DOE/BC/14431-1 (Vol. 5)
Distribution Category UC-122

AN EVALUATION OF KNOWN REMAINING
OIL RESOURCES IN THE STATE OF KANSAS

Project on Advanced Oil Recovery and the States

Volume V

November 1994

Work Performed Under Contract DE-FG22-89BC14431

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

R. Michael Ray, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Interstate Oil Compact Commission
900 N.E. 23rd Street
Oklahoma City, OK 73152

MASTER

DISTRIBUTION OF THIS DOCUMENT IS UNLIMITED

DISCLAIMER

This report was prepared as an account of work sponsored by an agency of the United States Government. Neither the United States Government nor any agency thereof, nor any of their employees, make any warranty, express or implied, or assumes any legal liability or responsibility for the accuracy, completeness, or usefulness of any information, apparatus, product, or process disclosed, or represents that its use would not infringe privately owned rights. Reference herein to any specific commercial product, process, or service by trade name, trademark, manufacturer, or otherwise does not necessarily constitute or imply its endorsement, recommendation, or favoring by the United States Government or any agency thereof. The views and opinions of authors expressed herein do not necessarily state or reflect those of the United States Government or any agency thereof.

DISCLAIMER

Portions of this document may be illegible in electronic image products. Images are produced from the best available original document.

Table of Contents

	<u>Page</u>
LIST OF FIGURES	v
LIST OF TABLES	vii
ACKNOWLEDGEMENTS	viii
EXECUTIVE SUMMARY	ix
 I. OVERVIEW	
A. THE PROBLEM: DECLINING KANSAS OIL PRODUCTION	I-1
B. THE OPPORTUNITY: OIL RECOVERY THROUGH ADVANCED TECHNOLOGY	I-2
C. BENEFITS DERIVED FROM IMPROVED OIL RECOVERY	I-5
D. CONCLUSIONS	I-9
 II. BACKGROUND AND OBJECTIVES	
A. TRENDS IN KANSAS OIL PRODUCTION AND RESERVES	II-1
B. IMPROVED RECOVERY ACTIVITIES TARGETING THE REMAINING RESOURCE	II-7
1. Enhanced Oil Recovery	II-8
2. Advanced Secondary Recovery	II-9
C. OBJECTIVES OF THE PRESENT STUDY	II-11
 III. APPROACH TO THE ANALYSIS	
A. INTRODUCTION	III-1
B. GENERAL METHODOLOGY: THE NPC BASIS	III-1
C. BUILDING ON TORIS: THE EVALUATION OF UNRECOVERED MOBILE OIL RESOURCES	III-6
D. SCOPE OF THE ANALYSIS	III-9
E. ADAPTATIONS FOR THE PRESENT STUDY	III-11
1. Data Editing and Additions	III-11
2. State and Federal Taxes	III-11
3. Cost and Price Data	III-12
4. Benefits Estimation	III-13
5. Project Timing	III-13
F. ESTIMATION OF BENEFITS, COSTS, AND ECONOMIC IMPACTS	III-14
1. Benefits to State and Local Treasuries	III-15
2. Direct State Economic Effects	III-15
3. National Effects	III-16
G. LIMITATIONS TO THE ANALYTICAL APPROACH	III-18

Table of Contents (Continued)

	<u>Page</u>
IV. INCREASED RECOVERY FROM THE KNOWN REMAINING OIL RESOURCE IN KANSAS UNDER IMPLEMENTED TECHNOLOGY	
A. INTRODUCTION	IV-1
B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE	IV-1
1. Production and Reserves	IV-1
2. Increases in State and Local Revenues	IV-2
3. Effects on the State Economy	IV-5
4. Effects on the National Economy and Budget	IV-6
C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE	IV-8
1. Production and Reserves	IV-8
2. Increases in State and Local Revenues	IV-13
3. Effects on the State Economy	IV-13
4. Effects on the National Economy and Budget	IV-14
D. CONCLUSIONS	IV-17
V. BENEFITS OF INCREASED RECOVERY FROM THE KNOWN REMAINING OIL RESOURCE IN KANSAS WITH TECHNOLOGY ADVANCES	
A. INTRODUCTION	V-1
B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE	V-1
1. "Advanced" Technology Defined	V-1
2. Production and Reserves	V-2
3. Effects on State Revenues and Economic Activity	V-4
4. Effects on the National Economy and Budget	V-9
C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE	V-11
1. "Advanced" Technology Defined	V-11
2. Production and Reserves	V-12
3. Effects on State Revenues and Economic Activity	V-16
4. Effects on the National Economy and Budget	V-18
D. CONCLUSIONS	V-20

List of Figures

<u>Figure</u>	<u>Page</u>
I-1	Kansas Oil Resource I-1
I-2	Kansas Production and Reserves I-3
I-3	Kansas Oil Resource: Data Coverage of EOR and ASR Analyses I-6
I-4	Potential Impact of Advanced Technology I-7
I-5	Kansas Remaining Oil Resource After Advanced Technology Recovery I-10
II-1	Kansas Crude Oil Production (1950-1991) II-2
II-2	Kansas Crude Oil Reserves (1950-1991) II-2
II-3	Kansas Producing Wells (1960-1991) II-4
II-4	Kansas Stripper Well Production and Abandonments (1970-1990) II-4
II-5	Total Oil and Gas Employment in Kansas (1970-1991) II-5
II-6	Annual Wellhead Value of Kansas Oil and Gas Production (1961-1991) II-5
II-7	Kansas Oil and Gas Severance Taxes (FY1983-1992) II-6
II-8	Kansas Oil and Gas Severance Taxes as a Percent of Total State Taxes (FY1983-1992) II-6
II-9	Kansas Oil Resource II-7
II-10	Kansas Oil Resource Remaining After Conventional Operations II-12
IV-1	Reserves and Production Response from EOR Techniques -- Implemented Technology IV-4
IV-2	Direct State and Local Revenues from EOR Production -- Implemented Technology IV-5
IV-3	Direct State Economic Activity from EOR Production -- Implemented Technology IV-7
IV-4	Jobs and Wages from EOR Production -- Implemented Technology IV-7
IV-5	National Impact of EOR Production -- Implemented Technology IV-9
IV-6	Reserves and Production Response from ASR Techniques -- Implemented Technology IV-12
IV-7	Direct State and Local Revenues from ASR Production -- Implemented Technology IV-14
IV-8	Direct State Economic Activity from ASR Production -- Implemented Technology IV-15
IV-9	Jobs and Wages from ASR Production -- Implemented Technology IV-15
IV-10	National Impact of ASR Production -- Implemented Technology IV-16
IV-11	Kansas Remaining Oil Resource After Implemented Technology Recovery IV-18
V-1	Incremental Reserves by EOR Process -- Implemented Technology vs. Advanced Technology V-3

List of Figures (Continued)

<u>Figure</u>	<u>Page</u>
V-2	Annual Production from EOR Reserves -- Implemented Technology vs. Advanced Technology V-6
V-3	State Impact of EOR Production -- Implemented Technology vs. Advanced Technology V-8
V-4	National Impact of EOR Production -- Implemented Technology vs. Advanced Technology V-10
V-5	Incremental Reserves by ASR Process -- Implemented Technology vs. Advanced Technology V-13
V-6	Annual Production from ASR Reserves -- Implemented Technology vs. Advanced Technology V-15
V-7	State Impact of ASR Production -- Implemented Technology vs. Advanced Technology V-17
V-8	National Impact of ASR Production -- Implemented Technology vs. Advanced Technology V-19
V-9	Kansas Remaining Oil Resource After Advanced Technology Recovery V-22

List of Tables

<u>Table</u>	<u>Page</u>
I-1	Summary of Benefits from Technology Advances in EOR and ASR in Kansas I-8
III-1	Key Elements in the Current TORIS Reservoir Data Base III-3
III-2	Screening Criteria for EOR Candidates - Implemented Technology Case III-4
III-3	Screening Criteria for EOR Candidates - Advanced Technology Case III-5
III-4	Screening Criteria for Advanced Secondary Recovery Processes III-8
III-5	Screening and Approach for Advanced Technology Infill Drilling III-9
III-6	Risk Premium for Implemented and Advanced EOR and ASR Processes III-10
III-7	Labor and Materials as Percentage of Total Cost in EOR Projects III-17
IV-1A	Incremental Reserves from EOR by Process -- Implemented Technology IV-3
IV-1B	Estimated Number of Economic EOR Projects by Process -- Implemented Technology IV-3
IV-2A	Incremental Reserves from ASR by Process -- Implemented Technology IV-11
IV-2B	Estimated Number of Economic ASR Projects by Process -- Implemented Technology IV-11
V-1A	Incremental Reserves from EOR by Process -- Implemented Technology vs. Advanced Technology V-5
V-1B	Estimated Number of Economic EOR Projects by Process -- Implemented Technology vs. Advanced Technology V-5
V-2A	Incremental Reserves from ASR by Process -- Implemented Technology vs. Advanced Technology V-14
V-2B	Estimated Number of Economic ASR Projects By Process -- Implemented Technology vs. Advanced Technology V-14

ACKNOWLEDGMENTS

An Evaluation of the Known Remaining Oil Resource in the State of Kansas is one in a series of reports of the Project on Advanced Oil Recovery and the States, conducted by the Interstate Oil and Gas Compact Commission (IOGCC). The overall project was initiated by "seed money" grants from the States of Oklahoma and New Mexico in 1985. This report was prepared under grant number FG22-89BC14431 from the U.S. Department of Energy, Bartlesville Project Office (BPO) to the IOGCC.

The analysis presented in this report is based on an updated and upgraded version of the databases and models developed by the National Petroleum Council (NPC) in 1984. 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 C. Wesson, BPO Director, for his encouragement and assistance.

Special recognition is due to those who directly performed the work of the project. ICF Resources Incorporated of Fairfax, Virginia, served as the IOGCC's principal contractor, responsible for the study design, computer modeling, analysis, interpretation, and report preparation. ICF's Project Director was Dr. Jerry P. Brashear; Mr. Khosrow Biglarbigi was the Project Manager; and the critical project staff included Mr. Hugh D. Guinn, and Mr. Donald J. Remson (engineering and computer modeling); Mr. Karl Lang, Dr. Frank Morra (Consultant), and Mr. Jeff Enright (analysis and report generation); Mr. Marc Greenberg, Ms. Sohinaz Sotoudeh, Mr. Mike Schildkraut and Mr. Sid Choudury (editing, research, and analytical support); Mr. Alan B. Becker (Final Review); Ms. Barbara Jones (Administrator), Ms. Cheryl A. Labrecque (Senior Staff Assistant), Ms. Mary Bowers (Staff Assistant) and Ms. Barbara Gillen (word processing support).

Special recognition is also due to the members of the DOE/IOGCC Peer Review Committee; Mr. Lloyd Elkins, Dr. Alan Emanuel, Dr. Lee Gerhard, Dr. Donald Green, Dr. John D. Haun, Mr. Joseph E. King, Dr. Charles Mankin, Dr. David Martin, Dr. Donald Oltz, Dr. Fred H. Poettmann, Mr. William C. Stewart, and Dr. G. Paul Willhite.

This analysis was conceived and commissioned by W. Timothy Dowd, Executive Director of the IOGCC through June 1993. Mr. Dowd's keen interest in promoting the development of the nation's resource base has been the guiding force behind this study. To the degree that the results of this work help to improve the recovery of oil from U.S. reservoirs, Mr. Dowd's goals for the IOGCC will have been furthered. Mr. Bob Cooper, former Associate Director of the IOGCC, and Mr. Jerry Simmons (Associate Director) provided liaison and coordination among the participating organizations.

While acknowledging the assistance of all these contributors, error of fact, analysis, or interpretation are the responsibility of the IOGCC and the principal contractor's project director.

Christine Hansen
Executive Director
November 1993

EXECUTIVE SUMMARY

The Interstate Oil and Gas Compact Commission (IOGCC) has conducted a series of studies to evaluate the known, remaining oil resource in twenty-three (23) states. The primary objective of the IOGCC's effort is to examine the potential impact of an aggressive and focused program of research, development, and demonstration (RD&D) and technology transfer on future oil recovery in the United States. As a part of this larger effort by the IOGCC, this report focuses on the potential economic benefits of improved oil recovery in the state of Kansas. Individual reports for seven other oil producing states and a national report have been separately published by the IOGCC. Several major technical insights for state and Federal policymakers and regulators can be reached from this analysis.

- At the conclusion of conventional recovery operations, two-thirds of the known original oil-in-place (OOIP) will remain in Kansas oil reservoirs.
- The remaining resource, over 12 billion barrels, is the target for future improved oil recovery techniques. However, a significant portion of this remaining oil resource has already been abandoned. An even greater portion is in imminent danger of abandonment if cost-effective and efficient recovery techniques are not applied.
- Resource abandonment will significantly impact the economic producibility of future production and reserves under improved oil recovery techniques. Major capital investments will be needed to reacquire the leases, rebuild the infrastructure, and more importantly, drill new wells to regain access to the Kansas target resource.
- Kansas' future as a significant energy producing state depends strongly on the development of efficient and cost-effective oil recovery technologies, technology transfer to domestic producers, and the timely and successful application of such technologies, given the steady decline in Kansas production and reserves and the accelerating level of well abandonment over the past decade.
- The effective transfer of existing technology could result in 370 to 490 million barrels of incremental reserves from analyzed Kansas reservoirs at oil prices ranging from \$20/B to \$28/B, potentially doubling the state's current proved reserves.
- Technology advances resulting from a focused RD&D effort could result in *additional* post-conventional reserves of 80 to 320 million barrels. The effective transfer of existing technology, coupled with the development and application of new technologies, could more than replace current proved reserves in Kansas.
- Public sector revenues from future improved oil recovery activity could total between \$1.7 billion and \$2.8 billion given currently available recovery practices and oil prices between \$20/B and \$28/B. Technology advances could increase these totals by \$190 to \$750 million over the same price range, with roughly 45% of the total flowing to the state treasury.

- Potential improved oil recovery would replace imports of foreign oil, keeping between \$7 billion and \$14 billion in the U.S. economy. This figure is only the direct cost of imports avoided due to increased domestic activity. The true value to the country is actually much higher due to multiplier effects as this money circulates in the economy.

The analysis presented in this report is based on the databases and models available in the Tertiary Oil Recovery Information System (TORIS). TORIS is a tested and verified system maintained and operated by the U.S. Department of Energy's Bartlesville Project Office. The TORIS system was used to evaluate 57% of the OOIP in Kansas in a consistent manner and on an individual basis, the results of which have been aggregated to arrive at the statewide total.

Overall, well abandonments and more stringent environmental regulations could limit economic access to Kansas' known, remaining oil resource. The high risk of near-term abandonment and the significant benefits of future application of improved oil recovery technology, clearly point to a need for more aggressive transfer of currently available technologies to oil producers. Development and application of advanced oil recovery technologies could have even greater benefits to the state and the nation. A collaborative, focused RD&D effort, integrating the resources and expertise of industry, state and local governments, and the Federal government, is clearly warranted. With effective RD&D and a program of aggressive technology transfer to widely disseminate its results, Kansas oil production could be maximized. The resulting increase in production rates, employment, operator profits, state and Federal tax revenues, and energy security will benefit both the state of Kansas and the nation as a whole.

I. OVERVIEW

A. THE PROBLEM: DECLINING KANSAS OIL PRODUCTION

Over two-thirds of the oil discovered in the state of Kansas will remain trapped in the reservoir at the conclusion of conventional oil recovery operations. The total known original oil-in-place in Kansas has been estimated at over 18 billion barrels (Figure I-1). More than 5.6 billion barrels had already been produced at the end of 1991. Nearly 300 million barrels of proved reserves are still producible under existing economic conditions, using currently available technologies. The remaining 12.4 billion barrels of oil is the target for newer, more efficient recovery technologies and advances in geoscientific understanding that must be developed through an integrated public and private research effort.

Figure I-1

Kansas Oil Resource

The urgency for technology development and its effective application by Kansas oil producers has never been greater. The two factors that have combined to make technology development critical are:

- Declining state production and reserves. Kansas oil production declined by 20% from 1985 through 1991 (Figure I-2A). Current production is comparable to that of the late 1970s, which was at a level 50% below the high water mark of the late 1950s. Crude oil reserves decreased by roughly 20% over the 1985 to 1991 time period (Figure I-2B). The average size of new field discoveries has been relatively small and reserves per well have decreased.
- Increased level of well abandonment. The state of Kansas currently produces oil from roughly 45,000 wells. Many of these wells are "marginal" wells producing at or near their economic limit. In a period of high production costs and low oil price, many of these wells are being abandoned. A recent analysis by the Department of Energy (DOE) has concluded that between 37% and 45% of the nation's remaining oil resources had been abandoned by the end of 1991.¹ Well abandonments will have a significant impact on economic access to the remaining resource for application of future improved recovery techniques. It is estimated that once a lease is abandoned, it will require an oil price *increase* of \$10/B to \$25/B to rebuild the infrastructure and drill replacement wells.² Such an economic burden will not likely be justified by the incremental revenues from future improved oil recovery techniques.

The future of Kansas oil production and reserves depends strongly on the development and application of cost-effective and efficient technology. In the past, technology advances have made substantial contributions to Kansas oil production. The development of new exploration techniques and secondary recovery technology has acted to reverse past production declines and has allowed Kansas to maintain and increase its producible oil and gas resources. Oil producers in the state of Kansas have also pioneered much of the development of improved waterflooding techniques. The opportunity exists for a program of research, development and demonstration (RD&D), combined with an integrated program of technology transfer to all sectors of the Kansas petroleum community, to arrest the decline in production and maximize recovery of the state's oil resource.

B. THE OPPORTUNITY: OIL RECOVERY THROUGH ADVANCED TECHNOLOGY

The remaining oil resource constitutes a huge target for future recovery operations. The 12.4 billion barrels of known unrecovered oil in the state of Kansas is of two types: mobile oil and immobile

¹ "Abandonment Rate of the Known Domestic Oil Resource", U.S. DOE, Bartlesville Project Office, Bartlesville, OK (June 1990).

² Brashear, J.P. et al. "Effect of Well Abandonments on EOR Potential," JPT, December 1991.

Figure I-2

Kansas Production and Reserves

A) Annual Production

B) Reserves

oil. Even though mobile oil is displaceable by water, it has been uncontacted or bypassed during conventional primary production or waterflooding and thus remains unrecovered. Immobile oil is trapped in the reservoir pores by viscous and capillary forces and cannot be displaced by water.

The estimated unrecovered mobile oil (UMO) resource in Kansas is 3 billion barrels. This oil is an important target for future improved recovery efforts. Several improved primary and secondary recovery processes (infill drilling, profile modification, and polymer flooding), collectively referred to as advanced secondary recovery (ASR), could be used in innovative ways to produce a substantial portion of this resource. ASR processes are relatively low in cost and could increase production levels quickly. While such techniques have already been used by some operators in selected reservoirs, continued research and aggressive technology transfer are critically needed to improve, streamline, and adapt these techniques to site-specific reservoir conditions and broaden their applications.

The 9.4 billion barrel remaining immobile oil resource in Kansas is the target of a number of other recovery techniques. Miscible, chemical, and thermal recovery processes directed at producing immobile oil are collectively referred to as enhanced oil recovery (EOR). While these processes generally require larger investments and higher operating costs than conventional recovery, they are capable of producing significant volumes of incremental oil with substantial economic benefits. Further advances in EOR technology are foreseeable if a focused, research-intensive approach is adopted to make process improvements ready for field application.

Technology Assessment Method

The assessment of RD&D in oil recovery technology is based on the models and databases available through the Tertiary Oil Recovery Information System (TORIS). The TORIS methodology and analytical tools were originally developed by the National Petroleum Council (NPC)³ for its 1984 evaluation of nationwide EOR potential. DOE has since maintained and updated the system through its Bartlesville Project Office (BPO).⁴ DOE has also upgraded the capability of the system to evaluate the

³ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

⁴ *Producing Unrecovered Mobile Oil: Evaluation of Potential Economically Recoverable Reserves in Texas, Oklahoma, and New Mexico*, DOE, May 1990.

nation's unrecovered mobile oil by modeling ASR processes. In this report, the future potential of EOR and ASR techniques are examined with the following key assumptions and considerations:

- A total of 60 Kansas reservoirs, accounting for 10.4 billion barrels (57%) of the known original oil-in-place in the state, were individually analyzed for their EOR and ASR potential (Figure I-3). No attempt is made to extrapolate the results to the remaining Kansas resource not available in the TORIS database.
- Two levels of technology are considered: (1) implemented technology -- defined as the application of currently available post-conventional techniques; and (2) advanced technology -- defined as the improvements in process performance and applicability which are likely to occur over the next decade as the result of ongoing RD&D efforts.
- For each technology level, benefits were evaluated at several oil prices ranging from \$16/B to \$36/B (1991 dollars).
- All economic analyses reflect the current Federal tax structure and the specific oil production tax situation in Kansas. The FY 1991 Federal EOR tax credit, as well as state EOR tax incentives, are included in this analysis.
- The recovery potential evaluated in this report is for future new projects only, and does not include incremental reserves from existing EOR projects. However, the expansion of existing projects, if technically and economically feasible, is evaluated as part of future new projects in this report.

C. BENEFITS DERIVED FROM IMPROVED OIL RECOVERY

Potential incremental reserves and resulting direct state and local revenues that could be generated through improved oil recovery (EOR and ASR) techniques under both the implemented and advanced technology cases are shown in Figure I-4 and Table I-1. Implemented technology, if more widely applied, could add between 370 and 490 million barrels of incremental reserves across the \$20/B to \$28/B oil price range. Advanced technology applied to the same resource base could stimulate an additional 80 to 320 million barrels of incremental resources for a total of 450 to 810 million barrels of incremental reserves. In effect, improvements in process performance and application could significantly increase the reserves possible under implemented technology conditions. This clearly provides a major justification for a focused RD&D and technology transfer program.

The potential for expanded application of EOR techniques using implemented technology is limited if prices remain at or below \$20/B. However, implemented technology EOR could stimulate 80 million barrels of incremental reserves at a higher oil price of \$28/B. At this oil price, advances in EOR technology could stimulate an additional 296 million barrels of incremental reserves. This means that a

Figure I-3

Kansas Oil Resource

Data Coverage of EOR and ASR Analyses

Source: BPO TORIS, 1992
EIA, 1992
API/AGA, 1980

Figure I-4

Potential Impact of Advanced Technology

A) Reserve Additions

B) Direct State and Local Revenues

Table I-1

Summary of Benefits from Technology Advances in EOR and ASR in Kansas

Oil Price and Technology Level	Potential Reserves (Million Barrels)	Incremental State and Local Revenues (\$ Millions)	Incremental Imports Avoided** (\$ Millions)	Increased Federal Revenues (\$ Millions)
<u>At \$20/B</u>				
Implemented Technology	371	381	7,281	1,313
<u>Advanced Technology*</u>	<u>77</u>	<u>82</u>	<u>1,569</u>	<u>109</u>
Total	448	463	8,850	1,422
<u>At \$24/B</u>				
Implemented Technology	411	496	9,733	1,676
<u>Advanced Technology*</u>	<u>117</u>	<u>124</u>	<u>2,692</u>	<u>154</u>
Total	528	620	12,425	1,830
<u>At \$28/B</u>				
Implemented Technology	492	678	13,628	2,102
<u>Advanced Technology*</u>	<u>323</u>	<u>343</u>	<u>8,882</u>	<u>412</u>
Total	815	1,021	22,510	2,514

*Advanced is incremental over implemented technology.

**Imports Avoided = Reserves times effective wellhead price; to the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided estimates the reduction in foreign trade deficit.

total of 376 million barrels of potential EOR reserves exists under the two levels of technology at a price of \$28/B.

Incremental reserves from ASR processes are impacted much less by oil price changes than EOR. About 370 million barrels of incremental reserves could be added by ASR processes in the implemented technology case at an oil price of \$20/B, increasing to 416 million barrels as oil prices increase to \$28/B. Research on process improvements, specifically improved polymer flooding and profile modification combined with geologically targeted infill drilling, could increase ASR potential by 6% to 7%. With advances in technology, incremental ASR reserves could total about 30 billion barrels more than implemented technology over the \$20/B to \$28/B price range, for a total of 400 to 440 million barrels of incremental reserves from ASR.

Future improved oil recovery activities will generate revenues for Kansas and the Federal treasury through increased production taxes, oil industry-related sales taxes, and state, corporate, and personal

income taxes. The estimated revenues 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 or national economy. Under implemented technology at \$20/B, newly implemented improved oil recovery projects in Kansas could directly generate \$381 million in state tax revenues. At the same oil price, advanced technology could generate an additional \$82 million, for a total of \$463 million in state revenues. At an oil price of \$28/B, application of currently available EOR and ASR technology could contribute \$678 million to the Kansas state treasury, while the application of advanced methods could increase these revenues by an additional \$343 million to a total of about \$1 billion (Figure I-4 and Table I-1).

Increased production from EOR and ASR could offset oil imports, which in turn could reduce the national trade deficit and increase national economic activity. The value of the oil produced, the product of reserves and their effective oil price, is a simple measure of Kansas' contribution to reducing imports. As shown in Table I-1, imports avoided could total between \$7.3 billion and \$13.7 billion under the implemented technology scenario, over the \$20/B to \$28/B range. Advanced technology could further decrease imports by an *additional* \$1.5 billion to \$8.9 billion. The additional value of domestically produced EOR and ASR generates significant direct economic activities as capital spending, profits, royalties, and taxes are circulated through the U.S. economy rather than exported to buy foreign oil.

D. CONCLUSIONS

The development, testing, and wide-scale application of currently available improved oil recovery techniques could stimulate incremental reserves ranging from 370 million to nearly 500 million barrels from the state of Kansas' largest, most mature reservoirs at oil prices of \$20/B to \$28/B. With the technology advances resulting from focused RD&D, an additional 80 to 320 million barrels could be produced over this oil price range using EOR and ASR techniques. Even with the successful development and application of these technologies, however, about 5.3 billion barrels of immobile oil would still remain in the analyzed reservoirs as a long-term target for future advances in EOR, and nearly 1.2 billion barrels of mobile oil would remain as a long-term target for future advances in ASR processes (Figure I-5). While this target is substantial, it is not indefinite. Well abandonments have already limited economic access to a portion of the resource. The timely development and application of new recovery technology is crucial to maintain economic access to the remaining domestic oil resource.

Figure I-5

Kansas Remaining Oil Resource After Advanced Technology Recovery

The results of this analysis have important policy implications. Domestic oil production generates significant direct revenues to Kansas and to the Federal government and substantial additional indirect benefits to both the state and national economies. In addition to stimulating reserves, production, and economic activity, the application of improved oil technology would enhance the nation's energy security. However, integrated efforts and initiatives are needed to achieve these goals. These efforts should include:

- Collaborative RD&D;
- Aggressive technology transfer; and
- Appropriate tax and regulatory policies at the state and Federal levels.

A collaborative RD&D effort between the oil industry, universities, state and local governments, and the Federal government focused on improving advanced oil recovery technology and its application in key geologic settings would benefit operators, the state of Kansas, and the entire nation. 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 both the state and the nation's treasuries, economies, and citizens. State and Federal tax incentives can be instituted, or where already in place could be modified to improve their effectiveness, in order to help domestic EOR and ASR projects compete with foreign investment opportunities. In addition, regulatory policymakers could design regulations which reflect both the true risks to health, safety and the environment and the economic risk of resource loss through abandonment.

II. BACKGROUND AND OBJECTIVES

A. TRENDS IN KANSAS OIL PRODUCTION AND RESERVES

Like most of the lower-48 oil producing states, oil production in Kansas has declined as its heavily developed reservoirs enter into the mature stages of their productive lives. Through the 1960s and into the 1970s, Kansas crude oil production declined for 19 consecutive years, slipping from a high of nearly 124 million barrels, recorded in 1956, to a low of fewer than 56 million barrels in 1978 (Figure II-1). Stable world oil prices at relatively low levels discouraged operators from making large capital expenditures in reservoir intensive development or exploration, leading to a stagnation in production. Once oil prices began their rapid rise in 1978, operators quickly capitalized on the opportunity by implementing long-planned expenditures. By 1984, production had rebounded to almost 76 million barrels, a six year increase of 33%. When oil prices plummeted in 1985-1986, so did oil production; by the decade's end, a new low annual production of fewer than 56 million barrels was established. This current trend seems likely to continue unless new technologies can be implemented to recover oil that has been bypassed by conventional recovery techniques.

The fall in the production levels was coupled with a continual decline in crude oil reserves (Figure II-2). Whereas almost 885 million barrels were established as proved reserves in 1960, less than 303 million were left unproduced in 1978. Although the production numbers declined, Kansas operators were unable to replace the oil produced. As higher oil prices stimulated exploration and development expenditures, the accompanying production increases negated most of the gains that would have otherwise been made in reserves levels. Reserves levels fluctuated in the early 1980s, and although some notable increases occurred, the end of the decade saw little progress toward a significant increase in the rate of reserve replacement. By 1991, just 300 million barrels remained in Kansas reservoirs as proved reserves, less than six years of production at current rates (as has been the case since 1977).

A further indication of the maturing nature of the Kansas resource has been the decline in average reserves per well. In 1991, there were 48,000 producing oil wells in Kansas, 8,000 more than in 1960. At the same time, the average amount of reserves per well declined from over 21,000 barrels to approximately 6,000 barrels (Figure II-3). The effect of more wells producing fewer resources has increased the percentage of Kansas wells that can be classified as stripper wells; by 1990, more than 73% of Kansas production came from marginal wells. The danger of such a reliance upon stripper wells is underscored by recent stripper well abandonments (Figure II-4). Between 1980 and 1990, more than

Figure II-1

Kansas Crude Oil Production (1950 - 1991)

Figure II-2

Kansas Crude Oil Reserves (1950 - 1991)

14,000 stripper wells have been abandoned, with over 8,000 being lost for future use since 1986. Since future economic improved recovery operations depend on using existing wells as points of reservoir access, these high levels of abandonment jeopardize not only current production, but also the economic viability of any future efforts to expand reserves and production.

Declining crude oil production activity has already had an adverse economic effect in Kansas. By 1991, the oil industry employment levels had been reduced by nearly 10,000 jobs, compared to the boom years of the early 1980s (Figure II-5). As production and oil prices have declined, so has the wellhead value of the oil produced in Kansas, leading to reductions in state tax revenues. The total oil and gas wellhead value of less than \$2 billion in 1991 was just 60% of that recorded in 1981 in constant 1991 dollars (Figure II-6).

Revenues from production taxes on oil and gas were nearly \$131 million in fiscal year 1984 (in constant 1991 dollars), but declined by 34% to \$86 million in fiscal year 1992 (Figure II-7). This significant loss in states revenues has been caused by the dual effect of lower product prices and declining oil and gas production, trends which are expected to continue. The loss of oil and gas revenue has had a significant impact on total state tax revenue. In fiscal year 1984, oil and gas production contributed nearly 6% of all state tax revenues in Kansas, but by fiscal year 1987, the oil and gas severance tax revenue as a percentage of total state tax revenue had fallen below 3%. It has remained in the 3% range for the past four fiscal years (Figure II-8).

Declining reserves and production trends in Kansas can be reversed. Significant quantities of oil will remain unrecovered in known Kansas reservoirs once conventional primary and secondary operations have been concluded (Figure II-9). The original oil-in-place in Kansas has been estimated at over 18 billion barrels, of which 5.6 billion barrels had been produced by 1991. Factoring in the 300 million barrels of proved reserves through 1991, ultimate recovery from Kansas reservoirs will amount to just 5.9 billion barrels. A total of 12.4 billion barrels, over 67% of the original oil-in-place, will remain in Kansas reservoirs as the target for improved recovery technologies. This unrecovered resource of 12.4 billion barrels consists of two components: mobile oil and immobile oil. In Kansas, 3.0 billion barrels are estimated to be unrecovered mobile oil (UMO) that has been areally or vertically bypassed by conventional secondary recovery. This oil is the target for a number of advanced secondary processes, collectively known as advanced secondary recovery (ASR). The remaining 9.4 billion barrels is immobile oil that is incapable of being recovered conventionally or by advanced secondary efforts. This oil is the target for any one of a number of tertiary recovery techniques that fall into the classification of enhanced oil recovery (EOR) operations.

Figure II-3

Figure II-4

Figure II-5

Total Oil and Gas Employment in Kansas (1970 - 1991)

Figure II-6

Annual Wellhead Value of Kansas Oil and Gas Production (1961 - 1991)

Figure II-7

Kansas Oil and Gas Severance Taxes (FY1983 - 1992)

Figure II-8

Kansas Oil and Gas Severance Taxes as a Percent of Total State Taxes (FY1983 - 1992)

Figure II-9

Kansas Oil Resource

B. IMPROVED RECOVERY ACTIVITIES TARGETING THE REMAINING RESOURCE

The oil remaining after conventional primary and secondary recovery lies in two defined regions within each reservoir: the swept and the unswept zones. In the swept 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 with water can produce very little of this oil; the swept zone is at the "waterflood residual" level of oil saturation. The volume previously occupied by displaced oil now contains injected water (or, in some cases, natural gas). In their current stage of development, EOR processes are generally expected to reach only those portions of reservoirs previously swept by conventional techniques.

In the unswept zone of the reservoir, conventional recovery processes have not swept the pore space, and the oil saturation can range from low to high depending upon the primary recovery mechanism (e.g., pressure depletion or water drive). The objective of many infill drilling programs, improved waterflooding projects (profile modification), and other reservoir management techniques is to contact the oil in the unswept zones. Only after these zones have been swept by water are EOR operations generally considered feasible. A brief discussion of the analyzed EOR and ASR processes is contained in Volume X, Appendix A.

1. Enhanced Oil Recovery

Proven enhanced recovery processes are classified into three EOR categories: gas-miscible, chemical, and thermal. Gas-miscible EOR processes have not been widely applied in Kansas. There have been only two reported gas-miscible flooding projects in the state. In 1979, Troutman Oil undertook a flue gas-immiscible flood in the Lacygne-Cadmus field, in Linn County. The size of the project was 225 acres with 48 production and 48 injection wells. In 1981, Ladd operated a flue gas-immiscible flood in the Berryman field in Morton County, which was 1,218 acres with eight production wells and six injection wells. Further developments and applications of this EOR technique in the state could bring about an increase in future oil recoveries.

Chemical flooding has been used extensively to increase oil recovery in Kansas. Although some chemical floods have been unsuccessful in the past, this form of recovery has been generally more promising than gas-miscible or thermal flooding. In August of 1992, NIPER began operating an alkaline-surfactant-polymer project in Hepler field.¹ It is much too early in the life of this pilot project to accurately assess its technical or economic success. However, in general, the relatively high cost of chemicals makes chemical flooding economically risky. The development of low cost, widely applicable, and thermally stable chemicals is necessary for this process to achieve its full potential in Kansas.

There have been seven reported thermal recovery projects in Kansas. Four of these were *in situ* combustion projects, and the remaining three were conventional steam drives. The *in situ* combustion efforts were performed in the 2,062-acre St. Paul-Walnut field of Neosho County, with three producing and two injecting wells, and in the Iola and Moran fields of Allen County.

¹ Moritis, Guntis, *The Oil and Gas Journal*, April 20, 1992.

