FOSSIL ENERGY

DOE/BC/14861-6 (Vol. 1)
(DE95000133)

HORIZONTAL OIL WELL APPLICATIONS AND OIL RECOVERY ASSESSMENT

Volume I: Success of Horizontal Well Technology

Final Report

By
W. Gregory Deskins
William J. McDonald
Robert G. Knoll
Selwyn J. Springer

March 1995

Performed Under Contract No. DE-AC22-93BC14861

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Houston, Texas

Bartlesville Project Office
U. S. DEPARTMENT OF ENERGY
Bartlesville, Oklahoma

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DOE/BC/14861-6 (Vol. 1)
Distribution Category UC-122

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Prepared for
U.S. Department of Energy
Assistant Secretary for Fossil Energy

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Abstract

VOLUME I: SUCCESS OF HORIZONTAL WELL TECHNOLOGY

Horizontal technology has been applied in over 110 formations in the U.S.A. Volume I of this study addresses the overall success of horizontal technology, especially in less-publicized formations, i.e., other than the Austin Chalk, Bakken, and Niobrara. Operators in the U.S.A. and Canada were surveyed on a formation-by-formation basis by means of a questionnaire. Response data were received describing horizontal well projects in 58 formations in the U.S.A. and 88 in Canada. Operators' responses were analyzed for trends in technical and economic success based on lithology (clastics and carbonates) and resource type (light oil, heavy oil, and gas). The potential impact of horizontal technology on reserves was also estimated. A forecast of horizontal drilling activity over the next decade was developed.

VOLUME II: APPLICATIONS OVERVIEW

Horizontal technology has been applied in a wide variety of applications and reservoir settings. Much information has been published on drilling, completion, and workover systems, tools and techniques for these wells, especially for the most active formations. Little has been presented describing overall production and economic success of the technology in the wider range of formation types. In Volume II of this study, numerous case studies and analyses are presented of horizontal technology projects in each major application and resource type. Field location, geology, production and economic success, reserves increases, and production problems are described for each project. Chapters are presented assessing horizontal applications in light-oil, heavy-oil, and gas reservoirs. To broaden the base of formation types, especially with respect to heavy-oil and gas reservoirs, Canadian operations are highlighted in the study along with those in the U.S.A. Additional objectives of the study include an assessment of the technical and economic limits of horizontal technology.

Executive Summary

INTRODUCTION

DOE sponsored Maurer Engineering Inc. to perform an industry-wide study examining the current status and direction of horizontal technology in the U.S.A. petroleum industry. The project was designed to address operators' success with the technology in a variety of formation types and applications. Canadian horizontal well projects were also overviewed.

In Volume I of this report, results are presented of a survey of U.S.A. and Canadian operators. Operators' responses were analyzed for trends in technical and economic success as a function of lithology and resource type. Other topics include the potential impact of horizontal technology on reserves and a forecast of horizontal drilling over the next decade.

PROBLEM STATEMENT (Chapter 2)

Horizontal drilling and completion technology has become established in the U.S.A. oil and gas industry and has moved from the realm of special-purpose technology and become almost routine in several geographic areas. Both the U.S.A. and Canada have seen significant growth in use of the technology in recent years (Figure i). While horizontal drilling technology has advanced significantly over the past few years, little has been presented regarding the overall impact of horizontal technology on resource production. Additionally, the work that has been published on activity in the U.S.A. generally focuses on either the Austin Chalk formation of the Gulf Coast or the Bakken Shale of the Rocky Mountain area.

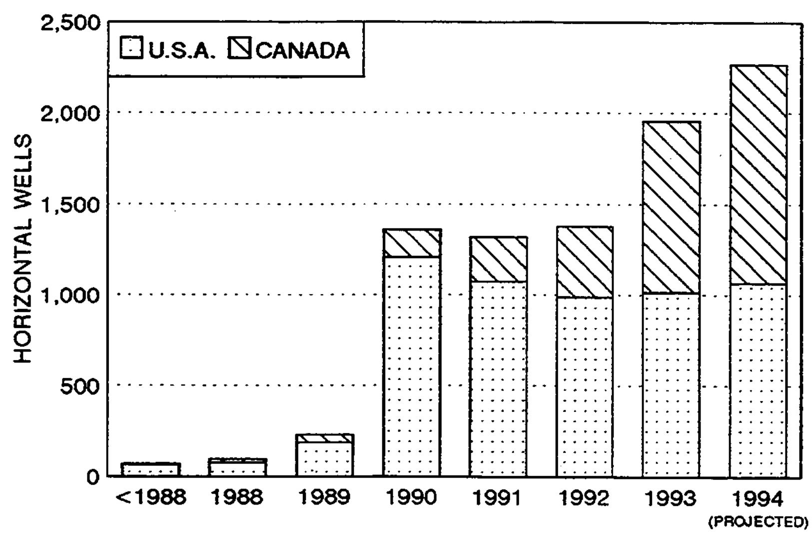

Figure i. U.S.A. and Canadian Horizontal Wells

The tasks performed for this DOE project were designed to evaluate horizontal applications in other less publicized formations to determine trends for technical and economic success or failure in these formations. Canadian applications were also included in the study to broaden the base of formation types, especially with respect to heavy-oil development. Other objectives of the study are to address technical and economic limits of horizontal technology, make projections of future drilling, and estimate the potential impact on overall reserves.

HORIZONTAL TECHNOLOGY APPLICATION TRENDS (Chapter 3)

A questionnaire survey (Table i) was conducted of U.S.A. and Canadian companies that operate horizontal wells for oil and gas production. A principal objective of the analyses was to determine relative rates of usage and levels of success of horizontal drilling in clastic and carbonate formations. Questionnaires were submitted on a one-per-formation basis, that is, not weighted by the number of wells.

TABLE i. Horizontal Well Project Survey Responses

	Horizontal Wells (As of 1/94)	Reservoirs With Horizontal Wells	Survey Responses	Response Rate
U.S.A.	4620	114	58	51%
CANADA	1786	220	88	40%

U.S.A. Horizontal Technology Trends

Results and conclusions from analyses of 58 surveys describing horizontal development in U.S.A. formations are summarized below.

1. Over 85% of domestic horizontal wells have been drilled in only three formations: the Austin Chalk (79%), Niobrara (2%) and Bakken Shale (5%). The number of wells in other formations continues to increase, from about 20 wells drilled before 1987 to over 670 by early 1994.

2. Over half (56%) of wells in "other" formations were drilled in clastic reservoirs. Based on operators' responses and the distribution of the U.S.A. resource base, clastic applications should continue to increase.

3. The most common applications for horizontal technology in the U.S.A. include intersecting fractures (53% of all fields) and delaying coning (33%) (Figure ii). Least used applications are for water drive, EOR, and to avoid surface restrictions.

   The most common applications for drilling horizontal wells in clastics are coning avoidance and favorable economics. In carbonates, the most common application by far has been to intersect fractures.

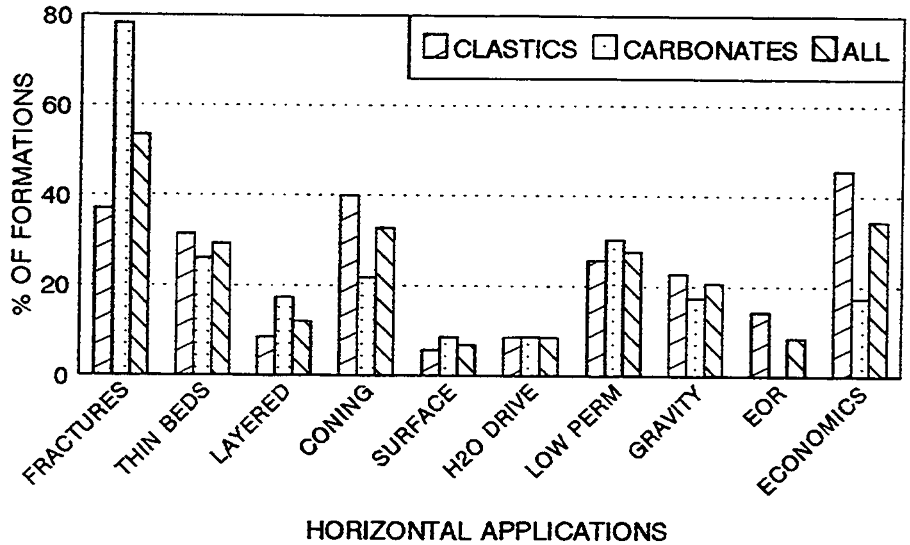

Figure ii. U.S.A. Horizontal Technology Applications

4. Production and cost ratios have been generally favorable for U.S.A. horizontal projects (Table ii). The benefit index (production ratio over cost ratio) for carbonates has been higher than for clastics.

TABLE ii. Production and Cost Ratios for U.S.A. Horizontal Wells

LITHOLOGY	PRODUCTION RATIO	COST RATIO	BENEFIT INDEX
Clastics	2.8	2.2	1.3
Carbonates	3.9	1.8	2.2
All Formations	3.2	2.0	1.6

5. Technical success has been achieved in almost all U.S.A. reservoir settings, as evidenced by a 95% technical success rate. Economic success of horizontal projects is not as widespread; about 54% of projects reported economic success. Projects in clastics were more economically successful than those in carbonates: 59% versus 45%, respectively.

6. Stimulation had no significant effect on economic success rates; economic success was reported for only half of the projects that included stimulation.

7. Operators' future plans show that 60% of operators in clastics plan the same or increased levels of drilling activity in their fields. Only 50% of operators in carbonates responded similarly.

Canadian Horizontal Technology Trends

The results and conclusions from analysis of 88 surveys describing horizontal projects in Canada are summarized below.

1. The pace of horizontal drilling in Canada continues to increase substantially, with over 930 wells drilled in 1993. Activity is expected to surpass that in the U.S.A. in 1994. Provinces with the highest activity levels are Saskatchewan (55% of all wells), Alberta (40%), and British Columbia and Manitoba (5%).

2. Light-oil applications make up 61% of all Canadian horizontal projects; heavy-oil projects are 31% of the total.

3. The most common applications for horizontal technology in Canada include delaying coning (48% of all horizontally exploited pools) and favorable economics (48%). Least used applications are water drive and avoiding surface restrictions above the target. Canadian light-oil clastics are most commonly developed with horizontal wells due to favorable economics, coning avoidance and low-permeability formations (Figure iii). In carbonates, the most common application is minimizing coning. Heavy-oil applications are most often for delaying coning and favorable economics.

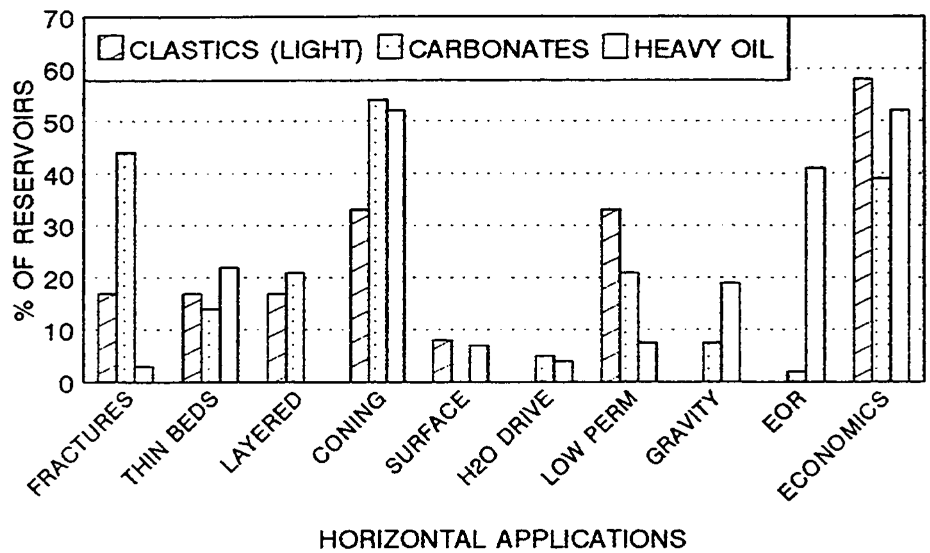

Figure iii. Canadian Horizontal Technology Applications

4. Production ratios have generally been higher for Canadian horizontal projects (Table iii) than for U.S.A. projects. Cost ratios are similar for both countries: U.S.A. = 2.0; Canada = 2.2. The highest benefit indices have been for Canadian clastics, both light and heavy oil.

TABLE iii. Production and Cost Ratios for Canadian Horizontal Wells

LITHOLOGY	PRODUCTION RATIO	COST RATIO	BENEFIT INDEX
Clastics (Light)	5.1	2.3	2.2
Carbonates (Light)	3.1	2.0	1.6
Heavy Oil	5.6	2.5	2.2
Gas	3.4	1.8	1.9
All Pools	4.1	2.2	1.9

5. Similar to the U.S.A., technical success in Canada has been achieved in almost all reservoir settings (over 90%). Economic success of Canadian projects has generally outpaced that of the U.S.A. Almost all heavy-oil projects were economically successful (92%). Projects in carbonate formations were also usually successful (79%). The success rate for light-oil clastics was close to that of the U.S.A. (58%).

6. Canadian operators' future plans show more optimism than was observed for the U.S.A. The same or increased levels of drilling activity are planned by 90% of operators in light-oil clastics, 70% in carbonates, and 74% in heavy oil.

RESERVES INCREASES WITH HORIZONTAL TECHNOLOGY (Chapter 4)

An international consensus is growing about the potential of horizontal wells to allow significant additions to oil and gas reserves. Typical settings where reserves are increased include intersecting isolated fractures or zones, delaying coning, and improving water-flood sweep efficiency. In some applications, a field cannot be economically exploited with vertical wells (e.g., many heavy-oil reservoirs) so that all production from horizontal wells is incremental.

U.S.A. Reserves Increases

Survey respondents listed a wide range of reserves increases for their fields (from 0% to 300%). The overall average increase in reserves is near 9% for U.S.A. fields. Extrapolated across the total current U.S.A. reserves base (27 BBO), an increase of this magnitude would represent an additional 2.3 BBO. In terms of incremental recovery, this volume of oil would correspond to an increase of 0.5% of OOIP.

Reserves increases for clastics have an average value of 8%, which corresponds to an overall incremental recovery of 0.4% of OOIP in clastics. For carbonates, the average reserves increase is 9%, representing an incremental recovery of 0.5% of OOIP.

Canadian Reserves Increases

The average reserves increase resulting from applying horizontal technology in Canadian reservoirs was near that for U.S.A. fields: about 10%. The volume of oil represented by this magnitude of increase is approximately 120 million m^3 (0.75 BBO), or about 1.0% of OOIP.

There was some variation by Canadian resource type. Reserves increases averaged about 9% for light-oil clastics, 7% for carbonates, and 11% for heavy oil.

HORIZONTAL APPLICATION FORECAST (Chapter 5)

The petroleum industry's experience has clearly demonstrated that horizontal technology is one of the most important tools for accomplishing the strategic goals of DOE for increasing reservoir recovery and decreasing the rate of reservoir abandonment. The use of horizontal technology is expected to continue to gradually increase each year as a result of decreasing costs, increasing tool/service availability (competition), and ongoing technical developments.

U.S.A. Horizontal Drilling Forecast

A horizontal drilling forecast for the U.S.A. was developed based on the National Petroleum Council's (NPC) model of the domestic resource base and future oil and gas consumption patterns (Figure iv). Two NPC cases were utilized (flat oil price and increasing oil price) and combined with horizontal drilling's share of the total drilling market (historic and current).

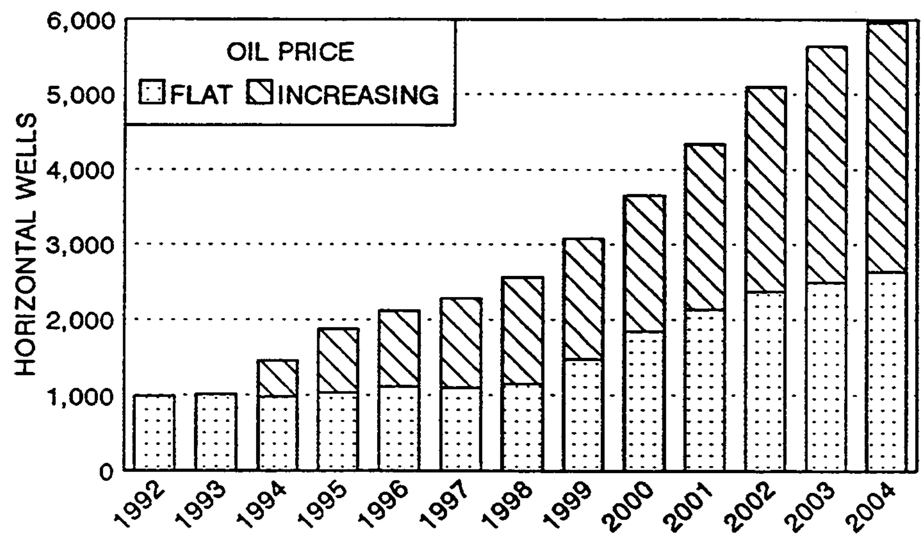

Figure iv. U.S.A. Horizontal Well Forecast

The average annual growth rate from 1994 to 2004 in the NPC-based forecast is about 10%/year for a flat oil price and 15%/year for an increasing oil price.

Canadian Horizontal Drilling Forecast

The forecast for Canadian horizontal drilling is quite optimistic for the next few years. Canadian activity should exceed that in the U.S.A. this year (1994) by about 150 wells. Several factors contribute to Canada's continuing rapid increase in annual well counts. Among them are pro-active fiscal regulatory regimes, a wide variety of application settings, numerous aggressive small operators, and the sale of many small-interest holdings as a result of restructuring of major operators.

The forecast of Canadian horizontal activity (Figure v) is based on ongoing and planned activity levels by the operators involved. The annual well count is expected to peak at about 1400 wells/year due to limitations imposed by supply and demand of rigs, trained personnel, specialized equipment, etc.

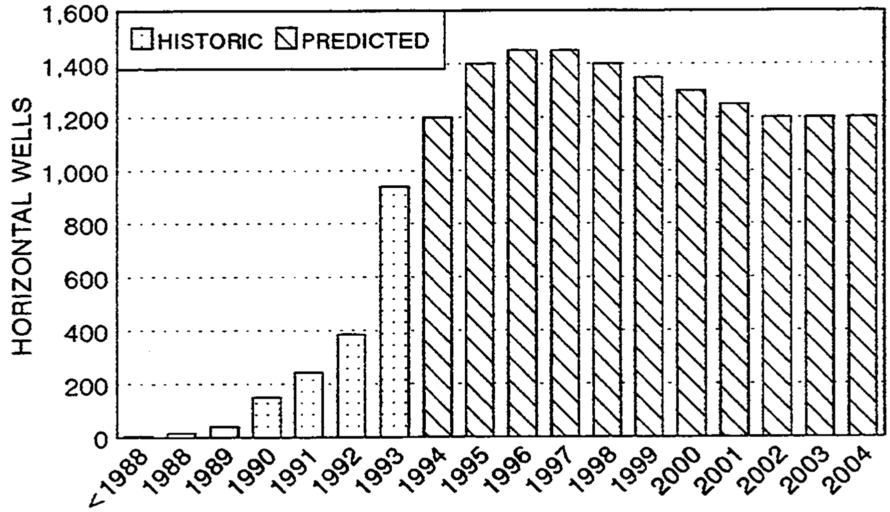

Figure v. Canadian Horizontal Well Forecast

1. Conclusions

This study was focused on the success of domestic and Canadian applications of horizontal technology. Numerous conclusions were reached as a result of analyses of questionnaire responses (Volume I) and literature surveys and other data from operators (Volume II). Among the most significant are the following:

1. A large percentage of horizontal wells (over 80% in the U.S.A. and 45% in Canada) were drilled in fractured carbonate formations for light oil.

2. About 60% of U.S.A. and Canadian horizontal projects (not wells) are in clastic formations. U.S.A. clastic applications and well counts should continue to increase, based on operators' plans.

3. The most common applications for horizontal technology projects in the U.S.A. are intersecting fractures and delaying coning. Canadian operators cite delaying coning and favorable economics most frequently.

4. Production and cost ratios have been favorable for horizontal wells. The average horizontal/vertical production ratio for all U.S.A. horizontal projects is 3.2; the average cost ratio is 2.0. For Canada, the average production ratio is 4.1 and cost ratio is 2.2.

5. U.S.A. carbonates have been more economically favorable than clastics. The converse has been true in Canada. In addition, Canadian heavy-oil projects have reported the most success of all.

6. The experiences of Canadian operators in heavy-oil reservoirs have demonstrated that horizontal wellbores are remarkably stable, sand production is much less than in vertical wells, well length is not limited, as well as other important lessons.

7. Canada's heavy-oil horizontal wells comprise about 40% of the total. The vast majority of these wells are on primary production.

8. Horizontal wells in U.S.A. heavy-oil operations have been very successful, although their application has been much less widespread than in Canada.

9. Horizontal gas wells have had the greatest success in naturally fractured formations, water coning/water drive applications, and compartmentalized reservoirs. Low success rates have been achieved in low-permeability, stratified, or shallow gas formations.

10. Horizontal wells have been very successful in gas-storage applications in the U.S.A. and Canada. Significant benefits include lower drawdown pressures, fewer wells, and reduced base-gas volumes.

11. Technical success has been achieved in almost all reservoir settings. U.S.A. and Canadian operators report a 95% and 91% technical success rate, respectively.

12. Canadian projects have been economically successful more often than in the U.S.A.: 79% versus 54%. Projects in carbonates were significantly more economically successful in Canada (79%) than in the U.S.A. (45%). Light-oil clastics projects have had similar success rates in both countries (59% and 58%).

13. Horizontal wells have been effective in EOR projects in both light- and heavy-oil reservoirs. Their use as line-drive injectors and producers has significantly increased recovery factor.

14. Among the most important technical barriers remaining for horizontal drilling are completion designs that permit modification of the production profile, water-exclusion workover technologies, the prevention of formation damage, and improved re-entry technology.

15. The average increase in reserves for U.S.A. fields as a result of horizontal development is about 9%, which corresponds to about 0.5% OOIP. Reserves increases for Canada were similar: 10% overall.

16. By the year 2004, annual U.S.A. horizontal well counts are predicted to range from about 2500 to 6000 wells/year, depending on the price of oil. By 2004, horizontal well counts for Canada are forecast to be relatively constant at about 1200 wells/year.

2. Problem Statement

2.1 STATE-OF-TECHNOLOGY

The years 1987 through 1991 were boom years in the growth of the application of horizontal drilling technology in the U.S.A. From a base of 50 horizontal wells drilled in 1986, activity grew to about 1200 horizontal wells drilled in 1990, as shown in Figure 2-1. Unfortunately, many domestic horizontal wells failed to produce expected results due to improper applications, over drilling, and poor engineering. Many wells were drilled to "add life to old fields," even though these old fields often did not have the proper characteristics for the application.

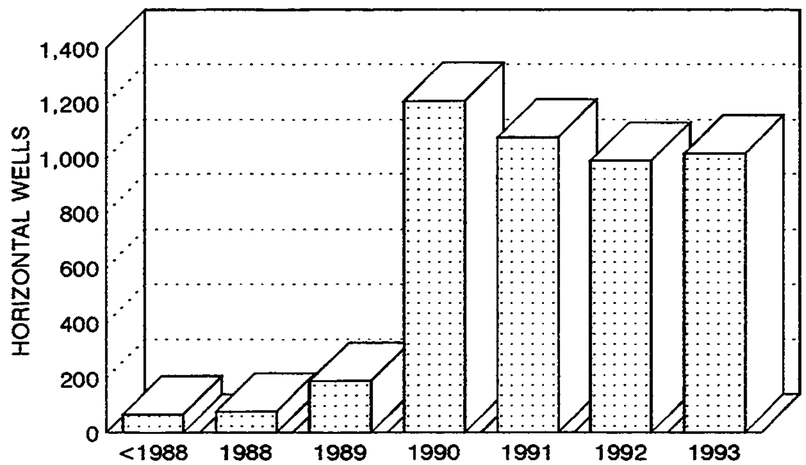

Figure 2-1. U.S.A. Horizontal Well Activity (Petroleum Information)

In cases where old fields were good candidates for horizontal well development, many drilling programs were disasters due to 1) poor planning, 2) poor engineering and supervision, 3) lack of data to characterize the reservoir in three dimensions, 4) over drilling, and/or 5) communication between horizontal wells. In some cases, good horizontal producers were watered out due to communication with other horizontal wells drilled nearby. Production life was very short in some circumstances due to poor completion and production practices in naturally-fractured formations. In the euphoria of using new, exciting technology, economic factors were sometimes stretched.

Horizontal wells have also produced impressive results internationally and have been used in a broad range of applications in different types of reservoirs. In the North Sea, Italy, France, Canada, the Middle East, Indonesia, and Australia, horizontal wells have improved recovery, made marginal producers into economical ones, and added life to old fields by increasing sweep efficiency in EOR projects.

Drilling technology has evolved to the point where the technology to drill horizontal holes is relatively well refined and widely available. Horizontal technology is generally accepted by the industry and is now being considered for most drilling projects. Questions regarding completion and production have now become the focus of technology development.

This report describes the evaluation of the production aspects of existing U.S. and Canadian horizontal wells with the purpose of forecasting the role of horizontal technology in years to come.

2.2 PROJECT OBJECTIVES

The oil industry has focused significant effort on the development of horizontal drilling technology. Many papers have been presented describing tools, techniques, and field case histories of drilling operations. Little has been presented, however, regarding the overall effect of horizontal drilling technology on production. Additionally, the work that has been published on production in the United States generally focuses on either the Austin Chalk formation of the Gulf Coast or the Bakken Shale of the Rocky Mountain area. Over 100 other formations have been explored with horizontal drilling for a variety of applications. This project closely examines the applications in other, less publicized formations to determine trends for technical and economic success or failure of horizontal wells in these formations. A primary objective is to show where horizontal wells should be used and where they can improve oil recovery.

Based on these findings, technical and economic limits of horizontal well technology are defined and projections are developed of the future extent of horizontal drilling in different environments. An estimate is also made of the impact of horizontal drilling on domestic oil reserves.

2.3 PROJECT TASK STATEMENT

Task 1: Develop Information Base

The initial task was to establish an information base on horizontal wells by review of the technical literature, interviews, and questionnaires from oil and gas companies active with horizontal well technology. This information was reviewed and categorized according to application, production success or failure, and increases in reserves.

Task 2: Develop Specialized Database for Horizontal Well Forecasting

The information from Task 1 was condensed and categorized into a specialized database for horizontal well forecasting.

Task 3: Determine Trends in Economic Failures and Successes

The database developed in Task 2 was analyzed to reveal trends in the technical and economic successes of horizontal exploitation in various formations. This information was then used to indicate where and in which applications horizontal wells are most effective and where they can be used to improve oil recovery.

Task 4: Forecast Type and Extent of Horizontal Well Applications

Based on the data collected in the first three tasks, the technical and economic limits of horizontal well technology were defined. Projections were made of the future extent of horizontal drilling in different environments with an estimate of the impact that horizontal technology will have on domestic oil reserves over the next decade.

Task 5: Analyze Canadian Horizontal Well Experience

In addition to examining the impact of horizontal drilling in the U.S.A., the use of horizontal technology by Canadian oil and gas operators was also compiled, documented, and analyzed. Canadian data were compared to analyses of U.S.A. data as described in Tasks 1-4. Special emphasis was given to horizontal technological applications where Canadian operations are more numerous and/or advanced than domestic, e.g., in heavy-oil production.

Task 6: Final Report

A final report was written that includes all the information generated during the performance of the first 5 tasks along with conclusions.

2.4 MAURER ENGINEERING BACKGROUND

Maurer Engineering Inc. (MEI), located in Houston, Texas, has been involved in horizontal well research since the company's inception in 1974. MEI participated in numerous horizontal field drilling projects including several Austin Chalk wells where medium-radius technology was developed and refined.

The Drilling Engineering Association's (DEA) *Project to Develop and Evaluate Horizontal Drilling Technology* (DEA-44) is directed by Maurer Engineering and is jointly funded by over 120 operating and service companies. The research performed, software developed, forums conducted, and schools presented have served to transfer technology worldwide in the techniques of horizontal drilling, completion, and reservoir and production engineering.

An extensive library of horizontal literature and references, personal contacts with key horizontal personnel, and a well-qualified engineering staff adapt at the theoretical, as well as the practical aspects of horizontal technology make MEI uniquely qualified to perform this study.

3. Horizontal Technology Application Trends

3.1 INTRODUCTION

The primary objective of this project is to gauge the overall success of horizontal technology in domestic oil and gas fields. Impressive technical successes have been achieved through a wide variety of improvements, new tools and technologies developed over the past several years. Early excitement within the industry about the new technology reached a fever pitch at times, leaving some with the impression that horizontal drilling is a panacea for all drilling environments. Industry's experiences showed this not to be the case, and that the technology had to be applied thoughtfully and site-specifically to achieve overall success.

The horizontal "boom" in the U.S.A. is now several years old, and over 4600 wells have been drilled in over 110 formations. (U.S.A. formations that have been exploited by horizontal wells are listed in **Appendix A**.) Most of these wells are part of multiwell development programs that included drilling, completion, workovers, and analyses. Many have been on production for several years. A basic assumption underlying this study is that there now exists sufficient experience with horizontal technology, including production history, to address whether early forecasts of the benefits of using this technology have been borne out within the industry. This study is thus designed to address a basic question: *Has the technology delivered as promised?*

A survey of U.S.A. and Canadian companies that operate horizontal wells for oil and gas production was conducted. Canada was included in this study due to their leadership and significant experience with horizontal technology, especially in heavy oil and gas. A questionnaire was sent to several hundred operators in both countries. Questionnaires were filled out on a formation basis, that is, not weighted by the number of wells. Each formation was counted once in each analysis. In this way, responses from the Austin Chalk and other highly active formations did not overshadow other applications in less-active formations. Data were returned describing overall experiences with horizontal wells in 58 formations in the U.S.A. and 88 in Canada (Table 3-1).

TABLE 3-1. Horizontal Well Project Survey Responses

	Horizontal Wells (As of 1/94)	Reservoirs With Horizontal Wells	Survey Responses	Response Rate
U.S.A.	4620	114	58	51%
CANADA	1786	220	88	40%

The development of the industry questionnaire and database of operators is described in detail in **Appendix B**. Evaluations of U.S.A. questionnaire data are presented in detail in **Appendix C**; Canadian analyses are presented in **Appendix D**. Overall trends in industry's experiences are summarized in this chapter in the sections that follow.

3.2 U.S.A. SURVEY TRENDS

The pace of drilling horizontal wells in the U.S.A. remains high at about 1000 wells/year. A large majority of wells has been drilled in the Austin Chalk formation in Texas. Well-count distribution by four categories (Austin Chalk, Niobrara, Bakken, and Others) is shown in Figure 3-1 for two dates: January 1993 (just before start of study) and May 1994 (near end of study).

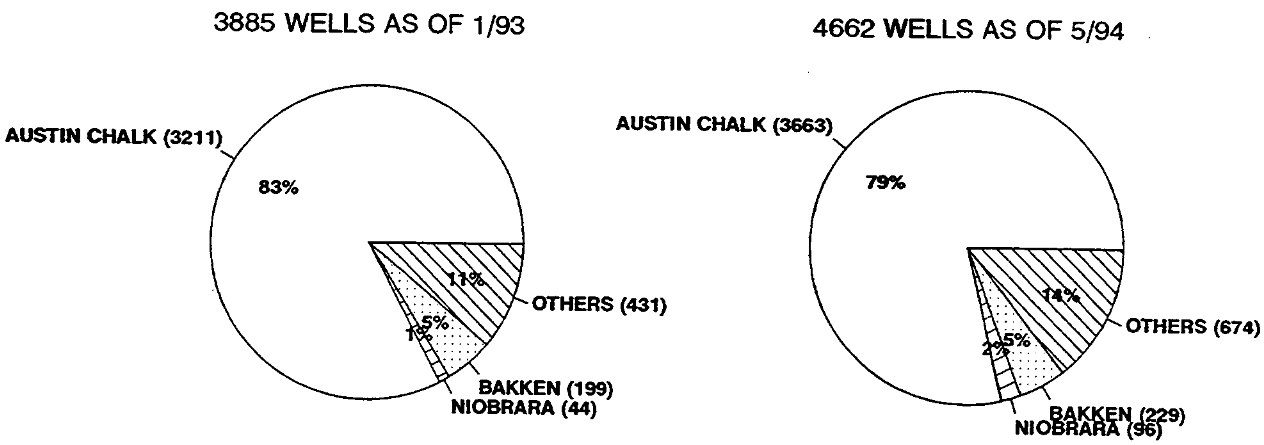

Figure 3-1. U.S.A. Horizontal Well Distribution (Petroleum Information)

High activity in the three most popular formations has been accompanied by numerous technical publications and presentations discussing many aspects of the application of horizontal technology in these fields. There has been much less discussion of results from other fields, that is, NANB (Non-Austin Chalk, Niobrara, Bakken) formations. NANB formations, including those previously drilled (see Appendix A) and those not yet drilled horizontally, will undoubtedly play an increasingly significant role in the future of horizontal technology. The number of wells in NANB formations increased from about 20 before 1987 to 674 by May 1994, with almost 140 wells drilled in 1993 alone (Figure 3-2).

