Problemen med utvinning av oljesand i Canada

Shells gigantiska projekt i Canada

I Canada finns verkligt stora fyndigheter av oljesand. Till skillnad från en oljekälla i Mellersta Östern, som sprutar enorma mängder av sig själv, måste man här gräva, frakta och behandla oljesanden med värme (energi) i stora dyrbara anläggningar innan man kan få fram oljan i ren form.
Även om fyndigheterna är mycket stora är detta knappast till någon glädje. Ingen gläds över att den sammanlagda mängden guld och diamanter i jordskorpan är mycket stor. Det gäller också att kunna ta fram dessa tillgångar.

När det gäller svåråtkomlig energi – t ex i oljesand eller fyndigheter i djuphav eller polarområden – så motverkas möjligheten till utvinning genom lågt s k EROIE –värde. Detta värde anger hur mycket energi man får i utbyte i förhållande till hur mycket man måste sätta in. Oljekällan i Kuwait har ett mycket högt EROIE. När värdet sjunker under 2 börjar det bli problem. Oljesanden har ett EROIE vid ca 1,5 i ett gynnsamt fall, vilket det är i början. Man exploaterar först det som är enklast att få tag i, ungefär som när man plockar bär i skogen och kan sitta stilla på en tuva. Efter hand får man gå allt längre sträckor innan man hittar bär och den energi man förbränner i kroppen är kanske större än den energi som kommer med sockret i bären. Därför bli utvinning av oljesand troligen ganska snart meningslös, då EROIE kryper mot 1.
Observera att man vid EROIE 1,5 kommer att förbränna 2 liter olja/gas för att få ut 3 liter olja. Dvs utsläppet av växthusgaser växer kraftigt med allt lägre EROIE-värde.

Nu tillkommer det ytterligare två problem. Dels har det enligt en av nedanstående artiklar visat sig att utvinningen av oljesand skadar utvinningen av naturgas, som är en viktig del i både det kanadensiska och amerikanska energisystemet – t ex för elektricitet i USA. Men även förbrukningen av gas blir så stor så att hela den gasledningen **Mackenzie Pipeline Project** kommer troligen att tas i anspråk. Annars har stora förhoppningar knutits till denna för att mildra den ansträngda gassituationen i Nordamerika.

Men det avgörande problemet är storleksordningen. Trots att Shells satsningar i Canada och oljesanden är enorma och ett av världens största industriprojekt, är detta nästan betydelselöst när det gäller att kompensera för den kommande oljebristen.

Den globala förbrukningen av olja ligger idag vid ca 80 miljoner fat per dygn. Enligt en av artiklarna nedan ligger den förväntade produktionen vid ca 100.000 – 150.000 fat per dygn år 2015 för en anläggning. Detta motsvarar drygt en promille av världens efterfrågan idag. Sammanlagt för hela Canada idag har också siffror vid 500.000 fat per dygn nämnts, dvs ungefär en halv procent av den globala efterfrågan.

Andra siffror anger att produktionen av olja från oljesand år 2025 totalt kan väntas ligga vid 2 miljoner fat, medan utvinningen från enbart Nordsjön då har minskat med kanske 4 miljoner fat per dygn. (Nordsjöoljan är redan på tillbakagång).

Bilagor om utvinningen av oljesand i Canada

SvD 3/9 2003

Kanadas skifferolja en okänd, omstridd reserv

OSLO Vilket land har världens näst största oljereserver? För ett halvår sedan hade rätt svar varit Irak, vars reserver uppskattas till 112 miljarder fat, jämfört med Saudiarabiens 259 miljarder fat. Men vid årsskiftet ökade Kanadas oljereserver med 3 600 procent, från fem miljarder fat till 180 miljarder fat. Den enorma ökningen skedde relativt obemärkt, eftersom världens och oljemarknadens ögon var koncentrerade om uppladdningen inför USA:s invasion av Irak. Vad det handlar om är att tidskriften Oil & Gas Journal, en av de viktigaste statistikkällorna i oljeindustrin, ändrade sin uppfattning om Kanadas enorma reserver av skifferolja. Från att ha klassats som "okonventionell" energi betecknas den nu som "konventionell". Detta beror på att det under senare år har det gjorts stora framsteg i att sänka kostnaderna för att utvinna skifferoljan.

Jämfört med att pumpa upp olja från Saudiarabiens enorma oljefält, vilket kostar ungefär två dollar per fat, är kostnaderna för att utvinna skifferolja fortfarande höga. Kapitalkostnaderna uppskattas ligga mellan 5-9 dollar per fat, medan produktionskostnaden varierar mellan 8 och 12 dollar per fat. Priset varierar därmed mellan 13 och 21 dollar per fat. Det kan jämföras med världsmarknadspriset för olja på ungefär 30 dollar per fat.

