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ASSESSMENT OF ECONOMIC IMPACTS OF OFFSHORE AND COASTAL DISCHARGE REQUIREMENTS ON PRESENT AND FUTURE OPERATIONS IN THE GULF OF MEXICO

Final Report

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By
Continental Shelf Associates, Inc.

June 1996

Performed Under Contract No. DE-AC22-92MT92001

Continental Shelf Associates, Inc.
Jupiter, Florida

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

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Assessment of Economic Impact of Offshore and Coastal Discharge Requirements on Present and Future Operations in the Gulf of Mexico

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

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ABSTRACT

The high potential costs of compliance associated with new effluent guidelines for offshore and coastal oil and gas operations could significantly affect the economics of finding, developing, and producing oil and gas in the Gulf of Mexico. This report characterizes the potential economic impacts of alternative treatment and discharge regulations for produced water on reserves and production in Gulf of Mexico coastal, territorial and outer continental shelf (OCS) waters, quantifying the impacts of both recent regulatory changes and possible more stringent requirements. The treatment technologies capable of meeting these requirements are characterized in terms of cost, performance, and applicability to coastal and offshore situations. As part of this analysis, an extensive database was constructed that includes oil and gas production forecasts by field, data on existing platforms, and the current treatment methods in place for produced water treatment and disposal on offshore facilities. This work provides the first comprehensive evaluation of the impacts of alternative regulatory requirements for produced water management and disposal in coastal and offshore areas of the Gulf of Mexico.

EXECUTIVE SUMMARY

More stringent environmental compliance requirements for produced water and produced sand discharges from coastal and offshore oil and gas facilities worldwide are compelling operators to assess and implement new processes and technologies for produced water treatment and disposal. The high potential costs of complying with increasingly stringent requirements in the U.S. could significantly impact the economics of finding, developing, and producing offshore oil and gas resources. This impact could be the greatest in the Gulf of Mexico, an area currently providing a significant portion of U.S. oil and gas supplies. As requirements become more stringent, many in industry and government are questioning whether the costs associated with these requirements are justifiable relative to the environmental benefits that result.

The U.S. Department of Energy (DOE) sponsored a study to assess the environmental and economic impacts associated with produced water discharges in the Gulf of Mexico. This report addresses only one aspect of this complex analysis -- the economic impacts of recently enacted and potential future requirements on produced water and produced sand discharges on the U.S. petroleum industry and on U.S. supplies of oil and gas. This report addresses the following areas:

- A brief summary of historical and current regulatory developments affecting produced water and produced sand discharges from offshore oil and gas facilities, as well as factors that could affect the direction of future requirements;
- A characterization of current technologies and practices used on offshore facilities in the Gulf of Mexico, to serve as a baseline for determining likely facility upgrades required;
- A description and comparison of the technologies and practices available for compliance with current and potential future requirements;
- An overview of the analysis methodology, data, and regulatory scenarios developed for this assessment; and
- An assessment of the impacts likely to result from new and potential future Federal and State regulatory requirements, measured in terms of:

- Incremental costs to the petroleum industry
- Current and future reductions in offshore oil and gas production
- Potentially recoverable oil and gas reserves that could become uneconomic to develop
- Lost revenues to Federal and State treasuries
- Lost government revenues from offshore lease sales.

It is important to note that this report focuses on the economic impact of potential produced water discharge effluent guidelines and new source performance standards in terms of the incremental costs incurred by the petroleum industry, the impacts of these incremental costs on future oil and gas supplies, and the impacts of decreased supplies on revenue collected by State and Federal treasuries. Evaluation of the possible economic impacts associated with reduced environmental degradation resulting from decreased discharges to offshore and coastal environments was not assessed as part of this effort.

It is also important to note that the majority of the analysis in this report was performed in the fall of 1993. Consequently, the analyses do not represent regulatory and operational developments taking place between the fall of 1993 and the eventual publication of the final report. Most notable is the fact that the Region 6 general permit for produced water discharges which became effective in February 1995, now prohibits discharges in Texas coastal waters, a requirement not considered in the baseline when the analyses were originally conducted.

ES.1 Produced Water and Produced Sand Technology Characterization

Offshore oil and gas operations take place in an extremely variable set of circumstances and environmental settings, even within a particular region. In response to this diversity, numerous operational and technological options are available to treat and dispose produced waters and sands. Any attempt to characterize and evaluate the costs and environmental performance of technologies for produced water and sand management and disposal must be done using a number of interrelated qualitative and quantitative criteria. These criteria underlie the decision-making process operators utilize when selecting a management and disposal technology. Several such criteria were developed to allow for the evaluation and comparison of each technology considered in this analysis:

- The *applicability* of each treatment technology;
- The *availability* of a technology as a result of successful field applications;
- A technology's *effectiveness* at removing contaminants from produced water;
- The *cost* of each treatment technology; and
- The *exposure pathways* (through which marine life or humans could be exposed to contaminants) associated with various treatment technologies applicable in offshore settings.

As summarized in **Table ES.1**, the produced water and produced sand treatment technologies considered in this analysis have been rated based on their typical applicability, availability, effectiveness, and cost.

ES.2 Overview of Assessment Methodology

Existing and anticipated future Federal and State offshore discharge requirements were assessed in terms of their potential impacts on existing production operations and on the exploration and development of oil and gas fields that remain to be discovered in the Gulf of Mexico. The analysis methodology used data bases and computer models previously developed by ICF Resources (1990) for DOE, some of which have been extensively used to conduct analyses similar to that undertaken in this task, and others that were built explicitly for this effort.

Evaluating the impact of alternate produced water and produced sand treatment and disposal practices requires explicit characterization of existing and potential oil and gas resources in the Gulf of Mexico which could be affected. To perform this analysis, data were developed at the field level for water discharges, water injection, and platform characteristics. For analytical purposes, the Gulf of Mexico was divided into six areas: Texas coastal, Texas State waters, Louisiana coastal, Louisiana State waters, central Federal outer continental shelf (OCS), and western Federal OCS.

Table ES.1. Oil and grease ratings of produced water treatment systems by four evaluation criteria.[a]

Treatment System/Technology	Typical Application	Availability[b]	Effectiveness[c]	Capital Cost	Operating Cost
Induced Gas Flotation (IGF)	Gas only platform, sufficient space	BAT	High	100%	100%
Plate Coalescer, then IGF	Oil platform, medium difficulty in treatment	BAT	High	140%	160%+
IGF, Media Filtration, then Reinjection	Tight disposed formation	Medium	Very High	1000%	1000%+
IGF, then Reinjection	Highly permeable disposal formation	High	Very High	700%	500%
Hydrocyclone	Widely applicable, especially where small footprint required	Medium	High	100%	90%
Centrifuge	Widely applicable, especially where small footprint required	Medium	High	290%	80%
Membrane Filtration	Uncertain performance to date	Low	Medium	190%[d]	90%[d]

Footnotes:

[a] Ratings are based on data collected by EPA and Industry for the Offshore Guidelines and peer reviewed studies. Other publicly available information is also used. Data have been evaluated, then used for ratings. All ratings are relative to improved gas flotation (IGF), which EPA selected as the basis for Offshore BAT.

[b] Availability means that the technology is demonstrated as successful in applications on produced water and, from a technical achievability standpoint, could be considered to be available. The rating are low, medium, or high, and are compared to improved gas flotation (IGF). The rating does not consider cost or other factors, such as non-water quality considerations or energy requirements, which might make the technology impractical.

[c] Effectiveness is a percentage estimated for the system with the BAT technology assumed to be highly effective for the given typical application. Effectiveness means the capability to remove more or less oil and grease than BAT technology, whose long-term average is 23.5 mg/l, as determined by EPA from OOC and EPA data (p. XII-25, 1993 Development Document, EPA 1993a).

[d] Cost data for membrane materials is highly uncertain.

The impacts of the new and potential future discharge requirements were evaluated for three future price scenarios:

- Real oil prices (i.e., West Texas Intermediate) remain constant at $20 per barrel (bbl), with real gas prices constant at $2.00 per million Btu (MMBtu);
- Real oil prices remain constant at $16/bbl, with real gas prices constant at $1.50/MMBtu; and
- 1994 Energy Information Administration (EIA) Annual Energy Outlook reference case oil and gas price forecast, as summarized in **Table ES.2.**

Table ES.2. Reference case oil and gas price forecast (From: EIA, 1994).

Year	World Oil Price (1992 $/bbl)	Natural Gas Average Wellhead Price (1992 $/Mcf[a])
1994	18.20	1.75
2000	20.72	2.42
2005	24.90	2.89
2010	28.16	3.47

Footnotes:

[a] 1 Mcf = 1.031 MMBtu

The impacts of new and possible future Federal and State regulations addressing produced water discharges in the Gulf of Mexico can be characterized in a variety of ways. For purposes of this report, several types of impacts are presented:

- Incremental costs (both investment and annual operating and maintenance) incurred for operators to comply with the requirements;
- Impacts of the requirements on future production from known producing offshore and coastal fields, at various points in time;
- Impacts of the requirements on the reserves potential in fields remaining to be discovered; and
- Public sector revenues (i.e., corporate income taxes, State severance taxes, and royalties) lost as a result of new compliance requirements.

Three possible future scenarios were considered in this analysis to represent the range of potential costs and impacts associated with the new or potential future regulatory requirements for produced water discharges from oil and gas facilities in offshore and coastal waters. These impacts were assessed explicitly for each of the regions considered, for each of the three price scenarios. The impacts were estimated for two future regulatory cases. The first regulatory case considered the change from existing requirements (i.e., at the time the analysis was prepared) to the current, newly imposed requirements. A second regulatory case considered a change from existing requirements to full zero discharge requirements in all areas. These new requirements were assumed to go into effect in 1993. This date reflects the timeframe in which this analysis was performed. Assuming that the *same* scenarios were implemented at a later date would slightly reduce the impacts observed (as some production was lost due to natural declines). The three scenarios assumed in this analysis are described below:

<u>"Existing" Requirements</u>

- This scenario assumes the effluent standards that were applicable in 1993, predating the recent change to the Federal effluent limitations guidelines and modification to the Region 6 OCS general permit (effective January 4, 1994). These standards are 48 mg/l monthly average and 72 mg/l daily average for oil and grease content in produced water discharges; and

- This scenario does *not* include the existing Louisiana requirement for discontinuation of discharges in coastal areas by January 1, 1995.

<u>New Requirements</u>

- This scenario is based on the new Federal effluent limitations guidelines and their implementation through general permits at the regional level (i.e., 29 mg/l monthly average and 42 mg/l daily maximum);

- This scenario includes the existing Louisiana requirement for the discontinuation of discharges in coastal areas by January 1, 1995;

- No change in the requirements applicable to the Texas coastal area is assumed;

- Under this scenario, operations in Louisiana coastal areas will be converted to injection to comply. For other areas, upgrades to existing equipment will be considered as needed for compliance. Unless alternative equipment that meets the new standard is already installed, improved gas flotation is assumed to be the applicable technology for produced water treatment; and

- This scenario represents the latest Federal and State requirements regarding the offshore and coastal discharge of produced water, as effective January 4, 1994, with full compliance by July 1994.

Full Zero Discharge

- This most stringent scenario assumes that a zero discharge standard for produced water is applicable in all coastal and offshore areas;
- All operations will be converted to injection for compliance. Where slots are not available on a platform for reinjection, produced water will be piped to a nearby platform or to shore, depending upon location; and
- This scenario provides a ceiling for potential compliance costs and impacts on resource recovery.

ES.3 Incremental Industry Compliance Costs

Future environmental requirements could result in substantial increases in industry expenditures for environmental compliance. Compliance expenditures resulting from the new requirements already promulgated could result in the industry spending from $600 to $630 million by 2000 in currently producing fields, depending on future prices, and from $810 to $920 million by 2010. If a zero discharge requirement was promulgated throughout the Gulf of Mexico beginning in 1993, operators of currently producing fields would have to expend from $2.2 to $2.5 billion by 2000, and from $2.8 to $3.3 billion by 2010, depending on future prices. This amounts to average incremental expenditures of $180 to $200 million per year. To put this in perspective, this corresponds to approximately 70 fewer production wells drilled per year due to a decrease in available cash flow, notwithstanding the impact of the requirements on future production economics.

ES.4 Impacts on Production from Currently Producing Fields

In addition to their impact on industry expenditures, new standards for offshore produced water discharges could impact oil and gas production from currently producing fields in the Gulf of Mexico. Assuming promulgation of new, more stringent regulatory requirements in 1992, an initial drop in annual production of 600,000 to one million bbl in 1995 could result, depending on price. Gas production could drop by 4 to 9 billion cubic feet per year (Bcf/yr), again depending on prices. Under the possible zero discharge scenario, depending on future prices, oil production in the entire Gulf of Mexico could drop by as much as 6 to 8 million bbl/yr in 1995, and by more than 2 million bbl/yr in 2000. Gas production could drop by as much as 25 to 58 Bcf/yr in 1995 because of the zero discharge requirements, and by as much as 11 Bcf/yr in 2000.

The impacts of the new and possible future regulatory requirements are even more significant when examined from the perspective of total reserves lost. By the year 2010, from 7 to 10 million bbl of oil and 54 to 76 Bcf of gas will not get produced from known producing fields because of the new discharge requirements, depending upon price. Under a zero discharge scenario, again depending on price, from 43 to 58 million bbl of oil and from 238 to 421 Bcf of gas that would otherwise be economic would not be produced by the year 2010.

ES.5 Impacts on Reserves in Fields Remaining to be Discovered

New and potential future environmental compliance requirements could also impact the economics of exploration for and development of new oil and gas fields in the Gulf of Mexico. Because of the already high costs associated with exploration for and development of currently undiscovered fields, the new discharge standards will not significantly impact future reserves. Nonetheless, the costs of developing these prospects will certainly increase, resulting in a maximum impact of 191 million bbl of reserves lost (a 3% reduction in otherwise recoverable reserves) under the 1994 AEO price scenario evaluated. Under a zero discharge requirement, on the other hand, from 785 million to 1.2 billion bbl of otherwise economic crude oil reserves are estimated to become uneconomic, depending on future prices; this represents a 10% to 20% reduction in economically recoverable reserves.

The impacts on undiscovered gas reserves could be even more significant. Depending on future prices, from 5 to 37 trillion cubic feet (Tcf) of otherwise economic reserves could become uneconomic because of the proposed standards, a 7% to 35% drop in otherwise economic reserves.

ES.6 Impacts on Public Sector Revenues

Future environmental compliance requirements on oil and gas exploration and production operations will also impact revenues collected by Federal and State governments as a result of offshore and coastal oil and gas production. Industry compliance with new standards for offshore produced water discharges are estimated to result in estimated lost revenue to public sector treasuries (i.e., both State and Federal) from producing fields. Lost revenue estimates range from $250 to $260 million between now and the year 2000, depending on future prices. By the year 2010, from $360 to $400 million could be lost. This represents a 1% to 2% loss in public sector revenues otherwise collected from oil and gas production in currently producing fields. If a zero discharge requirement is imposed on all currently producing fields in the Gulf of Mexico, depending on future oil and gas prices, from $0.9 to $1.0 billion in public sector revenues could be lost by the year 2000, a reduction of 5% from that otherwise received. By 2010, from $1.2 to $1.4 billion in public sector revenues could be lost.

New environmental compliance requirements could also impact public sector revenues ultimately received from production from oil and gas fields that remain to be discovered in the Gulf of Mexico. Compliance with the new standards for offshore produced water discharges could result in ultimate estimated losses in public sector revenues of $100 to $160 million, depending on price, from production from currently undiscovered fields. If a zero discharge requirement was universally imposed on offshore produced water discharges, from $10 to $25 billion in total public sector revenues could be lost from production of currently undiscovered oil and gas reserves in the Gulf of Mexico. In addition, nearly $100 million of ultimate public sector revenues from lease bonus payments could be lost as a result of a zero discharge requirement imposed on oil and gas production operations in the entire Gulf of Mexico.

