

National Energy
Board



Office national
de l'énergie

**Conventional Heavy Oil Resources
of the Western Canada
Sedimentary Basin**

August 2001

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Cat. No. NE23-101/2001E
ISBN 0-662-30799-2

This report is published separately in both official
languages.

Copies are available on request from:

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National Energy Board
444 Seventh Avenue SW
Calgary, Alberta, T2P 0X8
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Phone: (403) 299-3562
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Internet: www.neb-one.gc.ca

For pick-up at the NEB office:

Library
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Printed in Canada

© Sa Majesté la Reine du Chef du Canada représentée
par l'Office national de l'énergie 2001

No de cat. NE23-101/2001F
ISBN 0-662-86037-3

Ce rapport est publié séparément dans les deux
langues officielles.

Exemplaires disponibles sur demande auprès de la :

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Imprimé au Canada



This publication is printed on paper containing 20% Total Recovered Fiber/All Post-Consumer Fiber

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Acronyms

API	American Petroleum Institute
EUB	Alberta Energy and Utilities Board
GSC	Geological Survey of Canada
IVIP	Initial Volume In Place
OIP	Oil In Place
PADD	Petroleum Administration Defence District
PEEP	Petroleum Economic Evaluation Program
PETRIMES	Petroleum Resource Information Management and Evaluation System
RF	Recovery Factor
SAGD	Steam Assisted Gravity Drainage
SEM	Saskatchewan Department of Energy and Mines
VAPEX	Vapour Extraction
WCSB	Western Canada Sedimentary Basin
WTI	West Texas Intermediate

The National Energy Board (the Board or NEB), as part of its regulatory mandate, continually monitors the supply of all energy commodities in Canada (including electricity, oil, natural gas, and their by-products) and the demand for Canadian energy commodities in both domestic and export markets. The Board's Supply and Demand Reports provide a long-term outlook for the supply and demand for all energy commodities. The Board's Energy Market Assessment Reports address issues within a specific commodity. The Board also publishes, from time to time, reports of a technical nature focussing on specific commodity issues. *Conventional Heavy Oil Resources of the Western Canada Sedimentary Basin* is the latest of these technical reports.

The report presents the results of an extensive review of Canadian conventional heavy crude oil resources and is focussed on examining and updating estimates of the volume of conventional heavy oil contained in the ground (oil in place). Estimates are also provided for that portion of the oil in place that is recoverable. These estimates consider both the volume available from current technology and production practices, and the potential volume from future technologies which could increase recovery levels.

The results of an analysis of supply costs are also provided, as is a discussion of the relative economics of conventional heavy oil production. During the preparation of *Conventional Heavy Oil Resources of the Western Canada Sedimentary Basin*, a series of meetings and discussions were held with government agencies, petroleum research organizations, and operating companies involved in the exploration for, and production of conventional heavy oil. The Board thanks all those who provided their input, with special thanks to the Geological Survey of Canada for its contribution.

The Board welcomes any comments on the design, use of the selected methodology, or on the results of this report. Comments should be directed to the Secretary, National Energy Board, 444 - Seventh Avenue SW, Calgary, Alberta, Canada T2P 0X8.

Conventional Heavy Oil Resources of the Western Canada Sedimentary Basin has been undertaken as part of the Board's regulatory mandate of monitoring the Canadian supply of energy commodities. The nature of Canada's oil supply, especially in Western Canada, has been changing. This report focuses on the current and future supply availability of conventional heavy oil in Canada.

The Board generally defines conventional heavy oil as crude oil that is found in a liquid state in the ground, has the ability to flow into a wellbore, and has a specific gravity greater than 890 kg/m³ (API gravity of less than 25°).

Conventional Heavy Oil Resources of the Western Canada Sedimentary Basin provides an overview of the contribution of conventional heavy crude oil to Canada's total oil supply. It describes how the Board conducted the study and follows with the results of the study, which are provided on a geological play basis.