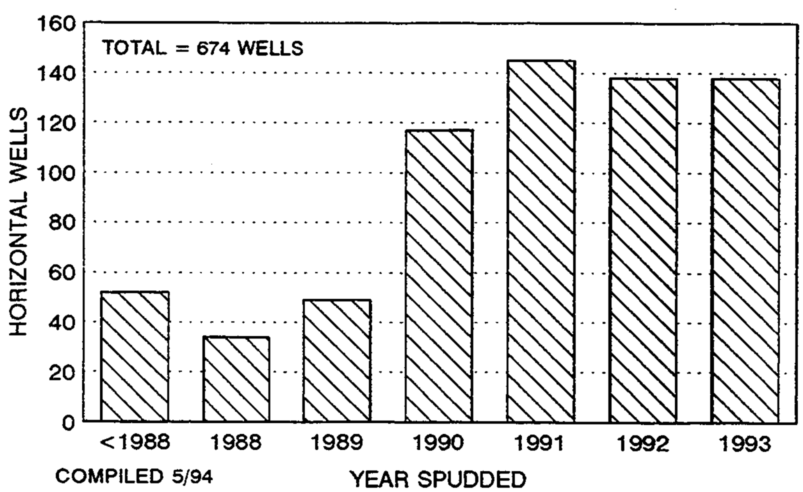

Figure 3-2. U.S.A. Horizontal Wells in NANB Formations (Petroleum Information)

About 90% of all U.S.A. horizontal wells were drilled in carbonate formations. This lithological distribution for horizontal wells contrasts sharply with the domestic resource base, in that only 24% of U.S.A. reservoirs are carbonate and only 30% of reserves are in carbonate formations. NANB wells are distributed in a manner more reflective of the resource base: over half (56%) of NANB wells were drilled in clastic formations. Based on the large proportion of clastic formations in the domestic resource base and the success of horizontal applications in these formations, the percentage of horizontal drilling in clastic formations should continue to increase, assuming the level of activity in the Austin Chalk and Niobrara does not increase significantly.

Questionnaires were sent to over 120 operators who have drilled horizontally in U.S.A. formations. Data were returned on 58 domestic horizontally exploited formations. Horizontally exploited formations listed by Petroleum Information (PI) are shown along with survey responses in Figure 3-3. Most states with activity show about a 50% response rate. Of the 58 survey responses, 60% cover clastic formations and 40% carbonate. The Austin Chalk, Niobrara, and Bakken are included in this formation count, as well as in the results reported in the following paragraphs. Since every formation gets one equal "vote," results are not skewed by high levels of activity in any field.

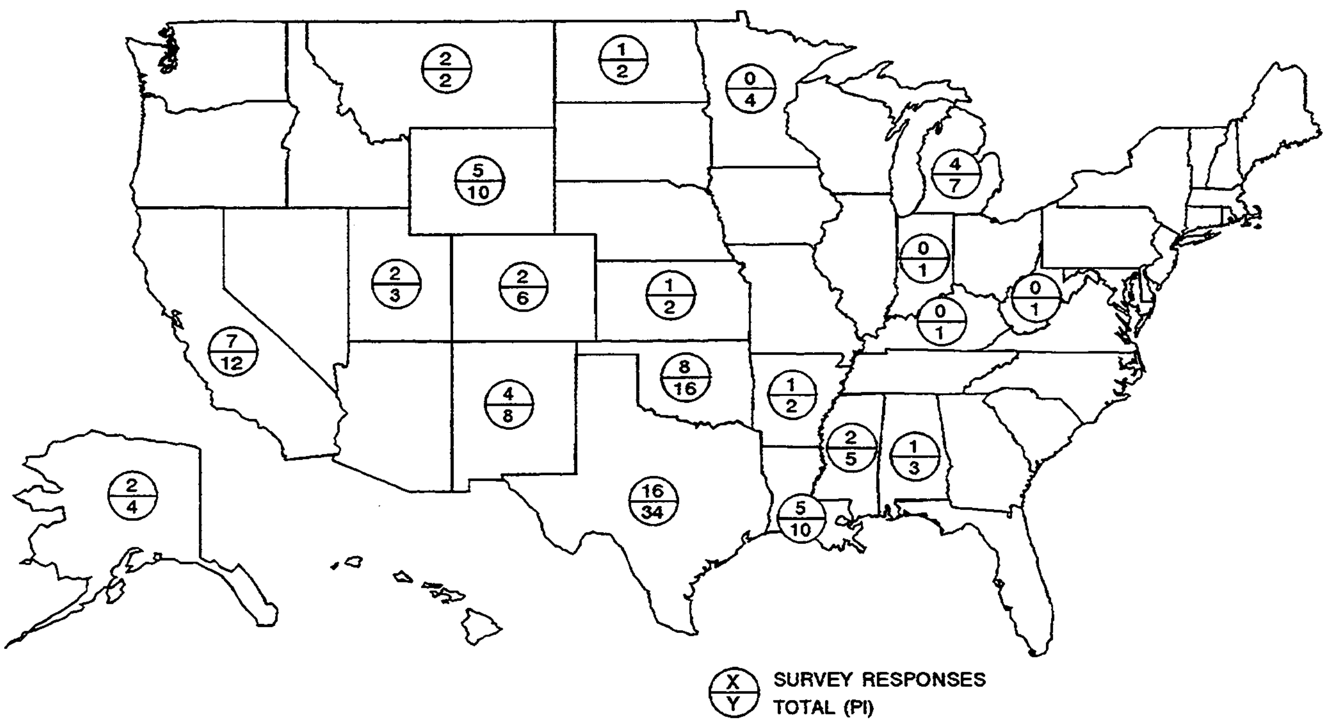

Figure 3-3. Location of Surveyed Formations

The most common applications for horizontal technology in the U.S.A. include intersecting fractures (53% of all fields) and delaying water and/or gas coning (33% of all fields) (Figure 3-4). Least used applications are for water drive (9%), EOR (9%), and to avoid surface restrictions above the target formation (7%). Note that multiple responses were typical; therefore, these data sum to more than 100%.

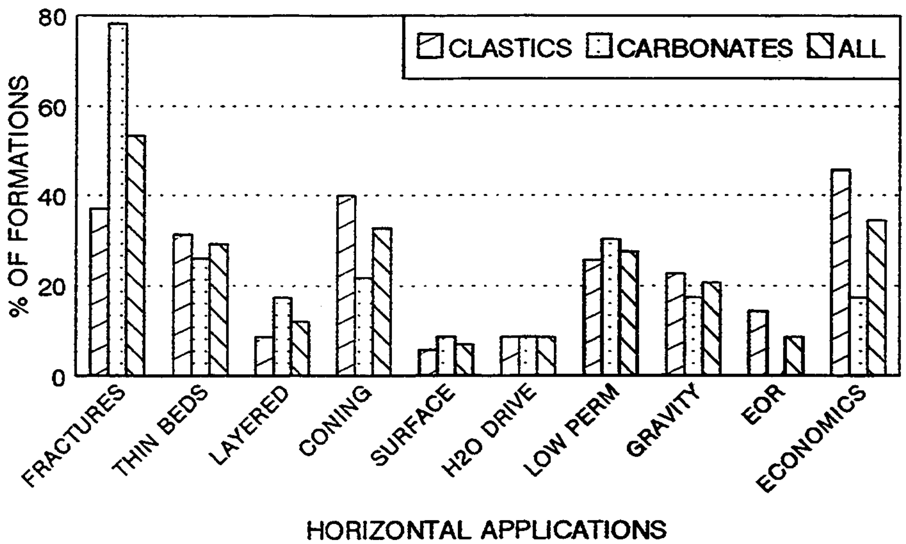

Figure 3-4. U.S.A. Horizontal Technology Applications

In clastic formations, the most common applications for horizontal wells are favorable economics (46%) and coning avoidance (40%), followed closely by intersecting fractures (37%) (see Figure 3-4). In carbonates, not surprisingly, the most common application by far is intersecting fractures (almost 80%). The next most popular applications in carbonates are in low-permeability formations and in thin beds, both at just over one fourth of the survey responses.

Ratios comparing costs and production of horizontal wells to those of vertical wells within the same field conditions, are often used as indicators of general success for individual wells. Even though they are imperfect metrics, production and cost ratios have become widely accepted as a first estimate of success in a given application. Ratios reported in the industry survey have generally been favorable for horizontal wells. The average horizontal/vertical production ratio for all U.S.A. horizontal wells is 3.2; the average cost ratio is 2.0 (Table 3-2). When lithology is considered, carbonates have been more economically favorable than clastics. Note that these average ratios are based on one formation/one vote. Cost ratios averaged on a well-by-well basis would be less than 2.0, given the learning curve benefits in the most active formations. The average Austin Chalk cost ratio is 1.4, based on the responses of several operators in that field. The "benefit index" reported in Table 3-2 is the ratio of the production ratio to the cost ratio.

TABLE 3-2. Production and Cost Ratios for U.S.A. Horizontal Wells

Lithology	Production Ratio		Cost Ratio		Benefit Index
	Average	Median	Average	Median	
Clastics	2.8	3.0	2.2	2.0	1.3
Carbonates	3.9	2.0	1.8	1.8	2.2
All Formations	3.2	2.5	2.0	2.0	1.6

Operators reported on their technical and economic success. Survey questions were added to allow the field operator to judge the "bottom line" of the overall project, and include the effects of factors not accounted for in a simple cost ratio comparing horizontal drilling and completion costs to vertical well costs. Technical and economic success were designed as yes/no questions. Technical success has been achieved in almost all reservoir settings. Operators report a 95% technical success rate overall (Figure 3-5), providing clear evidence that the implementation of horizontal drilling techniques has become almost routine.

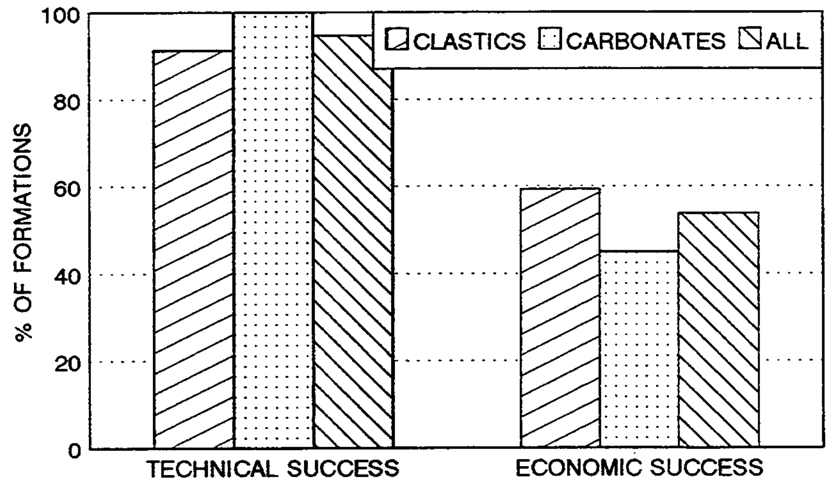

Figure 3-5. U.S.A. Technical and Economic Success

Economic success of horizontal projects has not been as widespread as technical success; 54% of all projects were reported as economically successful. Projects in clastics were more economically successful than those in carbonates: 59% versus 45%, respectively.

About half of the operators stimulated their horizontal wells by fracturing, matrix acidizing, washing, etc. Stimulation had no discernible effect on economic success rates. Economic success was reported for only half of the projects that included stimulation.

Operators' future plans (i.e., to increase or decrease activity levels) were used as an additional gauge of the overall success of the technology. Of course, an operator's plans for decreased horizontal activity in the future may reflect the impact of other factors not related to the success of the technology. For example, a drilled-up field may be slated for decreased activity in the future, even though horizontal technology was technically and economically successful.

Fifty-six percent of all operators plan the same or increased future activity (Figure 3-6). The categories of "same" and "increase" reflect a vote of confidence for horizontal technology in each particular application. In clastics, 60% of operators plan the same or increased levels of drilling activity in their fields. Only 50% of operators in carbonates responded similarly.

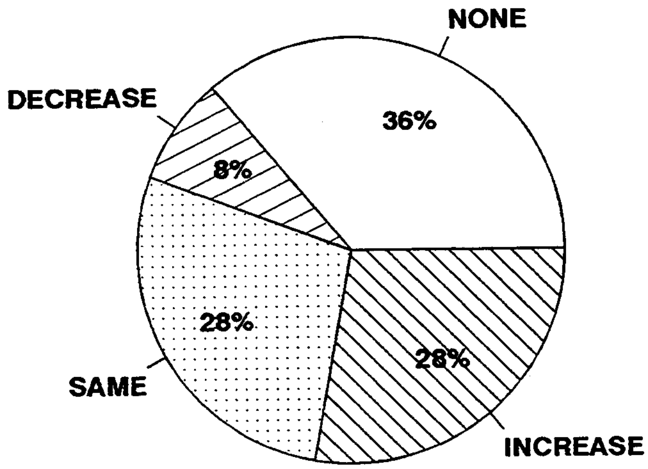

Figure 3-6. U.S.A. Future Activity with Horizontal Technology

Many horizontal completion and production problems remain to be solved. Problems indicated as significant by operators in clastic fields are: 1) avoiding or remediating formation damage, 2) better tools for reservoir modeling, 3) dealing with formation heterogeneity, and 4) logging operations. Operators in carbonates listed 1) artificial lift technology, 2) reservoir modeling, and 3) logging as their most serious problems. More discussion of horizontal production problems is presented in Appendix C.

3.3 CANADIAN SURVEY TRENDS

The pace of drilling horizontal wells in Canada has increased substantially. Activity in Canada was greatest in 1993 (the most recent year surveyed) with over 900 wells drilled, which represents over half of the total population of almost 1800 wells drilled since 1987. Horizontal technology has been applied in more diverse formation types in Canada than in the U.S.A. There is no Canadian "Austin Chalk," that is, a particular formation where the majority of activity is centered. More than half of Canada's horizontal wells were drilled in Saskatchewan, 40% in Alberta, and about 5% in other provinces (British Columbia and Manitoba).

A breakdown of the distribution of horizontally exploited Canadian pools by resource and lithology is presented in Figure 3-7. These data are based on responses to the DOE survey, and are assumed to be generally representative of the Canadian industry as a whole. As can be noted in Figure 3-7, a significant number of Canada's horizontal applications have been in heavy-oil pools, the great majority of which are clastic (unconsolidated sandstone).

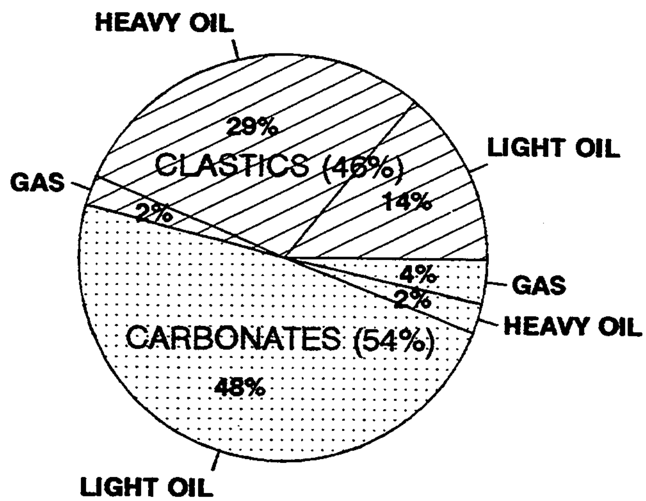

Figure 3-7. Distribution of Horizontally Exploited Canadian Pools

Questionnaires were sent to over 150 operators who have drilled horizontal wells in Canadian pools. One hundred and ten responses were returned, with multiple responses for several pools. Of the 88 unique pools described, 46% are clastic and 54% are carbonate. These 88 pools represent about 40% of all Canadian pools with one or more horizontal wells.

The most common applications for horizontal technology in Canada include 1) delaying water/gas coning (48% of all horizontally exploited pools), 2) favorable economics (48%), and 3) intersecting fractures (27%). Least used applications from the choices given are 1) water drive (5%) and 2) to avoid surface restrictions above the target zone (5%).

When lithology is considered, there are important differences in horizontal applications. In Canadian light-oil clastic pools, the most common applications are favorable economics (58%), followed by coning and low-permeability reservoirs (33% each) (Figure 3-8). Canadian carbonate pools are not dominated by fracturing applications as is true for the U.S.A. The carbonate application listed most often is minimizing coning (54%). The next most popular applications in carbonates are intersecting fractures (44%) and favorable economics (39%).

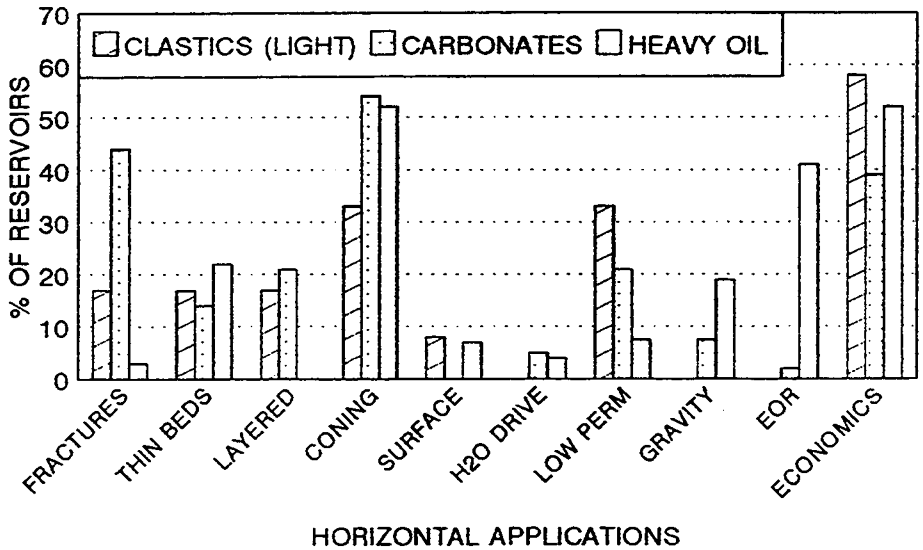

Figure 3-8. Canadian Horizontal Technology Applications

Heavy-oil pools are most often developed with horizontal wells to avoid/delay coning and due to favorable economics (52% of pools each). As expected, EOR was another significant application for heavy oil at 41%. Thin beds and gravity drainage were the only other applications mentioned to any significant degree.

Cost and production ratios reported for Canadian pools were generally comparable to those for domestic U.S.A. fields. The average horizontal/vertical production ratio for all Canadian horizontal wells is 4.1; the average cost ratio is 2.2 (Table 3-3). When lithology is considered, carbonates have tended to be more economically favorable than clastics. Heavy-oil applications report the highest benefit index (production ratio divided by cost ratio) of all, followed very closely by light-oil clastic applications.

TABLE 3-3. Production and Cost Ratios for Canadian Horizontal Wells

Lithology	Production Ratio		Cost Ratio		Benefit Index
	Average	Median	Average	Median	
Clastics (Light)	5.1	3.0	2.3	2.0	2.2
Carbonates (Light)	3.1	3.0	2.0	2.0	1.6
Heavy Oil	5.6	4.0	2.5	2.8	2.2
Gas	3.4	3.0	1.8	2.0	1.9
All Pools	4.1	3.0	2.2	2.0	1.9

Operators were asked to judge their overall technical and economic success. As in the U.S.A., technical success has been achieved in almost all reservoir settings (Figure 3-9). Over 90% of horizontal projects have been technically successful. When considering economic success, there has been variation by resource type: only 58% of projects in light-oil clastic pools were economically successful, compared to 79% in carbonates, and 92% in heavy-oil projects. Economic success rates in clastic pools are very similar in the U.S.A. and Canada. Carbonate economic success has been much more widespread in Canada than in the U.S.A. (79% versus 45%, respectively). The economic success rate in Canadian heavy-oil pools at 92% is significantly greater than other reservoir types in both Canada and the U.S.A.

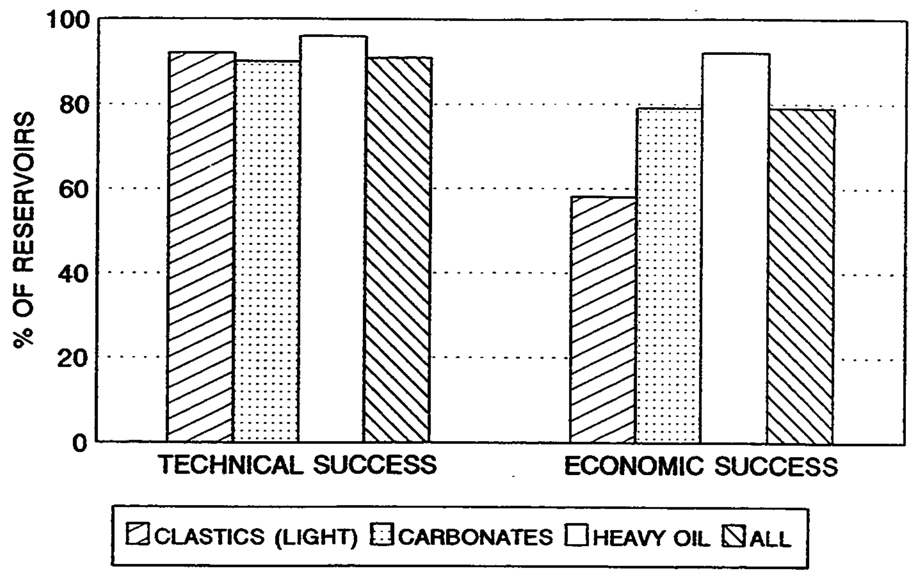

Figure 3-9. Canadian Technical and Economic Success Rates

About 36% of Canadian operators stimulated their horizontal wells by fracturing, matrix acidizing, washing, etc. These procedures were performed most extensively in carbonate pools; 69% of carbonates were stimulated, as compared to 10% of light-oil clastics and 7% of heavy-oil pools.

Operators' future plans were used as an additional gauge of the overall success of horizontal technology. Canadian drilling plans reflect significantly more optimism than was observed in the U.S.A. survey, where 56% of operators overall plan the same or increased future activity. In Canada, 75% of operators plan the same or increased activity levels (Figure 3-10). Canadian light-oil clastics are the most positive: 90% of operators plan the same or increased levels of drilling activity in their fields. Seventy percent of operators in carbonates and 74% in heavy oil responded positively.

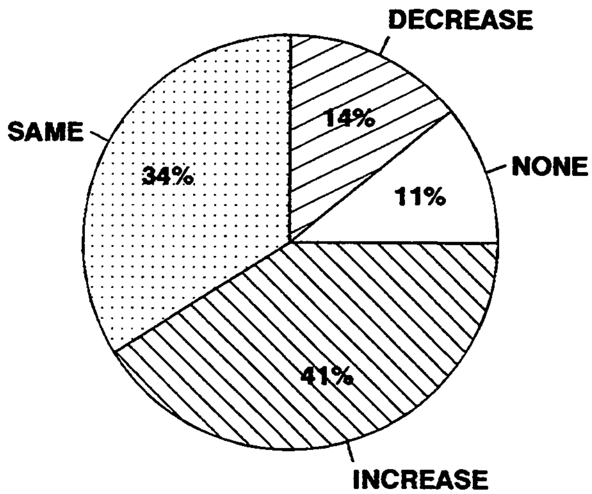

Figure 3-10. Canadian Future Activity with Horizontal Technology

Many horizontal completion and production problems remain to be solved. Problems indicated as significant by operators in light-oil clastic fields are: 1) avoiding or remediating formation damage, 2) stimulation tools/techniques, 3) dealing with formation heterogeneity, and 4) avoiding/minimizing coning. Operators in carbonates listed the same four problems as their most severe production concerns. In heavy-oil pools, the four problems mentioned most often were: 1) artificial lift, 2) formation damage, 3) sand production, and 4) avoiding/minimizing coning.

3.4 CANADIAN DEA-44 SURVEY TRENDS

The DEA-44 Canadian Group has undertaken informal annual activity surveys since 1990. Numerous workshops, forums, schools, etc. have been conducted through this group of active horizontal operators. The common lessons learned by this group should have general application in any area where horizontal technology is being used or considered.

1. **Growth in Canadian Activity.** Figure 3-11 illustrates the consistent increase in horizontal technology applications in Canada over the last 7 years, along with projections for 1994 and 1995.

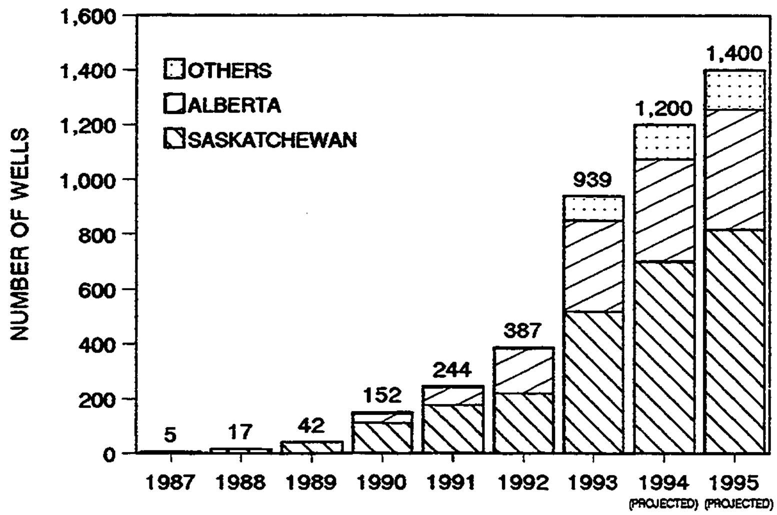

Figure 3-11. Horizontal Well Growth in Canada

It is anticipated that the exponential growth seen in the late 1980s and early 90s is simply not sustainable. A limit will soon be reached in the supply of appropriate rigs, trained personnel, specialized equipment, etc. Therefore, the growth rate is projected to slow in 1994 and 1995. Continued growth would not be sustained unless the operators were achieving positive economic results. This success has not come easy, or without painful and expensive field experience. Much remains to be learned and optimized.

2. **Site-Specific Design.** Figure 3-12 illustrates what can happen when a "standard" design is applied in different fields. Both of these re-entry gas wells were drilled by the same operator. Based on the success of the first well, which produced at a 5:1 productivity ratio, the operator applied the same design and operations program to a second well in another field, with disastrous results. This progression of events is common among new operators. It clearly demonstrates that horizontal wells must be designed and implemented in a multidisciplined, site-specific manner to provide the greatest chance of technical and economic success.

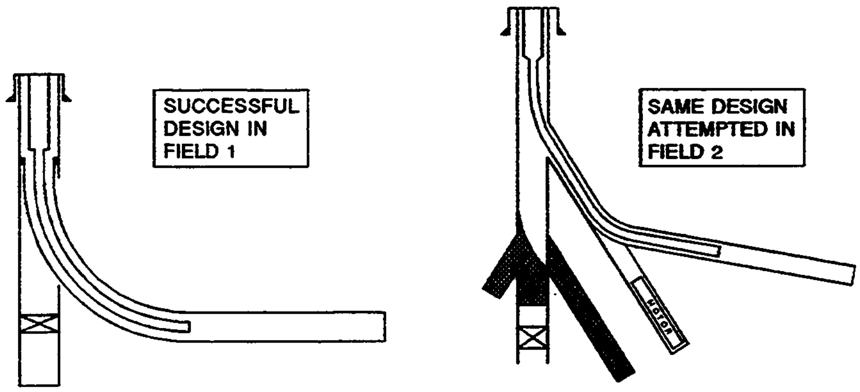

Figure 3-12. Ineffective Use of Standard Well Design

Even with the best planning and operations, subtle variations in geology, reservoir, fluid conditions, etc. can lead to less than optimal results. One fundamental lesson learned has been that there is no correct standard design. Each field, and perhaps each well, is unique. Site-specific field experience (and a corresponding learning curve) is a prerequisite to optimizing any given horizontal well development.

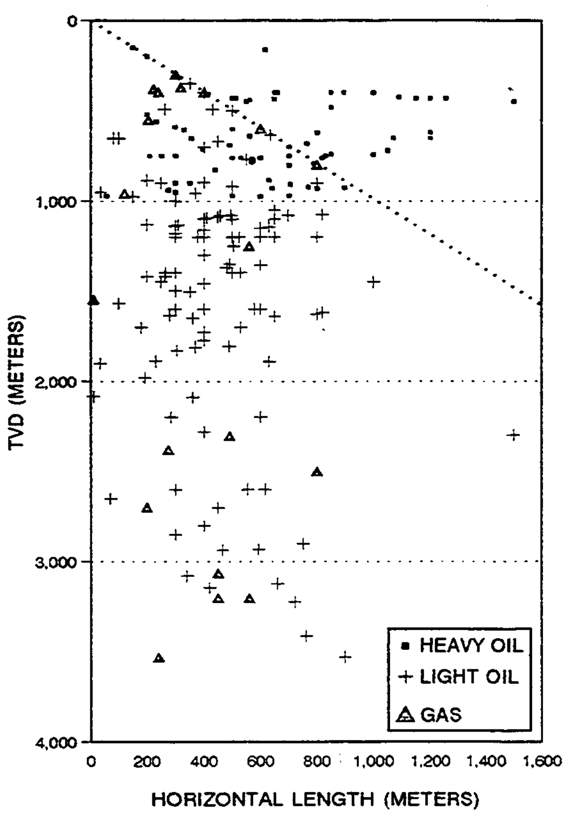

Figure 3-13. TVD and Horizontal Length

4. **Diversified Applications, Depth and Length.** Figure 3-13 illustrates the true vertical depth (TVD) and horizontal productive length of Canadian horizontal wells represented in the DEA-44 Canadian Group survey. Typically, the survey captures 35-50% of horizontal wells drilled in Western Canada each year. Each data point represents a field, and may be one well, or an average of 20 or more horizontal wells in the field. The data illustrate the dramatic variation of horizontal well applications in Canada.

   Any data point above or to the right of the dashed line in Figure 3-13 has a horizontal length greater than the TVD of the field. Shallow heavy-oil applications typically employ long-radius curves, and the corresponding horizontal departure of the curve (e.g., 800-1400 ft) is not considered productive length. In actuality, these wells are 4 to 5 times longer than they are deep. Thus, even in shallow applications, it appears that TVD has little impact on length capability.

5. **Depth and Cost Ratio.** TVD and cost ratio are compared in Figure 3-14. Cost ratio is defined as the total capital cost to drill, complete and equip an average horizontal well compared to an average vertical well in the same field. A clear trend is evident. As the TVD of the application increases, the incremental cost of a horizontal well decreases.

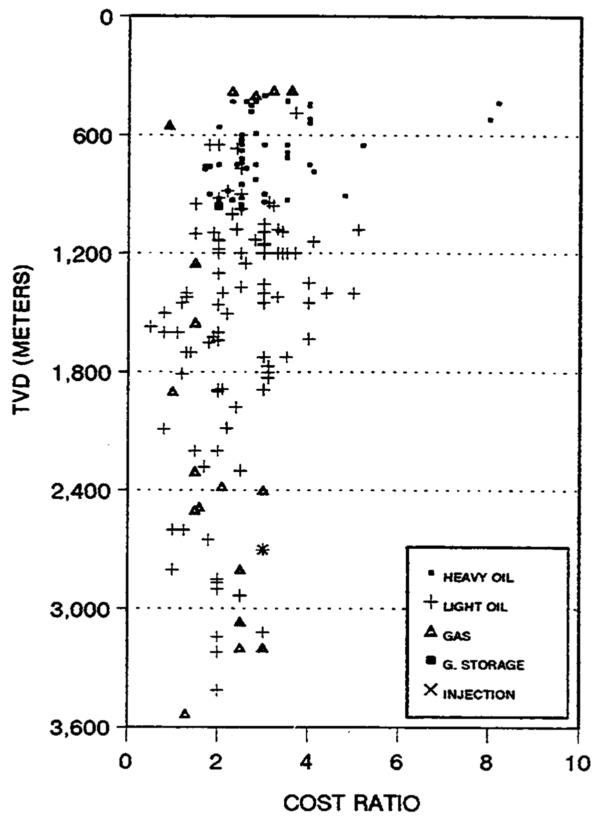

Figure 3-14. TVD and Cost Ratio

6. **Length and Cost Ratio.** Productive horizontal length versus cost ratio is shown in Figure 3-15. The relatively flat distribution suggests that the incremental cost of drilling additional horizonal length is relatively insignificant. Most cases of dramatic cost overruns and well problems occur while drilling the curve. After time and effort are expended to get to the end of the curve, the cost of drilling/completing an incremental 100 ft of horizontal section will be relatively small, especially where rapid drilling is expected. An exception would be an expensive completion design (e.g., case, cement, and perforate) that would add cost for each foot drilled horizontally. The average length of all wells drilled each year (shown on the x-axis for 1991-93) is consistently increasing. Operators and service companies are all gaining experience and confidence. Thus, designing and implementing wells with lengths of 4000-5000 ft, or greater, is now a common objective in many settings, and readily achieved.