2. Advanced Secondary Recovery

Mobile oil remains in the reservoir after conventional recovery for a variety of reasons. Foremost of these is reservoir heterogeneity, the complex variation of rock properties among zones in the producing interval. 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 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 wide well spacings, significant volumes of oil are areally bypassed due to small-scale variations in reservoir continuity, to the higher viscosity of oil than injected water, and to permeability variations within the reservoir. The effectiveness of water injection is further limited by vertical layering in the reservoir. 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 production of unrecovered mobile oil (UMO). 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 may have very similar internal reservoir architecture, but will be modified by post-depositional diagenesis. That modification will vary from basin to basin depending on geohistory.

Recovery of remaining mobile and immobile oil from known fields is a highly cost effective method for increasing oil production, as demonstrated by the prevalence of ASR techniques in larger oil producing states such as Texas. Several distinct methods for producing unrecovered mobile oil 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 test and proven methods for producing mobile oil remaining in the reservoir.

The Tertiary Oil Recovery Project (TORP) at the University of Kansas conducted a study on 30% of the polymer floods in Kansas. The results indicated that 40% of these projects could be classified as economic successes.² Accordingly, polymer flooding holds significant potential for future recoveries in Kansas. At least two profile modification projects have been conducted in Kansas. Murfin Drilling and Apache Petroleum both performed profile modifications in the Gillespie field of Decatur County and the Rifle field in Rooks County; results indicated successful incremental recovery.³ While profile modification is a widely used method in Kansas, the quantity of publically available information on projects using this method is limited.

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

There are several other processes and recovery techniques which were not included in this analysis which may have potential in Kansas. Application of these techniques would further increase potential recovery and add to the estimates contained in this analysis. Immiscible-gas and nitrogen gas EOR projects could enhance Kansas oil recovery. In addition, improvements in reservoir management and improvements in waterflood patterns, waterflood rates of injection, and the timing of inception of waterfloods show significant potential as recovery techniques. To the extent that these techniques and others currently being transferred (i.e., injection water compatibility) improve potential oil recovery, the results presented in this report will be understated.

² Schoeling, Lanny G., "Producing Site Applications of Polyacrylamide in Kansas," KS, p.144.

³ Pautz, J.F., Sellers, C.A., Nautiyal, C., Allison, E., *Enhanced Oil Recovery Projects Data Base*, Oklahoma, April 1992.

C. OBJECTIVES OF THE PRESENT STUDY

The present study analyzes the incremental reserves, public sector revenues, and statewide economic activity that could result from the implementation of the improved EOR and ASR techniques described above. The potentials for EOR and ASR production are evaluated separately, and each is considered for two technology levels: *implemented technology*, which assesses recovery potential given the widespread application of currently available technology, and *advanced technology*, which assesses the impact of the effective 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 RD&D. All of the analyses are conducted over a range of crude oil prices from \$16 to \$36 per barrel (in constant 1991 dollars). This price range encompasses the long-term prices likely to prevail over approximately the next 30 years.

Sixty reservoirs, accounting for 10.4 billion barrels of origin oil-in-place (nearly 57% of the total known resource in Kansas), were included in this analysis. These reservoirs contain 7.3 billion barrels of remaining oil resource (Figure II-10). The 1.6 billion barrels of UMO is the target for application of ASR processes and 5.7 billion barrels is the target for application of EOR processes. To achieve the required level of application, and therefore receive the maximum benefits of both levels of technology assessed in this report, it is critical that state and local governments, the Federal government, and the oil industry work collaboratively to: (1) effectively transfer to operators currently available technology (implemented technology), and (2) develop a focused R&D program to improve recovery methods (advanced technology) and subsequently transfer those methods to a broad public-private audience. The results and conclusion will provide valuable insights for state and Federal policymakers in their efforts to maximize domestic production and improve the nation's energy security.

Figure II-10

Kansas Oil Resource Remaining After Conventional Operations

III. APPROACH TO THE ANALYSIS

A. INTRODUCTION

This analysis was performed using the U.S. Department of Energy's Tertiary Oil Recovery Information System (TORIS) developed for the 1984 National Petroleum Council (NPC) analysis of the nation's enhanced oil recovery (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, the target for advanced secondary recovery (ASR). The upgraded TORIS system assessed the recovery potential of immobile oil and UMO in the United States. The following sections in this chapter will briefly discuss the:

- Development of TORIS;
- Enhancement of TORIS to evaluate the UMO resource;
- Scope of the current analysis;
- Adaptations to TORIS for this analysis;
- Estimation of benefits, costs, and economic impacts; and
- 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 the 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 industry (majors, independents, service companies, and consulting firms), universities, government, and private, non-profit organizations participated. The NPC EOR study committee utilized and built upon data bases

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

of individual reservoir characteristics and computer models that were under development by the U.S. Department of Energy's (DOE), Office of Fossil Energy. After augmentation, adaptation, and validation, the data bases and models were remanded to the 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.

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", or currently available, 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 focused research and development. Table III-3 displays the technical criteria for "advanced" EOR technology.
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

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
 - Pay continuity (estimated)
- 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	Thermal Recovery	
		Surfactant	Alkaline	(Carbon Dioxide)	Steam	In-Situ Combustion
Oil Gravity	°API	---	<30	≥25	10 to 34	10 to 35
In-situ 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	Thermal Recovery	
		Surfactant	Alkaline	(Carbon Dioxide)	Steam	In-Situ Combustion
Oil Gravity	°API	---	<30	≥25	---	---
In-situ 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 ($S_o X \phi$)	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.

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 research, development, and demonstration (RD&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 EVALUATION OF UNRECOVERED MOBILE OIL RESOURCES

TORIS evaluations have historically focused on the recovery of immobile or waterflood residual oil. In 1988, TORIS' capabilities were expanded to include an 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 are reported in detail in a topical report by the DOE.³

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. Department of Energy/Office of Planning and Environment/Office of Fossil Energy and Bartlesville Project Office, 1989.

Since 1989, the TORIS ASR models have been upgraded to more accurately describe and evaluate the UMO resources. The enhancements included the following:

- Development of an infill drilling model which processes five-spot waterflood to five-spot infill as well as five-spot waterflood to nine-spot infill;
- Development of a methodology to determine key reservoir heterogeneity elements needed for modeling infill drilling potential. The heterogeneity elements are "reservoir continuity" and "Vertical Permeability Stratification Index" (Dykstra-Parson coefficient). The methodology relies on a history match of production data to determine the heterogeneity elements;
- Validation of the infill drilling model and history match methodology on nine actual field results as well as results of a black oil simulator;
- Integration of a newly developed infill model with other models in TORIS to process infill drilling in combination with polymer flooding or profile modification; and
- Validation of criteria for implemented as well as advanced technology infill drilling.

A preliminary draft report of all developmental work is available through the U.S. Department of Energy, Bartlesville Project Office. The draft report is currently being finalized, and it will be available to the general public in the near future.

UMO, the target for advanced primary and secondary recovery operations, consists of oil that is uncontacted or bypassed during conventional production that can be displaced from the reservoir by waterflooding. "Uncontacted oil" refers to oil trapped in isolated compartments in reservoirs uncontacted by wells 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, the fluid characteristics of the oil, and the drilling and development history of the reservoir.

Potential incremental oil recovery and related economic benefits are estimated for the three processes currently used to improve mobile oil displacement. These processes are referred to as advanced secondary recovery (ASR) and include: infill drilling, profile modification treatments (permeability contrast reduction), and polymer-augmented waterflooding. A modified polymer-waterflood predictive model is used to evaluate each process. Selected combinations of these processes are also evaluated in this study.

Consistent with TORIS EOR evaluations, the analysis of UMO considers both current technology and advanced technology. The advanced technology analysis estimates the potential improvement in recovery possible after successful RD&D. For polymer flooding and profile modification treatments, advances in technology are projected to increase 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 Recovery Processes

	<u>Polymer Flooding*</u>		<u>Profile Modification</u>	
	<u>Current</u>	<u>Advanced</u>	<u>Current</u>	<u>Advanced</u>
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 under implemented and advanced technology scenarios. Current knowledge of reservoir heterogeneity limits drilling to highly favorable reservoirs where blanket-pattern drilling at uniform spacing can yield a profit. Increased continuity in the implemented technology case is estimated by the reservoir-wide average improvement in continuity 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 (homogeneous) region and a less continuous (heterogeneous) region. Each region 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 specific criteria for both the implemented technology and the advanced technology infill drilling is shown in Table III-5. The entire methodology (data, models, highgrading, and analytical systems) was developed and implemented in a manner fully compatible with the existing TORIS structure.

Table III-5

Screening and Approach for Advanced Technology Infill Drilling

Technology Level	Criteria
Implemented	<ul style="list-style-type: none"> - 5-spot waterflood to 5-spot infill - 15% minimum real rate of return - Minimum well spacing of 10 acres before infill drilling - One drill down
Advanced	<ul style="list-style-type: none"> - 5-spot waterflood to 5-spot infill - 10% minimum real rate of return - Highgrade into homogenous and heterogeneous portions - One drill down in homogeneous portion - Up to three drill downs in heterogeneous portion - Well spacing after infill greater than 5 acres

D. SCOPE OF THE ANALYSIS

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

The nominal crude oil prices (West Texas intermediate adjusted for transportation costs and gravities less than 40° API) range from \$16/B to \$36/B in \$4 increments, all stated in constant 1991 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. In addition, a risk premium is also considered depending on the EOR and ASR process and the

level of technology. The risk premium is modeled as an increase in the hurdle rate as shown by Table III-6. The risk premium was recommended by the TORIS peer review committee.

Table III-6

Risk Premium for Implemented and Advanced EOR and ASR Processes

	Cost of Capital	Risk Factors		Hurdle Rates	
		Implemented Technology (%)	Advanced Technology (%)	Implemented Technology (%)	Advanced Technology (%)
Alkaline	10	15	0	27	10
Surfactant	10	15	0	27	10
In-Situ	10	15	5	27	16
Polymer	10	5	0	16	10
Profile Modification	10	5	0	16	10
CO ₂ -Miscible	10	5	0	16	10
Steam	10	5	0	16	10
Infill Drilling	10	5	0	16	10

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 ASR) which are currently available. Advanced technology considers the likely improvements in process performance and applicability that can be achieved within the next decade if a focused, effective R&D program is successfully completed.

All cases are analyzed in detail to examine their impact on estimated oil reserves, oil production, state and Federal revenues, and the state and national economies. The results of these analyses, addressing the benefits from incremental production, are reported in Chapters IV and V which discuss the effects of EOR and ASR processes for implemented technology and advanced technology, respectively.

E. ADAPTATIONS FOR THE PRESENT STUDY

Several adaptations to the NPC approach were necessary to conduct the present analysis. 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 60 of the largest Kansas reservoirs, accounting for 57% of the estimated original oil-in-place (OOIP) in Kansas. The reservoirs represented in the data base include oil zones in every region of the state. The largest reservoirs are more completely represented in the data, but reservoirs as small as 5 million barrels are also analyzed in the study. The data base is, therefore, believed to be representative of the diverse oil producing formations across Kansas. Data from the Energy Information Administration on the production of oil, gas, and water from 1970 to 1992 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

The present study uses current tax structure along with the actual tax rates in the TORIS economic models. The Federal taxes are estimated based on the 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 34% marginal rate on corporate income taxes and changes the depreciation schedules and expense rules. In addition, the present study includes the new Federal EOR tax credit as passed by Congress in FY91. The new Federal EOR tax credit provides a credit equal to 15% of all qualified enhanced oil recovery costs on projects that began or were significantly expanded after December 31, 1990. The "qualified enhanced oil recovery costs" are defined as tangible property investments, intangible drilling and development costs, and purchase costs of tertiary injectants. The tax credit is contingent upon professional certification, in advance, that the EOR project is capable of producing more than an insignificant increase in ultimate recovery. Because the goal of the incentive is to make the application of EOR techniques economic at lower oil prices, where project economics are most impacted, the incentive is gradually phased out at oil prices above \$28/B. For every \$1/B that the average benchmark price for the preceding year exceeds

\$28/B, the incentive is reduced by 2.5 percentage points for the subsequent year, so that a complete phasing out of the incentive would occur at an oil price of \$34/B.

The study also accounts for the current state tax structure in Kansas, including a state tax incentive for EOR projects. This incentive provides forgiveness of all production taxes associated with qualified EOR projects. It is assumed in this study that all analyzed projects qualify for the incentive.

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 CO₂ 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:

$$\text{CO}_2 \text{ Price (\$/Mcf)} = \$0.50 + \$0.025 \times \text{Oil Price (\$/B)}.^4$$

However, the base price and adjustment equation were established at higher oil prices and before the completion of major CO₂ pipelines or significant CO₂ deliveries to the region. An informal poll of pipeline and field operators suggests that the CO₂ prices at present and into the near future will be lower (relative to oil prices) than the NPC had assumed. The CO₂ purchase price in West Texas has been adjusted for changes in oil price using the equation:

$$\text{CO}_2 \text{ Price (\$/Mcf)} = \$0.50 + \$0.02 \times \text{Oil Price (\$/B)}.$$

This equation results in a CO₂ price of \$0.90/Mcf at the \$20/B oil price. CO₂ prices in other regions of the state are assumed to be double the West Texas price, based on previous NPC surveys.

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

⁴ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

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 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.⁵ 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. A more detailed timing approach for both EOR and ASR was used in the present study. Timing for the application of EOR recovery techniques 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 start up 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 recovery is then phased in to occur reservoir-wide, at the latest, by three years following the estimated abandonment date. Projects that are not timed in by this data are assumed abandoned and are excluded from the analysis. The timing of ASR reserves development and production was accomplished using the Crude Oil Policy Model (COPM) because the TORIS timing model was not suited for ASR for technical reasons. COPM simulates the

⁵ Ray, et al., *Potential Crude Oil Production from Enhanced Oil Recovery*, U.S. Department of Energy, Bartlesville Project Office, 1986.

development of an aggregate resource as a function of project economics, while simultaneously accounting for abandonment of the undeveloped portion of the resource and technology transfer constraints. Inputs to COPM include the total resource potential, development and production costs, technology availability dates, technology penetration rates, abandonment rates, and reserves development rates. Outputs from the model include annual production, reserve additions, abandonments, development costs, operating costs, wages, and taxes. Reserves estimates were supplied by TORIS.

Total reserves were disaggregated into two categories, reserves available with implemented technology and incremental reserves available through the application of advanced technology. Appropriate model parameters were selected for each of these resource categories. The technology availability dates were set to 1993 for implemented technology and 2000 for advanced technology. Technology penetration rates were set at 75% in 12 years for implemented technology and 75% in 8 years for advanced technology, with the advanced technology case representing an aggressive technology transfer effort. Abandonment rates for both implemented and advanced technology were set to 3% of the undeveloped resource per year prior to technology availability and 1.5% per year after technology becomes available. Reserves development rates corresponded to typical field development profiles.

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 cash flow calculations of individual projects. Under each of the various cases analyzed, projects yielding a net present value greater than the hurdle rate are assumed to be developed. This assumption is the basis for the projection of potential incremental production and reserves.

The incremental benefits and costs of EOR and ASR 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-seven year period, 1993 to 2020. Cumulative benefits include the sum of the annual benefits plus any additional

benefits that would accrue after 2020. 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-seven year period of focus in this study. The additional benefits that occur after 2020 are generally small relative to the total benefit, but important to the overall aggregate analysis.

1. Benefits to State and Local Treasuries

The benefits to Kansas 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, sales tax on equipment and material purchases, and corporate and personal income taxes on operator profits and wages paid. 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 activities associated with 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 citizens of Kansas also gain from the increased economic activity. Only the direct effects of the incremental activity are included, not the economic "multiplier" or indirect "ripple effect" activities (e.g., pipeline construction, retail sales, etc.). The direct impact on the state's 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 of Kansas and its citizens.

Excluded from this state economic activity definition are cashflows that generally benefit citizens of other states in larger proportion than they benefit the citizens of Kansas. 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 Kansas, the direct benefits of these "retail pass-through" 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 Kansas (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 Kansas 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 for direct economic effects understates the actual benefits to Kansas and its citizens.

The additional jobs, wages, and benefits created by improved 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-7 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.⁶ Sales tax revenues are calculated based on the materials component of these costs, assuming purchasers would pay the appropriate state tax on these goods.

3. National Effects

The Federal government benefits substantially, both directly and indirectly, from increased recovery of the Kansas oil resource. Direct Federal taxes total 5% to 20% of the value of each barrel of oil recovered. Each additional barrel of domestic production can replace a barrel of imported oil. Therefore, each dollar used to purchase the incremental barrels of oil that would otherwise pay for imports is, potentially, a dollar reduction in the trade deficit.⁷ To estimate the direct effects on import replacement (i.e., excluding multiplier effects), the gross revenue from the additional production is used. This measure of gross revenues incorporates direct in-state economic activity and excluded elements discussed in the section above. In this sense, the estimated increase in import replacement represents a more complete measurement of direct economic impacts, excluding multiplier effects.

⁶ U.S. Department of Labor, Bureau of Labor Statistics, 1985.

⁷ 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.

Table III-7

Labor and Materials as Percentage of Total Cost in EOR Projects

<u>Investments</u>	<u>% Labor</u>	<u>% Materials</u>	<u>% Other</u>
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
<u>Expenses</u>			
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

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. It is also important to note that the results of this analysis are not forecasts of future oil recovery; they are estimates of the recovery potential of selected EOR and ASR processes.

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, unless advanced geoscientific knowledge allows 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 developed under EOR or ASR operations.

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 after completion of conventional production operations.

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 advanced oil recovery, but this is not reflected in the models.

An additional limitation arises from the methodological convention of "constant price" analysis. The use of this convention is consistent with the NPC's original 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 additional incremental investment not included in this analysis (although necessary workovers are included in the assumed cost). Redrilling would result in substantially increased costs and would thus increase the minimum oil price at which advanced oil recovery processes are profitable for certain reservoirs. The net effect of this analytic convention could 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 analysis.

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.

None of the above limitations invalidate the results of this analysis. Given the uncertainty of the size and combinations of the optimistic and pessimistic biases introduced by these limitations, it is assumed that the approach is valid and the resulting projections are reasonable. To avoid misinterpretation of particular reservoirs, and to respect the confidence in which some project and reservoir data were obtained, no reservoir specific date is provided in the reports generated from this analysis. However, in cases where the results seemed unusual, the modeling specifications for specific reservoirs were examined in-depth to ensure the validity of the results.

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

A. INTRODUCTION

This chapter discusses the post-conventional reserve additions and potential economic impacts attributable to the application of currently available (implemented technology) oil recovery methods in analyzed Kansas reservoirs. Chapter V discusses the incremental reserves and benefits under advanced technology methods attainable through RD&D. The TORIS reservoirs analyzed in this study are individually modeled to evaluate their potential for incremental production and reserves by tertiary and advanced secondary recovery techniques under a variety of oil prices and economic conditions. Some key technical assumptions and considerations regarding the analysis in this report are:

- The incremental production and reserves refers to future recovery estimated for the analyzed EOR and ASR techniques. Such production and reserves are above and beyond the recovery attainable by primary and secondary recovery techniques.
- Both light oil ($\text{API} > 20$ degrees) and heavy oil ($\text{API} \leq 20$ degrees) resources are considered in this analysis.
- All EOR and ASR recovery potential evaluated in this report reflect future new projects only, and they do not include incremental reserves from existing (ongoing) EOR and ASR projects. However, expansions to ongoing projects, if technically and economically feasible, are evaluated as part future new projects in this report.

All reservoirs are screened for technical criteria and are analyzed in detail using the process performance and economic models described in Chapter III. The results are based on the evaluation of 60 major Kansas reservoirs and were not extrapolated to the rest of the reservoirs making up the Kansas resource.

B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE

1. Production and Reserves

Based on the implemented technology assumptions outlined in Chapter III, there would be no economic EOR projects in Kansas until oil prices reach \$24/B. Carbon dioxide (CO_2) miscible EOR projects would account for the majority of the incremental reserves under implemented technology (Figure IV-1A and Table IV-1A). At \$24/B, only 8 million barrels in incremental reserves would be economically

producible. If prices were to increase to \$28/B, however, two additional projects could become economic and would add 72 million barrels of incremental reserves. The 80 million barrels of incremental reserves potential at \$28/B represents 27% of Kansas' 1991 proved reserves (300 million barrels). If oil prices were to reach \$36/B, one thermal project could become economic, and would contribute 20 million barrels of incremental reserves. Under implemented technology, high chemical costs preclude the implementation of chemical floods in Kansas at oil prices of \$36/B or less. Of the reservoirs evaluated in this analysis, less than 7% would be economic to develop with current EOR technology at oil prices of \$36/B or below. Table IV-IB displays the number of economic EOR projects by process. In most cases, the economic projects are in the large reservoirs, but size alone is not a major determinant of EOR economics.

Figure IV-1B displays the potential annual production from Kansas EOR projects at oil prices of \$24/B and \$32/B. At \$24/B, over 73% of the potential reserves could be produced by the year 2005. Annual production could peak in the year 2003 at 800,000 barrels per year, only marginally increasing Kansas' annual production rates. At \$32/B, the additions to annual production could be much more substantial. Annual production from EOR projects could peak in the years 2002 and 2003 at 7.9 million barrels per year. By the year 2005, over 85% of the incremental EOR reserves could have been produced, averaging nearly 4.9 million barrels per year. This average production through 2005 would be a 9% increase to Kansas' 1991 production rate (56.9 million barrels per year).

2. Increases in State and Local Revenues

EOR production could increase state and local revenues through production taxes, sales taxes on purchased materials used in the projects, and state corporate and personal income taxes. The estimated revenues are generated directly from oil production or operations in the analyzed Kansas reservoirs. A significant portion of these revenues result from corporate income and sales taxes (Figure IV-2). As discussed in Chapter III, EOR projects are exempt from production taxes, thereby eliminating most of the taxes directly associated with production. The implementation of EOR processes could generate \$6 million in additional state and local tax revenues at an oil price of \$24/B. As potential reserves increase, so do potential tax revenues; state and local revenues could increase by \$69 million as prices rise to \$28/B for a total potential of \$75 million. When the thermal project becomes economic at \$36/B, direct state and local revenues could increase to over \$110 million.

Table IV-1A

Incremental Reserves from EOR by Process*
Implemented Technology
(Million Barrels)

Oil Price (\$/B)	CO ₂ -Miscible	Thermal	Total
\$24	8	0	8
\$28	80	0	80
\$32	80	0	80
\$36	81	20	101

* Analyzed Kansas reservoirs did not exhibit potential at oil prices below \$24/B nor did they exhibit any chemical EOR potential under implemented technology.

Table IV-1B

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

Oil Price (\$/B)	CO ₂ -Miscible	Thermal	Total
\$24	1	0	1
\$28	3	0	3
\$32	3	0	3
\$36	3	1	4

* Analyzed Kansas reservoirs did not exhibit potential at oil prices below \$24/B nor did they exhibit any chemical EOR potential under implemented technology.

Figure IV-1

Reserves and Production Response from EOR Techniques Implemented Technology

A) Incremental Reserves by EOR Process

* No chemical EOR projects were economic in analyzed reservoirs.

** No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

B) Annual Production from EOR Reserves

Figure IV-2

Direct State and Local Revenues from EOR Production Implemented Technology

* No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

3. Effects on the State Economy

In addition to the incremental state and local revenues, EOR activities could directly benefit Kansas by increasing economic activity and by creating or maintaining oil-related jobs. 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 Kansas 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. Royalties may be overstated to the extent that they are paid to the Federal government (i.e., from production on Federal lands). While the excluded elements undoubtedly aid Kansas' 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

items provide economic benefits within Kansas, injectants produced or manufactured in Kansas are employed, or economic "multipliers" occur, the calculated economic effects reported here are understated.

Over the analyzed range of oil prices, operating costs could account for over 65% of these economic effects; royalties could represent around 20% of the total, with state tax revenue and intangible investment accounting for the remainder (Figure IV-3). At an oil price of \$24/B, the economic benefits to the state could be limited (\$123 million) due to the very small amount of EOR production at this price. At \$28/B, however, incremental benefits to the state economy could be over \$1.4 billion in additional tax revenues. Another substantial increase in economic activity could occur at an oil price of \$36/B; over \$2 billion in state economic activity could be generated by EOR projects at this price.

Wide-scale application of EOR processes could also increase employment in Kansas (Figure IV-4). At \$24/B, an average of nearly 47 jobs could be created or maintained annually through the year 2005. At an oil price of \$32/B, the increases could be much more substantial. Potential jobs created or maintained could peak in the year 2002 at nearly 922 jobs per year. Through the year 2005, an average of almost 618 jobs could be generated yearly by activities associated with EOR production. Annual wages could reach over \$40 million during the peak year of Kansas EOR production at an oil price of \$32/B.

4. Effects on the National Economy and Budget

Increased oil recovery from EOR in Kansas would benefit the nation as a whole. National benefits would accrue in several ways: increased Federal corporate and personal income tax revenues, replacement of oil imports, and reduction in the foreign trade deficit. EOR activity in Kansas directly contributes to the Federal treasury through personal and corporate income taxes (Figure IV-5A). At \$24/B, the additions could be relatively insignificant, totaling just \$3 million. Even at \$28/B, despite a large increase in reserves, additions to Federal revenues could still be relatively small (\$22 million). This is largely due to the FY91 EOR tax credit. This credit can be applied to any corporate income, leading to negative Federal corporate income taxes from Kansas at \$28/B. At an oil price of \$32/B, as the tax credit begins to be phased out, additional Federal tax revenues could markedly increase to \$164 million. With increased activity and a complete phaseout of the tax credit, potential Federal revenues could more than double to \$333 million over the \$4/B price increment from \$32/B to \$36/B.

Figure IV-3

Direct State Economic Activity from EOR Production Implemented Technology

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.

** No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B

Figure IV-4

Jobs and Wages from EOR Production Implemented Technology

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 Kansas. Thus, increases to Kansas production and reserves could directly lead to a reduction in the trade deficit estimated by the direct value of the avoided imports (reserves multiplied by the effective wellhead oil price) (Figure IV-5B). At \$24/B, the potential increase in avoided imports would be relatively small (just under \$200 million). As price increases to \$28/B, nearly \$2.1 billion of incremental imports avoided could be generated by implemented technology EOR activities, for a total potential of about \$2.3 billion. If oil prices were to increase to \$36/B, \$3.6 billion of imports avoided could result from implemented technology EOR production.

C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE

This section will discuss the application of currently available ASR processes in analyzed Kansas reservoirs. These two distinct recovery technologies, enhanced oil recovery and advanced secondary recovery, 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 Kansas reservoirs, and the results are independent and additive. Given the potential synergies in the simultaneous application of EOR and ASR technologies, incremental reserves and economic benefits could be even greater than the sum of the two.

1. Production and Reserves

Depending on the price of oil, ASR techniques applied in the reservoirs analyzed could stimulate between 357 million and 415 million barrels of additions to current proved reserves in Kansas (Figure IV-6A). ASR techniques are less costly to implement than EOR recovery processes, and therefore incremental reserves from ASR are less sensitive to changes in the oil price. At \$20/B, incremental ASR could amount to over 370 million barrels of incremental reserves, which is over 89% of the oil economically recoverable at \$36/B. The 412 million barrels of potential incremental reserves at \$28/B is only 1% lower than the \$36/B potential of 415 million barrels.

This analysis evaluates three categories of ASR processes: polymer flooding and profile modification, infill drilling, and combinations of infill drilling with polymer flooding or profile modification ("combination processes"). As shown in Figure IV-6A and Table IV-2A, combination

Figure IV-5

National Impact of EOR Production Implemented Technology

A) Direct Federal Revenues

* No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit.

** No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

processes could play a predominant role in ASR, accounting for most of the incremental reserves at all prices. At oil prices below \$24/B, the combination processes could contribute from 343 to 353 million barrels of incremental reserves, over 95% of the total potential. As oil prices increase, the incremental reserves attributable to infill drilling by itself could increase marginally, slightly lowering the percent contribution of the combination processes. At an oil price of \$28/B, the combination processes could contribute as much as 388 million barrels in incremental reserves, over 94% of the total ASR potential in analyzed Kansas reservoirs.

Polymer flooding, profile modification, and infill drilling applied alone would make marginal contributions relative to the combination processes, accounting for between 14 million and 27 million barrels of incremental reserves across all analyzed oil prices. The incremental reserves attributable to these projects do not rise with the oil price because these processes compete with the more prolific combination processes. In this analysis, only one of the three categories of analyzed ASR processes is implemented in each reservoir. As the oil price rises, and more reservoirs become economic, the more costly combination processes can be increasingly implemented.

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 combination process projects would be consistently higher than either infill drilling or polymer flooding and profile modification. The amount of incremental reserves per project is smaller for polymer flooding and profile modification.

Figure IV-6B displays the expected annual production from all ASR processes for oil prices of \$16 and \$32/B. ASR projects are undertaken as reservoirs reach their economic limit under conventional recovery. In this study, ASR projects are assigned initiation dates as a function of rig availability and technology transfer; projects are therefore phased in over time. As a result, some fields will be abandoned before ASR can be implemented. This abandonment, which is reflected in the timing of annual production, is on the order of 24% of the potential resource. Annual production from ASR reserves at an oil price of \$16/B could peak in the years 2015 and 2016 at 11.4 million barrels per year. Over the period from 2011 to 2020, production could average 10.5 million barrels per year, over 18% of Kansas's 56.9 million barrels per year production rate in 1991. Through the year 2010, production from incremental ASR reserves could average nearly 4.3 million barrels per year. At \$32/B, the timing of annual production would be similar to that under the \$16/B oil price. Production could peak in the years 2014 to 2016 at 13.1 million barrels per year. Annual production from the year 2011 to 2020 could average 12.2 million barrels per year, as compared to under 5 million per year through 2010.

Table IV-2A

**Incremental Reserves from ASR by Process
Implemented Technology**
(Million Barrels)

Oil Price (\$/B)	Polymer Flooding and Profile Modification	Infill Drilling	Infill Drilling and Polymer Flooding or Profile Modification	Total
\$16	3	11	343	357
\$20	4	14	353	371
\$24	5	14	384	403
\$28	5	19	388	412
\$32	5	20	387	412
\$36	5	22	388	415

Table IV-2B

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

Oil Price (\$/B)	Polymer Flooding and Profile Modification	Infill Drilling	Infill Drilling and Polymer Flooding or Profile Modification	Total
\$16	2	3	11	16
\$20	3	4	12	19
\$24	3	4	13	20
\$28	3	5	14	22
\$32	3	5	14	22
\$36	3	6	14	23

Figure IV-6

Reserves and Production Response from ASR Techniques Implemented Technology

A) Incremental Reserves by ASR Process

B) Annual Production from ASR Reserves

2. Increases in State and Local Revenues

Figure IV-7 displays the expected growth in state revenues from ASR production and the components of this growth. State corporate income taxes account for the largest portion (80%) of total state revenues from ASR over all prices considered. Corporate income taxes could account for \$306 million of the \$381 million in potential state revenues at \$20/B. At \$28/B, over \$600 million could be generated for the state treasury by implemented technology ASR activities, \$485 million of which could be attributed to corporate income taxes. If prices were to reach \$36/B, implemented ASR activities could stimulate over \$780 million in additional state and local revenues.

3. Effects on the State Economy

Figure IV-8 displays the total state economic activity associated with potential implemented technology ASR production. Total state economic activity (measured as state tax revenues plus non-injectant operating costs, intangible investments, and royalties) from the processes could range from \$2.6 billion at \$16/B to \$5.7 billion at \$36/B. At \$20/B, state economic activity could increase by \$3.2 billion; this potential could increase by over \$1 billion with a \$4/B increase in price, totaling \$4.2 billion at \$24/B. If oil prices increased another \$4/B to \$28/B, economic activity in Kansas could rise to \$4.8 billion. Non-injectant operating costs could be the largest component of in-state economic activity and could account for 30% to 38% of the total depending on the price. Royalties and intangible investments could make roughly equal contributions to the increases in state economic activity, each accounting for 21% to 32% of the total. State tax revenues could comprise the smallest portion of the increased economic activity, averaging about 12%, of the total activity across all oil prices. As discussed above, these effects are estimated conservatively with no multiplier or indirect effects considered. Even without "ripple" effects, ASR projects in Kansas could significantly add to future economic activity in the state.

The implementation of ASR techniques could increase employment in the state of Kansas. Figure IV-9 displays the annual number of new jobs that could be created or maintained by ASR projects at oil prices of \$16/B and \$32/B. At \$16/B, an average of nearly 102 jobs could be created or maintained annually by activities associated with ASR production through the year 2010. The number of jobs could peak in the year 2016 at 270, averaging 250 jobs per year from the year 2011 to 2020. At \$32/B, jobs created or maintained could again peak in 2016 at 457. Over the years 2011 to 2020, an average of 423 jobs could be generated yearly by ASR production activities; prior to that, an average of 172 jobs could be created or maintained each year.

Figure IV-7

Direct State and Local Revenues from ASR Production Implemented Technology

4. Effects on the National Economy and Budget

Figure IV-10 displays the national benefits of ASR production in Kansas. Federal revenues from ASR production could range from over \$960 million to nearly \$3.1 billion over the price range analyzed. Figure IV-10A shows that nearly all of these revenues (up to 97%) could stem from corporate income taxes. At \$20/B, additional Federal revenues from implemented technology ASR activities could reach as high as \$1.3 billion. With a \$4/B increase in price, potential Federal revenues could rise 27% to \$1.7 billion. At \$28/B, nearly \$2.1 billion in additional Federal revenues could be generated by ASR activities.

Imports avoided due to ASR production in Kansas could total between \$5.6 billion and \$14.8 billion over the price range analyzed (Figure IV-10B). At prices below \$24/B, imports avoided could grow by around 30% at each \$4/B increment. As prices increase to \$24/B and \$28/B, the rate of growth over the price increment would slow to 19%, reaching \$11.4 billion at \$28/B. As the increased Kansas production from ASR replaces oil imports, the U.S. trade deficit would be reduced and national energy security would be enhanced by the implementation of ASR techniques.

Figure IV-8

Direct State Economic Activity from ASR Production Implemented Technology

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.

Figure IV-9

Jobs and Wages from ASR Production Implemented Technology

Figure IV-10

National Impact of ASR Production Implemented Technology

A) Direct Federal Revenues

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit.

D. CONCLUSIONS

The existing level of EOR and ASR technologies could produce significant volumes of oil and increase tax revenues and economic activity in Kansas and the U.S. as a whole. At a \$20/B oil price, EOR and ASR techniques could add over 370 million barrels of oil, 24% greater than the state's 1991 proved reserves. Even without considering potential synergies, the application of current EOR and ASR technologies, in concert, could potentially add as much as 490 million barrels of incremental reserves at \$28/B, over one and one-half times greater than Kansas' 1991 proved reserves. While incremental reserves from these processes are smaller at lower oil prices, they would still generate substantial benefits to the state. As discussed in the next chapter, improved geoscientific understanding of reservoirs and enhanced process performance could increase these benefits if the required research can be cost effectively completed.

The state of Kansas and its citizens stand to gain significantly from the increased oil production due to improved recovery activities. Production increases could generate up to \$678 million in additional state and local revenues at an oil price of \$28/B over the life of the analyzed projects. Jobs would be created or maintained, and state economic activity would increase. The national economy would benefit through increased Federal corporate and personal income tax revenues, decreased oil imports, and reductions in the trade deficit. Maximizing recovery of the known oil resource in Kansas reservoirs should therefore be an important goal for state and Federal policymakers. While these benefits would be available using currently available technology, the true potential would not be realized without an aggressive program of technology transfer. The estimated potential assumes wide application of these technologies. A collaborative technology transfer effort between the public and private sectors is critical to the attainment of these estimated benefits.

