DRAFT

3/21/94

Response to Proposals from the Oil and Gas Industry
(Attachments to the NEC documents)

There are several false and/or misleading statements in the industry-supplied attachments to the NEC document.

Statements in the industry attachments:
1. Although relevant statutes do not require it, damages could include the emotional losses of people who do not use the resources.

First, we note that the somewhat pejorative or belittling reference to "emotional losses" in the attachments is ambiguous. It is not a term used in either the Oil Pollution Act [OPA] or Comprehensive Emergency Response, Conservation and Liability Act [CERCLA] statutes to describe the measure of natural resource damages. The authors could be intending to distinguish "emotional losses" from injuries associated with direct physical harm or from injuries associated with financial losses -- both definitions would rule out **most, if not all,** categories of losses claimed in natural resource damage assessment [NRDA] cases [following principles established in the statutes, regulations, and judicial decisions on challenges to the statutes and regulations.] For example, recreational losses, cultural/historical losses, ecological losses, and passive use losses, all involve losses in consumer surplus - the amount of value consumers gain from use of a resource in excess of the price they must pay for its use. A loss of consumer surplus does not imply a direct financial loss. In fact, the only category of losses that trustees may claim that does involve a direct financial loss is lost user fees or lost net income of public trustee enterprises - the least frequently relevant category of losses.

However, the authors of the proposals may have intended this term as a pejorative reference to passive uses losses only, since this has been a (the) major target of industry in the OPA and CERCLA rule-makings. [In contrast to "direct use" values, "passive use" values refer to the values individuals place on resources which are not linked to direct resource use by the individual. Passive use values include: the value of knowing the resource is available for use of family, friends, or the general public; the value derived from protecting the resource for its own sake; and the value of knowing that future generations will be able to use the resource.]

In the substantive discussion below, I assume that industry is referring to "passive use values" when using the term "emotional values".

<u>Current judicial and Congressional interpretations of the statutes clearly state that passive use value is a component of NRDA claims under CERCLA and OPA.</u>

In the 1980s, the Department of Interior promulgated regulations interpreting the NRDA provisions of CERCLA, and was sued by a wide range of parties on a wide range of issues, including contingent valuation. The D.C. Circuit Court decision in that case [*Ohio v. Department of Interior*] clearly indicated that diminution in value is to encompass both direct use (e.g., commercial and recreational) as well as passive use values that can be reliably calculated, i.e. calculated in a manner that is trustworthy or worthy of confidence. Further, the *Ohio* decision found **that CV methodology could be utilized as a "valid, proven technique when properly structured and professionally applied."** [Note: the DC Circuit Court will be the court to hear the inevitable challenges to the OPA NRDA rule.]

The measure of damages cited in the Oil Pollution Act, section 1006(d) is:

> the costs of restoration, replacement, rehabilitation, or acquisition of the equivalent of the injured natural resources, **plus** the diminution in value of those resources pending recovery.
>
> The Conference Report accompanying OPA clearly states that "'[d]iminution in value" refers to the standard for measuring natural resource damages used in the recent D.C. Circuit Court decision [*Ohio v. Department of Interior,* 880 F2d 432 (D.C. Cir. 1989).

2. A panel of economists created by NOAA was ***unable to confirm that CV was a reliable methodology.***

In fact the Blue Ribbon Panel on Contingent Valuation convened by NOAA found that **contingent valuation can produce estimates reliable enough to be presented in a judicial or administrative determination of natural resource damages, including passive use value,** provided that such studies adhere closely to the guidelines described in their report. Thus the statement in the NEC document is a false representation of the unanimous conclusion of the NOAA Panel.

The proposed NOAA regulations follow closely the guidelines recommended by the Blue Ribbon Panel.

property value with oil and gas extraction. When percentage depletion exceeds cost depletion the taxpayer may continue percentage depletion, generally at a 15 percent rate, as long as production continues. This deduction may cumulate to exceed the original cost of the property i.e., the taxpayer is able to recover as a deduction more than his or her original costs. Percentage depletion is limited to 365,000 barrels per year per taxpayer, may not exceed 100 percent of the net income from that property in any year (the "net income limitation") and may not exceed 65 percent of the taxpayer's overall taxable income (determined before such deduction and adjusted for certain loss carrybacks and trust distributions).[2] Estimated tax expenditures for percentage depletion total about $7.5 billion over 5 years.

Although percentage depletion is considered an incentive to maintain production from economically marginal wells, it may not be efficient. When operating costs approach the value of production, the percentage depletion allowed declines to zero, as it is limited to not exceed the net income from the property. Since percentage depletion is not allowed when there is no net income, it provides little incentive to produce from wells that are marginal, despite the substantial cost of percentage depletion to the Federal budget. The net income limitation, however, was designed to preclude any taxpayer from using percentage depletion attributable to production from one property to shelter income from another property or to shelter non-oil or gas-production income.

Non-Conventional Fuels Credit

The "non-conventional" fuels (or Section 29) credit provides a $3 per barrel of oil equivalent tax credit for gas production from "tight" formations and about a $6 per barrel credit (due to an inflation adjustment) for other qualified energy production. More specifically, fuels eligible for the credit are: (1) oil produced from shale and tar sands; (2) gas produced from tight formations, Devonian shale, coal seams, geopressured brine, and biomass; and (3) liquid, gaseous or solid synthetic fuels produced from coal. The credit generally applies to wells drilled before 1993, and credits extend for production through 2002. [Certain facilities qualify through 2007.] Qualifying gas well drilling grew rapidly in the last few years, particularly in 1992, to beat the 1993 deadline. The estimated tax expenditure for the Section 29 credit is about $6.7 billion over 5 years.

The Section 29 credit was effective in encouraging drilling and production in these formations. However, the size of the credit is sufficiently large that it likely reduced gas prices and harmed gas drilling and production from formations that do not qualify for the credit. Partly due to controversy in the industry about the wisdom of this provision and partly due to the cost, the credit was not extended for new wells drilled after 1992.

---

[2] Amounts disallowed as a result of this rule (65 percent of taxable income) may be carried forward and deducted in subsequent taxable years subject to the 65-percent taxable income limitation for those years.

Alternative Minimum Tax Relief

Oil and gas activities have largely been eliminated from the alternative minimum tax[3] (AMT), which was significantly strengthened in 1987. The Energy Policy Act of 1992 removed oil and gas percentage depletion and intangible drilling and development cost (IDC) expensing as preferences in the taxpayer's calculation of AMT beginning in years after 1992. Therefore, the taxpayer's potential alternative minimum tax is greatly reduced.[4]

The annual cost of the AMT relief is about $2.5 billion over 5 years. Little effect on production is expected (given the relaxation of the AMT for oil and gas), as the alternative minimum tax affects the timing of regular taxes rather than the total amount of tax eventually paid. (The AMT was designed to ensure that corporations with economic income would pay some tax. This may no longer be the case for oil and gas extraction.) The cost to the Federal budget of AMT relief for oil and gas is the time value of money.

Intangible Drilling and Development Costs

An integrated oil company can expense 70 percent and an independent oil company can expense 100 percent of intangible drilling and development costs (IDC). Intangible drilling and development costs are expenditures necessary for the drilling and preparation of wells for production that have no salvage value. Such expenditures include wages, fuel, repairs, hauling, supplies, etc. In practice, a number of companies have amortized a substantial portion of IDCs over 5 years. For the next five years the tax expenditure for this provision is expected to total $380 million. Calculated on a present value basis and recent levels of activity, future tax expenditures from continuing the practice is about three times this amount ($0.8 billion).

Expensing is equivalent (in the absence of debt financing) to providing an exemption from tax for the income from the investment. Thus, IDCs provide a substantial incentive for oil and gas drilling.

Enhanced Oil Recovery Credit

The enhanced oil recovery credit (Code Section 43) provides a 15 percent credit for qualified tertiary recovery expenditures which generally involve injecting substances into the reservoir to increase oil production (defined in Code Section 193). The credit was established in the Omnibus Budget Reconciliation Act of 1990 (OBRA) for expenditures after

---

[3] A taxpayer is subject to an alternative minimum tax to the extent that the taxpayer's minimum tax exceeds the taxpayer's regular income tax liability.

[4] Repeal of the excess IDC preference may not reduce the taxpayer's alternative minimum taxable income (AMTI) by more than 40 percent (30 percent in 1993) of the amount it would have been if the IDC preference had not been repealed.

1990. The 15 percent credit provides benefits in excess of expensing, i.e., the benefits are more favorable than tax exemption. Thus, this credit encourages use of tertiary methods in situations where it would not be profitable before tax. Based on 1991 corporate data, tax expenditures are expected to be about $750 million over 5 years. While the credit provides a substantial incentive, the expense of tertiary methods is sufficiently high that the increase in production from the credit is not expected to be substantial.

Increased Percentage Depletion for Stripper Wells

Oil and gas produced from stripper wells, defined as wells producing less than 5,475 barrels of oil per year (15 barrels per day) or producing heavy oil (mostly from California), are allowed an additional percentage depletion allowance equal to one percentage point for each whole dollar by which $20 exceeds the reference price for crude oil for the calendar year preceding the calendar year in which the taxable year begins. This provision was introduced in OBRA 1990 and it is limited to a 10 percentage point increase in the standard 15 percent percentage depletion rate. The growth in the depletion rate fully maintains percentage depletion allowances when oil declines in price from 20 to 15 dollars per barrel (as $20 times 15 percent equals $15 times 20 percent). It also offsets a large portion of reductions in percentage depletion allowances from oil price declines to $9 per barrel by raising the percentage depletion allowance by another 5 percentage points.

Based on 1991, 1992, and 1993 oil prices ($16.50, $15.98, and approximately $15.40, respectively), this provision gives rise to tax expenditures for 1992, 1993, and 1994. Qualifying 1992 production received an additional 3 percentage point depletion allowance over the standard 15 percent. Qualifying 1993 and 1994 production will receive an additional 4 percentage point depletion allowance (to 19 percent). The associated annual additional revenue cost will be less than $20 million. The incentive effect on production is small, as wells without net income are not eligible for percentage depletion[5]. Also, the one year lag between oil prices and the subsidy suggests that production may be encouraged in years of high oil prices and not encouraged in years of low prices. As the Administration does not forecast current low oil prices to continue, future tax expenditures are uncertain.

Other Provisions

Other recent provisions have affected the oil and gas industry. OBRA 1990 increased the net income limitation on oil and gas percentage depletion (i.e. the provision that restricts the percentage depletion allowance to not exceed 50 of net income) to 100 percent of net income from the property (valued at about $300 million over 5 years). Also, taxpayers who have working interests in oil and gas properties (rights to oil or gas income from a property), were exempted from passive loss limitations ($250 million over 5 years), and percentage depletion was allowed on properties transferred from integrated oil companies, which was not

[5]See section above on percentage depletion.

permitted under prior law (valued at about $160 million over 5 years).

II. B. Royalty Policies

DRAFT **March 24, 1994**

II. A. Royalty Policies

Royalty Rates for Outer Continental Shelf (OCS) Leases

Congress established in 1978 the following guidance for the administration of offshore Federal oil and gas leases:

- to make resources available to meet the Nation's energy needs as rapidly as possible;
- to balance orderly development with protection of the environment;
- to insure the public a fair and equitable return on the OCS resources; and
- to preserve and maintain free enterprise competition.

The Department of the Interior's Minerals Management Service (MMS) sets OCS lease terms, including royalty rates, based on this guidance. At the same time, MMS strives to achieve other Congressionally-set objectives, including meeting national economic and energy goals, assuring national security, reducing dependence on foreign sources, and maintaining a favorable balance of payments in world trade.[1]

The OCS Lands Act authorizes the Secretary of the Interior to use various systems for leasing the rights to develop offshore resources and to ensure a fair financial return to the public. The system MMS uses today consists of sealed-bid auctions of specified offshore tracts. Before each auction (lease sale), MMS announces the royalty rates that it will apply to production from those tracts (typically 16.67 percent of gross revenues from tracts in water depths of 400 meters or less, and 12.5 percent in deeper water or in certain frontier areas). Companies then bid for the tracts, which are awarded to the highest bidder, subject to a minimum bid of $25 per acre and a bid review process whereby MMS can reject high bids that do not meet certain criteria (e.g., level of competition, comparison to MMS' estimate of value).

MMS may reduce the royalty rate on any previously-issued lease in order "to promote increased production from the lease area." Relatively few lessees have ever applied for such royalty rate reductions. MMS has applied this authority only to leases that are already in production. MMS has granted reductions to fields where a reduction is needed either to:

(1) allow for continued production from a lease that is near the end of its productive life; or

[1] OCS Lands Act Amendments of 1978, 43 U.S.C. 1802.

(2) make economic additional investments that would increase or maintain production from the lease.

As authorized and directed by Congress, MMS has used several other bidding and royalty systems for offshore leases. The list below shows some of the systems previously tried and the basic reasons why MMS has opted to use the current system instead of these alternatives:

- variable royalty bidding, with a small fixed bonus payment. This system brings in minimal revenues to the Government except when and if production occurs. Furthermore, the high royalty rates that often resulted from such bidding provided a disincentive for the company to produce any resources found.

- cash bonus bidding with relatively high royalty rates (e.g. 33.3 percent). This system is similar to the current system, but it results in lower up-front bonus payment and less interest in marginal tracts. Furthermore, higher royalty rates tend to discourage producers from developing marginal prospects and from recovering the marginal resources remaining near the end of a field's productive life.

- cash bonus bidding with a sliding royalty rate which increases proportional to the lease production rate. This system has the potential to share risk between the lessor and lessee more effectively than the current system, since it charges higher royalties for larger discoveries than for smaller ones. The difficulty with such systems has been to define the sliding scales so that they are actually effective (particularly given the 12.5 percent statutory minimum discussed below) and do not distort lessees' production decisions.

- cash bonus bidding with a fixed share of net profits (typically 50 percent) associated with production from the lease. Net profit share leases have the advantage of effectively sharing risks between the lessor and lessee. However, the large accounting burdens associated with determining how much profit is attributable to a specific lease --and the difficulties in auditing such accounting-- have discouraged MMS from using this approach.

The OCS Lands Act sets a minimum royalty rate of 12.5 percent for all royalty-based systems. However, it allows the Secretary of the Interior to employ systems otherwise not allowed by the Act, provided that the Secretary submits to Congress the planned bidding system and neither the Senate nor the House passes a resolution disapproving the proposal within 30 days. Before using any new bidding system, MMS also would have to modify its regulations.

MMS' goals in designing it's bidding and royalty systems, in conformance with its Congressional mandate, can be summarized by two basic rules:

- maximize the net social value obtained from developing offshore leases. This goal implies letting companies explore and develop leases when and if the expected benefits of production (generally expressed by the production quantity times its market price) exceed the costs (primarily the exploration, development, and production costs)[2]. MMS' bidding and royalty policies generally are designed to be neutral with respect to the timing of leasing and development—companies may bid whenever they think a tract has a positive net value.

- ensure that the public receives a fair return on the resource. The current system is designed so that, on average, the government should receive a large portion of the economic "rent" resulting from development of offshore leases, while companies should be able to earn a reasonable return on their investment. The system shares much of the risk between the lessor and the lessee—the up-front bonus payment is risky for the lessee, who often does not discover sufficient resources to allow for production, while the relatively low royalty rate can allow for high rewards to those lessees who discover large, low-cost oil or gas reserves. (The Federal Government reaps additional economic benefits from offshore production operations in the form of income taxes collected on company profits. Higher royalty rates tend to reduce income tax collections by discouraging production of some otherwise profitable resources and by increasing company costs—royalties are tax-deductible costs—thereby reducing their profits.)

Changes in the oil and gas industry, such as lower oil prices than previously predicted, movement into deeper waters of the Gulf of Mexico, and declining discovery sizes, have led MMS to reevaluate it's current leasing policies. MMS issued a Federal Register notice on December 7, 1993, requesting input from the public on this issue. Based on comments received and on its own internal analyses, MMS is considering changes to make for its 1995 Gulf of Mexico lease sales, which could involve changing the royalty terms for new leases in deepwater and for certain types of new leases in shallow water. MMS also has evaluated and provided comments on legislative proposals for providing royalty incentives for deepwater production, and MMS is refining its policies for evaluating lessee's applications for lower royalty rates on existing leases.

---

[2] These costs and benefits are adjusted for external considerations not reflected in the market system, such as environmental advantages or disadvantages of developing certain leases.

DRAFT

March 24, 1994

Royalty Rates for Onshore Federal Leases

Royalty rates for onshore Federal oil and gas leases are set by the Department of the Interior's Bureau of Land Mangement (BLM). Prior to the enactment of the Federal Onshore Oil and Gas Reform Act of 1987, royalty rates ranged from 12.5 percent to 25 percent, depending on the average production level from the lease. The royalty rate is now 12.5 percent for almost all leases issued after passage of the Act. The royalty rate is 16.67 percent for noncompetitive leases reinstated after a single failure to pay penalty (plus a two percentage point increase for each additional reinstatement).

Authority for Reducing Royalty Rates--Case-by-Case Applications

The Act of August 8, 1946 amended Section 39 of the Mineral Leasing Act of 1920 to state, "The Secretary of Interior, for the purpose of encouraging the greatest ultimate recovery of coal, oil, or gas and in the interest of conservation of natural resources, is authorized to waive, suspend, or reduce the rental, or minimum royalty, or reduce the royalty on an entire leasehold, or on any tract or portion thereof segregated for royalty purposes, whenever in his judgement it is necessary to do so in order to promote development, or whenever in his judgement the leases cannot be successfully operated under the terms provided therein. In the event the Secretary of Interior, in the interest of conservation, shall direct or shall assent to the suspension of operations and production under any lease granted under the terms of this Act, any payment of acreage rental or of minimum royalty prescribed by such lease likewise shall be suspended during such period of suspension of operations and production; and the term of such lease shall be extended by adding any such suspension period thereto."

The regulations implementing these laws are found at 43 CFR 3103.4-1(a), and state, "In order to encourage the greatest ultimate recovery of oil or gas and in the interest of conservation, the Secretary, upon a determination that it is necessary to promote development or that the leases cannot be successfully operated under the terms provided therein may waive, suspend, or reduce the rental or minimum royalty or reduce the royalty on the entire leasehold, or any portion thereof.

(b)(1) An application for the above benefits on other than stripper oil well properties shall be filed in the proper BLM office. It shall contain the serial numbers of the leases, the names of the record title holders, operating rights owners (sublessee), and operators for each lease, the description of the lands by legal subdivision and a description of the relief requested.

(2) Each application shall show the number, location and status of each well drilled a tabulated statement for each month covering a period of not less than 6 months prior to the date of filing the application of the aggregate amount of oil or gas subject to royalty,the number of wells counted as producing each month and the average production per well per day.

/3

DRAFT March 24, 1994

(3) Every application shall contain a detailed statement of expenses and costs of operation of the entire lease, the income from the sale of any production and all facts tending to show whether the wells can be successfully operated upon the fixed royalty or rental. Where the application is for a reduction in royalty, full information shall be furnished as to whether overriding royalties payments out of production, or similar interests are paid to others than the United States, the amounts so paid and efforts made to reduce them. The applicant shall also file agreements of the holders to a reduction of all other royalties or similar payments in excess of one-half the royalties due the United States.

The practical implementation of this reduction for successful operations is quite difficult to manage as it is designed to be at the judgement of the Authorized Officer to review and approve these requests on the merit of each individual case. The information required to conduct an evaluation of economic viability can require a large amount of detailed data from the operator. It should be noted that under this royalty reduction provision that tn application from the operator is required before consideration. Approval of a royalty reduction is in recognition of lessee demonstrating the needs for the reduction in order to continue successful operations.

