1 INTRODUCTION

1.1 Issues and Definitions

1.1.1 The Scope of the Report

There are a number of unique operational issues relating to the production of heavy oil and super-heavy oil in Canada, and more specifically in Alberta. This Report will explore in detail the technical and environmental issues related to **C**old **H**eavy **O**il **P**roduction with **S**and (**CHOPS**). Also, extensive references to other new processes and emerging production technologies will be made.

With respect to CHOPS, heavy oil and oil sands in Alberta, some specific questions may arise:

- What are the similarities and differences in crude qualities and production practices between primary oil sands and conventional heavy oil production?
    - What are the average well sizes (productive capability)?
    - From an operational perspective, how many wells make up a project (for both crudes)?
    - How are wells and fields managed and sand disposed?
- What production technologies are appropriate for various technologies?
- What is the reservoir impact of CHOPS and is it negative or positive?
- What is CHOPS and how has it evolved?
    - How much production comes from other technologies?
    - What technologies complement CHOPS?
    - Are there other emerging technologies?
- Who is involved in the industry (name, size of company etc.)?
    - Who are the producers?
    - Who are the technology developers?

    - Who are the manufacturers?
- What is the status of related research and development?
- What is the future potential for these crudes?
    - Are there many CHOPS fields left to develop?
    - What are the possibilities for enhanced oil recovery after CHOPS?
- What are the economics?
    - How much are these crudes discounted relative to light crudes and why are they discounted?
    - If the growth potential is different for these crudes, what are the reasons for it?
    - What are the implications for Alberta?

Not all of these questions will be answered in detail, but many will be addressed in various degrees of completeness. For example, a collation of all the producing and local service companies that benefit form CHOPS activity, including information about the companies, is a huge task, albeit one that has merit. It cannot be achieved in this report. Rather, this report will focus on the technology of CHOPS, some of the economic issues, environmental aspects, and possible emerging possibilities for expanding or prolonging CHOPS production in Alberta. Are the National Energy Board of Canada's predictions of the potential for the Canadian Heavy Oil Belt realistic, given the new technologies that are emerging?

The Report will address in more specific detail the following areas, although different weights have been given to different areas.

- Definition of heavy oil and primary bitumen
- Description of the crude properties of heavy oil and primary bitumen
- Location and size of reserves
- Review of production technologies:
    - Which technologies have been successful?
    - Which technologies are experimental?

    - What technologies are emerging or envisioned?
    - What are the resultant production profiles?
    - What are the production economics?
    - Examples of case histories
- Market participants
- Environmental Considerations
- Research and Development
- Estimates of future production
    - Upgrading requirements and other downstream issues
    - Transportation considerations
- Strategic considerations for oil companies
    - The future of heavy oil in the world context
- Implications for Alberta
    - What are current problems with heavy oil development
    - What are possible mitigative measures for environmental issues

1.1.2 Definitions

The major heavy oil production technology addressed will be **CHOPS**: **C**old **H**eavy **O**il **P**roduction with **S**and. CHOPS is defined as primary heavy oil production that involves the deliberate initiation of sand influx into a perforated oil well, and the continued production of substantial quantities of sand along with the oil, perhaps for many years.

For this report, heavy oil is empirically defined as all liquid and semi-solid petroleum less than 20°API gravity, or more than 100 cP viscosity at reservoir conditions. No differentiation will be made between heavy oil and oil sands ("tar sands"), though some use <12°API gravity and >10,000 cP as criteria to define oil sands[i], and the value of 10°API gravity is often used to differentiate between heavy oil and super-heavy oil (or bitumen, or oil sands, or tar sands, or extra-heavy crudes).

A definition for "heavy oil" could also be expressed in terms of "produceability". One may assume that the oil in "oil sands" (or "super-heavy crude oil or "bituminous sands"…) is essentially an immobile fluid under existing reservoir conditions. This means that the oil is so viscous that it cannot be made to flow by non-thermal oil production methods (or other special methods), and this in turn means that there is no possibility to produce enough oil by conventional methods to be profitable. On the other hand, "heavy oils" have some mobility under naturally existing conditions and can flow to wells and be produced economically, with or without sand, although the production rate in each well may be modest. Such a definition is also empirical, as some low-cost operators may consider a certain production rate economical, whereas an integrated oil company would not.

All empirical or functional definitions are somewhat subjective; the writer prefers an *in situ* viscosity criterion to classify oils, although the specific values have not been widely agreed upon. Heavy oil could be defined as oil having a natural flowing viscosity in the reservoir between 100 and 10,000 cP, or between 50 and 20,000 cP, or some other reasonable limits. This has the virtue of being a fixed measure, and can be taken to refer to the viscosity *in situ* under actual conditions. Therefore, in the laboratory, all measurements must be made on oil to which the natural solution gas has been restored, and at the correct reservoir temperature. It has the drawback of combating two generations of industry density classification using the °API scale.

A common classification using the API density scale is: <10°API is super-heavy crude oil, and, 10° to 20°API is extra-heavy crude. Dr George Stosur (US Department of Energy, retired) advocated the following classification at *in situ* conditions:

- Heavy crude: 10° to 20°API, viscosity between 100 and 10,000 cP
- Extra-heavy crude: <10°API, viscosity between 100 and 10,000 cP
- Bitumen: <10°API, viscosity >10,000 cP

The world's heavy oil deposits are dominantly in high porosity (>28%) unconsolidated sandstones. The term "unconsolidated sandstones" (UCSS), widely used in the petroleum industry, refers to sandstones (or sands) that possess no true tensile strength arising from grain-to-grain mineral cementation. These materials are "friable", and an intact sample can be easily disaggregated with the hand. As with the issues of oil classification, there is no specific quantitative strength criterion associated with the term UCSS, but petroleum geomechanics engineers agree that a UCSS has negligible tensile strength and can be manually broken apart into individual grains. Although older and deeper sandstones are almost invariably more cemented and stronger, the definition of UCSS is a functional one, and is independent of the specifics of burial depth, geological history, granulometry and fabric, and mineralogy.

