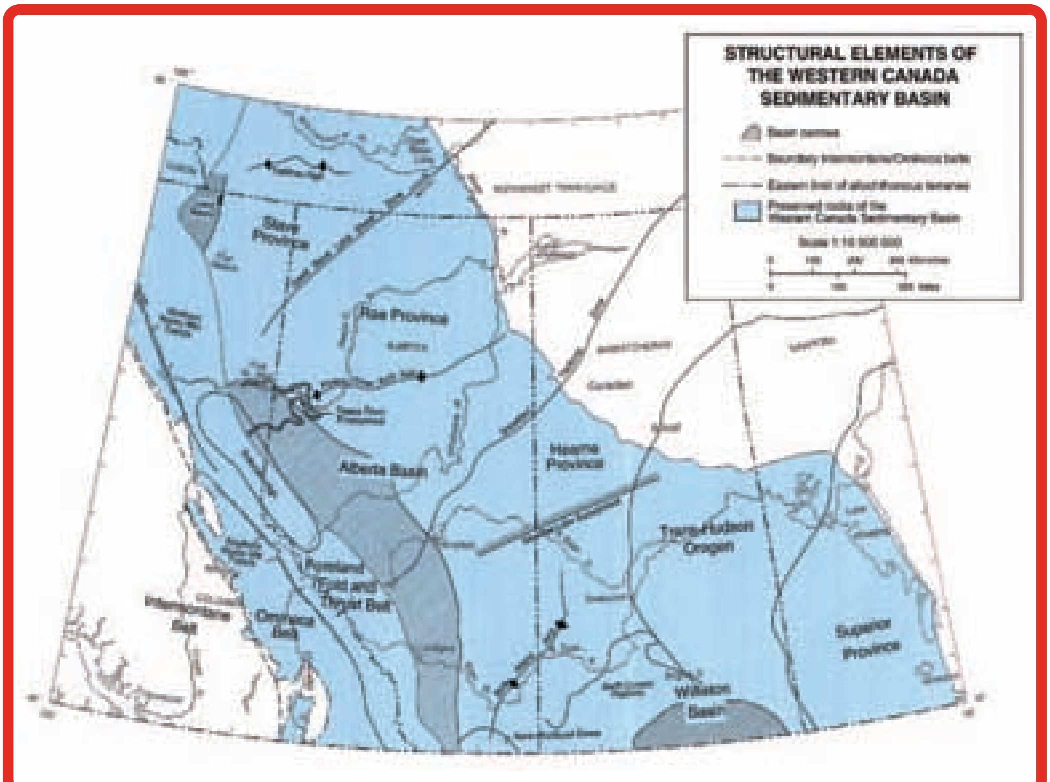
1. Duvernay Formation, Middle Devonian, approximately 385 million years old
2. Exshaw (Bakken) Formation, Late Devonian to Early Mississippian, approximately 360 million years old
3. Montney Formation, Early to Middle Triassic, approximately 245 million to 230 million years old
4. Cardium Formation, Late Cretaceous, approximately 85 million years old

However, this report will start with the Bakken Formation, specifically the Williston Basin portion located in the Canada. The Bakken is well-known, well-documented, and makes for a fine overview of the type of oil play that is revolutionizing today's oil industry.

The Bakken Formation – Late Devonian to Early Mississippian

The Bakken Formation is a well-known Late Devonian-age hydrocarbon source rock found blanketing the Williston Basin. The Exshaw Formation found in the WCSB is the stratigraphic equivalent of the Bakken and will be discussed in more detail further on. Since sweet-spot areas with higher than normal porosities and permeability exist in the Bakken, the Bakken has long been a bailout zone, often used to hopefully salvage a vertical well when the primary objective came in dry. It wasn't until 2005 that a clever and brave operator thought to drill the zone horizontally and then subject the formation to multiple hydraulic fracturing.

The Bakken Formation is found in the Williston Basin area of Saskatchewan and Manitoba at depths to 2,500 m (8,200 ft). The Bakken varies in thickness from 3 m (10 ft) to 40 m (131 ft) and consists of three separate layers. The top layer is an organic-rich black shale, deposited during a period of high sea level. The middle layer, the primary Bakken completion zone, is a mixed low porosity/permeability dolomitic siltstone/sandstone reservoir zone, deposited during a fall in sea level. The bottom layer is an organic-rich black shale source rock that was deposited during an earlier sea level rise (46). The Bakken is the primary Williston Basin source rock.



Source: Wright, G.N., McMechan, M.E. and Potter, D.E.G. (1994): Figure 3.1, Structural elements of the Western Canada Sedimentary Basin; in Geological Atlas of the Western Canada Sedimentary Basin, G.D. Mossop and I. Shetsen (comp.), Canadian Society of Petroleum Geologists and Alberta Research Council, Calgary, Alberta, URL http://www.ags.gov.ab.ca/publications/wcsb_atlas/atlas.html [November 2012]

Much of the Bakken, particularly in the deeper basin areas, is overpressured, with natural fracing occurring from the overpressure conditions. The middle Bakken completion zone is carbonate-rich, making it brittle and frac-prone under hydraulic fracing. The Bakken typically has total organic hydrocarbons (TOCs) ranging from 10% to 21%.

During the seven years that the Bakken has been unconventionally produced, industry has become increasingly efficient at extracting oil from the formation. Several years ago, 1.6-km-long (1-mile-long) laterals and up to 20 frac zones were the norm; today, it's often 3.2-km (2-mile) laterals with 60 or more frac zones.

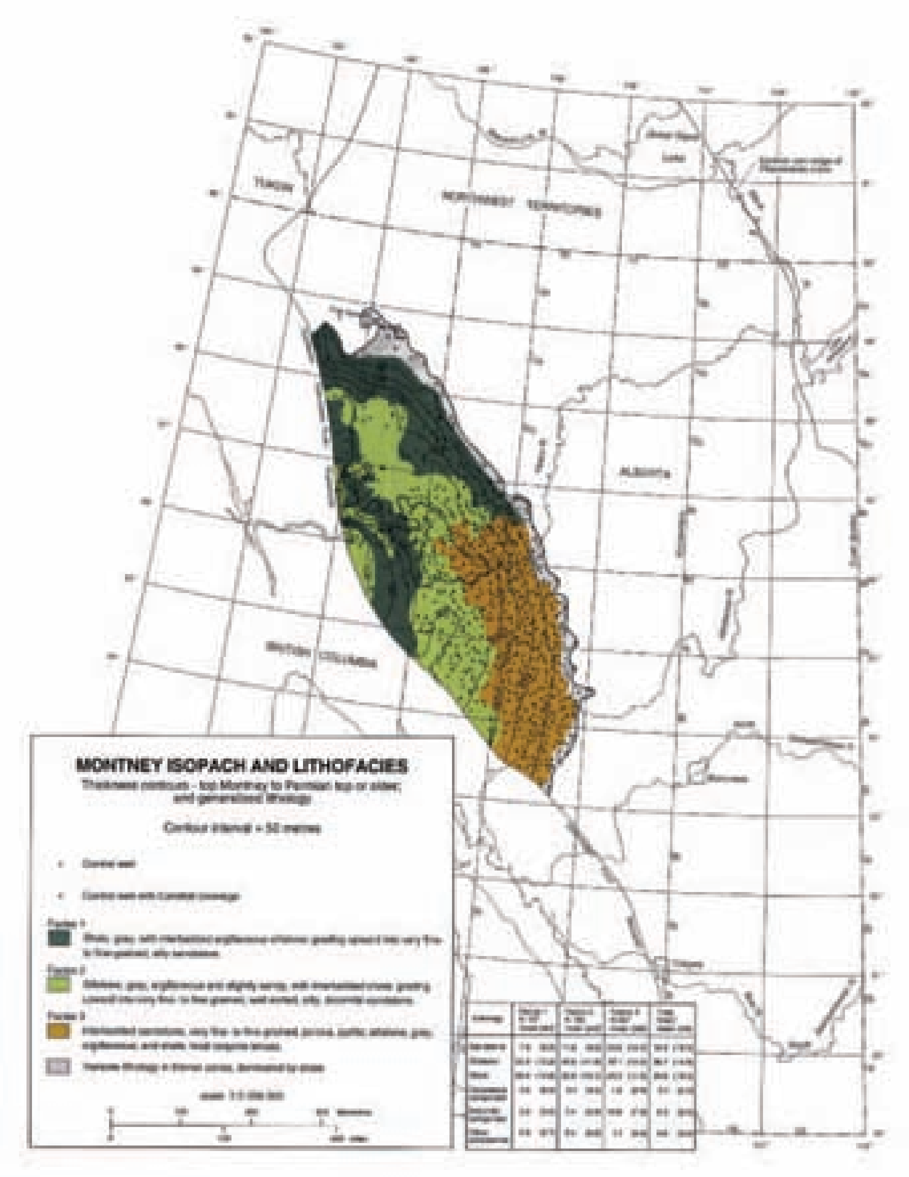
The Duvernay Formation – Middle Devonian

The Duvernay Formation, found in the WCSB in a 2,092-km-long (1,300-mile-long) fairway in central Alberta, is deposited at depths from 2,804 m (9,200 ft) to 3,597 m (11,800 ft). The formation is from 149 m (490 ft) to 250 m (820 ft) thick and is an overpressured, low porosity/permeability, organic-rich laminated black shale and argillaceous limestone source rock. The formation was deposited under hypoxic (low oxygen) and anoxic (no oxygen) conditions in basinal marine areas adjacent to carbonate reef structures along the carbonate shelf edge.

The central Alberta Duvernay Formation is also called the Muskwa Shale in areas of northwest Alberta and northeast British Columbia, where it is currently being exploited for shale gas. The Duvernay/Muskwa Formation has a long hydrocarbon source rock history, being recognized as the source rock for some of the oldest and largest Canadian oil discoveries. The formation is silica- and carbonate-rich with low clay content, making it brittle and an excellent candidate for hydraulic fracing. It was sourced from Type II kerogen and typically has TOCs ranging from 2% to 7.5%, averaging 6.5%. Hydrocarbon liquids of 56° API gravity have been produced. Depending on the report one reads, operators have been completing wells with initial productions ranging from 2 MMcf/d to 8 MMcf/d and 75 bbl to 100 bbl condensate per MMcf.

The Exshaw Formation – Late Devonian to Early Mississippian

The Bakken Formation of Williston Basin fame is known as the Exshaw Formation, or the Alberta Bakken in the WCSB. The main difference is that the Exshaw Formation lacks the upper shale member found in the Bakken Formation.



Montney Isopach and Lithofacies *Source: Edwards, D.E., Barclay, J.E., Gibson, D.W., Kvill, G.E. and Halton, E. (1994): Figure 16.24 Montney isopach map, and generalized lithofacies distribution; in Geological Atlas of the Western Canada Sedimentary Basin, G.D. Mossop and I. Shetsen (comp.), Canadian Society of Petroleum Geologists and Alberta Research Council, Calgary, Alberta, URL <http://www.ags.gov.ab.ca/publications/wcsb_atlas/atlas.html> [November 2012].*

The Exshaw Formation is found in the WCSB of Alberta and northeast British Columbia at depths of 914 m (3,000 ft) to 2,500 m (8,200 ft) and is overpressured. The Exshaw has a maximum thickness of 50 m (164 ft) near the Canadian Rockies and thins out to a minimum thickness of 7 m (23 ft) to the south and east. The Exshaw Formation is composed of two zones. The upper and thickest zone is composed of a dolomitic siltstone and silty limestone. The lower and thinner zone is composed of black organic-rich shale, which grades upwards into the siltstone composing the upper member. In the Peace River Embayment, the Banff Formation disconformably overlies the Exshaw Formation. In other areas of the WCSB, the Banff Formation conformably overlies the Exshaw Formation. Based on Exshaw core analysis, geologists believe that the formation was deposited in generally hypoxic/anoxic marine seafloor conditions. A recent thermal maturity study found Ro values ~0.6 in its eastern extent and >1.0 in its western and southern extents; oil generation is thought to take place between Ro values of ~0.65 and >~1.3, with the peak Ro at ~1.0, putting most of the Exshaw Formation within the oil window. Over the last few years, Canadian operators viewing the ongoing Bakken success to the south have been targeting the Exshaw for shale hydrocarbons with horizontal wells and hydraulic fracing. Well cores tested for TOCs found TOC values. ranging from 1.3% to 4.6% (50). Two wells drilled in the Exshaw produced 30° API gravity oil

The Montney Formation – Early to Middle Triassic

The Montney Formation is, found in the WCSB of northwest Alberta and northeast British Columbia at depths ranging from 792 m (2,600 ft) to 2,195 m (7,200 ft). The formation attains a maximum thickness of 280 m (918 ft) near the Canadian Rockies and thins out to an erosional edge in northwest Alberta and northeast British Columbia. The Montney Formation is composed of two zones. The upper zone is a light brown, blocky siltstone with interlaminated fine-grained sandstone. The lower zone is dark grey, dolomitic sandstone with shale interbeds.

The Doig Formation unconformably overlies the Montney Formation. However, at the Montney Formation's eastern erosional limits, the Montney is overlain by Jurassic and Cretaceous strata. During the Triassic, the adjoining land area was thought to be desert, and much of the sediment carried out onto the adjoining continental shelf was windblown. After initial deposition, the sediment was carried further out onto distal regions of the shelf edge by storm events, as well as downslope sediment slumping during seismic events and turbidites. Montney core analysis reveals very little bioturbation; this is thought to be because of existing hypoxic/anoxic seafloor conditions.

Over the last few years, operators have been targeting the deeper basin areas for shale with horizontal wells and hydraulic fracing. With the depressed gas market, operators using horizontal drilling and completion methods, including hydraulic fracing, have been moving updip to exploit the formations' shallower, less thermally mature, oilier sections. An example of Montney shale from northeast British Columbia revealed 45% quartz, 45% dolomite, and 10% other, with very little of the "other" being clay. In addition the Montney Formation has little to no interstitial water. Overall, being carbonate-rich with low clays making them brittle and frac-prone, with no interstitial water, the Montney Formation is an ideal candidate for hydraulic fracing. A study of the Montney Formation in Alberta, sampling 40 wells scattered throughout the Montney Formation's areal extent, found TOCs ranging from as low as 0.04% to as high as 19.09%. A further look at nine wells sampled in the eastern (oily) part of the play found TOCs ranging from .06% to 14.14%, with an average of 1.64% over 24 samples.

The Cardium Formation – Late Cretaceous

The Cardium Formation is found in the WCSB of western Alberta at depths ranging from 1,189 m (3,900 ft) to 2,286 m (7,500 ft). The formation attains a maximum thickness of 109 m (357 ft) and thins out to 23 m (74 ft). The Cardium Formation is generally made up of massive fine-grained sandstone interspersed with thin beds of marine and non-marine shale. Some of the lower massive sandstone units tend to be shaly.

The formation is the well-known reservoir rock for the giant Pembina Cardium Field, with 9.4 Bbbl of oil known in place and 1.5 Bbbl of oil produced since the field's discovery in the early 1950s. The Cardium Formation area currently of interest to operators is the marginal low-permeability mudstones surrounding the typical Cardium reservoirs. Operators have been calling this "halo oil." As of 2012, operators, using unconventional drilling and completion methods, have reported 130 MMbbl of proven and probable reserves from exploiting these marginal halo oil areas. These Cardium Formation mudstones are carbonate-rich, brittle, and frac-prone, making them ideal for hydraulic fracing. ■

References available.

Canadian Shales Pound Profit Path

Proven profits and potential for exports to the Far East lead Canada's shale boom.

By Don Lyle
Contributing Editor

Canada's shale plays have grown up. It shows in the production growth, acquisition and divestiture activity, the prices for prime property, the number of international companies joining the fun, and the markets for production. For example, Royal Dutch Shell plc sold a 20% share of its Groundbirch Montney property in British Columbia to PetroChina. Sinopec purchased Daylight Energy Ltd. for its production and its 130,000 net acres in the Duvernay play.

With natural gas prices near historic lows in Canada and the US, groups are planning two LNG plants at Kitimat on British Columbia's west coast to look for better prices in foreign markets. According to a Canadian Imperial Bank of Commerce report, the world LNG markets will grow from 200 million tonnes per year in 2010 to 470 million tonnes per year in 2035, and Canada will get a piece of that market.

In February 2012, Mitsubishi invested CAN $1.46 billion (US $1.49 billion) in Encana's Cutbank Ridge resource play for a 40% share in 409,000 net acres of properties with production from Montney, Cadomin, and Doig zones.

Japan's Inpex bought a 40% share of Nexen's shale holdings, principally in the Horn River, Cordova, and Liard basins for CAN $685.24 million (US $700,000 million) in early 2012, then Nexen agreed to sell the company to China National Offshore Oil Corp. Ltd. for CAN $14.78 billion (US $15.1 billion).

South Africa's Sasol bought a 50% share of Talisman's Farrell Creek properties for its Montney production and potential. That money and money from other partnerships is accelerating E&P and drilling from the tight, difficult, and expensive-to-produce formations.

The plays are huge. The Devonian Duvernay Shale covers territory from central Alberta into British Columbia and the Northwest Territories, and profit limits have not yet been found. Engineers estimate as much as 120 Bcfe per section in the richest part of the play, and 1 MMcf of gas can contain more than 100 bbl of liquids.

The Cretaceous Cardium, with shales mixed with conglomerates and tight sand, provided the foundation for Pembina, Canada's largest onshore conventional field. That field is just one of a number of high-production areas in the 644 km (400 miles) between Calgary and Grand Prairie in Alberta, and only about 1.5 Bbbl of the estimated 12 Bbbl of original oil in place have been extracted, according to an estimate by Canada's Energy Resources and Conservation Board.

Operators drilled more than 1,500 wells into the prolific formation, with production resulting from two-thirds of those wells with no sign that they are slowing down. Currently, about 10% of the Canadian rig fleet points its bits at the Cardium.

The Lower Triassic Montney presents three faces to operators. It is generally shale to the west in British Columbia, and transitions to a dolomitic siltstone moving east, and finally into a sandstone in Alberta. It is generally thicker in the south and thins toward the north.

Land sale bonuses dramatically indicate operators' feelings about the Montney. In 2011, those bonus payments made up 89% of all bonus payments in British Columbia. Shell was the most active driller in the British Columbia portion of the Montney in 2011 as it reported 64 rig releases, four more than second place Murphy Oil.

The Doig Shale overlies the Montney through most of the area and provides a bonus production target.

The British Columbia Ministry of Energy and Mines said estimates of original gas in place totaled 450 Tcf in that province's segment of the Montney and 120 Tcf in the Doig.

Apache, ExxonMobil, and Encana are major players in the Horn River Basin shales, principally the Muskwa and Evie. That natural gas play covers a large portion of northeastern British Columbia with initial potentials that often reach higher than 10 MMcf/d of gas.

With that play established and full-scale production waiting on higher gas prices or the completion to the LNG projects at Kitimat, operators are looking beyond its limits to similar shales in the Cordova Embayment to the east and the Liard Basin to the west.

A British Columbia Ministry of Energy and Mines report showed estimates of 448 Tcf of gas in place in the Horn River Basin and another 200 Tcf in the Cordova Embayment. Apache Corp. estimated it had more than 210 Tcf of gas in place on its property in the Liard Basin.

Apache drilled a horizontal well to the Besa Shale in the Liard Basin that tested for 48 MMcf/d and production of more than 1 Bcf in its first year online. In a 2012 press release, Apache said that may be the single best well ever to produce gas from shale, which is brittle and easily fractured, in an environment conducive to high flow rates of natural gas.

The company profiles that follow paint a picture of the second most active unconventional oil and gas producing nation in the world and the companies that contribute to that position.

Key Players

Angle Energy Inc.

- Plans to continue work in Harmattan and Edson areas
- Holds 93 gross sections of land at Edson and 110 gross sections at Harmattan

Angle Energy Inc. concentrated its efforts on the Cardium play in the Western Canadian Sedimentary Basin, but it also is testing potential from the Viking Formation and evaluating the Duvernay and Wilrich shales.

In its 2Q 2012 report to shareholders, Angle said it spent CAN $37.2 million (US $37.5 million) to drill seven gross successful wells at Harmattan and Lone Pine Creek. Five of those wells were horizontal wells that reached Cardium oil, bringing the company's production volume from all operations to more than 2,500 boe/d (91% light oil) during the quarter, up from no production in November 2011. Approximately 15,300 boe/d came from its Harmattan Field.

The company completed nine Harmattan Cardium wells in the quarter and continued drilling five additional wells to that zone, and it kept three rigs busy in the Cardium and Mannville formations.

The company also reported completion of one net non-operated Cardium well in the Edson area early in 3Q 2012 and completion activities on another one gross (0.3 net) Cardium well.

For 2013, the company planned continuing work in Harmattan and Edson. Adding nearby operations by other operators at Edson has given Angle information on the Duvernay Shale that will help evaluation of the company's 72-section block in that area. The company gathered further completion information from other operators on potential from the Wilrich and Rock Creek zones.

In the Cardium play, Angle holds 93 gross (62 net) sections of land at Edson with production of 20 boe/d from 0.4 net production horizontal wells.

CARDIUM OIL
PER WELL METRICS[1]

	Strachan/Ferrier Cardium	Harmattan Cardium	Edson Cardium
Capital per well (M$)	4.2	3.5	4.0
Drilling Locations	30	130	150 gross/75 net
Well IP1 (boe/d)	400	270	245
Reserves (mboe)	290 (42% Gas)	220 (11% Gas)	325 (38% Gas)
NPV 10% (M$)	3,300	3,800	3,300
IRR (%)	47	56	43
Payout (Yrs)	2.0	1.8	2.1
Netback ($/boe)	34.90	49.90	50.00
Recycle Ratio	2.4	3.1	2.8
Break Even IP (boe/day)	225	130	140
Break Even EUR (mboe)	160	105	125
1st Year Royalty Rate (%)	5	23	10
Life of Well Royalty Rate (%)	15	27	22

Cardium production offers different opportunities in different areas, but the high-return plays get higher priority. *(Table courtesy of Angle Energy Inc.)*

Production wells offer 79% oil and NGL, and the company had 75 net undrilled locations, according to an August 2012 presentation.

The company held 110 gross (106 net) sections producing 2,000 boe/d of 92% oil and NGL from 14 net producing horizontal wells at Harmattan. Those wells had production of 151,000 boe by the time of the presentation and offered payout in 1.8 years. From the company's inventory of 128 undrilled locations, it planned 21 horizontal wells in 2013 at a cost of CAN $70 million (US $70.7 million) to earn an internal rate of return of 52%. That return assumed a type well with an initial potential of 270 boe/d and estimated ultimate recovery of 220,000 boe.

In the Ferrier area, the company's Cardium properties covered 24 gross (22 net) sections and produced 1,150 boe/d with a 33% oil and NGL cut. That production came from 8.9 net producing wells among the company's 30 net locations.

The company also held a speculative potential of 50 bbl/MMcf to 200 bbl/MMcf at Edson for a net recoverable gas potential of 500 Bcf to 1.6 Tcf from 250 net locations in the Duvernay.

The company still had 60 unbooked locations each for Viking oil and gas at Harmattan. At that location, the company anticipated Viking wells with an initial potential of 260 boe/d for gas and 360 b/d for oil.

The company also had Wilrich and Viking potential at Edson.

Anglo Canadian Oil Corp.

- Holds 20 sections of land in Kindersley area
- Has production potential from Viking and Duvernay

Anglo Canadian Oil Corp. has its corporate eye on the potential of the Nordegg Shale and a possible 6.47 Bbbl of original oil in place on its 269 sections of 100%-interest land in the Valleyview/Grande Prairie/Rycoff area of northwestern Alberta.

The company also holds 20 sections of land with potential heavy oil production from the Bakken in the Kindersley area of southwestern Saskatchewan, where two wells currently produce from Buffalo Coulee Field.