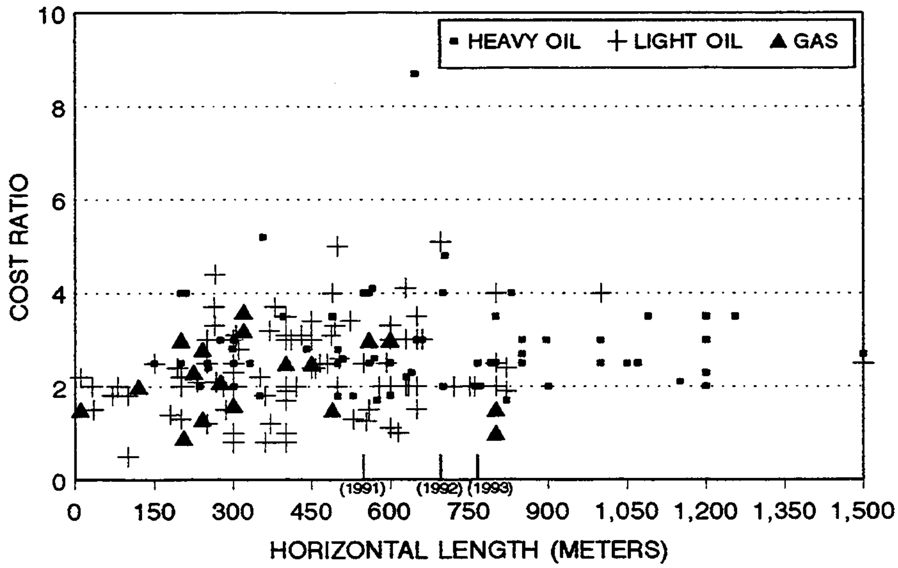

Figure 3-15. Horizontal Length and Cost Ratio

7. **Cost Ratio and Production Ratio.** Production ratio is a comparison of the average production of a horizontal well during the first 6 months to a vertical well counterpart in the field. Figure 3-16 compares the average production ratio and average cost ratio for each field. These data points are quite scattered, showing little correlation between production and cost ratio with resource type.

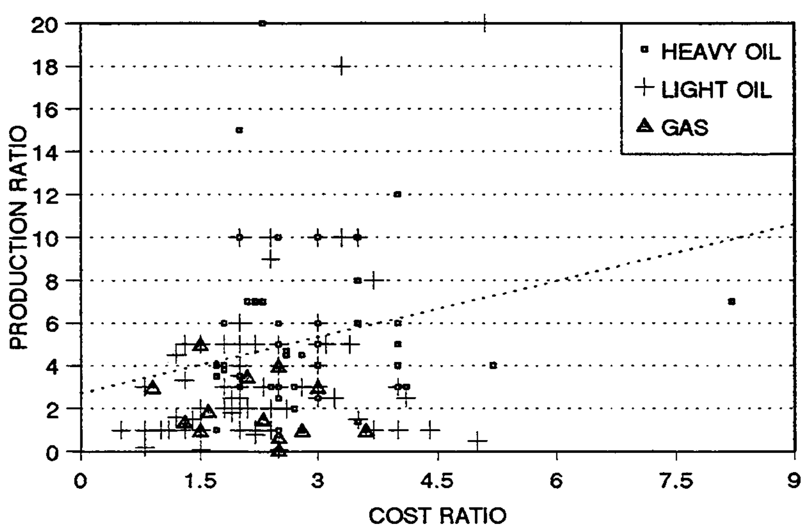

Figure 3-16. Production Ratio and Cost Ratio

Similar plots were made comparing completion type, reservoir type, mud system employed, year drilled, etc. In all cases, the data are scattered with no discernable correlation between production and cost ratio. This trend supports the premise that each horizontal application is unique. There is no common "correct" design, but each well should be customized to site-specific parameters.

Benefit index is shown in Figure 3-17, i.e., the ratio of production ratio to cost ratio. The solid line in each yearly bar is the average for all horizontal wells in that year. The population size (numbers in parenthesis to the left of each bar) in the early years is probably too small to be reliable. However, a significant population in 1989-1993 clearly shows an increasing incremental production gained versus incremental costs incurred for horizontal wells.

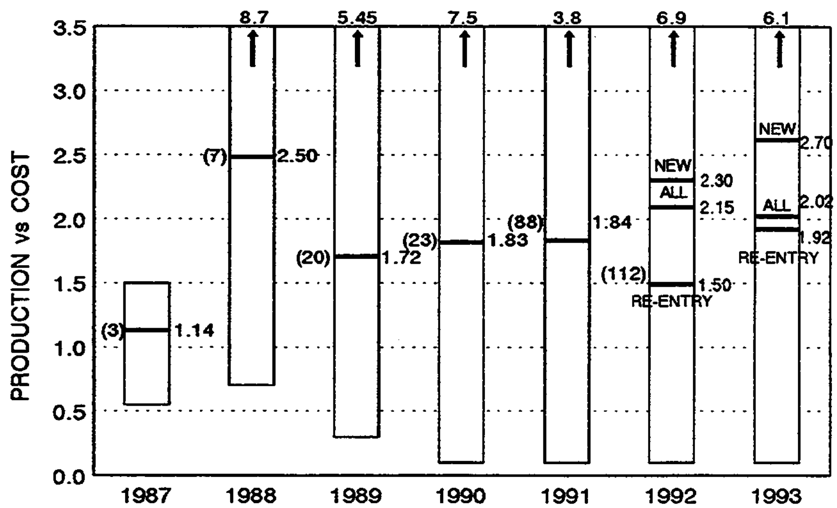

Figure 3-17. Production and Cost Ratio: Yearly Trends

Benefit index is considered a very gross measurement of success of all wells in general. The average of all horizontal wells, both new and re-entries, drilled in Canada in 1993 was 2.02. This means that the average horizontal well drilled in 1993 was 2.02 times more incrementally productive than incrementally expensive, compared to the average vertical well in the same field. The steady increase in this parameter over the years shows the general improvement in application success as the industry gains site-specific field experience.

8. **New Wells versus Re-entries.** An interesting comparison is seen in the 1992 and 93 data in Figure 3-17. The average benefit index for a new well is higher than for a re-entry. This suggests that an average new well performed significantly better (in terms of incremental production versus incremental cost) than did the average re-entry application.

9. **Completion Design.** The distribution of the three basic completion designs used in all horizontal wells surveyed over the period 1991-1994 are shown in Figure 3-18. The three types of completions are: OH = open hole; SL = slotted liners including combinations of casing packers, sliding sleeves, blank joints, plugged pre-perforated joints, etc.; CCP = cased, cemented and perforated.

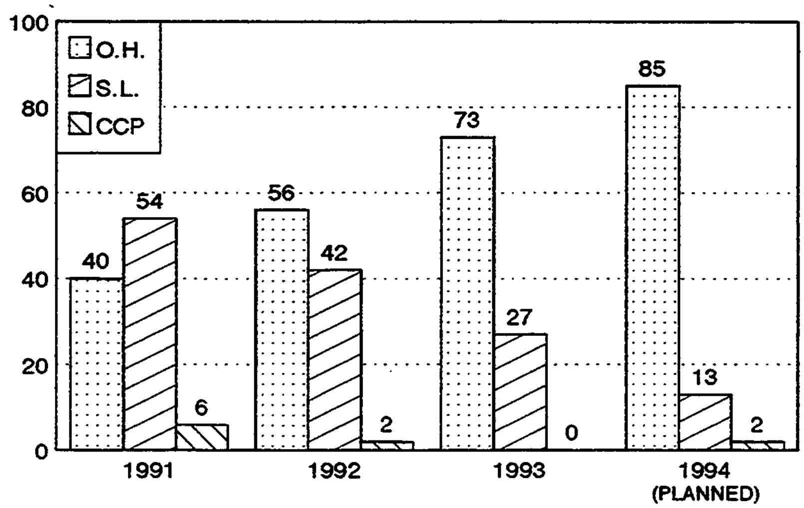

Figure 3-18. Canadian Completion Types

Over this period, the industry used an increasing percentage of OH completions, reflecting greater confidence regarding open-hole stability and workover capability. CCP completions remain relatively uncommon, reflecting the high cost, technical challenges, and risk of productivity impairment related to CCP design. Although some specific applications demand this "exotic" completion design, these situations are becoming less common in Western Canada.

Clearly, OH completion is the preferred design in simple light-oil applications (Figure 3-19), where rock types tend to be stable clastics or carbonates. SL completions still dominate in heavy-oil applications. However, in many planned heavy-oil wells, OH completions are being designed. Operator confidence in OH completions reflects the surprising degree of hole stability observed in the field, even in unconsolidated sand applications.

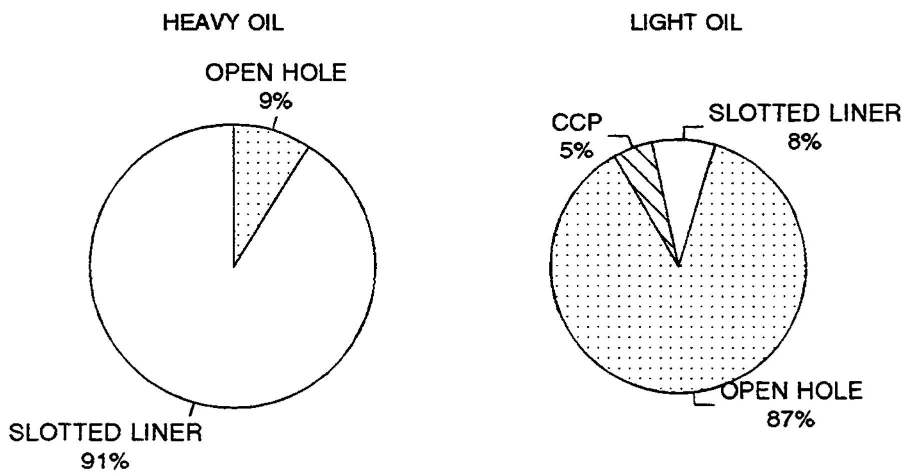

Figure 3-19. Horizontal Completion Types for 1993

10. **Resource Type.** Heavy-oil and light-oil applications dominate in Canada (Figure 3-20). The small proportion of gas applications might lead one to conclude that horizontal wells have not been as successful in gas applications as in other resource types. However, other factors may also have detracted from gas applications:

- There was a significant over-supply of gas deliverability during this period
- Gas prices and demand were relatively weak
- Transportation capability was limited

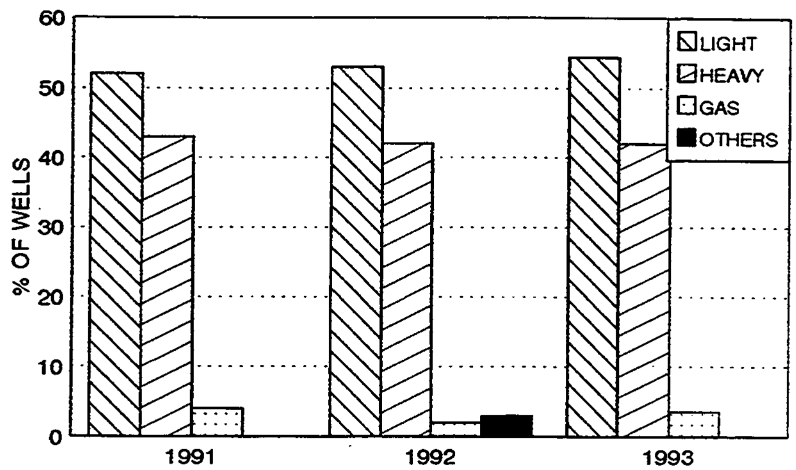

Figure 3-20. Canadian Horizontal Wells and Resource Type

These factors were dramatically altered in 1992 and 1993. Preliminary results from the 1994 survey suggest renewed interest in horizontal gas well applications in Canada.

4. Reserves Increases With Horizontal Technology

4.1 INTRODUCTION

Horizontal wells have been found by many operators to increase recoverable reserves (improve recovery factor) within their fields. An international consensus is growing about the potential of horizontal wells to allow significant additions to oil and gas reserves, e.g., up to 2% of original oil-in-place (OOIP) volumes (CIM, 1994). For the U.S.A., an incremental recovery of 2% of OOIP would represent an increase in reserves of almost 40%. Commonly cited situations where reserves increases are expected include:

1. Intersecting natural fractures that cannot be accessed feasibly or economically with vertical technology
2. Delaying the onset of water or gas coning so that more oil is produced before the well waters/gases out
3. Production improvement in thin or tight reservoirs
4. Improvement in water-flood sweep efficiency

Theoretical developments in production decline models and reserves estimations with horizontal wells are still in their infancy. One of the most important issues affecting economics, especially of re-entries, is whether production improvement will be accelerated production, reserves increase, or both (Figure 4-1). For a well with accelerated reserves production only, net present worth is improved, although total revenue is not increased. A well that increases reserves will provide more total revenue and will have substantially increased net present worth.

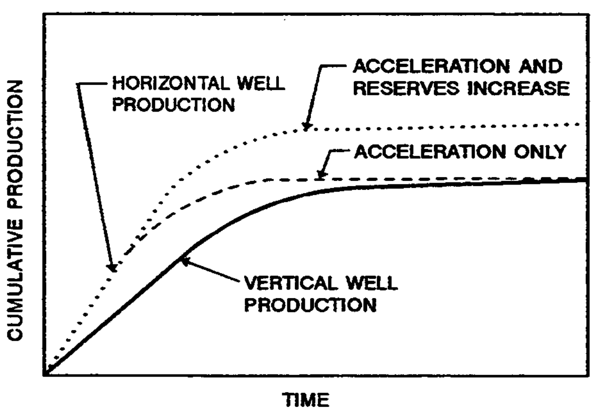

Figure 4-1. Horizontal Well Production Acceleration and Reserves Increase

Various factors that impact drainage may either increase or reduce the advantages of horizontal development. Factors that improve reservoir drainage by horizontal wells include (CIM, 1994):

- Enlarged drainage volume
- Heterogeneities within the drainage area (i.e., sweet spots or barriers to the influx of bottom water or gas)
- Reduced drawdown pressures
- Lowering of the economic production rate (one horizontal well replacing multiple vertical wells)

Reservoir and drilling factors that hinder reservoir drainage with horizontal wells include:

- Heterogeneities within the drainage area (i.e., stratification within the pay zone or by-passing of oil in water or gas floods)
- Zones that were drained or watered-out previously, creating pressure sinks or sources
- Skin damage along the wellbore
- Lateral pressure drops (multiphase flow, junk, turbulence)
- Undulating wellbore profile resulting in a decrease in effective wellbore length

In some applications, a field cannot be economically exploited with vertical wells; for example, many heavy-oil reservoirs. If horizontal technology can be economically applied for recovering these resources, the reserves increase for these fields is theoretically infinite and might be quantified by an operator as 100%, 1000%, or any other value.

Various authors have forecasted the impact on domestic reserves due to the widespread application of horizontal technology. Among them is Fisher (*Popular Horizontal* Staff, 1991) who predicted that horizontal wells could result in the addition of 10 BBO (billion bbl of oil) to U.S.A. reserves. Assuming a current reserves base of 27 BBO, this addition amounts to a 37% increase in domestic reserves.

Crouse (1991) made an even more optimistic forecast of the potential impact of horizontal drilling. He estimated that an additional 5% of a 700 BBO domestic resource could be recovered as a result of this technology. Thus, Crouse foresees an additional 35 BBO being added to current reserves, which amounts to a reserves increase of 130%.

Specific examples of reserves increases are mentioned in conjunction with the horizontal application summaries presented in Volume II of this report. Correlation with the standard basis for comparison used in this study is difficult in many cases, since the operator described his incremental reserves in terms other than percent increase. Descriptions of impact on reserves include the following:

- Elk Hills (light oil, California)—increased recovery to 70% of OOIP
- Abo Reef (light oil, New Mexico)—horizontal well cumulative production is 1.6 times vertical (without mention of effect on reserves)
- Helder Field (light oil, North Sea)—increased recovery an additional 7% of OOIP
- Frobisher (light oil, Saskatchewan)—incremental recovery 3-5% of OOIP

- Sparky (heavy oil, Saskatchewan)—recovery factor increased from 5% to 20% of OOIP (= 300% increase in reserves)
- Waseca (heavy oil, Saskatchewan)—recovery factor increased from 10% to 15% of OOIP (= 50% increase in reserves)

Saudi Arabia's Aramco estimated that its horizontal drilling program will make up half the company's drilling budget over the next 10 years (Aalund and Rappold, 1993). Horizontal wells are expected to increase their reserves by 5 to 10%. This translates into an additional 12.5 to 25 BBO to Saudi Arabia's 257 BBO of reserves.

Petroleum Development Oman (Al-Rawahi et al., 1993) has used horizontal technology extensively in the development of the Nimr Field in south Oman. Water coning in the field has limited recovery by vertical wells to about 12% of OOIP. Their analyses have shown that horizontal development could raise the recovery rate to 15% of OOIP. An increase in recovery from 12% to 15% OOIP corresponds to an increase in reserves of 25%.

Operators' responses from the project questionnaire describing reserves increases for individual formations are presented for the U.S.A. and Canada in the following sections.

4.2 U.S.A. RESERVES INCREASES

Proven U.S.A. oil reserves amount to around 27 BBO (Figure 4-2). This represents 5% of the total domestic resources of 513 BBO. These data are from the DOE TORIS database.

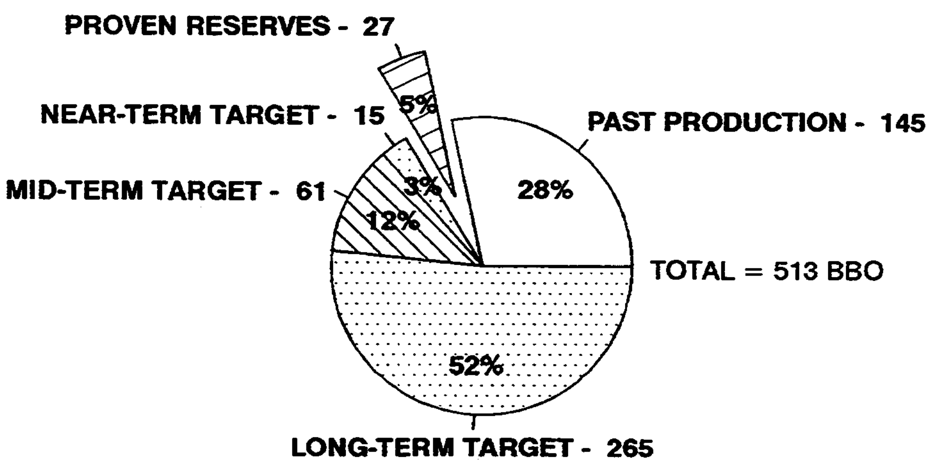

Figure 4-2. U.S.A. Reserves (TORIS, 1988)

Advanced technology, including horizontal development, is expected to play a critical role in increasing the oil and gas resource base. A recent DOE study concluded that the remaining U.S. oil resource base amounts to 204 BBO at a real price of $27/bbl, assuming the application of advanced technology (Figure 4-3).

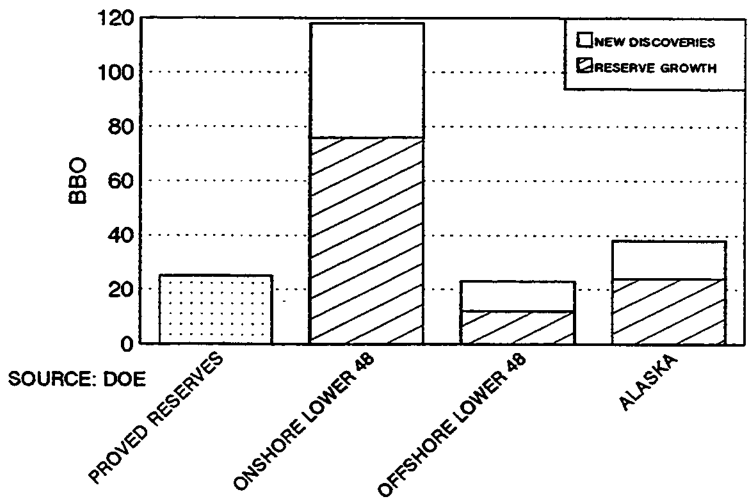

Figure 4-3. U.S.A. Oil Resource Base (*American Oil & Gas Reporter* Staff, 1994)

Horizontal technology is also expected to contribute to increases in domestic gas reserves in several resource categories (Figure 4-4).

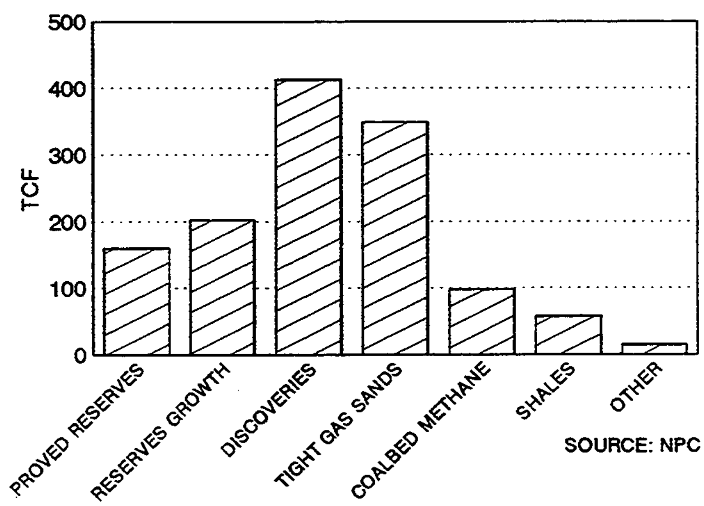

Figure 4-4. U.S.A. Gas Resource Base (NPC, 1992)

The current boom in the application of horizontal drilling has matured sufficiently such that a more concrete estimation of the impact of this technology on reserves can now be developed. Toward that end, operators were asked to estimate the increase in reserves in their own specific fields. Forty-seven U.S.A. survey responses listed some value for reserves increase. The overall average increase is **8.7%**. Extrapolated across the total U.S.A. reserves base, this represents an additional **2.3 BBO** of reserves. In terms of incremental recovery, this volume of oil represents 0.5% of OOIP (513 BBO, see Figure 4-2). The distribution of reserves increase responses for U.S.A. formations is shown in Figure 4-5.

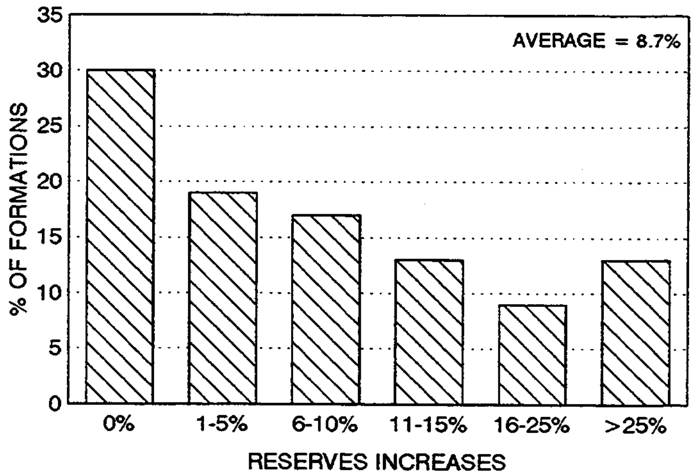

Figure 4-5. Reserves Increases for U.S.A. Formations

It was known during the design of the original questionnaire that most operators would not have a precise estimate of reserves increase for their projects. Few projects have sufficient horizontal development and production history for this quantity to be well defined. Therefore, the question regarding reserves increase was designed in a check-the-box format to encourage operators to give their best guess rather than skip the question. Six choices were provided: 1) 0%; 2) 1-5%; 3) 6-10%; 4) 11-15%; 5) 16-25%; and 6) other.

During the analyses, checked responses were assigned a numerical value so that an average could be calculated. The median of each range was assigned as the representative value for choices 2 to 5. For the "other" responses (choice 6), a conservative value of 25% was assigned. Some operators who checked "other" also provided specific values. All known values above 25% are listed in Table 4-1.

TABLE 4-1. U.S.A. Formations with Reserves Increases >25%

FORMATION	RESERVES INCREASE
Clastics	
Lakota	100%
Rasu	250%
Sycamore	50%
Carbonates	
Austin Chalk	100%
Niobrara	300%
Viola	100%

Some operators checked "other" without providing a specific value. In the analyses, all reserves increases in the "other" category were assigned a value of 25% for the calculation of a value that might be extrapolated across all U.S.A. reservoirs. This methodology was based on two considerations:

1. A consistent treatment was preferred for all reservoirs in the "other" category, both with and without known values.

2. A technique to moderate the effect of the "other" formations was deemed appropriate. The effect of including the highest values in the average was substantial. For example, average reserves increase for carbonates is 34% including the three formations of 100% and greater (see Table 4-1); without these values, the average falls to 6%.

In support of the second point mentioned above, it is known that these highly successful applications were not chosen randomly by operators from the U.S.A. reservoir population. Instead, most were sought out due to their high potential for success with horizontal development. As a consequence, it is not expected that a proportion equal to 6 out of 58, or 10%, of remaining U.S.A. formations not yet exploited with horizontal wells would repeat the successes of these formations. Therefore, the impact of these reservoirs on the overall average was reduced to develop a reasonable reserves increase for typical not-yet-exploited formations.

Prior to the initial application of horizontal technology in a given field, it could normally be forecast whether the reserves increase will be several percent versus 100% or more. Reservoirs that can be economically exploited with vertical wells would typically see a reserves increase in the range of 0 to 25%. Conversely, larger increases would be expected for reservoirs that cannot be economically exploited with vertical technology.

U.S.A. clastic formations had an average increase in reserves of 8.4% (Figure 4-6). Clastic reserves total approximately 18 BBO, based on remaining OIP estimates (see Table C-4). An 8.4% increase is equivalent to about 1.5 BBO.

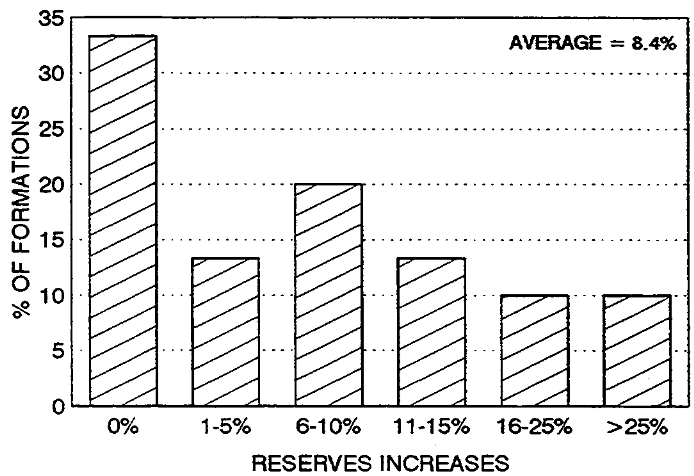

Figure 4-6. Reserves Increases for U.S.A. Clastics

Reserves increases in carbonate formations are shown in Figure 4-7. The average increase is 9.2%. Carbonate reservoir reserves in the U.S.A. total to about 8 BBO (see Table C-4). Thus, 0.74 BBO is the estimated addition to carbonate reserves.

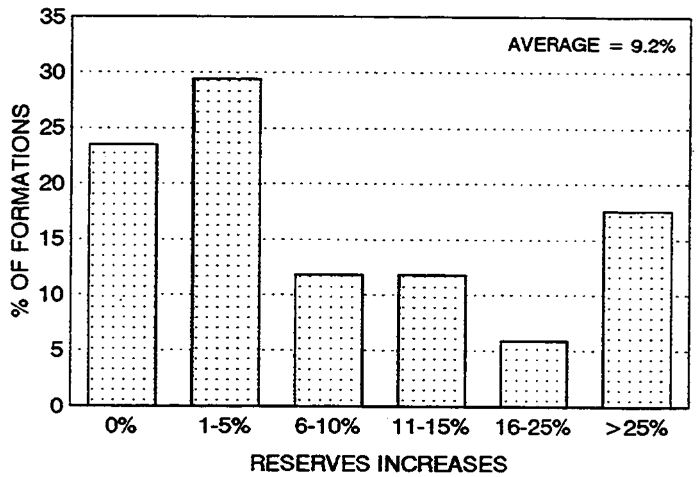

Figure 4-7. Reserves Increases for U.S.A. Carbonates

Reserves increase percentages and corresponding oil volumes are summarized for the three reservoir categories in Table 4-2.

TABLE 4-2. Increase in Reserves for U.S.A. Formations

Lithology	Increase in Reserves	
	(%)	(BBO)
Clastics	8.4	1.5
Carbonates	9.2	0.7
Unknown	—	0.1
All Formations	8.7	2.3

About 30% of the responding horizontal project operators indicated that the technology provided no increase in reserves. The data were evaluated to determine whether any of these projects were still considered economic successes even though reserves were not increased. Of the 14 formations with no increase, 13 (93%) were not economic successes. This suggests that an increase in reserves is important to the economic success of a horizontal program.

When lithology is considered, horizontal technology increases reserves more often in carbonate reservoirs. About 24% of carbonate operators reported no increase in reserves, compared to 33% of clastics operators.

Another type of formation grouping that shows interesting reserves trends is by major application (Table 4-3). Sufficient data are not available to analyze each of the 10 applications (see Appendix C) individually, since most are listed in combination with other applications. However, the two principal applications (intersecting fractures and minimizing coning) can be considered.

TABLE 4-3. U.S.A. Reserves Increases by Application

Application	Increase in Reserves		
	Clastics	Carbonates	All Formations
Fractures	6.9%	10.6%	9.0%
Coning	10.2%	6.5%	9.2%

Over half of the total U.S.A. questionnaires mentioned intersecting fractures, including 37% of clastic formations and 78% of carbonates. In these formations, the average reserves increase given by the operators was about 9%. Differences are seen with lithology: the average increase for clastic fracture applications is 7%; the average for carbonate fracture applications is 11%. All fractured formations with reserves increases ≥ 100% are carbonates. The highest clastic increase is 50%.

Coning applications show a similar (inverted) distribution of reserves increases than is the case for intersecting fractures. Forty percent of clastics and 22% of carbonates were minimizing coning applications. The average increase in reserves for all coning applications is 9%. The median value is 8%, illustrating the relative uniformity of the distribution of reserves increases. Coning applications in clastics were more effective for increasing reserves than those in carbonates: 10% versus 7%.

4.3 CANADIAN RESERVES INCREASES

Several publications address the impact of horizontal drilling on Canadian reserves. Among the most significant is a working document prepared by the National Energy Board of Canada (NEB, 1993), which specifically addresses in detail the potential impact of horizontal wells on reserves and supply.

NEB (1993) quotes several sources that estimate increases in incremental reserves ranging from 2-5% of OOIP. An increase of 5% is consistent with NEB's recent estimate, and implies a 75% increase in established reserves. An increase of this magnitude represents around 425 million m^3 (2.7 BBO).

In its Pembina leases, Amoco predicts an increase in ultimate recovery from 27% to 40% OOIP as a result of re-development with horizontal re-entries (NEB, 1993). This would represent a reserves increase of 48%. Another study of a Lloydminster heavy-oil pool showed an increase in recovery factor from 8.5% to 10.5% with horizontal wells—a reserves increase of 24%.

These impressive increases in reserves probably represent the most effective uses of the technology for improving recovery. In a much broader analysis, NEB estimated reserves increases for most clastic and carbonate fields in Alberta and Saskatchewan (Table 4-4). They calculated an overall average incremental recovery factor of 1.0%, which is less than the 2-5% mentioned previously.

TABLE 4-4. Canadian Reserves Increases (NEB, 1993)

LITHOLOGY	OOIP (10^6 M^3)	PRIMARY RECOVERY	INCREMENTAL RECOVERY	RESERVES INCREASE
Clastics				
Alta Heavy (Group 2)	185	5.83%	0.41%	7.0%
Sask Heavy (Group 2)	1535	5.11%	1.54%	30.0%
Alta Medium (Group 3)	4020	13.63%	1.82%	13.4%
Alta Heavy (Group 3)	687	5.83%	0.13%	2.2%
Clastics Average			0.98%	13.2%
Carbonates				
Sask Light (Group 2)	429	15.3%	0.87%	5.7%
Sask Medium (Group 2)	697	10.83%	0.81%	7.5%
Sask Light (Group 3)	316	15.3%	1.40%	9.2%
Carbonates Average			1.03%	7.5%
OVERALL AVERAGE			1.00%	9.8%

The results of the DOE project survey were then compared with these published values. As in the U.S.A. survey, the increase in field reserves for Canada was divided into six ranges, namely: 1) 0%, 2) 1 - 5%, 3) 6 -10%, 4) 11 - 15%, 5) 16 - 25%, and 6) >25%. A response from 70% of the operators indicated an increase of 9.5% for all reservoirs (Figure 4-8). Most of the responses came in the 1-5% range (39%), while 19% were in the range greater than 25%.

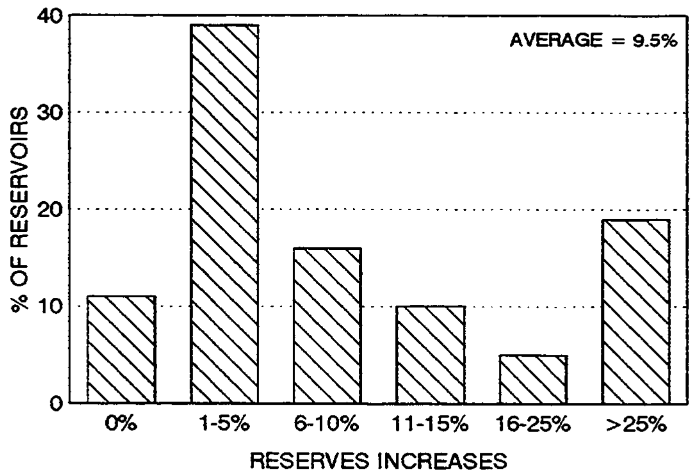

Figure 4-8. Reserves Increases For All Canadian Formations

In light-oil clastic formations (Figure 4-9), 50% responded in the 1-5% range with 20% in the greater than 25% range. The average for light-oil clastics was 9.3%.

