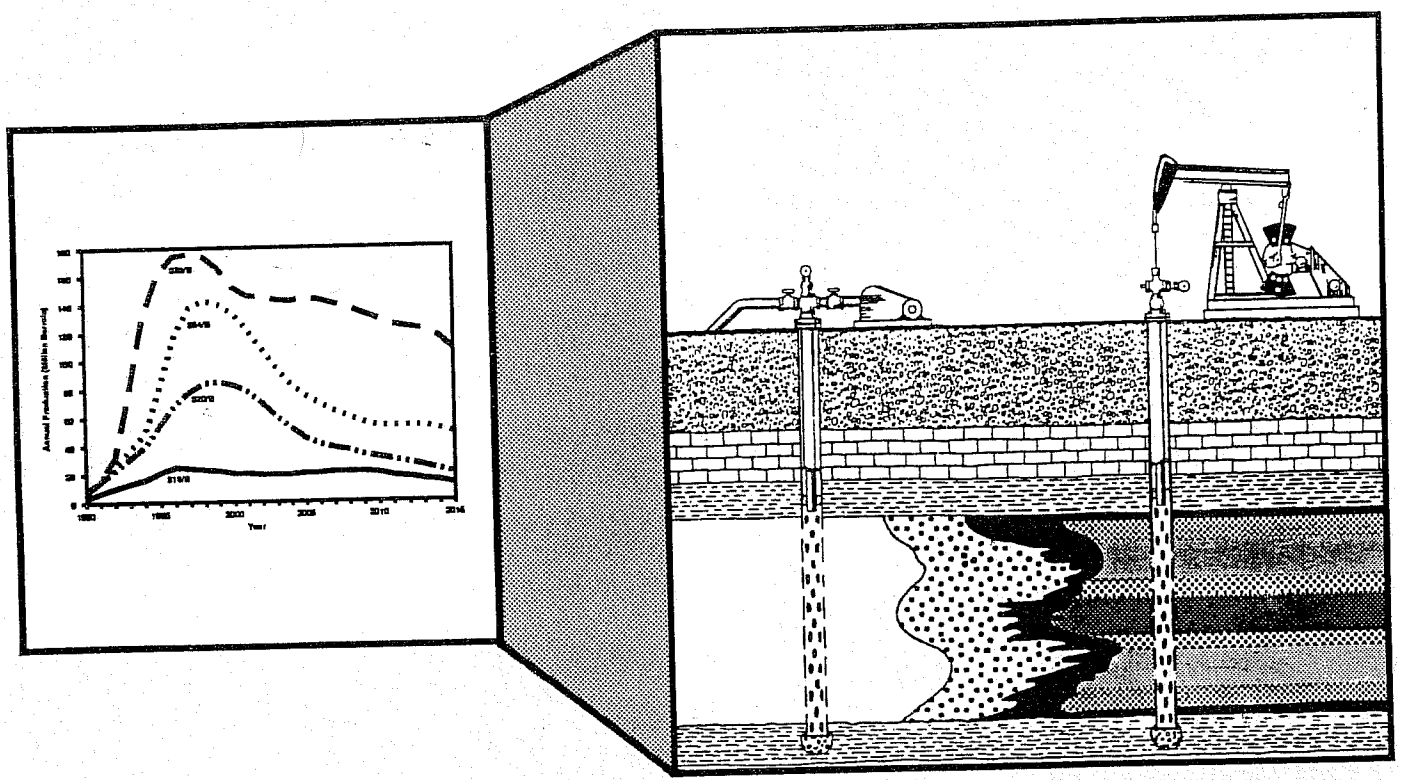
AN EVALUATION OF THE KNOWN REMAINING OIL RESOURCE IN THE STATE OF TEXAS



By the
Interstate Oil Compact Commission
Project On Advanced Oil Recovery
and the States

November 1989

INTERSTATE OIL COMPACT COMMISSION

An Evaluation of the Known Remaining Oil Resource in the State of Texas

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The basic data and models used in the analysis were developed and validated in the 1982-84 study of the nationwide potential of enhanced oil recovery by the National Petroleum Council (NPC). The NPC models and data, as well as computer time, were made available for this study by BPO. Special acknowledgment to Mr. R. Michael Ray, Deputy Director of BPO, is extended for his valuable technical advice and guidance and to Mr. Thomas Wesson, BPO Director, for his encouragement and assistance.

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W. Timothy Dowd
Executive Director
November 1989

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EXECUTIVE SUMMARY

The Interstate Oil Compact Commission (IOCC) has sponsored a series of analyses examining the known oil resources in various states. The evaluation of Texas is the third state analysis in this series. The huge remaining oil resource of this state is the largest of any state in the nation, representing close to one-third of the entire U.S. known resource. The study is designed to assess future recovery potential from the Texas resource, 64% of which will remain unrecovered at the conclusion of conventional recovery operations. A significant amount of the state's future oil production will result from projects that employ emerging techniques specifically designed to contact and recover the oil left after current operations reach their economic limit of production. Improved recovery methods applicable in Texas are the primary focus of this evaluation.

The purpose of this study is to identify and evaluate available methods for increasing recovery from Texas oil reservoirs and to assess options beneficial to the state for encouraging the wide-spread application of these post-conventional recovery processes. The specific objectives of the study are to:

- Determine the possible recovery and associated economic benefits of the application of improved recovery processes in major Texas reservoirs
- Assess potential increases in oil recovery under alternative state policies
- Identify key segments of the state's resource with the largest future recovery potential
- Describe an effective program design for a coordinated state policy of research and development and technology transfer to provide maximum assistance to state operators within fiscal constraints

The analysis estimates the impacts of effective research and development (R&D) programs on oil recovery, state tax revenues, and associated public-sector economic benefits over a range of possible future oil prices. Policy assessments compare these benefits with those occurring in the

absence of such an R&D program. The analysis therefore assesses potential recovery from processes as currently implemented as a base to measure the direct increase in recovery and associated economic benefits deriving from a coordinated state program of R&D. Both incremental and total benefits were considered in evaluating effective state program options.

Known reservoirs in the state, originally containing 161 billion barrels, will only yield 57 billion barrels of ultimate recovery. Over 100 billion barrels will remain in these reservoirs at the conclusion of conventional activities; producers currently lack the technology required to recover much of this oil. Enhanced oil recovery (EOR) and unrecovered mobile oil (UMO) extraction methods, which are designed to produce a portion of this resource, were assessed to determine the potential they offer for increasing recovery from the massive remaining oil resource in Texas. This analysis of the Texas resource examined over 500 reservoirs from the diverse producing provinces across the state. The EOR analysis considered reservoirs accounting for 120 billion barrels of original oil in place, 74% of the state total; the analysis of UMO extraction considered reservoirs initially containing 100 billion barrels of oil, 62% of the state total. The reported results were limited to recovery and benefits likely to accrue from these reservoirs only; no extrapolation of the results was undertaken to estimate recovery for the entire state resource.

The analysis was conducted using the Tertiary Oil Recovery Information System (TORIS), a tested and verified data base and modeling procedure maintained and operated by the Department of Energy's Bartlesville Project Office. The use of TORIS allowed consistent assessment of the potential oil recovery and production from the Texas oil resource at seven oil prices, ranging from $12 to $36 per barrel in $4 increments, and two levels of technology, implemented and advanced. Implemented technology includes recovery practices currently available for implementation in the field; advanced technology assumes improvements in recovery practices and reduction in their costs obtainable within ten years given a successful, focused R&D program. TORIS also contains data on the geologic setting of each analyzed reservoir. This descriptive information summarizes important geologic features that influence oil recovery and allows for quantitative evaluation of recovery potential in reservoirs with similar geologic histories.

The evaluation of potential oil recovery in Texas leads to the following major conclusions:

- The effective transfer of currently available EOR and UMO extraction technology could result in substantial post-conventional reserve additions from

analyzed Texas reservoirs, with significant increases in revenues and associated economic benefits.

- Advanced EOR and UMO extraction technology resulting from focused R&D plus technology transfer could lead to substantial incremental increases in reserves and economic benefits; the application of advanced technology at $32/Bbl in the reservoirs analyzed in this study could result in an incremental addition of 2.4 billion barrels of EOR reserves (50% more than implemented technology reserves) and 3.5 billion barrels of UMO extraction reserves (195% more than implemented technology reserves).

- Synergies resulting from the combined application of improved EOR and UMO extraction processes could further increase oil recovery and economic benefits with advances in recovery technology resulting from R&D.

- Focusing R&D in the geologic settings containing the greatest reserve potential would lead to maximum benefits from limited research budgets.

Although the volume of reserves added, revenues generated, and economic activity stimulated vary with the price of oil, the basic conclusions do not change. Over the price range considered in this study, application of EOR and UMO extraction processes in Texas reservoirs could substantially increase new reserves and with them, state, local, and oil operator revenues. The use of advanced technology processes resulting from focused R&D to recover immobile oil and UMO would clearly result in considerable increases in reserves and associated benefits over implemented technology potential. Research program costs would be recovered through the direct benefits generated to the state and federal treasuries in the form of additional tax revenues from the increased oil recovery.

Because the additional oil reserves added by advanced technology provide significant benefits for Texas and the nation, a concerted program of R&D is justified. Targeting of research activities can further focus the program to maximize recovery of both mobile and immobile oil by concentrating first on groups geologically similar reservoirs with the greatest resource and recovery potential. With effective R&D, and a program of technology transfer to widely disseminate its results, Texas oil production could be maximized, maintaining access to the huge remaining oil resource. The benefits of such a program would accrue to Texas oil operators, in terms of increased production and profits, to the state, in terms of increased tax revenues, and to the nation, in terms of improved energy security.

I. STUDY OVERVIEW

A. THE PROBLEM: DECLINING TEXAS OIL PRODUCTION

Nearly two-thirds of all oil ever discovered in Texas will remain in the reservoir at the conclusion of conventional primary and secondary oil recovery operators. The total known original oil-in-place in Texas is over 160 billion barrels (Figure I-1). In excess of 51 billion barrels had already been produced at the end of 1987, with 7 billion barrels of proved reserves still considered producible by ongoing recovery projects under existing economic conditions. This would leave 103 billion barrels remaining in Texas reservoirs as a target for newer, more efficient extraction technologies. This study evaluates state policy options for improving the application of emerging recovery processes in Texas reservoirs by estimating their potential impacts on oil production, reserves, and associated economic benefits. The assessment focuses on state policies which affect research and development (R&D) and outlines program considerations for developing and demonstrating advanced technology processes in critical Texas reservoirs.

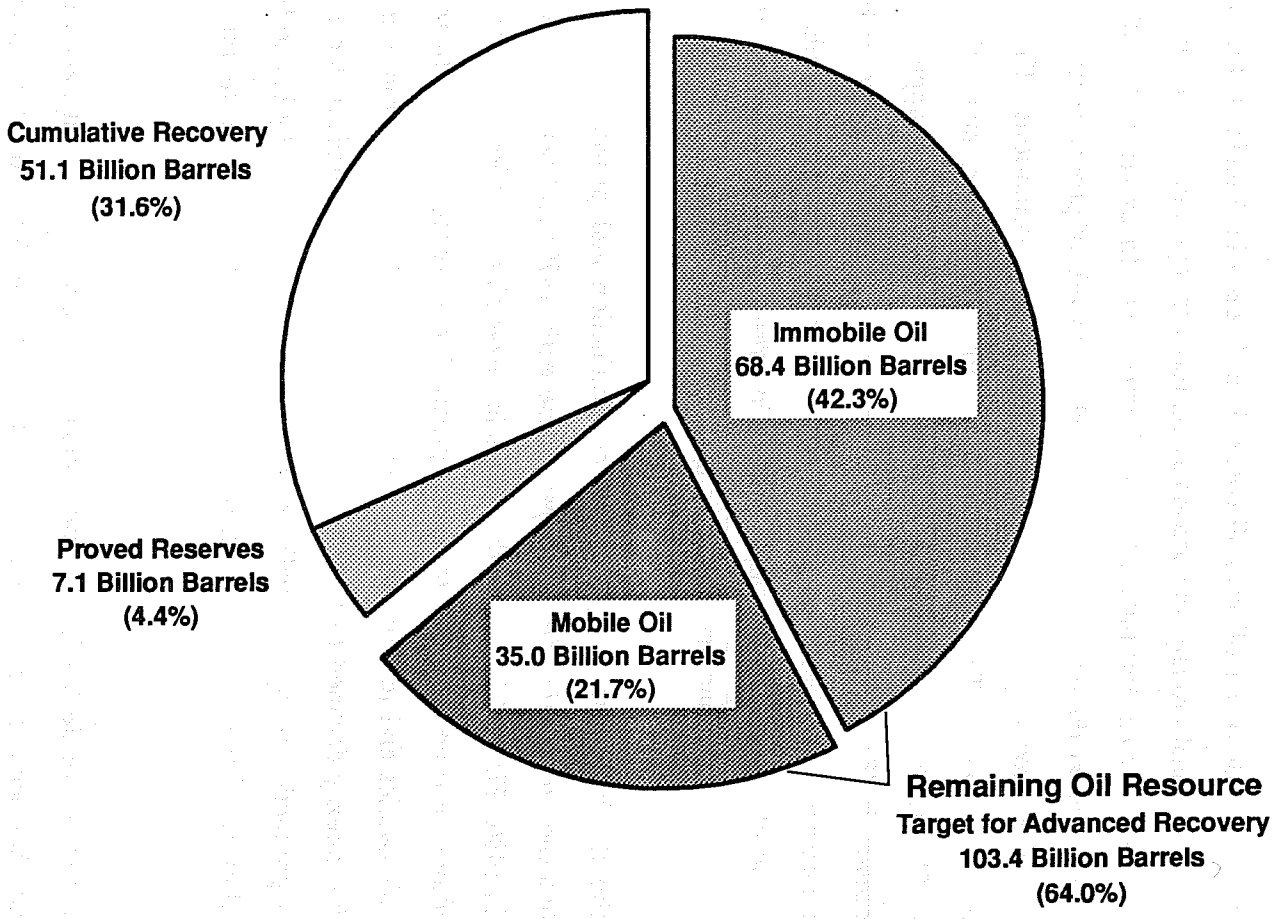
Despite the huge remaining resource, oil production and proved reserves in Texas are declining. Statewide production decline began in the early 1970s and was exacerbated by the fall in oil prices in 1986. Figure I-2 displays the trends in Texas oil production and reserves since 1935. Reserve additions have been unable to match production in recent years, with the average size of new field discoveries and reserves per well also declining. Production from a large number of Texas wells has already declined to or will soon reach the economic limit under current recovery practices. As production ceases and wells are shut-in, they are required by law to be plugged and abandoned, thus restricting economic access to the remaining resource in the reservoir they penetrate.

As production has declined, oil-related employment, economic activity, and federal and state revenues have also been reduced. Declining production, coupled with lower prices, has led to substantial reductions in the gross value of the oil produced and the resulting tax revenues. The state has revised its tax structure in recent years to compensate for the reduced contributions of oil and gas production taxes to the total budget.

Figure I-1

Texas Oil Resource

After Conventional Operations, Nearly Two-Thirds of the Texas Oil Resource Will Remain Unrecovered



Total Original Oil in Place: 161.6 Billion Barrels

Source: BPO TORIS, 1989
EIA, 1987
API/AGA, 1980
Fisher and Finley, 1986

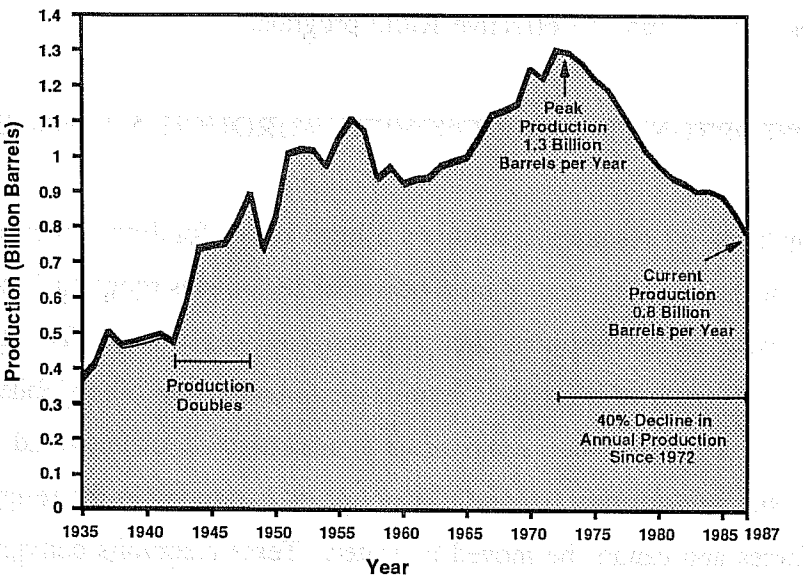
As of 12/31/87

Figure I-2

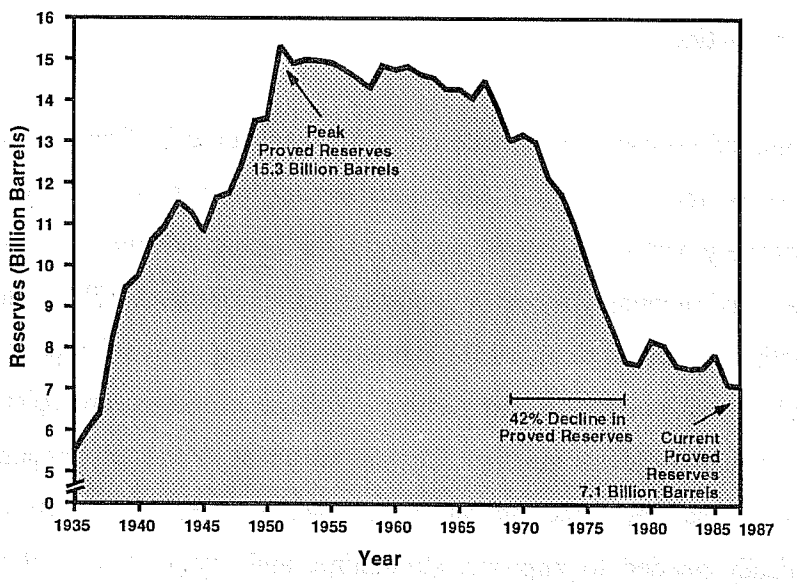
Texas Production and Reserves

After Decades of Increases, Texas Crude Oil Production and Reserves Have Recently Declined

A) Annual Production



B) Reserves



Source: OGJ Database, 1989

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Technology advances have historically made substantial contributions to Texas oil production. Waterflooding technology was responsible for notable increases in Texas production in the mid-1950s. The development of offshore drilling technology allowed Texas to develop its sizeable offshore oil and gas resources. In addition, Texas is the site of many pioneering projects in enhanced oil recovery. This study attempts to determine the role that improvements in technology will play in the future development of the remaining Texas oil resource. The key to maximizing recovery of the remaining Texas oil resource is continued technology advances which can be achieved only through an effective R&D program.

B. THE OPPORTUNITY: OIL RECOVERY THROUGH ADVANCED TECHNOLOGY

The remaining oil resource constitutes a huge target for future recovery operations. The application and further development of most advanced techniques require a thorough understanding of the characteristics of the resource they are designed to produce. The 103 billion barrels of unrecovered oil in Texas is of two types: mobile oil and immobile oil. Mobile oil can be displaced from the reservoir by water, but some of it is uncontacted or bypassed during conventional production and thus remains unrecovered. Immobile oil is trapped in the reservoir pores by viscous and capillary forces and cannot be moved by water. Texas reservoirs contain immense quantities of each of these resources, and the development, testing, and implementation of new recovery techniques that could cost-effectively, produce these resources offer tremendous potential benefits for Texas and the nation.

The estimated unrecovered mobile oil (UMO) resource in Texas is 35 billion barrels. This resource represents the mobile oil that will remain in reservoirs after the completion of conventional recovery and is an important target for future advanced recovery efforts. Several improved primary and secondary recovery processes (infill drilling, profile modification, and polymer flooding), collectively referred to as UMO extraction techniques, could be used in innovative ways to capture a substantial portion of this resource. These processes are relatively low in cost and could increase production levels quickly. Certain advances in the application of these techniques have already been used by some operators in selected reservoirs in the state, but continued research is critically needed to improve, streamline, and adapt these techniques to site-specific areas.

The 68 billion barrel immobile oil resource in Texas is the target of a number of tertiary extraction techniques. Gas-miscible, chemical, and thermal recovery processes directed at producing immobile oil are referred to as enhanced oil recovery (EOR) techniques. While these advanced recovery processes generally require a larger investment and higher operating costs than primary and secondary recovery processes, they are capable of producing substantial volumes of oil and generating large economic benefits. Further advances in EOR technology to improve upon current tertiary recovery practices are foreseeable if a focused, research-intensive approach is adopted to make identified improvements ready for field application.

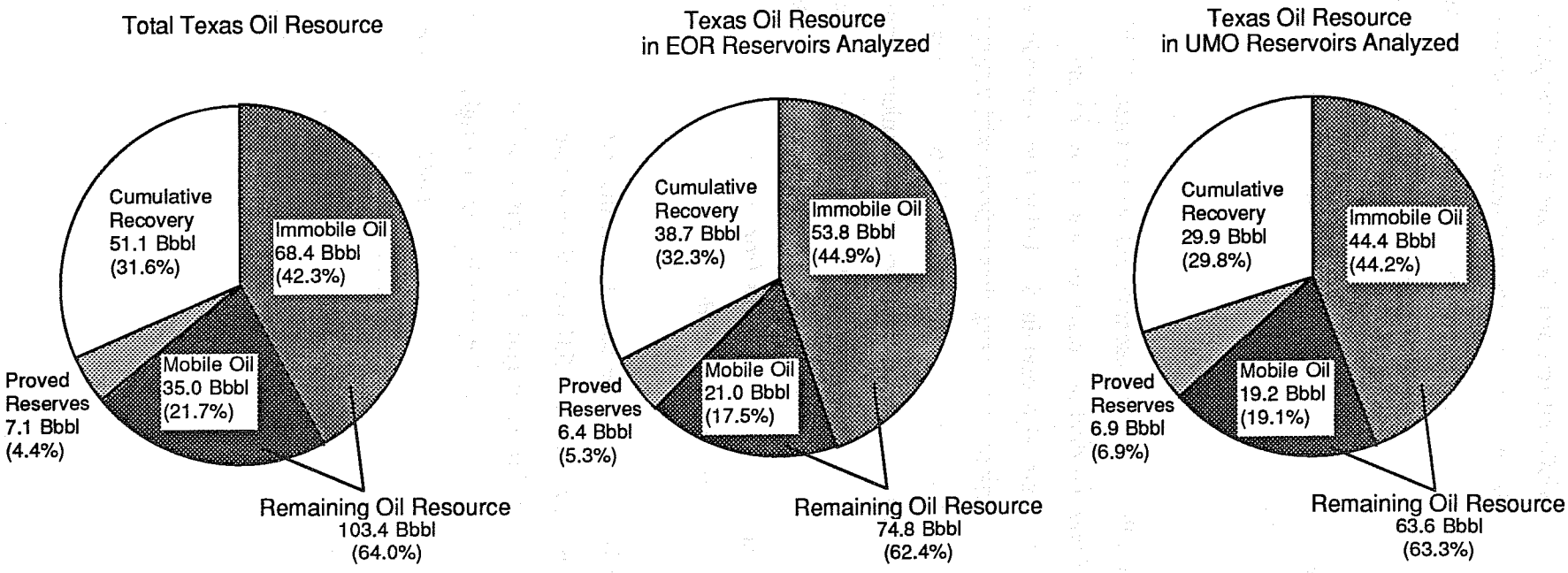
This analysis examines the effects of research and development (R&D) in UMO extraction and EOR techniques on Texas production, reserves, and state revenues. The economic and financial benefits for the nation are also examined. Using the methodology developed by the National Petroleum Council (NPC)[1/] for estimating these effects, with adaptations specific to Texas, the potential for EOR and UMO recovery are examined under two different technology scenarios: 1) application of currently available post-conventional recovery techniques (implemented technology case), and 2) application of advanced recovery practices developed through concerted R&D (advanced technology case). Estimates consider the benefits of the application of these two technology scenarios over a range of crude oil prices from $12 to $36 per barrel in constant 1988 dollars for reservoirs adequately described in the data base.

As shown in Figure I-3, the resource coverage in this evaluation represents a substantial percentage of the total Texas oil resource -- 501 reservoirs accounting for 119.9 billion barrels of original oil in place (74% of total known original oil in place in Texas) were analyzed for EOR potential; 534 reservoirs accounting for 100.4 billion barrels of original oil in place (62% of the total known original oil in place in Texas) were analyzed for UMO extraction potential. *The results presented in this report reflect solely the reserve potential of these analyzed reservoirs.* Data were insufficient for the state's resource base not described in this analysis to provide a basis for extrapolation. Therefore, no attempt was made to extrapolate these results to the entire Texas resource.

1/ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

Figure I-3

The Texas Oil Resource: Data Coverage of EOR and UMO Extraction Analyses



* Bbbl = billion barrels

Source: BPO/TORIS, 1989
EIA, 1987
API/AGA, 1980
Fisher and Finley, 1986

C. BENEFITS DERIVED FROM ADVANCED OIL RECOVERY

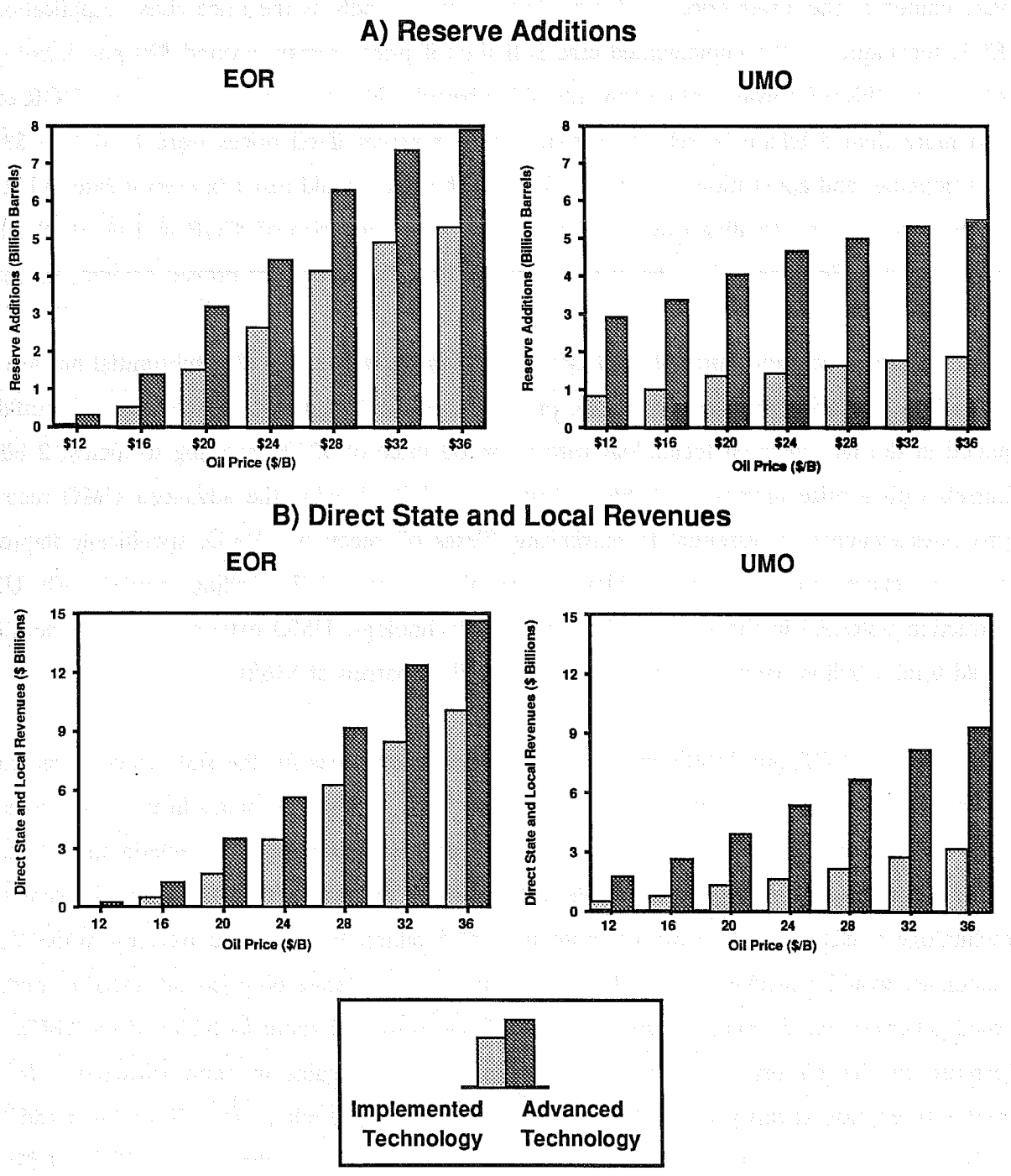
Potential reserve volumes and resulting direct state and local revenues that could be generated through EOR and UMO extraction are displayed in Figure I-4 under both the implemented and advanced technology cases for the range of oil prices evaluated. It is clear that EOR processes are very sensitive to changes in the price of oil. Potential reserve additions are very limited at the lower prices evaluated, but increase rapidly as the price rises. Application of EOR techniques in the implemented case is limited if prices remain around $20 per barrel (/B); recovery at this price would total about 1.5 billion barrels. However, implemented case EOR could add more than 5 billion barrels to current proved reserves if oil prices were to rise to $36/B. Development and application of advanced EOR technology would result in even greater additions to the reserve base, totaling over 3 billion barrels at an oil price of $20/B and nearly 8 billion barrels in the $36/B case. The latter would more than double current proved reserves in Texas.

Reserve additions attributed to UMO recovery techniques are also substantial but are less sensitive to oil price changes than EOR processes. Over 1 billion barrels of reserves could be added in the implemented technology case at an oil price of $20/B, growing to almost 2 billion barrels with a price increase to $36/B. Research to fully develop the advanced UMO recovery processes evaluated is essential to maximizing Texas oil recovery. R&D, specifically improved reservoir characterization that enables geologically targeted infill drilling, could triple UMO extraction potential in the state. With advanced technology, UMO extraction reserve additions could total 4 billion barrels at $20/B and over 5 billion barrels at $36/B.

Future EOR and UMO extraction will generate revenues for the state through increased production taxes and oil industry-related sales taxes. The revenue estimates in this study consider only direct revenues from recovery activities in the analyzed reservoirs and exclude any additional indirect benefits from multiplier or "ripple" effects within the state economy. Under implemented technology at $20/B, EOR could generate over $1.5 billion for the state treasury, while UMO techniques would contribute over $1 billion. Even at this moderate oil price, advanced technology could generate over $3 billion in state revenues from EOR and about $4 billion from UMO. An increase in the oil price to $36/B could yield substantial gains in state revenues. In the implemented case at this price, EOR could contribute over $10 billion and UMO could add over $3 billion in direct revenues to the state treasury. Application of technology advances at $36/B

Figure I-4

Potential Reserve Additions and Direct State and Local Revenues from EOR and UMO Extraction Could Be Restricted by Low Oil Prices and Limited Technologies



could increase state revenues to nearly $15 billion from EOR and to more than $9 billion from UMO extraction.

Besides adding to the tax base, EOR and UMO extraction projects would benefit the state by stimulating economic activity and creating new jobs. The benefits associated with the application of advanced recovery processes are shown in Table I-1 for EOR and Table I-2 for UMO extraction. Operating costs, royalties, taxes, and intangible investment could all dramatically increase the level of economic activity in the state. At the $20/B oil price under implemented technology, direct state economic activity could be increased by $13 billion from EOR and by another $13 billion from UMO extraction. Advanced technology at this price could double direct economic gain from EOR to $26 billion and triple the gain from UMO extraction to over $39 billion. At $36/B, under implemented technology, direct state economic activity could be increased by more than $70 billion from EOR and $31 billion from UMO extraction. With advanced technology at the $36/B price, direct economic activity from UMO extraction in Texas could increase by as much as 200% compared to the implemented case. Thousands of new jobs would be created or maintained by the increased activity from projects in both of these recovery classes.

Increasing the reserve base in Texas through EOR and UMO recovery would benefit the nation as well. Economically producible domestic reserves could replace future oil imports on a barrel for barrel basis. As oil imports are replaced with domestic oil, the trade deficit would be reduced. The nation would become less vulnerable to an oil supply disruption, thereby increasing energy security. The nation's gross domestic product would expand as new projects increase economic activity, and the money that was formerly paid to oil exporting nations would instead be circulated through the U.S. economy. Benefits would also accrue to the federal treasury as corporate and personal income taxes are generated on profits and wages resulting from EOR and UMO extraction projects in Texas.

Even under implemented technology at low oil prices, the application of EOR and UMO recovery techniques in Texas reservoirs could make sizeable contributions to the reserve base, production, state revenues, and economic activity. This evaluation clearly shows, however, that advances in recovery technology brought about through extensive R&D could reap the greatest benefits for the state and federal governments, increasing reserves and associated benefits by up to three times the levels attained with implemented technology potential.

Table I-1

Summary of Benefits from Technology Advances
Enhanced Oil Recovery (EOR) in Texas

Oil Price and Technology Level	Potential Reserves* (Bbbl)	State Economy: Incremental State and Local Local Revenues** (Bill.)	State Economy: Direct Economic Gain** ($ Bill.)	State Economy: Increased Employment (Thousand Labor-Years)	National Economy: Reduced Trade Deficit** ($ Bill.)	National Economy: Increased Federal Revenues** ($ Bill.)
At $12/B						
Implemented Technology	0.0	0.0	0.4	4	0.7	0.0
Advanced Technology	0.3	0.2	1.8	17	3.6	0.2
At $16/B						
Implemented Technology	0.5	0.5	3.8	33	7.6	0.5
Advanced Technology	1.4	1.2	9.4	83	20.1	1.7
At $20/B						
Implemented Technology	1.5	1.7	13.0	115	27.2	2.3
Advanced Technology	3.2	3.5	26.2	227	57.3	5.2
At $24/B						
Implemented Technology	2.6	3.5	26.6	237	56.5	4.9
Advanced Technology	4.4	5.7	41.9	341	95.4	9.7
At $28/B						
Implemented Technology	4.2	6.3	47.4	414	103.8	9.9
Advanced Technology	6.3	9.2	67.3	540	157.6	16.8
At $32/B						
Implemented Technology	4.9	8.5	62.7	540	142.0	15.0
Advanced Technology	7.4	12.4	88.5	714	212.7	24.5
At $36/B						
Implemented Technology	5.3	10.1	73.8	632	170.9	19.2
Advanced Technology	7.9	14.7	102.1	819	254.5	30.5

*Potential Reserves rounded to nearest 100 million barrels.

**State and federal economic benefits (except for employment) rounded to nearest 100 million dollars

Table I-2

Summary of Benefits from Technology Advances
Unrecovered Mobile Oil (UMO) Extraction in Texas

Oil Price and Technology Level	State Economy: Potential Reserves* (Bbbl)	State Economy: Incremental State and Local Local Revenues** ($Bill.)	State Economy: Direct Economic Gain** ($ Bill.)	State Economy: Increased Employment (Thousand Labor-Years)	National Economy: Reduced Trade Deficit** ($ Bill.)	National Economy: Increased Federal Revenues** ($ Bill.)
At $12/B						
Implemented Technology	0.9	0.5	5.4	23	9.2	1.4
Advanced Technology	2.9	1.8	18.0	78	31.1	4.8
At $16/B						
Implemented Technology	1.0	0.8	7.8	32	14.5	2.4
Advanced Technology	3.4	2.7	26.6	110	47.8	7.7
At $20/B						
Implemented Technology	1.4	1.4	13.4	55	24.5	4.0
Advanced Technology	4.0	4.0	39.7	162	71.9	11.7
At $24/B						
Implemented Technology	1.5	1.7	16.0	63	30.9	5.3
Advanced Technology	4.6	5.4	54.6	219	98.8	16.0
At $28/B						
Implemented Technology	1.6	2.2	21.0	81	40.8	7.1
Advanced Technology	5.0	6.7	67.4	263	123.9	20.4
At $32/B						
Implemented Technology	1.8	2.8	26.4	100	51.7	9.0
Advanced Technology	5.3	8.2	81.1	306	152.7	25.7
At $36/B						
Implemented Technology	1.9	3.2	30.6	114	60.4	10.6
Advanced Technology	5.5	9.4	91.8	336	175.0	29.8

*Potential reserves rounded to nearest 100 million barrels.

**State and federal economic benefits (except for employment) rounded for nearest 100 million dollars.

D. INCREASED RECOVERY WITH COMBINED APPLICATION OF EOR AND UMO EXTRACTION TECHNIQUES

EOR and UMO extraction processes target different segments of the remaining oil resource; EOR is directed towards producing oil that is immobile to water, while UMO extraction is directed towards oil that is mobile to water and is left in the reservoir after conventional recovery. For the most part, the reserves and associated benefits of EOR and UMO extraction are exclusive of one another, and therefore, additive. (For reasons of methodological consistency with earlier studies, a small volume of oil associated with chemical flooding in a few reservoirs is counted in the recovery estimates for both techniques.) Further, because EOR is generally limited to the portion of the reservoir where waterflooding has contacted and recovered the mobile oil, its combined application with infill drilling and other advanced waterflooding techniques creates a synergy.

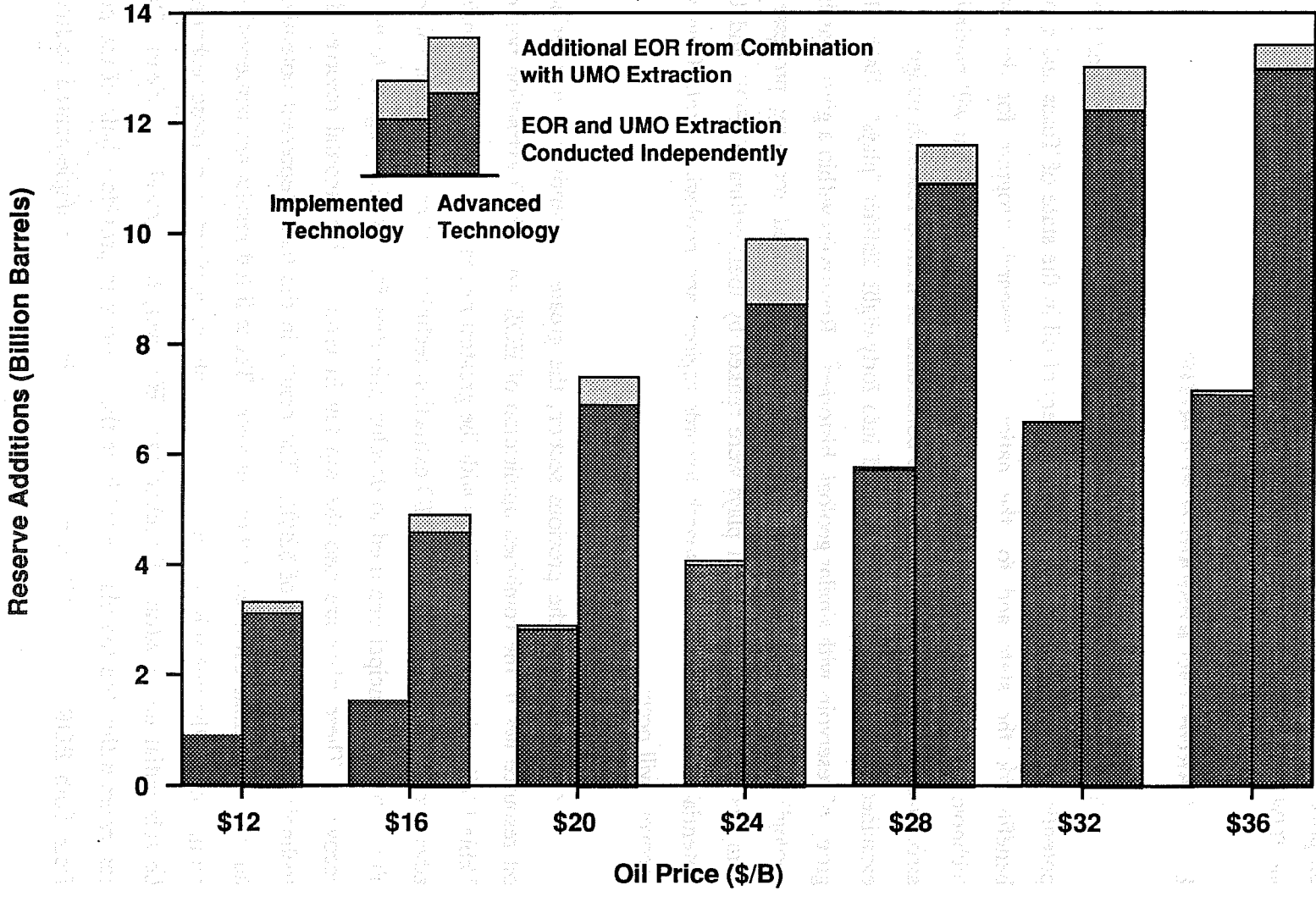
Figure I-5 shows the total reserve addition potential for both EOR and UMO applications in analyzed reservoirs state-wide, first as independently evaluated and then in combination with each other. The analysis shows that as much as 7 billion barrels could be recovered from the independent application of EOR and UMO extraction at an oil price of $36/B using implemented technology. With advances in technology, this volume of oil could be economically produced at an oil price of around $20/B with independent applications of the processes (dark shading). The potential synergy that would result from the combined application of UMO and EOR processes is shown in lighter shading. The synergy would be extremely small under implemented technology, resulting in less than 100 million additional barrels across the oil price range analyzed. However, with the advanced technology attainable through focused R&D, the synergy would be significantly larger. At intermediate oil prices in the $20 to $30/B range, the synergy would exceed 500 million barrels. At $24/B the total synergy under advanced technology would be nearly 1.2 billion barrels. The larger recovery potential at low oil prices and the substantial synergy created by the application of combined processes indicate the clear need for a coordinated, focused R&D program

The analysis of combined applications of EOR and UMO extraction indicates the significant potential in Texas for future recovery from the known, unrecovered oil resource in the state. However, recovery would be is maximized and the largest benefits would accrue to the state upon the successful completion of a focused R&D program designed to achieve critical improvements in process application, performance, and economics. With the synergistic application of the

Figure I-5

Incremental Reserve Additions Due to Synergies Between EOR and UMO Extraction

Implemented versus Advanced Technology



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analyzed recovery processes under the defined advanced technology scenario, Texas oil production, reserves, and associated economic benefits could be sustained well into the next century, even at oil prices around $20/B. Research is the critical key needed to unlock much of this future EOR and UMO recovery potential.

E. TARGETING RESEARCH PRIORITIES

The foregoing analysis demonstrates that the development of advanced technology has the potential to substantially increase the recovery of oil in the state of Texas and generate significant benefits for the state and for the nation. A research program for developing these new technologies will be most effective if priorities can be established that will maximize recovery and associated economic benefits within the constraints of limited research budgets. The reservoirs examined in this analysis were grouped into forty-eight distinct "plays". Each play consists of a group of reservoirs with similar geologic histories[2/]. Reservoirs within a given play have comparable geological characteristics and should respond to advanced recovery processes in a broadly comparable manner. Texas oil plays were ranked by their estimated EOR and UMO extraction potential in order to focus research towards regions and geological strata from which maximum recovery will occur.

As discussed in the previous section, the greatest potential for recovering the remaining oil resource lies in the combined application of EOR and UMO extraction potential techniques. Table I-3 lists the ten plays in Texas with the greatest incremental recovery potential resulting from advanced technology EOR and UMO extraction techniques at an oil price of $32/B. This criterion should be the principal one used to develop priorities for a R&D program to maximize Texas oil recovery. These plays are also the top ten in terms of incremental reserves due to advanced technology at an oil price of $20/B. The results in the table represent potential EOR reserves added to potential UMO extraction reserves. These listed results are conservative estimates that do not reflect the potential synergy with the combined application of these techniques, which could be substantial under advanced technology. However, these results do clearly illustrate that the reservoirs within the ten plays listed have the capacity to provide a bulk of the potential reserves from both EOR and UMO extraction state-wide, whether implemented technology, advanced

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2/ Galloway, et al., *Atlas of Major Texas Oil Reservoirs*, The Bureau of Economic Geology, University of Texas at Austin, 1983.

Table I-3

EOR and UMO Reserves Combined for Top Texas Oil Plays
Advanced Technology at an Oil Price of $32/B

Rank*	Oil Play	Implemented Technology Potential Reserves (MMB)	Advanced Technology Total Reserves (MMB)	Advanced Technology Incremental Reserves (MMB)
1.	San Andres/Grayburg Carbonate (SCBP**)	712	1,449	**737**
2.	Northern Shelf Permian Carbonate	1,296	1,909	**613**
3.	Frio Deep-Seated Salt Domes	297	839	**542**
4.	Strawn Sandstone	166	681	**515**
5.	Frio Barrier/Strandplain Sandstone	788	1,260	**472**
6.	Yates Area	117	448	**331**
7.	Yegua Deep-Seated Salt Domes	345	595	**250**
8.	Frio Fluvial/Deltaic Sandstone (Vicksburg)	175	398	**223**
9.	Woodbine Fluvial/Deltaic/Strandplain Sandstone	78	241	**163**
10.	San Andres/Grayburg Carbonate (NCBP***)	258	403	**145**
	TOTAL	4,232	8,223	3,991
	TOTAL, ALL PLAYS	**6,589**	**12,269**	**5,680**

* Rank is according to advanced technology increment
** South Central Basin Platform
*** North Central Basin Platform

technology, or the incremental potential between the cases is considered. Recognizing that the reservoirs in a limited number of plays could yield a bulk of the reserves estimated from all forty-eight plays is critical to the idea of focusing research.

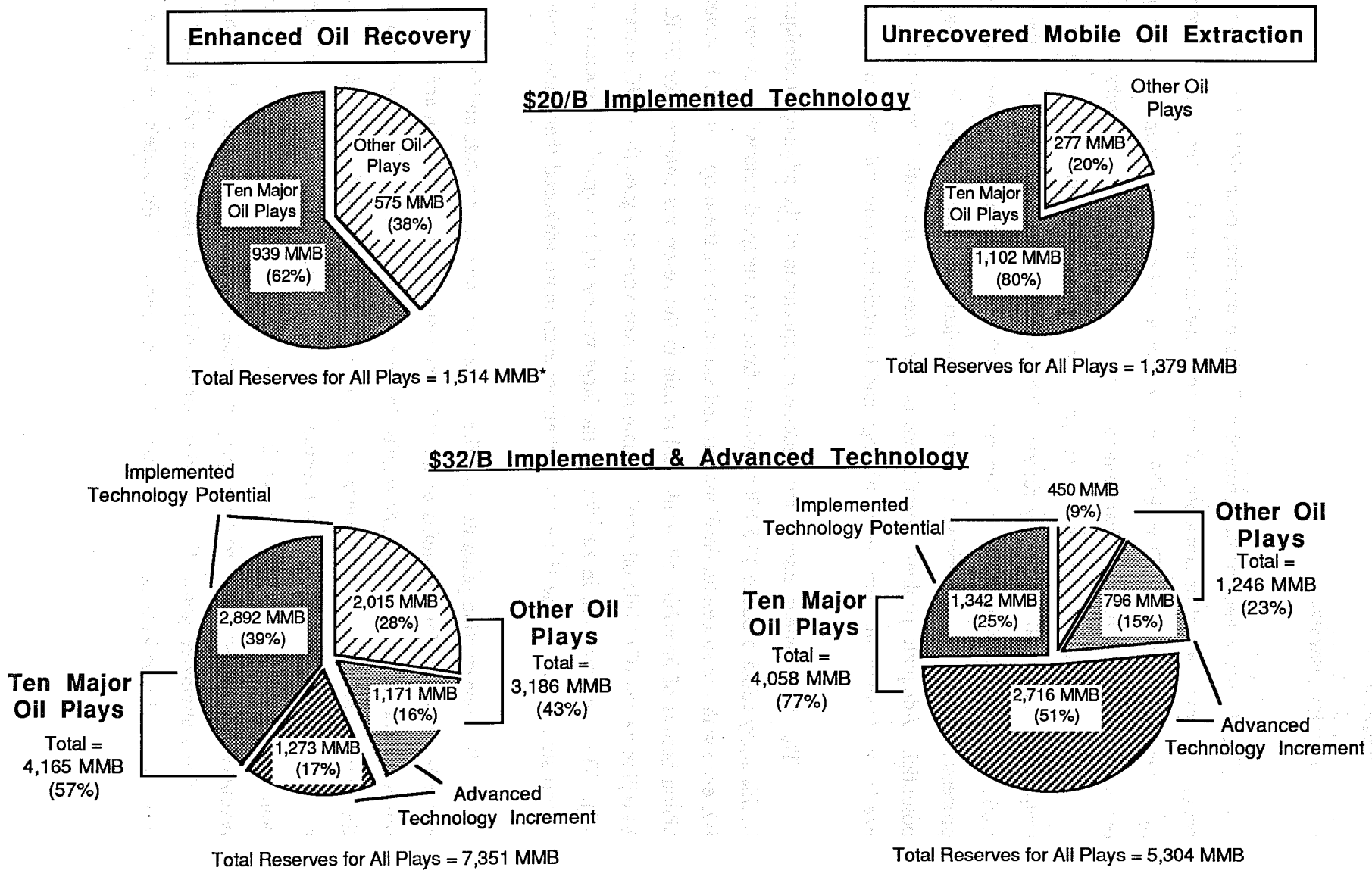
The ten geologic plays with the greatest incremental reserve potential due to technology advances at an oil price of $32/B would also account for major reserve potential under other oil price/technology combinations. These same ten plays are also estimated to have a bulk of the recovery potential at an oil price of $20/B under the implemented technology case and at an oil price of $32/B under the total advanced technology case. With a focused program of technology transfer and R&D in these ten plays, it is clear that reserves will be maximized in Texas under a number of oil price and technology combinations.

Figure I-6 shows the reserve potential for the ten major plays listed in Table I-3 under both implemented technology at the $20/B oil price and for both technology cases at $32/B. While the plays were selected based on the incremental recovery possible with advanced technology for EOR and UMO extraction combined, these same ten plays, 21% of the total plays identified in the state, contain well over half of the potential recovery for each process evaluated independently. For EOR, reservoirs in these ten plays constitute 62% of the implemented technology EOR state-wide at $20/B; UMO potential in these plays is over 80% of the total for this oil price and technology case. At the higher oil price, these ten plays contain 57% of the total advanced technology EOR and 77% of the total advanced technology UMO extraction reserve potential. The incremental recovery due to advanced technology for each process at this oil price also comes predominately from these plays. Over 61% of the advanced technology increment due to EOR and 77% of the advanced increment due to UMO extraction occur in reservoirs within these ten major oil plays.

Use of a classification system for grouping Texas reservoirs into plays and ranking these plays by total and incremental recovery potential makes research and development priorities much clearer. Given the substantial revenues that would accrue from future oil recovery in Texas, a research program focusing on problems in recovery associated with high-priority reservoirs could be justified and undertaken in the near-term. With a research program focused on problems specific to geologic plays and reservoirs with the highest recovery potential, advances in technology could produce maximum benefits for the state in terms of tax revenues, economic activity, and jobs.

Figure I-6

Ten Major Oil Plays Would Account For the Majority Of Reserves Under Different Price and Technology Criteria



* MMB = million barrels

F. CONCLUSIONS

The known remaining oil resource in Texas is massive; over 100 billion barrels will remain trapped in reservoirs after conventional recovery operations end. Advanced recovery processes made available through R&D in EOR and improved primary and secondary techniques (UMO extraction) could produce significant quantities of the resource. Advanced technology could double the amount of reserves estimated as producible through implementing currently available technology; advanced technology recovery from just the reservoirs analyzed in this study could triple current proved reserves in the state. Selected, combined application of the recovery processes analyzed could improve recovery and project economics, further increasing the reserve potential. Adequate geologic descriptions of the reservoir are critical to focusing the research needed to develop and improve technology and to maximize state-wide recovery.

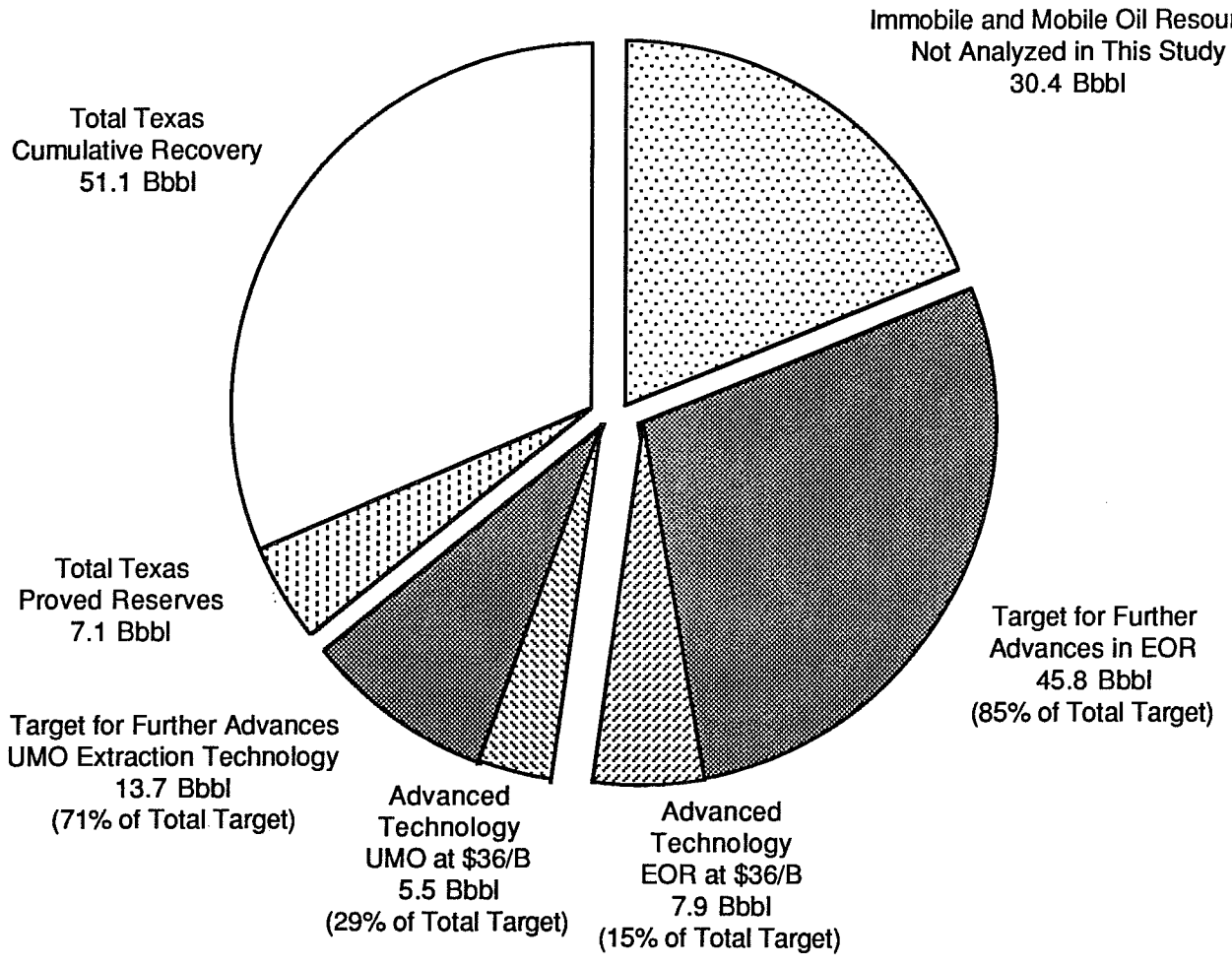
The development, testing, and wide-scale application of the advanced techniques evaluated in this study could produce 13.5 billion barrels from the analyzed reservoirs. As shown in Figure I-7, even with the successful development and application of these operations, however, almost 46 billion barrels of immobile oil would still remain in the reservoirs analyzed for EOR, and almost 14 billion barrels of mobile oil would remain in the reservoirs analyzed for UMO extraction (Figure I-7). This remaining oil, in addition to the large volume of the state's oil resource not assessed in this study, could be the target for techniques even more advanced than those evaluated.

Texas production generates significant direct revenues to the state and federal governments and substantial additional benefits to the state and national economies. In addition to stimulating reserves, production, and economic activity, the application of advanced technology would enhance the nation's energy security. Given the potentially massive benefits from future improved oil recovery, a coordinated R&D effort focused on critical uncertainties in key geologic settings would benefit operators, the state, and the entire nation. The investment of a small fraction of the direct revenues from advanced oil recovery projects could fund such a program. With sound planning and clear, attainable goals, state policies can be effectively integrated with federal and private programs to dramatically increase production, to the benefit of the state's treasury, economy, and citizens.

Figure I-7

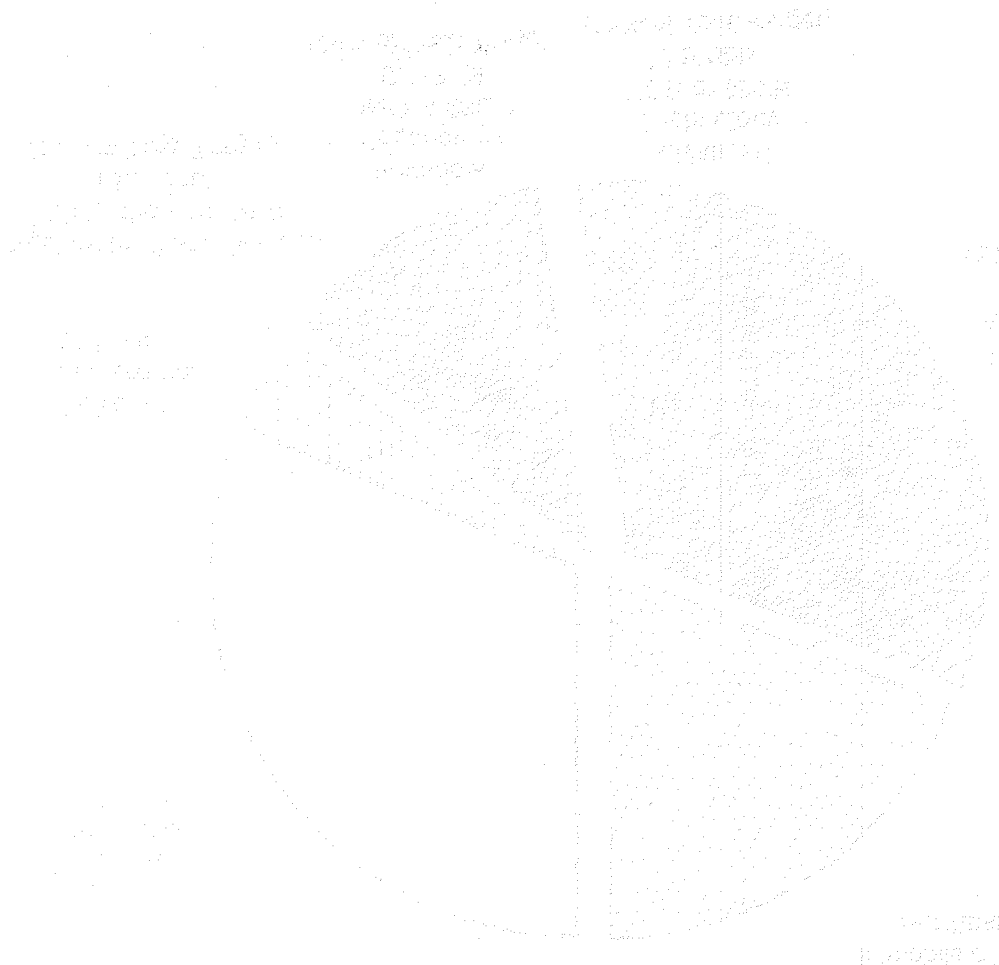
Texas Remaining Oil Resource After Advanced Technology Recovery

Nearly 60 Billion Barrels Will Remain in Analyzed Reservoirs



Total Original Oil-in-Place: 161.6 Bbbl*

* Bbbl = Billion Barrels



II. BACKGROUND AND OBJECTIVES

A. TRENDS IN TEXAS OIL PRODUCTION AND RESERVES

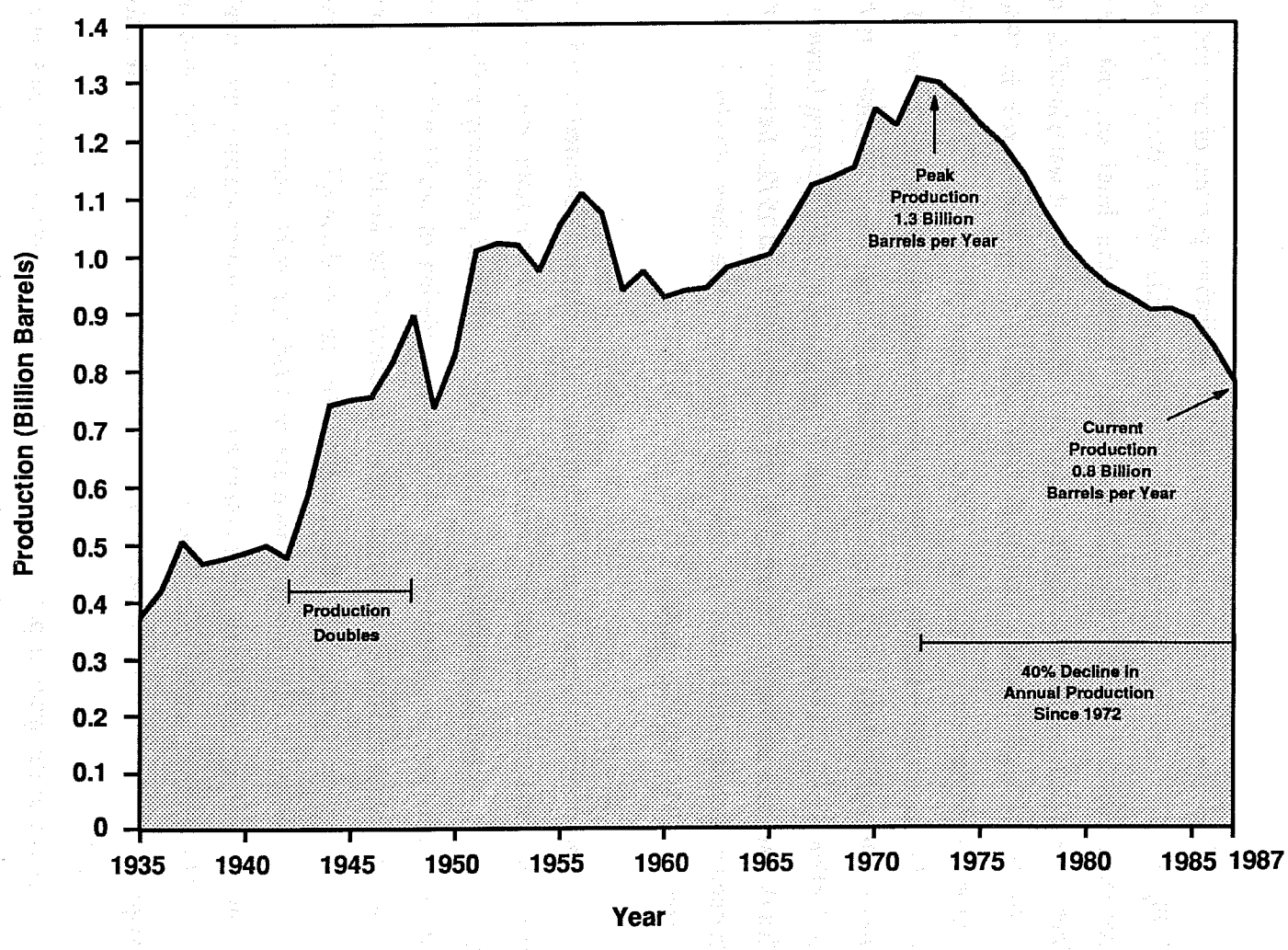
Oil production in Texas has been marked by distinct periods of rise and decline as shown in Figure II-1. Production increased dramatically during World War II; by 1945, the annual production of 751 million barrels was nearly double the level of only ten years before. Technological advances, including development and application of waterflooding, increased annual production to over 1 billion barrels in 1951, and to 1.1 billion barrels in 1956. As the U.S. economy struggled during the late 1950s, the state's oil output fell about 15%. After 1960, production increased relatively steadily for twelve years, peaking in 1972 when 1.3 billion barrels were produced, or 38% of all domestic production for that year. Following 1972, the state's oil production began a slow but steady decline, dropping about 2.5% per year between 1972 and 1977. This decline rate accelerated to over 5% per year for 1978 and 1979. Between 1979 and 1985, the production decline moderated to about 2% per year. The sharp decline in oil prices in 1986, however, accelerated the decline.

