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OIL & GAS

MISC.

STATE OF ALASKA
Department of Natural Resources
Division of Oil and Gas Conservation

Alaska Oil and Gas Conservation Committee
3001 Porcupine Drive
Anchorage, Alaska 99501

Re: The request of Atlantic Richfield Company and BP Alaska Inc. to present testimony to determine new pool rules and amend existing rules for the Prudhoe Oil Pool.

Conservation Order No. 145
Prudhoe Bay Field
Prudhoe Oil Pool

June 1, 1977

IT APPEARING THAT:

1. The referenced companies applied by letter received March 30, 1977, for a hearing to adopt new or amend existing pool rules.

2. Notice of public hearing was published in the Anchorage Daily News on April 2, 1977.

3. A public hearing was held in the Ramada Inn, Anchorage, Alaska on May 5 and 6, 1977.

4. The hearing record was continued until the close of business on May 16, 1977. Additional data was received.

FINDINGS:

1. Rules pertaining to the Prudhoe Oil Pool have been included in Conservation Order Nos. 98-B, 130, and 137.

2. Administrative approvals 98-B.3, 98-B.6, 98-B.7, and 98-B.8 written pursuant to Conservation Order No. 98-B, Rule 8 are currently in effect.

3. Waivers pertaining to blowout prevention practices written pursuant to Conservation Order No. 137, Rule 2 are currently in effect.

4. The applicants propose to raise and lower the vertical pool limits of the Prudhoe Oil Pool to include the "Put River Sandstone" and Ivishak Shale respectively.

5. No drill stem tests or production tests have been conducted in the "Put River Sandstone" or the Ivishak Shale.

6. No analysis of fluid from the "Put River Sandstone" or the Ivishak Shale are presently available to the Committee.

7. The areal extent of the Prudhoe Oil Pool as defined on March 12, 1971, in Conservation Order No. 98-B, is considerably larger than the area now proven to be productive by the drilling of additional wells since that time.

8. Most producing wells in the Prudhoe Oil Pool are deviated holes to minimize the number of drilling pads.

9. The applicants propose to eliminate reference to acreage spacing requirements but request that at least 2000 feet be maintained between the pay opened in the well bore in all wells in the Prudhoe Oil Pool.

10. The applicants propose that a distance of 1000 feet be maintained between the pay opened in any well and the boundary of the Prudhoe Oil Pool.

11. Data from the early production performance is needed for the proper regulation and operation of the reservoir.

12. Performance must be accurately observed and quickly analyzed for a timely assessment of reservoir behavior.

13. Performance during the first two years will be used to design the water flooding projects and will be vital in formulating and implementing future operating plans.

14. A reservoir surveillance program can provide for monitoring both reservoir and production data.

15. Monthly production tests will monitor changes in well productivity, gas-oil and oil-water ratios, and provide basic data for reservoir performance studies.

16. The reservoir is complex with many discontinuous interbedded shales.

17. The reservoir is underlain by a heavy oil or tar zone of varying thickness.

18. Some areas of the reservoir contain many faults.

19. The reservoir pressure data will provide information on well flow efficiency, reservoir permeability, reservoir discontinuities, and the need for a pressure maintenance program.

20. The use of specialized transient pressure testing techniques such as pulse testing, vertical permeability tests, and interference tests may prove useful.

21. Specific wells may be selected which are located outside the main area of the Sadlerochit oil column to monitor the pressure in the gas cap, the aquifer, the Eileen area, and the Sag River gas cap.

22. The applicants have agreed to a common datum plane of 8800 feet subsea for all pressure surveys.

23. Changes in the gas-oil fluid contact movement in the reservoir with response to production would provide information on shale continuity, effective vertical permeability, displacement efficiency of oil by gas and define areas of poor natural recovery.

24. Preliminary studies indicate that early run open hole or cased hole neutron logs may provide a suitable base log for monitoring the movement of the gas-oil contact by comparison with a later cased hole neutron log run in the same well.

25. Open hole neutron logs have already been run on the majority of wells.

26. Cased hole neutron logs have already been run in a number of wells and will continue to be run in selected wells until this technique is confirmed.

27. Monitoring the movement of the oil-water contact should help to determine the extent of water influx from the aquifer, identify areas of peripheral water influx and allow determination of the water displacement efficiency.

28. Monitoring the oil-water contact should provide information to help define locations where water injection would be beneficial.

29. A program is now in progress to evaluate the capability of monitoring the oil-water contact with one of three different methods, such as the Thermal Decay Tools (T.D.T.) or the Neutron Lifetime Log (N.L.L.), the Carbon-Oxygen Log and the Gamma Ray Log.

30. The capability of these methods to monitor the changing oil-water contact has not been demonstrated as yet.

31. The contribution of each of the various perforated intervals in each producing well may be determined through downhole spinner flow meter surveys.

32. A reliable assessment of the rate of the production from the various lithologic subdivisions within the reservoir will assist in the determination of the effectiveness of the well completions to drain the reservoir.

33. Numerous computer reservoir simulation model studies of the Sadlerochit Formation have been made by the State and the working interest owners. In these studies the offtake rates of oil and gas and the injection rates of gas and water have been varied.

34. The Trans-Alaska Pipeline will have an initial capacity of 1.2 million barrels per day and should be ready to accept oil near mid 1977.

35. The applicants have submitted a Plan of Operations which includes proposed average annual offtake rates of 1.5 million barrels per day for oil plus condensate production and 2.7 billion cubic feet per day for gas.

36. Production facilities to support an average oil offtake of 1.2 million barrels per day will be installed by the last quarter of 1977. Additions are planned during 1978 and 1979 to support an average oil offtake rate of 1.5 million barrels per day plus condensate production, when pipeline capacity is available.

37. Gas sales in large volumes from the Prudhoe Bay Field will not be possible until a gas conditioning plant and a large gas sales pipeline are constructed.

38. The completion of a large gas sales pipeline and plant to condition gas is estimated at approximately five years from start of oil production.

39. Until a large gas sales pipeline is available, all produced gas, except that used as fuel in the field and small local gas sales, will be reinjected into the gas cap.

40. Gas will be used to supply the operating requirements of the Prudhoe Bay Field, the first four pump stations of the Trans-Alaska Pipeline and other minor local fuel needs.

41. To meet pipeline sale quality it will be necessary to remove carbon dioxide from the gas.

42. Water production will be minimal initially and will be disposed of by injection into sands of Cretaceous age.

43. When water production becomes significant, the applicants plan to file a secondary recovery application for the injection of this water into the Prudhoe Oil Pool.

44. Injection of produced water into the Prudhoe Oil Pool could begin within two years after start of oil production.

45. The applicants will proceed with design and implementation studies concurrently with injectivity tests and reservoir data gathering to shorten the implementation time for a source water injection system.

46. The Sadlerochit Formation aquifer exhibits the best reservoir qualities near the Prudhoe Bay Field area and progressively deteriorates away from the field.

CONCLUSIONS:

1. To avoid confusion it would be desirable to consolidate the outstanding Pool rules effecting the Prudhoe Oil Pool into one order. Conservation Orders Nos. 98-B, 130, and Rule 2 of Conservation Order No. 137 should be canceled and the relevant portions included in Conservation Order No. 145.

2. Administrative Approvals 98-B.3, 98-B.6, 98-B.7, and 98-B.8 should remain in effect and will be applicable until stable production from the field is attained or until the time period stipulated expires.

3. Waivers pertaining to blowout preventers written pursuant to Conservation Order No. 137, Rule 2 should remain in effect.

4. There are insufficient data to justify raising or lowering the vertical limits of the Prudhoe Oil Pool, as proposed by the applicants, to correspond with the vertical limits of the Prudhoe Bay (Permo-Triassic) Reservoir as described in the Prudhoe Bay Unit Agreement.

5. The areal extent of the Prudhoe Oil Pool should be identical to the initial participating area of the Prudhoe Bay Unit which is described as the Prudhoe Bay (Permo-Triassic) Reservoir in the Unit Agreement.

6. A rule eliminating acreage spacing in the Prudhoe Oil Pool should facilitate present and future additional recovery operations and enable the unit operators to develop the productive capacity to meet the planned throughput of the Trans-Alaska Pipeline.

7. A distance of 2000 feet between the pay opened in the well bore in all wells in the Prudhoe Oil Pool should maintain an adequate drainage area, not unnecessarily restrict bottomhole target locations and protect correlative rights and prevent waste.

8. A distance of 1000 feet between the pay opened in any well and the boundary of the Prudhoe Oil Pool will protect correlative rights.

9. To gather the data necessary for proper regulation and operation of the reservoir, a rigorous surveillance program of reservoir performance should be accurately observed and assessed especially during the first two years of operation. The surveillance program should also provide guidelines for a long term key well surveillance program.

10. A surveillance program should include monitoring the reservoir pressures, gas-oil and oil-water contact movements, production tests, gas-oil and water-oil ratios, and productivity profiles of individual wells.

11. A gas-oil contact movement monitoring program, based on a comparison of open hole neutron base logs to be later compared with neutron logs run in the same wells should be attempted.

12. The data obtained during the first two years could lead to a key well program of periodic surveys that may adequately monitor the gas-oil contact movements.

13. Monitoring the movement of the oil-water contact is desirable to evaluate the water influx in the reservoir and the applicability of water injection systems. Three methods are potentially applicable as means of monitoring the movement of the oil-water contact. These methods are the Thermal Decay Tools or the Neutron Lifetime Log, the Carbon-Oxygen Log and the Gamma Ray Log. The program to evaluate the relative capability of these

logs should be continued and should any method be demonstrated capable of adequately monitoring the changing water saturations in the reservoir, a key well program should be set up.

14. Downhole spinner flow meter surveys to determine well productivity profiles should help determine the effectiveness of completions and provide information on reservoir drainage.

    To provide the necessary productivity profile data a base line survey should be run on each well with later follow up surveys on each well.

15. The injection of produced water into the sands of Cretaceous age will not contaminate fresh water sources or endanger other natural resources.

16. Studies of the aquifer have indicated that it probably will not offer much pressure support.

17. Reservoir studies have shown that both produced water injection and source water injection into the Prudhoe Oil Pool should increase oil recovery.

18. Reservoir studies have shown that large scale source water injection will probably be necessary to maximize oil recovery.

19. The planned reinjection of gas into the Sadlerochit gas cap prior to large gas sales will help to maintain reservoir pressure and will not adversely affect ultimate recovery.

20. The Plan of Operations proposed by the applicants which include average annual offtake rates of 1.5 million barrels per day for oil plus condensate production and 2.7 billion cubic feet per day for gas are consistent with sound conservation practices based on currently available data.

21. After field and local fuel requirements and the removal of carbon dioxide and liquids from the produced gas, it is estimated that a gas production rate of 2.7 billion standard cubic feet per day will yield 2.0 billion standard cubic feet per day of pipeline quality gas.

22. Production history will be needed to locate water injection wells and to refine reservoir model studies.

23. The offtake rates approved by the Committee at this time must be established without the benefit of production history. Therefore, these offtake rates may be changed as production data and additional reservoir data are obtained and analyzed.

NOW, THEREFORE, IT IS ORDERED THAT the rules hereinafter set forth apply to the following described area referred to in this order as the affected area:

UMIAT MERIDIAN			
T. 10N.,	R. 12E.,	Sections	1, 2, 3, 4, 10, 11, 12
T. 10N.,	R. 13E.,		1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 24
T. 10N.,	R. 14E.,		1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 36
T. 10N.,	R. 15E.,		all
T. 10N.,	R. 16E.,		5, 6, 7, 8, 17, 18, 19, 20, 29, 30, 31
T. 11N.,	R. 11E.,		1, 2, 3, 4, 9, 10, 11, 12, 13, 14, 15, 24, 25
T. 11N.,	R. 12E.,		all
T. 11N.,	R. 13E.,		all
T. 11N.,	R. 14E.,		all
T. 11N.,	R. 15E.,		all
T. 11N.,	R. 16E.,		30, 31, 32
T. 12N.,	R. 11E.,		15, 16, 17, 18, 19, 20, 21, 22, 25, 26, 27, 28, 29, 30, 32, 33, 34, 35, 36
T. 12N.,	R. 12E.,		23, 24, 25, 26, 27, 28, 33, 34, 35, 36
T. 12N.,	R. 13E.,		19, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, 36
T. 12N.,	R. 14E.,		25, 26, 27, 28, 29, 31, 32, 33, 34, 35, 36
T. 12N.,	R. 15E.,		27, 28, 29, 30, 31, 32, 33, 34

Rule 1 Pool Definition

The Prudhoe Oil Pool is defined as the accumulations of oil that are common to and which correlate with the accumulations found in the Atlantic Richfield - Humble Prudhoe Bay State No. 1 well between the depths of 8,110 and 8,680 feet.

Rule 2 Well Spacing

In the affected area, no pay shall be opened in a well closer than 2000 feet to any pay opened in another well in the Prudhoe Oil Pool or be nearer than 1000 feet to the boundary of the affected area.

Rule 3 Casing and Cementing Requirements

(a) Casing and cementing programs shall provide adequate protection of all fresh waters and productive formations and protection from any pressure that may be encountered, including external freezeback within the permafrost.

(b) For proper anchorage and to prevent an uncontrolled flow, a conductor casing shall be set at least 75 feet below the surface and sufficient cement shall be used to fill the annulus behind the pipe to the surface.

(c) For proper anchorage, to prevent uncontrolled flow and to protect the well from the effects of permafrost thaw, a string of surface casing shall be set at least 500 feet below the base of the permafrost section but not below 2,700 feet unless a greater depth is approved by the Committee upon showing that no potentially productive pay exists above the proposed casing setting depth, and sufficient cement shall be used to fill the annulus behind the pipe to the surface.

The surface casing shall have minimum post-yield strain properties of 0.9% in tension and 1.26. in compression.

(d) If the surface casing does not meet the strain requirements in (c) above, the integrity of the well shall be protected from the effects of permafrost thaw by running an inner string of casing also set at least 500 feet below the base of the permafrost section and properly cemented except that the two casing strings shall not be bonded together within the permafrost section. This inner string of casing shall not be utilized as production casing.

(e) Other means for maintaining the integrity of the well from the effects of permafrost thaw may be approved by the Committee upon application.

(f) Production casing shall be landed through the completion zone and cement shall cover and extend to at least 500 feet above each hydrocarbon-bearing formation which is potentially productive. In the alternative, the casing string may be set and adequately cemented at

at an intermediate point and a liner landed through the completion zone. If such a liner is run, the casing and liner shall overlap by at least 100 feet and the annular space behind the liner shall be filled with cement to at least 100 feet above the casing shoe, or the top of the liner shall be squeezed with sufficient cement to provide at least 100 feet of cement between the liner and casing. Cement must cover and extend at least 500 feet above each hydrocarbon-bearing formation which is potentially productive.

(g) Casing and liner, after being cemented, shall be satisfactorily tested to not less than 50% of minimum internal yield pressure or 1,500 pounds per square inch, whichever is less.

(h) No well shall be produced through the annulus between the tubing and the casing unless a cement sheath extends from the top of the pay to the shoe of the next shallower casing string.

Rule 4 Blowout Prevention Equipment and Practice

(a) The use of blowout prevention equipment shall be in accordance with good established practice and all equipment shall be in good operating condition at all times.

All blowout prevention equipment shall be adequately protected to ensure reliable operation under the existing weather conditions. All blowout prevention equipment shall be checked for satisfactory operation during each trip.

(b) Before drilling below the conductor string, each well shall have installed at least one remotely controlled annular type blowout preventer and flow diverter system. The annular preventer installed on the conductor casing shall be utilized to permit the diversion of hydrocarbons and other fluids. This low pressure, high capacity diverter system shall be installed to provide at least the equivalent of a 6-inch line with at least two lines venting in different directions to insure downwind diversion and shall be designed to avoid freeze-up. These lines shall be equipped with full-opening butterfly type valves or other valves approved by the Committee. A schematic diagram, list of equipment, and operational procedure for the diverter system shall be submitted with the application Permit to Drill or Deepen (Form 10-401) for approval. The above requirements may be waived for subsequent wells drilled from a multiple drill site.

(c) Before drilling below the surface casing all wells shall have three remotely controlled blowout preventers, including one equipped with pipe rams, one with blind rams and one annular type. The blowout preventers and associated equipment shall have 3000 psi working pressure and 6000 psi test pressure.

(d) Before drilling into the Prudhoe Oil Pool, the blowout preventers and associated equipment required in (c) above shall have 5000 psi working pressure rating and 10,000 psi test pressure rating.

(e) The associated equipment shall include a drilling spool with minimum three-inch side outlets (if not on the blowout preventer body), a minimum three-inch choke manifold, or equivalent, and a fill-up line. The drilling string will contain full-opening valves above and immediately below the kelly during all circulating operations with the kelly. Two emergency valves with rotary subs for all connections in use will be conveniently located on the drilling floor. One valve will be an inside blowout preventer of the spring-loaded type. The second valve will be of the manually-operated ball type, or any other type which will perform the same function.

(f) All ram-type blowout preventers, kelly valves, emergency valves and choke manifolds shall be tested to required working pressure when installed or changed and at least once each week therafter. Annular preventers shall be tested to 50% recommended working pressure when installed and once each week thereafter. Test results shall be recorded on written daily records kept at the well.

Rule 5 Automatic Shut-in Equipment

Upon completion, each well shall be equipped with a suitable safety valve installed below the base of the permafrost which will automatically shut in the well if an uncontrolled flow occurs.

Rule 6 Pressure Surveys

(a) Prior to initial sustained well production, a static bottomhole pressure survey shall be taken on each well.

(b) Between 90 and 100 days after commencement of sustained pool production, the applicants shall perform an initial key well bottomhole transient pressure survey on one specific well on each producing pad or drill site. Another survey of the same type shall be conducted each 90 days thereafter.

(c) Within the first six months following the initial sustained well production, the applicants shall conduct a transient pressure survey on each well.

(d) A semi-annual transient pressure survey shall be conducted on one well in each governmental section from which oil is being produced. This is in addition to the pressure surveys conducted in (b) and (c) above.

(e) A long-term key well pressure survey will be formulated and implemented in approximately two years from the start of production based upon evaluation of data submitted under (a), (b), (c), and (d) above.

(f) Data from the above mentioned surveys shall be filed with the Committee by the fifteenth day of the month following the month in which each survey is taken. Form No. 10-412, Reservoir Pressure Report, shall be utilized for all surveys with attachments for complete additional data. Data submitted shall include but is not limited to rate, pressure, time, depths, temperature, and other well conditions necessary for

complete analysis for each survey being conducted. The pool pressure datum plane shall be 8800 feet subsea. Bottomhole transient pressures obtained by a 24 hour buildup or multiple flow rate test will be acceptable.

(g) Results and data from any special reservoir pressure monitoring techniques, tests or surveys shall also be submitted as prescribed in (f) above.

(h) By administrative order the Committee shall specify additional pressure surveys if the survey program designated in this rule is found to be inadequate.

Rule 7 Gas-Oil Ratio Tests

Between 90 and 120 days after substantial production starts and each six months thereafter a gas-oil ratio test shall be taken on each producing well. The test shall be of at least 12 hours duration and shall be made at the producing rate at which the operator ordinarily produces the well. The test results shall be reported on gas-oil ratio test form P-9 within fifteen days after completion of the survey. The Committee shall be notified at least five days prior to each test.

Rule 8 Gas Venting or Flaring

The venting or flaring of gas is prohibited except as may be authorized by the Committee in cases of emergency or operational necessity.

Rule 9 Gas-Oil Contact Monitoring

Open hole and cased hole neutron logs shall be run in selected wells to confirm gas-oil contact movement unless this technique is proved unworkable or an alternative approach is recommended and accepted by the Committee.

The wells selected for this neutron log survey together with a summary of the survey analyses shall be submitted to the Committee by January 1, 1978, and each six months thereafter. The Committee may also specify additional wells to be surveyed should they decide the survey program being followed is inadequate.

The cased hole neutron logs run shall be filed with the Committee by the fifteenth day of the month following the month in which the logs were run.

Other methods of monitoring the gas-oil contact movement may be approved if they show to be more effective.

A long term key well gas-oil contact movement monitoring program may be formulated and implemented in approximately two years from start of production if workable technique is found.

Rule 10 Oil-Water Contact Monitoring

(a) A report on the evaluation program to determine the oil-water contact monitoring capability of the Thermal Decay Tools or the Neutron Lifetime Log, the Carbon-Oxygen Log and the Gamma Ray Log shall be submitted to the Committee by January 1, 1978.

(b) If the capability of monitoring the change in oil-water contact movement can be demonstrated by one or more of these methods, a key well program shall be set up by the applicants subject to the approval of the Committee.

Rule 11 Productivity Profiles

(a) A spinner flow meter survey shall be run in each well during the first six months the well is on production.

(b) A follow up survey shall be performed on a rotating basis so that a new production profile is obtained on each well periodically. Nonscheduled surveys shall be run in wells which experience an abrupt change in water cut, gas-oil ratio, or productivity.

(c) The complete spinner survey data and results shall be recorded and filed with the Committee by the 15th day of the month following the month in which each survey is taken.

(d) By administrative order the Committee shall specify additional surveys should they determine the surveys submitted under (a), (b) and (c) above are inadequate.

Rule 12 Changing the Affected Area

By administrative approval the Committee may adjust the description of the affected area to conform to future changes in the initial participating area.

Rule 13 Orders Cancelled

Conservation Orders Nos. 98-B, 130, and Rule 2 of Conservation Order No. 137 are hereby cancelled. Portions of Conservation Orders Nos. 98-B and 137 are made part of this order and the hearing records of these orders are also made part of the hearing record of this order.

Rule 14 Approvals Redesignated

Administrative Approvals made pursuant to CO 98-B, Rule 8 and the waivers made pursuant to Conservation Order No. 137, Rule 2 remain in effect and will now be authorized by this order.

Rule 15 Pool Off-Take Rates

The maximum annual average oil offtake rate is 1.5 million barrels per day plus condensate production. The maximum annual average gas offtake rate is 2.7 billion standard cubic feet per day, which contemplates an annual average gas pipeline delivery sales rate of 2.0 billion standard cubic feet per day of pipeline quality gas when treating and transportation facilities are available. Daily offtake rates in excess of these amounts are permitted only as required to sustain these annual average rates. The annual average offtake rates as specified shall not be exceeded without the prior written approval of the Committee.

Annual average offtake rates mean the daily average rate calculated by dividing the total volume produced in a calendar year by the number of days in the year. However, in the first calendar year that large gas offtake rates are initiated, following the completion of a large gas sales pipeline, the annual average offtake rate for gas shall be determined by dividing the total volume of gas produced in that calendar year by the number of days remaining in the year following initial delivery to the large gas sales pipeline.

DONE at Anchorage, Alaska, and dated June 1, 1977.

ALASKA OIL AND GAS CONSERVATION COMMISSION

Thomas R. Marshall, Jr., Executive Secretary
Alaska Oil and Gas Conservation Committee

Concurrence:

Hoyle H. Hamilton, Chairman
Alaska Oil and Gas Conservation Committee

Lonnie C. Smith, Member
Alaska Oil and Gas Conservation Committee

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 Porcupine Drive
Anchorage, Alaska 99501-3192

Re: Request by ARCO ALASKA, INC.) et al to present testimony) to revoke Conservation Order) No. 83-C and adopt new rules) for the Lisburne Oil Pool) in the Prudhoe Bay Field.)

Conservation Order No. 207

Prudhoe Bay Field
Lisburne Oil Pool

January 10, 1985

IT APPEARING THAT:

1. ARCO Alaska, Inc., on behalf of itself and Exxon Corporation, requested the Alaska Oil and Gas Conservation Commission to hold a public hearing in order to receive testimony for the revocation of Conservation Order No. 83-C and establishment of new pool rules for the development and depletion of the Lisburne Oil Pool in the Prudhoe Bay Field.

2. Notice of the public hearing was published in the Anchorage Times on October 26, 1984.

3. A public hearing was held at the Municipality of Anchorage Assembly Room, 3500 East Tudor Road, Anchorage, Alaska on November 29, 1984.

4. Members of the staff of ARCO Alaska, Inc. presented testimony on behalf of itself, Exxon Corporation and Sohio Alaska Petroleum Company. Exxon Corporation presented a statement in full support of the testimony. The hearing record remained open until 4:30 pm, December 10, 1984. Timely comments were submitted by Sohio Alaska Petroleum Company and Mr. Kelley Everette.

FINDINGS:

1. The Lisburne Group underlies the Sadlerochit Group and consists primarily of shallow marine limestone and dolomite with lesser amounts of shale, silt, sand, and chert.

2. Shaly or silty beds are fairly continuous over a broad area and are useful for correlation.

3. The Lisburne Group is characterized by abundant natural and predominately vertical fractures which allows for fluid movement through the carbonates as well as the thin silty and shaly beds.

4. The Lisburne Group of carbonate sediments was penetrated in it entirety by ARCO Prudhoe Bay State Well #1. The top of the Lisburne Group was encountered at a measured depth of 8,790 feet and the base at 10,440 feet measured depth.

5. The Lisburne Group has been partially or fully penetrated by numerous wells. Oil and gas has been encountered within the Lisburne Group as low as 10,050 feet subsea within the area described by Conservation Order No. 83-C.

6. Evidence indicates that an oil reservoir with an associated gas cap exists and that an oil pool should be defined. The hydrocarbon accumulation may appropriately be defined as the Lisburne Oil Pool.

7. The Lisburne Reservoir is an anticlinal structure that is bounded on the north by the Prudhoe Bay-Niakuk fault complex, by truncation and/or the Mikkelson Bay fault to the east and by dip of 135 feet per mile to the south and west.

8. Evidence is sufficient to establish a definitive gas-oil contact at 8,600 feet subsea. Data are anomalous and insufficient to definitively establish an area-wide planar oil-water contact for the Lisburne Oil Pool.

9. The affected area described in Conservation Order No. 83-C. appears to be adequate in the eastern portion of the Lisburne Oil Pool but should be expanded westward to reflect the current structural interpretation.

10. A spacing unit of one producing well per governmental quarter section appears adequate to drain the reservoir.

11. Conductor casing set and cemented a minimum of 75 feet below surface should provide adequate anchorage for a diverter system.

12. The effects of permafrost thaw-subsidence and freeze back loadings can be mitigated by setting and cementing surface casing of sufficient strength at least 500 feet below the base of the permafrost but no deeper than 5000 feet true vertical depth.

13. Several casing types and grades that are approved for use as surface casing in the Prudhoe Oil Pool and the Kuparuk River Oil Pool are appropriate for this pool.

14. Perforation of cemented casing or liners, slotted liners, screen wrapped liners, gravel packs and open hole completions appear to be equally effective completion techniques.

15. Significant concentrations of hydrogen sulfide gas were encountered in a production test of the ARCO Pingut State Well No. 1 and smaller amounts of hydrogen sulfide gas have been reported from other wells.

16. Installation of automatic surface shut-in valves is appropriate to prevent an uncontrolled flow of oil or gas.

17. Installation of automatic down hole shut-in valves in the tubing below the premafrost is appropriate to prevent an uncontrolled flow of oil or gas.

18. The flaring of a limited amount of gas will be necessary for the safety purposes and for operational necessities.

19. To aid in the evaluation of the effectiveness of the reservoir depletion, the reservoir pressure and the gas-oil ratio of wells should be monitored on a regular and continuous basis.

20. Current studies indicate that a daily oil rate of 160,000 barrels will not be detrimental to ultimate hydrocarbon recovery. However, pool withdrawal rates in excess of 160,000 barrels of oil per day may affect ultimate recovery.

21. Conservation Order No. 83-C is out-of-date and should be replaced.

22. Evidence is insufficient to determine the prudency of state of the art methods for enhancement of recovery from the Lisburne Oil Pool. Pilot field projects are necessary to develop data for determination of the applicability of methods for recovery enhancement.

23. Evidence indicates that the injection of produced gas into the gas cap will retard the rate of decline in reservoir pressure.

24. The average initial reservoir pressure for the Lisburne Oil Pool is 4,490 pounds per square inch at an 8,900 foot subsea datum. Reservoir temperature approximates 183° Fahrenheit at the datum.

25. The Lisburne Oil Pool contains in excess of 3 billion barrels of Original Oil In Place (OOIP). Primary depletion may recover no more than 7 percent of the OOIP.

26. It appears that most if not all of the Lisburne Oil Pool lies within the current boundary of the Prudhoe Bay Unit. However, it is possible that the pool limits may extend beyond the Prudhoe Bay Unit boundary.

27. Terms of the Prudhoe Bay Unit Agreement provide for the expansion of the Prudhoe Bay Unit boundary and for the establishment and expansion of an initial participating area for the Lisburne Oil Pool.

28. Management of the Lisburne Oil Pool under terms of the Prudhoe Bay Unit Agreement will effectively protect correlative rights, prevent waste and insure the maximum hydrocarbon recovery.

NOW, THEREFORE, IT IS ORDERED THAT the rules hereinafter set forth apply to the following described area and is referred to in the order as the affected area:

UMIAT MERIDIAN

T10N, R13E	Sections 1, 2, 3, 10, 11, and 12.
T10N, R14E	Sections 1, 2, 3, 4, 5, 6, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22. 23, 24, 25, 26, 35, and 36.
T10N, R15E	All.
T10N, R16E	All.
T10N, R17E	Sections 3, 4, 5, 6, 7, 8, 9, 10, 15, 16, 17, 18, 19, 20, 21, 22, 27, 28, 29, 30, 31, 32, 33, and 34.
T11N, R13E	Sections 1, 2, 3, 4, 7, 8, 9, 10, 11, 12, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, and 36.
T11N, R14E	All.
T11N, R15E	All.
T11N, R16E	All.
T11N, R17E	Sections 3, 4, 5, 6, 7, 8, 9, 10, 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30 ,31, 32, 33, 34, 35, and 36.
T12N, R13E	Sections 35 and 36.
T12N, R14E	Sections 13, 14, 15, 16, 21, 22, 23, 24, 25, 26, 27, 28, 31, 32, 33, 34, 35, and 36.
T12N, R15E	Sections 13, 14, 15, 16, 17, 18, 19, 20, 21, 22, 23, 24, 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, and 36.
T12N, R16E	Sections 25, 26, 27, 28, 29, 30, 31, 32, 33, 34, 35, and 36.

Rule 1. FIELD AND POOL NAME.

The field is the Prudhoe Bay Field and the pool is the Lisburne Oil Pool.

Rule 2. POOL DEFINITION.

The Lisburne Oil Pool is defined as the accumulations of oil and gas which occur in stratigraphic sections which correlate with the stratigraphic section found in the Atlantic Richfield-Humble Prudhoe Bay State No. 1 well between the depths of 8,790 feet measured depth and 10,440 feet measured depth.

Rule 3. WELL SPACING.

The spacing unit shall be one producing well per governmental quarter section. No pay may be opened in a well closer than 1,000 feet to the pay opened in another well or opened in a well which is closer than 500 feet to the boundary of the affected area.

Rule 4. CASING AND CEMENTING.

a) A conductor casing shall be set at least 75 feet below the surface and sufficient cement shall be used to fill the annulus behind the pipe to the surface. Rigid high density polyurethane foam may be used as an alternate to cement, upon approval by the Commission. The Commission may also administratively approve other sealing materials which are supported by sound engineering principles and performance data.

b) Surface casing to provide proper anchorage for equipment to prevent uncontrolled flow, to withstand anticipated internal pressure and to protect the well from the effects of permafrost thaw-subsidence or freeze back loadings shall be set at least 500 feet, measured depth, below the base of the permafrost but not below 5000 feet true vertical depth. Sufficient cement shall be used to fill the annulus behind the casing to the surface.

c) Surface casing types and grades approved for use through the permafrost interval include:

1) 13-3/8 inch, 72 pounds/foot, L-80 Buttress;
2) 13-3/8 inch, 72 pounds/foot, N-80 Buttress;
3) 13-3/8 inch, 68 pounds/foot, MN-80 Buttress.

Rule 7. AUTOMATIC SHUT-IN EQUIPMENT.

a) Any well which is capable of unassisted flow of hydrocarbons must be equipped with

1) a fail-safe automatic surface safety valve (SSV) capable of preventing an uncontrolled flow; and

2) a fail-safe automatic surface controlled subsurface safety valve (SSSV). This valve must be in the tubing string and located below permafrost. The valve must be capable of preventing an uncontrolled flow. For operational necessity the Commission may administratively waive the surface controlled requirement.

b) A representative of the Commission will witness performance tests at times prescribed by the Commission to confirm that the SSV, SSSV, and all associated equipment are in proper working condition.

c) When requested by the operator, a representative of the Commission will witness "no-flow tests" to verify that a well is no longer capable of unassisted flow. Upon approval by the Commission, the operator will no longer be required to maintain the SSSV's in that well until any subsequent workover or stimulation of the well makes it again capable of unassisted flow. The Commission may require additional "no-flow tests" following subsequent well work.

Rule 8. GAS VENTING OR FLARING.

a) The venting or flaring of gas is prohibited except for operational necessities and for safety volumes set out in this rule;

b) A daily average volume of 1,000 MCF per day is approved for the safety flare at the Lisburne Production Center;

c) Volumes of gas to provide safety flares for additional facilities may be approved by administrative order upon proper application;

d) The volumes of gas for safety flares may be decreased or increased by administrative order; and

e) Gas flaring may be approved by administrative order during commissioning of new equipment, purging, and start-ups after major repairs or interruptions.

Rule 9. GAS-OIL RATIO TESTS.

a) Between 90 and 120 days after regular production commences and each six months thereafter a gas-oil ratio test will be taken on each well for as long as it produces oil;

b) The gas-oil ratio tests will be for a minimum of four hours and shall be taken at the normal producing rate of the well; and

c) The results of the gas-oil ratio tests will be reported on Form 10-409, Gas-Oil Ratio Test and will be submitted in January and July of each year.

Rule 10. PRESSURE SURVEYS.

a) A static bottomhole pressure survey shall be taken prior to production or injection on each well drilled to the pool and results reported on Form 10-412, Reservoir Pressure Report;

b) The pressure datum for the Lisburne Oil Pool is 8,900 feet subsea. The Commission may administratively amend this datum or create an additional datum when more information on the reservoir is available.

c) Prior to July 10, 1987 the operator shall submit to the Commission a program to adequately monitor the reservoir pressure during depletion. Before the above date, any transient pressure surveys taken shall be timely submitted on Form 10-412 to the Commission.

Rule 11. UNITIZATION.

To ensure the protection of correlative rights and to prevent waste, the Lisburne Oil Pool shall be administered in accordance with the Prudhoe Bay Unit Agreement.

Rule 12. PILOT PROJECTS.

Upon application, the Commission may administratively approve field pilot projects, well production and injection tests and other field operations necessary for the purpose of developing a prudent enhanced recovery method and reservoir depletion program.

Rule 13. POOL OFFTAKE RATE.

No more than 160,000 barrels of oil per day may be produced from the Lisburne Oil Pool. However when evidence can be presented to the Commission showing that a higher offtake rate will not affect ultimate recovery, the Commission may increase the daily offtake rate by administrative order.

Rule 14. CONSERVATION ORDER NO. 83-C.

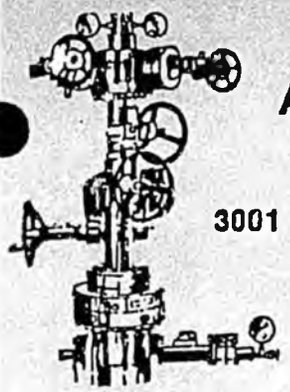
Conservation Order No. 83-C is hereby cancelled.

DONE at Anchorage, Alaska and dated January 10, 1985.

C. V. Chatterton, Chairman
Alaska Oil and Gas Conservation Commission

Harry W. Kugler, Commissioner
Alaska Oil and Gas Conservation Commission

Lonnie C. Smith, Commissioner
Alaska Oil and Gas Conservation Commission



STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION





3001 PORCUPINE DR. ANCHORAGE, ALASKA 99501

STEVE COWPER, GOVERNOR

BULLETIN

William W. Barnwell; Commissioner

C.V. Chatterton; Commissioner
Chairman of Commission

Lonnie C. Smith; Commissioner

AUGUST, 1987

ADMINISTRATIVE APPROVAL NO. 114.4

Administrative Approval No. 114.4 was issued July 14, 1987 to Unocal Corporation approving establishment of a safety flare on the Steelhead Platform, McArthur River Field, Trading Bay Unit. For each calendar month, the average daily volume of gas permitted to maintain a safety flare or flares for development of the Middle Kenai Gas Pool, Tyonek G-Zone Oil Pool, and West Foreland Oil Pool shall be 1000 MGFG/D.

ADMINISTRATIVE APPROVAL NO. 207.8

Administrative Approval No. 207.8 was issued July 23, 1987 to ARCO Alaska, Inc. granting approval to flare an additional 200 MMCFG at the Lisburne production and gas injection facilities during the forthcoming shutdown of Lisburne production, Prudhoe Bay Field. The planned shutdown is scheduled to commence August 6, 1987 and extend as long as necessary to allow corrections to be made to problems identified during startup and during the past seven months of operations. The Commission finds that the shutdown is an operational necessity and that additional flare volume is necessary.

AQUIFER EXEMPTION ORDER NO. 2

Aquifer Exemption Order No. 2 was issued July 8, 1987 to Conoco, Inc., and orders that portions of aquifers on the North Slope lying within and ¼ mile peripheral to the Milne Point Unit area are exempted for Class II injection activities. It was found that the portions of freshwater aquifers occurring beneath the Milne Point Unit area do not currently serve as sources for drinking water and are at a depth and location that make recovery of water for drinking purposes economically impractical.

NEW STAFF MEMBER

The Commission welcomes the recent placement of Patricia "Pat" Oldenburg as Administrative Assistant on the Commission staff. She comes to us from the Department of Natural Resources for whom she had worked since 1982, most recently with the Division of Forestry. Pat began her duties with the Commission on July 9.

ALASKA DRILLING STATISTICS FOR JULY, 1987

* DRILLING PERMITS APPROVED * * *

ALASKA DRILLING STATISTICS FOR JULY, 1987

* DRILLING PERMITS APPROVED * * *

ALASKA DRILLING STATISTICS FOR JULY, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

ALASKA DRILLING STATISTICS FOR JULY, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 08/05/87

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
COOK INLET BASIN					
ALASKAN CRUDE CORP	BURGLIN	31-1	50-133-20390-00	87-0070	07/31/87
AMOCO PRODUCTION CO	GRANITE PT ST 18742	13RD	50-133-20055-01	87-0044	04/28/87
AMOCO PRODUCTION CO	GRANITE POINT 18742	32RD	50-733-20298-01	87-0063	06/29/87
FAR NORTH OIL & GAS INC	MCCOY PROSPECT	1	50-133-10002-01	85-0208	10/04/85
UNION OIL CO OF CALIFORNIA	KENAI TYONEK UNIT	42X-6	50-133-20379-00	85-0180	10/14/85
UNION OIL CO OF CALIFORNIA	KENAI BELUGA UNIT	12X-8	50-133-20386-00	85-0298	12/20/85
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT	4	50-133-20387-00	87-0034	04/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	G-36DPN	50-733-20216-00	87-0049	05/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY ST	A-26DPN	50-733-20230-00	85-0258	11/25/85
UNION OIL CO OF CALIFORNIA	TRADING BY UNIT	M-1	50-733-20388-00	87-0046	05/12/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-2	50-733-20389-00	87-0061	06/26/87
ARCTIC SLOPE					
ALASKAN CRUDE CORP	ACC	F-2	50-029-21315-00	85-0053	04/10/85
ALASKAN CRUDE CORP	ACC	F-3	50-029-21316-00	85-0054	04/10/85
AMERADA HESS CORP	COLVILLE DELTA 32	1	50-103-20055-00	85-0279	11/29/85
ARCO ALASKA INC	W BEACH ST	1-A	50-029-20138-01	86-0056	03/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-25	50-029-20488-01	87-0011	02/04/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-11	50-029-21477-00	85-0267	10/31/85
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-25	50-029-21525-00	86-0006	01/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-22	50-029-21531-00	86-0019	01/13/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS4-19	50-029-21533-00	86-0021	01/15/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-6	50-029-21548-00	86-0038	02/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-31	50-029-21551-00	86-0041	02/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-10	50-029-21563-00	86-0058	03/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-11	50-029-21564-00	86-0059	03/10/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS1-27	50-029-21591-00	86-0088	05/02/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-12	50-029-21615-00	86-0120	06/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-26	50-029-21628-00	86-0134	07/07/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3K-14	50-029-21631-00	86-0137	07/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-27	50-029-21638-00	86-0148	07/28/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	LGI-16	50-029-21643-00	86-0153	08/15/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-1	50-029-21660-00	87-0012	02/10/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-24	50-029-21670-00	86-0182	11/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-30	50-029-21673-00	86-0185	12/04/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-1	50-029-21687-00	87-0003	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-3	50-029-21689-00	87-0005	01/21/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 08/05/87

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-4	50-029-21690-00	87-0006	01/21/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-28	50-029-21691-00	87-0007	01/28/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-12	50-029-21694-00	87-0010	01/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-2	50-029-21695-00	87-0013	02/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-3	50-029-21696-00	87-0014	02/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-4	50-029-21697-00	87-0015	02/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-5	50-029-21706-00	87-0025	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-6	50-029-21707-00	87-0026	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-7	50-029-21708-00	87-0027	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-8	50-029-21709-00	87-0028	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-9	50-029-21710-00	87-0029	03/10/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-8	50-029-21711-00	87-0030	03/16/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-10	50-029-21715-00	87-0035	03/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-28	50-029-21717-00	87-0037	04/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-11	50-029-21718-00	87-0038	04/13/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-12	50-029-21719-00	87-0050	05/22/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-13	50-029-21720-00	87-0040	04/13/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-29	50-029-21724-00	87-0045	04/30/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-14	50-029-21726-00	87-0051	05/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-15	50-029-21727-00	87-0052	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-16	50-029-21728-00	87-0053	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-17	50-029-21729-00	87-0054	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-18	50-029-21730-00	87-0055	06/03/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-21	50-029-21732-00	87-0057	05/29/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-19	50-029-21737-00	87-0064	07/02/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-20	50-029-21738-00	87-0065	07/01/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-21	50-029-21739-00	87-0066	07/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-22	50-029-21740-00	87-0067	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-5	50-029-21742-00	87-0069	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-27	50-029-21744-00	87-0082	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-4	50-103-20076-00	87-0076	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-5	50-103-20077-00	87-0077	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-6	50-103-20078-00	87-0078	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-7	50-103-20079-00	87-0079	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-8	50-103-20080-00	87-0080	07/31/87
NORTH SLOPE BOROUGH	S BARROW	NSB-1	50-023-20020-00	87-0071	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-2	50-023-20021-00	87-0072	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-3	50-023-20022-00	87-0073	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-4	50-023-20023-00	87-0074	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-7	50-023-20024-00	87-0075	07/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-3B	50-029-20306-01	87-0048	06/17/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	U-12	50-029-21409-00	85-0182	08/05/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	S-12A	50-029-21419-00	85-0193	08/13/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-25	50-029-21478-00	85-0268	10/31/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-26	50-029-21487-00	85-0277	11/25/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-28	50-029-21510-00	85-0303	12/13/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-24	50-029-21512-00	85-0305	12/20/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	D-25	50-029-21522-00	85-0320	12/27/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-29	50-029-21523-00	86-0014	01/06/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	C-31	50-029-21552-00	86-0042	02/07/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	D-28	50-029-21556-00	86-0050	02/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-22	50-029-21558-00	86-0052	02/28/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	M-28	50-029-21578-00	86-0074	04/11/86

AUGUST 1987

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 08/05/87

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-27/M33	50-029-21586-00	86-0083	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-23	50-029-21590-00	86-0087	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-24	50-029-21608-00	86-0113	06/10/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-19	50-029-21611-00	86-0116	06/13/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-30	50-029-21613-00	86-0118	06/17/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-31	50-029-21616-00	86-0121	06/19/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-47/Q21	50-029-21625-00	86-0131	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-29	50-029-21627-00	86-0133	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-19	50-029-21629-00	86-0135	07/10/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-32	50-029-21636-00	86-0146	07/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-20	50-029-21637-00	86-0147	07/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-14/O16	50-029-21639-00	86-0149	08/04/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-20/M35	50-029-21640-01	86-0173	10/10/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-23/N32	50-029-21645-00	86-0155	08/15/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-31	50-029-21647-00	86-0157	08/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-62/Q17	50-029-21648-00	86-0158	09/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-28	50-029-21649-00	86-0159	09/02/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-34/P14	50-029-21662-00	86-0172	10/09/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-33/K37	50-029-21668-00	86-0180	10/31/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-29/M25	50-029-21669-00	86-0181	11/07/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-35/O25	50-029-21672-00	86-0184	12/04/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-1/N29	50-029-21678-00	86-0190	12/11/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-24	50-029-21686-00	87-0002	01/14/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-8/P27	50-029-21692-00	87-0008	01/26/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-27/P20	50-029-21693-00	87-0009	01/28/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-22	50-029-21698-00	87-0017	02/12/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-35/L36	50-029-21701-00	87-0020	02/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-21	50-029-21705-00	87-0024	03/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-23	50-029-21712-00	87-0031	03/25/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-41/O23	50-029-21713-00	87-0032	03/26/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-21/L34	50-029-21714-00	87-0033	03/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-20	50-029-21716-00	87-0036	04/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-28	50-029-21721-00	87-0041	05/06/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-25/N22	50-029-21722-00	87-0042	04/24/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-6/Q32	50-029-21723-00	87-0043	04/24/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT N-23	50-029-21725-00	87-0047	05/22/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-42/P38	50-029-21731-00	87-0056	05/28/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-27	50-029-21733-00	87-0058	06/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-26	50-029-21734-00	87-0059	06/11/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-49/J40	50-029-21735-00	87-0060	06/17/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-9	50-029-21736-00	87-0062	06/26/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-25	50-029-21741-00	87-0068	07/07/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-9/J18	50-029-21743-00	87-0081	07/31/87

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR JUNE, 1987

OIL FIELDS	CRUDE OIL (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CRUDE OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL	12,304	19	3,384	2	3,408,098	18,030	1,398,612
FIELD TOTAL	12,304	19	3,384	2	3,408,098	18,030	1,398,612
ENDICOTT FIELD							
ENDICOTT POOL	4,522	2,132	57,680	3	26,866	2,132	627,887
FIELD TOTAL	4,522	2,132	57,680	3	26,866	2,132	627,887
GRANITE POINT FIELD							
MIDDLE KENAI POOL	235,395	88,785	210,775	28	105,513,719	7,057,867	91,140,107
FIELD TOTAL	235,395	88,785	210,775	28	105,516,483	7,057,867	91,141,697
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL	8,707,775	2,468,156	9,325,038	311	345,001,063	29,249,902	411,153,143
FIELD TOTAL	8,707,775	2,468,156	9,325,033	311	345,004,428	76,877,131	411,158,123
MCARTHUR RIVER FIELD							
HEMLOCK POOL	488,547	1,879,846	289,177	58	463,579,363	208,954,168	169,357,394
MIDDLE KENAI G POOL	84,637	45,337	35,674	11	35,542,793	3,919,127	17,700,051
WEST FORELAND POOL	30,231	41,805	10,340	4	18,959,696	4,752,980	5,400,475
FIELD TOTAL	603,415	1,966,988	335,191	73	518,081,852	217,626,275	192,457,920
MIDDLE GROUND SHOAL FIELD							
A POOL	1,675	684	7,821	1	1,971,271	1,107,558	4,317,946
B C AND D POOL	11,837	23,602	11,574	4	10,329,813	3,480,365	7,161,571
E F AND G POOL	213,362	305,753	95,521	36	139,492,035	65,845,328	64,648,301
FIELD TOTAL	226,874	330,039	114,916	41	151,793,119	70,433,251	76,127,818
PRUDHOE BAY FIELD							
LISBURNE POOL	1,468,754	129,830	5,696,228	36	13,176,643	808,525	39,192,629
PRUDHOE POOL	46,382,709*	17,413,797	102,638,372	640	5,203,485,385**	399,682,839	7,004,160,364
FIELD TOTAL	47,851,463	17,543,627	108,334,600	676	5,216,662,028	401,603,710	7,043,352,993
SWANSON RIVER FIELD							
HEMLOCK POOL	179,042	147,632	7,578,836	30	206,157,816	66,344,819	1,710,788,143
FIELD TOTAL	179,042	147,632	7,578,836	30	206,209,055	66,348,989	1,711,112,031
TRADING BAY FIELD							
HEMLOCK POOL	14,521	9,620	15,789	6	10,583,602	2,725,514	10,383,084
UNDEFINED POOL	720	189	550	1	557,078	97,141	283,318
MIDDLE KENAI B POOL	11,578	4,822	11,933	6	1,995,693	180,873	2,125,127
MIDDLE KENAI C POOL	12,138	20,548	21,470	5	18,454,214	16,645,052	11,284,564
MIDDLE KENAI D POOL	10,016	16,988	10,183	6	26,682,777	13,126,059	21,724,168
MIDDLE KENAI E POOL	5,767	9,589	5,953	4	7,453,319	2,773,836	6,337,082
G-NE/HEMLOCK-NE POOL	21,341	135,619	8,268	7	22,867,516	23,915,708	6,416,102
W FORELAND POOL	689		121	1	25,093	9,611	18,460
M.KENAI UNALLOCATED ZONE			13	1			1,090,783
FIELD TOTAL	76,770	197,375	74,4[illegible]	37	88,619,292	59,473,794	60,362,688
TOTAL ACTIVE FIELDS	57,897,560	22,744,753	126,034,82[illegible]	201	6,635,321,221	899,441,179	9,587,739,769
DAILY AVERAGE	1,929,918	758,158	4,201,16[illegible]	INACTIVE	5,608,178	6,611,768	1,908,411
				ALL FIELDS	6,640,929,399	906,052,947	9,589,648,180

*INCLUDES 1,886,697 BBLS OF CONDENSATE
**INCLUDES 96,223,081 BBLS OF CONDENSATE

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR JUNE, 1987

NGL PRODUCTION	NGL (BBL)	CUM NGL (BBL)
KUPARUK RIVER		
KUPARUK RIVER	106,683	2,440,785
FIELD TOTAL	106,683	2,440,785
MCARTHUR RIVER		
HEMLOCK	9,054	7,796,230
MIDDLE KENAI G	8,111	736,649
WEST FORELAND	806	197,330
FIELD TOTAL	17,971	8,730,209
PRUDHOE BAY		
LISBURNE	54,979	54,979
PRUDHOE	1,482,557	7,372,421
FIELD TOTAL	1,537,536	7,427,400
SWANSON RIVER		
HEMLOCK	2,787	1,168,902
FIELD TOTAL	2,787	1,168,902
TRADING BAY		
HEMLOCK	7	51,628
M.KENAI UNALLOCATED	21	307,454
FIELD TOTAL	28	359,082
TOTAL ACTIVE FIELDS	1,665,005	20,126,378
DAILY AVERAGE	55,500	
INACTIVE		0
ALL FIELDS		20,126,378

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR JUNE, 1987

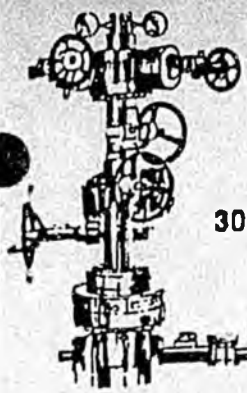
GAS FIELDS	CONDEN. (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CONDEN. (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL		22,357	1,510,399	4		223,651	56,536,882
FIELD TOTAL		22,357	1,510,399	4		223,651	56,536,882
BELUGA RIVER FIELD							
UNDEFINED POOL			1,577,774	13		810	241,348,429
FIELD TOTAL			1,577,774	13		810	241,348,429
EAST BARROW FIELD							
UNDEFINED POOL		10	22,952	4		672	3,653,375
FIELD TOTAL		10	22,952	4		672	3,653,375
KENAI FIELD							
STERLING 3 POOL		33	1,236,942	9		109,896	254,313,339
STERLING 4 POOL		391	1,337,666	12		84,654	357,860,178
STERLING 5.1 POOL		330	1,291,226	11		136,227	420,327,591
STERLING 6 POOL		205	1,603,963	11		41,842	387,170,650
UNDEFINED POOL		1,434	715,519	7		60,686	115,045,193
TYONEK POOL		361	414,706	4	11,877	30,812	206,955,557
FIELD TOTAL		2,754	6,600,022	54	11,877	476,817	1,785,704,713
MCARTHUR RIVER FIELD							
MIDDLE KENAI POOL			446,861	3			89,053,140
UNDEFINED POOL			374,185	2			39,244,490
FIELD TOTAL			821,046	5			128,297,630
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL			9,870	1			68,657
UNDEFINED POOL			25,210	1			1,971,817
FIELD TOTAL			35,080	2			2,040,474
NORTH COOK INLET FIELD							
TERTIARY POOL		1,599	3,402,754	12		86,614	796,975,793
FIELD TOTAL		1,599	3,402,754	12		86,614	796,975,793
PRETTY CREEK FIELD							
UNDEFINED POOL			84,976	1		82	439,921
FIELD TOTAL			84,976	1		82	439,921
SOUTH BARROW FIELD							
UNDEFINED POOL		14	50,774	5		247	17,549,168
FIELD TOTAL		14	50,774	5		247	17,549,168
TRADING BAY FIELD							
UNDEFINED POOL			33,733	1			3,004,326
FIELD TOTAL			33,733	1			3,004,326
TOTAL ACTIVE FIELDS		26,734	14,139,510	101	11,877	788,893	3,035,550,141
DAILY AVERAGE		891	471,317	INACTIVE	0	45	21,801,170
				ALL FIELDS	11,877	788,938	3,057,351,311

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS FOR JUNE, 1987

ENHANCED RECOVERY	OIL (BBL)	WATER (BBL)	GAS (MCF)	INJ. WELLS	CUM OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
ENDICOTT FIELD							
ENDICOTT POOL	1,707			2	16,456	1	
FIELD TOTAL	1,707*			2	16,456*	1	
GRANITE POINT FIELD							
MIDDLE KENAI POOL		386,834		10		127,319,468	
FIELD TOTAL		386,834		10		127,319,468	
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL		17,322,373	6,248,170	189		293,235,887	328,378,899
FIELD TOTAL		17,322,373	6,248,170	189		293,235,887	328,378,899
MCARTHUR RIVER FIELD							
HEMLOCK POOL		2,674,374		17		842,430,646	
MIDDLE KENAI G POOL		176,822		3		30,516,918	
FIELD TOTAL		2,851,196		20		872,947,564	
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL		55,975		2		25,794,491	
E F AND G POOL		410,093		14		223,967,916	
FIELD TOTAL		466,068		16		255,558,346	
PRUDHOE BAY FIELD							
LISBURNE POOL		28,857	5,696,228	3		58,633	23,336,638
PRUDHOE POOL		43,337,951	91,767,604	135	13,012,875	1,269,022,749	6,382,506,230
FIELD TOTAL		43,366,808	97,463,832	138	13,012,875*	1,269,081,382	6,405,842,868
SWANSON RIVER FIELD							
HEMLOCK POOL			7,957,530	7		8,337,995	1,972,857,254
FIELD TOTAL			7,957,530	7		8,337,995	1,972,857,254
TOTAL ACTIVE FIELDS	1,707	64,393,279	111,669,532	382	13,029,331	2,826,480,643	8,707,079,021
DAILY AVERAGE	56	2,146,442	3,722,317	INACTIVE	0	127,512,325	743,988
				ALL FIELDS	13,029,331	2,953,992,968	8,707,823,009

DISPOSAL PROJECTS	FLUIDS (BBL)	DISP. WELLS	CUM FLUIDS (BBL)
BEAVER CREEK FIELD			
UNDEFINED ZONE	2,567	1	2,567
FIELD TOTAL	2,567	1	2,567
ENDICOTT FIELD			
UNDEFINED ZONE	25,066	1	136,113
FIELD TOTAL	25,066	1	136,113
KENAI FIELD			
UNDEFINED ZONE	4,365	1	197,624
STERLING 4 POOL	27,737	1	27,737
FIELD TOTAL	32,102	2	225,361
KUPARUK RIVER FIELD			
KUPARUK RIVER POOL	41,421	2	151,553
FIELD TOTAL	41,421	2	2,285,775
PRUDHOE BAY FIELD			
UNDEFINED ZONE	1,751,221	8	113,419,677
FIELD TOTAL	1,751,221	8	113,419,677
TOTAL ACTIVE FIELDS	1,852,377	14	116,069,493
DAILY AVERAGE	61,745	INACTIVE	0
		ALL FIELDS	116,069,493

*FLUIDS RETURNED TO RESERVOIR, NOT ENHANCED RECOVERY



STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION





3001 PORCUPINE DR. ANCHORAGE, ALASKA 99501

STEVE COWPER, GOVERNOR

BULLETIN

C.V. Chatterton: Commissioner
Chairman of Commission

William W. Barnwell: Commissioner

Lonnie C. Smith: Commissioner

SEPTEMBER, 1987

BARROW GAS FIELD HEARING

A public hearing was held at the Commission on August 31, 1987 to take testimony regarding an order to establish pool rules to govern the drilling and production operation of the Barrow Gas Field, and to authorize disposal of non-hazardous waste fluids by injection into the South Barrow No. 5 well.

CONSERVATION ORDER NO. 231

Conservation Order No. 231 was issued on August 3, 1987 to Union Oil Company of California, operator of the Cannery Loop Unit. The order established pool rules to govern the operation of the Beluga Gas Pool, the Upper Tyonek Gas Pool, and the Tyonek "D" Gas Pool, all lying beneath the Cannery Loop Unit of the Kenai Gas Field.

ADMINISTRATIVE APPROVAL NO. 80.52

Administrative Order No. 80.52 was issued on August 26, 1987 to Union Oil Company of California, operator of the Trading Bay Unit, authorizing the drilling, completion, and production of Trading Bay Unit well No. M-25 as part of the pressure maintenance project approved by Conservation Order No. 80 for the purpose of recovering additional oil.

ADMINISTRATIVE APPROVAL NO. 119.5 AND 120.30

Administrative Approval No. 119.5 and 120.30 was issued to Marathon Oil Company on August 14, 1987 authorizing up to 15 MMSCF per day of gas to be flared at the onshore Trading Bay Production Facility between August 11, 1987 and September 25, 1987, or when the pipeline and all facilities have been restored to operational status. The flared volume will be metered and is subject to the Oil & Gas Properties Production Tax.

ADMINISTRATIVE APPROVAL NO. 145-A.25

Administrative Approval No. 45-A.25 was issued to Standard Alaska Production Company on August 10, 1987 permitting no more than 50 MMSCF of additional gas to be flared at Gathering Center No. 1, Prudhoe Bay Field, during testing of the modified flare control system. The flared volume will be metered and is subject to the Oil & Gas Properties Production Tax.

ADMINISTRATIVE APPROVAL NO. 213.10

Administrative Approval No. 213.10 was issued to ARCO Alaska, Inc. on August 11, 1987 waiving the requirement of Rule 11a of Conservation Order No. 165 for Prudhoe Bay Unit well DS 4-26. Rule 11a called for a spinner flow meter or tracer survey to be run during the first six months that the well is on production. Since all perforations are in zone 1B, a productivity profile need not be filed until additional zones are perforated.

ALASKA DRILLING STATISTICS FOR AUGUST, 1987

* DRILLING PERMITS APPROVED * * *

ALASKA DRILLING STATISTICS FOR AUGUST, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

SEPTEMBER 1987

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 09/08/87

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
COOK INLET BASIN					
ALASKAN CRUDE CORP	BURGLIN	31-1	50-133-20390-00	87-0070	07/31/87
ALASKAN CRUDE CORP	BURGLIN	BRX 22-1	50-283-20082-00	87-0084	08/24/87
AMOCO PRODUCTION CO	GRANITE PT ST 18742	13RD	50-133-20055-01	87-0044	04/28/87
AMOCO PRODUCTION CO	GRANITE POINT 18742	32RD	50-733-20298-01	87-0063	06/29/87
FAR NORTH OIL & GAS INC	MCCOY PROSPECT	?	50-133-10002-01	85-0208	10/04/85
UNION OIL CO OF CALIFORNIA	KENAI TYONEK UNIT	42X-6	50-133-20379-00	85-0180	10/14/85
UNION OIL CO OF CALIFORNIA	KENAI BELUGA UNIT	12X-8	50-133-20386-00	85-0298	12/20/85
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT	4	50-133-20387-00	87-0034	04/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	G-36DPN	50-733-20216-00	87-0049	05/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY ST	A-26DPN	50-733-20230-00	85-0258	11/25/85
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-1	50-733-20388-00	87-0046	05/12/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-2	50-733-20389-00	87-0061	06/26/87
UNION OIL CO OF CALIFORNIA	TRADING BY UNIT	M-25	50-733-20391-00	87-0086	08/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-3	50-733-20392-00	87-0089	09/03/87
ARCTIC SLOPE					
ALASKAN CRUDE CORP	ACC	F-2	50-029-21315-00	85-0053	04/10/85
ALASKAN CRUDE CORP	ACC	F-3	50-029-21316-00	85-0054	04/10/85
AMERADA HESS CORP	COLVILLE DELTA 32	1	50-103-20055-00	85-0279	11/29/85
AMERADA HESS CORP	NORTHSTAR	3	50-629-21747-00	87-0088	08/31/87
ARCO ALASKA INC	W BEACH ST	1-A	50-029-20138-01	86-0056	03/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-25	50-029-20488-01	87-0011	02/04/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-11D	50-029-21181-00	87-0087	08/24/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-11	50-029-21477-00	85-0267	10/31/85
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-25	50-029-21525-00	86-0006	01/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-22	50-029-21531-00	86-0019	01/13/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS4-19	50-029-21533-00	86-0021	01/15/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-6	50-029-21548-00	86-0038	02/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-31	50-029-21551-00	86-0041	02/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-10	50-029-21563-00	86-0058	03/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-11	50-029-21564-00	86-0059	03/10/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS1-27	50-029-21591-00	86-0088	05/02/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-12	50-029-21615-00	86-0120	06/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-26	50-029-21628-00	86-0134	07/07/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3K-14	50-029-21631-00	86-0137	07/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-27	50-029-21638-00	86-0148	07/28/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	LGI-16	50-029-21643-00	86-0153	08/15/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-1	50-029-21660-00	87-0012	02/10/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-24	50-029-21670-00	86-0182	11/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-30	50-029-21673-00	86-0185	12/04/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-1	50-029-21687-00	87-0003	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-3	50-029-21689-00	87-0005	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-4	50-029-21690-00	87-0006	01/21/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-28	50-029-21691-00	87-0007	01/28/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-12	50-029-21694-00	87-0010	01/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-2	50-029-21695-00	87-0013	02/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-3	50-029-21696-00	87-0014	02/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-4	50-029-21697-00	87-0015	02/10/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 09/08/87

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-5	50-029-21706-00	87-0025	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-6	50-029-21707-00	87-0026	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-7	50-029-21708-00	87-0027	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-8	50-029-21709-00	87-0028	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-9	50-029-21710-00	87-0029	03/10/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-8	50-029-21711-00	87-0030	03/16/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-10	50-029-21715-00	87-0035	03/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-28	50-029-21717-00	87-0037	04/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-11	50-029-21718-00	87-0038	04/13/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-12	50-029-21719-00	87-0050	05/22/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-13	50-029-21720-00	87-0040	04/13/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-29	50-029-21724-00	87-0045	04/30/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-14	50-029-21726-00	87-0051	05/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-15	50-029-21727-00	87-0052	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-16	50-029-21728-00	87-0053	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-17	50-029-21729-00	87-0054	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-18	50-029-21730-00	87-0055	06/03/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-21	50-029-21732-00	87-0057	05/29/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-19	50-029-21737-00	87-0064	07/02/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-20	50-029-21738-00	87-0065	07/01/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-21	50-029-21739-00	87-0066	07/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-22	50-029-21740-00	87-0067	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-5	50-029-21742-00	87-0069	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-27	50-029-21744-00	87-0082	07/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-10	50-029-21746-00	87-0085	08/12/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-16	50-029-21749-00	87-0091	09/04/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-4	50-103-20076-00	87-0076	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-5	50-103-20077-00	87-0077	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-6	50-103-20078-00	87-0078	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-7	50-103-20079-00	87-0079	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-8	50-103-20080-00	87-0080	07/31/87
NORTH SLOPE BOROUGH	S BARROW	NSB-1	50-023-20020-00	87-0071	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-2	50-023-20021-00	87-0072	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-3	50-023-20022-00	87-0073	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-4	50-023-20023-00	87-0074	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-7	50-023-20024-00	87-0075	07/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-3B	50-029-20306-01	87-0048	06/17/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-25	50-029-21478-00	85-0268	10/31/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-26	50-029-21487-00	85-0277	11/25/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-28	50-029-21510-00	85-0303	12/13/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-24	50-029-21512-00	85-0305	12/20/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	D-25	50-029-21522-00	85-0320	12/27/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-29	50-029-21523-00	86-0014	01/06/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	C-31	50-029-21552-00	86-0042	02/07/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	D-28	50-029-21556-00	86-0050	02/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-22	50-029-21558-00	86-0052	02/28/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	M-28	50-029-21578-00	86-0074	04/11/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	3-27/M33	50-029-21586-00	86-0083	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-23	50-029-21590-00	86-0087	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-24	50-029-21608-00	86-0113	06/10/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	S-19	50-029-21611-00	86-0116	06/13/86

SEPTEMBER 1987

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 09/08/87

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-30	50-029-21613-00	86-0118	06/17/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-31	50-029-21616-00	86-0121	06/19/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-47/Q21	50-029-21625-00	86-0131	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-29	50-029-21627-00	86-0133	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-32	50-029-21636-00	86-0146	07/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-20	50-029-21637-00	86-0147	07/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-14/O16	50-029-21639-00	86-0149	08/04/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-20/M35	50-029-21640-01	86-0173	10/10/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-23/N32	50-029-21645-00	86-0155	08/15/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-31	50-029-21647-00	86-0157	08/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-62/Q17	50-029-21648-00	86-0158	09/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-28	50-029-21649-00	86-0159	09/02/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-34/P14	50-029-21662-00	86-0172	10/09/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-33/K37	50-029-21668-00	86-0180	10/31/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-1/N29	50-029-21678-00	86-0190	12/11/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-8/P27	50-029-21692-00	87-0008	01/26/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-35/L36	50-029-21701-00	87-0020	02/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-21	50-029-21705-00	87-0024	03/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-23	50-029-21712-00	87-0031	03/25/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-21/L34	50-029-21714-00	87-0033	03/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-20	50-029-21716-00	87-0036	04/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-28	50-029-21721-00	87-0041	05/06/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-25/N22	50-029-21722-00	87-0042	04/24/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-6/Q32	50-029-21723-00	87-0043	04/24/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT N-23	50-029-21725-00	87-0047	05/22/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-42/P38	50-029-21731-00	87-0056	05/28/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-27	50-029-21733-00	87-0058	06/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-26	50-029-21734-00	87-0059	06/11/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-49/J40	50-029-21735-00	87-0060	06/17/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-9	50-029-21736-00	87-0062	06/26/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-25	50-029-21741-00	87-0068	07/07/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-9/J18	50-029-21743-00	87-0081	07/31/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-29	50-029-21745-00	87-0083	08/06/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-37/P24	50-029-21748-00	87-0090	09/03/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-52/S14	50-029-21750-00	87-0092	09/04/87

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR JULY, 1987

OIL FIELDS	CRUDE OIL (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CRUDE OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL	12,833	14	3,529	2	3,420,931	18,044	1,402,141
FIELD TOTAL	12,833	14	3,529	2	3,420,931	18,044	1,402,141
ENDICOTT FIELD							
ENDICOTT POOL	1,228		34,500	1	28,094	2,132	662,387
FIELD TOTAL	1,228		34,500	1	28,094	2,132	662,387
GRANITE POINT FIELD							
MIDDLE KENAI POOL	240,172	89,397	216,201	28	105,753,891	7,147,264	91,356,308
FIELD TOTAL	240,172	89,397	216,201	28	105,756,655	7,147,264	91,357,898
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL	8,212,446	3,121,183	7,919,835	321	353,213,509	32,371,085	419,072,978
FIELD TOTAL	8,212,446	3,121,183	7,919,835	321	353,216,874	79,998,314	419,077,958
MCARTHUR RIVER FIELD							
HEMLOCK POOL	521,031	2,045,142	239,933	58	464,100,394	210,999,310	169,597,327
MIDDLE KENAI G POOL	85,084	62,269	34,090	11	35,627,877	3,981,396	17,734,141
WEST FORELAND POOL	28,511	44,529	9,776	4	18,988,207	4,797,509	5,410,251
FIELD TOTAL	634,626	2,151,940	283,799	73	516,716,478	219,778,215	192,741,719
MIDDLE GROUND SHOAL FIELD							
A POOL	3,483	1,028	7,521	1	1,974,754	1,108,586	4,325,467
B C AND D POOL	18,102	23,4[illegible]	13,046	4	10,347,915	3,503,846	7,174,617
E F AND G POOL	213,607	[illegible]97,890	89,481	36	139,705,642	66,143,191	64,738,751
FIELD TOTAL	235,192	[illegible]22,399	110,048	41	152,028,311	70,755,623	76,238,835
PRUDHOE BAY FIELD							
LISBURNE POOL	1,414,551	130,209	6,074,948	36	[illegible],573,856	938,734	45,267,577
PRUDHOE POOL	48,170,902*	18,709,744	102,436,731	652	5,2[illegible],656,287**	418,392,583	7,106,597,095
FIELD TOTAL	49,585,453	18,839,953	108,511,679	689	5,266,230,143	420,443,663	7,151,864,672
SWANSON RIVER FIELD							
HEMLOCK POOL	200,741	170,475	6,902,957	28	206,358,557	66,515,294	1,717,691,100
FIELD TOTAL	200,741	170,475	6,902,957	28	206,409,796	66,519,464	1,718,014,988
TRADING BAY FIELD							
HEMLOCK POOL	15,496	8,835	19,175	6	10,599,098	2,734,349	10,402,259
UNDEFINED POOL	729	413	874	1	557,807	97,554	284,192
MIDDLE KENAI B POOL	12,626	5,641	10,341	7	2,008,319	186,514	2,135,468
MIDDLE KENAI C POOL	13,517	23,389	23,460	5	18,467,731	16,668,441	12,008,024
MIDDLE KENAI D POOL	8,367	17,103	10,381	6	26,691,144	13,143,162	21,734,549
MIDDLE KENAI E POOL	5,618	9,348	4,747	4	7,458,937	2,783,184	6,341,829
G-NE/HEMLOCK-NE POOL	20,623	134,506	7,956	7	22,888,139	24,050,214	6,424,058
W FORELAND POOL	805		141	1	25,898	9,611	18,601
M.KENAI UNALLOCATED ZONE			136	1			1,090,919
FIELD TOTAL	77,781	199,235	77,211	38	88,697,073	59,673,025	60,439,899
TOTAL ACTIVE FIELDS	59,200,472	24,894,596	124,059,759	1,220	6,694,504,355	924,335,748	9,711,800,497
DAILY AVERAGE	1,909,692	803,051	4,001,927	INACTIVE	5,608,178	6,611,768	1,908,411
				ALL FIELDS	6,700,112,533	930,947,516	9,713,708,908

* INCLUDES 1,882,684 BBLS OF CONDENSATE
**INCLUDES 98,105,765 BBLS OF CONDENSATE

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR JULY, 1987

NGL PRODUCTION	NGL (BBL)	CUM NGL (BBL)
KUPARUK RIVER		
KUPARUK RIVER	115,060	2,555,845
FIELD TOTAL	115,060	2,555,845
MCARTHUR RIVER		
HEMLOCK	9,334	7,805,564
MIDDLE KENAI G	8,181	744,830
WEST FORELAND	780	198,110
FIELD TOTAL	18,295	8,748,504
PRUDHOE BAY		
LISBURNE	71,028	126,007
PRUDHOE	1,490,152	8,862,573
FIELD TOTAL	1,561,180	8,988,580
SWANSON RIVER		
HEMLOCK	2,077	1,170,979
FIELD TOTAL	2,077	1,170,979
TRADING BAY		
HEMLOCK	7	51,635
M.KENAI UNALLOCATED	21	307,475
FIELD TOTAL	28	359,110
TOTAL ACTIVE FIELDS	1,696,640	21,823,018
DAILY AVERAGE	54,730	
INACTIVE		0
ALL FIELDS		21,823,018

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR JULY, 1987

GAS FIELDS	CONDEN. (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CONDEN. (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL		22,809	1,366,002	4		246,460	57,902,884
FIELD TOTAL		22,809	1,366,002	4		246,460	57,902,884
BELUGA RIVER FIELD							
UNDEFINED POOL			1,627,655	11		810	242,976,084
FIELD TOTAL			1,627,655	11		810	242,976,084
EAST BARROW FIELD							
UNDEFINED POOL		9	47,826	3		681	3,701,201
FIELD TOTAL		9	47,826	3		681	3,701,201
KENAI FIELD							
STERLING 3 POOL		192	1,213,718	9		110,088	255,527,057
STERLING 4 POOL		73	1,339,814	12		84,727	359,199,992
STERLING 5.1 POOL		1,008	1,344,783	11		137,235	421,672,374
STERLING 6 POOL		176	1,581,712	11		42,020	388,752,362
UNDEFINED POOL		367	829,659	7		61,053	115,874,852
TYONEK POOL		221	450,373	4	11,877	31,033	207,405,930
FIELD TOTAL		2,039	6,760,059	54	11,877	478,856	1,792,464,202
MCARTHUR RIVER FIELD							
MIDDLE KENAI POOL			428,660	3			89,481,800
UNDEFINED POOL			419,569	2			39,664,059
FIELD TOTAL			848,229	5			129,145,859
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL			10,757	1			79,414
UNDEFINED POOL			16,240	1			1,988,057
FIELD TOTAL			26,997	2			2,067,471
NORTH COOK INLET FIELD							
TERTIARY POOL		2,698	4,015,834	12		89,312	800,991,627
FIELD TOTAL		2,698	4,015,834	12		89,312	800,991,627
PRETTY CREEK FIELD							
UNDEFINED POOL			61,040	1		82	500,961
FIELD TOTAL			61,040	1		82	500,961
SOUTH BARROW FIELD							
UNDEFINED POOL		50	21,662	6		297	17,570,830
FIELD TOTAL		50	21,662	6		297	17,570,830
SWANSON RIVER FIELD							
UNDEFINED POOL			46,081	1			12,150,721
FIELD TOTAL			46,081	1			12,150,721
TRADING BAY FIELD							
UNDEFINED POOL			39,834	1			3,044,160
FIELD TOTAL			39,834	1			3,044,160
TOTAL ACTIVE FIELDS		27,605	14,861,219	100	11,877	816,498	3,062,516,000
DAILY AVERAGE		890	479,394	INACTIVE	0	45	9,696,530
				ALL FIELDS	11,877	816,543	3,072,212,530

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS FOR JULY, 1987

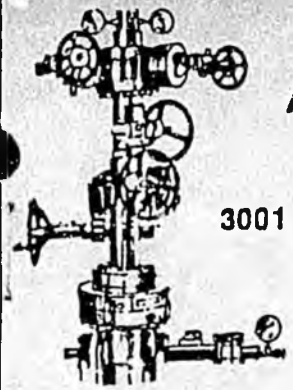
ENHANCED RECOVERY	OIL (BBL)	WATER (BBL)	GAS (MCF)	INJ. WELLS	CUM OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
ENDICOTT FIELD							
ENDICOTT POOL	1,228			1	17,684	1	
FIELD TOTAL	1,228*			1	17,684*	1	
GRANITE POINT FIELD							
MIDDLE KENAI POOL		386,094		12		127,705,562	
FIELD TOTAL		386,094		12		127,705,562	
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL		11,179,230	5,084,430	186		304,415,117	333,463,329
FIELD TOTAL		11,179,230	5,084,430	186		304,415,117	333,463,329
MCARTHUR RIVER FIELD							
HEMLOCK POOL		2,892,169		16		845,322,815	
MIDDLE KENAI G POOL		184,388		3		30,701,306	
FIELD TOTAL		3,076,557		19		876,024,121	
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL		55,434		2		25,849,925	
E F AND G POOL		390,087		14		224,358,003	
FIELD TOTAL		445,521		16		256,003,867	
PRUDHOE BAY FIELD							
LISBURNE POOL		71,337	5,527,387	3		129,970	28,324,127
PRUDHOE POOL		43,075,305	91,747,022	133	13,012,875	1,312,098,054	6,474,253,252
FIELD TOTAL		43,146,642	97,274,409	136	13,012,875*	1,312,228,024	6,502,577,379
SWANSON RIVER FIELD							
HEMLOCK POOL			7,220,359	7		8,337,995	1,980,977,613
FIELD TOTAL			7,220,359	7		8,337,995	1,980,977,613
TOTAL ACTIVE FIELDS	1,228	58,234,044	109,579,198	377	13,030,559	2,884,714,687	8,816,718,321
DAILY AVERAGE	39	1,878,517	3,534,812	INACTIVE	0	127,512,325	743,988
				ALL FIELDS	13,030,559	3,012,227,012	8,815,862,309

DISPOSAL PROJECTS	FLUIDS (BBL)	DISP. WELLS	CUM FLUIDS (BBL)
BEAVER CREEK FIELD			
UNDEFINED ZONE	18,924	1	21,491
FIELD TOTAL	18,924	1	21,491
ENDICOTT FIELD			
UNDEFINED ZONE	14,746	1	150,859
FIELD TOTAL	14,746	1	150,859
KENAI FIELD			
UNDEFINED ZONE	3,623	1	201,247
STERLING 4 POOL	3,890	1	31,627
FIELD TOTAL	7,513	2	232,874
KUPARUK RIVER FIELD			
KUPARUK RIVER POOL	45,896	2	197,449
FIELD TOTAL	45,896	2	2,331,671
PRUDHOE BAY FIELD			
UNDEFINED ZONE	2,109,697	6	115,529,374
FIELD TOTAL	2,109,697	6	115,529,374
TOTAL ACTIVE FIELDS	2,196,776	12	118,266,269
DAILY AVERAGE	70,863	INACTIVE	0
		ALL FIELDS	118,266,269

*FLUIDS RETURNED TO RESERVOIR, NOT ENHANCED RECOVERY

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 PORCUPINE DR ANCHORAGE, AK. 99501-3192

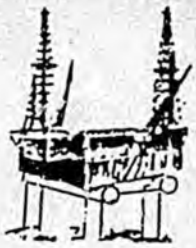
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STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION





3001 PORCUPINE DR. ANCHORAGE, ALASKA 99501

STEVE COWPER, GOVERNOR

BULLETIN

William W. Barnwell: Commissioner

C.V. Chatterton: Commissioner
Chairman of Commission

Lonnie C. Smith: Commissioner

OCTOBER 1987

1986 SUMMARY
ALASKA OIL AND GAS ACTIVITIES

EXPLORATION ACTIVITY

A total of 15 exploratory wells were active in Alaska in 1986 consisting of 8 on the North Slope, 6 in the Beaufort Sea, and 1 in the Cook Inlet Basin. Of these 15 wells, 1 was completed as an oil well; 1 was completed as a gas well; 1 was suspended and 12 were plugged and abandoned. One of the plugged and abandoned wells was determined "producible" by U.S. Minerals Management Service. Twelve exploratory well permits were issued in Alaska during 1986 consisting of 9 by the Minerals Management Service and 3 by the Alaska Oil and Gas Conservation Commission.

DEVELOPMENT ACTIVITY

There were 208 development and service wells active in Alaska during 1986 consisting of 97 in Prudhoe Bay Field, 92 in Kuparuk River Field, 8 in Endicott Field, and 11 in seven Cook Inlet Basin fields. Of the wells active in Prudhoe Bay Field, 40 were completed as oil wells; 5 were completed as injection wells; 47 were drilled and await completion; 2 were abandoned; and 3 were drilling at year's end. Active wells in the Kuparuk River Field consisted of 43 completed oil wells, 40 wells drilled but not yet completed, 3 suspended wells, and 5 abandoned wells. One Kuparuk well was drilling at year's end. The Alaska Oil and Gas Conservation Commission approved 172 development and 20 service well permit applications during 1986.

PRODUCTION AND RESERVES

A total of 682,895,891 barrels of oil and natural gas liquids were produced in Alaska during 1986, 2.3% more than in 1985. Prudhoe Bay Field accounted for 82.8% of the State's production,

Kuparuk River Field accounted for 14.0%, and the Cook Inlet Basin fields accounted for 3.2%. During 1986 the State's oil production rate averaged 1,870,948 BOPD, and at year's end there were a total of 1172 producing oil wells in the State. This production is equivalent to an average rate of 1596 BOPD per well. Total casinghead and dry gas production for the year amounted to 1.383 trillion CF, of which 1.065 trillion CF was reinjected.

Total water injected during 1986 amounted to 608,225,599 barrels. During December, 1986, an average of 1,983,066 barrels of water was injected daily into 371 water injection wells. This is equivalent to injecting at the rate of 5434 BWPD per well.

On January 1, 1987 total proven oil reserves in the eight producing fields and one soon to be producing field in Alaska amounted to approximately 6.6 billion barrels, a 9.3% decline from the January 1, 1986 estimate. Total Alaska gas reserves as of January 1, 1987 are 30.9 trillion standard cubic feet. These gas reserves occur in 27 separate reservoirs, the largest of which is the Prudhoe Oil Pool in Prudhoe Bay Field, which accounts for 25.8 TCF, or 83.5% of the total.

ALASKA OIL AND GAS CONSERVATION COMMISSION ACTIVITY

During 1986 the Oil and Gas Conservation Commission issued 7 Conservation Orders covering various practices aimed at achieving maximum recoveries from Alaska fields. Pursuant to having been granted primacy in mid-1986 for Class II injection wells, the Commission issued 12 Area Injection Orders and 1 Aquifer Exemption Order. A total of 37 Administrative Approvals were issued permitting various conservation related activities within the scope of pre-existing Conservation Orders and Area Injection Orders. During the year the Commission forwarded category determination on 89 wells to the Federal Energy Regulatory Commission pursuant to the Natural Gas Policy Act. On a continuous basis, the Commission maintains field surveillance over operator activities relative to drilling permit requirements and state conservation regulations. In this connection, Commission field personnel witnessed or inspected nearly 13,000 field operations to assure compliance.