ES.7 Conclusions

The high potential costs of compliance associated with new effluent guidelines for offshore and coastal oil and gas operations could significantly affect the economics of finding, developing, and producing oil and gas in the Gulf of Mexico. Regulations on the discharge of produced water generated from offshore oil and gas operations in the Gulf of Mexico are becoming increasingly stringent, reducing the options available for many producers to comply. Future trends indicate that requirements on produced water discharges are likely to continue to become more stringent. The impacts of these requirements can be significant, posing considerable compliance cost burdens on industry. The nation would also be affected by a reduction in domestically produced oil and gas that would need to be replaced by imports.

1.0 BACKGROUND

More stringent requirements for produced water and produced sand discharges from coastal and offshore oil and gas facilities are compelling operators to assess and potentially implement new processes and technologies for produced water treatment and disposal. Potential alternatives are considered relative to conventional gas flotation and plate coalescer systems, along the industry standards for removing oil and grease from produced water. These potential alternative systems include hydrocyclones, centrifuges, and membrane filtration units. In some areas considered environmentally sensitive, discharges of produced water have been severely restricted or prohibited, requiring that produced water be reinjected or transported by pipeline to shore for disposal.

1.1 Impetus for Report

The high potential costs of complying with these increasingly stringent environmental compliance requirements could significantly impact the economics of finding, developing, and producing both known and currently undiscovered offshore and coastal resources. This impact could be the greatest in the Gulf of Mexico, an area currently providing a significant portion of domestic oil and gas supplies and one that can be expected to continue to contribute to future energy supplies. As requirements become more stringent, many in industry and government have begun questioning whether the costs associated with these requirements are justifiable relative to the environmental benefits that result.

The U.S. Department of Energy (DOE) sponsored a study to assess the environmental and economic impacts associated with produced water discharges in the Gulf of Mexico. The objective of this effort is to increase scientific knowledge concerning: a) the fate and environmental effects of organics, trace metals, and naturally occurring radioactive materials (NORM) in water, sediment, and biota near several oil and gas facilities; b) the characteristics of produced water and sand discharges as they pertain to organics, trace metals, and radionuclide variability; c) the ecological recovery of the seabed near terminated produced water discharge sites in wetlands and open bays of Louisiana; d) the economic and energy supply impacts of existing and anticipated Federal and State offshore and coastal discharge regulations; and e) the catch, consumption and human use patterns of seafood species collected from coastal and offshore waters.

1.2 Structure and Objective of this Report

This report addresses only one aspect of this complex analysis -- the economic impacts of recently enacted and potential future requirements on produced water and produced sand discharges on the U.S. petroleum industry and on U.S. supplies of oil and gas. This report will cover the following areas:

- A brief summary of historical and current regulatory developments affecting produced water and produced sand discharges from offshore oil and gas facilities, as well as factors that could affect the direction of future requirements;
- A characterization of current technologies and practices used on offshore facilities in the Gulf of Mexico, to serve as a baseline for determining likely facility upgrades required;
- A description and comparison of the technologies and practices available for compliance with current and potential future requirements;
- An overview of the analysis methodology, data, and regulatory scenarios developed for this assessment;
- An assessment of the impacts likely to result from new and potential future Federal and State regulatory requirements, measured in terms of:
  - Incremental costs to the petroleum industry
  - Current and future reductions in offshore oil and gas production
  - Potentially recoverable oil and gas reserves that could become uneconomic to develop
  - Lost revenues to Federal and State treasuries.
- An assessment of the potential impacts of current and future requirements on offshore oil and gas lease sales;
- An overview of all of the major Federal environmental statutes and regulations affecting offshore oil and gas operations; and
- A comparison of the economic impacts on industry found in this assessment with the impacts identified in previous analyses.

It is important to note that this report focuses on the economic impact of potential produced water discharge effluent guidelines and new source performance standards in terms of the incremental costs incurred by the petroleum industry, the impacts of these incremental costs on future oil and gas supplies, and the impacts of decreased supplies on revenue collected by State and Federal treasuries. Evaluation of the possible economic impacts associated with reduced environmental degradation resulting from decreased discharges to offshore and coastal environments was not assessed as part of this effort.

It is also important to note that the majority of the analysis in this report was performed in the fall of 1993. Consequently, the analyses do not represent regulatory and operational developments taking place between the fall of 1993 and the eventual publication of the final report. Most notable is the fact that the Region 6 general permit for produced water discharges which became effective in February 1995, now prohibits discharges in Texas coastal waters, a requirement not considered in the baseline when the analyses were originally conducted.

1.3 Regulatory Developments

The applicable requirements for produced water discharge quality are dependent upon where the facility is located -- Outer Continental Shelf (OCS) [Federal offshore], State waters [territorial seas], or coastal. Discharge requirements have changed recently or are in the process of being amended in each of these areas. The applicable requirements for each area are discussed below.

1.3.1 Offshore Requirements

Effluent limitations guidelines are Federal standards that specify the allowable composition of effluent discharges. These guidelines are based on specific, available technologies that are determined to be economically feasible for meeting the proposed standards. Dischargers retain the option of using any treatment technology they choose, as long as they meet the standards that are established in the guidelines.

The effluent guidelines provide a basis for regional offices of the Environmental Protection Agency (EPA) to develop discharge permits. These permits must be at least as stringent as the Federal guidelines, but may be more stringent. Because of the large number of facilities operating offshore (particularly in the Gulf of Mexico), permitting each facility individually could be administratively difficult. Consequently, the EPA regions often issue general permits. The requirements of these general permits apply to all operations in the region unless they can demonstrate a strong rationale for alternative requirements. These general permits spell out the requirements with which operators must comply, and typically remain in force for a period of five years.

Until recently, most offshore oil and gas facilities in the U.S. have been discharging produced water and produced sand under permits following effluent guidelines issued in the late 1970s. These guidelines limited the oil and grease content of produced water discharges to 48 milligrams per liter (mg/l) as a monthly average, with a maximum level of 72 mg/l for any daily discharge. The EPA began attempting to issue new offshore effluent limitation guidelines in 1985. The development of new effluent guidelines proved to be a lengthy process, as summarized briefly below:

- In August 1985, a draft proposed rule (50 FR 34592; August 26, 1985) called for zero discharge of produced water from facilities in shallow water (<20 m), with an oil and grease limitation of 59 mg/l daily maximum and 48 mg/l monthly average in discharges from facilities in deeper water. Extensive industry comments were received by EPA concerning the potential significant impacts of these proposed requirements;

- In November 1990, responding to comments on the 1985 proposal, EPA requested additional information on the various technology-based alternatives under consideration (55 FR 49094; November 26, 1990);

- In March 1991, EPA issued a revised proposed rule (56 FR 10664; March 13, 1991), that responded to many of the commenters' concerns. It called for:

  — Oil and grease limits in produced water of 13 mg/l daily maximum and 7 mg/l monthly average for discharges from facilities within four miles of shore.

  — Continuation of existing requirements (72 mg/l daily maximum and 48 mg/l monthly average) for produced water discharges from facilities further than four miles from shore; and

- Industry again commented on this proposal, stating that the ceramic membrane filtration technology that formed the basis for EPA's proposed standard near shore had not been demonstrated to achieve the specified limits at field conditions, and was not justifiably a "proven" technology on which to base the new standard.

New effluent limitations guidelines and new source performance standards (NSPS) for offshore areas were finalized in a notice issued in March 1993 (58 FR 12454; March 4, 1993). The new guidelines lowered the allowable oil and grease content in produced water discharges to 29 mg/l monthly average, with daily maximum excursions limited to 42 mg/l. These standards were established based on the demonstrated performance of improved gas flotation technology. The guidelines also prohibited the discharge of produced sand. The notice specified an effective date for the guidelines of April 5, 1993, but most operators in the Gulf of Mexico would not be required to meet the more stringent standards until EPA Region 6 (which has jurisdiction over offshore Texas and Louisiana in the Gulf of Mexico) modified its applicable general permit.

During the lengthy period while EPA headquarters attempted to issue new effluent guidelines, Region 6 kept administratively extending the termination date of its existing general permit. In 1991, the Region began developing a revised permit in anticipation of the new effluent guidelines. When the guidelines process appeared to be taking longer than anticipated, Region 6 issued its permit for existing facilities in November 1992 (57 FR 54642; November 19, 1992) with a reopener clause that would allow the effluent standards to be revised when the Federal effluent guidelines were promulgated. Region 6 exercised the reopener clause to update requirements for oil and grease concentrations to those contained in the new Federal guidelines. The effective date for the revised permit was January 3, 1994 (58 FR 64964; December 3, 1993). Recognizing that a substantial number of operators may not be able to comply with the lower oil and grease content standards by this date because insufficient time for installation of new treatment systems was provided in the permit, EPA allowed operators a grace period to install/revamp equipment to achieve compliance. All operators, however, were required to comply with the more stringent standard by July 3, 1994. The Region 6 permit contained additional requirements beyond those in the Federal effluent guidelines, including: no chronic toxicity at the edge of a 100 m mixing zone, a discharge rate limit of 25,000 bbl/day, and a bioaccumulation monitoring study requirement.

Region 6 has also begun to develop an OCS general permit for new sources, which would apply to facilities installed after April 5, 1993. A draft permit was issued on October 14, 1993 (58 FR 53200). However, the issuance of a permit for new sources in the OCS triggers the National Environmental Policy Act (NEPA), thus requiring EPA to assure (i.e., through preparation and approval of an environmental impact statement [EIS]) that this activity would not endanger human health or the environment. The draft EIS was released with the draft permit. Until a general permit is issued, individual facility permits will be required for new sources in the OCS.

Operators in the territorial seas (i.e., State waters up to three miles from the coast) are currently operating under a general permit issued in 1983. Region 6 is working on an updated permit for both existing and new sources in the territorial seas consistent with the new effluent guidelines. Produced water limits for State waters have not yet been developed, but the updated permit will have limits designed to protect State water quality standards. Produced water discharges, at least in the shallower sections of the territorial seas, will probably be prohibited (Huffman, 1994). An EIS has also been required for this area; a draft EIS has been issued. The timing for the draft permit is unclear.

1.3.2 Coastal Requirements

EPA is currently in the process of developing effluent guidelines applicable to coastal areas. The process was initiated with a request for comments on possible actions in the coastal category (54 FR 46919; November 8, 1989). A detailed survey of coastal operators was conducted in 1993. On July 19, 1994, EPA held a public meeting in New Orleans to provide information about its plans for the coastal guidelines. At that meeting, EPA made it clear that it would be promulgating guidelines that mandated zero discharge of produced water in coastal areas. The draft coastal guidelines were issued February 17, 1995 (60 FR 9428), and their finalization is scheduled for July 1996.

Region 6 issued a draft general permit for coastal production operations in December 1992 (57 FR 60926; December 22, 1992). This draft permit would establish a zero discharge standard for produced water and produced sand in coastal areas of the Gulf of Mexico. It recommended the zero discharge standard to control toxic and nonconventional pollutants, the first time that controls have extended beyond oil and grease (which was traditionally assumed to be an indicator for other pollutants). Region 6 finalized its general permit on January 9, 1995 (60 FR 2387). Consistent with the earlier proposal, the permit mandates zero discharge. Operators in coastal areas must comply with this standard by January 1, 1997. This effective data was selected to correspond to the final phase-out of discharges under Louisiana state regulations.

The coastal states along the Gulf of Mexico are also imposing more stringent requirements on discharges to coastal waters. A discharge phase-out (for produced water, produced sand, and other wastes) is in process for Louisiana coastal areas based on regulations promulgated in 1991. Operators with multiple discharges were required to submit a schedule for phasing out discharges according to the following: 1) one-third by January 1, 1993; 2) the second third by January 1, 1994; and 3) final third by January 1, 1995 (Louisiana Department of Environmental Quality, 1991). Operators with a single discharge location were required to discontinue discharges by January 1, 1994. Small producers (i.e., <100 bbl of oil equivalent/day production) are given an extra year to comply, and a few other "hardship" exemptions/provisions that extend discharges until January 1, 1997 are offered. Under this scheduled phase-out, many discharges have already been discontinued.

Texas prohibits the discharge of produced salt water to fresh water locations. Texas issues individual permits for discharges of produced waters. Application requirements, in addition to logistics information, includes a total of 34 parameters. These include a complete mineral, nutrient, and toxic metals analysis; plus analyses for benzene, naphthalene, and phenol as indicators of the presence of toxic organics; and total organic carbon as an indicator of dissolved organic compounds. A case-by-case review is performed on each application, to assure the discharge: 1) will not cause a violation of the Texas Surface Water Quality Standards; 2) will not impact sensitive areas (oyster beds, wetlands, mud flats, etc.); and 3) will not contribute to a Texas Department of Health fish advisory notice. The Railroad Commission of Texas, as of April 1995, has 195 active permits into tidal waters; including 131 into coastal waters, 16 into the territorial seas (0 - 3 miles offshore), and 48 into the OCS waters (3 miles - 10 marine leagues).

1.3.3 Factors that Could Affect Future U.S. Requirements

In addition to the evolving Federal and State regulatory requirements, other recent developments may influence future requirements on discharges from OCS and coastal facilities, as summarized below.

Produced Sand

Federal effluent guidelines provide DOE and the Minerals Management Service (MMS) with the opportunity to provide new information on produced sand, which may be used to reconsider the existing ban on produced sand discharges. EPA has indicated that if the information is persuasive, it could reopen existing permits; "anti-backsliding provisions", which would normally prohibit a relaxation of standards would not apply. The information to be provided by DOE and MMS may include the performance of new sand washing technologies and the characteristics of produced sand, including radionuclide levels.

Naturally Occurring Radioactive Materials

NORM content in produced water discharges may also be targeted by future effluent restrictions. The National Resources Defense Council (NRDC) has filed suit against EPA for failing to regulate NORM levels as part of the recent Federal effluent limitations guidelines for offshore areas. Resolution of the legal issues could take several years, but increased requirements in the future are possible.

Soluble (Dissolved) Oil Content

EPA's effluent standards are currently based on total oil and grease content in produced water -- both soluble (dissolved) and dispersed (free) oil. Currently available treatment technologies are effective in removing dispersed oil, but not soluble oil. Many fields in the Gulf of Mexico typically produce water with soluble oil content of 10 to 20 mg/l, meaning that dispersed oil has to be removed almost completely to meet the existing standard. Any further reduction in the effluent standards could force a substantial number of operators to reinject their produced water. Another area of uncertainty is the test prescribed by EPA to determine whether the oil and grease content in produced water meets effluent standards. EPA is in the process of developing a new testing protocol, and operators are unsure how existing treatment systems will perform based on the new methodology.

2.0 PRODUCED WATER AND PRODUCED SAND TECHNOLOGY CHARACTERIZATION

Offshore oil and gas operations take place in an extremely variable set of circumstances and environmental settings, even within a particular region. In response to this diversity, an even wider set of operational and technological options to treat and dispose produced waters and sands are often available. The ability to develop single estimates of a technology's cost and ability to comply with specific regulatory requirements is inherently uncertain. Therefore, any attempt to characterize and regulate the costs and environmental performance of produced water and sand technologies must be done using a number of interrelated qualitative and quantitative criteria. This section will develop and utilize four criteria to rank treatment and disposal technologies that are feasible for use at offshore oil and gas facilities.

2.1 Treatment and Disposal Technology Utilization Criteria

Specific factors, or criteria, must be developed in order to understand the decision-making process operators go through when selecting a certain produced water management technology. Several criteria have been developed to allow for the evaluation and comparison of each technology to be considered:

- The *applicability* of each treatment technology must be considered. For example, many technologies are effective only for specific ranges of values for certain parameters (e.g., pH or influent concentration). Other factors such as facility design must also be taken into account (e.g., location and number of platform slots);

- The *availability* of the technology as the result of demonstrated successful applications, from a technical perspective, must be characterized;

- A technology's *effectiveness* at removing contaminants from produced water must be considered. For example, while some technologies are very effective at removing oil and grease, they are ineffective at removing NORM and heavy metals. Other technologies may be effective in onshore settings, but may have limited use in offshore settings;

- The *cost* of each treatment technology must also be examined. It is important that both capital and annual operating costs are considered. The different costs represented by an addition to an existing facility compared to a new installation must also be considered. In cases where additional or alternative waste streams are created by a particular process, the costs associated with managing these wastes must also be considered; and

- Various treatment technologies applicable in offshore settings have different *exposure pathways*. For example, alternatives that remove a constituent stream reduce offshore exposure pathways, but increase the potential for onshore exposure pathways.

