**ANALYSIS OF SELECTED ENERGY
SECURITY ISSUES RELATED TO U.S.
CRUDE OIL AND NATURAL GAS
EXPLORATION, DEVELOPMENT,
PRODUCTION, TRANSPORTATION AND
PROCESSING**

Final Report

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I. Introduction

In July 1989, President Bush directed the Secretary of Energy to initiate the development of a comprehensive National Energy Strategy (NES) built upon a national consensus. The overall principle for the NES, as defined by the President and articulated by the Economic Policy Council (EPC), is the continuation of the successful policy of market reliance, consistent with the following goals:

- Balancing of energy, economic, and environmental concerns
- Reduced dependence by the U.S. and its friends and allies on potentially unreliable energy suppliers.

The analytical objective of the NES is to identify market inefficiencies and security and environmental vulnerabilities, such as:

- Noncompetitive markets (not stemming from government policy)
- Market inefficiencies (resulting from government regulation)
- Strong externalities or spill-over effects (environmental, security, and economic)
- Distorted or ineffective market signals (stemming from government policy).

Where market inefficiencies, failures, and/or vulnerabilities are identified, their impacts are to be, to the extent possible, quantitatively assessed. In addition, options to overcome these market impediments are to be identified and analyzed.

A. PURPOSE OF ANALYSIS

The NES analysis effort was divided into three key areas of concern by the EPC: 1) energy security, with focus on petroleum supply and demand, 2) electricity generation, transmission, and end use, and 3) environment, with focus on interaction between energy and environmental regulatory and

statutory policy. Working groups were assigned with the responsibility of directing analyses under each of these areas of concern. The analyses presented in this report were performed primarily in support of the Energy Security Working Group.

Based on the analytical guidance set forth by the EPC, this study focuses on three specific areas identified as "market impediments and inefficiencies" or "security or environmental vulnerabilities". These areas are:

- Constraints on the successful performance of research and development (R&D) pertinent to crude oil and unconventional gas extraction technologies and transfer of R&D results to oil and gas producers
- Economic/fiscal disincentives for exploration and production of crude oil and unconventional natural gas
- Development restrictions and reduced economic viability of domestic crude oil and unconventional gas resources due to environmental considerations.

B. BASIS FOR ANALYSIS

The analyses presented in this report draw upon a large body of work previously conducted for DOE/Office of Fossil Energy, the U.S. Department of Interior/Minerals Management Service (DOI/MMS), and the Gas Research Institute (GRI), referenced throughout the text of this report. This work includes assessments in the following areas:

- The potential of advanced oil and gas extraction technologies as improved through R&D, along with the successful transfer of these technologies to the domestic petroleum industry
- The economic and energy impacts of environmental regulations on domestic oil and gas exploration, production, and transportation
- The potential of tax incentives to stimulate domestic oil and gas development and production
- The potential environmental costs associated with various options for leasing U.S. oil and gas resources in the Outer Continental Shelf (OCS)
- The economic impacts of environmental regulations affecting domestic crude oil refining.

This analysis was conducted within the framework and guidelines established by the NES staff as set forth by the EPC. Costs and benefits are presented in a consistent, net present value framework. The analytical results presented are intended to provide an evaluation of the impacts of the energy options that were assessed as part of the analysis, including an assessment of their contribution to economic, environmental, and security benefits, and their near- and long-term effects.

II. Analysis Methodology and NES Model Description

The basis for comparing the various energy options considered in this analysis is the NES reference case, which depicts a hypothetical U.S. energy future to the year 2030.

The NES reference case is guided by a number of macro-level assumptions about economic growth, world oil prices, domestic energy resources, and technical judgements about the performance of current and future energy technologies. Assumptions specific to the NES reference case that relate to the analyses summarized here are presented and discussed where appropriate below.

Given this reference set of conditions, the approach used for analyzing various energy options consists of the following components:

- A description of the analytical approach or methodology used for examining the option and the alternative mechanisms examined (if any) for implementing the option. This includes references to existing studies used in the analysis, along with mention of other studies which may be desirable but deferred to a later time. This description also includes a summary of basic assumptions and underlying information upon which the analysis is based.
- An enumeration of the costs and benefits (on a net present value basis) associated with implementing the options under the various mechanisms examined, over the NES time frame.
- An evaluation and comparison of the enumerated costs and benefits associated with the various options and implementing mechanisms. This is based on the net present value of quantifiable costs and benefits accrued over the NES time frame. This evaluation involves both financial analysis (i.e., from the perspective of an operator) and economic analysis (i.e., from the perspective of society, including, in some instances, external costs).
- A summary of the results and findings from the benefits/cost analysis, stated in terms of their contribution to the overall objectives and policy goals of the NES.

In the analyses presented in this report, the costs and benefits associated with the various options and implementing mechanisms considered are evaluated in terms of their effect on the following items:

- Ultimately recoverable domestic crude oil and unconventional gas reserves
- Future domestic crude oil and unconventional gas production
- Future crude oil imports
- Future net state and federal revenues collected from income taxes, royalties, and severance taxes resulting from domestic crude oil and unconventional gas operations
- Future estimated net environmental costs resulting from changes in domestic crude oil production and imports.

Not included in the analyses presented in this report are all of the environmental costs associated with increased domestic crude oil production and macro-economic benefits other than those listed that result from increased domestic crude oil production, such as increased employment and spin-off technologies resulting from R&D on improved extraction and reservoir characterization technologies.

A. OVERVIEW OF THE NES ANALYSIS SYSTEM FOR CRUDE OIL

The methodology used in this analysis differs in some respects for each set of options and implementation mechanisms analyzed, but has some fundamental features common to all analyses. The results presented are based on analytical systems previously developed and work previously conducted for DOE, DOI, and GRI. These systems have been designed and built to be sufficiently flexible to analyze a wide variety of economic, technological, and policy scenarios affecting U.S. oil and gas supplies, and have been tested and used extensively for a variety of purposes. The analytical systems fall into two major categories: 1) those designed to examine the impacts of various scenarios on future reserves of crude oil and unconventional natural gas, and 2) those designed to estimate some of the environmental costs associated with various oil and gas production scenarios. The first category of systems are the subject of this chapter; the following chapter discusses the second set of systems.

1. Baseline Modeling Assumptions and Key References

The future potential production from four categories of U.S. crude oil resources was evaluated:

- The continued conventional production of known fields in the Lower-48 onshore and offshore
- Future advanced secondary recovery (ASR) projects (consisting of infill drilling and improved waterflood projects) in known fields in the Lower-48 onshore (for producing unrecovered mobile oil (UMO))
- Future enhanced oil recovery (EOR) projects in known fields in the Lower-48 onshore (for producing unrecovered immobile oil)
- Onshore and offshore fields remaining to be discovered in the Lower-48 and Alaska (assuming only conventional primary and secondary recovery operations).

Each of these crude oil resource categories are discussed in more detail below.

a. **Known Resource.** The analysis of the production potential of the known (already discovered) oil resource is based on recovery performance and economic modeling which uses data on critical properties for major U.S. crude oil reservoirs. This analysis used the Tertiary Oil Recovery Information System (TORIS), developed by the National Petroleum Council (NPC, 1984) and maintained and updated by DOE's Bartlesville Project Office. TORIS utilizes comprehensive oil reservoir data bases and detailed engineering and economic evaluation models, considering data for individual reservoirs to estimate crude oil production, investment and operating costs, project economics, and, ultimately, potential crude oil reserves.

Previous studies of the future pace of crude oil resource abandonments (DOE, 1989) served as the basis for assessing the impact of various options and implementing mechanisms on the continued production from U.S. oil reservoirs. These analyses projected future production from individual reservoirs based on historic trends. Reservoirs were analyzed in nine major oil producing states: California, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming. These states were chosen for the availability and comprehensiveness of resource data, production data, and well counts; because the states represent various stages of oil resource maturity; and because they represent a significant portion of the Lower-48 resource, accounting for 83% of the original-oil-in-place and over 75% of the remaining oil-in-place in the Lower-48 states.

In the reference case, production projections assumed that historical activities to maintain and/or increase production in each reservoir are continued in the future. Oil production is viable

until the economic limit of production, when revenues from oil sales just offset associated production costs. As oil prices increase, the economic limit for production falls, extending the productive life of a reservoir. Similarly, increasing costs (e.g., due to increased costs of compliance with environmental regulations) raise the economic limit and reduce the productive life of a reservoir.

Unrecovered mobile oil (UMO) is displaceable by water but is left in the reservoir at the conclusion of conventional recovery operations; reservoir heterogeneity or mobility differences cause injected water to finger through or around the oil, leaving portions of the reservoir at near-original oil saturation. Producing the UMO resource requires additional wells drilled at closer spacing to improve contact with the uncontacted and/or unswept oil and improve waterflood sweep and pattern conformance. Additional improvements in secondary recovery can be achieved with the application of polymers to help improve mobility or gel treatments to reduce permeability contrasts between reservoir layers. In many reservoirs, a much higher recovery efficiency is obtained with the combined application of infill drilling and these improved secondary recovery techniques.

The assessment of the various advanced secondary recovery (ASR) processes considered for producing the UMO resource was based on analyses of 700 crude oil reservoirs in three states — Texas, Oklahoma, and New Mexico. The reservoirs in these states are estimated to have originally contained almost 112 billion barrels of oil-in-place, representing about one-fifth of the total resource-in-place in the U.S. The analysis of this resource expands upon previously sponsored work by DOE (ICF Resources and BEG, 1989).

Three ASR processes for improving the producibility of mobile oil were considered: infill drilling, permeability contrast modification treatments (which direct the flow of injected water to lower-permeability layers containing mobile oil), and polymer-augmented waterflooding (where polymers are added to the injected water to obtain a more favorable water-to-oil mobility ratio and improve recovery efficiency).

Enhanced oil recovery (EOR), for purposes of this study, is defined as the incremental recovery of oil that is immobile to waterflooding, so-called waterflood residual oil. EOR methods include miscible gas injection (typically carbon dioxide), chemical flooding (normally surfactants and alkalines), and thermal recovery, which relies on the introduction of thermal energy (most commonly

in the form of injected steam or a combustion front in the reservoir fueled by injected air) to reduce oil viscosity and increase recovery.

The analysis of EOR potential in this study is based on the TORIS analysis system, which includes a reservoir data base consisting of over 3,700 reservoirs located throughout the U.S. The individual reservoirs evaluated in the study contain over 72% of the total original oil resource in-place in the U.S. This analysis again expands upon previously conducted, DOE-sponsored work (DOE, 1990a).

b. Undiscovered Resource. The analysis of the undiscovered crude oil resource uses models also developed by DOE in its Replacement Costs of Crude Oil (REPCO) Supply Analysis System (Lewin and Associates, 1985). This system is designed to determine the cost of finding and developing U.S. undiscovered crude oil resources. Undiscovered crude oil resources, as defined by the U.S. Department of Interior (DOI, 1989), are those resources judged to exist in geologically promising but unexplored or undrilled areas. For purposes of this analysis, the economic feasibility of recovering undiscovered resources was determined under the assumption that the volume of crude oil associated with a discovered hydrocarbon accumulation must support all costs associated with its development and production, including all finding and lease bonus costs. The undiscovered resource base assessed as part of this study is based on the most recent DOI assessment (DOI, 1989).

In this analysis, the entire estimated U.S. undiscovered crude oil resource base was not considered in the reference case. The resource base accessible under the reference case assumes the continuation of recent Presidential and Congressional decisions concerning land set aside from leasing or currently under leasing moratoria, such as that in the Arctic National Wildlife Refuge (ANWR) and specific areas off the coasts of California and Florida. The resource base that exists under wetlands, wilderness lands, national forests, etc., was included in the evaluation.

2. Description of Model for Integrating/Analyzing Previous Results - the Crude Oil Policy Model

The results and findings presented in this report concerning crude oil are based upon previous analyses performed using the TORIS and REPCO systems. These results have traditionally been presented in terms of the economically recoverable resources (reserves) and the state and federal revenues (from federal royalty payments, federal income taxes, state income taxes, and state and local production and severance taxes) that are collected from the production of these reserves.

TORIS and REPCO have been extensively used in recent years for a series of analytical assessments of R&D, tax, and environmental policies and their impact on future domestic supplies. Detailed, comprehensive systems like TORIS and REPCO are critically needed to assess policy options accurately. However, these systems as currently configured are too complex and detailed to quickly provide meaningful input to the rapidly changing NES and oil policy debate; a full TORIS and REPCO analysis often requires weeks to complete while the NES and other policy analysis requirements demand numerous sensitivity runs within a few days or, in some cases, only hours. TORIS and REPCO, in spite of their obvious strengths, are not designed to allow rapid turnaround of highly detailed results at the level required by the NES analysis guidelines.

Therefore, a system was required for translating the results of previously conducted, detailed studies of the impacts of various policy options on domestic crude oil supplies to measures appropriate to the NES. Two options were available to carry this out:

- Use of existing models available to DOE, such as the EIA energy modeling system or the FOSSIL2 system maintained by the DOE Office of Policy, Planning, and Evaluation.
- The development and use of a system uniquely and appropriately suited for examining in detail the impacts of various policy options on domestic crude oil supplies.

The first option would offer the advantage of using a forecasting system familiar to most DOE analysts and would provide a consistent set of analyses across all energy sources. These systems can forecast energy production over time, and can estimate many of the costs and benefits associated with domestic energy policy options. However, as currently designed, these systems do not encompass the

necessary level of geologic detail and engineering sophistication required to perform detailed analyses of the impacts of successful R&D and technology transfer (which is the primary objective of the oil research program). These systems also do not explicitly forecast the response of oil and gas operators to policies affecting current and new domestic crude oil production.

Thus, the decision was made to develop a system that would be uniquely capable of incorporating the geologic and engineering detail explicit in the TORIS and REPCO systems but that could provide estimates for the measures of concern in the NES analysis within its time constraints. The objectives for this system were three-fold:

- Estimate the impact of various crude oil supply options in terms of the measures required in the NES analyses
- Represent accurately the results of the TORIS and REPCO systems within a time frame more appropriate for general policy analysis
- Provide a more detailed examination of the petroleum supply impacts of various energy options than that provided by the EIA or FOSSIL2 models.

For this analysis, a System Dynamics model (using the software package Professional Dynamo Plus by Pugh-Roberts) was developed by the Office of Fossil Energy and the DOE/Bartlesville Project Office which offers several advantages for policy analyses of the kind required by the NES process. A simpler version of this type of system had already been developed, which was consistent with previous TORIS analyses. The model relies on the results of complete and comprehensive TORIS and REPCO analyses, but allows a large number of sensitivity analyses to be completed more rapidly. The Dynamo computer code is relatively simple and the program can run on a personal computer. By providing results more rapidly and by estimating a greater variety of factors, especially the measures of interest in the NES evaluation process, the Dynamo model developed for this effort provides a valuable augmentation to TORIS and REPCO, which was critically needed for the NES analysis process.

The Dynamo-based Crude Oil Policy Model works on individual increments of resource economically recoverable over a defined price range, disaggregated by resource location, characteristics, and recovery process by the TORIS and REPCO systems. The model simulates the process of resource discovery, technology and recovery process screening, reserves development,

production, and reserves abandonment (and where economically justifiable, the redrilling and redevelopment of abandoned fields). Numerous decision steps are incorporated into the model to simulate operator decisions and market realities. For example, explicit steps are considered, where appropriate, to account for delays associated with leasing restrictions, the development and availability of advanced extraction technologies, and the time for performing pilot tests for various extraction technologies when they are economically justifiable and available. Moreover, should forecasts include events that fundamentally change the economic criteria implicit in detailed TORIS and REPCO analyses (such as a drop in oil price or a rapid increase in resource extraction costs), the Crude Oil Policy Model has the capability of performing additional cash flow analyses that can predict the likely changes in operator behavior that would result.

A detailed description of the Dynamo-based Crude Oil Policy Model, along with a preliminary User's Guide, will be developed and delivered to DOE/FE at a later date.

3. Calibration/Comparison of the Crude Oil Policy Model to the FOSSIL2 Oil Subsector Modules and to TORIS

To assess its consistency with other modeling efforts underway in support of the NES analysis process, the results of the Crude Oil Policy Model were compared with those obtained from FOSSIL2 (using the NES reference case as of 9/5/90). As shown in Figure II-1, the NES reference case and the ICF Resources' (ICFR) Baseline Scenario (developed with the intention of being similar to the NES reference case, as defined in Chapter IV) compare favorably to the late 1990's. The Crude Oil Policy Model forecasts production to respond more rapidly and with greater magnitude than FOSSIL2 to the higher prices established in the reference case price track. Crude oil production under the ICFR Baseline Scenario levels off by 2000 and increases rapidly from about 2005 until 2013, when, after a steady decline, it rejoins the FOSSIL2 NES reference case, which shows a steady production decline throughout the forecast period. This additional production in the ICFR Baseline Scenario is forecast to come from new discoveries in the Lower-48 (onshore and offshore), inferred reserves in the Lower-48 and Alaska, some infill drilling in existing fields, and new discoveries in areas on the Alaska North Slope (onshore and offshore) that are not currently subject to leasing moratoria.

Figure II-1

Crude Oil Production Forecast Comparison between ICFR Baseline Scenario and the NES Reference Case (as of 9/5/90)

a. **Comparison of the Crude Oil Policy Model to FOSSIL2**

A preliminary review was conducted of the assumptions and modeling approach used in the crude oil subsector of the FOSSIL2 model, as recorded in the FOSSIL2 Dynamo code listing (EEA, 1990). Admittedly, this review was conducted without much interaction with the DOE staff responsible for FOSSIL2 activities. Consequently, some potential exists for misinterpretation of FOSSIL2 modeling assumptions.

From this preliminary review, several important differences between the FOSSIL2 Model and the Crude Oil Policy Model appear to exist and may lead to the discrepancy in the forecasts shown in Figure II-1. They consist of both methodological differences and errors in some input data to FOSSIL2. The fundamental differences between FOSSIL2 and the Crude Oil Policy Model appear to be as follows:

- **Estimates of Resource Recovery Potential.** FOSSIL2 uses recent (1987) estimates of undiscovered resources in each subsector in the model as a baseline for forecasting subsector resource costs and production. Each initial resource estimate in the model represents an upper bound to technical recovery potential in the NES Reference Case. As resources are discovered, FOSSIL2 reduces the undiscovered resource pool and transfers the discoveries to unproven and proven reserves assuming a fairly linear, somewhat conservative cost/supply curve. In contrast, the Crude Oil Policy Model allows rising oil prices and advances in recovery technology to expand the recovery potential over time, based on TORIS and REPCO model results. Moreover, in FOSSIL2, some of the resource estimates used for some categories appear to be inconsistent with reported estimates, as summarized below:
 - **Conventional Offshore.** FOSSIL2's estimate for offshore undiscovered resources in 1987 is 9.0 billion barrels. This does not include California offshore, which is included in the conventional onshore estimate (Peterson, 1990). The DOI (1989) estimate, deducting California resources, is 12.7 billion barrels. If Alaska's offshore undiscovered resource (3.4 billion barrels) is also deducted, the FOSSIL2 and DOI estimates are quite close. FOSSIL2 also differs from DOI in the distribution between proven (measured) and unproven (inferred) reserves: FOSSIL2 estimates 2.4 billion barrels of unproven reserves and 2.8 billion barrels of proven reserves, while DOI estimates 0.4 and 4.0 billion barrels, respectively. This last discrepancy affects the timing of offshore production, delaying production projected by FOSSIL2.
 - **Conventional Onshore.** Assuming that offshore Southern California is included with conventional onshore resources, the FOSSIL2 estimates for undiscovered resources, at 31.9 billion barrels, is 13% below the corresponding

DOI estimate, 36.7 billion barrels. This lower baseline causes a more rapid decline in conventional onshore production than is projected by the Crude Oil Policy Model. It should also be noted that the 1987 estimate of "unproven" reserves used in FOSSIL2, 13.8 billion barrels, does not include the recovery potential of unrecovered mobile oil (UMO) which can be addressed by advanced secondary recovery (ASR) techniques, and which is included in the Crude Oil Policy Model.

- EOR (Non-Thermal). The FOSSIL2 estimate for initial resources for non-thermal EOR, at 11.8 billion barrels, matches the NPC's 1984 assessment of recovery potential using implemented technology at \$50 per barrel in 1983 dollars (about \$61 in 1989 dollars). This estimate does not account for advances in technology expected by 2000, as cited in the NPC study. Under the advanced technology case, the NPC estimated that ultimate non-thermal EOR recovery would be 22.0 billion barrels at the same price. Since 1984, the TORIS models have been enhanced and the data base has been expanded to cover a larger portion of the U.S. resource. The Crude Oil Policy Model incorporates recent TORIS estimates of ultimate recovery potential, at 26.8 billion barrels for the advanced technology case and \$50 per barrel (1989 dollars). These estimates of recovery potential by oil price and process are presented in Table IV-5 of this report.
- Thermal EOR. Whereas FOSSIL2 code cites the 1984 NPC estimates for thermal EOR recovery potential under implemented technology (7.2 billion barrels) and advanced technology (12.0 billion barrels), the model uses 15.7 billion barrels as its initial estimate, citing a more recent report by the Interstate Oil Compact Commission (IOCC, 1987b). This report used an expanded data base compared to the NPC (notable additions being Alaska and expanded coverage of Wyoming heavy oil resources), and evaluated recovery potential using implemented technology only. The report estimates 21.4 billion barrels of gross recovery potential, and the basis for the deduction used to arrive at FOSSIL2's lower estimate is not obvious. The Crude Oil Policy Model uses TORIS estimates based on the same data base and models used for the IOCC report, but excludes the huge West Sak field in Alaska. Ultimate recovery potential at \$60 per barrel and using advanced technology is 14.9 billion barrels, as reported in Table IV-5 of this report.
- Tar Sands. The 54.0 billion barrel resource estimate used by FOSSIL2 is actually the assessment of original oil-in-place in the referenced source (IOCC, 1984). This is not consistent with the other subsectors (which use as a basis "technically recoverable" reserves) and grossly overstates the recovery potential of the tar sands resource. It should be noted that in the NES reference case, tar sands are projected to provide a significant portion of domestic oil production by 2015, and the largest share of all sources by 2030. Technical recovery potential should be used for this resource. The Crude Oil Policy Model does not yet include the tar sands resource.

- Modeling of Alaska Oil Resources. The unique characteristics of the Alaska oil resource do not appear to be reflected adequately in FOSSIL2:
 - North Slope. The production stream for North Slope reserves is an exogenous input and appears to be independent of the price track. Total production is approximately equal to the DOI estimate of total measured and inferred reserves in Alaska (13.3 billion barrels). The rate of production over time, however, is fixed and not responsive to price.
 - Undiscovered Resources. Although undiscovered resources in Alaska account for one-third of the total for conventional onshore, the unique characteristics of Alaskan resource recovery operations do not appear to be explicitly reflected in the costing algorithms. The same costing algorithms for O&M and investment costs are applied to Alaskan undiscovered resources as are used for Lower-48 conventional production.
- Characterization of Operating and Investment Costs. In some cases, the structure of operating and investment costs used in FOSSIL2 does not appear to fully capture empirical findings:
 - Conventional Production. In general, FOSSIL2 uses exogenous projections of drilling costs and reserves found per foot drilled as the foundation for determining the costs of conventional offshore and onshore production. While this is a valid approach, it seems most appropriate for primary recovery operations. As waterflooding and pressure maintenance operations adopt ASR techniques to improve recovery, this cost structure may not be appropriate, particularly for development costs (in contrast to wildcat drilling costs). Additionally, this cost structure does not change over time despite important changes in the character of the undiscovered resource.
 - EOR and Thermal EOR. The EOR extraction cost inputs used in FOSSIL2 follow a nearly linear path as the resource is depleted. It is more generally held, however, that EOR costs will be more responsive to technology advances and injectant costs over the mid term than to resource depletion. By using TORIS results, the Crude Oil Policy Model incorporates costing algorithms that are technology-specific and have been extensively peer-reviewed by industry and academia.
- Effect of Technology Advances. R&D achievements have driven resource recovery at many points in the history of oil production, yet FOSSIL2 appears not to allow technology advances to have a significant impact on costs beyond 1990. This has a particularly distorting effect on EOR production, for which advances are projected by 2000 which will have a significant impact on costs and on resource potential (increments to initial assessment of technically recoverable resources). The Crude Oil Policy Model incorporates the impact of R&D explicitly through its use of TORIS and NPC-defined, technology-specific advances for EOR and ASR.

- **Effect of Abandonments.** FOSSIL2 does not capture the potential impact of resource abandonment on future recovery potential. It allocates a portion of onshore conventional production to stripper wells, of which a portion may cease production if the price of oil falls, but may also resume production if economics improve. Although FOSSIL2 does incorporate a "loss" factor for stripper production, it is not utilized in the reference case. Abandonments and their impact on recovery potential are modeled explicitly in the Crude Oil Policy Model.

b. Comparison of Crude Oil Policy Model to TORIS

A second calibration of the Crude Oil Policy Model was performed by comparing its forecast of EOR production to forecasts developed using TORIS. Comparisons were made at two constant crude oil prices -- \$20 and \$32 per barrel (TORIS evaluates EOR potential at constant oil prices) - - and at two technology levels -- implemented and advanced. To do this, TORIS technology timing assumptions were input to the Crude Oil Policy Model. These comparisons are illustrated in Figures II-2 and II-3.

At a \$20 per barrel price for both technology cases, the TORIS and Crude Oil Policy Models compare favorably. TORIS predicts slightly higher production in the early years, and then declines more rapidly in the later years. Similarly, at \$32 per barrel, TORIS predicts a more rapid rise in production, but also a more rapid fall.