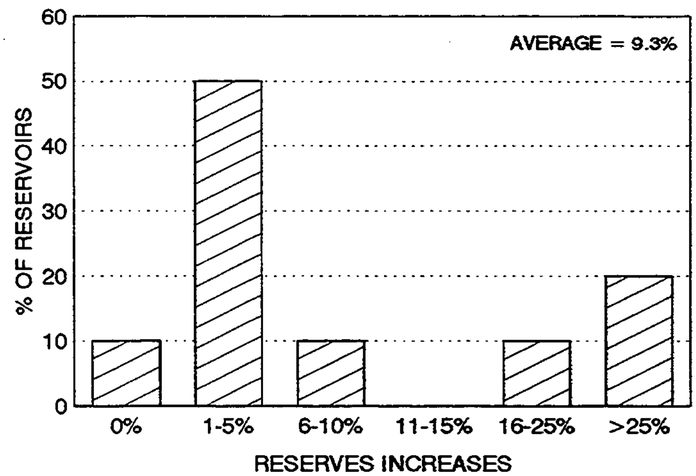

Figure 4-9. Reserves Increases For Canadian Light-Oil Clastics

Operators in carbonate formations reported 44% in the 1-5% range (Figure 4-10) but only 4% in the 16-25% and >25% range. The average was 7.0% for carbonates.

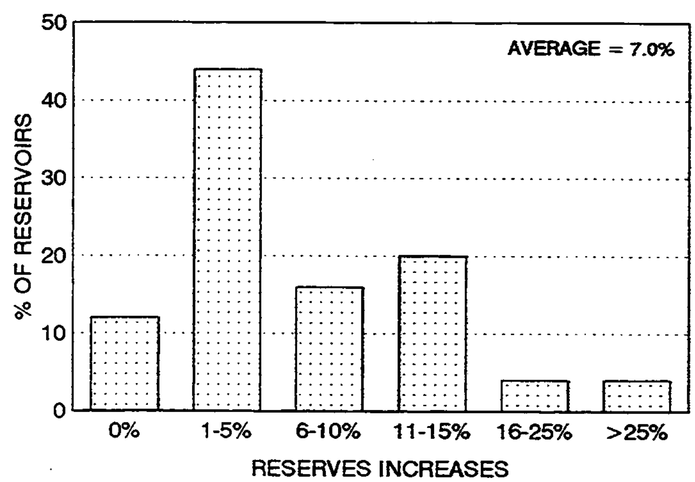

Figure 4-10. Reserves Increase For Canadian Carbonates

Canadian heavy-oil formations showed 36% in the 1-5% range, and a relatively high percentage (27%) in the >25% range (Figure 4-11). The average for heavy oil was 10.9%.

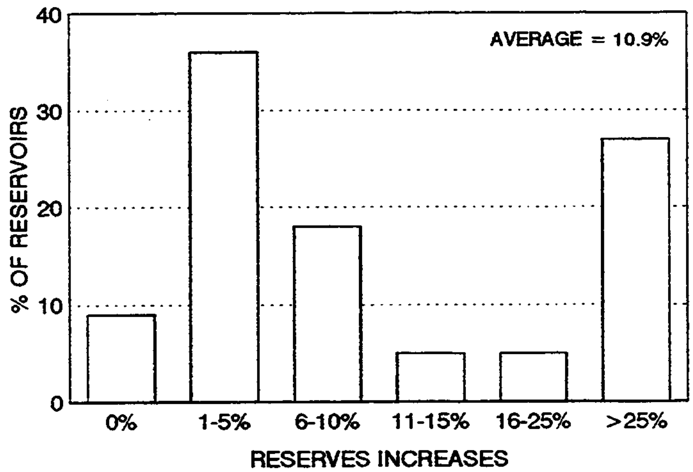

Figure 4-11. Reserves Increases For Canadian Heavy Oil

The overall average reserves increase of 9.5% for all Canadian pools compares very favorably with the NEB (1993) value of 9.8%. Compared to the Canadian resource base of about 12 billion m³ (75 BBO), this increase in recovered OOIP represents an additional 120 million m³ (750 MMBO) in reserves as a result of horizontal technology across the Canadian industry.

The overall impact on reserves over the next few years (Figure 4-12) shows that horizontal wells can significantly slow production decline if employed by the industry. The High Horizontal case assumes drilling rates increase to about 1200 wells/year in the near future. The Low Horizontal case is more conservative and is based on a peak drilling rate of 800 wells/year. More discussion of forecasted well counts is presented in Section 5.3.

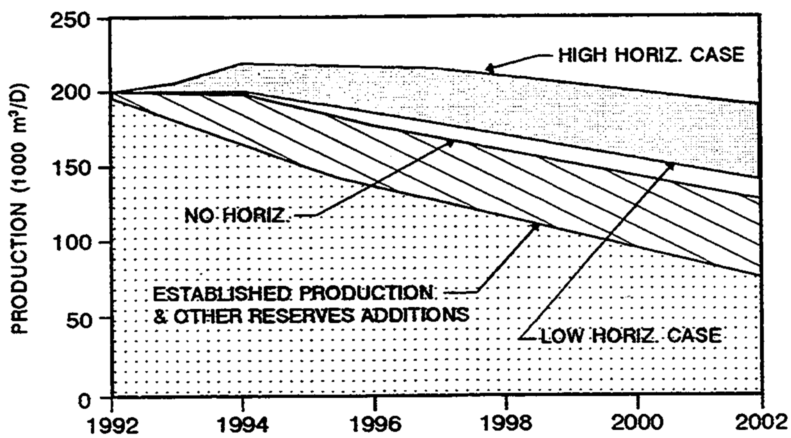

Figure 4-12. Impact of Horizontal Wells on Canadian Reserves (NEB, 1993)

5. Horizontal Application Forecast

5.1 INTRODUCTION

The strategic purpose for performing analyses and forecasts of the use of horizontal technology for domestic petroleum recovery is embodied in *The Domestic Natural Gas and Oil Initiative*, released by the Department of Energy in December 1993. Strategic Activity I from the Initiative is summarized as follows:

> "Increase domestic natural gas and oil production and environmental protection by advancing and disseminating new exploration, production, and refining technologies."

Under Strategic Activity I, DOE is directed in Action 1 to expand its oil R&D program to increase advanced oil recovery capabilities and reduce the rate of reservoir abandonment. Specific areas of development include computational analysis of geologic or geophysical data to improve drilling success rates, rock drilling systems for natural gas, advanced oil recovery technologies, and analyses of geologic basins to recover by-passed oil.

The petroleum industry's experience has clearly demonstrated that horizontal technology is one of the most important tools for accomplishing the goals of Strategic Activity I. Increasing reservoir recovery and decreasing the rate of reservoir abandonment have been demonstrated to be well served by exploiting reservoirs with horizontal wells.

A secondary objective of this analysis/forecast is to aid the oil and gas industry with an overview of what can and can not be done with horizontal technology. As discussed previously, important developments are needed and might be given attention and addressed as a result of the present study and similar projects. For example, one of the most important industry needs served by technology transfer is a better database of horizontal well operator experiences, especially in areas other than fractured carbonates, for planning optimum horizontal applications.

Forecasting the application of horizontal technology is fraught with uncertainty. Many unknowns are associated with the task, including:

- Oil price trends
- The role of future discoveries
- Rates of technical progress
- Constraints resulting from the availability of equipment and services
- Future consumption patterns
- Overall economic trends
- World events

Oil price trends, while affecting all drilling budgets, have a greater impact on horizontal drilling due to increased risks with the technology. Technical progress is expected to further decrease horizontal drilling and completion costs. However, as the technology matures, fewer significant breakthroughs should be forthcoming. Optimization and increased efficiencies of techniques, tools and services will continue to bring costs down to some extent. Optimization of rig design will improve costs, although no consensus exists on the design of a horizontal drilling rig.

In earlier days of the current horizontal drilling boom, forecasts of the growth of the technology were numerous and usually quite optimistic. A typical forecast from about 1989-90 predicted a steady annual increase in annual drilling rates to 5000-10,000 wells per year by the year 2000. An example of a forecast from about 1990 is shown in Figure 5-1. Projected growth rates average about 20%/year.

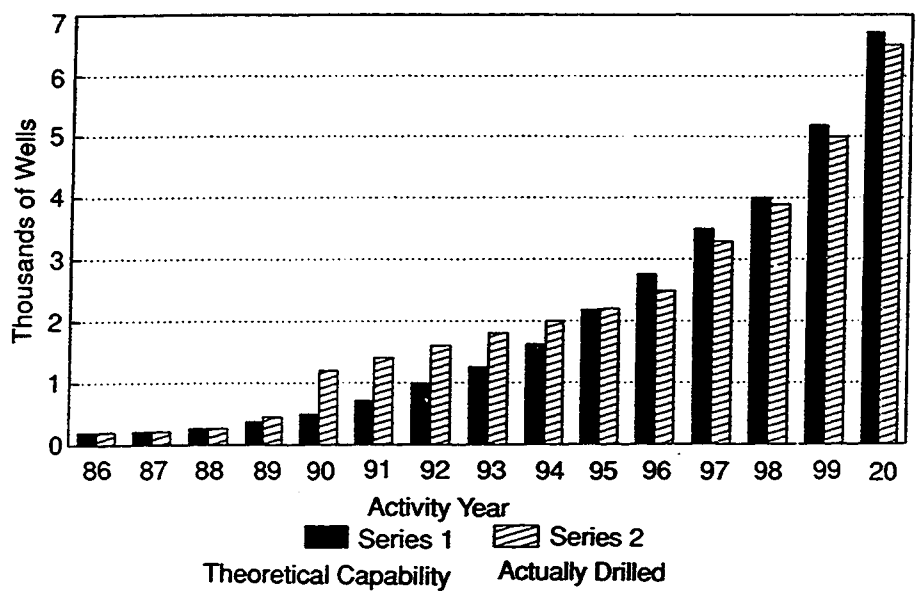

Figure 5-1. Early Worldwide Horizontal Drilling Forecast (Jelsma, 1991)

Domestic well counts for 1992 and 1993 (around 1000 wells/year) are relatively close to many predictions; however, the pathway to the current level of activity has not been a smooth increase as predicted by most. The Iraqi invasion of Kuwait in 1990 and subsequent increase in the price of oil caused a rapid acceleration in horizontal drilling. The U.S.A. horizontal well count exceeded 1200 for 1990, which is almost 6½ times as many wells as were drilled the preceding year. In fact, 1990 retains its status as the peak horizontal drilling year for the U.S.A. The drilling pace remained high in 1991, due in large part to events in the Middle East.

Spears and Associates performed a detailed horizontal well market study in early 1991 (Spears, 1991). Armed with some insight as to the effects of the Persian Gulf war, as well as anticipation of a possible slowdown of Austin Chalk drilling activity, they formulated a new forecast for the U.S.A. (Figure 5-2). Historic well counts are also presented in the figure for comparison. In hindsight, activity was greater than predicted in 1990. However, a slowdown occurred in 1992 and 1993 relative to expected activity levels.

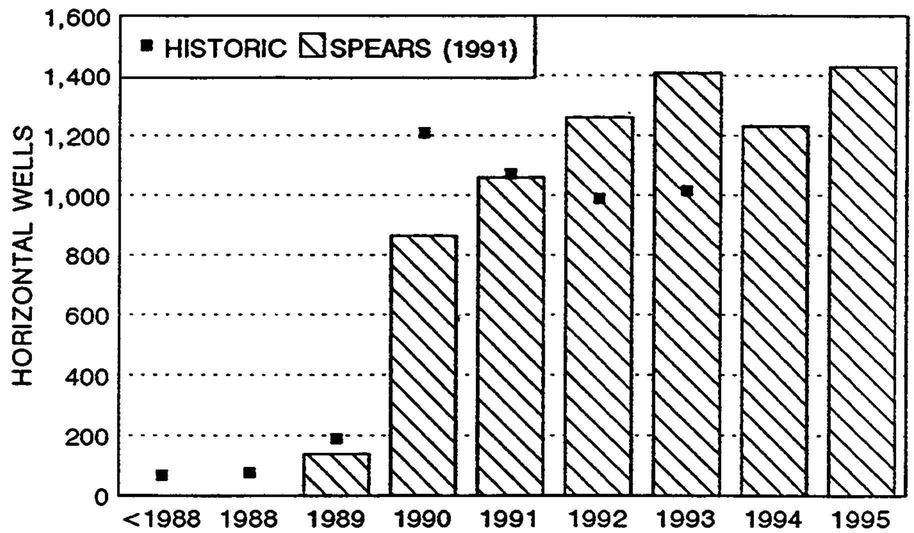

Figure 5-2. Spears and Associates (1991) U.S.A. Horizontal Well Forecast

5.2 U.S.A. HORIZONTAL DRILLING FORECAST

New horizontal drilling forecasts were developed for this project based on recent history and current expectations of the industry. Members of the project team analyzed questionnaire and other oil field data in an attempt to formulate reasonable trends for future activity. Key service company personnel (Schlumberger, Halliburton, Smith, etc.) were contacted to obtain recent forecasts and current expectations. Unfortunately, there has been an almost universal abandonment of well-count tracking and forecasting in the wake of industry restructuring, reduced budgets and staff cutbacks. Most service companies continue to do in-house estimates of future market requirements, but did not have any data that could be shared with the project.

The most recent well-count forecast that could be located was assembled by Spears and Associates in 1993 (Figure 5-3). A noteworthy trend in their more recent forecast is a significant decrease in drilling in 1994, due presumably to an expected slowdown in the Austin Chalk. The forecast calls for a near-term slowdown followed by a relatively sluggish recovery, with 1992 drilling levels not revisited until 1998. Historic horizontal well counts presented in the figure were presented by Spears and vary slightly from those obtained recently from PI (see Table 5-1).

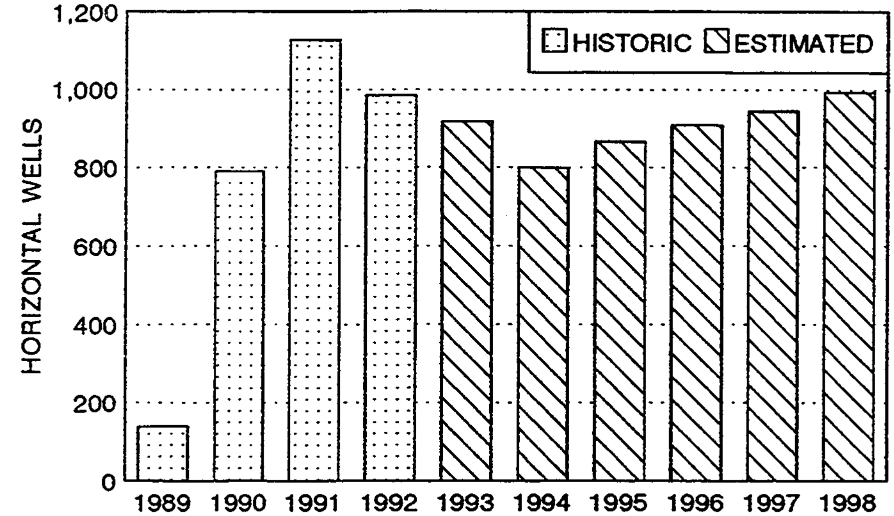

Figure 5-3. Spears and Associates (1993) U.S.A. Horizontal Well Forecast

The questionnaire that was distributed as part of this DOE project included a question relative to horizontal forecasting, namely: *Describe your future horizontal activity: (choose one) 1) none 2) decrease 3) same 4) increase.* Responses from operators to this question are presented in detail in Appendix C (section C.8). In summary, 56% of all responding U.S.A. operators plan the same or increased horizontal drilling activity in the future.

To incorporate these operator plans into a well-count forecast, an effort was made to devise a numeric value for the average plan. An average was calculated based on none=1, decrease=2, same=3, and increase=4 with each formation getting one vote. With this simple method, the overall average plan value is 2.49, corresponding to the point midway between "decrease" and "same."

Next, a weighted average based on each operators' well count was calculated. A weighted value is probably more representative than a simple average since the most experienced and active operators will have a proportionately greater impact on future activity across the industry. The weighted analysis yielded a higher average plan value. For all formation types, the average weighted plan for U.S.A. operators is 2.98 ("same" = 3.00). Operators in clastic formations have a weighted plan value of 2.92. Operators in carbonates are the most positive at 3.02. Even though future plans in carbonates are slightly higher, it is more noteworthy that differences as a function of lithology are insignificant and that the average plan across the industry is to continue the same activity level into the future.

Given that the plan of previously active operators (i.e., survey respondents) is to continue drilling horizontal wells at the same level, it is very reasonable to assume that the overall level of drilling will increase. Horizontal technology, while no longer a novel technology, is still in a relatively early stage of integration into the oil-field mainstream. Many operators have recently or will soon adopt the technology for the first time. Other experienced operators are formulating plans to develop new fields using only horizontal technology. With these types of contributions to the well count, the total activity level would be expected to increase.

A basic approach to the development of a forecast of horizontal drilling trends is to evaluate historic trends and then extrapolate those data into the future, incorporating estimated impacts of other pertinent factors and known or likely future events (e.g., lifting of offshore drilling moratoria, slowdowns in active areas). Unfortunately, historic data for horizontal drilling (Table 5-1) do not present an easily discernible trend.

TABLE 5-1. U.S.A. Historic Horizontal Well Counts (PI)

YEAR	HORIZONTAL WELL COUNT	WELL COUNT INCREASE
1987 and Prior	67	-
1988	77	+14.9%
1989	189	+145%
1990	1207	+539%
1991	1074	-11.0%
1992	990	-7.8%
1993	1016	+2.6%
Average	660	+114%

The historic average annual increase of 114% is obviously not useful as a predictor of future increases. It is clear that the increase in horizontal drilling activity for 1994 will be considerably less than 114%. The peak in activity in 1990 was followed by two years of decline, which may be considered as a return to "normal" sustainable drilling levels. The downward trend reversed in 1993, and the well count appears to have returned to a path of modest annual growth. What is a modest level? Experts from service companies and DEA-44 contacts suggest that an annual growth rate of 5-10% is a reasonable estimate, although conservative, considering all pertinent factors.

A forecast based on these expectations is presented in Figure 5-4. Growth rates are initially set at 5%/year for 1994, and then increased gradually to 10%/year over the next decade. This pattern of growth in horizontal drilling will result in an increase in the annual U.S.A. horizontal well count to about 2250 over the next decade, which represents an overall increase of 122% from 1993 activity levels. Of course, it is doubtful, in light of historic data, that the well count will increase along a pathway as smooth as shown in Figure 5-4. World events, oil price shocks, and/or changes in Austin Chalk drilling levels could cause significant variation in short-term growth of the technology. In any event, the long-term trend should be one of ongoing growth.

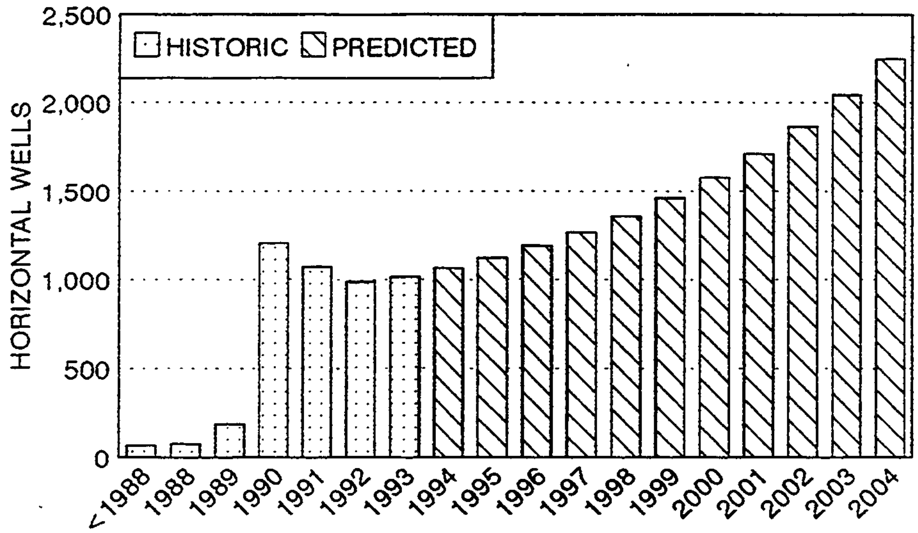

Figure 5-4. U.S.A. Horizontal Well Forecast Based on Historic Data

A second forecast was developed for comparison based on a different approach. This forecast began with data from a detailed modeling study by the National Petroleum Council (NPC, 1992) of the domestic resource base and future gas and oil consumption patterns. Sponsored by the DOE, this analysis is performed periodically by the NPC Source and Supply Task Group with assistance from numerous corporate, government, trade, and academic organizations. Toward meeting the stated goals of that study, an annual well count for the U.S.A. is forecast.

Two reference forecasts were developed by the NPC based on different economic scenarios. Reference Case 1 is based on the assumptions of healthy demand, a growing market, and an increasing oil price over the next two decades (Figure 5-5). Reference Case 2 represents a relatively weak demand outlook based on flat oil prices into the future. Both of these reference cases are believed to be realistic and neither is suggested as most likely.

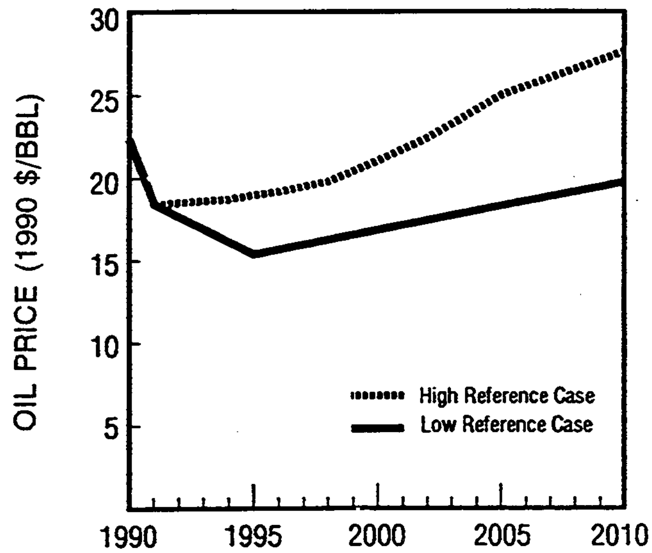

Figure 5-5. Crude Oil Price Projections for Reference Cases (NPC, 1992)

Total well counts (vertical, horizontal, and directional) projected for the U.S.A. are shown in Figure 5-6 for both the flat oil price and the increasing oil price cases (Low Reference and High Reference, respectively, in Figure 5-5). Projected well counts for the flat-price case increase from about 21,000 wells in 1994 to 44,000 wells in 2004, an increase of 112%. Increasing-price well counts increase from over 32,000 in 1994 to almost 60,000 in 2004, an increase of 85%. For the period 1994-2004, the increasing-price well count is on average about 50% higher than for the flat-price case. These data were also compared to the current GRI Baseline Projection (Woods, 1994). Well counts predicted by GRI fall between the two NPC cases.

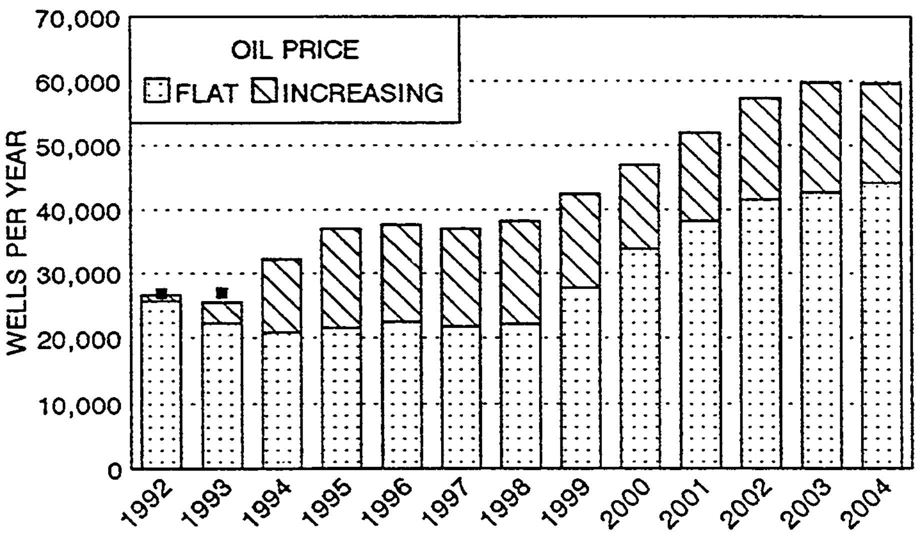

Figure 5-6. NPC U.S.A. Well-Count Forecasts (NPC, 1992)

Historic data from P.I. are shown for 1992 and 1993 as points in Figure 5-6. Based on the actual 1993 total and ongoing 1994 activity, the total well-count trend is expected to fall between the two NPC forecasts, at least in the near-term.

In recent years, horizontal drilling's share of the total drilling market has averaged about 4% and increased slightly since 1992 (Figure 5-7). The market share for horizontal drilling is expected to increase in upcoming years as the technology and services are made more widely available and competitive. The increase in market share will accelerate if the price of oil increases.

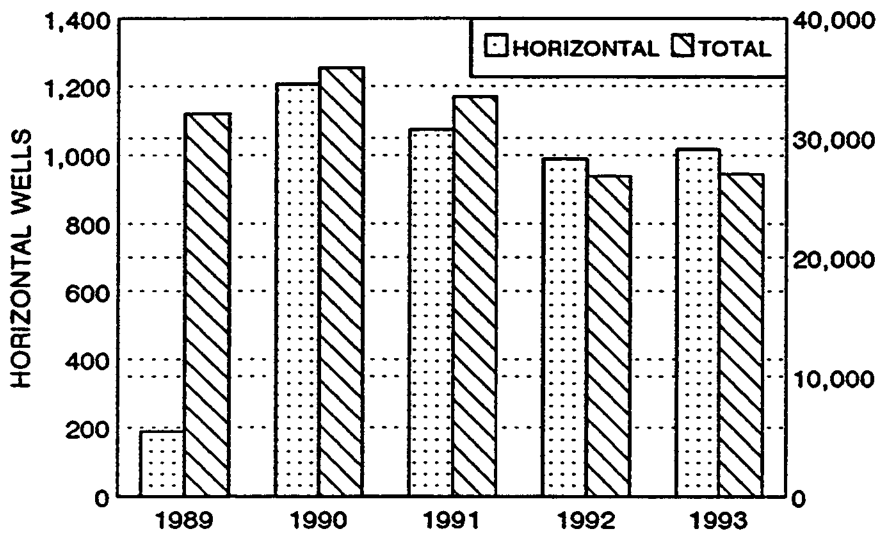

Figure 5-7. Horizontal Wells Versus Total Wells (PI)

An effort to predict the market share of horizontal drilling under price scenarios similar to the two NPC cases must take into account the weight of risk factors considered by a rational operator. His overall goal is to generate the highest overall rate of return. Horizontal wells undoubtedly have the potential to accomplish that goal, although usually with increased risk. However, based on fundamental considerations of typical drilling risk analysis, the market share of horizontal drilling should increase regardless of whether the price of oil increases or stays flat, although probably not by the same amount.

In the increasing-price case, higher oil prices reduce the risks associated with horizontal drilling and increase the potential payoff for increased production. Predicting the production performance of new wells *a priori* is often very difficult, even for vertical wells. However, vertical wellbore interaction with a reservoir is fairly well understood, relegating the investor risk primarily to reservoir and price uncertainty. This uncertainty is evaluated against an easily predicted investment requirement.

The interaction between reservoir and wellbore dynamics in a horizontal well is very complex and not yet well understood. As a result, the incremental production from a horizontal well over a vertical well (necessary to justify the incremental cost to drill horizontally) is often subject to considerable uncertainty. The incremental cost to drill a horizontal well thus comes under intense scrutiny. In addition, even though horizontal technology has advanced significantly, there is still an increased probability of increased trouble costs with the less familiar and more complex technology. This leads to an increased uncertainty with respect to total investment requirements.

Production and drilling uncertainties are clearly greater when no or few horizontal wells have been drilled in a given reservoir. Rational investors will always weigh risk versus potential return. Assuming the basic risks (i.e., ability to forecast production from horizontal wells and mechanical or trouble costs) remain flat into the future (no technology advancements), higher oil prices provide greater potential return on investment and should lead to an increasing number of horizontal wells in previously drilled and new reservoirs. For the increasing-price case, the average investor will be more willing to assume the added risks associated with the horizontal well.

In the flat-price scenario, horizontal technology may represent a more efficient development strategy in appropriate applications, assuming that the ability to predict incremental production and investment requirements becomes essentially equivalent to vertical wells in the area. This assumes that the ultimate cost to recover the reserves is less with horizontal wells (i.e., fewer total wells). Otherwise, all else being equal, from a macro analysis, horizontal technology would have to advance more rapidly in a flat-price scenario to approach the market share expected in an increasing-price (no technology advancement) scenario. If technology advances are equal for both cases, horizontal's market share will advance more rapidly in an increasing-price scenario because it is doubtful that risk with a horizontal well will ever be equivalent to that with a vertical well in the same reservoir.

The U.S.A. horizontal drilling forecast based on NPC projections and these market-share considerations is shown in Figure 5-8. The following rates of growth for horizontal drilling were assumed in the forecasts: 1) For the flat oil price case, a modest increase in the percentage of horizontal wells drilled is assumed, from 4% of all wells drilled in 1994 to 6% of all wells drilled in 2004; 2) For the increasing oil price case, a more significant increase in the percentage of horizontal wells drilled is assumed, from 4% of all wells drilled in 1994 to 10% of all wells drilled in 2004.

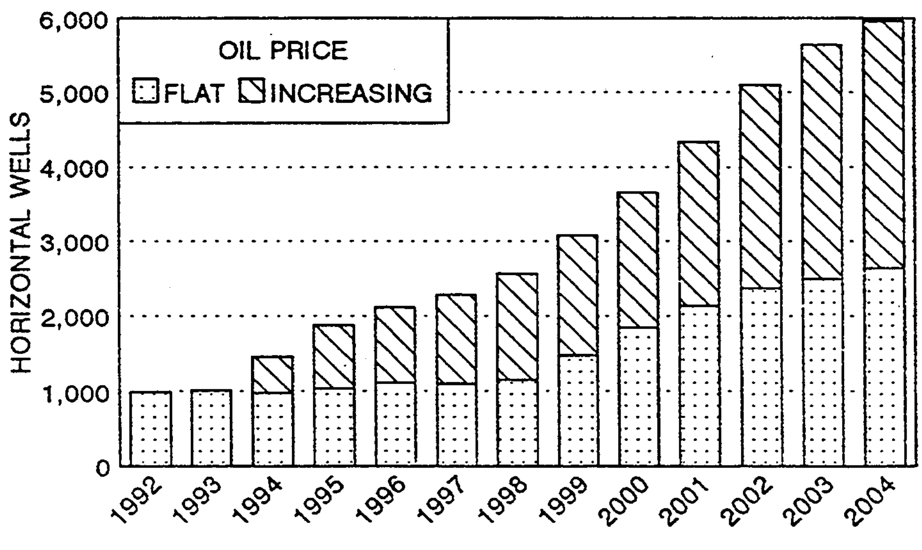

Figure 5-8. U.S.A. Horizontal Well Forecast Based on NPC Well Counts

The annual number of horizontal wells drilled under the conservative flat-price scenario increases from about 1000 in 1994 to over 2600 in 2004. This corresponds to an average annual increase in horizontal well count of about 10%. For the increasing-price forecast, the horizontal well count increases about 15% each year, from over 1400 wells in 1994 to 6000 wells in 2004. As evidenced by the current trend for all wells (see Figure 5-6), the actual horizontal well count will most likely fall between these two cases, with the flat-price case representing a conservative lower limit and the increasing-price case an optimistic view.

One other market-share case was run assuming that the percentage of horizontal wells drilled remains constant at 4% over the next decade. Increases in horizontal drilling under this assumption are directly tied to overall drilling patterns across the industry. For a constant 4% market-share, the horizontal well count in 2004 would increase to about 1800 wells with a flat price, and to 2400 wells with an increasing price.

5.3 CANADIAN HORIZONTAL DRILLING FORECAST

The forecast for Canadian horizontal drilling is quite optimistic by most accounts. Well counts are expected to increase to the range of 1400 wells/year in the near future. Canadian activity should exceed that in the U.S.A. this year (1994) by about 200 wells (±1200 versus ±1000 wells). An earlier Canadian forecast by Spears and Associates (Figure 5-9) shows how the well count in Canada has consistently outpaced most early expectations.

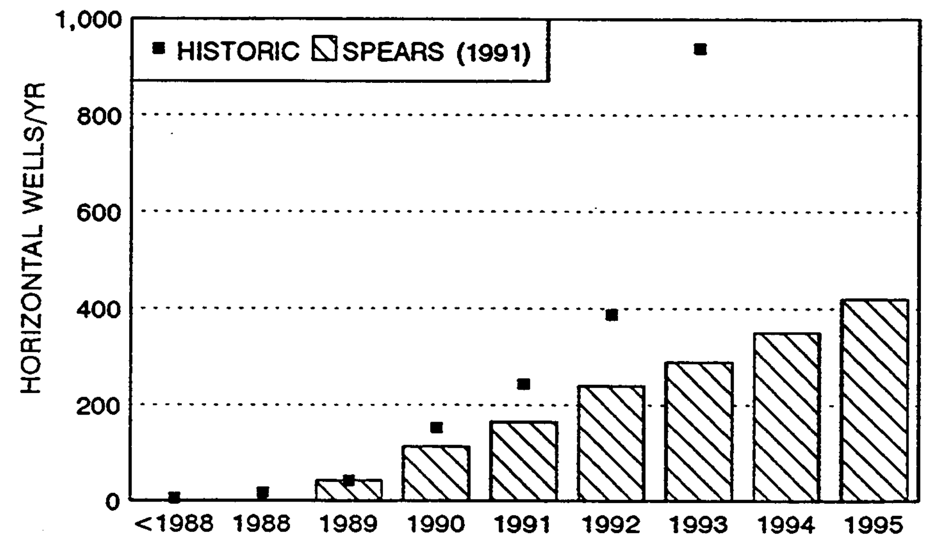

Figure 5-9. Early Canadian Horizontal Forecast (Spears and Associates, 1991)

Factors contributing to the more rapid-than-expected increase in Canadian horizontal drilling include pro-active fiscal regulatory regimes, a wide variety of application settings, numerous aggressive small operators, and restructuring/downsizing of major operators generating the sale of many small-interest holdings. Another important contributor to the rapid spread of horizontal drilling is the strong network within the Canadian industry that promotes rapid technology transfer and development.