Highlights of the report include the following:

- The results indicate that resources of conventional heavy oil have been understated in the past. The Board's analysis indicates that the oil in place for the studied plays has increased by 20 percent, to 7 927 million m³ (49.9 billion barrels)¹, from the estimate of 6 575 million m³ (41.4 billion barrels) provided in the Board's 1999 Supply and Demand Report. This increase in the oil in place estimate can be attributed to the fact that this study projects the existence of a significantly greater number of smaller-sized pools compared with previous studies.
- This analysis shows that 21 percent of the discovered resources, and 12 percent of currently undiscovered resources, can be technically recovered. These estimates include the contributions from the application of present day, proven technology and production practices, and the potential for improved recovery through the application of future technologies. The ultimate recoverable resources of heavy conventional crude oil in Western Canada are thus estimated to be some 1 391 million m³ (8.7 billion barrels), representing an increase of 8.2 percent compared with the Board's 1999 Supply and Demand Report.
- Finally, the Board estimated the supply cost to develop conventional heavy oil pools in Western Canada in the future, based on a cost review of present day heavy oil operations. This study projects that 65 percent of the technically recoverable volume can be recovered economically, if producers would be willing to absorb costs of at least \$Cdn 62.38/m³ (\$Cdn 9.91/bbl) in the field. If producers would absorb a cost of \$Cdn 83.91/m³ (\$Cdn 13.02/bbl), 80 percent could be recovered economically.

1 One cubic metre (m³) of crude oil is approximately equal to 6.3 barrels or one metric tonne.

1. Introduction

In 2000, Canada produced crude oil from a number of areas, including conventional light oil from Western Canada, the Northwest Territories, and from Hibernia (offshore Newfoundland); conventional heavy oil from Western Canada; and bitumen and synthetic crude oil from the oil sands in northern Alberta. *Conventional Heavy Oil Resources of the Western Canada Sedimentary Basin* examines the prospective future supply of conventional heavy oil in Western Canada, and is intended for a technical audience that is familiar with the terminology and concepts of resource assessment.

There are no oil sands volumes accounted for in this report. Readers are referred to the Board's report entitled *Canada's Oil Sands: A Supply and Market Outlook to 2015*, published in October 2000, for a discussion of the oil sands resources.

In general, the Board defines conventional heavy oil as crude oil that is found in a liquid state in the ground, has the ability to flow into a wellbore, and has a specific gravity greater than 890 kg/m³ or an API gravity of less than 25°. For the purpose of this report, both Saskatchewan medium and heavy oils are combined in the Board's classification. Some additional conventions used in preparing this report are listed below:

- Generally, resource volumes are given as million m³ (million cubic metres).
- Dollars are year 2000 Canadian, constant, unless stated otherwise.
- Future improved recovery has two components. The first relates to the optimization of production and initiation of additional recovery projects, based on currently commercialized technology. The second component relates to improved recovery through the future application of technology not yet available. In the main body of this report, the discussion of the resource potential of the various plays generally uses the term in the first sense, but estimates of the second component are provide in a summarized form.

The Board's projection of conventional heavy oil production in the 1999 Supply and Demand Report¹ was based on estimates of heavy oil resources published by the GSC² in 1998, the Board's own long-term forecast of an \$US 113.26/m³ (\$US18/bbl) oil price (WTI), the results of a cash-flow model, and trend analysis of heavy oil production. A price sensitivity projection, based on \$US 138.43/m³ (\$US22/bbl) was also provided. During the preparation of that report, it became apparent that although the historical trend of heavy oil production continued to ramp upwards, this trend could not be sustained for long. The diminishing volume of remaining recoverable reserves dictated a relatively steep decline would have to occur in the next few years. It became clear that an updated view of the conventional oil resource picture was necessary. This report attempts to address that concern.

1 *Canadian Energy Supply and Demand to 2025*, National Energy Board, 1999

2 GSC Open File 3674, *Oil Resources of Western Canada*, Lee, P. J., 1998

In 2000, conventional heavy oil production from the Western Canada Sedimentary Basin (WCSB) averaged 91 300 m³/d (574,000 bbls/d) and represented 26 percent of total Canadian production. This volume is 10 percent and six percent higher than in 1999 and 1998, respectively, and is 10 percent higher than the peak production that had been projected in Case 1 of the Board's 1999 Supply and Demand report. This increasing level of heavy oil production reinforces the need for an updated resource assessment.

Conventional light oil production from Western Canada continues to decline on an annual basis, averaging 108 800 m³/d (684,000 bbls/d) in 2000, only 19 percent higher than conventional heavy oil production. The gap between the conventional light and heavy production is expected to continue to narrow with heavy oil production exceeding light oil production before 2010.