Comparison of cumulative production over the 1990 to 2018 timeframe (the timeframe for TORIS analyses) shows that the results are also similar in total, as follows:

	<u>Cumulative Production Through 2018 (MMBbl)</u>	
	<u>TORIS</u>	<u>Crude Oil Policy Model</u>
\$20 per Barrel Price Track		
Implemented Technology	8,277	8,518
Advanced Technology	11,825	10,818
\$32 per Barrel Price Track		
Implemented Technology	18,366	18,315
Advanced Technology	26,055	24,815

Figure II-2

Comparison of TORIS and Crude Oil Policy Model Forecasts of Domestic EOR Production at Constant \$20/Bbl and \$32/Bbl Price Tracks

Figure II-3

Comparison of TORIS and Crude Oil Policy Model Forecasts of Domestic EOR Production at Constant \$20/Bbl and \$32/Bbl Price Tracks

Advanced Case

This shows that the EOR projections from TORIS and the Crude Oil Policy Model are comparable within about 10%. This comparability, given the completely different forecasting approaches used by the two systems, is quite acceptable.

B. OVERVIEW OF THE NES ANALYSIS SYSTEM FOR UNCONVENTIONAL NATURAL GAS

Unconventional natural gas refers to those reservoirs containing natural gas characterized by noncommercial rates of flow without some form of stimulation. The three main types of reservoirs are low permeability ("tight") sands, coal seams, and shales of Devonian age. Each resource has unique geological features and production mechanisms that make recovery from them difficult and generally require advanced extraction technology to make reservoirs economic to produce.

The methodology for calculating reserves, production, and costs for unconventional gas are based on explicit modeling of the most current resource data and production models (ICF Resources, 1990c). Resource data have been developed by ICF Resources in its work with GRI over the past five years and represent the most comprehensive description of the tight gas, coalbed methane, and Devonian age shale gas resource available.

The methodology and findings presented in this report are principally derived from two sources:

- An assessment of the entire U.S. natural gas resource base, which delineated the potential of proved reserves, inferred reserves, reserve growth, unconventional resources, and undiscovered resources (ICF Resources, 1990c).
- Previous results from ICF Resources technology and economic modeling of unconventional natural gas, consisting of various analyses and published and unpublished reports prepared for GRI and DOE.

Both of the sources represent the results of analyses that examined the unconventional gas resource base and derived estimates of potential recovery as a function of geology, technology, and economics. Supplemental analyses conducted by ICF Resources considered the impacts of production tax incentives and environmental compliance costs on potential unconventional gas supplies.

Each of the three unconventional gas resources (tight gas, coalbed methane, and Devonian shale gas) is characterized and modeled separately in this analysis. Within each resource category, plays, or geologically similar areas, are represented by one or more typical wells. These typical wells are modeled individually and multiplied by the number of potential wells in the play to get the total potential for the play. Plays are then aggregated to estimate the potential for the entire resource.

The resource estimates for tight gas sands are based on previous studies by the National Petroleum Council (NPC, 1980). ICF Resources integrated the data and the NPC analysis methodology into the Tight Gas Analysis System (TGAS) model in 1984. The TGAS model has been continuously updated to account for changes in extraction costs and taxation, and improvements have been made in the gas production, well stimulation, and financial analysis routines under sponsorship of GRI and DOE.

The NPC (1980) placed the low-permeability sands resource into two categories -- appraised and extrapolated. The appraised resource consists of 102 formations located in 10 basins that were studied in detail by the NPC. Appraised basins were those expected to contain the near-term development target for tight sands and all had some development in them. Each appraised formation was further defined by 5 to 10 typical wells, each well being associated with an explicit depth, pressure, productive area, gas-filled porosity, and net pay. The basins/formations having insufficient data for detailed analysis were grouped into four large regions: Western, Greater Southwest, Midcontinent, and Eastern. Geologic analogs were used to establish typical wells that, in turn, were used to estimate the economic gas potential in these regions.

The resource target and reserves estimates for coal seam gas rely on ICF Resources analyses of the Warrior, Piceance, Northern Appalachian, Central Appalachian, and San Juan Basins (Kelafant, et al., 1987; Kelso, et al., 1987; McFall, et al., 1986a; McFall, et al., 1986b). The methodology used incorporates detailed geologic mapping and township-by-township analyses to estimate technically recoverable gas. A two-phase, dual-porosity, finite-difference reservoir simulator, developed specifically for coalbed reservoirs, is used to calculate gas production. ICF Resources' own gas economics model was used, along with standard industry costing and cash flow evaluation methods, to estimate well economics.

The economically recoverable gas estimate from Devonian age (Devonian and Antrim) shales was developed by ICF Resources using recently updated geologic, reservoir, and production data from the Appalachian and Michigan Basins (Oliver, et al., 1989). Technically recoverable resource estimates were derived using reservoir data, previously published geologic and reservoir studies, and analyses of well logs. Long-term history matching of actual Devonian and Antrim shale gas production was also performed using a dual-porosity, finite-difference gas reservoir simulator. Operator surveys, case studies, and vendor quotes were used to develop accurate drilling and operating cost data. Although the Antrim play is quite new and ultimate recovery is still uncertain, the data contained in this report are the most credible available.

The methodologies employed for performing the assessments presented in this report are described in more detail in ICF Resources (1990c).

III. Minerals Management Service/ A.T. Kearney Environmental Cost Model

A. BACKGROUND FOR THE MMS ENVIRONMENTAL COST MODEL

The involvement of the Department of the Interior (DOI) in the leasing of oil and gas resources began with the enactment of the Outer Continental Shelf Lands Act of 1953. That Act defined the scope of federal jurisdiction and developed the initial rationale for lease sales to the private sector of the rights to produce oil and gas from the Outer Continental Shelf (OCS). In 1978, the OCS Lands Act Amendments were passed to respond to the increasingly complex issues of energy security, economics, and the environment surrounding the sale of OCS leases.

In response to this and related legislation and court decisions arising from a series of suits challenging the analyses used to support lease sales, DOI developed and refined a framework for evaluating the desirability of leasing OCS oil and gas tracts. A critical part of this framework is the determination of the net social value of the prospective development of these resources. Net social value is the market value of oil and gas resources less the costs of production and less environmental costs.

Historically, from the perspective of a private company, evaluation of the development prospects of oil and gas resources would entail a relatively simple comparison of the market value of these resources with the costs required to produce them. For DOI, such an analysis of what is termed "net economic value" fails to incorporate a broad range of environmental costs associated with societal losses and damages to natural resources caused by OCS oil and gas development and production, or with actions designed to reduce or eliminate these damages. Further, industry's costs of production may not fully reflect the cost of complying with future environmental regulations.

The Minerals Management Service (MMS) of DOI has responsibility for the leasing program and for the estimation of the net social value of OCS resources. To accomplish the latter, MMS has developed or sponsored the development of models to help estimate the net social value.

The purpose of the MMS Integrated Environmental Cost Model¹ is to produce and document estimates of the environmental costs of developing leased and unleased oil and natural gas resources in 26 MMS planning areas in the OCS. These areas encompass OCS areas off the Atlantic, Pacific, and Gulf Coasts and the OCS areas surrounding Alaska. For each planning area, the model provides estimates of 15 distinct cost elements.

B. OVERVIEW OF THE ENVIRONMENTAL COST MODEL

1. Evolution of Current Model

The current environmental cost model supersedes a model developed during planning for the 1987 to 1992 five-year OCS leasing program. Although similar in structure and purpose, this earlier model addressed a narrower range of costs than the current model and relied on a more limited number of data sources. To address shortcomings in the previous analyses and to reflect changes in regulatory climate and data availability, the current model updates, expands, and refines the structure of the model used for the 1987-1992 program.

The most significant changes incorporated in the current model are derived from several unrelated events. In its 1988 decision in *The Natural Resources Defense Council, Inc. v. the U.S. Interior Department*, the U.S. Court of Appeals for the District of Columbia Circuit found deficiencies in the analyses used to support lease sale decisions. These deficiencies related to cumulative impacts on migratory species, effects of oil spills that reach shorelines, assumptions related to "backing out" foreign oil, air quality costs, and wetlands losses. The decision required that the deficiencies be remedied in the current program. An unrelated case, *Ohio v. the Department of the Interior*, concerned with regulations for conducting natural resource damage assessments, also resulted in changes in the methodology for estimating the environmental damages from oil spills. The current model addresses all these issues.

The projection of costs in the model is largely based on past oil spills and the measurements of their effects. The *Exxon Valdez* oil spill has substantially increased the volume of available data

¹ Under development for the MMS by the Kearney/Centaur Division, A.T. Kearney Inc. et al., under contract number 14-35-0001-30500.

related to the cleanup of such spills and other spill-related environmental costs. In the *Exxon Valdez* case, these costs have been higher and more extensive than costs of previous spills. Consequently, estimating procedures for certain cost elements have been substantially revised.

The current model has other enhancements that improve and broaden its scope. The current model expands the scope of estimates by including non-spill-related costs corresponding to regulatory requirements for water quality and spill avoidance and spill-related costs for indirect values of wildlife and environmental resources and for degradation of property values.

2. Structure and Methodology of Current Model

In the current model, environmental costs have been organized into 15 cost elements. Each cost element includes the costs associated with a clearly defined impact of oil and gas development such as compliance with air quality regulations or spill-related losses to recreation and tourism.

These 15 cost elements have been grouped into three general categories: regulatory, non-spill-related, and spill-related. The regulatory category includes costs related to compliance with environmental controls on oil and natural gas production. Inevitably, normal oil and gas production causes disruptions or degradation to economic and other activities. Costs related to these impacts are grouped under the non-spill-related category. Finally, the spilling of oil creates a range of costs arising from the required cleanup or the unavoidable impacts of spilled oil on a variety of resources. Table III-1 presents the three general categories of environmental costs and related cost elements.

All costs estimated for each cost element are allocated to one of three cost types: direct regulatory control costs, substitution costs, and social costs. While these cost types can be defined as mutually exclusive categories, there remains in practice some ambiguity in certain cases.

A direct regulatory control cost is defined as a cost incurred to comply with environmental and other regulations associated with oil and natural gas production. The cost of purchasing and installing equipment to reduce emissions of carbon monoxide from power generating equipment on oil and natural gas platforms is an example of a direct regulatory control cost.

TABLE III-1
MMS ENVIRONMENTAL COST MODEL:
COST ELEMENTS BY CATEGORY

Regulatory Cost Elements

Air Emissions

Spill Avoidance

Water Quality

Non-Spill Related Cost Elements

Infrastructure

Wetlands Losses

Fishing Ground Preemption and Gear Loss

Changes in Property Value

Spill-Related Cost Elements

Oil Spill Control and Cleanup

Subsistence Losses

Tourism and Recreation Losses

Legal and Administrative Costs

Commercial Fishery Losses

Oil Spill Research Costs

Wildlife and Ecological Losses

Value of Lost Oil

Substitution costs refer to measures taken or installed before the fact to mitigate or substitute for adverse environmental effects. If a company chose to purchase pollutant offsets rather than to reduce emissions, such a purchase would be considered a substitution cost.

Social costs include costs of damages and other adverse environmental effects regardless of whether compensation is actually paid. These costs include both market and non-market values. A social cost based on market value would be wages and profits lost to commercial fishing companies because of an oil spill. Alternatively, the cost of wildlife destroyed by an oil spill would be a non-market value social cost.

Because costs related to spills from marine transport of petroleum products is a primary concern of the NES, the cost elements of prime interest here are the eight cost elements that are spill-related:

- Oil spill control and cleanup costs include the labor, equipment, supplies, and services used in the following spill-related activities; stemming the loss of oil from a tanker, pipeline, or offshore oil facility; recovery of oil at sea and preventing its encroachment on the shore; and removal and recovery of oil reaching shore.
- Tourism and recreation losses capture the changes in "willingness-to-pay" values of recreation experiences. These losses were designed to capture recreation and congestion losses in substitute recreational facilities.
- Commercial fishery losses refer to losses due to the temporary closing of fisheries or fishing harbors, fouling of vessels and equipment, or general disruption of fishing activities.
- Wildlife and ecological losses include damages to coastal habitats, marine habitats, and biota.
- Subsistence losses refer to losses in the ability of Native Americans to harvest marine mammals, fish, sea birds, eggs, and other foodstuffs that can account for up to 80% of their diet.
- Legal and administrative costs include the costs to administer the OCS leasing program, other federal programs such as the Coast Guard's oil spill monitoring efforts, and the legal and related costs associated with oil spills, including litigation costs.
- Research costs include the costs of analyzing the fate and effects of spilled oil.

- Losses to property values are temporary losses in value for structures and land directly affected by spilled oil that reaches the shore. It is assumed that this type of loss in property value is temporary and is realized only in the event that property is sold during the temporary period when the oil on the shore is an evident problem.
- Value of lost oil is the market value of the volume of oil lost as a result of spills.

3. Data Sources and Development of Oil Spill Probabilities

The MMS Integrated Environmental Cost Model integrates hundreds of data sources to estimate environmental costs. The principal sources of data for spill-related cost elements are case studies and analyses of historic spills. Case study data are supplemented by a range of other types of data including, but not limited to, hypothetical valuations of tourism losses, replacement costs for ecological resources, and the Federal budgets for administrative costs. A detailed manual on this process is presented elsewhere (Kearney/Centaur, 1990).

The MMS model was modified in order to simulate the costs exclusively for oil spills. The "customized" NES oil spill impact model also relies on a number of other key information inputs. These inputs are used primarily to predict the flow of oil, oil spill rates, and the probabilities of an individual oil spill reaching shore. The estimate of the probability of an oil spill reaching shore is critical to this analysis since the unit societal damages from an oil spill which reaches shore are approximately 10 times greater than those for oil which remains at sea. The key inputs used to derive the NES oil spill cost model as described in the following paragraphs.

Estimates of future domestic production (both on shore and OCS) are combined with projected national demand to estimate the future volumes of domestic and foreign oil consumed by the nation. The baseline forecast used in our analysis was the ICF Baseline Scenario run for the period 1990 to 2030 (discussed in Chapter IV).

The allocation of this consumption to the OCS planning area is based on the "North American Crude Oil Demand (NACOD)" model developed by ICF Resources Incorporated for the U.S. Department of Energy (ICF Resources, 1988). This report forecasts marine and other shipments of all petroleum products by region.

NACOD is a linear programming model that simulates the crude oil and petroleum products transportation network for the U.S. It divides the U.S. into 15 regions which are interconnected by marine and pipeline links for both crude oil and products. The model contains a series of factors that are applied against national crude oil and natural gas liquid (NGL) production values which results in the disaggregation of the national crude oil and NGL values to the relevant regions. Each region has a refining capability with an average percentage yield and utilization, while the demand for products within each region is related to population projections.

For the work undertaken for the NES, two of the NACOD regions were further subdivided so that all of the MMS regions in the Lower 48 could be represented. Alaska was left as one region, but it was assumed that northern Alaskan OCS production would move by pipeline to shore and then down the Trans-Alaska Pipeline System (TAPS), while oil produced from the southern and western Alaskan OCS would either move to shore first by pipeline or move directly by marine transport to refineries on the West Coast and Gulf Coast.

Minor regional movements and intra-regional movements were derived from other work recently undertaken for the SPR office and based on U.S. Army Corps of Engineers waterborne data. This work has been documented and submitted to the SPR office but is still in draft form. The documentation for NACOD was submitted in October 1988 (ICF Resources, 1988), and output from NACOD has been published by DOE.

Data on spills and the volumes of spilled data reaching shore were derived from "Revised Tanker Spill Rates and Mean Spill Sizes for NES Calculations," internal Department of the Interior memorandum from Cheryl Anderson to Rich Winor, August 21, 1990 (DOI, 1990). These data are summarized in the introduction to this document. The key assumptions used to estimate spill risks were as follows:

**Estimated Spill Risk and Mean Size of Large Oil Spills
(over 1,000 barrels) in the per Billion Barrels Shipped**

	<u>Baseline (Probability/Billion Bbl)</u>	<u>Mean Spill Size (Barrels)</u>
In Port:	0.45	8,265
Restricted Waters:	0.69	40,113
Open Waters:	0.23	50,746

4. Structure of Oil Spill Module of MMS Environmental Cost Model

Because of the number of OCS planning areas, cost elements, and years of production included in the analysis of environmental costs, the model is unavoidably complex. Consequently, there has been a deliberate attempt to make the cost estimation methodologies as simple as possible. Figure III-1 provides an overview of the model's methodology and operations.

The model's outputs are organized geographically by the OCS planning areas defined by MMS. The entire OCS is divided into 26 planning areas: four along the Atlantic coast, three along the Gulf coast, four along the Pacific coast, and the remaining 15 off Alaska. Because relatively little tanker transportation occurs in Alaska, the Alaskan planning areas have been considered as a whole for this analysis.

The basic unit of analysis is the estimated cost for a given cost type of a given cost element for a given year for one of the planning areas. For example, the estimated social costs from damages to commercial fishing resulting from oil spills in 2004 in the Southern California planning area is the most basic type of estimate produced by the model. For each projection of domestic production and oil imports, the model can generate over 13,000 estimates at this level.

Given the number of estimates involved, the formulas used to generate these basic estimates are kept as simple as possible. Typically, the formulas are driven by one of the following three variables: oil and natural gas production, oil spillage, and spilled oil reaching shore. Unit costs are attached to these variables to produce the estimate. To continue with the previous example, the estimated social costs from damages to commercial fishing resulting from oil spills in 2004 in the Southern California planning area would equal the sum of total oil spilled (expressed in barrels of

Figure III-1

MMS Environmental Cost Model

oil) in that area for 2004 multiplied by \$5.16 (the unit cost) plus total spilled oil reaching shore (expressed in barrels of oil) in that area for 2004 multiplied by \$50.27 (the unit cost).

In order to compare similar costs, the net present values of these individual costs are calculated for each planning area. The model produces the net present value for social costs from damages to commercial fishing resulting from oil spills in the Southern California planning area. This estimate brings all cost estimates from 1991 through 2030 back to a single present value.

IV. Analysis of Technology Development and Transfer

This chapter presents estimates of the costs, benefits, and energy and economic impacts of an expanded and accelerated federal research and development (R&D) program on improved oil and gas exploration and production (E&P) technologies. The scope of the study addresses the publicly identified NES goal of enhancing U.S. energy security by minimizing dependence on less secure sources of crude oil supplies and reducing U.S. vulnerability to the adverse impacts of supply disruptions. Since the issues and concerns are not entirely the same for domestic oil production as they are for domestic gas production, oil and gas resources are presented separately.

A. CRUDE OIL

1. Background

After currently proved crude oil reserves are produced by conventional (primary and secondary) recovery methods, nearly two-thirds of the known U.S. oil resource (over 300 billion barrels) will remain unrecovered (Figure IV-1). Nearly 100 billion barrels are theoretically displaceable by water but are left unrecovered in the reservoir at the end of conventional recovery operations because this oil has not been contacted or swept by existing waterfloods. Another 224 billion barrels are not displaceable by water; the recovery of a portion of this resource depends on the application of tertiary recovery processes. Although only a small portion of this remaining resource in place could ever be recovered, it represents a substantial target for future advanced recovery operations.

However, DOE has recently concluded that the U.S. will continue to face a rapid pace of crude oil production decline and resource abandonment (DOE, 1989), and that many factors (e.g., oil prices, extraction technologies, taxes, and regulatory costs) can influence the rate and level of these abandonments. This conclusion was based on analyses of the continued conventional production from U.S. oil reservoirs, using historic trends and projections of future production from

Figure IV-1

Over 300 Billion Barrels of Known U.S. Oil Resources Will Remain After Conventional Production (As of 12/31/87)

individual reservoirs in nine oil producing states — California, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming.

New U.S. discoveries are forecast to provide only a fraction of future U.S. petroleum needs. The most promising areas for new discoveries — the offshore and Alaska — are important, but will not on their own halt the decline in U.S. production from known reservoirs nor replace the reserves that are now being produced. Moreover, future access to much of the resource potentially existing in these frontier areas is currently under debate.

The price collapse in 1986 profoundly affected the U.S. petroleum industry, forcing many smaller companies to go out of business and many others to reorient their exploration and development strategies. To reduce costs, many operators cut R&D expenditures dramatically, and preferentially pursued lower-cost extraction technologies. To replenish reserves, U.S. producers increasingly have shifted their focus to foreign regions, reducing their commitment to efficiently develop domestic resources. At the same time, lower prices have increased the production level at which producing wells remain economic, accelerating the time when these wells must be abandoned. This leaves less time for the development and dissemination of new, cost-effective oil extraction technologies.

Several recent studies (DOE, 1987a; ERAB, 1987) have concluded that geoscientific and technological research at DOE receives relative low priority, and has traditionally been restricted to long-term, high-risk projects that show little near-term promise towards increasing domestic production. Moreover, these studies, along with other testimony submitted during the NES development process, commented on the fact that many in industry feel that, where federally funded R&D does take place, the results of this R&D are generally inaccessible to much of the U.S. petroleum industry, particularly to independent oil producers.

Most independent oil producers cannot engage in R&D activities. They rely on the results of research performed by others. Results of private research are slow to reach independent producers, due to the often proprietary nature of the R&D and the competitive advantages which justify the research expenditures of the major oil companies. In most cases, independent operators

do not begin to utilize a practice until many years after it has become standard for the larger companies.

Moreover, only a small number of the largest oil companies engage in significant R&D activities. The budgets of these private R&D programs, however, have shrunk in recent years, adjusting to lower crude oil prices. Cooperative R&D makes up only a small portion of industry research efforts. R&D in exploration and production usually results in better practices, not patentable processes. This underscores the proprietary nature of R&D and limits cooperative efforts. Further, public attitudes toward cooperation among major oil companies are negative, viewing them as monopolistic in nature.

Federal R&D plays an important role in oil and gas extraction technology development and transfer, because federal efforts benefit producers of all sizes and an aggressive technology transfer program can get research advances into the field quickly. In addition, the federal government is uniquely positioned to sponsor R&D for maximum effect on the resource base and to develop cooperative efforts between state and federal government agencies, universities, and operators of all sizes.

The recent studies of federal research have demonstrated that an aggressive, mission-oriented federal R&D program could overcome the market constraints currently affecting private-sector R&D and the short time frame within which technical and economic constraints to crude oil extraction must be overcome and disseminated to the petroleum industry (DOE, 1987a; ERAB, 1987; DOE, 1987b; DOE, 1990a).

In response, DOE has thoroughly revised its R&D program, publishing a revised program plan in April 1990 (DOE, 1990a). The goal of this program is to maximize the economic producibility of the domestic oil resource. This plan recognizes the time-sensitivity of declining domestic production and rising imports, and sets forth a targeted R&D program that focuses on the reduction of existing technical and economic constraints on domestic producibility.

The purpose of this analysis is to examine the impact of various R&D strategies in terms of potential reserves, future production, and net economic benefits to society.

2. Description of Options Analyzed

The methodology employed to examine the impacts of an expanded and accelerated federal R&D program is based on previous studies and existing models. To examine the impacts of various crude oil extraction R&D strategies, four scenarios were examined as part of this analysis. These R&D scenarios are consistent with the current DOE Oil Research Program Implementation Plan (DOE, 1990a). These scenarios are based on two technology cases, with several variations assumed for the timing of field installation of these technologies. The four scenarios are:

- A Baseline Scenario, developed to attempt to replicate the current NES reference case (as of 9/5/90). This scenario assumes the application of implemented (i.e., currently available) extraction technology in fields with reserves currently booked as a result of these technologies. Other fields are assumed to install implemented technology processes after a 15-year delay. No advanced technology is assumed.
- A technology transfer only scenario (Near-Term Alone Scenario), which assumes the application of implemented technology in all reservoirs where it is technically and economically feasible, with implementation occurring by 1994.
- An advanced technology with technology transfer scenario (Near- and Mid-Term Scenario), which assumes the application of implemented technology in all reservoirs where it is technically and economically feasible by 1994, with no delay in implementation. Advanced technology is assumed to be available by 1998 (the advanced technology assumptions are defined below for each resource category). This scenario is consistent with the Base Case budget scenario in the DOE Oil Research Program Implementation Plan (DOE, 1990a).
- An advanced technology only scenario (Mid-Term Alone Scenario), which assumes the application of advanced extraction technologies by 1998, but implemented technology in the near term is assumed not to be successfully and widely transferred to operators. This case assumes that some access to U.S. crude oil resources will be lost because of reservoir abandonments in the near term.

3. Technology Assumptions

The technology cases assumed in the evaluation of the potential of advanced secondary recovery processes (ASR) for producing the unrecovered mobile oil (UMO) resource were based on two different levels of geologic understanding and using two classes of polymers. The first level, corresponding to technologies that can currently be implemented in the field, reflects limited geologic understanding of reservoir heterogeneity and the technical shortcomings of currently available

polymers. This implemented technology scenario assumed a blanket or uniform approach to infill development, represented by a single, one-half reduction in reservoir-wide spacing. This scenario is based on the assumption that the operator would be unwilling to accept the risk of further, more costly infill development to closer spacings without the acquisition of additional geologic information on reservoir heterogeneity, and would therefore only pursue a "one-drilldown-at-a-time" approach.

The second level, corresponding to an advanced technology case, assumed a significantly improved understanding of reservoir heterogeneity and improvements in advanced waterflooding techniques that increase the applicability and productivity of these processes, including the development of improved polymers for field application in higher temperature and higher salinity settings. This scenario assumed that sufficient geologic data would exist to characterize the reservoir and delineate it into distinct segments, or facies, with reservoir parameters and heterogeneity relationships developed independently for each segment. The availability of more detailed geologic information would allow the operator to make a more informed assessment and to undertake a geologically targeted infill drilling program in each facies to the minimum spacing that is economically justified. The screening criteria for advanced secondary recovery technologies are shown in Table IV-1.