Figure 1.1 contains an approximate geographical classification of Canadian heavy oil deposits. These definitions do not correspond to the Alberta Energy Utilities Board (EUB) classifications or to the National Energy Board of Canada (NEB) Classifications.[2] EUB classifications for royalty and tax purposes are based on a geographical line, the south boundary to Township 53. North of this line, exclusive of the surface mining area in the Athabasca Deposit, the EUB classifies all deposits as oil sands, and the royalty regimes are determined by this classification. For a reservoir to be classified as oil sands, even north of Township 53, an application to so classify it must be made to the EUB, which then will give its approval for that classification, and allow the project to access a more favorable royalty regime. Primary oil production in such cases is referred to as "primary bitumen" production north of Township 53, but south of this Township, such production is called "primary heavy oil" production, even though the technologies may be identical, the strata contiguous, and the reservoir and oil properties completely similar. Production through CHOPS is therefore subjected to different royalty and taxation regimes, even though the deposits, the crude oil properties, and the extractive methods are perhaps identical.

The NEB in their studies uses a classification based on physical properties. Heavy oil is greater than 12°API gravity or less than 10,000 cP viscosity. The difference between the heavy oils and lighter oils is set at a density of 0.89 g/cm^3, or less than 25°API. They use the term "conventional heavy oil" as a functional definition describing heavy oil that can flow naturally into a well (i.e. under primary production conditions); this definition is therefore analogous to the EUB term "primary heavy oil".

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[2] Refer to the webpages for these two institutions for more details: www.eub.ab.ca and www.neb-one.gc.ca

The definition of the Heavy Oil Belt (HOB) used in this report is largely geographical, and excludes the generally more viscous (μ > 40,000 cP) Cold Lake Deposit in the Clearwater Formation. Not all the oil in the HOB can be accessed by current primary production technology, but the great majority, including all deposits south of Township 53 in Alberta, may be assumed to be amenable to primary heavy oil production technology, assuming that the reservoir thickness and saturations (e.g. oil saturations, water zones…) are appropriate.

1.2 General Geological Setting

The target of CHOPS technology is mainly the Heavy Oil Belt that straddles the Alberta-Saskatchewan border, but there are also a number of other heavy oil deposits that may be affected by CHOPS and other new and emerging production technologies. Appendix 1 contains a general introduction and geological summary of the major aspects of the Alberta deposits of heavy oil and oil sands. The major deposits are approximately outlined in Figure 1.1. They are all high porosity (~30%) unconsolidated sandstones, and with the exception of a few small heavy oil fields in Devonian sandstones in Saskatchewan, they are all found in a sequence of sands and shales of Cretaceous age. In terms of total oil in place, over 95% of the resource lies in Alberta (100% of the oil sands deposits are in Alberta).

There is an area in Alberta called the Carbonate Triangle where carbonate reservoir rocks (limestones and dolomites) much older than the Cretaceous UCSS also contain viscous oil deposits. It has a total oil-in-place volume that is on the order of 10-15% that in the sands. However, the Carbonate Triangle is fracture-dominated, highly competent, of low porosity (~10-14%), and will require the development and application of modified or new production schemes different from those that are being used and will be developed to exploit the high porosity, weak sandstones that do not have natural fractures to dominate flow behavior. Given the lower relative oil contents and the presence of the rich oil sands and heavy oil deposits, these carbonate deposits may be considered a resource for the distant future.

1.3 CHOPS and Other New Technologies

1.3.1 CHOPS

The major heavy oil production technology discussed will be **CHOPS**: **C**old **H**eavy **O**il **P**roduction with **S**and. CHOPS involves deliberate initiation of sand influx into a perforated oil well, and continued production of substantial quantities of sand along with the oil, perhaps for many years. CHOPS requires management of large quantities of sand in all phases of production; this is a radically different concept to conventional oil well production management. Also, there are physical processes occuring in the reservoir that are completely foreign to conventional oil production engineers (foamy oil behavior, massive stress redistribution, liquefaction of sand, flow of a four-phase slurry…). Because CHOPS requires a radically different approach to oil field management and because scientific and engineering personnel have to learn new physical principals and apply them, CHOPS qualifies as a new oil production technology. It is a **primary production method** because it exploits natural energy sources in the reservoir: energy from dissolution and expansion of gas (compressional energy), and energy from the downward motion of the overburden (gravitational energy).

It is now widely understood in heavy oil exploitation that the exclusion of sand during primary production through use of screens or gravel packs in vertical wells[3] means that the oil cannot be produced economically. Individual vertical well rates will be only a few cubic metres per day (0.5 – 5 m^3/d), and the best of these rates will be attained only in the lower viscosity heavy oils (<1000 cP) and the better reservoirs (k > 2 D, t > 10 m). If sand ingress is initiated and sustained in reservoirs that have the right characteristics, oil production rates as high as 15-50 m^3/day can be achieved in almost all cases.

Such rates have also been achieved without large-scale sand influx in some heavy oil reservoirs exploited with long horizontal wells. However, the cost of a horizontal well is and will remain about 3× to 5× more expensive than a vertical well, and well intervention costs are extremely high in horizontal wells. These horizontal wells usually have a life-span of 3-6 years only, and typically no more than 10% of the original oil in place (OOIP) is produced. Data will also be presented later to show that in most cases CHOPS wells are more profitable and produce more total oil than horizontal wells.

[3] A vertical well is assumed to be a well at an inclination (dip) of 90° (true vertical) to 40°. More specifically, a vertical well is one that does not intersect a length of the reservoir greater than 2×H, where H is the thickness of the reservoir. Many CHOPS wells are inclined, but generally >50° inclination (dip), and these are generically called vertical wells. Horizontal wells have inclinations of 0°, and are designed to intersect the reservoirs over great lengths, invariably >10×H.

CHOPS produces large quantities of oily sand as well as various categories of fluid wastes: chloride-rich water (dissolved NaCl), water-oil-clay emulsions, slops, tank bottom sludges, and soil-fluid mixes arising from spills. The handling of all these wastes, including the massive volumes of produced sand, can add as much as $3.00/bbl to the operating costs (OPEX) for CHOPS. Waste management is considered to be the major cost factor for CHOPS operations, resulting in about 15-35% of OPEX, depending on oil and sand rates. Understanding and minimizing these costs are fundamental to planning and executing a heavy oil project using CHOPS methods.

The other large OPEX costs category is the cost of well workovers. CHOPS wells need far more frequent workovers than conventional oil wells, and this results in about 15-25% of OPEX, depending on the field and the wells. Reducing not only the fraction of OPEX absorbed by workovers, but also reducing all OPEX costs from the current level of about $7.00/bbl could increase profits, open up more marginal fields for development, and also allow the redevelopment of currently inactive (but not abandoned) wells.

