# UNITAR

## Alberta's Oil Sands: The New Paradigm

Paul Precht and Carmen Rokosh, Alberta Department of Energy

### Historical Perspective

Many observers believe oil sands development in Alberta is now poised to enter a period of unprecedented growth and expansion. Similar expectations of growth have arisen in the past, but not to this level and not all have been realized. This paper will examine the basis for current development plans and why we believe these expectations are more realistic and sustainable.

For many years Alberta's oil sands have been recognized as a key strategic resource in Alberta's and Canada's energy and economic future. Alberta's oil sands underlie approximately 77,000 square kilometers, and contain some 1.7 trillion barrels of oil, of which approximately 300 billion barrels are believed to be ultimately recoverable. The oil sands are contained in three major areas within Alberta: Athabasca, Cold Lake, and Peace River (Figure 1). Alberta's oil sands are not included in aggregations of world oil reserves, such as in the BP Statistical Review of World Energy, as Alberta does not have comprehensive information on proven oil sands reserves. Alberta's Energy and Utilities Board (AEUB) publishes information on proven petroleum reserves periodically, however the number for proven (or established, as defined by the AEUB) oil sands reserves significantly understates the total, as it is largely based on reserves associated with existing approved projects.[1] This ignores a significant quantity of reserves that are now the basis for planned expansions or proposed new projects and further ignores reserves in those areas for which projects have yet to be proposed. A reliable quantification of these reserves is difficult because of the magnitude of the resource and the uneven knowledge on resource quality in various parts of the oil sands deposit. However, current development plans and activities are likely to lead to better information and identification of proven reserves. Because the published proven reserves numbers significantly understate the actual, we frequently refer to the ultimate potential.[2]

Notwithstanding uncertainty about the exact magnitude of the proven portion of the resource, the existence of the resource, and the fact that it is enormous, has been known for decades. Development of the oil sands has always captured the interest of entrepreneurial and innovative thinkers, but has traditionally been constrained by challenges of technology and economics. A history of oil sands development in Alberta was provided in a 1988 UNITAR paper[3], so references here will simply be to highlight and summarize some of that.

Alberta has been a major petroleum producer for many years, and especially since 1947 which was a pivotal year in terms of discovery of conventional crude oil reserves. Alberta is the major petroleum producing province in Canada, and traditionally has accounted for over 80% of Canada's oil and gas production. Production from Alberta's conventional crude oil reserves peaked in 1973, however declines since then have been largely offset by growth in production from the oil sands (Figure 2). In 1997, Alberta's total liquid petroleum production was just slightly lower than in the peak year of 1973. In 1998 we expect to exceed that 1973 threshold, and it is because of the oil sands that Alberta production is again on the increase.

Figure 3 shows historical production of bitumen and synthetic crude oil (SCO) from Alberta's oil sands and provides a good history of development in the industry, including some lessons that go with that history. Surges of oil sands activity occurred

[1] The paper by Houlihan and Sadler, in these Proceedings, will address the oil sands reserves issue more fully.

[2] The ultimate potential of crude bitumen reserves is defined by the AEUB in Alberta Reserves, 1996 as "the established reserves that will have been developed in an area by the time all exploratory and development activity has ceased, having regard for the geological prospects of that area and anticipated technology and economic conditions".

[3] Precht, Sullivan, and Kahler.

during the 60's and 70's, with the development of two major integrated oil sands mining, extraction and upgrading projects. The 80's can perhaps be best characterized as a period of modest development coupled with a number of false-starts. The 90's have shown considerably greater promise. By 1997, production of bitumen and SCO reached approximately 528 thousand barrels per day (mb/d). This represented 33% of Alberta's and 25% of Canada's total liquid petroleum production.

**Pioneers of Commercial Development in the 60'sand 70's - Suncor and Syncrude**

Suncor (then known as Great Canadian Oil Sands (GCOS)) was the first commercial producer from the oil sands, having commenced production in 1967. Its production was initially modest, which is not surprising given the unprecedented nature of the production technology of that project. Suncor officials today would tell you that the economics of that operation were not particularly attractive in those early years. The increase in production (Figure 3) that is seen in the late 70's is the commencement of Syncrude's project. The GCOS investment and Syncrude's initial investment decision were both made at a time when Canadian crude oil prices were less than $3/bbl [4,5]-- although the first OPEC price spike of 1973 occurred while Syncrude was in the early stages of construction, and the price spike associated with the Iranian crisis occurred just after Syncrude commenced production. We make this point to illustrate that these were pretty bold and visionary investors. Syncrude benefited by learning from the pioneering work at Suncor, but even Syncrude would likely concede that it was not a roaring success in its early years, measured by return on capital employed, for example. Yet, Syncrude continued to grow throughout the 80's as it continued to make investments that increased its production and improved its economics.

**Mega-Project False Starts in the Early 80's - Alsands and Esso Cold Lake**

During the late 70's, there were high expectations for oil sands development to take-off. Oil prices were growing at an unprecedented rate and there was a widespread view that the global economy would face increasing resource scarcity, which could only result in continued price growth. There was also pressure in the western world to reduce dependence on OPEC for oil supplies. In this atmosphere, two mega-projects were proposed for Alberta's oil sands. The Cold Lake project was an *in situ* project to be developed by Imperial, the Canadian subsidiary of Exxon, and the Alsands project was a mining project to be developed by Shell Canada. Both were integrated projects (i.e. bitumen production and upgrading), with intent to produce in the range of 140 mb/d of SCO. While both were driven by the price expectations of the time, they were also tempered by the concomitant inflationary expectations, which resulted in capital cost expectations reaching in the range of $13 billion per project. The projects were delayed by Canadian energy policy uncertainty, and finally derailed by the plateauing of prices and the deflated price expectations of the early 80's. In retrospect it may have been just as well they didn't proceed, as they may not have been viable following the price collapse of 1986.

**Small scale Projects of the 80's - *In Situ* Bitumen Production**

Evident from Figure 3, in the mid-80's, is a growing tranche of bitumen production from *in situ* projects, mostly in the Cold Lake area, and dominated by a scaled-down, non-integrated version of Imperial's Cold Lake project. Canada's regulated prices of the early 80's did not provide the differentials[6] to support upgrading. Consequently, many producers initiated smaller bitumen projects, which did not require investment in upgrading, and by their nature were more amenable to development in smaller modules. The converse of narrow differentials was high bitumen prices which attracted bitumen investors. Many of these *in situ* projects were conceived and initiated prior to the oil price collapse of 1986 and ultimate development plans were typically quite ambitious. Most were never fully realized as a consequence of the 1986 world oil price collapse and the wider differentials that arose from price deregulation in Canada.

**Expected Mega-Project Resurgence of the Late80's - OSLO and BPU**

The late 80's was another period of high expectations for significant oil sands growth. The most high profile projects being touted at that time were the OSLO (Other Six Lease Operators) project and the Bi-Provincial Upgrader. OSLO was a consortium of 6 companies, and had plans for a 130 mb/d integrated oil sands project. The Bi-Provincial Upgrader was a 50 mb/d stand-alone upgrader to convert heavy oil and bitumen to SCO. The economics of both projects was levered by significant government equity and fiscal concessions. Detailed engineering was completed for the OSLO project, but it was never constructed as it was not viable even with government support. The Bi-Provincial Upgrader was constructed, but experienced significant cost over-runs during construction. It

[4] All monetary figures are expressed in Canadian dollars, unless otherwise specified.
[5] $3/bbl denotes 3 dollars per barrel.
[6] The differential refers to the difference between light and heavy crude oil prices.

commenced operations at a time when differentials were at an historic low, so it was not able to cover its operating costs for the first few years of operations.

