Finding Pathways to Produce Heavy Oil From Canadian Carbonates

Stephen Rassenfoss, *JPT* Emerging Technology Editor

Nearly 2 million bbl of ultraheavy crude are produced each day from Canadian oil sands, but the notion of also producing bitumen from reservoirs made of carbonate rock can spark skeptical remarks.

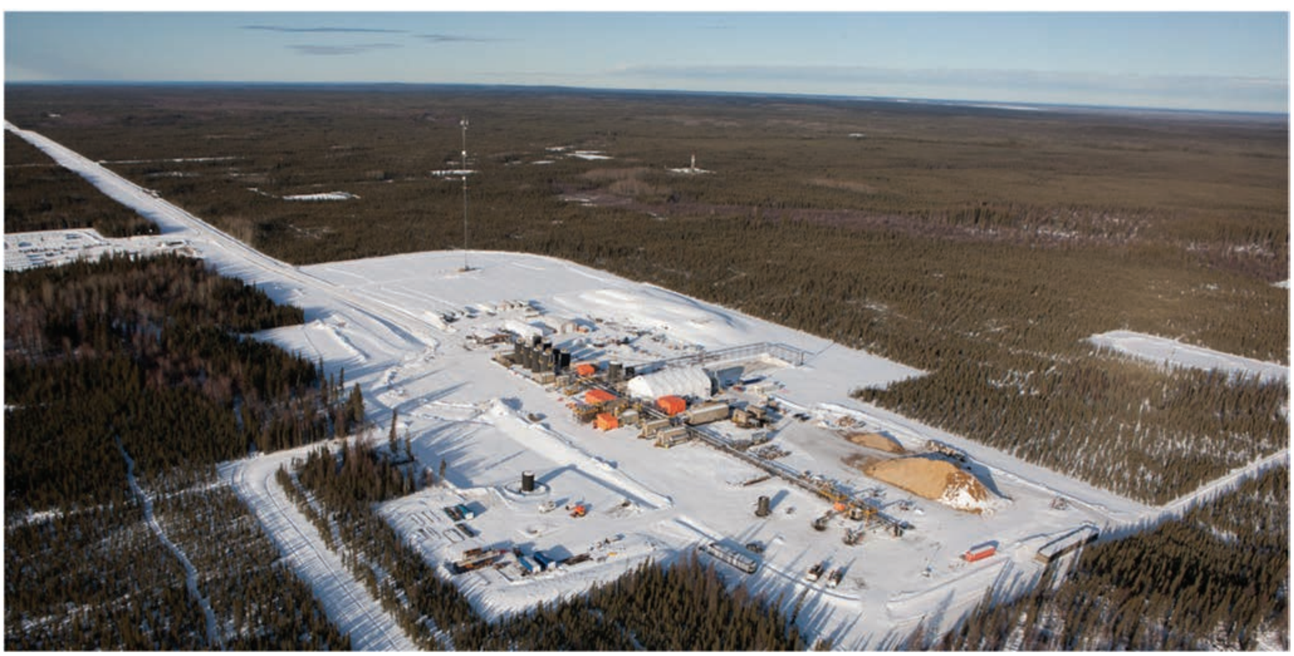
They are likely to say something like: "Carbonates are very different. In carbonates, it is just different," said Daniel Yang, director of reservoir engineering at Laricina Energy, who has a different reading of the exploration history of formations that hold more than 400 billion bbl of the crude.

Laricina has partnered with a second Calgary independent, Osum Oil Sands, to try to prove that bitumen can be commercially produced from the Grosmont formation, which holds 75% of the heavy crude known as bitumen in Alberta's carbonates.

The reality is the Grosmont is different. A pilot project by Laricina and Osum showed that the well design commonly used for oil sands is not a good fit in carbonates. But a mix of methods used for bitumen production worked well enough to convince the partners to plan a commercial test. that they plan to use for the first commercial development in the formation.

The Laricina-Osum joint venture has filed for a permit to produce as much as 10,700 B/D from up to 32 wells, with first oil in 2015. Husky and Shell have also filed for permission to do pilot projects with the Alberta Energy Regulator, the agency formerly known as the Energy Resources Conservation Board (ERCB).

"It is going like early development in major oil sands basins such as the Athabasca, where there were many field pilots," said Eddy Isaacs, chief executive officer of Energy and Environment Solutions at Alberta Innovates, a provincial agency that funds research, including past carbonates work.



This clearing was used for a pilot project testing bitumen production from the Grosmont Formation by a joint venture formed by Laricina Energy and Osum Oil Sands. They needed to build a road to the remote location in north central Alberta where they used various heating methods to produce the heavy crude from a carbonate formation.