Two levels of EOR process technology were also evaluated. The first level, the implemented technology case, represents technology currently available, tested, and proven in successful field applications. The second level, the advanced technology case, assumes technological improvements resulting from successful R&D which improves reservoir description and EOR efficiencies and expands the applicability of various EOR processes to a broader range of reservoirs. Each component in the advanced technology case has been demonstrated in the laboratory or the field, but has not yet been widely applied.

Three general classifications of EOR are considered by this study: 1) thermal methods; 2) miscible carbon dioxide flooding; and 3) micellar-polymer or surfactant flooding. Thermal methods are directed primarily at the heavy oil target, while chemical and miscible floods are designed to recover residual light oil. The advanced technology case for thermal EOR captures key process improvements (improved heat delivery and sweep efficiency) and enables thermal EOR to be applied to more difficult reservoirs (deeper, thinner reservoir settings and reservoirs in environmentally

TABLE IV-1

SCREENING CRITERIA FOR ADVANCED SECONDARY PROCESSES

<u>Screening Parameters</u>	<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

sensitive areas). Table IV-2 shows the reservoir screening criteria for implemented and advanced thermal technology.

The advanced technology case for miscible carbon dioxide flooding captures two process improvements: 1) improved CO₂ mobility control with chemical additives; and 2) increased use of infill wells to capture incremental mobile oil. The advanced technology case for micellar-polymer flooding assumes two technology improvements: 1) process improvements such as increased injection rates and displacement efficiencies, and decreased surfactant retention; and 2) improved chemical tolerance to heat and salinity. Table IV-3 shows the screening criteria for applying implemented and advanced technology for micellar-polymer and miscible CO₂ flooding in light oil reservoirs.

The analyses presented in this report do not include an assessment of the potential of recent advances in horizontal or deviated drilling technologies on domestic crude oil recovery.

4. Impacts of Advanced Extraction Technology on Crude Oil Reserves

The impact of expanded, successful crude oil extraction R&D can be measured in numerous ways. The first and most straightforward measure of the impact of advanced extraction technologies is the increase in crude oil reserves that result. Based on previous TORIS analyses, estimates have been made of the reserves recoverable at various prices from both ASR and EOR processes under both implemented and advanced technology conditions. Three mutually exclusive categories of reservoirs were considered for each price and technology scenario, defined by the type of recovery processing projected by TORIS to be economically applicable:

- Advanced secondary recovery processes for producing unrecovered mobile oil only
- Enhanced oil recovery processes for producing unrecovered immobile oil only
- Combined ASR and EOR processes for producing both unrecovered mobile and immobile oil.

TABLE IV-2

SCREENING CRITERIA FOR THERMAL ENHANCED OIL RECOVERY CANDIDATES

<u>Screening Parameters*</u>	<u>Implemented</u>		<u>Advanced</u>	
	<u>Steam</u>	<u>In-Situ Combustion</u>	<u>Steam</u>	<u>In-Situ Combustion</u>
Oil Gravity	10 to 34	10 to 35	--	--
Insitu Oil Viscosity (μ)	$\leq 15,000$	$\leq 5,000$	--	$\leq 5,000$
Depth	$\leq 3,000$	$\leq 11,500$	$\leq 5,000$	--
Pay Zone Thickness (h)	≥ 20	≥ 20	≥ 15	≥ 10
Reservoir Temperature (TR)	--	--	--	--
Porosity (ϕ)	$\geq 0.20^{**}$	$\geq 0.20^{**}$	$\geq 0.15^{**}$	$\geq 0.15^{**}$
Permeability Average (k)	250	35	≥ 10	≥ 10
Transmissibility (kh/ μ)	≥ 5	≥ 5		
Reservoir Pressure (PR)	$\leq 1,500$	$\leq 2,000$	$\leq 2,000$	$\leq 4,000$
Minimum Oil Content at Start of Process ($S_o \times \phi$)	≥ 0.10	≥ 0.08	≥ 0.08	≥ 0.08
Salinity of Formation Brine (TDS)	--	--	--	--
Rock Type	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate	Sandstone or Carbonate

* Other criteria of a geological 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.

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

Source NPC, 1984

TABLE IV-3

SCREENING CRITERIA FOR LIGHT OIL EOR CANDIDATES

Screening Parameters*	Units	Implemented		Advanced	
		Chemical Flooding Surfactant	Miscible Flooding (CO ₂)	Chemical Flooding Surfactant	Miscible Flooding (CO ₂)
Oil Gravity	°API	--	<30	--	<30
Insitu Oil Viscosity (μ)	cp	<40	<90	<100	--
Depth	Feet	--	--	--	--
Pay Zone Thickness (h)	Feet	--	--	--	--
Reservoir Temperature (TR)	°F	<200	<200	<250	<200
Porosity (ϕ)	Fraction	--	--	--	--
Permeability Average (k)	md	>40	>10	>10	--
Transmissibility (kh/ μ)	md-ft/cp	--	--	--	--
Reservoir Pressure (PR)	psi	--	--	--	≥MMP**
Minimum Oil Content at Start of Process (S _o %)	Fraction	--	--	--	--
Salinity of Formation Brine (TDS)	ppm	<100,000	<100,000	<200,000	--
Rock Type	--	Sandstone	Sandstone	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.

Source NPC, 1984.

An assessment of ASR recovery techniques was performed by applying the techniques to the UMO in the reservoirs analyzed in three states - Texas, Oklahoma, and New Mexico (see ICF Resources and BEG, 1989b). These results were then extrapolated to estimate the impact on reserves nationwide (based on the ratio of estimated OOIP in the reservoirs in the nation to the OOIP in the reservoirs analyzed in the three states). The application of ASR recovery techniques under the implemented technology case are predicted to result in reserve additions ranging from 5.8 billion barrels at \$16/Bbl to 7.8 billion barrels at \$60/Bbl. As shown in Table IV-4 and Figure IV-2, ASR technologies are effective at recovering a substantial portion of the UMO resource at lower oil prices. For example, recovery under the implemented technology case amounts to nearly 7.1 billion barrels at only \$20/Bbl, which is over 90% of the resource that is economically recoverable at \$60/Bbl.

The advanced technology case assumes a significantly improved understanding of reservoir heterogeneity and improvements in ASR techniques that increase the applicability and productivity of the recovery processes considered. Assumed advance include the development of improved polymers available for field application in higher temperature and higher salinity settings. Depending on oil price, ASR techniques under the advanced technology case will result in reserve additions ranging from 17.9 billion barrels at \$20/Bbl to 20.8 billion barrels at \$60/Bbl (Table IV-4). Similar to the implemented technology case, a large portion of the UMO resource is recoverable at lower oil prices.

EOR techniques under the implemented technology case, applied to the reservoirs analyzed and then extrapolated to the entire nation, are predicted to result in reserve additions ranging from 2.4 billion barrels at \$16/Bbl to 25.9 billion barrels at \$60/Bbl. EOR techniques under the advanced technology case will result in domestic reserve additions ranging from 9.1 billion barrels at \$20/Bbl to 41.7 billion barrels at \$60/Bbl. The results are summarized in Table IV-5 and Figure IV-3.

Finally, for reservoirs combining ASR and EOR techniques under the implemented technology case, estimated reserves are predicted to range from 1.0 billion barrels at \$20/Bbl to 7.1 billion barrels at \$60/Bbl. Under the advanced technology case, combined ASR and EOR processes will result in reserve additions ranging from 2.6 billion barrels at \$20/Bbl to 19.0 billion barrels at \$60/Bbl (Table IV-6 and Figure IV-4).

Potential reserves for all EOR and ASR recovery processes are summarized in Table IV-7 and Figure IV-5.

TABLE IV-4

**ESTIMATED POTENTIAL RESERVES FROM ADVANCED SECONDARY RECOVERY
OPERATIONS IN THE U.S. AT VARIOUS PRICES**

Crude Oil Reserves (MMBbls)							
	<u>\$16/Bbl</u>	<u>\$20/Bbl</u>	<u>\$24/Bbl</u>	<u>\$32/Bbl</u>	<u>\$40/Bbl</u>	<u>\$50/Bbl</u>	<u>\$60/Bbl</u>
<u>Implemented Technology</u>							
Infill Drilling Only	1,664	2,517	2,598	2,613	2,904	2,904	2,904
Infill Drilling Plus Polymer Flooding	1,133	1,590	1,590	1,889	1,889	1,889	1,889
Infill Drilling Plus Profile Modification	<u>2,970</u>	<u>3,018</u>	<u>3,018</u>	<u>3,018</u>	<u>3,018</u>	<u>3,018</u>	<u>3,018</u>
Total	5,767	7,125	7,207	7,520	7,812	7,812	7,812
<u>Advanced Technology</u>							
Infill Drilling Only	N/A	4,952	5,908	5,922	6,214	6,214	6,214
Infill Drilling Plus Polymer Flooding	N/A	4,553	5,358	5,708	6,188	6,188	6,188
Infill Drilling Plus Profile Modification	N/A	<u>8,417</u>	<u>8,417</u>	<u>8,417</u>	<u>8,417</u>	<u>8,417</u>	<u>8,417</u>
Total	N/A	17,922	19,682	20,048	20,819	20,819	20,819

All prices in 1989 dollars.

Numbers may not add precisely due to rounding.

N/A = Not Analyzed

Figure IV-2
Estimated Potential Reserves from Reservoirs
Amenable to ASR Operations Only

TABLE IV-5

**ESTIMATED POTENTIAL RESERVES FROM ENHANCED
OIL RECOVERY OPERATIONS IN THE U.S. AT VARIOUS PRICES**

Crude Oil Reserves (MMBbls)							
	<u>\$16/Bbl</u>	<u>\$20/Bbl</u>	<u>\$24/Bbl</u>	<u>\$32/Bbl</u>	<u>\$40/Bbl</u>	<u>\$50/Bbl</u>	<u>\$60/Bbl</u>
<u>Implemented Technology</u>							
Ongoing Thermal	128	1,305	1,810	3,024	3,024	3,024	3,024
New Steam Drive	-	161	679	2,053	2,297	2,410	2,625
New In-Situ Combustion	413	505	1,021	2,166	2,297	2,524	2,524
New W.Texas Miscible	1,267	2,540	4,235	4,643	5,262	5,578	5,777
New Non-W. Texas Miscible	591	1,245	1,804	4,338	5,573	7,106	8,964
New Alkaline	-	-	-	-	-	-	65
New Micellar-Polymer	-	<u>120</u>	<u>387</u>	<u>616</u>	<u>1,544</u>	<u>2,042</u>	<u>2,930</u>
Total	2,399	5,875	9,936	16,840	19,998	22,684	25,909
<u>Advanced Technology</u>							
Ongoing Thermal	N/A	1,305	1,810	3,024	3,024	3,024	3,024
New Steam Drive	N/A	722	4,027	5,402	6,281	6,653	7,123
New In-Situ Combustion	N/A	2,490	3,051	4,435	4,566	4,792	4,792
New W. Texas Miscible	N/A	2,540	4,235	4,766	5,385	5,734	5,933
New Non-W. Texas Miscible	N/A	1,245	1,804	4,338	5,573	7,106	8,964
New Alkaline	N/A	-	-	-	-	-	65
New Micellar-Polymer	N/A	<u>767</u>	<u>1,039</u>	<u>4,360</u>	<u>7,452</u>	<u>10,363</u>	<u>7,102</u>
Total	N/A	9,069	15,966	26,324	32,280	37,673	41,690

All prices in 1989 dollars.

Numbers may not add precisely due to rounding.

N/A = Not Analyzed

Figure IV-3
Estimated Potential Reserves from Reservoirs
Amenable to EOR Operations Only

TABLE IV-6

**ESTIMATED POTENTIAL RESERVES FROM COMBINED ASR AND
EOR OPERATIONS IN THE U.S. AT VARIOUS PRICES**

Crude Oil Reserves (MMBbls)							
	<u>\$16/Bbl</u>	<u>\$20/Bbl</u>	<u>\$24/Bbl</u>	<u>\$32/Bbl</u>	<u>\$40/Bbl</u>	<u>\$50/Bbl</u>	<u>\$60/Bbl</u>
<u>Implemented Technology</u>							
ASR + W. Texas Miscible	-	593	712	2,023	2,456	2,479	2,530
ASR + Non-W. Texas Miscible	-	376	641	1,398	1,410	1,459	1,519
ASR + Alkaline	-	-	-	-	47	47	47
ASR + Micellar-Polymer	-	22	377	1,986	2,423	3,034	3,045
ASR + Steam Drive	-	-	-	-	-	-	-
ASR + In-Situ Combustion	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>	<u>-</u>
Total	-	991	1,730	5,407	6,336	7,018	7,141
<u>Advanced Technology</u>							
ASR + W. Texas Miscible	-	2,001	3,267	6,111	6,627	6,675	6,800
ASR + Non-W. Texas Miscible	-	484	729	1,639	1,601	1,666	1,731
ASR + Alkaline	-	-	-	-	95	95	95
ASR + Micellar-Polymer	-	23	2,694	5,847	7,805	9,303	9,876
ASR + Steam Drive	-	-	-	-	-	58	58
ASR + In-Situ Combustion	<u>-</u>	<u>84</u>	<u>83</u>	<u>86</u>	<u>266</u>	<u>400</u>	<u>480</u>
Total	-	2,591	6,773	13,683	16,395	18,197	19,041

All prices in 1989 dollars.

Numbers may not add precisely due to rounding.

Figure IV-4

Estimated Potential Reserves from Reservoirs Amenable to Combined ASR and EOR Operations

TABLE IV-7

**ESTIMATED POTENTIAL RESERVES FROM IMPLEMENTED AND ADVANCED
CRUDE OIL EXTRACTION TECHNOLOGIES AT VARIOUS PRICES**

	Recoverable Reserves (MMBbls)*						
	<u>\$16/Bbl</u>	<u>\$20/Bbl</u>	<u>\$24/Bbl</u>	<u>\$32/Bbl</u>	<u>\$40/Bbl</u>	<u>\$50/Bbl</u>	<u>\$60/Bbl</u>
<u>Implemented Technology</u>							
Advanced Secondary Recovery (ASR)	5,767	7,125	7,207	7,520	7,812	7,812	7,812
Ongoing EOR Projects	128	1,305	1,810	3,024	3,024	3,024	3,024
New EOR Projects	2,271	4,570	8,126	13,816	16,974	19,660	22,885
ASR & EOR Projects	<u>-</u>	<u>991</u>	<u>1,730</u>	<u>5,407</u>	<u>6,336</u>	<u>7,018</u>	<u>7,141</u>
Total	8,166	13,991	18,872	29,768	34,145	37,514	40,862
<u>Advanced Technology</u>							
Advanced Secondary Recovery (ASR)	5,767	17,922	19,682	20,048	20,819	20,819	20,819
Ongoing EOR Projects	128	1,305	1,810	3,024	3,024	3,024	3,024
New EOR Projects	2,271	7,764	14,156	23,300	29,256	34,649	38,666
ASR & EOR Projects	<u>-</u>	<u>2,591</u>	<u>6,773</u>	<u>13,683</u>	<u>16,395</u>	<u>18,197</u>	<u>19,041</u>
Total	8,166	29,582	42,421	60,055	69,494	76,689	81,550

* All prices in 1989 dollars. Does not include booked EOR reserves, which are approximately 4 billion barrels. Numbers may not add precisely due to rounding.

Figure IV-5

Estimated Total Potential Reserves from EOR and ASR Operations

5. Impacts of Advanced Extraction Technology on Future Crude Oil Production

The extent of the impact of improved extraction technology on future domestic crude oil production is a function of the level of technological advance and the rate of its introduction to and installation by operators in the field. Consistent with DOE's Oil Research Program Implementation Plan (DOE, 1990a), several levels of technology and implementation timing were evaluated in this analysis. Each of the scenarios has a different impact on domestic crude oil production over the NES time frame. The levels of domestic crude oil production associated with each of the scenarios are summarized in Table IV-8, and shown on Figure IV-6.

Domestic crude oil production assuming the NES price track in the Baseline Scenario is predicted to decrease to 6.0 MMB/D by 2000, increase somewhat to about 6.9 MMB/D by 2010, and decline again to 3.6 MMB/D by 2030. In contrast, the Near- and Mid-Term Scenario, which represents the full implementation of the Base Case R&D scenario in DOE's Oil Research Program Implementation Plan (DOE, 1990a), could result in production rising to about 7.2 MMB/D by 2000, increasing to about 10.1 MMB/D by 2010, and declining again to 4.6 MMB/D by 2030.

Consequently, the DOE Oil Research Program as articulated (DOE, 1990a) could result in an increase in domestic crude oil production of over 3.0 MMB/D compared to the Baseline Scenario. Compared to the Near-Term Alone Scenario (which assumes a modest pace of technology transfer but no major technological advances), the Near- and Mid-Term Scenario would result in over 2.0 MMB/D of incremental production. Finally, the Near- and Mid-Term Scenario, when compared to the Mid-Term Alone Scenario (which assumes no near-term technology transfer but later improvements in extraction technology), could result in 300,000 to 600,000 barrels per day of incremental production in the next 20 years (one-third to one-half the production from California). This clearly demonstrates the important role of near-term technology transfer in slowing the decline in domestic production and the rate of domestic resource abandonments.

TABLE IV-8
IMPACTS OF ALTERNATIVE RESEARCH AND DEVELOPMENT
SCENARIOS ON U.S. CRUDE OIL PRODUCTION

<u>Forecast Crude Oil Production (MMB/D)</u>				
<u>Year</u>	<u>Baseline Scenario</u>	<u>Near-Term Alone Scenario</u>	<u>Near- & Mid-Term Scenario</u>	<u>Mid-Term Alone Scenario</u>
1995	6.2	6.2	6.2	6.2
2000	6.0	6.7	7.2	6.6
2005	6.1	7.5	9.2	8.6
2010	6.9	7.9	10.1	9.8
2015	6.7	7.0	9.3	9.2
2020	5.5	5.4	7.5	7.6
2025	4.5	4.0	5.9	6.2
2030	3.6	3.0	4.6	4.8

Figure IV-6
Impact of Various Oil Research Program Strategies on
Domestic Crude Oil Production

Over the NES time frame (1990-2030), total cumulative crude oil production from each scenario considered is as follows:

<u>Cumulative Crude Oil Production (BBbls)</u>	
Baseline Scenario	90.8
Near-Term Alone Scenario	95.6
Near- and Mid-Term Scenario	116.7
Mid-Term Alone Scenario	114.5

6. Impacts of Advanced Extraction Technology on Future Crude Oil Imports

In this analysis, the NES reference case, the world oil price track was assumed in all scenarios, and the forecast for U.S. crude oil consumption over the NES time frame was assumed to remain unchanged for all scenarios analyzed. Moreover, for purposes of this analysis, increases in U.S. crude oil production were assumed to offset crude oil imports in the U.S. on a barrel-for-barrel basis. Consequently, successful R&D and technology transfer programs that result in increased domestic crude oil production will also reduce crude oil imports.

The NES consumption forecast included both crude oil and petroleum products (which were not reported in a disaggregated manner). Adjustments were made to compare only crude oil consumption (i.e., input to refineries) to crude oil production (the output of the Crude Oil Policy model). These adjustments were performed using the ICF Resources' North American Crude Oil Demand (NACOD) model (ICF Resources, 1988). The forecasts of crude oil consumption are based on the assumption that environmental requirements and public concerns will continue to constrain major new refinery construction or capacity additions in the U.S. Consequently, crude oil imports to refineries are forecast to grow only moderately over the NES time frame. As a result, the increase in total U.S. consumption (crude oil plus products) forecast in the NES reference case will be met by an ever-increasing proportion of product imports.

Given this assumption and the domestic crude oil production forecasts associated with the four R&D/technology transfer scenarios, estimates of future crude oil imports were developed, which

are presented in Figure IV-7 and summarized in Table IV-9. As shown, crude oil imports under the Baseline Scenario are forecast to increase to 8.2 MMB/D by 2000, increasing to 10.6 MMB/D by 2030. In the Near- and Mid-Term Scenario, crude oil imports are forecast to decrease to 7.0 MMB/D by 2000 (a 15% decrease relative to the Baseline Scenario), decreasing to 4.1 MMB/D by 2010 (a 44% decrease relative to the Baseline Scenario), and then increase again to 9.6 MMB/D by 2030 (9% below the Baseline Scenario). The Near-Term Alone Scenario results in higher forecast imports than the Near- and Mid-Term Alone Scenario, but lower than the Baseline Scenario, while the Mid-Term Alone Scenario results in slightly lower imports than that predicted for the Near- and Mid-Term scenario in the long term, but considerably higher imports in the near term.

Total crude oil imports over the entire NES time frame are also summarized in Table IV-9 for each of the four R&D/technology transfer scenarios. The Near- and Mid-Term R&D Scenario could result in a 25.8 billion barrel decrease in U.S. crude oil imports over the 40-year NES time frame, compared to the Baseline Scenario. The Near-Term Alone Scenario could result in a 4.7 billion barrel reduction in crude oil imports, while the Mid-Term Alone Scenario could result in a 23.7 billion barrel reduction in imports over the NES time frame, relative to the Baseline Scenario.

7. Impacts of Advanced Extraction Technology on Future State and Federal Revenues from Oil Production Operations

Increases in U.S. crude oil production resulting from advanced extraction technologies will also result in increased revenues collected by federal, state, and local governments from income and production taxes. Thus, increased domestic crude oil production will result in greater public sector revenues.

Total public sector revenues over the NES time frame are summarized in Table IV-10 for each of the four R&D/technology transfer scenarios. The Near- and Mid-Term R&D scenario will result in an increase of \$97 billion in revenues collected by state and federal governments from income taxes, royalties, and production taxes collected from crude oil production over the 40-year NES time frame, compared to the Baseline Scenario. Approximately \$25 billion in additional revenues is forecast to be collected by state treasuries, with \$72 billion collected by the federal treasury. On a net present value basis (discounted at a 10% rate), this amounts to a \$2 billion increase to state treasuries and a \$8 billion increase to the federal treasury. For the Near-Term

Figure IV-7

Impact of Various Oil Research Program Strategies on U.S. Crude Oil Imports

TABLE IV-9
IMPACTS OF ALTERNATIVE RESEARCH AND DEVELOPMENT
SCENARIOS ON U.S. CRUDE OIL IMPORTS

<u>Year</u>	<u>Forecast Crude Oil Consumption*</u> (MMBbl/D)	<u>Forecast Crude Oil Imports (MMB/D)</u>			
		<u>Baseline Scenario</u>	<u>Near-Term Alone Scenario</u>	<u>Near- and Mid-Term Scenario</u>	<u>Mid-Term Alone Scenario</u>
1995	13.7	7.5	7.4	7.4	7.5
2000	14.2	8.2	7.4	7.0	7.6
2005	14.1	8.0	6.6	4.9	5.5
2010	14.2	7.3	6.3	4.1	4.4
2015	14.2	7.6	7.2	4.9	5.0
2020	14.3	8.7	8.9	6.8	6.7
2025	14.4	9.9	10.4	8.5	8.3
2030	14.2	10.6	11.2	9.6	9.4
Crude Oil Imports Over the NES Timeframe (Billion Barrels)					
Total		125.1	120.4	99.3	101.4
Import Reduction		--	4.7	25.8	23.7

* Based on NES Reference Case Forecast as of 9/5/90, adjusted to represent only crude oil input to refineries.

TABLE IV-10

**ECONOMIC IMPACTS OF ALTERNATIVE RESEARCH AND
DEVELOPMENT SCENARIOS OVER THE 1990-2030 TIME PERIOD**
(All values in Billions of 1989 Dollars)

	<u>Baseline Scenario</u>	<u>Near-Term Alone Scenario</u>	<u>Near- and Mid-Term Scenario</u>	<u>Mid-Term Alone Scenario</u>
Net Operator Profits				
Undiscounted	1,256	1,230	1,367	1,378
Discounted @ 10%	256	260	273	271
Energy Security Premium				
Undiscounted	N/A	N/A	N/A	N/A
Discounted @ 10%	N/A	N/A	N/A	N/A
Costs of Imports:				
Undiscounted	4,450	4,312	3,459	3,518
Discounted @ 10%	745	702	622	644
R&D Program Costs:				
Undiscounted	--	0.341	0.621	0.574
Discounted @ 10%	--	0.180	0.330	0.302
Environmental Costs from Oil Spills:				
Undiscounted	19.3	N/A	16.2	N/A
Discounted @ 10%	4.2	N/A	3.8	N/A
State Revenues Collected:				
Undiscounted	65	70	90	87
Discounted @ 10%	19	20	21	21
Federal Revenues Collected:				
Undiscounted	726	735	797	793
Discounted @ 10%	153	156	161	160

N/A = Not Analyzed

Alone Scenario, total public sector revenues (state and federal) are forecast to increase by \$4 billion over the Baseline Scenario (discounted), while the Mid-Term Alone Scenario will result in a \$10 billion increase in net present value public sector revenues over the NES time frame.

8. Impacts of Advanced Extraction Technology on the Environmental Costs Associated with Crude Oil Imports

Finally, the estimated environmental costs of tanker-related oil spills was determined over the NES time frame for two of the R&D/technology transfer scenarios — the Baseline Scenario and the Near- and Mid-Term Scenario. These costs were estimated as an estimated average annual equivalent value over the NES time period. The results for the Baseline Scenario for net present value are presented in Table IV-11. Similarly, the results for the Near- and Mid-Term Scenario are presented in Table IV-12. On a net present value basis, total environmental costs associated with tanker-related oil spills are estimated to decrease by approximately \$370 million dollars in the Near- and Mid-Term case relative to the Baseline Scenario over the NES time frame. This is because higher domestic production reduces import levels, hence reducing tanker-related spills.