Canadian heavy crude oil generally sells at a considerable discount compared with light crude oil, reflecting the relative market value of end products to the refiner. This discount can vary widely depending on market conditions. Historically, the light/heavy price differential, commonly defined as the price difference between Light Par at Edmonton and Bow River Heavy Blend at Hardisty, Alberta has ranged between \$Cdn 18.88 and 56.63/m³ (\$Cdn 3 and 9/bbl), averaging about \$31.46/m³ (\$5/bbl). Generally, when heavy oil supply is tight relative to demand, the differential decreases and vice versa. In the past year, the differential has increased substantially, peaking at \$134.34/m³ (\$21.35/bbl), offsetting much of the benefit of higher international oil prices. This spike in the differential was caused primarily by market conditions in U.S. PADD II, where lighter grades were preferentially run to meet increased demand for distillate and gasoline. Higher natural gas prices, which reduced the amount of natural gas liquids available for refinery blending and which also led to some fuel switching from natural gas to distillate, and cold winter weather, which disrupted the transportation of heavy crude, also supported a wider differential. The differential has moderated somewhat since then to \$101.05/m³ (\$16.06/bbl) in May 2001. Heavy oil generally costs more to produce than light oil, further impacting producers' cash flow.

The Board expects to use the results of this study to assist in its projection of future conventional heavy oil production to be published in its next Supply and Demand report, targeted for release in early 2003.

2. Previous Work

The number of known assessments of heavy oil resources in the WCSB is relatively small in comparison with the number of assessments that have been done for natural gas. Recent efforts made at assessing the oil resources include two studies completed by the GSC¹ (1988 & 1998) and one study by Bowers² (2000). The nature and conclusions of these studies are discussed below.

2.1 Conventional Oil Resources of Western Canada (Light and Medium), GSC, 1988

In 1988, the GSC published its first report on remaining conventional light and medium oil resources in the WCSB. It provided a comprehensive analysis of the resource endowment of the WCSB using geological, technical and statistical analyses. The report examined 78 established geological plays and an additional 49 conceptual plays. This GSC assessment used year-end 1984 reserves data from each of the provinces in Western Canada. The resource appraisal was done using the GSC's PETRIMES model and oil-in-place estimates for each discovered pool, both light and medium, to generate the undiscovered in-place volume for each established play. For conceptual plays, a subjective probability analysis was used. This subjective approach considered both the exploration risk that the play actually exists and probability risks for pool sizes. Average recovery factors representing a combination of primary and secondary recovery schemes were applied to the undiscovered pools that were considered to be large enough to cover the estimated drilling and development costs.

The GSC recognized 2 360 million m³ of recoverable oil (7 377 million m³ of oil in place) as already discovered in the established plays, an additional 509 million m³ of recoverable oil left to be discovered in those same plays, and 61 million m³ of undiscovered recoverable oil in conceptual plays. The established reserves were estimated to be contained within about 3,300 separate pools. The undiscovered potential from the established plays was expected to be found in about 4,000 new pools that were expected, for the most part, to be smaller in size than pools already found. Using half-cycle costs (discovery costs excluded) it was estimated that 70 percent of the undiscovered volumes could be recovered economically at an oil price of \$Cdn 94.38 to 141.58/m³ (\$Cdn 15.00 to 22.50/bbl), dollars of the day. In comparing this assessment with the Board's current report, almost all of the plays studied by the Board were included in GSC's 1988 report. The GSC's assessment did not include the Cretaceous heavy oil volumes found in the Lloydminster Region of Alberta and Saskatchewan.

¹ GSC Paper 87-26, *Conventional Oil Resources of Western Canada (Light and Medium)*, Podruski, J. A., et al, 1988

² Bowers, B. November 2000, *Conventional Natural Gas Resources of the Western Canada Sedimentary Basin*, in *Journal of Canadian Petroleum Technology*

2.2 Oil Resources of Western Canada, GSC 1998

In 1998, the GSC published its second report on remaining conventional oil resources in the WCSB. Using a similar approach to that used in its first report, 69 established and 25 immature (conceptual) plays were reviewed to estimate the resource potential. The assessment was done using year-end 1994 data from each province in Western Canada. The GSC used its PETRIMES model, with the oil-in-place estimates of individual pools, both light and heavy, to generate the undiscovered in-place volumes for established plays. For conceptual plays, the GSC used a non-parametric discovery process model. In this case, the expected values of the play potential and discovery dates were used to generate a play resource discovery sequence, which was analysed using the same method as the established plays. This report recognized discovered oil-in-place resources of 12 547 million m³ in the established plays, an additional mean value of 5 488 million m³ of undiscovered oil in place in the established plays and 1 470 million m³ of undiscovered oil in place in the immature plays. The discovered resources were contained in 7,142 oil pools. The undiscovered potential in established plays was expected to be found in over 18,000 pools, most of which are expected to be smaller in size than the discovered pools. This GSC report did not contain an estimate of recoverable volumes nor did it provide an economic assessment of the undiscovered potential. The report did assess Cretaceous heavy oil plays in the Lloydminster Region and provided a detailed assessment of the Cretaceous plays across the Basin. The GSC assigned pools to light or heavy categories based on a single specific gravity cut-off (900 kg/m³ or 24° API) for the entire Basin.