But moving from wells producing oil in situ in the relatively consistent sandstones and unconsolidated sands to carbonates will require significant advances in production methods and simulation software. The Grosmont was born complicated. It was formed hundreds of millions of years ago from the haphazard deposition of marine life off a long shoreline, was chemically transformed into dolomite, followed by water flows that carved it up, widening the fractures and carving out so many holes in the rock that it created weak spots in a formation that has been lifted and crushed and filled with oil that degraded into some of the world's heaviest crude.

"It is much more difficult still" than oil sands, said Ron Sawatzky, a principal researcher in the heavy oil and oil sands group for Alberta Innovates Technology Futures (AITF). "Mainly the carbonates are more complex. It is a poor architecture" compared with oil sands, which he said are more likely to offer a uniform medium for the steam used to thin the thick crude, allowing it to drain out of the well.

But those who have worked over the past 3 years on the pilot project in the Grosmont see useful patterns where others see troublesome disorder. They see a thick reservoir saturated with billions of barrels of oil, with consistent layers over large areas filled with networks of vertical passageways for heated bitumen to drain down to a production well.

The last well done in the pilot program, which was its best, averaged from 470 to 660 B/D during its first two steaming cycles. During its second cycle the heating efficiency—measured by the ratio of steam needed per barrel of oil output—was as low as 3.5 putting it around the commercial range, according to an Osum Investor presentation.

Laricina and Osum appear closer to reaching commercial production, but they are not there yet. "We cannot claim to have proven they are commercial," said Peter Putnam, senior vice president of geosciences at Osum. "This is a journey we are on."

Based on their understanding of the Grosmont, a successful installation in one place could be reproduced elsewhere because these formations

- Contain thick oil-bearing reservoirs, with sections 50 m thick or more. In the Grosmont that area covers about 3,700 km^2 or about 23% of the formation.
- Have consistently high levels of oil saturation in rock where the average porosity is about 20%.
- Are generally extremely permeable formations with an extensive network of cracks and holes, known as vugs, filled with bitumen offering both a significant percentage of oil in place and a path for gravity drainage.

There will be a substantial reward for anyone who can show how to turn these assertions into profitable production. "If we actually find a way to (open up this), then the potential is incredible," said Jian-Yang Yuan, principal enhanced oil recovery adviser at Osum. "It is not just here and some of the same thing there. It goes miles away and we do not have to change anything."

Shell revived interest in the Grosmont in 2006 when it paid nearly USD 500 million to lease much of the northern half of the formation, located about 60 km west of Fort McMurray, which is a center for oil sands production.

Since then, it has been work on what would be a giant step ahead in underground heavy oil production—using electric heat to, essentially, refine the heavy crude in the ground. Shell's in-situ upgrading process could yield lighter, more valuable crude and leave the dirty, low-value coke in the ground.

But it is a long-term project. An update on Shell's website posted in June said a decision on whether to commercially develop the project would not be made until "the next decade."

Thinking Differently

A long journey has a way of changing one's perspective. That seems to be the case for those who have spent years looking for an understanding of what it will take to get bitumen out of the carbonates in Alberta.

"Fractured carbonates are a different story from the usual experience we have had with bitumen in the sand," Yang said. "There are some things that are counterintuitive."

One example of that is those who are working on producing oil from the Grosmont see consistency in a place where core samples taken within a small area can all look different.

To explain, Yuan said, if it were possible to study a volume of rock the size of a conference room, the space where he was sitting might be rubble, the volume across the table where Putnam was listening could be an oil-filled cave, and a spot in the far corner might be impermeable. But on a larger scale, it looks different. "If you drill a few wells over the larger area, you will get a pattern," Yuan said. "If you go a mile away, you see the same pattern."