Skifferoljan ligger under jorden som bitumen, en mycket trög, asfaltliknande substans, som det finns två sätt att utvinna. Antingen kan det ske genom dagbrott, eller också genom att oljesanden hettas upp eller späds ut med kemikalier så att den blir tillräckligt flytande för att kunna pumpas upp. Bägge metoderna har stora miljömässiga nackdelar. Dagbrotten kräver att två ton med tjärsand grävs upp för varje fat (159 liter) olja som produceras. Bara en femtedel av de reserver av skifferolja som finns, kan utvinnas med den tekniken. En armé av lastbilar, grävmaskiner och bulldozers, som i sig själv kräver en stor mängd energi, behövs för att schakta massor som skulle fylla en fotbollsarena av största sort varannan dag. Efter att skifferoljan utvunnits krävs samma operation för att fylla igen dagbrottet och återställa naturen. Att använda ånga eller kemikalier för att göra bitumen flytande innebär å andra sidan stora risker för att grundvattnet ska skadas. Ytterligare energi, oftast i form av naturgas, används vid raffineringen av skifferoljan. Det betyder att om olje- och naturgaspriserna ökar, blir kostnaderna för att utvinna skifferoljan också högre.

I dag producerar Kanada 700 000 fat skifferolja. Mer än hälften, 400 000 fat, kommer från den dyrare metoden med dagbrott. Den kan bara användas när tjärsanden inte ligger djupare än ett 50-tal meter under jorden. Ser man på Kanadas energiprognoser på lång sikt räknar myndigheterna med att produktionen 2025 kan uppgå till 2,2 miljoner fat olja per dag, eller drygt två tredjedelar av vad Irak producerade innan Saddam Hussein störtades.

Ett tecken på att energiformen ses som allt mer kommersiell är att delstaten Alberta nu krävt att 938 naturgasbrunnar ska stängas för att produktionen från gasfälten kan göra det omöjligt att utvinna skifferoljan i framtiden. Förekomsterna av bitumen ligger i dessa fall under naturgasreservoarerna. Om inte naturgastrycket upprätthålls, kan den heta ångan försvinna upp i reservoaren, Det blir då omöjligt att utvinna skifferoljan, anser energimyndigheten, som påpekar att energimängden som därmed riskeras är 600 gånger större än energin i naturgasen i de fält som berörs. Även om alla de 938 naturgasbrunnarna stängs innebär det inte någon dramatisk förändring i utvinningen av naturgas i Kanada. Det finns nästan 70 000 naturgasbrunnar i delstaten Alberta.

Björn Lindahl

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Från BBC World Services:

The Athabasca oil sands project in Canada shows that Shell still places great faith in the potential for traditional fossil fuels, despite its stated desire to develop renewable energy. The project involves one of the largest construction sites on the planet, employing 14,000 workers. Shell is investing 2.3 billion Canadian dollars to bring it to fruition.

But extracting oil here is several times more expensive than from a conventional well. In a world where oil prices regularly rise and fall by large margins, and which could fall dramatically if Saddam Hussein were deposed in Iraq, can Shell be confident that it will always make a profit?

Shell Canada's Rob Seeley, Manager of Sustainable Development, told the BBC that even if the oil price fell to 10 dollars a barrel, dangerously close to the basic cost of recovering oil from the oilsands, the Athabasca project would be able to continue.

"The oil sands are a long term game' Seeley states, 'so at this point we've already committed our $6 billion and our oil pricing forecasts tell us that it wouldn't stay that low for a long time. The average pricing for crude oil in the world is probably closer to the $18 mark. If it dips into the lower range, we keep running the facilities. We have to keep running it. We have to continue to use the asset."

But Shell has many other concerns beyond making a simple profit. It's had to negotiate deals with indigenous people in the region, whose economy, based around fur-trapping, has suffered massively as a result of the anti-fur movement.

Shell has therefore been helping local people to set up a company operating trucks on the mine site, as part of business opportunities connected to the mine potentially worth millions of dollars.

The treatment of indigenous peoples is a sensitive subject. In the mid-nineties Shell came in for fierce criticism for its treatment of the Ogoni people in Nigeria, whose violent protests eventually forced Shell to abandon its oil wells on their land. In Canada, it seems, Shell is managing to keep peace with its neighbours.