CONSERVATION ORDER NO. 232

Conservation Order No. 232 was issued September 29, 1987 to Standard Alaska Production Company. The order amends Rule 9 of Conservation Order No. 202 by adding a section which allows the Commission to administratively approve modifications to the gas-oil contact monitoring program for the Endicott Oil Pool.

CONSERVATION ORDER NO. 233

Conservation Order No. 233 was issued September 30, 1987 to the North Slope Borough. The Order defines and sets forth operating rules for the South Barrow Gas Pool and the East Barrow Gas Pool of the Barrow Gas Field.

ADMINISTRATIVE APPROVAL NO. 145-A.26

Administrative Approval No. 145-A.26 was issued September 23, 1987 to ARCO Alaska, Inc. It allows additional flaring of gas at Flow Stations 1, 2 & 3, and at the Central Gas Facility for the Prudhoe Bay Unit, Prudhoe Oil Pool. It was necessitated by the scheduled Alyeska Pipeline System shutdown on September 29, 1987

ADMINISTRATIVE APPROVAL NO. 145-A 27

Administrative Approval No. 145-A.27 was issued September 28, 1987 to ARCO Alaska, Inc. It allows additional flaring of gas at Lisburne Production facility due to the scheduled Alyeska Pipeline shutdown and pending repairs of the LGI-6 well in the Lisburne Oil Pool.

ADMINISTRATIVE APPROVAL NO. 202.3

Administrative Approval No. 202.3 was issued September 17, 1987 to Standard Alaska Production Company. Data was presented and approval was given to use 13-3/8" 68lb/ft NT-80CYHE ERW buttress pipe for surface casing in the Endicott Field.

DISPOSAL INJECTION ORDER NO. 5

Disposal Injection Order No. 5 was issued September 30, 1987 to the North Slope Borough (NSB). The Order authorizes the injection of non-hazardous oil field waste fluids for the purpose of disposal into the permeable strata below 2276 feet in the NSB SB 5 well in the Barrow Gas Field.

RECEPTIONIST RETIRES

Virginia D. Leischner (Ginny) retired on September 30, 1987 to pursue her own business interests. She had been employed with the Commission as a receptionist/typist since July, 1981. Before joining the Commission, Ginny held various positions as receptionist/typist, cashier, and bookkeeper. We will miss her. Good luck with your retirement ventures, Ginny.

SENIOR PETROLEUM GEOLOGIST RETIRES

William Van Alen (Bill) retired on September 30, 1987. He had over 19 years of Alaska experience (6 with Amoco and 12 with Placid) as geologist and geological manager before joining the Commission in August, 1978. At the Commission Bill made geologic studies of the various Cook Inlet fields and of Prudhoe Bay, Kuparuk, Endicott, and various exploratory plays on the North Slope. We will miss Bill as a valued colleague and as a good friend. Good luck in your retirement, Bill.

PETROLEUM INSPECTOR COMPLETES WELL CONTROL REFRESHER COURSE

Petroleum Inspector Bobby D. Foster, on September 25, 1987, completed the USGS certified "subsea stack" well control refresher course sponsored by the Alaska Vocational Technical Center. Following a four-day "basic" course, certification is obtained in "surface" or "subsea" stack (BOPE), depending on the course. To maintain certification, a refresher course must be taken annually within 60 days of the basic course anniversary date. All Commission inspectors and engineers have obtained certification and take the annual classes to maintain certification.

ALASKA DRILLING STATISTICS FOR SEPTEMBER, 1987

* DRILLING PERMITS APPROVED * * *

ALASKA DRILLING STATISTICS FOR SEPTEMBER, 1987

* DRILLING PERMITS APPROVED * * *

ALASKA DRILLING STATISTICS FOR SEPTEMBER, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 10/07/87

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
GULF OF AK BASIN				
ALASKAN CRUDE CORP	KATALLA KS-1	50-069-20002-00	85-0124	07/01/85
COOK INLET BASIN				
ALASKAN CRUDE CORP	BURGLIN 31-1	50-133-20390-00	87-0070	07/31/87
ALASKAN CRUDE CORP	BURGLIN BRX 22-1	50-283-20082-00	87-0084	08/24/87
AMOCO PRODUCTION CO	GRANITE PT ST 18742 13RD	50-133-20055-01	87-0044	04/28/87
AMOCO PRODUCTION CO	GRANITE POINT 18742 32RD	50-733-20298-01	87-0063	06/29/87
FAR NORTH OIL & GAS INC	MCCOY PROSPECT 1	50-133-10002-01	85-0208	10/04/85
SHELL WESTERN E&P INC	MGS A-23-1RD	50-733-20238-01	87-0093	09/16/87
UNION OIL CO OF CALIFORNIA	KENAI TYONEK UNIT 42X-6	50-133-20379-00	85-0180	10/14/85
UNION OIL CO OF CALIFORNIA	KENAI BELUGA UNIT 12X-8	50-133-20386-00	85-0298	12/20/85
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT 4	50-133-20387-00	87-0034	04/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT G-36DPN	50-733-20216-00	87-0049	05/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY ST A-26DPN	50-733-20230-00	85-025[illegible]	11/25/85
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT M-1	50-733-20388-00	87-00[illegible]	05/12/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT M-2	50-733-20389-00	87-00[illegible]	06/26/87
UNION OIL CO OF CALIFORNIA	TRADING BY UNIT M-25	50-733-20391-00	87-0086	08/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT M-3	50-733-20392-00	87-0089	09/03/87
ARCTIC SLOPE				
ALASKAN CRUDE CORP	ACC F-2	50-029-21315-00	85-0053	04/10/85
ALASKAN CRUDE CORP	ACC F-3	50-029-21316-00	85-0054	04/10/85
AMERADA HESS CORP	COLVILLE DELTA 32 1	50-103-20055-00	85-0279	11/29/85
AMERADA HESS CORP	NORTHSTAR 3	50-629-21747-00	87-0088	08/31/87
ARCO ALASKA INC	W BEACH ST 1-A	50-029-20138-01	86-0056	03/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT DS11-25	50-029-20488-01	87-0011	02/04/87
ARCO ALASKA INC	PRUDHOE BAY UNIT DS18-11D	50-029-21181-00	87-0087	08/24/87
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-11	50-029-21477-00	85-0267	10/31/85
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-25	50-029-21525-00	86-0006	01/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT DS16-22	50-029-21531-00	86-0019	01/13/86
ARCO ALASKA INC	PRUDHOE BAY UNIT DS4-19	50-029-21533-00	86-0021	01/15/86
ARCO ALASKA INC	KUPARUK RIV UNIT 3I-6	50-029-21548-00	86-0038	02/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT DS16-31	50-029-21551-00	86-0041	02/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT 3I-10	50-029-21563-00	86-0058	03/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT 3I-11	50-029-21564-00	86-0059	03/10/86
ARCO ALASKA INC	PRUDHOE BAY UNIT DS1-27	50-029-21591-00	86-0088	05/02/86
ARCO ALASKA INC	PRUDHOE BAY UNIT DS11-26	50-029-21628-00	86-0134	07/07/86
ARCO ALASKA INC	KUPARUK RIV UNIT 3K-14	50-029-21631-00	86-0137	07/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT LGI-16	50-029-21643-00	86-0153	08/15/86
ARCO ALASKA INC	KUPARUK RIV UNIT 3M-1	50-029-21660-00	87-0012	02/10/87
ARCO ALASKA INC	PRUDHOE BAY UNIT L3-24	50-029-21670-00	86-0182	11/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT L3-30	50-029-21673-00	86-0185	12/04/86
ARCO ALASKA INC	KUPARUK RIV UNIT 3Q-1	50-029-21687-00	87-0003	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3Q-3	50-029-21689-00	87-0005	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3Q-4	50-029-21690-00	87-0006	01/21/87
ARCO ALASKA INC	PRUDHOE BAY UNIT DS11-28	50-029-21691-00	87-0007	01/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3M-2	50-029-21695-00	87-0013	02/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3M-5	50-029-21706-00	87-0025	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3M-6	50-029-21707-00	87-0026	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3M-7	50-029-21708-00	87-0027	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3M-8	50-029-21709-00	87-0028	03/10/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 10/07/87

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-9	50-029-21710-00	87-0029	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-10	50-029-21715-00	87-0035	03/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-28	50-029-21717-00	87-0037	04/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-11	50-029-21718-00	87-0038	04/13/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-12	50-029-21719-00	87-0050	05/22/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-13	50-029-21720-00	87-0040	04/13/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-29	50-029-21724-00	87-0045	04/30/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-14	50-029-21726-00	87-0051	05/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-15	50-029-21727-00	87-0052	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-16	50-029-21728-00	87-0053	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-17	50-029-21729-00	87-0054	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-18	50-029-21730-00	87-0055	06/03/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-21	50-029-21732-00	87-0057	05/29/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-19	50-029-21737-00	87-0064	07/02/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-20	50-029-21738-00	87-0065	07/01/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-21	50-029-21739-00	87-0066	07/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-22	50-029-21740-00	87-0067	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-5	50-029-21742-00	87-0069	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-27	50-029-21744-00	87-0082	07/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-10	50-029-21746-00	87-0085	08/12/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-16	50-029-21749-00	87-0091	09/04/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-16	50-029-21754-00	87-0097	09/11/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-15	50-029-21755-00	87-0098	09/22/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-13	50-029-21756-00	87-0100	09/25/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-14	50-029-21758-00	87-0102	10/02/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-4	50-103-20076-00	87-0076	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-5	50-103-20077-00	87-0077	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-6	50-103-20078-00	87-0078	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-7	50-103-20079-00	87-0079	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-8	50-103-20080-00	87-0080	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-17	50-103-20081-00	87-0099	09/25/87
NORTH SLOPE BOROUGH	S BARROW	NSB-1	50-023-20020-00	87-0071	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-2	50-023-20021-00	87-0072	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-3	50-023-20022-00	87-0073	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-4	50-023-20023-00	87-0074	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-7	50-023-20024-00	87-0075	07/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-3B	50-029-20306-01	87-0048	06/17/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-25	50-029-21478-00	85-0268	10/31/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-26	50-029-21487-00	85-0277	11/25/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-28	50-029-21510-00	85-0303	12/13/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-24	50-029-21512-00	85-0305	12/20/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	D-25	50-029-21522-00	85-0320	12/27/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-29	50-029-21523-00	86-0014	01/06/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	C-31	50-029-21552-00	86-0042	02/07/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	D-28	50-029-21556-00	86-0050	02/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-22	50-029-21558-00	86-0052	02/28/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	M-28	50-029-21578-00	86-0074	04/11/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	3-27/M33	50-029-21586-00	86-0083	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-23	50-029-21590-00	86-0087	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-24	50-029-21608-00	86-0113	06/10/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	S-19	50-029-21611-00	86-0116	06/13/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	G-30	50-029-21613-00	86-0118	06/17/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	G-31	50-029-21616-00	86-0121	06/19/86

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 10/07/87

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-47/Q21	50-029-21625-00	86-0131	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-29	50-029-21627-00	86-0133	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-32	50-029-21636-00	86-0146	07/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-20	50-029-21637-00	86-0147	07/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-14/Q16	50-029-21639-00	86-0149	08/04/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-20/M35	50-029-21640-01	86-0173	10/10/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-23/N32	50-029-21645-00	86-0155	08/15/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-31	50-029-21647-00	86-0157	08/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-62/Q17	50-029-21648-00	86-0158	09/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-28	50-029-21649-00	86-0159	09/02/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-34/P14	50-029-21662-00	86-0172	10/09/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-33/K37	50-029-21668-00	86-0180	10/31/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-1/N29	50-029-21678-00	86-0190	12/11/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-8/P27	50-029-21692-00	87-0008	01/26/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-35/L36	50-029-21701-00	87-0020	02/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-21	50-029-21705-00	87-0024	03/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-23	50-029-21712-00	87-0031	03/25/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-21/L34	50-029-21714-00	87-0033	03/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-20	50-029-21716-00	87-0036	04/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-28	50-029-21721-00	87-0041	05/06/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-6/Q32	50-029-21723-00	87-0043	04/24/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-42/P38	50-029-21731-00	87-0056	05/28/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-27	50-029-21733-00	87-0058	06/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-26	50-029-21734-00	87-0059	06/11/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-9	50-029-21736-00	87-0062	06/26/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-25	50-029-21741-00	87-0068	07/07/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-9/J18	50-029-21743-00	87-0081	07/31/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-29	50-029-21745-00	87-0083	08/06/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-37/P24	50-029-21748-00	87-0090	09/03/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-52/S14	50-029-21750-00	87-0092	09/04/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-15/K33	50-029-21751-00	87-0094	09/11/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-14	50-029-21752-00	87-0095	09/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-28	50-029-21753-00	87-0096	09/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-13	50-029-21757-00	87-0101	09/30/87

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR AUGUST, 1987

OIL FIELDS	CRUDE OIL (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CRUDE OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL	7,717	25	2,122	2	3,428,648	18,069	1,404,263
FIELD TOTAL	7,717	25	2,122	2	3,428,648	18,069	1,404,263
ENDICOTT FIELD							
ENDICOTT POOL	1,583		49,180	2	29,677	2,132	711,613
FIELD TOTAL	1,583		49,180	2	29,677	2,132	711,613
GRANITE POINT FIELD							
MIDDLE KENAI POOL	209,468	86,771	176,034	28	105,963,359	7,234,035	91,532,342
FIELD TOTAL	209,468	86,771	176,034	28	105,966,123	7,234,035	91,533,932
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL	8,052,409	3,896,342	8,351,873	332	361,265,918	36,267,427	427,424,851
FIELD TOTAL	8,052,409	3,896,342	8,351,873	332	361,269,283	83,894,656	427,429,831
MCARTHUR RIVER FIELD							
HEMLOCK POOL	499,642	1,862,751	254,893	59	464,600,036	212,862,061	169,852,220
MIDDLE KENAI G POOL	78,612	47,479	30,067	11	35,706 489	4,028,875	17,764,208
WEST FORELAND POOL	25,677	40,133	7,904	4	19,013,084	4,837,642	5,418,155
FIELD TOTAL	603,931	1,950,363	292,864	74	519,320,409	221,728,578	193,034,583
MIDDLE GROUND SHOAL FIELD							
A POOL	5,403	1,074	9,026	1	1,980,157	1,109,660	4,334,493
B C AND D POOL	18,847	21,814	12,936	4	10,330,528	3,525,360	7,180,127
E F AND G POOL	206,845	289,345	80,548	37	139,912,487	66,432,563	64,819,299
FIELD TOTAL	231,095	312,233	102,510	42	152,223,172	71,067,583	76,333,919
PRUDHOE BAY FIELD							
LISBURNE POOL	1,240,132	130,301	5,224,127	38	15,813,988	1,069,035	50,491,704
PRUDHOE POOL	48,537,065*	18,297,585	102,131,516	664	5,300,193,352**	436,690,168	7,208,728,611
FIELD TOTAL	49,777,197*	18,427,886	107,355,643	702	5,316,007,340**	438,871,549	7,259,220,315
SWANSON RIVER FIELD							
HEMLOCK POOL	183,823	185,249	6,226,188	25	206,542,380	66,700,543	1,723,917,288
FIELD TOTAL	183,823	185,249	6,226,188	25	206,593,619	66,704,713	1,724,241,176
TRADING BAY FIELD							
HEMLOCK POOL	15,177	8,017	17,182	6	10,614,275	2,742,366	10,419,441
UNDEFINED POOL	553	74	1,480	1	558,360	97,628	285,672
MIDDLE KENAI B POOL	10,961	3,789	9,747	7	2,019,280	190,303	2,145,215
MIDDLE KENAI C POOL	15,578	21,913	25,415	5	18,483,309	16,690,354	12,033,439
MIDDLE KENAI D POOL	9,246	17,799	8,147	6	26,700,390	13,160,961	21,742,696
MIDDLE KENAI E POOL	5,889	9,348	4,532	4	7,464,826	2,792,532	6,346,361
G-NE/HEMLOCK-NE POOL	16,044	135,537	6,572	7	22,904,183	24,185,751	6,430,630
W FORELAND POOL	593		104	1	26,491	9,611	18,705
M.KENAI UNALLOCATED ZONE			140	1			1,091,059
FIELD TOTAL	74,041	196,477	73,319	38	88,771,114	59,869,506	60,513,218
TOTAL ACTIVE FIELDS	59,141,264	25,055,346	122,629,733	1,245	6,753,609,385	949,390,821	9,834,422,850
DAILY AVERAGE	1,907,782	808,236	3,955,797	INACTIVE	5,608,178	6,611,768	1,908,411
				ALL FIELDS	6,759,217,563	956,002,589	9,836,331,261

* INCLUDES 1,962,331 BBLS OF CONDENSATE
**INCLUDES 100,068,096 BBLS OF CONDENSATE

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR AUGUST, 1987

NGL PRODUCTION	NGL (BBL)	CUM NGL (BBL)
KUPARUK RIVER		
KUPARUK RIVER	89,156	2,645,001
FIELD TOTAL	89,156	2,645,001
MCARTHUR RIVER		
HEMLOCK	7,706	7,813,270
MIDDLE KENAI G	5,339	750,169
WEST FORELAND	459	198,569
FIELD TOTAL	13,504	8,762,008
PRUDHOE BAY		
LISBURNE	46,828	172,835
PRUDHOE	1,519,193	10,381,766
FIELD TOTAL	1,566,021	10,554,601
SWANSON RIVER		
HEMLOCK	2,084	1,173,063
FIELD TOTAL	2,084	1,173,063
TRADING BAY		
HEMLOCK	6	51,641
M.KENAI UNALLOCATED	18	307,493
FIELD TOTAL	24	359,134
TOTAL ACTIVE FIELDS	1,670,789	23,493,807
DAILY AVERAGE	53,896	
INACTIVE		0
ALL FIELDS		23,493,807

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR AUGUST, 1987

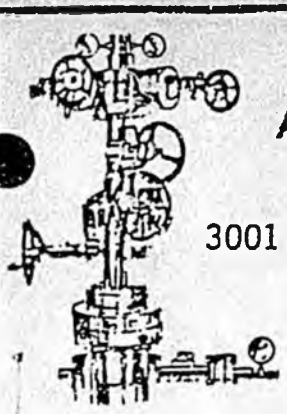
GAS FIELDS	CONDEN. (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CONDEN. (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL		19,609	1,095,026	4		266,069	58,997,910
FIELD TOTAL		19,609	1,095,026	4		266,069	58,997,910
BELUGA RIVER FIELD							
UNDEFINED POOL			1,713,537	12		810	244,689,621
FIELD TOTAL			1,713,537	12		810	244,689,621
EAST BARROW FIELD							
UNDEFINED POOL		9	32,318	3		687	3,734,104
FIELD TOTAL		9	32,318	3		687	3,734,104
KENAI FIELD							
STERLING 3 POOL		11	1,278,732	9		110,099	256,805,789
STERLING 4 POOL		53	1,346,725	12		84,780	360,546,717
STERLING 5.1 POOL		200	1,257,038	11		137,435	422,929,412
STERLING 6 POOL		84	1,384,195	11		42,104	390,136,557
UNDEFINED POOL		914	859,887	7		61,967	116,734,739
TYONEK POOL		312	470,110	4	11,877	31,345	207,876,040
FIELD TOTAL		1,574	6,596,687	54	11,877	480,430	1,799,060,889
MCARTHUR RIVER FIELD							
MIDDLE KENAI POOL			785,107	6			90,266,907
FIELD TOTAL			785,107	6			129,930,966
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL			8,618	1			88,032
UNDEFINED POOL			2,649	1			1,990,706
FIELD TOTAL			11,267	2			2,078,738
NORTH COOK INLET FIELD							
TERTIARY POOL		2,630	4,089,735	12		91,942	805,081,362
FIELD TOTAL		2,630	4,089,735	12		91,942	805,081,362
PRETTY CREEK FIELD							
UNDEFINED POOL		7	62,698	1		89	563,659
FIELD TOTAL		7	62,698	1		89	563,659
SOUTH BARROW FIELD							
UNDEFINED POOL		3	36,586	5		300	17,607,416
FIELD TOTAL		3	36,586	5		300	17,607,416
SWANSON RIVER FIELD							
UNDEFINED POOL			119,256	1			12,269,977
FIELD TOTAL			119,256	1			12,269,977
TRADING BAY FIELD							
UNDEFINED POOL			37,004	1			3,081,164
FIELD TOTAL			37,004	1			3,081,164
TOTAL ACTIVE FIELDS		23,832	14,579,221	101	11,877	840,327	3,077,095,806
DAILY AVERAGE		768	470,297	INACTIVE	0	45	9,696,530
				ALL FIELDS	11,877	840,372	3,086,792,336

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS FOR AUGUST, 1987

ENHANCED RECOVERY	OIL (BBL)	WATER (BBL)	GAS (MCF)	INJ. WELLS	CUM OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
ENDICOTT FIELD							
ENDICOTT POOL	1,583			1	19,267	1	
FIELD TOTAL	1,583*			1	19,267*	1	
GRANITE POINT FIELD							
MIDDLE KENAI POOL		333,460		12		128,039,022	
FIELD TOTAL		333,460		12		128,039,022	
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL		5,691,355	5,798,037	114		310,106,472	339,261,366
FIELD TOTAL		5,691,355	5,798,037	114		310,106,472	339,261,366
MCARTHUR RIVER FIELD							
HEMLOCK POOL		1,775,469		16		847,098,284	
MIDDLE KENAI G POOL		101,202		3		30,802,508	
FIELD TOTAL		1,876,671		19		877,900,792	
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL		59,249		2		25,909,174	
E F AND G POOL		367,677		13		224,725,680	
FIELD TOTAL		426,926		15		256,430,79[illegible]	
PRUDHOE BAY FIELD							
LISBURNE POOL		23,058	4,691,396	3		153,028	33,015,523
PRUDHOE POOL		43,079,268	91,269,166	132	13,012,875	1,355,177,322	6,565,522,418
FIELD TOTAL		43,102,326	95,960,562	135	13,012,875*	1,355,330,350	6,598,537,941
SWANSON RIVER FIELD							
HEMLOCK POOL			6,279,814	6		8,337,995	1,986,357,427
FIELD TOTAL			6,279,814	6		8,337,995	1,986,357,427
TOTAL ACTIVE FIELDS	1,583*	51,430,738	108,038,413	302	13,032,142*	2,936,145,425	8,924,156,734
DAILY AVERAGE	51	1,659,056	3,485,110	INACTIVE	0	127,512,325	743,988
				ALL FIELDS	13,032,142	3,063,657,750	8,924,900,722

DISPOSAL PROJECTS	FLUIDS (BBL)	DISP. WELLS	CUM FLUIDS (BBL)
BEAVER CREEK FIELD			
UNDEFINED ZONE	13,078	1	34,569
FIELD TOTAL	13,078	1	34,569
BELUGA RIVER FIELD			
UNDEFINED ZONE	497	1	497
FIELD TOTAL	497	1	497
ENDICOTT FIELD			
UNDEFINED ZONE	6,303	1	157,162
FIELD TOTAL	6,303	1	157,162
KENAI FIELD			
UNDEFINED ZONE	1,574	1	202,821
STERLING 4 POOL	9,432	1	41,059
FIELD TOTAL	11,006	2	243,880
KUPARUK RIVER FIELD			
KUPARUK RIVER POOL	30,063	2	227,512
FIELD TOTAL	30,063	2	2,361,734
PRUDHOE BAY FIELD			
UNDEFINED ZONE	2,258,711	7	117,788,085
FIELD TOTAL	2,258,711	7	117,788,085
SWANSON RIVER FIELD			
UNDEFINED ZONE	224,370	4	224,370
FIELD TOTAL	224,370	4	224,370
TOTAL ACTIVE FIELDS	2,544,028	18	120,810,297
DAILY AVERAGE	82,065	INACTIVE	0
		ALL FIELDS	120,810,297

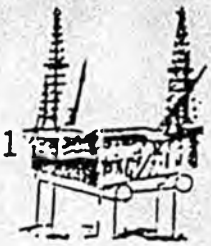
*FLUIDS RETURNED TO RESERVOIR, NOT ENHANCED RECOVERY



STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION





3001 PORCUPINE DRIVE ANCHORAGE, ALASKA 99501

Steve Cowper, Governor

BULLETIN

William W Barnwell, Commissioner

C V Chatterton, Commissioner
Chairman of Commission

Lonnie C Smith, Commissioner

NOVEMBER 1987

CONSERVATION ORDER NO. 234

Conservation Order No. 234 was issued October 30, 1987 to Union Oil Company of California. The order allows commingling of produced fluids from the Middle Kenai "G" and West Foreland Oil Pools in the McArthur River Field.

ADMINISTRATIVE APPROVAL NO. 44.40

Administrative Approval No. 44.40 was issued October 30, 1987 to Amoco Production Company. The Commission approved commingling production from the Middle Ground Shoal "BCD" and "EFG" Oil Pools in the MGS 17595 well No. 27.

ALASKA DRILLING STATISTICS FOR OCTOBER, 1987

* DRILLING PERMITS APPROVED * * *

ALASKA DRILLING STATISTICS FOR OCTOBER, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

ALASKA DRILLING STATISTICS FOR OCTOBER, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

ALASKA DRILLING STATISTICS FOR OCTOBER, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 11/04/87

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
COOK INLET BASIN					
ALASKAN CRUDE CORP	BURGLIN	31-1	50-133-20390-00	87-0070	07/31/87
ALASKAN CRUDE CORP	BURGLIN	BRX 22-1	50-283-20082-00	87-0084	08/24/87
AMOCO PRODUCTION CO	GRANITE PT ST 18742	13RD	50-133-20055-01	87-0044	04/28/87
AMOCO PRODUCTION CO	GRANITE POINT 18742	32RD	50-733-20298-01	87-0063	06/29/87
AMOCO PRODUCTION CO	GRANITE PT ST 18742	37	50-733-20394-00	87-0109	10/26/87
SHELL WESTERN E&P INC	MGS	A-23-1RD	50-733-20238-01	87-0093	09/16/87
UNION OIL CO OF CALIFORNIA	KENAI BELUGA UNIT	12X-8	50-133-20386-00	85-0298	12/20/85
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNI	4	50-133-20387-00	87-0034	04/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	G-36DPN	50-733-20216-00	87-0049	05/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY ST	A-26DPN	50-733-20230-00	85-0258	11/25/85
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-2	50-733-20389-00	87-0061	06/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-25	50-733-20391-00	87-0086	08/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-3	50-733-20392-00	87-0089	09/03/87
ARCTIC SLOPE					
ALASKAN CRUDE CORP	ACC	F-2	50-029-21315-00	85-0053	04/10/85
ALASKAN CRUDE CORP	ACC	F-3	50-029-21316-00	85-0054	04/10/85
AMERADA HESS CORP	COLVILLE DELTA 32	1	50-103-20055-00	85-0279	11/29/85
AMERADA HESS CORP	NORTHSTAR	3	50-629-21747-00	87-0088	08/31/87
ARCO ALASKA INC	W BEACH ST	1-A	50-029-20138-01	86-0056	03/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-11D	50-029-21181-00	87-0087	08/24/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-25	50-029-21525-00	86-0006	01/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-22	50-029-21531-00	86-0019	01/13/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS4-19	50-029-21533-00	86-0021	01/15/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-6	50-029-21548-00	86-0038	02/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-31	50-029-21551-00	86-0041	02/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-10	50-029-21563-00	86-0058	03/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-11	50-029-21564-00	86-0059	03/10/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS1-27	50-029-21591-00	86-0088	05/02/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3K-14	50-029-21631-00	86-0137	07/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	LGI-16	50-029-21643-00	86-0153	08/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-24	50-029-21670-00	86-0182	11/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-30	50-029-21673-00	86-0185	12/04/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-1	50-029-21687-00	87-0003	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-3	50-029-21689-00	87-0005	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-4	50-029-21690-00	87-0006	01/21/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-26	50-029-21691-00	87-0007	01/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-5	50-029-21706-00	87-0025	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-6	50-029-21707-00	87-0026	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-7	50-029-21708-00	87-0027	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-8	50-029-21709-00	87-0028	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-9	50-029-21710-00	87-0029	03/10/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-10	50-029-21715-00	87-0035	03/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-28	50-029-21717-00	87-0037	04/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-11	50-029-21718-00	87-0038	04/13/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-12	50-029-21719-00	87-0050	05/22/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-29	50-029-21724-00	87-0045	04/30/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-15	50-029-21727-00	87-0052	06/03/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 11/04/87

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-16	50-029-21728-00	87-0053	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-17	50-029-21729-00	87-0054	06/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-18	50-029-21730-00	87-0055	06/03/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-21	50-029-21732-00	87-0057	05/29/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-19	50-029-21737-00	87-0064	07/02/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-20	50-029-21738-00	87-0065	07/01/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-21	50-029-21739-00	87-0066	07/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-22	50-029-21740-00	87-0067	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-5	50-029-21742-00	87-0069	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-27	50-029-21744-00	87-0082	07/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-10	50-029-21746-00	87-0085	08/12/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-16	50-029-21749-00	87-0091	09/04/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-16	50-029-21754-00	87-0097	09/11/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-15	50-029-21755-00	87-0098	09/22/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-13	50-029-21756-00	87-0100	09/25/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-14	50-029-21758-00	87-0102	10/02/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-8	50-029-21761-00	87-0108	10/23/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-4	50-103-20076-00	87-0076	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-5	50-103-20077-00	87-0077	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-6	50-103-20078-00	87-0078	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-7	50-103-20079-00	87-0079	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-8	50-103-20080-00	87-0080	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-17	50-103-20081-00	87-0099	09/25/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-15	50-103-20082-00	87-0103	10/07/87
ARCO ALASKA INC	KUPARUK RIVER UNIT	3H-2	50-103-20083-00	87-0107	10/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-1	50-103-20084-00	87-0110	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-3	50-103-20085-00	87-0111	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-9	50-103-20086-00	87-0112	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-10	50-103-20087-00	87-0113	10/28/87
NORTH SLOPE BOROUGH	S BARROW	NSB-1	50-023-20020-00	87-0071	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-2	50-023-20021-00	87-0072	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-3	50-023-20022-00	87-0073	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-4	50-023-20023-00	87-0074	07/27/87
NORTH SLOPE BOROUGH	S BARROW	NSB-7	50-023-20024-00	87-0075	07/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-26	50-029-21487-00	85-0277	11/25/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-28	50-029-21510-00	85-0303	12/13/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	H-24	50-029-21512-00	85-0305	12/20/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	D-25	50-029-21522-00	85-0320	12/27/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	B-29	50-029-21523-00	86-0014	01/06/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	C-31	50-029-21552-00	86-0042	02/07/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	D-28	50-029-21556-00	86-0050	02/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-22	50-029-21558-00	86-0052	02/28/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	M-28	50-029-21578-00	86-0074	04/11/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	3-27/M33	50-029-21586-00	86-0083	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-23	50-029-21590-00	86-0087	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-24	50-029-21608-00	86-0113	06/10/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	S-19	50-029-21611-00	86-0116	06/13/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	G-30	50-029-21613-00	86-0118	06/17/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	G-31	50-029-21616-00	86-0121	06/19/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	1-47/Q21	50-029-21625-00	86-0131	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	F-29	50-029-21627-00	86-0133	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	G-32	50-029-21636-00	86-0146	07/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	S-20	50-029-21637-00	86-0147	07/28/86

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 11/04/87

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-14/O16	50-029-21639-00	86-0149	08/04/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-20/M35	50-029-21640-01	86-0173	10/10/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-23/N32	50-029-21645-00	86-0155	08/15/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-31	50-029-21647-00	86-0157	08/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-62/Q17	50-029-21648-00	86-0158	09/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-28	50-029-21649-00	86-0159	09/02/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-34/P14	50-029-21662-00	86-0172	10/09/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-21	50-029-21705-00	87-0024	03/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-26	50-029-21734-00	87-0059	06/11/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-9	50-029-21736-00	87-0062	06/26/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-29	50-029-21745-00	87-0083	08/06/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-37/P24	50-029-21748-00	87-0090	09/03/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-52/S14	50-029-21750-00	87-0092	09/04/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-15/K33	50-029-21751-00	87-0094	09/11/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-14	50-029-21752-00	87-0095	09/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-28	50-029-21753-00	87-0096	09/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-13	50-029-21757-00	87-0101	09/30/87
STANDARD ALASKA PRODUCTION CO	PRUHOE BAY UNIT K-12	50-029-21759-00	87-0104	10/15/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-27	50-029-21760-00	87-0105	10/15/87

NOVEMBER 1987

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR SEPTEMBER, 1987

OIL FIELDS	CRUDE OIL (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CRUDE OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL	22,127	114	6,296	2	3,450,775	18,183	1,410,559
FIELD TOTAL	22,127	114	6,296	2	3,450,775	18,183	1,410,559
ENDICOTT FIELD							
ENDICOTT POOL	2,198		68,339	2	31,875	2,132	779,952
FIELD TOTAL	2,198		68,339	2	31,875	2,132	779,952
GRANITE POINT FIELD							
MIDDLE KENAI POOL	209,945	86,453	187,772	28	106,173,262	7,320,485	91,720,114
FIELD TOTAL	209,945	86,453	187,772	28	106,176,026	7,320,485	91,721,704
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL	7,644,574	4,172,314	8,724,464	335	368,910,492	40,439,741	436,149,315
FIELD TOTAL	7,644,574	4,172,314	8,724,464	335	368,913,857	88,066,970	436,154,295
MCARTHUR RIVER FIELD							
HEMLOCK POOL	494,232	1,879,012	261,351	59	465,094,268	214,741,073	170,113,571
MIDDLE KENAI G POOL	73,586	56,528	55,861	11	35,780,075	4,085,403	17,820,069
WEST FORELAND POOL	25,163	40,542	7,311	4	19,039,047	4,878,184	5,425,466
FIELD TOTAL	592,981	1,976,082	324,523	74	519,913,390	223,704,660	193,359,106
MIDDLE GROUND SHOAL FIELD							
A POOL	5,069	1,242	5,735	1	1,985,226	1,110,902	4,340,228
B C AND D POOL	18,113	22,190	14,731	4	10,349,736	3,547,550	7,194,858
E F AND G POOL	189,169	269,465	72,935	36	140,100,561	66,656,874	64,892,234
FIELD TOTAL	212,351	292,897	93,401	41	152,435,523	71,315,326	76,427,320
PRUDHOE BAY FIELD							
LISBURNE POOL	1,372,481	177,621	5,963,017	38	17,186,469	1,246,656	56,454,721
PRUDHOE POOL	45,931,192*	18,033,463	96,937,294	653	5,346,124,544**	454,723,631	7,305,665,905
FIELD TOTAL	47,303,673*	18,211,084	102,900,311	691	5,363,311,013**	457,082,633	7,362,120,626
SWANSON RIVER FIELD							
HEMLOCK POOL	175,554	164,268	6,352,020	26	206,717,934	66,864,811	1,730,269,308
FIELD TOTAL	175,554	164,268	6,352,020	26	206,769,173	66,868,981	1,730,593,196
TRADING BAY FIELD							
HEMLOCK POOL	14,446	7,883	15,801	6	10,628,721	2,750,249	10,435,242
UNDEFINED POOL	440	206	1,451	1	558,800	97,834	287,123
MIDDLE KENAI B POOL	10,684	3,543	10,221	7	2,029,964	193,846	2,155,436
MIDDLE KENAI C POOL	13,806	19,672	27,045	5	18,497,115	16,710,026	12,060,484
MIDDLE KENAI D POOL	9,546	16,718	11,400	6	26,709,936	13,177,679	21,754,096
MIDDLE KENAI E POOL	5,600	9,089	6,142	4	7,470,426	2,801,621	6,352,503
G-NE/HEMLOCK-NE POOL	11,822	84,047	4,477	7	22,916,005	24,269,798	6,435,107
W FORELAND POOL	472		83	1	26,963	9,611	18,788
M.KENAI UNALLOCATED ZONE			133	1			1,091,192
FIELD TOTAL	66,816	141,158	76,753	38	88,837,930	60,010,664	60,589,971
TOTAL ACTIVE FIELDS	56,230,219	25,044,370	118,733,879	1,237	6,809,839,562	974,390,034	9,953,156,729
DAILY AVERAGE	1,874,340	834,812	3,957,795	INACTIVE	5,608,178	6,611,768	1,908,411
				ALL FIELDS	6,815,447,740	981,001,802	9,955,065,140

*INCLUDES 1,892,574 BBLS OF CONDENSATE
**INCLUDES 101,960,670 BBLS OF CONDENSATE

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR SEPTEMBER, 1987

NGL PRODUCTION	NGL (BBL)	CUM NGL (BBL)
KUPARUK RIVER		
KUPARUK RIVER	112,562	2,757,563
FIELD TOTAL	112,562	2,757,563
MCARTHUR RIVER		
HEMLOCK	3,758	7,817,028
MIDDLE KENAI G	2,485	752,654
WEST FORELAND	164	198,733
FIELD TOTAL	6,407	8,768,415
PRUDHOE BAY		
LISBURNE	70,795	243,630
PRUDHOE	1,449,404	11,831,170
FIELD TOTAL	1,520,199	12,074,800
SWANSON RIVER		
HEMLOCK	2,200	1,175,263
FIELD TOTAL	2,200	1,175,263
TRADING BAY		
HEMLOCK	5	51,646
M.KENAI UNALLOCATED	14	307,507
FIELD TOTAL	19	359,153
TOTAL ACTIVE FIELDS	1,641,387	25,135,194
DAILY AVERAGE	54,712	
INACTIVE		0
ALL FIELDS		25,135,194

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR SEPTEMBER, 1987

GAS FIELDS	CONDEN. (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CONDEN. (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL		7,361	725,954	4		273,430	59,723,864
FIELD TOTAL		7,361	725,954	4		273,430	59,723,864
BELUGA RIVER FIELD							
UNDEFINED POOL			2,243,837	14		810	246,933,458
FIELD TOTAL			2,243,837	14		810	246,933,458
EAST BARROW FIELD							
UNDEFINED POOL		18	55,224	4		705	3,789,328
FIELD TOTAL		18	55,224	4		705	3,789,328
KENAI FIELD							
STERLING 3 POOL		224	1,210,595	9		110,323	258,016,384
STERLING 4 POOL		58	1,291,331	12		84,838	361,838,048
STERLING 5.1 POOL		117	1,282,958	13		137,552	424,212,370
STERLING 6 POOL		138	1,369,304	11		42,242	391,505,061
UNDEFINED POOL		538	676,491	7		62,505	117,411,230
TYONEK POOL		263	360,879	4	11,877	31,608	208,236,919
FIELD TOTAL		1,338	6,191,558	56	11,877	481,768	1,805,252,447
MCARTHUR RIVER FIELD							
MIDDLE KENAI POOL			811,496	7			91,078,949
FIELD TOTAL			811,496	7			130,743,008
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL			5,040	1			93,072
UNDEFINED POOL			19,858	1			2,010,564
FIELD TOTAL			24,898	2			2,103,636
NORTH COOK INLET FIELD							
TERTIARY POOL		1,942	3,943,200	12		93,884	809,018,368
FIELD TOTAL		1,942	3,943,200	12		93,884	809,018,368
PRETTY CREEK FIELD							
UNDEFINED POOL		15	67,534	1		104	631,193
FIELD TOTAL		15	67,534	1		104	631,193
SOUTH BARROW FIELD							
UNDEFINED POOL		3	53,778	6		303	17,661,194
FIELD TOTAL		3	53,778	6		303	17,661,194
SWANSON RIVER FIELD							
UNDEFINED POOL			108,267	1			12,378,244
FIELD TOTAL			108,267	1			12,378,244
TRADING BAY FIELD							
UNDEFINED POOL			26,790	1			3,107,954
FIELD TOTAL			26,790	1			3,107,954
TOTAL ACTIVE FIELDS		10,677	14,252,536	108	11,877	851,004	3,091,342,694
DAILY AVERAGE		355	475,084	INACTIVE	0	45	9,696,530
				ALL FIELDS	11,877	851,049	3,101,039,224

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS FOR SEPTEMBER, 1987

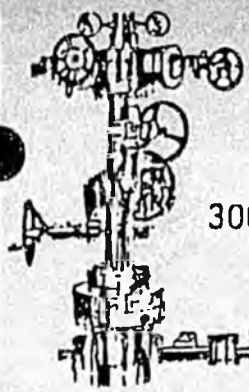
ENHANCED RECOVERY	OIL (BBL)	WATER (BBL)	GAS (MCF)	INJ. WELLS	CUM OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
ENDICOTT FIELD							
ENDICOTT POOL	1,769			1	21,036	1	
FIELD TOTAL	1,769*			1	21,036*	1	
GRANITE POINT FIELD							
MIDDLE KENAI POOL		329,823		12		128,368,845	
FIELD TOTAL		329,823		12		128,368,845	
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL		5,415,685	6,238,284	138		315,522,157	345,499,650
FIELD TOTAL		5,415,685	6,238,284	138		315,522,157	345,499,650
MCARTHUR RIVER FIELD							
HEMLOCK POOL		2,115,766		16		849,214,050	
MIDDLE KENAI G POOL		42,852		3		30,845,360	
FIELD TOTAL		2,158,618		19		880,059,410	
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL		50,491		2		25,959,665	
E F AND G POOL		347,882		13		225,073,562	
FIELD TOTAL		398,373		15		256,829,166	
PRUDHOE BAY FIELD							
LISBURNE POOL		110,948	5,361,651	3		263,976	38,377,174
PRUDHOE POOL		39,707,002	86,418,449	132	13,012,875	1,394,884,324	6,651,940,867
FIELD TOTAL		39,817,950	91,780,100	135	13,012,875*	1,395,148,300	6,690,318,041
SWANSON RIVER FIELD							
HEMLOCK POOL			6,585,896	6		8,337,995	1,992,943,323
FIELD TOTAL			6,585,896	6		8,337,995	1,992,943,323
TOTAL ACTIVE FIELDS	1,769*	48,120,449	104,604,280	326	13,033,911*	2,984,265,874	9,028,761,014
DAILY AVERAGE	58	1,604,014	3,486,809	INACTIVE	0	127,512,325	743,988
				ALL FIELDS	13,033,911	3,111,778,199	9,029,505,002

DISPOSAL PROJECTS	FLUIDS (BBL)	DISP. WELLS	CUM FLUIDS (BBL)
BEAVER CREEK FIELD			
UNDEFINED ZONE	2,452	1	37,021
FIELD TOTAL	2,452	1	37,021
BELUGA RIVER FIELD			
UNDEFINED ZONE	151	1	2,573
FIELD TOTAL	151	1	2,573
ENDICOTT FIELD			
UNDEFINED ZONE	8,866	1	166,028
FIELD TOTAL	8,866	1	166,028
KENAI FIELD			
UNDEFINED ZONE	1,574	1	204,395
STERLING 4 POOL	7,043	1	48,102
FIELD TOTAL	8,617	2	252,497
KUPARUK RIVER FIELD			
KUPARUK RIVER POOL	60,763	2	288,275
FIELD TOTAL	60,763	2	2,422,497
PRUDHOE BAY FIELD			
UNDEFINED ZONE	1,530,053	9	119,318,138
FIELD TOTAL	1,530,053	9	119,318,138
SWANSON RIVER FIELD			
UNDEFINED ZONE	207,512	4	1,165,914
FIELD TOTAL	207,512	4	1,165,914
TOTAL ACTIVE FIELDS	1,818,414	20	123,364,668
DAILY AVERAGE	60,613	INACTIVE	0
		ALL FIELDS	123,364,668

*FLUIDS RETURNED TO RESERVOIR, NOT ENHANCED RECOVERY

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 PORCUPINE DR ANCHORAGE, AK. 99501-3192

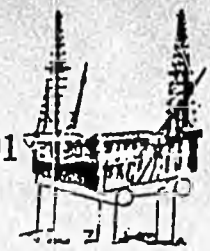
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STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION





3001 PORCUPINE DRIVE ANCHORAGE, ALASKA 99501

Steve Cowper, Governor

William W Barnwell, Commissioner

Chatterton, Commissioner
Chairman of Commission

Lonnie C Smith, Commissioner

BULLETIN

DECEMBER 1987

ENDICOTT FIELD PRODUCING

On October 2, 1987, fifty-one days after production facility modules were sealifted to the Endicott Field, Endicott oil began flowing down the 24-mile elevated pipeline which runs to Pump Station One at the beginning of the Trans-Alaska Pipeline. By November 1, 1987, 1,964,424 bbls of crude had been produced from the field. The project, which is located on two man-made gravel islands about 2½ miles offshore in the Beaufort Sea, was completed two months ahead of schedule.

ADMINISTRATIVE APPROVAL NO. 80.53

Administrative Approval No. 80.53 was issued on November 4, 1987 to Union Oil Company of California, operator of the Trading Bay Unit, authorizing the drilling, completion, and production of Trading Bay Unit well No. M-26 as part of the pressure maintenance project approved by Conservation Order No. 80 for the purpose of recovering additional oil.

ADMINISTRATIVE APPROVAL NO. 213.11

Administrative Approval No. 213.11 was issued to ARCO Alaska, Inc on November 16, 1987 waiving the requirement of Rule 11a of Conservation Order No. 165 for Prudhoe Bay Unit wells DS 18-9, DS 18-14, and DS 18-19. Rule 11a required that a spinner flow meter or a trace survey be run during the first six months that the well is on production. Since these wells are producing from a single interval, a productivity profile need not be filed until additional zones are perforated.

ADMINISTRATIVE APPROVAL NO. 207.9

Administrative Approval No. 207.9 was issued to ARCO Alaska, Inc on November 24, 1987 approving expansion of a pilot waterflood project in the Lisburne Oil Pool of the Prudhoe Bay Field. The pilot project is a necessary step for developing a prudent enhanced recovery method for the Lisburne Oil Pool.

ADMINISTRATIVE APPROVAL NO. 145-A.28

Administrative Approval No. 145-A.28 was issued on November 27, 1987 to ARCO Alaska, Inc permitting an additional 35MMSCF of gas to be flared at Flow Station No. 3, Prudhoe Bay Field. The additional flare volume is an operational necessity. It will be metered, and is subject to the Oil & Gas Properties Production Tax.

ALASKA DRILLING STATISTICS FOR NOVEMBER, 1987

* DRILLING PERMITS APPROVED * * *

ALASKA DRILLING STATISTICS FOR NOVEMBER, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

ALASKA DRILLING STATISTICS FOR NOVEMBER, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 12/03/87

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
COOK INLET BASIN					
ALASKAN CRUDE CORP	BURGLIN	31-1	50-133-20390-00	87-0070	07/31/87
ALASKAN CRUDE CORP	BURGLIN	BRX 22-1	50-283-20082-00	87-0084	08/24/87
AMOCO PRODUCTION CO	GRANITE POINT 18742	32RD	50-733-20298-01	87-0063	06/29/87
AMOCO PRODUCTION CO	GRANITE PT ST 18742	37	50-733-20394-00	87-0109	10/26/87
SHELL WESTERN E&P INC	MGS	A-23-1RD	50-733-20238-01	87-0093	09/16/87
UNION OIL CO OF CALIFORNIA	KENAI BELUGA UNIT	12X-8	50-133-20386-00	85-0298	12/20/85
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT	4	50-133-20387-00	87-0034	04/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	G-36DPN	50-733-20216-00	87-0049	05/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-2	50-733-20389-00	87-0061	06/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-25	50-733-20391-00	87-0086	08/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-3	50-733-20392-00	87-0089	09/03/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-26	50-733-20393-00	87-0106	11/04/87
ARCTIC SLOPE					
ALASKAN CRUDE CORP	ACC	F-2	50-029-21315-00	85-0053	04/10/85
ALASKAN CRUDE CORP	ACC	F-3	50-029-21316-00	85-0054	04/10/85
AMERADA HESS CORP	NORTHSTAR	3	50-629-21747-00	87-0088	08/31/87
ARCO ALASKA INC	W BEACH ST	1-A	50-029-20138-01	86-0056	03/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-11D	50-029-21181-00	87-0087	08/24/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-25	50-029-21525-00	86-0006	01/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-22	50-029-21531-00	86-0019	01/13/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS4-19	50-029-21533-00	86-0021	01/15/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-6	50-029-21548-00	86-0038	02/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-31	50-029-21551-00	86-0041	02/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-10	50-029-21563-00	86-0058	03/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-11	50-029-21564-00	86-0059	03/10/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS1-27	50-029-21591-00	86-0088	05/02/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3K-14	50-029-21631-00	86-0137	07/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	LGI-16	50-029-21643-00	86-0153	08/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-24	50-029-21670-00	86-0182	11/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-30	50-029-21673-00	86-0185	12/04/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-1	50-029-21687-00	87-0003	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-3	50-029-21689-00	87-0005	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-4	50-029-21690-00	87-0006	01/21/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-28	50-029-21691-00	87-0007	01/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-10	50-029-21715-00	87-0035	03/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-28	50-029-21717-00	87-0037	04/03/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-11	50-029-21718-00	87-0038	04/13/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-12	50-029-21719-00	87-0050	05/22/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-21	50-029-21732-00	87-0057	05/29/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-19	50-029-21737-00	87-0064	07/02/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-20	50-029-21738-00	87-0065	07/01/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-21	50-029-21739-00	87-0066	07/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-22	50-029-21740-00	87-0067	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-5	50-029-21742-00	87-0069	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-27	50-029-21744-00	87-0082	07/31/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 12/03/87

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-10	50-029-21746-00	87-0085	08/12/87
ARCO ALASKA INC	PRUDHOE BAY UNIT DS18-16	50-029-21749-00	87-0091	09/04/87
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-16	50-029-21754-00	87-0097	09/11/87
ARCO ALASKA INC	PRUDHOE BAY UNIT DS18-15	50-029-21755-00	87-0098	09/22/87
ARCO ALASKA INC	PRUDHOE BAY UNIT DS18-13	50-029-21756-00	87-0100	09/25/87
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-14	50-029-21758-00	87-0102	10/02/87
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-8	50-029-21761-00	87-0108	10/23/87
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-18	50-029-21766-00	87-0118	11/20/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-4	50-103-20076-00	87-0076	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-5	50-103-20077-00	87-0077	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-6	50-103-20078-00	87-0078	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-7	50-103-20079-00	87-0079	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-8	50-103-20080-00	87-0080	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-17	50-103-20081-00	87-0099	09/25/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-15	50-103-20082-00	87-0103	10/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-2	50-103-20083-00	87-0107	10/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-1	50-103-20084-00	87-0110	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-3	50-103-20085-00	87-0111	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-9	50-103-20086-00	87-0112	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-10	50-103-20087-00	87-0113	10/28/87
NORTH SLOPE BOROUGH	S BARROW NSB-1	50-023-20020-00	87-0071	07/27/87
NORTH SLOPE BOROUGH	S BARROW NSB-2	50-023-20021-00	87-0072	07/27/87
NORTH SLOPE BOROUGH	S BARROW NSB-3	50-023-20022-00	87-0073	07/27/87
NORTH SLOPE BOROUGH	S BARROW NSB-4	50-023-20023-00	87-0074	07/27/87
NORTH SLOPE BOROUGH	S BARROW NSB-7	50-023-20024-00	87-0075	07/27/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT B-28	50-029-21510-00	85-0303	12/13/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT H-24	50-029-21512-00	85-0305	12/20/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT D-25	50-029-21522-00	85-0320	12/27/85
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT B-29	50-029-21523-00	86-0014	01/06/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT C-31	50-029-21552-00	86-0042	02/07/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT D-28	50-029-21556-00	86-0050	02/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-22	50-029-21558-00	86-0052	02/28/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT M-28	50-029-21578-00	86-0074	04/11/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-27/M33	50-029-21586-00	86-0083	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-23	50-029-21590-00	86-0087	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-24	50-029-21608-00	86-0113	06/10/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-19	50-029-21611-00	86-0116	06/13/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-30	50-029-21613-00	86-0118	06/17/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-31	50-029-21616-00	86-0121	06/19/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-47/Q21	50-029-21625-00	86-0131	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-29	50-029-21627-00	86-0133	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-32	50-029-21636-00	86-0146	07/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-20	50-029-21637-00	86-0147	07/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-14/O16	50-029-21639-00	86-0149	08/04/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-20/M35	50-029-21640-01	86-0173	10/10/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-23/N32	50-029-21645-00	86-0155	08/15/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-31	50-029-21647-00	86-0157	08/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-62/Q17	50-029-21648-00	86-0158	09/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-28	50-029-21649-00	86-0159	09/02/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-34/P14	50-029-21662-00	86-0172	10/09/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-21	50-029-21705-00	87-0024	03/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-26	50-029-21734-00	87-0059	06/11/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 12/03/87

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-9	50-029-21736-00	87-0062	06/26/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-29	50-029-21745-00	87-0083	08/06/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-37/P24	50-029-21748-00	87-0090	09/03/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-52/S14	50-029-21750-00	87-0092	09/04/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-15/K33	50-029-21751-00	87-0094	09/11/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-28	50-029-21753-00	87-0096	09/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-13	50-029-21757-00	87-0101	09/30/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-12	50-029-21759-00	87-0104	10/15/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-27	50-029-21760-00	87-0105	10/15/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-10	50-029-21762-00	87-0114	11/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-23	50-029-21763-00	87-0115	11/05/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-39/J39	50-029-21764-00	87-0116	11/05/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-11	50-029-21765-00	87-0117	11/17/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-44/R12	50-029-21767-00	87-0119	11/23/87

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR OCTOBER, 1987

OIL FIELDS	CRUDE OIL (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CRUDE OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL	23,354	84	6,097	2	3,474,129	18,267	1,416,656
FIELD TOTAL	23,354	84	6,097	2	3,474,129	18,267	1,416,656
ENDICOTT FIELD							
ENDICOTT POOL	1,964,424	8,705	1,457,992	20	1,996,299	10,837	2,237,944
FIELD TOTAL	1,964,424	8,705	1,457,992	20	1,996,299	10,837	2,237,944
GRANITE POINT FIELD							
MIDDLE KENAI POOL	228,011	87,576	185,363	28	106,401,273	7,408,061	91,905,477
FIELD TOTAL	228,011	87,576	185,363	28	106,404,037	7,408,061	91,907,067
KUPARUK RIVER FIELD							
CRETACIOUS UNDEF ZONE		32,223		1		51,771,128	
KUPARUK RIVER POOL	8,458,790	2,573,984	10,399,076	331	377,369,282	38,902,049	446,548,391
FIELD TOTAL	8,458,790	2,606,207	10,399,076	332	377,372,647	90,673,177	446,553,371
MCARTHUR RIVER FIELD							
HEMLOCK POOL	478,693	1,723,515	207,913	59	465,572,961	216,464,588	170,321,484
MIDDLE KENAI G POOL	86,570	57,075	49,243	12	35,866,645	4,142,478	17,869,312
WEST FORELAND POOL	31,035	41,618	8,389	4	19,070,082	4,019,802	5,433,855
FIELD TOTAL	596,298	1,822,208	265,545	75	520,509,688	225,526,868	193,624,651
MIDDLE GROUND SHOAL FIELD							
A POOL	4,895	1,278	6,039	1	1,990,121	1,112,180	4,346,267
B C AND D POOL	17,864	22,119	12,202	4	10,367,600	3,569,669	7,207,060
E F AND G POOL	197,526	270,064	80,891	36	140,298,087	66,926,938	64,973,125
FIELD TOTAL	220,285	293,461	99,132	41	152,655,808	71,608,787	76,526,452
PRUDHOE BAY FIELD							
LISBURNE POOL	1,387,835	145,297	6,360,072	42	18,574,304	1,391,953	62,814,793
PRUDHOE POOL	48,436,227*	18,482,867	111,225,386	665	5,394,560,771**	473,206,498	7,416,891,291
FIELD TOTAL	49,824,062*	18,628,164	117,585,458	707	5,413,135,075**	475,710,797	7,479,706,084
SWANSON RIVER FIELD							
HEMLOCK POOL	170,892	147,737	6,688,149	27	206,888,826	67,012,548	1,736,957,457
FIELD TOTAL	170,892	147,737	6,688,149	27	206,940,065	67,016,718	1,737,281,345
TRADING BAY FIELD							
HEMLOCK POOL	15,367	8,397	14,900	6	10,644,088	2,758,646	10,450,142
UNDEFINED POOL	407	320	2,947	1	559,207	98,154	290,070
MIDDLE KENAI B POOL	10,853	3,363	8,744	6	2,040,817	197,209	2,164,180
MIDDLE KENAI C POOL	13,931	23,317	30,806	5	18,511,046	16,733,343	12,091,290
MIDDLE KENAI D POOL	10,927	18,206	12,464	6	26,720,863	13,195,885	21,766,560
MIDDLE KENAI E POOL	5,089	8,556	4,577	4	7,475,515	2,810,177	6,357,080
G-NE/HEMLOCK-NE POOL	18,213	139,262	7,327	6	22,934,218	24,409,060	6,442,434
W FORELAND POOL	840		147	1	27,803	9,611	18,935
M.KENAI UNALLOCATED ZONE			138	1			1,091,330
FIELD TOTAL	75,627	201,421	82,050	36	88,913,557	60,212,085	60,672,021
TOTAL ACTIVE FIELDS	61,561,743	23,705,563	136,768,862	1,268	6,871,401,305	998,185,597	10,089,925,591
DAILY AVERAGE	1,985,862	767,598	4,411,898	INACTIVE	5,608,178	6,611,768	1,908,411
				ALL FIELDS	6,877,009,483	1,004,797.365	10,091,834,002

*INCLUDES 2,232,284 BBLS OF CONDENSATE
**INCLUDES 104,192,954 BBLS OF CONDENSATE

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR OCTOBER, 1987

NGL PRODUCTION	NGL (BBL)	CUM NGL (BBL)
KUPARUK RIVER		
KUPARUK RIVER	108,070	2,865,633
FIELD TOTAL	108,070	2,865,633
MCARTHUR RIVER		
HEMLOCK	7,067	7,824,095
MIDDLE KENAI G	6,916	759,570
WEST FORELAND	454	199,187
FIELD TOTAL	14,437	8,782,852
PRUDHOE BAY		
LISBURNE	74,507	318,137
PRUDHOE	1,590,314	13,421,484
FIELD TOTAL	1,664,821	13,739,621
SWANSON RIVER		
HEMLOCK	2,626	1,177,889
FIELD TOTAL	2,626	1,177,889
TRADING BAY		
HEMLOCK	7	51,653
M.KENAI UNALLOCATED	18	307,525
FIELD TOTAL	25	359,178
TOTAL ACTIVE FIELDS	1,789,979	26,925,173
DAILY AVERAGE	57,741	
INACTIVE		0
ALL FIELDS		26,925,173

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR OCTOBER, 1987

GAS FIELDS	CONDEN. (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CONDEN. (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL		8,479	975,014	3		281,909	60,698,878
FIELD TOTAL		8,479	975,014	3		281,909	60,698,878
BELUGA RIVER FIELD							
UNDEFINED POOL			2,000,213	14		810	248,933,671
FIELD TOTAL			2,000,213	14		810	248,933,671
EAST BARROW FIELD							
UNDEFINED POOL		8	40,649	4		713	3,829,977
FIELD TOTAL		8	40,649	4		713	3,829,977
KENAI FIELD							
STERLING 3 POOL		69	1,591,746	9		110,392	259,608,130
STERLING 4 POOL		150	1,705,185	11		84,988	363,543,233
STERLING 5.1 POOL		190	1,678,127	12		137,742	425,890,497
STERLING 6 POOL		154	1,825,700	11		42,396	393,331,561
UNDEFINED POOL		862	835,208	7		63,367	118,246,438
TYONEK POOL		402	513,730	4	11,877	32,010	208,750,649
FIELD TOTAL		1,827	8,149,696	54	11,877	483,595	1,813,402,143
LEWIS RIVER FIELD							
UNDEFINED POOL		3	191,388	2		48	3,903,391
FIELD TOTAL		3	191,388	2		48	3,903,391
MCARTHUR RIVER FIELD							
MIDDLE KENAI POOL			1,160,786	7			95,591,511
FIELD TOTAL			1,160,786	7			131,903,794
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL			10,292	1			103,364
UNDEFINED POOL			13,900	1			2,024,464
FIELD TOTAL			24,192	2			2,127,828
NORTH COOK INLET FIELD							
TERTIARY POOL		2,154	3,951,721	12		96,038	812,970,089
FIELD TOTAL		2,154	3,951,721	12		96,038	812,970,089
PRETTY CREEK FIELD							
UNDEFINED POOL		10	67,308	1		114	698,501
FIELD TOTAL		10	67,308	1		114	698,501
SOUTH BARROW FIELD							
UNDEFINED POOL		2	50,000	5		305	17,711,194
FIELD TOTAL		2	50,000	5		305	17,711,194
SWANSON RIVER FIELD							
UNDEFINED POOL			106,779	1			12,485,023
FIELD TOTAL			106,779	1			12,485,023
TRADING BAY FIELD							
UNDEFINED POOL			36,917	1			3,144,871
FIELD TOTAL			36,917	1			3,144,871
TOTAL ACTIVE FIELDS		12,483	16,754,663	106	11,877	863,532	3,111,809,360
DAILY AVERAGE		402	540,473	INACTIVE	0	0	5,984,527
				ALL FIELDS	11,877	863,532	3,117,793,887

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS FOR OCTOBER, 1987

ENHANCED RECOVERY	OIL (BBL)	WATER (BBL)	GAS (MCF)	INJ. WELLS	CUM OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
ENDICOTT FIELD							
ENDICOTT POOL			448,055	2	21,036	1	448,055
FIELD TOTAL			448,055	2	21,036*	1	448,055
GRANITE POINT FIELD							
MIDDLE KENAI POOL		306,554		12		128,675,399	
FIELD TOTAL		306,554		12		128,675,399	
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL		13,891,875	7,619,995	193		329,414,032	353,119,645
FIELD TOTAL		13,891,875	7,619,995	193		329,414,032	353,119,645
MCARTHUR RIVER FIELD							
HEMLOCK POOL		2,483,045		16		851,697,095	
MIDDLE KENAI G POOL		131,223		3		30,976,583	
FIELD TOTAL		2,614,268		19		882,673,678	
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL		55,061		2		26,014,726	
E F AND G POOL		333,575		13		225,407,137	
FIELD TOTAL		388,636		15		257,217,802	
PRUDHOE BAY FIELD							
LISBURNE POOL		82,107	5,775,321	4		296,082	44,152,495
PRUDHOE POOL		37,849,437	99,543,462	130	13,012,875	1,432,733,761	6,751,484,329
FIELD TOTAL		37,931,544	105,318,783	134	13,012,875*	1,433,029,843	6,795,636,824
SWANSON RIVER FIELD							
HEMLOCK POOL			6,865,773	6		8,337,995	1,999,809,096
FIELD TOTAL			6,865,773	6		8,337,995	1,999,809,096
TOTAL ACTIVE FIELDS		55,132,877	120,252,606	381	13,033,911*	3,039,348,750	9,149,013,620
DAILY AVERAGE		1,778,479	3,879,116	INACTIVE	0	127,512,325	743,988
				ALL FIELDS	13,033,911*	3,166,861,075	9,149,757,608

DISPOSAL PROJECTS		FLUIDS (BBL)		DISP. WELLS		CUM FLUIDS (BBL)	
BEAVER CREEK FIELD							
UNDEFINED ZONE		313		1		37,334	
FIELD TOTAL		313		1		37,334	
BELUGA RIVER FIELD							
UNDEFINED ZONE		1,738		1		4,311	
FIELD TOTAL		1,738		1		4,311	
ENDICOTT FIELD							
UNDEFINED ZONE		9,788		1		175,816	
FIELD TOTAL		9,788		1		175,816	
KENAI FIELD							
UNDEFINED ZONE		1,827		1		206,222	
STERLING 4 POOL		8,079		1		56,181	
FIELD TOTAL		9,906		2		262,403	
KUPARUK RIVER FIELD							
CRETACIOUS UNDEF ZONE	329,678	1,127,176	341,798	11	329,678	3,549,673	341,798
FIELD TOTAL	329,678	1,127,176	341,798	11	329,678	3,549,673	341,798
PRUDHOE BAY FIELD							
UNDEFINED ZONE		1,514,244		9		120,832,382	
FIELD TOTAL		1,514,244		9		120,832,382	
SWANSON RIVER FIELD							
UNDEFINED ZONE		207,512		4		1,373,426	
FIELD TOTAL		207,512		4		1,373,426	
TOTAL ACTIVE FIELDS	329,678	2,870,677	341,798	29	329,678	126,235,345	341,798
DAILY AVERAGE		92,602		INACTIVE		0	
				ALL FIELDS		126,235,345	

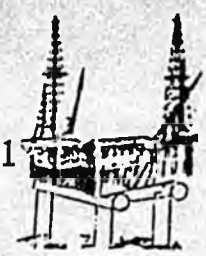
*FLUIDS RETURNED TO RESERVOIR, NOT ENHANCED RECOVERY



STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION





3001 PORCUPINE DRIVE ANCHORAGE, ALASKA 99501

Steve Cowper, Governor

William W Barnwell, Commissioner

C V Chatterton, Commissioner
Chairman of Commission

Lonnie C Smith, Commissioner

BULLETIN

JANUARY 1988

* N O T I C E *

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ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 PORCUPINE DRIVE
ANCHORAGE, AK 99501-3192

* * *

ENDICOTT PILOT WATERFLOOD

Standard Alaska Production Company made application for a pilot waterflood project in the Endicott Oil Pool. The pilot will consist of three or four injection wells and an expected injection volume of 30,000 to 40,000 barrels of water per day. Injection will be into the downdip areas of the 2A, 2B, and 3A zones beginning in January, 1988.

CORRECTION TO THE OCTOBER, 1987 PRODUCTION SUMMARY

Under "Disposal Projects", 329,678 barrels of oil and 341,798 MCF of gas were inadvertently reported as being injected into the Cretacious zone in the Kuparuk Field when, in fact, only the reported 1,127,176 barrels of water were injected. All other statistics for October are correct as reported.

NGPA DETERMINATIONS

In December, applications seeking category determination under the Natural Gas Policy Act (NGPA) of 1978 for six Prudhoe Bay Unit wells were acted upon. All six wells qualified as new onshore production wells under Section 103(c) of the NGPA. The natural gas produced from these wells qualifies for the maximum lawful price under Section 274.204 of the NGPA regulations.

The applications and the Commission's determinations have been forwarded to the Federal Energy Regulatory Commission for final consideration.

ALASKA DRILLING STATISTICS FOR DECEMBER, 1987

* DRILLING PERMITS APPROVED *

API NUMBER / PERMIT NUMBER / PERMIT APPROVED	OPERATOR NAME / SURFACE LOCATION / BOTTOM HOLE OBJECTIVE	WELL NAME AND NUMBER	CLASSIFICATION / GEOLOGIC AREA / FIELD AND POOL
50-029-21768-00 87-0120 11/30/87	ARCO ALASKA INC 1242FT FNL AND 146FT FEL, SEC 24, T11N, R014E, UM. 2330FT FNL AND 866FT FEL, SEC 23, T11N, R014E, UM.	PRUDHOE BAY UNIT DS18-17	DEVELOPMENT ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL
50-223-20016-00 87-0121 12/16/87	ARCO ALASKA INC 746FT FSL AND 2335FT FWL, SEC 33, T06N, R013E, UM. 746FT FSL AND 2335FT FWL, SEC 33, T06N, R013E, UM.	PIPELINE STATE 1	EXPLORATORY ARCTIC SLOPE
50-029-21769-00 87-0122 12/03/87	STANDARD ALASKA PRODUCTION CO 1786FT FNL AND 501FT FEL, SEC 06, T11N, R014E, UM. 1124FT FNL AND 1695FT FEL, SEC 07, T11N, R014E, UM.	PRUDHOE BAY UNIT E-24	DEVELOPMENT ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL
50-029-21770-00 87-0123 12/04/87	ARCO ALASKA INC 1157FT FNL AND 281FT FWL, SEC 12, T12N, R008E, UM. 1834FT FSL AND 1605FT FEL, SEC 01, T12N, R008E, UM.	KUPARUK RIV UNIT 3H-14	DEVELOPMENT ARCTIC SLOPE KUPARUK RIVER, KUPARUK RIVER OIL POOL
50-029-21771-00 87-0124 12/04/87	ARCO ALASKA INC 1232FT FNL AND 281FT FWL, SEC 12, T12N, R008E, UM. 1325FT FNL AND 1102FT FEL, SEC 12, T12N, R008E, UM.	KUPARUK RIV UNIT 3H-11	DEVELOPMENT ARCTIC SLOPE KUPARUK RIVER, KUPARUK RIVER OIL POOL
50-029-20056-01 87-0125 12/04/87	STANDARD ALASKA PRODUCTION CO 1800FT FNL AND 1067FT FEL, SEC 23, T11N, R013E, UM. 3165FT FNL AND 3868FT FEL, SEC 13, T11N, R013E, UM.	PRUDHOE BAY UNIT D-4A	DEVELOPMENT ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL
50-733-20395-00 87-0126 12/14/87	SHELL WESTERN E&P INC 619FT FSL AND 1550FT FEL, SEC 23, T08N, R013W, SM. 1300FT FSL AND 2155FT FWL, SEC 14, T08N, R013W, SM.	MGS C24A-14	DEVELOPMENT COOK INLET BASIN MIDDLE GROUND SHOAL, A OIL POOL
50-733-20396-00 87-0127 12/23/87	UNION OIL CO OF CALIFORNIA 188FT FSL AND 392FT FEL, SEC 07, T05N, R011W, SM. 188FT FSL AND 1858FT FWL, SEC 08, T05N, R011W, SM.	CANNERY LOOP UNIT 5	DEVELOPMENT COOK INLET BASIN KENAI
50-029-21772-00 87-0128 12/17/87	STANDARD ALASKA PRODUCTION CO 2703FT FNL AND 3093FT FEL, SEC 13, T11N, R013E, UM. 2683FT FNL AND 2803FT FEL, SEC 13, T11N, R013E, UM.	PRUDHOE BAY UNIT GC-1D	SERVICE ARCTIC SLOPE PRUDHOE BAY, UNDEFINED
50-103-20088-00 87-0129 12/17/87	ARCO ALASKA INC 1207FT FNL AND 281FT FWL, SEC 12, T12N, R008E, UM. 1473FT FSL AND 1264FT FWL, SEC 01, T12N, R008E, UM.	KUPARUK RIV UNIT 3H-12	DEVELOPMENT ARCTIC SLOPE KUPARUK RIVER, KUPARUK RIVER OIL POOL
50-103-20089-00 87-0130 12/17/87	ARCO ALASKA INC 1182FT FNL AND 281FT FWL, SEC 12, T12N, R008E, UM. 1465FT FSL AND 1413FT FEL, SEC 02, T12N, R008E, UM.	KUPARUK RIV UNIT 3H-13	DEVELOPMENT ARCTIC SLOPE KUPARUK RIVER, KUPARUK RIVER OIL POOL
50-029-21773-00 87-0131 12/22/87	STANDARD ALASKA PRODUCTION CO 1720FT FNL AND 501FT FWL, SEC 06, T11N, R014E, UM. 430FT FNL AND 3550FT FEL, SEC 07, T11N, R014E, UM.	PRUDHOE BAY UNIT E-25	DEVELOPMENT ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL

ALASKA DRILLING STATISTICS FOR DECEMBER, 1987

* DRILLING PERMITS APPROVED *

API NUMBER / PERMIT NUMBER / PERMIT APPROVED	OPERATOR NAME / SURFACE LOCATION / BOTTOM HOLE OBJECTIVE	WELL NAME AND NUMBER	CLASSIFICATION / GEOLOGIC AREA / FIELD AND POOL
50-029-21774-00 87-0132 12/22/87	STANDARD ALASKA PRODUCTION CO 1866FT FNL AND 4012FT FEL, SEC 16, T11N, R013E, UM. 2655FT FNL AND 3710FT FEL, SEC 16, T11N, R013E, UM.	PRUDHOE BAY UNIT GC-2C	SERVICE ARCTIC SLOPE PRUDHOE BAY, UNDEFINED
50-103-20090-00 87-0133 12/23/87	ARCO ALASKA INC 1032FT FNL AND 282FT FWL, SEC 12, T12N, R008E, UM. 1125FT FNL AND 1383FT FEL, SEC 02, T12N, R008E, UM.	KUPARUK RIV UNIT 3H-19	DEVELOPMENT ARCTIC SLOPE KUPARUK RIVER, KUPARUK RIVER OIL POOL
50-029-21775-00 87-0134 12/23/87	ARCO ALASKA INC 1007FT FNL AND 282FT FWL, SEC 12, T12N, R008E, UM. 1109FT FNL AND 1820FT FEL, SEC 01, T12N, R008E, UM.	KUPARUK RIV UNIT 3H-20	DEVELOPMENT ARCTIC SLOPE KUPARUK RIVER, KUPARUK RIVER OIL POOL
50-029-21776-00 87-0135 12/22/87	STANDARD ALASKA PRODUCTION CO 1461FT FNL AND 1454FT FEL, SEC 21, T11N, R012E, UM. 4757FT FNL AND 128FT FEL, SEC 21, T11N, R012E, UM.	PRUDHOE BAY UNIT W-40	DEVELOPMENT ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL
50-029-21777-00 87-0136 12/28/87	STANDARD ALASKA PRODUCTION CO 1616FT FNL AND 882FT FEL, SEC 19, T11N, R014E, UM. 2529FT FNL AND 4332FT FEL, SEC 20, T11N, R014E, UM.	PRUDHOE BAY UNIT C-30	DEVELOPMENT ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL
50-029-21778-00 87-0137 12/24/87	ARCO ALASKA INC 2085FT FSL AND 1164FT FWL, SEC 18, T11N, R015E, UM. 1221FT FNL AND 448FT FEL, SEC 08, T11N, R015E, UM.	PRUDHOE BAY UNIT L2-32	DEVELOPMENT ARCTIC SLOPE PRUDHOE BAY, LISBURNE OIL POOL

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS *

API NUMBER / PERMIT NUMBER / COMPLETION DATE	OPERATOR NAME / SURFACE LOCATION / BOTTOM HOLE LOCATION	WELL NAME AND NUMBER	CLASSIFICATION AND STATUS / GEOLOGIC AREA / FIELD AND POOL	TOTAL DEPTH / T.V. DEPTH
50-029-21487-00 85-0277 12/25/85	STANDARD ALASKA PRODUCTION CO 535FT FNL AND 1735FT FEL, SEC 21, T11N, R013E, UM. 2275FT FSL AND 1925FT FWL, SEC 16, T11N, R013E, UM.	PRUDHOE BAY UNIT H-26	DEVELOPMENT, 1-OIL ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL	10,075FT 9,242FT
50-023-20023-00 87-0074 05/02/87	NORTH SLOPE BOROUGH 2641FT FSL AND 2180FT FEL, SEC 05, T21N, R017W, UM. 2641FT FSL AND 2180FT FEL, SEC 05, T21N, R017W, UM.	S BARROW NSB-4	EXPLORATORY, SUSP ARCTIC SLOPE	2,295FT 2,295FT
50-023-20022-00 87-0073 05/14/87	NORTH SLOPE BOROUGH 1852FT FSL AND 701FT FWL, SEC 18, T21N, R017W, UM. 1852FT FSL AND 701FT FWL, SEC 18, T21N, R017W, UM.	S BARROW NSB-3	EXPLORATORY, SUSP ARCTIC SLOPE	2,424FT 2,424FT

ALASKA DRILLING STATISTICS FOR DECEMBER, 1987

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 01/05/88

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
GULF OF AK BASIN					
ALASKAN CRUDE CORP	KATALLA	KS-1	50-069-20002-00	85-0124	07/01/85
COOK INLET BASIN					
ALASKAN CRUDE CORP	BURGLIN	31-1	50-133-20390-00	87-0070	07/31/87
ALASKAN CRUDE CORP	BURGLIN	BRX 22-1	50-283-20082-00	87-0084	08/24/87
AMOCO PRODUCTION CO	GRANITE POINT 18742	32RD	50-733-20298-01	87-0063	06/29/87
AMOCO PRODUCTION CO	GRANITE PT ST 18742	37	50-733-20394-00	87-0109	10/26/87
SHELL WESTERN E&P INC	MGS	A-23-1RD	50-733-20238-01	87-0093	09/16/87
SHELL WESTERN E&P INC	MGS	C24A-14	50-733-20395-00	87-0126	12/14/87
UNION OIL CO OF CALIFORNIA	KENAI BELUGA UNIT	12X-8	50-133-20386-00	85-0298	12/20/85
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT	4	50-133-20387-00	87-0034	04/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	G-36DPN	50-733-20216-00	87-0049	05/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-2	50-733-20389-00	87-0061	06/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-25	50-733-20391-00	87-0086	08/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-3	50-733-20392-00	87-0089	09/03/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-26	50-733-20393-00	87-0106	11/04/87
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT	5	50-733-20396-00	87-0127	12/23/87
ARCTIC SLOPE					
ALASKAN CRUDE CORP	ACC	F-2	50-029-21315-00	85-0053	04/10/85
ALASKAN CRUDE CORP	ACC	F-3	50-029-21316-00	85-0054	04/10/85
AMERADA HESS CORP	NORTHSTAR	3	50-629-21747-00	87-0088	08/31/87
ARCO ALASKA INC	W BEACH ST	1-A	50-029-20138-01	86-0056	03/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-11D	50-029-21181-00	87-0087	08/24/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-25	50-029-21525-00	86-0006	01/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-22	50-029-21531-00	86-0019	01/13/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS4-19	50-029-21533-00	86-0021	01/15/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-6	50-029-21548-00	86-0038	02/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-31	50-029-21551-00	86-0041	02/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-10	50-029-21563-00	86-0058	03/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-11	50-029-21564-00	86-0059	03/10/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS1-27	50-029-21591-00	86-0088	05/02/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3K-14	50-029-21631-00	86-0137	07/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	LGI-16	50-029-21643-00	86-0153	08/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-24	50-029-21670-00	86-0182	11/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-30	50-029-21673-00	86-0185	12/04/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-1	50-029-21687-00	87-0003	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-3	50-029-21689-00	87-0005	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-4	50-029-21690-00	87-0006	01/21/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-28	50-029-21691-00	87-0007	01/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-12	50-029-21719-00	87-0050	05/22/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-19	50-029-21737-00	87-0064	07/02/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-20	50-029-21738-00	87-0065	07/01/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-21	50-029-21739-00	87-0066	07/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-22	50-029-21740-00	87-0067	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-5	50-029-21742-00	87-0069	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-27	50-029-21744-00	87-0082	07/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-16	50-029-21749-00	87-0091	09/04/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-16	50-029-21754-00	87-0097	09/11/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-15	50-029-21755-00	87-0098	09/22/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-13	50-029-21756-00	87-0100	09/25/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 01/05/88

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-14	50-029-21758-00	87-0102	10/02/87
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-8	50-029-21761-00	87-0108	10/23/87
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-18	50-029-21766-00	87-0118	11/20/87
ARCO ALASKA INC	PRUDHOE BAY UNIT DS18-17	50-029-21768-00	87-0120	11/30/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-14	50-029-21770-00	87-0123	12/04/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-11	50-029-21771-00	87-0124	12/04/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-20	50-029-21775-00	87-0134	12/23/87
ARCO ALASKA INC	PRUDHOE BAY UNIT L2-32	50-029-21778-00	87-0137	12/24/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-4	50-103-20076-00	87-0076	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-5	50-103-20077-00	87-0077	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-6	50-103-20078-00	87-0078	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-7	50-103-20079-00	87-0079	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-8	50-103-20080-00	87-0080	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-17	50-103-20081-00	87-0099	09/25/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-15	50-103-20082-00	87-0103	10/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-2	50-103-20083-00	87-0107	10/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-1	50-103-20084-00	87-0110	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-3	50-103-20085-00	87-0111	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-9	50-103-20086-00	87-0112	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-10	50-103-20087-00	87-0113	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-12	50-103-20088-00	87-0129	12/17/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-13	50-103-20089-00	87-0130	12/17/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-19	50-103-20090-00	87-0133	12/23/87
ARCO ALASKA INC	PIPELINE STATE 1	50-223-20016-00	87-0121	12/16/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT D-4A	50-029-20056-01	87-0125	12/04/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT B-29	50-029-21523-00	86-0014	01/06/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT C-31	50-029-21552-00	86-0042	02/07/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT D-28	50-029-21556-00	86-0050	02/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-22	50-029-21558-00	86-0052	02/28/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT M-28	50-029-21578-00	86-0074	04/11/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-27/M33	50-029-21586-00	86-0083	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-23	50-029-21590-00	86-0087	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-24	50-029-21608-00	86-0113	06/10/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-19	50-029-21611-00	86-0116	06/13/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-30	50-029-21613-00	86-0118	06/17/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-31	50-029-21616-00	86-0121	06/19/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-47/Q21	50-029-21625-00	86-0131	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-29	50-029-21627-00	86-0133	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-32	50-029-21636-00	86-0146	07/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-20	50-029-21637-00	86-0147	07/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-14/O16	50-029-21639-00	86-0149	08/04/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-20/M35	50-029-21640-01	86-0173	10/10/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-23/N32	50-029-21645-00	86-0155	08/15/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-31	50-029-21647-00	86-0157	08/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-62/Q17	50-029-21648-00	86-0158	09/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-28	50-029-21649-00	86-0159	09/02/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-34/P14	50-029-21662-00	86-0172	10/09/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-21	50-029-21705-00	87-0024	03/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-26	50-029-21734-00	87-0059	06/11/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-9	50-029-21736-00	87-0062	06/26/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 01/05/88

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-29	50-029-21745-00	87-0083	08/06/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-37/P24	50-029-21748-00	87-0090	09/03/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-52/S14	50-029-21750-00	87-0092	09/04/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-15/K33	50-029-21751-00	87-0094	09/11/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-28	50-029-21753-00	87-0096	09/09/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-13	50-029-21757-00	87-0101	09/30/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-12	50-029-21759-00	87-0104	10/15/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-27	50-029-21760-00	87-0105	10/15/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-10	50-029-21762-00	87-0114	11/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-23	50-029-21763-00	87-0115	11/05/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-39/J39	50-029-21764-00	87-0116	11/05/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-11	50-029-21765-00	87-0117	11/17/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-44/R12	50-029-21767-00	87-0119	11/23/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-24	50-029-21769-00	87-0122	12/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT GC-1D	50-029-21772-00	87-0128	12/17/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-25	50-029-21773-00	87-0131	12/22/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT GC-2C	50-029-21774-00	87-0132	12/22/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT W-40	50-029-21776-00	87-0135	12/22/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT C-30	50-029-21777-00	87-0136	12/28/87

