**WHY DID ROYAL DUTCH SHELL PAY A KING'S RANSOM FOR A RESOURCE THAT HAS YET TO YIELD COMMERCIAL OIL? FOR A CLUE, TALK TO HUSKY ENERGY.** BY PAT ROCHE

# carbonate Klondike: The Next Oilsands?

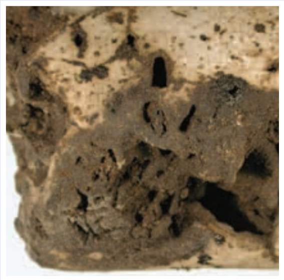


Photo courtesy of Alberta Geological Survey

More than a few eyebrows were raised in the Calgary oilpatch earlier this year when a subsidiary of Royal Dutch Shell plc bought a stake in bitumen-bearing carbonate rock in northern Alberta. Those carbonates are believed to hold vast amounts of bitumen, but no one has figured out how to economically extract it. Nonetheless, Shell plunked down nearly half a billion dollars in a government lease sale.

Even more astounding is the unit price. At $464.7 million for 88 576 hectares, Shell paid an average of $5,246 a hectare. To get an idea of just how much money this is, one can look at the prices companies have been paying for acreage in Alberta's oilsands region.

In the first quarter of this year the average price paid at government sales for acreage in the oilsands region, a legally defined area covering much of northern Alberta, was $2,006 per hectare, Nickle's Daily Oil Bulletin reported. That average (which includes Shell's high-priced acquisition) represents more than a six-fold jump from $318 a hectare in first-quarter 2005. And it's almost 19 times the average price of $107 a hectare in the first quarter of 2003. No other lands anywhere in Western Canada have seen inflation rates even close to that level.

But the most remarkable aspect of all is that Shell would pay so much more than the already inflated price — for rights to a resource that's never seen commercial production. Most or all of the other leases sold in the region are for traditional oilsands — bitumen mixed with unconsolidated sand. This resource has been commercialized for four decades and is now the object of the biggest investment frenzy in Alberta's history. Thanks to high world oil prices and declining discoveries of conventional crude, billions of dollars are being poured into oilsands surface mining and in-situ drilling projects.

Alberta's bitumen-bearing carbonate formations, on the other hand, were unknown to most of the industry before Shell's acquisition, which is in a remote wilderness area about 100 kilometres west of Fort McMurray. Access is hampered by muskeg and lack of permanent roads. It's also a caribou migration area, which implies wildlife protection headaches.

A handful of pilot tests were done on the bitumen carbonates between 1975 and 1987 and achieved mixed results (see sidebar on page 6). At five-degree to nine-degree API gravity, the oil is even heavier than the Athabasca oilsands bitumen in the Fort McMurray area. The reservoir is extremely variable over short distances and permeability is a problem because of the low viscosity of the bitumen.

For its part, Shell can't be accused of hyping bitumen carbonates. Apart from its initial terse announcement of the purchase, the company has said virtually nothing. It won't discuss development timeframes, technologies or budgets, and it declined an interview request for this article.

A media spokeswoman in Houston declined to comment on the price paid for the leases. Nor would Shell say why the purchase was made through its wholly owned Houston-based subsidiary, Shell Exploration & Production Company, rather than 78%-owned Shell Canada Limited. (A new, wholly-owned Canadian subsidiary, SURE Northern Energy Ltd., was created to develop the bitumen carbonates.)

Although Shell hogged the headlines because of its blockbuster bids, it isn't the only player in the bitumen carbonates. For more than two years, Husky Energy Inc. has been doing an intensive evaluation of a similar land position amassed over the years for a tiny fraction of what Shell paid.

This is Husky's 72 261-hectare Saleski property, which is just east of Shell's newly acquired bitumen carbonate acreage (see map on next page). Husky, a powerhouse in the oilpatch, was thrilled that a super-major would speak with its wallet.