An overview of each produced water and produced sand treatment and disposal technology is provided below, both in terms of its technical characteristics and the criteria discussed above. Each technology, with the exception of the experimental processes discussed, will then be compared and rated.

2.2 Produced Water Treatment and Disposal Technologies

Clearly, the trend in offshore produced water treatment and disposal requirements is toward increasingly stringent, often technology-based, standards. As technologies for treating produced water continue to evolve, more stringent compliance requirements are likely to follow. However, as discussed in more detail below, new technologies may not be able to achieve acceptable performance levels under all conditions operators are likely to confront, requiring even move sophisticated and expensive technologies in these types of settings. In many cases, reinjection may be the only alternative. Growing concerns about NORM, heavy metals, and other possible constituents of produced water may also force many operators to reinject as their only disposal option.

To determine the technologies and practices necessary to comply with current or potential new treatment requirements for offshore produced water discharges in the Gulf of Mexico, a characterization and comparison of the technologies and practices likely to be utilized to comply with these requirements are provided below.

2.2.1 Characterization of Current Technologies and Practices Utilized in the Gulf of Mexico

In 1992, the Offshore Operators Committee (OOC) conducted a survey of operators in the Gulf of Mexico to determine the equipment upgrades that could be required to meet the new Federal standards for OCS platforms. Data were collected for 292 platforms owned by 13 different companies located in the Federal OCS. Operators were asked to supply the following information: a) 12 sequential months of test data for oil and grease (i.e., monthly maximum, monthly average, number of observations in the average, and any silica-gel tests to quantify the amount of dissolved organics in the discharge stream); b) the type of water treatment equipment currently in use (i.e., primary, secondary, and tertiary); c) whether or not chemicals had been added for treatment; d) if organics were present; and e) the predominant production (oil or gas) stream on the platform.

The following summary statistics were derived from the data collected (Otto and Associates, 1993):

- Roughly 50% of the platforms examined were gas producing, with the other half producing oil;
- Equipment was categorized into one of six types, including skimmer tanks, plate coalescers, hydraulic gas flotation, mechanical gas flotation, hydrocyclones, and filters;
- Gas flotation, skimmer tanks, and plate coalescers were predominately found on gas platforms (42%, 31%, and 26%, respectively);
- Gas flotation units were most frequently found on oil platforms (86%);
- Gas flotation units accounted for nearly 65% of the equipment overall;
- Over 60% of all platforms added chemicals for treatment (87% of the oil platforms, compared to 36% of the gas platforms); and
- In analyzing the relationship between chemical additions and equipment, chemicals were added to more than 70% of the gas flotation units (mechanical and hydraulic), and to less than 40% of the skimmers and plate coalescers.

In order to comply with the new Federal OCS standards for produced water treatment, the following conclusions were drawn from the survey results:

- Implementation of the 42/29 mg/l requirement would result in nearly 35% of the platforms failing the 42 mg/l maximum at least once during the 12 month period (compared to over 12% failing the current 72 mg/l daily maximum);
- Nearly 60% would violate the 29 mg/l monthly average at least once during the test period (compared to under 3% failing the current monthly average of 48 mg/l); this is equally divided between oil and gas platforms;
- Of the 60% in non-compliance, nearly 30% would violate the 29 mg/l monthly average three or more times; and
- Of the non-compliant oil platforms (at least one monthly value over 29 mg/l), almost 90% used gas flotation equipment, 98% used chemicals in treatment and over 77% reported the presence of dissolved organics.

In addition to required effluent characteristics and cost, the proper choice of treatment technology for a specific setting and application also depends, at a minimum, on oil quality, oil droplet distribution solids, particle size, presence and type of other treating chemicals, flow rates of produced water (including its variability), concentrations of oil and grease in produced water (including its variability), water salinity, and inlet pressure fluctuations.

The appropriate choice of technology to meet potential, more stringent requirements for produced water and produced sand discharges in the Gulf of Mexico depends greatly on the site-specific operation conditions for each platform. The following produced water treatment and disposal technologies are considered in this assessment:

- Gas flotation;
- Plate coalescers;
- Media filtration;
- Hydrocyclones;
- Centrifuges;
- Membrane filtration; and
- Reinjection

In addition, brief summaries of several experimental water treatment processes that have been shown to have potential application to oil and gas field produced water treatment are described.

2.2.2 Applicability and Effectiveness of Produced Water Treatment and Disposal Technologies

Gas Flotation

Gas flotation technology, which is the basis for the new EPA effluent limitation guidelines, is the only commonly used produced water treating equipment that does not rely on gravity separation to remove oil and grease from water. This process involves the injection of small gas bubbles below the surface of the produced water. As the gas bubbles rise through the water, the oil droplets adhere to the bubbles, carrying the oil to the surface. The droplets are trapped in the foam that forms on the surface and skimmed off. Two types of gas flotation units have been developed and are distinguished by the method employed to produce the small gas bubbles (Sikes, 1987).

Dissolved gas units take a portion (typically 20% to 50%) of the produced water effluent and saturates it with natural gas in a contactor. The gas-saturated water is then injected into a flotation chamber with the full oily-water stream, where the dissolved gas breaks out of solution as small bubbles, contacting the oil droplets and bringing them to the surface. Dissolved gas units normally require a retention time of 10 to 40 minutes. Dispersed (or induced) gas units inject gas bubbles directly into the total produced water stream, either by the use of an inductor or through a vortex created by mechanical rotors. Most dispersed gas units include three or four individual cells, with water moving from one cell to the next via underflow baffles. In each cell, a portion of the treated water is pumped beneath the oily water. Gas from the vapor space above the water surface is induced into the injected stream, and the bubbles travel to the surface, creating an oily froth. The oil is skimmed from the surface while the clean water exits from the bottom to an adjacent cell. Each cell is designed for a retention time of approximately one minute.

Dissolved gas units have often not worked well in oil field situations. Since these units can be fairly large, available space is often a consideration, particularly offshore.

Problems associated with scale, corrosion, and bacterial growth have also been encountered as a result of introducing a gas into treatment equipment. A recent study of treatment equipment utilized on 43 platforms in the North Sea showed that 27 were equipped with induced gas flotation units (Simms *et al.*, 1990). However, this technology does have a number of drawbacks, including the inability to handle emulsions, sensitivity to platform motion, poor mechanical durability, and the susceptibility to scale/sludge buildup.

Tables 2.1 and **2.2** provide information on the performance of induced gas flotation equipment used at operations at Weeks Island, Louisiana. At flow rates ranging from 860 to 3,430 bbl of water per day (BWPD), induced gas flotation equipment removes from 83% to 92% of the oil in the produced water. With the addition of chemicals, from 88% to 97% of the oil was removed.

Table 2.1. Oil removal performance for induced gas flotation equipment operating without chemicals (From: Schulz, 1993).

Flow Rate (BWPD)	Influent Oil Concentration (ppm)	Effluent Oil Concentration (ppm)	Oil Removal (%)
860	24	2	92
1,710	26	3	88
2,570	30	3	90
3,430	36	6	83

Table 2.2. Oil removal performance for induced gas flotation equipment operating with chemicals (From: Schulz, 1993).

Flow Rate (BWPD)	Chemical Feed (ppm)	Influent Oil Concentration (ppm)	Effluent Oil Concentration (ppm)	Oil Removal (%)
860	5	65	2	97
1,710	3	26	3	88
1,710	5	368	17	95
1,710	10	10	2	95
2,570	5	48	3	94
3,430	2.4	322	23	93

Plate Coalescers

Coalescers employ gravity separation to remove oil and grease from produced water streams. In addition, they simultaneously induce the coalescence of oil droplets to improve separation. There are two basic types of coalescers: 1) parallel plate coalescers, which utilize multiple, parallel surfaces on which oil droplets impinge, coalesce, and travel to the surface; and 2) the corrugated plate intercepter (CPI), a refinement of the parallel plate coalescer. The CPI, which takes up less space (for the same particle size removal capability) at a lower cost than the parallel plate coalescer, utilizes parallel plates that are corrugated (like roofing material), with the axis of the corrugation parallel to the flow direction. As the water is forced downward, the coalesced oil droplets rise upward (i.e., counter to the water flow) and are concentrated at the top of each corrugation (Sikes, 1987).

A CPI unit is seldom used as "stand alone" equipment. They are more commonly used as a unit upstream from primary treating equipment. The new EPA effluent guidelines of 29 mg/l monthly average will further reduce, if not eliminate, the applicability of the CPI as the only equipment for water treatment on oil producing platforms. However, a skimmer followed by a CPI could continue to be used for many offshore gas production facilities.

A CPI is usually designed to remove droplets $\geq$ 50-60 microns (μm) in diameter. By comparison, flotation cells can generally remove droplets $\geq$ 10-30 μm in size. Hydrocyclones and centrifuges remove droplets in the range of 10-20 μm and 2 μm, respectively (K. Arnold, Paragon Engineering, 1993, pers. comm.). In general, a CPI is effective only when the compositional nature and relative volumes of oil and water make separation relatively easy.

Media Filtration

In the early 1950s, produced water was sometimes directed through a bed of wood shavings or similar medium as an aid in coalescing oil droplets. The next generation of filtration units were filters utilizing sand and other granular media. However, such media had a tendency to plug, requiring backwashing. Backwashing is accomplished through flowing a portion of the filtered water back through the filter media in the reverse direction. Some onshore operators have had success with sand filters when the water has already been treated to 25-75 mg/l oil. Granular media filtration as a primary means of removing oil from produced water has never been widely employed in offshore environments. In a recent study of produced water treatment technologies utilized at 43 platforms in the North Sea, only one used a granular media filtration system (Simms *et al.*, 1990).

Granular media filters are efficient at removing dispersed oil, but have a tendency to plug easily. They generally require an influent with less than 25 mg/l oil in water. Filter backwashing is difficult and results in an oily backwash fluid which must be treated again before disposal (Sikes, 1987). This second waste stream can have a much greater potential to damage the environment than the original waste stream, if introduced into the environment (which does not usually occur) (Stephenson and Bartels, 1990).

Hydrocyclone

One of the most promising new technologies for treating produced water in an offshore environment is the hydrocyclone. The basic principle of hydrocyclone operation is that oil and grease particles are separated from produced water by the centrifugal force induced by a swirling flow pattern (i.e., 600 - 1,000 times the force of gravity), and the density difference between oil and water. There are two basic types of hydrocyclones: 1) a static model, where inertial forces result from the internal fluid swirl; and 2) a rotary model, which uses mechanical rotation to generate the vortex (Simms *et al.*, 1990). Because most research and development efforts have focused on the static hydrocyclone, its use has spread into field operations more quickly than the rotary system.

Produced water enters the hydrocyclone at a high pressure through an inlet where the fluid velocity is accelerated. The gentle tapered design of the hydrocyclone helps to maintain the centrifugal acceleration that forces the denser water phase to the outer wall and the oil phase to the center. Clean water flows down the hydrocyclone to an outlet, while the oil flows counter-current to the water stream to an outlet leading to a recycling tank (Choi, 1990).

Hydrocyclones are not "stand-alone" equipment; supporting equipment such as a solids removal strainer, a downstream enhancement vessel, a low shear pump, and chemical injection equipment may all be necessary.

Hydrocyclones possess a number of advantages that make them ideally suited for many offshore applications. These include the following:

- *Compact size* - a hydrocyclone may require one-tenth the platform space of a conventional treatment system;
- *Lightweight* - a conventional treatment system with a treatment capacity of 120,000 BWPD can weigh in excess of 500,000 pounds, while a comparable hydrocyclone system can weigh less than 100,000 pounds;
- *Flexible design* - hydrocyclone units can easily be added as water treatment demands increase; they can also be mounted either horizontally or vertically; and
- *Stability* - hydrocyclones are insensitive to platform motions, making them ideally suited for deep sea and floating structures.

According to Choi (1990), hydrocyclones possess a number of other advantages that make their use applicable in any number of different settings, including: 1) a broad and predictable operating range; 2) quick recovery from upsets; 3) low utility requirements (i.e., a static hydrocyclone has no moving parts); and 4) generally low maintenance requirements (e.g., liners can last in excess of five years).

However, hydrocyclones can suffer from a number of drawbacks that have prevented their widespread application. If sufficient pressure (typically 50 lbs/in^2) is not present to drive the system, a low shear pump may have to be added to the system. As a result, operating and maintenance costs of the system may rise. Also, due to the extremely short residence time of produced water in the system (i.e., about two seconds), major upsets in the upstream production system can not be caught in time to prevent excess oil discharge from the system (Cornitius, 1988). Lastly, the possible need to use water treatment chemicals and supporting treatment equipment may reduce some of the design and cost advantages enjoyed by the hydrocyclone relative to conventional systems.

According to Hayes *et al.* (1985), in general, the efficiency of a hydrocyclone is based on a number of factors. These include: produced water specific gravity, oil droplet size, water temperature (i.e., higher temperatures reduce the oil viscosity and increase efficiency), flow rate (i.e., efficiency increases as the flow rate increases), and configuration (i.e., a parallel series arrangement increases the efficiency).

Hydrocyclones have been shown to be capable of removing oil and grease concentrations down to the 15-25 mg/l range. The addition of an upstream free-flow coalescer may result in an increase in oil removal efficiency. Recent offshore hydrocyclone installations equipped with special filters have shown the capability to treat oil to 5 mg/l and remove 98% of solid particles greater than 2 μm in size. **Table 2.3** summarizes the results of hydrocyclone performance tests at several platforms in Bass Strait, Australia.

Table 2.3. Oil removal performance for static hydrocyclone equipment (From: Hayes *et al.*, 1985).

Platform	Produced Water Stream		
	Inlet Oil Concentration (mg/l)	**Outlet Oil Concentration (mg/l)**	**Removal Efficiency**
Kingfish B	40-528	4-16	90-97%
Barracuda	80-160	8-16	90%
Snapper[a]	2,960	48	98%
Tuna[a]	272-560	32-96	83-94%
Fortescue	4-136	0-16	88-100%

Footnote:

[a] These platforms used two hydrocyclones in series.

Although most performance tests of hydrocyclones have dealt exclusively with the static model, rotary hydrocyclone performance has also been evaluated. Recent tests have indicated that rotating systems are actually more effective at removing oil and grease from water than static units. However, long-term operational reliability comparisons have not yet been made. As the summary of a recent rotary hydrocyclone performance test indicates

(**Table 2.4**), rotational speeds and inlet flow rates have a great impact on oil removal efficiency (Jones, 1990).

Table 2.4. Oil removal performance for rotary hydrocyclone equipment (From: Jones, 1990).

Rotations per Minute	**Oil Removal Efficiency (%) by Inlet Flow Rate (Gallons per Minute)**			
	30	**50**	**70**	**90**
1,600	82	72	65	55
2,500	93	89	87	81
3,000	96	95	93	88

Centrifuge

Despite its long history, centrifuge technology has only recently been applied to treating produced water in the Gulf of Mexico. The centrifuge works on the same principle as the hydrocyclone, except that it produces six to ten times the centrifugal force of a hydrocyclone.

Centrifuges can handle a high inlet concentration of oil and grease, and often treat down to 10 to 12 mg/l, removing 99% of the 5 μm size droplets and up to 98% of the 2 μm size droplets. Chemicals are not normally required to achieve these results, and chemicals used upstream (e.g., well treatments, corrosion inhibitors) do not affect the performance of the equipment. The size and weight of centrifuge packages are very attractive to many offshore operators (K. Arnold, Paragon Engineering, 1993, pers. comm.). One negative aspect of the centrifuge is that it is "rotating" equipment that often experiences operational difficulties and therefore requires significant maintenance. However, it has proven to be reliable in power and marine applications, as well as North Sea and Gulf of Mexico produced water treatment applications.

Membrane Filtration

Cross-flow membrane filtration is a produced water treatment technology that, although promising, has not yet been commercially proven in an oil or gas field setting. Membrane filtration works by directing produced water parallel to the membrane surfaces, instead of perpendicular to them. As a result, the force of the flow allows the clean water to pass through the membranes, while the oil and grease constituents are carried away in a concentrate. The concentrate is coalesced and removed from the water polishing train. This technique of cross-flow filtration prevents the majority of constituents from coming in direct contact with the membrane surfaces, therefore reducing clogging of the filter (Fitzgerald, 1992).