In a May presentation, the company said three wells have tested the Nordegg on its properties, since it started a two-well program in Sep-

	Cardium	Bakken	Viking	L. Shaunavon	Nordegg*
Area	Pembina	Viewfield	Dodsland	Leitchville	Grande Prairie
Depth (m)	1,250 – 1,400	1,550 – 1,650	670 – 730	1,350	1,160 – 2,400
Net Pay (m)	6 – 14	6 – 12	3 – 8	4 – 8	21 – 27
Reservoir Porosity (%)	6 – 16	9 – 12	21 – 24	15 – 18	5 – 18
Water Saturation (Fraction)	0.40	0.40 – 0.60	0.45	0.30 – 0.45	0.15 – 0.30
Permeability (mD)	0.5 – 10	0.2 – 1.0	1.0 – 150	0.1 – 0.9	0.1 – 10
API (Oil)	36 – 41	42	32 – 38	22	23 – 41
Lithology	vf sandstone, argillaceous	siltstone, dolomitic	vf sandstone, argillaceous	microcrystalline limestone	vf sandstone / siltstone, shale, carbonate, coquina
Water Present?	No	Oil-water contact to the southwest	No	Yes	No/Yes

The Nordegg Formation in Alberta compares favorably with other popular reservoirs in Western Canada. *(Table courtesy of Anglo Canadian Oil Corp.)*

tember 2011 to study the Nordegg and Montney at Ante Creek. The company owns rights to 269 sections of potential Nordegg oil land in west-central Alberta, another 140 sections of potential Beaverhill Lake and Duvenay oil properties in central Alberta, and another 27 sections of potential Bakken and Mannville oil land in the Kindersley area of southwestern Saskatchewan.

Plans for 2012 and 2013 called for the company to apply multistage fracturing techniques on horizontal wells to define the potential resource. In its area, the Nordegg is 30 m (98 ft) to 40 m (131 ft) thick, according to a May 2012 presentation.

A Nordegg well with a 200 boe/d initial potential and a 200,000 boe estimated ultimate recovery should pay out in 0.7 years, based on a CAN $89.20 (US $89.99) oil price, a cost of CAN $3 million (US $3.02 million) per well, and four wells per section.

The company also has production potential from Viking and Duvernay from two of its 104 sections of land in central Alberta.

Apache Corp.

- Plans a 61-pad development program
- Focusing on shale gas in Horn River Basin

Houston-based Apache Corp. showed its enthusiasm for Canadian operations as it accumulated 7.5 million gross acres of land in British Columbia, Alberta, and Saskatchewan since 1995; embraced operations in the Montney and Horn River shales; and evaluated emerging Viking Dunvegan and Cardium formations for pay possibilities, according to the company's website.

Apache runs an active drilling program as it works the shale layers in the Horn River Basin. *(Photo courtesy of Apache Corp.)*

The company's real coup, however, is the apparent world's most prolific gas shale well in the Liard Basin bridging the border between British Columbia and the Northwest Territories.

The company completed the D 34 K horizontal well with six fracture stages and tested 21 MMcf/d of gas over a 30-day period. The big news came two years later in June 2010 during an Apache investor presentation when the company said the well produced 3.5 MMcf/d per fracture stage, produced 3.1 Bcf in one year online, and offered the company an estimated ultimate recovery of 17.9 Bcf.

Apache plans a 61-pad development program with 12 wells per pad and 731 locations, and an estimated cost of CAN $34.65 million (US $35.4 million) through pipeline hookup, or a total development cost of more than CAN $24.47 billion (US $25 billion). That development may wait on higher gas prices or completion of the Kitimat LNG plant with higher export prices.

Apache assembled 430,000 net acres in the play and estimated a recoverable 48 Tcf from that property.

Near-term, Apache focused its gas activity on shale gas in the Horn River Basin, the Cadomin conglomerates and sands in the Noel area and fractured reservoirs in the Ojay area. The company's investment as operator of the Kitimat LNG plant will drive those gas operations.

The company holds more than 400,000 gross (200,000 net) acres in the Horn River Basin Shale play in northeastern British Columbia, which, according to its website, has evolved into one of the "highest-quality unconventional shale gas plays in North America."

By September 2012 the company had drilled, completed, and placed on production 69 horizontal wells with a peak production rate of 149 MMcf/d of natural gas.

The company uses multiwell pads to minimize production footprints, and its Debolt Water Treatment plant allows it to use non-potable saline water in its operations. It is the first plant of its kind in North America.

In central Alberta, the company's Kaybob project northwest of Edmonton aims at the Montney and Bluesky tight gas formations.

Apache's West 5 area in west-central Alberta covers an area north from Sundre through James River, Stauffer, and Willesden Green to Buck Lake and overlies the Glauconite, Cardium, Viking, Rock Creek, and Ellerslie producing formations. Wells in that area produce 21,740 boe/d.

A big bump for its Canadian operations occurred on Oct. 8, 2010, when the company bought nearly all of BP's upstream assets in Western Canada, an asset with interests in 1.28 million net mineral and lease acres, some 1,800 active wells, and eight operated and 15 non-operated gas processing plants. Those properties also gave the company access to Montney, Cardomin, and Doig Shale production with estimated net proved reserves of 224 MMboe, 94% gas.

ARC Resources Ltd.

- Second-largest operator in Pembina Cardium Field
- Commissioned a 30 MMcf/d gas plant in the Ante Creek area

ARC Resources Ltd., after converting its 15-year operations as an energy trust to a corporation in January 2011, continued a growth streak with high input from unconventional formations.

To make sure that growth continued, the company invested CAN $600 million (US $605.5 million) before land and net acquisitions to drill approximately 150 gross operated wells aimed at liquids projects with the highest rates of return, according to the company's website.

The company's northeastern British Columbia and northwestern Alberta properties provide tight Montney gas production. ARC came into that area early and pioneered multistage fracturing treatments in horizontal wells. The company drilled its first horizontal Montney well in 2005. The company remains the third largest operator in the area with its 400 net sections of land. The company's key properties in that area are the Dawson, Parkland, and Sunrise/Septimus fields. They produce approximately 43,300 boe/d.

In a January 2012 presentation, the company called its British Columbia Montney properties a "major growth engine," as it produced 240 MMcf/d in 2Q 2012. The company plans to commission a new 60 MMcf/d in that area late in 2013 with a 130 bbl/MMcf liquids capacity in the Parkland/Tower area.

ARC's property in that area is north of Encana/Mitsubishi's Cutbank Ridge, east and north of Shell's Groundbirch, and east of Talisman/Sasol's Farrell Creek area.

An engineering company's best estimate, using a 30% porosity cut off, calculated 39.6 Tcf of original total petroleum in place with a best estimate of reserves totaling 4.1 Tcf of gas and 101 MMbbl of liquids.

The company also claimed the industry's highest initial potential production rates in that area, with more than 5 MMcf/d compared to competitors with less than 4 MMcf/d.

ARC's northern Alberta properties, which include Ante Creek and Swan Hills, are in the Montney oil zone, as well as the Slave Point carbonate reef. A prime focus for 2012, that area produces approximately 14,600 boe/d.

The Montney is the company's best target for near-term growth, according to a September 2012 presentation. The company commissioned a 30 MMcf/d gas plant in the Ante Creek area in February and planned to drill to meet that capacity during 2012.

The Pembina Cardium Field is a core legacy area for ARC, and the company is the second-largest operator in that area. It is the largest conventional oil field in Western Canada with more than 7.8 Bbbl of oil in place. That area produces approximately 11,500 boe/d for the company, which drilled 20 horizontal wells at Pembina in the first half of 2012.

Artek Exploration Ltd.

- Estimated second-half 2012 production between 1,600 boe/d and 1,700 boe/d
- Holds 47 gross sections of Doig rights

Artek Exploration Ltd. started operations in 2005 and grew its conventional and unconventional production to more than 3,000 boe/d by August 2012.

In 2012, the company committed up to CAN $49 million (US $50.27 million) in capex to drill 14 gross (8.6 net) wells, all for oil and condensate with associated gas. Seven horizontal (four net) wells will go to the company's prime unconventional play, the Inga/Fireweed area in British Columbia, which produces Doig condensate and gas. Production from the Inga area grew from 60 boe/d to more than 1,500 boe/d in two years with current production from seven wells, according to an August 2012 presentation. Artek estimated second-half 2012 production between 1,600 boe/d and 1,700 boe/d.

The company holds 47 gross (29 net) sections of Doig rights in the area with 50 gross (31 net) horizontal wells sited at Inga/Fireweed. The company's test rate on six wells to the Doig averaged 2,100 boe/d per well. Payout on those wells ranged from 6.5 to 15 months.

Baytex Energy Corp.

- Has 30,000 net acres prospective for Viking production
- Has 185 Viking wells and 20 Cardium wells planned for 2012-2017

Baytex Energy Corp. holds a strong position in the Viking play in southwestern Saskatchewan and eastern Alberta, properties in the Cardium play, and Bakken holdings in the US and southwestern Saskatchewan.

Baytex began working the Viking resource play in 2008 in the Bon Accord area of southeastern Alberta targeting the less permeable, but undeveloped, areas. Viking properties were added as a bonus with the company's 2009 acquisition of heavy oil assets in the Kerrobert area. Now the company has approximately 30,000 net acres prospective for Viking production with 55% of those properties in Alberta.

The company drilled two successful Viking horizontal wells, one each in Alberta and Saskatchewan in 2008 and added three more in Alberta the following year. In 2010, the company added another seven successful multilateral wells in Alberta and eight more horizontal Viking wells in Saskatchewan.

The 2011 drilling season hosted 11 successful horizontal wells in Alberta, and the company continued drilling in 2012. Ultimately, the company anticipates up to 200 net drilling locations.

A Sproule Associates contingent resource assessment for the Viking properties offered a best estimate of 11.2 MMboe.

According to the Baytex website, the company has interests in approximately 13,000 gross (7,700 net) acres of land in the Pembina. Drilling in that area included five net operated and 12 gross (1.5 net) non-operated Cardium horizontal wells. The company planned approximately six operated Cardium wells in 2012 on its 60 gross (34 net) locations.

In the period from 2012 to 2017, Baytex planned 185 Viking wells and 20 Cardium wells, according to a September presentation.

The company's Alberta, Viking wells offer initial potential production of 110 boe/d, with estimated ultimate recoveries (EURs) of 100,000 boe. Wells cost CAN $2 million (US $2.02 million) to drill. The company has 105 potential net locations with a best estimate of 9.3 MMboe in net resource. Across the border in Saskatchewan, Viking wells showed initial potentials of 50 boe/d, EURs of 50,000 boe, and cost CAN $1.1 million (US $1.11 million). The company has 100 net locations in that province with a best estimate of 1.9 MMboe in net resource.

The company also has 72,000 net acres of land in the Bakken/Three Forks play, but only 10% of that land is in Saskatchewan. The remainder is in North Dakota. The company has 20 remaining net drilling locations in Saskatchewan.

Bellatrix Exploration Ltd.

- Has 44 gross sections in Duvernay Shale
- Plans to drill 12 gross wells in Cardium

Bellatrix Exploration Ltd. put together a multi-year inventory of drilling locations in British Columbia, Alberta, and Saskatchewan, but it has drawn a bead on Cardium and Notikewin production in west-central Alberta as a primary growth engine with Duvernay potential waiting in the background.

In an August 2012 presentation, the company said its properties included 900 net locations southwest of Edmonton with potential to produce from those three formations. The area was producing 15,000 boe/d at that time.

The company held 377 net drilling locations for the Cardium Formation in the Pembina area, drilled 37 gross (27 net) wells in 2011, and planned 24 gross (21 net) wells in 2012. Those wells cost CAN $3.7 million (US $3.8 million) to drill, case, and complete

and offered an initial potential of 536 boe/d with an estimated ultimate recovery of 270,000 boe. Bellatrix estimated its rate of return at 262%.

The company had 44 gross (43 net) sections in the liquids-rich fairway of the Duvernay Shale, where it expected recoveries of up to 100 bbl/MMcf. The company said other industry companies had invested CAN $1.3 million (US $1.4 billion) on offset Duvernay rights.

Production makes a big difference in returns in the play. The estimated rate of return for a dry gas Duvernay well is 15% with payout in 4.1 years, while a well that makes 30 bbl/MMcf offers a 71% rate of return and payout in 1.4 years.

During the first six months of 2012, Bellatrix drilled or participated in 15 gross (12.44 net) wells, including 11 gross (8.94 net) Cardium light oil horizontal wells and four gross (3.5 net) liquids-rich gas horizontal wells.

In the second half, the company planned to drill 12 gross (11.35 net) Cardium light oil and liquids-rich wells.

Blackbird Energy Inc.

- Plans four new horizontal wells in Montney play
- Acquired eight gross sections in Bigstone area

A major milestone in any company's growth marks that company's graduation from an explorer to a producer, and Blackbird Energy reached that milestone in the Montney Formation in western Alberta.

The company's Bigstone HZ 14-29-60-22w5 Montney discovery well, in which Blackbird holds a 37.5% working interest, produced to sales in mid-June 2012, offering an average 1.62 MMcf/d of gas (605 Mcf/d net) to Blackbird, and 72.8 b/d of condensate (27.3 b/d net) to Blackbird, during its first 42 days on pipeline. Blackbird's share reverts to 25% after payout of costs.

The second well, the Bigstone HZ 15-32-60-22W5M, in which the company holds a 25% working interest, started producing in mid-July after technical problems that limited completion to six of the planned 23 fracture stages.

The Bigstone 13-33-60-22w5, operated by Trilogy, was completed with a 23-stage frac and awaited hookup to the Donnybrook pipeline in November 2012.

Those results encouraged the partners in Blackbird's operations to plan four new horizontal Montney wells, two of them by year-end at a cost of CAN $4 million (US $4.07 million).

Blackbird acquired eight gross (1.75 net) sections in the Bigstone area for CAN $66,000 (US $67,400) and a 12.5% promote on the first well. The property can support 28 total wells.

Bonavista Energy Corp.

- Controls 300 net sections in Cardium play
- Holds 55 net sections in Montney play

Bonavista Energy Corp. taps a number of conventional and unconventional targets in its quest for growth. Among them are the unconventional Montney, Cardium, and Viking plays.

In the Montney, the company classifies its Blueberry Montney project area in northeastern British Columbia as an emerging play. The company holds 55 net sections in the area, with potential for liquids-rich gas in both the upper and lower Montney. Typically, wells yield 100 bbl/MMcf.

According to an August 2012 presentation, the company has drilled six horizontal wells to date and planned to delineate and derisk properties with potential during 2012 with two to four additional horizontal wells. The company has an additional 80 drilling locations on that property.

As for economics, the Montney in this area gives the company a netback of CAN $23.50/boe (US $23.92/boe) and a 13% internal rate of return (IRR) on a CAN $7 million (US 7.13 million) well. If well costs drop to CAN $5 million (US $5.09 million), the IRR rises to 37%.

Bonavista also holds properties with 25 horizontal Montney locations in the Fir area of western Alberta's Deep Basin, but it did not publicize operating plans for those properties. They offer 50 bbl/MMcf to 100 bbl/MMcf.

The company is more active in the Cardium light oil lay in west-central Alberta, where it controls 300 net sections with Cardium rights. The company drilled 68 wells in that area by the time of the August presentation, and 2012 plans called for 28 to 30 wells as it identifies remaining sweet spots and works economies of scale to lower costs. The company has another 120 future drilling locations on that property.

Cardium wells typically show an initial potential of 330 boe/d with estimated ultimate recoveries of 153,000 boe. Wells give the company a CAN $45.20/boe (US $46.03/boe) netback and a 28% IRR.

Among emerging plays, Bonavista lists Viking oil and Duvernay natural gas in south-central Alberta, but it has not revealed detailed plans to work those plays.

Canadian Natural Resources Ltd.

- Second-largest holder of undeveloped land in British Columbia
- Septimus project in Phase 1 of production

While Canadian Natural Resources Ltd. claims the title as the most prolific heavy oil producer in Canada, the company continues its development of other unconventional pay from the Cardium, Montney, and Doig formations and the Muskwa Shale in the Horn River Basin.

The company is the second-largest holder of undeveloped land in British Columbia, a position that gave it a low-cost entry to the Montney Shale. Further, the company brought its experience from the Lower Doig and Montney play in the Deep Basin in Alberta into its Septimus operations in British Columbia.

According to the Canadian Natural Resources website, the Septimus project is in its first phase of production.

According to a July 2011 presentation, the Septimus project held 1.3 Tcfe in contingent resource and 300 Bcfe in proved and probable reserves in liquids-rich gas.

At that time, the company had completed a 50 MMcf/d refrigerated gas processing plant and produced 60 MMcf/d of gas and 2,000 b/d of liquids. The company planned eight horizontal wells in 2011 and 20 wells in 2012 to match the capacity of the processing plant.

Also in northeastern British Columbia, the company's Helmet project features "significant thicknesses of natural gas pay in the Muskwa Shale," according to the company's website. Canadian Natural Resources directed long-term capital to its experimental stage on that project and plans to drill more wells to determine if it is a viable development project.

The company's northwest Alberta properties lie along the border between that province and British Columbia west of Edmonton. The company has 1.8 million net acres, 26 operated facilities, and an extensive pipeline network. The company works multiple horizons in the area.

This area of the Deep Basin includes the company's Lower Doig/Montney resource project. Here again, Canadian Natural Resources' large land position gives it low entry costs. According to the company's website, "Our initial position in the Montney was greatly enhanced by the timely acquisition of Anadarko Canada Corporation [in 2006]. We capitalized on our existing land position at that time, giving us early exposure to the play. This allowed us to acquire strategic sections of prime Montney land at a fraction of today's cost."

The southern portion of the Northwest Alberta property opened exposure to the Cardium Formation.

Canadian Spirit Resources Inc.

- Increased holdings to 40.8 net sections in Montney play
- Installed a pipeline from Williston Lake Reservoir to Farrel Creek Montney play

Canadian Spirit Resources Inc. joined Canbriam Energy Inc. in early 2011 in a joint venture to develop properties in the Farrell Creek area of northwestern Alberta.

The company's website said the companies tied five Montney wells to a 10 MMcf/d gas plant, all from the west portion of the venture's holdings. Canbriam, as operator, also drilled a vertical well on its east Farrell Creek lands to test potential for NGL.

The companies also acquired rights to 30.3 Mcf of water a day for 20 years and installed a pipeline from Williston Lake Reservoir to the Farrell Creek Montney play. That water will allow companies, including the venture partners, to complete 180 typical horizontal Montney wells a year using 70.6 Mcf of water for each well.

A Sproule engineering report at year-end 2010 said the company's 29.4 net acres in the play contained gross 1 Tcf of discovered and 1.3 Tcf of undiscovered initial gas in place, net to Canadian Spirit.

Since then, the company increased its holdings to 40.8 net sections.

Combining the two companies' 67 gross sections of land, the analysis showed 2.7 Tcf of discovered and 2.4 Tcf of undiscovered original gas in place.

Canbriam Energy Inc.

- Holds 94 sections in Montney Shale
- Drilled and cased a vertical well on eastern Farrell Creek land

Canbriam Energy Inc. started operations in 2009 with a CAN $300 million (US $305.34 million) infusion of cash from investors led by Warburg Pincus and ARC Financial.

Some of the company's work went into the Utica Shale in southern Quebec, but government studies have delayed those operations. That obstacle led Canbriam to focus on its Montney properties in the heart of the Montney Shale gas play in British Columbia.

The company holds 94 sections in that area, generally around Talisman Energy's Farrell Creek Montney Shale operations.

By 1Q 2011, Canbriam had drilled three vertical wells and 13 horizontal wells on the property, according to the company's website.

Additional information comes from Canadian Spirit Resources Inc., Canbriam's partner in a Montney joint venture formed in January 2011. That company said five Montney wells currently are tied into a 10 MMcf/d gas plant, all from the western portion of the venture's Montney property. Canbriam also drilled and cased a vertical well on eastern Farrell Creek land to test for gas liquids potential.

The partners set up a water project for their operations, with Canbriam controlling 75%. They gained access to 30.3 Mcf of water a day for the next 20 years and built a pipeline from Williston Lake Reservoir to the Farrell Creek Montney play. That line will support drilling approximately 180 typical horizontal Montney well completions a year using 70.6 Mcf of water per well.

A March 2010 Canadian Spirit release said Canbrian, as operator of the joint venture, had drilled and cased the c-A48-I/94-B-1 horizontal well to the lower Montney at Farrell Creek and was completing the well. Previously, it successfully tested the b-17-I well, and the companies planned to drill the c-18-I horizontal well and continue with more drilling.

Celtic Exploration Ltd.

- Present in multiple unconventional zones in Alberta
- Planned 12 gross (11 net) wells in Resthaven Montney in Alberta in 2012

Celtic Exploration Ltd. maintains a strong presence in multiple unconventional zones in Alberta and a smaller position in British Columbia and is making a statement as a solid producer.

According to a July 2012 company presentation, the company had 50,880 boe in proved and probable reserves at the end of 2011, up from 3,590 boe a year earlier at its Resthaven Montney operations in Alberta. The company planned 12 gross (11 net) wells in the area in 2012, with an anticipated netback of CAN $52.1/bbl (US $52.23/bbl) for oil wells and $20.17/boe for gas.

The company controlled 711 sections at Resthaven by mid-year 2012 with the potential to drill up to eight wells per section. By July 2012, the company had 2,960 remaining drilling locations at Resthaven. Since beginning operations, the company had drilled 23 horizontal wells.

Internal rates of return (IRR) from the area ranged from 17% for production with an 82% gas cut in Resthaven South Montney wells to 70% in the Resthaven North Kakwa area with a 78% oil cut.

The company claimed 19.55 MMboe in proved and probable reserves at its Fir Montney project at year-end 2011, up from 985,000 boe a year earlier. The company held 27 net sections of land in that area and planned three wells during 2012.

The company also held 123 sections with Montney rights in the Kaybob area.

Celtic recorded 10.71 MMboe in proved and probable reserves at its Kaybob Duvernay play at year-end 2011, up from 558,000 boe on Dec. 31, 2010. The company achieved a netback on wells in that area of CAN $35/boe (US $35.27/boe) on six wells. The company planned eight gross (six net) wells on its 172 net sections of land in that area in 2012.

Celtic expected a 57% IRR on wells with a 59% gas cut on its 1.1 MMboe in proved and probable reserves in the Kaybob Duvernay and a 65% IRR

from production with a 53% gas cut on 1.2 MMboe of proved and probable reserves.

Celtic held 25 net sections in the Dunvegan oil play at Kaybob and Fir and planned to drill six wells in that combined area in the last nine months of 2012. Wells in the Kaybob area offered the company a CAN $45.3/boe (US $45.54/boe) netback.

Production from all zones at Kaybob and Fir averaged 12.4 boe/d in July 2012, and the company expected to exit the year producing 15,000 boe/d.

The company also works in the Inga Doig Shale play in British Columbia, where it raised proved and probable reserves to 3.84 MMboe on Dec. 31, 2011 from 1.47 MMboe at the end of the previous year. The company planned six gross (three net) wells in that play during 2012.

Chevron Corp.

- Most Canadian oil production comes from interest in Hibernia Field
- By year-end 2011, had accumulated leases totaling 253,000 acres in Duvernay Shale

Chevron Corp. is a veteran producer around the world. In Canada, the company is a strong advocate of production from shales, but it is a relative newcomer to Canadian shales.

Most of the company's Canadian oil production comes from its interest in Hibernia Field off the coast of Newfoundland. The company also holds a 20% nonoperating interest in the Athabasca Oil Sands project in northern Alberta.

In 2011, the company produced an average 197,000 b/d gross (29,000 b/d net) of oil and 28 MMcf/d gross (4 MMcf/d net) of natural gas, along with 210,000 b/d gross (40,000 b/d net) of synthetic oil from the oil sands project.

None of the company's production comes from shales, but it has been assembling shale acreage. By year-end 2011, the company had accumulated leases totaling 253,000 acres in the Duvernay Shale.

The company started drilling its first well in a three-year multiwell exploration and testing program in 3Q 2011. The company planned a long-term test on that well in 4Q 2012, when it expects to tie that well into a processing plant.

Chinook Energy Inc.

- Focused on activities in the Dunvegan
- Made a Montney discovery at Kaybob

Chinook Energy Inc. controls more than 450,000 net acres of undeveloped properties in Western Canada. Those properties contain a number of shale production opportunities, but the company currently directs its activities to the Dunvegan.

Specifically, the company has equipped and tied in one Dunvegan well in which it holds a 37.5% net working interest. That well came online early in 3Q 2012 at an initial rate of 450 boe/d with a 25% oil cut and a 15% NGL cut. The company drilled and cased a second well and expected to put that well online early in fall 2012.