The decline in Texas oil production since 1972 can be attributed to price changes and the decreasing yield from conventional recovery as the fields in the state have matured. This decline in production cannot be attributed to a drop in the number of producing wells, as this number has increased over the last fifteen years. Federal deregulation of crude prices in the mid- to late-1970s exposed oil production in Texas to the influences of the world energy market. The doubling of world oil prices during 1979-1981 moderated the rate of decline for oil production in the state. Production experienced a marginal increase in 1984, the only exception to the fifteen years of decline. However, with the oil price collapse of 1986, annual production has plummeted by nearly 110 million barrels, a 6% annual decline between 1985 and 1987. The abandonment of many marginal or "stripper" wells accompanying the price collapse contributed significantly to this decline.

Despite the drop in production over the last several years, Texas still accounted for 26% of total U.S. production and 33% of the lower-48 state total in 1987. It is clear that Texas has played and will continue to play a crucial role in the supply of domestic oil and that production

Figure II-1

Annual Texas Crude Oil Production 1935 to 1987



Source: OGJ Database, 1989

trends for the state will have important implications for the entire nation. The remaining oil resource in Texas is immense and efforts at producing this resource will be regarded closely from all levels of the public and private oil industry sector.

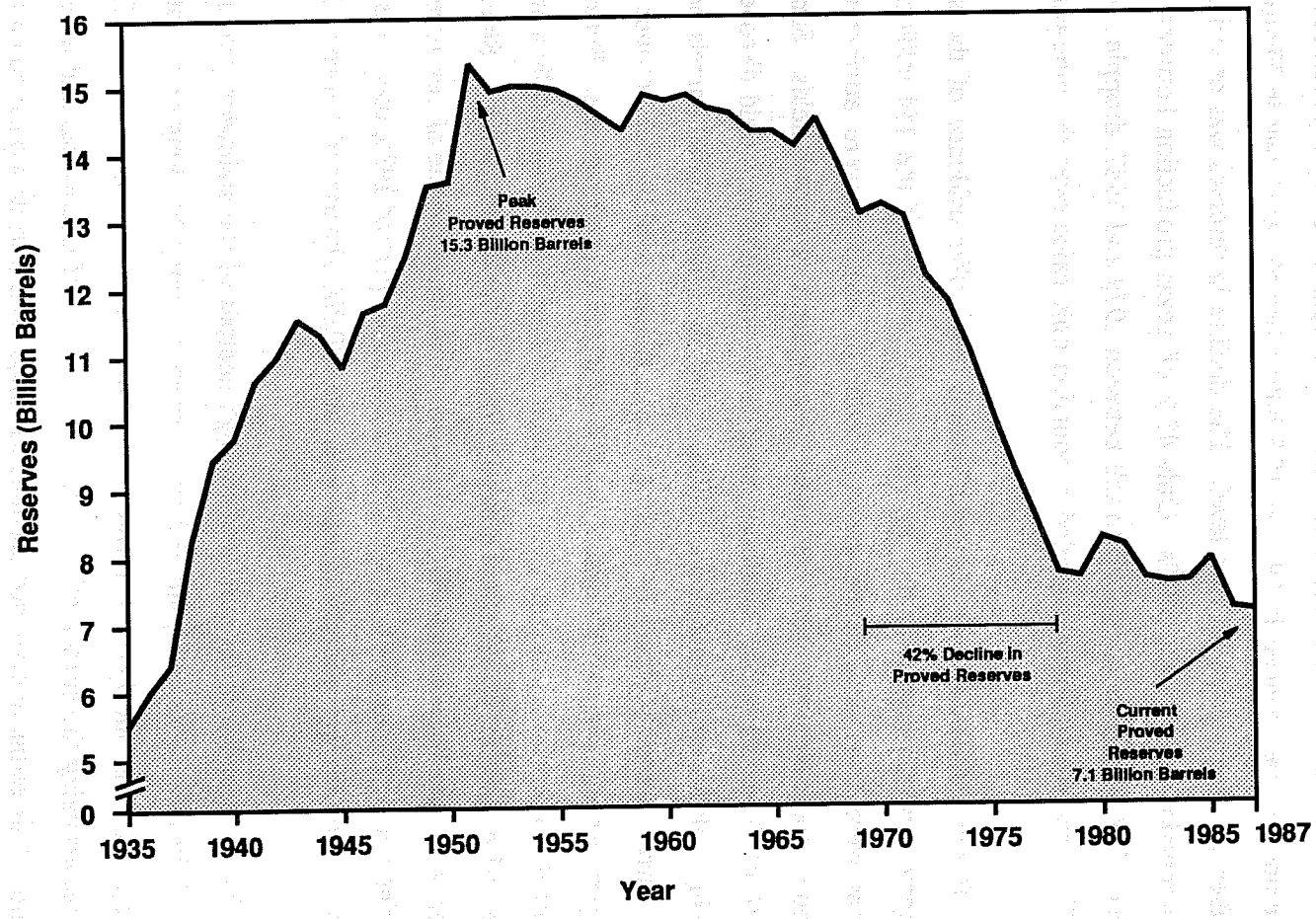
The fall in Texas oil production has been accompanied by a general reduction in reserves. State crude reserves peaked in 1951 at 15.3 billion barrels, as shown in Figure II-2, and by 1987, had fallen to less than half of that level. The decline in reserves was especially steep during the high production years of the 1970s. Only 45% of Texas production between 1971 and 1978 was replaced. Total reserves continued to fall between 1979 and 1987, dropping to 7.1 billion barrels in 1987, as reserve additions exceeded production only twice over the nine-year period.

Reserve additions over the past several years offer evidence of the success of intensive development within known fields. In 1986, only 2 million of the 154 million barrels of reserve additions were from new fields; the remainder of additions were attributed to net revisions, extensions, and new pools from continued development of known fields. Similarly, in 1987, less than 1% of Texas net reserve additions could be attributed to new field discoveries. Reserves per producing well have plummeted since 1973, falling from over 75,000 barrels per well to less than 36,000 barrels per well (Figure II-3). In addition, stripper wells, which account for 18% of current Texas production, now provide access to 27% of Texas proved reserves. Future economic events that threaten the viability of continued production from these economically marginal wells, such as another price collapse, would affect a large portion of the Texas resource. Since 1970, over 73,000 stripper wells have been abandoned, limiting economic access to the oil resource remaining in older producing zones (Figure II-4). From 1982 to the latter part of 1986, there was a sharp rise in the number of stripper well abandonments, with over 20,000 abandoned between 1985 and 1987.

Future trends can be estimated through analysis of the statewide production decline. The projected decline curve in Figure II-5 was developed using the long-term statewide decline rate and projecting this rate into the future. The curve accounts for production from future reserve additions, assuming the continuation of the historic rate of discoveries and development activity in the state. This estimate does not account for major shifts in economic conditions or advances in recovery technology. Based on these assumptions, annual Texas production in 1995 would be just under 600 million barrels; it would fall to about 545 million barrels in 2000, and to 510 million

Figure II-2

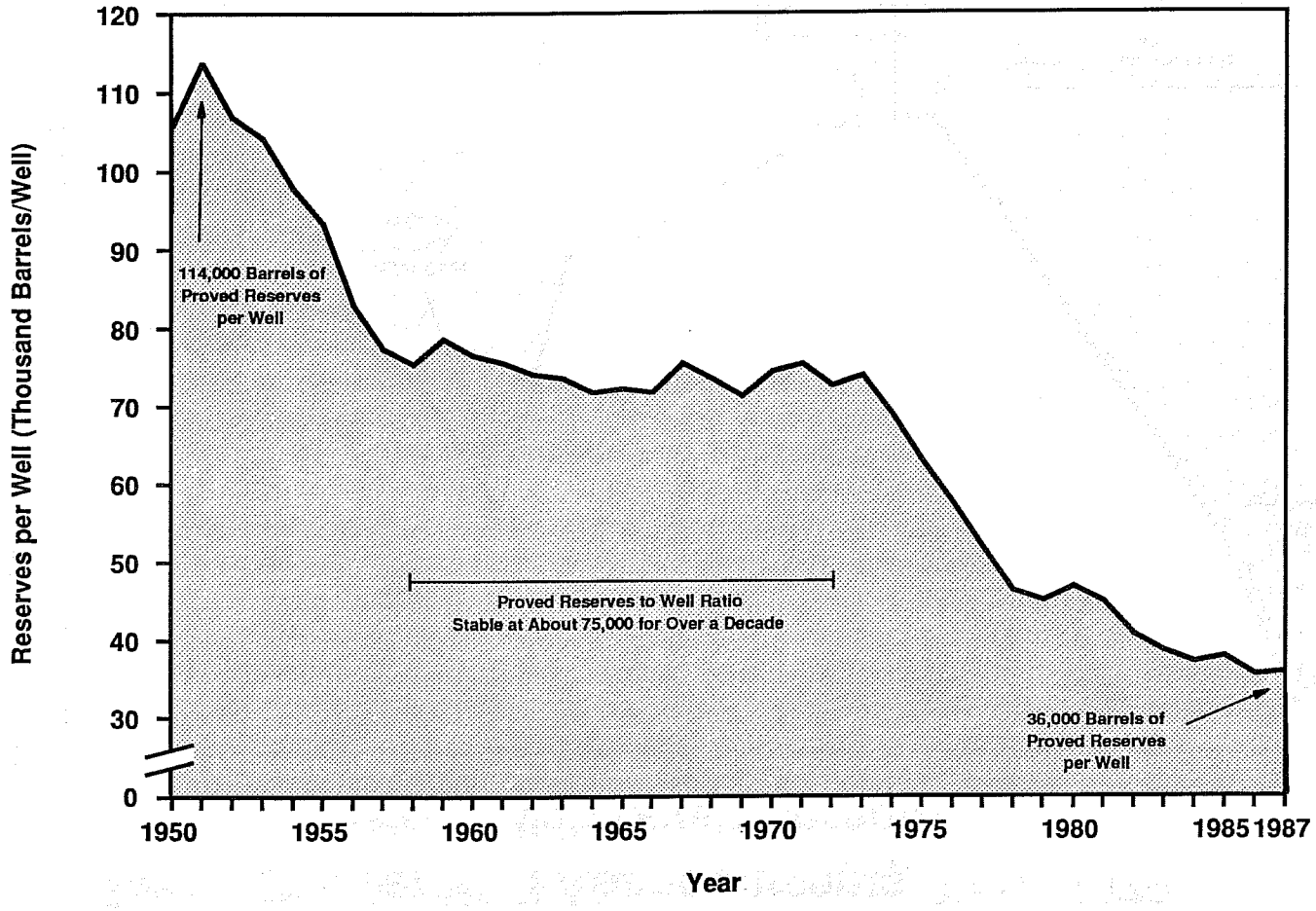
Texas Crude Oil Reserves 1935 to 1987



Source: OGJ Database, 1989

Figure II-3

Reserves per Producing Well
1950 to 1987

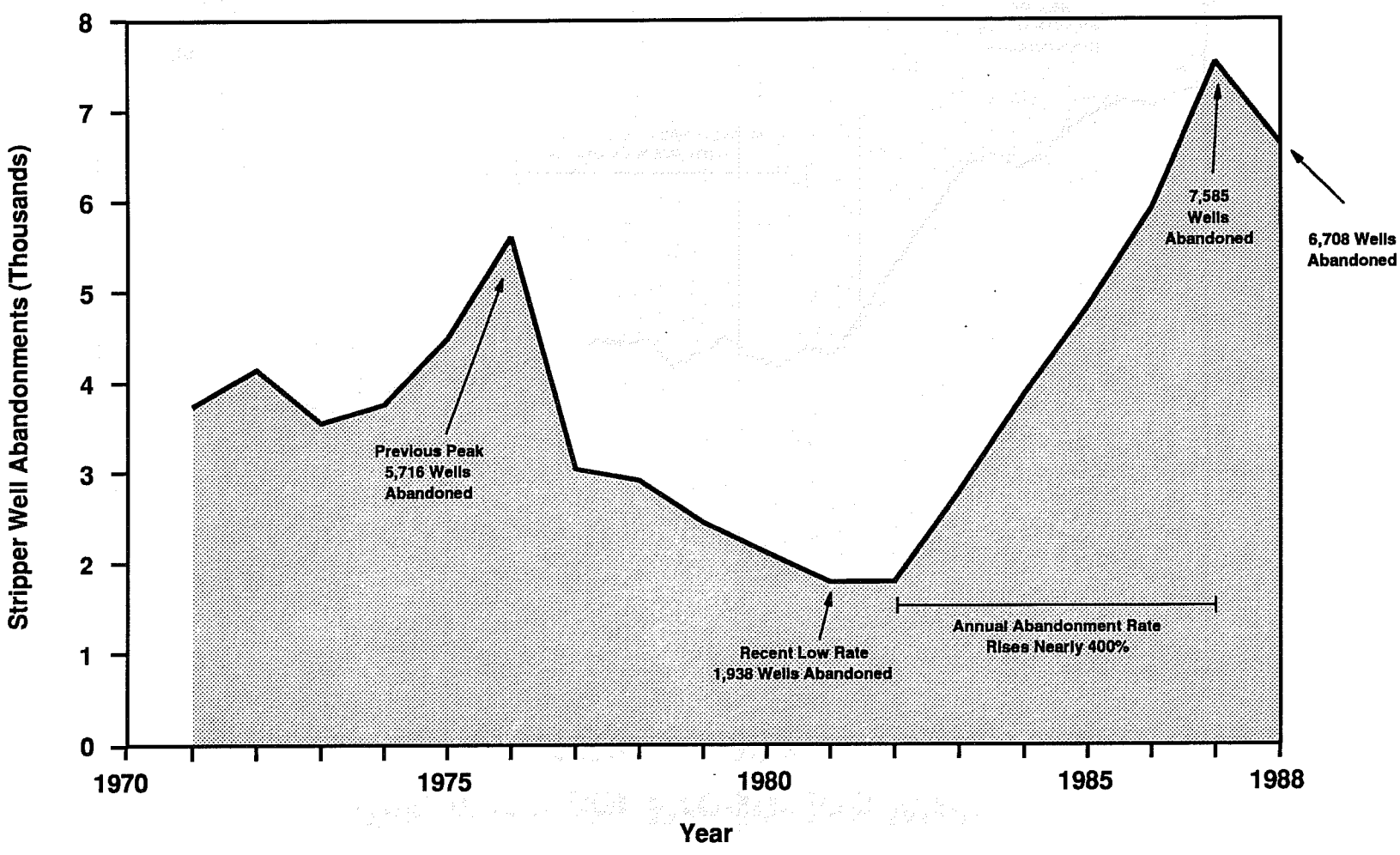


Source: OGJ Database, 1989
API, 1988

Figure II-4

Texas Stripper Well Abandonments Since 1970

Historic High Levels Recently



Source: API, 1989
As of Jan. 1

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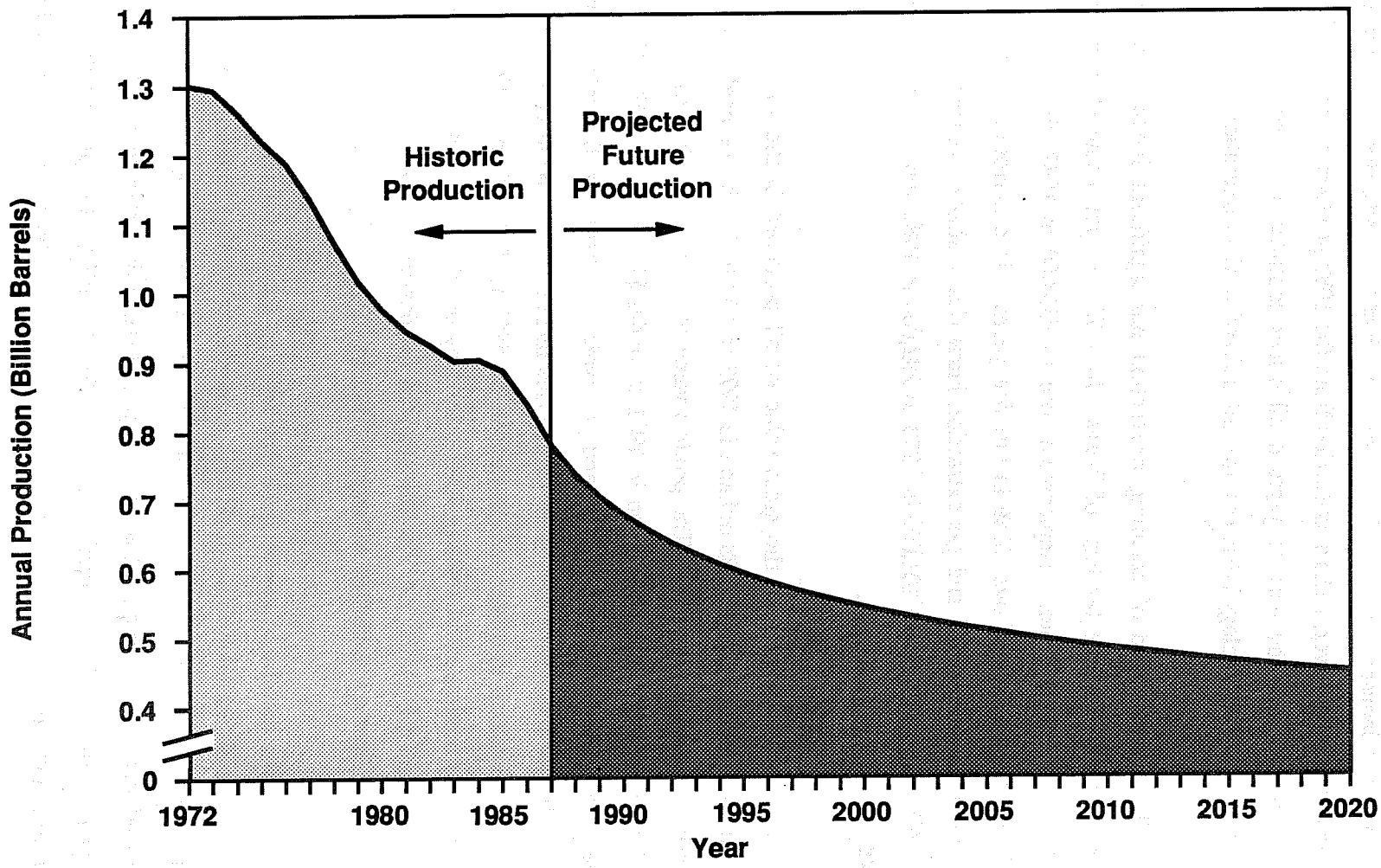
Figure II-5

Texas Historical and Projected Production Decline, 1972 to 2020

A 30% Drop from Current Levels Is Possible by 2000



Source: OGJ Database, 1989

barrels in 2005. Barring major new discoveries or significant technological changes, future production in Texas will approximate the curve shown. To the extent that changes in oil prices, regulations, and industry practices alter historic production trends, this projection will be in error. By all indications, however, a sharp reduction from the 1987 production level of 779 million barrels can be expected over the next 15 years if oil prices continue at current or lower levels and if recent and future technology advances are not utilized in field operations.

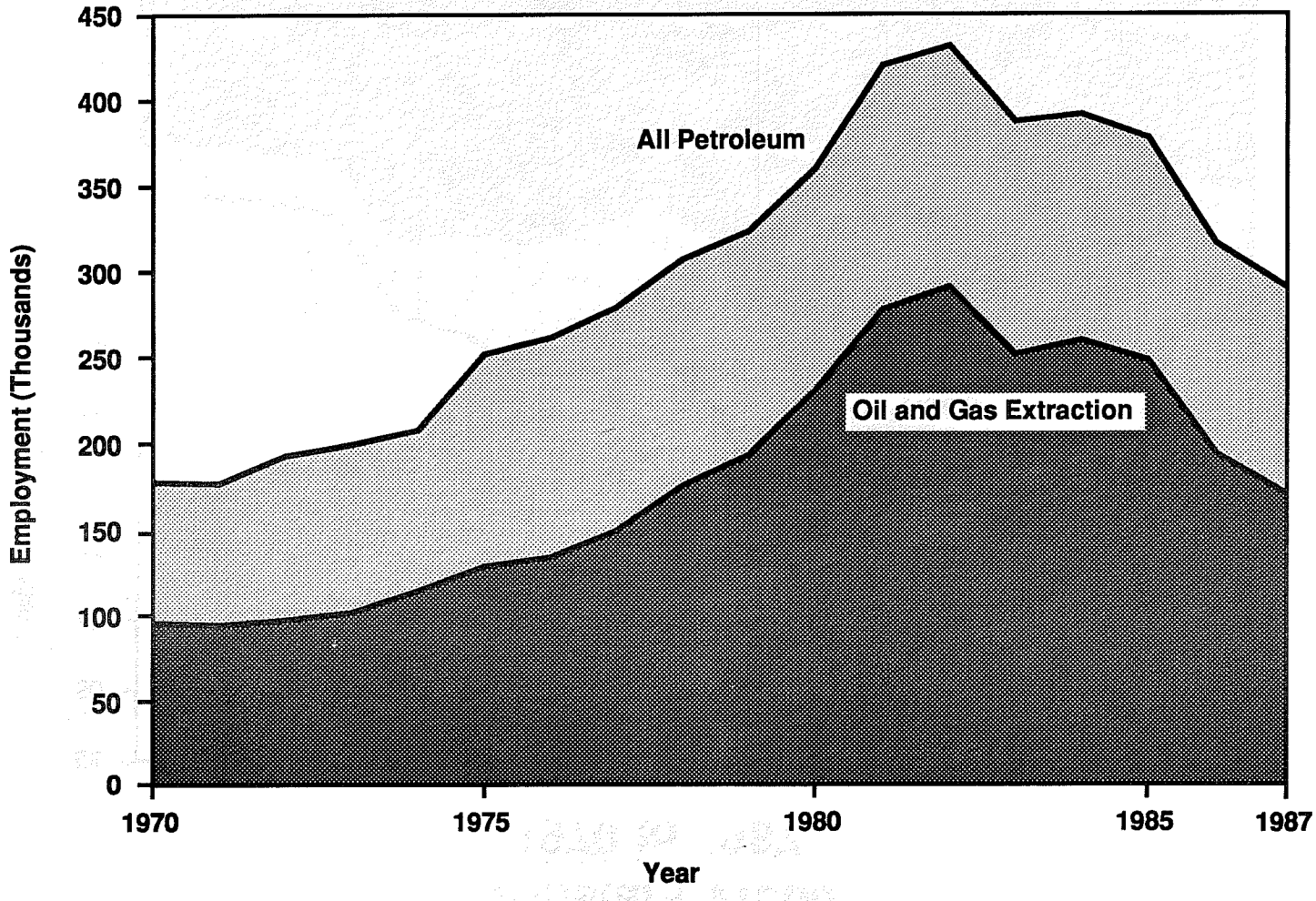
Clearly, this trend of declining production has significant implications for employment, economic activity, and the tax base of Texas. In 1973, the petroleum industry employed nearly 200,000 people in the state. Employment rose to 433,000 in 1982, then fell sharply to about 290,000 in 1987, a drop of over 33% in just five years. In a narrower measure of employment which considers just the oil and gas extraction industries, a similar contraction appears in recent years. After increasing from 101,000 in 1973 to 292,000 in 1982, employment fell by over 40% to 171,000 in 1987 (Figure II-6).

Over the same period, the gross value of oil produced in the state increased from $12 billion (all values in constant 1988 dollars) in 1973 to $37 billion in the peak year of 1981, before decreasing to $14 billion in 1987. The product value of oil and gas, taken together, exhibits similar behavior, falling from over $50 billion in 1981 to under $24 billion in 1987 (Figure II-7), a 55% plunge. Total production taxes on oil and gas, which are based on the value of production, are shown in Figure II-8. Revenues from these taxes increased from $790 million in 1973 to a peak of nearly $2.6 billion in 1982, only to decline by 58% to $1.1 billion in fiscal year 1988. This significant loss in state revenues has been caused by the dual effect of lower product prices and declining oil and gas production. The state expects the downward trend to continue with production tax revenue projected to decline to under $1 billion in 1990 (Figure II-8).

The loss of oil and gas revenue has made a significant impact on total state revenues. Figure II-9 shows the importance of oil and gas production taxes to the total state budget. In fiscal year 1981, when oil prices were at their peak, oil and gas production taxes contributed more than 28% of all state tax revenues. This percentage has fallen dramatically, to 8.5% of all revenues in fiscal year 1988, and is projected to fall to 7.5% by 1990. Oil production (severance) taxes represent slightly more than half of the total. The state government ran deficits in fiscal years 1986

Figure II-6

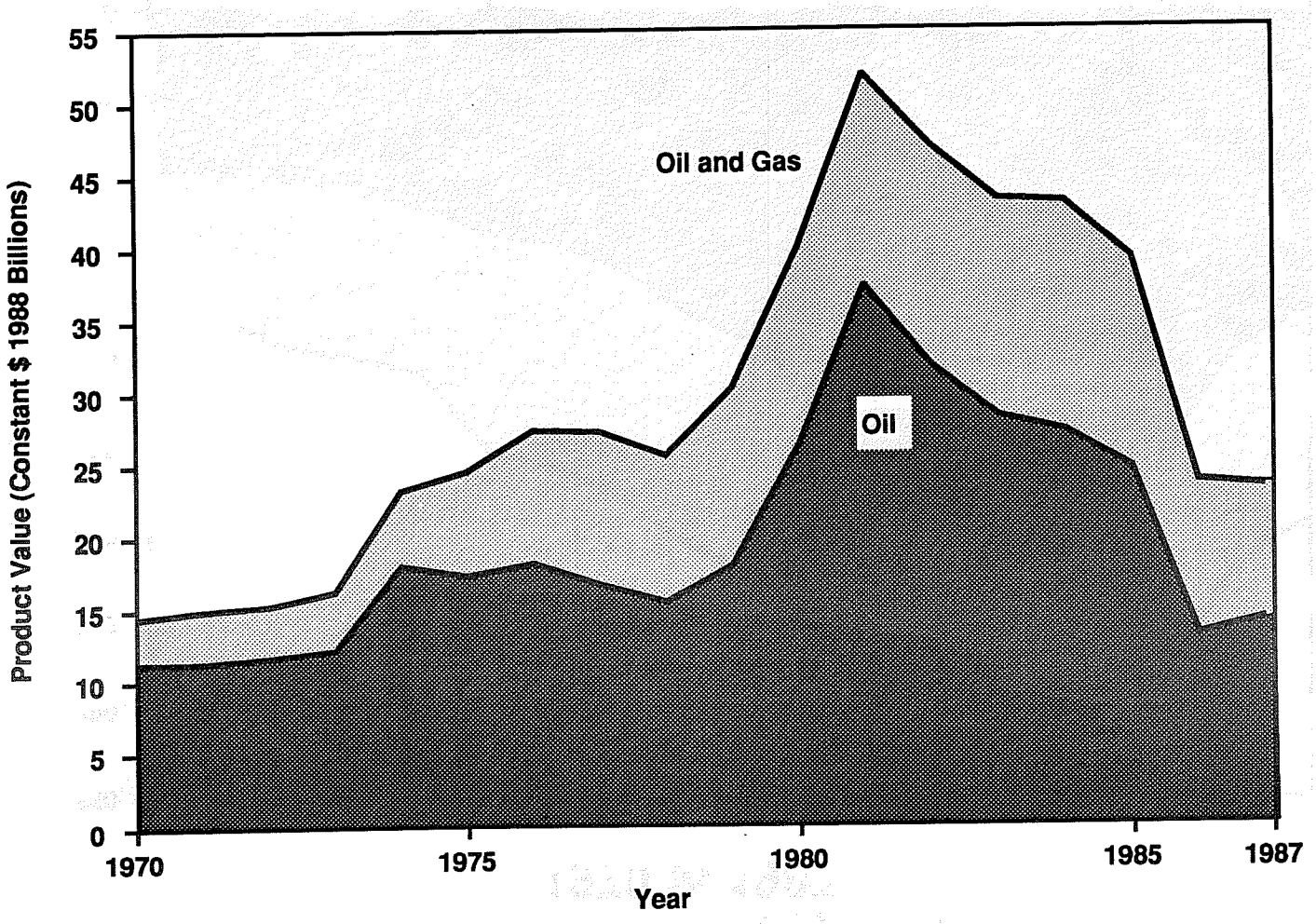
Texas Petroleum Industry Employment 1970 to 1987



Source: OGJ Database, 1989

Figure II-7

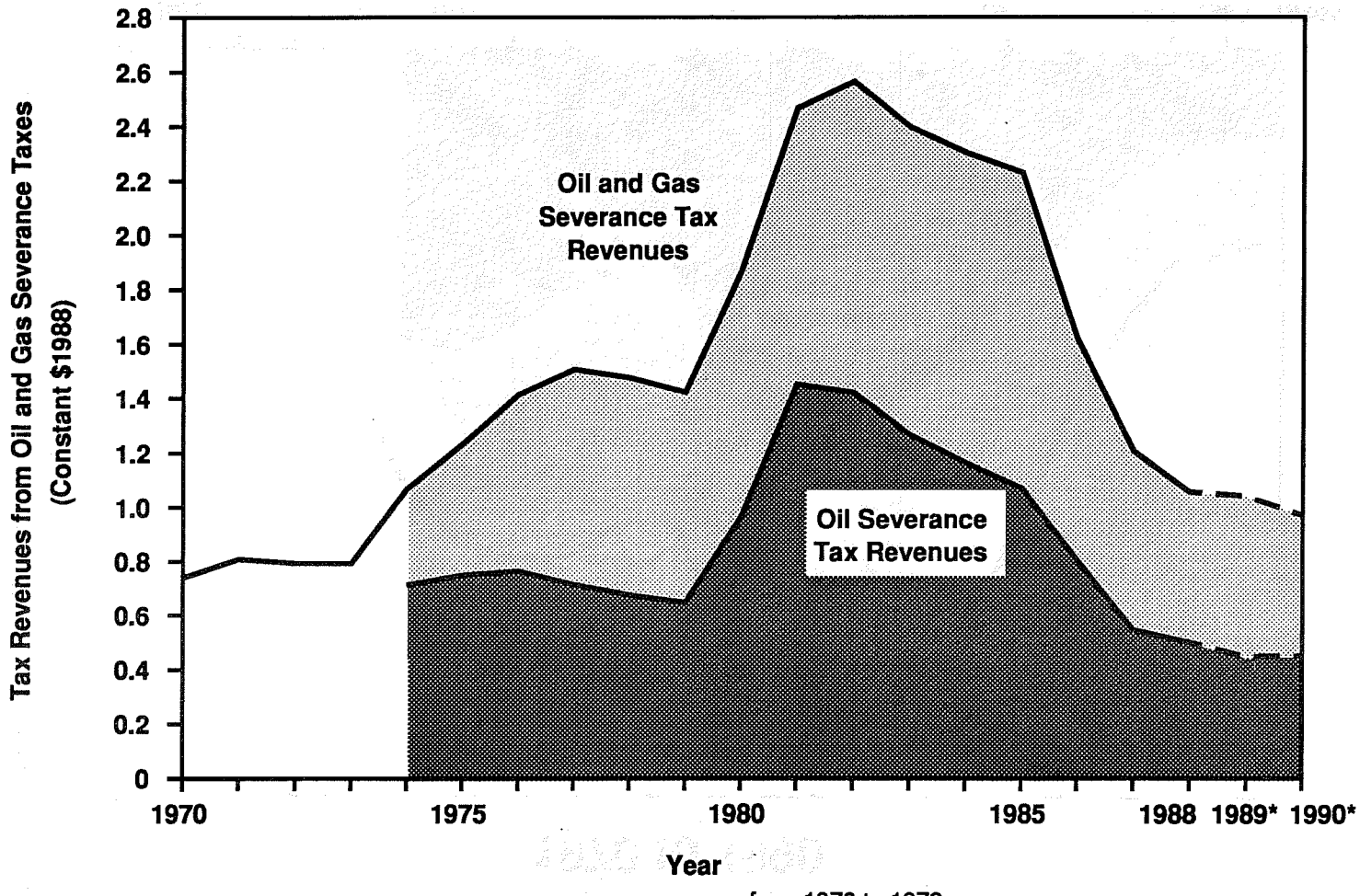
Annual Value of Texas Oil and Gas Production
Constant $1988
1970 to 1987



Source: OGJ Database, 1989

Figure II-8

Texas Severance Tax Revenues
Constant $1988
1970 to 1990



from 1970 to 1973

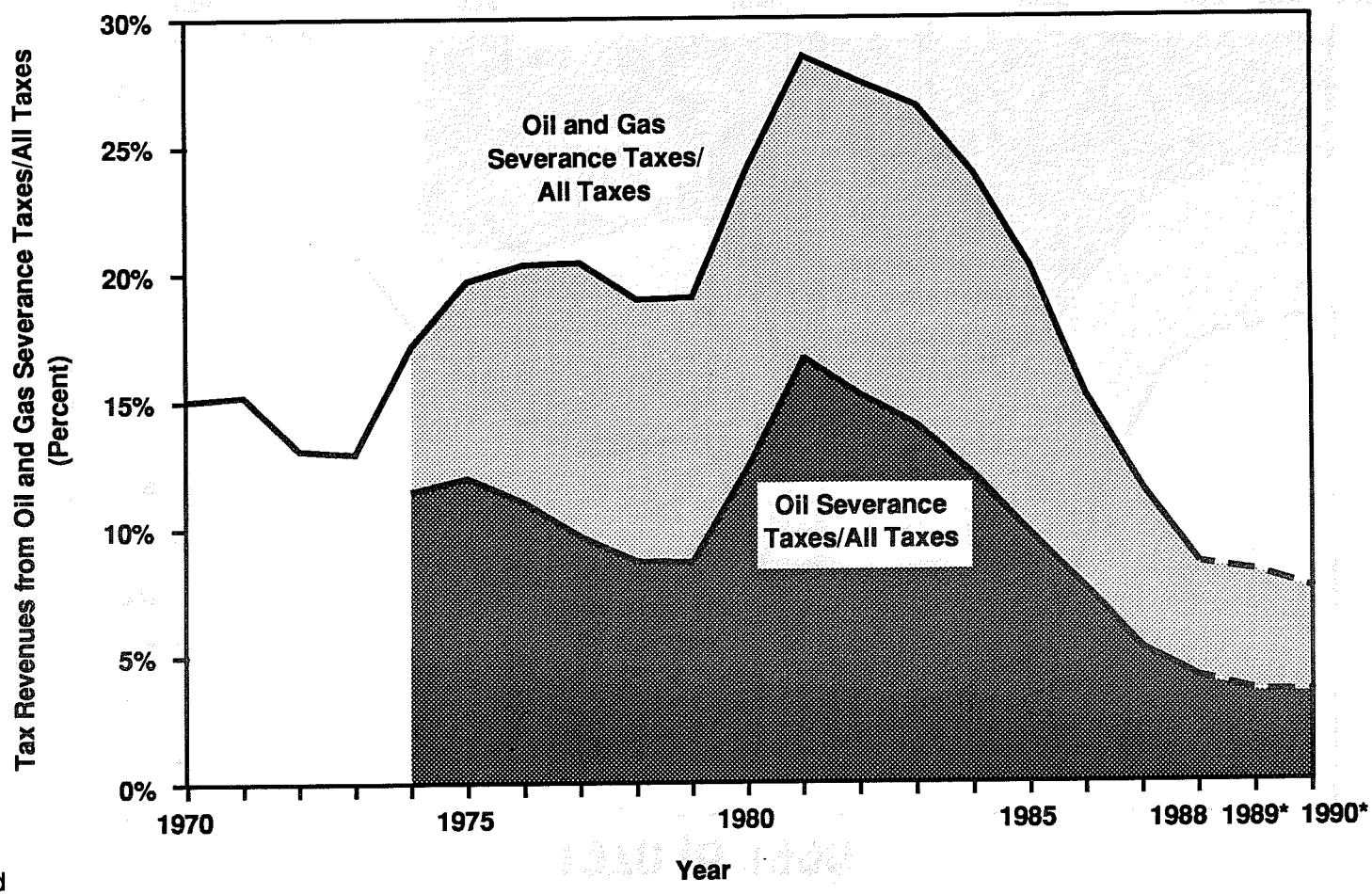
*Projected

Breakdown of severance tax revenues into oil and gas components not available

Source: State Comptroller Office

Figure II-9

Oil and Gas Severance Tax Revenues as a Percent of Total State Taxes 1970 to 1990



*Projected

Breakdown of severance tax revenues into oil and gas components not available from 1970 to 1973

Source: State Comptroller Office

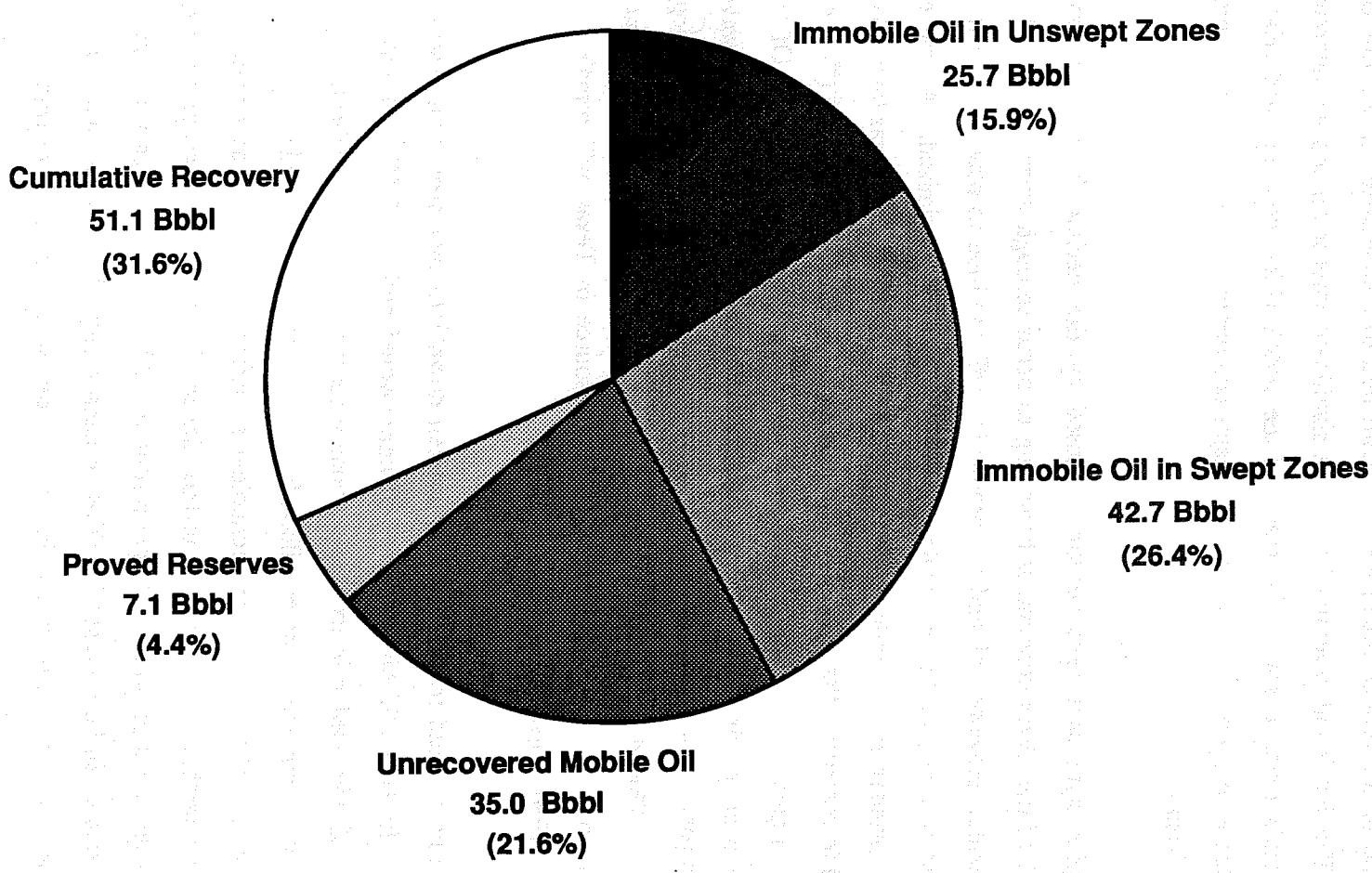
and 1987, and reductions in spending combined with a range of tax increases (higher sales, franchise, and motor vehicle taxes) were implemented to compensate for the loss of oil and gas revenues. The fall in oil revenues has had a significant impact on the ad valorem tax base in Texas, the main revenue source for many of the state's cities, counties, and school and water districts. Clearly, oil production has been a major component of the economic, employment, and tax bases of Texas.

Despite significant revenue losses caused by the decline in oil and gas production, revitalization of the Texas economy is beginning to occur through diversification of the industrial base in the state. However, oil and gas production will continue to play a vital role in the state's economy and recovery of the remaining resource should be maximized. At the conclusion of conventional primary and secondary operations, vast quantities of the Texas known oil will remain unrecovered in reservoirs that are currently discovered and mostly developed (Figure II-10). The total known original oil in place (OOIP) in Texas is over 160 billion barrels. Of this, 51 billion barrels have been produced and 7 billion barrels are recognized as proved reserves as of the beginning of 1988, for a total estimated ultimate recovery by conventional technology of over 58 billion barrels. This figure is 36% of the original oil in place (OOIP). Therefore, 103 billion barrels, or almost two-thirds of the total known resource in Texas, will remain as a target for newer, more efficient extraction technologies.

This unrecovered resource can be broken down into two main components: mobile and immobile oil. In Texas, 35 billion barrels of unrecovered mobile oil (UMO) make up the target of a number of advanced primary and secondary recovery processes, collectively referred to as UMO extraction techniques. The 68 billion barrels of remaining immobile oil represent the target for a number of tertiary extraction technologies, defined generically as enhanced oil recovery (EOR). The immobile oil resource is further divided into previously swept and unswept zones. Previously swept zones provide the target resource for EOR processes as currently applied, while the unswept zones can be accessed by EOR processes only after primary and secondary recovery operations have contacted and swept the zone. Recovery operations directed at each of these resources could play a critical role in sustaining the Texas oil industry and reducing the nation's dependence on imported oil. A brief overview of these recovery technologies follows in the next two sections.

Figure II-10

Distribution of Known Oil-in-Place in Texas By Resource Component After Conventional Recovery



Total Original Oil-in-Place: 161.6 Bbbl *

* Bbbl = Billion Barrels

Source: BPO TORIS, 1989; EIA, 1987; API/AGA, 1980; Fisher and Finely, 1986.

B. ENHANCED OIL RECOVERY

The oil remaining after conventional recovery lies in two defined regions within each reservoir. In one zone of the reservoir, conventional operations have recovered a significant portion of the original concentration of oil. The oil remaining in this swept zone is trapped in the reservoir pore spaces or on the surface of the pores by capillary and surface tension forces. Additional flooding by water can produce very little of this oil; the zone is at the "waterflood residual" level of saturation. The volume previously occupied by displaced oil now contains injected water (or, in some cases, natural gas). In its current stage, EOR is generally expected to reach only portions of reservoirs previously swept by conventional techniques. In the other zone of the reservoir, conventional recovery processes have not swept the pore space, so the oil saturation can range from a low of the pressure-depleted, post-primary level up to the original reservoir level. The objective of many infill drilling, waterflooding, and other reservoir management techniques is to contact the oil in these unswept zones. Only after these zones have been swept by water are EOR operations assumed feasible. The issues of secondary recovery and EOR potentials in unswept zones are addressed in Chapter VI, which considers the prospects of combining recovery techniques in more advanced methods than those routinely conducted in the field.

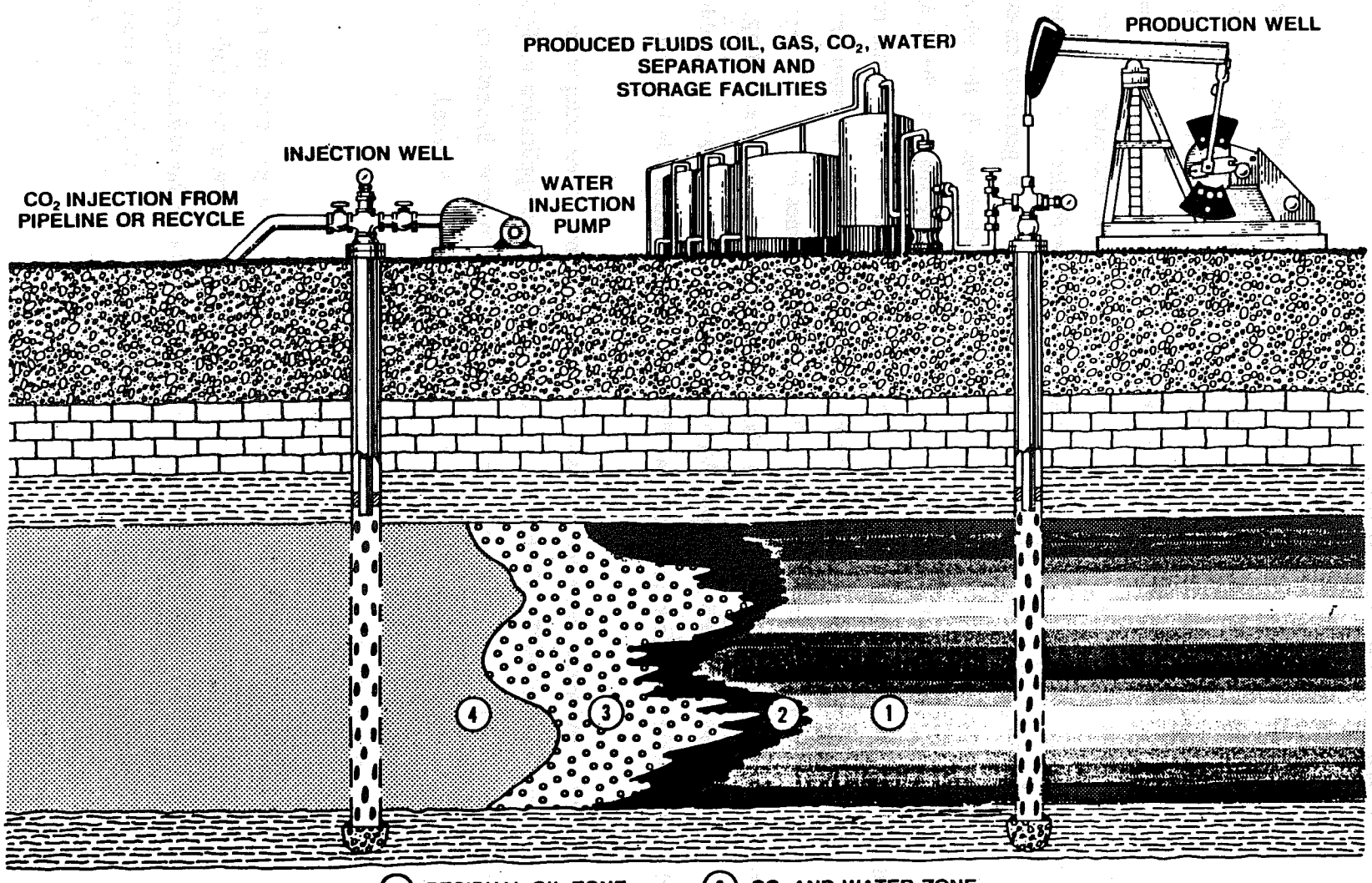
Proven enhanced recovery processes are classified into three categories: gas-miscible, chemical, and thermal EOR. Each of these techniques has some application to Texas reservoirs. The following sections describe how each process works to recover incremental oil. Current applications of these processes in the state's fields are also briefly discussed.

1. Gas-Miscible EOR

Gas-miscible EOR is comprised of processes in which a gas, such as carbon dioxide, nitrogen, flue gas, or enriched natural gas, is injected into a reservoir to mobilize and displace waterflood residual oil. These processes have been shown to be highly effective in both sandstone and carbonate reservoirs, especially if injected at a pressure high enough to cause the gas and components of the oil to completely mix and stay mixed (achieve miscibility). The process is illustrated in Figure II-11.

Figure II-11

MISCIBLE FLOODING
(CARBON DIOXIDE)



(1) RESIDUAL OIL ZONE (3) CO_2 AND WATER ZONE

(2) OIL BANK/MISCIBLE FRONT (4) DRIVE WATER

SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

The injected gas generally flows into the previously water-swept zones where it displaces the mobile water and mixes with and swells the oil left in the pore space. With repeated contact of injected gas and oil, the gas extracts the more volatile portions of the crude oil to form an enriched injected gas-hydrocarbon mixture. This mixture then displaces most of the oil it contacts, leaving behind a very small quantity of tar-like residue.

Because the injected gas has low viscosity relative to crude oil, it tends to sweep through the more permeable parts of the reservoir and often overrides the oil. To minimize these effects, water is sometimes injected in alternating "slugs" with the gas (particularly in carbon dioxide floods), to increase the portion of the previously water-swept zone that is also swept by the injectant. Other materials (e.g., surfactant foams) are under development to sweep larger portions of the reservoir. The combination of swelling, mixing, and sweeping can effectively contact, mobilize, and recover a significant portion of the immobile oil remaining in the reservoir. As gas injection continues, water, oil, and the gas injectant are recovered at the producing wells. In larger projects, the recovered gas is separated, repressurized, and reinjected.

Miscible flooding, the most common and most promising means of enhanced recovery in Texas, dates back over 40 years. Many of the state's earliest EOR projects used flue gas or hydrocarbon injectants; a flue gas project was begun on ARCO's Block 31 (Crane county - RRC District 8) in 1949, and hydrocarbon miscible projects were begun in 1956 on Exxon's Bronte Field (District 7C), in 1957 on Humble's Seeligson Field, Zone 20B-07 (District 4), and in 1960 on Amoco's Midland Farms Field (District 8). Active hydrocarbon miscible projects include Hunt's Fairway Field in Northeast Texas, begun in 1966, and Amoco's Levelland Field in Hockley County (District 8A), begun in 1971. There have also been several nitrogen flooding projects in the western part of the state, including Texaco's Vealmoor East Field in Borden and Howard Counties (terminated) and Phillips' Andector Ellenburger Field in Ector County.

Carbon dioxide is the state's most common injectant, used in nearly all of the largest EOR projects in the state (those with enhanced productions of over 1,000 barrels per day [b/d]), and is the dominant process used in West Texas (especially District 8A). Carbon dioxide flooding is prevalent in this region of the state for several reasons. The carbonate (limestone and dolomite) reservoirs of this area are especially well suited to the injectant; below-average conventional

recovery efficiencies have spurred operators to implement enhanced recovery projects to contact and produce the resultant large volumes of remaining oil. In addition, the region is well-located in relation to several major sources of CO_2 and is serviced by three large pipelines and several trunklines that cross the area. Two 500 million cubic feet per day (cf/d) capacity pipelines from Sheep Mountain, Colorado and Bravo Dome, New Mexico and a 650 million cf/d pipeline from McElmo Dome, Colorado, which may ultimately be expanded to 1 billion cf/d, already supply gas to West Texas, terminating in the Denver City area. The Permian Basin is now the world leader in carbon dioxide EOR.[1/] Carbon dioxide is used in the state's largest EOR project, Chevron's SACROC unit, located in Scurry county (District 8A), begun in 1972 and now producing over 17,600 b/d. More than 33,000 acres (with 2.1 billion barrels OOIP) are being flooded with CO_2. Before CO_2 flooding began, calculations showed that the ultimate recovery (primary and waterflooding) in the unit would be less than 44% of OOIP. With CO_2 flooding, an additional 6.7% of the OOIP in the pattern area is expected to be recovered. In early 1988, Chevron announced a three stage project for the North Ward Estes Field of Ward and Winkler Counties. The new project could ultimately recover 65 million barrels of oil and 32 billion cubic feet of natural gas with a miscible CO_2 EOR project.[2/] Other notable CO_2 projects, all in West Texas, include ARCO's Willard Unit of Wasson Field, Enron's Twofreds Field, and Amoco's Slaughter Field.

2. Chemical EOR

Chemical EOR involves the injection of chemicals into a reservoir to reduce the interfacial tension between residual oil and water and/or improve the mobility ratio (the contrast in viscosities and relative permeabilities) between the injected, displacing fluids and the displaced fluid. The major chemical processes are surfactant flooding, alkaline injection, and polymer flooding (which is directed at UMO displacement and will be discussed in Section C).

Surfactant flooding (Figure II-12) involves the injection of a chemical that is both oil and water soluble to reduce the interfacial tension between these fluids at reservoir conditions. The

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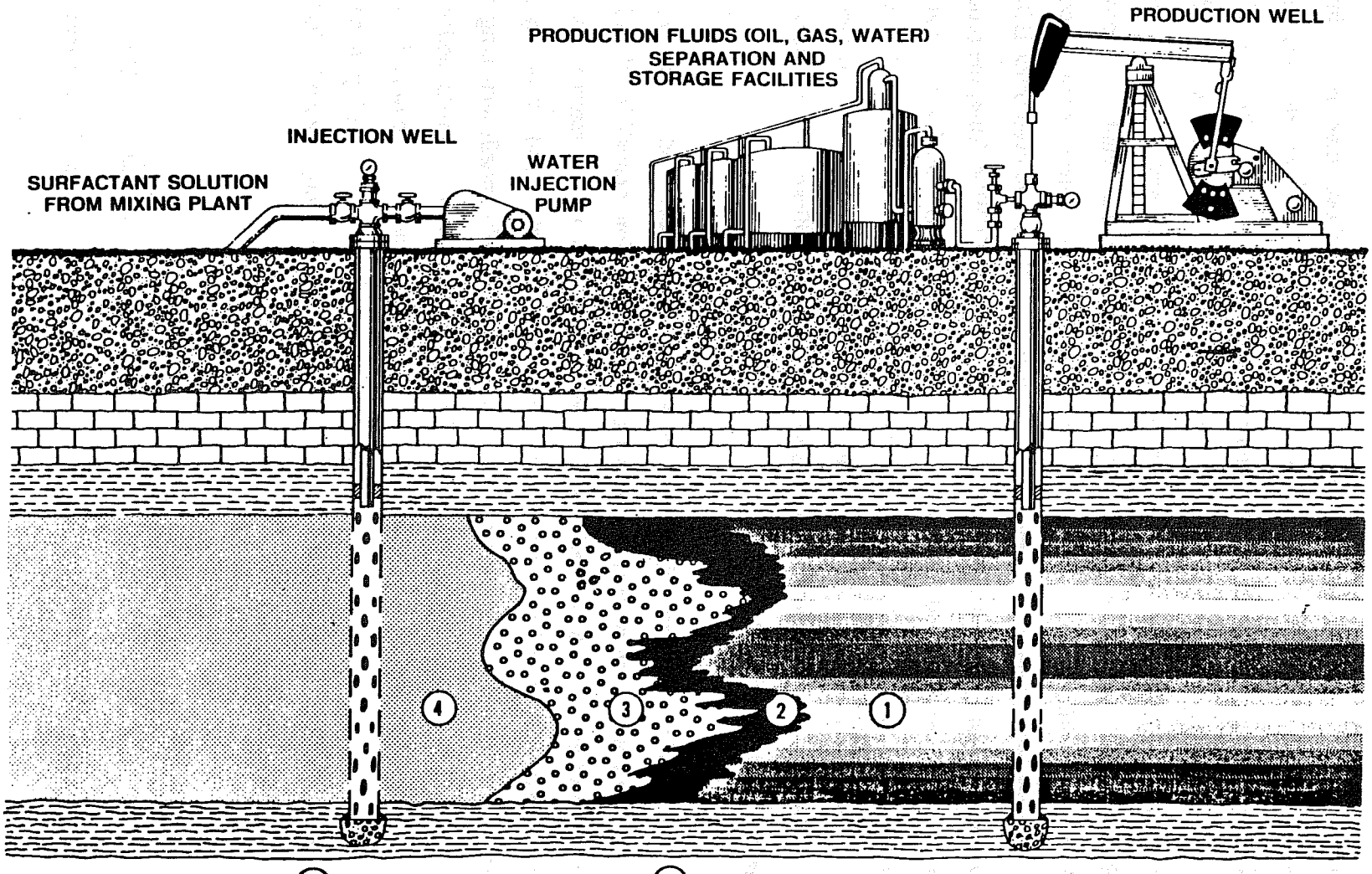
1/ Stalkup, Fred I. "Miscible Displacement," SPE-AIME, New York, 1983.

2/ *Oil and Gas Journal*, April 18, 1988.

Figure II-12

SURFACTANT FLOODING



SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

chemical "slug" may include surfactant, water, hydrocarbons, alcohols, polymers, and inorganic salts to mobilize the residual oil. Polymer slugs, injected before and after the surfactant, provide mobility control and help maintain the integrity of the chemical slug. Due to the high cost of surfactants, the slug is typically small relative to the volume of control agents injected before and after it. Surfactant floods must be designed specifically for each reservoir as the most effective combination of chemicals is highly dependent on the temperature, salinity, rock properties, and crude oil composition of the reservoir. As such, the process is relatively complicated, expensive, and therefore risky compared to conventional recovery operations and even other EOR processes. However, pilot tests have yielded recovery of up to 22% of the OOIP.[3/] Thus, the process is highly attractive if the cost and risk factors can be reduced. Mobil operated a surfactant project in Wichita County Regular Field (District 9) from 1973 to 1982, recovering about 3% of the OOIP. Exxon conducted a surfactant flooding mini-test in Borregos Field (District 4), recovering 12% of the OOIP.[4/] More recently, in 1981, Exxon initiated a significant test in Hockley County's Slaughter Field (District 8A).