9. Summary and Conclusions

The vast majority of the economic impacts associated with a federal R&D program for crude oil extraction will be associated with the reduction in crude oil imports. The value of the crude oil imports avoided that would be associated with each R&D/technology transfer scenario was summarized in Table IV-10. As shown, the value of the reduction in crude oil imports corresponding to the Near- and Mid-Term Scenario over the NES time frame, relative to the Baseline Scenario, is \$991 billion in 1989 dollars. Discounting at a 10% discount rate, the costs of crude oil imports are reduced by \$123 billion, on a net present value basis, in the Near- and Mid-Term Scenario relative to the Baseline Scenario. The net present value reduction in the costs of imports for the Near-Term Alone Scenario, relative to the Baseline case, is \$43 billion, while for the Mid-Term Alone case, the net present value reduction in import costs could amount to about \$101 billion relative to the Baseline.

TABLE IV-11

**ESTIMATED NET PRESENT VALUE OF
ENVIRONMENTAL COSTS OF TANKER-RELATED OIL SPILLS
FOR THE PERIOD 1991-2030 BY SOURCE OF OIL**

Baseline Scenario
(Millions of 1990 Dollars)

<u>OCS Region/Planning Area</u>	<u>Estimated Net Present Value of Environmental Costs of Tanker-Related Oil Spills</u>		
	<u>Domestic Oil</u>	<u>Imports</u>	<u>Total</u>
Atlantic Region			
North Atlantic	70.9	29.8	100.7
Mid-Atlantic	1033.2	180.5	1213.6
South Atlantic	58.0	9.7	67.8
Straits of Florida	5.1	8.1	13.2
Gulf of Mexico Region			
Eastern Gulf	97.6	1.1	98.7
Central Gulf	558.6	333.1	891.6
Western Gulf	344.6	175.8	520.4
Pacific Region			
Southern California	447.5	110.0	557.5
Central California	397.3	30.4	427.7
Northern California	0.4	0.0	0.4
Washington/Oregon	99.8	19.6	119.4
Alaska Region			
All Areas	<u>75.4</u>	<u>8.6</u>	<u>84.0</u>
Total	3,188.4	906.8	4,095.2

Source: MMS/A.T. Kearney model, see text for discussion

TABLE IV-12

**ESTIMATED NET PRESENT VALUE OF
ENVIRONMENTAL COSTS OF TANKER-RELATED OIL SPILLS
FOR THE PERIOD 1991-2030 BY SOURCE OF OIL**

Near- and Mid-Term R&D Scenario

(Millions of 1990 Dollars)

<u>OCS Region/Planning Area</u>	<u>Estimated Net Present Value of Environmental Costs of Tanker-Related Oil Spills</u>		
	<u>Domestic Oil</u>	<u>Imports</u>	<u>Total</u>
Atlantic Region			
North Atlantic	70.9	29.8	100.8
Mid-Atlantic	1033.2	180.3	1213.6
South Atlantic	58.1	9.7	67.7
Straits of Florida	5.1	8.1	13.2
Gulf of Mexico Region			
Eastern Gulf	97.6	1.1	98.7
Central Gulf	499.2	322.9	822.0
Western Gulf	321.0	164.3	485.3
Pacific Region			
Southern California	315.0	105.6	420.7
Central California	266.1	27.1	293.3
Northern California	0.4	0.0	0.4
Washington/Oregon	95.3	17.5	112.8
Alaska Region			
All Areas	<u>83.4</u>	<u>9.4</u>	<u>92.8</u>
Total	2845.4	875.8	3721.2

Source: MMS/A.T. Kearney model, see text for discussion

Another measure of the economic benefits associated with various oil and gas extraction R&D programs is the net operator profits resulting from the incremental production. Net operator profits, or what economists generally refer to as the economic rent, are the difference between the revenues from the sale of oil and gas and the full costs associated with its exploration, development, and production. As shown in Table IV-10, the increase in net operator profits in the Near- and Mid-Term Scenario, relative to the Baseline Scenario, could be \$17 billion, discounted at 10%. For the Near-Term Alone Scenario, net operator profits, discounted, could be \$4 billion higher than the Baseline; while net operator profits in the Mid-Term Alone Scenario could be \$15 billion greater than those in the Baseline Scenario.

In addition, many economists acknowledge that there are external costs, in excess of the price of oil, that result from importing crude oil from a market dominated by a cartel. Offsetting imports with increased domestic production represents an additional external benefit not reflected in the world oil price. This cost, called an energy security premium, is still being analyzed for purposes of the NES.

The costs of the proposed Base Case R&D/technology transfer program set forth in DOE's Oil Research Program Implementation Plan, which corresponds to the Near- and Mid-Term Scenario, is estimated to be approximately \$620 million over 15 years (this amounts to approximately \$330 million on a net present value basis, discounted at a 10% rate). Accounting for only the reduction in U.S. expenditures on crude oil imports and the reduction of oil spill control, cleanup, and mitigation costs associated with crude oil imports, the benefits of this R&D program could amount to as much as \$994 billion (undiscounted), in 1989 dollars, or approximately \$123 billion in net present value terms. This could have a substantial impact on the domestic trade deficit over the NES time frame. These dollar values do not include the increased public sector revenues associated with taxes and royalties collected from domestic oil and gas production (which may only be considered a transfer payment) or other second order and spin-off benefits that could result from expanded and accelerated federal R&D on crude oil extraction.

B. UNCONVENTIONAL NATURAL GAS

1. Background

Unlike crude oil, most industry analysts believe that natural gas resources in the U.S. are abundant (DOE, 1988). Today, over 700 Tcf of natural gas has been produced and another 187 Tcf has been proven in the Lower-48. An estimated additional 1,200 Tcf of technically recoverable natural gas resources remain to be developed or discovered, as discussed in detail in ICF Resources (1990a) and DOE (1988).

The primary obstacle identified in the NES public hearing process concerning natural gas production was the inadequate level of R&D directed at natural gas recovery. This obstacle has two components. First, many testifiers stated that market inefficiencies (such as the persistent natural gas bubble) are inhibiting the conduct of needed research to improve the extraction of natural gas. According to the public testimony, "advanced recovery technologies are not being developed adequately to recover the estimated 700 Tcf of conventional and low-permeability gas available at moderate market prices in the United States" (DOE, 1990c). In addition, the testifiers at the public hearings felt that "there is insufficient Federal support of natural gas research" (DOE, 1990c).

Three principal mechanisms or policy options were identified to reduce costs and increase recovery of unconventional gas supplies. First, it was claimed in the public testimony that "technological improvements could reduce costs of the methods currently used to find, develop and produce gas." Second, testifiers claimed that "coalbed methane could be encouraged as an available source of natural gas." Third, it was recommended that "the federal government could provide more financial support for R&D on natural gas recovery techniques" (DOE, 1990c).

Although many companies produce both oil and gas, a larger proportion of the nation's total gas (two-thirds compared to one-half of all oil) is produced by the independents. As such, the capacity to develop and deploy advanced gas extraction technologies is vested in relatively few companies. In addition to these companies, the federal government and the Gas Research Institute (GRI) conduct advanced extraction R&D. On the utilization side, the Electric Power Research Institute (EPRI) also conducts gas-oriented research. With the dramatic changes in gas markets and

estimates of potential supplies, the federal gas R&D program has recently been under review as to possible changes in priorities and objectives.

Because private companies and institutions other than the federal government perform advanced gas extraction R&D, the benefits of an expanded and accelerated federal program for gas extraction R&D are more difficult to measure. The measures presented in this report relating to the impacts of advanced gas extraction R&D do not differentiate between R&D that is federally funded and that which is funded from other sources.

The purpose of this analysis is to examine the impact of a successful R&D program on domestic unconventional gas supplies. The technology assumptions serving as the basis for this analysis are discussed in detail in the following section.

2. Technology Assumptions

For purposes of the analyses of unconventional gas summarized in this report, two technology scenarios are defined: implemented and advanced. The implemented technology case is defined as the drilling, completion, stimulation and operating practices generally used by the most sophisticated operators today. It represents the state of the art in extraction technology, although not all operators are currently employing these techniques.

Advanced technology is defined in this analysis as the achievement and deployment of technologies that are currently the subject of ongoing R&D. Industry R&D efforts have specific performance criteria that are used also as specifications for advanced technology performance. Advanced technologies include formation evaluation and reservoir characterization techniques along with stimulation design and diagnostic processes.

The assumptions concerning the performance of unconventional gas extraction technology, which served as the basis for these analyses, are characterized by each of the three unconventional gas resources:

a. Tight Gas. The economic analysis of recoverable gas from low-permeability ("tight") reservoir settings is presented for the two technology scenarios, as follows:

- Implemented Technology. Assumes a hydraulic fracture half-length of 200 feet (with moderate fracture conductivity) and a well spacing of 160 acres per well. Multiple completions, although now practiced by more sophisticated operators in some areas, were excluded from analysis.
- Advanced Technology. Assumes a hydraulic fracture half-length of 600 feet (with high fracture conductivity) and optimum well spacing. This case also assumes that the productive lenticular sand lenses can be delineated by logs and multiple completions are possible. This case assumes that formation evaluation technologies are used to reduce dry hole rates, minimize fracture height growth, and increase fluid efficiency.

b. Coalbed Methane. The economically recoverable gas from coal seams is also estimated for two technology scenarios:

- Implemented Technology. Assumes an achieved, well-propped fracture half-length of 150 feet with a maximum number of three completions, and historical or regulated well spacings.
- Advanced Technology. Assumes an achieved, well-propped fracture half-length of 600 feet, the ability to interconnect several thin coal seams, with a maximum of three completions, and optimum well spacing.

c. Devonian and Antrim Shale Gas. Estimates of economically recoverable gas from Devonian and Antrim shales are also presented for two technology scenarios:

- Implemented Technology. Assumes a dual zone completion in the historically produced Devonian shale formations of the Appalachian Basin and the Antrim shale formations of the Michigan Basin, with an achieved, well-propped fracture half-length of 50 feet.
- Advanced Technology. Assumes improved well siting, well logging and the ability for multiple completions into the productive shale gas zones of the Appalachian Basin with an achieved, well-propped fracture half-length of 400 to 600 feet. Similarly, achieved fracture half-lengths of 300 feet are assumed for the Antrim shale.

3. Impacts of Advanced Extraction Technology on Unconventional Gas Reserves

Estimation of technology impacts on unconventional gas is based on explicit modeling of these technologies for wells that are representative of areas with the most potential. For those basins and formations that are identified as highest potential (or are currently being developed), a set of typical wells was identified. These wells are defined by a unique set of reservoir properties (e.g., thickness, porosity, saturations, pressure, temperature, gas gravity).

An appropriate production model is used to determine the annual production streams possible using various technologies. An industry standard cash flow model is then used to determine well economics. Costing of wells is based on published surveys of well and equipment costs and confirmed with operators.

Reserves were estimated as the amount of gas that is economic at a specified wellhead price and level of technology. The modeling of each typical well considered for each geographic and geologic setting analyzed is performed by determining the minimum levelized selling price required for an operator to achieve a 10% return on investment. All recoverable resources characterized by the typical well for that category with a minimum economic price below the specified market price are considered as reserves at that market price.

The prices and quantities recoverable from the areas represented by typical wells are aggregated into price-supply curves. From these curves, the amount of economically recoverable gas available at each price can be determined.

It is important to note that these unconventional gas price-supply curves are unrisks for exploration timing. It is a common misconception that simply reading the price supply curve is all that is required to determine reserves available at a given price. Only if the location and characteristics of these resources is fairly well known would reading off the curve directly be appropriate. This is the case for EOR, where the location and characteristics of each reservoir are well documented, allowing thorough evaluation prior to project implementation.

The complex reservoirs characteristic of unconventional gas make drilling of only the best prospects first an unrealistic assumption. In actual development, some information and basic geology leads an operator to the better area of a basin. Highly localized variation in reservoir quality, however, leads to initial average well costs that are somewhat higher than the lowest cost on the curve. As more knowledge is gained in a maturing play, the ability to locate the best prospects improves and the average cost decreases. Finally, as a basin matures, only the lower quality prospects are left, increasing the average cost of reserve additions.

Because many of these resources are located in basins that are only now being developed, it is not yet possible to characterize the trends in average costs over time as a function of basin maturity. As such, the analytical results presented here in the price/supply curves indicate the "exploration unrisks" potential reserves available at a given price. The impact of better information and exploration data could be explicitly incorporated into this analysis only if basin development could be modeled.

Economically recoverable gas reserves at various prices are presented in the sections below for each category of unconventional gas.

a. Tight Gas. Table IV-13 and Figure IV-8 present the results of the economic analysis of the tight gas resource at various prices. At wellhead gas prices of \$2.00 per Mcf and today's (implemented) technology, 23.5 Tcf of tight gas are economically recoverable. Gas reserves increase by 16.5 Tcf to 40 Tcf at wellhead prices of \$3.00 per Mcf without a change in technology, and rise to 66 Tcf at prices of \$5.00 per Mcf. With the full implementation of advanced technology, however, 93 Tcf of tight gas can be recovered at \$2.00 per Mcf, 141 Tcf is recoverable at \$3.00 per Mcf, and 182 Tcf of natural gas can be recovered at \$5.00 per Mcf.

b. Coalbed Methane. Table IV-14 and Figure IV-9 present the reserves estimates for coalbed methane. At \$3.00 per Mcf with existing technology, 11.5 Tcf of gas can be recovered, with a significant portion of this being low-cost gas (9.1 Tcf are economically recoverable at \$2.00/Mcf). This resource comes primarily from basins with established coalbed methane production such as the Warrior (Alabama) and San Juan (Colorado and New Mexico). At higher wellhead gas prices (\$5.00 per Mcf) for the same technology level, an additional 4.6 Tcf of natural gas reserves can be recovered

for a total of 16.1 Tcf. With advanced coalbed methane extraction technology, gas reserves from coal seams increase significantly to 29.8 Tcf at near-term (\$2.00 per Mcf) gas prices, rising to 41.4 Tcf of economically recoverable coal seam gas supplies at higher prices (\$5.00 per Mcf).

The significant increase in reserves from advanced extraction techniques over implemented technology, combined with the high level of current operator activity, indicate that coalbed methane should rapidly become a significant near-term source for low-cost gas. In addition, the reserves estimates for coalbed methane should increase as the gas potential in important coal basins such as the Arkoma, Powder River, Raton, Green River, and Western Washington becomes better defined.

c. Devonian and Antrim Shale. The estimates for economically recoverable gas from Devonian and Antrim shales are shown in Table IV-15 and Figure IV-10. At near-term wellhead gas prices (\$2.00 per Mcf) with implemented technology, 16.3 Tcf of gas can be recovered from the Huron and Rhinestreet shales of the Appalachian Basin and the Antrim shale in the Michigan Basin. The gas reserves increase to 24.5 Tcf at \$3.00 per Mcf, rising to 42.4 Tcf at a price of \$5.00 per Mcf. However, advances in technology, particularly the ability to target and stimulate multiple shale horizons, increase gas reserves appreciably to 32.7 Tcf, even at near-term wellhead gas prices (\$2.00 per Mcf). At higher gas prices (\$5.00 per Mcf), a total of 102.5 Tcf of natural gas can be recovered from the Devonian and Antrim shales.

d. Summary. This analysis shows that advanced gas extraction technology will have a significant impact on increasing reserves from unconventional gas sources, as summarized in Tables IV-16 and IV-17 for implemented and advanced technology scenarios, including all domestic natural gas resources, and for only unconventional gas resources in Figure IV-11. With advanced technology, the three main unconventional gas sources — tight gas sands, coalbed methane, and Devonian and Antrim shale gas — could contribute up to 326 Tcf of economically producible gas resources at high (\$5.00 per Mcf) gas prices.

Even with the considerable work by GRI, DOI, DOE and private concerns, the U.S. natural gas resource base remains incompletely defined and only partly accessible. Large volumes of gas in unconventional reservoir settings are unrecoverable even with advanced technology. Some examples of such resources, which were not considered in this analysis, include those in discovered fields whose

TABLE IV-13
ECONOMICALLY RECOVERABLE NATURAL GAS RESERVES
FROM "TIGHT" GAS SANDS

<u>Gas Price</u> (\$/Mcf)	<u>Economically Recoverable Gas (Tcf)</u>	
	<u>Implemented Case</u>	<u>Advanced Case</u>
\$2.00	23.5	93.4
\$3.00	40.0	141.3
\$5.00	66.0	182.5

Figure IV-8

Economically Recoverable Tight Gas Reserves for Implemented and Advanced Technology Conditions

TABLE IV-14
ECONOMICALLY RECOVERABLE NATURAL GAS RESERVES
FROM COAL SEAMS

<u>Gas Price</u> <u>(\$/Mcf)</u>	<u>Economically Recoverable Gas (Tcf)</u>	
	<u>Implemented Case</u>	<u>Advanced Case</u>
\$2.00	9.1	29.8
\$3.00	11.5	33.7
\$5.00	16.1	41.4

Figure IV-9

Economically Recoverable Coalbed Methane Reserves for Implemented and Advanced Technology Conditions

TABLE IV-15

**ECONOMICALLY RECOVERABLE NATURAL GAS RESERVES
FROM DEVONIAN AND ANTRIM SHALES**

<u>Gas Price</u> (\$/Mcf)	<u>Economically Recoverable Gas (Tcf)</u>	
	<u>Implemented Case</u>	<u>Advanced Case</u>
\$2.00	16.3	32.7
\$3.00	24.5	70.5
\$5.00	42.4	102.5

Figure IV-10

Economically Recoverable Devonian and Antrim Shale Gas Reserves for Implemented and Advanced Technology Conditions

reservoir heterogeneity precludes efficient drainage, and undiscovered gas resources in geologically difficult and costly settings — small fields and deep (greater than 1,200 feet) water. Advances in gas exploration and production technology could help convert these resources into reserves. Also, only the better known basins have been characterized and evaluated in this study. Additional basins contain large volumes of gas, appraisals of which will further increase the estimates of potential described above.

4. Impacts of Advanced Extraction Technology on Future Natural Gas Production

Unlike that for crude oil, the impacts of advanced natural gas extraction technologies are difficult to predict. The economic impacts of increased production, specifically on wellhead prices and local transportation costs, are the most uncertain. Whereas incremental oil from advanced technologies primarily competes against imports, incremental natural gas competes for markets against both crude oil and coal, as well as other supplies of gas. Recent oil shocks have provided the incentive to invest in fuel-switchable capacity for many industrial users. Since the Persian Gulf crisis has increased the price of oil relative to gas, most switching has already taken place, with little additional capacity left. Close to maximum gas demand is now being met. Thus, North America (including Canada) will probably be able to maintain a balance in supply and demand for the foreseeable future.

Without rapidly expanding gas markets, increased unconventional gas production could result, at least regionally, in an abundance of gas supply, thereby depressing gas prices. Depressed gas prices, if significant, could in turn increase gas demand. A comprehensive examination of natural gas supply and demand is necessary to assess the impact of increased unconventional gas production resulting from advanced extraction R&D.

This examination was performed via a FOSSIL2 model excursion run using the cost/supply relationships for unconventional gas presented above, and compared this to the NES Reference Case as of 9/27/90. This excursion assumed an aggressive federal R&D program for the development of advanced unconventional gas extraction technologies, phased in over the 1995 to 2005 time period.

TABLE IV-16
SUMMARY OF U.S. NATURAL GAS RESOURCES AND RESERVES
(Implemented Technology)

	<u>Economically Recoverable with Implemented Technology (Tcf)</u>	
	<u>\$3.00/Mcf</u>	<u>\$5.00/Mcf</u>
1. Proved Reserves	158*	167
2. Inferred Reserves	111	111
3. Reserve Growth	86	115
4. Unconventional Gas		
a. Tight Gas Sands	40	66
b. Coalbed Methane	12	16
c. Devonian Shales	25	42
5. Undiscovered Resources	<u>144</u>	<u>233</u>
TOTAL	576	750

* Assumes North Slope Alaskan proved natural gas reserves will not be economic until wellhead gas prices exceed \$3.00 per Mcf.

Source: Unpublished resource estimates; ICF Resources, 1990; DOE, 1988.

TABLE IV-17
SUMMARY OF U.S. NATURAL GAS RESOURCES AND RESERVES
(Advanced Technology)

<u>Economically Recoverable with Advanced Technology (Tcf)</u>		
	<u>\$3.00/Mcf</u>	<u>\$5.00/Mcf</u>
1. Proved Reserves**	158	168
2. Inferred Reserves**	111	111
3. Reserve Growth**	86	115
4. Unconventional Gas		
a. Tight Gas Sands	141	183
b. Coalbed Methane	34	41
c. Devonian Shales	71	102
5. Undiscovered Resources**	<u>144</u>	<u>233</u>
TOTAL	746	953

* Assumes North Slope Alaskan proved natural gas reserves will not be economic until wellhead gas prices exceed \$3.00 per Mcf.

** No advanced technology scenario available for resource category

Source: Unpublished resource estimates; ICF Resources, 1990; DOE, 1988.

Figure IV-11

Economically Recoverable Unconventional Gas Reserves for Implemented and Advanced Technology Conditions

The gas extraction excursion, given the unconventional gas cost/supply curves presented above, will result in increased production of 0.2 Tcf/year in 2000, increasing to 1.4 Tcf/year by 2015, and increasing again to 1.8 Tcf/year by the year 2030, in comparison to the NES Reference Case (the most recent reference case run comparable to the gas R&D excursion). These results are summarized in Table IV-18.

Increased supplies of unconventional natural gas will result in lower gas prices in the gas R&D excursion, relative to the Reference Case. As shown in Table IV-18, gas prices will decrease by up to \$0.29/Mcf by the year 2010, with gas prices differences between the gas R&D excursion and the Reference Cases ranging from \$0.50 to \$0.70/Mcf after 2015.

These decreases in gas prices will result in increases in U.S. natural gas consumption (Table IV-18). Natural gas consumption under the gas extraction R&D excursion will increase by as much as 1.0 Tcf/year after 2015, increasing to 1.5 Tcf/year by the year 2030.

The difference in these two R&D cases is an estimate of the cost of unsuccessful or unperformed R&D. The increase in gas prices caused by unrealized production is a real cost to the economy and can be used as a basis for assessing the relative costs and benefits of an aggressive R&D effort, compared to a more modest R&D program.

TABLE IV-18

COMPARISON OF GAS R&D EXCURSION TO NES REFERENCE CASE

<u>Year</u>	<u>Natural Gas Price (\$/Mcf)</u>		<u>Natural Gas Production (Tcf)</u>		<u>Natural Gas Consumption (Tcf)</u>	
	<u>Reference</u>	<u>R&D Excursion</u>	<u>Reference</u>	<u>R&D Excursion</u>	<u>Reference</u>	<u>R&D Excursion</u>
1990	1.81	1.81	17.5	17.5	18.4	18.4
1995	2.34	2.33	18.7	18.8	20.6	20.6
2000	3.63	3.67	20.8	21.0	23.2	23.2
2005	4.40	4.11	20.0	20.3	22.8	23.1
2010	5.31	5.02	19.7	20.4	22.5	23.1
2015	6.53	5.86	20.5	21.9	23.3	24.3
2020	6.77	6.28	19.5	20.8	21.9	23.0
2025	7.20	6.80	18.7	20.0	21.2	22.3
2030	7.65	6.95	16.7	18.5	19.3	20.8

V. Economic/Fiscal Disincentives to Exploration/Development Investments - Analysis of Tax Incentives

A. BACKGROUND

The profitability of the domestic oil and gas industry is significantly affected by state and federal taxes. Many countries with oil and gas resources have effective royalty and tax rates which are lower than those in the U.S.; this is an important factor affecting investments in domestic exploration and production operations. Without sufficient incentives to produce domestic crude oil, U.S. companies will continue to shift their investment strategy toward exploration abroad, smaller independents will leave the oil business, and domestic crude oil production could decline rapidly, with significant impacts on domestic energy security.

Financial incentives, including state and federal tax incentives, could increase domestic oil recovery. Oil industry activity in the U.S. is highly sensitive to changes in oil price. The marginal nature of many advanced oil recovery projects in this country makes financial incentives necessary to justify the substantial risk associated with them. The structure of the Windfall Profits Tax Act and the Tertiary Recovery Incentive Program recognized the unique financial requirements of newly developing recovery processes. Current state and federal tax structures offer ample latitude to provide adequate financial incentives to operators that apply new technology in their reservoirs. Recent analyses by the Interstate Oil Compact Commission (IOCC) indicate that well-structured state tax incentives could have an impact similar to a \$4 per barrel increase in oil prices (IOCC, 1987a; 1986). Federal tax incentives previously analyzed by DOE could have nearly the same results at current oil price levels around \$20 per barrel (Brashear, et al., 1989).

Increased exploratory drilling stimulated by effective tax policies could also increase recovery, even in mature producing regions. With the limited amount of undiscovered resource and the relatively small size of the fields remaining to be discovered in the U.S., incentives for exploration could be critical. The majority of oil discoveries in the U.S. are by independent operators. The Administration has recognized the need for incentives to encourage exploration. Recent proposals

include allowing tax credits for exploration investments and relaxing the Alternative Minimum Tax (AMT) restrictions that currently prevent independent operators from expensing a large portion of their investments for intangible drilling costs.

Overall, effective policy options at the state and federal levels could stimulate new reserve additions cost-effectively, thereby increasing domestic production and enhancing U.S. energy security. The Texas Railroad Commission, the New Mexico Conservation Commission, the Petroleum Recovery Research Center, Oklahoma Conservation Commission, the Oklahoma Geologic Survey, and many state legislatures have all been actively engaged in formulating policies to improve oil recovery in their respective states. The states of Oklahoma and Texas recently passed state tax incentives for new EOR activity. If these efforts are effectively linked with federal measures, such as currently proposed research and tax policy initiatives, the nation would benefit through greater domestic oil production and enhanced U.S. energy security.