Stripper Property Royalty Rate Reduction

In addition to the case-by-case royalty reduction authority discussed above, BLM also has authority for a more automatic reduction for leases with low production rates (stripper properties). In a final rule published in the Federal Register on August 11, 1992, BLM amended 43 CFR section 3103.4-1 relating to waiver, suspension, or reduction of rental, royalty, or minimum royalty. BLM alerted the field offices of these changes in responsibility through WO IM No. 92-310 dated August 12, 1992. The purpose of the amendment was to establish conditions under which an operator or an owner of a stripper oil well property can obtain a reduction in the royalty rate. This action was necessary in order to encourage operators of Federal stripper oil properties to place marginal or currently uneconomical shut-in oil wells back in production and to provide the economic incentive to increase production by reworking such wells, drilling new wells, and/or by implementing enhanced oil recovery projects. The rule contains information and procedures for operators to follow in determining whether a property qualifies and in calculating the royalty rate.

Further program guidance to clarify appeals was forwarded to the field offices in WO IM No. 93-55 dated November 13, 1992. Additional guidance concerning well classification, critical definitions and determinations were sent to the field on November 20, 1992 in WO IM No. 93-64.

It should also be noted that under this royalty reduction provision that no formal application is necessary. Royalty reductions are considered on the basis of promoting development. The attached Appendix provides more detail on the program.

DRAFT March 24, 1994

Through reinvestment of the differential savings from royalty reduction numerous valid industry benefits can occur including:

- Encourage new and continued development of Federal lands
- Improve ultimate recovery of finite resources
- Reduce abandonment rate for marginally economic wells
- Return shut-in wells to production
- Increase domestic reserve base
- Lessen exposure to foreign imports
- Help maintain a viable and healthy domestic energy industry

BLM is coordinating with MMS to develop a list of operators taking advantage of royalty rate reduction, in both hard copy and automated format. BLM will use this list to conduct a program review by sending a letter to operators evaluating accomplishments and reinvestment which will help in the 5 year program review required within the regulation.

DRAFT March 24, 1994

Royalty Collections

MMS collects royalties and related payments due on production from Federal onshore and offshore leases and distributes these payments to appropriate accounts in the U.S. Treasury and to certain states and counties that receive a share of these revenues. In fulfilling this function, MMS follows the mandates of the various leasing statutes mentioned above as well as the provisions of the Federal Oil and Gas Royalty Management Act.

MMS' basic policy is that lessees are responsible for:

- measuring the amount of oil and gas they produce from Federal leases and the revenues they receive for this production;

- reporting this information to MMS; and

- paying all royalties and related payments due on such production.

After companies submit their reports and payments, MMS uses computerized routines to properly account for and verify the submissions and follows up with comprehensive audits of selected leases and time periods. Where MMS finds that lessees have not reported or paid properly, MMS requires them to correct the reporting problems and pay any additional royalties due, plus interest (the short-term Federal bond rate plus three percentage points—a rate that is below many companies' cost of borrowing).

MMS has three ways for discouraging companies from inaccurate reporting and paying:

- assessments for filing reports that are late or that have errors. These assessments are set at relatively low amounts intended to cover the additional costs that MMS incurs as a result of improper reporting.

- civil penalties for "non-intentional" violations of its regulations. Before MMS can assess such penalties, companies are allowed a 20-day cure period, allowing them to correct the problem and avoid the penalty.

- civil penalties for "knowing and willful" violations. In these cases, companies are not allowed a cure period. However, it is difficult to prove that violations are "knowing and willful," so MMS very rarely exercises this authority.

The general policy for royalty collections is to efficiently and accurately collect the amount of revenues properly due under the applicable statutes, regulations, and lease terms. The goal is to receive more accurate payments in the first place and to catch any problems earlier and resolve them faster than in the past. MMS tries to encourage timely and accurate reports and payments through a variety of methods:

- simplifying and clarifying regulations and procedures;

- identifying, resolving, and implementing policy issues so as to provide industry with timely and clear guidance on how to report and pay properly;

- providing comprehensive training to industry; and

- applying incentives to promote accuracy and timeliness, including assessments for improper reporting.

In response to prior strategic planning efforts and the National Performance Review process, MMS has launched a number of efforts to work with industry and states to simplify reporting requirements, revise regulations to make it easier for companies to determine their royalty liability, develop systems for MMS to detect problems efficiently and early, resolve policy issues faster, and institute more meaningful incentives for reporting and paying properly the first time (including proposed penalties for substantial underreporting).

DRAFT March 24, 1994

Appendix
Stripper Program Summary

The definitions for the stripper royalty rate reduction program are:

Stripper Well Property: A Federal lease or portion thereof segregated for royalty purposes, a communitization agreement, or a participating area of a unit agreement, operated by the same operator, that produces an average of less than 15 barrels of oil per eligible well per well-day for the qualifying period.

Eligible Well: An eligible well is an oil well that produces or an injection well that injects and is integral to production for any period of time during the qualifying or subsequent 12-month period.

Oil Well: An oil completion from which the energy equivalent of the oil exceeds the energy equivalent of the gas produced or any completion producing oil and less than 60 MCF of gas per day.

Injection Well: An injection well is a well that injects a fluid, including gas, for secondary or enhanced oil recovery, including reservoir pressure maintenance operations.

Calculation of Average Daily Production: Total oil production for the subject period from the eligible wells on the property is totaled and then divided by the total number of well days. Average production is always rounded down to the next whole number.

Qualifying Periods:

Initial: August 1, 1990 through July 31, 1991

Shut-in for 12 consecutive months: 12-month production period immediately prior to the shut-in.

Does not qualify During Initial Period: First 12-month consecutive period beginning after September 1, 1990.

Qualifying Royalty Rate Calculation:
0.5% + (0.8 x average daily production rate) = royalty rate

Effective Date: First day of the month after the Regulations are effective or after MMS receives notification whichever occurs later.

18

II. C. Import, Export, and Security Policies

[not yet received]

II. D. Regulatory Policies: Environmental and Others

EPA

Domestic Gas and Oil Incentives

Section II, D

Regulatory Policies: Environmental and Other

The Environmental Imperative

The interrelationship between energy and the environment is complex. The ways in which natural gas and oil are produced, transported, and consumed help determine our quality and style of life. Yet we are often reminded that fossil fuel consumption brings its own problems, sometimes undercutting the quality of life that it has made possible. Energy production, transportation, and use have significant adverse impacts on air, water, land use, and larger global environmental systems. Energy-related environmental accidents, such as oil spills, are notorious and very visible reminders of the potential risks we take to enjoy the benefits of fossil fuels. Air and water pollution are well known adverse side effects of fossil fuel use. The land use impacts of energy production, transportation, and consumption have also become of greater concern in recent years. The potential for climate change due to heightened concentrations of carbon dioxide has served to renew and heighten concern regarding energy's pervasive effect on the environment. Energy production and consumption are responsible for the bulk of air pollutants that comprise or cause urban air pollution, acidic deposition, air toxins, and greenhouse gases.

Since enactment of the Clean Air Act of 1970, increasingly stringent federal and state regulations have reduced or stabilized emissions of several energy-related pollutants. Other key pieces of environmental regulations enacted in the 1970s, 1980s, and 1990s have helped control the growth in pollution and produced numerous environmental success stories: volatile organic compounds and carbon monoxide from mobile sources have been reduced; lead emissions have been reduced dramatically. However, the rising awareness of the ubiquity and persistence of an industrial society's environmental impacts challenges policy makers to find effective and efficient ways to mitigate adverse environmental effects. Environmental policy makers will increasingly need to examine alternatives that help ensure that energy is produced and consumed efficiently so as to minimize adverse environmental impacts. Market-based strategies that create economic incentives to reduce adverse environmental impacts can help provide society the flexibility to maximize its diverse goals. In addition, a credible and efficient long-term mitigation strategy will recognize the importance of regional, state and local action, as well as promote the economically efficient goals of sustainability, waste minimization, and recycling.

Specific Environmental Regulations

A wide range of environmental regulations affect the domestic gas and oil industries. Environmental protection is provided for at all stages: exploration and production, transportation and transmission, refining and processing, and end use. It is often convenient to break down a discussion of environmental controls by medium. The discussion below highlights the key environmental laws and regulations affecting the domestic gas and oil industries.

SOLID WASTES: The Resource Conservation and Recovery Act (RCRA) is intended to provide a cradle-to-grave regulatory framework to monitor and control the production, storage, transportation, and eventual disposal of wastes that pose a risk to health and the environment. Amendments to RCRA in 1984 added regulation of petroleum and hazardous wastes stored in underground tanks. However, wastes associated with oil and gas operations were exempt from Federal regulations pending further review by EPA. **[Discuss current status of proposed changes to definition definition of Solid Waste. Discuss Hazardous Waste Identification Rule. Discuss Land disposal Restriction Regulations.] [State regulations of oil and gas wastes.]**

[Discuss Superfund.]

WATER AND WETLANDS: The Federal Water Pollution Control Act of 1972 and the Clean Water Act (CWA) of 1977 set as a goal "to restore and maintain the chemical, physical, and biological integrity of the nation's waters." The CWA establishes a system of effluent standards by industrial category, provides for a permitting system, sets waste water quality standards, provides for grants for municipal waste treatment, and addresses special issues like toxic wastes and oil spill. The effluent limitation standards and the National Pollutant Discharge Elimination System (NPDES) permit program are the primary regulatory tools under the CWA. Within the domestic gas and oil sector, CWA requirements primarily affect offshore drilling and refinery activity.

Section 404 of the CWA provides authority for the protection of wetlands. **[Fuller discussion.]**

The Safe Drinking Water Act of 1984 (SDWA) established the Underground Injection Control (UIC) program to protect drinking water aquifers from contamination by subsurface injection fluids. SDWA requires EPA to establish minimum requirements for state programs or for Federal primacy in the absence of state programs. The UIC affect all underground injection associated with oil and gas exploration and production activities. A Federal Advisory Committee composed of representatives of the petroleum production industry, environmental groups, states, and Federal agencies issued a final report recommending a requirement for double containment systems for injected fluids. In addition, surface casing would be required to extend to the base of aquifers containing less than 3,000 mg/l total dissolved solids and be cemented to the surface. Virtually all wells drilled by the major oil producers already employ these construction standards. The rule would require existing injection wells that do not meet the new construction standards to be tested more frequently. The frequency of testing would be based on the level of protection offered by these wells.

The Oil Pollution Liability and Compensation Act of 1990 raised liability limits for oil tankers. The Act allows unlimited liability against tanker owners where gross negligence or willful misconduct is involved, and does not preclude states from imposing their own unlimited liability requirements. In addition to the liability provisions, the Act requires that, over a 15 year phase-in period, double hulls be used for all new tankers and for vessels trading with the United States.

[Discuss Great Lakes Water Quality Initiative.]

AIR: The 1970 Clean Air Act (CAA) produced notable environmental gains. Two key parts of the CAA affecting the oil refining industry were related to end-products: the lead phase-out in gasoline and the requirements for low sulfur distillate and residual fuel use at electric utilities. The CAA established a schedule for reducing lead additives and required automobile manufactures to design and construct vehicles that could run on low-lead and unleaded fuel. The legislation required that all gasoline stations of specific sizes offer at least one grade of unleaded gasoline. The allowable lead in gasoline was reduced to 1.1 grams per gallon in 1982, and a system of waivers was established that allowed refiners to build up lead credits. Further reductions in 1986 brought the allowable lead to a maximum of 0.1 grams per gallons. All grades of gasoline must be completely lead-free as of January 1, 1996. The lead regulation resulted in a greater than 90% reduction in airborne lead emissions.

The 1990 Clean Air Act Amendments (CAAA) expanded the effort to reduce harmful emissions from auto fuels, putting new requirements on refineries. As of November 1, 1992, the oxygenate fuels program requires that gasoline sold in the 39 areas of the country designated as carbon monoxide nonattainment areas to contain a minimum of 2.7% oxygen by weight during at least 4 winter months. As of October 1, 1993, the sulfur content of highway diesel fuel must be reduced from the current maximum of 0.25% to 0.05% by weight. Finally, as of January 1, 1995, reformulated gasoline will be required in the nine metropolitan areas with the worst ozone problems. The reformulated gasoline requirements will control VOC and NO_x emissions, as well as benzene and other toxic air pollutants. **[Discuss Ethanol/ETBE mandate for reformulated gasoline.]** Earlier regulations to combat urban smog precursors control the summertime volatility of motor gasolines. **[Discuss testing of fuels and fuel additives for motor vehicles.]**

In addition to environmental requirements for products sold by refiners, the refineries themselves must meet standards for emissions of VOCs, NO_x, and air toxins. **[Add detail]** **[Discuss Enhanced Monitoring.]**

Reporting required by the Superfund Amendments and Reauthorization Act (SARA) identified approximately 1.4 million tons of toxic air pollutants released in 1987 by a wide range of chemical and other manufacturing facilities. EPA estimates that facilities in 37 states, primarily in those states along the Atlantic, Gulf, and Pacific coasts, are associated with toxic releases that pose high individual cancer risks. Energy-related sources of toxic air emissions include oil-and coal-fired utility boilers, petroleum refineries, and oil and gas exploration and production operations. In addition, VOC emissions from the transportation sector are among the largest sources of toxic air emissions in many urban areas. **[Discuss MACT for hazardous air pollutants.]**

Natural gas and oil pipelines are subject to CAA requirements for NO_x and VOC controls. New pipeline compressor stations will be required to have the most efficient, clean-burning prime movers technology available, and existing stations my be required to undergo extensive retrofitting or replacement. In non-attainment areas along with advanced controls, enhance emission offset requirements will be required for permitting of new or modified facilities.

Land Use Impacts and Public Lands Access: Much of the land within the United States is public property subject to Federal control. Wilderness areas, parks and monuments, and some wildlife refuges are not available for oil and gas E&P. National forests and other public lands, however, may be available. Actions by Federal agencies likely to have a significant environmental impact, such as leasing land or granting right-of-ways, require a formal Environmental Impact Assessment (EIA). States and other levels of government have similar requirements for EIAs. In addition, the Endangered Species Act may place severe constraints on economic activity in sensitive areas. These protections can affect gas and oil E&P and pipeline construction permitting.

Outer Continental Shelf Moratoria: The Outer Continental Shelf is subject to the jurisdiction and control of the United Sates by Authority of the OCS Lands Act and the Submerged Lands Act. The OCS is made available for oil and gas E&P through a bonus bid leasing system. Leasing activity is planned and announced in a 5-year OCS leasing program schedule specifying the proposed size, timing, and location of each lease sale. Since 1982, Congress has used the appropriations process to adjust the 5-year program schedule through "moratoria" blocking the DOI from conducting lease sales in certain OCS planning areas. **[discuss why]**

Underground Injection Control--Class II (Oil & Gas) Wells

Status

The proposed rule is currently undergoing final EPA review.

Background

Several efforts over the last five years have identified deficiencies in the Class II (oil and gas well) UIC regulations. EPA formed a FACA advisory committee composed of representatives from environmental groups (Friends of the Earth, National Audubon Society), petroleum producing companies (ARCO, Conoco), trade associations (American Petroleum Institute, Independent Petroleum Association of America), and state (Kansas, Ohio, California, Texas) and federal agencies (EPA, DOE, BLM) to develop recommendations for revisions to the regulations to correct those deficiencies.

The Advisory Committee issued a final report in March 1992. All committee members endorsed the final report with the following caveats: 1) The Independent Petroleum Association and the state of Ohio did not endorse the provision requiring annual mechanical integrity testing for injection wells with only one layer of protection; 2) Ohio and Kansas reminded EPA of its obligation under §1425 of the Safe Drinking Water Act (SDWA) to allow states to attempt to demonstrate the effectiveness of their in-place program (instead of adopting the regulation virtually verbatim); and 3) Kansas wanted EPA to interpret the SDWA prohibition against impeding oil and gas production, unless essential to protect underground sources of drinking water (USDW), based on local production impacts, not merely national impacts; 4) The Department of Energy expressed concerns that a specified schedule of mechanical integrity testing may be overly stringent when frequent monitoring can be equally protective; and that the Committee's recommendations provided no incentive for EPA regions to establish area of review variance programs in those States whose programs are administered by EPA.

Components of the Rule

The proposed rule reflects the Advisory Committee's recommendations and proposes modification to the Class II regulations in three areas.

a) **Construction Standards:** The rule would require double containment systems for injected fluids. In addition, it would require that the surface casing be extended to the base of aquifers containing less than 3,000 mg/l total dissolved solids and be cemented to the surface. (Virtually all wells drilled by the major oil producers already employ these construction standards.)

b) **Increased Monitoring:** The rule would require existing injection wells that do not meet the new construction standards to be tested more frequently. The frequency of testing would be based on the level of protection afforded by these wells.

c) **Area of Review:** The current regulations require owners or operators of new injection wells to assess the potential for contamination of USDWs by fluids migrating through open conduits (i.e. improperly plugged abandoned wells) in the vicinity of the well (area of review). The proposed rule would require owners or operators of existing wells to conduct the same area of review. New and existing wells could be exempted from these requirements through a variance procedure proposed in the rule, based on the absence of risk to USDWs.

Regulatory Impact Analysis

Costs: The RIA estimates the total direct and indirect compliance costs at $47.1 million annually for the first five years. In addition, the value of the oil that will not be produced as a result of this rule is estimated at $40 million annually.

Direct compliance costs for injection wells average $19.3 million annually for the first five years. Annual indirect compliance costs for production wells are estimated at $27.8 million. The proposed rule would indirectly affect oil production since well owners would have to build production wells to injection well standards to retain the option of converting the well to an injection well at a later date.

The value and percentage of the foregone production is negligible from a national perspective. The RIA estimates a decline in oil production from existing projects of up to 0.05 percent to 0.005 percent nationally, depending on the price of oil.

The proposed rule may severely affect stripper production in some states. For example, 85% of stripper wells in Kentucky and 78% of stripper wells in Arkansas would not be drilled. In contrast, only 7% of the stripper wells in Oklahoma would not be drilled (97 wells). EPA is concerned with the potential impact on small operators and is therefore requesting comment in the preamble on possible mitigation measures.

Benefits: Injected fluids can contain many different chemical contaminants depending on geographic and geologic factors. Primarily the contaminants fall into three categories--hydrocarbons, metals, and radionuclides. The proposed rule focuses on preventing well failures which can introduce contaminants into USDWs. The benefits include reduction in damage to current or future public health and protecting ecosystems. Because Class II injection projects rarely feature ground water monitoring systems and most incidents of USDW contamination occur in rural areas and are settled directly with the land owner, relatively few documented cases exist that directly implicate Class II injection wells as the source of large-scale USDW contamination.

The primary constituents of concern in injected fluids are chloride and sodium compounds. Their introduction into a USDW at high concentrations usually present in oil field brines (up to 141,000 mg/l Cl) can render it totally unfit for human consumption. Treatment costs for chloride removal are high.

The costs imposed by the rule are likely to be offset by the plausible benefit scenarios developed in the RIA. The scenarios examined the potential carcinogenic effects of three contaminants in injected fluids--benezene, arsenic, and radium. (The benefits analysis in the RIA only compared the benefits with the direct costs on injection wells.)

II. E. Direct Expenditures

DOE materials supplemented by Treasury materials

Oil Technology Program

The Oil Technology Program attempts to counter the forces of premature abandonment by supporting the development and dissemination of improved and advanced technology to the industry to facilitate maximum, cost-effective and environmentally sound production of the domestic oil resources.

