DOE/BC/14861-6 (Vol. 2)
(DE95000134)

FOSSIL ENERGY

HORIZONTAL OIL WELL APPLICATIONS AND OIL RECOVERY ASSESSMENT

Volume II: Applications Overview

Final Report

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

March 1995

Performed Under Contract No. DE-AC22-93BC14861

Maurer Engineering Inc.
Houston, Texas

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

DOE/BC/14861-6 (Vol. 2)
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 to examine 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 II of this report, industry's experiences with horizontal well applications in light-oil, heavy-oil and gas formations are addressed. Summaries of numerous horizontal well projects are presented arranged by primary application for U.S.A., Canadian, and international fields. Aspects described include primary justification for using horizontal technology, field location, geology, production and economic success, reserves increases attributed to horizontal wells, and specific problems. Lastly, a discussion is presented of horizontal well technology barriers and limitations.

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 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.

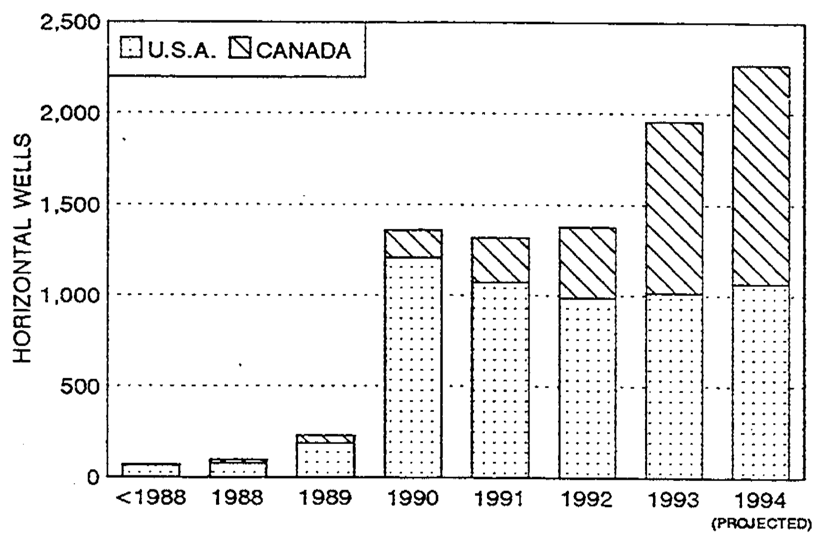


Figure i. U.S.A. and Canadian Horizontal Wells

The tasks performed for this DOE project were designed to examine 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.

LIGHT-OIL APPLICATIONS (Chapter 3)

The most numerous and among the most successful horizontal applications have been in light-oil formations. A large majority of U.S.A. horizontal wells (over 80%) has been drilled in fractured carbonates to recover light oil. In Canada, horizontal drilling has been applied in a wider variety of formations, with about 45% of wells drilled in fractured carbonates for light oil. Significant results for a few representative projects are summarized below.

Gas and Water Coning

Coning avoidance has been one of the two more popular applications of horizontal technology, along with intersecting fractures. Because horizontal wells are usually operated at lower drawdown pressures, gas and water coning are usually delayed. In addition, the wellbore can be positioned at an optimum distance from the gas and/or water contacts, further delaying unwanted production.

Prudhoe Bay (Alaska). Most wells in this field are influenced by a large expanding gas cap. Inverted high-angle wells (greater than 90°) have been used to permit incrementally blocking off the encroaching gas cone in the inverted portion of the hole (Figure ii). Relatively inexpensive coiled-tubing operations have been used to recomplete these wells and reduce gas production after breakthrough.

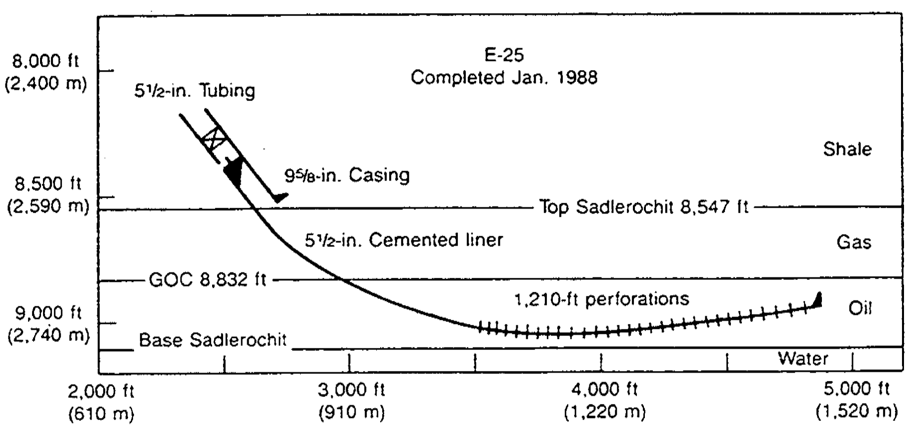


Figure ii. Inverted Horizontal Well to Allow Recompletion After Gas Breakthrough (Stagg and Relley, 1990)

Abo Reef (New Mexico). This field represents one of the earliest applications of horizontal wells, which were first drilled here in the late 1970's. Even though horizontal wellbores are located closer to the gas/oil contact than nearby vertical well perforations, GOR is less in a horizontal well. Overall economics were favorable for horizontal development, despite horizontal costs about twice those of vertical wells.

Helder Field (North Sea). Horizontal wells were successfully used to decrease water production and increase reserves. Even though water coning in this field was not found to be very sensitive to rate, horizontal wells significantly improved resource recovery—an additional 7% of OOIP across the field.

Nimr Field (Southern Oman). Water coning from an active aquifer underlying the field was delayed with horizontal wells. An increase in reserves of more than 25% (ultimate recovery increased from 12% to 15% of OOIP) was observed.

Intersecting Fractures

Intersecting natural fractures remains a primary application for horizontal technology around the world. Within the U.S.A., it continues to be preeminent, due to activity in the Austin Chalk. The increased probability of intersecting a fracture with a horizontal well has made previously uneconomic fields economic.

Austin Chalk (Texas). As of May 1994, over 3800 horizontal wells have been drilled in the Austin Chalk. Vertical wells have a low success rate in this naturally fractured carbonate formation. Horizontal development has turned the economics of the field around. This field has provided the setting for numerous technical advances and equipment/tool developments and refinements. The Austin Chalk provides an important example of the development of a learning curve. Experiences in this field show that costs in a new area may decline 25-50% as tools and techniques are improved and optimized.

Bakken Shale (North Dakota). The Bakken Shale is the second most active area for horizontal drilling in the U.S.A., with about 6% of domestic horizontal wells. Matrix porosity is essentially zero; all hydrocarbons are stored in fractures. Horizontal production ratios of about 3 times vertical are typical. As in the Austin Chalk, costs have been reduced almost 50% as the learning curve has matured.

Midale (Saskatchewan). Several Midale pools have been developed with horizontal technology. Operators have found that the optimum wellbore orientation with respect to the horizontal permeability anisotropy is site-specific and dependent on several factors. In some cases, low matrix permeability requires that the horizontal wellbore be drilled *perpendicular* to the fractures to produce at economic rates. In other cases, wells drain unswept oil when drilled *parallel* to the fracture trends. Though originally unprofitable, horizontal development in the Midale has become economic through experience and optimization of tools and techniques. Typical cost ratios are now 1-2 with production ratios in the range of 3-5.

Frobisher/Alida (Saskatchewan). This is one of the most active formations for horizontal technology in Saskatchewan. Horizontal wells have generated significant incremental reserves. As with the Midale, optimum orientation of horizontal wellbores with respect to major fracture trends has been found to be specific to each pool. In one Alida development (Figure iii), wells are oriented both perpendicular and parallel to the regional fracture trend.

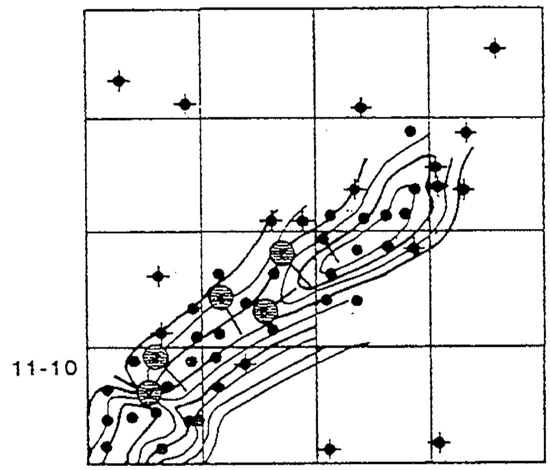


Figure iii. Horizontal Wells Both Perpendicular and Parallel to Natural Fractures (DEA-44 WH#66)

Layered/Heterogeneous Reservoirs

Horizontal drilling allows steering a well to productive pay zones that may be otherwise inaccessible, such as connecting productive intervals separated by impermeable barriers or isolated in areal extent.

North Valiant (North Sea). High-permeability dunal sand zones are embedded within low-permeability Rotliegendes sands. Dunes are often small patches and there is a low probability of encountering them with vertical wells. Horizontal wells have been successfully used to target multiple dunes (Figure iv).

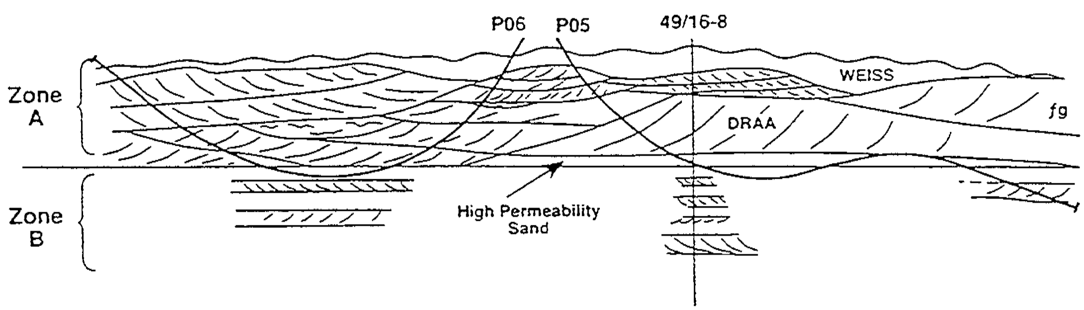


Figure iv. Horizontal Wells Connecting Isolated Productive Dunes (Tehrani, 1992)

Surface Restrictions

Directional drilling has been used to avoid surface obstacles, drill beneath bodies of water, or access a productive zone with several wellbores from one surface location, as is common practice offshore.

Antrim Shale (Michigan). In one case, a vertical well could not be drilled to the Antrim because the surface location would have been in wetlands protected by the Department of Natural Resources. A horizontal well was drilled from a nearby location to reach the target and increase production.

Low Permeability

Horizontal wells have been successfully used to exploit low-permeability reservoirs. In many applications, increased exposure of the wellbore to the productive zone can significantly increase production.

Spraberry (Texas). Operators have found it difficult to sustain economic production rates in this low-permeability naturally fractured sand. Hydraulic fracturing, water flooding, and more recently, horizontal drilling have been tried in the field. None of the early horizontal wells has been an economic success. Currently, an optimized hydraulically fractured vertical well is more successful than a horizontal well.

Dan Field (North Sea). The first horizontal wells with multiple hydraulic fractures were drilled in the Dan Field. Most initial wells were very successful (cost ratio = 1.4; production ratio = 4-6). In this application, the horizontal wellbore was oriented so that fractures were created parallel to the wellbore at a density of 4-5 fractures/1000 ft.

EOR in Light Oil

Horizontal wellbores have begun to be used in EOR (enhanced oil recovery) projects. As a line drive, a horizontal well can be more efficient than conventional vertical wells in 5-spot patterns. Combinations of vertical and horizontal wells have also been used successfully.

New Hope (Texas). Horizontal wells were drilled as line-drive injectors in a waterflood project. Average vertical well production was increased 4-fold and productive life of the field was extended 10-15 years.

HEAVY-OIL APPLICATIONS (Chapter 4)

Horizontal wells have been used in heavy-oil reservoirs where increased exposure to the production zone can significantly increase oil production. There are significant heavy-oil deposits in the U.S.A.; however, most heavy-oil horizontal applications to date have occurred in Western Canada.

Many lessons have been learned by Canadian heavy-oil operators. Among them are the following:

1. **Hole Stability** is much greater than previously thought. Large, long holes are routinely drilled without significant problems.

2. **Sand Production** is a much less common problem in horizontal heavy-oil wells than for vertical wells.

3. **Horizontal Well Length** has not been limited in these applications, with routine lengths out to 4000-5000 ft.

4. **Geosteering** expertise developed through multiwell programs has been shown to have a major impact on overall success.

5. **Pad-Spiral Well Layout** has been found to be an effective and economic development strategy. Long-radius drilling design allows azimuthal bends in the curve, as required.

6. **Increased Reserves** are a proven benefit in most heavy-oil fields, including new fields and infill development of old fields.

7. **EOR** of heavy oil has been dramatically successful. Hugh reserves of bitumen may be exploitable with similar advanced horizontal technology.

Primary Heavy-Oil Recovery

Horizontal wells for primary recovery of heavy oil have represented a consistent portion of the Canadian well count at an average of over 40% annually. The vast majority of horizontal wells in heavy-oil fields are on primary production. Many are equipped for future EOR capability.

McLaren (Saskatchewan). Cactus Lake North, a major horizontal project in the McLaren Sand, was identified as a low-risk, low finding-cost opportunity suitable for horizontal development. Vertical wells are uneconomic. Horizontal wells, drilled on a pad-spiral layout to lateral lengths of 3000-4000 ft, have proven very successful, paying out in about 18 months.

Cummings/Dina (Saskatchewan). This is among the most active heavy-oil formations being drilled horizontally. The Senlac pool is the largest horizontal multiwell project in Western Canada. Many typical evolutionary trends were exhibited in this project as experience was gained, including increasing the length of the lateral, optimizing well orientation, varying well spacing, drilling wells in groups, and using pad drilling to reduce cost and environmental impact. Several other recent projects have followed the general pattern of this development.

EOR in Heavy Oil

Horizontal well technology has been tested in several thermal EOR projects in recent years. Steam-assisted gravity drainage (SAGD) has been used in various arrangements for increasing recovery factor. A commercially successful example of this technology is the Tangleflags project in Saskatchewan (Figure iv). Recovery factors in some pools have been increased from 25% with vertical-well EOR to 60% with horizontal-well EOR.

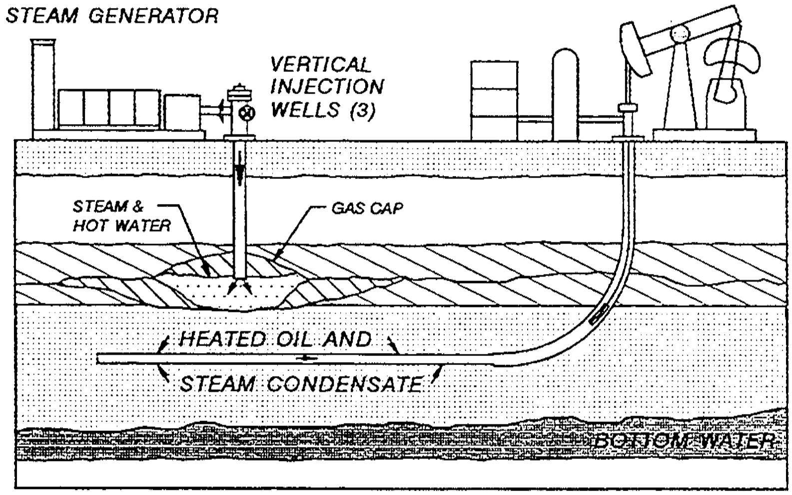


Figure v. Tangleflags SAGD Project (DEA-44 WH#18)

Shell Midway Sunset (California). Horizontal technology was first used at Midway Sunset in 1990 to enhance steam-flood operations. Vertical wells suffered from water coning and subsequent slumping of the oil/water contact. Horizontal wells were drilled near the oil/water contact to stabilize the interface and reduce coning. Average production for horizontal wells drilled in the second program was 16 times vertical, and tends to increase linearly with horizontal length.

Shell Cadot (Alberta). A pilot project is underway that uses an enhancement to the SAGD process, based on applying a small pressure differential between adjacent pattern steam chambers. This enhancement has resulted in accelerated steam zone growth, up to 50% improvement in ultimate recovery, and no impairment of the thermal efficiency.

GAS APPLICATIONS (Chapter 5)

The number of horizontal wells targeting gas, while much less than for oil, has been growing. Overall success rates for gas wells have not equaled those of oil. Industry's experience shows that the most successful applications for horizontal gas wells include intersecting natural fractures, delaying water coning, reservoirs with active water drives, and gas-storage reservoirs. Other applications are often less economically successful: reservoirs that have low permeability, stratified pay zones, or are shallow.

Gas Production

Economic success of horizontal gas wells in the U.S.A. has been most consistent in 2 areas: the Austin Chalk and the Gulf of Mexico. Several other projects have been experimental in nature with few wells drilled in any particular formation.

Devonian Shale (West Virginia). DOE has sponsored five wells in the Devonian. All have produced more than comparable vertical wells, although long-term performance is not verified. Several technological improvements have increased the efficiency of these air-drilling operations. Cost ratios have decreased from 5 down to 3.

Harmattan East (Alberta). Vertical wells were not economic in this pool. Two horizontal re-entries were recently drilled; both wells were very successful. The wells paid out in 6 months, despite significant drilling cost overruns. Gas and liquids rates were almost double those predicted. The mechanism responsible for the higher-than-expected liquids production has yet to be identified. This phenomenon has also been observed in at least one other pool.

Gas Storage

The gas-storage industry first began applying horizontal technology in its reservoirs in the late 1980s. Several wells have been drilled successfully in the U.S.A. and Canada, and more are planned. The principal benefits for gas storage are greater deliverability at low drawdown pressures, fewer wells and surface sites, and reduced base-gas requirements.

ONG West Edmond Project (Oklahoma). One of the first storage applications was the Gaffney S-1, which was re-entered and extended horizontally over 1500 ft. Production was 6 times vertical rates. Costs were high (about twice vertical) due to an immature learning curve. Project objectives were met or exceeded, and additional horizontal wells have since been drilled in the field.

AECO HUB Upper Manville Project (Alberta). In an effort to increase this field's deliverability, options were considered for reducing turbulence at high flow rates. After fracturing proved unsuccessful, horizontal wells were drilled, resulting in significantly expanded deliverability. Average production ratio for the first ten horizontal wells was 4 at the wellhead and 29 at the sandface. Economic results were very positive for this project.

TECHNICAL AND ECONOMIC TRENDS (Chapter 6)

The use of horizontal technology for oil and gas exploitation is increasing, due to the success rate within the industry and the wide variety of technical innovations and improvements. Operators and service companies are continually refining their tools and procedures to increase production and decrease costs.

Recent advances in horizontal technology are manifold. *Multibranch horizontal wells*, both dual and trilaterals, are being used to reduce drilling costs 20-30% and the size and number of drilling platforms by up to 50%. *Geosteering* and *near-bit measurements* allow more accurate steering of the wellpath within or toward desirable zones. *Advanced drill bits and motors* are being developed that will significantly improve ROPs and increase the life of downhole tools. New *short-radius tools* will allow operators to reap the benefits of short-radius drilling with fewer limitations than in the past. *Slim-hole drilling systems* are providing cost savings and making possible economic re-entries from smaller diameter casing.

There are important technical barriers and limitations remaining for horizontal technology. Among the most significant are:

1. **Completion Design.** Modifying the production profile during the life of a horizontal well, such as shutting off water-producing zones, has proven to be a major problem. Advanced tools are needed to identify the optimal completion design based on the reservoir conditions encountered.

2. **Workover Technologies.** Improved water/gas identification and isolation tools are needed, as well as chemicals for remedial operations. Most water exclusion attempts to date have only been marginally successful, at best. Improved production logging tools and techniques are also needed to identify production profiles.

3. **Minimizing Formation Damage.** Improved operations and fluids are needed to minimize skin damage from fluid invasion. More development is needed for underbalanced air and foam drilling, including equipment and procedures.

4. **Slim-Hole Drilling Technology.** Barriers, both real and perceived, have limited the growth of slim-hole technology. Ongoing development and education are needed.

5. **Stimulation.** Improved technologies under development include minifracs and multiple short laterals to by-pass skin damage, fracture control, closed-fracture acidizing, and bottom-hole tools with zone-isolation capability.

6. **Re-entry Technology.** Despite the potential for significant cost savings, the industry has recently shown decreased interest in horizontal re-entries. Disadvantages that have damped enthusiasm include old well problems (worn casing, poor cement, etc.), design restrictions (maximum hole size, equipment options), and well preparation (time and expense of window or section milling).

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%). 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 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.

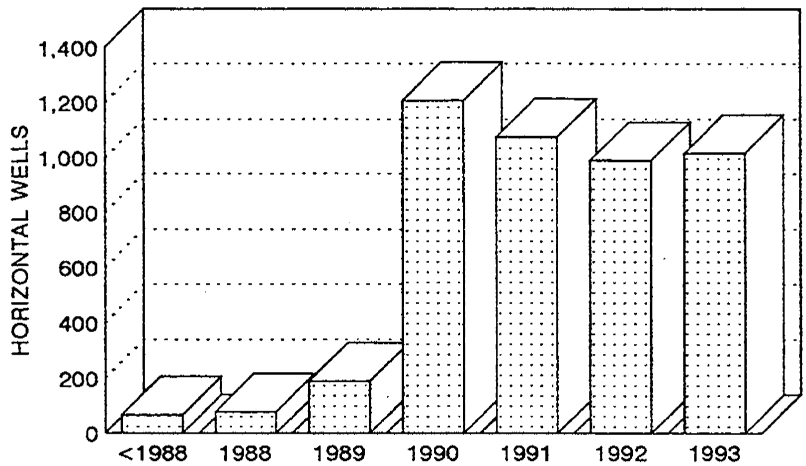


Figure 2-1. U.S.A. Horizontal Well Activity (Petroleum Information)

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. Light-Oil Applications

3.1 INTRODUCTION

The concept of using horizontal or high-angle wells to improve recovery and drainage of subterranean fluids is not new. Patents were filed early in the 1920s on devices to drill lateral wells (Figure 3-1). These tools were complicated and never fully developed, as they were not based on conventional drilling methods.

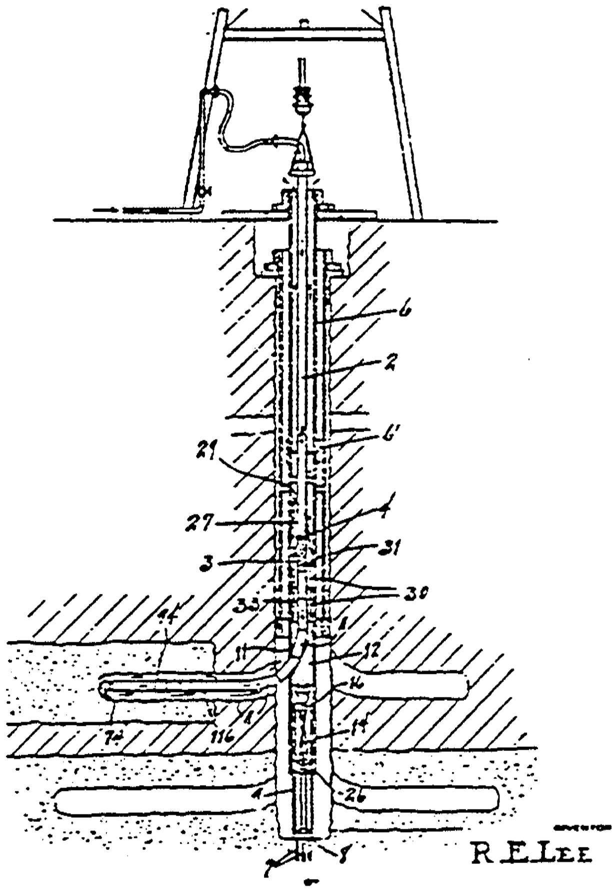
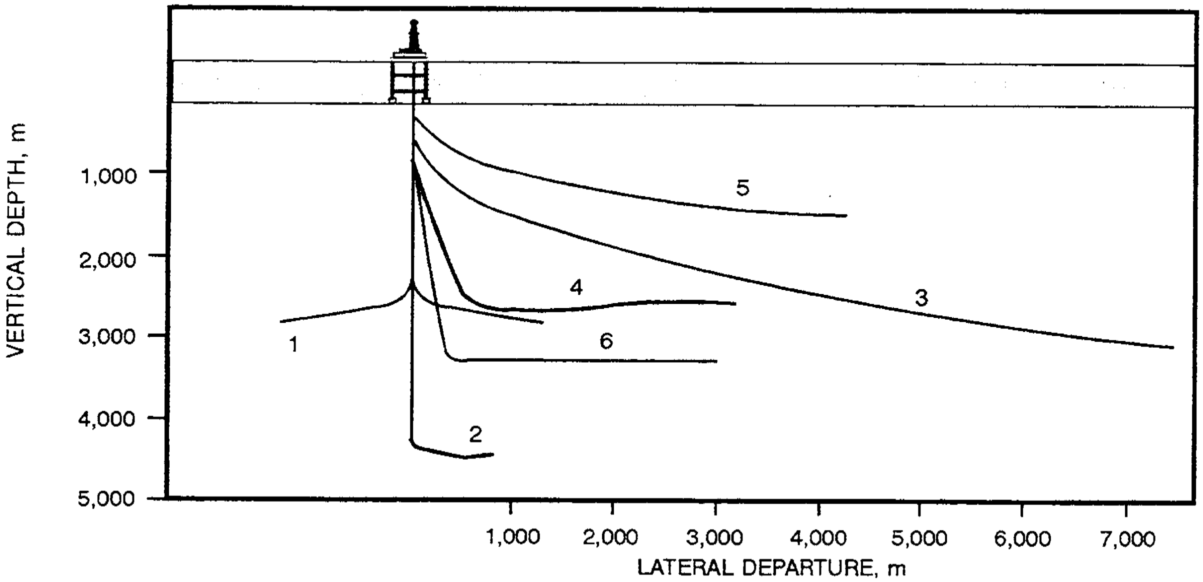


Figure 3-1. Early Patent of Drilling System

Short-radius horizontal drilling tools (from vertical to horizontal in 20-40 ft) were extensively used in 1940s and 1950s. They disappeared from use with the development of hydraulic fracturing in the 1950s.

Interest in horizontal drilling resumed in the late 1970s with the long-radius (1000 to 3000 ft) efforts of Elf, Exxon, Texaco, etc., and the short-radius wells drilled by ARCO. Advancements in directional drilling technology brought on by offshore "extended-reach" requirements further increased horizontal drilling interest and capability (Figure 3-2).



1. GEMINI: DUAL LATERAL = 2,495 m (8,185 ft)
2. CLIFF'S: DEEPEST HORIZONTAL AT 4,675 m TVD (15,337 ft)
3. STATOIL: LONGEST EXTENDED REACH = 7,288 m (23,911 ft)
4. C. WILLIAMS Jr.: 2nd LONGEST HORIZONTAL SECTION = 2,235 m (7,332 ft)
5. UNOCAL: LONGEST LATERAL REACH (USA) = 4,472 m (14,670 ft)
6. MAERSK: LONGEST HORIZONTAL SECTION : 2,501 m (8,205 ft)

Figure 3-2. Horizontal Well Records (*Petroleum Engineer International*, 1993)

The development of medium-radius drilling tools (200-600 ft) by ARCO in 1985 and the 3- to 10-fold production increases obtained with many horizontal wells led to the horizontal drilling boom underway today. The number of horizontal wells increased from 50 in 1985 to over 1200 in 1990. The number of horizontal wells drilled in the U.S. alone exceeded 4600 by the beginning of 1994 (Figure 3-3).

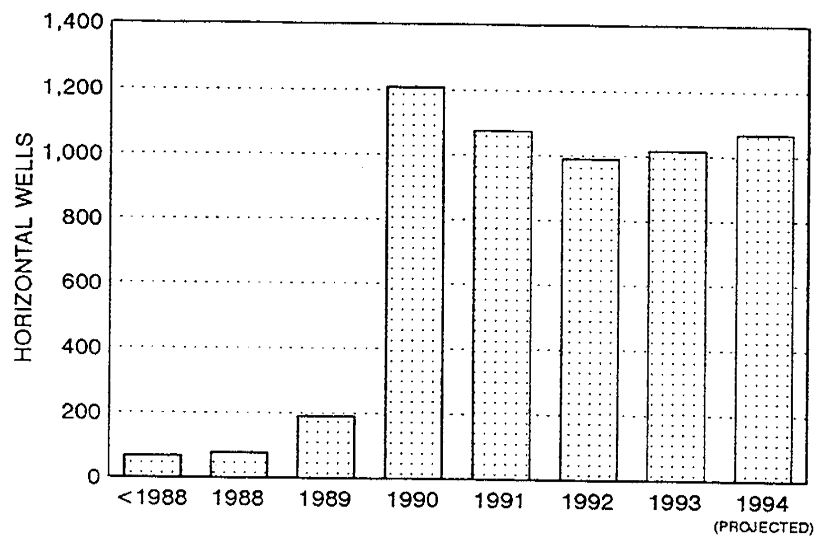


Figure 3-3. Growth of Horizontal Drilling in the U.S.A. (Petroleum Information)

Interest in horizontal drilling is also evidenced by the number of published articles, books and horizontal technology research projects, including the present study. However, the majority of research has been focused on the planning, drilling, and completion stages. Relatively little work has been directed toward compiling and analyzing production results.

This study is focused on production from horizontal wells. Relatively little information on hardware or drilling techniques will be presented. The study summarizes actual production results from horizontal wells in a wide variety of applications. These will allow future planners to determine where horizontal technology can best increase oil production and reserves.

A major objective of this study is to assess the success of past applications of horizontal drilling technology. Summaries are provided of projects in U.S.A., Canadian, and international fields. The overall goal is to provide the reader with a sufficient number of examples to begin addressing the feasibility of the technology in similar situations. The reader will note that the character of the information gathered, organized and presented in Chapters 3-5 is different for the U.S.A. and Canada. U.S.A. operations were, in general, summarized by example projects chosen from the best technical papers. There was no significant attempt to include discussion of every active U.S.A. formation, given the magnitude of that task (as well as the scope of this project).

Discussion of Canadian operations is more thorough, with almost every significant horizontal project described. While technical articles served as a major source of information, much Canadian data came directly from operators through the DEA-44 network. In contrast to U.S.A. operations, there are several specific attributes of the community of Canadian horizontal drillers/operators that facilitated the gathering of relatively complete data on Canadian activity:

1. The number of companies involved in the technology is smaller in Canada than in the U.S.A.

2. Major players and fields in Canada's operations are geographically closer together.

3. Key drilling/production engineers are closely networked, i.e., actively involved in sharing and exchanging information for mutual benefit.

4. Well data and records are in public domain. Little incentive exists to attempt to keep data confidential.

For these reasons, the discussion of Canadian horizontal applications presented in Chapters 3-5 is relatively complete and offered as an important supplemental discussion to U.S.A. operations.

3.2 GAS AND WATER CONING

Many oil-bearing formations are underlain by water-bearing zones which may either be static or act as a drive mechanism. In either case, the pressure gradient caused by production will induce movement of both oil and water. If the relative permeability to water is greater than to oil, the mobility of the water is greater and a cone-shaped drainage pattern develops, as shown in Figure 3-4. Similarly, many oil-bearing formations are beneath a gas cap that expands with production. The lower viscosity of gas also results in higher mobility than oil, leading to a similar (but inverted) coning situation. A third and frequently occurring situation is a combination of both water and gas coning (Figure 3-5).

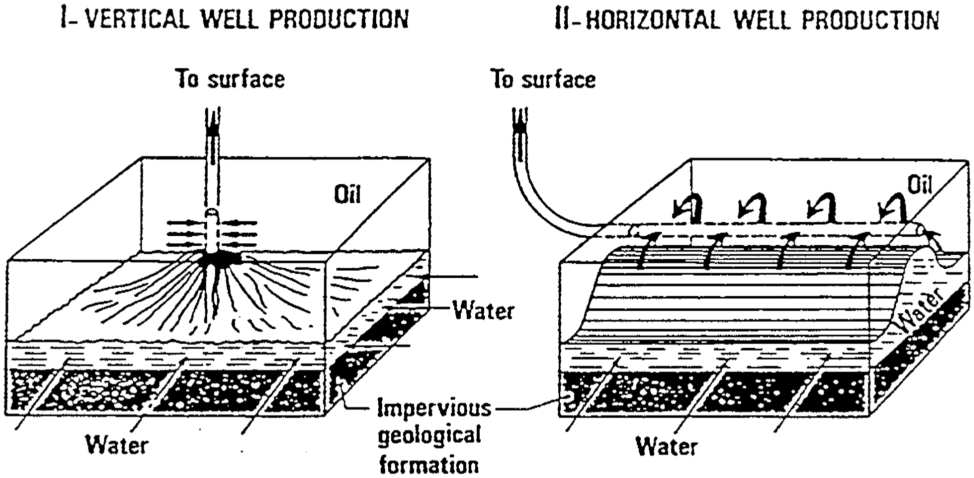


Figure 3-4. Comparison of Vertical Water Coning to Horizontal Water Cresting

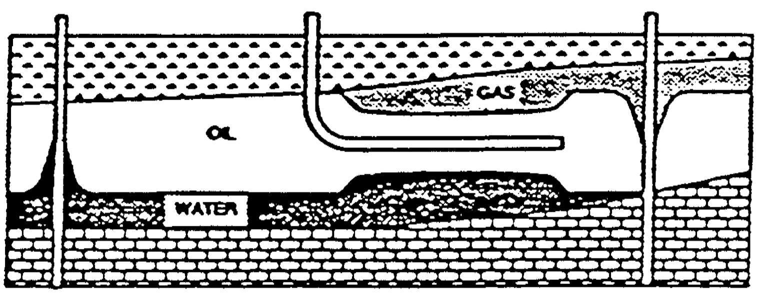


Figure 3-5. Gas and Water Coning Application (Dech et al., 1987)

Because horizontal wells are usually operated at lower drawdown pressures, water and gas coning are delayed. This is one of the most significant applications of horizontal technology, since this development strategy can actually increase the amount of available economic oil reserves compared to a vertical well in the same location. Figure 3-6 shows how a horizontal well produces significantly less water than a vertical well, given the same gross fluid production. This has several benefits, the most significant being an increase in producible reserves and, thus, an extension in the economic life of a project (Mutalik and Joshi, 1993). In addition, reduced water production means less disposal and lower pumping costs. The following case studies give field examples of the application of horizontal wells to minimize coning.

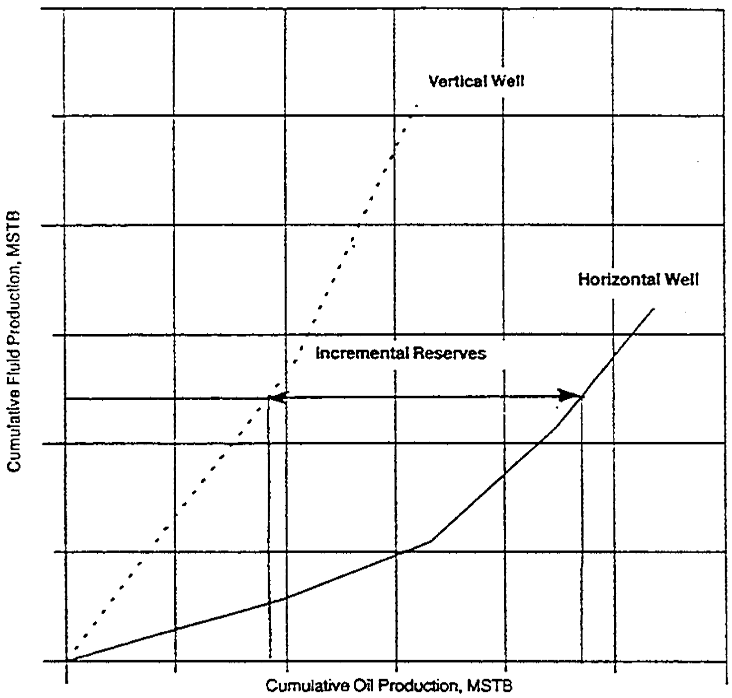


Figure 3-6. Conceptual Water Coning Study (Mutalik and Joshi, 1993)

3.2.1 U.S.A. Coning Applications

Prudhoe Bay (Alaska)

The Western Operating Area of the Prudhoe Bay Unit is an excellent example of the use of horizontal technology for water and gas coning problems. As of October 1992, there were 27 nonconventional wells (NCW) in the Sadlerochit formation of the PBU (Broman, 1992). The operators of Prudhoe Bay define NCW as horizontal wells that fall into four categories: 1) horizontal wells drilled at an angle of about 90° to vertical, 2) high-angle wells which are drilled from 85°—88°, 3) inverted high-angle wells with angles exceeding 90° (Figure 3-7), and 4) drainholes that are characterized as conventional vertical wells that are sidetracked and drilled horizontally into the producing formation.

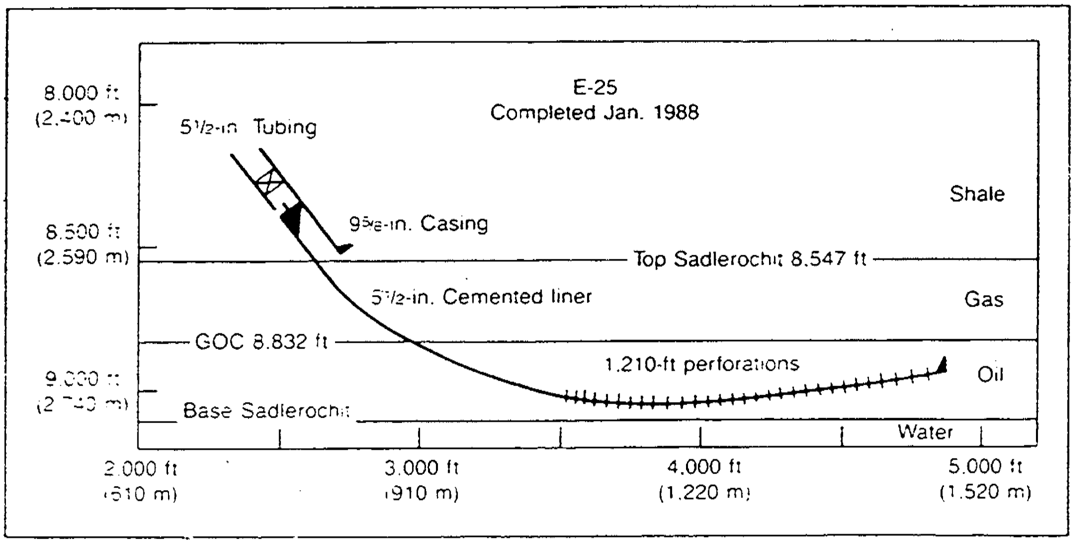


Figure 3-7. Inverted Horizontal Well at Prudhoe Bay (Stagg and Relley, 1990)

The majority of wells in Prudhoe Bay are influenced by a large expanding gas cap, which necessitates production rate control to avoid gas coning. Both horizontal and high-angle inverted wells have been used to address gas coning. Inverted high-angle wells permit production from above and below flow-impeding shale layers and also present the unique ability to block off the encroaching gas cone in the inverted portion of the hole by coiled tubing and other completion techniques.

These are long-radius wells and generally cost 1.3 to 1.5 times more than a conventional well with production rates 2 to 3 times that of the conventional wells. In addition, results at Prudhoe Bay have shown additional cumulative recovery due to horizontal technology. Figure 3-8 shows the additional cumulative recoveries of E-25 and E-28 to be about 4.0 and 2.0 million barrels, respectively, compared to offset vertical wells.

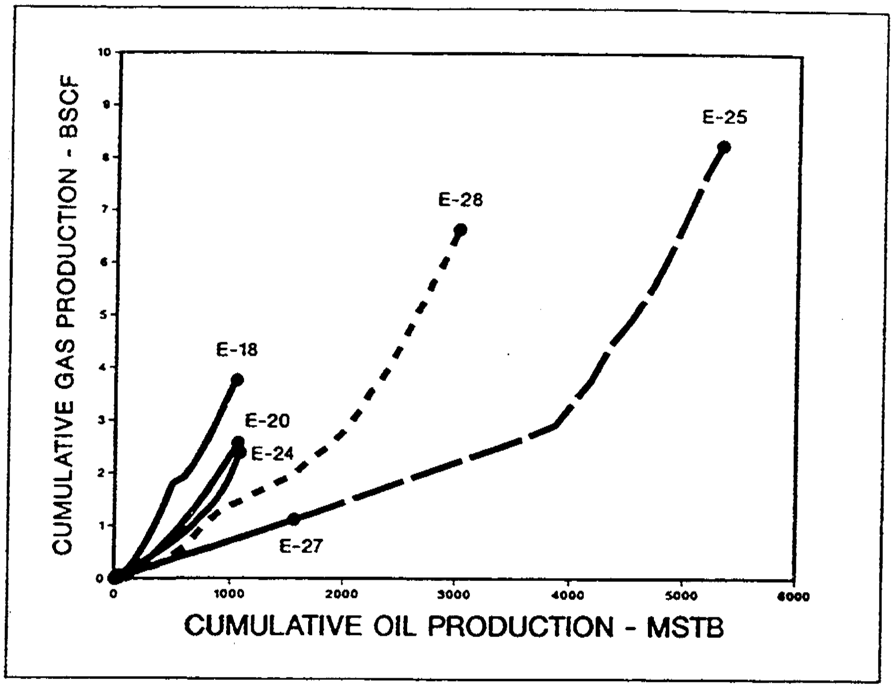


Figure 3-8. Comparison of Horizontal (E-25 and E-28) Well Performance to Vertical Wells (Broman, 1992)

Horizontal wells have also been used in Prudhoe Bay as producers in a waterflood operation and as gas injection wells for pressure maintenance. Prudhoe Bay is an excellent example of the use of horizontal technology in developing giant fields. It also highlights the use of advanced technology, such as inverted high-angle wells, to handle gas coning that occurs in many other normal size fields.

Elk Hills (California)

The Naval Petroleum Reserve in Kern County, California is another example of the application of horizontal technology to reduce gas coning problems (Gangle et al., 1991). The Stevens structure shown in Figure 3-9 is part of the Elk Hills oil field, located southwest of Bakersfield, California. Eight horizontal wells have been drilled in the field since 1989 and the use of horizontal technology is considered a major success.

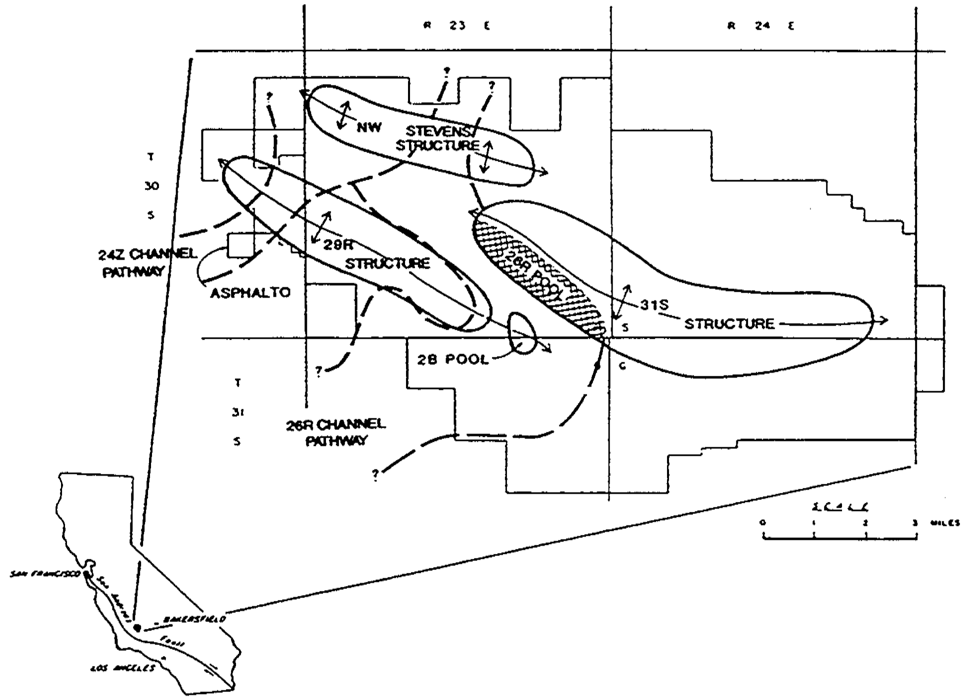


Figure 3-9. Major Structures and Sand Channels in Elk Hills Field (Gangle et al., 1991)

The Stevens reservoir is geologically different from Prudhoe Bay in that the Stevens sand is steeply dipping, as great as 60° in some areas (Figure 3-10). The original 1500-ft oil column has been reduced to approximately 275 ft, with a pressure-maintained gas cap and an underlying water zone.

WELL #372-35R RD#1 (HORIZONTAL REDRILL)

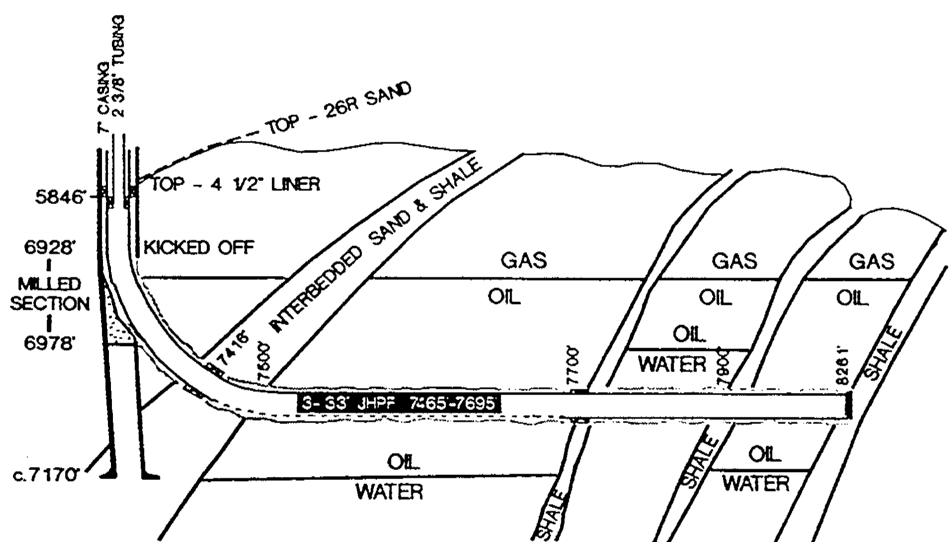


Figure 3-10. Typical Horizontal Well in Stevens Sand (Gangle et al., 1991)

The use of horizontal wells in the Elk Hills field was designed to control excessive gas production due to coning in the vertical wells. The first two horizontal wells were studied closely with respect to surrounding vertical wells and the results were impressive. Both horizontal wells produced in excess of 1000 BOPD compared to an average of 300 BOPD for similar vertical wells. In addition, the horizontal wells produced only solution gas while the vertical wells declined at a rate of approximately 16% per year. A third benefit from the horizontal wells was a detailed description of layering and other reservoir characteristics, which was a by-product of the drilling and completion phases of the project.

Cost comparisons between horizontal and vertical wells showed that horizontal wells were approximately 3 times more expensive to drill and complete. The principal cost increases were attributed to the drilling fluid system, directional drilling control, casing strings and completion equipment, and rig time. Despite the increase in costs, the horizontal wells were economically successful. It was estimated that each horizontal well would yield an additional 10 million barrels of oil and that horizontal technology applied field-wide would increase the ultimate recovery to 70% of original oil-in-place.