As shown in Figure IV-11, the oil that will remain in the analyzed reservoirs after production by both current operations and by wide-scale application of currently available EOR and ASR processes constitutes an important resource target for improved recovery technologies. Of the 5.7 billion barrels of immobile oil resource analyzed in this study, implemented technology EOR practices as defined in this report could produce an estimated 100 million barrels at an oil price of \$36/B, leaving over 5.6 billion barrels of remaining immobile oil in these reservoirs. Of the 1.6 billion barrels of unrecovered mobile oil in the reservoirs analyzed, implemented technology practices could produce an estimated 415 million barrels at \$36/B, leaving 1.2 billion barrels in these reservoirs. The large size of the remaining resource

clearly warrants a focused RD&D program that will test and speed the implementation of advanced technology to capture additional oil reserves.

Figure IV-11

Kansas Remaining Oil Resource After Implemented Technology Recovery

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

A. INTRODUCTION

While currently available EOR and ASR techniques could contribute substantially to Kansas reserves, technological advances in these processes resulting from a focused, concerted RD&D effort would significantly increase the state's production and reserves. Development and wide-scale demonstration and 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. The present analysis evaluates the benefits of advanced technology on oil recovery and its associated economic impacts. Evaluations of advanced EOR and ASR in the state of Kansas 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. However, well abandonments could limit access to the resource and increase project costs if EOR and ASR processes are not applied before conventional production ceases. Immediate actions are therefore necessary to realize the economic benefits of these advanced processes.

B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE

1. "Advanced" Technology Defined

Enhanced oil recovery processes, as currently "implemented," have 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 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. In this report, the IOGCC has delayed the advanced technology availability date from the NPC's assumption of 1995 to the year 2000 in order to reflect the slower pace of RD&D activities in recent years caused by relatively low oil prices.

The major improvements in technology that are likely to impact Kansas enhanced oil recovery will be advances in CO₂-miscible flooding and chemical flooding techniques. For miscible flooding, the advanced technology is modeled by improving the reservoir conformance through the application of polymer gels or 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, chemical retention, and lower costs thereby improving the recovery and economics of these relatively prolific processes. Additionally, the study assures substantial reductions in the associated risk of EOR processes modeled as a reduction in the minimum rate of return, or hurdle rate, required for project implementation. For advanced technology thermal recovery, the NPC modeled the effects of an improvement in the ability to inject steam at regular depths and into thinner, lower permeability reservoirs.

2. Production and Reserves

With technology advances, EOR could stimulate a substantial amount of incremental reserves over the applicable oil price range analyzed in this study (\$16/B to \$36/B). It is important to note here that technology advancements still do not lead to projects becoming economic at oil prices below \$20/B. Figure V-1 and Table V-1A show the comparison between the incremental EOR reserves generated through the application of advanced technology EOR processes and implemented technology EOR processes as discussed in Chapter III. The greatest increase in incremental reserves due to advanced technology could occur in the upper end of the analyzed price range, at oil prices of \$28/B and greater. Significant reserve additions could be attributable to advanced technology EOR at lower oil prices, however. At \$20/B, incremental reserves in the advanced case could reach 50 million barrels as chemical flooding becomes economic. In the \$28/B to \$32/B price range, the incremental reserves attributable to advanced technology EOR processes could be nearly five times greater than those for current EOR processes at each respective oil price considered. The 376 million barrels of potential incremental reserves at \$28/B could more than replace Kansas' 1991 proved reserves (300 million barrels).

Figure V-1

Incremental Reserves by EOR Process Implemented Technology vs. Advanced Technology

* No EOR projects were economic in analyzed reservoirs for oil prices below \$20/B.

The potential incremental reserves contributed by each of the advanced EOR processes considered in this analysis are also shown in Figure V-1. Under implemented technology, chemical flooding processes would not be economic at any of the oil prices analyzed. At \$20/B and \$24/B, chemical flooding could become economic under advanced technology, contributing up to 50 million barrels of incremental reserves. At oil prices of \$28/B and greater, advanced chemical flooding could become a major source of incremental reserves, accounting for 246 million barrels. With advances in technology, thermal recovery in Kansas could become economic at lower prices and could contribute twice the total thermal potential under implemented technology; over the \$24/B to \$36/B price range, advanced thermal EOR projects could account for between 39 million and 43 million barrels of incremental reserves. CO₂-miscible flooding could become slightly more proficient under advanced technology. At \$28/B, advances in CO₂-miscible flooding could add only 11 million barrels of incremental reserves to the implemented technology potential. At prices of \$32/B and \$36/B, the incremental reserves attributable to advances in CO₂-miscible recovery technology could total 12 million barrels, a 15% increase over

implemented technology. It is important to note here that although there is long-range potential for CO₂-miscible flooding, there is no easy supply of CO₂ in Kansas. This lack of an inexpensive CO₂ supply will remain an impediment to the future development of reservoirs with CO₂-miscible flooding potential in Kansas.

The number of economic 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. Chemical floods could become economic under advanced technology. Technology advancements could improve chemical flood project economics and increase their efficiency for application in Kansas reservoirs, resulting in a substantial number of new chemical floods and a large increase in incremental reserves (particularly at the higher oil prices analyzed). Technology advances in CO₂-miscible and thermal EOR processes could lead to some improvements in efficiency and project economics, but not to the degree seen in chemical processes.

Figure V-2 shows the expected annual EOR production for oil prices of \$24/B and \$32/B for both the implemented and advanced technology scenarios. At \$24/B, trends in annual production associated with advanced technology EOR would be very similar to those of implemented technology until the year 2015 when an advanced technology thermal EOR project is implemented. Production associated with advanced chemical EOR would not occur until after 2020. At \$32/B, advanced technology EOR production would not peak until between the years 2016 and 2020. Through the year 2010, however, production attributable to advances in technology could average 5.9 million barrels per year. Advanced technology could add over 10% of the state's 1991 level of production (56.9 million barrels per year).

3. Effects on State Revenues and Economic Activity

At most of the oil prices considered in this analysis, the direct revenues to the state of Kansas attributable to EOR could significantly increase with advanced technology (Figure V-3A). Similar to the implemented technology case, corporate income tax and sales tax receipts could contribute most of the potential increases in state revenue at oil prices of \$24/B and higher. At \$24/B, advances in technology could increase state revenues by \$88 million over implemented technology for a total potential of \$94 million. At \$28/B, the potential increases due to technology advances are more dramatic; \$311 million in additional state revenues could be generated by advances in technology, resulting in over \$385 million in total state and local revenues. If prices were to reach \$36/B, \$485 million in total state and local

Table V-1A

**Incremental Reserves from EOR by Process
Implemented Technology vs. Advanced Technology
(Million Barrels)**

Oil Price** (\$/B)	CO ₂ -Miscible		Chemical		Thermal		Total	
	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*
\$20	0	0	0	50	0	0	0	50
\$24	8	8	0	49	0	39	8	96
\$28	80	91	0	246	0	39	80	376
\$32	80	92	0	246	0	39	80	377
\$36	81	93	0	246	20	43	101	382

* This is the total reserves with advanced technology -- implemented technology plus the increment due to technology advances.

** Analyzed Kansas reservoirs did not exhibit potential at oil prices less than \$20/B.

Table V-1B

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

Oil Price** (\$/B)	CO ₂ -Miscible		Chemical		Thermal		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
\$20	0	0	0	2	0	0	0	2
\$24	1	1	0	2	0	1	1	4
\$28	3	3	0	6	0	1	3	10
\$32	3	3	0	6	0	1	3	10
\$36	3	3	0	6	1	1	4	10

** Analyzed Kansas reservoirs did not exhibit potential at oil prices less than \$20/B.

Figure V-2

Annual Production from EOR Reserves

Implemented Technology vs. Advanced Technology

A) At \$24/B

B) At \$32/B

revenues could be generated by EOR projects, 77% of which could be attributed to advances in technology.

Direct state economic activity generated by Kansas EOR could also increase under advanced technology conditions. The gain in economic benefits would be roughly proportional to the gain in reserves. Figure V-3B displays the total potential direct economic benefits to the state for both the implemented and advanced technology cases. The advanced technology distribution of total economic benefits among the contributing components would be similar to the trend shown for the implemented technology case. At \$20/B, all of the \$628 million in incremental state economic gain would be due to advanced EOR technology. At an oil price of \$24/B with advanced technology development, in-state economic activity could increase by over \$1.4 billion, reaching nearly \$1.6 billion in additional economic activity. At \$28/B, the \$5.4 billion of potential direct state-wide economic gain attributable to EOR technology advances would be almost four times the total potential under implemented technology. Clearly, the state of Kansas could accrue substantial benefits from the development and application of advanced EOR technology.

Production from EOR reserves could also create a substantial number of jobs under advanced technology at oil prices of \$24/B and \$32/B (not illustrated). At \$24/B, the number of jobs created or maintained under advanced technology EOR would be similar to the implemented technology potential. From the year 2015 to 2020, advances in technology could create or maintain an additional 97 jobs each year over implemented technology. While a significant portion (nearly 52%) of the additional jobs generated through advanced EOR production at \$32/B occur after 2011, substantial gains could be realized in the next 20 years. An average of over 234 additional jobs over implemented technology could be generated or maintained annually through the year 2010; in this time period, advanced technology EOR activities could generate or maintain an average of nearly 724 additional jobs yearly.

Figure V-3

State Impact of EOR Production

Implemented Technology vs. Advanced Technology

A) Direct State and Local Revenues

* No EOR projects were economic in analyzed reservoirs for oil prices below \$20/B

B) Direct State Economic Activity

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.

** No EOR projects were economic in analyzed reservoirs for oil prices below \$20/B

4. Effects on the National Economy and Budget

As discussed in Chapter III, increased oil recovery in the state of Kansas through EOR methods would significantly benefit the nation in the areas of enhanced energy security, import replacement, an improved foreign trade deficit, and expanded direct revenues to the Federal treasury. The potential benefits are even more pronounced with the development of advanced technology; up to 376 million barrels of crude oil could be added to proved reserves due to advanced EOR technology at \$28/B, 296 million barrels more than the incremental reserves estimated under the implemented case.

Under advanced technology, increased numbers of chemical floods are implemented, and it is assumed that operators use foams to increase the sweep efficiency of CO₂-miscible floods. Given the FY91 EOR tax credit, which provides a 15% credit for eligible EOR costs, it is conceivable that, with increased costs caused by utilization of these chemicals and foams, the total additional Federal revenues attributable to advanced technology could decrease. The results of this study demonstrate this potential scenario (Figure V-4A). As advanced technology projects are implemented at oil prices of \$20/B and \$24/B, the amount of the available tax credit could increase, resulting in negative corporate income tax payments (as tax credits are taken and used to offset profits from other operations). Increases in personal income tax revenues, however, could be larger, leading to net positive Federal income tax revenues. At \$28/B, the large increase in incremental reserves could result in positive corporate and personal income taxes, and substantial gains over implemented technology could be realized; \$280 million in additional direct Federal revenues attributable to EOR technology advances could be generated, for a total potential of \$302 million.

Technology advancements could also lead to a decrease in oil imports, due to increased oil production associated with these projects (Figure V-4B). To the extent that one barrel of domestically produced oil replaces one barrel of imported oil, the value of imports avoided due to technology advances could be substantial. At \$20/B, over \$1 billion in avoided imports could be generated, all of which could be attributed to technology advances in EOR processes. At an oil price of \$24/B, nearly \$2 billion of the total \$2.2 billion in imports avoided due to the application of advanced technology EOR would be attributable to technology advances. At oil prices above \$24/B, technology advances could quadruple the level of imports avoided. The potential import replacement at these prices (\$10.3 billion to \$13.6 billion) represents a not insignificant reduction in the foreign trade deficit.

Figure V-4

National Impact of EOR Production

Implemented Technology vs. Advanced Technology

A) Direct Federal Revenues

* No EOR projects were economic in analyzed reservoirs for oil prices below \$20/B.

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit.

** No EOR projects were economic in analyzed reservoirs for oil prices below \$20/B.

C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE

1. "Advanced" Technology Defined

The ASR 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 RD&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 ASR, 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 homogeneous and a less continuous heterogeneous 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 ASR reserve additions. Improved geologic characterization of the resource provides the basis for targeted infill drilling, which could significantly increase economic ASR 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 profile modification and polymer flooding projected under the implemented technology case whether they are applied alone or in combination with infill drilling. Additional benefits are estimated from the reduction of the associated risk (modeled as a reduction in hurdle rates with technology advances as discussed in Chapter III) of ASR processes as currently implemented.

2. Production and Reserves

The development of advanced technology ASR methods through RD&D could increase the state's oil reserves. The incremental reserves from advanced technology ASR could range from 385 million to 443 million barrels in the analyzed Kansas reservoirs, 6% to 8% greater than the incremental reserves generated under implemented technology across the oil prices considered (Figure V-5). Incremental reserves could be substantial at lower prices, 385 million barrels and 398 million barrels at \$16/B and \$20/B, respectively. The potential at \$20/B is almost 90% of the total potential at \$36/B. At all oil prices considered in this study, advances in technology could account for 27 million to 29 million in potential incremental reserves over implemented technology ASR. Despite the relatively low growth in incremental reserves as the price of oil increases, the total reserves from advanced technology ASR could be substantial. The 439 million barrels of potential reserves at \$28/B would be 46% greater than Kansas' 1991 proved reserves (300 million barrels).

Table V-2A shows the distribution of the incremental reserves by ASR process. Infill drilling in combination with profile modification or polymer flooding could be the most prolific advanced technology ASR method, contributing over 94% of total potential incremental reserves. Practically all of the increases over implemented technology potential could be attributed to the combination process. These increases could be caused by advances in the polymers and gels used and by an improved understanding of reservoir architecture and the nature of heterogeneity which 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 improve. 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 previously noted, the competition of profile modification, polymer flooding, and infill drilling applied alone with the more prolific combination processes limits the contribution of these processes.

Table V-2B shows the estimated number of economic ASR projects for both the implemented and advanced technology cases. At all oil prices considered, the number of infill drilling projects could decrease with the implementation of advanced ASR techniques. This indicates that the efficiency and economics of polymer flooding and profile modification could be significantly improved with advances in technology. The maintenance of reserve levels despite the decrease in projects emphasizes the effectiveness of targeting infill wells to the more prolific portions of the reservoir. Advanced technology

Figure V-5

Incremental Reserves by ASR Process Implemented Technology vs. Advanced Technology

could have a much larger impact on the number of combination projects and on the number of profile modification and polymer flooding projects that could become economic. For combination projects, the efficiency and economics of most projects are favorably improved by advanced technology because of advances in the polymers, gels, and foams used and because of 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 profile modification and polymer flooding projects could increase significantly from the implemented case. 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 and economically amenable to the application of chemical treatment processes.

Figure V-6 displays the projected annual production that could result from ASR technology advances at oil prices of \$16/B and \$32/B from the analyzed Kansas reservoirs. In both cases, a significant amount of oil could be added to the state's production over the next 25 years. As discussed

Table V-2A

**Incremental Reserves from ASR by Process
Implemented Technology vs. Advanced Technology
(Million Barrels)**

Oil Price (\$/B)	Polymer Flooding and Profile Modification		Infill Drilling		Infill Drilling and Polymer Flooding or Profile Modification		Total	
	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*
\$16	3	4	11	9	343	372	357	385
\$20	4	5	14	13	353	380	371	398
\$24	5	6	14	13	384	413	403	432
\$28	5	6	19	16	388	417	412	439
\$32	5	6	20	17	387	416	412	439
\$36	5	7	22	17	388	419	415	443

* This is the total reserves with advanced technology -- implemented technology plus the increment due to technology advances.

Table V-2B

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

Oil Price (\$/B)	Polymer Flooding and Profile Modification		Infill Drilling		Infill Drilling and Polymer Flooding or Profile Modification		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
\$16	2	4	3	1	11	15	16	20
\$20	3	5	4	2	12	16	19	23
\$24	3	5	4	2	13	19	20	26
\$28	3	5	5	2	14	19	22	26
\$32	3	5	5	3	14	19	22	27
\$36	3	5	6	3	14	19	23	27

Figure V-6

Annual Production from ASR Reserves

Implemented Technology vs. Advanced Technology

A) At \$16/B

B) At \$32/B

in Chapter III, annual production from ASR has been determined in this study as a function of rig availability and technology transfer. As a result, some fields will be abandoned before ASR can be implemented. The timing assumptions also lead to production increases after the year 2000 as advanced technology is phased in and increasing numbers of reservoirs reach their economic limit under conventional recovery. Under advanced technology, there is a time delay as RD&D is performed; 25% of the potential resource could be abandoned before advanced technology ASR can be implemented.

At \$16/B, annual production from advanced ASR reserves could peak in the year 2016 at 12.2 million barrels per year. From the year 2000 to 2010, technology advances could account for just over 3% of the 6.9 million barrels per year average. From the year 2011 to 2020, advances in technology could add an average of 750,000 barrels per year to implemented technology potential for a total of 11.3 million barrels per year. At \$32/B, advanced technology ASR could produce an average of 7.9 million barrels per year from the year 2000 to 2010. Annual production could peak in the years 2015 and 2016 at 13.9 million barrels per year, 24% of Kansas's 1991 annual production rate (56.9 million barrels per year).

3. Effects on State Revenues and Economic Activity

Under advanced technology, Kansas could receive over \$820 million in total additional revenues from production taxes and oil industry-related corporate income and sales taxes from ASR if oil prices reach \$36/B (Figure V-7A). As under the implemented technology case, the revenue accrued under the advanced technology case would mostly be generated from corporate income taxes; these taxes could account for over 79% of the additional direct state tax revenues over the analyzed price range. At an oil price of \$20/B, additional state and local revenues attributable to technology advances would be 7% of the \$408 million in total potential state and local revenues. At a \$28/B oil price, additional state and revenues from ASR projects could reach \$635 million, over 5% of which would be attributable to technology advances.

In addition to the increases in state and local revenues, Kansas would benefit from increased economic activity. At \$20/B, advances in ASR technology could add up to \$234 million in economic activity over the implemented technology potential, for a total of \$3.4 billion. At \$28/B, advanced technology could increase implemented technology potential by over \$288 million, resulting in a \$5.1 billion potential increase in state economic activity. Figure V-7B displays the components of this increase. Non-injectant operating costs from ASR projects could make the most substantial contribution to the

Figure V-7

State Impact of ASR Production

Implemented Technology vs. Advanced Technology

A) Direct State and Local Revenues

B) Direct State Economic Activity

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.

state's economic activity, accounting for around 30% to 37% of total activity. Intangible investments and royalties could make roughly equal contributions (23% to 32%), with direct state taxes comprising the remainder.

Annual production of advanced ASR reserves could also create or maintain a substantial number of jobs. Over the period from the year 2011 to 2020, at an oil price of \$16/B, a yearly average of greater than 275 jobs per year could be generated or maintained under the advanced technology case (not illustrated). At \$32/B, an average of 271 jobs could be generated or maintained each year under advanced technology from the year 2000 to 2010. The number of jobs created or maintained could average 443 jobs annually from the year 2011 to 2020. These jobs, and the associated wages, are a source of additional economic stimulus for the state economy.

4. Effects on the National Economy and Budget

The development of advanced technology for the recovery of the known UMO resource in Kansas could also benefit the nation. Figure V-8A shows a 6% to 7% increase over implemented technology in the incremental revenues to the Federal treasury from personal and corporate income taxes due to advanced technology ASR. Advances in ASR technology at \$20/B could add nearly \$100 million to the potential Federal revenues under implemented technology for a total of \$1.4 billion. At an oil price of \$28/B, \$132 million of the \$2.2 billion in additional Federal revenues could be attributed to advances in technology.

As discussed in the previous chapter, the nation would also benefit from increased ASR in Kansas through enhanced energy independence and security as the domestic resource base expands. Each barrel of reserves added through advanced ASR techniques in Kansas could replace a barrel of imported oil and reduce the nation's trade deficit. At \$20/B, application of advanced technology could increase in imports avoided from \$7.3 billion under implemented technology to \$7.8 billion. At \$28/B, technology advances could generate over \$753 million in imports avoided, for a total potential of over \$12 billion (Figure V-8B).

Figure V-8

National Impact of ASR Production

Implemented Technology vs. Advanced Technology

A) Direct Federal Revenues

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit.

D. CONCLUSIONS

As discussed in Chapter IV, currently available EOR and ASR technologies have the potential to increase reserves and provide economic benefits to operators, the states, and the nation. An aggressive and efficient technology transfer program in both the public and private sectors would bring these available technologies to operators and expedite their field application.

Advances in technology could significantly increase the potential incremental reserves and associated economic benefits which are possible using implemented technology EOR and ASR. At an oil price of \$20/B, implemented technology EOR and ASR process could contribute over 370 million barrels to the Kansas reserves base. At \$28/B, potential incremental reserves could reach over 490 million barrels. Technology advances could increase potential incremental reserves by over 20%, adding 80 million barrels of incremental reserves at an oil price of \$20/B. The total potential reserves at this price, nearly 450 million barrels, is one and one-half times Kansas' 1991 proved reserves. At an oil price of \$28/B, technology advances could add over 325 million barrels of incremental reserves for a total EOR and ASR reserve potential of 815 million barrels. If this potential were to be realized, advanced technology EOR and ASR would nearly triple Kansas' 1991 proved reserves.

The activities associated with advanced technology EOR and ASR could generate substantial direct state and local tax revenues. At \$20/B, \$80 million of the \$460 million of potential state and local revenues could be attributed to technology advances. At an oil price of \$28/B, over 35% (\$340 million) of the \$1 billion in total potential state and local revenues could be due to advances in technology.

The potential benefits estimated in this analysis will not be possible, however, without effective technology transfer and RD&D programs. Aggressive technology transfer needs to be undertaken by all oil-related entities (operators, producer associations, research universities, state geologic surveys, and state and Federal government agencies) in order to ensure that currently available technologies are disseminated in the oil producing community and widely applied in the field. The significant additional benefits derived from technology advances clearly warrant a focused RD&D program to improve advanced oil recovery technologies.

A collaborative effort between the public and private sectors is essential to pool resources and expertise while leveraging risk. Operators, oil companies, research universities, and state geologic surveys

need to join with state and local governments and the Federal government to identify the highest priority problems in reservoirs with the largest remaining resources and the greatest threat of abandonment. A focused RD&D effort targeting the identified problems then needs to be undertaken. An RD&D effort alone is not enough, however; the newly developed technologies need to be transferred to the field for wide-scale demonstration and application. The U.S. Department of Energy's program of cost-shared technology demonstrations implemented through the Program Opportunity Notice (PON) process is currently applying some of these concepts. The PON process targets those classes of reservoirs with the largest potential resource and greatest threat of abandonments. Near- and mid-term RD&D efforts, jointly funded by the Federal government and private industry, are directed towards the producing problems of these reservoirs. The results, once successfully developed and demonstrated, are to be transferred to other operators facing similar producing conditions. While they are an important beginning, efforts like the PON process are not enough. A more aggressive and focused collaborative RD&D effort can significantly increase domestic production, enhance national energy security, reduce imports, and increase economic benefits associated with oil recovery.

Even after application of advanced technology EOR and ASR, large portions of the Kansas oil resource will remain unrecovered in the analyzed reservoirs (Figure V-9). At the improbably high oil price of \$36/B, total ASR reserves potential would be 380 million barrels, while EOR reserves potential would total 430 million barrels. Even if this reserves potential were realized, 1.2 billion barrels of mobile oil (75% of the mobile oil target) and 5.3 billion barrels of immobile oil (93% of the immobile oil target) would remain in the analyzed Kansas reservoirs. In addition, over 5.1 billion barrels of remaining oil not included in this analysis, and any newly discovered oil, would still be unrecovered after application of advanced technology EOR and ASR. This remaining resource of nearly 12 billion barrels is the target for further advances in EOR and ASR technologies.

Figure V-9

Kansas Remaining Oil Resource After Advanced Technology Recovery

DOE/BC/14431-1 (Vol. 5)
Distribution Category UC-122

AN EVALUATION OF KNOWN REMAINING
OIL RESOURCES IN THE STATE OF ILLINOIS

Project on Advanced Oil Recovery and the States

Volume V

November 1994

Work Performed Under Contract DE-FG22-89BC14431

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

R. Michael Ray, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Interstate Oil Compact Commission
900 N.E. 23rd Street
Oklahoma City, OK 73152

TABLE OF CONTENTS

	<u>Page</u>
LIST OF FIGURES	v
LIST OF TABLES	vii
ACKNOWLEDGEMENTS	viii
EXECUTIVE SUMMARY	ix
 I. OVERVIEW	
A. THE PROBLEM: DECLINING ILLINOIS OIL PRODUCTION	I-1
B. THE OPPORTUNITY: OIL RECOVERY THROUGH ADVANCED TECHNOLOGY	I-4
C. BENEFITS DERIVED FROM IMPROVED OIL RECOVERY	I-5
D. CONCLUSIONS	I-10
 II. BACKGROUND AND OBJECTIVES	
A. TRENDS IN ILLINOIS OIL PRODUCTION AND RESERVES	II-1
B. IMPROVED RECOVERY ACTIVITIES TARGETING THE REMAINING RESOURCE	II-7
1. Enhanced Oil Recovery	II-7
2. Advanced Secondary Recovery	II-8
C. OBJECTIVES OF THE PRESENT STUDY	II-11
 III. APPROACH TO THE ANALYSIS	
A. INTRODUCTION	III-1
B. GENERAL METHODOLOGY: THE NPC BASIS	III-1
C. BUILDING ON TORIS: THE EVALUATION OF UNRECOVERED MOBILE OIL RESOURCES	III-6
D. SCOPE OF THE ANALYSIS	III-9
E. ADAPTATIONS FOR THE PRESENT STUDY	III-11
1. Data Editing and Additions	III-11
2. State and Federal Taxes	III-11
3. Cost and Price Data	III-12
4. Benefits Estimation	III-13
5. Project Timing	III-13

TABLE OF CONTENTS (continued)

	<u>Page</u>
F. ESTIMATION OF BENEFITS, COSTS, AND ECONOMIC IMPACTS	III-14
1. Benefits to State and Local Treasuries	III-15
2. Direct State Economic Effects	III-15
3. National Effects	III-16
G. LIMITATIONS TO THE ANALYTICAL APPROACH	III-18
 IV. INCREASED RECOVERY FROM THE KNOWN REMAINING OIL RESOURCE IN ILLINOIS UNDER IMPLEMENTED TECHNOLOGY	
A. INTRODUCTION	IV-1
B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE	IV-1
1. Production and Reserves	IV-1
2. Increases in State and Local Revenues	IV-2
3. Effects on the State Economy	IV-2
4. Effects on the National Economy and Budget	IV-3
C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE	IV-5
1. Production and Reserves	IV-5
2. Increases in State and Local Revenues	IV-6
3. Effects on the State Economy	IV-9
4. Effects on the National Economy and Budget	IV-11
D. CONCLUSIONS	IV-11
 V. BENEFITS OF INCREASED RECOVERY FROM THE KNOWN REMAINING OIL RESOURCE IN ILLINOIS WITH TECHNOLOGY ADVANCES	
A. INTRODUCTION	V-1
B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE	V-1
1. "Advanced" Technology Defined	V-1
2. Production and Reserves	V-2
3. Effects on State Revenues and Economic Activity	V-5
4. Effects on the National Economy and Budget	V-8
C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE	V-9
1. "Advanced" Technology Defined	V-9
2. Production and Reserves	V-11
3. Effects on State Revenues and Economic Activity	V-12
4. Effects on the National Economy and Budget	V-15
D. CONCLUSIONS	V-18

LIST OF FIGURES

<u>Figure</u>		<u>Page</u>
I-1	Known Illinois Oil Resource	I-1
I-2	Illinois Production and Reserves	I-3
I-3	Illinois Oil Resource Data Coverage of EOR and ASR Analyses	I-6
I-4	Potential Impact of Advanced Technology	I-8
I-5	Illinois Remaining Oil Resource After Advanced Technology Recovery	I-11
II-1	Illinois Crude Oil Production (1950-1991)	II-2
II-2	Illinois Crude Oil Reserves (1950-1991)	II-2
II-3	Illinois Producing Wells (1960-1991)	II-4
II-4	Illinois Stripper Well Production and Abandonments (1970-1990)	II-4
II-5	Total Oil and Gas Employment in Illinois (1970-1991)	II-5
II-6	Annual Wellhead Value of Illinois Oil and Gas Production (1961-1991)	II-5
II-7	Illinois Oil Resource	II-6
II-8	Illinois Remaining Oil Resource After Conventional Recovery Operations	II-12
IV-1	Direct State and Local Revenues from EOR Production Implemented Technology	IV-3
IV-2	Direct State Economic Activity Implemented Technology	IV-4
IV-3	Jobs and Wages from EOR Production Implemented Technology	IV-4
IV-4	Reserves and Production Response from ASR Techniques Implemented Technology	IV-8
IV-5	Direct State and Local Revenues from ASR Production Implemented Technology	IV-9
IV-6	Direct State Economic Activity Implemented Technology	IV-10
IV-7	Jobs and Wages from ASR Production Implemented Technology	IV-10
IV-8	National Impact of ASR Production Implemented Technology	IV-12
IV-9	Illinois Remaining Oil Resource After Implemented Technology Recovery ...	IV-14
V-1	Incremental Reserves by EOR Process Implemented Technology vs. Advanced Technology	V-3
V-2	Annual Production from EOR Implemented Technology vs. Advanced Technology	V-6
V-3	State Impact of EOR Production Implemented Technology vs. Advanced Technology	V-7

LIST OF FIGURES (Continued)

<u>Figure</u>		<u>Page</u>
V-4	National Impact of EOR Production Implemented Technology vs. Advanced Technology	V-10
V-5	Incremental Reserves by ASR Process Implemented Technology vs. Advanced Technology	V-12
V-6	Annual Production from ASR Implemented Technology vs. Advanced Technology	V-14
V-7	State Impact of ASR Production Implemented Technology vs. Advanced Technology	V-16
V-8	National Impact of ASR Production Implemented Technology vs. Advanced Technology	V-17
V-9	Illinois Remaining Oil Resource After Advanced Technology Recovery	V-20

LIST OF TABLES

<u>Table</u>	<u>Page</u>
I-1	Summary of Benefits from Technology Advances in EOR and ASR in Illinois I-9
III-1	Key Elements in the Current TORIS Reservoir Data Base III-3
III-2	Screening Criteria for EOR Candidates - Implemented Technology Case III-4
III-3	Screening Criteria for EOR Candidates - Advanced Technology Case III-5
III-4	Screening Criteria for Advanced Secondary Recovery Processes III-8
III-5	Screening and Approach for Advanced Technology Infill Drilling III-9
III-6	Risk Premium for Implemented and Advanced EOR and ASR Processes III-10
III-7	Labor and Materials as Percentage of Total Cost In EOR Projects III-17
IV-1A	Incremental Reserves from ASR by Process Implemented Technology IV-7
IV-1B	Estimated Number of Economic ASR Projects by Process Implemented Technology IV-7
V-1A	Incremental Reserves from EOR by Process Implemented Technology vs. Advanced Technology V-4
V-1B	Estimated Number of Economic EOR Projects by Process Implemented Technology vs. Advanced Technology V-4
V-2A	Incremental Reserves from ASR by Process Implemented Technology vs. Advanced Technology V-13
V-2B	Estimated Number of Economic ASR Projects By Process Implemented Technology vs. Advanced Technology V-13

ACKNOWLEDGMENTS

An Evaluation of the Known Remaining Oil Resource in the State of Illinois is one in a series of reports of the Project on Advanced Oil Recovery and the States, conducted by the Interstate Oil and Gas Compact Commission (IOGCC). The overall project was initiated by "seed money" grants from the States of Oklahoma and New Mexico in 1985. This report was prepared under grant number FG22-89BC14431 from the U.S. Department of Energy, Bartlesville Project Office (BPO) to the IOGCC.

The analysis presented in this report is based on an updated and upgraded version of the databases and models developed by the National Petroleum Council (NPC) in 1984. 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 C. Wesson, BPO Director, for his encouragement and assistance.

Special recognition is due to those who directly performed the work of the project. ICF Resources Incorporated of Fairfax, Virginia, served as the IOGCC's principal contractor, responsible for the study design, computer modeling, analysis, interpretation, and report preparation. ICF's Project Director was Dr. Jerry P. Brashear; Mr. Khosrow Biglarbigi was the Project Manager; and the critical project staff included Mr. Hugh D. Guinn, and Mr. Donald J. Remson (engineering and computer modeling); Mr. Karl Lang, Dr. Frank Morra (Consultant), and Mr. Jeff Enright (analysis and report generation); Mr. Marc Greenberg, Ms. Sohinaz Sotoudeh, Mr. Mike Schildkraut and Mr. Sid Choudhury (editing, research, and analytical support); Mr. Alan B. Becker (Final Review); Ms. Barbara Jones (Administrative Assistant), Ms. Cheryl A. Labrecque (Senior Staff Assistant), Ms. Mary Bowers (Staff Assistant) and Ms. Barbara Gillen (word processing support).

Special recognition is also due to the members of the DOE/IOGCC Peer Review Committee; Mr. Lloyd Elkins, Dr. Alan Emanuel, Dr. Lee Gerhard, Dr. Donald Green, Dr. John D. Haun, Mr. Joseph E. King, Dr. Charles Mankin, Dr. David Martin, Dr. Donald Oltz, Dr. Fred H. Poettmann, Mr. William C. Stewart, and Dr. G. Paul Willhite.

This analysis was conceived and commissioned by W. Timothy Dowd, Executive Director of the IOGCC through June 1993. Mr. Dowd's keen interest in promoting the development of the nation's resource base has been the guiding force behind this study. To the degree that the results of this work help to improve the recovery of oil from U.S. reservoirs, Mr. Dowd's goals for the IOGCC will have been furthered. Mr. Bob Cooper, former Associate Director of the IOGCC, and Mr. Jerry Simmons (Associate Director) provided liaison and coordination among the participating organizations.

While acknowledging the assistance of all these contributors, error of fact, analysis, or interpretation are the responsibility of the IOGCC and the principal contractor's project director.

Christine Hansen
Executive Director
November 1993

EXECUTIVE SUMMARY

The Interstate Oil and Gas Compact Commission (IOGCC) has conducted a series of studies to evaluate the known, remaining oil resource in twenty-three (23) states. The primary objective of the IOGCC's effort is to examine the potential impact of an aggressive and focused program of research, development, and demonstration (RD&D) and technology transfer on future oil recovery in the United States. As a part of this larger effort by the IOGCC, this report focuses on the potential economic benefits of improved oil recovery in the state of Illinois. Individual reports for seven other oil producing states and a national report have been separately published by the IOGCC. Several major technical insights for state and Federal policymakers and regulators can be reached from this analysis.