The objective of this analysis is to examine the impact of various tax incentive options intended to correct existing disincentives to domestic oil and gas exploration and production. The analysis is based on recent provisions in legislation before Congress to provide incentives for domestic oil and gas exploration and production and to stimulate the recovery of tertiary oil and unconventional natural gas. Because the tax incentives for crude oil and unconventional natural gas are quite distinct by nature, and the characteristics of these two domestic sources of hydrocarbons are so different, oil and gas will be considered separately.

B. CRUDE OIL

1. Background

A number of alternative federal tax structures have previously been analyzed to determine their effectiveness in stimulating recovery and the net loss (or gain) in revenues to the federal treasury as a result of the incentive. Design and targeting of tax incentives were found to be critical to their effectiveness. An analysis of 673 reservoirs in Texas, Oklahoma, and New Mexico showed that tax incentives aimed at conventional production may have only a minor impact on production rates and ultimate well abandonments (ICF Resources, 1990b). A government tax policy designed

to extend conventional production and save existing wells would require massive subsidies and achieve minimal short-term benefits. The key to maintaining access to domestic crude oil reservoirs is clearly to encourage the implementation of new extraction processes in producing reservoirs.

This same analysis considered various tax incentives and estimated the impact of these incentives on the future development of domestic crude oil reserves and on public sector revenues. The most effective federal tax option considered in this analysis, in terms of incremental barrels stimulated per dollar of tax revenue foregone, was a 10% credit granted for all investment plus tertiary (EOR) injectant purchases. For the reservoirs in the three states analyzed, a federal tax incentive of this type was estimated to generate from 100 to 400 million barrels (MMB) under implemented technology conditions from ASR projects. Under advanced technology conditions, as much as 700 MMB of incremental ASR production could result. However, this incremental recovery is not sufficient to offset the direct losses to the federal treasury caused by the incentive (ICF Resources, 1990b).

On the other hand, EOR reserves (in contrast to ASR reserves) could more than double in the reservoirs analyzed if a federal 10% tax credit were instituted for investments and injectant purchases. Under implemented technology conditions at an oil price of \$20/Bbl, reserves in the reservoirs analyzed grew from 2.0 billion barrels under the current tax structure to 3.9 billion barrels with the federal incentive. Under advanced technology conditions, similar results were obtained, with reserves at \$20/Bbl growing from 2.3 billion barrels under current tax conditions to 5.3 billion barrels with the incentive. This incentive, if granted for the life of the project, would result in a net loss to public sector treasuries of as much as \$5 billion.

This analysis considered the 10% tax credit in combination with a reinstatement of the depletion allowance at 27.5%, with a 100% net income limitation and no restriction by operator type. It was found that this combined tax incentive was even more effective in stimulating production, but at a somewhat higher cost. Finally, the analysis examined this incentive with a restriction that the tax credit and depletion allowance could no longer be applied once the project's net revenues had paid off its initial investment (the payback, or breakeven point). The incentive-to-payback structure showed similar stimulatory effects on oil recovery to incentives granted over a project's life, but

without incurring most of the costs to the federal treasury imposed by longer-term incentive structures.

In the present analysis, three combinations of tax credits and depletion allowances, with variations on the durations of the tax incentives, were considered:

- An investment tax credit of 10% for EOR, ASR, and exploration projects, effective for the life of the project
- The combination of an investment tax credit of 10% with a 27.5% depletion allowance, effective for the life of the project
- The combination of an investment tax credit of 10% with a 27.5% depletion allowance, effective only until project payback.

This analysis also examined the effect of combining R&D policy with cost-effective tax incentive legislation, representing a partial integration of two NES options. Synergies between technology advances and state/federal tax incentives could increase oil production beyond the impact of either scenario taken alone. This analysis of the synergies between R&D and tax policies was conducted only for recovery operations from the known oil resource.

2. Analytical Approach

The key dependent variables considered in the tax incentive analyses were crude oil reserves, production, and imports, along with direct public sector revenues (at both the state and federal level) and the amount expended for imports. These values were evaluated for each of the selected tax policy alternatives. The results of this analysis are based on a more detailed assessment of potential tax policy options designed to stimulate domestic oil recovery (ICF Resources, 1990b).

The analytical approach involved the use of cash flow modules in the Crude Oil Policy Model to simulate explicitly the operator's economic decision-making process. For each recovery technology and resource category considered, these modules simulated the operator's response to changes in tax policy. The analysis compares the impact of the tax incentive scenarios to the Near- and Mid-Term R&D/Technology Transfer Scenario and to the Baseline Scenario.

3. Impacts of Tax Incentives on Domestic Crude Oil Reserves

Previous analyses have shown that federal tax incentives in the form of tax credits and depletion allowances could increase domestic EOR reserves by over 100% at constant oil prices less than \$24 per barrel compared to predicted EOR potential under the current tax structure (ICF Resources, 1990b). At higher constant oil prices, incremental reserves are still realized as a result of incentives, but the percentage increases are considerably lower (on the order of 30% to 60%, depending on the incentive, for prices ranging from \$28 to \$32 per barrel).

Direct net federal revenues from EOR projects were shown to decline under all cases and at all oil prices considered. Direct federal revenues from EOR projects under current taxes could decline from 12% to over 160% for the combination of the 10% tax credit and depletion allowance for project life. Federal tax revenues decline by smaller amounts under some incentives, ranging from a 12% to 30% decrease with a combination of a 10% tax credit and the 27.5% depletion allowance when limited to payback.

4. Impacts of Tax Incentives on Domestic Crude Oil Production

Forecasts of domestic crude oil production for several tax incentive options compared to the Baseline Scenario are presented in Table V-1 and Figure V-1, and compared to the Near- and Mid-Term R&D/Technology Transfer Scenario in Table V-2 and Figure V-2. Relative to the Baseline Scenario, a 10% investment tax credit on all capital and tertiary injectant costs could result in increased domestic crude oil production of as much as 200,000 barrels per day (B/D) by 2010. Adding a 27.5% depletion allowance to the 10% tax credit, with a 100% income limitations and no restrictions by operator type, could add another 600,000 B/D to this production, an increase of 9%. The total production over the 1990 to 2030 NES time frame for the Baseline Scenario comparison is summarized as follows:

TABLE V-1
IMPACTS OF ALTERNATIVE TAX INCENTIVES
ON U.S. CRUDE OIL PRODUCTION COMPARED TO BASELINE SCENARIO

Forecast Crude Oil Production (MMB/D)				
<u>Year</u>	<u>Baseline Scenario</u>	<u>10% ITC</u>	<u>10% ITC Plus 27.5% Depletion Allowance</u>	<u>10% ITC Plus 27.5% Depletion Allowance Until Payback</u>
1995	6.2	6.2	6.4	6.4
2000	6.0	6.0	6.3	6.3
2005	6.1	6.1	6.4	6.4
2010	6.9	7.1	7.5	7.5
2015	6.7	6.9	7.1	7.1
2020	5.5	5.7	5.6	5.6
2025	4.5	4.6	4.5	4.5
2030	3.6	3.6	3.4	3.4

Figure V-1
Impact of Various Tax Incentives on
Domestic Crude Oil Production
 ICFR Baseline (No R&D Expansion)

TABLE V-2

**IMPACTS OF ALTERNATIVE TAX INCENTIVES
ON U.S. CRUDE OIL PRODUCTION COMPARED TO NEAR- AND MID-TERM R&D SCENARIO**

<u>Forecast Crude Oil Production (MMB/D)</u>				
<u>Year</u>	<u>Near- and Mid-Term R&D Scenario</u>	<u>10% ITC</u>	<u>10% ITC Plus 27.5% Depletion Allowance</u>	<u>10% ITC Plus 27.5% Depletion Allowance Until Payback</u>
1995	6.2	6.3	6.4	6.4
2000	7.2	7.6	8.0	8.0
2005	9.2	9.6	10.2	10.2
2010	10.1	10.6	11.0	11.0
2015	9.3	9.6	9.9	9.9
2020	7.5	7.8	7.7	7.7
2025	5.9	6.1	5.9	5.9
2030	4.6	4.5	4.2	4.2

Figure V-2
Impact of Various Tax Incentives on
Domestic Crude Oil Production
 Near- and Mid-Term R&D Baseline

Ultimate Crude Oil Production (BBbls)

Baseline Scenario	90.8
10% ITC	92.5
10% ITC Plus 27.5% Depletion Allowance	93.8
10% ITC Plus 27.5% Depletion Allowance Until Payback	93.7

Similarly, relative to the Near- and Mid-Term R&D Scenario, the 10% tax credit would result in incremental production ranging from 350,000 B/D for the 10% credit, to as much as 1.0 million barrels per day (MMB/D) of incremental production for the 10% credit plus 27.5% depletion allowance, effective only to project payback. This amounts to about an 11% increase in production relative to the Near- and Mid-Term Scenario without any incentives. A comparison of ultimate crude oil production over the NES time frame for the cases compared to the Near- and Mid-Term R&D Scenario is presented below:

Ultimate Crude Oil Production (BBbls)

Near- and Mid-Term R&D Scenario	116.7
10% ITC	120.8
10% ITC Plus 27.5% Depletion Allowance	123.2
10% ITC Plus 27.5% Depletion Allowance Until Payback	123.1

This analysis also confirms the results of previous analyses (ICF Resources, 1990d; Brashear et al., 1989) that effective tax incentives in combination with successful R&D on crude oil extraction could provide synergistic effects beyond just the sum of the two factors. The combination of successful R&D and tax incentives could increase ultimate domestic crude oil production by 4.0 MMB/D over that achieved under the Baseline Scenario without incentives.

Tax incentives are shown here to stimulate a net increase in crude oil production over the NES time frame. The 10% tax credit plus 27.5% depletion allowance combination could increase

ultimate production by as much as 3.0 billion barrels compared to the Baseline Scenario, and by as much as 6.5 billion barrels compared to the Near- and Mid-Term R&D Scenario. However, given the NES reference case price track considered in this analysis, which increases with time in real terms, the primary impact of the tax incentives is to accelerate the development of reserves that would otherwise be developed later, rather than stimulating new reserves that would otherwise not be developed. This is because the effect of the tax credit is to make many marginal projects economic which would otherwise become economic anyway some year in the future, once prices rise sufficiently, which they do under the NES price track. Under constant prices, in contrast, many of these projects would not become economic unless costs are reduced. Tax incentives achieve this and hence have a strong impact on oil production. Consequently, the impacts of tax incentives on domestic crude oil production (as shown in Figures V-1 and V-2) appear less significant under the NES price track than one might expect for a more constant oil price track.

To illustrate the effect of the oil price track on the effectiveness of incentives, the three tax incentive proposals were compared at two constant crude oil prices -- \$20 and \$28 per barrel (in 1989 dollars) for the Near- and Mid-Term R&D Scenario. At \$20 per barrel, total domestic crude oil production could increase by nearly 0.9 MMB/D with a 10% tax credit (an 11% increase) by the year 2010. If a tax credit plus 27.5% depletion allowance is implemented, domestic oil production could increase by 2.0 MMB/D by 2010, a 20% increase over baseline conditions (Figure V-3).

At \$28 per barrel, the incremental increase in production as a result of tax incentives is somewhat less. As shown in Figure V-4, tax incentives at \$28 per barrel would result in incremental production of only about 0.9 MMB/D by 2000. This confirms previous analyses (Brashear et al; 1989; ICF Resources, 1990b) that showed that the impact of tax incentives on domestic crude oil supplies is greatest at low oil prices.

Almost all of the incremental domestic production stimulated by tax incentives will result from incremental production from EOR operations. As shown in Figure V-5 at \$20 per barrel and Figure V-6 at \$28 per barrel (where EOR in this scenario includes reservoirs amenable to EOR processes only and those amenable to both EOR and ASR processes), nearly all of the domestic incremental production comes from EOR processes.

Figure V-3

Impact of Various Tax Incentives on Domestic Crude Oil Production at Constant \$20/Bbl Oil Price Near- and Mid-Term R&D Baseline

Figure V-4
Impact of Various Tax Incentives on
Domestic Crude Oil Production at Constant \$28/Bbl Oil Price
Near- and Mid-Term R&D Baseline

Figure V-5

Impact of Various Tax Incentives on Domestic Crude Oil Production at Constant \$20/Bbl Oil Price

Near- and Mid-Term R&D Baseline
EOR Only

Figure V-6

Impact of Various Tax Incentives on Domestic Crude Oil Production at Constant \$28/Bbl Oil Price **Near- and Mid-Term R&D Baseline EOR Only**

The cumulative incremental production over the NES time frame for the constant \$20 and \$28 per barrel price tracks, in comparison to the Near- and Mid-Term R&D Scenario at these prices, is summarized as follows:

	<u>Cumulative Production from EOR Processes Only (BBbls)</u>	
	<u>\$20/Bbl</u>	<u>\$28/Bbl</u>
Near- and Mid-Term R&D Scenario	17.1	27.3
10% ITC	23.8	32.4
10% ITC Plus 27.5% Depletion Allowance	31.9	33.6
10% ITC Plus 27.5% Depletion Allowance Until Payback	31.5	33.6

For EOR processes only, tax incentives could result in 39% to 87% increase in cumulative production over the NES time frame at \$20 per barrel. At \$28 per barrel, tax incentives could result in a 19% to 23% increase in cumulative production over the 1990 to 2030 time period.

This analysis underscores the sensitivity of the stimulatory effects of tax incentive to the price of oil. However, it should be noted that from the operator's point of view, this type of change in the tax structure has a far more certain impact on profitability than does an equivalent rise in oil prices, which are known to fluctuate widely. Operators may not act on rising prices as quickly as they would a tax incentive, because they require some assurance that price stability or a long-term upward trend has been established. Although it was beyond the scope of this study to model such behavioral impacts, they may be important qualitative considerations in the evaluation of tax incentive policies.

5. Impacts of Tax Incentives on Future Crude Oil Imports

Crude oil imports resulting from the various tax incentive cases, assuming the NES reference case price track, are presented in Table V-3 and Figure V-7 in comparison to the Baseline Scenario, and in Table V-4 and Figure V-8 in comparison to the Near- and Mid-Term R&D Scenario. Over the 40-year NES time frame, U.S. crude oil imports are estimated to be 125.1 billion barrels in the Baseline Scenario. Tax incentives could result in a reduction in imports ranging from 1.6 billion barrels with the 10% tax credit for project life, to 2.8 billion barrels with the combination of the tax credit and 27.5% depletion allowance, effective to project payback. Relative to the Near- and

TABLE V-3

**IMPACTS OF ALTERNATIVE TAX INCENTIVES
ON U.S. CRUDE OIL IMPORTS COMPARED TO BASELINE SCENARIO**

<u>Year</u>	<u>Forecast Crude Oil Consumption*</u> (MMBbl/D)	<u>Forecast Crude Oil Imports (MMB/D)</u>			
		<u>Baseline Scenario</u>	<u>10% ITC</u>	<u>10% ITC Plus Depletion Allowance</u>	<u>10% ITC Plus Depletion Allowance Until Payback</u>
1995	13.7	7.5	7.4	7.4	7.4
2000	14.2	8.2	8.1	7.9	7.9
2005	14.1	8.0	8.0	7.7	7.7
2010	14.2	7.3	7.0	6.7	6.7
2015	14.2	7.6	7.3	7.1	7.1
2020	14.3	8.7	8.5	9.9	9.9
2025	14.4	9.9	9.8	9.9	9.9
2030	14.2	10.6	10.6	10.8	10.8
 Crude Oil Imports Over the NES Timeframe (Billion Barrels)					
Total		125.1	123.5	122.2	122.3
Import Reduction		--	1.6	2.9	2.8

* Based on NES Reference Case Forecast as of 9/5/90, adjusted to represent only crude oil input to refineries.

Figure V-7

Impact of Various Tax Incentives on U.S. Crude Oil Imports ICFR Baseline (No R&D Expansion)

TABLE V-4

**IMPACTS OF ALTERNATIVE TAX INCENTIVES
ON U.S. CRUDE OIL IMPORTS COMPARED TO NEAR- AND MID-TERM R&D SCENARIO**

<u>Year</u>	<u>Forecast Crude Oil Consumption*</u> (MMBbl/D)	<u>Near- and Mid-Term R&D Scenario</u>	<u>10% ITC</u>	<u>10% ITC Plus Depletion Allowance</u>	<u>10% ITC Plus Depletion Allowance Until Payback</u>
1995	13.7	7.4	7.4	7.3	7.3
2000	14.2	7.0	6.6	6.1	6.1
2005	14.1	4.9	4.5	4.0	4.0
2010	14.2	4.1	3.6	3.2	3.2
2015	14.2	4.9	4.6	4.3	4.3
2020	14.3	6.8	6.4	6.5	6.5
2025	14.4	8.5	8.3	8.6	8.6
2030	14.2	9.6	9.6	10.0	9.9
 Crude Oil Imports Over the NES Timeframe (Billion Barrels)					
Total		99.3	95.2	92.8	92.8
Import Reduction		--	4.1	6.5	6.5

* Based on NES Reference Case Forecast as of 9/5/90, adjusted to represent only crude oil input to refineries.

Figure V-8

Impact of Various Tax Incentives on U.S. Crude Oil Imports Near- and Mid-Term R&D Baseline

Mid-Term R&D Scenario, tax incentives could result in a 4.1 billion barrel reduction with a 10% tax credit, to as much as a 6.5 billion barrel reduction if the tax credit and depletion allowance (effective until payback) are implemented.

6. Summary and Conclusions

The estimated benefits from federal tax incentive policies, as with the benefits of R&D, will primarily manifest themselves in the form of reduced U.S. crude oil imports resulting from increased domestic production. Relative to the Near- and Mid-Term R&D Scenario, tax incentives could result in a \$22 to \$44 billion decrease in net present value expenditures on crude oil imports, at a net cost to the Federal treasury of from \$4 to \$53 billion (Table V-5). The wide range in costs is directly attributable to the tax incentive design, as discussed below. Similarly, relative to the Baseline Scenario, tax incentives could result in a \$7 to \$20 billion decrease in expenditures on crude oil imports (on a net present value basis), relative to a net present value cost to the federal treasury from only \$4 billion to as much as \$48 billion, depending on the nature of the incentive (Table V-6). The combination of tax incentives and successful R&D/technology transfer could result in import reductions as high as \$1,210 billion.

Increases in crude oil production resulting from federal tax incentives could at least partially offset decreased federal government revenues, if tax incentives are appropriately designed. Total public sector revenues (state and federal) decrease significantly for both types of incentives (10% tax credit and 10% credit plus depletion allowance) if these incentives are effective over the life of a project, as shown in Table V-5 for the comparison to the Baseline Scenario, and in Table V-6 for the comparison to the Near- and Mid-Term Scenario. If the combination of a 10% tax credit and depletion allowance is effective only until project payback, total public sector revenues decline only slightly. Under this scenario, because the federal government is the entity foregoing revenues to implement the incentive, state treasuries gain while federal treasuries lose revenues.

The "cost-effectiveness" of the incentive, as measured by the value of imports offset against foregone revenues, is strikingly sensitive to the type or design of the incentive. Under the Baseline Scenario (Table V-6), the tax credit plus depletion allowance to project life offsets \$20 billion in import costs at a cost of \$48 billion in foregone tax revenues, in discounted terms. Restricting the

TABLE V-5

**NET ECONOMIC COSTS OF ALTERNATIVE TAX INCENTIVES
OVER THE 1990-2030 TIME PERIOD COMPARED
TO THE NEAR- AND MID-TERM R&D SCENARIO**
(All values in Billions of 1989 Dollars)

	<u>Near- and Mid-Term R&D Scenario</u>	<u>10% ITC</u>	<u>10% ITC Plus Depletion Allowance</u>	<u>10% ITC Plus Depletion Allowance Until Payback</u>
Costs of Imports:				
Undiscounted	3,459	3,308	3,241	3,241
Discounted @ 10%	622	600	578	579
State Revenues Collected:				
Undiscounted	90	99	105	105
Discounted @ 10%	21	23	24	24
Federal Revenues Collected:				
Undiscounted	797	770	540	789
Discounted @ 10%	161	155	108	157

TABLE V-6

**NET ECONOMIC COSTS OF ALTERNATIVE TAX INCENTIVES
OVER THE 1990-2030 TIME PERIOD COMPARED TO BASELINE SCENARIO**
(All values in Billions of 1989 Dollars)

	<u>Baseline Scenario</u>	<u>10% ITC</u>	<u>10% ITC Plus Depletion Allowance</u>	<u>10% ITC Plus Depletion Allowance Until Payback</u>
Costs of Imports:				
Undiscounted	4,450	4,387	4,348	4,353
Discounted @ 10%	745	738	725	727
State Revenues Collected:				
Undiscounted	65	68	70	70
Discounted @ 10%	19	19	19	19
Federal Revenues Collected:				
Undiscounted	726	701	505	717
Discounted @ 10%	153	147	105	149

incentive to project payback reduces the import cost savings to \$18 billion, but the cost to state and federal treasuries drops to \$4 billion. The benefit/cost ratio by this measure improves from 0.4 to 4.5, or by 1,125%. The effect is similarly dramatic under the Near- and Mid-Term R&D Scenario; the combination incentive-to-project life offsets \$44 billion at a cost of \$50 billion, while restricting the incentive to payback offsets \$43 billion at a net cost of \$1 billion.

This analysis shows that over the NES time frame, properly designed federal tax incentives could have a significant impact on domestic crude oil production. Moreover, because of the impact of increased production on reducing imports, substantial benefits to society can result. These benefits are greatest when the synergistic effects of effective tax policy and R&D programs are realized.

C. UNCONVENTIONAL NATURAL GAS

1. Background

In 1988, nearly half of new gas reserve additions in the Lower-48 states came from the Federal waters of the Gulf of Mexico and from tight gas and coalbed methane deposits in the Black Warrior and San Juan basins. This was the result of advancements in both resource characterization, production technologies, and tax incentives. This trend in unconventional gas development has continued. In 1990, over 2,500 coalbed wells are estimated to be completed in the Warrior Basin in Alabama and the San Juan Basin in Colorado and New Mexico, almost one-fourth of all gas completions in the U.S. Approximately one-third of the new gas wells drilled since 1986 have been classified as Natural Gas Policy Act (NGPA) Section 107 gas wells -- wells considered high-risk because they exist in technologically challenging (unconventional) settings.

If new technologies for the production of natural gas are to be available, then market mechanisms must exist to support them. The principal market mechanism should be wellhead prices high enough to generate sufficient revenues to provide an appropriate level of R&D and exploration expenditures. These revenues must be used both to cover costs of operations as well as the costs of exploration and development activities required to replace reserves.

Over the long term, gas markets will likely stabilize and gas prices will be sufficient to stimulate new technology and development of resources. Over the short term, however, lack of adequate incentives could hamper the inherently long-term exploration and R&D efforts required of the petroleum industry. Market-based incentives that complement wellhead prices provide the long-term stability needed for R&D and exploration against short-term aberrations in prices, especially those due to economic downturns and oil price fluctuations. Tax policy is the most direct mechanism available to provide short-term mitigation of short-term market aberrations.

The focus of this chapter is an analysis of the effectiveness of one economic incentive to add reserves and increase gas production from these unconventional resources. The specific incentive studied is the Alternative Fuels Production Credit, more commonly referred to as the Section 29 tax credit for unconventional gas, named after the reference in the Internal Revenue Code by which it is described.

Created during a time when gas supplies were thought to be limited, Section 29 was part of a package of incentives to bring on new supplies. The NGPA provided for higher regulated wellhead prices when markets were strong. Section 29 provided for the time when markets might soften and alternative fuel prices decrease below the equivalent unconventional gas price. Both incentives were designed to provide the risk insurance that would allow industry to develop the prospects and technology to exploit these "new" resources.

When ceiling prices effectively disappeared with the 1986 oil price decline, Section 29 was the only remaining vehicle to provide this risk insurance and economic support for unconventional supplies. At the same time, excess gas deliverability decreased the need for new supplies from any source, especially those considered high-cost or risky. Any interpretation of the effectiveness of these incentives by examination of development activity in the late 1980's, therefore, must consider that the highest cost gas sources would be shut in and development slowed until the markets firmed up.

At this writing there are several bills in Congress which intend to extend the Section 29 tax credit. Two of the bills deal specifically with the extension of the credit and the reinstatement of the credit for tight sands; another treats the extension as one of many incentives.

The two Section 29-specific bills both attempt to extend the availability of credits for qualified fuels produced from wells spudded during an additional two years (prior to January 1, 1993), reinstate the credit for tight formations, and index the credit for tight sands to inflation in the same manner as currently implemented for other unconventional gas resources. The main differences in the two bills is that one ties the reinstatement of credit for tight sands to the date that FERC Order 519 took effect, while the other attempts to bypass all previous legislation and offers the credit independently of previous eligibility requirements that existed under NGPA and the Windfall Profits Tax Act.

Another pending piece of legislation which contains an extension to the Section 29 tax credit is the Domestic Energy Security Act of 1989, the so-called Archer-Andrews-Boren Bill. At the writing of this report, the legislation was still active in the House Ways and Means Committee. The Domestic Energy Security Act is a "catch all" bill for the petroleum industry, which contains a provision (Section 205) which proposes a seven-year extension of the Section 29 tax credit for unconventional gas. The tax credit for tight sands is also reinstated under the same inflation adjustment rates as for Devonian shale or coalbed methane.