In the 10 years between the GSC reports, discovered conventional oil resources in Western Canada for those plays studied in both reports grew from 7 153 to 9 549 million m³ of oil in place, a growth of 33 percent. It should be noted that the number of designated pools doubled from 2,612 to 5,245, which confirms that new pools are generally smaller than previously discovered pools. For undiscovered conventional oil resources, the mean potential estimate grew from 1 874 to 3 492 million m³ of oil in place, a growth of 86 percent. The number of undiscovered pools expected to be found increased from 3,133 to 12,126, a growth of 287 percent. This illustrates that the size of discovered pools are expected to be smaller in the future. New technology, in particular 3D seismic and horizontal drilling, in that 10 year period reduced the cost of finding and developing smaller pools.

2.3 Conventional Natural Gas Resources of the Western Canada Sedimentary Basin, Bowers 2000

In 2000, Bowers published an estimate of conventional natural gas which included an estimate of conventional crude oil of 16 000 million m³ of oil in place in the WCSB. His estimate was 18 percent lower than the most recent GSC estimate. It was generated by plotting the discovery rate of conventional crude oil on an annual basis against the cumulative discovered oil-in-place resources. The discovery rate is a reflection of the amount of oil added for every metre of drilling in the basin that is specifically directed for oil. The number of oil-directed metres drilled, in any particular year, is the total metreage of all exploratory and development wells that are classified as oil wells, plus a proportional share of the dry hole metreage. The resulting exponential decline curve is projected out to the point where there is no additional oil added by drilling more exploratory wells.

Bowers' study reviewed data from 1965 to 1997 on an annual basis; however, the resources found prior to 1965 and the amount of drilling to that date were included. At year-end 1997, there were about 14 000 million m³ of known resources. Therefore, this study estimated the undiscovered oil-in-place resources of conventional light and heavy crude oil in the WCSB to be 2 000 million m³.

Table 2.1 shows the comparative results of these three studies.

T A B L E 2 . 1

Summary of Previous Studies

	GSC 1988	GSC 1998	Bowers 2000
Discovered Oil In Place (10 ⁶ m ³)	7 377	12 547	14 000
Number of Discovered Pools	3,300	7,142	NA
Undiscovered Oil In Place (10 ⁶ m ³)	1 874	6 958	2 000
Number of Undiscovered Pools	4,000	18,000	NA
Total Oil In Place (10 ⁶ m ³)	9 251	19 505	16 000

3. Methodologies

This chapter describes the geological, engineering and economic analyses used and provides an overview of the consultation process.

3.1 Geological Data Analysis – Overview

The NEB used a discovery process model to generate its estimates of undiscovered potential in the geological plays. Year-end 1998 data was used for British Columbia, Alberta and Manitoba, and year-end 1997 data for Saskatchewan.

The geological plays as defined by the GSC in its 1998 report were adopted, generally without revision, in this assessment. The oil-in-place volume for each discovered pool in each of the studied geological plays was entered into a spreadsheet, along with the field name, pool name, date of discovery and specific gravity. This information was then provided to the GSC to run in its PETRIMES discovery process model. The output data from PETRIMES was inconsistent on a statistical basis and the Board agreed with the GSC's subsequent recommendation to use the geo-anchored discovery process method. The output data consisted of a range of oil-in-place volumes for each undiscovered pool. The Board used the mean pool size estimate for each undiscovered pool to complete the Basin assessment. As with any model, the reliability of the output data is dependent on the reliability of the input data. While the Board made a concentrated effort to validate the input data used, the intensive detailed stratigraphic analysis required to validate each specific pool was considered to be beyond the scope of this study. Therefore, reliance on the provincial agencies' analysis and naming conventions was required. As a general observation, discovery process model outputs tend to be conservative in nature, so the full potential may be somewhat higher than stated in this report.