The company's Dunvegan focus at this point lies in its Karr and Wapiti areas in the Grande Prairie district. "We are pleased with the results of the Dunvegan program to date and anticipate expanding our capital program on the play," the company said on its website.

The company planned to drill a minimum of four gross (1.5 net) Dunvegan wells at Karr and two gross (0.75 net) Dunvegan wells at Wapiti in the second half of 2012.

The company also made a Montney discovery at Kaybob. Depending on production information from that well, the company could drill additional wells in 4Q 2012 or early in 2013.

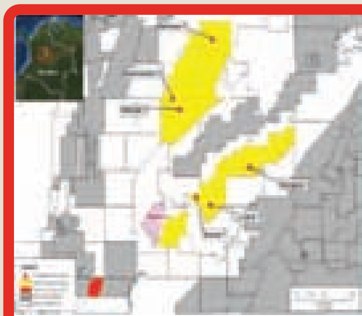
In July 2011, Chinook said it completed a Doig oil and gas discovery, the 15-1-86-22W6M in the Red Creek area of northeastern British Columbia. That horizontal well tested for 450 b/d of oil and 4.2 MMcf/d of gas. The company expected to recover 16 bbl/MMcf. The company held a 74.55% interest in the well and controlled 12,800 gross (9,600 net) acres on that prospect.

Chinook also said it had identified both development and exploration opportunities on its properties that are ready to drill now or will be ready during 2013. Those unconventional opportunities include horizontal Dunvegan wells at Karr and Wapiti, Montney wells at Kaybob, Cardium wells at Lochend, and Viking wells at Gilby. All those opportunities are on Chinook properties that currently produce.

Among the company's properties, Lochend produces from the Cardium and Viking Formation; Gilby produces from various formations, including the Viking; and Jarrow produces from the Mannville and Viking Formations.

In addition, Paddle River and Whitecourt produce from the Nordegg and other formations.

Chinook also holds non operated interests in more than 30 working units in Alberta and British Columbia, including the Pembina Lindale Cardium unit.



The Liard, Horn River, and Cordova basins across extreme northern British Columbia offer huge gas resources from multiple zones. *(Diagram courtesy of Nexen Inc.)*

CNOOC Ltd.

- Plans to set up Canadian headquarters in Calgary
- Canadian shale properties include 90,000 acres in the Horn River Basin

Life got interesting at Nexen Inc. in 2012. During the year, the company brought Japan's Inpex Inc. in for a big chunk of its shale activities for CAN $685.93 million (US $700 million). Later in the year, the company agreed to allow China National Offshore Oil Corp. Ltd. (CNOOC) to buy the company for CAN $15 billion (US $15.1 billion).

Shareholders and Canadian courts approved the deal in September 2012, and CNOOC planned to set up a Canadian headquarters office in Calgary to oversee operations in the country.

Both deals show respect for Nexen's position not only in shales in Canada, but its conventional and heavy oil activities, as well. The company also has shale operations in Poland and Colombia.

The company's Canadian shale properties include 90,000 acres of land in the Horn River Basin with Muskwa, Otter Creek, and Evie Shale targets; 82,000 acres in the Cordova Basin with Muskwa, Otter Park, Evie, and Klua Shale potential; and 128,000 acres in the Liard Basin with production prospects in the Exshaw, Muskwa, Otter Park, and Evie shales.

Before the CNOOC acquisition, Nexen estimated its Horn River and Cordova Basin land held 4 Tcf to 15 Tcf in recoverable resource and its Liard properties held 5 Tcf to 23 Tcf of prospective resource.

Total production from all operators in the Horn River Basin reached 440 MMcf/d, and 80% of that production comes from land that touches Nexen's holdings, the company said in a July 2012 presentation.

In 2011, the company drilled a nine-well pad with 18 fracture treatments per well. Early results revealed initial potentials of 18 MMcf/d per well. The company finished the pad ahead of schedule with results that met company expectations.

For 2012, the company is finishing work on an 18-well pad with production scheduled for 4Q 2012. The company is completing facilities that would raise its production capacity to 175 MMcf/d. The company started working the Horn River Basin in April 2007 at Dilly Creek and averaged about 38 MMcf/d during 2011.

The company built a camp 215 km (135 miles) northeast of Fort Nelson, British Columbia, to house more than 300 people working the Horn River Basin. The company planned to finish 28 total wells by year-end 2012.

The company also drilled lease-earning and appraisal wells in the Cordova and Liard Basins. During 2012, the company started planning for access roads and a camp in the Cordova Basin and expected to start drilling work there late in 2013. The company also continues to work on understanding development potential in the Liard Basin.

Inpex, which now holds a 40% share of the Nexen-operated shale plays, said it expected, with full development, production of 1.25 Bcf/d at some point in the future. The companies said LNG may provide a more profitable sales line for the shale gas.

ConocoPhillips Co.

- Controls 8.8 million gross (6.1 million net) acres in Western Canada
- Biggest operator and largest producer in the Deep Basin

ConocoPhillips Co. controls 8.8 million gross (6.1 million net) acres in Western Canada and holds the title of one of the top three gas producers in the nation, with net production of 193,000 boe/d in 2011, according to the company's Canada fact sheet.

Although most of the company's Western Canada operations are in British Columbia and Alberta, it has production in Saskatchewan, as well. The company's prime Western Canada operations are in the Deep Basin, Kaybob, and O'Chiese, all gas-prone areas.

The company is the biggest operator and largest producer in the Deep Basin in northwestern Alberta and northeastern British Columbia, with lease rights to 2.4 million gross (1.6 million net) acres.

The company controlled another 600,000 gross (400,000 net) acres in the Kaybob area and 2 million gross (1.4 million net) acres at O'Chiese. All three areas offer production from multiple zones.

Earlier releases from the company said it had drilled eight horizontal wells to the Cardium in the Deep Basin with encouraging results and had 137,000 acres in the area. ConocoPhillips also said it had 1.7 Bboe in resource potential in the area and planned another nine operated and six non-operated wells to the Cardium in 4Q 2011.

ConocoPhillips holds 1.6 million net acres of land in the Deep Basin of Alberta where it is the largest operator and biggest production. *(Photo courtesy of ConocoPhillips Co.)*

Among shale plays, the company controls 812,000 net acres in the Montney and Duvernay plays in Alberta and British Columbia, the Muskwa in the Horn River Basin of northeastern British Columbia, and the Canol Shale in the Mackenzie Valley.

Information released in 2011 said the company had 363,000 acres of properties in the Montney play and the Horn River Basin.

The company said it was conducting drilling and seismic activities to assess the shale potential of those shales.

Contact Exploration Inc.

- Focused on the Montney play
- Started drilling its second well to the Montney in August 2012

Contact Exploration Inc. switched its focus from operations in New Brunswick to potentially more profitable operations in the Montney play in the Deep Basin area of Alberta. The change paid off.

Contact farmed in to, and acquired, 16 contiguous gross sections in the Kakwa area and is operator with a 25% interest.

According to a spring 2012 presentation, the company has an opportunity to drill 64 gross wells with two to three laterals per well on the property.

The Contact-operated Montney 13-17-63-5W6 well at Kakwa tested for 1,150 b/d of condensate (431 b/d of condensate net) and 8.29 MMcf/d of gas (3.1 MMcf/d of gas net) to Contact. The company said it could get another 70 bbl of NGL/MMcf from the production stream.

The company planned to tie the well into a production line in September 2012.

The company started drilling its second well, the CEX HZ 14-30-63-5W6, also to the Montney, in August 2012 and expected completion in September.

Corridor Resources Inc.

- Plans to develop a Frederick Brook Shale
- Exploring production potential from Macasty Shale with partner Petrolia Inc.

Corridor Resources Inc. plans to develop a Frederick Brook Shale prospect in New Brunswick and started work with an industry partner on the Macasty Shale on Anticosti Island.

Currently, the Nova Scotia company produces only from McCully Field near Sussex, New Brunswick, but it also discovered the Frederick Brook Shale gas resource in Elgin, New Brunswick, in the same area.

The company hired Macquarie Tristone to find partners for a farm-out on the prospect in which Corridor holds an 89% working interest in 116,018 gross acres of rights. Those rights cover an estimated 67 Tcf of original free gas initially in place, with 45 Tcf of that gas located in the Corridor farm-in acreage.

Of the seven completed wells in the shale, six have tested gas. One well, the Green Road G-41, tested 11.7 MMcf/d and 980 Mcf/d, respectively, from two Frederick Brook zones.

In addition, Corridor and partner Petrolia Inc. announced a plan in early September 2012 to explore production potential from the Macasty Shale, a Utica-equivalent shale oil prospect on Anticosti Island in the Quebec sector of the Gulf of St. Lawrence.

The companies initially plan three coreholes through the shale. They will evaluate cores to determine future activity. The companies also will evaluate 15 previously drilled wells on the island and compare results with Utica wells in Ohio and the St. Lawrence Lowlands of Quebec. That analysis should be completed in 2013.

Corridor holds nearly 1.5 million gross (900,000 net) acres on the island, with a calculated 33.9 Bbbl of oil gross (19.8 Bbbl of oil net).

Crescent Point Energy Corp.

- Largest acreage holder in Viewfield Field
- Has properties in Manitoba and southern Alberta, Viking properties in western Alberta

Crescent Point Energy Corp. parlayed six purchases to become the largest acreage holder in Viewfield Field in Saskatchewan, the biggest Bakken play in Canada. The company added to that position with Bakken properties in Manitoba and southern Alberta and Viking properties in western Alberta.

The company also holds non-operated Bakken wells across the border in the US.

In a September 2012 presentation, the company said it held 238.7 MMboe in proved and probable resource in Viewfield Field, but that did not include potential recovery from a waterflood in that field.

An August 2011 report said the company raised its production from Viewfield from 275 boe/d in 2001 to an anticipated 75,600 boe/d by year-end 2011, and wells under primary production offered a 394% rate of return.

By September, the company was injecting water in 35 wells in the field, and it planned to complete 40 water-injection wells during the year.

The company also instituted a monitoring program to measure the efficiency of its waterflood design.

The company controlled 1,100 net sections of land at Viewfield with 3,800 net well locations and planned to invest 33% of its 2012 capital program in the area. That investment should support 154 net wells.

The company held 53.2 MMboe in proved and probable resource in the Viking, also without counting waterflood potential.

In a February 2012 press release, the company said the waterflood operation at Viewfield should increase ultimate recoveries from 19% of the original oil in place (OOIP) to approximately 30% of the OOIP.

Crescent Point's Viking properties include more than 300 net sections in the Halkirk area of Alberta, with a 555-well potential drilling inventory and an estimated 1.15 Bbbl of OOIP.

In its 2Q 2012 report, the company said it drilled 12 gross (10 net) horizontal wells for Bakken light oil during the quarter, all of which were successful. The company produced 9,800 b/d from the Bakken during the period, but added a rail facility that raised throughput to 16,000 b/d to the Stoughton terminal and another 1,000 b/d to third-party processors.

The company also drilled one net well in the unconventional Bakken in Alberta, with two net horizontal wells to conventional zones. The company plans 14 net unconventional and conventional wells at this location during all of 2012.

The company added to its Bakken production in May 2012 with the acquisition of Reliable Energy Ltd. That gave Crescent Point all of the Bakken properties in southwestern Manitoba in which it previously held a joint venture interest with Reliable.

The purchase gave Crescent Point an additional 1,000 boe/d of production and more than 135 net sections of land.

The following month, the company bought Cutpick Energy Inc., which included 5,600 boe/d of production and more than 300 net sections of land in the Halkirk area of Alberta and 83 net sections with potential for Viking production.

Crew Energy Inc.

- Planned to spend CAN $3.5 million on Cardium properties in 2012
- Acquired Cardium properties at Wapiti, Elmworth, and Kakwa with acquisition of Caltex Energy Inc.

Crew Energy Inc. holds properties in the Horn River Basin, Cardium, and Montney plays, and it actively works its Cardium properties in Alberta and Montney holdings in British Columbia.

The British Columbia properties include prospects in both the gas-liquids segment of the play and the oil segment broken down into four main operating areas.

The company has assigned reserves in only 15 of its 56 sections of land in the Septimus area of the Montney play, according to a September 2012 presentation. At that time, the company produced 6,100 boe/d with a 15% condensate cut. The company also operated a 50 MMcf/d gas processing plant in that area.

Crew holds 30 net sections of land in the Tower Montney segment. A discovery well in that area tested for 342 b/d of liquids and 1.7 MMcf/d, while a second discovery offered 375 b/d of liquids and 750 Mcf/d of gas. The company drilled and completed its first operated oil well in that area in 2Q 2012.

The company's Kobes Montney area covers 23 contiguous sections and produced 900 boe/d with a 24% condensate cut in September 2012. Production consisted of 88 bbl/MMcf. The company determined the Upper, Middle, and Lower Montney all were productive in the area. It planned one well at Kobes late in 2012.

The company held 32 contiguous sections of land in its Portage Montney area. It drilled two gross (one net) wells there in 2012.

The company planned to spend CAN $3.5 million (US $3.6 million) on its Cardium properties in the Alberta Deep Basin in 2012. The company held 180 drilling locations in the Greater Wapiti area, with a September production rate of 300 Mcf/d. The properties had produced a cumulative 480 MMcf by that time.

The company's Cardium wells produced 90 bbl/MMcf of natural gas, and it controlled a potential 455,000 boe at a cost of CAN $7.69/boe (US $7.90/boe) for a 29% rate of return.

The company acquired Cardium properties at Wapiti, Elmworth, and Kakwa with its acquisition of Caltex Energy Inc.

Delphi Energy Corp.

- Company's prime property is Bigstone Montney play
- Holds ownership interests in eight natural gas processing plants

Delphi Energy Corp. controls a significant property position with more than 400 sections of land focused on Alberta's Deep Basin. That land holds Duvernay Shale production, but the company's prime property is its Bigstone Montney play.

The company also holds ownership interests in eight natural gas processing plants in the area, with a total processing capacity of 1 Bcf/d.

Delphi lists its most important holding as Bigstone East, a light oil, condensate-rich NGL Montney play that yields 50 bbl/MMcf to 60 bbl/MMcf. The company controls 45 gross (41.5 net) sections of land, acquired for CAN $11 million (US $11.28 million).

The company drilled, completed, and brought online three extended-reach horizontal wells at Bigstone East in 2011 and 2012. Those wells featured a combined 8,000-m (26,248-ft) horizontal wellbore, equivalent to six or seven conventional horizontal wells, the company said.

The company's best well is the Delphi No. 3 14-23 well, which showed an initial potential of 26 MMcf/d of gas and 800 b/d of liquids.

An extended-reach well costs CAN $9.25 million (US $9.49 million) to complete with a two-mile extended-reach section, but it offers a finding and development cost of CAN $8/bbl (US $8.21/bbl) to CAN $10/bbl (US $10.26/bbl) and a field netback of

CAN $21/boe (US $21.55/boe) at a gas price of CAN $2/Mcf (US $2.05/Mcf).

Delphi planned one well offsetting the 14-23 well in 2012, another six horizontal wells to delineate the field in 2013, and eight to 12 wells each in 2014 and 2015.

The company also holds 27 net sections of land, with four to six drilling locations per section at its Bigstone West Montney light oil play.

At that location, the company drilled the Delphi 9-4 for a 30-day initial potential of 206 boe/d, a 60-day initial potential of 142 boe/d and a production rate of 75 boe/d at the end of six months online. That production stream contained 52% liquids.

Delphi sold its Cardium assets at Bigstone during 2Q 2012.

The company held 108 gross (79 net) sections of land at its Sturgeon Lake Duvernay play. That property is prospective for light oil and associated gas, and Delphi plans field activity for it during 2013.

Direct Energy/Centrica plc

- Operates more than 4,600 producing wells in Canada
- Main production operations are in Medicine Hat, Stettler, and Wildcat Hills

Direct Energy, the North American arm of the UK's Centrica plc, operates more than 4,600 producing wells in Canada. The company acquired exposure to the Cardium play late in 2011.

The company's three main production operations are in Medicine Hat, Stettler, and Wildcat Hills in Alberta, and its 170 MMcfe/d, or 59 Bcfe a year, provides enough natural gas to supply approximately 420,000 homes. The company doubled its production since 2007, according to its website.

The company holds 600 Bcfe in proven and probable reserves on its 382,000 net acres of undeveloped land.

Most of its production comes from conventional sources, but the company added unconventional potential with a December 2011 purchase.

The company bought a package of liquids-rich gas assets when it acquired Carrot Creek properties in west-central Alberta from Encana for CAN $58 million (US $59.3 million) and producing gas wells in southern Alberta.

Carrot Creek gave Direct Energy 80 producing wells, infrastructure, a gas processing plant, and 25.6 Bcfe in proven and probable reserves with a 58% liquids cut. Carrot Creek also gave the company 6.4 MMcfe/d about 160 km (100 miles) west of Edmonton, adjacent to the Cardium oil development. This development is in addition to the Cardium production that Direct Energy had from horizontal wells at the time.

Donnybrook Energy Inc.

- Focused operations on the Bigstone and Resthaven-Simonette areas
- Donnybrook 4-14 is company's best well in Resthaven-Simonette

Donnybrook Energy Inc. has focused its operations on the Bigstone and Resthaven-Simonette areas in the southern part of the Montney play in Alberta, an area that also holds potential for Duvernay and Nordegg production.

The company controls 43 gross (23 net) sections of land in the liquids-rich part of the Montney in an area that contains more than 20 Bcf of gas with 1.2 MMbbl of NGL in place per section, with two-thirds of the property derisked by drilling.

The company planned to reach production of 600 boe/d from the area in 4Q 2012 from its three wells. Donnybrook plans a fourth extended-reach well in 1Q 2013.

The company's best well in the Resthaven-Simonette area, the Donnybrook 4-14, tested for 8.9 MMcf/d of gas and 40 b/d of oil. The company's best Fir/Bigstone area well tested for 16 MMcf/d of gas and 800 b/d of NGL. Currently, its production goes into the Delphi gathering systems for processing and sales.

A 2012 independent study by GLJ Petroleum Consultants Ltd. calculated 587,000 boe in proved reserves and 1.6 MMboe in proved, probable, and possible (3P) reserves at Bigstone. A similar study at Simonette estimated 2.65 MMboe in proved reserves and 5.99 MMboe in 3P reserves.

The company's land position includes 32 gross (16 net) sections of land prospective for Duvernay production and 45 gross (23 net) sections with Nordegg rights.

Encana Corp.

- Owns large land position in Canada's unconventional assets
- Holds more than 400,000 net acres in the Duvernay

Encana Corp. owns a big portion of Canada's conventional activity, as well as a large land position in that nation's unconventional assets.

For example, the company assembled more than half of the high-graded, liquids-rich Duvernay gas condensate fairway, a position with approximately 30 Tcf of gas and 4 Bbbl of petroleum liquids initially in place.

According to its 2012 investor presentation, the company holds more than 400,000 net acres in the Duvernay with 1,000 to 1,600 potential well locations on 160-acre to 330-acre projected well spacing. The company planned 10 wells in that play in 2012, along with continuing reservoir characterization on its properties in the Kaybob, Edson, and Willesden Green area.

In those areas, the company targets a cost of CAN $15 million (US $15.39 million) to reach 350,000 boe to 600,000 boe of hydrocarbons using 1,060-m (3,500-ft) to1,980-m (6,500-ft) laterals on wells with vertical depths of 2,530 m (8,300 ft) to 3,960 m (13,000 ft).

In the same presentation, Encana said it held 435,000 net acres of land in the Peace River Arch area with 36 Tcf of gas and 1 Bbbl to 3 Bbbl of liquids at a well cost between CAN $7.5 million (US $7.69 million) and CAN $11.5 million (US $11.8 million). That investment would give the company 4 Bcfe to 16 Bcfe. For 2012, Encana planned to accelerate liquids production in this area and advance its multiwell pad development program.

The company planned 21 Montney wells in the Peace River Arch area in 2012 from an inventory of more than 300 well sites.

The company's Bighorn area covers 383,000 net acres of land, with 33 Tcf of gas and 1 Bbbl to 2 Bbbl of liquids initial in play. The company planned 33 wells in this area during 2012 from its potential

Drilling operations continue through the night at a rig site at Ft. Nelson, British Columbia. *(Photo courtesy of Encana Corp.)*

1,400 well sites. That inventory includes 100 horizontal Cardium sites. The company plans one Cardium well in 2012. In February 2012, Encana partnered with Mitsubishi in the Cutbank Ridge resource play on the border of British Columbia and Alberta. Under the agreement, Mitsubishi invested CAN $1.45 billion (US $1.49 billion) up front and agreed to pay the same amount to cover half of Encana's capital costs for development in the area for approximately five years. That investment would earn Mitsubishi a 40% interest in the partnership with 409,000 net acres of properties in the Saturn, Swan, Cutbank Montney, and Cutbank Cadomin areas, as well as the Steeprock Doig play.

The Cutbank Ridge resource play holds an estimated 130 Tcf of gas and 1 Bbbl to 2 Bbbl of liquids initially in place. Approximately 70 gross wells are planned in 2012 from an inventory of some 4,500 well sites.

Encana used a resource play hub system for Montney development, with eight to 12 wells per hub. With an average 11 stages per well, that amounts to 100 completions to 200 completions per hub with laterals spaced 200 m to 300 m (656 ft to 984 ft) apart.

According to the company's website, Encana said it held approximately 288,000 net acres in the Devonian Shales in the Horn River Basin of northeastern British Columbia, including the Muskwa, Otter Park, and Evie formations. By year-end 2011, 112 gross wells had been drilled on the property and 70 were put on long-term production.

The company's resource play hub design in that basin reduced supply cost attributed to well capital and operating expenses to 54% in 2011, down from 60% in 2010 and 66% in 2009.

In addition to the unconventional properties listed above, an early 2012 presentation said the company had more than 1,800 sections of land in the Bakken/Exshaw play in southern Alberta and more than 200 sections in the Viking play in eastern Alberta.

Enerplus Corp.

- Has substantial Canadian properties
- Plans to increase oil production

Most of the oil and gas activities of Canada's Enerplus Corp. focus on its US operations, but the company has substantial Canadian properties and solid plans to increase oil production.

In an article by Leslie Haines, editor of Oil and Gas Investor, Robert A. Kehrig, vice president, Resource Development with Enerplus, said, "The returns of the Bakken are brilliant, with IRRs (internal rates of return) of 60%." That's a substantial incentive, and Enerplus directed 80% of its CAN $209 million (US $214.38 million) to its Bakken/Three Forks oil properties on the Fort Berthold Reservation in the US and to its oil-producing waterflood projects in Canada. Some 40% of its 2012 capex aim at the Bakken/Three Forks in North Dakota.

The company's tight-oil floods included work in the Viking Formation in the Joarcam and Gleaneath areas and the Cardium at Pembina, according to a September 2012 presentation.

Most of the company's gas spending in 2Q 2012 worked to hold leases in the Marcellus play in the US.

In addition to its established activities, Enerplus continued delineation activities in the Montney and Duvernay, but in an August 2012 press release, the company also said, "We continue to progress on our plans for the partial sale and/or monetization of a portion of our early stage asset portfolio, which includes the Duvernay, Montney, and operated Marcellus."

Inpex Corp.

- Taking a 40% interest in the shale properties of Nexen Inc.
- Development of the properties could raise joint venture production to 1.25 Bcf/d

Inpex Corp. of Japan joined the shale hunt early in 2012 when it agreed to take a 40% interest in the shale properties of Nexen Inc. in the Horn River, Cordova, and Liard basins for CAN $685.94 million (US $700 million).

Nexen, which is scheduled for acquisition by China National Offshore Oil Corp. Ltd. in 4Q 2012, will remain operator of the shale resources in the three basins in northeastern British Columbia. Nexen valued that sale at CAN $14.8 billion (US $15.1 billion).

The Inpex agreement called for a 50% upfront payment and the rest in capital carries. The legal owner of the 40% interest is Inpex Gas British Columbia Ltd., a venture in which Inpex Corp. holds an 82% interest and JGC Corp. the remaining 18%.