Because abandonment of high value, light oil reservoirs is proceeding at a recent rate of 3%/year -- upwards of 40% of our remaining resources are effectively abandoned -- and the 1994 abandonment rate is projected as high as 5% (if the $14 to 15 per barrel oil prices continue) Time is growing short for the program is to have a meaningful impact. This is the reason behind FE's request for a 42% increase in Oil Technology funds in FY 1995 above FY 1994's: $107 million compared to $75.3 million last year. The Program has four sub-programs:

1. <u>Exploration and Production Supporting Research.</u> About 45% of the Oil Technology funds in FY 1995 will be directed to the development of improved and advanced geoscience and extraction technology (including work with the National Labs); the transfer of program as well as non-program improved technology to the oil producing industry, particularly independents; and field management and direction of both the supporting research efforts and the field demonstration activities. (FY 1994 budget is $25.3 million; FY 1995 request is $47.9 million)

2. <u>Recovery Field Demonstrations.</u> Forty of the Oil Technology FY 1995 budget will be earmarked to support cost-shared field demonstrations of improved and advanced reservoir characterization techniques, oil production methods, and oil recovery processes within the various geologic classes of reservoirs. These demonstrations are designed to further practical transfer of technology to operators within the respective reservoir classes, as well as to better define optimum approaches to secure additional recovery above that obtainable with current technology. (FY 1994 budget is $42.0 million; FY 1995 request is $43.1 million)

3. <u>Exploration and Production Environmental Research.</u> Approximately six percent of the Oil Technology funds in FY 1995 will support development of accurate environmental impact information to support the development and implementation of streamlined, risk-based environmental regulation of our producing oil industry on the part of federal, state, and local governing bodies. Additional support is directed for the development of more cost-effective E&P compliance technologies. (FY 1994 budget is $3.7 million; FY 1995 request is $6.0 million)

4. <u>Processing Research and Downstream Operations.</u> About nine percent of the Oil Technology funds in FY 1995 will support research directed to more efficient and environmentally compliant upgrading and related refining technology needed to convert our substantial heavy oil reserves (and heavy ends of our lighter, domestic and imported crudes) to the light, environmentally preferred liquid fuels essential to our economy. (FY 1994 budget is $4.3 million; FY 1995 request is $10.0 million)

Natural Gas RD&D Program

- FE's natural gas RD&D program utilizes the "systems approach" and consists of four program areas: Resource and Extraction; Utilization; Delivery and Storage; and Environmental Regulatory Impact. Fossil Energy has refocused the supply area to reflect near and mid-term RD&D needs and to better reflect the requirements of the gas industry.

- The gas program will address constraints to efficient use of natural gas exploration, production, storage, transmission distribution, and end-use. Most importantly, this new "systems approach" allows DOE to evaluate the merits of gas programs based on benefits to be realized in achieving energy security, economic efficiency, and environmental quality.

- DOE's proposed FY 1995 natural gas RD&D budget request is $289 million, a 49% increase compared to FY 1994 appropriations. Fossil Energy's FY 1995 natural gas RD&D budget request is $153.4 million, a 60% increase compared to the FY 1994 appropriations and consists of $27.5 million for Resource and Extraction, $3.4 million for Delivery and Storage, $116.6 million for Utilization, and $5.9 million for Environmental/ Regulatory Impact. Below is the DOE natural gas RD&D program crosscut budget for FY 1994 and 1995 by organizations and program sectors.

Department of Energy Natural Gas RD&D Program Crosscut ($ in millions)

PROGRAM SECTORS	Total DOE 94	Total DOE 95	FE 94	FE 95	EE 94	EE 95	ER 94	ER 95
Resource and Extraction								
Appropriated	[illegible]	-	[illegible]	-			8.7	-
Requested	26.0	36.2	17.3	27.5			8.7	8.7
Delivery and Storage								
Appropriated	1.0	-	1.0	-	-	-		-
Requested	3.4	3.4	3.4	3.4	-	-		-
Utilization								
Appropriated	163.1	-	77.3	-	71.9	-	12.9	-
Requested	[illegible]	[illegible]	77.4	116.5	69.3	109.5	12.8	12.9
Environmental/Regulatory Impact								
Appropriated	7.9	-	2.5	-	-	-	5.5	-
Requested	7.4	10.4	[illegible]	5.9	-	-	4.5	4.5
Total								
Appropriated	194.9	-	[illegible]	-	71.9	-	26.1	-
Requested	196.4	289.0	101.6	153.4	69.3	109.5	26.1	26.1

Congressional Directives and NPC Recommendations Satisfied by the Domestic Natural Gas and Oil Initiative

DNGOI	EPACT (section)	Approp Language	NPC Gas Recommend	NPC Refining Recommend
1.2 Advanced drilling for gas	2013			
1.3 Advanced oil recovery technologies	2011 [1]			
1.5 Research Program for small producers	2011			
1.7 Technology transfer	2011	X [2]		
2.1 Environmental compliance technologies	2011		X	X
2.2 Coordination on environmental research			X	
3.1 Data collection on gas production			X	
3.3 Real time monitoring for gas			X	
3.4 Natural gas storage	2014 [3]			
3.5 Natural gas storage and end use	2014			
3.6 Demonstrate gas storage optimization	2014			
3.7 Improve gas storage effectiveness	2014			
6.1 Streamline regulations			X	

[1] 5 Year Plan Required - Draft to be completed September 1994.

[2] 5 Year Plan Required - Delivered to Congress on February 2, 1994.

[3] 5 Year Plan Required - Natural Gas Strategic Plan to Congress February 1994.

DNGOI	EPACT (section)	Approp Language	NPC Gas Recommend	NPC Refining Recommend
6.2 Enhance government decision making			X	
6.3 Beyond command and control regulation			X	X
6.4 Industry/government/ public partnerships			X	X
6.5 Review NPC refining study				X
7.1 Interagency Energy Coordination Group			X	
8.1 Work with states			X	

II. E. DIRECT EXPENDITURES

The Strategic Petroleum Reserve had stored 575 million barrels of oil by the end of 1992. Assuming a cost of $18 per barrel, this reserve required an expenditure of over $10 billion between 1977 and 1992. The additional demand may have had a small effect in increasing domestic oil prices and sales benefiting domestic producers. Given that this oil is available for emergencies, the true cost of the reserve is perhaps better measured by the interest cost of holding the reserve, rather than the direct expenditure for its purchase (about $3.1 billion over 5 years assuming an interest cost of 6 percent to the Treasury).

The low income housing energy assistance program by the Department of Housing and Urban Development, which totaled $1.1 billion in FY 1992, was the largest direct federal subsidy for oil and gas products. About 63 percent of this amount is used for winter heating assistance that would primarily affect gas and oil demand. The total revenue cost is about $3.6 billion over 5 years for oil and gas products.

Synthetic fuels grants, which guarantee a minimum price to producers, cost about $70 million a year. While the Synthetic Fuels Corporation was abolished in 1986, two price guarantees remain in effect. Dow Chemical's Syngas project, with $622 million in guarantees expiring in 1997, and the Forest Hills heavy oil project in Texas, with $60 million in price guarantees expiring in 1995, were transferred to Treasury's "Energy Security Reserve" account. Treasury outlays for these residual obligations were $72 million in FY 1992, primarily for the production of gas from western coal. The total cost is about $0.3 billion through 1997.

Also, DOE attributes $96 million in R&D expenditures to oil and gas and a further $307 million for the cost of regulation. Additional amounts could be imputed from the Tennessee Valley Authority expenditures and DOE Technical Assistance programs but would be difficult to allocate to oil and gas.

III. A. Tax Proposals

CURRENT OIL AND GAS TAX LEGISLATION

H.R.1024. Andrews, introduced February 3, 1993.

The proposal provides:

For an import fee (excise tax) on all crude oil and refined petroleum products that are imported into the United States after the date of enactment. The fee on crude oil would be the excess of $25 over the "energy policy price" per barrel of crude oil. The fee on refined petroleum products would be the tax on crude oil plus an additional $3 per barrel of product. The "energy policy price" would be determined weekly by the Secretary of the Treasury, based on the weighted average international price of a barrel of crude oil for the preceding 4 weeks. The imported oil tax would be deductible by the taxpayer;

For an increase in percentage depletion for stripper wells, defined as wells producing less than 15 barrels per day, and for wells producing heavy oil. Under current law, production from these wells is allowed an additional percentage depletion allowance (normally 15 percent) equal to one percentage point for each whole dollar by which $20 exceeds that reference price for crude oil for the calendar year preceding the calendar year in which the taxable year begins, up to 25 percent. (For example, based on 1993 crude oil prices of approximately $15.40 per barrel, qualifying 1994 production would receive an additional 4 percentage point depletion allowance over the standard 15 percent.) The proposal increases 25 percent to 27.5 percent and $20 to $28, effective for taxable years beginning after December 31, 1992;

For the elimination of the net income limitation on the deduction for percentage depletion (a percentage of oil and gas revenue), which cannot currently exceed 100 percent of the net income from a particular property in any year, thus allowing the percentage depletion deduction for an uneconomic well to offset income from an economic well and income from non-oil or gas-production income. This provision would be effective for taxable years beginning after December 31, 1992;

For a credit equal to the sum of 20 percent of a "qualified investment" that does not exceed $1,000,000 plus 10 percent of such investment that exceeds $1,000,000 for expenditures paid or incurred after the date of enactment. A "qualified investment" is defined as an expenditure for crude oil and natural gas exploration and development, including geological and geophysical (G&G) costs, well drilling and equipment expenditures, or secondary or tertiary recovery costs. The credit can be used against the alternative minimum tax and can be carried forward and back (to offset taxable income in future and previous years);

For a credit equal to 20 percent of the "qualified cost" of each barrel of crude oil or gas produced from stripper wells, heavy oil wells, and wells using tertiary recovery methods, and up to 15 percent for harsh environment oil wells (oil produced from a property located north of the 49th parallel or under at least 400 feet of water). "Qualified cost" is defined as the prorata share of the lease operating expenses paid or incurred by the producer of such barrels plus the amount of severance tax paid or incurred with respect to such barrels. The credit can be used against the alternative minimum tax and can be carried forward and back (to offset taxable income in future and previous years). This provision would be effective for expenditures paid or incurred after the date of enactment;

For an expansion of the enhanced oil recovery credit, which provides a 15 percent credit for qualified tertiary recovery expenditures (generally injecting substances into the reservoir to increase oil production), to include a 15 percent credit for "advanced secondary recovery costs." "Advance secondary recovery costs" are defined as costs paid or incurred for extraction, exploration, and drilling methods used other than by conventional or traditional methods. This provision would be effective for expenditures paid or incurred after the date of enactment;

For an expansion of the definition for stripper well by increasing eligible wells to those producing 25 barrels per day from 15 barrels per day, effective after the date of enactment;

For the amortization of G&G costs, paid or incurred after the date of enactment, ratably over a 5-year period versus amortized over the life of the well when oil or gas is located;

For the elimination of depreciation adjustments used in computing alternative minimum taxable income for environmental improvement assets, thereby reducing potential alternative minimum tax liability. This provision would be effective for property placed in service in taxable years beginning after December 31, 1992.

S.403. Breaux, introduced February 18 (legislative day, January 5), 1993.

The proposal provides a $5 credit per barrel of qualifying oil or energy-equivalent amount of gas produced after 1995 from properties that did not produce commercial quantities of oil or gas before 1993. To qualify, domestic crude oil or domestic natural gas must be produced from a property a portion of which is located under at least 400 meters of water. The credit can be used against the alternative minimum tax and can be carried forward but may not be carried back.

S.1622. Breaux, introduced November 4 (legislative day, November 2), 1993.

H.R.3533. Andrews, introduced November 18, 1993.

The proposal provides that G&G costs, and surface casing costs, paid or incurred after date of enactment, be treated like intangible drilling and development costs. Under current tax law, intangible drilling and development costs are generally deductible when incurred, whereas G&G costs are amortized over the life of the well when oil or gas is located and are "expensed" when oil or gas is not found. G&G costs include costs incurred for geologists, seismic surveys, gravity meter surveys, magnetic surveys, and (perhaps) the drilling of core holes. Surface casing costs are currently capitalized for tax purposes. Surface casing, which is cemented into place, is heavy steel pipe that is used to keep the newly drilled well from caving in and to keep outside and inside fluids from mixing.

Draft: Subject to Change and Revision

A Tax Credit to Preserve Marginal Production and to Encourage New Drilling

The provision will first establish a tax credit for existing marginal wells. The provision will allow a $3 per barrel tax credit for the first 3 barrels of daily production from an existing marginal oil well and a $0.50 per Mcf tax credit for the first 18 Mcf of daily natural gas production from a marginal well.

- The current definition of marginal wells will be expanded to include a new category for "high water cut property" -- producing 25 barrels per day or less per well, with produced waters accounting for 95 percent of total production. In addition, techniques such as waterflooding and disposal, cyclic gas injection, horizontal drilling, and gravity drainage should be encouraged to enable domestic producers to capture more of the oil in a given marginally economic property.

- The provision will also include a tax credit for production from new wells that have been drilled after June 1, 1994. The provision will allow a $3 per barrel tax credit for the first 15 barrels of daily production for such oil wells and a $0.50 per Mcf for the first 300 Mcf per day for such gas wells.

The tax credit will be phased out in equal increments as prices for oil and natural gas rise. The phaseout prices, which are based on BTU equivalence, are as follows:

Oil--phase out between $14 and $20
Gas--phase out between $2.49 and $3.55

The tax credit is creditable against regular tax and AMT.

Additional Legislative Initiatives

Geological and Geophysical Costs. We continue to urge the administration to support the current expensing of G&G costs. We understand that the administration is studying the tax treatment of G&G costs, and we recognize that legislative action may be required.

Eliminate the Net Income Limitations on Percentage Depletion. Currently, the depletion deduction cannot exceed 100% of income from the property, and the deductions from all properties cannot exceed 65% of taxable income. Many of producers have so little income from the property that the net income limitations further restrict the value of their deductions. We support the repeal of both these limitations.

Limitation on Exports. We favor abolishing the existing prohibitions against the export of domestic crude oil production provided that full and adequate protections for the domestic merchant marine industry are assured.

OCS Deepwater and Frontier Area Production. With domestic reserves dwindling, areas with potential for new production are the deepwater of the Outer Continental Shelf (water depths greater than 400 meters) and frontier areas. The costs of finding and producing most oil and gas in these areas exceed the current price for that oil and gas. We support the consideration of a per barrel tax credit to encourage deepwater and frontier production.

Administrative/Regulatory Initiatives

Oil Pollution Act of 1990. We believe that the financial responsibility provisions of OPA 90 are onerous and unnecessary, and we support a reduction of the dollar limits. In addition, these financial responsibility provisions should be made more realistic in a number of ways. First, OPA must recognize that insurers function as indemnitors, rather than guarantors, and are therefore not secondarily liable for all the insured's debts. Second, because not all claims under OPA are payable on the day of a spill, we support a thorough examination of resources to identify those that are available for the immediate clean-up and those that are available in the longer term to pay any damage claims and restoration costs. Third, we believe that MMS should structure a regulation regarding *de minimis* quantities. Finally, MMS' definition of "navigable waters" under OPA '90 should be reasonable and appropriately narrow in light of Congressional intent to apply OPA '90 to true "offshore facilities" not facilities onshore.

- **Royalty Reduction.** To remain competitive in attracting capital, U.S. royalty laws should be reassessed. The existing royalty reduction for marginal oil wells on public lands (onshore) should be expanded to include marginal natural gas wells. The royalty reduction for offshore production should be extended for new activity, especially deep water and other frontier areas, and marginal properties. Finally, we support legislation that would temporarily suspend the collection of royalties from wells in deep water, such as the bill that was approved by the Senate Energy and Natural Resources Committee.

- **Royalty Collection.** "Reinventing Government" legislative proposals establish an unworkable, unfair penalty regime that will have particularly adverse affects on natural gas production. The Administration should withdraw this proposals and work with industry to eliminate royalty collection problems.

- **Underground Injection Control.** The EPA is developing revised regulations, reportedly deviating from recommendations made by the Advisory Committee on UIC. Indications that the EPA is considering tightening regulations are disappointing, especially in light of its report to Congress which found that any problems could be solved by enforcing existing regulations, rather than adopting new rules. This proposal could be extremely costly to the industry without improving environmental protection. We oppose the EPA proposed revision of existing UIC regulations.

Natural Resources Damage Assessment. The Departments of Interior and Commerce are developing regulations to impose liability on natural resource producers for injuries caused by hazardous discharges. Although relevant statutes do not require it, damages could include *emotional loss of persons who do not suffer from direct contact or use* of the natural resources. The "non-use" damage proposal relies on an economic methodology known as contingent valuation (CV).[1] However, a panel of economists created by NOAA was unable to confirm that CV was a reliable methodology. We believe that CV for damage assessments is seriously flawed and oppose the inclusion of liability for non-use value loss in the final regulations.

Oil and Gas Leasing on Public Lands. The Interior Department is conducting an internal review of leasing to promote a new approach called "ecosystem management." Current law, the Federal Land Policy Management Act (FLMPA), is based on multiple use, including oil and gas leasing activity. We urge the Interior Department to abide by the principle of multiple use.

---

[1] An example of CV is as follows: after the Exxon Valdez oil spill, there were some who claimed to have suffered emotional loss due to reports of dying Alaskan wildlife. As a method to determine Exxon's liability for this emotional loss, the CV process begins with asking a group of households to estimate the monetary value of their indirect emotional loss. The damages to be paid by Exxon are determined from the data collected in the CV survey.

III. A. Tax Proposals

DRAFT

Expensing of Geological and Geophysical Costs

0. Introduction

Geological and geophysical (G&G) expenditures include the costs incurred for geologists, seismic surveys, gravity meter surveys, magnetic surveys, and (perhaps) the drilling of core holes.

1. Proposal

Immediate expensing of all G&G.

2. Fit with criteria
[to be supplied]

3. Existing policy baseline

G&G expenditures are "expensed" for tax purposes when oil or gas is not found and amortized over the life of the well when oil or gas is located according to rules set forth in Rev. Rul. 77-188 and amplified by Rev. Rul. 83-105.

These regulations are somewhat complex and are a source of dispute between the IRS and the taxpayer as to when expensing is allowed. Generally expenditures may be expensed when no oil or gas is found and a decision is made to terminate interest in the property. Gaming the tax system can take place when "areas of interest" are narrowly defined to increase the proportion of G&G that can be expensed under the regulations.

The DOE Domestic Natural Gas and Oil Initiative calls for DOE and Treasury to review the tax treatment of certain advanced exploration and production techniques and to complete a study of this issue in May 1994. 3-D seismic technology for geological and geophysical exploration, which promotes the finding of oil and gas by providing higher quality pictures of subsurface geology, has been found to be profitable by oil companies and has nearly supplantd 2-D seismic for offshore exploration. Although more expensive than 2-D seismic, 3-D seismic reduces the occurrence of dry holes which justifies the higher cost. As computation continues to become less expensive, 3-D seismic will make inroads for onshore exploration, where its use has been hampered by the need for numerous permits, and the requirement that a sufficient pool of oil must be expected to justify the cost.

Proposals are being analyzed by Treasury for costs and by DOE for benefits.

4. Possible variations

Several variations of G&G proposals are possible.

