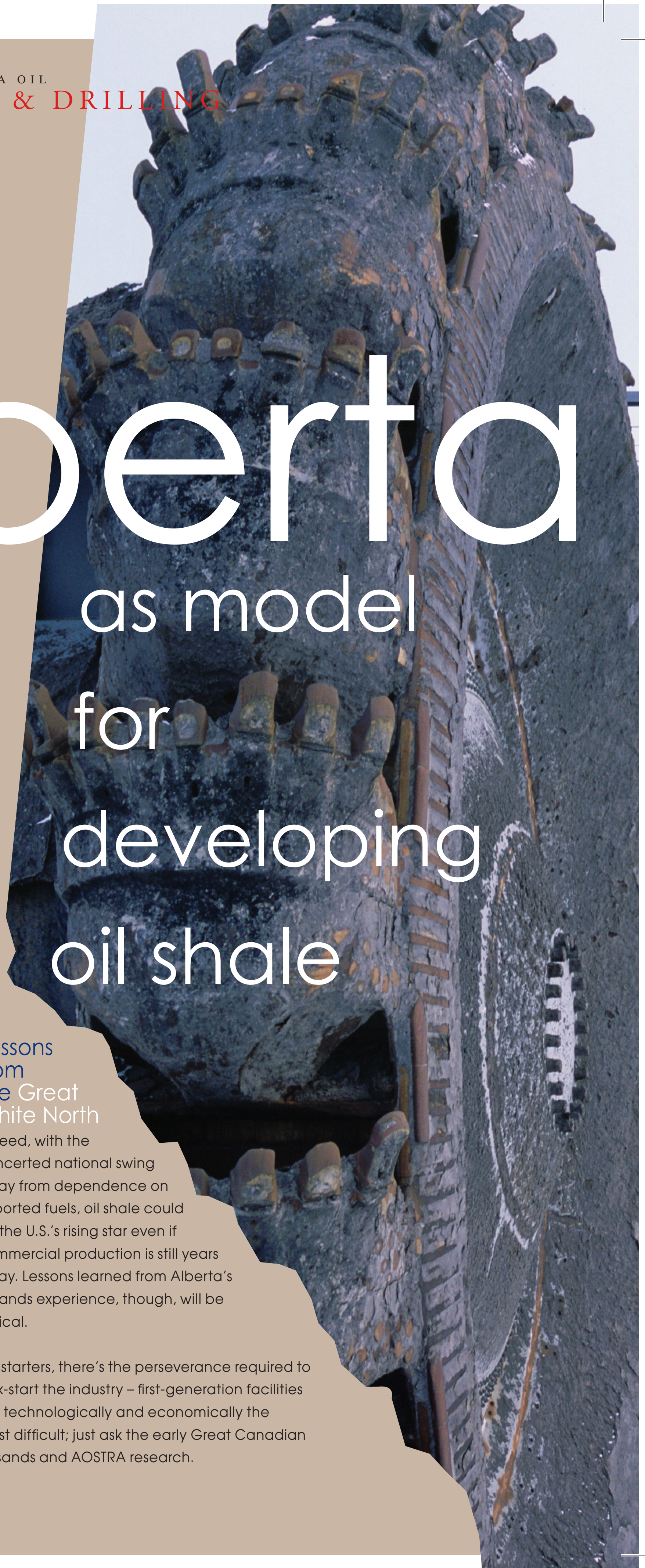
U.S. eyes Alberta as model for developing oil shale



BY GRAHAM CHANDLER

When country rockers Creedence Clearwater Revival immortalized Colorado's Green River back in the sixties, it was about cross-tie walkers and catfish. Now it's the U.S. Department of Energy's turn, but it's not about the bucolics of the region. It's about oil – lots of it in the Green River formation of Colorado, Utah and Wyoming that contains up to 1.8 trillion barrels. The hitch? It's locked in over half of the world's known reserves of oil shale – a sedimentary rock comprising muds and clays that yields oil when heated.

Prompted by President Bush's 2005 Energy Policy Act, the DOE-driven Unconventional Fuels Task Force is taking serious looks at developing the country's 800 billion barrels of recoverable reserves from these deposits. But while there may be another revival afoot in Green River, it's the resources' similarity to the richness, accessibility, production assurance and product quality of Alberta's oilsands that's driving new interest.

"We've recommended that we use the Alberta model as a template," gushes Anton Dammer, Director of the Office of Naval Petroleum and Oil Shale Reserves for the U.S. Department of Energy. "Just as a matter of course we use the Alberta model a lot down here. What Alberta has done is truly remarkable. It's just tremendous to look at and has a number of similarities to our resource."