A number of companies have experimented with membrane systems that utilize membranes of various materials and pore size. Pore sizes tested have ranged from 0.03 to 0.8 μm, with the membrane surfaces being made of either organic or inorganic materials. Cellulose and polysulphone are examples of organic materials and alumina, titanium oxide, carbon, ceramic, and stainless steel are examples of inorganic materials that have been used in membranes (Simms *et al.*, 1990).

Membrane technology has many advantages that make its use applicable to offshore operations. These include the relatively small size and low weight of the unit[1], and its insensitivity to platform motion. Other advantages of membrane filtration that could make it suitable for a wide range of settings include the ability to withstand high temperatures, strong cleaning agents, high concentrations of suspended solids, and fluctuations in influent oil concentration (Simms *et al.*, 1990; Zaida *et al.*, 1992).

Membrane filtration suffers from one major drawback though, as the membrane surfaces tend to easily clog with solids, chemicals, and free oil. As a result, membrane filtration systems are quite operator intensive, as membrane pre-treatment, frequent back-pulsing and fast-flushing, or waste pre-filtering is required to keep the surfaces from plugging. Moreover, capillary exclusion membranes can suffer from an endemic problem,

[1] While actual membrane surfaces may be relatively small, the complete membrane polishing train can be sizable when the feed preparation unit, waste disposal system, and cleaning skids are added.

namely, that if microemulsions are generated in the system due to effects of production chemicals, they plug off instantaneously. They are also susceptible to scale buildup and NORM accumulation. A recent study comparing four different membrane units revealed that two of the four required waste pre-filtering, which renders these units impractical for offshore applications (Arnold, 1991). A membrane filtration unit being tested as part of an ARCO pilot project had an average monthly downtime of 25% during testing (Zaida *et al.*, 1992).

Membrane filtration is the technology upon which EPA had based its 1991 revised proposed effluent limitation guidelines. The proposed rule had called for oil and grease limits of 13 mg/l daily maximum and 7 mg/l monthly average for discharges within four miles of shore. Although long-term testing of membrane filtration systems to date is somewhat limited, some tests have indicated that such systems are capable of reducing concentrations of oil and grease and total suspended solids below 5 mg/l. On the other hand, one highly visible long-term test was conducted on a Petrolax unit on Marathon's Eugene Island 349-B platform. This ceramic membrane unit of the gamma alumina type failed. **Table 2.5** summarizes the results of two studies that tested the effectiveness of membrane filtration in several offshore settings.

Table 2.5. Oil and grease and total suspended solids removal performance for membrane filtration equipment.

Location	Oil and Grease (mg/l)		Total Suspended Solids (mg/l)	
	Influent	Effluent	Influent	Effluent
North Sea[a]	50,000	4	-	-
Louisiana[b]	166 - 582	<9	-	-
Gulf of Mexico[b]	27 - 108	<5	100 - 290	<1
Gulf of Mexico[b]	105 - 574	2 - 5	73 - 350	<1

Footnotes:

[a] Goodboy, 1989;
[b] Chen *et al.*, 1991.

It remains to be seen if these levels of performance can be consistently achieved while treating the various types of produced water encountered at onshore and offshore oil and gas production facilities.

Reinjection

Reinjection of produced water to subsurface stratum is the predominant disposal method for onshore applications, but has not been extensively used in offshore situations. Current offshore use is primarily limited to situations where the *soluble* oil content approaches or exceeds the current effluent standards for total oil and grease in produced water discharges. For reinjection to take place, formations must be available that are able to accept the brine reinjected, and the produced water must be compatible with the formation into which it is injected. Reinjection wells can plug, even with unusual precautions. This plugging can increase operating costs and can result in workovers and/or the drilling of new wells.

Produced water reinjection facilities include preliminary treatment equipment to "polish" the water prior to reinjection and pumps and prime movers to inject the produced water into the substrata. The ability of reinjection to achieve required offshore discharge standards is assured, eliminating the risk of unsatisfactory performance of treatment systems, resulting in non-compliance.

The costs of reinjection depend on the compatibility of the produced water with the formations, the availability of platform slots for drilling injection wells, the cost of those wells, and the pumping equipment and facilities required. Reinjection is usually more expensive than traditional produced water treatment options such as gas flotation and plate coalescers.

Experimental Technologies

There are a number of treatment technologies that have successfully demonstrated their ability to remove various constituents from water. Although most focus on the removal of constituents not currently mandated by regulatory requirements, interest in some of the following technologies is likely to grow as future regulations place limits on constituents other than oil and grease.

In laboratory studies, *air stripping* has been shown to effectively remove volatile organic compounds (VOCs) from produced water streams. Improvements in air stripping as a viable treatment process are driven by concern over benzene and toluene, two of EPA's priority pollutants. Current effluent guidelines address only oil and grease concentrations in produced waters, but potential inclusion of VOCs in future effluent limitation guidelines could significantly impact offshore oil and gas operations.

Air stripping works by placing VOCs in contact with a gas so that they can be removed from the produced water. Three types of equipment can be used to achieve this transfer: 1) a tray column where air bubbles rise through produced water that is flowing through each tray, 2) a vertical packed column through which air and produced water run in a counter-current flow, and 3) a tank with a release mechanism, a sparger, that discharges air bubbles into the produced water. Currently, it is this last piece of equipment that has gained the most interest, as it has a low initial cost and existing holding tanks in the field can be easily converted for air stripping (Fang and Lin, 1988). Air stripping has been shown to remove up to 99% of all halogenated hydrocarbons, benzene, and toluene in a waste water stream (ENSR, 1990).

However, air stripping has several disadvantages. Organic compounds removed from produced water by air stripping can be released into the atmosphere, potentially increasing air pollution and thereby replacing one environmental concern with another. Air stripping is unable to remove organic compounds that have been added to the production system in the form of treating chemicals, so the removal of organics may not be complete when chemical treatment is employed upstream. High concentrations of metals such as iron and magnesium can cause operational difficulties. The presence of iron, available in quantity as a corrosion product, oxidizes from ferrous to the ferric form and forms a precipitate that can easily foul any type of air blown system. In addition, it creates a sold waste that can both flocculate oil and accumulate heavy metal ions. Also, changes in waste stream properties such as pH and temperature can lead to operational difficulties (ENSR, 1990).

Both carbon adsorption and reverse osmosis are uniquely used to remove soluble components from produced water. The water requires extensive pretreatment which, for large flow rates, is prohibitively expensive. *Carbon adsorption* removes a wide range of organic constituents from aqueous waste streams, as selected dissolved constituents leave solution and adhere to the surface of activated carbon molecules. The adsorption of specific chemicals depends primarily on the carbon properties and the physical-chemical characteristics and concentrations of the compounds. It also depends on the contact time between the carbon and the aqueous stream. Constituents commonly removed by this technology include polynuclear aromatic hydrocarbons (PAHs) and phenols. Tests have indicated that carbon adsorption can remove up to 99% of phenols and PAHs in a waste stream. This process has also demonstrated the potential to effectively reduce metals such as arsenic, chromium, and silver (ENSR, 1990).

Reverse osmosis is a pressure-driven process that separates waste water into a purified "permeate" and a residual "concentrate" stream by selectively feeding it through a semipermeable membrane. The performance of this process largely depends on the parameters such as water temperature and pH, constituent concentration, polarization, membrane compaction, fouling or scaling tendencies, and the presence of chlorine. To prevent plugging of the membranes, the waste streams being treated must be free of oils, suspended solids, and other minerals. Reverse osmosis is usually employed to remove dissolved salts such as chloride, nitrate, and phosphate (ENSR, 1990).

Another "nontraditional" technology that has shown promise as an effective produced water treatment technology is *diffusion barrier technology*. This technology, which is essentially polymer membrane filtration, could work in tandem with more traditional treatment technologies such as centrifuges and hydrocyclones. This process uses a filtration system made up of hundreds of barriers that resemble drinking straws. A diffusion barrier system attached to the tail end of a centrifuge has the potential to treat water down to the 4 mg/l level. A recent pilot project in the Gulf of Mexico used a diffusion barrier separator to reduce oil levels from 120 to 400 mg/l to less than 8 mg/l for 30 days. The greatest drawback to this technology (as with membrane filtration) is that it is susceptible to scale buildup. Undissolved gas and heavy oil influent concentrations also tend to cause such problems. Cost estimates for a diffusion barrier separator range from $350,000 (1,000 BWPD capacity) to $1,250,000 (40,000 BWPD) (K. Arnold, Paragon Engineering, 1993, pers. comm.).

2.2.3 Costs of Offshore Produced Water Treatment and Disposal

The costs associated with produced water treatment and disposal at offshore facilities can vary considerably depending on the technology employed, the treatment capacity, the facility upon which it will be deployed, and the characteristics of the produced water stream. Typical costs associated with the technologies described above are presented in **Table 2.6**, for produced water treatment capacities ranging from 1,000 to 40,000 BWPD.

The effective performance of most of the non-traditional technologies described above and summarized in **Table 2.6** requires upstream pretreatment prior to input to the produced water treatment facility. The costs associated with this pretreatment equipment are summarized for various treatment capacities in **Table 2.7**.

2.2.4 Exposure Pathways Associated with Produced Water Treatment and Disposal

Different produced water treatment and disposal technologies can result in various exposure pathways of concern. The principal exposure pathway associated with produced water technologies is oil and grease in the marine environment, leading to exposure and the potential for uptake by marine and benthic organisms. Since all of the produced water treatment and disposal alternatives described are designed to achieve the established effluent limits, the differential risk to the marine environment associated with each alternative corresponds primarily to its likelihood of malfunction. Some processes, such as media filtration, that require periodic back washing or comparable operations can increase discharge pollutants for a short period of time, increasing marine exposures, or resulting in barged wastes to onshore facilities, increasing exposure to air pollutants (from barges) and to potential exposures from onshore disposal facilities. The installation of equipment to reinject produced water can involve the drilling or conversion of wells, which can result in potential discharges of drilling fluids, workover fluids, etc., increased barge traffic to support these operations (increasing air pollution), and possible increases of wastes generated from offshore facilities disposed at onshore waste disposal facilities.

Table 2.6. Cost comparison of produced water treatment technologies.

Technology	Cost ($)	Treatment Capacity (Barrels of Water per Day)					
		1,000	2,000	5,000	10,000	15,000	40,000
Gas Flotation	Capital[a]	240,000	240,000	265,000	345,000	375,000	550,000
	Annual Operating[a]	35,000	35,000	40,000	50,000	55,000	90,000
Plate Coalescers	Capital[a]	85,000	85,000	95,000	110,000	125,000	190,000
	Annual Operating[a]	25,000	25,000	25,000	25,000	25,000	40,000
Media Filtration[b]	Capital[c]	712,816	-	3,056,612	3,240,000	-	4,102,176
	Annual Operating[c]	70,504	-	187,998	249,925	-	604,665
Hydrocyclone	Capital[a]	181,900	198,900	266,900	351,900	401,900	716,500
	Annual Operating[a]	31,000	31,700	37,600	48,200	65,000	104,300
Centrifuge	Capital[a]	-	525,000	755,000	1,225,000	1,235,000	3,350,000
	Annual Operating[a]	-	21,100	28,200	42,000	52,000	134,000
Membrane Filtration	Capital[d]	-	-	405,900	597,300	-	944,400
	Annual Operating[d]	-	-	34,200	45,100	-	73,600
Reinjection (OCS, State waters)	Capital[e,f]	-	2,745,300/315,300	2,826,100/396,100	5,817,200/957,200	8,720,000/1,430,000	20,158,700/3,148,700
	Annual Operating[e]	-	50,500	87,500	137,800	160,000	271,500
Reinjection (coastal waters)	Capital[e,f]	-	755,100/104,800	803,900/153,600	1,607,900/307,200	2,411,800/460,800	5,709,200/1,156,800
	Annual Operating[e]	-	15,500	38,800	77,500	116,283	310,100

Footnotes:

- a K. Arnold, Paragon Engineering, 1993, pers. comm.
- b Granular media filtration/surface water discharge system.
- c EPA, 1991. Capacity greater than 1,000 bbl includes $2.1 million capital expenditure for platform addition.
- d EIA, 1992.
- e ICF Resources, 1991.
- f The first number represents cost the cost to drill an injection well, the second number represents the cost of converting an existing well to an injection well.

Table 2.7. Upstream pretreatment costs for new installations (From: Paragon Engineering, 1993).

Treatment Capacity (BWPD)[a]	Capital Costs ($)[b]	Operating Costs ($)[b]
2,000	41,000	15,000
5,000	46,000	15,000
10,000	54,000	15,000
15,000	62,000	15,000
40,000	96,000	24,000

Footnotes:

[a] BWPD = barrels of water per day;
[b] These additional costs apply only to new installations of hydrocyclones, flotation units, plate coalescers, and centrifuges. These technologies require the following upstream pretreatment equipment: stainer, produced water vessel, downstream enhancement vessel, and chemical injection equipment.

2.3 Produced Water Technology Rating

Based on the analysis of the produced water and produced sand treatment technologies presented previously, it is possible to rank the technologies considered based on the following parameters:

- Waste stream treated;
- Constituents removed (primary and secondary); and
- Utilization criteria (applicability, effectiveness, exposure pathway, cost).

Table 2.8 presents a summary rating of produced water treatment systems.

2.4 Produced Sand Treatment and Disposal Technologies

Produced sand often comes to the surface during oil and gas production, collecting in production measurement vessels, separation tanks, storage facilities (including pits), and other equipment. Depending on individual reservoir characteristics, produced sand can fill in the bottom 10-20% of a piece of equipment within one year (Cornwell, 1993). The treatment and disposal of this sand has long been a problem for offshore operators. Due to the recent

Table 2.8. Oil and grease ratings of produced water treatment systems by four evaluation criteria.[a]

Treatment System/Technology	Typical Application	Availability[b]	Effectiveness[c]	Capital Cost	Operating Cost
Induced Gas Flotation (IGF)	Gas only platform, sufficient space	BAT	High	100%	100%
Plate Coalescer, then IGF	Oil platform, medium difficulty in treatment	BAT	High	140%	160%+
IGF, Media Filtration, then Reinjection	Tight disposed formation	Medium	Very High	1000%	1000%+
IGF, then Reinjection	Highly permeable disposal formation	High	Very High	700%	500%
Hydrocyclone	Widely applicable, especially where small footprint required	Medium	High	100%	90%
Centrifuge	Widely applicable, especially where small footprint required	Medium	High	290%	80%
Membrane Filtration	Uncertain performance to date	Low	Medium	190%[d]	90%[d]

Footnotes:

[a] Ratings are based on data collected by EPA and Industry for the Offshore Guidelines and peer reviewed studies. Other publicly available information is also used. Data have been evaluated, then used for ratings. All ratings are relative to improved gas flotation (IGF), which EPA selected as the basis for Offshore BAT.

[b] Availability means that the technology is demonstrated as successful in applications on produced water and, from a technical achievability standpoint, could be considered to be available. The rating are low, medium, or high, and are compared to improved gas flotation (IGF). The rating does not consider cost or other factors, such as non-water quality considerations or energy requirements, which might make the technology impractical.

[c] Effectiveness is a percentage estimated for the system with the BAT technology assumed to be highly effective for the given typical application. Effectiveness means the capability to remove more or less oil and grease than BAT technology, whose long-term average is 23.5 mg/l, as determined by EPA from OOC and EPA data (p. XII-25, 1993 Development Document, EPA 1993a).

[d] Cost data for membrane materials is highly uncertain.

regulatory ban on offshore discharges of produced sand, the only option currently available to operators is to transport the sand to onshore facilities for treatment and disposal. Disposal of produced sand onshore can be quite expensive, with significant costs incurred both in transporting the sand to shore and in disposing the sand at an onshore waste disposal facility.