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR NOVEMBER, 1987

OIL FIELDS	CRUDE OIL (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CRUDE OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL	25,990	156	7,147	2	3,500,119	18,423	1,423,803
FIELD TOTAL	25,990	156	7,147	2	3,500,119	18,423	1,423,803
ENDICOTT FIELD							
ENDICOTT POOL	3,361,738	24,086	3,011,900	20	5,358,037	34,923	5,249,844
FIELD TOTAL	3,361,738	24,086	3,011,900	20	5,358,037	34,923	5,249,844
GRANITE POINT FIELD							
MIDDLE KENAI POOL	218,051	86,549	186,870	28	106,619,324	7,494,610	92,092,347
FIELD TOTAL	218,051	86,549	186,870	28	106,622,088	7,494,610	92,093,937
KUPARUK RIVER FIELD							
CRETACIOUS UNDEF ZONE		1,000,397		7		53,883,766	
KUPARUK RIVER POOL	8,548,419	2,780,392	11,196,708	330	385,917,701	41,682,441	457,745,099
FIELD TOTAL	8,548,419	3,780,789	11,196,708	337	385,921,066	95,566,207	457,750,079
MCARTHUR RIVER FIELD							
HEMLOCK POOL	487,960	1,863,735	207,819	58	466,060,921	218,328,323	170,529,303
MIDDLE KENAI G POOL	79,498	49,771	36,625	11	35,946,143	4,192,249	17,905,937
WEST FORELAND POOL	27,748	39,448	7,918	4	19,097,830	4,959,250	5,441,773
FIELD TOTAL	595,206	1,952,954	252,362	73	521,104,894	227,479,822	193,877,013
MIDDLE GROUND SHOAL FIELD							
A POOL	5,301	1,940	6,657	1	1,995,422	1,114,120	4,352,924
B C AND D POOL	14,370	23,320	9,192	4	10,381,970	3,592,989	7,216,552
E F AND G POOL	187,858	260,886	79,266	36	140,485,945	67,187,824	65,052,391
FIELD TOTAL	207,529	286,146	95,415	41	152,863,337	71,894,933	76,621,867
PRUDHOE BAY FIELD							
LISBURNE POOL	1,414,989	168,456	6,621,713	45	19,989,293	1,560,409	69,436,506
PRUDHOE POOL	47,418,098*	19,159,325	114,146,987	674	5,441,978,869**	492,365,823	7,531,038,278
FIELD TOTAL	48,833,087*	19,327,781	120,768,700	719	5,461,968,162**	495,038,578	7,600,474,784
SWANSON RIVER FIELD							
HEMLOCK POOL	177,558	175,961	7,092,330	27	207,066,384	67,188,509	1,744,049,787
FIELD TOTAL	177,558	175,961	7,092,330	27	207,117,623	67,192,679	1,744,373,675
TRADING BAY FIELD							
HEMLOCK POOL	13,659	8,823	17,184	6	10,657,747	2,767,469	10,467,326
UNDEFINED POOL	719	415	2,923	1	559,926	98,569	292,993
MIDDLE KENAI B POOL	12,291	3,583	11,390	8	2,053,108	200,792	2,175,570
MIDDLE KENAI C POOL	12,348	24,551	29,803	5	18,523,394	16,757,894	12,121,093
MIDDLE KENAI D POOL	12,054	18,642	9,761	6	26,732,917	13,214,527	21,776,321
MIDDLE KENAI E POOL	4,595	9,940	5,020	4	7,480,110	2,820,117	6,362,100
G-NE/HEMLOCK-NE POOL	16,265	139,744	6,861	6	22,950,483	24,548,804	6,449,295
W FORELAND POOL	787		138	1	28,590	9,611	19,073
M.KENAI UNALLOCATED ZONE			143	1			1,091,473
FIELD TOTAL	72,718	205,698	83,223	38	88,986,275	60,417,783	60,755,244
TOTAL ACTIVE FIELDS	62,040,296	25,840,120	142,694,655	1,285	6,933,441,601	1,025,137,958	10,232,620,246
DAILY AVERAGE	2,068,009	861,337	4,756,488	INACTIVE	5,608,178	6,611,768	1,908,411
				ALL FIELDS	6,939,049,779	1,031,749,726	10,234,528,657

*INCLUDES 2,407,030 BBLS OF CONDENSATE
**INCLUDES 106,599,984 BBLS OF CONDENSATE

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR NOVEMBER, 1987

NGL PRODUCTION	NGL (BBL)	CUM NGL (BBL)
KUPARUK RIVER		
KUPARUK RIVER	111,913	2,977,546
FIELD TOTAL	111,913	2,977,546
MCARTHUR RIVER		
HEMLOCK	13,456	7,837,551
MIDDLE KENAI G	3,484	763,054
WEST FORELAND	893	200,080
FIELD TOTAL	17,833	8,800,685
PRUDHOE BAY		
LISBURNE	71,331	389,4[illegible]
PRUDHOE	1,618,756	15,040,[illegible]
FIELD TOTAL	1,690,087	15,429,708
SWANSON RIVER		
HEMLOCK	2,915	1,180,804
FIELD TOTAL	2,915	1,180,804
TRADING BAY		
HEMLOCK	10	51,663
M.KENAI UNALLOCATED	34	307,559
FIELD TOTAL	44	359,222
TOTAL ACTIVE FIELDS	1,822,792	28,747,965
DAILY AVERAGE	60,759	
	INACTIVE	0
	ALL FIELDS	28,747,965

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR NOVEMBER, 1987

GAS FIELDS	CONDEN. (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CONDEN. (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL		6,733	991,182	4		288,642	61,690,060
FIELD TOTAL		6,733	991,182	4		288,642	61,690,060
BELUGA RIVER FIELD							
UNDEFINED POOL			1,947,335	13		810	250,881,006
FIELD TOTAL			1,947,335	13		810	250,881,006
EAST BARROW FIELD							
UNDEFINED POOL		355	48,746	4		1,068	3,878,723
FIELD TOTAL		355	48,746	4		1,068	3,878,723
KENAI FIELD							
STERLING 3 POOL		37	1,714,616	9		110,429	261,322,746
STERLING 4 POOL		270	1,845,500	11		85,258	365,388,733
STERLING 5.1 POOL		40	1,687,886	10		137,782	427,578,383
STERLING 6 POOL		297	1,999,064	11		42,693	395,330,625
UNDEFINED POOL		1,340	921,363	7		64,707	119,167,801
TYONEK POOL		361	507,693	4	11,877	32,371	209,258,342
FIELD TOTAL		2,345	8,676,122	52	11,877	485,940	1,822,078,265
LEWIS RIVER FIELD							
UNDEFINED POOL		60	114,815	2		108	4,018,206
FIELD TOTAL		60	114,815	2		108	4,018,206
MCARTHUR RIVER FIELD							
MIDDLE KENAI POOL			827,296	6			96,418,807
FIELD TOTAL			827,296	6			132,731,090
MIDDLE GROUND SHOAL FIELD							
UNDEFINED POOL			19,858	1			2,044,322
FIELD TOTAL			19,858	1			2,147,686
NORTH COOK INLET FIELD							
TERTIARY POOL		1,943	3,742,856	12		97,981	816,712,945
FIELD TOTAL		1,943	3,742,856	12		97,981	816,712,945
PRETTY CREEK FIELD							
UNDEFINED POOL		4	70,377	1		118	768,878
FIELD TOTAL		4	70,377	1		118	768,878
SOUTH BARROW FIELD							
UNDEFINED POOL		3	55,529	6		308	17,766,723
FIELD TOTAL		3	55,529	6		308	17,766,723
SWANSON RIVER FIELD							
UNDEFINED POOL			93,697	1			12,578,720
FIELD TOTAL			93,697	1			12,578,720
TRADING BAY FIELD							
UNDEFINED POOL			33,625	1			3,178,496
FIELD TOTAL			33,625	1			3,178,496
TOTAL ACTIVE FIELDS		11,443	16,621,438	103	11,877	874,975	3,128,430,798
DAILY AVERAGE		381	554,047	INACTIVE	0	0	5,984,527
				ALL FIELDS	11,877	874,975	3,134,415,325

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS FOR NOVEMBER, 1987

ENHANCED RECOVERY	OIL (BBL)	WATER (BBL)	GAS (MCF)	INJ. WELLS	CUM OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
ENDICOTT FIELD							
ENDICOTT POOL			2,562,807	2	21,036	1	3,010,862
FIELD TOTAL			2,562,807	2	21,036*	1	3,010,862
GRANITE POINT FIELD							
MIDDLE KENAI POOL		333,200		12		129,008,599	
FIELD TOTAL		333,200		12		129,008,599	
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL		19,741,373	8,056,914	209		349,155,405	361,176,559
FIELD TOTAL		19,741,373	8,056,914	209		349,155,405	361,176,559
MCARTHUR RIVER FIELD							
HEMLOCK POOL		2,787,909		16		854,485,004	
MIDDLE KENAI G POOL		127,897		3		31,104,480	
FIELD TOTAL		2,915,806		19		885,589,484	
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL		51,850		2		26,066,576	
E F AND G POOL		385,012		13		225,792,149	
FIELD TOTAL		436,862		15		257,654,664	
PRUDHOE BAY FIELD							
LISBURNE POOL		41,544	6,036,943	4		337,626	50,189,438
PRUDHOE POOL		37,969,509	102,353,497	129	13,012,875	1,470,703,270	6,853,837,826
FIELD TOTAL		38,011,053	108,390,440	133	13,012,875*	1,471,040,896	6,904,027,264
SWANSON RIVER FIELD							
HEMLOCK POOL			7,339,836	7		8,337,995	2,007,148,932
FIELD TOTAL			7,339,836	7		8,337,995	2,007,148,932
TOTAL ACTIVE FIELDS		61,438,294	126,349,997	397	13,033,911	3,100,787,044	9,275,363,617
DAILY AVERAGE		2,047,943	4,211,666	INACTIVE	0	127,512,325	743,988
				ALL FIELDS	13,033,911*	3,228,299,369	9,276,107,605

DISPOSAL PROJECTS	FLUIDS (BBL)	DISP. WELLS	CUM FLUIDS (BBL)
BELUGA RIVER FIELD			
UNDEFINED ZONE	1,830	1	6,141
FIELD TOTAL	1,830	1	6,141
ENDICOTT FIELD			
UNDEFINED ZONE	19,678	1	195,494
FIELD TOTAL	19,678	1	195,494
KENAI FIELD			
UNDEFINED ZONE	2,465	1	208,687
STERLING 4 POOL	11,093	1	67,274
FIELD TOTAL	13,558	2	275,961
KUPARUK RIVER FIELD			
CRETACIOUS UNDEF ZONE	35,988	2	2,473,420
FIELD TOTAL	35,988	2	2,473,420
PRUDHOE BAY FIELD			
UNDEFINED ZONE	1,623,898	10	122,456,280
FIELD TOTAL	1,623,898	10	122,456,280
SWANSON RIVER FIELD			
UNDEFINED ZONE	170,274	3	1,543,700
FIELD TOTAL	170,274	3	1,543,700
TOTAL ACTIVE FIELDS	1,865,226	19	126,950,996
DAILY AVERAGE	62,174	INACTIVE	37,334
		ALL FIELDS	126,988,330

*FLUIDS RETURNED TO RESERVOIR, NOT ENHANCED RECOVERY

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 PORCUPINE DR ANCHORAGE, AK. 99501-3192

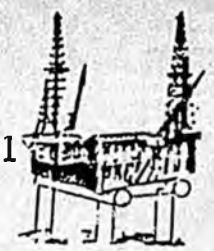
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PERMIT NO. 356



STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION





3001 PORCUPINE DRIVE ANCHORAGE, ALASKA 99501

Steve Cowper, Governor

William W Barnwell, Commissioner

C V Chatterton, Commissioner
Chairman of Commission

Lonnie C Smith, Commissioner

BULLETIN

FEBRUARY 1988

ADMINISTRATIVE APPROVAL NO. 213.12

Administrative Approval No. 213.12 was issued to ARCO Alaska, Inc on January 25, 1988 waiving the requirement (Rule 11a, CO 165) that productivity profiles be run in the single zone completed DS 4-20, DS 4-23, and DS 4-29 wells, Prudhoe Bay Oil Pool.

ADMINISTRATIVE APPROVAL NO. 120.31

Administrative Approval No. 120.31 was issued to Marathon Oil Company on January 21, 1988 approving 10 days of excess flaring in the first calendar quarter of 1988 in addition to the 15 days allowed by Conservation Order No. 120. This additional time is necessary to allow the operator to locate, analyze, and correct problems in the emergency flare system.

ALASKA DRILLING STATISTICS FOR JANUARY, 1988

* DRILLING PERMITS APPROVED * * *

ALASKA DRILLING STATISTICS FOR JANUARY, 1988

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

ALASKA DRILLING STATISTICS FOR JANUARY, 1988

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS *

API NUMBER / PERMIT NUMBER / COMPLETION DATE	OPERATOR NAME / SURFACE LOCATION / BOTTOM HOLE LOCATION	WELL NAME AND NUMBER	CLASSIFICATION AND STATUS / GEOLOGIC AREA / FIELD AND POOL	TOTAL DEPTH / T.V. DEPTH
50-029-21758-00 87-0102 11/26/87	ARCO ALASKA INC 1556FT FSL AND 1272FT FWL, SEC 18, T11N, R015E, UM. 1273FT FSL AND 3965FT FWL, SEC 18, T11N, R015E, UM.	PRUDHOE BAY UNIT L2-14	DEVELOPMENT, 1-OIL ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL	9,976FT 9,275FT
50-029-21736-00 87-0062 12/02/87	STANDARD ALASKA PRODUCTION CO 2113FT FNL AND 4787FT FEL, SEC 04, T11N, R014E, UM. 4030FT FNL AND 2287FT FEL, SEC 05, T11N, R014E, UM.	PRUDHOE BAY UNIT K-9	DEVELOPMENT, 1-OIL ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL	9,975FT 9,071FT
50-029-21751-00 87-0094 12/03/87	STANDARD ALASKA PRODUCTION CO 2526FT FNL AND 807FT FEL, SEC 08, T11N, R017E, UM. 325FT FNL AND 3007FT FEL, SEC 04, T11N, R017E, UM.	DUCK IS UNIT SDI 3-15/K33	DEVELOPMENT, 1-OIL ARCTIC SLOPE ENDICOTT, ENDICOTT OIL POOL	14,640FT 10,180FT
50-029-21745-00 87-0083 12/15/87	STANDARD ALASKA PRODUCTION CO 1668FT FNL AND 883FT FEL, SEC 06, T11N, R014E, UM. 4550FT FNL AND 2463FT FEL, SEC 36, T12N, R013E, UM.	PRUDHOE BAY UNIT E-29	DEVELOPMENT, 1-OIL ARCTIC SLOPE PRUDHOE BAY, PRUDHOE OIL POOL	12,545FT 9,184FT

NOTE: CORRECTED API NUMBER FOR THE FOLLOWING WELLS

KUPARUK RIV UNIT	3H-11	103-20091-0
KUPARUK RIV UNIT	3H-14	103-20092-0
KUPARUK RIV UNIT	3H-20	103-20093-0

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 02/08/88

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
GULF OF AK BASIN					
ALASKAN CRUDE CORP	KATALLA	KS-1	50-069-20002-00	85-0124	07/01/85
COOK INLET BASIN					
ALASKAN CRUDE CORP	BURGLIN	31-1	50-133-20390-00	87-0070	07/31/87
ALASKAN CRUDE CORP	BURGLIN	BRX 22-1	50-283-20082-00	87-0084	08/24/87
AMOCO PRODUCTION CO	GRANITE POINT 18742	32RD	50-733-20298-01	87-0063	06/29/87
AMOCO PRODUCTION CO	GRANITE PT ST 18742	37	50-733-20394-00	87-0109	10/26/87
SHELL WESTERN E&P INC	MGS	A-23-1RD	50-733-20238-01	87-0093	09/16/87
SHELL WESTERN E&P INC	MGS	C24A-14	50-733-20395-00	87-0126	12/14/87
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT	4	50-133-20387-00	87-0034	04/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	G-36DPN	50-733-20216-00	87-0049	05/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-25	50-733-20391-00	87-0086	08/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-3	50-733-20392-00	87-0089	09/03/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-26	50-733-20393-00	87-0106	11/04/87
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT	5	50-733-20396-00	87-0127	12/23/87
ARCTIC SLOPE					
ALASKAN CRUDE CORP	ACC	F-2	50-029-21315-00	85-0053	04/10/85
ALASKAN CRUDE CORP	ACC	F-3	50-029-21316-00	85-0054	04/10/85
AMERADA HESS CORP	NORTHSTAR	3	50-629-21747-00	87-0088	08/31/87
ARCO ALASKA INC	W BEACH ST	1-A	50-029-20138-01	86-0056	03/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-11D	50-029-21181-00	87-0087	08/24/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-6	50-029-21548-00	86-0038	02/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS16-31	50-029-21551-00	86-0041	02/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-10	50-029-21563-00	86-0058	03/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-11	50-029-21564-00	86-0059	03/10/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS1-27	50-029-21591-00	86-0088	05/02/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3K-14	50-029-21631-00	86-0137	07/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	LGI-16	50-029-21643-00	86-0153	08/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-24	50-029-21670-00	86-0182	11/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-30	50-029-21673-00	86-0185	12/04/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-1	50-029-21687-00	87-0003	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-3	50-029-21689-00	87-0005	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-4	50-029-21690-00	87-0006	01/21/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-28	50-029-21691-00	87-0007	01/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-12	50-029-21719-00	87-0050	05/22/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-21	50-029-21739-00	87-0066	07/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-22	50-029-21740-00	87-0067	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L5-5	50-029-21742-00	87-0069	07/07/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-27	50-029-21744-00	87-0082	07/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-16	50-029-21749-00	87-0091	09/04/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-13	50-029-21756-00	87-0100	09/25/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-8	50-029-21761-00	87-0108	10/23/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-18	50-029-21766-00	87-0118	11/20/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-17	50-029-21768-00	87-0120	11/30/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-28	50-029-21770-00	88-0003	01/14/88
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-32	50-029-21778-00	87-0137	12/24/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 02/08/88

OPERATOR NAME	WELL NAME AND NUMBER	API NUMBER	PERMIT	APPROVED
ARCO ALASKA INC	PT. MCINTYRE 3	50-029-21779-00	88-0005	01/15/88
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-4	50-103-20076-00	87-0076	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-5	50-103-20077-00	87-0077	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-6	50-103-20078-00	87-0078	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-7	50-103-20079-00	87-0079	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-8	50-103-20080-00	87-0080	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-17	50-103-20081-00	87-0099	09/25/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-15	50-103-20082-00	87-0103	10/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-2	50-103-20083-00	87-0107	10/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-1	50-103-20084-00	87-0110	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-3	50-103-20085-00	87-0111	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-9	50-103-20086-00	87-0112	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-10	50-103-20087-00	87-0113	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-12	50-103-20088-00	87-0129	12/17/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-13	50-103-20089-00	87-0130	12/17/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-19	50-103-20090-00	87-0133	12/23/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-11	50-103-20091-00	87-0124	12/04/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-14	50-103-20092-00	87-0123	12/04/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-20	50-103-20093-00	87-0134	12/23/87
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-21	50-103-20094-00	88-0008	01/29/88
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-18	50-103-20095-00	88-0009	01/29/88
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-16	50-103-20096-00	88-0010	01/29/88
ARCO ALASKA INC	KUPARUK RIV UNIT 3H-22	50-103-20097-00	88-0011	01/29/88
ARCO ALASKA INC	PIPELINE STATE 1	50-223-20016-00	87-0121	12/16/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT D-4A	50-029-20056-01	87-0125	12/04/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT D-28	50-029-21556-00	86-0050	02/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-22	50-029-21558-00	86-0052	02/28/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT M-28	50-029-21578-00	86-0074	04/11/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-27/M33	50-029-21586-00	86-0083	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-23	50-029-21590-00	86-0087	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT Y-24	50-029-21608-00	86-0113	06/10/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-19	50-029-21611-00	86-0116	06/13/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-30	50-029-21613-00	86-0118	06/17/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-31	50-029-21616-00	86-0121	06/19/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-47/Q21	50-029-21625-00	86-0131	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-29	50-029-21627-00	86-0133	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT G-32	50-029-21636-00	86-0146	07/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT S-20	50-029-21637-00	86-0147	07/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-14/O16	50-029-21639-00	86-0149	08/04/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 4-20/M35	50-029-21640-01	86-0173	10/10/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI 3-23/N32	50-029-21645-00	86-0155	08/15/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-31	50-029-21647-00	86-0157	08/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-62/Q17	50-029-21648-00	86-0158	09/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT F-28	50-029-21649-00	86-0159	09/02/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-34/P14	50-029-21662-00	86-0172	10/09/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT J-21	50-029-21705-00	87-0024	03/09/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 1-37/P24	50-029-21748-00	87-0090	09/03/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI 2-52/S14	50-029-21750-00	87-0092	09/04/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-13	50-029-21757-00	87-0101	09/30/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-12	50-029-21759-00	87-0104	10/15/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT E-27	50-029-21760-00	87-0105	10/15/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT K-10	50-029-21762-00	87-0114	11/03/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 02/08/88

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	E-23	50-029-21763-00	87-0115	11/05/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	3-39/J39	50-029-21764-00	87-0116	11/05/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	K-11	50-029-21765-00	87-0117	11/17/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	2-44/R12	50-029-21767-00	87-0119	11/23/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	E-24	50-029-21769-00	87-0122	12/03/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	2-08/K16	50-029-21771-00	88-0004	01/15/88
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	GC-1D	50-029-21772-00	87-0128	12/17/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	E-25	50-029-21773-00	87-0131	12/22/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	GC-2C	50-029-21774-00	87-0132	12/22/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	C-31	50-029-21775-00	88-0006	01/20/88
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	W-40	50-029-21776-00	87-0135	12/22/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	C-30	50-029-21777-00	87-0136	12/28/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	3-09/L28	50-029-21780-00	88-0002	01/13/88
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	E-26	50-029-21781-00	88-0007	01/20/88

ALASKA PRODUCTION SUMMARY BY FIELD AND POOL FOR 1987

FIELD AND POOL NAME	- OIL PRODUCTION - OIL (BBL) ANNUAL	OIL (BBL) CUM	CAS.HD.GAS (MCF) ANNUAL	CAS.HD.GAS (MCF) CUM	WATER (BBL) ANNUAL	WATER (BBL) CUM	- GAS PRODUCTION - NAT.GAS.LIQ (BBL) ANNUAL	NAT.GAS.LIQ (BBL) CUM	DRY GAS (MCF) ANNUAL	DRY GAS (MCF) CUM
ALBERT KALOA, UNDEFINED										118,774
FIELD TOTAL										118,774
BEAVER CREEK, UNDEFINED	185,084	3,520,778	53,143	1,429,485	1,084	18,993				
BEAVER CREEK, UNDEFINED					178,253	298,051			15,475,239	62,925,906
FIELD TOTAL	185,084	3,520,778	53,143	1,429,485	179,337	317,044			15,475,239	62,925,906
BELUGA RIVER, UNDEFINED						810			23,985,428	253,191,671
FIELD TOTAL						810			23,985,428	253,191,671
BIRCH HILL, UNDEFINED										65,331
FIELD TOTAL										65,331
EAST BARROW, UNDEFINED					822	1,115			590,437	3,947,529
FIELD TOTAL					822	1,115			590,437	3,947,529
ENDICOTT, ENDICOTT	8,795,758	8,806,770	8,237,450	8,433,197	171,363	171,363				
FIELD TOTAL	8,795,758	8,806,770	8,237,450	8,433,197	171,363	171,363				
FALLS CREEK, UNDEFINED										18,983
FIELD TOTAL										18,983
GRANITE POINT, MIDDLE KENAI	2,789,688	106,837,864	2,431,177	92,287,953	1,058,756	7,582,441				
GRANITE POINT, HEMLOCK		2,764		1,590						
FIELD TOTAL	2,789,688	106,840,628	2,431,177	92,289,543	1,058,756	7,582,441				
KATALLA, KATALLA		154,000								
FIELD TOTAL		154,000								
KENAI, STERLING 3					1,454	110,443			17,206,158	252,981,820
KENAI, STERLING 4					6,797	85,449			18,843,500	367,178,726
KENAI, STERLING 5.1					3,924	137,833			18,297,459	429,265,359
KENAI, STERLING 5.2						12,700				44,031,635
KENAI, STERLING 6					2,772	42,789			20,627,815	397,336,068
KENAI, UNDEFINED					11,677	65,191			10,011,285	120,071,481
KENAI, TYONEK					4,174	32,695			5,500,651	209,757,749
							11,877			

ALASKA PRODUCTION SUMMARY BY FIELD AND POOL FOR 1987

FIELD AND POOL NAME	- OIL PRODUCTION - OIL (BBL) ANNUAL	OIL (BBL) CUM	CAS.HD.GAS (MCF) ANNUAL	CAS.HD.GAS (MCF) CUM	WATER (BBL) ANNUAL	WATER (BBL) CUM	- GAS PRODUCTION - NAT.GAS.LIQ (BBL) ANNUAL	NAT.GAS.LIQ (BBL) CUM	DRY GAS (MCF) ANNUAL	DRY GAS (MCF) CUM
FIELD TOTAL					30,798	487,100		11,877	90,486,868	1,830,622,838
KUPARUK RIVER, CRETACIOUS UNDEF					6,851,978	54,479,207				
KUPARUK RIVER, KUPARUK RIVER	102,447,904	394,823,160	124,744,441	469,416,611	27,358,597	44,836,855	1,256,790	3,089,934		
KUPARUK RIVER, W SAK UNDEFINED		3,365		4,980						
FIELD TOTAL	102,447,904	394,826,525	124,744,441	469,421,591	34,210,575	99,316,062	1,256,790	3,089,934		
LEWIS RIVER, UNDEFINED					63	108			344,527	4,022,052
FIELD TOTAL					63	108			344,527	4,022,052
MCARTHUR RIVER, HEMLOCK	6,042,795	466,557,522	2,970,220	170,778,715	22,623,211	220,376,943	125,290	7,849,453		
MCARTHUR RIVER, MIDDLE KENAI G	993,018	36,016,80[illegible]	495,651	17,939,702	646,855	4,242,776	61,971	766,417		
MCARTHUR RIVER, WEST FORELAND	339,001	19,114,960	120,689	5,450,344	490,542	4,993,278	9,281	200,954		
MCARTHUR RIVER, MIDDLE KENAI									7,448,554	97,240,537
MCARTHUR RIVER, UNDEFINED									2,442,793	36,312,283
FIELD TOTAL	7,374,814	521,689,366	3,586,560	194,168,761	23,760,608	229,612,997	196,542	8,816,824	9,891,347	133,552,820
MIDDLE GROUND SHOAL, A	67,956	1,999,651	117,321	4,357,185	10,850	1,115,640				
MIDDLE GROUND SHOAL, B C AND D	205,322	10,397,981	150,483	7,227,175	263,056	3,613,537			74,082	103,364
MIDDLE GROUND SHOAL, E F AND G	2,560,467	140,704,317	996,773	65,146,863	3,569,312	67,458,562				
MIDDLE GROUND SHOAL, UNDEFINED									227,766	2,060,480
FIELD TOTAL	2,833,745	153,101,949	1,264,577	76,731,223	3,843,218	72,187,739			301,848	2,163,844
MILNE POINT, KUPARUK RIVER	39,997	5,452,582	11,130	1,907,955	14,807	1,436,774				
MILNE POINT, TERTIARY UNDEFINED					61,996	5,174,745				
FIELD TOTAL	39,997	5,452,582	11,130	1,907,955	76,803	6,611,519				
MOQUAWKIE, UNDEFINED									985,059	
FIELD TOTAL									985,059	
NICOLAI CREEK, UNDEFINED									1,062,055	
FIELD TOTAL									1,062,055	
NORTH COOK INLET, TERTIARY					20,185	100,074			42,888,708	820,297,556
FIELD TOTAL					20,185	100,074			42,888,708	820,297,556

ALASKA PRODUCTION SUMMARY BY FIELD AND POOL FOR 1987

FIELD AND POOL NAME	- OIL PRODUCTION - OIL (BBL) ANNUAL	OIL (BBL) CUM	CAS.HD.GAS (MCF) ANNUAL	CAS.HD.GAS (MCF) CUM	WATER (BBL) ANNUAL	WATER (BBL) CUM	- GAS PRODUCTION - NAT.GAS.LIQ (BBL) ANNUAL	NAT.GAS.LIQ (BBL) CUM	DRY GAS (MCF) ANNUAL	DRY GAS (MCF) CUM
NORTH FORK, UNDEFINED										104,595
FIELD TOTAL										104,595
PRETTY CREEK, UNDEFINED					61				775,750	
						125				842,437
FIELD TOTAL					61				775,750	
						125				842,437
PRUDHOE BAY, UNDEFINED						1,112,346				
PRUDHOE BAY, LISBURNE	16,152,361		64,908,349		1,709,526		457,849			
		21,461,376		76,362,089		1,783,496		457,849		
PRUDHOE BAY, PRUDHOE	572,370,310*		1,228,526,802		205,013,034		14,598,026			
		5,490,169,510**		7,651,943,702		510,267,884		16,715,714		
FIELD TOTAL	588,522,671*		1,293,435,151		206,722,560		15,055,875			
		5,511,630,886**		7,728,305,791		513,163,726		17,173,563		
REDOUBT SHOAL, UNDEFINED		1,596		456		249				
FIELD TOTAL		1,596		456		249				
SOUTH BARROW, UNDEFINED					208				621,511	
						311				17,823,710
FIELD TOTAL					208				621,511	
						311				17,823,710
STERLING, UNDEFINED										2,088,135
FIELD TOTAL										2,088,135
SWANSON RIVER, HEMLOCK	2,030,384		82,926,168		1,887,694		30,263			
		207,255,715		1,751,952,218		67,437,690		1,184,238		
SWANSON RIVER, UNDEFINED		51,239		323,888		4,170				
SWANSON RIVER, UNDEFINED									554,913	
										12,659,553
FIELD TOTAL	2,030,384		82,926,168		1,887,694		30,263		554,913	
		207,306,954		1,752,276,106		67,441,860		1,184,238		12,659,553
TRADING BAY, HEMLOCK	174,973		212,613		102,116		138			
		10,672,341		10,488,713		2,775,922		51,672		
TRADING BAY, UNDEFINED	19,203		40,581		7,829					
		563,033		300,090		100,167				
TRADING BAY, MIDDLE KENAI B	137,834		102,657		31,270					
		2,068,868		2,190,324		203,682				
TRADING BAY, MIDDLE KENAI C	168,255		330,554		257,835					
		18,533,950		12,153,993		16,781,567				
TRADING BAY, MIDDLE KENAI D	122,406		139,652		203,319					
		26,743,058		21,789,375		13,233,698				
TRADING BAY, MIDDLE KENAI E	67,087		68,146		110,416					
		7,485,282		6,367,930		2,829,900				
TRADING BAY, G-NE/HEMLOCK-NE	236,452		92,481		1,617,016					
		22,969,176		6,456,699		24,686,170				
TRADING BAY, W FORELAND	8,737		1,531		13					
		29,392		19,213		9,611				
TRADING BAY, UNDEFINED									442,983	
										3,207,872

*INCLUDES 23,310,115 BBLS OF CONDENSATE
**INCLUDES 109,145,756 BBLS OF CONDENSATE

ALASKA PRODUCTION SUMMARY BY FIELD AND POOL FOR 1987

FIELD AND POOL NAME	- OIL PRODUCTION - OIL (BBL) ANNUAL	OIL (BBL) CUM	CAS.HD.GAS (MCF) ANNUAL	CAS.HD.GAS (MCF) CUM	WATER (BBL) ANNUAL	WATER (BBL) CUM	- CAS PRODUCTION - NAT.GAS.LIQ (BBL) ANNUAL	NAT.GAS.LIQ (BBL) CUM	DRY GAS (MCF) ANNUAL	DRY GAS (MCF) CUM
TRADING BAY, M.KENAI UNALLOCATE			3,233	1,091,524			455	307,588		
FIELD TOTAL	934,947	89,065,100	991,448	60,857,961	2,329,814	60,620,717	593	359,260	442,983	3,207,872
WEST FORK, UNDEFINED										1,541,595
FIELD TOTAL										1,541,595
STATE TOTAL	715,954,992	7,002,397,134	1,517,681,245	10,385,822,069	274,292,865	1,057,615,360	16,540,063	30,635,696	186,359,559	3,151,242,315

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS SUMMARY BY FIELD AND POOL FOR 1987

FIELD AND POOL NAME	- ENHANCED RECOVERY - OIL (BBL) ANNUAL	OIL (BBL) CUM	WATER (BBL) ANNUAL	WATER (BBL) CUM	GAS (MCF) ANNUAL	GAS (MCF) CUM	- DISPOSAL PROJECTS - FLUIDS (BBL) ANNUAL	FLUIDS (BBL) CUM
BEAVER CREEK, UNDEFINED								37,334
								37,334
BEAVER CREEK, UNDEFINED						547,457		
FIELD TOTAL						547,457		37,334
								37,334
BELUGA RIVER, UNDEFINED								6,141
								6,141
FIELD TOTAL								6,141
								6,141
ENDICOTT, UNDEFINED								278,714
								322,691
ENDICOTT, ENDICOTT		14,269				5,615,130		
		21,036*		1		5,615,130		
FIELD TOTAL		14,269				5,615,130		278,714
		21,036		1		5,615,130		322,691
GRANITE POINT, MIDDLE KENAI			4,097,553					
			129,337,612					
FIELD TOTAL			4,097,553					
			129,337,612					
KENAI, UNDEFINED								129,516
								210,696
KENAI, STERLING 4								79,191
								79,191
FIELD TOTAL								208,707
								289,887
KUPARUK RIVER, CRETACIOUS UNDEF								360,595
								2,494,817
KUPARUK RIVER, KUPARUK RIVER			177,668,828		89,190,562			
			370,269,607		369,578,116			
FIELD TOTAL			177,668,828		89,190,562			360,595
			370,269,607		369,578,116			2,494,817
MCARTHUR RIVER, HEMLOCK			28,269,782					
			856,803,607					
MCARTHUR RIVER, MIDDLE KENAI G			1,593,104					
			31,220,482					
MCARTHUR RIVER, WEST FORELAND			9,470					
			9,470					
FIELD TOTAL			29,872,356					
			888,033,559					
MIDDLE GROUND SHOAL, UNDEFINED				150,390				
MIDDLE GROUND SHOAL, A				5,645,549				
MIDDLE GROUND SHOAL, B C AND D			670,614					
			26,123,728					
MIDDLE GROUND SHOAL, E F AND G			5,069,236					
			226,182,695					
FIELD TOTAL			5,739,850					
			258,102,362					
MILNE POINT, KUPARUK RIVER			76,803					
			6,498,464			196,531		
FIELD TOTAL			76,803					
			6,498,464			196,531		

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS SUMMARY BY FIELD AND POOL FOR 1987

FIELD AND POOL NAME	- ENHANCED RECOVERY - OIL (BBL) ANNUAL	OIL (BBL) CUM	WATER (BBL) ANNUAL	WATER (BBL) CUM	GAS (MCF) ANNUAL	GAS (MCF) CUM	- DISPOSAL PROJECTS - FLUIDS (BBL) ANNUAL	FLUIDS (BBL) CUM
PRUDHOE BAY, UNDEFINED							22,545,082	124,500,796
PRUDHOE BAY, LISBURNE			337,626	337,626	56,741,269	56,741,269		
PRUDHOE BAY, PRUDHOE		13,012,875	488,253,247	1,505,896,682	1,097,171,064	6,962,065,416		
FIELD TOTAL		13,012,875*	488,590,873	1,506,234,308	1,153,912,333	7,018,806,685	22,545,082	124,500,796
SWANSON R VER, UNDEFINED							1,744,452	1,744,452
SWANSON RIVER, HEMLOCK			8,337,995	8,337,995	85,688,349	2,014,875,361		
FIELD TOTAL			8,337,995	8,337,995	85,688,349	2,014,875,361	1,744,452	1,744,452
TRADING BAY, HEMLOCK			343,518					
TRADING BAY, MIDDLE KENAI C			26,762,433					
TRADING BAY, MIDDLE KENAI D			60,389,470					
TRADING BAY, G-NE/HEMLOCK-NE			33,518,440					
FIELD TOTAL			121,013,861					
STATE TOTAL	14,269	13,033,911*	706,046,263	3,287,827,769	1,334,406,374	9,409,619,280	25,181,025	129,396,118

*FLUIDS RETURNED TO RESERVOIR, NOT ENHANCED RECOVERY

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR DECEMBER, 1987

OIL FIELDS	CRUDE OIL (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CRUDE OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL	20,659	570	5,682	2	3,520,778	18,993	1,429,485
FIELD TOTAL	20,659	570	5,682	2	3,520,778	18,993	1,429,485
ENDICOTT FIELD							
ENDICOTT POOL	3,448,733	136,440	3,183,353	25	8,806,770	171,363	8,433,197
FIELD TOTAL	3,448,733	136,440	3,183,353	25	8,806,770	171,363	8,433,197
GRANITE POINT FIELD							
MIDDLE KENAI POOL	218,540	87,831	195,606	29	106,837,864	7,582,441	92,287,953
FIELD TOTAL	218,540	87,831	195,606	29	106,840,628	7,582,441	92,289,543
KUPARUK RIVER FIELD							
CRETACIOUS UNDEF ZONE		595,441		7		54,479,207	
KUPARUK RIVER POOL	8,905,459	3,154,414	11,671,512	329	394,823,160	44,836,855	469,416,611
FIELD TOTAL	8,905,459	3,749,855	11,671,512	336	394,826,525	99,316,062	469,421,591
MCARTHUR RIVER FIELD							
HEMLOCK POOL	496,601	2,048,620	249,412	58	466,557,522	220,376,943	170,778,715
MIDDLE KENAI G POOL	70,741	50,527	33,765	11	36,016,884	4,242,776	17,939,702
WEST FORELAND POOL	17,130	34,028	8,571	4	19,114,960	4,993,278	5,450,344
FIELD TOTAL	584,472	2,133,175	291,748	73	521,689,366	229,612,997	194,168,761
MIDDLE GROUND SHOAL FIELD							
A POOL	4,229	1,520	4,261	1	1,999,651	1,115,640	4,357,185
B C AND D POOL	16,011	20,548	10,623	4	10,397,981	3,613,537	7,227,175
E F AND G POOL	218,372	270,738	94,472	36	140,704,317	67,458,562	65,146,863
FIELD TOTAL	238,612	292,806	109,356	41	153,101,949	72,187,739	76,731,223
PRUDHOE BAY FIELD							
LISBURNE POOL	1,447,722	223,087	6,860,023	47	21,461,376	1,783,496	76,362,089
PRUDHOE POOL	48,190,641*	17,902,061	120,905,424	675	5,490,169,510**	510,267,884	7,651,943,702
FIELD TOTAL	49,638,363*	18,125,148	127,765,447	722	5,511,630,886**	513,163,726	7,728,305,791
SWANSON RIVER FIELD							
HEMLOCK POOL	189,331	249,181	7,902,431	29	207,255,715	67,437,690	1,751,952,218
FIELD TOTAL	189,331	249,181	7,902,431	29	207,306,954	67,441,860	1,752,276,106
TRADING BAY FIELD							
HEMLOCK POOL	14,594	8,453	21,387	6	10,672,341	2,775,922	10,488,713
UNDEFINED POOL	3,107	1,598	7,097	1	563,033	100,167	300,090
MIDDLE KENAI B POOL	15,760	2,890	14,754	8	2,068,868	203,682	2,190,324
MIDDLE KENAI C POOL	10,556	23,673	32,900	5	18,533,950	16,781,567	12,153,993
MIDDLE KENAI D POOL	10,141	19,771	13,054	6	26,743,058	13,233,698	21,789,375
MIDDLE KENAI E POOL	5,172	9,783	5,830	4	7,485,282	2,829,900	6,367,930
G-NE/HEMLOCK-NE POOL	18,693	137,366	7,404	6	22,969,176	24,686,170	6,456,699
W FORELAND POOL	802		140	1	29,392	9,611	19,213
M.KENAI UNALLOCATED ZONE			151	1			1,091,624
FIELD TOTAL	78,825	202,934	102,717	38	89,065,100	60,620,717	60,857,961
TOTAL ACTIVE FIELDS	63,322,994	24,977,940	151,227,852	1,295	6,996,788,956	1,050,115,898	10,383,913,658
DAILY AVERAGE	2,042,677	805,740	4,878,317	INACTIVE	5,608,178	6,611,768	1,908,411
				ALL FIELDS	7,002,397,134	1,056,727,666	10,385,822,069

*INCLUDES 2,545,772 BBLS OF CONDENSATE
**INCLUDES 109,145,756 BBLS OF CONDENSATE

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR DECEMBER, 1937

NGL PRODUCTION	NGL (BBL)	CUM NGL (BBL)
KUPARUK RIVER		
KUPARUK RIVER	112,388	3,089,934
FIELD TOTAL	112,388	3,089,934
MCARTHUR RIVER		
HEMLOCK	11,902	7,849,453
MIDDLE KENAI G	3,363	766,417
WEST FORELAND	874	200,954
FIELD TOTAL	16,139	8,816,824
PRUDHOE BAY		
LISBURNE	68,381	457,849
PRUDHOE	1,675,474	16,715,714
FIELD TOTAL	1,743,855	17,173,563
SWANSON RIVER		
HEMLOCK	3,434	1,184,238
FIELD TOTAL	3,434	1,184,238
TRADING BAY		
HEMLOCK	9	51,672
M.KENAI UNALLOCATED	29	307,588
FIELD TOTAL	38	359,260
TOTAL ACTIVE FIELDS	1,875,854	30,623,819
DAILY AVERAGE	60,511	
	INACTIVE	0
	ALL FIELDS	30,623,819

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR DECEMBER, 1987

GAS FIELDS	CONDEN. (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CONDEN. (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL		9,409	1,235,846	4		298,051	62,925,906
FIELD TOTAL		9,409	1,235,846	4		298,051	62,925,906
BELUGA RIVER FIELD							
UNDEFINED POOL			2,310,665	14		810	253,191,671
FIELD TOTAL			2,310,665	14		810	253,191,671
EAST BARROW FIELD							
UNDEFINED POOL		47	68,806	4		1,115	3,947,529
FIELD TOTAL		47	68,806	4		1,115	3,947,529
KENAI FIELD							
STERLING 3 POOL		14	1,659,074	9		110,443	262,981,820
STERLING 4 POOL		191	1,789,993	11		85,449	367,178,726
STERLING 5.1 POOL		51	1,686,976	10		137,833	429,265,359
STERLING 6 POOL		96	2,005,443	11		42,789	397,336,068
UNDEFINED POOL		484	903,680	7		65,191	120,071,481
TYONEK POOL		324	499,407	4	11,877	32,695	209,757,749
FIELD TOTAL		1,160	8,544,573	52	11,877	487,100	1,830,622,838
LEWIS RIVER FIELD							
UNDEFINED POOL			3,846	1		108	4,022,052
FIELD TOTAL			3,846	1		108	4,022,052
MCARTHUR RIVER FIELD							
MIDDLE KENAI POOL			821,730	7			97,240,537
FIELD TOTAL			821,730	7			133,552,820
MIDDLE GROUND SHOAL FIELD							
UNDEFINED POOL			16,158	1			2,060,480
FIELD TOTAL			16,158	1			2,163,844
NORTH COOK INLET FIELD							
TERTIARY POOL		2,093	3,594,280	12		100,074	820,297,556
FIELD TOTAL		2,093	3,594,280	12		100,074	820,297,556
PRETTY CREEK FIELD							
UNDEFINED POOL		7	73,559	1		125	842,437
FIELD TOTAL		7	73,559	1		125	842,437
SOUTH BARROW FIELD							
UNDEFINED POOL		3	56,987	5		311	17,823,710
FIELD TOTAL		3	56,987	5		311	17,823,710
SWANSON RIVER FIELD							
UNDEFINED POOL			80,833	1			12,659,553
FIELD TOTAL			80,833	1			12,659,553
TRADING BAY FIELD							
UNDEFINED POOL			29,376	1			3,207,872
FIELD TOTAL			29,376	1			3,207,872
TOTAL ACTIVE FIELDS		12,719	16,836,659	103	11,877	887,694	3,145,257,788
DAILY AVERAGE		410	543,118	INACTIVE	0	0	5,984,527
				ALL FIELDS	11,877	887,694	3,151,242,315

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS FOR DECEMBER, 1987

ENHANCED RECOVERY	OIL (BBL)	WATER (BBL)	GAS (MCF)	INJ. WELLS	CUM OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
ENDICOTT FIELD							
ENDICOTT POOL			2,604,268	2	21,036	1	5,615,130
FIELD TOTAL			2,604,268	2	21,036*	1	5,615,130
GRANITE POINT FIELD							
MIDDLE KENAI POOL		329,013		12		129,337,612	
FIELD TOTAL		329,013		12		129,337,612	
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL		21,114,202	8,401,557	208		370,269,607	369,578,116
FIELD TOTAL		21,114,202	8,401,557	208		370,269,607	369,578,116
MCARTHUR RIVER FIELD							
HEMLOCK POOL		2,318,603		16		856,803,607	
MIDDLE KENAI G POOL		116,002		4		31,220,482	
WEST FORELAND POOL		9,470		1		9,470	
FIELD TOTAL		2,444,075		21		888,033,559	
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL		57,152		2		26,123,728	
E F AND G POOL		390,546		15		226,182,695	
FIELD TOTAL		447,698		17		258,102,362	
PRUDHOE BAY FIELD							
LISBURNE POOL			6,551,831	3		337,626	56,741,269
PRUDHOE POOL		35,193,412	108,227,590	133	13,012,875	1,505,896,682	6,962,065,416
FIELD TOTAL		35,193,412	114,779,421	136	13,012,875*	1,506,234,308	7,018,806,685
SWANSON RIVER FIELD							
HEMLOCK POOL			7,726,429	7		8,337,995	2,014,875,361
FIELD TOTAL			7,726,429	7		8,337,995	2,014,875,361
TOTAL ACTIVE FIELDS		59,528,400	133,511,675	403	13,033,911*	3,160,315,444	9,408,875,292
DAILY AVERAGE		1,920,270	4,306,828	INACTIVE	0	127,512,325	743,988
				ALL FIELDS	13,033,911*	3,287,827,769	9,409,619,280

DISPOSAL PROJECTS	FLUIDS (BBL)	DISP. WELLS	CUM FLUIDS (BBL)
ENDICOTT FIELD			
UNDEFINED ZONE	127,197	2	322,691
FIELD TOTAL	127,197	2	322,691
KENAI FIELD			
UNDEFINED ZONE	2,009	1	210,696
STERLING 4 POOL	11,917	1	79,191
FIELD TOTAL	13,926	2	289,887
KUPARUK RIVER FIELD			
CRETACIOUS UNDEF ZONE	21,397	2	2,494,817
FIELD TOTAL	21,397	2	2,494,817
PRUDHOE BAY FIELD			
UNDEFINED ZONE	2,044,516	9	124,500,796
FIELD TOTAL	2,044,516	9	124,500,796
SWANSON RIVER FIELD			
UNDEFINED ZONE	200,752	4	1,744,452
FIELD TOTAL	200,752	4	1,744,452
TOTAL ACTIVE FIELDS	2,407,788	19	129,352,643
DAILY AVERAGE	77,670	INACTIVE	43,475
		ALL FIELDS	129,396,118

*FLUIDS RETURNED TO RESERVOIR, NOT ENHANCED RECOVERY

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 PORCUPINE DR ANCHORAGE, AK. 99501-3192

BULK RATE
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ANCHORAGE, AK.
PERMIT NO. 356



STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION





3001 PORCUPINE DRIVE ANCHORAGE, ALASKA 99501

Steve Cowper, Governor

William W Barnwell, Commissioner

C V Chatterton, Commissioner
Chairman of Commission

Lonnie C Smith, Commissioner

BULLETIN

MARCH 1988

ADMINISTRATIVE APPROVAL NO. 213.13

Administrative Approval No. 213.13 was issued on February 4, 1988, to ARCO Alaska, Inc. waiving the requirement of Rule 11a of Conservation Order No. 165 for Prudhoe Bay Unit well DS 11-26. Rule 11a required that a spinner flow meter or a trace survey be run during the first six months that the well is on production. Since this well is producing from a single interval, a productivity profile need not be filed until additional zones are perforated.

ADMINISTRATIVE APPROVAL NO. 120.32

Administrative Approval No. 120.32 was issued on February 4, 1988 to Marathon Oil Company permitting 10 additional excess flare days during the first calendar quarter of 1988, on the Dolly Varden platform in the McArthur River Field. This will allow up to 25 days of flaring for operational necessities during the 1st quarter; the excess flared gas will be metered, and is subject to the Oil and Gas Properties Production Tax.

Administrative Approval AIO No. 10.2

Administrative Approval AIO No. 10.2 was issued on February 10, 1988, to Conoco, Inc. amending Rule 2 of Area Injection Order (AIO) No. 10, to allow for the pumping of excess nonhazardous fluids that are developed solely from well operations, or necessary to control the fluid level of reserve pits, into surface/production casing annuli. Aquifer Exemption Order No. 2 has exempted all aquifers lying beneath the Milne Point Unit for Class II injection activities, and was issued after approval of AIO No. 10, thus prompting the amendment.

Administrative Approval No. 120.33

Administrative Approval 120.33 was issued on February 18, 1988 to Marathon Oil Company permitting 10 additional excess flare days during the first calendar quarter of 1988, on the Dolly Varden platform in the McArthur River Field. This will allow up to 35 days of flaring for operational necessities during the 1st quarter while Marathon continues its efforts to alleviate the cause of the excess flaring. All excess gas flared shall be metered, and is subject to the Oil and Gas Properties Production Tax.

Administrative Approval No. 114.5

Administrative Approval No. 114.5 was issued on February 26, 1988 to Union Oil Company of California, operator of the McArthur River Field, amending item 9 of Conservation Order No. 114. This will allow a daily average volume of 2500 MCF per day (of produced gas) per calendar month to maintain a safety flare on Dolly Varden platform in the McArthur River Field. The increase of 1500 MCF per day was granted to allow Marathon Oil Company to identify and alleviate the problem. The amendment is subject to change upon periodic review of the situation on the Dolly Varden platform.

Administrative Approval No. 145-A.29

Administrative Approval 145-A.29 was issued on February 26, 1988 to ARCO Alaska, Inc. permitting an additional 5 MMSCF of gas to be flared at the Central Compressor Plant Prudhoe Bay Field. The additional flare volume was granted so that repairs might be made on the compressor fuel inlet header. The excess flared gas will be metered, and is subject to the Oil and Gas Properties Production Tax.

ALASKA DRILLING STATISTICS FOR FEBRUARY, 1988

* DRILLING PERMITS APPROVED * * *

ALASKA DRILLING STATISTICS FOR FEBRUARY, 1988

* RELEASABLE INFORMATION ON RECENTLY COMPLETED WELLS * * *

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 03/02/88

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
GULF OF AK BASIN					
ALASKAN CRUDE CORP	KATALLA	KS-1	50-069-20002-00	85-0124	07/01/85
COOK INLET BASIN					
ALASKAN CRUDE CORP	BURGLIN	31-1	50-133-20390-00	87-0070	07/31/87
ALASKAN CRUDE CORP	BURGLIN	BRX 22-1	50-283-20082-00	87-0084	08/24/87
AMOCO PRODUCTION CO	GRANITE POINT 18742	32RD	50-733-20298-01	87-0063	06/29/87
AMOCO PRODUCTION CO	GRANITE PT ST 18742	37	50-733-20394-00	87-0109	10/26/87
SHELL WESTERN E&P INC	MGS	A-23-1RD	50-733-20238-01	87-0093	09/16/87
SHELL WESTERN E&P INC	MGS	C24A-14	50-733-20395-00	87-0126	12/14/87
UNION OIL CO OF CALIFORNIA	TRADING BAY ST	A-19RD	50-133-20151-01	88-0001	02/19/88
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT	4	50-133-20387-00	87-0034	04/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	G-36DPN	50-733-20216-00	87-0049	05/28/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-25	50-733-20391-00	87-0086	08/26/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-3	50-733-20392-00	87-0089	09/03/87
UNION OIL CO OF CALIFORNIA	TRADING BAY UNIT	M-26	50-733-20393-00	87-0106	11/04/87
UNION OIL CO OF CALIFORNIA	CANNERY LOOP UNIT	5	50-733-20396-00	87-0127	12/23/87
ARCTIC SLOPE					
ALASKAN CRUDE CORP	ACC	F-2	50-029-21315-00	85-0053	04/10/85
ALASKAN CRUDE CORP	ACC	F-3	50-029-21316-00	85-0054	04/10/85
AMERADA HESS CORP	NORTHSTAR	3	50-629-21747-00	87-0088	08/31/87
ARCO ALASKA INC	W BEACH ST	1-A	50-029-20138-01	86-0056	03/06/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-11D	50-029-21181-00	87-0087	08/24/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-10	50-029-21563-00	86-0058	03/10/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3I-11	50-029-21564-00	86-0059	03/10/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS1-27	50-029-21591-00	86-0088	05/02/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3K-14	50-029-21631-00	86-0137	07/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	LGI-16	50-029-21643-00	86-0153	08/15/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-24	50-029-21670-00	86-0182	11/19/86
ARCO ALASKA INC	PRUDHOE BAY UNIT	L3-30	50-029-21673-00	86-0185	12/04/86
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-1	50-029-21687-00	87-0003	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-3	50-029-21689-00	87-0005	01/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3Q-4	50-029-21690-00	87-0006	01/21/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS11-28	50-029-21691-00	87-0007	01/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3M-12	50-029-21719-00	87-0050	05/22/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-27	50-029-21744-00	87-0082	07/31/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-16	50-029-21749-00	87-0091	09/04/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-13	50-029-21756-00	87-0100	09/25/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-8	50-029-21761-00	87-0108	10/23/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-18	50-029-21766-00	87-0118	11/20/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS18-17	50-029-21768-00	87-0120	11/30/87
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-28	50-029-21770-00	88-0003	01/14/88
ARCO ALASKA INC	PRUDHOE BAY UNIT	L2-32	50-029-21778-00	87-0137	12/24/87
ARCO ALASKA INC	PT. MCINTYRE	3	50-029-21779-00	88-0005	01/15/88
ARCO ALASKA INC	PRUDHOE BAY UNIT	DS7-29	50-029-21782-00	88-0012	02/02/88
ARCO ALASKA INC	PRUDHOE BAY UNIT	LGI-4	50-029-21783-00	88-0013	02/02/88
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-4	50-103-20076-00	87-0076	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-5	50-103-20077-00	87-0077	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-6	50-103-20078-00	87-0078	07/31/87

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 03/02/88

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-7	50-103-20079-00	87-0079	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-8	50-103-20080-00	87-0080	07/31/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-17	50-103-20081-00	87-0099	09/25/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-15	50-103-20082-00	87-0103	10/07/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-2	50-103-20083-00	87-0107	10/21/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-1	50-103-20084-00	87-0110	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-3	50-103-20085-00	87-0111	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-10	50-103-20087-00	87-0113	10/28/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-12	50-103-20088-00	87-0129	12/17/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-13	50-103-20089-00	87-0130	12/17/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-19	50-103-20090-00	87-0133	12/23/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-11	50-103-20091-00	87-0124	12/04/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-14	50-103-20092-00	87-0123	12/04/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-20	50-103-20093-00	87-0134	12/23/87
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-21	50-103-20094-00	88-0008	01/29/88
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-18	50-103-20095-00	88-0009	01/29/88
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-16	50-103-20096-00	88-0010	01/29/88
ARCO ALASKA INC	KUPARUK RIV UNIT	3H-22	50-103-20097-00	88-0011	01/29/88
ARCO ALASKA INC	PIPELINE STATE	1	50-223-20016-00	87-0121	12/16/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	M-28	50-029-21578-00	86-0074	04/11/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	3-27/M33	50-029-21586-00	86-0083	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-23	50-029-21590-00	86-0087	05/02/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	Y-24	50-029-21608-00	86-0113	06/10/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	S-19	50-029-21611-00	86-0116	06/13/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	G-30	50-029-21613-00	86-0118	06/17/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	G-31	50-029-21616-00	86-0121	06/19/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	1-47/Q21	50-029-21625-00	86-0131	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	F-29	50-029-21627-00	86-0133	07/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	G-32	50-029-21636-00	86-0146	07/25/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	S-20	50-029-21637-00	86-0147	07/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	2-14/O16	50-029-21639-00	86-0149	08/04/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	4-20/M35	50-029-21640-01	86-0173	10/10/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	3-23/N32	50-029-21645-00	86-0155	08/15/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	F-31	50-029-21647-00	86-0157	08/28/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	2-62/Q17	50-029-21648-00	86-0158	09/03/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	F-28	50-029-21649-00	86-0159	09/02/86
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	2-34/P14	50-029-21662-00	86-0172	10/09/86
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	J-21	50-029-21705-00	87-0024	03/09/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	2-52/S14	50-029-21750-00	87-0092	09/04/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	K-13	50-029-21757-00	87-0101	09/30/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	K-12	50-029-21759-00	87-0104	10/15/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	E-27	50-029-21760-00	87-0105	10/15/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	K-10	50-029-21762-00	87-0114	11/03/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	E-23	50-029-21763-00	87-0115	11/05/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	3-39/J39	50-029-21764-00	87-0116	11/05/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	K-11	50-029-21765-00	87-0117	11/17/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	2-44/R12	50-029-21767-00	87-0119	11/23/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	E-24	50-029-21769-00	87-0122	12/03/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT MPI	2-08/K16	50-029-21771-00	88-0004	01/15/88
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	GC-1D	50-029-21772-00	87-0128	12/17/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	E-25	50-029-21773-00	87-0131	12/22/87

MARCH 1988

OUTSTANDING DRILLING PERMITS FOR ALASKA AS OF 03/02/88

OPERATOR NAME	WELL NAME AND NUMBER		API NUMBER	PERMIT	APPROVED
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	GC-2C	50-029-21774-00	87-0132	12/22/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	C-31	50-029-21775-00	88-0006	01/20/88
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	W-40	50-029-21776-00	87-0135	12/22/87
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	C-30	50-029-21777-00	87-0136	12/28/87
STANDARD ALASKA PRODUCTION CO	DUCK IS UNIT SDI	J-09/L28	50-029-21780-00	88-0002	01/13/88
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	E-26	50-029-21781-00	88-0007	01/20/88
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	W-39	50-029-21784-00	88-0014	02/29/88
STANDARD ALASKA PRODUCTION CO	PRUDHOE BAY UNIT	C-34	50-029-21785-00	88-0015	02/09/88

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR JANUARY, 1988

OIL FIELDS	CRUDE OIL (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CRUDE OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL	14,609	55	4,018	2	3,535,387	19,048	1,433,503
FIELD TOTAL	14,609	55	4,018	2	3,535,387	19,048	1,433,503
ENDICOTT FIELD							
ENDICOTT POOL	3,575,240	173,979	3,323,535	27	12,382,010	345,342	11,756,732
FIELD TOTAL	3,575,240	173,979	3,323,535	27	12,382,010	345,342	11,756,732
GRANITE POINT FIELD							
MIDDLE KENAI POOL	215,149	86,991	198,687	29	107,053,013	7,669,432	92,486,640
FIELD TOTAL	215,149	86,991	198,687	29	107,055,777	7,669,432	92,488,230
KUPARUK RIVER FIELD							
CRETACIOUS UNDEF ZONE		258,770		3		54,737,977	
KUPARUK RIVER POOL	8,867,132	3,389,138	11,595,187	330	403,690,292	48,225,993	481,011,798
FIELD TOTAL	8,867,132	3,647,908	11,595,187	333	403,693,657	102,963,970	481,016,778
MCARTHUR RIVER FIELD							
HEMLOCK POOL	495,742	2,545,347	299,411	58	467,053,264	222,922,290	171,078,026
MIDDLE KENAI G POOL	89,939	59,584	43,875	12	36,106,823	4,302,360	17,983,577
WEST FORELAND POOL	33,982	54,756	12,335	4	19,148,942	5,048,034	5,462,679
FIELD TOTAL	619,663	2,659,687	355,621	74	522,309,029	232,272,684	194,524,282
MIDDLE GROUND SHOAL FIELD							
A POOL	2,297	932	5,527	1	2,001,948	1,116,572	4,362,712
B C AND D POOL	15,918	21,430	10,387	4	10,413,899	3,634,967	7,237,562
E F AND G POOL	213,908	247,249	92,594	36	140,918,225	67,705,811	65,239,457
FIELD TOTAL	232,123	269,611	108,508	41	153,334,072	72,457,350	76,839,731
PRUDHOE BAY FIELD							
LISBURNE POOL	1,377,964	212,859	7,641,307	46	22,814,979	2,013,116	83,937,836
PRUDHOE POOL	46,812,573*	20,674,344	119,210,260	689	5,536,982,083**	530,942,228	7,771,153,962
FIELD TOTAL	48,190,537*	20,887,203	126,851,567	735	5,559,797,062**	534,067,690	7,855,091,798
SWANSON RIVER FIELD							
HEMLOCK POOL	178,011	201,380	8,244,695	32	207,433,726	67,639,070	1,760,196,913
FIELD TOTAL	178,011	201,380	8,244,695	32	207,484,965	67,643,240	1,760,520,801
TRADING BAY FIELD							
HEMLOCK POOL	12,420	6,633	17,438	6	10,684,761	2,782,555	10,506,151
UNDEFINED POOL	2,412	857	3,593	1	565,445	101,024	303,683
MIDDLE KENAI B POOL	15,624	6,019	18,318	8	2,084,492	209,701	2,208,642
MIDDLE KENAI C POOL	11,560	26,786	31,989	5	18,545,510	16,808,353	12,185,982
MIDDLE KENAI D POOL	11,723	19,180	14,600	6	26,754,781	13,252,878	21,803,975
MIDDLE KENAI E POOL	5,77[illegible]	9,933	5,959	4	7,491,056	2,839,833	6,373,889
G-NE/HEMLOCK-NE POOL	18,86[illegible]	137,228	7,396	6	22,988,043	24,623,398	6,464,095
W FORELAND POOL	798		140	1	30,190	9,611	19,353
M.KENAI UNALLOCATED ZONE			159	1			1,091,783
FIELD TOTAL	79,178	206,636	99,592	38	89,144,278	60,827,353	60,957,553
TOTAL ACTIVE FIELDS	61,971,642	28,133,450	150,781,410	1,311	7,058,736,237	1,078,266,109	10,534,629,408
DAILY AVERAGE	1,999,085	907,530	4,863,916	INACTIVE	5,608,178	6,611,768	1,908,411
				ALL FIELDS	7,064,344,415	1,084,877,877	10,536,537,819

*INCLUDES 2,576,802 BBLS OF CONDENSATE
**INCLUDES 111,722,558 BBLS OF CONDENSATE

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR JANUARY, 1988

NGL PRODUCTION	NGL (BBL)	CUM NGL (BBL)
KUPARUK RIVER		
KUPARUK RIVER	116,236	3,206,170
FIELD TOTAL	116,236	3,206,170
MCARTHUR RIVER		
HEMLOCK	16,158	7,865,611
MIDDLE KENAI G	4,116	770,533
WEST FORELAND	1,679	202,633
FIELD TOTAL	21,953	8,838,777
PRUDHOE BAY		
LISBURNE	81,260	539,109
PRUDHOE	1,636,345	18,352,059
FIELD TOTAL	1,717,605	18,891,168
SWANSON RIVER		
HEMLOCK	3,074	1,187,312
FIELD TOTAL	3,074	1,187,312
TRADING BAY		
HEMLOCK	7	51,679
M.KENAI UNALLOCATED	28	307,616
FIELD TOTAL	35	359,295
TOTAL ACTIVE FIELDS	1,858,903	32,482,722
DAILY AVERAGE	59,964	
INACTIVE		0
ALL FIELDS		32,482,722

ALASKA PRODUCTION SUMMARY BY ACTIVE POOLS FOR JANUARY, 1988

GAS FIELDS	CONDEN. (BBL)	WATER (BBL)	GAS (MCF)	PROD. WELLS	CUM CONDEN. (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
BEAVER CREEK FIELD							
UNDEFINED POOL		9,554	1,248,499	4		307,605	64,174,405
FIELD TOTAL		9,554	1,248,499	4		307,605	64,174,405
BELUGA RIVER FIELD							
UNDEFINED POOL			2,219,244	14		810	255,410,915
FIELD TOTAL			2,219,244	14		810	255,410,915
EAST BARROW FIELD							
UNDEFINED POOL		29	70,864	4		1,144	4,018,393
FIELD TOTAL		29	70,864	4		1,144	4,018,393
KENAI FIELD							
STERLING 3 POOL		120	1,644,791	9		110,563	264,626,611
STERLING 4 POOL		326	1,786,373	11		85,775	368,965,099
STERLING 5.1 POOL		177	1,619,410	10		138,010	430,884,769
STERLING 6 POOL		261	2,003,838	11		43,050	399,339,906
UNDEFINED POOL		1,233	862,529	7		66,424	120,934,010
TYONEK POOL		504	496,496	4	11,877	33,199	210,254,245
FIELD TOTAL		2,621	8,413,437	52	11,877	489,721	1,839,036,275
MCARTHUR RIVER FIELD							
MIDDLE KENAI POOL			1,012,501	4			98,253,038
FIELD TOTAL			1,012,501	4			134,565,321
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL			10,664	1			114,028
UNDEFINED POOL			20,741	1			2,081,221
FIELD TOTAL			31,405	2			2,195,249
NORTH COOK INLET FIELD							
TERTIARY POOL		3,157	3,966,366	12		103,231	824,263,922
FIELD TOTAL		3,157	3,966,366	12		103,231	824,263,922
PRETTY CREEK FIELD							
UNDEFINED POOL			75,291	1		125	917,728
FIELD TOTAL			75,291	1		125	917,728
SOUTH BARROW FIELD							
UNDEFINED POOL		5	55,359	6		316	17,879,069
FIELD TOTAL		5	55,359	6		316	17,879,069
SWANSON RIVER FIELD							
UNDEFINED POOL			103,542	1			12,763,095
FIELD TOTAL			103,542	1			12,763,095
TRADING BAY FIELD							
UNDEFINED POOL			29,134	1			3,237,006
FIELD TOTAL			29,134	1			3,237,006
TOTAL ACTIVE FIELDS		15,366	17,225,642	101	11,877	902,952	3,158,461,378
DAILY AVERAGE		495	555,665	INACTIVE	0	108	10,006,579
				ALL FIELDS	11,877	903,060	3,168,467,957

ALASKA ENHANCED RECOVERY AND DISPOSAL PROJECTS FOR JANUARY, 1988

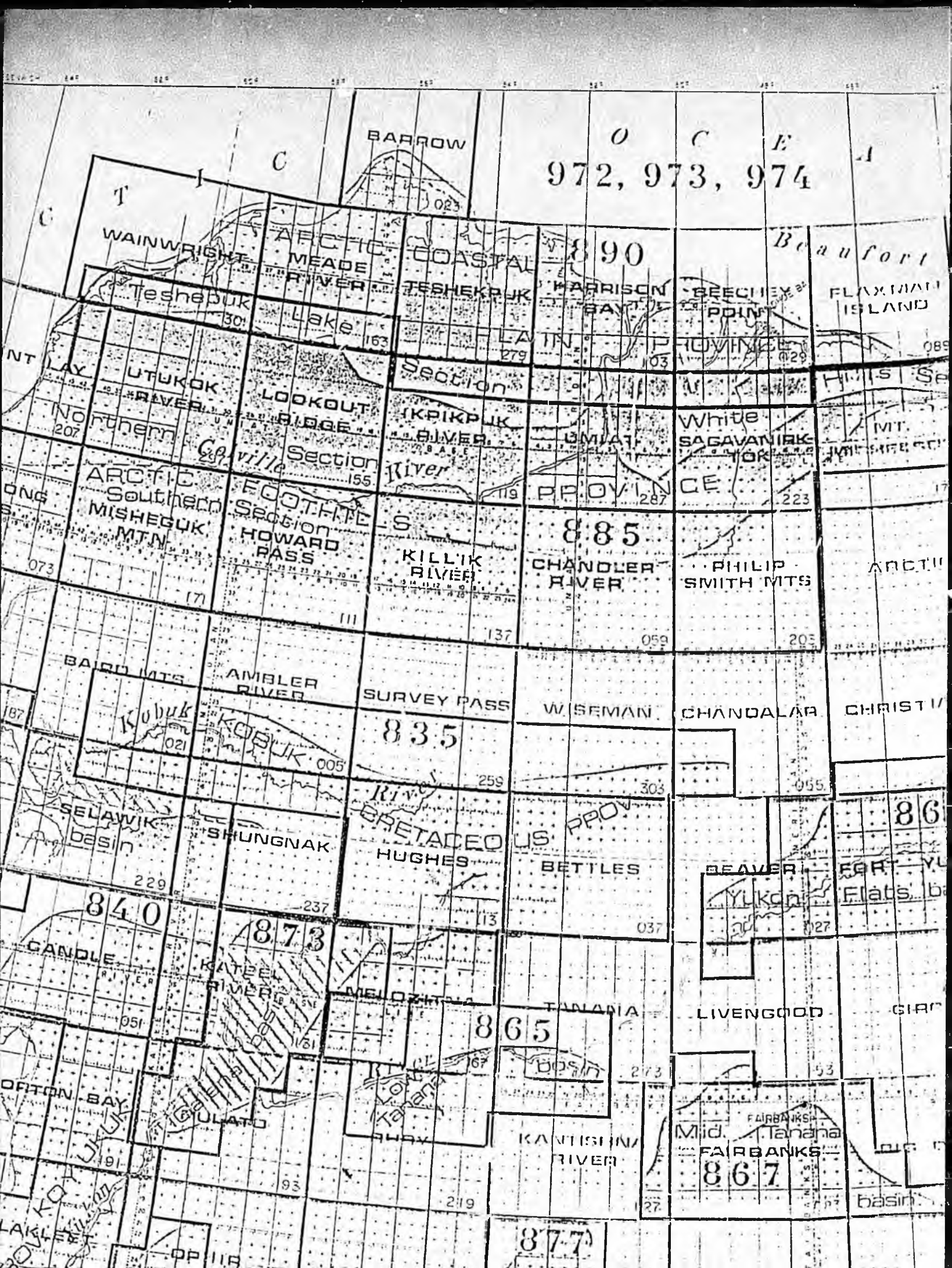
ENHANCED RECOVERY	OIL (BBL)	WATER (BBL)	GAS (MCF)	INJ. WELLS	CUM OIL (BBL)	CUM WATER (BBL)	CUM GAS (MCF)
ENDICOTT FIELD							
ENDICOTT POOL		3,981	2,747,915	3	21,036	3,982	8,363,045
FIELD TOTAL		3,981	2,747,915	3	21,036*	3,982	8,363,045
GRANITE POINT FIELD							
MIDDLE KENAI POOL		332,595		12		129,670,207	
FIELD TOTAL		332,595		12		129,670,207	
KUPARUK RIVER FIELD							
KUPARUK RIVER POOL		21,778,204	8,535,802	211		392,047,811	378,113,918
FIELD TOTAL		21,778,204	8,535,802	211		392,047,811	378,113,918
MCARTHUR RIVER FIELD							
HEMLOCK POOL		2,382,067		16		859,185,674	
MIDDLE KENAI G POOL		142,036		5		31,362,518	
WEST FORELAND POOL		32,920		1		42,390	
FIELD TOTAL		2,557,023		22		890,590,582	
MIDDLE GROUND SHOAL FIELD							
B C AND D POOL		60,316		2		26,184,044	
E F AND G POOL		406,472		15		226,589,167	
FIELD TOTAL		466,788		17		258,569,150	
PRUDHOE BAY FIELD							
LISBURNE POOL			7,343,480	3		337,626	64,084,749
PRUDHOE POOL		36,528,950	106,074,042	133	13,012,875	1,542,425,632	7,068,139,458
FIELD TOTAL		36,528,950	113,417,522	136	13,012,875*	1,542,763,258	7,132,224,207
SWANSON RIVER FIELD							
HEMLOCK POOL			8,050,939	7		8,337,995	2,022,926,300
FIELD TOTAL			8,050,939	7		8,337,995	2,022,926,300
TOTAL ACTIVE FIELDS		61,667,541	132,752,178	408	13,033,911*	3,221,982,985	9,541,527,470
DAILY AVERAGE		1,989,275	4,282,328	INACTIVE	0	127,512,325	743,988
				ALL FIELDS	13,033,911*	3,349,495,310	9,542,371,458

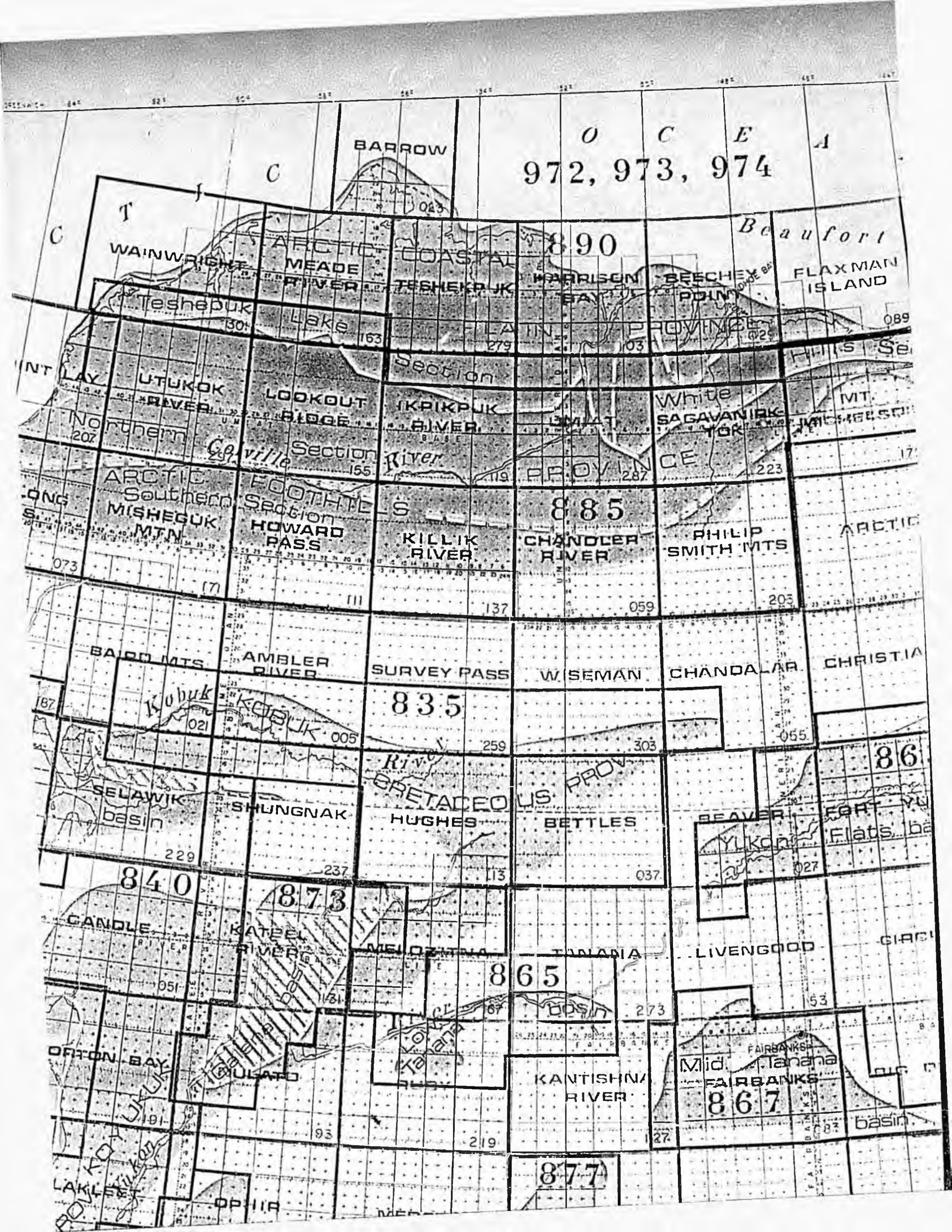
DISPOSAL PROJECTS	FLUIDS (BBL)	DISP. WELLS	CUM FLUIDS (BBL)
ENDICOTT FIELD			
UNDEFINED ZONE	165,867	2	488,558
FIELD TOTAL	165,867	2	488,558
KENAI FIELD			
UNDEFINED ZONE	2,852	1	213,548
STERLING 4 POOL	13,946	1	93,137
FIELD TOTAL	16,798	2	306,685
KUPARUK RIVER FIELD			
CRETACIOUS UNDEF ZONE	27,173	1	2,521,990
FIELD TOTAL	27,173	1	2,521,990
PRUDHOE BAY FIELD			
UNDEFINED ZONE	2,413,152	8	126,913,948
FIELD TOTAL	2,413,152	8	126,913,948
SWANSON RIVER FIELD			
UNDEFINED ZONE	210,429	3	1,954,881
FIELD TOTAL	210,429	3	1,954,881
TOTAL ACTIVE FIELDS	2,833,419	16	132,186,062
DAILY AVERAGE	91,400	INACTIVE	43,475
		ALL FIELDS	132,229,537

*FLUIDS RETURNED TO RESERVOIR, NOT ENHANCED RECOVERY

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 PORCUPINE DR ANCHORAGE, AK. 99501-3192

BULK RATE
U.S. POSTAGE
PAID
ANCHORAGE, AK.
PERMIT NO. 356


OCEA
972, 973, 974
BARROW
WAINWRIGHT
ARCTIC COASTAL
MEADE RIVER
TESHEKPUK
Teshepuk Lake
890
HARRISON BAY
BEECHEY POINT
Beaufort
FLAXMAN ISLAND
LAKE
UTUKOK RIVER
Northern
LOOKOUT RIDGE
Section
IKPIKPUK RIVER
UMIAT
White
SAGAVANIRKTOK
MT. MICHELSON
ARCTIC FOOTHILLS
Southern
Section
MISHEGUK MTN
HOWARD PASS
KILLIK RIVER
885
CHANDLER RIVER
PHILIP SMITH MTS
ARCTIC
BAIRD MTS
AMBLER RIVER
SURVEY PASS
835
WISEMAN
CHANDALAR
CHRISTIAN
Kobuk
KOBUK
SELAWIK basin
SHUNGNAK
CRETACEOUS
HUGHES
BETTLES
BEAVER
FORT YUKON
Yukon Flats basin
840
873
CANDLE
KATEEL RIVER
MEDFRA
TANANA
LIVENGOOD
865
basin
KOYUKUK
KANTISHNA RIVER
FAIRBANKS
Mid. Tanana
867
877
LAKE


OCEA
972, 973, 974
BARROW
Beaufort
WAINWRIGHT
ARCTIC COASTAL
MEADE RIVER
TESHEKPUK
HARRISON BAY
BEECHEY POINT
FLAXMAN ISLAND
Teshepuk Lake
Section
UTUKOK RIVER
LOOKOUT RIDGE
IKPIKPUK RIVER
White
SAGAVANIRKTOK
MT MICHELSON
Northern
Colville
Section
River
PROVINCE
ARCTIC FOOTHILLS
Southern Section
MISHEGUK MTN
HOWARD PASS
KILLIK RIVER
CHANDLER RIVER
PHILIP SMITH MTS
ARCTIC
BALDWIN MTS
AMBLER RIVER
SURVEY PASS
WISEMAN
CHANDALAR
CHRISTIA
Kobuk
KOBUK
SELAWIK basin
SHUNGNAK
CRETACEOUS
HUGHES
BETTLES
BEAVER
FORT YU
Yukon Flats ba
CANDLE
KATEEL RIVER
MELOZITNA
TANANA
LIVENGOOD
KANTISHNA RIVER
Mid. Tanana
FAIRBANKS
basin
ORTON BAY
BULLATO
LAKLEET
OPHIR
840
873
865
867
877

gas. Prim. y objectives were the shallow Stevens sands with the average depth of wells completed in 1975 about 4,088 ft.

The five-year program is designed to increase the field's daily producing capability to about 400,000 bbls of oil. Nine rigs were drilling on the Elk Hills development program at the end of the year.

Bids were taken during the year for a deep test, 20,000 ft, on the Naval Reserve in 4-31s-24e. The test was expected to begin in early 1976. The deepest previous test at Elk Hills was drilled to 12,856 ft.

Alaska

Development drilling in the Prudhoe Bay field dominated activity in Alaska during 1975 as operators pushed ahead full speed during the first full year of construction on the trans-Alaska pipeline. Atlantic Richfield and BP Alaska completed 26 development wells at Prudhoe, most of them unperforated Sadlerochit formation wells.

Six North Slope exploratory wells were plugged and abandoned, one was completed, and six were suspended pending further evaluation. The single completion was Mobil Oil's Gwydyr Bay South 1 wildcat, which flowed 2,300 BOPD through a half-inch choke during testing. Atlantic Richfield suspended several exploratory wells west of Prudhoe Bay which found oil in the shallow Kuparuk River oil pool, an area which could be producing by 1980 if a water flood project can be economically designed. The primary exploratory target in 1975 was the Lisburne formation, which didn't produce any significant discoveries.

In the Cook Inlet area, 23 development wells were completed, mostly offshore in Cook Inlet and in the Swanson River field on the Kenai Peninsula. There were four exploratory wells plugged and abandoned in the Cook Inlet area last year. One of them was the Standard Oil Company of California's Kasilof 1, drilled by the George F. Ferris jack-up rig. Cities Service had a gas discovery on the west side of Cook Inlet when its Lewis River 1 well flow tested 7.4 million cu ft per day from two zones.