Including some aspects that even give shale an edge over oilsands. Such as higher area energy density of the oil. According to the *Oil & Gas Journal*, measured on a per-acre yield, about 700 billion barrels of shale oil in the U.S. occurs in concentrations much richer than Alberta oilsands oil – 1.3 million barrels per acre compared to oilsands' average of about 100,000. Higher yields can be expected for oil shale, too: 0.73 barrels per ton versus 0.53 for oilsands.

Lessons from the Great White North

Indeed, with the concerted national swing away from dependence on imported fuels, oil shale could be the U.S.'s rising star even if commercial production is still years away. Lessons learned from Alberta's oilsands experience, though, will be critical.

For starters, there's the perseverance required to kick-start the industry – first-generation facilities are technologically and economically the most difficult; just ask the early Great Canadian Oilsands and AOSTRA research.

Further, much like in the sands, there are two approaches to harvesting oil from shale: mining and in situ.

The mining method is followed by surface retorting to separate the oil from the shale. Previous projects have involved surface retorting – or heating (see sidebar.) But perhaps the most promising retort technology right now is the Alberta Taciuk process, originally developed by Calgary-based engineer Bill Taciuk for AOSTRA and subsequently piloted elsewhere in the world. In 2005, Taciuk's group wrapped up a 6000-ton-per-day test facility in Australia, producing 1.6 million barrels over a five-year project before sponsor Southern Pacific Petroleum in that country ran into financial difficulties and was absorbed into a U.S.-based venture capital fund. The Taciuk Process is also poised to be deployed in China, where Taciuk's company, UMATAC Industrial Processes, is designing another 6000-ton-per-day facility scheduled for operation in 2008. Testing work is also being done in the U.S.

"It's in the process of becoming commercial," says Taciuk, adding his process will produce anywhere from 0.4 barrels to about 1 barrel of oil per ton. "We're certainly in the advanced stages of development."

Not everyone, however, is convinced: a recent Rand Corporation brief estimated crude prices would have to hold steady in the $70-$95 per barrel range to make an oil shale venture commercially profitable. Moreover, they anticipate full-scale commercial surface retorting plants are at least six years away and an industry capable of producing more than a million barrels per day is at least 20 years off.

Light at the end of the electrode

One company active in developing oil shale is more optimistic. For the past two decades, Shell Oil Company has been conducting a small-scale field test in the Piceance basin of northwestern Colorado using an in situ technique that slowly heats the shale with electric power probes. Heating the rock to around 370 degrees C at depths of up to 700 m for a few years causes the raw shale oil, or kerogen, to be released as oil and gas. Heavy compounds partially convert into lighter end products where they are recovered at the surface.

Known as the Mahogany Project, it recently produced 1,700 barrels of 35 API crude and associated gases. Although not commercial scale, Shell is looking to ensure that any of its unconventional hydrocarbon developments "are economically viable at oil prices (per barrel) in the low $30s," says Jill Davis, the Project's Denver-based Public Affairs Representative.

"To date, we have learned a tremendous amount about the technology and its potential to produce oil and gas products from oil shale," added Davis. "We have increasing confidence that the technology could result in responsible oil shale development, but we still have much to learn and demonstrate before any large-scale commercial development commitments can be made."

The advantage of in situ technology, of course, is that it's efficient and environmentally attractive, resulting in an absence of leftover tailings, unwanted byproducts and minimal usage of water. An attractive proposition to be sure. However, there are other environmental considerations like protection of groundwater. Davis says Shell is currently developing and will test what's called a Freeze Wall designed to protect adjacent groundwater.

"The Freeze Wall Test will be used to demonstrate that the groundwater surrounding any potential oil shale development can be protected," she explains. "During the test we will attempt to successfully construct, break and repair an underground ice wall around a notional oil shale production area." It's a long term test, expected to run until 2010, but "it's fundamental to demonstrating the successful environmental protection of groundwater during any potential future oil shale commercial development," says Davis.

The Alberta advantage

And when it comes to environmental protection, DOE's Dammer admires the operations and methodologies of Alberta's institutions, especially the EUB. "That's one of the very novel institutions that was really able to overcome a lot of the barriers," he says, pointing to the necessity for communications amongst stakeholders. "You find in developing big projects that, a lot of the time, the biggest problem is communications and understanding the problem. There are just so many myths and misconceptions about developing projects of this scale that people don't understand. And there are no processes to work through these things. In terms of bringing the public, the state, the feds and the industry together so they can work through development problems in a meaningful way – I think that is one of the largest successes of the Alberta model."