## The New Paradigm

No major new mega-projects have been constructed to date in the 90's. But this period shows growing oil sands production as a result of continuous growth of existing projects and many new *in situ* projects. The production growth in recent years is impressive (Figure 3). What is more impressive, however, is the spate of announced intentions to expand existing projects and/or develop new projects. Oil sands development in Alberta now appears poised for a major take-off. This development is based on a new paradigm and it is on this period that we want to focus. We have traditionally viewed oil sands development prospects with cautious optimism and lamented the slow pace at which development appeared to be occurring. In the past, governments were willing to intervene directly to seek to provide the impetus needed for development. However, it is contrary to current Alberta government policies to invest public funds into these types of projects and oil sands development in the 90's is being financed solely by private corporations. Today's outlook is not only much more bullish, but is based on a set of circumstances that allow a great deal of confidence that the current outlook is realistic and realizable. We used to speak of *when*, not *if*, the oil sands would be developed. The new paradigm is that the *when* is *now*, and it is being financed by the private sector, not the public sector.

## Indicators of Recent Activity in Alberta's Oil Sands

Today's revived interest in Alberta's oil sands resources is evidenced by several measures, which indicate the magnitude of both current activity levels and prospective development.

### Oil Sands Land Sales

An indicator that we track in the Energy Department is public land sales of oil sands rights. Almost all of the oil sands resource is on Crown land[7]. Prior to 1994, annual sales of oil sands mineral rights were zero or very small. Figure 4 shows that oil sands land sales have been strengthening continuously since 1993, both in terms of the quantity of land sold and the price per hectare that this land has commanded. There has also been a large number of land sales in the "secondary market" in recent years, which we believe is driven by different factors than Crown land sales (i.e. impending expiries of the second term of leases that were acquired some 40 years ago). These secondary sales are also indicative of increased interest in developing these leases -- indeed, the leases have to be developed or they will be forfeited.

### Historical Capital Spending

Looking at statistics on industry capital spending, Figure 5 does not reveal a strong trend towards increased oil sands spending to date, although 1996 was the highest single year of oil sands capital spending ever, including the years when Syncrude was being constructed. Oil sands spending has always been a small portion of total industry capital spending, although there is now reason to believe that portion could increase dramatically.

### Capital Spending Intentions

Table 1 is the Department's monitoring of oil sands investment intentions that were announced between 1995 and 1997. Our total comes to $19.1 billion of capital spending over the next decade for oil sands projects, plus perhaps another $1.6 billion for intra-Alberta pipelines to transport all this new production to refineries and upgraders in Alberta and/or to interprovincial and international pipeline connecting points.

This level of investment is certainly good news for Alberta and there should not be concerns with the ability of the Alberta economy to accommodate this level of investment activity. The magnitude of the $19.1 billion can be better understood by contrasting it against historical capital investment in Alberta's energy industry. For example, if this investment is spread over 10 years (which it will be, although not necessarily uniformly), it represents only about 25% of recent years' annual investment in conventional oil and gas exploration and development. Looking back to the early 80's, when there were concerns about the ability of Alberta's economy to absorb the high level of investment being forecasted at that time, a single project to produce 137 mb/d of SCO was estimated to cost $13 billion by itself. One of the reasons that project did not proceed was its escalating capital cost. Today, we're not looking at any single mega-project of that magnitude, as the capital cost per barrel of output has fallen dramatically.

### Potential Oil Sands Production

We've already seen that production has been gradually increasing over the last two decades, with 1996 and 1997 showing especially significant growth (Figure 3). Oil sands production grew 4% in 1996 and 19% in 1997; the bitumen

[7] Crown land refers to lands for which the mineral rights are owned by the Government of Alberta.

portion of that grew 10% in 1996 and 46% in 1997. The growth to date has been at fairly modest investment levels compared to what is being touted for the next decade. Clearly, $19.1 billion of investment would increase production from the oil sands substantively.

The vast majority of this proposed investment (over $15 billion of the $19.1 billion) is targeted for the Athabasca oil sands area. Most of the incremental production in the Athabasca region will come from large-scale surface mining projects. Plans are also underway to develop a number of *in situ* projects in both the Athabasca and the Cold Lake oil sands areas. Although the majority of oil sands production in Alberta has been by means of surface mining, the future potential for bitumen recovery by *in situ* applications is much greater. The AEUB estimates that of the total ultimate potential crude bitumen reserves in Alberta, roughly 80% is recoverable by *in situ* methods and only 20% by surface mining.[8]

Figure 6 shows the Department's forecast of the potential production level that could be achieved if all the announced oil sands projects went ahead as planned. It is estimated that the $19.1 billion of investment represents over 1,700 mb/d of production from the oil sands. The SCO production forecast is based on our understanding of the individual project plans that have been publicly announced by Suncor, Syncrude and Shell, and who represent the only SCO producers in Alberta in this time frame.[9] It includes a more than doubling of production by Suncor from 79 mb/d in 1997 to 210 mb/d by 2002, a doubling of Syncrude's production from 207 mb/d in 1997 to 407 mb/d by 2005 and 180 mb/d of SCO from Shell by 2003. These three projects together represent $11.8 of the $19.1 billion figure. The bitumen production levels in Figure 6 also represent an accumulation of planned increases in primary and thermal *in situ* bitumen production in both the Athabasca and Cold Lake oil sands areas.

The projected level of production shown in Figure 6 is not likely to be achieved in this timeframe, particularly in the current environment of limited markets and low oil prices. Oil sands production levels will be constrained by prices and other market factors. Our production expectations, which will be discussed in subsequent sections of this paper, are constrained by markets and prices, and imply a slower pace of investment and development than what is set out in the $19.1 billion of investment expectations.

## Underlying Factors

Notwithstanding the current price weakness and the expected slowdown in production growth in the short-term, we want to address the factors that have led to this resurgence in interest and investment in oil sands development in recent years. Probably the highest profile recent oil sands event was a signing ceremony at Fort McMurray in June 1996, attended by the Prime Minister of Canada, the Premier of Alberta and senior executives of some 18 oil companies. This was the culminating event to the deliberations of a National Task Force on Oil Sands Strategies. The signatures of the 18 oil companies attested to their intent at that time to invest some $6 billion in oil sands development. This began the tracking of investment intentions that has now led to $19.1 billion. The National Task Force on Oil Sands Strategies commenced in 1993 under the leadership of Dr. Erdal Yildirim, to identify impediments to oil sands development and seek strategies to overcome these impediments.[10] The Task Force commenced at a time when no imminent take-off in development was foreseen. In fact, oil sands development had been fairly stagnant since the demise of the OSLO project in 1991. The Task Force was an important activity. It provided a great deal of the impetus to revitalize oil sands development, particularly by bringing about tax and royalty changes and increasing awareness of the oil sands industry. Although these changes to the existing fiscal regime were important, the new paradigm would not have emerged without the significant achievements that were made in developing new technology.

### Generic Oil Sands Royalty

In the spring of 1995, the Task Force recommended changes to the fiscal treatment of oil sands under the Federal Income Tax Act and to Alberta's treatment of oil sands production. The Alberta government responded with the new generic royalty regime.[11] Prior to this, oil sands royalties were negotiated on a project by project basis through separate agreements. With an increasing number of participants in the oil sands industry, it became desirable to standardize the royalty terms for all new projects. This new regime provides attractive and certain terms for companies contemplating investment in the oil sands.

Under the generic royalty regime, the Alberta Government will collect a 1% royalty until project payout, with payout being

[8] Alberta Energy and Utilities Board.

[9] Mobil's proposed Kearl Lake Oil Sands Project in the Athabasca area is also is expected to be an integrated project that will produce SCO, however Mobil is still considering where to locate its upgrader, and has not firmly committed to upgrading at this point. Mobil's production is not expected to commence until close to the end of this time frame under any circumstance. The Bi-Provincial Upgrader in Lloydminster is also expected to increase its SCO capacity from 53 mb/d in 1997 to at least 80 mb/d and possibly to 100 mb/d, but that is not included as SCO in this forecast as the upgrader is actually located in Saskatchewan.

[10] See paper by Dr. Erdal Yildirim in these Proceedings.