Smackover (Alabama)

Horizontal drilling is being applied not only in large fields by major operators, but also by independents. Water coning was occurring in a 14,300-ft well in the dolomite Smackover formation (Powers et al., 1990). Prior to the horizontal re-entry, the vertical well was producing only 90 BPD of oil with 300 BPD of water. Eventually, the oil production went to zero and the decision was made to sidetrack and drill to an angle greater than 90° (Figure 3-11). Initial results indicate that the horizontal well was technically and economically successful. The well came back on line at 300 BOPD and eventually stabilized at 200 BOPD with 270 BPD of salt water. Small horizontal projects like this one highlight the use of horizontal wells by independents and the potential for their use in many similar fields.

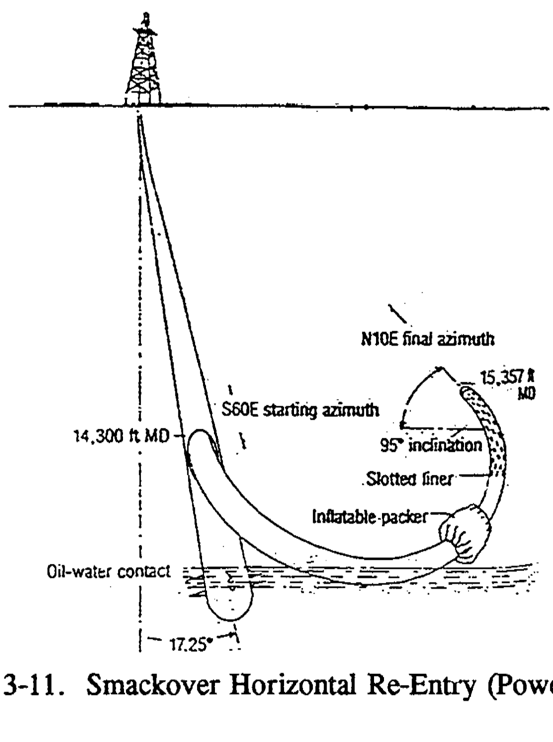


Figure 3-11. Smackover Horizontal Re-Entry (Powers et al., 1990)

Abo Reef (New Mexico)

Horizontal wells have been used to reduce gas coning in the Empire Abo Unit, located in Eddy County, New Mexico. The unit produces from the Permian Abo Reef at a depth of about 6200 ft. The field was originally produced with gravity drainage into vertical wells. Later, gas was injected into the gas cap to increase production. Gas coning then became a significant problem in the field.

ARCO began drilling horizontal wells in the field in the late 1970s and early 80s (Stramp, 1980). Even though the horizontal wellbores are located closer to the gas/oil contact than nearby vertical well perforations, the GOR was less in a horizontal well (Figure 3-12).

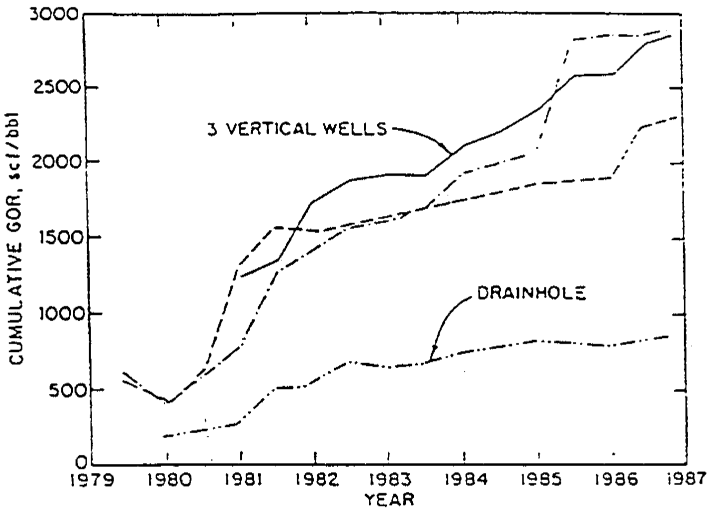


Figure 3-12. Cumulative GOR from Three Vertical Wells and Horizontal Drainhole (Ding et al., 1991)

Cumulative oil production from horizontal wells was about 1.6 times greater than from vertical wells (Figure 3-13). Costs for the horizontal drainholes were about double those of conventional wells. Although specific economics are unknown for this case, payouts in excess of 3:1 would be expected.

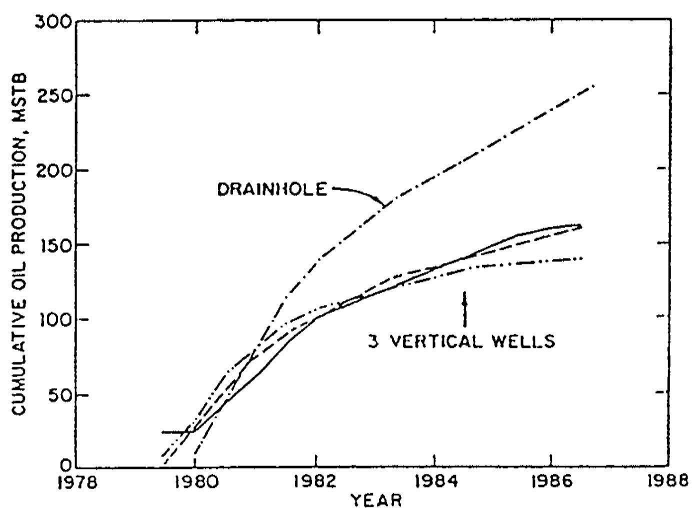


Figure 3-13. Cumulative Oil Production from Three Vertical Wells and Horizontal Drainhole (Ding et al., 1991)

3.2.2 Canadian Coning Applications

Shaunavon (Saskatchewan)

A horizontal well was recently drilled in this pool, which was being depleted by three vertical wells at that time. The initial stabilized rate of the horizontal well was 780 BOPD, which is 6 times the rate of the vertical wells (Strashok, 1991). The horizontal well was drilled in the Jurassic Upper Shaunavon formation, which consists of fine-grained calcite cemented quartzose sandstone, oolitic limestone, shell calcarenite, coquina and argillaceous limestone. Major reservoir properties are summarized in Table 3-1.

TABLE 3-1. Typical Reservoir Properties: Battle Creek Lower Shaunavon

Net Pay	30 to 40 ft	Initial Reservoir Pressure	1,960 psi
Porosity	10 to 15%	Density	23° API
Water Saturation	25%	Horizontal Perm	80 to 100 md
Drive Mechanism	Solution Gas/Water		

The vertical wells produced at a high water cut before the horizontal well was drilled. The horizontal well produced at a low water cut and, as a result, the overall water cut of the pool was improved. The horizontal well is currently producing in excess of 500 BOPD. It is not yet possible to predict the incremental reserves that will be produced as a result of the horizontal well.

Bonanza Doig (Alberta)

Another interesting light-oil coning application is the Bonanza project in Alberta. The Bonanza Doig oil pool is a high GOR pool with bottom water and a small gas cap. Oil production has been restricted by gas penalty. The additional volume produced by horizontal wells resulted in elimination of GOR penalty and a more economically attractive project. Six wells were drilled in the project. Two wells had excellent results; four wells provided poor to satisfactory results. Overall, horizontal to vertical production ratio was 4:1. Table 3-2 summarizes the general rock and fluid properties.

TABLE 3-2. Typical Reservoir Properties: Bonanza Doig

Net Pay	20 to 40 ft	Reservoir Temperature	100 to 140°F
Porosity	15 to 20%	Initial Reservoir Pressure	800 to 1,200 psi
Water Saturation	10%	Formation Volume Factor	1.29
Horizontal Perm	3 to 5 md	Density	35 to 38° API
K_V/K_H	0.1	Drive Mechanism	Solution Gas/Water

3.2.3 International Coning Applications

Helder Field (North Sea)

The Helder oil field on the Dutch Continental Shelf was the first in the North Sea to utilize horizontal drilling (Murphy, 1990). The Vlieland sandstone is Lower Cretaceous with extremely high permeability (1-6 darcies) and underlain by water throughout the entire 1140 acres (Figure 3-14). Water breakthrough generally occurred within the first few days of production in the vertical wells, and history- matched simulation of the horizontal wells indicated that water production was not rate-sensitive. Water encroachment in a horizontal well would therefore occur at approximately the same time as a similar vertical well. However, horizontal wells were still selected with the objective of maximizing gross fluid production.

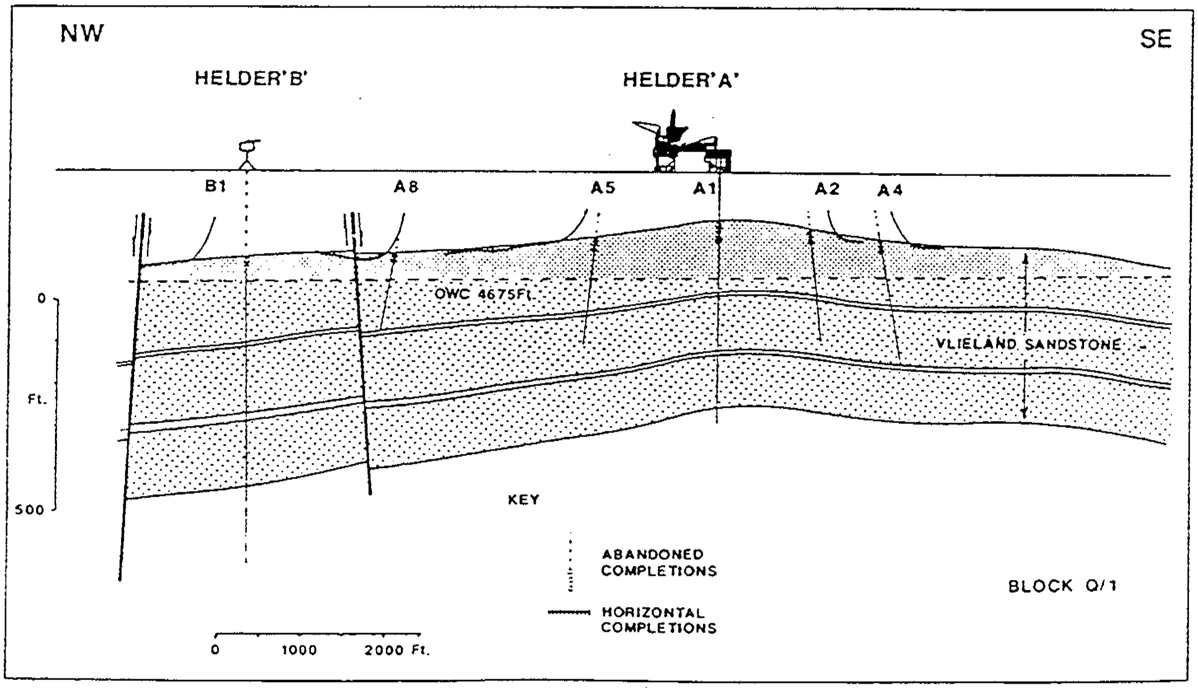


Figure 3-14. Helder Field Cross Section (Murphy, 1990)

The decision to use horizontal technology proved successful for several reasons, most notably the increase in oil recovery. Over a specific time period of investigation, the incremental oil recovery from the horizontal wells was 1.05 MMstb above the predicted amount from the original vertical wells. In addition, the decrease in water production due to horizontal wells was predicted at 12.3 MMstb (Table 3-3).

TABLE 3-3. Comparison of Production Rates From Horizontal Sidetracks With Predicted Rates From Original Wells (Murphy, 1990)

WELL	OIL PRODUCTION RATE (BOPD)	GROSS PRODUCTION RATE (BFPD)	WATER CUT (%)
Horizontal	4500	25,500	82.5
Original	2700	64,000	95.8
Difference	1800	(38,500)	

Additional advantages included productivity indexes for horizontal wells as much as 20 times those of vertical wells, due to increased reservoir exposure. Smaller pumps were used with less power consumption since the productivity was increased and the gross fluid production decreased. Also, a slower decline in reservoir pressure was observed due to reduced off-take from the horizontal wells.

The most noteworthy result from the Helder field's horizontal program is the increase in reserves due to the horizontal wells. It is estimated that an additional 7% of the original oil-in-place (4.4 MMstb) will be recovered due to the use of horizontal technology (Figure 3-15). This case exemplifies horizontal usage in relatively homogenous high-porosity sandstone formations, which are also prevalent in the United States.

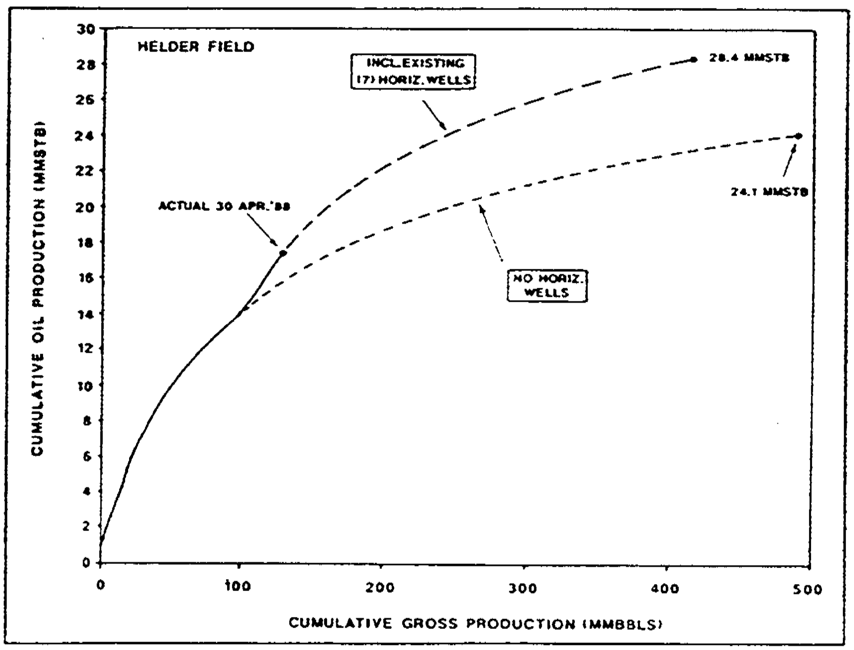


Figure 3-15. Total Helder Field Cumulative Oil vs. Cumulative Gross Production (Murphy, 1990)

Palmer Largo (Argentina)

The Palmer Largo field in Argentina is breccia rock and volcanic conglomerates with a sandy peletic matrix (Garcia and Saul, 1991) (Pacovi et al., 1992). Approximately 764 ft of producing formation is underlain by water. The original vertical well entered the Palmer Largo formation low on the structure in the water. Either a new vertical well or a horizontal well that entered up structure (Figure 3-16) was required. A horizontal re-entry was selected and the results were good.

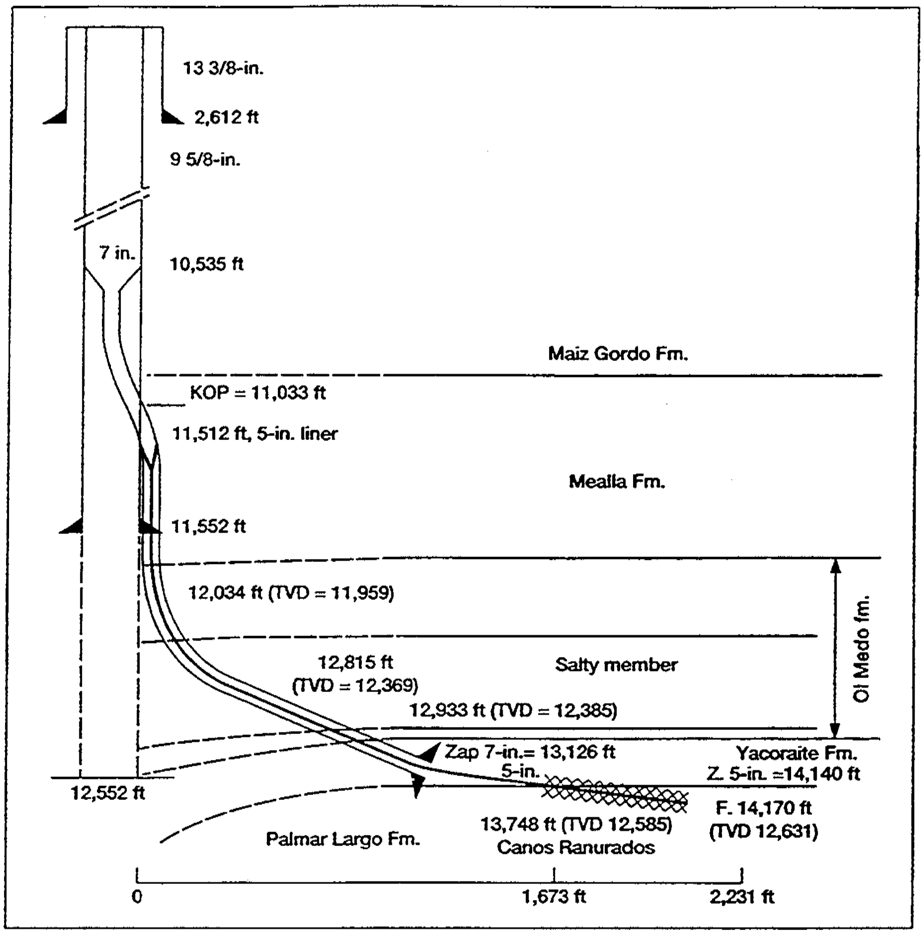


Figure 3-16. Palmer Largo Horizontal Project (Pacovi et al., 1992)

The sidetrack exited the 7-inch casing, built angle through an evaporite section and extended 2057 ft from the vertical well, exposing over 400 ft of pay in the Palmer Largo. This well, like others previously discussed, showed a doubling of oil production rate with a decline in water production. In addition, it was shown that horizontally re-entering an existing well cost 20% less than drilling a vertical well in the same location. And finally, the operator of this field states that horizontal drilling will not only increase recovery but also reserves.

Safah Field (Northern Oman)

Horizontal wells have been successfully used in the Safah field in Oman to delay gas coning (Chen, 1993). The field is located over 400 km west of Muscat, Oman. Production is from the Upper Shuaiba, which is a lime mudstone of Lower Cretaceous age. The field originally contained about 650 MMbbl of oil and 54 Bcf of gas and is underlain by a water zone (Figure 3-17).

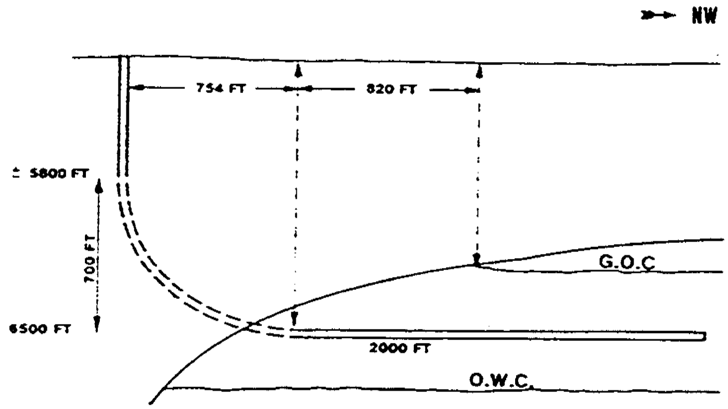


Figure 3-17. Safah Field Gas Coning Application (Chen, 1993)

The operator, Occidental of Oman, observed premature gas coning in many vertical wells. After a modeling analysis showed that only 6% of OOIP under the gas cap was being recovered by vertical wells, horizontal development was initiated to increase oil recovery factor.

A 7-well horizontal project was successfully completed across the field (Chen, 1993). Production ratios for the horizontal wells were over 5 times greater than new vertical wells. Costs averaged about 3 times vertical ($1.7 million U.S. per horizontal). These wells contributed significantly to field oil production (Figure 3-18), accounting for 7% of the number of producing wells while producing 28% of the field's production.

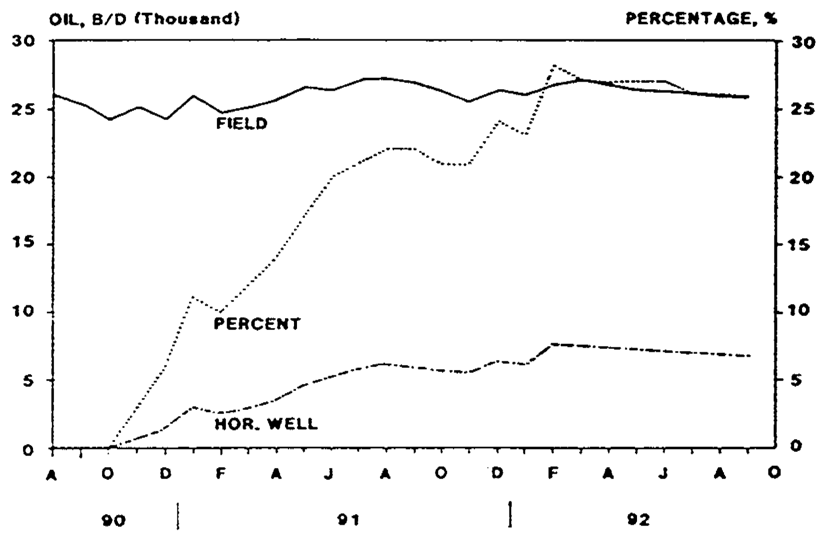


Figure 3-18. Safah Field Horizontal Well Production (Chen, 1993)

Ultimate oil recovery under the gas cap is increased in this application, and is dependent on pressure support and the distance to the gas/oil contact. The operator found that gas production has a far greater impact on oil rate than does water production. The first 4 horizontal wells were placed an average of 33 ft and 46 ft from the gas/oil and oil/water contacts, respectively. Future horizontal wells are to be positioned farther from the gas/oil contact.

Nimr Field (Southern Oman)

Horizontal wells have been used to delay water coning in the Nimr field, one of the largest fields in southern Oman. Oil is produced from the Haima and Gharif clastic formations, which are Cambro-Ordovician and Permo-Carboniferous in age. These formations are relatively unconsolidated and produced oil is relatively viscous (21°API, 400 cp). An extensive aquifer underlies the formations and acts as the principal drive mechanism.

Rapid water breakthrough was a significant challenge in the field's vertical wells, water having a mobility several hundred times greater than the oil. Horizontal wells showed both significantly increased initial production, as well as delayed water production (Figure 3-19).

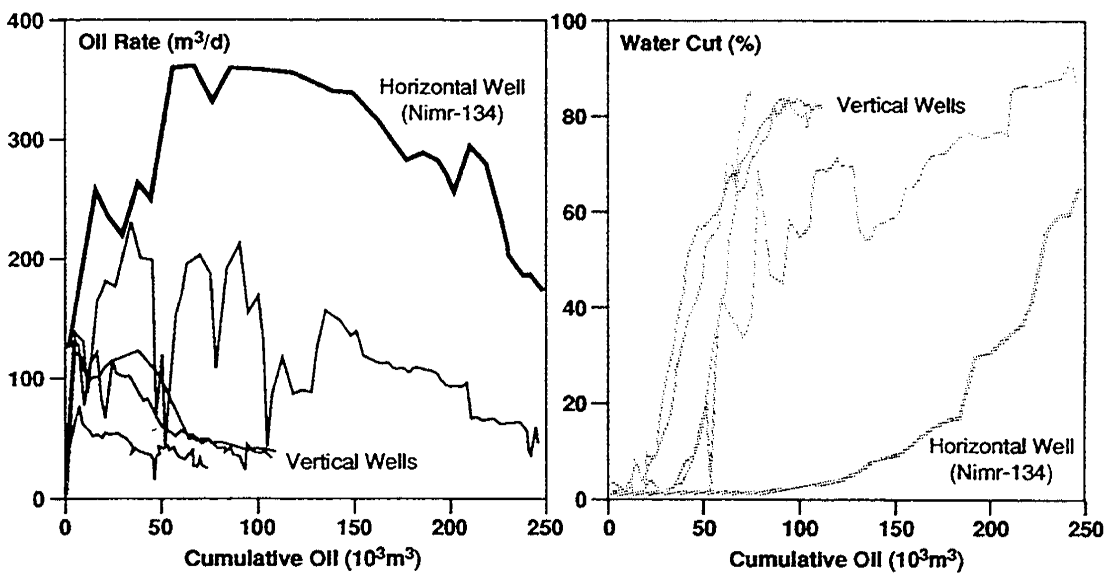


Figure 3-19. Typical Oil and Water Production in Nimr Field (Al-Rawahi et al., 1993)

Ultimate recovery with vertical wells was about 12% OOIP. Modeling suggested horizontal wells might raise the recovery to 15%, that is, a 25% increase in reserves. Experience has shown the actual improvement in recovery to exceed the calculated estimates.

Cost ratio for the first horizontal drilling campaign (about 22 horizontal wells) averaged about 1.5 times vertical costs. Productivity ratios ranged from 1.3 to 9.3, with an average value of 4.1.

Other Formations

In addition to the formations mentioned in the preceding paragraphs, several other fields have been drilled horizontally to delay water or gas coning. Additional sandstone reservoirs include the Troll field in the North Sea, and the North Herald, South Pepper, and Chervil fields in Australia. Other carbonate reservoirs include Elk Hills in California.

3.3 INTERSECTING FRACTURES

Naturally-fractured reservoirs are ideal candidates for horizontal drilling. Most natural fractures in deeper beds (>2000 ft) are oriented perpendicular to the direction of the least principal stress and are typically vertical to sub-vertical in orientation. This is true of a vertical fracture system as found in the Austin Chalk and the Bakken Shale. If the exact location of the fractures is unknown, then a vertical well has only a limited chance of intersecting a fracture. Conversely, a horizontal well oriented perpendicular to the fracture plane has a good chance of intersecting not only one, but possibly multiple fractures (Figure 3-20). This increased probability of success has made horizontal wells highly advantageous in fractured fields worldwide. A discussion of some of the noteworthy horizontal drilling projects in fractured formations follows.

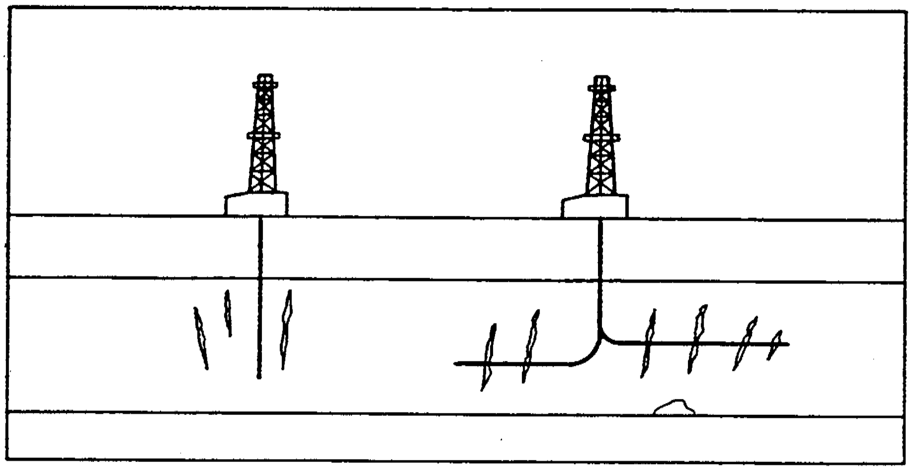


Figure 3-20. Fractured Reservoir Application

3.3.1 U.S.A. Intersecting Fracture Applications

Austin Chalk (Texas)

A well count through December 1993 indicates that of the 4219 completed horizontal wells in the United States, approximately 3400 (81%) were completed in the Austin Chalk or Buda formations in Texas. A significant amount of literature regarding the Austin Chalk formation already exists, so the amount of discussion here will not be commensurate with the percentage of wells drilled or level of current effort. However, the technical and economic highlights of the Austin Chalk do merit attention.

The Austin Chalk is an Upper Cretaceous fractured limestone that extends from Mexico to Sabine County in Texas (Figure 3-21), and across the Gulf States all the way to Florida. The Buda is Lower Cretaceous fractured limestone, and is very similar to the Austin Chalk. The Chalk was originally developed in the mid 1930s. Interest in the formation has cycled several times since initial development. Typical operator experience has shown limited success from vertical drilling (Sheikholeslami et al., 1989). In 1984, Amoco began testing variations of existing directional drilling equipment to drill horizontally into the Austin Chalk. The radius of curvature ranged from 15°-20° per hundred feet of hole drilled so that the wellbore was turned from vertical to horizontal in approximately 300-400 ft (TVD). In modern-day terminology this is referred to as "medium-radius" horizontal drilling.

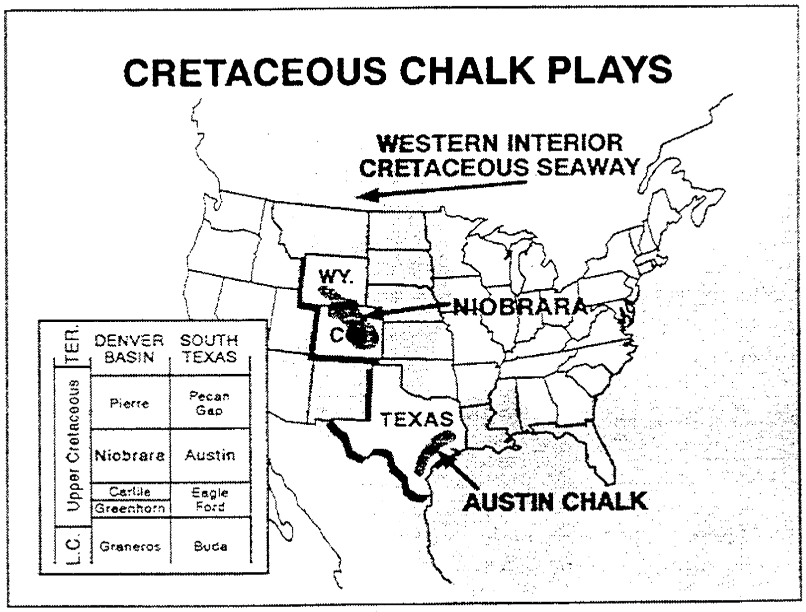


Figure 3-21. Cretaceous Chalk Plays (Campbell, 1991)

The economics of an Austin Chalk well requires a separate study in itself due to the difficulty in predicting production from fractured reservoirs. The cost to drill in the Austin Chalk now is significantly less than during the boom years of 1989-91. This is due to an increase in suppliers of horizontal services and also to the industry's present position on the learning curve (Figure 3-22). The cost of a horizontal well now ranges from $200,000 for a re-entry to approximately $1.0 million for a new well with stimulation included in the cost. The Austin Chalk development presents clear evidence that horizontal costs in a new area will generally decline 25-50% as experience progresses along the learning curve.

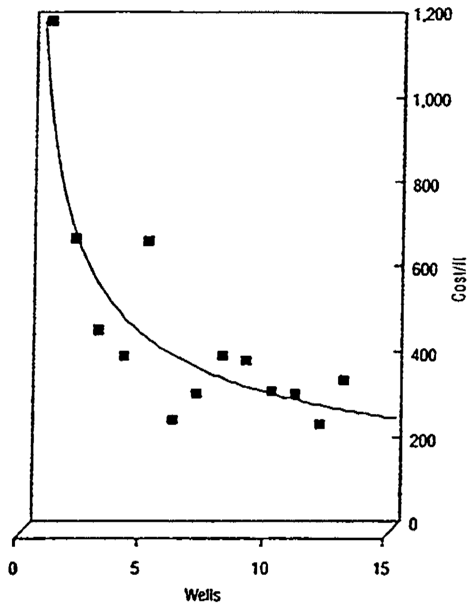


Figure 3-22. Oryx's Austin Chalk Drilling Costs (Moore, 1990)

Production records from the Giddings field indicate that average production from a vertical well is 68 MBO (Maloy, 1992), the majority being recovered early in the life of the well. The average production from a horizontal well is approximately 195 MBO. The incremental increase in ultimate recovery from vertical to horizontal would be over 127 MBO. For the Giddings field alone, this incremental increase due to horizontal technology could yield an estimated 400 MMBO of additional reserves.

An additional significant economic factor driving the use of horizontal wells in the Austin Chalk is the relatively low success rate of vertical wells. A study conducted in 1982 (Maloy, 1992) showed that 33% of vertical wells were unprofitable, 17% were marginally profitable, and about 50% were highly profitable. These results are in the context of an oil price of $32.50/bbl. Current economic success rates for vertical wells are much lower, given a significantly lower oil price. Since vertical wells are currently not an economically viable technique, the increase in reserves in the Austin Chalk due to horizontal exploitation is greater than that indicated by a purely technical comparison of vertical versus horizontal drilling costs and ultimate recoveries. In fact, operators report field reserves increases in the range of 100 to 300% with horizontal wells.

Bakken Shale (North Dakota)

The Bakken Shale in the Williston Basin is the second most active area for horizontal drilling in the United States. Approximately 215 horizontal wells (5.7% of horizontal U.S. wells) have been completed in the Bakken Shale since 1987. The Bakken Shale is Mississippian-Devonian in age and is centered on the border between Montana and North Dakota (Figure 3-23). The trend also extends into Saskatchewan where the Mission Canyon and Charles formations have been drilled horizontally.

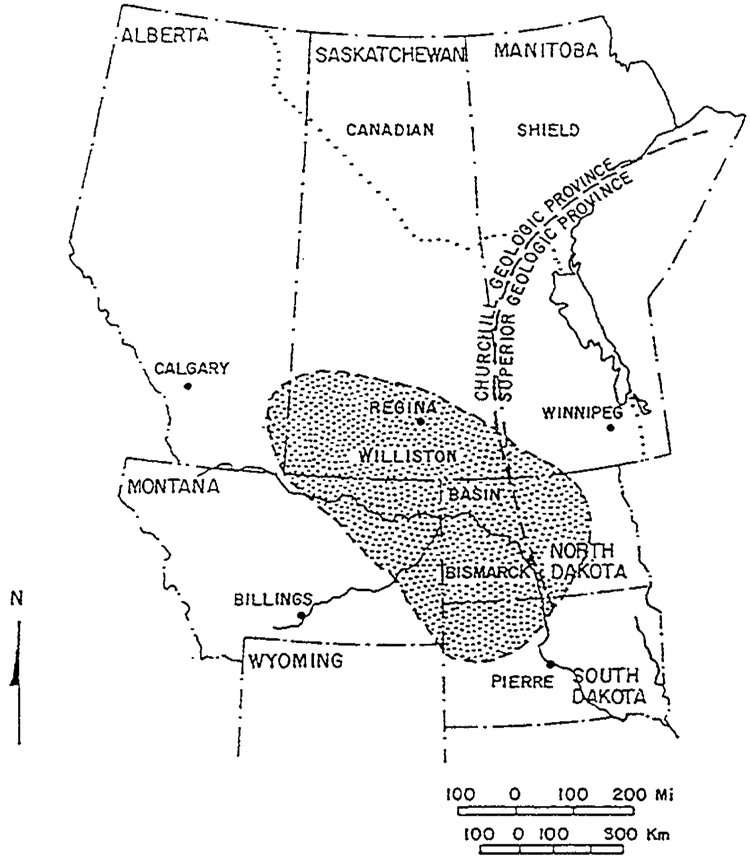


Figure 3-23. The Bakken Shale (LeFever, 1991)

The Bakken is an organic-rich shale that forms oil at depths below 9500 ft. The generation of hydrocarbons causes a volume expansion and subsequent microfractures. Since there is essentially no matrix porosity, all hydrocarbon storage is in the fractures and best exploited with a horizontal well.

A typical Bakken Shale horizontal well averages 265 BOPD compared to 84 BOPD for a vertical well (LeFever, 1991). Thus, a 3:1 increase in production is typical. The cost for a horizontal well is approximately \$1.25—\$1.50 million: approximately double the cost of a vertical well. Significant cost reductions have been enjoyed by operators in the Bakken as experience is gained (Figure 3-24).

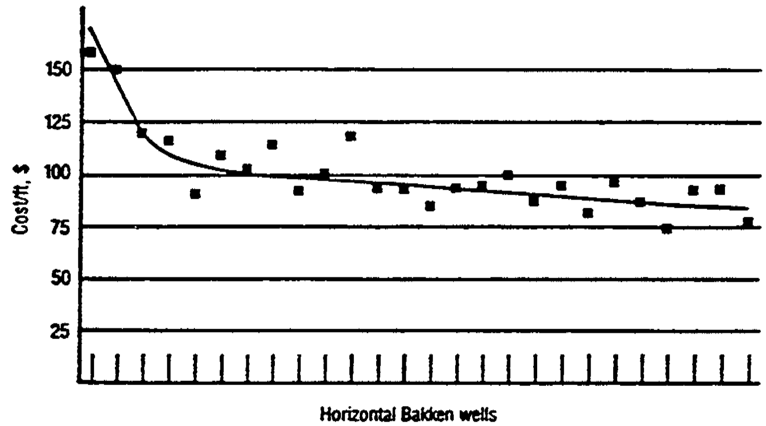


Figure 3-24. Meridian's Bakken Well Costs (Moore, 1989)

The main justification for drilling the Bakken horizontally is the same as for the Austin Chalk. The probability of intersecting a vertical fracture with a vertical well is relatively low; a horizontal well significantly increases the probability of success. With that in mind, it can be stated that horizontal drilling has the potential to increase the reserves in the Williston Basin by several hundred million barrels. This is oil that would not have been economically available by vertical exploitation.

The Ratcliffe interval (DOE Class II) of the Madison group (Figure 3-25) lies above the Bakken Shale and has been tested several times with horizontal drilling. This argillaceous limestone has some porosity (10-17%) but no permeability, and the oil is trapped in fractures. Initial attempts at horizontal drilling in the Ratcliffe proved unsuccessful (LeFever, 1991).

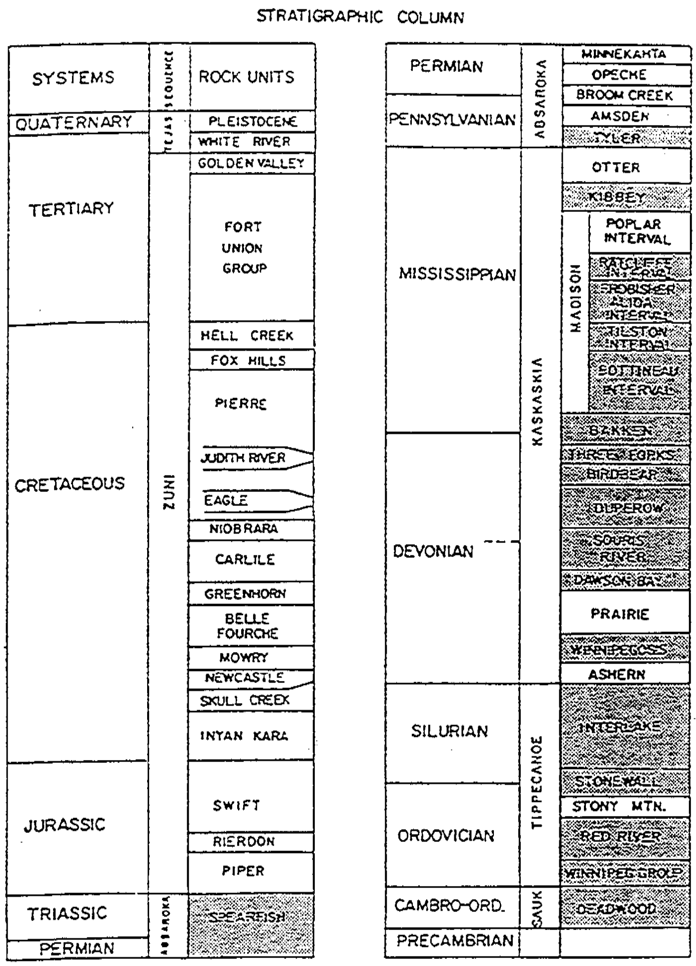


Figure 3-25. Stratigraphic Column of Williston Basin

There have been at least five horizontal wells attempted in the Ordovician Red River (Figure 3-25). Results to date have shown no significant improvement due to horizontal wellbores (LeFever, 1991).

Niobrara (Wyoming)

The Niobrara formation is Cretaceous in age and exists in at least four Rocky Mountain states as shown in Figure 3-26.

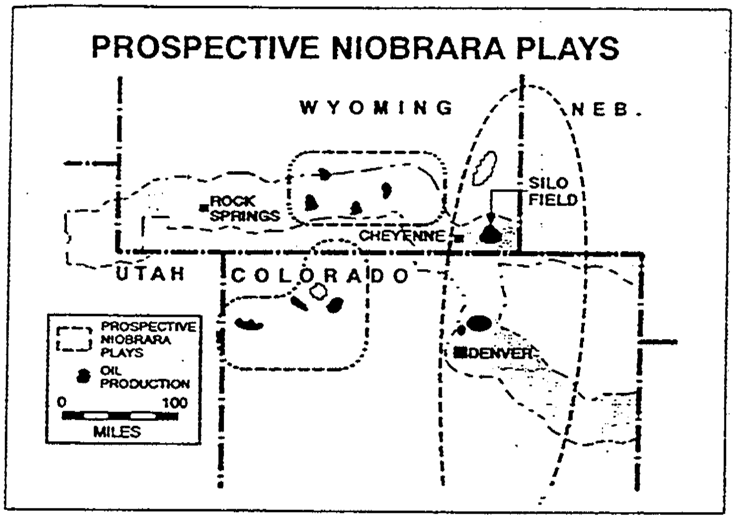


Figure 3-26. Niobrara Formation (Campbell, 1991)

The Niobrara consists of regionally correlational "benches" of calcareous chalk separated by sequences of organic-rich marlstones. The brittleness of the chalk combined with the high source potential of the marlstones cause the Niobrara to be an excellent candidate for extensive oil-filled fractures (Campbell, 1991). The Silo field has seen the most horizontal activity, but initial production results were not encouraging. Initial production rates exceeding 200 BOPD rapidly declined to below 30 BOPD. However, the practice of choking back on initial production appears to slow decline and increase cumulative production.

Trenton/Black River (Michigan)

Other fractured carbonates explored with horizontal drilling are the Ordovician-aged Trenton and Black River formations in southern Michigan. Short-radius drilling was used in the late 1980s to drill 300-700 ft laterals in approximately 10 wells (*Oil World* Staff, 1990). The cost for these horizontal wells ranged from $140,000-$225,000 and, in some cases, increased production by more than 100 BOPD. Other Michigan Basin formations targeted for horizontal drilling include the Antrim Shale (gas) and Silurian Reef.

Devonian Shale (Appalachian Basin)

The Appalachian Basin covers an area of 185,000 square miles and encompasses oil and gas production from Alabama, Georgia, Kentucky, Maryland, New York, North and South Carolina, Ohio, Pennsylvania, Tennessee, Virginia, and West Virginia (Garton, 1990). As of the end of 1990, approximately 26 horizontal wells had been drilled in this area, with 21 being attributed to coalbed degasification in Alabama. At least three of the remaining five horizontal wells were drilled in the Devonian Shale. Two of those wells were co-funded by DOE/Morgantown and are well publicized. However, their importance in the growth of this technology merits their inclusion in this discussion of horizontal activity.

The Devonian Shale has low porosity and permeability, yet is highly fractured. It underlies much of the Appalachian Basin and has been penetrated by thousands of vertical wells since the 1980s. Formation damage resulting from drilling operations is a major problem in the Devonian Shale. DOE-funded operations have emphasized the development of air-drilling techniques for horizontal wells. DOE-sponsored wells have been classified as technical successes with open flows from 2 to 11 times that of the average vertical well in the area. Detailed discussion of activity in the Devonian Shale is presented in Chapter 5 (Gas Applications).

Other Formations

Several other naturally-fractured fields in the U.S. have been tested with horizontal drilling. Various operators have attempted to transfer tools and techniques developed for use in the Austin Chalk to other fields with similar lithology. Success from these efforts has been mixed.

The Saratoga Chalk lies across the border of Texas and Louisiana, is Upper Cretaceous in age, and is naturally fractured. Several operators have acquired drilling rights in this formation. Even though early projects did not produce an economically successful well (Lyle, 1990), recent efforts have resulted in economically successful wells, according to project survey results (see Volume 1).

Several formations in Oklahoma have been drilled horizontally to connect and drain fracture networks, among them the Chester, Viola, Morrow, Woodford Shale, and Mississippi (Bryant et al., 1991). Of 23 horizontal wells across Oklahoma, almost half have targeted these fractured formations (Figure 3-27).

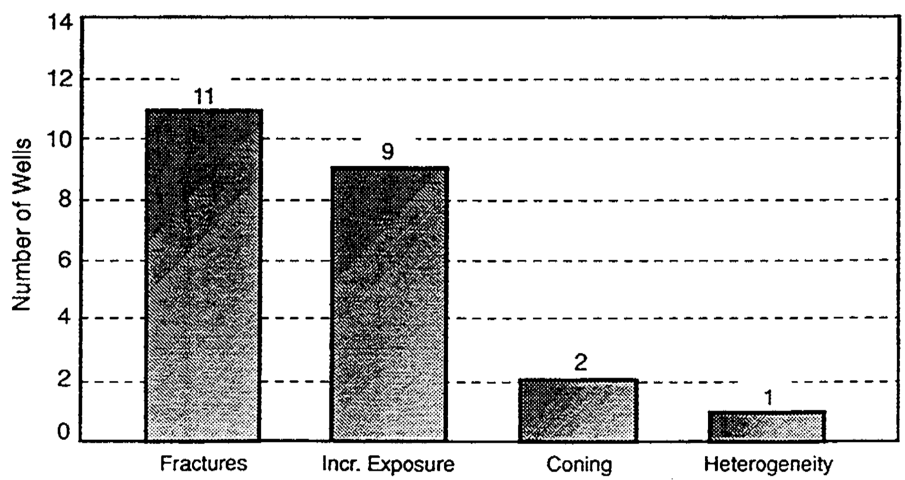


Figure 3-27. Primary Objective of Oklahoma Horizontal Wells (Bryant et al., 1991)

Early results show that economic application of horizontal technology is difficult in the various Oklahoma formations. Among the reasons are: 1) difficult geologic conditions including high formation dips, hard rocks, low reservoir pressures, and structural variations, 2) learning curves are immature in most areas due to the small number of wells, and a consistent or typical well plan for this area is unlikely, and 3) most Oklahoma horizontal well activity has been performed by small independents (Bryant et al., 1991). This early picture is expected to improve, although success will continue to hinge on careful planning and knowledge of the geology.

3.3.2 Canadian Intersecting Fracture Applications

Horizontal wells drilled in fractured carbonates for light oil account for 45% of the total horizontal wells drilled in Western Canada. These wells have been drilled in more than 100 different pools/project areas. All of these fractured carbonate pools are categorized as Intersecting Fracture applications since they all involve crossing or paralleling fracture trends.

Characteristics considered, where available, are: reservoir geology, reservoir rock and fluid properties, hydrocarbon in place, existing pressure and permeability, size of the drilling spacing unit in the initial pool development, drive mechanism, length of the horizontal lateral, production ratio, and accelerated and/or incremental reserves developed. Other advantages of horizontal well technology, such as environmental, are also examined. These reservoirs can be subdivided into general geographic areas as follows: Manitoba Carbonate Pools, Saskatchewan Midale Beds; Frobisher/Alida; Tilston, Miscellaneous Saskatchewan Carbonate Pools, Alberta Carbonate Pools, and British Columbia Carbonate Pools. The location of the these major oil plays in Western Canada is shown in Figure 3-28.