Alkaline flooding uses chemicals such as sodium hydroxide, sodium silicate, and sodium carbonate to enhance oil recovery by reducing interfacial tension, emulsifying the oil, or altering formation wettability. These mechanisms create a surfactant in the reservoir as the alkaline solution neutralizes petroleum acids. Interfacial tension reduction and wettability reversal can reduce oil saturation below the waterflood residual saturation, substantially increasing displacement efficiency and, therefore, ultimate recovery.[5/] Potential recovery is highest with moderately viscous, napthenic, low API gravity, high acid-number crude oils. Increased oil recovery from this process may differ substantially from one application to another, depending upon the particular oil/water/rock system investigated.[6/] As currently understood and implemented, alkaline flooding has very limited potential in Texas.

3/ Willhite, G. Paul, Presentation to National Academy of Science, June 1989.

4/ Kuuskraa, Vello A., "The Potential and Performance of Enhanced Oil Recovery," November, 1985.

5/ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

6/ *Ibid.*

Nearly all of the ongoing chemical flooding projects in Texas employ polymer flooding. Several alkaline flooding projects were initiated in the late 1970s and early 1980s, but most have been discontinued. Among the projects were Unocal's South Van and Carroll Units in Van Zandt County (District 5). There have also been several micellar-polymer projects throughout the state, such as Mitchell Energy's Wizard Wells Field (Jack County, District 9), but they also have been discontinued.

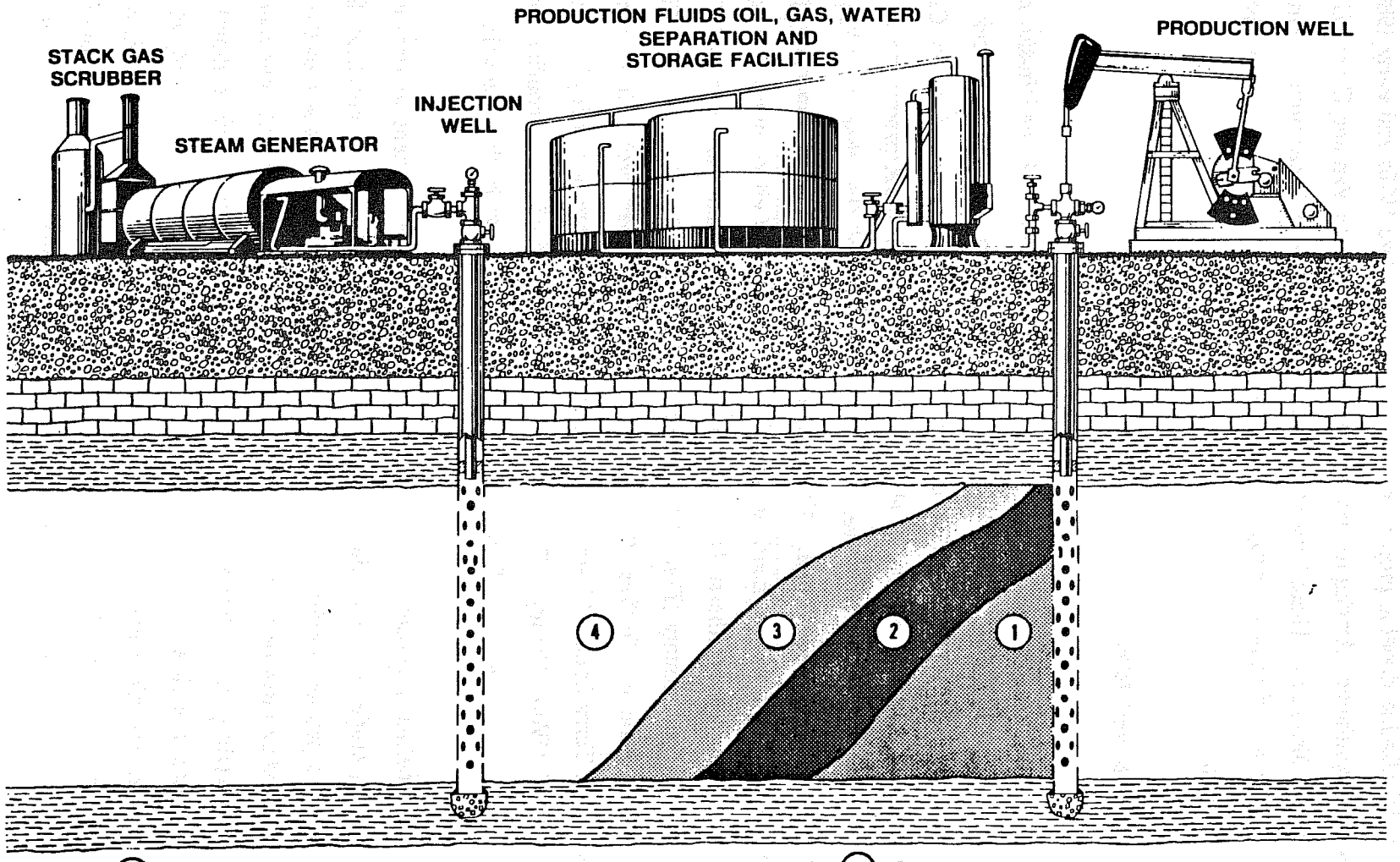
3. Thermal EOR

Thermal EOR processes include steam drive, steam soak, and in-situ combustion. The hydrocarbon displacement properties and process economics of steam soak and steam drive processes have been extensively demonstrated in several locations, especially California. In fact, steam EOR projects account for about three-fourths of all EOR production in the U.S. and are recognized as commercially proven technologies in heavy oil (less than 20° API gravity) reservoirs at depths less than 3,000 feet. Although several steam projects are underway in Texas, thermal recovery projects are not nearly as prevalent in the state as either miscible or chemical projects. Steam projects in Northeast Texas include Texaco's Sour Lake Field and Mobil's Saratoga Field, both in Hardin County (District 3), as well as DCR Petroleum's Camp Hill Field in Anderson County (District 6). In West Texas, Chevron operates a steam project in its Kingdom Abo Field, located in Terry County (District 8A). Greenwich Oil operates a combustion project in its Forest Hill Field (Wood County - District 6), but development of in-situ combustion projects is still somewhat constrained by a limited understanding of its action in the reservoir.

Thermal recovery processes involve the introduction of heat to reduce the viscosity of remaining crude oil, to partially "crack" the heavy oil into lighter constituents. This process produces a pressure gradient to drive the oil through the reservoir and into the producing wells. Steamflooding involves the injection of steam to heat the reservoir oil, thus reducing its viscosity and stimulating its production. A schematic of a typical steamflood is shown in Figure II-13. Steam heats the oil and either pushes or drags it towards a production well, where it is pumped to the surface. When steam flows into the reservoir, it condenses as the latent heat is transferred to the rocks and reservoir fluids. The adjacent formations above and below the reservoir are also heated as the steam expands outward from the injection well. The steam vapor tends to rise to

Figure II-13

STEAM FLOODING



(1) OIL AND WATER ZONE NEAR ORIGINAL RESERVOIR TEMPERATURE (3) HOT WATER ZONE

(2) HEATED OIL ZONE (4) STEAM AND CONDENSED WATER ZONE

SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

the top of the reservoir, while the condensed water tends to under-run the steam zone. This separation of the vapor and liquid phase, frequently called gravity segregation, is due to their different densities. As the oil is heated, its viscosity is reduced, thus allowing both the steam and condensed water phases to displace the oil toward a production well.[7/]

In-situ combustion (Figure II-14) is normally applied to reservoirs containing low-gravity oil, but has been tested over perhaps the widest spectrum of conditions of any EOR process. Heat is generated within the reservoir by injecting air and burning part of the crude oil, which reduces the oil viscosity and partially vaporizes the oil in place. The oil is driven forward by a combination of steam, hot water, and gas drive. The relatively small portion of the oil that remains after these displacement mechanisms have acted becomes the fuel for the in-situ combustion process. In some applications, the efficiency of the total in-situ combustion operation can be improved by alternating water and air injection. The injected water tends to improve the utilization of heat by transferring heat from the rock behind the combustion zone to the rock immediately ahead of the combustion zone. Although its further applications to Texas reservoirs may be limited compared to the other EOR processes, thermal recovery remains the predominant EOR technique in the U.S. and could, ultimately, have wider applications in Texas.

C. UNRECOVERED MOBILE OIL

Mobile oil remains in the reservoir after conventional recovery for a variety of reasons, foremost of which is reservoir heterogeneity, the complex variation of rock properties among zones in the producing interval. Figure II-15 contains simplified illustrations of several of the geologic and operational features that limit mobile oil production by primary and secondary recovery methods. Figure II-15A shows that reservoirs may consist of a large number of individual compartments, reflecting internal heterogeneity. These compartments are formed by depositional processes that originally formed the reservoir, or by diagenesis or tectonic activity that later altered the rock bodies. Exceedingly complex reservoirs may have compartments formed by all of these processes. At a given well spacing, some compartments containing oil are not in pressure communication with existing producing wells. At wide well spacings, much of the rock volume in

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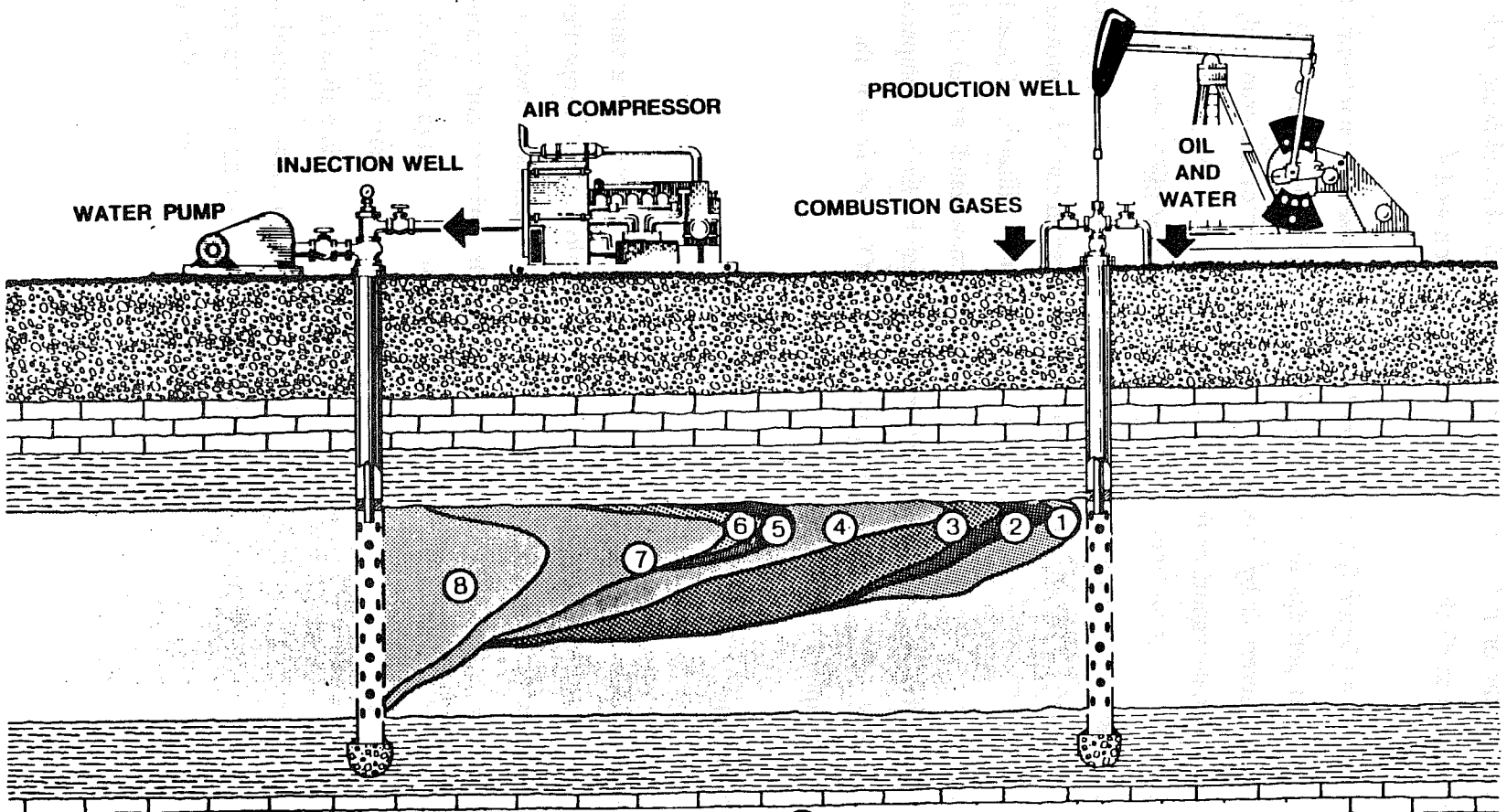
7/ *Ibid.*

Figure II-14

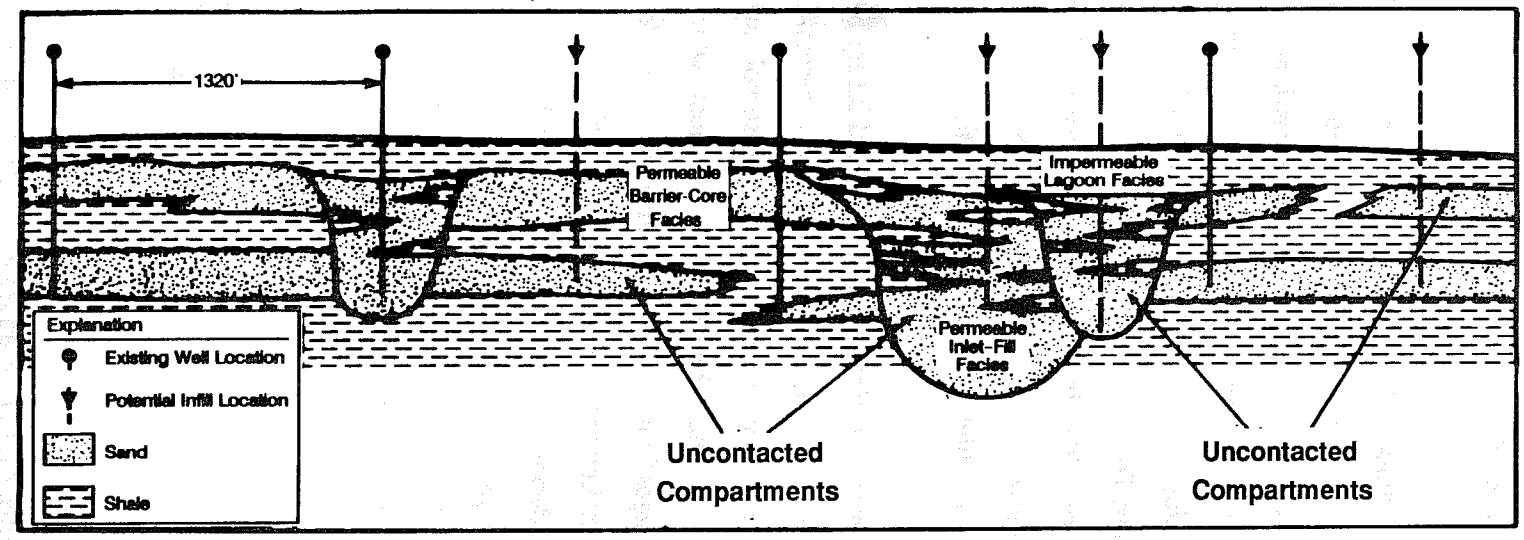
IN SITU COMBUSTION



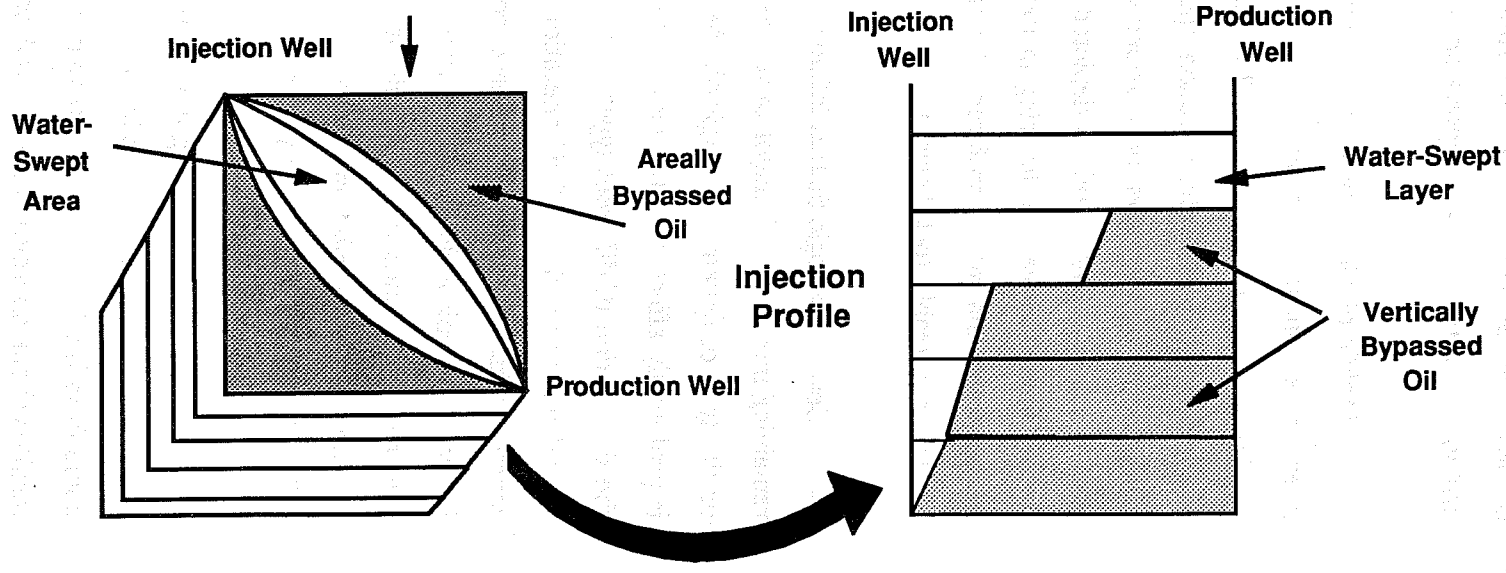
1. COLD COMBUSTION GASES
2. OIL BANK (NEAR INITIAL TEMPERATURE)
3. CONDENSING OR HOT WATER ZONE (50° – 200°F ABOVE INITIAL TEMPERATURE)
4. STEAM OR VAPORIZING ZONE (APPROXIMATELY 400°F)
5. COKING REGION
6. BURNING FRONT AND COMBUSTION ZONE (600° – 1200°F)
7. AIR AND VAPORIZED WATER ZONE
8. INJECTED AIR AND WATER ZONE (BURNED OUT)

SOURCE: Adapted from original drawings by Joe R. Lindley, U.S. Department of Energy, Bartlesville Energy Technology Center.

Trapping and Classification of Unrecovered Mobile Oil
Uncontacted and Bypassed Oil Targets



A. Uncontacted Compartments



B. Areally Bypassed Oil
(Within Contacted Compartments)

C. Vertically Bypassed Oil
(Cross-section of Contacted Compartment)

a heterogeneous reservoir will not be contacted by existing wells, leaving large volumes of oil at or near original pressure and saturation. These compartments provide a major target for infill drilling and future recovery operations conducted at closer spacing.

Mobile oil also remains in reservoir compartments that have been contacted but inefficiently swept by secondary recovery methods that utilize existing well configurations. At large well spacings, significant volumes of oil are areally bypassed due to small-scale variations in reservoir continuity. Although water injection operations are the most effective secondary recovery method in a majority of reservoirs, poor sweep efficiencies, due to the higher viscosity of oil than water, lead to the bypassing of oil, as depicted in Figure II-15B. The effectiveness of water injection is further limited by vertical layering in the reservoir. The injection profile shown in Figure II-15C demonstrates that water preferentially enters the more permeable layers of the reservoir, leaving the less permeable rock layers unswept at relatively high remaining oil saturations.

Several geologic factors influence the volume, distribution, and potential future recovery of remaining mobile oil. A major factor commonly influencing recovery potential is reservoir genesis, or the type of system that originally deposited the reservoir rock. Internal reservoir architecture is profoundly affected by the depositional system of the initial reservoir sediment, which controls the distribution of different types of rock "packages," and by the pore structure that plays host to later diagenetic rock and fluid alterations. Other important geologic factors include trap style and source rocks. Reservoirs that have common depositional histories will also have very similar internal reservoir architecture. A group of such geologically similar reservoirs is known as a play. This analysis assumes that reservoirs in a given play will have very similar rock properties and will also demonstrate similar production potential. An assessment of the reserve potential (UMO and EOR) for individual plays is presented in Chapter VII.

Recovery of remaining mobile and immobile oil from known fields is a highly cost effective method for increasing oil production. Over 80% of reserve additions in Texas since 1979 have come from the intensive development of older fields. A large portion of these new reserves have resulted from improved primary and secondary recovery methods, including implementation of waterflooding and pressure maintenance programs, drilling of additional wells to improve reservoir contact, and selective recompletion of existing wells to improve performance.

Several distinct methods for producing UMO have emerged: infill drilling to tap uncontacted reservoir compartments, recompletion of production and injection wells to contact and sweep previously bypassed portions of the reservoir, polymer flooding to overcome unfavorable waterflood injection fluid characteristics, and profile modification to reduce the permeability contrast between reservoir layers. These techniques are all proven for producing mobile oil remaining in the reservoir. The following sections discuss the UMO extraction processes analyzed in this study.

1. Infill Drilling

Infill drilling contacts compartments of oil that have little or no communication with wells at current spacing. As illustrated in Figure II-16, infill drilling reduces existing well spacing and recovers oil from some of these previously uncontacted compartments. Figure II-16A illustrates the uncontacted compartments that result from wide spacing. When wells are drilled on a blanket basis (Figure II-16B), some new wells penetrate uncontacted compartments (well 1) and produce large volumes of oil, while others penetrate compartments that have already been contacted (well 2). The wells drilled into previously contacted segments of the reservoir contribute somewhat to production, but recovery from these wells is limited to bypassed oil, as discussed below. Targeted drilling schemes, utilizing detailed geologic and engineering analyses, are effective precisely because they avoid such relatively inefficient and generally unnecessary drilling. Figure II-16C illustrates the impact of a targeted drilling program designed to penetrate and produce oil from uncontacted reservoir segments. Portions of the zone that were efficiently contacted under the initial drilling scheme and swept by existing operations are left at current spacing, while poorly swept, uncontacted segments are drilled to closer well spacing. Blanket infill drilling is assumed for implemented technology in this analysis, while the advanced technology case includes the increased recovery and improved economics of targeted drilling.

The effectiveness of infill drilling has been demonstrated in many Texas reservoirs. Exxon recently drilled a significant number of new wells in the Robertson Clear Fork Unit[8/] and the

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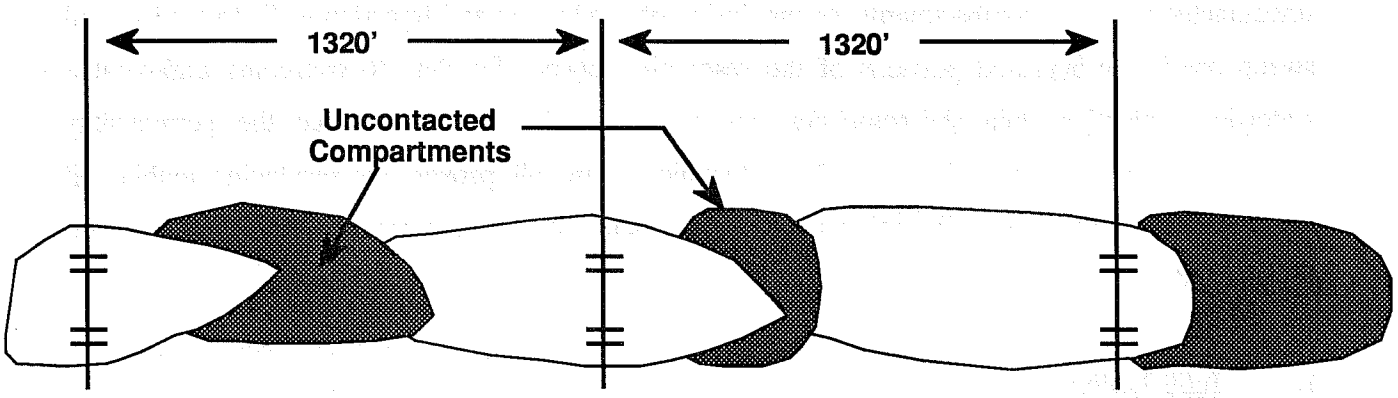
8/ Barbe, J.A., "Quantitative Analysis of Infill Performance: Robertson Clear Fork Unit," *Journal of Petroleum Technology*, December 1987.

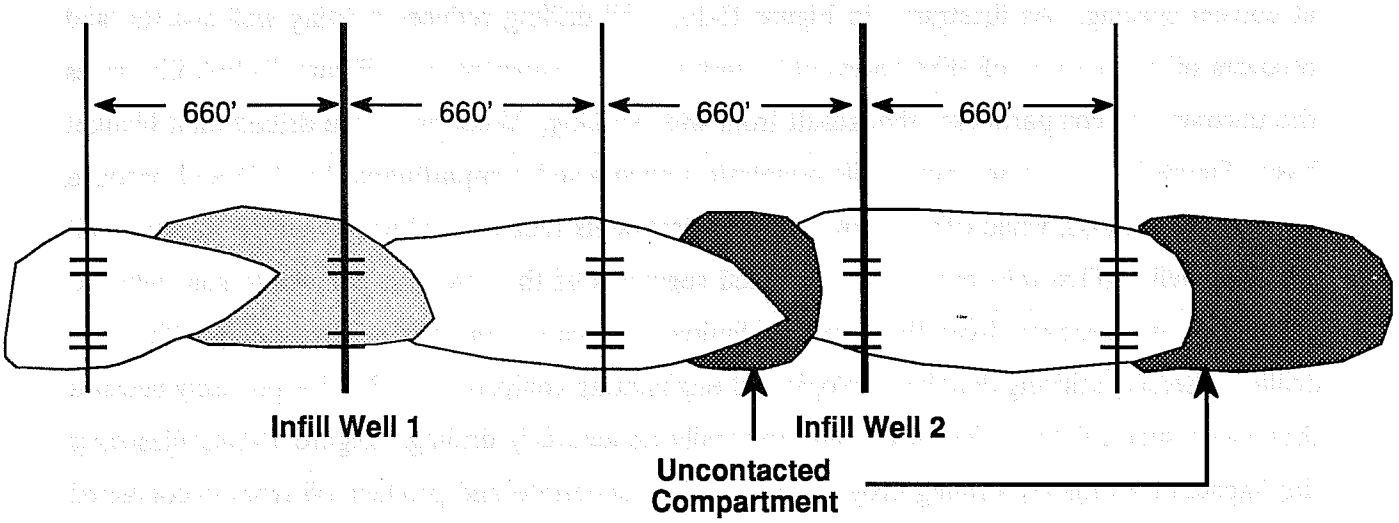
Figure II-16

Recovery of Uncontacted Mobile Oil by Infill Drilling

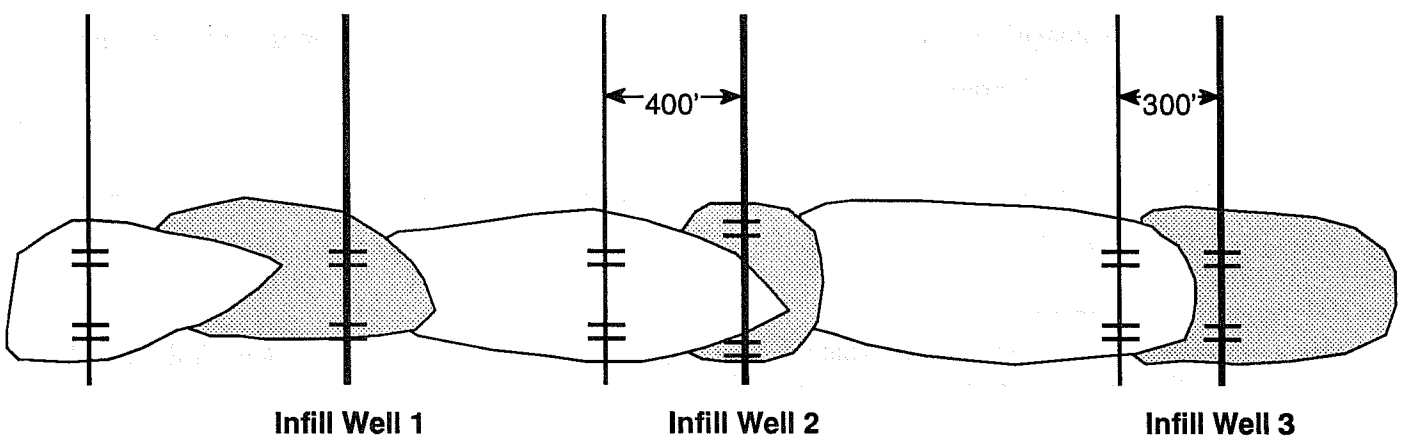
A. At Existing Well Spacing



B. With Blanket Infill Drilling



C. With Strategic Infill Drilling



Means San Andres Unit.[9/] Several publications have also discussed the large potential of infill drilling in specific reservoir settings.[10/] In some cases, infill drilling to close spacing can double the reservoir volume effectively contacted at conventional spacing, if economics will support the cost of the relatively large number of wells required.

The potential benefits of geologically targeted infill drilling have been assessed by several studies.[11/] The process has been evaluated in detail by the Bureau of Economic Geology (BEG) at the University of Texas at Austin. The evaluation in Dune Field[12/] indicates the substantial recovery potential and economic enhancement possible through targeted drilling.

2. Polymer Flood

Polymers increase the viscosity and sweep efficiency of injected water, thereby improving mobile oil recovery from contacted, but areally bypassed reservoir segments. This recovery technique, commonly recognized as an EOR process, alters apparent rock and fluid properties to reduce the flow of water into previously swept regions, thus redirecting the injected water into poorly swept portions of the reservoir. Figures II-17A (waterflooding) and II-17B (polymer

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9/ Magruder, et al., "A Review of the Means San Andres Unit Full-Scale CO_2 Tertiary Project," SPE Paper No. 17349, April 1988.

10/ Gould, et al., "Infill Drilling for Incremental Recovery," *Journal of Petroleum Technology*, March 1989.

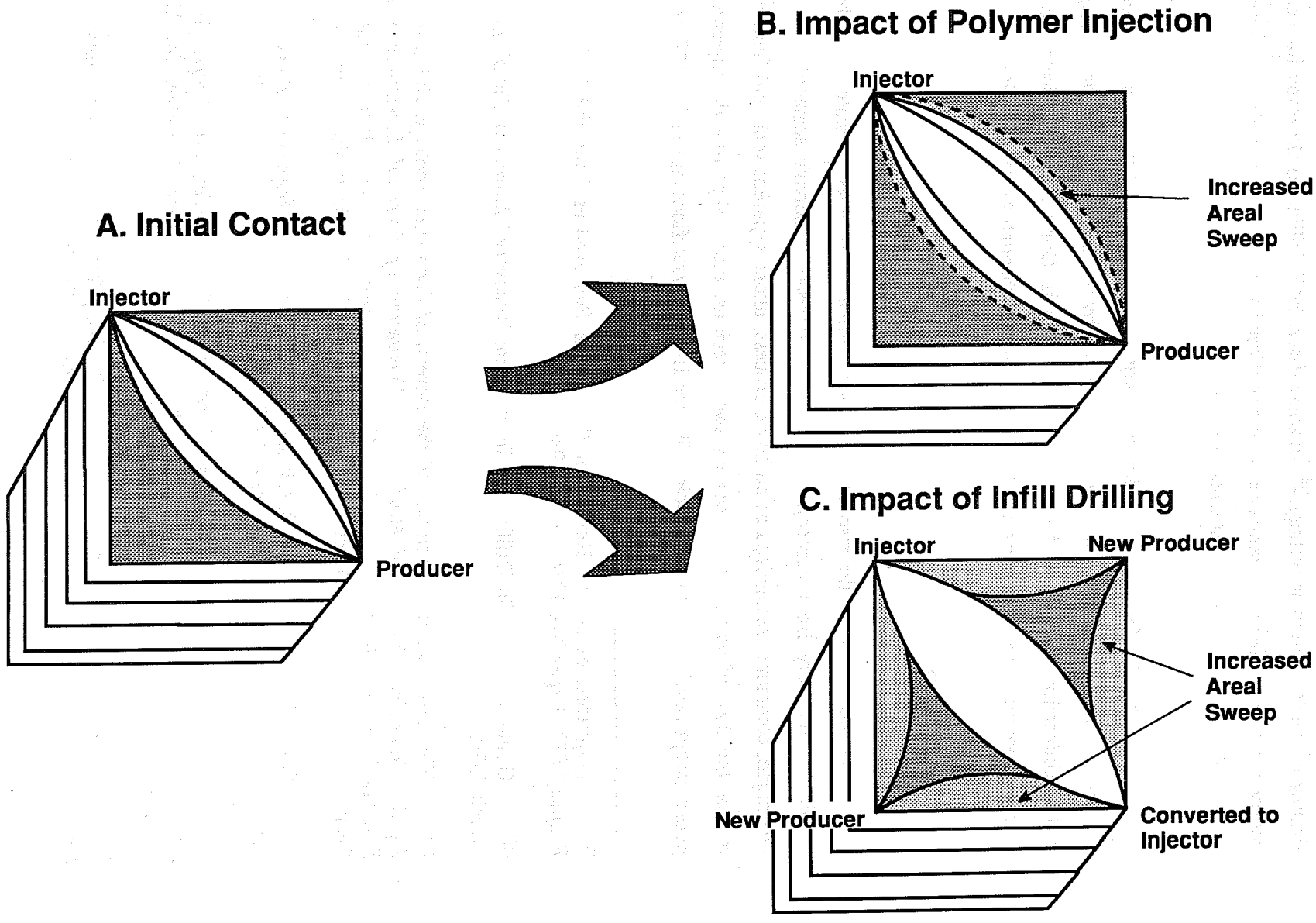
11/ ICF Resources Incorporated and the Bureau of Economic Geology, University of Texas at Austin, *Producing Unrecovered Mobile Oil: Evaluation of Potential Economically Recoverable Reserves in Texas, Oklahoma, and New Mexico*, prepared for: U.S. Dept. of Energy/Office of Planning and Environment/Office of Fossil Energy and Bartlesville Project Office, 1989.

Fisher, W.L., "Can the U.S. Oil and Gas Resource Base Support Sustained Production?" *Science*, Volume 236, No. 4809, 26 June 1987, pp. 1631-1636.

Tyler, et al., *Oil Accumulations, Production Characteristics, and Target for Additional Recovery in Major Oil Reservoirs in Texas*, the Bureau of Economic Geology, The University of Texas at Austin, Geological Circular 84-2, 1984.

12/ Bebout, et al., *Characterization of the Grayburg Reservoir, University Lands Dune Field, Crane County, Texas*, the University of Texas at Austin, Bureau of Economic Geology, Report of Investigations, No. 168, 1987.

Recovery of Areally Bypassed Oil By Infill Drilling or Polymer Flooding



injection) illustrate the impact of this technique in one-quarter of a normal 5-spot pattern; the areal extent of the reservoir swept by water injection expands slightly with polymer injection. Infill drilling is another effective method of recovering bypassed oil from contacted reservoir compartments. Figure II-17C depicts the increased waterflood sweep after infill drilling and injection pattern modification. Clearly, some portion of the oil bypassed at current spacing can be recovered by well-designed, advanced waterflooding techniques. Significant portions of this oil could be recovered with the combined application of both polymer injection and infill drilling. Over 30 polymer projects are currently in operation throughout Texas, including Salt Creek Field (Mobil) in District 8A, which currently produces over 2,800 b/d by the enhanced recovery technique.

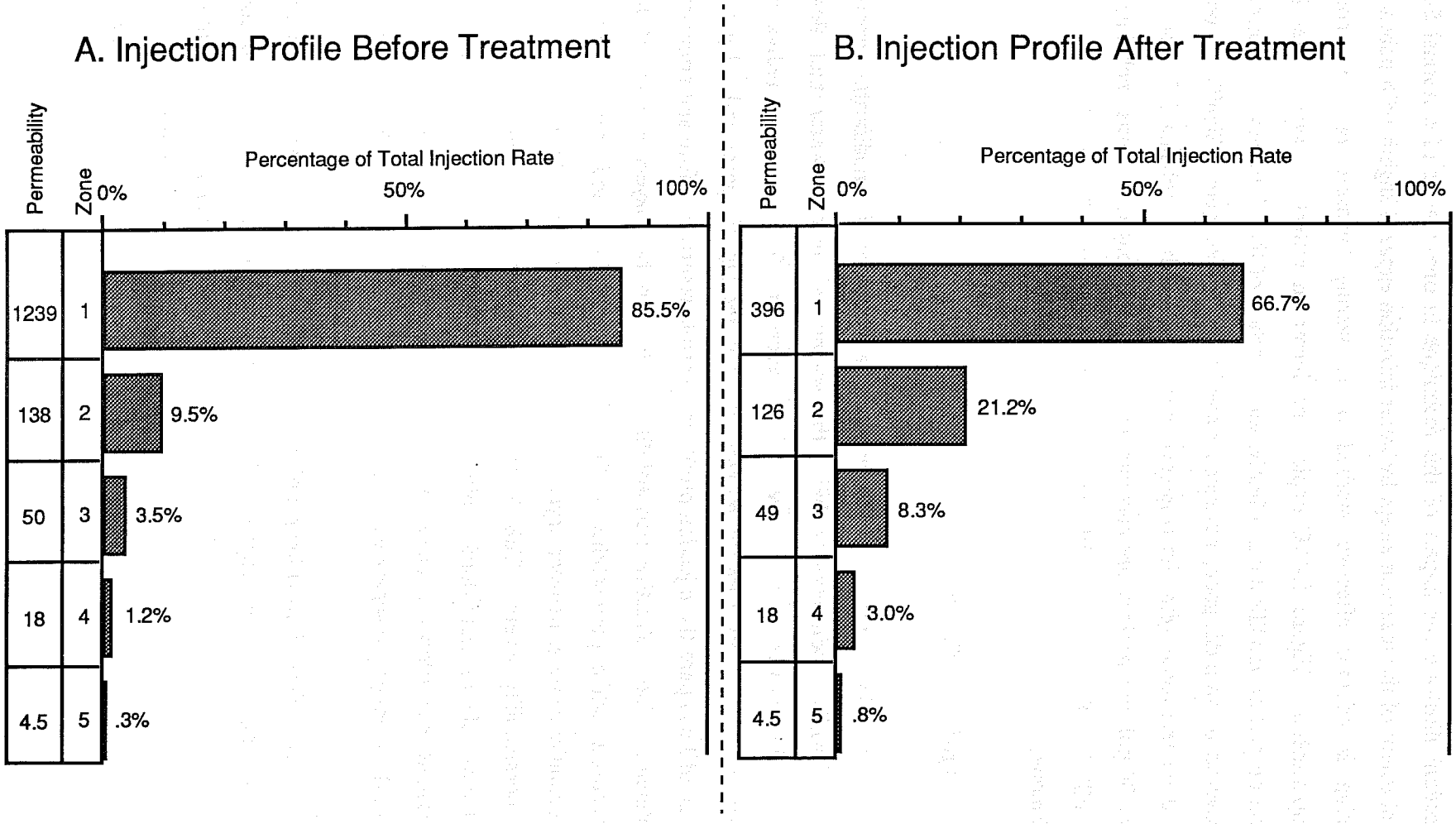
3. Profile Modification

Vertically bypassed oil is the principal target for profile modification treatment of injection wells. Profile modification reduces the volume of injected water that flows through high permeability, previously swept layers of the reservoir. The treatments reduce rock permeability somewhat in all layers, with the greatest effect in the highest permeability layers. Figures II-18A and II-18B compare the injection profile in a sample reservoir before and after profile modification treatment. The effective permeability in the top two layers is reduced by 68% and 9% respectively, while permeability in the other layers is not noticeably reduced. Reducing the permeability contrast between layers allows more injected water to enter and to recover oil from low permeability layers. This increase in oil recovery effectively extends the economically productive life of waterflood projects. Some of this bypassed oil can also be recovered by redesigning waterfloods to place injector and producer perforations in bypassed zones, particularly where these zones are separated by tight streaks or shale breaks forming non-communicating layers.

Taken alone, infill drilling, polymer flooding, and profile modification are effective processes for producing mobile oil; they are often even more effective when applied in combination, which allows the processes to complement one another. For example, polymer injection and profile modification can be used to increase the waterflood sweep efficiency not only in previously contacted compartments, but also in compartments newly contacted by infill drilling. These

Figure II-18

Recovery of Vertically Bypassed Oil



synergies maximize the cost-effectiveness of mobile oil recovery and encourage the coordinated, multiple application of techniques in selected reservoir settings.

D. OBJECTIVES OF THE PRESENT STUDY

The present study is the third part of the Interstate Oil Compact Commission's *Project on Advanced Oil Recovery and the States*. The overall study was originally designed to examine the potential impact of EOR on production, state revenues, and economic activity as a function of oil price and the availability of technology resulting from R&D. The first report of this series evaluated the potential of carbon dioxide flooding in New Mexico under a variety of economic scenarios. The second report assessed the potential of enhanced oil recovery in the state of Oklahoma, with special emphasis given to state tax incentives and advanced technology to further increase EOR production.

The present study is designed to encompass a wider scope than the preceding works. While the Oklahoma and New Mexico analyses focused exclusively on enhanced oil recovery, the Texas evaluation also analyzes the incremental reserves, public sector revenues, and statewide economic activity that could result from the implementation of the improved UMO-targeted extraction techniques described above. The potentials for EOR and UMO production are evaluated separately, and each is considered for two technology levels: *implemented technology*, which assesses recovery potential given the statewide application of currently available technology, and *advanced technology*, which assesses the impact of the statewide application of potential technological advances. Comparison of the results of these two evaluations provides the basis for assessing the benefits of improved technology provided by R&D. To achieve the statewide application, and therefore receive the maximum benefits of both levels of technology assessed in this report, it is critical that the state of Texas work to: 1) effectively transfer to operators currently available technology (implemented technology), and 2) develop an R&D program to improve recovery methods (advanced technology) and subsequently transfer those methods to a broad public-private audience. All of the analyses are conducted over a range of crude oil prices from $12 to $36 per barrel (in constant 1988 dollars). This price range encompasses the long-term prices likely to prevail over the next 30 or so years.

In addition to independent evaluations of EOR and UMO recovery, this study examines the synergistic effects of a program designed to produce oil from both of these resource targets. This combined analysis is conducted for the same price and technology scenarios, focusing on potential reserve additions and the effectiveness of combining recovery operations in order to maximize Texas oil production and associated benefits.

III. APPROACH TO THE ANALYSIS

A. INTRODUCTION

This analysis was performed using the Tertiary Oil Recovery Information System (TORIS) developed for the 1984 National Petroleum Council (NPC) analysis of the nation's EOR potential.[1/] Although TORIS was originally designed to evaluate EOR potential only, the system's capabilities have since been expanded to incorporate evaluations of the unrecovered mobile oil (UMO) resource. This evaluation utilizes the upgraded TORIS system to assess the recovery potential of immobile and unrecovered mobile oil in the state of Texas. The following sections in this chapter will briefly discuss:

- The development of TORIS
- The enhancement of TORIS to evaluate the UMO resource
- Scope of the analysis
- Adaptations to TORIS for the present study
- Estimation of benefits, costs, and economic impacts
- Limitations of the analytical approach.

B. GENERAL METHODOLOGY: THE NPC BASIS

In March 1982, the U.S. Secretary of Energy requested that the NPC prepare a report on the nationwide potential and economics of incremental EOR. The NPC is the official petroleum industry advisory committee to the Secretary. Members of NPC, who are appointed by the Secretary, represent all segments of petroleum interest, such as production, refining, marketing, and environmental, and include many chief executive officers. The NPC is supported entirely by the voluntary contributions of its members.

In response to the Secretary's request, the NPC mounted a two-year effort that consumed more than 50 professional man-years and nearly $7 million of in-kind services. EOR experts from

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1/ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

industry (majors, independents, service, consulting firms), universities, government, and private non-profit organizations participated. The NPC EOR study committee utilized and built upon data bases of individual reservoir characteristics and computer models then under development by the U.S. Department of Energy (DOE), Office of Fossil Energy. After augmentation, adaptation, and validation, the data bases and models were returned to DOE's Bartlesville Project Office (BPO) for maintenance, updating, and subsequent application. These data bases and models are components of a larger system, the Tertiary Oil Recovery Information System (TORIS).

By the agreement of the Assistant Secretary for Fossil Energy, the present study enjoys access to TORIS and the assistance of BPO, although its participation is limited strictly to providing the data base, models, and assistance for the technical analysis. The BPO and DOE neither contribute to nor endorse the study design or the interpretations presented in this report.

The approach used by the NPC and in the present study to evaluate the EOR resource consists of the major phases listed below. Adaptations and augmentations to these phases for the present study, including those developed to incorporate the evaluation of the UMO resource, are discussed in the following sections.

1. Reservoir Data Compilation. Detailed data describing the properties of the individual, significant oil reservoirs are compiled. Numerous public and private sources of information are consulted to complete and validate the reservoir data base. The principal elements of the TORIS data base are displayed in Table III-1. Representatives of the operating companies review the data elements of each reservoir at least three times for consistency and accuracy; automated validity checks are performed on the entire data base.

2. Resource Screening Models. Each reservoir is subjected to a screening process designed to identify the technical applicability of the respective EOR processes under what the NPC defined as "implemented technology." The specific criteria applied to screen each EOR process are shown in Table III-2. In addition, the reservoirs are screened under what the NPC defined as "advanced" technology, available through concerted research and development. Table III-3 displays the technical criteria for "advanced" EOR technology.

Table III-1

Key Elements in the Current TORIS* Reservoir Data Base

- Original Volumetrics
  - -- Original Oil-in-Place
  - -- Reservoir area
  - -- Net thickness
  - -- Porosity
  - -- Initial water saturation
  - -- Initial oil saturation
  - -- Initial formation volume factor
- Current Volumetrics
  - -- Current oil saturation (swept zone)
  - -- Current formation volume factor
- Fluid Data
  - -- Oil gravity and viscosity
  - -- Connate water viscosity
  - -- Connate water salinity
  - -- Initial GOR
  - -- Current GOR
  - -- Injection water salinity
  - -- Crude oil fractions & properties (being added)
- Geologic Variables
  - -- Lithology
  - -- Depth
  - -- Temperature
  - -- Original and current pressure
  - -- Permeability
  - -- Permeability variation index
  - -- Clay content
  - -- Gross thickness
  - -- Dip angle
  - -- Geologic age code
  - -- Presence of gas cap, faults, shale breaks
  - -- Geologic play, depositional system, trap type
  - -- Areal and vertical heterogeneity descriptors
- Development & Performance Data
  - -- Recovery efficiency
  - -- Cumulative production
  - -- Annual production
  - -- Current injection rate
  - -- Cumulative volume of injectant by type
  - -- Well spacing
  - -- Number of producing & injecting wells
  - -- Water cut

*Tertiary Oil Recovery Information System, maintained and operated by the Bartlesville Project Office of the U.S. Department of Energy

Table III-2

Screening Criteria for EOR Candidates-Implemented Technology Case

Screening Parameters*	Units	Chemical Flooding		Miscible Flooding (Carbon Dioxide)	Thermal Recovery	
		Surfactant	Alkaline		Steam	In-Situ Combustion
Oil Gravity	°API	--	<30	≥25	10 to 34	10 to 35
Insitu Oil Viscosity (μ)	cp	<40	<90	--	≤15,000	≤5,000
Depth	Feet	--	--	--	≤3,000	≤11,500
Pay Zone Thickness (h)	Feet	--	--	--	≥20	≥20
Reservoir Temperature (TR)	°F	<200	<200	--	--	--
Porosity (ϕ)	Fraction	--	--	--	≥0.20***	≥0.20***
Permeability Average (k)	md	>40	>20	--	250	35
Transmissibility (kh/μ)	md-ft/cp	--	--	--	≥5	≥5
Reservoir Pressure (PR)	psi	--	--	≥MMP**	≤1,500	≤2,000
Minimum Oil Content at Start of Process ($S_O X \phi$)	Fraction	--	--	--	≥0.10	≥0.08
Salinity of Formation Brine (TDS)	ppm	<100,000	<100,000	--	--	--
Rock Type	--	Sandstone	Sandstone	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate

* Other criteria of a geological and depositional nature were also considered. Generally, reservoirs with extensive faulting, lateral discontinuities, or overlying gas caps are not prime candidates for field-wide EOR application. These factors were considered during the manual screening step when they could be identified.

** MMP denotes minimum miscibility pressure, which depends on temperature and crude oil composition.

*** Ignored if oil saturation (S_O) X porosity (ϕ) criteria are satisfied.

Source: NPC, 1984.

Table III-3

Screening Criteria for EOR Candidates-Advanced Technology Case

Screening Parameters*	Units	Chemical Flooding		Miscible Flooding (Carbon Dioxide)	Thermal Recovery	
		Surfactant	Alkaline		Steam	In-Situ Combustion
Oil Gravity	°API	--	<30	≥25	--	--
Insitu Oil Viscosity (μ)	cp	<100	<100	--	--	≤5,000
Depth	Feet	--	--	--	≤5,000	--
Pay Zone Thickness (h)	Feet	--	--	--	≥15	≥10
Reservoir Temperature (TR)	°F	<250	<200	--	--	--
Porosity (ϕ)	Fraction	--	--	--	≥0.15***	≥0.15***
Permeability Average (k)	md	>10	>10	--	≥10	≥10
Transmissibility (kh/μ)	md-ft/cp	--	--	--	--	--
Reservoir Pressure (PR)	psi	--	--	≥MMP**	≤2,000	≤4,000
Minimum Oil Content at Start of Process ($S_oX\phi$)	Fraction	--	--	--	≥0.08	≥0.08
Salinity of Formation Brine (TDS)	ppm	<200,000	<200,000	--	--	--
Rock Type	--	Sandstone or Carbonate	Sandstone	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate

* Other criteria of a geological and depositional nature were also considered. Generally, reservoirs with extensive faulting, lateral discontinuities, or overlying gas caps are not prime candidates for field-wide EOR application. These factors were considered during the manual screening step when they could be identified.

** MMP denotes minimum miscibility pressure, which depends on temperature and crude oil composition.

*** Ignored if oil saturation (S_o) X porosity (ϕ) criteria are satisfied.

Source: NPC, 1984.

3. Process Performance Models. Each reservoir that satisfies the technical criteria is then analyzed by a detailed process performance model at each level of technical applicability. The models for each process have been previously reviewed in detail and calibrated to actual field results. NPC study committees review and test this calibration. The models are reservoir-specific and therefore estimate incremental oil production from EOR as a function of reservoir properties and process design for each reservoir independently. Incremental production is that which is recovered in excess of production by conventional primary and secondary techniques at current field conditions.

4. Economic Evaluation. Each reservoir is then evaluated for its economic feasibility by estimating the income attributable to the incremental EOR production and the investment, operating costs, and taxes required to support the implementation of the process as designed and installed in the field. Detailed costing algorithms reflect EOR design (both "implemented" and "advanced"), reservoir depth, region, and other factors. The energy component of each cost element is adjusted to reflect the oil price being analyzed. A discounted cashflow analysis is performed for each reservoir at a number of oil prices and minimum rates of return.

5. Technology Development. For each reservoir that is determined to be economic at a given price, the performances of the applicable EOR processes are compared. Each reservoir is then assigned the process producing the greatest quantity of incremental oil. In the NPC assessment, the reservoirs are then scheduled for development on the basis of their relative economic attractiveness and time-phased against a series of supply and environmental constraints. This procedure is modified somewhat in the present study, as described below.

The NPC reported its findings on a national basis for four oil prices, ranging from $20 to $50 per barrel, three minimum rates of return (zero, ten, and twenty percent), and two levels of technology performance -- "implemented," meaning available at present, and "advanced," meaning available in the future due to successful completion of currently ongoing R&D. The present study uses the NPC reservoir data base, models, and methodology just as the NPC developed them,

except as described in sections C and E. The NPC methodology is described at length in its final report.[2/]

C. BUILDING ON TORIS: THE DOE UMO STUDY

TORIS evaluations have historically focused on recovery of immobile or waterflood residual oil. In 1988, TORIS' capabilities were expanded to include evaluation of the unrecovered mobile oil (UMO) resources in Texas, Oklahoma, and New Mexico.[3/] This expansion was accomplished by enlarging the system to consider the recovery potential of extended primary and secondary recovery operations in unswept portions of the reservoir, in a manner consistent with the current capabilities to analyze the tertiary recovery target (residual oil in previously swept zones). The system development and initial limited applications that were completed under the DOE UMO study included activities required for the following tasks:

- Development of methodologies to incorporate pertinent geologic data, in conjunction with the TORIS data and production information, to describe the reservoir's deposition and post-depositional history in sufficient detail to evaluate and characterize the UMO resource;
- Validation of these methodologies on actual reservoirs in Texas, Oklahoma, and New Mexico, insofar as data permitted;
- Modification of TORIS to estimate potential UMO production in individual reservoirs as a function of economic and technological conditions; and
- Validation of the models and analytical systems to determine recovery potential in the three states evaluated.

UMO, the target for advanced primary and secondary recovery operations, consists of uncontacted or bypassed oil that is physically displaceable by water or steam injection. "Uncontacted oil" refers to oil trapped in isolated compartments in reservoirs uncontacted by wells

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2/ *Ibid.*

3/ ICF Resources Incorporated and the Bureau of Economic Geology, University of Texas at Austin, *Producing Unrecovered Mobile Oil: Evaluation of Potential Economically Recoverable Reserves in Texas, Oklahoma, and New Mexico*, prepared for: U.S. Dept. of Energy/Office of Planning and Environment/Office of Fossil Energy and Bartlesville Project Office, 1989.

at current spacing, while "bypassed" oil has been contacted by existing wells but unswept by secondary recovery processes. The volume, location, and properties of the UMO depend on the geologic history of the reservoir and the fluid characteristics of the oil. The task of analyzing the UMO resource requires extensive updates and enhancements to the TORIS data base and models to evaluate potential recovery in a consistent, scientific manner. The analysis requires a detailed description of the resource remaining in each reservoir in terms of oil distribution and volume. The data base is supplemented with geologic information pertaining to the reservoir's geologic system and geologic play. Based on the predominant geologic system in each reservoir, semi-quantitative vertical and areal heterogeneity indicators are assigned. A detailed description and interpretation of these heterogeneity descriptors is given in the DOE UMO study.[4/]

Potential incremental oil recovery and related economic benefits are estimated for the three processes currently used to improve mobile oil displacement: infill drilling, profile modification treatments (permeability contrast reduction), and polymer-augmented waterflooding. An upgraded polymer-waterflood predictive model is used to evaluate each process. Selected combinations of these processes are also evaluated.

Potential incremental recovery from infill drilling is estimated from the increased sweep efficiency of similar reservoirs already operating at closer well spacing. Detailed investigations of ongoing waterfloods in Texas and New Mexico yield relationships between the assigned heterogeneity descriptors, well spacing, and proven conventional recovery. This analysis demonstrates that waterflood sweep efficiency increases as well spacing decreases, but the magnitude of this increase depends on the reservoir's geologic system and on the final well spacing achieved. These findings lead to the derivation of continuity functions that relate reservoir areal sweep to well spacing for various geologically determined reservoir classes.[5/]

Consistent with TORIS EOR evaluations, the analysis of UMO considers both current technology and advanced technology. The advanced technology analysis projects the potential improvement in recovery possible after successful research and development (R&D). For polymer flooding and profile modification treatments, advances in technology are projected to increase

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4/ *Ibid.*

5/ *Ibid.*

both the reservoir temperature and the formation salinity thresholds that currently limit the application of these processes. Table III-4 shows the process technical screens that are used in evaluating reservoirs for polymer flooding and profile modification treatments under current and advanced technology scenarios.

Table III-4

Screening Criteria for Advanced Secondary Processes

	Polymer*		Profile Modification	
	Current	Advanced	Current	Advanced
Reservoir Temperature (°F)	<200	<250	<180	<250
Formation Brine Salinity (ppm)	<100,000	<200,000	<100,000	<200,000
Permeability (md)	>20	>10	>20	>10
Oil Viscosity (cp)	<100	<150	<100	<150

* Source: NPC, 1984

Infill drilling potential is also evaluated as currently implemented and as could be advanced through R&D. Current knowledge of reservoir heterogeneity limits drilling to highly favorable reservoirs where blanket-pattern drilling at uniform spacing can yield a profit. Improved sweep efficiency in the implemented technology case is estimated by the reservoir-wide average improvement in sweep possible with a reduction in spacing to one-half the current level. The advanced technology scenario assumes that improved geologic description would target infill wells to more promising segments of each reservoir. The TORIS models represent this assumption by dividing the reservoir into two parts, a more continuous and a less continuous region. Each segment is then separately analyzed to determine its economic potential for infill drilling at subsequent one-half reductions in well spacing down to five acre spacing, or one-eighth of current spacing, the maximum reduction evaluated in this study.

The impact of applying EOR after the application of UMO recovery techniques is also evaluated. This portion of the analysis involves estimating the improvement in EOR recovery possible after infill drilling, profile modification, or polymer flooding has successfully increased conventional sweep efficiency. EOR production is accelerated as the reservoir is drilled to closer spacing. These changes are incorporated by adjusting the EOR model input data to reflect the new reservoir situation after the successful application of UMO recovery techniques. To account for cases in which advanced geoscientific knowledge improves the understanding of the reservoir, EOR potential is analyzed in distinct reservoir segments as well, consistent with the methodology used in assessing advanced, geologically targeted infill drilling. EOR could be implemented in either region of the reservoir independent of the economic viability of the process in the other region or in the reservoir as a whole. If R&D can successfully develop the procedures necessary to allow the application of these techniques, project costs could be substantially reduced and immobile oil recovery in Texas substantially increased.

The entire methodology (data, models, and analytical systems) is developed in a manner fully compatible with the existing TORIS structure. Thus, the delineation of oil plays and the expanded data collection allows for a consistent analysis of the recovery potential of mobile oil from the unswept zones and enhanced oil recovery from both the swept zone and the additional portions of the reservoirs impacted by advanced mobile oil recovery. Consistency of the data and models is critical due to their interaction regarding the reservoir conditions that affect recovery from the respective components of the resource.

D. SCOPE OF THE ANALYSIS

The cases selected for this analysis include seven oil price assumptions and two levels of technology application. The cases are run, first incorporating either EOR or UMO processes individually, and then in combination. TORIS selects from five EOR recovery methods and five UMO extraction methods for each reservoir in the database. A reservoir could be assigned only one EOR process and/or one UMO extraction method for each case considered.

The nominal crude oil prices (adjusted for gravities less than 40° API) range from $12/B to $36/B in $4 increments, all stated in constant 1988 dollars. The prices are selected to bracket

the likely prices over the next 30 years. A minimum real (after inflation) rate of return of 10% is used to estimate discounted cash flows and project profitability for all analyses.

At each oil price, two technology cases are analyzed; the "implemented" and the "advanced" case. Implemented technology reflects the applicability and level of performance of the respective processes (EOR or UMO extraction) used routinely today. Advanced technology considers the likely improvements in process performance and applicability that can be achieved within the next decade if a R&D program is successfully completed.

All fourteen cases (seven prices, two technologies) are analyzed in detail to examine their impact on estimated oil reserves, oil production, treasury revenues, and the economy for the state of Texas and for the U.S. In addition, all cases are evaluated relative to whether only EOR or only UMO methods could be used for each reservoir, or whether a combination of the two could be employed. The results of these analyses, addressing the benefits from incremental production, are reported in Chapters IV through VI. Chapters IV and V discuss the effects of EOR and UMO processes for implemented technology and advanced technology, respectively. Chapter VI presents the results of using combinations of EOR and UMO recovery processes. Chapter VII provides regional geologic detail and further discussion of the recovery potential for various, highly promising plays in Texas.

E. ADAPTATIONS FOR THE PRESENT STUDY

To conduct the present analysis, several adaptations to the NPC approach are necessary, although none is a significant departure from the NPC methodology.

1. Data Editing and Additions

Based on a lengthy data search using state and library sources, the NPC reservoir data have been reviewed and updated for the 683 largest Texas reservoirs in terms of estimated original oil-in-place (OOIP). Subsequently, 206 reservoirs have been added, bringing the total to 889. Whereas the NPC study included only about 72% of the known OOIP in Texas reservoirs, the present study includes nearly 80% of the OOIP. The reservoirs represented in the data base include oil zones in every region of the state. Depths range from less than 500 feet to more than

13,500 feet. The largest reservoirs are more completely represented in the data, but reservoirs as small as 8 million barrels are also analyzed in the study. The data base is, therefore, believed to be representative of the diverse oil producing formations across Texas.