The Section 29 credit is a production tax credit (in contrast to an investment tax credit) of approximately \$0.86/Mcf for gas produced from qualified wells. The credit is available for production through 2000 from wells drilled before the end of 1990. The current issue before Congress and industry is whether to extend the allowed spud date for another two years to continue incentives to develop additional unconventional gas resources.

Much of the current debate centers around whether the existing Section 29 credit is achieving its original goals. The resource base, deliverability, prices, rig utilization, marketing methods, regulation, and technology all have changed significantly since the debate a decade ago that created Section 29. With a view to the potential extension, it is more prudent to ask whether the credit mechanism can add reserves in a cost effective manner and in sufficient quantities to meet anticipated demand over the near term.

2. Analytical Approach

The principal purpose of this analysis is to determine the impact of extension of the alternative fuels production tax credit on potential reserve additions, production, and cost to the public treasuries. To perform this analysis, the ICF Resources unconventional gas economics model (discussed in Chapter IV) was modified to incorporate the Section 29 rules.

Typical coalbed, Devonian, and tight gas wells were selected to represent groups of wells thought to be likely to be developed in the near term. The recovery potential under implemented and advanced technology conditions was estimated for these wells both with and without the tax credit to determine the reduction in required wellhead price caused by the tax credit. Volumes associated with each typical well at each required price level were multiplied by the areas each well represents and aggregated into overall cost/supply curves.

3. Impacts of Tax Incentives on Domestic Unconventional Gas Reserves

This analysis shows that a permanent extension of the Section 29 tax credit can have a major impact on domestic unconventional gas supplies. We examined the impact from two perspectives: the maximum effect on the entire resource base of a permanent extension of the credit, and the specific two-year extension proposed.

Under implemented technology conditions at a price of \$2.00 per Mcf, 49 Tcf of unconventional gas reserves are recoverable. Making the credit available for the entire resource base (with no time limit) increases potential unconventional gas reserves by 45%, to 71 Tcf. At \$5.00 per Mcf, 124 Tcf are recoverable under implemented technology conditions without the credit, while as much as 143 Tcf could be recoverable with the credit.

With advanced technology and a price of \$2.00 per Mcf, 155 Tcf of unconventional gas reserves could be recoverable without the extension of the credit. Availability of the credit for an unlimited time could increase potential reserves to 232 Tcf. At a higher price of \$5.00 per Mcf, 326 Tcf are recoverable under advanced technology conditions without the credit, where as much as 343 Tcf could be recoverable with the credit.

Economically recoverable unconventional gas reserves estimates with and without the permanent extension of the Section 29 tax credit are summarized in Table V-7 and in Figures V-9 and V-10, for the implemented and advanced technology situations, respectively. Figures V-11 and V-12 show the benefit of the Section 29 tax credit extension for tight gas under implemented and advanced technology conditions, respectively. Similarly, Figures V-13 and V-14 show the benefit of the Section 29 tax credit extension for coalbed methane under implemented and advanced technology conditions, respectively. Finally, Figures V-15 and V-16 show the benefit of the Section 29 tax credit extension for Devonian age shale gas under implemented and advanced technology conditions, respectively.

It is important to remember when interpreting time-independent cost/supply curves of inadequately characterized unconventional resources that the lowest cost resource is not necessarily developed first. Only by developing the resource can operators know where the highest quality, lowest cost resource is located, and initial development will thus consist of a sampling of the entire resource.

Although it appears that a certain volume of reserves may be recovered at a fairly low price, the need to sample from the entire resource base means that, at least initially, average costs will be higher than those found at the lower-cost portions of the curve. Consequently, comparison of curves at a single price indicates only the general level of impact, and usually the maximum impact likely. Without more detailed knowledge of finding rates, well productivity, and time-specific economics, this is the best indicator of potential impact available.

An additional analysis was conducted on the effects of in-drilling, reserve additions, and production of the proposed two-year extension of the Section 29 credit. Four critical factors were addressed: technology advances, gas markets, corporate planning, and regional geologic and producing distinctions between resources.

First, since only a two-year extension was analyzed, we assumed technology did not significantly improve over the 1991-1992 period. Although one of the stated purposes of the Section 29 credit is its ability to provide for operators to develop new technologies and explore new

TABLE V-7

**POTENTIAL IMPACT OF THE SECTION 29 TAX CREDIT
ON DOMESTIC UNCONVENTIONAL GAS RESERVES**

(Trillion Cubic Feet)

	<u>Implemented Technology</u>		<u>Advanced Technology</u>	
	<u>\$2.00/Mcf</u>	<u>\$5.00/Mcf</u>	<u>\$2.00/Mcf</u>	<u>\$5.00/Mcf</u>
Tight Gas				
- w/o credit	24	66	93	182
- w/ credit	32	73	120	193
Coalbed Methane				
- w/o credit	9	16	30	41
- w/ credit	12	18	35	44
Devonian and Antrim Shale				
- w/o credit	16	42	32	103
- w/ credit	27	52	77	106
Total Unconventional Gas				
- w/o credit	49	124	155	326
- w/ credit	71	143	232	343

Figure V-9
Unconventional Gas
Impact of Section 29 Tax Credit
Implemented Technology Case

Figure V-10
Unconventional Gas
 Impact of Section 29 Tax Credit
 Advanced Technology Case

Figure V-11

Tight Gas

Impact of Section 29 Tax Credit
Implemented Technology Case

Figure V-12
Tight Gas
 Impact of Section 29 Tax Credits
 Advanced Technology Case

Figure V-13
Coalbed Methane
 Impact of Section 29 Tax Credit
 Implemented Technology Case

Figure V-14
Coalbed Methane
 Impact of Section 29 Tax Credit
 Advanced Technology Case

Figure V-15
Devonian Shale
 Impact of Section 29 Tax Credit
 Implemented Technology Case

Figure V-16
Devonian Shale
 Impact of Section 29 Tax Credit
 Advanced Technology Case

geological settings, the only technology modeled was that implemented by the most sophisticated operators active today.

Second, since gas markets are expected to change substantially over the next few years, only wells that are marginal at factor prices should be modeled. The minimum required price of a currently marginal well will increase if market prices increase as expected over the next few years. For this reason, many more wells will be economic when prices rise and the impact of production tax credits on marginal well economics also changes. Because wellhead prices will increase, we modeled wells that will be marginal at 1991-1992 prices instead of at current prices. Marginal wells were judged to be those requiring \$2.00/Mcf (1990 dollars), that would be made economic by eligibility for the tax credit.

Third, the rapid increase in development of coalbed and Antrim wells (affected in part by the imminent expiration of the credit), has distorted company plans for the next few years. In most cases, development will decrease with or without the extension of the credit. The magnitude of decrease depends on how much future development was accelerated into 1989-1990. Estimated development plans with and without the extension were based on extensive interviews with the most active unconventional gas operators.

Fourth, each unconventional gas geological setting and recovery mechanism is unique. Because project economics respond differently to alternative formulations of a tax credit, the near-term unconventional resource was disaggregated into eight resource/region-specific typical wells for analysis:

- Black Warrior basin coalbed methane
- San Juan basin coalbed methane
- Appalachian basin coalbed methane
- Other coalbed methane
- Appalachian Devonian shale
- Michigan (Antrim) shale
- Appalachian tight sands
- Western tight sands

Production streams were calculated using ICF Resources' in-house, resource-specific reservoir models (COMET-PC for coalbed, SRP2 for Devonian shale, and TGAS-PC for tight sands). Costing and cash flow accounting were modeled using ICF Resources' Gas Economics Model (GEM). Costs were derived from published surveys of drilling, equipment, and operating costs and confirmed during interviews with operators.

Typical well reservoir characteristics were based on ICF Resources natural gas databases and confirmed by operators. Technology scenarios were based on work completed for GRI and industry-accepted descriptions of currently implemented production technology. Additional assumptions specific to various results sections are discussed below.

The availability of the Section 29 credit (currently \$0.89/Mcf for coalbed methane and Devonian shale and \$0.52/Mcf for tight sands, if reinstated) does add significantly to an operator's revenues. A marginal well in 1991-1992 would require at least \$2.00/Mcf at the wellhead without the credit to pay back the cost of capital. This would be uneconomic at prevailing 1990 wellhead prices of \$1.53/Mcf. The credit provides an equivalent increment of revenue to effectively lower the wellhead price to make a well profitable.

The availability of a tax credit is assumed to affect neither ultimate recovery or rates from a well. While an operator could increase rates to capture more of the credit, it was assumed that a prudent operator would already be producing a well at the maximum efficient rate consistent with sound engineering principles and applicable regulations. Since unconventional gas wells drilled in 1991-1992 will produce beyond the expiration of the credit in 2000, no adjustment for extending the economic limit was made. To estimate the impact of a tax credit on project economics, we conducted cash flow analyses on typical wells. Both rate of return and net present value were estimated for wells with and without the credit.

Companies traditionally require at least a nominal return of 25-35% to account for risks of geologic or technical failure. Given today's depressed market for gas, companies varied widely in their willingness to develop prospects that didn't meet the company's desired return on investment criteria. The impact on single well project economics for the proposed formulation of the credit is summarized in Table V-8 for three typical wells. Each well has a current required price to make a

Table V-8

Impact of Section 29 Tax Credit on Project Economics

	<u>NPV</u> <u>(\$MM)</u>	<u>IRR</u>	<u>D&C Cost</u> <u>(\$MM)</u>	<u>Reserves</u> <u>(Bcf)</u>
Tight Sands (Cotton Valley)	0.53	24.5%	1.13	1.7
Coalbed Methane (Warrior Basin)	0.23	25.9%	0.33	0.5
Devonian shale (Appalachian basin)	0.17	27.3%	0.30	0.5

Source: ICF Resources analysis (1990)

return on capital of approximately \$2.00/Mcf, and would not be economic at near-term prices. Without the credit well, NPV would be \$0 and IRR 10%. These are unrisked evaluations, and projects approved by companies would generally have to have a 15% IRR at a minimum.

All three typical wells receiving the tax credit would be within the desired corporate guidelines for investment needed to attract outside capital. The credit can, therefore, turn marginal wells into economic ones.

For the historically dominant unconventional gas producing regions, we tabulated wells drilled over the past five years, and estimated drilling both without the credit and with a two-year extension (see Table V-9). These estimates are the most sensitive to assumptions about company capacity to develop new prospects, project financing, company planning, and lease availability. Estimates of drilling with and without the credit were based on extensive interviews with the most active operators in the current unconventional gas plays.

All figures reported beyond this point are based on the net wells drilled as a result of the credit. An estimated 6,600 well completions can be attributed to a two year extension of the credit beyond what would be drilled if the credit expires as scheduled. This estimate is higher than previously thought.

Table V-9

**Expected Drilling and Reserve Additions from Section 29 Extension
(Wells and Bcf Reserves)**

	COALBED			DEVONIAN			TIGHT SAND		Total
	Warrior	San Juan	Other	Appalachian	Antrim	Appalachian	Eastern	Western	
1985	75	29	0	0	15	1093	5053	1263	7528
1986	73	48	0	0	32	738	3570	893	5354
1987	129	43	0	0	91	615	2371	593	3842
1988	479	255	0	2	230	494	1689	520	3640
1989	1079	462	45	9	553	863		600	5211
1990	1800	900	270	25	900	900		700	6795
Anticipated Successful Wells Without Credit Extension									
1991	200	300	100	10	200	300	1000	500	2610
1992	200	300	100	10	200	300	1000	500	2610
Anticipated Successful Wells With Credit Extension									
1991	800	500	300	100	800	800	1500	700	5500
1992	800	500	400	210	1000	800	1700	900	6310
Net Effect of Credit									
1991	600	200	200	90	600	500	500	200	2890
1992	600	200	300	200	800	500	700	400	3700
1200									
1200									
1200									
Avg. Reserves/Well	0.4	2.0	0.4	0.3	0.7	0.3	0.3	1.5	

Table V-9 (Continued)

Expected Drilling and Reserve Additions from Section 29 Extension
(Wells and Bcf Reserves)

	COALBED			DEVONIAN			TIGHT SAND		Total
	Warrior	San Juan	Other	Appalachian	Antrim	Appalachian	Eastern	Western	
Total Unconventional Gas Reserve Additions (Bcf)									
1988	192	510	0	1	161	148	504	750	2266
1989	432	924	18	3	387	259	480	900	3403
1990	720	1800	108	8	630	270	390	1050	4976
Estimated Incremental Reserve Additions Due to 2-Year Section 29 Extension (Bcf)									
1991	240	400	80	27	420	150	150	300	1767
1992	240	400	120	60	560	150	210	600	2340
2-Year Total	480	800	200	87	980	300	360	900	4107

Sources: FERC 121 well filings, state regulatory agencies, DOE/EIA, GRI, ICF Resources.

The impact of the credit is different for coalbed and Devonian shale than for tight sands, since tight sands currently is not eligible for the credit. First, for coalbed and Antrim shales, the dramatic increase in drilling this year has left companies with a need to complete and put on line all these wells in the first part of 1991. This leaves little capacity, even with the credit extension, to drill as many wells next year as in 1990. Therefore, coalbed development will decrease from 1990 levels with or without the credit, but only more so without the credit. Also, the potential for additional development in the recently tested portions of active basins is still limited by geologic and market risks. Without the Section 29 credit, development in new basins will slow considerably.

For tight sands, the reinstatement of eligibility can be expected to increase drilling, especially in the Appalachian basin. Much of the current western tight gas activity is infill wells. For example, Cotton Valley formation (a tight sandstone) infill development made Panola County, Texas the 7th most actively drilled county in the country in 1989. This increased infill activity was primarily due to remaining eligibility for Section 29 credits scheduled to expire in 1990, but many tight sands wells are drilled without benefit of the credit. Therefore, there should be a smaller increase in drilling resulting from tight gas reinstatement in western basins than in the East.

Finally, the existence of Section 29 eligible gas in many of the most actively drilled counties and fields in 1989 shows the impact the credit has already had. In 1989, the top ten drilled (oil and gas) counties in the U.S. contained five that produce predominantly unconventional gas. In 1985, only one of these counties (Weld, Colorado) made the top ten, and it had significant tight sands production at this time. The top 15 drilled fields in 1989 include 8 that produce mostly unconventional gas. In 1985, only two of these fields made the top 15 (Wattenburg, Colorado and Basin, New Mexico), both among the earliest tight gas plays in the U.S. Thus, the credit is clearly adding reserves that otherwise would not have been developed.

At the average reserves per well shown in Table V-9, 4.1 Tcf would be added in the next two years from these incremental wells. This is equal to more than 10% of the total expected gas reserve additions for those years from conventional sources.

4. Impacts of Tax Incentives on Domestic Unconventional Gas Production

For each resource/play combination a typical well production profile was selected to estimate incremental production during the next 10 years. Figure V-17 and Table V-10 show the average daily production rates for these wells, and the total annual production from incremental wells drilled in 1991-1992 as a result of the tax credit (Table V-10).

An additional 104 Bcf of production would be added in 1991, increasing to 266 Bcf in 1992. Due to the late peaking of coalbed wells, this production volume could be maintained for several years, until when it would start to decline at about 6% per year. Over a five year period, 1.1 Tcf could be produced, and 2.2 Tcf would be produced over a 10 year period.

5. Impact of Tax Incentives on Future Federal and State Revenues from Unconventional Gas Production

Given the need to minimize the costs of tax incentives to the U.S. Treasury, the cost of the Section 29 credit is a major concern. We analyzed the cost to the Treasury as a function of how much credit could be generated if all producers were eligible and the expected percentage usage of the credit (based on tax circumstances of the companies or drilling partnerships).

Detailed information on the usage of the Section 29 credit is only available in aggregate from the IRS for corporate returns. It is reported for partnership and individual returns aggregated with "Other Credits." It is expected that integrated producers, who are most likely to be able to make direct use of the credit, will have reported it on their corporate returns. Independents, who are much less able to take the credit would report it on their corporate returns. Thus, while it is unknown how much credit is being used by individuals or partnerships, the small number of drilling partnerships active recently indicates that this number is likely to be small.

Figure V-17
Unconventional Gas Resources
Typical Well Production Profiles

SOURCE: ICF RESOURCES INC.

Table V-10

Expected Per Well and Total Production
From Section 29 Extension (Mcf/d)

	Warrior	COALBED			DEVONIAN			TIGHT SAND		
		San Juan	Other	Appalachian	Antrim	Appalachian	Eastern	Western		
1	37	85	37	58	77	93	93	465		
2	113	210	113	66	77	61	61	307		
3	164	203	164	74	77	54	54	272		
4	122	246	122	72	77	49	49	246		
5	96	285	96	66	77	46	46	229		
6	84	304	84	60	73	42	42	211		
7	73	323	73	55	69	39	39	193		
8	61	342	61	49	66	36	36	180		
9	49	361	49	44	62	34	34	168		
10	37	380	37	38	59	31	31	155		
Estimated Total Production for Incremental (1991-1992) Section 29 Wells (Bcf/Year)										
1991	8	6	3	2	17	17	17	34	104	104
1992	33	22	12	6	39	28	35	90	266	369
1993	61	30	24	7	39	21	26	65	273	643
1994	63	33	27	8	39	19	23	58	269	911
1995	48	39	20	7	39	17	21	53	244	1156
1996	40	43	17	7	38	16	19	49	229	1384
1997	34	46	15	6	36	15	18	45	215	1599
1998	29	49	12	6	35	14	16	41	202	1801
1999	24	51	10	5	33	13	15	39	190	1991
2000	19	54	8	4	31	12	14	36	178	2170
Total	358	372	149	59	347	171	205	509	2170	

Source: ICF Resources Analyses (1990).

As of 1987, the latest year for which statistics have been compiled by the IRS, about 10% of independents were in a net operating loss position, making them ineligible for credits. Of the remainder who weren't, about 75% were under AMT rules, also effectively restricting their use of the credit. For integrated producers, about 35% were under AMT rules. Since being under AMT probably only reduces the eligibility to receive the credit and not eliminates it, we assume that the incentive still has some value, although less than intended.

In 1986 and 1987, the latest years for which data are available, Section 29 claims on corporate returns were \$64 million and \$53 million, respectively. Large corporations receive most of the corporate credits, with over 80% of claims made by corporations with over \$250 million in assets, and only about 2% by corporations with assets under \$10 million. Of the \$64 million total claims made in 1986, \$50 million were made by companies classified as oil, gas or coal related.

Based on eligible 1986 Devonian and coalbed production of about 90 Bcf and a credit amount of \$0.74/Mcf, a maximum of \$67 million potentially could have been paid out for unconventional gas production, assuming no tight sands production recovered the credit. This suggests that only about 75% of potential credits were paid (\$50 million/\$67 million). Given that these returns are weighted toward larger companies that are less likely to lose eligibility because of net operating losses or AMT, this 75% estimated credit usage is probably optimistic. Therefore, an estimated two-thirds of the maximum payable credit would be actually paid by the Treasury.

The five year undiscounted (1990 dollars) maximum cost of the credit to the U.S. Treasury for incremental wells only is \$848 million (Table V-11). The ten year cost is \$1,601 million. Given 4.1 Tcf reserve additions, this is equivalent to a total undiscounted incentive of \$0.39/Mcf (or \$2.26/BOE). Likely costs, due to restrictions on eligibility to claim the full credit, are about one-third lower. Because there is no risk to the Treasury for unsuccessful wells (the credit is only paid on production), this is the full cost of the incentive, paid out over ten years, for incremental wells. This amounts to \$1.50/BOE, compared to other proposed petroleum incentives ranging to more than \$10/BOE.

This is not, however, the full cost of a two-year extension of Section 29. As currently proposed, the credit would be paid on all eligible unconventional gas production, not just for wells

Table V-11

**Maximum and Most Likely Section 29 Credits Paid by Treasury
(Millions of 1990 Dollars)**

	<u>Incremental Wells</u>		<u>Total Wells</u>		<u>Total</u>	<u>Total Wells</u>		<u>Total</u>
	<u>Coalbed</u>	<u>Devonian</u>	<u>Tight Gas</u>	<u>Coalbed</u>		<u>Devonian</u>	<u>Tight Gas</u>	
1991	17	30	25	29	72	44	85	158
1992	65	60	60	109	185	85	155	349
1993	109	54	42	177	204	75	110	362
1994	116	52	36	188	203	72	94	354
1995	102	50	31	175	183	70	83	327
1996	94	48	28	170	171	67	73	310
1997	90	46	24	167	160	63	65	294
1998	85	43	22	163	150	60	57	280
1999	81	41	19	160	141	56	51	267
2000	76	38	17	157	132	52	46	255
1991-1995	409	246	194	678	848	345	526	1,549
1991-2000	835	462	304	1,495	1,601	642	819	2,955
Incr. Resv (Bcf)	1,567	1,280	1,260	1,567	4,107	1,280	1,260	4,107
Cost/Mcf	\$0.53	\$0.36	\$0.24	\$0.95	\$0.39	\$0.50	\$0.65	\$0.72
Cost/BOE	\$3.09	\$2.09	\$1.40	\$5.53	\$2.26	\$2.91	\$3.77	\$4.17
Likely Utilization (2/3 of maximum possible claims) paid resulting from partial ineligibility due to corporate tax circumstances								
1991-2000	\$557	\$308	\$203	\$997	\$1,068	\$428	\$546	\$1,970
Cost/Mcf	\$0.36	\$0.24	\$0.16	\$0.64	\$0.26	\$0.33	\$0.43	\$0.48
Cost/BOE	\$2.06	\$1.39	\$0.93	\$3.69	\$1.51	\$1.94	\$2.51	\$2.78

Note: Incremental wells are the 6,590 wells stimulated by the 2-year extension. Total wells includes those wells that would have been drilled even without the credit extension (11,810 total).

stimulated by the credit. An estimated 5,220 unconventional gas wells would be drilled in 1991-1992 even without the credit. This is fewer than the more than 12,000 unconventional gas wells drilled in 1989-1990. This decrease is both because many 1991-1992 prospects were accelerated into 1990 to beat the current Section 29 expiration date, as well as the effect of project economics with the loss of the credit.

The estimated total wells drilled for 1991-1992 with the credit extension is 11,810. Reserves added by these wells would be 8.1 Tcf, 1991-2000 production would be 4.3 Tcf, and maximum Section 29 credits paid over the 1991-2000 period would be \$2,955 million. Because only 4.1 Tcf of incremental reserves are added, however, the maximum cost of these reserves is therefore \$0.72/Mcf or (\$4.17/BOE). Presuming one-third of this would not be paid, the likely undiscounted loss of Treasury receipts of a two-year extension of Section 29 would be \$1,970 over 10 years or \$0.48/Mcf (\$2.78/BOE). The breakdown by resource type is shown in Figure V-18 and Table V-11.

This is the gross loss in U.S. Treasury receipts of adding 4.1 Tcf of gas reserves. It does not include the estimated \$336 million in new production and severance taxes to states and localities, \$150 million in royalty payments for production on federal lands, or the \$1,345 million in net increased state and federal income taxes paid. Increased energy security, decreased environmental costs, and increase economic activity in local economies and tribal communities are not included in these estimates. Thus, the undiscounted net public costs of the Section 29 extension are \$139 million, or \$0.03/Mcf (\$0.20/BOE).

Figure V-18
Estimated Section 29 Credits Paid on Unconventional Gas

SOURCE: ICF RESOURCES INC.
 NOTE: DOES NOT INCLUDE RECEIPTS OF PRODUCTION AND SEVERENCE TAXES,
 STATE AND FEDERAL INCOME TAXES, OR ROYALTIES ON FEDERAL LANDS

VI. Costs and Benefits of Environmental Regulations Affecting Domestic Oil and Gas Exploration

Market inefficiencies caused by environmental regulations and the inadequate accounting of environmental externalities could affect future domestic crude oil supplies. The objective of the analyses presented in this chapter is to examine the energy and economic impacts of future environmental regulations on U.S. crude oil supplies.

A number of legislative and regulatory initiatives being considered to protect the environment could affect the economics of U.S. oil and gas exploration and production (E&P) operations. Not all environmental statutes require the Environmental Protection Agency (EPA) or other regulatory agencies to consider costs and/or energy impacts when establishing regulations. Even when energy impact analyses are performed, they are often limited in scope, because they generally only consider the impacts associated with a specific regulation, and almost always assume no impacts from regulations in other areas. Many in government and industry, as articulated in comments in testimony provided as part of the NES (DOE, 1990c), have expressed concerns that the cumulative costs of multiple regulatory initiatives could significantly affect U.S. crude oil supplies. Furthermore, while the costs of these initiatives are additive, the benefits may not be.

This chapter summarizes the results of a comprehensive assessment of the potential cumulative energy and economic impacts of environmental initiatives on U.S. crude oil supplies, which is presented in more detail in ICF Resources (1990a). This assessment expands upon the previous DOE assessments of the recovery potential of U.S. crude oil supplies, summarized above, which have assumed no change in the costs of environmental compliance.

A review of selected environmental initiatives under consideration by EPA and/or other state and federal agencies that could affect U.S. oil and gas exploration and production was conducted. Potential initiatives being considered under the authority of the Resource Conservation and Recovery Act (RCRA), the Safe Drinking Water Act (SDWA), the Clean Water Act (CWA), and the Clean Air Act (CAA) were included. The initiatives represent requirements above and beyond those

currently required for compliance. In the analysis, the costs of complying with current environmental regulations are included in baseline E&P costs.