However, since both DOE and MMS have the opportunity to provide information that may be used to reconsider the ban of offshore discharges of produced sand, new technologies are being developed, and could be implemented if the ban is reconsidered and eventually reversed. One new technology that has recently been demonstrated, the sand scrubber system, could be used at offshore facilities to treat produced sand, if it can perform cost-effectively compared to the option of transporting and discharging onshore. This sand scrubber technology, as tested on several platforms in the Gulf of Mexico and certified by MMS, has a two barrel capacity and contains a feed tank, screw conveyor, scrubber, wash tank, and a recycle/discharge pump. The oily sands begin in the feed tank, where they then pass through a stream of dilution water, into the scrubber, and then into the wash tank. When all the sand has entered the wash tank, the sand is recycled up to the feed tank for another run through the system. Depending on the level of free oil in the sand, this closed loop circuit retention time ranges from 5 to 20 minutes.

While in the scrubber, sand particles flow through two cells where attrition takes place. Attrition is the abrasion of one sand particle against another. Each cell contains two blades attached to a single rotating shaft. The pitch of the blades forces the sand particles to collide with each other, causing the oil to shear away from the sand surface (Schlittler, 1993). Once the scrubbing is completed, the sand is collected in the wash tank, where water enters tangentially while an agitator runs. After 20 minutes, the sand is pumped overboard, with the free oil floating to the surface of the wash tank. Infrared tests have confirmed that this technology removes all parts of free oil found in produced sand (Abraham and Teel, 1992).

3.0 ASSESSMENT METHODOLOGY AND ASSUMPTIONS

3.1 Overview of Methodology

The objective of this effort is to assess the economic and energy supply impacts of existing and anticipated future Federal and State offshore discharge requirements. These requirements will be assessed in terms of their potential impacts on existing production operations and on the exploration and development of oil and gas fields that remain to be discovered in the Gulf of Mexico. The analysis methodology used data bases and computer models previously developed by ICF Resources (1990) for DOE, some of which have been extensively used to conduct analyses similar to that undertaken in this task, and others that were developed specifically for this effort. The analysis was performed for several oil price scenarios.

Evaluating the impact of alternate produced water and produced sand treatment and disposal practices requires explicit characterization of existing and potential oil and gas resources in the Gulf of Mexico which could be affected. To perform this analysis, data were developed at the field level for water discharges, water injection, and platform characteristics. For analytical purposes, the Gulf of Mexico was divided into six areas: Texas coastal, Texas State waters, Louisiana coastal, Louisiana State waters, central Federal OCS, and western Federal OCS. The Louisiana coastal fields were defined using information developed from the Louisiana Geological Survey (Lindstedt, 1991) and Texas coastal fields were determined by locating fields east of the Chapman Line (47 FR 31554, July 21, 1982). The number of fields analyzed in the six areas are shown in **Table 3.1**.

Table 3.1. Number of fields analyzed during the current project.

Location	Total Historical Fields	Fields Producing as of 1/1/92[a]
Federal OCS Central	560	513
Federal OCS Western	219	202
Louisiana Coastal	381	280
Louisiana State Waters	92	75
Texas Coastal	512	290
Texas State Waters	134	81

Footnote:

[a] Excludes fields not producing in 1990 and 1991.

The methodology and assumptions used in this assessment are described in greater detail below.

3.1.1 Decline Curves for Currently Producing Fields

A detailed database of information on existing platforms and oil and gas fields in the Gulf of Mexico was developed. Data on production (i.e., of oil, gas, and water) by field, obtained from Petroleum Information Corp. (PI), was matched with data from MMS for all production platforms in the Gulf of Mexico. For each field, regression analyses were performed on historical production data to develop a production forecast (i.e., oil, gas, and water) for the remaining life of each field. Each field was assumed to produce until its economic limit, or the point where revenues no longer exceed the costs of operations, is reached. When incremental compliance costs are imposed, the economic limit of production in these fields is reached earlier than would otherwise be the case, with a corresponding loss of potential reserves and production.

The 1992 production forecast for the State water (territorial seas) areas and Federal OCS areas were compared with production data for 1992 reported to the Energy Information Administration (EIA). These data are presented in **Table 3.2** (EIA, 1993). Production data were not compared for coastal areas, since EIA does not categorize production explicitly for coastal areas. Nonetheless, the table shows that forecast production for 1992 was within 15% of reported values.

Table 3.2. Forecast and reported 1992 regional oil and gas production figures (From: EIA, 1993).

Area	Forecast		Reported	
	Gas (Bcf)	Oil (MMB)	Gas (Bcf)	Oil (MMB)
OCS - Central	2,750	221	3,292	253
OCS - Western	1,133	20	1,284	14
Louisiana State Waters	127	20	128	21
Texas State Waters	85	2	74	2

3.1.2 Estimates of Oil and Gas Resources Remaining to be Discovered

Estimates of oil and gas resources under State and Federal waters of the Gulf of Mexico that remain to be discovered are based on resource estimates developed by the U.S. Department of the Interior (USDOI, 1989), adjusted for new discoveries and production from these discoveries since that time. These resources were estimated for various regions and water depth ranges. Estimates of the distribution of the fields that remain to be discovered were developed for each area based on the total resources estimated in the area and the largest field found to date in each area, using traditional methods for estimating the distribution of field sizes remaining to be discovered in hydrocarbon plays. The economic feasibility of recovering these resources was determined assuming that the volume of hydrocarbons associated with a discovery must support all costs associated with its development, including all exploration and lease acquisition costs. A description of the economic analysis models used in this assessment is provided below.

3.1.3 Discharge Points for Produced Water

A database of discharge information was also developed for fields located in coastal areas, State waters, and Federal OCS areas. This database was developed using information gathered from the Louisiana Department of Environmental Quality, the Texas Railroad Commission, and discharge monitoring reports from EPA Region 6. Also available for the Louisiana coastal areas was water injection information supplied by the Louisiana Department of Natural Resources. This information characterized the field locations injecting water, the associated volumes of water injection, and the sources of the water. This information provided a cross-check as to the reasonableness of injection and discharge data. The discharge and injection databases were matched with the production database to ensure continuity.

3.1.4 Platform Locations/Size/Characteristics in Producing Fields

The platform data provided by MMS provides the characteristics of platforms located in Federal OCS areas including: location, water depth, distance from shore, number of slots available, number of slots drilled, installation date, removal date, equipment (production equipment, storage tanks, fired vessels, compressors, electric generating, heliport), and production activity (oil, gas, condensate, and water). For this analysis, platform information was compiled on a field basis, to correspond to the field-specific production data described above. The data used in the analysis on a field basis included the number of drilled slots, platforms, water depth, and distance from shore.

3.1.5 New Injection Well Capacity

For all regions, the average injection volume per well was assumed to be 6,000 BWPD, with backup injection capacity assumed for each well. This well capacity, in conjunction with the quantity of water requiring injection in excess of the current maximum, was used to determine when, and how much, new injection capacity will be required. Using a database containing the quantity of water discharged from various fields for the year 1992, corresponding water injection volumes for each field could be determined. However, the fact that some fields transport their water to other fields to be discharged created some problems: some fields discharge more water than they produce, while other fields have no water discharge. To address this problem, procedures were established to estimate produced water discharges and reinjection by field, based on the historical discharge data and the quantity of water produced at the field. **Table 3.3** describes these procedures.

Table 3.3. Procedures to estimate amount of water currently injected.

Discharge Status	Estimation Criteria
No Water Discharge Reported for the Field	No water assumed to be injected under the assumption that it all was transported to another field for discharge.
Water Discharge Exceeds Water Production for the Field	No water assumed to be injected under the assumption that it all was discharged on-site, along with water from other fields.
Water Production Exceeds Water Discharge for the Field (Assuming positive water discharge)	Assumed 1992 water injection equals 1992 water production less 1992 water discharge.
Using these rules, all water production is allocated as either discharged or reinjected.	

When reinjection is the alternative considered, the number of required injection wells was calculated based on the forecast water production for the field, with wells drilled or converted as needed. From the platform database, the number of slots per field for those fields located within OCS areas was known. Using these data, along with the number of producing wells in the year 1991, the number of slots available for conversion could be estimated. Once this was determined, it was assumed that all available wells are converted before new drilling occurs. All non-OCS fields, OCS fields with no slot information, and fields that remain to be discovered, were assumed to drill all of their injection wells.

The assumed cost of drilling a new injection well within the area is a function of water depth and is based on an average well depth of 4,000 feet. The assumed cost of drilling a new injection well in OCS and State waters was assumed to be $2.7 million. Conversion costs for offshore fields were assumed to be $850,000. Injection well drilling costs for fields located in coastal areas was assumed to be $722,600 per well. These cost estimates are based on prior ICF Resources analyses (1990, 1991, 1994) and on personal communications with Ken Arnold, Paragon Engineering and industry members of the Scientific Review Committee for this effort.

3.2 Technical/Economic Analysis of the Impacts on Existing Production and on New Field Discoveries

Given the description of the undiscovered oil and gas resources, the objective of this step was to estimate the technical and economic potential of finding, developing, and producing these undiscovered resources under various future scenarios. For this step, ICF Resources used its Replacement Costs of Crude Oil Supply Analysis System (REPCO), which has been developed, peer reviewed, and used extensively for similar past analyses for DOE (Lewin & Associates, Inc., 1985). REPCO uniquely characterizes the resources for various distinct regions, disaggregating the resource into characteristic fields. Appropriate facilities are selected for the characteristic fields in each region, and the recovery potential and economic viability of each characteristic field was determined based on the regional and reservoir characteristics describing it. Explicit field-level evaluations were performed. Relationships between field size and well productivity for each region, based on historical development and production data, were used to determine the number of wells required, the timing of development, and anticipated production rates over the life of a project.

The economic analysis includes all costs associated with development, including pre-development costs for geological and geophysical activity, lease acquisition, and other pre-exploration activities (where appropriate); exploration costs for the initial successful wildcat well and associated allocated unsuccessful wildcats (where appropriate); all other conventional development costs for wells, equipment and facilities (including development dry holes), operation and maintenance costs; and all royalties, taxes, and return on capital.

3.3 Characterization of Environmental Regulatory Scenarios

Three possible future scenarios were considered in this analysis to represent the range of potential costs and impacts associated with the new or potential future regulatory requirements for produced water discharges from oil and gas facilities in offshore and coastal waters. The basis for these potential increased costs are those associated with applying the new treatment and disposal technologies necessary to meet increasingly stringent standards. The three scenarios assumed in this analysis are described below:

"Existing" Requirements

- This scenario assumes the effluent standards that were applicable in 1993, predating the recent change to the Federal effluent limitations guidelines and modification to the Region 6 OCS general permit (effective January 4, 1994). These standards are 48 mg/l monthly average and 72 mg/l daily average for oil and grease content in produced water discharges; and
- This scenario does *not* include the existing Louisiana requirement for discontinuation of discharges in coastal areas by January 1, 1995.

New Requirements

- This scenario is based on the new Federal effluent limitations guidelines and their implementation through general permits at the regional level (i.e., 29 mg/l monthly average and 42 mg/l daily maximum);
- This scenario includes the existing Louisiana requirement for the discontinuation of discharges in coastal areas by January 1, 1995;
- No change in the requirements applicable to the Texas coastal area is assumed;

- Under this scenario, operations in Louisiana coastal areas will be converted to injection to comply. For other areas, upgrades to existing equipment will be considered as needed for compliance based on existing platform equipment characteristics described in the API/OOC 292 platform survey (Otto and Associates, 1993). Unless alternative equipment that meets the new standard is already installed, improved gas flotation is assumed to be the applicable technology for produced water treatment; and

- This scenario represents the latest Federal and State requirements regarding the offshore and coastal discharge of produced water.

<u>Full Zero Discharge</u>

- This most stringent scenario assumes that a zero discharge standard for produced water is applicable in all coastal and offshore areas;

- All operations will be converted to injection for compliance. Where slots are not available on a platform for reinjection, produced water will be piped to a nearby platform or to shore, depending upon location; and

- This scenario provides a ceiling for potential compliance costs and impacts on resource recovery.

4.0 ASSESSMENT OF ECONOMIC IMPACTS ON GULF OF MEXICO OPERATIONS

The potential costs of compliance associated with the three scenarios were assessed using economic analysis models described in the previous chapter. The impacts were considered separately for each region (i.e., Texas coastal, Louisiana coastal, Texas State waters, Louisiana State waters, and Federal OCS). The impacts of the new discharge requirements were evaluated for three future price scenarios:

- Real oil prices (West Texas Intermediate) remain constant at $20/bbl; with real gas prices constant at $2.00/MMBtu;
- Real oil prices remain constant at $16/bbl; with real gas price constant at $1.50/MMBtu; and
- 1994 EIA Annual Energy Outlook reference case oil and gas price forecast; summarized in **Table 4.1.**

Table 4.1. Reference case oil and gas price forecast (From: EIA, 1994).

Year	World Oil Price (1992 $/bbl)	Natural Gas Average Wellhead Price (1992 $/Mcf[a])
1994	18.20	1.75
2000	20.72	2.42
2005	24.90	2.89
2010	28.16	3.47

Footnote:

[a] 1 Mcf = 1.031 MMBtu

The impacts of new and possible future Federal and State regulations addressing produced water discharges in the Gulf of Mexico can be characterized in a variety of ways. For purposes of this report, several types of impacts are presented:

- Incremental costs (both investment and annual operating and maintenance) incurred for operators to comply with the requirements;
- Impacts of the requirements on future production from known producing offshore and coastal fields, at various points in time;

- Impacts of the requirements on the reserves potential in fields remaining to be discovered; and

- Public sector revenues (i.e., corporate income taxes, State severance taxes, and royalties) lost as a result of new compliance requirements.

These impacts were assessed for each of the three price scenarios, explicitly for each of the regions considered. The impacts were considered for two future regulatory cases. The first regulatory case considered the change from existing requirements (i.e., at the time the analysis was prepared) to the current, newly imposed requirements. A second regulatory case considered the change from existing requirements to full zero discharge requirements in all areas. These new requirements were assumed to go into effect in 1993. This date reflects the timeframe in which this analysis was performed. Assuming that the *same* scenarios were implemented at a later date would slightly reduce the impacts observed (as some production was lost due to natural declines).

4.1 Incremental Industry Compliance Costs

Future environmental compliance requirements could result in substantial cost impacts on industry expenditures. Compliance expenditures resulting from the new requirements already promulgated could result in the industry spending from $600 to $630 million by 2000 in currently producing fields, depending on future prices, and from $810 to $920 million by 2010 (**Tables 4.2** through **4.4**). This averages out to about $55 million a year of incremental expenditures devoted to compliance activities.

If a zero discharge requirement was promulgated throughout the Gulf of Mexico, effective in 1993, operators of currently producing fields would have to expend from $2.2 to $2.5 billion by 2000, and from $2.8 to $3.3 billion by 2010, depending on future prices (**Tables 4.5** through **4.7**). This amounts to average incremental expenditures of $180 to $200 million per year. To put this in perspective, this corresponds to approximately 70 fewer production wells drilled per year due to a decrease in available cash flow, notwithstanding the impact of the requirements on future production economics.

Table 4.2. Summary of incremental compliance costs associated with new Federal effluent limitation guidelines with Louisiana coastal areas complying with zero discharge requirements for produced water (Cumulative compliance costs: $ millions; constant $16/bbl oil price; $1.50/MMBtu gas price).

Area	1995	2000	2010
Federal OCS			
Central	80	121	160
Western	31	47	69
Subtotal	111	168	229
Louisiana			
State	10	14	16
Coastal	334	411	563
Subtotal	344	425	579
Texas			
State	2	3	3
Coastal	--	--	--
Subtotal	2	3	3
GRAND TOTAL	**457**	**596**	**811**

Table 4.3. Summary of incremental compliance costs associated with new Federal effluent limitation guidelines with Louisiana coastal areas complying with zero discharge requirements for produced water (Cumulative compliance costs: $ millions; constant $20/bbl oil price; $2.00/MMBtu gas price).

Area	1995	2000	2010
Federal OCS			
Central	84	128	177
Western	31	49	74
Subtotal	115	177	251
Louisiana			
State	11	16	19
Coastal	355	436	603
Subtotal	366	452	622
Texas			
State	2	3	4
Coastal	--	--	--
Subtotal	2	3	4
GRAND TOTAL	**483**	**632**	**877**

Table 4.4. Summary of incremental compliance costs associated with new Federal effluent limitation guidelines with Louisiana coastal areas complying with zero discharge requirements for produced water (Cumulative compliance costs: $ millions; 1994 AEO Reference Case Price Forecast).