Under the direction of Dr. Noel Tyler, the Bureau of Economic Geology (BEG) at the University of Texas at Austin has provided critical geologic interpretation, data review, and expert consultation on the analysis and the interpretation of the results for the DOE UMO updates. The BEG has also added data for the additional Texas resource in reservoirs not fully described for the NPC study. The BEG has completed several studies of the oil resource base in Texas, and has compiled a detailed, multi-faceted description of this resource.[6/] The oil recovery potential recognized in these studies has been validated by detailed analyses at the reservoir level.

Data from the Energy Information Administration on the production of oil, gas, and water since 1970 has been added for all reservoirs, thereby permitting decline curve analyses (used in the timing algorithm, discussed below) and validation of the estimated ultimate conventional recovery.

2. State and Federal Taxes

Because the NPC took a national perspective, it simplified its analysis by assuming uniform state severance and income taxes. The present study replaces these rates with the current Texas tax structure. The state production tax rate on oil produced in Texas is currently fixed at 4.6 percent of the gross value of production at the wellhead. Texas has no corporate or individual income tax.

Federal taxes are estimated based on new corporate tax rules established by Congress in the Tax Reform Act of 1986 and signed into law in October 1986. This law provides for a lower (34%) rate on corporate income taxes and changes the depreciation schedules and expense rules.

6/ Galloway, et al., *Atlas of Major Texas Oil Reservoirs*, the Bureau of Economic Geology, University of Texas at Austin, 1983.

Tyler, et al., *Oil Accumulation, Production Characteristics, and Target for Additional Recovery in Major Oil Reservoirs of Texas*, the Bureau of Economic Geology, University of Texas at Austin, Geological Circular 84-2, 1984.

3. Cost and Price Data

An informal survey of industry representatives has determined that the NPC costing algorithms for investments are still valid for the present study, provided that prices analyzed are consistent with the year of the cost data. The only exception to the use of the NPC's cost algorithms is the cost of enhanced recovery injectants delivered to the field. The NPC assumed a CO_2 purchase price in the Permian Basin of West Texas and Eastern New Mexico of $1.25 per thousand standard cubic feet (Mcf) at an oil price of $30/B. The NPC adjusted for changes in oil price using the equation:

$$CO_2 \text{ Price (\$/Mcf)} = \$0.50 + \$0.025 \text{ X Oil Price (\$/B)}.^{7/}$$

However, the base price and adjustment equation were established at higher oil prices and before the completion of major CO_2 pipelines or significant CO_2 deliveries to the region. An informal poll of pipelines and field operators suggests that the CO_2 prices at present and into the near future are lower (relative to oil prices) than the NPC had assumed. The CO_2 purchase price in West Texas has been adjusted for changes in oil price using the equation:

$$CO_2 \text{ Price (\$/Mcf)} = \$0.50 + \$0.02 \text{ X Oil Price (\$/B)}.$$

This equation results in a CO_2 price of $0.90/Mcf at the $20/B oil price. CO_2 prices in other regions of the state are assumed to be double the West Texas price, based on previous NPC surveys. Nitrogen costs have been adjusted in a similar manner, with $0.65/Mcf as the base price at $28/B.

Chemical injectant costs have also been adjusted based on a survey of operators and suppliers. Polymer costs, assumed to be $1.60 per active pound by the NPC, have been reduced to $1.33 per active pound based on the current cost of low temperature, low salinity polymers. The cost is increased where oil and reservoir properties dictate the use of high molecular weight polymers. Surfactant costs used by the NPC were based on a primary surfactant cost of $0.32 per

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7/ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

active pound and a secondary surfactant cost of $0.44 per active pound. The surfactant slug cost based on these components was $7.00/B. Prices paid by operators in recent field tests show this cost to be too low. Survey information shows that primary surfactant costs are higher ($0.63/active pound), resulting in a $10.17/B surfactant slug cost at a $30/B oil price.[8/] Chemical costs have been adjusted for oil price changes as had been done in the NPC analysis, based on the energy component of the chemicals for different oil prices.

4. Benefits Estimation

The NPC did not calculate all of the individual items used in the present study's estimation of benefits. Special algorithms have been developed to estimate the number of jobs created, wages paid, and personal income taxes collected based on other elements already contained in the economic model. These algorithms are discussed further in Section F of this chapter.

5. Project Timing

The NPC's national perspective permitted a timing algorithm based principally on the assumption that the most economically attractive reservoirs would be developed first, given some broad constraints. For the present, state-level study, a more detailed timing approach is necessitated by the smaller geographic scale of the analysis. Timing for the application of EOR and/or UMO recovery techniques in Texas reservoirs (assuming they were economic) is estimated in two steps. First, project starting dates for EOR that are documented in the literature are used to time recently started operations. Second, when project startup dates are not available, the year that average well abandonment will occur for each reservoir under conventional recovery is estimated. This abandonment date is based on the projected rate of decline and economic limit of conventional recovery for each reservoir. EOR and/or UMO recovery is then phased in to occur reservoir-wide, at the latest, by the year of estimated abandonment. In addition, UMO infill drilling projects are limited to 10 new project starts per year, consistent with rig constraints that limit the annual number of new wells drilled state-wide.

8/ Ray, et al., *Potential Crude Oil Production from Enhanced Oil Recovery*, U.S. Department of Energy, Bartlesville Project Office, 1986.

F. ESTIMATION OF BENEFITS, COSTS, AND ECONOMIC IMPACTS

The NPC study analyzed each reservoir from the perspective of the operator deciding whether to implement advanced oil recovery processes. The present study does the same in evaluating the economic viability of each reservoir. Thus, the benefits and costs to the operators are explicitly captured in the net present value calculations of individual projects. Under each of the various cases analyzed, reservoirs yielding a net present value greater than zero at a 10 percent minimum rate of return are assumed to be developed. This assumption is the basis for the statewide projection of potential incremental production and reserves.

The incremental benefits and costs of enhanced oil recovery and production of unrecovered mobile oil are estimated and reported on an annual as well as a cumulative basis. As previously discussed, reservoir timing is based on the estimated abandonment of the resource due to production decline, except for major reservoirs in which activity suggests earlier project start dates. Projects are phased in over a 5- to 10-year period to achieve full project development before this abandonment would occur. Annual estimates of benefits are based on the total economic resource produced in a given year. These annual values are reported for a twenty-five year period, 1990 to 2015. Cumulative benefits include the sum of the annual benefits plus any additional benefits that would accrue after 2015. The total length of time for the life of all projects varies considerably depending on the process, oil price, and tax treatment. The vast majority of cumulative production and benefits occur in the twenty-five year period of focus in this study. The additional benefits that occur after 2015 are small relative to the total benefit but important to the overall aggregate analysis.

1. Benefits to State and Local Treasuries

The benefits to the state and local treasuries from advanced oil recovery processes are the additional tax revenues attributable to implementation of the projects. These taxes include gross production taxes on oil and sales tax on equipment and material purchases. Evaluating these benefits under the current tax structure involves estimating the sum of these revenues as they apply to the development of the projects and the incremental production from advanced recovery projects.

2. Direct State Economic Effects

The effect on the state's treasury is only one segment of the benefits of advanced oil recovery processes. The state's citizens also gain from the increased economic activity. This study includes only the direct effects of the incremental activity, not the economic "multiplier" or indirect "ripple effect" activities (e.g., pipeline construction, retail sales, etc.). The direct impact on the state economy is defined as the sum of net revenues to the state and local treasuries (as presented above); royalties to individuals, corporations, and the state; expendable (intangible) drilling materials and services; and operating costs excluding injectant purchases. It is assumed that these funds flow predominantly to the state and its citizens.

Also excluded from this definition are cashflows that generally benefit citizens of other states in larger proportion than they benefit Texas' citizens. These include costs for tubular steel products installed in wells, injection and production equipment, purchased tertiary injectants, and other oil field materials typically manufactured out-of-state. To the extent that these goods are marketed by distributors in Texas, the direct benefits of these "retail pass-throughs" to the state are omitted from the estimates of direct state economic activity. Similarly, while it is recognized that a portion of tertiary injectants, especially chemicals, may originate in Texas (generating royalties, employment, taxes, and/or other economic activity), estimating these quantities is outside the scope of the present study. Other excluded items include federal taxes, corporate debt service, and return on capital. While the citizens of Texas obviously benefit from these excluded elements as U.S. citizens, or as employees and stockholders of companies providing services, they share them with a much larger population. Thus, the definition used here for direct economic effects understates the actual benefits to Texas and its citizens.

The additional jobs, wages, and benefits created by advanced oil recovery are also estimated. Labor costs (wages and fringe benefits) are calculated by isolating the labor component of all major cost elements. Table III-5 summarizes the major cost elements and their respective labor and material components. Labor costs are converted into estimated numbers of jobs by dividing total wages by the average oil field wages (including benefits) reported by the U.S. Department of Labor.[9/] Sales tax revenues are calculated based on the materials component of these costs, assuming purchasers would pay the 4% state tax on these goods.

9/ U.S. Department of Labor, Bureau of Labor Statistics, 1985.

Table III-5

Labor and Materials as Percentage of Total Cost in EOR Projects

Investments	% Labor	% Materials	% Other
Drilling Wells	18	55	27
Work-overs	15	63	22
Equipping Wells	10	50	40
Pipe Installation	10	50	40
Plant Installation	16	46	38
Expenses			
Field Operations	33	58	9
Plant Operations	38	57	5
Production Treating	0	100	0
Overhead	100	0	0

Sources:

Investments

- Drilling and Work-overs
  - -- NPC, 1984
  - -- EIA, 1984
  - -- Professor Neil J. Dikeman, University of Oklahoma, 1986
- Equipping Wells
  - -- Industry estimate
- Pipe Installation
  - -- Industry estimate
- Plant Installation
  - -- Modern Cost Engineering Technologies, Herbert Popper, page 82-83

Expenses

- Field Operations
  - -- EIA, 1984
- Plant Operations
  - -- NPC, 1984
  - -- EIA, 1984 (power and chemicals)
- Production Treating
  - -- By definition
- Overhead
  - -- NPC, 1984

3. National Effects

The nation as a whole benefits from increased oil production in Texas. Each additional barrel of domestic production can replace a barrel of imports. Each dollar of increased gross domestic product that would otherwise pay for imports is, potentially, a dollar reduction in the trade deficit.[10/] To estimate the direct effects on the gross domestic product (i.e., excluding multiplier effects), this study uses the gross revenue from the additional production. This measure of gross revenues incorporates both the included and excluded elements discussed in the section above on direct state economic activity. In this sense, the estimated increase in gross domestic product represents a more complete measurement of direct economic impacts on Texas, excluding multiplier effects. In addition, corporate and individual federal income taxes are estimated to assess the direct effects of incremental oil recovery on the federal treasury.

G. LIMITATIONS TO THE ANALYTICAL APPROACH

The approach followed by this study has limitations that should be considered in utilizing its results. Some of these follow from the adoption of the NPC methodology; others result from the need to limit the scope of the present effort.

The NPC approach, while the most credible and flexible methodology available, has certain distinct limitations. One problem is the reliance on averaged reservoir and fluid properties. Oil reservoirs are actually highly heterogeneous, with erratic properties throughout the field. The use of averaged properties belies the fact that portions of an individual reservoir could be highly attractive as an advanced technology oil recovery prospect even if the whole reservoir, on average, is not economic. Given the present methodology, reservoirs must be economically accepted or rejected as whole units, except when advanced geoscientific knowledge is assumed, allowing the reservoir to be evaluated in segments. The methodologies of both the present study and the NPC assume that the least favorable 20 percent of any reservoir would not be flooded.

10/ Although constraints caused by limited financial or personnel resources may result in delayed national benefits due to short-term deferral of projects in other states, the aggregate benefits to the nation should be achieved as all economic projects will ultimately be developed.

A second limitation is the use of regional costing algorithms. Although developed from the best available data and explicitly adjusted for variations in energy costs and specific reservoir characteristics, they do not reflect site-specific cost variations applicable to specific operators. Thus, this study does not necessarily use the actual costs of individual projects. To the extent that the average costs used understate or overstate the true project costs, the actual results will be higher or lower than the analysis estimates.

A third limitation is the use of simplified process performance models. While the models used in this project are extensively calibrated, they are designed to analyze large numbers of individual reservoirs quickly and simultaneously. Therefore, while they incorporate all the relevant reservoir engineering concepts, they are relatively simplified and generalized. In this simplified state, the models cannot be as accurate as highly detailed reservoir simulators in which very specific reservoir features and process designs may be evaluated (such as assessments used in the actual design of specific projects). The present study assumes these models are appropriate for aggregate analyses but not necessarily for individual reservoirs. Further, these models are explicitly designed to estimate only incremental recovery resulting from advanced oil recovery processes. Laboratory and limited field data suggest that application of some of these techniques before the economic limit of conventional recovery could yield more than the sum of conventional and unconventional recovery, but this is not reflected in the models.

None of these limitations invalidates the approach for a statewide study. However, to avoid misinterpretation of particular reservoirs, and to respect the confidence in which some project and reservoir data were obtained, no reservoir-specific data is provided in this report.

An additional limitation arises from the methodological convention of "constant price" analysis. The use of this convention is consistent with the NPC's nationwide study, conducted during a period of relatively stable, rising oil prices, and differentiates the effect of oil price from other effects. It can, however, cause a distortion, especially in times of declining or radically changing oil prices. The "hidden" assumption of this convention is that each of the respective oil prices analyzed must be attained by the time (and be expected to continue at that level after) the decision to commit specific reservoirs to enhanced recovery or advanced mobile oil recovery operations is made. This decision is generally made several years before the reservoir's final, actual economic limit is reached under conventional technology. To the extent this condition is

not met, existing wells reaching their economic limits at lower prices will be shut-in and abandoned, making them unavailable for use in advanced oil recovery projects, as assumed. The economic model assumes that all existing wells will be utilized in future operations, although older wells may require workovers. Should "premature" abandonments occur, these wells would need to be redrilled, resulting in investment requirements not included in this analysis (although necessary workovers are included in the assumed cost). Redrilling would result in substantially increased costs, and thus increase the minimum oil price at which advanced oil recovery processes are profitable for certain reservoirs. The net effect of this analytic convention, then, could be to overstate the economic reserves and production and the corresponding economic benefits. Under these conditions, the "constant price" convention introduces an optimistic bias to the present approach.

Further, some Texas reservoirs have been excluded from this analysis due to data limitations. In the EOR analysis, these excluded reservoirs account for approximately 26% of the state's original oil in place and 21% of the remaining immobile oil resource; in the UMO analysis, these excluded reservoirs account for approximately 38% of the state's original oil in place and 45% of the remaining mobile oil resource. The excluded reservoirs lie in over 9,000 producing oil and gas fields in Texas. Due to study limitations and the difficulty of obtaining required data on some smaller Texas reservoirs, no results were estimated or extrapolated for the missing resource. Data collection efforts in the reservoirs included in this study incorporate rock, fluid, production, and geologic data available from the Texas Railroad Commission (RRC) and BEG. The research performed by state personnel dramatically improved the data, and similar efforts in the future could further improve and extend the data available for other fields. Information available on tape from the RRC is particularly relevant to the study. Significant use is made of the file *Secondary and Enhanced Oil Recovery Projects*, last updated in 1982. If more current information were available in machine-readable format, the data coverage and accuracy could be further improved.

Finally, the analysis follows the NPC approach, which assumed that project operation would be conducted by an integrated major oil company. This approach, in most cases, presents the least favorable corporate tax treatment for investments and revenues from advanced oil recovery projects and assumes a relatively high overhead on operations. Independent producers operate with a different corporate structure, tax situation, and overhead rate. Because most costs used in this analysis are not affected by total project size and some non-integrated operators would enjoy more

favorable tax treatment, smaller independent producers should receive the same benefit as a major oil company from application of advanced oil recovery processes, possibly even at lower oil prices than projected in this evaluation.

IV. INCREASED RECOVERY FROM THE KNOWN REMAINING OIL RESOURCE IN TEXAS UNDER IMPLEMENTED TECHNOLOGY

A. INTRODUCTION

The reservoirs selected for use in this study are individually analyzed to evaluate their potential for incremental production by tertiary and advanced primary and secondary recovery techniques. All reservoirs are screened for technical criteria and are analyzed in detail using the process performance and economic models described in Chapter III. No effort is made to extrapolate the results of this analysis to the rest of the reservoirs making up the total state resource. This chapter discusses the post-conventional reserve additions and potential economic impacts attributable to the statewide application of currently available oil recovery methods. Chapter V presents the incremental reserves and benefits under advanced technology methods attainable through R&D.

B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE

1. Production and Reserves

Over the price range analyzed, EOR processes (gas miscible, chemical, and thermal) could stimulate from nearly 70 million to 5.3 billion barrels of reserve additions under implemented technology. This potential represents up to a 75% increase in the state's current proved reserves (7.1 billion barrels). At oil prices of $16/B or less, reserve additions would be relatively small. However, as the oil price rises above $20/B, EOR processes could become increasingly prolific, and substantial incremental reserves could become economically attainable (Figure IV-1A and Table IV-1A). The 1.5 billion barrels of potential EOR reserves at $20/B could increase by an estimated 1.1 billion barrels, or 73%, with a $4/B increase in the oil price. An additional $4/B increase in the oil price to $28/B could add another 1.5 billion barrels of EOR reserves for a total of over 4.1 billion barrels. As oil prices increase to $36/B, EOR techniques could generate total reserve additions of 5.3 billion barrels.

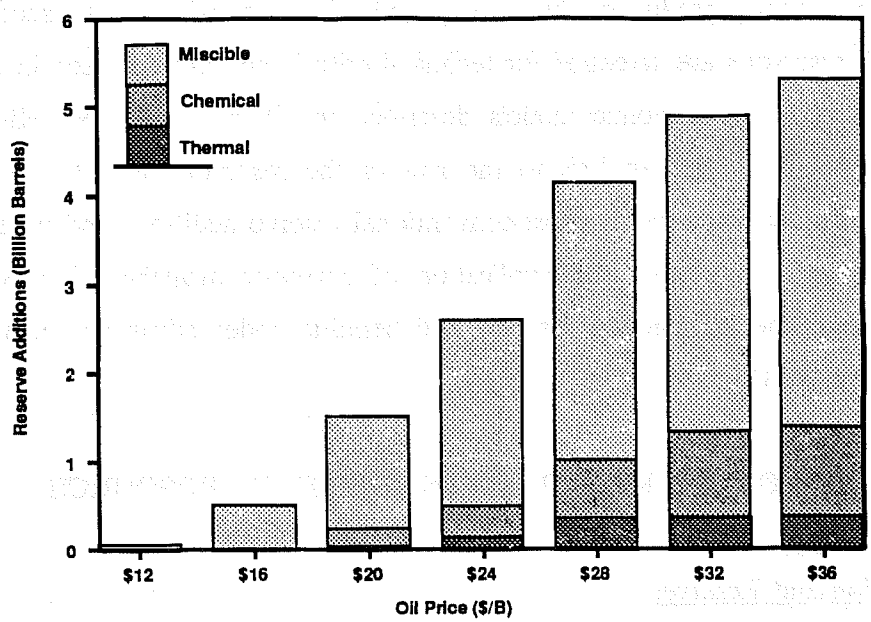
Among the EOR processes considered in this analysis, gas-miscible (carbon-dioxide and nitrogen) generates the largest additions at all oil prices. The relatively inexpensive supply of CO_2

Figure IV-1

Reserves and Production Response from EOR Techniques in Texas

Implemented Technology

A) EOR Reserves by Recovery Process



B) Annual Production from EOR Reserves

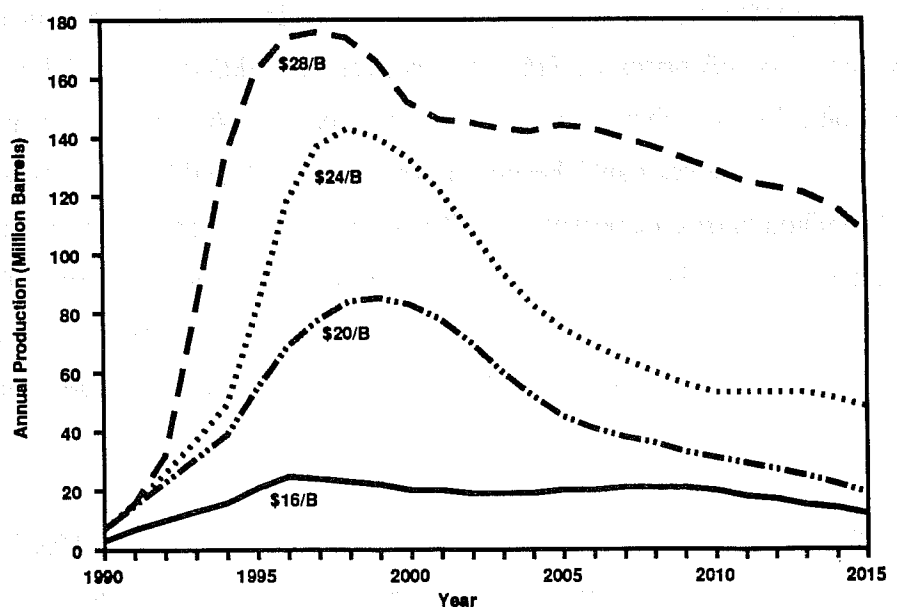


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Table IV-1A

Incremental Reserve Additions from EOR by Process
Implemented Technology
(Millions of Barrels)

Oil Price ($/B)	Miscible	Chemical	Thermal	Total
$12	69	0	0	69
$16	503	17	0	520
$20	1,261	206	47	1,514
$24	2,112	362	152	2,626
$28	3,135	661	366	4,162
$32	3,560	978	369	4,907
$36	3,825	1,120	376	5,321

Table IV-1B

Estimated Number of Economic EOR Projects by Process
Implemented Technology
(Project Counts)

Oil Price ($/B)	Miscible	Chemical	Thermal	Total
$12	13	0	0	13
$16	24	1	0	25
$20	44	4	1	49
$24	68	8	4	80
$28	96	19	6	121
$32	121	29	6	156
$36	137	37	6	180

in West Texas gives this technique an economic advantage over other EOR processes at lower oil prices. At an oil price of $12/B, miscible flooding would account for all EOR reserve additions. At $16/B and $20/B, miscible flooding would comprise 97% and 83% of the estimated EOR reserve additions, respectively. At higher prices, other EOR processes, particularly chemical flood, become more attractive, and the dominance of miscible flooding declines, but at $36/B, miscible flooding would still contribute 72% of the total potential reserve additions from the analyzed reservoirs. Given oil prices at or above $32/B, miscible floods could recover over 3.5 billion barrels, a resource roughly equivalent to one-half of Texas' current proved reserves.

The recovery potential of other EOR processes is more limited in Texas. Chemical flooding (mainly micellar-polymer) exhibits significant potential at higher oil prices. As shown in Figure IV-1A and Table IV-1A, chemical flooding could add from 660 million to over 1.1 billion barrels to Texas proved reserves over the oil price range from $28 to $36/B. At lower oil prices, however, chemical flooding potential under implemented technology is small due to high chemical costs; a threshold price of at least $20/B is needed to make chemical flooding cost-effective in the analyzed Texas reservoirs under implemented technology. The application of thermal flooding is also limited due to the small volumes of heavy oil (reservoirs with API<20 degrees) in Texas, but thermal processes still contribute up to 9% of the total EOR reserve additions at a $28/B oil price and above.

Table IV-1B shows the number of EOR projects that would be started at different oil prices. Of the reservoirs evaluated in this analysis, all of which are technically amenable to one or more EOR process, only 36% are economic to develop with current EOR technology at oil prices of $36/B or below. Miscible floods account for more than 75% of the EOR projects considered economic in the price range evaluated, and at oil prices of $20/B or less miscible floods account for essentially all economic Texas EOR projects. In most cases, the economic projects are in the large reservoirs, but size alone is not a major determinant of EOR economics. The reservoirs that have been found to be uneconomic for EOR tend to be characterized by heterogeneities that cause sweep, by both conventional and tertiary injectants, to be less than optimal. As a result, these reservoirs show poor recovery and require larger volumes of the injectant to contact and recover the tertiary oil. Technological advances that effectively address these problems could substantially increase the potential production from EOR methods in Texas.

Such improvements in EOR technology are clearly a target for concentrated R&D; their potential impact in Texas is discussed in Chapter V.

The timing of project initiation in each reservoir that is economic at a specific price is scheduled according to that reservoir's projected decline rate. The annual incremental production resulting from enhanced oil recovery is determined by phasing in economic projects based on the demonstrated economic limit of conventional production as discussed in Chapter III. Figure IV-1B shows the expected annual production from all EOR processes for oil prices of $16 to $28 per barrel. Projected annual production peaks between 1996 and 1999, depending on the oil price. At $16/B, EOR production reaches 25 million barrels per year by 1996, and remains around the 20 million barrel level until the year 2010. The $20/B annual production curve peaks at 85 million barrels in the year 1999, falling sharply to 45 million barrels in 2005, and dropping to 20 million barrels by 2015. This same trend holds true at $24/B, where production reaches 145 million barrels in 1998. At $28/B, EOR production peaks at around 175 million barrels per year in 1997, and declines at a much slower rate than at lower prices.

2. Increases in State and Local Revenues

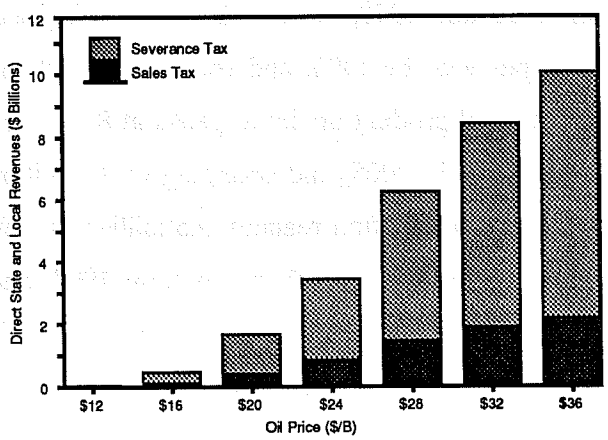
EOR production could also increase state and local revenues by severance taxes and by sales taxes on purchased materials used in the projects. The revenues projected in this study are generated directly from oil production or operations in the analyzed reservoirs. Again, the results are not extrapolated to determine the potential revenues that would be generated from EOR projects in the remaining Texas reservoirs, nor are the revenues from other activities indirectly stimulated by the increase in economic activity considered. State and local revenues generated over the life of the EOR projects vary considerably with oil prices, as shown in Figure IV-2A. A significant portion of these revenues result from production taxes. At $20/B, nearly $1.7 billion in incremental revenues could be generated, with production taxes contributing over 74% of the total and sales tax revenues accounting for the remainder. A $24/B oil price could yield production tax revenues of $2.6 billion plus $840 million in sales tax receipts. At $28/B, additional revenues total $6.3 billion, while at the highest price case of $36/B, $10.1 billion of additional state and local revenues are generated.

Figure IV-2

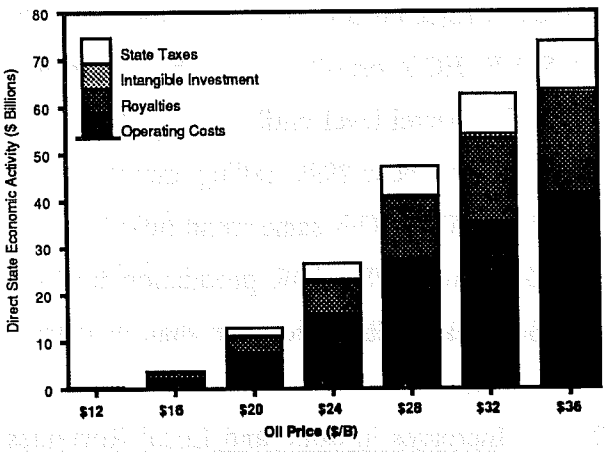
State Impact of EOR Production

Implemented Technology

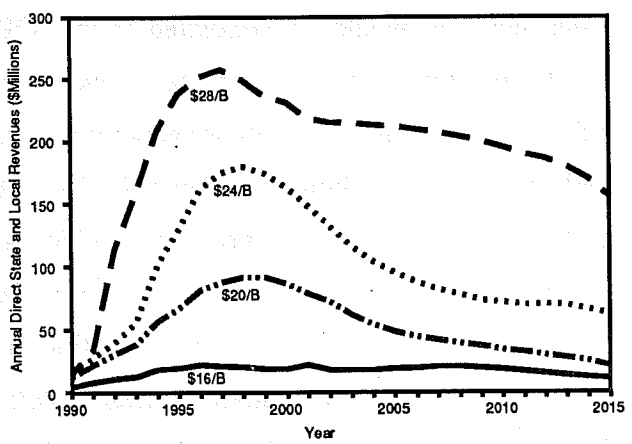
A) Direct State and Local Revenues



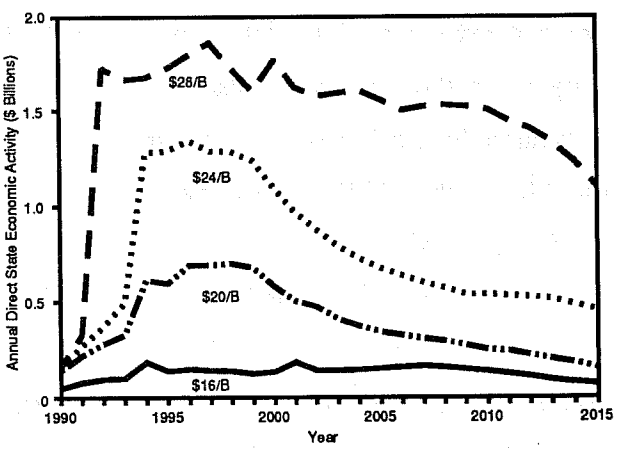
C) Direct State Economic Activity



B) Annual Direct State and Local Revenues



D) Annual Direct State Economic Activity



Annual state and local revenues (Figure IV-2B) follow a pattern similar to the annual production trends shown in Figure IV-1B. At $20/B, annual revenues from EOR operations peak in 1998, at over $90 million. At $24/B, the peak is also in 1998, at $180 million. If oil prices were to rise to $28/B, over $255 million in state and local revenues would be generated in the peak year of 1997. Even in the lower price cases, additional state and local revenues generated from EOR production and sales taxes are substantial. Clearly the successful application of EOR processes in Texas reservoirs would be beneficial for the state.

3. Effects on the State Economy

In addition to the incremental state and local revenues, enhanced oil recovery would benefit Texas by increasing economic activity and by creating new jobs. As stated in Chapter III, the effects of EOR on the state economy are estimated conservatively: (1) only direct effects are included (i.e., no economic multiplier due to secondary effects); and (2) the direct effects are limited to benefits believed to accrue predominantly to the state of Texas and its citizens. Only intangible drilling costs, royalties, state and local taxes (as defined in the previous section), and operating costs, exclusive of purchased injectants, are included in the calculation of state economic activity. Tubular steel products, injection and production equipment, purchased EOR injectants, corporate return on capital, and federal taxes are all excluded from this definition of state economic activities. While the excluded elements undoubtedly aid Texas' citizens to some degree, a substantial portion of the benefits will be enjoyed by citizens of other states. However, to the extent that local manufacture or retail sales of these cost items provide economic benefits within Texas, injectants produced or manufactured in Texas are employed, or economic "multipliers" occur, the calculated economic effects are understated.

Figure IV-2C displays the total direct economic gains for the state, as defined, over the oil price range analyzed. In all cases, operating costs would account for at least 50% of these economic effects; state taxes represent around 13%; intangible investment is about 2%; and royalties constitute about 25% of the total. At an oil price of $12/B, the economic benefits to the state would be very limited due to the very small EOR production at this price. At $16/B, incremental benefits to the state economy would exceed $3.7 billion. A substantial increase in economic activity occurs at oil prices above $20/B; $47 billion and $63 billion would be generated

at the oil prices of $28 and $32/B, respectively. At the highest oil price considered, $36/B, an estimated $74 billion of statewide direct economic activity would be stimulated by EOR projects.

Figure IV-2D shows how this estimated economic activity occurs over time. At an oil price of $20/B, the annual direct economic effects would peak at nearly $700 million in 1996. At the oil prices of $24 and $28/B, direct economic effects would peak at $1.3 and $1.9 billion in 1996 and 1997, respectively. These results illustrate the magnitude of the impact that the application of EOR processes to appropriate reservoirs could have on the Texas economy.

Successful EOR projects could add a substantial number of jobs statewide, as shown in Figure IV-3. In contrast to the 171,000 Texans employed in the oil and gas extraction industry in 1988, the number of additional jobs attributable to new EOR projects during peak years could reach from 2,000 to nearly 24,000 per year, depending on the oil price. Total annual wages paid could peak between $50 and $600 million.

4. Effects on the National Economy and Budget

Increased oil recovery from EOR in Texas would benefit the nation as a whole. National benefits would accrue in three ways: replacement of oil imports, increased federal corporate and personal income tax revenues, and increased Gross Domestic Product (GDP). The addition of as much as 5.3 billion barrels of reserves in Texas would expand the nation's proved reserve base. Since an additional barrel of domestic oil production replaces a barrel of imported oil, the nation's energy security would be enhanced through the implementation of EOR in Texas.

EOR activity in Texas contributes to the federal treasury through personal and corporate income taxes. As shown in Figure IV-4A, increases in federal revenues attributable to EOR would range from $500 million at $16/B to more than $19 billion at $36/B over the life of the projects. Corporate income taxes would account for between 65% and 78% of this total, depending on the oil price, and personal income taxes would make up the remainder.

Figure IV-4B shows annual Texas EOR additions to federal revenues. The negative annual federal revenues in the early years result from the taxable losses generated by the initial implementation phases of many EOR projects; it is assumed that these losses are used to offset

Figure IV-3

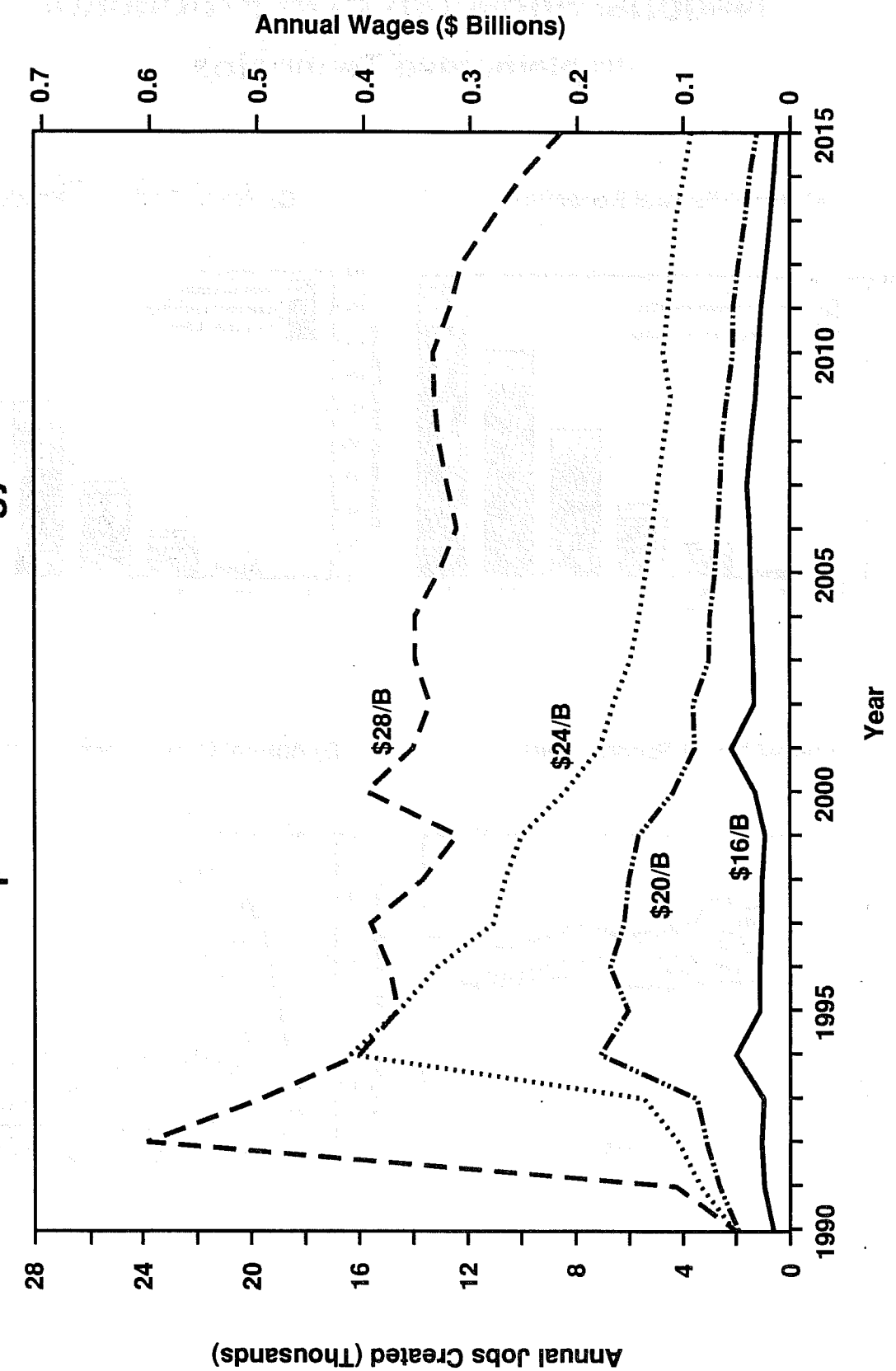


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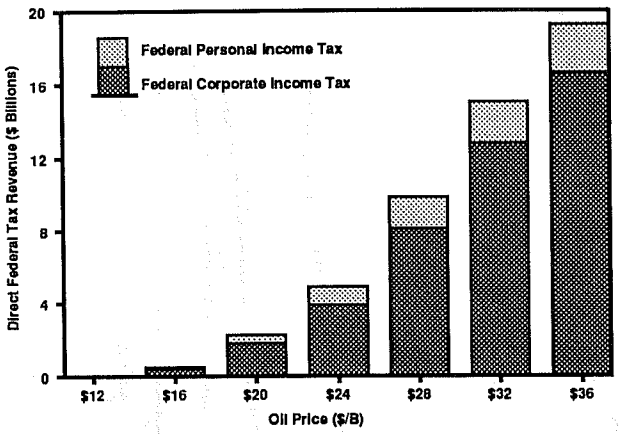
Figure IV-4

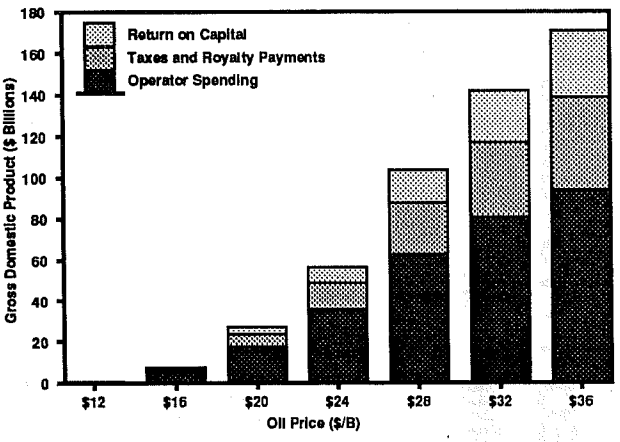
National Impact of EOR Production

Implemented Technology

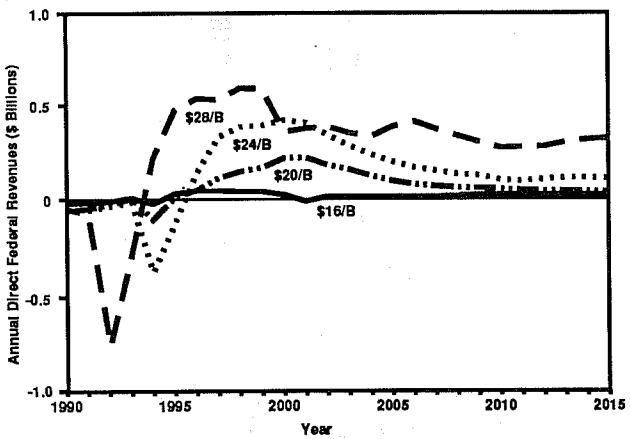
A) Direct Federal Revenues



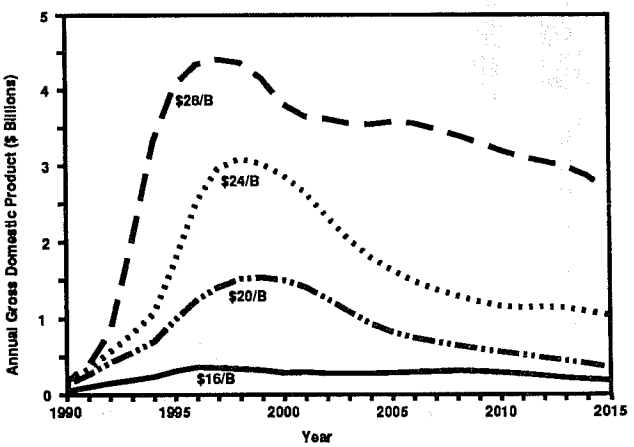
C) Gross Domestic Product



B) Annual Direct Federal Revenues



D) Annual Gross Domestic Product



federal income tax liabilities from other profitable activities within the operating company, thus reducing overall federal income tax revenues. In this context, it is useful to note that federal corporate income taxes are evaluated at the highest corporate marginal tax rate (34%) under the Tax Reform Act of 1986. At $28/B, federal revenues would range from around negative $770 million in 1992 to positive $590 million in 1998. This compares to revenues of negative $380 million in 1994 and positive $418 million in 2000 at $24/B. Despite negative revenues in the early years, the application of EOR processes in Texas clearly would generate substantial future federal revenues.

The third benefit to the nation is that an increase in Texas oil production would directly correspond to an increase in national GDP, while directly reducing the merchandise trade deficit. As shown in Figure IV-4C, the additional GDP from Texas EOR could range from $7.6 billion (at $16/B) to $171 billion (at $36/B) over the life of the projects.

Operator spending on investments and production related costs represent over half of the total increase in GDP over the price range. Taxes and royalty payments on the production represent about 30% while return on capital makes up the remaining 20%. Figure IV-4D displays the estimated annual increases in GDP that would result from Texas EOR production. At the intermediate oil price of $24/B, EOR projects in Texas could contribute over $3 billion in GDP in 1998 alone. At $28/B, the increase in GDP could be over $4 billion per year from 1995 to 1999, peaking at more than $4.4 billion in 1997. These gains in GDP represent funds that would otherwise flow to oil exporting countries to pay for U.S. oil imports. EOR in Texas would thus help reduce the trade deficit, enabling these monies to instead circulate through the U.S. economy, creating additional benefits.

C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE

The previous section focused on the potential impact of implementing EOR processes in selected Texas reservoirs. This section will discuss the effect of implementing UMO extraction processes in analyzed reservoirs throughout the state. These two distinct recovery technologies, enhanced oil recovery and unrecovered mobile oil extraction, have been addressed separately to illustrate the potential benefits of each. However, since the resource target of these two technologies is different, both could be implemented in Texas. Given the potential synergies in

the simultaneous employment of the EOR and UMO technologies, reserve additions and economic benefits could be even greater than the sum of the two. Combined totals and possible synergies are discussed in Chapter VI.

1. Production and Reserves

Depending on the oil price, UMO recovery techniques applied in the reservoirs analyzed could stimulate between 0.9 billion and 1.9 billion barrels of additions to current proved reserves in Texas. UMO extraction techniques are less costly to implement than EOR recovery processes, and therefore UMO reserve additions are less sensitive to changes in the oil price. A larger percentage of the UMO target could be recovered at low oil prices than is possible with EOR. At the lowest oil price analyzed, $12/B, over 855 million additional barrels could be recovered. At $20/B, incremental UMO recovery could amount to nearly 1.4 billion barrels, which is nearly 73% of the oil economically accessible at $36/B.

This analysis evaluates three categories of UMO recovery processes: advanced secondary techniques (polymer flooding and profile modification), infill drilling, and combinations of infill drilling with advanced secondary processes. As shown in Figure IV-5A and Table IV-2A, infill drilling, both by itself and in combination with other processes, plays a predominant role in UMO recovery, accounting for the bulk of the reserve additions at all prices. At oil prices below $20/B, the combination processes could contribute from 553 to 689 million barrels of reserves, while infill drilling could contribute 85 million to 468 million barrels of reserves. Below $20/B, the percentage of total UMO reserves stemming from infill drilling, either alone or in combination with advanced secondary techniques, would range from 75% to 84% of the total potential at the given price. As oil prices increase, infill drilling by itself would become more economical since revenues increase along with oil prices. At $28/B, infill drilling by itself would contribute over 40% of the 1.6 billion barrels of total reserves, close to the 45% contribution by the combination processes. At the higher oil prices of $32 and $36/B, both infill drilling by itself and the combination processes make nearly equal contributions (about 44%) to the total reserves.

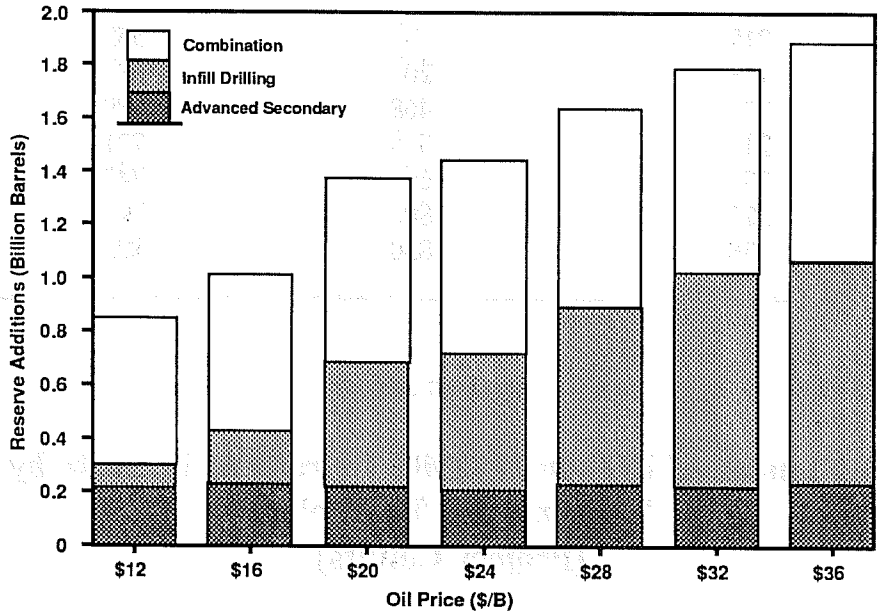
Advanced secondary processes, applied alone, would contribute around 220 to 240 million barrels to total reserves across all oil prices considered in this analysis. The reason that reserves from the advanced secondary projects do not rise with the oil price is that these processes compete with the more prolific infill drilling-related techniques. In this analysis, only one of the five

Figure IV-5

Reserves and Production Response from UMO Extraction Techniques in Texas

Implemented Technology

A) UMO Reserves by Recovery Process



B) Annual Production from UMO Reserves

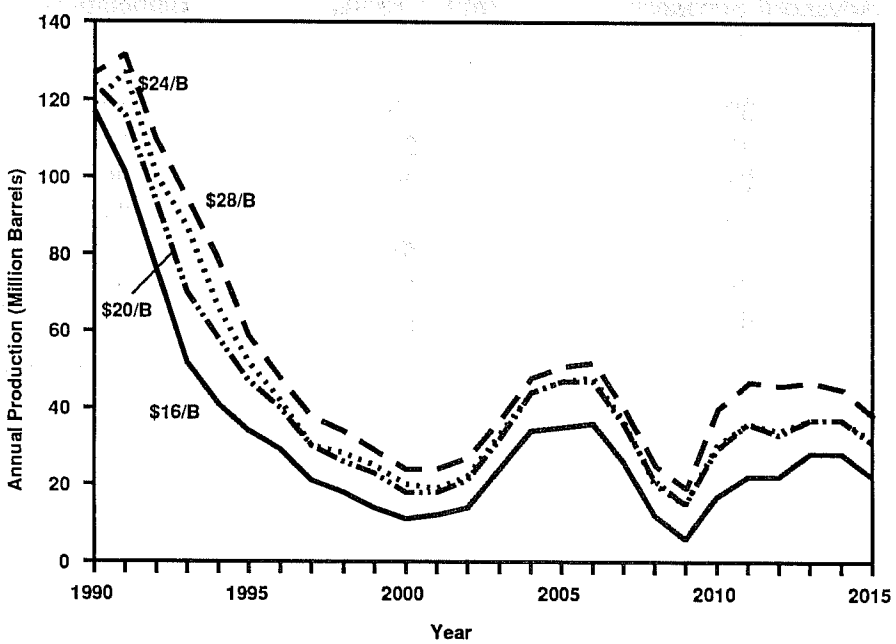


Table IV-2A

Incremental Reserve Additions from UMO Extraction by Process Implemented Technology (Millions of Barrels)

Oil Price ($/B)	Advanced Secondary	Infill Drilling	Combination	Total
$12	218	85	553	856
$16	233	201	581	1,015
$20	222	468	689	1,379
$24	212	515	721	1,448
$28	233	663	747	1,643
$32	225	803	764	1,792
$36	238	830	823	1,891

Table IV-2B

Estimated Number of Economic UMO Extraction Projects by Process Implemented Technology (Project Counts)

Oil Price ($/B)	Advanced Secondary	Infill Drilling	Combination	Total
$12	59	16	19	94
$16	71	27	23	121
$20	75	40	29	144
$24	75	46	34	155
$28	77	55	40	172
$32	79	65	40	184
$36	81	69	43	193

analyzed processes is implemented in each reservoir. As the oil price rises, thereby justifying the more expensive infill drilling and combination projects, reservoirs that were assigned to advanced secondary recovery projects at lower oil prices are reassigned to the now economically feasible, more prolific techniques.

Table IV-2B shows the number of projects expected to be economic at each price for each recovery method. At all prices, the number of advanced secondary projects would be consistently higher than either infill drilling or combination projects, even though these projects produce smaller incremental reserves. Advanced secondary recovery projects yield smaller recoveries because they are concentrated in smaller fields. The more prolific, but more costly, infill drilling projects (either alone or in combination) are economically feasible only in fields with relatively large UMO targets.

Figure IV-5B displays the expected annual production from all UMO extraction processes for oil prices from $16 to $28/B. Fluctuations in the production curves are caused by the initiation of new UMO extraction projects as major groups of reservoirs reach their conventional recovery economic limit, or by the selective early initiation of some projects to prevent the reservoirs from being abandoned prematurely. For this study, UMO projects are assigned initiation dates based on the time when that reservoir will reach its economic limit under conventional recovery techniques at the specific oil price considered. The economic limit is projected by a decline curve analysis, and the project start date is adjusted according to the availability of rigs to drill the required wells.

Annual UMO production at an oil price of $16/B would peak in 1990 at 115 million barrels and average about 35 million barrels per year over the 1990 to 2015 period. At an oil price of $28/B, annual production would peak at over 130 million barrels in 1991 and average over 50 million barrels per year over the 25 year period. To put the potential contribution of UMO into perspective, 50 million barrels per year would add about 7% to current Texas annual production. Potential UMO production peaks earlier, but then declines more rapidly than EOR production. This trend is representative of the nature of these processes in that infill drilling prompts an immediate response in production while EOR projects require longer response times to allow injectants to flow through the reservoir.

2. Increases in State and Local Revenues

Figure IV-6A shows the expected growth in state revenues from UMO production and the proportional contributions of production and sales taxes to the total. Production tax receipts account for the largest portion of total state revenues from UMO extraction over all prices considered. Production taxes could generate $420 million for the state at $12/B. At $36/B, $3.2 billion could be generated for the state through UMO activities, with 87% of that amount from production taxes. Annual state revenues from UMO recovery shown in Figure IV-6B follow the same trend as UMO production. The peak annual state revenues stimulated by UMO production could range from $90 to $175 million over the $16 to $28/B oil price range shown.

3. Effects on the State Economy

Figure IV-6C displays the total state economic activity associated with potential UMO production. Total state economic activity from the processes could range from $5.4 billion at $12/B to $30.1 billion at $36/B. At intermediate oil prices, state economic activity would total $13.4 billion at $20/B and $20.9 billion at $28/B.

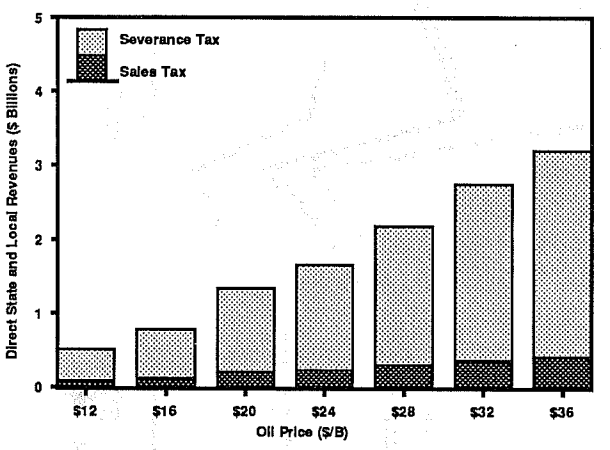
Operating costs would be the largest component of these increases in state economic activity, accounting for 31% to 41% of the total. These costs would approach $10 billion at the $36/B oil price. Intangible investment and royalties would be the next largest components of increased economic activity, averaging about 32% and 26%, respectively, of the total activity across all oil prices. State taxes would contribute the remaining 10%.

The implementation of UMO techniques could significantly contribute to employment in the state of Texas. Figure IV-7 displays the annual number of new jobs that would be generated by UMO projects. The annual trends in jobs created closely match the production trends for UMO recovery, peaking early and then declining until a new wave of activity begins around 2010. At an oil price of $16/B, jobs would peak in 1990 at around 3,500, decline to about 250 in 2009, then increase to around 1,200 in 2013. At $28/B, the number of new jobs generated would peak in 1991 at about 5,600, drop to about 1,000 by 2009, then rise to over 3,000 in 2010. At this price as much as $140 million in wages would be paid in the peak employment year at the higher oil prices.

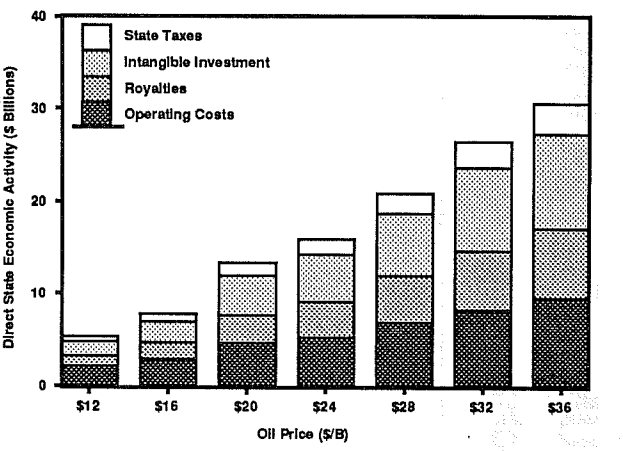
Figure IV-6

State Impact of UMO Extraction
Implemented Technology

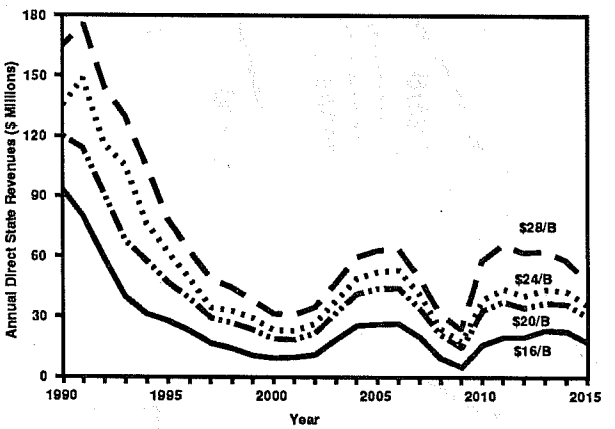
A) Direct State and Local Revenues



C) Direct State Economic Activity



B) Annual Direct State and Local Revenues



D) Annual Direct State Economic Activity

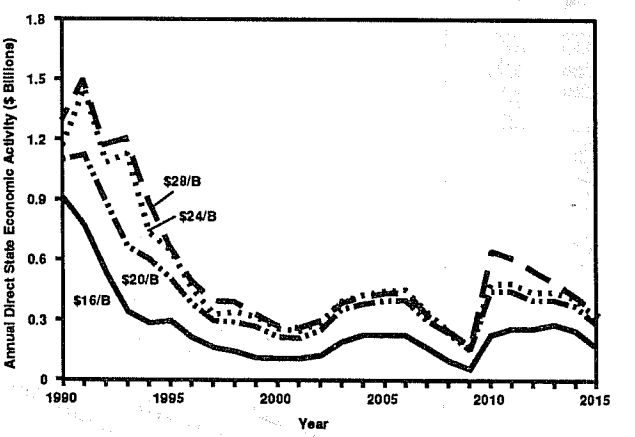
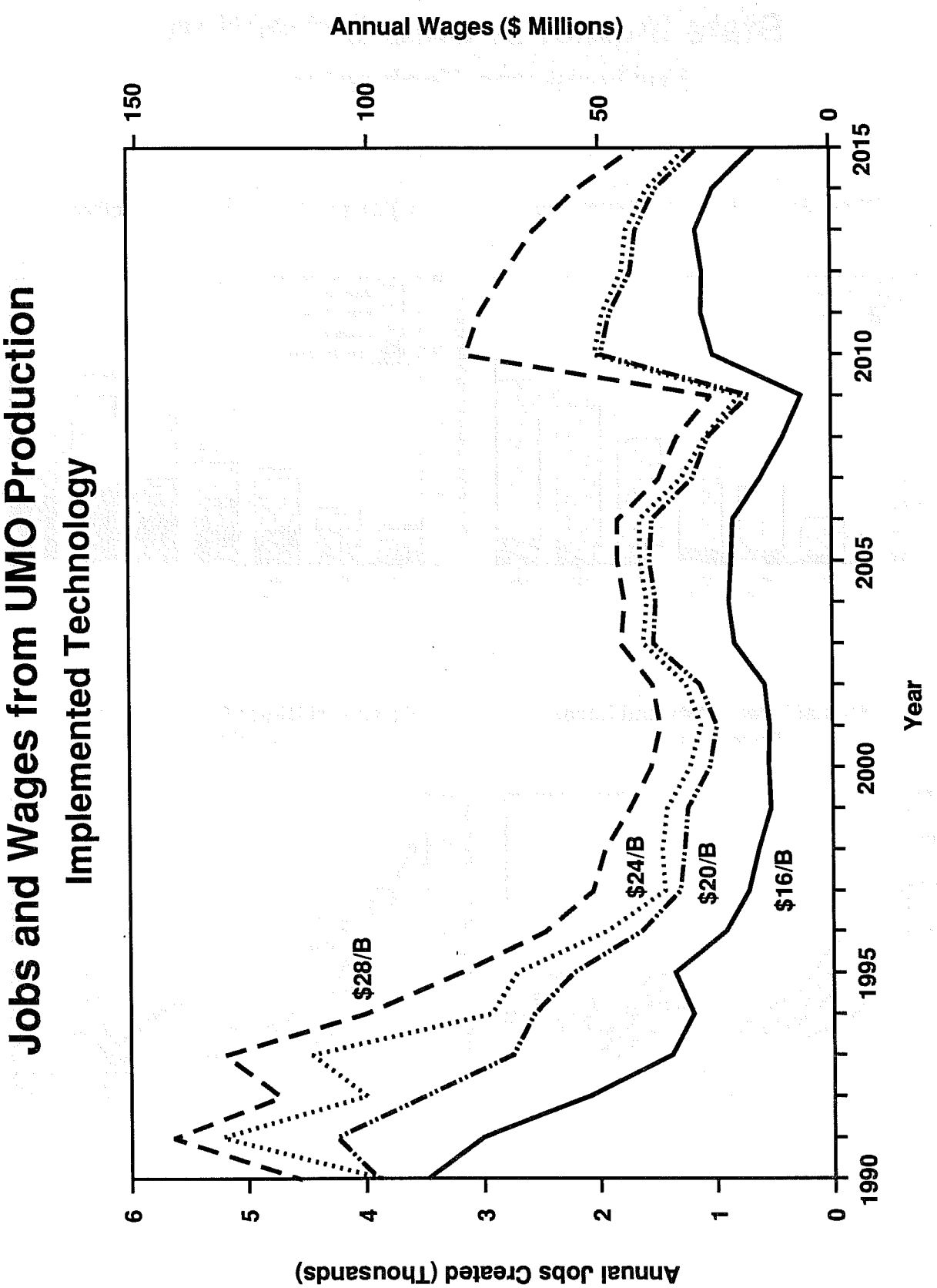


Figure IV-7


Jobs and Wages from UMO Production
Implemented Technology
Annual Wages ($ Millions)
150
100
50
0
Annual Jobs Created (Thousands)
6
5
4
3
2
1
0
1990
1995
2000
2005
2010
2015
Year
$28/B
$24/B
$20/B
$16/B
f9505320

4. Effects on the National Economy and Budget

Figure IV-8 shows the national benefits of UMO production in Texas. Federal revenues from UMO production could range from about $1.4 billion to more than $10.6 billion over the price range analyzed. Figure IV-8A shows that nearly all of these revenues would stem from corporate income taxes. Annual federal revenues generated (Figure IV-8B) follow the general trend in annual production, peaking around 1990 and then again rising several years later. At an oil price of $16/B, the annual federal revenues due to UMO production would peak at about $300 million in 1990. At $28/B, incremental federal revenues could reach $640 million in 1990.