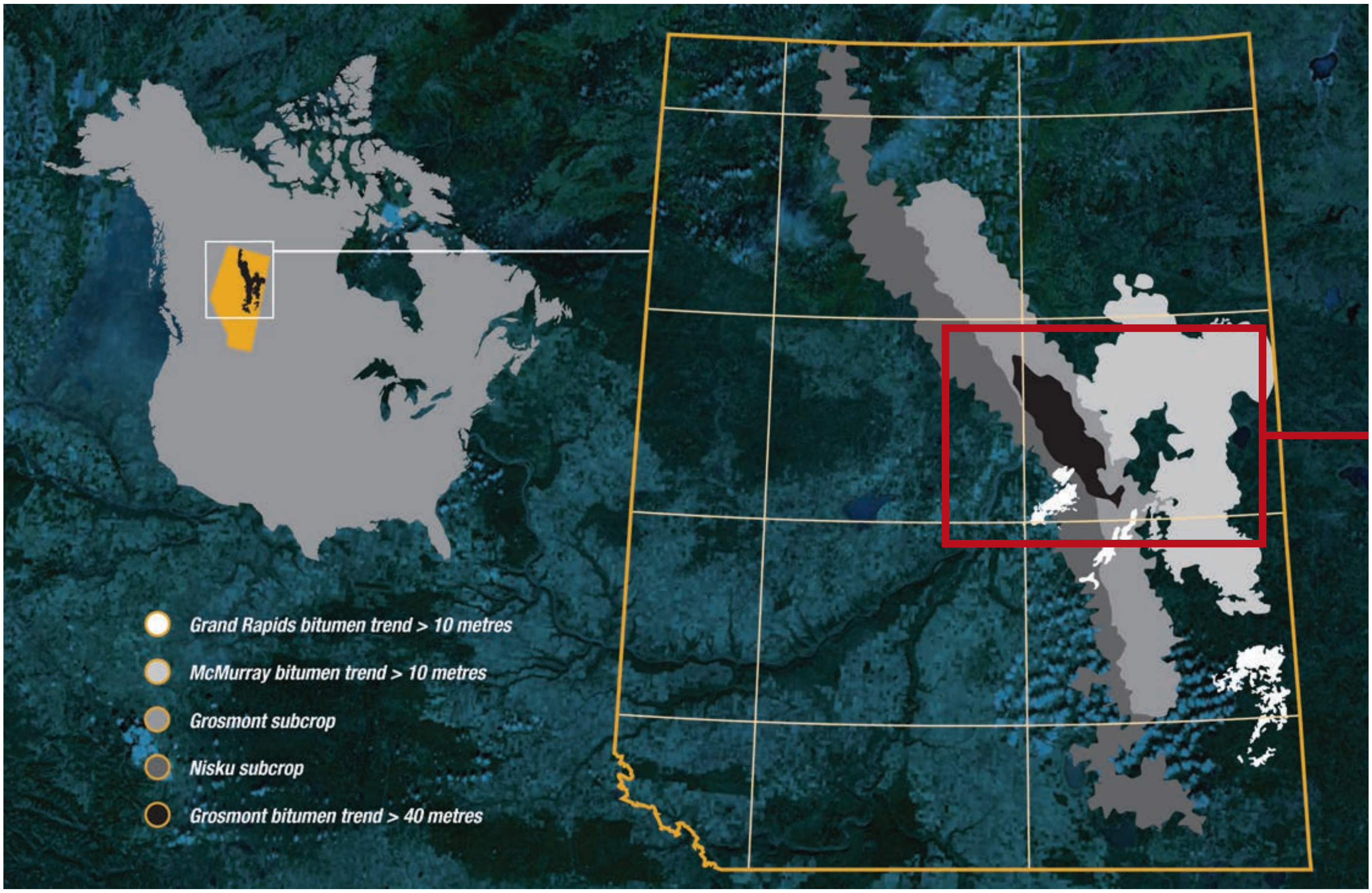
The critical feature is a network of fractures. Since most of these fractures are too small to see using seismic imaging, they studied the cracks in core samples from more than 100 evaluation wells.

"We counted fractures and measured them," and there is consistently one fracture per meter, and in some places they are more closely spaced, Yang said. To determine if they interconnected, they considered "the distribution and the density of the fractures."

What they found is that those cracks, plus the holes in the rock ranging in size from up to the size of a small finger, called vugs, form a broad, highly permeable network for draining a reservoir. "The most important thing is that the fracture length is greater than the space between fractures," Yang said. As a result, the fractures create an extensive system of well connection fractures.

In the Grosmont the permeability varies enormously, with the most open pathways in the vertical direction in the C level, which was the target for the recent pilot program.

"In the Grosmont C reservoir the average horizontal permeability is about 1,200 mD, although this is believed to underestimate true reservoir-scale permeability due to the difficulty in collecting intact samples from fractured, vuggy core that are suitable for analysis," Putnam said. "From in-reservoir tests the in-situ permeability is several orders of magnitude larger than the core-measured permeability and is closer to 100 D."



The carbonate formations holding bitumen in north central Alberta are found among some of the largest oil sands deposits. The Grosmont formation is by far the largest carbonate formation with the ultraheavy oil, with 300 billion bbl of the more than 400 billon bbl in these formations.

Oil sands appear to offer a far more consistent medium for injecting steam, but Yang said observations during the pilot program suggested otherwise. A series of seismic images taken over time (4D seismic) showed steam evenly spreading along the full length of the well in the Grosmont. In comparison, in oil sands, the steam is observed flowing into the space around about two-thirds of the length of the well.

"On this scale (100 m), it (carbonate rock) is more homogenous than any sand," Yang said. "You can run a well 800 m and put steam in every meter because of the fractures."