Area	1995	2000	2010
Federal OCS			
Central	83	125	183
Western	31	48	76
Subtotal	114	173	259
Louisiana			
State	11	17	21
Coastal	360	440	633
Subtotal	371	457	654
Texas			
State	2	3	4
Coastal	--	--	--
Subtotal	2	3	4
GRAND TOTAL	**487**	**633**	**917**

Table 4.5. Summary of incremental compliance costs associated with zero discharge requirements for produced water (Cumulative compliance costs: $ millions; constant $16/bbl oil price; $1.50/MMBtu gas price).

Area	1995	2000	2010
Federal OCS			
Central	952	1,266	1,597
Western	262	348	440
Subtotal	1,214	1,614	2,037
Louisiana			
State	118	133	138
Coastal	334	411	563
Subtotal	452	545	701
Texas			
State	14	14	14
Coastal	89	107	139
Subtotal	103	121	153
GRAND TOTAL	**1,769**	**2,279**	**2,891**

Table 4.6. Summary of incremental compliance costs associated with zero discharge requirements for produced water (Cumulative compliance costs: $ millions; constant $20/bbl oil price; $2.00/MMBtu gas price).

Area	1995	2000	2010
Federal OCS			
Central	1,058	1,406	1,819
Western	278	365	463
Subtotal	1,336	1,771	2,282
Louisiana			
State	160	182	188
Coastal	355	436	603
Subtotal	515	618	791
Texas			
State	25	26	26
Coastal	100	120	157
Subtotal	125	146	183
GRAND TOTAL	**1,976**	**2,535**	**3,256**

Table 4.7. Summary of incremental compliance costs associated with zero discharge requirements for produced water (Cumulative compliance costs: $ millions; 1994 AEO Reference Case Price Forecast).

Area	1995	2000	2010
Federal OCS			
Central	950	1,128	1,389
Western	282	301	348
Subtotal	1,232	1,429	1,737
Louisiana			
State	163	185	199
Coastal	360	440	633
Subtotal	523	625	832
Texas			
State	25	26	29
Coastal	102	121	171
Subtotal	127	147	200
GRAND TOTAL	**1,882**	**2,201**	**2,769**

The cost impacts of future regulatory requirements have two types of impacts. First, for those projects which still remain economically viable despite the increased costs, their income is reduced, and therefore, income taxes collected by Federal and State governments are reduced. The result is less income generated for Federal and State treasuries. Second, some projects become uneconomic, and are abandoned sooner than would otherwise be the case. This results in reduced domestic production, even lower public sector revenues, and greater dependence on imports. The impacts of future requirements both on future supplies of oil and gas and on future public sector revenues are summarized below.

4.2 Impacts on Production from Currently Producing Fields

In addition to their impact on industry expenditures, new standards for offshore produced water discharges (i.e., 29 mg/l monthly average and 42 mg/l daily maximum; with discontinuation of discharges for coastal Louisiana by January 1, 1995) could impact oil and gas production from currently producing fields in the Gulf of Mexico. Promulgation of these standards in 1993 would result in an initial drop in annual production of 600,000 to one million bbl by 1995, depending on price. Gas production could drop by 4 to 9 Bcf per year, again depending on prices, as indicated in **Tables 4.8** through **4.10**. The largest impacts are likely to occur in the Central Gulf and in coastal Louisiana. In the Central Gulf, at an oil price of around $16/bbl, 1995 production could decrease by 50,000 bbl of oil and 2 Bcf of gas. In the Louisiana coastal waters, oil production could drop by 900,000 bbl, with gas production decreasing by 5 Bcf.

Under the possible zero discharge scenario, the impacts on future oil and gas production could be considerable, with the impacts on oil production greater than on gas production. Under this scenario, depending on future prices, oil production in the entire Gulf of Mexico could drop by as much as 6 to 8 million bbl per year in 1995, and by more than 2 million bbl per year in 2000 (**Tables 4.11** through **4.13**). Gas production could drop by as much as 25 to 58 Bcf per year in 1995 because of the zero discharge requirements, and by as much as 11 Bcf per year in 2000. In the Federal OCS, oil production impacts are significant in the Central Gulf, especially at prices of $16/bbl. In 1995, production could drop by over 2 million bbl per year, a 2% drop. At higher prices, the impacts on production are delayed until 2010, as many fields are abandoned earlier than would otherwise be the case.

Table 4.8. Summary of production impacts associated with new Federal effluent limitation guidelines with Louisiana coastal areas complying with zero discharge requirements for produced water (Change in annual production: thousand bbl per year or Bcf per year; constant $16/bbl oil price; $1.50/MMBtu gas price).

Area	1995		2000		2010	
	Oil	Gas	Oil	Gas	Oil	Gas
Federal OCS						
Central	50 (0.1%)	2 (0.1%)	--	0.4 (0.1%)	30 (1%)	1 (1%)
Western	--	1 (0.1%)	--	--	2 (1%)	1 (3%)
Subtotal	50	3	--	0.4	32	2
Louisiana						
State	10 (0.1%)	1 (1%)	--	--	--	--
Coastal	912 (3%)	5 (2%)	327 (3%)	1 (1%)	559 (20%)	2 (9%)
Subtotal	922	6	327	1	559	2
Texas						
State	--	--	--	--	17 (90%)	.1 (5%)
Coastal	--	--	--	--	--	--
Subtotal					17	.1
GRAND TOTAL	**972**	**9**	**327**	**1**	**608**	**4**

Table 4.9. Summary of production impacts associated with new Federal effluent limitation guidelines with Louisiana coastal areas complying with zero discharge requirements for produced water (Change in annual production: thousand bbl per year or Bcf per year; constant $20/bbl oil price; $2.00/MMBtu gas price).

Area	1995		2000		2010	
	Oil	Gas	Oil	Gas	Oil	Gas
Federal OCS						
Central	--	--	--	--	31 (1%)	0.7 (1%)
Western	--	--	--	0.2 (0.1%)	44 (7%)	0.3 (1%)
Subtotal	--	--	--	0.2	75	1
Louisiana						
State	10 (0.1%)	1 (1%)	--	--	--	--
Coastal	585 (2%)	3 (1%)	197 (2%)	1 (1%)	521 (18%)	2 (7%)
Subtotal	595	4	197	1	521	2
Texas						
State	--	--	--	--	--	--
Coastal	--	--	--	--	--	--
Subtotal	0	0	0	0	0	0
GRAND TOTAL	**595**	**4**	**197**	**1**	**596**	**3**

Table 4.10. Summary of production impacts associated with new Federal effluent limitation guidelines with Louisiana coastal areas complying with zero discharge requirements for produced water (Change in annual production: thousand bbl per year or Bcf per year; 1994 AEO Reference Case Price Forecast).

Area	1995		2000		2010	
	Oil	Gas	Oil	Gas	Oil	Gas
Federal OCS						
Central	--	--	--	--	20 (0.3%)	6 (10%)
Western	--	--		0.3 (0.1%)	10 (2%)	1 (2%)
Subtotal				0.3	30	3
Louisiana						
State	10 (0.1%)	1 (11%)			290 (10%)	1 (3%)
Coastal	585 (2%)	3 (1%)	200 (2%)	1 (1%)	290	2 (1%)
Subtotal	595	4	200	1	290	1
Texas						
State	--	--	--	--	20 (55%)	0.1 (1%)
Coastal	--	--	--	--	--	--
Subtotal	0	0	0	0	20	0.1
GRAND TOTAL	**595**	**4**	**200**	**1**	**340**	**3**

Table 4.11. Summary of production impacts associated with potential zero discharge requirements for produced water (Change in annual production: thousand bbl per year or Bcf per year; constant $16/bbl oil price; $1.50/MMBtu gas price).

Area	1995		2000		2010	
	Oil	Gas	Oil	Gas	Oil	Gas
Federal OCS						
Central	2,252 (2%)	26 (2%)	1,554 (3%)	6 (1%)	27 (1%)	0.8 (2%)
Western	41 (0.3%)	10 (2%)	9 (0.2%)	2 (1%)	1 (1%)	0.3 (1%)
Subtotal	2,293	36	1,563	8	28	1.1
Louisiana						
State	3,917 (38%)	14 (19%)	94 (3%)	1 (4%)	- (-)	- (-)
Coastal	912 (3%)	5 (2%)	327 (3%)	1 (1%)	559 (20%)	2 (9%)
Subtotal	4,829	19	421	2	559	2
Texas						
State	330 (26%)	1 (2%)	133 (31%)	0.2 (1%)	- (-)	-
Coastal	489 (11%)	2 (4%)	140 (7%)	1 (2%)	184 (49%)	2 (37%)
Subtotal	819	3	273	1.2	184	2
GRAND TOTAL	**7,941**	**58**	**2,257**	**11**	**771**	**5**

Table 4.12. Summary of production impacts associated with potential zero discharge requirements for produced water (Change in annual production: thousand bbl per year or Bcf per year; constant $20/bbl oil price; $2.00/MMBtu gas price).

Area	1995		2000		2010	
	Oil	Gas	Oil	Gas	Oil	Gas
Federal OCS						
Central	1,578 (1%)	8 (1%)	1,286 (2%)	7 (1%)	1,588 (32%)	6 (10%)
Western	22 (0.2%)	5 (1%)	6 (0.1%)	1 (0.4%)	48 (7%)	0.4 (1%)
Subtotal	1,600	13	1,292	8	1,636	6
Louisiana						
State	3,412 (31%)	9 (11%)	333 (10%)	0.7 (3%)	- (-)	- (-)
Coastal	585 (2%)	3 (1%)	197 (2%)	1 (1%)	521 (18%)	2 (7%)
Subtotal	3,997	12	530	2	521	2
Texas						
State	65 (5%)	.2 (0.4%)	137 (23%)	0.3 (1%)	- (-)	- (-)
Coastal	309 (7%)	1.5 (2%)	89 (5%)	0.4 (1%)	125 (32%)	2 (32%)
Subtotal	374	2	226	1	125	2
GRAND TOTAL	**5,971**	**27**	**2,048**	**11**	**2,282**	**10**

Table 4.13. Summary of production impacts associated with potential zero discharge requirements for produced water (Change in annual production: thousand bbl per year or Bcf per year; 1994 AEO Reference Case Price Forecast).

Area	1995		2000		2010	
	Oil	Gas	Oil	Gas	Oil	Gas
Federal OCS						
Central	1,578 (1%)	7 (0.4%)	1,286 (2%)	7 (1%)	190 (3%)	2 (37%)
Western	22 (0.2%)	5 (0.7%)	10 (0.1%)	1 (0.4)	10 (2%)	1 (1%)
Subtotal	1,600	12	1,296	8	200	3
Louisiana						
State	0 (31%)	8 (10%)	340 (10%)	1 (3%)	--	--
Coastal	585 (2%)	3 (1%)	200 (2%)	1 (1%)	290 (10%)	1 (13%)
Subtotal	3,995	11	540	2	290	1
Texas						
State	65 (5%)	.2 (0.4%)	140 (23%)	0.3 (1%)	10 (31%)	--
Coastal	300 (7%)	4 (2%)	90 (5%)	0.4 (1%)	70 (15%)	0.2 (4%)
Subtotal	365	1.6	230	0.7	80	0.2
GRAND TOTAL	**5,960**	**25**	**2,066**	**11**	**570**	**4**

Gas production impacts are not as severe, with production dropping by 1% by the year 2000 in the Central Gulf over what would otherwise occur under current regulations.

In State waters, the impacts on future oil production are significant under both price scenarios, with an initial 30% to 40% drop in oil production in 1995 in Louisiana and Texas. The impact continues in Texas, with a drop in production also occurring in 2000.

Production in coastal waters also may drop significantly. For example, at a $16/bbl price, oil production in coastal Texas could drop by 11% in 1995, and by 7% in 2000, over that otherwise occurring. Similar impacts are experienced at a $20/bbl oil price.

The impacts of the new and possible future regulatory requirements are even more significant when examined from the perspective of total reserves lost. By the year 2010, from 7 to 10 million bbl of oil and 54 to 76 Bcf of gas will not get produced from known producing fields because of the new discharge requirements, depending upon price. Under a zero discharge scenario, again depending on price, from 43 to 58 million bbl of oil and 238 to 421 Bcf of gas that would otherwise be economic would not be produced by the year 2010.

4.3 Impacts on Reserves in Fields Remaining to be Discovered

In addition to impacting current production operations, new and potential future environmental compliance requirements could impact the economics of exploring for and developing new oil and gas fields in the Gulf of Mexico, potentially resulting in otherwise economic prospects to become uneconomic. Because of the already high costs associated with exploring for and developing currently undiscovered fields in the Gulf of Mexico, the proposed new discharge standards will not significantly impact future reserves, although the costs of developing these prospects will certainly increase (**Tables 4.14** through **4.19**), resulting in a maximum impact of 191 million bbl of reserves lost (a 3% reduction in otherwise recoverable reserves) under the 1994 AEO price scenario evaluated. Under a zero discharge requirement, on the other hand, from 785 million to 1.2 billion bbl of otherwise economic crude oil reserves are estimated to become uneconomic, depending on future prices; 10% to 20% less than would otherwise be the case. The greatest impact would be on potential undiscovered reserves in Federal waters, as illustrated in **Tables 4.14** through **4.16**.

Table 4.14. Estimated impacts of environmental compliance requirements on crude oil reserves in fields remaining to be discovered ($16/bbl constant price).

Scenario	Federal Waters	State & Coastal Waters	Total
Base Case Reserves (MMbbl)[a]	4,334	1,760	6,094
New Requirements Scenario			
Reserves (MMbbl)	4,334	1,760	6,094
Reserves Lost (MMbbl)	-	-	-
Percentage Lost	-	-	-
Zero Discharge Scenario			
Reserves (MMbbl)	3,134	1,760	4,894
Reserves Lost (MMbbl)	1,200	-	1,200
Percentage Lost	28%	-	20%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

Table 4.15. Estimated impacts of environmental compliance requirements on crude oil reserves in fields remaining to be discovered ($20/bbl constant price).

Scenario	Federal Waters	State & Coastal Waters	Total
Base Case Reserves (MMbbl)[a]	5,131	1,855	6,986
New Requirements Scenario			
Reserves (MMbbl)	5,131	1,855	6,986
Reserves Lost (MMbbl)	-	-	-
Percentage Lost	-	-	-
Zero Discharge Scenario			
Reserves (MMbbl)	4,367	1,834	6,201
Reserves Lost (MMbbl)	764	21	785
Percentage Lost	15%	1%	11%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

Table 4.16. Estimated impacts of environmental compliance requirements on crude oil reserves in fields remaining to be discovered (1994 AEO Reference Case Price Forecast).

Scenario	Federal Waters	State & Coastal Waters	Total
Base Case Reserves (MMbbl)[a]	5,157	2,046	7,203
New Requirements Scenario			
Reserves (MMbbl)	5,157	1,855	7,012
Reserves Lost (MMbbl)	-	191	191
Percentage Lost	-	9%	3%
Zero Discharge Scenario			
Reserves (MMbbl)	4,385	1,855	6,240
Reserves Lost (MMbbl)	772	191	963
Percentage Lost	15%	9%	13%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

Table 4.17. Estimated impacts of environmental compliance requirements on natural gas reserves in fields remaining to be discovered ($1.50/MMBtu constant price).

Scenario	Federal Waters	State & Coastal Waters	Total
Base Case Reserves (Bcf)[a]	24,803	44,021	68,824
New Requirements Scenario			
Reserves (Bcf)	24,803	44,021	68,824
Reserves Lost (Bcf)	-	-	-
Percentage Lost	-	-	-
Zero Discharge Scenario			
Reserves (Bcf)	21,460	41,472	62,932
Reserves Lost (Bcf)	3,343	2,549	5,892
Percentage Lost	13%	6%	9%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

Table 4.18. Estimated impacts of environmental compliance requirements on natural gas reserves in fields remaining to be discovered ($2.00/MMBtu constant price).