That a company such as Shell — the world's third-largest publicly traded oil company by market capitalization — would pay such high prices for bitumen carbonate leases bodes well for commercialization of the resource, Husky president John Lau told reporters after Husky's annual meeting in April.

While Husky's main focus in northern Alberta is currently its Sunrise in-situ oilsands project, which is expected to come onstream by 2012, Lau suggested the Saleski bitumen carbonates could be Husky's next megaproject in that region.

Given the technical and logistical challenges, why would Husky — or Shell — be so enthusiastic about bitumen carbonates? The answer is simple. Husky estimates its Saleski property contains 19.5 billion barrels (bbls) of original oil in place, says Garry Mihaichuk, Husky's vice-president of oilsands. Even if only 20% of that bitumen could be recovered, that's nearly four billion bbls — more than triple the latest estimate of recoverable oil for the giant Hibernia field off Newfoundland.

Alberta's Energy and Utilities Board estimates four bitumen-bearing carbonate formations in two regions of northern Alberta hold a combined total of nearly 450 billion bbls of original oil in place. (At this point none is included in the province's estimated recoverable bitumen reserves of 170-plus billion bbls.) In the Athabasca region of northeastern Alberta the major bitumen-bearing carbonate formations are the Grosmont (318 billion bbls in place) and the Nisku (65 billion bbls in place). In the Peace River region of northwestern Alberta the combined estimates for the Debolt and Shunda formations total about 65 billion bbls of oil in place.

Husky's Saleski property is in the Grosmont while Shell's newly acquired leases — which Husky also bid on — are in the shallower Nisku formation, says Mihaichuk. Both formations are Devonian, but each is slightly different. Asked how much Husky bid, Mihaichuk says with a broad grin: "We were outbid by Shell."

He assumes Shell's bid reflects a higher degree of certainty about the technology it plans to use to extract the oil. Husky bid less because until it finishes all its evaluations of the carbonates, the company is attaching a higher degree of technology risk to the project.

While Shell's land wasn't cheap on a per-hectare basis (compared to the average oilsands parcels sold in government land sales), Mihaichuk says the super-major actually paid less than 10 cents a bbl on the basis of original oil in place. "So if they have a process that they can use to get the oil out, then … they got the oil for a very reasonable price on an original-oil-in-place basis. So I understand their logic in doing it."

On an oil-in-place basis, Husky's Saleski carbonate property — with an estimated 19.5 billion bbls of original bitumen in place — is far bigger than both its Tucker (1.27 billion bbls in place) and Sunrise (10.6 billion bbls in place) oilsands properties combined.

The difference, of course, is recoverability. Husky estimates it can economically recover 348 million bbls of bitumen at Tucker and 3.2 billion bbls at Sunrise, while the economic viability of bitumen carbonates has yet to be proven. But that's what Husky and Shell plan to do.

"We brought in some experts [for] sort of a regional look at the overall geology in the area," says Mihaichuk. There are hundreds of cores in the area, including old cores and fresh samples cut for this project. Information about the cores has been entered into a large database that Husky can use for its overall analysis.

As well, Husky is studying the results of several pilot tests (which it wasn't involved in) that produced bitumen from the Saleski leases in the 1970s and 1980s, trying to understand why some pilots succeeded but not others. Mihaichuk says there were six pilots — five using steam and one using in-situ combustion.

One big constraint was the lack of permanent, year-round roads. Produced bitumen could only be trucked out when the ground was frozen. So if a successful pilot exceeded the on-site oil storage capacity during the rest of the year, the produced oil had to be either burned or re-injected, or the pilot had to be shut in.

One pilot at Buffalo Creek in 1977 — which produced up to 550 bbls a day of bitumen — was actually shut in because it was "producing too much oil," Mihaichuk says with a grin. In reviewing these results, Husky is trying to determine which failures were due to reservoir problems and which resulted from other factors.