A detailed forecast of the Canadian horizontal well count was recently prepared by the National Energy Board (NEB) of Canada (NEB, 1993). Important factors taken into account included historic well counts and trends, Canadian operators' near-term drilling plans, and an estimated drilling potential of a total of 12,000 horizontal oil wells in Canadian pools.

NEB developed two scenarios to provide a realistic range for the future well count. The low case was based on a projected well-count plateau of 800 wells/year by the year 2000. Cost reductions of 32%/well are assumed for the low case (from $550,000 in 1992 to $375,000 by 1999).

The high case was more optimistic and was based on a projected plateau of 1200 wells/year. Greater cost reductions are assumed for the high case: 41%/well, i.e., total cost of $325,000/well by 1999. It is anticipated that these cost reductions, should they occur, will arise from technological improvements and an increasing percentage of re-entries.

NEB's forecast is shown in Figure 5-10. A total of 7390 horizontal wells is represented by the low-case forecast; 9900 wells would be drilled under the high-case scenario. It should be noted that these well counts do not include oil sands or enhanced recovery projects.

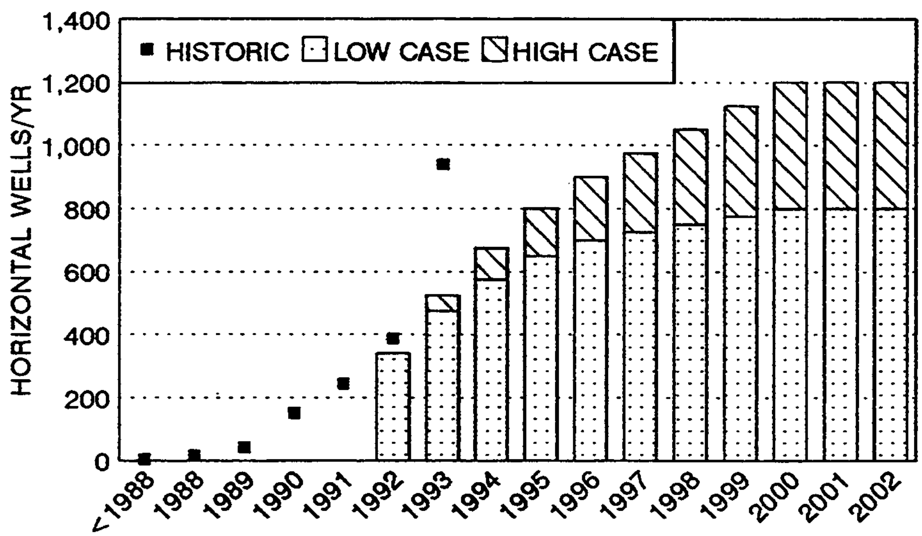

Figure 5-10. NEB Canadian Horizontal Well Forecast (NEB, 1993)

Historic well counts for 1992 and 93 show these predictions to be conservative. As mentioned previously, royalty incentives in Saskatchewan and Manitoba and the normalization of royalty rates in Alberta have contributed to the recent rapid increase in horizontal drilling activity.

Data compiled and analyzed by the Canadian DEA-44 group were used to assemble a new forecast of Canadian horizontal drilling activity. Current expectations are higher than at the time of the NEB forecast. Future drilling plans, as gauged by the DOE project questionnaire, are positive. Figure D-23 in Appendix D shows that 41% of operators plan to increase their activity, 34% plan the same, 14% plan to decrease, and only 11% plan no activity. Thus, 75% of operators plan the same or increased activity. The DEA-44 Group annual survey done in 1993 supports this trend: 73% planned the same or increased activity for 1994.

The forecast developed for Canadian activity takes full advantage of the unique attributes of Canadian horizontal drilling operations. As compared to their counterparts in the U.S.A., Canadian operators involved in horizontal drilling form a relatively small group, are well networked, and geographically close together. Well data and records are in public domain. These factors result in a greater willingness to share information with colleagues and competitors.

Well counts for 1994 and 1995 will each be higher than previous years, based on ongoing drilling programs and operators' plans for the near future. It is anticipated that the growth rate will slow soon and that the well count will peak in the next 1-2 years. Continued growth cannot be sustained due to supply and demand of rigs, trained personnel, specialized equipment, etc. Current expectations for horizontal drilling in Canada are summarized in Figure 5-11. A slight decline in well count is forecast for the later years of this decade and on into the next.

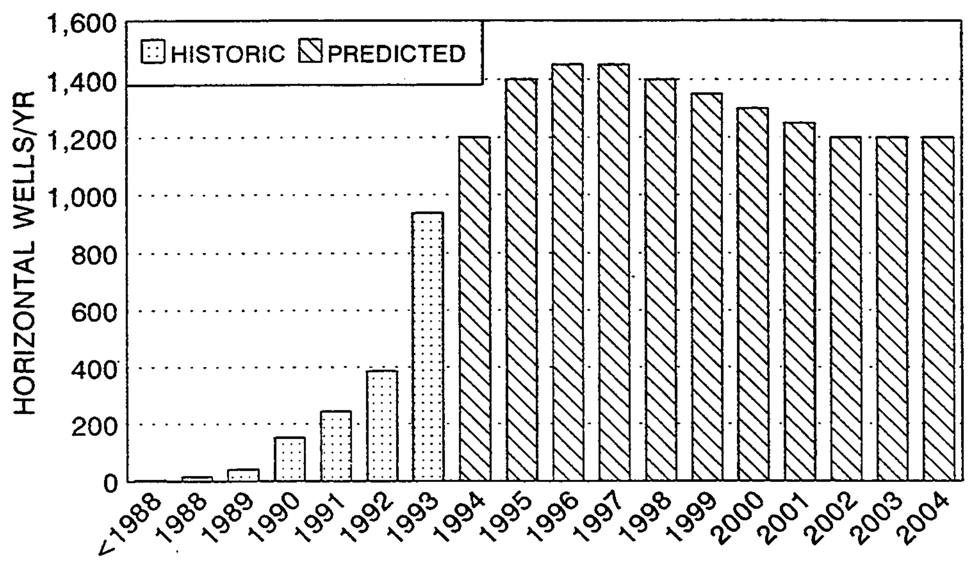

Figure 5-11. Canadian Horizontal Well Forecast

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Appendix A
U.S.A. Formations Drilled Horizontally

GEO CODE	GEOLOGIC SYSTEM	FORMATION	LITHOLOGY	STATE
000	PRECAMBRIAN	SERPENTINE	BASEMENT	TEXAS
169	CAMBRIAN	ARBUCKLE	CARBONATE	OKLAHOMA
201	ORDOVICIAN	ELLENBERGER	CARBONATE	TEXAS
201	ORDOVICIAN	PRAIRIE DU CHIEN	CARBONATE	MICHIGAN
202	ORDOVICIAN	BLACK RIVER	CARBONATE	MICHIGAN
202	ORDOVICIAN	BROMIDE	CARBONATE	OKLAHOMA
202	ORDOVICIAN	McLISH	CARBONATE	OKLAHOMA
202	ORDOVICIAN	SIMPSON	CLASTIC	OKLAHOMA
202	ORDOVICIAN	TRENTON	CARBONATE	MICHIGAN, ILL
202	ORDOVICIAN	VIOLA	CARBONATE	KANSAS, OKLA
202	ORDOVICIAN	WILCOX	CLASTIC	TEXAS, OKLA
203	ORDOVICIAN	RED RIVER	CARBONATE	SOUTH DAKOTA
203	ORDOVICIAN	SLYVAN	CLASTIC	OKLAHOMA
251	SILURIAN	INTERLAKE	CARBONATE	MONTANA
252	SILURIAN	FUSSELMAN	CARBONATE	TEXAS
252	SILURIAN	NIAGRAN	CARBONATE	MICHIGAN
253	SILURIAN	A-2 CARBONATE	CARBONATE	MICHIGAN
269	SILURIAN	HUNTON	CARBONATE	OKLAHOMA
306	DEVONIAN	DUPEROW	CARBONATE	NORTH DAKOTA
319	DEVONIAN	ANTRIM	SHALE	MICHIGAN
319	DEVONIAN	BAKKEN	SHALE	NORTH DAKOTA
319	DEVONIAN	MISENER	CLASTIC	OKLAHOMA
351	MISSISSIPPIAN	KEKIKTUK		ALASKA
352	MISSISSIPPIAN	MISSION CANYON	CARBONATE	MINNESOTA
352	MISSISSIPPIAN	SYCAMORE	CARBONATE	OKLAHOMA
353	MISSISSIPPIAN	MICHIGAN STRAY	CARBONATE	MICHIGAN
353	MISSISSIPPIAN	RATCLIFFE	CARBONATE	NORTH DAKOTA
353	MISSISSIPPIAN	SALEM LIME	CARBONATE	INDIANA
354	MISSISSIPPIAN	WALTERSBURG SAND	CLASTIC	KENTUCKY, ILL
359	MISSISSIPPIAN	MISSISSIPPI LIME	CARBONATE	OKLAHOMA, TEXAS
401	PENNSYLVANIAN	SPRINGER	CLASTIC	OKLAHOMA
402	PENNSYLVANIAN	AMSDEN	CARBONATE	MINNESOTA
402	PENNSYLVANIAN	ATOKA	CLASTIC	TEXAS
402	PENNSYLVANIAN	CANE CREEK	CLASTIC	UTAH
402	PENNSYLVANIAN	MORROW	CLASTIC	TEXAS
403	PENNSYLVANIAN	BEND	CLASTIC	TEXAS
403	PENNSYLVANIAN	POTTSVILLE	CLASTIC	ALABAMA
404	PENNSYLVANIAN	BARTLESVILLE	CLASTIC	OKLAHOMA
404	PENNSYLVANIAN	MARMATON	CARBONATE	OKLAHOMA
404	PENNSYLVANIAN	McLOUTH		KANSAS
404	PENNSYLVANIAN	RED FORK	CLASTIC	OKLAHOMA

GEO CODE	GEOLOGIC SYSTEM	FORMATION	LITHOLOGY	STATE
404	PENNSYLVANIAN	STRAWN	CLASTIC	TEXAS
405	PENNSYLVANIAN	CANYON	CLASTIC	TEXAS
405	PENNSYLVANIAN	PALO PINTO	CLASTIC	TEXAS
419	PENNSYLVANIAN	MINNELUSIA	CLASTIC	WYOMING
419	PENNSYLVANIAN	TENSLEEP	CLASTIC	WYOMING
451	PERMIAN	BROWN	CARBONATE	TEXAS
451	PERMIAN	WOLFCAMP	CARBONATE	TEXAS
452	PERMIAN	ABO REEF	CARBONATE	NEW MEXICO
452	PERMIAN	BONE SPRINGS	CARB/CLAS	NEW MEXICO
452	PERMIAN	CLEAR FORK	CLASTIC	TEXAS
452	PERMIAN	LEONARD SAND	CLASTIC	TEXAS
452	PERMIAN	PHOSPHORIA	CLASTIC	COLORADO
452	PERMIAN	SPRAYBERRY	CLASTIC	TEXAS
453	PERMIAN	DELAWARE	CLASTIC	NEW MEXICO
453	PERMIAN	GRAYBURG	CARBONATE	TEXAS
453	PERMIAN	SAN ANDRES	CARBONATE	TEXAS
501	TRIASSIC	SADLEROCHIT	CLASTIC	ALASKA
551	JURASSIC	NUGGET	CLASTIC	WYOMING
552	JURASSIC	SAWTOOTH	CLASTIC	MINNESOTA
553	JURASSIC	CURTIS	CLASTIC	WYOMING
553	JURASSIC	ENTRADA	CLASTIC	NEW MEXICO
553	JURASSIC	SMACKOVER	CARBONATE	ARKANSAS, ALA
601	CRETACEOUS	PITTSBURG	CLASTIC	TEXAS
602	CRETACEOUS	BUDA	CARBONATE	TEXAS
602	CRETACEOUS	CUTBANK	CLASTIC	MONTANA
602	CRETACEOUS	DAKOTA	CLASTIC	COLORADO, N. MEX
602	CRETACEOUS	EDWARDS	CARBONATE	TEXAS
602	CRETACEOUS	FREDERICKSBURG	CARB/CLAS	MISSISSIPPI, LOU
602	CRETACEOUS	GEORGETOWN	CARBONATE	TEXAS
602	CRETACEOUS	GLEN ROSE	CARBONATE	TEXAS
602	CRETACEOUS	MUDDY	CLASTIC	WYOMING
602	CRETACEOUS	PEARSALL	CARBONATE	TEXAS
602	CRETACEOUS	RODESSA	CARBONATE	TEXAS
602	CRETACEOUS	WASHITA-FRED.	CLASTIC	MISSISSIPPI
603	CRETACEOUS	CODELL	CLASTIC	COLORADO
603	CRETACEOUS	GALLUP	CLASTIC	NEW MEXICO
603	CRETACEOUS	NIOBRARA	CARBONATE	WYOMING, COLO
603	CRETACEOUS	WALL CREEK	CLASTIC	WYOMING
604	CRETACEOUS	CHACRA		
604	CRETACEOUS	COZZETTE	CLASTIC	COLORADO
604	CRETACEOUS	FRUITLAND	CLASTIC	NEW MEXICO, COLO

GEO CODE	GEOLOGIC SYSTEM	FORMATION	LITHOLOGY	STATE
604	CRETACEOUS	PIERRE	CLASTIC	COLORADO
605	CRETACEOUS	ANACACHO	CARBONATE	TEXAS
605	CRETACEOUS	ANNONA	CARBONATE	LOUISIANA
605	CRETACEOUS	AUSTIN CHALK	CARBONATE	TEXAS
605	CRETACEOUS	BUCKRANGE	CLASTIC	ARKANSAS
605	CRETACEOUS	DALE		TEXAS
605	CRETACEOUS	ECDD (?)		TEXAS
605	CRETACEOUS	EUTAW	CLASTIC	ALABAMA, MISS
605	CRETACEOUS	NACATOCH	CLASTIC	LOUISIANA
605	CRETACEOUS	OLMOS	CLASTIC	TEXAS
605	CRETACEOUS	SAN MIGUEL	CLASTIC	TEXAS
605	CRETACEOUS	SARATOGA	CARBONATE	LOUISIANA, TEXAS
605	CRETACEOUS	SELMA	CARBONATE	MISSISSIPPI
605	CRETACEOUS	TUSCALOOSA	CLASTIC	ALABAMA, MISS
605	CRETACEOUS	WOODBINE	CLASTIC	TEXAS
652	TERTIARY	ALMY	CLASTIC	WYOMING
652	TERTIARY	CRUSE	CLASTIC	LOUISIANA
652	TERTIARY	GREEN RIVER	CLASTIC	UTAH
652	TERTIARY	WASATCH	CLASTIC	UTAH
652	TERTIARY	WILCOX	CLASTIC	MISSISSIPPI, LOU
653	TERTIARY	FRIO	CLASTIC	TEXAS
654	TERTIARY	AURIGNAC	CLASTIC	CALIFORNIA
654	TERTIARY	DAUPHIN	CLASTIC	ALABAMA
654	TERTIARY	McLURE	CLASTIC	CALIFORNIA
654	TERTIARY	MONARCH	CLASTIC	LOUISIANA, TEXAS
654	TERTIARY	MONTERREY	SHALE	CALIFORNIA
654	TERTIARY	POTTER	CLASTIC	CALIFORNIA
654	TERTIARY	STEVENS/TEMBLOR	CLASTIC	CALIFORNIA
655	TERTIARY	PICO	CLASTIC	CALIFORNIA
655	TERTIARY	PLIOCENE	CLASTIC	ALASKA, CALIF
701	QUATERNARY	PLEISTOCENE	CLASTIC	LOUISIANA

Appendix B
Horizontal Applications Survey

Appendix B — Horizontal Applications Survey

B.1 INITIAL WELL FILE

Horizontal drilling technology has been applied widely within the domestic oil industry. Wells have been drilled in over 20 states and offshore. A relative breakdown by state is shown in Figure B-1. As is well documented, the majority of the activity has been in Texas in the Austin Chalk Trend.

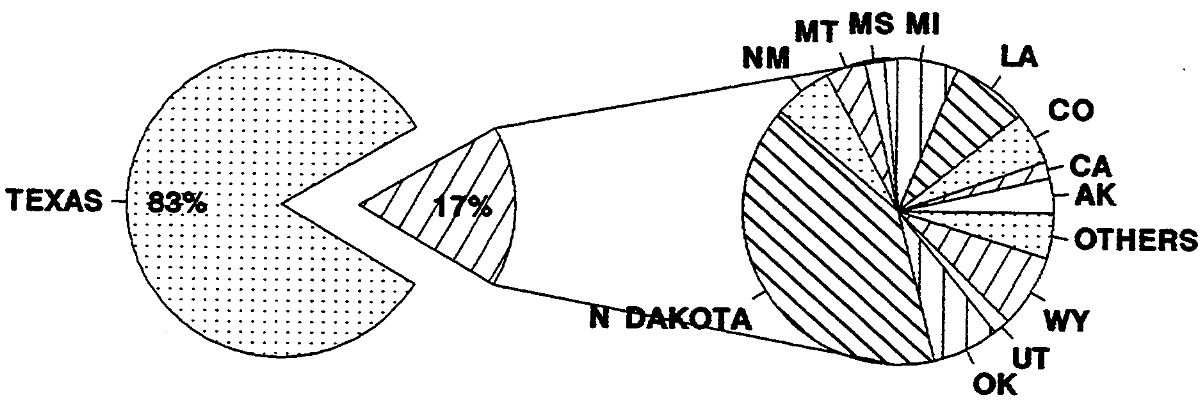

Figure B-1. U.S.A. Horizontal Well Distribution

In order to achieve the stated objectives of this project, it was necessary to obtain current and relevant information describing horizontal well applications. Several commercial providers of petroleum data were investigated with the final selection being the well files of Petroleum Information (PI). The records on individual wells were compiled from the regulatory bodies of each state as wells were permitted, drilled, completed and, if required, abandoned. Most records are not entirely complete and some discrepancies were encountered; however, the data were more than adequate for the intended purpose of identifying horizontal wells in the United States.

A large list of data fields was available with a charge for each unit of data. Due to the limited budget for data acquisition only the most relevant fields were selected. Production records were specifically omitted due to their high cost and their questionable accuracy due to the reporting methods of the various states. Instead, it was decided that production success would be determined by individual canvassing of the operators and from the literature. The list of parameters obtained by MEI is shown in Table B-1. Primary parameters were obtained (well name, operator, formation, etc.) along with several secondary parameters (FTP and BHP) that were included in the "blocks" of data downloaded from PI.

TABLE B-1. PI Well File Data Parameters

API Number
Well Name
Well Number
Operator
Spud Date
Completion Date
Status
Total Depth (TD)
Formation @ TD
Producing Formation
Initial Production Formation
Initial Production Oil (BOPD)
Initial Production Gas (MCFD)
Initial Production H_2O (BW)
Flowing Tubing Pressure
Bottom-Hole Pressure

B.2 DATA SELECTION

PI's U.S. well file contained 3885 horizontal wells as of the end of 1992. The well count was updated in May of 1994 and showed that the U.S.A. total had increased 20% to 4662 wells. The majority of these wells (over 80%) were either Austin Chalk or Buda wells of the Gulf Coast Cretaceous system. It was decided by the DOE and Maurer Engineering to eliminate these wells from the well file since a significant body of published information was already available on these horizontal projects. However, the important aspects of the Austin and Buda were included in this report in the assessment of applications and also for their contribution in terms of reserves increases.

Removal of the Austin/Buda data reduced the data file to 723 wells. Upon closer scrutiny of the data it was determined that 17 of these 723 wells were either Austin/Buda wells that were incorrectly reported or the wells were only "high angle" and did not approach horizontal status of approximately 85° or higher. These 17 wells were removed to reduce the total horizontal well count to 706.

The large amount of data contained in these 706 records made data manipulation slow and cumbersome with LOTUS 123. A decision was made to separate out horizontal wells in the Bakken Shale and the Niobrara formations. As with the Austin/Buda formations, these were fairly well documented compared to the remaining formations and could be removed without diluting the effectiveness of the data in meeting the project objectives. The well file listed 199 wells with the Bakken as the Producing Formation and 44 wells with the Niobrara as the Producing Formation. These were removed. The final data file breakdown is presented in Figure B-2 for both the original project file and a recent update.

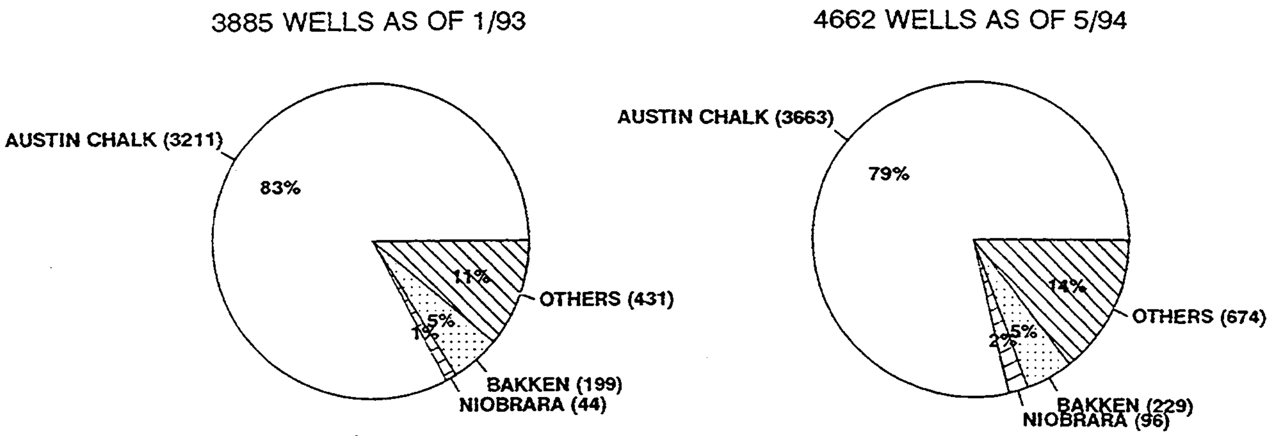

Figure B-2. U.S.A. Horizontal Well Counts (Petroleum Information)

B.3 LITERATURE SEARCH

Horizontal drilling technology has existed since the 1930s where it was utilized in Russia, and since the 1940s in the United States. It received only limited publicity until 1985, when horizontal activity began in the Austin Chalk of South Texas. Since then, numerous technical papers, books and articles have been written along with a variety of seminars covering all aspects from reservoir engineering to completion practices. Maurer Engineering has been at the forefront of horizontal drilling technology with its leadership in the Drilling Engineering Association's (DEA) Horizontal Technology projects. Numerous horizontal drilling technology reports have been compiled as part of these projects and, as a prerequisite for preparation of these documents, Maurer Engineering has compiled an extensive library of technical papers, magazine articles, news releases, books and other publications necessary for the task. These same documents were utilized for this DOE project.

The MEI library was the major source of published literature since it provided the vast majority of information needed, yet it did not burden the project budget with costly literature searches that would have otherwise been required. In addition, it reduced the time necessary for literature review since all documents in the horizontal technology notebooks, which date back to 1941, were in some way related to horizontal drilling and/or production.

B.4 QUESTIONNAIRE

B.4.1 Survey Objective

The published literature was an excellent source for details on high-profile horizontal projects. However, many applications of horizontal technology are not addressed. The published literature also presents the noteworthy highlights of a project but also tends to minimize (or fails to mention) the negative aspects. To supplement the published literature, a questionnaire was prepared for distribution to the operators of horizontal wells.

The questionnaire, shown in Figure B-3, was designed to review horizontal technology at the level of the formation. A well-by-well analysis would obviously be unmanageable while an analysis of the formations would allow the ability to extrapolate information between formations and thus, identify future targets of horizontal technology. A survey by formation also reduced the amount of paperwork required by the survey participant, enhancing the likelihood of response.

B.4.2 Description of Questions

1. *Number of Horizontal Wells Drilled*: This question confirms and updates the PI well file for wells per formation.

2. *Type of Application*: Ten major applications for horizontal wells were listed as choices and more than one application could be selected for any formation. The responses to this question address the issue of why a horizontal well is used in a certain formation as opposed to a vertical well.

3. *Primary Objective*: This question addresses the selection of a horizontal well versus a vertical well in economic terms. It also, when compared to questions 6 and 7, gives an indication of how successfully operators are predicting and planning their horizontal wells.

4. *Horizontal to Vertical Production Ratio*: This question provides a quantitative evaluation of the production increase of horizontal over vertical. This ratio provides a much more accurate indication of the success of horizontal technology since it considers production over the long term instead of initial production, which is often misleading. It also considers field-wide results as opposed to a single well's history.

5. *Horizontal to Vertical Cost Ratio*: This addresses the same issues as question 4 with respect to cost.

6. *Were Horizontal Wells a Technical Success?* From a technical standpoint (i.e., drilling and completing), was the horizontal project successfully implemented as planned?

7. *Were Horizontal Wells an Economic Success?* This question may be the most important part of the entire survey since it addresses the bottom-line issue of whether or not the wells met the economic criterion imposed on them. In most cases, technical success alone would not merit continuation of a program; economic success certainly would.

8. *Were Any of These Wells Stimulated?* To completely evaluate the economics of horizontal technology, the additional costs of any stimulation efforts must be considered.

9. *Increase in Reserves Due to Horizontal*: Horizontal wells have increased economically recoverable reserves in many types of fields. Operators' responses, used in combination with published results, will be applied to oil-in-place estimates to project the increase in reserves due to horizontal technology.

10. *Please Describe Your Future Horizontal Activity*: This question may reveal the operator's overall assessment of the success of horizontal technology in his field. Often, an unsuccessful start does not necessarily halt a project. This question may indicate formations that will require additional technology to be successfully exploited. In some cases, the return on investment may justify such diligence.

11. *What Developments Would Increase the Use of Horizontal Wells in Your Fields?* This write-in question allows the operator to note areas requiring additional research. This open forum for expressing concerns will hopefully reveal issues that could benefit all those involved in horizontal technology.

12. *What Horizontal Well Production Problems Have You Encountered?* A list of 12 frequently occurring problems specifically relating to production are presented to operators. This question should provide trends in certain problem areas that may initiate research that would benefit the maximum number of operators.

13. *Would You Like a Summary of the Survey Results?* An incentive (to complete the survey) to those already participating in horizontal drilling projects would be to see the success in ''other'' areas.

B.5 CONFIDENTIALITY

The data gathered by Maurer Engineering for this DOE project is maintained solely by MEI/DOE personnel and will not be released for public review without permission of all parties involved. All company names and/or well names are omitted from the Final Report to maintain operator confidentiality. No references are made in the Final Report text to operators or well names unless derived from published material that is properly referenced.

HORIZONTAL WELL PRODUCTION QUESTIONNAIRE

PLEASE COMPLETE FOR EACH FIELD (MAKE COPIES IF NECESSARY).

NAME: ____________________ COMPANY: ____________________

ADDRESS: ____________________ FAX NO.: ____________________

FIELD: ____________________ FORMATION: ____________________

STATE: ____________________ COUNTY: ____________________

1. NUMBER OF HORIZONTAL WELLS DRILLED: ☐ 1-4 ☐ 5-10 ☐ 11-25 ☐ 26-50 ☐ >50 ________

2. TYPE OF APPLICATION: (Check all applicable)
   - ☐ INTERSECT FRACTURES
   - ☐ THIN BEDS (Increase production rate)
   - ☐ LAYERED BEDS (Establish communication)
   - ☐ MINIMIZE CONING (Water, gas, etc.)
   - ☐ SURFACE RESTRICTIONS (Lakes, bldgs., etc.)
   - ☐ IMPROVE WATER DRIVE/WATER INJECTION
   - ☐ LOW PERMEABILITY (Poor fracture candidate)
   - ☐ IMPROVE GRAVITY DRAINAGE
   - ☐ ENHANCED OIL RECOVERY (Steam, polymer, etc.)
   - ☐ FAVORABLE ECONOMICS OVER VERTICAL

   COMMENTS ____________________

3. PRIMARY OBJECTIVE: ☐ REDUCE COST (vs. vertical) ☐ INCREASE PRODUCTION RATE ☐ INCREASE RESERVES

4. HORIZONTAL TO VERTICAL PRODUCTION RATIO: ☐1:1 ☐1.5:1 ☐2:1 ☐3:1 ☐4:1 ☐5:1 OTHER ____

5. HORIZONTAL TO VERTICAL COST RATIO: ☐1:1 ☐1.5:1 ☐2:1 ☐3:1 ☐4:1 ☐5:1 OTHER ____

6. WERE HORIZONTAL WELLS A TECHNICAL SUCCESS? ☐ YES ☐ NO COMMENTS: ____________________

7. WERE HORIZONTAL WELLS AN ECONOMIC SUCCESS? ☐ YES ☐ NO COMMENTS: ____________________

8. INCREASE IN RESERVES DUE TO HORIZONTAL: ☐ 0% ☐ 1-5% ☐ 6-10% ☐ 11-15% ☐ 16-25% OTHER ____

9. PLEASE DESCRIBE YOUR FUTURE HORIZONTAL ACTIVITY: ☐ NONE ☐ DECREASE ☐ SAME ☐ INCREASE

10. WHAT DEVELOPMENT(S) WOULD INCREASE THE USE OF HORIZONTAL WELLS IN YOUR FIELDS? ________

11. WHAT HORIZONTAL WELL PRODUCTION PROBLEMS HAVE YOU ENCOUNTERED?:
    - ☐ ARTIFICIAL LIFT
    - ☐ FORMATION DAMAGE
    - ☐ RESERVOIR MODELING
    - ☐ STIMULATION
    - ☐ CEMENT PROBLEMS
    - ☐ FORMATION HETEROGENEITY
    - ☐ SAND CONTROL
    - ☐ WATER OR GAS CONING
    - ☐ COMPARTMENTALIZATION
    - ☐ LOGGING (Prd., MWD, Other)
    - ☐ SCALE OR CORROSION
    - ☐ WORKOVER PROBLEMS

    COMMENTS: ____________________

12. WOULD YOU LIKE A SUMMARY OF THE SURVEY RESULTS? ☐ YES ☐ NO

    COMMENTS (Include additional sheets if necessary) ____________________

PLEASE RETURN FORM BY FAX TO MAURER ENGINEERING INC. AT FAX: (713) 683-6418 PH.: (713) 683-8227

Figure B-3. Project Questionnaire

Appendix C

U.S.A. Survey Evaluation

Appendix C — U.S.A. Survey Evaluation

C.1 INTRODUCTION

The results of a survey of U.S.A. operators that have drilled horizontal wells are presented in detail within this Appendix. Overall results and trends from analyses of the data are presented in summary form in Chapter 3 of this volume.

The questionnaire described in Appendix B (see Figure B-3) was sent to 120 companies in the United States that performed horizontal drilling projects. A total of 170 companies was listed in the PI database, but 50 companies were no longer in business or their addresses and phone numbers could not be determined.

A total well count of 431 wells was used as the basis for all **NANB (Non-Austin, Niobrara, or Bakken)** formation percentages, unless stated otherwise. ***(Note: One objective of this study is to analyze the impact of horizontal technology is U.S.A. fields other than the three most widely publicized fields. See Section B.2).*** This NANB total represents the wells reported to PI through the regulatory agency of each state that were classified as horizontal wells drilled and completed or drilled and abandoned.

Operators were requested to complete and return separate questionnaires describing overall experience in each formation, not on a well-by-well basis. When more than one operator submitted a questionnaire covering any particular formation, these questionnaire responses were averaged into a new composite survey. In this way, each formation drilled horizontally was only counted once in the analyses.

C.2 INDUSTRY RESPONSE

The horizontal production questionnaire was sent out to the domestic industry during the summer of 1993. Additional questionnaires were submitted by attendees of horizontal technology forums hosted by Maurer Engineering under sponsorship of the DEA-44 project. One forum was held in Calgary on June 8-11, 1993. Over 50 questionnaires were returned at the forum; most cover Canadian fields. Another forum was held in Houston on September 29-October 1, 1993. The majority of the forum attendees active in horizontal drilling had already been contacted about the project. However, over 20 new questionnaires were received from the attendees, about half covering formations in the U.S.A.

A total of 51 operators in the U.S.A. eventually responded with a questionnaire(s), representing 43% of those surveyed and 30% of operators that had drilled horizontal wells in the U.S.A. as of January 1993 (Figure C-1).