Before 1985-1990, heavy oil production was based largely on thermal stimulation (ΔT – changes in temperature) to reduce viscosity and large pressure drops (Δp – changes in pressure) to induce flow. Projects used cyclic steam stimulation (huff-‘n-puff), steam flooding, wet or dry combustion using air or oxygen injection, and combinations of these methods. Until recently, these technologies employed arrays of vertical to mildly deviated wells (<45°). Only three projects in Canada still use these old techniques.

Some methods have never proven viable for heavy oil: these include solvent injection, biological methods, cold gas (CH_4, CO_2…) injection, polymer methods, and *in situ* emulsification. Up to about 1985-88, marginally economical non-thermal production with vertical wells was used in a limited manner in Alberta and Saskatchewan, but these wells produced less than 10 m^3/d, recovery was invariably less than 5-8% OOIP (**O**riginal **O**il **I**n **P**lace), and small amounts of sand generally entered the wellbore during production.

Note that all high-pressure methods experience advective instabilities such as viscous fingering, permeability channeling, water or gas coning, and uncontrolled (upward) hydraulic fracture propagation. These instabilities result in bypassing oil, isolating bodies of the oil by sweeping permeable channels clear of oil, early loss of wells because of excessive water production or gas production, early loss of reservoir energy, and so on.

1.3.2 Other New Production Technologies

Several new production technologies have been developed and proven in Alberta since 1985. Furthermore, there are emerging technologies that may impact future heavy oil production. Technologies defined as "proven" are those for which several commercial projects producing oil economically have been implemented in Canada or elsewhere by the year 2001-2002. The discussion here is expanded in Chapter 13.

Steam **A**ssisted **G**ravity **D**rainage (**SAGD**), based on horizontal wells, involves steam injection for viscosity reduction and gravity segregation for flow.[ii] The first prototypes were drilled from an underground mine in 1984-86 (funded by the Alberta government), and the first commercial projects commenced production in Canada in 2001.

Cold **P**roduction (**CP**) is non-thermal heavy oil production without sand. To achieve economical rates, the large drainage area of long horizontal wells completed with slotted liners is exploited. In Canada, economic success in oils less viscous than ~1500 cP is common, even though well production rates may drop at 40%/yr and the OOIP recovery is less than 10%. This technology has found major application in the Faja del Orinoco in Venezuela, where multi-lateral branches are added to further increase the drainage area of each well.[iii]

Pressure **P**ulsing **T**echnology (**PPT**) is a flow rate enhancement method first introduced in Canadian heavy oil fields using CHOPS in the period 1999-2001.[iv] The approach, applicable to any liquid-saturated porous medium, involves applying repeated tailored pressure pulses to the liquid phase of the reservoir. This has the effect of suppressing advective instabilities such as viscous fingering or permeability channeling, overcoming capillary barriers, and reducing pore throat blockage. PPT promises to have general value for any type of oil, and has also found application as a workover method.

There are also several "emerging" heavy oil production technologies. An "emerging" method is a promising approach that has perhaps seen laboratory and field trials, but has not been commercially implemented. The two major emerging technologies for heavy oil are VAPEX and THAI™.

Vapor-**A**ssisted **P**etroleum **EX**traction (**VAPEX**) is, from the point of view of physics and flow processes, the same process as SAGD, except that a mixture of condensable and non-condensable gases (e.g. CH_4 to C_4H_{10}, perhaps CO_2, some N_2…) is used to diffuse into the heavy oil to reduce viscosity and also to cause oil "swelling".[v] VAPEX approaches can be integrated in SAGD approaches in various ways, such as cycling between steam and miscible gases, using a mixture of gases in the steam, "warm" VAPEX using heated gas injection, and so on. As with SAGD, all VAPEX variations use gravitationally stabilized flow to avoid advective instabilities (such as coning and viscous fingering) and achieve high recovery factors.

Toe-to-**H**eel **A**ir **I**njection (**THAI™**) is essentially *in situ* combustion, but using horizontal wells so that the combustion products and heated hydrocarbons flow almost immediately downward into the horizontal production well, rather than having to channel through long distances.[vi] (Long distance of combustion gases almost always leads to gravitational override and fingering.)

These proven and emerging new technologies will, in the future, be used more and more in hybrid and mixed modes to achieve better recovery ratios and better return on investment. For example, CHOPS gives high early production rates, but SAGD gives better recovery ratios, suggesting phased or simultaneous use of the two methods. Also, different technologies will be found to be suitable for different reservoirs and conditions: SAGD and other thermal methods become very inefficient in reservoirs less than 15 m thick, whereas CHOPS and PPT have been economically successful in such cases. All these technologies will benefit from improvements in thermal efficiency, process control, and cost reductions.[vii]

Appendix 2 contains a "stand-alone" summary of the new heavy oil production technologies and a brief discussion of related issues.

1.4 Canadian Heavy Oil Production

1.4.1 Production and Upgrading

Canada is the world's largest producer of extra-heavy oil (<10° API or Baumé gravity[4]). Large-scale open cast mining projects include the Syncrude and Suncor open-pit mines in the

[4] API gravity is a measure of specific gravity at room temperature and pressure, with all *in situ* solution gas evolved. A value of 10° is equivalent to a specific gravity of 1.0 (water), a value of 25° is equivalent to a specific gravity of

Athabasca Oil Sands, with upgrading facilities on site. Approximately 300,000 b/d (US oil field barrels per day, 1 m^3 ~ 6.3 barrels) of synthetic crude oil is produced from the extra-heavy oil (bitumen) in the mining projects. EUB data for the year 2000 for these two operations are 317,000 b/d.

The Imperial Oil Cold Lake cyclic steam stimulation (CSS) project in the Cold Lake Oil Sands and the much smaller Shell Canada thermal project[5] in the Peace River Oil Sands (Figure 1.1) produce an aggregate of over 100,000 b/d (EUB data for the year 2000 give 119,000 b/d for Imperial Oil and 4,200 b/d for Peace River), but neither thermal project has local upgrading. Primrose Lake and Wolf Lake, and a number of smaller thermal projects bring the aggregate thermal production and mining production from <10° bitumen to about 600,000 b/d (EUB data give 605,000 b/d for the year 2000).