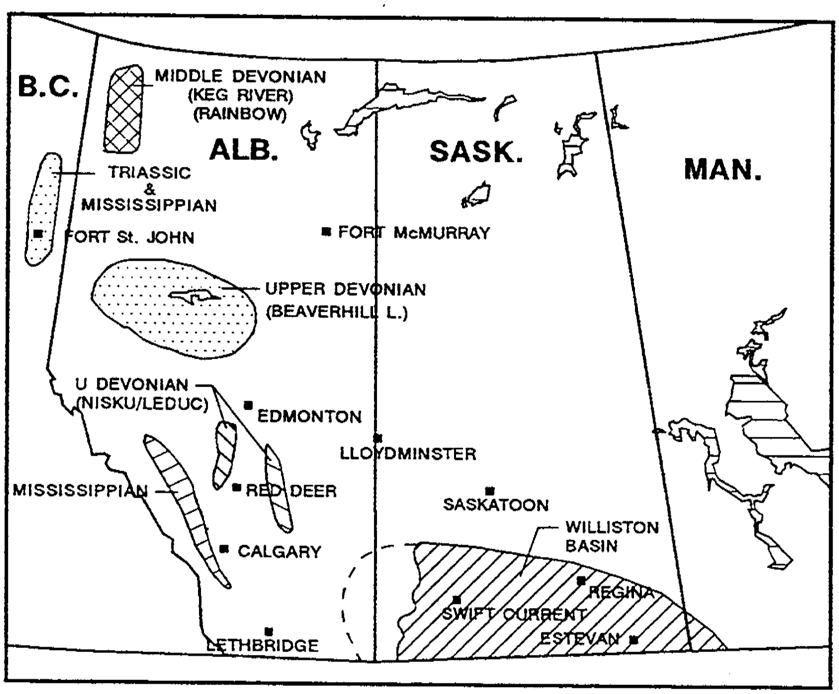


Figure 3-28. Carbonate Light-Oil Pools in Western Canada Exploited With Horizontal Technology

Lodgepole (Manitoba)

At the present early stage of horizontal technology in the province of Manitoba, the primary target appears to be the Lodgepole Formation, particularly the large Lodgepole pools of the Virden type, and small Lodgepole pools along the sub-crop edge of the Virden and Whitewater Lake members (Fox et al., 1994).

Horizontal drilling activity in Manitoba is gaining momentum. There was one well drilled at the end of 1992. This number had increased to 17 wells by the end of 1993. Eleven wells are completed in the Lodgepole Formation, a low-porosity, low-permeability fractured carbonate reservoir. A number of these pools have been developed with water floods. This may be an asset to a horizontal well project since the maintenance of reservoir energy is essential to maximize recovery. However, in most projects, this results in high water production, leading to higher operating cost. Water floods may also have a negative impact on oil production and ultimate recovery if proper water handling facilities are not available. Fortunately, for most mature projects, this is not a problem.

Mission Canyon (Manitoba)

The Mission Canyon Formation is another fractured carbonate formation with potential for development by horizontal wells. The primary trapping mechanism is the truncation of the porous grainstone, packstone, and wackestone reservoir beds at the Mississippian erosional surface. There are over 40 Mission Canyon and small Lodgepole pools with recoverable reserves each of about 200 MBO that may be economically attractive for horizontal development. General pool parameters are summarized in Table 3-4.

TABLE 3-4. Typical Reservoir Properties: Mission Canyon

Depth	200-3500 ft	API Oil Gravity	25-45°
Porosity	9-14%	Initial Prod. (Vert.)	20-50 BOPD
Water Saturation	35-50%	Primary Recovery	5-15%
Horizontal Perm.	10 md	Secondary Recovery	20-35%

Midale Beds (Saskatchewan)

A cross-section of the Midale pools in Saskatchewan that are developed with horizontal wells includes: Weyburn (35 wells), Tatagua (24 wells), Midale (10 wells), Steelman (3 wells), West Kingsford (3 wells), Machon (3 wells), Lougheed (10 wells), Glen Ewan (1 well), Elswick (3 wells), Pinto (2 wells), and others (7).

The Midale Beds Reservoir is the most westerly oil accumulation (currently identified) along the stratigraphic producing trend of the Mississippian Beds of the northeast flank of the Williston Basin. The Midale Beds reservoir is divided into a lower Vuggy Zone and an overlying Marly. The Vuggy consists of heterogeneous sub-tidal limestone. Carbonate mud (mudstone and wackestone) were deposited in quiet waters in the intershoal regions. Carbonate sands (packstones and grainstones) were deposited in the higher energy shoals or bar regions. This resulted in a depositional environment with a wide range of porosities and matrix permeabilities. In addition, the zone is generally highly fractured. The fractures and highly permeable carbonate sand bodies within the reservoir control the magnitude and direction of the permeability anisotropy. Horizontal permeability along the fracture direction may be 10 to 20 times greater than that perpendicular to the fracture direction.

The average permeability in the Marly is generally less than in the Vuggy. Moreover, the Marly zone is fractured less intensely. As a result, the Marly has a higher remaining oil saturation and is usually the target for horizontal wells (Galas et al., 1994). Table 3-5 summarizes the rock and fluid properties for these pools.

TABLE 3-5. Typical Reservoir Properties: Midale Beds/Mississippian Formation

Depth	4,500 ft	Marly Connate Water Saturation	30%
Marly Porosity	20-30%	Vuggy Connate Water Saturation	50%
Vuggy Porosity	10-15%	API Oil Gravity	28°
Marly Permeability	5-15 md	Formation Volume Factor	1.1
Vuggy Permeability	5-10 md	Oil Viscosity	3.4 cp

These pools are typically mature, and have been on production for more than thirty years. Initial reservoir pressure was about 2200 psi. Some pools, such as Tatagua, have strong aquifer support. As a result, the pressure has been maintained close to original. Many of the pools, however, have experienced only partial water drive, with solution gas drive as the main drive mechanism. Most of the major pools have been under water injection for several years.

By the end of 1993, there were about 100 horizontal wells drilled in the Midale. Wells were initially drilled perpendicular to the fracture trend. Conventional mud systems were typically used. Shell Canada was among the first operators to employ horizontal wells in the Midale beds. Table 3-6 illustrates the reduction in both normal and problem time and costs achieved in the first three horizontal wells placed in the Midale pool. Since these early efforts, well productive lengths have been extended through improved geosteering, and re-entries have been attempted with mixed results. In general, new well costs have been reduced to about $680,000 at a TVD of $\pm$6300 ft.

TABLE 3-6. Time and Cost for Shell Canada Midale Wells

	TIME		COST	
	NORMAL	TROUBLE	NORMAL	TROUBLE
Well 1:	23 days	16 days	$1,286,000	$448,000
Well 2:	42 days	11 days	$1,126,000	$172,000
Well 3:	27 days	4 days	$ 751,000	$ 93,000

Although a rapidly declining learning curve was achieved for trouble time, the results of the wells drilled in 1989-92 were not very attractive. Formation damage was apparently a major problem. Moreover, the location of wells in the formation and the orientation of wells relative to the fracture trend may not have been optimized. In the Weyburn project, a comparison of the performance of wells drilled perpendicular to the fracture trend versus wells drilled parallel to the fractures suggested that higher oil production was obtained from the wells drilled parallel to the fracture trend. In addition, underbalanced drilling, using either a nitrogen system or natural gas, substantially improved well performance (Deis et al., 1993). This use of underbalanced or near-balanced systems, though expensive, appears to be economic and is becoming a popular technique for drilling in this formation.

The optimum well orientation (with respect to the direction of minimum and maximum horizontal permeability) appears to be site specific and sensitive to horizontal permeability anisotropy, drive mechanism, and waterflood efficiency. In some cases, wells drain unswept oil when oriented parallel to the fracture trends. In other cases, the low permeability of the matrix requires the horizontal well to cross natural fractures perpendicularly to produce at economic rates.

The Midale formation is one of the major light-oil bearing formations in Western Canada. OOIP in these pools is in excess of 6 BBO. Due to the relatively low permeability, recovery to date by primary and secondary methods is about 20%. Initial horizontal wells drilled in this formation were marginally attractive. However, as technology improves, the number of horizontal wells drilled continues to increase.

The first horizontal wells in the Midale Beds cost 3 times as much as vertical wells and had production ratios in the range of 1 to 2. Operators' drilling and completion experiences have shown that hole stability is not a major problem. Open-hole completions have begun to be used, leading to reduced drilling times. Cost ratios have been reduced to 1-2. With improved reservoir characterization, geosteering performance and balanced/underbalanced drilling practices, horizontal well production ratios have increased to the range of 3-5. Recovery factors are also improving. Detailed incremental reserves data have not yet been generated, although it is generally anticipated that incremental reserves will be proved as these applications mature.

Frobisher/Alida (Saskatchewan)

The Frobisher/Alida Beds are the most active and exciting formations for horizontal well technology in Southeastern Saskatchewan. More than 150 horizontal wells have been drilled in the formation. Several of the pools have been producing for more than 35 years. In some cases, waterflood projects are in place, resulting in recovery factors of about 35%. Horizontal wells have initial production rates between 200 to 300 BOPD. This is typically 5 times greater than neighboring vertical wells. In addition, the estimated ultimate horizontal well production for the spacing unit (ranging from 80 to 160 acres) is 200 to 300 MBO.

Horizontal wells have been drilled in 30 Frobisher/Alida Beds pools. The major pools are Gainsborough (10 wells), Hastings (14 wells), Ingoldsby (26 wells), Willmar (14 wells), Rosebank (10 wells), Alida (11 wells), Nottingham (5 wells), Central (6 wells), Manor (17 wells), Workman/Sherwood (8 wells), Lost Horse Hills (2 wells), and Wauchope (3 wells).

Along the northeastern flank of the Williston Basin, the Sub-Waterous unconformity truncates the Mississippian section so that progressively older beds lie below the erosional surface towards the northeast. The following listing illustrates that detailed stratigraphic review is necessary where layering and bedding characteristics control productivity. Attributes of the main rock units of the Frobisher/Alida from the base upwards are as follows:

1. Lower Oolite. The reservoir is dominated by Oolite grainstones, packstones, and wackestones. Original porosity in the grainstone and packstone was coarse interparticle. However, some of the porosity has been modified to Vuggy porosity. Horizontal permeabilities are near 100 md. Vertical permeability is usually low and water saturation high (Vigrass et al., 1994).

2. Skeletal Wackestone. The skeletal wackestone consists mainly of fossil hash in an abundant lime-mud matrix. Some dolomitization has increased the porosity in sections. Vertical fractures are present, though not as abundant as the Upper and Lower Oolite. Porosity tends to be higher, permeability lower (7 to 20 md), and water saturation higher than the Upper Oolite. This unit may be a major oil source.

3. Upper Oolite. The Upper Oolite is predominantly Oolite grainstone and packstone with inter-Oolite, Vuggy, and Fenestal porosity. Permeability is sporadic, but may be up to 100 md. Some vertical fractures are present. This unit is an important oil-bearing formation.

4. Frobisher Limestone. Where present, this zone is directly under the impermeable Marly. The zone consists of fragmental to crystalline limestone with thin stringers of anhydrite and Marly dolomite. In some areas, the unit is a major source of hydrocarbons.

5. Caprock. The Caprock consists of Mississippian carbonate rocks immediately below the sub-Waterous unconformity where original pore space has been rendered inaccessible by anhydrite plugging.

These formations represent a good setting for horizontal well technology. Permeabilities vary widely (5 to 100+ md). However, the reservoirs are heterogenous, and the effective drainage areas for vertical wells are apparently smaller than previously estimated (i.e., less than 80 acres). Horizontal wells appear to be capable of improving the aerial sweep efficiency. Coning of vertical wells may also restrict the drainage areas. The presence of fractures undoubtedly has a positive impact on recovery with horizontal wells. However, the optimum orientation of horizontal wells with respect to major fracture trends appears to be pool-specific. Table 3-7 summarizes general parameters and rock and fluid properties. Recoveries in the drainage areas of the horizontal wells range from 15 to 25%. Incremental reserves due to horizontal well technology are estimated as 3 to 5%.

TABLE 3-7. Typical Reservoir Properties: Frobisher/Alida

Formation Depth	3500-5000 ft	Temperature	109°F
Gross Thickness	50-80 ft	API Oil Gravity	37.5°
Net Pay	30-50 ft	Initial Pressure	1520 psi
Porosity	10-15%	Drive Mechanism	Water Drive

Vertical wells drilled today generally produce about 50 BOPD. The production ratio for horizontal wells is 4-5. Where a strong aquifer is present, water cut generally increases to 70-80% after about 1 year of production. However, since most projects are in mature pools, the combined water cut for the field may decrease.

The cost for drilling and completing a well is \$600,000-700,000 at a TVD of 4800-5500 ft. Most wells pay out in less than 2 years. Formation damage and high water production are the major concerns. Figure 3-29 shows the layout and spacing of an Alida development. Note that the wells are oriented both normal and parallel to the regional fracture trend (NE-SW).

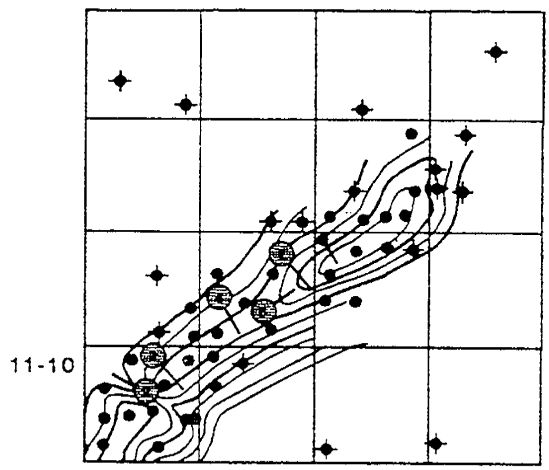


Figure 3-29. Horizontal Wells Both Normal and Parallel to Natural Fractures (DEA-44 WH#66)

In this particular pool (Figure 3-29), a second set of fractures was identified on the flanks of the structure oriented perpendicular to the regional fracture trend. It has been observed that these flank fractures may extend down to the underlying aquifer, while the "crest" fractures do not. This requires customizing workover and stimulation activities to ensure the wells are not short-circuited by a direct flow path to the underlying aquifer. Typical stimulation is HCl acid wash to remove drilling damage. Water shut-off has been accomplished with open-hole packers.

Table 3-8 summarizes the productivity of some of the wells depicted in Figure 3-29. Well #2 is effectively non-productive due to an unexpected variation in geology. A second lateral was then drilled from this well in an attempt to access productive reservoir. No production data are currently available for the second lateral.

TABLE 3-8. Rosebank Horizontal Well Performance Summary

		LENGTH (ft)			PROD. (BOPD)	
		PLAN	ACTUAL	PAY	ESTIMATED	ACTUAL
INITIAL WELL	15-14	2100	1470	1181	340	300
2nd WELL	11-10	1640	1240	1033	353	18
3rd WELL	15-10	1988	2000	1960	340	393
4th WELL	7-14	2234	2132	1170	272	435
5th WELL	5-14	2312	1700	1125	408	206

Detailed review of this pool development suggests that significant incremental reserves have been generated by these horizontal wells. Production from vertical wells surrounding the horizontal wells does not appear to be affected, even though the horizontal wells are crossing within the vertical wells' 40-acre spacing unit (Vigrass et al., 1994).

Tilston/Souris Valley (Saskatchewan)

The Tilston Beds and Souris Valley are the upper zones of the Lodgepole Formation. The major pools that have been drilled horizontally in this formation are Parkman (10 wells), Hazlewood (13 wells), Moose Valley (5 wells), Nottingham N. (4 wells), Edenvale (3 wells), Frys (2 wells), and Lightning (2 wells). Most of these were drilled in 1993. As a result, the production history is limited. The major active operator in this area has reported good results from horizontal wells with lower total cost per produced barrel.

Miscellaneous Saskatchewan Carbonates

Other fractured carbonates where horizontal technology has been applied in Saskatchewan include Oungre Field Ratcliffe Beds Limestone Formation (6 wells), Minton Red River Ordovician Dolomitic Limestone, and Zaller Birdbear Devonian Limestone. These applications began in 1993; thus, there are insufficient field data currently available for any analysis or projections.

Rundle/Pekisko (Alberta)

The major pools in which horizontal wells have been drilled in the Pekisko in Alberta are Twining (5 wells), Gilby (6 wells), Del Bonita (1 well), Spring Coulee (1 well), Sylvan Lake (2 wells), and Medicine River (1 well). These pools are generally tight limestone. However, in some areas, the geology may be classified as crinidoal or dolomitic limestone. There are also some fractures present, but their frequency and orientation are locally controlled. General reservoir properties are summarized in Table 3-9.

TABLE 3-9. Typical Reservoir Properties: Rundle/Pekisko

Matrix Porosity	1-10%	API Oil Gravity	<30°
Horizontal Permeability	1-10 md	Reservoir Pressure	1200-1800 psi
Oil Viscosity	0.5-1.5 cp	TVD	4000-6000 ft
Water Saturation Res.	8-18%	Oil Saturation Res.	20-40%

Results of horizontal applications in this formation have not generally been attractive. One well in the Twining pool produced at an initial rate of 157 BOPD and a stabilized rate of 80 BOPD, representing a horizontal production ratio of 5. The typical horizontal cost ratio is 3. The well drilled in the Medicine River pool has provided the best results to date. Production improved after three months to 250 BOPD. This formation is a major resource base of more than 1 BBOIP, with a recovery factor to date (from vertical wells) of less than 5%. The key issue in this play appears to be the low permeability of the matrix. Underbalanced drilling has shown marginal success to date. This major oil resource may represent an excellent candidate for horizontal development when (and if) this tight matrix problem is overcome.

Banff Formation (Alberta)

The major Alberta pools with horizontal wells in the Banff Formation are Cherhill (12 wells), Glenevis (10 wells), Watts (1 well), and Michichi (1 well). Horizontal drilling in the Cherhill and Glenevis areas began in 1992. Early production results are economically attractive. Production is from a limestone or dolomitic limestone. A strong bottom aquifer is sometimes present. Wells are generally new drills, as opposed to re-entries. The horizontal lateral is typically completed open hole. Cost ratio is typically 2. Initial production rates are 300 to 350 BOPD; the production ratio is about 2. The Glenevis pool produces at a high water cut ratio. Very little detailed production or economic data are available on these projects and no reports have been made describing increased reserves. Table 3-10 summarizes the general fluid and rock properties of these plays.

TABLE 3-10. Typical Reservoir Properties: Banff Formation

Total Porosity	12-22%	Initial Reservoir Pressure	1400-1800 psi
API Oil Gravity	20-30°	Viscosity	1-6 cp
Horizontal Permeability	10-20 md	TVD	5000-9000 ft

Upper Devonian Nisku/Leduc (Alberta)

The Upper Devonian Nisku/Leduc is a major carbonate oil and gas accumulation in Central Alberta with OOIP in excess of 7 BBO. The pools are generally mature and have been on production since the mid-1950s.

In general, the pools are medium- to coarse-grained dolomite with large vugs. The Ireton shale separates the Nisku from the Leduc. The Leduc sits on the Cooking Lake aquifer, which is made up of a fragmental limestone and provides the common energy source for the complex. Where the natural water drive is not very effective, water injection schemes and/or solvent flood schemes have been implemented. As a result, many of these pools have recovery factors in excess of 50%. Table 3-11 summarizes rock and fluid properties.

TABLE 3-11. Typical Reservoir Properties: Nisku/Leduc

Matrix Permeability	30-45 md	Porosity	5-10%
Viscosity	0.25-0.5 cp	Initial Water Cut	8-14%
API Oil Gravity	35-40°	TVD	7000-10,000 ft

The matrix porosity of these reservoirs ranges from 5 to 10%; however, secondary porosity, consisting of vugs and fractures, generally enhances the porosity. Effective reservoir permeability may range up to hundreds of millidarcies, and the production rates reflect these good reservoir qualities. Horizontal wells drilled in these pools are located in the sandwich zone between the advancing aquifer and the secondary gas cap (Figure 3-30). Wells have also been located in sections of the pool exhibiting poor sweep efficiency.

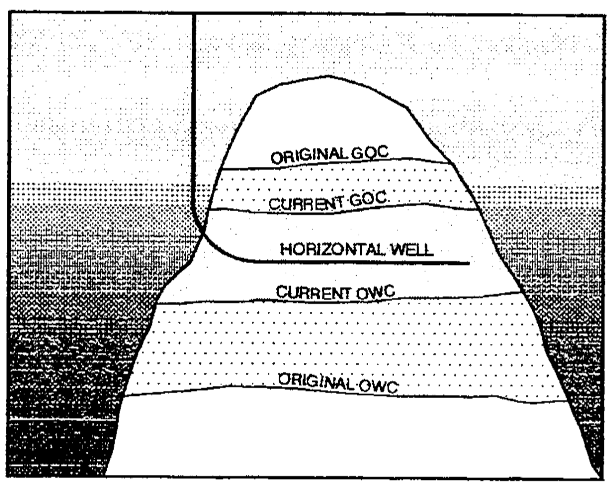


Figure 3-30. Horizontal Well in Oil Sandwich Between Gas Cap and Bottom Water

These horizontal wells have been very successful in reducing coning, and have been responsible for substantial incremental oil recovery. Despite the high vertical-well recovery of these pools, it is anticipated that additional horizontal wells will be drilled in these formations as additional candidates are identified.

Beaverhill Lake (Alberta)

The Beaverhill Lake complex is a major oil and gas accumulation with OOIP in excess of 6 BBO. The reservoirs are generally fossil atolls with a well defined flanking reef and central lagoon. Widespread dense beds divide the reservoirs into separate porous units. Secondary and tertiary schemes have been established to augment primary production. As a result, recovery factors in the range of 40 to 60% are estimated for the pools in this area.

The Virginia Hills pool was discovered in 1957. The main reef is 150 ft thick. A waterflood project implemented in the pool is expected to increase recovery factor from 35% to 45%. Horizontal re-entries are being used to improve the sweep efficiency of the water flood and further enhance recovery factor. Nine horizontal wells have been drilled in the pool to date.

The Swan Hills pool was also discovered in 1957, and is one of the major oil accumulations in North Central Alberta. The estimated OOIP is in excess of 2.5 BBO. Both waterflood and solvent-flood projects have been implemented. Estimated recovery ranges from 40 to 60%. To date, 15 horizontal wells have been drilled in the pool. These are expected to improve the sweep efficiency and to capture unswept oil. The major operator (Amoco Canada) has indicated that the project is technically and economically successful, and expects to drill additional horizontal wells.

Baldonnel (British Columbia)

The Triassic Baldonnel formation is a 180-200 ft dolomite sequence that unconformably overlies the Triassic Charlie Lake formation and is itself unconformably overlain by the Jurassic Nordeg. The Birch oil/gas pool is located south of the Nig Creek Baldonnel gas pool (GIP 655 Bcf) and is part of this large stratigraphic trap. Post-Triassic erosion of the Baldonnel north and east of Nig Creek and anticlines generated during laramide thrusting created the stratigraphic and structural elements of this trap. Hydrocarbon migration post-dated these events and the resulting distribution of hydrocarbons consists of gas in structurally high areas, while oil occupies lower structural positions.

The Birch Baldonnel oil pool (Table 3-12), discovered in 1978, lies southwest of the associated Birch Baldonnel gas pool. The pool produces from porous dolomite zones at a depth of 4000 to 5000 ft. The gas/oil contact in the pool is $\pm$1400 ft subsea. An oil/water contact in the pool has been tentatively established from completion work. The 110-ft oil column has been tapped by 15 vertical wells and has produced 446 MBO (0.5% recovery factor) from 1978 to 1986.

TABLE 3-12. Typical Reservoir Properties: Triassic Baldonnel

Formation Thickness	150-180 ft	TVD	4000-5000 ft
Net Oil Thickness	90-110 ft	Porosity	8-12%
API Oil Gravity	39-42°	Horizontal Permeability	12-20 md

Production is predominantly from the Baldonnel zones 'B' through 'D.' Not all zones were completed in each well, however. Natural fracturing is evident in all cored wells and is a very important factor in the productivity of the Baldonnel. Eleven horizontal wells have been drilled to date, with two wells being drilled presently.

An operator has licensed two horizontal wells northeast of Birch in the Nig pool offsetting a Baldonnel oil well that produced 127 MBO. A potentially large oil pool exists in this area and local operators are formulating development plans.

3.3.3 International Intersecting Fracture Applications

Rospo Mare (Italy)

One of the first oil fields drilled with horizontal technology was the Rospo Mare field in the Adriatic Sea. This karstic-type carbonate has nearly zero matrix porosity and yet has oil-in-place of approximately 470 MMBO. Oil is contained in fractures, vugs and cavities throughout the 490-ft pay interval (Figure 3-31).

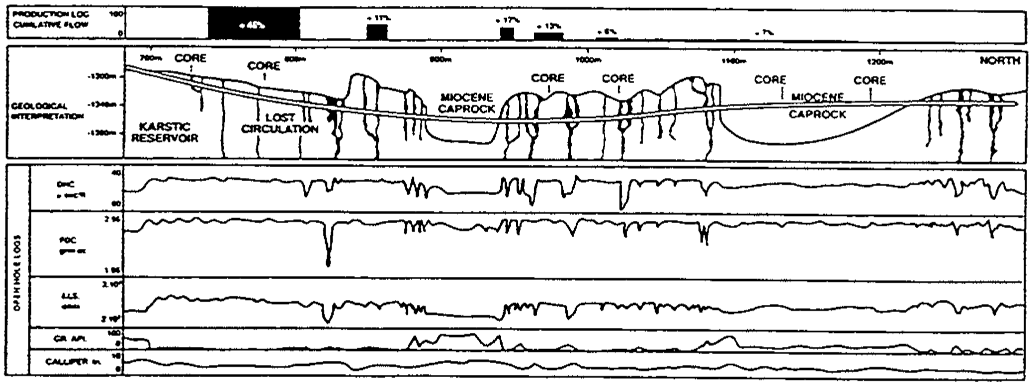


Figure 3-31. Elf Rospo Mare Horizontal Well (de Montigny et al., 1988)

As of early 1991, 18 horizontal wells had been drilled from two platforms. Elf Aquitaine estimated that horizontal production was about 3 to 4 times greater than a vertical well (*Petrole Informations* Staff, 1988). Comparison was difficult since only a few vertical wells were drilled in the pilot program. Cost ratio for horizontal development was estimated as 1.2 times conventional costs. Rospo Mare is a typical example of an application where only horizontal drilling can allow economic development of a field's resources.

3.4 LAYERED/HETEROGENEOUS RESERVOIRS

Directional and horizontal drilling allows the operator to steer his well to productive pay zones otherwise inaccessible by a vertical wellbore. One possible application is the use of horizontal wellbores to connect productive intervals separated by impermeable barriers, as shown in Figure 3-32. Another potential use is to access productive zones that are isolated in areal extent. Channel sands and reefs (Figure 3-33) are examples of this type of application.

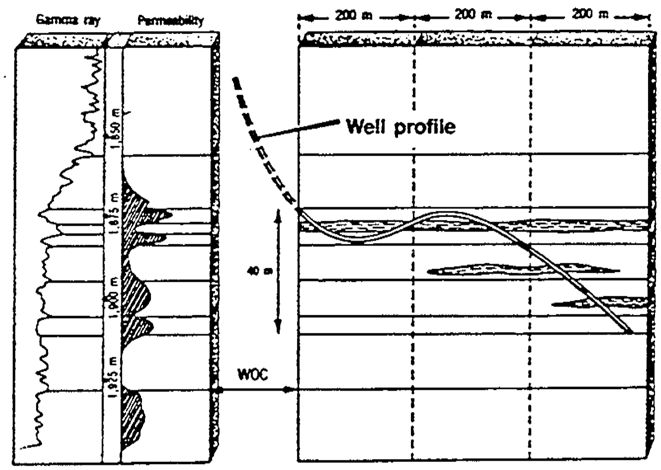


Figure 3-32. Elf Layered Reservoir (de Montigny et al., 1988)

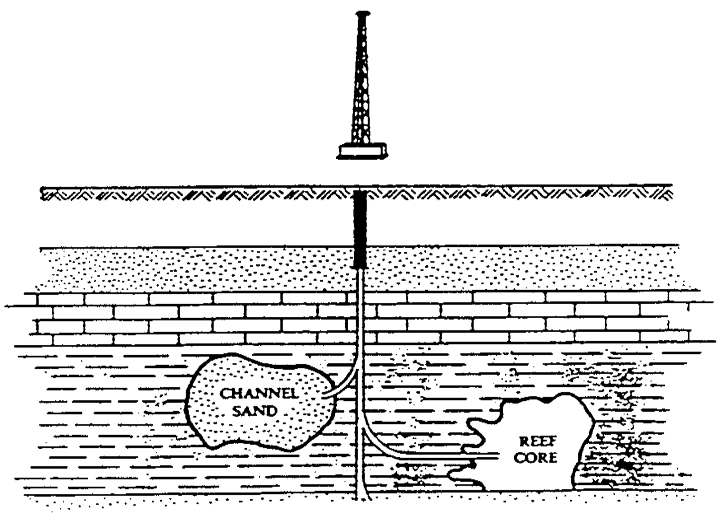


Figure 3-33. Channel Sand and Reef Core (Eastman Whipstock Brochure, 1985)

Thin-bed applications for horizontal wells are similar to layered applications in that precise directional control is essential for success. The wellbore must be accurately placed in both types of reservoirs so that coning and other production problems can be avoided. Production ratios for horizontal wells are often higher in thin-bed applications. For any length of horizontal well, the increase in formation contact area is relatively larger in a thin zone than in a thick zone. A plot of horizontal well length and productivity ratio (Figure 3-34) shows the influence of formation thickness, h. These data are based on the assumption of permeability isotropy.

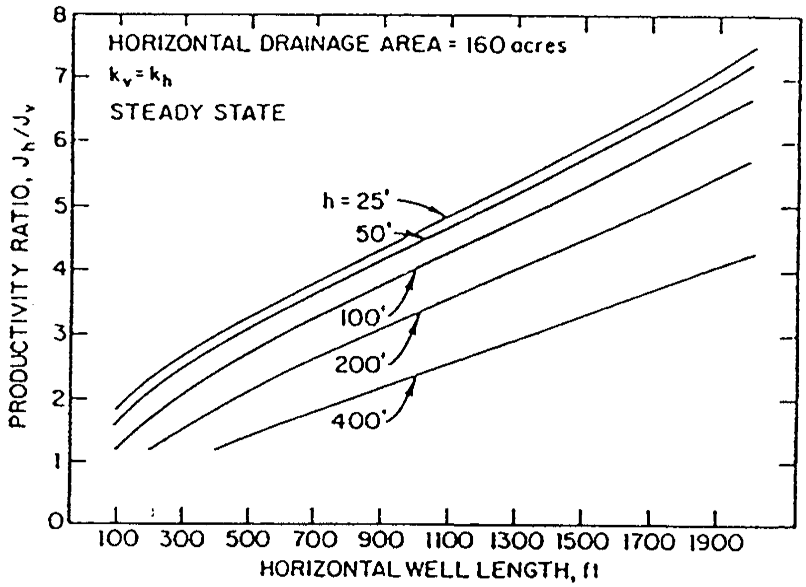


Figure 3-34. Reservoir Thickness and Horizontal Well Productivity (Ding et al., 1991)

For example, a 1000-ft horizontal well in a 50-ft formation would have a production ratio of about 4.4. The same well in a 200-ft formation would produce about 3.3 times as much as a vertical. This analysis shows clearly that productivity ratio increases with thinner formations. It also demonstrates that well length is often a more significant determinant of production ratio than formation thickness.

Thin-bed applications and coning avoidance are often related. For example, at Prudhoe Bay on Alaska's North Slope, the best results with horizontal wells have been seen in the thin oil column on the periphery of the field where conventional wells suffer from low oil rate and early water coning.

3.4.1 Canadian Layered/Heterogeneous Applications

Granite Wash (Alberta)

The Granite Wash development in Alberta is an example of a horizontal application in a light-oil heterogeneous reservoir. The pool is located in Northern Alberta. To date, 7 horizontal wells have been drilled.

Granite Wash sandstone (Table 3-13) is deposited on precambrian granite basement, and represents a low-relief coastal plain with coalescing alluvial fans and fan deltas. Reservoir sandstone was developed in a braided fluvial environment. Granite Wash deposits occurred preferentially in erosional lows, which were partially controlled by deep-seated basement faults. The reservoir exhibits excellent secondary intergranular porosity and permeability.

TABLE 3-13. Typical Reservoir Properties: Granite Wash Sandstone

Net Pay	15-20 ft
Porosity	15-24%
Horizontal Permeability	3-40 md
Drive Mechanism	Solution Gas/Part Water

The most interesting aspect of this pool is the degree of reservoir heterogeneity. Due to the complex structural and stratigraphic setting, the horizontal wells had an element of reservoir delineation. Although no detailed production data are available, informal reports suggest initial rates of 200-300 BOPD, which would represent an economic success.

Manor Spearfish (Saskatchewan)

The Manor Spearfish project is being successfully developed with horizontal wells. This application is important because vertical wells drilled in the pool were uneconomic due to low flow rates and high water production. As a result, all production from the horizontal wells can be classified as incremental.

Spearfish deposition at Manor took place in a marginal marine, tidal flat environment. Sandstone accumulation occurred within Mississippian lows during a pause in the Lower Watrous transgression. The productive reservoir is a wavy interbedded to bioturbated sandstone and muddy siltstone facies that are interpreted as subtidal channel deposits. Sandstone beds and laminations are bimodal mixtures of very fine grains and frosted medium to coarse grains that were presumably derived from a reworking of aeolean sands (Musial et al., 1994). Rock and fluid properties of the Spearfish formation are summarized in Table 3-14.

TABLE 3-14. Typical Reservoir Properties: Manor Spearfish

Net Pay	15-20 ft	Initial Reservoir Pressure	1520 psi
Porosity	15-24%	API Oil Gravity	35°
Horizontal Permeability	3-50 md	Drive Mechanism	Solution Gas/Part Water

Present development drilling indicates that the pool may have 200 MMBOOIP. Fifty-three horizontal wells have been drilled in the pool in the last 2 years, and the present production is approximately 10,000 BOPD. The long-term performance of this pool is uncertain since very little production history is available. However, a combination of solution-gas drive and a weak water drive should provide a recovery factor of 10 to 15%. If a successful enhanced recovery scheme can be implemented, the recovery may be increased to 25 to 30%.

3.5 SURFACE RESTRICTIONS

Directional drilling has been used on many occasions to avoid surface obstacles, drill beneath lakes or rivers (Figure 3-35) or, as the offshore environment dictates, access a producing zone with several wellbores from only one location. Horizontal drilling could eventually replace directional drilling in many of its applications since horizontal wellbore exposure allows greater production potential as compared to vertical penetration from a directional well.

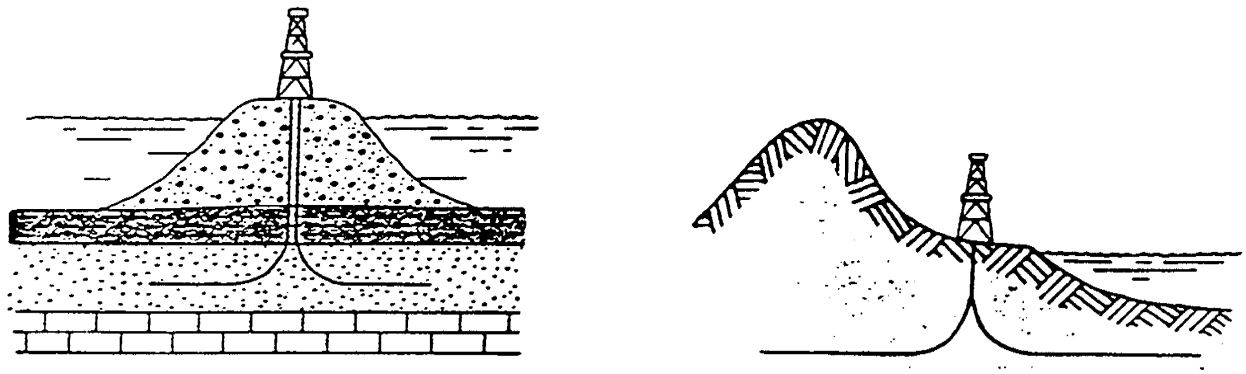


Figure 3-35. Horizontal Wells Where Surface Access is Restricted

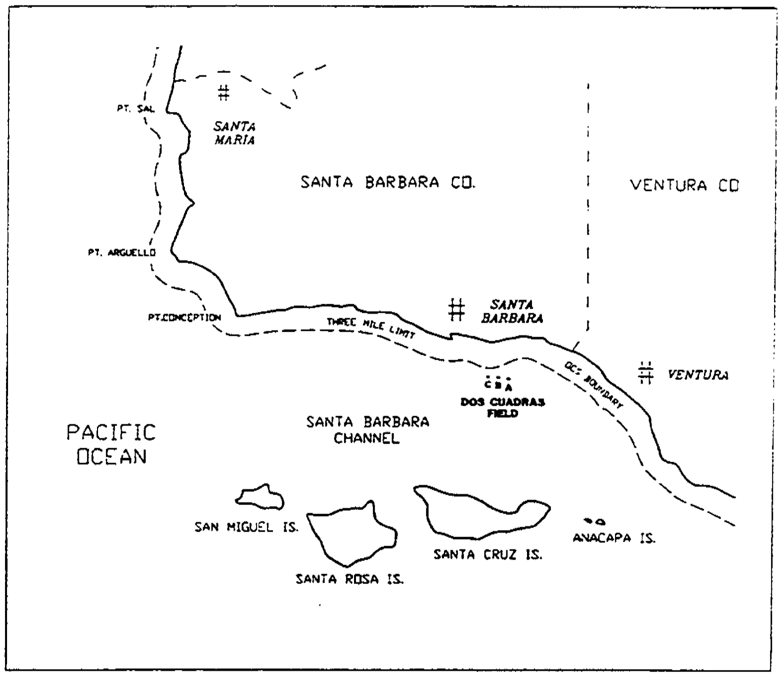
3.5.1 U.S.A. Surface Restriction Applications

Antrim Shale (Michigan)

The target zone for one operator in the Antrim Shale was beneath wetlands protected by the U.S. Department of Natural Resources. A horizontal well was successfully used to access the formation from a remote surface location. More discussion of this project is presented in Section 5.2.1 (U.S.A. Gas Applications).

Dos Cuadras (Offshore California)

Restrictions on the setting of additional offshore platforms led to the use of horizontal development in the Dos Cuadras field (Payne et al., 1992), located offshore southeast of Santa Barbara, California (Figure 3-36). These reserves could not previously be economically recovered.



PLATFORMS A,B,C, RELATIVE TO THE CALIFORNIA COAST

Figure 3-36. Dos Cuadras Field (Payne et al., 1992)

The Dos Cuadras is a doubly plunging anticline producing from the Repetto formation, which is an alternating sandstone/siltstone sequence of early Pliocene age. The operator found that extended-reach horizontal wells could be used to economically develop this shallow unconsolidated reservoir from existing platforms (Figure 3-37). Production and cost ratios were not available.

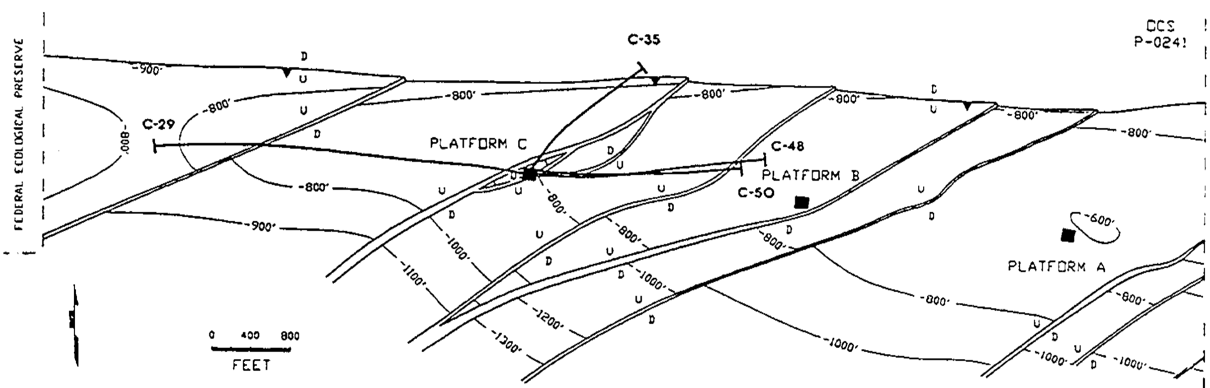


Figure 3-37. Dos Cuadras Field Well Paths (Payne et al., 1992)

3.6 LOW PERMEABILITY

Horizontal wells have been used to exploit low-permeability, or tight, reservoirs. In many of these applications, increased wellbore exposure to the productive zone can significantly increase production (Figure 3-38). The horizontal hole acts like a pipeline to increase the effective drainage radius of the reservoir.

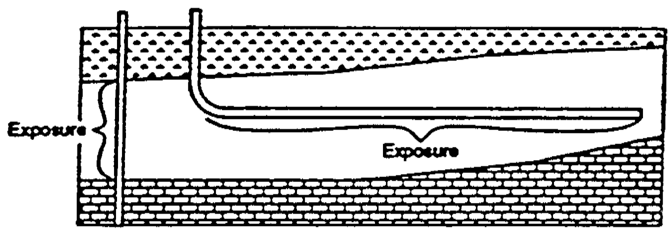


Figure 3-38. Increased Reservoir Exposure in Low-Permeability Formations

Properly applied, horizontal wells can have advantages over hydraulically fractured vertical wells in tight reservoirs, including:

- Horizontal wells can be greater than 2000 ft long, whereas it is difficult to orient and prop a hydraulic fracture of this length.
- Horizontal wells have nearly infinite conductivity compared to much lower conductivities in propped fracs.
- The trajectory of the hole can be controlled; orientation of a hydraulic fracture depends on the stresses in the reservoir.
- A horizontal well can be fractured at several points along its length.
- Hydraulic fractures provide a low resistivity flow path for water or gas production into the well.

3.6.1 U.S.A. Low-Permeability Applications

Spraberry Trend (Texas)

The Spraberry Trend is an expansive reservoir in west Texas characterized as a low-permeability sandstone with natural fractures. Extensive drilling has been performed since the field's discovery in 1949. Wells drilled in the field have been characterized by high initial flow rates after stimulation, followed by rapid decline. Difficulties in sustaining economic production rates led operators to try various techniques, especially hydraulic fracturing and waterflooding.

More recently, several attempts have been made to drill and complete horizontal wells in the Spraberry. Studies have suggested that horizontal technology may overcome low recovery efficiency.

Completion techniques are usually focused on connecting the wellbore to the natural-fracture system with hydraulic fractures to drain the tight matrix. In one typical horizontal well, Mobil E & P produced 5 hydraulic fractures in a 1619-ft medium-radius wellbore that was surrounded by several vertical wells (Figure 3-39).

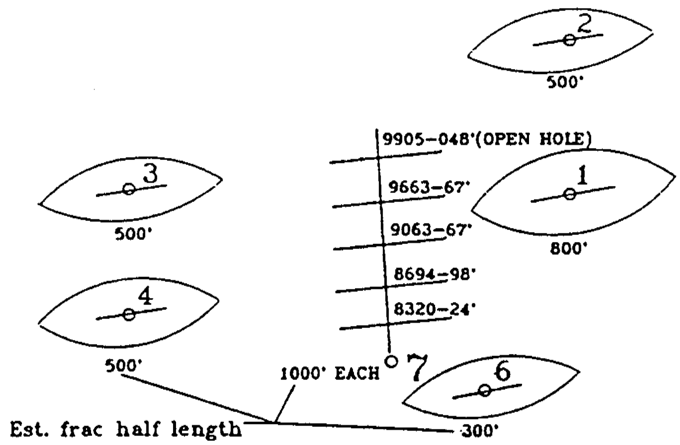


Figure 3-39. Fractured Horizontal Well in Spraberry (White, 1989)

None of the first 8 horizontal wells in the Spraberry was economically successful (Barba and Cutia, 1992). The average horizontal production has been less than that of vertical offset wells. Horizontal cost ratio is an estimated 2.7. Current experience in the Spraberry indicates that an optimized hydraulically fractured vertical completion is more successful than horizontal development.

3.6.2 Canadian Low-Permeability Applications

Cardium (Alberta)

The Cardium zone in the Upper Cretaceous is the largest light-oil accumulation in Western Canada. The estimated OOIP is in excess of 10 billion barrels. The major pool, the Pembina Cardium, was discovered in 1953. About 5500 vertical wells have been drilled in the pool, mostly on 160- and 80-acre spacing. Several water flood projects have been implemented in the pool. However, the recovery is less than 10%. This pool is thus a prime candidate for horizontal well technology.

Lithology varies for the Cardium pools. In general, pools are complex multilayered systems. The upper layer is a conglomerate deposit that parallels the underlying sandstone layers. Permeability varies in the tight sandstone layers and is generally less than 10 md. The conglomerate, however, has a much higher permeability (>20 md). Table 3-15 summarizes rock and fluid properties of the Cardium pools.

TABLE 3-15. Typical Reservoir Properties: Cardium Upper Cretaceous

Net Pay	20-40 ft	Reservoir Temperature	100-140°F
Porosity	15-20%	Initial Reservoir Pressure	800-1200 psi
Water Saturation	10%	Formation Volume Factor	1.29
Horizontal Permeability	3-15 md	API Oil Gravity	35-38°
K_v/K_h	0.1	Drive Mechanism	Solution Gas/Partial Water

Enhanced oil recovery projects have been initiated in more than 75% of the Cardium pools. About 15 horizontal wells have been drilled. Amoco drilled 9 wells (Figure 3-40) between November 1992 and February 1993. The reported results have generally not been economically favorable.

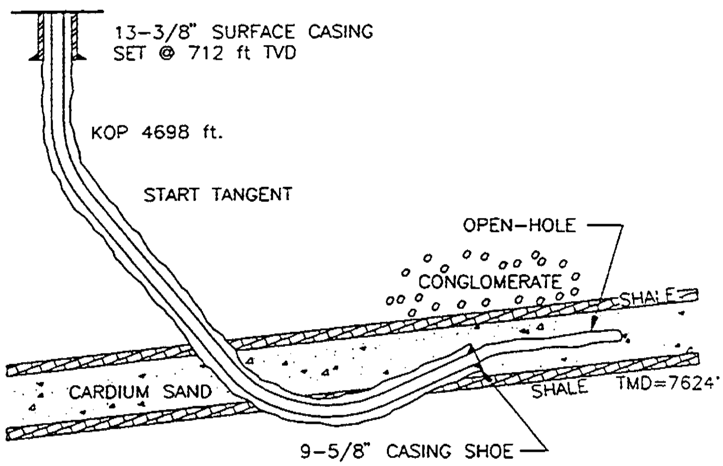


Figure 3-40. Amoco Cardium Well Profile

After this first well, a number of re-entries were attempted. The mud systems were varied and a cross-section of production logging and build-up tests was conducted. Some of the results are:

1. The wells were drilled to the desired lengths in good quality reservoir.
2. Water/oil ratios were higher than expected.
3. Stimulations of the horizontal wells have been unsuccessful.

There is still a huge oil potential in these pools. Additional test wells are being drilled to establish techniques to successfully apply horizontal technology to this formation.

3.6.3 International Low-Permeability Applications

Dan Field (North Sea)

Maersk Oil and Gas (Andersen et al., 1988) drilled three long-radius horizontal wells in the North Sea Dan field (Figure 3-41).

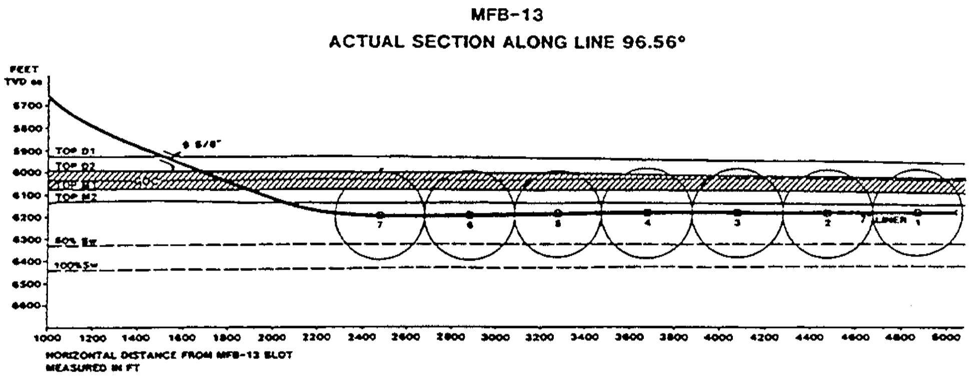


Figure 3-41. Maersk North Sea Dan Field Well (Andersen et al., 1988)

These wells, which had 1000- to 3000-ft horizontal sections, are important because they are the first horizontal wells where multiple hydraulic fractures were used extensively. Reservoir simulations showed that production from Dan field horizontal wells with matrix acidizing would be only marginal in this tight chalk reservoir, so a reservoir study of multiple hydraulic fracturing was conducted. This study showed that 4 to 6 fractures per 1000 ft would significantly increase the Productivity Index (PI), but that additional fractures had less effect due to interference between the fractures. Maersk made the decision to use 4 to 5 hydraulic fractures per 1000 ft in these wells.