According to Nexen, its Horn River and Cordova Basins hold between 4 Tcf and 15 Tcf of recoverable contingent resource, and the Liard Basin land contains another 5 Tcf to 23 Tcf.

Nexen planned to complete its first 18-well pad in 4Q 2012 to raise production from the Horn River Basin to approximately 155 MMcf/d early in 2013. With LNG expertise supplied by Inpex, the companies will assess the feasibility of an LNG export project.

Nexen started producing Horn River Basin shales in 2007 at Dilly Creek and produced an average 38 MMcf/d during 2011.

The company built a camp in the basin about 215 km (134 miles) northeast of Fort Nelson, British Columbia, to host more than 300 workers. The company planned to complete 28 wells by year-end 2012.

The company also started to develop plans for an access road and camp in the Cordova Basin to begin drilling operations in 2013. The company is still assessing the development potential of the Liard Basin properties.

Full-scale development of the properties could raise joint venture production to 1.25 Bcf/d at some point in the future.

Junex Inc.

- Most important license holder in Quebec
- Currently active in exploration of its 233,275 acres on Anticosti Island in the St. Lawrence Seaway.

Junex Inc., the most important license holder in Quebec with more than 5 million net acres of exploration licenses and participating interests in another 1.3 million acres, counts that province's shales among its targets with high potential.

The company's Utica Shale licenses alone in the St. Lawrence Lowlands contain an unrisked, potential recoverable 3.7 Tcf of gas, according to a Netherland, Sewell, and Associates Inc. report.

The Utica properties total 1.67 million acres. Unfortunately, development of that shale is off limits until the Quebec government completes a study on the impact of development.

The company also holds 1.8 million gross acres prospective for production from Ordovician and Devonian shales on the Canadian side of the Appalachian Basin in Quebec with test wells drilled in the St. Georges, Windsor, and South basins.

The company has other resources. Its current active project is exploration of its 233,275 acres in five exploration license areas on Anticosti Island in the St. Lawrence Seaway. There, the Macasty Shale, a geological equivalent of the Utica Shale, is a prime target with two dolomites and a sandstone also with production potential. Netherland, Sewell, and Associates estimated 12.2 Bbbl of oil initially in place on the company's land on the island.

Junex completed the acquisition of 224 km (140 miles) of 2-D seismic data on a solely owned 233,275-acre block of permits on the island in September 2012. The company plans to use the analysis of that survey to identify drilling targets and well locations.

In a September 2012 press release, the company said, "Junex's interpretation of pertinent lab data indicates that the organic-rich Macasty on its acreage places it within the oil window of thermal maturity,

with the top of the Macasty ranging in depth from approximately 800 m (2,620 ft) to 2,200 m (7,220 ft). Junex's technical evaluation indicates that the level of thermal maturity observed thus far in the Macasty in the Deep Macasty Fairway compares favorably with published findings for the oil-rich Utica/Point Pleasant Shale in Ohio and the Eagle Ford Shale in Texas."

LGX Oil + Gas Inc.

- Increasing production in its Bakken properties in southern Alberta
- Holds 155,974 net acres on the Blood Tribe Reserve

LGX Oil + Gas Inc., formerly Bowood Energy Inc., acquired Bakken properties in southern Alberta and is increasing production in the area.

According to the company's website, LGX drilled its first two Alberta Bakken horizontal wells and put them on production. Early technical data from those wells gave the company positive first steps toward commercial development on the property.

The company holds 155,974 net acres, including 60,512 net contiguous acres, on the Blood Tribe Reserve in the fairway prospective for Bakken production, an area in which the oil and gas industry has spent more than CAN $239 million (US $244.23 million) on Crown land purchases since April 2010, the company said. More than 60 wells have been licensed by the industry in that Alberta play, and 22 wells have started producing. Ten additional wells were producing on the Montana side of the play in 3Q 2012.

Bowood bought the southern Alberta assets in July 2012 from Legacy Oil + Gas Inc.

According to an August 2012 press release from LGX, the company and its predecessor operations increased average production from 430 boe/d in 2Q 2011 to 485 boe/d in 2Q 2012.

Magnum Energy Inc.

- Developing its Viking light oil holdings in Provost area
- Holds a half interest in 4.25 sections of land in Viking play

Magnum Energy Inc. controls two producing core properties in southeast-central Alberta and set its corporate strategy on developing its Viking light oil holdings in the Provost area.

The Viking, which occurs from southwestern Saskatchewan into northwestern Alberta, is second only to the Cardium for oil originally in place. More than 500 horizontal wells have been drilled into the Viking oil trend.

Magnum holds a half interest in 4.25 sections of land in the Viking play.

In September 2012, the company said a horizontal well operated by Magnum flowed at a rate of 230 b/d of oil over 5.4 days on a restricted choke. This was the third of seven horizontal wells identified for drilling on the section of land, and the company planned to start a fourth horizontal well before year-end 2012.

MFC Industrial Ltd.

- Acquired Compton Petroleum Corp. in September 2012
- Lists the Wilrich as a primary target

MFC Industrial Ltd., a global supply chain company, took on the Canadian shale play with its September 2012 acquisition of Compton Petroleum Corp.

Compton worked the Deep Basin in Alberta with traditional production from the conventional Rock Creek Sandstone.

The company's primary production came from the Niton area south of Calgary. In addition to the Rock Creek sands, the company controlled 71 sections of land with more than 35 potential Cardium oil and gas locations, 123 sections with more than 40 locations for Viking gas, 135 sections with more than 100 locations for Wilrich gas, and 18 sections with more than 20 locations for Duvernay gas.

The company listed the Wilrich as a primary target in the area and the Viking and Duvernay formations as secondary targets.

In addition, the company claimed the Viking as a secondary target in its Alberta Southern Plains area.

Murphy Oil Corp.

- Holds 156,000 acres of land in the Montney play
- Holds 168,000 acres in that Duvernay-equivalent play

Murphy Oil Corp. staged a strong campaign to develop its Canadian properties in the Montney, Three Forks, and Muskwa formations in Canada with an emphasis on oil production in the face of low natural gas prices.

In a May 2012 presentation, the company said it held 156,000 acres of land in the Montney play, nearly all at Groundbirch, Tupper West, Tupper, Brassey, and Sundown in British Columbia but with some Tupper properties in Alberta.

The company estimated a total resource at approximately 3 Tcf with estimated ultimate recoveries of 4 Bcf per well. The company said it would curtail 30 MMcf/d of gas production for the rest of 2012 and would drill new wells only to hold its land position. After the curtailment, it still plans to produce 208 MMcf/d during 2012.

The company planned to produce 130 MMcf/d in 2013 with another 50 MMcf/d available for possible curtailment. In 2014, the plan called for 137 MMcf/d in gas production with another 28 MMcf/d optional, and in 2015, the solid production number dropped to 123 MMcf/d and the option to 44 MMcf/d, all depending on gas prices.

The company planned 14 Montney wells in 2012, eight solid wells and seven optional wells in 2013, eight solid and six optional wells in 2014, and eight solid and 15 optional wells in 2015.

Murphy produced about 35,000 boe of Montney oil in 2012 and expected that number to drop to 30,000 boe/d the following year and level out at 25,000 boe/d in 2014 and 2015.

The company called its southern Alberta holdings a new play with an accumulated 150,000 acres. The company originally planned to work the Exshaw Formation in this area, but changed its emphasis to the deeper Three Forks. The company's Kainai 15-21 well tested for 350 b/d with a net potential production of 130 MMbbl on its property, based on 160-acre spacing, initial production potentials of 250 b/d and ultimate recoveries of 250,000 bbl per well. That formula resulted in a 22% rate of return. The company also said that resource estimate could double.

The company has not abandoned the Exshaw. At Hart Energy's DUG Canada conference in Calgary, Murphy's Jon Noad said, "What puts the southern Alberta Exshaw play head and shoulders above? It lies above the Devonian Three Forks. The total organic content is up to 12%, and much of it is oil-prone."

Another new area for the company is the Muskwa Shale in northeastern British Columbia. The company holds 168,000 acres in that Duvernay-equivalent play. The company drilled the Murphy 4-1-109 and tested it for 150 b/d. The company put the well on pump and is still evaluating the potential of the play.

Nextraction Energy Corp.

- Active in the Viking light oil play
- Spent about CAN $4 million in the first half of 2012

Nextraction Energy Corp. occupies a small but active position in the Viking light oil play in the Provost area of east-central Alberta.

The company has access to 5.25 sections of land with a drilling inventory of eight Viking wells with a 100% working interest and 28 additional wells with a half interest.

At the time of a May 2012 presentation, the company had drilled one well for 55 boe/d, 45% oil. The company planned to drill 16 horizontal wells per section with 700-m (2,300-ft) laterals and seven to 10 fracture treatments per well.

The company spent about CAN $4 million (US $4.1 million) in the first half of 2012 to drill and complete five Viking light oil wells in the half-interest area. The company also completed a multiwell tank battery and brought online a horizontal well drilled in 2011.

Reporting test results from a horizontal well in the Provost area, in a July 2012 press release Nextraction said that after a 10-stage frac treatment and 50 hours of flowback, the well produced 431 bbl of oil, 545 bbl of water, and half the frac fluid. During the final 24 hours of the flow test, the well produced at a rate of 210 b/d of oil with a 65% oil cut.

The company planned to drill two to four more horizontal wells on the property during the remainder of 2012 and identified 35 potential follow-up locations.

NuVista Energy Ltd.

- Has sold off non-core properties
- Concentrating activities on the Montney condensate-rich play in the Wapiti area

NuVista Energy Ltd. took a big step as it sold off non-core properties to concentrate its activities on the Montney condensate-rich play in the Wapiti area of Alberta.

In a July 2012 presentation, the company said it produced 14,875 boe/d that month from 249,000 net acres of land.

In the same presentation, the company said it would prove up potential and delineate its position in its core Montney area, 100,000 net acres on three contiguous blocks at Wapiti, Elmsworth, and Bilbo.

The company has drilled four horizontal wells in the area, with three more in the works. Typically, the wells produce 30 bbl/MMcf to 40 bbl/Mmcf, and NuVista has more than 500 locations in the Upper Montney alone.

That gives the company room for CAN $3 billion (US $3.06 billion) to CAN $4 billion (US $4.08 billion) in profitable investment, the company said.

Two of the company's horizontal wells tested for 10 MMcf/d of gas. One of those wells also produced 250 b/d of condensate, while the other produced 500 b/d of condensate. Another horizontal well tested for 9.5 MMcf/d of gas and 370 b/d of condensate. The fourth horizontal well online produced 4.4 MMcf/d and 330 b/d of condensate.

The company planned to spend CAN $110 million (US $112.63 million) to CAN $124 million (US $126.96 million) in 2012.

The sale of three property packages for a gross CAN $236 million (US $241.63 million) will help finance that activity.

The company's Montney properties also have potential for production from the shallower Cardium and Dunvegan zones. The company drilled 8.5 gross (5.8 net) wells, all successful, to the Cardium in its Pembina properties in 2010 to complete seven oil wells and one gas well.

Painted Pony Petroleum Ltd.

- Has expanded operations into the Montney area
- Has started working the Viking prospect

Painted Pony Petroleum Ltd., one of the early leaders in the Canadian Bakken play in Saskatchewan, expanded its operations into the prolific Montney area of British Columbia and has started working the Viking prospect in Alberta.

The company counts the Bakken and Viking plays, both oil-heavy, as its prime targets, but it is not neglecting the gas-prone Montney.

The company continues to prove up Montney resources and expand processing capacity to prepare for the Kitimat LNG export terminal on the west coast. The company is a co-operative member of the Kitimat group and has a 230 MMcf/d gas export permit.

Painted Pony holds 101,700 net Montney acres and produced 28.9 MMcfe/d – 99% gas – in the first half of 2012 from its Cypress, Blair/Town, and Cameron/Kobes areas. The company calculated 785 Bcfe proved and probable reserves, including 14 MMbbl of liquids with reserves assigned to only 12% of its Montney holdings, according to a September 2012 presentation. The company expects a 72.3% rate of return from that production and can earn a 10% internal rate of return at a gas price of CAN $1.12/Mcf (US $1.15/Mcf).

The company expects 38 MMcfe/d from its Blair/Cameron area for all of 2012. The company plans to exit 2016 in that area producing 460 MMcf/d of gas and 9,700 b/d of liquids.

The Triassic Montney is not the company's only shale prospect. The company also can produce from the shallower Cretaceous Buckinghorse Shale, a relatively permeable shale at a total vertical depth of 400 m (1,300 ft) that can be drilled at a well cost of only CAN $500,000 (US $512,000). The company has placed three wells on production from that zone.

The company holds 80,200 net acres in the Bakken oil play in Saskatchewan and produced 1,560 boe/d in the first half of 2012 with a CAN $53/boe (US $54.30/boe) netback. The company is expanding its operations to the south into its Flat Lake Field along the Canadian/US border. The company has a 46% working interest, or 13,700 net acres, in that area and expects a 52% rate of return. The company plans 16 gross (10 net) wells on its Bakken properties in the second half of 2012.

The company started exploring the Alberta Viking light oil play in 2011 and by September 2012 had access to 28,100 net acres, including farm-ins. The company completed its first well in July 2012 and planned to spud two more in 4Q 2012.

Paramount Resources Ltd.

- The Kaybob area is prime focus
- Produces from the Montney at Musreau, Resthaven, and Smoky

Paramount Resources Inc. runs operations in the Western Canadian Sedimentary Basin that range from oil sands through conventional oil and gas and emerging shale plays.

The company works through four operating units: Kaybob in the Deep Basin, Grande Prairie south of Kaybob, the Northern area that includes the Liard Basin, and the Southern that reaches through southern Alberta into the Bakken/Three Forks play in Montana and North Dakota.

Within the Kaybob area, the company produces from the Montney at Musreau, Resthaven, and Smoky, where it holds 113,000 net acres.

The company drilled 19 horizontal wells at Musreau, including five Montney wells in 2011, and planned 20 wells in the area in 2012. The company drilled nine horizontal wells in the Resthaven/Smoky area and planned eight wells in 2012, including three Montney wells drilled through June 2012.

Paramount planned to produce 6,500 boe/d in 2012 from its Grand Prairie area, up from an average 3,790 boe/d in 1Q 2012.

The Grande Prairie area includes 95,000 net acres at Karr-Gold Creek, with multizone potential that includes Montney sour gas.

The area also includes Valhalla, a Montney-Doig Shale play. According to a June 2012 presentation, the company had tied eight wells into the processing plant at rates restricted by the facility's capacity. The company has two more wells awaiting tie-in and four wells awaiting completion. The company is continuing land acquisition in the area.

In the Birch area, Paramount completed a Montney well with Prospex. The well was producing at a restricted 3 MMcf/d.

In the company's Northern area, part of its CAN $60 million (US $61.44 million) in strategic investments will go to evaluation of Liard Basin Shale gas potential, where it holds 127,000 net acres of land prospective for Besa River Shale production.

Pennant Energy Inc.

- Signed farm-out agreement with Donnybrook Energy in March 2011
- Gained access to the Montney play in the Bigstone area of Alberta

Pennant Energy Inc. took its place as one of a number of smaller companies tapping the Montney resource play as a path of profits.

The company signed a farm-out agreement with Donnybrook Energy Inc. in March 2011 to gain access to the Montney oil and liquids-prone gas play in the Bigstone area of Alberta.

The companies drilled a 3,818-m (12,527-ft) well with a 1,200-m (3,937-ft) horizontal leg at Bigstone in October 2011, tested it for 1,011 boe/d, and tied it in to a sales line. That earned Pennant a one-fourth interest in 4,480 gross acres of land.

In January 2012, the companies drilled a 5,500-m (18,046-ft) Montney well with a 2,744-m (8,127-ft) lateral. Downhole problems held completion to only six of the planned 24 fracture stages, but the well still tested for 1.1 MMcf/d of gas and 50 b/d of condensate and NGL.

The company completed the third well in June 2012 with a 2,590-m (8,498-ft) horizontal leg, tested it for 2.87 MMcf/d of gas and 520 b/d of condensate, and planned to tie it to sales in late 2012.

The company now has a 25% interest in six sections of land and a 12.5% working interest in two more sections. The company planned the fourth well for 1Q 2013.

Penn West Exploration Ltd.

- Major player in Canadian oil, gas operations
- Focusing efforts on light oil

Penn West Exploration Ltd., a major player in Canadian oil and gas operations, locked in solid land positions in some of the major emerging plays in the nation.

In a September 2012 presentation, the company said, "Penn West has the most leverage to large-scale oil development using horizontal multistage technology in North America."

The company's affinity to developing plays makes sense. They are more profitable. The company's old oil production gives it a netback of about CAN $38/bbl (US $38.89/bbl) and represents about 40% of its production, while its newer oil, including production from Viking and Cardium formations, represents 20% of production and offers a netback of about 74%.

Overall, the company is focusing its efforts on light oil, and it planned to devote 85% of its 2012 capital spending to development of that resource.

Penn West has some 2,000 gas drilling locations in the Viking Formation and Cordova Embayment shales and about 3,600 drilling locations for oil in the Viking and Cardium formations. On the gas side, the company has a joint venture program with Mitsubishi to find exports in the southern portion of the Cordova Embayment.

On the oil side, the company has 665,000 net acres of land – about 40% of the land in the trend – in the West Pembina, Alder Flats, and Willesden Green areas in Alberta and plans to spend CAN $250 million (US $255.68 million) to CAN $300 million (US $306.8 million) to drill 100 to 150 wells in the areas during 2012. The company planned to finish 2012 producing 120,000 boe/d from those Cardium fields. The company had five rigs working those areas in early 2012.

Breaking down the holdings, the company's Alder Flats wells give it rates of return between 35% and 55% at a cost of CAN $3.2 million (US $3.27 million) to CAN $3.6 million (US $3.68 million) through tie-in to production lines and payout in 2.3 years or less. The company has 20 wells in that area.

The company's West Pembina Cardium wells yield returns from 30% to 40% at the same cost as the Alder Flats wells and pay out in two to 2.5 years. The company has 31 wells in West Pembina. The companys' 43 Willesden Green paid out in two to four years at a cost of CAN $4 million (US $4.09 million) to CAN $4.8 million (US $4.91 million) and offered returns between 25% and 30%. The company has 43 wells in that area.

In addition to the Cardium presence in Willesden Green, Penn West has more than 100,000 net acres focused on the liquids-rich Duvernay fairway. The company completed one well there in 2012 and may drill vertical and horizontal wells in 2013.

The company's Viking properties lie in the Esther area in eastern Alberta and western Saskatchewan and in the Kerrobert and Dodsland areas of Saskatchewan. The company holds 750,000 net acres of land in the three areas and planned to spend CAN $125 million (US $127.88 million) to CAN $175 million (US $179.03 million) to drill 75 to 100 wells in 2012. The Saskatchewan portion of that trend has graduated to a pure development play with three rigs at work.

The company has 171 wells at Dodsland, giving it internal rates of return between 65% and 75% with payout in 1.2 years to 1.7 years. The wells cost between CAN $1.2 million (US $1.23 million) and CAN $1.4 million (US $1.43 million) to drill, complete, and tie in to production lines.

The company's Viking wells at Esther offer internal rates of return from 40% to 50% with payout in less than 2.2 years and a cost to tie in of CAN $1.5 million (US $1.53 million) to CAN $1.8 million (US $1.84 million). Penn West has 12 wells in that area.

PetroChina Co. Ltd.

- Bought a 20% share of Shell Canada's Groundbirch Montney project
- Wants to use western expertise in developing shale resources in China

Although PetroChina stops short of operating shale activities in Canada, it welcomes ownership and plans to use Canadian shales as a stepping stone to get Canadian gas to China.

In 2011, the company launched a campaign to buy a half-interest in shale and deep-gas assets in northeastern British Columbia and northwestern Alberta for CAN $5.4 billion (US $5.53 billion) in an area of 1.3 million acres at Cutbank Ridge. That deal fell through.

In 2012, in a deal with an undisclosed value, the largest company in China bought a 20% share of Shell Canada's Groundbirch Montney project.

Shell purchased Duvernay Oil Co. in 2008 for CAN $5.9 million (US $5.7 million) at the time. That gave Shell approximately 450,000 acres of Montney properties at Groundbirch and the Deep Basin in Alberta.

At the time of the deal with PetroChina, Shell produced 125 MMcfe/d from its Groundbirch properties, apparently down from 190 MMcfe/d during 2011.Those properties also include five natural gas processing plants, more than 250 wells, and more than 900 km (559 miles) of pipeline.

It is no secret that PetroChina wants to add western know-how to help develop shale resources in China. That nation has roughly three times the estimated shale resources that exist in the US.

"PetroChina and Shell intend to further advance the exchange of technology in the development of unconventional gas. Furthermore, PetroChina hopes to achieve reasonable returns from the investment," the company said in a statement about the deal.

The Groundbirch agreement is only part of the supply chain. Shell holds a 40% interest in LNG Canada, an LNG export project that will move gas from the Western Canadian Sedimentary Basin to the west coast of British Columbia for export. That project will follow the Kitimat LNG project and also will move gas to the Kitimat port. PetroChina, Korea Gas Corp., and Mitsubishi Corp. each have a 20% share of LNG Canada.

Pétrolia Inc.

- Wants to supply 5% of Quebec's oil demand by 2014
- Has partnered with Corridor Resources on Anticosti properties

Pétrolia Inc. has a straightforward goal. The company wants to supply 5% of Quebec's oil demand, 20,000 bbl, by 2014, and one key to reach that goal is the company's Macasty Shale properties on Anticosti Island in Quebec.

The company started drilling for cores on various locations on the island in early August 2012. The company will test the cores and determine maturity, organic content, porosity, permeability, and formation location at each point, with particular attention to the Utica-equivalent Macasty. Then, the company will decide whether to drill and where to drill.

The company also will analyze more than 500 samples from 15 wells drilled to the Macasty, three wells drilled to the Utica in Ohio, and one well drilled with shale oil recovered from the Macasty in the St. Lawrence Lowlands.

If the company decides to develop, it has the land position, some 3.5 million gross acres, most on the Gaspé Peninsula and Anticosti Island.

Pétrolia is no newcomer. The company drilled the first commercial well in Quebec in 2006 to a formation equivalent to the Bakken, according to a March 2012 presentation. The company is also the largest holder of petroleum rights in Quebec, with some 17% of the total available. That land represents some 70% of the oil potential in the province. The company's gross Macasty holdings contain a best estimate of 30.9 Bbbl of oil (14.1 Bbbl net) in place.

The company has partnered with Corridor Resources on the Anticosti properties, with both companies holding operating rights on some parts of the properties. The two companies hold a combined 1.5 million acres on the island.

Questerre Energy Corp.

- Holds a net potential recoverable resource of 4.4 Tcf of gas in Quebec
- Resthaven is company's new core area

Locked out of its 1 million gross (340,000 net) acres of Utica/Lorraine Shale rights in the St. Lawrence Lowlands of Quebec until a 2014 regulatory deadline, Questerre Energy Corp. spread its unconventional resource scope to the Bakken/Torquay light oil play in Saskatchewan and the Montney play at Resthaven in western Alberta.

Questerre holds a net potential recoverable resource of 4.4 Tcf of gas in Quebec.

The company holds more than 45,000 net acres under a 100,000-acre parcel in the Bakken/Torquay play at Antler, with a potential 2 MMbbl of net recoverable resource, but its Resthaven Montney play offers a potential 8 MMbbl and 72 Bcf of net recoverable resource.

The company planned 10 more wells at Wildcat Hills in Saskatchewan in late 2012 and early 2013. The company also is analyzing potential for a waterflood on its Bakken/Torquay properties. A similar flood nearby in Manitoba raised project recoveries from 9% of the oil in place to between 16% and 24% of the oil in place. The company started a pilot water injection program in August 2012 and anticipated results by year-end. The company plans to expand the waterflood in 2013 to three sections.

Resthaven is the company's new core area, and it holds a 25% working interest in 16 sections in the liquids-rich fairway of the Montney trend. The company's first well tested for 8.3 MMcf/d, with 1,150 b/d of liquids at a rate of 138 bbl/MMcf. The company started drilling a second well to the Montney to delineate its acreage north of the discovery well.

Quicksilver Resources Inc.