The admiration notwithstanding, Dammer realizes there are also a number of philosophical differences – including the two countries' approaches to government involvement.

"There are quite a few differences," he says. "In fact, I don't think we can take the Alberta model lock, stock and barrel. We simply won't be able to do that because the rights and prerogatives your provincial government has are considerably different from our state governments. On federal lands it's kind of the same but what you have in Alberta is the owner of that public land is generally the province of Alberta."

Still, Dammer likes the way Alberta has demonstrated that if you're going to develop large unconventional processes, it's going to take time.

"This is a two decade play for any appreciable amount of production, so it's most important to protect the local population," he says, and gives an example of past failings with local sentiment. "I had a breakfast a couple of weeks ago in Rifle, Colorado and they're still talking about Black Sunday when the company pulled the plug on their project. How economically destructive that was and how much pain that caused. That's something we can prevent this time around. In the 80s it was almost a gold rush mentality and that just doesn't work in this society any more just like it wouldn't work in Canada any more. I think what we can bring to this process is the Alberta approach." Dammer says the second big lesson the U.S. can learn from the Alberta model is, "don't let oil prices scare you away." He says everyone walked away from the industry in the 1980s when the Saudis dumped oil on the market. "A lesson from Canada," he says, "is you guys stuck with it. And today Alberta is realizing tremendous mineral wealth. We shouldn't allow the inevitable to guide us into crisis-type development."

Dammer said a "realistic" timeline for development has 2.5 million bpd coming on stream by 2035 after about six years of development and something like 300,000 bpd produced after the first couple of years.

"A million and a half by 2025," says Dammer, "but I'd be cautious – this is just a development model, not a policy of the federal government. The only valid thing is we feel certain it can be achieved given the resources available (manpower, capital, materials) and the magnitude of the resource itself."

And here, too, Dammer looks to Alberta, in this case in what not to model – namely, an ambitious expansion with it's attendant labour and supply shortages.

"How many Caterpillar trucks can you build, how many tires?" he says. "Can you get pipe fitters?" AO

Oil Shale History in the Green River Basin – HIGHLIGHTS

1910–1912 Colorado residents stake first oil shale claims.

1912–1916 U.S. Geological Survey reconnaissance team estimates 40 billion barrels of oil recoverable from Green River shale formation.

1917 First oil shale retort (kiln) in Colorado.

1924–1929 U.S. Bureau of Mines produces 3,600 bbl of oil from an experimental retort

1944-1956 Experimental extraction technologies funded by U.S. Synthetic Liquid Fuels Act at Anvil Points; some production

1955–1961 Union Oil of California (Unocal) builds oil shale plant north of Parachute, Colorado. Plant operates for 18 months and produces as much as 800 bpd. Operation is shut down due to operational problems and price uncertainties.

1964–1972 The Oil Shale Company (Tosco), along with partners Sohio and Cleveland-Cliffs, builds and operates the Colony oil shale plant 17 miles north of Parachute, and produce 270,000 bbl by 1972.

Early 1970s Shell conducts in situ steam injection research in oil shale and nacholite located along Piceance Creek, Colorado.

1966–1982 PARAHO Company, in partnership with 17 other companies and the U.S. federal government, operates new Anvil Points facility. Retort problems and high costs force the program to close.

1974 Federal government agrees to lease two tracts of oil shale lands in Piceance Creek Basin, Colorado. Shell and Ashland Oil join Colony project.

Late 1970s Shell, Ashland Oil, Cleveland-Cliffs and Sohio sell out of Colony Project, leaving Arco and Tosco each with 50 per cent interest.

1980 Congress approves $14 billion for synthetic fuels development. Exxon buys Arco's interest in Colony project. Exxon and Tosco begin construction of Colony II, which produces 47,000 bpd by 1987. Amoco produces about 1,900 bbl of in situ shale oil.

1982 World oil demand drops dramatically.

1982 On "Black Sunday" (May 2nd), Exxon announces closure of Colony II project, citing higher than expected construction costs and lower demand for oil.

1985 Congress ends funding under Synthetic Liquid Fuels program.

1991 Occidental Petroleum announces closure of project near Rio Blanco. California's Lawrence Livermore National Laboratory plans to build $20 million experimental oil shale plant at Parachute.

1993 U.S. House of Representatives ends funding of additional oil shale tests to Lawrence Livermore Laboratory.

2000–present Shell conducts in situ heating technology research program at its Mahogany oil shale property.

(adapted from *Western Colorado Oil Shale: A Chronology*, Shell Oil Company)