The company also maintains ongoing consultations with local environmental groups over the impact of the Athabasca project. Gail McCrimon from the environmental consultancy the Pembina Institute, said Shell is getting better, but must do more.

"The problem that we have', McCrimon says, 'is that overall industrial development on a global basis is not sustainable, and so whatever Shell does, they have to do thinking over the long term and not just the short term. So they need to do more of what they're trying to do now, which is to be more efficient, and to cause the least possible disturbance that they possibly can."

Shell is performing a difficult balancing act in a world which is ever more hungry for energy. It knows that the biggest profits are still to be found in fossil fuels. But it also knows that it must be seen to be paying heed to environmental and social concerns, and keeping a hand in the rapidly developing technologies of renewable energy.

If it fails to balance these interests, its long term future may be in jeopardy.

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Artikel i tidningen Calgary Herald i Canada

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Oh, how the patch has changed
Technology, finances revamp landscape

Scott Haggett
Calgary Herald

Saturday, August 02, 2003

Intermediate producers are gone, senior companies are significantly altered and significant growth is very expensive in today's Canadian oilpatch.

Time Marches On: The past decade has seen a revolutionary change in the nature of the Canadian oil industry.

It's just not the oilpatch it once was.

The past decade has been marked by a revolutionary change in the nature of the Canadian oil industry. The intermediate producers are gone, the senior companies are vastly altered and significant growth has become hard to come by and very, very expensive.

It's a radical revamping of the industry brought on by massive technological and financial change, as well as the depletion of Western Canada's conventional oil and gas reserves.

"The fact of the matter is that the basin is maturing and all the low-hanging fruit has been picked," says Raymond Chan, chief financial office of Baytex Energy Ltd., a mid-sized heavy oil producer that's in the middle of converting much of its operation into an income trust. "What's left is the megaproject."

Growth in Canada's petroleum industry has moved to the extremes. Now, boosting output is a game for the entrepreneurial junior companies that can double in size with one successful well, or the massive senior producers who have moved into the oilsands to add tens of thousands of barrels a day of production at a cost of billions.

Shell Canada Ltd.'s Athabasca Oil Sands Project cost $5.7 billion. While two other partners each have a 20 per cent share, financing the 155,000-barrel-a-day megaproject would more than stretch the resources of a smaller firm.

In many ways, oil and gas production outside of the junior companies is moving toward a manufacturing model, where the challenge is no longer exploration but financing the long run up to production of an oilsands or coalbed methane project -- both can add significant new production but require much patience and much capital.

"The growth in Western Canada is coming from oilsands and, three to five years down the road, coalbed methane," says Brian Prokop, an analyst with Peters & Co. in Calgary.

For the companies in the middle, there's very few options -- they can struggle to find enough conventional petroleum to have an impact on their production, they can, like Baytex and most of its peers, convert to an income trust or find backers with very deep pockets form a large-scale steam-assisted gravity drainage (SAGD) bitumen project or an oilsands mine.

"SAGD requires hundreds of millions or billions in investment," Chan says. "We weren't of a size to commit that . . . The industry has become a game of the really big companies or small companies that don't do something big to boost their growth."

The fact of the matter is conventional oil production in Western Canada has been declining for the better part of the past decade. Growth has come from the oilsands or from the province's abundant heavy oil deposits.

It's the same situation for the natural gas industry. It's now been a couple of years since anyone found a really big pool of natural gas.

The last big discovery was the Ladyfern field in northeastern British Columbia. The field had initial reserves of more than half-a-trillion cubic feet of gas but has declined rapidly.

Where it once produced 700 million cubic feet of gas a day just more than a year ago, its output is now about a third of that.

"Ladyferns are wonderful when they happen but discoveries of that size are very rare and anomalous in our industry," says Steve Savidant, chief executive of Esprit Energy Ltd., one of the few remaining mid-sized gas producers. "I think anyone who is out there would agree that the size of the gas pools we are finding has shrunk significantly."

Savidant, one of the petroleum industry's most seasoned executives, says that a few decades ago, it wasn't hard for for a gas company to tap into a field 10 billion or 20 billion cubic feet in size.

Those have now become rare. Instead producers are more likely to find fields of two billion cubic feet or less.

It makes it a challenge to grow. For him, the answer is to shape a company that can prosper from small finds. Savidant expects than mid-sized Esprit can grow for the next decade at least from finding conventional gas deposits.

However for larger companies that need more sizeable discoveries in order to offset declining production from existing fields. the only route to expanding their Western Canadian gas production may mean moving to coalbed-methane production.