5. Pros and Cons of proposal

Pros
-
-
-

Cons
-
-

6. Legislative outlook

[to be supplied]

7. Costs to Federal budget

Revenue

5-year
10-year

Outlay equivalent tax expenditure

5-year
10-year

8. Other Impacts

[to be supplied]

III. A. Tax Proposals **DRAFT**

<u>Oil and Gas Production Tax Credits</u>

1. Proposal

[Tentative as not determined.] The proposal provides for a $3 credit per barrel of oil for several categories of wells. The credit applies to the first 15 barrels per day for all new wells drilled after June 1, 1994. The credit is phased out over oil prices between $14 and $20 per barrel. A similar credit applies the first 50 barrels equivalent for new gas wells. Credit and phase out prices are indexed for inflation and creditable against the AMT. A $3 per barrel credit also applies to the first 3 barrels of existing "marginal well" production (wells producing up to 15 barrels per day plus "heavy" oil producers and a new category of "high water cut property" [25 barrels per day or less with produced water accounting for 95 percent of total production]). A similar provision is applied to gas [details as to whether gas wells have to be marginal wells not clear].

In what appears to be a variation, the $3 credit would apply to the first three barrels of oil for marginal wells producing 5 barrels per day or less at depths of less than 4,000 feet and to marginal wells producing 10 barrels or less per day for other wells.

In addition the definition of marginal wells is expanded to include injection and water disposal wells in the calculation of whether a property qualifies as marginal.

2. Fit with criteria
[to be supplied]

3. Existing policy baseline

No oil or gas credits are generally available on new primary production of regular oil and gas. (Credits are available through the year 2002 for the production of qualified non-conventional fuels from wells drilled before 1993. Tax credits are available for certain enhanced oil recovery expenditures. See the description of current law oil and gas tax incentives.)

4. Possible variations

To reduce revenue costs the level of the credit could be reduced, the proposal could become effective at a later date, qualifying marginal wells could be redefined, or other restrictions could be placed on the availability of the credit.

5. Pros and Cons of proposal

Pros

-

Cons

-
-

6. Legislative outlook

[to be supplied]

7. Costs to Federal budget

Revenue cost to be supplied. A preliminary DOE analysis estimates a revenue loss of over $2 billion per year.

8. Other Impacts

[to be supplied]

III. A. Tax Proposals

DRAFT

Deep-water Oil and Gas Production Tax Credits

1. Proposal

The proposal (S.403) provides a $5 credit per barrel of qualifying oil or energy equivalent amount of gas produced after 1995 from properties that did not produce commercial quantities of oil or gas before 1993. To qualify, domestic crude oil or domestic natural gas must be produced from a property a portion of which is located under at least 400 meters of water. The credit can be used against the alternative minimum tax and can be carried forward but may not be carried back (to reduce taxable income in previous years).

2. Fit with criteria

[to be supplied]

3. Existing policy baseline

No oil or gas credits are generally available on new primary production of regular oil and gas. (Credits are available through the year 2002 for the production of qualified non-conventional fuels from wells drilled before 1993. Tax credits are available for certain enhanced oil recovery expenditures. See the description of current law oil and gas tax incentives.)

4. Possible variations

To reduce revenue costs the level of the credit could be reduced from $5 per barrel, the credit level could be affected by oil prices, the proposal could become effective at a later date, or other restrictions could be placed on the availability of the credit.

5. Pros and Cons of proposal

Pros

-

Cons

-
-

6. Legislative outlook

[to be supplied]

7. Costs to Federal budget

Revenue cost to be supplied. A preliminary (MMS) analysis

8. Other Impacts

[to be supplied]

DEPARTMENT OF THE TREASURY

--If Received INCOMPLETE call (202) 622-2222--

mom

CLASSIFICATION

4431

DATE: 3/24/94

TO: (Name) Brian Burke

COUNTRY USA

(Office Phone #) 202 456-7777

Fax Nr. (VERIFY) 202 456-7028

FROM: (Name) Hudson Milner

(Office Symbol) XAA

(Phone #) 202 622-1785

HANDLE AS: ROUTINE PRIORITY ✓ URGENT

PAGE 1 OF 45 PAGE(s)

[illegible]

REMARKS/SUBJECT:

[illegible]

Sender's FAX Number: (202) 622-2599

R&D - TOR

SSN NUMBER: 4431

94 MAR 24 PM 4:34

DEPARTMENT OF THE TREASURY
TELECOMMUNICATIONS

DOMESTIC GAS AND OIL INCENTIVES

Materials received for meeting on Friday, March 25 at 10:00am
Treasury

Outline Sections

II. Current U.S. Policies toward the Gas and Oil Industry

A. Tax Policies

B. Royalty Policies

C. Import, export and security policies

D. Regulatory Policies

E. Direct Expenditures

III. Current Proposals Involving Gas and Oil

A. Tax Proposals

II. A. Tax Policies

II. A. OIL AND GAS TAX INCENTIVES

Introduction

Preferential tax treatment is the principal source of assistance provided by the federal government to the domestic oil and gas industry. These subsidies, known as "tax expenditures", total in excess of $17 billion over 5 years. Tax expenditures that benefit the oil and gas industry are considerably larger than direct Federal expenditures. Direct expenditures are projected to total $7 billion over 5 years.[1] (To be superceded by DOE's direct expenditures information.)

Tax expenditures are intended to encourage the exploration and production of domestic oil and gas. These incentives are generally justified on the ground that they increase U.S. energy security by reducing vulnerability to an oil supply disruption through increases in production, reserves, and exploration and production capacity. However, these various means of achieving energy security gains are not equally cost effective, nor are the security and economic considerations relating to oil the same as those relating to natural gas. For example, in contrast to oil, natural gas production is expected to continue to increase, gas prices are at their highest levels since 1985, and, in addition, natural gas production will surpass crude oil in value and energy content within two or three years.

Oil and Gas Tax Expenditures

Under current law, six tax expenditures are specifically targeted for the oil and gas industry. These are noted below in order of the size of the associated tax expenditure, with a brief description of the tax provision and its effectiveness. (See attached Schedule 1 of recent oil and gas tax legislation.)

The tax expenditures discussed below are measured on an "outlay equivalent" basis, i.e., they show the amount of outlay that would be required to provide taxpayers the same after-tax income as are received through the tax preference. The outlay equivalence measure allows a direct comparison of the cost of a tax expenditure and a direct federal outlay.

Percentage Depletion

A taxpayer other than an integrated oil company (an oil company that engages in substantial refining or marketing) may, as an option under Section 613A (c), deduct from taxable income a percentage of oil and gas revenue known as "percentage depletion." The cost of the property may be first amortized through cost depletion reflecting the decline in

---

[1] The largest direct expenditures involve HUD energy assistance outlays projected to be $3.6 billion over 5 years and $3.1 billion over 5 years of forgone interest on purchases of oil for the Strategic Petroleum Reserve. Figures extrapolated from data in Federal Energy Subsidies: Direct and Indirect Interventions in Energy Markets, November 1992, EIA Service Report SR/EMEU/92-02.

March 17, 1994

MEMORANDUM FOR DISTRIBUTION

FROM: Heather Ross

SUBJECT: Domestic Gas and Oil Incentives

As previously advised, the working group will meet Friday, March 18. Because of late-arising room availability problems, the meeting will now occur from 10 am to 12 noon in Room 10-103 NEOB. I apologize for any inconvenience this causes.

Yesterday's Deputies meeting agreed to consider together all proposals for assistance to the gas and oil industry and tasked the working group to do a number of things in preparation for a further Deputies meeting in three weeks time.

1. Identify the full scope of proposals to wrap into this process. Those agreed at the meeting are Senator Johnston's royalty relief bill S318, Senator Breaux's four proposals in his March 7 letter to the President, and the proposals under development by Senator Boren's group.

2. Prepare a legislative analysis considering these proposals and proponents in the context of other legislative initiatives.

3. Prepare a paper presenting relevant economic background, describing existing tax preferences and other pertinent elements of current policy toward the industry, and evaluating the current proposals. This will ultimately accompany a succinct options paper forward in the decision process.

4. Consider and advise the proper relationship between this effort and other related activities, including the study of costs and benefits of oil imports under the Domestic Gas and Oil Initiative.

5. In light of the above, propose a schedule for arriving at an agreed Administration position and strategy on these issues, including an approach to the President's meeting requested by Senator Boren et al.

6. Prepare talking points for use while the Administration is conducting its deliberations. These are intended not to convey excessive expectations, and any comment outside them should be agreed first at the Deputies level.

This list of tasks will form our agenda. The major effort will be item 3; a broad proposed outline to get us started is attached.

DOMESTIC GAS AND OIL INCENTIVES

I. Overview of the Gas and Oil Industry

A. Nature of the Industry

Global and domestic characteristics
Long-term trends and recent experience

B. Criteria for Evaluating Government policy

Microeconomic considerations
Macroeconomic considerations
Security considerations
Budgetary considerations

II. Current U.S. Policies toward the Gas and Oil Industry

A. Tax Policies

B. Royalty Policies

C. Import, export and security policies

D. Regulatory policies: environmental and other

III. Current Proposals Involving Gas and Oil

A. Tax Proposals

B. Royalty Proposals

C. Import/Export/Security Proposals

D. Regulatory Proposals

Building blocks for Section 3: Paper for each proposal, up to 5 pages in common format.

1. Proposal
2. Fit with criteria
3. Existing policy baseline
4. Possible variations
5. Pros and cons
6. Legislative outlook
7. Costs: federal budget; gross and net; 5yr and 10yr

Minerals Management Service

Facsimile Transmission

		FAX	Phone
To:	Heather Ross		
From:	Carolita Kallaur	(202) 208-7242	(202) 208-3500

COMMENT: Attached are the two papers you requested. Please call if you have any questions.

622-9260

Date: March 14 ,1994 Number of Pages (including cover): 8

Revenue Neutrality of Deep-water Incentive Proposals

Congress is considering two bills that would provide incentives to deep-water natural gas and oil production. S. 318 would suspend royalties until a project's gross revenues exceed its exploration and development costs. S. 403 proposes a $5.00 per barrel of oil equivalent (boe) tax credit on new production. Both bills would stimulate new development, but at a potentially high cost in forgone revenues to the Government. This paper addresses means to reduce the revenue impacts of these bills.

What is revenue neutrality?

From a budget perspective, revenue neutrality means that any revenues forgone due to an incentive program must be offset by increased revenues from other sources, primarily from additional production that would not otherwise occur. Furthermore, budget rules require that a proposal be revenue neutral in each year of the planning period--five years for Administration and House bills and ten years for Senate bills.

From a long term perspective, incentive programs can be designed that would have substantial near-term costs in terms of forgone revenues, but that would provide for a long-term increase in the present value of both Federal revenues and economic benefits to the nation. While such a program would not meet the requirements of the budget rules, the incentive could be viewed as an investment that pays long term dividends.

What approaches can be used to diminish revenue impacts?

Revenue losses derive from incentives that provide more relief than is necessary to stimulate production. These losses take three forms:

- Providing relief to profitable projects that would proceed in the absence of an incentive.
- Providing greater relief to a marginal project than it needs to enter production.
- Providing enough relief to spur production from fields for which development and production costs exceed the expected market value of the oil and gas resources.

The most successful policies to diminish revenue impacts would both prevent undeserving projects from receiving relief and allow for variation in the amount of relief. The following policies, listed roughly in descending order of effectiveness, could reduce revenue impacts.

- *Case-by-case review:* Reviewing the economics of each deepwater project would allow the Department to determine whether relief is needed and to fine-tune the size of the relief to the specific project. However, analyses of fields that have not produced are subject to considerable uncertainties, which could result in determinations that prove to be wrong, ex-post. In addition, conducting careful analyses of these projects requires considerable budget and FTE resources.

- *Limit relief to new leases:* Limiting relief to new leases eliminates near-term revenue concerns. In deep water, lead times between leasing and development are long enough to delay actual royalty relief several years into the future. In addition, bonuses bid on new leases eligible for financial incentives allow the Government to recapture some of the value of the incentive.

- *"Pay-back" provisions:* The Department of Interior proposed that incrementally higher royalty rates apply to post-suspension production. Short term revenue losses would fall to the extent that firms with large discoveries might prefer current royalty terms over a combination of the suspension and higher future payments. In the long term, the Treasury would recover all or part of the forgone royalties from large discoveries through the higher royalty rate. For the marginal fields to which incentives should be targeted, post-suspension production would be too small to recover the forgone royalties. Existing authority to reduce royalties on producing leases would still allow the Secretary to grant relief to prevent premature abandonment.

- *Additional screens:* In the absence of case-by-case reviews, some general screens can reduce the likelihood of granting relief to projects that would proceed anyway. For example, the incentive could apply only to fields for which no development plan had been filed prior to enactment, since development plans are a strong indicator of an intention to proceed. While this would eliminate those existing discoveries most likely to proceed in the next few years, other future discoveries, or existing discoveries that have not yet filed a plan, might still receive unnecessary relief. Screens based on a combination of other factors, such as field size and water depth, could be used to either deny relief or to set the size of relief to be offered.

- *Reduce the incentive.* The size of the incentive could be reduced through such means as reducing the size of the tax credit or limiting the relief to a specified volume of production. While these approaches would reduce revenue losses, they are not effective screens for eliminating projects that do not require relief or for including all projects that might benefit from relief.

S. 318 (Royalty Suspension)

S. 318 suspends royalties on new production until exploration and development costs are recovered from gross project revenues. The bill applies to tracts in at least 200 meters of water in the Central and Western Gulf of Mexico. Prior to the recent mark-up, an analysis of existing discoveries estimated that this approach would result in revenue losses of about $500 million (nominal) over the next five years, and about $300 million (present value) less revenues in the long term compared to the status quo.

The MMS proposal to revise S. 318 would grant a smaller automatic suspension, allow for case-by-case fine-tuning of the suspension size, and charge a higher royalty rate for post-suspension production. This approach could result in long-term gains to the Treasury, but there would be near-term budget impacts unless the case-by-case review permitted the denial of suspension.

S. 318, as amended, gives the Secretary 90 days to review applications for royalty suspension and deny relief to those projects that would be economic under current royalty terms. If the Secretary does not make a determination within the 90-day period, the royalty suspension automatically applies to lease production. The review does not allow the Secretary to adjust the size of the suspension for individual projects. The workload associated with these reviews, along with the potential for scores of simultaneous applications, may preclude the careful evaluation of applications if the 90-day limit is enacted. This increases the probability that there will be revenue losses from granting relief to fields where production would occur anyway.

S. 403 (Tax Credit)

S. 403 provides a tax credit of $5.00 per boe for production in at least 400 meters of water. Preliminary analysis of the tax credit estimated a long-term revenue loss of over $5 billion from fields that would produce in the absence of an incentive. In addition, the tax credit would result in production from several fields for which development and production costs exceed the expected market value of the resources. Several limitations were considered, including a smaller credit, restricting the credit to new leases or to a specific volume of production, and limiting the credit so that project specific taxes would be no less than zero. However, in the absence of case-by-case review, no combination of these limitations would clearly result in revenue neutrality.

Royalty Rate Reduction Program For Stripper Oil Properties

Background

In an effort to increase domestic oil production, the Bureau of Land Management (BLM) amended regulations at 43 CFR 3100 (1992) for stripper oil properties. The final rule, "Promotion of Development, Reduction of Royalty on Stripper Wells," published August 11, 1992, and effective September 10, 1992, established the Stripper Program whereby operators can file for reduced royalty rates on stripper oil properties. A stripper oil property is classified as one producing less than 15 barrels of oil per day, as averaged over a 12-month qualifying period. Under the Program the amount of royalty reduction is dependent on the rate of production. The Federal lease royalty rate can be reduced to as little as 0.5 percent.

The Program is designed to operate for five years. The Program can terminate prematurely if the oil price, adjusted for inflation, remains on average above $28 per barrel, based on West Texas Intermediate crude average posted price for a period of six consecutive months. Under these circumstances, the benefits of the royalty rate reduction may be terminated upon six months notice.

The BLM initiated the Stripper Program to encourage operators "to place marginal or currently uneconomical shut-in oil wells back in production and to provide the economic incentive to increase production by reworking such wells, drilling new wells, and/or by implementing enhanced oil recovery projects." A Department of Energy study concluded that a royalty rate reduction initiative on stripper oil properties could increase annual domestic oil production by 4.7 million barrels.

The Royalty Management Program (RMP) is now administering the Stripper Program for the Bureau of Land Management (BLM). In implementing the Program, the RMP issued "Dear Operator" letters on August 20 and September 2, 1992, describing the Program and providing instructions on filing the required form. In addition, a number of regional informational sessions were held in September 1992 to provide operators with Program details. Every effort was made to notify industry of the availability and requirements of the Program.

In administering the Program, the RMP is primarily tasked with verifying the reduced royalty rates submitted by the operator. Operators of qualifying properties must notify RMP of the intent to take the reduced rate via a notification form. Operators are required to calculate the reduced rate based on their production records for the initial qualifying base period, which is defined in the regulations. While the notification form is very simple to complete, the time the operator invests in calculating the reduced rate can vary depending on the number of wells involved in the property in question. It is important to emphasize that one notification will meet the regulatory requirements for a five-year royalty reduction; submission of an additional notification is needed only if the operator wants to further reduce their royalty rate based on reduced production levels.

Experience Under The Program

The RMP received notification forms on approximately 3,800 properties in the initial year of the Program; this represents over 60 percent of the properties anticipated to qualify for a reduced royalty rate. Although there is not a single explanation for the other properties not coming under the Program, a number of operators told us they decided against submitting for the royalty rate reduction because of privately-executed contracts they had with overriding royalty interests. The contracts provided that if the lessee received a royalty rate reduction on Federal royalties, they must pass the windfall on to the overriding royalty interests thereby negating any economic gain from the royalty rate reduction on the Federal percentage.

Of the approximately 3500 property notifications that have been reviewed by RMP to date, 74 % of the notifications resulted in a match between the royalty rate reduction submitted by the operator and the royalty rate reduction calculated by RMP. Approximately 7 % of the properties reviewed were confirmed for a rate lower than the operator calculated while about 8 % of the properties were confirmed for a higher rate than what the operator submitted. Only about 6 % of the reviewed notifications resulted in a denial of the reduced royalty rate. Approximately 5 % of the notifications received were duplicates of previous submissions.

Since September 28, 1993, RMP has received notification forms on 780 properties. Of the 780 properties, approximately 85 percent are properties on which operators are submitting for a further reduction of their first-year reduced royalty rate.

Overall reactions of operators toward the Program have been favorable. However, several small operators have expressed concerns regarding the availability of production information. Usually these operators have encountered problems in obtaining production information on properties they took over from other operators. In these cases, RMP provides the available production history to them. In a few other cases, RMP has been asked why operators are required to submit a notification form to qualify for a reduced rate. These operators feel RMP should calculate the rate on behalf of the operators and not require operators to calculate the rate themselves. The RMP feels strongly that the obligation should be with the operator to seek the royalty rate reduction. Individual operators have also expressed an interest in having the program extended to gas wells.

Effectiveness Of The Program

The overall feedback that RMP has gained from day-to-day contacts with the industry is that the Program is well received. The effectiveness of the Program in terms of accomplishing BLM's overall objectives has not yet been determined. The BLM is currently conducting a study that is intended to provide an overall assessment of the Program's effectiveness.

March 14, 1994

MEMORANDUM FOR DISTRIBUTION

FROM: Heather Ross

SUBJECT: Domestic Gas and Oil Incentives

Attached are materials for the subject NEC Deputies meeting on Wednesday, March 16, from 8 am to 9 am in Room 180 OEOB.

* Senator Breaux letter

* Senator Boren et al letter

* proposals under development by Boren group

* summary list of proposals

The purpose of the meeting is to consider these proposals and agree on a process for establishing an Administration position and strategy in this area.