The nature of estimated incremental compliance costs associated with each initiative were based on the likely practices that would be required to comply with the initiative if implemented. From a review of these initiatives, three environmental regulatory scenarios were developed, representing low, medium, and high levels of incremental compliance costs. The high scenario represents a stringent yet conceivable level of regulation, but should not be considered a "worst case" scenario. For example, in reference to authority under RCRA, this could represent a level of stringency similar to "modified" RCRA Subtitle C regulations (which pertain to solid wastes characterized as hazardous under the statute), but would not include all aspects of those regulations as currently implemented by EPA for hazardous wastes. The low scenario represents a case that recognizes that some change in existing regulations is inevitable (though not necessarily the set of initiatives defined), and therefore some impact on U.S. E&P activities is likely. Finally, the medium scenario represents a case that is between the high and low cases, but should not be considered a most likely scenario. Again, using RCRA as an example, this could represent a set of regulations corresponding to a substantially expanded and modified RCRA Subtitle D program (which pertains to regulations affecting solid wastes not classified as hazardous under the statute). The environmental initiatives considered under each scenario are summarized in Tables VI-1 through VI-4, organized by environmental statute.

This assessment does not consider every potential regulatory initiative that may affect the economics of U.S. E&P activities. Estimated compliance costs associated with many initiatives have not yet been assessed. In addition, the regulatory initiatives proposed or under consideration are constantly evolving; this study represents only the initiatives under consideration at the time of the analysis. Because it does not consider all regulations that may potentially affect U.S. crude oil supplies, the results of the assessment could be considered somewhat conservative.

TABLE VI-1

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Resource Conservation and Recovery Act

<u>Regulatory Initiative</u>	<u>Regulatory Scenario</u>		
	<u>Low</u>	<u>Medium</u>	<u>High</u>
1. Management and Disposal of Drilling Waste	Oil-based muds disposed into lined pits Salt water-based muds disposed into lined pits	Oil-based muds use closed systems Salt water-based muds disposed into lined pits	Oil-based muds use closed systems All water-based muds disposed into lined pits
2. Disposal of Associated Wastes into Central Disposal Facilities	Liquid wastes into offsite disposal well; solid wastes into nonhazardous waste landfill	Liquid wastes into offsite disposal well; solid wastes into hazardous waste landfill	Liquid wastes into offsite disposal well; combustible solid wastes into incinerator; non-combustible solid wastes into hazardous waste landfill
3. Upgrading Emergency Pits	All emergency pits must be lined.	Existing emergency pits must be lined; new pits must be replaced with tanks	Tanks must replace emergency pits for both new and existing pits
4. Replace Workover Pits with Portable Rig Tanks	Required on all rigs	Required on all rigs	Required on all rigs
5. Organic Toxicity Characteristic Test	Applied to all facilities and new wells	Applied to all facilities and new wells	Applied to all facilities and new wells
6. Corrective Action (Soil Remediation Only)	Land treatment of hydrocarbon contamination at 50% of tank batteries and EOR projects*	Excavation of salt water contamination at 100% of SWD wells and 75% of EOR projects* and tank batteries	Excavation of hydrocarbon and salt water contaminated sites at same frequency as Medium Scenario

* EOR projects refers to both secondary and tertiary recovery projects

TABLE VI-2

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS
Safe Drinking Water Act

	<u>Regulatory Initiative</u>			<u>High</u>
	<u>Low</u>	<u>Regulatory Scenario</u> <u>Medium</u>		
1. Mechanical Integrity Testing*				
Part 1	No incremental requirements (5-year pressure test)	Pressure test frequency based on corrosive potential of basin	Continuous positive annular pressure monitoring and 5-year pressure test	
Part 2	Radioactive tracer test every five years	Radioactive tracer test and noise or temperature log run to injection zone, frequency based on basin corrosivity	Radioactive tracer test, noise, and temperature log run to injection zone, frequency based on basin corrosivity	
Non Injection-Related Fluid Movement	No incremental requirements	Oxygen activation log and noise or temperature log run to lowermost underground source of drinking water.	Oxygen activation, noise, and temperature log run to lowermost underground source of drinking water	
2. Area of Review (on wells drilled prior to 1984)	No incremental requirements	1/4 mile area of review (AOR) under area permit	1/4 mile area of review (AOR) under individual injector permit	
3. Corrective Action (on wells drilled prior to 1984)	No incremental requirements	5% of producing wells within AOR assumed to require remedial squeeze	15% of producing wells within AOR assumed to require remedial squeeze	
		10% of abandoned wells within AOR assumed to require reentering and replugging	30% of abandoned wells within AOR assumed to require reentering and replugging	
		1% of producing wells within AOR must be redrilled	3% of producing wells within AOR must be redrilled	
4. Construction Requirements	No incremental requirements	10% of injectors require remedial squeeze	30% of injectors require remedial squeeze	
		2% of injectors must be redrilled	6% of injectors must be redrilled	

* MIT Part 1 addresses tubing, casing, and packer integrity. MIT Part 2 addresses fluid movement behind the casing.

TABLE VI-3

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Clean Water Act

<u>Regulatory Initiative</u>	<u>Regulatory Scenario</u>		
	<u>Low</u>	<u>Medium</u>	<u>High</u>
1. NSPS for Offshore Discharge of Muds and Cuttings	EPA Approach A (EPA's estimate of facilities affected and associated compliance costs)	API Partial Discharge Limitation Scenario (EPA Approach A with API estimates of compliance costs)	API Zero Discharge Limitation Scenario (API assumption that all facilities are affected, using API cost estimates)
2. NSPS for Offshore Discharge of Produced Water	Existing facilities: no change New facilities: treat to 59 mg/l	Existing facilities: treat to 59 mg/l New facilities: shallow water, no discharge; deep water, treat to 59 mg/l	Existing facilities: shallow water, no discharge; deep water, treat to 59 mg/l New facilities: no discharge all depths
3. NPDES Stormwater Permits	Required for 55% of facilities	Required for 55% of facilities	Required for 55% of facilities
4. Above Ground Storage Tanks	Only leak detection and financial responsibility for new tanks larger than 1,000 barrels	All aspects ⁺ considered for new tanks larger than 500 barrels; financial responsibility for all tanks	All aspects ⁺ considered for all new and existing tanks
5. Ban on Onshore Surface and Coastal Discharge of Produced Waters	No incremental requirements	Ban on discharges from new facilities	Ban on discharges from all facilities

* See EAI, 1988.

+ Aspects of regulations include injection and integrity testing, overflow prevention equipment, leak detection equipment, additional corrosion protection, and financial responsibility requirements.

TABLE VI-4

SUMMARY OF ASSUMPTIONS CORRESPONDING TO THREE REGULATORY SCENARIOS

Clean Air Act

<u>Regulatory Initiative</u>	<u>Regulatory Scenario</u>		
	<u>Low</u>	<u>Medium</u>	<u>High</u>
1. Onshore Air Toxics Emissions Standards*	API Case I scenario	API Case I Scenario	API Case II Scenario
2. Offshore Air Toxics Emissions Standards	California only; no mitigation costs considered	California only; mitigation costs considered	Entire OCS; mitigation costs for California only

* See Jones, Marfin, and Hoffman, 1989

The assessment also assumes that the environmental initiatives considered are, for the most part, universally applied. Except in specific situations (e.g. coastal or offshore areas), no distinction among acceptable potential compliance practices by region, recovery process, or site-specific conditions is assumed. If more site-specific, risk-based environmental regulations are implemented, the impacts are likely to be different than those estimated in this analysis.

The three sets of initiatives proposed in this analysis do not necessarily represent any set of regulations recommended or supported by EPA, any other federal or state agency, or any specific association, company, or institution. The scenarios proposed are intended to represent a range of possible combinations of regulations, corresponding to options which have been under consideration or discussion. These scenarios are used only for estimating the impact of various initiatives on U.S. crude oil supplies.

The estimated compliance costs used in this assessment are based on data developed in other recent analyses. These analyses were primarily performed by EPA and/or the American Petroleum Institute (API). The form of the compliance cost estimates used were often modified to incorporate them appropriately into the analysis models used in the study; these modifications had no major effect on the magnitude or applicability of the compliance costs.

The initial step in the assessment involved estimating economic recovery potential under baseline conditions, which assumed costs of compliance with environmental regulations currently in place. This analysis was based on regional average costs determined as a function of reservoir depth and other relevant reservoir parameters. The analysis established recovery potential under baseline conditions, providing the reference case against which the other scenarios were compared.

For purposes of comparison, the results for the different environmental compliance scenarios are compared to the Near- and Mid-Term Scenario, presented in Chapter IV (which corresponds to the program proposed in DOE's Oil Program Implementation Plan) (DOE, 1990a), and to the ICFR Baseline Scenario (which assumes a slow pace of advance in crude oil extraction technologies).

A. CRUDE OIL

1. Analytical Approach

For purposes of this analysis, the Crude Oil Policy Model was modified to include the incremental costs associated with the compliance with new environmental regulations, developed for both levels of technology considered. The incremental compliance cost estimates used in the analyses presented below were based on previous, detailed analyses performed by ICF Resources for DOE and reported elsewhere (ICF Resources, 1990a). Additional, specific methodological issues in the analysis of various resource categories are discussed in greater detail in the sections below.

2. Cumulative Impacts of Environmental Initiatives on Domestic Crude Oil Reserves

Incremental compliance costs associated with potential regulatory initiatives considered in this assessment could be substantial. Potential industry compliance costs could range from \$15 to \$79 billion initially, and from \$2 to \$7 billion dollars per year thereafter (1989 dollars), assuming the continuation of 1985 levels of oil and gas drilling and development (ICF Resources, 1990a). These estimates assume that the increased environmental compliance costs would not affect petroleum industry activity except by adding costs to operations that would be pursued regardless of whether or not the regulations would be implemented. Under this assumption, additional environmental regulations would lead to greater industry expenditures.

Industry expenditures will not necessarily increase because of increased environmental regulations, however. Increased environmental regulations could lead to some previously viable projects becoming uneconomic to pursue. Consequently, the effects of reduced development of crude oil resources could more than offset the effects of increased compliance costs. Ultimately, overall industry investment and operating expenditures could decrease as a result of the increased environmental requirements.

The cumulative energy and economic impacts of the environmental initiatives were considered in previous analyses (ICF Resources, 1990a). The results of this work are presented below for four constant crude oil prices (\$16, \$20, \$24 and \$32/Bbl, in 1989 dollars) in terms of the economically recoverable resources (reserves) that become uneconomic as a result of increased environmental regulations. Tables VI-5 through VI-8 summarize the impacts on crude oil reserves for constant

prices of \$16/Bbl, \$20/Bbl, \$24/Bbl and \$32/Bbl, respectively, for a selected set of resources considered (ICF Resources, 1990a). The results of this analysis are discussed separately below for each of the resource categories considered.

a. Current Production. In the analyses presented previously, production projections assumed that historical activities to maintain and/or increase production in each reservoir are continued in the future. Oil production is viable until the economic limit of production is reached, when revenues from oil sales just offset associated production costs. As oil prices increase, the economic limit for production falls, extending the productive life of a reservoir. Similarly, increasing costs (e.g., due to increased costs of compliance with environmental regulations) raise the economic limit and shorten the productive life of a reservoir.

The impacts of the incremental costs associated with the environmental scenarios were examined by performing a discounted cash flow analysis on a selected set of reservoirs over their productive life, assuming that each reservoir must incur the incremental investment and operating costs associated with the environmental scenario (ICF Resources, 1990a). The analysis is performed from the perspective of the operator of each reservoir, who would conduct a financial analysis to determine the impact on project profitability of the incremental costs of compliance over the productive life of the reservoir. This analysis would be performed at the time the regulations went into effect. At this point in time, each operator would make a decision whether to continue with production and incur the incremental costs of regulatory compliance, or begin to shut-in production. As a result, a considerable portion of current production could be shut-in and the associated resource abandoned immediately after the implementation of the new regulations. For those reservoirs that continue to operate, the imposition of additional environmental regulations could rapidly accelerate the point of abandonment (economic limit), because of increased environmental compliance costs. Many reservoirs would be abandoned and their production shut-in much earlier than would happen under current practices.

TABLE VI-5
IMPACT OF POTENTIAL ENVIRONMENTAL REGULATIONS
ON U.S. CRUDE OIL SUPPLIES
AT AN OIL PRICE OF \$16/BBL

	Resource Category			
	<u>Conventional Production*</u>	<u>Unrecovered Mobile Oil</u>	<u>Enhanced Oil Recovery</u>	<u>Undiscovered</u>
Level of Assessment	Nine States**	Texas, Oklahoma and New Mexico	Lower 48 States (Onshore)	Entire U.S.
Implemented Technology				
Resource Lost (%)				
Low Scenario	3	4	<1	12
Medium Scenario	21	21	46	25
High Scenario	26	26	53	36
Public Sector Revenues Lost (%)				
Low Scenario	N/A	7	4	13
Medium Scenario	N/A	29	58	21
High Scenario	N/A	34	72	36
Advanced Technology				
Resource Lost (%)				
Low Scenario	N/A	4	21	N/A
Medium Scenario	N/A	14	51	N/A
High Scenario	N/A	24	66	N/A
Public Sector Revenues Lost (%)				
Low Scenario	N/A	5	32	N/A
Medium Scenario	N/A	21	58	N/A
High Scenario	N/A	32	84	N/A

N/A = Not Analyzed

* Represents incremental resource lost (over the reference case) immediately (in 1990) from premature abandonment

** California, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming

TABLE VI-6
IMPACT OF POTENTIAL ENVIRONMENTAL REGULATIONS
ON U.S. CRUDE OIL SUPPLIES
AT AN OIL PRICE OF \$20/BBL

	Resource Category			
	<u>Conventional Production*</u>	<u>Unrecovered Mobile Oil</u>	<u>Enhanced Oil Recovery</u>	<u>Undiscovered</u>
Level of Assessment	Nine States**	Texas, Oklahoma and New Mexico	Lower 48 States (Onshore)	Entire U.S.
Implemented Technology				
Resource Lost (%)				
Low Scenario	2	16	3	9
Medium Scenario	23	35	24	18
High Scenario	30	43	29	42
Public Sector Revenues Lost (%)				
Low Scenario	N/A	16	5	7
Medium Scenario	N/A	35	32	17
High Scenario	N/A	45	40	36
Advanced Technology				
Resource Lost (%)				
Low Scenario	N/A	6	11	N/A
Medium Scenario	N/A	24	36	N/A
High Scenario	N/A	28	42	N/A
Public Sector Revenues Lost (%)				
Low Scenario	N/A	7	15	N/A
Medium Scenario	N/A	26	42	N/A
High Scenario	N/A	31	47	N/A

N/A = Not Analyzed

* Represents incremental resource lost (over the reference case) immediately (in 1990) from premature abandonment

** California, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming

TABLE VI-7

**IMPACT OF POTENTIAL ENVIRONMENTAL REGULATIONS
ON U.S. CRUDE OIL SUPPLIES
AT AN OIL PRICE OF \$24/BBL**

	Resource Category			
	<u>Conventional Production*</u>	<u>Unrecovered Mobile Oil</u>	<u>Enhanced Oil Recovery</u>	<u>Undiscovered</u>
Level of Assessment	Nine States**	Texas, Oklahoma and New Mexico	Lower 48 States (Onshore)	Entire U.S.
Implemented Technology				
Resource Lost (%)				
Low Scenario	1	1	7	8
Medium Scenario	17	25	11	17
High Scenario	29	34	23	38
Public Sector Revenues Lost (%)				
Low Scenario	N/A	5	10	7
Medium Scenario	N/A	30	18	17
High Scenario	N/A	38	28	35
Advanced Technology				
Resource Lost (%)				
Low Scenario	N/A	5	5	N/A
Medium Scenario	N/A	22	20	N/A
High Scenario	N/A	28	32	N/A
Public Sector Revenues Lost (%)				
Low Scenario	N/A	7	6	N/A
Medium Scenario	N/A	26	23	N/A
High Scenario	N/A	32	37	N/A

N/A = Not Analyzed

* Represents incremental resource lost (over the reference case) immediately (in 1990) from premature abandonment

** California, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming

TABLE VI-8

**IMPACT OF POTENTIAL ENVIRONMENTAL REGULATIONS
ON U.S. CRUDE OIL SUPPLIES
AT AN OIL PRICE OF \$32/BBL**

	Resource Category			
	<u>Conventional Production*</u>	<u>Unrecovered Mobile Oil</u>	<u>Enhanced Oil Recovery</u>	<u>Undiscovered</u>
Level of Assessment	Nine States**	Texas, Oklahoma and New Mexico	Lower 48 States (Onshore)	Entire U.S.
Implemented Technology				
Resource Lost (%)				
Low Scenario	2	3	3	10
Medium Scenario	20	21	15	12
High Scenario	29	25	20	22
Public Sector Revenues Lost (%)				
Low Scenario	N/A	5	4	7
Medium Scenario	N/A	26	19	12
High Scenario	N/A	32	25	29
Advanced Technology				
Resource Lost (%)				
Low Scenario	N/A	6	1	N/A
Medium Scenario	N/A	14	20	N/A
High Scenario	N/A	21	29	N/A
Public Sector Revenues Lost (%)				
Low Scenario	N/A	7	2	N/A
Medium Scenario	N/A	20	24	N/A
High Scenario	N/A	27	36	N/A

N/A = Not Analyzed

* Represents incremental resource lost (over the reference case) immediately (in 1990) from premature abandonment

** California, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming

The future recovery of the known remaining crude oil resource presupposes that the existing wells and infrastructure in producing reservoirs will be available for the application of future, advanced recovery technologies. Moreover, it assumes that operators can retain production rights (leases) to produce oil from these reservoirs. Once abandoned, the resource in these reservoirs becomes essentially inaccessible to future development unless oil prices increase by \$10 to \$15 per barrel over the price at which the resource is abandoned, even with further improvements in recovery technologies (Biglarbigi, et al., 1990).

As the costs of compliance with environmental regulations increase, the costs of operating marginally economic wells in producing reservoirs will increase, resulting in the accelerated abandonment of these wells. As well abandonments erode access to the remaining resource, fewer future recovery projects will be economically justifiable. These projects will not recover sufficient oil to justify both the high start-up costs associated with advanced recovery technologies and the costs of redrilling or re-entering wells in abandoned oil reservoirs. The impact of the increased compliance costs are therefore two-fold. First, reserves are lost because of the earlier abandonment of these wells. Second, access to the remaining resources associated with these abandoned wells will be lost, and hence, the potential future production from advanced recovery technologies in reservoirs containing these wells will be economically prohibitive.

At a \$20 per barrel price, about 2% more of the resource in place in the nine states could be immediately abandoned (in 1990) under the low scenario than that abandoned in the reference case at the same point in time. Under the medium scenario, 23% more of the resource in place could be abandoned immediately, compared to the reference case, while an additional 30% of the resource could be immediately abandoned under the high scenario, when compared to the reference case. The analysis shows that by the year 2000, the imposition of the incremental regulations have little effect on resources ultimately abandoned, but could have a significant impact on the rate of these abandonments, if no new development of these currently producing reservoirs takes place. The results for the four oil prices considered are summarized in Tables VI-5 through VI-8.

By 1995, resource abandonments are predicted to reach over 70% of the U.S. resource base under both the medium and high scenarios, assuming no future drilling or development activities in these producing reservoirs take place. Therefore, increased regulations can increase the pace of U.S.

crude oil resource abandonments by approximately ten years. This can result in a significant reduction in the time available for technological development to make a contribution to production in these reservoirs on the verge of abandonment.

b. Unrecovered Mobile Oil in Known Fields. The assessment of the impact of environmental initiatives on UMO development from ASR techniques in Texas, Oklahoma, and New Mexico demonstrated that under all regulatory, technology, and oil price scenarios considered, the development of otherwise economically viable projects may not be pursued (ICF Resources, 1990a). Depending on the level of environmental regulations implemented and the crude oil price, as much as 43% of UMO reserves in these states could become uneconomic to develop, assuming the application of current recovery technologies. While the development and introduction of advanced UMO extraction technologies could result in substantial additional crude oil reserves, the impacts of environmental regulations on reserves recoverable from advanced technology could still be considerable. Again depending on price and the level of environmental regulations implemented, as much as 28% of potentially recoverable UMO reserves in these states could become uneconomic to develop, even if the application of advanced recovery technologies becomes widespread.

Under the implemented technology case, depending on oil price, 16% of the reserves that would otherwise be economic could become uneconomic in the low scenario. Under the medium scenario, as much as 35% of otherwise recoverable UMO reserves become uneconomic. Finally, under the high scenario, as much as 43% of UMO reserves otherwise recoverable become uneconomic.

In the advanced technology case, low scenario, about 6% of the reference case reserves become uneconomic, again depending on oil price. Under the medium scenario, as much as 24% of the reference case reserves become uneconomic to develop. Finally, under the high scenario, as much as 28% of otherwise recoverable reserves become uneconomic.

The development of the UMO resource requires that a considerable number of new production and injection wells be drilled. Environmental regulations that apply directly to drilling these wells (e.g., management and disposal requirements for drilling muds and cuttings, area-of-review

and corrective action requirements for siting new injection wells) are the most significant environmental regulatory cost factors influencing the economics of developing the UMO resource.

c. Enhanced Oil Recovery in Known Fields. The analyses of the impact of environmental initiatives on EOR development in the U.S. show that under all environmental and oil price scenarios considered, the development of otherwise economic EOR reserves may not take place because of increased environmental regulations. Similar to the results for the UMO resource category, economic and energy impacts are forecast for all scenarios, oil prices, and levels of technology considered, with recovery from all EOR processes affected (Tables VI-5 through VI-8).

In the low scenario under the implemented technology case, depending on oil price, as much as 7% of the reserves that could be economic under reference conditions become uneconomic. In the medium scenario, as much as 46% of the reserves that could otherwise be economic become uneconomic. Finally, in the high scenario, as much as 53% of the reserves that could otherwise be economic under the reference case become uneconomic to produce, depending on oil price.

In the advanced technology case, low scenario, as much as 21% of otherwise recoverable reserves become uneconomic to develop and produce. In the medium scenario, as much as 51% of the reserves that could otherwise be economic at this price become uneconomic. In the high scenario, depending on price, as much as 66% of otherwise recoverable reserves become uneconomic.

The impact on EOR of increased environmental compliance costs is similar to that associated with the development of the UMO resource. EOR projects also generally require the drilling of additional production and injection wells; consequently the incremental compliance costs associated with this activity will greatly influence project economics.

d. Undiscovered Crude Oil Resources. The three environmental scenarios considered are expected to all have a significant impact on the economic viability of finding, developing, and producing U.S. undiscovered crude oil reserves. Under the low scenario, as much as 12% of otherwise recoverable reserves could become uneconomic, depending on price. Under the medium scenario, as much as 25% of otherwise recoverable reserves could become uneconomic. Finally, under the high scenario, up to 42% of otherwise recoverable reserves could be lost.

Increased regulations will have the greatest impact on undiscovered crude oil reserves in the onshore Lower-48. They will have a lesser impact on the discovery and development of oil reserves in Alaska and the offshore Lower-48 than that on onshore Lower-48 reserves under the low and medium scenarios. In the offshore and Alaska, the increased costs of environmental compliance will make up a smaller portion of total project costs than that in the Lower-48 onshore. Consequently, the environmental initiatives considered under the low and medium scenarios are estimated to have a relatively small impact on project economics in these regions.

It should be noted, however, that in this analysis, incremental environmental compliance costs in Alaska, with the exception of the management and disposal costs for drilling muds and cuttings, were assumed to be the same as those in the Lower-48. No incremental compliance cost estimates explicitly developed for Alaska operations were available. Environmental compliance costs in Alaska will probably be considerably greater than those in the Lower-48. Therefore, the analysis of Alaska in this assessment will likely represent somewhat of an underestimate of the impacts of environmental regulations on Alaskan undiscovered crude oil production.

3. Cumulative Impacts of Environmental Initiatives on Domestic Crude Oil Production

The impacts of alternative environmental compliance scenarios on U.S. crude oil production are summarized in Table VI-9 and Figure VI-1 relative to the Baseline Scenario, and in Table VI-10 and Figure VI-2 relative to the Near- and Mid-Term R&D/Technology Transfer Scenario. Relative to the Baseline Scenario, domestic crude oil production could decrease by as much as 0.7 MMB/D as a result of increased costs of environmental compliance. Similarly, relative to the Near- and Mid-Term Scenario, production could decrease by as much as 1.4 MMB/D in the high environmental compliance scenario.

Ultimate crude oil production over the NES time frame, relative to the Baseline Scenario, is summarized as follows:

TABLE VI-9

**IMPACT OF ALTERNATIVE ENVIRONMENTAL COMPLIANCE
SCENARIOS ON U.S. CRUDE OIL PRODUCTION, UNDER THE BASELINE SCENARIO**

<u>Forecast Crude Oil Production (MMB/D)</u>				
<u>Year</u>	<u>Baseline Scenario</u>	<u>Low Environmental Scenario</u>	<u>Medium Environmental Scenario</u>	<u>High Environmental Scenario</u>
1995	6.2	6.1	5.7	5.6
2000	6.0	5.9	5.7	5.5
2005	6.1	6.0	5.8	5.6
2010	6.9	6.9	6.6	6.4
2015	6.7	6.5	6.2	6.0
2020	5.5	5.4	5.0	4.8
2025	4.5	4.4	4.1	3.9
2030	3.6	3.5	3.2	3.1

Figure VI-1

Impact of Various Environmental Initiatives on Domestic Crude Oil Production

ICFR Baseline (No R&D Expansion)

TABLE VI-10

**IMPACT OF ALTERNATIVE ENVIRONMENTAL COMPLIANCE
SCENARIOS ON U.S. CRUDE OIL PRODUCTION,
UNDER THE NEAR- AND MID-TERM R&D SCENARIO**

Forecast Crude Oil Production (MMB/D)				
<u>Year</u>	<u>Near- and Mid-Term R&D Scenario</u>	<u>Low Environmental Scenario</u>	<u>Medium Environmental Scenario</u>	<u>High Environmental Scenario</u>
1995	6.3	6.2	5.8	5.6
2000	7.2	7.1	6.6	6.4
2005	9.2	9.0	8.1	7.8
2010	10.1	9.9	9.1	8.7
2015	9.3	9.1	8.3	7.9
2020	7.5	7.3	6.7	6.3
2025	5.9	5.8	5.3	5.1
2030	4.6	4.5	4.1	3.9

Figure VI-2

Impact of Various Environmental Initiatives on Domestic Crude Oil Production

Near- and Mid-Term R&D Baseline

Ultimate Crude Oil Production (BBbls)

Baseline Scenario	90.8
Low Environmental Scenario	89.5
Medium Environmental Scenario	84.0
High Environmental Scenario	81.6

Ultimate crude oil production over the NES time frame, relative to the Near- and Mid-Term R&D Scenario, is summarized for each environmental compliance scenario as follows:

Ultimate Crude Oil Production (BBbls)

Near- and Mid-Term R&D Scenario	116.7
Low Environmental Scenario	114.7
Medium Environmental Scenario	104.7
High Environmental Scenario	100.7

Over the 40-year NES time frame, the increased costs of environmental compliance could result in a 10% decrease in production relative to the Baseline Scenario, and 14% decrease in ultimate production relative to the Near- and Mid-Term Scenario, depending on the level of incremental environmental compliance costs that domestic crude oil producers must incur.