[11] See paper by Mitchell, Anderson, Kaga and Eliot, in these Proceedings, for a more complete discussion of the Alberta's new generic oil sands royalty regime.

defined to include a return allowance on unrecovered costs based on the Government of Canada long-term bond rate. Following payout, the royalty is 25% of net revenues. Under the new regime, the government, in effect, shares in the high initial capital costs during the development phase. The regime stimulates investment by allowing all costs to be deducted against royalties immediately, deferring royalty payments until later in the project life when the project becomes profitable, thus reducing barriers to projects with high initial capital costs.

## Tax Changes in 1996 Federal Budget

The federal government also responded to the Task Force by improving the treatment of oil sands investment under the Income Tax Act. The tax treatment of oil sands investments used to differ between new mines and existing mines, and between mining and *in situ* production. Now, all oil sands capital expenditures in excess of 5% of project revenues get immediate write-off, for both mining and *in situ*.[12] The 5% threshold is intended to reflect a level of investment that would occur for sustaining capital (i.e. those investments required just to maintain production). Therefore, the attractive write-off provisions apply to investment in new projects and to expansions of existing projects.

## Technology

While the revised tax and royalty treatment provided a big impetus to oil sands development, the technology improvements in recent years may have been an even larger contributing factor.

### *In Situ Technology*

*In situ* production's biggest recent breakthrough has been the use of horizontal drilling, both for primary production using multi-lateral completions (many secondary branches connecting to a main horizontal well) and for steam-stimulated production using Steam Assisted Gravity Drainage (SAGD).[13] SAGD technology appears to be suitable for widespread commercial applications in the Alberta oil sands and is the technology of choice for many of the new *in situ* projects. Horizontal drilling was pioneered in the 80's and the technology has improved to the point that most new *in situ* projects are using some form of horizontal wells, with or without steam, resulting in substantive improvements in production economics.

[12] The Income Tax Act was also revised to extend similar favorable tax treatment to investments in renewable energy development and in energy efficiency projects, in order to maintain a level playing field among these areas.

[13] See paper by Komery, Luhning, Pearce, and Good in these Proceedings for further information on the SAGD process.

### *Mining Technology*

Mining production's big technological breakthrough has been hydrotransport, which replaces conveyer belt systems connecting the mine to the extraction plant, thereby allowing more remote mining to become viable. Hydrotransport involves adding water to the oil sands to create a slurry, and then transporting the slurry by pipeline. This new innovation allows companies to mine the best reserves, not just the closest reserves, with the added benefit that the hydrotransport itself results in some conditioning of the oil sands, thereby complementing and providing economies in extraction. The other important development in mining is the use of truck and shovel technology, made possible in part by the increasing size of trucks. Replacing bucket-wheels with truck and shovel technology contributed to Suncor's achievement of reducing cash costs per barrel by 22% from $19.00/bbl in 1991 to $14.75/bbl in 1997.[14]

### *Upgrading Synergies*

Although research efforts continue, no major breakthroughs in upgrading technology have been achieved to date. However, a factor that is helping upgrading economics in Alberta is the increasing presence of facilities that allow for add-ons to existing upgraders or refineries, as opposed to more expensive grassroots projects. For example, the incremental supply costs for the expansions of both the Syncrude and Suncor plants are much lower due to the presence of existing facilities, and one of the aspects that makes Shell's upgrader attractive is the synergies with its Scotford refinery. Similar synergies will allow for fairly low cost expansion of the Bi-Provincial Upgrader.

### *Other Synergies/Innovations*

New oil sands projects are being designed to incorporate current technological accomplishments and to take advantage of synergies and new opportunities. Developers can capitalize on opportunities to extract other resources from the oil sands along with the bitumen, thereby obtaining the maximum value from the resource. The existence of a variety of other valuable minerals has been found within Alberta's oil sands deposits.[15] A number of projects have looked at incorporating mineral extraction into their oil sands mining projects.

Another example of maximizing value from the oil sands resource is the recently announced joint venture between Suncor and Novagas Canada Ltd. to extract and separate natural gas liquids and olefins from its off-gases, a by-product of the cokers in the upgrading process. Developers are also taking advantage of synergies between steam used in extraction and thermal *in situ* projects and electricity generation (cogeneration projects).

[14] Suncor Energy Inc.

[15] Gulf Resources Ltd., and H.A. Simons Ltd.

By incorporating these synergies and technological innovations, further improvements are being achieved in the economics of oil sands production and new projects are becoming more attractive.

### Price/Price Expectations

Combined with these fiscal regime and technology enhancements was a very favorable price environment during 1996 and 1997. The strong market, along with the other factors mentioned, provided a strong stimulus to oil sands investment prospects, and contributed to the $19.1 billion in investment intentions that were announced between 1995 and 1997. Despite low oil prices in 1994 and 1995, Canadian heavy oil prices remained fairly strong during this period due to narrow light/heavy differentials (Figure 7). Bitumen prices reached levels of over $20/bbl in the first half of 1996 (Figure 8). The strength in light oil prices from 1996 throughout the first part of 1997 helped to maintain heavy oil prices at high levels even as differentials were widening. Widening differentials during this period were due to the decline in excess conversion capacity at refineries resulting from the growing heavy crude oil supply.

The price strength underlying these investment plans have obviously eroded in the later months of 1997 and early 1998, as North American crude oil prices have dropped to lows under US$14/bbl and differentials have widened considerably. But the advances in technology and the growing range of synergy opportunities makes oil sands production far less vulnerable to today's price weakness than it would have been in previous cycles, and it is poised to recover more quickly and more strongly.

## Risks

Looking ahead, there are a number of uncertainties which threaten the pace of investment in Alberta's oil sands. The most critical of these uncertainties is oil price. Canadian crude oil prices are impacted by supply/demand balances in both global and regional markets. Heavy crude oil[16] producers face some additional and unique risks, which will also be examined. Some of these threats to oil sands development have already begun to affect the oil sands industry in the form of reduced producer netbacks. Recently, Canadian heavy crude producers have been hurt by the combination of weakening light crude prices and a widening light/heavy oil price differential. Bitumen prices are extremely low today, having gone from around $20/bbl in the first half of 1996 to under $3/bbl at present. Our discussion will focus on the major uncertainties facing Canadian heavy crude oil producers and will cover issues with respect to global and North American crude oil markets,

diluent supply, export pipeline capacity, and government policy on greenhouse gas emissions.

### Global Crude Oil Markets

Within the last year world oil prices have weakened considerably, pushing Edmonton Par light prices down from $32.42/bbl (WTI US$25.18/bbl) in January 1997 to lows of $17.76/bbl (US$13.21/bbl) in March 1998 (Figure 9). Oil price expectations are strongly tempered by the current price, so the current price weakness has an important bearing on petroleum industry investment activity, and especially in the relatively high cost oil sands portion of the business. For the most part, oil sands developers have taken a long term perspective and projects are expected to go forward unless prices remain below US$15/bbl for an extended period. Our view in the Department of Energy is that current prices of less than US$15/bbl are too low to be sustained for the long-term, just as the 1996 and 1997 prices of US$22-$24/bbl were too high to be sustained for the long-term. The Department's crude oil production forecasts are based on the premise that crude oil prices will fluctuate within a sustainable range of US$17/bbl to US$22/bbl over the medium to longer term.

### North American Markets for SCO and Bitumen

Both bitumen and SCO can only be accommodated by refineries that possess some degree of specialized processing capability. Because of its nature, only a small portion of bitumen can be converted into high value light products in a conventional refinery. Efficient bitumen refining requires more specialized conversion capability, typically in the form of a coking or hydrocracking unit. This represents a more expensive refinery, but can be justified by being able to process lower valued crudes, such as bitumen.

With the tremendous growth expected in bitumen production from the oil sands, producers will face new challenges in marketing this heavy crude into the North American market, where most refiners traditionally have used conventional light crude as feedstock. Existing markets for Alberta's heavy crude oil production include Western Canada, Ontario, and the US. In Western Canada, some incremental demand for heavy crude oil and bitumen is expected from increased asphalt production and some upgrader expansions. In Ontario no significant new upgrading capacity is foreseen at this time, and that market may be lost with a pipeline reversal that will allow offshore crudes to

---

[16] Heavy crude oil refers to both conventional heavy crude and bitumen. Conventional heavy crude is considered to be between 15 to 30 degrees API and is generally produced by primary production methods. Bitumen, which is produced from the oil sands through both primary and thermal processes, is considered to be less than 15 degrees API.

reach Ontario refiners directly.