Scenario	Federal Waters	State & Coastal Waters	Total
Base Case Reserves (Bcf)[a]	59,485	47,869	107,354
New Requirements Scenario			
Reserves (Bcf)	59,485	47,869	107,354
Reserves Lost (Bcf)	-	-	-
Percentage Lost	-	-	-
Zero Discharge Scenario			
Reserves (Bcf)	25,426	44,407	69,833
Reserves Lost (Bcf)	34,059	3,462	37,521
Percentage Lost	57%	7%	35%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

Table 4.19. Estimated impacts of environmental compliance requirements on natural gas reserves in fields remaining to be discovered (1994 AEO Reference Case Price Forecast).

Scenario	Federal Waters	State & Coastal Waters	Total
Base Case Reserves (Bcf)[a]	67,009	47,869	114,878
New Requirements Scenario			
Reserves (Bcf)	67,009	47,869	114,878
Reserves Lost (Bcf)	-	-	-
Percentage Lost	-	-	-
Zero Discharge Scenario			
Reserves (Bcf)	59,485	47,869	107,354
Reserves Lost (Bcf)	7,524	-	7,524
Percentage Lost	11%	-	7%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

The impacts on undiscovered gas reserves could be even more significant. Depending on future prices, from 5 to 37 Tcf of otherwise economic reserves could become uneconomic because of the proposed standards, a 7% to 35% drop in otherwise economic reserves. Again, the largest economic impact of potential future zero discharge requirements for produced water from offshore facilities will be for new discoveries in Federal waters. The results for undiscovered gas reserves are summarized in **Tables 4.17** through **4.19**.

4.4 Impacts on Public Sector Revenues

Future environmental compliance requirements on oil and gas exploration and production operations will also impact revenues collected by Federal and State governments as a result of offshore and coastal oil and gas production. This includes revenues collected from Federal income taxes, severance and State income taxes from production in State waters, and from royalties on production in Federal waters. Public sector revenues from lease bonus payments are addressed in the following chapter.

Industry compliance with new standards for offshore produced water discharges are estimated to result in estimated lost revenue to public sector treasuries (both Federal and State) from producing fields on the order of $250 to $260 million between now and the year 2000, depending on future prices. By the year 2010, from $360 to $400 million could be lost. This represents a 1% to 2% loss in public sector revenues otherwise collected from oil and gas production in currently producing fields. As shown in **Tables 4.20** through **4.24**, most of these lost revenues are the result of decreased revenues from Federal and State income taxes.

If a zero discharge requirement is imposed on all water produced in association with oil and gas production from currently producing fields in the Gulf of Mexico, lost revenue to public treasuries could be significant. By the year 2000, depending on future oil and gas prices, from $0.9 to $1.0 billion in public sector revenues could be lost, a reduction in 5% of that otherwise received. By 2010, from $1.2 to $1.4 billion in public sector revenues could be lost.

Table 4.20. Estimated impacts of new environmental compliance requirements on public sector revenues from oil and gas production impacts on currently producing fields (Oil price: $16/bbl constant; gas price: $1.50/MMBtu constant).

Scenario	Severance Taxes		Income Taxes		Total	
	By 2000	By 2010	By 2000	By 2010	By 2000	By 2010
Base Case Revenues ($MM)[a]	1,091	1,321	15,846	19,725	16,936	21,046
New Requirements Scenario						
Revenues ($MM)	1,079	1,298	15,609	19,386	16,688	20,684
Revenues Lost ($MM)	12	22	237	339	249	361
Percentage Lost	1%	2%	1%	2%	1%	2%
Zero Discharge Scenario						
Revenues ($MM)	1,034	1,251	14,979	18,583	16,013	19,834
Revenues Lost ($MM)	57	70	867	1,142	924	1,212
Percentage Lost	5%	5%	5%	6%	5%	6%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

Table 4.21. Estimated impacts of new environmental compliance requirements on public sector revenues from oil and gas production impacts on currently producing fields (Oil price: $20/bbl constant; gas price: $2.00/MMBtu constant).

Scenario	Severance Taxes		Income Taxes		Total	
	By 2000	By 2010	By 2000	By 2010	By 2000	By 2010
Base Case Revenues ($MM)[a]	1,323	1,608	21,958	27,518	23,281	29,126
New Requirements Scenario						
Revenues ($MM)	1,313	1,590	21,712	27,159	23,025	28,749
Revenues Lost ($MM)	10	18	246	359	256	377
Percentage Lost	1%	1%	1%	1%	1%	1%
Zero Discharge Scenario						
Revenues ($MM)	1,263	1,533	21,037	26,287	22,300	27,820
Revenues Lost ($MM)	60	75	922	1,232	982	1,307
Percentage Lost	5%	5%	4%	4%	4%	4%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

Table 4.22. Estimated impacts of new environmental compliance requirements on public sector revenues from oil and gas production impacts on currently producing fields (1994 AEO Reference Case Price Forecast).

Scenario	Severance Taxes		Income Taxes		Total	
	By 2000	By 2010	By 2000	By 2010	By 2000	By 2010
Base Case Revenues ($MM)[a]	1,379	1,758	23,350	34,434	24,729	36,192
New Requirements Scenario						
Revenues ($MM)	1,369	1,742	23,100	32,054	24,469	33,796
Revenues Lost ($MM)	10	16	250	380	260	396
Percentage Lost	1%	1%	1%	1%	1%	1%
Zero Discharge Scenario						
Revenues ($MM)	1,314	1,681	22,409	31,131	23,723	32,812
Revenues Lost ($MM)	65	77	941	1,303	1,006	1,380
Percentage Lost	5%	4%	4%	4%	4%	4%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

Table 4.23. Estimated impacts of new environmental compliance requirements on public sector revenues from oil and gas production, presenting ultimate impact on fields remaining to be discovered (Oil price: $16/bbl constant; gas price: $1.50/MMBtu constant).

Scenario	Royalties	Severance and Income Taxes	Total
Base Case Revenues ($MM)[a]	25,093	51,635	76,728
New Requirements Scenario			
Revenues ($MM)	25,093	51,527	76,527
Revenues Lost ($MM)	—	108	108
Percentage Lost	—	<1%	<1%
Zero Discharge Scenario			
Revenues ($MM)	21,588	44,521	66,109
Revenues Lost ($MM)	3,505	7,114	10,619
Percentage Lost	14%	14%	14%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

Table 4.24. Estimated impacts of new environmental compliance requirements on public sector revenues from oil and gas production, presenting ultimate impacts on fields remaining to be discovered (Oil price: $20/bbl constant; gas price: $1.50/MMBtu constant).

Scenario	Royalties	Severance and Income Taxes	Total
Base Case Revenues ($MM)[a]	44,304	87,801	132,105
New Requirements Scenario			
Revenues ($MM)	44,304	87,637	131,941
Revenues Lost ($MM)	—	164	164
Percentage Lost	—	<1%	<1%
Zero Discharge Scenario			
Revenues ($MM)	32,961	73,704	106,665
Revenues Lost ($MM)	11,343	14,097	25,440
Percentage Lost	26%	16%	19%

Footnote:

[a] Assuming compliance with existing regulatory requirements.

New environmental compliance requirements could also impact public sector revenues ultimately received from production from oil and gas fields that remain to be discovered in the Gulf of Mexico. Compliance with the new standards for offshore produced water discharges could result in ultimate estimated losses in public sector revenues of $100 to $160 million, depending on price, from production from currently undiscovered fields. If a zero discharge requirement was universally imposed on offshore produced water discharges, from $10 to $25 billion in total public sector revenues could be lost from production of undiscovered oil and gas reserves in the Gulf of Mexico.

5.0 ASSESSMENT OF IMPACTS ON LEASE BONUS REVENUES FROM OFFSHORE OIL AND GAS LEASE SALES

The objective of this task was to assess the impacts of existing and anticipated future offshore discharge requirements on bonus revenues from future Federal and State offshore lease sales in the Gulf of Mexico. These impacts are estimated based on the assumed perceptions of offshore operators concerning the viability of future offshore prospects and the perceived value of these prospects, which is demonstrated by the amount operators are willing to bid on offshore leases in the Gulf of Mexico.

In evaluating the risks associated with offshore exploration prospects, and hence the potential profitability of finding and developing these prospects, a successful bidder must properly account for technical, economic, political, and regulatory uncertainty. Clearly, the greater the uncertainty for any of these factors, all other factors being equal, the greater the uncertainty in the expected value of the prospect. For an operator assessing the risked value of a particular offshore prospect, the potential of significantly more stringent environmental compliance requirements could have a significant effect on that assessment. Similarly, the prospect of increased environmental compliance requirements will affect the decision of an operator to aggressively pursue the acquisition of leases to explore. The objective of this task was to develop algorithms necessary to estimate the impact of increased compliance costs on bonus revenues from offshore leasing activity in the Gulf of Mexico. The steps undertaken in this assessment are summarized below.

In order to perform an assessment of government revenues received from leasing untested oil and gas prospects in the Federal and State waters of the Gulf of Mexico, the full expected value of each prospect must be estimated, and then an estimate must be made of the lease bonus payment an operator would be willing to pay for the lease based on the expected value of the prospect. Two possible outcomes for the development of each prospect were considered in this analysis: 1) that a successful discovery is made, and 2) that a dry hole is the result of exploratory drilling. A discounted cash flow was performed and the expected net present value of each prospect was estimated based on the two possible outcomes. The expected net present value after depletion adjustment and dry hole write-off is considered to be the full value of the prospect on which the lease bonus would be paid by the operator for the right to conduct exploration activity on the property.

Loss in government revenues received from Federal OCS and State water leases due to the increased cost of environmental compliance was evaluated only for the zero discharge scenario, since the impacts assumed for the new requirements case were shown to be negligible.

As shown in **Table 5.1**, nearly $100 million of ultimate public sector revenues from lease bonus payments could be lost as a result of a zero discharge requirement imposed on oil and gas production operations in the entire Gulf of Mexico. Most of this impact will be felt on bonus bids for leases in Federal waters, since the fields likely to become uneconomic as a result of the increased compliance requirements are considerably larger in Federal waters than those at the margin in State waters, which would have otherwise received greater bonus bids.

Table 5.1. Estimated impact of potential zero discharge requirements on estimated ultimate revenues from bonus payments for offshore leases.

Scenario	Potential Bonus Revenues Lost ($MM)		
	State Waters	**Federal Waters**	**Total**
$16/bbl oil price; $1.50/MMBtu gas price			
- Oil leases	0.2	17	17
- Gas leases	1.1	63	64
Total	**1.3**	**80**	**81**
$20/bbl oil price; $2.00/MMBtu gas price			
- Oil leases	0.2	19	19
- Gas leases	1.2	63	64
Total	**1.4**	**82**	**83**
1994 AEO Price Forecast			
- Oil leases	0.3	23	23
- Gas leases	1.4	73	75
Total	**1.7**	**96**	**98**

6.0 COMPARISON TO OTHER ECONOMIC IMPACT ASSESSMENTS

A number of assessments characterizing the impacts of various potential regulatory initiatives on domestic oil and gas supplies have been completed within the past five years. They include assessments of:

- Potential cumulative impacts of environmental regulatory initiatives on domestic crude oil exploration and production (E&P) operations;
- Potential economic and energy supply impacts of proposed regulations on the discharge of drilling fluids and cuttings, produced water, and other effluents on domestic offshore undiscovered crude oil resources;
- Potential economic impacts associated with proposed air pollution control regulations for oil and gas E&P operations on the OCS;
- Potential impact of future environmental regulations on the domestic oil and gas industry; and
- Potential impact of final effluent limitations guidelines and standards of performance for the offshore oil and gas industry.

These reports assess the potential economic impacts of a number of different Federal environmental statutes and proposed rules, both individually and cumulatively, affecting the oil and gas E&P industry.

The purpose of this task was to summarize the methodology and results associated with previous impact assessments of potential future environmental regulatory initiatives of the U.S. oil and gas E&P industry, with the intent of comparing these results to those resulting from the current effort. This section will summarize both the methodology used in each analysis and the anticipated impacts of the potential regulatory initiatives examined. Impacts will be discussed in terms of potential future compliance costs, as well as oil and gas reserves and production lost.

6.1 Potential Cumulative Impacts of Environmental Regulatory Initiatives on U.S. Crude Oil Exploration and Production

6.1.1 Summary

ICF Resources (1990), in a report prepared for the U.S. Department of Energy, described the cumulative effect that future environmental regulations could have on the recovery of crude oil in the U.S. The study developed three regulatory scenarios that represented a range of incremental costs that may be incurred by the domestic oil industry as a result of possible future regulatory initiatives under Resource Conservation and Recovery Act (RCRA), Safe Drinking Water Act (SDWA), Clean Water Act (CWA), and Clean Air Act (CAA). The three scenarios considered included: 1) a "high scenario", which represented a stringent but conceivable level of regulation (not necessarily to be considered a worst case scenario); 2) a "low scenario", which represented existing regulations with some change (though not necessarily the initiatives defined); and 3) a "medium scenario", which represented a case balancing the high and low scenarios (but which was not intended to represent a most-likely scenario).

This study did not consider every potential environmental initiative that may affect the economics of domestic E&P activities, since estimated compliance costs associated with many initiatives have not been assessed. In addition, the initiatives proposed or under consideration were constantly evolving; this study represented only those under consideration at the time of the analysis.

Using available DOE models, the cumulative impacts associated with each scenario were estimated. Impacts were presented in terms of the estimated incremental compliance costs operators would have to incur to comply with each scenario and the crude oil reserves and/or production that would become uneconomic as a result of these increased costs. Other impacts such as the impact on Federal and State revenues from royalties and tax receipts and the impact on industry expenditures for oil development were also considered.

The initial step in the analysis was to develop an estimate of economic recovery potential under baseline conditions, which assumed costs of compliance with environmental regulations currently in place. Four constant crude oil prices (i.e., $16, $20, $24, and

$32/bbl) were used to estimate recovery potential for a "reference scenario", against which other scenarios were compared.

The future production potential from the following four crude oil resource categories was considered, with energy impacts associated with the imposition of increased environmental compliance costs assessed for each category:

- Continued conventional production of crude oil in known onshore fields in the Lower-48;
- Future infill drilling and waterflood projects in known onshore fields in the Lower-48;
- Future enhanced oil recovery projects in known onshore fields in the Lower-48; and
- Onshore and offshore crude oil fields remaining to be discovered in the Lower-48 and Alaska.

6.1.2 Results

As discussed above, this assessment analyzed the potential energy impacts of increased environmental regulations on four categories of crude oil supplies (i.e., conventional production, unrecovered mobile oil, enhanced oil recovery, and undiscovered oil). These impacts are presented in terms of: a) the percent of economically recoverable resources that become uneconomic as a result of increased environmental regulations; and b) the percent of Federal and State revenues (e.g., Federal royalty payments and State severance taxes) that are not collected as a result of lost reserves. Although four crude oil prices were considered in this assessment, **Table 6.1** presents only the resource impacts at a price of $20/bbl.

Table 6.1. Impact of potential environmental regulations on U.S. crude oil supplies at an oil price of $20/bbl (From: ICF Resources, 1990).

Level of Assessment	Resource Category			
	Conventional Production[a]	Unrecovered Mobile Oil	Enhanced Oil Recovery	Undiscovered
	Nine States[b]	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

Note: N/A = Not analyzed.

Footnotes:

[a] Represents incremental resource lost (over the reference case) immediately (in 1990) from premature abandonment;
[b] California, Colorado, Illinois, Kansas, Louisiana, New Mexico, Oklahoma, Texas, and Wyoming.

6.2 The Impact of Proposed Regulations on the Discharge of Effluents from Offshore Facilities on U.S. Undiscovered Crude Oil Reserves

6.2.1 Summary

ICF Resources (1991) examined the potential economic and energy supply impacts of the 1991 proposed Federal offshore effluent limitation guidelines on the costs of developing U.S. undiscovered crude oil reserves in the offshore areas of the Lower-48 and Alaska. The proposed regulations set limitations on the discharge of drilling muds; produced water and deck drainage; produced sand; and well treatment, completion, and workover fluids. A detailed discussion of these requirements has been previously presented in **Section 1.3.1.**

Impacts of the proposed requirements for the following two alternate scenarios were developed:

- Scenario 1. Assumed compliance with the proposed rule. Under this scenario, two separate cost cases were considered. The first case was based on EPA's characterization of potential future offshore operations that would be subject to the new standards, with EPA's estimate of the associated unit compliance costs. The second case was based on API's characterization of potential future offshore operations, with API estimates of the incremental compliance costs necessary to achieve the new standards; and

- Scenario 2. Assumed zero discharge for drilling muds, drill cuttings, and produced water based on a somewhat stricter interpretation and/or implementation of the proposed guidelines, considered only for API's characterization of future compliance requirements.