Increases in Gross Domestic Product (GDP) from UMO production in Texas could total between $9.1 and $60.4 billion over the price range analyzed. The three components of GDP, operator spending, taxes and royalty payments, and return on capital, make roughly equal contributions to total GDP additions. On an annual basis, GDP would peak in 1990 at around $1.7 billion, assuming a $16/B oil price, or at $3.2 billion in 1991, assuming a $28/B oil price. As the increased Texas production replaces oil imports, the U.S. trade deficit would be reduced and national security would be enhanced as the nation's vulnerability to a supply disruption is diminished. As the GDP directly arising from UMO production is created, additional GDP will be indirectly stimulated as a result of economic multipliers.

D. SUMMARY

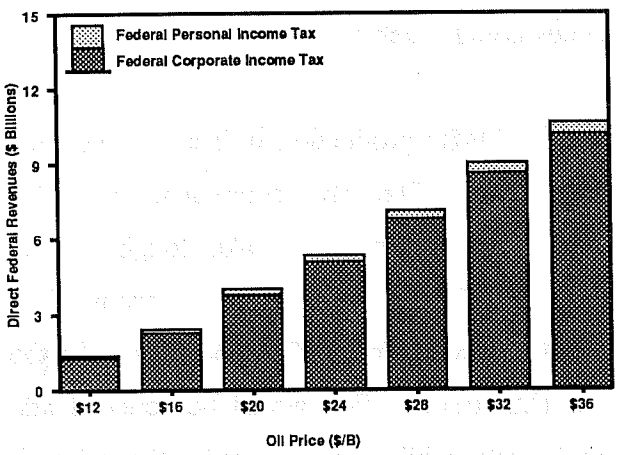
Even at implemented technology levels, EOR and UMO extraction processes could make substantial contributions to the Texas and national economies, as well as to domestic energy security. At a $36/B oil price, EOR processes could add 5.3 billion barrels to Texas reserves while UMO extraction techniques could add another 1.9 billion barrels of oil. Although a small amount of double-counting exists (as will be discussed in Chapter VI), the application of current EOR and UMO technologies in concert could potentially add as much as 7.2 billion barrels of reserves at this price, doubling Texas' current proved reserves. While these reserve additions are smaller at lower oil prices they would still generate substantial benefits to the state. The higher production and increased reserves along with the associated economic benefits presented in this chapter are based on the application of currently available, state-of-the-art technology in the reservoirs analyzed. As discussed in the next chapter, improved geoscientific understanding of reservoirs and enhanced

Figure IV-8

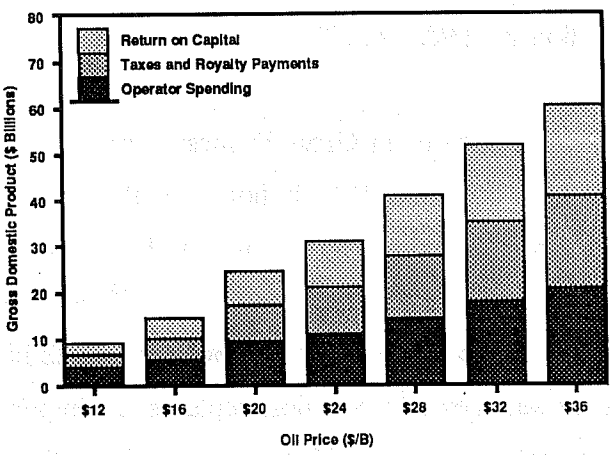
National Impact of UMO Production

Implemented Technology

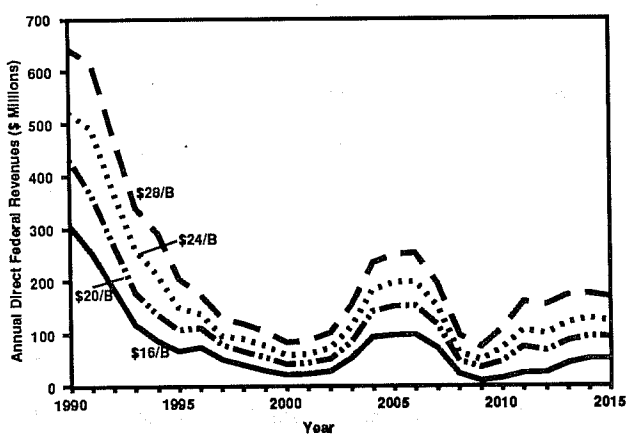
A) Direct Federal Revenues



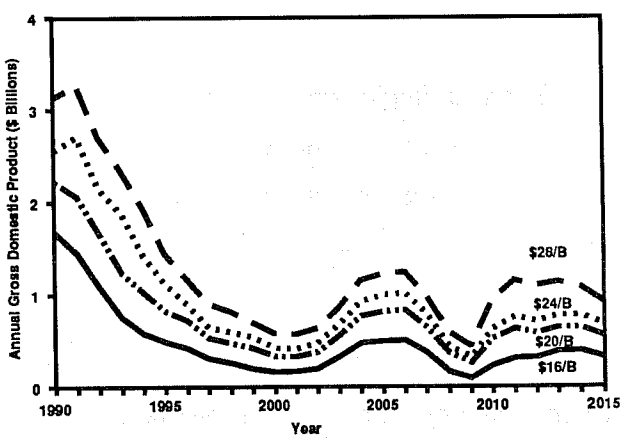
C) Gross Domestic Product



B) Annual Direct Federal Revenues



D) Annual Gross Domestic Product



process performance could increase these benefits if the required research can be cost effectively completed.

The state and its citizens stand to gain significantly from the increased production resulting from incremental reserve additions. Production increases could generate up to $13 billion in additional state and local revenues over the next 25-plus years. Jobs would be created or maintained, and state economic activity would increase. The national economy would benefit through decreased oil imports, reductions in the trade deficit, increased gross domestic product and increased federal corporate and personal income tax revenues. Maximizing recovery of the known oil resource should therefore be an important goal for state and federal policy makers.

V. BENEFITS OF INCREASED RECOVERY FROM THE KNOWN REMAINING OIL RESOURCE IN TEXAS WITH TECHNOLOGY ADVANCES

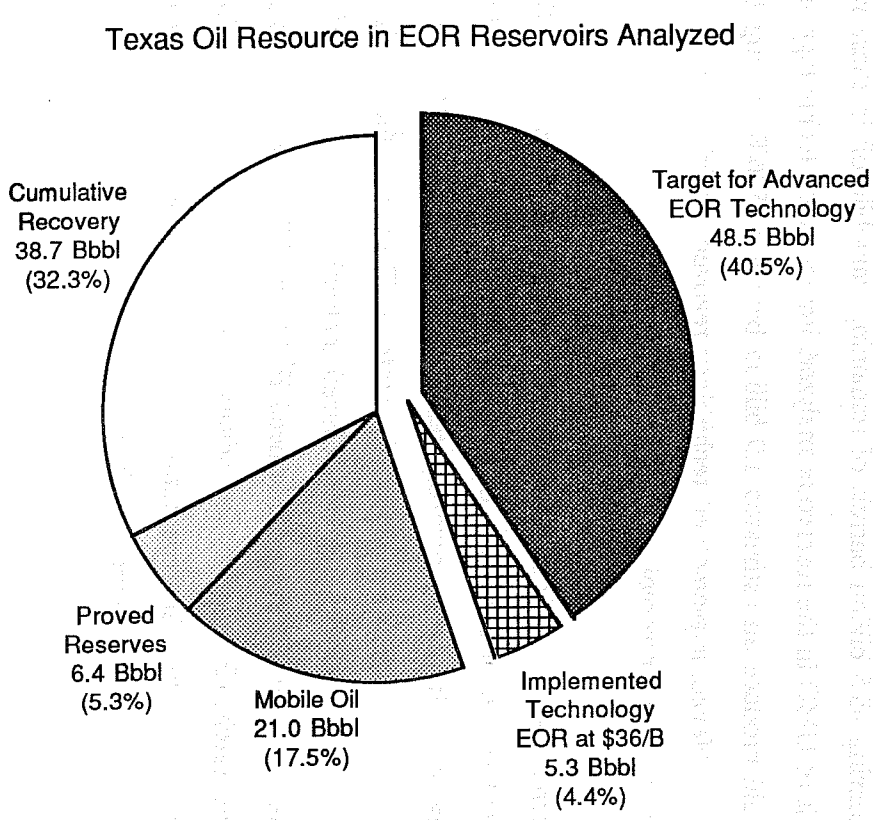
A. INTRODUCTION

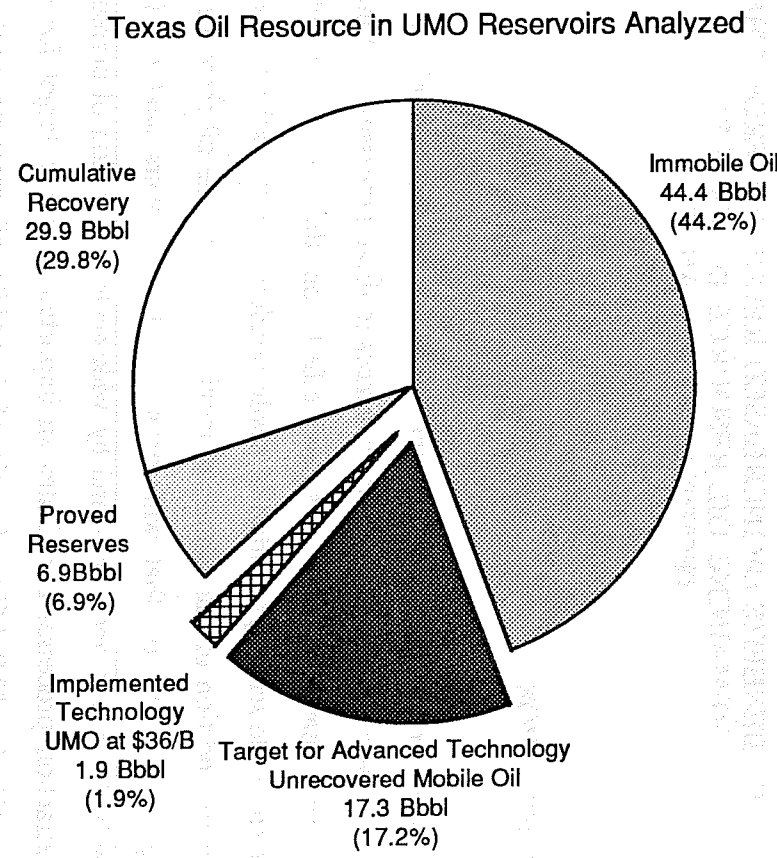
While currently available EOR and UMO extraction techniques could contribute substantially to Texas reserves, technological advances in these processes resulting from a concerted R&D effort would have far more dramatic effects on the state's production and reserves. Development and wide-scale application of newly developed methods could result in the recovery of a much greater portion of the remaining mobile and immobile oil resources in the state. As shown in Figure V-1, the oil that will remain in the reservoirs analyzed in this study after production by both current operations and by wide-scale application of currently available EOR and UMO extraction processes constitutes an important resource target for advanced recovery technologies. Of the 53.8 billion barrels of immobile oil resource analyzed in this study, implemented technology EOR practices could produce an estimated 5.3 billion barrels at an oil price of $36/B, leaving 48.5 billion barrels of remaining immobile oil in these reservoirs. Of the 19.2 billion barrels of UMO in the reservoirs analyzed, implemented technology practices as defined in this report could produce an estimated 1.9 billion barrels at $36/B, leaving 17.3 billion barrels in these reservoirs. Hence, implemented technology recovery practices leave as much as 90% of their target resource in the reservoir.

The extremely large size of the remaining resource clearly warrants an R&D program that will test and speed the implementation of advanced technology procedures designed to capture additional oil reserves. Improved recovery resulting from such an R&D program would have considerable direct and indirect benefits to the state of Texas and the nation as a whole. The present analysis evaluates the benefits of advanced technology on oil recovery and its associated economic impacts. The evaluations of advanced EOR and UMO recovery in the state of Texas are presented separately. Given that the advances in technology modeled in this analysis are conservatively defined, further improvements in recovery processes that result from research and development not currently envisioned could add substantially to the reported estimated reserve totals.

Figure V-1

Resource Target for Advanced Technology in Texas





B. ENHANCED OIL RECOVERY

1. "Advanced" Technology Defined

Enhanced oil recovery processes, as currently "implemented," have some severe limitations. Some current EOR techniques can only be applied in a limited number of reservoirs that exhibit a narrow range of suitable property values (e.g., temperature, salinity, oil viscosity). The resulting sweep efficiency of EOR processes is also often relatively poor, contacting only a small portion of the residual oil remaining in the previously waterflooded zone. Injectants are expensive, often approaching the value of the oil they are designed to recover. The NPC predicted gradual improvements in EOR performance and project economics as current processes are improved and further tested in the lab and field. These advanced processes will gain operator acceptance as the research and development efforts of oil companies, universities, and the federal government proceed and as field applications are tested and are proven commercially. The NPC formulated a set of realistic, potential advances that could be achieved by 1995 by a concerted program focused on the key limitations that currently restrict EOR potential.

The assumptions used in this analysis to project the impact of advanced technology are fully described in Chapter III. The major improvements in technology that are likely to impact Texas EOR will be advances in miscible flooding and chemical flooding. For advanced technology miscible flooding, the NPC modeled the effects of a larger miscible slug size and improved sweep possible with the injection of foams. For advanced technology chemical flooding, the NPC modeled the effects of increasing the salinity and temperature tolerance of injectants, thus enabling them to be applied in a larger number of reservoirs. This study assumes that advances in chemical flood technology would result in improvements in injection rate, interfacial tension, and chemical retention, thereby improving the recovery and economics of these relatively prolific processes. This study further assumes that advanced technology surfactant slug costs will decline from $10/B, as used in the implemented case, to the $7/B cost developed by the NPC.[1/]

1/ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

2. Production and Reserves

Under advanced technology, EOR could potentially stimulate incremental reserves of slightly more than 300 million to nearly 8 billion barrels over the price range analyzed in this study ($12/B to $36/B). Figure V-2 and Table V-1A show the comparison between the EOR reserves potentially generated through the application of advanced technology EOR processes and implemented technology EOR processes as discussed in Chapter IV. The greatest increase in reserve additions due to advanced technology would occur in the lower end of the analyzed price range, at oil prices of $20/B and below. At $12/B, reserve additions in the advanced case would be almost five times greater than those generated in the implemented technology case. At $20/B, advanced technology could add over 3.1 billion barrels of reserves, more than double the potential reserves under implemented technology at the same oil price. Over the $24/B to $36/B price range, advanced technology EOR processes are about 50% more prolific than current EOR processes at each respective oil price considered.

The potential reserve additions contributed by each of the advanced EOR processes considered in this analysis are also shown in Figure V-2. At $12/B, advanced chemical flooding would be the primary source of incremental reserves, adding almost 240 million barrels of oil. Advanced technology gas-miscible flooding could recover 85 million barrels of oil, nearly 16 million barrels more than would be generated under implemented technology. Thermal recovery would not be economic in Texas at a $12/B oil price under either the implemented or advanced case conditions.

At $16/B, gas-miscible flooding could produce 900 million barrels of oil under advanced technology, nearly double the recovery possible from this process under the implemented case. Advanced chemical processes could contribute as much as 480 million barrels to the total reserve additions at this oil price, essentially all of which is incremental recovery due to technology advances attainable through R&D. At an oil price of $20/B, 870 and 650 million more barrels of oil could be stimulated by the advanced technology chemical and gas-miscible flooding processes, respectively, compared to results under implemented technology. Advanced miscible flooding processes represent the greatest absolute potential at all oil prices above $16/B, stimulating up to 4.7 billion barrels of reserve additions at the $36/B oil price. At all oil prices over $20/B, advances in miscible flooding technology would generate from 400 to 800 million barrels of reserve additions

Figure V-2

Texas EOR Reserves by Process

Implemented versus Advanced Technology

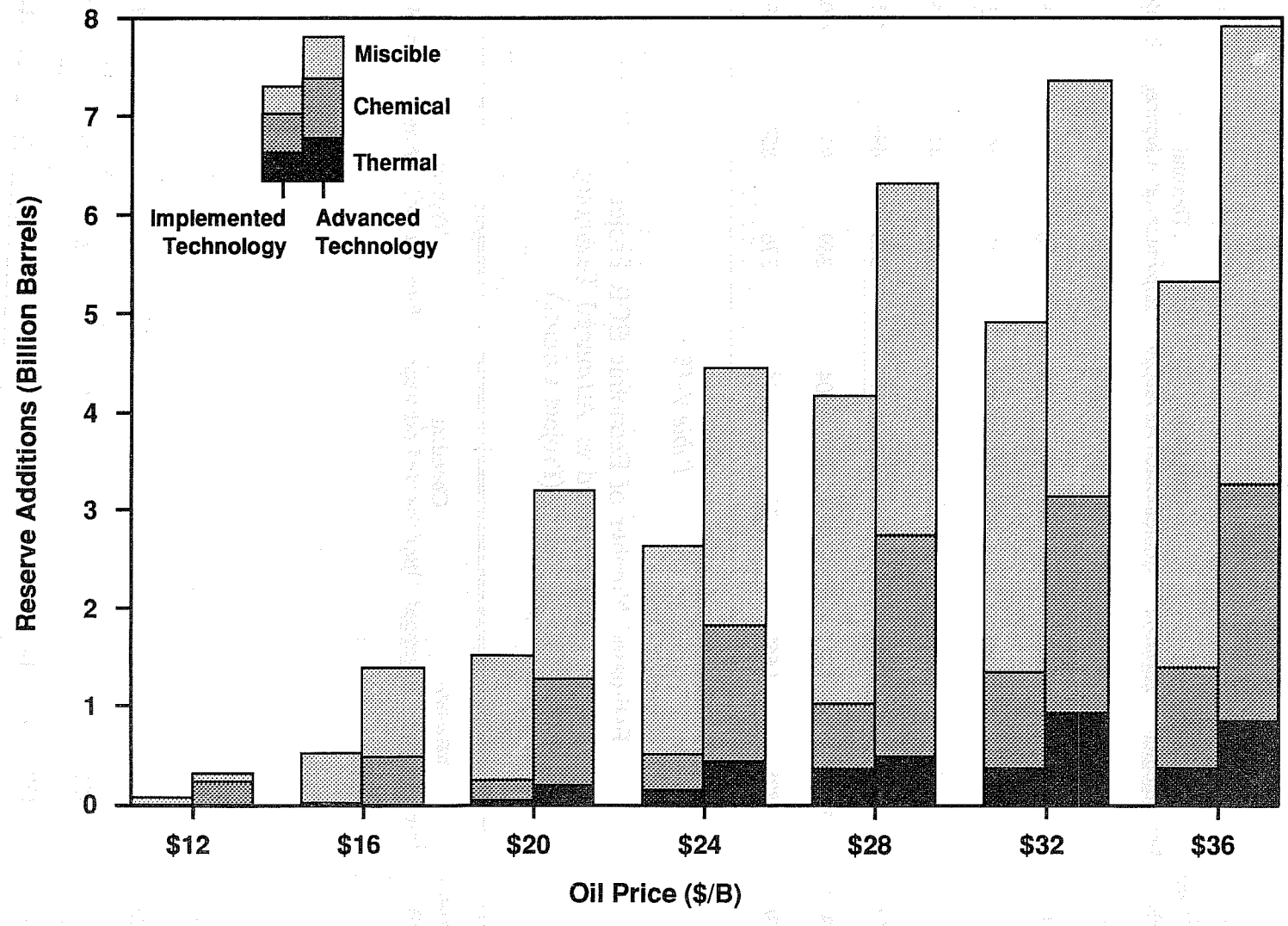


Table V-1A

Incremental Reserve Additions from EOR by Process Implemented vs. Advanced Technology (Million Barrels)

Oil Price ($/B)	Miscible		Chemical		Thermal		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
$12	69	85	0	239	0	0	69	324
$16	503	905	17	484	0	0	520	1,389
$20	1,261	1,908	206	1,078	47	199	1,514	3,185
$24	2,112	2,615	362	1,374	152	444	2,626	4,433
$28	3,135	3,561	661	2,247	366	493	4,162	6,301
$32	3,560	4,217	978	2,204	369	930	4,907	7,351
$36	3,825	4,662	1,120	2,408	376	857	5,321	7,927

Table V-1B

Estimated Number of Economic EOR Projects by Process Implemented vs. Advanced Technology (Project Counts)

Oil Price ($/B)	Miscible		Chemical		Thermal		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
$12	13	13	0	2	0	0	13	15
$16	24	25	1	7	0	0	25	32
$20	44	44	4	20	1	2	49	66
$24	68	76	8	38	4	8	80	122
$26	96	101	19	56	6	10	121	167
$32	121	126	29	69	6	16	156	211
$36	137	143	37	75	6	18	180	236

over and above those economically feasible under currently implemented technology. Advances in the chemical flooding processes are even more effective at increasing oil recovery, producing 1.6 and 1.3 billion barrels more reserves than under implemented technology at oil prices of $28 and $36/B, respectively. Advanced technology thermal processes could contribute nearly 200 million barrels to the total EOR reserves at $20/B. With increases in the oil price, the additional reserves due to thermal flooding could increase by as much as 290 million barrels at $24/B and 560 million barrels at $32/B compared to recovery under implemented technology.

The number of EOR projects for each process type is shown in Table V-1B. The comparison of the project count by process indicates the reasons for the increase in reserves under advanced technology. The number of economic miscible projects increases only marginally despite the substantial increase in reserves, indicating that advanced technology miscible flooding is more efficient than the implemented technology process in the reservoirs where it is economically applied. The number of chemical and thermal projects in the advanced case is double to triple the number in the implemented technology case. This increase is roughly proportional to the increase in reserve additions, indicating that the bulk of the reserves due to advances in these processes result from improved project economics; the additional reserves due to advanced technology are coming from reservoirs that were not economic to develop under implemented technology.

Figure V-3 shows the expected annual EOR production for oil prices of $16/B to $28/B for both the implemented and advanced technology cases. Even at $16/B, up to 80 million barrels per year could be added to Texas oil production by the turn of the century as a direct result of advanced EOR. At $20/B, advanced technology EOR could generate as much as 180 million barrels in 2001, the peak production year. This figure is nearly 100 million barrels per year more than the production estimated under implemented technology at this oil price. At the upper two prices displayed, annual EOR production could reach 225 and 255 million barrels per year with advanced technology, in each case about 50% more than the peak production under the implemented case.

3. Effects on State Revenues and Economic Activity

At all oil prices considered in this analysis, the direct revenues to the state of Texas attributable to EOR could significantly increase with advanced technology (Figure V-4A). Similar

Figure V-3

Annual EOR Production due to Advanced Technology

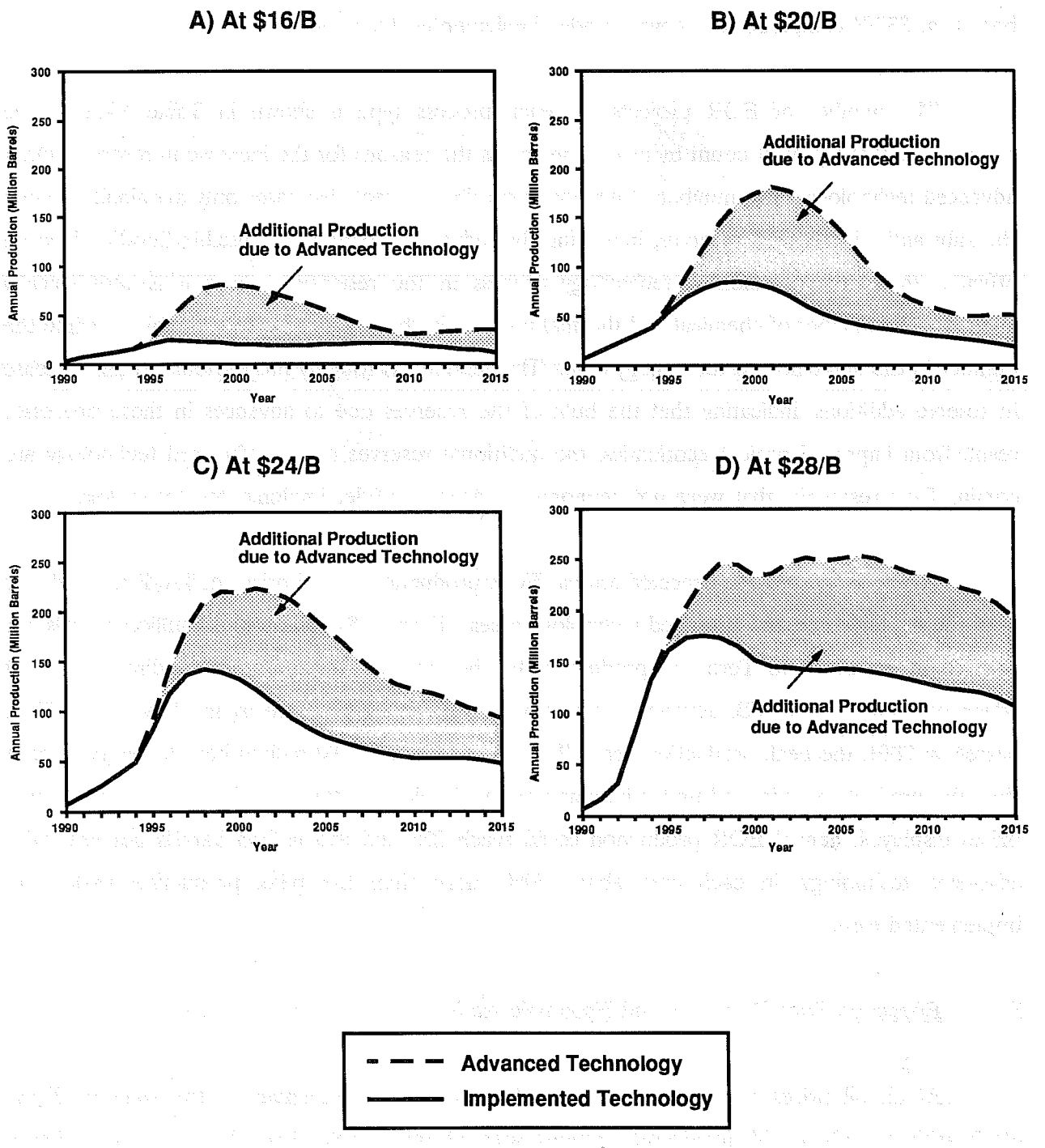
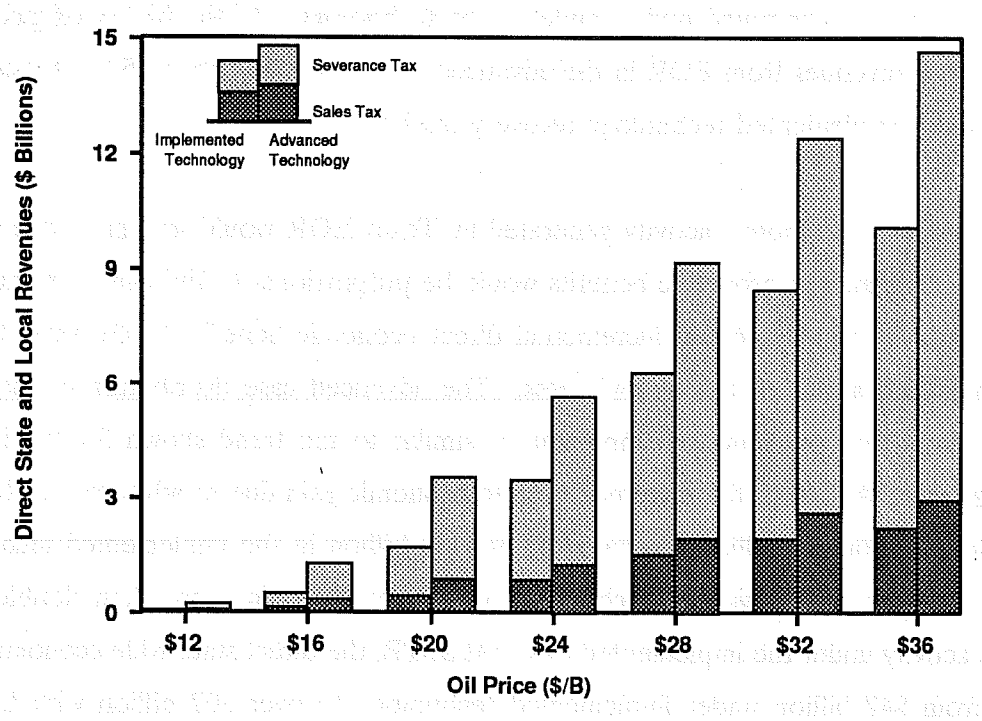


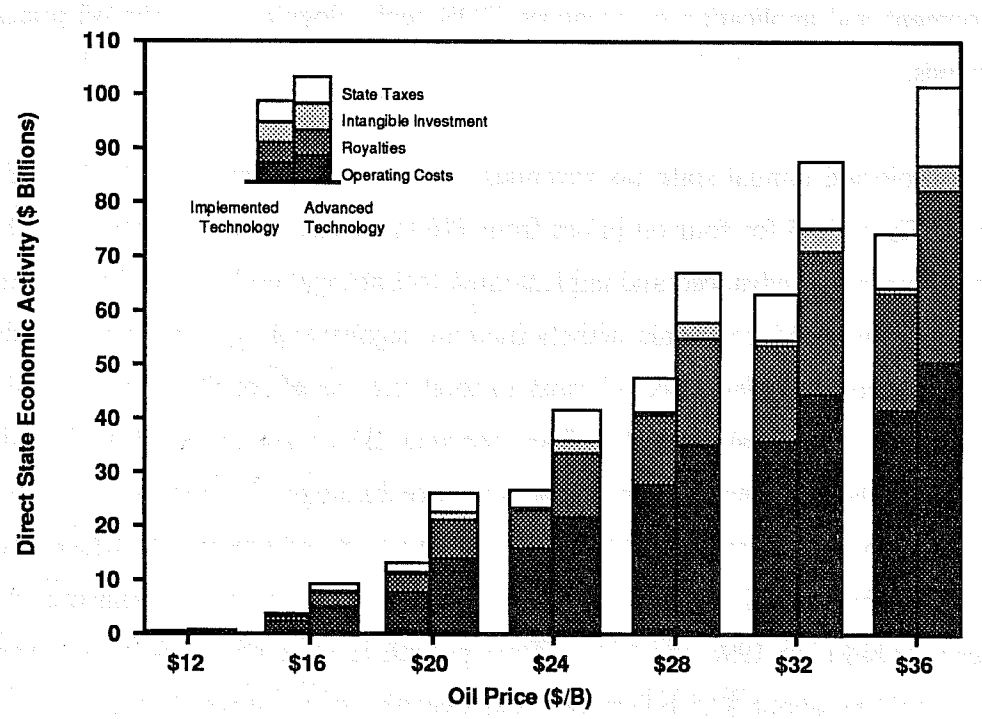
Figure V-4

State Impact of EOR Production
Implemented versus Advanced Technology

A) Direct State and Local Revenues



B) Direct State Economic Activity



to the implemented case, production taxes make up over 75% of the state's total direct revenues and sales tax receipts contribute the remaining 25%. At the two lowest oil prices evaluated, state revenues from advanced technology EOR could amount to just over $200 million and $1.2 billion, an increase over implemented technology of 330% and 160%, respectively. At $20/B, advanced technology could generate incremental revenues from EOR of nearly $3.5 billion, more than double the revenues generated under implemented technology. At the higher oil prices of $24/B to $36/B, state revenues from EOR in the advanced case would be around 50% higher than those generated with implemented technology recovery methods.

Direct state economic activity generated by Texas EOR would also grow due to advanced technology. The gain in economic benefits would be proportional to the gain in reserves. Figure V-4B displays the total potential incremental direct economic benefits to the state for both the implemented and advanced technology cases. The advanced case distribution of total economic benefits among the contributing components is similar to the trend shown for the implemented technology case. At $16/B, the incremental state economic gain due to advanced EOR technology is estimated at about $9 billion compared to only $4 billion in the implemented technology case. A $20/B oil price with advanced technology development would more than double the state's economic activity under the implemented case. At $28/B, the direct state-wide economic gain could increase from $47 billion under implemented technology to over $67 billion with full advanced EOR technology development. Clearly, the state of Texas could accrue substantial benefits from the development and application of advanced EOR technology at all of the oil prices considered in this analysis.

The projected annual state tax revenues and direct economic activity from EOR projects are shown in Figure V-5 for four oil prices from $16 to $28/B. These figures show the significant differences between the advanced and implemented technology results. At all oil prices, the annual direct state revenues and economic activity increase significantly with advanced technology. At $20/B, EOR technology advances could result in total state revenues of up to $190 million per year by the turn of the century, about $120 million per year more than under implemented technology. Total benefits to the state economy under advanced technology are estimated at up to $1.4 billion per year, about double the annual peak under implemented technology. At $28/B, the benefits of advanced technology would be more pronounced, with state revenues estimated at about $350 million per year between 1996 and 2010. Total growth in state economic activity from advanced technology would be about $2.5 billion per year over the same period at this price. Similar

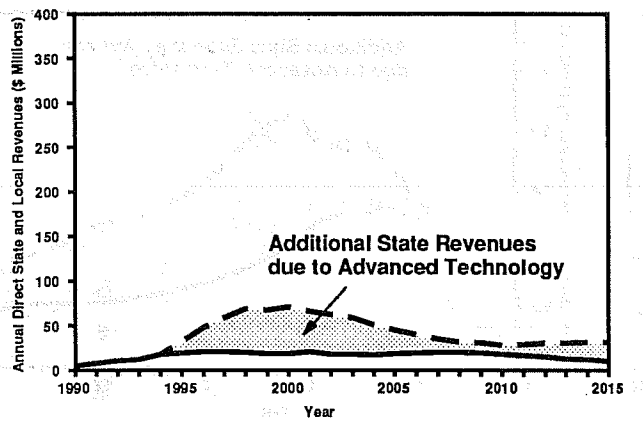
Figure V-5

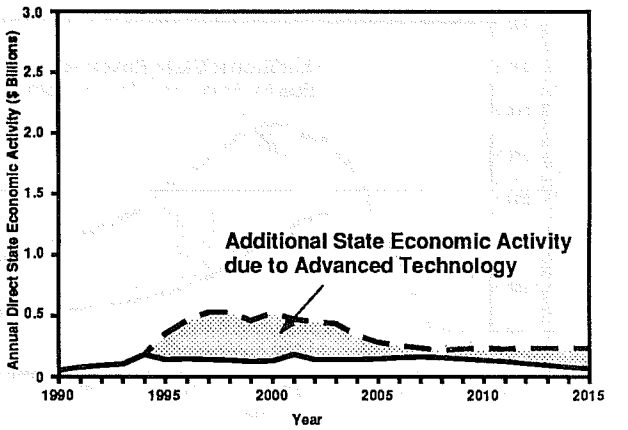
Annual State Impact of EOR Production
Implemented versus Advanced Technology

Direct State and Local Revenues

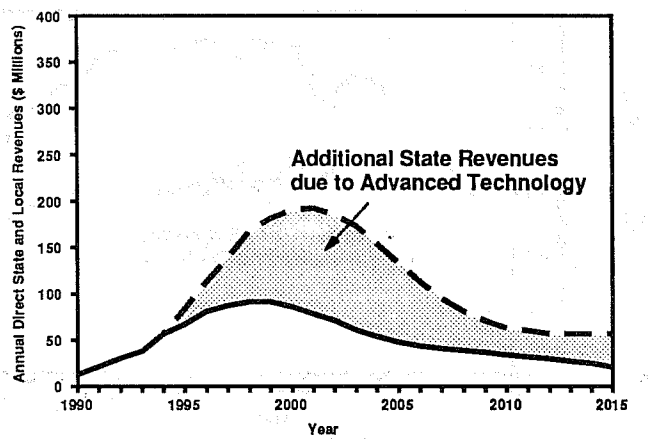
Direct State Economic Activity

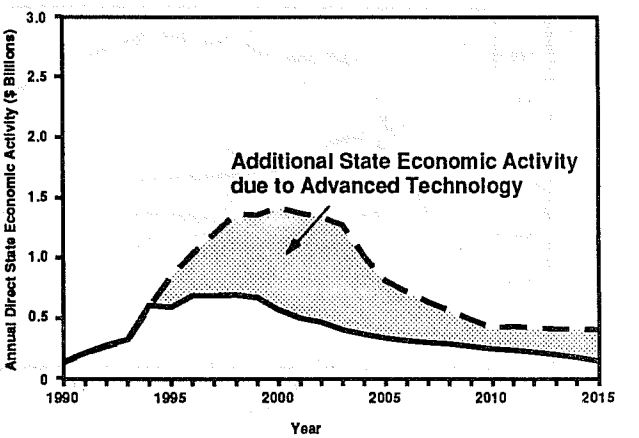
A) At $16/B





B) At $20/B

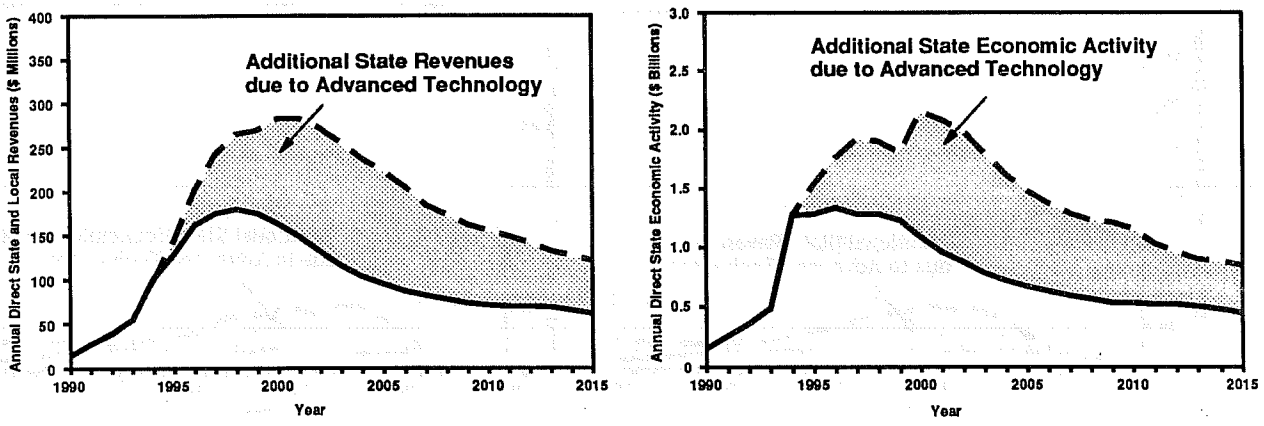




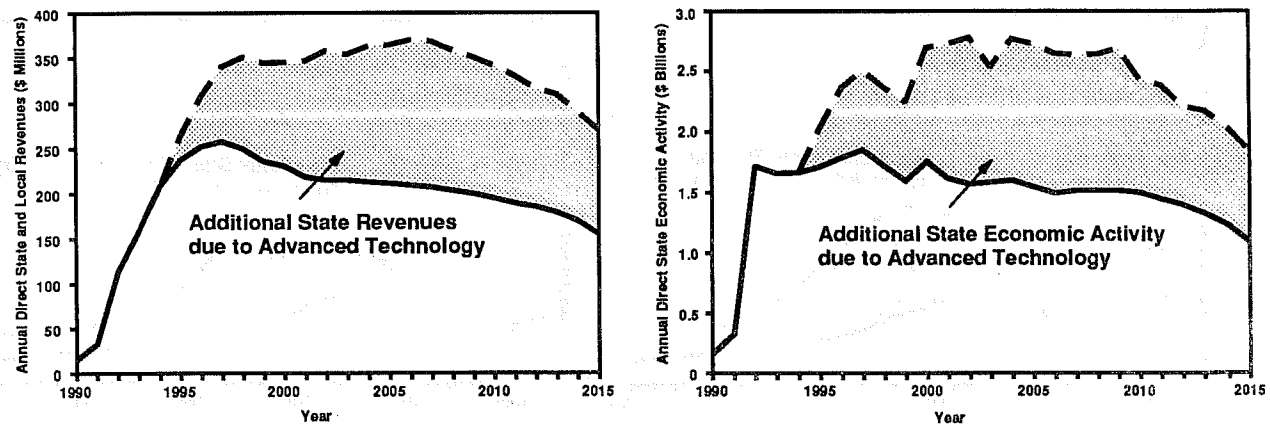
Annual State Impact of EOR Production
Implemented versus Advanced Technology

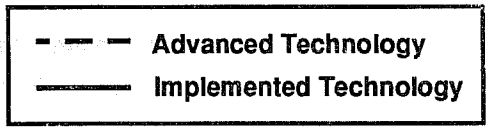
Direct State and Local Revenues | **Direct State Economic Activity**

C) At $24/B



D) At $28/B





proportional increases in state revenues and direct economic activity result from advanced technology EOR at the other prices displayed.

Advanced technology has a substantial impact on the state's employment. Even at a relatively low oil price of $16/B, the development of advanced technology could create over 5,000 new jobs per year by 1996 (Figure V-6), more than twice the jobs than could be created in the peak year under implemented technology. At the higher oil prices of $20 to $24/B, up to 6,000 more jobs per year than those created under implemented technology could result from development of advanced technology processes by the end of the next decade. At an oil price of $28/B, jobs under the advanced case could exceed those in the implemented case by about 8,000 per year, with annual totals as high as 22,000. Wages paid could total as much as $600 million per year at the highest oil price considered. Peak wages at $16/B and $20/B with advanced technology EOR are estimated at $130 and $340 million, respectively, and would occur before the year 2000.

4. Effects on the National Economy and Budget

As discussed in Chapter IV, increased oil recovery in the state of Texas through EOR methods would significantly benefit the nation in the areas of enhanced energy security, increased Gross Domestic Product (GDP), and expanded direct revenues to the federal treasury. The potential benefits are even more pronounced with the development of advanced technology. Up to 7.7 billion barrels of crude oil could be added to proved reserves due to advanced EOR technology, 2.4 billion barrels more than the reserve additions estimated under the implemented case.

Revenues to the federal treasury, in the form of corporate and individual income taxes, would grow along with the increase in reserves as a result of advanced technology, as shown in Figure V-7A. EOR production under advanced technology could contribute from $223 million up to $30.5 billion to the federal treasury over the price range analyzed. Furthermore, as shown in Figure V-7B, the increased Texas oil production could significantly increase GDP while directly reducing the merchandise trade deficit. Total GDP from EOR production over the life of these projects could range from $3.6 billion to nearly $255 billion over the price range considered in this analysis.

Figure V-6

Annual Jobs and Wages from EOR Production
Implemented versus Advanced Technology

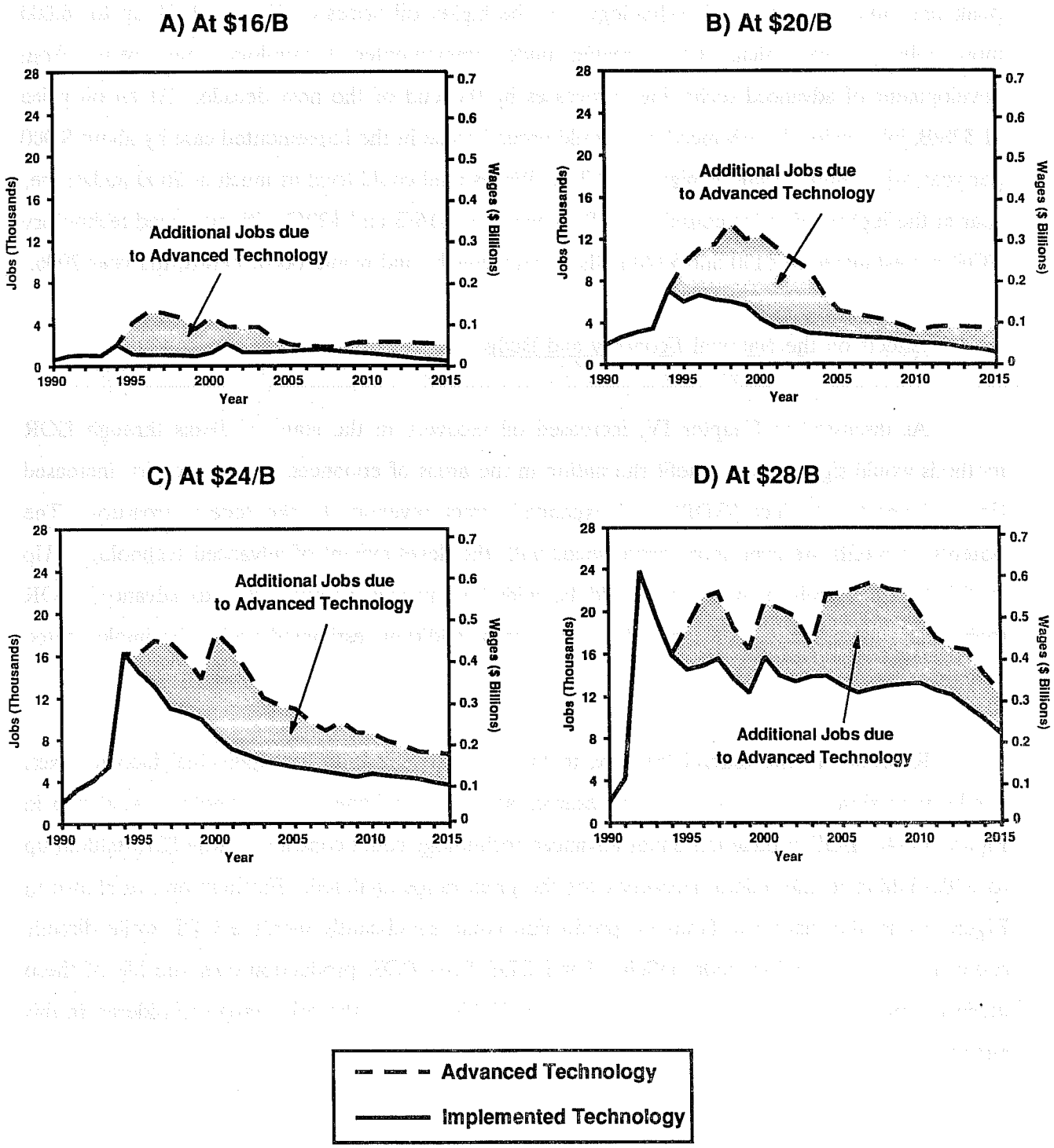
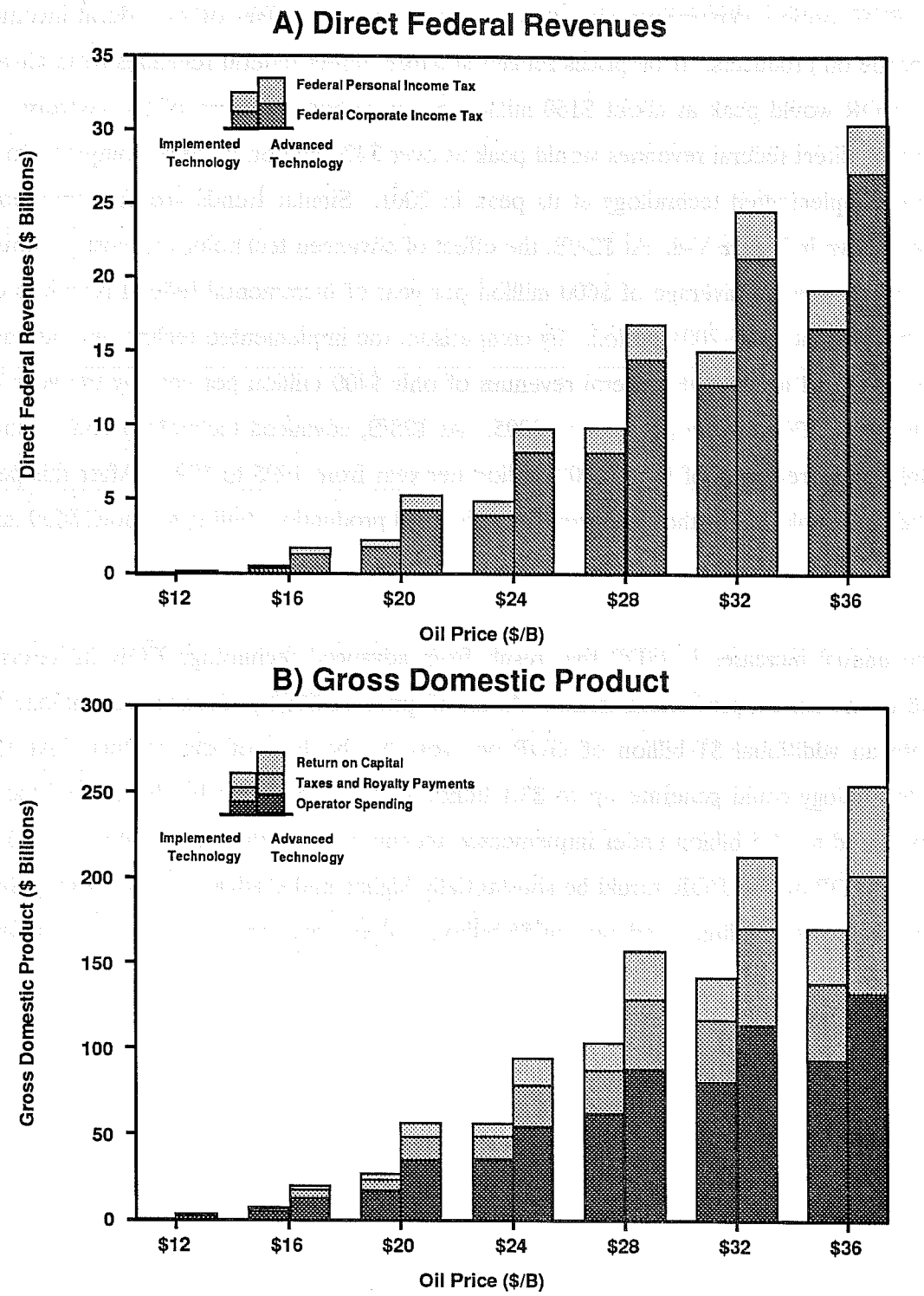


Figure V-7

National Impact of EOR Production
Implemented versus Advanced Technology



The projected annual direct federal revenues and GDP from Texas advanced technology EOR projects are displayed in Figure V-8 for oil prices between $16 and $28/B. As described in Chapter IV, federal revenues would be negative in the early years of EOR projects (1990 through 1996 for both the implemented and advanced technology cases) as the taxable losses incurred during the EOR project implementation phase would be used to offset other federal income tax liabilities of the oil producers. If oil prices remain at $16/B, direct federal revenues from advanced technology EOR would peak at about $160 million per year near the turn of the century. At a $20/B oil price, direct federal revenues would peak at over $420 million in 2004, compared to $220 million under implemented technology at its peak in 2001. Similar trends are also apparent for other prices shown in Figure V-8. At $24/B, the effect of advanced technology is most pronounced in the late 1990s when an average of $600 million per year of incremental federal revenues could be generated over the 1996-2004 period. By comparison, the implemented technology case at this oil price is estimated to generate federal revenues of only $400 million per year by the year 2000, declining to about $200 million per year in 2005. At $28/B, advanced technology could generate incremental federal revenues of up to $900 million per year from 1995 to 1999. After this period, federal revenues would follow the same trend as annual oil production, falling to about $650 million in 2015.

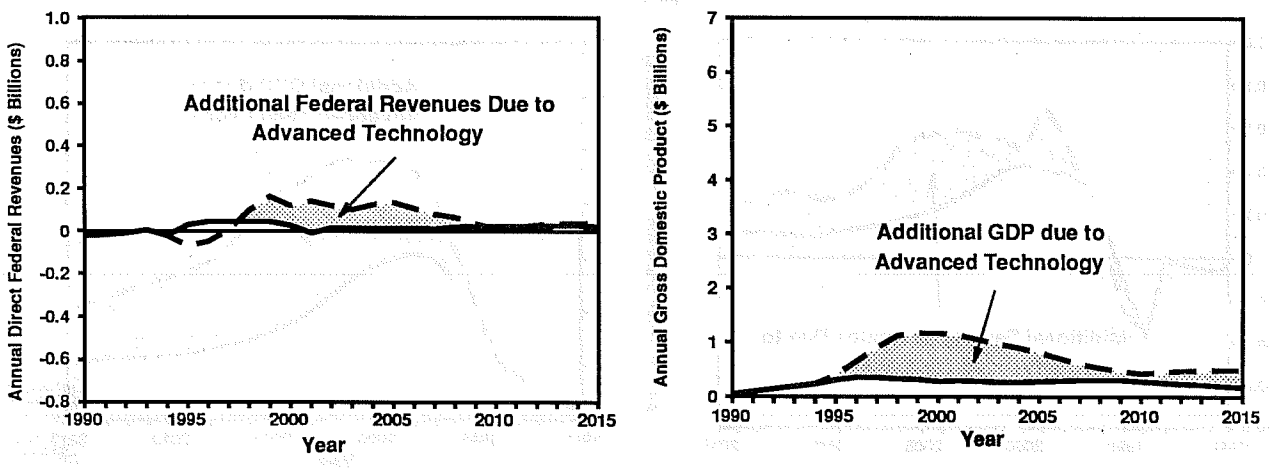
The annual increases in GDP that result from advanced technology EOR in Texas also correspond to the annual production trends. At an oil price of $16/B, advanced technology EOR could create an additional $1 billion of GDP per year by the turn of the century. At $20/B, advanced technology could generate up to $3.1 billion of GDP per year by the end of the next decade, compared to $1.5 billion under implemented technology. At the higher oil price of $28/B, the growth in GDP due to EOR would be substantially higher under advanced technology than in the implemented case, totaling an average of $6 billion per year over the period between 1998 and 2005.

Figure V-8

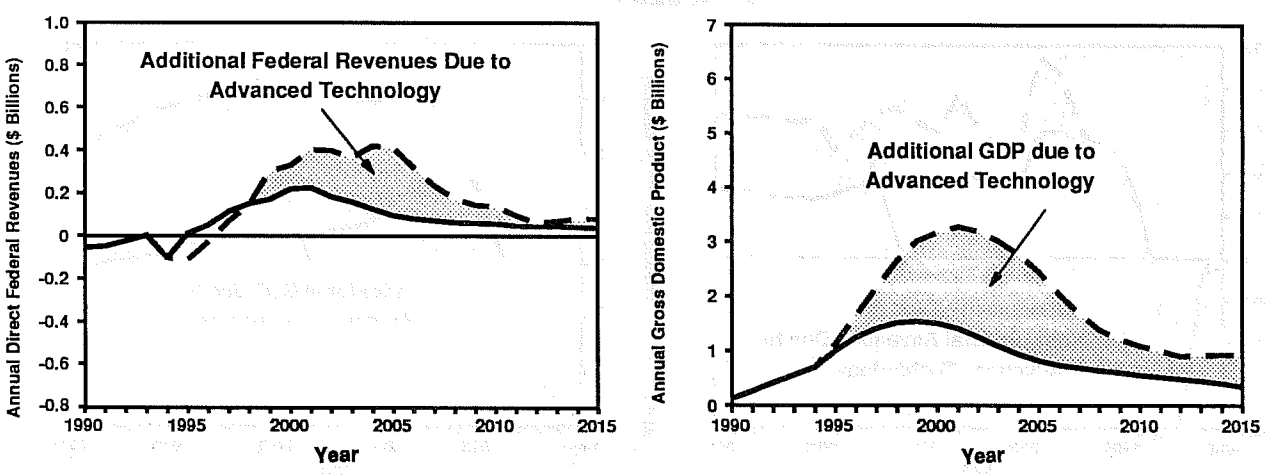
Annual National Impact of EOR Production
Implemented versus Advanced Technology

Direct Federal Revenues | **Gross Domestic Product**

A) At $16/B



B) At $20/B



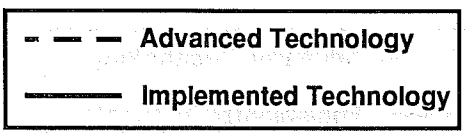
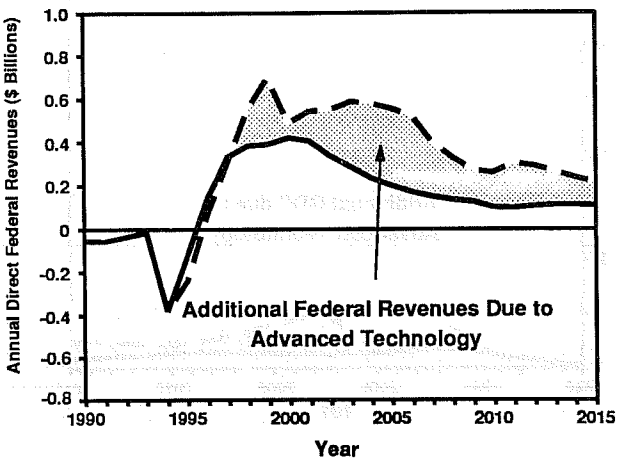


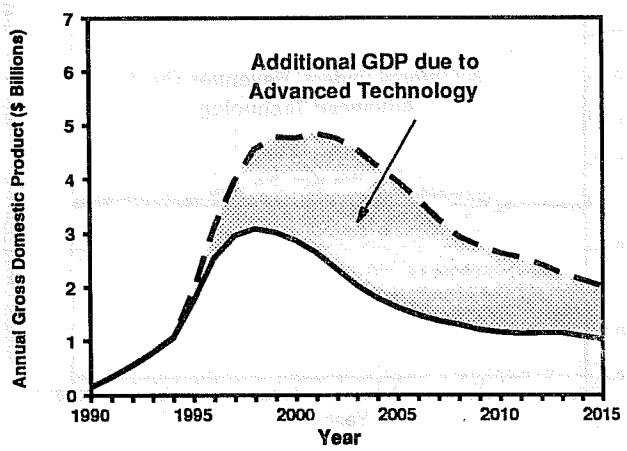
Figure V-8 (cont.)

Annual National Impact of EOR Production
Implemented versus Advanced Technology

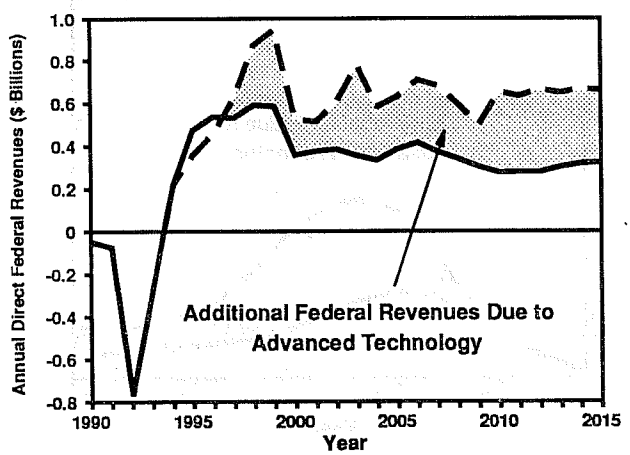
Direct Federal Revenues | **Gross Domestic Product**

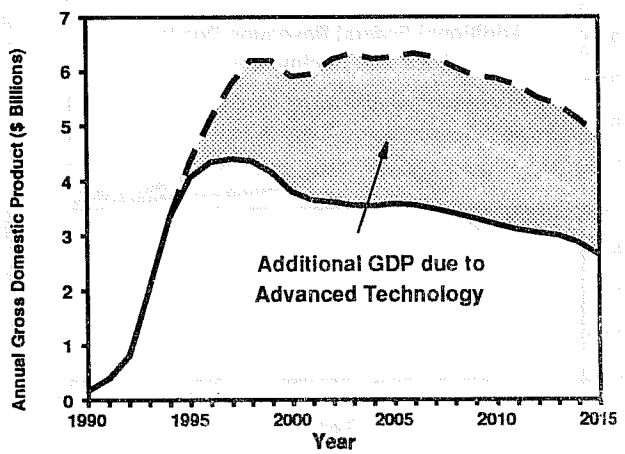
C) At $24/B

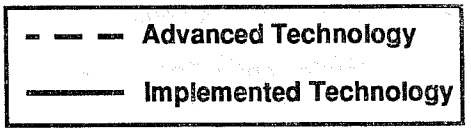




D) At $28/B







C. UNRECOVERED MOBILE OIL

1. "Advanced" Technology Defined

The UMO advanced case analysis, designed to reflect the potential technological improvements possible from a focused research program in geological reservoir characterization, is conducted in a manner consistent with the implemented technology case analysis. A major assumption is that R&D will allow geologic reservoir characterization techniques to be widely applied, resulting in infill drilling that is targeted only into those portions of the reservoir where project economics will allow drilling to closer spacings. This will improve the project economics of UMO recovery, resulting in more activity and much greater recovery under the advanced case than would be possible under the reservoir-wide, blanket drilling program assumed in the implemented technology case. Heterogeneous portions of reservoirs contain a proportionally larger amount of UMO that is trapped in isolated compartments or bypassed by the injection fluids in conventional recovery operations. By contrast, the more homogenous portions of reservoirs exhibit more efficient conventional recovery and require less intensive drilling. In this study, infill drilling potential is evaluated by dividing each reservoir into two parts, a more continuous segment and a less continuous segment. The economic recovery potential is evaluated independently in each segment, and the closest economic well spacing for each segment is independently selected.