Production from two of these fractured wells is 4 to 6 times higher than average conventional wells. One well could have produced at even higher rates, but it was choked back to prevent gas coning. The third well produced only 1.8 times faster than a conventional well because two-thirds of the well was in the tight Danian D-2 formation where there was apparently insufficient sand in the fractures to hold them open.

The total cost of a fractured horizontal well in the North Sea is $19.5 million versus $13.5 million for a conventional well (these figures include $7.5 million for the platform slots). Therefore, horizontal wells must produce 1.4 times more oil than conventional wells to be economical. The two good horizontal wells are therefore very economical since they are producing 4 to 6 times more than conventional wells.

Twenty-five percent of Maersk's production from the Dan field comes from these three multifractured horizontal wells even though there are 41 producing wells in this field.

Valhall Field (North Sea)

Valhall is a medium-size field in the Norwegian Sector of the North Sea. Horizontal drilling has been applied in Valhall to increase productivity in the low-permeability non-fractured flank areas of the reservoir. There is natural fracturing on the crest areas of this overpressured, undersaturated chalk. Matrix permeability ranges from 1-10 md.

The first horizontal well was drilled in the Valhall Field in 1991. Production was about double that of a conventional well even though there were problems with the completion of the horizontal section. Costs were about 25% above conventional costs. The operator planned that about 60% of all future wells would be horizontal.

3.7 ENHANCED OIL RECOVERY IN LIGHT OIL

Many reservoirs that are considered "depleted" still contain as much as 50% or more of the original oil-in-place. This amounts to more than 100 billion barrels of oil in depleted reservoirs in the U.S. alone. These potential oil resources include oil shales, tar sands, heavy oils and tertiary recovery from depleted reservoirs (van Poolen, 1980).

Three major areas of enhanced oil recovery (EOR) are recognized: thermal, chemical and miscible displacement. Thermal EOR processes include steam stimulation, in-situ combustion and steam flooding, which is the most widely used. Steam flooding contributes over half of the daily production provided by all EOR techniques. The application of horizontal technology and its ability to increase reserves in EOR processes is described in the following sections.

3.7.1 U.S.A. EOR Applications

New Hope Field (Texas)

The first onshore horizontal injection wells in Texas were drilled by Texaco E & P in the New Hope Field (PEI Staff, 1992). The wells are used as line-drive injectors to enhance production. Horizontal wells increased average vertical well production from about 100 to 400 BOPD per well, the highest in the field's 45-year history.

The Pittsburg is the producing formation in the New Hope Field and is a relatively thin, hard sandstone with low permeability. Injection wells are placed downdip on the large anticline structure; production wells are placed updip.

Costs were maintained by completing the horizontal wells open hole. The hard formation has been found to limit injection rates to some extent. However, parts of the reservoir previously considered uneconomical can now be produced through the use of horizontal injectors. Texaco estimates that the productive life of the field has been extended by 10 to 15 years.

Olla Field (Louisiana)

Oxy USA was economically successful drilling horizontally in a Wilcox reservoir (unconsolidated sandstone) in the Olla Cruse Waterflood Unit in central Louisiana (Hansen and Verhyden, 1991). Horizontal development was chosen for this field as a result of several considerations, including:

- Premature water breakthrough in vertical wells resulted in significant by-passed oil
- Attic oil could best be produced with a horizontal wellbore
- Water injection minimized problems with the gas cap
- Excessive sand production caused problems in vertical wells
- Structural control was excellent as a result of data from previous drilling efforts

Production ratio was about 5; cost ratio was estimated at 2.0-2.5. Problems with drilling and completion of the first well added about $250,000 to the expected cost of the first well.

Oxy USA was very pleased with the project and concluded that "results from this well indicate that not only was this project an economic success, but that other fields with similar conditions can be produced in a more profitable manner with horizontal wells."

Lockhart Field (Louisiana)

Lockhart Field, located in Southwest Louisiana, was discovered in 1982. As in the Olla field described above, the producing formation is the lower Wilcox sandstone, a 40-ft near-shore marine bar. Waterflood operations began in the Lockhart field in 1986. An analysis of the conventional waterflood performance showed that considerable oil reserves were being by-passed due to poor sweep efficiency (Little et al., 1992). Several wells experienced premature water breakthrough. The operator (Callon Petroleum) determined that a horizontal wellbore positioned at the top of the sand (Figure 3-42) would provide the best geometry for recovering lost reserves.

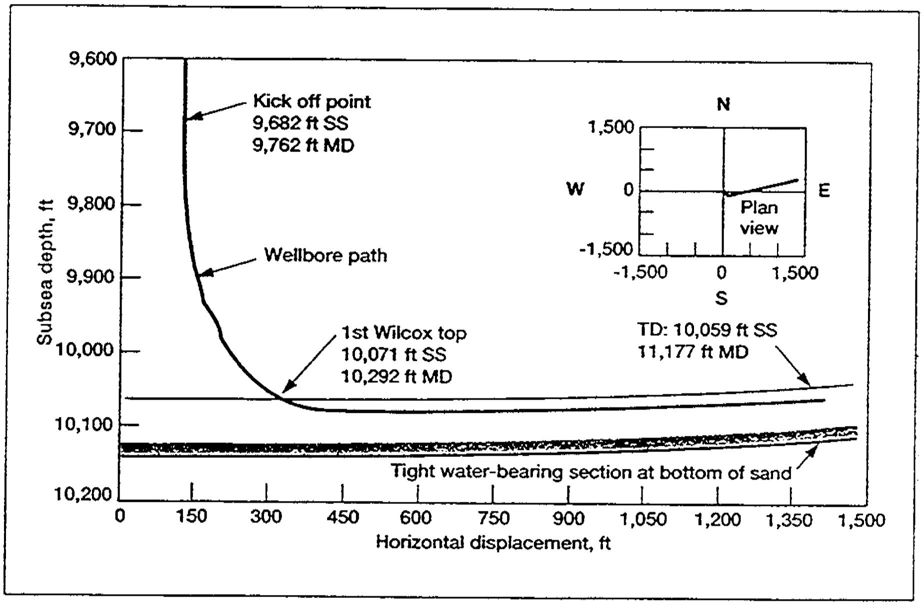


Figure 3-42. Lower Wilcox Well (Little et al., 1992)

A 5-fold increase in oil production was obtained with this re-entry, at a total cost of \$540,000, compared to about \$700,000 for a new vertical well. Ultimate recovery with the horizontal wellbore over a 5-year production life is expected to approach 500 MBO, whereas a vertical would only produce about 150 MBO.

The high level of success with the initial well led the operator to design similar projects for other parts of the reservoir.

4. Heavy-Oil Applications

4.1 INTRODUCTION

Due to the unique technical and economic aspects of heavy-oil development, horizontal well applications in heavy-oil fields are discussed within a separate chapter. There are significant heavy-oil deposits in South American (Venezuela) and the continental U.S.A. (California). Other deposits have been found in various locations around the globe, including Indonesia, Middle East, China, Alaska, and Eastern Europe. However, the vast majority of horizontal well heavy-oil applications to date have occurred in Western Canada.

This chapter is focused primarily on Canadian horizontal well heavy-oil experience. It is anticipated that many of the technical advances achieved in Canada will be applicable to deposits in the U.S.A. and other areas around the globe. General technical advances achieved and insights gained from heavy-oil experience are summarized as follows:

1. **Hole Stability.** Heavy-oil sands tend to be completely unconsolidated. Conventional heavy-oil core can actually pour out of a core barrel when pulled to surface. This observation has caused significant concern in the minds of many operators that drilling, evaluating, and completing horizontal wells in heavy-oil sands would entail significant risk of hole instability. Canadian industry experience has revealed these holes to be amazingly stable. Long (>5000 ft), large (9⅝-in.) holes are now routinely drilled with conventional muds and drilling systems without significant hole problems.

2. **Sand Production.** High sand production can be a limiting factor for heavy-oil development with vertical wells. In general, sand production in horizontal wells appears to be a less common problem. A significantly smaller proportion of horizontal wells has been observed to suffer from serious sand production problems.

3. **Well Length.** With increased field experience and confidence regarding hole stability, typical well lengths have increased. Horizontal heavy-oil wells are routinely drilled to 4000-5000 ft lengths, at TVDs of 1000-1800 ft. There are many examples where production ratio appears to be directly related to well length, so that the longer the wellbore, the greater the production increase.

4. **Geosteering.** A major element contributing to success in a heavy-oil program is site-specific geosteering expertise. Productive length, rather than geometric length, is the critical issue. Many field examples illustrate that expertise in horizontal technology, including well orientation within the target interval, must be developed through phased multiwell programs.

5. **Pad-Spiral Well Layout.** Most major heavy-oil multiwell developments have a common layout: a central pad is used and wells fan out to drain an entire section (e.g., 1 sq. mile). Since these wells have azimuthal bends in the curve, long-radius drilling design appears to be optimal for accurate placement of the wellbore and to allow pumping when required.

6. **Increased Reserves/Interwell Spacing.** There are many documented cases of increased reserves due to horizontal development of heavy-oil pools. Some pools were completely uneconomic with vertical development. Many applications illustrate the benefits of infill development with horizontal wells. The optimum interwell spacing is site-specific and sensitive to various parameters including mobility ratio, strength of bottom water drive, formation thickness, economic limits, water handling costs, etc.

7. **EOR.** There has been dramatic success in a number of thermal EOR (enhanced oil recovery) applications. Many heavy-oil projects currently on primary production have been designed for future EOR techniques. Huge reserves of bitumen appear to be exploitable with advanced horizontal well EOR techniques (SAGD, ESAGD, etc.), and even more exotic concepts are being developed. Several field pilot projects are currently under way to pursue this potential.

4.2 PRIMARY HEAVY-OIL RECOVERY

4.2.1 Canadian Heavy-Oil Applications

The oil industry in Western Canada has witnessed consistent exponential growth of horizontal well applications since 1987. Heavy-oil applications represent a significant proportion of these horizontal wells over that time period (Figure 4-1).

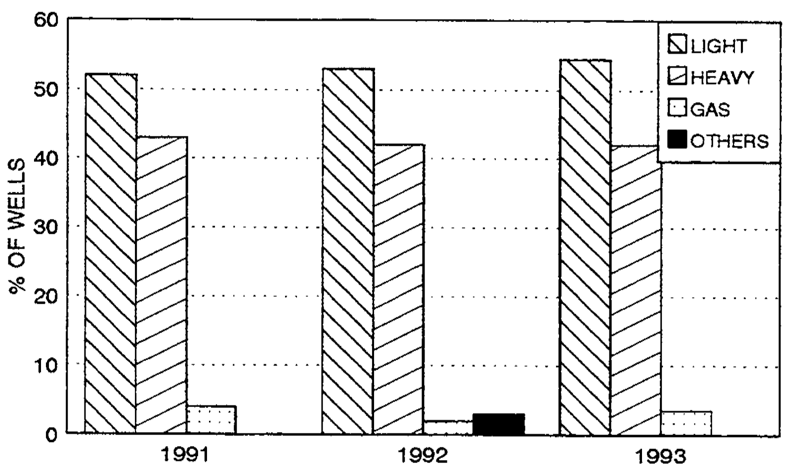


Figure 4-1. Canadian Horizontal Well Data Base - Resource Type (DEA-44 Survey)

This phenomenal growth rate is a reflection of the economic and technical success operators have enjoyed with horizontal wells in heavy-oil pools. Figure 4-2 shows the location of major heavy-oil and tar-sand pools in Western Canada.

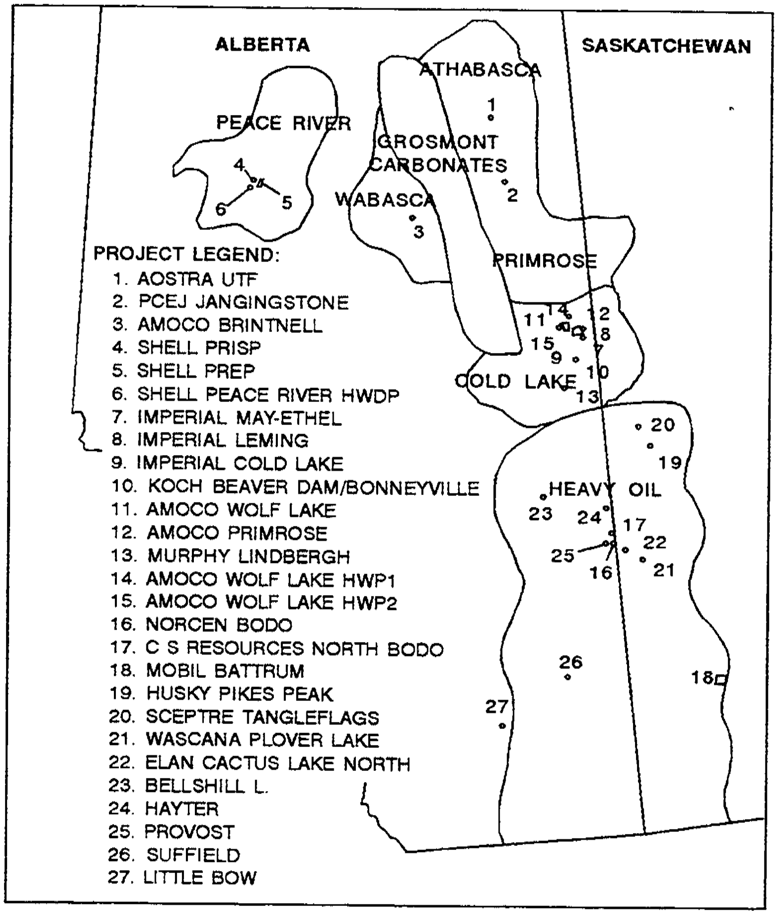


Figure 4-2. Major Heavy-Oil/Tar-Sand Pools in Western Canada (Good, 1994)

The vast majority of heavy-oil deposits (typically defined as 20° API oil gravity or less) in Western Canada occur in Cretaceous-age sandstones in both sheet and channel deposits. The tar-sand or bitumen deposits are differentiated from "primary" heavy oil in terms of *in-situ* viscosity. A typical heavy-oil pool in Western Canada has *in-situ* viscosity in the range of 5000 to 10,000 centipoise. This oil can be produced with conventional equipment. Tar sands or bitumen reserves have *in-situ* viscosities from 10,000 up to 1,000,000 cp, and until recently, could only be economically exploited by strip-mining on a large scale (e.g., Syncrude, Suncor).

Even though horizontal bitumen and thermal EOR projects have met with success and are growing in number in Canada, the vast majority of horizontal wells in heavy-oil applications are on primary production. Many of these wells are designed and equipped with thermal stimulation capability for the future, but a number are proving economically productive without steam stimulation, at least in the early stages of production. Primary heavy-oil pools in Saskatchewan and Alberta are a major target for horizontal wells. The estimated OOIP for this resource is 38 BBO.

Saskatchewan Primary Heavy Oil

More than 500 heavy-oil horizontal wells have been drilled in the Mannville group of the Lower Cretaceous in Saskatchewan. Production of heavy oil (10°-20° API inclusive, *in-situ* viscosity 100 to 10,000 cp) from these pools with horizontal wells is about 30 MBOPD (Figure 4-3). The major formations in which horizontal wells have been drilled may be divided into two groups as follows: McLaren, Sparky/G.P. (about 100 wells) and Waseca, Lloydminster and Cummings-Dina (about 400 wells). The first group consists essentially of solution-gas-drive reservoirs, with possible weak aquifers. The second group consists of pools with strong water drives.

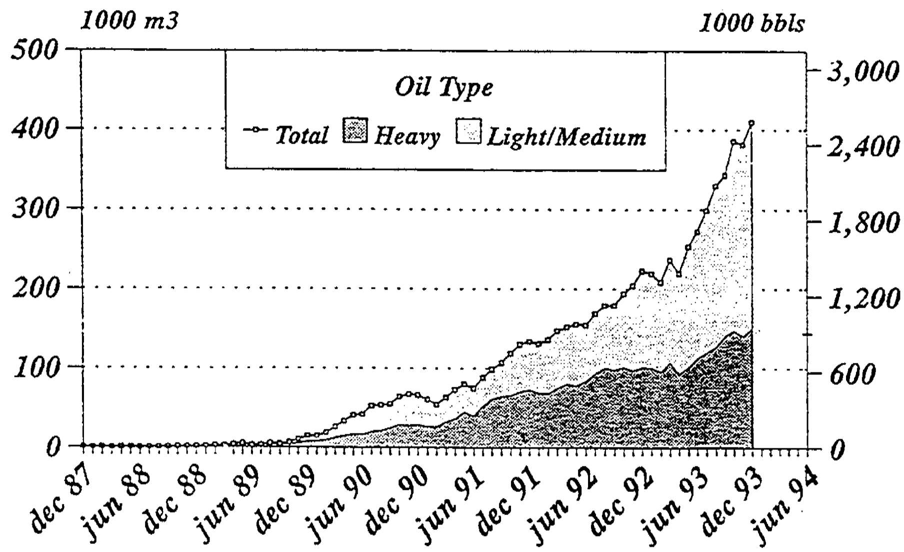


Figure 4-3. Horizontal Well Heavy-Oil Production in Saskatchewan (Stalwick, 1994)

The presence of heavy oil is related to structural deformation caused by partial dissolution of the underlying Prairie Salt of Devonian age, and the sedimentological history of the area during the Lower Cretaceous time. Removal of the salt produced structures that formed a barrier to oil migration in the Mannville sands at a depth of about 2000 ft. The reservoirs in which oil is trapped are coastal and fluvial in origin. The sands are unconsolidated and have preserved relatively high porosity and permeability. However, gases and light fractions have escaped, leaving behind a viscous crude oil.

During the Lower Cretaceous (Dina to Colony) period, complex river systems and shallow seas deposited sands, silts, and clays in the form of thin sheets intersected by thick channels. Depositional processes were very complicated, sometimes resulting in unpredictable reservoir patterns (Jefferies et al., 1991). Many of these reservoirs are associated with bottom water that provides the drive energy desirable for primary production.

McLaren (Saskatchewan)

The Cactus Lake North project is a major horizontal well project in the McLaren Sand of the Upper Mannville group. It is located in West Central Saskatchewan on the Alberta/Saskatchewan border. Project development commenced in 1990. There was one producing vertical well in the pool at the beginning of the project. The operators identified the project as a low-risk, low finding-cost opportunity that was suitable for horizontal well technology. The reservoir was essentially in the virgin stage; however, there were limited historical data on primary production from vertical wells.

Key aspects of the original development strategy were:

- Existing 2-D seismic data were used (no additional 3-D seismic was run)
- Well trajectories were aligned with the channel
- Wells were drilled close to the top of the reservoir, and were about 3000 ft long
- A pad concept was used both for drilling locations and for locating facilities

The Upper Mannville channel is one major sand body; however, it was divided into sub-reservoirs as a result of collapse due to salt solution in the Devonian. The McLaren (Table 4-1) is a clean unconsolidated sand with variable grain size and very little shale. The drive mechanism appears to be solution gas. Water production is low compared to horizontal wells drilled in the Lower Mannville.

TABLE 4-1. Typical Reservoir Properties: McLaren Formation

Oil Thickness	40-60 ft	Reservoir Pressure	200-800 psi
Porosity	31-35%	API Oil Gravity	12°
Horizontal Permeability	2-5 Darcies	*In-Situ* Viscosity	6000-10,000 cp
Vertical Permeability	0.5-3 Darcies	TVD	1200-2000 ft

Most horizontal wells have average production during the first year in excess of 200 BOPD. The horizontal to vertical production ratio is 5:1; however, this ratio is not very meaningful since most vertical wells were uneconomic. Water/oil ratio was generally less than 0.3, and there was no indication of sand production in the first year of operations. Drilling and completion cost was about $600,000; operating cost was about $4/bbl. As a result of a favorable tax regime, typical payout time for a horizontal well was about 18 months. Wells are usually long-radius design with 3000-4000 ft horizontal lengths. A typical well takes 6 to 9 days to drill and complete. The lateral is usually completed with an uncemented slotted liner. Screw or rod pumps are used for artificial lift.

The McLaren is one of the most attractive horizontal heavy-oil projects in Saskatchewan. The apparent lack of pressure support may suggest that the primary recovery may not be very high. Nevertheless, since vertical wells were uneconomic, reserves generated by this horizontal development may be considered as essentially incremental. Two pilot thermal projects were implemented in 1993. If these are economically attractive, the recovery from the pool will be further enhanced.

Cactus Lake North is the only sizable horizontal project in the McLaren Sand in Saskatchewan. However, the project has been extended into Alberta where another 50 horizontal wells have been drilled. The pad drilling layout and spiral drilling concept (i.e., azimuthal turn in build section) used at Cactus Lake (Figure 4-4) allow efficient use of surface facilities. In effect, much of the gathering system is placed in the ground. This reduces both capital and operating costs, as well as environment impact. As heavy-oil developments tend to be marginal and very sensitive to oil price, these "minor" advantages can have significant impact on overall project economics.

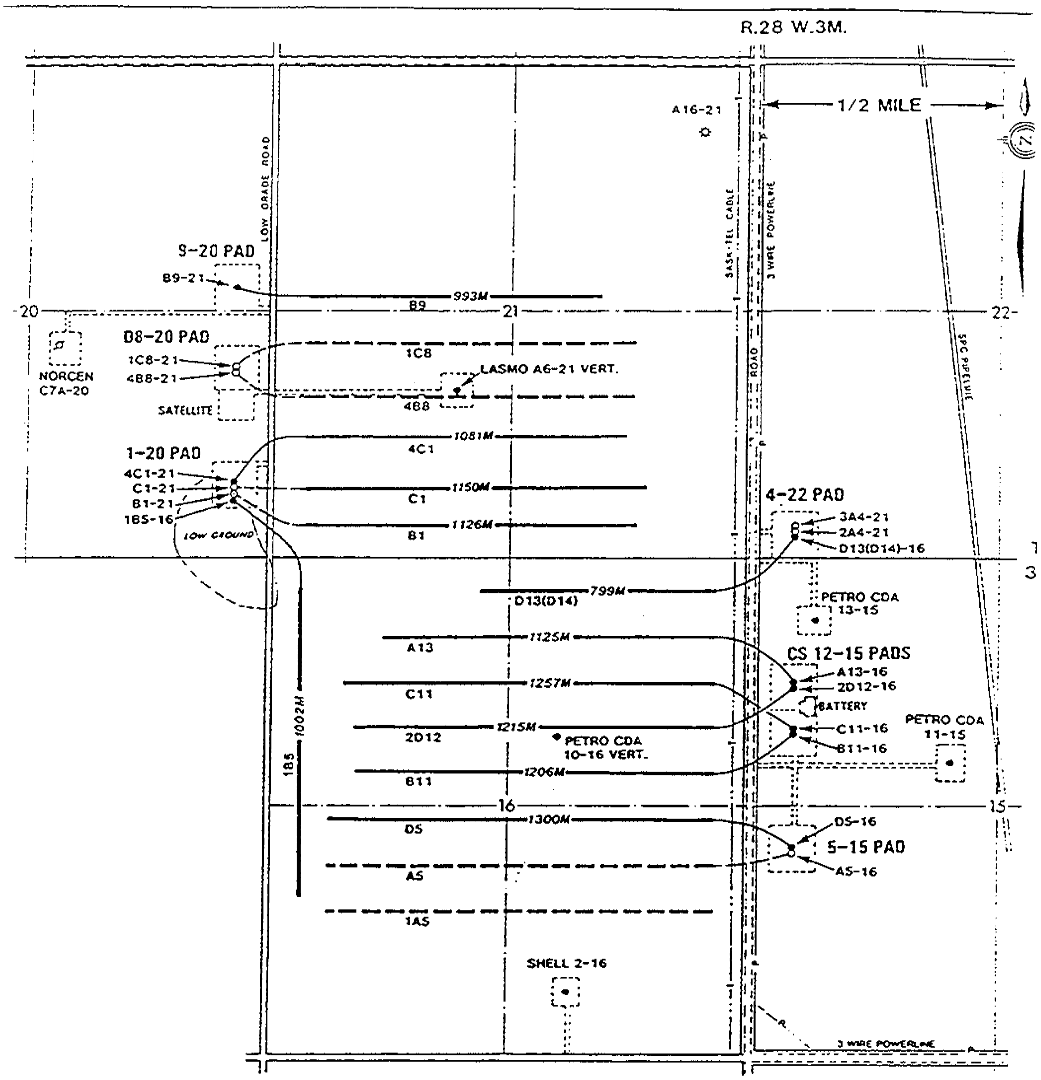


Figure 4-4. Cactus Lake Horizontal Well Layout (Sametz, 1992)

Sparky (Saskatchewan)

About 25 horizontal wells have been drilled in the Sparky formation of the Lower Mannville group. Most of these wells are drilled in the Edam West pool, which was originally developed on 40-acre spacing with vertical wells. The Edam West Sparky horizontal well project differs from the Cactus Lake North project (described previously) since it was an established vertical heavy-oil project. The estimated ultimate recovery using vertical wells in the Sparky was 5% of OOIP. Further pool development by infill drilling on 20-acre spacing, or implementing an enhanced recovery scheme such as a thermal project, was not economically attractive at existing oil prices. Vertical wells had initial rates of 30 to 50 BOPD. However, water and sand production resulted in rapid oil production decline and high operating costs. As a result, these wells became economically unattractive prematurely. Horizontal development has completely reversed the economics of the project, and production at the Edam West Sparky development has increased from 250 to 900 BOPD in the last 5 years.

The Sparky sand can be sub-divided into two major facies: regional and channel. Regionally, the Sparky sand is characterized by a coarsening upwards sheetlike sandstone, interbedded with siltstone/shales. In some areas, this regional facies and parts of the underlying formation have been eroded by channels, which were subsequently filled by sandstone. These sandstone-filled channels may be well sorted and slightly coarser grained than the regional facies. Typical channel reservoirs are 60-100 ft thick, 0.2 to 1.2 miles wide, and 0.3 to 3 miles long (Table 4-2). The sandstone-filled channels are unconsolidated.

TABLE 4-2. Typical Reservoir Properties: Sparky Channel

Oil Thickness	60-100 ft	Channel Width	0.2-1.2 miles
Porosity	34%	Channel Length	0.3-3 miles
Horizontal Permeability	1-10 Darcies	Dead Oil Viscosity	5000-20,000 cp

The initial horizontal wells were 1500-2000 ft long. As the technology improved and concerns about hole stability decreased, well length was increased to 2500-3000 ft. Initial production rates increased from about 150 to 200 BOPD with the longer horizontal wells. Generally, water production appeared to be insensitive to production rate. Conventional mud systems were used, and wells were completed with slotted liners. Underbalanced drilling systems have been used in some wells drilled recently. This should reduce fluid loss to the formation that may occur due to reduced reservoir pressures. Figure 4-5 illustrates the general layout of the horizontal well development.

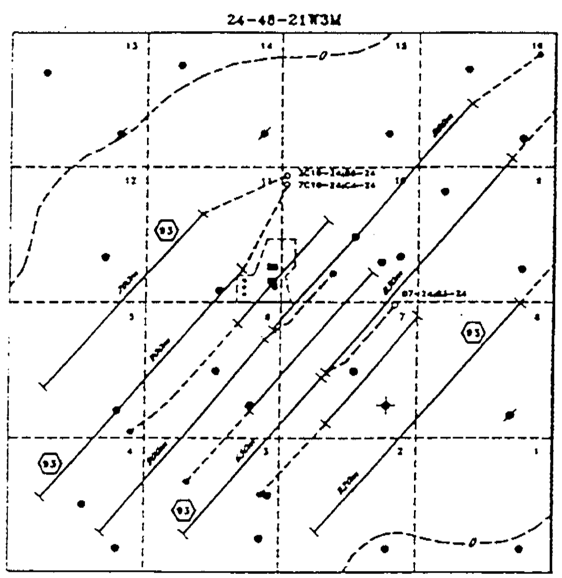


Figure 4-5. Sparky Horizontal Well Layout (Bohun et al., 1994)

As a result of six horizontal wells drilled in Section 24-48-21W3M (Figure 4-5), production increased from 250 BOPD to more than 900 BOPD. Analysis of production performance suggests that primary recovery from the section could be increased by 2.26 MMBO, or an average of 587 MBO per well. Preliminary analysis suggests an enhancement of recovery factor from less than 5% to 20%. Project production performance is summarized in Figures 4-6 and 4-7.

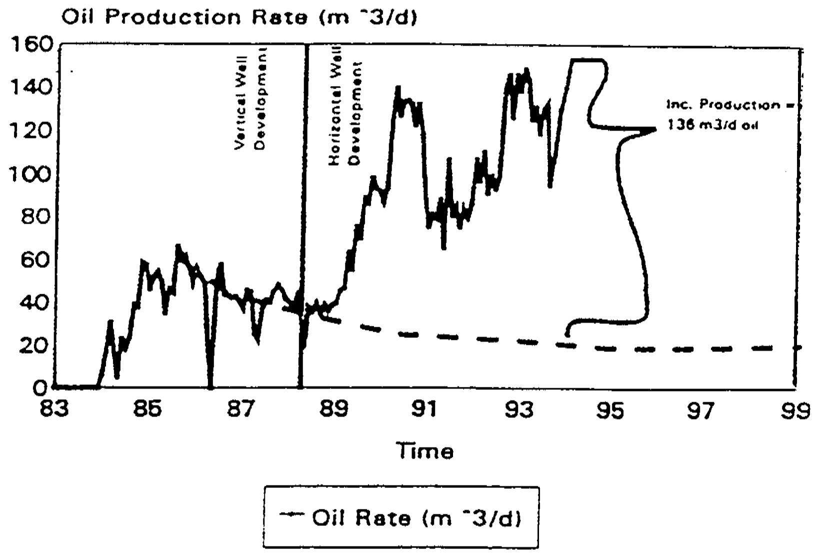


Figure 4-6. Sparky Horizontal Well Daily Production (Bohun et al., 1994)

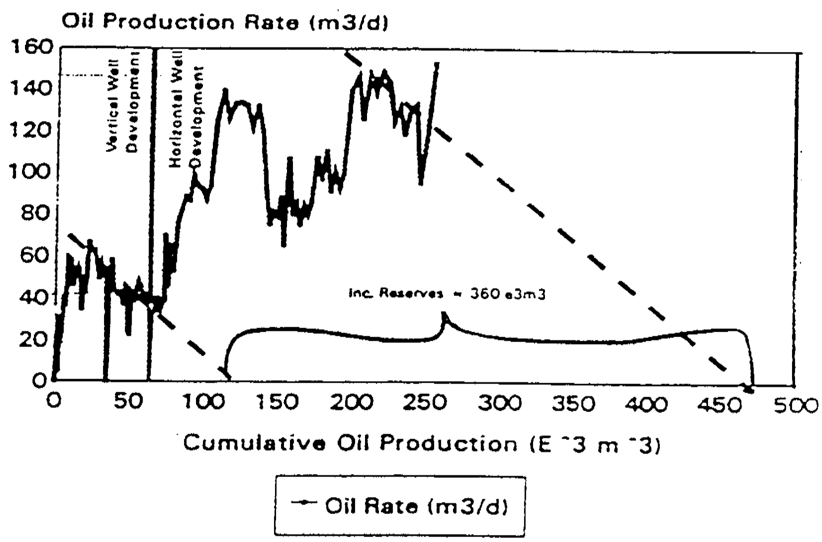


Figure 4-7. Sparky Horizontal Well Cumulative Production (Bohun et al., 1994)

The Edam West is a unique horizontal multiwell project in the Sparky formation in Saskatchewan. Present performance seems to be much better than would be expected for a solution-gas-drive reservoir.

Waseca (Saskatchewan)

The Long Lake Waseca horizontal well project was implemented in 1990 by Morgan Hydrocarbons, and more than 60 horizontal wells have been drilled in the project. The Waseca formation directly underlies the McLaren formation, and in some areas the two formations are indistinguishable. As was the case in the Cactus Lake project, vertical wells were not economically attractive, and few vertical wells were drilled in the pool. The geological setting is a distributory channel sandstone of deltaic-marine alternation. The sands are predominantly quartzose, with excellent porosity and permeability (Table 4-3).

TABLE 4-3. Typical Reservoir Properties: Lower Mannville Waseca

Oil Thickness	30-60 ft	Oil Viscosity	5000-10,000 cp
Porosity	30%	Reservoir Pressure	500-700 psi
Horizontal Permeability	0.5-3 Darcies		

Initial production rate of horizontal wells is 150-200 BOPD. The major difference between Long Lake and the heavy-oil pools described previously is that Long Lake has an active water drive. As a result, many wells produce at water cuts of 70% after 1 year of production.

Early horizontal wells had productive lengths of 1500-2000 ft. By the middle of 1991, productive well lengths had been extended to 2500-3000 ft, and initial production rates increased to 300 BOPD. Economics of the project, however, are controlled by water handling costs. Cumulative production of 150 to 200 MBO is expected from this development. This represents 7 to 10% of the OOIP in a 40-acre drainage spacing. Test wells are being drilled at closer spacing. If these are found to produce similar volumes, primary recovery factor may be increased to 15%.

There are several small Waseca horizontal well projects in the area. The performance of these projects varies; however, very little data are currently available.

Cummings/Dina (Saskatchewan)

The Cummings/Dina formation has continued to be among the most active heavy-oil formations for horizontal technology. There are seven major active multiwell projects in Saskatchewan in this formation: Senlac (135 wells), Saskoil/Wascana Winter (35 wells), Beau Canada Winter (25 wells), Soda Lake (54 wells), Carruthers (15 wells), Koch Eyehill (15 wells), Rutland (40 wells), and others (30 wells). In addition, there are about eight projects with five or fewer wells. These projects are all located within a radius of 100 miles east and south of Lloydminster on the Alberta/Saskatchewan border.

The first horizontal well drilled in the Winter pool was spudded in September 1988. This was the second horizontal well drilled in Saskatchewan. The project was developed in three phases, with analysis of the success of the previous phase before the next phase was commenced. The Senlac project is the single largest horizontal multiwell project in Western Canada and provides a textbook example of the evolution of horizontal well technology. Many typical trends were exhibited in the project, including increasing the length of the horizontal lateral (Figure 4-8), varying/decreasing well spacing, modifying well orientation concepts, installing facilities to handle large volumes of produced water, drilling wells in groups, and using pad drilling to reduce cost and environmental impact. Many other multiwell projects were patterned after this project.

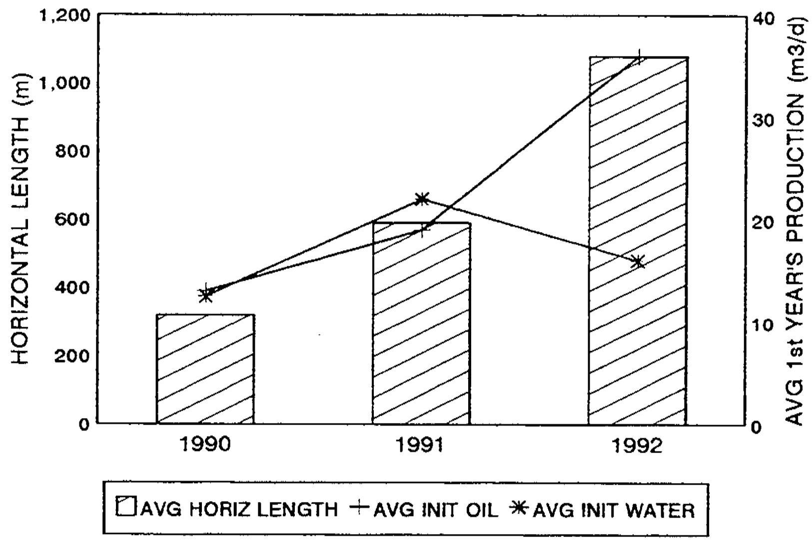


Figure 4-8. Senlac Production Versus Horizontal Length (Springer et al., 1993)

The lower Cretaceous Mannville consists of a complex of interbedded sandstones, siltstones, with minor quantities of shales, coals, and conglomerates. The Cummings sits unconformably upon the Duperow (Devonian) carbonate strata. The main Cummings sandstone (Table 4-4), which is the oil reservoir of interest, appears to form a sandstone body that is almost devoid of shale. In many sections of the main Cummings, the sandstone tends to become finer towards the top. The entire accumulation is underlain by water.

TABLE 4-4. Typical Reservoir Properties: Winter/Cummings

Pay Thickness	100 ft	Porosity	30-35%
Net Oil Thickness	40-50 ft	Sand Body Length	4.3 miles
Horizontal Permeability	4.5-7.5 Darcies	Sand Body Width	2.5 miles
Vertical Permeability	3-6 Darcies		

The first five wells of the Winter project were drilled in 1988 and 1989. The average horizontal well length was 2000-2500 ft along the axis of the pool. In later developmental phases, however, wells were drilled in an east-west or north-south orientation (Figure 4-9). The long- to medium-radius wells were completed with slotted liners. Well lengths were increased to 3000-4000 ft and well spacings were from 350 to 450 ft.

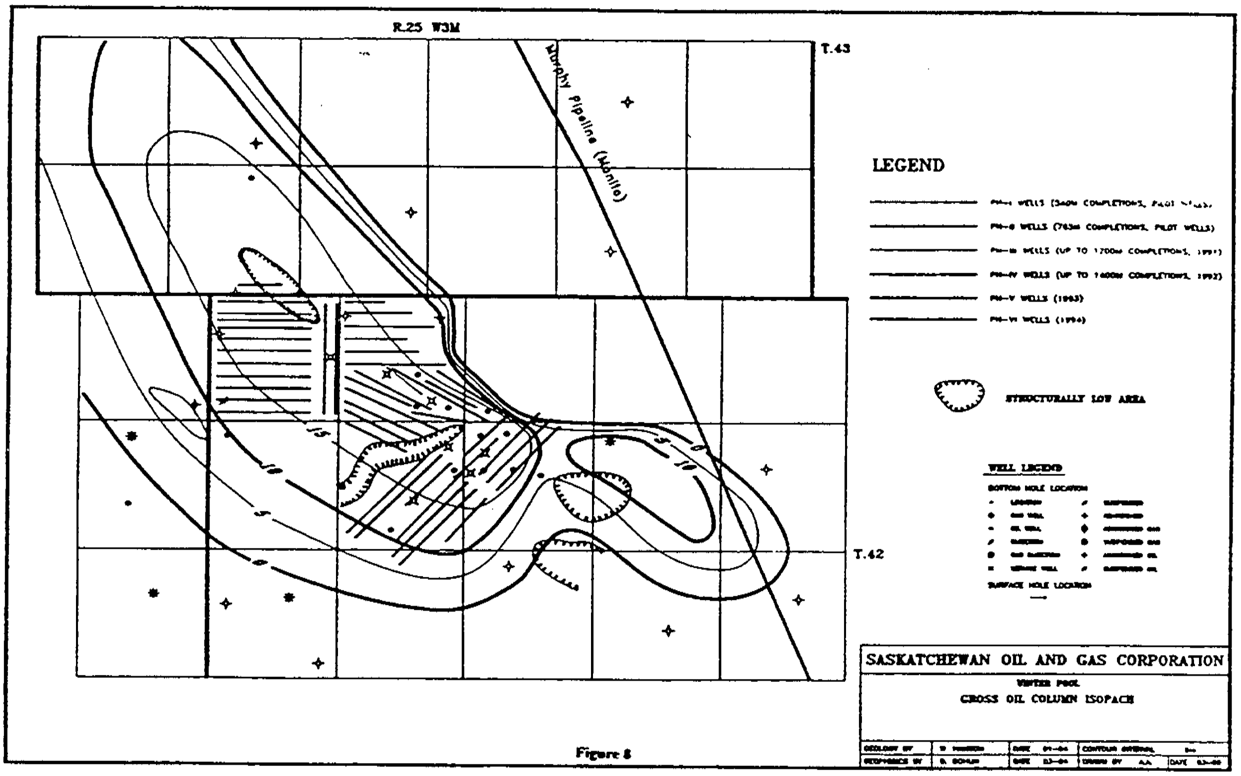


Figure 4-9. Winter Horizontal Well Layout (Bohun et al., 1994)

The Senlac Cummings project was developed by Morgan Hydrocarbons. Drilling activity has been steady over recent years: 1990 (35 wells), 1991 (25 wells), 1992 (35 wells), and 1993 (40 wells). Orientation of the wells was east-west and north-south (Figure 4-10). Wells drilled in 1990 had laterals ranging from 1500 to 2000 ft. Lateral lengths were continuously increased, and by 1992 wells were typically 4000 ft long. Inter-well spacing was about 400-500 ft; however, some infill drilling to 200 ft has been proposed. Senlac wells were all completed with slotted liners; 1994 plans may include some open-hole lengths and multibranch wells.

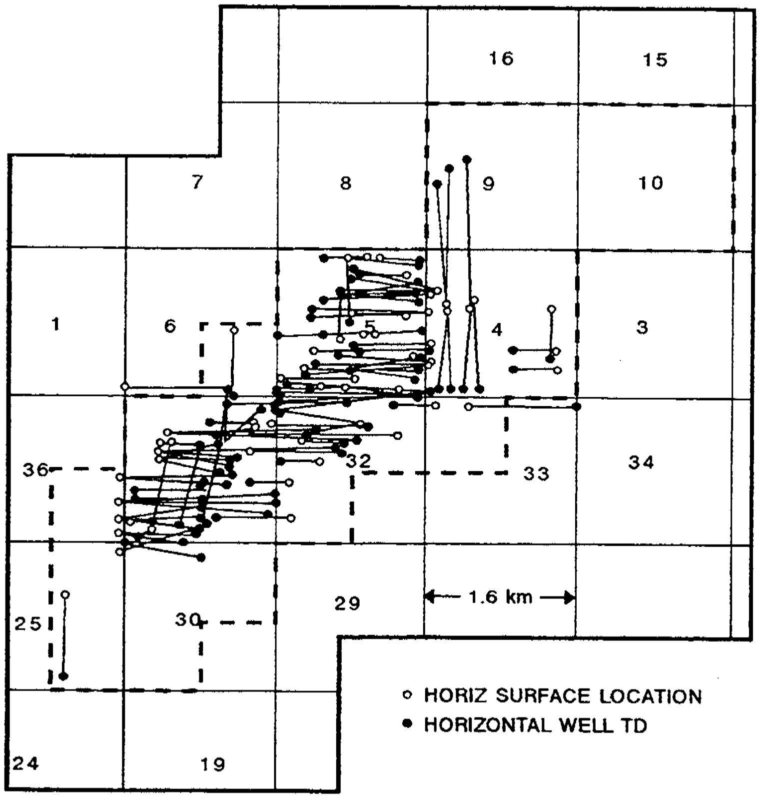


Figure 4-10. Senlac Cummings Horizontal Well Layout (Vigrass et al., 1994)

Other recent projects have generally followed the pattern of the Winter and Senlac projects. Wells in the Eyehill project drilled by Koch are 3500-4000 ft in length and were completed with slotted liners. Drilling and completion time was 10 to 15 days and reported cost was $500,000.

Initial production from an early Cummings/Dina horizontal well was about 90 BOPD. As the technology evolved and wells were drilled with longer laterals, initial production rates increased to 150 BOPD. Again, it is important to note that productive length appears to be the key to this steady improvement in productivity (see Figure 4-8). As site-specific geosteering expertise is gained, length within the ''sweet spot'' of the target is increased.

The Cummings/Dina formation is the most actively drilled heavy-oil formation. The area contains more than 3 billion barrels in place. Recovery from vertical wells is usually not attractive, and often is less than 5% of OOIP. Water production is generally high. Analysis of the Senlac pool indicates that the average horizontal well will produce 150 MBO. Sand production is not a major problem. The 30 to 50 feet of oil pay and strong water drive enable long horizontal wells to produce the heavy crude at economic rates. However, the economics of these projects is strongly influenced by oil price and water handling cost. The rapid and continuous growth of horizontal activity in these pools is a clear indication of the attractive economics of horizontal technology for this application.

Alberta Heavy Oil Pools

Heavy-oil pools in Alberta can be divided into two groups: 1) the heavy-oil belt of South-Eastern Alberta, extending from Little Bow in the south to Lindbergh (see Figure 4-2), and 2) the oil-sands/bitumen area in northeast Alberta. The total number of horizontal wells drilled in Alberta is 250, of which 66 have been drilled in the oil-sands area (second group).

Heavy-oil formations in Alberta to which there has been significant horizontal drilling include the Upper Mannville, Glauconite, and Dina. These pools are relatively shallow. TVD is about 3000 ft or less. API Oil gravity ranges from 15-20°. Major multiwell project areas are Suffield, Provost, and Hayter.

Suffield Glauconite (Alberta)

The Suffield project includes about 40 horizontal wells. The first well was drilled in 1987. Several drilling problems were encountered. However, the operators realized the potential of enhancing the pool's reserves and have proceeded with horizontal well development.

The reservoir was deposited within a coastal dune complex. West tending fluvial channels periodically cut through the north-south trending dune system and broke the pool into a number of discrete pods joined by the underlying water leg (Figure 4-11). Typical reservoir properties are summarized in Table 4-5.

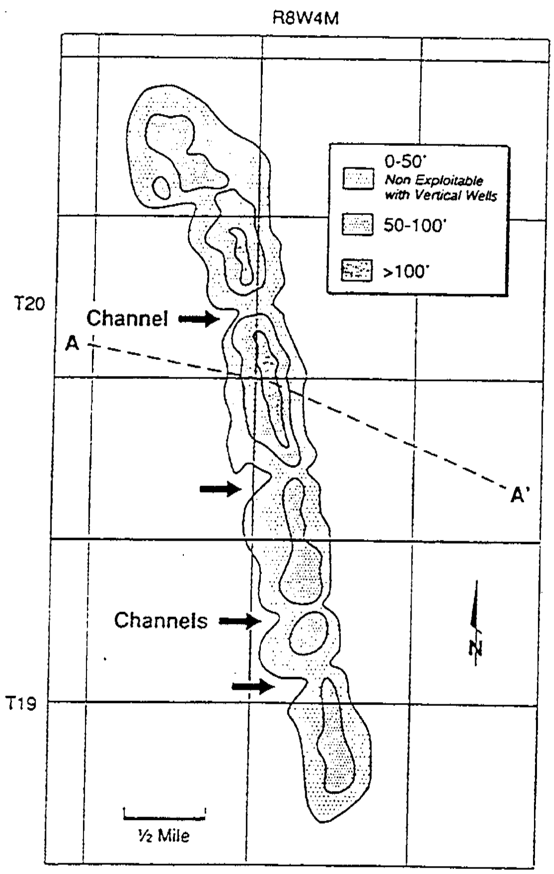


Figure 4-11. Deposition of Suffield Pool (Espiritu et al., 1993)

TABLE 4-5. Typical Reservoir Properties: Suffield/Glauconite

Gross Pay	50-200 ft	Horizontal Permeability	0.5-2 Darcies
Net Oil Pay	35-95 ft	Vertical Permeability	0.3-1 Darcies
Porosity	26-28%		

A 3-D seismic program was recorded in the field and has been used to assist in positioning the horizontal wells. Detailed reprocessing of the seismic data has been performed using about 200 infill wells. These data are also used during drilling operations to assist in decision making with respect to steering and occasionally to terminating drilling.