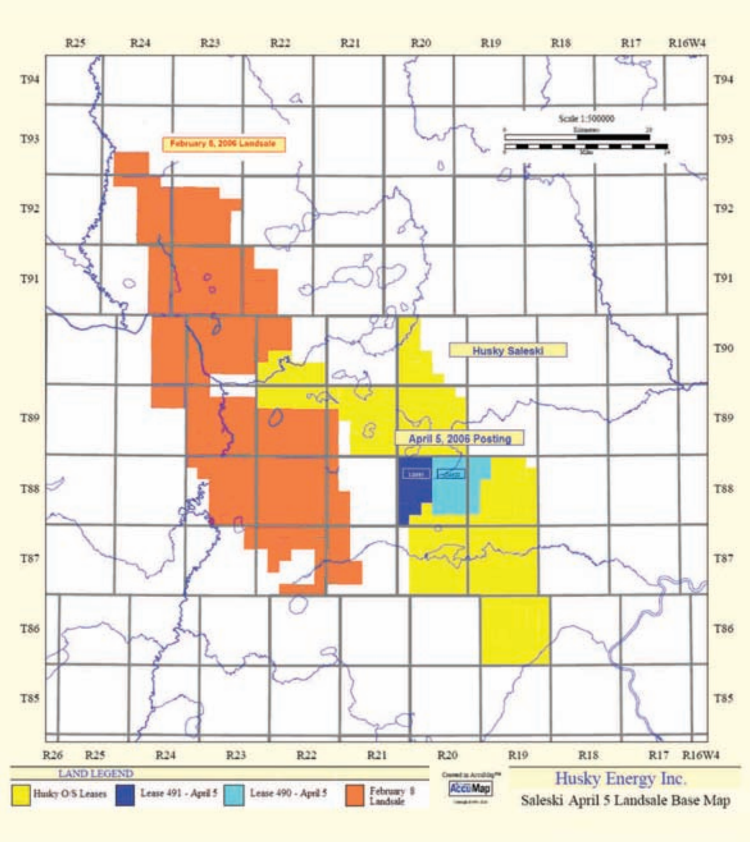
He says probably the best results were achieved during 1980-87, when some wells produced up to 740 bbls a day of bitumen and achieved steam/oil ratios as low as 4.9 — less than half the steam/oil ratio on some of the initial pilots.

Husky's ultimate goal is to do its own pilot, followed by a commercial-scale development. "We're progressing toward getting some pilot opportunities, but we're not there yet," says Mihaichuk. The company is almost finished its regional core analysis and is now trying to identify specific enhanced recovery processes that might work in specific areas of the reservoir.

One of the challenges is the extreme variability in the reservoir over short distances. So a production process that works in one area might not work a short distance away.

Mihaichuk says there are essentially two types of carbonate reservoir — karsted and unkarsted limestone. Karst is limestone in which erosion has produced fissures, tunnels and caverns. At Saleski, the karsted limestone — which some people at Husky call dolo-fudge — is crumbled to the point where it would behave like sandstone. Mihaichuk suspects the most successful pilots were producing from karsted limestone.

The permeability in a karst could be five




Map courtesy of Husky Energy Inc./IHS Energy

**CAPTURING THE CARBONATES**
Map details the land positions of Shell (in orange) and Husky in the Grosmont Platform west of Fort McMurray.

darcies while the dense limestone is about 100 millidarcies. The latter would be fine for light-oil production, but Husky and Shell are dealing with oil viscosity of a million centipoise.

A different approach may well be needed for the dense limestone than for the highly permeable karst. “I think the karst you could probably do with a simple steam process. But I don’t think you can do that for the limestone,” says Mihaichuk. Processes for producing the dense limestone might include injecting carbon dioxide or using electricity to heat the reservoir. (Shell has been experimenting with in-situ electric heaters to coax oil from kerogen-bearing shale at its oil shale research project in Colorado. See story on page 8.)

Once it finishes its geological analysis and review of the old pilots, the next step for Husky will be to create some theory-based simulation models. Because of the extreme variability in the reservoir, the models will need to be much more sophisticated than the typical model, which assumes a homogeneous reservoir.