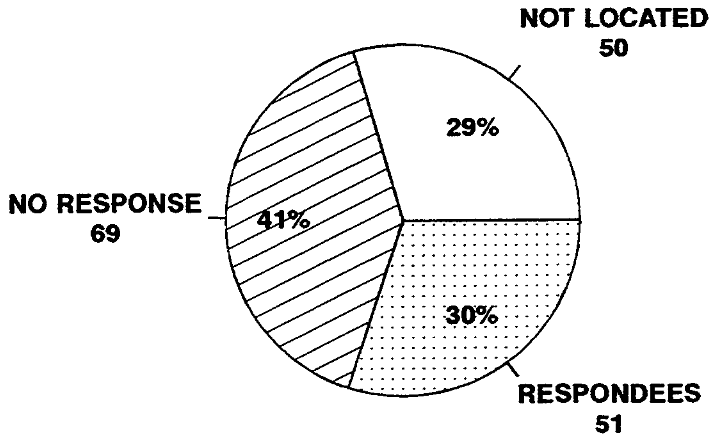

Figure C-1. Survey Response by Operator

Questionnaires describing activity in 58 U.S.A. formations were returned. A comparison by state of survey responses versus horizontally exploited formations is shown in Figure 3-3. Ninety-five individual questionnaires were received for the U.S.A., with 23 formations described by 2 or more operators. As mentioned previously, multiple responses for any given formation were combined into a single composite survey.

The 51 companies responding to the survey accounted for over 280 of the 431 wells in the NANB well file. This represents 66% of the NANB horizontal wells drilled in the U.S.A. (Figure C-2). It should be noted that the true response rate in the context of this 431-well survey is probably less than 66% because some of the 280 reported wells were undoubtedly not listed in the original database due to incompleteness in PI's data or to the fact that they were drilled/completed after the database was originally compiled in early 1993. A more conservative estimate of the number of NANB wells represented in these analyses is 50-60% of the total.

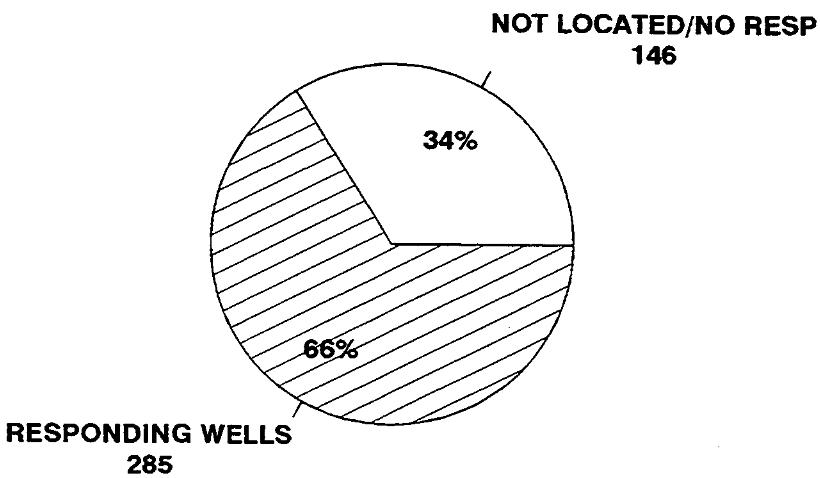

Figure C-2. Survey Response by NANB Well Count

The PI well file lists about 114 U.S.A. formations that have been exploited by one or more horizontal wellbores. A list of these formations and their geologic age is presented in Appendix A. Fifty-five NANB formations have had one or more questionnaires returned by the operators (Figure C-3). This represents 50% of the formations drilled horizontally.

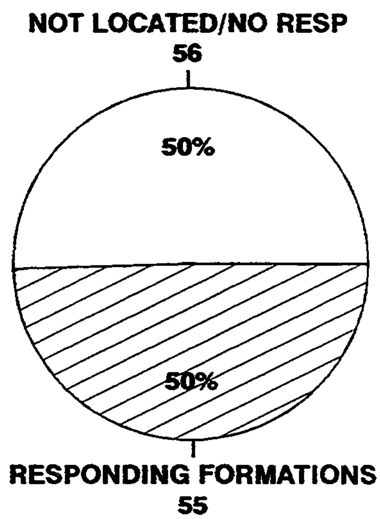

Figure C-3. Survey Response by Formation

C.3 FORMATION LITHOLOGY

In addition to analyses of the total population of horizontally exploited reservoirs, formations were grouped by lithology to highlight similar application success in similar reservoir settings. Two basic lithological classifications were used:

1. Clastics (sandstones, most shales, etc.)
2. Carbonates (dolomites, chalks, limestone, etc.)

Table C-1 presents a listing of the geological classes comprising the DOE TORIS (Tertiary Oil Recovery Information System) formation classification system. Twenty-two geologic classes are described along with original oil-in-place (OOIP) and remaining oil-in-place (ROIP). These data are known by DOE to be incomplete. The DOE estimate of total U.S.A. OOIP is 513 BBO. The formations accounted for in the TORIS database represent about 70% of this 513 BBOOIP.

TABLE C-1. Geological Classes and U.S.A. Reserves

Geological Class	OOIP (BBO)	ROIP (BBO)	ROIP (%)
A. Shallow Shelf/Open	46.25	33.38	72.2%
B. Delta/Fluvial-Dominated	45.09	30.80	68.3%
C. Slope-Basin	51.87	37.94	73.1%
D. Strandplain/Barrier Cores	21.04	13.13	62.4%
E. Shelf	22.44	16.07	71.6%
F. Shallow Shelf/Restricted	24.58	17.81	72.5%
G. Fluvial/Braided Streams	27.59	19.75	71.6%
H. Delta/Tide-Dominated	5.37	3.80	70.8%
I. Delta/Wave-Dominated	24.14	12.97	53.7%
J. Reefs	14.29	9.34	65.4%
K. Delta	7.57	4.28	56.5%
L. Eolian	6.82	3.96	58.1%
M. Peritidal	10.56	7.43	70.4%
N. Strandplain	7.33	5.19	70.8%
O. Strandplain/Back Barriers	2.30	1.53	66.5%
P. Slope-Basin/Carbonate	2.40	1.68	70.0%
Q. Alluvial Fan	11.39	8.55	75.1%
R. Fluvial/Meandering Streams	3.09	2.34	75.7%
S. Lacustrine	0.75	0.60	80.0%
T. Shelf Margin	4.51	2.05	45.5%
U. Fluvial	0.38	0.27	71.1%
V. Basin	8.27	6.47	78.2%
Unknown	11.15	7.10	63.7%
TOTAL	359.18	246.44	68.6%

Clastic geological classes are summarized in Table C-2 and **carbonate** geological classes in Table C-3. Table C-4 summarizes total oil volumes by lithology.

TABLE C-2. Clastic Geological Classes and U.S.A. Reserves

CLASTICS GEOLOGICAL CLASS	OOIP (BBO)	ROIP (BBO)	ROIP (%)
B. Delta/Fluvial-Dominated	45.09	30.80	68.3%
C. Slope-Basin	51.87	37.94	73.1%
D. Strandplain/Barrier Cores	21.04	13.13	62.4%
E. Shelf	22.44	16.07	71.6%
G. Fluvial/Braided Streams	27.59	19.75	71.6%
H. Delta/Tide-Dominated	5.37	3.80	70.8%
I. Delta/Wave-Dominated	24.14	12.97	53.7%
K. Delta	7.57	4.28	56.5%
L. Eolian	6.82	3.96	58.1%
N. Strandplain	7.33	5.19	70.8%
O. Strandplain/Back Barriers	2.30	1.53	66.5%
Q. Alluvial Fan	11.39	8.55	75.1%
R. Fluvial/Meandering Streams	3.09	2.34	75.7%
S. Lacustrine	0.75	0.60	80.0%
U. Fluvial	0.38	0.27	71.1%
V. Basin	8.27	6.47	78.2%
TOTAL	245.44	167.65	68.3%

TABLE C-3. Carbonate Geological Classes

Carbonates Geological Class	OOIP (BBO)	ROIP (BBO)	ROIP (%)
A. Shallow Shelf/Open	46.25	33.38	72.2%
F. Shallow Shelf/Restricted	24.58	17.81	72.5%
J. Reefs	14.29	9.34	65.4%
M. Peritidal	10.56	7.43	70.4%
P. Slope-Basin/Carbonate	2.40	1.68	70.0%
T. Shelf Margin	4.51	2.05	45.5%
TOTAL	102.59	71.69	69.9%

TABLE C-4. Summary of U.S.A. Oil-In-Place by Lithology

Lithology	OOIP (BBO)	ROIP (BBO)	ROIP (%)	
			By Lithology	Of Total
Clastics	245.4	167.7	68.3	70.1
Carbonates	102.6	71.7	69.9	29.9
Total[1]	348.0	239.4	—	100

1 11.8 BBO in "unknown" reservoirs omitted (See Table C-1).

These data show that about 70% of U.S.A. ROIP (remaining oil-in-place) is in clastic formations and about 30% in carbonates. Similarly, the number of each type of reservoir in the TORIS database yields a ratio of 76% clastics and 24% carbonates (Figure C-4).

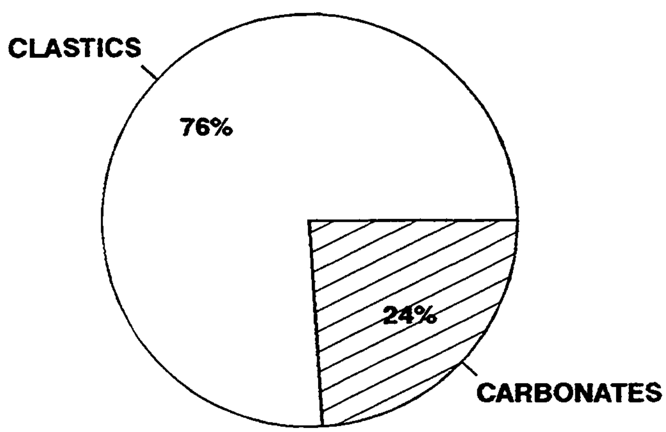

Figure C-4. Lithology of TORIS Reservoirs

Thus, the reservoir lithological and reserve profiles show that clastics dominate the domestic reservoir and reserves picture. Although a large majority (over 80%) of the horizontal wells drilled in the U.S.A. have been in shallow-shelf carbonates (including the Austin Chalk and the Niobrara), more NANB horizontal wells have been drilled in clastic formations (56%) than in carbonates (44%) (Figure C-5).

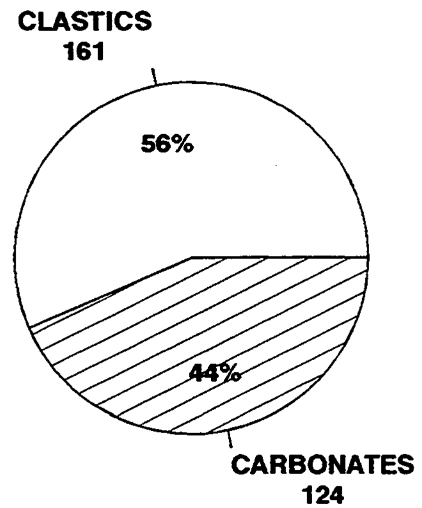

Figure C-5. Well Count of Responding NANB Formations

Operators in 58 of the 114 horizontally exploited formations responded to the project questionnaire. The lithology of these formations is summarized in Figure C-6. The three formations where the majority of horizontal activity has been focused (the Austin Chalk, Niobrara, and Bakken) are included in these data. Note that in this case each formation is given the same weighting, so the results are not affected by the level of drilling in the most active formations.

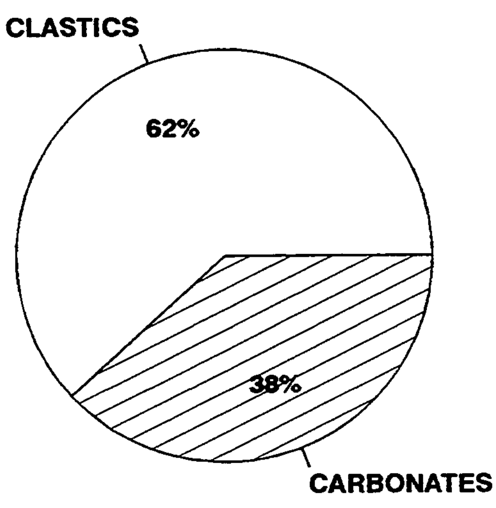

Figure C-6. Lithology of Responding Formations

C.4 HORIZONTAL WELL APPLICATIONS

Operators were asked to choose from a list of 10 applications describing the specific purpose(s) for their horizontal wells in each field. Application choices included:

1. Intersect fractures
2. Thin beds (increase production rate)
3. Layered beds (establish communication)
4. Minimize coning (water, gas, etc.)
5. Surface restrictions (lakes, buildings, etc.)
6. Improve water drive/water injection
7. Low permeability (poor fracture candidate)
8. Improve gravity drainage
9. Enhanced oil recovery (steam, polymer, etc.)
10. Favorable economics as compared to vertical

Multiple responses were provided by most operators. A total of 136 responses was given for the 58 formations in the database. Responses are summarized in Table C-5 for all fields and by lithology.

TABLE C-5. U.S.A. Horizontal Well Applications

APPLICATIONS	% OF RESPONDING FORMATIONS		
	ALL FIELDS	CLASTICS	CARBONATES
INTERSECTING FRACTURES	53.4	37.1	78.3
FAVORABLE ECONOMICS	34.5	45.7	17.4
CONING	32.8	40.0	21.7
THIN BEDS	29.3	31.4	26.1
LOW PERMEABILITY	27.6	25.7	30.4
GRAVITY DRAINAGE	20.7	22.7	17.4
LAYERED BEDS	12.1	8.6	17.4
WATER DRIVE	8.6	8.6	8.7
EOR	8.6	14.3	0
SURFACE RESTRICTIONS	6.9	5.7	8.7
NUMBER OF FORMATIONS	58	35	23
NUMBER OF RESPONSES	136	84	52
RESPONSES PER FORMATION	2.35	2.40	2.26

The most popular application overall, listed by over half the operators, was intersecting fractures (Figure C-7). The next most popular application was favorable economics (35%), followed closely by minimizing coning (33%). Applications listed the least were surface restrictions (7%), water drive (9%), and EOR (9%).

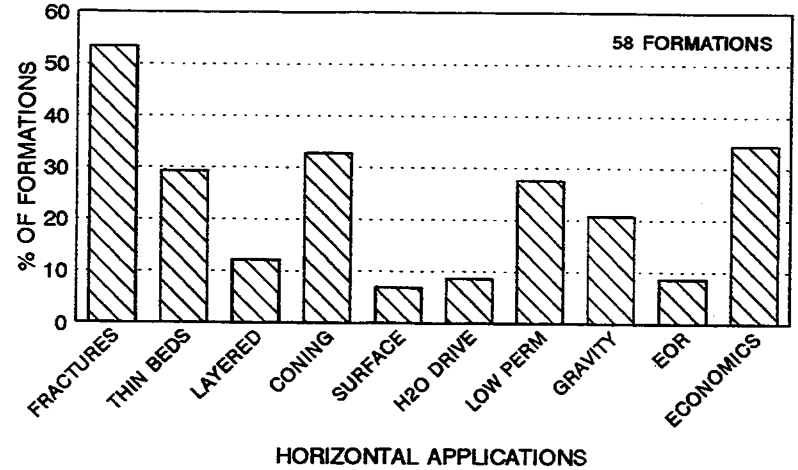

Figure C-7. Horizontal Applications: All U.S.A. Formations

Of the 35 clastic formations in the survey, 46% were exploited horizontally due in part to favorable economics (Figure C-8). The most popular specific application was minimizing coning (40%). Intersecting fractures was also an important clastic application (37%). The least used applications in clastics were surface restrictions (6%), layered beds (9%) and water drive (9%). EOR applications were listed for 14% of U.S.A. clastic formations. Four out of these five projects are in heavy-oil formations.

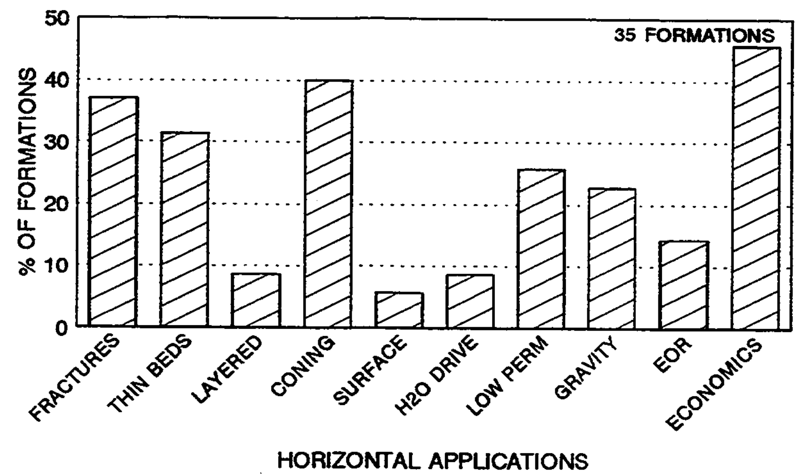

Figure C-8. Horizontal Applications: U.S.A. Clastics

In contrast to clastic formations, no carbonate formations have been drilled horizontally for EOR. Not unexpectedly, a significant majority (78%) of carbonate formations were drilled to intersect fractures (Figure C-9). This application dominates all others. An associated application, low permeability, was listed for 30% of the carbonates. Least used applications were EOR (0%), surface restrictions (9%) and water drive (9%).

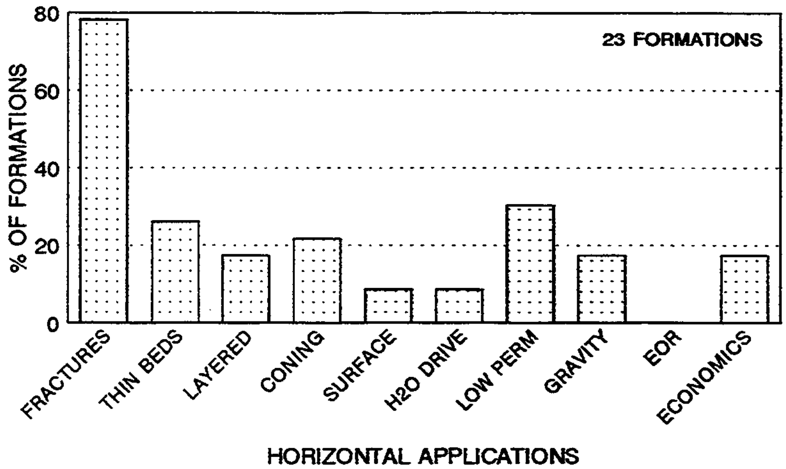

Figure C-9. Horizontal Applications: U.S.A. Carbonates

Clastic and carbonate applications are compared in Figure C-10. Applications that are apparently a function of formation lithology include:

1. Intersecting fractures (more carbonates)
2. Layered beds (more carbonates)
3. Minimizing coning (more clastics)
4. EOR (more clastics)
5. Favorable economics (more clastics)

Applications that have been applied to a similar degree in clastics and carbonates include:

1. Thin beds
2. Surface restrictions
3. Improve water drive/water injection
4. Low permeability
5. Improve gravity drainage

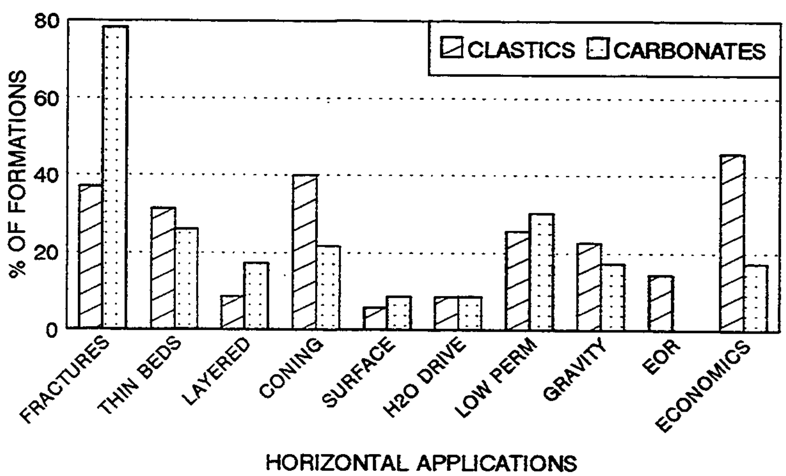

Figure C-10. Horizontal Applications: U.S.A. Clastics and Carbonates

Another analysis that may highlight areas of special concentration is to consider single horizontal applications, that is, formations for which an operator chose only 1 of the 10 listed applications. There were 18 single applications in clastic formations and 12 in carbonates. Single applications are summarized in Figure C-11. Note that no single applications were given for surface restrictions, water drive, or improving gravity drainage. For both fracturing and water coning, single applications constitute about half of the total responses. Favorable economics, by comparison, is most often combined with other applications.

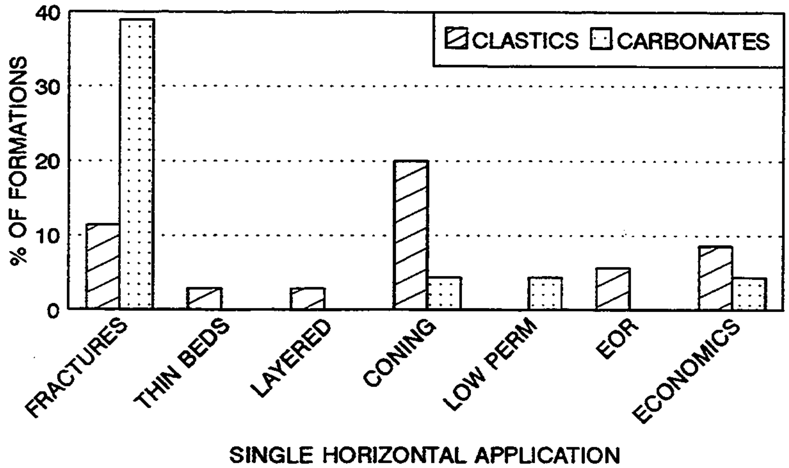

Figure C-11. Single U.S.A. Applications

In summary, slightly over one-half of responding operators (30 out of 58) listed only one application for their specific field. The percentage of single-application responses was nearly the same for clastics and carbonates. The remaining operators listed multiple applications, up to five per field.

The most popular response for carbonates was as expected: intersecting fractures (78% response rate). For clastics, minimizing coning was expected to be the most popular choice, based on its treatment in the literature. Coning was a popular application in clastics; over 40% of operators listed it. However, the most popular clastic response was favorable economics over vertical technology. It might be argued that every field for which horizontal technology has been economically applied could list favorable economics as an application. Achieving a favorable economic return was likely considered feasible in every case, else the project would not have been attempted.

Operators who actually indicated favorable economics showed that attribute to be of primary importance with a weight similar to any specific benefit due to the orientation of the wellbore. This trend underscores the fact that horizontal wells are being considered beyond the realm of special-purpose technology to be used only within a particular set of well-defined conditions. The experiences of more and more operators show that horizontal wells simply produce more oil more economically than vertical wells in a variety of fields.

C.5 PRIMARY OBJECTIVE

Operators were given the choice of three primary objectives for using horizontal technology in each particular field. These were:

1. Reduce cost as compared to vertical
2. Increase production rate
3. Increase reserves

A majority of operators answered this question with more than one objective, despite the use of "primary" in the question. Many operators' inability to specify one overriding objective is indicative of the fact that horizontal drilling has moved from the realm of experimental or special-purpose technology into routine usage for reservoir production in many applications. Additionally, these objectives are certainly interconnected (e.g., increasing production leads to reduced costs), making a single choice difficult for many operators.

All responses to the question on primary objective are summarized in Figure C-12. Of 57 survey responses, 41 (72%) indicated increased production rate and an equal number indicated increased reserves as primary objective(s). Only 17% marked reduce cost.

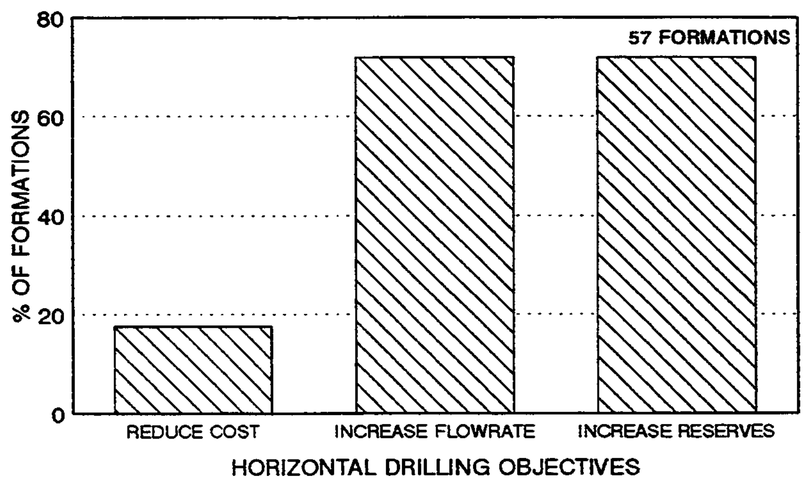

Figure C-12. Primary Project Objectives: All U.S.A. Formations

Combinations of responses given by the operators are shown in detail in Figure C-13. The most common response combination was the dual objectives of increase production rate and increase reserves ('Q + R' in the figure). Over 40% of operators responded in this fashion. Two combinations occurred in only 3 of the 57 responses: 1) reduce cost, and 2) reduce cost and increase production rate. One combination, reduce costs and increase reserves ('$ + R'), did not appear in any response.

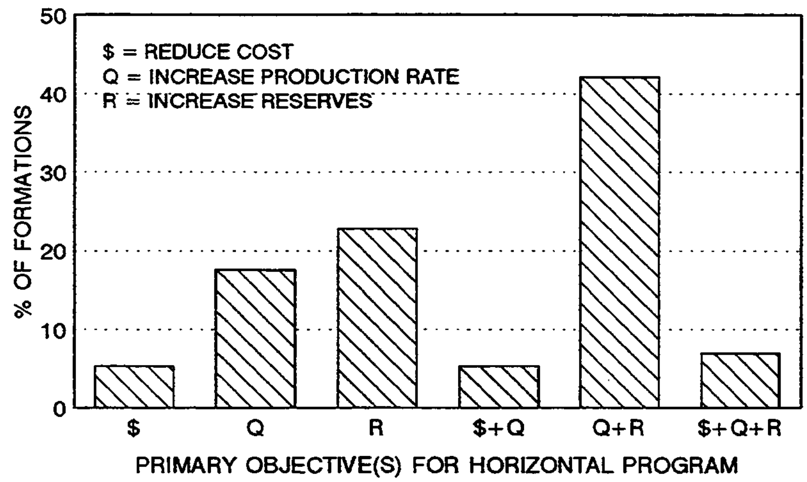

Figure C-13. Primary Project Objectives: All U.S.A. Formations

The pattern of responses for clastic formations (Figure C-14) was similar to that for all reservoirs except that the response 'Q + R' was given by an even larger percentage of operators.

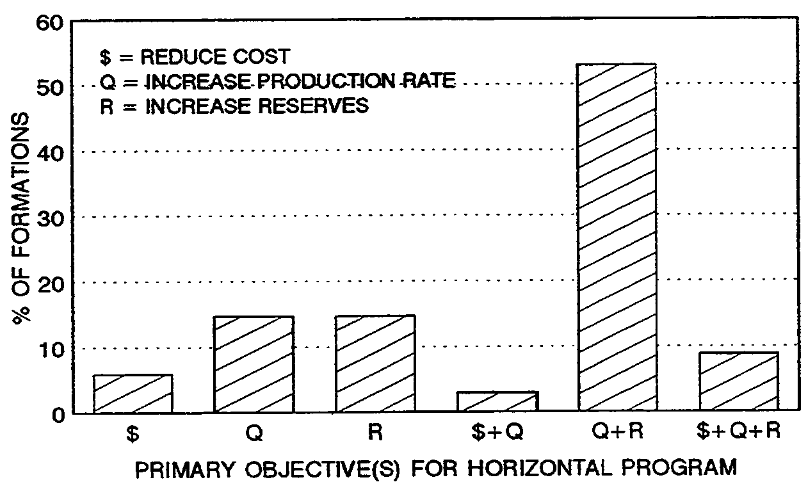

Figure C-14. Primary Project Objectives: U.S.A. Clastics

The responses for carbonate formations (Figure C-15) show that increasing reserves is the most common objective for using horizontal technology to develop these fields. Increasing reserves is directly related to intersecting fracture applications.

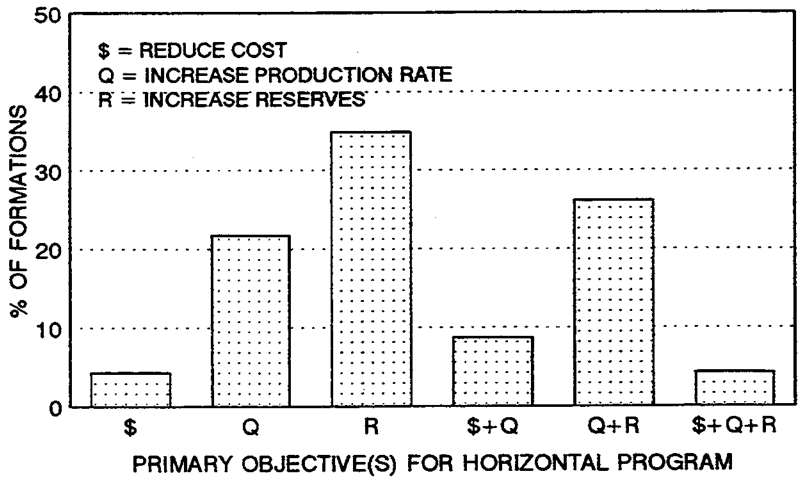

Figure C-15. Primary Project Objectives: U.S.A. Carbonates

In summary, objectives for using horizontal technology to exploit a particular field varied with lithology. Over 50% of operators in clastic formations had the dual objectives of increasing production rate and increasing reserves. The most popular response in carbonates was to increase reserves.

Over 60% of operators in carbonates responded with a single objective from the three choices provided. Only 32% of clastics operators responded with one primary objective. These data suggest that the goals and design of a horizontal project are more multifaceted in clastic formations than in carbonates.

C.6 PRODUCTION AND COST RATIOS

Production and cost ratios are often used as a simple relative measure of the benefits of a horizontal well compared to a vertical well in the same application. Forty-eight formations (83% of the total 58 formations) listed an average production ratio for the horizontal wells in their field. The average response from all but one formation was a production ratio of 3.2. One operator reported a production ratio of 1300. Since it would significantly skew the average if considered, this datum was omitted from the analysis. If included, the overall average production ratio would be increased to about 30.

As shown in Figure C-16, the most common range of production ratios was 1-2 times vertical rates (33%), followed by 3-5 (27%). A significant number of formations (21%) report overall production ratios greater than 5.

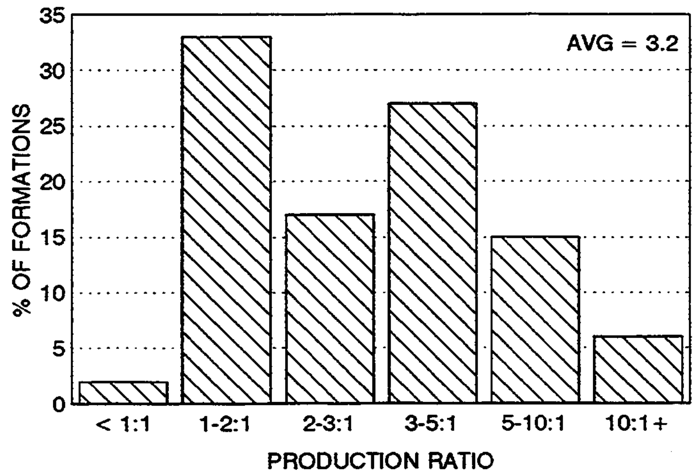

Figure C-16. Production Ratio: All U.S.A. Formations

Cost ratios for all formations ranged from a low of 0.33 up to 5. Responses were received for 53 formations, representing 91% of the survey total. The average ratio is 2.0 times the cost of a vertical well. About two-thirds of the responses fell in the range 1.5-3 (Figure C-17).

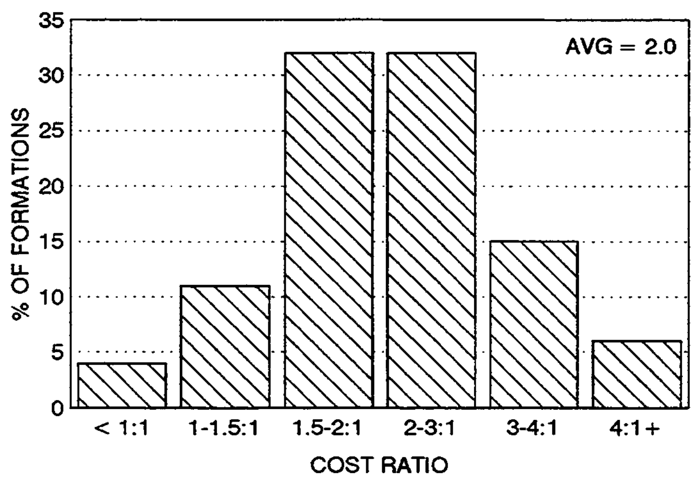

Figure C-17. Cost Ratio: All U.S.A. Formations

A comparison of production ratios and cost ratios shows that the average horizontal application produces at a rate 3.2 times greater than a vertical and costs 2.0 times as much. Thus, the economics of horizontal development have been favorable for the average application.

The average production ratio for clastic formations is 2.8, somewhat less than that for all formations. The distribution of production ratios for clastic formations is shown in Figure C-18.