Canada is also probably the world's largest producer of primary heavy oil in the viscosity range of 10,000 to 100 cP (~10° to 20° API gravity), although Venezuela also produces similar amounts. Heavy oil in Canada is produced through thousands of relatively shallow wells (depths of 350-1000 m) found mainly in the **H**eavy **O**il **B**elt (**HOB**) straddling the Alberta-Saskatchewan border (Figure 1.1), and in smaller areas to the west and south west of the Cold Lake Oil Sands deposit.

The total amount of primary heavy oil produced in Canada (2000) is approximately 574,000 b/d, inclusive of "primary bitumen" and "primary heavy oil" but exclusive of the oil sands mining areas (NEB Report, 2001). Of this amount, Alberta produced about 360,000 b/d. The total represents 26% of Canadian oil production that year, and a far larger percent of Saskatchewan production. Of the 360,000 b/d of primary heavy oil production in Alberta, over 90% (i.e. over 320,000 b/d) is produced through CHOPS technology, close to 20% of the total. The remaining amount comes mainly from horizontal wells that produce either no sand, or only small amounts. One may debate the specific classification of what constitutes a CHOPS well, but it is assumed that essentially all primary heavy oil production from vertical wells (±40° inclination in the

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0.89. Although there is a strong relationship with viscosity, it is by no means unique, and oil companies are more and more reporting *in situ* oil viscosity rather than API gravity to describe their reservoirs.

5 Shell Peace River is technically not cyclic steam stimulation, but it is a high-pressure difference thermal process.

reservoir zone) in Alberta (and Saskatchewan) can be assumed to take place with some amount of sand influx, generally greater than 1% by volume.

A small percentage of the primary heavy oil production is beneficiated to asphalt products in the small Husky Oil Refinery in Lloydminster[6]. Some of it (~100,000 b/d or ~18% of Canadian total primary heavy oil production) is upgraded into synthetic crude oil in the Lloydminster Upgrader and the Co-op Refinery in Regina, both facilities designed to handle the extremely viscous feedstock. Several refineries in the Edmonton area accept heavy oil as a fraction of their feedstock, and there are programs in most of these refineries to increase the heavy oil input. Most of the primary heavy oil, perhaps 60 to 70%, is diluted and shipped to the United States for processing.

The produced heavy oil that is not upgraded in Canada to synthetic crude oil is shipped via pipeline (in slugs, separated from other higher quality feedstock) to the United States after the addition of up to 15% low molecular weight HC diluent (naphtha) to reduce the viscosity to permit pipelining. The major upgrading and refining facilities that accept Canadian heavy oil feedstocks are located in Chicago, Minneapolis, Kansas City and Billings (Montana).

Conventional oil in Alberta continues to slowly deplete, and upgrading heavy oil in Alberta to high quality synthetic crude oil makes a great deal of economic sense because of the proximity of hydrogen (CH_4), because of a differential price that can be very large, and because of other advantages.

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[6] Because of a relatively flat viscosity-temperature curve and the high relative content of aromatics, asphalt products manufactured from Canadian heavy oil have substantially better performance characteristics than asphalt products made from the refining process bottoms of conventional oil. However, the demand for asphalt products is low, local refineries in the US and eastern Canada virtually give away their heavy bottoms, and there is no significant market growth potential in this area.

Table 1.1: Alberta Crude Oil and Equivalent Production (AEUB), thousands of b/d

	1994	1996	1998	2000
BITUMEN PRODUCTION				
Imperial Oil Other Total thermal production	78 24 **103**	74 33 **108**	137 48 **185**	119 44 **162**
Wabasca primary production Other Total primary production	2 15 **17**	8 33 **40**	32 57 **89**	41 63 **105**
Conventional and Exper.	**15**	**18**	**13**	**21**
TOTAL BITUMEN PRODUC.	***135***	***166***	***287***	***288***
SYNTHETIC CRUDE PRODUC.				
Syncrude Canada Ltd Suncor Limited	193 71	201 78	210 95	204 113
TOTAL SYNTHETIC CRUDE OIL	***264***	***280***	***305***	***317***
CONVENTIONAL LIGHT & MED	734	682	603	510
CONVENTIONAL HEAVY	218	262	252	238
PENTANES, CONDENSATES	135	153	154	145
TOTAL ALBERTA OIL PROD.	1,485	1,542	1,601	1,497

1.4.2 Increase in Heavy Oil vs. Conventional Oil Production

Canada's overall oil production rate, which includes conventional oil, heavy oil and the extra heavy oil produced by thermal methods or open-pit mining, experienced a peak in 1983, at a rate of approximately 1.8×10^6 b/d (exclusive of natural gas liquids). Then it declined slowly for several years before again starting to grow slowly, reaching a level of approximately $2.1\text{-}2.2\times10^6$ b/d total production (exclusive of natural gas liquids) in the period September 1999 to September 2000 (published totals are 2.1×10^6 b/d for 1999, 2.17×10^6 b/d in 2000). This oil production response, a peak followed by a decline, then a reversal of the decline to achieve a level of production substantially above the initial peak, sketched qualitatively in Figure 1.2, is absolutely exceptional in the world. No other major producing country has yet succeeded in reversing the decline curve through the development of heavy oil (Venezuela is likely to be the second to achieve this in 2004-2005, but it will not exceed its previous peak production rate at that time).

This reversal-of-decline behavior has not been noted during the development of any other sedimentary basin in the world. This is because there have always been new conventional oil resources that could be accessed in other basins to meet increased demand. Worldwide, searching for new conventional resources has always been more profitable and technologically simpler than developing viscous heavy oil. In the next decade, this may change (see Chapter 2) because exploration costs for conventional oil are increased inexorably throughout the world.

The oil production focus in Canada has shifted from the low viscosity ($\mu < 100$ cP) medium and light gravity conventional oils, largely in carbonate reef structures (e.g. Leduc, Redwater and Rainbow Lake) and well-consolidated sandstones and conglomerates (e.g. Pembina), to the production of heavy oil ($\mu > 100$ cP) from high porosity unconsolidated sandstones spread across eastern Alberta and western Saskatchewan. In a mature basin, such as the Western Canadian Sedimentary Basin, it is observed that exploration costs per barrel of new conventional oil production continue to rise until it is no longer economical to pursue general exploration, unless the price of oil is high.[7] Therefore, if large resources that are technologically challenging to develop, i.e. extensive heavy oil deposits, co-exist beside the depleting conventional oil, attention and economic investment are gradually but naturally displaced toward the more difficult resources.