Cyclic Steam Gravity Drainage

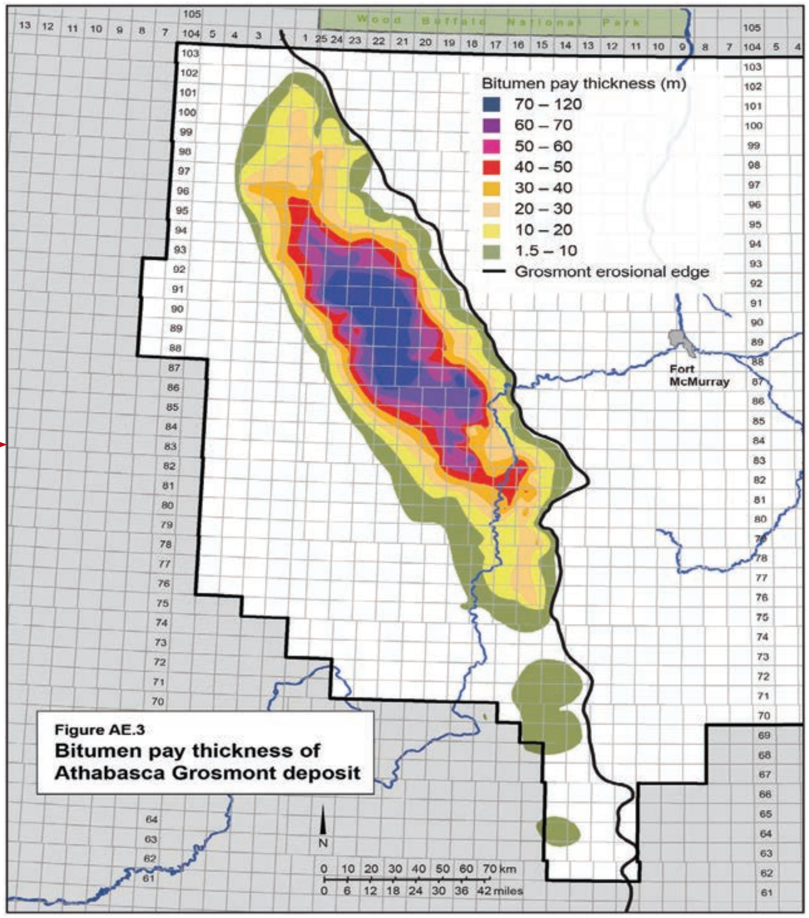
The Laricina-Osum joint venture found that methods used to produce bitumen from oil sands can be used with a twist. The method developed by the joint venture partners mixes the steam-assisted gravity drainage (SAGD) approach widely used in the oil sands with cyclic steam stimulation (CSS), which Unocal used on its most successful test in the 1980s.

The hybrid approach was adopted because the starting point—using a pair of horizontal wells about 6 m apart as in SAGD—proved to be a disappointment

That led to a revised, two-step development plan. The first step will be a single horizontal well bore. Cycles of low-pressure steam alternating with production of the oil thinned by heating will be used to clear out the network of fractures and vugs, which can represent about half of the oil in place, Yang said.

Eventually the first well is expected to create production pathways for the harder-to-reach oil in the more solid sections of the reservoir and open the way to the second stage, SAGD. An upper injection well will be drilled, delivering a steady steam to drain oil down to the lower production well. Compared with the oil sands SAGD, one difference is that the spacing will be wider, with the injection well about 15 m above the producer.

In addition to thinning the oil, heat has other benefits. It can reduce the physical attraction between carbonate rocks and oil, changing it from oil wet to water wet, Yuan said. This is expected to aid production over time in the less permeable matrix rocks, with the water imbibed by the rock moving out the oil. Heat is also expected to expand the fluids in the pores and fractures, adding pressure in the system, pushing more oil into the production well, Yang said.



This map shows the large area within the Grosmont formation with a reservoir that is 50 m thick or greater. Each grid block is 10 km by 10 km, in this map from Alberta's Energy Reserves & Supply/Demand Outlook.

Carbonates and Bitumen in Alberta

Estimated Oil in Place: 406 billion bbl

Location: North central Alberta

Leaseholders: Shell, Laricina Energy, Osum Oil Sands, Husky, Suncor, Sunshine Oilsands

Formations: Grosmont, Upper Ireton, Winterburn

Largest: Grosmont with about 75% of reserves

Porosity: 20% (5% to 40%)

Oil Saturation: 85% to 90%

Weight : 7 °API (5-9 range)

Viscosity: 1 million cP (centipoise)

Reservoir Temperature: About 11°C

Mineral Content: Dolomite—93% to 99.5% in Grosmont and 87% in Upper Ireton

But there is a limit to how far the steam will travel, which answers a question raised about steaming carbonates: Will the heat source spread outside the productive zone, wasting energy? Yang said the area heated was comparable to an oil sands well.