Standard Oil Company of California drilled two rank wildcats in the Selawik Basin near Kotzebue on Alaska's northwest coast. The wells were drilled under SoCal's exploration agreement with the NANA native regional corporation and both were plugged and abandoned. Late in 1975 Louisiana Land and Exploration was preparing to drill the first of four rank wildcats in the Kandik Basin between Fairbank and the Canadian border. LL&E was to drill the four on native lands belonging to the Doyon, Ltd native regional corporation, headquartered in Fairbanks. At the end of the year six other oil companies had exploration agreements with four other native regional corporations and some observers were anticipating an increase in wildcatting on native lands during 1976.

Probably the biggest industry disappointment in Alaska during 1975 was the failure of the COST 1 stratigraphic test to reach its 16,000-foot objective in the storm-swept Gulf of Alaska. After a late season start, the drillship Glomar Conception struggled with boulder strewn bottom conditions and 30-foot waves for 10 weeks before abandoning the strat hole at a total depth of only 5,150 feet, far too shallow to provide the solid geologic information needed to evaluate the sediments of the Gulf of Alaska before this spring's proposed OCS lease sale. More than $12 million was reportedly spent on the well by the 26 participating companies.

In Naval Petroleum Reserve No. 4, the Navy drilled two exploratory wells during 1975. One was completed as a shallow gas producer and the deep exploratory test at Camp Halkett was plugged and abandoned after finding only non-commercial oil shows. Husky Oil NPR Operations won a five-year contract to conduct a seismic and drilling exploratory program for the Navy on the huge reserve and the first of two dozen exploratory wells in the project was due to be spudded early in 1976.

The Alaska state legislature passed a 20-mill tax on oil and gas reserves in-place during the 1975 session. The levy takes effect during 1976 and is expected to cost the owners of Prudhoe Bay reserves hundreds of millions of dollars during the next two years. An environmental lawsuit blocked Shell Oil and SoCal from beginning exploratory drilling on $25 million worth of leases in Kachemmak Bay won during the 1973 state lease sale. The administration of Gov. Jay Hammond has also called for legislative approval for canceling the leases to protect the rich fishing area from exploratory drilling. The Beaufort Sea lease sale was postponed by the Hammond administration and that area offshore from Prudhoe Bay had not been drilled at year's end.

Overall, there were 70 drilling permits issued by the state during 1975, a slight increase over the 61 permits issued the year before, but more than twice the 31 permits issued in 1972. The record year for drilling in Alaska was 1969, following the discovery of the Prudhoe Bay giant, when 122 drilling permits were issued.

Marine seismic work was at record levels during 1975 as companies prepared for the series of OCS sales scheduled in Alaskan waters during the following three years. At one time there were 24 seismic vessels operating in the Gulf of Alaska, Bristol Bay, the Bering Sea, the Beaufort Sea, and Lower Cook Inlet.

More than 55 percent of the pipeline portion of the oil pipeline from Prudhoe Bay to Valdez was completed during 1975 and Alyeska Pipeline Service Company and its contractors had more than 21,000 persons at work during the peak of the construction season. More than 370 miles of the 400-mile pipeline were installed by the end of the year. Alyeska is right on schedule to meet its 600,000 BOPD start-up of the pipeline in mid-1977 and 1.2 million BOPD throughput by the end of that year.

West Coast-Alaska Region
1975 New Field Wildcat Discoveries

Alaska

Operator	Well Name	Location	Initial Potential	Total Depth
Barrow Quad				
U.S.Navy	1 Iko	16-21n-16w	F 1,000 MCFGPD	2,700
Beechy Point Quad				
Mobil Oil	Gwydyr Bay South #1	8-12n-13e	F 2,300 BOPD	12,237
Tyonek Quad				
Cities Service Oil	Lewis River #1	2-14n-9w	F 7,400 MCFGPD	9,480

California

Operator	Well Name	Location	Initial Potential	Total Depth
Fresno County				
Quintana Petroleum	1 McDonald	18-17s-16e	F 117 BOPD	10,081
Glenn County				
Occidental Petroleum	1-12 Morrissey	12-22n-3w	F 4,335 MCFGPD	5,711
Kern County				
Tenneco Oil	22X-34 N. San Emidio	34-12n-21w	F 550 BOPD	16,520
Santa Barbara County				
Atlantic Richfield	1 U.S. Miller	4-9n-26w	F 320 BOPD	8,400
Solano County				
Atlantic Oil	1 McCune	4-7n-1e	F 3,000 MCFGPD	not reptd
Yolo County				
Shell Oil	1-28 Stephens	28-9n-2e	shut in	7,504
Shell Oil	1-15 Russell	15-9n-2e	shut in	6,712

continued to increase. Total state output of oil since t' · trans-Alaska pipeline went on stream in 1977 increased to where Alaska ranked third in the nation in crude production. While still well behind the national leader, Texas, Alaska could pass second place Louisiana in 1979.

Washington and Oregon

Two dry holes were completed in the two-state area in 1978, one in Oregon and one in Washington. A 7684 ft wildcat was abandoned in Hearney County, Oregon; while a 377 ft wildcat drilled in Lewis County, Washington, proved unsuccessful. However, at year-end, Mobil Oil was drilling at a projected 14,000 ft (Eocene) wildcat in Oregon's Douglas County. The 1 Sutherlin Unit, 36-24s-5w, will be, upon completion, the deepest well ever drilled in the state. Mobil had leased approximately one million acres in the state, including a large portion of the southern end of the Willamette Valley. The company scheduled two Linn County wildcat ...a proposed 10,500 ft well in 28-15s-3w and a 12,000 ft well in 14-13s-3w...to be drilled after the Sutherlin is complete. Six 4500 ft Eocene wells were scheduled by Farnham Chemical, also in Linn County.

1978 U.S. Drilling
West Coast-Alaska Region
Well Completions by County

Alaska

	NFW					OEXP					All Wells				
Quad	Oil	Gas	Dry	Total	Footage	Oil	Gas	Dry	Total	Footage	Oil	Gas	Dry	Total	Footage
Barrow	0	0	0	0	0	0	0	0	0	0	0	2	0	2	4,682
Beechey Point	1	1	4	6	67,839	0	0	1	1	7,626	21	4	5	30	308,591
Chandler Lake	0	0	1	1	16,457	0	0	0	0	0	0	0	1	1	16,457
Harrison Bay	0	0	3	3	27,686	0	0	0	0	0	0	0	3	3	27,686
Kenai	0	0	1	1	14,200	0	0	0	0	0	20	1	3	24	156,814
Meade River	0	0	1	1	12,588	0	0	0	0	0	0	0	1	1	12,588
Teshekpuk	0	0	1	1	7,946	0	0	0	0	0	0	0	1	1	7,946
Tyonek	0	1	1	2	17,124	0	0	0	0	0	0	1	1	2	17,124
Total	1	2	12	15	163,840	0	0	1	1	7,626	41	8	15	64	551,888
Alaska—Offshore															
Icy Bay	0	0	3	3	37,204	0	0	0	0	0	0	0	3	3	37,204
Middleton Island	0	0	1	1	13,507	0	0	0	0	0	0	0	1	1	13,507
Albatross Bank	0	0	0	0	0	0	0	0	0	0	0	0	1	1	9,357
Total	0	0	4	4	50,711	0	0	0	0	0	0	0	5	5	60,068
California															
Alameda	0	0	0	0	0	0	0	0	0	0	0	0	2	2	2,445
Butte	0	0	0	0	0	0	0	1	1	3,920	0	0	1	1	3,920
Colusa	0	1	2	3	17,271	0	0	3	3	18,359	0	9	10	19	123,053
Contra Costa	0	0	4	4	32,299	0	2	0	2	9,209	0	5	13	18	82,290
Fresno	1	0	3	4	36,217	0	1	4	5	26,665	76	2	13	91	250,986
Glenn	0	0	6	6	22,016	0	2	9	11	28,632	0	6	21	27	96,428
Humboldt	0	0	2	2	7,215	0	1	0	1	6,016	0	3	2	5	17,643
Kern	0	0	14	14	83,245	14	1	35	50	302,408	1,442	9	90	1,541	3,753,109
Kings	0	0	8	8	83,551	0	0	2	2	18,831	1	1	15	17	117,081
Lake	0	0	1	1	8,231	0	0	0	0	0	0	0	1	1	8,231
Los Angeles	0	0	0	0	0	1	0	5	6	57,161	49	0	12	61	237,579
Madera	0	0	0	0	0	0	1	1	2	14,601	0	1	1	2	14,601
Merced	0	0	2	2	10,800	0	0	0	0	0	0	0	2	2	10,800
Modoc	0	0	0	0	0	0	0	1	1	3,400	0	0	1	1	3,400
Monterey	0	0	6	6	23,167	0	0	1	1	1,023	30	0	8	38	95,100
Orange	0	0	0	0	0	0	0	0	0	0	20	0	2	22	58,025



Alaska

The costly plunge into the icy waters of the Beaufort Sea became a reality for Alaskan wildcatters in 1980, as Sohio Alaska Petroleum Co was the first operator to sink a drill bit on leases that drew $1.056 billion in December, 1979. Other highlights in the state had work continuing on two major projects designed to enhance oil recovery from proved reserves, a massive waterflood for the Prudhoe Bay oil field and a drilling and development program for the Kuparuk formation about 30 miles west of Prudhoe Bay.

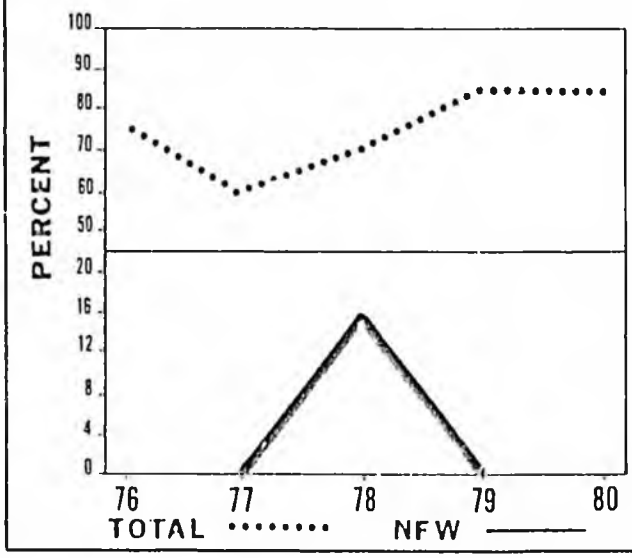
On the production side, Alaska wells produced about 1.6 million bbls of oil daily to keep the state in number two position in the ranks of the nation's oil producing

Alaska

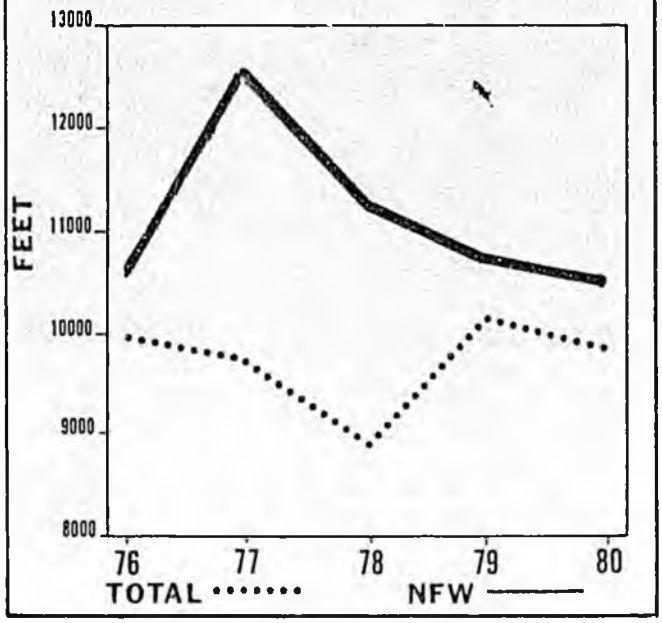
New Field Wildcats

	Oil	Gas	Dry	Total	Footage
1980	0	0	19	19	199,965
1979	0	0	14	14	150,734
1978	1	2	16	19	214,551
1977	0	0	17	17	214,928
1976	0	0	11	11	117,351
Other Exploratory Wells					
1980	2	0	0	2	16,765
1979	0	1	1	2	13,755
1978	0	0	1	1	7,626
1977	1	0	0	1	11,926
1976	1	0	1	2	19,492
All Wells Drilled for Oil or Gas					
1980	136	4	24	166	1,027,538
1979	87	4	15	106	1,073,506
1978	41	8	20	69	611,956
1977	33	7	25	65	635,756
1976	36	3	13	52	518,125

1976-1980 Comparison Success Rate For All Wells and New Field Wildcats Alaska



1976-1980 Comparison Average Depth of All Wells and New Field Wildcats Alaska



states. Texas was first with its production of 2.7 million bbls of oil per day. Alyeska Pipeline Service Co completed 1980 operations with two mileposts in December: the passage of the 1.5 billionth bbl of oil from the Prudhoe Bay field to Valdez, and the departure from the trans-Alaska pipeline's Marine Terminal of the 2,000th tanker loaded with North Slope crude.

A record number of state drilling permits were issued during 1980, a total of 149. It was the largest number of drilling permits issued in one year since 1969, when 122 were issued following the Prudhoe Bay discovery. The number of development wells completed in 1980, 103, was also a record. The previous high was 85 in 1968. Nine exploratory wells were drilled on state and private land during the year, the third lowest number on record. Seven were drilled in 1959, eight in 1971 and nine each in 1960 and 1972. The high was 49 in 1969. The 166 total completions in Alaska in 1980 is 60 more than were completed in 1979.

1980 U.S. Drilling Alaska Ten Leading Quads

Rank	Quad	State	Completions
1	Beechey Point	Alaska	131
2	Kenai State Offshore	Alaska	12
3	Kenai	Alaska	5
4	Barrow	Alaska	4
5	Gulkana	Alaska	2
5	Harrison Bay	Alaska	2
5	Soldovia Federal Offshore	Alaska	2
5	Teshekpuk	Alaska	2
9	Iliamna Federal Offshore	Alaska	1
9	Killik River	Alaska	1
9	Tyonek	Alaska	1
9	Umnak	Alaska	1
9	Umiat	Alaska	1
9	Wainwright	Alaska	1

1980 U.S. Drilling Alaska Estimated Drilling and Completion Costs by Depth Range

All Wells Drilled for Oil or Gas

Depth Range	Wells	Footage	Estimated Cost
02	2	4,441	$ 4,599,915
03	1	3,666	3,045,713
04	1	4,170	3,460,683
05	10	67,333	33,983,475
06	51	454,099	162,022,356
07	83	848,167	356,517,462
08	13	161,485	64,295,710
09	4	63,842	93,455,337
11	1	20,335	16,876,017
1980 Total	166	1,627,538	$738,256,668
1979 Total	106	1,073,506	$399,349,227
1978 Total	69	611,956	$232,852,382
1977 Total	65	635,756	$230,208,829
1976 Total	52	518,125	$144,245,008

Depth Range

01 = 00000-01249	06 = 07500-09999
02 = 01250-02499	07 = 10000-12499
03 = 02500-03749	08 = 12500-14999
04 = 03750-04999	09 = 15000-17499
05 = 05000-07499	10 = 17500-19999

11 = 20000-deeper

Sohio spudded the first Beaufort Sea probe, Challenge Island #1, on November 1, and was drilling below 12,000 ft at year-end. The hole is being directionally drilled from tract BF 109 to the three-way intersection of BF 95, BF 108 and BF 109. BF 95 is held by BP, Sohio, NANA, Koniag and Sealaska; BF 108 by Mobil, Phillips and Chevron; and BF 109 by Exxon. All lessees are participating in the well, with Sohio acting as operator.

Sohio also was preparing to drill three other exploratory probes in the Beaufort Sea at the end of the year. The wells will be drilled in the Sag Delta area, two from

1980 U.S. Drilling
Alaska
Well Completions by Quad

Alaska

	NFW					OEXP					All Wells				
Quad	Oil	Gas	Dry	Total	Footage	Oil	Gas	Dry	Total	Footage	Oil	Gas	Dry	Total	Footage
Barrow	0	0	2	2	7,836	0	0	0	0	0	0	1	3	4	12,277
Beechey Point	0	0	1	1	11,372	2	0	0	2	16,765	126	1	4	131	1,356,101
Gulkana	0	0	2	2	13,605	0	0	0	0	0	0	0	2	2	13,605
Harrison Bay	0	0	2	2	20,544	0	0	0	0	0	0	0	2	2	20,544
Kenai	0	0	1	1	12,903	0	0	0	0	0	2	2	1	5	42,947
Killik River	0	0	1	1	17,000	0	0	0	0	0	0	0	1	1	17,000
Teshekpuk	0	0	2	2	22,986	0	0	0	0	0	0	0	2	2	22,986
Tyonek	0	0	1	1	11,776	0	0	0	0	0	0	0	1	1	11,776
Umiat	0	0	1	1	15,611	0	0	0	0	0	0	0	1	1	15,611
Umnak	0	0	1	1	7,505	0	0	0	0	0	0	0	1	1	7,505
Wainwright	0	0	1	1	20,335	0	0	0	0	0	0	0	1	1	20,335
Total	0	0	15	15	161,473	2	0	0	2	16,765	128	4	19	151	1,540,687

Alaska—Offshore

Seldovia	0	0	2	2	14,517	0	0	0	0	0	0	0	2	2	14,517
Iliamna	0	0	1	1	14,975	0	0	0	0	0	0	0	1	1	14,975
Kenai	0	0	1	1	9,000	0	0	0	0	0	10	0	2	12	57,359
Total	0	0	4	4	38,492	0	0	0	0	0	10	0	5	15	86,851

1980 U.S. Drilling
Alaska
Reported Discovery Well Completions
Including New Field Wildcats, New Pay Discoveries & Field Extensions

Discovery Type	Operator	Well Name	Location	Producing Formation	Total Depth	Initial Potential
Beechey Point Quad						
Extension	Arco O&G	12 West Sak 25647	5-11n-10e	Formation not reported 6001-6259	6382	F 1390 BOPD
Extension	Arco O&G	1 West Bay State	1-11n-14e	Formation not reported 8560-8902	10,383	F 3300 BOPD + 23,600 MCFGPD



Alaska

Efforts to develop Alaska's existing producing areas remained constant in 1981, but a decrease in exploration resulted in an overall three percent decline in statewide activity. The year's 161 completions were five less than a year ago, but resulted in an equal number of productive wells, 142, as the success rate improved two percentage points to 88 percent. Successful completions included 139 oil wells, one more than last year, and three gas, one less than in 1980.

Though several promising wildcats were being tested at year's end, completions in that category were down 37 percent and no new field discoveries were reported complete for the third straight year. Twelve wells were drilled in search of new producing areas in 1981, seven fewer than a year ago and four less than the 16 wildcats drilled on the average for each of the past four years.

Four wells were drilled in search of new pays or to extend known reservoirs, but only one, a gas well, was successful. Only two "other exploratory" wells were drilled last year, neither of which produced, and from

Alaska

New Field Wildcats

	Oil	Gas	Dry	Total	Footage
1981	0	0	12	12	120,020
1980	0	0	19	19	199,965
1979	0	0	14	14	150,734
1978	1	2	16	19	214,551
1977	0	0	17	17	214,923

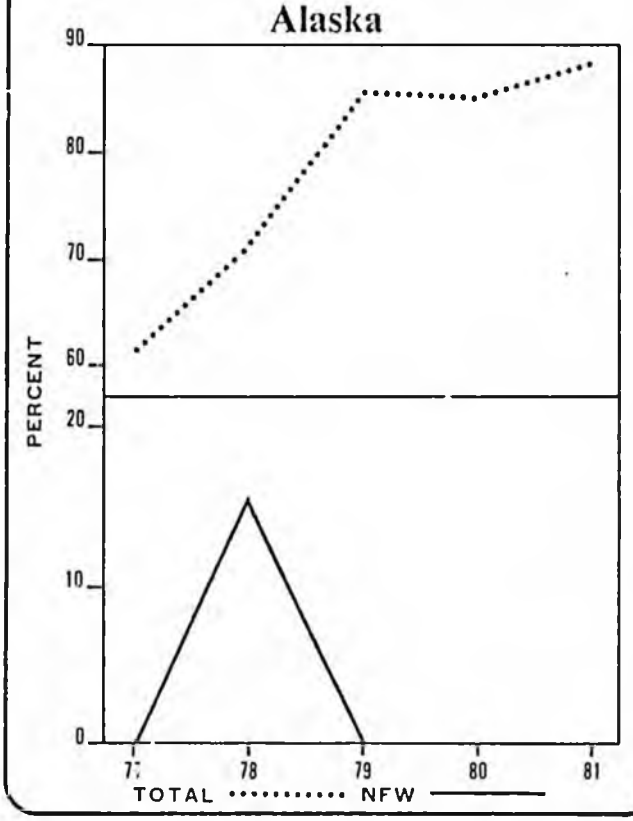
Other Exploratory Wells

1981	0	1	3	4	38,190
1980	2	0	0	2	16,765
1979	0	1	1	2	13,755
1978	0	0	1	1	7,626
1977	1	0	0	1	11,926

All Wells Drilled for Oil or Gas

1981	139	3	19	161	1,487,672
1980	138	4	24	166	1,627,538
1979	87	4	15	106	1,073,506
1978	41	8	20	69	611,956
1977	33	7	25	65	635,756

1977-1981 Comparison
Success Rate for All Wells and New Field Wildcats
Alaska



1981 U.S. Drilling
Alaska
Estimated Drilling and Completion Costs by Depth Range

All Wells Drilled for Oil or Gas

Depth Range	Wells	Footage	Estimated Cost
02	1	2,278	$ 2,562,613
04	2	8,375	7,076,767
05	8	33,786	23,585,599
06	34	307,875	147,975,482
07	104	982,721	371,777,078
08	9	104,905	46,072,601
09	3	47,732	80,675,347
1981 Total	161	1,487,672	$679,725,487
1980 Total	166	1,627,538	$838,927,251
1979 Total	106	1,073,506	$463,782,888
1978 Total	69	611,956	$263,483,387
1977 Total	65	635,756	$244,521,797

Depth Range

01=00000-01249 06=07500-09999
02=01250-02499 07=10000-12499
03=02500-03749 08=12500-14999
04=03750-04999 09=15000-17499
05=05000-07499 10=17500-19999
11=20000-deeper

expenditures were down 19 percent in Alaska in 1981, to $679,725,487. The state ranked 10th nationally in total expenditures although it accounted for only one of every 475 wells drilled in the U.S. The average well in Alaska cost $4,221,848 to drill in 1981.

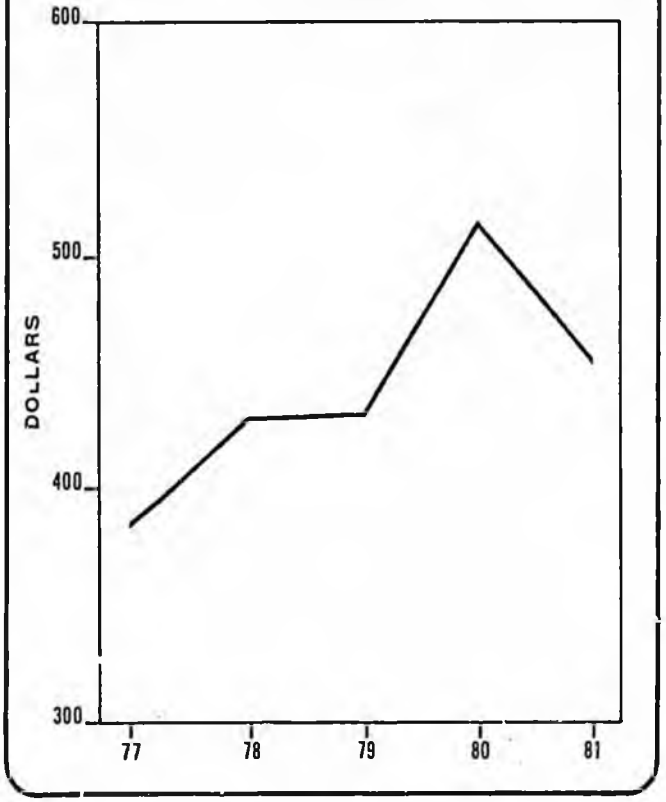
North-central Alaska's Beechey Point Quad, which includes the Prudhoe Bay area, continued to attract better than three-quarters of all Alaska activity with 122 completions in 1981. Last year, when 131 wells were completed in the quad, Beechey Point accounted for about 79 percent of Alaska activity. The state's second most active quad was Kenai State Offshore with 16 completions followed by Kenai Quad in third with six completions. Both quads are in south-central Alaska. Barrow Quad was the fourth most active in the state with three completions, while a pair of wells each were completed in three quads and eight quads reported one well completion each in 1981.

Sohio, with 66 Alaska completions, replaced ARCO Oil & Gas as the state's leading operator. The company's efforts resulted in 63 oil wells and three dry holes, one of which was a wildcat. A year ago, Sohio ranked second with 58 completions, 56 oil wells and two dry holes. ARCO dropped a notch to second completing 14 fewer wells than a year ago. Out of 57 completions, ARCO had 55 oil wells and two failures, one drilled in search of a new field. Last year, ARCO drilled 71 wells, 67 of which were successful.

Union Oil of California again ranked third, completing 15 wells in 1981. Thirteen of those produced oil and two were dry holes. The company was 100 percent successful in its 1980 completions with eight oil and two gas wells. Chevron USA replaced the U.S. Geological Survey in fourth place completing seven wells, four oil, one gas and two dry wildcats. No completions were reported for Chevron in 1980. The U.S.G.S., with four completions, two gas and two wildcat failures, ranked fifth in 1981. Last year, the U.S.G.S. drilled seven dry holes, six of which were wildcats. Husky Oil, which completed five wells a year ago, was not listed among the state's top five operators in 1981.

Thirteen years after the discovery of Prudhoe Bay, Alaska's North Slope boasts several recent, probably commercial discoveries, and December 15 began producing its first oil beyond Prudhoe Bay boundaries. Oil

1977-1981 Comparison
Average Cost per Foot—All Wells
Alaska



from the Kuparuk River field, about 40 miles west of Prudhoe Bay, began flowing about 50,000 bbls of oil per day through ARCO's gathering system to the trans-Alaska oil pipeline in mid-December and was expected to reach a daily production rate of 95,000 barrels by mid-January 1982.

The search for what industry hopes could be Alaska's

1981-1980 U.S. Drilling Comparison—Five Leading Operators Ranked by Total Completions

Alaska

Operator		New Field Wildcats				All Wells Drilled			
		Oil	Gas	Dry	Total	Oil	Gas	Dry	Total
1. Sohio	1981	0	0	1	1	63	0	3	66
	1980	0	0	0	0	56	0	2	58
2. Arco	1981	0	0	1	1	55	0	2	57
	1980	0	0	3	3	66	1	4	71
3. Union Oil of California	1981	0	0	0	0	13	0	2	15
	1980	0	0	0	0	8	2	0	10
4. Chevron	1981	0	0	2	2	4	1	2	7
	1980	0	0	0	0	0	0	0	0
5. USGS	1981	0	0	2	2	0	2	2	4
	1980	0	0	6	6	0	0	7	7

next giant field centers on the icy waters of the Beaufort Sea where seven new field wildcats were being drilled from natural barrier islands and man-made islands at year-end. Three were drilled last year.

The Interior Department is looking at offshore frontier basins in Alaskan waters for more energy self-sufficiency, and in July announced a proposed five-year offshore oil and gas leasing plan that calls for 16 sales in Alaskan waters during 1982-86. In anticipation of the sales, ARCO and 17 other companies plan to spend about $150 million to drill three stratigraphic tests during 1982 in the Bering Sea off the west coast of Alaska. The Sedco 708 semi-submersible and the Key Singapore jackup rig will do the drilling.

The state also has an ambitious oil and gas leasing schedule that calls for 16 sales during 1982-85. In addition, the Bureau of Land Management will offer 1.5 million acres at its oil and gas lease sale #821 scheduled to be held January 27, 1982 in Fairbanks. The sale was originally scheduled for December 16, but was postponed because of the oil industry's uncertainty about anti-trust regulations established by the U.S. Department of Justice. Some of the regulations contested by the industry were subsequently eliminated and the lease sale rescheduled. The Justice Department regulations eliminated called for cost estimates of recoverable crude oil and natural gas, accompanied by detailed explanations of how the estimates were arrived at.

On December 15 President Reagan signed into law a waiver package designed to remove government obstacles hindering development of a private sector financing plan for the Alaska Natural Gas Transportation System. The congressional battle over the complex financing package, intended to make private financing of the project less risky, won final approval in the House of Representatives just five days before the December 15 deadline. Opponents of the legislation are considering court action to try and overturn it. Despite the potential lawsuit, the pipeline's builders were visiting the world's finest financial institutions, seeking to borrow billions of dollars for the largest privately-funded construction project in world history.

1981 U.S. Drilling Alaska Ten Leading Quads

Rank	Quad	State	Completions
1	Beechey Point	Alaska	122
2	Kenai State Offshore	Alaska	16
3	Kenai	Alaska	6
4	Barrow	Alaska	3
5	Flaxman	Alaska	2
5	Harrison Bay	Alaska	2
5	Tyonek	Alaska	2
8	Afognak Federal Offshore	Alaska	1
8	Ikpikpuk River	Alaska	1
8	Lookout Ridge	Alaska	1
8	Meade River	Alaska	1
8	Point Lay	Alaska	1
8	Seldovia Federal Offshore	Alaska	1
8	Sutwik Island	Alaska	1
8	Tyonek State Offshore	Alaska	1

On the production side, Alaskan wells produced about 1.6 million bbls of oil daily during the year allowing the state to maintain its number two position in the ranks of oil producing states. Texas remains number one with its daily production of nearly 2.6 million bbls per day.

1981 U.S. Drilling
Alaska
Well Completions by Quad

Alaska

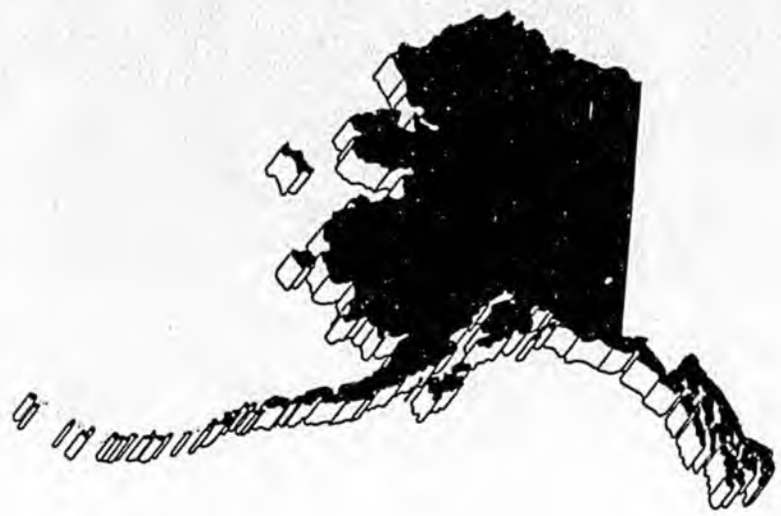
Quad	NFW Oil	NFW Gas	NFW Dry	NFW Total	NFW Footage	OEXP Oil	OEXP Gas	OEXP Dry	OEXP Total	OEXP Footage	All Wells Oil	All Wells Gas	All Wells Dry	All Wells Total	All Wells Footage
Barrow	0	0	1	1	4,015	0	1	0	1	4,360	0	2	1	3	10,653
Beechey Point	0	0	1	1	11,356	0	0	0	0	0	118	0	4	122	1,271,607
Flaxman	0	0	1	1	13,587	0	0	1	1	15,074	0	0	2	2	28,661
Harrison Bay	0	0	2	2	17,310	0	0	0	0	0	0	0	2	2	17,310
Ikpikpuk River	0	0	1	1	5,882	0	0	0	0	0	0	0	1	1	5,882
Kenai	0	0	0	0	0	0	0	1	1	10,731	5	0	1	6	10,733
Lookout River	0	0	1	1	11,200	0	0	0	0	0	0	0	1	1	11,200
Meade River	0	0	1	1	6,690	0	0	0	0	0	0	0	1	1	6,690
Point Lay	0	0	1	1	17,038	0	0	0	0	0	0	0	1	1	17,038
Sutwik Island	0	0	1	1	10,907	0	0	0	0	0	0	0	1	1	10,907
Tyonek	0	0	0	0	0	0	0	1	1	8,025	0	1	1	2	14,844
Total	0	0	10	10	97,985	0	1	3	4	38,190	123	3	16	142	1,405,525

Alaska Offshore

Afognak	0	0	1	1	8,907	0	0	0	0	0	0	0	1	1	8,907
Seldovia	0	0	1	1	13,128	0	0	0	0	0	0	0	1	1	13,128
Kenai	0	0	0	0	0	0	0	0	0	0	15	0	1	16	60,111
Tyonek	0	0	0	0	0	0	0	0	0	0	1	0	0	1	1
Total	0	0	2	2	22,035	0	0	0	0	0	16	0	3	19	82,147

1981 U.S. Drilling
Alaska
Reported Discovery Well Completions
Including New Field Wildcats, New Pay Discoveries & Field Extensions

Discovery Type	Operator	Well Name	Location	Producing Formation	Total Depth	Initial Potential
Extension	U.S.G.S.	2 Walakpa	31-20n-19w	Formation & Interval not reported	4360	Gas Well



Alaska

Marking a year of substantial expansion in Alaskan development drilling, 1982 brought a 33.5 percent rise in total reported completions. Of the 215 new wells, all but 17 were infill and resulted in 180 field oil producers, a gain of 29.5 percent. Gas completions in existing fields more than tripled from two in 1981 to nine this past year.

Alaskan wildcat activity increased 8.3 percent, from 12 to 13 wells, but returned mixed results. Though encouraging gas shows were encountered in several wells, 1982 became the fourth consecutive year without a single new field discovery. At the same time, four "other exploratory" wells drilled in search of new pays or to extend known reservoirs were also unsuccessful. This matches the number completed a year ago, when one test was reported successful. The overall success rate for 1982 completions remained close to the five-year high of 1981, showing only a 9.3 percent dip to 87.9 percent.

Alaska's average 1982 well was drilled 557 ft deeper to 9797 ft. A total of 41.6 percent more rock was penetrated, with operators having drilled 2,106,338 ft by year-end. Despite this increase, the average cost per ft of hole dropped by 7.2 percent to $386.11. Though Alaska's total estimated drilling and completion expenditures were 31.4 percent higher than in 1981, the average 1982 well cost an estimated $3,782,678—1.6 percent less than the average 1981 well. This was 9.4 times the national average and continued to distinguish Alaska as the most expensive state in which to drill. While ranking eighth in terms of total estimated expenditures, the state was the site of only one in every 394 U.S. wells completed in 1982.

Alaska's average wildcat hit bottom at 10,530 ft, 528 ft deeper than in the previous year. This reverses an average 4.7 percent per year shallowing trend which had continued since 1978. Footage cut in wildcatting increased 14.1 percent, to 136,887 ft. "Other exploratory" wells averaged 600 ft deeper at 10,148 ft than in 1981, and in total, penetrated 6.0 percent more hole.

ARCO again took the lead as Alaska's most active operator, replacing Sohio with 119 wells, more than double its 1981 completion total. Sohio decreased its drilling by 12.1 percent to 58 reported completions, but held second place among the top operators. Both companies completed no new gas wells, concentrating on the more lucrative infill oil drilling, with ARCO successfully completing 111 wells and Sohio 56. Union Oil of California ranked third for the third straight year, achieving a [illegible] percent success rate by completing seven new oil wells and eight new gas producers. Chevron USA retained its four

Alaska

New Field Wildcats

	Oil	Gas	Dry	Total	Footage
1982	0	0	13	13	136,887
1981	0	0	12	12	120,020
1980	0	0	19	19	199,965
1979	0	0	14	14	150,734
1978	1	2	16	19	214,551

Other Exploratory Wells

1982	0	0	4	4	40,474
1981	0	1	3	4	38,196
1980	2	0	0	2	16,768
1979	0	1	1	2	13,758
1978	0	0	1	1	7,628

All Wells Drilled for Oil or Gas

1982	180	9	26	215	2,106,338
1981	139	3	19	161	1,487,672
1980	138	4	24	166	1,627,534
1979	87	4	15	106	1,073,550
1978	41	8	20	69	611,[illegible]

1982 U.S. Drilling
Alaska
Ten Leading Quads

Rank	Quad	State	Completions
1	Beechey Point	Alaska	179
2	Kenai	Alaska	15
3	Kenai State Offshore	Alaska	10
4	Harrison Bay	Alaska	3
5	Chandler Lake	Alaska	1
5	Davidson Bank	Alaska	1
5	Flaxman	Alaska	1
5	Gulkana	Alaska	1
5	Killik River	Alaska	1
5	Point Lay	Alaska	1
5	St. Michael	Alaska	1
5	Tyonek	Alaska	1

semisubmersible. The Sedco 708 was also used on the North Aleutian Shelf COST well and was scheduled to drill another COST well in the remote Navarin Basin of the Bering Sea in the summer of 1983.

In Cook Inlet Basin, ARCO began a three-well exploratory drilling program on the Kenai Peninsula under an agreement with Cook Inlet Region, Inc. The drilling follows three winters of seismic work on the native-owned lands. The initial wildcat, spudded in December, was the first exploratory drilling on the peninsula by ARCO since Richfield Oil Co drilled the Swanson River oil discovery in 1957.

Offshore in Cook Inlet, the new Penrod jackup #96 was brought in to drill the first rank wildcat tests in several years. Phillips Petroleum Co's initial well, #1A SRS Tern, was plugged and abandoned in August. Mobil Oil Corp's #1A South McArthur River was completed and the rig released in mid-December. No results were immediately announced by the operator. Also drilled in the Inlet was Marathon's 6 Beaver Creek Unit, an infill gas completion that was Alaska's only well to reach total depth below 15,000 ft in 1982.

Rig employment tapered off sharply in 1982. Though Hughes Tool Co counts show a yearly average of 22 rigs per week—only 1.5 less than in 1981—on a monthly basis figures dropped. In January, 34 rigs were running or under contract. Five others were idle and four more were under construction or enroute to Alaska. As the year ended, there were 43 rigs in Alaska, 19 of which were active. Of the 38 land rigs, four workover units and one semisubmersible, 17 land rigs, one workover rig and the semisubmersible were drilling. The rig count excludes equipment permanently assigned to Cook Inlet offshore platforms and used intermittently.

Development Operations

Field development work continued at a high level during 1982, with the pressure maintenance projects at Prudhoe Bay and infill drilling in Kuparuk Field providing the bulk of the work. Other activity included Conoco's Milne Point drilling program on the North Slope and Marathon Oil's development of the natural gas zone in the Beaver Creek oil field on the Kenai Peninsula. Gas deliveries to the pipeline serving the Anchorage area were scheduled for early 1983.

The first step toward development of the Sag Delta/Duck River "Endicott" reservoir was initiated in September. A proposed operating plan was submitted to the U.S. Army Corps of Engineers for review by a group of 10 leaseholders. Under the plan, completion of the

1982-1981 U.S. Drilling
Comparison—Five Leading Operators
Ranked by Total Completions
Alaska

	Operator		New Field Wildcats				All Wells Drilled			
			Oil	Gas	Dry	Total	Oil	Gas	Dry	Total
1	ARCO	1982	0	0	1	1	111	0	8	119
		1981	0	0	1	1	55	0	2	57
2	Sohio	1982	0	0	1	1	56	0	2	58
		1981	0	0	1	1	63	0	3	66
3	Union Oil of California	1982	0	0	1	1	7	8	1	16
		1981	0	0	0	0	13	0	2	15
4	Chevron	1982	0	0	5	5	2	0	5	7
		1981	0	0	2	2	4	1	2	7
5	Amoco	1982	0	0	2	2	2	0	3	5
		1981	0	0	0	0	3	0	0	3

appear to be poor. Substantial interest was expressed in the geothermal tracts, but at year-end, no decision had been made by the Department on whether to offer the tracts for competitive leasing.

For the third straight year, the Alaska Oil and Gas Conservation Commission issued a record number of drilling permits. The 219 permits exceeded by 31 the previous year's high of 188, an increase of 17 percent. Of the 219 permits, 188 were for development locations, 16 for exploratory locations and 15 for service operations.

1982 U.S. Drilling
Alaska
Well Completions by Quad

Alaska

	NFW					OEXP					All Wells				
Quad	Oil	Gas	Dry	Total	Footage	Oil	Gas	Dry	Total	Footage	Oil	Gas	Dry	Total	Footage
Beechey Point	0	0	3	3	37,305	0	0	2	2	24,330	168	0	11	179	1,802,926
Chandler Lake	0	0	1	1	11,512	0	0	0	0	0	0	0	1	1	11,512
Flaxman	0	0	1	1	13,050	0	0	0	0	0	0	0	1	1	13,050
Gulkana	0	0	1	1	5,677	0	0	0	0	0	0	0	1	1	5,677
Harrison Bay	0	0	2	2	22,330	0	0	1	1	6,625	0	0	3	3	28,955
Kenai	0	0	2	2	14,659	0	0	0	0	0	4	9	2	15	117,776
Killik River	0	0	1	1	12,492	0	0	0	0	0	0	0	1	1	12,492
Point Lay	0	0	1	1	8,212	0	0	0	0	0	0	0	1	1	8,212
Tyonek	0	0	1	1	11,650	0	0	0	0	0	0	0	1	1	11,650
Total	0	0	13	13	136,887	0	0	3	3	30,955	172	9	22	203	2,012,250

Alaska Offshore

Davidson Bank	0	0	0	0	0	0	0	0	0	0	0	0	1	1	14,626
Kenai	0	0	0	0	0	0	0	1	1	9,519	8	0	2	10	64,573
St. Michael	0	0	0	0	0	0	0	0	0	0	0	0	1	1	14,689
Total	0	0	0	0	0	0	0	1	1	9,519	8	0	4	12	94,088

was canceled for lack of industry interest. The next sale for the area is now scheduled for early 1991.

The presale process for OCS Sale #107 (Navarin Basin), scheduled for 1988, continued and if the sale is held it would be the second offering in the area. The first sale, #83 held in 1984, resulted in the issuance of 163 leases. Leaseholders there, however, have been enjoined from further drilling activity.

The state proposed two versions of a new five-year oil and gas leasing program for the years 1987-1991. Alternative A would follow the state's past practice of holding three sales per year, while Alternative B, which the state said was developed in response to the falling price of oil and reductions in the budgets of state agencies and exploration departments of major oil companies, would offer two sales per year. The state said it would announce which alternative it would adopt in 1987.

Predictions that state oil and gas lease sales in 1986 would draw only moderate interest proved correct: Sale #48 (Kuparuk Uplands) and Sale #48A (Mikkelson), both held in February, sold 54 and 11 tracts, respectively. High bids for the sales, which offered onshore state lands near the Kuparuk River and offshore lands near Mikkelson Bay, totaled less than $3 million.

State Oil & Gas Lease Sale #49 (Cook Inlet) also attracted only moderate interest, with high bonus bids totaling under $1 million for 98 tracts. The sale offered offshore acreage throughout Cook Inlet and onshore acreage as far south as Anchor Point. In conjunction with Sale #49, the state held its second geothermal lease sale ever, awarding leases on one of two tracts offered on the south slope of Mount Spur about 40 miles west of Tyonek.

Two other proposed 1986 state lease sales were rescheduled during the year. The decisions to reschedule Beaufort Sea Sale #52 (now set for January 1989), and to combine acreage contained in Nechelik Sale #52A with lands offered in Kuparuk Uplands Sale #54 (scheduled for January 1988) were made for a variety of reasons. Boundary disputes between the state and the federal government, an ownership dispute between the state and a Native corporation and uncertainty regarding the costs of developing the state's submerged lands all contributed to rescheduling the sales.

Two state lease sales, meanwhile, were scheduled for 1987. January's Sale #51 (Prudhoe Bay Uplands) is expected to draw only moderate interest. However, Sale #50 (Camden Bay), set for June, is expected to draw significant interest in that the acreage to be offered lies north of the Arctic National Wildlife Refuge. Sale #50's schedule date is tentative as the state and federal governments continue negotiations concerning the location of Alaska's territorial sea boundary and the seaward boundary of ANWR.

Production

The North Slope's third field to go on production fell victim to the drastic decline in oil prices when Conoco Inc shut down production at Milne Point

Alaska

New Field Wildcats

	Oil	Gas	Dry	Total	Footage
1986	0	0	2	2	20,557
1985	0	0	17	17	164,613
1984	0	0	18	18	189,125
1983	0	0	4	4	46,283
1982	1	0	12	13	149,906
1981	0	0	14	14	139,112
1980	0	0	23	23	242,086
1979	0	1	15	16	171,908
1978	0	1	12	13	151,817
1977	1	0	21	22	247,028

Other Exploratory Wells

1986	0	0	2	2	18,738
1985	0	0	5	5	53,579
1984	1	0	5	6	55,706
1983	0	0	1	1	13,060
1982	0	0	3	3	33,849
1981	0	1	1	2	12,385
1980	0	0	0	0	0
1979	0	0	1	1	7,028
1978	2	0	1	3	24,391
1977	0	0	0	0	0

Development Wells

1986	163	3	15	181	1,694,335
1985	173	5	7	185	1,603,524
1984	160	0	7	167	1,429,312
1983	144	1	3	148	1,413,403
1982	160	9	9	178	1,690,535
1981	138	2	6	146	1,454,856
1980	117	3	6	126	1,249,737
1979	75	3	2	80	747,261
1978	63	3	0	66	580,610
1977	43	4	6	53	515,543

All Wells Drilled for Oil and Gas

1986	163	3	19	185	1,733,630
1985	173	5	29	207	1,821,716
1984	161	0	30	191	1,674,143
1983	144	1	8	153	1,472,746
1982	161	9	24	194	1,874,290
1981	138	3	21	162	1,606,353
1980	117	3	29	149	1,491,823
1979	75	4	18	97	926,197
1978	65	4	13	82	756,818
1977	44	4	27	75	762,571

1986 "As Reported" Well Completions

NFW	0	0	3	3	28,591
OEXP	1	0	2	3	31,816
Dev.	204	4	15	223	2,018,246
All	205	4	20	229	2,078,653

1986-1985 Comparison
Permits
Alaska

	NFW	1986 OEXP	Dev.	Total	1985 Total	% Change
Alaska	0	3	164	167	279	(40. 1)
Alaska Offshore	9	0	2	11	34	(67. 6)
Total	9	3	166	178	313	(43. 1)

in the tanks from previous shipments and is treated in facilities owned by Alyeska in Valdez before being dumped into the bay. The EPA, alleging that the ballast water contains chemical wastes not eliminated by the treatment, filed suit against Alyeska asking for records, shipping documents and access to past and present Alyeska employees (for sworn testimony) in order to investigate the procedure.

Alyeska claimed that EPA overstepped its authority when it subpoenaed the records under the Federal Toxic Substance Control Act, since the initial investigation was begun under the Federal Clean Water Act. Alyeska earlier had offered to make employees available to EPA if the request came under the Clean Water Act, which does not allow sworn testimony. As the year ended, Alyeska was ordered by a federal judge to release the records and make the employees accessible to EPA, but the company appealed that ruling and the matter is still pending.

A trans-Alaska gas pipeline proposed by a group of investors headed by former Govenor Walter Hickel was still in the planning stages during 1986. A contract to prepare a draft environmental impact statement for the project was awarded by Yukon Pacific Corp, which during the year added two former Arco executives, Robert O. Anderson and Glenn Simpson, to its board of directors.

The company wants to build a pipeline to ship North Slope natural gas to one of two proposed sites in south-central Alaska. Plans call for the gas to be marketed to Pacific Rim countries.

Two transportation milestones were reached in 1986: the 6,000th tanker carrying North Slope crude departed from Valdez early in the year; and, according to Alyeska Pipeline Service, the five-billionth bbl of oil was shipped through the line in mid-September. The line shortly thereafter suffered a 32-hour shutdown as pieces of a scraper pig became lodged in the internal piping of Pump Station #10. The problem was resolved without any oil spillage and operations resumed at a full capacity of approximately 1.8 million bbls per day.

Arco Alaska during the year spent $15 million to install 60 miles of pipeline in Kuparuk field for its new production facility. Alyeska spent a similar amount to reline the pipes in its ballast water treatment

1986-1985 Comparison
Starts
Alaska

	NFW	1986 OEXP	Dev.	Total	1985 Total	% Change
Alaska	0	8	166	174	267	(34. 8)
Alaska Offshore	4	0	4	8	28	(71. 4)
Total	4	8	170	182	295	(37. 6)

plant. Alyeska officials said the project was part of planned maintenance and not in response to investigations by EPA into ballast water discharges.

Processing

Two new refineries were planned for Alaska in 1986, one near Fairbanks and a second near Valdez.

Arctic Energy announced in August that it was proceeding with plans to build a $10 million refinery in the town of Fox, near Fairbanks. The company planned to buy crude oil from Chevron USA and others in order to produce 2,500 bbls per day of diesel and jet fuel. At year-end, the refinery was still in the planning stages.

The second refinery planned for Alaska was proposed by California-based Alaska Pacific Refinery Inc. That company plans to build a 100,000-bbl-per-day refinery near Valdez to produce jet fuel, high-octane unleaded gasoline, asphalt and other products primarily for export to Pacific Rim countries. When completed, it will be the largest refinery in the state and the first in the country to export refined products. Construction is scheduled to begin in 1987.

An offer made by the state in February to sell 18,000 bbls per day of state royalty oil received no takers, which, in light of the uncertainty of oil prices, did not surprise state officials.

MAPCO Petroleum in November was engaged in cleanup operations at its North Pole refinery as workers disposed of about 100,000 gallons of various oil products that allegedly seeped into the ground over a period of years. The spill, which was not believed to have contaminated local water supplies, was blamed on leaking concrete sumps designed to collect oil, water and other wastes from refining operations.

Arctic National Wildlife Refuge

One of the most closely watched developments in Alaska during 1986 was the debate over the future of the Arctic National Wildlife Refuge, specifically the refuge's 1.5 million-acre coastal plain.

The refuge was created and designated as a "wildlife range" by the secretary of the interior during the Eisenhower adminstration. It was subsequently doubled in size by the Alaska National Interests Lands Conservation Act to its present configuration of 19.3 million acres, making it the second largest wildlife sanctuary in the country. That act also decreed that eight million acres within the refuge be classified as wilderness and that a study of the refuge's coastal plain be done by the Interior Department to determine its oil and gas potential. Interior also was charged with making a recommendation as to whether the coastal plain should be opened to oil and gas leasing.

Interior in its draft report of that study released in November called the coastal plain "clearly one of the most outstanding oil and gas areas remaining in the U.S.," recommending the coastal plain be opened for hydrocarbon leasing. The report estimates there is a 95 percent chance that the coastal plain contains more than 4.8 billion bbls of oil, and a five percent chance that it holds more than 29.4 billion bbls of oil in place.

Pro-development forces praised the report and agreed that the area should be opened, arguing that new fields need to be discovered and developed to reduce the nation's dependence on foreign oil. The pro-development groups also pointed out that the coastal plain is a small percentage of the refuge's total acreage and that the oil industry has proven it can drill in environmentally sensitive areas, citing Prudhoe Bay as an example.

Virtually every major environmental organization opposed Interior's recommendation to open the plain for leasing, arguing that it would jeopardize the future of the porcupine caribou herd, which uses the coastal plain as a calving ground. Those groups also contend that industrial activity in the region would alter the way of life of local residents, from one based on subsistence to one based on cash, disrupting traditional Native values. Finally, the groups contend that oil and gas development in Prudhoe Bay and its effect on caribou herds there cannot be compared to the possible effect such activity would have on the refuge's porcupine caribou herd, since it's much larger.

Alaska Governor Steve Cowper and most Native leaders in the state for the most part are in favor of opening the coastal plain for exploration and development. A public opinion poll commissioned by the Alaska Oil and Gas Association indicated that Alaskans, by a margin of seven-to-one, favor exploration and development of the plain.

1986 Completion Date Statistics

Operator Summary
Alaska

			Oil	Gas	Dry	Total
1	Arco Alaska	1986	108	0	6	114
		1985	137	0	11	148
2	Standard Alaska	1986	33	0	2	35
		1985	0	0	0	0
3	Sohio Petroleum	1986	15	0	1	16
		1985	25	0	2	27
4	Amoco Production	1986	3	0	2	5
		1985	1	0	4	5
5	Union Oil	1986	3	1	1	5
		1985	4	2	1	7
6	Chevron USA	1986	0	2	2	4
		1985	1	3	1	5
7	Amerada Hess	1986	0	0	2	2
		1985	0	0	0	0
7	Shell Oil	1986	1	0	1	2
		1985	3	0	3	6
7	Texaco Inc	1986	0	0	2	2
		1985	0	0	1	1

The Alaskan coal faced competition from lower-priced Canadian and Australian coal, but a 15 percent reduction in the price of the Alaska coal—to $44 per ton—and quick repair of railroad tracks damaged by floods secured the new contract, which runs to 1988. That contract is subject to yearly price reviews. The coal is supplied by Usibelli Coal Co at Healy and is shipped to Seward by the Alaska Railroad. Since 1984, one million tons of coal have been shipped to Korea. The Alaska Division of Mining and Geological and Geophysical Survey has estimated the state's coal reserves at 5.5 billion short tons, equal to about half the nation's estimated reserves.

An agreement between two Native groups and the Alaska Power Authority cleared the way for an economic feasibility study to get under way involving the first geothermal power plant in the state, near Unalaska/Dutch Harbor. The study is designed to examine the potential of the geothermal reservoir of the Mushkin Volcano to produce 13 megawatts of power. Falling state revenues threatened the continuation of the study as the year ended. □

1986 Completion Date Statistics
Alaska
Well Completions by Quad

Quad	Oil	Gas	Dry	Total	Footage	Oil	Gas	Dry	Total	Footage	Oil	Gas	Dry	Total	Footage
Barter Island	0	0	0	0	0	0	0	0	0	0	0	0	1	1	15,193
Beechey Point	0	0	0	0	0	0	0	1	1	11,921	138	0	9	147	1,438,243
Harrison Bay	0	0	0	0	0	C	0	1	1	6,817	18	0	4	22	166,695
Kenai	0	0	0	0	0	0	0	0	0	0	0	1	0	1	7,017
Tyonek	0	0	0	0	0	0	0	0	0	0	0	2	1	3	17,097
Total	0	0	0	0	0	0	0	2	2	18,738	156	3	15	174	1,644,245
As Reported Total	0	0	0	0	0	1	0	2	3	31,816	193	3	15	211	1,973,541
Alaska Offshore															
Beechey Point	0	0	1	1	12,575	0	0	0	0	0	0	0	2	2	27,558
Harrison Bay	0	0	1	1	7,982	0	0	0	0	0	0	0	1	1	7,982
Kenai Offshore	0	0	0	0	0	0	0	0	0	0	7	0	1	8	53,845
Total	0	0	2	2	20,557	0	0	0	0	0	7	0	4	11	89,385
As Reported Total	0	0	3	3	28,591	0	0	0	0	0	12	1	5	18	141,112

ALASKA OIL PRICES AND PRODUCTION

	Prudhoe Bay				Kuparuk			Milne Point			Lisburne			
	WHP	Exh B	In-value	(000 Bbl)	WHP	In-value	(000 Bbl)	WHP	Exh B	In-value	(000 Bbl)	WHP	Exh B	In-value	(000 Bbl)
85: 1	$17.0	$17.1	$16.3	43,993.1	$16.2	$15.8	5,297.2								
2	$16.7	$17.0	$16.0	45,234.2	$15.8	$15.4	5,753.8								
3	$16.8	$17.0	$16.1	49,430.0	$16.0	$15.6	6,581.1								
4	$16.9	$17.2	$16.2	45,448.6	$16.1	$15.7	6,438.7								
5	$16.9	$17.2	$16.2	50,053.1	$16.0	$15.6	6,771.3								
6	$17.0	$17.2	$16.3	48,340.8	$15.7	$15.3	6,380.7								
7	$16.8	$17.1	$16.1	47,943.0	$15.4	$15.0	6,724.5								
8	$16.8	$17.1	$16.1	47,064.3	$15.3	$14.9	7,240.0								
9	$16.9	$17.1	$16.2	47,552.9	$15.6	$15.2	7,132.7								
10	$16.9	$17.1	$16.2	48,576.0	$15.7	$15.3	7,255.1								
11	$16.9	$17.1	$16.2	45,883.5	$16.1	$15.7	6,429.4	$14.1	$14.3		205.5				
12	$17.6	$17.8	$16.9	48,428.9	$17.1	$16.7	6,794.4	$14.4	$14.7		498.4				
86: 1	$15.4	$16.2	$14.7	48,666.2	$15.7	$15.3	7,194.4	$12.6	$13.0		529.8				
2	$10.9	$11.9	$10.2	44,385.0	$9.5	$9.1	6,937.9	$8.3	$8.7		478.8				
3	$7.5	$7.8	$6.8	47,256.1	$5.4	$5.0	8,076.7	$4.0	$4.7		548.6				
4	$5.8	$6.1	$5.1	44,391.3	$4.1	$3.7	8,366.9	$4.5	$5.0		479.6				
5	$4.9	$5.1	$4.2	48,934.7	$4.3	$3.9	8,461.1	$2.5	$2.6		396.8				
6	$4.4	$4.6	$3.7	46,272.0	$4.5	$4.1	8,099.9								
7	$3.1	$3.4	$2.4	48,821.7	$2.8	$2.4	8,139.9								
8	$3.7	$4.2	$3.0	46,763.1	$3.4	$3.0	7,479.2					$3.7	$4.2	$3.0	175.8
9	$5.6	$5.7	$4.9	44,422.4	$5.5	$5.1	7,062.3					$5.6	$5.7	$4.9	7.3
10	$5.7	$5.8	$5.0	49,807.0	$5.3	$4.9	8,010.8					$5.7	$5.8	$5.0	118.4
11	$5.8	$5.9	$5.1	47,031.4	$5.5	$5.1	7,745.5					$5.8	$5.9	$5.1	298.7
12	$6.9	$7.3	$6.2	45,850.9	$6.6	$6.2	8,471.5					$6.9	$7.3	$6.2	675.0
87: 1	$8.8	$8.9	$8.1	51,824.3	$9.1	$8.7	9,261.9					$8.8	$8.9	$8.1	1,409.3
2	$9.8	$10.0	$9.1	42,605.7	$9.1	$8.7	8,037.5					$9.8	$10.0	$9.1	1,192.3
3	$10.0	$10.1	$9.3	50,474.3	$9.4	$9.0	9,196.7					$10.0	$10.1	$9.3	1,293.7
4	$10.8	$11.0	$10.1	49,711.5	$10.0	$9.6	8,767.3					$10.8	$11.0	$10.1	1,177.8
5	$11.0	$11.2	$10.3	51,031.9	$10.4	$10.0	9,030.6					$11.0	$11.2	$10.3	1,325.9
6	$11.6	$11.6	$10.9	46,381.1	$10.6	$10.2	8,806.2					$11.6	$11.6	$10.9	1,413.8
7	$12.2	$12.3	$11.5	48,170.9	$11.4	$11.0	8,340.7					$12.2	$12.3	$11.5	1,414.6
8	$12.5	$12.9	$11.8	49,775.7	$12.0	$11.6	8,131.8					$12.5	$12.9	$11.8	1,240.1

1-88 46.8 ?

8.867 in 1/88

ALASKA OIL PRICES AND PRODUCTION

	Prudhoe Bay				Kuparuk			Milne Point			Lisburne		
	WHP	Exh B	In-value	(000 Bbl)	WHP	In-value	(000 Bbl)	WHP	Exh B In-value	(000 Bbl)	WHP	Exh B In-value	(000 Bbl)
81: 7	$22.7	$23.4	$22.1	47,116.1									
8	$22.7	$23.0	$22.0	47,124.2									
9	$22.0	$22.3	$21.4	45,765.4									
10	$22.0	$22.2	$21.4	46,917.3									
11	$22.1	$22.2	$21.4	45,997.6									
12	$21.8	$21.9	$21.2	46,763.3	$19.7	$19.3	1,091.5						
82: 1	$21.2	$21.5	$20.5	47,980.7	$19.7	$19.3	2,503.6						
2	$19.5	$20.1	$18.8	43,467.6	$19.6	$19.2	2,219.7						
3	$18.4	$18.8	$17.7	47,439.8	$18.0	$17.6	2,856.8						
4	$18.7	$19.0	$18.1	45,811.9	$17.7	$17.3	2,757.1						
5	$18.9	$19.0	$18.3	47,745.2	$17.9	$17.5	2,896.6						
6	$20.4	$20.9	$19.7	44,958.5	$17.9	$17.5	2,767.5						
7	$20.4	$21.0	$19.7	48,037.7	$17.8	$17.4	2,680.0						
8	$20.4	$21.0	$19.8	47,460.6	$17.9	$17.5	2,711.8						
9	$20.4	$20.9	$19.7	46,216.7	$17.7	$17.3	2,669.0						
10	$20.2	$20.7	$19.6	47,820.6	$18.0	$17.6	2,729.4						
11	$19.8	$20.1	$19.2	45,223.3	$18.5	$18.1	2,791.0						
12	$19.2	$19.4	$18.6	47,105.2	$18.0	$17.6	2,795.5						
83: 1	$18.3	$18.7	$17.6	48,244.5	$17.8	$17.4	3,197.0						
2	$17.4	$17.7	$16.8	43,167.5	$16.6	$16.2	2,838.7						
3	$17.3	$17.6	$16.7	48,504.2	$16.2	$15.8	3,017.4						
4	$17.3	$17.5	$16.6	46,543.9	$16.2	$15.8	2,966.8						
5	$17.3	$17.6	$16.7	45,955.5	$16.2	$15.8	3,394.0						
6	$17.4	$17.6	$16.7	45,365.2	$16.0	$15.6	3,239.7						
7	$17.5	$17.8	$16.8	47,456.5	$16.5	$16.1	3,671.3						
8	$17.8	$18.3	$17.1	47,305.9	$16.4	$16.0	3,282.6						
9	$17.8	$18.3	$17.1	46,681.0	$16.7	$16.3	3,426.8						
10	$17.7	$18.2	$17.1	48,382.2	$16.8	$16.4	3,310.9						
11	$17.6	$18.0	$16.9	45,952.7	$16.8	$16.4	3,686.7						
12	$17.7	$18.0	$17.0	47,231.7	$16.8	$16.4	3,828.9						
84: 1	$17.5	$17.8	$16.8	48,311.5	$16.7	$16.3	3,983.4						
2	$17.6	$18.0	$16.9	45,089.7	$16.6	$16.2	3,810.6						
3	$17.6	$18.0	$16.9	42,889.4	$16.6	$16.2	4,241.7						
4	$17.7	$18.1	$17.0	47,766.3	$16.2	$15.8	3,352.2						
5	$17.7	$18.1	$17.0	49,258.5	$16.6	$16.2	3,372.5						
6	$17.7	$18.1	$17.0	44,619.1	$16.7	$16.3	3,290.8						
7	$17.8	$18.2	$17.1	47,259.5	$17.0	$16.6	3,349.2						
8	$17.8	$18.2	$17.1	45,459.1	$16.6	$16.2	3,169.2						
9	$18.0	$18.4	$17.3	47,677.5	$16.9	$16.5	3,359.3						
10	$17.9	$18.3	$17.3	47,866.9	$16.9	$16.5	4,030.4						
11	$18.0	$18.2	$17.3	46,779.7	$17.1	$16.7	4,922.3						
12	$17.5	$17.6	$16.8	45,942.3	$16.8	$16.4	5,631.5						

RIGS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
Brinkerhoff Drlg. Co.				
National 110	36	18,500	Put River B-5 W.O.	BP Alaska
Oilwell 96	59	16,000	West Sak River #7	ARCO
National T20	31	7,000	South Barrow #16	Husky
Challenger Drlg. Co.				
National 110	49	16,000	Tiglukpuk #1	Chevron
Miller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Loffland Brothers Drlg. Co.				
National 110	162	17,000	Pt. Thomson U. #2	Exxon
Nabors Alaska Drlg. Co.				
Emsco A-800-83	1	16,000	South Meade Test #1	Husky
National 110	25	19,000	Drew Point Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Put River C-7 W.O.	BP Alaska
Parker Drilling Co.				
National 130	95	25,000	Kugrua Test #1	Husky
National 130	96	25,000	Will move to North Kalikpik Test #1	Husky
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay NGI-11	ARCO
National 80	97	15,000	Sag Delta #4	BP Alaska
TBA 2000	128	20,000	Eagle Creek #1	Chevron
TBA 2000	147	20,000	Will move to W. Mikkelsen Bay St. #1	ARCO
Rowan Drilling Co.				
National 110	26	17,500	Stacked @ Mukluk Yard	
National 110	29	20,500	West Sak 25548 #11	BP Alaska
Turbine Electric	34	20,500	Prudhoe Bay DS 4-11	ARCO
Turbine Electric	35	20,500	Prudhoe Bay DS 1-15	ARCO
U. S. Navy Department				
Cardwell	3	**5,000	Stacked @ NPRA	

NORTHERN GULF OF ALASKA

ODECO				
Ocean Ranger Semisubmersible		25,000	Lower Cook Inlet on Standby	
Emsco C-3 Type II Draw Works				
ODECO				
Ocean Bounty Semisubmersible		25,000	OCS . 0032 #1	Texaco
EXXON				
Alaskan Star Semisubmersible		30,000	OCS Y-0072 #1	North Star Drilling

LOWER COOK INLET

JAPAN DRILLING CO., LTD.				
White Dragon II & III Semisubmersibles		30,000	May move from Japan to Lower Cook Inlet	
GLOBAL MARINE				
Glomar Grand Isle Drillship			May move to Lower Cook Inlet	
Glomar Conception Drillship			May move to Lower Cook Inlet	
Glomar Tasman Drillship			May move to Lower Cook Inlet	
DIAMOND M DRILLING				
Diamond M Dragon Drillship			May move to Lower Cook Inlet	Marathon

Continued on page 2...

Rig List, Continued

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/4B			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/58		15,000+	On Platform - TBU K-23	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle	
Brinkerhoff Drilling Company				
Wilson 120	58	12,500	Stump Lake Unit #41-33	Chevron/Standby
Oilwell 52T (Helicopter Rig)	60	10,000*	Simpco Kaloa #1	Simasko
Oilwell 96	43	16,000	Moose Point U. #1	Amarex
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - TBU D-7RD	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000	150	20,000	Platform Baker - Standby	AMOCO/Parker
TBA 2000	152	20,000	Platform Anna - GPS 18742-17	AMOCO/Parker
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - MGS C-44-14RD	Shell
National 110/8		15,000	Shell Platform A - MGS A-12-1	Shell
Union Oil Co. of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - TBU G-17RD	Union
Oilwell 860 on Monopod	56	15,000+	On Platform - idle	

1/ On Texaco - Superior Platform A***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
6/ On Shell's MGS Platform "C"
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depth shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

IGS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
rinkerhoff Drlg. Co.				
National 110	36	18,500	Put River B-4 W.O.	BP Alaska
Oilwell 96	59	16,000	West Sak River #10	ARCO
National T	31	7,000	South Barrow #17	Husky
hallenger Drlg. Co.				
National 110	49	16,000	Tiglukpuk #1	Chevron
Miller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
offland Brothers Drlg. Co.				
National 110	162	17,000	Pt. Thomson U. #2	Exxon
abors Alaska Drlg. Co.				
Emsco A-800-83	1	16,000	South Meade Test #1	Husky
National 110	25	19,000	Drew Point Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Put River C-2 W.O.	BP Alaska
arker Drilling Co.				
National 130	95	25,000	Kugrua Test #1	Husky
National 130	96	25,000	North Kalikpik Test #1	Husky
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay NGI-11	ARCO
National 80	97	15,000	Sag Delta #4	BP Alaska
TBA 2000	128	20,000	Eagle Creek #1	Chevron
TBA 2000	147	20,000	W. Mikkelsen Bay St. #1	ARCO
wan Drilling Co.				
National 110	26	17,500	Stacked @ Mukluk Yard	
National 110	29	20,500	West Sak 25645 #9	BP Alaska
Turbine Electric	34	20,500	Prudhoe Bay DS 4-11	ARCO
Turbine Electric	35	20,500	Prudhoe Bay DS 1-16	ARCO
J. S. Navy Department				
Cardwell	3	**5,000	Stacked @ NPRA	

NORTHERN GULF OF ALASKA

ODECO			
Ocean Bounty Semisubmersible	25,000	Seward on Standby	
EXXON			
Alaskan Star Semisubmersible	30,000	OCS Y-0072 #1	North Star Drilling

LOWER COOK INLET

ODECO			
Ocean Ranger Semisubmersible	25,000	Lower Cook Inlet on Standby	
Emsco C-3 Type II Draw Works			
JAPAN DRILLING CO., LTD.			
White Dragon II & III Semisubmersible	30,000	May move from Japan to Lower Cook Inlet	
GLOBAL MARINE			
Glomar Grand Isle Drillship		May move to Lower Cook Inlet	
Glomar Conception Drillship		May move to Lower Cook Inlet	
Glomar Tasman Drillship		May move to Lower Cook Inlet	
Glomar Atlantic		May move to Lower Cook Inlet	
MOND M DRILLING			
Diamond M Dragon Drillship		Will move to Lower Cook Inlet	Marathon
WODECO			
Western Offshore IX Drillship		May move to Lower Cook Inlet	

Continued on page 2

Rig List, Continued

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/4B			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/58		15,000+	On Platform - TBU K-23	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle	
Brinkerhoff Drilling Company				
Wilson 120	58	12,500	Stump Lake Unit #41-33	Chevron
Oilwell 52T (Helicopter Rig)	60	10,000*	Simpco Kaloa #1	Simasko
Oilwell 96	43	16,000	Moose Point U. #1	Amarex
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - TBU D-7RD	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000	150	20,000	Platform Baker - Standby	AMOCO/Parker
TBA 2000	152	20,000	Platform Anna - GPS 18742 MUC I-3	AMOCO/Parker
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - MGS C-44-14RD	Shell
National 110/8		15,000	Shell Platform A - MGS A-12-1	Shell
Union Oil Co. of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - TBU G-17RD	Union
Oilwell 860 on Monopod	56	15,000+	On Platform - idle	

1/ On Texaco - Superior Platform A***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
6/ On Shell's MGS Platform "C"
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depth shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

RIGS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
Brinkerhoff Drlg. Co.				
National 110	36	18,500	Prudhoe Bay Unit B-7	Sohio Petroleum
Oilwell 96	59	16,000	West Sak River #8	ARCO
National T20	31	7,000	South Barrow #17	Husky
Challenger Drlg. Co.				
National 110	49	16,000	Tiglukpuk #1	Chevron
Miller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Loffland Brothers Drlg. Co.				
National 110	162	17,000	Pt. Thomson U. #2	Exxon
Nabors Alaska Drlg. Co.				
Emsco A-8000-83	1	16,000	South Meade Test #1	Husky
National 110	25	19,000	Inigok Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Prudhoe Bay GC-3A	Sohio Petroleum
Parker Drilling Co.				
National 130	95	25,000	Kugrua Test #1	Husky
National 130	96	25,000	North Kalikpik Test #1	Husky
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay DS 5-17	ARCO
National 80	97	15,000	Stacked @ Deadhorse on BP Central Pad	
TBA 2000	128	20,000	Eagle Creek #1	Chevron
TBA 2000	147	20,000	W. Mikkelsen Bay St. #1	ARCO
Rowan Drilling Co.				
National 110	26	17,500	Stacked @ Mukluk Yard	
National 110	29	20,500	West Sak 25645 #9	Sohio Petroleum
Turbine Electric	34	20,500	Prudhoe Bay DS 4-13	ARCO
Turbine Electric	35	20,500	Prudhoe Bay DS 1-18	ARCO
U.S. Navy Department				
Cardwell	3	**5,000	Stacked @ NPRA	

NORTHERN GULF OF ALASKA

ODECO			
Ocean Bounty Semisubmersible		25,000	Seward on Standby
EXXON			
Alaskan Star Semisubmersible		30,000	OCS Y-0035 #1 North Star Drilling

LOWER COOK INLET

ODECO			
Ocean Ranger Semisubmersible		25,000	Lower Cook Inlet on Standby
Emsco C-3 Type II Draw Works			
JAPAN DRILLING CO., LTD.			
White Dragon II & III Semisubmersibles		30,000	May move from Japan to Lower Cook Inlet
GLOBAL MARINE			
Glomar Grand Isle Drillship			May move to Lower Cook Inlet
Glomar Conception Drillship			May move to Lower Cook Inlet
Glomar Tasman Drillship			May move to Lower Cook Inlet
Glomar Atlantic			May move to Lower Cook Inlet
DIAMOND M DRILLING			
Diamond M Dragon Drillship			Will move to Lower Cook Inlet Marathon
ODECO			
Western Offshore IX Drillship			May move to Lower Cook Inlet

Continued on page 6 .....

Rig List, Continued

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/48			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/58		15,000+	On Platform - TBU K-23	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle	
Brinkerhoff Drilling Company				
Wilson 120	58	12,500	Stump Lake Unit #41-33	Chevron
Oilwell 52T (Helicopter Rig)	60	10,000*	Simpco Kaloa #1	Simasko
Oilwell 96	43	16,000	Stacked-Clam Gulch U. #1	Union/Standoy
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - TBU D-15RD	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000	150	20,000	Platform Baker - Standby	AMOCO/Parker
TBA 2000	152	20,000	Platform Anna - GPS 18742 MUC I-3	AMOCO/Parker
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - MGS C42-23	Shell
National 110/8		15,000	Shell Platform A - idle	
Union Oil Co. of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - W. O. Status	Union
Oilwell 860 on Monopod	56	15,000+	On Platform - idle	

1/ On Texaco - Superior Platform A***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
5/ On Shell's MGS Platform "C"
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depth shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

RIGS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
Brinkerhoff Drlg. Co.				
National 110	36	18,500	Prudhoe Bay Unit B-3A	Sohio Petroleum
Oilwell 96	59	16,000	West Sak River #8	ARCO
National T20	31	7,000	South Barrow #19	Husky
Challenger Drlg. Co.				
National 110	49	16,000	Tiglukpuk #1	Chevron
Miller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Loffland Brothers Drlg. Co.				
National 110	162	17,000	Pt. Thomson U. #2	Exxon
Nabors Alaska Drlg. Co.				
Emsco A-8000-83	1	16,000	South Meade Test #1	Husky
National 110	25	19,000	Inigok Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Prudhoe Bay GC-3A	Sohio Petroleum
Parker Drilling Co.				
National 130	95	25,000	Kugrua Test #1	Husky
National 130	96	25,000	North Kalikpik Test #1	Husky
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay DS 6-2	ARCO
National 80	97	15,000	Stacked @ Deadhorse on BP Central Pad	
TBA 2000	128	20,000	Eagle Creek #1	Chevron
TBA 2000	147	20,000	W. Mikkelsen Bay St. #1	ARCO
Rowan Drilling Co.				
National 110	26	17,500	Stacked @ Mukluk Yard	
National 110	29	20,500	Stacked @ Mukluk Yard	
Turbine Electric	34	20,500	Prudhoe Bay DS 4-14	ARCO
Turbine Electric	35	20,500	Prudhoe Bay PWDW 3-1	ARCO
U.S. Navy Department				
Cardwell	3	**5,000	Stacked @ NPRA	

RESURRECTION BAY - SEWARD

ODECO			
Ocean Bounty Semisubmersible		25,000	Seward on Standby
ODECO			
Ocean Ranger Semisubmersible		25,000	Seward on Standby
Emsco C-3 Type II Draw Works			

NORTHERN GULF OF ALASKA

EXXON			
Alaskan Star Semisubmersible		30,000	OCS Y-0035 #1 — North Star Drilling
JAPAN DRILLING CO., LTD.			
White Dragon II & III Semisubmersibles		30,000	May move from Japan to Lower Cook Inlet
GLOBAL MARINE			
Glomar Grand Isle Drillship			May move to Lower Cook Inlet
Glomar Conception Drillship			May move to Lower Cook Inlet
Glomar Tasman Drillship			May move to Lower Cook Inlet
Glomar Atlantic			May move to Lower Cook Inlet
DIAMOND M DRILLING			
Diamond M Dragon Drillship			Will move to Lower Cook Inlet — Marathon
ODECO			
Western Offshore IX Drillship			May move to Lower Cook Inlet

Continued on page 2 .....

Rig List, Continued

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/4B			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/58		15,000+	On Platform - TBU K-2RD	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle	
Brinkerhoff Drilling Company				
Wilson 120	58	12,500	Stump Lake Unit #41-33	Chevron
Oilwell 52T (Helicopter Rig)	60	10,000*	Simpco Kaloa #1	Simasko
Oilwell 96	43	16,000	Stacked-Clam Gulch U. #1	Union/Standby
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - TBU D-15RD	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000	150	20,000	Platform Baker - Standby	AMOCO/Parker
TBA 2000	152	20,000	Platform Anna - GPS 18742 MUC I-3	AMOCO/Parker
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - MGS C42-23	Shell
National 110/8		15,000	Shell Platform A - idle	
Union Oil Co. of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - W. O. Status	Union
Oilwell 860 on Monopod	56	15,000+	On Platform - idle	

1/ On Texaco - Superior Platform A***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
6/ On Shell's MGS Platform "C"
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depth shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

RIGS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
Brinkerhoff Drlg. Co				
National T20	31	7,000	Stacked @ South Barrow #6	Husky
National 110	36	18,500	Prudhoe Bay Unit B-3A	Sohio Petroleum
Oilwell 96	59	16,000	Stacked @ West Sak River #12	ARCO
Challenger Drlg. Co.				
National 110	49	16,000	Tiglukpuk #1	Chevron
Miller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Loffland Brothers Drlg. Co.				
National 110	162	17,000	Point Thomson Unit #2	Exxon
Nabors Alaska Drlg. Co.				
Emsco A-8000-83	1	16,000	Stacked @ South Meade Test #1	Husky
National 110	25	19,000	Inigok Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Prudhoe Bay GC-3B	Sohio Petroleum
Parker Drilling Co.				
National 130	95	25,000	Moving to DEW Line - NPRA	Husky
National 130	96	25,000	Ikpikpuk Test Well #1	Husky
National 80	97	15,000	Stacked @ Duck Island #1	ARCO
TBA 2000	128	20,000	Eagle Creek #1	Chevron
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay DS 6-5	ARCO
TBA 2000	147	20,000	W. Mikkelsen Bay St. #1	ARCO
Rowan Drilling Co.				
National 110	26	17,500	Stacked @ Mukluk Yard	
National 110	29	20,500	Will Move To Staines River #1	Mobil
Turbine Electric	34	20,500	Prudhoe Bay DS 7-1	ARCO
Turbine Electric	35	20,500	Will Move To West Bay State #1	ARCO
U.S. Navy Department				
Cardwell	3	**5,000	Stacked @ NPRA	

RESURRECTION BAY - SEWARD

ODECO			
Ocean Bounty Semisubmersible		25,000	Seward on Standby
ODECO			
Ocean Ranger Semisubmersible		25,000	Seward on Standby
Emsco C-3 Type II Draw Works			

NORTHERN GULF OF ALASKA

EXXON			
Alaskan Star Semisubmersible		30,000	OCS Y-0035 #1 — North Star Drilling
JAPAN DRILLING CO., LTD.			
White Dragon II & III Semisubmersible		30,000	May move from Japan To Lower cook Inlet
GLOBAL MARINE			
Glomar Grand Isle Drillship			May move to Lower Cook Inlet
Glomar Conception Drillship			May move to Lower Cook Inlet
Glomar Tasman Drillship			May move to Lower Cook Inlet
Glomar Atlantic			May move to Lower Cook Inlet
DIAMOND M DRILLING			
Diamond M Dragon Drillship			Will move to Lower Cook Inlet — Marathon
WODECO			
Western Offshore IX Drillship			May move to Lower Cook Inlet

Continued on page 2.....