3.2 Reservoir Data Analysis – Overview

The recovery factors for the discovered pools were adopted from the provincial databases. These recovery factors pertain mostly to primary recovery in the heavy oil pools, but some pertain to enhanced recovery. To date, the enhanced component applied to heavy oil pools has been limited to waterflood and some thermal projects. The estimates for the reservoir properties and other engineering parameters are based on the assumption that similar size pools in the same geological play would exhibit similar characteristics. Each undiscovered pool was assigned a recovery factor via comparison with already discovered pools through a data-matching process using information stored in the existing provincial databases.

The Board also made an estimate of the extent to which recovery factors would appreciate over time. This was made under the assumption that more efficient and economical recovery will be made possible by improved operating practices and new technologies. This future improved recovery has two components. The first includes the contribution to improved recovery through

the application of commercially-proven current technologies: including primarily the use of in-fill drilling with both horizontal and vertical wells, improved production practices, and the improvement and extension of waterflood and steam injection projects. In this regard, screening criteria were applied to each undiscovered pool based on geological play, expected oil type, lithology and other reservoir parameters, as described in Bowers and Drummond, 1997¹. The second component is more speculative and refers to the potential contribution of technologies still not commercially-proven in conventional heavy oil pools. These could include steam-assisted-gravity-drainage (SAGD), vapour-extraction (VAPEX), as well as future technologies at various stages of research and those that may not be conceived yet.

3.3 Supply Cost Evaluation – Overview

The Board conducted an economic analysis of both the remaining recoverable oil volumes of the discovered pools and the estimated recoverable oil volumes of the undiscovered pools, based on upstream supply costs. The supply cost analysis is a financial calculation involving economic assumptions including discount rates, net present values, project risk and time. Supply cost is defined as the average cost per unit of production over the project life, and includes a 10 percent after-tax rate of return to the producer. It includes capital costs associated with exploration, development and production, fixed and variable operating costs, royalties and taxes. Transportation costs to the markets are not included. The supply costs were calculated using Merak's Canadian Petroleum Economic Evaluation Program (PEEP) model. The supply cost analysis establishes the threshold size that a single well pool must be in order to be developed economically.

3.4 Geological Data Analysis

3.4.1 Input Data

The oil-in-place data used in the Board's assessment was obtained from the respective provincial governments' reserves databases. There are three categories of data: designated pools, Alberta potential pools, and Saskatchewan miscellaneous pools.

The designated pool information is the reserves information specific to each discovered and identified pool. In most cases, the database provided the field name, pool name, original oil in place, primary recovery factor, enhanced recovery factor, total recovery factor, primary reserves, enhanced reserves, total reserves, cumulative production (to year-end 1997 or 1998), remaining reserves, pool area, net pay, porosity, water saturation, formation volume or shrinkage factor, specific gravity, depth and discovery year.

In cases where there were commingled pools, the pool information was subdivided to the individual pool component level and each component pool was counted in its respective play. For example, if there was a commingled Rundle and Cretaceous pool, the portion of oil in place belonging to the Rundle zone was counted as one pool in its proper Rundle play and the Cretaceous portion was counted as one pool in its proper Cretaceous play. The proportion assigned to each pool was taken from the provincial databases or calculated by comparing the respective size of each component pool with the total size of the commingled pool. For Saskatchewan, the unit and non-unit portions of pools were combined and the combined data

¹ Bowers, B., and Drummond, K.J., 1997, *Conventional Crude Oil Resources of the Western Canada Sedimentary Basin*; Journal of Canadian Petroleum Technology, Volume 36, No. 2, February, 1997.

entered as a single pool in its proper play. In cases where the provincial government designated a pool to the general Blairmore or Mannville Group, the NEB reviewed the geological information in order to assign the pool to the appropriate stratigraphic interval. The decision on whether to assign a pool as light or heavy was dependent upon the respective provincial government agency. As it defines heavy oil, the NEB includes those pools designated as heavy in British Columbia or Alberta, and those pools designated as medium or heavy in Saskatchewan. All Manitoba pools were considered to be light oil regardless of the specific gravity.

Information on potential pools in Alberta was accessible to the NEB through the Common Reserves Database Agreement between the Alberta Energy and Utilities Board (EUB) and the NEB. This information was prepared by the EUB and NEB as part of an internal evaluation process that is completed on all wells in the province. Evaluators have the option of identifying zones as having potential resources of light oil, heavy oil, bitumen or natural gas. The information includes the field name, well location, zone name, depth, net pay, porosity, water saturation and drill date. In this study, the NEB provided a nominal area assignment to each potential discovery and a shrinkage factor representative for that zone in that area of the province. The area assignment was generally one-half of the province's minimum assignment for that zone in that area. From this information, the NEB calculated a potential oil-in-place volume for each potential pool. While this calculated potential volume was counted as a discovered pool in the modelling process, it had to be added to the generated undiscovered potential total and removed from the discovered volume total because the potential pools are still not developed and confirmed pools. These potential pools helped to better define the actual pool distribution of a particular play.