- At the conclusion of conventional recovery operations, three-fifths of the known original-oil-in-place will remain in Illinois oil reservoirs.
- The remaining resource, over 5.6 billion barrels, is the target for future improved oil recovery techniques. However, a significant portion of this remaining oil resource has already been abandoned. An even greater portion is in imminent danger of abandonment if cost-effective and efficient recovery techniques are not applied.
- Resource abandonment will significantly impact the economic producibility of future production and reserves under improved oil recovery techniques. Major capital investments will be required to reacquire the leases, rebuild the infrastructure, and more importantly, drill new wells to regain access to the Illinois target resource.
- Illinois' future oil production depends on the development of efficient and cost-effective oil recovery technologies, technology transfer to domestic producers, and the timely and successful application of such technologies, given the steady decline in Illinois production and reserves and the accelerating level of well abandonment over the past decade.
- The effective transfer of existing technology could result in 60 to 70 million barrels of new reserves from analyzed Illinois reservoirs at oil prices ranging from \$20/B to \$28/B, potentially increasing the state's current proved reserves by 50%.
- Technology advances resulting from a focused RD&D effort could result in *additional* post-conventional reserves of 15 to 70 million barrels. The effective transfer of existing technology, coupled with the development and application of new technologies, could more than replace current proved reserves in Illinois.
- Public sector revenues from future improved oil recovery activity would total between \$160 and \$320 million, given currently available recovery practices and oil prices of \$20/B to \$28/B. Technology advances could increase these totals by \$40 to \$190 million over the same price range, with roughly 50% of the total flowing to the state treasury.
- Potential improved oil recovery would replace imports of foreign oil, keeping between \$1 billion and \$2 billion in the U.S. economy. This figure is only the direct cost of imports

avoided due to increased domestic activity. The true value to the country is actually much higher due to multiplier effects as this money circulates in the economy.

The analysis presented in this report is based on the databases and models available in the Tertiary Oil Recovery Information System (TORIS). TORIS is a tested and verified system, maintained and operated by the Department of Energy's Bartlesville Project Office. The TORIS system was used to evaluate 54 major Illinois reservoirs in a consistent manner and on an individual basis, the results of which have been aggregated to arrive at the statewide total.

Overall, well abandonments and more stringent environmental regulations could limit economic access to Illinois' known, remaining oil resource. The high risk of near-term abandonment and the significant benefits of future application of improved oil recovery technology, clearly point to a need for more aggressive transfer of currently available technologies to oil producers. Development and application of advanced oil recovery technologies could have even greater benefits to the state and the nation. A collaborative, focused RD&D effort, integrating the resources and expertise of industry, state and local governments, and the Federal government, is clearly warranted. With effective RD&D and a program of aggressive technology transfer to widely disseminate its results, Illinois oil production could be maximized. The resulting increase in production rates, employment, operator profits, state and Federal tax revenues, and energy security will benefit both the state of Illinois and the nation as a whole.

I. OVERVIEW

A. THE PROBLEM: DECLINING ILLINOIS OIL PRODUCTION

Over three-fifths of the oil discovered in the state of Illinois will remain trapped in the reservoir at the conclusion of conventional oil recovery operations. The total known original oil-in-place in Illinois has been estimated at nearly 9.2 billion barrels (Figure I-1). Almost 3.4 billion barrels had already been produced at the end of 1991. Nearly 130 million barrels of proved reserves are still producible under existing economic conditions, using currently available technologies. The remaining 5.6 billion barrels is the target for newer, more efficient recovery technologies and advances in geoscientific understanding that must be developed through an integrated public and private research effort.

Figure I-1

Known Illinois Oil Resource

The urgency for technology development and its effective application by Illinois oil producers has never been greater. The two factors that have combined to make technology development critical are:

- Declining state production and reserves. Illinois oil production has declined by 75% from 1962 through 1991 (Figure I-2A). Crude oil reserves decreased by roughly the same percentage over the same time period (Figure I-2B). Although this decline has leveled off over the past 20 years, reserve additions have not been sufficient to replace production volume. The average size of new field discoveries has been relatively small and reserves per well have decreased.
- Increased level of well abandonment. The state of Illinois currently produces oil from roughly 33,000 wells. Many of these wells are "marginal" wells producing at or near their economic limit. In a period of high production costs and low oil price, many of these wells are being abandoned. A recent analysis by the Department of Energy (DOE) has concluded that from 37% to 45% of the nation's remaining oil resources had been abandoned by the end of 1991.¹ Well abandonments will have a significant impact on economic access to the remaining resource for application of future improved recovery techniques. It is estimated that once a lease is abandoned, it will require an oil price *increase* of \$10/B to \$25/B to rebuild the infrastructure and drill replacement wells.² Such an economic burden will not likely be justified by the incremental oil revenues from future improved recovery techniques.

The future of Illinois oil production and reserves depends strongly on the development and application of cost-effective and efficient technology. In the past, technology advances have made substantial contributions to Illinois oil production. The development of new exploration techniques and secondary recovery technology has acted to reverse past production declines and has allowed Illinois to maintain and increase its producible oil and gas resources. Oil producers in the state of Illinois have also pioneered significant developments in enhanced oil recovery technology, particularly in the case of chemical flooding and improved waterflooding techniques. The opportunity exists for a program of research, development and demonstration (RD&D), combined with an integrated program of technology transfer to all sectors of the Illinois petroleum community, to arrest the decline in production and maximize recovery of the state's oil resource.

¹ "Abandonment Rate of the Known Domestic Oil Resource", U.S. DOE, Bartlesville Project Office, Bartlesville, OK (June 1990).

² Brashear, J.P. et al. "Effect of Well Abandonments on EOR Potential," JPT, December 1991.

Figure I-2

Illinois Production and Reserves

A) Annual Production

B) Reserves

B. THE OPPORTUNITY: OIL RECOVERY THROUGH ADVANCED TECHNOLOGY

The remaining oil resource constitutes a large target for future recovery operations. The 5.6 billion barrels of known unrecovered oil in the state of Illinois is of two types: mobile oil and immobile oil. Even though mobile oil is displaceable by water, it has been uncontacted or bypassed during conventional primary production or water flooding and thus remains unrecovered. Immobile oil is trapped in the reservoir pores by viscous and capillary forces and cannot be displaced by water.

The estimated unrecovered mobile oil (UMO) resource in Illinois is 1.3 billion barrels. This oil is an important target for future improved recovery efforts. Several improved primary and secondary recovery processes (infill drilling, profile modification, and polymer flooding), collectively referred to as advanced secondary recovery (ASR), could be used in innovative ways to produce a substantial portion of this resource. These processes are relatively low in cost and could increase production levels quickly. While such techniques have already been used by some operators in selected reservoirs, continued research and aggressive technology transfer are critically needed to improve, streamline, and adapt these techniques to site-specific reservoir conditions and broaden their applications.

The 4.3 billion barrels of remaining immobile oil in Illinois is the target of a number of other recovery techniques. Miscible, chemical, and thermal recovery processes directed at producing immobile oil are referred to as enhanced oil recovery (EOR). While these processes generally require larger investments and higher operating costs than conventional recovery operations, they are capable of producing substantial volumes of incremental oil with significant economic benefits. Further advances in EOR technology are foreseeable if a focused, research-intensive approach is adopted to make process improvements ready for field application.

Technology Assessment Method

This assessment of the benefits of RD&D in oil recovery technology is based on the models and databases available through the Tertiary Oil Recovery Information System (TORIS). The TORIS methodology and analytical tools were originally developed by the National Petroleum Council (NPC)³ for its 1984 evaluation of nationwide EOR potential. DOE has since maintained and updated the system

³ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

through its Bartlesville Project Office (BPO).⁴ DOE has also upgraded the capability of the system to evaluate the nation's unrecovered mobile oil by modeling ASR processes. In this report, the future potential of EOR and ASR techniques are examined with the following key assumptions and considerations:

- A total of 54 Illinois reservoirs, accounting for 5.6 billion barrels (60%) of the known original oil-in-place in the state, were individually analyzed for their EOR and ASR potential (Figure I-3). No attempt is made to extrapolate the results to the remaining Illinois resource not available in the TORIS database.
- Two levels of technology are considered: (1) implemented technology -- defined as the application of currently available post-conventional techniques; and (2) advanced technology -- defined as the improvements in process performance and applicability which are likely to occur over the next decade as the result of ongoing RD&D efforts.
- For each technology level, benefits were evaluated at several oil prices ranging from \$16/B to \$36/B (1991 dollars).
- All economic analyses reflect the current Illinois and Federal tax structures. The FY 1991 Federal EOR tax credit is included in this analysis.
- The recovery potential evaluated in this report is for future new projects only and does not include incremental reserves from existing EOR projects. However, the expansions to the existing projects, if technically and economically feasible, are evaluated as part of future new projects.

C. BENEFITS DERIVED FROM IMPROVED OIL RECOVERY

Potential incremental reserves and resulting direct state and local revenues that could be generated through improved oil recovery (EOR and ASR) techniques under both the implemented and advanced technology cases are shown in Figure I-4. Implemented technology, if more widely applied, could add between 12 and 71 million barrels of incremental reserves across the entire oil price range. Advanced technology applied to the same resource base could stimulate an additional 49 to 72 million barrels of incremental resources for a total of 61 to 143 million barrels beyond currently proven reserves. In effect, improvements in process performance and application could more than double the reserves possible under implemented technology conditions. This clearly provides a major justification for a focused RD&D and technology transfer program.

⁴ *Producing Unrecovered Mobile Oil: Evaluation of Potential Economically Recoverable Reserves in Texas, Oklahoma, and New Mexico*, DOE, May 1990.

Figure I-3

Illinois Oil Resource

Data Coverage of EOR and ASR Analyses

Source: BPO TORIS, 1992
EIA, 1992
API/AGA, 1980

The potential for expanded application of EOR techniques using implemented technology is limited, only about 11 million barrels across the entire oil price range. Advances in EOR technology could stimulate an additional 60 million barrels of incremental reserves at higher oil prices. This means that over 70 million barrels of potential incremental reserves from EOR exists under the two levels of technology for the analyzed reservoirs.

Reserve additions attributed to ASR techniques are impacted much less by oil price changes than EOR. About 60 million barrels of ASR reserves could be added in the implemented technology case at oil prices of \$20/B to \$36/B. Research on process improvements, specifically improved polymer flooding and profile modification combined with geologically targeted infill drilling, could increase ASR potential by 20%. With advances in technology, incremental ASR reserves could total about 12 to 14 million barrels more than implemented technology over the price range analyzed, for a total of 70 million barrels of potential ASR reserves.

Future improved oil recovery activities will generate revenues for Illinois and the Federal treasury through increased state corporate and personal income 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 or national economy. Under implemented technology at \$20/B, newly implemented improved oil recovery projects in Illinois could directly generate \$48 million in state revenues. At the same oil price, advanced technology could generate an additional \$18 million, for a total of \$66 million in state revenues (Figure I-4). At an oil price of \$28/B, application of currently available EOR and ASR technology could contribute \$87 million to the Illinois public treasury while the application of advanced methods could increase these revenues by an additional \$119 million to a total of \$206 million.

Increased production from EOR and ASR could offset oil imports, which in turn, would reduce the national trade deficit, and increase national economic activity. The value of the oil produced, the product of reserves and their effective wellhead oil price, is a simple measure of Illinois' contribution to reducing the trade deficit. As shown in Table I-1, this figure could total between \$1.1 billion and \$2.0 billion under the implemented technology scenario, over the \$20/B to \$28/B range. Advanced technology could further decrease imports by an *additional* \$0.3 billion to \$2.0 billion. The additional value of domestically produced EOR and ASR generates significant direct economic activities as capital spending, profits, royalties, and taxes are circulated through the U.S. economy rather than exported to buy foreign oil.

Figure I-4

Potential Impact of Advanced Technology

A) Reserve Additions

B) Direct State and Local Revenues

Table I-1

**Summary of Benefits from Technology Advances
in EOR and ASR in Illinois**

Oil Price and Technology Level	Potential Reserves (Million Barrels)	Incremental State and Local Revenues (\$ Millions)	Incremental Imports Avoided** (\$ Millions)	Increased Federal Revenues (\$ Millions)
<u>At \$16/B</u>				
Implemented Technology	12	10	193	24
<u>Advanced Technology*</u>	<u>49</u>	<u>35</u>	<u>781</u>	<u>38</u>
Total	61	45	974	62
<u>At \$20/B</u>				
Implemented Technology	56	48	1,108	111
<u>Advanced Technology*</u>	<u>14</u>	<u>18</u>	<u>287</u>	<u>21</u>
Total	70	66	1,395	132
<u>At \$24/B</u>				
Implemented Technology	69	70	1,638	167
<u>Advanced Technology*</u>	<u>29</u>	<u>37</u>	<u>723</u>	<u>30</u>
Total	98	107	2,361	197
<u>At \$28/B</u>				
Implemented Technology	71	87	1,978	234
<u>Advanced Technology*</u>	<u>71</u>	<u>119</u>	<u>1,979</u>	<u>67</u>
Total	142	206	3,957	301
<u>At \$32/B</u>				
Implemented Technology	71	99	2,266	311
<u>Advanced Technology*</u>	<u>65</u>	<u>118</u>	<u>2,085</u>	<u>195</u>
Total	136	217	4,351	506
<u>At \$36/B</u>				
Implemented Technology	71	113	2,598	382
<u>Advanced Technology*</u>	<u>72</u>	<u>145</u>	<u>2,539</u>	<u>306</u>
Total	143	258	5,137	688

*Advanced is incremental over implemented technology.

**Imports Avoided = Reserves times effective wellhead price; to the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided estimates the reduction in foreign trade deficit.

D. CONCLUSIONS

The development, testing, and wide-scale application of currently available improved oil recovery technologies could stimulate incremental reserves ranging from 12 million to nearly 70 million barrels from the state of Illinois' largest, most mature reservoirs at oil prices of \$16/B to \$24/B. With the technology advances resulting from focused RD&D, an additional 30 million barrels to nearly 50 million barrels could be produced over this price range using EOR and ASR techniques. Even with the successful development and application of these technologies, however, about 2.6 billion barrels of immobile oil would still remain in the analyzed reservoirs as a long-term target for future advances in EOR, and 0.7 billion barrels of mobile oil would remain as a long-term target for future advances in ASR processes (Figure I-5). While this target is substantial, it is not indefinite. Well abandonments have already limited economic access to a portion of the resource. The timely development and application of new recovery technology is crucial to maintain economic access to the remaining domestic oil resource.

The results of this analysis have important policy implications. Domestic oil production generates significant direct revenues to Illinois and to the Federal government and substantial additional indirect benefits to both the state and national economies. In addition to stimulating reserves, production, and economic activity, the application of improved oil technology would enhance the nation's energy security. However, integrated efforts and initiatives are needed to achieve these goals. These efforts should include:

- Collaborative RD&D;
- Aggressive technology transfer; and
- Appropriate tax and regulatory policies at the state and Federal levels.

A collaborative RD&D effort between the oil industry, universities, state and local governments, and the Federal government focused on improving advanced oil recovery technology and its application in key geologic settings would benefit operators, the state of Illinois, and the entire nation. 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 both the state and the nation's treasuries, economies, and citizens. State and Federal tax incentives can be instituted in order to help domestic EOR and ASR projects compete with foreign investment opportunities. In addition, regulatory policymakers could design regulations which reflect both the true risks to health, safety and the environment and the economic risk of resource loss through abandonment.

Figure I-5

Illinois Remaining Oil Resource After Advanced Technology Recovery

II. BACKGROUND AND OBJECTIVES

A. TRENDS IN ILLINOIS OIL PRODUCTION AND RESERVES

As would be expected of a state in the mature stage of its production history, since the early 1960s oil production in Illinois has consistently declined except for a period of growth in the first half of the 1980s (Figure II-1). Between 1955 and 1962, Illinois production remained consistently high at approximately 80 million barrels per year. Over the seventeen years from 1962 to 1979, Illinois production dropped by an average of 4% per year, reaching a low of fewer than 22 million barrels in 1979. The 75% fall in Illinois oil production over the last thirty years can be attributed to price changes and the decreasing yield from conventional recovery as the fields in the state have matured. Crude oil price increases in the mid to late 1970s exposed oil production in Illinois to the influences of the world energy market. The doubling of world oil prices from 1979 to 1981 accounted for the short term reversal of the decline in Illinois oil production. However, with the oil price collapse of 1986, annual production declined again, hitting an all-time low of fewer than 20 million barrels in 1991.

The decrease in Illinois oil production has been accompanied by a general reduction in reserves (Figure II-2). State crude oil reserves peaked in 1956 at 700 million barrels. By 1980, reserves had fallen by almost 84% to just 113 million barrels. Increased oil prices did restore some activity by Illinois operators during the first half of the 1980s, increasing reserves to approximately 150 million barrels. The general trend in Illinois suggests that even a restoration of moderately high oil prices would not significantly extend the conventional recovery life of mature Illinois fields.

The general declines in production and reserves cannot be attributed to a drop in the number of producing wells, as this number has increased steadily over the last fifteen years. In 1975, Illinois had just over 23,000 producing wells before major increases in field development saw that number rise to 31,000 in 1985 (Figure II-3). In the past six years, lower oil prices have caused a leveling off in the number of producing wells as stripper wells have been abandoned and development has declined. As of 1991, there were over 32,000 producing wells in Illinois. Reserves per producing well have plummeted as the number of wells have increased. Through 1970, reserves per well averaged more than 8,000 barrels; that number has since dropped to approximately 4,000 barrels per well in 1991.

Figure II-1

Illinois Crude Oil Production (1950 - 1991)

Figure II-2

Illinois Crude Oil Reserves (1950 - 1991)

Compounding the problem of recent production slides has been the increasing reliance on stripper wells, which produce fewer than 10 barrels of oil per day on average. As of 1990, stripper wells accounted for more than 92% of Illinois production (Figure II-4). These marginal wells maintain economic access to the reservoirs they penetrate and are critical to future applications of new, modern recovery techniques. Future economic events that threaten the viability of continued production, such as another oil price collapse, would dramatically reduce access to a large portion of the Illinois resource, making improved oil recovery economically impossible. Between 1980 and 1990, over 4,400 Illinois stripper wells have been abandoned, limiting access to the oil resource remaining in older producing zones.

Clearly, this trend of declining production has implications for employment and economic activity in Illinois. In 1979, the Illinois oil and gas industry employed nearly 77,000 people, with only 5,300 in the extraction sector (Figure II-5). Since then, however, oil and gas employment in Illinois has been steadily declining. In 1991, fewer than 59,000 people in the state were employed in the oil and gas industries, and the number of people employed in the extraction sector has fallen by about 50% since the mid-1980s. With production and reserves trends likely to continue on their present course, these employment figures may drop even further in the near future.

Over this same period, the gross annual value of Illinois oil production has experienced dramatic changes (Figure II-6). The value of production, in constant 1991 dollars, increased rapidly in the late 1970s and early 1980s along with the price of oil, reaching an all-time high of over \$1 billion in 1980. With the oil price collapse of the mid-1980s, however, the value of oil production dropped over 65% to a low of around \$365 million in 1988. Recent increases in the value of oil production reflect a mild recovery in oil price which may help to spur future development efforts.

The loss of tax revenue, caused by declining production in the oil and gas industries, has not had a significant impact on total state tax revenues, because Illinois does not levy severance taxes on oil and gas production. Thus, it is unlikely that future declines in production will severely impact the Illinois tax base. However, because of the effect on employment levels and income tax revenues, oil and gas production have played an important role in the state's economy. It is in the state's, and the nation's, best interest to maximize the future recovery of Illinois' remaining resource.

Figure II-3

Illinois Producing Wells (1960 - 1991)

Figure II-4

Illinois Stripper Well Production and Abandonments (1970 - 1990)

Figure II-5

**Total Oil and Gas Employment in Illinois
(1970 - 1991)**

Figure II-6

**Annual Wellhead Value of Illinois Oil and Gas
Production (1961 - 1991)**

Figure II-7

Illinois Oil Resource

At the conclusion of conventional primary and secondary operations, vast quantities of oil will remain unrecovered in Illinois reservoirs (Figure II-7). The total known original oil-in-place (OOIP) in Illinois is estimated at 9.2 billion barrels. Approximately 3.4 billion barrels are estimated to be recovered through the use of conventional oil recovery techniques (37%). Over 5.6 billion barrels, 61% of the oil resource, will remain in Illinois reservoirs after conventional recovery techniques have been applied and wells reach their economic limit. This remaining oil is the target for newer, more efficient extraction techniques.

This unrecovered resource can be broken down into two main components: mobile and immobile oil. In Illinois, 1.3 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 advanced secondary recovery (ASR). The 4.3 billion barrels of remaining immobile oil represents the target for a number of tertiary extraction technologies, defined generally as enhanced oil recovery (EOR). Recovery operations directed at each of these resources could play a critical role in sustaining the Illinois oil industry. A brief overview of these recovery technologies is contained in Volume X, Appendix A.

B. IMPROVED RECOVERY ACTIVITIES TARGETING THE REMAINING RESOURCE

The oil remaining after conventional primary and secondary recovery lies in two defined regions within each reservoir: the swept and the unswept zones. In the swept 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 with water can produce very little of this oil; the swept zone is at the "waterflood residual" level of oil saturation. The volume previously occupied by displaced oil now contains water (or, in some cases, natural gas). In their current stage of development, EOR processes are generally expected to reach only those portions of reservoirs previously swept by conventional techniques, either natural influx or water injection.

In the unswept zone of the reservoir, conventional recovery processes have not swept the pore space, and the oil saturation can range from low to high depending upon the primary recovery mechanism (e.g., pressure depletion or water drive). The objective of many infill drilling programs, improved waterflooding projects (profile modification and polymer-augmented waterflooding), and other reservoir management techniques is to contact the oil in the unswept zones, prior to or along with EOR applications.

1. Enhanced Oil Recovery

Proven enhanced recovery processes are classified into three categories: gas-miscible, chemical, and thermal. Very few gas-miscible or thermal projects have been implemented in known Illinois reservoirs at this time. Chemical flooding is the most prevalent EOR technique used in the state of Illinois. As early as 1980, Marathon Oil Company had established three chemical EOR projects in the S formation of Crawford county's Main Consolidated field. Two of these were established as micellar polymer floods, a unique type of surfactant flood in which polymer slugs are added to the chemical slug.

The third project was established as a straight polymer flood, and will be discussed in Section C. They were producing a total of about 100 barrels of oil per day (BOPD) when Marathon sold the projects to Crete Oil.¹ These projects were not determined to be profitable for Marathon, but the technical recovery potential of chemical flooding has been clearly established. Marathon also initiated two surfactant flooding projects in the S formation of Lawrence county's Lawrence-Robinson field. These two projects were established in 1982 and 1985 and produce a combined total of approximately 70 incremental barrels per year. These projects, while not yet profitable, appear promising.² At least a dozen small (usually 10 acres) surfactant microemulsion projects were reportedly initiated between 1977 and 1980.³ The literature makes no further mention of them.

2. Advanced Secondary Recovery

Mobile oil remains in the reservoir after conventional recovery for a variety of reasons. Foremost of these is reservoir heterogeneity, the complex variation of rock properties among zones in the producing interval. 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 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 wide well spacings, significant volumes of oil are areally bypassed due to small-scale variations in reservoir continuity, to the higher viscosity of oil than injected water, and to permeability variations within the reservoir. The effectiveness

¹ *Oil and Gas Journal*, Moritis, Guntis, 20 April 1992.

² *Ibid.*

³ U.S. Department of Energy, Bartlesville Project Office, Enhanced Oil Recovery Project Data Base, April 1992.

of water injection is further limited by vertical layering in the reservoir. 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 production of unrecovered mobile oil (UMO). 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 may also have very similar internal reservoir architecture, but will be modified by post-depositional diagenesis. That modification will vary from basin to basin depending on geohistory.

Recovery of remaining mobile and immobile oil from known fields is a highly cost effective method for increasing oil production, as demonstrated by the prevalence of ASR techniques in larger oil producing states such as Texas. Several distinct methods for producing unrecovered mobile oil 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 tested and proven methods for producing mobile oil remaining in the reservoir.

Fifty infill wells have been drilled by Exxon in the Loudon field of Illinois since 1979. Prior to the infill drilling, production from the Loudon field averaged approximately 25 barrels of oil per day. Now, these wells produce an estimated total of 600 barrels of oil per day (BOPD), or 18% of Exxon's total field production. Because of the maturity of the Loudon field, essentially all production from these wells is considered increased recovery due to the infill drilling program. These infills are expected to increase the Loudon field oil reserves by 970,000 barrels⁴.

⁴ Barber, A.H., Jr. et al., "Infill Drilling to Increase Reserves -- Actual Experience in Nine Fields in Texas, Oklahoma, and Illinois," *Society of Petroleum Engineers (SPE) Paper #11023*, 1982.

The potential benefits of geologically targeted infill drilling have been assessed by several research studies.^{5,6,7} One study, mounted by the Illinois State Geological Survey, is evaluating reservoir development strategies for some of the state's older producing oil fields.⁸ This study is currently focusing on infill drilling techniques and injection patterns in two of Illinois' most prolific producing formations -- the Mississippian Cypress and Aux Vases sandstones. These studies indicate substantial recovery potential from targeted infill drilling.

Two polymer flooding projects have been reported in Illinois. The first was established by Marathon in Crawford county's Main Consolidated field. This project was discontinued and the property sold. The second project, established by South Fork, Inc. in the S formation of Clark county's S. Johnson field, while considered profitable, has been postponed pending further analysis. Of the 36 BOPD produced by the 50 acre, 60 well project, 20 BOPD was considered to have been the result of enhanced recovery.⁹ Currently, there are no profile modification processes being implemented in Illinois reservoirs.

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

⁵ 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. Department of Energy/Office of Planning and Environment/Office of Fossil Energy and Bartlesville Project Office, 1989.

⁶ Fisher, W.L., "Can the U.S. Oil and Gas Resource Base Support Sustained Production?" *Science*, Volume 236, No. 4809, 26 June 1987, 1631-1636.

⁷ 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.

⁸ *Improved Recovery Week*, Pasha Publications, Arlington, VA, 27 July 1992.

⁹ *Oil and Gas Journal*, Moritis, Guntis, 20 April 1992.

There are several other processes and recovery techniques which were not included in this analysis which may have potential in Illinois. Application of these techniques would further increase potential recovery and add to the estimates contained in this analysis. Immiscible gas and nitrogen gas EOR projects could enhance Illinois oil recovery. In addition, improvements in reservoir management and improvements in waterflood patterns, waterflood rates of injection, and the timing of inception of waterfloods show significant potential as recovery techniques. To the extent that these techniques and others currently being transferred (i.e., injection water compatibility) improve potential oil recovery, the results presented in this report will be understated.

C. OBJECTIVES OF THE PRESENT STUDY

The present study analyzes the incremental reserves, public sector revenues, and statewide economic activity that could result from the implementation of the improved EOR and ASR techniques described above. The potentials for EOR and ASR production are evaluated separately, and each is considered for two technology levels: *implemented technology*, which assesses recovery potential given the widespread application of currently available technology, and *advanced technology*, which assesses the impact of the effective 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 RD&D. All of the analyses are conducted over a range of crude oil prices from \$16 to \$36 per barrel (in constant 1991 dollars). This price range encompasses the long-term prices likely to prevail over approximately the next 30 years.

Fifty-four reservoirs, accounting for 5.6 billion barrels of origin oil-in-place (over 60% of the total known resource in Illinois), were included in this analysis. These reservoirs contain 3.4 billion barrels of remaining oil resource (Figure II-8). The 800 million barrels of UMO is the target for application of ASR processes and 2.7 billion barrels is the target for application of EOR processes. To achieve the required level of application, and therefore receive the maximum benefits of both levels of technology assessed in this report, it is critical that state and local governments, the Federal government, and the oil industry work collaboratively to: 1) effectively transfer to operators currently available technology (implemented technology), and 2) develop a focused R&D program to improve recovery methods (advanced technology) and subsequently transfer those methods to a broad public-private audience. The

results and conclusion will provide valuable insights for state and Federal policymakers in their efforts to maximize domestic production and improve the nation's energy security.

Figure II-8

Illinois Remaining Oil Resource After Conventional Recovery Operations

III. APPROACH TO THE ANALYSIS

A. INTRODUCTION

This analysis was performed using the Department of Energy's Tertiary Oil Recovery Information System (TORIS) developed for the 1984 National Petroleum Council (NPC) analysis of the nation's enhanced oil recovery (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, the target for advanced secondary recovery (ASR). The upgraded TORIS system assessed the recovery potential of immobile oil and UMO in the United States. The following sections in this chapter will briefly discuss the:

- Development of TORIS;
- Enhancement of TORIS to evaluate the UMO resource;
- Scope of the current analysis;
- Adaptations to TORIS for this analysis;
- Estimation of benefits, costs, and economic impacts; and
- 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 the 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 industry (majors, independents, service companies, and consulting firms), universities, government, and private, non-profit organizations participated. The NPC EOR study committee utilized and built upon data bases

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

of individual reservoir characteristics and computer models that were under development by the U.S. Department of Energy's (DOE), Office of Fossil Energy. After augmentation, adaptation, and validation, the data bases and models were remanded to the 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.

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," or currently available, 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 focused research and development. Table III-3 displays the technical criteria for "advanced" EOR technology.
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

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
 - Pay continuity (estimated)
- 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	Thermal Recovery	
		Surfactant	Alkaline	(Carbon Dioxide)	Steam	In-Situ Combustion
Oil Gravity	°API	---	<30	≥25	10 to 34	10 to 35
In-situ 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	Thermal Recovery	
		Surfactant	Alkaline	(Carbon Dioxide)	Steam	In-Situ Combustion
Oil Gravity	°API	---	<30	≥25	---	---
In-situ 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 ($S_o X \phi$)	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.

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 RD&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 EVALUATION OF UNRECOVERED MOBILE OIL RESOURCES

TORIS evaluations have historically focused on the recovery of immobile or waterflood residual oil. In 1988, TORIS' capabilities were expanded to include an evaluation of the 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 are reported in detail in a topical report by the DOE.³

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. Department of Energy/Office of Planning and Environment/Office of Fossil Energy and Bartlesville Project Office, 1989.

Since 1989, the TORIS ASR models have been upgraded to more accurately describe and evaluate the UMO resources. The enhancements included the following:

- Development of an infill drilling model which processes five-spot waterflood to five-spot infill as well as five-spot waterflood to nine-spot infill;
- Development of a methodology to determine key reservoir heterogeneity elements needed for modeling infill drilling potential. The heterogeneity elements are "reservoir continuity" and "Vertical Permeability Stratification Index" (Dykstra-Parson coefficient). The methodology relies on the history match of production data to determine the heterogeneity elements;
- Validation of the infill drilling model and history match methodology on nine actual field results as well as results of a black oil simulator;
- Integration of a newly developed infill model with other models in TORIS to process infill drilling in combination with polymer flooding or profile modification; and
- Validation of criteria for implemented as well as advanced technology infill drilling.

A preliminary draft report of all developmental work is available through the U.S. Department of Energy, Bartlesville Project Office. The draft report is currently being finalized, and it will be available to the general public in the near future.

UMO, the target for advanced primary and secondary recovery operations, consists of oil that is uncontacted or bypassed during conventional production that can be displaced from the reservoir by waterflooding. "Uncontacted oil" refers to oil trapped in isolated compartments in reservoirs uncontacted by wells 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, the fluid characteristics of the oil, and the drilling and development history of the reservoir.

Potential incremental oil recovery and related economic benefits are estimated for the three processes currently used to improve mobile oil displacement. These processes are referred to as advanced secondary recovery (ASR) and include: infill drilling, profile modification treatments (permeability contrast reduction), and polymer-augmented waterflooding. A modified polymer-waterflood predictive model is used to evaluate each process. Selected combinations of these processes are also evaluated in this study.

Consistent with TORIS EOR evaluations, the analysis of UMO considers both current technology and advanced technology. The advanced technology analysis estimates the potential improvement in recovery possible after successful RD&D. For polymer flooding and profile modification treatments, advances in technology are projected to increase 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 Recovery Processes

	<u>Polymer Flooding*</u>		<u>Profile Modification</u>	
	<u>Current</u>	<u>Advanced</u>	<u>Current</u>	<u>Advanced</u>
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 under implemented and advanced technology scenarios. Current knowledge of reservoir heterogeneity limits drilling to highly favorable reservoirs where blanket-pattern drilling at uniform spacing can yield a profit. Increased continuity in the implemented technology case is estimated by the reservoir-wide average improvement in continuity 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 (homogeneous) region and a less continuous (heterogeneous) region. Each region 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 specific criteria for both the implemented technology and the advanced technology infill drilling is shown in Table III-5. The entire methodology (data, models, highgrading, and analytical systems) was developed and implemented in a manner fully compatible with the existing TORIS structure.

Table III-5

Screening and Approach for Advanced Technology Infill Drilling

Technology Level	Criteria
Implemented	<ul style="list-style-type: none"> - 5-spot waterflood to 5-spot infill - 15% minimum real rate of return - Minimum well spacing of 10 acres before infill drilling - One drill down
Advanced	<ul style="list-style-type: none"> - 5-spot waterflood to 5-spot infill - 10% minimum real rate of return - Highgrade into homogenous and heterogeneous portions - One drill down in homogeneous portion - Up to three drill downs in heterogeneous portion - Well spacing after infill greater than 5 acres

D. SCOPE OF THE ANALYSIS

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

The nominal crude oil prices (West Texas intermediate adjusted for transportation costs and gravities less than 40° API) range from \$16/B to \$36/B in \$4 increments, all stated in constant 1991 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. In addition, a risk premium is also considered depending on the EOR or ASR process and the

level of technology. The risk premium is modeled as an increase in the hurdle rate as shown by the following table. The risk premium was recommended by the TORIS peer review committee.

Table III-6

Risk Premium For Implemented and Advanced EOR and ASR Processes

	Cost of Capital	Risk Factors		Hurdle Rates	
		Implemented Technology (%)	Advanced Technology (%)	Implemented Technology (%)	Advanced Technology (%)
Alkaline	10	15	0	27	10
Surfactant	10	15	0	27	10
In-Situ	10	15	5	27	16
Polymer	10	5	0	16	10
Profile Modification	10	5	0	16	10
CO ₂ -Miscible	10	5	0	16	10
Steam	10	5	0	16	10
Infill Drilling	10	5	0	16	10

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 ASR) which are currently available. Advanced technology considers the likely improvements in process performance and applicability that can be achieved within the next decade if a focused, effective RD&D program is successfully completed.

All cases are analyzed in detail to examine their impact on estimated oil reserves, oil production, state and Federal revenues, and the state and national economies. The results of these analyses, addressing the benefits from incremental production, are reported in Chapters IV and V which discuss the effects of EOR and ASR processes for implemented technology and advanced technology, respectively.

E. ADAPTATIONS FOR THE PRESENT STUDY

Several adaptations to the NPC approach were necessary to conduct the present analysis. 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 54 of the largest Illinois reservoirs, accounting for over 60% of estimated original oil-in-place (OOIP) in the Illinois. The reservoirs represented in the data base include oil zones in every region of the state. The largest reservoirs are more completely represented in the data, but reservoirs as small as 5 million barrels are also analyzed in the study. The data base is, therefore, believed to be representative of the diverse oil producing formations across Illinois. Data from the Energy Information Administration on the production of oil, gas, and water from 1970 to 1992 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

The present study uses current tax structure along with the actual tax rates in the TORIS economic models. The Federal taxes are estimated based on the 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 34% marginal rate on corporate income taxes and changes the depreciation schedules and expense rules. In addition, the present study includes the new Federal EOR tax credit as passed by Congress in FY91. The new Federal EOR tax credit provides a credit equal to 15% of all qualified enhanced oil recovery costs on projects that began or were significantly expanded after December 31, 1990. The "qualified enhanced oil recovery costs" are defined as tangible property investments, intangible drilling and development costs, and purchase costs of tertiary injectants. The tax credit is contingent upon professional certification, in advance, that the EOR project is capable of producing more than an insignificant increase in ultimate recovery. Because the goal of the incentive is to make the application of EOR techniques economic at lower oil prices, where project economics are most impacted, the incentive is gradually phased out at oil prices above \$28/B. For every \$1/B that the average benchmark price for the preceding year exceeds \$28/B, the incentive is reduced by 2.5 percentage points for the subsequent year, so that a complete

phasing out of the incentive would occur at an oil price of \$34/B. The study also accounts for the current state tax structure in Illinois.