The starting point for the well design for the commercial project will be based on the most productive well in the pilot project, which was short—450 m long—and simple. It was heated using bullhead steam injection, with steam pumped into the wellbore without the pipes and valves used to ensure even steaming in the oil sands, Yang said.

All those details are open to adjustment as they work to improve well performance. Yuan said the biggest variables will be in managing thermal heating to reduce the steam needed per barrel of production. That will include the length of cycles, the injection rate, the volume of steam, the distance between the upper and lower well in each pair, and the timing of the switch from CSS to SAGD production.

There is still a lot to learn about how these wells will perform over time. They will be working to identify the ideal well spacing. Too close and the wells will be heating overlapping zones, wasting steel and capital; too far and some areas will be missed. They will also be considering the ideal distance between the upper and lower well when they go to SAGD. They have looked at adding solvents to the steam to increase production, but at this point it is not in the plan.

Those working to commercialize the carbonates at Laricina and Osum—both of which have extensive holdings outside the joint venture—have had to make key decisions, such as using cyclic steam at first, even when they do not agree on the cause of problems they need to solve. Yuan said, "Different people had different reasons for using CSS. But in the end, we agreed."

Moving up the Learning Curve

The results of the pilot project by Laricina-Osum venture have added to the evidence that the Grosmont can be technically produced. The bigger challenge is showing that it can be done profitably. The obstacles they face are not as daunting as those faced by Unocal three decades ago when it first tested the Grosmont, but there are similarities.

The rising tide of oil produced from the oil sands is already exceeding pipeline capacity, depressing the price of bitumen, which cannot be moved through a pipeline without the added expense of thinning it by adding lighter hydrocarbons, known as diluents, or upgrading it using a refining process to create synthetic crude.

Projects to build pipelines to the US Gulf Coast and the Canadian West Coast have been stymied by opposition on multiple fronts. A large export outlet to Asian markets will be needed because the growth in heavy oil production will challenge the capacity of US refineries to handle the hard-to-refine crude, said Brian Fowler, senior director of upstream development at Enbridge, during a panel discussion at the SPE Heavy Energy Conference held in June in Calgary.

Canada's oil production is expected to more than double in 18 years, from 3.2 million B/D in 2012 to 6.7 million B/D in 2030, when oil sands output is expected to pass 5.2 million B/D, according to the recently released projection from the Canadian Association of Petroleum Producers. The study makes no mention of bitumen production from carbonates.

Logistics in the north central Alberta area also pose a problem, though it is not the daunting barrier it was in the 1980s, during the first phase of testing in the carbonates. The Laricina-Osum joint venture partners had to build a road to their pilot site, which is just north of a large conventional oil field with pipeline access.

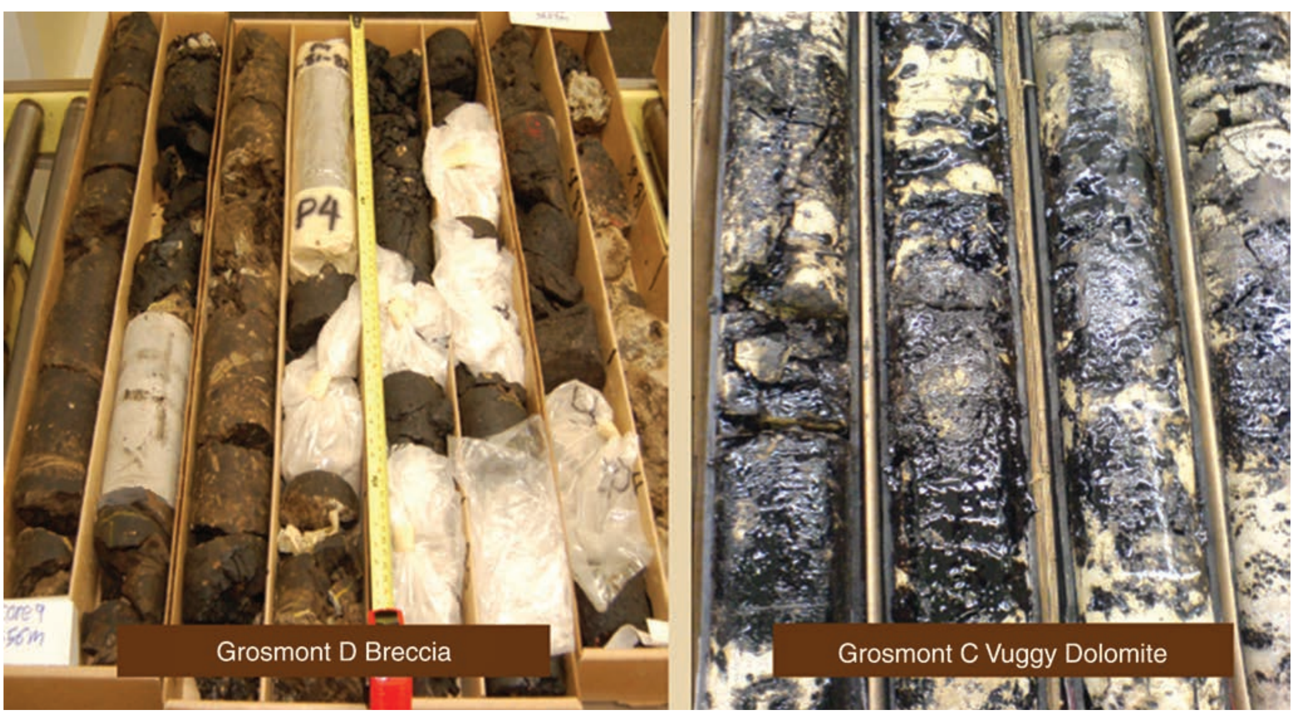
Also the Grosmont is flanked on both sides by enormous oil sands areas, the Athabasca and Cold Lake, so there are multiple large supplies of crude nearby to justify pipeline construction to places in northern Alberta that can be extended to the Grosmont.