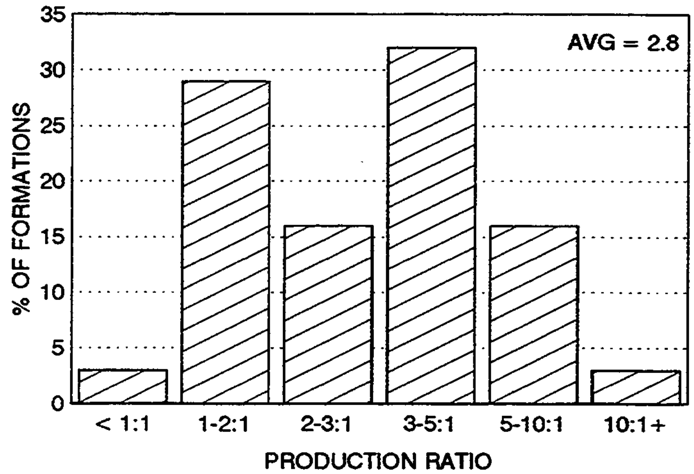

Figure C-18. Production Ratio: U.S.A. Clastics

Cost ratios for clastic formations are higher than the overall formation population. The average clastic cost ratio is 2.2 (Figure C-19). All formations in the survey reporting cost ratios of 4 and greater are clastic, suggesting that novel or experimental applications are among these programs.

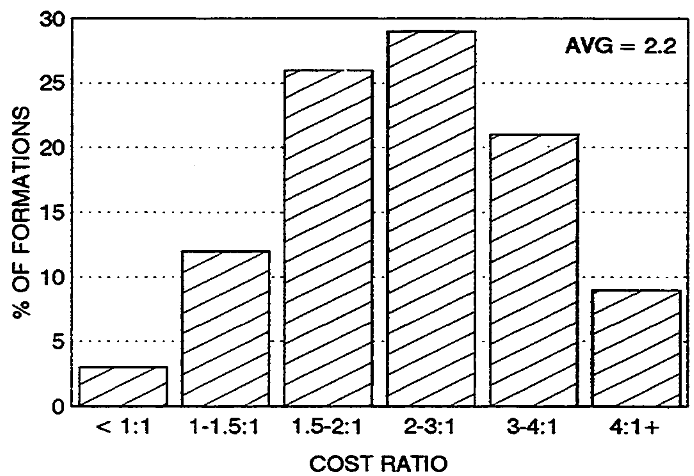

Figure C-19. Cost Ratio: U.S.A. Clastics

Carbonate formation production ratios are presented separately in Figure C-20. More carbonate formations report production ratios in the range of 1-2 as compared to clastic formations (41% versus 29%). However, carbonate formations have more production ratios of 10 and greater. The average ratio for carbonates is 3.9, which is almost 40% above the average clastic ratio.

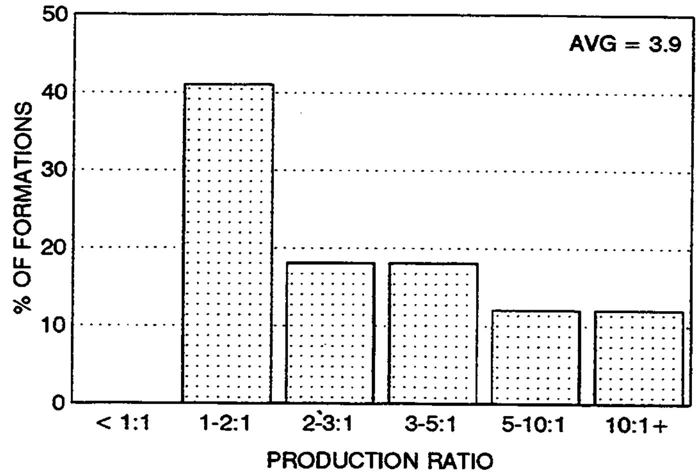

Figure C-20. Production Ratio: U.S.A. Carbonates

Cost ratios for carbonate formations are less than those for clastics, reflecting the effects of a maturing learning curve on intersecting fracture applications, which are typically drilled with water and completed open-hole. The average cost ratio for carbonates is about 1.8 (Figure C-21).

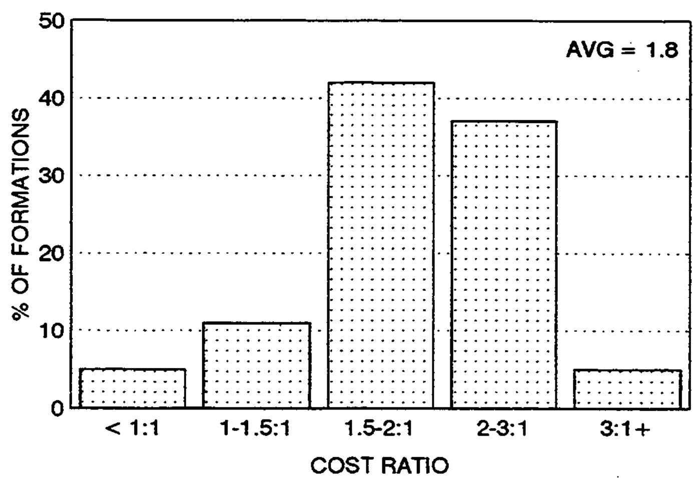

Figure C-21. Cost Ratio: U.S.A. Carbonates

Production and cost ratios are summarized by lithology in Table C-6.

TABLE C-6. Average and Median Production and Cost Ratios for U.S.A. Formations

Lithology	Production Ratio		Cost Ratio	
	Average	Median	Average	Median
Clastics	2.8	3	2.2	2
Carbonates	3.9	2	1.8	1.75
All Formations	3.2	2.5	2.0	2.0

C.7 TECHNICAL AND ECONOMIC SUCCESS

Operators were asked whether their horizontal applications in each field were technical and/or economic successes. Not unexpectedly, most programs were indicated as technically successful. Of 57 responses, 54 were technically successful, representing a 95% success rate. This high rate of success suggests that horizontal technology has advanced to the point that the majority of technical barriers have been overcome. The industry learning curve, begun in the current cycle in about 1986, has become relatively mature, and most tools and techniques are widely available.

Economic success has not been as widespread as technical success. Of 56 responding formations, 28 were economic successes (50%) and 24 were economically unsuccessful (43%). An additional 4 formations (7%) had mixed economic results, that is, multiple operators in a particular field reported both successful and unsuccessful projects. If fields with mixed results are excluded from the analysis, the average economic success rate is 54%.

Economic success rates assessed by the operators are expected to be lower than those resulting from a controlled experimental comparison of vertical and horizontal well technologies. Economic success can be negatively affected by several factors not related to horizontal technology per se, including poor choice of well location and improper application. A played-out field may not yield enough flow to rate economic success, even though horizontal implementation was successful.

Technical and economic success of the formations in the survey are summarized by lithology in Figure C-22.

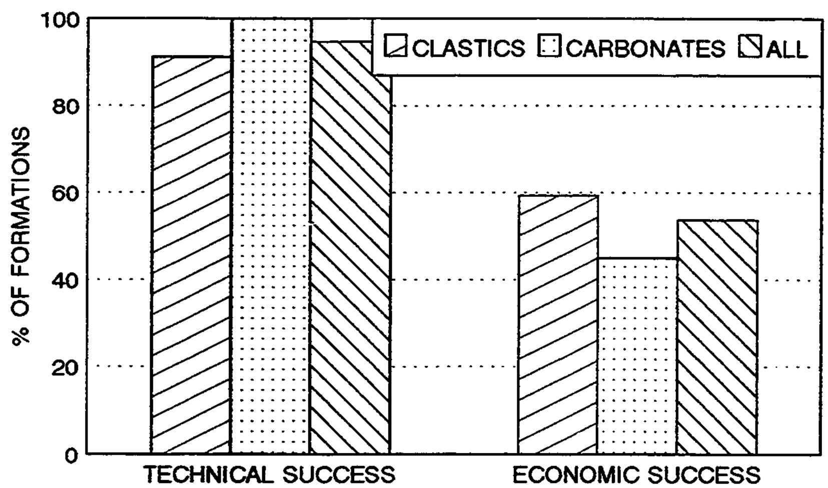

Figure C-22. Technical and Economic Success: U.S.A. Formations

When lithology is considered, the data suggest that carbonate applications have been slightly more technically successful than clastic: 100% versus 91%. This difference may be due to typically more difficult drilling conditions and completions required in clastics; carbonate formations are often competent and completed open hole. Conversely, clastic formations were reported to have more economic success than carbonates: 59% versus 45%, respectively.

The two general indicators of horizontal application economic success show divergent trends. As mentioned in the preceding paragraph, clastics were reported as more economically successful than carbonates. Production and cost ratios (see Table C-6), however, suggest that carbonates produce more oil and are relatively cheaper to drill than clastics.

In a broad analysis, lower cost ratios for carbonates may reflect the fact that it is now relatively easy to drill an Austin Chalk-type well and cross a fracture. Many clastic applications, however, are more technically challenging to drill and complete, resulting in higher incremental costs as compared to vertical wells. Higher overall economic success rates for clastics indicate that the production performance of many of these wells makes up for increased initial costs.

In another area related to economic success, operators were also asked whether their wells were stimulated by matrix methods or fracturing. This question was designed to determine if stimulation has a significant effect on the economic success of the wells. Almost half (49%) reported that their wells were stimulated by some method. Of these formations, the stimulation distribution consists of fracturing (37%), matrix (48%), and both fracturing and matrix (15%).

Of those projects that included stimulation of at least some of the wells, 50% were economically successful and 50% were not. These results show no significant correlation between stimulation and economic success. If lithology is considered, 58% of the stimulated formations are carbonates, of which 60% were economically successful. Stimulation was accompanied by a lower success rate in clastic formations. Only 45% of stimulated clastics were economically successful.

C.8 FUTURE ACTIVITY

Operators were asked to describe their future activity in each field as one of four options: **none, decrease, same, increase**. As with economic success, negative responses in this category may reflect other factors not directly related to horizontal technological success or failure. For example, a drilled-up field may be slated for decreased activity in the future, even though the horizontal program was very successful.

The distribution of future activity responses for all formations is shown in Figure C-23. If "same" and "increase" are considered positive responses regarding the use of the technology, then over half (56%) of the operators are positive and plan to pursue horizontal programs.

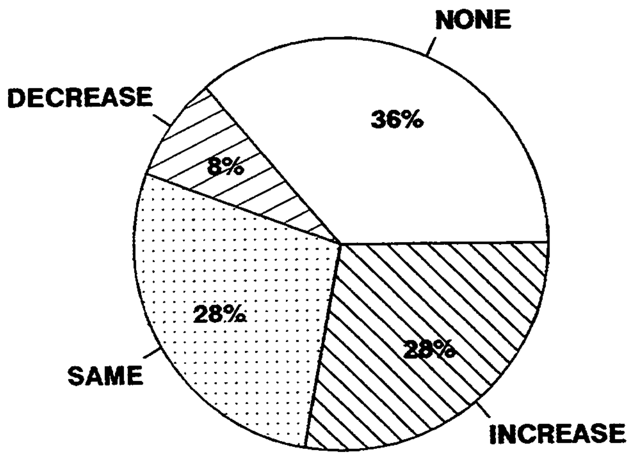

Figure C-23. Future Horizontal Activity: All U.S.A. Formations

Operators drilling in clastic reservoirs are even more committed to the ongoing use of horizontal technology than the overall survey population. About 60% of clastic operators plan the same or increased activity in the future (Figure C-24).

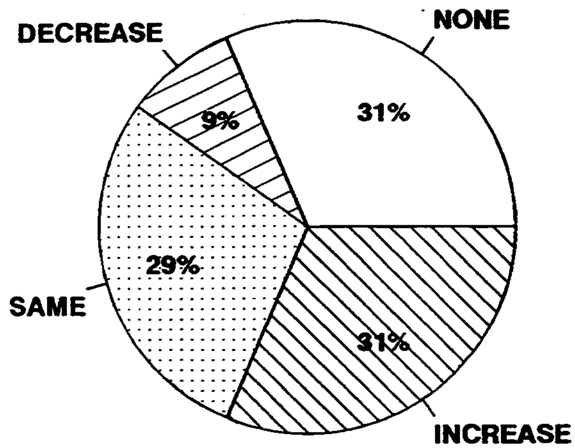

Figure C-24. Future Horizontal Activity: U.S.A. Clastics

Future plans for carbonate operations are summarized in Figure C-25. For these formations, 50% of the operators plan the same or increased activity. This is lower than clastics and may suggest that some carbonate applications are now or nearly drilled up.

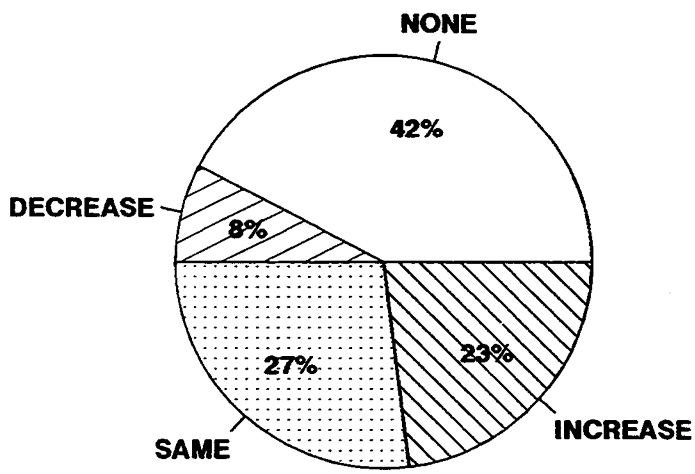

Figure C-25. Future Horizontal Activity: U.S.A. Carbonates

In summary, 50-60% of operators surveyed stated their plan was to increase their horizontal applications or continue at the same level. A figure representing the industry's overall judgment of the technology would be expected to fall in the range 60-70% or higher, if unrelated bias could be removed from the negative responses.

C.9 HORIZONTAL WELL PRODUCTION PROBLEMS

As the level of execution, reliability, and acceptability of horizontal drilling technology has matured, the problems associated with completions and production have increased in relative importance. Significant research and development is being directed toward effective completion and remediation designs that allow horizontal production profiles to be modified after the initial completion, as well as other production-related problems.

Operators were given a list of horizontal production problems to rate as important or unimportant with respect to their operations. Choices included the following:

1. Artificial lift
2. Formation damage
3. Reservoir modeling
4. Stimulation
5. Cement problems
6. Formation heterogeneity
7. Sand control
8. Water or gas coning
9. Compartmentalization
10. Logging (production, MWD, other)
11. Scale or corrosion
12. Workover problems

Forty-seven surveys were marked with at least one production problem. A total of 125 responses was received. The average response rate was 2.7 problems per field.

The distribution of production problems (Figure C-26) shows that no single problem was mentioned above all others. Five problems were indicated for about 25% of the formations. These include artificial lift, formation damage, reservoir modeling, heterogeneity, and logging. Problems mentioned least include scale or corrosion (2%), sand control (7%), and cementing (10%).

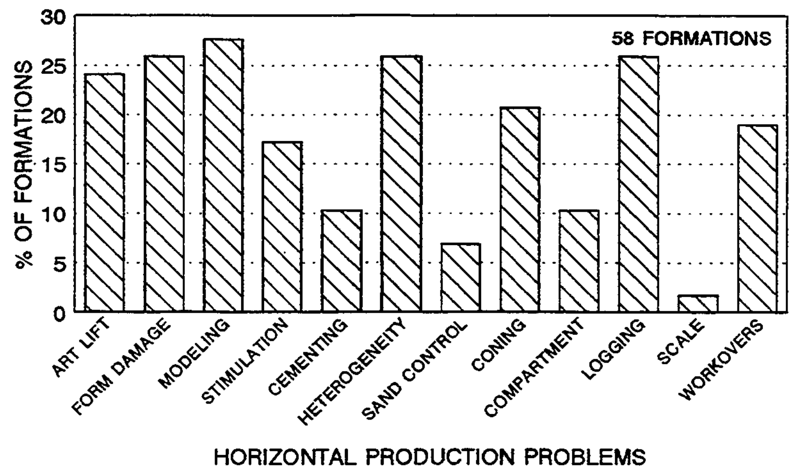

Figure C-26. Horizontal Production Problems: All U.S.A. Formations

Problems in clastic formations (Figure C-27) are similar to those of the overall population except for less mention of artificial lift, stimulation, and compartmentalization.

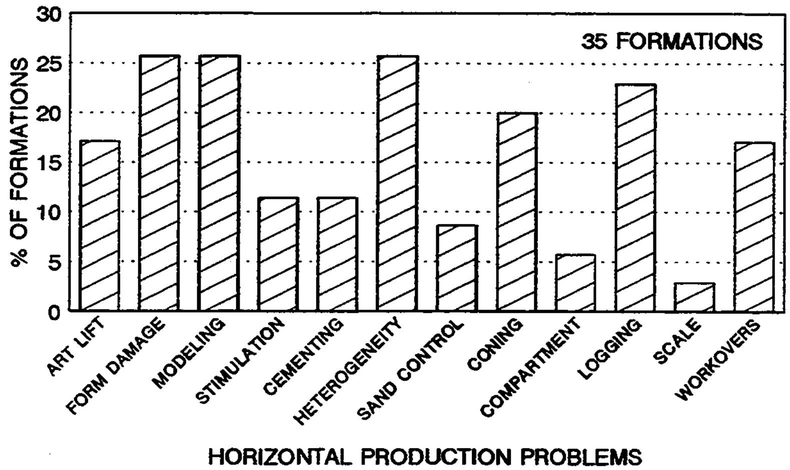

Figure C-27. Horizontal Production Problems: U.S.A. Clastics

Carbonate formations (Figure C-28) show an increase in problems with artificial lift, stimulation, compartmentalization, and logging, as compared to clastic formations.

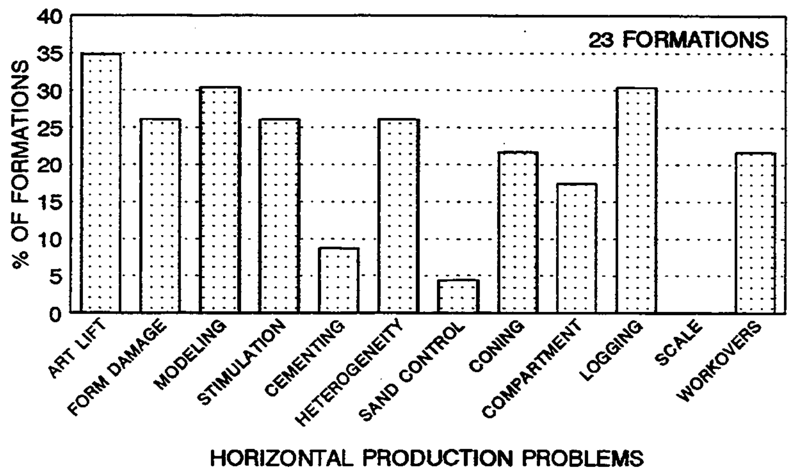

Figure C-28. Horizontal Production Problems: U.S.A. Carbonates

Significant additional discussion of production problems and technological needs for horizontal operations is presented in Volume II — Chapter 6.

Appendix D

Canadian Survey Evaluation

Appendix D — Canadian Survey Evaluation

D.1 INTRODUCTION

The first recorded horizontal well in Canada was spudded in March of 1978. Esso Resources drilled the well in the Cold Lake Clearwater 'A' oil-sands deposit. Horizontal drilling activity began in earnest in 1987. The number of horizontal wells has grown exponentially, from less than ten wells at the beginning of 1988, to more than 1700 total wells at the end of 1993. Figure D-1 provides a chronological summary of horizontal well drilling activity since 1987, along with projections for 1994 and 1995.

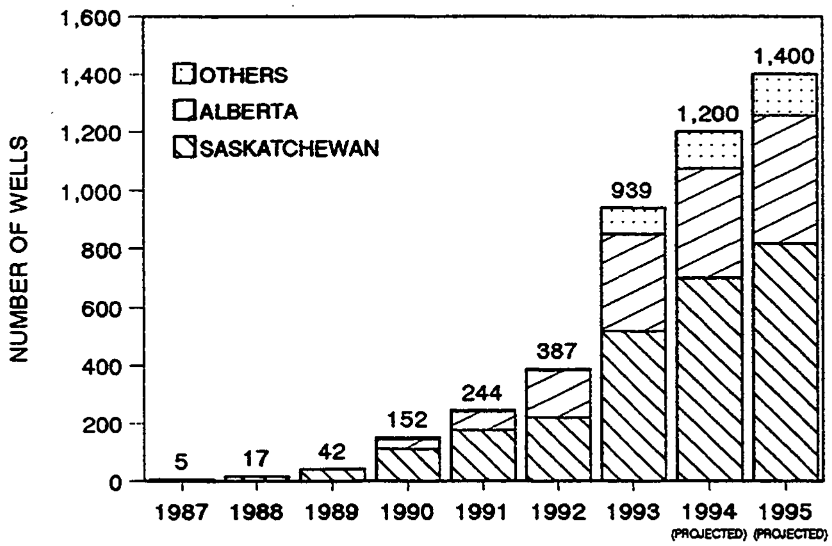

Figure D-1. Canadian Horizontal Wells

Production from horizontal wells has also increased proportionately (Figure D-2). Most of these horizontal wells have been drilled in Alberta and Saskatchewan. Close to 100 horizontal wells were drilled in British Columbia and Manitoba combined in 1993. There is no record of "conventional" horizontal wells drilled in Eastern Canada to date.

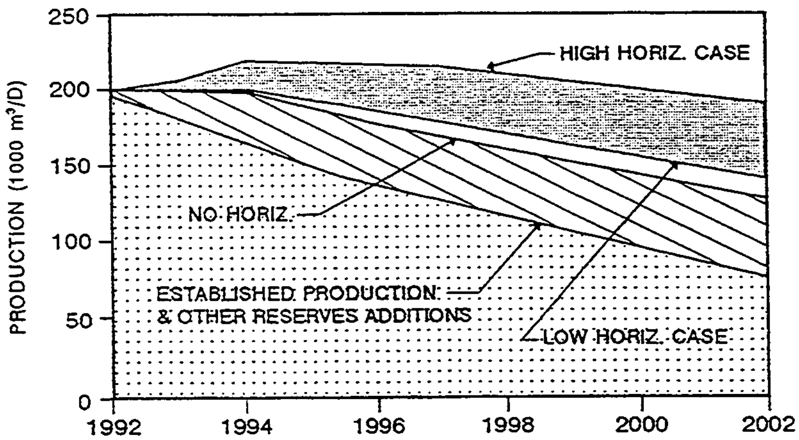

Figure D-2. Production From Canadian Horizontal Wells (NEB, 1993)

Horizontal well activity can be divided into three separate categories:

1. Light Oil (carbonates and clastics)
2. Heavy Oil
3. Gas and Special Applications

More than 95% of horizontal wells drilled in Western Canada fall in the first two categories. Projects classified in the light-oil clastic (±25° API gravity) group are mainly located in Northern Alberta and N.E. British Columbia. The most important exception is the Upper Cretaceous Cardium deposits of West-Central Alberta. This formation is estimated to contain the largest OOIP light-oil deposits in Western Canada. Gas and special applications account for less than 5% of the wells presently drilled; however, this percentage is expected to increase in the future. Horizontal activity in gas is strongly influenced by demand as well as commodity price. Both factors have taken a positive turn recently, and as a result there was some activity in this category in 1993. "Gas and Special Applications" also includes gas-storage projects.

D.2 DATA SOURCES

The major sources of information for this survey of formations drilled before the end of 1993 in Western Canada include a detailed review of technical papers and discussions with the operators of various projects. These included presentations at CANMET/CIM/SPE conferences; Horizontal Well Special Interest Group seminars and monthly meetings; the SRC Study on *Effects of Drilling/Completion on the Performance of Horizontal Wells*; responses to the project questionnaire sent to operators of horizontal wells; and various publications by the Alberta, British Columbia, and Saskatchewan regulatory bodies. The special (Horizontal Well) issues of *Discovery Digest* also provided valuable information, in addition to the data bases of Maurer Engineering Inc. (MEI) and Outrim Szabo & Assoc. (OSA), and the production and horizontal well directional data bases from Virtual Computing Services.

D.3 CANADIAN APPLICATIONS SURVEY

The questionnaire discussed in Appendix B was sent to about 150 Canadian companies who had drilled five or more horizontal wells. The total number of responses received was 110. The responses contained data on about 88 pools, representing about 40% of pools with horizontal wells at the time of the survey. The number of wells represented in the survey is 450. A recent NEB (National Energy Board) survey suggests that, with existing technology, there are presently 2,000 pools in Western Canada suitable for exploitation with horizontal wells. The present projection is that 12,000 horizontal wells could be drilled in these pools.

D.4 HORIZONTAL WELL APPLICATIONS

Operators were asked to choose from a list of 10 applications describing the specific purposes for their horizontal wells in each field. Application choices included:

1. Intersect fractures
2. Thin beds (increase production rate)
3. Layered beds (establish communication)
4. Minimize coning (water, gas, etc.)
5. Surface restrictions (lakes, buildings, etc.)
6. Improve water drive/water injection
7. Low permeability (poor fracture candidate)
8. Improve gravity drainage
9. Enhanced oil recovery (steam, polymer, etc.)
10. Favorable economics as compared to vertical

Multiple responses were provided by most operators. Favorable economics and minimize coning were the two most popular applications (48% each), followed by intersecting fractures (27%) and low permeability (22%). The least used applications were surface restrictions and improved water drive (5% each) (Figure D-3).

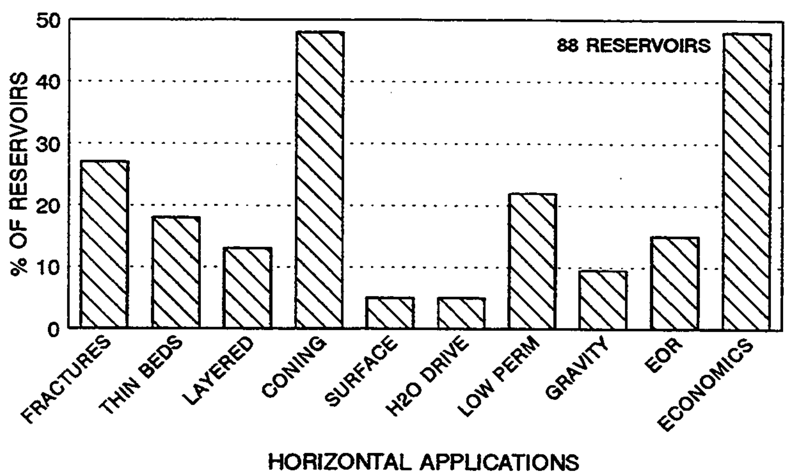

Figure D-3. Horizontal Applications: All Canadian Pools

Of the 12 light-oil clastic pools described by surveys, 58% were exploited due to favorable economics (Figure D-4). Low permeability and minimizing coning (33%) were the next most popular applications. Intersecting fractures, thin beds, and layered beds, all at 17%, were the remaining noteworthy reasons for drilling horizontal wells in these clastic formations.

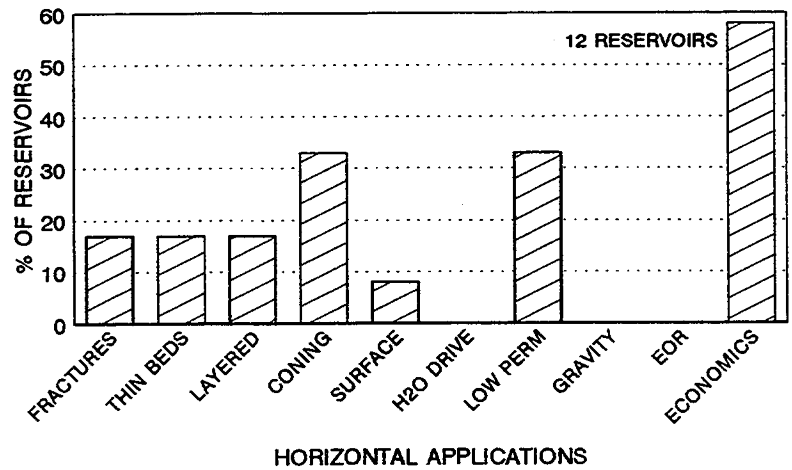

Figure D-4. Horizontal Applications: Canadian Light-Oil Clastics

In the 41 light-oil carbonate pools that listed one or more applications, 54% of horizontal drilling was to combat coning, followed closely by intersecting fractures (44%) and favorable economics (39%) (Figure D-5). The least used applications were EOR (2%) and surface restrictions (0%).

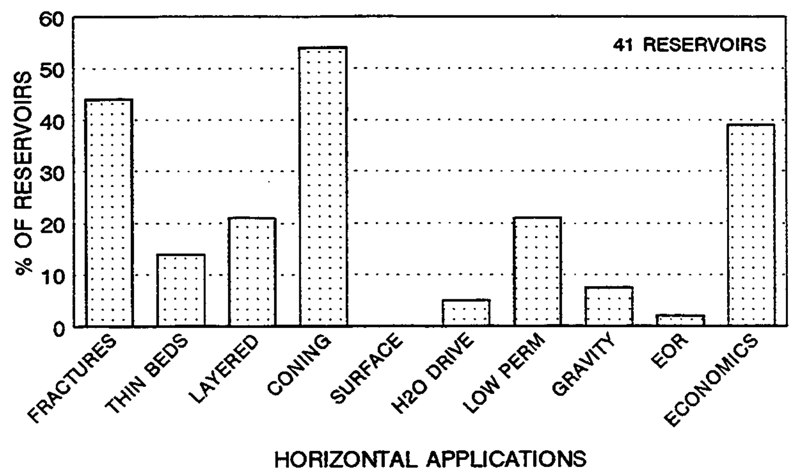

Figure D-5. Horizontal Applications: Canadian Carbonates

Twenty-seven responses were identified as heavy-oil applications. The great majority of these are in clastic formations (25 of the 27 pools). In these heavy-oil pools, coning and favorable economics tied as the most popular application (52%) (Figure D-6). However, unlike light-oil clastic and carbonate pools, EOR (41%) was a significant reason for horizontal drilling. Thin beds (22%) and gravity drainage (19%) were also relatively popular applications. All other applications were listed for less than 10% of the pools.

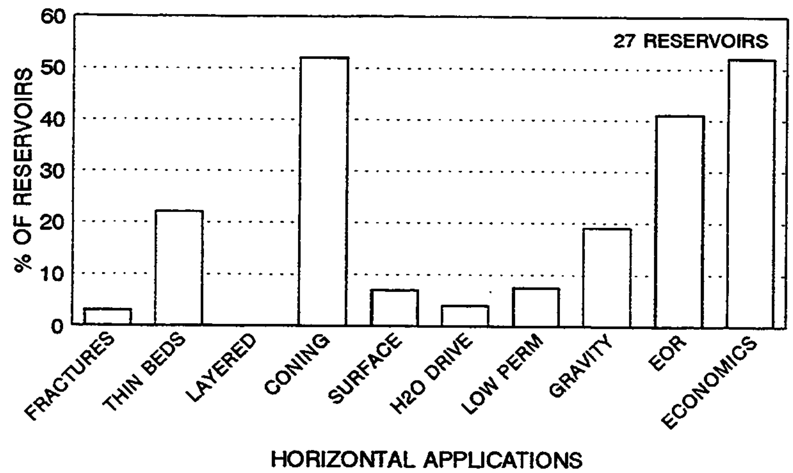

Figure D-6. Horizontal Applications: Canadian Heavy-Oil Pools

Light-oil clastic, carbonate and heavy-oil applications are compared in Figure D-7. The most prominent similarities are the choices of favorable economics and minimizing coning. The most significant differences are the choice of intersecting fractures for carbonates, low permeability for clastics, and EOR for heavy oil.

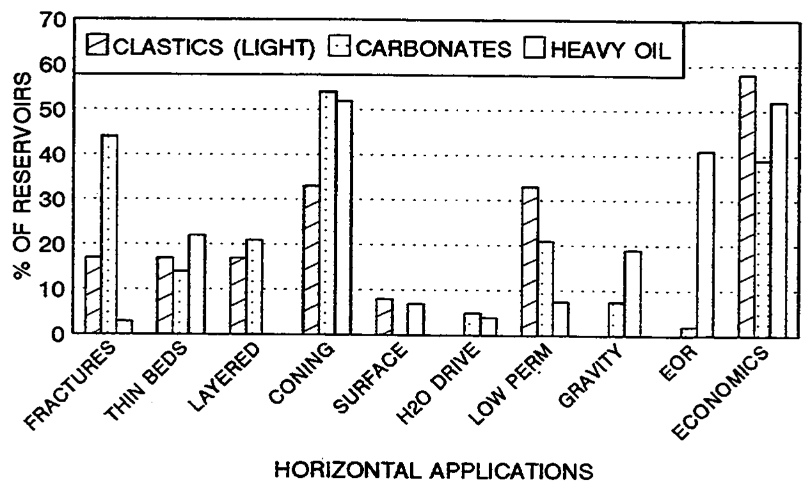

Figure D-7. Horizontal Applications: Canadian Resource Type

D.5 PRIMARY OBJECTIVE

A choice of three primary objectives was given for using horizontal technology in each particular field. These were:

1. Reduce cost as compared to a vertical well
2. Increase production rate
3. Increase reserves

Of the 88 pools surveyed, 86% indicated increase production rate, 72% indicated increase reserves and only 9% indicated reduce cost as a primary objective (Figure D-8).