At the same time, technology never is static. Continued improvements in technology and the emergence of novel production concepts (next Chapter, Chapter 13 and Appendix 2) have reduced the relative costs of developing technologically challenging heavy oil resources (Figure 1.3). Because the marginal operating cost of "technology-intensive" heavy oil production has become less that the exploration cost to find a new barrel of production from conventional oil, and because the development costs have dropped recently, continued development of heavy oil

[7] General statements such as these are incorrect in detail as small companies develop local expertise and new technology becomes available. These factors mean that there is always some exploration activity going on, even in ultra-mature basins, but the overall exploration level drops nonetheless.

and oil sands in Alberta will continue unabated unless environmental factors or unforeseen events arise.

Thus, in Alberta the oil industry is no longer driven by exploration but by technological developments. All basins throughout the world that have large amounts of non-conventional resources can expect a similar sequence of events over the next few decades (e.g. Venezuela, Oman, Russia). The international oil industry in these other areas will be in an advantageous position to profit from the technology development for heavy oil production that is being driven largely by Canadian advances. Perhaps Canadian companies can be in the lead of this changing technological thrust.

Primary heavy oil production with CHOPS continued to rise in the period 1998-2000, despite depressed prices. In the entire HOB, it is estimated that CHOPS produces about 460,000 barrels of crude oil a day, and this is 20% of Canadian oil production. It should continue to have a major impact, and even grow substantially, provided that upgrading facilities increase the beneficiation capacity. This is considered the major impediment to increased oil production from the HOB.

1.4.3 Heavy Oil Price Cyclicity

Heavy oil in Canada has had a strong cyclic price history (Figure 1.4) that has made it extremely difficult to maintain best business practice and has also resulted in a substantial loss of general revenues and benefits to Alberta. Many professional industry personnel and economists fail to recognize that there is somewhat of a "disconnect" between the world oil market and the heavy oil market in west-central North America. Several important factors must be understood.

Beneficiation: Heavy crude oil cannot be sent to a conventional refinery: it has too high a carbon content, and there are also large amounts of sulfur and heavy metals (Ni, V, Ti). The massive excess carbon content[8] must be overcome by a combination of rejection of some of the carbon (coking) and addition of hydrogen (hydrogenation, with CH_4 as the H_2 source). Thus,

[8] Heavy oil may be viewed as having too much carbon, or not enough hydrogen, for direct use as a refinery feedstock. The reason for this is that the heavy oil is made up largely from large molecules with 5- and 6-fold carbon rings (aromatics), which have a much lower H:C ratio than conventional linear (aliphatic) hydrocarbons.

"upgrading" is needed, and this is carried out in complex and costly industrial facilities, "upgraders".

In upgraders, large coking towers heat the viscous feedstock to break apart the molecules and deposit elemental carbon. The resulting solid coke with >90% carbon content is a by-product of limited value in Canada (2001), as it has a high sulfur content and coke combustion residues have relatively high contents of heavy metals (nickel, vanadium…). After coking, elemental hydrogen is formed from methane, and high pressures and temperatures are used to increase the hydrogen-to-carbon (H:C) ratio of the liquids to generate synthetic crude oil for refining. The methane for the hydrogenation process is sourced from natural gas. It is the cheapest hydrogen source for this process, and no substitute hydrogen doner source is in sight.

Facilities Costs and Cyclicity: Long lead times and capital costs make investment in upgrading facilities difficult in a world oil price market that has seen large fluctuations in the last 20 years. Although heavy oil production is a vital part of Canada's production, exceeding 45% if all oil sands mines and heavy oil production is included (~1,000,000 b/d), the impact of Canada's heavy oil production is irrelevant in terms of the world price. Only ~8% of world oil production, about 5.8 MBOD (1999) comes from heavy oil (the amount one assigns to this category depends on the definition of heavy oil, and the value of ~8% refers to <20°API oil). Demand-supply variations related largely to Middle East conventional oil recently (1998) resulted in a crude oil price drop to US$10.00/bbl oil. It then climbed to US$33.00/bbl in 2000, and dropping in late 2001 to as low as US$20.00/bbl. Investing in a large upgrader (75,000 – 100,000 b/d) requires an investment exceeding CAN$1,250,000,000 over 4-5 years, and if the world price of oil is less than about US$14-15/bbl, it becomes impossible for both heavy oil producing companies and upgrading facilities to be profitable. Thus, price cyclicity is not conducive to the generation of large capital expenditures (CAPEX) needed for upgrading facilities: the perceived risks are too high in a volatile market.

The Price Differential: The upgrading facility must purchase heavy oil from producers at a price that is sufficient to meet fixed asset capital costs, operating expenses, and generate a reasonable profit. This price is lower than the posted price for light, sweet crude oil, and it is referred to as the "differential". It is estimated that the Husky Oil Lloydminster upgrader (75,000 b/d) needs a price differential of approximately CAN$7.00-8.00/bbl to be reasonably profitable. It has been as low as CAN$4.50/bbl in 1996, and for much of 2001, it was in the range CAN$16.00-18.00/bbl.

The Heavy Oil Price Cycle: If there is a shortage of feedstock for the upgraders, the price differential becomes less, but if there is a surplus, the differential expands. In part, this is also set by the world oil price: a high world oil price allows a much higher differential in principle than a low world oil price. Because there are only a limited number of upgrading facilities that accept the Canadian heavy oil, when new capacity becomes available, there is a period of high demand, and the differential sinks; when producers meet this demand (and invariably exceed it), the demand is low, and the differential rises, with far better returns to the upgrader operations than to the production operations. As producers ramp up production after new capacity becomes available, they always "overshoot", and this leads to prolonged periods of excess production capacity, the situation in late 2001.