Rig List, Continued

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/4B			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/58		15,000+	On Platform - TBU K-2RD	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle	
Brinkerhoff Drilling Company				
Wilson 120	58	12,500	Stacked @ Stump Lake Unit #41-33	
Oilwell 52T (Helicopter Rig)	60	10,000*	Simpco Kaloa #1	Simasko
Oilwell 96	43	16,000	Clam Gulch Unit #1	Union
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - TBU D-15RD	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000	150	20,000	Platform Baker - Stacked	
TBA 2000	152	20,000	Platform Anna - GPS 18742 MUC I-3	AMOCO/Parker
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - MGS C42-23	Shell
National 110/8		15,000	Shell Platform A - idle	
Union Oil Co. of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - TBU G-12RD-2	Union
Oilwell 860 on Monopod	56	15,000+	On Platform - idle	

1/ On Texaco - Superior Platform A***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
6/ On Shell's MGS Platform "C"
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depth shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

RIGS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
Brinkerhoff Drlg. Co.				
National T20	31	7,000	Stacked @ South Barrow #6	Husky
National 110	36	18,500	Prudhoe Bay Unit B-6	Sohio Petroleum
Oilwell 96	59	16,000	West Sak River #12	ARCO
Challenger Drlg. Co.				
National 110	49	16,000	Tiglukpuk	Chevron
Miller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Loffland Brothers Drlg. Co.				
National 110	162	17,000	Point Thomson Unit #2	Exxon
Nabors Alaska Drlg. Co.				
Emsco A-800-83	1	16,000	Stacked @ South Meade Test #1	Husky
National 110	25	19,000	Inigok Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Prudhoe Bay GC-2 W.O.	Sohio Petroleum
Oilwell 860	17	19,000	Enroute to NPRA	Husky
Nabors Well Servicing, Inc.				
Cont'l. Emsco Electro-Hoist 2C	1-ES	20,000	Rigging up @ Prudhoe Bay DS 5-17	ARCO
Parker Drilling Co.				
National 130	95	25,000	Stacked @ DEW Line - NPRA	Husky
National 130	96	25,000	Stacked @ Ikpikpuk Test Well #1	Husky
National 80	97	15,000	Stacked @ Duck Island #1	ARCO
TBA 2000	128	20,000	Eagle Creek #1	Chevron
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay Unit DS 6-7	ARCO
TBA 2000	147	20,000	W. Mikkelsen Bay St. #1	ARCO
TBA 2000-E	176	18,000	Rigging up @ Prudhoe Bay DS 14-1	ARCO
Rowan Drilling Co.				
National 110	26	17,500	Stacked @ Mukluk Yard	
National 110	29	20,500	Will Move to Staines River #1	Mobil
Turbine Electric	34	20,500	Prudhoe Bay DS 7-2	ARCO
Turbine Electric	35	20,500	West Bay State #1	ARCO
U.S. Navy Department				
Cardwell	3	**5,000	Stacked @ NPRA	

RESURRECTION BAY - SEWARD

ODECO			
Ocean Bounty Semisubmersible	25,000	Seward on Standby	Phillips
ODECO			
Ocean Ranger Semisubmersible	25,000	Seward on Standby	
Emsco C-3 Type II Draw Works			

NORTHERN GULF OF ALASKA

EXXON			
Alaskan Star Semisubmersible	30,000	Enroute o Brazil--FINAL REPORT	North Star Drilling

LOWER COOK INLET

DIAMOND M DRILLING			
Diamond M Dragon Drillship		OCS Y-0086 #1	Marathon
JAPAN DRILLING CO. LTD.			
White Dragon II & III Semisubmersible	30,000	May Move from Japan to Lower Cook Inlet	
GLOBAL MARINE			
Glomar Grand Isle Drillship		May Move to Lower Cook Inlet	
Glomar Conception Drillship		May Move to Lower Cook Inlet	
Glomar Tasman Drillship		May Move to Lower Cook Inlet	
Glomar Atlantic		May Move to Lower Cook Inlet	
ODECO			
Western Offshore IX Drillship		May Move to Lower Cook Inlet	

Continued on page 2

Rig List, Continued

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/4B			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/58		15,000+	On Platform - TBU K-30 W.O.	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle	
Brinkerhoff Drilling Company				
Wilson 120	58	12,500	Stacked @ Stump Lake Unit #41-33	
Oilwell 52T (Helicopter Rig)	60	10,000*	Simpco Moquawkie #1	Simasko
Oilwell 96	43	16,000	Clam Gulch Unit #1	Union
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - TBU D-15RD W.O.	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000	152	20,000	Platform Anna-May move to Platform Bruce	AMOCO/Parker
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - idle	Shell
National 110/8		15,000	Shell Platform A - idle	
Union Oil Co. of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - TBU G-8RD	Union
Oilwell 860 on Monopod	56	15,000+	On Platform - idle	

1/ On Texaco - Superior Platform A***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
6/ On Shell's MGS Platform "C"
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depth shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

RIGS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
Brinkerhoff Drlg. Co.				
National T20	31	7,000	Stacked @ South Barrow #6	Husky
National 110	36	18,500	Prudhoe Bay Unit B-9	Sohio Petroleum
Oilwell 95	59	16,000	West Sak River #12	ARCO
Challenger Drlg. Co.				
National 110	49	16,000	Tiglukpuk	Chevron
Miller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Loffland Brothers Drlg. Co.				
National 110	162	17,000	Stacked @ Point Thomson U. #2	Exxon
Nabors Alaska Drlg. Co.				
Emsco A-800-83	1	16,000	Stacked @ South Meade Test #1	Husky
National 110	25	19,000	Inigok Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Prudhoe Bay Unit Q-3	Sohio Petroleum
Oilwell 860	17	19,000	Being upgraded @ NPRA's Camp Lonely	Husky
Nabors Well Servicing, Inc.				
Cont'l. Emsco Electro-Hoist 2C	1-ES	20,000	Rigging up @ Prudhoe Bay DS 5-17	ARCO
Parker Drilling Co.				
National 130	95	25,000	Stacked @ DEW Line - NPRA	Husky
National 130	96	25,000	Stacked @ Ikpikpuk Test Well #1	Husky
National 80	97	15,000	Stacked @ Duck Island #1	Exxon
TBA 2000	128	20,000	Eagle Creek #1	Chevron
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay - Being modified	ARCO
TBA 2000	147	20,000	W. Mikkelsen Bay St. #1	ARCO
TBA 2000-E	176	18,000	Prudhoe Bay DS 14-1	ARCO
Rowan Drilling Co.				
National 110	26	17,500	Stacked @ Mukluk Yard	
National 110	29	20,500	Will Move to Staines River #1	Mobil
Turbine Electric	34	20,500	Prudhoe Bay DS 7-2	ARCO
Turbine Electric	35	20,500	West Bay State #1	ARCO
U.S. Navy Department				
Cardwell	3	**5,000	Stacked @ NPRA	

RESURRECTION BAY - SEWARD

ODECO			
Ocean Bounty Semisubmersible	25,000	Seward on Standby	Phillips
CDECO			
Ocean Ranger Semisubmersible	25,000	Seward on Standby	
Emsco C-3 Type II Draw Works			

LOWER COOK INLET

DIAMOND M DRILLING			
Diamond M Dragon Drillship		OCS Y-0086 #1	Marathon
JAPAN DRILLING CO. LTD.			
White Dragon II & III Semisubmersible	30,000	May Move from Japan to Lower Cook Inlet	
GLOBAL MARINE			
Glomar Grand Isle Drillship		May Move to Lower Cook Inlet	
Glomar Conception Drillship		May Move to Lower Cook Inlet	
Glomar Tasman Drillship		May Move to Lower Cook Inlet	
Glomar Atlantic		May Move to Lower Cook Inlet	
ODECO			
Western Offshore IX Drillship		May Move to Lower Cook Inlet	

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Rig List, Continued

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/48			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/58		15,000+	On Platform - TBU K-12RD	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle	
Brinkerhoff Drilling Company				
Wilson 120	58	12,500	Stacked @ Stump Lake Unit #41-33	
Oilwell 52T (Helicopter Rig)	60	10,000*	Simpco Moquawkie #1	Simasko
Oilwell 96	43	16,000	Kenai Deep Unit #5	Union
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - W. O. Status	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000 /5	152	20,000	Platform Bruce-GPS 18742-12RD	AMOCO/PARKER
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - idle	Shell
National 110/8		15,000	Shell Platform A - idle	
Union Oil Co. of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - Deactivated	Union
Oilwell 860 on Monopod	56	15,000+	On Platform - W.O. Status	Union

1/ On Texaco - Superior Platform A***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
6/ On Shell's MGS Platform "C"
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depth shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

GS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
tic Alaska Drilling Co.				
Oilwell 2000	PNJV #1	25,000	ETA - NOV. 1	Sohio Petroleum
nkerhoff Drilling Co.				
National T20	31	7,000	Stacked @ South Barrow #6	Husky
National 110	36	18,500	Prudhoe Bay Unit B-10	Sohio Petroleum
Oilwell 96	59	16,000	Stacked @ W. Sak River #12	ARCO
llenger Drilling Co.				
National 110	49	16,000	Tiglukpuk	Chevron
ller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
ffland Brothers Drilling Co.				
National 110	162	17,000	Stacked @ Point Thomson U. #2	Exxon
ors Alaska Drilling Co.				
Emsco A-800-83	1	16,000	Stacked @ South Meade Test #1	Husky
National 110	25	19,000	Inigok Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Prudhoe Bay Unit Q-1	Sohio Petroleum
Oilwell 860	17	19,000	Being upgraded @ NPRA's Camp Lonely	Husky
ors Well Servicing, Inc.				
Cont'l. Emsco Electro-Hoist 2C	1-ES	20,000	Moving to Prudhoe Bay DS 7-3 WO	ARCO
rker Drilling Company				
National 130	95	25,000	Stacked near Icy Cape-NPRA	Husky
National 130	96	25,000	Stacked @ Ikpikpuk Test Well #1	Husky
National 80	97	15,000	Duck Island #1	Exxon
TBA 2000	128	20,000	Eagle Creek #1	Chevron
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay DS 6-8	ARCO
TBA 2000	147	20,000	W. Mikkelsen Bay St. #1	ARCO
TBA 2000-E	176	18,000	Prudhoe Bay DS 14-2	ARCO
wan Drilling Company				
National 110	26	17,500	Stacked @ Mukluk Yard	
National 110	29	20,500	Will Move to Staines River #1	Mobil
Turbine Electric	34	20,500	Prudhoe Bay DS 7-5	ARCO
Turbine Electric	35	20,500	West Bay State #1	ARCO
S. Navy Department				
Cardwell	3	**5,000	Stacked @ NPRA	

RESURRECTION BAY - SEWARD

ECO			
Ocean Ranger Semisubmersible Emsco C-3 Type II Draw Works		25,000	Seward on Standby

LOWER COOK INLET

MOND M DRILLING			
Diamond M Dragon Drillship		OCS Y-0086 #1	Marathon
ECO			
Ocean Bounty Semisubmersible		25,000	Enroute to OCS Y-0168 #1	Phillips

Continued on page 2

Rig List, Continued

Lower Cook Inlet, Continued

JAPAN DRILLING CO. LTD.			
White Dragon II & III Semisubmersible	30,000	May Move from Japan to Lower Cook Inlet	
GLOBAL MARINE			
Glomar Grand Isle Drillship		May Move to Lower Cook Inlet	
Glomar Conception Drillship		May Move to Lower Cook Inlet	
Glomar Tasman Drillship		May Move to Lower Cook Inlet	
Glomar Atlantic		May Move to Lower Cook Inlet	
WODECO			
Western Offshore IX Drillship		May Move to Lower Cook Inlet	

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/4B			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/5B		15,000*	On Platform - TBU K-12RD	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle	
Brinkerhoff Drilling Company				
Oilwell 96	43	16,000	Kenai Deep Unit #5	Union
Wilson 120	58	12,500	Stacked @ Stump Lake Unit 41-33	
Oilwell 52T (Helicopter Rig)	60	10,000*	Simpco Moquawkie #1	Simasko
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - TBU D-40	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000 /5	152	20,000	Platform Bruce-GPS 18742-12RD	AMOCO/Parker
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - idle	Shell
National 110/8		15,000	Shell Platform A - idle	
Union Oil Co. of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - Deactivated	Union
Oilwell 860 on Monopod	56	15,000+	On Platform - W.O. Status	Union

1/ On Texaco - Superior Platform A***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
6/ On Shell's MGS Platform "C".
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depth shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

RIGS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
Arctic Alaska Drilling Co.				
Oilwell 2000	PNJV #1	25,000	Enroute To North Slope	Sohio Petroleum
Brinkerhoff Drilling Co.				
National T20	31	7,000	Stacked @ South Barrow #6	Husky Oil
National 110	36	18,500	Prudhoe Bay Unit B-11	Sohio Petroleum
Oilwell 96	59	16,000	Stacked @ W. Sak River #12	ARCO
Challenger Drilling Co.				
National 110	49	16,000	Tiglukpuk	Chevron
Miller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Loffland Brothers Drilling Co.				
National 110	162	17,000	Stacked @ Point Thomson Unit #2	Exxon
Nabors Alaska Drilling Co.				
Emsco A-800-83	1	16,000	Stacked @ South Meade Test #1	Husky
National 110	25	19,000	Inigok Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Prudhoe Bay Unit Q-2	Sohio Petroleum
Oilwell 860	17	19,000	Stacked @ NPRA's Camp Lonely	Husky
Emsco Electro-Hoist 2	22-E	25,000	Enroute To North Slope	Sohio Petroleum
Nabors Well Servicing, Inc.				
Cont'l. Emsco Electro-Hoist 2C	1-ES	20,000	Prudhoe Bay DS 6-3 WO	ARCO
Parker Drilling Company				
National 130	95	25,000	Tunalik Test #1	Husky
National 130	96	25,000	Stacked @ Ikpikpuk Test Well #1	Husky
National 80	97	15,000	Duck Island #1	Exxon
TBA 2000	128	20,000	Eagle Creek #1	Chevron
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay DS 6-8	ARCO
TBA 2000	147	20,000	W. Mikkelsen Bay State #1	ARCO
TBA 2000-E	176	13,000	Prudhoe Bay DS 14-2	ARCO
Rowan Drilling Company				
National 110	26	17,500	Stacked @ Mukluk Yard	
National 110	29	20,500	Will Move To Staines River #1	Mobil
Turbine Electric	34	20,500	Prudhoe Bay DS 7-5	ARCO
Turbine Electric	35	20,500	NGI #2 WO	ARCO
U.S. Navy Department				
Cardwell	3	##5,000	Stacked @ NPRA	

RESURRECTION BAY - SEWARD

ODECO				
Ocean Ranger Semisubmersible Emsco C-3 Type II Draw Works		25,000	Seward on Standby	

LOWER COOK INLET

DIAMOND M DRILLING				
Diamond M Dragon Drillship		20,000	OCS Y-0086 #1	Marathon
ECO				
Ocean Bounty Semisubmersible		25,000	OCS Y-0124 #1	Phillips

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Rig List, Continued

Lower Cook Inlet, Continued

JAPAN DRILLING CO. LTD.			
White Dragon II & III Semisubmersible	30,000	May Move from Japan to Lower Cook Inlet	
GLOBAL MARINE			
Glomar Grand Isle Drillship		May Move to Lower Cook Inlet	
Glomar Conception Drillship		May Move to Lower Cook Inlet	
Glomar Tasman Drillship		May Move to Lower Cook Inlet	
Glomar Atlantic		May Move to Lower Cook Inlet	
WODECO			
Western Offshore IX Drillship		May Move to Lower Cook Inlet	

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/48			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/58		15,000*	On Platform - TBU K-12RD	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle.	
Brinkerhoff Drilling Company				
Oilwell 96	43	16,000	Kenai Deep Unit #5	Union
Wilson 120	58	12,500	Stacked @ Stump Lake Unit 41-33	
Oilwell 52T (Helicopter Rig)	60	10,000*	Stacked @ Simpco Moquawkie #1	Simasko
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - TBU D-40	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000 /5	152	20,000	Platform Bruce-GPS 18742-30	AMOCO/Parker
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - idle	
National 110/8		15,000	Shell Platform A - idle	
Union Oil Co. of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - Deactivated	
Oilwell 860 on Monopod	56	15,000+	On Platform - W.O. Status	Union

1/ On Texaco - Superior Platform A***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
6/ On Shell's MGS Platform "C"
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depth shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

RIGS LOCATED IN ALASKA (published monthly)

ARCTIC NORTH SLOPE

Contractor	Rig No.	Approx. Capacity	Present Location	Operator
Arctic Alaska Drilling Co.				
Oilwell 2000	PNJV #1	25,000	Enroute To North Slope	Sohio Petroleum
Brinkerhoff Drilling Co.				
National T20	31	7,000	Stacked @ South Barrow #6	Husky Oil
National 110	36	18,500	Prudhoe Bay Unit B-13	Sohio Petroleum
Oilwell 96	59	16,000	Stacked @ W. Sak River #12	ARCO
Challenger Drilling Co.				
National 110	49	16,000	Tiglukpuk - Moving To Canada	
Miller & Miller Auctioneers				
National 50		8,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Cardwell II		4,000	Stacked @ Deadhorse	
Loffland Brothers Drilling Co.				
National 110	162	17,000	Stacked @ Point Thomson Unit #2	Exxon
Nabors Alaska Drilling Co.				
Emsco A-800-83	1	16,000	South Meade Test #1	Husky
National 110	25	19,000	Inigok Test #1	Husky
Emsco Electro-Hoist 2	18-E	25,000	Prudhoe Bay Unit Q-4	Sohio Petroleum
Oilwell 860	17	19,000	Peard Test Well #1	Husky
Nabors Well Servicing, Inc.				
Con't. Emsco Electro-Hoist 2	1-ES	20,000	Stacked @ Deadhorse	ARCO-Standby
22-E, Inc.				
Emsco Electro-Hoist 2	22-E	25,000	Enroute To North Slope	Sohio Petroleum
Parker Drilling Company				
National 130	95	25,000	Tunalik Test #1	Husky
National 130	96	25,000	Ikpikpuk Test Well #1	Husky
National 80	97	15,000	Duck Island #1	Exxon
TBA 2000	128	20,000	Stacked @ Eagle Creek #1	Chevron
TBA 2000 (HeliHoist)	141	20,000	Prudhoe Bay DS 13-2	ARCO
TBA 2000	147	20,000	Stacked @ W. Mikkelsen Bay State #1	Idle
TBA 2000-E	176	18,000	Prudhoe Bay DS 14-2	ARCO
Rowan Drilling Company				
National 110	26	17,500	Stacked @ Mukluk Yard	Idle
National 110	29	20,500	Will Move To Staines River #1	Mobil
Turbine Electric	34	20,500	Prudhoe Bay DS 7-7	ARCO
Turbine Electric	35	20,500	NGI #12	ARCO
U.S. Navy Department				
Carqwell	3	5,000	Stacked @ NPRA	

RESURRECTION BAY - SEWARD

ODECO				
Ocean Ranger Semisubmersible		25,000	Seward on Standby	
Emsco C-3 Type II Draw Works				

LOWER COOK INLET

DIAMOND M DRILLING				
Diamond M Dragon Drillship		20,000	OCS Y-0086 #1	Marathon
ODECO				
Ocean Bounty Semisubmersible		25,000	Y-0124 #1	Phillips

Continued on page 2

Rig List, Continued

COOK INLET BASIN

Amoco Production Co.				
Brewster N-7 (Platform Bruce)			On Platform - idle	
Cont'l. Emsco GB-250 5/48			On Platform - idle	
Atlantic Richfield Company				
National 1320 DE 13/58		15,000*	On Platform - idle	Union/ARCO
Cont'l. Emsco Electrohoist 11/80		15,000	On Platform - idle	
Brinkerhoff Drilling Company				
Oilwell 96	43	16,000	Kenai Deep Unit #6	Union
Wilson 120	58	12,500	Stacked @ Stump Lake Unit 41-33	Idle
Oilwell 52T (Helicopter Rig)	60	10,000*	Simpco Moquawkie #2	Simasko
Marathon Oil Company				
National 1320 UE 10/	76	20,000	On Platform - TBU D-25RD	Union/Marathon
National 1320 UE 10/	77	20,000	On Platform - Deactivated	
Mobil Oil Company				
Wilson 120 H 9/			On Granite Point Platform	Mobil
Parker Drilling Company				
TBA 2000 /5	152	20,000	Platform Bruce - GPS 18742-30	AMOCO/Parker
Shell Oil Company				
Cont'l. Emsco Electrohoist "C"		20,000	Shell Platform C - idle	
National 110/8		15,000	Shell Platform A - idle	
Union Oil Company of California				
National 1320 DE 12/	54	12,500+	On Platform - idle	
National 1320 DE 12/	55	15,000+	On Platform - TBU G-27	Union
Oilwell 860 on Monopod	56	15,000+	On Platform - W.O. Status	Union

1/ On Texaco - Superior Platform ***
2/ On Phillips North Cook Inlet Platform
3/ On Amoco's Platform Baker (B)
4/ On Amoco's Platform MGS Dillion (D)
5/ On Amoco's Granite Point Platform Bruce
6/ On Shell's MGS Platform "C"
7/ On Amoco's Platform Anna (A)
8/ On Shell's MGS Platform A
9/ On Mobil's Granite Point Platform
10/ On Marathon's Dolly Varden Platform
11/ On ARCO's Platform Spark
12/ On Union's Grayling Platform
13/ On ARCO's King Platform

*Depth capacities shown represent the depth to which the rig, as modified, should be able to drill. Figures differ from book rating due to rig modifications. All depths shown would be using 4½" or 5" OD drill pipe--except those with (**) where a 3½" OD drill pipe or tubing is used.

***The Texaco-Superior Platform A, which is operated by ARCO, does not have drilling capability and so is not carried in the normal rig section. If it is returned to a status of drilling capability, it will again be carried in the rig list.

North Dakota

Fiftieth Legislative Assembly, State of North Dakota, begun and held at the Capitol in the City of Bismarck, on Tuesday, the sixth day of January, one thousand nine hundred and eighty-seven.

SENATE BILL NO. 2079
(Legislative Council)
(Interim Taxation Committee)

AN ACT to amend and reenact subsections 4 and 5 of section 38-08-04, and sections 57-51.1-01, 57-51.1-02, and 57-51.1-03 of the North Dakota Century Code, relating to the duties of the industrial commission, the definitions of stripper well property, qualifying secondary recovery project, and qualifying tertiary recovery project for oil extraction purposes, the definition of average price, the rate of the oil extraction tax, and exemption from the oil extraction tax; and to declare an emergency.

BE IT ENACTED BY THE LEGISLATIVE ASSEMBLY OF THE STATE OF NORTH DAKOTA:

SECTION 1. AMENDMENT. Subsections 4 and 5 of section 38-08-04 of the 1985 Supplement to the North Dakota Century Code are hereby amended and reenacted to read as follows:

4. To classify wells as oil or gas wells for purposes material to the interpretation or enforcement of this chapter, and to classify and determine the status and depth of wells that are stripper well property as defined in subsection 5 8 of section 57-51.1-01, to certify to the tax commissioner which wells are stripper wells and the depth of these wells, and to certify to the tax commissioner which wells involve secondary or tertiary recovery operations under section 2 of this Act, and the date of qualification for the reduced rate of oil extraction tax for secondary and tertiary recovery operations.

5. To adopt and to enforce rules and orders to effectuate the purposes and the intent of this chapter and of subsections 1 and, 4, 5, 6, and 8 of section 57-51.1-01.

SECTION 2. AMENDMENT. Section 57-51.1-01 of the North Dakota Century Code is hereby amended and reenacted to read as follows:

57-51.1-01. Definitions for oil extraction tax. For the purposes of the oil extraction tax law, the following words and terms shall have the meaning ascribed to them in this section:

1. "Average daily production" of a well means the qualified maximum total production of oil from the well during a calendar month period divided by the number of calendar days in that period; and "qualified maximum total production" of a well means that the well must have been maintained at the maximum efficient rate of production as defined and determined by rule adopted by the industrial commission in furtherance of its authority under chapter 38-08.

2. "Average price" of a barrel of crude oil means the average daily price for a barrel of west Texas intermediate cushing crude oil, as those prices appear in the wall street journal, midwest edition, for the period June first through October thirty-first of any year.

3. "Oil" means petroleum, crude oil, mineral oil, casinghead gasoline, and all liquid hydrocarbons that are recovered from gas on the lease incidental to the production of the gas.

~~3.~~ 4. "Property" means the right which arises from a lease or fee interest, as a whole or any designated portion thereof, to produce oil. A producer shall treat as a separate property each separate and distinct producing reservoir subject to the same right to produce crude oil; provided, that such reservoir is recognized by the ~~appropriate governmental regulatory authority~~ industrial commission as a producing formation that is separate and distinct from, and not in communication with, any other producing formation.

5. "Qualifying secondary recovery project" means a project employing water flooding. To be eligible for the tax reduction provided under section 57-51.1-02, a secondary recovery project must be certified as qualifying by the industrial commission, the project must have been unitized after the effective date of this Act, and the project operator must have achieved for six consecutive months an average production level of at least twenty-five percent above the level that would have been recovered under normal recovery operations.

6. "Qualifying tertiary recovery project" means a project for enhancing recovery of oil which meets the requirements of section 4993(c), Internal Revenue Code of 1954, as amended through December 31, 1986, and includes the following methods for recovery:

a. Miscible fluid displacement.

b. Steam drive injection.

c. Microemulsion.

d. In situs combustion.

e. Polymer augmented water flooding.

f. Cyclic steam injection.

g. Alkaline flooding.

h. Carbonated water flooding.

i. Immiscible carbon dioxide displacement.

j. New tertiary recovery methods certified by the industrial commission.

It does not include water flooding, unless the water flooding is used as an element of one of the qualifying tertiary recovery techniques described in this subsection, or immiscible natural gas injection. To be eligible for the tax reduction provided under section 57-51.1-02, a tertiary recovery project must be certified as qualifying by the industrial commission, the project operator must continue to operate the unit as a qualifying tertiary recovery project, and the project operator must have achieved for at least one month a production level of at least fifteen percent above the level that would have been recovered under normal recovery operations.

~~4.~~ 7. "Royalty owner" means an owner of what is commonly known as the royalty interest and shall not include the owner of any overriding royalty or other payment carved out of the working interest.

~~5.~~ 8. "Stripper well property" means a "property" whose average daily production of oil, excluding condensate recovered in nonassociated production, per well did not exceed ten barrels per day for wells of a depth of six thousand feet or less, fifteen barrels per day for wells of a depth of more than six thousand feet but not more than ten thousand feet, and twenty barrels per day for wells of a depth of more than ten thousand feet during any preceding consecutive twelve-month period beginning after December 31, 1972. Wells which did not actually yield or produce oil during the qualifying twelve-month period, including disposal wells, dry wells, spent wells, and shut-in wells, are not production wells for the purpose of determining whether the stripper well property exemption applies.

SECTION 3. AMENDMENT. Section 57-51.1-02 of the North Dakota Century Code is hereby amended and reenacted to read as follows:

57-51.1-02. Imposition of oil extraction tax. There is hereby imposed an excise tax, to be known as the "oil extraction tax", upon the activity in this state of extracting oil from the earth, and every owner, including any royalty owner, of any part of the oil extracted shall be deemed for the purposes of this chapter to be engaged in the activity of extracting that oil. The rate of tax shall be six and one-half percent of the gross value at the well of the oil extracted, except that for wells drilled and completed after the effective date of this Act, and not otherwise exempt under section 57-51.1-03, and for a qualifying secondary recovery project or for a qualifying tertiary recovery project, the rate of tax shall be four percent of the gross value at the well of the oil extracted. However, if the average price of a barrel of crude oil between June first and October thirty-first of any year is thirty-three dollars or more then the rate of tax for the following calendar year on all taxable wells is six and one-half percent of the gross value at the well of the oil extracted.

SECTION 4. AMENDMENT. Section 57-51.1-03 of the North Dakota Century Code is hereby amended and reenacted to read as follows:

57-51.1-03. Exemptions from oil extraction tax. The following activities are specifically exempted from the oil extraction tax:

1. The activity of extracting from the earth any oil that is exempt from the gross production tax imposed by chapter 57-51.

2. The activity of extracting from the earth any oil from a stripper well property.

3. ~~The activity not otherwise exempt of extracting from the earth the oil that is owned by a royalty owner or royalty owners in the first one hundred barrels, or any lesser amount, of the average daily production of oil that is produced during each calendar day from any well.~~ For a well drilled and completed after the effective date of this Act, the initial production of oil from the well is exempt from any taxes imposed under this chapter for a period of fifteen months. Oil recovered during testing prior to well completion is exempt from the oil extraction tax. The exemption under this subsection becomes ineffective if the average price of a barrel of crude oil between June first and October thirty-first of any year is thirty-three dollars or more.

SECTION 5. EMERGENCY. This Act is declared to be an emergency measure and is in effect upon its filing with the secretary of state, except the portion of the amendment to

subsection 3 of section 57-51.1-03 relating to removal of the oil extraction tax exemption for oil owned by a royalty owner becomes effective July 1, 1987.

President of the Senate

Secretary of the Senate

Speaker of the House

Chief Clerk of the House

This certifies that the within bill originated in the Senate of the Fiftieth Legislative Assembly of the State of North Dakota and is known on the records of that body as Senate Bill No. 2079.

Secretary of the Senate

This certifies that two-thirds of the members of the Senate present and voting, voted in favor of said law.

Vote: Ayes 44 Nays 9 Absent 0

President of the Senate

Secretary of the Senate

This certifies that two-thirds of the members of the House of Representatives present and voting, voted in favor of said law.

Vote: Ayes 88 Nays 10 Absent 8

_____
Speaker of the House

_____
Chief Clerk of the House

Received by the Governor at _____M. on _____, 1987.

Approved at _____ M. on _____, 1987.

_____
Governor

Filed in this office this _____ day of _____, 1987, at _____ o'clock __M.

_____
Secretary of State

North Dakota

Fiftieth Legislative Assembly of State of North Dakota, begun and held at the Capitol in the City of Bismarck, on Tuesday, the sixth day of January, one thousand nine hundred and eighty-seven.

SENATE BILL NO. 2078
(Legislative Council)
(Interim Taxation Committee)

AN ACT to amend and reenact section 57-51.1-03 of the North Dakota Century Code, relating to removal of the royalty owners' exemption from the oil extraction tax.

BE IT ENACTED BY THE LEGISLATIVE ASSEMBLY OF THE STATE OF NORTH DAKOTA:

SECTION 1. AMENDMENT. Section 57-51.1-03 of the North Dakota Century Code is hereby amended and reenacted to read as follows:

57-51.1-03. Exemptions from oil extraction tax. The following activities are specifically exempted from the oil extraction tax:

1. The activity of extracting from the earth any oil that is exempt from the gross production tax imposed by chapter 57-51.

2. The activity of extracting from the earth any oil from a stripper well property.

3. ~~The activity not otherwise exempt of extracting from the earth the oil that is owned by a royalty owner or royalty owners in the first one hundred barrels, or any lesser amount, of the average daily production of oil that is produced during each calendar day from any well.~~

President of the Senate

Secretary of the Senate

Speaker of the House

Chief Clerk of the House

This certifies that the within bill originated in the Senate of the Fiftieth Legislative Assembly of the State of North Dakota and is known on the records of that body as Senate Bill No. 2078.

Vote:	Ayes	40	Nays	11	Absent	2
Vote:	Ayes	95	Nays	11	Absent	0

Secretary of the Senate

Received by the Governor at _____ M. on _____, 1987.

Approved at 8:07 A M. on 4-7, 1987.

Governor

Filed in this office this 9 day of April, 1987, at 11:24 o'clock A. M.

Secretary of State

North Dakota.

71053.0100

Fiftieth
Legislative Assembly
of North Dakota

HOUSE BILL NO. 1667

Introduced by

Representative Strinden

(Approved by the Committee on Delayed Bills)

A BILL for an Act to create and enact two new subsections to section 57-51.1-01 of the North Dakota Century Code, relating to definition of the terms "extension well" and "wildcat well"; and to amend and reenact section 57-51.1-03 of the North Dakota Century Code, relating to exemptions from the oil extraction tax for oil from extension wells and wildcat wells.

BE IT ENACTED BY THE LEGISLATIVE ASSEMBLY OF THE STATE OF NORTH DAKOTA:

SECTION 1. Two new subsections to section 57-51.1-01 of the North Dakota Century Code are hereby created and enacted to read as follows:

"Extension well" means an oil or gas well located within one mile outside the boundaries of an established oilfield and which is drilled and completed after March 31, 1987, and before July 1, 1989.

"Wildcat well" means an oil or gas well located more than one mile outside the boundaries of an established oilfield and which is drilled and completed after March 31, 1987, and before July 1, 1989.

SECTION 2. AMENDMENT. Section 57-51.1-03 of the North Dakota Century Code is hereby amended and reenacted to read as follows:

57-51.1-03. Exemptions from oil extraction tax. The following activities are specifically exempted from the oil extraction tax:

1. The activity of extracting from the earth any oil that is exempt from the gross production tax imposed by chapter 57-51.

2. The activity of extracting from the earth any oil from a stripper well property.

3. The activity not otherwise exempt of extracting from the earth the oil that is owned by a royalty owner or royalty owners in the first one hundred barrels, or any lesser amount, of the average daily production of oil that is produced during each calendar day from any well.

4. The activity of extracting from the earth oil from a wildcat well is exempt from the tax imposed by section 57-51.1-02 for forty-eight months after drilling is completed.

5. The activity of extracting from the earth oil from an extension well is exempt from the tax imposed by section 57-51.1-02 for twenty-four months after drilling is completed.

ALASKA REPORT

RECEIVED
JUL 24 1987
DIVISION OF OIL & GAS
ANCHORAGE, ALASKA

Vol. 33, No. 29
7-22-87

Arco to Resume Development Drilling in Prudhoe Bay Field

Arco Alaska, which hasn't drilled a development well in Prudhoe Bay field since early this year, announced plans to drill five development wells there beginning in September. Arco was last active in the field in February.

Susan Andrews, spokesperson for Arco, said "resuming production drilling in Prudhoe is good news and strictly the result of higher oil prices." The wells represent a $13 million investment, according to Andrews.

Arco also cancelled plans to stack the rig currently drilling in Lisburne field. Currently, bid requests for a rig for the Prudhoe program are out but a successful bidder has not yet been named.

This week's drilling activity in Lisburne field shows crews logging the coring hole at 12,752 ft at Arco Alaska's L5-21, while in Kuparuk field casing is being run at 4,855 ft at the company's 3M-21.

In Endicott field, completion work is under way on the Arco 0-23, while drilling is at 13,673 ft on Standard Alaska Production's J-40.

In Prudhoe Bay field, Standard began redrill operations at the B3B, while crews are running liner after competing drilling operations at the J-26 at 10,715 ft.

In Cook Inlet, Unocal is conducting fishing operations at the G-36 from the Grayling Platform. Onshore, at the Unocal Cannery Loop #4, crews are drilling out cement after setting 13 5/8-inch casing to 8,234 ft.

$10 Million Law Suit Filed Over Cook Inlet Oil Spill

A $10 million class action lawsuit filed Monday in Kenai Superior Court names the owner of the tanker Glacier Bay, Tesero Alaska Inc, and the Cook Inlet Response Organization as defendants.

The suit was filed on the behalf of commercial fisherman, processors and cannery workers claiming they suffered economic harm as the result of an oil spill earlier this month in Cook Inlet.

The nearly 3,100-bbl spill fouled fishing gear and contaminated some salmon caught at the beginning of what is expected to be a record run of red salmon.

Cleanup operations in Cook Inlet continue and those operations combined with the extreme tidal action in the inlet have eliminated the danger of the oil to the fish and commercial fishing operations. About 15 percent of the oil has been recovered to date.

A total of $100 million is available to compensate the fisherman. Trinidad Corp, owner of the tanker, carried $14 million in mandatory insurance and is liable to claims up to that amount. If claims exceed that amount additional funds are available from the Trans-Alaska Pipeline Liability Fund, created by Congress as part of the Trans-Alaska Pipeline Authorization Act and designed to cover major spills of North Slope crude.

Separately, crews on Monday were cleaning up an oil-like substance that was discovered seeping out of a bluff near some oil storage tanks near Kenai.

The substance has not yet been identified and was discovered by clean up crews patrolling the beach for oil washed ashore from the inlet spill. Chevron USA, which among other companies, has tanks near the seepage is conducting the cleanup. Samples of the substance have been sent away for analysis and work is under way to find the source of the material.

The seep was discovered Sunday and is flowing at a rate of about five to 10 gallons per day.

Petroleum Information
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SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

SCHEDULE 13E-3

Rule 13e-3 Transaction Statement
(Pursuant to Section 13(e) of the
Securities Exchange Act of 1934)

THE STANDARD OIL COMPANY (OH)
(Name of the Issuer)

BP NORTH AMERICA INC.
(Name of Person(s) Filing Statement)

COMMON STOCK, WITHOUT PAR VALUE
(Title of Class of Securities)

0008537341
(CUSIP Number of Class of Securities)

George H. Hagle
BP North America Inc.
620 Fifth Avenue
New York, New York 10020
(212) 887-9300

(Name, Address and Telephone Number of Person Authorized to Receive Notices and Communications on Behalf of Person(s) Filing Statement)

Copies To:

Benjamin F. Stapleton
Sullivan & Cromwell
125 Broad Street
New York, New York 10004
(212) 558-4000

K.J.M. Walder
The British Petroleum
Company p.l.c.
Britannic House, Moor Lane
London EC2Y 9BU
England
(01) 920-8000

Total Of Sequentially Numbered Pages 28

Exhibit Index on Sequentially Numbered Page 11

This statement is filed in connection with (check the appropriate box):

a. [ ] The filing of solicitation materials or an information statement subject to Regulation 14A, Regulation 14C or Rule 13e-3(c) under the Securities Exchange Act of 1934.

b. [ ] The filing of a registration statement under the Securities Act of 1933.

c. [X] A tender offer.

d. [ ] None of the above.

Check the following box if the soliciting materials or information statement referred to in checking box (a) are preliminary copies: [ ]

Calculation of Filing Fee

Transaction valuation	Amount of filing fee
$7,341,167,120*	$1,468,233.42**

*up to 104,873,816 shares at $70 per share

**1/50th of 1% of Transaction Valuation.

[X] Check box if any part of the fee is offset as provided by Rule 0-11(a)(2) and identify the filing with which the offsetting fee was previously paid. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

Amount Previously Paid: $1,468,233.42

Form or Registration No.: SCHEDULE 14D-1

Filing Party: BP NORTH AMERICA INC.

Date Filed: April 1, 1987

This Schedule 13E-3 relates to the offer by BP North America Inc., a Delaware corporation (the "Purchaser") and an indirect wholly-owned subsidiary of The British Petroleum Company p.l.c., a company organized under the laws of England, to purchase any and all of the outstanding shares of Common Stock, without par value, of The Standard Oil Company, an Ohio corporation (the "Company"), at $70 per share, net to the seller in cash, upon the terms and subject to the conditions set forth in the Offer to Purchase dated April 1, 1987 (the "Offer to Purchase") and the related Letter of Transmittal, copies of which are annexed hereto as Exhibits (d)(1) and (d)(2), respectively.

The cross reference sheet below is being supplied pursuant to Instruction F to Schedule 13E-3 and shows the location in the Schedule 14D-1 filed by the Purchaser with the Securities and Exchange Commission contemporaneously herewith (the "Schedule 14D-1") of the information required to be included in response to the Items of this Schedule. The information in the Purchaser's Schedule 14D-1 is incorporated herein by reference. A copy of the Schedule 14D-1 is attached hereto as Exhibit (g).

CROSS REFERENCE SHEET

Item in Schedule 13E-3	Where located in the Purchaser's Schedule 14D-1
Item 1(a)	Item 1(a)
Item 1(b)	Item 1(b)
Item 1(c)	Item 1(c)
Item 1(d)	*
Item 1(e)	*
Item 1(f)	*
Item 2	Item 2
Item 3	Item 3
Item 4	*
Item 5(a)	Item 5(a)
Item 5(b)	Item 5(b)
Item 5(c)	Item 5(c)
Item 5(d)	Item 5(d)
Item 5(e)	Item 5(e)

* Information is not required to be included in the Schedule 14D-1. Such information is hereinafter provided.

Item in Schedule 13E-3	Where located in the Purchaser's Schedule 14D-1
Item 5(f)	Item 5(g)
Item 5(g)	*
Item 6(a)	Item 4(a)
Item 6(b)	*
Item 6(c)	Item 4(b)
Item 6(d)	Item 4(c)
Item 7(a)	Item 5
Item 7(b)	*
Item 7(c)	*
Item 7(d)	*
Item 8	*
Item 9	*
Item 10	Item 6
Item 11	Item 7
Item 12	*
Item 13	*
Item 14	*
Item 15(a)	*
Item 15(b)	Item 8
Item 16	Item 10(f)
Item 17	Separately included herewith

Item 1. Issuer and Class of Security Subject to the Transaction.

(a) - (c) The answer to Items 1(a)-(c) of the Schedule 14D-1 is incorporated herein by reference.

(d) The information set forth under the caption "MARKET PRICES OF AND DIVIDENDS ON SHARES" in the Offer to Purchase is incorporated herein by reference. The Purchaser believes that the Company is subject to covenants contained in certain loan agreements which would restrict dividends payable by the Company, but that such restrictions are not material to the Company's ability to pay regular quarterly cash dividends.

(e) Not applicable.

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* Information is not required to be included in the Schedule 14D-1. Such information is hereinafter provided.

(f) Not applicable.

Item 2. Identity and Background.

The answer to Item 2 of the Schedule 14D-1 is incorporated herein by reference.

Item 3. Past Contacts, Transactions or Negotiations.

The answer to Item 3 of the Schedule 14D-1 is incorporated herein by reference.

Item 4. Terms of the Transaction.

(a) The information set forth under the captions "INTRODUCTION", "SPECIAL FACTORS -- Purpose, Structure and Benefits of the Offer" and "THE TENDER OFFER" in the Offer to Purchase is incorporated herein by reference.

(b) The information set forth under the caption "SPECIAL FACTORS -- Purpose, Structure and Benefits of the Offer" in the Offer to Purchase is incorporated herein by reference.

Item 5. Plans or Proposals of the Issuer or Affiliate.

(a)-(f) The answer to Item 5 of the Schedule 14D-1 is incorporated herein by reference.

(g) Not applicable.

Item 6. Source and Amount of Funds or Other Consideration.

(a), (c) and (d) The answer to Item 4 of the Schedule 14D-1 is incorporated herein by reference.

(b) The information set forth under the caption "THE TENDER OFFER -- Fees and Expenses" in the Offer to Purchase is incorporated herein by reference.

Item 7. Purpose(s), Alternatives, Reasons and Effects.

(a) The answer to Item 5 of the Schedule 14D-1 is incorporated herein by reference.

(b) The information set forth under the captions "SPECIAL FACTORS -- Background of the Offer" and "SPECIAL FACTORS -- Reasons for the Offer" in the Offer to Purchase is incorporated herein by reference.

(c) The information set forth under the captions "SPECIAL FACTORS -- Background of the Offer", "SPECIAL FACTORS -- Purpose, Structure and Benefits of the Offer" and "SPECIAL FACTORS -- Reasons for the Offer" in the Offer to Purchase is incorporated herein by reference.

(d) The information set forth under the captions "SPECIAL FACTORS -- Purpose, Structure and Benefits of the Offer", "SPECIAL FACTORS -- Plans for the Company After the Offer", "SPECIAL FACTORS -- Certain Effects of the Offer" and "SPECIAL FACTORS -- "Federal Income Tax Consequences to Shareholders" in the Offer to Purchase is incorporated herein by reference.

Item 8. Fairness of the Transaction.

(a) - (e) The information set forth under the captions "SPECIAL FACTORS -- Background of the Offer", "SPECIAL FACTORS -- Fairness of the Offer" and "SPECIAL FACTORS -- Position of the Company with Respect to the Offer" in the Offer to Purchase is incorporated herein by reference.

(f) Not applicable.

Item 9. Reports, Opinions, Appraisals and Certain Negotiations.

The information set forth under the captions "SPECIAL FACTORS -- Fairness of the Offer" and "SPECIAL FACTORS -- The Financial Advisors" in the Offer to Purchase is incorporated herein by reference.

Item 10. Interest in Securities of the Issuer.

The answer to Item 6 of the Schedule 14D-1 is incorporated herein by reference.

Item 11. Contracts, Arrangements or Understandings with Respect to the Issuer's Securities.

The answer to Item 7 of the Schedule 14D-1 is incorporated herein by reference.

Item 12. Present Intention and Recommendation of Certain Persons with Regard to the Transaction.

The information set forth under the captions "SPECIAL FACTORS -- Purpose, Structure and Benefits of the Offer" and "SPECIAL FACTORS -- Position of the Company with Respect to the Offer" in the Offer to Purchase is incorporated herein by reference.

Item 13. Other Provisions of the Transaction.

(a) The information set forth under the caption "SPECIAL FACTORS -- Purpose, Structure and Benefits of the Offer" in the Offer to Purchase, and in Schedule II thereto, is incorporated herein by reference.

(b) and (c) Not applicable.

Item 14. Financial Information.

(a) The information set forth under the caption "THE COMPANY -- Historical Summary Financial Information" in the Offer to Purchase is incorporated herein by reference. In addition, the financial statements annexed hereto as Exhibit (h) are incorporated herein by reference.

(b) Not material.

Item 15. Persons and Assets Employed, Retained or Utilized.

(a) The information set forth under the captions "SPECIAL FACTORS -- Purpose, Structure and Benefits of the Offer", "SPECIAL FACTORS -- Reasons for the Offer" and "SPECIAL FACTORS -- Plans for the Company After the Offer" in the Offer to Purchase is incorporated herein by reference.

(b) The answer to Item 8 of the Schedule 14D-1 is incorporated herein by reference.

Item 16. Additional Information.

The answer to Item 10(f) of the Schedule 14D-1 is incorporated herein by reference.

Item 17. Material to be Filed as Exhibits.

(a) See Exhibit (b) to the Schedule 14D-1.

(b) Report of Goldman, Sachs & Co., dated March 25, 1987.

(c)(1) See Exhibit (c) to the Schedule 14D-1.

(d) See Exhibits (a)(1)-(9) to the Schedule 14D-1.

(e) See Schedule II to the Offer to Purchase.

(f) Not applicable.

(g) Schedule 14D-1.

(h) Consolidated Financial Statements of the Company and its subsidiaries, as excerpted from the Company's 1986 Annual Report to Shareholders.

(i) See Exhibit (h) to the Schedule 14D-1.

SIGNATURE

After due inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

Dated: April 1, 1987

BP NORTH AMERICA INC.

By _____
Title: Vice President

EXHIBIT INDEX

Exhibit	Description	Page
(a)	See Exhibit (b) to the Schedule 14D-1.	150
(b)	Report of Goldman, Sachs & Co., dated March 25, 1987.	13
(c)(1)	See Exhibit (c) to the Schedule 14D-1.	201
(d)	See Exhibits (a)(1)-(9) to the Schedule 14D-1.	75
(e)	See Schedule II to the Offer to Purchase.	114
(f)	Not applicable.	
(g)	Schedule 14D-1.	65
(h)	Consolidated Financial Statements of the Company and its subsidiaries, as excerpted from the Company's 1986 Annual Report to Shareholders.	266
(i)	See Exhibit (h) to the Schedule 14D-1.	244

EXHIBIT (b)

HIGHLY CONFIDENTIAL

DRAFT of
March 25, 1987

SNOW

Prepared by

Goldman, Sachs & Co.

TABLE OF EXHIBITS

	EXHIBITS
Summary of Valuation Methodology	1
Common Stock Price and Trading History	2
- Five Year Price and Volume History - Indexed Common Stock Price History - Volumes Traded at Various Prices	
Comparison of Snow to Certain Other Publicly Traded Integrated Oil and Gas Companies	3
Valuation Based on Transaction Multiples From Selected Major Oil and Gas Transactions	4
Range of Estimated Values	5
Oil and Gas Exploration and Production Valuation	6
- Prudhoe Bay Field - Other Alaskan Properties - Lower 48 and Canadian Properties - Probable Reserves and Unexplored Acreage	
Analysis of Master Limited Partnership of Prudhoe Bay Interest	7
Trans Alaska Pipeline System Valuation	8
Refining & Marketing System Valuation	9

EXHIBIT I

PROJECT WINTER

Overview of Valuation Methodology

Factors considered in our valuation of Snow:

A. **Total Company**

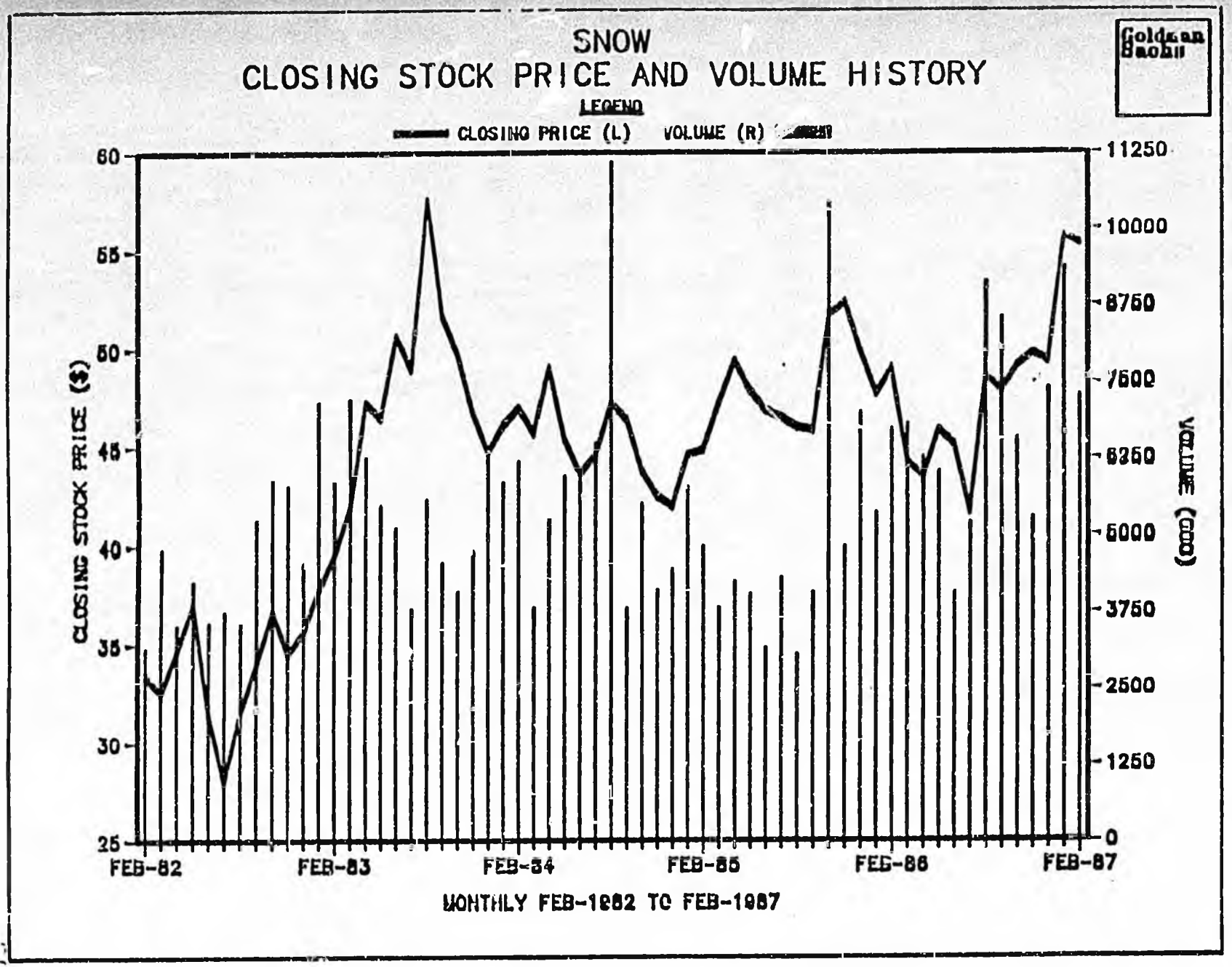
- Past and current market prices and trading activity of Snow common stock (Exhibit 2)
- Historical and projected financial performance
- Comparison of Snow with certain other publicly traded integrated oil and gas companies (Exhibit 3)
- Comparable mergers and acquisitions in the oil and gas industry (Exhibit 4)

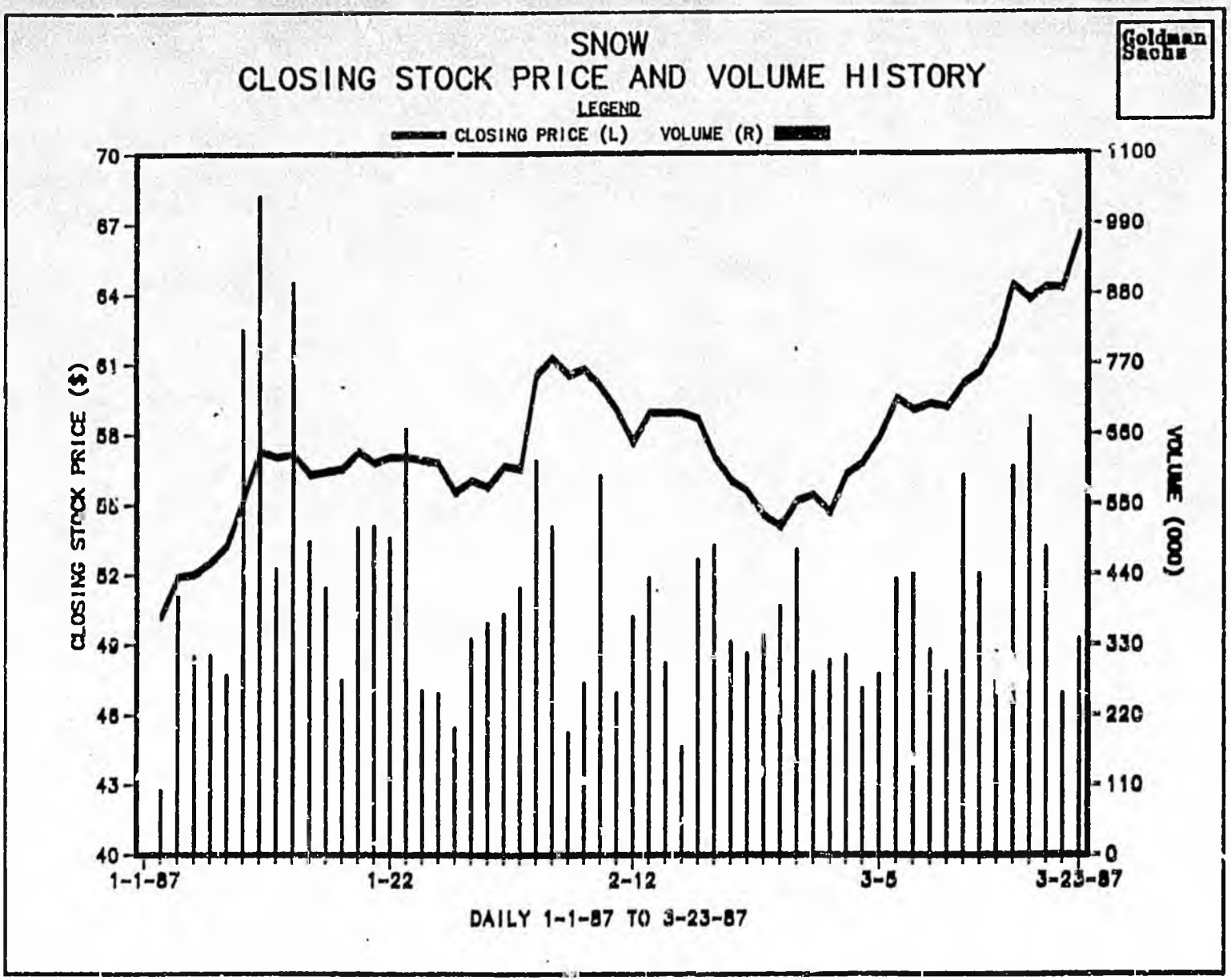
B. **Valuation by Business Segment** (Summary in Exhibit 5)

- Oil and Gas Exploration and Production (Exhibits 6 and 7)
  - discounted cash flow analyses of the oil and gas reserves
  - publicly traded master limited partnership and other vehicles
  - comparable acquisition transactions
- Trans Alaska Pipeline System (Exhibit 8)
  - discounted cash flow analyses
  - publicly traded master limited partnership and other vehicles
  - comparable acquisition transactions
- Refining & Marketing System (Exhibit 9)
  - discounted cash flow analyses
  - public market data for certain refining and marketing companies
  - comparable acquisition transactions

- Extraction Businesses and Chemicals and Industrial Products
  - discounted cash flow analyses
  - public market valuations of comparable companies
  - comparable acquisition transactions
  - values potentially achievable in leveraged buyout transactions

EXHIBIT 2

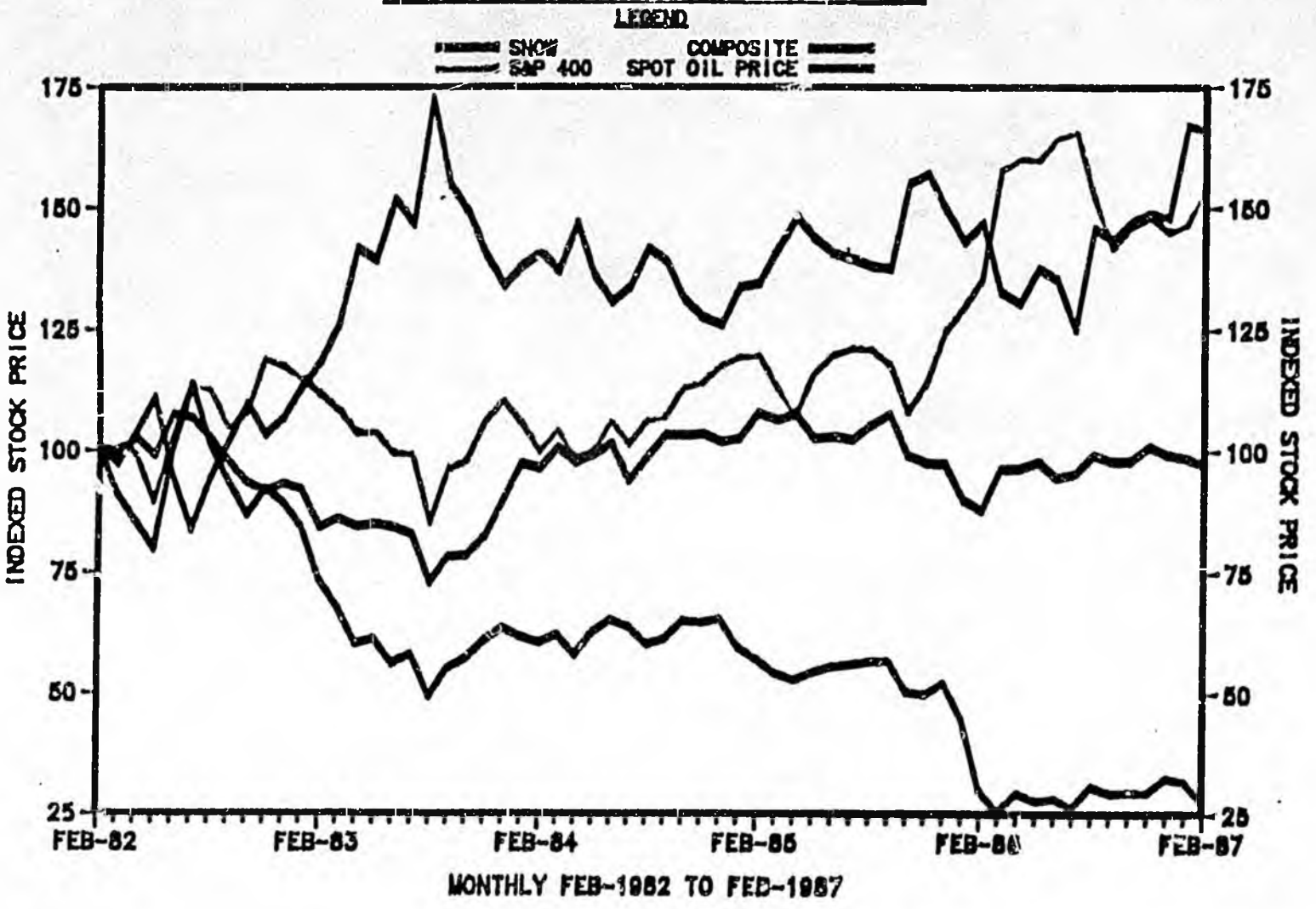

SNOW
CLOSING STOCK PRICE AND VOLUME HISTORY
Goldman Sachs
LEGEND
CLOSING PRICE (L)
VOLUME (R)
CLOSING STOCK PRICE ($)
60
55
50
45
40
35
30
25
11250
10000
8750
7500
6250
5000
3750
2500
1250
0
VOLUME (000)
FEB-82
FEB-83
FEB-84
FEB-85
FEB-86
FEB-87
MONTHLY FEB-1982 TO FEB-1987

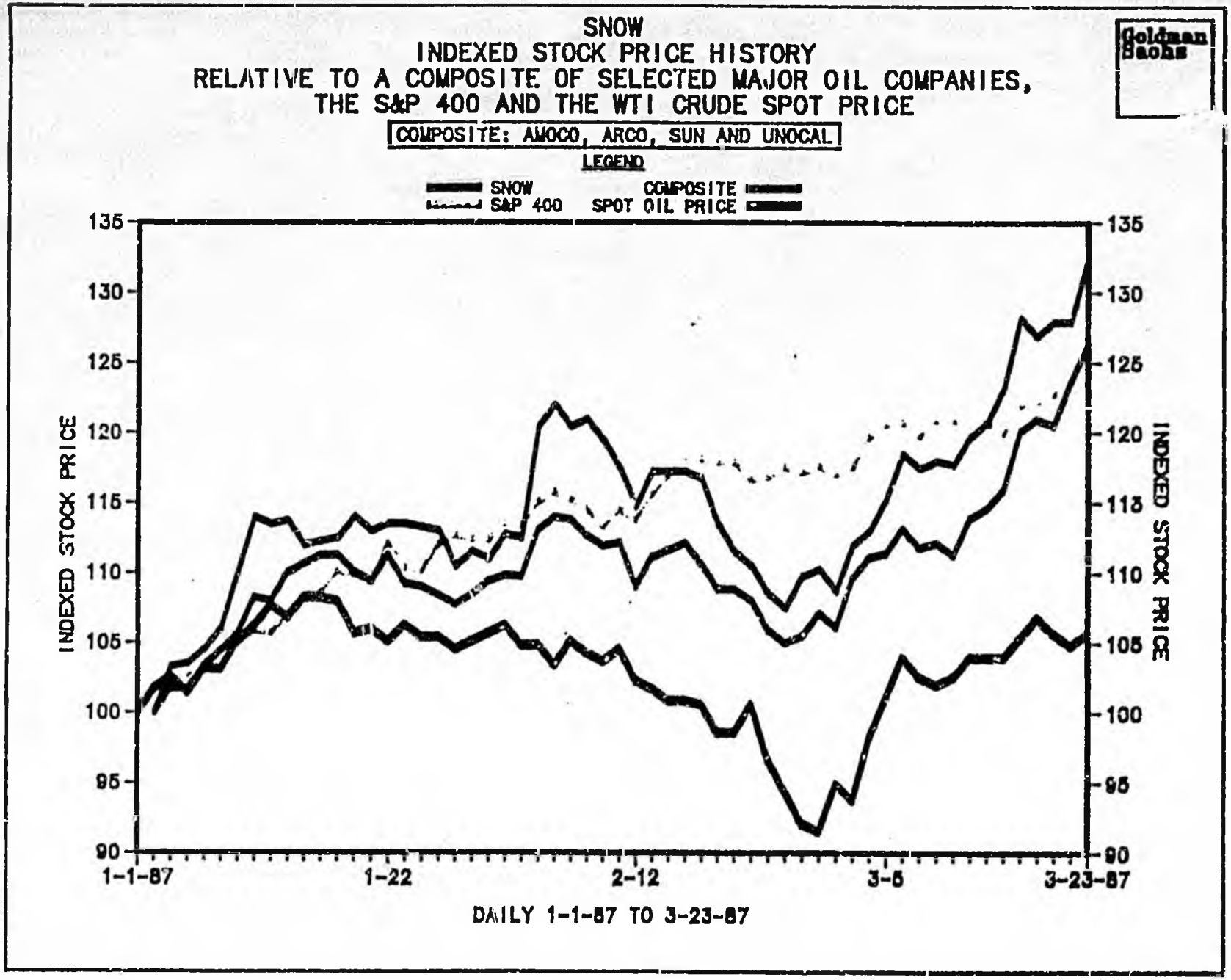

SNOW
CLOSING STOCK PRICE AND VOLUME HISTORY
Goldman Sachs
LEGEND
CLOSING PRICE (L)
VOLUME (R)
CLOSING STOCK PRICE ($)
VOLUME (000)
70
67
64
61
58
55
52
49
46
43
40
1100
990
880
770
660
550
440
330
220
110
0
1-1-87
1-22
2-12
3-5
3-23-87
DAILY 1-1-87 TO 3-23-87

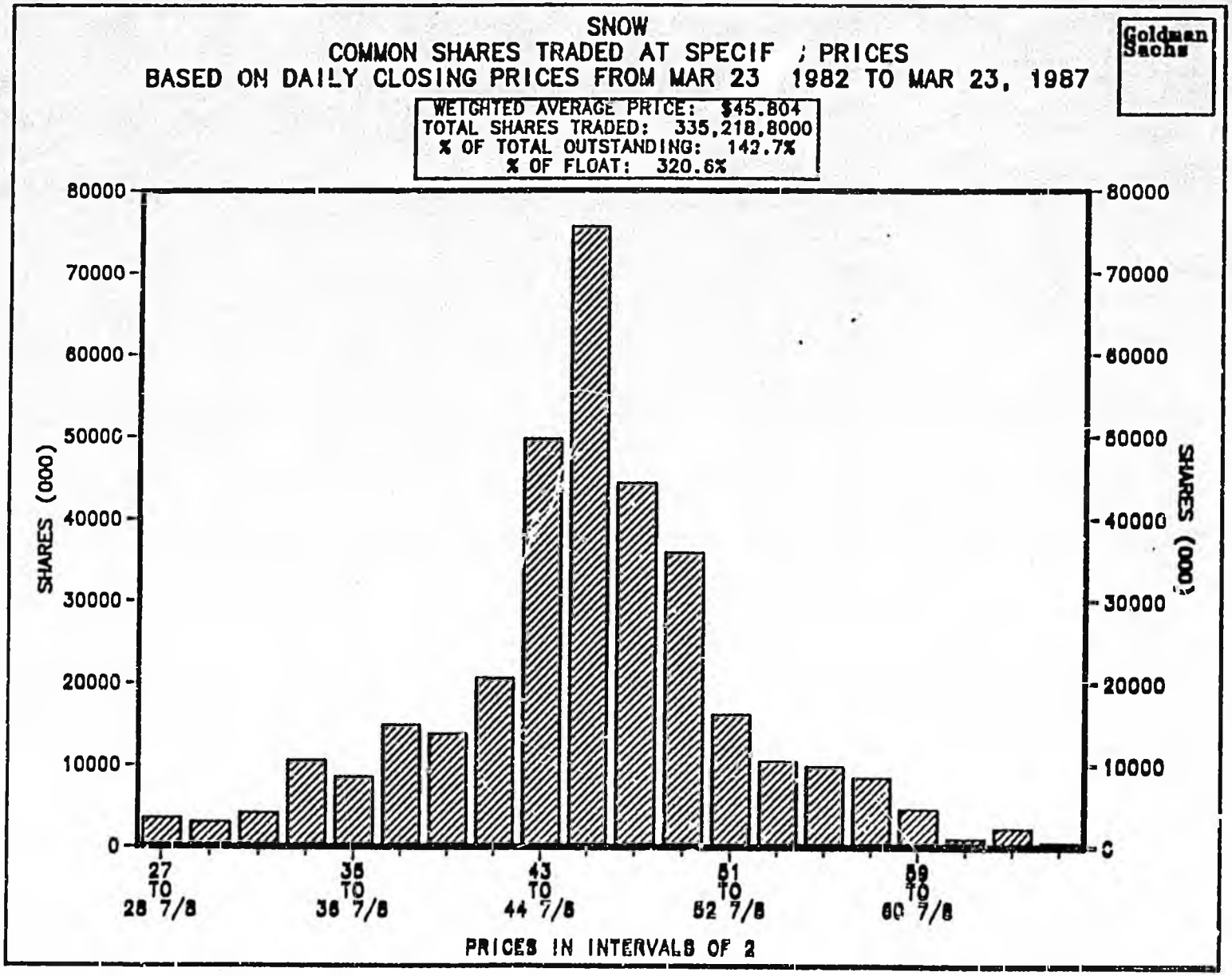
SNOW
INDEXED STOCK PRICE HISTORY
RELATIVE TO A COMPOSITE OF SELECTED MAJOR OIL COMPANIES, THE S&P 400 AND THE WTI CRUDE SPOT PRICE

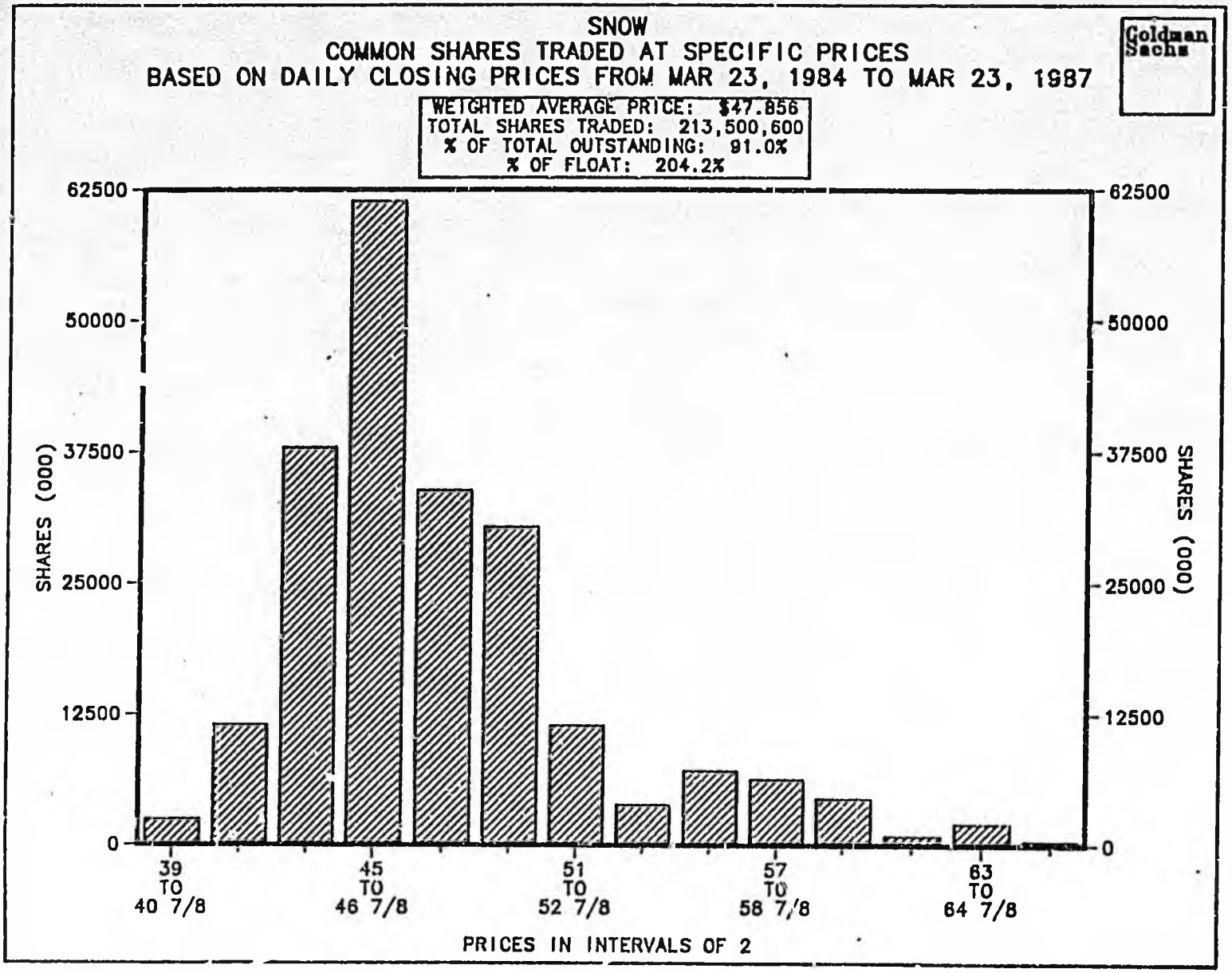
Goldman Sachs

COMPOSITE: AMOCO, ARCO, SUN AND UNOCAL.