- Has completed an eight-well pad on its 130,000 net acres in Horn River Basin
- Completed five Muskwa and three Klua wells on the pad

Quicksilver Resources Inc. completed an eight-well pad on its 130,000 net acres in the Horn River Basin in British Columbia to assure its production commitments to midstream facilities from the Klua and Muskwa Horn River shales through 2013.

The company completed five Muskwa and three Klua wells on the pad, with laterals ranging from 1,650 m (5,400 ft) to 2,620 m (8,600 ft) and 16 to 26 fracture stages per well.

Although the wells are on restricted production, according to a September 2012 presentation, they tested at flow rates between 23 MMcf/d and 34 MMcf/d of gas. At that time, three wells were producing to treatment facilities at a combined rate of 73 MMcf/d. The pad has the capacity to produce more than 150 MMcf/d.

By year-end 2011, Quicksilver had booked 99 Bcfe reserves from a resource potential of 10 Tcf.

Quicksilver also formed a 50-50 partnership with Kohlberg Kravis Roberts (KKR) in the area in December 2011. Under that agreement, Quicksilver contributed a 20-in. pipeline and compression capacity and KKR paid in $125 million. The partners agreed to build a $120 million, 150-MMcf/d gas treatment plant.

The agreement also gave Quicksilver the option of being carried for 50% of capital costs in return for a preferential payout to KKR.

Royal Dutch Shell Plc

- Has multiple operations throughout Canada
- Holds a 40% interest in LNG Canada

Royal Dutch Shell Plc has multiple operations throughout Canada, and its shale activities offer a substantial benefit in present profits, future operations, and potential.

On the present profits side of that equation, Shell's Groundbirch Montney siltstone-sandstone-shale operation in British Columbia hosts more than 300 wells, five natural gas processing plants, and more than 900 km (560 miles) of pipeline.

The company's wells produced approximately 170 MMcfe/d in mid-2012.

Recent drilling concentrates upstream activity on pads containing up to 26 wells, with two pads per 8 sq km (3 sq miles) of land, according to Shell's website. The company produced from 50 of those pads by June 2012.

Shell acquired Groundbirch in its 2008 acquisition of Duvernay Oil Co. for CAN $5.9 billion (US $5.7 billion at that time). The purchase included 450,000 acres of Montney land at Groundbirch in British Columbia and additional property in the Deep Basin in Alberta.

The company has 375,000 acres of Deep Basin properties in two fields in west-central Alberta that produce 140 MMcfe/d. Although the company did not break out the producing formations in this stacked-pay area, the Grande Prairie and Edson areas produce from the Montney for other operators.

On the future operations side of its ledger, Shell holds a 40% interest in LNG Canada, a new system – announced in May 2012 – that will follow the Kitimat LNG project in bringing gas from the Western Canadian Sedimentary Basin to Kitimat on the west coast for export as LNG to foreign markets.

Mitsubishi Corp., Korea Gas Corp., and PetroChina Co. Ltd. each have a 20% share of that project. With low gas prices in North America, gas from Canadian shales could command higher prices in foreign markets.

PetroChina also acquired a 20% interest in Shell's Groundbirch development program.

LNG Canada will start operations with two trains, each able to produce 6 MMtonnes of LNG a year, and the partners have the option to expand the system in the future.

Shell displayed its interest in the potential of Canadian shales with a June 2012 announcement that it had farmed in to a deal with MGM Energy Corp. Under that agreement, Shell will fund drilling and completion of up to two wells into the Canol Shale oil play in the central Mackenzie valley to earn a 37.5% interest in MGM's exploration license in the area.

The first well depends on regulatory approval, but it could be drilled as early as winter 2012 to 2013.

After drilling the first well – a vertical well – Shell has the option of drilling a horizontal well to earn an additional 37.5% of the license area.

MGM will take over operations after Shell completes the wells. When Shell earns its 75% interest after the second well, it will become operator of the land and the wells.

Storm Resources Ltd.

- Prime target is Umbach liquids-rich Montney properties
- Plans to develop Horn River Basin Muskwa, Evie, and Otter Park shales

Storm Resources Ltd. started operating in August 2010 after the sale of Storm Exploration Inc. to ARC Resources Ltd. The new Storm kept 117,200 net acres of land in the Horn River Basin, Umbach, and Cabin/Kotcho/Junior area of British Columbia; undeveloped land in the Red Earth area of Alberta; and shares of stock in four other companies.

Growing from that point, the company currently plans to concentrate its efforts on two large resource plays. In the near term, the company's prime target is increasing production from its Umbach liquids-rich Montney properties, where it holds 55,000 net acres and produces 700 boe/d, according to a September presentation. The company has four gross (2.4 net) wells on production. The company planned to complete its fifth horizontal well in October 2012 and was moving to drill the sixth horizontal well.

In the longer term, the company plans to develop Horn River Basin Muskwa, Evie, and Otter Park shales. The company holds 87,700 net acres in that basin and produces 400 boe/d. The company drilled two vertical and two horizontal wells in the area to confirm commerciality, but completion of its second horizontal wells depends on gas prices in the area.

Additional properties include the Grande Prairie area, with 36,200 undeveloped acres and production of 1,500 boe/d, and the Cordova Basin, where the company controls 5,900 net acres with no production.

The Grimshaw area in Alberta produces 375 boe/d from the Montney Formation. The company started a waterflood in the formation in August 2012. The company also has four to six infill locations to drill at Grande Prairie for Montney light oil.

Strongbow Resources Inc.

- In Saskatchewan, company targeting the Dodsland area
- Has four sections of land in the Compeer area

Strongbow Resources Inc. drew a bead on the Viking play in two areas, one each in Alberta and Saskatchewan.

In Saskatchewan, the company's target is the Dodsland area, while it looks for Viking oil in the Compeer area of western Alberta.

The company chose the Compeer area because it could assemble a large block of land, and that concentration can create operating efficiencies in a large-scale operation and lower geological risk. Strongbow has four sections of land in the Compeer area.

According to a September 2012 presentation, Strongbow assumes it can recover 2.9 MMbbl of oil per section, with up to four wells per section. The company also assumes production of 2.9 Bcf of gas per section with the same well count.

In addition, the company's first Compeer area well showed a full Bakken section, and the company planned to core and test that formation for petroleum potential.

The company's Big Lake Compeer 5-29-33-2W4 offered a high enough oil cut that the company planned in August 2012 to put the well on pump.

Surge Energy Inc.

- Prime Doig property is Valhalla South in western Alberta
- Latest well at Valhalla South gave a 30-day average of 1,570 boe/d

Surge Energy Inc. holds land throughout the Western Canadian Sedimentary Basin and into the Saskatchewan, Montana, and North Dakota segments of the Williston Basin. The company is still looking for higher profits and increased production from the Doig, Nordegg, Montney, and Duvernay zones.

The company's prime Doig property is Valhalla South in western Alberta. The company calculates 15 MMbbl of light oil in place (99 MMbbl net) and gets a 180% rate of return on its drilling activities in the area. That translates to payout in 9.6 months.

So far, the company has recovered less than 4% of the oil in place at Valhalla South, according to a September 2012 presentation. The company calculates it can recover 9.9 MMbbl, or 10%, under primary recovery techniques, and another 9.9 MMbbl under secondary recovery.

Surge drilled 11 gross (10 net) wells at Valhalla South and has another 28 gross (19.9 net) wells remaining to be drilled.

The company's latest well at Valhalla South, completed in 2Q 2012, gave it a 30-day average of 1,570 boe/d. The company planned to drill two gross (1.25 net) horizontal multifracture wells in the area in the second half of 2012.

Since the company acquired the property in 2010, it raised production from 725 boe/d to more than 4,000 boe/d.

The company recently bought an additional 3.75 net sections of land at Wembley, a township south of Valhalla South, to add another 18 MMbbl of petroleum initially in place in the Doig. That addition gives the company room for six more horizontal, multistage frac wells. The company plans to drill five gross (3.13 net) wells on the Wembley property.

Surge also acquired 131 acres in the Goose River area of western Alberta with nearby production from Montney, Duvernay, and Nordegg. That property is in the early evaluation and delineation stage.

Talisman Energy Inc.

- Holds 144,000 prime net acres in British Columbia
- Signed two agreements in a JV with Sasol to develop the Montney

Talisman Energy Inc. exercised its commitment to shale operations by taking substantial positions in some of Canada's highest-potential shale plays.

The company holds 144,000 prime net acres in British Columbia, where it is developing the Montney Shale at the Greater Cypress, Greater Groundbirch, Cypress A, and Farrell Creek areas.

The company held 2,600 net well locations with 12 Tcf of contingent gas resource in its Cypress Creek area and another 1,300 net well locations with 7 Tcf of contingent gas resource at Greater Groundbirch.

In addition, the company signed two agreements in a joint venture with South Africa's Sasol to develop the Montney. The company sold a half-interest to Sasol in its Farrell Creek area for approximately CAN $1 billion (US $1.02 billion) and a half-interest in its Cypress A area for approximately CAN $1.1 billion (US $1.12 billion) in 2011. Both agreements involved upfront payments and commitments to fund future development costs.

The companies also started a feasibility study for a gas-to-liquids plant in Western Canada. That study was supposed to be completed by mid-2012, but no details have yet been released.

The Farrell Creek and Cypress A joint venture areas contain an estimated 10 Tcf in contingent resources in 1,800 well locations. Currently, the companies are delineating their holdings at Cypress A.

During 2012, Talisman estimated its shale production at 60 MMcfe/d to 75 MMcfe/d. The company had three rigs working in the second half of 2012.

In the greater Edson area of the Deep Basin in Alberta, Talisman held 230,000 net acres with Cardium potential, 150,000 acres with Wilrich potential, and 15,000 acres in the conventional area of the Montney play. That 700,000-net-acre area held 1,900 locations and 880 MMboe in unrisked prospective resources from all of its stacked formations.

Talisman also started a pilot program in the Duvernay Shale in Alberta in its North and South areas, containing a total 360,000 net acres. The company drilled wells to the formation by July 2012 and planned to drill three more in the second half of the year. By year-end, the company anticipated four producing wells.

The company's 753,000 net acres in the Utica/Lorraine Shale play in the Quebec Lowlands currently is under a regulatory halt until 2013. The company's St. Edouard horizontal well, drilled before the regulatory halt, tested for 5.3 MMcfe/d.

Tamarack Valley Energy Ltd.

- Drilled two Cardium oil wells in its Lochend area of Alberta
- Planned to drill six to eight additional Viking wells starting in October 2012.

Tamarack Valley Energy Ltd. works the Cardium and Viking formations in Alberta.

At the company's Garrington Cardium location, it drilled two horizontal wells in 2Q 2012 and completed both with slickwater, 18-stage fracture treatments. The company completed the wells for approximately CAN $2.85 million (US $2.91 million) each, well under the budgeted CAN $3.9 million (US $3.98 million).

One well tested for 545 b/d gross (294 b/d net) and 615 Mcf/d gross (332 Mcf/d net) of natural gas. The other started production at 404 b/d gross (206 b/d net) and 292 Mcf/d gross (149 Mcf/d net) of gas restricted by lifting equipment.

The company drilled two Cardium oil wells in its Lochend area of Alberta in 3Q 2012 and planned frac treatments on both wells. One well, drilled early, has produced more than 31,000 bbl of oil.

Tamarack drilled four gross (3.7 net) shallow Viking oil wells in the Redwater area in 2Q 2012 on land acquired from Exchoex in April 2012. Those wells gave the company a combined average production of 360 b/d gross (335 b/d net) during the first 30 days on production. The wells produced a cumulative 31,600 bbl of oil between June and September. The company planned to drilled six to eight additional Viking wells, starting in October 2012.

Tourmaline Oil Corp.

- Produces 38,000 boe/d from 1,800 sections in the Deep Basin of Alberta
- Plans to be fifth-largest producer from the Montney in Western Canada by second half of

Tourmaline Oil Corp. produces 38,000 boe/d from 1,800 sections of land in the Deep Basin of Alberta, with production from Cardium, Wilrich, Viking, and conventional zones. The company also has Montney production in Alberta and British Columbia.

The company plans six rich-condensate horizontal wells to the Cardium in the second half of 2012 and into 2013, according to a September 2012 presentation.

In the same period, the company anticipates drilling 25 to 30 Wilrich wells in the Edson, Lovett, Banshee, Resthaven, Wroe, and Wild River areas, where it holds 760 sections with 1,520 locations. One of the company's Wilrich wells tested for 20 MMcf/d of gas and another for 15 MMcf/d of gas and 50 b/d of condensate.

The company drilled 51 Montney horizontal wells on the Peach River High from 2010 through 1Q 2012 and has more than 500 locations in the area.

At the company's Sunrise/Dawson Montney/Doig area in northeastern British Columbia, it produces 70 MMcf/d to 75 MMcf/d of gas and 2,000 b/d to 2,500 b/d of condensate and liquids. The company drilled 48 horizontal wells through April 2012 and completed 41 of those wells at an average rate of 8.14 MMcf/d of gas and 231 b/d of liquids and condensate. The company planned 15 to 20 horizontal wells from its 300-well inventory of drill sites during 2012. The company has one gas plant in the area.

Tourmaline plans to be the fifth biggest producer from the Montney in Western Canada by the second half of 2013.

The company earns a 34% rate of return on its Montney wells in Alberta and a 69% rate of return from its British Columbia Montney wells.

The company also counts a handful of emerging E&P plays. Tourmaline has 500 locations and plans to drill two to three wells at its Outer Foothills Cardium play in Alberta.

Farther south along the foothills, the company drilled three high-rate vertical wells to the Wilrich. The company plans to drill one to three wells from its 150 locations in 2013.

The company drilled three horizontal wells in the emerging Upper Montney gas condensate play at Elmsworth and plans two more in 2013 and 2014. The company has 200 locations in the area.

The company also has 85 sections of Montney rights in the Resthaven/Smoky area of Alberta. It plans two horizontal wells in that area in 2013. ■

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Unlocking Canadian Tight Oil Plays

Improved technologies and drilling efficiencies are driving unconventional resource development in several Canadian plays.

By Jerry Greenberg
Contributing Editor

Technology lies at the crux of understanding a formation's characteristics and ultimately designing the optimal completion designs, fracture fluid formulas, and shale stimulation strategies for developing unconventional resources. Perhaps nowhere is this truer than in Canada's unconventional and shale formations.

The Duvernay Formation has deep reservoirs with high temperatures and pressures as well as a thermogenic aspect, all of which results in a very complex formation that can be difficult to exploit. A large piece of the Duvernay play, for example, needs fracturing equipment rated for 15,000 psi pressures.

Meanwhile, a very different play is developing in the Cardium Formation, where an economic field redevelopment is taking place thanks to new technology. Although operators have been drilling and producing in the Cardium Formation since the 1950s, they are beginning to exploit the halo around the core-producing areas, which is challenging. Exploitation strategies and completion designs are evolving as the industry begins to understand these halo areas while drilling and designing the appropriate completion systems. The same can be said of areas in the Montney and Exshaw formations.

Mineralogy services

"One tool that we have developed to exploit tight shale plays is the Formation Lithology eXplorer (FLeX) elemental spectroscopy wireline logging tool," said Grant Ferguson, technical support manager, Wireline Systems for Baker Hughes in Canada. "It is the first pulse neutron spectroscopy tool designed to operate in openhole environments for that purpose. It quantifies certain elements present in the formation and allows for the interpretation of the rock's mineralogy."

The wireline logging tool is the only one in the industry that directly measures carbon, according to the company. Once the carbon is apportioned into each mineral's composition to satisfy chemical stoichiometry, any excess carbon measured by the tool is quantified into either total organic content (TOC) or liquid hydrocarbons.

The wireline logging tool uses both capture and inelastic neutron spectroscopy to measure and quantify elements such as hydrogen, carbon, silica, oxygen, magnesium, and iron. From the chemistry data gathered by the logging tool, geoscience interpretations are performed by the company's RockView service, which begins by computing a general lithology and then breaks that into specific lithologies. From that point, it can analyze and quantify mineralogy, such as carbonate minerals like calcite and dolomite.

The company is developing additional measurements for the services. For example, when MReX, the company's nuclear magnetic resonance service, is used with the FLeX services and bulk density, an independent secondary TOC measurement can be taken.

Openhole completion system

The FracPoint multistage fracturing system is the company's openhole completion technology used in Canadian unconventional and shale formations.

Short radius openhole packers and fracturing sleeves isolate intervals in horizontal wells to better target fracture treatments. The system also can use the company's REPacker openhole packer, which is a self-energizing swelling elastomer packer. The system works when a reaction with wellbore fluids causes the rubber element of the packers to swell.

Coiled tubing fracture stimulation

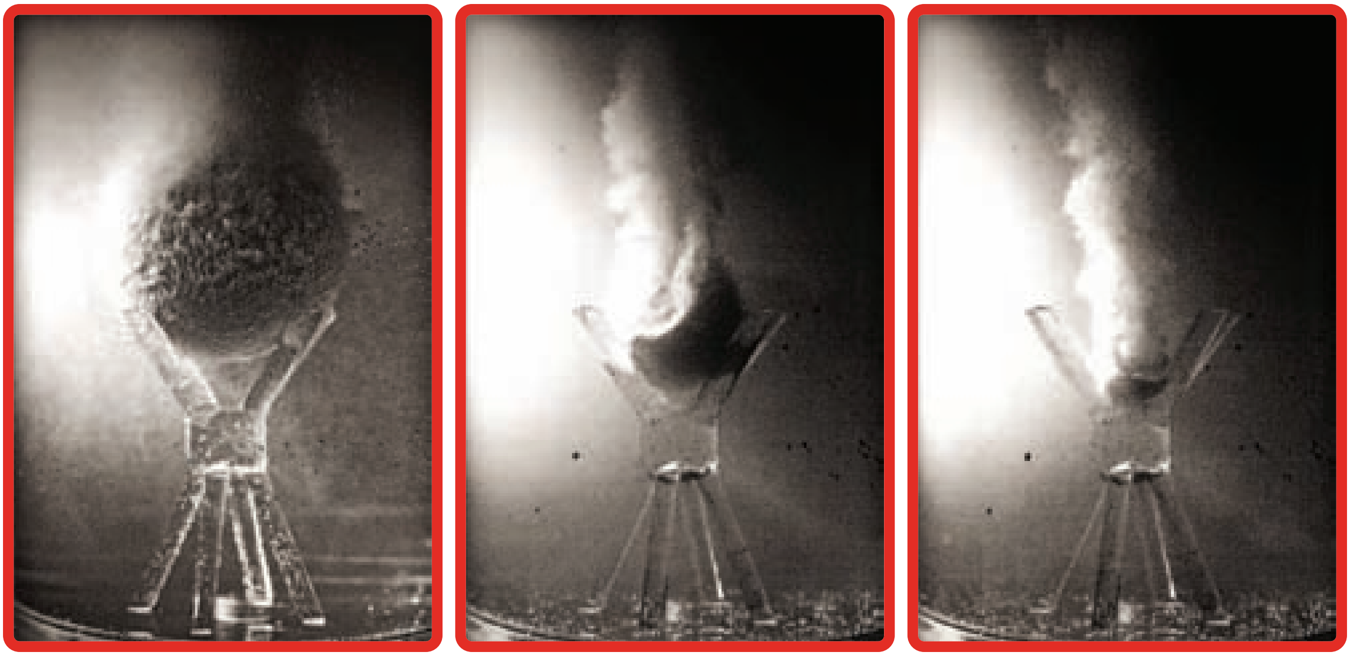
One fracturing method used in Canada with success is the company's OptiPort coiled tubing fracturing system. The company brought it to the US in 2011. The technology uses the annulus coil tubing fracturing method. In Canada, the cemented-in sliding sleeve tool allows the service company to pump the fracturing fluid and proppant into an isolated formation. Another feature is the ability to circulate sand out of the well in the event of a sand-off, minimizing delays.

The OptiPort system uses sliding sleeves like those found in ball-drop systems; however, the sleeves are cemented in and opened by the SureSet packer assembly rather than sequentially sized balls. The fracturing process occurs down the annulus between the casing and the coiled tubing, ensuring that the well is isolated from the previous zone. Because the fracturing fluid is pumped down the annulus, lower pumping horsepower is required. This allows for a virtually unlimited number of stages and leaves the coiled tubing in the well to perform a quick cleanout if required after a screenout.

Disintegrating fracturing balls

Baker Hughes developed fracturing balls that are lighter and stronger than those made of phenolic or fiber glass resin material, but the significant difference is that the IN-Tallic fracturing balls disintegrate when exposed to brine or acid solutions. This eliminates the risk of balls not being produced back to surface or remaining on corresponding seats, which could result in lost production. The fracturing balls can be used with the FracPoint completion system.

Disintegrating fracturing balls are composed of controlled electrolytic metallic nanostructured material that is lighter than aluminum and stronger than some mild steels. The disintegration process works through electrochemical reactions controlled by nanoscale coatings within the composite grain structure. The rate of disintegration depends on temperature and the concentration of the brine. Acid will disintegrate the balls at a much faster rate, allowing the flexibility to pump acid on the ball



IN-Tallic disintegrating fracturing balls are lighter and stronger than those made of phenolic or fiber glass resin material. The significant difference is they disintegrate when exposed to brine or acid solutions as shown here. *(Image courtesy of Baker Hughes)* after the fracture is complete. It will not disintegrate in an oil-based or neutral solution.

"We are seeing a growing interest in our IN-Tallic fracturing balls," said Marc Carriere, Canadian product line manager for Completions with Baker Hughes. "More operators are considering running these tools to avoid having to immediately drill out the ball seats and at the same time increasing the confidence of production from each interval."

New cutter technology

The company recently introduced a new technology in its cutting structures called Advanced Metal Muncher Technology (AMT). "The type of cutter we use is called the Glyphaloy," Carriere said. "It is designed carbide used to form cutting structures. They are stronger and made of higher grade carbide than others currently available.

"These cutters are milling out up to 40 composite plugs in one run," he said, "which limits fluid exposure to the formation and improves operating efficiencies."

The cutters are engineered using pressed sintered tungsten carbide available in a variety of shapes and metallurgies. A milling tool can include several types of AMT cutters to optimize various aspects of the milling operations. The self-sharpening cutters are designed to mill high chrome and nickel-content materials. The technology increases milling penetration rates, extends effective time on the bottom in high-volume milling applications, and enables greater flexibility during the milling process, the company said.

Advanced Metal Muncher Technology uses pressed sintered tungsten carbide and has milled out up to 40 composite plugs in one run. *(Image courtesy of Baker Hughes)*

Operators have reported as much as a 300% improvement in wear resistance and longevity with the inserts, according to the company. In North Dakota, for example, an AMT mill successfully milled out 79 composite plugs in two horizontal wells in one trip per well, achieving a new record for fracturing plug removal, the company said on its website.

Openhole technology

Exploration and development of the Montney and Cardium formations have been ongoing the past five years. The Duvernay and Exshaw formations have only been attracting interest for the past 12 to 18 months as far as drilling and completing horizontal laterals. Calgary-based Packers Plus has been active in each formation because of its openhole completion designs and equipment.

The Exshaw is the least explored of the four formations, and information is held tight by the operators for the most part. The formation is considered to be very complex because it is close to the Canadian Rockies with different layers and depths. "The geology repeats as you drill," said John Zukowski, Canadian sales manager for the company. "Sometimes you drill the same section four times. Still, there aren't many drilling issues, but there are a lot of issues with formation stress and subsequent stimulation."

The company has been working in the Montney since 2007, but activity really took off in 2010 with a doubling of the number of wells over 2009. The company saw a continuing upward trend in completions since then, completing 775 openhole horizontal laterals as of the end of July 2012. The numbers are even higher in the Cardium Formation. The company became active there in 2007 and by 2010 completed six times the number of wells it completed in 2009. Activity in the Cardium continues to increase each year, with the company completing 950 openhole horizontal lateral wells as of the end of July 2012.

With much less drilling and completion activity in the Duvernay and Exshaw formations, the company completed fewer than 50 openhole horizontal lateral wells in these formations as of July 2012.

"We are seeing a trend in all four of the areas with operators trying to complete more stages," said Mike Kenyon, Technical Sales for Packers Plus, "partly because our technology has advanced to allow for higher stage numbers, but also because operators see better results with longer laterals and a higher density of fracs."