That will lead to Husky concluding, “Here are the one, two or three best opportunities that we see, and here are the one, two or three best processes that we think that we can do,” says Mihaichuk.

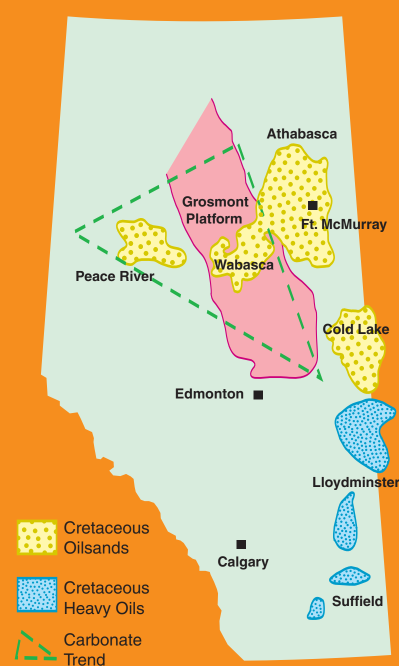
The next step would be to do its own pilot, but it’s still too early to decide the scale or type of pilot. One or two wells might be enough to test raw limestone. But to test the karst — and accurately map the caverns and how they’re interconnected — a much bigger pilot may be needed. A test could probably be as short as a couple of years, suggests Mihaichuk. “The pilot is probably going to tell you in the first year or so whether your theory is working,” he says, but it would likely run longer to get some idea of ultimate recoveries.

At the same time, if steam-assisted recovery is being considered, the company would assess groundwater availability. Husky is also looking at transportation and utilities into the site. Mihaichuk says it’s reasonable to assume Husky will work with Shell on shared needs such as roads and electrical or gas utilities.

Site access has improved since the first pilots, but not for heavy loads. “You wouldn’t want to be trucking oil out of there,” says

# forgotten treasure

## PILOT PROJECTS TESTED ALBERTA’S BITUMEN CARBONATES MORE THAN 20 YEARS AGO




Map courtesy Alberta Geological Survey

Fear that the world may be running out of energy has focused attention on futuristic resources such as oil shale and gas hydrates, but another unconventional resource that may be easier to tap into was largely forgotten.

While the world now knows about Alberta’s vast oilsands resource, many people — even in the Calgary oilpatch — are unaware that a bitumen resource of similar magnitude is locked in carbonate rock. According to a report by Petroleum Technology Alliance Canada (PTAC), 26% of Alberta’s bitumen resources are contained in carbonate rather than sand formations.

One northern Alberta carbonate formation alone — the Devonian-age Grosmont complex — has bitumen volumes in place comparable to the huge Athabasca oilsands deposit.

This comparison is made in the 176-page official history of the Alberta Oil Sands Technology and Research Authority (AOSTRA), the long-since disbanded provincial agency set up in 1974 to promote bitumen recovery technologies. The history devotes four well-illustrated pages to bitumen carbonates.

The resource received serious attention during the AOSTRA years with a series of pilot tests running in the Grosmont formation between 1975 and 1987. But then oil prices fell and funding was cut. The remotely located and little-known bitumen carbonates were largely forgotten until Royal Dutch Shell plc paid nearly half a billion dollars for leases earlier this year.

Contained in a roughly triangular 70 000-square-kilometre area of northern Alberta called the Carbonate Triangle, the deposits may be the most technically challenging of the province’s bitumen resources.

The basic difference between oilsands and bitumen carbonates is the former is bitumen mixed with unconsolidated sand, which can be either mined or produced from wells. The latter, as the name implies, is bitumen in carbonate rock — both dense limestone and heavily karsted rock.

Grosmont bitumen is even heavier than the Athabasca bitumen and the reservoir is extremely variable, meaning that a single recovery method is unlikely to work throughout the formation.