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 CO₂ 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:

$$\text{CO}_2 \text{ Price (\$/Mcf)} = \$0.50 + \$0.025 \times \text{Oil Price (\$/B)}.^4$$

However, the base price and adjustment equation were established at higher oil prices and before the completion of major CO₂ pipelines or significant CO₂ deliveries to the region. An informal poll of pipeline and field operators suggests that the CO₂ prices at present and into the near future will be lower (relative to oil prices) than the NPC had assumed. The CO₂ purchase price in West Texas has been adjusted for changes in oil price using the equation:

$$\text{CO}_2 \text{ Price (\$/Mcf)} = \$0.50 + \$0.02 \times \text{Oil Price (\$/B)}.$$

This equation results in a CO₂ price of \$0.90/Mcf at the \$20/B oil price. CO₂ prices in other regions of the state are assumed to be double the West Texas price, based on previous NPC surveys.

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 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

⁴ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

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.⁵ 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. A more detailed timing approach for both EOR and ASR was used in the present study. Timing for the application of EOR recovery techniques 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 start up 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 recovery is then phased in to occur reservoir-wide, at the latest, by three years following the estimated abandonment date. Projects that are not timed in by this data are assumed abandoned and are excluded from the analysis. The timing of ASR reserves development and production was accomplished using the Crude Oil Policy Model (COPM) because the TORIS timing model was not suited for ASR for technical reasons. COPM simulates the development of an aggregate resource as a function of project economics, while simultaneously accounting for abandonment of the undeveloped portion of the resource and technology transfer constraints. Inputs to COPM include the total resource potential, development and production costs, technology availability dates, technology penetration rates, abandonments rates, and reserves development rates. Outputs from

⁵ Ray, et al., *Potential Crude Oil Production from Enhanced Oil Recovery*, U.S. Department of Energy, Bartlesville Project Office, 1986.

the model include annual production, reserve additions, abandonments, development costs, operating costs, wages, and taxes. Reserves estimates were supplied by TORIS.

Total reserves were disaggregated into two categories, reserves available with implemented technology and incremental reserves available through the application of advanced technology. Appropriate model parameters were selected for each of these resource categories. The technology availability dates were set to 1993 for implemented technology and 2000 for advanced technology. Technology penetration rates were set at 75% in 12 years for implemented technology and 75% in 8 years for advanced technology, with the advanced technology case representing an aggressive technology transfer effort. Abandonment rates for both implemented and advanced technology were set to 3% of the undeveloped resource per year prior to technology availability and 1.5% per year after technology becomes available. Reserves development rates corresponded to typical field development profiles.

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 cash flow calculations of individual projects. Under each of the various cases analyzed, projects yielding a net present value greater than the hurdle rate are assumed to be developed. This assumption is the basis for the projection of potential incremental production and reserves.

The incremental benefits and costs of EOR and ASR 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-seven year period, 1993 to 2020. Cumulative benefits include the sum of the annual benefits plus any additional benefits that would accrue after 2020. 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-seven year period of focus in this study. The additional

benefits that occur after 2020 are generally small relative to the total benefit, but important to the overall aggregate analysis.

1. Benefits to State and Local Treasuries

The benefits to Illinois state and local treasuries from advanced oil recovery processes are the additional tax revenues attributable to implementation of the projects. These taxes include sales tax on equipment and material purchases and corporate and personal income taxes on wages paid and operator profits. 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 activities associated with the incremental production from improved 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 citizens of Illinois also gain from the increased economic activity. Only the direct effects of the incremental activity are included, not the economic "multiplier" or indirect "ripple effect" activities (e.g., pipeline construction, retail sales, etc.). The direct impact on the state's 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 of Illinois and its citizens.

Excluded from this state economic activity definition are cashflows that generally benefit citizens of other states in larger proportion than they benefit the citizens of Illinois. 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 Illinois, the direct benefits of these "retail pass-through" 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 Illinois (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 Illinois 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 for direct economic effects understates the actual benefits to the state of Illinois and its citizens.

The additional jobs, wages, and benefits created by improved 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-7 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.⁶ Sales tax revenues are calculated based on the materials component of these costs, assuming purchasers would pay the appropriate state tax on these goods.

3. National Effects

The Federal government benefits substantially, both directly and indirectly, from increased recovery of the Illinois oil resource. Direct Federal taxes total 5% to 20% of the value of each barrel of oil recovered. Each additional barrel of Illinois oil production can replace a barrel of imported oil. Therefore, each dollar used to purchase the incremental barrels of oil that would otherwise pay for imports is, potentially, a dollar reduction in the trade deficit.⁷ To estimate the direct effects on import replacement (i.e., excluding multiplier effects), the gross revenue from the additional production is used. This measure of gross revenues incorporates direct in-state economic activity and excludes elements discussed in the section above. In this sense, the estimated increase in import replacement represents a more complete measurement of direct economic impacts, excluding multiplier effects. In addition, corporate and individual Federal income taxes are estimated to assess the direct effects of incremental oil recovery in Illinois on the Federal treasury.

⁶ U.S. Department of Labor, Bureau of Labor Statistics, 1985.

⁷ 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.

Table III-7

Labor and Materials as Percentage of Total Cost in EOR Projects

<u>Investments</u>	<u>% Labor</u>	<u>% Materials</u>	<u>% Other</u>
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
<u>Expenses</u>			
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

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. It is also important to note that the results of this analysis are not forecasts of future oil recovery; they are estimates of the recovery potential of selected EOR and ASR processes.

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, unless advanced geoscientific knowledge allows 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 developed under EOR or ASR operations.

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 after completion of conventional production operations.

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 advanced oil recovery, but this is not reflected in the models.

An additional limitation arises from the methodological convention of "constant price" analysis. The use of this convention is consistent with the NPC's original 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 additional incremental investment not included in this analysis (although necessary workovers are included in the assumed cost). Redrilling would result in substantially increased costs and would thus increase the minimum oil price at which advanced oil recovery processes are profitable for certain reservoirs. The net effect of this analytic convention could 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 analysis.

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.

None of the above limitations invalidate the results of this analysis. Given the uncertainty of the size and combinations of the optimistic and pessimistic biases introduced by these limitations, it is assumed that the approach is valid and the resulting projections are reasonable. To avoid misinterpretation of particular reservoirs, and to respect the confidence in which some project and reservoir data were obtained, no reservoir specific date is provided in the reports generated from this analysis. However, in cases where the results seemed unusual, the modeling specifications for specific reservoirs were examined in-depth to ensure the validity of the results.

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

A. INTRODUCTION

This chapter discusses the post-conventional reserve additions and potential economic impacts attributable to the application of currently available (implemented technology) oil recovery methods in analyzed Illinois reservoirs. Chapter V discusses the incremental reserves and benefits under advanced technology methods attainable through RD&D. The TORIS reservoirs analyzed in this study are individually modeled to evaluate their potential for incremental production and reserves by tertiary and advanced secondary recovery techniques under a variety of oil prices and economic conditions. Some key technical assumptions and considerations regarding the analysis in this report are:

- The incremental production and reserves refers to future recovery estimated for the analyzed EOR and ASR techniques. Such production and reserves are above and beyond the recovery attainable by primary and secondary recovery techniques.
- Both light oil ($\text{API} > 20$ degree) and heavy oil ($\text{API} \leq 20$ degree) resources are considered in this analysis.
- All EOR and ASR recovery potential evaluated in this report reflect future new projects only, and they do not include incremental reserves from existing (ongoing) EOR and ASR projects. However, the expansion to the ongoing projects, if technically and economically feasible, are evaluated as part of future new projects in this report.

All reservoirs are screened for technical criteria and are analyzed in detail using the process performance and economic models described in Chapter III. The results are based on the evaluation of 54 reservoirs in Illinois for their EOR and ASR potential. The results of this analysis were not extrapolated to the rest of the reservoirs making up the Illinois resource.

B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE

1. Production and Reserves

Over the price range analyzed, EOR processes (carbon dioxide-miscible, chemical, and thermal) could stimulate only 11 million barrels of incremental reserves under implemented technology. This

potential represents a single CO₂-miscible flooding project which could be economic at oil prices of \$24/B and above.

2. Increases in State and Local Revenues

This 11 million barrels of EOR production could increase direct state and local revenues through state corporate and personal income taxes and sales taxes on purchased materials used in the projects. (The state of Illinois does not levy a production tax on oil or gas.) The estimated revenues are generated directly from oil production or operations in the analyzed Illinois reservoirs. State and local revenues generated over the life of the single EOR project vary with oil prices (Figure IV-1). The most significant portion of these revenues could result from sales taxes. A \$24/B oil price could yield sales tax revenues of \$6 million plus \$4 million in other tax receipts. At \$36/B, corporate income and sales tax receipts each could contribute \$8 million with personal income taxes comprising the remainder of the \$18 million total.

3. Effects on the State Economy

In addition to the incremental state and local revenues, enhanced oil recovery would benefit Illinois by increasing economic activity and by creating new jobs. The effects of EOR on the state economy are estimated conservatively: (1) only direct effects are included (i.e., no economic multiplier); and (2) the direct effects are limited to benefits believed to accrue predominantly to the state of Illinois and its citizens. Only intangible drilling costs, royalties, state and local taxes, 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 activity. However, to the extent that royalties go to the Federal government, the royalties portion of state economic activity could be overstated. While the excluded elements undoubtedly aid Illinois' citizens to some degree, a substantial portion of the benefits will be enjoyed by citizens of other states. As local manufacture or retail sales of these items provide economic benefits within Illinois, injectants produced or manufactured in Illinois are employed, or economic "multipliers" occur, the calculated economic impacts are understated.

Figure IV-2 displays the total direct economic gains for the state over the applicable oil price range analyzed. Operating costs could account for about 70% of these economic effects; royalties could represent around 20%; intangible investment could be about 5%, and state revenues could be about 5%

Figure IV-1

Direct State and Local Revenues from EOR Production Implemented Technology

*No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

to 7% of the total. At \$24/B, incremental benefits to the state economy could exceed \$190 million. At the highest oil price considered, \$36/B, an estimated \$262 million of statewide direct economic activity could be stimulated by this single EOR project. Successful EOR projects can create or maintain jobs in the local economy, as shown in Figure IV-3. The number of jobs created or maintained by this EOR project during peak years could nearly reach 120 per year. Total incremental annual wages paid could reach over \$5 million.

4. Effects on the National Economy and Budget

Increased oil recovery from EOR in Illinois would benefit the nation as a whole. National benefits would accrue in several ways: replacement of oil imports, increased Federal corporate and personal income tax revenues, and reduction in the foreign trade deficit. Of course, the addition of only 11 million barrels of reserves in Illinois would not appreciably expand the nation's proved reserve base. However, as each additional barrel of domestic oil production replaces a barrel of imported oil, the nation's energy security would be enhanced.

Figure IV-2

Direct State Economic Activity*

Implemented Technology

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.

** No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

Figure IV-3

Jobs and Wages from EOR Production

Implemented Technology

EOR activity in Illinois contributes to the Federal treasury through personal and corporate income taxes. Increases in Federal revenues stimulated by implemented technology EOR could range from \$3 million at \$24/B to \$43 million at \$36/B, over the life of the projects (not illustrated). Corporate income taxes could account for between 50% and 80% of this total at oil prices of \$28/B and above, and personal income taxes would make up the remainder. Negative Federal revenues result from taxable losses generated during the initial implementation phases of many EOR projects, as well as from the Federal EOR tax credit, both of which are assumed to be used as offsets to Federal income tax liabilities from other profitable activities. Federal corporate income taxes were evaluated at a marginal tax rate of 34%.

In addition to directly replacing imported oil, increased domestic production would reduce the foreign trade deficit. The money spent purchasing domestic rather than imported oil circulates back through the U.S. economy instead of adding to the trade deficit. Implemented technology EOR in Illinois could stimulate from \$261 million (at \$24/B) to \$410 million (at \$36/B) of imports avoided, over the life of the project.

C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE

This section will discuss the application of currently available advanced secondary recovery (ASR) processes in analyzed Illinois reservoirs. These two distinct recovery technologies, enhanced oil recovery and advanced secondary recovery, 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 simultaneously implemented, making the results at least additive. Given the potential synergies in the simultaneous employment of EOR and ASR technologies, reserve additions and economic benefits could be even greater than the sum of the two.

1. Production and Reserves

ASR processes applied in the reservoirs analyzed could stimulate 12 to 60 million barrels of incremental reserves over the analyzed oil price range. ASR processes are less costly to implement than EOR processes, and therefore ASR reserve additions are less sensitive to changes in the oil price. At \$20/B, ASR could generate 56 million barrels of incremental reserves, more than 90% of the oil economically accessible at oil prices above \$28/B.

This analysis evaluates five ASR processes: polymer flooding, profile modification, infill drilling, and combinations of infill drilling with polymer flooding or profile modification. Polymer flooding and profile modification projects are grouped together in the following discussion, as are infill drilling combinations with polymer flooding and profile modification. As shown in Figure IV-4A and Table IV-1A, infill drilling, both by itself or in combination with the other processes, could account for all of the reserve additions at all prices. At \$16/B, the combination processes could be the only economic processes and could stimulate 12 million barrels of incremental reserves. As oil prices increase, infill drilling alone becomes more economic since revenues increase along with oil prices. Between \$20/B and \$36/B, there would be little change in the total incremental reserves or in their distribution between infill drilling and combination processes. Table IV-1B shows the number of projects expected to be economic at each price for individual recovery methods. At all prices above \$16/B, the number of advanced secondary recovery projects in each category could remain relatively constant.

Figure IV-4B displays the expected annual production from ASR processes for oil prices of \$16/B and \$32/B. Timing of the ASR potential has been carried out according to the methodology discussed in Chapter III. The peak at \$16/B is about 360,000 barrels of oil per year from two projects. At \$32/B, production from ASR could peak at is about 2 million barrels annually from eight projects. To put the potential contribution of ASR into perspective, 2 million barrels per year is equivalent to about 10% of current Illinois annual oil production.

ASR projects are undertaken as reservoirs reach their economic limit. In this study, ASR projects are assigned initiation dates as a function of rig availability and technology transfer; projects are therefore phased in over time. Some fields could therefore be abandoned before ASR can be implemented. This abandonment, which is reflected in the annual production, is on the order of 25% to 35% of the potential incremental reserves. Accelerated technology transfer can reduce this loss.

2. Increases in State and Local Revenues

Figure IV-5 shows the expected growth in state revenues from ASR production and the proportional contributions of state corporate and personal income taxes and sales taxes to the total. Corporate income taxes could account for 40% to 70%, with sales taxes making up most of the remaining revenues. At moderate oil prices (\$20/B to \$28/B), between \$48 million and \$73 million in additional direct state and local revenues could be generated from activities associated with ASR production. At \$36/B, \$95 million in direct state and local revenues could be stimulated.

Table IV-1A

Incremental Reserves from ASR by Process*
Implemented Technology
(Million Barrels)

Oil Price (\$/B)	Infill Drilling	Infill Drilling and Polymer Flooding or Profile Modification	Total
\$16	0	12	12
\$20	43	13	56
\$24	45	13	58
\$28	47	13	60
\$32	47	13	60
\$36	47	13	60

* Polymer flooding and profile modification, applied alone, did not exhibit potential using implemented technology.

Table IV-1B

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

Oil Price (\$/B)	Infill Drilling	Infill Drilling and Polymer Flooding or Profile Modification	Total
\$16	0	2	2
\$20	3	3	6
\$24	4	3	7
\$28	5	3	8
\$32	5	3	8
\$36	5	3	8

* Polymer flooding and profile modification, applied alone, did not exhibit potential using implemented technology.

Figure IV-4

Reserves and Production Response from ASR Techniques

Implemented Technology

A) Incremental Reserves by ASR Process

B) Annual Production from ASR Reserves

Figure IV-5

Direct State and Local Revenues from ASR Production Implemented Technology

3. Effects on the State Economy

Figure IV-6 displays the total state economic activity associated with potential ASR production. Total state economic activity from the processes could range from about \$100 million at \$16/B to about \$1.2 billion at \$36/B. Intangible investments would be the largest component of these increases in state economic activity and could amount to about 50% of the total. These costs could range from nearly \$420 million to over \$540 million at oil prices between \$20/B and \$36/B. Operating costs and royalties would be the next largest components of increased economic activity, each averaging approximately 20% of the total activity across all oil prices. State taxes would contribute the remaining 5% to 10%.

The implementation of ASR techniques could significantly contribute to employment in the state of Illinois. Figure IV-7 displays the annual number of jobs that could be created or maintained by ASR projects. The annual trend in jobs created or maintained closely matches the production trend for ASR.

Figure IV-6

Direct State Economic Activity

Implemented Technology

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.

Figure IV-7

Jobs and Wages from ASR Production

Implemented Technology

At \$32/B, the number of jobs created or maintained could peak in year 2016 at a level of about 100. At this price, \$4.7 million in wages could be paid in the peak employment year.

4. Effects on the National Economy and Budget

Tax revenues from activities associated with ASR production could significantly add to the Federal treasury (Figure IV-8A). At moderate oil prices (\$20/B to \$28/B), between \$111 million and \$220 million in additional direct Federal revenues could be stimulated by ASR production, mostly from corporate income taxes. At \$36/B, nearly \$340 million in direct Federal revenues could be added to the national treasury.

Sixty million barrels of increased domestic ASR production through implemented technology would also enhance the nation's energy security and reduce reliance on imported oil. To the extent that one barrel of domestic production replaces one barrel of imports, the foreign trade deficit is reduced as dollars which would be paid for foreign oil are spent domestically (Figure IV-8B). Between \$1.1 billion and \$1.7 billion could be spent on domestic oil rather than imports at oil prices ranging from \$20/B to \$28/B. At \$36/B, the value of imports avoided could reach over \$2.1 billion.

D. CONCLUSIONS

The existing level of EOR and ASR technologies could make small, but important, contributions to the reserve base and the Illinois and national economies, as well as to domestic energy security. At a \$24/B oil price, EOR processes could add 11 million barrels to Illinois reserves while ASR techniques could add 58 million barrels of incremental reserves. The application of current EOR and ASR technologies, in concert, could potentially add nearly 70 million barrels of incremental reserves at this price, adding over half Illinois's current proved reserves. As discussed in the next chapter, improved geoscientific understanding of reservoirs and enhanced process performance could increase these benefits if the required research can be cost effectively completed and transferred to the producers.

The state of Illinois and its citizens stand to gain significantly from the increased production resulting from incremental reserve additions. Production increases could generate \$50 million to \$100 million in additional state and local revenues over the life of the analyzed projects assuming oil prices of \$20/B to \$32/B. Total state economic activity would be boosted by \$780 million to \$1.3 billion. Jobs

Figure IV-8

National Impact of ASR Production

Implemented Technology

A) Direct Federal Revenues

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit.

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, and increased Federal corporate and personal income tax revenues. Maximizing recovery of the known oil resource in Illinois should therefore be an important goal for state and Federal policy makers. While these benefits would be available using currently available technology, the true potential would not be realized without an aggressive program of technology transfer. The estimated potential assumes wide application of these technologies. A collaborative technology transfer effort between the public and private sectors is critical to the attainment of these estimated benefits.

As shown in Figure IV-9, the oil that will remain in the analyzed reservoirs after production by both current operations and by wide-scale application of currently available EOR and ASR processes constitutes an important resource target for improved recovery technologies. Of the 2.7 billion barrels of immobile oil resource analyzed in this study, implemented technology EOR practices as defined in this report could produce an estimated 11 million barrels of incremental reserves at an oil price of \$36/B, leaving over 2.6 billion barrels of remaining immobile oil in these reservoirs. Of the 750 million barrels of unrecovered mobile oil in the reservoirs analyzed, implemented technology practices could produce an estimated 60 million barrels of incremental reserves at \$36/B, leaving 690 million barrels in these reservoirs. The large size of the remaining resource clearly warrants a focused RD&D program that will test and speed the implementation of advanced technology to capture additional oil reserves.

Figure IV-9

Illinois Remaining Oil Resource After Implemented Technology Recovery

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

A. INTRODUCTION

While currently available enhanced oil recovery (EOR) and advanced secondary recovery (ASR) techniques could contribute substantially to the Illinois reserve base, technological advances in these processes resulting from a focused RD&D effort would have far more dramatic effects on the state's oil production. Development and wide-scale application of improved recovery methods could result in the recovery of a much greater portion of the remaining mobile and immobile oil resources in the state.

The present analysis evaluates the impact of advanced technology on oil recovery and the associated economic benefits. Evaluations of advanced technology EOR and ASR reserves potential in the state of Illinois are presented separately. Given that the modeled advances in technology are conservatively defined, improvements in recovery processes resulting from RD&D not envisioned in this report could add substantially to the estimated potentials. However, well abandonments could limit access to the resource and increase project costs if EOR and ASR are not applied before conventional production ceases. Immediate actions are therefore necessary to realize the economic benefits of these advanced processes.

B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE

1. "Advanced" Technology Defined

Enhanced oil recovery processes, as currently applied, have severe limitations. Some current EOR techniques can only be applied in a limited number of reservoirs with properties which fall within a narrow range of suitable values (temperature, salinity, oil viscosity, etc.). The sweep efficiency of EOR processes is often relatively poor; only a small portion of the residual oil remaining in the previously waterflooded zone is contacted. Injectants are expensive, often approaching the value of the oil they are designed to recover, which places a burden on project economics. The National Petroleum Council (NPC) predicted gradual improvements in EOR performance and project economics as current processes are improved and tested in the lab and field. These advanced processes are predicted to gain operator acceptance as the research and development efforts of oil companies, universities, geologic surveys, and

the Federal government proceed and as field applications prove commercial viability. In this report, the IOGCC delayed the advanced technology availability date from the NPC's assumption of 1995 to the year 2000, to reflect the slower pace of RD&D activities in recent years caused by relatively low oil prices.

The major improvements in technology that are likely to impact enhanced oil recovery in Illinois will be advances in chemical EOR applications. For advanced technology thermal recovery, the NPC modeled the effects of an improvement in the ability to inject steam at greater depths and into thinner, lower permeability reservoirs. 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 also assumes that advances in chemical flood technology would result in improvements in injection rate, interfacial tension reduction, lower costs, and reduced chemical retention, thereby improving the recovery and economics of chemical projects. Additionally, substantial reductions in the associated risk of EOR projects are modeled as a reduction in the minimum rate of return, or hurdle rate, required for project implementation.

2. Production and Reserves

With technology advances, EOR could stimulate a substantial amount of incremental reserves over the applicable oil price range (\$24/B to \$36/B) analyzed in this study (EOR was not found to be economic at prices below \$24/B). Figure V-1 and Table V-1A show the comparison between the incremental reserves potentially generated through the application of advanced technology EOR processes and implemented technology EOR processes. At \$24/B, the incremental reserves due to advances in technology could be greater than those generated in the implemented technology case. At \$28/B, advances in EOR technology could add 60 million barrels of incremental reserves to implemented technology potential for a total of over 70 million barrels of incremental reserves (more than six times implemented technology reserves).

The potential incremental reserves contributed by each of the advanced EOR processes considered in this analysis are also shown in Figure V-1. Over the \$28/B to \$36/B range, advanced chemical flooding and advanced CO₂-miscible flooding processes could contribute approximately 60% and 40%, respectively to the total potential. Advanced technology chemical flooding potential would not be economic in the analyzed Illinois reservoirs below a \$28/B oil price under advanced technology conditions, and would not be economic under implemented technology conditions at any price evaluated in this study.

Figure V-1

Incremental Reserves by EOR Process Implemented Technology vs. Advanced Technology

* No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.
 ** Analyzed Illinois reservoirs exhibited no thermal EOR potential.

At \$24/B and above, advanced CO₂-miscible flooding could increase implemented technology incremental reserves by over 150% for a total potential of about 28 million barrels. Advanced chemical processes could stimulate over 40 million barrels to the total incremental reserves at oil prices of \$28/B and greater, all of which could be incremental recovery due to technology advances attainable through RD&D. Advanced thermal processes were not found economic at any of the oil prices considered in this analysis under either of the technology scenarios.

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 CO₂-miscible projects does not change, but reserve potential increases, indicating that advanced technology CO₂-miscible flooding is more efficient than the implemented technology process in the reservoirs analyzed, but that the project economics were not significantly improved. The chemical projects could first become economic in the advanced case at oil prices of \$28/B and greater; this process was not economic under implemented technology. This increase indicates that improved project economics are attainable from advanced technology; the additional reserves due to advanced technology would come from reservoirs that were not economic to develop under implemented technology.

Table V-1A

Incremental Reserves from EOR by Process*
Implemented Technology vs. Advanced Technology
(Million Barrels)

Oil Price** (\$/B)	CO ₂ -Miscible		Chemical		Total	
	Implemented	Advanced+	Implemented	Advanced+	Implemented	Advanced+
\$24	11	28	0	0	11	28
\$28	11	28	0	43	11	71
\$32***	11	28	0	37	11	65
\$36	11	28	0	43	11	71

+ This is the total reserves due to advanced technology -- implemented technology plus the increment due to technology advances.

* Analyzed Illinois reservoirs did not exhibit thermal EOR potential.

** The analysis reported no economic projects at prices below \$24/B.

*** Decrease at \$32/B caused by the phaseout of the Federal EOR tax credit.

Table V-1B

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

Oil Price** (\$/B)	CO ₂ -Miscible		Chemical		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
\$24	1	1	0	0	1	1
\$28	1	1	0	6	1	7
\$32***	1	1	0	5	1	6
\$36	1	1	0	6	1	7

* Analyzed Illinois reservoirs did not exhibit thermal EOR potential.

** The analysis reported no economic projects at prices below \$24/B.

*** Decrease at \$32/B caused by the phaseout of the Federal EOR tax credit.

Figure V-2 shows the expected annual EOR production at oil prices of \$24/B and \$32/B for both the implemented and advanced technology cases. At \$24/B, over 1.6 million barrels per year could be added to Illinois oil production within 10 years as a direct result of advances in EOR technology. At \$32/B, the same production trends could be seen; production from advanced technology chemical floods would not occur until after the year 2020. The total peak annual production of 2.7 million barrels could increase 1991 Illinois production levels by 14%.

3. Effects on State Revenues and Economic Activity

At all applicable oil prices considered in this analysis, the direct revenues to the state of Illinois attributable to EOR could significantly increase due to advanced technology (Figure V-3A). Similar to the implemented technology case, state corporate income and sales taxes could make up most of the state's total direct revenues, and personal income tax receipts could contribute the remainder (Illinois does not levy a production tax on oil or gas). At \$24/B, total direct state revenues stimulated by advanced technology EOR could amount to \$27 million, \$16 million greater than implemented technology. At oil prices of \$28/B to \$32/B, advances in EOR technology could generate up to \$95 million in incremental revenues (over six times implemented technology potential). The \$110 million in direct state tax revenues at these prices would be a significant addition to the state treasury.

Direct state economic activity generated by Illinois EOR could also grow due to advanced technology. Figure V-3B displays the potential incremental direct economic benefits to the state for both the implemented and advanced technology cases. The advanced technology distribution of total economic benefits among the contributing components would be similar to the trend shown for the implemented technology case. At \$24/B, the incremental state economic gain attributable to advances in EOR technology could nearly double the amount in the implemented technology case, for a total potential of over \$540 million. At \$28/B, the direct state-wide economic gain could increase from less than \$225 million under implemented technology to over \$1.4 billion with advanced EOR technology development. At \$36/B, an additional \$1.6 billion in direct state economic activity could be generated by advanced technology EOR activities. At oil prices above \$24/B, advances in EOR technology could account for \$1.2 billion to \$1.4 billion of the increases in direct state economic activity. Clearly, the state of Illinois could accrue substantial benefits from the development and application of advanced EOR technology at all of the applicable oil prices considered in this analysis.

Figure V-2

Annual Production from EOR

Implemented Technology vs. Advanced Technology

A) At \$24/B

B) At \$32/B

Figure V-3

State Impact of EOR Production

Implemented Technology vs. Advanced Technology

A) Direct State and Local Revenues

* No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

B) Direct State Economic Activity*

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated

** No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

Advanced technology also has a substantial impact on the state's employment. Even at a moderate oil price of \$24/B, the development of advanced technology could create or maintain over 146 jobs more than implemented technology EOR by the year 2002 (not illustrated). At the higher oil price of \$32/B, over 157 jobs per year could be attributable to the development of advances in technology by the year 2002, for a total of over 283 jobs per year created or maintained by advanced technology EOR projects. Peak wages at \$24/B and \$32/B due to advances in EOR technology are estimated at \$6.7 and \$7.1 million, respectively, and would occur before the year 2005. Total peak wages at these prices would be \$11.6 and \$12.7 million, respectively.

4. Effects on the National Economy and Budget

As discussed in Chapter IV, increased oil recovery in the state of Illinois through EOR methods would benefit the nation in the areas of enhanced energy security, a reduced foreign trade deficit, import replacement, and expanded direct revenues to the Federal treasury. The potential benefits are significantly more pronounced with the development of advanced technology. Over 70 million barrels of crude oil could be added to proved reserves due to advanced EOR technology, 60 million barrels of which is attributable to technology advances.

Revenues to the Federal treasury, in the form of corporate and personal income taxes, could grow along with the increase in reserves as a result of advances in technology (Figure V-4A). At moderate oil prices below \$28/B, there would be no increase in Federal revenues. In fact, at \$24/B, there could be a decrease from implemented technology potential. This could be caused by the Federal EOR tax credit which provides an operator with a tax credit on investment costs for EOR projects. This credit can be used to offset profits from the project or other operators. At \$28/B, the increase in potential reserves could outweigh the value of the tax credit leading to an increase in direct Federal revenues. At this price, \$36 million in direct Federal revenues (75% of the \$48 million total potential) could be attributable to technology advances. At \$36/B, after the phaseout of the EOR tax credit, EOR technology advances could stimulate \$194 million in revenues over implemented technology, for a total potential of \$237 million in direct Federal revenues.

The increase in potential reserves could also lead to a decrease in imports which would reduce the trade deficit by the effective value of the increased domestic production. To the extent that one barrel of domestic production replaces one barrel of imported oil, the value of imports avoided due to technology

advances could be substantial. At \$24/B, over \$420 million of the total \$680 million in imports avoided through application of advanced technology EOR could be attributed to technology advances. At oil prices above \$24/B, EOR technology advances could stimulate \$1.7 billion to \$2.1 billion in avoided imports (Figure V-4B). The total import replacement at these prices (\$2.0 billion to \$2.6 billion) would represent a significant reduction in the foreign trade deficit.

C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE

I. "Advanced" Technology Defined

The unrecovered mobile oil (advanced secondary recovery) advanced technology analysis, designed to reflect the potential technological improvements possible from a focused RD&D program in geological reservoir characterization, is conducted in a manner consistent with the implemented technology analysis. A major assumption is that RD&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 at closer spacings. This will improve the project economics of advanced secondary recovery (ASR), resulting in more activity and much greater recovery under the advanced technology 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 unrecovered mobile oil 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 (homogeneous) segment and a less continuous (heterogeneous) segment. The economic recovery potential is evaluated independently in each segment, and the closest economic well spacing for each segment is independently selected.

The improved recovery methods discussed in this analysis could have a substantial impact on ASR reserve additions. Additional recovery could 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 parts per million). These improvements would increase the marginal impact of the profile modification and polymer flooding projected under the implemented technology case whether they are applied alone or in combination with infill drilling. Additional benefits were estimated from the reduction of the associated risk (modeled as a reduction in hurdle rates with technology advances as discussed in Chapter III) of ASR processes as currently implemented.

Figure V-4

National Impact of EOR Production

Implemented Technology vs. Advanced Technology

A) Direct Federal Revenues

* No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit.

** No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

2. Production and Reserves

The development of advanced technology ASR methods through RD&D could significantly increase the state's oil reserves. Advances in ASR technology could stimulate 12 million to nearly 40 million barrels of incremental reserves in the analyzed Illinois reservoirs. At oil prices of \$20/B and greater, incremental reserves due to technology advances could be 15% to 20% of the 70 million barrels of total potential incremental reserves from ASR. ASR is less sensitive than EOR to increases in oil price, and essentially the same increase is seen over the range of prices analyzed. The only exception would be at \$16/B when incremental reserves could increase by nearly 50 million barrels over implemented technology potential to over 60 million barrels of total incremental reserves from ASR (Figure V-5).

Table V-2A shows the distribution of incremental reserves by ASR process. Infill drilling in combination with profile modification or polymer flooding could be the most prolific advanced technology ASR method, contributing 88% to 98% of the total incremental reserves. Polymer flooding and profile modification alone increases from zero in the implemented technology case to only about 8 million barrels with advances in ASR technology. Under advanced technology, many of the implemented technology infill drilling projects could be converted to the more prolific combination projects, resulting in a sharp decrease in infill drilling potential.

Table V-2B shows the estimated number of economic ASR projects for both the implemented and advanced technology scenarios. At all oil prices analyzed, the number of infill drilling projects (applied alone) could drop by three to five projects under advanced technology. The number of combination projects (infill and polymer flooding or profile modification) could triple or quadruple, and a more than proportionate increase in incremental reserves attributable to combination processes could result. This can be explained by a shift to combination projects from infill drilling alone by those infill drilling projects which were less effective. Table V-2B also shows that the number of economic polymer flooding and profile modification projects under the advanced technology case could increase from the implemented case; the increase in incremental reserves from these processes at all oil prices considered could be directly attributable to technology advances. 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 (e.g., higher temperature and higher salinity). Such technological advances would make more reservoirs technically amenable to the economic application of chemical treatment processes. However, even with advanced technology, the number of polymer flooding and profile modification projects would not be not significant relative to the combination processes.

Figure V-5

Incremental Reserves by ASR Process Implemented Technology vs. Advanced Technology

Figure V-6 displays the projected annual production that could result from ASR technology advances for oil prices of \$16/B and \$32/B from the analyzed Illinois reservoirs. In both cases, a small, but significant, incremental amount of oil could be added to the state's production over the next 25 years. At \$16/B, yearly production would still be increasing by the year 2020, reaching as high as 1.7 million barrels in that year (1.3 million barrels of which is attributable to technology advances). At \$32/B, production would peak in the year 2016; advances in ASR technology would contribute 0.3 million barrels per year, 14% of the 2.2 million barrel per year peak.

3. Effects on State Revenues and Economic Activity

As in the implemented technology scenario, state corporate income taxes could make the largest contribution to state and local revenues, accounting for 50% to 75% of the additional direct state tax revenues at each analyzed oil price (Figure V-7A). At an oil price of \$16/B, ASR technology advances could account for \$35 million (78%) of the \$45 million in total potential state revenues. At oil prices of

Table V-2A

**Incremental Reserves from ASR by Process
Implemented Technology vs. Advanced Technology
(Million Barrels)**

Oil Price (\$/B)	Polymer Flooding and Profile Modification		Infill Drilling		Infill Drilling and Polymer Flooding or Profile Modification		Total	
	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*
\$16	0	1	0	0	12	60	12	61
\$20	0	8	43	0	13	62	56	70
\$24	0	8	45	0	13	62	58	70
\$28	0	8	47	0	13	63	60	71
\$32	0	8	47	0	13	63	60	71
\$36	0	8	47	0	13	64	60	72

* This is the total reserves from advanced technology -- implemented technology plus the increment due to technology advances.