For example, the company is pumping as many as 30 stages in both the Duvernay and Montney, with an average of 16 stages in the Montney and 22 in the Duvernay.

"We worked with an operator on a study comparing plug and perf completions to open hole (in the Montney) and found that openhole results in about 36% more cumulative production after a 12-month period on average," Kenyon said. "It was an incentive for operators to move to open hole for a significant cost savings, but even more so because of the production comparisons."

Operators are mainly running 15,000 psi high-pressure tools through the Duvernay just below the Montney, Kenyon said. The company is typically running its StackFRAC and QuickFRAC Titanium XV high-pressure systems. All Packers Plus systems as well as the SF Cementor are available in Titanium XV 15,000-psi-rated versions. In addition, the systems are modular, enabling operators to customize the system design to deliver the desired stimulation program by combining technologies such as the StackFRAC and QuickFRAC systems.

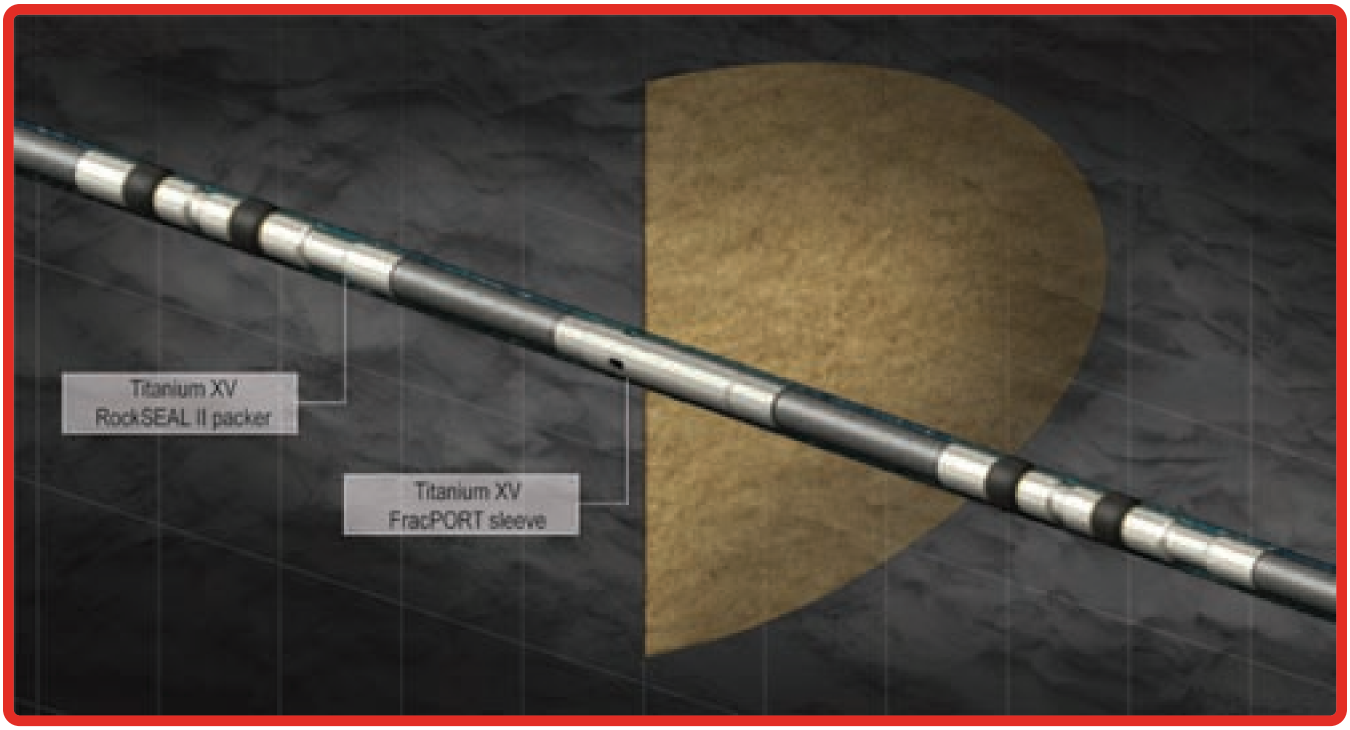
"The trend for the horizontal sections was plug and perf in the beginning until the operator better understood the formation's characteristics," Zukowski said. "However, the cost [for plug and perf] for the initial wells was about 70% higher than openhole completions."

Cardium Formation the most active

In the early stages of developing the Cardium Formation, Packers Plus would set casing down to 90° and then run liners. Adopting experience gained in the Canadian Bakken, operators would begin with 15- to 17-stage completions in the lateral, but that has evolved over the years with many operators now averaging about 20 stages and some operators experimenting with longer length laterals and stage numbers up to 40.

"The other trend is toward openhole monobore well construction," Kenyon said, "especially on the west Pembina side of the formation where operators will set 4½-in. casing from surface to toe and cement the heel and vertical section, leaving the lateral section uncemented with StackFRAC equipment.

"Initially the fracs used oil-based fluids because most operators were worried about pumping a



One stage of a Packers Plus StackFRAC Titanium XV system for HP/HT completions. *(Image courtesy of Packers Plus)* water-based frac, but that also has changed," Kenyon said. "We started out using foam fracs, and now almost everyone is using a slickwater frac with 10% to 20% nitrogen."

About 90% of the wells drilled into the Cardium Formation are completed openhole, according to the company. The formation ranges from 1,400 m to 2,100 m (4,600 ft to 6,800 ft) true vertical depth. "The comfort level of openhole at that depth was very high," Zukowski said, "and operators wanted the efficiency of openhole completions."

Openhole completion systems

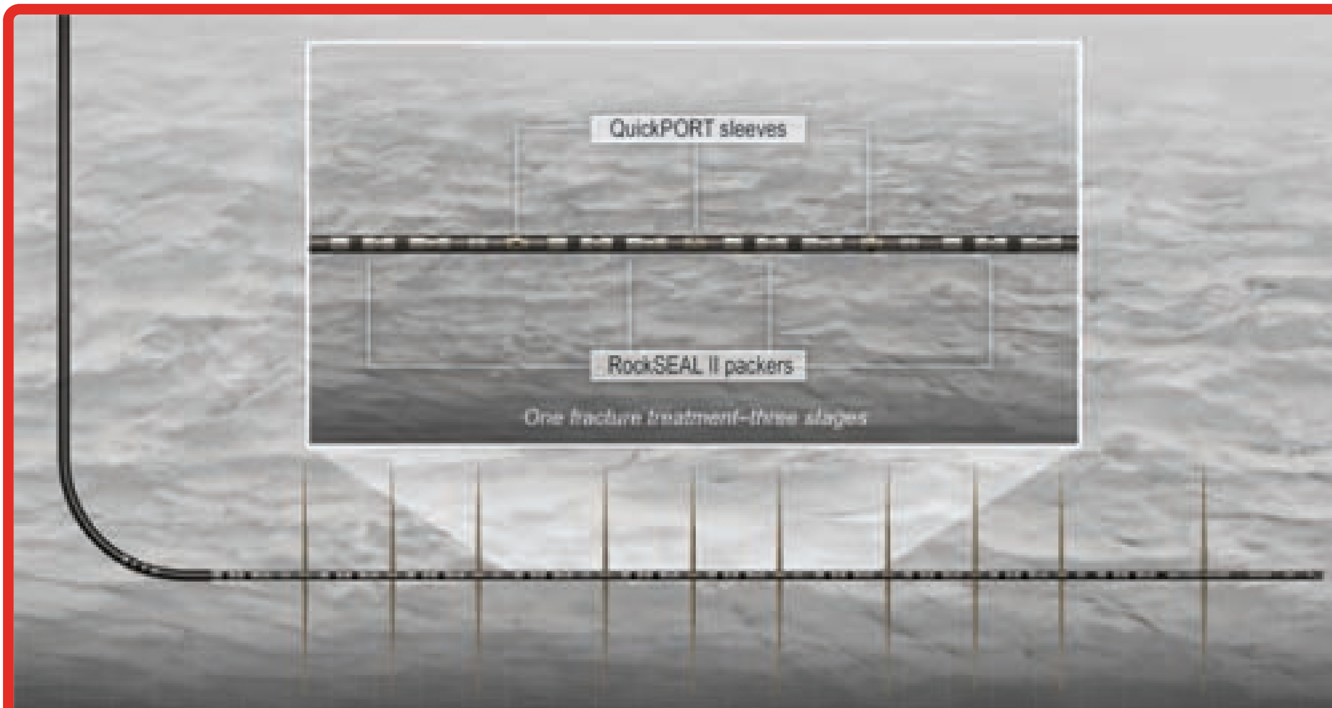
The company's QuickFRAC system is capable of fracturing 60 stages while pumping only 15 treatments at surface, according to Packers Plus. Using limited entry diversion techniques, the system allows the operator to fracture several isolated stages at one time through a batch fracturing method. For each treatment zone, the system includes a number of QuickPORT sleeves flanked by RockSEAL II packers, which creates multiple, individually isolated stages within a single treatment zone.

The appropriate size ball is inserted into the string and pumped down onto the seat. The tool string is pressured up to activate and open multiple QuickPORT sleeves to allow stimulation fluid to flow into the annulus. A variety of ball sizes are available, allowing multiple rounds of fracture treatments to be run in sequence. After the stimulation is completed, the balls can be flowed back.

SF Cementor

The SF Cementor, a stage collar developed by the company and used with any of its openhole completion systems, eliminates the need for intermediate casing, resulting in significant reductions in well construction costs. The tool is hydraulically activated and designed to close without the use of a plug or dart, reducing post-cement cleanout operations and lowering the likelihood of issues associated with debris in the completion system.

The tool is assembled in the completion string above the openhole stimulation system. When the packers are set, the tool string is pressured up to hydraulically open the tool. Once the cement is pumped, it is displaced with a high viscous pill and



Packers Plus QuickFRAC multistage batch fracturing system enables simultaneous stimulation of multiple stages with a single fracture treatment at surface. *(Image courtesy of Packers Plus)*

spacer fluid, eliminating a wiper plug operation to clean out the casing and the potential challenges associated with drilling out a plug. When the cementing operation is complete, the tool is mechanically closed and locked by applying compression on the tool to isolate the ports.

The efficiencies of the stage collar were tested by a major operator in multiple field trials in the lower Montney, cementing back 17 wells completed with 12- to 14-stage StackFRAC systems. The stage collar was run at an average depth of 2,650 m (8,700 ft) and the tools were landed between 45° and 90° from the vertical. Since then, the operator has cemented back more than 100 wells with 12- to 25-stage StackFRAC systems.

In one well, the tool was run in the Montney and landed at 3,160 m (10,380 ft)and 56° from the vertical. A 15,000-psi-rated stage collar was run above a 14-stage StackFRAC Titanium XV HPHT system. The stage collar was opened at 2,750 psi and cement was placed in the annulus followed by a viscous pill and spacer fluid to displace the cement from the liner. The tool was closed using set-down compression in a single attempt and only one drill-out trip was performed.

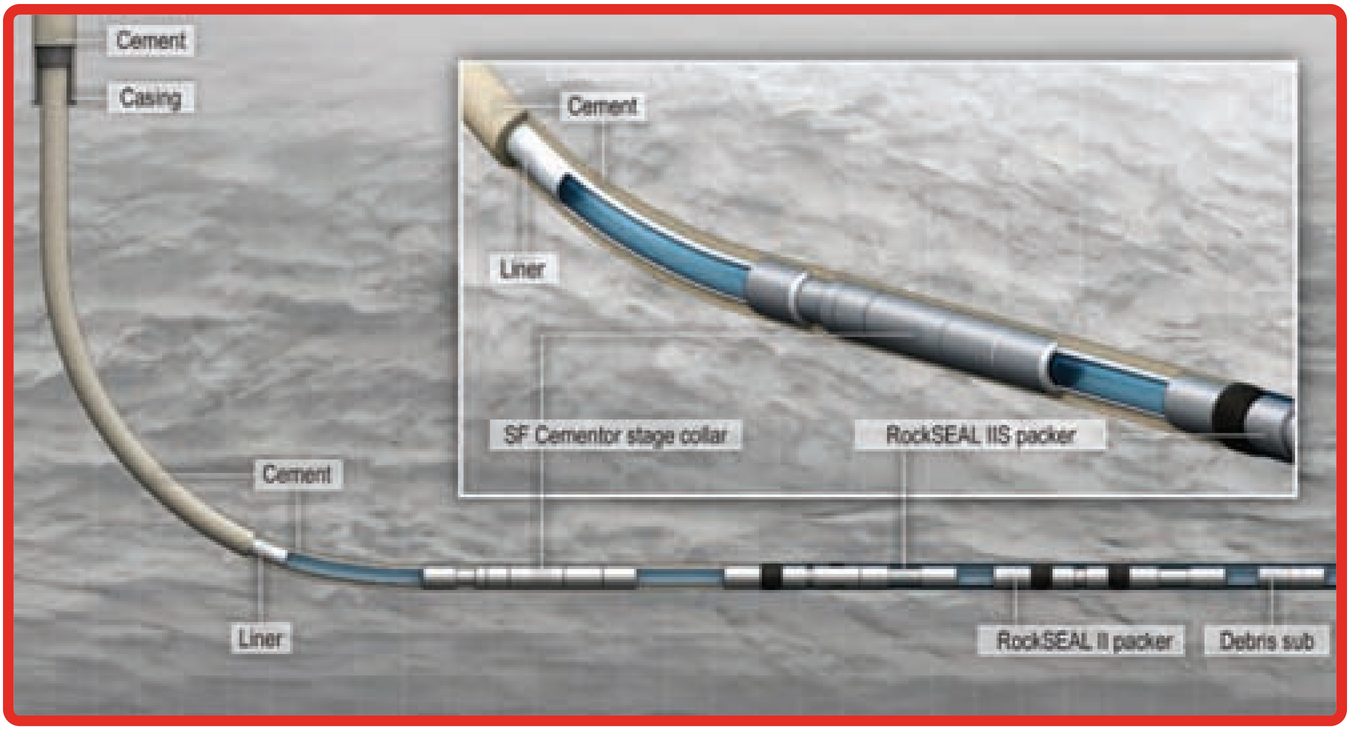
Geomechanics, stimulation modeling, and flow channel hydraulic fracturing

"Unconventional reservoirs need out-of-the-box thinking," said Stan Cena, Canada TerraTek operations manager, Schlumberger. "They need integration with other segments to leverage as much information and data from the rock in designing the programs that will deliver a successful completion."

TerraTek rock mechanics and core analysis services measure reservoir quality and completion quality. "The reservoir quality looks to how much hydrocarbon is in the reservoir, where it is in the reservoir, the permeable porosity, and saturation," Cena said. "The completion quality speaks to the geomechanic properties."

Services include geomechanics testing for assessment of reservoir geomechanical properties; hydraulic fracture testing, providing simulation for effective fracturing; and core geology and petrographic analysis for describing rock fabric, which goes into fluid flow and how the rock will fracture during stimulation.

"Operators are using a certain amount of science in all of their wells," said Timothy Pope, Stim-



Components of an openhole cemented-back monobore StackFRAC system completion are shown. *(Image courtesy of Packers Plus)*

Geoscientists validate a core-to-log correlation for classifying heterogeneous rock types. *(Photo courtesy of Schlumberger)*

ulation Domain manager, Canada, Schlumberger, "although less science in the Cardium completions than in the emerging plays, the Duvernay and Exshaw, which tend to be more complex than a lot of the plays."

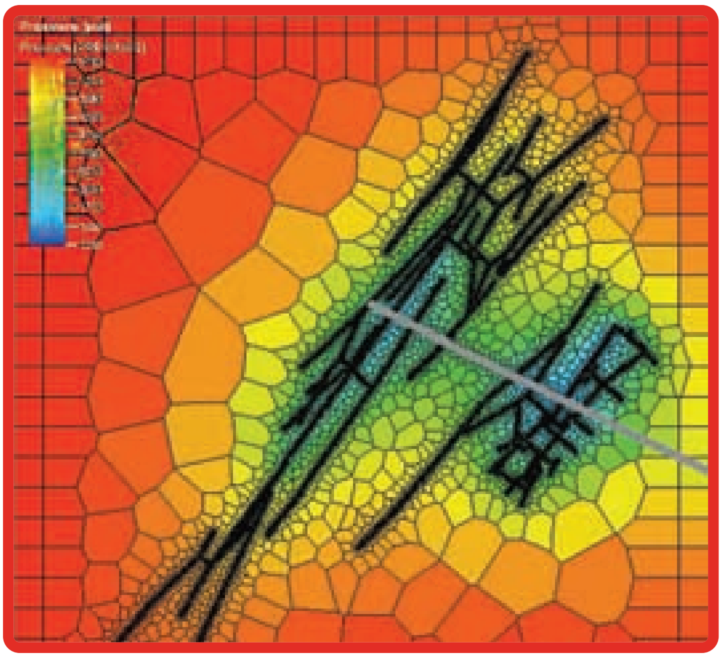
One of Duvernay's challenges is fracture containment. "We can create a fairly large fracture height," Pope said. "If we pump slickwater treatments we are going to have a nice conductive bed of sand in the bottom 20 m to 30 m [66 ft to 98 ft] of the fracture.

"We are now pumping hybrid treatments, beginning with slick water in the beginning of the stimulation followed with crosslink fluids at the end of the treatment," Pope said, "giving better vertical proppant distribution so we stimulate the entire height of the Duvernay."

There are similar challenges in the Montney Formation, he said. This formation can have frac heights twice the size of what is experienced in the Duvernay, which makes it important to assure vertical proppant distribution. "We have done some hybrid treatments in Montney that have been very promising," Pope said. "We pump slickwater treatment in a continuous operation followed by our HiWAY flow-channel fracturing service. In the last 12 months, we have pumped the HiWAY service in 11 different reservoirs."

The Cardium is an older field where poorer qualities on the edges of the field presently are being exploited through horizontal completion technologies, Pope said. The company has been fracturing the Cardium with its flow-channel service. The technique requires about 40% less proppant than a conventional fracturing treatment and about 25% less water on average.

With the flow-channel technique, proppant works as a supporting agent to prevent closure within the channels rather than as a conductive media as in the case of conventional treatments. Fracture performance becomes independent of retained proppant pack conductivity. The open



Unstructured gridding of complex hydraulic fracture shows production simulation pressure depletion over 30 years. *(Image courtesy of Schlumberger)* channels extend from the near-wellbore area to the tip of the fracture, significantly increasing the effective fracture length. The channels are created within the proppant pack through a patented technique that combines a pulse pumping procedure, perforation scheme, and fiber technology.

Reservoir stimulation modeling

The company's Mangrove reservoir-centric stimulation design software enables an integrated workflow in reservoir characterization to understand unconventional reservoir heterogeneity. It functions as a plug-in for the Petrel E&P software platform, allowing close integration with geoscience and engineering asset teams. Completion and stimulation models can be calibrated using microseismic measurements in the context of local geology and structure. The calibrated model then is represented in a production model for forecasting and optimization. Field production data are used to calibrate the production model. An operator can determine an optimal number of perforation clusters, design fewer stages if the right spot to fracture (based on laboratory measurements calibrating log measurements) is determined, and pump the right size job rather than going for the biggest job possible. The software also can work efficiently if an operator wants to maintain the number of stages while gaining a production improvement.

"Mangrove provides the opportunity to model complex fracture networks as well as proppant transport within these networks," Pope said. "This becomes extremely important when the well's conductivity is coming from where there is proppant.

"We can take this complex hydraulic fracture network and grid it directly into our reservoir simulator to perform production predictions as well as treatment optimization," he said.

A completion advisor is one of the software's key elements. It provides an optimal way of placing the perforations and grouping them in a stage by providing automated workflows for specific well orientation. There are separate advisors for tight sands and shale.

The Mangrove software provides rigorous and repeatable solutions for optimizing staging and perforation design, the company said. The staging algorithms are linked to fit-for-purpose hydraulic fracture models ranging from Pseudo3D to the newly developed complex fracture models, the UFM unconventional fracture model and Wiremesh. The complex fracture models are specifically developed for simulating non-planar complex fractures applicable in naturally fractured reservoirs commonly found in shale.

"The field is a very, very expensive laboratory," Pope said. "The Mangrove workflow allows us to perform complex optimizations that reduce uncertainty."

Fracture fluids in Canadian unconventional formations

Exploration in the Montney and Cardium plays in Alberta has been ongoing for about 50 years in the Cardium. However, in each of these plays, horizontal drilling has been taking place only in the last five to six years. Today, much of the drilling taking place in these two formations is developmental, with pad drilling that could contain as many as six wells.

In the less developed Duvernay and Exshaw formations, operators are taking their time in order to understand them. As a result, Exshaw is experiencing little activity, and Duvernay only slightly more. "Six months ago there was a big push to see what the Exshaw contains and how [operators] were going to complete the different wells," said Greg Henderson, technical manager, Acid and Fracturing Services for Trican Well Service.

Among other things, operators discovered that the Exshaw contains poorer quality rock than found in the eastern portion of what sometimes is referred to as the Alberta Bakken. The situation makes it more expensive to drill, complete, and stimulate. Part of the higher cost is because of drilling and completion services not being readily available due to the remoteness of the play, according to Henderson. Also, the Exshaw is a deeper formation than most in Alberta, which also creates certain issues, and water supply for fracing is scarce because "it's like a desert down south," he said.

"The service companies would come if the rock quality was there," said David Quirk, technical manager, Unconventional Resources for Trican. "It really begins with the reservoir quality, but all of the other challenges aren't helping the situation."

Trican fracturing operation with frac pumpers is shown. *(Photo courtesy of Trican Well Service)*

The Duvernay is a fairly complex reservoir, and a lot of operators were comparing it to the Eagle Ford because of its liquid content. "We are finding it difficult to fracture and are approaching the Duvernay with a similar design as found in the Eagle Ford," Henderson said. "It's not all slick water; we are using some crosslink guar-base fluid for viscosity to place the proppant."

As far as completion design, some operators were using a ball drop openhole system, he said, but those systems add more complexity and cost to the operation when working in the harder-to-fracture formation. "The industry generally is moving toward the plug and perf method," Henderson said. "We can pump higher rates down larger diameter casing and it becomes easier to work in higher pressure formations as well."

Trican stimulated fewer than 10 Exshaw wells due to the slowdown in drilling and completion activity in the play. Henderson said operators became somewhat active about two years ago but "it probably didn't take long to find out about the [poor] rock quality."

The Duvernay Formation below the Montney spreads over most of Alberta. The favored frac fluid is a slickwater system with 40/70 natural sand. The Duvernay is in the development stage, and the industry has not yet found the right fracing formula. "We are getting closer every day. We typically are using smaller natural sand and intermediate strength proppants," Henderson said.

Depth of the Duvernay Formation can vary significantly depending upon the area. The farther north of Calgary the shallower it becomes. The formation can vary from 1,200 m to 3,500 m (4,000 ft to 11,480 ft) deep, although most of the exploration and development activity is in the deeper portion of the formation, generally ranging from 2,800 m to 3,500 m (9,200 ft to 11,480 ft) total vertical depth, according to Henderson. The horizontal laterals can be as long as about 1,500 m (4,900 ft) but average about 1,200 m (4,000 ft).

"These days in the Duvernay, we are pumping relatively large slickwater treatments," Quirk said.

In the Montney Formation, the company is fracing with smaller proppant due to its depth. Also, it is a fairly easy formation to fracture, Henderson said, until an operator drills into areas that can be highly faulted. Slick water is the formula of choice in the Montney, with a foam surfactant, depending upon which part of the formation is being worked. There is an Upper and Lower Montney and also a Middle and Middle Lower. Different frac fluids are used in each interval.

Operators in the Cardium recently have been drilling into the tighter portions of the formation with openhole horizontal laterals and multistage fracturing systems. The completion system and fluid formula are dictated by the sensitivity of the rock to the fluids.

"Multistage ball drop systems are used extensively in the Cardium, because it is a shallower play," Henderson said. "We don't see many plug and perf systems in the typical Cardium due to its depths."

The Cardium Formation ranges between 1,500 m to 2,500 m (4,900 ft to 8,200 ft) total vertical depth with horizontal laterals ranging between 600 m to 1,000 m (2,000 ft to 3,300 ft), although some laterals can be as long as 1,500 m (4,900 ft).