Production of heavy crude oil in Canada far exceeds domestic demand and over 75% of Canadian heavy crude oil is currently exported into the US. Much of the planned increases in Western Canadian crude oil production is expected to be absorbed by the US Midwest market. A proprietary study by Purvin & Gertz estimates that by 2005, 322 mb/d of incremental conversion capacity in the US Midwest will be filled by imports of Canadian heavy crude oil importers.[17] However, even with this incremental upgrading capacity, growth in Western Canadian heavy crude oil supply is still expected to outpace demand.

The US market is also a major market for Latin American crude oils. Aggressive plans exist to increase production of heavy crude oil in Venezuela and Mexico. Major projects in Venezuela are being developed through joint ventures between international investors and Venezuela's state oil company PDVSA. Purvin & Gertz forecasts "extra heavy" oil (bitumen) production in Venezuela to increase from 500 mb/d in 1996 to over 2,000 mb/d in 2015.[18] Incremental production from Venezuela and Mexico will also be targeted to US refineries, directly competing with Canadian heavy crude exports. One very important aspect of the Venezuelan strategy is that PDVSA is, and is expected to continue, purchasing equity interests in US refineries in order to secure a market for its heavy crudes. This represents formidable competition to Canadian heavy producers, most of whom do not have the same advantage of downstream integration.

Increasing supply of heavy crude from both Canada and Latin America will exceed available upgrading capacity in the US market. This will result in the North American market for heavy crude oil being oversupplied, until refineries add sufficient upgrading capacity to balance with supply. The result will be strong discounts for heavy crudes relative to light crudes (differentials) until this market imbalance is redressed. The good news is that wide differentials provide a strong incentive to address this problem by encouraging the requisite investment in additional upgrading capacity.

Differentials have widened significantly throughout 1997 and into 1998, reflecting the growth in heavy crude supply, particularly from Canada at this time, that has already begun to flood the market. Canadian light/heavy price differentials have widened from $4.27/bbl average in 1996 to $6.72/bbl in 1997 (Figure 7).[19]

[17] Crandall, Kelly, Kromm, Vermette
[18] Ibid
[19] The differential is measured here by Par @ Edmonton minus Bow River @ Hardisty prices.

**Condensate Supply**

The viscous nature of bitumen makes if difficult to transport by pipeline[20]. The most common method of getting bitumen to flow in a pipeline is by diluting it with a much lighter hydrocarbon, such as condensate. The blended substance has a lower viscosity, which allows it to flow in a pipeline. It still flows more slowly than light or synthetic crudes, so requires more pipeline capacity to accommodate than for a similar volume of light crudes. As the production slate becomes increasingly heavier, transportation constraints keep re-emerging and the requirement to add capacity continues. This has led to a number of new pipelines and/or pipeline capacity expansions in recent years.

Although other diluents have been experimented with over the years, the availability and price of condensate has made it the diluent of choice.[21] Condensate is a by-product of natural gas, so its availability is a function of natural gas production, which is currently not growing as rapidly in Alberta as bitumen production is. Thus, more and more condensate is being used for diluent and shortages are appearing to the point that condensate is currently priced at a 25% premium to light crudes (traditionally it has been priced at approximately par with light crude). This additional cost of transporting bitumen lowers the netback at the field (in effect, widening the differential), and thereby represents an economic constraint to bitumen production.

Consequently, in addition to declining light prices and widening differentials, Canadian heavy oil netbacks have been hit threefold by rising condensate prices. This is a regional problem as Alberta producers of bitumen and heavy oils must rely on condensate availability from within Western Canada. The vulnerability of Alberta producers is evidenced by the premium on condensates in Western Canada relative to the rest of North America.

Producers are attempting to resolve the diluent shortage problem and a number of potential solutions are on the table. Short-term solutions include diverting condensates from other uses within Alberta, allowing sour condensates, light sour crudes, or SCO to be added to the diluent pool, and using refined naphtha as a diluent. Longer-term solutions include:

- partial upgrading of the heavy crude oil or bitumen (making it pipelineable, but less than an SCO),

[20] The definition of bitumen in the Mines and Minerals Act (administered by the Department of Energy) and the Oil and Gas Conservation Act (administered by the Energy and Utilities Board) is "a naturally occurring viscous mixture… that, in its naturally occurring state, will not flow to a well" (emphasis added).
[21] Bitumen-water emulsions are used in Venezuela and, although pioneered in Alberta, have never been used commercially in Alberta.

- recycling the diluent (this is already done by upgraders within the region, and Shell is proposing to recycle diluent from its refinery back to the mine for reuse), and
- heated pipelines which allow pipeline specifications for density and viscosity of heavy crude to be reduced. For example, the ECHO pipeline (East Central Heavy Oil Pipeline, a regional pipeline serving the bitumen and heavy oil producing areas north of Hardisty) operates at a higher temperature and requires no diluent. Also, IPL's 350 centistoke project will raise the temperature in Line 3, and reduce the amount of diluent required.

**Export Pipeline Capacity**

Another uncertainty facing Western Canadian heavy oil producers is access to export pipeline capacity. Historically, production of both heavy and light crudes from Western Canada has been periodically constrained by export pipeline capacity additions lagging production growth. The ratio of heavy to light crude exports is increasing faster than anticipated by pipeline companies, resulting in a capacity shortage on export systems, particularly on the IPL system, which is the largest pipeline system, transporting crude oil and liquids from Western Canada to our primary markets in Eastern Canada and the US Midwest. Capacity on IPL is expected to be expanded by 1999 with the completion of IPL's Terrace Project. Therefore, physical apportionment is likely to persist until 1999. The potential for lags in construction of new pipeline capacity will likely continue to be an uncertainty for oil sands producers, as long as growth in heavy oil production continues.

**Government Policy on GHG Emissions**

At the Kyoto Summit in December of 1997, Canada's federal government agreed that Canada would reduce its greenhouse gas (GHG) emissions by 6% from 1990 levels by the year 2010. If implemented, this commitment will most certainly impact the $19.1 billion of planned investment in Alberta's oil sands. However, at this time the extent is not known as it is highly dependent on the combination of techniques used to meet the targeted reductions in GHG's. Use of internationally tradable emission permits and of joint implementation projects with developing countries offer the greatest potential for meeting the targets for reducing global GHG's while minimizing the disruption to the economies of energy producing countries like Canada.

## Constrained Production Forecast

Taking into account these various risks that face oil sands producers in the future, we have developed, in consultation with the AEUB, a revised production forecast for bitumen and SCO that is constrained by both markets and prices. Our production expectations imply a slower pace of investment and

development than set out in the $19.1 billion of investment expectations.

**Constrained Bitumen Production**

Our forecast anticipates production from the oil sands reaching 1,042 mb/d by 2005, consisting of 441 mb/d of bitumen and 602 mb/d of SCO (Figure 10). This is considerably less than the production levels implied by the $19.1 billion of projects proceeding, as estimated in Figure 6. The bitumen portion of our constrained forecast reflects both the short term price constraints and market constraints which are based on limited processing capacity in North American markets, limited diluent supply, and pipeline transportation constraints. Despite these constraints, production from the oil sands is still expected to offset production from declining conventional crude sources.

The weakness in crude oil prices in early 1998 can also be expected to take its toll on oil sands production, at least in the short-term. The bitumen portion of oil sands production can be expected to be especially hardest hit, as this general price weakness occurs at a time when the light/heavy price differential is especially high. The result of this double whammy of low oil prices and high differentials is that bitumen netback prices in early 1998 are under $3/bbl, which is lower than operators' production costs. At these low prices, bitumen producers have begun to shut-in some of their production and have reduced drilling plans for 1998. These low prices clearly delay investment plans for increasing bitumen production, as most investments can occur over a short enough time horizon that producers are not likely to make the investment until prices are at least strong enough to cover operating costs. These influences are incorporated in our expectations for production (Figure 10).