Table V-2B

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

Oil Price (\$/B)	Polymer Flooding and Profile Modification		Infill Drilling		Infill Drilling and Polymer Flooding or Profile Modification		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
\$16	0	1	0	0	2	8	2	9
\$20	0	2	3	0	3	9	6	11
\$24	0	2	4	0	3	9	7	11
\$28	0	2	5	0	3	9	8	11
\$32	0	2	5	0	3	9	8	11
\$36	0	2	5	0	3	12	8	14

Figure V-6

Annual Production from ASR

Implemented Technology vs. Advanced Technology

A) At \$16/B

B) At \$32/B

\$24/B and higher, \$20 million to \$25 million in additional direct state revenues could be attributable to advances in technology, leading to a total direct state revenue potential of \$80 million to \$120 million.

Illinois could also benefit from the stimulation of additional in-state economic activity by advanced technology ASR activities; however, advances in ASR technology only marginally increase state economic activity relative to the implemented technology case at oil prices above \$16/B (Figure V-7B). At \$16/B, ASR technology advances could add over \$550 million to state economic activity, for a total of over \$700 million. At higher oil prices, \$44 million to over \$112 million (4% to 10%) of the \$870 million to \$1.3 billion in additional state economic activity could be attributed to advances in ASR technology.

4. Effects on the National Economy and Budget

The development of advanced technology for recovery of the known UMO resource in the state of Illinois could also benefit the nation. An additional 60 to 70 million barrels of reserves could replace imports and enhance the nation's energy security and independence. The additional reserves could also have an economic impact at the national level.

Application of advanced ASR technology would significantly increase direct Federal revenues, specifically through increases in corporate and personal income tax receipts (Figure V-8A). At oil prices below \$32/B, technology advances account for between \$20 million and \$40 million of the \$60 million to \$260 million in additional direct Federal revenues. At oil prices of \$32/B and \$36/B, the additional direct Federal revenues could be even higher as the EOR tax credit (which can be applied to the use of polymer gels and foams in ASR processes) begins to phaseout. ASR technology advances could contribute from \$80 million to over \$110 million in direct Federal revenues for a total potential of over \$450 million in direct Federal revenues from advanced technology ASR activities.

To the extent that each additional barrel of domestic oil production replaces a barrel of imports, the foreign trade deficit could be reduced as the value of the produced oil is spent domestically rather than abroad. The avoided imports due to advanced technology ASR could be most substantial at \$16/B (Figure V-8B). At this oil price, ASR technology advances could contribute over \$780 million (80%) of the \$975 million of avoided imports. At higher oil prices, the increment due to technology advances could be between \$300 million and \$450 million of the \$1.4 billion to \$2.6 billion in total replaced imports.

Figure V-7

State Impact of ASR Production

Implemented Technology vs. Advanced Technology

A) Direct State and Local Revenues

B) Direct State Economic Activity*

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated

Figure V-8

National Impact of ASR Production

Implemented Technology vs. Advanced Technology

A) Direct Federal Revenues

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit.

D. CONCLUSIONS

As discussed in Chapter III, currently available EOR and ASR technologies have the potential to significantly increase reserves and provide substantial economic benefits to operators, the states, and the nation. An aggressive and efficient technology transfer program in both the public and private sectors would bring these available technologies to operators and expedite their field applications. At an oil price of \$20/B, implemented technology EOR and ASR process could contribute over 55 million barrels to Illinois' reserves base. At \$28/B, potential incremental reserves could reach over 70 million barrels.

Advances in technology could significantly increase the potential incremental reserves and associated economic benefits which are possible using implemented technology EOR and ASR. Technology advances could increase implemented technology incremental reserves by over 20%, adding 15 million barrels of oil, at an oil price of \$20/B. The total potential at this price, over 70 million barrels of incremental reserves, is nearly 55% of Illinois 1991 proved reserves. At an oil price of \$28/B, technology advances could stimulate over 70 million barrels of incremental reserves for a total EOR and ASR potential of over 140 million barrels. If this potential were to be realized, advanced technology EOR and ASR could more than replace Illinois 1991 proved reserves.

The activities associated with advanced technology EOR and ASR would generate substantial direct state tax revenues. At \$20/B, \$18 million of the \$66 million of potential direct state revenues are attributable to technology advances. At an oil price of \$28/B, over 55% (\$118 million) of the \$206 million in total potential state revenues are due to advances in technology.

The potential benefits estimated in this analysis will not be possible, however, without effective technology transfer and RD&D programs. Aggressive technology transfer needs to be undertaken by all oil-related entities (operators, producer associations, research universities, state geologic surveys, and state and Federal government agencies) in order to ensure that currently available technologies are disseminated in the oil patch and widely applied in the field. The significant additional benefits derived from technology advances clearly warrant a focused RD&D program to improve advanced oil recovery technologies.

A collaborative effort between the public and private sectors is essential to pool resources and expertise while leveraging risk. Operators, oil companies, research universities, and state geologic surveys

need to join with state and local governments and the Federal government to identify the highest priority problems in reservoirs with the largest remaining resources and the greatest threat of abandonment. A focused RD&D effort targeting the identified problems then needs to be undertaken. An RD&D effort alone is not enough, however; the newly developed technologies need to be transferred to the field for wide-scale demonstration and application. The Department of Energy's Program Opportunity Notice (PON) process is currently applying some of these concepts. The PON process targets those classes of reservoirs with the largest potential resource and greatest threat of abandonments. Near- and mid-term RD&D efforts, jointly funded by the Federal government and private industry, are directed towards the producing problems of these reservoirs. The results, once successfully developed and demonstrated, are to be transferred to other operators facing similar producing conditions. While they are a start, efforts like the PON process are not enough. A more aggressive and focused collaborative RD&D effort will greatly increase domestic production, enhance national energy security, reduce imports, and increase economic benefits associated with oil recovery.

Even after application of advanced technology EOR and ASR, large portions of the oil resource will remain unrecovered in the analyzed reservoirs (Figure V-9). At the improbably high oil price of \$36/B, total ASR reserves potential would be 72 million barrels while EOR reserves potential would total 71 million barrels. If this reserves potential were realized, over 680 million barrels of mobile oil (91% of the mobile oil target) and 2.6 billion barrels of immobile oil (97% of the immobile oil target) would remain in analyzed Illinois reservoirs. In addition, over 2.2 billion barrels of remaining oil not included in this analysis, and any newly discovered oil, would still be unrecovered after application of advanced technology EOR and ASR. The known remaining oil-in-place of over 5.5 billion barrels is the target for further advances in EOR and ASR technologies.

Figure V-9

Illinois Remaining Oil Resource After Advanced Technology Recovery

DOE/BC/14431-1 (Vol. 5)
Distribution Category UC-122

AN EVALUATION OF KNOWN REMAINING
OIL RESOURCES IN THE STATE OF OKLAHOMA

Project on Advanced Oil Recovery and the States

Volume V

November 1994

Work Performed Under Contract DE-FG22-89BC14431

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

R. Michael Ray, Project Manager
Bartlesville Project Office
P.O. Box 1398
Bartlesville, OK 74005

Prepared by
Interstate Oil Compact Commission
900 N.E. 23rd Street
Oklahoma City, OK 73152

TABLE OF CONTENTS

	<u>Page</u>
LIST OF FIGURES	v
LIST OF TABLES	vii
ACKNOWLEDGEMENTS	viii
EXECUTIVE SUMMARY	ix
 I. OVERVIEW	
A. THE PROBLEM: DECLINING OKLAHOMA OIL PRODUCTION	I-1
B. THE OPPORTUNITY: OIL RECOVERY THROUGH ADVANCED TECHNOLOGY	I-2
C. BENEFITS DERIVED FROM IMPROVED OIL RECOVERY	I-5
D. CONCLUSIONS	I-10
 II. BACKGROUND AND OBJECTIVES	
A. TRENDS IN OKLAHOMA PRODUCTION AND RESERVES	II-1
B. IMPROVED RECOVERY ACTIVITIES TARGETING THE REMAINING RESOURCE	II-8
1. Enhanced Oil Recovery	II-8
2. Advanced Secondary Recovery	II-9
C. OBJECTIVES OF THE PRESENT STUDY	II-12
 III. APPROACH TO THE ANALYSIS	
A. INTRODUCTION	III-1
B. GENERAL METHODOLOGY: THE NPC BASIS	III-1
C. BUILDING ON TORIS: THE EVALUATION OF UNRECOVERED MOBILE OIL RESOURCES	III-6
D. SCOPE OF THE ANALYSIS	III-9
E. ADAPTATIONS FOR THE PRESENT STUDY	III-11
1. Data Editing and Additions	III-11
2. State and Federal Taxes	III-11
3. Cost and Price Data	III-12
4. Benefits Estimation	III-13
5. Project Timing	III-13
F. ESTIMATION OF BENEFITS, COSTS, AND ECONOMIC IMPACTS	III-14
1. Benefits to State and Local Treasuries	III-15
2. Direct State Economic Effects	III-15
3. National Effects	III-16
G. LIMITATIONS TO THE ANALYTICAL APPROACH	III-18

TABLE OF CONTENTS (continued)

	<u>Page</u>
IV. INCREASED RECOVERY FROM THE KNOWN REMAINING OIL RESOURCE IN OKLAHOMA UNDER IMPLEMENTED TECHNOLOGY	
A. INTRODUCTION	IV-1
B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE	IV-1
1. Production and Reserves	IV-1
2. Increases in State and Local Revenues	IV-2
3. Effects on the State Economy	IV-5
4. Effects on the National Economy	IV-6
C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE	IV-8
1. Production and Reserves	IV-8
2. Increases in State and Local Revenues	IV-13
3. Effects on the State Economy	IV-13
4. Effects on the National Economy and Budget	IV-14
D. CONCLUSIONS	IV-16
V. BENEFITS OF INCREASED RECOVERY FROM THE KNOWN REMAINING OIL RESOURCE IN OKLAHOMA WITH TECHNOLOGY ADVANCES	
A. INTRODUCTION	V-1
B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE	V-1
1. "Advanced" Technology Defined	V-1
2. Production and Reserves	V-2
3. Effects on State Revenues and Economic Activity	V-5
4. Effects on the National Economy and Budget	V-8
C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE	V-9
1. "Advanced" Technology Defined	V-9
2. Production and Reserves	V-11
3. Effects on State Revenues and Economic Activity	V-14
4. Effects on the National Economy and Budget	V-16
D. CONCLUSIONS	V-19

LIST OF FIGURES

<u>Figure</u>	<u>Page</u>
I-1	Oklahoma Oil Resource I-1
I-2	Oklahoma Production and Reserves I-3
I-3	Oklahoma Oil Resource - Data Coverage of EOR and ASR Analyses I-6
I-4	Potential Impact of Advanced Technology I-8
I-5	Oklahoma Remaining Oil Resource After Advanced Technology Recovery I-11
II-1	Oklahoma Crude Oil Production (1950-1991) II-2
II-2	Oklahoma Crude Oil Reserves (1950-1991) II-2
II-3	Oklahoma Producing Wells (1960-1991) II-3
II-4	Oklahoma Stripper Well Production and Abandonments (1970-1990) II-3
II-5	Total Oil and Gas Employment in Oklahoma (1970-1991) II-5
II-6	Annual Wellhead Value of Oklahoma Oil and Gas Production (1961-1991) II-5
II-7	Oklahoma Oil and Gas Severance Taxes (FY1971-1992) II-6
II-8	Oklahoma Oil and Gas Severance Taxes as a Percent of Total State Taxes (FY1971-1992) II-6
II-9	Oklahoma Oil Resource II-7
II-10	Oklahoma Remaining Oil Resource After Conventional Operations II-13
IV-1	Reserves and Production Response from CO ₂ -Miscible EOR Techniques - Implemented Technology IV-4
IV-2	Direct State and Local Revenues from EOR Production - Implemented Technology IV-5
IV-3	Direct State Economic Activity from EOR Production IV-7
IV-4	Jobs and Wages from EOR Production IV-7
IV-5	National Impact of EOR Production - Implemented Technology IV-9
IV-6	Reserves and Production Response from ASR Techniques - Implemented Technology IV-12
IV-7	Direct State and Local Revenues from ASR Production - Implemented Technology IV-14
IV-8	Direct State Economic Activity from ASR Production IV-15
IV-9	Jobs and Wages from ASR Production IV-15
IV-10	National Impact of ASR Production - Implemented Technology IV-17
IV-11	Oklahoma Remaining Oil Resource After Implemented Technology Recovery IV-18
V-1	Incremental Reserves by EOR Process - Implemented Technology vs. Advanced Technology V-3
V-2	Annual Production from EOR Reserves - Implemented Technology vs. Advanced Technology V-6
V-3	State Impact of EOR Production - Implemented Technology vs. Advanced Technology V-7

LIST OF FIGURES (continued)

<u>Figure</u>		<u>Page</u>
V-4	National Impact of EOR Production	
	- Implemented Technology vs. Advanced Technology	V-10
V-5	Incremental Reserves by ASR Process	
	- Implemented Technology vs. Advanced Technology	V-12
V-6	Annual Production from ASR Reserves	
	Implemented Technology vs. Advanced Technology	V-15
V-7	State Impact of ASR Production	
	- Implemented Technology vs. Advanced Technology	V-17
V-8	National Impact of ASR Production	
	- Implemented Technology vs. Advanced Technology	V-18
V-9	Oklahoma Remaining Oil Resource After Advanced Technology Recovery	V-21

LIST OF TABLES

<u>Table</u>	<u>Page</u>
I-1	Summary of Benefits from Technology Advances in EOR and ASR in Oklahoma I-9
III-1	Key Elements in the Current TORIS Reservoir Data Base III-3
III-2	Screening Criteria for EOR Candidates - Implemented Technology Case III-4
III-3	Screening Criteria for EOR Candidates - Advanced Technology Case III-5
III-4	Screening Criteria for Advanced Secondary Recovery Processes III-8
III-5	Screening and Approach for Advanced Technology Infill Drilling III-9
III-6	Risk Premium for Implemented and Advanced EOR and ASR Processes III-10
III-7	Labor and Materials as Percentage of Total Cost In EOR Projects III-17
IV-1A	Incremental Reserves from EOR by Process - Implemented Technology IV-3
IV-1B	Estimated Number of Economic EOR Projects by Process - Implemented Technology IV-3
IV-2A	Incremental Reserves from ASR by Process - Implemented Technology IV-11
IV-2B	Estimated Number of Economic ASR Projects by Process - Implemented Technology IV-11
V-1A	Incremental Reserves from EOR by Process - Implemented Technology vs. Advanced Technology V-4
V-1B	Estimated Number of Economic EOR Projects by Process - Implemented Technology vs. Advanced Technology V-4
V-2A	Incremental Reserves from ASR by Process - Implemented Technology vs. Advanced Technology V-13
V-2B	Estimated Number of Economic ASR Projects By Process - Implemented Technology vs. Advanced Technology V-13

ACKNOWLEDGMENTS

An Evaluation of the Known Remaining Oil Resource in the State of Oklahoma is one in a series of reports of the Project on Advanced Oil Recovery and the States, conducted by the Interstate Oil and Gas Compact Commission (IOGCC). The overall project was initiated by "seed money" grants from the States of Oklahoma and New Mexico in 1985. This report was prepared under grant number DE-FG22-89BC14431 from the U.S. Department of Energy, Bartlesville Project Office (BPO) to the IOGCC.

The analysis presented in this report is based on an updated and upgraded version of the databases and models developed by the National Petroleum Council (NPC) in 1984. 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 C. Wesson, BPO Director, for his encouragement and assistance.

Special recognition is due to those who directly performed the work of the project. ICF Resources Incorporated of Fairfax, Virginia, served as the IOGCC's principal contractor, responsible for the study design, computer modeling, analysis, interpretation, and report preparation. ICF's Project Director was Dr. Jerry P. Brashear; Mr. Khosrow Biglarbigi was the Project Manager; and the critical project staff included Mr. Hugh D. Guinn, and Mr. Donald J. Remson (engineering and computer modeling); Mr. Karl Lang, Dr. Frank Morra (Consultant), and Mr. Jeff Enright (analysis and report generation); Mr. Marc Greenberg, Ms. Sohinaz Sotoudeh, and Mr. Mike Schildkraut (editing, research, and analytical support); Mr. Alan B. Becker (Final Review); Ms. Barbara Jones (Administrator), Ms. Cheryl A. Labrecque (Senior Staff Assistant), Ms. Mary Bowers (Staff Assistant) and Ms. Barbara Gillen (word processing support).

Special recognition is also due to the members of the DOE/IOGCC Peer Review Committee; Mr. Lloyd Elkins, Dr. Alan Emanuel, Dr. Lee Gerhard, Dr. Donald Green, Dr. John D. Haun, Mr. Joseph E. King, Dr. Charles Mankin, Dr. David Martin, Dr. Donald Oltz, Dr. Fred H. Poettmann, Mr. William C. Stewart, and Dr. G. Paul Willhite.

This analysis was conceived and commissioned by W. Timothy Dowd, Executive Director of the IOGCC through June 1993. Mr. Dowd's keen interest in promoting the development of the nation's resource base has been the guiding force behind this study. To the degree that the results of this work help to improve the recovery of oil from U.S. reservoirs, Mr. Dowd's goals for the IOGCC will have been furthered. Mr. Bob Cooper, former Associate Director of the IOGCC, and Mr. Jerry Simmons (Associate Director) provided liaison and coordination among the participating organizations.

While acknowledging the assistance of all these contributors, error of fact, analysis, or interpretation are the responsibility of the IOGCC and the principal contractor's project director.

Christine Hansen
Executive Director
November 1993

EXECUTIVE SUMMARY

The Interstate Oil and Gas Compact Commission (IOGCC) has conducted a series of studies to evaluate the known, remaining oil resource in twenty-three (23) states. The primary objective of the IOGCC's effort is to examine the potential impact of an aggressive and focused program of research, development, and demonstration (RD&D) and technology transfer on future oil recovery in the United States. As a part of this larger effort by the IOGCC, this report focuses on the potential economic benefits of improved oil recovery in the state of Oklahoma. Individual reports for seven other oil producing states and a national report have been separately published by the IOGCC. Several major technical insights for state and Federal policymakers and regulators can be reached from this analysis.

- At the conclusion of conventional recovery operations, nearly two-thirds of the known original-oil-in-place will remain in Oklahoma oil reservoirs.
- The remaining resource, over 27 billion barrels, is the target for future improved oil recovery techniques. However, a significant portion of this remaining oil resource has already been abandoned. An even greater portion is in imminent danger of abandonment if cost-effective and efficient recovery techniques are not applied.
- Resource abandonment will significantly impact the economic producibility of future production and reserves under improved oil recovery techniques. This is because major capital investments will be needed to reacquire the leases, rebuild the infrastructure, and more importantly, drill new wells to regain access to the Oklahoma target resource.
- Oklahoma's future as a premier energy producing state depends very strongly on the development of efficient and cost-effective oil recovery technologies, technology transfer to domestic producers, and the timely and successful application of such technologies, given the steady decline in Oklahoma production and reserves and the increased level of well abandonment over the last decade.
- The effective transfer of existing technology could result in 900 million to 1.2 billion barrels of new reserves from analyzed Oklahoma reservoirs at oil prices ranging from \$20/B to \$28/B, more than replacing Oklahoma 1991 proved reserves.
- Technology advances resulting from a focused RD&D effort could result in *additional* post-conventional reserves of 0.6 to 1.1 billion barrels. The effective transfer of existing technology, coupled with the development and application of new technologies, could double or triple current proved reserves in Oklahoma, over the \$20/B to \$28/B price range.
- Public sector revenues from future improved oil recovery activity would total between \$4.5 and \$7.5 billion given currently available recovery practices and oil prices of \$20/B to \$28/B. Technology advances could increase these totals by \$2.0 to \$4.7 billion over the same price range, with roughly 50% of the total flowing to the state treasury.

- Potential improved oil recovery would replace imports of foreign oil, keeping between \$18 billion and \$31 billion in the U.S. economy. This figure is only the direct cost of imports avoided due to increased domestic activity. The true value to the country is actually higher due to multiplier effects as this money circulates.

The analysis presented in this report is based on the databases and models available in the Tertiary Oil Recovery Information System (TORIS). TORIS is a tested and verified system maintained and operated by the Department of Energy's Bartlesville Project Office. The TORIS system was used to evaluate over 117 major Oklahoma reservoirs in a consistent manner and on an individual basis, the results of which have been aggregated to arrive at the statewide total as discussed in this report.

Overall, well abandonments and more stringent environmental regulations could limit economic access to Oklahoma's known, remaining oil resource. The high risk of near-term abandonment and the significant benefits of future application of improved oil recovery technology clearly point to a need for more aggressive transfer of currently available technologies to oil producers. Development and application of advanced oil recovery technologies could have even greater benefits to the state and the nation. A collaborative, focused RD&D effort, integrating the resources and expertise of industry, state and local governments, and the Federal government, is clearly warranted. With effective RD&D and a program of aggressive technology transfer to widely disseminate its results, Oklahoma oil production could be maximized. The resulting increase in production rates, operator profits, state and Federal tax revenues, and energy security will benefit both the state of Oklahoma and the nation as a whole.

I. OVERVIEW

A. THE PROBLEM: DECLINING OKLAHOMA OIL PRODUCTION

Nearly two-thirds of the oil discovered in the state of Oklahoma will remain trapped in the reservoir at the conclusion of conventional oil recovery operations. The total known original oil-in-place in Oklahoma has been estimated at 41.5 billion barrels (Figure I-1). More than 13 billion barrels had already been produced at the end of 1991. Roughly 700 million barrels of proved reserves are still producible under existing economic conditions, using currently available technologies. The remaining 27.4 billion barrels is the target for newer, more efficient recovery technologies and advances in geoscientific understanding that must be developed through an integrated public and private research effort.

Figure I-1

Oklahoma Oil Resource

The urgency for technology development and its effective application by Oklahoma oil producers has never been greater. The two factors that have combined to make technology development critical are:

- Declining state production and reserves. Oklahoma oil production has declined by 35% from 1984 through 1991 (Figure I-2A). Crude oil reserves decreased by more than 20% over the same time period (Figure I-2B). The average size of new field discoveries has been relatively small and reserves per well has decreased.
- Increased level of well abandonment. The state of Oklahoma currently produces oil from roughly 94,000 wells. Many of these wells are "marginal" wells producing at or near their economic limit. In 1990, over 70% of Oklahoma production came from stripper wells. Once production ceases, these wells must be routinely tested to prove that they are not pollution hazards, and plugged and abandoned if they fail the test. In a period of high production costs and low oil price, many of these wells are being abandoned. A recent analysis by the Department of Energy (DOE) has concluded that from 37% to 45% of the nation's remaining oil resources had been abandoned by the end of 1991.¹ Well abandonments will have a significant impact on economic access to the remaining resource for application of future improved recovery techniques. It is estimated that once a lease is abandoned, it will require an oil price *increase* of \$10/B to \$25/B to rebuild the infrastructure and drill replacement wells.² Such an economic burden will not likely be justified by the incremental oil revenues from future improved recovery techniques.

The future of Oklahoma oil production and reserves depends very strongly on the development and application of cost-effective and efficient technology. In the past, technology advances have made substantial contributions to Oklahoma oil production. The development of new exploration techniques and secondary recovery technology has acted to reverse past production declines and has allowed Oklahoma to maintain and increase its producible oil and gas resources. Oil producers in the state of Oklahoma have also pioneered the development of enhanced oil recovery technologies, particularly improved waterflooding techniques. The opportunity exists for a program of RD&D, combined with an integrated program of technology transfer to all sectors of the Oklahoma petroleum community, to arrest the decline in production and maximize recovery of the state's oil resource.

B. THE OPPORTUNITY: OIL RECOVERY THROUGH ADVANCED TECHNOLOGY

The remaining oil resource constitutes a huge target for future recovery operations. The 27.4 billion barrels of known unrecovered oil in the state of Oklahoma is of two types: mobile oil and

¹ "Abandonment Rate of the Known Domestic Oil Resource", U.S. DOE, Bartlesville Project Office, Bartlesville, OK (June 1990).

² Brashear, J.P. et al "Effect of Well Abandonments on EOR Potential," JPT, December 1991.

immobile oil. Even though mobile oil is displaceable by water, it has been uncontacted or bypassed during conventional primary production or water flooding and thus remains unrecovered. Immobile oil is oil that is trapped in the reservoir pores by viscous and capillary forces and cannot be displaced by water.

The estimated unrecovered mobile oil (UMO) resource in Oklahoma is 9.6 billion barrels. This oil is an important target for future improved recovery efforts. Several improved primary and secondary recovery processes (infill drilling, profile modification, and polymer flooding), collectively referred to as advanced secondary recovery (ASR), could be used in innovative ways to produce a substantial portion of this resource. Processes such as these are relatively low in cost and could increase production levels quickly. While such techniques have already been used by some operators in selected reservoirs, continued research and aggressive technology transfer are critically needed to improve, streamline, and adapt these techniques to site-specific reservoir conditions and broaden their applications.

The 17.8 billion barrel remaining *immobile* oil resource in Oklahoma is the target of a number of other recovery techniques. Miscible, chemical, and thermal recovery processes directed at producing immobile oil are referred to as enhanced oil recovery (EOR). While these processes generally require larger investments and higher operating costs than conventional recovery ones, they are capable of producing substantial volumes of incremental oil with substantial economic benefits. Further advances in EOR technology are foreseeable if a focused, research-intensive approach is adopted to make process improvements ready for field application.

Technology Assessment Method

The benefits of RD&D in oil recovery technology assessed in this report are based on the models and databases available through the Tertiary Oil Recovery Information System (TORIS). The TORIS methodology and analytical tools were originally developed by the National Petroleum Council (NPC)³ for its 1984 evaluation of nationwide EOR potential. DOE has since maintained and updated the system through its Bartlesville Project Office (BPO).⁴ DOE has also upgraded the capability of the system to

³ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

⁴ *Producing Unrecovered Mobile Oil: Evaluation of Potential Economically Recoverable Reserves in Texas, Oklahoma, and New Mexico*, DOE, May 1990.

Figure I-2

Oklahoma Production and Reserves

A) Annual Production

B) Reserves

Figure I-3

Oklahoma Oil Resource

Data Coverage of EOR and ASR Analyses

Source: BPO TORIS, 1992
EIA, 1992
API/AGA, 1980

evaluate the nation's unrecovered mobile oil through ASR techniques. In this report, the future potential of EOR and ASR techniques are examined with the following key assumptions and considerations:

- A total of 117 Oklahoma reservoirs, accounting for nearly 27 billion barrels of original oil-in-place, were individually analyzed for their EOR and ASR potential.
- Two levels of technology are considered: (1) implemented technology -- defined as the application of currently available post-conventional techniques, and (2) advanced technology -- defined as the improvements in process performance and applicability which are likely to occur over the next decade as the result of ongoing RD&D efforts.
- For each technology level, benefits were evaluated at several oil prices ranging from \$16/B to \$36/B (1991 dollars).
- All economic analyses reflect the current Federal tax structure and the specific oil production tax situation in Oklahoma. The FY 1991 Federal EOR tax credit, as well as state EOR and ASR tax incentives are included in this analysis.
- The results presented in this report reflect only the benefits and reserve potential associated with the 117 analyzed reservoirs (more than 64% of total known Oklahoma OOIP as shown in Figure I-3). No attempt is made to extrapolate the results to the remaining Oklahoma resource not available in the TORIS database.
- All recovery potential evaluated in this report are for future new projects only, and they do not include incremental reserves from existing EOR projects. However, the expansion to the existing projects, if technically and economically feasible, are evaluated as part of future new projects in this report.

C. BENEFITS DERIVED FROM IMPROVED OIL RECOVERY

Potential incremental reserve volumes and resulting direct state and local revenues that could be generated through improved oil recovery (EOR and ASR) techniques under both the implemented and advanced technology cases are shown in Figure I-4. Implemented technology, if more widely applied, could add between 0.9 and 1.2 billion barrels of incremental reserves across the entire oil price range. Advanced technology applied to the same resource base could stimulate an additional 0.4 to 1.3 billion barrels of incremental resources. In effect, improvements in process performance and application could nearly double the reserves possible under implemented technology conditions. This clearly provides a major justification for a focused RD&D and technology transfer program.

The potential for expanded application of EOR techniques using implemented technology is negligible if prices remain at or below \$20/B. Incremental recovery at a price of \$28/B would total only about 160 million barrels. However, over a price range of \$20/B to \$28/B, advances in EOR technology

could stimulate an additional 220 to 810 million barrels of incremental reserves. This means that a total of 220 million to 970 million barrels of potential EOR recovery exists under the two levels of technology at oil prices of \$20/B to \$28/B.

Reserve additions attributed to ASR techniques are substantial but are impacted much less by oil price changes than EOR. About 900 million barrels of ASR reserves could be added in the implemented technology case at an oil price of \$20/B, growing only slightly to 960 million barrels as oil prices increase to \$28/B. Research on process improvements, specifically improved polymer flooding and profile modification combined with geologically targeted infill drilling, could increase ASR potential by more than 40%. With advances in technology, incremental ASR reserves could total about 400 million barrels more than implemented technology over the price range analyzed, for a total of 1.3 billion barrels of potential ASR reserves.

Future advanced oil recovery activities will generate revenues for Oklahoma and the Federal treasury 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 or national economy. Under implemented technology at \$20/B, newly implemented improved oil recovery projects in Oklahoma could directly generate \$1.3 billion in state revenues. At the same oil price, advanced technology could generate an additional \$0.7 billion, for a total of \$2.0 billion in state revenues (Figure I-4B). At an oil price of \$28/B, application of currently available EOR and ASR technology could contribute \$2.4 billion to the Oklahoma state treasury while the application of advanced methods could increase these revenues by an additional \$2.3 billion to a total of \$4.7 billion.

Increased production from EOR and ASR could offset oil imports, which in turn, would reduce the national trade deficit, and increase national economic activity. The value of the oil produced, the product of reserves and their effective oil price, is a simple measure of Oklahoma's contribution to reducing the trade deficit. As shown in Table I-1, this figure could total between \$18 billion and \$31 billion under the implemented technology scenario, over the \$20/B to \$28/B range. Advanced technology could further decrease imports by an *additional* \$12 billion to \$34 billion. The additional value of domestically produced oil by EOR and ASR techniques generates significant direct economic activities as capital spending, profits, royalties, and taxes are circulated through the U.S. economy rather than paid internationally to buy foreign oil.

Figure I-4

Potential Impact of Advanced Technology

A) Incremental Reserves

B) Direct State and Local Revenues

**Summary of Benefits from Technology Advances
in EOR and ASR in Oklahoma**

Table I-1

Oil Price and Technology Level	Potential Reserves (Billion Barrels)	Incremental State and Local Revenues (\$ Billions)	Incremental Imports Avoided** (\$ Billions)	Increased Federal Revenues (\$ Billions)
At \$16/B	0.9 0.4 1.3	1.0 0.5 1.5	13.8 8.0 21.8	2.3 1.0 3.3
At \$20/B	0.9 0.6 1.5	1.3 0.7 2.0	17.8 11.9 29.7	3.2 1.4 4.6
At \$24/B	1.0 1.0 2.0	1.8 1.6 3.4	23.8 24.3 48.1	4.1 1.8 5.9
At \$28/B	1.2 1.1 2.3	2.4 2.3 4.7	31.1 33.5 64.6	5.1 2.4 7.5
At \$32/B	1.2 1.2 2.4	2.9 2.5 5.4	37.4 37.5 74.9	6.6 4.1 10.7
At \$36/B	1.3 1.2 2.5	3.4 3.3 6.7	43.3 49.5 92.8	8.1 5.7 13.8
Implemented Technology Advanced Technology*	Total	Implemented Technology Advanced Technology*	Total	Implemented Technology Advanced Technology*

*Advanced is incremental over implemented technology.

**Imports Avoided = Reserves times effective wellhead price; to the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided estimates the reduction in foreign trade deficit.

D. CONCLUSIONS

The development, testing, and wide-scale application of currently available improved oil recovery technologies could stimulate incremental reserves of roughly 1 billion barrels from the state of Oklahoma's largest, most mature reservoirs at oil prices of \$16/B to \$24/B. With the technology advances resulting from focused RD&D, an additional one-half to one billion barrels could be produced over this price range using EOR and ASR techniques. Even with the successful development and application of these technologies, however, more than 10 billion barrels of immobile oil would still remain in the analyzed reservoirs as a long-term target for future advances in EOR, and more than 9 billion barrels of mobile oil would remain as a long-term target for future advances in ASR processes (Figure I-5). While this target is substantial, it unfortunately will not remain a target indefinitely. Well abandonments have already limited economic access to a portion of the resource. The timely development and application of new recovery technology is crucial to maintain economic access to the remaining domestic oil resource.

The results of this analysis have important policy implications. Domestic oil production generates significant direct revenues to Oklahoma and to the Federal government and substantial additional indirect benefits to both the state and national economies. In addition to stimulating reserves, production, and economic activity, the application of improved oil technology would enhance the nation's energy security. However, integrated efforts and initiatives are needed to achieve these goals. These efforts should include:

- Collaborative RD&D;
- Aggressive technology transfer; and
- Appropriate tax and regulatory policies at state and Federal levels.

A collaborative RD&D effort between the oil industry, universities, state and local governments, and the Federal government focused on improving advanced oil recovery technology and its application in key geologic settings would benefit operators, the state of Oklahoma, and the entire nation. 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 both the state and the nation's treasuries, economies, and citizens. State and Federal tax incentives can be instituted, or where already in place could be modified to improve their effectiveness, in order to help domestic EOR/ASR projects compete with foreign investment opportunities. In addition, regulatory policy makers could design regulations which reflect both the true risks to health, safety and the environment and the economic risk of resource loss through abandonment.

Figure I-5

Oklahoma Remaining Oil Resource After Advanced Technology Recovery

II. BACKGROUND AND OBJECTIVES

A. TRENDS IN OKLAHOMA OIL PRODUCTION AND RESERVES

Oil production in Oklahoma, the nation's fourth largest oil producing state, accounted for over 5% of the U.S. lower-48 production in 1991, even though statewide production had fallen to a post-World War II low. Technology advances, including waterflooding, caused Oklahoma production to increase throughout much of the 1960s, reaching a decade high level of almost 231 million barrels in 1967 (Figure II-1). Production then began a long decline continuing to this day, which was interrupted only by a brief period of recovery from 1980 to 1984 when oil prices reached their highest levels ever. From 1967 until 1979, the first period of major decline, production dropped to a 1979 low of 144 million barrels annually, an average decline of over 3% per year (Figure II-1). Production stabilized and increased slightly from 1980 to 1984, rebounding to almost 168 million barrels in 1984. The price collapse of 1985-1986 ended this period of improvement, and production has since dropped to an all-time low of 92 million barrels in 1992. This downward trend (over 5% decline per year) seems likely to continue in the future due to poor project economics brought about by low oil prices, limited technologies, and a relatively restricted number of remaining exploration and development opportunities in what has been an actively explored state.