The Dilemma of Small Producers: In the last decade, dominantly because of CHOPS, the issue of economical production has largely been solved. The emergence of new production technologies (SAGD, PPT, VAPEX) is likely to maintain this situation: large volume production of heavy oil is no longer a problem. It is believed that CHOPS technology could easily add several hundred thousand barrels of oil per day to the market in a period of 2-3 years if the upgrading facilities became available. The handful of new SAGD projects initiated in 2000-2001 will be producing at least an additional 100,000 b/d by the end of 2002, and these companies (CNRL, AEC, Conoco-Gulf, Petro-Canada, Suncor) will be anxious to produce more. Efficiencies are improving, and OPEX has dropped substantially in the last decade. However, small companies without guaranteed access to upgrading capacity have a dilemma: if they produce more, the differential rises because of oversupply; if they produce less, their cash flow can suffer.

Upgrading facilities want the highest differential they can get, producers the lowest. Small producers do not collude to fix production because companies such as IOL and Husky, who have access to their own upgrading capacity, simply increase production because they can obtain profits from either production or from the price differential. If the differential is high, it is more profitable to Husky Oil to buy the depressed price heavy oil from other producers; if the differential is low, they benefit more from increasing their own production levels.

Cyclicity Example on Producers: Figure 1.5 shows an example of the effect on price cyclicity and demand on one operator in the Alberta Lindbergh Field over a four-year period covering a serious cycle of price changes. The major points are:

As demand increased to late 1997, more and more production capacity was installed by drilling more wells. New wells are usually better producers.

With the sudden price drop in heavy oil prices in late 1997, the company started withdrawing the "worst" wells from production, focusing on the better wells with lower operating costs.

Well count went from 523 to 268 wells in a relatively short period (Nov 97 to Feb 99).

With 1999 price recovery underway, the trend was reversed, and the number of wells was increased gradually, mainly by rehabilitating inactive wells.

However, changing differentials as demand varied seriously affected producer profitability, requiring careful cost controls at all times.

All heavy oil companies, with the possible exception of Husky Oil, which has sufficient "in-house" upgrading capacity to accommodate their own production, can produce examples such as this one to demonstrate the pernicious effect of cyclicity. Note that the cost of rehabilitating a well in this study was estimated to be on the order of $CDN25,000, and the reactivated wells averaged initial production rates of only 7 m3/d, declining to 3 m3/d within a year. Of course, these were the "worst" wells in the field, not the best, which tended to produce closer to 8 m3/d average.

Summary: Up to now, the relatively rapidly changing relative balance between demand and production has driven the price cycle. However, the demand for heavy oil from the producing companies is limited in the market area by the volume of heavy crude that the upgrading and refining facilities companies can accept (in oil sands mines, upgrading is done on site). This leads to the following cycle, which has been experienced by the heavy oil industry at least three times in Alberta:

Prices increase, production rises.

- Producers lose money, and are regularly bought out at bargain prices by larger oil companies who may understand the value of heavy oil in the future world picture.
- High profits on upgrading leads to investments in altering existing facilities, perhaps to the construction of new, dedicated facilities.
- As new upgrading is brought on stream, the price differential drops, production is needed, and small companies once again start up in the heavy oil industry, repeating the cycle

There are strong arguments to be made that this cycle is pernicious, but in the absence of increases in upgrading capacity in Canada, it is difficult to see how the worst elements of the cycle can be mitigated. Also, because the majority of the upgrading facilities are in the United States, a large differential means a direct export of potential returns to the producing sector, which is largely the small to intermediate size Canadian companies. For example, if 250,000 b/d heavy oil is exported and the differential is CAN$15.00/bbl, and if the "reasonable profits" level is CAN$8.00/bbl for upgrading, at least CAN$600,000,000/yr is being directly expatriated. The total continued economic activity that this could generate if put toward the construction of additional upgrading facilities seems substantial.