The longer the price weakness persists, the more bitumen production will be shut-in. The decision to shut-in production is more difficult than a simple comparison of prices and operating costs, as the costs of mothballing and re-starting must be compared against the expected duration of the price weakness. Primary production would likely be shut-in first, and steam stimulated production would be shut-in as operators face decisions about the next steaming cycle. Because most bitumen production is based on *in situ* rather than mining technology, and because of the relatively short time to bring *in situ* production on-stream, the production profile in Figure 10 can change fairly quickly in response to a stronger price environment. The very actions of shutting-in production represent the seeds of market response that leads to prices re-gaining strength, in the macro sense of reducing global crude supply and in the micro sense of reducing heavy crude supply and thereby reducing the light/heavy differential.

**Constrained SCO Production**

SCO production can also be expected to grow more slowly under a weaker price environment. No SCO is expected to shut-in, as current prices for SCO of around $19/bbl remain well above SCO production costs (of around $13-$15/bbl). However, expansions may occur more slowly as the rate of investment slows down. The SCO producers are all major players in the petroleum industry, and as such can be expected to take a long-term view of the market. As investments in integrated projects are made in large increments and typically take 3-4 years from start of investment to production start-up, these players cannot afford to make investments based on a short-term market outlook. While we have little doubt about their long-term commitment to their projects, these investments can also be constrained by weaker project and/or corporate cash flows available during a period of general market weakness. Syncrude's investment plans may be particularly vulnerable to cash flow constraints as it is a consortium of ten parties, including two royalty trusts, and obtaining agreement among all ten parties may be challenging. Suncor and Shell may be less constrained to project cash flow and obviously don't face the same challenge of getting agreement among multiple parties. But they may nevertheless be inclined to slow their pace of investment as long as the price uncertainty persists.

Therefore, we have prepared a lower forecast of SCO production, to reflect a slower pace of investment (see Figure 10). Under this lower forecast, we see SCO production reaching 602 mb/d by 2005, rather than the 780 mb/d that the companies had announced intentions of reaching in Figure 6. This still represents a 110% growth in production, and still requires a very substantial level of investment over this period to achieve.

**Risk Amelioration Factors**

The above risk elements clearly can be expected to have an impact on investment in Alberta's oil sands. It is our view that the $19.1 billion of investment will occur over a longer time horizon that originally envisaged and we have presented an estimate of the impact on oil sands production levels. We have not attempted to determine which projects are represented in these production forecasts, however we believe there are some common elements among the successful projects. Our approach will be to try to identify some of these elements that are required for projects to succeed over the long term, (i.e. elements that reduce the project's risk).[22]

[22] The views expressed here are our own, and are not based on any specific discussions with any companies or operators.

The projects least at risk are the integrated projects -- those that produce SCO, not bitumen. They have a natural hedge against fluctuating differentials by profiting from bitumen when differentials are low and from upgrading when differentials are high. They also are not subject to diluent shortages, and are less vulnerable to pipeline capacity constraints. Syncrude, Suncor and Shell represent $11 billion of the $19.1 billion, and this $11 billion of investment is expected to proceed, albeit potentially spread over a longer time frame than what was originally intended.

The projects more at risk are the non-integrated bitumen producers, who face the full brunt of lower prices and higher differentials. Some of the factors that can reduce risk for both integrated and non-integrated producers include:

- *a relationship with a downstream refinery that provides a market for the bitumen* - There are a significant number of heavy oil and bitumen producers that benefit from this relationship, including companies such as Suncor, Imperial, Husky, Koch and Amoco.

- *an attractive lease which provides opportunities for low cost production* - Imperial's Cold Lake lease is often viewed as the most attractive of the *in situ* leases, although recent activity in the Wabasca/Pelican area by players such as Amber, Amoco, CNRL and PanCanadian indicate some very low cost production in that area. Shell is seen to be holding one of the most attractive mining leases at its Lease 13.

- *projects backed by companies with deep pockets* - This factor is applying to more and more companies, as evidenced by the acquisitions of heavy oil producers by big companies over the last year. In addition, the renewed interest in the oil sands by big players like Shell and Mobil is a very good sign.

- *research spending* - Research spending can help to lower production costs substantially. Some good examples of producers focusing on research include CS Resources (now PanCanadian), Imperial, and Syncrude.

- *niche market* - Companies that have found a niche market for their production will improve their profitability and help to ensure their viability in difficult times. Suncor is a good example of a company successfully pursuing this strategy.

- *energy efficiency* - Energy efficient producers will protect themselves from environmental opponents and lower their vulnerability to pressures for further emissions reductions. We note that the oil sands industry has been among the leaders in Canadian industry in seeking to voluntarily reduce emissions.

Pursuing any of these strategies will strengthen a project, particularly against the cyclicality of oil prices and differentials, and allow the company to take a longer term outlook. Fortunately there are many examples of strong companies with good projects that have been doing the right things. No doubt at current prices some shutting-in of heavy oil and bitumen production will occur. We are even more likely to see investment delays by various players that will result in lower growth in bitumen production in 1998 relative to earlier expectations. However, the current economic conditions reflect the cyclic nature of all resource industries, and these conditions will change and improve as the market recovers. We believe the $19.1 billion of investment will still be realized, just over a longer time frame. The length of the extension will very much depend on how courageous these investors are in the face of today's prices, and how ephemeral they believe the current price weakness may be. The GCOS example of 1967 should remind us that the oil sands has a history of bold decision-makers who take a long-term view of things.

In the meantime, the Alberta economy will still continue to prosper on the basis of the expected investments in integrated projects and a somewhat scaled down level of investment in bitumen projects, and any concerns over manpower shortages may be alleviated, making the oil sands investment bubble that much easier to accommodate.

Continued development of the oil sands is always going to face challenges and may not always occur in the manner initially envisaged. However, the new paradigm is that oil sands development prospects today are far more robust and sustainable than ever before. The fiscal terms are set and provide a very equitable and attractive basis for development. The technology for oil sands recovery has made remarkable progress in terms of lowering costs and continued progress in technology and lowering of costs can be expected. The players in the industry are strong and committed. In our view, the oil sands still represent Alberta's and Canada's best energy future.

REFERENCES

1. Alberta Energy and Utilities Board. *Reserve Report Statistical Series 18, Alberta's Reserves 1996*. Alberta Energy and Utilities Board, 1997

2. Alberta Energy and Utilities Board. *Alberta Energy Resource Industry Statistics.* Alberta Energy and Utilities Board, 1997

3. Canadian Association of Petroleum Producers. *Statistical Handbook for Canada's Upstream Petroleum Industry*. Canadian Association of Petroleum Producers, 1997

4. Crandall G.R., S.J. Kelly, R.B. Kromm, R.O. Vermette. *Canadian Heavy Crude Market Environment,* Purvin & Gertz Inc., 1998

5. Gulf Resources Ltd. *Phase I of A Study to Assess the Potential of Co-Product Minerals and Metals in Alberta's Oil Sands Deposits.* The Canada/Alberta Partnership of Mineral Development, 1993

6. H.A. Simons Ltd. *MDA Co-Products Study Final Report.* The Canada/Alberta Partnership of Mineral Development, 1996

7. Precht P., K. Sullivan and P. Kahler. *Economics of Alberta's Oil Sands Development*. UNITAR/UNDP Fourth International Conference on Heavy Crude and Tar Sands, Proceedings, 1988