The first well drilled in the project was cased and cemented. The second group of wells was completed with pre-perforated liners. A third group was completed open hole. This experience represents a common progression in well design reflecting increasing confidence in hole stability, and illustrates that, even in relatively weak heavy-oil sands, open-hole completion appears viable. No sand production was observed after several months of production. Some of the more recent wells were placed on the flanks of the pool. This was found to be more challenging since the pay thickness is less along the flank.

Most of the wells drilled have the capacity to produce at rates in excess of 500 BOPD. Cumulative production expected from Suffield horizontal wells is 200-300 MBO (Figure 4-12).

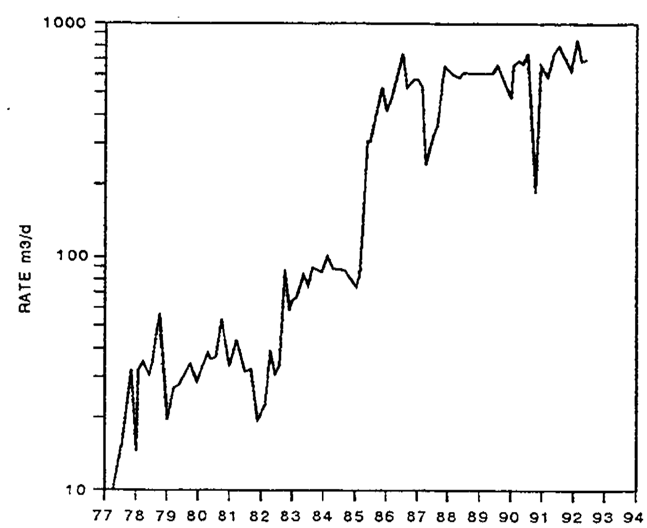


Figure 4-12. Suffield Heavy-Oil Production (Espiritu et al., 1993)

The Suffield project is one of the most successful heavy-oil horizontal well projects in Western Canada. The net pay and active aquifer are amenable to horizontal exploitation. Infill drilling with horizontal wells has improved recovery. A typical infill drilling layout is shown in Figure 4-13.

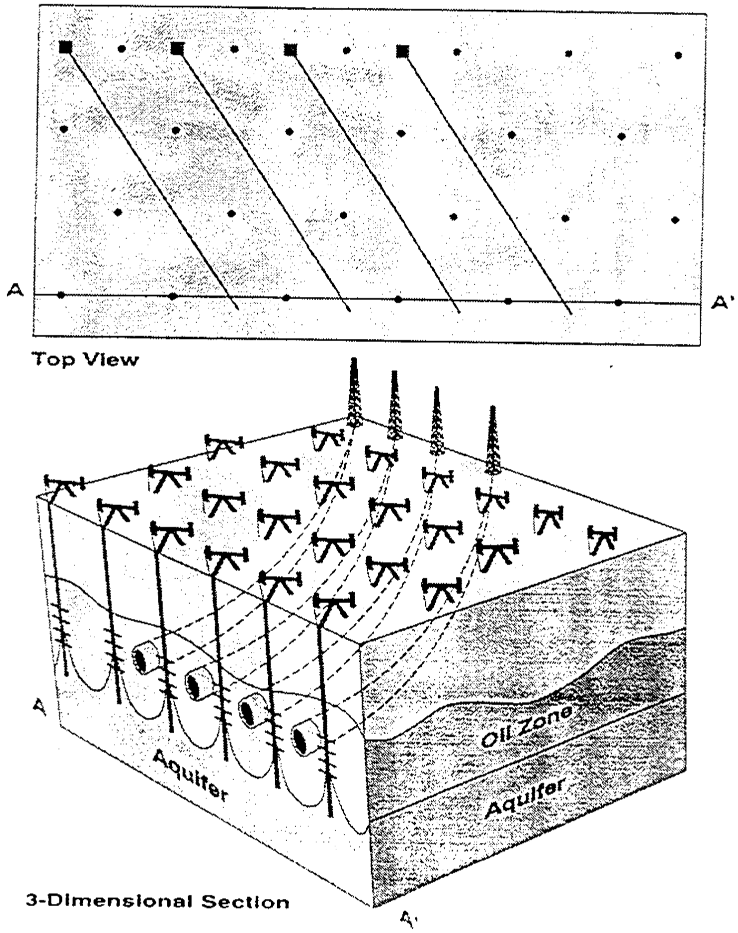


Figure 4-13. Horizontal Infill Drilling Layout (Espiritu et al., 1993)

There are a number of similar Mannville/Glauconite horizontal developments in Alberta. Net pay of the reservoirs is slightly less than Suffield; however, the reservoir depletion is less. Production data on these pools are limited. Initial rates are about 200-300 BOPD. In general, these pools are expected to perform as well as Suffield. Although development is still in early stages, incremental reserves resulting from horizontal wells are expected to be near 5%. An additional 50 wells have been drilled in the Upper Mannville in other smaller pools.

Other Glauconite Pools (Alberta)

The Glauconite formation is located at the base of the Upper Mannville. Some of the horizontal well projects in this formation are: Taber (5 wells), Bow Island (3 wells), Grand Forks (5 wells), Little Bow (8 wells), Hayter (10 wells), and Killam (4 wells). Most of these wells have been drilled as infill wells in established pools. The major objective of these infill projects is to recover by-passed oil resulting from coning of the vertical wells. The inner portion of the reservoir is generally a massive sandstone with porosity in the range of 25-30%. The upper channel facies are more heterogeneous, comprised of sandstone, siltstone, and shales. The units are deposited as a sandbar sequence within an estuarine environment.

Horizontal wells have initial production of 200-300 BOPD. However, as a result of the active aquifer, water production increases after about 6 months of production. At the end of the first year of production, water cut is near 75%. Estimated recovery from these wells is 200-300 MBO.

Dina Formation (Alberta)

The Dina formation in Alberta, like the Cummings/Dina in Saskatchewan, is a major target for horizontal wells. The number of wells in any pool is generally fewer than in Saskatchewan. There are about 20 wells drilled in Dina pools near Provost, several of which were drilled in 1989 and 1990 when the technology was just being developed. Some wells were drilled too close to the oil/water contact, and coned water almost immediately. Others had problems with formation damage, or were drilled too short, and thus performed poorly. Generally, wells with net pay of 30-50 ft where the horizontal lateral was located about 20 ft above the oil/water contact have performed satisfactorily. These had initial rates of 200 to 300 BOPD and average rates of 100 BOPD during the first 20 months of production. Estimated total recovery is 200 MBO.

Pelican Lake (Alberta)

The Pelican Lake project is an unusually thin heavy-oil project. Net pay is about 15 to 20 ft. The operator has been successful in drilling long horizontal wells (3000 ft), achieving initial rates of 100-150 BOPD of 14° API gravity oil. Several vertical wells drilled in the project were uneconomic to produce at present oil prices.

The pool was developed in three phases. The first phase served as a learning phase for the project. The productive sand is in the Wabiskaw sands of the Mannville group of the Lower Cretaceous age. The pool is situated in the middle of the heavy-oil deposits (Figure 4-14). Eight horizontal wells were drilled during the project.

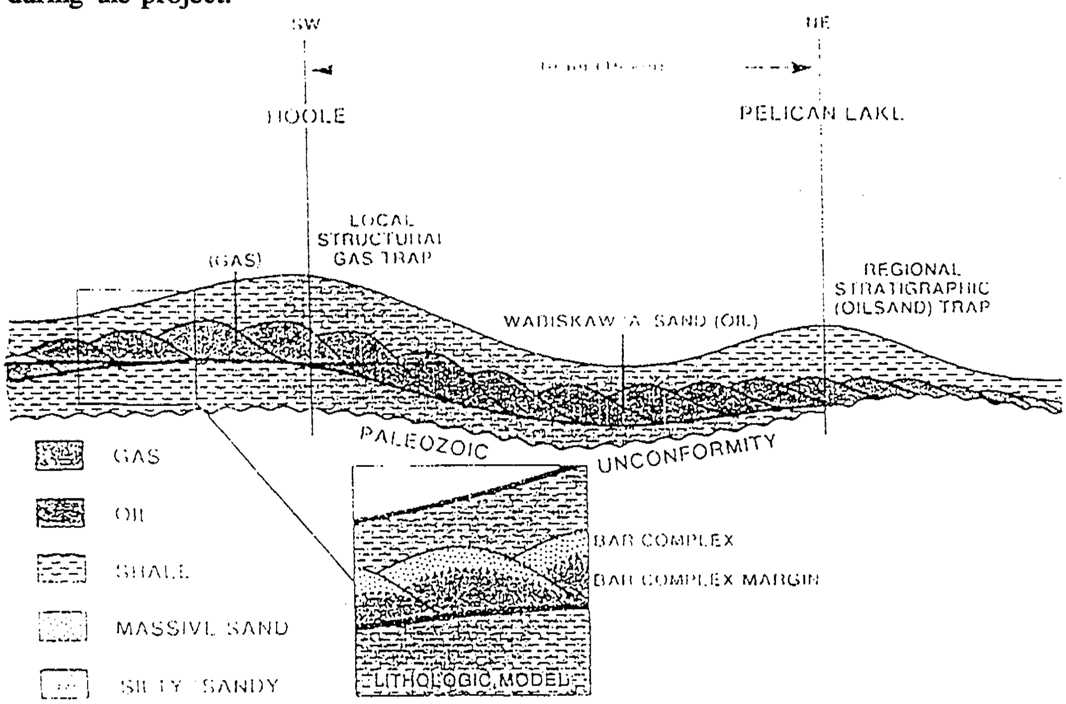


Figure 4-14. Depositional Model of the Wabiskaw Complex (Fontaine et al., 1992)

Evaluation of the eight wells drilled in the first phase indicated that four wells were drilled in portions of the pool with higher water saturation. In addition, wells penetrating more of the Bar Margin had lower productivity. In the second phase, wells were drilled in a section of the reservoir with lower water saturation. Wells were also longer, and effort was made to maintain the trajectory in the Bar Complex. In fact, the best results were obtained by allowing the bottom assembly to drill in the best reservoir without major corrections or concerns as to whether the trajectory was high or low in the sand portion of the reservoir. This behavior may be a function of drillability, such that in this case the "sweet" portion of the reservoir is most easily drilled, and the drill string tends to track along this rock type. Further modification of the program in the third phase resulted in additional improvement in well performance. Figure 4-15 shows the plan layout of all three phases of this development.

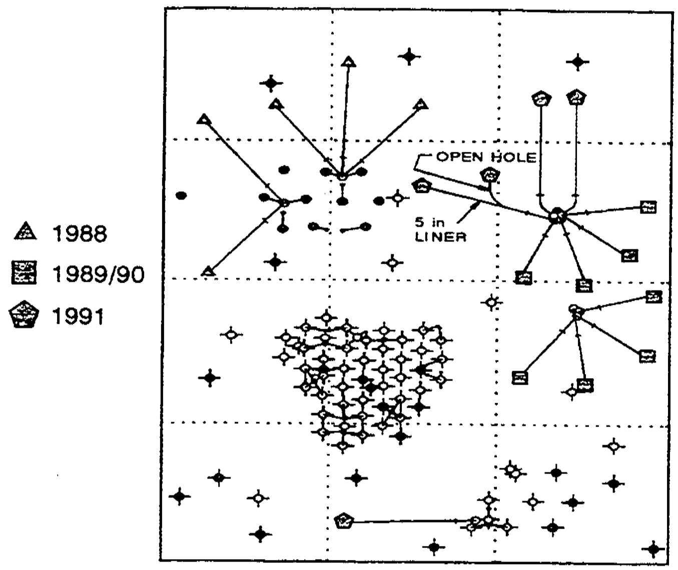


Figure 4-15. Pelican Lake Horizontal Well Layout (Fontaine et al., 1992)

The results of this project demonstrate a very effective application of horizontal well technology. Several enhanced recovery processes were tried previously, but they proved uneconomic. However, a primary recovery scheme using horizontal wells appears to be economically attractive. Currently, the pool is essentially under primary production. It may soon be necessary to reintroduce some of the enhanced recovery schemes previously evaluated for the pool. Figures 4-16 and 4-17 illustrate the improved geosteering performance and reduced cost per productive meter accomplished over the three phases of development to date. Over this time period, the average production ratio for horizontal wells increased from 3 in 1988 to 6 in 1990, and to over 10 in 1991.

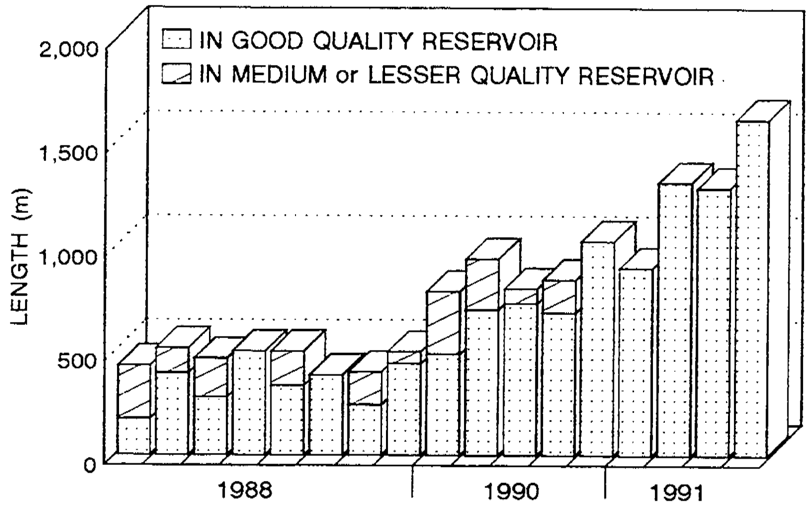


Figure 4-16. Geosteering Performance at Pelican Lake (Fontaine et al., 1992)

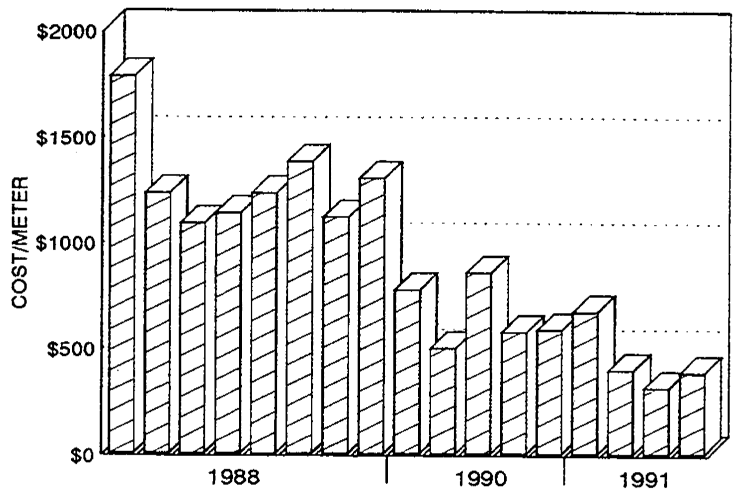


Figure 4-17. Pelican Lake Project Cost per Productive Meter (Fontaine et al., 1992)

4.2.2 International Heavy-Oil Applications

The Rospo Mare development in the Adriatic Sea (discussed in Section 3.3.3) is technically a heavy-oil application. Due to the relatively high *in-situ* temperature, the 13° API oil is very thin and behaves more like a light-oil reservoir than the Canadian applications previously described.

There have been limited applications reported in China and interest has also been expressed in various international locations, i.e., Indonesia, central and eastern Europe, and others. There are very limited published data available on these areas. However, there is no apparent reason why the significant success experienced in the Canadian pools will not eventually be mirrored in these other areas.

4.3 ENHANCED OIL RECOVERY IN HEAVY OIL

4.3.1 U.S.A. EOR Applications

Midway Sunset (California)

The Midway Sunset Field is one of the few domestic EOR projects using horizontal technology to recover heavy oil. The field is located in the southwest portion of the San Joaquin Basin in southern California. The field is a "super giant" with ultimate reserves of 2.75 BBO.

The Upper Miocene turbidite sand reservoirs contribute most of the field's production. These sands were deposited in a series of interfingering submarine sands. The Sub-Hoyt Sands are massive to thin-bedded unconsolidated sands and sandy conglomerates. Sub-Hoyt E consists of amalgamated very fine- to coarse-grained sands with an average thickness of 400 ft.

Sub-Hoyt E Sands contain 12-13° API oil and were first developed in the early 1900s. Primary production continued until 1966, when steam soaks were first used. A full-scale steam flood was initiated in 1982. Horizontal technology was first used in the field in late 1990 when three short-radius wells were drilled (Figure 4-18).

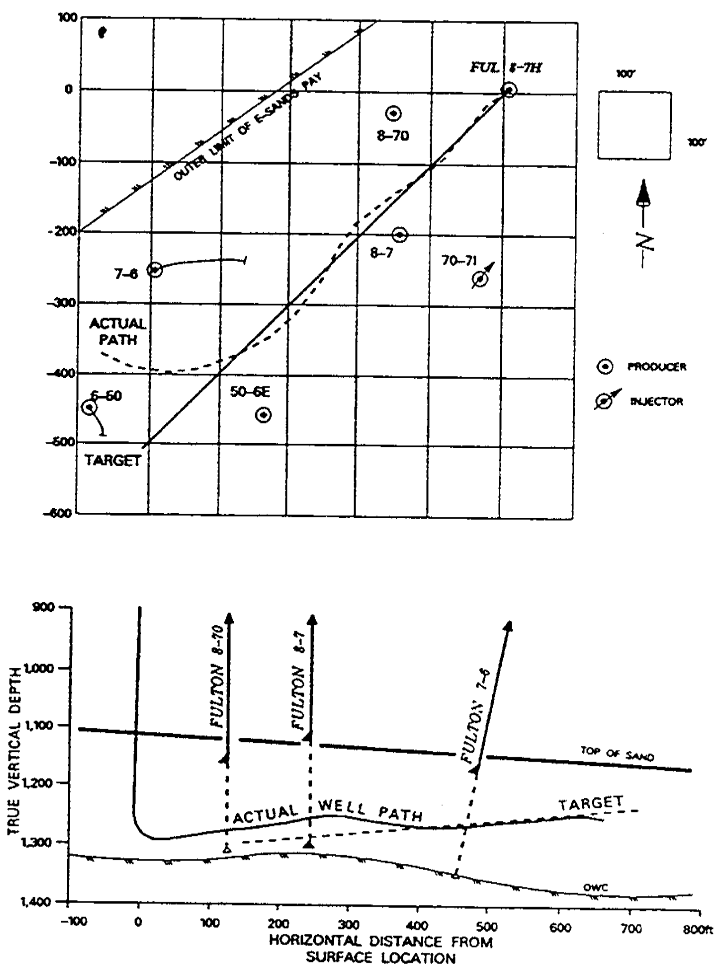


Figure 4-18. Sub-Hoyt Short-Radius Horizontal Well (Carpenter and Dazet, 1992)

The operator (Shell) made the decision to drill horizontal wells after simulation studies indicated that this approach would provide better areal sweep, accelerate production, shorten project life and increase profitability (Carpenter and Dazet, 1992). Cost ratios for the first 3 wells ranged from 2 to 3. Production ratios were 2 to 3 for 400-ft horizontal wells and about 6 for a 700-ft well.

After initial horizontal development, a simulation study was performed to answer several questions: 1) are horizontal wells the optimal depletion method? 2) how should they be used? 3) where should they be positioned? and 4) how can their performance be optimized? Simulation parameters used to characterize the field are shown in Figure 4-19.

Porosity, %	25
Absolute Permeability, md	
K_X	1338-2378
K_Y	$K_Y=K_X$
K_Z (turbidite sand)	$K_Z=0.5K_X$
Dip, degrees	36
Reservoir Temperature, °F	
Original	100
Steam Zone	290
Oil Viscosity, cp	
at Original Temperature	2000
at Steam Zone Temperature	2
Oil Saturation, %	
Initial	80
Residual to water, S_{orw}	25
Residual to Steam, S_{org}	10
Water Saturation, %	
Conate Water, Initial Conditions, S_{wc}	20
Residual to oil, S_{wro}	20
Residual Steam Zone, S_{wr}	50
Critical Gas Saturation, %	5

Figure 4-19. Midway Sunset Simulation Parameters (Kuhach and Myhill, 1994)

A significant result of the simulation studies was the observation that the oil/water contact (OWC) slumps after coning to nearby wells (Figure 4-20). The sands are underlain by an inactive aquifer. The OWC thus becomes irregular and drops over time. A significant consequence of this behavior is that most wells in the field are now too shallow. Vertical wells, which were completed with open-hole gravel packs, cannot be effectively recompleted at deeper intervals.

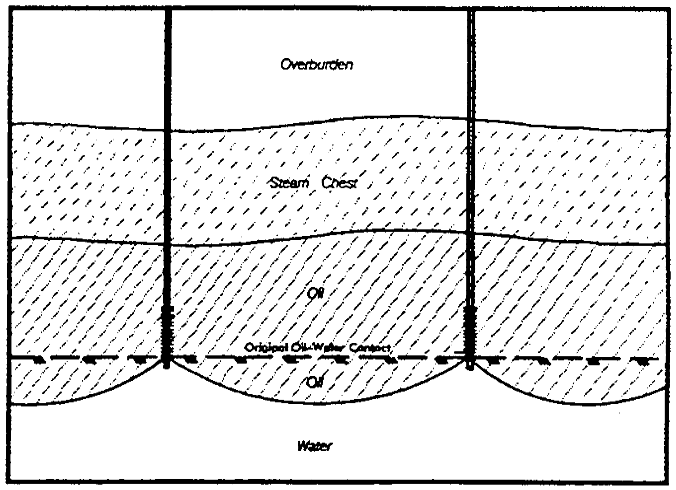


Figure 4-20. Coning and Slumping of OWC (Kuhach and Myhill, 1994)

The operators concluded that the most efficient technique to recover oil from the slumped zones is with horizontal wells. Since gravity drainage is the primary recovery mechanism, wellbores must be located close to the OWC. Horizontal wells should stabilize the OWC since they require a smaller pressure drop near the wellbore and, consequently, cone much less than vertical wells.

Medium-radius techniques were chosen for the second horizontal drilling program. Compared to earlier short-radius wells, medium-radius techniques allow longer horizontal sections, better directional control, lower pump placement, and other benefits. Four medium-radius wells were recently drilled in the field. The seven horizontal wells now account for over half the production from the E sand. One-hundred twenty vertical wells produce the balance.

Average production ratio for the medium-radius wells is 16, and tends to increase linearly with horizontal length. Cost ratio increases only slightly with horizontal length; thus, longer wells provide the highest profitability. Capital cost, productivity ratio and horizontal length are compared in Figure 4-21.

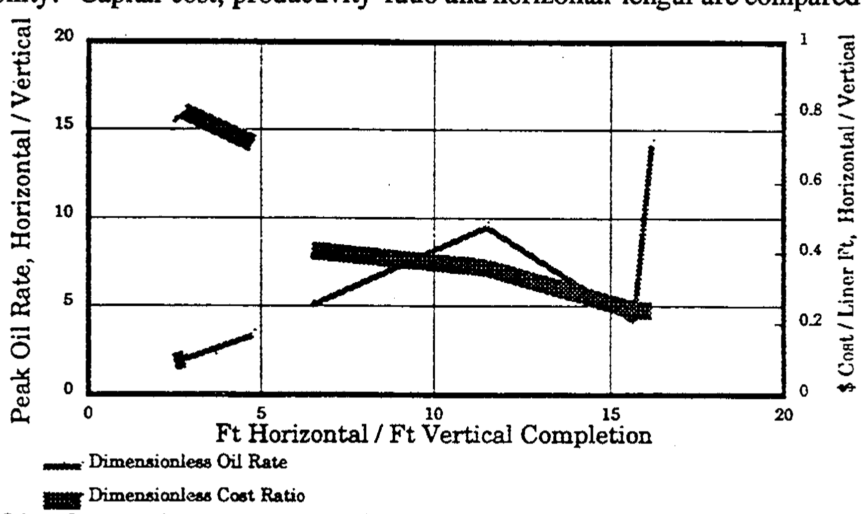


Figure 4-21. Cost and Production Performance of Medium-Radius Horizontal Wells (Kuhach and Myhill, 1994)

Shell concluded that "horizontal wells are the most economical means of depleting the reservoir. Compared with vertical wells, they produce at high oil rates for low capital costs per productive length." In addition, "because of the similarity of heavy oil, steep dip, and inactive bottom water zones in most Midway Sunset reservoirs, the results of this study are applicable to other thermal recovery projects."

4.3.2 Canadian EOR Applications

Various horizontal well thermal processes (e.g., SAGD - Steam-Assisted Gravity Drainage, HASDRIVE - Heated Annulus Steam Drive) have been tested in pilot projects over the last 4 to 5 years. The most notable of these is the UTF (Underground Test Facility) operated by AOSTRA (Alberta Oil Sands Technology and Research Authority) at Fort McMurray, Alberta. In this facility, the tar-sand deposits (1200-1400 ft TVD) are underlain by a competent massive limestone. A conventional mine shaft was employed and tunnels (approximately 10 ft high) were placed in the limestone immediately below the base of the tar-sand deposit. Pairs of horizontal wells were then drilled up into the tar sands, the upper well (steam injection) strategically located 3 to 10 ft directly above the lower well (production) (Figure 4-22).

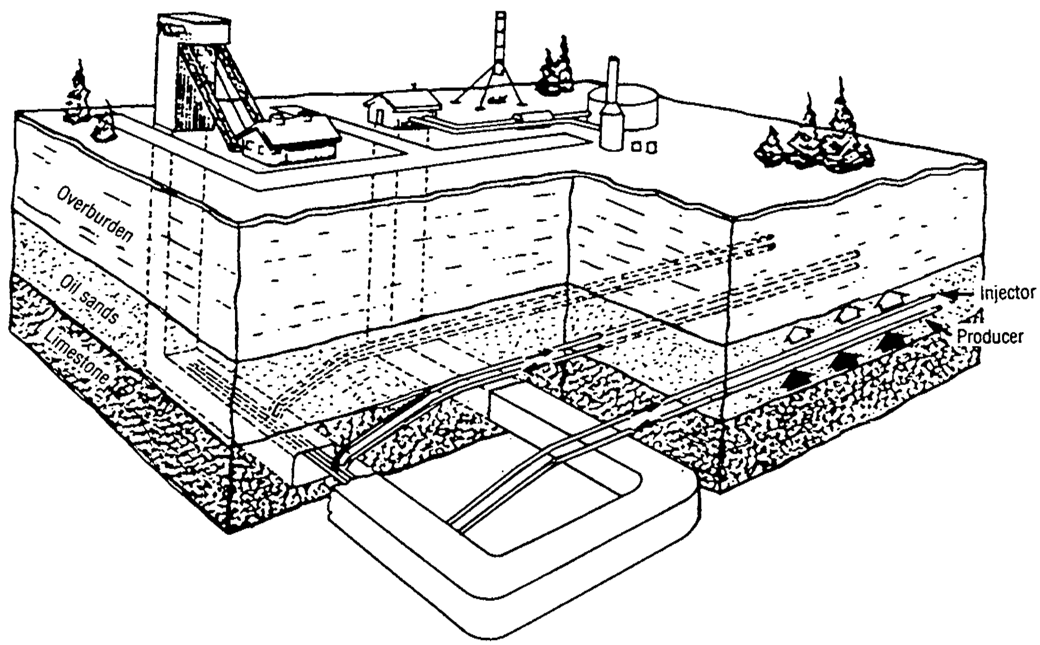


Figure 4-22. Schematic of AOSTRA Horizontal Well Pairs (Moore, 1988)

In this process, steam is injected in the upper well, leading to the formation of a rising steam chamber. The heated oil is considerably more mobile and flows down the sides of the chamber to the production well along with the condensed water (Figure 4-23).

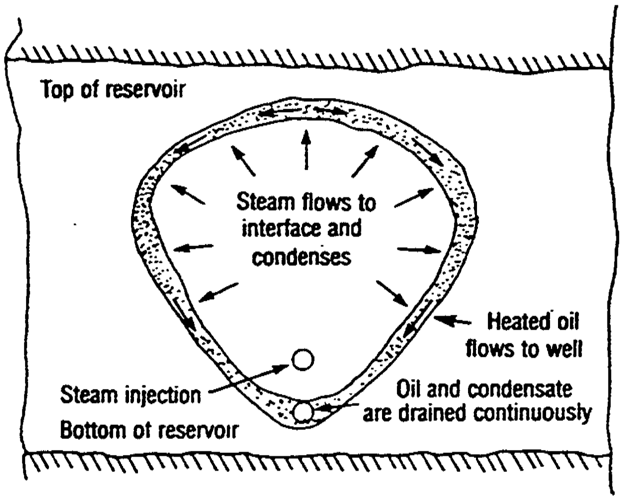


Figure 4-23. SAGD Steam Chamber (Moore, 1988)

Preliminary reports from the pilot tests have been encouraging, so much so that at least one major operator, Shell Canada, has already started a full-scale field pilot of the process utilizing well pairs drilled conventionally from surface. The tar-sand deposits of Western Canada are extremely large, with OOIP reserves in excess of 1.5 trillion bbl. Should the SAGD and other thermal horizontal well processes prove viable, they may very well be the technical key to unlock these huge oil reserves to economic exploitation.

Adaption of the SAGD process has already been commercially employed in conventional heavy-oil projects in Canada. The most notable of these is the Tangleflags project operated by Sceptre Resources in Saskatchewan (Figure 4-24).

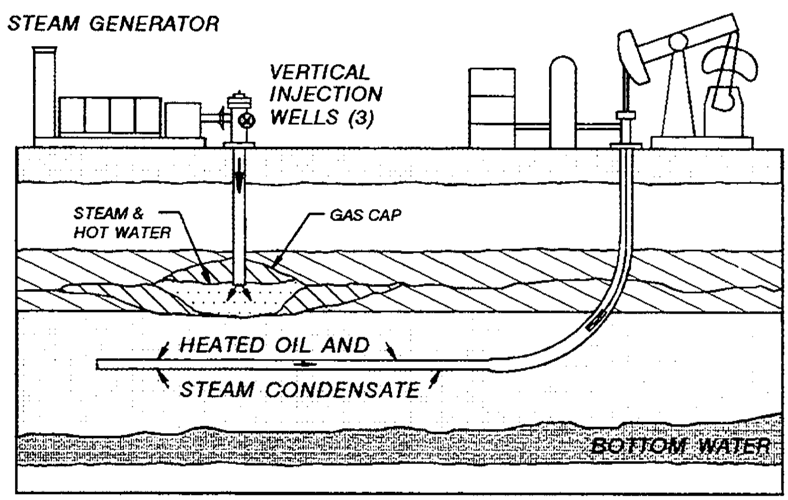


Figure 4-24. Schematic of Tangleflags Horizontal Well (DEA-44 WH #18)

In this development, vertical wells are used to inject steam into an existing gas cap, thereby heating (thinning) and driving the heavy oil down into a horizontal producer placed immediately above the oil-water contact. The first well in this project was put on production in 1988, and has a cumulative oil production to date of approximately 1 MMbbl. The project has since been expanded to three horizontal producers. Recovery factor is around 60% of OOIP. This success is in stark contrast to a 0.5% recovery from primary vertical wells (i.e., rod pumping without steam stimulation) and 25% from conventional vertical EOR applications (e.g., huff and puff or steam-drive projects). The use of horizontal wells in heavy-oil thermal EOR projects is gaining acceptance within the industry with projects currently under way by a number of major and intermediate operators including Amoco, Mobil, Shell, Sceptre, Wascana (Saskoil), Elan, and others.

Horizontal wells are being used in several oil-sands projects in Alberta to complement thermal processes, and in some areas to produce primary oil. Some of the project areas are: Esso Cold Lake (9 wells), Amoco Primrose (7 wells), Brintnell (15 wells), Shell Cadot/Peace River Project (6 wells), Texaco (3 wells), McMurray (3 wells), and CS Resources Brintnell/Highly (27 wells).

Esso Cold Lake (Alberta)

This is the first heavy-oil project that utilized horizontal wells. The daily production of the field is 85-95 MBOPD. There are about 1800 vertical wells in the pool. The major production process is cyclic steam stimulation (CSS). The expected recovery factor is 20%. Horizontal wells are being tested to determine whether they will enhance recovery (Figure 4-25).

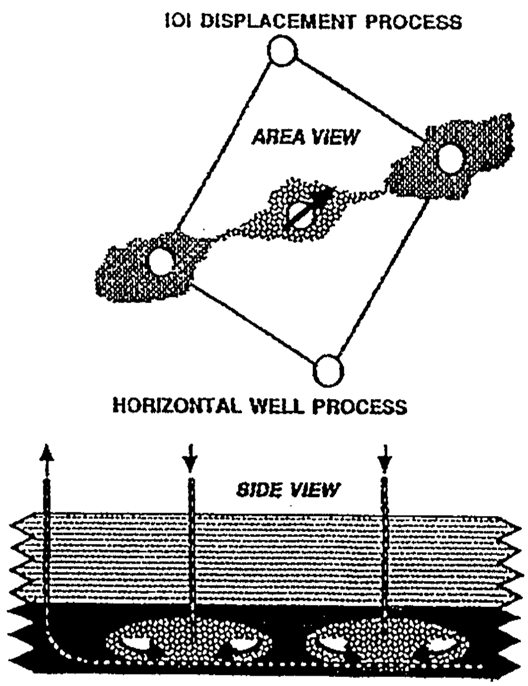


Figure 4-25. Esso Cold Lake Cyclic Steam Stimulation (Taylor, 1994)

Amoco Primrose/Britnell (Alberta)

These are major heavy-oil projects with hundreds of vertical wells. Pilot projects have been initiated using steam and horizontal wells to improve both recovery and rate. These pilot projects have "experimental" status and, therefore, production and economics data are currently unavailable. A number of pilots employ horizontal production wells placed below or between existing vertical well steam cycle patterns.

Shell Cadot (Alberta)

Shell is conducting a pilot program using a dual horizontal well system to produce oil from the Peace River oil sands (Hamm and Ong, 1994). The process is a modification of the SAGD process used in the UTF project (see Figure 4-22). The SAGD well configuration consists of two parallel horizontal wells with continuous steam injection through the upper well, and liquid and gas production from the lower well. A performance enhancement (ESAGD) to the SAGD process is obtained through the application of a small pressure differential between adjacent pattern steam chambers. This enhancement results in accelerated steam zone growth, improved bitumen production, up to a 50% improvement in ultimate recovery, and no impairment of thermal efficiency.

The Peace River oil sands contain 75 billion barrels of bitumen. The production horizon is found in the Bullhead member of the Cretaceous Bluesky/Gething. The SAGD process instituted at Peace River consists of three operational components: 1) start up, 2) SAGD operation, and 3) SAGD/steam drive. A horizontal well pair 3280 ft long is shown in Figure 4-26.

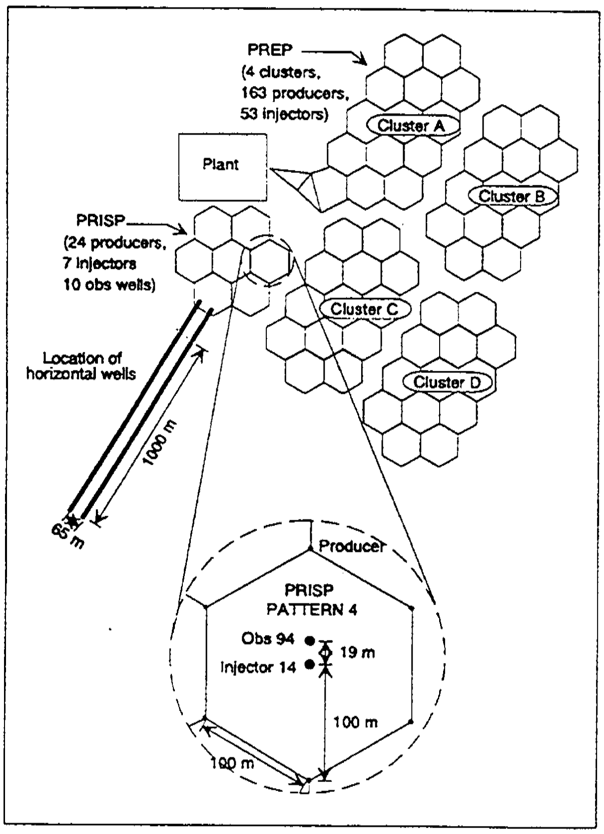


Figure 4-26. Peace River Field Schematic (Hamm and Ong, 1994)

Texaco McMurray (Alberta)

One of the earliest horizontal heavy-oil thermal pilots was conducted by Texaco in the McMurray oil-sand deposit in Central East Alberta. Three slant-rig horizontal wells were drilled in an existing vertical steam-flood project area. The well profile and basic design used for all three wells are shown in Figure 4-27. The three wells were placed parallel to each other. Steam was injected through the middle well; the outer two wells were used as producers. Interwell spacing was 250 ft and 410 ft.

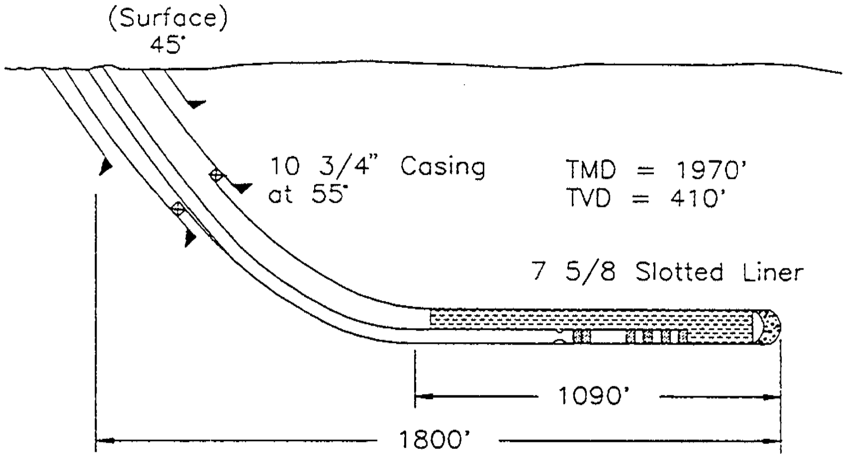


Figure 4-27. Texaco McMurray Well Profile

The McMurray oil-sand deposit is typical of the Athabasca-type bitumen deposits found in central and eastern Alberta. The mid- to lower-Cretaceous sand has an oil pay thickness ranging from 30 to 180 ft, porosity of 28-32% and permeability of 2-4 darcies. The high viscosity (i.e., 1,000,000 cp) of this heavy oil (10 to 12° API gravity) necessitates thermal recovery techniques.

In addition to evaluating the merits of a horizontal wellbore in a steam-flood application, Texaco wanted to evaluate the benefits of slant-rig drilling. A slant rig was required since conventional directional drilling techniques available at that time could not reach horizontal at the shallow depth of the reservoir. The slant rig allowed the three wells to be spudded at 45° from a central pad. This reduced lease construction and maintenance costs and eased operational logistics. Two of the wells had to be designed with relatively sharp bends in both the vertical and horizontal planes to achieve the desired parallel interwell geometry.

Since these three wells were drilled as a pilot project, detailed production response data are confidential. The third well (spaced 410 ft from the central injector) reportedly responded well to the steam-flood process, producing approximately 300 BOPD with a water cut exceeding 50%. This compares to a typical vertical steam-flood well in the field that might produce on average 36 BOPD and cost $100,000 to drill and complete.

The first well (250-ft spacing from middle injector well) appeared to suffer from early steam-flood breakthrough, apparently caused by a zone of relatively low oil saturation at the heel of the well. This low-saturation zone may have caused a preferential path for the steam to travel from injector to producer, thus "short-circuiting" the steam-flood process. Attempts to remedy this problem led to mechanical problems in the well. In early 1986, low oil prices resulted in termination of the pilot project.

Since this was the first project using slant/horizontal drilling in Canada, mechanical problems with the prototype slant rig were expected. The hydraulic systems experienced "teething problems" due to winter weather (i.e., sub-zero) and mechanical problems related to properly making up tubulars and casing at a 45° angle.

Problems experienced in the third well (stuck and parted liner) were the result, in part, of extreme bends in the wellbore. This well was required to make a strong azimuthal bend in addition to a sharp bend to horizontal as necessitated by the shallow path. In general, the operator was pleased with the operational success of the drilling program, which met all objectives. Table 4-6 presents average time and cost reported on these three early wells.

TABLE 4-6. Average Time/Cost Per Well: Texaco McMurray

	Time (Days)		Cost ($1000)	
	Normal	Trouble	Normal	Trouble
Vertical Hole	2.50	2.50	38.5	36.0
Curved Section	13.10	4.75	200.0	67.0
Horizontal Section	6.40	7.75	87.5	111.0
Horizontal Length	0.90	0.70	14.0	9.0
Horizontal Compl. & Stim	1.50	5.00	22.0	69.0
TOTALS	24.40	20.70	362.0	292.0

4.4 NEW TECHNOLOGIES FOR HEAVY OIL

Two advanced heavy-oil EOR concepts are mentioned in this section.

VAPEX (Vapor Extraction)

A series of papers has been presented by Dr. Roger Butler et al. describing a vapor extraction process (e.g., Das and Butler, 1994). A brief description of the concept is presented here. A number of laboratory model runs have been completed. However, no field tests or pilots have been reported to date.

Recovery using vaporized hydrocarbon solvents near their dew points, termed VAPEX (vapor extraction), is emerging as a possible alternative to the inefficient thermal processes currently in use for the recovery of the huge reserves of heavy oil and bitumen. In the VAPEX process, solvent is used to dilute highly viscous heavy oil and bitumen and increase production rate by reducing viscosity (Figure 4-28).

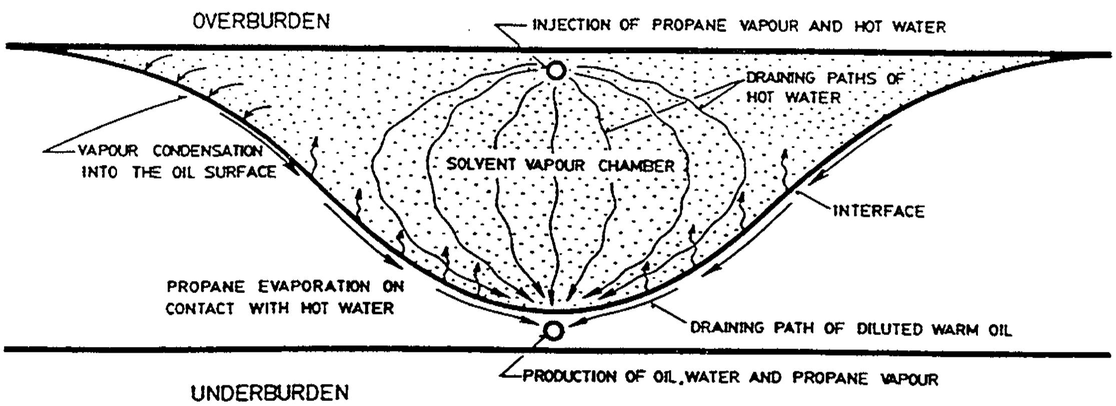


Figure 4-28. VAPEX Solvent Vapor Chamber (Das and Butler, 1994)

Propane and ethane are considered to be the most suitable solvents for this process. However, a mixture of butane, propane and ethane can also be used, depending on the prevailing pressure in the reservoir. After solvent injection, oil is produced by gravity drainage to horizontal wells.

One important advantage of this approach is the *in-situ* upgrading of heavy oil by deasphalting, making the produced crude comparable to lighter oils in quality. Moreover, elimination of the undesired asphaltenes from the crude can solve several downstream problems.

GAGI (Gravity Assisted Gas Injection)

An excerpt from the abstract of Bansal and Islam (1994) describing a gas injector process using horizontal wells is presented below. The concept is discussed in reference to application in the West Sak heavy-oil reservoir of the North Slope, Alaska. No field tests of this process have been reported to date.

"Gas injection is one of the oldest enhanced oil recovery techniques used for recovering light oils. Recently, there has been renewed interest in gas injection in both light- and heavy-oil reservoirs. This recovery technique is particularly of interest for the heavy-oil reservoirs of Alaska where the application of thermal techniques is limited due to reservoir depth and the existence of permafrost. It has been pointed out that, in order to apply gas injection, gravity stabilization is required. In absence of a natural dip, such gravity stabilization may be achieved through horizontal wells placed on top of the reservoir while producing through another horizontal well placed at the bottom of the reservoir. The possibility of such a recovery technique has been investigated in laboratory studies."

5. Gas Applications

5.1 INTRODUCTION

Horizontal technology has been successfully applied to gas exploration and development. Horizontal wells have been increasingly drilled for gas production in the U.S.A., Canada, Europe, and South America. An international well count (Figure 5-1) shows that almost three-fourths of horizontal gas wells have been drilled in the U.S.A.

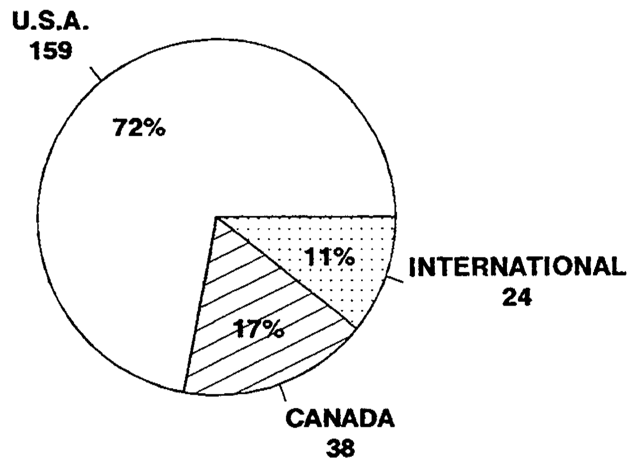


Figure 5-1. Horizontal Gas Wells (Jochen et al., 1993)

Annual activity in the U.S.A. continues to grow (Figure 5-2). In contrast, Canadian activity has been relatively stagnant.

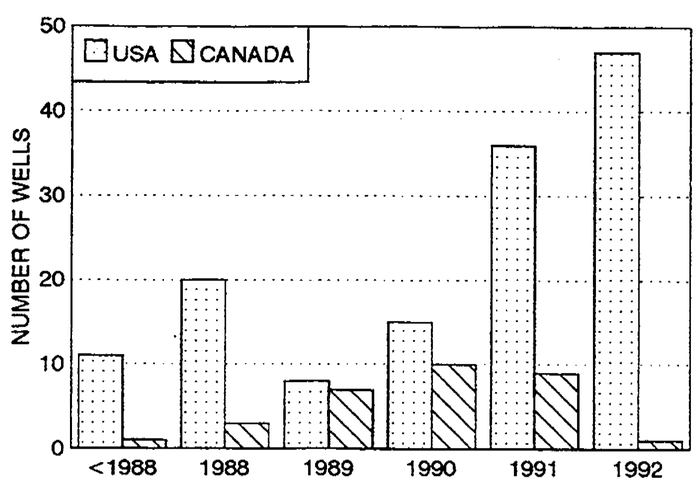


Figure 5-2. U.S.A. and Canadian Horizontal Gas Wells (Jochen et al., 1993)

Historically, the industry's success in the use of horizontal technology for gas production has not equaled that of oil production. There are important applications for horizontal wells in gas reservoirs; however, the range of those applications is not as extensive as for oil production. The most successful applications for horizontal development of gas reservoirs include the following:

1. **Intersecting Fractures.** Horizontal wells drilled perpendicular to natural fracture trends can produce gas from multiple fractures, whereas vertical wells can normally connect with, at most, one fracture system. As is the case for oil wells, intersecting fractures has historically been the most popular application for gas reservoirs. In fact, about 40% of U.S.A. horizontal gas wells have been drilled in the Austin Chalk (Jochen et al., 1993).