Similar trends can be seen in Oklahoma's crude oil reserves (Figure II-2). Reserves peaked in 1955 at two billion barrels, but since then have declined steadily to less than 35% of that total. Although reserves fluctuated briefly during the exploration boom from 1980 to 1984, lower oil prices brought a resumption of the downward trend in the years that followed. At the peak of exploration, the number of Oklahoma producing wells jumped over 40%, climbing from fewer than 72,000 in 1975 to more than 102,000 in 1985 (Figure II-3). Well levels in the following five years declined to around 95,000 in 1990 but increased to over 101,000 wells in 1991. This increase is partially due to an increase in the number of well recompletions and operation of extra rigs. Most of these additional producing wells represent more intensive field development efforts by Oklahoma operators, as can be witnessed by the consistent declines in reserves per producing well since 1975 (Figure II-3). Oklahoma reserves per producing well now stand at close to 7,000 barrels, less than 40% of the 18,000 barrels reported in 1971.

Compounding the problem of reduced reserves and production is the increased number of economically marginal stripper wells over the past twenty years (Figure II-4). Stripper wells produce

Figure II-1

Figure II-2

Figure II-3

Oklahoma Producing Wells (1960 - 1991)

Source: World Oil; DOE/EIA

Figure II-4

Oklahoma Stripper Well Production and Abandonments (1970 - 1990)

Source: U.S. EIA and IOGCC

small quantities of oil (and often large volumes of water) and are extremely vulnerable to price changes. Another oil price collapse would result in mass abandonments of stripper wells and immediate loss of access to the reservoirs which are penetrated by them. For all intents and purposes, once reservoirs are abandoned and the wells are plugged, improved recovery techniques are economically infeasible.

Together, these trends indicate the maturity and advanced stage of development of Oklahoma's resource base. These trends have major implications for employment, economic activity, and the tax base in Oklahoma. In 1975, Oklahoma had over 38,000 people employed in the extraction of oil and gas (Figure II-5). This number rose to 102,000 in 1982, when drilling activity reached its peak, but has since declined to just over 40,000 in 1991. Over the same period, the wellhead value of oil produced in Oklahoma increased from \$2.8 billion (in constant 1991 dollars) in 1975 to a peak of \$6.5 billion in 1981, before plunging back to \$2.1 billion in 1991 (Figure II-6). These changes in employment and the production value of oil have adversely affected Oklahoma's tax base. Persistence of the oil production decline will continue to have a detrimental effect on the economic vitality of the state and its treasury, unless the slide can somehow be arrested.

Revenues from production taxes on oil and gas increased from \$211 million (in constant 1991 dollars) in 1973 to a peak of nearly \$871 million in fiscal year 1984, only to decline by 53% to \$412 million in fiscal year 1992 (Figure II-7). This significant loss in state revenues has been caused by the dual effect of lower product prices and declining oil and gas production, trends which expected to continue. The loss of oil and gas revenue has had a significant impact on total state tax revenues. In fiscal year 1983, when oil prices were still high, oil and gas production taxes contributed more than 26% of all state tax revenues in Oklahoma (Figure II-8). This percentage has fallen dramatically, to just over 10% of total tax revenues in fiscal year 1992. Oil production severance taxes represent more than 4% of the total taxes collected in Oklahoma. Despite significant revenue losses caused by the decline in oil and gas production, revitalization of the Oklahoma 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 could be maintained by encouraging the application of enhanced recovery techniques.

Vast quantities of Oklahoma's known oil resource will remain unrecovered in known reservoirs at the conclusion of conventional primary and secondary operations. The total known original oil-in-place (OOIP) in Oklahoma is estimated at 41.5 billion barrels (Figure II-9). Of this resource, 13.4 billion barrels

Figure II-5

Total Oil and Gas Employment in Oklahoma (1970 - 1991)

Figure II-6

Annual Wellhead Value of Oklahoma Oil and Gas Production (1961 - 1991)

Figure II-7

Oklahoma Oil and Gas Severance Taxes (FY1971 - 1992)

Figure II-8

Oklahoma Oil and Gas Severance Taxes as a Percent of Total State Taxes (FY1971 - 1992)

have already been produced, and 700 million barrels were recognized as proved reserves at the end of 1991, for a total estimated ultimate recovery by conventional technology of 14.1 billion barrels. The remaining 27.4 billion barrels, nearly two-thirds of the total known resource, remains as the target for newer, more efficient extraction technologies.

The 27.4 billion barrels of remaining unrecovered oil falls into two categories: mobile and immobile oil. Unrecovered mobile oil, which has been bypassed by conventional primary and secondary recovery efforts, accounts for 9.6 billion barrels of the unrecovered resource. This oil is the target for polymer flooding, profile modification, and infill drilling, known collectively as advanced secondary recovery (ASR). The remaining 17.8 billion barrels represent immobile oil that must be recovered by a variety of tertiary recovery technologies that are collectively known as enhanced oil recovery (EOR).

Figure II-9

Oklahoma Oil Resource

Should ASR and EOR projects be actively initiated in Oklahoma, much of the state's production and oil activity could be sustained well into the next century. A brief discussion of the analyzed EOR and ASR processes is contained in Volume X, Appendix A.

B. IMPROVED RECOVERY ACTIVITIES TARGETING THE REMAINING RESOURCE

The oil remaining after conventional primary and secondary recovery lies in two defined regions within each reservoir: the swept and the unswept zones. In the swept 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 with water can produce very little of this oil; the swept zone is at the "waterflood residual" level of oil saturation. The volume previously occupied by displaced oil now contains injected water (or, in some cases, natural gas). In their current stage of development, EOR processes are generally expected to reach only those portions of reservoirs previously swept by conventional techniques.

In the unswept zone of the reservoir, conventional recovery processes have not swept the pore space, and the oil saturation can range from low to high depending upon the primary recovery mechanism (e.g., pressure depletion or water drive). The objective of many infill drilling programs, improved waterflooding projects (profile modification), and other reservoir management techniques is to contact the oil in the unswept zones. Only after these zones have been swept by water are EOR operations generally considered feasible.

1. Enhanced Oil Recovery

Proven enhanced recovery processes are classified into three EOR categories: gas-miscible, chemical, and thermal. Miscible flooding projects have been ongoing for several years in Oklahoma. At least two of this state's projects used nitrogen as an injectant. Phillips has performed nitrogen flooding in the Binger field of Caddo County since 1977. The results have been very successful with production of 1,800 barrels of oil per day. Another type of injectant used in Oklahoma is hydrocarbon; Oxy USA has been using this in the Northeast Purdy field in Garvin County to produce more than 2,000 barrels of oil per day. Despite limited availability of carbon dioxide, operators commonly utilize it for flooding. Several pilot projects and at least one commercial project have been conducted using this injectant.

ARCO's Garber field in Garfield County showed successful recovery results utilizing carbon dioxide flooding. The carbon dioxide-miscible projects in Oklahoma received this gas from an industrial source. Cities Service and Atlantic Richfield built a 140-mile pipeline to take carbon dioxide from Farmland Industries' fertilizer plant near Enid, and deliver it to the Garvin and Stephens counties' fields. This pipeline, which can transport 33 million cubic feet of carbon dioxide per day, started its delivery in September 1982.

Chemical flooding EOR (surfactant and alkaline flooding) has shown some promise in Oklahoma. Nevertheless, the high cost of chemicals combined with limited field applications have made these projects economically risky, especially in periods of fluctuating oil prices. The development of low cost, widely applicable chemicals is necessary for this technique to achieve its full potential. In particular, alkaline flooding has limited applications and potential, due to the characteristics of the reservoirs in Oklahoma.

Thermal EOR processes include steam drive, steam soak, and in-situ combustion. The hydrocarbon displacement properties and the economics of steam soak and steam drive processes have been extensively demonstrated in several locations, especially California. 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. At least one steam project is underway in Sho-Vel-Tum field of Carter County in Oklahoma, with promising results. Despite some promising projects, its further application to Oklahoma's reservoirs may be limited due to unfavorable reservoir characteristics and relatively higher process costs. Thermal recovery, however, remains the prevalent EOR technique in the U.S., and therefore, could ultimately have wider applications in Oklahoma.

2. Advanced Secondary Recovery

Mobile oil remains in the reservoir after conventional recovery for a variety of reasons. Foremost of these is reservoir heterogeneity, the complex variation of rock properties among zones in the producing interval. 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 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 wide well spacings, significant volumes of oil are areally bypassed due to small-scale variations in reservoir continuity, to the higher viscosity of oil than injected water, and to permeability variations within the reservoir. The effectiveness of water injection is further limited by vertical layering in the reservoir. 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 production of unrecovered mobile oil (UMO). 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 may have very similar internal reservoir architecture, but will be modified by post-depositional diagenesis. That modification will vary from basin to basin depending on geohistory.

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 tested and proven methods for producing mobile oil remaining in the reservoir.

The effectiveness of infill drilling has been demonstrated in many Oklahoma reservoirs. In the Mississippi Limestone in southwestern Garfield County, Oklahoma, infill drilling began as early as 1970. Union Texas Division of Allied Chemical Corporation drilled new wells to test the adequacy of drainage by the original well. The results justified additional developments, and a significant number of new wells

have since been drilled.¹ Throughout the years, operators have been able to decrease the average drilling times and well costs by approximately 45% through the optimization of both air and mud drilling practices, streamlining of casing programs, and an increased ability to avoid downhole problems.² The results have indicated recovery improvements that are attractive under the current economic conditions. Further advancement in technologies used in this process will optimize the recovery level, and thus increase this technique's profitability.

Clearly, some portion of the oil bypassed at current spacing can be recovered by well-designed, advanced waterflooding techniques, and significant portions of this oil could be recovered with the combined application of both polymer injection and infill drilling. Polymer flooding seems to be the current process of choice in Oklahoma. Over 20 polymer projects have been conducted since 1980 by Mobil, Phillips, and other operators. These projects have been generally proven to be economically profitable. Although high chemical costs constrain its utilization at low oil prices, polymer flooding holds significant potential for future recoveries. Profile modification also could significantly increase production in Oklahoma.

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

There are several other processes and recovery techniques which were not included in this analysis which may have potential in Oklahoma. Application of these techniques would further increase potential recovery and add to the estimates contained in this analysis. Immiscible gas and nitrogen gas EOR projects could enhance Oklahoma oil recovery. In addition, improvements in reservoir management and

¹ Maddox, G.D., "Infill Drilling in the Mississippi Limestone — Garfield County, Oklahoma," SPE Paper No. 6462, 1977.

² Flournoy, C.M., "The Optimization of the Red Oak Infill Drilling Program in the Arkoma Basin," SPE Paper No. 18054, 1988.

improvements in waterflood patterns, waterflood rates of injection, and the timing of inception of water floods show significant potential as recovery techniques. To the extent that these techniques and others currently being transferred (i.e., injection water compatibility) improve potential oil recovery, the results presented in this report will be understated.

C. OBJECTIVES OF THE PRESENT STUDY

The present study analyzes the incremental reserves, public sector revenues, and statewide economic activity that could result from the implementation of the improved EOR and ASR techniques described above. The potentials for EOR and ASR production are evaluated separately, and each is considered for two technology levels: *implemented technology*, which assesses recovery potential given the widespread application of currently available technology, and *advanced technology*, which assesses the impact of the effective 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 RD&D. All of the analyses are conducted over a range of crude oil prices from \$16 to \$36 per barrel (in constant 1991 dollars). This price range encompasses the long-term prices likely to prevail over approximately the next 30 years.

One hundred and seventeen reservoirs, accounting for 26.6 billion barrels of original oil-in-place (over 64% of the total known resource in Oklahoma), were included in this analysis. These reservoirs contain 18.2 billion barrels of remaining oil resource (Figure II-10). The 6.6 billion barrels of UMO is the target for application of ASR processes and 11.6 billion barrels is the target for application of EOR processes. To achieve the required level of application, and therefore receive the maximum benefits of both levels of technology assessed in this report, it is critical that state and local governments, the Federal government, and the oil industry work collaboratively to: (1) effectively transfer to operators currently available technology (implemented technology), and (2) develop a focused RD&D program to improve recovery methods (advanced technology) and subsequently transfer those methods to a broad public-private audience. The results and conclusion will provide valuable insights for state and Federal policymakers in their efforts to maximize domestic production and improve the nation's energy security.

Figure II-10

Oklahoma Remaining Oil Resource After Conventional Operations

III. APPROACH TO THE ANALYSIS

A. INTRODUCTION

This analysis was performed using the Department of Energy's Tertiary Oil Recovery Information System (TORIS) developed for the 1984 National Petroleum Council (NPC) analysis of the nation's enhanced oil recovery (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, the target for advanced secondary recovery (ASR). The upgraded TORIS system assessed the recovery potential of immobile oil and UMO in the United States. The following sections in this chapter will briefly discuss the:

- Development of TORIS;
- Enhancement of TORIS to evaluate the UMO resource;
- Scope of the current analysis;
- Adaptations to TORIS for this analysis;
- Estimation of benefits, costs, and economic impacts; and
- 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 the 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 industry (majors, independents, service companies, and consulting firms), universities, government, and private, non-profit organizations participated. The NPC EOR study committee utilized and built upon data bases

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

of individual reservoir characteristics and computer models that were under development by the U.S. Department of Energy's (DOE), Office of Fossil Energy. After augmentation, adaptation, and validation, the data bases and models were remanded to the 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.

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," or currently available, 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 focused research and development. Table III-3 displays the technical criteria for "advanced" EOR technology.
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

Table III-1

Key Elements in the Current TORIS* Reservoir Data Base

• <u>Original Volumetrics</u>   -- Original Oil-in-Place -- Reservoir area -- Net thickness -- Porosity -- Initial water saturation -- Initial oil saturation -- Initial formation volume factor • <u>Current Volumetrics</u>   -- Current oil saturation (swept zone) -- Current formation volume factor • <u>Fluid Data</u>   -- Oil gravity and viscosity -- Connate water viscosity -- Connate water salinity -- Initial GOR -- Current GOR -- Injection water salinity -- Crude oil fractions & properties
(being added)	• <u>Geologic Variables</u> -- 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 -- Pay continuity (estimated) • <u>Development & Performance Data</u> -- 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	Thermal Recovery	
		Surfactant	Alkaline	(Carbon Dioxide)	Steam	In-Situ Combustion
Oil Gravity	°API	---	<30	≥25	10 to 34	10 to 35
In-situ 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 (kD/ 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	Thermal Recovery	
		Surfactant	Alkaline	(Carbon Dioxide)	Steam	In-Situ Combustion
Oil Gravity	°API	---	<30	≥25	---	---
In-situ 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 ($S_o X \phi$)	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.

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 research, development, and demonstration (RD&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 EVALUATION OF UNRECOVERED MOBILE OIL RESOURCES**

TORIS evaluations have historically focused on the recovery of immobile or waterflood residual oil. In 1988, TORIS' capabilities were expanded to include an 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 are reported in detail in a topical report by the DOE.³

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. Department of Energy/Office of Planning and Environment/Office of Fossil Energy and Bartlesville Project Office, 1989.

Since 1989, the TORIS ASR models have been upgraded to more accurately describe and evaluate the UMO resources. The enhancements included the following:

- Development of an infill drilling model which processes five-spot waterflood to five-spot infill as well as five-spot waterflood to nine-spot infill;
- Development of a methodology to determine key reservoir heterogeneity elements needed for modeling infill drilling potential. The heterogeneity elements are "reservoir continuity" and "Vertical Permeability Stratification Index" (Dykstra-Parson coefficient). The methodology relies on the history match of production data to determine the heterogeneity elements;
- Validation of the infill drilling model and history match methodology on nine actual field results as well as results of a black oil simulator;
- Integration of a newly developed infill model with other models in TORIS to process infill drilling in combination with polymer flooding or profile modification; and
- Validation of criteria for implemented as well as advanced technology infill drilling.

A preliminary draft report of all developmental work is available through the U.S. Department of Energy, Bartlesville Project Office. The draft report is currently being finalized, and it will be available to the general public in the near future.

UMO, the target for advanced primary and secondary recovery operations, consists of oil that is uncontacted or bypassed during conventional production that can be displaced from the reservoir by waterflooding. "Uncontacted oil" refers to oil trapped in isolated compartments in reservoirs uncontacted by wells 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, the fluid characteristics of the oil, and the drilling and development history of the reservoir.

Potential incremental oil recovery and related economic benefits are estimated for the three processes currently used to improve mobile oil displacement. These processes are referred to as advanced secondary recovery (ASR) and include: infill drilling, profile modification treatments (permeability contrast reduction), and polymer-augmented waterflooding. A modified polymer-waterflood predictive model is used to evaluate each process. Selected combinations of these processes are also evaluated in this study.

Consistent with TORIS EOR evaluations, the analysis of UMO considers both current technology and advanced technology. The advanced technology analysis estimates the potential improvement in recovery possible after successful RD&D. For polymer flooding and profile modification treatments, advances in technology are projected to increase 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 Recovery Processes

	<u>Polymer*</u>		<u>Profile Modification</u>	
	<u>Current</u>	<u>Advanced</u>	<u>Current</u>	<u>Advanced</u>
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 under implemented and advanced technology scenarios. Current knowledge of reservoir heterogeneity limits drilling to highly favorable reservoirs where blanket-pattern drilling at uniform spacing can yield a profit. Increased continuity in the implemented technology case is estimated by the reservoir-wide average improvement in continuity 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 (homogeneous) region and a less continuous (heterogeneous) region. Each region 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 specific criteria for both the implemented technology and the advanced technology infill drilling is shown in Table III-5. The entire methodology (data, models, highgrading, and analytical systems) was developed and implemented in a manner fully compatible with the existing TORIS structure.

Table III-5

Screening and Approach for Advanced Technology Infill Drilling

Technology Level	Criteria
Implemented	<ul style="list-style-type: none"> - 5-spot waterflood to 5-spot infill - 15% minimum real rate of return - Minimum well spacing of 10 acres before infill drilling - One drill down
Advanced	<ul style="list-style-type: none"> - 5-spot waterflood to 5-spot infill - 10% minimum real rate of return - Highgrade into homogenous and heterogeneous portions - One drill down in homogeneous portion - Up to three drill downs in heterogeneous portion - Well spacing after infill greater than 5 acres

D. SCOPE OF THE ANALYSIS

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

The nominal crude oil prices (West Texas intermediate adjusted for transportation costs and gravities less than 40° API) range from \$16/B to \$36/B in \$4 increments, all stated in constant 1991 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. In addition, a risk premium is also considered depending on the EOR or ASR process and the

level of technology. The risk premium is modeled as an increase in the hurdle rate as shown by Table III-6. The risk premium was recommended by the TORIS peer review committee.

Table III-6

Risk Premium For Implemented and Advanced EOR and ASR Processes

	Cost of Capital	Risk Factors		Hurdle Rates	
		Implemented Technology (%)	Advanced Technology (%)	Implemented Technology (%)	Advanced Technology (%)
Alkaline	10	15	0	27	10
Surfactant	10	15	0	27	10
In-Situ	10	15	5	27	16
Polymer	10	5	0	16	10
Profile Modification	10	5	0	16	10
CO ₂ -Miscible	10	5	0	16	10
Steam	10	5	0	16	10
Infill Drilling	10	5	0	16	10

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 ASR) which are currently available. Advanced technology considers the likely improvements in process performance and applicability that can be achieved within the next decade if a focused, effective R&D program is successfully completed.

All cases are analyzed in detail to examine their impact on estimated oil reserves, oil production, state and Federal revenues, and the state and national economies. The results of these analyses, addressing the benefits from incremental production, are reported in Chapters IV and V which discuss the effects of EOR and ASR processes for implemented technology and advanced technology, respectively.

E. ADAPTATIONS FOR THE PRESENT STUDY

Several adaptations to the NPC approach were necessary to conduct the present analysis. 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 117 of the largest Oklahoma reservoirs, accounting for over 64% of estimated original oil-in-place (OOIP) in Oklahoma. The reservoirs represented in the data base include oil zones in every region of the state. The largest reservoirs are more completely represented in the data, but reservoirs as small as 5 million barrels are also analyzed in the study. The data base is, therefore, believed to be representative of the diverse oil producing formations across Oklahoma. Data from the Energy Information Administration on the production of oil, gas, and water from 1970 to 1992 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

The present study uses current tax structure along with the actual tax rates in the TORIS economic models. The Federal taxes are estimated based on the 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 34% marginal rate on corporate income taxes and changes the depreciation schedules and expense rules. In addition, the present study includes the new Federal EOR tax credit as passed by Congress in FY91. The new Federal EOR tax credit provides a credit equal to 15% of all qualified enhanced oil recovery costs on projects that began or were significantly expanded after December 31, 1990. The "qualified enhanced oil recovery costs" are defined as tangible property investments, intangible drilling and development costs, and purchase costs of tertiary injectants. The tax credit is contingent upon professional certification, in advance, that the EOR project is capable of producing more than an insignificant increase in ultimate recovery. Because the goal of the incentive is to make the application of EOR techniques economic at lower oil prices, where project economics are most impacted, the incentive is gradually phased out at oil prices above \$28/B. For every \$1/B that the average benchmark price for the preceding year exceeds

\$28/B, the incentive is reduced by 2.5 percentage points for the subsequent year, so that a complete phasing out of the incentive would occur at an oil price of \$34/B.

The study also accounts for the current state tax structure in Oklahoma, including tax incentives for EOR and ASR projects. This incentive provides forgiveness for production taxes for the first three project years or until project payback (whichever comes first) for all qualified EOR and ASR projects. In this analysis, it is assumed that all EOR and ASR projects qualify for the incentive.

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 CO₂ 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:

$$\text{CO}_2 \text{ Price (\$/Mcf)} = \$0.50 + \$0.025 \times \text{Oil Price (\$/B)}.^4$$

However, the base price and adjustment equation were established at higher oil prices and before the completion of major CO₂ pipelines or significant CO₂ deliveries to the region. An informal poll of pipeline and field operators suggests that the CO₂ prices at present and into the near future will be lower (relative to oil prices) than the NPC had assumed. The CO₂ purchase price in West Texas has been adjusted for changes in oil price using the equation:

$$\text{CO}_2 \text{ Price (\$/Mcf)} = \$0.50 + \$0.02 \times \text{Oil Price (\$/B)}.$$

This equation results in a CO₂ price of \$0.90/Mcf at the \$20/B oil price. CO₂ prices in other regions of the state are assumed to be double the West Texas price, based on previous NPC surveys.

⁴ National Petroleum Council, *Enhanced Oil Recovery*, Washington, DC, 1984.

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 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.⁵ 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. A more detailed timing approach for both EOR and ASR was used in the present study. Timing for the application of EOR recovery techniques 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 start up 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 recovery is then phased in to occur reservoir-wide, at the latest, by three years following the estimated abandonment date. Projects that are not timed in by this data are assumed abandoned and are excluded from the analysis. The timing of ASR

⁵ Ray, et al., *Potential Crude Oil Production from Enhanced Oil Recovery*, U.S. Department of Energy, Bartlesville Project Office, 1986.

reserves development and production was accomplished using the Crude Oil Policy Model (COPM) because the TORIS timing model was not suited for ASR for technical reasons. COPM simulates the development of an aggregate resource as a function of project economics, while simultaneously accounting for abandonment of the undeveloped portion of the resource and technology transfer constraints. Inputs to COPM include the total resource potential, development and production costs, technology availability dates, technology penetration rates, abandonment rates, and reserves development rates. Outputs from the model include annual production, reserve additions, abandonments, development costs, operating costs, wages, and taxes. Reserves estimates were supplied by TORIS.

Total reserves were disaggregated into two categories, reserves available with implemented technology and incremental reserves available through the application of advanced technology. Appropriate model parameters were selected for each of these resource categories. The technology availability dates were set to 1993 for implemented technology and 2000 for advanced technology. Technology penetration rates were set at 75% in 12 years for implemented technology and 75% in 8 years for advanced technology, with the advanced technology case representing an aggressive technology transfer effort. Abandonment rates for both implemented and advanced technology were set to 3% of the undeveloped resource per year prior to technology availability and 1.5% per year after technology becomes available. Reserves development rates corresponded to typical field development profiles.

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 cash flow calculations of individual projects. Under each of the various cases analyzed, projects yielding a net present value greater than the hurdle rate are assumed to be developed. This assumption is the basis for the projection of potential incremental production and reserves.

The incremental benefits and costs of EOR and ASR 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-seven year period, 1993 to 2020. Cumulative benefits include the sum of the annual benefits plus any additional benefits that would accrue after 2020. 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-seven year period of focus in this study. The additional benefits that occur after 2020 are generally small relative to the total benefit, but important to the overall aggregate analysis.

1. Benefits to State and Local Treasuries

The benefits to Oklahoma 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, sales tax on equipment and material purchases, and corporate and personal income taxes on wages paid and operator profits. 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 activities associated with 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 citizens of Oklahoma also gain from the increased economic activity. Only the direct effects of the incremental activity are included, 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 of Oklahoma and its citizens.

Excluded from this state economic activity definition are cashflows that generally benefit citizens of other states in larger proportion than they benefit the citizens of Oklahoma. 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 Oklahoma, the direct benefits of these "retail pass-through" 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 Oklahoma (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 Oklahoma 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 for direct economic effects understates the actual benefits to Oklahoma and its citizens.

The additional jobs, wages, and benefits created by improved 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-7 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.⁶ Sales tax revenues are calculated based on the materials component of these costs, assuming purchasers would pay the appropriate state tax on these goods.

3. National Effects

The Federal government benefits substantially, both directly and indirectly, from increased recovery of the Oklahoma oil resource. Direct Federal taxes total 5% to 20% of the value of each barrel of oil recovered. Each additional barrel of domestic production can replace a barrel of imports. Therefore, each dollar used to purchase the incremental barrels of oil that would otherwise pay for imports is, potentially, a dollar reduction in the trade deficit.⁷ To estimate the direct effects on import replacement (i.e., excluding multiplier effects), the gross revenue from the additional production is used. This measure of gross revenues incorporates direct in-state economic activity and excludes elements discussed in the section above. In this sense, the estimated increase in import replacement represents a more complete measurement of direct economic impacts, excluding multiplier effects. In addition, corporate and

⁶ U.S. Department of Labor, Bureau of Labor Statistics, 1985.

⁷ 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.

Table III-7

Labor and Materials as Percentage of Total Cost in EOR Projects

<u>Investments</u>	<u>% Labor</u>	<u>% Materials</u>	<u>% Other</u>
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
<u>Expenses</u>			
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

individual Federal income taxes are estimated to assess the direct effects of incremental oil recovery in Oklahoma 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. It is also important to note that the results of this analysis are not forecasts of future oil recovery; they are estimates of the recovery potential of selected EOR and ASR processes.

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, unless advanced geoscientific knowledge allows the reservoir to be evaluated in segments. The methodologies of both the present study and the NPC assume that the least favorable 20% of any reservoir would not be developed under EOR or ASR operations.

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 after completion of conventional production operations. Laboratory and limited field data suggest that the application of some of these techniques before the economic limit of conventional recovery could yield more than the sum of conventional and advanced oil recovery, but this is not reflected in the models.

An additional limitation arises from the methodological convention of "constant price" analysis. The use of this convention is consistent with the NPC's original 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 additional incremental investment not included in this analysis (although necessary workovers are included in the assumed cost). Redrilling would result in substantially increased costs and would thus increase the minimum oil price at which advanced oil recovery processes are profitable for certain reservoirs. The net effect of this analytic convention could 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 analysis.

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.

None of the above limitations invalidate the results of this analysis. Given the uncertainty of the size and combinations of the optimistic and pessimistic biases introduced by these limitations, it is assumed that the approach is valid and the resulting projections are reasonable. 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 the reports generated from this analysis. However, in cases where the results seemed unusual, the modeling specifications for specific reservoirs were examined in-depth to ensure the validity of the results.

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

A. INTRODUCTION

This chapter discusses the post-conventional reserve additions and potential economic impacts attributable to the application of currently available (implemented technology) oil recovery methods in analyzed Oklahoma reservoirs. Chapter V discusses the incremental reserves and benefits under advanced technology methods attainable through RD&D. The TORIS reservoirs analyzed in this study are individually modeled to evaluate their potential for incremental production and reserves by tertiary and advanced secondary recovery techniques under a variety of oil prices and economic conditions. Some key technical assumptions and considerations regarding the analysis in this report are:

- The incremental production and reserves refer to future recovery estimated for the analyzed EOR and ASR techniques. Such production and reserves are above and beyond the recovery attainable by primary and secondary recovery techniques.
- Both light oil (API > 20 degree) and heavy oil (API ≤ 20 degree) resources are considered in this analysis.
- All EOR and ASR recovery potential evaluated in this report reflect future new projects only, and they do not include incremental reserves from existing (ongoing) EOR and ASR projects. However, the expansion to the ongoing projects, if technically and economically feasible, are evaluated as part of future new projects in this report.

All reservoirs are screened for technical criteria and are analyzed in detail using the process performance and economic models described in Chapter III. The results are based on the evaluation of 117 reservoirs for their EOR and ASR potential. The results of this analysis were not extrapolated to the rest of the reservoirs making up the Oklahoma resource.

B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE

1. Production and Reserves

With currently implemented technology, potential recovery using EOR technologies in Oklahoma is severely limited over the price range analyzed. EOR processes (carbon dioxide (CO₂)-miscible) would

not be economic until oil prices reach \$24/B, and then could yield 90 million barrels of incremental reserves. The outside potential of implemented technology at \$36/B is 160 million barrels, representing a 23% increase in the state's current proved reserves (700 million barrels in 1991) (Table IV-1A and Figure IV-1A).

The analysis model (as discussed in Chapter III) projects the timing of incremental reserves and production from projects which (a) have completed primary production; (b) are economically viable; and (c) may be started under a series of national-level constraints on financial factors (such as investment capital) and resources (such as carbon dioxide). Since the potential for implemented technology in Oklahoma is limited to one CO₂-miscible project at \$24/B and two such projects at prices over \$28/B, the precise timing of reserve additions has considerable uncertainty. The expected time-series of production at \$24/B and \$32/B is shown in Figure IV-1B.

At \$24/B, the single EOR project would not be available for tertiary operations until the year 2000. Conventional waterflooding will not reach its economic limit until the year 2000, at which time the CO₂-miscible EOR project would be started, using current implemented technology. In this case, production could gradually increase as patterns are added, reaching a peak of 8.4 million barrels per year, in 2012. At \$32/B, two projects could be economic and production could peak at 10 million barrels in 2013. Although those quantities are small, they would represent 9% and 11%, respectively, of Oklahoma's 1991 oil production of 92 million barrels.

2. Increases in State and Local Revenues

Production from Oklahoma EOR projects could also increase state and local revenues through production taxes, sales taxes on purchased materials used in the projects, and corporate and personal income taxes. Oklahoma does have an EOR tax incentive which provides production tax forgiveness for three years or until project payback, whichever comes first. The potential production tax revenue presented here represents tax receipts after expiration of the incentive. The estimated revenues would be generated directly from oil production or operations in the analyzed reservoirs. Once a project is economically viable, the state and local revenues generated over the life of the EOR project is largely a function of oil prices. A significant portion of these revenues could result from production taxes. At prices below \$24/B, no projects would be economically viable using current technology, and therefore, no additional revenue would be generated for the state (Figure IV-2). However, at \$24/B, about \$192

Table IV-1A

**Incremental Reserves from EOR by Process
Implemented Technology
(Million Barrels)**

Oil Price (\$/B)	CO ₂ -Miscible	Chemical	Thermal	Total
\$16	0	0	0	0
\$20	0	0	0	0
\$24	90	0	0	90
\$28	159	0	0	159
\$32	160	0	0	160
\$36	160	0	0	160

Table IV-1B

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

Oil Price (\$/B)	CO ₂ -Miscible	Chemical	Thermal	Total
\$16	0	0	0	0
\$20	0	0	0	0
\$24	1	0	0	1
\$28	2	0	0	2
\$32	2	0	0	2
\$36	2	0	0	2

Figure IV-1

Reserves and Production Response from CO₂-Miscible EOR Techniques

Implemented Technology

A) Incremental EOR Reserves from CO₂-Miscible Projects

- * There was no economic thermal or chemical reserves potential in analyzed reservoirs.
- ** No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

B) Annual Production from CO₂-Miscible EOR Reserves

Figure IV-2

Direct State and Local Revenues from EOR Production Implemented Technology

* No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

million in incremental revenues could be generated, with production taxes contributing over 75% of the total and corporate income and sales tax revenues accounting for most of the remainder. At a \$28/B oil price, one additional project could be economic. Production tax revenues of \$308 million plus \$35 million in sales tax receipts and income taxes of \$58 million, for a total of \$401 million could be received by the state. At the outside potential, \$512 million in state revenue could be generated by implemented technology at an oil price of \$36/B.

3. Effects on the State Economy

In addition to increasing direct state and local tax revenues, implemented technology EOR would benefit Oklahoma by increasing economic activity and by creating new jobs. 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 Oklahoma 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. Royalties may be overstated to the extent that they are paid to the Federal government (i.e., for production on Federal lands). While the excluded elements undoubtedly aid Oklahoma's citizens to some degree, a substantial portion of the benefits will be enjoyed by citizens of other states. The calculated economic effects are understated, however, to the extent that local manufacture or retail sales of these cost items provide economic benefits within Oklahoma, injectants produced or manufactured in Oklahoma are employed, or economic "multipliers" occur.

At oil prices below \$24/B, current EOR technology would not increase in-state economic activities. At high oil prices, operating costs could account for at least 62% of these economic effects; state taxes could represent around 15%; intangible investment could be about 2%; and royalties could constitute about 21% of the total (Figure IV-3). At \$24/B, incremental benefits to the state economy could exceed \$1.3 billion. At the highest oil price considered, an estimated \$3.4 billion of statewide direct economic activity could be stimulated by EOR projects. The small number of implemented technology EOR projects could generate from \$36 million at \$24/B to \$49 million at \$32/B in additional wages during peak years and create or maintain from 800 to 1,100 additional jobs (Figure IV-4).

4. Effects on the National Economy

Increased oil recovery from EOR in Oklahoma would also benefit the nation as a whole. National benefits would accrue in several ways: increased Federal corporate and personal income tax revenues, replacement of oil imports, and a reduction in the foreign trade deficit. An additional barrel of domestic oil production could replace a barrel of imported oil; thus, any increase in production could enhance the nation's energy security. The addition of as much as 90 million to 160 million barrels of reserves in Oklahoma would expand the nation's proved reserve base.

EOR activity in Oklahoma contributes to the Federal treasury through personal and corporate income taxes on operator profits and wages (Figure IV-5A). At \$24/B, EOR activity could increase direct Federal revenue by \$13 million. At \$36/B, \$578 million could be stimulated by EOR. At or above \$32/B, corporate income taxes could account for between 77% and 84% of this total, depending on the oil price, and personal income taxes makes up the remainder.

Figure IV-3

Direct State Economic Activity* from EOR Production

- * To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.
- ** No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

Figure IV-4

Jobs and Wages from EOR Production

As imports are replaced by domestic production, funds that would otherwise flow to oil exporting countries to pay for imported oil could be spent domestically. Thus, EOR in Oklahoma could help reduce the trade deficit, enabling this money to instead circulate through the U.S. economy, creating additional benefits. Imports avoided through the implementation of current EOR technology in Oklahoma would be valued at \$2.2 billion added over the life of the projects at an oil price of \$24/B (Figure IV-5B). The outside potential of imports avoided could reach \$5.8 billion at \$36/B. The benefit of the avoided imports reflects the value of increased domestic production (effective wellhead price multiplied by reserves).