8. Suncor Energy Inc. *Annual Report 1997*, Suncor Energy Inc., 1998

Table 1

| Announced Oil Sands Projects & Pipelines in Alberta (1997 - 2007) | | | |
|---|---|---|---|
| **Company** | **Project/Location** | **Investment (Cdn$ Million)** | **Timing** |
| **Athabasca Projects:** | | **$15,154** | |
| Amber Energy Inc. | Wabasca | $300 | 1997 2000 |
| Amoco Canada Petroleum Company Ltd. | Brintnell | $100 | 1996 2000 |
| Canadian Natural Resources Ltd. | Pelican Lake | included below | 1997 2002 |
| Canada Oil Sands Co. Ltd. | Hangingstone | $200 | 1998 2001 |
| Gulf Canada Resources Ltd. | Surmont | $1,100 | 1999 2005 |
| Mobil Oil Canada Ltd. | Kearl Lake | $1,000 | 2000 2003 |
| PanCanadian Petroleum Limited | Christina Lake | $370 | 1998 2003+ |
| Petro-Canada | MacKay River | $250 | 1998 2000 |
| Shell Canada Ltd. | Muskeg River Mine | $1,000 | 1998 2002 |
| | Upgrading Facility at Scotford Refinery | $1,800 | 1999 2002 |
| Suncor Energy Inc. | Fort McMurray Plant, Steepbank Mine | $2,870 | 1997 2002 |
| Suncor Energy/NOVA GAS Canada | Fort McMurray Plant - Off Gas Project | $164 | 1998 1999 |
| Syncrude Canada Ltd. | Mildred Lake, Aurora Mine, Upgrader Expansion | $6,000 | 1996 2007 |
| **Cold Lake Projects:** | | **$3,825** | |
| Alberta Energy Company Ltd. | Cold Lake - Foster Creek | $212 | 1998 2000 |
| Amoco Canada Petroleum Company Ltd. | Primrose /Wolf Lake | $675 | 1996 2000+ |
| BlackRock Ventures Inc. | Cold Lake | $8 | 1996 1997 |
| Canadian Natural Resources Ltd. | Cold Lake - Beartrap and Charlotte Lakes | $800 | 1997 2002 |
| Ranger Oil Limited | Lindbergh (Elk Point/Wolf Lake/Cold Lake) | $225 | 1996 2000 |
| Imperial Oil Limited | Cold Lake | $700 | 1996 2001 |
| Koch Exploration Canada Ltd. | Elk Point | $200 | 1996 1998 |
| Mobil Oil Canada Ltd. | Bonnyville - Iron River | $116 | 1996 2005 |
| Murphy Oil Company Ltd. | Lindbergh | $157 | 1996 1999 |
| Norcen Energy Resources | Cold Lake, Provost, Lindbergh | $440 | 1996 1998 |
| Numac Energy Inc. | Manatokan Lake | $57 | 1996 1998 |
| PanCanadian Petroleum Limited | Elk Point (Lindbergh, Frog Lake, Marwayne) | $100 | 1996 2000 |
| Suncor Energy Inc. | Primrose - Burnt Lake | $100 | 1999 2000 |
| Texaco Canada Petroleum Inc. | Frog Lake | $35 | 1997 1998 |
| **Peace River Projects:** | | **$120** | |
| Shell Canada Ltd. | Peace River | $120 | 1998 2002 |
| | | | |
| **Total Projects:** | | **$19,099** | |
| | | | |
| **Intra-Alberta Pipelines:** | | | |
| Alberta Energy Company Ltd. & Husky Oil Ltd. | Lakeland Pipeline (Fort McMurray area to Hardisty) | $400 | 1998 1999 |
| Alberta Energy Company Ltd. | Alberta Oil Sands Pipeline (Fort McMurray area to Edmonton) | $220 | 1998 1999 |
| Amber, CNRL, Amoco, PanCdn, Chevron | Pelican Lake Pipeline System (Pelican Lake connection to Rainbow Pipeline) | n/a | 1998 1999 |
| IPL Energy Inc. (Wild Rose Pipe Line Inc.) | Athabasca Pipeline (Fort McMurray through Cold Lake to Hardisty) | $325 | 1998 1999 |
| Imperial Oil (58%)/Amoco, Koch (21%) | Thicksilver Pipeline (Cold Lake to Hardisty) | $250 | 1999 2000 |
| Shell Canada Ltd. | Corridor Pipeline (Fort McMurray area to Edmonton) | $375 | 2000 2002 |
| | | | |
| **Total Oil Sands Pipelines:** | | **$1,570** | |
| | | | |
| **Total Oil Sands Projects & Pipelines:** | | **$20,669** | |

**Table 1: Announced Oil Sands Projects and Pipelines in Alberta (1997–2007)**

Attachment

Figure 1: Alberta Oil Sands Area

Figure 2: Alberta Total Liquid Petroleum Production (1973-1997)

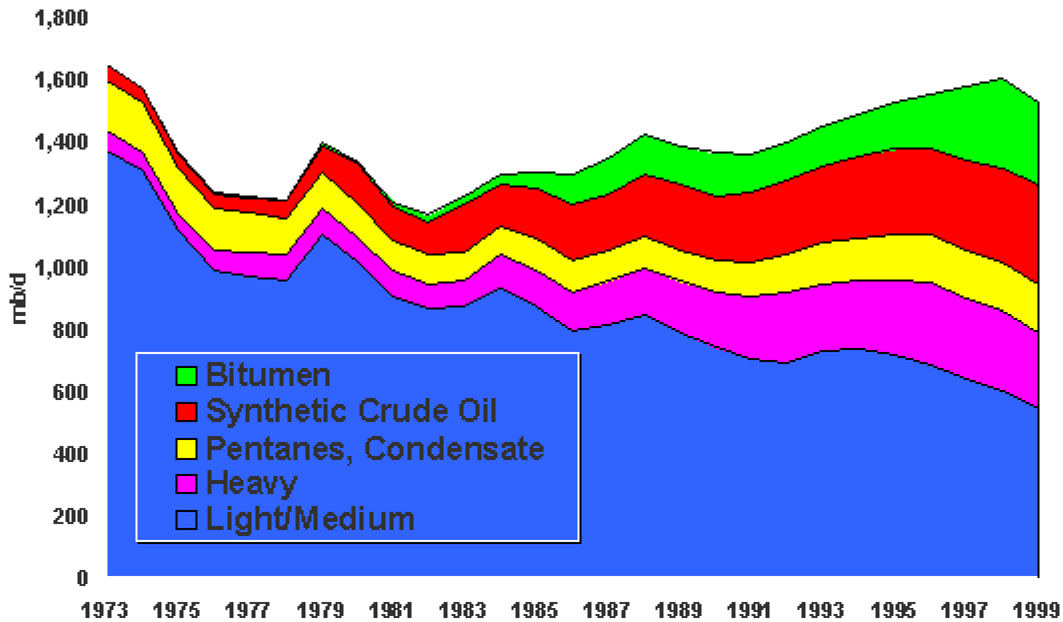



Figure 3: Alberta Oil Sands Production (1967-1997)

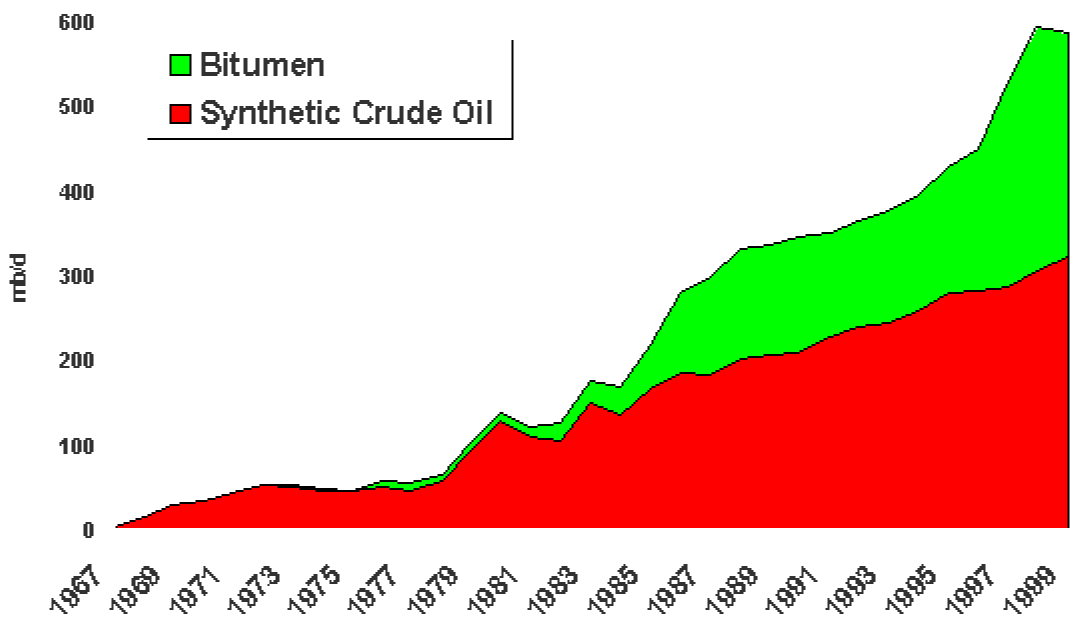


Figure 4: Alberta Oil Sand Land Sales (1992-1997)