2. **Water Coning.** Reservoirs with water-coning problems and velocity-induced sand production are more effectively produced with horizontal wells. Horizontal wells delay the onset of coning in gas production just as in oil production.

3. **Active Water Drives.** Horizontal wells have also been applied in reservoirs where vertical wells could not be fractured due to the presence of active aquifers under the gas. Several wells have been drilled successfully for this application, resulting in economic (marginal) gas rates with low water cuts. However, where conditions permit, hydraulically fractured vertical wells are usually more economic than unfractured horizontal wells.

4. **Layered/Heterogeneous Reservoirs.** Horizontal wells have been effectively used in compartmentalized reservoirs to connect multiple high-productivity zones.

5. **High-Cost Locations.** Horizontal wells have been economically advantageous in high-cost areas, such as offshore, where the cost of developing the field with vertical wells makes the project uneconomical. Fewer wells, slots, and platforms are required for horizontal development. Consequently, many of these marginal prospects are viable with horizontal technology.

6. **Sour-Gas Reservoirs.** Horizontal wells have application in sour-gas reservoirs near urban areas so that surface locations, which are potential release sites, can be located a distance from populated areas. Where necessary, horizontal development will allow the use of fewer surface locations, thereby reducing environmental risk.

7. **Gas-Storage Reservoirs.** Tremendous potential exists for the application of horizontal wells for developing gas-storage reservoirs. Horizontal production rates 5 to 10 times greater than vertical wells allow operators to meet peak deliverability requirements with fewer wells and lower sand-face velocities. Several successful gas-storage applications are described in Section 5.3.

Gas reservoir types for which horizontal technology has been less successful include:

1. **Low-Permeability Reservoirs.** Production improvements for horizontal wells in thick, tight reservoirs are often not high enough to make their use economic. Hydraulically fractured vertical wells are usually a better option in these cases.

2. **Low K_v/K_h Reservoirs.** Many domestic gas reservoirs are in tight formations that have low ratios of vertical to horizontal permeability. Horizontal wells are often not economical in these formations unless the wells are fractured. Vertical wells are often more effective in low K_v/K_h reservoirs because they intersect all of the productive layers.

   This disadvantage for horizontal wells may be overcome by hydraulic fracturing, which allows stratified pay zones to be connected to the wellbore. If the wellbore is oriented parallel to the plane of least principal stress, multiple hydraulic fractures can be created along the wellbore. In gas reservoirs with low K_v/K_h, a single horizontal well with multiple hydraulic fractures should be more economical than several vertical wells with a single fracture.

3. **Shallow Reservoirs.** In shallow gas reservoirs where vertical wells produce at economic rates, the benefits of increased access to the pay zone by drilling horizontally may not be economically justifiable due to the low cost of vertical wells.

Another characteristic of gas that affects the success of horizontal technology applications is its high mobility. Drainage areas of gas wells are much larger than for oil wells due to this high mobility. The drainage radius of a vertical gas well can be greater than the drillable length of a horizontal well. Gas mobility often makes it uneconomical to appreciably increase the drainage area (and producible reserves) of a gas well with horizontal technology.

Industry's experiences with horizontal technology in gas reservoirs are summarized in the following sections.

5.2 GAS PRODUCTION

5.2.1 U.S.A. Gas Applications

GRI recently sponsored a survey of horizontal gas wells in the U.S.A., as well as Canada, and international fields (Jochen et al., 1993). This study lists a total of 221 horizontal gas wells, of which 159 are in the U.S.A. A breakdown by state (Figure 5-3) shows that almost half of domestic horizontal gas wells were drilled in Texas. States with wells in the "Other" category include: Kentucky (2 wells), Oklahoma (4 wells), Pennsylvania (4 wells), and Virginia (1 well).

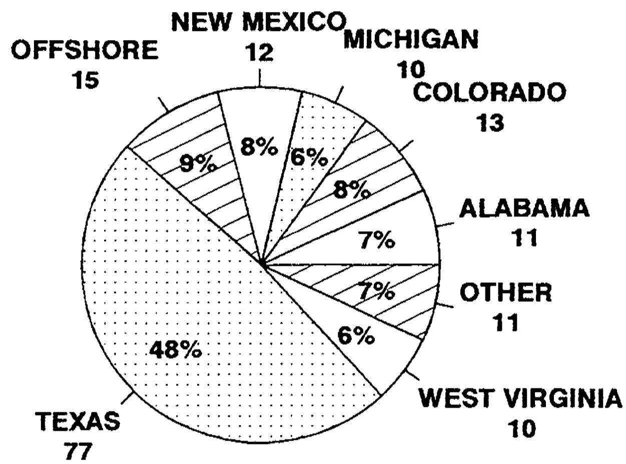


Figure 5-3. U.S.A. Horizontal Gas Wells (Jochen et al., 1993)

The most active formation in the U.S.A. for horizontal gas wells is the Austin Chalk in Texas; 60 of Texas' wells were completed there. The 17 Texas wells not in the Austin Chalk were drilled in 14 different formations. Low well counts in any particular formation are the trend for most states. Horizontal drilling has been applied experimentally in many cases to determine its potential in various gas-bearing formations.

Other U.S.A. formations with more than 4 wells include the Cozzette with 10 wells (Colorado/New Mexico); Devonian Shale with 9 wells (West Virginia); Antrim Shale with 8 wells (Michigan); Fruitland Coal with 7 wells (Colorado/New Mexico); and Pottsville Coal with 8 wells (Alabama). A lithological distribution of U.S.A. horizontal gas wells (Figure 5-4) shows that well counts in clastic and carbonate reservoirs are similar.

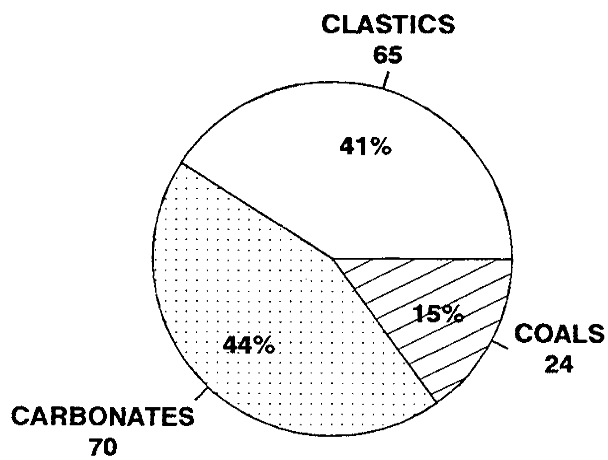


Figure 5-4. U.S.A. Horizontal Gas Well Lithology (Jochen et al., 1993)

Economic success of horizontal gas wells has been most consistent in the Austin Chalk and the Gulf of Mexico. In many formations, success has been difficult to achieve. Jochen et al. (1993) estimated that 52% of U.S.A. horizontal gas wells overall were successful. If the Austin Chalk and Gulf of Mexico wells are excluded from the averages, the success rate is reduced to only 20%. Success rates for each formation type are summarized in Table 5-1.

TABLE 5-1. Success Rates of U.S.A. Horizontal Gas Wells (Jochen et al., 1993)

FORMATION TYPE	NO. WELLS	SUCCESSFUL
Carbonates	70	67%
Coals	24	47%
Offshore (Clastics)	15	100%
Sandstones	29	36%
Shales	21	5%
Total	159	52%

U.S.A. operators' experiences in specific formations are described in the following paragraphs.

Devonian Shale (West Virginia)

The Devonian Shale is a large gas resource, with estimated gas-in-place of 577-1100 Tcf (Salamy et al., 1987). Only a small fraction of this resource has been exploited with vertical well technology. Recovery factor with vertical wells is only 10-20%. DOE has conducted research to determine means of increasing gas production from the Devonian. Horizontal wells were indicated as a promising technology to increase recovery efficiency.

The DOE (Yost et al., 1987) air-drilled a 2000-ft horizontal well in the Devonian Shale in an attempt to intersect fractures and increase gas production in this tight formation (Figure 5-5).

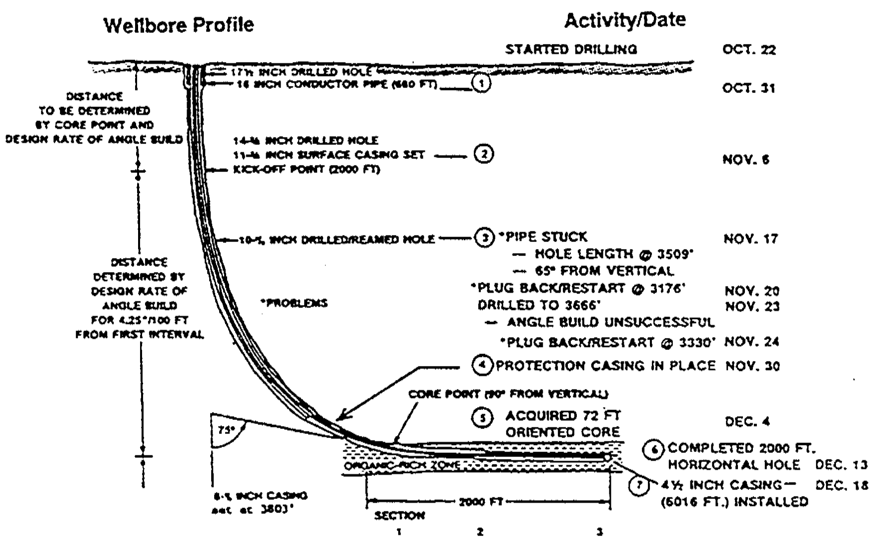


Figure 5-5. DOE Devonian Shale Well (Yost et al., 1987)

This well cost $1.32 million including $0.45 million for R&D and management costs (Table 5-2). This is about 4 times the cost of a vertical well in this area.

TABLE 5-2. DOE Devonian Shale Well Costs (Yost et al., 1987)

	Third Party Costs	R&D Costs	Project Management
Site Selection, Reclamation, Well Design, Site Acquisition and Preparation		$280,082	
Drilling (Including Directional Driller)	$700,572		
Coring and Analysis		$ 54,758	
Logging	$ 41,248		
Well Testing and Analysis	$ 21,950		
Contingency (Plug Back #1 & #2)	$102,147		
Well Site Management (Drilling, Coring, Logging, & Well Testing)			$116,143
Subtotals	$865,917	$334,840	$116,143
Total Well Costs (Excluding Stimulation)			$1,316,900.00

The well intersected over 250 fractures in the 2200-ft horizontal section, corresponding to one fracture every 8.8 feet. The number of fractures varied from a low of 5 fractures per 200 ft near the beginning of the horizontal well to more than 40 fractures per foot near the end.

The well was drilled in a 200-ft thick section in a depleted area of the field. A vertical well would not have been drilled in this uneconomical area of the field. The initial production from this well was 65 Mcfd of gas from 2213 ft of open hole, compared to 13 Mcfd for a vertical well in this area.

After this first successful field test, four more wells were drilled with DOE funding in the Devonian Shale in West Virginia and Kentucky (Table 5-3). Each of these wells initially produced more than comparable vertical wells. Long-term performance and increased recovery have not yet been verified.

TABLE 5-3. DOE Devonian Shale Horizontal Gas Wells (Yost and Javins, 1991)

WELL NAME	PARTICIPANTS	HORIZONTAL PRODUCTION (MCFD)	VERTICAL PRODUCTION (MCFD)	PRODUCTION RATIO	HORIZONTAL LENGTH (FT)
Ret #1	DOE/BDM/ENEGER	65	13	5.0	2035
Hardy HW #1	DOE/BDM/Cabot	125	40	3.1	1824
PDC #21747	DOE/Columbia	3100	270	11.5	2086
Hunter/Bennett #3997	DOE/BDM/CNG/ Prime Energy	147	83	1.8	1689
Boggs #1240	DOE/GRI/Sterling/ CNR/Pennzoil	1400	450	3.1	1557

DOE-sponsored wells in the Devonian Shale resulted in several technological improvements to reduce the costs of air-drilling horizontal wells. Drilling-related costs have been decreased from 5 times vertical costs on the first well to about 3 times vertical for a recent well. A 5-fold increase in downhole motor and steering tool life has also been achieved through these projects.

Pliocene (Gulf of Mexico)

The first horizontal well in the Gulf of Mexico was drilled by Texaco in the East Cameron field offshore Louisiana (Fisher and French, 1992). The Pliocene formation is a highly permeable unconsolidated sandstone. The target depth was shallow: less than 1500 ft.

The horizontal well was drilled near the top of a gas sand with underlying water. The target window was 22 ft wide at the point of entry and 5 ft wide at the end of the projected path. A high-angle tangent section was required because of the shallow depth of the reservoir (Figure 5-6). A special mixed-metal hydroxide (MMH) mud was used to keep the hole clean and open, and to minimize formation damage.

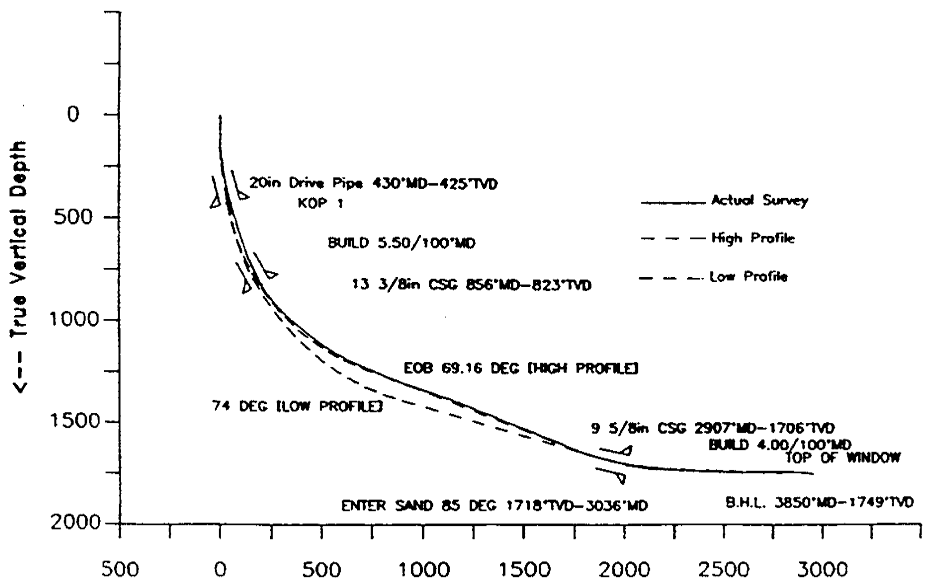


Figure 5-6. Gulf of Mexico Gas Well Profile (Fisher and French, 1992)

The well was very successful, initially testing at 11 MMscfd with minimal drawdown. Pressure-transient test results showed that the optimum production rate with respect to reservoir management was 20 MMscfd. However, due to compressor limitations, production over the first 6 months averaged 12-15 MMscfd. Production ratio with respect to a conventional well was estimated as 4-5.

Based on the success of the first well, the operator drilled and completed 2 more horizontal wells in shallow gas sands. Production rates for these wells are shown in Table 5-4.

TABLE 5-4. Gulf of Mexico Gas Well Production (Fisher and French, 1992)

WELL NO.	RATE (MMSCFD)	SITP (PSI)	FTP (PSI)
B-12	7.3	714	672
B-14	12.2	714	644
A-12	4.5	806	790

The cost to drill and complete the first well ($1.6 million) was $100,000 less than a comparable extended-reach well in the same field. The operator was very pleased with the results of this application.

Barnett Shale (Texas)

The Barnett Shale is a naturally fractured gas reservoir in north-central Texas. Vertical wells are usually hydraulically fractured and produce at rates of over 1 MMscfd. GRI co-funded an experimental well in the Barnett Shale with Mitchell Energy and CER Corporation to investigate the effectiveness of horizontal drilling in this formation (Middlebrook and Peterson, 1993). The T.P. Sims B No. 1 was drilled to 10,000 ft MD at a TVD of 7868 ft. The top of the Barnett was entered at an angle of 83°. An angle of 83-86° was maintained while traversing a formation thickness of 210 ft. Multiple natural fractures were encountered; average distance between fractures along the wellbore was about 3 ft.

After completion and a series of acid treatments, average production during the first 67 days was 250 Mcfd. Average permeability was measured in the range 0.004-0.008 md. After a propped hydraulic fracture treatment, production stabilized at 350-400 Mcfd.

Analysis of fractures showed a significant difference between the natural- and hydraulic-fracture strikes. The two fracture planes were found to be separated by an angle of 58°. Hydraulic fractures created in the horizontal well were seen to be less conductive than those in a vertical well.

Drilling and fracturing costs were substantially more for the horizontal well than for a typical vertical well. In addition, the production ratio was less than 0.5. GRI's project team concluded that horizontal drilling does not appear to be viable in this formation.

Mancos B (Colorado)

Another GRI-cofunded experimental horizontal gas well was drilled in the Mancos B in October 1991 (Middlebrook and Peterson, 1993). The drilling plan for the Chandler & Associates Southwest Rangely 8H-1-2 Federal well was to drill a 1500-ft lateral that would cross 75 ft of prime reservoir thickness at an angle of 85°. Sixty vertical feet were successfully crossed over 1400 ft MD.

Production from the Mancos B is characterized as matrix flow from several thin sandstone laminations that have limited communication with the wellbore prior to hydraulic fracturing. Fracture aspect ratios for vertical wells are relatively low; however, significant gas production was obtained from vertical wells in the vicinity of the horizontal well.

The horizontal well was air-drilled to minimize formation damage. Logs indicated that no natural fractures were intersected. Porosity along the wellbore was about 14% and water saturation was 50%. The well would not sustain flow during post-drilling flow tests. The well was subsequently cased and cemented and hydraulically fractured with two treatments, both of which were unsuccessful due to premature screen-out. No cause for failure of the fracture treatments could be uniquely identified.

Drilling and completion costs were substantially more for the horizontal well than for a nearby vertical well. As in the case of the Barnett Shale, the project team concluded that horizontal drilling does not appear to be viable in the Mancos B.

Davis Sandstone (Texas)

A third GRI-cofunded experimental horizontal gas well was drilled in the Davis Sandstone in the Fort Worth Basin in north-central Texas in late 1991 (Middlebrook and Peterson, 1993). Project plans were to test the viability of horizontal technology in this formation by air-drilling a 2000-ft lateral normal to the natural fracture trend. Completion was designed to be open hole, with production from the matrix and fractures.

The Dallas Production Merrill No. 1 was drilled over a period of about 2 months. Problems during drilling operations resulted in the wellbore exiting below the Davis. The final well profile was "U-shaped." Liquids and solids introduced during air-mist drilling and completion operations may have damaged the fractures, which appeared to make minimal contribution to production.

The well production rate was 53 Mcfd during flow tests; average permeability was calculated as 0.0037 md. After an acid treatment, flow increased to over 100 Mcfd.

Analysis of data from this well was deemed as insufficient to determine whether horizontal drilling may be effective in the Davis. This first experimental well had several problems and was not an economic success.

Piceance Basin (Colorado)

The DOE sponsored a project to drill a directional horizontal well in the coal seams and tight sandstone formations in the Piceance Basin (*Western Oil World* Staff, 1990). The Mesaverde sands in the Piceance are densely packed, lens-shaped formations that could contain as much as 420 Tcf of gas. A vertical well might penetrate 25-30 lens but decline very rapidly due to the sand's discontinuous nature. A horizontal wellbore would provide greater exposure to the lenses, reducing the decline rate.

Below the Mesaverde sand and coal zones is the Cozzette sandstone. It is a tight, naturally-fractured zone approximately 65-ft thick. The DOE well was first drilled directionally through the Paludal coal/sand section and cased off (Figure 5-7). The hole was then turned horizontal and drilled through approximately 300 ft of Cozzette.

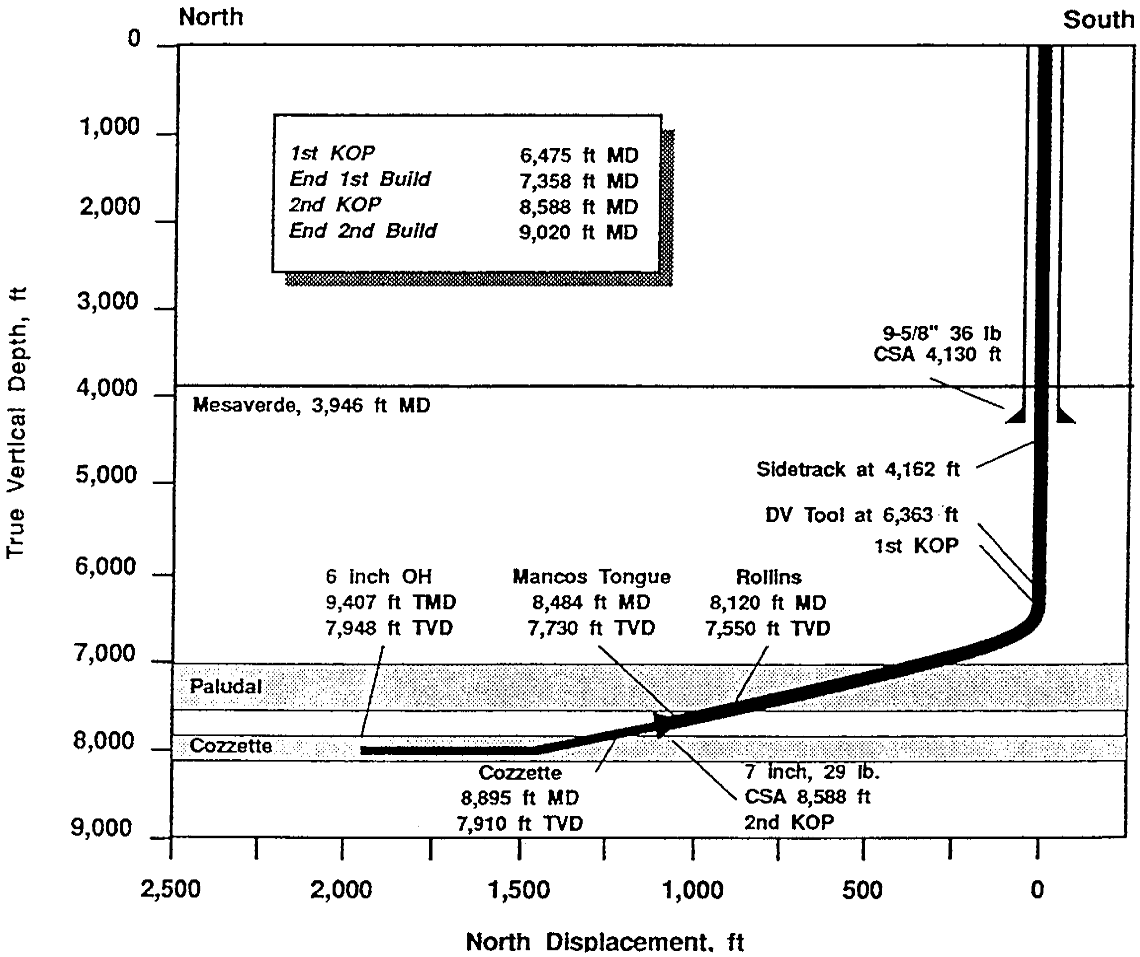


Figure 5-7. DOE-Sponsored Piceance Basin Well (Myal et al., 1992)

The initial production tests in the Cozzette sand indicate a production potential of 5-10 times that of a vertical well (Myal et al, 1992). In the second phase of the project, the coal and sand lenses in the Paludal section will be opened and commingled with the Cozzette and tested for commercial viability. If successful, this dual-zone completion could greatly improve recovery compared to vertical wells.

Antrim Shale (Michigan)

The Antrim Shale is a Devonian age black shale with vertical structural relief fractures containing gas (Conti, 1989). An average vertical well in the Antrim will produce 70-80 Mcfd of dry gas with 40-80 BPD of water. A horizontal well was drilled in Otsego County, Michigan with the intention of intersecting fractures in the Antrim to increase production (Figure 5-8).

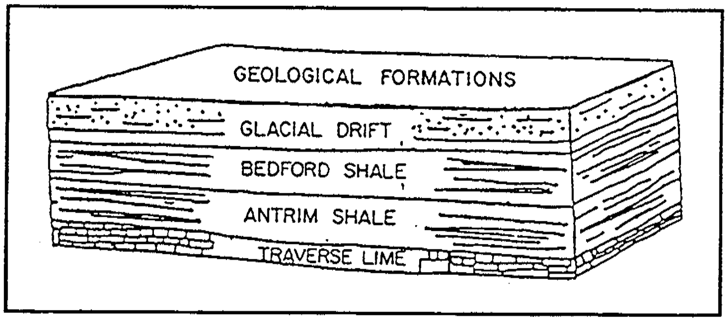


Figure 5-8. Antrim Shale Stratigraphy (Conti, 1989)

This well is a good example of horizontal drilling being used to intersect targets displaced from the surface location. A vertical well could not be drilled since the surface location would have been in wetlands protected by the Department of Natural Resources. A horizontal well was chosen to reach the target (Figure 5-9), and to increase production by increasing exposure in the shale.

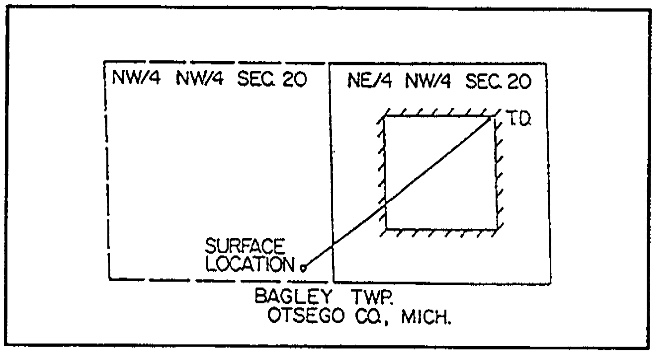


Figure 5-9. Horizontal Well Drilled to By-Pass Surface Wetlands (Conti, 1989)

The horizontal hole required over twice the amount of time to drill as a vertical and was therefore more costly. Limited production results have been obtained thus far, but the horizontal well has been only a marginal producer. The open-hole completion did not increase production. However, subsequent foam fractures in the horizontal section did increase production to nearly double the vertical rate. The increased cost of horizontal drilling and the marginal production results do not give strong support for the use of horizontal technology in this area. However, this field case does demonstrate the capability of horizontal wells to replace directional wells for remote targets and locations with restricted surface access.

5.2.2 Canadian Gas Applications

A horizontal well was first used to produce a tight gas reservoir in Alberta by Canadian Hunter in December 1987. This was followed by several more horizontal gas wells during the period 1988 to mid-1991. With one exception, these wells were drilled to improve the productivity of tight sandstone reservoirs. Results were generally unsatisfactory. No technology was available to prevent formation damage in these tight reservoirs. As a result, the production ratio was insufficient to justify the incremental costs.

Leduc Limestone (Alberta)

Production from horizontal gas wells in Alberta is about 20 MMscfd. The Esso Chedderville in the Leduc formation is presently producing about 3.5 MMscfd (18% of the total). The well was located at the top of the formation (Figure 5-10), and positioned to minimize coning. Production remained near 14 MMscfd for about 2 years. This rate was adequate to minimize coning tendency at the initial reservoir pressure. However, as reservoir pressure decreased, water began to encroach into the wellbore. As water production increased, gas rate decreased.

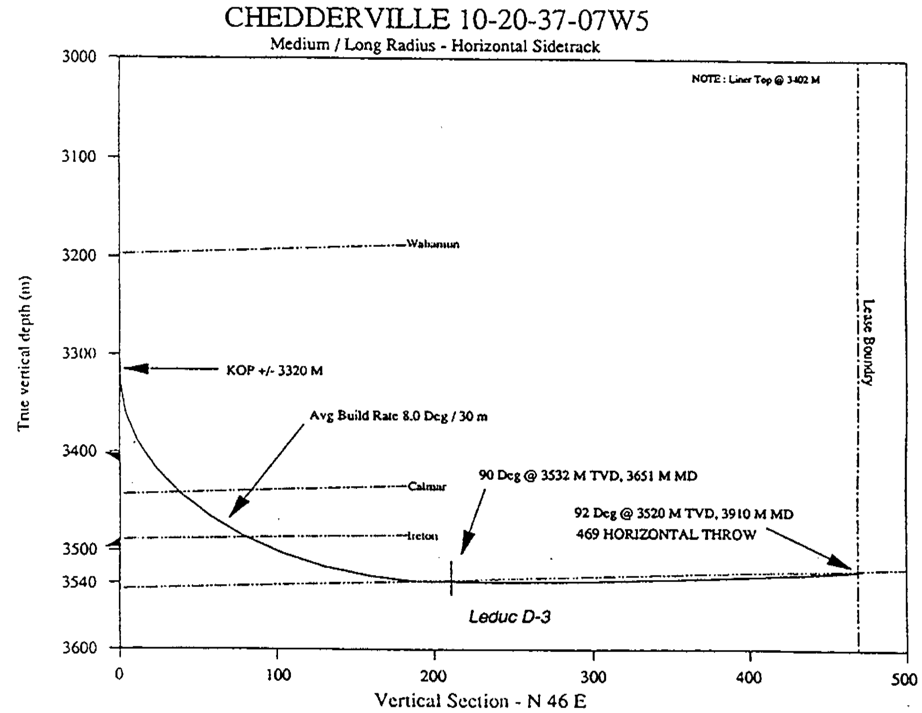


Figure 5-10. Esso Chedderville Horizontal Gas Well Profile (DEA-44 WH #75)

This re-entry application was plagued by operational problems related to the old vertical well. The time/cost data (Table 5-5) illustrate the cost overruns related to preparing the vertical well for re-entry applications.

TABLE 5-5. Esso Chedderville Time and Cost

	Time (Days)		Cost ($1000)	
	Normal	Trouble	Normal	Trouble
Vertical Hole	2.25	2.00	562	30
Kickoff	4.50	3.25	161	91
Curved Section	9.50	2.25	278	73
Horizontal Section	7.00	0.50	231	16
Horizontal Completion & Stimulation	2.50		635	129
TOTALS	25.75	8.00	1,867	339

Although expensive, the well was deemed an economic success. Unexpectedly high liquids production dramatically improved the economics of this application. This aspect is discussed further with respect to Shell Harmattan.

Bluesky/Gething (Alberta)

In the Boyer project, Norcen drilled four wells in March of 1990 in the Bluesky/Gething formation. Two of the wells are still under experimental status, and their production rates are confidential. Detailed operational well histories were documented for all four wells in the DEA-44 Well History Library (WH #35, 38, 57, and 58). The two wells with available production data produced at rates of 100-400 Mscfd, with no water production. These data suggest that low rates are a result of the tight formation.

These horizontal wells were drilled in an area of the field underlain by a strong aquifer. Typical vertical wells require a fracture stimulation to deliver economic production. In this setting, fracture stimulations are not confined to the gas leg, but extend down into the water. Therefore, standard stimulation strategy was not viable in an area of the field underlain by water. Horizontal wells were employed in the water-underlain areas to replace the fracture productivity. Figure 5-11 provides a general well profile.

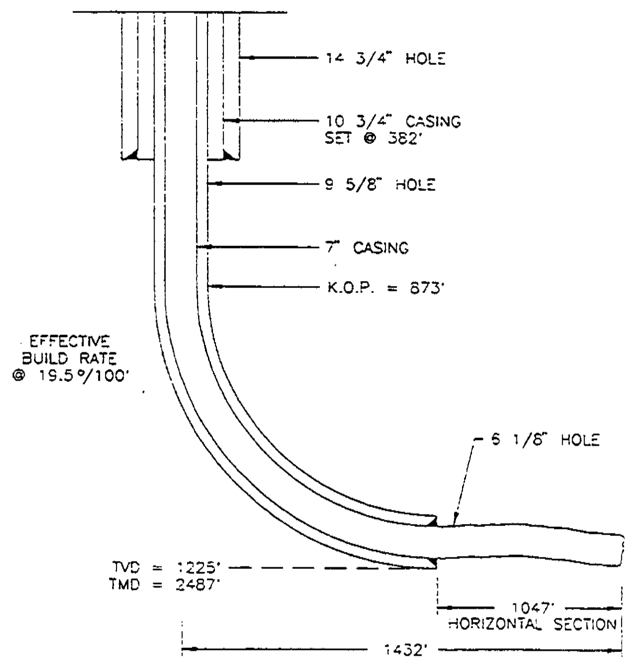


Figure 5-11. Norcen Boyer Horizontal Gas Well

The limited production data available indicate that water production has not yet occurred; thus, the "fracture replacement" concept of this application appears to have been successful. However, the relatively low gas rates (100-400 Mscfd) indicate that the economics of horizontal development in this field are tenuous.

Cadomin (Alberta)

Canadian Hunter has drilled three wells in the Cadomin formation. One well at Ansel (Figure 5-12) is under experimental status. The other two wells were drilled at the Sinclair field. The combined rates of the wells are about 3 MMscfd. Here again, horizontal technology has not yet been very satisfactory in these tight gas reservoirs.

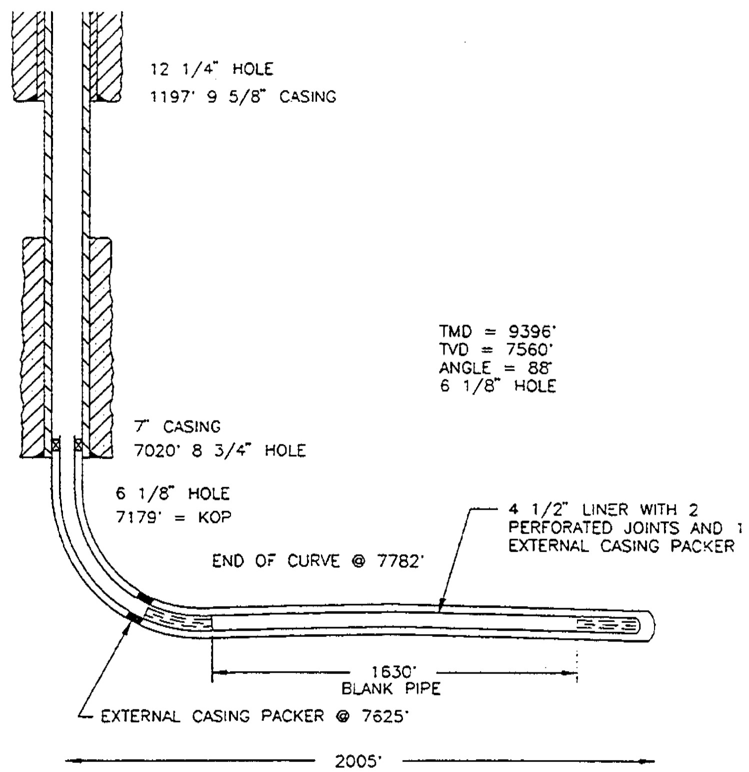


Figure 5-12. Ansel Horizontal Gas Well

Table 5-6 presents a summary of cost and time data for this gas well.

TABLE 5-6. Ansel Well Time and Cost

	Time (Days)		Cost ($1000)	
	Normal	Trouble	Normal	Trouble
Vertical Hole	20.00	2.25	487	28
Kickoff	0.50	0	14	0
Curved Section	4.75	0.25	123	7
Horizontal Section	7.25	1.25	178	31
Horizontal Completion & Stimulation	4.50	0.25	234	8
TOTALS	37.00	4.00	1,036	74

There are five other horizontal gas wells drilled in the tight sandstone of North Central Alberta. Operators have reported poor production rates to date, and these are not classified as economically successful applications.

Harmattan East (Alberta)

Two wells were drilled in 1993 in the Harmattan East pool (Towers, 1993) in the tight Rundle gas cap. Drilling vertical wells in the pool to recover the known reserves of gas and hydrocarbon liquids was not considered to be economically attractive. Shell used re-entry techniques to take advantage of the existing network of producing and suspended wells. The gas and liquid rates achieved with the re-entries were almost double those assumed in the economics. Payout was in 6 months, as compared to 1-4 years as predicted by horizontal modeling. General rock and fluid properties are presented in Table 5-7.

TABLE 5-7. Reservoir and Well Data: Harmattan (Towers, 1993)

Gas Cap Thickness	-	30-60 ft
Current Recovery	-	55%
TVD	-	8400-8500 ft
Horizontal Length	-	1800-2800 ft
Reserves OGIP	-	±1 Tcf
Horizontal Well Cost	-	$1-2 MM
Reserve Additions (Horizontal)	-	5.7-5.8 Bcf
Payout	-	6-12 months

The first re-entry well (Figure 5-13) experienced serious differential sticking problems, which resulted in a stuck drill string and a short side-track. The second re-entry encountered a geologic anomaly and a second leg was placed into more productive rock.

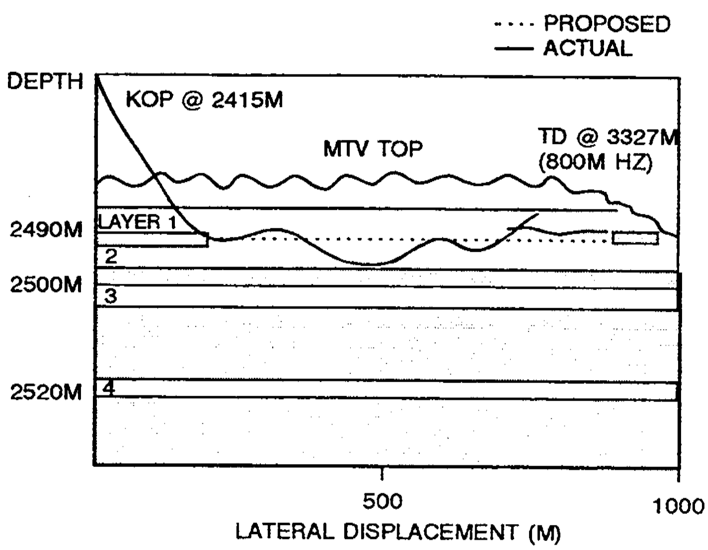
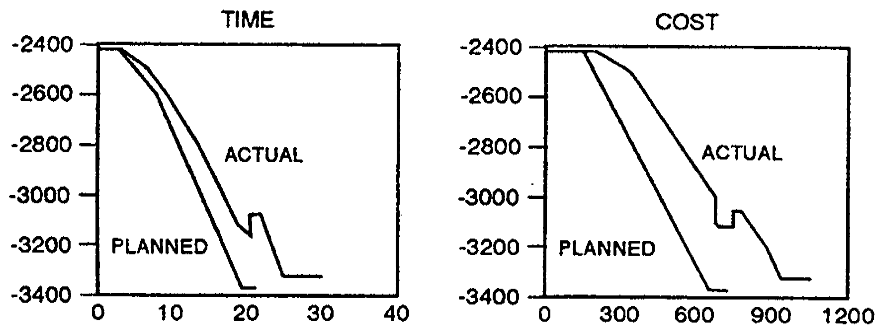


Figure 5-13. Harmattan Gas Well Profile (Towers, 1993)

Due to these operational problems, both wells incurred significant cost overruns. Figure 5-14 presents the time and cost curves for the first well.



- SEVERE DIFFERENTIAL CONDITIONS EXPERIENCED DUE TO SIGNIFICANT OVERBALANCE
- PARTED MOTOR: UNSUCCESSFUL FISHING ATTEMPT LED TO OPEN-HOLE SIDETRACK
- OPEN-HOLE LOGS CANCELLED DUE TO STICKING RISK
- TOTAL LATERAL DISPLACEMENT: 796M

Figure 5-14. Harmattan Gas Well Time and Cost (Towers, 1993)

The impact of drilling cost overruns was damped by reducing the planned evaluation program and simplifying the completion design. The production response from this first well was better than expected (Figure 5-15). A vertical well production profile and a horizontal well model prediction also appear in the figure.

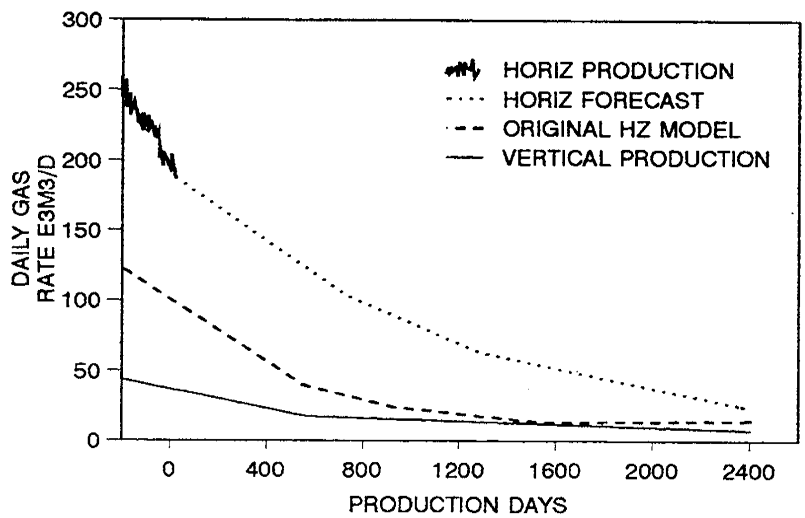


Figure 5-15. Harmattan Gas Well Production Profile (Towers, 1993)

The second well delivered similar response. Table 5-8 summarizes the early economics of these two gas wells.

TABLE 5-8. Early Economics: Shell Harmattan (Towers, 1993)

	WELL 7-29		WELL 5-1	
	PLANNED	ACTUAL	PLANNED	ACTUAL
Capital Cost DCE ($1 MM)	1.20	1.38	2.70	2.68
Initial Rates - Gas (Mscfd)	4025	9100	7350	12,250
Liquids - BPD	88	227	157	372
Payout (months)	17	6	19	10

In both wells, both gas and liquids production are considerably greater than expected. Liquid production is higher on a bbl/mcf gas ratio basis than from the surrounding vertical wells. A similar unexpected benefit was reported in the Esso Chedderville application. The mechanism responsible for this higher-than-anticipated liquids production has yet to be defined. It is also unknown whether this phenomenon is unique to these two pools, or can be expected in other pools of similar character.

In summary, these horizontal gas wells in the Harmattan East pool represent a highly economic project for the operator. Attractive economics were supported by: 1) significant liquids contribution, 2) comparable capital cost relative to vertical wells, 3) high initial production due to multilayer reservoir contact, and 4) lateral length and multibranch wells. Additional wells are planned in this pool for 1994, even though it is still early in the production history.

5.2.3 International Gas Applications

North Valiant (North Sea)

The North Valiant is a complex gas reservoir with some high-permeability (100 md) dunal sand zones embedded within Rotliegendes sands (<1 md). Dunes are often small patches and there is a low probability of encountering them with vertical wells. Horizontal wells were used first by Conoco to target as many dunes as possible (Tehrani, 1992). Profiles of the first 2 wells are shown in Figure 5-16.

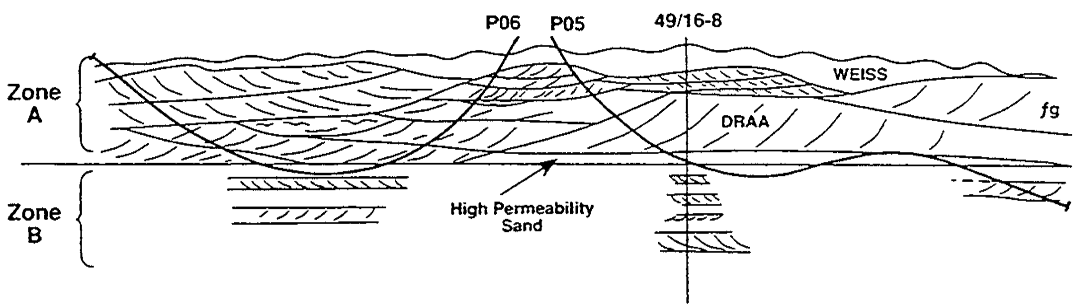


Figure 5-16. North Valiant Wells (Tehrani, 1992)

Cost ratio was estimated as 1.35 as compared to a conventional vertical. Production from the first horizontal well was twice that of a vertical.

Zuidwal (The Netherlands)

The Zuidwal field in The Netherlands is another layered sandstone reservoir. Two sand layers of high quality are separated by about 60 ft of low-permeability rock. Three long-radius horizontal wells drilled in the field (Figure 5-17) constitute the first use of horizontal wells for gas recovery. ''Stair-step'' horizontal wells were drilled to tap both high-quality layers (Figure 5-18). The three original horizontal wells drilled in this field had productivity ratios of about 1.8 and cost ratios of 1.2.

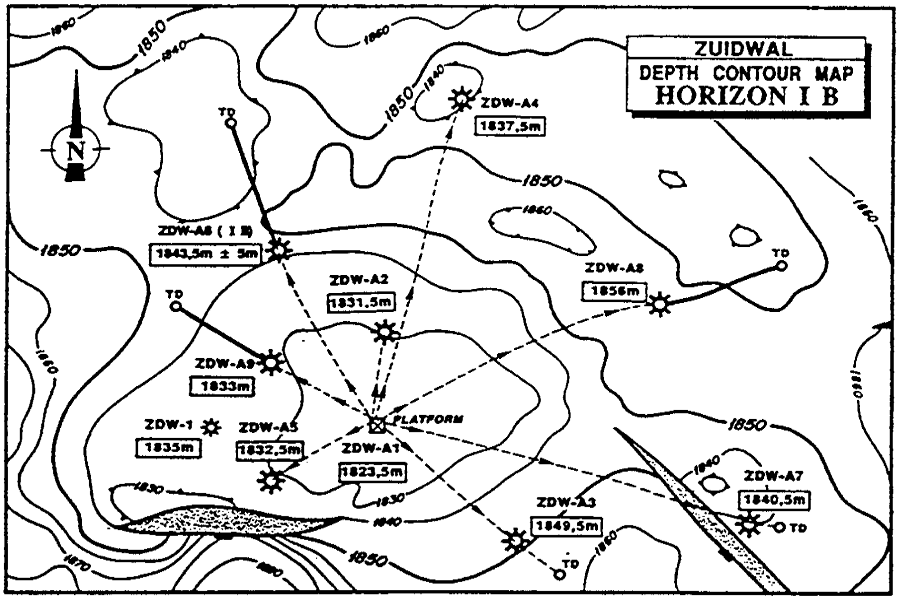


Figure 5-17. Zuidwal Field Horizontal Wells (Celier et al., 1989)

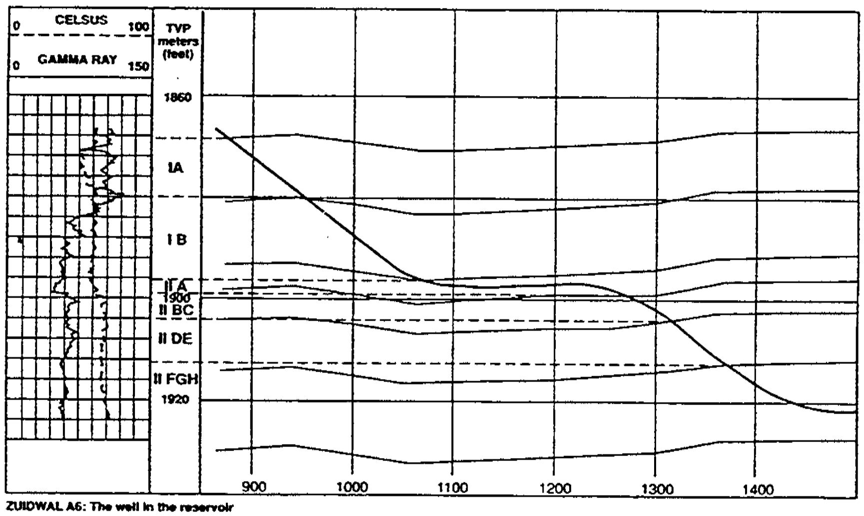


Figure 5-18. North Valiant Wells (Tehrani, 1992)

Initial production rates for the wells were less than expected. However, after a few weeks on production, the wells began to clean up and production increased. Ultimately, the horizontal wells (ZDWA6, 8, and 9) made a significant contribution to field production (Figure 5-20).