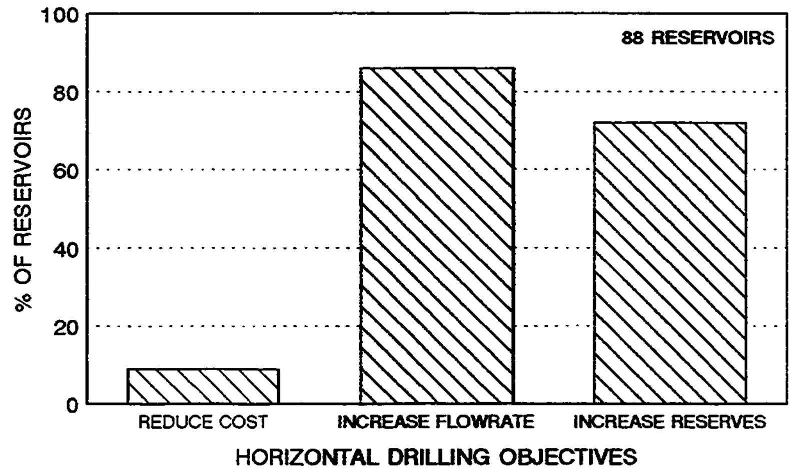

Figure D-8. Primary Project Objectives: All Canadian Pools

As can be deduced from Figure D-8, most operators indicated more than one primary objective. Combinations of responses given for all 88 pools are shown in Figure D-9. The most common combination was that of increase production rate and increase reserves (56%) (Q+R in the figure). The single choice of reduce cost ($) and the combination of reduce cost with increase production rate ($ + Q) and reduce cost with increase reserves ($ + R) accounted for only 1% of the responses.

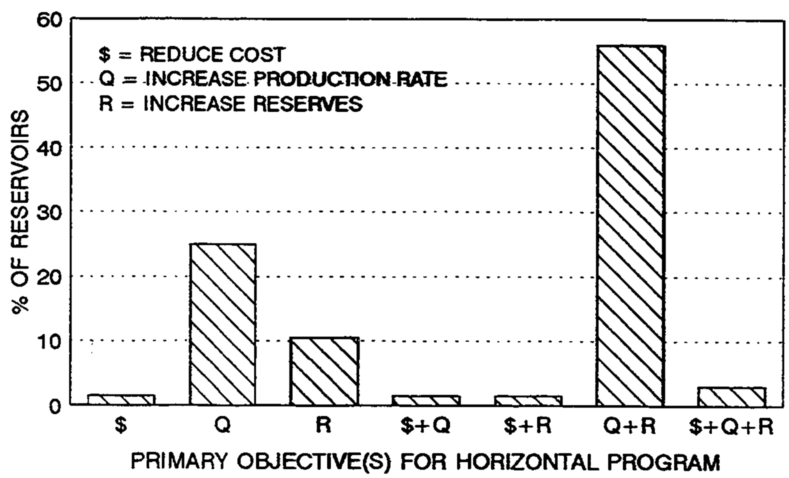

Figure D-9. Primary Project Objectives: All Canadian Pools

The trend in primary objectives for light-oil clastic formations is similar to the trend for all pools. Fifty percent of the respondents indicated the most popular combination of increase production rate and increase reserves (Figure D-10).

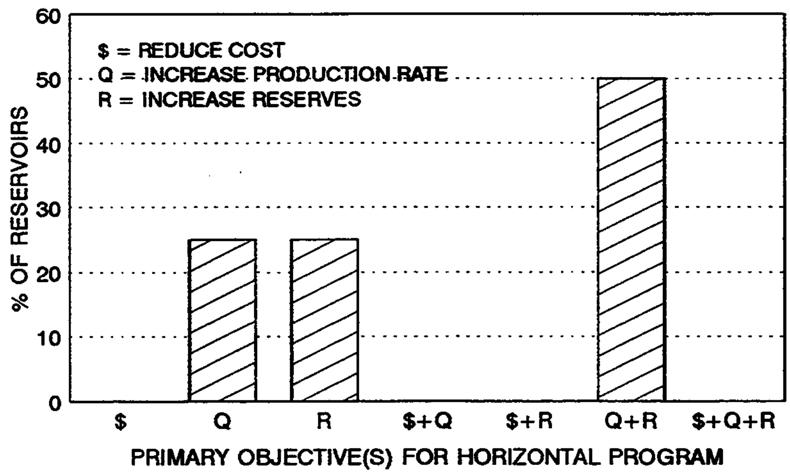

Figure D-10. Primary Project Objectives: Canadian Light-Oil Clastics

Carbonate formations also showed the same general trend with 61% choosing the combination of increase production rate and increase reserves (Figure D-11). No operator chose reduce costs as part of any combination.

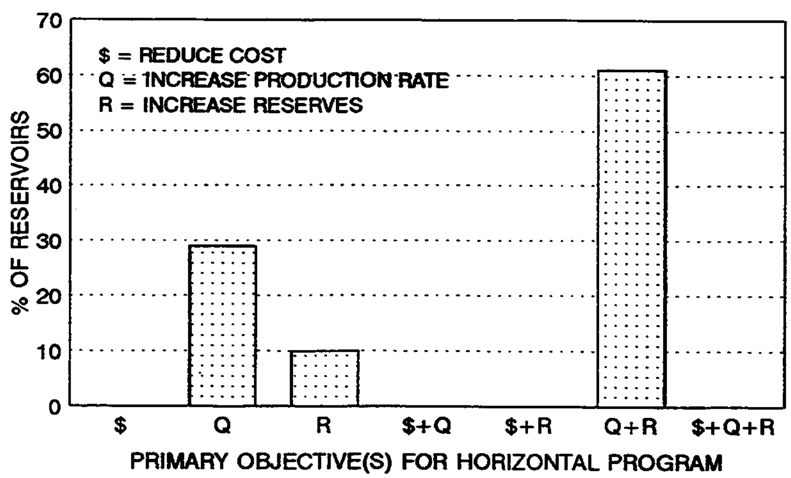

Figure D-11. Primary Project Objectives: Canadian Carbonates

In heavy-oil pools, the trend was largely the same, with 59% choosing the combination of increase production rate and increase reserves (Figure D-12). However, the combinations of reduce cost plus increase production rate and reduce cost plus increase reserves (4%) were higher than both the light-oil clastic and carbonate formations.

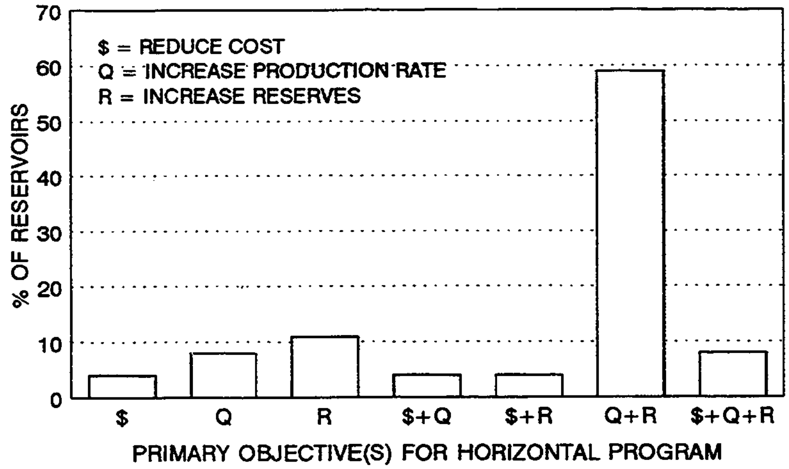

Figure D-12. Primary Project Objectives: Canadian Heavy-Oil Pools

D.6 PRODUCTION AND COST RATIOS

Production and cost ratios were used as simple tools to gauge the benefits of horizontal wells over vertical wells. Production ratios (horizontal production divided by typical vertical production) were used to establish incremental production improvements due to horizontal wells. Of the 88 pools, 91% responded with values for their pools. The ratio of 3-5:1 (38%) was the highest response followed by 1-2:1 (23%) and 2-3:1 (15%) (Figure D-13). The average for all the pools was 4.1.

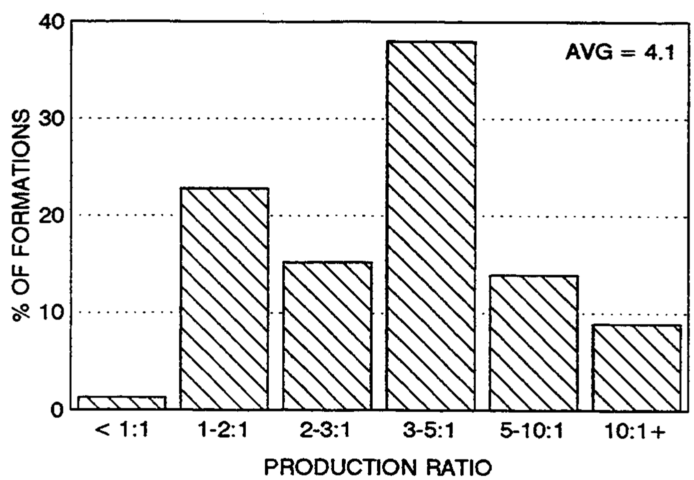

Figure D-13. Production Ratio: All Canadian Pools

Light-oil clastic formations showed an average production rate of 5.1 (Figure D-14). Ratios of 1-2:1 and 3-5:1 shared the highest response rate at 40%. Ten percent of the clastic pools reported ratios of 10:1 and above.

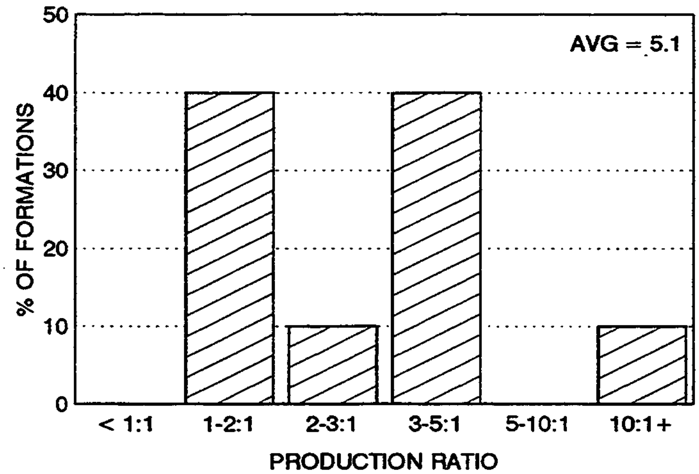

Figure D-14. Production Ratio: Canadian Light-Oil Clastics

Carbonate formations reported an average ratio of 3.1. The highest ratio range was 3-5:1, followed by 1-2:1 and 2-3:1. Figure D-15 also shows that only a few carbonate pools have production ratios less than 1:1 (3%) or greater than 10:1 (6%).

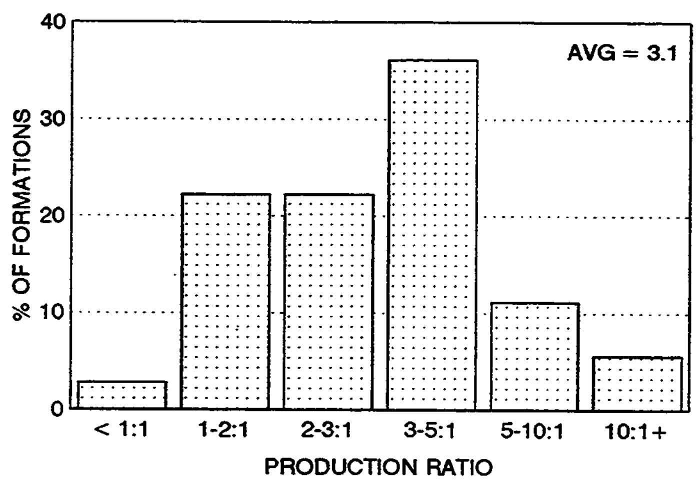

Figure D-15. Production Ratio: Canadian Carbonates

In Canadian heavy-oil pools (Figure D-16), the average production ratio is 5.6. As in light-oil clastic and carbonate pools, the most common production ratio for heavy oil was 3-5:1. Heavy-oil pools differ from clastic and carbonate pools in a higher percentage of production ratios greater than 5:1 (33%). Some pools that were unproductive using vertical wells are now viable with horizontal wells.

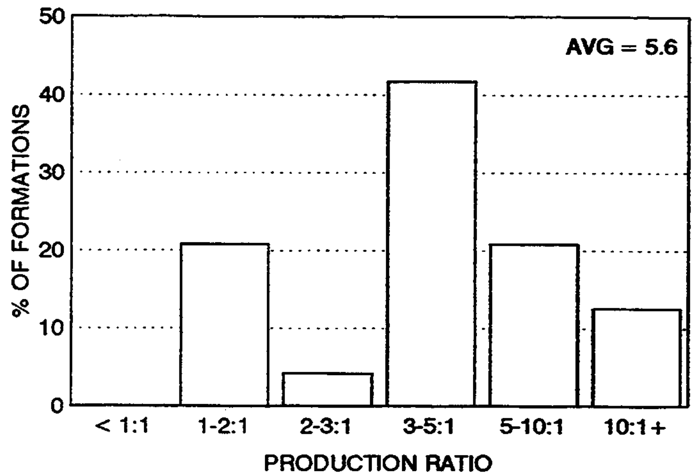

Figure D-16. Production Ratio: Canadian Heavy-Oil Pools

Cost ratios were used to compare horizontal to vertical costs. The response rate of the 88 pools was 97%. The average cost ratio was 2.2 for all pools. Figure D-17 shows the highest response was for cost ratios of 2-3:1 (45%) followed by a ratio of 3-4:1 (24%).

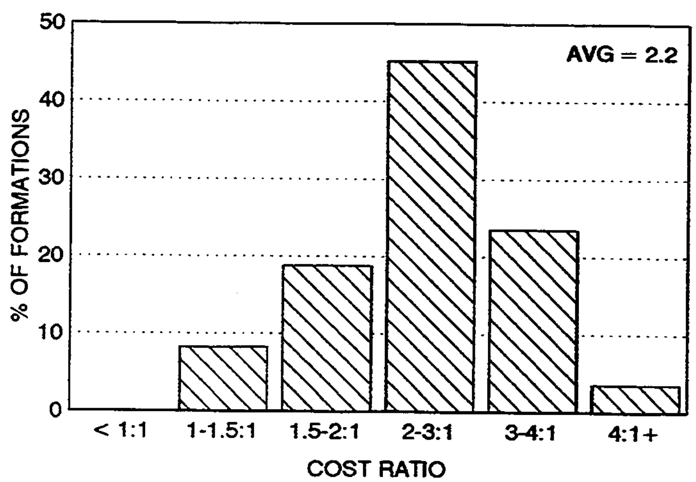

Figure D-17. Cost Ratio: All Canadian Pools

Operators in light-oil clastic formations reported an average cost ratio of 2.3. A ratio of 2:1 was a very common response (i.e., 42% of clastic pools). Twenty-five percent of pools had a cost ratio of 3:1 or greater (Figure D-18).

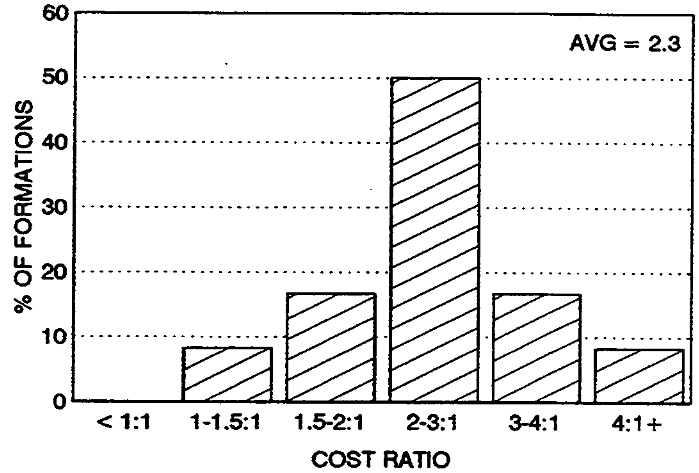

Figure D-18. Cost Ratio: Canadian Light-Oil Clastics

Carbonate formations showed a trend similar to the light-oil clastic formations, with 2:1 being the most popular cost ratio at 38% of the responses (Figure D-19). The average cost ratio is 2.0. No carbonate formations reported cost ratios greater than 3:1. (Note: the data in the 3:1+ bar in Figure D-19 are all exactly 3:1).

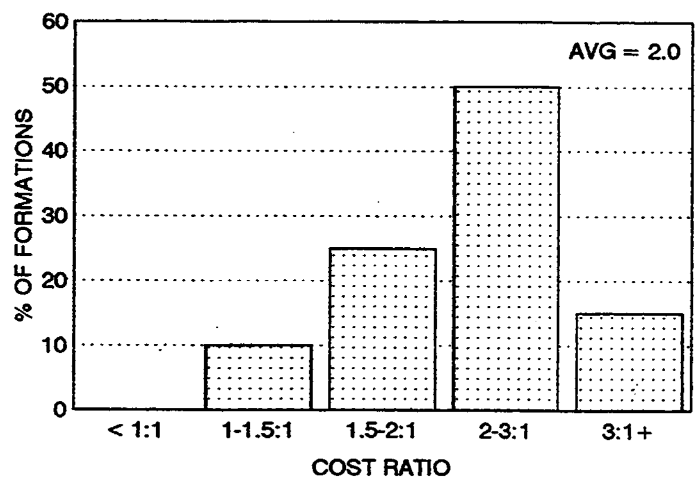

Figure D-19. Cost Ratio: Canadian Carbonates

Heavy-oil pools differ from carbonate and light-oil clastic pools in that the most commonly reported cost ratio was 3:1 (46%) and the average ratio was 2.5 (Figure D-20). In addition, these pools showed the highest percentage of cost ratios of 4:1 and greater (4%).

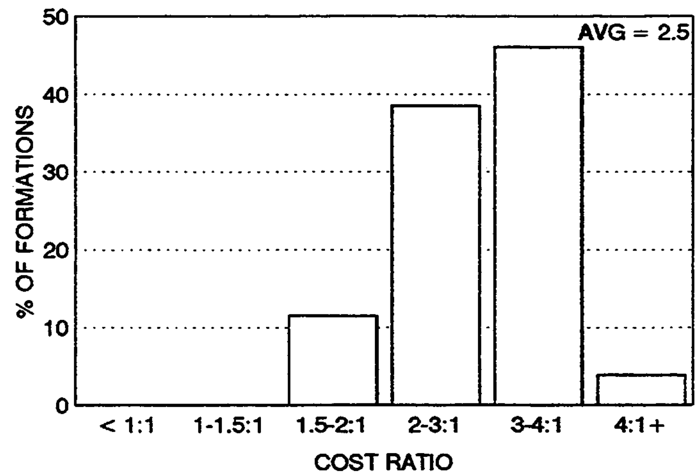

Figure D-20. Cost Ratio: Canadian Heavy-Oil Pools

D.7 TECHNICAL AND ECONOMIC SUCCESS

There was a 100% response from operators on the question of technical success. Results showed a 91% success rate with 9% unsuccessful or partially successful.

Economic success was reported by 97% of operators, with 79% overall claiming success and 21% with some degree of success to no success.

Light-oil clastic formations had a 92% technical success rate and a 58% economic success rate. Carbonate formations had a 90% technical success rate with a 79% economic success rate. Heavy-oil pools were reported with a 96% technical success rate and a 92% economic success rate. Technical and economic success are summarized by resource type in Figure D-21.

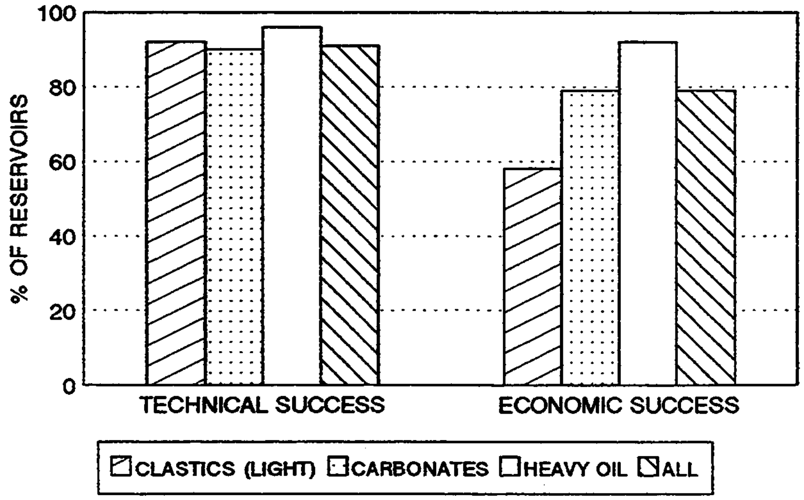

Figure D-21. Technical and Economic Success by Canadian Resource Type

On the question of formation stimulation, 64% indicated that no stimulation method was used; 36% said that some form of stimulation was used. Of those that did stimulate, 91% used matrix stimulation and 3% used fracturing. Six percent of these operators did not indicate which method was used.

Fracturing was reported for clastic formations only. Only 10% of the clastic formations were stimulated (Figure D-22). Carbonate formations were stimulated at a much higher rate than the other resource types: 69% of the carbonates were matrix stimulated. Only 7% of the heavy-oil formations were stimulated as part of the drilling/completion operations.

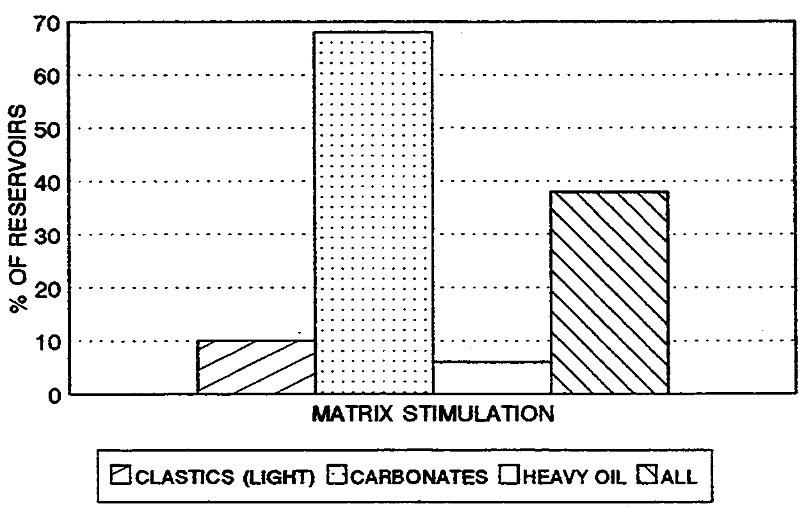

Figure D-22. Matrix Stimulation by Canadian Resource Type

D.8 FUTURE ACTIVITY

The future horizontal drilling activity of the operators was researched to gain insight into the future direction of horizontal technology. The four optional responses were: 1) None, 2) Decrease, 3) Same, and 4) Increase.

An 83% response rate was received. For all pools, 41% indicated an increase (Figure D-23) and 34% indicated the same level. This implies that 75% of the operators have had positive experience with horizontal technology and plan to continue implementing it.

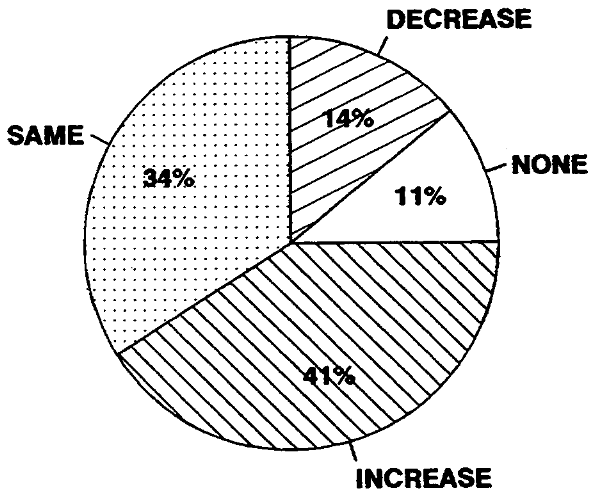

Figure D-23. Future Activity: All Canadian Pools

In light-oil clastic formations, 50% of operators indicated that they plan the same level of future activity (Figure D-24) while 40% showed an increase in activity; thus, a 90% positive response.

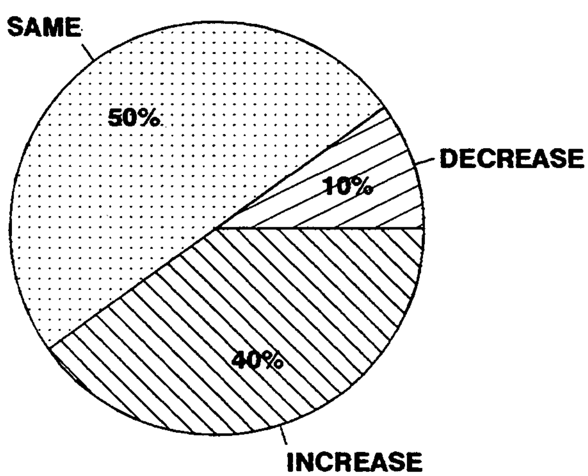

Figure D-24. Future Activity: Canadian Light-Oil Clastics

Operators in carbonate formations were less positive than clastics, though still very positive, with 35% indicating the same drilling level and 35% indicating an increased level (Figure D-25).

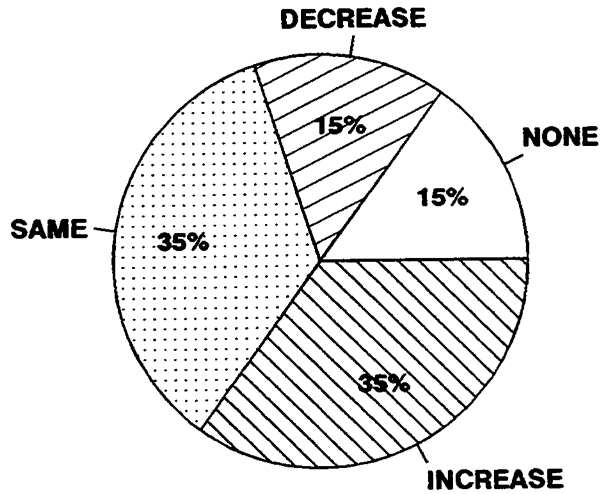

Figure D-25. Future Activity: Canadian Carbonates

A 74% positive response (Figure D-26) was returned for the heavy-oil pools , very similar to that for all formations.

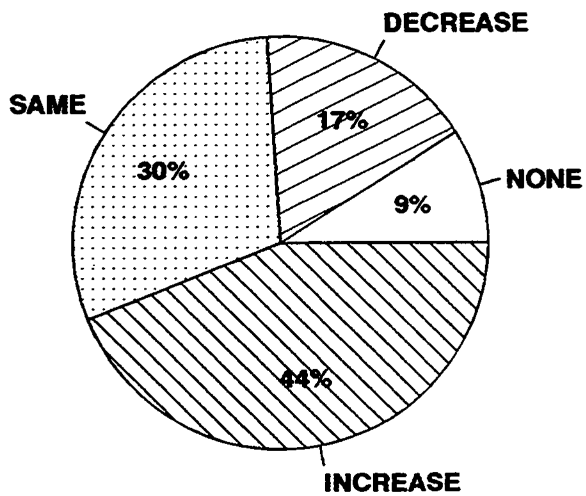

Figure D-26. Future Activity: Canadian Heavy-Oil Pools

D.9 HORIZONTAL WELL PRODUCTION PROBLEMS

Operators were given a list of 12 potential production problems typical of horizontal operations and asked to indicate which problems they have encountered. These were:

1. Artificial lift
2. Formation damage
3. Reservoir modeling
4. Stimulation
5. Cement Problems
6. Formation heterogeneity
7. Sand control
8. Water or gas coning
9. Compartmentalization
10. Logging
11. Scale or corrosion
12. Workover problems

The distribution of operator responses for all pools (Figure D-27) shows that formation damage (41%) was the most common problem, followed by coning (34%), formation heterogeneity (27%), and artificial lift (24%).

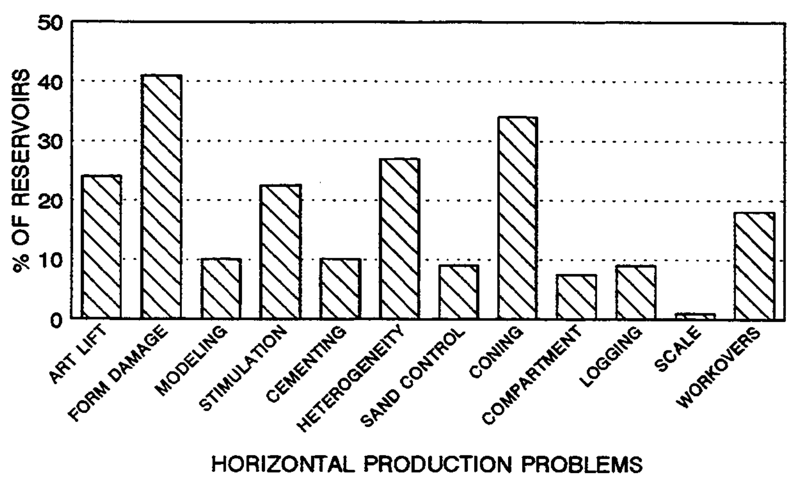

Figure D-27. Horizontal Well Production Problems: All Canadian Pools

In light-oil clastic pools, formation damage was mentioned for 33% of the pools (Figure D-28), while stimulation, heterogeneity and coning were cited in 25% of the responses.

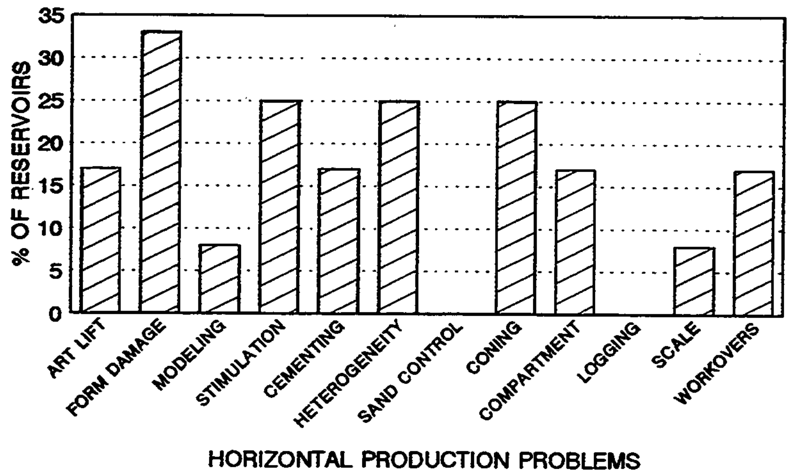

Figure D-28. Horizontal Well Production Problems: Canadian Light-Oil Clastics

Carbonate formations were reported with problems similar to clastic formations. Formation damage (41%) was the most common problem followed by coning (37%), stimulation (34%) and formation heterogeneity (32%) (Figure D-29).

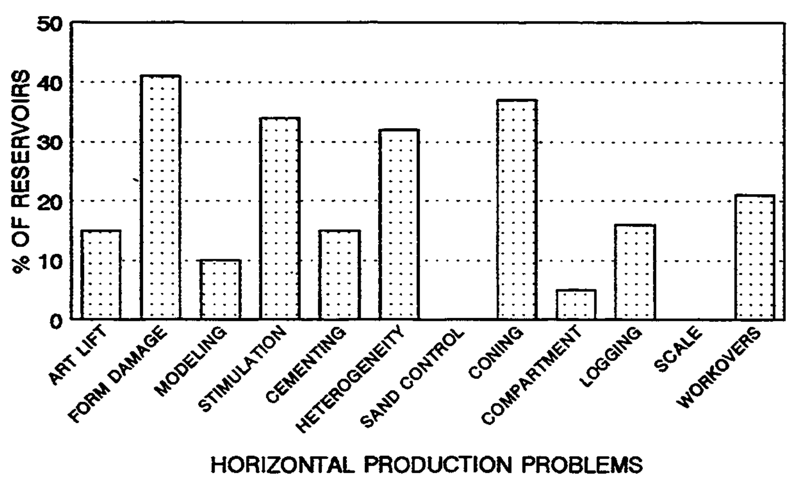

Figure D-29. Horizontal Well Production Problems: Canadian Carbonates

Heavy-oil pools showed a different trend, with artificial lift the most common problem (48%) (Figure D-30). Coning (33%), formation damage (30%) and sand control (30%) were the other noteworthy problems mentioned by Canadian operators.

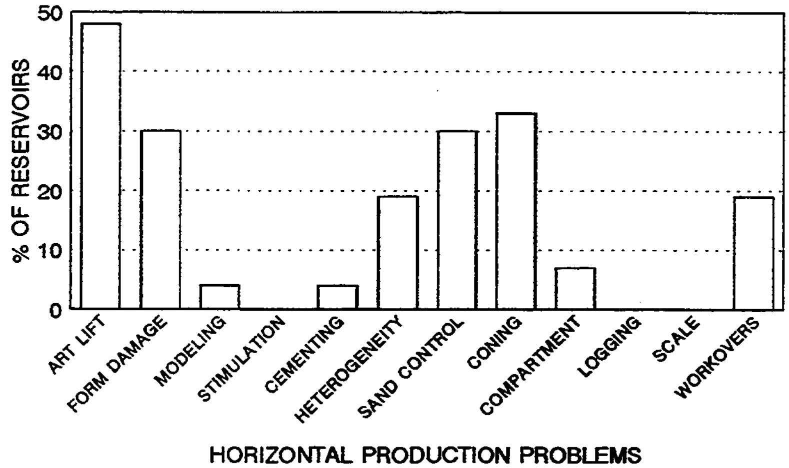

Figure D-30. Horizontal Well Production Problems: Canadian Heavy-Oil Pools

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