The Saskatchewan Department of Energy and Mines (SEM) miscellaneous reserves information raised more complex issues. For many of the geological formations, in each of its Production and Disposition Areas, and for different oil types, the SEM carries a miscellaneous reserves listing. This listing includes the same reserves information as noted in the designated pool information. The listing is dynamic, and the volume of reserves carried is capable of changing by a significant amount, positively or negatively, each year depending on events. The reserves represent a compilation of data from a number of single well pools, abandoned wells and pools that are waiting on full designation by the SEM. In order to account for these volumes, the NEB determined the number of producing wells for each zone in Saskatchewan that were not assigned to designated oil pools. These wells were then grouped on a geographical basis, such that if two wells were located within a section of each other, they were considered to comprise a single pool. These grouped pools were then assigned an in-place volume assuming normal distribution. The sum of the in-place volumes assigned to all the grouped pools in a zone equalled the in-place volume assigned to that miscellaneous category by the SEM.

3.4.2 Geological Modelling

The GSC initially entered only the data for the designated heavy oil pools (oil in place and discovery date) into its PETRIMES discovery process model. The output results obtained from PETRIMES were considered to be statistically suspect by the GSC. Discussion as to why the results were suspect centred on two areas: input data and discovery history.

Inputting only the heavy oil data may skew the data for particular plays since the definition of heavy oil changes across provincial boundaries. In addition, classifications may change from time to time depending on marketing and transportation considerations, and this may have some impact as well.

The discovery history of heavy oil has been sporadic in nature in the WCSB. Industry activity levels respond to the profitability of producing heavy oil, which can be seriously affected both by the price of crude oil and the relative price differential between light and heavy crude oil. When heavy oil production is profitable, industry responds by drilling a large number of wells. The PETRIMES model is partly dependent on the timing of discoveries, since one of its assumptions is that the larger pools tend to be found early in the development history. The boom and bust cycles of heavy oil development may impact that assumption since exploration may be delayed by the economic cycles.

The GSC then recommended the use of its geo-anchored discovery process model. This model does not make assumptions on the shape of the pool size distribution, but does assume that the probability of discovering a pool is proportional to the size of the pool. This method generally predicts the resources contained within the interval of the largest and smallest discovered pools. The geo-anchored method is a variation of the Arps-Roberts methodology, which was originally developed for the Denver Basin in Colorado. As a result, the geo-anchored model will predict a large number of undiscovered small pools when there are small pools present in the distribution. One of the advantages of this methodology is that it can handle a slight mixing of the population within a play. That mixing may result from either including pools that more properly belong to a different play or mixing of light with heavy pools. Readers are referred to papers by Kaufman, 1986¹ and Chen & Sinding-Larsen, 1999² which describe this methodology. A “pool” is defined as any accumulation of crude oil in the ground regardless of size, for the remainder of this report.

The second GSC run used the designated and potential pool information from both light and heavy oil pools as inputs for the geo-anchored model. The output was considered to be statistically sound by the GSC. However, a closer review of the plays in Saskatchewan revealed a new challenge. For those plays with a large miscellaneous volume, the generated undiscovered resource estimates were insufficient to account for the already discovered miscellaneous oil-in-place volumes. In order to overcome this challenge, it was necessary to include the information from the miscellaneous pools on the discovered resource side of the input data.

The final GSC run used the designated, potential and miscellaneous pool information from light and heavy oil pools (the whole play population) as inputs for the geo-anchored model. The output of these runs was sub-divided into separate light and heavy oil populations. The heavy oil outputs used in this report are the sum of the mean values generated for each undiscovered pool in each play.

3.5 Reservoir Data Analysis

The methodology used by the Board is based on the statistical analysis of reservoir properties. The process basically consists of organizing the reservoir properties data into the groups or categories consistent with the geological play model and then using this information to apply appropriate reservoir properties to the undiscovered pools (Table 3.1).