An number of big firms, like EnCana Corp. or Nexen Inc. or Devon Canada Corp., have started coalbed methane pilot projects, while others are toying with the idea. The gas comes from deposits associated with the coal reserves that are ubiquitous in Western Canada. However production from a single well is low, so a lot of drilling is required, and it can sometimes take years to de-water the coal deposits so that the gas can be produced.

It's an expensive proposition but, much like the oilsands, high prices for gas can make the economics of such projects seem reasonable. And again like the oilsands, it's not finding the resource that's the trouble, it's having the pockets and the patience to be able to produce it.

"I don't disagree with the people who are getting into coalbed methane," Savidant says.

"But we don't have to get into it yet. Coalbed methane is very much like the oilsands industry 25 years ago, when Suncor (Energy Inc.) had a small project and Syncrude was just getting ready to go into production."

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Bitumen recovery at risk in northern Alberta: Conoco

James Stevenson
The Canadian Press

Saturday, August 02, 2003

Alberta Energy and Utilities Board chairman Neil McCrank is the author of a report that suggests "there is an immediate and continued risk to bitumen recovery from the production of natural gas from an area of concern within the Athabasca oilsands area."

Sue Riddell Rose, president of Paramount Resources, says evidence is inconclusive in showing there is interaction between gas reservoirs and nearby oilsands deposits when they are injected with steam.

Massive oilsands deposits in northern Alberta would be rendered inaccessible with current technology if nearby natural gas reserves are removed, energy giant ConocoPhillips said Friday.

Releasing hundreds of pages of previously confidential documents, ConocoPhillips said years of study at its Surmont oilsands pilot project northeast of Edmonton prove steam pressure is not contained by rock layers underground.

And if the gas is removed, the pressure levels would be too low to extract the oilsands feedstock, or bitumen, with existing technology, the company said.

The ConocoPhillips data echoes the belief of Alberta's energy regulator, which decided last week to shut in 938 gas wells by September to protect the underlying bitumen.

"We can't rely on shale layers as a seal to keep steam pressure up in the chamber," said Tom Trowell, manager of ConocoPhillips Surmont project.

"And we now know that steam does get around or through these layers to the gas above."

The Alberta Energy and Utilities Board "believes there is an immediate and continued risk to bitumen recovery from the production of natural gas from an area of concern within the Athabasca oilsands area," it said in a written ruling released in late July.

The previously confidential ConocoPhillips report has long been sought after by natural gas producers in the area, led by Paramount Resources, which claims that up to half of its production could be affected by the shut-in.

Paramount said Friday that it was waiting to fully review the ConocoPhillips data before commenting.

President Sue Riddell Rose has previously said scientific evidence to date is inconclusive in showing there is interaction between gas reservoirs and nearby oilsands deposits when they are injected with steam.

ConocoPhillips says that isn't the case.

"Anyone who claims that the steam hasn't reached the gas is being premature," said company spokesman Peter Hunt.

By releasing its data, the Texas-based oil and gas company runs the risk of getting dragged back into the heated debate between oilsands producers, gas producers and the province of Alberta, which claims it wants to protect the resource for maximum benefits.

ConocoPhillips joins the ranks of other large oilsands producers, like Petro-Canada, in supporting the shut-in of gas production in the area.

Those fighting the order are a variety of gas producers ranging from Paramount and other smaller companies all the way to global giant BP.

The dispute is so heated that anyone not directly involved is loathe to take sides.

"This is kind of a dogfight that we're not involved in," Rick George, president of oilsands giant Suncor Energy, told analysts this week.

"And if you're not involved in a dogfight there's no reason to go in one."

The shut-in affects about 90 billion cubic feet of gas, or about two per cent of Alberta's remaining reserves.

Conversely, the Alberta Energy and Utilities Board says the amount of bitumen in the area is about 600 times larger.

ConocoPhillips says its Surmont lease alone is roughly the size of the city of Calgary, with an estimated average bitumen thickness of a 10-storey building.

The company also says that if Alberta hadn't ordered the shut-in of wells on the Surmont release back in 2000, its pilot plant would not have been as successful as it has been.

As a result, ConocoPhillips, along with partners TotalFinaElf and Devon Energy, are poised to make a go-ahead decision on a Surmont megaproject before the end of this year that would cost about $1 billion and produce around 100,000 barrels per day by 2014.

Following a meeting this week with all affected companies, Alberta's energy regulator ordered a regional geological study -- to be completed by December -- in order to closely assess which gas pools in the area are in close contact with bitumen deposits.