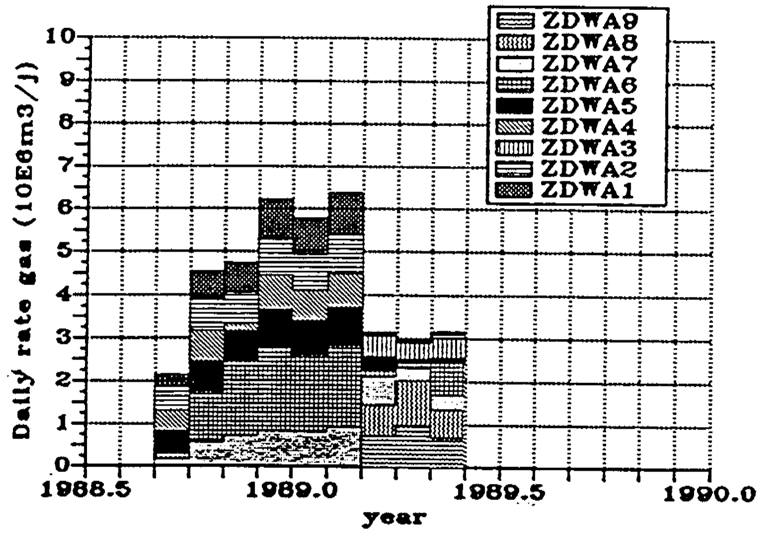


Figure 5-19. Zuidwal Average Production Rates (Celier et al., 1989)

5.3 GAS STORAGE

Underground storage of natural gas plays a significant role in meeting peak demands, both seasonal and short-term, of the gas consumer. There are presently over 400 active storage projects in North America with a total capacity of about 8 Tcf of working and base gas. Maximum peak-day deliverability of these projects recently exceeded 50 Bcfd. Most companies believe that the demand for storage service, both capacity and deliverability, will grow over the next several years. Industrial and power-generation use of gas is expected to play a prominent role in the future growth of the market. FERC Order No. 636, which calls for the unbundling of storage and transportation services, has created a rush to build new storage facilities in the U.S.A. Nearly 100 new storage projects are being planned. New technologies, including horizontal wells, are being developed to increase storage capacity and deliverability.

One of the principal determinants of the cost of storage is deliverability rate. A recent study for GRI (Young and Deskins, 1993) showed that horizontal drilling has high potential to economically increase U.S.A. storage-field deliverability and decrease overall storage operational costs. Horizontal technology promises important benefits for storage operations including greater deliverability at reduced drawdown (such as near the end of the winter heating season) (Figure 5-21), fewer wells and surface sites, the ability to develop parts of the reservoir less favorable for vertical wells, and reduced base-gas requirements.

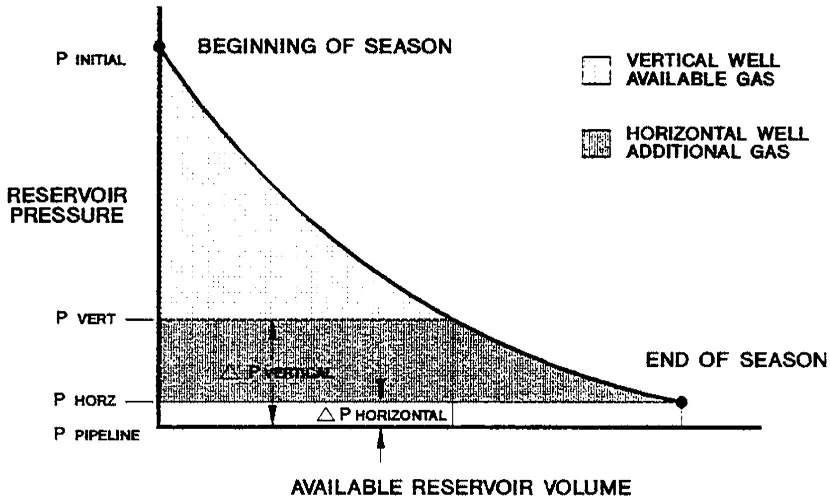


Figure 5-20. Increase in Volume of Working Gas with Horizontal Storage Well

As a result of these considerations, horizontal technology has recently been implemented to a limited extent by the gas-storage industry in both the U.S.A. and Canada. Several successful wells have been drilled in both countries. These field applications have confirmed the anticipated benefits and yielded production ratios of 6-10 at cost ratios of about 2.

There are several special considerations for applying horizontal technology in gas-storage reservoirs (Young et al., 1993):

1. **Long Life**. Gas-storage wells must be designed for a life of up to 50 years. In addition, wellbore pressures are cycled seasonally from low to high throughout the life of the well.

2. **Caprock Integrity**. Horizontal wells must be designed to prevent escape of gas outside the casing through the caprock (the impermeable layer overlying the storage formation). Concern for caprock integrity usually precludes the use of hydraulic fracturing for increasing deliverability. Casing and cementing programs for horizontal wellbores must be well-planned and carefully implemented to assure a durable seal at the caprock. Special care is essential when setting casing into the caprock at an angle.

3. **Drilling Fluids**. Because many storage fields are depleted oil/gas fields, low reservoir pressure will significantly impact the design of the drilling program. Lightweight, low-solid fluids are normally required for these operations.

4. **Skin Damage**. Most storage formations are sands with high permeability and porosity. The tendency for fluid loss and skin damage is high, resulting in decreased deliverability and injectivity. Again, extra consideration is required in selecting drilling fluids, well-control procedures, and completion operations to assure a low skin factor.

Additional concerns for gas-storage wells include injection/production strategies, equipment for high-volume/low-pressure flow, and completion options.

Several horizontal gas-storage wells have been successfully drilled and are currently in service. The storage industry's use of horizontal wells in the U.S.A. and Canada is discussed in the sections that follow, along with specific case histories.

5.3.1 U.S.A. Gas-Storage Applications

The U.S.A. gas-storage industry began considering the potential benefits of horizontal technology in its reservoirs in the late 1980s. One of the first efforts was carried out by Northern Illinois Gas (Young et al., 1993). A horizontal re-entry was drilled into a relatively thin section using short-radius technology. Results with this well were much less than hoped for. The short lateral did not produce more than the vertical well. The poor performance of this well soured the normally conservative gas-storage industry on horizontal technology for a few years.

One of the first successful horizontal storage wells was drilled by Oklahoma Natural Gas in its West Edmond Field in Oklahoma in 1992. Cofunded by GRI, the Gaffney S-1 had a horizontal section of 1520 ft and yielded a deliverability about 6 times greater than a vertical well (Shikari and Bergin, 1993).

At least 20 horizontal wells have been drilled in U.S.A. gas storage fields, including:

1. American Oil and Gas (2 wells)
2. ANR Pipeline Company (7 wells)
3. ANR Storage (2 wells)
4. Citizens Gas and Coke (1 well)
5. Colorado Interstate Gas Company (2 wells)
6. Columbia Gas Transmission (1 well)
7. Lower Colorado River Authority (1 well)
8. Michcon (1 well)
9. Northern Illinois Gas (1 well)
10. Oklahoma Natural Gas (4 wells)
11. Pacific Gas & Electric/EPRI (1 well for air storage)
12. Panhandle Eastern (1 well)
13. Williams Brothers (1 well)

Most of these wells have been reported as technical and economic successes.

Other horizontal wells are being planned within the gas-storage industry. Due to concerns about competitive advantage, the U.S.A. gas-storage industry tends to treat their horizontal projects as tight holes and is reluctant to share results. Consequently, not much information or data on U.S.A. projects are available.

ONG West Edmond Project (Oklahoma)

Oklahoma Natural Gas Company drilled one of the first U.S.A. horizontal storage wells in its West Edmond Field near Oklahoma City in 1992 (Shikari and Bergin, 1993). The Gaffney S-1 was re-entered, section milled, kicked off, and drilled horizontally over 1500 ft. The planned length of 1500 ft was determined from reservoir modeling (Figure 5-22) based on a desired flow rate at late-season drawdown (450 psi). Calculations showed that over 25 MMcfd could be produced from this well under these conditions.

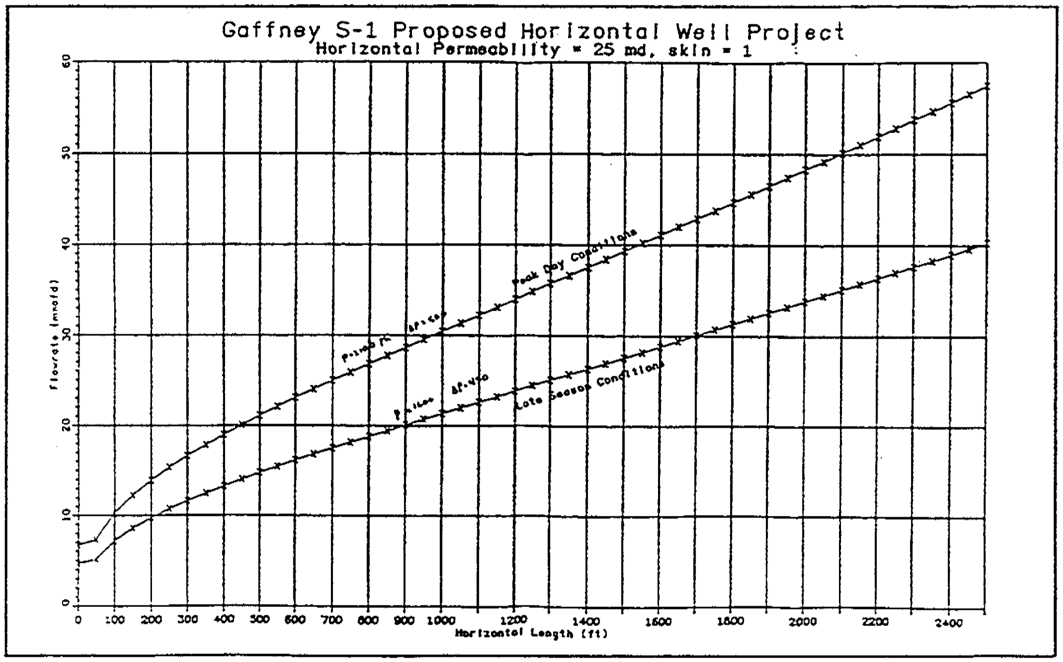


Figure 5-21. Horizontal Well Flow Rate Calculation (Young and McDonald, 1993)

The Red Fork sandstone is the storage formation at a depth of about 6500 ft. The Pennsylvanian-aged rock is about 15 ft thick and relatively clean and uniform with a few thin, discontinuous shale lenses. The formation grades to a shale above and below the sand. The caprock overlying the Red Fork is an excellent high-strength limestone and shale section. Average reservoir properties are summarized in Table 5-9.

TABLE 5-9. Average Reservoir Properties: Red Fork (Young and McDonald, 1993)

Original GIP	60 BCF	Reservoir Pressure	1600-2100 psi
Current GIP	48 BCF	Horizontal Permeability	25-30 md
Pay Thickness	15-22 ft	Vertical Permeability	7 md
Porosity	15%	TVD	6500 ft

A medium-radius 6⅛-in. bit entered the top of the Red Fork at an inclination of 85° and was steered toward the center of the relatively thin sand (Figure 5-23). A lightweight oil-base mud system was used to minimize skin damage. The horizontal section was left open-hole.

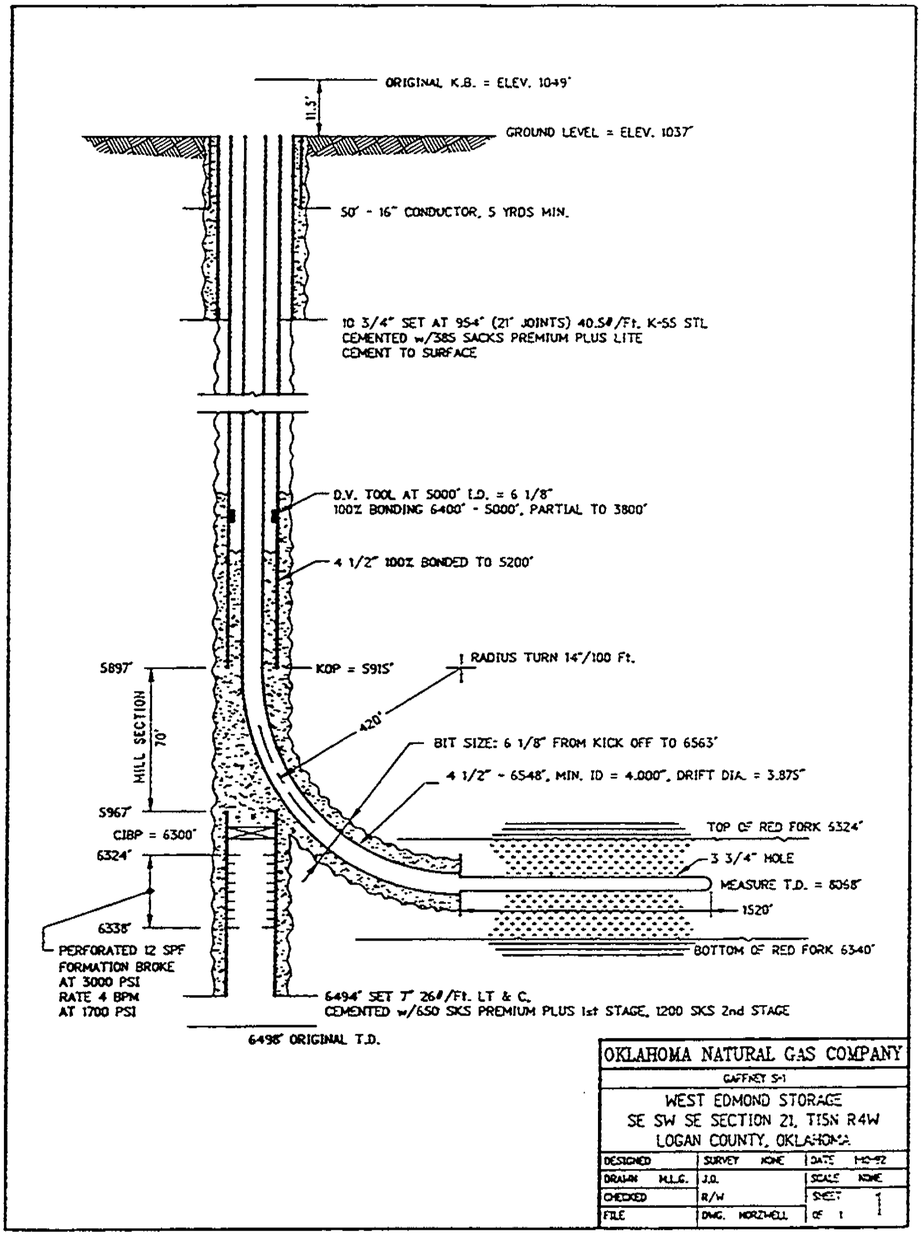


Figure 5-22. Storage Well Re-entry Schematic (Young and McDonald, 1993)

Re-entry costs were budgeted at $425,000 versus a new vertical well cost of $350,000. Actual costs exceeded budget by about 68%, resulting in a final project cost ratio of 2.0. Extra drilling days accounted for most of the excess costs. Cost analysis also showed that a new horizontal well could have been drilled for about the same cost as this re-entry.

A value function was used to estimate overall benefits of the project by relating costs, deliverability increase, and probability of success. Calculations showed that the re-entry has a cost per unit deliverability of $21/Mcf, compared to a new vertical well cost of $99/Mcf.

Multipoint production tests were run after completion operations. Isochronal test results are shown in Figure 5-23. The estimated open-flow potential was 73 MMcfd. Peak deliverability was 45 MMcfd, compared to 8 MMcfd for a vertical well (production ratio = 6) (Shikari and Bergin, 1993). Early production was consistent with test results.

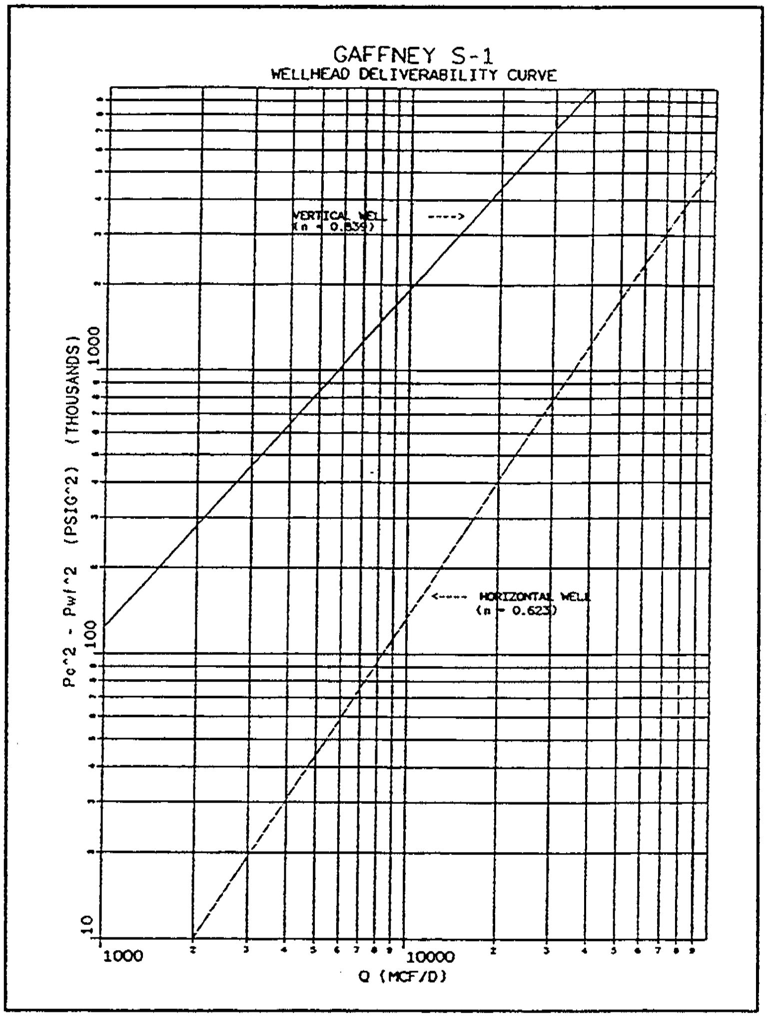


Figure 5-23. Storage Well Isochronal Tests (Young and McDonald, 1993)

The overall project objectives were met or exceeded. The operator believes that costs could be reduced in the future as the learning curve matures. As a result of the success of this initial effort, at least three additional horizontal wells have been drilled by the operator.

CIG Latigo Field Project (Colorado)

Colorado Interstate Gas Company (CIG) recently drilled two horizontal wells in the Latigo Storage Field near Denver (*Coastal World* Staff, 1993). Vertical wells in sections of the field were prone to load up with water near the end of the withdrawal season. Horizontal wells were used to combat water production.

The Latigo Storage Field is part of the Dakota Sandstone (TVD = 6800 ft) and has a maximum field deliverability of 120 MMcfd. Geologic lessons learned on the first horizontal well allowed better directional control and improved hole stability on the second well.

Horizontal length achieved on the first well was over 400 ft. The second well exposed over 1200 ft of the formation. Both of these wells were technical and economic successes. Production ratio for the second well was near 5; cost ratio was about 2.

5.3.2 Canadian Gas-Storage Applications

The improvement in both gas price and demand, increased transportation capability, and deregulation of gas marketing have resulted in a rapid growth of gas-storage demand in Western Canada. Over the last 18 months this has led to a number of gas-storage developments using horizontal wells. The two most significant projects are outlined. Several other projects are underway or in the planning stage.

AECO-HUB Upper Manville Project (Alberta)

Alberta Energy Company (AEC) has employed horizontal wells to dramatically expand their gas-storage facility in the Upper Mannville Pool in Suffield, Alberta (Graham and Eresman, 1994). Table 5-10 lists the five largest gas-storage facilities in North America (as of Nov. 1993).

TABLE 5-10. Largest Gas-Storage Facilities (North America) (Graham and Eresman, 1994)

COMPANY	MAX DELIVERABILITY (BSCFD)
Pacific Gas & Electric Co.	2.01
Southern California Gas Co.	1.65
Michigan Consolidated Gas Co.	1.50
Union Gas Company Ltd.	1.40
AEC-AECO-HUB	1.30

Figure 5-24 shows the layout of the existing vertical storage wells in the Upper Mannville pools.

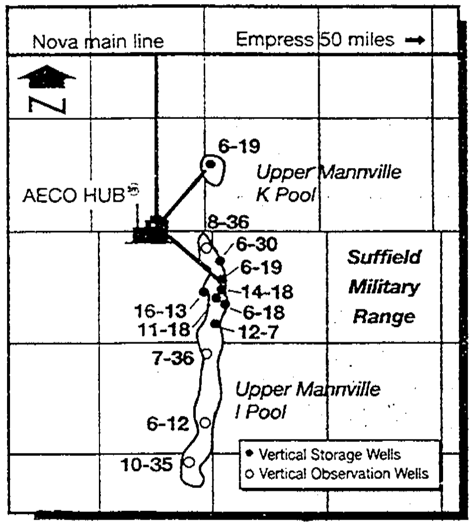


Figure 5-24. Vertical Well Map AECO HUB (Graham and Eresman, 1994)

The HUB facility is strategically located in South East Alberta adjacent to the main gas transmission line (Nova Main Line) and in close proximity to the large Empress Petrochemical Complex. The two existing gas-storage reservoirs used by AEC are Glauconitic (Upper Mannville) sandstones, which are depleted dry gas pools of lower Cretaceous age. The Glauconitic reservoirs are marine beach deposits with a thickness of about 20 ft and are highly permeable with porosity averaging 25% and permeability in excess of 1 Darcy. Vertical permeability in the sands generally exceeds 90% of horizontal permeability. The pools occur at a depth of approximately 3200 ft and have an initial reservoir pressure of 1530 psig. A schematic geologic section is shown in Figure 5-25.

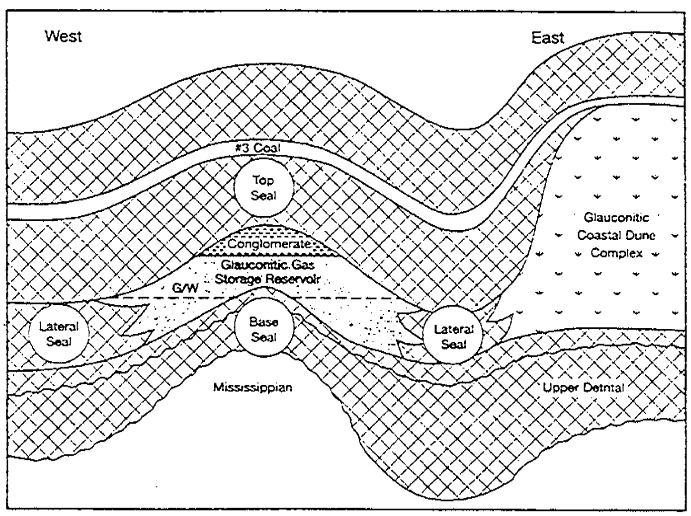


Figure 5-25. AECO HUB Upper Mannville Sandstone Schematic (Graham and Eresman, 1994)

The Glauconitic (e.g., Upper Mannville) reservoirs are relatively thin sands with combined structural/stratigraphic trapping mechanisms. The beaches pinch out laterally and are entirely sealed by shale. Differential compaction and erosion of underlying sediment have caused the pools to undulate along their length, resulting in structural highs and lows. Within the reservoirs, gas overlies a residual oil zone, which in turn is underlain by static water in the lows.

The pools have been extensively mapped by over 30 miles of 3-D seismic to enhance the geologic interpretation. The resulting seismic analysis has been used extensively for pool delineation, identification of structural highs, identification of areas of partial closure, and well programming. As a result of seismic work and follow-up drilling, it was discovered that in some areas, the beach is overlain with a clean, well-sorted pebble conglomerate that averages about 10 ft in thickness and has permeability as high as 10,000 md.

To overcome an observed turbulence effect, AEC tried several remedial actions including acidizing, reperforating, solvent washes and abrasive jetting. Each of these operations had some positive effects, and combined flow increases were substantial. Vertical wells previously capable of 20 MMscfd at design conditions were now capable of an average of 33 MMscfd. With the addition of one more well, project capacity increased to 180 MMscfd. These data are summarized in Table 5-11.

TABLE 5-11. Vertical Well Data: AECO HUB (Graham and Eresman, 1994)

Well No.	Net Pay (ft)	Casing OD (in.)	Wellhead Deliverability (MMscfd)	Sandface Deliverability (MMscfd)
1	26	7	48	60
2	22	7	30	32
3	23	7	30	32
4	12	7	25	46
Average	21		33	42

Enhancements made by recompletions of the original vertical gas-storage wells were significant. However, testing of the wells confirmed that the improvements did not have a major impact on the primary problem of turbulence. Apparent skin factors of ± 100 were observed during high flow rate conditions at several vertical gas-storage wells. It was concluded that there were only two possible options that could allow substantial increases in deliverability: 1) a successful fracture treatment, or 2) a horizontal completion. Either of these, if successful, would have the desired effect of reducing velocities in the near-wellbore or fracture-face area, if costs and technical considerations could be effectively managed.

A single fracture treatment was attempted by the operator. Difficulties were experienced due to high fluid loss caused by high permeability, a relatively thin zone, underlying water, and concern about the potential of fracturing the caprock seal. The latter eventuality could prove disastrous for a gas-storage reservoir. Consequently, the fracture treatment design was small and nonaggressive. Although marginal improvement was observed after recovery of the carrying fluid, the risks were deemed to be greater than the rewards, and fracturing was dropped from further consideration.

AEC designed and drilled its first horizontal gas-storage well in 1992. AEC has since drilled 10 long-radius horizontal gas-storage wells. All of the wells have been completed, tested, and put into gas-storage operation. One well was completed with 9⅝-in. casing for the production string; the remainder were completed with 8⅝-in. production casing. All wells are completed open hole, some with production liners installed where the reservoir integrity was questionable. The open-hole sections were drilled with 7⅞-in. bits and range from 66 ft to 400 ft in length. Well lengths were limited by space constraints in the crestal areas of the reservoir. A map of existing and future horizontal well locations is shown in Figure 5-26 and a typical well schematic is shown in Figure 5-27.

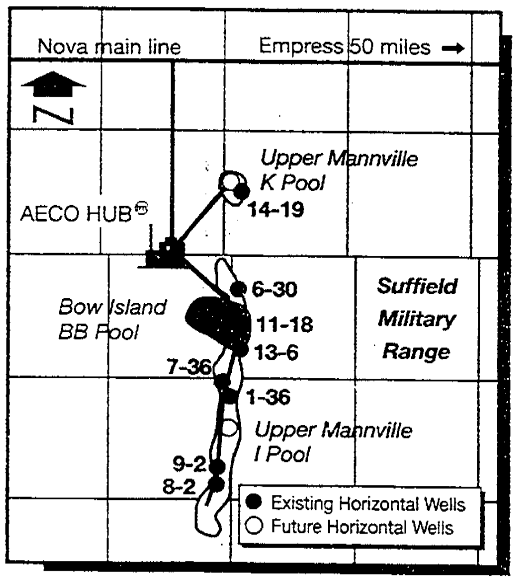


Figure 5-26. AECO HUB Horizontal Well Locations (Graham and Eresman, 1994)

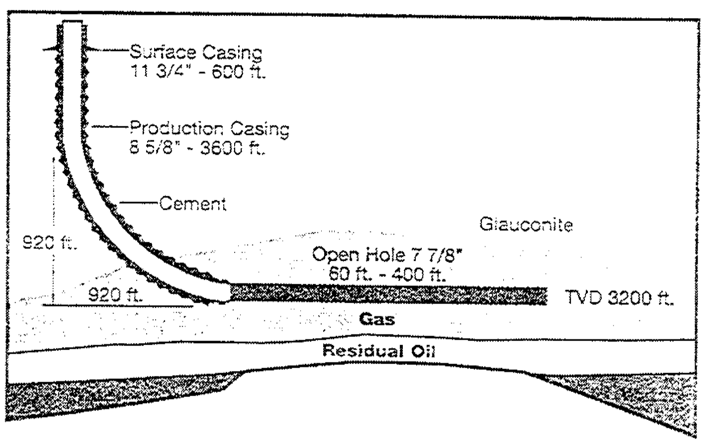


Figure 5-27. AECO HUB Gas-Storage Well Schematic (Graham and Eresman, 1994)

Single and multipoint test results for these horizontal wells at design conditions indicate an average wellhead deliverability of 130 MMscfd and a sandface deliverability of 1.2 Bscfd. Although test results indicate a significant improvement in well productivity, they also indicate that maximum productivity is highly constrained by the wellbore tubulars (Table 5-12).

TABLE 5-12. AECO HUB Horizontal Well Deliverability (Graham and Eresman, 1994)

WELL NO.	OPEN HOLE (FT)	CASING OD (IN.)	WELLHEAD DELIVERABILITY (MMSCFD)	SANDFACE DELIVERABILITY (MMSCFD)
1	400	9⅝	216	3675
2	331	8⅝	157	2284
3	394	8⅝	150	1003
4	66	8⅝	105	136
5	154	8⅝	91	136
6	233	8⅝	59	66
Average	263		130	1223

To completely analyze the economic benefits of horizontal wells over vertical wells, an examination of productivity increase, capital cost increment, as well as operating costs and royalty differences must be undertaken. For AEC's gas-storage wells, the predominant differences are in productivity capital. The average productivity of AEC's horizontal wells was observed to be approximately 4 times greater than a vertical well (Table 5-13).

TABLE 5-13. AEC Horizontal/Vertical Production Comparison (Graham and Eresman, 1994)

TYPE	PRODUCTION CASING (IN.)	WELLHEAD DELIVERABILITY (MMSCFD)	SANDFACE DELIVERABILITY (MMSCFD)
Horizontal	8⅝	130	1223
Vertical	7	33	42
Ratio		3.9	29.1

The average cost to acquire seismic data, drill, complete and tie in a horizontal well was about 1½ times the cost of a vertical well. Cost data are summarized in Table 5-14.

TABLE 5-14. AEC Horizontal/Vertical Well Cost Comparison (Graham and Eresman, 1994)

Type	Production Casing (in.)	Seismic Acquisition ($1000)	Drilling ($1000)	Completion ($1000)	Tie-In ($1000)	Total ($1000)
Horizontal	8⅝	150	450	150	100	850
Vertical	7	125	275	75	75	550
Ratio			1.6	2.0	1.3	1.5

AEC's expansion of storage withdrawal capacity from 180 MMscfd to 1.3 Bscfd would have required about 40 vertical wells at a cost of $22 million. The same results can be achieved with 10 horizontal wells at a cost of $9 million — a savings of $13 million. Compared to overall expansion costs, including pipelines and compression facilities, a $13 million savings represents a reduction in the total project cost of more than 10%.

The horizontal gas well test results at wellhead conditions (Figure 5-28) indicate an average deliverability of 130 MMscfd, compared to an average deliverability of 33 MMscfd for vertical wells. This represents a productivity enhancement of 4 fold at wellhead conditions. Similarly, test results indicate an average sandface deliverability at design conditions for the horizontal wells of 1.2 Bscfd versus 42 MMscfd for vertical wells. These results indicate that AEC achieved a theoretical 29-fold improvement at sandface conditions.

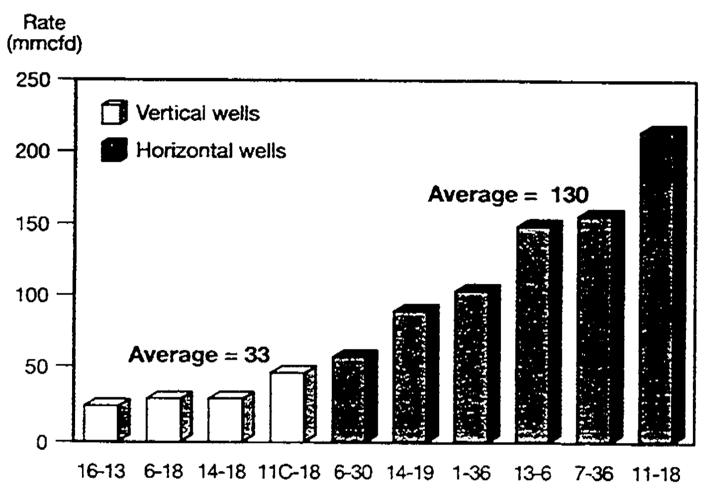


Figure 5-28. AECO HUB Productivity Comparison (Graham and Eresman, 1994)

The sandface enhancement of 29-fold is far beyond the theoretical production improvement for a horizontal well. Much of the potential improvement is the result of identifying the pebble conglomerates with 3-D seismic and the ability to place horizontal wells through those zones. More than half of the bottom-hole enhancement is likely attributable to placing the wells in better quality rock. The combination of horizontal drilling and 3-D seismic was critical to achieving this level of improvement.

The majority of these horizontal wells was drilled during 10-day breaks in activity on the Suffield Military Range. Due to time constraints, most of the horizontal wells had to be drilled quickly. Smaller casing (8⅝-in.) was selected in the interest of time and availability of equipment. The large difference between sandface and wellhead deliverability for these horizontal wells is due to the tubulars being undersized for high flow rates and relatively low operating pressures. Horizontal well test results have been limited to the low end of deliverability potential. A re-evaluation of casing size will be undertaken for future wells to determine if it is feasible to run larger sizes during periods of inactivity on the military range.

A special concern with gas-storage reservoirs is the Joule-Thomson cooling effect caused by gas expansion during both injection and withdrawal, which may result in hydrate problems. AEC has observed substantial cooling effects while performing tests on some of the vertical wells. Bottom-hole temperatures have been as low as 32°F while injecting at high pressure differentials. Since horizontal wells substantially reduce pressure loss across the sandface, the formation of hydrates near the wellbore should also be significantly reduced.

AEC has had very positive results with horizontal wells drilled in Upper Mannville sandstone gas-storage reservoirs at Suffield. Their economic expectations have been met and exceeded, and the performance data suggest that there are considerable potential economic benefits with larger casing sizes.

Factors that have made a significant contribution to this success include:

- The operator's considerable experience gained in drilling horizontal oil wells at Suffield
- Correct application of horizontal gas wells where high flow rates are required, turbulent skin was identified as a problem and where alternative measures had been exhausted
- The decision to extensively use 3-D seismic data to enhance the geologic description of the reservoirs and for detailed design of the horizontal drilling program
- Excellent properties of AEC's Suffield Upper Mannville sandstones, which have high horizontal and vertical permeability and lateral heterogeneity

Amoco Crossfield Project

Amoco Canada and partners have initiated a gas-storage project in the Elkton (Mississippian layered carbonate) 'A' pool in Crossfield, Alberta. This project is located 10 miles north of Calgary in close proximity to the main gas transmission line and the Cochrane petrochemical facility. A summary of the general rock and properties is presented in Table 5-15.

TABLE 5-15. General Reservoir Properties: Crossfield

Original GIP	67 Bscf	Reservoir Pressure Range	600-2800 psi
Current GIP	6 Bscf	Horizontal Permeability	10 md
Pay Thickness	72 ft	Vertical Permeability	1 md
Porosity	14%	TVD	7250-7350 ft

This layered limestone/dolomite reservoir may have 3 to 4 productive layers. The first well (Figure 5-29) was completed in February 1994. (A detailed history is available in DEA-44 Well History #76.)

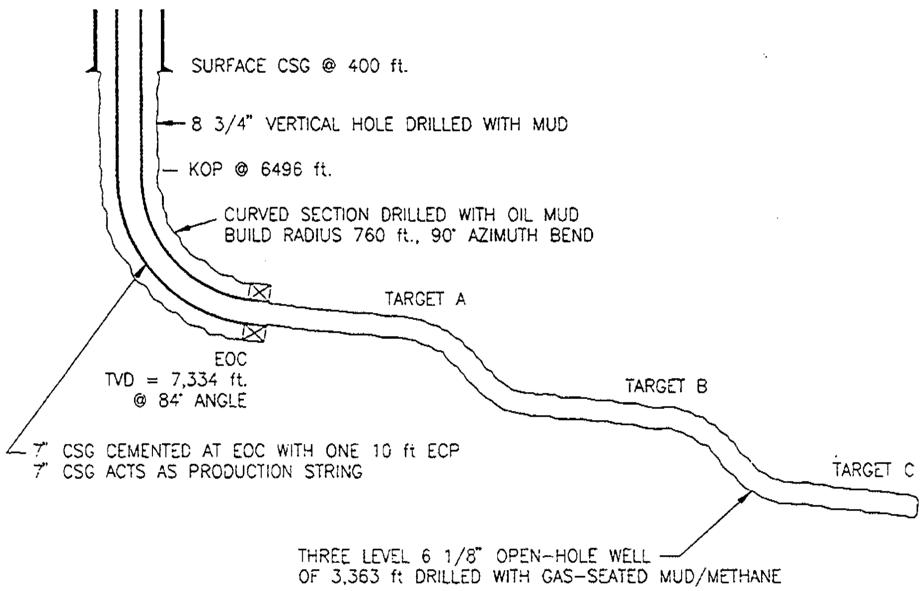


Figure 5-29. Horizontal Well Schematic - Crossfield

Due to low-reservoir pressure (blown-down condition due to high seasonal demand for gas), the horizontal section was drilled under near-balance conditions with natural gas. This was done primarily to reduce the risk of differential sticking. Gas was injected into the water-base polymer starch drilling fluid through the standpipe. The intent was to lower the BHP to within 200 psi of reservoir pressure by injecting about 3 MMscfd of gas while drilling.

The well was both a technical and economic success. A typical vertical well cost $500,000 to drill, complete and acid wash, and would deliver 5-8 MMscfd production/injection capacity. Early limited production/injection testing results suggest that this horizontal well has improved performance 3-4 fold. This project represents a relatively aggressive application employing balanced/underbalanced drilling and a long multilayer wellpath.

Table 5-16 shows the time/cost performance achieved. Amoco Canada is encouraged by these results and is currently expanding the project with three additional horizontal wells and related surface compression facilities. The objective is to increase the project's production/injection capacity to 0.4 Bscfd. A second stage expansion is also being considered that consists of another four to six horizontal wells with a target project capacity of 0.8 Bscfd.

TABLE 5-16. Time and Cost Data: Crossfield

	TIME (Days)		COST ($1000)	
	Normal	Trouble	Normal	Trouble
Vertical Hole	13.75	1.50	357	26
Kickoff	0.50		14	
Curved Section	8.50	1.00	308	24
Horizontal Section (inc. evaluations)	12.25	2.75	474	109
Horizontal Completion & Stimulation	0.25		290	
TOTAL	35.25	5.25	1,443	159

The basic open-hole design of the first well is being used on the current three-well expansion. The most important alterations are:

1. Improved geosteering performance is hoped to be gained through site-specific experience. The first well has less than 50% of its length in high-quality reservoir.

2. The three wells are being located to allow for multibranch expansion in the future.

6. Technical and Economic Trends

6.1 TECHNICAL ACHIEVEMENTS WITHIN THE INDUSTRY

The use of horizontal technology for oil and gas exploitation is increasing, due in large part to the wide variety of technical innovations and improvements. Impressive technical achievements by operators have extended the capabilities of the technology, as well as the expectations of the industry. Horizontal section lengths of over 8200 ft (2500 m) have been achieved.

Extended-reach drilling has also set new records, especially in offshore environments. Originally, a ratio of well displacement to true vertical depth (TVD) of 2:1 was considered readily achievable. For example, at 5000 ft TVD, a total horizontal displacement of up to 10,000 ft from the surface location was considered reasonable. Currently, displacement/TVD ratios of over 5:1 have been achieved in several areas with plans for over 7:1 in the UK.

Operators and service companies are continually refining their tools and procedures to increase production and decrease costs. Maurer (1994) discussed the most significant recent advances in horizontal technology. These are summarized in the following paragraphs.

Multibranch Wells

Multibranch horizontal wells are being increasingly used by operators. Recent projects have seen drilling costs reduced by 20-30% and the size and number of drilling platforms required to develop a field reduced by as much as 50%. Operators' experiences around the world indicate that multibranch drilling is rapidly becoming an accepted practice with significant cost-saving potential.

Unocal recently drilled four trilateral wells in the Dos Cuadras Field offshore California (*Offshore* Staff, 1993). Each well targeted three zones (Figure 6-1) and was completed with a slotted liner and ECP.

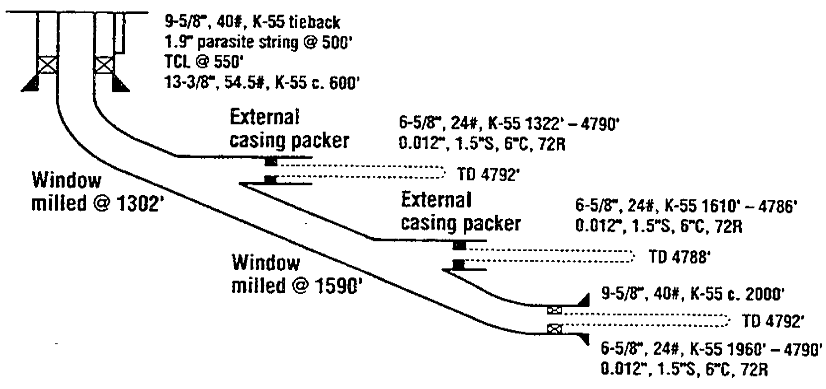


Figure 6-1. Unocal Trilateral Well Design (*Offshore* Staff, 1993)

These trilaterals cost only twice as much as previous single-bore horizontal wells. Unocal concluded that this field could have been developed much more economically with trilaterals, which would have required only two platforms instead of the four that were used.

A record length multibranch well was drilled in the Austin Chalk by Texaco (*O&G Journal* Staff, 1993A). Total horizontal length achieved was 9432 ft (2875 m) (Figure 6-2). This well was a successful producer and cost about $500,000 less than two vertical wells in the field.

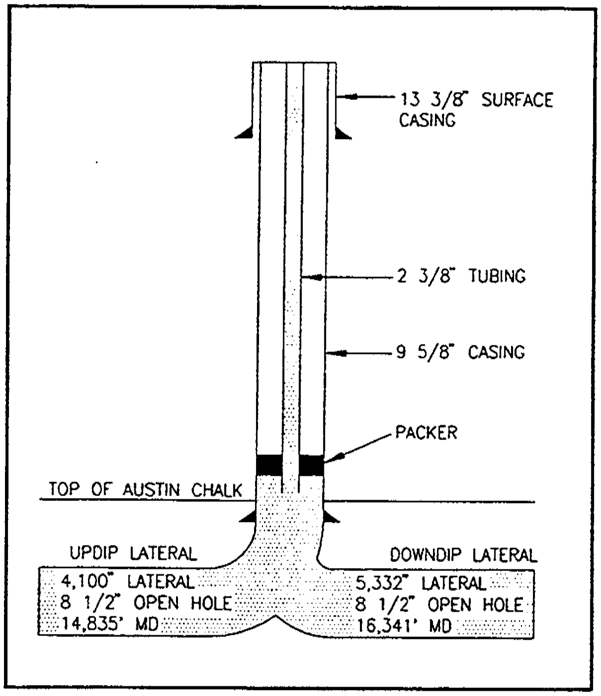


Figure 6-2. Multilateral Austin Chalk Well (*O&G Journal* Staff, 1993A)

UPRC recently completed the first trilateral horizontal well in the Austin Chalk trend (*O&G Journal* Staff, 1993B). Laterals were drilled in three formations: Austin Chalk (4700 ft horizontal length at 6700 ft TVD), Buda (4500 ft at 7200 ft TVD), and Georgetown (4500 ft at 7300 ft TVD). The three branches were completed open hole, and production was commingled and produced through a single string of $2\frac{7}{8}$-in. tubing. Total well cost was about $1.5 million.

Geosteering

Geosteering is an important technology whose development will continue to accelerate the use of horizontal drilling. Geosteering entails the use of conventional and special logging instruments to obtain real-time geological and geophysical data describing the formation being drilled. Using these data, drillers can accurately steer drilling assemblies within or toward desirable zones, and modify well paths as drilling progresses.

Early horizontal wells were drilled with measurement-while-drilling (MWD) geometric steering, that is, positioning of the wellbore based on geologic cross-sections drawn from seismic and vertical-well data. Reservoir data were obtained while drilling the horizontal well by analyzing rock and fluid/gas samples. Reservoir heterogeneities, complexities and uncertainties about the location of productive zones make this technique unreliable or at least less than optimum in some areas.

The addition of formation evaluation logging capabilities to MWD systems allows improved geologic guidance (geosteering). However, measurements have typically been taken some distance behind the bit (Figure 6-3), which introduces a time lag between the true bit position and current data. Steering errors from misleading data have resulted, along with subsequent operational difficulties.

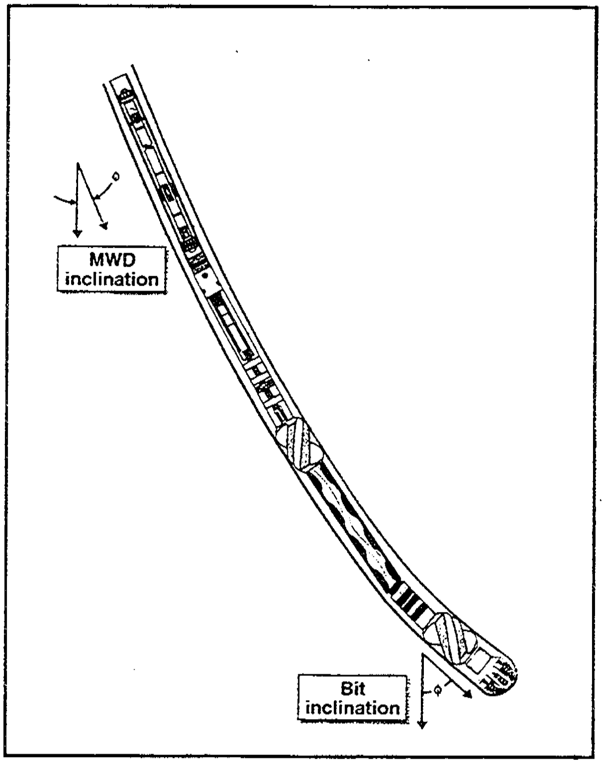


Figure 6-3. Bit Inclination MWD Measurement Error (Burgess, 1993)

The evolution of MWD technology has continued with new tools being developed that allow measurement of various reservoir properties close to the bit (Figure 6-4). Data from near-bit sensors are transmitted back to a conventional mud-pulse MWD telemetry system, which then relays the data to the surface. Resistivity at the bit (RAB) allows the driller to correct the wellpath to minimize penetration of undesired formations, fluid contacts, etc. Additionally, the formation can be logged soon after drilling and before any significant fluid invasion has occurred.

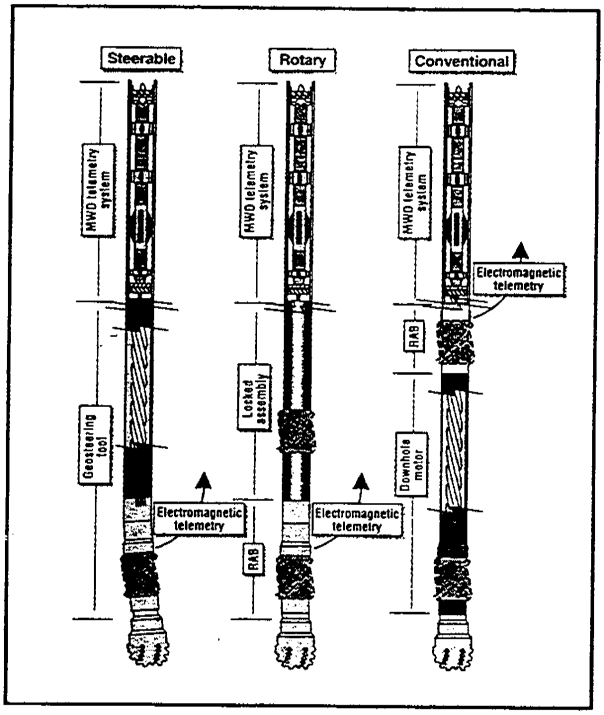


Figure 6-4. Geosteering and RAB Assemblies (Burgess, 1993)

The use of RAB systems will allow more accurate drilling in thin beds, reduce dogleg severity, optimize well placement, increase productive hole length, and reduce production problems such as water coning.