As only oil-in-place volumes of each play were modelled in the geological model, the reservoir properties of each pool are based on the latest reserves databases from the provincial agencies. Oil recovery factors and reservoir parameters, ordered by crude oil type and recovery mechanism,

1 Kaufman, G.M., 1986, *Finite Population Sampling Methods for Oil and Gas Resource Estimation*.

2 Chen, Z. and Sinding-Larsen, 1999, *Estimating Petroleum Resources Using the Geo-Anchored Method - A Sensitivity Study*, Natural Resources Research V. 8, No. 1, p. 49-58.

T A B L E 3 . 1**Reservoir Data Analysis Methodology**

1	Construct a database using the reservoir data from the provincial databases.
2	Statistical analysis of oil recovery factors and reservoir parameters by crude oil type and recovery mechanism.
3	Separate the output results from the geological model into two groups; discovered and undiscovered pools.
4	Match reservoir information from the database in Step 1 to the corresponding discovered pools.
5	Assign reservoir properties of the discovered pools from the database in Step 1 to similar sized undiscovered pools in Step 3.
6	Eliminate the undiscovered pools in Step 5 that are smaller than the cut-off limit for future pool development from further evaluation.
7	Determine the remaining recoverable volumes for discovered pools.
8	Estimate the recoverable volumes of the remaining undiscovered pools.
9	Estimate possible additional recoverable volumes for each of the discovered and undiscovered pools based on the screening criteria for improved recovery.
10	Estimate possible additional recoverable volumes through use of new proven technology and improvements from better production practices.
11	Analyse the results of steps 6 to 9 using pool size distributions.

were statistically analysed in order to establish oil recovery factors for future discoveries from the set of undiscovered pools.

The geological model results are separated into two groups – the discovered and undiscovered pools. The discovered pools are matched with the corresponding reservoir information from the provincial databases, and appropriate reservoir information of similar sized pools is assigned to corresponding undiscovered pools. Pools having an oil-in-place volume larger than the minimum cut-off are included for further evaluation.

Future production will come from the recoverable resources in both the discovered pools and undiscovered pools. This future production includes the volumes from improved recovery, which has two components. The first includes the contribution from the application of commercially-proven current technologies. This includes primarily the use of in-fill drilling with both horizontal and vertical wells, optimized production practices, and the improvement and extension of waterflood and steam injection projects. In this regard, screening criteria were applied to each undiscovered pool based on the geological play, the expected oil type, lithology and other reservoir parameters as described in Bowers and Drummond, 1997. The second component of future improved recovery is more speculative and refers to the potential contribution of technologies still not commercially-proven in conventional heavy oil pools, such as steam-assisted-gravity-drainage (SAGD), vapour-extraction (VAPEX), and future technologies that may not be conceived yet. The respective potential of these components was assessed using the reservoir and production data, enhanced recovery selection criteria and statistically established recovery factor guidelines. The results are further analysed to determine the effects of pool size distributions.

3.6 Consultation Process – Overview

The Board used the results of the geological and engineering evaluations to establish preliminary estimates of the undiscovered resources and also to do a preliminary assessment of recoverable volumes, based on currently available technology and production practices. Subsequently, relevant provincial government agencies, petroleum research organizations, and active exploration and producing oil companies were asked to comment on the Board’s resource estimates. After considering information from all parties, the Board finalized its estimates, including estimates of future improved recovery.

3.7 Supply Cost Evaluation

The analysis of the economics of conventional heavy oil exploration and development made extensive use of the wealth of available general well information and production data. Statistical and graphical analyses of this data were used to generate average or typical well production profiles, organized by geological play and by well recovery category, which were used in turn to generate supply cost curves (Table 3.2).

3.7.1 Typical Well Profile

Most of the production analysed was based on primary production, or cold heavy oil production, practices. The problems associated with heavy oil production include frequent equipment failures, wellbore problems, saltwater disposal and sand disposal. In recent years, technological innovations (including innovative completion techniques, pumping optimization, surface monitoring and control systems) developed to handle these problems have made significant contributions in reducing the supply costs of conventional heavy oil.