Long-term development plans in those areas may reduce the appetite of the biggest companies to put up the large sums needed to develop carbonates, which come with higher technical risks. For example, Suncor, a pioneer in producing oil using mining and currently developing in-situ megaprojects, holds carbonate acreage and is considering how to produce it.

"Technology advancements will be the key to economically unlocking this potential and we are participating in a number of industry initiatives to that effect," said Kelli Stevens, a spokeswoman at Suncor. "At the same time, the company holds immense opportunities within other in-situ oil sands properties."

"We already have a proven track record of performance in both our MacKay River and Firebag properties and for that reason, our short-term in-situ growth will be focused on the significant opportunities within those prospects," she said.

For small companies working to build a resource base—Osum has booked more than 400 million bbl of probable reserves—or big ones considering long-term growth, the Alberta carbonates offer potential that can no longer be found in the oil sands in which the best reservoir rock appears largely leased.



These core samples from the Grosmont Carbonates show the range of what comes out of the formation. The ones on the left are from the shallowest layer in the formation, and are examples of the loose rock, known as breccia, which is prevalent. The heavy oil in those samples has been reduced by a core flooding test. The rock on the right has empty spaces, known as vugs, filled with ultra-heavy oil, and comes from the C layer, which is the richest.

It is difficult to profitably produce an oil sands reservoir that is 10 m to 15 m thick because the oil in place is limited and more steam will be needed per barrel of production because a lot will be wasted heating unproductive rock above and below the oil zone, said Ian Gates, a chemical and petroleum engineering professor at the University of Calgary.

While carbonates also present a lot of unanswered questions, ultimately the rewards for working with a reservoir that is 50 m thick are greater, even when it is difficult to simulate the path of the liquids through the complex reservoir. "Right now, given the technology, the easier target would be the Grosmont," Gates said. **JPT**

Learning from History

In the early 1980s, the Canadian arm of Union Oil of California (Unocal) did a wide-ranging series of field tests seeking a way to produce ultraheavy oil out of the carbonate formations in northern Alberta.

The program tried most of the methods available then to pushing heavy oil out of the ground using heat: cyclic steam stimulation, steam floods, and underground combustion. It is still widely cited by those working to find a way to produce oil from these enormous formations, and also by those who question whether that is possible.

In those days, producing crude as thick as peanut butter from a reservoir too deep for surface mining was at the edge of what was possible. At the time, nearly all oil sands production was done using surface mining. Imperial Oil was developing an underground method using cycles of steam injection and production at Cold Lake, but that in-situ method, which was a key to unlocking the oil sands, was not considered commercial until the mid-1980s.

The methods applied by Unocal to get that bitumen out of carbonates were developed in places such as southern California, where the crude was not nearly as heavy and could be pushed out using high-pressure steam injection.

The technique that opened up underground, in-situ production from the oil sands—steam-assisted gravity drainage (SAGD)—had been conceived by Roger Butler, an engineer at Imperial Oil, but it was not an option for operators until horizontal drilling became widely used a decade later.