“The lack of understanding of the heterogeneous nature of the reservoir is the main hurdle for developing successful bitumen recovery schemes,” the Alberta Geological Survey said in a short note in the spring/summer 2003 issue of its newsletter Rock Chips.

The bitumen is contained in a dual porosity system — both in the vugs (cavities or fractures) and in the rock matrix itself, says Marc Godin, co-author of a May 2006 PTAC report on expanding heavy oil and bitumen resources.

The vugs could potentially be good news in that they could conceivably improve permeability once the viscosity of the bitumen is raised by heat or other means, but bad news if they serve as channels for steam to escape from the area of interest, says Godin, president of engineering consultancy Portfire Associates Inc.

In the karsted areas, these irregular cavities and tunnels are often the diameter of a man’s arm, and sometimes much larger. During drilling on some of the pilots, the bit dropped by a few metres while passing through large karsts.

According to the PTAC review of the pilot results, challenges of drilling through this karsted rock include the potential for loss of drilling fluids into the formation, and problems with the placement of cement to maintain a strong well-to-formation bond.

Another problem was lack of year-round sur-

Mihaichuk. One of Husky's priorities is improved site access.

At this point it's impossible to say how much Husky will spend on Saleski-related work next year because that will depend heavily on the outcome of the modelling. "The capital is dependent on our success this year," says Mihaichuk. "But we see it as a pretty important area."

Husky's bitumen carbonate prospects aren't limited to the Saleski assets. The company's vast Lloydminster area straddling the Alberta/Saskatchewan border is underlain by carbonates as well. The Lloydminster carbonates aren't as thick or as karsted as the Saleski rocks. But if the company can figure out the secret of producing the denser limestone at Saleski, then presumably it could tap the resource beneath its conventional heavy-oil producing zones, where infrastructure is already in place.

Meantime, if Shell's valuation of bitumen carbonate leases proves correct, then Husky is sitting on one of the most cheaply acquired resources anywhere. Most of Husky's 72 261-hectare Saleski property was amassed over time through corporate acquisitions. In fact, the most Husky paid for any of its Saleski acreage was probably the $10 million it bid to pick up 9 583 hectares in a government land sale this year.

Like a longtime property owner who learns the house next door just sold for an astronomical sum, Husky is thrilled that Shell paid $400 million (US) for adjacent lands. "All of our oilsands, we think, are undervalued, but in particular Saleski would show up as zero value in most analysts' minds. They look and say, 'Well, this is so far out, there's nothing here.' But we know it's at least worth $400 million (US)," Mihaichuk says with a hearty laugh.

And no doubt there's a misery-loves-company component. "When you're in sort of a new technology, you love to see company because we can hopefully learn from them as well as they can learn from us," says Mihaichuk. So when Shell starts its first pilot test, "we'll be watching over the fence," he says. "And I imagine they'll look over the fence to see what we're doing." ntm

face access. The most promising bitumen carbonate resources are in a remote wilderness area with no permanent roads. According to the AOSTRA history, the isolated location doubled to tripled piloting costs.

The first pilot was undertaken in 1975 when Union Oil of Canada Limited began a single-well steam-stimulation test at its Chipewyan River 14-21-88-19 W4M site near the eastern margin of the Grosmont formation, says a paper by Rand Harrison of the Alberta Geological Survey. Two years later Canadian Superior Oil Limited and AOSTRA joined the program and a new test site was established to the south at Buffalo Creek 14-5-88-19 W4M.

(Union Oil was a unit of Unocal Corporation, which was acquired by Chevron Corporation in 2005. In 1986, Canadian Superior Oil was acquired by Mobil Canada Ltd., which is now owned by Exxon Mobil Corporation.)

Harrison's paper says steam drive, steam stimulation and in-situ combustion (fireflooding) tests were done with sufficiently encouraging results to prompt a further series of tests at nearby Buffalo Creek 10-05-88-19 W4M.