C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE

This section will discuss the application of currently available advanced secondary recovery (ASR) processes, which target mobile oil, on the same set of reservoirs. These recovery technologies are distinct, and, since they focus on mutually exclusive resource targets, the amounts of oil recoverable from each are additive. Both technologies could be implemented in individual Oklahoma reservoirs and, if done, the benefits (resource, revenues, economic activity, etc.) would be additive. There are some potential synergies due to economic efficiencies associated with simultaneous employment of the EOR and ASR technologies; thus, there is the possibility that economic benefits could be even greater than the sum of the benefits from this separate analysis of EOR and ASR techniques.

1. Production and Reserves

The resource potential from applying ASR techniques to Oklahoma reservoirs is not particularly sensitive to oil price. At oil prices ranging from \$16/B to \$36/B, ASR could stimulate between 870 million and 1.1 billion barrels of incremental reserves in Oklahoma. At \$20/B, incremental ASR reserves could amount to nearly 900 million barrels, which is 83% of the nearly 1.1 billion barrels of oil economically accessible at \$36/B.

This analysis evaluates three categories of ASR processes -- profile modification and polymer flooding, infill drilling, and infill drilling in combination with profile modification or polymer flooding (combination processes). As shown in Figure IV-6A and Table IV-2A, infill drilling, both by itself and in combination with other processes, could play a predominant role in ASR recovery, accounting for most of the incremental reserves at all analyzed oil prices. At oil prices of \$20/B and lower, the combination processes could contribute from 454 to 458 million barrels of reserves, while infill drilling alone could

Figure IV-5

National Impact of EOR Production

Implemented Technology

A) Direct Federal Revenues

* No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit.
** No EOR projects were economic in analyzed reservoirs for oil prices below \$24/B.

contribute 329 million to 354 million barrels of reserves. At or below \$32/B, the percentage of total ASR reserves stemming from infill drilling, either alone or in combination with other processes, would account for at least 90% of the total potential.

As oil prices increase, infill drilling by itself could become more economic. At \$28/B, infill drilling alone would contribute nearly 40% of the 957 million barrels of total incremental reserves, close to the 51% contribution by the combination processes. At an oil price of \$32/B, infill drilling by itself could stimulate 431 million barrels (about 43%) of the 1.0 billion barrels of incremental reserves while the combination processes account for 49% (over 490 million barrels). At \$36/B infill accounts for 41% of the 1.1 billion barrel potential, while combination processes yield 47%.

Table IV-2B shows that between 51 and 57 ASR projects could be economic in Oklahoma over the analyzed oil price range. Most of these projects use infill drilling, either alone or in combination with other processes. Across all considered oil prices, infill drilling projects account for 83% to 86% of all projects, roughly split between infill drilling applied alone and the combination processes.

Applied without infill drilling, polymer flooding and profile modification projects could contribute between 87 to 126 million barrels to Oklahoma reserves across all oil prices considered in this analysis, about 10% of the total potential. This apparent lack of sensitivity to oil price does not mean that these techniques are of marginal importance. Rather, as the oil price rises, the more expensive, but more prolific, infill drilling and combination projects become economic. Thus, reservoirs that would utilize polymer flooding and profile modification projects at lower oil prices would switch to the more prolific techniques at higher oil prices. In fact, the bulk of incremental reserves could be attributed to combining polymer flooding and profile modification with infill drilling at all considered oil prices.

Figure IV-6B displays the expected annual production from all ASR processes at oil prices of \$16/B and \$32/B. As shown above, the dominant ASR technique could be infill drilling, either alone or in combination with polymer flooding or profile modification. The incremental reserves from ASR therefore require a considerable amount of drilling. At \$16/B, the incremental ASR reserves could replace Oklahoma's existing reserves. However, ASR must compete for drilling capital and infrastructure capacity (rigs, crews, investment dollars) with other oil industry activities such as domestic exploration, gas drilling, and international ventures. This could slow the pace of ASR development in some reservoirs. A substantial portion of the potential ASR reserves is thus at risk of abandonment prior to the availability

Table IV-2A

**Incremental Reserves from ASR by Process
Implemented Technology
(Million Barrels)**

Oil Price (\$/B)	Polymer Flooding and Profile Modification	Infill Drilling	Infill Drilling with Profile Modification or Polymer Flooding	Total
\$16	87	329	454	870
\$20	87	354	458	899
\$24	89	356	460	905
\$28	90	381	486	957
\$32	90	431	492	1013
\$36	126	432	492	1050

Table IV-2B

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

Oil Price (\$/B)	Polymer Flooding and Profile Modification	Infill Drilling	Infill Drilling with Profile Modification or Polymer Flooding	Total
\$16	9	21	21	51
\$20	9	23	21	53
\$24	9	23	21	53
\$28	8	25	22	55
\$32	8	27	22	57
\$36	8	27	22	57

Figure IV-6

Reserves and Production Response from ASR Techniques

Implemented Technology

A) Incremental Reserves by ASR Process

B) Annual Production from ASR Reserves

of drilling resources for its development. Over 36% of the potential reserves could be abandoned over the life of the projects.

Annual ASR production at an oil price of \$16/B could average about 9.9 million barrels per year over the 1993 to 2020 period. At an oil price of \$32/B, annual production could average over 11.6 million barrels per year over the same period. To put the potential contribution of ASR into perspective, 9.9 million barrels per year would add about 11% to Oklahoma's 1991 oil production rates and 11.6 million barrels per year would add 13%.

2. Increases in State and Local Tax Revenues

Figure IV-7 shows the expected growth in state revenues from ASR production and the proportional contributions of production taxes, sales taxes, and corporate and personal income taxes to the total. Production tax receipts account for the largest portion of total state revenues from ASR over all prices considered. Production taxes alone would generate \$613 million of the \$992 million in direct state tax revenues at \$16/B. At \$24/B, about \$1.6 billion could be generated for the state through ASR activities, with 61% of that amount from production taxes. At \$36/B, nearly \$2.9 billion in direct state and local revenues could be generated from implemented technology ASR activities. State corporate income tax receipts could contribute \$310 to \$900 million (around 32%) of the total direct state revenues across the analyzed oil price range.

3. Effects on the State Economy

Figure IV-8 displays the total state economic activity in Oklahoma associated with potential ASR production. Total state economic activity from the processes could range from \$6.5 billion at \$16/B to \$15.8 billion at \$36/B. At intermediate oil prices, state economic activity could be increased by \$7.9 billion at \$20/B and \$11.4 billion at \$28/B due to ASR activities. Due to the predominance of infill drilling projects, the intangible portion of drilling and developing investment could be a significant contributor to state economic activity. At \$16/B, 42 of 51 economic projects could involve infill drilling and intangible investment could account for \$1.9 billion (29%) of the \$6.5 billion of direct in-state economic benefits. At the \$16/B price, operating costs (excluding injectants) could provide 29% of the benefits, while royalties could provide 26%. At \$36/B, 49 of 57 viable projects could involve infill drilling. At this very high price, royalty payments of \$4.7 billion could contribute nearly 30% of the

Figure IV-7

Direct State and Local Revenues from ASR Production Implemented Technology

\$15.8 billion in state economic activity. Intangibles could drop to 27% of the total, while operating cost could account for over 25%.

The implementation of ASR techniques could significantly contribute to employment in the state of Oklahoma. Figure IV-9 displays the annual number of jobs that would be created or maintained by ASR projects. The annual trends in jobs created or maintained closely match the production trends for ASR. At an oil price of \$16/B, jobs could peak at 486. At \$32/B, the number of jobs created or maintained could peak at about 875. At this price, as much as \$39 million in wages could be paid in the peak employment year.

4. Effects on the National Economy and Budget

Figure IV-10 shows the national benefits of implementing current technology ASR in Oklahoma. Federal revenues from ASR production could range from about \$2.3 billion to more than \$7.5 billion over the oil price range analyzed. Figure IV-10A shows that nearly all of these revenues could stem from corporate income taxes. At moderate oil prices (\$20/B to \$28/B), implemented technology ASR activities could increase direct Federal revenues by \$3.2 billion to nearly \$5.0 billion.

Figure IV-8

Direct State Economic Activity* from ASR Production

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.

Figure IV-9

Jobs and Wages from ASR Production

The addition of 870 million to 1.1 billion barrels of domestic oil could significantly replace imported oil. To the extent that one barrel of domestic oil replaces one barrel of imported oil, the trade deficit would be reduced and the value of the domestic oil would be spent in the U.S. economy rather than abroad. Imports avoided by ASR production in Oklahoma could be valued between \$13.8 billion and \$37.5 billion over the oil price range analyzed (Figure IV-10B). As the increased Oklahoma production replaces oil imports, the U.S. trade deficit would be reduced and national security would be enhanced as the nation's vulnerability to future supply disruptions is diminished. This additional domestic spending from avoided imports could greatly impact the economy, as other activity is indirectly stimulated by economic multipliers.

D. CONCLUSIONS

At implemented technology levels, EOR and ASR processes could make a significant contribution to the reserve base and the Oklahoma and national economies, as well as to domestic energy security. At a \$24/B oil price, EOR processes could add 90 million barrels to Oklahoma reserves while ASR techniques could add nearly 900 million barrels of incremental reserves. The application of current EOR and ASR technologies in concert could potentially add nearly 1.0 billion barrels of incremental reserves at this price, more than replacing Oklahoma's current proved reserves. As discussed in the next chapter, improved geoscientific understanding of reservoirs and enhanced process performance could increase these benefits if the required research can be cost effectively completed and transferred to the producers.

The state of Oklahoma and its citizens stand to gain significantly from the increased production resulting from incremental reserves. Production increases could generate \$1.3 billion to \$2.8 billion in additional state and local revenues over the next 25-plus years assuming oil prices range between \$20/B to \$32/B. Total state economic activity could be boosted by \$7.9 billion to over \$17 billion. Furthermore, several hundred jobs could be created or maintained with the successful implementation of EOR and ASR. The national economy would benefit through decreased oil imports, reductions in the trade deficit, and increased Federal corporate and personal income tax revenues. Maximizing recovery of the known oil resource in Oklahoma should therefore be an important goal for state and Federal policy makers. While these benefits would be available using currently available technology, the true potential would not be realized without an aggressive program of technology transfer. The estimated potential assumes wide application of these technologies. A collaborative technology transfer effort between the public and private sectors is critical to the attainment of these estimated benefits.

Figure IV-10

National Impact of ASR Production

Implemented Technology

A) Direct Federal Revenues

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit.

As shown in Figure IV-11, the oil that will remain in the analyzed reservoirs after production by both current operations and by wide-scale application of currently available EOR and ASR processes, constitutes an important resource target for improved recovery technologies. Of the 11.7 billion barrels of immobile oil resource analyzed in this study, implemented technology EOR practices could produce an estimated 160 million barrels at an oil price of \$36/B, leaving over 11.5 billion barrels of remaining immobile oil in the analyzed Oklahoma reservoirs. Of the 6.6 billion barrels of unrecovered mobile oil in the reservoirs analyzed, implemented technology practices could produce an estimated 1.1 billion barrels at \$36/B, leaving 5.5 billion barrels in these reservoirs. The large size of the remaining resource clearly warrants a focused RD&D program that will test and speed the implementation of advanced technology to capture additional oil reserves.

Figure IV-11

Oklahoma Remaining Oil Resource After Implemented Technology Recovery

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

A. INTRODUCTION

While currently available EOR and ASR extraction techniques could contribute substantially to Oklahoma's reserve base, technological advances in these processes resulting from a concerted RD&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.

The present analysis evaluates both the benefits and the associated economic impacts of advanced technology oil recovery. Evaluations of advanced technology EOR and ASR in the state of Oklahoma are presented separately; moreover, because they target different portions of the resource, EOR and ASR potentials are independent and additive. Given that the modeled advances in technology are conservatively defined, improvements in recovery processes resulting from RD&D not envisioned in this analysis could add substantially to the estimated reserve potentials. Well abandonments, however, could limit access to the resource and increase project costs if EOR and ASR are not applied before conventional production ceases. Immediate action is therefore necessary to realize the benefits of these advanced technology processes.

B. RECOVERY OF THE REMAINING IMMOBILE OIL RESOURCE

1. "Advanced" Technology Defined

EOR processes, as currently "implemented," have severe limitations. Some current EOR techniques can only be applied to 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 National Petroleum Council (NPC) predicted gradual improvements in EOR performance and project economics as current processes are improved and further tested both in the lab

and in the field. These advanced processes will gain operator acceptance as the research and development efforts of oil companies, universities, state geologic surveys, and the Federal government proceed and as field applications are tested and proven commercially. In this report, the IOGCC delayed the advanced technology availability date from the NPC's assumption of 1995 to the year 2000 to reflect the slower pace of RD&D activities in recent years caused by relatively low oil prices.

The major improvements in technology that are likely to impact Oklahoma enhanced oil recovery will be advances in chemical flooding, and to a lesser extent, in miscible and stream flooding. 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 to a larger number of reservoirs. This study also assumes that advances in chemical flood technology will result in improvements in injection rate, interfacial tension reduction, reduced chemical retention, and lower costs, thereby improving the recovery and economics of chemical projects. In addition, the study assumes substantial reductions in the associated risk of EOR processes, modeled as a reduction in the minimum rate of return or hurdle rate required for project implementation. For advanced technology thermal recovery, the NPC modeled the effects of an improvement in the ability to inject steam at greater depths and into thinner, lower permeability reservoirs.

2. Production and Reserves

With technology advances, EOR in Oklahoma could stimulate a substantial amount of incremental reserves over the oil price range analyzed (\$16/B to \$36/B). Table V-1A and Figure V-1 show the comparison between the EOR reserves potentially generated through the application of advanced technology EOR processes. The greatest increase in incremental reserves due to advanced technology could occur near the upper end of the analyzed price range, at oil prices of \$36/B, where advances in EOR technology could stimulate an additional 980 million barrels of oil over implemented technology potential for a total of over 1.1 billion barrels in incremental reserves. At oil prices of \$20/B and below, there is no potential for incremental EOR reserves under implemented technology. Therefore, all incremental reserves (130 million to over 220 million barrels) could be attributed to advances in EOR technology.

The potential incremental reserves that could be contributed by each of the advanced technology EOR processes considered in this analysis are also shown in Table V-1A. At \$16/B, advanced chemical flooding could be the only source of incremental reserves, adding over 130 million barrels of oil. At

Figure V-1

Incremental Reserves by EOR Process Implemented Technology vs. Advanced Technology

\$20/B, advances in chemical EOR techniques could contribute over 220 million barrels. CO₂-miscible flooding would not be economic in Oklahoma until oil prices reach \$24/B under both advanced and implemented technology. At \$28/B, technology advances to CO₂-miscible flooding could generate only marginal additions to implemented technology potential. Advanced technology CO₂-miscible flooding could generate a total potential of over 160 million barrels of incremental reserves at oil prices ranging from \$28/B to \$36/B.

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 CO₂-miscible projects could remain the same, as a limited number of geological settings in Oklahoma are amenable to this process. The estimated increase in reserves could be largely due to the improving performance of chemical processes in the advanced case; 22 of 25 advanced case projects use chemical EOR processes. Only one small thermal project would be economic and only at relatively high oil prices. If RD&D efforts are effective, the improvement of surfactant flooding techniques (both in terms of reduced injectant cost and increased salinity resistance) could result in this technology becoming the dominant EOR process in Oklahoma.

Table V-1A

**Incremental Reserves from EOR by Process
Implemented Technology vs. Advanced Technology
(Million Barrels)**

Oil Price (\$/B)	CO ₂ -Miscible		Chemical		Thermal		Total	
	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*
\$16	0	0	0	132	0	0	0	132
\$20	0	0	0	224	0	0	0	224
\$24	90	90	0	622	0	0	90	712
\$28	159	162	0	809	0	0	159	971
\$32	160	162	0	809	0	11	160	982
\$36	160	162	0	969	0	11	160	1,142

* This potential reflects the total reserves with advanced technology - implemented technology reserves plus the increment due to technology advances.

Table V-1B

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

Oil Price (\$/B)	CO ₂ -Miscible		Chemical		Thermal		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
\$16	0	0	0	2	0	0	0	2
\$20	0	0	0	4	0	0	0	4
\$24	1	1	0	14	0	0	1	15
\$28	2	2	0	19	0	0	2	21
\$32	2	2	0	19	0	1	2	22
\$36	2	2	0	22	0	1	2	25

Figure V-2 displays the expected annual production from incremental EOR reserves for oil prices of \$24/B and \$32/B for both the implemented and advanced technology cases. At \$24/B, annual EOR production using advanced technology could peak at 14.9 million barrels per year in the year 2008 (Figure V-2A). This could occur four years earlier and yield about 7 million barrels per year more than the implemented technology peak potential. At \$32/B, production could peak in 2007 at 36 million barrels per year and could occur six years earlier and yield about 27 million barrels per year more than the implemented technology peak potential (Figure V-2B). The increases over the implemented technology potential could be attributed to advances in EOR technology.

3. Effects on State Revenues and Economic Activity

At all oil prices considered, the direct tax revenues to the state of Oklahoma attributable to EOR could increase significantly with advanced technology. Of the state's direct revenues, the share of production taxes could be 66% to 76%, corporate income taxes could comprise 18% to 19%, sales tax receipts could contribute around 10%, and personal income taxes could make up the remainder (Figure V-3A). At the two lowest oil prices evaluated (\$16/B and \$20/B), state revenues from advanced technology EOR could range between \$170 million and \$374 million, all of which would be attributable to technology advances at these prices. At \$24/B, advances in EOR technology could generate incremental revenues over implemented technology of nearly \$1.2 billion, for a total of \$1.4 billion. At higher oil prices between \$28/B and \$36/B, total direct state revenues from EOR in the advanced case could be between \$2.2 billion and \$3.2 billion, 81% to 84% of which would be attributable to technology advances.

Direct state economic activity generated by Oklahoma EOR would also grow due to advanced technology (Figure V-3B). The gain in economic benefits would be proportional to the gain in reserves. The advanced case distribution of total economic benefits among the contributing components would be 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 to be about \$1.4 billion, all of which is due to the application of technology advances. At \$20/B, advances in technology could stimulate almost \$2.8 billion of additional state economic activity. At oil prices of \$24/B and \$28/B, direct state economic activity could increase by \$9.5 billion to nearly \$15 billion due to technology advances, for a total potential increase of \$11 billion to nearly \$18 billion. At \$36/B, over \$26 billion in economic activity could be generated, 87% of which would be attributable to application of technology advances. Clearly, the state of Oklahoma could accrue substantial benefits from the development and application of advanced EOR technology at any of the oil prices considered in this analysis.

Figure V-2

Annual Production from EOR Reserves

Implemented Technology vs. Advanced Technology

A) At \$24/B

B) At \$32/B

Figure V-3

State Impact of EOR Production

Implemented Technology vs. Advanced Technology

A) Direct State and Local Revenues

B) Direct State Economic Activity*

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.

Advanced technology EOR activities could also have a substantial effect on future employment in Oklahoma. At \$24/B, advanced technology EOR could sustain over 960 jobs in the peak production year 2006 (not illustrated). This is about 170 more jobs than the peak employment rate under implemented technology recovery. At \$32/B, advanced technology could create or maintain more than 4,100 jobs in the peak year 2005. Peak wages could increase by \$8 million to \$136 million over implemented technology due to technology advances, for total peaks of \$44 million to \$185 million.

4. Effects on the National Economy and Budget

As discussed in Chapter III, increased oil recovery in the state of Oklahoma through EOR methods would significantly benefit the nation in the areas of enhanced energy security, avoided imports, a reduced foreign trade deficit, and expanded direct revenues to the Federal treasury. The potential benefits could be even more pronounced with the development of advanced technology. Up to 1.1 billion barrels of crude oil could be added to proved reserves using advanced EOR technology, 900 million barrels of which would be attributable to advances in technology. The additional reserves would decrease the nation's reliance on imported oil and consequently enhance energy security.

Revenues to the Federal treasury, in the form of corporate and personal income taxes, could grow along with the increase in reserves as a result of advanced technology (Figure V-4A). At oil prices below \$24/B, all of the increase in direct Federal revenues could be due to the application of EOR technology advances; between \$30 million and \$110 million could be added to the Federal treasury. At oil prices of \$24/B and \$28/B, direct Federal revenues due to technology advances could surpass the implemented technology potential by \$230 million to \$340 million, for a total advanced technology potential of over \$240 million to over \$460 million. At oil prices of \$28/B and below, Federal corporate income tax revenues could be negative for several analyzed projects. This is caused by the Federal EOR tax credit which can be used to offset the tax obligations of other profitable activities, leading to negative corporate income taxes. At \$36/B, after the complete phaseout of the EOR tax credit, applications of technology advances could generate over \$2.8 billion in additional direct Federal revenues, 83% of \$3.4 billion in total potential direct Federal revenues.

To the extent that the increase in EOR production replaces imported oil on a barrel-by-barrel basis, the foreign trade deficit would be reduced by advances in technology. Money spent on domestic oil production rather than on imports would be recirculated within the U.S. economy. The value of the

imports avoided (reserves multiplied by the effective wellhead price of oil) would approximate the improvement in the trade deficit (Figure V-4B). At oil prices of \$16/B and \$20/B, the entire value of imports avoided (from nearly \$2.0 billion to over \$4.3 billion) could result from advances in EOR technology. At oil prices of \$24/B to \$28/B, application of EOR technology advances could generate from about \$15 billion to over \$23 billion of imports avoided over implemented technology for a total potential of almost \$17 billion to more than \$27 billion. At \$36/B, \$35 billion (86%) of the \$41 billion in imports avoided could be attributed to advances in technology.

C. RECOVERY OF THE REMAINING MOBILE OIL RESOURCE

1. "Advanced" Technology Defined

The unrecovered mobile oil (advanced secondary recovery) advanced technology 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 RD&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 at closer spacings. This will improve the project economics of advanced secondary recovery (ASR), 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 unrecovered mobile oil 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 (homogeneous) segment and a less continuous (heterogeneous) segment. The economic recovery potential is evaluated independently in each segment, and the closest economic well spacing for each segment is independently selected.

The improved recovery methods could have a substantial impact on ASR reserve additions in Oklahoma. Additional recovery would 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 parts per million). These improvements would increase the marginal impact of the profile modification and polymer flooding projected under the implemented technology case, whether applied

Figure V-4

National Impact of EOR Production

Implemented Technology vs. Advanced Technology

A) Direct Federal Revenues

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit

independently or in combination with infill drilling. Additional benefits are estimated from the reduction of the associated risk of ASR processes as currently implemented. This was modeled as a reduction in the hurdle rates with technology advances as discussed in Chapter III.

2. Production and Reserves

The development of advanced technology ASR methods through RD&D could significantly increase Oklahoma's oil reserves. The incremental reserves from advanced technology ASR could range between 1.2 and 1.4 billion barrels for the analyzed Oklahoma reservoirs across the oil prices considered. Over the price range analyzed, the advanced technology potential exhibits about a 30% increase in reserves over the implemented technology potential. This increment could be attributed solely to advances in technology (Figure V-5).

Advances in ASR technology could shift the price-supply relationship to make significant amounts of oil economic to develop at lower prices. Between oil prices of \$16/B and \$20/B, technology advances could increase implemented technology reserves potential by over 370 million barrels to a total of about 1.3 billion barrels of incremental reserves. As oil prices increase above \$20/B, reserve growth through advanced technology ASR would be relatively insensitive to further increases in oil price. Technology advances could generate around 400 million barrels of the 1.3 billion to 1.4 billion barrels of total incremental reserves from ASR.

Table V-2A shows the distribution of the incremental reserves by ASR process. Infill drilling in combination with profile modification or polymer flooding could be the most frequently applied advanced technology recovery method and could generate the largest incremental reserves, contributing about 87% of the total reserve additions. The full potential of the advanced technology case depends both on targeted infill drilling and improved polymer flooding and profile modification techniques; infill drilling by itself could generate 11% to 20% of total advanced case reserve growth, while polymer and profile modification techniques could account for only 14% of the total recovery in the advanced technology case.

In the advanced technology case, incremental reserves from combination projects are more than double those from the implemented case (with technology advances accounting for the difference). The incremental reserves from geologically targeted infill drilling are only half those generated using blanket infill drilling. Advanced polymer and profile modification techniques could add 65 million to 70 million

Figure V-5

Incremental Reserves by ASR Process Implemented Technology vs. Advanced Technology

barrels of incremental reserves, for a total of between 150 million and nearly 200 million barrels. Improvements in polymer flooding and profile modification could justify the increased costs involved in implementing these processes, leading to a shift from infill drilling alone to the combination processes. Thus, attainment of the total potential would be critically dependent on linking targeted infill with better secondary chemical processes, since heterogeneity allows wells to be economically justified at much closer spacing than is currently possible, and waterflooding in either old or new wells would contact additional portions of the mobile oil resource bypassed at current spacing using conventional waterfloods. Targeting infill wells would also reduce the front-end investment for each project undertaken by reducing the number of dry holes, thereby making some otherwise uneconomic projects cost-effective at lower oil prices. The number of new ASR projects in Oklahoma ranges from 51 to 57 in the implemented technology case, increasing to only between 58 and 63 with advances in ASR technology. Thus, efficiencies associated with the advanced technology would assist operators in producing an additional 300 to 400 million barrels from roughly the same reservoirs.

Table V-2B shows the estimated number of economic ASR projects by process for both the implemented and advanced technology cases. At oil prices above \$20/B, the number of infill drilling projects (applied alone or in combination with other processes) could be only marginally higher under

Table V-2A

**Incremental Reserves from ASR by Process
Implemented Technology vs. Advanced Technology
(Million Barrels)**

Oil Price (\$/B)	Polymer Flooding and Profile Modification		Infill Drilling		Infill Drilling with Polymer Flooding and Profile Modification		Total	
	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*	Implemented	Advanced*
\$16	87	152	329	145	454	944	870	1,241
\$20	87	158	354	146	458	974	899	1,278
\$24	89	160	356	154	460	987	905	1,301
\$28	90	196	381	183	486	970	957	1,349
\$32	90	196	431	202	492	971	1,013	1,369
\$36	126	196	432	281	492	972	1,050	1,449

* This potential reflects the total reserves with advanced technology - implemented technology reserves plus the increment due to technology advances.

Table V-2B

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

Oil Price (\$/B)	Polymer Flooding and Profile Modification		Infill Drilling		Infill Drilling with Polymer Flooding and Profile Modification		Total	
	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced	Implemented	Advanced
\$16	9	9	21	7	21	42	51	58
\$20	9	9	23	7	21	43	53	59
\$24	9	8	23	9	21	44	53	61
\$28	8	9	25	10	22	44	55	63
\$32	8	10	27	9	22	44	57	63
\$36	8	10	27	9	22	44	57	63

advanced technology, although the incremental reserves associated with these projects could increase markedly. This increase in recovery from projects that were already economic under implemented technology emphasizes the effectiveness of improvements in polymer flooding and profile modification and targeting infill wells to the more prolific portions of the reservoir. The economics of most projects at these prices are greatly improved by advanced technology because a well-designed, strategic infill drilling program reduces the overall investment and associated operating costs required in a given reservoir.

Figure V-6 displays the projected annual production that could result from ASR technology advances for oil prices ranging of \$16/B and \$32/B from the Oklahoma reservoirs analyzed in this study. In all cases, a significant amount of oil could be added to the state's production over the next 30 years. ASR techniques require considerable amounts of drilling and must compete with other activities (e.g., exploration) and products (e.g., gas) for drilling rigs. A substantial portion of the target resource could be subject to abandonment before drilling capacity is available; 38% of the potential reserves could be abandoned over the life of the projects. Rapid development, transfer, and application of new ASR techniques is necessary to maximize potential.

At \$16/B, advanced case ASR production could reach nearly 30 million barrels per year by the year 2020, 27% of which is attributable to technology advances. At \$32/B oil prices, advances in ASR technology could increase the peak annual production of ASR under the implemented case by nearly 8 million barrels per year, for a total of nearly 33 million barrels per year. At \$16/B the average production over the period of 1993 to 2020 is 12.4 million barrels per year, while at \$32/B, the average is about 13.8 million barrels per year.

3. Effects on State Revenues and Economic Activity

Advanced technology ASR production activities could contribute significantly to state and local tax revenues in Oklahoma (Figure V-7A). At moderate oil prices (\$20/B to \$28/B), technology advances could account for \$330 million to \$510 million (20%) of the \$1.6 billion and \$2.5 billion in total potential state and local revenues. At \$36/B, nearly \$600 million could be added to implemented technology potential by advances in technology, for a total of almost \$3.5 billion in additional state and local revenues. Production taxes (55% to 58%) and state corporate income taxes (36% to 38%) comprise the largest portions of direct state revenues.

Figure V-6

Annual Production from ASR Reserves

Implemented Technology vs. Advanced Technology

A) At \$16/B

B) At \$32/B

In addition to the increases in state and local revenues, Oklahoma would benefit from the stimulation of economic activity and creation of new jobs. State economic activity at oil prices \$20/B to \$24/B could increase by over \$11 billion to nearly \$16 billion using advanced technology ASR. Of this increase, \$3.3 billion to \$4.5 billion could be attributed to technology advances. At \$36/B, the increase due to technology advances could be more substantial; nearly 38% (\$6.2 billion) of the \$22 billion in additional state economic activity is due to advances in ASR technology (Figure V-7B).

A significant number of jobs could be created or maintained by the widespread application of advanced ASR technology in Oklahoma. As the price of oil rises, the total number of jobs created or maintained could grow substantially, with the incremental jobs stimulated directly by advanced technology accounting for much of the increase. In the peak year, advanced ASR technology could result in over 630 jobs annually at \$16/B and 1,060 jobs annually at the \$32/B, about 30% more than those generated under the implemented case (not illustrated). Even at lower prices, the number of jobs created or maintained by advanced technology ASR processes would be highly beneficial to the Oklahoma economy.

4. Effects on the National Economy and Budget

The development of advanced secondary recovery technology could also benefit the nation. Figure V-8A shows a large increase in the incremental revenues to the Federal treasury from personal and corporate income taxes due to advanced technology. At moderate oil prices (\$20/B to \$28/B), total Federal revenues from advanced ASR could range from \$4.5 billion to nearly \$7.0 billion. Of this increase in direct Federal revenues, \$1.2 billion to \$2.0 billion could be attributed to applications of ASR technology advances. At \$36/B, nearly \$2.9 billion (28%) of the more than \$10 billion in potential direct Federal revenues could be generated by technology advances.

The increase in domestic production due to advanced technology ASR could also replace imports and enhance the nation's energy security and independence. The direct value of the increased domestic production could, therefore, represent a decrease in the foreign trade deficit as money spent on domestic oil circulates throughout the U.S. economy rather than abroad. At oil prices ranging from \$20/B to \$28/B, the value of imports avoided could be between \$25 billion and \$38 billion, 30% of which would be attributable to technology advances (Figure V-8B). At \$36/B, 28% (over \$14 billion) of the \$52 billion in avoided imports could be due to the application of advanced technology. Increased production due to advanced technology ASR could therefore increase national security while decreasing the foreign trade deficit.

Figure V-7

State Impact of ASR Production

Implemented Technology vs. Advanced Technology

A) Direct State and Local Revenues

B) Direct State Economic Activity*

* To the extent that royalties go to the Federal government (i.e. fields on Federal lands), royalties as a portion of state economic activity may be overstated.

Figure V-8

National Impact of ASR Production

Implemented Technology vs. Advanced Technology

A) Direct Federal Revenues

B) Imports Avoided*

* To the extent that 1 barrel of domestic oil replaces 1 barrel of imported oil, imports avoided measures the reduction in the foreign trade deficit

D. CONCLUSIONS

As discussed in Chapter III, currently available EOR and ASR technologies have the potential to significantly increase reserves and provide substantial economic benefits to operators, the states, and the nation. An aggressive and efficient technology transfer program in both the public and private sectors would bring these available technologies to operators and expedite their field applications. At an oil price of \$20/B, implemented technology EOR and ASR process could contribute nearly 900 million barrels to Oklahoma's reserves base. At \$28/B, potential incremental reserves could reach over 1.1 billion barrels.

Advances in technology could significantly increase the potential reserves and associated economic benefits which are possible using implemented technology EOR and ASR. Technology advances could increase implemented technology potential by over 40%, adding 600 million barrels of incremental reserves, at an oil price of \$20/B. The total potential reserves at this price, over 1.5 million barrels, is more than double Oklahoma's 1991 proved reserves. At an oil price of \$28/B, technology advances could stimulate over 1.2 billion barrels of incremental reserves for a total EOR and ASR reserves potential of over 2.5 billion barrels, three times more than Oklahoma 1991 proved reserves.

The activities associated with advanced technology EOR and ASR would generate substantial direct state tax revenues. At \$20/B, 700 million of the \$2.0 billion of potential direct state revenues would be attributable to technology advances. At an oil price of \$28/B, over 50% (\$2.4 billion) of the \$4.7 billion in total potential state revenues could be due to advances in technology.

The potential benefits estimated in this analysis will not be possible, however, without effective technology transfer and RD&D programs. Aggressive technology transfer needs to be undertaken by all oil-related entities (operators, producer associations, research universities, state geologic surveys, and state and Federal government agencies) in order to ensure that currently available technologies are disseminated in the oil patch and widely applied in the field. The significant additional benefits derived from technology advances clearly warrant a focused RD&D program to improve advanced oil recovery technologies.

A collaborative effort between the public and private sectors is essential to pool resources and expertise while leveraging risk. Operators, oil companies, research universities, and state geologic surveys need to join with state and local governments and the Federal government to identify the highest priority

problems in reservoirs with the largest remaining resources and the greatest threat of abandonment. A focused RD&D effort targeting the identified problems then needs to be undertaken. An RD&D effort alone is not enough, however; the newly developed technologies need to be transferred to the field for wide-scale demonstration and application. The Department of Energy's Program Opportunity Notice (PON) process is currently applying some of these concepts. The PON process targets specific classes of reservoirs that with exhibit both the largest potential resources and the greatest threats of abandonment. Near- and mid-term RD&D efforts, jointly funded by the Federal government and private industry, are directed towards the producing problems of these reservoirs. The results, once successfully developed and demonstrated, are to be transferred to other operators facing similar producing conditions. While they are a start, efforts like the PON process are not enough. A more aggressive and focused collaborative RD&D effort will greatly increase domestic production, enhance national energy security, reduce imports, and increase economic benefits associated with oil recovery.

Even after application of advanced technology EOR and ASR, a significant portion of the oil resource will remain unrecovered in the analyzed Oklahoma reservoirs (Figure V-9). At the improbably high oil price of \$36/B, total ASR reserves potential would be 1.4 billion barrels while EOR reserves potential would total 1.1 billion barrels. If this reserves potential were realized, over 5.1 billion barrels of mobile oil (78% of the mobile oil target) and 10.5 billion barrels of immobile oil (91% of the immobile oil target) would remain in analyzed reservoirs. In addition, over 9.2 billion barrels of remaining oil not included in this analysis, and any newly discovered oil, would still be unrecovered after application of advanced technology EOR and ASR. The known remaining oil-in-place of nearly 25 billion barrels is the target for further advances in EOR and ASR technologies.

Figure V-9

Oklahoma Remaining Oil Resource After Advanced Technology Recovery