The advanced recovery methods discussed in this analysis could have a substantial impact on UMO reserve additions. Improved geologic characterization of the resource provides the basis for targeted infill drilling, which could significantly increase economic UMO recovery over the price range evaluated. Additional recovery would also be stimulated as the chemical composition of polymer injectants is improved to withstand higher reservoir temperatures (up to 250° F) and/or formation salinities (up to 200,000 ppm). These improvements would increase the marginal impact of the advanced secondary methods (profile modification and polymer flooding) projected under the implemented technology case whether they are applied alone or in combination with infill drilling.

2. Production and Reserves

The development of advanced technology UMO recovery methods through R&D could significantly increase the state's oil reserves. The advanced case UMO reserves are estimated at 2.9 to 5.5 billion barrels in the reservoirs evaluated for this study, nearly three times the reserves generated under implemented technology across the oil prices considered (Figure V-9).

UMO extraction is less sensitive than EOR to increases in oil price. However, growth in reserves would be substantial at lower prices, increasing by 400 million barrels between $12 to $16/B, and by nearly 700 million barrels between $16 and $20/B. Around 600 million barrels could be added if oil prices increase from $20 to $24/B. Reserve growth through advanced technology would be less sensitive to further increases in oil price. Reserve additions for each $4/B increment above $24/B would average less than 300 million barrels.

Table V-2A shows the distribution of UMO reserve additions by process. Infill drilling in combination with advanced secondary processes (profile modification or polymer flood) would be the most prolific advanced technology recovery method, contributing from 50% to over 60% of the total additions. Infill drilling by itself could generate between 23% and 35% of total advanced case reserve growth. Advanced secondary processes could contribute 7% to 15% of the total recovery in the advanced technology case, a smaller portion than under implemented technology.

Geologically targeted infill drilling, by itself or in combination with advanced secondary processes, could generate reserve additions nearly three times those estimated in the implemented technology blanket infill drilling case at all oil prices over $12/B. These dramatic increases occur for two related reasons. First, an improved understanding of reservoir architecture and the nature of heterogeneity would allow wells to be economically justified at much closer spacing than is currently possible. As these new wells contact additional volumes of oil, ultimate recovery would be improved. Second, the ability to target infill wells would eliminate the unnecessary wells that would be drilled under a blanket infill drilling program. Targeting infill wells would reduce the front-end investment for each project undertaken, making some otherwise uneconomic projects cost-effective. As observed in the implemented case, the contribution of advanced secondary processes to total reserves would be fairly constant across the oil prices analyzed, adding 390 to

Figure V-9

Texas UMO Extraction Reserves by Process
Implemented versus Advanced Technology

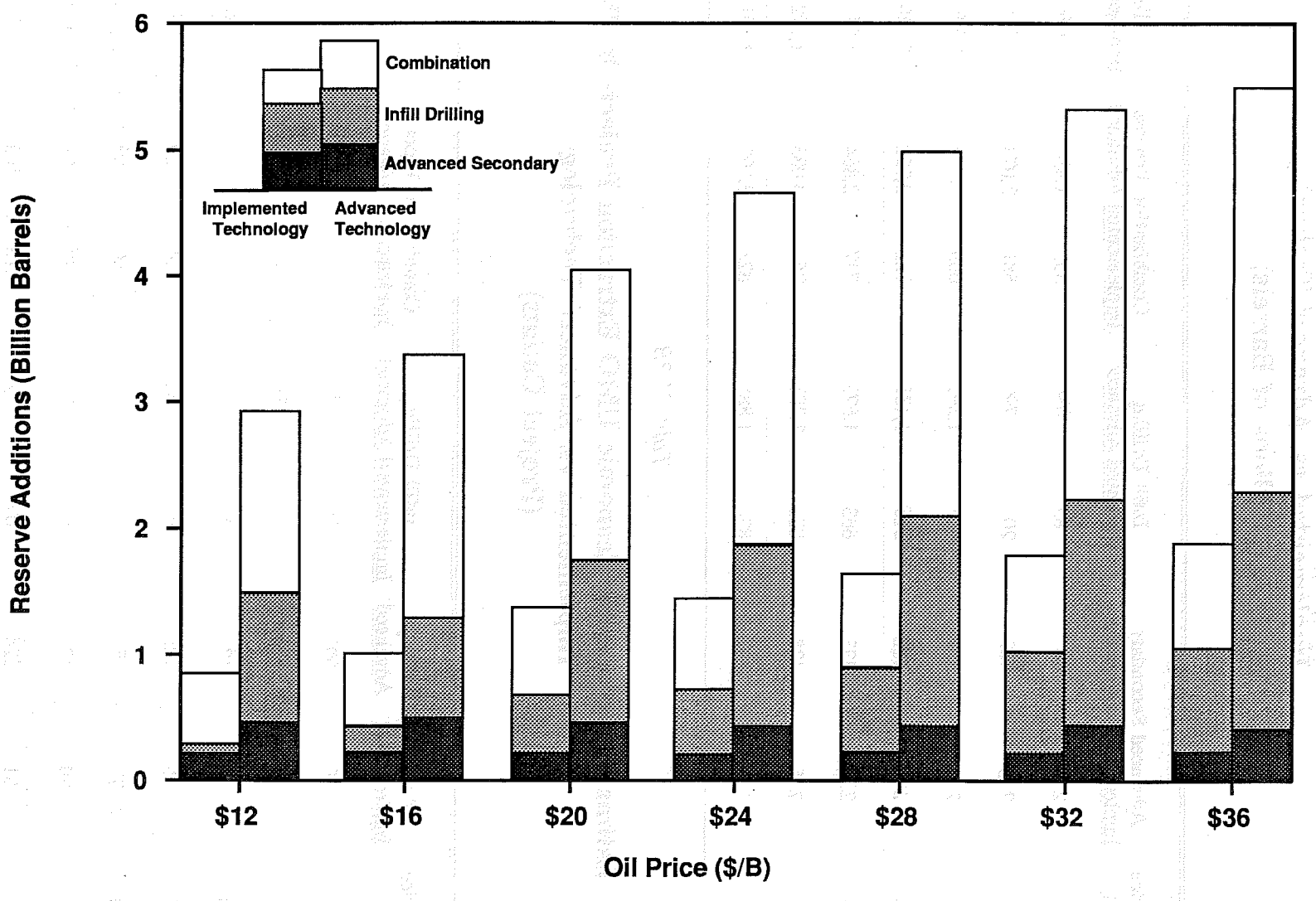


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Table V-2A

Incremental Reserve Additions from UMO Extraction by Process Implemented vs. Advanced Technology (Millions of Barrels)

Oil Price ($/B)	Advanced Secondary		Infill Drilling		Combination Process		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
$12	218	447	85	1,030	553	1,435	856	2,912
$16	233	482	201	799	581	2,073	1,015	3,354
$20	222	452	468	1,291	689	2,294	1,379	4,037
$24	212	412	515	1,435	721	2,792	1,448	4,639
$28	233	433	663	1,673	747	2,884	1,643	4,990
$32	225	428	803	1,793	764	3,083	1,792	5,304
$36	238	391	830	1,885	823	3,197	1,891	5,473

Table V-2B

Estimated Number of Economic UMO Extraction Projects by Process Implemented vs. Advanced Technology (Project Counts)

Oil Price ($/B)	Advanced Secondary		Infill Drilling		Combination Process		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
$12	59	107	16	35	19	42	94	184
$16	71	119	27	39	23	62	121	220
$20	75	126	40	47	29	76	144	249
$24	75	126	46	52	34	87	155	265
$28	77	131	55	58	40	93	172	282
$32	79	126	65	72	40	94	184	292
$36	81	124	69	72	43	103	193	299

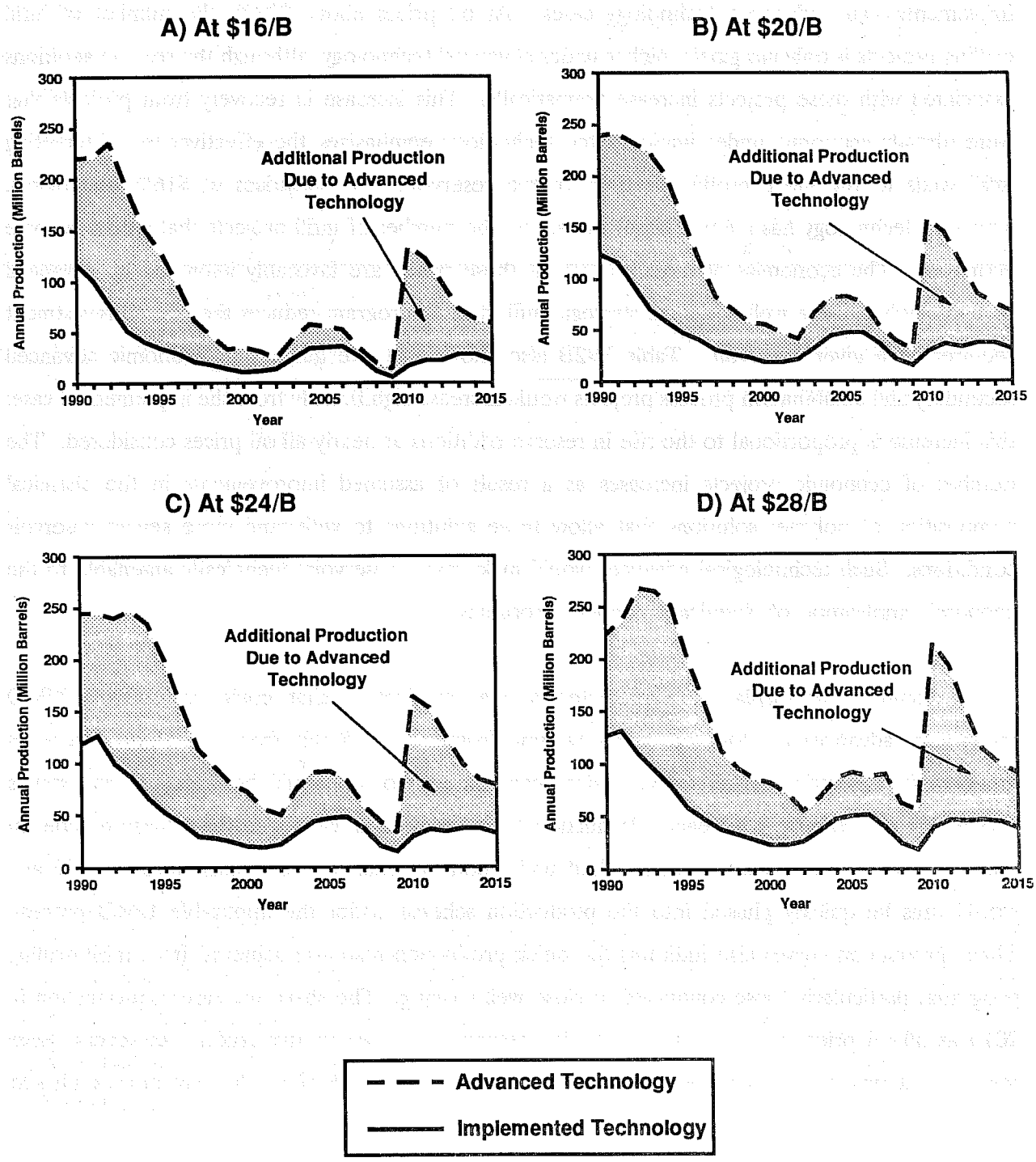
482 million barrels, or about double the reserves from these processes under implemented technology. As previously noted, the competition of these processes with more prolific methods such as infill drilling and combination processes limits the contribution of advanced secondary processes applied alone.

Table V-2B shows the estimated number of economic UMO projects for both the implemented and advanced technology cases. At oil prices above $20/B, the number of infill drilling projects is only marginally higher under advanced technology, although the reserve additions associated with these projects increase dramatically. This increase in recovery from projects that were already economic under implemented technology emphasizes the effectiveness of targeting infill wells to the more prolific portions of the reservoir. At oil prices of $16/B and below, advanced technology has a much larger impact on the number of infill projects that would become economic. The economics of most projects at these prices are favorably improved by advanced technology because a well-designed, strategic infill drilling program reduces the overall investment required in a given reservoir. Table V-2B also shows that the number of economic advanced secondary and combination process projects would increase significantly from the implemented case; this increase is proportional to the rise in reserve additions at nearly all oil prices considered. The number of economic projects increases as a result of assumed improvements in the chemical composition of polymer solutions that allow these solutions to withstand more severe reservoir conditions. Such technological advances would make more reservoirs technically amenable to the economic application of chemical treatment processes.

Figure V-10 displays the projected annual production that could result from UMO technology advances for four oil prices ranging from $16 to $28/B from the Texas reservoirs analyzed in this study. In all cases, a significant amount of oil could be added to the state's production over the next 20 years. Production peaks early in all cases because a large number of reservoirs would reach their economic limit under conventional recovery techniques by 1995 and would thus be quickly phased into the production scheme under the applicable UMO process. These production curves also indicates the quick production response achieved from infill drilling programs, particularly those conducted to close well spacing. The sharp increase in production in 2010 at all oil prices is caused by the timing assumptions used in this study. As several large reservoirs approach their economic limit of production around this time, they are quickly phased

Figure V-10

Annual UMO Production due to Advanced Technology



into development. These large zones increase UMO production nearly immediately as drilling is rapidly conducted to close well spacing.

At $16/B, advanced case UMO production could quickly reach 235 million barrels per year, declining to 35 million barrels by 2000. This is nearly double the production achieved under the implemented case. At a moderate oil price of $20/B, peak production would exceed 240 million barrels per year, declining to around 50 million barrels in 2000, and rebounding to 80 million barrels in the year 2005, again about twice the implemented case potential. Production would then decline until the year 2010, when it would again rise to 150 million barrels as an influx of new projects are initiated, as discussed above. At higher oil prices, peak annual production of UMO under the advanced case would increase slightly, reaching 245 and 270 million barrels per year in the first several years at oil prices of $24/B and $28/B, respectively. These two advanced case UMO production peaks are nearly two times those of the implemented case. Annual production would then fall and rise similar to pattern shown at the $20/B oil price. Production would again decline quickly, falling to 80 million barrels by 2010 at $28/B and to 70 million barrels in 2000 at $24/B before rebounding.

3. Effects on State Revenues and Economic Activity

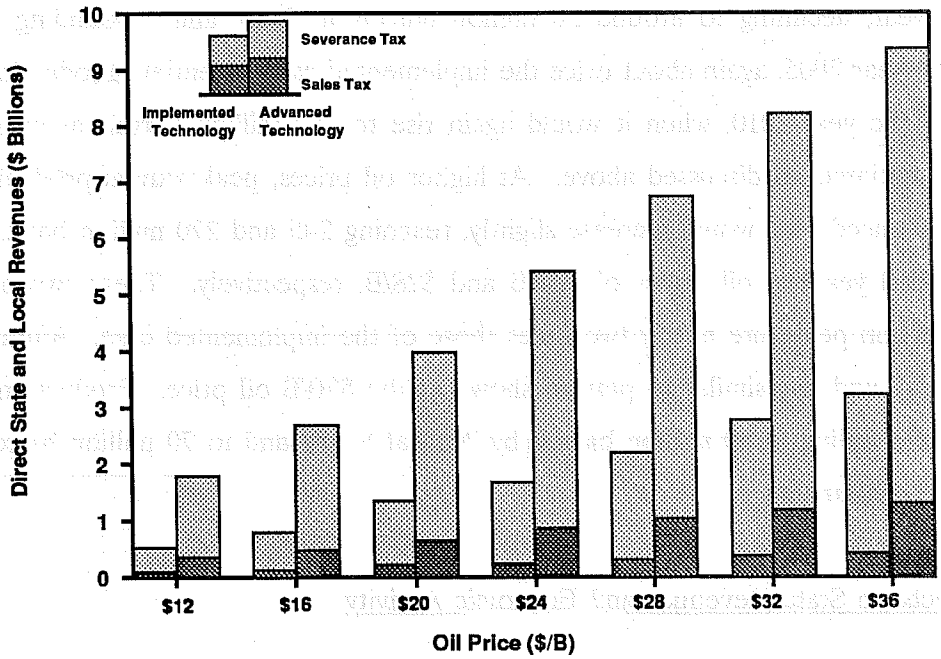
Under advanced technology, Texas could receive over $9 billion in total additional revenues from production taxes and oil industry-related sales taxes from UMO extraction if oil prices reach $36/B. As in the implemented technology case, the revenue is mostly generated from production taxes. These taxes account for over 80% of the direct state tax revenues added at each of the price levels considered in this analysis. Figure V-11A shows that total revenues to the state from UMO extraction projects in the reservoirs evaluated could increase nearly three-fold as a result of the technology advances defined for this analysis.

In addition to the increases in state and local revenues, Texas would benefit from the stimulation of economic activity and creation of new jobs. The advanced technology UMO recovery case could increase economic activity by $18 billion to $90 billion, depending on the oil price. These figures compare to only $5 billion to just over $30 billion of increased economic activity generated by projects under implemented technology over the price range analyzed. Figure

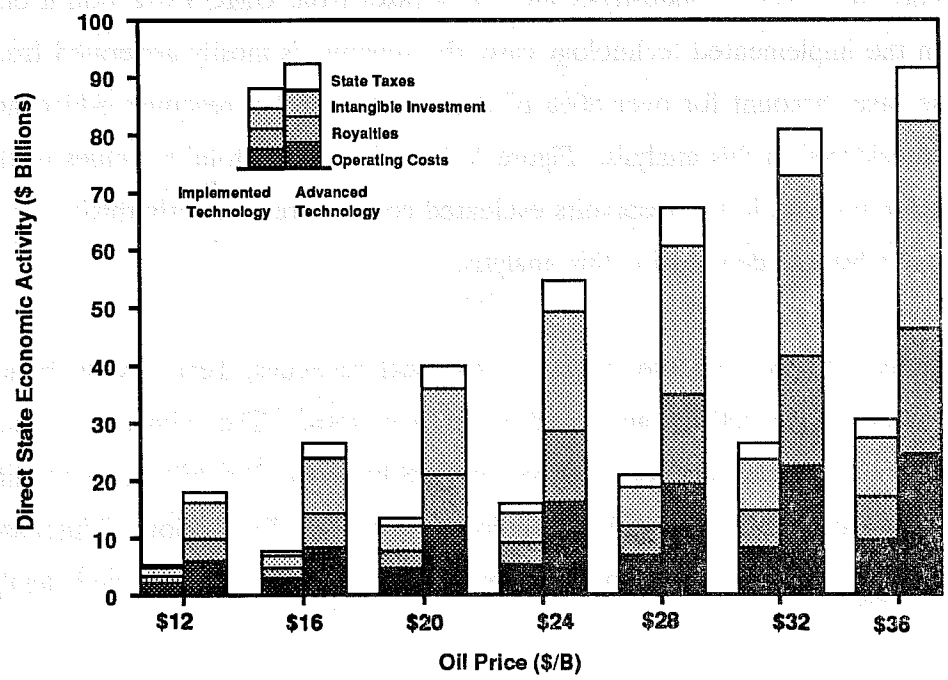
Figure V-11

State Impact of UMO Production
Implemented versus Advanced Technology

A) Direct State and Local Revenues



B) Direct State Economic Activity



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V-11B displays the components of this increase. Operating costs, royalties, and intangible investment from UMO extraction projects all make substantial contributions to the state's economic activity. Direct state revenues (taxes) comprise the smallest portion of the increase.

Annual estimates of state revenues and economic activity from UMO recovery are shown in Figure V-12 for oil prices from $16 to $28/B. The additions to state revenues and total economic activity with UMO technology advances are substantial for all years. The trend observed closely follows the production trend discussed earlier. Peak revenues range from $192 to $370 million per year around 1992, depending on the price of oil, more than double the implemented case results. The second peak around 2010 occurs as a significant number of new projects are initiated.

Figure V-13 presents estimates for the number of jobs that could result from the application of advanced UMO extraction technology in Texas. As the price rises, the total number of jobs created or maintained grows substantially, with the incremental jobs stimulated directly by advanced technology accounting for much of the increase. In the peak year, advanced UMO extraction technology could result in over 8,500 jobs annually at $16/B and 15,500 jobs per year at the $28/B oil price, around three times those generated under the implemented case. Even at lower prices, the number of jobs created or sustained by advanced technology UMO extraction processes would be highly beneficial to the Texas economy.

4. Effects on the National Economy and Budget

The development of advanced technology for the recovery of the known UMO resource in the state of Texas could also benefit the nation. Figure V-14A shows a dramatic increase in the incremental revenues to the federal treasury from personal and corporate income taxes due to advanced technology. Total federal revenues from advanced UMO recovery could range from $5 billion at the $12/B oil price to nearly $30 billion at $36/B. Most of these revenues would stem from increased corporate income taxes. Growth in gross domestic product (GDP) is also substantial; Figure V-14B shows that the operator spending, taxes and royalty payments, and return on capital associated with advanced UMO extraction techniques could total as much as $175 billion in the $36/B price case, nearly a three-fold increase over the implemented technology case.

Figure V-12

Annual State Impact of UMO Production
Implemented versus Advanced Technology

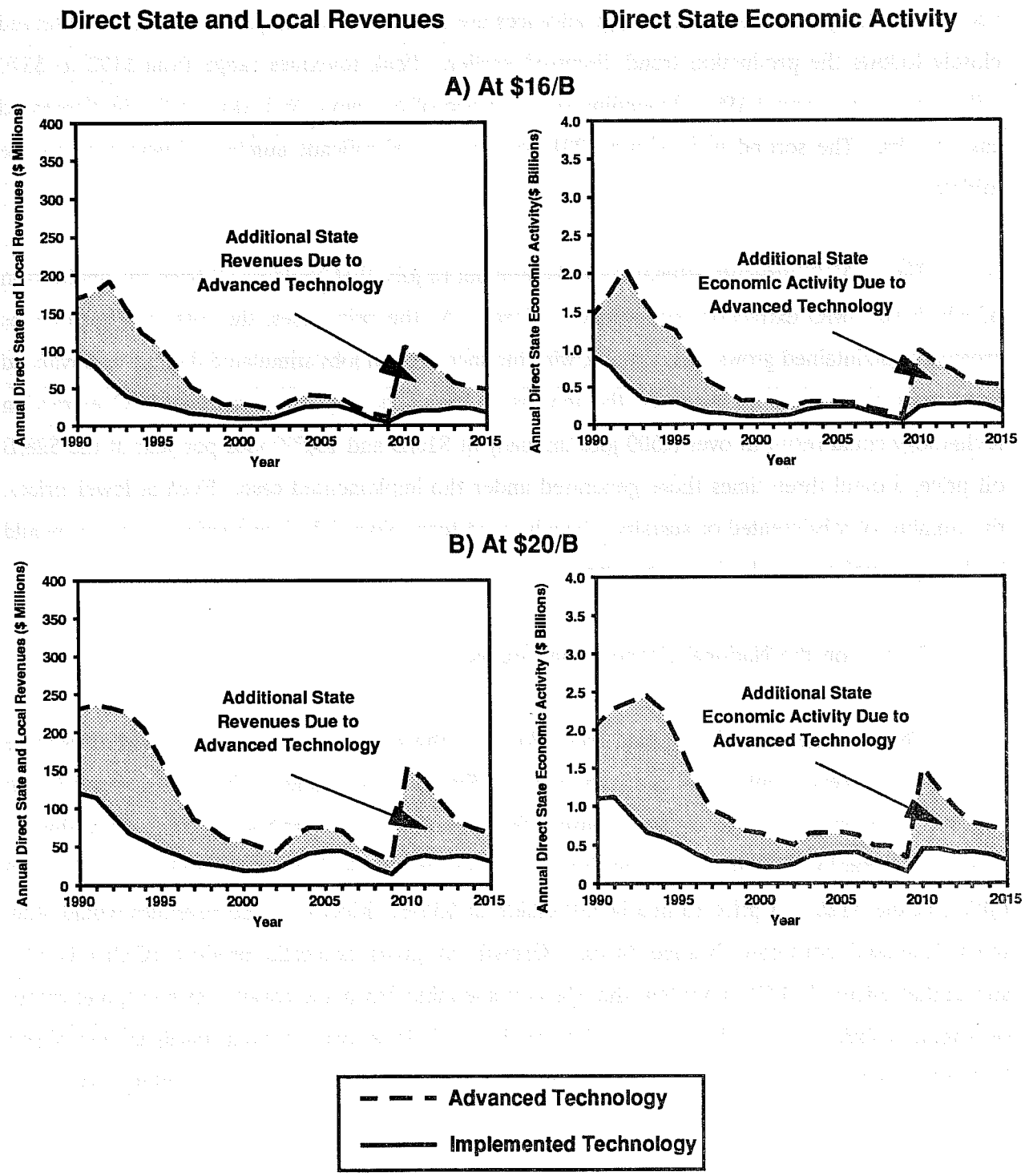


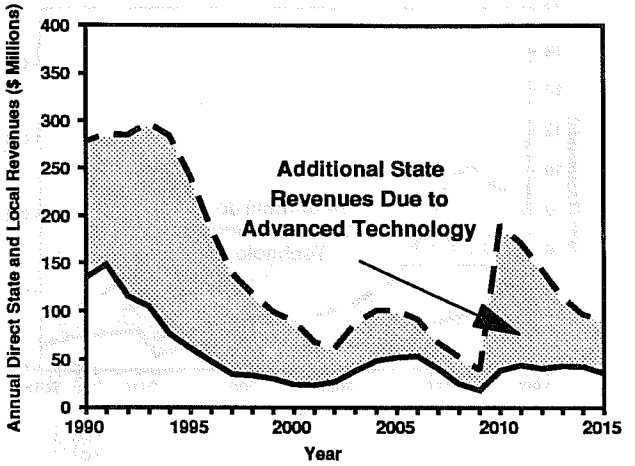
Figure V-12 (cont.)

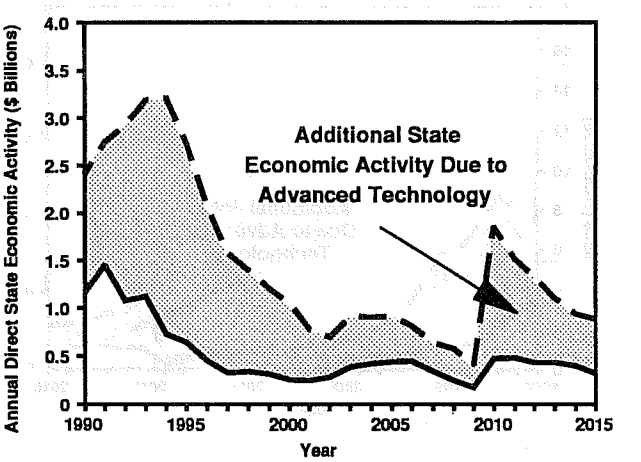
Annual State Impact of UMO Production
Implemented versus Advanced Technology

Direct State and Local Revenues

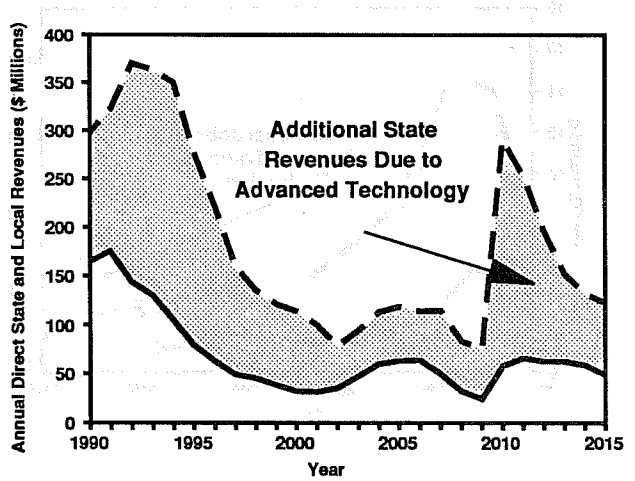
Direct State Economic Activity

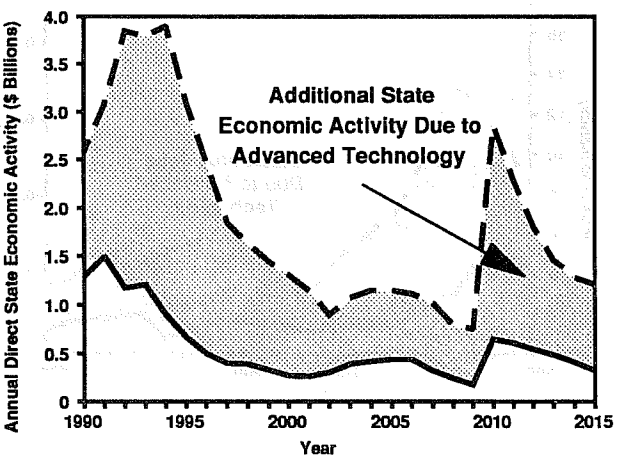
C) At $24/B





D) At $28/B





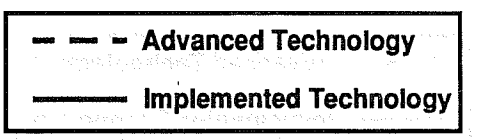


Figure V-13

Annual Jobs and Wages from UMO Production
Implemented versus Advanced Technology

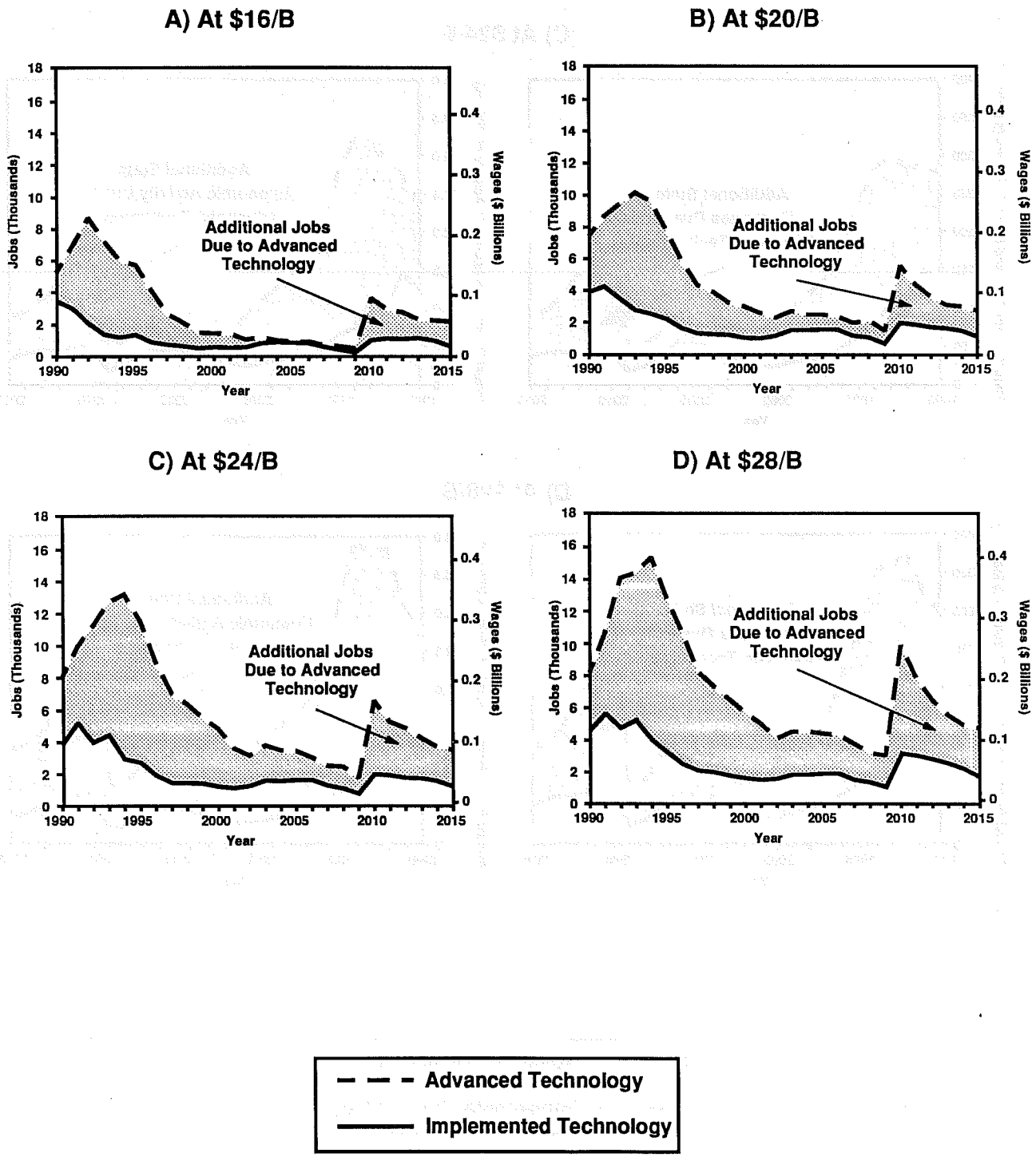
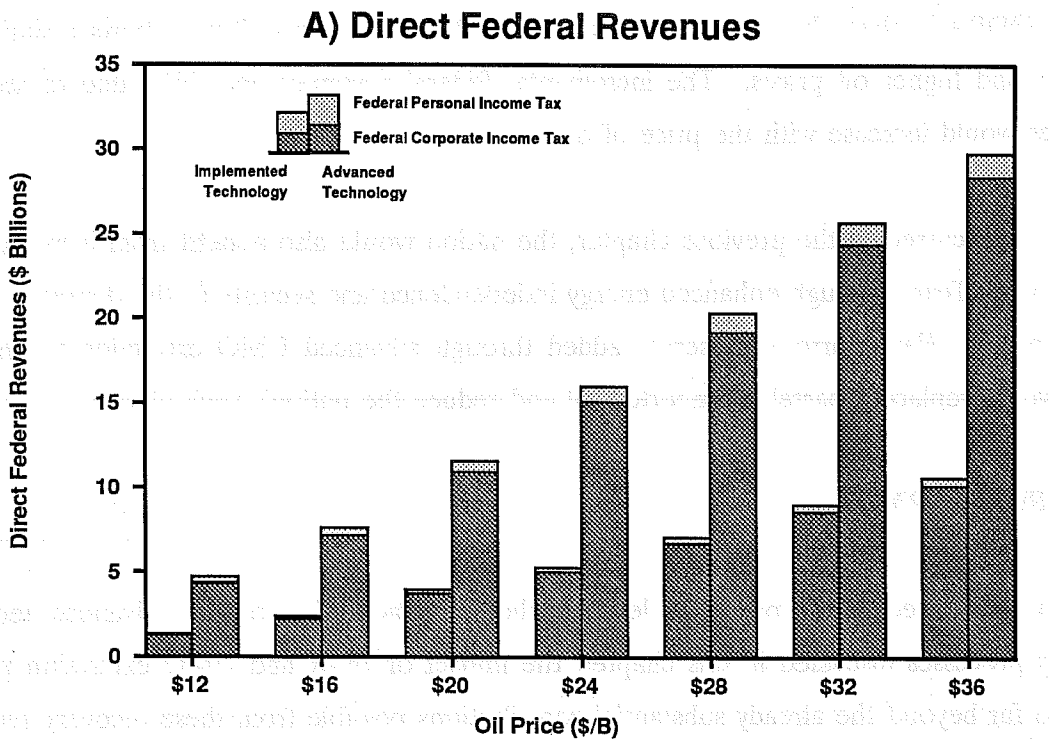


Figure V-14

National Impact of UMO Production
Implemented versus Advanced Technology



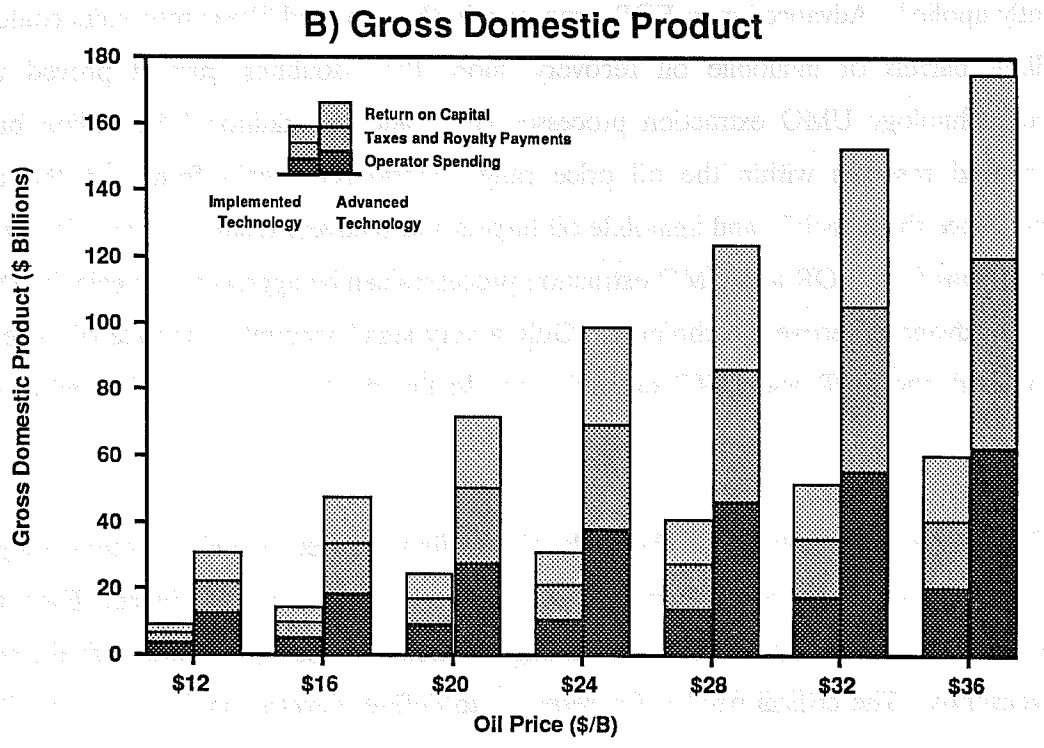


Figure V-15 shows the annual impact of UMO extraction in Texas on the national economy at prices from $16 to $28/B. At the lower oil prices (Figure V-15A, B), initial federal revenues from advanced technology UMO extraction would be double the amount estimated under implemented technology. This increment decreases, falling to near the implemented level around the turn of the century before new project starts again expand activity and increase revenues. Annual GDP stimulated by advanced technology UMO extraction in Texas shows a similar trend at these and higher oil prices. The incremental federal revenues and GDP due to technology advances would increase with the price of oil.

As discussed in the previous chapter, the nation would also benefit from increased UMO extraction in Texas through enhanced energy independence and security as the domestic resource base expands. Each barrel of reserves added through advanced UMO extraction techniques in Texas would replace a barrel of imported oil and reduce the nation's trade deficit.

D. SUMMARY

If concerted R&D programs lead to the implementation of the advanced technology recovery processes discussed in this chapter, the impact of EOR and UMO extraction programs could go far beyond the already substantial contributions possible from these recovery techniques as currently applied. Advanced case EOR processes in the analyzed Texas reservoirs could add up to 8 billion barrels of immobile oil recovery, more than doubling current proved reserves. Advanced technology UMO extraction processes could add an additional 5.5 billion barrels to current proved reserves within the oil price range considered, again from just the analyzed reservoirs. Since these mobile and immobile oil targets and recovery techniques are clearly distinct, reserve additions from EOR and UMO extraction processes can be aggregated to calculate the total potential of advanced recovery techniques. Only a very small amount of mobile oil reserves are counted in both the EOR and UMO extraction totals; this double count is addressed in Chapter VI.

Clearly, reserve additions on the scale of 13 billion barrels would represent a significant boost to the state and national economies, and to domestic energy independence. Even at lower oil prices, advanced technology would create a large number of jobs and benefit both the state and federal treasuries. The critical need is for research to define, develop, and test more efficient

Figure V-15

Annual National Impact of UMO Production
Implemented versus Advanced Technology

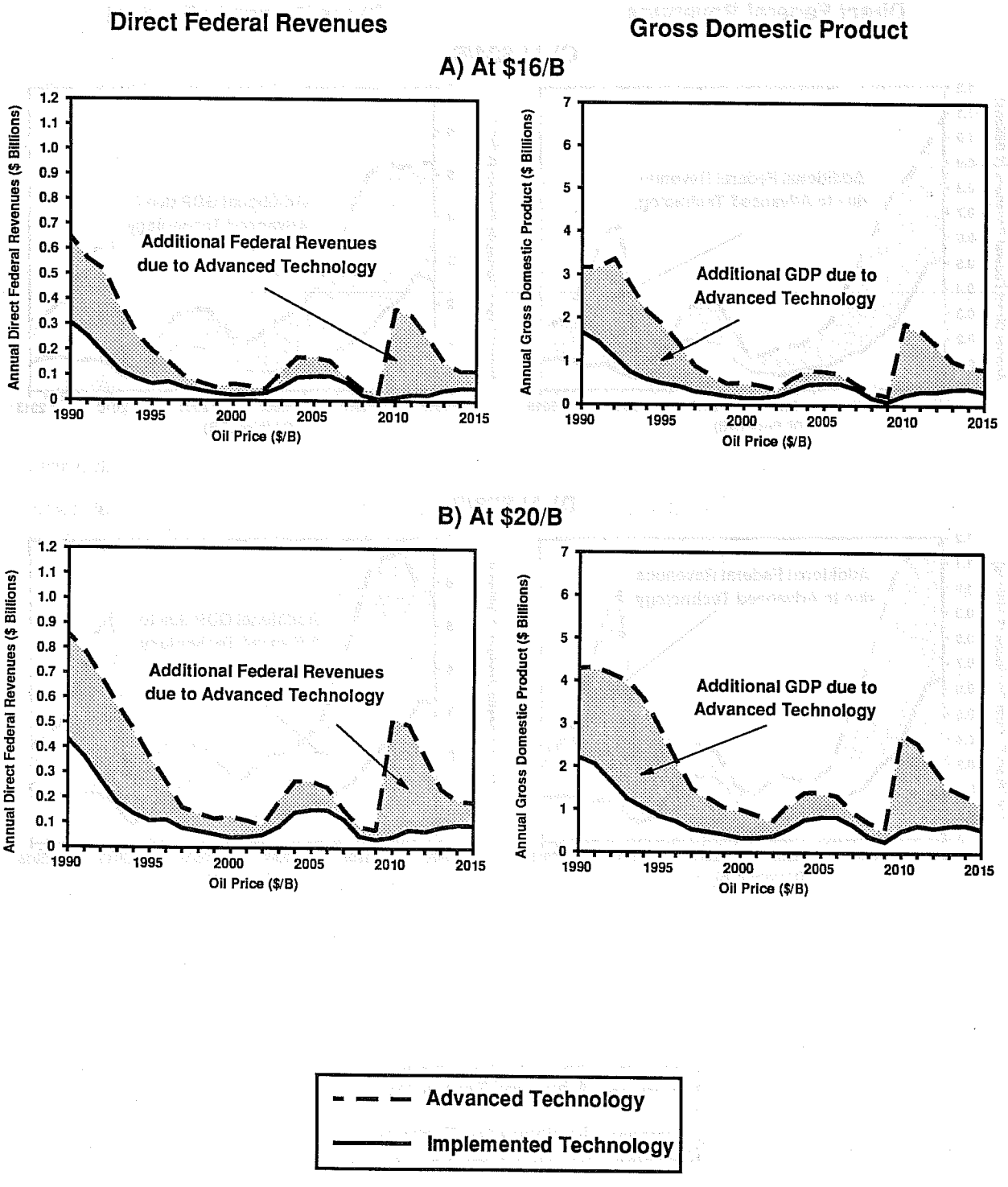
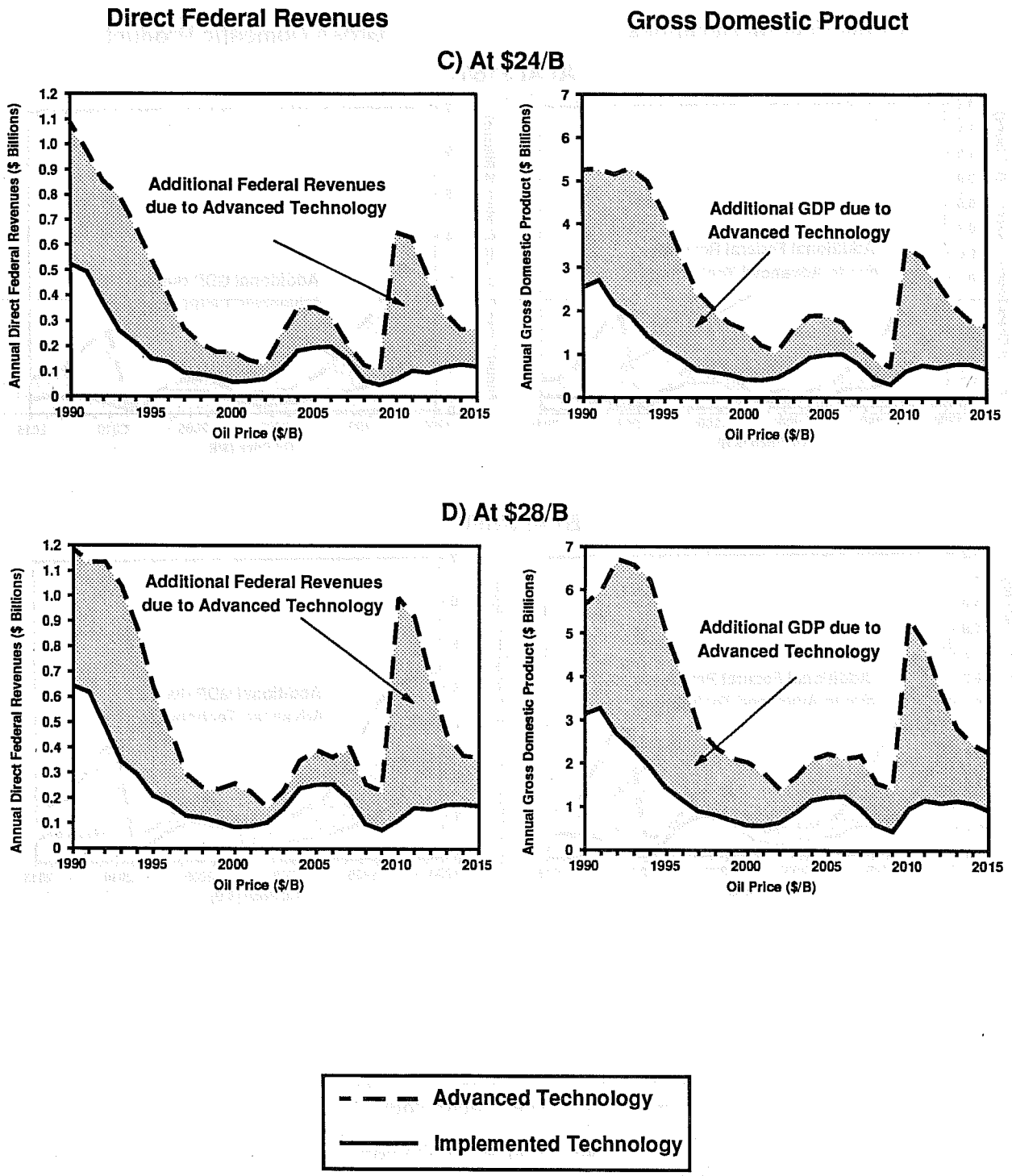


Figure V-15 (cont.)

Annual National Impact of UMO Production
Implemented versus Advanced Technology



recovery processes and procedures for contacting and recovering remaining mobile and immobile oil. If this research effort can effectively refine and encourage the implementation of the recovery processes analyzed in this chapter, Texas oil production could be sustained well into the next century.

VI. SYNERGISTIC EFFECT OF COMBINED EOR AND UMO APPLICATIONS

A. INTRODUCTION

This chapter evaluates the recovery potential possible with the effective, synergistic application of both the EOR and UMO extraction processes in the Texas reservoirs analyzed in this study. Previous chapters discuss the production potential of these recovery processes as specifically designed to recover mobile oil or immobile oil. The separate EOR and UMO analyses assume the application of just one EOR or UMO extraction process in each reservoir, thus eliminating nearly all potential for "double counting" oil recovery. The UMO advanced primary and secondary recovery processes (infill drilling, polymer flooding, and profile modification treatments) are all directed at increasing the waterflood sweep efficiency, and hence the recovery of mobile oil. EOR processes (miscible flooding, chemical flooding, and thermal recovery) are all primarily directed at the recovery of immobile oil using tertiary recovery methods.

The analysis in this chapter develops and discusses the total potential recovery from the economic application of all processes in the analyzed Texas reservoirs. The first section discusses the reserve additions possible with the single application of either advanced primary and secondary recovery methods or tertiary recovery methods. This section aggregates the previously discussed EOR and UMO extraction results while eliminating the slight overlap in these analyses -- the small volume of mobile oil recovery associated with some chemical flood projects. The second section discusses the potential increase in recovery possible from the application of UMO extraction processes along with EOR operations. The results of these two sections are compared, allowing the synergies associated with the combination of EOR and UMO extraction techniques to be quantified. Combining EOR with UMO extraction techniques enables recovery not only from previously swept portions of reservoirs, but also from the immobile oil resource that lies in previously unswept zones. The final section discusses and evaluates the potential increase in recovery possible from the application of infill drilling and advanced secondary recovery in combination with miscible flooding techniques in Texas reservoirs.

Recent results have indicated that operations to recover UMO, infill drilling in particular, can significantly increase total oil recovery when implemented along with EOR. Exxon recently

published the results of their operations in Means San Andres Unit in Andrews County, Texas.[1/] Figure VI-1 shows the production response of the unit under the application of CO_2 miscible flooding, including the original estimate of unit response. Part B of this figure shows the production response by recovery component as estimated by the operator. The oil production resulting from the combination of infill drilling and improved secondary methods doubled the base production from the unit in only two years. Although tertiary recovery started slowly, it increased substantially from 1985 to 1987, leveling total unit production at around 16,000 barrels of oil per day. Production to date has greatly exceeded Exxon's original forecast; actual recovery in 1987 was nearly 50% above its projected levels. This success in Means indicates the potential for maximizing recovery through the effective application of both advanced primary and secondary along with tertiary oil recovery methods.

The combination of UMO and EOR techniques enhances both the technical response of the reservoir and the economics of advanced oil recovery processes. Applying recovery processes designed to produce mobile oil increases reservoir sweep efficiency, thus increasing the target immobile oil available for EOR. Project economics are enhanced as investment and operating costs are recaptured through a larger production response. In addition, the multiple, simultaneous application of recovery processes limits operating costs and investments by reducing overall project life. Therefore, a significant synergy could be exploited through the effective combination of these separate but related operations.

B. TOTAL RECOVERY WITH INDIVIDUAL PROCESSES

The results discussed in Chapters IV and V indicate the significant potential for oil recovery in Texas through EOR or advanced primary and secondary recovery. The true potential in the state includes recovery from projects utilizing both of these process classes. The simplest method for estimating this potential is to add the recoveries estimated for each class, eliminating any mobile oil recovery associated with some chemical flooding projects. The cost-effective application of surfactant (micellar-polymer) chemical flooding in most reservoirs requires relatively close well spacings. Therefore, in reservoirs in which current spacing would result in a project life longer

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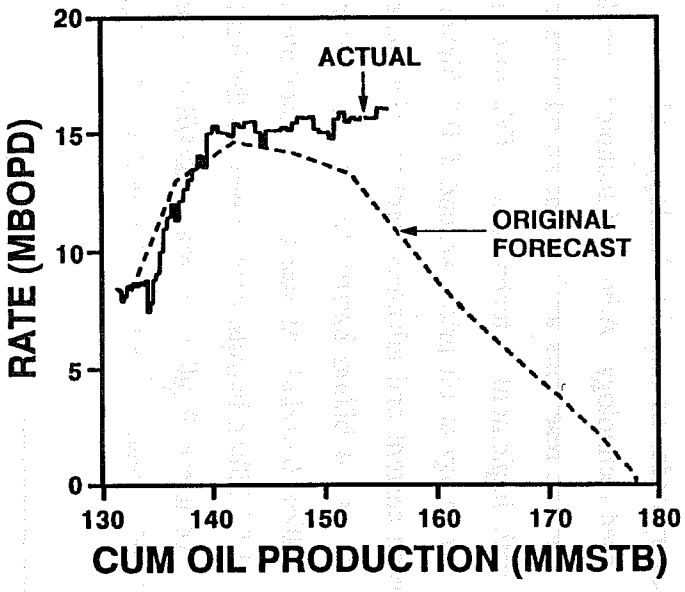
[1/] Magruder, J.G., L.H. Stiles, and T.D. Yelverton, "A Review of the Means San Andres Unit Full-Scale CO_2 Tertiary Project," SPE/DOE 17349, 1988.

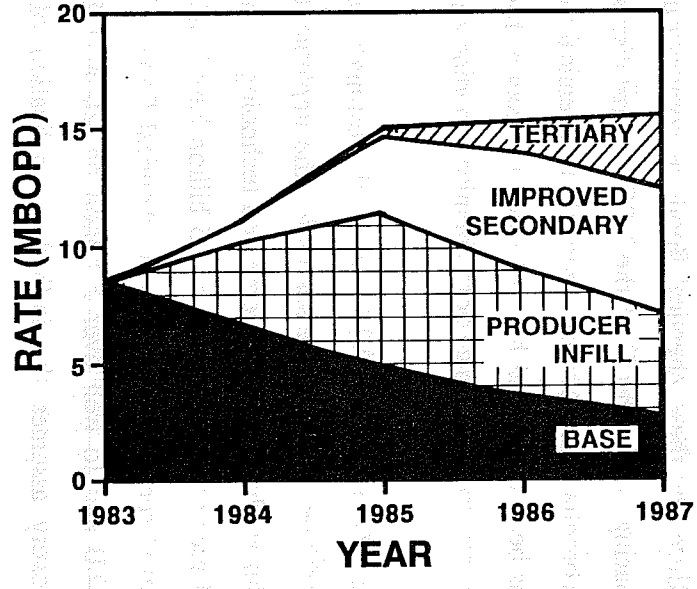
Figure VI-1

Production Response of Means San Andres Unit, A Full Scale Advanced Recovery Project

A) Total Production Profile



B) Breakdown of Response Components



Source: Magruder et. al., SPE Paper No. 17349, April 1989

than eight years, infill drilling is assumed to precede the application of EOR techniques. Some UMO is produced by these chemical floods as conventional recovery efficiency increases due to closer well spacing. Appendix D of the NPC report[2/] discusses the procedure used to estimate the oil recovery potential in reservoirs amenable to chemical flooding at closer spacing. An analytical procedure has been developed for this study to account for and eliminate the double counting of oil recovery in reservoirs in which both chemical flooding and infill drilling for UMO are applicable.

Figure VI-2 and Table VI-1A show the estimated total recovery from the addition of the EOR and UMO extraction processes under the implemented and advanced technology scenarios analyzed in this study. Under implemented technology at an oil price of $16/B, the total potential for additional recovery is estimated at 1.5 billion barrels after adjusting the EOR total to account for the increased secondary recovery in chemical floods. This total increases to nearly 3 billion barrels at $20/B and to well over 5 billion barrels at $28/B. This simple analysis of the total potential recovery assumes the individual application of current EOR and UMO extraction processes. That 5.5 billion barrels is estimated to be producible at foreseeable oil price levels through these currently applied techniques indicates the significant future oil recovery possible from the known resource in Texas.

With the application of advanced technology practices for both EOR and UMO extraction, the potential recovery in Texas increases substantially. Figure VI-2 and Table VI-1B shows that combined recovery under advanced technology could more than double the total reserve additions under implemented technology. Advanced techniques could result in recovery of almost 5 billion barrels of oil from the reservoirs analyzed at an oil price of $16/B -- nearly 3 times the potential at this price with implemented techniques. This total is comparable to the potential under implemented technology at oil prices around $10/B higher. As oil prices rise, the difference in recovery between current and advanced technologies increases. At $20/B, advanced technology could add more than 4 billion barrels to recovery under implemented technology, for a total recovery of 7 billion barrels. At the two intermediate oil prices, advanced technology could contribute 5 and 5.5 billion barrels, respectively, to the implemented technology totals, resulting in a total recovery of nearly 9 billion barrels at $24/B or almost 11 billion barrels at $28/B. At the two highest oil prices analyzed, advanced techniques for EOR and UMO extraction could recover

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2/ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

Figure VI-2

Total Reserve Additions from EOR and UMO Extraction

Implemented versus Advanced Technology

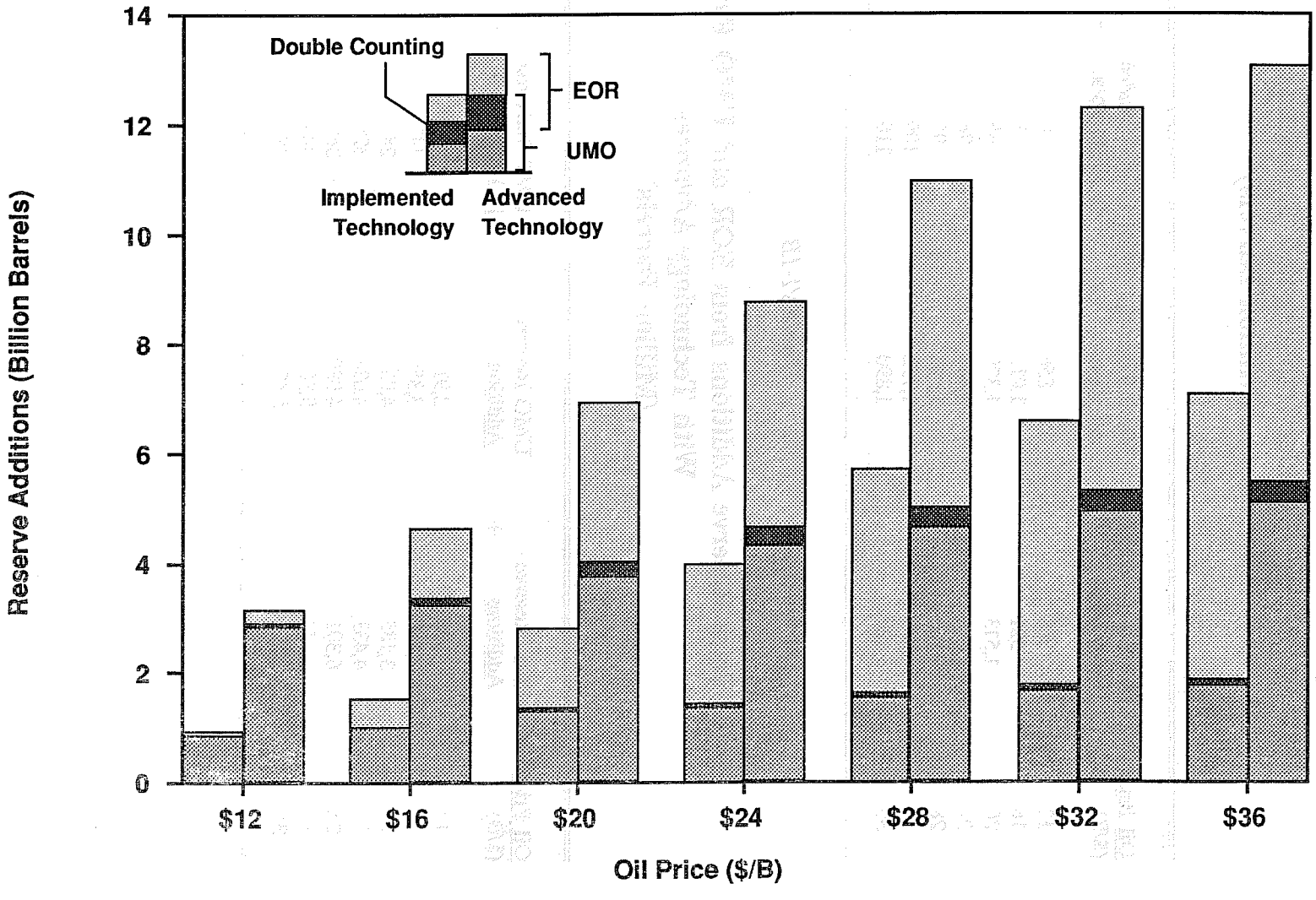

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Table VI-1A

Total Reserve Additions from EOR and UMO Extraction Under Implemented Technology (Million Barrels)

Oil Price ($/B)	EOR Reserve Additions	+	UMO Reserve Additions	-	UMO Included in EOR Total	=	Total EOR and UMO Reserve Additions
12	68		856		0		924
16	521		1,015		3		1,534
20	1,513		1,379		65		2,827
24	2,626		1,448		76		3,998
28	4,162		1,643		91		5,714
32	4,906		1,792		109		6,589
36	5,320		1,890		116		7,094

Table VI-1B

Total Reserve Additions from EOR and UMO Extraction With Technology Advances (Million Barrels)

Oil Price ($/B)	EOR Reserve Additions	+	UMO Reserve Additions	-	UMO Included in EOR Total	=	Total EOR and UMO Reserve Additions
12	324		2,911		72		3,163
16	1,389		3,353		142		4,600
20	3,185		4,037		286		6,936
24	4,433		4,638		328		8,744
28	6,301		4,989		360		10,930
32	7,350		5,304		385		12,269
36	7,926		5,473		385		13,013

around 13 billion barrels, double the potential under implemented technology. In comparison, the current proved reserves in the state of Texas total 7.1 billion barrels.