Where specifically the Cardium is drilled also dictates the frac fluid type. Trican has pumped slickwater systems, surfactant gels, and foam into Cardium as well as crosslink systems, the latter not as often as the other fluid system options. The company's slickwater systems are trending to high salt-tolerant additives.

Operators in the Cardium and Montney are in the cost-reduction stage, Henderson said. Most operators by now know which fluids they want to use in a particular area. In those cases, it is a matter of reaching the efficiency on multiwell pads to operate in a 24/7 mode with continuous fracing, which can reduce the cost of each frac job.

Trican believes there could be a fourth-quarter slowdown in the pumping business as operators spend their budgets near year-end. The company anticipates a good 1Q 2013 as new budgets are implemented. However, one potential kink could be an excess of pumping equipment: "From the capital build during 2012 that is just wrapping up," Quirk said, "there will be some idle equipment."

Single and multi-array sleeve systems, RFID technology

Weatherford has been active in several Canadian unconventional plays, including, in varying degrees, the Montney, the Cardium, the Duvernay, and the Exshaw. The company is more active in the Montney and Cardium than the other plays with openhole and cemented casing systems. "The Exshaw and Duvernay are in their infancy stage," said Randal Biedermann, sales manager, Completion and Liner Systems for Weatherford in Canada. "Operators are walking into them a little slower with regard to new or advanced technologies, especially in the Duvernay because it is a higher-pressure formation."

Biedermann noted that some equipment components necessary for optimal completion of the Duvernay are not yet available, but the industry is currently field testing applicable equipment. The requirement includes 15,000-psi equipment. There is not a large track record for the high-pressure equipment, he noted, so many operators are choosing to complete the formation with cemented casing and the plug and perf method. "Operators are learning about the reservoir and how it is stimulated before pursuing an optimization method, like a ball drop system," he said.

"As an industry, we are still installing many cemented-in casing strings," Biedermann said. "The technology path typically pursued starts with perforating single intervals, stimulating, and successively isolating with drillable bridge plugs and plug and perf.

The MASS sleeves system can currently segment a maximum of 10 stages, each consisting of five sleeves in a single installation. *(Image courtesy of Weatherford International)*

"The first optimization step would be to move on to a cluster-style fracing and perforating using limited-entry frac technology, where each perforated interval consists of multiple exit points along the formation," he said. "The goal is to eliminate the well intervention operations to minimize the time to stimulate the well.

"Using plug and perf, an operator can readily produce each interval and evaluate the productivity and the effectiveness of the stimulation chosen," Biedermann said. "With a ball drop system we are trying to reduce the time that pressure pumping equipment is on location and minimize nonproductive time once the drilling rig has moved on."

Zone completions

The company has been using its ZoneSelect system in the Montney Formation for nearly four years. The modular completion system enables operators to choose from a variety of sleeve actuation options and zonal isolation methods to create the optimal completion for the particular formation. The method uses sliding sleeves that can be ball drop actuated, mechanically shifted, or pressure activated in the case of the toe sleeve. Zonal isolation is achieved with either swellable or hydraulically activated packers or cement.

The system's sleeves feature up to 40 ball drop sizes that allow segmenting up to 41 zones using 4½-in. casing. The additional zone is accessed by using a pressure-activated sleeve at the toe of the well. A unique feature of the sleeves is their shear rings rather than shear screws or pins, which provide more precise opening pressures and consistent opening pressure indications, the company said.

The system also can be fitted with Multiple Array Stimulation System (MASS) sleeves in which multiple sleeves can be opened with a single ball size. The MASS sleeve groups up to five sliding sleeves per stimulation stage. Opening the sleeves allows a segmented seat to shift into a recess that in turn releases the shifting ball, and the ball continues to be pumped to the next sleeve. This process continues until the ball lands on a solid seat sleeve. The MASS sleeves system can currently segment a maximum of 10 stages each consisting of five sleeves in a single installation, the company said.

In one well in the Montney Formation, an operator wanted to isolate and fracture multiple zones in a 6,130-m (20,111-ft) measured depth horizontal well. The well was kicked off at 1,873 m (6,145 ft). The horizontal section was about 4,000 m (13,123 ft). The well was cased with 4½-in. cemented liner casing.

The ZoneSelect SingleShot sleeves and ARES hydraulic openhole packers were successfully deployed to the total depth of the well. Eighteen sleeves and 22 packers were used to isolate 21 intervals and stimulate 18 intervals. The operator was able to access a significant portion of the formation and realized a well production increase of 25% over an 18-month period, according to the company's website.

Additionally, the company said, the completion system minimized extraneous time and services required to stimulate the well, saving associated rig costs and reducing the overall environmental impact.

Multizone fracturing system

"The company has also acquired a diverter system, the i-ball system, that requires only one ball to activate any number of sleeves one at a time," Biedermann said, "and it is the same size ball for each sleeve.

"We installed a couple of these systems in Canada. They are being pilot-tested here; however, a client in the US has already installed multiple systems and plans to continue using the technology," he said.

The i-ball system requires only one ball to activate any number of sleeves at one time. *(Image courtesy of Weatherford International)*

Traditional ball drop systems for multizone operations require the deployment of balls and ball seats of successively smaller sizes moving from the heel to toe of a well. This contributes to increased surface pressure pumping requirements and can limit the accessibility to the toe of the well in a screenout scenario because the size of coil cannot fit through a seat restriction. In some cases, the operator may sacrifice shorter segmented interval length to minimize the number of sleeves required and thus the smallest inside diameter (ID) seat restriction installed.

The company's new i-ball system can be run as part of the ZoneSelect system. It permits high-rate stimulating at the toe, provides large ID access throughout the well, and eliminates quality control concerns by using only one ball and seat size. The near-drift diameter of the system enables nearly an unlimited amount of zones to be stimulated, and the zones are fractured one at a time. Once stimulation is completed through the sleeve, the seat system then retracts back to a size that is close to the ID of the host tubing. This feature eliminates the need to drill out and allows the large outside diameter activation balls to easily be recovered at surface during flowback. The technology has been tested in openhole and cemented wellbores and is currently rated to 10,000 psi. It can be run in temperatures up to 135°C (275°F). The company said it will be running as many as 100 i-ball systems during the next few months in five wells for a single operator.

RFID technology

The company is advancing its use of radio frequency indentification (RFID) to activate sleeves. "We have undergone numerous field tests and have successfully proven the technology works downhole," Biedermann said.

With RFID technology, an electronic chip is pumped downhole to signal a tool to function as desired. In conjunction with ZoneSelect, the technology eliminates the need for ball, seats, and drilling out. It can be used to function sleeves in a sequence other than toe to heel, the only option with conventional technology. While the use of this technology is new to the oil and gas industry, the company has installed and uses the RFID technology in various downhole applications. ■

References available.

Weaving the Web

Unconventional plays have delivered light oil and rich gas to Canada's midstream sector, which is busy building new facilities and expanding old ones to handle the bounty.

By Hart Energy Staff

Adapted from Hart Energy's North American Shale Quarterly *and* Midstream Business

Western Alberta and eastern British Columbia are enjoying a boom in unconventional resource drilling. At the same time dry, shallow gas areas in eastern Alberta have gone quiet, and coalbed methane (CBM) drilling in central Alberta is down tremendously from years past. This dramatic shift in activity is precipitating an equally dramatic alteration of Western Canada's midstream sector.

Operators wielding horizontal drilling and multistage fracturing technology are delivering fresh volumes of rich natural gas and light oils to market in Western Canada. The most prolific of the new resource plays are the Montney, a rich-gas powerhouse, and the Cardium, a prodigious light-oil producer. Shale plays that show considerable promise, but that are still in early days of development, are the Duvernay and Exshaw (also called the Alberta Bakken). The Cardium and Duvernay plays overlap across much of their extent, and portions of the Cardium also overlap the Montney play. Additionally, vertical, stacked-pay reservoirs in the Deep Basin are contributing to the overall mix.

Of the highlighted plays, the Montney is impacting Western Canada's midstream to the greatest degree. That is because the Montney reservoir, a hybrid tight sand-shale play, yields a bounty of rich gas. The play lies in eastern British Columbia and north central Alberta, with the British Columbia side enjoying particularly brisk action in such areas as Groundbirch, Septimus, and Farrell Creek.

For the Cardium play, Pembina Field is the center of action. The Cardium produces light crude, and horizontal drilling has revived oil production to levels not experienced since the early 1970s. Beginning in 2009, a surge of "new era" wells – drilled horizontally and fraced in multiple stages – has rocketed production from levels that had declined to some 50,000 b/d back to more than 120,000 b/d. A lot of the midstream assets have been in place since the 1950s, and some of the conventional systems are being expanded to handle the new unconventional volumes.

The Duvernay, meanwhile, is a play in its early days that appears to be making good on its promise. Located in central Alberta, the Duvernay covers a vast area and much of its prospective area overlaps the Cardium and Montney plays. The focus of most efforts to date is in the wet gas window, in the Kaybob, Edson, and Pembina areas. Of those, Kaybob is the busiest. Liquids yields are quite good, with wells in the rich-gas window making 75 bbl to 100 bbl of NGL per Mmcf, and also producing significant free condensate.

Development in the Alberta Bakken/Exshaw, located in the southern part of the Alberta Basin and reaching down into the US in northwestern Montana, has been progressing in fits and starts. Volumes from the play are still minor and are being handled by existing infrastructure. Oil produced in this region is shipped south into the US, and flows via the Glacier or Cenex pipelines to refineries in Billings and Laurel, Mont. or onward to other markets through either Plains All American's Beartooth line or Kinder Morgan's Express pipeline.

Western Canada's new normal

The new volumes of rich gas being produced from these new plays, particularly the Montney, are overwhelming existing infrastructure. Additionally, the quality of the natural gas crosses a wide spectrum – in various areas the Montney reservoir makes sour gas, carbon dioxide (CO_2), or condensate. Consequently, all sorts of facilities are needed to treat and process the gas and its various constituents.

And producers have options: they can extract the NGL in field plants, and that gas can be further processed in one of Western Canada's immense straddle plants. Or, they can ship their rich gas to the US to be processed there. Each approach has pros and cons, naturally.

Field-level processing has long been popular in Western Canada, and these unconventional plays are being developed in areas that host many legacy shallow-cut plants that recover heavier NGL. Now, newer technology, deep-cut plants are being built and expanded throughout the region, and that's raising production of NGL, including ethane. Straddle plants are the next step after field processing. These are centralized plants that lie along transmission pipelines, and they are used to extract ethane and NGL that were not recovered at the smaller field facilities. Straddle plants generally produce NGL mix, which is sent to fractionators to be separated into individual products.

Notable new and expanded deep-cut plants include Musreau, Resthaven, Saturn, Gordondale, and Rimbey. Many more field deep cuts have been announced; sizes range from 25 MMcf/d to more than 100 MMcf/d.

Pembina Pipeline Corp., one of Canada's major midstream companies, has been very active in the Canadian NGL business and has a network of existing pipelines, storage, rail, and trucking facilities. The company has a couple of major expansions under way, and it recently acquired certain assets from Provident Energy Ltd. that relate directly to the Montney play.

Pembina's Saturn and Resthaven projects are two of the large ethane-plus extraction facilities that will service producers in western Alberta. The new 200 MMcf/d Saturn facility, located in the Berland area, will have capacity to extract up to 13,500 b/d of NGL and will be in service in the 4Q 2013. At the existing Resthaven plant, Pembina is partnering with Encana Corp. to expand the facility to 200 MMcf/d. Commissioning for the project, which will be able to produce up to 13,000 b/d of incremental NGL, is expected in early 2014.

Pembina has also just completed an expansion of its Musreau gas plant by 50 MMcf/d. The plant, also in western Alberta, is part of the company's Cutbank Complex sweet gas processing capability, and the addition has raised total capacity to 410 MMcf/d. Pembina has also put in a deep-cut plant at Musreau, and it just went to full operation in September 2012.

Furthermore, to help handle all the new NGL production, Pembina is adding 17,000 b/d of capacity to its Northern NGL system and 35,000 b/d to its Peace Pipeline, part of Alberta's NGL pipeline grid. Some incremental capacity will come onstream at the end of 2012 and some at the end of 2013. Most of that expansion involves installation of pumping stations.

Keyera Corp.'s Rimbey gas plant will get a new 400-MMcf/d turbo expander unit and construction of a 34-km (21.1-mile), 6-in.-diameter ethane pipeline to connect to the Alberta Ethane Gathering System. The CAN $210 million (US $214 million) project will allow Keyera to recover more than 90% of the ethane at the Rimbey gas plant, up to 20,000 b/d of ethane. The extracted ethane will be sold to a large consumer in Alberta under a long-term sales agreement.

As the industry develops more deep-cut plants, there's also more need for fractionation plants in the area. Western Canada's major fractionators include Redwater (65,000 b/d), Dow (70,000 b/d), Keyera (35,000 b/d), and Plains (50,000 b/d). Between these four facilities, estimated capacity is 135,000 b/d of C2 and 85,000 b/d of C3 and C4.

Pembina is currently expanding capacity at its Redwater fractionator by 8,000 b/d, and that will be finished by the end of 2014. Keyera plans to construct a 30,000 b/d de-ethanizer at its NGL fractionation and storage facility in Fort Saskatchewan, Alberta. The de-ethanizer will allow Keyera to process an ethane-rich stream of NGL and a propane-rich stream of NGL. The CAN $110 million (US $112 million) project is expected to be onstream in the first half of 2014.

Rather than investing in field-processing facilities, some operators send rich gas to the Alliance Pipeline. Alliance is a 1.6-Bcf/d, high-pressure, rich gas gathering and transmission system that runs from the Montney region to Aux Sable's Channahon, Ill., facility. For producers, this option allows them access to

Major rich gas gathering and processing facilities, Montney/Deep Basin area				
Operator	**Gas gathering, processing plant, NGL capability**	**Capacity (g) Gas (MMcf/d) (l) NGL (b/d)**	**Existing (E) Expansion (X)**	**Timeline**
Advantage Oil & Gas Ltd.	Glacier gas plant and gathering system (sour) Expansion	(g)100 (g)40	E X	In service 2Q 2012
Alliance Pipeline Canada	Added receipt points to receive wet gas	Not provided	E	In service
AltaGas	Blair gas plant Gordondale gas plant and gathering system Groundbirch sour gas plant Plant expansions: Pounce Coupe, Ante Creek, Acme	(g) 20 (g)120 (g) 28 (g) 32	E X E X	In service 4Q 2012 In service In service
AltaGas Income Trust/ Provident Energy Ltd. Joint Venture	Younger deep-cut NGL extraction plant Younger Septimus gathering pipeline	(g)750 (g)250	E E	In service In service
ARC Resources Ltd. **ARC Petroleum Inc.**	Sunrise gas plant Dawson gas plant	(g)120 (g)120 (g)60	E E X	In service In service 3Q 2012
Aux Sable Canada Ltd.	Septimus gas plant Septimus gathering (to Alliance Pipeline)	(g)50 (g)20	E E	In service In service
Birchcliff Energy Ltd.	Pouce Coupe South gas plant (sour) Expansion Expansion	(g) 60 (g) 60 (g)120	E X X	In service 4Q 2012 Future
Canadian Natural Resources Ltd.	Cypress A and B gas plants Septimus gas plant expansion Boundary Lake South	(g)45 (g)50 (g)70 (g) 100	E E X E	In service In service Late 2012 In service
Canadian Spirit Resources Inc./ Canbriam Energy BC Partnership Joint Venture	Farrell Creek gas plant Expansion	(g)10 (g)40	E E	In service Expandable as needed

Major rich gas gathering and processing facilities, Montney/Deep Basin area *(Cont.)*

Operator	Gas gathering, processing plant, NGL capability	Capacity (g) Gas (MMcf/d) (l) NGL (b/d)	Existing (E) Expansion (X)	Timeline
ConocoPhillips	Noel gas plant	(g)150	E	In service
	Ring/Border gas plant	(g)104	E	In service
	South Ring gas plant	(g)38	E	In service
	Wembley gas plant (sour) and acid gas re-injection	(g)89	E	In service
Delphi Energy Corp.	Bigstone East shallow cut gas plant and gathering system	(g)30	E	In service
	Bigstone West shallow cut gas plant and gathering system	Not Provided	E	In service
Encana Corp.	Sexsmith gas plant (sweet) Sexsmith gas plant (sour)	(g)50 (g)125	E	In service
	Resthaven gas plant	(g)200	E	In service
Keyera Corp.	Caribou gas plant and Keyera gathering system	(g)105	E	In service
	Simonette gas plant	(g)150	E	In service
	Rimbey gas plant	(g)400	E	4Q 2014
Murphy Oil Corp.	Tupper West gas plant and gathering system	(g)180	E	In service
Paramount Resources Ltd.	Musreau gas plant Musreau expansion and conversion to deep cut plant	(g)45 (g)145	E X	In service
Pembina Pipeline Corp.	Cutbank Ridge processing complex (Cut Ridge, Musreau, and Kakwa plants) Musreau expansion	(g)155 (g)205 (l)14	E X	In service In service
	Saturn liquids extraction facility	(g)200 (l)13	E X	4Q 2013
	Pembina Northern NGL System pipeline expansions	(l)115 (l)20 (l)35	E X X	In service 4Q 2012 4Q 2013
Penngrowth Energy Corp.	Groundbirch gas plant	(g)28	E	In service
	Swan Hills South gas plant	(g)148	E	In service
Progress Energy	Altares area gathering and gas plant	(g)50	X	2012 budget
Shell Canada Ltd.	Groundbirch Phase 2 Groundbirch Phase 3 Groundbirch Phase 4 Saturn gas plant	(g)55 (g)80 (g)100 (g)200	E E E E	In service In service In service In service

Major rich gas gathering and processing facilities, Montney/Deep Basin area *(Cont.)*				
Operator	**Gas gathering, processing plant, NGL capability**	**Capacity (g) Gas (MMcf/d) (l) NGL (b/d)**	**Existing (E) Expansion (X)**	**Timeline**
Spectra Energy Corp.: BC – Midstream	1,014-km (603-mile) gas gathering 11 gas plants, including: Boundary Lake Brazeau River Buckinghorse Highway Jedney Fourth Creek Gordondale East Gordondale West Nevis Pouce Coupe West Doe Complex Acid gas injection capability 16-in. Bissette Pipeline (sour gas) Bessborough Pipeline (residue gas to TCPL)	(g) 1 (g)782 (total, net) (g)17 (g)200 (g)200	E E E E E	In service In service In service In service In service
Spectra Energy – BC Field Services	Dawson processing plant Phase 1 (sour) Dawson Processing Plant Phase 2 (sour) McMahon Gas Plant Aitken Creek gas plant (re-activated) North Montney gathering expansion Sikanni gas plant	(g)100 (g)100 (g)737 (g)82 (g)210 (g)102	X X X X X X	In service 1Q 2013 In service 3Q 2013 3Q 2013 In service
Spectra Energy Corp.: Transmission	South Peace Pipeline T-North gathering expansion	(g)220 (g)210	X X	In service 3Q 2012
Suncor Energy Inc.	Boundary Lake plant (sweet) Boundary Lake plant (sour)	(g)20 (g)46	E E	In service In service
Talisman Energy Inc.	Bigstone gas plant Wild River gas plant Edson gas plant and acid gas recovery (sour)	(g)85 (g)100 (g)372	E E E	In service In service In service
Talisman Energy Inc./Sasol Ltd. Joint Venture	Farrell Creek gas plant and dehydration plant	(g)180	E	In service
TCPL: Nova Gas Transmission Ltd.	Groundbirch Pipeline (residue gas delivery from various plants) Expansion	(g)250 (g)1,400	E X	In service Expandable as needed
Tourmaline Oil Corp.	Sunrise gas plant expansion	(g)25 (g)50	E X	In service In service
Trilogy Energy Corp.	North Kaybob gas plant (sour) and acid gas disposal facilities Presley Pipeline (to Alliance)	(g)100 (g)100	E E	In service In service
Veresen Inc.	357-km (222-mile) gas gathering system (from Encana) Steeprock gas plant BC (sour) Hythe gas plant AB (sweet) Hythe gas plant (sour) Various wet gas gathering connections into Alliance Pipeline	(g)200+ (g)198 (g)340 (g)176 (g)various	E E E E E	In service In service In service In service In service

an alternate NGL market with superior pricing, reduced capital, and reduced or eliminated trucking. Alliance has been actively working to attract rich gas from the region and has added facilities that allow it to receive greater volumes.

In an interesting development, Talisman Energy has completed a transaction with South Africa's Sasol Ltd. for joint development in the Farrell Creek and Cypress A areas in the Montney play. Sasol has a proprietary gas-to-liquids (GTL) technology and is seeking commercial applications. The partners are studying the feasibility of a GTL facility in Western Canada.

The oil side

In addition to expansions of conventional oil pipeline systems to handle unconventional oil volumes in localized areas, producers in Canada are also turning to rail logistics for light and heavy crude takeaway.

Canadian National Railway Co. (CN) and Canadian Pacific Railway Ltd. (CP) are taking the lead in the nation to build out crude-by-rail terminals and transloading capacities. In CP's 2Q 2012 results presentation, the company said it expected crude-by-rail loadings would grow from 13,000 tanker carloads in 2011 to 70,000 tanker carloads in 2013. At the same time, CN is targeting more than 30,000 carloads in 2012, up from a media-reported baseline of 5,000 carloads in 2011. Hart Energy Research estimates that combined Canadian crude-by-rail shipment capacity on CN and CP out of Western Canada could reach 235,000 b/d in 2013.

Third-party terminals are another option for producers. Such firms as Torq Transloading and G Seven Generations Ltd. provide these services.

On the trucking side, some small projects are under way, mainly crude related. Anderson Energy and a few other third parties are trucking oil volumes to Anderson's Garrington Cardium oil battery, which is connected to the Rangeland pipeline system. Trucking to this facility helps to mitigate pipeline interruptions in Cardium.

Pembina Pipeline Corp. is planning to expand the region's truck terminals with an investment of CAN $50 million (US $51 million). The company's new truck terminals will secure volumes for its pipeline systems and will be in service in 2013. Pembina's current truck-terminal assets include 12 oil facilities and an interest in the LaGlace Full Service Terminal and the Rimbey Truck Terminal. Pembina is nearing completion of its Baptiste Truck Terminal, which will serve Cardium producers in the Willesden Green area.

LNG facilities

While most companies are focused on drilling for light oil and rich gas plays at present, the abundance of natural gas being produced from all these plays also needs markets. The US, the traditional market for excess Canadian natural gas, is currently awash in its own shale gas product.

Consequently, Canadian firms have been working assiduously to develop LNG export terminals on the west coast of British Columbia, with an eye to selling LNG to energy-hungry Asian buyers. Construction of multiple LNG export facilities is being considered for mid- to long-term takeaway, and three major pipeline systems have been proposed hand-in-hand with these projects. These are all slated to pick up gas from the Montney and other Deep Basin plays, as well as from the world-class dry gas reservoirs in the Horn River Basin, Liard Basin, and Cordova Embayment.

Kitimat LNG is the farthest along of the export projects. The Environmental Assessment process is complete, and Canada's National Energy Board (NEB) has granted Kitimat LNG a 20-year export license. Apache Canada Ltd. operates the project and owns 40%, and Encana Corp. and EOG Resources Canada each own 30%.

Kitimat LNG's Phase 1 would process 700 MMcf/d of gas for liquefaction, beginning in 2017. A second phase would double the capacity at a later date. The facility will be served by the Pacific Trails Pipeline, which will connect to Spectra Energy's pipeline system. Pacific Trails is owned by the Kitimat LNG partners, and its pipeline application is in the review stage.