Fig 1.1: Heavy and Extra-Heavy Oil Sand Regions, Alberta and Saskatchewan

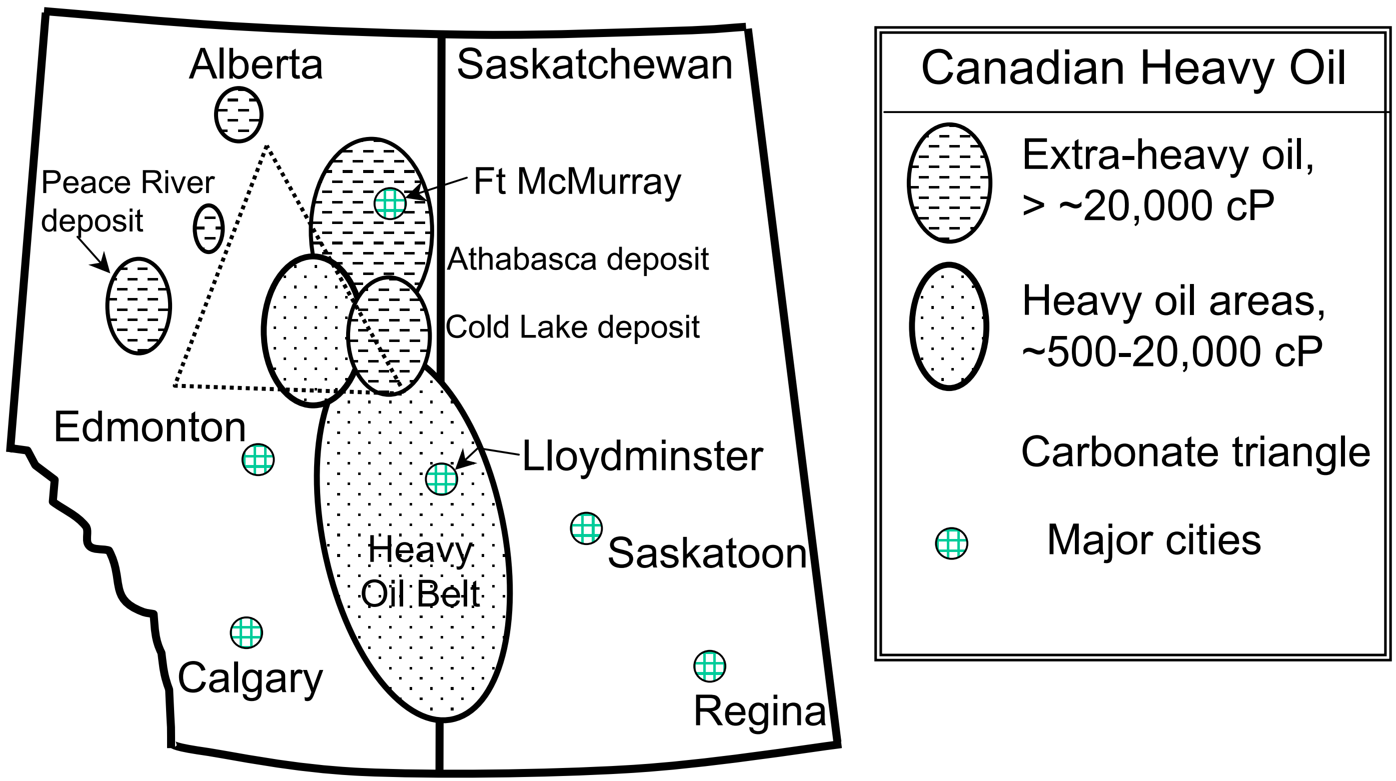

Figure 1.2: : Oil Production in Canada: the Effect of Heavy Oil

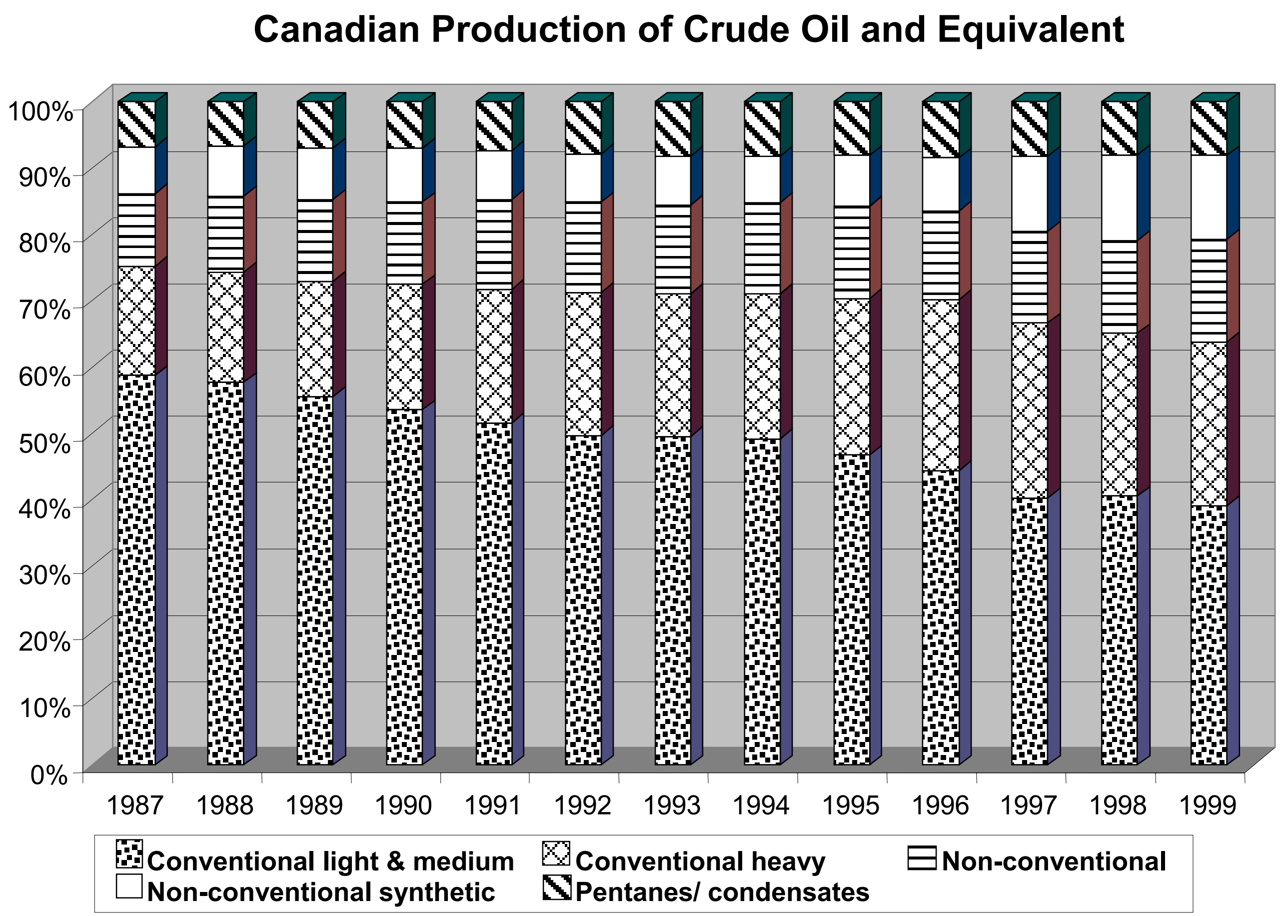

Figure 1.3: Oil From Exploration Becomes More Expensive Than Oil From Technology as Basin Matures (CSS refers to estimate costs for cyclic steam stimulation~$12.00/bbl)