Based on the success of its Buffalo Creek efforts, Union Oil expanded the program to a multi-well pattern in the McLean area in 1982. However, loss of steam containment occurred because fractures, or vugs, established communication between separate units of the Grosmont complex. Also, there was premature steam breakthrough from injection to producing wells. The McLean pilot ended in 1986.

Around the same period, AOSTRA and Chevron Canada Resources did a single-well, steam-stimulation test in the Algar area. Results weren't encouraging due to a gas zone near the target Grosmont bitumen formation.

The best results were obtained at Buffalo Creek, which on at least one test produced up to 740 bbls a day of bitumen, according to Husky Energy Inc. Some of the Buffalo Creek wells underwent multiple steam stimulation cycles over several years until the pilot ended in 1986.

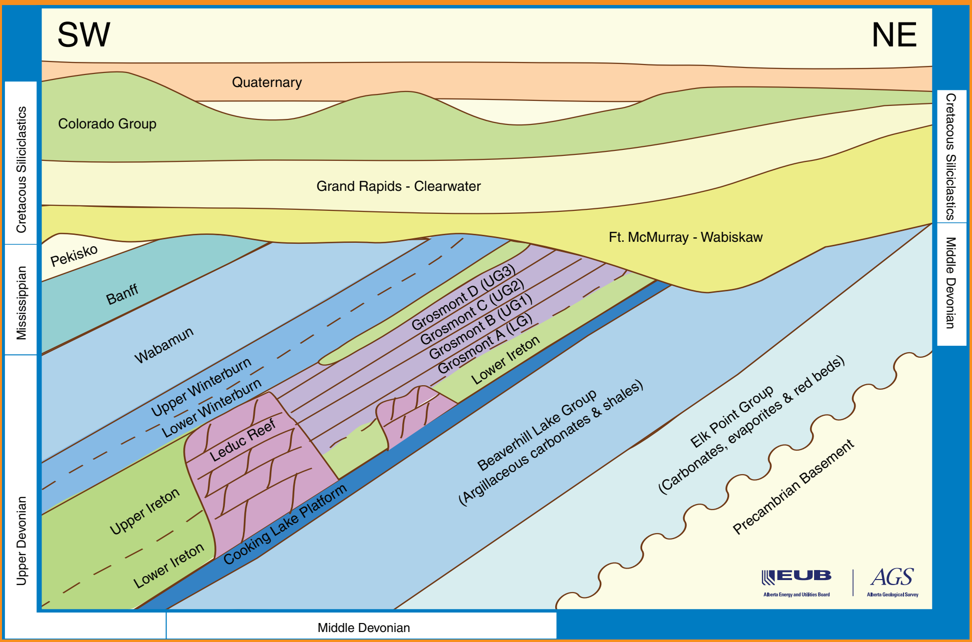
PTAC made several recommendations to spur commercialization of Alberta's bitumen carbonates. Godin underscores the need to collect much more information such as geological and geochemical data. Learning more about the highly irregular networks of natural fractures, for example, would aid in planning a recovery process.

The PTAC report also calls for the full release of all data on pilots done 20 to 30 years ago. At the time reports were prepared for AOSTRA and other project participants and most of the key findings have been made public.

"However, a great deal of the value of these reports [is] in the details of geology, reservoir characteristics, drilling and observations during production. These reports are currently confidential, but need to be made available and re-analyzed in light of current understanding of bitumen production and access methods," the report recommends.

The PTAC report is upbeat on the outlook for bitumen carbonate development, saying the problems encountered 20 years ago could be solvable today: "The industry now has drilling … and well completion technologies which could increase the likelihood of successful recovery of bitumen from carbonates." ntm

— By Pat Roche




Graphic courtesy Alberta Geological Survey

**DOWN UNDER** The Grosmont formation's most productive zones are the Upper Grosmont 2 and Upper Grosmont 3 (C and D), with a combined average thickness of 70 to 90 metres at about 280 metres depth.