"There was no horizontal drilling, no 4D seismic, no electric submersible pumps, and no SAGD. You are missing a lot," said Peter Putnam, senior vice president of geosciences at Osum Oil Sands, which is one of two companies that has completed the first pilot project on the largest carbonate formation in Alberta, the Grosmont.

The road to the test site was usable only in winter, said Eddy Isaacs, chief executive officer of Alberta Innovates Energy and Environment Solutions, who was then on a technical advisory committee for the government-backed pilot project looking for ways to make steam injections more effective.

It was expensive to get supplies to that remote location. "When we did a surfactant test, we had to move chemicals in by helicopter to the pilot site. You had to reinject the produced oil back into the ground. There was no way to transport it out. They were locked into the space they had" for much of the year, he said. "The challengers were high, the operational logistics were difficult, and yet there were some successes."

Learning from Buffalo Creek

One of the wells drilled back then—the Buffalo Creek well—is mentioned so often in conversations about current work that it is easy for a newcomer to think it is a recent well, rather than one that stopped producing about 25 years ago.

The method used at Buffalo Creek has been incorporated into the techniques that will be used in the first commercial test of the Grosmont by the joint venture, and the data generated is often used to test formulas predicting how the formation will perform.

Using cyclic steam injection, the Buffalo Creek well produced about 100,000 bbl of oil. The efficiency of the well, as measured by the amount of steam per barrel of oil—the steam/oil ratio—averaged 6 over 10 cycles of steaming. But it got as low as 3.65, which is approaching the level needed for profitable production, according to SPE papers written about the well.

Other wells tested using other methods were considerably less successful. All the available data has been reviewed by researchers at the University of Calgary, who are trying to create computer simulations for bitumen production in carbonates.

"On some cycles, the steam/oil ratio was very high, and some were very good compared to what was going on at Cold Lake" in the 1980s, said Ian Gates, a professor in the department of chemical and petroleum engineering.

The project showed it was technically possible to produce oil from the Grosmont formation, but oil prices were so low then that commercial production was not an option. Unocal began the project when there were predictions of USD 100/bbl oil coming soon. The boom ended in the early 1980s and by 1986, as the project was winding down, oil prices had fallen dramatically.

The pilot was shut down as Unocal closed its Canadian operation, Issacs said. Adjusted for inflation, the value of oil in 1986 would be USD 30 in current US currency. That is well below the cost of in-situ oil sands production now, which the Canadian Energy Research Institute puts at USD 48 for in-situ production at the wellhead, and USD 78 when the cost of diluting bitumen and delivering it to Cushing, Oklahoma, is added in, which was near the price paid for bitumen in western Canada in June.

The value of Grosmont bitumen would be even lower because it is extremely heavy (7 °API) and the lack of pipeline access in what was then a more remote region.

"There was not a road, not a pipeline, not a local market," Putnam said. "In aggregate, it was a science project, not a commercial project."

That project did help pay for a key test of the production method that made the oil sands possible, said Ron Sawatzky, a principal researcher in the heavy oil and oil sands group at Alberta Innovates Technology Futures.

In the mid-1980s, money from the Alberta Oil Sands Research and Technical Authority was diverted from the carbonates test to see what a horizontal well could do in the oil sands. The horizontal shaft was drilled using mining methods because horizontal drilling techniques that are used now were in their infancy.

"That demonstrated it was a technical success," Sawatzky said. Horizontal drilling "provoked a flurry of activity. There was no interest in carbonates when that opened up the oil sands."

Looking back, Jian-Yang Yuan, principal enhanced oil recovery advisory at Osum, said he is amazed by the ambition and the persistence of those working in the 1980s. "The people from that time seem to have more guts than us," he said. **JPT**

Like Other Carbonates, but Different

Getting the crude out of carbonate rock in northern Alberta is a technical challenge that brings together expertise from previously separate worlds.

It combines the engineering expertise needed to heat the ultraheavy crude known as bitumen in the oil sands, which is widely available in Calgary, and knowledge of carbonates, which is not so common.

Formations such as the Grosmont, which holds three-quarters of the more than 400 billion bbl of bitumen in Alberta carbonate, presents unique challenges because the combination of the world's heaviest crude and the history of the reservoir is unique.

There is a heavy oil project that uses heat to extract it from a carbonate formation—the Qarn Alam in Oman, where Petroleum Development of Oman and Shell are producing crude that is light compared with bitumen—16 ºAPI in Oman versus 7 ºAPI in Canada—in a reservoir with natural gas above and water below.

The Grosmont is a dry, low-pressure reservoir with rock made largely of dolomite saturated with bitumen with little natural gas that is nearly immobile at the normal reservoir temperature from 8°C to 10°C.

It also stands out because this shallow formation has been uplifted, eroded, and crushed over time making a complex sort of rock even more so.