There are additional benefits of RAB systems that will contribute to improved drilling efficiency. Casing and coring points can be detected before the bit drills through the formation. With conventional MWD systems, the opportunity to core a thin zone may be missed before the sensors detect the boundary. Bit rotation sensors can provide important benefits with RAB systems. These can be effectively used for improving downhole motor efficiency and detecting stalling. Stalling is normally inferred from mud pressure readings and flow rates. Direct bit-rotation measurements allow the driller to run the motor at maximum power and achieve maximum ROPs.

Advanced Drill Bits and Motors

Significant advances continue to be made in downhole motors and bits used in horizontal drilling. ROPs are currently 2-3 times higher than only a few years ago. Improvements are expected to continue as the technologies are fine-tuned.

Downhole motors have been improved by the development of adjustable housings, improved sealed and diamond thrust bearings, higher power capacities, and longer power sections.

An example of an improvement in motor design and performance is seen in Maurer Engineering's GRI-sponsored development of high-power downhole motors. In one experiment, a 2⅜-in. motor designed for increased power output delivered about 51 HP, as compared to 23 HP for a standard design at the same flow rate (Figure 6-5). These motors can lead to significant increases in ROP, since drilling rate is approximately proportional to motor power output.

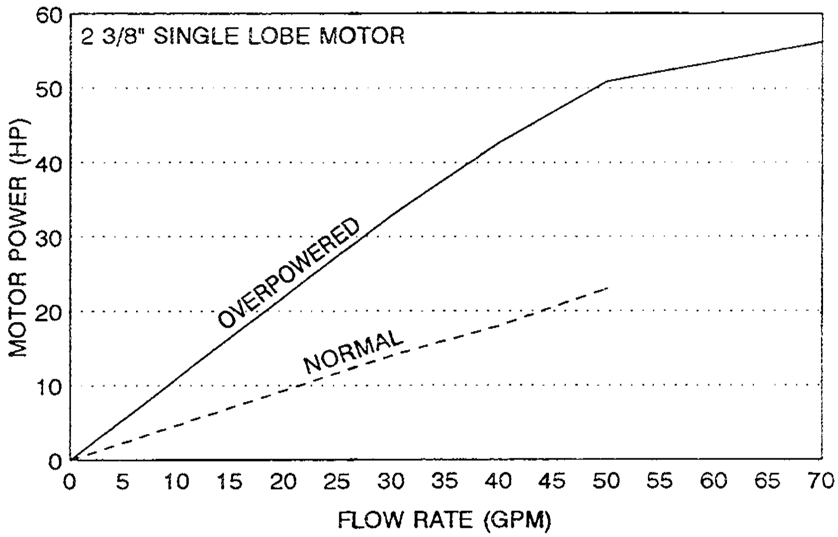


Figure 6-5. High-Power Motor Development (Cohen et al., 1994)

Significant effort has been directed toward the development of efficient drill bits for horizontal drilling applications. Typical purpose-designed horizontal PDC drill bits have shorter shanks, flattened profiles, and shorter gauge length than conventional designs (Figure 6-6). These modifications improve life and steerability.

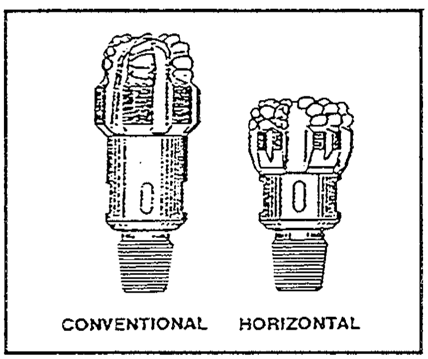


Figure 6-6. Fixed-Cutter PDC Drill Bits (Jones, 1990)

Various bit design innovations have been introduced to counter the high impact loads typical of horizontal drilling. These include impact arresters behind the PDC cutters (Figure 6-7A) and deep-pocket mounting of the cutters (Figure 6-7B). Impact arresters are designed to limit the depth of cut, thus allowing smoother operation. They also absorb impact loads when the bit bounces off bottom. Deep-pocket mounting results in better cutter retention and less cutter breakage from impact loads.

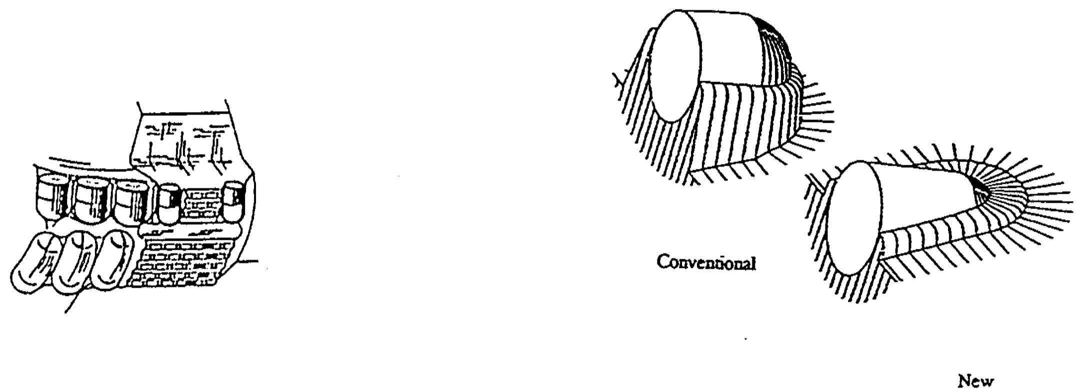


Figure 6-7. A) Impact Arresters for Horizontal Drill Bits (King and Mott, 1990)

B) Deep-Pocket Mounting of PDC Cutters (Knowlton, 1991)

New Short-Radius Tools

Build radius affects horizontal hole size and length to a significant degree, as well as impacting formation evaluation, borehole steering, and completion capabilities. Medium- and long-radius systems generally allow the largest range of options and capabilities. Smaller turning radii usually introduce more limitations. However, improvements in drilling systems (motors) and evaluation/steering systems (MWD) are beginning to reduce the magnitude of these limitations.

Short-radius horizontal wells can have several advantages over medium- and long-radius wells. Among the potential advantages of short-radius drilling are the following:

- Short-radius wells may allow sidetracking and kick-offs below gas caps (that need to be cased off) or difficult shales
- Build sections are often as short as 60-160 ft MD, allowing shorter drilling times and reduced costs for drilling the curve section
- Longer horizontal sections can be fit on small leases due to decreased curve length
- Fractures close to the vertical section can be intersected by the horizontal wellbore
- Pumps that must be placed in the vertical section of the hole are closer to the producing depth in a short-radius well

There is an important trend in the industry toward short-radius wells that can be completed with conventional tubulars. The average turning radius of 5½-in. re-entries decreased from about 550 ft in 1987 to 250 ft in 1992 (Figure 6-8). These radii correspond to 10°/100 ft in 1987 and 23°/100 ft in 1992. Developments in 1992-93 allow radii as short as 50-60 ft to be drilled using conventional drilling assemblies (i.e., motor/bent sub) and standard steering tools with articulated pressure housings. These data suggest that operators have become more comfortable with shorter-radius drilling operations.

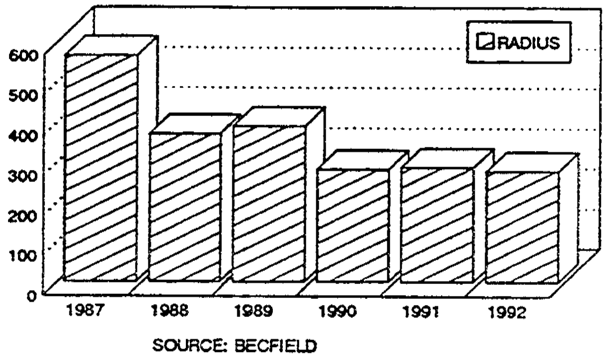


Figure 6-8. Average Build Radius (ft) for 5½-In. Re-entries

Improved short-radius drilling tools are being developed and introduced. Important improvements have been made in motors. Preussag used an articulated motor (Figure 6-9) to drill short-radius wells in Italy. Ultrashort double-bend motors (Figure 6-10) have been used to drill curves at turning radii from 50 to 100 ft.

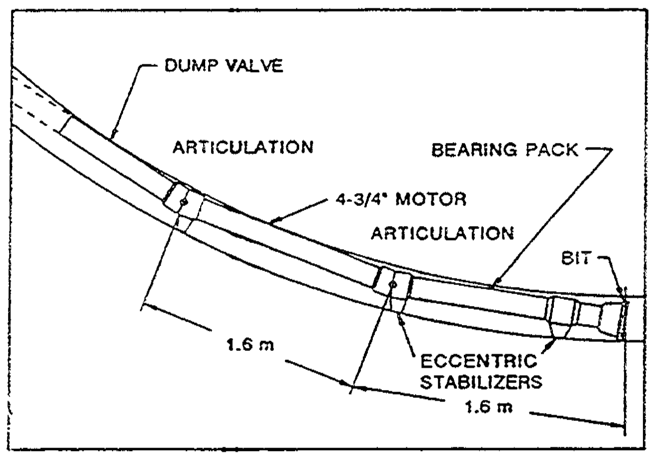


Figure 6-9. Short-Radius Articulated Motor (Prevedel, 1987)

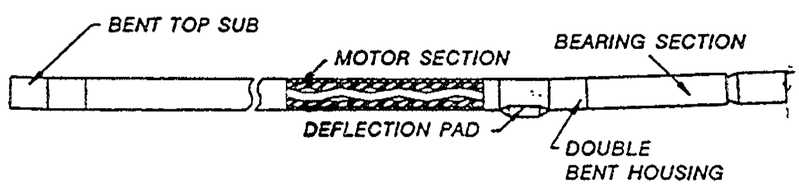


Figure 6-10. Ultrashort-Radius Double-Bend Motor (Pittard et al., 1992)

The advantages of short-radius drilling and the recent improvements in tools and systems have led many industry experts to forecast that the use of short-radius systems will eventually supersede that of medium-radius systems.

Slim-Hole Drilling Systems

Slim-hole drilling is advancing as operators develop smaller-than-usual technology to reduce costs and allow sidetracking from smaller diameter casing. Many of the technological problems associated with slim-hole drilling have been overcome, and operators are now focusing on how slim-hole drilling can be used to reduce costs.

Costs savings arise in most slim-hole projects in five categories: materials (especially tubulars and drilling fluids), labor, transportation, location size/preparation, and environmental impact. Relative cost savings vary depending on the particular location and conditions.

Smaller rigs, motors, bits, and equipment have become more widely available due to demand across the industry. A large number of slim-hole re-entries have been performed. In many cases, the decision to drill a slim hole is not based on an independent technological or economic choice by the operator. Instead, re-entry hole size is dictated by the casing size in the pre-existing vertical well.

Currently, horizontal wells are routinely being sidetracked out of 4½-in. casing. Several of these operations have been performed in the Austin Chalk. Additionally, operators have also successfully drilled multibranch slim-hole horizontal wells. In one operation in the Austin Chalk, two 3⅞-in. sidetracks were drilled out of 4½-in. casing (Figure 6-11). Medium-radius drilling techniques were used: 18°/100 ft for the first branch and 13°/100 ft for the second.

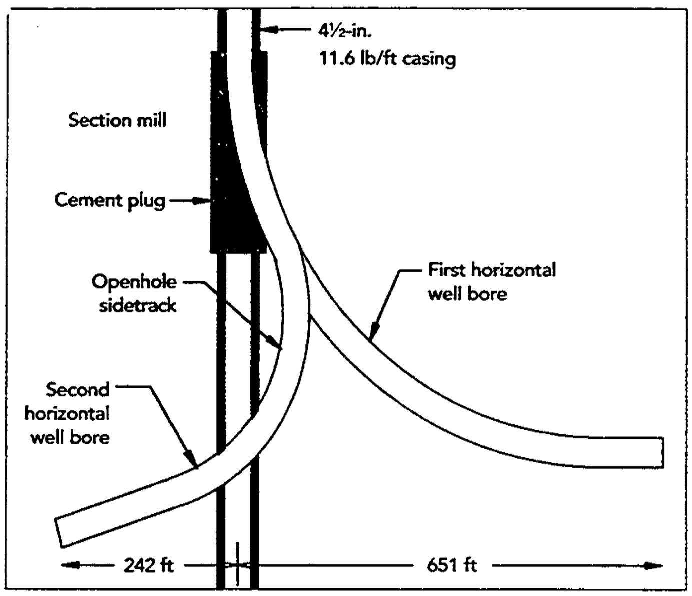


Figure 6-11. Multibranch Slim Horizontal Well (Pittard et al., 1992)

6.2 TECHNOLOGICAL NEEDS

Ongoing technical developments within the horizontal community are expected to continue to advance the application and improve the economics of horizontal technology. Chief among the industry's needs are tools to define reservoir characteristics and match them with optimum horizontal well length, completion design, etc. Not all reservoirs are economic candidates for horizontal drilling. For example, low-productivity horizontal wells that require gravel-packing often have a prohibitively high cost-to-benefit ratio. Other reservoirs may require a specific horizontal well length (longer is not always better) and completion to be economic.

Other major technical limits for horizontal well length are the inability to adequately complete and work over the horizontal wellbore when an unwanted fluid encroaches. An 8000+ ft horizontal well has been drilled and a 10,000 ft horizontal section is feasible; however, insufficient completion and remedial capabilities may keep operators from attempting it.

Both operators and service companies continue to make innovative technical advances in horizontal technology. Important technical barriers and hindrances for which solutions are being or remain to be developed include the following:

1. **Completion Design.** Advanced tools are needed to identify optimal completion designs based on reservoir conditions actually encountered. Horizontal completion technology has advanced in recent years, although it has generally been outpaced by advances in drilling technology. Horizontal wells are susceptible to a variety of production problems as a result of unintentional vertical undulations along the wellbore. The industry's experience has shown that many long open-hole horizontal wells would be far more effective producers had they been drilled as shorter laterals with completions that allow zonal control.

   Production profile modification during the life of the well, such as shutting off water-producing zones, has proven to be a major problem in many fields. The solution for vertical wells—cementing casing and perforating—is prohibitively expensive in most horizontal wells due to the great lengths involved. A solution available in fields that are undergoing water flooding is to use the horizontal wells exclusively as injectors and vertical wells as producers.

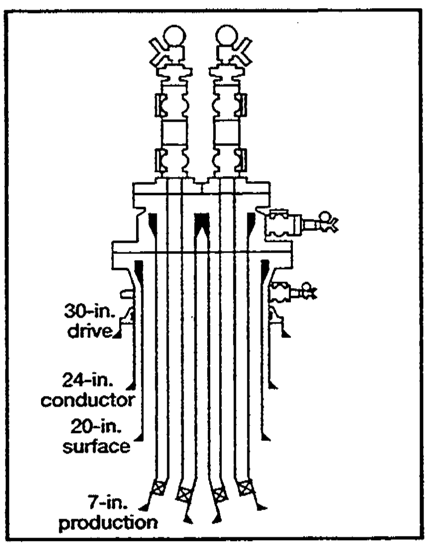


Figure 6-12. Marathon's Splitter Multibranch Completion (Teel, 1993)

   Completion options for multibranch wells are also in need of development. Completions are needed that allow selective stimulation, workovers, logging, testing, and artificial lift of the individual legs. Early versions did not allow for hydraulic isolation between the individual legs, but efforts continue to be directed toward solving this problem. One ongoing project is Marathon's Splitter system (Figure 6-12) for completing multibranch wells with cemented liners. Each branch is produced through a separate production string.

2. **Workover Technologies.** Improved water/gas identification and isolation tools and chemicals are needed for remedial operations. There now exists sufficient horizontal production history from many areas around the world to highlight the critical need to be able to modify production profiles during the life of the well. Water exclusion technology has recently become an area of intense interest due to the difficulty in controlling water production after breakthrough along an openhole or slotted-liner completion.

   Most systems designed to remediate water influx are based on the assumption that water does not enter uniformly along the well, but flows from high-permeability zones intersected by the well. Attempts to reduce water influx have been based on chemical injection, such as polymers and sodium silicate, that will selectively block water flow from high-permeability zones. Mechanical methods have also been tried, such as straddle packer assemblies. Unfortunately, most water exclusion attempts to date have only been marginally successful, at best.

   Long-term success with horizontal technology requires addressing the issues that impact the well's effectiveness beyond the initial drilling operation. Improvements in production logging tools and techniques are also needed to identify production profiles along horizontal wellbores.

3. **Minimizing Formation Damage.** Improved operations and fluids are needed to minimize formation damage (skin damage). Fluid invasion can cause a significant reduction in effective permeability in many formations. Most of the damage results from drilled solids entering the formation. Key parameters controlling skin damage include drilling time, fluid type, and clean-up/stimulation methods. Drilling longer horizontal sections results in damaging drilling fluids being in contact with the formation for longer times.

   It is far preferable to avoid formation damage, if possible. Underbalanced drilling, including air and foam operations, has been used in many formations to combat this problem. More experience is needed with air and foam drilling, including equipment and procedures to build, break, and clean foams. Improved rotary motors and downhole hammers designed for drilling with lightweight fluids will also contribute to more successful operations.

   Significant growth has occurred in balanced/underbalanced drilling technology in Canada and the U.S.A. since 1992. Detailed well counts in these applications are not available. It is evident that these applications have grown dramatically in 1993 and 1994. Approximately 10 such applications were carried out in 1992, and about 100 in 1993. It is expected that over 200 will be conducted in 1994. The main objective of this type of operation is to reduce formation damage. A second, related application is in significantly pressure-depleted reservoir settings where the well will not support a column of conventional drilling fluid, e.g., gas-storage applications. Figure 6-13 illustrates a common layout of the special surface facilities required. The key components are gas compression, rotating BOP, sealed sample catchers, and large separators.

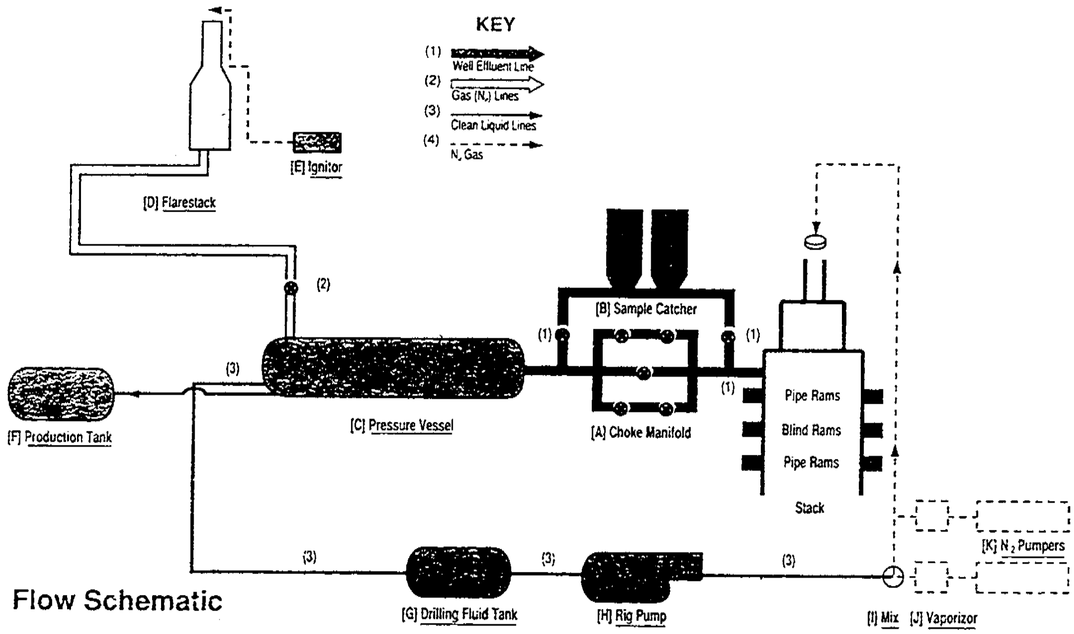


Figure 6-13. Surface Facilities for Underbalanced Drilling (Northland, 1994)

Two basic methods have been employed for balanced/underbalanced operations. The first method involves gas or nitrogen injection down a parasitic string installed with the intermediate casing (Figure 6-14). Once opened, this flow path allows gas lift in the annulus to reduce hydrostatic head.

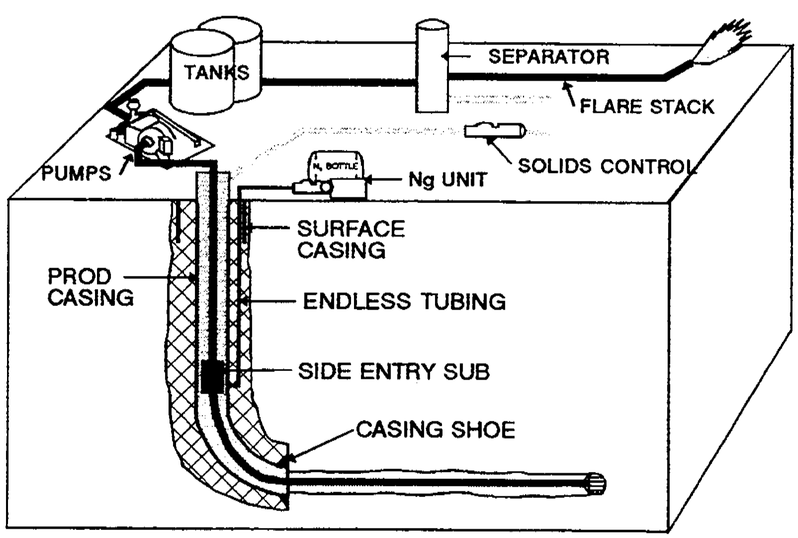


Figure 6-14. Underbalanced Drilling With Parasitic String

The second approach is to inject gas into the drilling fluid in the standpipe, effectively gas-seating all the drilling fluid both inside the drill pipe and in the annulus. Even though this second approach adds additional complications (i.e., inability to use mud-pulse MWD, requirement to seal or kill the drill string on each connection, necessity for special motors that will operate with two-phase fluid, etc.), this method appears to be gaining popularity as compared to the parasitic string method. Common explanations for this preference are: 1) higher costs and technical challenges/risks of parasitic string installation, and 2) smaller volumes of gas required to achieve equivalent reduction in pressure for the standpipe injection method.

Although balanced/underbalanced drilling applications have increased dramatically, they are not always successful and tend to be relatively expensive. Cost of the injected gas can be prohibitively expensive (particularly nitrogen). Another disadvantage is that a continuous volume of gas (about 3 MMscfd) must be separated and vented from the drilling fluid as the drilling proceeds.

Service companies offering this special service typically use analytical models to predict gas injection pressure and volume as a function of the specific hydraulics program, reservoir pressure and degree of pressure reduction required. However, the three-phase flow conditions in the wellbore tend to be quite dynamic. As a consequence, the actual degree of underbalance or reduction in overbalance achieved while drilling is difficult to confirm.

The dynamic nature of actual bottom-hole pressure (BHP) is complicated by variations in reservoir pressure, section inflow capability, drilled solids loading, and other factors. Figure 6-15 illustrates the fluctuation in BHP measured by a downhole sensor/recorder included in an MWD package in a balanced/underbalanced drilling operation. The pressure output is the upper trace; the lower trace is temperature. Although attempts were made at surface to stabilize BHP at a steady level, the actual BHP was fluctuating through a 700-1800 psi range. This highlights one reason why balanced/underbalanced drilling applications are not always successful. If a brief occurrence of overbalance occurs due to BHP dynamics or to killing the drill string or well for connections, bit trips, completion operations, etc., then how much benefit of the balanced/underbalanced drilling process has been nullified?

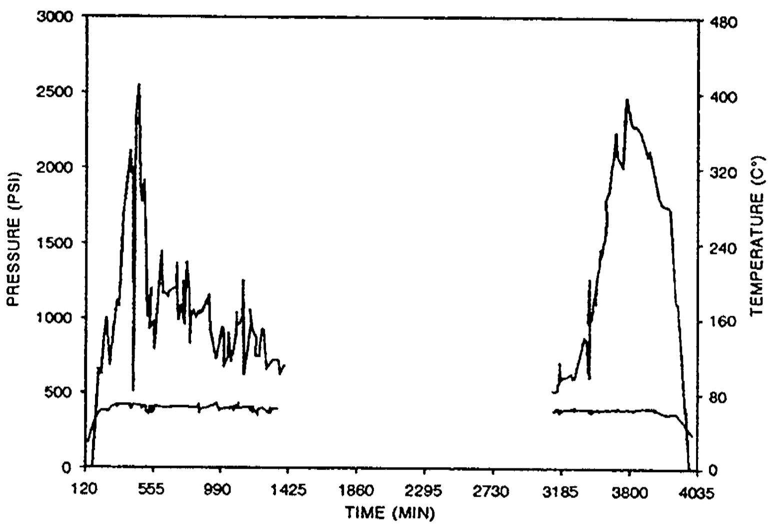


Figure 6-15. Downhole Pressure Fluctuations in Underbalanced Drilling Operations (DEA-44 WH #78)

Other potential problems in balanced/underbalanced operations can be caused by the lack of conventional filter cake and imbibition of the liquid phase of the lightened (gas-seated) fluid (Bennion et al., 1994). A stable filter cake is not developed during balanced/underbalanced drilling, due to continual inflow from the formation face. This could increase the severity of losses to the formation or lead to solids plugging the formation face. This may be of particular concern if the underbalanced condition is not maintained 100% of the time.

In reservoirs where the fluid saturations attract the liquid phase of the drilling or completion fluid, the possibility of invasion still exists due to a strong ''counter-current spontaneous imbibition'' effect as the fluids are in continuous contact with the wellbore face. This could lead to the entrainment of potentially damaging aqueous fluid filtrate in the matrix of the near-wellbore region. Figure 6-16 describes the mechanism of counter-current imbibition. When a well is on production, imbibition effects can draw water hundreds of feet from water/oil or water/gas contacts. Similar forces may exist in the near-wellbore region during balanced/underbalanced drilling operations. The impact of this phenomenon on field operations has yet to be documented.

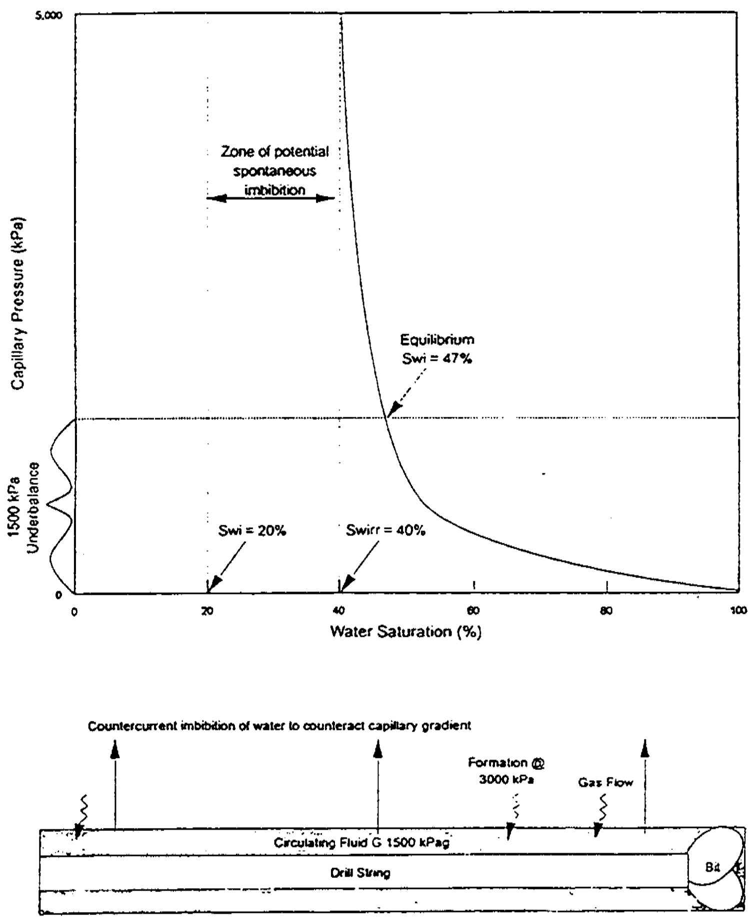


Figure 6-16. Spontaneous Imbibition During Underbalanced Drilling (Bennion and Thomas, 1994)

Finally, carrying capacity of the lightened liquid may be less than that of a conventional drilling mud, especially in situations with varying bottom-hole pressures. Thus, even when underbalanced conditions are maintained, there remains the possibility that crushed and milled cuttings will be driven into the wellbore wall by the mechanical action of the drill string. Since a typical balanced/underbalanced drilling fluid will not build a significant filter cake, solids invasion and formation damage is still a potential problem.

Even though there are disadvantages, balanced/underbalanced drilling technology appears to offer significant advantages. Dramatic productivity responses have been achieved (Deis et al., 1993). In applications where the formation is particularly sensitive to damage, balanced/underbalanced drilling may provide the only viable method to successfully drill a horizontal well.

Improvements in bits and motors that increase ROP will, as a secondary benefit, decrease formation damage, since drilling time will also be decreased. Other solutions to address the problem of formation damage include the development of nondamaging drilling and completion fluids. Improved techniques and tools are needed to flush the formation or to underream damaged permeable zones.

4. **Slim-Hole Drilling Technology**. The promise of significant cost savings in both exploration and development wells will drive the continued development of solutions for barriers to the widespread use of slim-hole techniques combined with horizontal technology. Maurer Engineering (Shook and Maurer, 1994) recently completed a survey for GRI to identify and rank barriers hindering slim-hole drilling. A summary of these barriers, listed in approximate order of significance, is shown in Table 6-1. These rankings were derived from a consideration of the importance of the barrier, whether the barrier is real, perceived, or both, and the potential for funded research to make a positive impact on the implementation of the technology.

TABLE 6-1. Slim-Hole Drilling Barriers (Shook and Maurer, 1994)

BARRIER	BARRIER
1. Downhole Motors	14. Drill-String Vibrations
2. Cementing Small Annuli	15. Lost Circulation Materials
3. Drill Bits (Hard Rocks)	16. Rig Equipment
4. Psychological Barriers	17. Well Control (Coring)
5. Air/Foam/Mist Drilling Fluid	18. Differential Sticking
6. Borehole Stability	19. Fishing Tools
7. Directional Guidance	20. Regulations
8. Surveying/MWD	21. Running Casing (Sticking)
9. Coiled-Tubing Fatigue	22. Tubulars
10. Coiled-Tubing Orienter	23. Coiled-Tubing Torque Reactor
11. Drilling Fluids	24. Hole Cleaning
12. Wellbore Hydraulics	25. Rig Automation
13. Coiled-Tubing Thruster	26. Well Control (Noncoring)

Important advances in downhole motor design have recently resulted in slim motors with higher power output, allowing higher ROPs. Smaller (4¾ in.) roller-cone bits with improved bearing designs have recently been made available to the industry. These bits will promote the drilling of slim wells through hard formations not effectively drilled with PDC/TSP bits.

Psychological barriers have been a strong hindrance for many operators. Deep-seated opinions on why slim-hole technology won't work have prevented most companies from considering the technology. Some of these opinions are based on invalid assumptions. For example, many suppose that all slim-hole operations require rapid, advanced well-control procedures after a kick. In fact, well control is a critical concern only in the small-annuli continuous coring systems. In addition, most operators using these types of rigs have increased the size of the annulus so that well control is not nearly as critical as it was with earlier well-publicized systems. Technology transfer and sharing play a primary role in countering the problem of these psychological barriers.

5. **Stimulation.** Wellbore stimulation is critical to the success of a horizontal well, both after drilling, if required as part of the initial completion, and during remedial workover operations. Operators and service companies are developing improved tools and chemicals for stimulation operations. Interesting technologies and systems currently undergoing development include the use of fracturing techniques (multiple minifracs) to overcome formation damage, hydraulic fracture design and control, by-passing formation damage by drilling several short laterals, closed-fracture acidizing, and bottom-hole tools with zone isolation capability.

6. **Re-entry Technology.** "First-look" economics tend to favor a re-entry over a new well in most applications since the lease, cased wellbore, etc., already exist for the re-entry option. The industry's interest in re-entry technology has varied over the last few years. For example, the proportion of re-entries and new wells drilled in Canada in 1991 to 1994 is compared in Figure 6-17. There are over 150,000 cased wellbores in Western Canada. As a consequence, there was strong interest in re-entry applications in 1991 and 1992. That interest decreased in 1993 apparently as a result of the industry's re-entry experiences in 1992.

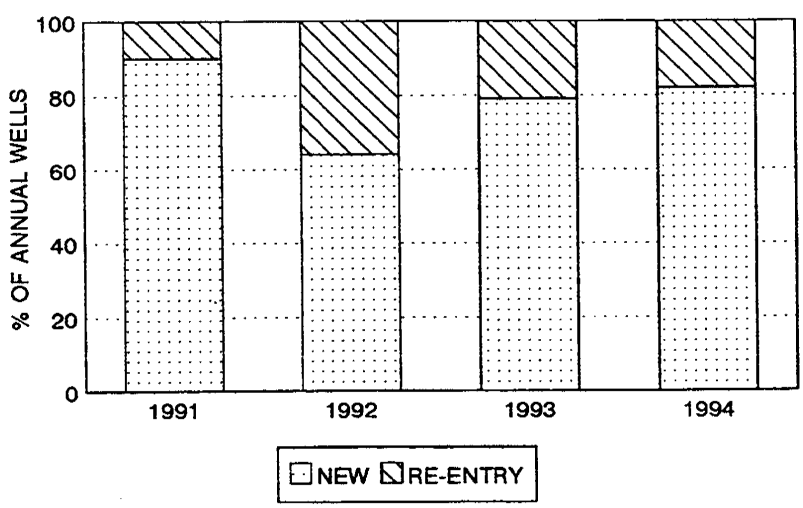


Figure 6-17. Distribution of Canadian New Horizontal Wells and Re-entries (DEA-44)

Although a re-entry should entail less geologic risk than a new well, the industry collectively learned that there are three critical disadvantages of a re-entry versus a new well in most applications:

Old Well Problems. When re-entering an existing well, the application inherits all the problems of the old vertical well, such as worn casing, poor cement jobs, pressure depletion near the wellbore from production, etc.

Design Restrictions. Since the old well was typically cased, re-entry design must start at a size small enough to travel through the existing casing. This can lead to significant limitations in achievable length, steerability, completion design, workover options, etc.

Well Preparation. Unless the existing casing can be easily removed, there are two basic options to prepare the well for kicking off the lateral: 1) mill a window or 2) section-mill a length of the casing. Many well histories reveal that the cost and technical difficulties related to these operations are typically underestimated.

As improvements in well preparation technology (i.e., milling, sectioning) and slim-hole/coiled-tubing technology evolve, it is anticipated that the huge re-entry market in mature fields will be pursued with rapidly increasing well counts. However, in 1993 and 1994, it appears that the industry drilled fewer horizontal re-entries due to these three general issues.

7. **Pressure Testing.** Tools, operations and computer models need to be developed to effectively analyze horizontal wells using pressure transient testing. Well test results from a horizontal well are complex and often difficult to interpret. Problems arise as a result of the complex geometry and possible existence of four flow regimes, as compared to simple radial flow for (unfractured) vertical wells. The analysis is complicated by nonuniform skin factors along the horizontal wellbore. The mechanics of horizontal wells also dictates that a long time is usually required to reach pseudo-radial flow. Reservoir boundaries often affect pressure response before pseudo-radial flow can develop. These and other factors complicate pressure testing in horizontal wells.

8. **Wellbore Location.** Tools need to be refined to assist in identifying the optimal wellbore location within the reservoir. Real-time geosteering, that is, looking ahead of the bit and adjusting the wellpath based on the geology encountered or about to be encountered, continues to be an important area of technical development.

9. **Field Development.** New screening tools, e.g., computer analysis and simulation programs, are needed to identify the optimal field development using horizontal wells in new and previously developed fields. Toward that end, a well-designed and regularly updated horizontal technology industry database would provide a significant source of useful information on applications, production, techniques, etc.

10. **Regulations.** Technical solutions are being developed for new and existing environmental and bureaucratic regulations. Changes are needed in domestic regulations to encourage all drilling operations, especially those in marginal areas. Clear-cut regulatory and permitting procedures are needed.

Industry experiences in Canada illustrate the effects of regulations on horizontal drilling. The provincial distribution of horizontal wells in Canada from 1991 to 1993 (Figure 6-18) indicates that many more horizontal wells were drilled in Saskatchewan than in Alberta in 1991. This was true despite the fact that the total gas and oil reserve base of Alberta is significantly larger than Saskatchewan. The proportion of Alberta wells has increased in 1992 and 1993. It is generally accepted that the disproportionate utilization of horizontal well technology in Saskatchewan in the late 1980s and early 1990s was, in part, a result of the favorable regulatory and fiscal regime implemented by the Province of Saskatchewan. These regulations tended to promote horizontal well applications above their Alberta counterparts. In 1992-1993, Alberta regulations were modified to be more favorable toward horizontal drilling. The larger proportion of Alberta wells since then may be, in part, an industry response to these regulatory and fiscal regime alterations.

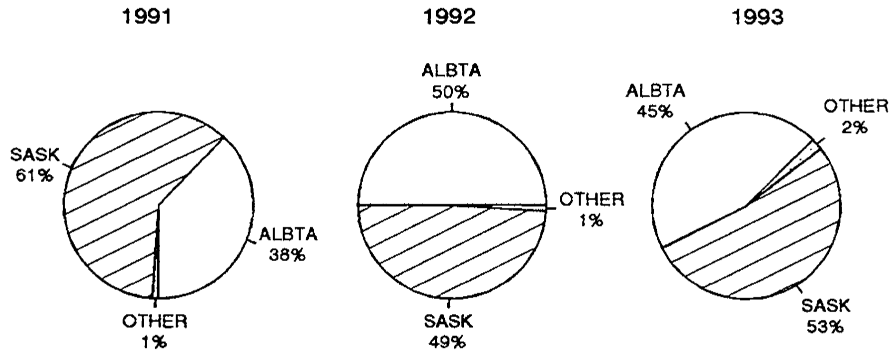


Figure 6-18. Provincial Distribution of Canadian Horizontal Drilling

6.3 ECONOMIC NEEDS

The economics of each horizontal drilling project are site-specific. Factors impacting horizontal drilling, completion, and workover costs include the following:

1. **Location.** Typically, incremental costs for all systems will be greater for a land operation than for an offshore operation. In offshore operations, some of the directional drilling equipment is already used in normal extended-reach operations so that incremental costs for going horizontal are small.

2. **Target Constraints.** The tighter the target tolerances are, the greater the need for more sophisticated guidance equipment (geometric and geologic). An intrinsic advantage rests with short-radius techniques: the distance from the kick-off point to the target is the shortest. Unfortunately, there are less geologic directional tools for short-radius systems.

3. **Hole Size.** Drilling smaller holes is not necessarily cheaper, due principally to the current lack of availability of slim-hole drilling tubulars, as well as operators' and service companies' lack of significant slim-hole experience. Currently, the greatest cost savings with slim holes are seen with multiwell programs where the learning curve can be developed and unit costs can be reduced.

4. **Horizontal Length.** The choice of drilling system (short, medium, or long radius) and other parameters affects the maximum attainable horizontal length. Both medium- and long-radius systems have length capabilities in excess of 7000 ft (in certain areas), whereas short-radius systems can currently achieve a maximum of about 1500 ft. Therefore, drilling system cost savings must be balanced against the impact of horizontal length on production.

5. **Curve Length.** The angle-build section, or curve, usually serves only as a transitional conduit to the horizontal producing section. Consequently, shorter curves are preferred. However, a trade-off exists between curve length and horizontal section length, as mentioned above.

After considering all pertinent operational and economic parameters, many operators have suggested that medium-radius systems appear to be the most economic. This is not universally true, of course. In some operations, location, completion design, logistics, and/or other conditions may define the build radius, hole size, and horizontal length requirements so that relative economic distinctions become moot.

In many sectors of the horizontal market, equipment and tool reliability has a significant impact on the success of the application of the technology. Extra costs incurred as a result of problems with tool reliability or availability can significantly alter the economics, especially in a field where the profit margin is low at the outset. Similarly, the potential for cost savings through horizontal re-entries as compared to new wells remains unachieved in most areas due to the relatively high cost and lack of reliability of sidetracking tools and techniques.

Multiple horizontal wellbores, including multibranch wells, seem to be another promising direction for overall economic savings. New technological developments have made multibranch techniques a cost-effective reality. Early completion technologies did not allow for hydraulic isolation between the individual branches, but current developments are solving this problem (e.g., see Figure 6-12).

Slim-hole technology is being pursued in horizontal applications for the same reason as in vertical applications: cost savings. Savings have been seen in several areas. An illustration of the distribution of cost savings for a typical modern slim-hole vertical well is shown in Figure 6-19. Costs are decreased in bits, mud disposal, casing/cement, services, and rig rates. The comparisons given here are for 4⅛-in. versus 5⅞-in. holes. The savings are greater when compared to larger holes.

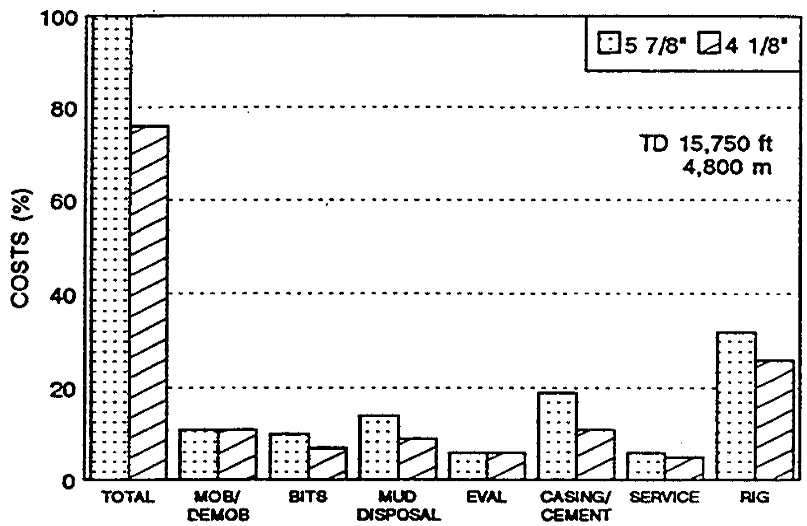


Figure 6-19. Shell/Eastman Slim-Hole Costs (Worrall et al., 1992)

Horizontal drilling technology has been effectively applied in slim-hole applications. Horizontal re-entry of an existing vertical well has provided substantial economic benefits due to increased production and reduced drilling costs.

Slim mud motors are routinely used in the Austin Chalk and other areas to drill 3½- to 4½-in. horizontal wells. Costs have dropped significantly as techniques for slim-hole medium-radius horizontal drilling have been optimized. Under ideal conditions, a 5000- to 6000-ft vertical well can be re-entered through 5½-in. casing and horizontally extended 2000 ft for about $250,000. A new horizontal slim hole might cost $325,000 to $425,000 in these conditions. A large hole might cost twice as much (Figure 6-20). These costs are based on a 6000-ft TVD and 10,000-ft TD.

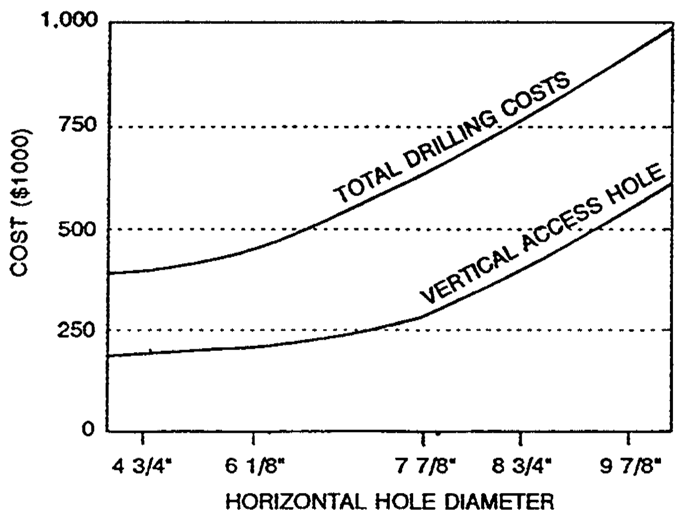


Figure 6-20. Horizontal Well Costs (Rehm, 1991)

Oryx recently conducted a detailed cost analysis of slim-hole horizontal re-entry costs in the Austin Chalk (Hall and Ramos, 1992). Costs for eight wells re-entered during 1991 and 1992 are presented in Table 6-2. The cost of a slim-hole lateral exceeded conventional lateral costs for each of these wells. Oryx reports that high costs associated with drilling the lateral were principally due to low rate of penetration (ROP) resulting from wiring problems with the steering tool. A dependable wet-connect steering tool system was developed as part of this slim-hole program. This improvement increased slim-hole ROP by 55%.

TABLE 6-2. 1991 and 1992 Oryx Slim-Hole Re-Entry Costs (1991 Conventional Cost = 1.00) (Hall and Ramos, 1992)

DAYS	DEPARTURE	LATERAL COST	TOTAL COST
18	1458	3.88 (CT)	0.63
38	2018	3.31	0.74
24	2002	1.84	0.41
21	2692	1.46	0.43
20	2242	1.83	0.45
18	1927	2.36	0.50
14	1600	1.75	0.31
22	1900	2.60	0.54
Avg 22	1980	2.38	0.50

Data are presented for one coiled-tubing re-entry (the first well in Table 6-2). Although lateral costs were much greater than conventional, overall re-entry costs with coiled tubing were 63% conventional.

New horizontal slim-hole wells have also provided cost reductions for Oryx. Their first new slim hole (Table 6-3) cost 83% of a conventional 8½ in. Experiences with this first well led to modifications in the plan for the second slim hole. These included the use of a larger mud motor, a larger bit for increased clearance through the curve, and 2⅞-in. drill pipe in the vertical section to increase WOB. Total costs for the second well were 68% of conventional.

TABLE 6-3. Oryx New Horizontal Slim-Hole Costs (Hall and Ramos, 1992)

	HOLE SIZE	DEPTH/DISPLACEMENT	LATERAL COST	TOTAL COST
Conventional	8½ in.	10,289 ft/3741 ft	1.00	1.00
Reduced Hole	6⅛ in.	9698 ft/3257 ft	0.87	0.82
1st Slim Hole	4½ in.	9568 ft/3110 ft	0.89	0.83
2nd Slim Hole	4¾ in.	9697 ft/3154 ft	0.73	0.68

Oryx's operation showed that slim-hole horizontal technology offers significant potential for cost savings for both re-entries and new wells (Table 6-4).

TABLE 6-4. Summary of Horizontal Slim-Hole Costs (Hall and Ramos, 1992)

	HOLE SIZE	DEPTH/DISPLACEMENT	LATERAL COST	TOTAL COST
Conventional	8½ in.	10,289 ft/3741 ft	1.00	1.00
Reduced Hole	6⅛ in.	9698 ft/3257 ft	0.87	0.82
Slim-Hole Re-entry	3⅞ in.	——/1980 ft	2.38	0.50
New Slim Hole	4¾ in.	9697 ft/3154 ft	0.73	0.68

Oryx concluded that "slim-hole technology is at roughly the same technological position as horizontal and extended-reach drilling was five years ago. It has been proven to be feasible and economical, but is waiting for the push to become an industry accepted practice."

If the cost of horizontal drilling services can be decreased, especially for simple short-radius, short-length re-entries in mature and/or marginal fields, then the domestic market potential would increase substantially.

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