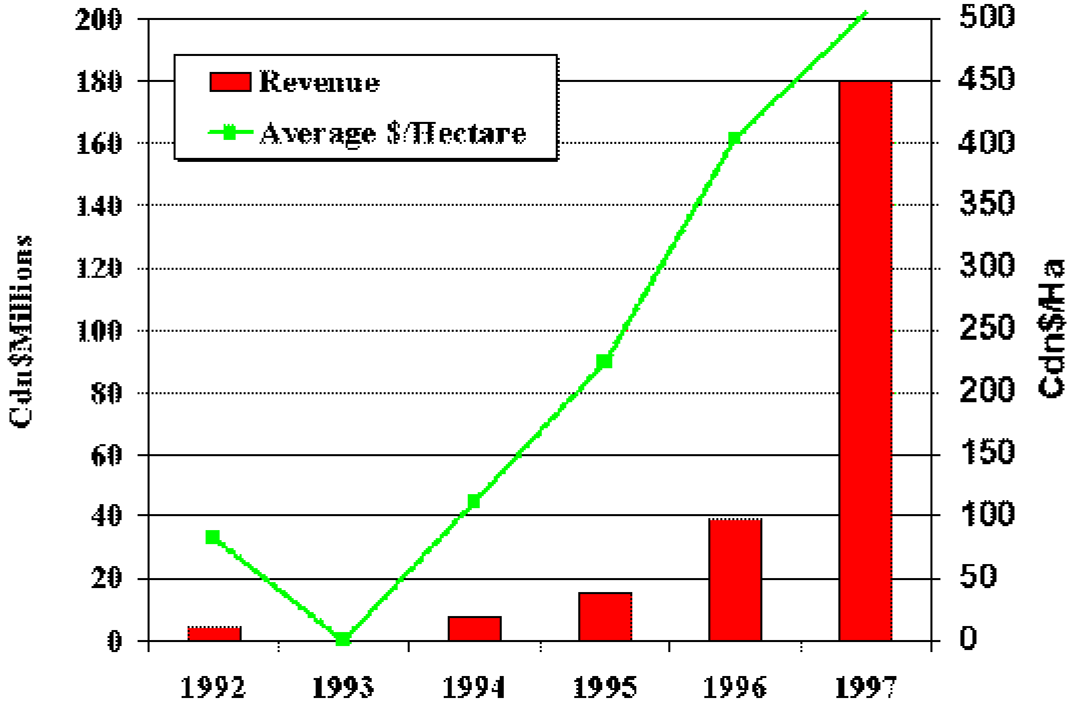



Figure 5: Investment in Alberta's Petroleum Industry (1970-1996)

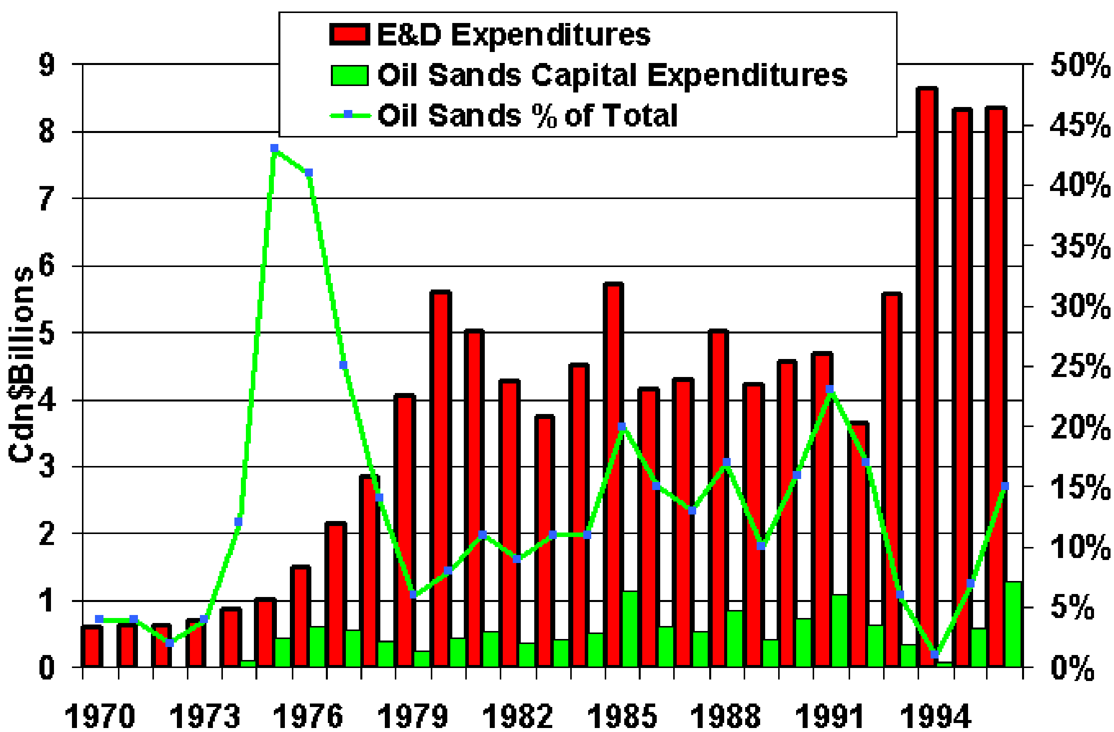


Figure 6: Potential Alberta Oil Sands Production (1997-2005)