Alberta's energy department has also begun meetings on the issue, looking at possible compensation for affected gas producers. Paramount has warned that this could end up costing the province hundreds of millions of dollars.

Greg Stringham, vice-president of the Canadian Association of Petroleum Producers, says the geological study is crucial in determining the full impacts of the shut-in.

And Stringham said there are a number of other tests continuing from companies like giant EnCana Corp. looking at repressuring reservoirs with waste gas or even putting pumps at the bottom of the well to pump up the bitumen.

"I think that's where the real answer to this dilemma lies, it's not in the back and forth between the companies, it's how do we apply technology so that both of the concerns can be resolved."

Subject: Lehman: Oil Sands Projects May Consume Entire Mackenzie Pipe Supply

NGI's Daily Gas Price Index
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Lehman: Oil Sands Projects May Consume Entire Mackenzie Pipe Supply
While the proposed 800-mile Mackenzie Delta gas pipeline project in Canada's Northwest Territories has often been cited as a solution to the North American natural gas supply problem, the initial 1.2 Bcf/d of gas transported on the line may end up being consumed by oil sands projects in northern Alberta, according to a new report by Lehman Brothers analyst Thomas Driscoll.

Driscoll calculates that future oil sands projects, including the Horizon, Muskeg River and Syncrude bitumen mining projects and the Voyager, Kearl Lake, Lewis Creek and Meadow Creek steam assisted gravity drainage (SAGD) projects could consume about 1,173-1,520 MMcf/d of gas by 2010. He estimates that 514,000 b/d of bitumen will be produced by 2010 through the mining process, requiring about 257-360 MMcf/d of gas. In addition, about 610,000 b/d of bitumen will be produced through SAGD, requiring 916-1,160 MMcf/d of gas.

According to Lehman Brothers' estimates, the average SAGD project uses 1-1.2 Mcf of natural gas for every barrel of bitumen produced in the steaming process, and the average mining project uses 0.5-0.7 Mcf of gas per barrel of bitumen produced. By 2012, up to 1.1 million b/d of bitumen may be under production and upgraded into synthetic light oil by natural gas-consuming oil sands projects, requiring as much as 1.5 Bcf/d of gas.

In addition, Mackenzie pipeline project developers also have promised to create markets along the pipeline route to enable regional communities to purchase some of the natural gas.

"While a first test of demand provides support for initial capacity of 1.2 Bcf/d, we estimate that all of the incremental production could be consumed by oil sands projects, thus providing no relief to tight North American natural gas markets," Driscoll said.

However, he notes that Devon currently is pushing for the project to have much larger pipeline capacity of 2.3 Bcf/d. A substantial amount of supply exists for the project to grow. There are an estimated 67 Tcf of recoverable reserves in the region, according to the Geological Survey of Canada. Only 9 Tcf has been discovered to date.

About 6 Tcf of the discovered resource is located in the three onshore fields that will anchor the pipeline project: Imperial Oil's estimated 3 Tcf Taglu field, ConocoPhillips' 1.8 Tcf Parson's Lake field (ExxonMobil holds 25% working share), and Shell Canada's 1 Tcf Niglintgak Field. Significant gas discoveries also have been made in the shallow waters of the Beaufort Sea, including the 1.5 Tcf Amauligak field by Gulf Canada, which is now owned by ConocoPhillips.

Meanwhile, substantial progress has been made on the pipeline with a commercial agreement recently signed between producers, northern

Aboriginal groups and TransCanada PipeLines, which has agreed to fund the Aboriginals' portion of the project.

The pipeline is expected to cost C$5 billion and is slated to be in service sometime between 2008 and 2010. However, Driscoll notes that substantial risks to project development remain. The regulatory review and environmental impact assessment could extend into 2006 and require 500-600 separate approvals. Native groups or individuals also may step in to try and block the project.

Once the project makes it through the regulatory process, the construction phase also may prove to be tricky, requiring at least two full winter-only construction periods. Missing one winter could delay the project an entire year. Driscoll believes there also is the potential for labor shortages and cost overruns, particularly if producers decide to build a parallel liquids line to Norman Wells from Inuvik.

Nevertheless, if project developers are able to cross all hurdles, their supply could be quite competitive in the North American gas market. According to Lehman Brothers, Mackenzie Delta gas could sell at roughly a US$1.30-1.50/MMBtu discount to the Henry Hub and roughly a US$0.70-0.80 discount to AECO. Tolls are expected to be about US$0.70-0.80/MMBtu from Inuvik to an interconnect with TransCanada PipeLines in northern Alberta. It typically costs US$0.20-0.25/MMBtu to ship gas through the province.