Bill White	DOE
Roger Altman	TRS
Bob Armstrong	DOI
Jeff Garten	DOC
Bob Sussman	EPA
Bill Burton	C of S
Pat Griffin	Leg. Aff.
Joe Stiglitz	CEA
Alice Rivlin	OMB
Bill Galston	DPC
Katie McGinty	OEP
Bo Cutter	NEC

JOHN BREAUX
LOUISIANA

MAJORITY
CHIEF DEPUTY WHIP
COMMITTEES:
COMMERCE, SCIENCE, AND TRANSPORTATION
FINANCE
SPECIAL COMMITTEE ON AGING
WASHINGTON OFFICE:
(202) 224-4623

United States Senate

WASHINGTON, DC 20510

STATE OFFICES:
American Place, Suite 2030
Baton Rouge, LA 70825
(504) 382-2050

The Federal Building
Jefferson Street, Room
Lafayette, LA 70501
(318) 262-6871

Washington Square Annex Building
211 North 3rd Street, Room 102A
Monroe, LA 71201
(318) 325-3320

Hale Boggs Federal Building
501 Magazine Street, Suite
New Orleans, LA 70130
(504) 589-2531

Central Louisiana:
(318) 487-8446

March 7, 1994

The Honorable William J. Clinton
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President:

I appreciate the time and attention your Administration has given to the development of an energy policy. Your Domestic Natural Gas and Oil Initiative (the Initiative) issued in December of 1993 is an important first step towards developing a long-term strategic policy for domestic energy security. I have been meeting with key officials of your Administration on suggestions which I believe will build upon what you have already started in the Initiative. I am writing to bring these proposals directly to your attention and urge your support.

Clearly, for the foreseeable future, oil and natural gas will be the key components of domestic energy supply. However, with the continuing drop in oil prices and increase in energy imports, domestic energy security continues to be at risk. Costs of exploration and production are, in most cases, greater than the rate of return. If steps are not taken, this country will lose valuable energy production, thereby further increasing our reliance on imports. The following are proposals that, if adopted, will strengthen domestic energy security.

<u>Expensing of Geological and Geophysical costs</u>. Currently, a taxpayer can deduct geological and geophysical exploration costs only if the well is dry. In order to make state of the art technology financially available to all producers and to encourage exploration and production, I have introduced legislation (S. 1622) to provide that these expenses are deductible regardless of whether the well is dry or producing.

<u>Deepwater Production Incentives.</u> Some of the last remaining oil and gas reserves are prohibitively expensive to recover. In particular, an estimated 8 billion barrels of oil equivalent are located in the deepwater, water depths of 400 meters or more, of the Outer Continental Shelf (OCS) in the Gulf of Mexico.

A state of the art rig in deepwater can cost more than $1 billion, as opposed to $300 million for a conventional fixed leg platform. Because of the high cost and high risk associated with deepwater production, most will only occur with a production incentive. Legislation I have introduced, S. 403, would provide a $5 per barrel equivalent production tax credit for oil and gas produced in the deepwater of the OCS. It is estimated that this tax credit proposal will create up to 105,000 new jobs in 1998 and will sustain job creation at a level of up to 80,000 in the year 2017.

<u>Marginal Production Incentives.</u> The drop in oil prices has, in many cases, made the cost of production greater than the rate of return. This situation is particularly problematic for marginal and stripper producers that provide 14% of the domestic energy supply. Tax relief for these producers in the form of a production tax credit is critical to ensure that the country does not lose this valuable production.

<u>Environmental Equalization Fee</u>. Domestic refining capacity is important to the national security of the United States. During the 1980's, 130 U.S. refineries closed--a 42% decrease of the number of U.S. refineries. There was a corresponding decrease of refining capacity of 20%. A private study predicts that 37 more refineries with a 1.5 million barrels per day capacity (or 10%) of U.S. domestic capacity will be at risk over the next five years.

Moreover, the production costs of U.S. refiners are much higher than those of foreign owned refiners due to important and stringent environmental laws such as the Clean Air Act. There is a significant cost differential associated with the environmental requirements. This decline in refining capacity is a threat to U.S. national security. To guard against losing refining capacity, a fee on gasoline imports should be imposed to eliminate the differential.

I appreciate your consideration of these proposals. There is strong urgency to act now, and I look forward to continuing to work with you and your Administration on these solutions to develop a comprehensive and effective energy policy that will help reduce reliance on oil imports and strengthen domestic energy security.

Sincerely,

John Breaux

John Breaux
UNITED STATES SENATOR

Congress of the United States
Washington, DC 20515

March 10, 1994

The Honorable William J. Clinton
President of the United States
The White House
Washington, D.C. 20500

Dear Mr. President,

We join in this letter to call your attention to the alarming deterioration of a vital American industry -- the domestic oil and natural gas producing industry. The collapse of oil prices that began last October has driven U.S. prices below the cost of much of our domestic production. This situation has sent shock waves through the communities we represent as businesses are forced to close and thousands of Americans become unemployed.

The statistics speak clearly to the crisis which the domestic industry and the nation face. 10,500 Americans have lost their jobs since October because of the extraordinarily low prices. This job loss is in addition to the nearly 500,000 jobs that have been lost in the last decade.

Precious natural resources as well as jobs are at stake. Low prices also result in lost natural resources. Most of the nation's 450,000 marginal oil wells are unprofitable to produce at current prices. If these prices persist for much longer, many of these wells will be plugged and abandoned, which means that their reserves will be lost permanently. It is estimated that nearly 50,000 wells will be abandoned in 1994 if oil prices remain at $14 a barrel. We are particularly concerned about this possibility because marginal wells account for 14 percent of domestic oil production and are an integral part of the domestic oil business and our States' economies. Many people don't understand that once these wells are plugged, the oil and natural gas are lost forever. Our nation cannot afford to waste these resources.

Production is already declining precipitously. U.S. oil production averaged only 6.8 million barrels per day in 1993, our nation's lowest oil production level since 1958. It is almost certain that the 1994 production levels will be even lower. This is particularly disturbing in light of the fact that we currently import over 49 percent of U.S. consumption of oil. Further deterioration of the domestic industry will only increase this nation's dependence on foreign sources of energy. Imported oil currently accounts for an astonishing $ 44.7 billion of our trade deficit. That represents capital fleeing our nation that leaves our economy struggling to find the capital to invest and create jobs in the United States.

The job loss and resource loss described in this letter cause real economic dislocation and drain scarce federal, state, and local resources that could be spent for the education, infrastructure, and investments necessary for our nation to compete in a global market. Many sectors of our national economy have reaped economic windfalls resulting from extraordinarily low oil prices. We do not want to impede economic growth in any sector of the United States' economy. However, we feel strongly that it is in the best economic interest of the entire nation that our domestic energy industry survives and that we obtain the maximum value from our current investment in the resources extracted through marginal and stripper wells.

Mr. President, we urgently request a meeting with you at the earliest possible time to discuss policy options to address this situation. A prompt and effective response to this crisis is required. Although the domestic oil and natural gas producing industry is highly efficient and technologically advanced, unless U.S. energy and investment policies are made competitive, the U.S. will remain at great risk of the premature and permanent loss of vital production.

Sincerely,

David L Boren — Bill K. Brewster

Don Nickles — [illegible]

Max Baucus — Dave McCurdy

Jeff Janner — Pete V Domenici

[illegible] — Jerry Costello

Glenn Poshard — Hank Brown

**Letter to President Clinton
on the domestic oil and gas industry
March 10, 1994**

Senators:

Max Baucus (D-MT)
Robert Bennett (R-UT)
Jeff Bingaman (D-NM)
David L. Boren (D-OK)
John B. Breaux (D-LA)
Hank Brown (R-CO)
Dale Bumpers (D-AR)
Conrad Burns (R-MT)
Ben Nighthorse Campbell (D-CO)
Thad Cochran (R-MS)
Kent Conrad (D-ND)
Larry Craig (R-ID)
Bob Dole (R-KS)
Pete V. Domenici (R-NM)
Byron L. Dorgan (D-ND)
Wendell Ford (D-KY)
Phil Gramm (R-TX)
Orrin Hatch (R-UT)
Kay Bailey Hutchison (R-TX)
Nancy Landon Kassebaum (R-KS)
J. Bennett Johnston (D-LA)
Trent Lott (R-MS)
Mitch McConnell (R-KY)
Frank H. Murkowski (R-AK)
Don Nickles (R-OK)
David Pryor (D-AR)
Richard C. Shelby (D-AL)
Paul Simon (D-IL)
Alan K. Simpson (R-WY)
Ted Stevens (R-AK)
Malcolm Wallop (R-WY)

Representatives:

Wayne Allard (R-CO) [4th]
Bill Archer (R-TX) [7th]
Michael A. Andrews (D-TX) [25th]
Spencer Bachus (R-AL) [6th]
Scotty Baesler (D-KY) [6th]
Joe L. Barton (R-TX) [6th]
Tom Bevill (D-AL) [4th]
Henry Bonilla (R-TX) [23rd]
Bill Brewster (D-OK) [3rd]
John Bryant (D-TX) [5th]
Jack Brooks (D-TX) [9th]
Sonny Callahan (R-AL) [1st]
Dave Camp (R-MI) [4th]
Jim Chapman (D-TX) [1st]
Larry Combest (R-TX) [19th]
Gary A. Condit (D-CA) [18th]
Jerry F. Costello (D-IL) [12th]
Cal Dooley (D-CA) [20nd]
Chet Edwards (D-TX) [11th]
Thomas W. Ewing (R-IL) [15th]
Jack Fields (R-TX) [8th]
Martin Frost (D-TX) [24th]
Pete Geren (D-TX) [12th]
Dan Glickman (D-KS) [4th]
Henry B. Gonzalez (D-TX) [20th]
Ralph M. Hall (D-TX) [4th]
Jimmy Hayes (D-LA) [7th]
Wally Herger (R-CA) [2nd]
Joel Hefley (R-CO) [5th]
Peter Hoagland (D-NE) [2nd]
Amo Houghton (R-NY) [31st]
Earl Hutto (D-FL) [1st]
James M. Inhofe (R-OK) [1st]
Ernest Istook (R-OK) [5th]
William J. Jefferson (D-LA) [2nd]
Eddie Bernice Johnson (D-TX) [30th]
Scott L. Klug (R-WI) [2nd]
Blanche Lambert (D-AR) [1st]
Greg Laughlin (D-TX) [14th]
Robert L. Livingston (R-LA) [1st]
Jim McCrery (R-LA) [5th]
Dave McCurdy (D-OK) [4th]
Scott McInnis (R-CO) [3rd]
Alan B. Mollohan (D-WV) [1st]
G.V. "Sonny" Montgomery (D-MS) [3rd]
Solomon Ortiz (D-TX) [27th]
Michael G. Oxley (R-OH) [4th]
Mike Parker (D-MS) [4th]
Ed Pastor (D-AZ) [2nd]
Collin C. Peterson (D-MN) [7th]

J.J. Pickle (D-TX) [10th]
Earl Pomeroy (D-ND) [AL]
Glenn Poshard (D-IL) [19th]
Nick J. Rahall II (D-WV) [3rd]
Bill Richardson (D-NM) [3rd]
Pat Roberts (R-KS) [1st]
Dana Rohrabacher (R-CA) [45th]
J. Roy Rowland (D-GA) [8th]
George E. Sangmeister (D-IL)
Rick Santorum (R-PA) [18th]
Bill Sarpalius (D-TX) [13th]
Patricia Schroeder (D-CO) [1st]
David E. Skaggs (D-CO) [2nd]
Joe Skeen (R-NM) [2nd]
Jim Slattery (D-KS) [2nd]
Lamar Smith (R-TX) [21st]
Charles W. Stenholm (D-TX) [17th]
Mike Synar (D-OK) [2nd]
W.J. "Billy" Tauzin (D-LA) [3rd]
Frank Tejeda (D-TX) [28th]
Bill Thomas (R-CA) [21st]
Craig Thomas (R-WY) [AL]
Walter R. Tucker III (D-CA) [37th]
Pat Williams (D-MT) [AL]
Charles Wilson (D-TX) [2nd]
Bob Wise (D-WV) [2nd]
Don Young (R-AK) [AL]

A Proposal to Preserve Marginal Production, Encourage New Drilling

Existing Marginal Wells Under Section 613A(c)(6)(D):

a. provide a $3 per barrel tax credit for the first 3 barrels of daily production from an existing marginal well;

b. provide a $0.50 per Mcf credit for the first 18 Mcf of daily natural gas production;

c. include in the current Section 613A(c)(6)(D) definition of "marginal well" a new category for "high water cut property" -- producing 25 barrels per day or less per well, with produced waters accounting for 95 percent of total production.

d. include injection and water disposal wells in the calculation to determine whether a property qualifies as a marginal property.

New Wells:

a. provide a $3 per barrel tax credit for the first 15 barrels of daily production for oil wells drilled after June 1, 1994.

b. provide a $0.50 per Mcf for the first 300 Mcf per day for gas wells drilled after June 1, 1994.

Other Characteristics:

- For existing marginal wells and new wells, the tax credit would be phased out in equal increments as prices for oil and natural gas rise, as follows:
  Oil--phase out between $14 and $20
  Gas--phase out between $2.49 and $3.55 (BTU equivalent of oil price)

- Both the tax credit and the phase out prices would be indexed for inflation.

- The credit must be creditable against regular tax and AMT.

Consensus Additional Legislative Initiatives

Geological and Geophysical Costs. We continue to urge the administration to support the current expensing of G&G costs. We understand that the administration is studying the tax treatment of G&G costs, and we recognize that legislative action may be required.

Strategic Petroleum Reserve (SPR). The SPR is intended as a backup oil resource to prevent an interruption of oil supplies in the U.S. in the event of a loss of imported oil. Oil imports are growing, and the amount of oil needed to provide the 90 day cushion has risen above the 580 mm bbls that are currently stored. To protect domestic consumers, the U.S. must resume filling the SPR. We strongly suggest that oil purchases for the SPR should be targeted at the most marginal wells (wells certified to average one or less barrels of production per day) or wells that are eligible to receive the new well tax credit

Consensus Administrative/Regulatory Initiatives

Oil Pollution Act of 1990. We believe that the financial responsibility provisions of OPA 90 are onerous and unnecessary, and we support a reduction of the dollar limits.

Royalty Reduction. To remain competitive in attracting capital, U.S. royalty laws should be reassessed. The existing royalty reduction for marginal oil wells on public lands (onshore) should be expanded to include marginal natural gas wells. The royalty reduction for offshore production should be extended for new activity, especially deep water and other frontier areas, and marginal properties. Finally, we support legislation that would temporarily suspend the collection of royalties from wells in deep water, such as the bill that was approved by the Senate Energy and Natural Resources Committee.

Royalty Collection. "Reinventing Government" legislative proposals establish an unworkable, unfair penalty regime that will have particularly adverse affects on natural gas production. The Administration should withdraw this proposals and work with industry to eliminate royalty collection problems.

- **Underground Injection Control.** The EPA is developing revised regulations, reportedly deviating from recommendations made by the Advisory Committee on UIC. Indications that the EPA is considering tightening regulations are disappointing, especially in light of its report to Congress which found that any problems could be solved by enforcing existing regulations, rather than adopting new rules. This proposal could be extremely costly to the industry without improving environmental protection. We oppose the EPA proposed revision of existing UIC regulations.

- **Natural Resources Damage Assessment.** The Departments of Interior and Commerce are developing regulations to impose liability on natural resource producers for injuries caused by hazardous discharges. Although relevant statutes do not require it, damages could include emotional loss of persons who do not use the natural resources. The "non-use" damage proposal relies on an economic methodology known as contingent valuation (CV). However, a panel of economists created by NOAA was unable to confirm that CV was a reliable methodology. We believe that CV for damage assessments is seriously flawed and oppose the inclusion of liability for non-use value loss in the final regulations.

- **Oil and Gas Leasing on Public Lands.** The Interior Department is conducting an internal review of leasing to promote a new approach called "ecosystem management." Current law, the Federal Land Policy Management Act (FLMPA), is based on multiple use, including oil and gas leasing activity. We urge the Interior Department to abide by the principle of multiple use.

Other Legislative and Administrative/Regulatory Approaches

- **Limitations on Exports.** We favor abolishing the existing prohibitions against the export of domestic crude oil production.

Revised March 7, 1994

DOMESTIC GAS AND OIL INCENTIVES

Boren	Breaux	
✓	✓	Tax credit for first x barrels and first y MCF per day of production from designated existing and new wells
✓	✓	Expensing of geological and geophysical costs
✓		Purchasing of marginal and new well oil for Strategic Petroleum Reserve
	✓	Tax credit for deepwater oil and gas production
	✓	Gasoline import fee
✓		Reduce financial responsibility requirements under Oil Pollution Act of 1990
✓		Reduce federal onshore and offshore royalties
✓		Eliminate royalty collection problems
✓		Terminate revision of EPA's existing Underground Injection Control regulations
✓		Exclude liability for non-use value loss from DOI/DOC regulations on natural resource producers' liability for hazardous discharges
✓		Maintain multiple use principle in oil and gas leasing on public land
✓		Abolish prohibition against export of domestic crude oil production

DOMESTIC GAS & OIL INCENTIVES WORKING GROUP

Kyle Simpson	DOE	586-0148
Rich Rosenzweig	DOE	586-7644
Elizabeth Wagner	TRS	622-9260
Carolita Kallaur	DOI	208-7242
Joe Yancik	DOC	482-0170
Dick Morgenstern	EPA	260-0780
Bill Burton	CofS WHO	456-2271
Barbara Chow	Leg. Aff.	456-2604
Mark Mazur	CEA	395-6809
Gary Bennethum	OMB	395-3165
Brian Burke	DPC	456-7028
Wesley Warren	OEP	456-2710
Heather Ross	NEC	456-2223

Following are papers received from OMB.

EXECUTIVE OFFICE OF THE PRESIDENT
OFFICE OF MANAGEMENT AND BUDGET
WASHINGTON, D.C. 20503

OMB ENERGY & SCIENCE DIVISION FAX TRANSMISSION (202) 395-3165

March 14, 1994

Please deliver to:
Heather Ross, OPD

Fax was sent from:
Daren Wong (202) 395-3810
Energy Branch

Total transmission: 11 pages

< M E S S A G E >

The "Draft Analysis of a Proposal for a National Security Fee on Imported Gasoline" is attached. Please direct any questions or comments to me. I can be reached on phone 395-3810, or fax 395-3165.

ANALYSIS

The industry's own recent National Petroleum Council report (U.S. Petroleum Refining, August, 1993) and other related analyses raise serious questions about the Coalition's conclusion that there is a national security crises in the domestic refining industry. The Coalition's arguments simply are not substantiated by the facts. The argument's put forth to justify the imported gasoline tax are based on faulty premises.

U.S. Gasoline imports are declining - not increasing (1980-1993).

Historical data on gasoline and refined product trade do not support the Coalition's claim that imports are currently a threat to U.S. domestic production. Based on the data, we find a five year trend toward *decreased* dependence on imports. There is no basis to conclude that the U.S. has increased its dependence on gasoline imports or refined products.

Energy Information Administration (EIA) volume data for the period 1980 to 1993 indicates that net imports of finished gasoline have not increased, and that net imports for all refined products fell by 40%. For finished gasoline, net imports accounted for 2.1% of U.S. finished gasoline supply in both 1980 and 1993. Net gasoline imports rose to 5.4% of U.S. supply in 1985 and have declined every year since 1989. EIA data shows that total imports of finished gasoline rose only 78% from 1980 to 1993, rather than the tripling claimed by the Coalition. In fact, total gasoline imports have declined 39% since 1988, and in 1993, stood at their lowest level since 1983.