A large amount of production data was reviewed to assure the quality of the inputs used. Although each well has a degree of unique production characteristics, most wells display a similar exponential depletion pattern, when production rate is plotted versus time (Figure 3.1). Curves representing cumulative production versus time also exhibit similar patterns for different wells. In general, wells have a life span of less than 10 years. More than 50 percent of the cumulative volume is recovered within two years of startup and approximately 80 percent is recovered within

T A B L E 3 . 2

Supply Cost Evaluation Methodology

1	Evaluate performance of individual sampled wells to establish typical well profiles. Performance factors considered were: monthly rates, oil cuts, water cuts, and cumulative production.
2	Establish production profile for typical wells with different categories of production rates.
3	Within each geological play, establish the distribution profile for each well recovery category.
4	Establish cumulative frequency distributions for each play type.
5	Calculate supply cost for each well recovery category.
6	Calculate supply cost for each geological play.
7	Establish supply cost curve for each geological zone.
8	Establish aggregate supply cost curve for conventional heavy oil.

four years. The parameters for a typical well profile (Figure 3.2) were established based on the common depletion patterns described above. The typical well production profiles were used to generate monthly oil and water production rates for input into the supply cost calculations. The supply cost also included an assumption of two percent sand production.

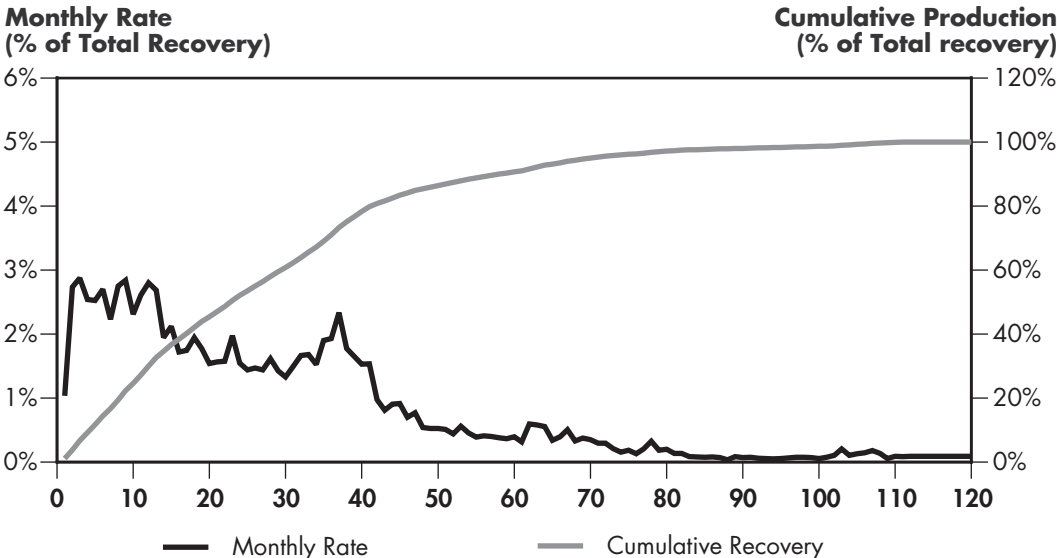
3.8 Data Presentation

In subsequent chapters, the input data, output summary, and analysis is provided in the following format for each play:

- A map, indicating the geographical location and outlining any relevant geological information.
- A datasheet (using a format designed by the Canadian Gas Potential Committee), presenting the discovered and undiscovered resource information, the minimum, maximum and average values for the primary reservoir parameters, and individual pool information for the larger discovered pools and largest 40 undiscovered pools. Note, the recoverable volumes on the datasheets only reflect the portion that can be recovered using current technology and production practices.
- A summary table, with the input and output data totals and a breakdown of the undiscovered pool sizes and total undiscovered resource estimates for each size class (Note that this summary table has not been corrected for potential pools).
- A pool-rank plot, showing the distribution of the largest 50, 100 or 200 pools in a particular play, depending on the number of pools projected for that play. This plot will illustrate where the largest missing or undiscovered pools are likely to be found in comparison with the largest discovered pools. Readers who wish to see the full distribution can create the plot using the input and output data available from the Board’s website.
- A cross plot, which displays the net pay and area of discovered pools as a function of pool size. This cross plot is used to provide a general indication of the net pay and area characteristics that an undiscovered pool of a given pool size could exhibit. It is

FIGURE 3.1

Typical Well Performance



extremely unlikely that a newly-discovered pool will exactly match either the projected area or net pay. This cross plot is meant to be a reference check to the projected pool size.

- The Board has made available on its Web site (www.neb-one.gc.ca) the data output files received from the GSC. They can be accessed through the electronic version of this report on the Board's Web site under Energy Overview, Assessment (Energy Resources). This file provides the input data, the output data including the range of values for each undiscovered pool, and the resources totals for the discovered and undiscovered pools (Note that this output file has not been corrected for potential pools).

FIGURE 3.2

Typical Well Profile