C. COMBINED APPLICATION OF PROCESSES

Although the total recovery estimates resulting from simply adding EOR and UMO extraction are impressive, they understate the true potential of the wide-spread application of both processes in the state. The combined application of EOR and UMO processes in Texas reservoirs could further increase recovery by improving sweep efficiencies and enhancing project economics. For most cases considered in this study, the synergy more than offsets the small double count discussed in the previous section. This section discusses the potential increased recovery possible with the synergistic, coordinated application of EOR and UMO extraction techniques in Texas reservoirs. The adjusted recovery totals developed above for the individual process applications are presented for comparison.

The combined application of EOR with selected UMO recovery techniques would result in significant additional oil recovery in Texas. As shown in Figure VI-3, under implemented technology, the synergistic application of processes could result in total reserve additions in Texas of from 1.5 to over 5.7 billion barrels at prices from $16/B to $28/B. The increment due to the synergistic effect of simultaneous application is small, ranging from essentially no change at the two lower oil prices to over 80 million barrels at oil prices of $24/B and $36/B. Table VI-2A shows the total recovery estimates for the individual and combined application cases analyzed under implemented technology.

While the incremental gain from the combination is relatively small under implemented technology, it is substantially larger when the impact of advanced technology is considered. The results of the combined case assume the full development and implementation of advanced geologically targeted infill drilling, as well as the improved applicability and recovery possible through advanced EOR techniques. Further, the analysis assumes the targeted application of EOR in certain reservoirs where a portion of the zone is highly favorable for tertiary recovery, even when the entire reservoir cannot economically support full-scale development. Figure VI-3 also compares the recovery potential under implemented and advanced technology for the individual and

Figure VI-3

Incremental Reserve Additions Due to Synergies Between EOR and UMO Extraction

Implemented versus Advanced Technology

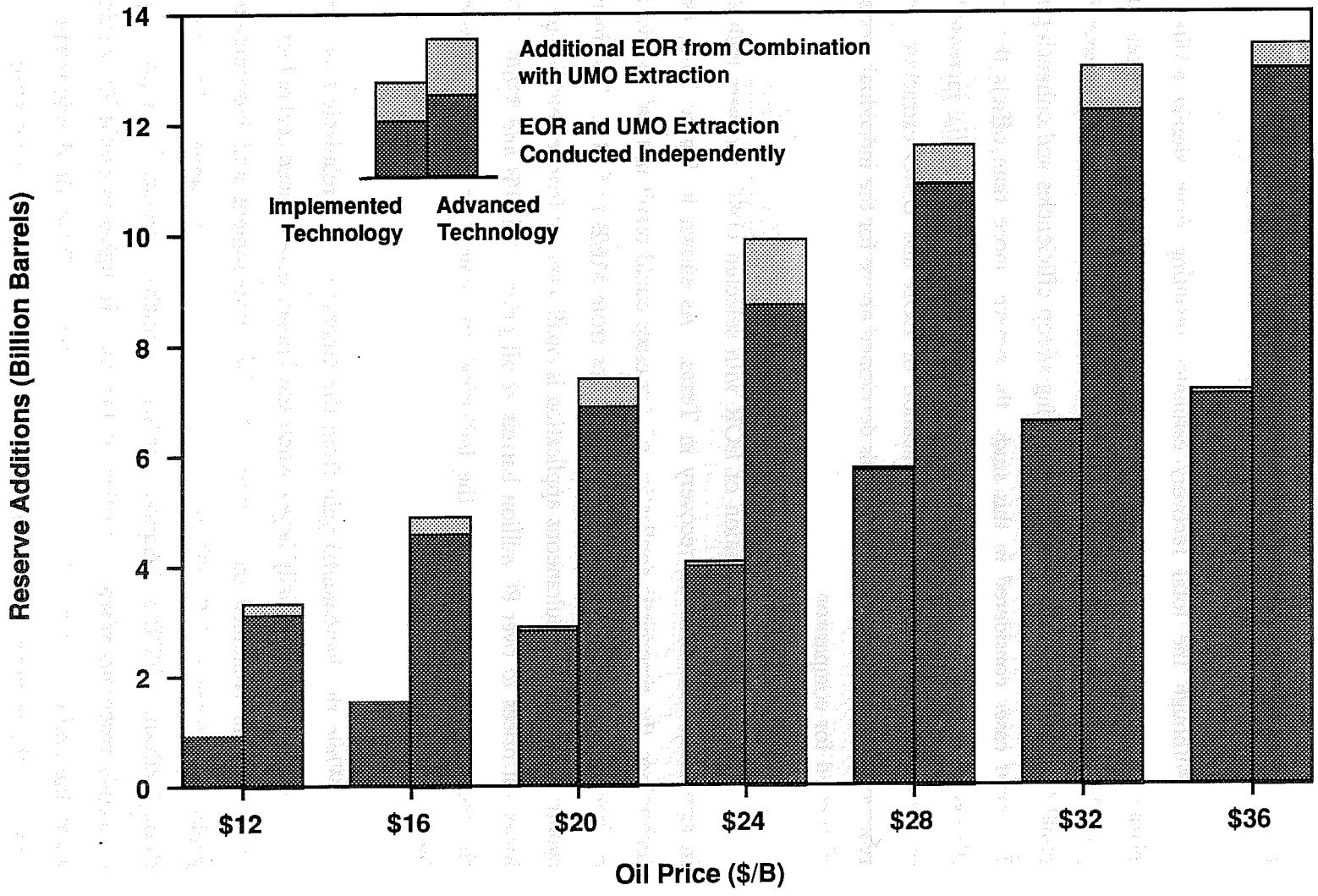

Table VI-2A

Synergistic Reserve Additions with Combined Application of EOR and UMO Processes Incremental Reserves Under Implemented Technology (Million Barrels)

Oil Price ($/B)	Individual Application of EOR and UMO Processes	Combined Application of EOR and UMO Processes	Incremental Reserve Additions
12	924	924	0
16	1,534	1,536	2
20	2,827	2,898	71
24	3,998	4,081	83
28	5,714	5,768	54
32	6,589	6,606	17
36	7,094	7,175	81

Table VI-2B

Synergistic Reserve Additions with Combined Application of EOR and UMO Processes Incremental Reserves with Technology Advances (Million Barrels)

Oil Price ($/B)	Individual Application of EOR and UMO Processes	Combined Application of EOR and UMO Processes	Incremental Reserve Additions
12	3,163	3,371	208
16	4,600	4,924	324
20	6,936	7,443	507
24	8,744	9,928	1,184
28	10,930	11,616	686
32	12,269	13,055	786
36	13,013	13,447	434

combined cases. The results indicate that the combination of EOR and UMO extraction under the advanced technology case could substantially increase recovery. Incremental recovery due to the combination ranges from 200 million to 1.2 billion barrels more than the sum of the individual process results. The largest increment is at the $24/B oil price. Large incremental reserve increases could also occur at the $20/B level, where over 500 million barrels could be added due to the combination, and at both the $28/B and $32/B oil prices, where additions of nearly 690 and 790 million barrels could result. Table VI-2B displays the results under the advanced case assumptions for the individual and combined cases analyzed.

D. MISCIBLE FLOODING POTENTIAL COMBINED WITH UMO EXTRACTION

Miscible EOR flooding is by far the most promising process analyzed under the combination case. These processes, and the CO_2 miscible process in particular, account for essentially all of the incremental production resulting from the combined application of techniques. Other EOR processes show little potential; chemical processes already include some impact of infill drilling in the EOR assessment; thermal recovery estimates are already conducted with relatively close spacing, limiting additional mobile oil recovery. The miscible process, which is particularly effective in West Texas carbonate reservoirs, holds significant promise in the state even under implemented technology, application of the process alone, and moderate oil prices. While laboratory studies have shown high oil displacement efficiencies for the process, miscible flooding recovery in the reservoir is currently limited by its relatively poor sweep efficiency. Since the injected gas has lower viscosity than oil, and sometimes lower density, it tends to finger through the reservoir and will often recover immobile oil from only a small fraction of the reservoir segment swept by water. Improvements in sweep efficiency are critical to enhancing the economic performance of these processes. Combining miscible flooding with advanced geoscience, improved secondary recovery, and targeted infill drilling has the potential to achieve some of the required improvement.

The potential of miscible flooding could increase by as much as 5% with implemented technology if its application is linked with UMO extraction technology. This increase occurs in the $24/B case where over 100 million barrels are added by the effective application of miscible flooding in combination with blanket infill drilling. The incremental recovery comes from those miscible flooding projects where the process can be economically implemented at closer well spacing. At other oil prices, additional reserves under implemented technology (as shown in Figure

VI-4A and Table VI-3A) range up to 170 million barrels, clearly illustrating the significant oil production possible upon the wide-scale implementation of multiple recovery processes in selected reservoirs.

With the development of advanced EOR technology and advanced geoscientific techniques, processes combining UMO recovery and miscible flooding techniques could substantially increase Texas oil recovery. This section focuses on the improved recovery and project economics possible through miscible flooding after geologically targeted infill drilling. Because targeted drilling leads to much higher recoveries than blanket drilling at lower oil prices, economic implementation of targeted drilling can enhance miscible flooding potential by expanding the swept zone and the immobile oil target for these tertiary processes. In addition, the targeted use of miscible flooding in certain reservoir segments could improve process economics if advanced geoscientific characterization techniques can effectively identify these areas for exploitation. The advanced case analysis assumes the full development of the resource with both targeted drilling and targeted EOR application.

As shown in Figure VI-4B and Table VI-3B, the combination of miscible flooding and advanced UMO recovery could increase Texas reserves considerably. The reserves added as a direct result of the combination range from less than 150 million barrels at the lowest oil price analyzed ($12/B) to over 1.2 billion at the intermediate price of $24/B. Incremental reserves at $16/B and $20/B are estimated at 300 and 400 million barrels, respectively. At the $32/B oil price, the increment is about 800 million barrels, declining to around 500 million barrels as the price increases to $36/B. While these reserve additions are small in some cases relative to total EOR potential, they supplement the recovery achieved by the application of miscible flooding alone up to 47%. This substantial increase indicates the critical need for, and potential payoff of, research to improve the recovery efficiency of the miscible flooding process.

Total reserve additions from miscible flooding could total up to 3.8 billion barrels at oil prices of less than $25/B if the process is fully developed in combination with UMO extraction processes. Combination process miscible recovery could exceed 5 billion barrels at oil prices above $32/B. The magnitude of this recovery is further indication of the importance of the efficient application of miscible flooding in Texas reservoirs.

Figure VI-4

Incremental Reserve Additions from Miscible Flooding Due to Synergies Between EOR and UMO Extraction

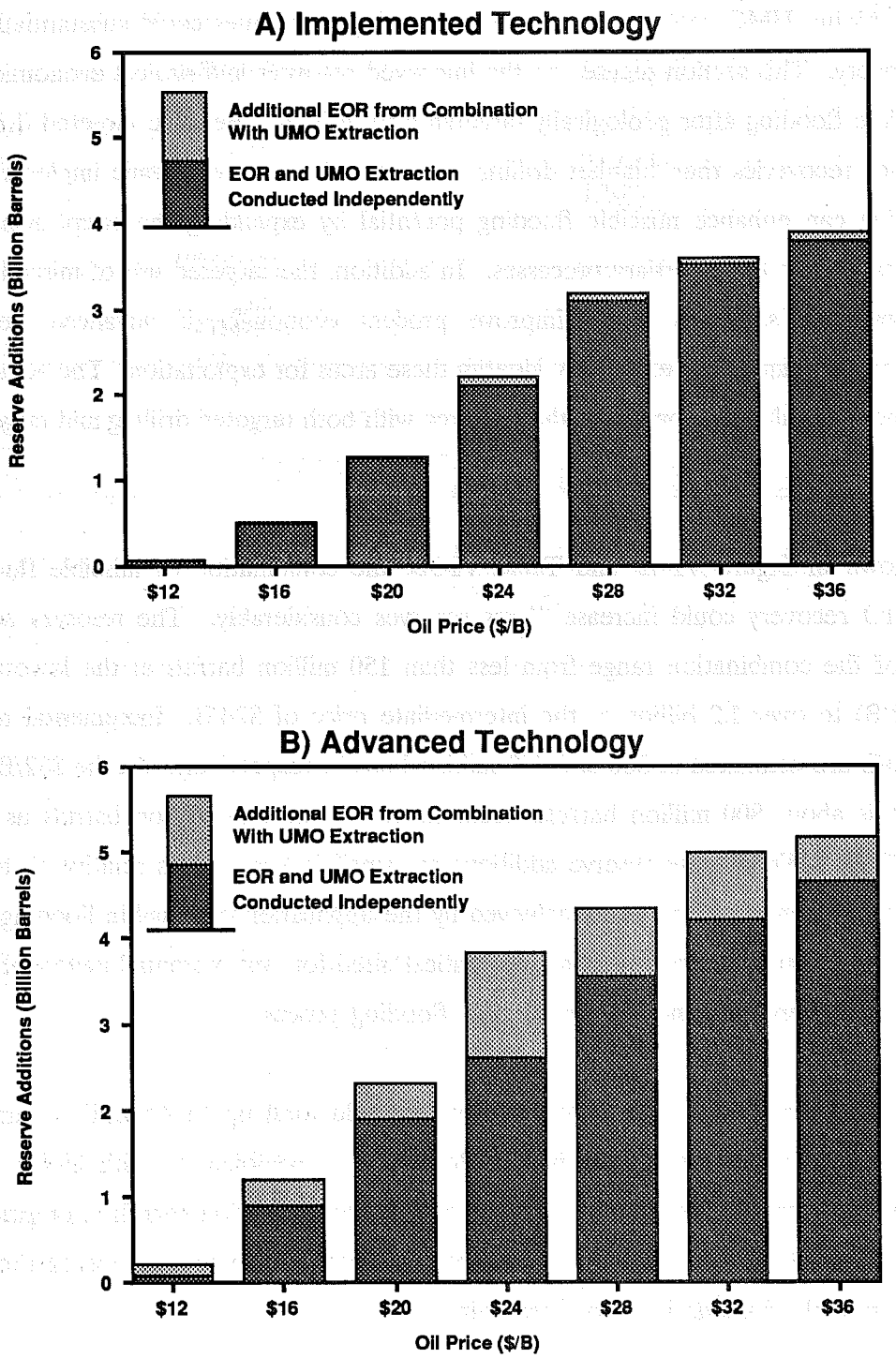

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Table VI-3A

Miscible Flooding Potential With Combined Application of EOR and UMO Extraction Processes Incremental Reserves Under Implemented Technology (Million Barrels)

Oil Price ($/B)	Miscible Flooding by Itself	Miscible Flooding Combined With UMO Extraction Processes	Incremental Reserve Additions
12	69	69	0
16	503	503	0
20	1,261	1,266	5
24	2,112	2,215	103
28	3,135	3,196	61
32	3,560	3,604	44
36	3,726	3,896	170

Table VI-3B

Miscible Flooding Potential With Combined Application of EOR and UMO Extraction Processes Incremental Reserves With Technology Advances (Million Barrels)

Oil Price ($/B)	Miscible Flooding by Itself	Miscible Flooding Combined With UMO Extraction Processes	Incremental Reserve Additions
12	85	221	136
16	905	1,209	304
20	1,908	2,325	417
24	2,615	3,836	1,221
28	3,561	4,351	790
32	4,217	4,995	778
36	4,662	5,170	508

E. CONCLUSIONS

Significant synergies clearly exist when EOR and UMO extraction techniques are applied to selected reservoirs in combination. Such combined application could increase recovery potential by as much as 1.2 billion barrels in the analyzed Texas reservoirs. Research addressing the geologic description of reservoirs can contribute not only to UMO extraction but also to total EOR potential, since the increased conventional recovery would expand the tertiary target oil volume. Improved description of reservoir heterogeneities would improve EOR project designs and process descriptive modeling. The targeted application of EOR in highly favorable segments of selected reservoirs could also improve project economics. If all recovery processes could be fully exploited in combination, oil recovery in Texas under advanced technology could double current proved reserves at an oil price as low as $20/B.

Miscible flooding, and in particular CO_2 injection, holds significant promise in Texas if the sweep efficiency associated with this process can be improved. With increased understanding of reservoir flow paths, improved sweep efficiency of secondary recovery processes, and the decreased spacing resulting from the application of targeted infill drilling, miscible recovery could substantially add to the reserve base of the state. Additional analyses will be required to focus research on critical aspects of this combined recovery scenario.

The results in this chapter point to the clear and imperative nature of research needs in Texas. Many of the limitations imposed by the current state of post-conventional oil recovery can be overcome through advanced methods. The selective combination of recovery processes appears to offer particularly promising synergies in this regard. With appropriate experimentation and testing, the successful implementation of the findings of this research could increase recovery and improve project economics. The benefactors of this improvement will be oil companies, but the state and its citizens will also share significantly in the proceeds. Pursuing and achieving the goal of maximizing recovery of the known oil resource would greatly benefit the entire state.

VII. RANKING THE GEOLOGIC AND GEOGRAPHIC DISTRIBUTION OF EOR AND UMO RESOURCE AND RESERVE POTENTIAL

A. INTRODUCTION

The previous chapters demonstrate the significant benefits which could accrue to Texas if an effective research program could successfully achieve improvements in the oil recovery processes analyzed in this study. The first step in determining the critical requirements for such research is to identify the regions and geologic strata in Texas with the largest volume of remaining mobile and immobile oil resources and reserve potential. R&D efforts focused in these high-priority areas, combined with technology transfer to aid operators in applying improved recovery methods, could lead to the maximum production of the state's known oil resource. This chapter identifies the oil plays and associated regions within Texas that contain the largest UMO and immobile oil resources analyzed in this evaluation, as well as those with the greatest potential for future reserve additions. The term *play* is used here to distinguish groups of reservoirs with similar geologic histories[1/]. This chapter also discusses the most promising recovery processes applicable to the top Texas plays.

The geologic properties and architecture of a reservoir have a profound effect on the recovery performance of both EOR and UMO extraction operations. Recovery efficiency correlates closely with the geologic history of a reservoir[2/3/4/], which includes the original depositional environment and subsequent post-depositional modifications. The wide range of recovery efficiencies for Texas reservoirs clearly reflects the diversity of geologic types within the state. As earlier chapters of this report demonstrate, increased knowledge of the geologic nature of reservoirs

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1/ Galloway, et al., *Atlas of Major Texas Oil Reservoirs*, The Bureau of Economic Geology, University of Texas at Austin, 1983.

2/ ICF Resources Incorporated and the Bureau of Economic Geology, University of Texas at Austin, *Production Potential of Unrecovered Mobile Oil Through Infield Development: Integrated Geologic and Engineering Studies*, August, 1989.

3/ Tyler, et al., *Oil Accumulation, Production Characteristics, and Target for Additional Recovery in Major Oil Reservoirs of Texas*, The Bureau of Economic Geology, University of Texas at Austin, Geological Circular 84-2, 1984.

4/ Galloway, et al., *Atlas of Major Texas Oil Reservoirs*, The Bureau of Economic Geology, University of Texas at Austin, 1983.

and better predictive capability of process recovery in these reservoirs could significantly increase the future production of UMO and immobile oil from the Texas resource analyzed.

The purpose of this study is to estimate the benefits of an effective R&D program and to outline appropriate methods for establishing such a program. Increased knowledge and understanding of reservoir heterogeneity and of how it affects oil recovery processes in Texas reservoirs could increase ultimate EOR and UMO extraction three-fold. While the state-wide benefits of advanced technology development are clearly substantial, the increased oil recovery and resultant incremental state revenues and economic activity are not distributed randomly among the state's reservoirs. A small number of major geologic plays contain a bulk of the target resource and a large portion of the potential recovery possible from the analyzed reservoirs. Therefore, a strategic R&D program to exploit the geologic similarity and resource concentration of major Texas plays could focus research efforts on the highest payoff targets. Additional efforts to transfer existing and emerging technology developments to oil operators could also be similarly focused. Therefore, a R&D program designed to address current recovery problems in significant Texas geologic plays could maximize recovery and associated economic benefits to the state.

B. OIL PLAYS ANALYZED

Five hundred of the most productive oil-bearing reservoirs in Texas were grouped into forty-eight distinct plays in the *Atlas of Major Texas Oil Reservoirs*.[5/] The *Atlas* play classification was used in this evaluation. Reservoirs from the *Atlas* not previously included in the TORIS reservoir data base have been added and analyzed during this study. For those reservoirs contained in the TORIS data base but not in the *Atlas*, play codes and other geologic information consistent with the previously developed groupings were assigned as part of the data base upgrade. The names and geographic locations of the forty-eight Texas plays used in this evaluation are shown in Figure VII-1. Reservoirs from each of these plays are represented in the data base used in this analysis.

Of the plays analyzed, 27 are located in West Texas and the Texas Panhandle region (16 carbonate plays -- limestone and dolostone; 9 sandstone plays; and 2 combined sandstone and carbonate plays), 10 plays occur in a belt including East and Central Texas (4 carbonate and 6

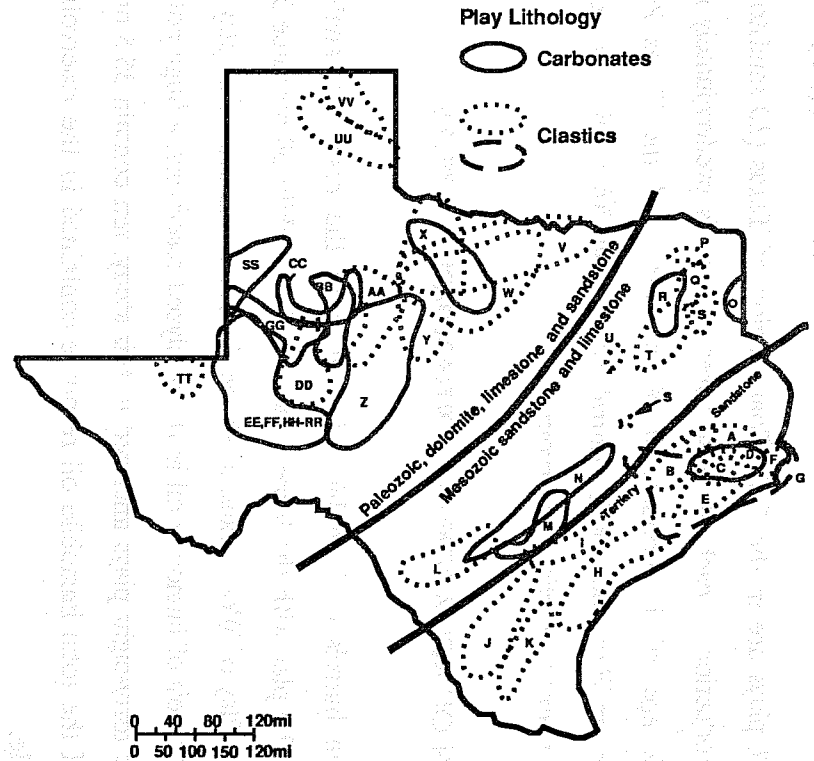
[5/] *Ibid.*

Figure VII-1

Location of Major Oil Plays in Texas

Texas Oil Plays

A. Eocene deltaic sandstone
B. Yegua deep-seated salt domes
C. Yegua salt-dome flanks
D. Cap rock
E. Frio deep-seated salt domes
F. Frio (Buna) barrier/strandplain sandstone
G. Piercement salt domes
H. Frio barrier/strandplain sandstone
I. Wilcox fluvial/deltaic sandstone
J. Jackson-Yegua barrier/strandplain sandstone
K. Frio fluvial/deltaic sandstone (Vicksburg fault zone)
L. San Miguel - Olmos deltaic sandstone
M. Edwards restricted-platform carbonate
N. Austin-Buda fractured chalk
O. Glen Rose carbonate (stratigraphic/structural traps)
P. Paluxy fault line
Q. Cretaceous sandstone (salt-related structures)
R. Glen Rose carbonate (salt-related structures)
S. East Texas Woodbine sandstone
T. Woodbine fluvial/deltaic/strandplain sandstone
U. Woodbine fault line
V. Strawn sandstone
W. Bend conglomerate
X. Caddo reef
Y. Upper Pennsylvanian shelf sandstone
Z. Pennsylvanian reef/bank
AA. Upper Pennsylvanian slope sandstone
BB. Eastern Shelf Permian carbonate
CC. Horseshoe Atoll
DD. Spraberry-Dean Sandstone
EE. Central Basin Platform unconformity
FF. Ellenburger fractured dolomite
GG. Silurian-Devonian ramp carbonate
HH. Silurian-Devonian ramp carbonate (South Central Basin Platform)
II. Silurian-Devonian ramp carbonate (North Central Basin Platform)
JJ. Yates area
KK. San Andres - Grayburg carbonate (Ozona Arch)
LL. San Andres - Grayburg carbonate (South Central Basin Platform)
MM. San Andres - Grayburg carbonate (North Central Basin Platform)
NN. Permian sandstone and carbonate
OO. Clear Fork platform carbonate
PP. Queen platform/ strandplain sandstone
QQ. Wolfcamp platform carbonate
RR. Pennsylvanian platform carbonate
SS. Northern Shelf Permian carbonate
TT. Delaware sandstone
UU. Panhandle granite wash/dolomite
VV. Panhandle Morrow Sandstone



(after Tyler et al., 1984)

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sandstone plays), and 11 plays are in the Gulf Coast region of Texas (10 sandstone plays and 1 carbonate play). Oil production in each of these three regions is predominately from reservoirs of one distinct geologic age; oil is produced in West Texas and the Texas Panhandle from Paleozoic-aged reservoirs, in East and South-Central Texas from Mesozoic reservoirs, and in the Gulf Coast region from younger Tertiary reservoirs.

C. DISTRIBUTION OF REMAINING OIL RESOURCE BY PLAY

Almost 54 billion barrels of immobile oil remain in the reservoirs analyzed for EOR potential in this study. The play with the largest volume of immobile oil resource is the Northern Shelf Permian Carbonate Play of West Texas, as shown in Table VII-1A. This play alone contains an estimated 7.9 billion barrels of immobile oil in the analyzed reservoirs, a huge potential resource target for EOR. Of the forty-eight plays analyzed in this study, ten contain 35.5 billion barrels of immobile oil, or 66% of the total immobile oil resource contained in the reservoirs analyzed for EOR potential state-wide.

More than 19 billion barrels of mobile oil will remain after conventional recovery in the reservoirs analyzed for UMO extraction potential in this study. The single largest play in terms of UMO resource is the San Andres/Grayburg Carbonate (South Central Basin Platform) Play in West Texas, as shown in Table VII-1B. An estimated 2.9 billion barrels of UMO will remain in the analyzed reservoirs of this play after completion of conventional recovery operations. The average recovery efficiency of conventional production for these reservoirs, weighted by reservoir OOIP, is 25%, clearly suggesting that a significant amount of oil will remain untapped in this play once current operations reach their economic limit. The top ten plays in terms of UMO resource contain 13.1 billion barrels, or 68% of the total UMO resource directly analyzed. The location of the top ten plays ranked by their immobile oil and UMO resources is shown in Figure VII-2. Eight of the plays shown rank in the top ten for both immobile oil and UMO resources.

The concentration of the remaining oil resource in reservoirs within a relatively small number of Texas geologic plays has important implications for state R&D planning. The recovery of a substantial portion of this remaining resource should be the goal of hydrocarbon-related R&D planning for the state. Within the near-and mid-term, R&D should focus on maximizing recovery from the top reservoirs in those plays which appear to have the greatest potential with foreseeable

Table VII-1

Immobile Oil and UMO Resource in Major Oil Plays in Texas*

A. Immobile Oil

Rank	Map Code**	Oil Play	Resource (MMB)
1.	SS	Northern Shelf Permian Carbonate	7,861
2.	LL	San Andres/Grayburg Carbonate (SCBP***)	5,284
3.	DD	Spraberry/Dean Sandstone	4,097
4.	UU	Panhandle Granite Wash/Dolomite	3,757
5.	OO	Clear Fork Platform Carbonate	2,666
6.	X	Caddo Reef	2,436
7.	V	Strawn Sandstone	2,385
8.	BB	Eastern Shelf Permian Carbonate	2,361
9.	HH	Permian Sandstone and Carbonate	2,336
10.	H	Frio Barrier/Strandplain Sandstone	2,289
		TOTAL	**35,472**
		TOTAL, ALL PLAYS	**53,823**

B. UMO

Rank	Map Code**	Oil Play	Resource (MMB)
1.	LL	San Andres/Grayburg Carbonate (SCBP***)	2,915
2.	SS	Northern Shelf Permian Carbonate	2,713
3.	DD	Spraberry/Dean Sandstone	1,234
4.	OO	Clear Fork Platform Carbonate	1,156
5.	H	Frio Barrier/Strandplain Sandstone	1,065
6.	V	Strawn Sandstone	1,019
7.	E	Frio Deep-seated Salt Domes	829
8.	X	Caddo Reef	778
9.	HH	Permian Sandstone and Carbonate	767
10.	JJ	Yates Area	628
		TOTAL	**13,104**
		TOTAL, ALL PLAYS	**19,166**

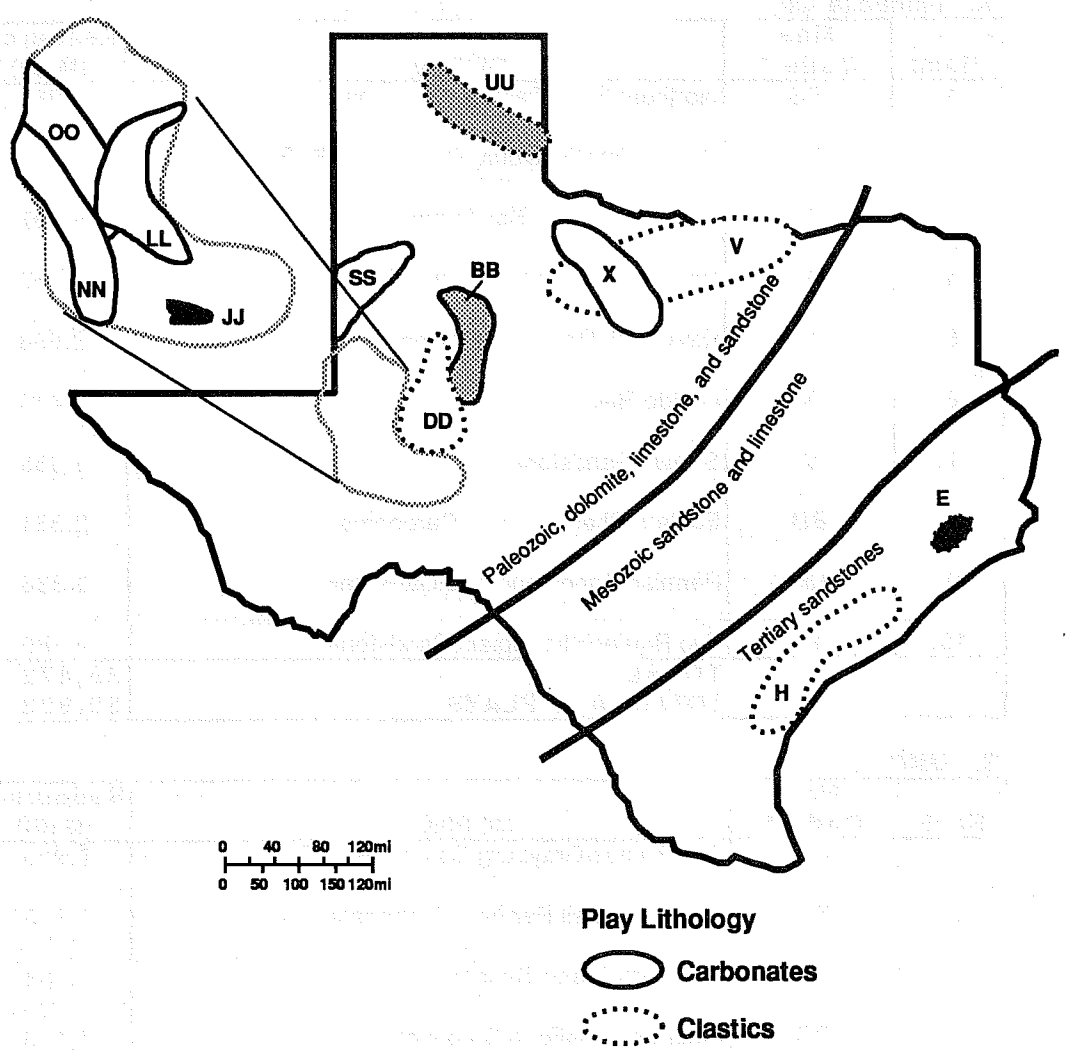
* Resource figures represent resource after waterflooding in reservoirs from TORIS data base

** see Figure VII-2

*** SCBP symbolizes South Central Basin Platform

Figure VII-2

Location of Top Oil Plays for Immobile Oil and UMO Resource in Texas



(modified from Tyler et al., 1984)

LEGEND	
E. Frio Deep-Seated Salt Domes H. Frio Barrier-Strandplain Sandstone V. Strawn Sandstone X. Caddo Reef BB. Eastern Shelf Permian Carbonate DD. Spraberry/Dean Sandstone JJ. Yates Area LL. San Andres/Grayburg Carbonate (SCBP *) NN. Permian Sandstone and Carbonate OO. Clear Fork Platform Carbonate SS. Northern Shelf Permian Carbonate UU. Panhandle Granite Wash Dolomite * South Central Basin Platform	In Top 10 Immobile and Mobile Oil Remaining Resource Plays Only in Top 10 Immobile Oil Resource Plays Only in Top 10 Remaining Mobile Oil Resource Plays

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technology improvements under projected economic conditions. These foreseeable advances would include the enhancement of current recovery processes in conjunction with better methods of characterizing reservoirs. The knowledge gained from the study of improving recovery in the top reservoirs within the top plays would then quite possibly be applicable to other, less prolific reservoirs within the same play. In the longer term, however, possible improvements in recovery in areas which currently hold relatively little potential under analyzed processes should also be considered in R&D planning. For example, the reservoirs in the Spraberry/Dean Sandstone Play will still contain a substantial remaining resource even after currently envisioned advances in recovery are applied. Improvements in recovery resulting from R&D may in fact generate substantial reserves from resources such as in this complex play. The next section evaluates EOR and UMO recovery potential from the remaining Texas oil resource and identifies the most significant geologic plays in terms of their oil production potential under the technology and economic cases analyzed in this study.

D. DISTRIBUTION OF POTENTIAL OIL RESERVES BY PLAY

1. Introduction

Knowledge of the resource distribution of UMO and immobile oil in Texas indicates where the potential for future recovery exists. However, the actual extraction of this resource is determined by field operation parameters which limit the volume of economically producible reserves. Parameters that affect the costs of producing the resource include the depth of the producing formation, the gravity of the oil, and the technical capability of the recovery processes available to produce the oil. The sections below discuss the potential incremental oil reserves from EOR and UMO extraction processes by play evaluated under the two technology cases, implemented and advanced. The purpose of this analysis is to determine which oil plays have the greatest economic potential under currently available technology as well as with R&D advances achievable over the next ten years. The implemented and advanced technology cases are analyzed at oil prices of $20/B and $32/B to reflect near- and mid- to long-term economic conditions of Texas oil production, respectively. Once the plays with the greatest reserve potential are identified, research planning can be focused in these areas in order to maximize ultimate recovery.

2. Enhanced Oil Recovery

a. Reserves in Top Oil Plays

Even at an oil price of $20/B, economic EOR potential in Texas is considerable -- over 1.5 billion barrels of reserves could be added from the reservoirs analyzed in this study using currently available recovery techniques (implemented technology). The Northern Shelf Permian Carbonate Play, located in the West Texas Permian Basin area, has the greatest EOR potential at this price and technology, with 320 million barrels of estimated reserves, or 21% of the projected total recovery from all of the reservoirs analyzed state-wide. The ten plays with the most EOR potential under implemented technology could produce over 1.3 billion barrels of oil, or 87% of the total economic EOR from the reservoirs analyzed in all forty-eight plays (Table VII-2A).

The use of advanced technology at a $20/B oil price could increase producible EOR reserves substantially, to nearly 3.2 billion barrels, or over twice the amount estimated under implemented technology at the same price. The oil play with the greatest economic reserve potential under this case is again the Northern Shelf Permian Carbonate Play, with around 750 million barrels of EOR possible. Advanced technology would increase the EOR potential of this one play by 135% over recovery with implemented technology. The ten plays with the most potential could collectively produce 2.5 billion barrels of oil with advanced EOR technology, or 78% of the total oil economically recoverable under this case from the reservoirs analyzed in all forty-eight Texas oil plays (Table VII-2B). Eight of the top ten plays in terms of advanced technology recovery also appear in the top ten plays in terms of implemented technology recovery at this price. Taking these eight plays collectively, advanced technology could increase recovery potential by 75%, from 1.2 billion barrels to 2.1 billion barrels.

If oil prices were to increase to $32/B, as anticipated in the mid- to long-term, implemented technology EOR could result in a total of 4.9 billion barrels of oil from the reservoirs analyzed state-wide in this study. The play with the greatest economic potential, the Northern Shelf Permian Carbonate Play, could produce 1.2 billion barrels, 24% of the total for reservoirs evaluated under implemented technology at this price. The ten plays with the greatest economic potential could collectively produce almost 3.5 billion barrels, 71% of the estimated state EOR reserves from the reservoirs evaluated in this analysis (Table VII-2C).

EOR Reserve Estimates For Top Oil Plays in Texas

A. Implemented Technology, $20/Bbl

Rank	Map Code	Oil Play	Reserves (MMB)	No. of Economic Reservoirs	Dominant Process*
1.	SS	Northern Shelf Permian Carbonate	320	7	CO2
2.	MM	San Andres/Grayburg Carbonate (NCBP**)	196	2	CO2
3.	LL	San Andres/Grayburg Carbonate (SCBP***)	173	3	CO2
4.	H	Frio Barrier/Strandplain Sandstone	170	1	SURF
5.	BB	Eastern Shelf Permian Carbonate	125	4	CO2
6.	CC	Horseshoe Atoll	93	4	CO2
7.	K	Frio Fluvial/Deltaic Sandstone (Vicksburg)	80	3	NI
8.	FF	Ellenburger Fractured Dolomite	65	4	CO2
9.	PR	Pennsylvanian Platform Carbonate	52	3	CO2-NI
10.	D	Cap Rock	47	1	SI
		TOTAL	1,321	32	
		TOTAL, ALL PLAYS	1,514	44	

B. Advanced Technology, $20/Bbl

Rank	Map Code	Oil Play	Reserves (MMB)	No. of Economic Reservoirs	Dominant Process*
1.	SS	Northern Shelf Permian Carbonate	752	7	CO2
2.	H	Frio Barrier/Strandplain Sandstone	448	8	SURF
3.	E	Frio Deep-Seated Salt Domes	234	3	ISCOM
4.	MM	San Andres/Grayburg Carbonate (NCBP**)	218	2	CO2
5.	V	Strawn Sandstone	217	1	SURF
6.	K	Frio Fluvial/Deltaic Sandstone (Vicksburg)	200	5	NI
7.	LL	San Andres/Grayburg Carbonate (SCBP***)	173	3	CO2
8.	BB	Eastern Shelf Permian Carbonate	141	4	CO2
9.	CC	Horseshoe Atoll	100	4	CO2
10.	FF	Ellenburger Fractured Dolomite	65	4	CO2
		TOTAL	2,548	41	
		TOTAL, ALL PLAYS	3,185	60	

C. Implemented Technology, $32/Bbl

Rank	Map Code	Oil Play	Reserves (MMB)	No. of Economic Reservoirs	Dominant Process*
1.	SS	Northern Shelf Permian Carbonate	1,245	16	CO2
2.	H	Frio Barrier/Strandplain Sandstone	494	15	SURF
3.	LL	San Andres/Grayburg Carbonate (SCBP***)	371	12	CO2
4.	CC	Horseshoe Atoll	260	8	CO2
5.	B	Yegua Deep-Seated Salt Domes	249	4	SURF
6.	MM	San Andres/Grayburg Carbonate (NCBP**)	206	2	CO2
7.	E	Frio Deep-Seated Salt Domes	173	5	ISCOM
8.	P	Paluxy Fault Line	167	1	ISCOM
9.	BB	Eastern Shelf Permian Carbonate	155	5	CO2
10.	FF	Ellenburger Fractured Dolomite	153	11	CO2
		TOTAL	3,473	79	
		TOTAL, ALL PLAYS	4,907	143	

D. Advanced Technology, $32/Bbl

Rank	Map Code	Oil Play	Reserves (MMB)	No. of Economic Reservoirs	Dominant Process*
1.	SS	Northern Shelf Permian Carbonate	1,433	17	CO2
2.	H	Frio Barrier/Strandplain Sandstone	748	22	SURF
3.	LL	San Andres/Grayburg Carbonate (SCBP***)	543	14	CO2
4.	E	Frio Deep-Seated Salt Domes	352	10	ISCOM
5.	K	Frio Fluvial/Deltaic Sandstone (Vicksburg)	297	13	NI
6.	CC	Horseshoe Atoll	274	8	CO2
7.	V	Strawn Sandstone	267	5	SURF
8.	B	Yegua Deep-Seated Salt Domes	254	5	SURF
9.	BB	Eastern Shelf Permian Carbonate	245	7	CO2
10.	MM	San Andres/Grayburg Carbonate (NCBP**)	227	3	CO2
		TOTAL	4,640	104	
		TOTAL, ALL PLAYS	7,351	190	

* CO2 = Carbon dioxide injection; NI = Nitrogen injection; SURF = Surfactant injection; SI = Steam injection; ISCOM = In situ combustion

** North Central Basin Platform

*** South Central Basin Platform

Utilization of advanced EOR technology at an oil price of $32/B could result in estimated post-conventional reserves of nearly 7.4 billion barrels, a significant increase over the total under implemented technology. The top EOR play for this case would again be the Northern Shelf Permian Carbonate Play, potentially producing 1.4 billion barrels of oil, almost twice the recovery from the next highest play, the Frio Barrier-Strandplain Play, which produces 750 million barrels. The top ten plays could account for recovery of 4.6 billion barrels from the analyzed reservoirs, 62% of the total EOR potential from all Texas plays (Table VII-2D). Of these ten plays, eight are also included in the top ten plays at the $32/B oil price under implemented technology. The locations of the top implemented and advanced technology EOR plays within the state at both the $20/B and $32/B oil price are shown in Figure VII-3.

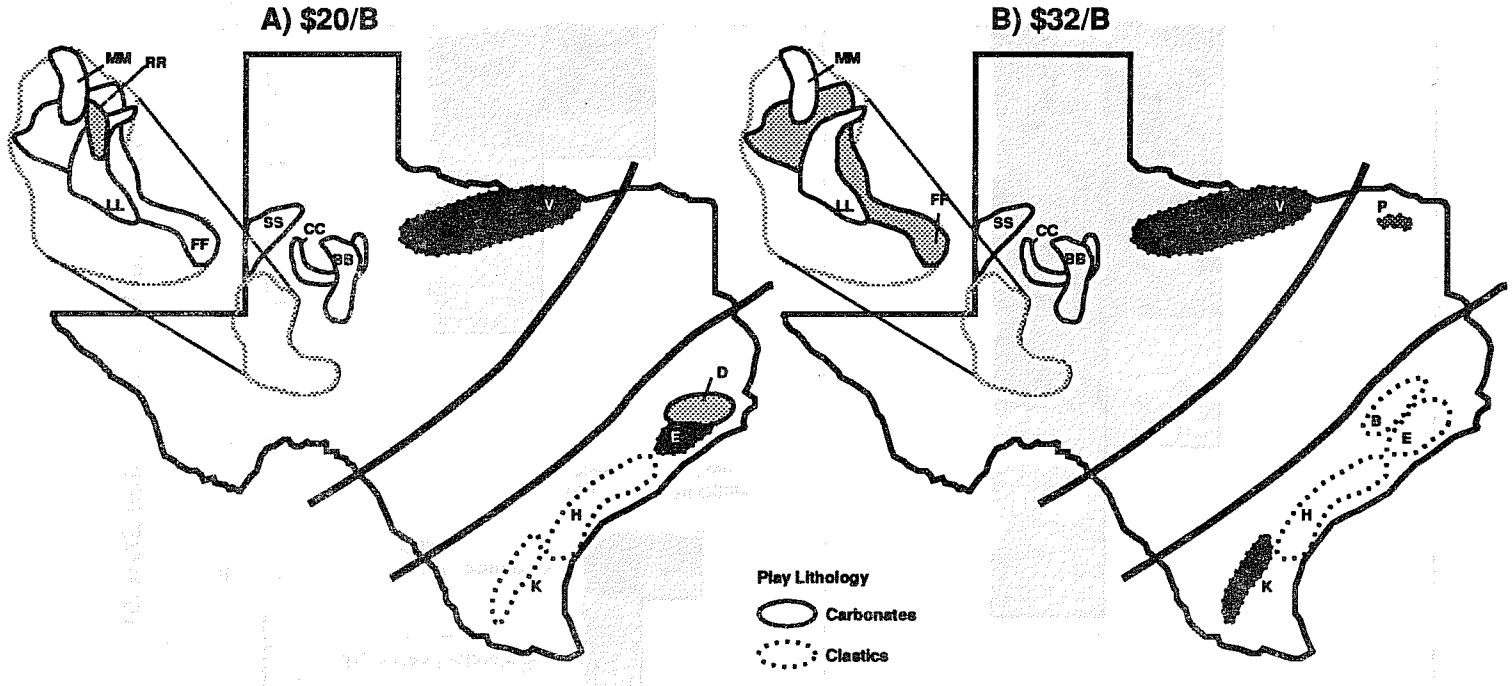
b. Focus for EOR Related R&D

For purposes of EOR R&D planning, it is critical to focus on the plays that would contribute the greatest incremental reserves resulting directly from advances in technology. For example, at the $32/B oil price in the Northern Shelf Permian Carbonate Play, 1,245 million barrels could be recovered under implemented technology while 1,433 million barrels could be recovered under advanced technology. This difference in oil recovery, nearly 200 million barrels, is directly attributable to advances in technology resulting from R&D. At both the $20/B and $32/B oil price, substantial incremental increases in reserves due to advanced technology would occur. As demonstrated for the total potential under each technology case, the bulk of the incremental reserves due strictly to advances in technology is concentrated in a handful of top plays. Figure VII-4 contrasts the EOR recovery potential for the top 10 plays ranked in terms of incremental recovery due to advances in technology with the incremental recovery potential in the other 38 Texas plays. At the $32/B oil price, the incremental EOR reserves due to advanced technology for the ten plays with the greatest incremental potential would account for 62% of all advanced technology incremental EOR reserves state-wide (Table VII-3). Even more dramatic increases would occur in these plays at the $20/B price. The ten plays with the greatest combined incremental reserves from both EOR and UMO extraction are discussed in section E of this chapter.

Figure VII-3

Location of Top EOR Reserve Oil Plays in Texas

Implemented and Advanced Technology



LEGEND

B. Vegus Deep-Seated Salt Domes
D. Cap Rock
E. Frio Deep-Seated Salt Domes
H. Frio Barrier-Strandplain Sandstone
K. Frio Fluvial/Deltaic Sandstone (Vicksburg)
P. Pekuy Fault Line
V. Strawn Sandstone

* South Central Basin Platform
** North Central Basin Platform

BB. Eastern Shelf Permian Carbonate
CC. Horseshoe Atoll
FF. Ellenburger Fractured Dolomite
LL. San Andres/Grayburg Carbonate (SCBP*)
MM. San Andres/Grayburg Carbonate (NCBP**)
RR. Pennsylvanian Platform Carbonate
SS. Northern Shelf Permian Carbonate

Implemented and Advanced Technology
Implemented Technology Only
Advanced Technology Only

0 40 80 120mi
0 60 100 180 190mi

(modified from Tyler et al., 1984)

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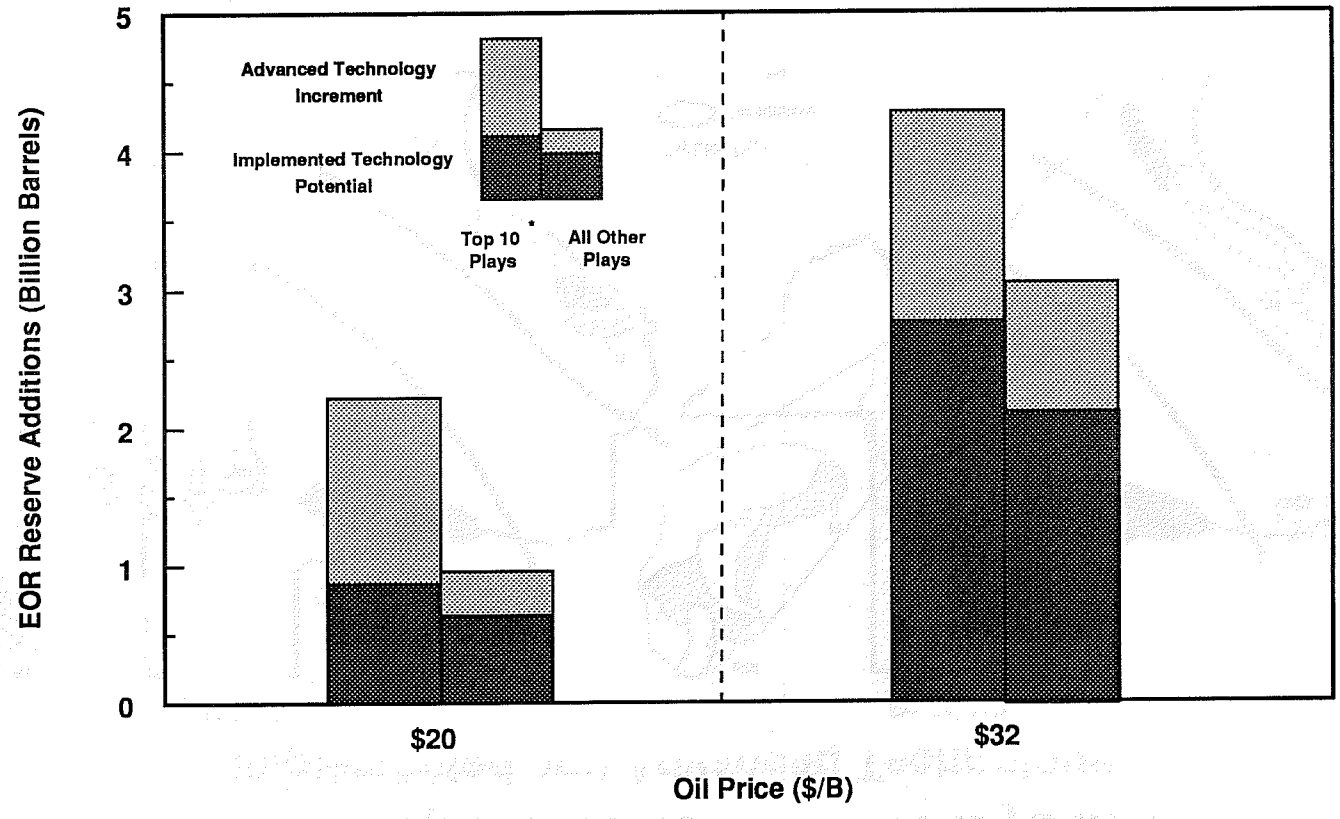
Figure VII-4

EOR Advanced Technology Incremental Reserves are the Target for Research and Development

Top Plays Hold the Majority of the Improved Recovery Potential



* Ranked by Incremental EOR Reserve Potential under Advanced Technology, $32/B

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Table VII-3

Ten Major Oil Plays Ranked by EOR Advanced Technology Incremental Reserves At $32/B

Rank*	Map Code	Oil Plays	$20/B Implemented Technology Potential Reserves (MMB)	$20/B Advanced Technology Total Reserves (MMB)	$20/B Advanced Technology Incremental Reserves (MMB)	$32/B Implemented Technology Potential Reserves (MMB)	$32/B Advanced Technology Total Reserves (MMB)	$32/B Advanced Technology *Incremental Reserves** (MMB)
1.	H	Frio Barrier/Strandplain Sandstone	170	448	278	494	748	*254*
2.	V	Strawn Sandstone	0	217	217	14	267	*253*
3.	SS	Northern Shelf Permian Carbonate	320	752	432	1,245	1,433	*188*
4.	E	Frio Deep-Seated Salt Domes	0	234	234	173	352	*179*
5.	LL	San Andres/Grayburg Carbonate (SCBP**)	173	173	0	371	543	*172*
6.	K	Frio Fluvial/Deltaic Sandstone (Vicksburg)	80	200	120	140	297	*157*
7.	EE	Central Basin Platform Unconformity	9	9	0	26	121	*95*
8.	BB	Eastern Shelf Permian Carbonate	125	141	16	155	245	*90*
9.	OO	Clear Fork Platform Carbonate	0	0	0	132	198	*66*
10.	Q	Cretaceous Sandstone (Salt-related Structure)	0	51	51	22	82	*60*
		TOTAL	**877**	**2,225**	**1,348**	**2,772**	**4,286**	***1,514***
		TOTAL, ALL PLAYS	**1,514**	**3,185**	**1,671**	**4,907**	**7,351**	***2,444***

* Plays are ranked by incremental reserves due to advances in EOR technology at an oil price of $32/B
** South Central Basin Platform

c. Reserves by Process and Play

Because potential recovery is play- and process-specific, identifying the most promising EOR processes in each play could help state and federal researchers and operators focus R&D efforts on the highest payoff recovery techniques within each play. Table VII-2, also discussed previously, lists the dominant EOR recovery process associated with each of the top ten plays. Figure VII-5 shows the quantity of potential reserves from miscible flooding under implemented and advanced technology at $20/B and $32/B, indicating that most of these reserves are concentrated in a small number of plays. At the $20/B oil price under implemented technology, miscible recovery could generate an estimated 1.3 billion barrels out of the 1.5 billion barrels of total EOR reserve potential in Texas. CO_2 miscible flooding would be used to produce the largest portion of the state's miscible EOR. Six carbonate plays collectively account for the bulk of this miscible recovery, contributing 973 million in EOR reserve additions from the analyzed reservoirs, 77% of the total Texas miscible recovery at this price and technology. One sandstone play accounts for 71 million barrels of nitrogen miscible flooding recovery, around 6% of the total miscible potential. Under advanced technology, total miscible reserves could increase to 1.9 billion barrels, with 75% of these reserves occurring in six carbonate plays.

Similar trends in miscible flooding production potential are seen at the higher oil price of $32/B under both implemented and advanced technology. Six carbonate plays in each technology case would collectively contribute almost 70% of the total estimated miscible recovery reserves. Four sandstone plays could collectively account for almost 300 million barrels of oil under implemented technology and over 320 million barrels under advanced technology, around 8% of the total potential state-wide.

The distribution of potential reserves from chemical flooding in Texas oil plays can be seen in Figure VII-6. At an oil price of $20/B under implemented technology, chemical processes could recover 197 million barrels of oil from three major sandstone plays, 86% of which would come from surfactant injection in the Frio Barrier/Strandplain Sandstone Play. Under advanced technology at the same price, surfactant injection could result in a total of 795 million barrels from three sandstone plays, over four times the amount estimated under implemented technology from the same plays. Recovery in these plays accounts for 74% of the total chemical recovery potential in Texas for this oil price and technology case.

Figure VII-5

Distribution of Potential Reserves from Miscible Flooding in Texas

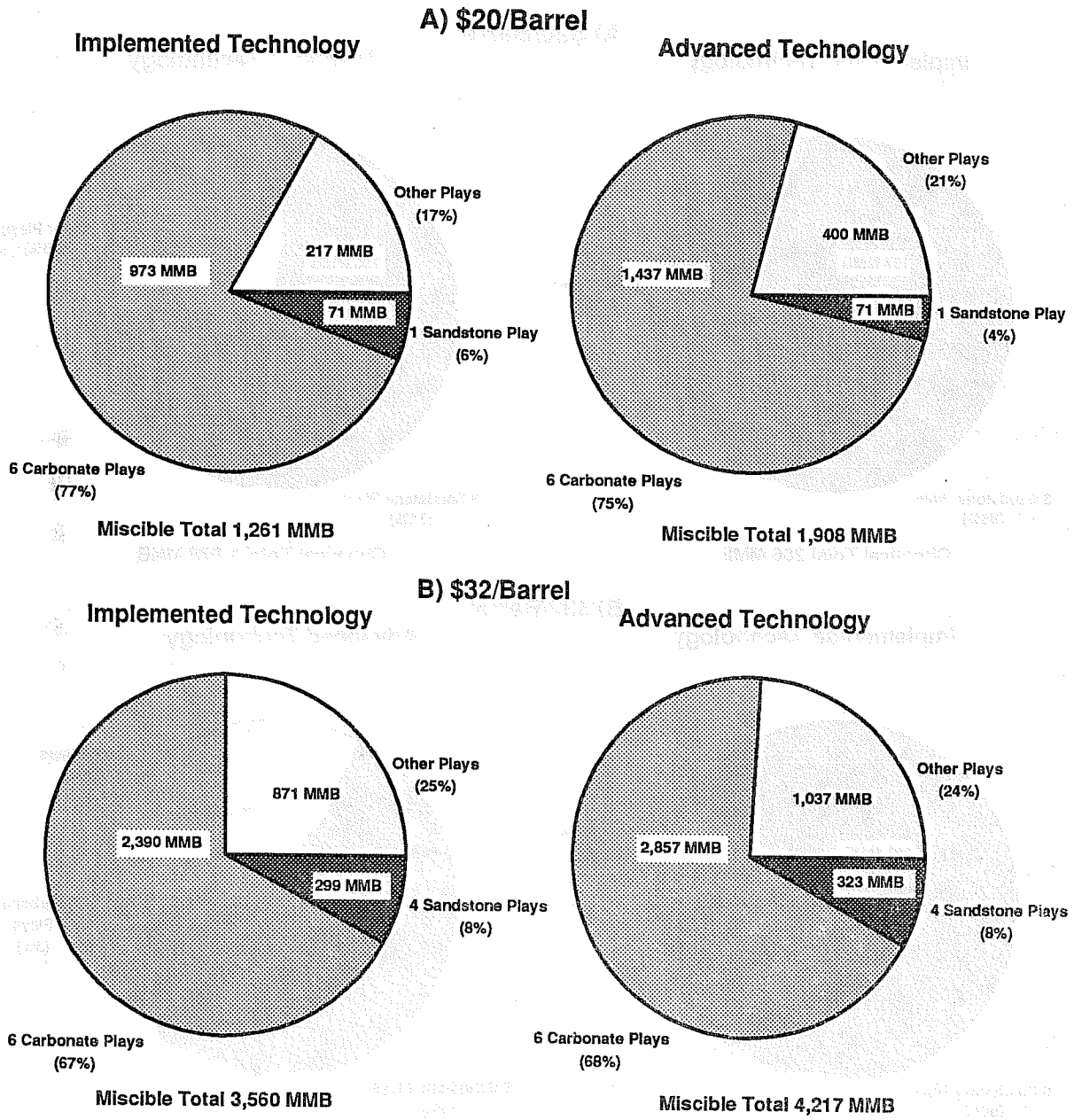
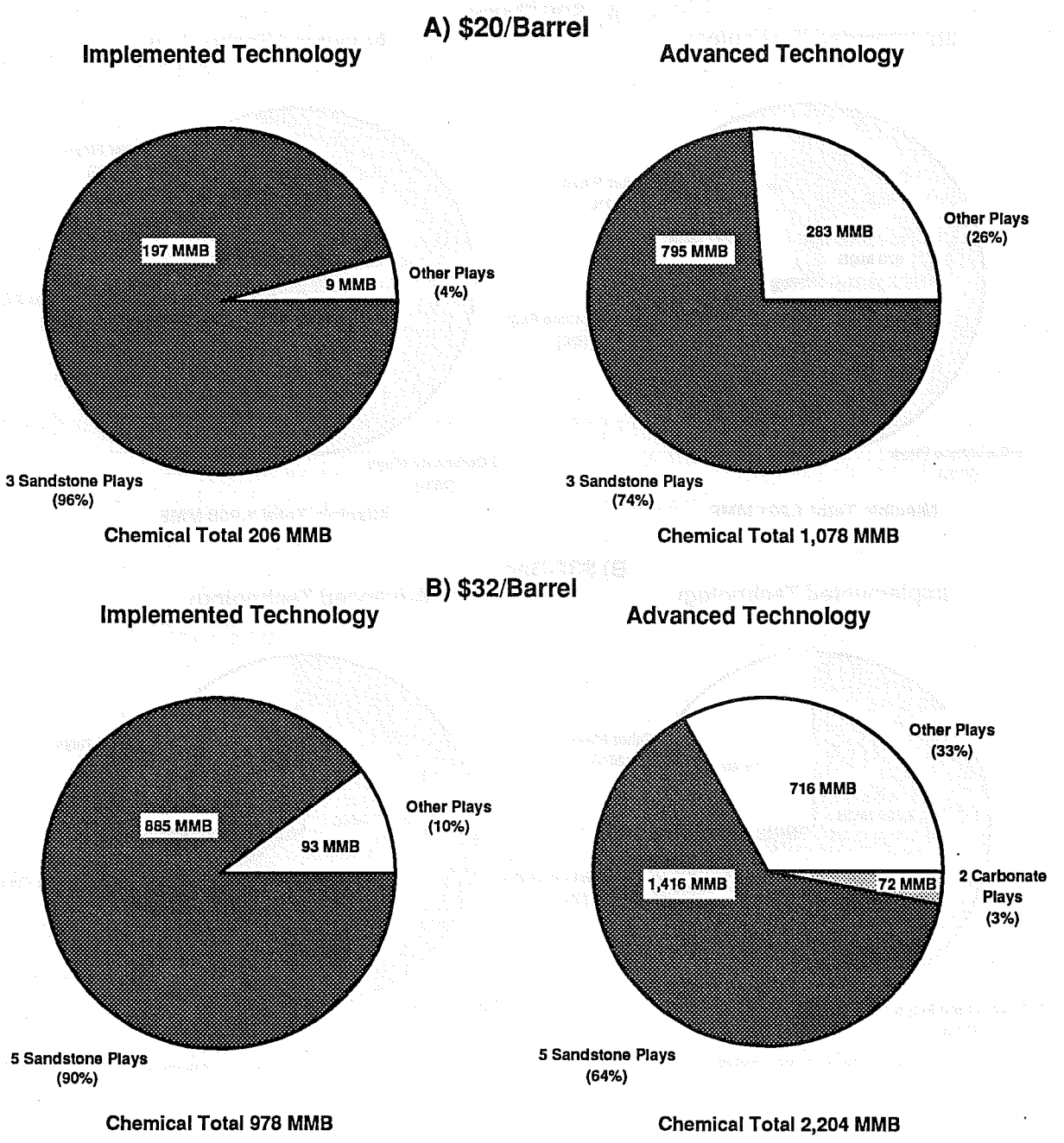


Figure VII-6

Distribution of Potential Reserves from Chemical Flooding in Texas



At $32/B under implemented technology, the reservoirs analyzed in five sandstone plays could potentially produce nearly 900 million barrels through chemical flooding, 90% of the state's total chemical process recovery. Under advanced technology at $32/B, chemical injection, primarily using surfactants, could recover 1.4 billion barrels of oil from the same five plays, a 60% increase over recovery under implemented technology. At this higher oil price, a number of reservoirs in other plays would become economic for chemical EOR, to some degree shifting the distribution of the EOR reserves. In fact, the five plays that collectively represented 90% of the total chemical flooding reserves under implemented technology would account for only 64% of the total in the advanced technology case.