4. Cumulative Impacts of Environmental Initiatives on Domestic Crude Oil Imports

Increased environmental compliance requirements could lead to a decrease in domestic crude oil production, and therefore result in an increase in U.S. crude oil imports. The impact of increased environmental regulations on U.S. crude oil imports are summarized in Table VI-11 and Figure VI-3 relative to the Baseline Scenario, and in Table VI-12 and Figure VI-4 relative to the Near- and Mid-Term Scenario. Over the NES time frame, U.S. crude oil imports could increase by up to 9 billion barrels, depending on the level of increased environmental compliance required. Similarly, relative to the Near- and Mid-Term Scenario, crude oil imports could increase by as much as 16 billion barrels

under the high environmental scenario. These increases in crude oil imports could have a dramatic impact on domestic energy security over the critical period of concern to the NES.

5. Cumulative Impacts of Environmental Initiatives on Public Sector Revenues

Declining domestic production resulting from the increased costs of environmental compliance could lead to significant reductions in revenues collected by state and federal governments. As summarized in Table VI-13, relative to the Baseline Scenario, public sector revenues could decrease by as much as \$16 billion (on a net present value basis) over the NES time frame. Relative to the Near- and Mid-Term Scenario, as shown in Table VI-14, public sector revenues could decrease by as much as \$18 billion, discounted over the NES time frame, under the high environmental scenario.

6. Summary and Conclusions

The net economic impacts of the various environmental scenarios considered are summarized in Table VI-13 relative to the Baseline Scenario, and in Table VI-14 relative to the Near- and Mid-Term Scenario. The primary impact of increased environmental regulation is increased crude oil imports resulting from decreased domestic production. As shown relative to the Baseline Scenario (Table VI-13), the increased costs of environmental compliance could result in an increase in expenditures on crude oil imports of \$62 billion (discounted at 10%). Moreover, public sector revenues would decrease by \$11 billion, because of declining domestic production. Similarly, relative to the Near- and Mid-Term Scenario (Table VI-14), expenditures on crude oil imports could increase by \$97 billion (net present value) over the NES time frame under the high environmental scenario, while public sector revenues decrease by \$12 billion from decreased domestic production.

Net operator profits, or the economic rent collected from crude oil production, decreases with increasing environmental compliance costs. Relative to the Baseline Scenario, discounted net operator profits decrease by \$2 billion in the low environmental scenario, \$16 billion in the medium scenario, and \$21 billion in the high environmental scenario. Similarly, relative to the Near- and Mid-Term

TABLE VI-11

**IMPACT OF ALTERNATIVE ENVIRONMENTAL COMPLIANCE
ON U.S. CRUDE OIL IMPORTS UNDER THE BASELINE SCENARIO**

<u>Year</u>	<u>Forecast Crude Oil Consumption*</u> (MMBbl/D)	<u>Forecast Crude Oil Imports (MMB/D)</u>			
		<u>Baseline Scenario</u>	<u>Low Environmental Scenario</u>	<u>Medium Environmental Scenario</u>	<u>High Environmental Scenario</u>
1995	13.7	8.3	7.5	7.9	8.1
2000	14.2	9.4	8.2	8.5	8.7
2005	14.1	9.3	8.1	8.3	8.5
2010	14.2	8.2	7.3	7.6	7.8
2015	14.2	7.5	7.7	8.1	8.2
2020	14.3	7.2	8.9	9.2	9.7
2025	14.4	7.6	10.0	10.3	10.5
2030	14.2	8.6	10.6	11.0	11.1
 Crude Oil Imports Over the NES Timeframe (Billion Barrels)					
Total		125.1	126.5	132.0	134.4
Import Increase			1.4	6.9	9.3

* Based on NES Reference Case Forecast as of 9/5/90, adjusted to represent only crude oil input to refineries.

Figure VI-3

Impact of Various Environmental Initiatives on U.S. Crude Oil Imports

ICFR Baseline (No R&D Expansion)

TABLE VI-12

**IMPACT OF ALTERNATIVE ENVIRONMENTAL COMPLIANCE
ON U.S. CRUDE OIL IMPORTS UNDER THE NEAR- AND MID-TERM R&D SCENARIO**

<u>Year</u>	<u>Forecast Crude Oil Imports (MMB/D)</u>				
	<u>Forecast Crude Oil Consumption*</u> (MMBbl/D)	<u>Near- and Mid-Term R&D Scenario</u>	<u>Low Environmental Scenario</u>	<u>Medium Environmental Scenario</u>	<u>High Environmental Scenario</u>
1995	13.7	7.4	7.5	7.9	8.1
2000	14.2	7.0	7.1	7.6	7.8
2005	14.1	4.9	5.1	6.0	6.3
2010	14.2	4.1	4.3	5.1	5.5
2015	14.2	4.9	5.2	6.0	6.3
2020	14.3	6.8	7.0	7.6	8.0
2025	14.4	8.5	8.6	9.1	9.3
2030	14.2	9.6	9.6	10.1	10.2
 Crude Oil Imports Over the NES Timeframe (Billion Barrels)					
Total		99.3	101.3	111.3	115.3
Import Increase			2.0	12.0	16.0

* Based on NES Reference Case Forecast as of 9/5/90, adjusted to represent only crude oil input to refineries.

Figure VI-4

Impact of Various Environmental Initiatives on U.S. Crude Oil Imports

Near- and Mid-Term R&D Baseline

TABLE VI-13

**ECONOMIC IMPACTS OF ALTERNATIVE ENVIRONMENTAL COMPLIANCE
SCENARIOS OVER THE 1990-2030 TIME PERIOD, COMPARED TO BASELINE SCENARIO**
(All values in Billions of 1989 Dollars)

	<u>Baseline Scenario</u>	<u>Low Environmental Scenario</u>	<u>Medium Environmental Scenario</u>	<u>High Environmental Scenario</u>
Costs of Imports:				
Undiscounted	4,450	4,497	4,682	4,764
Discounted @ 10%	745	753	791	807
Net Operator Profits:				
Undiscounted	1,256	1,249	1,196	1,173
Discounted @ 10%	256	254	240	235
Energy Security Premium:				
Undiscounted	N/A	N/A	N/A	N/A
Discounted @ 10%	N/A	N/A	N/A	N/A
State Revenues Collected:				
Undiscounted	65	64	60	58
Discounted @ 10%	19	18	17	16
Federal Revenues Collected:				
Undiscounted	726	719	689	675
Discounted @ 10%	153	151	144	141
Incremental Compliance Costs				
Undiscounted	--	7	20	30
Discounted @ 10%	--	1	2	4

N/A = Not Analyzed

TABLE VI-14

**ECONOMIC IMPACTS OF ALTERNATIVE ENVIRONMENTAL COMPLIANCE
SCENARIOS OVER THE 1990-2030 TIME PERIOD,
COMPARED TO NEAR- AND MID-TERM R&D SCENARIO
(All values in Billions of 1989 Dollars)**

	<u>Near- and Mid-Term R&D Scenario</u>	<u>Low Environmental Scenario</u>	<u>Medium Environmental Scenario</u>	<u>High Environmental Scenario</u>
Costs of Imports:				
Undiscounted	3,459	3,533	3,886	4,007
Discounted @ 10%	622	634	696	720
Net Operator Profits:				
Undiscounted	1,367	1,354	1,269	1,238
Discounted @ 10%	273	270	252	245
Energy Security Premium:				
Undiscounted	N/A	N/A	N/A	N/A
Discounted @ 10%	N/A	N/A	N/A	N/A
State Revenues Collected:				
Undiscounted	90	88	80	77
Discounted @ 10%	21	21	19	18
Federal Revenues Collected:				
Undiscounted	798	787	745	727
Discounted @ 10%	161	160	151	147
Incremental Compliance Costs				
Undiscounted	--	8	25	36
Discounted @ 10%	--	1	3	5

N/A = Not Analyzed

R&D Scenario, net operator profits decrease by \$3 billion in the low scenario, \$21 billion in the medium scenario, and \$28 billion in the high environmental scenario. As shown in Table VI-13 for the Baseline Scenario and Table VI-14 for the Near- and Mid-Term R&D Scenario, the economic impacts of increased environmental compliance, measured in terms of both decreased economic rent and increased expenditures on imports, are substantial.

Unfortunately, in this analysis, no estimate was made of the benefits associated with stricter environmental requirements. Admittedly, this analysis only presents the cost impacts. Regardless, the economic impact of increased environmental compliance, regardless of the compliance scenario and level of advance in extraction technology, could be significant.

B. NATURAL GAS

1. Analytical Approach

The methodology employed to examine the potential cumulative impacts of environmental initiatives on domestic unconventional gas reserves is exactly the same as that used in the previously conducted analyses for crude oil (ICF Resources, 1990a). For unconventional gas, only the incremental compliance costs associated with the initiatives described in Tables IV-1 through IV-4 that specifically apply to onshore natural gas production were considered. Analyses were considered for each of the three environmental scenarios considered in the analysis for crude oil.

2. Cumulative Impacts of Environmental Initiatives on Domestic Unconventional Gas Reserves

This analysis shows that the increased costs of environmental compliance could have a measurable impact on domestic unconventional gas supplies, though the impact will not be as great as that for crude oil. The impact on unconventional gas will be greater at lower prices (around \$2.00 per Mcf) than at higher prices (around \$5.00 per Mcf). For example, under implemented technology conditions at a price of \$2.00 per Mcf, 49 Tcf of unconventional gas reserves are recoverable when no incremental environmental compliance costs are assumed. In the low environmental scenario, 40 Tcf are economically recoverable, a 9 Tcf (18%) reduction. In the medium scenario, 37 Tcf are economically recoverable, a 12 Tcf (24%) reduction over the reference case. Finally, in the high

scenario, only 29 Tcf are economically recoverable under implemented technology conditions, a 20 Tcf (41%) reduction in reserves over the reference case.

At higher prices of \$5.00 per Mcf, 124 Tcf are recoverable under implemented technology conditions. Increased environmental compliance costs could result in as much as an 16 Tcf reduction in reserves (under the high scenario) compared to the base case, a 13% decrease in reserves.

Under advanced technology conditions at \$2.00 per Mcf, 155 Tcf of unconventional gas reserves are recoverable when no incremental environmental compliance costs are assumed. In the high environmental scenario, 34 Tcf become uneconomic to develop because of increased compliance costs, a 22% reduction over the reference case. Lesser amounts become uneconomic under the other, less severe environmental scenarios. At higher prices of \$5.00 per Mcf, up to 37 Tcf of recoverable unconventional gas reserves become uneconomic under advanced technology conditions and the high environmental scenario, an 11% decrease in reserves relative to reference conditions.

Economically recoverable unconventional gas reserves estimates under the various environmental and technological conditions considered are summarized for two natural gas prices in Table VI-15 and in Figures VI-5 and VI-6, for the implemented and advanced technology conditions, respectively.

TABLE VI-15
POTENTIAL CUMULATIVE IMPACT OF ENVIRONMENTAL
INITIATIVES ON DOMESTIC NATURAL GAS SUPPLIES
(Trillion Cubic Feet)

	<u>Implemented Technology</u>		<u>Advanced Technology</u>	
	<u>\$2.00/Mcf</u>	<u>\$5.00/Mcf</u>	<u>\$2.00/Mcf</u>	<u>\$5.00/Mcf</u>
Tight Gas				
Base Case	24	66	93	182
Low Scenario	18	62	85	180
Medium Scenario	16	60	81	178
High Scenario	12	55	75	172
Coalbed Methane				
Base Case	9	16	30	41
Low Scenario	8	16	28	41
Medium Scenario	8	16	28	41
High Scenario	8	15	22	36
Devonian and Antrim Shale				
Base Case	16	42	32	103
Low Scenario	14	40	32	98
Medium Scenario	13	39	31	98
High Scenario	9	38	24	81
Total Unconventional Gas				
Base Case	49	124	155	326
Low Scenario	40	118	145	319
Medium Scenario	37	115	140	317
High Scenario	29	108	121	289

Figure VI-5
Unconventional Gas
Cumulative Impact of Environmental Regulation
Implemented Technology Case

Figure VI-6
Unconventional Gas
 Cumulative Impact of Environmental Regulation
 Advanced Technology Case

VII. Costs and Benefits of Environmental and Siting Regulations Affecting Domestic Oil and Gas Refineries

There are three broad categories of environmental legislation and regulations affecting the U.S. petroleum refining industry:

- Restrictions on petroleum product specifications and content
- Air, water, and solid waste stationary source restrictions
- Federal and state siting restrictions for new refineries.

These three forms of regulatory control may adversely affect the economic performance of petroleum refineries, lead to the closure of marginal U.S. refineries, and thereby increase U.S. energy vulnerability by making the U.S. more dependent on foreign sources for petroleum products.

Petroleum product specification restrictions include EPA regulations promulgated under the Clean Air Act limiting the Reid Vapor Pressure (RVP) of gasoline and the sulfur content of diesel fuel. Stationary source regulations include the hazardous waste regulatory program promulgated under the authority of the Resource Conservation and Recovery Act as well as the hazardous air pollutant components of the Clean Air Act amendments recently passed by both houses of Congress. Federal and state siting restrictions include New Source Performance Standards promulgated under the Clean Air Act.

Petroleum refineries must make capital investments to modify refining processes in order to comply with petroleum product specifications. However, since all refineries, domestic and foreign, selling petroleum products in the U.S. market must comply with these product specifications, U.S. refineries are not placed at an inherent competitive disadvantage relative to their foreign competitors. As a result, U.S. refineries should be able to recover the costs of complying with these product specification regulations. However, some U.S. refineries, particularly small, simple ones, may elect to shut down rather than make the significant capital investment required to comply with product

specification regulations. A loss of U.S. refining capacity will increase U.S. energy vulnerability by making the U.S. more dependent on foreign sources for petroleum products.

In contrast, foreign refineries are not subject to U.S. stationary source regulations controlling air, water, and solid waste emissions from petroleum refineries. As a result, U.S. refineries may not be able to recover the compliance costs associated with stationary source regulations. Consequently, stationary source regulations may place U.S. refineries at a competitive disadvantage relative to foreign competition and may lead to closure of some marginal refineries. Again, a loss of domestic refining capacity would increase petroleum product imports and raise the level of U.S. energy vulnerability.

The third type of regulatory control, federal and state siting restrictions, may also lead to additional refinery costs. In addition, siting restrictions may limit the construction of new and the expansion of existing U.S. refineries. Given the rising demand for petroleum products in the U.S., siting restrictions could lead to an increase in foreign petroleum product imports, thereby raising the level of U.S. energy vulnerability.

While each of these three types of environmental restrictions can negatively impact the U.S. petroleum refining industry, the following section focuses only on the impact of the hazardous air pollutant components of the proposed amendments to the Clean Air Act.

A. SOURCE OF INCREMENTAL COMPLIANCE COST ESTIMATES

Estimates of the costs that may be incurred by the U.S. refining industry to comply with the hazardous air pollutant components of the Clean Air Act amendments were taken from two reports. Cost estimates for the entire U.S. refining industry were taken from a report prepared by the Delta Management Group for the American Petroleum Institute (Jones, Marfin and Hoffman, 1989). In a report prepared for the Office of Fossil Energy of the U.S. Department of Energy, ICF Resources used the API cost analysis to develop compliance cost estimates for representative simple and complex U.S. refineries (ICF Resources, 1989b).

The cost estimates developed in these two reports were based on the Administration's proposed amendments to the Clean Air Act. Both the Senate and House of Representatives have since passed new Clean Air Act legislation. Consequently, the following cost estimates do not reflect any changes made to the Administration's Clean Air bill by Congress.

B. ALTERNATIVE REGULATORY SCENARIOS FOR THE PETROLEUM REFINING INDUSTRY

The existing process for regulating hazardous air pollutants under the provisions of the Clean Air Act has proven difficult to implement:

- To date, final National Emission Standards for Hazardous Air Pollutants (NESHAP's) have been promulgated for only seven chemicals.
- Currently, the Clean Air Act stipulates that the NESHAP must provide an "ample margin of safety to protect the public health." Determining a margin of safety for individual chemical compounds that is acceptable to industry and environmentalists alike, that is not cost prohibitive, and that can withstand legal challenge has been extremely difficult and time consuming.

The proposed process for controlling hazardous air pollutants in the amendments to the Clean Air Act is substantially different from the existing regulatory approach:

- Prespecified List. The air toxic chemicals to be regulated would be listed specifically as part of the legislation, thereby bypassing the process under existing law that requires EPA to formally list a substance as an air toxic before developing a proposed rule.
- Source Categories. Rather than regulating individual hazardous air pollutants, the proposed legislation would regulate all hazardous air pollutants by source category (e.g., petroleum refineries). EPA would be required to provide the list of major source categories. Regulating source categories would allow EPA to control numerous air pollutants with a single regulation.
- Level of Control Technology. Under current law, the control technology required to reduce air toxic emissions is tied to the measure of acceptable risk. In contrast, the proposed legislation contains language requiring the use of the maximum achievable control technology (MACT). The bill requires EPA to define MACT for each source category. Risk would not be a determinant of the control technology required under the proposed legislation.

- Timing of Risk Determination. The proposed legislation requires that after MACT has been installed, a residual risk determination be made to assess whether further emission controls are required. The risk determination is shifted from the beginning to the end of the regulatory process. Thus, this approach would permit the maximum currently achievable reductions in air toxic emissions to occur prior to the problematic risk determination process that has brought progress to a standstill under current regulations.

Two alternative regulatory scenarios for controlling hazardous air pollutants from the petroleum refining industry were developed. These scenarios are not intended to represent an assessment of the most likely regulatory developments, nor do they represent the recommended regulatory approach of any agency, institution, or association. Rather the scenarios are designed to bound the range of possible cost impacts that could result.

The first regulatory scenario represents a case in which EPA is assumed to interpret the MACT appropriate for controlling air toxic emissions from refineries to be equivalent to control technologies currently required in California non-attainment areas.¹ Because of serious air quality non-attainment problems, California has generally more stringent air quality regulations than most other states and the federal government.

The major components of the first regulatory scenario include:

- Monthly inspection and maintenance of fugitive emission sources
- Modification of cone roof storage tanks
- Installation of vapor recovery systems at all refinery marine loading facilities.

The second regulatory scenario assumes that MACT is interpreted by EPA to require additional and more costly technologies that are not regularly used by the petroleum refining industry. Thus, all of the compliance costs of the first scenario are also incurred in the second scenario. In addition, in the second scenario incremental costs are also incurred for the following items:

¹ For example, the South Coast Air Quality Management District has had regulations in place since 1982 that stipulate monthly inspection of pumps, valves, flanges, and compressors at petroleum refineries.

- Leakless equipment to control fugitive emissions
- External and internal floating roofs for non-cone roof tanks.

Leakless equipment will be used to replace currently installed conventional valves, flanges, pumps, and compressors. Leakless equipment refers to components which have little or no fugitive emissions. It represents a technology-based solution to fugitive emissions rather than relying solely on improved inspection and maintenance.

C. IMPACT OF HAZARDOUS AIR POLLUTANT LEGISLATION ON REFINERY MARGINS

The cost of compliance with the legislation would depend on the definition of MACT that is adopted. Based on the analysis conducted by Delta Management Group for API (Jones, Martin, and Hoffman, 1989), compliance costs could be as follows:

- Minimum costs would be incurred if EPA interprets MACT to be equivalent to control measures currently required in California and other non-attainment areas. These measures would include improved inspection and maintenance programs and might have capital costs of only \$1.3 billion, in 1989 dollars.
- Maximum costs would be incurred if EPA interprets MACT more aggressively, leading to higher cost control strategies, or if further controls are required as a result of a residual risk determination. Control strategies in this scenario would include the installation of leakless valves and pumps. Total compliance costs could rise to \$15.0 billion, in 1989 dollars.

ICF Resources estimates that API costs would yield annualized per barrel costs of compliance between \$0.07 and \$0.50 per barrel. With a lenient MACT interpretation, compliance costs for refineries were estimated to be about \$0.07 per barrel. With a stringent MACT interpretation, compliance costs would vary. Typical refinery costs would range from \$0.31 to \$0.41 per barrel. For a simple refinery, compliance costs would range from \$0.41 to \$0.51 per barrel, as shown in Figure VII-1.

Figure VII-1

Annualized Cost of Proposed Hazardous Air Pollutant Legislation (Including Operational and Maintenance Costs)

D. ECONOMIC IMPACT OF REGULATIONS

The impact of these compliance costs would depend on the U.S. refining industry's financial condition during the implementation period and each refinery's financial situation.

Refineries located in the Gulf Coast provide the marginal barrel of product to other regions, and have tended to have lower profit margins than refineries located in other regions of the U.S., and would be most at risk from the legislation (Figures VII-2 and VII-3).

Refineries on the U.S. Gulf Coast operated at a loss over much of the period from 1984 through 1987 due primarily to declining consumption, excess refinery capacity, and low capacity utilization. Financial performance showed marked improvement in 1988 and 1989 due to rising demand and capacity utilization. Refinery margins should remain strong in the near-term due to strong demand growth and high refinery capacity utilization.

Small, simple refineries with no specialty products or market niche have had worse financial performance than larger, more complex refineries. Most small refineries on the U.S. Gulf Coast that did not make specialty products like asphalt have closed down since 1980.

In 1987, a generally bad year for the petroleum refining industry, while typical refineries on the Gulf Coast were estimated to have cash operating losses of about \$0.10 per barrel, simple refineries were estimated to have lost about \$0.75 per barrel.

In 1988, a much better year in general for the refining industry, typical U.S. Gulf Coast refineries were estimated to have cash operating margins of \$1.41 per barrel, while simple refineries were estimated to have continued to lose money, with operating losses of \$0.25 per barrel, as shown in Figure VII-4.

Because U.S. Gulf Coast refineries have the lowest operating margins, the proposed hazardous air pollutant legislation could cause them the most difficulty. If EPA interprets MACT to require more costly technology-based improvements, profit margins for typical U.S. Gulf Coast refineries may be sharply cut and some small, simple refineries may be forced to shut down.

Figure VII-2

Typical Refinery Operating Margins in 1988

Figure VII-3

U.S. Gulf Refinery Typical Operating Margins

Figure VII-4

U.S. Gulf Refinery Operating Margins

Under high profitability conditions as in 1988, typical U.S. Gulf Coast refinery profit margins are estimated to decline from \$1.41 per barrel to \$1.00 per barrel, a decline of 29 percent. Operating losses for Gulf Coast simple refineries are estimated to increase from \$0.25 per barrel to \$0.75 per barrel. Continued losses of this order of magnitude may cause the few simple refineries on the Gulf Coast to close (Figure VII-5 and VII-6). (Small, simple refineries account for only about 2 percent of U.S. refining capacity.)

Under the low profitability conditions, typical U.S. Gulf Coast refinery operating losses would increase from \$0.10 per barrel to \$0.51 per barrel. Small, simple refineries in the Gulf Coast would see their losses rise from \$0.75 per barrel to \$1.25 per barrel. Continuing losses of this order of magnitude could lead to the closure of small, simple refineries as well as some marginal larger refineries in the Gulf Coast region.

E. SUMMARY AND CONCLUSIONS

The above analysis examined the impact of the hazardous air pollutant legislation as contained in the proposed Clean Air Act Amendments on the U.S. refining industry. These cost estimates are provided as an illustration of the potential impact of stationary source regulations on the U.S. refining industry.

The hazardous air pollution legislation could have a substantial adverse impact on refinery profit margins. Some marginal refineries could opt to close down. The impact of the hazardous air pollutant legislation on U.S. petroleum refineries will critically depend on EPA's interpretation of the Maximum Achievable Control Technology concept.

The impact of the proposed legislation could be largest in the Gulf Coast region, where profit margins are lower due to strong competition. However, small refineries in isolated locations could also be adversely affected.

The concurrent imposition of fuel specification regulations would exacerbate the small refinery's plight. Although the costs of fuel specification regulations are incurred by all refiners supplying the U.S. market and can generally be passed on to consumers, they do require that refiners

Figure VII-5

U.S. Gulf Refinery Margins High Profitability

Figure VII-5

Figure VII-6

U.S. Gulf Refinery Margins **Low Profitability**

make substantial capital investments. While petroleum refineries may be willing to make the investments required to comply with fuel specification regulations, the concurrent large investments potentially required by hazardous air pollutant legislation and other stationary source regulations may lead marginal U.S. refineries to decide to shut down.

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