SNOW
INDEXED STOCK PRICE HISTORY
RELATIVE TO A COMPOSITE OF SELECTED MAJOR OIL COMPANIES,
THE S&P 400 AND THE WTI CRUDE SPOT PRICE
COMPOSITE: AMOCO, ARCO, SUN AND UNOCAL
Goldman Sachs
LEGEND
SNOW
S&P 400
COMPOSITE
SPOT OIL PRICE
INDEXED STOCK PRICE
135
130
125
120
115
110
105
100
95
90
1-1-87
1-22
2-12
3-5
3-23-87
DAILY 1-1-87 TO 3-23-87


SNOW
COMMON SHARES TRADED AT SPECIF ; PRICES
BASED ON DAILY CLOSING PRICES FROM MAR 23 1982 TO MAR 23, 1987
Goldman Sachs
WEIGHTED AVERAGE PRICE: $45.804
TOTAL SHARES TRADED: 335,218,8000
% OF TOTAL OUTSTANDING: 142.7%
% OF FLOAT: 320.6%
SHARES (000)
80000
70000
60000
50000
40000
30000
20000
10000
0
27 TO 28 7/8
35 TO 36 7/8
43 TO 44 7/8
51 TO 52 7/8
59 TO 60 7/8
PRICES IN INTERVALS OF 2


SNOW
COMMON SHARES TRADED AT SPECIFIC PRICES
BASED ON DAILY CLOSING PRICES FROM MAR 23, 1984 TO MAR 23, 1987
Goldman Sachs
WEIGHTED AVERAGE PRICE: $47.856
TOTAL SHARES TRADED: 213,500,600
% OF TOTAL OUTSTANDING: 91.0%
% OF FLOAT: 204.2%
62500
50000
37500
25000
12500
0
SHARES (000)
39 TO 40 7/8
45 TO 46 7/8
51 TO 52 7/8
57 TO 58 7/8
63 TO 64 7/8
PRICES IN INTERVALS OF 2

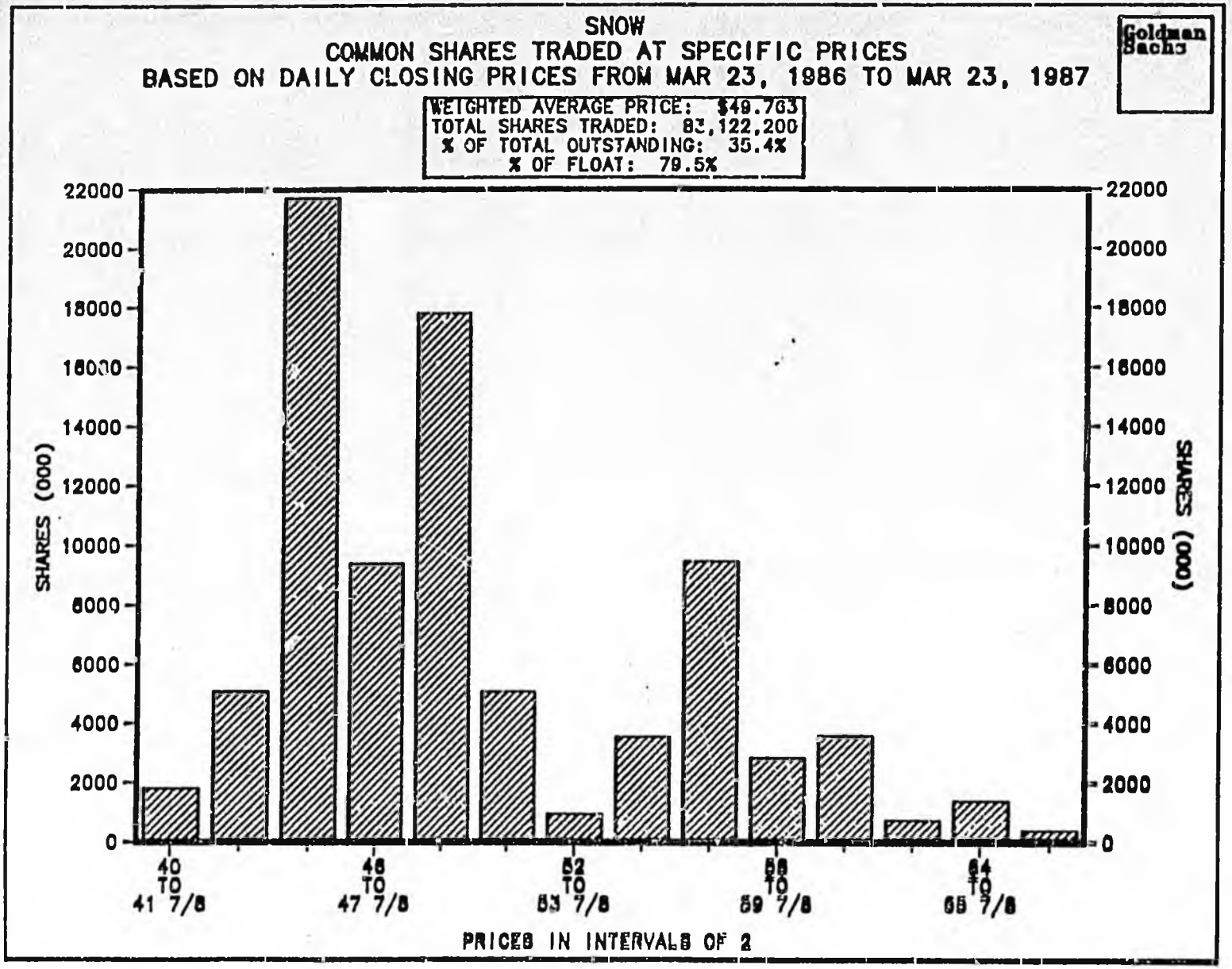

SNOW
COMMON SHARES TRADED AT SPECIFIC PRICES
BASED ON DAILY CLOSING PRICES FROM MAR 23, 1986 TO MAR 23, 1987
Goldman Sachs
WEIGHTED AVERAGE PRICE: $49.763
TOTAL SHARES TRADED: 83,122,200
% OF TOTAL OUTSTANDING: 35.4%
% OF FLOAT: 79.5%
SHARES (000)
22000
20000
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
40 TO 41 7/8
46 TO 47 7/8
52 TO 53 7/8
58 TO 59 7/8
64 TO 65 7/8
PRICES IN INTERVALS OF 2

EXHIBIT 3

COMPARISON OF SELECTED OIL AND GAS COMPANIES
SUMMARY

	SNEW	AMOCO CORP	ATLANTIC RICHFIELD CO	SUN CO INC	UNOCAL CORP
Capitalization ($MM)					
Aggregate Values (MM)	09/30/86	12/31/86	12/31/86	09/30/86	09/30/86
Short-Term Debt	$ 295.0	$ 410.0	$ 1,746.0	$ 869.0	$ 95.0
Long-Term Debt	4,048.0	3,320.0	6,969.0	1,626.0	5,382.0
Preferred Stock	0.0	0.0	2.0	1.0	0.0
Common Equity	7,152.0	11,324.0	5,257.0	5,292.0	1,659.0
Total Capitalization	$11,495.0	$15,054.0	$13,974.0	$7,788.0	$7,136.0
Cash & Equivalents	917.0	441.0	2,307.0	1,951.0	380.0
Deferred Taxes	2,027.0	3,997.0	3,562.0	2,063.0	1,688.0
Book Value ($/Share)	$30.47	$44.05	$28.85	$49.14	$14.26
Percentages					
Short-Term Debt	2.6%	2.7%	12.5%	11.2%	1.3%
Long-Term Debt	35.2	22.1	49.9	20.9	75.4
Preferred Stock	0.0	0.0	0.0	0.0	0.0
Common Equity	62.2	75.2	37.6	68.0	23.2
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%
Market Data	03/23/87	03/23/87	03/23/87	03/23/87	03/23/87
Market Capitalization (MM)	$15,606.6	$21,579.5	$14,001.1	$7,257.1	$4,259.7
Price Per Share	$ 66.50	$ 83.88	$ 78.88	$ 67.38	$ 36.63
Price Range (Latest 12 Months)					
High	$66.75	$84.00	$79.88	$67.50	$37.00
Low	40.25	54.50	45.25	44.13	15.63
Common Shares Outstanding (M)	234,685.0	257,282.0	177,510.0	107,712.0	116,305.0
Dividend	$2.80	$3.30	$4.00	$3.00	$1.00
Dividend Yield	4.2%	3.9%	5.1%	4.5%	2.7%
Latest Fiscal Year	12/31/85	12/31/86	12/31/86	12/31/85	12/31/85
Oper Income: Aggregate (MM)	$3,333.0	$1,588.0	$1,303.0	$1,062.0	$1,133.0
Per Common Share	$ 14.18	$ 6.18	$ 7.15	$ 9.54	$ 8.22
Net Income: Aggregate (MM)	$1,322.0	$ 747.0	$ 615.0	$ 802.0	$ 325.0
Per Common Share	$ 5.63	$ 2.91	$ 3.38	$ 7.20	$ 2.36
Cash Flow: Aggregate (MM)	$3,571.0	$3,369.0	$3,550.0	$1,758.0	$1,836.0
Per Common Share	$ 15.20	$ 13.10	$ 19.48	$ 15.79	$ 13.32
Market Price/Oper Income	4.7X	13.6X	11.0X	7.0X	4.5X
Market Price/Net Income	11.8X	28.9X	23.4X	9.4X	15.5X
Market Price/Cash Flow	4.4X	6.4X	4.0X	4.3X	2.7X
Market Price/Book Value	1.9X	1.9X	2.7X	1.4X	3.1X
Latest 12 Months	09/30/86	12/31/86	12/31/86	09/30/86	09/30/86
Oper Income: Aggregate (MM)	$ 932.0	$1,588.0	$1,303.0	$ 844.0	$ 666.0
Per Common Share	$ 3.97	$ 6.18	$ 7.15	$ 7.84	$ 5.73
Net Income: Aggregate (MM)	$1,225.0	$ 747.0	$ 615.0	$ 753.0	($ 8.0)
Per Common Share	$ 5.22	$ 2.91	$ 3.38	$ 6.99	($ 0.07)
Cash Flow: Aggregate (MM)	$3,451.0	$3,369.0	$3,550.0	$1,325.0	$1,564.0
Per Common Share	$ 14.70	$ 13.10	$ 19.48	$ 12.30	$ 13.45
Market Price/Oper Income	16.7X	13.6X	11.0X	8.6X	6.4X
Market Price/Net Income	12.7X	28.9X	23.4X	9.6X	(532.5X)
Market Price/Cash Flow	4.5X	6.4X	4.0X	5.5X	2.7X
Market Price/Book Value	2.2X	1.9X	2.7X	1.4X	2.6X
Accounting Method	SE	SE	SE	SE	SE
Worldwide Reserves (Geo. Dist.)	12/31/85	12/31/86	12/31/85	12/31/85	12/31/85
United States	100.0%	65.4%	92.1%	82.1%	75.7%
Canada	0.0	10.9	0.0	7.9	0.0
North Sea & Europe	0.0	6.7	0.0	0.0	2.3
Other	0.0	16.9	7.9	9.9	22.0
Total	100.0%	100.0%	100.0%	100.0%	100.0%

COMPARISON OF SELECTED OIL AND GAS COMPANIES
SUMMARY

	SNOW	AMOCO CORP	ATLANTIC RICHFIELD CO	SUN CO INC	UNOCAL CORP
Proved Reserves	12/31/85	12/31/86	12/31/85	12/31/85	12/31/85
Oil (MM Bbl)	2,647.8	2,424.0	2,931.0	848.0	887.0
% NEB	74.6%	55.8%	76.8%	68.1%	53.4%
% Developed	73.1%	93.1%	70.4%	74.1%	79.0%
Gas (Bcf)	7,219.0	15,375.0	7,065.0	3,174.0	6,189.0
% NEB	25.4%	48.2%	23.2%	31.9%	36.6%
% Developed	7.5%	91.2%	70.7%	73.1%	66.4%
Total Proved Reserves (MM)					
(8/1 NEB)	3,550.2	4,345.9	3,824.1	1,244.8	1,660.6
% Change from Last Year	(5.9%)	(6.8%)	(21.0%)	(2.2%)	2.1%
(10/1 NEB)	3,369.7	3,961.5	3,637.5	1,165.4	1,505.9
% Change from Last Year	(6.4%)	(7.5%)	(18.3%)	(2.5%)	2.3%
Production					
Oil (MM Bbl)	262.3	294.0	260.0	82.0	101.0
% NEB	96.8%	70.1%	78.3%	70.8%	66.6%
Gas (Bcf)	69.7	1,004.0	576.0	270.0	405.0
% NEB	3.2%	29.9%	21.7%	29.2%	33.4%
Total Production (MM)					
(8/1 NEB)	271.0	419.5	332.0	115.8	151.6
% Change from Last Year	13.3%	(3.7%)	0.1%	(5.0%)	3.8%
(10/1 NEB)	269.3	394.4	317.6	109.0	141.5
% Change from Last Year	13.3%	(3.8%)	0.0%	(4.3%)	4.1%
Reserve Life Data (Years)					
Oil	10.1	8.2	11.3	10.3	8.8
Gas	103.6	15.3	12.3	11.8	15.3
(8/1 NEB)	13.1	10.4	11.5	10.8	11.0
(10/1 NEB)	12.5	10.0	11.5	10.7	10.6
Domes. Avg Sales Price (Latest Fis. Yr)					
$ per Bbl (Oil)	21.78	14.61	19.96	25.70	23.31
$ per Mcf (Gas)	1.76	2.23	2.52	2.47	2.21
Market Value Ratios					
Market Cap/Tot Prvd Res. ($/NEB)	4.40	4.97	3.67	5.83	2.57
Std Measure of Prvd Res. (MM)	$ 9,100.0	$12,191.0	$12,100.0	$5,041.0	$ 6,464.0
Market Cap/Std. Measure of Res.	171.5%	177.0%	115.7%	144.0%	65.9%
Adjusted Net Worth (FY End) (MM)	$11,949.0	$12,347.0	$ 8,171.0	$6,330.3	N/A
Market Cap/Adjusted Net Worth	130.6%	174.8%	171.6%	116.5%	N/A
Pre-Tax Disc. FNR (SEC #) (MM)	$15,909.9	$18,171.5	$21,625.5	$9,039.0	$11,691.2
Market Cap/SEC Number	98.1%	118.8%	64.7%	80.3%	36.4%
SEC % Change from Last Year's	(13.2%)	(46.4%)	0.7%	(8.0%)	6.3%
Herold Report Valuation	12/31/85	12/31/85	12/31/85	12/31/85	12/31/85
Asset Value (MM) (Herold)	10,629.0	23,592.0	12,214.0	8,174.0	4,957.0
Market Cap/Asset Val (Herold)	146.8%	91.5%	114.6%	88.8%	85.9%
Debt Ratios (Latest Fis. Yr.)					
Pvd. Reserves/$M of Total Debt					
(8/1 NEB)	958.2	1,165.1	437.7	458.3	288.3
(10/1 NEB)	909.5	1,062.1	417.4	429.1	261.4
SEC Number/Total Debt	4.3X	4.9X	2.5X	3.3X	2.0X
Std. Measure of Reserves/Total Debt	2.5X	3.3X	1.4X	1.8X	1.1X
Long-Term Debt/Adjusted Net Worth	27.7%	26.9%	85.3%	29.0%	N/A
Total Debt/Adjusted Net Worth	31.0%	30.2%	106.7%	42.9%	N/A
Cash Flow/Total Debt	96.4%	90.3%	40.7%	64.7%	31.9%
Average Cost of Debt (Latest 12 Mos.)	7.80	11.93	7.90	5.20	10.50
Current Credit Ratings (S&P/Mdy/D&P)	AA-/A1/5	AAA/Aaa/1	AA-/A2/7	AA/Aa3/6	BBB-/Baa3/9
Domestic Exploration Information					
Latest Fiscal Year E&D Costs (MM)	$1,605.0	$1,491.0	$2,246.0	$718.0	$689.0
as a % of Latest Year's Cash Flow	44.9%	44.3%	63.3%	40.8%	37.5%
3 Year Domestic Reserve Additions	632.4	616.3	N/A	242.1	250.8
as a % of Domestic Production	85.4%	90.4%	N/A	76.7%	81.1%
3 Year Avg. Domestic Finding Costs	$ 7.37	$ 9.86	N/A	$ 8.72	$ 6.89
Latest Year Domestic Finding Costs	$ 37.30	$ 17.46	N/A	$ 7.04	$ 8.13
Herold Report Domestic Finding Costs	$ 8.57	$ 8.20	$ 6.59	$ 7.75	$ 8.06
Latest Year NEBs added/NEBs prod.	15.9%	39.2%	N/A	101.1%	83.0%
Domestic Net Undeveloped Acreage (M)	4,282.0	16,273.0	15,366.0	4,672.0	3,262.0

COMPARISON OF SELECTED OIL AND GAS COMPANIES
COMPANY RANKING

	ENOW	High Value For Companies In This Report	Low Value For Companies In This Report	Median For Companies In This Report	Mean For Companies In This Report	ENOW Rank
Capitalization ($MM)						
Aggregate Values ($MM)	09/30/86					
Short Term Debt	$ 295.0	$1,746.0	$95.0	$410.0	$683.0	2
Long Term Debt	4,048.0	6,969.0	1,626.0	4,048.0	4,260.0	3
Preferred Stock	0.0	2.0	0.0	0.0	0.6	3
Common Equity	7,152.0	11,324.0	1,659.0	5,292.0	6,136.0	2
Total Capitalization	$11,495.0	$15,054.0	$7,336.0	$11,495.0	$11,088.4	1
Cash & Equivalents	917.0	2,397.0	388.0	917.0	1,217.2	3
Deferred Taxes	2,027.0	3,997.0	1,888.9	2,863.0	2,667.4	2
Book Value ($/Share)	$38.47	$48.1	$14.3	$30.5	$33.4	3
Percentages						
Short-Term Debt (%)	2.6%	12.5%	1.3%	2.7%	6.1%	2
Long-Term Debt (%)	35.2	75.4	20.9	35.2	40.7	3
Preferred Stock (%)	0.0	0.0	0.0	0.0	0.0	3
Common Equity (%)	62.2	75.2	23.2	62.2	53.3	3
Total Capitalization	100.0%	100.0%	100.0%	100.0%	100.0%	1
Market Data	03/23/87					
Market Capitalization ($MM)	$15,888.0	$21,579.5	$4,259.7	$14,901.1	$12,540.8	2
Dividend Yield	4.2%	5.1%	2.7%	4.2%	4.1%	3
Latest Fiscal Year	12/31/85					
Net Oper Income Aggregate ($MM)	$3,333.0	$3,333.0	$1,662.0	$1,383.0	$1,683.0	1
Per Common Share	$ 14.18	$ 14.18	$ 6.18	$ 8.22	$ 9.85	1
Net Income Aggregate ($MM)	$1,322.0	$1,322.0	$ 325.0	$ 747.0	$ 742.2	1
Per Common Share	$ 5.63	$ 7.20	$ 2.36	$ 3.38	$ 4.29	2
Cash Flow Aggregate ($MM)	$3,571.0	$3,571.0	$1,258.0	$3,369.0	$2,816.8	1
Per Common Share	$ 15.20	$ 19.40	$ 13.10	$ 15.20	$ 15.38	3
Market Price/Oper Income	4.7X	13.0X	4.5X	7.0X	8.2X	4
Market Price/Net Income	11.8X	28.9X	6.4X	13.5X	17.8X	4
Market Price/Cash Flow	4.4X	6.4X	2.7X	4.3X	4.4X	2
Market Price/Book Value	2.9X	3.1X	1.4X	1.9X	2.2X	3
Latest 12 Months	09/30/86					
Net Oper Income Aggregate ($MM)	$ 932.0	$1,588.0	$ 666.0	$ 932.0	$1,066.6	3
Per Common Share	$ 3.97	$ 7.86	$ 3.97	$ 6.18	$ 6.17	5
Net Income Aggregate ($MM)	$1,225.0	$1,225.0	[$ 8.0]	$ 747.0	$ 666.4	1
Per Common Share	$ 5.21	$ 6.99	[$ 0.07]	$ 3.38	$ 3.68	2
Cash Flow Aggregate ($MM)	$3,451.0	$3,550.0	$1,325.0	$3,369.0	$2,651.3	2
Per Common Share	$ 14.70	$ 19.48	$ 12.30	$ 13.45	$ 14.51	2
Market Price/Oper Income	16.7X	16.7X	6.4X	11.0X	11.3X	1
Market Price/Net Income	12.7X	28.9X	(532.5X)	12.7X	(91.6X)	3
Market Price/Cash Flow	4.8X	6.4X	2.7X	4.5X	4.4X	3
Market Price/Book Value	2.9X	2.7X	1.4X	2.2X	2.2X	3
Worldwide Reserves (Gas, Oil.)	12/31/85					
United States	100.0%	100.0%	65.4%	82.1%	83.1%	1
Canada	0.0	10.9	0.0	0.0	3.0	3
North Sea & Europe	0.0	6.7	0.0	0.0	1.8	3
Other	0.0	22.0	0.0	0.0	11.4	5
Total	100.0%	100.0%	100.0%	100.0%	100.0%	1
Proved Reserves	12/31/85					
Oil (MM Bbl)	2,647.0	2,931.0	848.0	2,424.0	1,947.6	2
% NEO	74.0%	76.8%	53.1%	68.1%	65.7%	2
% Developed	73.1%	93.1%	70.4%	74.1%	77.6%	4
Gas (Bcf)	7,219.0	15,375.0	3,174.0	7,965.0	7,884.4	2
% NEO	25.4%	46.6%	22.2%	31.9%	33.3%	4
% Developed	7.5%	91.2%	7.5%	70.7%	61.8%	5
Total Proved Reserves ($MM)						
(B/E NEO)	3,550.2	4,345.9	1,244.8	3,550.2	2,823.1	3
% Change from Last Year	(5.9%)	2.1%	(21.0%)	(5.9%)	(6.8%)	3
(10/1 NEO)	3,369.7	3,961.5	1,165.4	3,369.7	2,728.8	3
% Change from Last Year	(6.4%)	2.3%	(10.3%)	(6.4%)	(6.5%)	3
Production						
Oil (MM Bbl)	262.3	294.0	82.8	260.8	199.9	2
% NEO	96.8%	96.8%	66.6%	70.8%	76.5%	1
Gas (Bcf)	69.7	1,004.8	69.7	485.0	461.8	5
% NEO	3.2%	33.4%	3.2%	29.2%	23.5%	5
Total Production ($MM)						
(B/E NEO)	271.0	419.5	115.8	271.0	258.8	3
% Change from Last Year	13.3%	13.3%	(5.8%)	0.1%	1.7%	1
(10/1 NEO)	269.3	394.4	109.8	269.3	246.4	1
% Change from Last Year	13.3%	13.3%	(4.3%)	0.8%	1.9%	1

COMPARISON OF SELECTED OIL AND GAS COMPANIES
COMPANY RANKING

	SNOW	High Value For Companies In This Report	Low Value For Companies In This Report	Median For Companies In This Report	Mean For Companies In This Report	SNOW Rank
Reserve Life Data (Years)						
Oil	10.1	11.3	8.2	10.1	9.7	3
Gas	103.6	103.6	11.8	15.3	31.6	1
(6/1 NEB)	13.1	13.1	10.4	11.0	11.3	1
(10/1 NEB)	12.5	12.5	10.0	10.7	11.1	1
Domes. Av. Sales Price (Latest Fis. Yr)						
$ per Bbl (Oil)	21.78	25.70	16.61	21.78	21.08	3
$ per Mcf (Gas)	1.76	2.52	1.76	2.23	2.24	5
Market Value Ratios						
Market Cap/Tot Prvd Res. ($/NEB)	4.40	5.83	2.57	4.40	4.29	3
Std Measure of Prvd Res. (MM)	$ 9,188.0	$12,191.0	$5,081.0	$ 9,190.0	$ 8,979.2	3
Market Cap/Std. Measure of Res.	171.5%	177.6%	65.9%	144.6%	134.8%	2
Adjusted Net Worth (FY End) (MM)	$11,949.0	$12,347.0	$6,338.3	$10,960.0	$ 9,699.3	2
Market Cap/Adjusted Net Worth	130.6%	174.8%	110.6%	151.8%	147.8%	3
Pre-Tax Disc. FNR (SEC $) (MM)	$15,988.0	$21,625.5	$9,039.0	$15,960.9	$15,287.1	3
Market Cap/SEC Number	98.1%	118.8%	36.4%	80.3%	79.2%	2
SEC % Change from Last Year's	(13.2%)	6.3%	(46.4%)	(8.8%)	(12.1%)	4
Herold Report Valuation	12/31/85					
Asset Value (MM) (Herold)	10,629.0	23,592.0	4,957.0	10,629.0	11,913.2	3
Market Cap/Asset Val (Herold)	146.8%	146.8%	85.9%	91.5%	105.5%	1
Debt Ratios (Latest Fis. Yr.)						
Prvd Reserves/$M Total Debt						
(6/1 NEB)	958.2	1,165.1	288.3	458.3	661.5	2
(8/1 NEB)	888.5	1,062.1	261.4	429.1	615.9	2
SEC Number/Total Debt	4.3X	4.9X	2.0X	3.3X	3.4X	2
Std. Measure of Reserves/Total Debt	2.5X	3.3X	1.1X	1.9X	2.0X	2
Long-Term Debt/Adjusted Net Worth	27.2%	85.3%	26.9%	28.3%	42.2%	2
Total Debt/Adjusted Net Worth	31.8%	106.7%	30.2%	37.8%	52.7%	2
Cash Flow/Total Debt	98.4%	98.4%	31.9%	64.7%	64.8%	1
Average Cost of Debt	7.88	11.93	5.20	7.98	8.67	2
Domestic Exploration Information						
Latest Fiscal Year E&D Costs (MM)	$1,605.0	$2,246.0	$689.0	$1,491.0	$1,349.8	2
as a % of Latest Year's Cash Flow	44.9%	63.3%	37.5%	44.3%	46.2%	2
3 Year Domestic Reserve Additions	632.4	632.4	242.1	433.5	433.4	1
as a % of Domestic Production	85.4%	90.4%	76.7%	83.2%	83.4%	2
3 Year Avg Domestic Finding Costs	$ 7.37	$ 6.89	$ 9.36	$ 8.85	$ 8.21	3
Latest Year Domestic Finding Costs	$ 37.30	$ 7.01	$37.30	$ 12.80	$ 17.48	1
Herold Report Domestic Finding Costs	$ 8.57	$ 8.57	$ 6.59	$ 8.06	$ 7.83	5
Latest Year NEBs added/NEBs prod	15.7%	101.1%	15.9%	61.1%	59.8%	4
Domestic Net Undeveloped Acreage (M)	4,282.0	16,273.0	3,262.0	4,672.0	8,771.0	4

EXHIBIT 4

PROJECT WINTER

Implied Valuation of Snow Based on Transaction Multiples from Selected Oil and Gas Transactions (a)
(Dollars in millions except per share amounts)

	Dupont/ Conoco	U.S Steel/ Marathon	Occidental/ Cities Service	Phillips/GAO Co. of TX	Texaco/ Getty	Chevron/ Gulf	Mobil/ Superior	Royal Dutch Shell/ Shell Oil (b)
Closing Date	8/81	3/82	12/82	3/83	2/84	5/84	9/84	/85
Snow Net Income - $499 (c)								
Multiple of Net Income	8.8x	18.0x	16.5x	20.6x	14.9x	13.6x	23.7x	11.4x
Snow - Per Share	$18.58	$37.74	$34.57	$43.14	$31.34	$28.55	$49.69	$23.86
Snow Cash Flow - $2,328 (d)								
Multiple of Funds Flow	4.8x	7.5x	4.2x	5.2x	5.8x	5.0x	7.1x	5.1x
Snow - Per Share	$47.20	$73.59	$41.27	$51.33	$56.76	$48.52	$69.04	$50.25
Snow Est. PV of FNR (SEC) - $4,290 (e)								
Price/SEC Value	1.0x	0.8x	0.9x	1.0x	1.1x	1.1x	1.0x	0.8x
Snow - Per Share	$17.43	$14.45	$15.66	$17.83	$20.28	$19.02	$20.28	$15.1[illegible]
Snow Herold Value (5/86) - $10,629								
Premium over Herold Value	(43.3)%	(48.6)%	(46.2)%	(15.4)%	(16.4)%	(32.5)%	(2.3)%	(32.9)%
Snow - Per Share	$25.35	$22.95	$24.04	$37.81	$37.36	$30.18	$43.65	$38.92
Snow BOE - 2,510 MMBBL (f)								
Consideration Per Barrel	$3.71	$3.55	$4.94	$6.63	$4.22	$4.45	$5.62	$5.28
Snow - Per Share	$39.18	$37.49	$52.19	$69.99	$44.50	$47.00	$59.37	$55.72
Snow Long-term Debt - $3,276								
Consideration plus LTD per Barrel of Oil Equivalent	$4.68	$4.59	$6.48	$6.63	$4.69	$5.22	$6.72	$6.54
Snow - Per Share	$55.61	$34.66	$54.61	$56.19	$35.72	$41.31	$57.14	$55.24
West Texas Intermediate Price on Closing Date (g)	$35.00	$35.10	$33.50	$30.00	$30.00	$30.00	$[illegible]0.00	$27.50
Average of Implied Values	$30.53	$36.81	$37.06	$46.05	$37.66	$35.76	$49.86	$39.86
Average of All Implied Values	$39.20							
Median of All Implied Values	$37.36(h)							

(a) Per share amounts based on 237,863,359 fully diluted shares as of 12/31/86.
(b) Acquisition of minority interest of 30.5%. Multiples are calculated using aggregate consideration for the entire company derived from the price per share of $58 paid for the minority interest.
(c) From 1986 Snow Annual Report.
(d) Defined as net income from continuing operations plus non-cash charges as reported in Snow's 1987 Operating Plan.
(e) From 1986 Snow Annual Report calculated using year end 1986 oil and gas prices.
(f) Snow's proved reserves as of 12/31/86, excluding Alaskan natural gas. Other natural gas converted to crude oil on basis of 6 Mcf = 1 barrel.
(g) The current price of West Texas Intermediate crude is approximately $18.50 per barrel.
(h) Average of the two mid-sample values.

EXHIBIT 5

The following table provides a range of estimated potential values for Snow in the acquisition market derived by valuing the principal assets of Snow with methodologies and assumptions which we believe would be used by potential acquirors under current market conditions. The valuation assumes a purchase of all of the outstanding shares of Snow by a purchaser which does not subsequently elect to allocate its purchase price to the assets of Snow in order to increase the depreciable or depletable tax bases of such assets. The purchaser foregoes any tax benefits from such a writeup and assumes carryover tax bases in the assets. Neither the purchaser nor Snow would incur any corporate level capital gains or recapture taxes in such a transaction. Based on information available to us, we believe that under the provisions of the Tax Reform Act of 1986, the corporate level taxes payable upon any write-up would exceed the increases in value arising therefrom.

In addition to reviewing publicly available information regarding Snow in the preparation of our valuation, we reviewed certain non-public information regarding Snow which was supplied to us by Blizzard. Such non-public information included certain internal planning documents, memoranda and financial forecasts prepared by the management of Snow regarding its business operations.

The valuation of Snow's oil and gas assets was prepared using certain information supplied to us by Blizzard including estimates of future oil and gas production, operating costs, capital expenditures for future development, abandonment costs, royalty costs and federal, state and local taxes. For purposes of our valuation, we have relied upon such information. Blizzard requested that we use our independent judgment as to the appropriate oil and gas price scenario for our valuation. The oil and gas price scenario used in connection with our valuation is based on our current assessment of assumptions being used by prospective purchasers of oil and gas reserves in the acquisition market. A $1 per barrel increase or decrease in our oil price assumption for such scenario has the effect of increasing or decreasing the value of Snow's proved oil and gas reserves by an amount equivalent to approximately $4 per share.

For purposes of valuing Snow's interest in the Trans Alaska Pipeline System ("TAPS"), we have made the assumption that TAPS is operated as a profit center and any tariff paid by Snow to transport oil through TAPS is deducted as an operating cost in our valuation of its oil and gas reserves and included as income for purposes of valuing TAPS.

PROJECT WINTER

Range of Estimated Values
(Dollars in millions)

	Low	High
Oil and Gas Exploration and Production (a) (b)	$7,150	$9,150
Pipeline Interests (c)	2,300	2,500
Refining & Marketing	2,100	2,600
Extractive Businesses	1,200	1,350
Chemicals and Industrial Products	400	500
Estimated Proceeds from Asset Sales Currently in Progress (d)	300	400
Other (e)	(954)	(754)
Net Debt Position (f)	(3,217)	(3,217)
Total Value	$9,279	$12,529
Per Share (g)	$39.01	$52.67

(a) Based on an oil price scenario which assumes a West Texas Intermediate price of $17 per barrel in 1987, $18 per barrel in 1988 and $19 per barrel in 1989, increasing 5% per year thereafter. See Exhibit 6 for estimated present values of proved reserves at various discount rates. Includes valuation of probable reserves and unexplored acreage. Also see Exhibit 6 for detail on assumptions for such reserves and acreage.

(b) Lower 48 offshore proved reserves (for which no estimates of oil and gas production, operating costs, capital expenditures and abandonment costs were available from Blizzard) have not been analyzed in the same manner as the other proved reserves. The range presented for oil and gas reserves includes an estimated value of $150 million for the offshore Lower 48 reserves utilizing analyses similar to those used in valuing the probable reserves. In addition, the reserve values have been reduced by $100 million and $125 million, respectively, for the estimated present value of future dividends to be paid on preferred stock owned by Blizzard in a subsidiary of Snow (the "NPRI Preferred Stock"), which dividends are effectively equal to a net profits royalty interest in certain Alaskan production.

(c) Includes Snow's interest in TAPS, Kuparuk and wholly- and partially-owned pipelines in the Lower 48 States.

(d) Estimated after-tax proceeds of asset sales provided by Blizzard.

(e) Capitalized cost of corporate overhead not allocated to the business segments valued separately, reduced by the proceeds of assumed exercise of employee stock options. Yearly overhead cost has been supplied by Blizzard.

(f) Net debt represents the excess of all liabilities over all assets not allocated to the business segments valued separately above. Long term debt and certain other liabilities were adjusted to estimated present value from historic book value in this calculation.

(g) Based on 237,863,359 common shares and equivalents as of 12/31/86 (assumes exercise of 3,150,714 options existing at 12/31/86 plus the common share equivalents associated with the 1,000 shares of special stock held by Blizzard).

PROJECT WINTER

Estimates of Additional Values Potentially Achievable Through Various Corporate Restructuring Scenarios (a)
(Dollars in millions)

	Potential Increase in Value over High Range Endpoint	Incremental Value Per Share
Publicly Traded Master Limited Partnership (Prudhoe Bay Field Interest Only) (b) (c)	$800 - $1,400	$3.36 - $5.89
Publicly Traded Leveraged Limited Partnership Recapitalization for Snow's Interest in TAPS (b)	0 - 0	0.00 - 0.00
Tax-Free Spinoff to Shareholders of Refining & Marketing System (b)	100 - 600	0.42 - 2.52
Potential Value of Unrealized Capital Loss (d)	510 - 680	2.14 - 2.86
Other (e)(f)	NA	NA
TOTAL	$1,410 - $2,680	$5.93 - $11.27

(a) Potential increase is net of estimated corporate level taxes incurred, if any, as a result of each transaction.

(b) There may be certain operating, financial and legal/regulatory impediments to carrying out each of these restructuring scenarios. See Exhibits 7, 8 and 9, respectively.

(c) The range of increased value for the MLP reflects only the allocation of taxes between capital gains and ordinary income and assumes full realization of the estimated $12.0 billion trading value. If the trading value were to be less than $12.0 billion due to certain factors, the range of increased values would be lower than those presented. See Exhibit 7 for further details.

(d) Value is derived from the available offset to capital gains taxes incurred in forming the MLP on Prudhoe Bay or the leveraged limited partnership recapitalization for Snow's interest in TAPS. Amount of gross unrealized capital loss has been provided by Blizzard.

(e) Given the limited information available to us, we are unable to determine the potential additional value, if any, which may be attributable to (i) proceeds potentially available to Snow on termination of the Snow employee benefit plans, (ii) the potential value of real estate in excess of costs of relocation, (iii) claims by Snow for U.S. federal income tax refunds for years ending prior to 1986, or (iv) the potential value of certain recent oil and gas discoveries not otherwise addressed in our analysis of proved and probable reserves.

(f) In light of insufficient information, the foregoing analysis does not reflect the potential for material additional expense or liability in certain areas, including (i) additional overhead costs; (ii) excess costs associated with repairs, disposals or abandonments in connection with the operation of natural resource businesses; (iii) the pending redetermination of condensate reserves in Prudhoe Bay from the oil-derived category to the gas-derived category in which Snow has a significantly lower share; (iv) drilling obligations not currently accrued; and (v) other contingent liabilities.

EXHIBIT 6

PROJECT WINTER

Summary Present Value Analysis of After-tax Cash Flows from Proved Oil and Gas Reserves
(Dollars in millions)

	Nominal After Tax Rate of Return						
	7.0%	8.0%	9.0%	10.0%	11.0%	12.0%	13.0%
Prudhoe Bay	$7,108	$6,618	$6,184	$5,799	$5,455	$5,148	$4,871
Other Alaska	788	718	654	597	545	497	454
Lower 48 Onshore (a)	463	438	417	396	378	360	345
Total (b)	$8,359	$7,774	$7,255	$6,792	$6,378	$6,005	$5,670

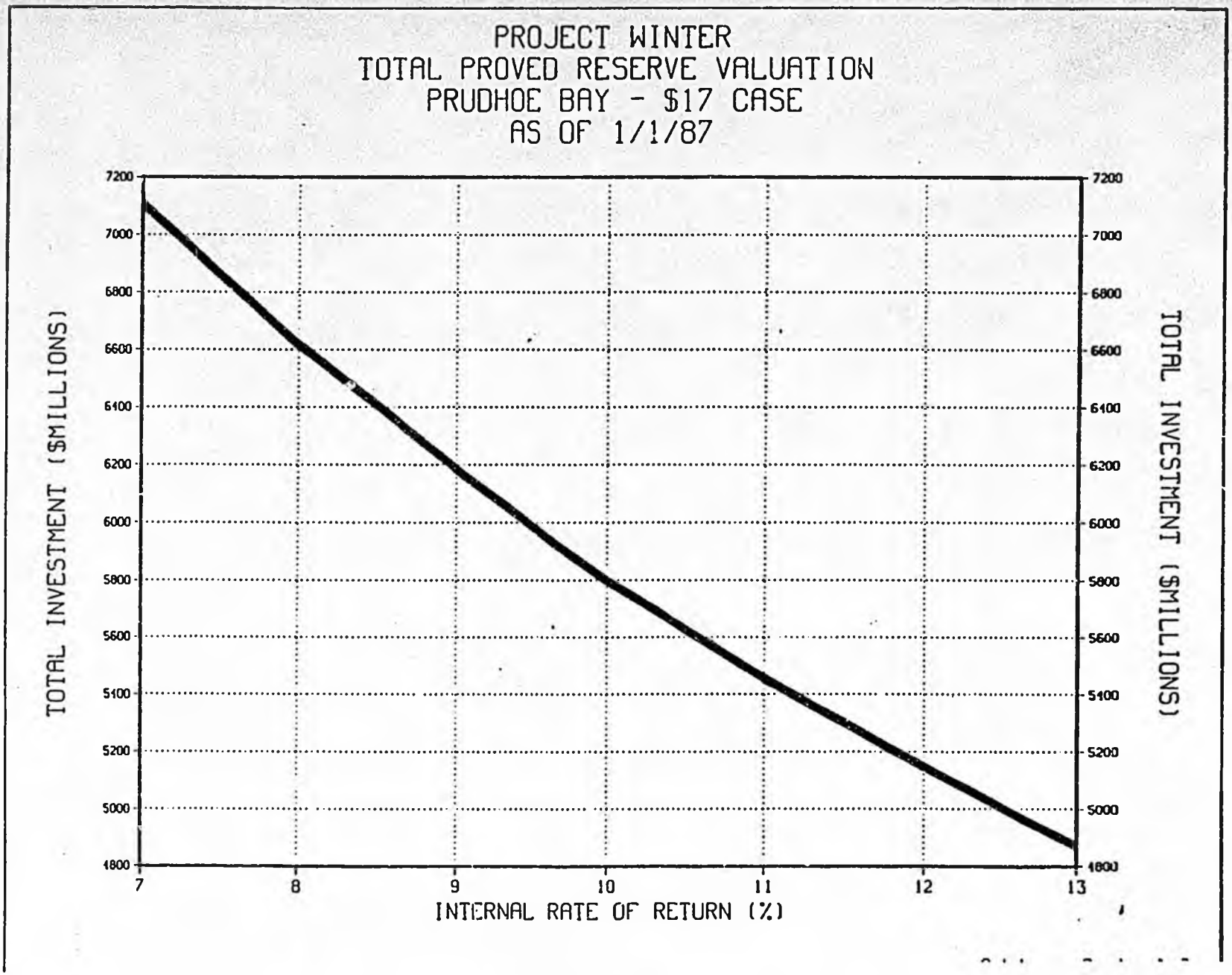
(a) Does not include any value for the Lower 48 offshore reserves, for which no estimates of oil and gas production, operating costs, capital expenditures and abandonment costs were available from Blizzard. The range of values for oil and gas reserves presented in Exhibit 5 includes an estimated value of $150 million for the Lower 48 offshore reserves utilizing analyses similar to those used in valuing the probable reserves. In addition, these values have not been reduced for the estimated present-value of the future dividends to be paid on the NPRI Preferred Stock. The low and high values for oil and gas exploration and production in Exhibit 5 have been reduced by $100 million and $125 million, respectively, for such present value.

(b) We were unable to determine the impact of two factors on the present value of the after-tax cash flows from the proved oil and gas reserves:

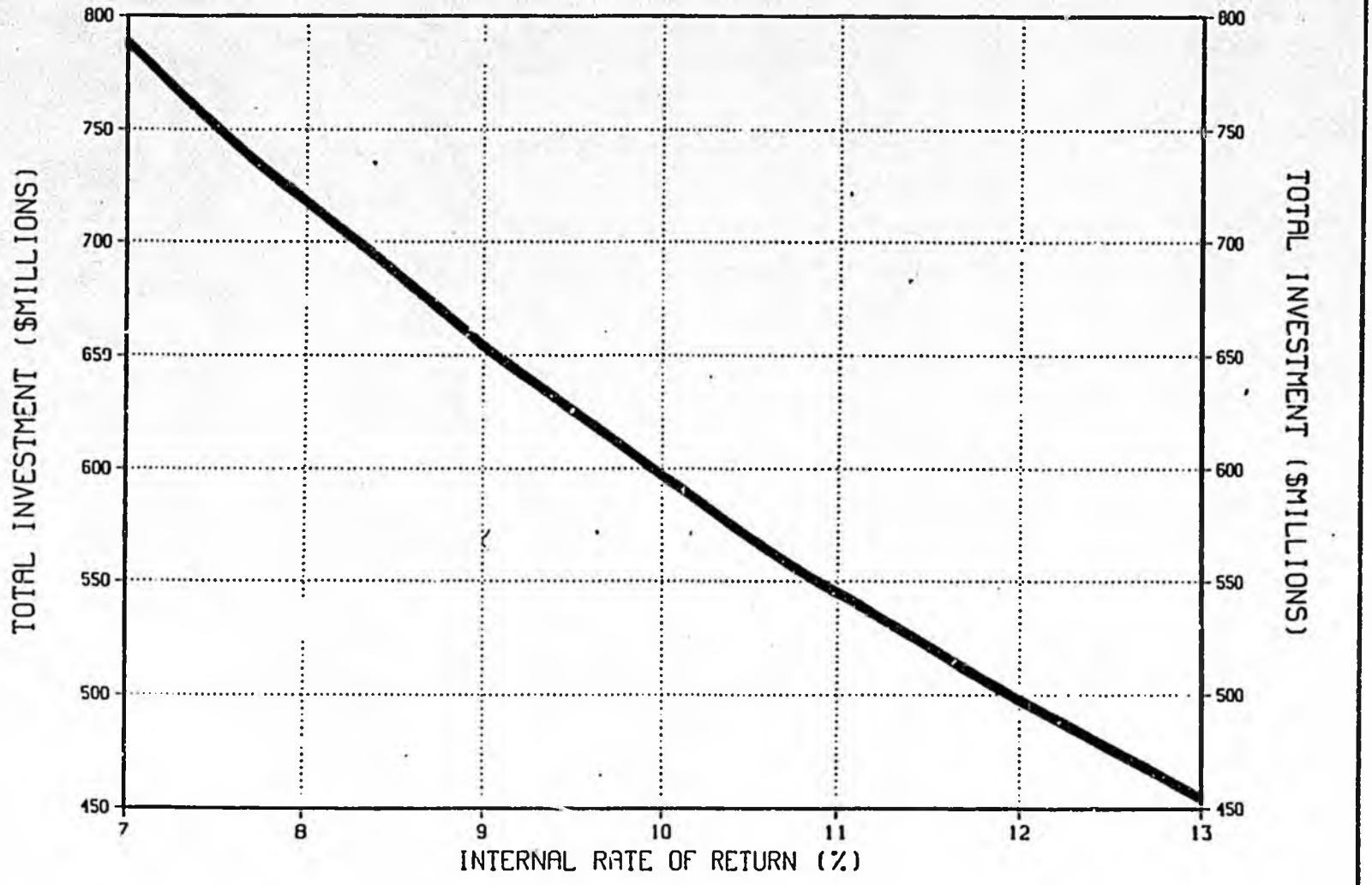
1. When the total proved reserves, as reported to Blizzard by Snow, are compared to their respective decline curves, as estimated by Blizzard, to provide a schedule of future production, we noted that such reserves are fully produced by the year 2010. Normal reserve decline characteristics suggest that a portion of the oil and gas reserves would be produced after 2010. In order to produce all reserves by 2010, our analysis assumed that the rate of production is higher than that for a more conventional reserve production profile. As a result, the present values in the table above are higher than those which would result if a portion of the reserves were produced in periods beyond the year 2010, in accordance with normal reserve decline patterns.

2. We have been unable to estimate the amount or timing of the utilization of the depletable and depreciable tax bases for the reserves and associated equipment; accordingly, the present values set forth above assume such tax bases are zero. To the extent such bases exist, such present values would increase by the present values of the reduction in taxes on oil and gas income arising from the depletion and depreciation deductions available in future years. In our analysis of a Master Limited Partnership for Snow's interest in the Prudhoe Bay Field, we have assumed at Blizzard's direction an aggregate tax basis thereof of $2 billion. See Exhibit 7.

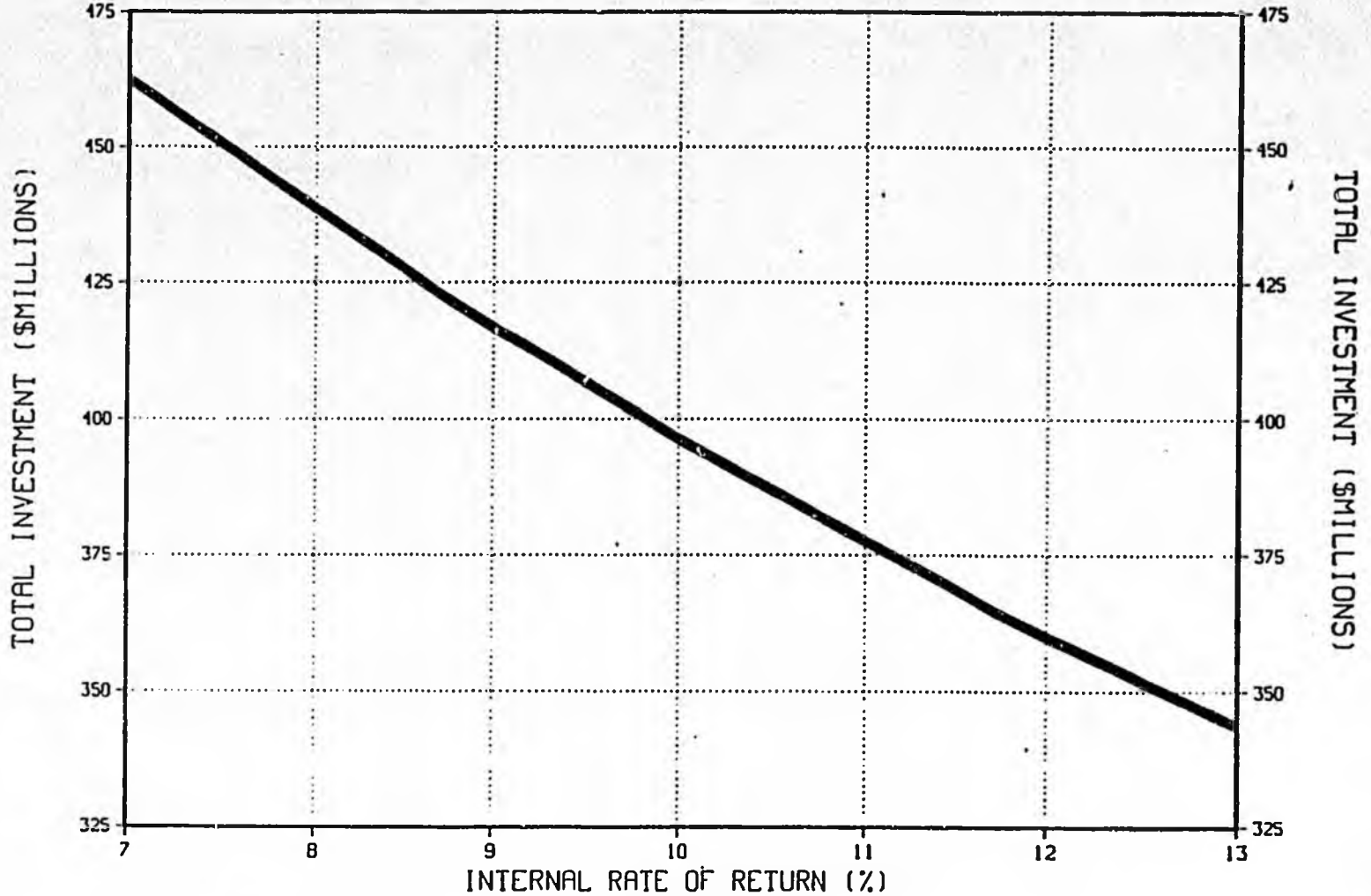
We have made certain estimates of the effect of both foregoing uncertainties under various assumptions which indicate that the net effect on present values is probably minimal.


PROJECT WINTER
TOTAL PROVED RESERVE VALUATION
PRUDHOE BAY - $17 CASE
AS OF 1/1/87
TOTAL INVESTMENT ($MILLIONS)
7200
7000
6800
6600
6400
6200
6000
5800
5600
5400
5200
5000
4800
7
8
9
10
11
12
13
INTERNAL RATE OF RETURN (%)

PROJECT WINTER
TOTAL PROVED RESERVE VALUATION
OTHER ALASKA $17 CASE
AS OF 1/1/87



PROJECT WINTER
TOTAL PROVED RESERVE VALUATION
LOWER 48 STATES ONSHORE - $17 CASE
AS OF 1/1/87



PROJECT WINTER

Valuation Analysis of Probable Reserves and Unexplored Acreage
(Dollars in millions)

I. Probable Reserves	Estimated Value Low	Estimated Value High
Prudhoe Bay	$300	$1,000
• Current recovery rate of approximately 41% to 42% could be increased to 52% in higher oil price environment		
• Potentially 1 billion additional barrels net to Snow's interest		
• Because of current oil economics, the current value may be minimal		
Other Alaska	$100	$200
• Low recovery rates at Lisburne may be improved, although only in higher oil price environment		
• Probable reserves at Niakuk of up to 50 million barrels although not currently economic		
• Endicott and Kuparuk may have additional reserves although they have little present value		
• Snow may have a potential advantage in bidding on acreage in the Alaskan National Wildlife Refuge, if such area is allowed to be explored and developed. We have estimated that such advantage has relatively little present value.		
Lower 48 and Canada	$200	$400
• Mobile Bay has had recent additions and has indicated probables		
• Anadarko Basin has substantial gas reserves of up to 200 bcf		
• New gas discovery relating to Canadian Hunter may have meaningful value.		
Total for Probable Reserves	$600	$1,600

II. Unexplored Acreage	Acreage (Thousands)	Estimated Value Low	Estimated Value High
Alaska	70	$25	$50
Lower 48 - Onshore	1,090	40	90
Lower 48 - Offshore	370	60	135
Total for Unexplored Acreage	1,530	$125	$275
Total for Probable Reserves and Unexplored Acreage		$725	$1,875

EXHIBIT 7

PROJECT WINTER

Analysis of Master Limited Partnership of Snow's Interest in the Prudhoe Bay Field (Dollars in millions)

I. Valuation Criteria

- The Master Limited Partnership ("MLP") market for oil and gas properties is primarily a yield oriented market with valuation in such market derived as a function of the amount of distributable cash flow that is perceived to be sustainable over time, reserve lives, amounts and types of reserves, finding costs, leverage and other factors. The Prudhoe Bay Field ("Prudhoe Bay") currently is forecast by Blizzard to experience a significant decline in production over the next five to ten years and therefore will probably generate a declining level of annual cash flow in the absence of substantial future increases in the price of oil.

- In the current environment, those oil and gas MLPs similar to a potential Prudhoe Bay MLP generally trade in the public market at current yields of approximately 7% to 16%, discretionary cash flow multiples of 10x to 12x, adjusted values per barrel of oil equivalent ("BOE") of $6.00 to $7.50 and total capitalization to adjusted year end 1985 SEC value ratios of 80% to 120%. See Tables I to V for additional details.

- Based on our oil price scenario and production data supplied by Blizzard, the 1987 estimated distributable cash flow for Prudhoe Bay is approximately $1.3 billion. The table below summarizes potential theoretical capitalized values for a Prudhoe Bay MLP based on those multiples which we believe most appropriate for such an MLP.

Valuation Criteria	Public MLP Range Low	Public MLP Range High	Estimated Prudhoe Bay MLP Data	Prudhoe Bay Implied Capitalized Value Low	Prudhoe Bay Implied Capitalized Value High
Current Yield (%)	9%	11%	$1.300	$11.818	$14.444
Cash Flow Multiples	9	11	1.300	11.700	14.300
Value per BOE	$5.50	$7.00	2.023(a)	11.126	14.161
Total Capitalization/ Adjusted Year End 1985 SEC Value	80%	100%	$13.520(b)	10.816	13.520

	Implied Capitalized Value
High	$14.444
Mean	12.736
Median (c)	12.669
Low	10.816

(a) Millions of barrels of oil equivalent after deducting barrels of oil associated with existing royalty interests. For cash flow purposes, however, royalty is deducted as an expense rather than against actual barrels. North Slope gas reserves are not included.

(b) Calculated assuming that Prudhoe Bay represents approximately 85% of 1985 year end SEC Value based on reserve barrels and our valuation of reserves.

(c) Average of the two mid-sample values.

- The following table shows implied capitalized values for an MLP of Snow's interest in Prudhoe Bay based on various sustainable distributable cash flow and current yield assumptions, since the market's perception of such sustainable level is meaningful.

Current Yield	Sustainable Distributable Cash Flow			
	$ 900	$1,000	$1,100	$1,200
9%	$10,000	$11,111	$12,222	$13,333
10%	9,000	10,000	11,000	12,000
11%	8,182	9,091	10,000	10,909

II. Analysis of MLP Spinoff

- A spinoff of MLP units to the shareholders of Snow would be a taxable transaction to Snow. Consequently, Snow would pay some combination of capital gains and recapture taxes as if the assets included in the MLP had been sold to a third party. Assuming an implied capitalized value of $12.0 billion for the MLP and a tax basis of $2 billion for the assets contributed to the MLP, $10.0 billion of gain would be subject to tax at some combination of capital gains and ordinary income tax rates. Using 1987 corporate capital gains and ordinary income tax rates of 34% and 40%, respectively, the tax liability would be between $3.4 billion and $4.0 billion. These taxes payable by Snow would reduce the value of the MLP to Snow shareholders to a range of $8.0 to $8.6 billion, which would be approximately $0.8 to $1.4 billion greater than our high end total value for Prudhoe Bay proved and probable reserves.

- The effect of the Prudhoe Bay decline curve on annual distributable cash to unitholders may cause investors to require a higher current yield than is the case with other similar MLPs, which would in turn lower the actual market value of the Prudhoe Bay MLP. To the extent the actual valuation was lower than the implied capitalized value of $12.0 billion, the after tax value to Snow's shareholders also would be lower.

- Since tax exempt shareholders of Snow may not wish to hold MLP units distributed to them because of tax filing requirements and because holding such units could create unrelated business taxable income, a substantial amount of selling pressure by such institutions could reduce the market value of the MLP for some period of time. Institutions hold approximately 23.3% of the outstanding shares of Snow. Assuming 80% of those institutions are tax exempt, approximately 18.6% of the value of the MLP or $2.2 billion of MLP units could be for sale in the market shortly after creation of the MLP. In addition, shareholders other than tax-exempt institutions may sell units which would contribute to the short-term downward pressure on the market value of the MLP. This selling pressure by institutions and others may drive the value of the MLP down by as much as 10% to 15% until such time as the units could be absorbed by other investors. It is unclear how much market demand exists to absorb this amount of selling pressure without an increase in yield.

- In addition, the total market capitalization of the Prudhoe Bay MLP in public hands following a spinoff to shareholders would be several times greater than that of any other existing MLP, which may cause the Prudhoe Bay MLP to trade at some modest discount to theoretical value for a sustained period of time. We

are assuming for purposes of this analysis that essentially no such discount would exist and that Snow shareholders could sell MLP units in the market at their pro rata share of theoretical value.

- Finally, while the creation and spinoff of the Prudhoe Bay MLP to Snow shareholders may be an option open to Snow, there is no assurance that such a step would be a viable or attractive alternative to a prospective purchaser of Snow, including Blizzard. In addition, there may be legal or other impediments to the formation and distribution of a Prudhoe Bay MLP.

- We are ignoring, for purposes of this analysis, the potential tax consequences to Snow shareholders of the receipt of units in the Prudhoe Bay MLP in the spinoff.

III. Analysis of an Initial Public Offering of a Prudhoe Bay MLP

- Another approach to creating value through an MLP would be for Snow to contribute its interest in Prudhoe Bay to an MLP and then sell a portion of the MLP in an initial public offering. We believe initial public offering of MLP units of at most approximately $500 million could be accomplished in today's market. This approach would have the effect of establishing a value for Snow's interest in Prudhoe Bay and would raise some amount of cash for Snow.

- This is also a taxable transaction to Snow to the extent of the value represented by the units sold. Additional sales of units would also generate similar taxes. The redistribution pressure in the spinoff scenario would not be present in an initial public offering because the units in the MLP would be sold to new investors. However, only a small portion of the total MLP value could be realized in cash because of the limited size of the public offering market for MLP units.

- An initial public offering of an MLP holding Snow's interest in Prudhoe Bay would benefit Snow shareholders only to the extent that the creation of the MLP and Snow's majority ownership in the MLP increased Snow's stock price. Experience in similar transactions demonstrates that this is not a guaranteed result. Although in some cases the announcement of such a transaction has caused a temporary modest increase in the parent's stock price, there has been no predictable positive long-term impact. We have assumed for purposes of this analysis that units in the MLP retained by Snow (or new units) would not be distributed regularly to shareholders in the future in order to increase Snow's effective common stock dividend.

Table 1. Master Limited Partnerships Cash Flow and Distributions 1986-87E
(Dollars per unit)

	1986E			1987E					
	Cash Flow	Distribution	Distr./ Cash Flow	Estimated Cash Flow(a)	Distribution	Distr./ Cash Flow	Price as of 23-Mar-87	Estimated 1987 Cash Flow Multiple	Implied Yield Based on Distribution
Diamond Shamrock Offshore Partners	$1.70	$2.80 (fixed)	165%	$1.55	$2.80 (fixed)	181%	$16.750	10.8x	16.7%
Enserch Exploration Partners (b)	1.30E	2.40 (fixed)	185	1.15	1.20 (fixed)	104	17.375	15.1	6.9
Mesa Limited Partnership (c)	1.30	2.00	154	0.80	2.00E	250	16.75	20.9	11.9
Sun Energy Partnership	1.70	1.75	103	1.60	2.00	125	19.50	12.2	10.3
Union Exploration Partners	1.75	1.88 (d)	107	1.30	1.73 (d)	96	20.00	11.1	8.7

(a) Based on average price for West Texas Intermediate of $17.50 per barrel.
(b) Distribution reduced to $1.20 at year end.
(c) Cash flow from operations excluding take or pay gas settlement and all other extraordinary items including trading profits.
(d) Distribution is equal to cash flow with a three month lag period.

Table II. Master Limited Partnerships Implied Value of Reserves per BOE as of December 31, 1985 (a)
(Dollars in millions except per unit price and implied value of reserves)

	Unit Price as of 23-Mar-87	Estimated Units Outstanding as of 31-Dec-86	Market Capitalization	Debt(b)	Adjusted Market Capitalization	Total Reserves BOE as of 31-Dec-85 (MMBOE)	Implied Value of Reserves per BOE	Implied Value of Reserves per MCF Equivalent
Diamond Shamrock Offshore Partners	$16.750	50.5	$ 846	($44)	$ 802	48.6	$16.50	$2.75
Enserch Exploration Partners	17.375	95.3	1,656	78	1,734	187.9	9.23	1.54
Mesa Limited Partnership (c)	16.75	158.9	2,662	652(d)	3,314	425.9(e)	7.78	1.30
Sun Energy Partners	19.50	300.0	5,850	1,087	6,937	1,149.7	6.03	1.01
Union Exploration Partners	20.00	237.4	4,748	206	4,954	675.2	7.34	1.22

(a) BOE = Barrel of oil equivalent; 1 barrel of oil per 6 mcf of gas.
(b) Net of working capital as of September 30, 1986.
(c) Information includes the acquisition of Pioneer Corp. and the liquidation of Mesa Petroleum Co. Also included is the estimated effect of the offering of preference "A" units in 1986.
(d) Debt less estimated working capital after the issuance of 23 million preference "A" units and the liquidation of Mesa Petroleum Corporation.
(e) Includes the acquisition of Pioneer Corp.

Table III. Master Limited Partnerships Estimated Adjusted SEC Value of Future Net Revenues as of December 31, 1985 and Estimated 1986
(Dollars in millions except per unit amounts)

	Approximate Market Capitalization	Approximate Market Value of Public Float[a]	Unit Price as of 3-Mar-87	SEC Value as of 31-Dec-85[b]	Net Debt as of Year End 1985[c]	1985 SEC Value Net of Debt	Price as a Percentage of 1985 Adjusted SEC Value	Estimated 1986 Adjusted SEC Value Net of Debt [d]	Estimated Units Outstanding for 1986	Price as a Percentage of Estimated 1986 Adjusted SEC Value	Reserve Life
Diamond Shamrock Offshore Partners	$ 846	$ 83.8	$16.75	$ 588	$ (35)	$ 623	140%	$ 383	50.5	221%	6.2
Enserch Exploration Partners	1,656	297.8	17.375	1,436	57	1,379	120	956	95.3	173	12.3
Mesa Limited Partnership	2,662	2,291.4	16.75	2,436[e]	1,032[f]	1,404	190	1,268	158.9	211	13.6
Sea Energy Partners	5,850	156.0	18.50	6,744	741	6,003	126	3,633	300.0	161	10.6
Union Exploration Partners	4,748	286.4	29.00	4,612	292	4,410	108	3,253	237.4	146	15.6

[a] Where information is not available, may include only market value of units originally offered to the public.
[b] The SEC value is the estimated net present value of future net revenues discounted at 10%.
[c] Net of working capital
[d] To calculate the estimated 1985 adjusted SEC value, we assumed a $15 crude oil price scenario (supplied by Goldman Sachs Research) and developed the following table of adjustment factors to be applied against the respective 1985 SEC values. The choice of adjustment factor for each MLP was based on its respective reserve life (See Table IV):

MLP Reserve Life	Adjustment Factor
5 yrs.	58.00%
6	57.50
7	65.00
10	70.00
13	73.00
15	75.00
18	78.00

[e] Pro forma as of June 30, 1986 to reflect the acquisition of Pioneer Corporation.
[f] Amount reflects the acquisition of Pioneer Corp., the issuance of 23 million preference "A" units and the liquidation of Mesa Petroleum Co.

Table IV. Master Limited Partnerships
Reserve Life as of December 31, 1985
(Years)

	BOE	Oil	Gas
Diamond Shamrock Offshore Partners	6.2	7.6	5.7
Enserch Exploration Partners	12.3	8.1	13.1
Mesa Limited Partnership (a)	13.6	10.8	14.5
Sun Energy Partners	10.4	10.0	11.0
Union Exploration Partners	15.4	10.2	19.4

(a) Reflects the acquisition of Pioneer Corp.

Table V. Master Limited Partnerships
Implied Finding Costs 1982-1985 (a)
(Dollars per BOE)

	1982	1983	1984	1985	Weighted Average 1982-85
Diamond Shamrock Offshore Partners	N.A.	$22.99	$10.64	$22.20	$18.25
Enserch Exploration Partners	$11.14	8.84	3.99	4.58	5.34
Mesa Limited Partnership	N.A.	12.60	6.75	20.32	10.52
Sun Energy Partners	12.12	14.98	9.93	7.15	10.30
Union Exploration Partners	30.57	9.24	33.60	10.16	12.50(b)

(a) We believe the oil and gas industry average implied finding cost for 1982-85 is approximately $10 per BOE.
(b) Estimate of Goldman Sachs Research. The years 1982 and 1984 include larger than usual acquisitions of unproven properties.

EXHIBIT 8

PROJECT WINTER

Valuation Analysis of Trans Alaska Pipeline System

I. Valuation Approaches

- Discounted Cash Flow Analysis
- Divestiture Value in the Acquisition Market
- Recapitalization Values

II. Valuation Criteria

- Our valuation of Snow's interest in TAPS utilizes the current forecast of the production profile of Prudhoe Bay supplied to us by Blizzard. The profile anticipates declining production from Prudhoe. Tariff revenues for TAPS are determined by the volume of oil transported from Prudhoe Bay. Consequently, TAPS' annual tariff revenues and cash flows are projected to decline over time.

- The valuation of pipeline assets such as TAPS is primarily a function of the amount of the annual cash flow that is generated over time and the sustainability and predictability of those cash flows. Differences in values result mainly from differences in the required rate of return of the corresponding lender or purchaser/investor. For example, acquisition market buyers generally require a higher rate of return than public market or private limited partnership investors. Consequently, the public or private limited partnership markets may place a higher valuation on TAPS, to the extent TAPS may be recapitalized to access these markets.

- Our analysis assumes the recapitalization of TAPS in a leveraged partnership form where leverage is maximized through placement of serial senior secured debt (subject to adequate coverage of debt service and other factors). Lenders generally require lower rates of return than equity investors given the fixed income nature of the obligation they hold and their senior position in the capital structure. Limited partnership interests are placed either publicly or privately in amounts such that residual cash flow to such interests (net of debt service and capital expenditures) would provide after tax rates of return in excess of 9% on a cash-on-cash basis. These returns make no assumption as to the terminal value of the interest, if any, after the debt is retired. The public market currently requires 9% to 11% current yields on the limited partnership interests of similar types of assets, although in most cases these limited partnerships are less leveraged than the structure assumed in our analysis presented below.

III. Valuation Summary

- The value of Snow's interest in TAPS included in Exhibit 5 is in the range of $2.1 billion to $2.3 billion (based on a discounted cash flow analysis - see Table I). Although a sale of Snow's interest in TAPS in the acquisition market probably would achieve higher values, we believe that the after-tax proceeds to Snow of such a sale would be less than $2.1 to $2.3 billion.

- If TAPS were structured as a leveraged recapitalization with debt maturities that match the cash flows, as described above, potential values of up to $3.1 billion before taxes might be achievable. However, as the table below sets forth, such a transaction would incur substantial corporate taxes.

Leveraged Recapitalization
(Dollars in millions)

Proceeds to Snow from Partnership:	
Debt	$2,940
MLP Interest	160
Total Proceeds	$3,100
Estimated Corporate Taxes	925(a)
Net Proceeds	$2,175

(a) Assumes a tax basis for Snow's interest in TAPS assets of $600 million for Snow's interest in the assets of TAPS and a blended corporate tax rate of 37%, which reflects an equal weighting of 1987 capital gains and ordinary income tax rates.

IV. Certain Potential Structural and Financial Impediments to a Leveraged Recapitalization

- Rights of first refusal held by other companies holding interests in TAPS
- Consent of at least a two-thirds majority ownership interest in TAPS
- Potential assignment of the benefit of Snow Prudhoe Bay production throughput agreement to new recapitalized entity
- Recapitalization structured to be deemed a sale for cash
- Existing debt covenants, if any, including throughput and other requirements
- State and Federal right of way considerations
- Potential dismantlement and environmental restoration obligations
- Existing depreciable tax basis and corporate taxes due when partnership is formed

V. Conclusion

- A leveraged recapitalization of TAPS does not appear to add incremental value over that shown in Exhibit 5 for TAPS, except to the extent that such a transaction could utilize a portion of the available capital loss shown therein.

PROJECT WINTER

Table I. Summary of Discounted Cash Flow Analysis for Trans Alaska Pipeline System
(Dollars in millions)

Nominal Discount Rate	Net Present Value
8%	$2.337
9	2.267
10	2.200
11	2.138
12	2.079
13	2.023
14	1.970

The discounted cash flow model was constructed by Blizzard. Certain assumptions in the model were provided by Blizzard and reviewed by us, including assumptions as to throughput, tariffs and taxes.

Future throughput assumptions were derived by Blizzard from figures provided by Snow. Future tariffs have been assumed to be approximately $4.00 per barrel. Blizzard assumed a carried forward tax basis of $600 million for Snow's share of TAPS. Capital expenditure assumptions are from the Snow Development Plan, grown by Blizzard under the assumption that capital expenditures are increased every three years.

EXHIBIT 9

PROJECT WINTER

Refinery & Marketing System Valuation

In determining our value range for Snow's Refining & Marketing System of $2.1 to $2.6 billion presented in Exhibit 5, we have considered, among other things, certain statistics regarding recent acquisitions of large refining and marketing systems shown in Table I, a discounted cash flow analysis shown in Table II, current conditions in the oil and gas industry, the number of potential acquirors and the size of transaction indicated for Snow's Refinery & Marketing System.

In preparing our estimate of the public market value for Snow's Refining & Marketing System, we have assumed that the shares of a corporation holding the refining and marketing operations of Snow would be distributed to Snow shareholders. Such a distribution should not result in a tax liability for Snow or its shareholders and our valuation assumes this result.

Based on available public information on Ashland Oil Inc. and Diamond Shamrock R&M Inc. presented in Table III, we believe that the fully distributed market value of Snow's Refining & Marketing System would be in the range of $2.7 to $3.2 billion (see Table IV). This range represents an incremental value of $100 to $600 million over the high range value presented in Exhibit 5.

In arriving at our valuation, we have not considered certain operational and financial impediments which may be inherent in such a spinoff and which may arise in its separation from its present status as part of an integrated oil company.

PROJECT WINTER

Table I: Refinery Acquisition Statistics
(Dollars in millions)

Date	Acquirer/Acquired	Consideration	Capacity of Acquired Refinery (MBPD)	Consideration/ Capacity Barrel
11/80	MAPCO/Earth Resources	$395	68	$5,812
9/81	APEX/Clark Oil	531	135	3,939
11/81	KOCH/Sun Co. Refinery	265	57	4,649
8/83	Southland/CITGO Petroleum	834	330	2,526
12/84	Standard Oil/Alliance Assets	740	200	3,700
9/85	Atlantic Petroleum/ARCO Eastern Region	420	96	4,370
9/86	Petroleos de Venezuela/50% of CITGO Petroleum	290	330	1,757(a)

	Implied Value of Snow's R&M System (b)
Low Value ($1,757)	$1,152
Mean Value ($3,822)	2,507
Median Value ($3,939)	2,584
High Value ($5,812)	3,812
Alliance Value ($3,700)	2,427

(a) Calculated using implied value for total company of $580.
(b) Based on a system capacity of 656 MBPD.

PROJECT WINTER

Table II: Summary of Discounted Cash Flow Analysis for Snow Refining & Marketing System (Dollars in millions)

Nominal Discount Rate	Net Present Value
8%	$2.977
9	2.780
10	2.600
11	2.435
12	2.285
13	2.148
14	2.022

The discounted cash flow model was constructed by Blizzard. Certain assumptions in the model were provided by Blizzard and reviewed by us:

	Refinery Capacity (MBPD)	1986 Refining Margins Per Barrel
Alliance	200	$1.50
Ohio	288	0.60
Pennsylvania	168	0.50
Total/Weighted Avg.	656	$0.85

Refining margins are assumed to grow with inflation at 4% per year. Product volume sales are grown at approximately 1% per year until they reach the refining system capacity of 656 MBPD and are held constant thereafter. Marketing margins, as supplied by Blizzard, are assumed to be $1.50 per barrel and inflate at 4% per year.

The present values shown above were calculated using ten years of cash flows with an assumed terminal value of the Refining & Marketing System of ten times net income at the end of the tenth year.

PROJECT WINTER

Table III: Public Market Valuation of Refining & Marketing Businesses
(Dollars in millions except where noted)

I. ASHLAND OIL, INC.

Market Capitalization (3/23/87):	$2,074	(32.541MM shares @ $63.75)
Short and Long-Term Debt:	794	
Total Capitalization	$2,868	

A. Public Market Multiple Valuation	Ashland Corporate Multiple	Ashland R & M 1986 Results	Implied Value of Ashland R&M Segment
Total Cap./Operating Income (1986: $473)	6.1x	$ 326	$1,989
Total Cap./Operating Cash Flow (1986: $714)	4.0x	425	1,700
Market Cap./Net Income (1986: $209)	9.9x	176(a)	1,742
Market Cap./Net Cash Flow (1986: $496)	4.2x	275	1,155

B. Physical Capacity and Volumes Valuation	Low	Mean	Median (b)	High
Ashland R&M Implied Valuation	$1,155	$1,647	$1,721	$1,989
Implied Refinery Capacity Value (c)($1/BPD)	$3,235	$4,612	$4,821	$5,571
Implied Throughput Value (d) ($1/BPD)	3,587	5,115	5,345	6,177
Implied Product Sales Volume Value (e) ($1/BPD)	3,113	4,439	4,639	5,361

II. DIAMOND SHAMROCK R&M INC.

Diamond Shamrock recently announced its intention to spin off its refining and marketing operations to its shareholders. A preliminary Form S-10 has been filed with the SEC for Diamond Shamrock R&M Inc. ("DSRM"), which will hold such operations. As of March 23, 1987, there has been no established trading price for the shares of DSRM. Goldman Sachs Investment Research has published a report that estimates a future market value of about $18.00 per share. The estimate is based on an average annual operating cash flow for DSRM in the range of $115 - $130 million and a 3.5 times cash flow multiple which yields a total market capitalization of $403 - $455 million or $17.68 - $19.96 per share. The estimated DSRM cash flow multiple is less than the 4.0x multiple for Ashland in the public market.

Based on the relative system sizes of DSRM (135 MBPD), Ashland (357 MBPD) and Snow's Refining and Marketing System (656 MBPD) and the perceived quality of their respective operations, we believe that the public market valuation of Ashland rather than that of DRSM would give a better indication as to the potential public market valuation of Snow's Refining and Marketing System should it be spun off to Snow's shareholders in a tax-free distribution.

(a) Operating income tax-effected using a 46% tax rate.
(b) Average of the two middle of the range values.
(c) 357 MBPD in 1986.
(d) 322 MBPD in 1986.
(e) 371 MBPD in 1986.

PROJECT WINTER

Table IV: Snow Refining and Marketing System: Implied Public Market Valuation
(Dollars in millions except where noted)

	Ashland Corporate Multiple	Snow R&M 1986 Results (a)	Implied Value of Snow R&M System
I. Public Market Multiple Valuation			
Total Capitalization/Operating Income	6.1x	$436	$2,660
Total Capitalization/Operating Cash Flow	4.0	545(b)	2,180
Market Capitalization/Net Income	9.9	235(c)	2,327
Market Capitalization/Net Cash Flow	4.2	344(d)	1,445
Average of Implied Values			$2,153

	Ashland R&M (e)	Snow R&M Capacity/Volume Data	Implied Value of R&M System
II. Physical Capacity and Volumes Valuation			
A. Refining Capacity Value			
Mean	$4,612	656 MBPD	$3,025
Median	$4,825	656 MBPD	$3,165
B. Throughput Value			
Mean	$5,115	622 MBPD	$3,182
Median	$5,345	622 MBPD	$3,325
C. Product Sales Volume Value			
Mean	$4,439	630 MBPD(f)	$2,797
Median	$4,639	630 MBPD(f)	$2,923
Average of Capacity, Throughout and Product Sales Volume Implied Values			$3,070

(a) From projections provided by Blizzard.
(b) Operating income plus non-cash charges of $109 million.
(c) Operating income using a 46% tax rate.
(d) Net income plus $109 million in non-cash charges.
(e) Ashland R&M capacity and volumes values in this column are in $/BPD.
(f) Estimated from historical performance.

EXHIBIT (g)

SECURITIES AND EXCHANGE COMMISSION
Washington, D.C. 20549

SCHEDULE 14D-1

Tender Offer Statement Pursuant to
Section 14(d)(1) of the Securities Exchange Act of 1934

THE STANDARD OIL COMPANY
(Name of Subject Company)

BP NORTH AMERICA INC.
(Bidder)

COMMON STOCK, WITHOUT PAR VALUE
(Title of Class of Securities)

0008537341
(CUSIP Number of Class of Securities)

George H. Hagle
BP North America Inc.
620 Fifth Avenue
New York, New York 10020
(212) 887-9300

(Name, Address and Telephone Number of Person Authorized to Receive Notices and Communications on Behalf of Bidder)

Copies to:

Benjamin F. Stapleton
Sullivan & Cromwell
125 Broad Street
New York, New York 10004
(212) 558-4000

K.J.M. Walder
The British Petroleum
Company p.l.c
Britannic House, Moor Lane
London EC2Y 9BU
England
(01) 920-8000

Calculation of Filing Fee

Transaction valuation	Amount of filing fee
$7,341,167,120*	$1,468,233.42**

* up to 104,873,816 shares at $70 per share

** 1/50th of 1% of Transaction Valuation

[ ] Check box if any part of the fee is offset as provided by Rule 0-11(a)(2) and identify the filing with which the offsetting fee was previously paid. Identify the previous filing by registration statement number, or the Form or Schedule and the date of its filing.

Amount Previously Paid:_____

Form or Registration No.:_____

Filing Party:_____

Date Filed:_____

This Schedule 14D-1 relates to the offer by BP North America Inc., a Delaware corporation (the "Purchaser") and an indirect wholly-owned subsidiary of The British Petroleum Company p.l.c., a company organized under the laws of England ("BP"), to purchase any and all of the outstanding shares of Common Stock, without par value, of The Standard Oil Company, an Ohio corporation, at $70 per share, net to the seller in cash, upon the terms and subject to the conditions set forth in the Offer to Purchase dated April 1, 1987 (the "Offer to Purchase") and the related Letter of Transmittal, copies of which are annexed hereto as Exhibits (a)(1) and (a)(2), respectively.

Item 1. Security and Subject Company.

(a) The name of the subject company is The Standard Oil Company, an Ohio corporation (the "Company"), and the address of its principal executive offices is 200 Public Square, Cleveland, Ohio 44114.

(b) The class of securities to which this statement relates is the Common Stock, without par value, of the Company. The information set forth under the caption "INTRODUCTION" in the Offer to Purchase is incorporated herein by reference.

(c) The information set forth under the caption "MARKET PRICES OF AND DIVIDENDS ON SHARES" in the Offer to Purchase is incorporated herein by reference.

Item 2. Identity and Background.

(a)-(d); (g) The information set forth under the captions "INTRODUCTION" and "PARENT GROUP AND THE PURCHASER" in the Offer to Purchase is incorporated herein by reference.

(e); (f) During the last five years, neither the Purchaser nor any person controlling the Purchaser, nor, to the best knowledge of the Purchaser, any of the directors or executive officers of the Purchaser or BP, has been

convicted in a criminal proceeding (excluding traffic violations or similar misdemeanors) or was a party to a civil proceeding of a judicial or administrative body of competent jurisdiction and as a result of such proceeding was or is subject to a judgment, decree or final order enjoining future violations of, or prohibiting activities subject to, federal or state securities laws or finding any violation of such laws.

Item 3. Past Contracts, Transactions or Negotiations with the Subject Company.

(a)-(b) The information set forth under the captions "SPECIAL FACTORS -- Background of the Offer", "SPECIAL FACTORS -- Plans for the Company After the Offer", "SPECIAL FACTORS -- Fairness of the Offer", "THE COMPANY -- Projections" and "THE COMPANY -- Certain Relationships with BP" in the Offer to Purchase is incorporated herein by reference.

Item 4. Source and Amount of Funds or Other Consideration.

(a)-(c) The information set forth under the caption "THE TENDER OFFER -- Source and Amount of Funds" in the Offer to Purchase is incorporated herein by reference.

Item 5. Purpose of the Tender Offer and Plans or Proposals of the Bidder.

(a)-(g) The information set forth under the captions "SPECIAL FACTORS -- Purpose, Structure and Benefits of the Offer", "SPECIAL FACTORS -- Reasons for the Offer", "SPECIAL FACTORS -- Plans for the Company After the Offer", "SPECIAL FACTORS -- Fairness of the Offer" and "SPECIAL FACTORS -- Certain Effects of the Offer" in the Offer to Purchase is incorporated herein by reference.

Item 6. Interest in Securities of the Subject Company.

(a)-(b) The information set forth under the captions "INTRODUCTION" and "THE COMPANY -- Certain Relationships with BP" in the Offer to Purchase, and the information set forth in Schedule I thereto, is incorporated herein by reference.

Item 7. Contracts, Arrangements, Understandings or Relationships with Respect to the Subject Company's Securities.

The information set forth under the captions "SPECIAL FACTORS -- Background of the Offer" and "THE COMPANY -- Certain Relationships with BP" in the Offer to Purchase, and the information set forth in Schedule I thereto, is incorporated herein by reference.

Item 8. Persons Retained, Employed or to be Compensated.

The information set forth under the captions "SPECIAL FACTORS -- The Financial Advisors" and "THE TENDER OFFER -- Fees and Expenses" in the Offer to Purchase is incorporated herein by reference.

Item 9. Financial Statements of Certain Bidders.

The financial statements annexed hereto as Exhibit (g) are incorporated herein by reference.

Item 10. Additional Information.

(a) The information set forth in Schedule I to the Offer to Purchase is incorporated herein by reference.

(b)-(c) The information set forth under the caption "THE TENDER OFFER -- Certain Legal Matters" in the Offer to Purchase is incorporated herein by reference.

(d) Not applicable.

(e) The information set forth under the caption "SPECIAL FACTORS -- Litigation Relating to the Offer" in the Offer to Purchase is incorporated herein by reference.

(f) Additional information is set forth in the Offer to Purchase, which is, in its entirety, incorporated herein by reference.

Item 11. Material to be filed as Exhibits.

(a)(1) Offer to Purchase.

(a)(2) Letter of Transmittal relating to the Offer to Purchase.

(a)(3) Form of letter, dated April 1, 1987, from Goldman, Sachs & Co. to brokers, dealers, commercial banks, trust companies and other nominees.

(a)(4) Form of letter to be sent by brokers, dealers, commercial banks, trust companies and other nominees to their clients.

(a)(5) Form of newspaper advertisement, dated April 1, 1987.

(a)(6) Notice of Guaranteed Delivery.

(a)(7) IRS Guidelines for Certification of Taxpayer Identification Number on Substitute Form W-9.

(a)(8) Press Release dated March 26, 1987.

(a)(9) Press Release dated April 1, 1987.

(b) Facility Agreement among BPI and the Purchaser, as Borrowers, BP, as Guarantor, the Banks to be named therein and Morgan Guaranty Trust Company of New York, as Agent and Tender Agent.

(c) Agreement, dated August 7, 1969, among BP, British Petroleum (Overzee) N.V. and the Company.

(g) Consolidated Financial Statements of BP and its subsidiaries, as excerpted from BP's Report on 6-k for the month of March, 1987 filed with the Securities and Exchange Commission.

(h) Shareholders' Class Action Complaint for Preliminary and Injunctive Relief filed in the Court of Common Pleas, Cuyahoga County, Ohio on March 26, 1987.

SIGNATURE

After due inquiry and to the best of my knowledge and belief, I certify that the information set forth in this statement is true, complete and correct.

Dated:

BP NORTH AMERICA INC.

By /s/ George H. Hagle
Title: Vice President and
General Counsel

EXHIBIT INDEX

Exhibit	Description	Page
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(a)(7)	IRS Guidelines for Certification of Taxpayer Identification Number on Substitute Form W-9.	
(a)(8)	Press Release dated March 26, 1987.	
(a)(9)	Press Release dated April 1, 1987.	
(b)	Facility Agreement among BPI and the Purchaser, as Borrowers, BP, as Guarantor, the Banks to be named therein and Morgan Guaranty Trust Company of New York, as Agent and Tender Agent.	
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EXHIBIT (a)(1)

Offer to Purchase for Cash
Any and All of the Outstanding Shares of Common Stock
of

The Standard Oil Company

at

$70 Net Per Share

by

BP North America Inc.

an indirect wholly-owned subsidiary of

The British Petroleum Company p.l.c.

THE OFFER AND WITHDRAWAL RIGHTS WILL EXPIRE AT 12:00 MIDNIGHT, NEW YORK CITY TIME, ON TUESDAY, APRIL 28, 1987, UNLESS EXTENDED.

THE OFFER IS NOT CONDITIONED UPON ANY MINIMUM NUMBER OF SHARES BEING TENDERED.

IMPORTANT

Any shareholder desiring to tender all or any portion of his Shares should either (1) complete and sign the Letter of Transmittal or a facsimile thereof, have his signature thereon guaranteed if required by Instruction 1 of the Letter of Transmittal and mail or deliver the Letter of Transmittal or such facsimile with his certificate(s) evidencing Shares and any other required documents to the Depositary or tender such Shares pursuant to the procedure for book-entry tender set forth under "THE TENDER OFFER—Procedure for Tendering Shares", or (2) request his broker, dealer, commercial bank, trust company or other nominee to effect the transaction for him. Shareholders having Shares registered in the name of a broker, dealer, commercial bank, trust company or other nominee must contact such broker, dealer, commercial bank, trust company or other nominee if they desire to tender their Shares so registered.

A shareholder who desires to tender Shares and whose certificates for such Shares are not immediately available, or who cannot comply with the procedure for book-entry tender on a timely basis, should tender such Shares by following the procedures for guaranteed delivery set forth under "THE TENDER OFFER—Procedure for Tendering Shares".

Questions and requests for assistance may be directed to the Information Agent or the Dealer Managers at their respective addresses and telephone numbers set forth on the back cover of this Offer to Purchase. Requests for additional copies of this Offer to Purchase and the Letter of Transmittal may be directed to the Information Agent or to brokers, dealers, commercial banks or trust companies.

THIS TRANSACTION HAS NOT BEEN APPROVED OR DISAPPROVED BY THE SECURITIES AND EXCHANGE COMMISSION NOR HAS THE COMMISSION PASSED UPON THE FAIRNESS OR MERITS OF SUCH TRANSACTION NOR UPON THE ACCURACY OR ADEQUACY OF THE INFORMATION CONTAINED IN THIS DOCUMENT. ANY REPRESENTATION TO THE CONTRARY IS UNLAWFUL.

The Dealer Managers for the Offer are:

Goldman, Sachs & Co.

April 1, 1987

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To the Holders of Shares of Common Stock
of The Standard Oil Company:

INTRODUCTION

BP North America Inc., a Delaware corporation (the "Purchaser") and an indirect wholly-owned subsidiary of The British Petroleum Company p.l.c., a company organized under the laws of England ("BP"), hereby offers to purchase any and all of the outstanding shares of Common Stock, without par value ("Shares"), of The Standard Oil Company, an Ohio corporation (the "Company"), at $70 per Share, net to the seller in cash, upon the terms and subject to the conditions set forth in this Offer to Purchase and the related Letter of Transmittal (which together constitute the "Offer"). BP and its subsidiaries are herein referred to as either "BP" or the "BP Group". Tendering shareholders will not be obligated to pay brokerage fees or commissions or, except as provided in Instruction 6 to the Letter of Transmittal, transfer taxes with respect to the purchase of Shares pursuant to the Offer. The Purchaser will pay all charges and expenses of The Chase Manhattan Bank, N.A., the Depositary, and D.F. King & Co., Inc., the Information Agent, in connection with the Offer.

The Offer is not conditioned upon any minimum number of Shares being tendered. The Offer is conditioned, among other things, upon its approval by a resolution passed on a show of hands by a majority of the shareholders present and voting or, if a poll is called for, by a majority of the votes cast, at a meeting of the shareholders of BP to be convened for April 22, 1987.

According to the Company, as of March 25, 1987, there were outstanding 109,193,816 Shares, 40,388 shares of 3¾% Cumulative Preferred Stock, Series A, par value $100.00 per share (the "Preferred Stock"), and 1,000 shares of Special Stock, without par value (the "Special Stock"). The Offer is not being made for the Preferred Stock but if, as described in the following paragraph, the Purchaser effects a merger of the Company, it is expected that the Preferred Stock will be redeemed. See "SPECIAL FACTORS—Purpose, Structure and Benefits of the Offer". According to the Company, as of March 27, 1987, there were options outstanding to purchase 2,512,325 Shares, at exercise prices ranging from $15.63 to $52.00 per Share, pursuant to the Company's employee stock option plans. BP, through its direct wholly-owned subsidiary BP International Limited ("BPI"), owns all the Special Stock (equivalent to 125,840,000 Shares) and 4,320,000 Shares, constituting an aggregate of 130,160,000 Shares and Share-equivalents, or approximately 55.4% of the outstanding Shares and Share-equivalents.

If the Purchaser acquires approximately 60 million or more Shares pursuant to the Offer or otherwise (so that the Purchaser and its affiliates would own at least 80% of the then outstanding Shares and Share-equivalents), the Purchaser intends to effect a merger of a wholly-owned subsidiary of the Purchaser into the Company, pursuant to which the Company would become a direct wholly-owned subsidiary of the Purchaser and an indirect wholly-owned subsidiary of BP and the remaining holders of Shares, other than the Purchaser and holders of Shares who perfect their dissenters' rights under Ohio law, would become entitled to receive $70 in cash per Share. *Dissenters' rights will not be available with respect to Shares sold pursuant to the Offer.* See "SPECIAL FACTORS —Purpose, Structure and Benefits of the Offer".

SPECIAL FACTORS

Background of the Offer. On January 1, 1970, the Company acquired from a wholly-owned subsidiary of BP all of the outstanding capital stock of a corporation which owned the Company's present interest in the Prudhoe Bay area on the Alaskan North Slope, retail gasoline outlets in 16 states, two refineries and related pipeline and terminal facilities, in exchange for 1,000 shares of Special Stock. The Special Stock initially provided the BP Group with rights (including voting

rights) equivalent to an approximate 25% common stock interest in the Company, except that the Special Stock did not initially bear dividends. The rights attaching to the Special Stock were capable of increasing to the equivalent in all respects of an approximate 54% common stock interest in the Company, depending on the future levels of sustainable crude oil production at Prudhoe Bay. By June 16, 1978, sustainable crude oil production from Prudhoe Bay had reached a level such that the rights attaching to the Special Stock reached the maximum Share-equivalency and, together with other Shares then held by a wholly-owned subsidiary of BP, became equivalent in all respects (including dividend rights) to an approximate 54% common stock interest at that time. BP has maintained its ownership of a majority of the outstanding Shares and Share-equivalents from that date to the present.

The agreement pursuant to which the Special Stock was issued provides that so long as BP or any company controlled by BP owns all of the Special Stock, the Company will use its best efforts to cause at least two persons nominated by BP to be members of the Board of Directors of the Company. Pursuant to the agreement, initially two persons nominated by BP were elected to the Company's Board. Since 1972, at least three nominees of BP have been members of the Company's Board.

BP has regularly reviewed its investment in the Company because of its significance. In the summer of 1985, because of BP's increasing concern over the Company's performance, BP commenced a study of the possibility of acquiring the Shares not then owned by BP or of changing the Company's management. BP did not then hold discussions with the Company concerning the acquisition of such Shares. Due primarily to the continuing decline in oil prices, BP determined in mid-February 1986 not to pursue the acquisition of the minority Shares further at that time.

However, contemporaneously with this determination and because of BP's continuing concern over the Company's performance, BP proposed several changes in the Company's management in a letter, dated February 20, 1986, from BP's Chairman to certain members of the Company's Board of Directors (the "Board"). In that letter, BP's Chairman noted the Company's continuously declining net income over the preceding five years and pointed out that "some $14 billion of capital investment has been made, of which half has produced no return." Following discussions regarding BP's proposals among members of the Board and BP's management, the Board announced on February 27, 1986 major changes in the Company's management. Effective April 1, 1986, Robert B. Horton, formerly a Managing Director of BP and a member of the Board since 1983, replaced Alton W. Whitehouse, Jr. as Chairman of the Board and Chief Executive Officer, and Frank E. Mosler, formerly Executive Vice President of the Company, replaced John R. Miller as the Company's President and Chief Operating Officer.