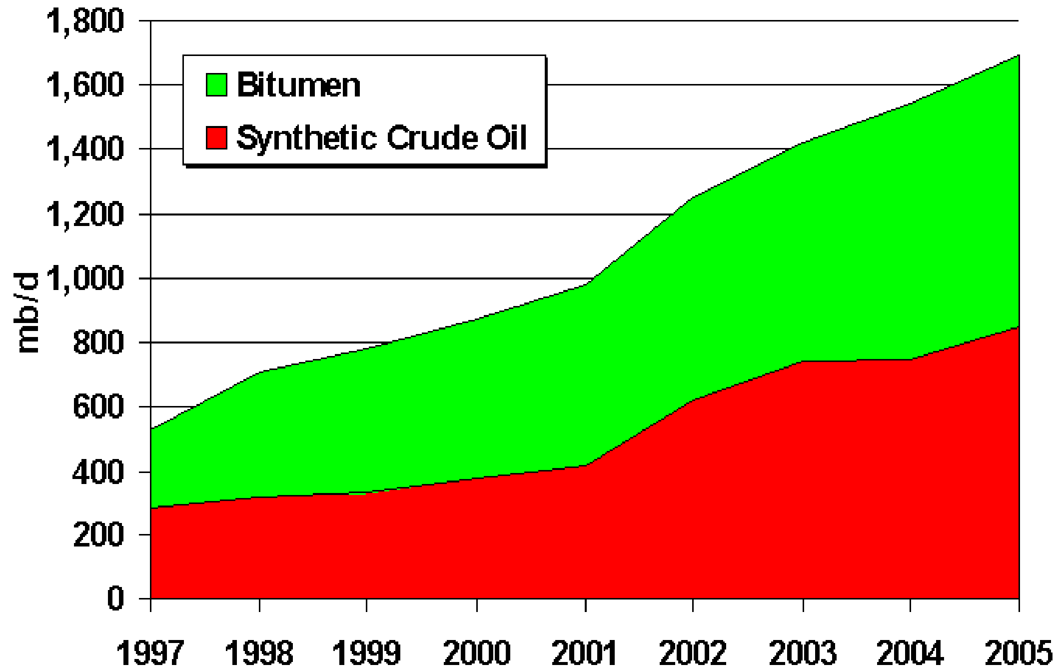
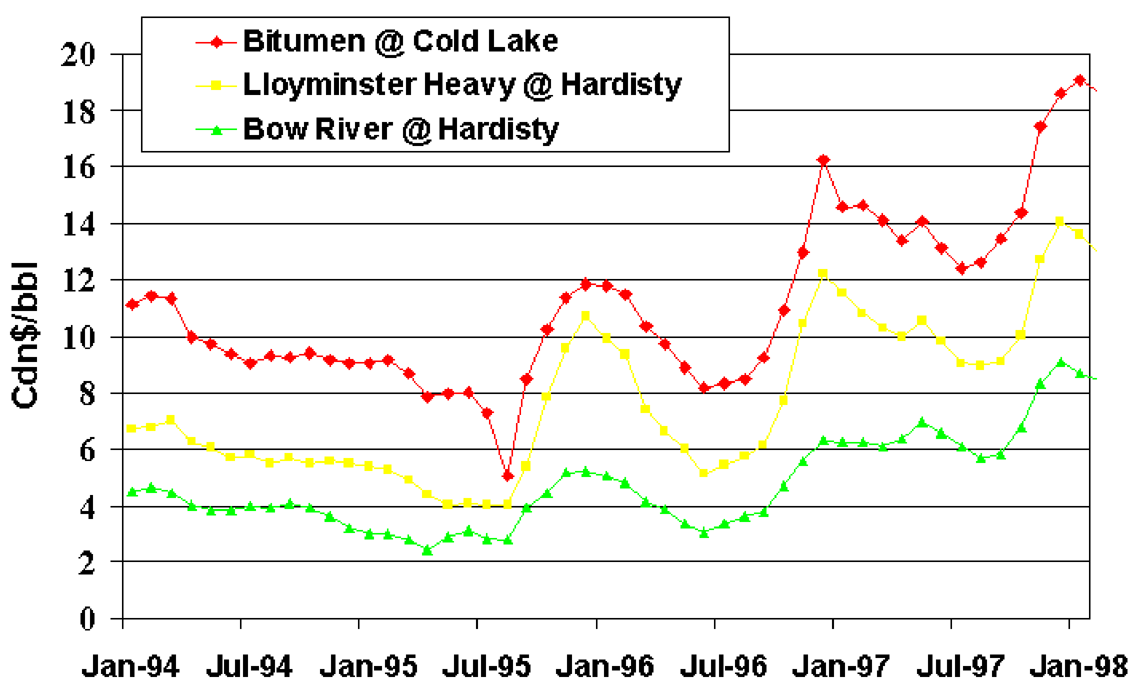



Figure 7: Alberta Light/Heavy Oil Price Differentials (1994-1998)




*Relative to Edmonton Par Postings

Figure 8: Alberta Heavy Crude Oil Netback Prices (1994-1998)

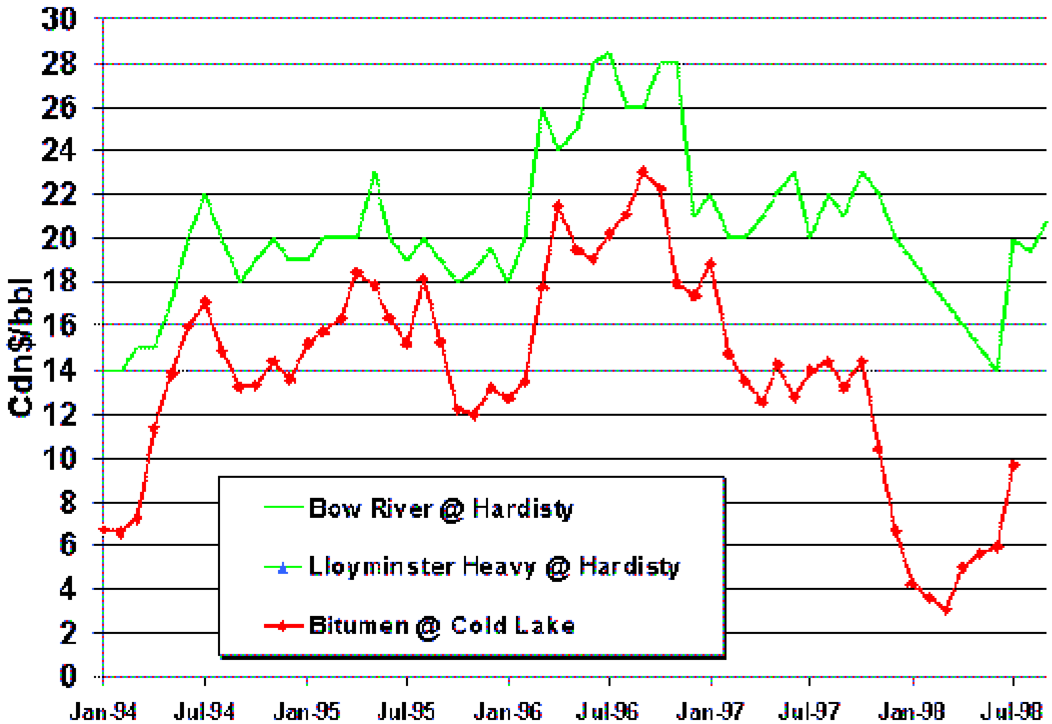



Figure 9: Historical WTI Prices (1991-1998)

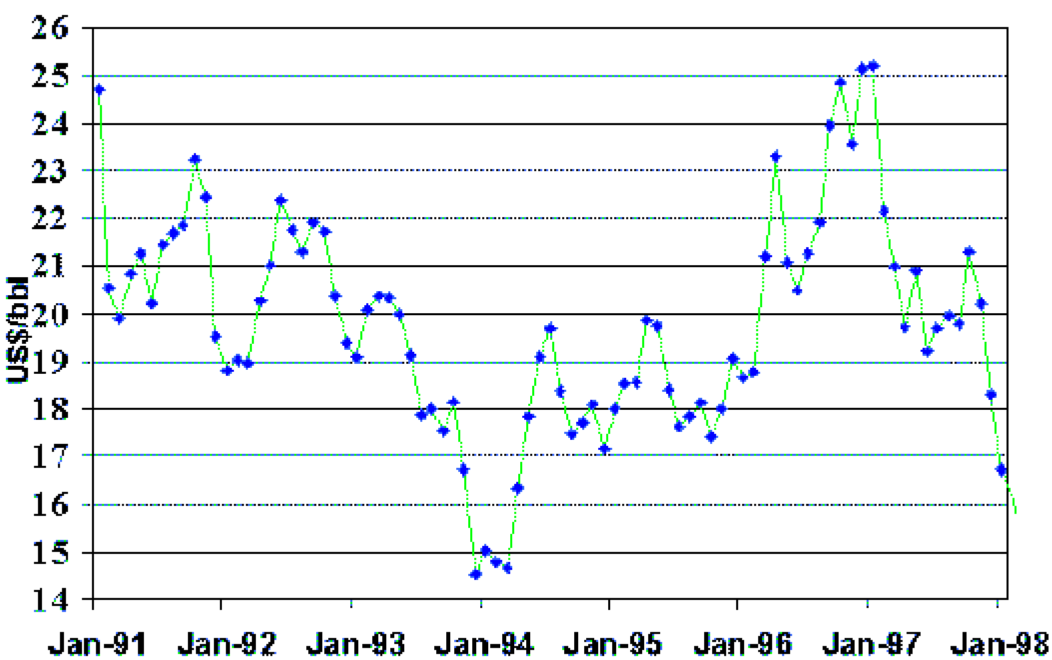


Figure 10: Constrained Alberta Oil Sands Production (1997-2005)