The LNG Canada project, meanwhile, is the largest export facility yet proposed. The project is in the midst of its Environmental Assessment process, and its application for an export license has been filed. Shell holds 40% in the venture, and PetroChina, Mitsubishi Corp., and Korea Gas Corp. each hold 20%. The project is also sited in Kitimat, and plans call for four liquefaction trains with capacity to export up to 3.2 Bcf/d in total. The project will be fed by TransCanada's Coastal GasLink

Proposed LNG projects, British Columbia

Project	Owners	Proposed Capacity	Pipeline	Status	Timeline
Kitimat LNG	Kitimat LNG Partners: Apache Canada (40%), Encana Corp. (30%), EOG Resources Inc. (30%)	Initial 5mtpa; (700 MMcf/d) expansion plans for additional 5 mtpa (additional 700 MMcf/d)	Pacific Trail Pipeline, 1 Bcf/d, 463-km (288-mile) pipeline from Summit Lake, British Columnbia. Owned by Kitimat LNG Partners	20-year export license granted. Environmental Assessment process complete Pipeline FEED completed January 2012	2015 for Phase 1; 2017 for Phase 2
BC LNG Export Co-op LLC –Kitimat	Partnership: LNG Partners LLC (50%), Haisla Nation (50%) To be operated by Douglas Channel Energy Partnership	1.8 mtpa (250 MMcf/d)		NEB approved 20-year export license	Q1 2014
LNG Canada	LNG Canada Development Co.: Shell Canada, China National Petroleum Corp., Mitsubishi Corp., Korea Gas	Up to 24 mtpa; 4 trains; 3.2 Bcf/d	TransCanada's proposed Coastal Link Pipeline, 1.7 Bcf/d, 700-km (435-mile) line from Dawson Creek	Purchased Kitimat site; study phase continues; filed for export license with NEB in July 2012.Pipeline in early planning stages	2019
Prince Rupert LNG Petronas	Partnership: Petronas (80%) Progress Energy Ltd. (20%)	2 trains, 7.4 mtpa; 1 Bcf/d		Feasibility study nearing completion	Decision by Q4 2014
BG Prince Rupert LNG	BG Group	2 trains; size unknown	Spectra Energy's proposed 850-km (528-mile) line, 4.2 Bcf/d, to be owned 50/50 by Spectra and BG	BG holds an option for 80-hectare site in the Ridley Island industrial development area owned by Prince Rupert Port Authority. Pipeline agreement announced in October 2012	Sanctioning decision late 2015; onstream in 2019

Source: Adapted from Hart Energy's Midstream Business, June 2012

Pipeline, which will stretch approximately 700 km (435 miles) from near Dawson Creek to Kitimat. The CAN $4 billion (US $4.1 billion) line, currently in the early planning stages, will have an initial capacity of 1.7 Bcf/d.

BG Group has also waded into the fray. The multinational is looking at a potential LNG export facility at Prince Rupert. This venture is in the early planning stages, and BG has an option on a possible site. Recently, Spectra Energy and BG announced plans to build an 850-km (528-mile) line that could carry 4.2 Bcf/d to the facility. The line will be owned 50/50 by the partners.

Additionally, Petronas and Progress Energy Resources have put together an 80/20 joint venture to prepare a feasibility study for an export facility at Lelue Island at Prince Rupert. Petronas Group has announced its intent to acquire Progress Energy and also recommitted to its prior JV arrangements between the two firms.

A small project is being proposed at Douglas Island. The BC LNG Export Co-Operative (BC LNG), venture is owned 50% by Haisla First Nation and more than a dozen other parties, including Talisman Energy Inc. and Tenaska Inc. The facility's initial capacity will be 250 MMcf/d. The NEB has approved a 20-year export license for this project.

Additional projects are also under discussion with provincial officials. The export of LNG from Western Canada is an attractive option for producers, and the number, size, and pedigrees of the interested parties show it makes economic sense. Not all these projects will be built, of course, but some certainly will. ■

Looking for Liquids North of the Border

Cardium, Exshaw, and Montney plays are all getting attention.

By Andrei Sardo
Hart Energy Research

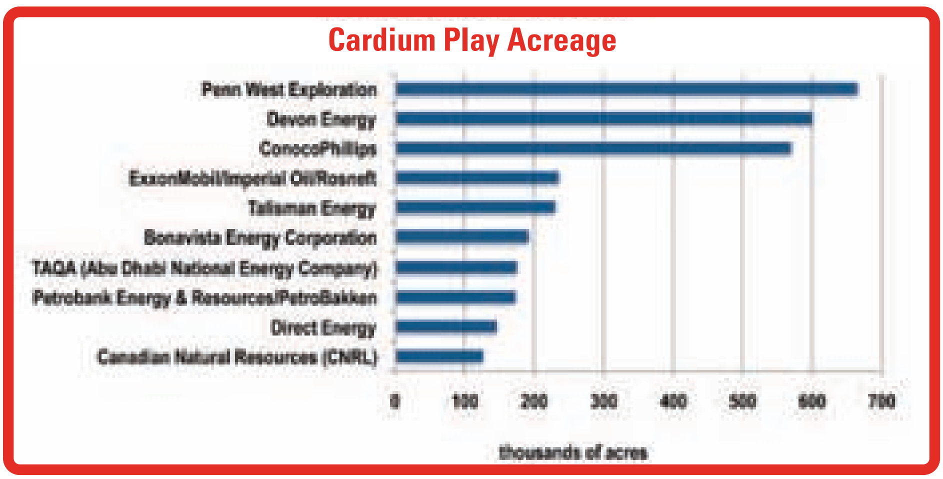
While Canada's vast energy reserves have long been of interest to both large international and small domestic players, a climate of declining natural gas prices since their peak in 2008 has left many Canadian operators searching for refuge in the more liquids-rich shale plays.

Accordingly, Canadian operators find themselves turning to a long-trusted source of liquids-rich reserves, the crown jewel of Canadian oil resources: the Cardium Formation. Since conventional production began in the 1950s in the Pembina Fields, the Cardium has been a significant source of conventional oil production in Western Canada. Stretching over an area of approximately 1,000 sq km (621 sq miles), the Cardium's stratigraphic traps had an initial oil in place that is almost one-quarter of the total oil resource in the Western Canada Sedimentary Basin. In recent years, the super-giant Pembina Field has undergone a renaissance, as a combination of new hydraulic fracturing and horizontal drilling technology has unlocked tight oil resources around the periphery of the field, creating what is known as a "halo" play. The key operators in the Cardium tight oil play are shown below.

The largest operator by acreage in the Cardium play is Penn West Exploration, which holds 665,000 net acres, followed closely by Devon Energy (600,000 net acres), and ConocoPhillips (569,000 net acres). Other notable positions in the play include the ExxonMobil/Imperial Oil/Rosneft joint venture of approximately 235,000 acres and Talisman Energy's 230,000 net acres, which are divided over three core areas: Cardium oil, Cardium wet gas, and Sundance Medlodge.

Furthermore, it warrants mentioning that production forecasts only incorporate a relevant range of hydrocarbon prices, and significant shifts in market price should be expected to be met with correlated shifts in production.

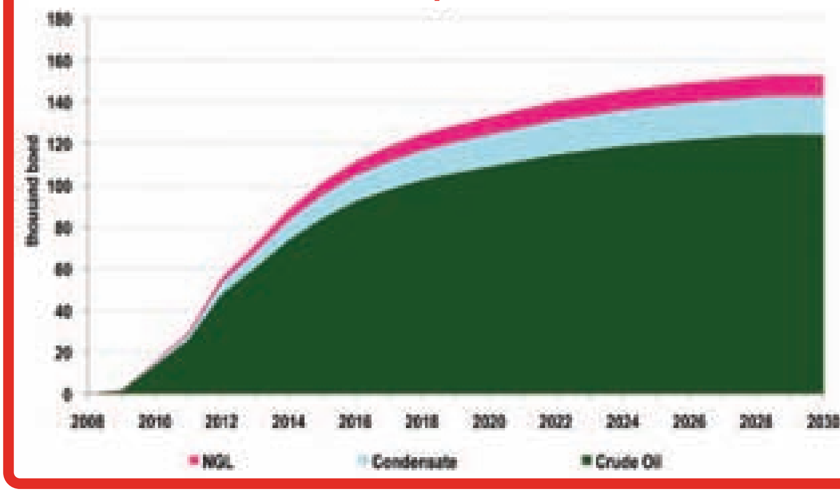
The hydrocarbon production potential of the Cardium is considerable especially when contrasted with other plays in the region. According to Rystad Energy and Hart Energy's third-quarter North American Shale Quarterly (NASQ), the production



Major operators in the Cardium tight oil play. (*Illustrations courtesy of the North American Shale Quarterly)* forecast for the Cardium play consists primarily of crude oil (approximately 730 MMboe over the period) with significant amounts of both NGL and condensate (57.6 MMboe and 102 MMboe, respectively).

The weighted average (by net acreage) economics of the operators in the play are shown in the Cardium Play Acreage table. Though the 30-day initial production (IP) rates are low, reflecting the tight reservoir, capital costs are also low, resulting in a break-even price of CAN $53.86 (US $54.23).The half-cycle break-even prices for the existing operators vary from CAN $39.96 (US $40.23) to CAN $60.09 (US $60.50), reflecting the variation in both the scale of production from operator to operator (and well to well) and the life cycle phase of each play. The average capex on the Cardium was just under CAN $2.98 million (US $3 million) per well, and the average net present value (NPV) per well ranged from CAN $993,000 (US $1 million) to CAN $2.98 million (US $3 million), with an average of CAN $1.67 million (US $1.68 million).

Cardium Play Production



Cardium Play Economics			
Average 30 day IP MMcfe/d	Average well capex $million	Average BE oil price $/Bbl	Average type well NPV $mm
228	2.97	54.23	1.68

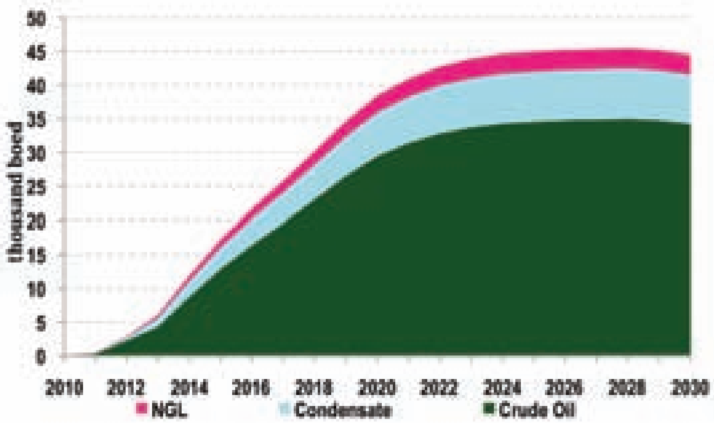
While the aforementioned metrics make the Cardium an excellent prospect for many, some operators have aimed to diversify their holdings by obtaining positions on the Alberta Bakken/Exshaw Formation. Liscensing activity on the Exshaw first began in late 2009 to early 2010 and has been encouraged by positive play economics. The Exshaw reports low gas fractions of around 25% and oil API gravities ranging from 35°API to 40°API. The existing infrastructure in the region makes the formation attractive to both larger and smaller operators. The play's hydrocarbon content is anticipated to be primarily comprised of crude oil with some natural gas and condensate. Production can grow more rapidly than other plays in Western Canada because of favorable weather conditions, which allow the area to be drilled throughout the year (a quality uncharacteristic of many other Canadian plays).

The Exshaw Formation is currently in the early development stage, and accordingly, operators are assuming explorative positions. Crescent Point Energy is the largest operator in the Exshaw with holdings over 1,000,000 net acres, followed by Arc Resources, which holds a comparatively small 180,000-net-acre position. Other notable operators in the play include Encana Corp., DeeThree Exploration, which holds approximately 159,000 net acres, and LGX Oil + Gas (formerly known as Bowood Energy Inc.), which holds a 155,000-net-acre position. The Blood Tribe (Kainai) First Nation holds the rights to approximately 885 sq km (550 sq miles) between the Oldman, St. Mary, and Belly rivers. The Blood Tribe has entered agreements with various operators on the play including Murphy Oil, which holds a 150,000-net-acre position.

It is likely that existing operators will expand current holdings and new operators will enter the play as production increases during the next five years and a greater number of positive results are reported.

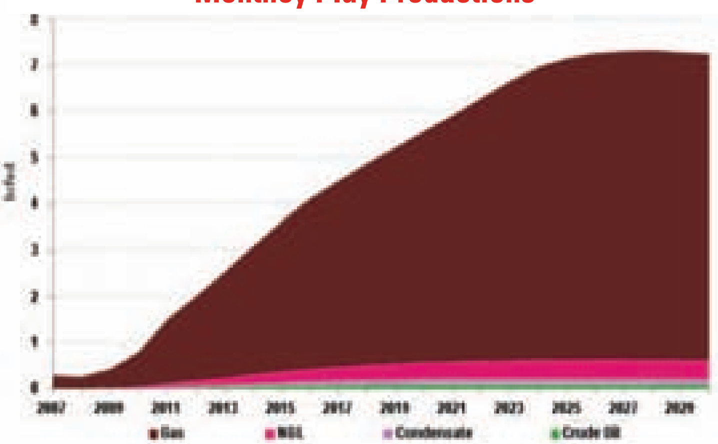
While the forecasted production estimates from the Exshaw appear to be distinctly lower than those of the Cardium play at this time, further development will likely increase these estimates. The hydrocarbon distribution is quite similar to that of the Cardium, which has proved to be a key factor of motivating development in the play. Over 292 MMboe is forecasted to be extracted during the 2010 to 2030 production window; the majority of which (175 MMboe) will

Exshaw Production



Alberta Bakken/Exshaw Play Economics			
Average 30 day IP MMcfe/d	Average well capex $million	Average BE oil price $/Bbl	Average type well NPV $mm
224	3.45	48.30	2.40

Montney Play Productions



Montney Play Economics			
Average 30 day IP MMcfe/d	Average well capex $million	Average BE oil price $/Bbl	Average type well NPV $mm
3.9	5.54	3.67	0.47

come in the form of light crude oil destined for North American markets.

The weighted average economics by acreage for the Alberta Bakken are shown in the above table. According to the NASQ, the lowest break-even price on the Exshaw was calculated at CAN $39.08 (US $39.35). This result was significantly below the average break-even price of CAN $47.97 (US $48.30) and can be attributed in part to a lower-than-average capex for this operator. Capex costs are expected to fall in coming years as operators benefit from gained experience and infrastructure developments. The average capex on the Exshaw at CAN $3.48 million (US $3.5 million) per well is slightly higher than the capex on the Cardium, while the NPV per well has a similar range from CAN $993,000 (US $1 million) to CAN $2.78 million (US $3 million), though with a higher average of CAN $2.38 million (US $2.4 million).

Though primarily a gas play, the Montney Shale has recently come to the attention of many Canadian operators as liquids-rich portions of the play are currently being drilled. Arc Resources' Ante Creek property has reported a hydrocarbon breakdown of 30% oil and condensate, 40% gas, and 21% NGL with an estimated ultimate recovery (EUR) of 265,000 boe. Arc Resources' Tower property has reported 47% oil (remainder gas) and a 398,000 boe EUR. Bonavista Energy's Blueberry land also looks appealing, with an estimated EUR of 496,000 boe and a hydrocarbon distribution of 25% oil and condensate, 58% gas, and 17% NGL. These portions of the Montney promise to be rewarding in the current hydrocarbon price environment while allowing operators to acquire strategic acreage in the vicinity of more gassy sections of the play, which could be of future benefit should pending infrastructure developments in the region allow for the export of gas to international markets. The NASQ forecast still demonstrates that the Montney will be a dry gas play, and the liquids production of a few wells in the Ante Creek, Tower, and Blueberry regions of the play haven't provided enough empirical evidence to construct half-cycle break-even prices for liquids. The average gas content of the production is 84%, which affects the economics. The weighted average break-even gas price for the Montney is CAN $3.65/Mcfe (US $3.67/Mcfe), ranging from CAN $3.07 (US $3.09) to CAN $4.15 (US $4.18), which is more than the current gas price. The NPV shown in the table to the left was calculated using a CAN $3.97/Mcfe (US $4/Mcfe) gas price and on average is positive. Thus, the Montney gas play could again become economic once LNG exports are initiated.

The Duvernay is an emerging liquids-rich gas play consisting of bituminous shale and limestone. Geologically, it is an overpressured Devonian-age shale rock. The play exhibits the characteristics that are crucial for a successful shale play: it is overpressured and has high organic content, good porosity, and overall thickness of 10 m (33 ft) to 70 m (230 ft). However, the shale is deep and relatively thin; its depth ranges from 2,500 m (8,203 ft) to 4,000 m (13,124 ft). The depth increases drilling costs, and because it is thin, horizontal drilling is more complicated.

The largest acreage holders in the Duvernay are Encana, Canadian Natural Resources Ltd, and Talisman. The companies are in the early stages of drilling; Encana plans to drill 10 wells in 2012, and Talisman has two wells on production and plans to drill two more in 2012. According to NASQ forecasts, the Duvernay Shale will reach plateau production at about 350 kboe/d in 2022.

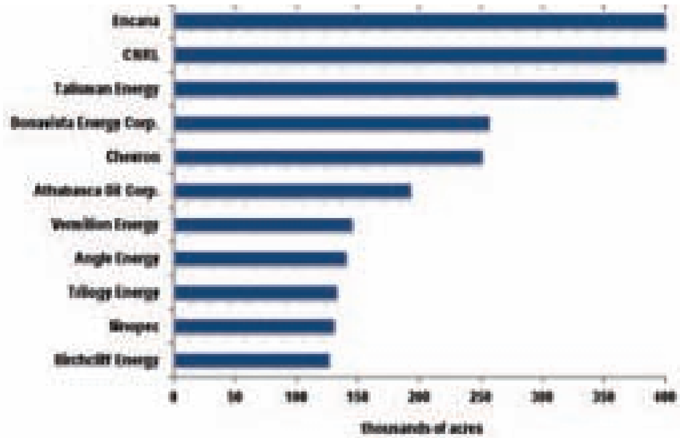
Because it is deep and overpressured, the weighted average 30-day IP for the Duvernay is higher than most Canadian plays at 4.6 MMcfe/d, but the range is large from a low of 3.65 MMcfe/d to a high of 5.01 MMcfe/d. The average capex is also high, reflecting the depth of the formation. However, the average break-even gas price is lower than the Montney at CAN $3.23/Mcfe (US $3.25/Mcfe), though still below current prices. In some parts of the play, the break-even price is below CAN $2.98 (US $3). The NPV at CAN $3.97/Mcfe (US $4/Mcfe) is quite favorable, because of the higher liquid content of the gas, indicating that this play could become highly economic under an LNG export scenario.

To boost gas-production activity, the Alberta government reduced the royalty for shale gas wells to 5% for three years with unlimited production volumes. This incentive program applies to all wells drilled in the Duvernay Shale play.

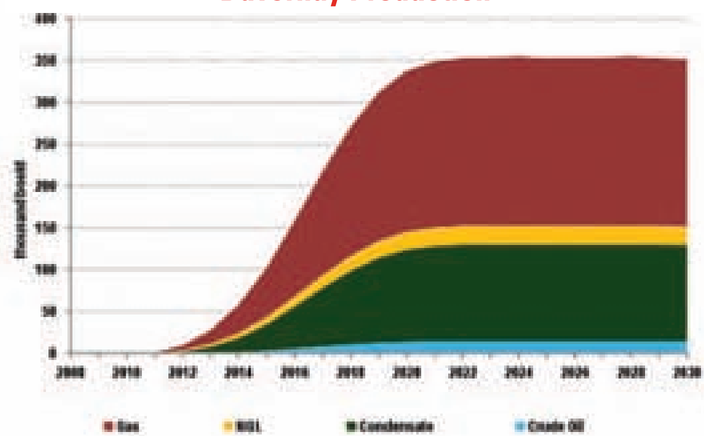
One other aspect worth mentioning from the Canadian liquids production is condensate, which has been priced higher than Edmonton light crude oil, due to the demand for diluents to mix with Canadian heavy crude oil production that allows it to be piped south to the US. According to Hart Energy's Heavy Crude Oil Outlook, Canada could utilize over 1 MMbbl of diluents per annum by 2030, given the forecasted increased production of heavy crude oil. The NASQ currently forecasts condensate production to reach a tenth of the expected demand.

Liquids-rich Canadian shale plays should continue to attract investor interest, especially from Asia. While plans to export LNG are well known, a pipeline linking Canadian oil production (both heavy and light oil) to British Columbia is being considered, either for a crude export terminal or a refinery able to produce petroleum products for export principally to the US west coast and Asia. ■

Duvernay Acreage



Duvernay Production



Duvernay Play Economics			
Average 30 day IP MMcfe/d	Average well capex $million	Average BE oil price $/Bbl	Average type well NPV $mm
4.6	12.20	3.25	2.28

Additional Information on Canadian Plays

For more details, consult the selected sources below.

By Cody Özcan
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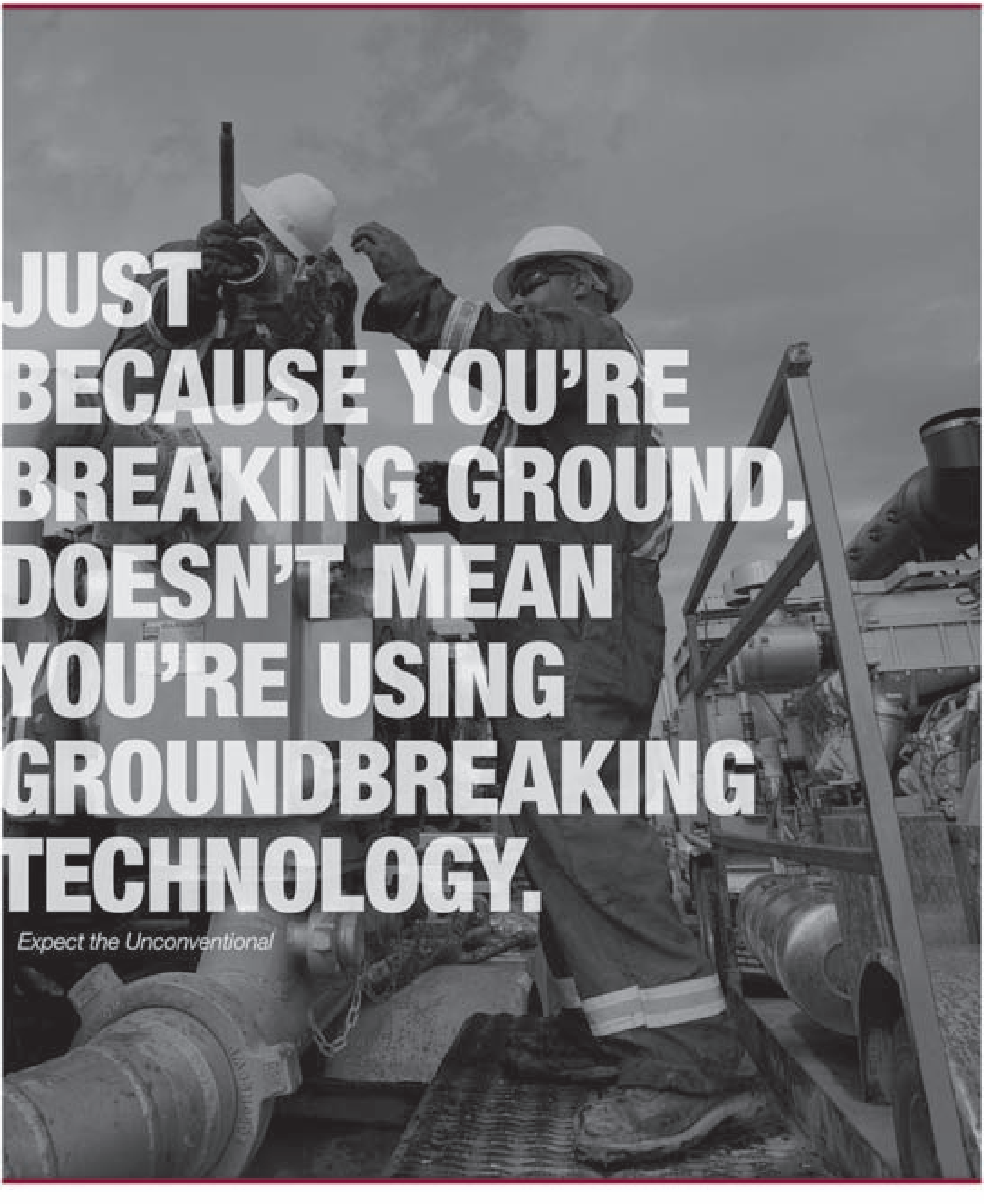
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