Net imports of all refined products was 7.8% of U.S. supply (on a volume basis) in 1980, peaked at 8.6% in 1988, and declined to 4.7% in 1993. Total imports declined 22% from 1988 to 1993, see Figure 1. Also, see Figure 2 which shows that net imports of several refined products as percent of U.S. supply are actually trending downward since the late 1980s.

With regard to future gasoline imports, the industry studies differ markedly with the EIA's projections. As shown in Figure 3 the NPC's growth and declining demand scenario's project little or no increase in future gasoline imports. The NPC projections include the impact on foreign refineries of the availability of foreign capital and foreign regulatory requirements. Also the NPC believes it is important to recognize that the U.S. age cohort that drives vehicles the most has peaked, that licensed drivers with access to vehicles has reached the saturation point, and that vehicle performance improvements will translate to efficiency savings.

Reductions in refinery capacity resulted from market pressures and overcapacity - not imports.

EIA data are consistent with the Coalition's claim that U.S. refining capacity and the number of operating U.S. refineries dropped during the period 1980 to 1993. During the period, operating refinery capacity declined from 17.6 million to 14.8 million barrels/day, while the number of operating U.S. refineries dropped from 311 in 1980 to 175 in 1993. However, refinery shutdowns occurred because of market pressures to reduce excess refining capacity, not because of product imports or regulatory related costs. From 1980 to 1984, U.S. refinery utilization rates ranged from 67% to 77%, compared to a consistent historical range of 85% to 90%. Markets adjusted to bring supply in line with demand, as utilization rates reached 85% in 1989, and surpassed 90% in 1993.

While it is true that many, particularly small independent, refineries have shut down over the last decade these closures are largely the result of competitive pressures and the prospect of the need to make large capital investments. The small, less technologically sophisticated refineries face a significant disadvantage whenever they are required to upgrade. Figure 4 shows the technology gap which exists between the small and large refineries. While small, less efficient and technically less complex refineries have had to close, the productivity of the larger refineries has increased. From 1983 through 1993, the industry operated with a crude oil throughput capacity in the narrow range of 14.8 to 15.0 million barrels/day, but with 58 fewer refineries in 1993 than in 1983. In the last decade, refinery productivity dramatically increased due to the use of new technology and improved operational efficiencies.

Finally, with respect to the adequacy of existing capacity to refine Strategic Petroleum Reserve (SPR) crude oil in an emergency, total domestic daily refining capacity is about 15 million barrels per day compared with SPR's maximum daily drawdown rate of 2 million barrels per day. Clearly, there is sufficient U.S. capacity to refine SPR oil. In addition, there is nothing to prevent SPR oil from being refined abroad. Total world crude oil refinery capacity is about 73 million barrels per day. About one-fifth is located in the U.S., the largest percentage of any country.

Refining costs outside the U.S. are expected to rise and most domestic refiners are expected to meet the regulatory challenge.

Based on their modeling efforts using EIA product demand data, the National Petroleum Council, an industry advisory group to the Energy Secretary, concluded that "imports may be expected to play a diminishing role in U.S. light product supply" in their 1993 refinery study [NPC, p.26]. Underlying this projection is the NPC assessment that *current foreign refinery cost advantages will not grow, or will diminish in the future*. The NPC was explicit in its assessment that the U.S. market will be a formidable challenge to foreign refiners given their limited offshore financial and operating resources:

> "First, health, safety, and environmental costs are expected to increase in all foreign locations. Second, product consumption is expected to increase outside the U.S. and product quality is expected to shift toward environmental fuels, making processing costs increase significantly more than in the U.S. Finally, the cost of moving products from foreign supply points to U.S. demand centers is expected to increase." [NPC, p.203]

The cost of meeting environment, safety, and health (ES&H) regulations will be a major challenge for the U.S. refining industry. According to the NPC, U.S. refiner capital spending (per unit of capacity) will be about 17% higher (or $7.3 billion) in the 1990s than the 1980s, but 39% lower during 2001-2010 than the 1980s. Furthermore, ES&H compliance and reformulated fuels production costs will also increase refiners' operating and maintenance expenses dramatically.

The NPC estimated capital expenditures by U.S. refiners for stationary source regulatory compliance and product quality, amounting to $37 billion during the 1990s. They projected that two-thirds of this spending will occur in the period 1991 to 1995. The NPC projects that the industry will have to seek external financing to support its cash flow needs and that this will make it more sensitive to upswings in interest rates and downturns in demand. Cash poor refiners will have to decrease costs, and may have to sell, merge, partner with other firms, or go out of business. In particular, small refiners, known to be generally behind in modernizing their facilities, will carry an extra burden to upgrade their plants.

Although this level of investment will stress the industry's ability to finance the needed changes it will also eventually affect non-domestic refiners as well. Foreign refineries must also meet domestic product specifications. And in many countries, environmental regulatory requirements are becoming equal to those in the U.S.

The profitability of domestic refining increased in 1993.

It is difficult to argue that the state of U.S. refining industry is a national security threat when many of companies are making good profits on their downstream operations. Refining and marketing profits for the 19 companies tracked by **The Oil Daily** increased 64% in 1993 over 1992, while profit margins increased 60%. Profits and profit margins of most of the member companies of the Independent Refiners Coalition also increased in 1993. Because of an improved economic climate encouraging gasoline consumption, and prices of crude oil at five-year lows, the 1994 profit picture for refining and marketing continues to look favorable. It seems that it would be difficult for the Administration, in light of the current refinery profit outlook to justify providing import fee protection.

The National security fee would likely violate international agreements.

Unless it is applied to domestic as well as imported gasoline, the proposed fee on gasoline would violate the GATT, NAFTA, and the CFTA. If the U.S. determined that imported gasoline threatened the nation security, a fee could be justified under GATT, NAFTA, and the CFTA.

Undoubtedly, such a fee would be challenged under GATT. Nothing in the GATT permits the imposition of fees on imports to equalize the economic burden borne by domestic industry in complying with environmental or other standards that take the form of mandates, rather than taxes affecting domestic products.

Under the Canada Free Trade Agreement, the U.S. would have to exempt Canada from the import fee. Because Canada is a primary source of gasoline imports to the U.S., exemption would significantly reduce the intended effect of the fee.

A gasoline import fee of 7 to 13 cents per gallon would, of course, raise the prices consumers, truckers, farmers, other businesses and all gasolines users must pay for fuel. This of course would adversely affect the international competitiveness of non-refining U.S. industry.

The import fee would also have a significant effect on income distribution, transferring billions of dollars from consumers and business to the domestic gasoline refining industry. Consumers objected strongly to last year's 4.3¢/gallon gasoline tax.

<u>The macro-economic effects of the loss of refinery capacity are overstated.</u>

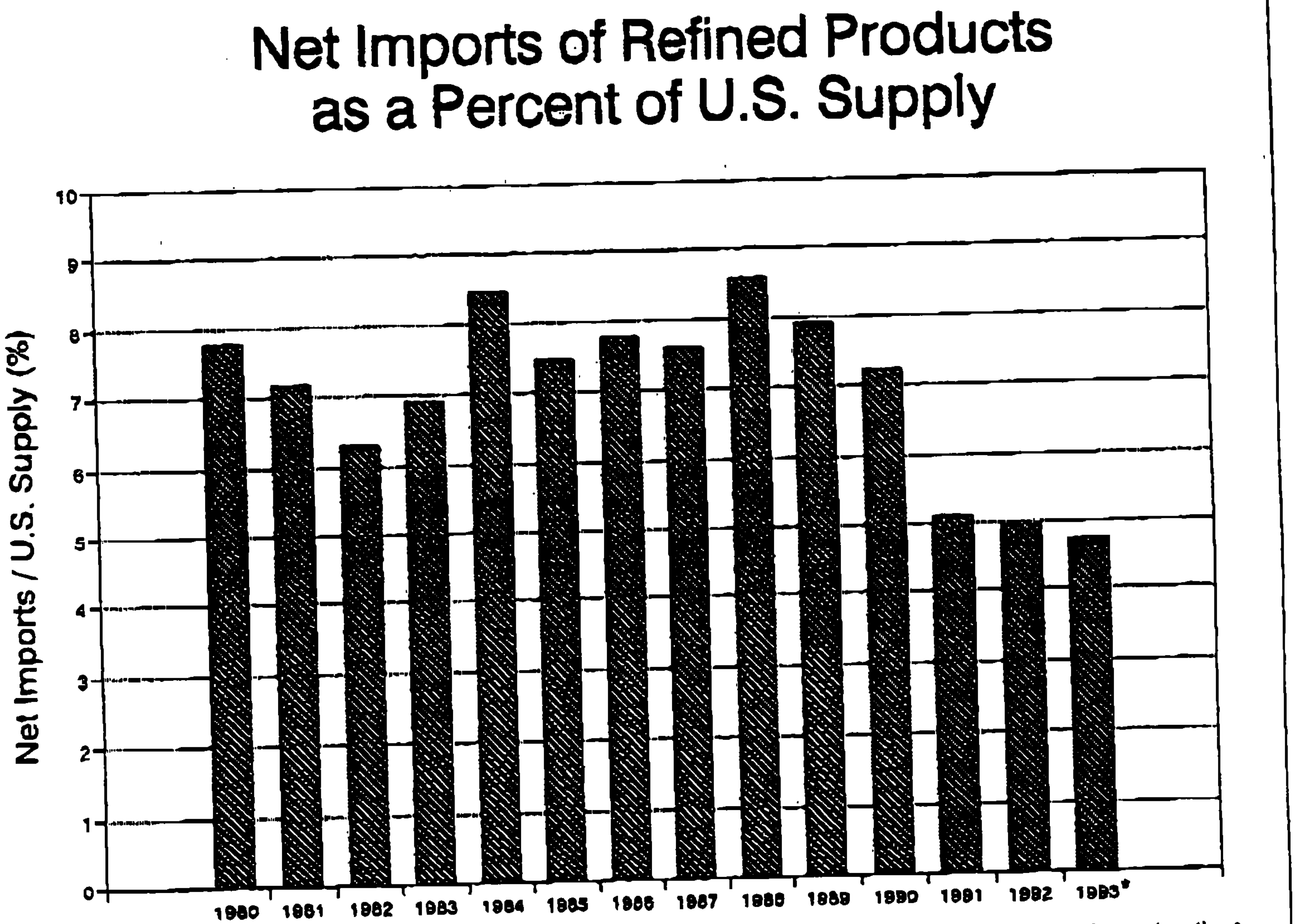
U.S. Bureau of Labor Statistics data in 1980 the petroleum refining industry employed 155,000 workers. By 1992 there was a 25 percent drop in employment (mostly because of productivity increases) to 116,000 workers. However, the rate of decrease was substantially less in more recent years declining only 7 percent between 1987 and 1992. The Coalition's argument that the loss of 10 percent of U.S. refining capacity would result in the loss of 570,000 jobs when the industry only employs less than 120,000 is difficult to understand.

<u>Revenue gains from the proposed sale would be much smaller than alleged by the Coalition.</u>

Levels of finished gasoline imports may be much less than that estimated by the Coalition. Revenues from the fee may be much lower than the Coalition projects.

- The level of finished gasoline imports assumed by the fee's proponents is about 122 million barrels/year, which is 34 percent higher than the 1993 import level of 91 million barrels (11 month estimate annualized). We believe this places an upper bound on 1994 revenues at $267 million, $92 million less than the Coalition estimate.
- The national security fee is a significant percentage of importer's profits. Some importers may stop shipments to the U.S. totally, and others may curtail imports because of reduced demand. Imports may drop beyond 1994 because the fee escalates through 1994. Revenues may be far below the upper bounds we calculated above.

Figure 1. Reduced dependence on imports of refined products.

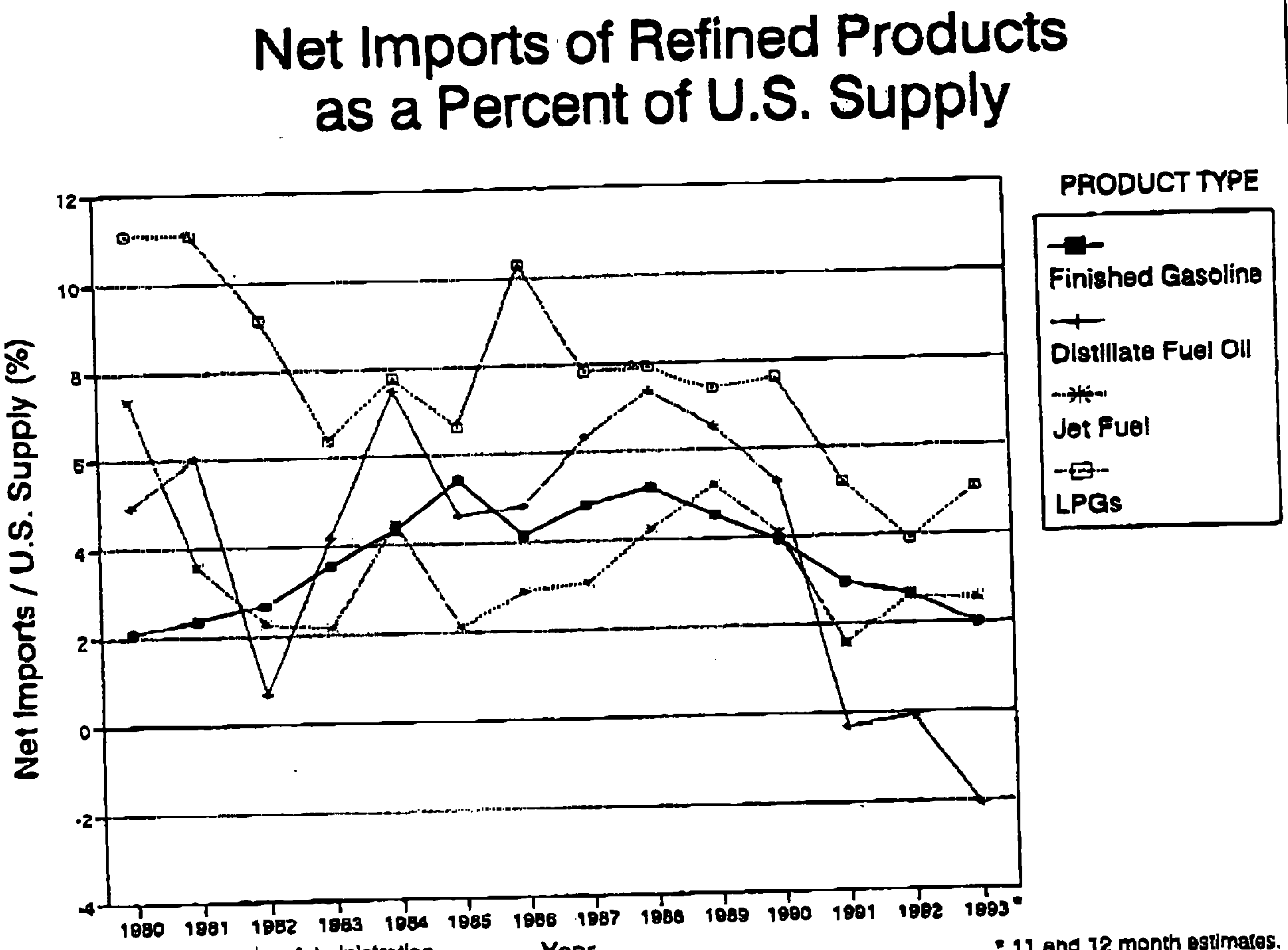


Source: Energy Information Administration, Monthly Energy Review, January 1994, Tables 3.4-3.10.

* 11 and 12 month estimate.

While it is true U.S. refiners have shutdown many refineries over the past years, increased productivity and output at operating refineries have kept pace with overall domestic demand. Figure 1 shows a trend toward decreased dependence on imported refined products. Net imports, as a proportion of total supply dropped by over 50 percent in the last decade. This is true for most classes of products tracked by the EIA.

Figure 2. Import dependence for a variety of refined products, including gasoline.



Source: Energy Information Administration, Monthly Energy Review, Janaury 1994

* 11 and 12 month estimates.

03/14/94

Figure 3.