Four crude oil prices ($16, $20, $24, and $32/bbl) were used to establish recovery potentials for a "base scenario", against which the other scenarios were compared.

6.2.2 Results

The estimated impacts presented in the study were based on the incremental costs of compliance with alternative regulatory scenarios (as described above) when compared to a "reference" case. The reference scenario assumed no incremental costs for waste management and disposal beyond those currently required (at the time) and practiced by offshore operators.

Table 6.2 displays the potential impacts of the proposed rule (under Scenarios 1 and 2) in terms of the amount of offshore undiscovered crude oil in the Gulf of Mexico that would become uneconomic at a given price. The offshore Gulf of Mexico region accounts for approximately 50% of the total amount of offshore crude oil reserves in the Lower-48 region.

The only direct comparison with the current work is the "Produced Water Only" case under Scenario 2, at $16 and $20/bbl (shown in **Table 6.2**), compared to the $16 and $20/bbl cases for the zero discharge scenario in this study (see **Tables 4.14** and **4.15**). As shown, the more recent characterization results in substantially greater impacts in terms of volume of oil at $16/bbl (1.2 billion bbl compared to 170 million bbl), but lower impacts at $20/bbl (i.e., 764 million compared to 890 million bbl). However, because of the substantial difference in estimated reserves under reference case conditions for the two studies, these two estimates of impacts are not adequately comparable.

Table 6.2. Estimated impacts of earlier proposed offshore effluent guidelines on U.S. undiscovered crude oil reserves (From: ICF Resources, 1991).

Scenario		Estimated Impacts on Potential Crude Oil Reserves (Billion Barrels)				
Crude Oil Price (1988$/bbl)	Reference Case	Scenario 1		Scenario 2		
		EPA Costs	API Costs	Mud and Cuttings	Produced Water Only	Both
$16/bbl						
Reserves	1.71	1.71	1.71	1.70	1.54	1.51
Reserves Lost		---	---	0.01	0.17	0.20
Percentage Lost		---	---	<1%	10%	12%
$20/bbl						
Reserves	2.60	2.58	2.08	2.08	1.71	1.71
Reserves Lost		0.02	0.52	0.52	0.89	0.89
Percentage Lost		1%	20%	20%	34%	34%
$24/bbl						
Reserves	2.79	2.79	2.78	2.78	2.78	2.75
Reserves Lost		---	0.01	0.01	0.01	0.04
Percentage Lost		---	<1%	<1%	<1%	1%
$32/bbl						
Reserves	3.79	3.79	3.16	3.14	2.82	2.79
Reserves Lost		---	0.63	0.97	0.65	1.00
Percentage Lost		---	17%	26%	17%	26%

6.3 Impact of Proposed Regulations on Air Emissions From Outer Continental Shelf (OCS) Sources

6.3.1 Summary

ICF Resources (1992) assessed the potential economic impacts associated with EPA's 1991 proposed air quality control regulations for oil and gas E&P operations in specific areas of the OCS. As directed under the 1990 amendments to the CAA, EPA proposed that air pollution controls for OCS activities within 25 miles of the State seaward boundary in the Pacific, Atlantic, Eastern Gulf of Mexico, and Alaska OCS Planning Areas be the same as those applicable for their "corresponding onshore area" (COA). For OCS sources located beyond 25 miles of these State boundaries, the proposed regulations would be subject to

Federal requirements for New Source Performance Standards (NSPS), National Emission Standards for Hazardous Air Pollutants, and Prevention of Significant Deterioration.

This analysis examined the impacts of the proposed regulation on the costs of developing new OCS oil and gas resources and on producing oil and gas resources associated with existing OCS facilities. The analysis was primarily based on methodologies and control cost estimates originally developed by MMS. Compliance costs associated with EPA's proposal included the costs of control technologies and the cost of acquiring emission offsets, which would be required if the COA is a non-attainment area for specific criteria pollutants. The cost of acquiring the emission offsets and the rate of growth in these costs over time were the factors having the greatest influence on total compliance costs. The primary pollutants of concern that are associated with OCS oil and gas operations are oxides of nitrogen (NO_x) and volatile organic compounds (VOCs).

Estimated potential annualized compliance costs associated with the proposed rule, including the costs of control technology and the cost of acquiring emission offsets, were developed for the following scenarios:

- Scenario 1. Considers all OCS projects initiated and developed over the next 40 years, with no increase in the cost of emission offsets for NO_x and VOCs over that period;

- Scenario 2. Considers all OCS projects initiated and developed over 40 years, with a 5% annual increase in the cost of emission offsets for NO_x and VOCs;

- Scenario 3. Considers all OCS projects initiated and developed over 40 years, with a 17% annual increase in the cost of emission offsets for NO_x and VOCs for 5 years, and a 5% annual increase thereafter;

- Scenario 4. Considers all OCS projects initiated and developed over 40 years, with electrified platforms and a 17% annual increase in the cost of emission offsets for NO_x and VOCs for 5 years, and a 5% annual increase thereafter; and

- Scenario 5. Considers the entire life of OCS projects initiated within the first five years of promulgation of the proposed rule, with a 17% annual increase in the cost of emission offsets for NO_x and VOCs for 5 years, and a 5% annual increase thereafter.

In addition to these scenarios, a number of assumptions were developed to account for future development activities, control technologies and the costs associated with these controls, and with acquiring emission offsets. These assumptions were used to estimate the potential costs of compliance associated with the proposed rule, and in determining the energy supply impacts that could result from the promulgation of the proposed rule.

6.3.2 Results

The cost of acquiring the emission offsets and the rate of growth in these costs over time were the factors found to have greatest influence on total compliance costs. The estimated potential annualized compliance costs associated with the proposed rule, assuming that leasing of emissions would be required, was estimated to range from $9 to $26 million, as shown in **Table 6.3**.

Table 6.3. Estimated potential annualized compliance costs associated with proposed regulatory requirements for OCS air emissions sources in areas under the jurisdiction of EPA (From: ICF Resources, 1992).

Scenario	Estimated Cost Impacts (Million 1991$)
1	9
2	16
3	25
4	26
5	24

6.4 The Potential Role of Future Environmental Regulations on the Domestic Petroleum Industry

6.4.1 Summary

Godec *et al.* (1993) summarized the results of the published National Petroleum Council (NPC) assessment of constraints on future North American natural gas production and use (NPC, 1992), along with a concurrent study of future oil supplies for DOE (ICF Resources, 1994). The paper identifies possible environmental and legislative initiatives affecting domestic E&P operations, characterizes the potential impacts of these initiatives on future compliance costs, and estimates their potential impacts on future oil and gas supplies.

The assessment was performed for two potential future environmental regulatory scenarios: a "balanced" scenario and a more stringent regulatory scenario, defined as follows:

- Balanced Regulatory Case. The compliance costs developed for this scenario are intended to represent a "balanced" future characterized by a level of environmental regulation adequate to protect human health and the environment, which balances the costs and benefits of compliance requirements and oil and gas production. This scenario also recognizes that such a regulatory approach allows states to retain regulatory primacy under the authority of the various environmental statues considered; and

- High Regulatory Case. The environmental compliance costs developed for this more stringent regulatory scenario are intended to correspond to a future level of environmental regulation which may sacrifice some level of U.S. oil and gas supplies to gain perceived environmental benefits, notwithstanding the costs associated with decreased supplies. The philosophy of this scenario is that domestic production is important, but assumes that the U.S. will not abandon its thrust towards increased environmental protection for the foreseeable future.

For purposes of this analysis, the balanced regulatory scenario was assumed to be a reference (though not necessarily a most likely) case, against which the high regulatory case was compared.

The estimated impacts of potential increased environmental requirements were developed in terms of: a) unit compliance costs; b) economically recoverable resources (reserves) and future production potential lost; and c) incremental industry expenditures.

6.4.2 Results

Depending on the level of future economic growth, the study showed that the U.S. petroleum industry could incur an additional $70 to $86 billion in increased environmental compliance expenditures over the 1992 to 2010 time period. Under a more stringent regulatory scenario, a substantial portion of otherwise economic oil and gas resources could become uneconomic to develop and produce. Stringent environmental compliance requirements could result in 26% higher initial costs for new gas wells and 32% higher costs for new oil wells. Annual operating costs for existing wells could increase by 59% for gas wells and 43% for oil wells. **Table 6.4** displays the average percent increase in costs associated with "typical" wells under the balanced and more stringent regulatory scenarios, for both onshore and offshore wells.

Table 6.4. Average percent increase in compliance costs (From: Godec *et al.*, 1993).

Well Category	Oil		Gas	
	Balanced Scenario	**More Stringent Scenario**	**Balanced Scenario**	**More Stringent Scenario**
Lower-48 Onshore Wells				
New Well				
Initial Cost	9.6%	32%	10.5%	26%
Annual Cost	9.3%	41%	13.0%	59%
Existing Well				
Initial Cost	9.0%	620%	98%[a]	319%[a]
Annual Cost	9.3%	43%	10%	59%
Lower-48 Offshore Wells				
New Well				
Initial Cost	1.5-3%	29-39%	1-2%	23-31%
Annual Cost	4%	15-18%	4%	15-18%
Existing Well				
Initial Cost	<1%	33%	<1%	30%
Annual Cost	<1%	2%	<1%	2%

Footnote:

[a] One-time cost increase presented relative to normal O&M costs.

In addition to the potential cost impacts shown above, the study showed that oil and gas production and the future production of undiscovered oil resources could also be impacted. Crude oil production could decrease by 290,000 to 620,000 bbl/day by 2010 under a more stringent regulatory scenario depending on the level of future economic growth. Under this stringent scenario, domestic gas production could decrease 2.0 to 2.3 Tcf during the first year when compared to the balanced scenario. By 2010, 5.0 to 5.5 Tcf more than that lost under the balanced scenario could become uneconomic.

In addition to impacts on current production levels, the regulatory scenarios considered can be expected to have a significant impact on the economic viability of finding, developing, and producing undiscovered crude oil and gas reserves. Under the more stringent regulatory scenario (assuming an oil price of $20/bbl), up to 2.4 billion bbl of otherwise recoverable reserves could be lost. This is a 25% greater loss than that under the balanced regulatory case. Approximately 37 Tcf of undiscovered gas could become uneconomic to develop under this scenario; this represents 13% of otherwise recoverable reserves.

6.5 Economic Impact Analysis of Final Effluent Limitations Guidelines and Standards of Performance for the Offshore Oil and Gas Industry

6.5.1 Summary

EPA issued an economic impact analysis in support of the promulgation of final effluent limitations guidelines and standards for the offshore oil and gas industry in 1993 (EPA, 1993b). **Table 6.5** summarizes the final guidelines, which were published in the *Federal Register* on March 4, 1993.

Two sets of "regulatory packages" were developed for comparison with a baseline scenario. Package "A" consists of the following requirements (these requirements represent EPA's final rule):

- *Drilling Wastes.* For all regions except Alaska, drilling wastes from wells within three miles of shore must meet zero discharge requirements. Drilling waste disposal from wells located beyond three miles from shore must meet limitations on toxicity, no discharge of diesel oil or free oil, and limitations on mercury and cadmium;
- *Produced Water.* Induced gas flotation is used for all structures to meet Best Available Technology (BAT)/NSPS limitations;
- *Well Treatment, Completion, and Workover Fluids.* BAT/NSPS limitations must be achieved; and
- *Produced Sand.* Zero discharge of produced sand.

Table 6.5. Final BAT and NSPS limitations for offshore oil and gas operations.

Facilities	Pollutant Parameter	Effluent Limitation
	Produced Water	
All	Oil and Grease	No discharge if daily maximum exceeds 42 mg/l, and monthly average exceeds 29 mg/l
	Drilling Fluids and Drill Cuttings	
Within 3 miles of shore	—	No discharge[a]
Beyond 3 miles of shore	Toxicity Free/Diesel oil Mercury Cadmium	No discharge No discharge 1 mg/kg maximum in stock barite 3 mg/kg maximum in stock barite
	Well Treatment, Completion, and Workover Fluids	
All	Oil and Grease	No discharge if daily maximum exceeds 42 mg/l, and monthly average exceeds 29 mg/l
	Produced Sand	
All	—	No discharge
	Deck Drainage	
All	Free oil	No discharge

Footnote:

[a] Alaskan facilities are exempt from no discharge limitation. They are required to comply with the same discharge requirements as facilities located beyond three miles from shore.

Regulatory package "B" consists of the following, more stringent requirements (only produced water requirements have changed):

- *Drilling Wastes*. For all regions except Alaska, drilling wastes from wells within three miles from shore must meet zero discharge requirements. Drilling waste disposal from wells located beyond three miles from shore must meet limitations on toxicity, no discharge of diesel oil or free oil, and limitations on mercury and cadmium;
- *Produced Water*. Zero discharge is allowed for Gulf of Mexico platforms within three miles from shore. Induced gas flotation is utilized for Gulf of Mexico platforms beyond three miles from shore and all structures in the Pacific OCS;
- *Well Treatment, Completion, and Workover Fluids*. BAT/NSPS limitations must be achieved; and
- *Produced Sand*. Zero discharge of produced sand.

6.5.2 Results

The initial annualized cost of implementing the required pollution control options in order to meet regulatory package A is approximately $134 million in the first year of implementation and $38 million in year fifteen (in 1991 dollars). The cost declines in time as existing projects meeting BAT requirements become uneconomic. NSPS costs have been assumed to increase year by year as projects come into operation. The costs of regulatory package B have been estimated at $160 million (year one) and $94 million (year fifteen).

EPA also estimated impacts in terms of potential production and Federal and State revenues that are lost. When compared with the total, baseline production from BAT and NSPS structures, the range in production loss was found to vary from less than 0.1% (package A) to 0.3% (package B). Federal revenues can be impacted by the tax effects of expenditures made to meet effluent guidelines and by potential reductions in lease/bonus bids. The potential impact of the regulations in Federal revenues in the first year was estimated at between $129 to $153 million, depending on the regulatory package. State revenues can be affected by reductions in lease/bonus bids. The maximum estimated impact of these guidelines on State revenues was estimated at between $8 and $10 million.

7.0 CONCLUSIONS

The high potential costs of compliance associated with new effluent guidelines for offshore and coastal oil and gas operations could significantly affect the economics of finding, developing, and producing oil and gas in the Gulf of Mexico. This report characterizes the potential impacts of alternative treatment and discharge regulations on reserves and production in Gulf of Mexico coastal, territorial and outer continental shelf (OCS) waters, quantifying the impacts of both recent regulatory changes and possible more stringent requirements. The treatment technologies capable of meeting these requirements are characterized in terms of cost, performance, and applicability to coastal and offshore situations. As part of this analysis, an extensive database was constructed that includes oil and gas production forecasts by field, data on existing platforms, and the current treatment methods in place for produced water treatment and disposal on offshore facilities. This work provides the first comprehensive evaluation of the impacts of alternative regulatory requirements for produced water management and disposal in coastal and offshore areas of the Gulf of Mexico.

Regulations on the discharge of produced water generated from offshore oil and gas operations in the Gulf of Mexico are becoming increasingly stringent, reducing the options available for many producers to comply. Future trends indicate that requirements on produced water discharges are likely to continue to become more stringent. The impacts of these requirements can be significant, posing considerable burdens on industry to incur the costs, and on the nation to assure adequate supplies of domestically produced oil and gas. To comply with a possible zero discharge requirement for the entire Gulf of Mexico, for example, industry would have to expend nearly $200 million a year between now and 2010. As much as 58 million bbl of reserves from currently producing oil fields and 1.2 billion bbl of reserves from oil fields yet to be discovered could be lost. Similarly, as much as 421 Bcf from producing gas fields and 67 Tcf from undiscovered gas fields could be lost. Therefore, balancing the costs of future compliance requirements with the environmental benefits that result from more stringent standards is the challenge facing both industry and governments in the years ahead as it affects the development and production of offshore oil and gas resources.

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