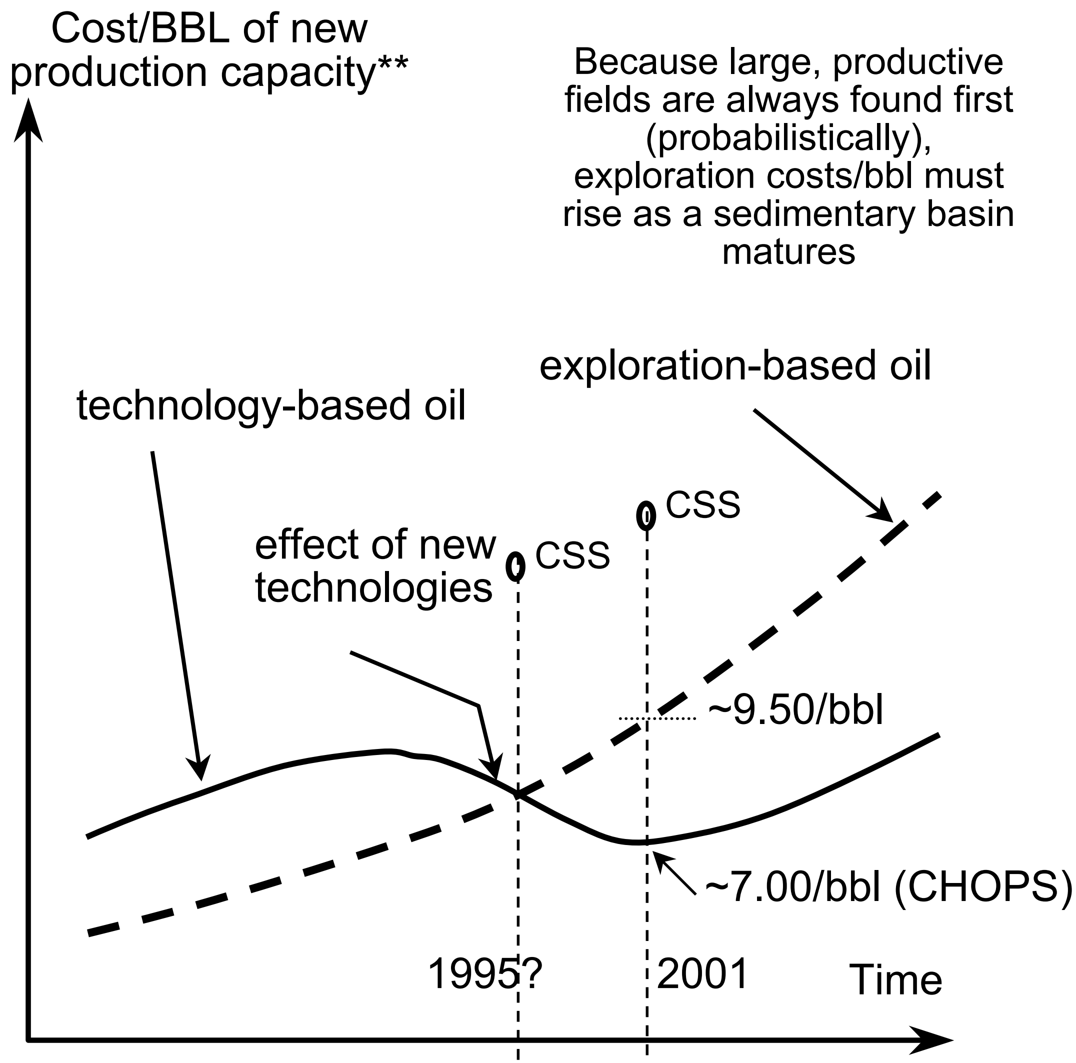

Figure 1.4: Heavy Oil Has Experienced Several Cyclic Changes in Price Because of Production and Processing Capacity Differences

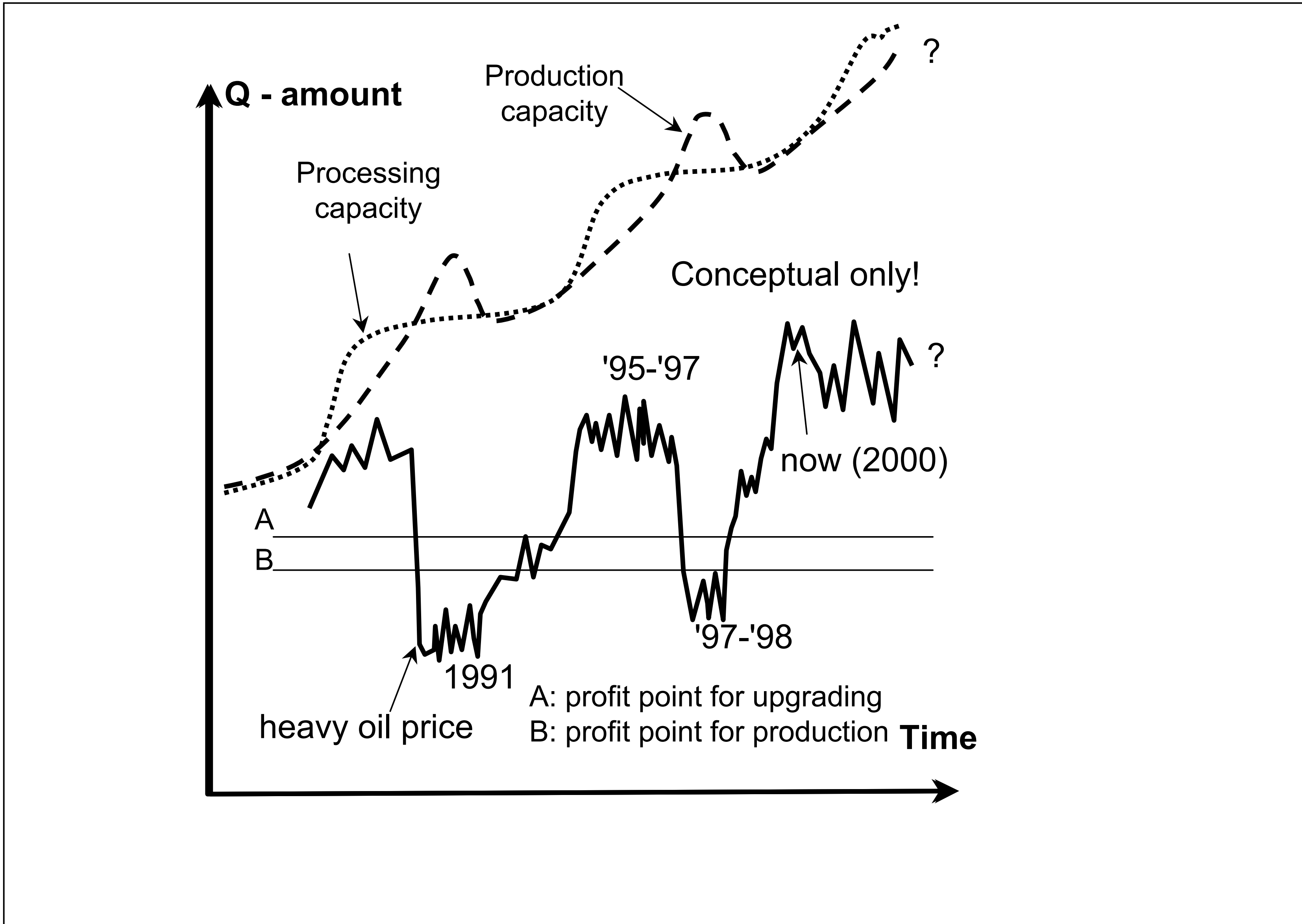

Figure 1.5: An Example of Well Count and Price Cyclicity