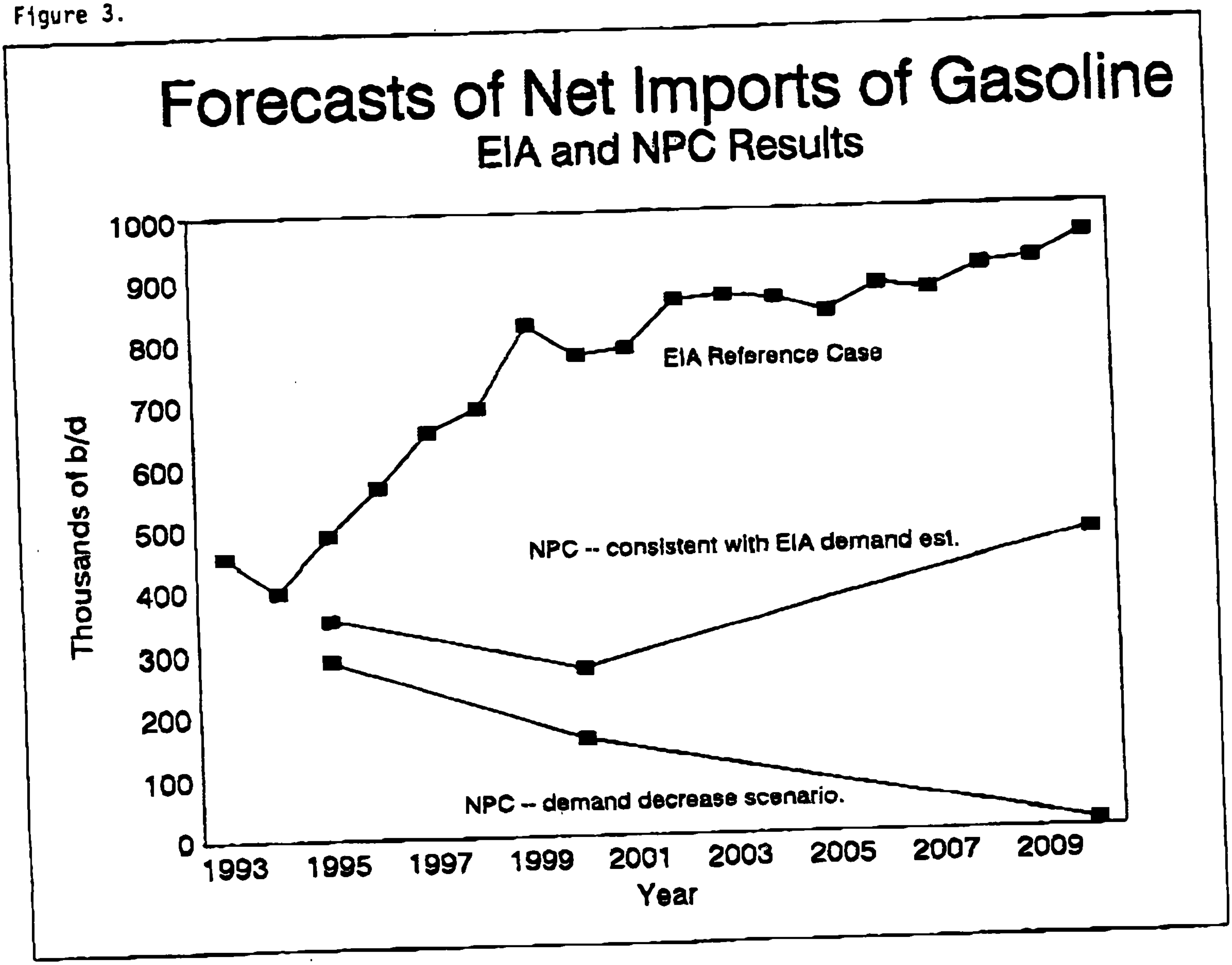
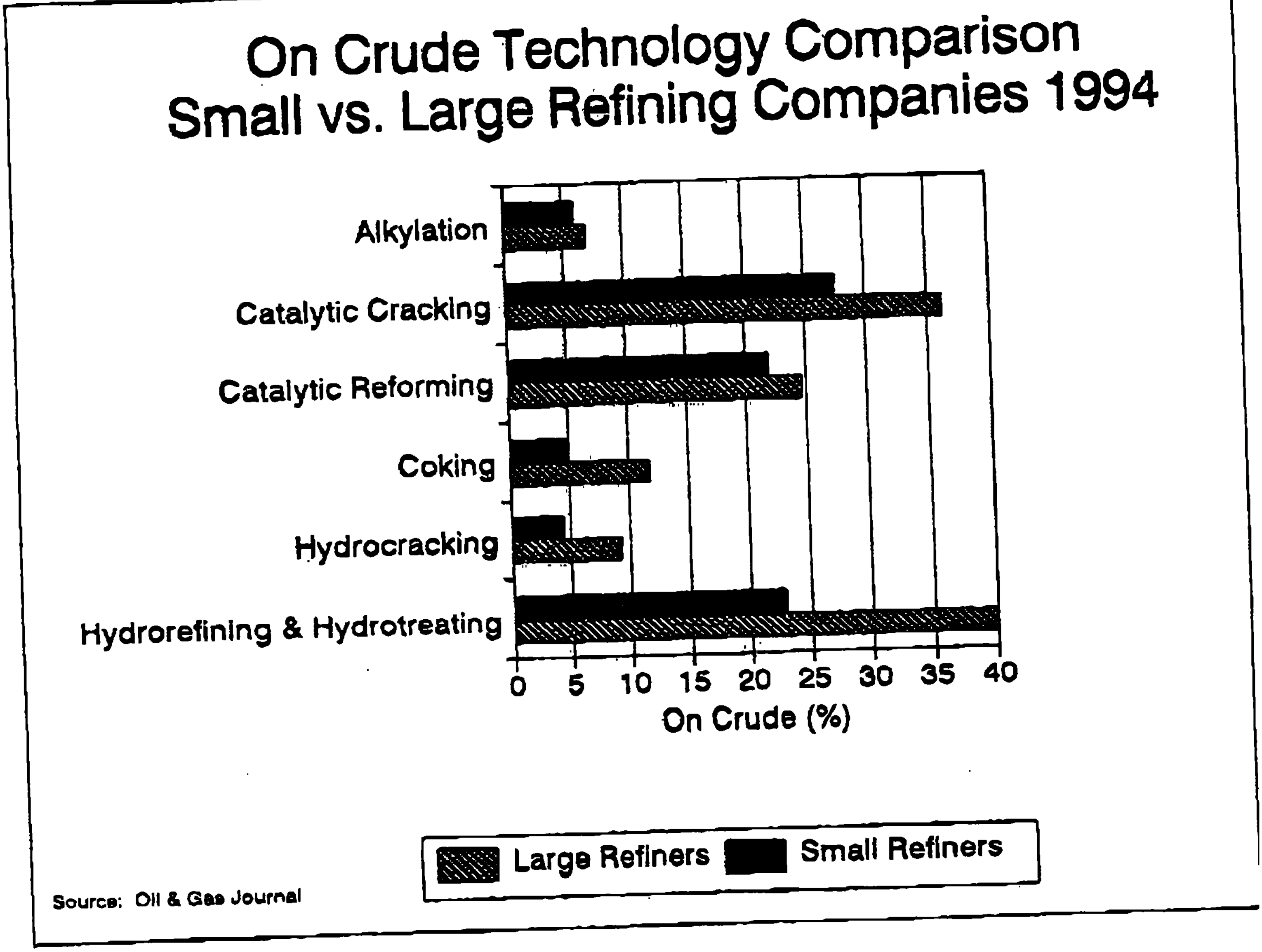


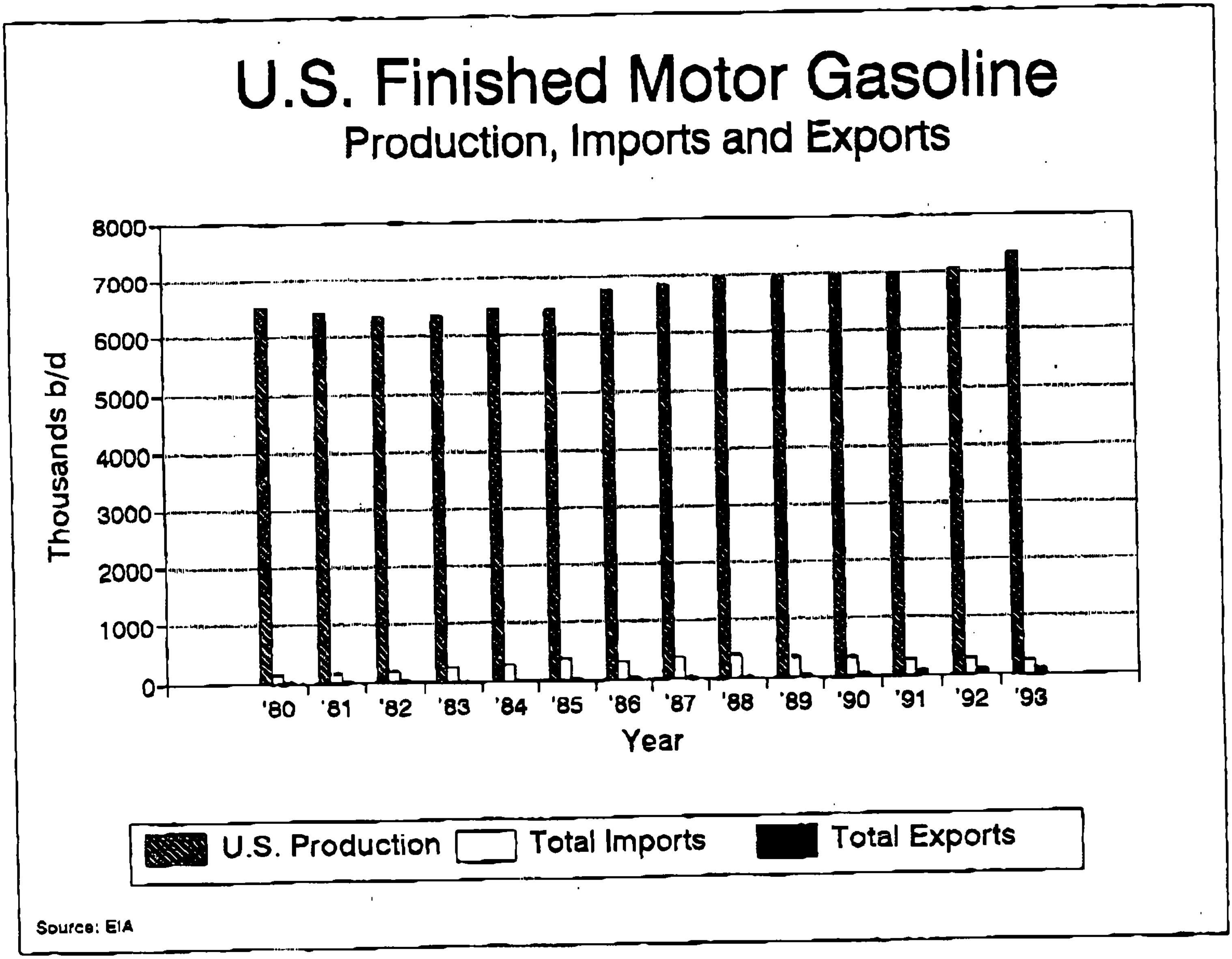
Figure 4. Technologies implemented at small and large refining companies.



Source: Oil & Gas Journal

Companies capable of refining more than 200,000 b/d of crude oil utilize sophisticated refining technologies at a much higher level than small refiners.

The 87 refineries owned by large refiners have an average capacity of 137,670 b/d of crude, compared to an average of 34,772 b/d for the 91 refineries owned by small refiners.


U.S. Finished Motor Gasoline
Production, Imports and Exports
8000
7000
6000
5000
4000
3000
2000
1000
0
Thousands b/d
'80
'81
'82
'83
'84
'85
'86
'87
'88
'89
'90
'91
'92
'93
Year
U.S. Production
Total Imports
Total Exports
Source: EIA

U.S. DEPARTMENT OF COMMERCE

BUREAU OF EXPORT ADMINISTRATION
OFFICE OF INDUSTRIAL RESOURCE ADMINISTRATION
14TH & CONSTITUTION AVENUE, N.W., ROOM 3878
WASHINGTON, DC 20230

FACSIMILE NUMBER: (202) 482-5650

DATE: 3-24-94

SEND TO: See attached list

RECIPIENTS FAX NUMBER: 482-5650

FROM: Steve Goldman

MESSAGE:

NUMBER OF PAGES INCLUDING COVER: 8

If this transmission is incomplete or illegible, please call (202) 482-3695

DOMESTIC GAS & OIL INCENTIVES WORKING GROUP

NAME	AGENCY	PHONE	FAX
Kyle Simpson	DOE	586-5500	586-0148
Rich Rosenzweig	DOE	582-6210	586-7644
Elizabeth Wagner	TRS	622-1778	622-9260
Carolita Kallaur	DOI	208-3500	208-7242
Eric Toder	TRS	622-0120	622-0646
Dick Morgenstern	EPA	260-4034	260-0780
Bill Burton	CofS WHO	456-6797	456-2271
Barbara Chow	Leg. Aff.	456-2604	456-2604
Mark Mazur	CEA	395-5147	395-6809
Gary Bennethum	OMB	395-3634	395-3165
Brian Burke	DPC	456-7777	456-7028
Wesley Warren	OEP	456-6224	456-2710
Heather Ross	NEC	45602802	456-2223
Daren Wong	OMB	395-3810	395-3165
Don Eiss	USTR	395-5656	395-3911
Bernie Kritzer	DOC	482-0074	482-3195
Lori Krauss	OMB	395-3463	395-1086
Michael Shelby	EPA	260-5492	260-0512
Steven Goldman	DOC/BXA	482-4060	482-3195
Hudson Milner	TRS	622-1785	622-1772
Ray Squitieri	TRS	622-2340	622-1294
Janet Minkler	OMB	395-4993	395-6895
Len Coburn	DOE	586-5667	586-4341

Reminder: The next Working Group meting is Friday, March 25, from 10:00 a.m. until noon in Room 476 OEOB. We will discuss progress on current assignments and preparations for April 6 Deputies Meeting.

Following this notice, is a listing of names on our permanent clearance list for the Gas & Oil Incentives Working Group. Hereafter, everyone on this listing will be cleared into the G&OIWG meetings. If you are not on the listing, you need to call Gaylen Barbour at 456-2802 to arrange for clearance.

UNITED STATES DEPARTMENT OF COMMERCE
Bureau of Export Administration
Washington, D.C. 20230

March 24, 1994

To: Distribution

From: Steven C. Goldman S. G.
Deputy Director
Office of Industrial Resource Administration

Subject: California Crude Oil Notice

Attached for your review and comment is DOC's proposed rule regarding exports of California heavy crude oil.

Attachment

flight, replace the bolt with a serviceable magnafluxed bolt or with a new bolt, in accordance with the service bulletin.

(2) Replace each existing MLG retract actuator bracket retaining bolt, Item 840 (P/N AIR 123940), with a new bolt, P/N AIR 134736, in accordance with the service bulletin.

(c) At the next MLG overhaul, or within 12,000 landings after the effective date of this AD, whichever occurs earlier, remove the existing nose landing gear trunnion pin cross bolt, P/N NAS 1305-54D, and replace it with a new bolt, P/N NAS 1305-50D, in accordance with Paragraphs C. through F. of the Accomplishment Instructions of Saab Service Bulletin 340-32-094, dated October 29, 1993.

(d) An alternative method of compliance or adjustment of the compliance time that provides an acceptable level of safety may be used if approved by the Manager, Standardization Branch, ANM-113, FAA, Transport Airplane Directorate. Operators shall submit their requests through an appropriate FAA Principal Maintenance Inspector, who may add comments and then send it to the Manager, Standardization Branch, ANM-113.

Note: Information concerning the existence of approved alternative methods of compliance with this AD, if any, may be obtained from the Manager, Standardization Branch, ANM-113.

(e) Special flight permits may be issued in accordance with Federal Aviation Regulations (FAR) 21.197 and 21.199 to operate the airplane to a location where the requirements of this AD can be accomplished.

Issued in Renton, Washington, on March 18, 1994.

Darrell M. Pederson,

Acting Manager, Transport Airplane Directorate, Aircraft Certification Service.

[FR Doc. 94-6909 Filed 3-23-94; 8:45 am]

BILLING CODE 4910-13-U

DEPARTMENT OF COMMERCE

Bureau of Export Administration

15 CFR Part 777

[Docket No. 930653-3153]

RIN 0694-AA70

Exports of Certain California Crude Oil

AGENCY: Bureau of Export Administration, Commerce.

ACTION: Proposed rule with a request for comments.

SUMMARY: The Bureau of Export Administration (BXA) is proposing to amend the short supply provisions of the Export Administration Regulations (EAR) by revising the restrictions on exports to initially allow the export of up to 25,000 barrels per day of California heavy crude oil having a gravity of 20 degrees API or lower. The changes proposed by this rule are based on the President's October 22, 1992, memorandum to the Secretary of Commerce to modify existing restrictions on the export of certain California heavy crude oil. This notice delineates the actions the Department is taking to implement the President's decision. It also proposes specific regulatory changes implementing those actions and solicits public comments.

DATES: Comments must be received by April 25, 1994.

ADDRESSES: Written comments (six copies) should be sent to Bernard Kritzer, Senior Industry Analyst, Office of Foreign Availability, room 1087, U.S. Department of Commerce, 14th Street and Pennsylvania Avenue NW., Washington, DC 20230.

FOR FURTHER INFORMATION CONTACT: Bernard Kritzer, Office of Foreign Availability (OFA), Bureau of Export Administration, Telephone: (202) 482-0074.

SUPPLEMENTARY INFORMATION:

Background

Section 777.6(d)(1) of the Export Administration Regulations (EAR) restricts exports of crude petroleum, including reconstituted crude petroleum, tar sands and crude shale oil. This rule proposes to amend § 777.6(d)(1) to permit exports of certain California crude oil pursuant to a Presidential Memorandum of October 22, 1992,[1] in which the President determined that exports of California heavy crude oil having a gravity of 20 degrees API or lower were in the national interest. Before the President authorized this export of crude oil, he made findings and determinations under three statutes: Section 103 of the Energy Policy and Conservation Act (42 U.S.C. 6212(b)); section 28(u) of the Mineral Leasing Act, as amended by the Trans-Alaska Pipeline Authorization Act of 1973 (30 U.S.C. 185(u)); and provisions of the Export Administration Act, as amended, and to the extent consistent with law, continued in effect through the President's invocation of the International Emergency Economic Powers Act. The Export Administration Act was continued on March 27, 1993, by Public Law 103-10. The President made findings that exports of California heavy crude oil having a gravity of 20 degrees API or lower: (1) Were in accord with the provisions of the Export Administration Act of 1979, as amended;

(2) Were consistent with the purposes of the Energy Policy and Conservation Act; and

(3) Would not diminish the total quality or quantity of petroleum available to the United States.

Based upon the above findings, the President authorized the Secretary of Commerce to modify the existing restrictions on the export of crude oil produced in the lower 48 states to initially allow the export of an average quantity of 25,000 barrels per day (MB/D) of California heavy crude oil having a gravity of 20 degrees API or lower.

The President also directed the Secretary of Energy, in consultation with the Secretaries of Commerce, the Interior, Transportation, and other interested agencies, to conduct periodic reviews of such exports in light of then-existing market circumstances. Based upon the results of these market reviews, the President authorized the Secretary of Energy to recommend to the Secretary of Commerce that adjustments be made in the quantity of California heavy crude oil that may be authorized for export (i.e., adjustments to the initial average authorized level of 25 MB/D).

Department of Commerce Actions

The Department proposes to take the following actions to implement the President's decision: (1) Propose rules to implement the President's decision;

(2) Solicit public comments on the rules; and

(3) Publish a final rule implementing the President's findings and taking into account public comments on this proposed rule and other relevant evidence.

The Department of Commerce's Proposals

This notice proposes to amend § 777.6 of the Export Administration Regulations (EAR) to allow the licensing of exports of up to 25 MB/D per day of California heavy crude oil having a gravity of 20 degrees API or lower.

To implement this program, the Department proposes to: (1) Grant licenses for these exports on a first-come-first-served basis; (2) authorize the export of up to 25 percent (2.28 million barrels) of the annual authorized volume (9.125 million barrels) of such California crude oil per license; (3) approve only one application per company, including its affiliates, as long as there are other outstanding non-affiliate company applications in that month; (4) allow the licensee up to 90 days from the issuance of the license to export the oil; (5) require the licensee to

[1] The President's memorandum of October 22, 1992, "Exports of Domestically Produced Heavy Crude Oil" (3 CFR, 1992 Comp., p. 382).

certify to the Department in writing that the export(s) occurred during the 90-day license term; (6) carry forward any portion of the 25 MB/D quota that the Department has not licensed, except that the Department will not carry forward unlicensed portions more than 30 days into a new calendar year; (7) return to the available quota volume all licensed volumes not shipped during the 90-day term of an export license, except that the Department will not carry forward unshipped portions more than 30 days into the new calendar year; and (8) allow a 10 percent shipping tolerance on the licensed, but not shipped volume of barrels and a 25 percent shipping tolerance on the total dollar value of the license, respectively.

The Department proposes to require that a prospective exporter: (1) Submit an application on BXA Form 622–P; (2) state the total number of barrels for export during the 90-day license term not a per day rate; (3) include supporting documents proving that the applicant has: (i) Title to the quantity of barrels stated in the application, or an accepted order for the purchase of the quantity of barrels stated in the application, (ii) a verifiable contract of sale to export the crude oil contingent on the applicant obtaining an export license, (iii) documentation proving that the crude oil to be exported has a gravity of 20 degrees API or lower, (iv) documentation proving that the crude oil was derived from production within the state of California, including its state submerged lands, (v) documentation certifying that the crude oil was not produced or derived from a U.S. Naval Petroleum Reserve, and (vi) documentation certifying that the crude oil was not produced from the submerged lands of the U.S. Outer Continental Shelf; and (4) export the licensed volumes within 90 days of the issuance of the license and to report the export to the Department of Commerce. In addition, the Department will allow the applicant to combine licensed quantities into one or more shipments, provided that the validity period of none of the affected licenses has expired. As set forth in the EAR, the applicant cannot transfer a license to another person.

An applicant can file for a license at any time during the calendar year. The Department, however, will process only one license per applicant per month as long as there are other non-affiliated applications pending during that month. The Department will issue validated licenses expeditiously as long as there are sufficient quantities of the authorized heavy crude oil volumes available. If there is no available volume of heavy crude oil, the Department will return the application without action. If the volume of heavy crude oil available for export is less than the applicant requested, the Department will contact the applicant and determine if the applicant wants the available volume. If not, the Department will return the application without action. If the applicant wants the available volume, the Department will request that the applicant amend its application to reflect the lesser volume.