At the Company's 1986 Annual Meeting of Shareholders, E. John P. Browne, formerly Group Treasurer of BP and Chief Executive of BP Finance International, was elected to the Board and J. Colin E. Webster, formerly President of the Purchaser, was re-elected as a member of the Board. The Board then elected Mr. Browne as Executive Vice President and Chief Financial Officer of the Company and Mr. Webster as Executive Vice President of the Company. Messrs. Horton, Browne and Webster resigned their respective positions with BP or the Purchaser upon assuming their duties with the Company.

In commenting on the proposed changes at the time they were announced, BP's Chairman said: "This is a critical time for the oil industry and especially for Standard Oil. BP believes it is also an appropriate time to strengthen Standard Oil's management to cope with the difficult environment ahead. We are making available three top people from BP, each with a proven track record, to ensure that Standard Oil has the best possible professional leadership, to maximize returns for all Standard Oil shareholders."

In conjunction with these management changes, Basil R.R. Butler, Ian G.S. Hartigan and Kenneth R. Kemp, none of whom had previously served on the Board, were nominated for election as directors by the Board at BP's request and were elected at the Company's 1986 Annual Meeting of Shareholders.

The six directors on the Board at February 27, 1986 who were not members of the Company's management or nominees of BP (namely Elizabeth E. Bailey, Dewitt W. Buchanan, Jr., Douglas D. Danforth, William J. De Lancey, John J. Hangen and Charles F. Knight) have continued to serve as directors, and were re-elected at the Company's 1987 Annual Meeting of Shareholders. Messrs. Whitehouse and Miller were not re-nominated for election as directors.

At the time of these management changes, BP publicly announced that it then had "no current intention of making an offer for the minority shares." However, oil prices began to steady during the fall of 1986 and industry confidence in medium-term oil price stability generally increased. In light of these developments, in late November 1986, BP's management began to study actively the possibility of making an offer for the minority Shares. BP and the Purchaser have now decided to make the Offer for the reasons set forth under "Reasons for the Offer" below.

On March 5, 1987, Sir Peter Walters, Chairman of BP, telephoned Douglas D. Danforth, chairman of a Special Committee of the Board composed of all independent directors of the Company which was established in 1986 and charged with monitoring the relationship between BP and the Company, to request that Mr. Danforth give BP's Chairman an opportunity to address the directors of the Company on March 9 or 10. Later the same day, BP's Chairman telephoned George J. Dunn, Vice President and General Counsel of the Company and secretary of the Special Committee, to advise him of his conversation with Mr. Danforth and to request his assistance in arranging the meeting. Messrs. Danforth and Dunn arranged such a meeting for March 9, 1987.

On the evening of March 8, 1987, BP's Chairman met with Mr. Danforth and Charles F. Knight, another member of the Special Committee, to inform them of the reason he had asked to meet with the directors and to outline the presentation he planned to make at that meeting.

The following persons were present at the March 9th meeting: BP's Chairman; D.A.G. Simon, a Managing Director of BP; K.J.M. Walder, Legal Adviser to the BP Group; Peter G. Sachs, a partner of Goldman, Sachs & Co. ("Goldman Sachs"); Frank E. Mosier, President and Chief Operating Officer of the Company; Mr. Dunn; and all directors of the Company not employed by BP or the Company other than Joseph T. Gorman, who joined the Board in 1987, and Mr. De Lancey. At that meeting, BP's Chairman stated that BP was giving serious consideration to the possibility of making a tender offer for the minority Shares. He said that BP was not at that time in a position to make an offer, but that BP had retained Goldman Sachs to assist BP in a valuation of the Company. He informed those present that BP was advising them of BP's position in order to give them sufficient time to prepare their response to any possible offer and expressed his hope that it would be possible to convince the Board that the offer, if made, would be in the interests of the Company's shareholders and that it should be supported by the Board. BP's Chairman also explained the reasons why BP was considering making an offer for the minority Shares at this time (as discussed under "Reasons for the Offer" below) and stated that he hoped that the Board would be able to respond should BP's board of directors decide to proceed with an offer, which decision could be reached as early as March 20, 1987.

BP's Chairman outlined BP's intentions for the Company assuming a successful offer, which are set forth under "Plans for the Company After the Offer" below. He then stated that BP and Goldman Sachs believed that the Shares were currently fully valued in the market (which had closed on the prior trading day at $59.50 per Share).

Mr. Sachs then made a presentation in which he reviewed the work which Goldman Sachs had completed to date and discussed their preliminary analysis, the final version of which is discussed below.

BP's representatives then left the room to allow the directors to discuss the situation. When they were asked to return, Mr. Danforth informed them that the Special Committee had decided to retain The First Boston Corporation ("First Boston") as its independent financial advisor and to retain independent counsel for advice with respect to any offer which might be made.

During the course of the March 9th meeting there was a general discussion of various matters related to a possible offer, including the tax treatment of an offer to shareholders, the impact of an offer on employee benefit and stock option plans and the time periods applicable to an offer. At the meeting, BP's Chairman indicated that following a merger he might desire to have the members of the Board act as advisory directors for the Purchaser.

On March 13, 1987, Mr. Danforth informed BP's Chairman that the Special Committee would require more time to consider the Company's position than would be possible if a decision on whether to proceed with an offer were made on or around March 20 (as BP's Chairman had suggested as a possibility at the March 9th meeting), and asked that such a decision be postponed by approximately one week. Thereafter, there were additional phone conversations between Mr. Danforth and BP's Chairman concerning the possible timing of any offer and of the Company's 1987 Annual Meeting of Shareholders, and on the evening of March 25, 1987, BP's Chairman informed Mr. Danforth of BP's decision to proceed with the Offer.

On March 26, 1987, the Purchaser provided drafts of the Offer to Purchase to the Company and to the counsel and financial advisor of the Special Committee and requested that the Company review it for accuracy and completeness, including the need to provide any non-public information which would be considered material by a holder of Shares in making a decision whether or not to tender Shares pursuant to the Offer. On March 30, 1987, counsel to the Special Committee, in a letter to the Purchaser's counsel, while noting that the Company would provide BP with any information it would like, stated that neither the Special Committee nor the Company was in a position to assume responsibility for BP's disclosure obligations and therefore, the letter provided no comments on the draft Offer to Purchase. The letter also reiterated an earlier statement by Mr. Danforth to BP's Chairman in a telephone conversation that BP's proceeding by tender offer did not allow the Special Committee sufficient time to review BP's offer fully and Mr. Danforth's requests previously made at the same time, that commencement of the Offer be postponed and BP proceed by merger proposal and that the Special Committee be given one to two months to evaluate the price offered. On March 31, 1987, Mr. Dunn on behalf of the Company, in a letter to the Purchaser's counsel, pointed out certain information in the draft Offer to Purchase which was either inaccurate with respect to the Company or which the Company considered competitively sensitive, while declining to state whether the Company considered such competitively sensitive information material to a decision to tender. The comments made in such letter have been reflected in the Offer to Purchase. On April 1, 1987, the Purchaser's counsel, by letter to counsel of the Special Committee, reaffirmed BP's decision to proceed by tender offer.

For information concerning certain relationships between the BP Group and the Company, see "THE COMPANY—Certain Relationships with BP".

Purpose, Structure and Benefits of the Offer. The purpose of the Offer is for the Purchaser to acquire as many additional Shares as possible pursuant to the terms and conditions of the Offer as a first step in acquiring all the minority Shares. Upon completion of the Offer, if approximately 60 million or more Shares are purchased pursuant to the Offer (so that the Purchaser and its affiliates would own at least 80% of the outstanding Shares and Share-equivalents), BP presently intends to cause BPI to transfer the Special Stock and the Shares held by it to the Purchaser and subsequently to cause the Purchaser to acquire any remaining Shares not owned by it by means of a merger of a wholly-owned subsidiary of the Purchaser into the Company, pursuant to which each outstanding Share not then owned by the Purchaser or holders who perfect their dissenters' rights under Ohio law would be converted into the right to receive $70 in cash (a "Merger"). If a Merger is effected, it is presently contemplated that the Preferred Stock would be redeemed by the Company at the redemption price of $100 per Share. It is intended that each holder of an employee stock option, whether or not then exercisable, would be entitled in connection with a Merger to receive in cash the difference between the exercise price under the option and $70, multiplied by the number of Shares subject to option.

If fewer than approximately 60 million Shares are purchased pursuant to the Offer, the Purchaser presently intends, subject to many factors, including the number of Shares purchased pursuant to the Offer, the availability of Shares at prices acceptable to the Purchaser, future conditions in the oil and securities markets, results and prospects of the Company's and the BP Group's businesses, general economic conditions and the status of any pending litigation, to acquire sufficient additional Shares to bring the ownership of the Purchaser and its affiliates to at least 80% of the outstanding Shares and Share-equivalents and thereafter to effect a Merger. Such purchases may be effected through privately negotiated or open market purchases, subsequent tender offers or by any other means BP deems advisable and may be at prices more or less than $70 per Share. Unless the Purchaser acquires sufficient Shares to bring the ownership of the Purchaser and its affiliates to at least 80% of the outstanding Shares and Share-equivalents, it is not presently contemplated that a Merger would be proposed.

While the Purchaser presently intends to effect a Merger if it purchases pursuant to the Offer or otherwise approximately 60 million or more Shares, a Merger could be delayed or abandoned or its terms amended, depending on many of the same factors set forth above which could affect the acquisition of additional Shares by the Purchaser following the Offer.

Under the Company's Articles of Incorporation, a vote of at least 80% of the outstanding Shares, Share-equivalents and Preferred Stock, voting together as a single class, would be required to approve a Merger. If the Purchaser purchases approximately 60 million or more Shares pursuant to the Offer or otherwise, the Purchaser and its affiliates would have the power to approve a Merger without the consent of any other shareholders. However, a vote would have to be taken at a shareholders meeting called for that purpose and an information statement disclosing certain information relating to the Company and the transaction would have to be distributed to shareholders at least 20 days before the meeting, unless the Purchaser effects a "short-form" Merger, *i.e.*, a Merger without a shareholders meeting or a shareholder vote which would not necessitate the distribution of an information statement. Under Ohio law, the Purchaser could effect a short-form Merger if it owns at least 90% of each class of capital stock of the Company. Accordingly, in order to do so, the Purchaser would have to acquire approximately 96.2 million or more Shares pursuant to the Offer or otherwise, have transferred to it the Special Stock and Shares held by BPI, and cause the Company to redeem the Preferred Stock. The Purchaser intends to effect a short-form Merger if it acquires approximately 96.2 million or more Shares pursuant to the Offer or otherwise.

Under Ohio law, a Merger, whether or not it is short-form, must be approved by the Board. At the present time the Purchaser and its affiliates have sufficient voting power to remove and elect at least a majority of the Board at any annual or special meeting of shareholders and, upon not less than seven nor more than sixty days' notice to shareholders, to call a special meeting of shareholders.

If a Merger is consummated, each shareholder of the Company who does not vote his Shares in favor of it will have, if he complies with the statutory procedures, certain rights under Ohio law to demand payment of the fair cash value of such Shares. Such rights, if perfected, would result in an agreement on or a judicial determination of the fair cash value required to be paid in cash by the Company for such Shares. "Fair cash value" is defined under Section 1701.85 of the Ohio General Corporation Law ("Section 1701.85") to mean the amount that a willing seller, under no compulsion to sell, would be willing to accept, and that a willing buyer, under no compulsion to purchase, would be willing to pay, but, under Section 1701.85, such amount could not be in excess of the amount demanded by the shareholder as explained below and would exclude any appreciation or depreciation in market value resulting from a Merger. The fair cash value per Share could be more or less than the amount paid per Share pursuant to the Offer and a Merger. To perfect dissenters' rights under Section 1701.85, a dissenting shareholder must not have voted his Shares in favor of a Merger and is required, within 10 days after the meeting of shareholders approving a Merger (or, in the case of a short-form Merger, within 20 days after written notice of approval of a Merger is sent to

him), to deliver to the Company a written demand of payment of the fair cash value of such Shares stating his address, the number and class of such Shares, and the amount claimed as the fair cash value of such Shares. Thereafter a dissenting shareholder would have the rights and be subject to the procedures set forth in Section 1701.85, set forth in its entirety in Schedule II hereto. The foregoing description of dissenters' rights under the Ohio General Corporation Law is qualified in its entirety by reference to Schedule II, which is incorporated herein by reference. ***Dissenters' rights would only arise in connection with the consummation of a Merger and not by virtue of the Offer or the purchase of Shares pursuant thereto.***

The primary benefit of the Offer to the Company's shareholders, other than the Purchaser and its affiliates, is that they are being afforded an opportunity to sell all their Shares at a price which, in the opinion of BP and the Purchaser, is fair to such holders and fully reflects the value of the Company. However, shareholders who do sell their Shares will cease to have any equity interest in the Company and to participate in its earnings and any future growth.

To the best knowledge of the Purchaser, each person listed on Schedule I hereto who owns Shares intends to tender his Shares pursuant to the Offer.

As a result of the Offer, the interest of the BP Group in the Company's net book value and net income will increase to the extent of the number of Shares acquired in the Offer. If a Merger is consummated, the BP Group's common equity interest in the Company would increase to 100% and the BP Group would be entitled to all benefits resulting from that interest, including all income generated by the Company's operations and any future increase in the Company's value.

Reasons for the Offer. BP's investment in the Company represents its largest single asset, yet because the BP Group does not own the entire common equity interest in the Company, the Company is required by law to be managed by the Board in the best interests of all the Company's shareholders rather than just BP and its shareholders, and BP, as a majority shareholder, has certain legal duties to the minority shareholders of the Company. Because each decision made by BP which could affect the Company must be made with a view to its effect on the Company's minority shareholders, BP's flexibility in dealing with this major asset and its existing and potential North American operations is materially restricted. If the Company were wholly-owned by BP, decisions regarding the Company's operations and the utilization of the Company's substantial cash flow could be made without possible limitations arising out of the existence of a minority interest. At the present time, BP's only cash return on its investment in the Company is the dividends received on the BP Group's Shares and Share-equivalents. Because the United States is an area of strategic importance for BP and because the sale of the Shares and Share-equivalents held by BPI, at present market levels, would result in very substantial United States federal income taxes for BPI, BP has no intention of disposing of its investment in the Company. Accordingly, BP reached the conclusion that in order to eliminate the foregoing constraints and limitations and to realize the full value and potential of its current approximately 55.4% equity interest in the Company, it should make the Offer.

While the foregoing are BP's principal reasons for the Offer, BP believes that, given the Purchaser's existing and growing activities in the United States in businesses which are similar or complementary to the Company's businesses, BP may be able to achieve certain operating benefits by integrating some of the Purchaser's operations and those of the Company. Moreover, the interest costs on borrowing incurred in connection with the acquisition of additional Shares may be offset against the future pre-tax income of the Purchaser and its consolidated subsidiaries, which would, assuming the Purchaser were to own at least 80% of the Shares and Share-equivalents, include the income of the Company; the Purchaser's after tax cost of borrowing would therefore be reduced by a percentage equal to the marginal tax rates that will be applicable to the Purchaser and its subsidiaries from time to time. See "THE TENDER OFFER—Source and Amount of Funds".

The Purchaser is making the Offer at this time for the following reasons: (i) BP now considers that oil prices are likely to remain within price ranges sufficient to justify making the investment; (ii) as a result of the management changes made in 1986 and the subsequent operations of the Company, BP feels confident that the Company can operate successfully even in a lower oil price environment; and (iii) BP's own financial position together with the fact of declining interest rates in the United States over recent years facilitate the financing of the Offer.

Plans for the Company After the Offer. BP anticipates that the Company's headquarters will remain in Cleveland and the corporate headquarters of the BP Group's United States operations will be moved there. BP does not currently plan to replace the Company's management personnel and anticipates that few redundancies will arise in the Company's operating subsidiaries or corporate headquarters as a result of the Offer and a Merger. BP intends that the Company's employees will continue to receive compensation and benefits which, in the aggregate, are not materially less favorable than those presently received. Except for the Company's plans to sell certain assets as set forth below, following completion of the Offer and, if consummated, a Merger, BP currently intends to continue the operation of all the Company's business segments.

It is intended that the BP Group's existing worldwide management principles, consisting of a system of international management reporting relationships within business segments, will be applied to the Company. BP's management has begun and intends to continue a study, in which it will involve the Company's management, on how best to organize and integrate the activities of the Purchaser and the Company and to implement the foregoing management principles. As a result of such study, BP may decide to make changes in the management structure and operations of the Company. Following a Merger, BP presently intends to involve American reoresentatives, which could include present members of the Board, in the BP Group's United States operations, but the Board may consist solely of employees of the BP Group (including the Company).

Except for the possible redemption of the Preferred Stock discussed under "Purpose, Structure and Benefits of the Offer", neither the Purchaser nor BP has any plan or proposal regarding activities or transactions which are to occur after the Offer and prior to a Merger which would relate to or result in any material change in the present dividend rate or policy or capitalization of the Company. As discussed under "Fairness of the Offer", the Company has indicated to BP that it is considering the restructuring and sale of the common stock of a subsidiary of the Company, which sale may be to BPI and which could occur prior to a Merger. BP and the Company have from time to time internally considered and jointly discussed the possibility of selling or distributing to the Company's shareholders all or a portion of its interest in Prudhoe Bay or in the Trans Alaska Pipeline System ("TAPS"), either directly or through an alternate structure, such as a master limited partnership or a royalty trust. Any such sale or distribution involves certain contractual, regulatory, tax, structural, market and other constraints and uncertainties. Neither BP nor the Purchaser has any current intention to sell or distribute any significant assets of the Company or to merge the Company with any other corporation (other than by a Merger), although they do intend to continue to study the feasibility and desirability of selling limited partnership or similar interests in a portion of the Company's interests in Prudhoe Bay and/or TAPS. Decisions as to future dispositions or acquisitions of assets by the Company would be made based on normal business considerations. The Company has previously announced its intention to sell certain of the businesses of its Industrial Products division, and BP understands that the Company is considering selling part of a group of properties which include precious metals operations.

Fairness of the Offer. BP and the Purchaser believe that the price per Share offered hereby is fair to the Company's shareholders. In reaching this conclusion, BP and the Purchaser considered primarily internal valuations of the Company prepared by BP based in part on certain non-public information concerning the Company.

BP's valuations were performed under six different oil price scenarios and assumed, for purposes of the discounted cash flow analyses, a discount rate of 7% over inflation which was assumed to be 4% per annum over the long term. The results were as follows:

BP's VALUATIONS OF THE COMPANY

	$10-$15/bbl(a)	$15/bbl(b)	$15-$20/bbl(c)	$18/bbl(b)	$20/bbl(b)	$20-$25/bbl(d)
	(In millions, except per Share amounts)					
Oil and Gas Exploration and Production(e)	$ 3,516	$ 5,630	$ 6,706	$ 8,635	$10,620	$11,718
Pipeline Interests(f)	2,325	2,325	2,325	2,325	2,325	2,325
Refining and Marketing(g)	2,670	2,600	2,600	2,540	2,490	2,490
Non-Petroleum Extractive Businesses(g)	1,335	1,335	1,335	1,335	1,335	1,335
Chemicals and Industrial Products(g)	455	455	455	455	455	455
Other(h)	(618)	(718)	(718)	(768)	(818)	(818)
Net Debt(i)	(3,217)	(3,217)	(3,217)	(3,217)	(3,217)	(3,217)
Total Value	$ 6,466	$ 8,410	$ 9,486	$11,305	$13,190	$14,288
Per Share(j)	$ 27.18	$ 35.36	$ 39.88	$ 47.53	$ 55.45	$ 60.07

(a) Price level for North Sea Brent crude oil assumed to be constant at $10 per barrel through the year 1989, then constant at $15 per barrel thereafter, in each case in 1987 dollars.

(b) Price level for North Sea Brent crude oil assumed to be constant at the level indicated in 1987 dollars.

(c) Price level for North Sea Brent crude oil assumed to be constant at $15 per barrel through the year 1991, then rising at approximately $0.55 per barrel each year to $20 per barrel by the year 2000 and holding constant thereafter, in each case in 1987 dollars.

(d) Price level for North Sea Brent crude oil assumed to be constant at $20 per barrel through the year 1991, then rising at approximately $0.55 per barrel each year to $25 per barrel by the year 2000 and holding constant thereafter, in each case in 1987 dollars.

(e) Valuations were principally based on estimates of future cash flow from the Company's reserves, computed primarily from:

(i) data on proved reserves at January 1, 1987 provided to BP by the Company;

(ii) estimates of probable reserves derived from, among other things, data provided to BP by the Company; and

(iii) BP's estimates of the production profiles for the Company's various properties.

In certain limited instances, value was estimated not on a discounted cash flow basis but rather on the basis of value per barrel of oil equivalent and/or data provided by the Company with respect to values. In addition, there was an assessment of the value of the Company's undeveloped acreage.

Proved and probable reserve levels used by BP in its valuations were as follows:

Reserves net of royalty

(millions of barrels of oil equivalent)

Proved Reserves	2,536
Probable Reserves under the $18 per Barrel Case	489
Total Reserves under the $18 per Barrel Case	3,025

BP's valuations reflect the fact that the extent of economically viable probable reserves varies depending on oil prices, but in no case were the amounts used in the valuations below 350 million barrels of oil equivalent. These figures did not include an allowance for discoveries through future exploration, the value of which is reflected in the valuation of undeveloped acreage. Despite limited information available at this time, BP's valuation reflects a value for the Company's exploration venture in western Canada, which the Company believes to be promising. For the reasons set forth following Goldman Sachs' analysis, these valuations do not include any value for natural gas reserves on the Alaskan North Slope and include only a nominal value for the Company's potential involvement in any development in the Alaskan National Wildlife Refuge.

(f) Valuations were based on estimates of future cash flows from the Company's 33.34% interest in TAPS. Values were also ascribed to its 10% interest in the Kuparuk pipeline and its wholly- and partially-owned pipelines in the lower 48 States ("Lower 48").

(g) Valuations were based on estimates of future cash flows. In addition, BP considered information provided by Goldman Sachs with respect to values in the acquisition, leveraged buy-out and securities markets.

(h) Consists of (A) (I) estimated after tax proceeds from asset sales currently in progress or envisaged and (II) assumed proceeds from exercises of outstanding employee stock options less (B) an estimate of the present value of (I) the future cost of Company overhead, not allocated to the business segments separately valued, and (II) future dividends to be paid to BPI on preferred stock owned by BPI in a subsidiary of the Company (the "NPRI Preferred Stock"), which dividends are determined by reference to production from Prudhoe Bay. See "THE COMPANY". Goldman Sachs have provided the methodology of the computation of the capitalized cost of corporate overhead.

(i) Net debt represents the excess of all liabilities over all assets not allocated to the business segments. Long-term debt and certain other liabilities were adjusted to estimated present value from historic book value in this calculation.

(j) Based upon 234,712,645 Shares and Share-equivalents outstanding at December 31, 1986 plus exercise of the options outstanding at that date to purchase 3,150,714 Shares.

Although future oil price trends are very uncertain, BP considers a price in the region of $18 per barrel for North Sea Brent crude oil to be the appropriate planning assumption while OPEC maintains its quota arrangement to support price stability. Between January 1, 1987 and March 30, 1987, the spot price for North Sea Brent crude oil ranged from $15.95 per barrel to $18.82 per barrel, with an average price over such period of $17.87 per barrel.

Any valuation of the Company is highly dependent on estimates of future oil prices. A change of $1 per barrel in the average price of oil during a year will change annual net income of the Company, according to the Company's 1987 Operating Plan (the "Operating Plan"), by between $125 million and $150 million. BP estimates that if there were a $1 per barrel change in the starting oil price assumptions used in the valuations, the effect of which were sustained over the valuation period, it would result in a change in the stated valuations of the Company by approximately $4 per Share. Due to the many uncontrollable factors that affect oil prices, future oil prices could vary widely from those considered by BP, in which case BP's valuations of the Company would change accordingly. See "THE COMPANY" for a description of certain information contained in the Operating Plan and the Company's five-year Development Plan (the "Development Plan").

The foregoing table does not reflect any increase in values which might be obtained by selling or distributing to the Company's shareholders all or a portion of the Company's interest in Prudhoe Bay or TAPS, either directly or through a master limited partnership or other alternate structure, or any of the other financial alternatives described below, including utilization of the Company's potential unrealized capital loss, which in the aggregate Goldman Sachs believed might add value in excess of that attributed to the Company in Goldman Sachs' acquisition analysis of the Company. BP and the Purchaser decided to make the Offer at a price which exceeds the values reflected in the foregoing table and in Goldman Sachs' analysis for the reasons set forth above under "Reasons for the Offer".

In contemplation of the Offer, BP retained Goldman Sachs to assist in BP's evaluation of the Company and to provide the analysis set forth below, which analysis BP and the Purchaser also considered in reaching the conclusion that the Offer is fair to holders of Shares. Goldman Sachs were requested to review BP's internal valuations, the Operating Plan, the Development Plan and other data relating to the Company which was supplied by BP, as well as published financial and market information, to advise with respect to certain alternative means of valuation of the Company and its several businesses and to provide advice as to potential market reaction to the Offer. Goldman Sachs were not requested to provide any opinion as to the fairness of the Offer to BP and its shareholders or to the minority shareholders of the Company or to perform any independent examination or investigation of the Company's businesses or assets. Accordingly, Goldman Sachs did not attempt to verify the accuracy or completeness of any of the information supplied by BP or obtained through other sources, nor did Goldman Sachs conduct any discussions with, or obtain any information from, any officers or employees of the Company in connection with their advice to BP and the Purchaser. Because of the limited number of BP employees involved in BP's valuation process prior to March 26, 1987, the date on which BP and the Purchaser announced their intention to make the Offer, Goldman Sachs did not have complete access to information concerning the Company contained within the BP Group although, because information received by BP from the Company is generally monitored, BP believes that all information available to BP which could materially affect the valuation of the Company was provided to Goldman Sachs.

On March 25, 1987, Goldman Sachs advised BP that, based upon the then current conditions and the assumptions described below and assuming the accuracy and completeness of the information supplied by BP and publicly available information concerning the Company, it was the view of Goldman Sachs that the values of the Company's principal businesses in the acquisition market fell within the ranges shown in the following table. The ranges of values for the Company's businesses were derived by applying methodologies and assumptions which Goldman Sachs believed would be used by potential acquirors under then current market conditions. The analysis assumes a purchase of all of the outstanding Shares of the Company by a purchaser which does not subsequently elect to allocate its purchase price to the assets of the Company in order to increase the depreciable or depletable tax bases of such assets. In such a case a purchaser would forgo any tax benefits from such a write-up and assume a carryover tax basis in the assets acquired; at the same time, the Company would not incur any corporate level capital gains or recapture taxes.

SUMMARY OF RANGE OF VALUES

(In millions, except per Share amounts)

	Low	High
Oil and Gas Exploration and Production (a)	$7,150	$ 9,150
Pipeline Interests (b)	2,300	2,500
Refining and Marketing	2,100	2,600
Non-Petroleum Extractive Businesses	1,200	1,350
Chemicals and Industrial Products	400	500
Estimated Proceeds from Asset Sales (c)	300	400
Other (d)	(954)	(754)
Net Debt Position (e)	(3,217)	(3,217)
Total Value	$9,279	$12,529
Per Share (f)	$39.01	$ 52.67

(a) The value for offshore Lower 48 proved reserves (for which no estimates of oil and gas production, operating costs, capital expenditures and abandonment costs were available from BP) was set at $150 million utilizing analyses similar to those used in valuing the probable reserves, rather than a discounted cash flow analysis. The low and high values in the table have been reduced by $100 and $125 million, respectively, for an estimate of the present value of the future dividends to be paid on the NPRI Preferred Stock. In addition, Goldman Sachs were unable to determine the impact of two factors on the present value of the after-tax cash flows from the proved oil and gas reserves:

1. When the total proved reserves, as reported to BP by the Company, are compared to their respective decline curves, as estimated by BP to provide a schedule of future production, Goldman Sachs noted that such reserves are fully produced by the year 2010. Normal reserve decline characteristics suggest that a portion of the oil and gas reserves would be produced after 2010. In order to produce all reserves by 2010, the decline curve supplied by BP assumes a rate of production that is higher than would be the case for a more conventional reserve production profile. As a result, the present values in the table above are higher than those which would result if a portion of the reserves were produced beyond the year 2010, in accordance with normal reserve decline patterns.

2. In the absence of definitive information, Goldman Sachs have been unable to estimate the amount or timing of the utilization of the depletable and depreciable tax bases for the reserves and associated equipment; accordingly, the present values set forth above assume such tax bases are zero. To the extent such bases exist, such present values of such reserves would increase by the present values of the reduction in taxes on oil and gas income arising from the depletion and depreciation deductions available in future years.

Goldman Sachs have made certain estimates of the effect of both foregoing uncertainties under various assumptions which indicate that, assuming an aggregate $2 billion tax basis for all oil and gas properties, the net effect of these two factors on the present value of such reserves is probably minimal. In Goldman Sachs' analysis of a master limited partnership for the Company's interest in Prudhoe Bay which is discussed below, Goldman Sachs have assumed on BP's advice an aggregate tax basis thereof of $2 billion.

(b) Includes the Company's interest in TAPS, the Kuparuk pipeline and wholly- and partially-owned pipelines in the Lower 48.

(c) Estimated after tax proceeds of assets sales currently in progress or envisaged provided by BP.

(d) Capitalized cost of corporate overhead not allocated to the business segments valued separately above reduced by the proceeds of assumed exercise of employee stock options. BP has provided the estimate of yearly overhead cost used in performing this calculation.

(e) Net debt represents the excess of all liabilities over all assets not allocated to the business segments. Long-term debt and certain other liabilities were adjusted to estimated present value from historic book value in this calculation.

(f) Based on 234,712,645 Shares and Share-equivalents outstanding as of December 31, 1986 plus exercise of the options then outstanding to purchase 3,150,714 Shares.

As noted above, the value of the Company is extremely sensitive to assumptions as to future oil prices. In connection with their analysis, Goldman Sachs were requested by BP to exercise their independent judgment as to the appropriate oil price assumptions to make in this regard. Accordingly, the reserve valuations included in the Goldman Sachs analysis reflect Goldman Sachs' assessment of the oil price and rate of return scenarios likely to be utilized at the time the analysis was prepared by prospective purchasers in evaluating oil and gas properties for purchase in the acquisition market. Assumptions made in this context may differ from the oil price assumptions used by securities analysts (including those at Goldman Sachs) in estimating earnings of oil and gas companies over the next year or two for the purpose of formulating recommendations as to the purchase or sale of securities.

The Goldman Sachs analysis set forth above assumes West Texas Intermediate crude oil prices of $17, $18 and $19 per barrel, in nominal terms, in years 1987, 1988 and 1989, respectively, escalating 5% per year thereafter. If oil prices were to vary from this scenario, the range of values for the Company as a whole set forth in the table above could be materially affected.

The oil price scenarios used by BP and Goldman Sachs in their analyses are based on North Sea Brent crude oil ("Brent") and West Texas Intermediate crude oil ("WTI"), respectively. Each has used the crude oil market with which it is most familiar for generating its oil price scenario. Although the price differential between Brent and WTI varies, Brent and WTI generally trade in their markets at prices close to one another. Historically, Brent has traded at prices which are below WTI prices and generally such differential has been small. Alaskan North Slope crude oil sold on the Gulf Coast ("ANS Gulf Coast"), which is the type of crude oil which the Company uses for planning purposes, generally trades in its market at a modest discount below WTI and Brent prices.

The foregoing analysis of the Company reflects Goldman Sachs' judgment as to values in the acquisition market. Goldman Sachs also considered several alternatives with respect to the Company's interest in Prudhoe Bay, including a production payment financing and a master limited partnership ("MLP") which might be sold to the public or spun off to shareholders. Goldman Sachs advised BP that they believed that the greatest potential additional value above that shown in the table with respect to Prudhoe Bay might be achieved by spinning off to shareholders units of an MLP holding the Company's interest in such asset. However, Goldman Sachs advised BP that because of a variety of factors, including the unique characteristics of Prudhoe Bay production, the size of any such transaction relative to other similar MLPs, the probability that tax-exempt institutional holders might not wish to hold MLP units and possible structural impediments, they believed that there were significant uncertainties as to the ability of the Company to realize the potential additional value. In addition, any such additional value is difficult to determine in the absence of information relating to the Company's tax basis in Prudhoe Bay and, hence, the amount of taxes which would be payable by the Company in such a spinoff, and the unavailability to Goldman Sachs of certain additional information relating to Prudhoe Bay.

Goldman Sachs also considered a number of different alternatives relating to the Company's interest in TAPS, including the possibility of the creation of an MLP and a leveraged recapitalization in partnership form. Goldman Sachs advised BP that a leveraged recapitalization in partnership form appeared to be the most favorable of these alternatives, but that this alternative was unlikely to

create increased value above that shown in the table due to the estimated amount of taxes which would be payable by the Company in connection with such a transaction, based on the tax basis assumptions provided by BP, and that such a transaction might not be feasible in light of significant contractual, regulatory and other impediments.

Goldman Sachs also considered the possibility of a tax-free spinoff of the Company's refining and marketing operations to shareholders. Goldman Sachs advised BP that there was some uncertainty as to the additional value which might be created by such a transaction due to the availability of few comparable publicly traded entities, the cyclical character of such business, and the absence of complete information regarding the Company's current operations. Because refining and marketing operations have recently provided a cushion against down-swings in exploration and production earnings, BP and Goldman Sachs recognize that it might be imprudent for the Company to separate its refining and marketing operations from its exploration and production operations.

Goldman Sachs also considered separately the value of a potential unrealized capital loss of the Company but did not include the value of this potential tax loss in their acquisition analysis because it cannot be utilized until the Company realizes the loss and uses it to offset a recognized capital gain for U.S. federal income tax purposes. In March 1987, the Company indicated to BP that it is considering a restructuring and subsequent sale of the common stock of a subsidiary of the Company which, if effected, would enable the Company to utilize the benefit of such potential capital loss, provided that such loss were in fact realized.

Goldman Sachs advised BP that if all of the foregoing transactions were consummated notwithstanding the uncertainties outlined above and if the potential unrealized capital loss were in fact realized, under current conditions in the petroleum and securities markets the aggregate additional value in excess of the high end of the range of values for the entire Company shown in the table above which could be generated from these transactions would be in the range of approximately $1,410—$2,680 million, or approximately $5.93—$11.27 per Share.

Goldman Sachs further advised BP that, in light of insufficient information, the foregoing analysis does not reflect the potential for material additional expense or liability in certain areas, including (i) additional overhead costs; (ii) excess costs associated with repairs, disposals or abandonments relating to the operation of the Company's natural resource businesses; (iii) pending redetermination of condensate reserves in Prudhoe Bay from the oil-derived category to the gas-derived category in which the Company has a significantly lower share; (iv) drilling obligations not currently accrued; and (v) any other contingent liabilities.

A copy of Goldman Sachs' written report has been filed by the Purchaser as an Exhibit to its Rule 13e-3 Transaction Statement on Schedule 13E-3 filed with the Securities and Exchange Commission ("SEC") in connection with the Offer and may be examined and copied at the office of the SEC in Washington, D.C. as set forth under "THE COMPANY—Available Information". In addition, such report is available for inspection and copying at the principal executive offices of the Purchaser during its regular business hours by any interested holder of Shares or his representative who has been so designated in writing.

For information concerning Goldman Sachs' relationships with the Company and with BP, see "The Financial Advisors" below.

It should be noted that neither BP's nor Goldman Sachs' analysis of the Company places any value on natural gas reserves on the Alaskan North Slope because of the time delay inherent in any development of such reserves. Moreover, the value of natural gas is a function of oil prices and, at the range of energy prices considered by BP and Goldman Sachs, the costs of recovering and transmitting to market these gas reserves is likely to exceed their realizable market value. Additionally, BP and Goldman Sachs placed only a nominal value on the Company's potential involvement in any development in the Alaskan National Wildlife Refuge, as there can be no assurance that such area will be opened to drilling and development, that economically recoverable

quantities of hydrocarbons will be discovered and developed or that the Company will participate in any such activities. Finally, due to the lack of sufficient information to permit a valuation, BP and Goldman Sachs placed no value on any excess assets in the Company's pension plans which might revert to the Company upon their termination, any net value arising from a sale of the Company's headquarters building at a price exceeding the cost of relocating and providing office space for the employees located there and claims by the Company for U.S. federal income tax refunds for years ended prior to 1986.

In addition to BP's valuations, Goldman Sachs' analysis and certain non-public information concerning the Company, BP and the Purchaser considered, among other things, historical market prices of the Shares, comparisons of the Company's stock market performance and operating performance with those of other United States publicly-held integrated oil and gas companies, information concerning the Company's financial condition, the fact that BP beneficially owns approximately 55.4% of the outstanding Shares and Share-equivalents, and prices paid in other merger and acquisition transactions involving integrated oil and gas companies.

BP's internal valuations and Goldman Sachs' analysis referred to above were the most important factors considered by BP and the Purchaser in determining that the price per Share offered in the Offer was fair to the holders of Shares; BP and the Purchaser have not found it practicable to assign relative weights to each of the other factors considered by them as described above.

BP has not obtained from any outside party an opinion as to the fairness of the Offer to BP and its shareholders or to the minority shareholders of the Company. The Offer is not structured so that approval of at least a majority of the unaffiliated shareholders of the Company is required; however, in order for a Merger to be effected, more than a majority of the minority shareholders must have sold their Shares to the Purchaser pursuant to the Offer or otherwise or voted in favor of the Merger.

The Financial Advisors. In selecting Goldman Sachs to act as its financial advisors in connection with the Offer, BP considered primarily Goldman Sachs' reputation and experience in investment banking and mergers and acquisitions, as well as their experience with the oil and gas industry. Goldman Sachs have from time to time provided financial advice and other services to the BP Group and to the Company.

In the fall of 1985, Goldman Sachs reviewed at the request of the Company certain financial alternatives available to the Company to maximize value to holders of Shares, assuming the Company had no controlling shareholder. In connection with their review, Goldman Sachs were furnished certain non-public information about the Company, including, among other things, production estimates for Prudhoe Bay, separate financial statements for TAPS and a ten-year strategic plan prepared by the Company which projected net income for the Company on various price assumptions. The projections then deemed by Goldman Sachs to be the most reasonable were based on the assumption that the price of oil ranged from $28 per barrel in 1987 to $47.35 per barrel, in nominal terms, in 1995 and showed net income ranging from $2,002 million in 1987 to $3,270 million in 1995. Goldman Sachs were not requested to perform any independent examination or investigation of the Company's businesses or assets and did not attempt to verify any of the information supplied by the Company. In the course of this review, Goldman Sachs prepared analyses with respect to potential write-downs of asset values, common stock repurchase programs, increases in the Company's dividends, leveraged buyouts, sales to third parties and spinoffs to the Company's shareholders of certain of the Company's businesses as well as master limited partnerships for certain of the Company's oil and gas and coal reserves. Based on the information made available by the Company, certain of the foregoing analyses, the then current price of oil, the prevailing treatment of such actions under the then current tax laws and rates of return then prevailing in the acquisition market, Goldman Sachs prepared a preliminary liquidation analysis of the Company which showed an estimated aggregate after tax liquidation value of the Company in the range of $12,783 million to $19,283 million, or approximately $54.51 to $82.23 per Share on a fully diluted basis. At the time Goldman Sachs performed this preliminary liquidation analysis, the price

of oil (as evidenced by the spot price for WTI) ranged from approximately $28.70 per barrel to $30.80 per barrel. In light of intervening changes in oil prices and United States federal tax laws as well as the economic environment in general, Goldman Sachs believe that this estimated range of values is no longer reasonable.

Since March 1985, Goldman Sachs have received approximately $500,000 and approximately $900,000 from the BP Group (excluding the Company) and the Company, respectively, as compensation for investment banking services, including the underwriting of the Company's Swiss Franc Notes in February 1987. As of March 31, 1987, Goldman Sachs beneficially owned 40,000 Ordinary Shares of BP, had a net long position in June options for 39,800 Shares, and had net short positions of American Depositary Receipts representing 60,400 Ordinary Shares of BP and 26,800 Shares, which positions were incurred in the ordinary course of its trading activities prior to March 26, 1987.

BP and the Purchaser have agreed to pay Goldman Sachs, as compensation for their services as Dealer Managers and as financial advisors in connection with the Offer, a minimum fee of $1,000,000, which will be credited against a fee of $0.08 per Share acquired by the Purchaser pursuant to the Offer or a Merger. If in excess of approximately 60 million Shares are purchased pursuant to the Offer, it will be assumed for purposes of these arrangements that all outstanding Shares have been acquired by the Purchaser. In addition, BP and the Purchaser have agreed to reimburse Goldman Sachs for their reasonable out-of-pocket expenses, including the fees and expenses of their counsel, in connection with the Offer, and have agreed to indemnify Goldman Sachs against certain liabilities and expenses in connection with the Offer, including liabilities under the federal securities laws.

Position of the Company with Respect to the Offer. Following the announcement of the Offer by BP and the Purchaser on March 26, 1987, the Company announced that the proposed tender offer was being referred to the Special Committee, which would consider the Offer in due course.

Certain Effects of the Offer. The purchase of Shares pursuant to the Offer will reduce the number of Shares that might otherwise trade publicly and the number of holders of Shares and could adversely affect the liquidity and market value of the remaining Shares held by the public.

Depending upon the number of Shares purchased pursuant to the Offer, the Shares may no longer meet the requirements for continued listing on the New York Stock Exchange (the "NYSE"), although, in view of the number of Shares currently outstanding and the current number of holders of record of Shares, this result appears unlikely unless and until a Merger occurs. The NYSE's published guidelines indicate that it would consider delisting the Shares if, among other things, the number of record holders of 100 or more Shares should fall below 1,200, the number of publicly-held Shares (exclusive of holdings of officers and directors of the Company and members of their immediate families and other concentrated holdings of 10% or more) should fall below 600,000 or the aggregate market value of the publicly-held Shares should fall below $5 million. According to the published guidelines of the Midwest Stock Exchange (the "MSE"), it would consider delisting the Shares if, among other things, the number of publicly-held Shares (exclusive of management and other concentrated holdings) is less than 100,000 or there are fewer than 500 record holders. According to the Company, as of February 23, 1987 there were approximately 52,400 holders of record of Shares.

Even if the NYSE and MSE were to delist the Shares as a result of the Offer, it is possible that such Shares would continue to trade in the over-the-counter market and that price quotations would be reported through the National Association of Securities Dealers' Automated Quotation System, Inc. ("NASDAQ") or other sources. The extent of the public market for the Shares and the

availability of such quotations would, however, depend upon the number of holders of such Shares remaining at such time, the interest in maintaining a market in such Shares on the part of securities firms, the possible termination of registration of such Shares under the Securities Exchange Act of 1934 (the "Exchange Act") as described below, and other factors.

The Shares are presently "margin securities" as that term is defined under the rules of the Board of Governors of the Federal Reserve System, which has the effect, among other things, of allowing brokers to extend credit on the collateral of such Shares. Depending upon factors similar to those above regarding listing and market quotations, the Shares might no longer constitute "margin securities" and, therefore, could no longer be used as collateral for margin loans made by brokers.

The Shares are currently registered under the Exchange Act. Such registration of the Shares may be terminated upon application by the Company to the SEC if the Shares are not listed on a national securities exchange and if there are fewer than 300 record holders of the Shares. Termination of registration of the Shares under the Exchange Act would reduce the information required to be furnished by the Company to holders of Shares and would render inapplicable to the Company certain provisions of the Exchange Act, including requirements that the Company furnish shareholders with proxy materials regarding meetings of shareholders of the Company, requirements that the Company's officers, directors and 10% shareholders file certain reports concerning ownership of the Company's securities and provisions that any profit by such officers, directors and 10% shareholders through purchases and sales of the Company's equity securities within any six-month period may be recaptured by the Company. Termination of registration of the Shares under the Exchange Act could also deprive affiliates and any holders of "restricted securities" of the Company of their ability to dispose of their securities pursuant to Rule 144 promulgated under the Securities Act of 1933, as amended. In addition, if the Shares were de-registered, they would no longer be eligible for NASDAQ reporting or constitute 'margin securities". Even if the Shares are de-registered, however, the Exchange Act requirement that the Company file periodic reports would remain applicable as long as any of the Company's debt securities which are presently listed on the NYSE and registered under the Exchange Act remain so.

See "Purpose, Structure and Benefits of the Offer" for ... effect of the Offer and a Merger on the interest of the Purchaser and its affiliates in the Comp... net book value and net income.

Federal Income Tax Consequences to Shareholders. The receipt of cash pursuant to the Offer or a Merger will be a taxable transaction for federal income tax purposes and may also be a taxable transaction under applicable state, local and other tax laws. A s... shareholder will recognize gain or loss equal to the difference between such shareholder's adjusted tax basis in the Shares surrendered and the cash received therefor. Such gain or loss will be capital gain or loss if the Shares are capital assets in the hands of the shareholder and will be long-term if the holding period of the Shares is more than six months on the date the Purchaser accepts such Shares for payment pursuant to the Offer or on the date of a Merger, as the case may be.

THE FEDERAL INCOME TAX CONSEQUENCES SET FORTH ABOVE ARE FOR GENERAL INFORMATION ONLY AND ARE BASED UPON PRESENT LAW. EACH SHAREHOLDER IS URGED TO CONSULT HIS OWN TAX ADVISOR TO DETERMINE THE PARTICULAR TAX EFFECTS TO HIM OF THE OFFER OR A MERGER, INCLUDING THE APPLICATION AND EFFECT OF STATE, LOCAL AND OTHER TAX LAWS AND THE POSSIBLE EFFECTS OF CHANGES IN FEDERAL OR OTHER TAX LAWS. THE FOREGOING DISCUSSION MAY NOT BE APPLICABLE WITH RESPECT TO SHARES RECEIVED PURSUANT TO THE EXERCISE OF EMPLOYEE STOCK OPTIONS OR OTHERWISE AS COMPENSATION.

Litigation Relating to the Offer. On March 26, 1987, the day the Offer was announced, three shareholders of the Company brought a purported class action against the Company, BP, the Purchaser, BPI and eight directors of the Company in the Ohio Court of Common Pleas in Cleveland, alleging that the Offer and a Merger constitutes a fraud on the Company's shareholders other than the BP Group in that $70 per share is a grossly inadequate and unfair price. The BP Group regards the action as baseless.

MARKET PRICES OF AND DIVIDENDS ON SHARES

The Shares are principally traded and listed on the NYSE and the MSE. The following table sets forth the high and low sales prices on the NYSE Composite Tape and the dividends paid per Share for the calendar quarters indicated:

	Sales		Dividends
	High	Low	
1985:			
First Quarter	$48¼	$39⅝	$.70
Second Quarter	50⅛	45⅛	.70
Third Quarter	48	42¼	.70
Fourth Quarter	55¾	45½	.70
1986:			
First Quarter	$51¾	$43	$.70
Second Quarter	48	42¾	.70
Third Quarter	51⅜	40¼	.70
Fourth Quarter	51⅛	45¼	70
1987:			
First Quarter	$49¼	$72¼	$.70

On March 25, 1987, the last full day of trading prior to the announcement of the Purchaser's intention to make the Offer, the reported closing sales price per Share on the NYSE Composite Tape was $64¾. On March 31, 1987, the last full day of trading prior to the commencement of the Offer, the reported closing sales price per Share on the NYSE Composite Tape was $70¼. *Shareholders are urged to obtain a current market quotation for the Shares.*

THE COMPANY

Except as otherwise noted, the following information with respect to the Company was taken from the Company's publicly available information.

The Company and its subsidiaries are engaged in all phases of the petroleum business primarily in the United States, including the exploration for and production of crude oil and natural gas and the transportation, refining and marketing of crude oil and petroleum products. In addition, the Company is a major producer and marketer of copper, gold, silver and coal and a leading supplier of refractories, copper and brass mill products and process systems and equipment. The Company also manufactures and markets certain chemical products and products produced from ilmenite. The Company was incorporated in Ohio in 1870 and has its principal offices at 200 Public Square, Cleveland, Ohio 44114 (telephone (216) 586-4141).

The Company's oil and gas reserves and production facilities are located primarily in Alaska; its principal copper reserves and facilities are located in Utah; its principal coal reserves and mines are located in Illinois, Indiana, Kentucky and Pennsylvania; and its ilmenite mine and processing facilities are located in Quebec, Canada.

In 1986, the Company's petroleum businesses accounted for approximately 80% of the Company's revenues and substantially all of the Company's income before unusual items, interest, income taxes and an extraordinary item. Of the approximately 726,600 net barrels per day of crude oil and natural gas liquids produced by the Company in 1986, approximately 680,700 net barrels per day were attributable to production from Prudhoe Bay.

Historical Summary Financial Information. The following information concerning the Company and its subsidiaries for the five years ended December 31, 1986 has been derived from the Company's 1985 and 1986 Annual Reports. The summary below is qualified by reference to such documents and all the financial information and related notes contained therein.

THE STANDARD OIL COMPANY AND SUBSIDIARIES

SUMMARY CONSOLIDATED FINANCIAL INFORMATION

	Years ended December 31,				
	1982	1983	1984	1985	1986
	(Dollars in millions, except per Share amounts)				
Sales and operating revenue	$13,113	$11,490	$11,692	$13,002	$9,219
Excise taxes	377	468	559	816	803
Income before unusual items, interest, income taxes and extraordinary item	3,697	3,046	3,038	2,874	713
Unusual items and extraordinary item	—	(137)	(90)	(1,699)	(1,113)
Net income (loss)	1,879	1,512	1,488	308	(345)
Cash provided from operations	3,091	2,946	3,183	3,474	1,804
Capital expenditures	2,708	2,298	2,329	2,484	1,618
Total assets	16,016	16,362	17,487	17,508	15,955
Shareholders' equity	7,221	8,094	8,390	8,018	7,020
Long-term debt and capital lease obligations	4,192	3,850	3,577	3,305	3,276
Per Share or Share-equivalent					
Income before unusual items, interest, income taxes and extraordinary item	15.03	12.38	12.56	12.23	3.03
Unusual items and extraordinary item	—	(0.56)	(0.37)	(7.23)	(4.74)
Net income (loss)	7.63	6.14	6.14	1.31	(1.47)
Shareholders' equity	29.35	32.90	34.67	34.12	29.87
Cash dividends	2.55	2.60	2.65	2.80	2.80
Ratio of earnings to fixed charges	5.3	5.7	6.0	2.6	*
Ratio of debt to borrowed and invested capital	34%	30%	27%	27%	27%

* Earnings for 1986 were inadequate to cover fixed charges. The amount of the deficiency in total adjusted earnings was $679 million.

Projections. The Company does not, as a matter of course, make public projections as to its future performance or earnings. However, the Company has provided BP with the Company's Development Plan and Operating Plan, the former of which includes five-year projections of financial performance and the latter of which contains 1987 projections materially more favorable than those contained in the Development Plan.

The projected data in the table below, extracted from the Development Plan which was prepared in October 1986, is based upon the assumptions described below. The Development Plan noted that

over the five year period, the Company would generate excess cash totalling $2.2 billion while retiring debt of $1.4 billion; accordingly, if profitable opportunities to utilize the cash generated were not identified, the equity base would need to be reduced either by Share repurchases or increases in dividends.

Development Plan

	1987	1988	1989	1990	1991
	(Dollars in millions, except per Share amounts)				
Cash Generation					
Net Income	$ [illegible]	$ 845	$ 900	$ 900	$ 965
Non-Cash Charges	1,600	1,640	1,600	1,650	1,675
Divestitures	350	50	—	—	—
Total	2,610	2,535	2,500	2,550	2,640
Capital Expenditures	1,585	1,295	1,320	1,345	1,035
Cash Flow After Mandatory Debt Retirement	960	425	215	240	470
Earnings Per Share	2.80	3.60	3.85	3.85	4.10
Liquid Resources	1,550	1,760	2,100	2,460	3,040
Return on Borrowed and Invested Capital	7.2%	9.5%	10.3%	10.4%	11.3%
Net Debt/Capital Ratio*	29%	24%	19%	14%	5%

* Ratio of total debt less surplus financial assets to total debt less surplus financial assets plus shareholders' equity. Surplus financial assets are cash and marketable securities greater than $200 million.

In preparing the projections, the following assumptions, among others, were used:

1. Price per barrel of oil was assumed to be $15 for the entire period, adjusted for inflation at an assumed rate of 4% per annum. The Company also prepared five-year projections assuming a $20 per barrel (inflation adjusted) oil price for the entire period and assuming a scenario in which oil prices are at $10 per barrel (inflation adjusted) for three years and then $15 per barrel (inflation adjusted) for the next two years. In the former case, net income for the years 1987 to 1991 would be, in millions, $1,335, $1,680, $1,720, $1,720 and $1,820, respectively, and in the latter case, net income for such years would be, in millions, $(60), $70, $145, $875 and $890, respectively.

2. In light of the United States federal tax law changes which took effect at the beginning of 1987, the following main assumptions were adopted: effective combined state and federal tax rate of 42% for 1987 and 36% in 1988 to 1991; no investment tax credit for assets placed in service after January 1, 1986 (except for transition rule affected properties); and continuation of laws in effect in 1986 for depreciation and depletion.

3. General United States inflation is assumed to be 4% per annum, although not all business expenses are assumed to escalate at this level. Most notably, oil and gas exploration and production operating and capital expenses are assumed to increase at 2% per annum nominal during the period, due to deflation of prices as a result of oversupply of goods and services in the service and construction industry.

4. Financial projections have assumed maintenance of the Company's current dividend.

Shortly after preparation of the Development Plan in October 1986, the Company prepared the Operating Plan, which contains updated financial projections for 1987 based upon information unavailable at the time the Development Plan was prepared. The financial highlights of the Operating Plan are as follows:

1987 Operating Plan

(Dollars in millions, except per share amounts)

Operating Income	$1,541
Net Income	787
Earnings per Share	3.35
Capital Expenditures	1,574
Total Funds Generated	1,184
Borrowed and Invested Capital—Year-End	13,843
Liquid Resources—Year-End	1,777
Return on Average Capital Employed	6.5%
Net Debt/Capital Ratio*	25.8%

* Ratio of total debt less liquid resources to total debt less liquid resources plus shareholders' equity.

The 1987 projections contained in the Operating Plan are materially more favorable than the projections for 1987 earlier forecasted by the Development Plan, in part because certain assumptions, different from the assumptions made in the Development Plan, were made in preparation of the Operating Plan. It was assumed that the price of ANS Gulf Coast will average $14.90 per barrel in 1987, which is $0.25 per barrel higher than was assumed in the Development Plan, and that inflation would be 3% during 1987, as compared to the 4% assumed in the Development Plan. The $389 million improvement in operating income from the $1,152 million projected in the Development Plan is a result of: the higher operating income due to the increase in the price of Alaskan North Slope crude oil ($55 million), lower marine transportation costs ($90 million), an improved West Coast price ($45 million), increased Prudhoe Bay production ($30 million), lower production costs ($60 million) and other factors ($109 million).

The key targets outlined in the Operating Plan include:

(a) capital expenditure will be kept at or below about $1,575 million;

(b) crude oil production and refinery runs will be increased by 4% over 1986's level;

(c) exploration capital and expense will be kept at no more than $283 million, some $60 million less than 1986;

(d) a federal tax refund of about $830 million, resulting from ordinary losses arising from 1986 operating results, the abandonment of exploration leases, and the sale, at a tax loss, of coal properties in 1986, will be received in May 1987;

(e) restructuring plans, started in 1986, will be completed by the sale of the Industrial Products division and the reorganizations of Kennecott staff and Standard Oil Chemicals Company;

(f) corporate overheads will be reduced to $68 million, a 6% real decline from the 1986 level;

(g) a borrowing program of $500 million of long-term debt will be completed;

(h) a thorough examination of probable acquisition targets in exploration and downstream petroleum will be conducted. No funds were included in the Operating Plan for any acquisition;

(i) research and development expenditures will not exceed $97 million, a reduction of $28 million from the 1986 level. Of this amount, $24 million will be spent in corporate sponsored projects;

(j) the Sohio Oil retail efficiency program will improve station throughput by 2%; West Coast marine costs will be decreased by 12%, to 95 cents per barrel;

(k) exploration and production will add reserves of 40 million barrels of oil equivalent and resources by 65 million barrels of oil equivalent;

(l) the Utah Copper Division modernization project will be 90% completed by the end of 1987; and

(m) Standard Oil Chemicals will prove the low-cost technology for production of maleic anhydride and butanediol.

In March 1987, BP received a copy of the Company's Financial Report for March 1987 (the "March Report") which constitutes the Company's most recent update of the Operating Plan. The March Report was not received in time for it to be considered in connection with BP's internal valuations of the Company or Goldman Sachs' analysis. The Company also prepared a Financial Report for February 1987 which did not amend the projections contained in the Operating Plan in any material respect. The March Report contained the following projections for 1987:

March Report
(Dollars in millions, except per Share amount)

Operating Income	$ 1,680
Net Income	876
Earnings per Share Before Special Items	3.73
Capital Expenditures	1,637
Total Funds Generated	949
Borrowed and Invested Capital—Year-End	13,457
Liquid Resources—Year-End	1,422
Return on Average Capital Employed	7.3%
Adjusted Debt to Debt Plus Equity Ratio*	25.8%

*Excludes liquid resources except minimum requirement of $100 million.

The March Report reflects a revised crude oil price forecast along with other known events and forecasted changes of a material nature. It assumes that the ANS Gulf Coast price will average $15.95 per barrel in 1987, $1.05 higher than the Operating Plan. As a result, however, spot refining and marketing margins were forecasted for the year to be down 18% from those projected in the Operating Plan. Assuming an average ANS Gulf Coast price of $17.20 per barrel for the year (approximately the ANS Gulf Coast price at the time the March Report was prepared) net income and funds flow were forecasted at $1,004 million and $1,077 million, respectively.

The projections and targets noted above were prepared by the Company, and are included herein for the general information of the Company's shareholders. Because the estimates and assumptions underlying the above projections are inherently subject to significant economic and competitive uncertainties beyond the Company's control, there can be no assurance that the projected results can be realized, or that actual results will not be higher or lower than those projected. In particular, the projections are extremely sensitive to the actual price of crude oil. As noted in the Operating Plan, a change of $1 per barrel in the average price of oil during a year will change annual net income of the Company by between $125 million and $150 million. In addition, such projections and targets were not prepared with a view to public disclosure or compliance with

published guidelines of the SEC regarding projections, and are included in this Offer to Purchase only because the projections and targets were available to BP and the Purchaser prior to the time they made the decision to commence the Offer. BP and the Purchaser do not assume any responsibility for the accuracy of such projections and targets.

Certain Relationships with BP. Except as set forth herein and in Schedule I hereto, (i) neither the Purchaser nor any person controlling the Purchaser, nor any pension, profit sharing or similar plan of the Purchaser, nor, to the best knowledge of the Purchaser, any of the persons listed in Schedule I hereto or any associate or majority-owned subsidiary of any of the foregoing, (x) beneficially owns or has a right to acquire any Shares of the Company or (y) effected any transactions in the Shares during the past 60 days, (ii) there are no contracts, arrangements, understandings or relationships (whether or not legally enforceable) between the Purchaser, any person controlling the Purchaser, or, to the best knowledge of the Purchaser, any of the persons listed in Schedule I hereto, on the one hand, and any other person, on the other hand, with respect to securities of the Company, (iii) since January 1, 1984, there have been no transactions which would be required to be disclosed under the rules of the SEC between the Purchaser, any person controlling the Purchaser, any subsidiary of the Purchaser or, to the best knowledge of the Purchaser, any of the persons listed on Schedule I hereto, on the one hand, and the Company or any of its executive officers, directors or subsidiaries, on the other hand, (iv) since January 1, 1984, there have been no contacts, negotiations or transactions between the Purchaser, any person controlling the Purchaser, any subsidiary of the Purchaser or, to the best knowledge of the Purchaser, any of the persons listed in Schedule I hereto, on the one hand, and the Company or any of its subsidiaries, on the other hand, concerning a merger, consolidation or acquisition, a tender offer or other acquisition of securities, an election of directors, or a sale or other transfer of a material amount of assets, except that in 1986, the Company discussed with BP a possible acquisition on an unsolicited basis of an unaffiliated corporation, pursuant to which the Company and the unaffiliated corporation would merge and BP would acquire additional securities of the surviving corporation, which transaction BP determined not to pursue and (v) since January 1, 1985, there have been no contacts or negotiations concerning the matters referred to in (iv) above (x) between any affiliates of the Company or (y) between the Company or any of its affiliates and any other person unaffiliated with the Company who would have a direct interest in such matters.

The NPRI Preferred Stock which BPI owns in a subsidiary of the Company entitles BPI to preferential dividends equal to 75% of the net profits from oil and gas production from Prudhoe Bay leases multiplied by a fraction, of which the numerator is the number of net barrels per day of crude oil production from the Company's Prudhoe Bay leases between 600,000 net barrels per day and 1,050,000 net barrels per day, and the denominator is the total number of net barrels per day of crude oil production from such leases. Dividends paid on the NPRI Preferred Stock amounted to $44 million in 1986, $108 million in 1985 and $36 million in 1984. No dividends were paid on such stock during the two-year period ended September 30, 1984 because the Company's Prudhoe Bay production was below 600,000 net barrels per day. Also, no dividends are paid on such stock in respect of most of the approximately 13,500 net barrels per day being overlifted during the two-year period which commenced September 1, 1985 as a result of a 1985 arbitration decision.

The BP Group: (1) receives payments from the Company ($197 million in 1986, $309 million in 1985 and $260 million in 1984) and makes payments to the Company ($34 million in 1986, $33 million in 1985 and $24 million in 1984) for pipeline transportation through TAPS in accordance with tariffs filed by the Company and a subsidiary of BP with the Federal Energy Regulatory Commission (a refund of $69 million was paid by a subsidiary of BP in 1985 related to an agreement with the State of Alaska to have the tariff rate, both past and future, be governed by the same tariff methodology as that agreed to by all the other TAPS owners in 1985); (2) sells to the Company ($44 million in 1986, $84 million in 1985 and $67 million in 1984) and purchases from the Company ($124 million in 1986, $187 million in 1985 and $116 million in 1984) petroleum and chemicals in the

ordinary course of business at prevailing competitive prices; (3) is a party to an agreement which provides that, whenever TAPS operates at less than mechanical capacity, the crude oil produced by the Company or a subsidiary of BP from the North Slope will be shipped through the interests of their pipeline subsidiaries in TAPS in the approximate proportions that such ownership interests in TAPS bear to one another, so long as the pipeline subsidiary requesting such throughput protection maintains a competitive tariff rate; (4) contracts with the Company for services related to marine operation and exploration and production; and (5) is a party with the Company in a number of other transactions and arrangements in the ordinary course of business.

Available Information. The Company is subject to the information and reporting requirements of the Exchange Act and in accordance therewith is obligated to file reports and other information with the SEC relating to its business, financial statements and other matters. Certain information, as of particular dates, concerning the Company's directors and officers, their remuneration, stock options granted to them, the principal holders of the Company's securities, any material interests of such persons in transactions with the Company and other matters is required to be disclosed in proxy statements distributed to the Company's shareholders and filed with the SEC. Such reports, proxy statements and other information may be inspected at the SEC's offices at 450 5th Street, N.W., Judiciary Plaza, Washington, D.C. 20549, and should be available for inspection at the following regional offices of the Commission: Everett McKinley Dirksen Building, 219 South Dearborn Street, Chicago, Illinois 60604 and Jacob K. Javits Federal Building, 26 Federal Plaza, New York, New York 10278. Copies may be obtained, by mail, upon payment of the SEC's customary charges by writing to its principal office at 450 5th Street, N.W., Judiciary Plaza, Washington, D.C. 20549.

THE BP GROUP AND THE PURCHASER

BP was incorporated in 1909. Although the United Kingdom Government has since 1914 had a substantial shareholding interest (presently approximately 31.6%) BP has always been managed and operated as a private business enterprise. On March 18, 1987, the United Kingdom Government announced its intention to dispose of its interest in BP over the next twelve months, subject to market conditions.

The BP Group is the largest industrial concern in the United Kingdom, the second largest in Europe and the fifth largest in the non-communist world, on the basis of 1985 sales proceeds. It is engaged in all phases of the petroleum industry, including exploration, production, transportation, processing and marketing of crude oil, petroleum products and natural gas. The BP Group has pioneered the discovery and development of oil in several important oil producing areas, including Alaska and the North Sea, and is currently exploring in some thirty countries. It also has substantial investments in minerals and coal and investments in a range of other interests. Its activities, excluding the Company, are organized into eleven businesses: oil and gas exploration and production; oil supply, refining and marketing; chemicals; minerals; gas processing and marketing; coal; nutrition; detergents; ventures; computer and communications systems; and shipping. Overall control is exercised by a corporate head office. BP's principal executive offices are located at Britannic House, Moor Lane, London EC2Y 9BU.

Historical Summarized Financial Information of the BP Group. The following information concerning BP and its subsidiaries for the four years ended December 31, 1985 has been derived from the audited financial statements of the BP Group included within BP's annual reports on Form 20-F for the relevant years which have been filed with the SEC, as restated to conform with the accounting policies and presentation adopted in BP's 1985 Annual Report. Information for the year ended December 31, 1986 has been derived from the financial statements of the BP Group included within BP's report on Form 6-K for the month of March, 1987 which has been filed with the SEC. The

summary below is qualified by reference to such documents and all the financial information and related notes contained therein.

	Years ended December 31,				
	1982	1983	1984	1985	1986
			(In millions)		
Turnover	£29,314	£32,381	£37,933	£40,986	£27,171
Profit before taxation	2,305	2,597	3,455	3,613	958
Profit before extraordinary items	716	866	1,402	1,598	817
Profit for the year applicable to ordinary shares	711	1,030	1,103	668	498
Profit for the year applicable to ordinary shares as adjusted to accord with U.S. generally accepted accounting principles (1)	488	888	1,159	663	422
Funds generated from operations	3,657	4,587	5,734	6,070	4,461
Total assets	26,264	27,174	34,214	30,221	28,375
Capital expenditure including acquisitions	3,760	3,301	3,815	4,398	3,787

(1) The adjustments comprise (a) supplementary pension costs being charged over periods not exceeding 40 years rather than being charged against income when paid and the inclusion of an annual charge to meet unfunded pension obligations (£3 million charged against income in 1986); (b) certain leases being capitalized, with depreciation and interest charged accordingly, rather than lease rentals being expensed as incurred (£9 million credit to income in 1986); (c) deferred taxation being provided on a full deferral basis rather than only where timing differences are expected to reverse in the foreseeable future (£126 million charged against income in 1986); and (d) the effect on minority interests of these adjustments (£44 million credit to income in 1986).

BPI owns 98.6% of the common stock of the Purchaser and the remainder is owned by other wholly-owned subsidiaries of BP. The Purchaser was incorporated in Delaware in 1974 and adopted its present name in 1978. Through its subsidiary companies, the Purchaser is engaged in all phases of the petroleum industry other than refining and has interests in all other BP Group businesses except for detergents and shipping. Through wholly-owned subsidiaries, the Purchaser owns an undivided interest of approximately 16.7% in TAPS and an approximate 29% interest in the Kuparuk oilfield in Alaska. For the year ended December 31, 1986, the Purchaser's consolidated sales and net income amounted to approximately $4.2 billion and $76 million, respectively. Total assets and shareholders' equity at December 31, 1986 amounted to approximately $4.2 billion and $1.4 billion, respectively. All of the foregoing numbers are computed in accordance with U.K. generally accepted accounting principles. The principal executive offices of the Purchaser are located at 620 Fifth Avenue, New York, New York 10020, telephone (212) 887-9300.

THE TENDER OFFER

1. *Terms of the Offer.* Upon the terms and subject to the conditions of the Offer, the Purchaser will accept for payment and pay for all Shares which are validly tendered at or prior to the Expiration Date and not properly withdrawn in accordance with Section 4 of this Offer to Purchase. The term "Expiration Date" shall mean 12:00 Midnight, New York City time, on Tuesday, April 28, 1987, unless and until the Purchaser shall have extended the period of time for which the Offer is open, in which event the term "Expiration Date" shall mean the latest time and date at which the Offer, as so extended, shall expire. For a description of the Purchaser's rights to extend the period of time during which the Offer is open and to terminate or amend the Offer, see Section 7.

The Offer is not conditioned upon any minimum number of Shares being tendered.

The Offer to Purchase and related Letter of Transmittal are being mailed to record holders of Shares and are being furnished to brokers, banks and similar persons whose names, or the names of whose nominees, appear on the Company's shareholder list or, if applicable, who are listed as participants in a clearing agency's security position listing for subsequent transmittal to beneficial owners of Shares.

2. *Acceptance for Payment and Payment for Shares.* Upon the terms and subject to the conditions of the Offer (including, if the Offer is extended (see Sections 1 and 7 herein), the terms and conditions of any such extension), the Purchaser will accept for payment, and thereby purchase, all Shares validly tendered prior to the Expiration Date and not withdrawn as permitted by Section 4 as promptly as practicable after the Expiration Date. In addition, the Purchaser expressly reserves the right, in its sole discretion, to delay the acceptance for payment of or payment for Shares in order to comply, in whole or in part, with any applicable law. See Section 7. In all cases, payment for Shares purchased pursuant to the Offer will be made only after timely receipt by the Depositary of certificates for such Shares, or timely confirmation of book-entry transfer of such Shares into the Depositary's account at The Depository Trust Company, the Midwest Securities Trust Company, the Pacific Securities Depository Trust Company or the Philadelphia Depository Trust Company (collectively,the "Book-Entry Transfer Facilities") pursuant to the procedures set forth in Section 3 for book-entry transfer and the Letter of Transmittal (or facsimile copy thereof), properly completed and duly executed, and any other documents required by the Letter of Transmittal.

For purposes of the Offer, the Purchaser shall be deemed to have accepted for payment and purchased tendered Shares if, as and when the Purchaser gives oral or written notice to the Depositary, as agent for the tendering shareholders, of the Purchaser's acceptance of such Shares for payment pursuant to the Offer. Payment for Shares purchased pursuant to the Offer will be made through the Depositary which will act as agent for the tendering shareholders for the purpose of receiving payments from the Purchaser and transmitting such consideration to tendering shareholders. Under no circumstances will interest be paid by the Purchaser by reason of any delay in making such payment.

If any tendered Shares are not accepted for payment and paid for pursuant to the terms and conditions of the Offer for any reason (see Section 8), or if certificates are submitted for more Shares than are tendered, certificates for such unpurchased or untendered Shares will be returned, without expense to the tendering shareholder, or, in the case of Shares tendered by book-entry transfer with a Book-Entry Transfer Facility, such Shares will be credited to an account maintained with such Book-Entry Transfer Facility, as promptly as practicable following the expiration or termination of the Offer.

The Purchaser reserves the right to assign to one or more affiliates the right to purchase any of the tendered Shares pursuant to the Offer, but any such assignment will not relieve the Purchaser of its obligations under the Offer or prejudice the rights of tendering shareholders to receive payment for Shares validly tendered and accepted for payment and paid for pursuant to the Offer.

3. *Procedure for Tendering Shares.* In order for a holder of Shares to tender validly any of his Shares pursuant to the Offer, the Letter of Transmittal (or facsimile thereof), properly completed and duly executed, with any required signature guarantees and any other required documents, must be received by the Depositary at one of its addresses set forth on the back cover of this Offer to Purchase and either certificates representing such Shares must be delivered to the Depositary, along with the Letter of Transmittal or a facsimile copy thereof properly completed and duly executed, or such Shares must be tendered pursuant to the procedure for book-entry transfer set forth below (and a confirmation of receipt of such tender must be received by the Depositary), in each case prior to the Expiration Date, or the guaranteed delivery procedure set forth below must be complied with. Delivery of documents to a Book-Entry Transfer Facility does not constitute delivery to the Depositary.

The Depositary will establish accounts with respect to the Shares at the Book-Entry Transfer Facilities for purposes of the Offer within two business days after the date of this Offer to Purchase, and any financial institution that is a participant in any of the Book-Entry Transfer Facilities' systems may make book-entry delivery of such Shares by causing a Book-Entry Transfer Facility to transfer such Shares into the Depositary's account, in accordance with such Book-Entry Transfer Facility's procedure for such transfer. However, although delivery of Shares may be effected through book-entry transfer at a Book-Entry Transfer Facility, the Letter of Transmittal (or facsimile thereof), properly completed and duly executed, with any required signature guarantees and any other required documents, must, in any case, be received by the Depositary at one of its addresses set forth on the back cover page of this Offer to Purchase prior to the Expiration Date, or the guaranteed delivery procedure described below must be complied with.

Signatures on all Letters of Transmittal must be guaranteed by a member firm of a registered national securities exchange, a member of the National Association of Securities Dealers, Inc. (the "NASD"), or a commercial bank or trust company having an office or correspondent in the United States (an "Eligible Institution"), unless the Shares tendered thereby are tendered (i) by a registered holder of Shares who has not completed either the box entitled "Special Delivery Instructions" or the box entitled "Special Payment Instructions" on the Letter of Transmittal or (ii) for the account of an Eligible Institution. See Instruction 1 of the Letter of Transmittal. If the certificates are registered in the name of a person other than the signer of the Letter of Transmittal, or if payment is to be made or certificates for unpurchased Shares are to be issued to a person other than the registered holder, the certificates must be endorsed or accompanied by appropriate stock powers, in either case signed exactly as the name or names of the registered owner or owners appear on the certificates, with the signatures on the certificates or stock powers guaranteed as aforesaid. See Instruction 5 of the Letter of Transmittal. **THE METHOD OF DELIVERY OF CERTIFICATES FOR SHARES AND ALL OTHER REQUIRED DOCUMENTS IS AT THE OPTION AND RISK OF THE TENDERING SHAREHOLDER. IF SENT BY MAIL, REGISTERED MAIL WITH RETURN RECEIPT REQUESTED, PROPERLY INSURED, IS RECOMMENDED.**

Under the backup withholding rules, unless an exception applies under the applicable law and regulations, the Depositary will be required to withhold 20% of the gross proceeds otherwise payable to a shareholder or other payee pursuant to the Offer unless the shareholder or other payee provides his tax identification number (employer identification number or social security number) and certifies that such number is correct and that he is not subject to backup withholding as a result of failure to report all interest or dividends. Therefore, unless such an exception exists and is proved in a manner satisfactory to the Depositary, each shareholder and, if applicable, each other payee should complete and sign the Substitute Form W-9 included as part of the Letter of Transmittal, so as to provide the information and certification necessary to avoid backup withholding.

If a shareholder desires to tender Shares pursuant to the Offer and such shareholder's certificates are not immediately available or time will not permit all required documents to reach the Depositary prior to the Expiration Date, or if the procedure for book-entry transfer cannot be completed on a timely basis, such Shares may nevertheless be tendered if all of the following conditions are met:

(i) such tender is made by or through an Eligible Institution;

(ii) a properly completed and duly executed Notice of Guaranteed Delivery substantially in the form provided by the Purchaser herewith is received by the Depositary as provided below prior to the Expiration Date; and

(iii) the certificates for all tendered Shares, in proper form for transfer and delivery, or confirmation of a book-entry transfer of such Shares into the Depositary's account at a Book-Entry Transfer Facility, in each case together with the Letter of Transmittal or facsimile copy thereof, properly completed and duly executed, with any required signature guarantees and any other required documents, are received by the Depositary within eight NYSE trading days after the date of such Notice of Guaranteed Delivery.

The Notice of Guaranteed Delivery may be delivered by hand or transmitted by telegram, telex, facsimile transmission or mail to the Depositary and must include a signature guarantee by an Eligible Institution in the form set forth in such Notice.

In all cases, payment for Shares tendered and purchased pursuant to the Offer will be made only after timely receipt by the Depositary of certificates for such Shares or confirmation of a book-entry transfer of such Shares into the Depositary's account at a Book-Entry Transfer Facility, the Letter of Transmittal or facsimile copy thereof, properly completed and duly executed, and any other required documents.

The tender of Shares pursuant to any of the procedures described above will constitute an agreement between the tendering shareholder and the Purchaser upon the terms and subject to the conditions of the Offer.

By executing the Letter of Transmittal, a tendering shareholder irrevocably appoints, with respect to the Shares purchased by the Purchaser, designees of the Purchaser as his proxies, with full power of substitution, in the manner set forth in the Letter of Transmittal, to vote and exercise all of the shareholder's rights with respect to the Shares tendered by such shareholder pursuant to such Letter of Transmittal and accepted for payment by the Purchaser and with respect to any and all other Shares or other securities issued or issuable in respect of such Shares on or after March 25, 1987. Such appointment is effective when, and only to the extent that, the Purchaser deposits the Offer consideration for such Shares with the Depositary.

Upon the effectiveness of such appointment, all prior proxies given by such shareholder with respect to such Shares (and any such other Shares or other securities) will be, without further action, revoked and no subsequent proxies may be given by such shareholder (and, if given, will not be deemed effective). The designees of the Purchaser will, with respect to the Shares for which the appointment is effective, be empowered to exercise all voting and other rights of such shareholder as they, in their sole discretion, may deem proper at any annual, special or adjourned meeting of the Company's shareholders, by written consent in lieu of any such meeting or otherwise.

All questions as to the form of documents and the validity, eligibility (including time of receipt) and acceptance for payment of any tender of Shares will be determined by the Purchaser, in its sole discretion, which determination shall be final and binding. The Purchaser reserves the absolute right to reject any or all tenders of any particular Shares determined by it not to be in proper form or the acceptance for payment or payment of which may, in the opinion of the Purchaser's counsel, be unlawful. The Purchaser also reserves the absolute right to waive any of the conditions of the Offer, and the Purchaser reserves the right to waive any defect or irregularity in the tender of any particular Shares. The Purchaser's interpretation of the terms and conditions of the Offer (including the Letter of Transmittal and the instructions thereto) will be final. No tender of Shares will be deemed to have been validly made until all defects and irregularities have been cured or waived. Neither BP, the Purchaser, the Dealer Managers, the Depositary, the Information Agent nor any other person will be under any duty to give notification of any defects or irregularities in tenders or incur liability for failure to give any such notification.

4. *Withdrawal Rights.* Tenders of Shares made pursuant to the Offer are irrevocable, except that Shares tendered pursuant to the Offer may be withdrawn at any time prior to the Expiration Date, and, unless theretofore accepted for payment by the Purchaser pursuant to the Offer, may also be withdrawn at any time after May 30, 1987.

For a withdrawal to be effective, a written, telegraphic, telex or facsimile notice of withdrawal must be timely received by the Depositary at one of its addresses set forth on the back cover of this Offer to Purchase. Any notice of withdrawal must specify the name of the tendering shareholder, the number of Shares to be withdrawn and the names in which the certificate(s) evidencing such Shares are registered, if different from that of the tendering shareholder. If certificate(s) evidencing such Shares have been delivered to the Depositary, then, prior to the release of such certificate(s), the serial numbers shown on such certificate(s) must be submitted and the signature(s) on the notice

of withdrawal must be guaranteed by an Eligible Institution, unless such Shares have been tendered for the account of any Eligible Institution. If Shares have been tendered pursuant to the procedures for book-entry transfer as set forth in Section 3, any notice of withdrawal must also specify the name and number of the account at a Book-Entry Transfer Facility to be credited with the withdrawn Shares.

All questions as to the form and validity (including time of receipt) of any notice of withdrawal will be determined by the Purchaser, in its sole discretion, which determination shall be final and binding. None of the Purchaser, BP, the Dealer Managers, the Depositary, the Information Agent or any other person will be under any duty to give notification of any defects or irregularities in any notice of withdrawal or incur any liability for failure to give such notification. Any Shares properly withdrawn will be deemed not validly tendered for purposes of the Offer; however, tendered Shares withdrawn pursuant to the withdrawal rights described above may be re-tendered by following the procedures described in Section 3, at any subsequent time prior to the expiration of the Offer.

If the Purchaser extends the Offer, is delayed in its purchase of Shares or is unable to purchase such Shares pursuant to the Offer for any reason, then, without prejudice to the Purchaser's rights under this Offer, the Depositary may, nevertheless, on behalf of the Purchaser, retain such tendered Shares and such Shares may not be withdrawn except to the extent that tendering shareholders are entitled to withdrawal rights as set forth in this Section 4.

5. *Source and Amount of Funds.* The total amount required by the Purchaser to purchase all of the outstanding Shares, other than Shares owned by BPI, pursuant to the Offer and to pay the related fees and expenses is estimated to be approximately $7.5 billion. The Purchaser will obtain approximately one-third of such amount from the BP Group's existing internal resources, which funds will be on-lent to the Purchaser by other members of the BP Group on arm's length terms. The balance will be obtained partly from borrowings by BPI under a four year credit facility to be entered into with a number of commercial banks, which borrowings would then be on-lent to the Purchaser on arm's length terms, and partly from the issuance by the Purchaser of commercial paper in the United States, backed by the Purchaser's own ability to borrow directly under the credit facility. Total borrowings under the credit facility may not exceed $5 billion. Borrowings by BPI under the credit facility may be made for periods of one, three or six months at an interest rate per annum equal to LIBOR plus 0.125% for the applicable period (or such other rate or rates as may be offered by the banks under a bidding system provided in the credit facility). Borrowings by the Purchaser under the credit facility may be made for periods of up to 10 days at Morgan Guaranty Trust Company of New York's prime rate as in effect from time to time. BPI will be obligated to pay a facility fee of 0.125% per annum of the aggregate commitments under the credit facility, regardless of the amounts outstanding thereunder from time to time. All amounts owing under the credit facility and the Purchaser's commercial paper program will be guaranteed by BP. Morgan Guaranty Trust Company of New York will be designated Agent for the banks under the credit facility. It is intended that these borrowings will be repaid or replaced from funds generated by the BP Group and by means of restructuring or refinancing of existing facilities, including the credit facility.

6. *Certain Legal Matters.* Pursuant to requirements of The Stock Exchange in London, the Offer must be approved by a resolution passed on a show of hands by a majority of the shareholders present and voting or, if a poll is called for, by a majority of the votes cast, at a meeting of BP's shareholders (the "Shareholder Approval"). Such meeting will be convened for April 22, 1987 and the Offer is conditioned upon receipt of the Shareholder Approval. BP has received in a form acceptable to it the consent of H.M. Treasury of the United Kingdom pursuant to Section 482, Income and Corporation Taxes Act 1970, to the issuance of certain debt by the Purchaser and the exchange of the Shares and the Special Stock held by BPI for shares of common stock of the Purchaser and clearance from The Inland Revenue of the United Kingdom that the transfer of the Shares and the Special Stock held by BPI to the Purchaser in exchange for shares of common stock of the Purchaser will not result in a tax on chargeable gains under the provisions of Section 87, Capital Gains Tax Act, 1979.