Regardless of the oil price or technology level, EOR potential in Texas is focused in a small number of highly promising geologic plays. Out of a state-wide total of forty-eight oil plays, only fifteen plays are listed as one of the top ten plays in terms of EOR potential across all oil prices and technology levels considered in this study. Recovery from each of these plays is dominated by one EOR process which consistently accounts for the bulk of the production potential. Further, a large portion of the EOR reserves estimated to be recoverable by miscible and chemical flooding occurs in a handful of highly promising geologic plays. This analysis points to the advantage of focused research designed to maximize EOR potential in major plays within the state.

3. Unrecovered Mobile Oil Extraction

a. Reserves in Top Oil Plays

The use of implemented technology recovery processes at $20/B could result in the production of almost 1.4 billion barrels of UMO from the Texas reservoirs analyzed. The San Andres/Grayburg Carbonate (South Central Basin Platform) Play, located in the Permian Basin of West Texas, has the greatest potential at this price with just over 280 million barrels of producible UMO. The ten plays with the highest potential under implemented technology conditions collectively produce almost 1.2 billion barrels of oil, or 86 percent of the estimated state-wide UMO recovery (Table VII-4A).

Advanced technology recovery processes at a $20/B oil price could produce more than 4 billion barrels of UMO in Texas from the reservoirs evaluated in this study, almost three times the

UMO Extraction Reserve Estimates For Top Oil Plays in Texas

A. Implemented Technology, $20/Bbl

Rank	Map Code	Oil Play	Reserves (MMB)	No. of Economic Reservoirs	Dominant Process*
1.	LL	San Andres/Grayburg Carbonate (SCBP**)	281	3	ID
2.	H	Frio Barrier/Strandplain Sandstone	246	31	ID/PM
3.	V	Strawn Sandstone	146	14	ID/PM
4.	JJ	Yates Area	115	1	ID/POLY
5.	B	Yegua Deep-Seated Salt Domes	94	4	ID/PM
6.	E	Frio Deep-Seated Salt Domes	93	9	ID/PM
7.	T	Woodbine Fluvial/Deltaic/Strandplain Sandstone	78	4	ID/PM
8.	FF	Ellenburger Fractured Dolomite	58	4	PM
9.	K	Frio Fluvial/Deltaic Sandstone (Vicksburg)	34	7	ID/PM
10.	EE	Central Basin Platform Unconformity	32	5	PM
		TOTAL	1,177	82	
		TOTAL, ALL PLAYS	1,379	144	

B. Advanced Technology, $20/Bbl

Rank	Map Code	Oil Play	Reserves (MMB)	No. of Economic Reservoirs	Dominant Process*
1.	LL	San Andres/Grayburg Carbonate (SCBP**)	655	8	ID
2.	E	Frio Deep-Seated Salt Domes	463	22	ID/PM
3.	JJ	Yates Area	448	1	ID/POLY
4.	H	Frio Barrier/Strandplain Sandstone	414	46	ID/PM
5.	V	Strawn Sandstone	377	18	ID/PM
6.	B	Yegua Deep-Seated Salt Domes	323	5	ID/PM
7.	T	Woodbine Fluvial/Deltaic/Strandplain Sandstone	191	4	ID/PM
8.	SS	Northern Shelf Permian Carbonate	121	7	ID
9.	MM	San Andres/Grayburg Carbonate (NCBP***)	114	1	ID
10.	FF	Ellenburger Fractured Dolomite	103	15	PM
		TOTAL	3,209	127	
		TOTAL, ALL PLAYS	4,037	249	

C. Implemented Technology, $32/Bbl

Rank	Map Code	Oil Play	Reserves (MMB)	No. of Economic Reservoirs	Dominant Process*
1.	LL	San Andres/Grayburg Carbonate (SCBP**)	341	3	ID
2.	H	Frio Barrier/Strandplain Sandstone	295	37	ID/PM
3.	V	Strawn Sandstone	152	17	ID/PM
4.	E	Frio Deep-Seated Salt Domes	123	12	ID/PM
5.	JJ	Yates Area	117	1	ID/POLY
6.	B	Yegua Deep-Seated Salt Domes	96	5	ID/PM
7.	CC	Horseshoe Atoll	87	4	ID
8.	T	Woodbine Fluvial/Deltaic/Strandplain Sandstone	78	4	ID/PM
9.	FF	Ellenburger Fractured Dolomite	58	4	PM
10.	MM	San Andres/Grayburg Carbonate (NCBP***)	52	2	ID
		TOTAL	1,399	89	
		TOTAL, ALL PLAYS	1,792	184	

D. Advanced Technology, $32/Bbl

Rank	Map Code	Oil Play	Reserves (MMB)	No. of Economic Reservoirs	Dominant Process*
1.	LL	San Andres/Grayburg Carbonate (SCBP**)	906	12	ID
2.	H	Frio Barrier/Strandplain Sandstone	512	49	ID/PM
3.	E	Frio Deep-Seated Salt Domes	487	22	ID/PM
4.	SS	Northern Shelf Permian Carbonate	476	9	ID
5.	JJ	Yates Area	448	1	ID/POLY
6.	V	Strawn Sandstone	413	20	ID/PM
7.	B	Yegua Deep-Seated Salt Domes	341	6	ID/PM
8.	T	Woodbine Fluvial/Deltaic/Strandplain Sandstone	197	4	ID/PM
9.	MM	San Andres/Grayburg Carbonate (NCBP***)	176	2	ID/PM
10.	CC	Horseshoe Atoll	170	8	ID
		TOTAL	4,126	133	
		TOTAL, ALL PLAYS	5,304	289	

* ID = Infill drilling
POLY = Polymer injection
PM = Profile modification

** South Central Basin Platform
*** North Central Basin Platform

production estimated under implemented technology. The oil play which could account for the greatest economic reserve potential at this price is again the San Andres/Grayburg Carbonate (South Central Basin Platform) Play, with over 650 million barrels estimated as economically producible. Eighty percent, or 3.2 billion barrels, of the total advanced technology UMO estimated as recoverable in the reservoirs analyzed throughout the state would be produced from the ten plays with the most potential (Table VII-4B). Eight of the top ten plays under advanced technology at $20/B are also included in the top ten potential plays under implemented technology at this price. The collective recovery potential from these eight plays alone could increase by almost three times with technology advances at this oil price, from close to 1.1 billion to nearly 3.0 billion barrels.

A significant portion of the increase in reserves under advanced technology in some plays would occur as a direct result of improvements in project economics that would allow many reservoirs that cannot be economically exploited under implemented technology to become viable projects. This increase can be seen by comparing the number of economic reservoirs within the plays shown in Tables VII-4A and VII-4B. For example, the number of economic reservoirs developed for UMO extraction in the San Andres/Grayburg Carbonate (South Central Basin Platform) Play would increase from three under implemented technology to eight under advanced technology. The total number of reservoirs economic state-wide under implemented technology at $20/B would be 144, compared with 249 under advanced technology at the same price.

At a $32/B oil price, nearly 1.8 billion barrels of incremental UMO could be produced by implementing processes using current technology in reservoirs analyzed in this study. The San Andres/Grayburg Carbonate (South Central Basin Platform) Play has the greatest UMO potential under this case, with around 340 million barrels of estimated producible UMO. The ten plays with the greatest recovery potential under implemented technology at this oil price could collectively produce almost 1.4 billion barrels of oil, 78% of the state-wide UMO reserves estimated as recoverable under this case (Table VII-4C). Of these ten plays, eight are also in the top ten plays in the $20/B implemented technology case. Regardless of the oil price considered, most of the UMO recovery occurs in a few Texas plays.

A considerable increase in incremental UMO reserves would also occur at the $32/B oil price with the application of advanced technology. Over 5.3 billion barrels of UMO could be

economically produced with advanced technology from the reservoirs evaluated in this study. The San Andres/Grayburg Carbonate (South Central Basin Platform) Play again shows the greatest recovery potential at this price, with over 900 million barrels of producible UMO. The ten plays with the most potential could collectively produce 4.1 billion barrels of oil, or 77% of the total UMO estimated as recoverable in Texas for this case (Table VII-4D). This represents a reserve increment of 3.5 billion attributable to R&D. Of the top ten plays under advanced technology at this price, nine also appear in the top ten plays of the $32/B implemented technology case. Figure VII-7 shows the geographic locations of the top UMO potential plays under both implemented and advanced technology at the $20/B and $32/B oil prices.

b. Focus for UMO Extraction R&D

As with EOR R&D, program planning to improve UMO extraction processes should focus on those top plays with the greatest incremental reserve potential due strictly to attainable advances in technology. For example, the reserve increment due to advanced recovery processes in the San Andres/Grayburg Carbonate (South Central Basin Platform) Play at $32/B would be 565 million barrels (906 million barrels under advanced technology less 341 million barrels under implemented technology), ranking this play at the top of the advanced recovery increment list. The top ten plays ranked by incremental recovery due to advanced technology at $32/B account for the bulk of the state-wide incremental reserves at both the $20/B and $32/B oil prices, as shown in Figure VII-8 and Table VII-5. At the $20/B oil price, for example, the advanced recovery incremental reserves from those ten major oil plays would account for 66% of the total reserves for these plays and for 79% of the total incremental reserves for all Texas plays.

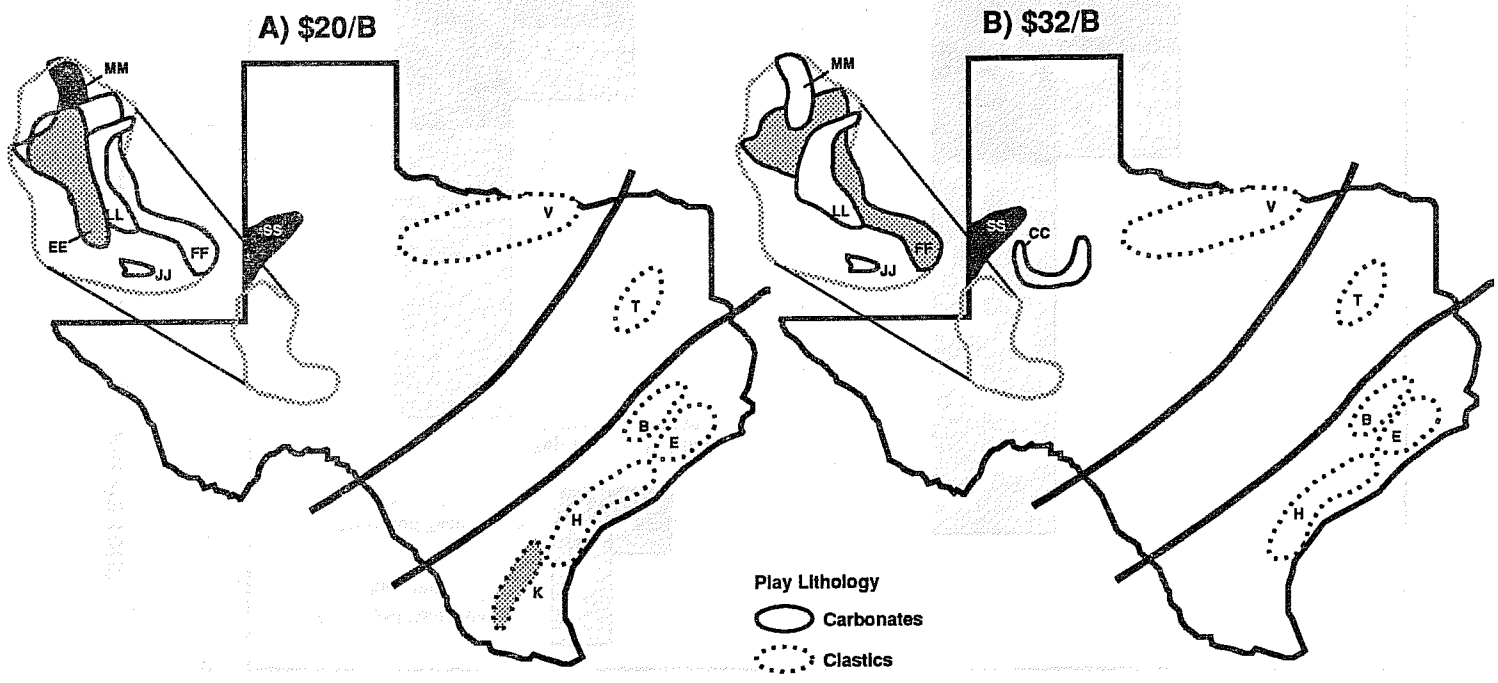
c. Reserves by Process and Play

One dominant UMO recovery process would account for the bulk of the potential reserve additions in each play, but the process varies from play to play. As shown in Figure VII-9 and Table VII-6, however, the greatest production from carbonate and sandstone plays at all prices would occur under extraction techniques using either combined processes (infill drilling/profile modification or infill drilling/polymer injection) or infill drilling alone. For example, at $20/B under implemented technology, combined processes could account for around 680 million barrels of oil reserves from sandstone and carbonate plays out of a total potential of nearly 1.4 billion barrels.

Figure VII-7

Location of Top UMO Reserve Oil Plays in Texas

Implemented and Advanced Technology



LEGEND

B. Yegua Deep-Seated Salt Domes
E. Frio Deep-Seated Salt Domes
H. Frio Barrier-Strandplain Sandstone
K. Frio Fluvial/Deltaic Sandstone (Vicksburg)
T. Woodbine Fluvial/Deltaic/Strandplain Sandstone
V. Strawn Sandstone
CC. Horseshoe Atoll
* South Central Basin Platform
** North Central Basin Platform
EE. Central Basin Platform Unconformity
FF. Ellenburger Fractured Dolomite
JJ. Yates Area
LL. San Andres/Grayburg Carbonate (SCBP*)
MM. San Andres/Grayburg Carbonate (NCBP**)
SS. Northern Shelf Permian Carbonate

Implemented and Advanced Technology
Implemented Technology Only
Advanced Technology Only

0 40 80 120mi
0 50 100 150 120mi

(modified from Tyler et al., 1984)

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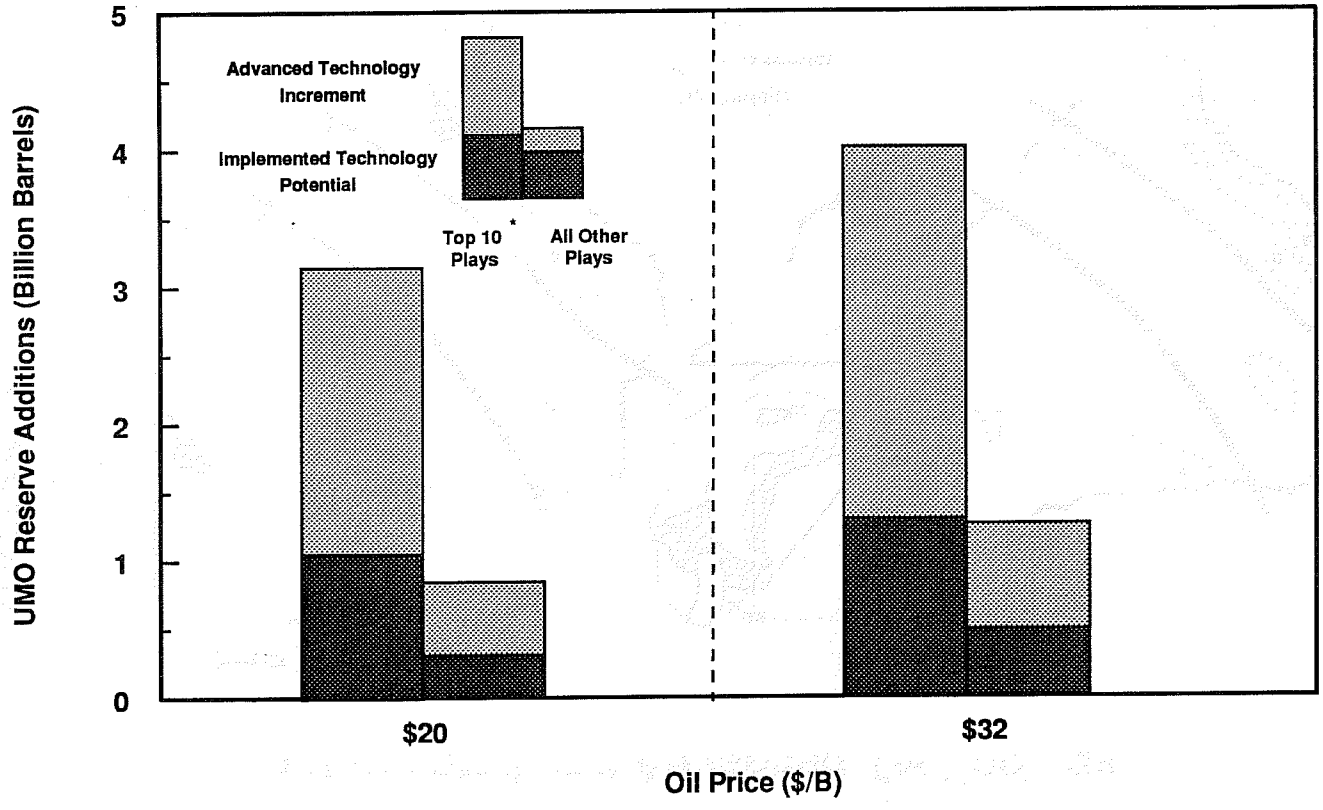
Figure VII-8

UMO Advanced Technology Incremental Reserves are the Target for Research and Development

Top Plays Hold the Majority of the Improved Recovery Potential



* Ranked by Incremental UMO Reserve Potential under Advanced Technology, $32/B

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Table VII-5

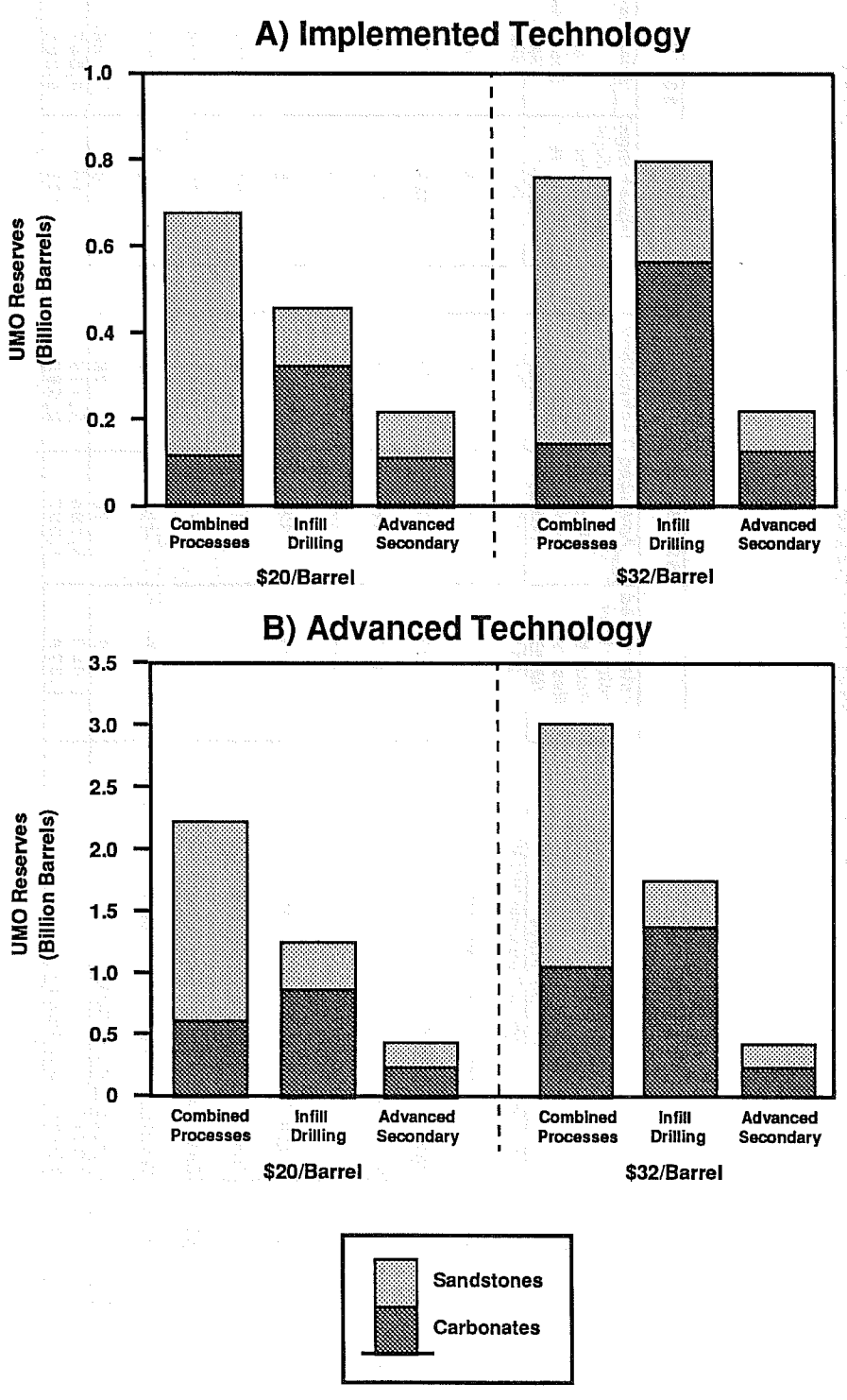
Ten Major Oil Plays Ranked by UMO Extraction Advanced Technology Incremental Reserves at $32/B

Rank*	Map Code	Oil Plays	$20/B			$32/B		
			Implemented Technology Potential Reserves (MMB)	Advanced Technology		Implemented Technology Potential Reserves (MMB)	Advanced Technology	
				Total Reserves (MMB)	Incremental Reserves (MMB)		Total Reserves (MMB)	Incremental Reserves* (MMB)
1.	LL	San Andres/Grayburg Carbonate (SCBP**)	281	655	374	341	906	***565***
2.	SS	Northern Shelf Permian Carbonate	15	121	106	56	481	***425***
3.	E	Frio Deep-Seated Salt Domes	93	463	370	123	487	***364***
4.	JJ	Yates Area	115	448	333	117	448	***331***
5.	V	Strawn Sandstone	146	377	231	152	413	***261***
6.	B	Yegua Deep-Seated Salt Domes	95	323	228	96	341	***245***
7.	H	Frio Barrier/Strandplain Sandstone	246	414	168	295	512	***217***
8.	MM	San Andres/Grayburg Carbonate (NCBP***)	0	114	114	52	176	***124***
9.	T	Woodbine Fluvial/Deltaic/Strandplain Sandstone	78	191	113	78	197	***119***
10.	C	Yegua Salt Dome Flanks	0	78	78	0	86	***86***
		TOTAL	1,069	3,184	2,115	1,310	4,047	***2,737***
		TOTAL, ALL PLAYS	1,379	4,037	2,658	1,792	5,304	***3,512***

* Plays are ranked by incremental reserves due to advances in UMO extraction technology at an oil price of $32/B
** South Central Basin Platform
***North Central Basin Platform

Figure VII-9

UMO Reserves by Process and Lithology*



* Does not include reserves for reservoirs with mixed sandstone and carbonate lithology

Table VII-6

UMO Reserves and Percentages by Recovery Process In Sandstone and Carbonate Plays

(Million Barrels)

Extraction Techniques	Implemented Technology				Advanced Technology			
	$20/Bbl		$32/Bbl		$20/Bbl		$32/Bbl	
	Reserves	(%**)	Reserves	(%**)	Reserves	(%**)	Reserves	(%**)
Combined Processes								
Carbonate Plays	120	(18)	152	(20)	640	(28)	1,128	(37)
Sandstone Plays	561	(81)	602	(79)	1,598	(70)	1,902	(62)
Infill Drilling								
Carbonate Plays	336	(72)	578	(72)	897	(70)	1,384	(77)
Sandstone Plays	125	(27)	206	(26)	371	(29)	371	(21)
Advanced Secondary								
Carbonate Plays	119	(54)	131	(58)	253	(56)	237	(55)
Sandstone Plays	102	(46)	94	(42)	199	(44)	191	(45)
Total	1,363		1,763		3,958		5,213	

* Potential reserves from mixed carbonate and sandstone plays not included.
** Percent is percentage of total potential for process.

Also at this price and technology, infill drilling alone could account for over 450 million barrels of the total potential. Although individual advanced secondary processes (profile modification, polymer injection) could make important additions to Texas reserves, they would be far less productive than the combined and infill drilling processes. At $20/B under implemented technology, advanced secondary processes would account for only around 220 million barrels of UMO recovery.

Combined processes would result in the greatest amount of UMO production from sandstone plays, while infill drilling alone would be the most prolific technique in carbonate plays, an important consideration in research planning. At $20/B under advanced technology, combined processes could result in the production of nearly 1.6 billion barrels of oil in sandstone plays and 640 million barrels in carbonate plays. Infill drilling, on the other hand, could result in nearly 900 million barrels in carbonate plays and around 370 million barrels in sandstone plays. Of the two combined processes, infill drilling/profile modification would be responsible for the majority of potential UMO reserves in sandstone plays. Advanced secondary processes could produce roughly equal amounts of UMO reserves in both carbonates and sandstones. At the $20/B price under advanced technology, advanced secondary processes could produce nearly 200 million barrels from sandstone plays and approximately 250 million barrels from carbonate plays.

E. MAXIMIZING RECOVERY THROUGH TECHNOLOGY TRANSFER AND FOCUSED R&D

The previous sections in this chapter have discussed several combinations of oil price and technology and ranked oil plays in terms of recovery potential under each combination. The results of each oil price/technology analysis clearly indicate that the bulk of reserve additions from EOR and UMO extraction would occur from reservoirs within a relatively small number of plays. In addition, the results have shown that many of the same oil plays would account for the greatest potential recovery under each oil price/technology combination. The previous sections have also demonstrated that certain EOR and UMO extraction processes are more prolific in certain plays. The purpose of this section is to select the oil price/technology criteria which most closely reflect future oil recovery conditions and then suggest R&D and technology transfer planning based on the results of these selected criteria. Careful program planning should ensure the maximum oil recovery from the remaining resource for the state.

To be successful, technology transfer and R&D program planning should consider near- to long-term oil price and technology conditions likely to occur and focus efforts around these conditions. Because of the recent volatile nature of the world oil market, determining likely future conditions is difficult; however, this study defines three goals that reflect probable oil prices and technology combinations. These goals are listed as follows:

- Current technology transfer goal:
  - maximize reserve potential under implemented technology
- Current R&D goal:
  - focus on improving recovery in plays with the highest potential
- Future technology transfer and combined R&D goal:
  - transfer advances resulting from R&D to the field
  - continue to focus R&D on improving recovery in high-potential areas

In addition, as shown in the previous chapter, maximum recovery of the remaining oil resource would also occur through the combined application of advanced technology EOR and UMO extraction techniques. The potential for synergies between EOR and UMO extraction processes is indicated by the fact that most of the geologic plays with the greatest EOR potential also have the greatest UMO extraction potential. For example, at an oil price of $32/B under advanced technology, eight of the top ten EOR potential plays also appear in the top ten plays when ranked by UMO reserve potential. The fact that reservoirs within these top plays hold the greatest reserve potential for both EOR and UMO extraction processes represents a significant advantage for conducting research to improve oil recovery -- research on both EOR and UMO extraction could be focused in essentially the same plays, thus exploiting the synergies between the two techniques and maximizing recovery.

The implemented technology case at the $20/B oil price most accurately reflects the economic and technology climate for oil recovery operations in the near future. Therefore, the most immediate task for maximizing recovery is to effectively transfer currently available technologies to a broad state-wide public/private - industry group. The most extensive technology

transfer efforts would need to target those operators with production from reservoirs in the top plays identified in this analysis under implemented technology at the $20/B oil price (Table VII-7). However, additional efforts to transfer available technology to those involved in the management of other reservoirs in the state could also aid in maximizing recovery of the Texas remaining oil resource. Technology transfer of currently available recovery techniques would ensure that optimal production efforts are implemented and that a maximum number of wells remain on production, thus maintaining economic access to the remaining oil resource.

Advanced technology recovery potential at the $32/B oil price provides the most important indication of benefits derived from a longer term, coordinated R&D program. Under this price/technology case, two critical criteria are considered. The incremental recovery of advanced technology processes over that of the implemented case establishes the benefits of applied research designed to develop and refine the recovery processes analyzed in this study. The major oil plays in the state which contain the largest volume of incremental advanced case reserves should be the focus of this applied, longer range research. Table VII-8 lists the top ten plays in Texas established by the $32/B oil price/advanced technology criteria. The geographic locations of these plays are shown on Figure VII-10. Although this criteria establishes a longer term target for the R&D program, the top ten plays at the $32/B oil price are also all on top of the list in terms of incremental advanced case potential at the lower oil price of $20/B, minimizing concerns about focusing research efforts in times of changing oil prices.

The top ten plays in terms of incremental, advanced technology reserve additions for EOR and UMO extraction combined contain around two-thirds of the state-wide potential, as shown in Figure VII-11. The concentration of incremental reserve potential indicates the significant benefit to the state of focused research addressing the limitations of these recovery techniques in these large plays. These same plays also represent a bulk of the incremental reserves due to advanced technology for EOR and UMO extraction separately. The bottom portion of Figure VII-11 shows that the ten identified plays, 21% of all Texas oil plays, hold 52% and 77% of the incremental advanced technology EOR and UMO extraction potential, respectively. Research focused in these plays could provide critical answers to questions about new processes and heterogeneities, ultimately increasing oil recovery dramatically in the reservoirs they contain.

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Ten Major Oil Plays Ranked by EOR and UMO Extraction Combined Implemented Technology Reserves

Target for Near-term Technology Transfer

Rank*	Map Code	Oil Plays	$20/B Implemented Technology		
			EOR Reserves (MMB)	UMO Reserves (MMB)	*Total Reserves (MMB)*
1.	LL	San Andres/Grayburg Carbonate (SCBP**)	173	281	***454***
2.	H	Frio Barrier/Strandplain Sandstone	170	246	***416***
3.	SS	Northern Shelf Permian Carbonate	320	15	***335***
4.	MM	San Andres/Grayburg Carbonate (NCBP***)	196	0	***196***
5.	V	Strawn Sandstone	0	146	***146***
6.	BB	Eastern Shelf Permian Carbonate	125	1	***126***
7.	FF	Ellenburger Fractured Dolomite	65	58	***123***
8.	JJ	Yates Area	0	115	***115***
9.	K	Frio Fluvial/Deltaic Sandstone (Vicksburg)	80	34	***114***
10.	CC	Horseshoe Atoll	93	12	***105***
		TOTAL	**1,222**	**908**	***2,130***
		TOTAL, ALL PLAYS	**1,514**	**1,379**	***2,893***

* Plays are ranked by combined total of EOR and UMO extraction
** South Central Basin Platform
***North Central Basin Platform

Table VII-8

Top Ten Oil Plays in Texas Ranked by Combined Total of Reserve Increments From Technology Advances in EOR and UMO Extraction Processes

Reserves Target for R&D and Technology Transfer

Rank*	Map Code	Oil Plays	$32/B EOR + UMO Extraction Reserves			Dominant Process	
			Implemented Technology Potential Reserves (MMB)	Advanced Technology			
				Total Reserves (MMB)	*Incremental Reserves** (MMB)	EOR	UMO Extraction
1.	LL	San Andres/Grayburg Carbonate (SCBP**)	712	1,449	***737***	CO2	ID
2.	SS	Northern Shelf Permian Carbonate	1,296	1,909	***613***	CO2	ID
3.	E	Frio Deep-Seated Salt Domes	297	839	***542***	ISCOM	ID/PM
4.	V	Strawn Sandstone	166	681	***515***	SURF	ID/PM
5.	H	Frio Barrier/Strandplain Sandstone	788	1,260	***472***	SURF	ID/PM
6.	JJ	Yates Area	117	448	***331***	–	ID/PM
7.	B	Yegua Deep-Seated Salt Domes	345	595	***250***	SURF	ID/PM
8.	K	Frio Fluvial/Deltaic Sandstone (Vicksburg)	175	398	***223***	SURF	ID/PM
9.	T	Woodbine Fluvial/Deltaic/Strandplain Sandstone	78	241	***163***	SURF	ID/PM
10.	MM	San Andres/Grayburg Carbonate (NCBP***)	258	403	***145***	CO2	CO2
		TOTAL	**4,232**	**8,223**	***3,991***		
		TOTAL, ALL PLAYS	**6,589**	**12,269**	***5,680***		

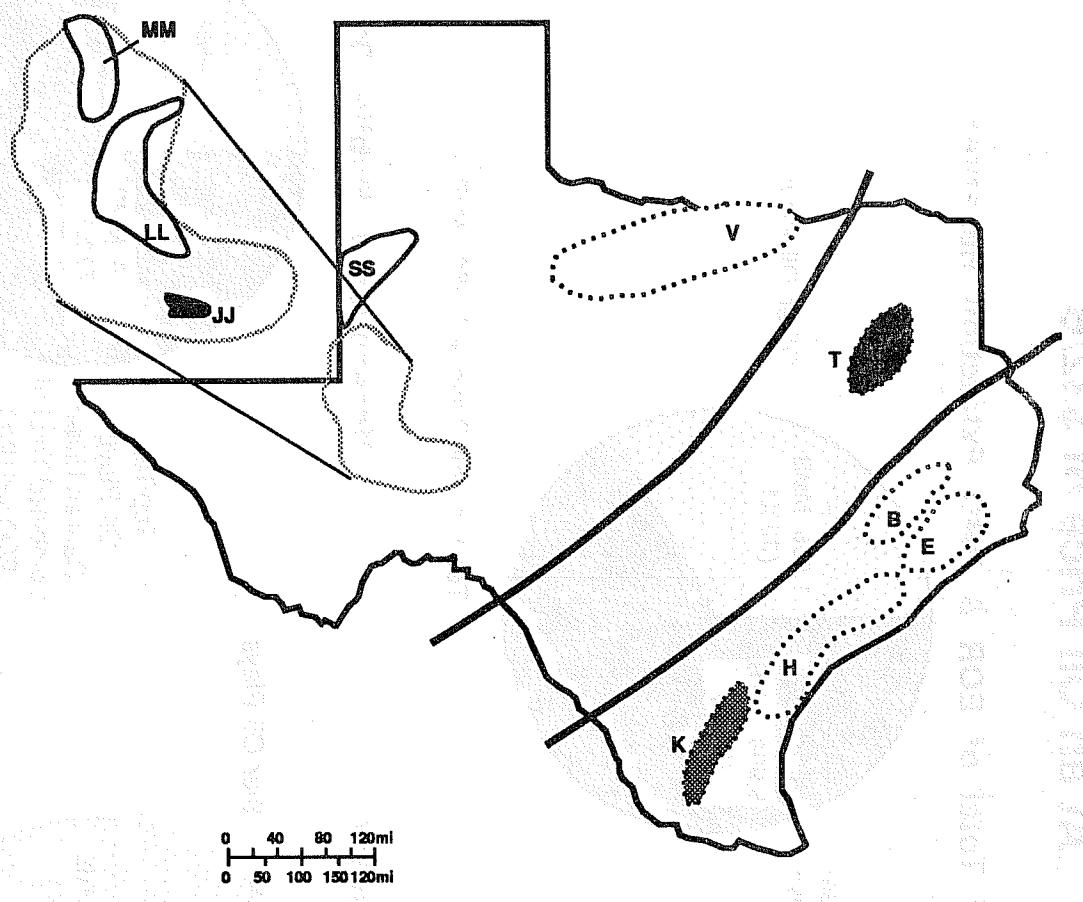
* Plays are ranked by the combined total of incremental reserves due to advances in EOR and UMO extraction technology at an oil price of $32/B
** South Central Basin Platform
***North Central Basin Platform

*EOR PROCE	CO2 = Carbon dioxide injection
	SURF = Surfactant injection
	ISCOM = In-situ combustion
*UMO PROCE	ID = Infill drilling
	POLY = Polymer injection
	PM = Profile modification

Figure VII-10

Location of Top Texas Oil Plays

EOR and UMO Reserves Combined, Advanced Technology at an Oil Price of $32/B



Play Lithology

Carbonates

Clastics

LEGEND

B. Yegua Deep-Seated Salt Domes
E. Frio Deep-Seated Salt Domes
H. Frio Barrier-Strandplain Sandstone
K. Frio Fluvial/Deltaic Sandstone (Vicksburg)
T. Woodbine Fluvial/Deltaic/Strandplain Sandstone
V. Strawn Sandstone
JJ. Yates Area
LL. San Andres/Grayburg Carbonate (SCBP*)
MM. San Andres/Grayburg Carbonate (NCBP**)
SS. Northern Shelf Permian Carbonate

* South Central Basin Platform
** North Central Basin Platform

Occurs in both Immobile and Mobile Oil Top Ten Reserve Plays

Occurs only in Top 10 Immobile Oil Reserve Plays

Occurs only in Top 10 Remaining Mobile Oil Reserve Plays

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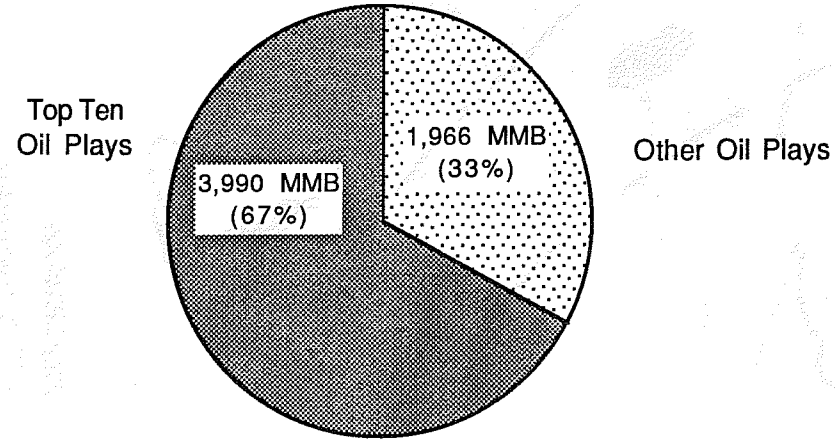
Figure VII-11

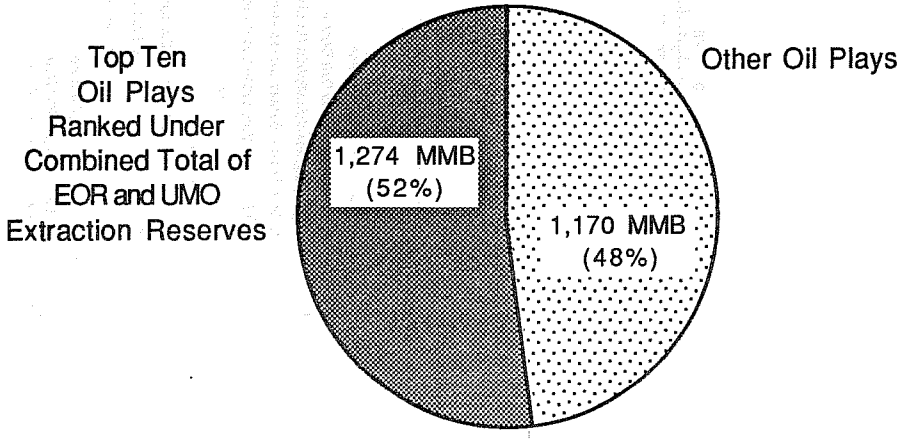
Incremental Reserves From Technology Advances At an Oil Price of $32/B

Combined Total of EOR & UMO Extraction Reserves



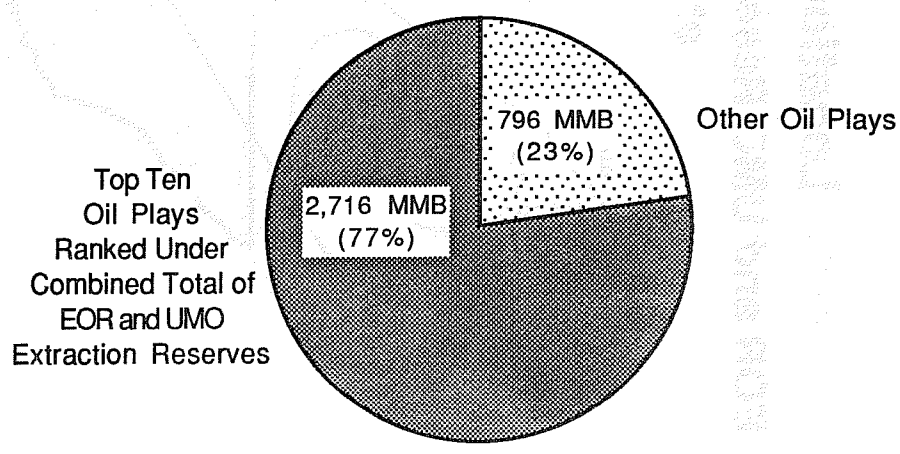
Total for All Plays = 5,956 MMB

Enhanced Oil Recovery



Total for All Plays = 2,444 MMB

Unrecovered Mobile Oil Recovery



Total for All Plays = 3,512 MMB

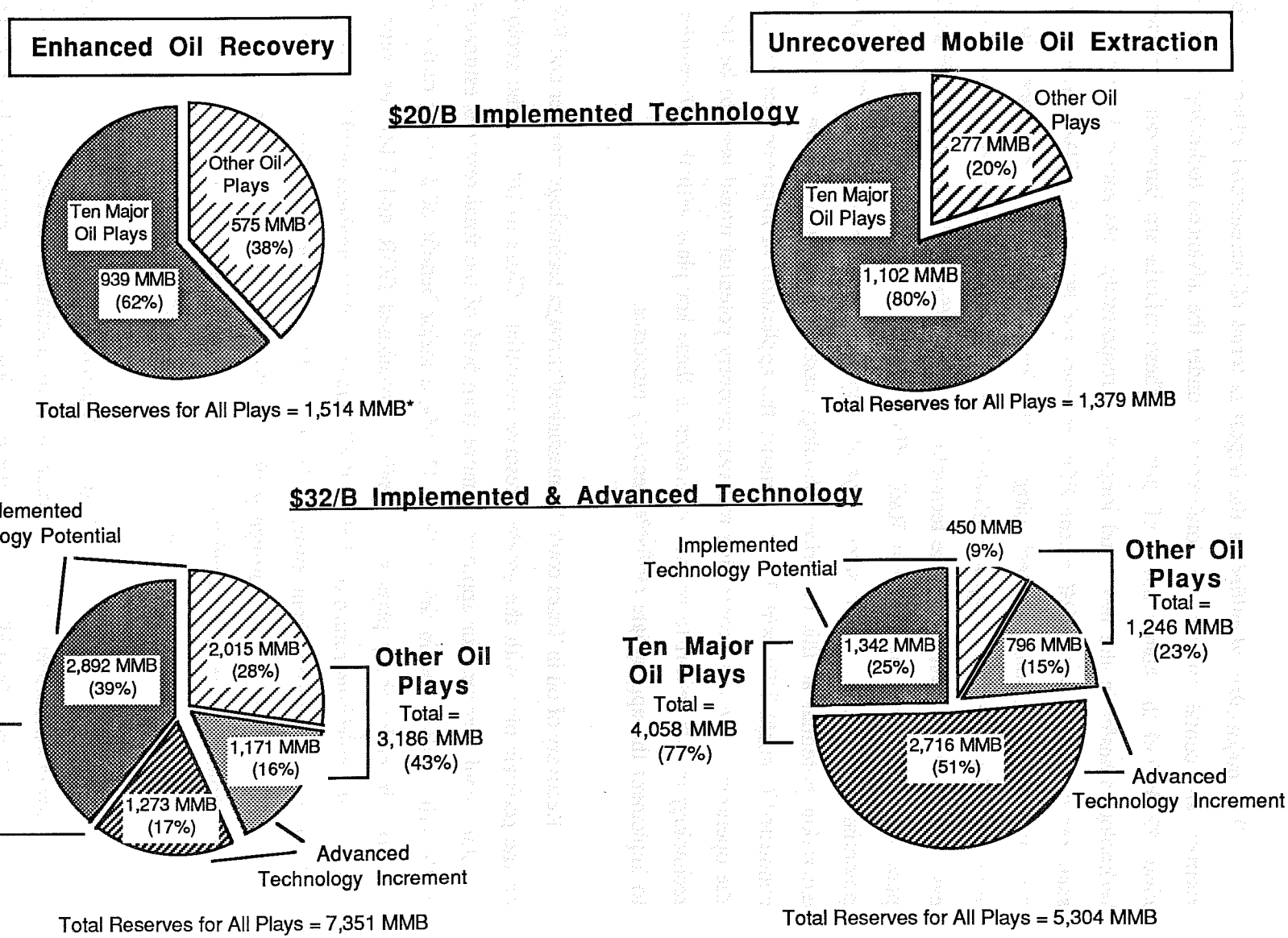
The major plays identified as the largest in terms of incremental advanced technology oil recovery also contain most of the total reserves under the advanced technology case at both the lower $20/B and the higher $32/B oil prices. These criteria are important considerations for technology transfer in the near- and long-terms, respectively. As shown in Figure VII-12, the same ten plays account for 62% of the EOR reserves and 80% of the UMO extraction potential state-wide under implemented technology at the lower oil price. If oil prices rise and R&D successfully improves technology as evaluated in this study, total recovery potential in the advanced case indicates the benefits of future technology transfer efforts. At an oil price of $32/B, the ten plays which are the focus of Texas R&D efforts contain 57% of the total advanced case EOR potential in the state. These same plays also contain reservoirs with over 77% of the UMO extraction potential at this oil price/technology case. Technology transfer would need to be conducted in conjunction with R&D to ensure the application of improved recovery processes by the operators. The plays containing this vast recovery potential would need to be the focus of a technology transfer effort to provide operators in these key plays with the information necessary to implement the appropriate available recovery processes.

Recovery of oil in Texas could be maximized through technology transfer and R&D focused on the geologic plays with the greatest reserve potential. Close to 20% of the geologic plays in the state would account for appreciably more than 50% of the total reserves estimated under all of the criteria discussed in this section. Clearly, a major benefit of focusing future research on reservoirs in high-priority plays with significant combined EOR and UMO extraction potential would be the maximum return on limited R&D budgets. Such analyses would be critical in efforts to improve the recovery from either EOR and UMO extraction methods or their synergistic combined application. The thorough geological characterization of the reservoirs in each play resulting from these analyses could also expedite the application of improved recovery in other reservoirs within the same play as well as to other reservoirs in the state.

The focus of research efforts in those plays with the greatest incremental reserve potential due to advanced recovery methods would lead to maximum reserves and enhanced economic benefits for Texas. In addition, it is entirely possible that the benefits of these focused studies would not be limited strictly to the reservoirs within these plays. Research results from studies of these plays might even be applied on a larger scale, as plays may be grouped into a broader classification of geologic systems related to common depositional processes and/or post-depositional

Figure VII-12

Ten Major Oil Plays Would Account For the Majority Of Reserves Under Different Price and Technology Criteria



* MMB = million barrels

alterations of reservoirs. For example, the reservoirs of the Northern Shelf Permian Carbonate, Eastern Shelf Permian Carbonate, and San Andres/Grayburg Carbonate (Ozona Arch) plays were all deposited in a restricted platform geologic setting and could all be grouped into one geologic system type for certain areas of research. The concept that results from the study of one play could be used for reservoir management in another play would have to be tested and any localized play differences resulting in production response differences would have to be accounted for. However, the possibility exists that at least some of the knowledge gained from the R&D focus on one play could be used in the management of reservoirs of other plays in the same geologic system.

F. CONCLUSIONS AND RECOMMENDATIONS

The results of the analysis presented in this chapter provide critical insights that can be used to focus research efforts in order to maximize production from the enormous remaining mobile and immobile oil resources in Texas. Consideration should be given to the following major conclusions of this analysis when planning such a strategic R&D program:

- Additional research to improve the recovery efficiency and project economics of advanced oil recovery processes is a key aspect of a successful R&D program in Texas.
- R&D activities should be focused on the few plays which contain the reservoirs with the largest amount of incremental recovery potential that would result directly from defined advances in technology.
- A majority of the oil recovery potential from advanced recovery processes comes from reservoirs in a small number of the forty-eight defined geologic plays in Texas.
- Research to fully describe the geologic characteristics and heterogeneities of reservoirs in these key plays and their impact on fluid flow is essential for maximizing recovery from both EOR and UMO extraction processes.
- Most of the top oil plays for EOR are also the top plays for potential UMO extraction; advances in technology for the combined application of EOR and UMO extraction techniques in a few, carefully selected plays would account for the greatest incremental reserve additions in Texas.
- The EOR process with the greatest recovery potential is carbon dioxide injection in carbonate plays, while surfactant injection recovers the most immobile oil in sandstone plays.

- Dominant UMO extraction processes include infill drilling in carbonate plays and the combination of infill drilling and profile modification in sandstone plays.
- Technology transfer efforts must be ongoing to ensure maximum recovery in the near- and long-term.

Focusing the limited financial resources available for R&D efforts by analyzing and developing new recovery techniques tailored to the plays with the greatest economic recovery potential is essential to the success of a strategic program. This analysis has shown that a few plays account for the majority of the reserve potential at all oil prices and technology cases analyzed. To fully develop the potential of advanced technology, private industry and the state and federal governments will need to focus their research efforts towards developing a better understanding of reservoir architecture. Increasing the knowledge of reservoir heterogeneities and how they affect fluid flow will allow all of the processes analyzed in this study to be targeted into the most economically attractive portions of reservoirs, improving project economics by increasing ultimate recovery and decreasing associated investments and operating costs.

Because plays consist of groups of geologically similar reservoirs, specimen reservoirs with representative properties and production performance could be selected from each play for detailed study. Of the candidate specimen reservoirs, those with the greatest potential should be chosen. Important geologic parameters that control reservoir performance, such as reservoir deposition, diagenesis, and tectonics, would be characterized in detail in the specimen reservoirs to improve process understanding and performances for EOR and UMO extraction. In addition, specific technical constraints that limit current advanced oil recovery potential could be addressed and overcome through this focused research program. Pertinent information on the other reservoirs within the plays would also be required to provide a basis for integrating the detailed results of the specimen studies to the ultimate exploitation of the remaining resource in the entire play. At least two reservoirs in each play should be evaluated to determine whether the results from the detailed study of the specimen reservoir are applicable across the play. In addition, distinct plays with similar geologic characteristics could be grouped into a broader classification structure called a geologic system. It may be possible, then, to apply the results of R&D from reservoirs within a given play to reservoirs in other plays, regardless of size and geographic location, within the same geologic system.

The results of the characterization phase should be analyzed and implemented into a subsequent development phase. The ultimate goal of the program is to improve recovery technology in site-specific reservoirs and plays. This phase would build on the advanced techniques considered in this study to capture additional UMO and immobile oil as well as other recovery methods derived from future research. UMO extraction methods would include techniques such as the geologically-targeting of infill drilling based on differences in reservoir architecture, trends in intra-reservoir pay continuity, changes in net pay, and volumes of remaining mobile oil. Advanced secondary techniques such as profile modification and polymer flooding could be used to capture bypassed mobile oil. These processes could be improved by developing new polymers which can work effectively in more adverse reservoir settings. EOR development would encompass existing and emerging processes for immobile oil recovery. For example, the application of CO_2 miscible flooding is currently limited by poor sweep efficiencies. This limitation could be overcome to some extent by an improved understanding of reservoir heterogeneities and their impact on fluid flow. Chemical flooding using surfactants is currently limited by technical constraints related to reservoir temperature and by high project costs. These limitations could be managed or overcome if the process recovery efficiency is increased through more effective application techniques. In many cases, UMO and EOR development would be closely related. EOR processes commonly benefit from the closer spacing of wells that results from infill drilling, the principal method for increasing UMO recovery.

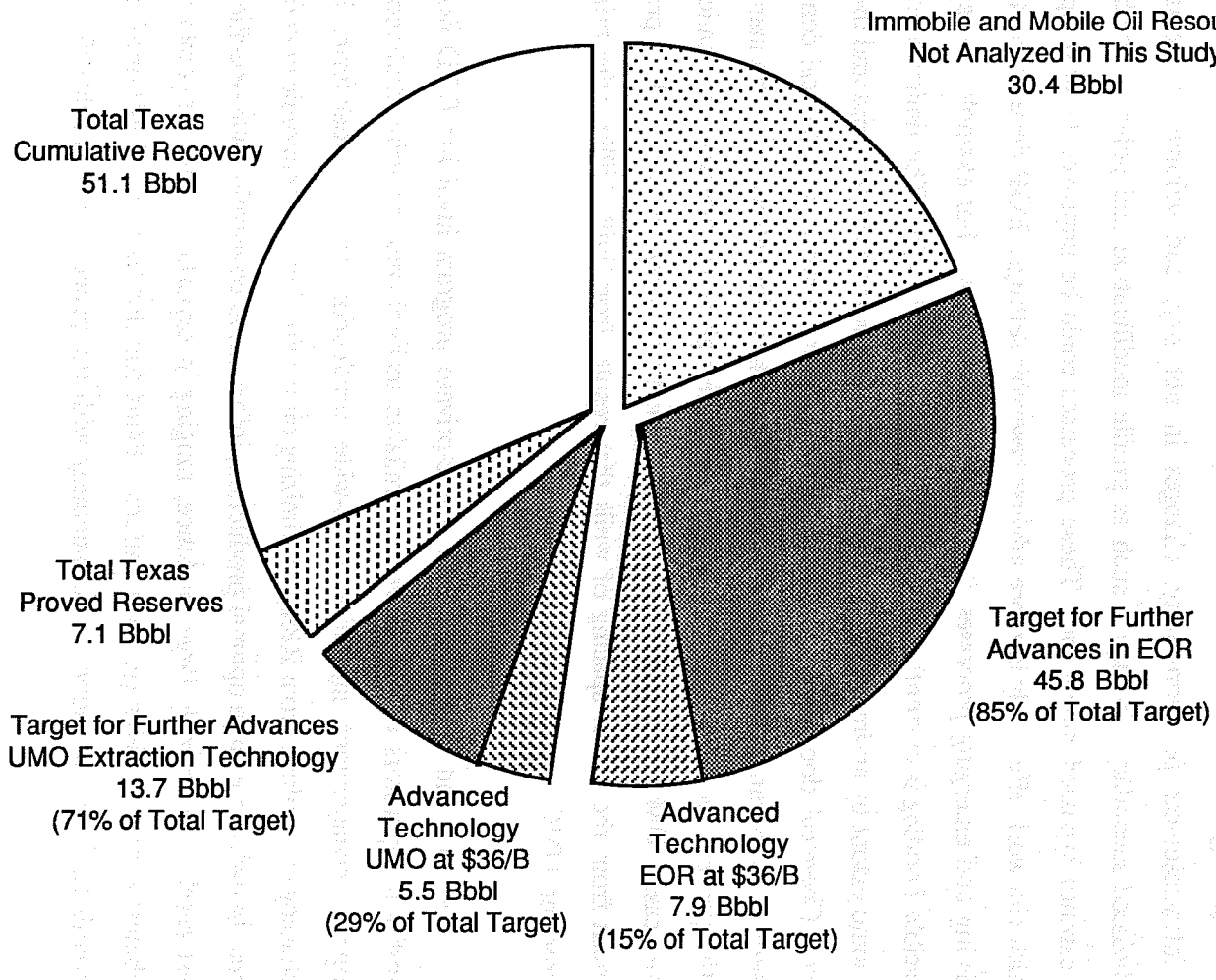
A final and crucial step in a public-private program involving R&D would be the timely transfer to operators of: 1) currently available technologies, ensuring that those involved in oil property management maximize state-wide production in the near-term, and 2) advanced technologies resulting from R&D, maximizing oil production and economic benefits over the longer term. In order to ensure optimal production, information concerning play-specific recovery methods must reach an extremely large audience, ranging in expertise from one-person operations to the technical staffs of major oil corporations. Plans for the transfer of information about improved methods could be developed simultaneously with the process- and play-specific R&D program.

Even if Texas reserves are maximized with the development of improved recovery methods through advanced technology R&D as defined in this study, an extremely large immobile and mobile oil resource will still remain in Texas oil fields (Figure VII-13). The continued development of these fields is vital, as it will maintain access to this remaining resource and may lead to recovery

Figure VII-13

Texas Remaining Oil Resource After Advanced Technology Recovery

Nearly 60 Billion Barrels Will Remain in Analyzed Reservoirs



Total Original Oil-in-Place: 161.6 Bbbl*

* Bbbl = Billion Barrels

improvements that will tap significant new quantities of this oil in the future. Nearly 13.7 billion barrels of mobile oil and 45.8 billion barrels of immobile oil would still remain in the reservoirs analyzed in this study after the completion of advanced UMO extraction and EOR projects judged to be economic at an oil price of $36/B. The potential benefits of capturing a significant portion of this remaining resource through even further advances in technology would be considerable. Oil remaining in other Texas reservoirs not analyzed in this study could also significantly increase these recovery and target totals. The size of the remaining resource in each play after conventional and post-conventional recovery operations, under any scenario, should therefore also be considered in R&D planning.

In conclusion, advances in technology in the near future and their timely transfer to operators clearly offer the most substantial potential for increasing oil reserves, as well as state and operator revenues, in Texas. These advances include developing a more detailed knowledge of the geologic components of reservoirs and, specifically, how these components affect recovery from both EOR and UMO extraction techniques. As each play has its own unique geologic character, it follows that improvements in recovery must reflect this uniqueness. Therefore, it is essential to study each high-priority play, and selected reservoirs for study within them, in order to maximize production and ultimate recovery from advanced processes. Through the use of the TORIS data base and predictive models, this study has provided a basis for prioritizing R&D in key Texas oil plays and the critical oil recovery processes. Now that the Texas plays with the greatest potential have been identified, R&D planning can be directed to achieve the greatest return on limited research budgets.