The Department will apply the procedures eventually adopted in response to this proposed rulemaking with additional notice and comment to any future increase in the export volume that the Secretary of Energy may from time to time recommend to the Department of Commerce.

Nature of the Export Market

In developing an approach to implementing the President's decision, the Department is taking into account the nature of the heavy crude oil export market. The Department's 1989 "Report to the Congress on U.S. Crude Oil Exports," (pp. IV–4–IV–11) concluded that opportunities to export California heavy crude generally consist of spot market rather than year-round export activity. The report found that opportunities to export California heavy crude oil occur intermittently and randomly throughout the year when the price of these oils are low and the price of Pacific Rim substitutes are high. The Department's recent experience monitoring licensed export volumes strongly supports this position. The Department recognized the need, therefore, to develop licensing procedures permitting firms to take advantage of brief windows of opportunity and to conduct spot market export transactions.

The 1989 Commerce Report also identified numerous potential participants in such a market with a wide range of economic strengths and capabilities. The study found that allowing limited exports of California heavy crude oil would enable some firms (e.g., the independent producers) to expand their crude oil marketing opportunities, to maintain their existing oil production, and to earn additional revenue to reinvest in exploring for new domestic oil reserves.

The Department also recognized that having only one applicant could reduce the effectiveness of the export program. For example, an exporter could, in a licensing program without time limits, apply for and obtain an export license for the entire 25 MB/D per day for a one year period. If, however, the firm did not export the oil because of some problem with the transaction, the license would never be used. This would limit the number of potential exporters, deny commercial opportunities to other participants, and frustrate the intent of the President's export initiative. This concern argued for limiting the term of an export license to insure that the licensee used the license and exported the oil, or that the volume of oil quickly became available to other interested applicants.

There was also a need to assure that licenses issued to exporters would be in commercially viable volumes since the total volume initially authorized for export is low—9.125 million barrels annually. It would be difficult to achieve economically viable shipments if the Department were to issue numerous licenses for small volumes (e.g., 100,000 barrels).

Departmental Considerations

Given the noted market dynamics and commercial consideration, the Department considers it necessary to develop a licensing regime that: (1) Is equitable; (2) minimizes government involvement in commercial transactions; (3) makes licenses available to a wide number of participants; (4) reviews license applications expeditiously to allow firms to take advantage of time-sensitive spot market trading opportunities; (5) prevents a firm from obtaining a license and not exporting the oil; (6) allows for economically viable export cargoes; and (7) does not impose unnecessary administrative burdens on exporters.

Although the Department proposes to implement the option of first-come-first-served, the Department will consider and may adopt any of the options in this rulemaking, or an alternative proposal that addresses the above considerations. In fact, the Department did consider several different options; they are discussed below. The Department is soliciting comments from interested parties on the most effective approach for the Department to implement the President's decision.

Option #1—First-Come-First-Served

Under this option, the Department would grant licenses for the export of California heavy crude oil on a first-come-first-served basis. This option involves the minimum government management of an export licensing regime and intervention in the market. There are numerous variations to this option which involve the number of times per year that the Department would review and authorize export licenses. The Department could grant the licenses annually, quarterly or monthly on a first-come-first-served basis. There are also numerous variations on the volume of oil the Department could authorize per license. Under one variation the Department could license the entire export volume (9.125 million barrels) to the first firm that filed an export license application.

Although licensing the entire volume at one time would achieve the Department's objective of minimizing the government's role in export transactions, it may result in limiting this export opportunity to the first firm that filed a license application. The Department, however, wants to ensure that the potential benefits of the program are diffused among many firms and utilized. This option, therefore, calls for limiting the quantity per license (i.e., 25 percent of the total authorized volume) and for each license to have a 90 day limit. In addition, a company and its affiliates can receive only one license per month as long as there are other outstanding applications.

The Department considers this option to be the best means available to provide a number of opportunities (at least four) for a number of firms to participate in heavy crude oil exports with a minimum of government interference in the export transaction. The Department also considers that the 90 day license term would assure the utilization of the license or the rapid return of the volume of oil to the quota so others may use it.

On the negative side, a single company could request and receive for four months in a row a license covering 25 percent of the authorized volume of oil just by being the earliest applicant to file with the Department. In addition, this option would require the Department to keep running accounts on the amount available for licensing at any one time. The Department, however, should be able to handle this because the authorized export volumes are small and the exports are likely to occur intermittently rather than year round.

Option #2—Prorationing

Prorationing procedures, such as the one the Department uses for the Alaskan North Slope/Canada (ANS/Canada) crude oil export regime, offer some advantages but also involve a greater measure of government involvement than does licensing on a first-come-first-served basis.

On the positive side, this option may ensure that more firms could participate in the export program than would be the case under licensing option #1. This option also would assure everyone who applies would get some portion of the authorized export volume.

On the negative side, this option would entail active government involvement in administering an export prorationing regime on a year round basis. In addition, a prorationing scheme could be difficult to administer and could result in economically not viable volumes. The volume of California heavy crude oil exports (25 MB/D) allowed under the President's October 22, 1992 decision amounts to one-half of the volume authorized for the ANS/Canada export regime (50 MB/D). Over the past four years the demand for ANS exports to Western Canada has not forced the Department to prorate exports among competing applications. This may not be the case in the California situation where the volume is much smaller and more firms have expressed an interest in participating in this program. Although several licensees with small volumes could possibly combine volumes to make one shipment, it would not help exporters that had contracts to deliver large volumes.

Option #3—Pre-Qualification With Export Nominations

This option would result in a greater degree of government management than would be the case under any of the other options described above because it would involve a two step review process of all export licensing transactions.

Under this procedure, potential exporters would provide enough information to allow the Department to pre-qualify a firm as an exporter and subsequently grant final export authorization to the firm upon the provision of satisfactory information regarding end-users and intermediate consignees, if any.

The first step would involve the Department pre-qualifying exporters based upon the following criteria: (1) The firm is a commercial entity that is interested in exporting California heavy crude oil; (2) the applicant can demonstrate that an end-user is interested in purchasing oil from them as evidenced by a letter/telex.

The nominations process—step 2—would operate as follows:

1. On a monthly basis, a pre-qualified exporter would nominate the quantity it would like to export during the month.

2. A pre-qualified exporter would have to submit his nomination no later than 10 calendar days before the first day of the month.

3. At the outset of each month, the Department would notify pre-qualified exporters of how much oil was available for export pursuant to the quota for the month. (It could provide notice by having firms telephone a special number and/or talk with a licensing officer.)

4. When nominating export volumes, the licensee would be required to provide the Department with documentation establishing: (a) Title to the oil or a contract to purchase the oil subject to approval of the export transaction; (b) a contract or contingent contract to export the oil subject to approval of the export transaction. The Department would also have to approve the intermediate and ultimate foreign consignees for the oil, and;

5. The licensee would have 30 days to complete the export. If the export did not occur during the 30 day license term, the Department would return the volume to the quota. If the licensee shipped part of the volume, the Department would return unshipped volumes to the quota.

Other key provisions include:

1. The Department would allow the export of up to a total of 2,281,000 barrels during any 30 day period.

2. The Department would limit individual company exports to 1,000,000 barrels of oil during any 30 day period.

3. The Department would process only one nomination per firm per 30 day period as long as there are outstanding nominations from non-affiliated firms.

The Department would implement the following provision in the event the volume of crude oil nominated for export exceeds the amount allowed during a 30 day period: 1. It would allocate to each applicant an equal share of the authorized volume. For example, if five licensees nominated a total over the authorized volume of exports, the Department would allocate each party 20 percent of the volume available for export (i.e., 456,000 barrels out the total of 2,281,000 barrels available), and

2. Licensees would be allowed to combine volumes to achieve economic-sized cargoes.

On the positive side, this option would be responsive to the spot-market nature of the market. The pre-qualifying process may ensure that many firms had the opportunity to participate in the export program.

On the negative side, the Departm considers the two-step review process unnecessarily bureaucratic. This approach would require the Department to actively manage licenses and keep running accounts on the amounts available for licensing at any one time. In addition, exporters would have to contact the Department on an ongoing basis to determine what volume was available for export during a given month. Exporters would have to constantly report on whether they conducted exports and whether they exceeded their authorized export level. The Department would also have to establish a procedure to screen and prequalify new entrants on a continuous basis to ensure that they would receive an opportunity to participate in the export program.

The Department invites written comments from interested parties that may assist it in implementing the President's decision. Specifically, we solicit information concerning the following:

(1) What are the pros and cons of each of the licensing options presented, and which, if any, do you prefer?

(2) Are there other licensing approaches that would better allow U.S. exporters to take advantage of this opportunity? If you have a specific licensing scheme in mind, please explain it, discuss the pros and cons of the selected option, and explain how the Department should implement your approach.

(2) Should the Department review export license applications monthly, or more or less frequently (e.g., quarterly, semiannually, annually, continuously)? Are exports of up to 2.28 million barrels per license sufficient to make licenses available to more than one company while retaining the commercial viability of the exports? If not, what is the optimal cargo size (barrels) for economically viable export shipments?

(3) Should an exporter have more or less than a 90-day license to export California crude oil in a spot market trading environment? What would be the optimal time to allow an exporter to pursue business activities while not denying opportunities to other exporters?

(4) Should the Department carry over export volumes not shipped in one calendar year to the next year? What is the optimal time that the Department should carry over volumes not shipped during one calendar year?

(5) Are there any specific heavy crudes, with particular assay properties, that the Department should exclude from licensing? Comments in this area should indicate the specific source and type of crude, its full assay, the unique nature of the assay, the availability of substitutes and the special user.

Comment Procedures

The Department is issuing this rule in proposed form and will consider public comments in the development of the final regulations. The Department encourages interested persons who wish to comment to do so at the earliest possible time to permit the fullest consideration of their views.

The following procedures will apply to any comments submitted pursuant to this procedure: (1) Interested parties are invited to submit written comments (6 copies), opinions, data, information, or advice with respect to this notice to the address above by the dates specified above;

(2) The Department will consider all comments received before the close of the comment period in developing final regulations. While comments received after the end of the comment period will be considered if possible, this cannot be assured;

(3) All public comments on these regulations will be a matter of public record and will be available for public inspection and copying. (Communications from agencies of the United States Government or foreign governments will not be made available for public inspection.);

(4) In the interest of accuracy and completeness, the Department requires comments in written form. Oral comments must be followed by written memoranda which will also be a matter of public record and will be available for public review and copying;

(5) The Department will not accept public comments accompanied by a request that a part or all of the material be treated confidentially because of its business proprietary nature or for any other reason. The Department will return such comments and materials to the person submitting the comments and will not consider them in the development of final regulations; and

(6) The comments received in response to this notice will be maintained in the Bureau of Export Administration Freedom of Information Records Inspection Facility, room 4525, Department of Commerce, 14th Street and Pennsylvania Avenue, NW., Washington, DC 20230. Interested parties may inspect and copy records in this facility, including written public comments and memoranda summarizing the substance of oral communications, in accordance with regulations published in part 4 of title 15 of the Code of Federal Regulations. Information about the inspection and copying of records at the facility may be obtained from Margaret Cornejo, Bureau of Export Administration Freedom of Information Officer, at the above address or by calling (202) 482-5653.

Rulemaking Requirements

1. This proposed rule contains collections of information subject to the requirements of the Paperwork Reduction Act of 1980 (44 U.S.C. 3501 *et seq.*) The public reporting burden for this collection of information is estimated to average 12 hours per response, including the time required for reviewing instructions, searching and maintaining the necessary data, and completing and reviewing the collection of information. Send comments regarding this burden to: Bernard Kritzer, Senior Industry Analyst, Office of Foreign Availability, room 1087, U.S. Department of Commerce, 14th Street and Pennsylvania Avenue, NW., Washington, D.C., 20230; and to the Office of Information and Regulatory Affairs, Office of Management and Budget, Washington, DC 20503. Project No. 0694–AA70.

2. Because a notice of proposed rulemaking and an opportunity for public comment are not required to be given for this rule by section 553 of the Administrative Procedure Act (5 U.S.C. 553) or by any other law, under section 3(a) of the Regulatory Flexibility Act (5 U.S.C. 603(a) and 604(a)) no initial or final Regulatory Flexibility Analysis has to be or will be prepared.

3. This proposed rule does not contain policies with Federalism implications sufficient to warrant preparation of a Federalism assessment under Executive Order 12612.

4. This rule was not subject to review by the Office of Management and Budget under Executive Order 12866.

List of Subjects in 15 CFR Part 777

Administrative practice and procedure, Exports, Forest and forest products, Petroleum, Reporting and recordkeeping requirements.

Accordingly, part 777 of the Export Administration Regulations (15 CFR parts 730–799) is proposed to be amended as follows:

1. The authority citation for 15 CFR part 777 continues to read as follows:

Authority: Pub. 90–351, 82 Stat. 197 (18 U.S.C. 2510 *et seq.*), as amended; sec. 101, Pub. L. 93–153, 87 Stat. 576 (30 U.S.C. 185), as amended; sec. 103, Pub. L. 94–163, 89 Stat. 877 (42 U.S.C. 6212), as amended; secs. 201 and 201(11)(e), Pub. L. 94–258, 90 Stat. 309 (10 U.S.C. 7420 and 7430(e)), as amended; Pub. L. 95–223, 91 Stat 1626 (50 U.S.C. 1701 *et seq.*); Pub. L. 95–242, 92 Stat. 120 (22 U.S.C. 3201 *et seq.* and 42 U.S.C. 2139a); sec. 208, Pub. L. 95–372, 92 Stat. 668 (43 U.S.C. 1354); Pub. L. 96–72, 93 Stat. 503 (50 U.S.C. App. 2401 *et seq.*), as amended; E.O. 11912 of April 13, 1976 (41 FR 15825, April 15, 1976); E.O. 12002 of July 7, 1977 (42 FR 35623, July 7, 1977), as amended; E.O. 12058 of May 11, 1978 (43 FR 20947, May 16, 1978); E.O. 12214 of May 2, 1980 (45 FR 29783, May 6, 1980); E.O. 12730 of September 30, 1990 (55 FR 40373, October 2, 1990), as continued by Notice of September 25, 1992 (57 FR 44649, September 28, 1992); and E.O. 12735 of November 16, 1990 (55 FR 48587, November 20, 1990), as continued by Notice of November 14, 1991 (56 FR 58171, November 15, 1991).

PART 777—[AMENDED]

3. Section 777.6 is amended by adding a new paragraph (d)(1)(xii) and a new paragraph (k) to read as follows:

§ 777.6 Petroleum and petroleum products.

* * * * *

(d) * * *

(1) * * *

(xii) *Exports of certain California crude oil.* California heavy crude oil can be exported under the following conditions: (A) The commodity has a gravity of 20 degrees API or lower;

(B) The commodity is produced in the state of California, including its submerged state lands;

(C) The applicant certifies by affidavit that: (*1*) The commodity is not produced or derived from a U.S. Naval Petroleum Reserve;

(*2*) The commodity is not produced from the submerged lands of the U.S. Outer Continental Shelf; and

(*3*) All aspects of the transaction comply with the provisions of paragraph (k) of this section.

* * * * *

(k) *Exports of California heavy crude oil pursuant to § 777.6(d)(1)(xii).* The export of California heavy crude oil will be allowed for an average of no more than 25,000 barrels per day (MB/D) (or such greater or lesser volume as the Secretary of Commerce authorizes based on the determination and recommendation of the Secretary of Energy) California heavy crude oil having a gravity of 20 degrees API or lower as follows:

(1) Applicants must submit applications on Form BXA–622P to the following address: Office of Export Licensing, ATTN: Short Supply, Petroleum, Bureau of Export Administration, U.S. Department of Commerce, P.O. Box 273, Washington, DC 20044.

(2) The quantity stated on each application must be the total number of barrels—not a per day rate. This quantity must not exceed 2.28 million barrels or 25 percent of the annual authorized export quota.

(3) Each application shall be accompanied by documents that show: (i) The applicant has or will acquire a title to the quantity of barrels stated in the application by providing either an accepted contract or bill of sale for the quantity of barrels stated in the application, or a contract to purchase the quantity of barrels stated in the application, which may be contingent upon issuance of an export license to the applicant;

(ii) Contract(s) to export the quantity of barrels stated in the application, which may be contingent upon issuance of the export license to the applicant.

(iii) The crude oil: (A) Has a gravity of 20 degrees API or lower;

(B) Was produced within the state of California, including its submerged state lands;

(C) Was not produced or derived from a U.S. Naval Petroleum Reserve; and

(D) Was not produced from submerged lands of the U.S. Outer Continental Shelf.

(4) OEL will adhere to the following procedures for licensing exports of California crude oil:

(i) OEL will issue validated licenses for approved applications in the order in which OEL received the application (date-time stamped), with the total quantity authorized not to exceed 25 percent (2.28 million barrels) of the annual (9.125 million barrels) authorized volume per license. If any unused quota exists, OEL will continue to issue licenses for the unused portion of the quota.

(ii) OEL will approve only one application per month for each company and its affiliates, as long as there are other non-affiliated applications pending during that month.

(iii) OEL will carry forward any portion of the 25 MB/D quota that OEL has not licensed, except that OEL will not carry over any unallocated portions more than 30 days into a new calendar year.

(iv) OEL will return to the available authorized export quota any portion of the 25 MB/D quota that OEL had licensed but a licensee had not shipped within the 90 day authorized license term, except that OEL will not carry over unshipped volumes more than 30 days into a new calendar year.

(5) License holders:

(i) Have 90 calendar days from the date OEL issued the license to export the quantity authorized on the license. The exporter is required to provide OEL with a certified statement confirming the date and quantity of exports.

(ii) May combine authorized quantities into one or more shipments, provided that the validity period of none of the affected licenses has expired.

(iii) Are prohibited from transferring the license to another party. See, 15 CFR part 787.

(6) OEL will allow, pursuant to § 786.7(c) of this subchapter, a 10 percent shipping tolerance on the unshipped balance based upon the volume of barrels it has authorized. In addition to the 10 percent tolerance on the unshipped volume of barrels, OEL will allow a 25 percent shipping tolerance on the total dollar value of the license.

(7) OEL:

(i) Will not carry over to the next calendar year pending applications from the previous year.

(ii) Will apply the procedures described in this section without notifying the public concerning any increase in export volume authorized by the Secretary of Energy from time to time.

Dated: March 17, 1994.

Sue E. Eckert,

Assistant Secretary for Export Administration.

[FR Doc. 94–6885 Filed 3–23–94; 8:45 am]

BILLING CODE 3510–DT–P

DEPARTMENT OF STATE

Bureau of Economic and Business Affairs

22 CFR Part 89

[Public Notice 1969]

Foreign Prohibitions on Longshore Work by U.S. Nationals

AGENCY: Department of State.

ACTION: Advance notice of proposed rulemaking.

SUMMARY: In accordance with the Immigration and Nationality Act of 1952, as amended, the Department of State is compiling information to update the list, by particular activity, of countries that prohibit by law, regulation or in practice crewmembers aboard U.S. vessels from performing longshore work.

DATES: Interested parties are invited to submit comments in triplicate by April 25, 1994.

ADDRESSES: For mailing public comments: Office of Maritime and Land Transport (EB/TRA/MA), room 5828, Department of State, Washington, DC 20520–5816.

FOR FURTHER INFORMATION CONTACT: Stephen M. Miller, Office of Maritime and Land Transport, Department of State, (202) 647–6961.

SUPPLEMENTARY INFORMATION: Section 258(d)(2) of the Immigration and Nationality Act of 1952, as added by the Immigration Act of 1990, Public Law 101–649, 8 U.S.C. § 1288 (hereinafter the Act) directs the Secretary of State