The Grosmont formation was formed in the Upper Devonian period from extensive tidal flats off an ancient coast. It spread as the shoreline moved in and out, creating a formation now covering about 15,850 km^2.It was uplifted to the surface leaving it open to water flows that changed the chemistry of the rock, which is now nearly all dolomite, and carved up, leaving holes known as vugs that range in size from pinpoint-sized pores to caves, while also expanding the many fractures.

Later, the formation was buried and the weight of the overburden, which at times included glaciers several kilometers thick, crushed weakened spots and broke up an already jumbled array. Small natural fractures are a common in the Grosmont, which includes large areas where the rock has been broken into rubble, known as breccia.

The result is an unpredictable mix for drillers, who have had to learn how to deal with sections of wells where all the drilling mud flows out of the wellbore.

"It holds 22% of Alberta's bitumen. It is important that we develop this resource for our country," said Chandra Angle, a senior research scientist at CanmetENERGY, who presented a paper on chemical analysis of the heavy crude in the Grosmont at the SPE Heavy Oil Conference held in June in Calgary.

The study showed the bitumen in the carbonates is a bit heavier than is commonly found in the oil sands, though that difference is not expected to affect production. The production from the Laricina-Osum pilot has fetched the same price as heavy oil sands oil, said Heidi Christensen Brown, senior analyst in charge of investor relations at Laricina.

The porosity of the formation ranges from 18% to 30% with an average near the lower end, according to Jinxiu Qi, a senior reservoir engineer at Osum Oil Sands, in a presentation on reservoir modeling at the conference. Studies show that it is highly permeable, but the numbers vary widely. "It is big. It is a challenge to model it. It is complex and hard-to-observe" features, such as vugs are not big enough to show up on seismic images, Qi said.

That paper and others presented at the conference represent work that will provide the foundation for computer simulations.

Laboratory tests now measuring heat transfer properties of the formation will be used to predict how long it will take to heat the reservoir enough to start up production.

Creators of reservoir simulations will need to find a mathematical way to model the web of flow paths in fractures and vugs created by erosion and crushing in a formation with multiphase flows.

A team at the University of Calgary presented an update on its work on object-based geological modeling for reservoir simulation based on core data and well logs provided by Laricina, which is supporting the work, said Ian Gates, a professor in the chemical and petroleum engineering department and leader of the project. They have been unable to obtain the corresponding seismic data, but Gates said they have seen "pretty good matches" of earlier pilot data as they work to understand the nature of flows through the many sorts of features found in carbonates.

Jian-Yang Yuan, principal enhanced oil recovery adviser at Osum, suggested using fractal geometry, which has been used to explain a variety of shapes in nature, from trees to mountains, to identify patterns in the fractured carbonates.

Collin Card, a consultant at Computer Modeling Group, said he had been thinking along the same lines and thought that fractals could be applied. But as with many things entailed with the Grosmont, it was an idea that presented a significant challenge.

Large-scale development of the carbonates will require a way to accurately predict production and costs, because steam projects demand long-term commitment because of the high cost and long lead time required to warm a reservoir enough to start getting oil out.

"Keep in mind with big projects in heavy oil, you cannot turn them on and off," said Ron Sawatzky, principal researcher at Alberta Innovates Technology Futures, adding: once a project goes into production, "You are riding a tiger." **JPT**

For Further Reading

SPE 137941 Evolving Recovery Technologies Directed Towards Commercial Development of the Grosmont Carbonate Reservoirs *by J-Y. Yuan, Osum Oil Sands*

SPE 165560 History Matching Grosmont C Carbonate Thermal Production Performance *by Jinxiu Qi, Osum Oil Sands Corp., et al.*

SPE 165391 Physicochemical Properties of Bitumen and Solids from Grosmont Carbonate Cores *by Chandra W. Angle, CanmetENERGY, et al.*

PETSOC 09-09-26 Prospects for Commercial Bitumen Recovery from the Grosmont Carbonate, Alberta *by Neil Edmunds, Laricina Energy Ltd./University of Calgary, et al.*

IPTC 16802 Rock-Fluid Interactions of a Carbonate Bitumen Reservoir Rock Under Steam-Soak Conditions—Importance of Testing Under Reservoir Temperature and Stress Conditions *by J.W.Dudley, Shell International Exploration & Production, et al.*

PETSOC-2009-144 Drilling Challenges in the Bitumen Saturated Grosmont Formation *by S. E. Arseniuk, Laricina Energy, et al.*

IPTC 16860 Object Characterisation and Simulation of Thermal Recovery from Karstified, Brecciated, and Fractured Bitumen Carbonate Reservoirs *by Ezeuko C.C., Kallos M.S., and Gates, I.D. University of Calgary, Canada*