Except as set forth in this Section, the Purchaser is not aware of any license or other regulatory permit which appears to be material to the business of the Company and which might be adversely affected by the Purchaser's acquisition of the Shares pursuant to the Offer, or of any approval or clearance by or reference to any domestic or foreign governmental or administrative agency that would be required prior to the acquisition of the Shares by the Purchaser pursuant to the Offer. The Company and its subsidiaries conduct operations in several foreign countries. Should any such approval or other action be required, it is the Purchaser's present intention that such approval or action would be sought or taken. The Purchaser is unable to predict whether it may determine that it is required to delay the purchase of Shares pursuant to the Offer pending such approval or other action. There can be no assurance that any such approval or action, if needed, would be obtained or, if obtained, that it will be obtained without substantial conditions or that adverse consequences might not result to the Company's business or that certain parts of the Company's business might not have to be disposed of in the event that such approvals were not obtained or such other actions were not taken, any of which could cause the Purchaser to elect to terminate the Offer pursuant to Section 7. The Purchaser's obligation under the Offer to accept for payment and pay for Shares is subject to certain conditions. See Section 8.

State Takeover Laws. A number of states have adopted takeover laws which purport, to varying degrees, to be applicable to attempts to acquire securities of corporations which are incorporated in such states or which have substantial assets, security holders, principal executive offices or principal places of business therein. To the extent that certain provisions of these state takeover laws purport to apply to the Offer, the Purchaser believes that such laws conflict with federal law and constitute an unreasonable burden on interstate commerce. In this regard, it should be noted that the Supreme Court of the United States in *Edgar v. MITE Corporation* held that the Illinois Business Takeover Act was unconstitutional.

The Purchaser has not complied with any state takeover laws and the Company has agreed not to seek application of any such laws to the Offer without first giving the Purchaser at least 48 hours' notice. The Purchaser has commenced litigation in federal district courts in Louisiana, Nebraska, Ohio and South Carolina seeking declaratory judgments that certain provisions of certain takeover statutes in such states are unconstitutional as applied to the Offer and injunctions against their enforcement in connection with the Offer. In three of these actions (Nebraska, Louisiana and South Carolina), there have been entered orders of the court under agreement by the parties, pursuant to which no action will be taken by the relevant state officials to seek enforcement of such laws, except on at least 48 hours', or in the case of Louisiana 72 hours', notice to the Purchaser. In the fourth action (Ohio), the relevant state official has been enjoined by court order from taking any such enforcement steps prior to April 13, 1987; in that action, the Purchaser intends to seek a further order preventing any such enforcement action subsequent to April 13, 1987. Should any government official or third party seek to apply any state takeover law to the Offer, the Purchaser and BP will take such action as then appears desirable and currently anticipate that they will contest the validity of such law in appropriate court proceedings. The Purchaser notes that the Ohio Control Share Acquisition Act, which requires shareholder approval of certain "control share acquisitions", does not apply to the Offer as BP and its subsidiaries already own Shares and Share-equivalents entitling them to a majority of the voting power of the Company.

If it is asserted that any state takeover laws apply to the Offer and it is not determined by an appropriate court that such laws do not apply or are invalid as applied to the Offer, the Purchaser might be required to file certain information with, or receive approvals from, the relevant state authorities. In addition, if enjoined, the Purchaser might be unable to accept for payment any Shares tendered pursuant to the Offer, or be delayed in consummating the Offer. In such case, the Purchaser may not be obligated to accept for payment any Shares tendered. See Section 8.

7. *Extension of the Offer; Termination; Amendment.* The Purchaser expressly reserves the right, in its sole discretion, at any time, or from time to time, to extend the period of time during which the Offer is open by giving oral or written notice of such extension to the Depositary and by

making a public announcement thereof, such announcement in the case of an extension to be issued no later than 9:00 A.M., New York City time, on the next business day after the previously scheduled Expiration Date. There can be no assurance that the Purchaser will exercise its right to extend the Offer. If the Purchaser shall decide, in its sole discretion, to increase or decrease the price offered in the Offer to holders of Shares and, at the time that notice of such increase or decrease is first published, sent or given to holders of Shares in the manner specified below, the Offer is scheduled to expire at any time earlier than the tenth business day from the date that such notice is first so published, sent or given, the Offer will be extended until the expiration of such ten business day period. For purposes of the Offer, a "business day" means any day other than a Saturday, Sunday or federal holiday and consists of the time period from 12:01 A.M. through 12:00 Midnight, New York City time.

The Purchaser also reserves the right to postpone acceptance for payment of or, regardless of whether such Shares were theretofore accepted for payment, payment for any Shares to be purchased by it pursuant to the Offer and to amend the Offer or to terminate the Offer and not accept for payment any Shares not theretofore accepted for payment, or paid for, upon the occurrence of any of the conditions specified in Section 8 herein, by giving oral or written notice of such postponement, amendment or termination to the Depositary and by making a public announcement thereof.

Without limiting the manner in which the Purchaser may choose to make any public announcement of the termination or any extension or amendment of the Offer, except as may otherwise be required by the SEC's rules, the Purchaser will have no obligation to publish, advertise or otherwise communicate any such public announcement, other than by making a release to the Dow Jones News Service or, in the case of an announcement of an extension of the Offer, by issuing a notice of such extension by press release or other public announcement, which notice shall be issued no later than 9:00 A.M., New York City time, on the next business day after the previously-scheduled Expiration Date of the Offer.

8. *Certain Conditions of the Offer.* Notwithstanding any other provisions of the Offer, the Purchaser shall not be required to accept for payment or pay for any Shares, may postpone the acceptance for payment of and payment for Shares tendered and to be purchased by it, and may terminate or amend the Offer as provided in Section 7 herein if the Shareholder Approval is not obtained or if, on or after March 25, 1987 and prior to the time of payment for any such Shares (whether or not any Shares have theretofore been accepted for payment or paid for pursuant to the Offer), any of the following events shall occur:

(a) there shall be threatened, instituted or pending any action or proceeding before any domestic or foreign court or governmental agency or other regulatory or administrative agency or commission, (i) challenging the acquisition by the Purchaser of the Shares, seeking to restrain or prohibit the making or consummation of the Offer or a Merger, seeking to obtain any material damages or otherwise directly or indirectly relating to the transactions contemplated by the Offer or a Merger, (ii) seeking to prohibit or restrict the Purchaser's (or any of its affiliates') ownership or operation of any material portion of its or the Company's business or assets, or to compel the Purchaser (or any of its affiliates) to dispose of or hold separate all or any material portion of its or the Company's business or assets as a result of the Offer or a Merger, (iii) seeking to make the purchase of, or payment for, some or all of the Shares or a Merger illegal, (iv) resulting in a delay in the ability of the Purchaser to accept for payment or pay for some or all of the Shares or to effect a Merger, (v) imposing material limitations on the ability of the Purchaser effectively to acquire or hold or to exercise full rights of ownership of the Shares, including, without limitation, the right to vote the Shares purchased by it on all matters properly presented to the shareholders of the Company or (vi) which, in the sole judgment of the Purchaser, otherwise is reasonably likely to materially adversely affect the Company or any of its subsidiaries or affiliates or the value of the Shares; or

(b) any statute, rule, regulation, order or injunction shall be sought, proposed, enacted, promulgated, entered, or deemed applicable to the Offer, or any other action shall have been taken, proposed or threatened, by any government or governmental authority (or any political subdivision thereof) or by any court, domestic or foreign, which, in the sole judgment of the Purchaser, is likely, directly or indirectly, to result in any of the consequences referred to in subsection (a)(i) through (a)(vi) of this Section 8; or

(c) any change (or any condition, event or development involving a prospective change) shall have occurred or be threatened in the business, properties, assets, liabilities, capitalization, shareholders' equity, financial condition, results of operations or prospects of the Company or any of its subsidiaries which, in the sole judgment of the Purchaser, is or may be materially adverse to the Company and its subsidiaries, taken as a whole, or the Purchaser shall become aware of any fact (including, but not limited to, any such change, condition, event or development) which, in the sole judgment of the Purchaser, has or may have materially adverse significance with respect to the Company and its subsidiaries, taken as a whole, or the value of the Shares; or

(d) there shall have occurred (i) any general suspension of, or limitation on prices for, trading in securities on the NYSE or The Stock Exchange in London, (ii) the declaration of a banking moratorium or any suspension of payments in respect of banks in the United States or the United Kingdom, (iii) the commencement of a war, armed hostilities or other international or national calamity directly or indirectly involving the United States or the United Kingdom, (iv) any limitation by any governmental authority or any other event which, in the sole judgment of the Purchaser, might affect the extension of credit by banks or other lending institutions in the United States or the United Kingdom, (v) a material change in United States or United Kingdom currency exchange rates or a suspension of or limitation on the markets therefor or (vi) in the case of any of the foregoing existing at the time of the Offer, any material acceleration or worsening thereof; or

(e) the Company shall have (i) conducted its business or those of its subsidiaries other than in the ordinary course or made any material changes in the operations of the Company or its subsidiaries; (ii) amended or otherwise changed the articles of incorporation or code of regulations (or similar constituent documents) of the Company or any of its subsidiaries; (iii) issued or sold, or authorized for issuance or sale, additional shares of any class of capital stock, or securities convertible into such shares of capital stock or rights or warrants with respect to shares of capital stock, except pursuant to the Company's existing employee stock option plans; (iv) declared, set aside, made or paid any dividend or other distribution with respect to its capital stock, other than regular quarterly cash dividends at a rate not in excess of $0.70 per Share; (v) altered or proposed to alter any material term of any outstanding security; (vi) redeemed, purchased or otherwise acquired, directly or indirectly, any of its capital stock; (vii) entered into any other agreement or arrangement with any other party or with the officers or other members of its management that in the sole discretion of the Purchaser could adversely affect the value of the Shares; or (viii) shall have reached an agreement or understanding with BP and the Purchaser that the Offer be terminated or amended, or the Purchaser and BP shall have entered into a definitive agreement to acquire the Company;

which in the sole judgment of the Purchaser with respect to each and every matter referred to above and regardless of the circumstances (including any action or inaction by the Purchaser or BP) giving rise to any such condition, makes it inadvisable to proceed with the Offer or with such acceptance for payment or payment.

The foregoing conditions are for the sole benefit of the Purchaser and may be asserted by the Purchaser regardless of the circumstances giving rise to any such conditions (including any action or inaction by the Purchaser or BP) or may be waived by the Purchaser in whole or in part at any time and from time to time in its sole discretion. The failure by the Purchaser at any time to exercise

any of the foregoing rights shall not be deemed a waiver of any such right and each such right shall be deemed a continuing right which may be asserted at any time and from time to time.

9. *Dividends and Distributions.* If, on or after March 25, 1987, the Company should split, combine or otherwise change the Shares or its capitalization, or disclose that it has taken any such action, then the Purchaser, in its discretion, may make such adjustments in the Offer consideration and other terms of the Offer as it deems appropriate to reflect such split, combination or other change.

If, on or after March 25, 1987, the Company should declare or pay any cash or stock dividend, stock split or other distribution on, or issue any rights with respect to, the Shares, payable or distributable to shareholders of record on a date occurring on or after March 25, 1987 and prior to the transfer to the name of the Purchaser or its nominees or transferees on the Company's stock transfer records of the Shares purchased pursuant to the Offer, then (i) the Offer consideration payable by the Purchaser pursuant to the Offer shall be reduced by the amount of any such cash dividend or distribution and (ii) the whole of any non-cash dividend, distribution or right (including additional Shares or rights as aforesaid) received by a tendering shareholder shall be required to be promptly remitted and transferred by the tendering shareholder to the Depositary for the account of the Purchaser, accompanied by appropriate documentation of transfer. Pending such remittance or appropriate assurance thereof, the Purchaser shall be, subject to applicable law, entitled to all rights and privileges as owners of any such non-cash dividend, distribution or right and may withhold the entire purchase price or deduct from the purchase price the amount or value thereof, as determined by the Purchaser in its discretion.

10. *Fees and Expenses.* Goldman Sachs are acting as Dealer Managers in connection with the Offer and have provided certain financial advisory services to BP and the Purchaser in connection therewith. See "SPECIAL FACTORS—The Financial Advisors" for information with respect to Goldman Sachs' fees for such services.

The Purchaser has retained D.F. King & Co., Inc. to act as the Information Agent in connection with the Offer. The Information Agent may contact holders of Shares by mail, telephone, telex, telegraph and personal interviews and may request brokers, dealers and other nominee shareholders to forward the Offer materials to beneficial owners of Shares. The Information Agent will receive reasonable and customary compensation for such services, plus reimbursement of out-of-pocket expenses.

The Purchaser has retained The Chase Manhattan Bank, N.A. to act as the Depositary, and will pay the Depositary reasonable and customary compensation for its services in connection with the Offer, plus reimbursement of out-of-pocket expenses, and will indemnify the Depositary against certain liabilities and expenses in connection therewith, including liabilities under the federal securities laws.

The estimated costs and fees in connection with the Offer are as follows:

Bank Commitment and Other Fees	$ 7,250,000
SEC Filing Fee	1,468,233
Financial Advisory and Dealer Managers' Fees	8,600,000
Accounting Fees	35,000
Legal Fees	3,500,000
Printing and Mailing	750,000
Depositary's Fees	450,000
Information Agent's Fees	200,000
Miscellaneous	246,767
Total	$22,500,000

The Purchaser will not pay any fees or commissions to any broker or dealer or any other person for soliciting tenders of Shares pursuant to the Offer. The Purchaser will, upon request, reimburse brokers, dealers, commercial banks and trust companies for customary handling and mailing expenses incurred in forwarding the Offer to their customers. The Company has not paid and will not be responsible for paying any of the above expenses.

11. *Miscellaneous.* The Offer is not being made to nor will tenders be accepted from or on behalf of holders of Shares in any jurisdiction in which the Offer or the acceptance thereof would not be in compliance with the laws of any such jurisdiction. However, the Purchaser may in its sole discretion take such action as it may deem necessary to make the Offer in any such jurisdiction and extend the Offer to holders of Shares in such jurisdiction.

In those jurisdictions where securities laws require the Offer to be made by a licensed broker or dealer, the Offer shall be deemed to be made on behalf of the Purchaser by Goldman Sachs.

No person has been authorized to give any information or make any representation on behalf of the Purchaser not contained in this Offer to Purchase and, if given or made, such information or representation must not be relied upon as having been authorized.

The Purchaser has filed with the SEC a Rule 13e-3 Transaction Statement on Schedule 13E-3 and a Tender Offer Statement on Schedule 14D-1, together with exhibits in each case, pursuant to Rule 13e-3 and Regulation 14D, respectively, of the General Rules and Regulations under the Exchange Act, which require the furnishing of certain additional information with regard to the Offer. Such statements and any amendments thereto, including exhibits, may be examined and copies may be obtained at the same places and in the same manner as set forth in "THE COMPANY— Available Information", except that such information is not available at the regional offices of the SEC.

BP North America Inc.

April 1, 1987

DIRECTORS AND EXECUTIVE OFFICERS OF THE BRITISH PETROLEUM COMPANY p.l.c. AND CERTAIN RELATED COMPANIES

Set forth below are the name, business address, citizenship, present principal occupation or employment and other material occupations, positions, offices or other employments held during the last five years of each director and executive officer of BP or the Purchaser.

Name and Business Address	Citizenship	Present Principal Occupation or Employment and Other Material Occupations, Offices or Employments Held During the Last Five Years
Sir Peter Walters*	Great Britain	Chairman of BP since 1981. Director of National Westminster Bank PLC in London, England since 1981; director on various civic and cultural boards.
P. G. Cazalet*	Great Britain	Deputy Chairman of BP since 1986. Managing Director of BP since 1981. Director of: The Peninsular & Oriental Steam Navigation Co. (shipping) in London, England since 1980; the De La Rue Company p.l.c. (printing) in London, England since 1983; Kuwait Oil Company Ltd. (oil) in London, England from 1978 to 1982; Iranian Oil Participants Ltd. (oil) in London, England from 1978 to 1982.
B.R.R. Butler*	Great Britain	Managing Director of BP since 1986. Chief Executive of BP Exploration Company Ltd., 1981-1986.
P. J. Gillam*	Great Britain	Managing Director of BP since 1981. Director of the Consolidated Petroleum Co. (oil) in London, England from 1981 to 1982.
R. Malpas*	Great Britain	Managing Director of BP since 1983. Director of the BOC Group plc (gas manufacturer) in London, England since 1981; President of Halcon SD Group Inc. (chemicals) in New York, New York from 1979 to 1983.
D.A.G. Simon*	Great Britain	Managing Director of BP since 1986. Chief Executive of BP Oil International Ltd. from 1982 to 1986. Director of The Plessey Company plc (telecommunications; electronics; semi conductors) in Ilford, England since 1986.

* Business address is The British Petroleum Company plc., Britannic House, Moor Lane, London EC2Y 9BU.

Name and Business Address	Citizenship	Present Principal Occupation or Employment and Other Material Occupations, Offices or Employments Held During the Last Five Years
Sir Lindsay Alexander..... Lloyds Bank p.l.c. 71 Lombard Street London EC 3P 3BS	Great Britain	Deputy Chairman of Lloyds Bank p.l.c. in London, England since 1985. Chairman and Director of Lloyds Bank International Limited since prior to 1981. Director of: BP since 1975; Hawker Siddeley Group plc (aircraft) in London, England since 1981; Wellington Underwriting Agencies (insurance) in London, England since 1986; Overseas Containers Holdings Ltd. (shipping business) in London, England from 1976 to 1982; Jebsens Drilling Ltd. (oil drilling) in London, England from prior to 1981 to 1986; Ocean Transport & Trading plc (shipping) in Liverpool England from 1959 to 1986. Director or officer of various civic and cultural boards.
Lord Barber ..... Standard Chartered PLC 38 Bishopsgate London EC2N 40E	Great Britain	Chairman of Standard Chartered PLC (a commercial bank) in London, England since 1974. Director of: BP since 1979; Bridon plc (rope manufacturer) in Doncaster, England from prior to 1981 to 1983; and Midland and International Bank P.L.C. (banking) in London from prior to 1981 to 1983.
The Honorable Sir John Baring ..... Barings plc 8 Bishopsgate London EC2N 4AE	Great Britain	Chairman of Barings plc (merchant bankers) in London, England since 1985 and Director of Barings plc since prior to 1981. Director of: BP since 1982; Iterate Investments Ltd. (investment company) in London since 1976; Abbotstone Dealing Ltd. (share dealing) in London, England since 1970; Bank of England in London, England since 1983; Houmout Farms Ltd. (farming) in London, England since 1983; Royal Insurance Co. Ltd. in London, England from 1964 to 1982; Dunlop Holdings Ltd. (rubber and tires) in London, England from 1981 to 1984; G.B.S. (Galleries) Ltd. (art dealers) in London, England from 1968 to 1985; Outwich Investment Trust Ltd. (trust company) in London, England from 1965 to 1986; Stratton Investment Co. Ltd. (investment company) in London from 1966 to February 1987.

Name and Business Address	Citizenship	Present Principal Occupation or Employment and Other Material Occupations, Offices or Employments Held During the Last Five Years
Sir Campbell Fraser Scottish Television p.l.c. 7 Adelaide Street London WC2N 4LZ	Great Britain	Chairman of Scottish Television p.l.c. (television company) in London, England since 1975. Director of: BP since 1978; BAT Industries p.l.c. (tobacco and financial services) in London, England since 1980; Bridgewater Paper Co. Ltd. (paper manufacturer) in London, England since 1984; Tandem Computers Ltd. (computers) in London, England since 1985; Green Park Health Care p.l.c. (nursing homes) in Haywards Heath since 1985; Dunlop Holdings Ltd. (rubber company) in London, England from 1969 to 1983.
Sir James Menter	Great Britain	Retired. Director of: BP since 1976; TI Group p.l.c. (tube manufacturers) in Birmingham, England from 1981 to 1986; Steetley p.l.c. (minerals) in Worksop, England from 1981 to 1985.
Sir Alastair Pilkington Pilkington Brothers P.L.C. Prescott Road St. Helens Merseyside WA10 3TT	Great Britain	President of Pilkington Brothers P.L.C. (glass manufacturers) in Merseyside, England since 1985. Director of: BP since 1976; Pilkington Brothers p.l.c. from 1955 to 1985.
P. Sheehy BAT Industries p.l.c. Windsor House 50 Victoria Street London SW1H 0NL	Great Britain	Chairman of BAT Industries p.l.c. (tobacco and financial services) since 1982. Director of BP since 1984.
Ian G. S. Hartigan*	Great Britain	Director and President of the Purchaser since June, 1986. Director, The Standard Oil Company, Cleveland, Ohio and BP Canada, Inc., Calgary, Alberta since June, 1986. From April, 1984 to June, 1986, Managing Director, BP Shipping Limited, London. Prior to April, 1984, Executive Vice President of Stolt Nielsen, Inc.
Stephen O. Jaeger*	United States	Director and Senior Vice President, Finance and Accounts of the Purchaser since July, 1985. From June, 1984 to July, 1985, BP International in London in planning and financial positions. From February, 1981 to July, 1985, Vice President of the Purchaser.
Edward T. Libbey*	Great Britain	Director and Senior Vice President, Business Support of the Purchaser since July, 1986. From March, 1986 to July, 1986, Vice President, Corporate Planning of the Purchaser. From February, 1984 to March 1986, Production Manager, BP's Rotterdam Refinery. From March, 1981 to February, 1984, BP's Trade and Supply Department, London.

* Business address is BP North America Inc., 620 Fifth Avenue, New York, New York 10020.

Name and Business Address	Citizenship	Present Principal Occupation or Employment and Other Material Occupations, Offices or Employments Held During the Last Five Years
Peter A. Aslet*	Great Britain	Vice President, Investor Relations of the Purchaser since December, 1985. Manager of U.S. Investor Relations, Imperial Chemical Industries Inc. (chemicals) in New York, from August 1983 to December 1985. Vice President and Manager of Imperial Chemicals Industries PLC from June 1978 to August 1983.
Keith S. Cheverallis*	Great Britain	Vice President, Money Market Operations of the Purchaser since October, 1985. Vice President and chief dealer of Hill Samuel International Banking Corporation (finance) in New York from October, 1983 to October, 1985. Foreign exchange dealer of certain banks of Switzerland in London from June, 1982 to October, 1983.
Paul Chinn*	Great Britain	Vice President, Information Systems of the Purchaser since July, 1986. From May, 1980 to July, 1986, BP Petroleum Development, Dyce, Scotland, computer services manager.
Thomas W. Everitt*	United States	Vice President, Administration of the Purchaser since August, 1986. From August, 1985 to August, 1986, BP Exploration, London, Personnel officer. From November, 1981 to August 1985, BP North America Petroleum, Houston, Personnel Manager.
Richard C.H. Genochio*	Great Britain	Vice President, Government and Public Affairs of the Purchaser since March, 1984. From January, 1980 to March, 1984, BP, London, Government and Public Affairs, Assistant Manager, Europe.
George H. Hagle*	United States	Vice President and General Counsel of the Purchaser since January, 1981.
Glyn D. Harris*	Great Britain	Vice President, Corporate Finance of the Purchaser since October, 1985. From August, 1983 to October, 1985, BP, London, finance coordination and management. From July, 1981 to August, 1983, BP Canada, Calgary, Manager, Finance and Accounts.
Peter C. Mostyn*	Great Britain	Vice President, Nutrition of the Purchaser since January, 1984. From April, 1978 to January, 1984, BP Nutrition, London, specialist.
S. Mark Seymour*	United States	Vice President, Taxation of the Purchaser since August, 1984. Senior tax counsel of Union Pacific Corp. (transportation) in New York since 1980.
John C. Gore*	United States	Vice President, Government Affairs of the Purchaser since March, 1986. Director, Federal Government Affairs of the Purchaser from January, 1980 to March, 1986.

* Business address is BP North America Inc., 620 Fifth Avenue, New York, New York 10020.

Sir Peter Walters and Mr. B.R.R. Butler presently own 1,000 Shares and 150 Shares, respectively, and they presently intend to tender such Shares pursuant to the Offer.

Section 1701.85 of the Ohio General Corporation Law

1701.85 RELIEF FOR DISSENTING SHAREHOLDERS; QUALIFICATION; PROCEDURES—(A)(1) A shareholder of a domestic corporation is entitled to relief as a dissenting shareholder in respect of the proposals in sections 1701.74, and 1701.76, and 1701.84 of the Revised Code, only in compliance with this section.

(2) If the proposal must be submitted to the shareholders of the corporation involved, the dissenting shareholder shall be a record holder of the shares of the corporation as to which he seeks relief as of the date fixed for the determination of shareholders entitled to notice of a meeting of the shareholders at which the proposal is to be submitted, and such shares shall not have been voted in favor of the proposal. Not later than ten days after the date on which the vote on such proposal was taken at the meeting of the shareholders, the shareholder shall deliver to the corporation a written demand for payment to him of the fair cash value of the shares as to which he seeks relief, stating his address, the number and class of such shares, and the amount claimed by him as the fair cash value of the shares.

(3) The dissenting shareholder entitled to relief under division (c) of section 1701.84 of the Revised Code in the case of a merger pursuant to section 1701.80 of the Revised Code and a dissenting shareholder entitled to relief under division (e) of section 1701.84 of the Revised Code in the case of a merger pursuant to section 1701.801 of the Revised Code shall be a record holder of the shares of the corporation as to which he seeks relief as of the date on which the agreement of merger was adopted by the directors of that corporation. Within twenty days after he has been sent the notice provided in section 1701.80 or 1701.801 of the Revised Code, the shareholder shall deliver to the corporation a written demand for payment with the same information as that provided for in division (A)(2) of this section.

(4) In the case of a merger or consolidation, a demand served on the constituent corporation involved constitutes service on the surviving or the new corporation, whether served before, on, or after the effective date of the merger or consolidation.

(5) If the corporation sends to the dissenting shareholder, at the address specified in his demand, a request for the certificates representing the shares as to which he seeks relief, he, within fifteen days from the date of the sending of such requests, shall deliver to the corporation the certificates requested, in order that the corporation may forthwith endorse on them a legend to the effect that demand for the fair cash value of such shares has been made. The corporation promptly shall return such endorsed certificates to the shareholder. Failure on the part of the shareholder to deliver such certificates terminates his rights as a dissenting shareholder, at the option of the corporation, exercised by written notice sent to him within twenty days after the lapse of the fifteen-day period, unless a court for good cause shown otherwise directs. If shares represented by a certificate on which such legend has been endorsed are transferred, each new certificate issued for them shall bear a similar legend, together with the name of the original dissenting holder of such shares. Upon receiving a demand for payment from a dissenting shareholder who is the record holder of uncertificated securities, the corporation shall make an appropriate notation of the demand for payment in its shareholder records. If uncertificated shares for which payment has been demanded are to be transferred, any new certificate issued for the shares shall bear the legend required for certificated securities as provided in this paragraph. A transferee of the shares so endorsed, or of uncertificated securities where such notation has been made, acquires only such rights in the corporation as the original dissenting holder of such shares had immediately after the service of a demand for payment of the fair cash value of the shares. Such request by the corporation is not an admission by the corporation that the shareholder is entitled to relief under this section.

(B) Unless the corporation and the dissenting shareholder shall have come to an agreement on the fair cash value per share of the shares, as to which he seeks relief the shareholder or the corporation, which in case of a merger or consolidation may be the surviving or the new corporation, within three months after the service of the demand by the shareholder, may file a complaint in the court of common pleas of the county in which the principal office of the corporation which issued such shares is located, or was located at the time when the proposal was adopted by the shareholders of the corporation, or, if the proposal was not required to be submitted to the shareholder, was approved by the directors. Other dissenting shareholders, within the period of three months may join as plaintiffs, or may be joined as defendants in any such proceeding, and any two or more such proceedings may be consolidated. The complaint shall contain a brief statement of the facts, including the vote and the facts entitling the dissenting shareholder to the relief demanded. No answer to such complaint is required. Upon the filing of the complaint the court, on motion of the petitioner, shall enter an order fixing a date for a hearing on the complaint, and requiring that a copy of the complaint and a notice of the filing and of the date for hearing be given to the respondent or defendant in the manner in which summons is required to be served or substituted service is required to be made in other cases. On the day fixed for the hearing on the complaint or any adjournment thereof, the court shall determine from the complaint and from such evidence as is submitted by either party whether the shareholder is entitled to be paid the fair cash value of any shares and, if so, the number and class of such shares. If the court finds that the shareholder is so entitled, the court may appoint one or more persons as appraisers to receive evidence and to recommend a decision on the amount of the fair cash value. The appraisers have such power and authority specified in the order of their appointment. The court thereupon shall make a finding as to the fair cash value of a share, and shall render judgment against the corporation for the payment of it, with interest at such rate and from such date as the court considers equitable. The costs of the proceeding, including reasonable compensation to the appraisers to be fixed by the court, shall be assessed or apportioned as the court considers equitable. The proceeding is a special proceeding, and final orders in it may be vacated, modified, or reversed on appeal pursuant to the Rules of Appellate Procedure and, to the extent not in conflict with those rules, Chapter 2505. of the Revised Code. If, during the pendency of any proceeding instituted under this section, a suit or proceeding is or has been instituted to enjoin or otherwise to prevent the carrying out of the action as to which the shareholder has dissented, the proceeding instituted under this section shall be stayed until the final determination of the other suit or proceeding. Unless any provision in division (D) of this section is applicable, the fair cash value of the shares as agreed upon by the parties or as fixed under this section shall be paid within thirty days after the date of final determination of such value under this division the effective date of the amendment to the articles, or the consummation of the other action involved, whichever occurs last. Upon the occurrence of the last such event, payment shall be made immediately to a holder of uncertificated securities entitled to such payment. In the case of holders of shares represented by certificates, payment shall be made only upon and simultaneously with the surrender to the corporation of the certificates representing the shares for which such payment is made.

(C) If the proposal was required to be submitted to the shareholders of the corporation, fair cash value as to those shareholders shall be determined as of the day prior to that on which the vote by the shareholders was taken, and, in the case of a merger pursuant to section 1701.80 or 1701.801 of the Revised Code, fair cash value as to shareholders of a constituent subsidiary corporation shall be determined as of the day before the adoption of the agreement of merger by the directors of the particular subsidiary corporation. The fair cash value of a share for the purposes of this section, is the amount that a willing seller, under no compulsion to sell, would be willing to accept, and that a willing buyer, under no compulsion to purchase, would be willing to pay, but in no event shall the fair cash value exceed the amount specified in the demand of the particular shareholder. In computing such fair cash value, any appreciation or depreciation in market value resulting from the proposal submitted to the directors or to the shareholders shall be excluded.

(D) The right and obligation of a dissenting shareholder to receive such fair cash value and to sell such shares as to which he seeks relief, and the right and obligation of the corporation to purchase such shares and to pay fair cash value of them terminates if:

(1) Such shareholder has not complied with this section, unless the corporation by its directors waives such failure;

(2) The corporation abandons, or is finally enjoined or prevented from carrying out, or the shareholders rescind their adoption, of the action involved;

(3) The shareholder withdraws his demand, with the consent of the corporation by its directors;

(4) The corporation and the dissenting shareholder shall not have come to an agreement as to the fair cash value per share, and neither the shareholder nor the corporation shall have filed or joined in a complaint under division (B) of this section within the period provided.

(E) From the time of giving the demand, until either the termination of the rights and obligations arising from it or the purchase of the shares by the corporation, all other rights accruing from such shares, including voting and dividend or distribution rights, are suspended. If during the suspension, any dividend or distribution is paid in money upon shares of such class, or any dividend, distribution, or interest is paid in money upon any securities issued in extinguishment of or in substitution for such shares, an amount equal to the dividend, distribution, or interest which, except for the suspension, would have been payable upon such shares or securities, shall be paid to the holder of record as a credit upon the fair cash value of the shares. If the right to receive fair cash value is terminated otherwise than by the purchase of the shares by the corporation, all rights of the holder shall be restored and all distributions which, except for the suspension, would have been made shall be made to the holder of record of the shares at the time of termination.

Facsimile copies of the Letter of Transmittal will be accepted. The Letter of Transmittal, certificates for Shares and any other required documents should be sent or delivered by each shareholder or his broker, dealer, commercial bank, trust company or other nominee to the Depositary at one of its addresses set forth below:

The Depositary

THE CHASE MANHATTAN BANK, N.A.

By Hand:
14th Floor
67 Broad Street
New York, New York

By Mail:
P.O. Box 396
Bowling Green Station
New York, New York 10274

By Overnight Courier:
c/o Mellon Securities Transfer Services
Fort Lee Executive Park
1 Executive Drive
Fort Lee, N.J. 07024
Att: Reorganization Department
Fifth Floor

By Facsimile:
(201) 592-4475
or
(212) 558-6896

By TWX:
7109904992

Any questions or requests for assistance or additional copies of this Offer to Purchase and the Letter of Transmittal may be directed to the Information Agent or the Dealer Managers at their respective telephone numbers and locations listed below. Shareholders may also contact their local broker, dealer, commercial bank or trust company for assistance concerning the Offer.

The Information Agent

D.F. KING & CO., INC.

One North LaSalle Street	60 Broad Street	9841 Airport Boulevard
Chicago, Illinois 60602	New York, NY 10004	Los Angeles, CA 90045
(312) 236-5881 (Collect)	(212) 269-5550 (Collect)	(213) 215-3860 (Collect)

Call Toll-Free 1-800-223-3604 Except in New York Call Toll-Free 1-800-522-5001.

The Dealer Managers

Goldman, Sachs & Co.
85 Broad Street
New York, New York 10004

Call Toll-Free 1-800-323-5678
Except in New York
Call Collect (212) 902-1000.

EXHIBIT (a)(2)

(Leave Blank)

Ticket No. _____

THE OFFER AND WITHDRAWAL RIGHTS WILL EXPIRE AT 12:00 MIDNIGHT, NEW YORK CITY TIME, ON TUESDAY, APRIL 28, 1987, UNLESS EXTENDED.

LETTER OF TRANSMITTAL

To Tender Shares of Common Stock of

The Standard Oil Company

at

$70 Net Per Share

Pursuant to the Offer to Purchase Dated April 1, 1987

by

BP North America Inc.

an indirect wholly-owned subsidiary of

The British Petroleum Company p.l.c.

To the Depositary:

THE CHASE MANHATTAN BANK, N.A.

For Information Call:

(201) 592-4432
(201) 592-4430

By Hand:
14th Floor
67 Broad Street
New York, New York

By Mail:
P.O. Box 396
Bowling Green Station
New York, New York 10274

By Overnight Courier:
c/o Mellon Securities Transfer Services
Fort Lee Executive Park
1 Executive Drive
Fort Lee, N.J. 07024
Att: Reorganization Department
Fifth Floor

By Facsimile:
(201) 592-4475
or
(212) 558-6896

By TWX:
7109904992

Delivery of this instrument to an address other than as set forth above or transmission of instructions via a facsimile or telex number other than the one listed above will not constitute a valid delivery.

This Letter of Transmittal is to be completed by shareholders either if certificates are to be forwarded herewith or if delivery is to be made by book-entry transfer to the account maintained by the Depositary at The Depository Trust Company, the Midwest Securities Trust Company, the Pacific Securities Depository Trust Company or the Philadelphia Depository Trust Company (collectively, the "Book-Entry Transfer Facilities") pursuant to the procedures set forth under "THE TENDER OFFER—Procedure for Tendering Shares" in the Offer to Purchase. Shareholders whose certificates are not immediately available or who cannot cause their certificates, or confirmation of the book-entry transfer of their Shares into the Depositary's account at a Book-Entry Transfer Facility ("Book-Entry Confirmation"), and all other documents required hereby to be received by the Depositary prior to the Expiration Date must tender their Shares according to the guaranteed delivery procedure set forth under "THE TENDER OFFER—Procedure for Tendering Shares" in the Offer to Purchase. See Instruction 2. Delivery of documents to a Book-Entry Transfer Facility does not constitute delivery to the Depositary.

☐ **CHECK HERE IF TENDERED SHARES ARE BEING DELIVERED BY BOOK-ENTRY TRANSFER MADE TO THE ACCOUNT MAINTAINED BY THE DEPOSITARY WITH A BOOK-ENTRY TRANSFER FACILITY AND COMPLETE THE FOLLOWING:**

Name of Tendering Institution _____
Check box of Book-Entry Transfer Facility:
☐ The Depository Trust Company
☐ Midwest Securities Trust Company
☐ Pacific Securities Depository Trust Company
☐ Philadelphia Depository Trust Company

Account Number _____

Transaction Code Number _____

☐ **CHECK HERE IF TENDERED SHARES ARE BEING DELIVERED PURSUANT TO A NOTICE OF GUARANTEED DELIVERY PREVIOUSLY SENT TO THE DEPOSITARY AND COMPLETE THE FOLLOWING:**

Name(s) of Registered Owner(s) _____

Date of Execution of Notice of Guaranteed Delivery _____

Name of Institution which Guaranteed Delivery _____

DESCRIPTION OF SHARES TENDERED			
Name(s) and Address(es) of Registered Holder(s) (Please fill in, if blank)	**Certificate(s) Tendered (Attach additional list if necessary)**		
	Certificate Number(s)*	**Total Number of Shares Represented by Certificate(s)***	**Number of Shares Tendered****
	Total Shares		

* Need not be completed by shareholders tendering by book-entry transfer.
** Unless otherwise indicated, it will be assumed that all Shares described above are being tendered. See Instruction 4.

NOTE: SIGNATURES MUST BE PROVIDED BELOW.

PLEASE READ CAREFULLY THE ACCOMPANYING INSTRUCTIONS.

Gentlemen:

The undersigned hereby tenders to BP North America Inc., a Delaware corporation (the "Purchaser") and an indirect wholly-owned subsidiary of The British Petroleum Company p.l.c., a company organized under the laws of England, the above described shares of Common Stock, without par value ("Shares"), of The Standard Oil Company, an Ohio corporation (the "Company"), pursuant to the Purchaser's offer to purchase any and all outstanding Shares at a price of $70 per Share, net to the seller in cash, upon the terms and subject to the conditions set forth in the Offer to Purchase dated April 1, 1987 (the "Offer to Purchase"), receipt of which is hereby acknowledged, and in this Letter of Transmittal (which together constitute the "Offer").

Subject to, and effective upon, acceptance for payment of the Shares tendered herewith in accordance with the terms and subject to the conditions of the Offer, the undersigned hereby sells, assigns, and transfers to, or upon the order of, the Purchaser all right, title and interest in and to all the Shares that are being tendered hereby (and any and all other Shares or other securities issued or issuable in respect thereof on or after March 25, 1987) and irrevocably constitutes and appoints the Depositary the true and lawful agent and attorney-in-fact of the undersigned with respect to such Shares (and any such other Shares or securities) with full power of substitution (such power of attorney being deemed to be an irrevocable power coupled with an interest), to (a) deliver certificates for such Shares (and any such other Shares or securities), or transfer ownership of such Shares on the account books maintained by a Book-Entry Transfer Facility, together in either such case with all accompanying evidences of transfer and authenticity, to or upon the order of the Purchaser upon receipt by the Depositary, as the undersigned's agent, of the purchase price (adjusted, if appropriate, as provided in the Offer to Purchase), (b) present such Shares (and any such other Shares or securities) for transfer on the books of the Company and (c) receive all benefits and otherwise exercise all rights of beneficial ownership of such Shares (and any such other Shares or securities), all in accordance with the terms of the Offer.

The undersigned hereby irrevocably appoints K. J. M. Walder and P. B. P. Bevan, and each of them, and any other designees of the Purchaser, the attorneys and proxies of the undersigned, each with full power of substitution, to vote in such manner as each such attorney and proxy or his substitute shall in his sole discretion deem proper, and otherwise exercise all of the undersigned's rights (including pursuant to written consent) with respect to, all the Shares tendered hereby which have been accepted for payment by the Purchaser prior to the time of such vote or exercise of rights (and any and all other Shares or securities issued or issuable in respect thereof on or after March 25, 1987). This proxy is irrevocable and is granted in consideration of, and is effective upon, the deposit by the Purchaser with the Depositary of the purchase price for such Shares in accordance with the terms of the Offer. Effectiveness of this proxy shall automatically revoke all prior proxies granted by the undersigned at any time with respect to such Shares (and any such other Shares or securities) and no subsequent proxies will be given by the undersigned (and, if given, will be deemed not to be effective) with respect thereto.

The undersigned hereby represents and warrants that the undersigned has full power and authority to tender, sell, assign and transfer the Shares tendered hereby (and any and all other Shares or other securities issued or issuable in respect thereof on or after March 25, 1987) and that, when the same are accepted for payment by the Purchaser, the Purchaser will acquire good and unencumbered title thereto, free and clear of all liens, restrictions, charges and encumbrances and the same will not be subject to any adverse claim. The undersigned, upon request, will execute and deliver any additional documents deemed by the Depositary or the Purchaser to be necessary or desirable to complete the sale, assignment and transfer of the Shares tendered hereby (and any such other Shares or securities).

All authority herein conferred or agreed to be conferred in this Letter of Transmittal shall not be affected by, and shall survive, the death or incapacity of the undersigned and any obligation of the undersigned hereunder shall be binding upon the successors, assigns, heirs, executors, administrators and legal representatives of the undersigned. Except as stated in the Offer to Purchase, this tender is irrevocable.

The undersigned understands that tenders of Shares pursuant to any one of the procedures described under "THE TENDER OFFER—Procedure for Tendering Shares" in the Offer to Purchase and in the Instructions hereto will constitute a binding agreement between the undersigned and the Purchaser upon the terms and subject to the conditions of the Offer.

Unless otherwise indicated herein under "Special Payment Instructions", please issue the check for the purchase price and/or any certificates for Shares not tendered or not accepted for payment in the name(s) of the undersigned. Similarly, unless otherwise indicated under "Special Delivery Instructions," please mail the check for the purchase price and/or return any certificates for Shares not tendered or not accepted for payment (and accompanying documents, as appropriate) to the undersigned at the address shown below the undersigned's signature. In the event that both the Special Payment Instructions and the Special Delivery Instructions are completed, please issue the check for the purchase price and/or any certificates for Shares not tendered or not accepted for payment in the name of the person or persons so indicated and deliver said check and/or return such certificates to the address so indicated. Shareholders delivering Shares by book-entry transfer may request that any Shares not accepted for payment be returned by crediting the account maintained at a Book-Entry Transfer Facility as such shareholder may designate by making an appropriate entry under "Special Payment Instructions". The undersigned recognizes that the Purchaser has no obligation pursuant to the Special Payment Instructions to transfer any Shares from the name of the registered holder thereof if the Purchaser does not accept for payment any of the Shares so tendered.

SPECIAL PAYMENT INSTRUCTIONS
(See Instructions 1, 5, 6 and 7)

To be completed ONLY if certificates for Shares not tendered or not purchased and/or the check for the purchase price of Shares purchased are to be issued in the name of someone other than the undersigned, or if Shares delivered by book-entry which are not purchased are to be returned by credit to an account maintained at a Book-Entry Transfer Facility other than that designated above.

Issue ☐ check ☐ certificates to:

Name _____
(Please Print)

Address _____

_____
(Include Zip Code)

(See Substitute Form W-9 on reverse side)

_____
(Tax Identification or Social Security Number)

☐ Credit Shares delivered by book-entry transfer and not purchased to the Book-Entry Transfer Facility account set forth below:

Check appropriate box:

- ☐ The Depository Trust Company
- ☐ Midwest Securities Trust Company
- ☐ Pacific Securities Depository Trust Company
- ☐ Philadelphia Depository Trust Company

_____
(Account Number)

SPECIAL DELIVERY INSTRUCTIONS
(See Instructions 1 and 7)

To be completed ONLY if certificates for Shares not tendered or not purchased and/or the check for the purchase price of Shares purchased are to be sent to someone other than the undersigned, or to the undersigned at an address other than that shown above.

Mail ☐ check ☐ certificates to:

Name _____
(Please Print)

Address _____

_____
(Include Zip Code)

(See Substitute Form W-9 on reverse side)

_____
(Tax Identification or Social Security Number)

SIGN HERE
(Please Complete Substitute Form W-9 on Reverse Side)





(Signature(s) of Owner(s))

Dated _____, 1987

(Must be signed by registered holder(s) exactly as name(s) appear(s) on stock certificate(s) or on a security position listing or by person(s) authorized to become registered holder(s) by certificates and documents transmitted herewith. If signature is by trustees, executors, administrators, guardians, attorneys-in-fact, agents, officers of corporations or others acting in a fiduciary or representative capacity, please provide the capacity in which such person is acting. See Instruction 5.)

Name(s) _____

_____

(Please Print)

Capacity (full title) _____

Address _____

_____

(Include Zip Code)

Area Code and
Telephone Number _____

Tax Identification or
Social Security No. _____

(Complete Substitute Form W-9 on reverse)

Guarantee of Signature(s)
(If Required—See Instructions 1 and 5)

Name of Firm _____

Authorized
Signature _____

Dated _____, 1987

INSTRUCTIONS
Forming Part of the Terms and Conditions of the Offer

1. *Guarantee of Signatures.* No signature guarantee on this Letter of Transmittal is required if (i) this Letter of Transmittal is signed by the registered holder of the Shares (which term, for purposes of this document, shall include any participant in a Book-Entry Transfer Facility whose name appears on a security position listing as the owner of Shares) tendered herewith, unless such holder has completed either the box entitled "Special Payment Instructions" or the box entitled "Special Delivery Instructions" on the reverse hereof or (ii) such Shares are tendered for the account of a member firm of a registered national securities exchange, a member of the National Association of Securities Dealers, Inc. or a commercial bank or trust company having an office or correspondent in the United States (an "Eligible Institution"). In all other cases, all signatures on this Letter of Transmittal must be guaranteed by an Eligible Institution. See Instruction 5.

2. *Delivery of Letter of Transmittal and Certificates.* This Letter of Transmittal is to be completed by shareholders either if certificates are to be forwarded herewith or if tenders are to be made pursuant to the procedures for delivery by book-entry transfer set forth under "THE TENDER OFFER—Procedure for Tendering Shares" in the Offer to Purchase. Certificates for all physically tendered Shares, or any Book-Entry Confirmation, as the case may be, as well as a properly completed and duly executed Letter of Transmittal (or facsimile thereof) and any other documents required by this Letter of Transmittal, must be received by the Depositary at one of its addresses set forth herein prior to the Expiration Date (as defined under "THE TENDER OFFER—Terms of the Offer" in the Offer to Purchase). Shareholders whose certificates are not immediately available or who cannot deliver their certificates and all other required documents to the Depositary prior to the Expiration Date may tender their Shares by properly completing and duly executing the Notice of Guaranteed Delivery pursuant to the guaranteed delivery procedure set forth under "THE TENDER OFFER—Procedure for Tendering Shares" in the Offer to Purchase. Pursuant to such procedure, (i) such tender must be made by or through an Eligible Institution, (ii) a properly completed and duly executed Notice of Guaranteed Delivery, substantially in the form provided by the Purchaser, must be received by the Depositary prior to the Expiration Date and (iii) the certificates for all physically tendered Shares or Book-Entry Confirmation, as the case may be, together with a properly completed and duly executed Letter of Transmittal (or facsimile thereof) and any other documents required by this Letter of Transmittal, must be received by the Depositary within eight New York Stock Exchange trading days after the date of execution of such Notice of Guaranteed Delivery, all as provided under "THE TENDER OFFER—Procedure for Tendering Shares" in the Offer to Purchase.

The method of delivery of this Letter of Transmittal, the certificates for Shares and all other required documents, including delivery through a Book-Entry Transfer Facility, is at the option and risk of the tendering shareholder and the delivery will be deemed made only when actually received by the Depositary. If delivery is by mail, registered mail with return receipt requested, properly insured, is recommended.

No alternative, conditional or contingent tenders will be accepted and no fractional Shares will be purchased. All tendering shareholders, by execution of this Letter of Transmittal (or facsimile thereof), waive any right to receive any notice of the acceptance of their Shares for payment.

3. *Inadequate Space.* If the space provided herein is inadequate, the certificate numbers and/or the number of Shares should be listed on a separate signed schedule attached hereto.

4. *Partial Tenders. (Not applicable to shareholders who tender by book-entry transfer).* If fewer than all the Shares evidenced by any certificate submitted are to be tendered, fill in the number of Shares which are to be tendered in the box entitled "Number of Shares Tendered". In such case, new certificate(s) for the remainder of the Shares that were evidenced by your old certificate(s) will be sent to you, unless otherwise provided in the appropriate box on this Letter of Transmittal, as soon as practicable after the Expiration Date. All Shares represented by certificates delivered to the Depositary will be deemed to have been tendered unless otherwise indicated.

5. *Signatures on Letter of Transmittal, Stock Powers and Endorsements.* If this Letter of Transmittal is signed by the registered holder(s) of the Shares tendered hereby, the signature(s) must correspond exactly with the name(s) as written on the face of the certificate(s) without alteration, enlargement or any change whatsoever.

If any of the Shares tendered hereby are owned of record by two or more joint owners, all such owners must sign this Letter of Transmittal.

If any tendered Shares are registered in different names on several certificates, it will be necessary to complete, sign and submit as many separate Letters of Transmittal as there are different registrations of certificates.

If this Letter of Transmittal or any certificates or stock powers are signed by a trustee, executor, administrator, guardian, attorney-in-fact, agent, officer of a corporation or other person acting in a fiduciary or representative capacity, such person should so indicate when signing, and proper evidence satisfactory to the Purchaser of such person's authority so to act must be submitted.

When this Letter of Transmittal is signed by the registered owner(s) of the Shares listed and transmitted hereby, no endorsements of certificates or separate stock powers are required unless payment or certificates for Shares not tendered or purchased are to be issued to a person other than the registered owner(s). Signatures on such certificates or stock powers must be guaranteed by an Eligible Institution.

If this Letter of Transmittal is signed by a person other than the registered owner(s) of the Shares listed, the certificates must be endorsed or accompanied by appropriate stock powers, in either case signed exactly as the name or names of the registered owner or owners appear on the certificates. Signatures on such certificates or stock powers must be guaranteed by an Eligible Institution.

6. *Stock Transfer Taxes.* Except as set forth in this Instruction 6, the Purchaser will pay or cause to be paid any stock transfer taxes with respect to the transfer and sale of purchased Shares to it or its order pursuant to the Offer. If payment of the purchase price is to be made to, or if certificates for Shares not tendered or not purchased are to be issued in the name of, any person other than the registered holder, or if tendered certificates are registered in the name of any person other than the person(s) signing this Letter of Transmittal, the amount of any stock transfer taxes (whether imposed on the registered holder or such person) payable on account of the transfer to such person will be deducted from the purchase price unless satisfactory evidence of the payment of such taxes or exemption therefrom is submitted.

Except as provided in this Instruction 6, it will not be necessary for transfer tax stamps to be affixed to the certificates listed in this Letter of Transmittal.

7. *Special Payment and Delivery Instructions.* If a check and/or certificates for Shares not tendered or not purchased are to be issued in the name of a person other than the signer of this Letter of Transmittal or if a check is to be sent and/or such certificates are to be returned to someone other than the signer of this Letter of Transmittal or to an address other than that shown above, the appropriate boxes on this Letter of Transmittal should be completed. Shareholders tendering Shares by book-entry transfer may request that the Shares not purchased be credited to the account maintained at a Book-Entry Transfer Facility as such shareholder may designate hereon. If no such instructions are given, such Shares not purchased will be returned by crediting the account at the Book-Entry Transfer Facility through which the tender was made.

8. *Requests for Assistance or Additional Copies.* Requests for assistance may be directed to or additional copies of the Offer to Purchase and this Letter of Transmittal may be obtained from the Information Agent or the Dealer Managers at their respective addresses set forth below or from your broker, dealer, commercial bank or trust company.

9. *Substitute Form W-9.* The tendering shareholder is required to provide the Depositary with a correct Taxpayer Identification Number ("TIN") on Substitute Form W-9 which is provided under "Important Tax Information" below. Failure to provide the information on the Substitute Form W-9 may subject the tendering shareholder to 20% federal income tax withholding on the payment of the purchase price. The box in Part 3 of the Substitute Form W-9 may be checked if the tendering shareholder has not been issued a TIN and has applied for a number or intends to apply for a number in the near future. If the box in Part 3 is checked and the Depositary is not provided with a TIN within 60 days, the Depositary will withhold 20% on all payments of the purchase price thereafter until a TIN is provided to the Depositary.

Important: This Letter of Transmittal (or a facsimile thereof), together with certificates or confirmation of book-entry transfer and all other required documents, or the Notice of Guaranteed Delivery, must be received by the Depositary prior to the Expiration Date.

(DO NOT WRITE IN SPACE BELOW)

Shares Surrendered	Shares Tendered	Shares Accepted	Check No.	Amount of Check	Certificate No.	Block No.

Delivery Prepared By _____ Checked By _____ Date _____

IMPORTANT TAX INFORMATION

Under federal income tax law, a shareholder whose tendered Shares are accepted for payment is required to provide the Depositary with such shareholder's correct TIN on Substitute Form W-9 below. If such shareholder is an individual, the TIN is his social security number. If the Depositary is not provided with the correct TIN, the shareholder may be subject to a $50 penalty imposed by the Internal Revenue Service. In addition, payments that are made to such shareholder with respect to Shares purchased pursuant to the Offer may be subject to backup withholding.

Certain shareholders (including, among others, all corporations and certain foreign individuals) are not subject to these backup withholding and reporting requirements. In order for a foreign individual to qualify as an exempt recipient, that shareholder must submit a statement, signed under penalties of perjury, attesting to that individual's exempt status. The form for such statement may be obtained from the Depositary. See the enclosed Guidelines for Certification of Taxpayer Identification Number on Substitute Form W-9 for additional instructions.

If backup withholding applies, the Depositary is required to withhold 20% of any payments made to the shareholder. Backup withholding is not an additional tax. Rather, the tax liability of persons subject to backup withholding will be reduced by the amount of tax withheld. If withholding results in an overpayment of taxes, a refund may be obtained.

Purpose of Substitute Form W-9

To prevent backup withholding on payments that are made to a shareholder with respect to Shares purchased pursuant to the Offer, the shareholder is required to notify the Depositary of his correct TIN by completing the form below certifying that the TIN provided on the Substitute Form W-9 is correct (or that such shareholder is awaiting a TIN).

What Number to Give the Depositary

The shareholder is required to give the Depositary the social security number or employer identification number of the record owner of the Shares. If the Shares are in more than one name or are not in the name of the actual owner, consult the enclosed Guidelines for Certification of Taxpayer Identification Number on Substitute Form W-9 for additional guidelines on which number to report.

SUBSTITUTE Form **W-9** Department of the Treasury Internal Revenue Service **Payer's Request for Taxpayer Identification Number (TIN)**	**Part 1—PLEASE PROVIDE YOUR NAME, ADDRESS AND TIN IN THE BOX AT RIGHT AND CERTIFY BY SIGNING AND DATING BELOW**	Name Address Social Security or Employer identification number
	Part 2—Check the box if you are NOT subject to backup withholding under the provisions of section 3406(a)(1)(C) of the Internal Revenue Code because (1) you have not been notified that you are subject to backup withholding as a result of failure to report all interest or dividends or (2) the Internal Revenue Service has notified you that you are no longer subject to backup withholding ☐	
	CERTIFICATION—UNDER THE PENALTIES OF PERJURY, I CERTIFY THAT THE INFORMATION PROVIDED ON THIS FORM IS TRUE, CORRECT, AND COMPLETE. SIGNATURE..... DATE.....	Part 3 Awaiting TIN ☐

NOTE: FAILURE TO COMPLETE AND RETURN THIS FORM MAY RESULT IN BACKUP WITHHOLDING OF 20% OF ANY PAYMENTS MADE TO YOU PURSUANT TO THE OFFER. PLEASE REVIEW THE ENCLOSED GUIDELINES FOR CERTIFICATION OF TAXPAYER IDENTIFICATION NUMBER ON SUBSTITUTE FORM W-9 FOR ADDITIONAL DETAILS.

The Information Agent

D.F. KING & CO., INC.

One North LaSalle Street Chicago, Illinois 60602 (312) 236-5881 (Collect)	60 Broad Street New York, NY 10004 (212) 269-5550 (Collect)	9841 Airport Boulevard Los Angeles, CA 90045 (213) 215-3860 (Collect)

Call Toll-Free 1-800-223-3604 Except in New York Call Toll-Free 1-800-522-5001.

The Dealer Managers

Goldman, Sachs & Co.

85 Broad Street
New York, New York 10004

Call Toll-Free 1-800-323-5678
Except in New York
Call Collect (212) 902-1000.

THE PRECEDING PAGES WERE TREATED AS
A UNIT IN THE ORIGINAL FILE.

BECHTEL

Information Services

15740 Shady Grove Road
Gaithersburg, Maryland 20877-1454

EXHIBITS FOLLOW

EPD-33805 10/85

EXHIBIT (a)(3)

Goldman, Sachs & Co. | 85 Broad Street | New York, New York 10004
Tal: 212-902-1000

Goldman Sachs

Offer To Purchase For Cash
Any and All of the Outstanding Shares of Common Stock
of

The Standard Oil Company

at

$70 Net Per Share

by

BP North America Inc.

an indirect wholly-owned subsidiary of

The British Petroleum Company p.l.c.

THE OFFER AND WITHDRAWAL RIGHTS WILL EXPIRE AT 12:00 MIDNIGHT, NEW YORK CITY TIME, ON TUESDAY, APRIL 28, 1987, UNLESS EXTENDED.

THE OFFER IS NOT CONDITIONED UPON ANY MINIMUM NUMBER OF SHARES BEING TENDERED.

April 1, 1987

To Brokers, Dealers, Commercial Banks,
Trust Companies and Other Nominees:

We have been appointed by BP North America Inc., a Delaware corporation (the "Purchaser") and an indirect wholly-owned subsidiary of The British Petroleum Company p.l.c., a company organized under the laws of England, to act as Dealer Managers in connection with its offer to purchase any and all of the outstanding shares of Common Stock, without par value ("Shares"), of The Standard Oil Company, an Ohio corporation (the "Company"), at a price of $70 per Share, net to the seller in cash, upon the terms and subject to the conditions set forth in the Offer to Purchase and the related Letter of Transmittal (which together constitute the "Offer") enclosed herewith.

Enclosed are copies of each of the following documents:

1. Offer to Purchase dated April 1, 1987.

2. Letter of Transmittal to tender Shares for your use and for the information of your clients. Facsimile copies of the Letter of Transmittal may be used to tender Shares.

3. Notice of Guaranteed Delivery.

4. Letter to your clients for whose account you hold Shares registered in your name or the name of your nominee, with space provided for obtaining such clients' instructions with regard to the Offer.

5. Guidelines of the Internal Revenue Service for certification of Taxpayer Identification Number on Substitute Form W-9.

6. Return envelope addressed to The Chase Manhattan Bank, N.A., the Depositary.

The Purchaser will not pay any fees or commissions to any broker or dealer or other person for soliciting tenders of Shares pursuant to the Offer. You will be reimbursed for customary mailing and handling expenses incurred by you in forwarding any of the enclosed materials to your clients. The Purchaser will pay or cause to be paid any transfer taxes payable on the transfer of Shares to it, except as otherwise provided in Instruction 6 of the enclosed Letter of Transmittal.

Your prompt action is requested. We urge you to contact your clients as promptly as possible. The Offer and withdrawal rights will expire at 12:00 Midnight, New York City time, on Tuesday, April 28, 1987, unless extended.

In order to take advantage of the Offer, a duly executed and properly completed Letter of Transmittal and any other required documents should be sent to the Depositary and certificates representing the tendered Shares should be delivered, or such Shares should be tendered by book-entry transfer, all in accordance with the instructions set forth in the Letter of Transmittal and the Offer to Purchase.

If holders of Shares wish to tender, but it is impracticable for them to forward their certificates or other required documents prior to the expiration of the Offer, a tender may be effected by following the guaranteed delivery procedures specified under "THE TENDER OFFER—Procedure for Tendering Shares" in the Offer to Purchase.

Any inquiries you may have with respect to the Offer should be addressed to Goldman, Sachs & Co. or to D.F. King & Co., Inc. at their respective addresses and telephone numbers set forth on the back cover page of the Offer to Purchase.

Additional copies of the above documents may be obtained from D.F. King & Co., Inc., the Information Agent, at (212) 269-5550.

Very truly yours,

Goldman, Sachs & Co.

NOTHING CONTAINED HEREIN OR IN THE ENCLOSED DOCUMENTS SHALL CONSTITUTE YOU OR ANY PERSON AS AN AGENT OF THE PURCHASER, ANY AFFILIATE OF THE PURCHASER, THE INFORMATION AGENT, THE DEPOSITARY OR THE DEALER MANAGERS, OR AUTHORIZE YOU OR ANY OTHER PERSON TO MAKE ANY STATEMENTS ON BEHALF OF ANY OF THEM WITH RESPECT TO THE OFFER, EXCEPT FOR STATEMENTS EXPRESSLY MADE IN THE OFFER TO PURCHASE OR THE LETTER OF TRANSMITTAL.

EXHIBIT (a)(4)

Offer To Purchase For Cash
Any and All of the Outstanding Shares of Common Stock
of

The Standard Oil Company

at

$70 Net Per Share

by

BP North America Inc.

an indirect wholly-owned subsidiary of

The British Petroleum Company p.l.c.

To Our Clients:

Enclosed for your consideration is an Offer to Purchase any and all of the outstanding shares of Common Stock, without par value ("Shares"), of The Standard Oil Company, an Ohio corporation, at a price of $70 per Share, net to the seller in cash, by BP North America Inc., a Delaware corporation (the "Purchaser") and an indirect wholly-owned subsidiary of The British Petroleum Company p.l.c., a company organized under the laws of England, together with a specimen Letter of Transmittal. **This material is being forwarded to you as the beneficial owner of Shares carried by us in your account but not registered in your name. A tender of such Shares may only be made by us as the holder of record and pursuant to your instructions. The Letter of Transmittal is furnished to you for your information only and cannot be used by you to tender Shares held by us for your account.**

Accordingly, we request instructions as to whether you wish to tender any or all such Shares held by us for your account, upon the terms and subject to the conditions set forth in the Offer to Purchase and the related Letter of Transmittal (which together constitute the "Offer").

Your attention is invited to the following:

1. The tender price is $70 per Share, net to you in cash, upon the terms and subject to the conditions set forth in the Offer.

2. The Offer is being made for any and all Shares, and is not conditioned upon any minimum number of Shares being tendered.

3. **The Offer and withdrawal rights will expire at 12:00 Midnight, New York City time, on Tuesday, April 28, 1987, unless extended.**

4. Any stock transfer taxes or brokerage commissions applicable to a sale of the Shares pursuant to the Offer will be paid by or on behalf of the Purchaser, except as otherwise provided in Instruction 6 of the Letter of Transmittal.

If you wish to have us tender any or all of your Shares, please so instruct us by completing, executing and returning to us the Instruction form set forth below. If you authorize tender of your Shares, all such Shares will be tendered unless otherwise specified below. Your instructions should be forwarded to us in ample time to permit us to submit a tender on your behalf prior to the expiration of the Offer.

The Offer is not being made to, nor will tenders be accepted from or on behalf of, holders of Shares in any jurisdiction in which the making or acceptance of the Offer would not be in compliance with the laws of any such jurisdiction.

Instructions with Respect to the Offer to Purchase Shares of Common Stock of The Standard Oil Company

The undersigned acknowledge(s) receipt of your letter enclosing the Offer to Purchase shares of Common Stock, without par value ("Shares"), of The Standard Oil Company by BP North America Inc., an indirect wholly-owned subsidiary of The British Petroleum Company p.l.c., and the related specimen Letter of Transmittal.

This will instruct you to tender the number of Shares indicated below held by you for the account of the undersigned, under the terms and subject to the conditions set forth in the Offer to Purchase and the related Letter of Transmittal.

Number of Shares to be tendered
Shares*
*I (we) understand that if I (we) sign this instruction form witnout indicating a lesser number of Shares in the space above, all Shares held by you for my (our) account will be tendered.

_____

_____

_____

Signature(s)

_____

_____

_____

(Please print name(s) and address(es) here)

Dated: , 1987

EXHIBIT (a)(5)

This announcement is neither an offer to purchase nor a solicitation of an offer to sell Shares. The Offer is made solely by the Offer to Purchase dated April 1, 1987 and the related Letter of Transmittal, and is not being made to nor will tenders be accepted from or on behalf of holders of Shares residing in any jurisdiction in which the making of the Offer or the acceptance thereof would not be in compliance with the securities, blue sky or other laws of such jurisdiction. In those jurisdictions whose securities, blue sky or other laws require the Offer to be made by a licensed broker or dealer, the Offer shall be deemed to be made on behalf of the Purchaser by Goldman, Sachs & Co.

Notice of Offer to Purchase for Cash
Any and All Outstanding Shares of Common Stock
of

The Standard Oil Company

at

$70 Net Per Share

by

BP North America Inc.

an indirect wholly-owned subsidiary of

The British Petroleum Company p.l.c.

BP North America Inc., a Delaware corporation (the "Purchaser") and an indirect wholly-owned subsidiary of The British Petroleum Company p.l.c., a company organized under the laws of England, is offering to purchase any and all outstanding shares of Common Stock, without par value ("Shares"), of The Standard Oil Company, an Ohio corporation (the "Company"), at $70 per Share, net to the seller in cash, upon the terms and subject to the conditions set forth in the Offer to Purchase dated April 1, 1987 (the "Offer to Purchase") and the related Letter of Transmittal (which together constitute the "Offer").

The Offer is not conditioned upon any minimum number of Shares being tendered.

THE OFFER AND WITHDRAWAL RIGHTS WILL EXPIRE AT 12:00 MIDNIGHT, NEW YORK CITY TIME, ON TUESDAY, APRIL 28, 1987, UNLESS EXTENDED.

For purposes of the Offer, the Purchaser will be deemed to have accepted for payment and purchased tendered Shares if, as and when the Purchaser gives oral or written notice to the Depositary, as agent for tendering shareholders, of the Purchaser's acceptance of such Shares for payment pursuant to the Offer. In all cases, payment for Shares purchased pursuant to the Offer will be made only after timely receipt by the Depositary of certificates for such Shares or confirmation of a book-entry transfer of such Shares into the Depositary's account at a Book-Entry Transfer Facility (as defined in the Offer to Purchase), the Letter of Transmittal or facsimile copy thereof, properly completed and duly executed, and any other required documents. The Purchaser expressly reserves the right, at any time or from time to time, to extend the period of time during which the Offer is open by giving oral or written notice of such extension to the Depositary and by making a public announcement thereof.

Tenders of Shares made pursuant to the Offer will be irrevocable, except that Shares tendered pursuant to the Offer may be withdrawn at any time prior to 12:00 Midnight, New York City time, on Tuesday, April 28, 1987 (or, if the Purchaser shall have extended the period of time for which the Offer is open, the latest time and date at which the Offer as so extended, shall expire), and, unless theretofore accepted for payment by the Purchaser pursuant to the Offer, may also be withdrawn at any time after May 30, 1987. For a withdrawal to be effective, a written, telegraphic, telex or facsimile notice of withdrawal must be timely received by the Depositary at one of its addresses set forth on the back cover of the Offer to Purchase and must specify the name of the person having tendered the Shares to be withdrawn, the number of Shares to be withdrawn and the name in which the certificates evidencing such Shares are registered, if different from that of the person having tendered such Shares. If certificates evidencing such Shares have been delivered to the Depositary, then, prior to the release of such certificates, the serial numbers shown on such certificates must be submitted and the signatures on the notice of withdrawal must be guaranteed by an Eligible Institution (as defined in the Offer to Purchase), unless such Shares have been tendered for the account of any Eligible Institution. If Shares have been tendered pursuant to the procedures for book-entry transfer as set forth in the Offer to Purchase, any notice of withdrawal must also specify the name and number of the account at a Book-Entry Transfer Facility to be credited with the withdrawn Shares.

The information required to be disclosed by Rule 14d-6(e)(1)(vii) of the General Rules and Regulations under the Securities Exchange Act of 1934 is contained in the Offer to Purchase and is incorporated herein by reference.

A request is being made to the Company for the use of its stockholder list and security position listings for the purpose of disseminating the Offer to shareholders. Upon compliance by the Company with such request, the Offer to Purchase, the related Letter of Transmittal and other tender offer materials will be mailed to record holders of Shares and will be furnished to brokers, banks and similar persons whose names appear or whose nominees appear on the shareholder list or, if applicable, who are listed as participants in a clearing agency's security position listing for subsequent transmittal to beneficial owners of Shares.

The Offer to Purchase and the related Letter of Transmittal, which are being mailed to shareholders, contain important information which should be read before any decision is made with respect to the Offer.

Requests for copies of the Offer to Purchase, the Letter of Transmittal and other tender offer materials may be directed to the Information Agent or the Dealer Managers as set forth below, and copies will be furnished promptly, at the Purchaser's expense.

The Information Agent

D.F. KING & CO., INC.

One North LaSalle Street	60 Broad Street	9841 Airport Boulevard
Chicago, Illinois 60602	New York, NY 10004	Los Angeles, CA 90045
(312) 236-5881 (Collect)	(212) 269-5550 (Collect)	(213) 215-3860 (Collect)

Call Toll Free 1-800-223-3604 Except in New York. Call Toll Free 1-800-522-5001.

The Dealer Managers

Goldman, Sachs & Co.

85 Broad Street
New York, New York 10004
Call Toll Free 1-800-323-5678 Except in New York. Call Collect (212) 902-1000.

April 1, 1987

EXHIBIT (a)(6)

NOTICE OF GUARANTEED DELIVERY OF SHARES OF COMMON STOCK OF THE STANDARD OIL COMPANY

As set forth under "THE TENDER OFFER—Procedure for Tendering Shares" in the Offer to Purchase described below, this form or one substantially equivalent hereto must be used to accept the Offer (as defined below) if certificates for Shares are not immediately available or time will not permit all required documents to reach the Depositary prior to the Expiration Date (as defined under "THE TENDER OFFER—Terms of the Offer" in the Offer to Purchase) of the Offer. Such form may be delivered by hand or sent by telex, facsimile transmission or mail to the Depositary.

The Depositary

THE CHASE MANHATTAN BANK, N.A.

By Hand:	*By Mail:*	*By Overnight Courier:*	*By Facsimile:*
14th Floor 67 Broad Street New York, New York	P.O. Box 396 Bowling Green Station New York, New York 10274	c/o Mellon Securities Transfer Services Fort Lee Executive Park 1 Executive Drive Fort Lee, N.J. 07024 Att: Reorganization Department Fifth Floor	(201) 592-4475 or (212) 558-6896 *By TWX:* 7109904992

DELIVERY OF THIS INSTRUMENT TO AN ADDRESS OTHER THAN AS SET FORTH ABOVE DOES NOT CONSTITUTE A VALID DELIVERY.

Gentlemen:

The undersigned hereby tenders to BP North America Inc., a Delaware corporation, upon the terms and subject to the conditions set forth in its Offer to Purchase dated April 1, 1987 and the related Letter of Transmittal (which together constitute the "Offer"), receipt of which is hereby acknowledged, shares of Common Stock, without par value, of The Standard Oil Company, an Ohio corporation, pursuant to the guaranteed delivery procedure set forth under "THE TENDER OFFER—Procedure for Tendering Shares" in the Offer to Purchase.

Certificate Nos. (if available):

_____

_____

Area Code and Telephone Number:

_____

_____

Dated: _____, 1987

Name(s) of Record Holder(s):

_____

_____

Address(es):

_____

_____

Zip Code

_____

_____

Signature(s)

IF SHARES WILL BE TENDERED BY BOOK-ENTRY TRANSFER:

Account No. ..... at (check one):

☐ The Depository Trust Company

☐ Midwest Securities Trust Company

☐ Pacific Securities Depository Trust Company

☐ Philadelphia Depository Trust Company

NOTE: DO NOT SEND STOCK CERTIFICATES WITH THIS FORM. STOCK CERTIFICATES SHOULD BE SENT WITH YOUR LETTER OF TRANSMITTAL.

GUARANTEE
(Not to be used for signature guarantee)

The undersigned, a member firm of a registered national securities exchange or of the National Association of Securities Dealers, Inc., or a commercial bank or trust company having an office or correspondent in the United States, (a) represents that the above-named person(s) "own(s)" Shares tendered hereby within the meaning of Rule 10b-4 under the Securities Exchange Act of 1934, (b) represents that such tender of Shares complies with Rule 10b-4 and (c) guarantees delivery to the Depositary of certificates for Shares tendered hereby, in proper form for transfer, or delivery of Shares pursuant to the procedure for book-entry transfer into the Depositary's account at The Depository Trust Company, the Midwest Securities Trust Company, the Pacific Securities Depository Trust Company or the Philadelphia Depository Trust Company, in either case with delivery of a properly completed and duly executed Letter of Transmittal (or facsimile thereof) and any other required documents, all within eight (8) New York Stock Exchange trading days after the date hereof.

_____
(Firm)

_____
(Authorized Signature)

_____
(Name)

_____
(Title)

_____
(Address)

Dated: _____, 1987

_____
(Area Code and Telephone No.)

EXHIBIT (a)(7)

GUIDELINES FOR CERTIFICATION OF TAXPAYER IDENTIFICATION NUMBER ON SUBSTITUTE FORM W-9

Guidelines for Determining the Proper Identification Number to Give the Payer.—Social Security numbers have nine digits separated by two hyphens: i.e. 000-00-0000. Employer identification numbers have nine digits separated by only one hyphen: i.e. 00-0000000. The table below will help determine the number to give the payer.

For this type of account:	Give the SOCIAL SECURITY number of—
1. An individual's account	The individual
2. Two or more individuals (joint account)	The actual owner of the account or, if combined funds, any one of the individuals[1]
3. Husband and wife (joint account)	The actual owner of the account or, if joint funds, either person[1]
4. Custodian account of a minor. (Uniform Gift to Minors Act)	The minor[2]
5. Adult and minor (joint account)	The adult or, if the minor is the only contributor, the minor[1]
6. Account in the name of guardian or committee for a designated ward, minor, or incompetent person	The ward, minor, or incompetent person[3]
7. a The usual revocable savings trust account (grantor is also trustee)	The grantor-trustee[1]
b So-called trust account that is not a legal or valid trust under State law	The actual owner[1]

For this type of account:	Give the EMPLOYER IDENTIFICATION number of—
8. Sole proprietorship account	The Owner[4]
9. A valid trust, estate, or pension trust	Legal entity (Do not furnish the identifying number of the personal representative or trustee unless the legal entity itself is not designated in the account title.)[5]
10. Corporate account	The Corporation
11. Religious, charitable, or educational organization account	The organization
12. Partnership account held in the name of the business	The partnership
13. Association, club, or other tax-exempt organization	The organization
14. A broker or registered nominee	The broker or nominee
15. Account with the Department of Agriculture in the name of a public entity (such as a State or local government, school district, or prison) that receives agricultural program payments	The public entity

[1] List first and circle the name of the person whose number you furnish.

[2] Circle the minor's name and furnish the minor's social security number.

[3] Circle the ward's, minor's or incompetent person's name and furnish such person's social security number.

[4] Show the name of the owner.

[5] List first and circle the name of the legal trust, estate, or pension trust.

Note: If no name is circled when there is more than one name, the number will be considered to be that of the first name listed.

GUIDELINES FOR CERTIFICATION OF TAXPAYER IDENTIFICATION NUMBER ON SUBSTITUTE FORM W-9

Obtaining a Number

If you don't have a taxpayer identification number or you don't know your number, obtain Form SS-5, Application for a Social Security Number Card, or Form SS-4, Application for Employer Identification Number, at the local office of the Social Security Administration or the Internal Revenue Service and apply for a number.

Payees Exempt from Backup Withholding

Payees specifically exempted from backup withholding on ALL payments include the following:

- A corporation.
- A financial institution.
- An organization exempt from tax under section 501(a), or an individual retirement plan.
- The United States or any agency or instrumentality thereof.
- A State, the District of Columbia, a possession of the United States, or any subdivision or instrumentality thereof.
- A foreign government, a political subdivision of a foreign government, or any agency or instrumentality thereof.
- An international organization or any agency, or instrumentality thereof.
- A registered dealer in securities or commodities registered in the U.S. or a possession of the U.S.
- A real estate investment trust.
- A common trust fund operated by a bank under section 584(a).
- An exempt charitable remainder trust, or a non-exempt trust described in section 4947(a)(1).
- An entity registered at all times under the Investment Company Act of 1940.
- A foreign central bank of issue.

Payments of dividends and patronage dividends not generally subject to backup withholding include the following:

- Payments to nonresident aliens subject to withholding under section 1441.
- Payments to partnerships not engaged in a trade or business in the U.S. and which have at least one nonresident partner.
- Payments of patronage dividends where the amount received is not paid in money.
- Payments made by certain foreign organizations.
- Payments made to a nominee.

Payments of interest not generally subject to backup withholding include the following:

- Payments of interest on obligations issued by individuals. **Note:** You may be subject to backup withholding if this interest is $600 or more and is paid in the course of the payer's trade or business and you have not provided your correct taxpayer identification number to the payer.
- Payments of tax-exempt interest (including exempt interest dividends under section 852).
- Payments described in section 6049(b)(5) to nonresident aliens.
- Payments on tax-free covenant bonds under section 1451.
- Payments made by certain foreign organizations.
- Payments made to a nominee.

Exempt payees described above should file Form W-9 to avoid possible erroneous backup withholding. FILE THIS FORM WITH THE PAYER, FURNISH YOUR TAXPAYER IDENTIFICATION NUMBER, WRITE "EXEMPT" ON THE FACE OF THE FORM, AND RETURN IT TO THE PAYER. IF THE PAYMENTS ARE INTEREST, DIVIDENDS, OR PATRONAGE DIVIDENDS, ALSO SIGN AND DATE THE FORM.

Certain payments other than interest, dividends, and patronage dividends that are not subject to information reporting are also not subject to backup withholding. For details, see the regulations under sections 6041, 6041A(a), 6045, and 6050A.

Privacy Act Notice.—Section 6109 requires most recipients of dividend, interest, or other payments to give taxpayer identification numbers to payers who must report the payments to IRS. IRS uses the numbers for identification purposes. Payers must be given the numbers whether or not recipients are required to file tax returns. Beginning January 1, 1984, payers must generally withhold 20% of taxable interest, dividend, and certain other payments to a payee who does not furnish a taxpayer identification number to a payer. Certain penalties may also apply.

Penalties

(1) Penalty for Failure to Furnish Taxpayer Identification Number.—If you fail to furnish your taxpayer identification number to a payer, you are subject to a penalty of $50 for each such failure unless your failure is due to reasonable cause and not to willful neglect.

(2) Failure to Report Certain Dividend and Interest Payments.—If you fail to include any portion of an includible payment for interest, dividends, or patronage dividends in gross income, such failure will be treated as being due to negligence and will be subject to a penalty of 5% on any portion of an under-payment attributable to that failure unless there is clear and convincing evidence to the contrary.

(3) Civil Penalty for False Information With Respect to Withholding.—If you make a false statement with no reasonable basis which results in no imposition of backup withholding, you are subject to a penalty of $500.

(4) Criminal Penalty for Falsifying Information.—Falsifying certifications or affirmations may subject you to criminal penalties including fines and/or imprisonment.

FOR ADDITIONAL INFORMATION CONTACT YOUR TAX CONSULTANT OR THE INTERNAL REVENUE SERVICE

EXHIBIT (a)(8)

Adams & Rinehart, Inc.
708 Third Avenue
New York, New York 10017
212 557 0100

News

FOR IMMEDIATE RELEASE

For: British Petroleum Company p.l.c.

Contact: Jonathan Rinehart
or David Duffy
(212) 557-0100

BP TO TENDER FOR MINORITY SHARES OF THE STANDARD OIL COMPANY

NEW YORK, March 26, 1987 — The British Petroleum Company p.l.c. announced today that its wholly owned subsidiary, BP North America Inc., intends to make a tender offer for any and all of the outstanding shares of common stock of The Standard Oil Company at US$70.00 per share in cash. The BP group already owns approximately 55 percent of the common stock. BP said it is intending to commence the offer no later than Wednesday, April 1, 1987.

Approval of BP's shareholders will be required, and will be included among the detailed conditions to the offer which will be set out in full in the Offer to Purchase. The offer will not, however, be conditioned upon any minimum number of shares being tendered.

Following completion of the offer, BP intends to effect a merger of a wholly owned subsidiary into Standard Oil whereby any remaining public shareholders will receive US$70.00 per share.

BP said that Standard will remain headquartered in Cleveland, Ohio, which will also become the corporate headquarters of BP's US operations. There are no current plans to replace the company's management personnel and BP expects that few redundancies will arise in Standard's operating subsidiaries or corporate headquarters as a result of the transaction.

– more –

BP said the US$70.00 per share offer price was based on its own valuations of Standard as well as those of its financial advisors, Goldman, Sachs & Co. The valuations included reviews of both public and non-public information about Standard; discounted cash flow analyses of Standard's reserves, including its probable reserves, and analysis of undeveloped acreage; discounted cash flow analyses and market valuations for Standard's non-exploration and production assets; and analyses of Standard's current and historic stock prices and comparisons with those of similar companies. BP said that both it and Goldman Sachs concluded that Standard's shares have been more than fully valued by the market in recent weeks.

BP Chairman Sir Peter Walters said: "BP's investment in Standard represents its largest single asset, and full ownership of Standard would enable decisions on our investments and operations to be made without limitations that may arise out of the existence of a minority interest. We also believe the acquisition of the minority shares of Standard represents the optimum use of BP's own financial resources.

"BP feels confident in making the acquisition decision now because it considers that oil prices are likely to remain within price ranges sufficient to justify making the investment. In addition, as a result of the management changes made in 1986 and the subsequent operations of Standard, BP feels confident that Standard can operate successfully, even in a lower oil price environment. Furthermore, the strength of BP's financial position facilitates the financing of the offer."

Sir Peter also said that BP wants to consolidate its presence in the US, focusing its activities in each business segment, especially oil and gas exploration and production.

- more -

The total cash payable under the offer, if accepted in full, will be some US$7.4 billion. Approximately one third of the total offer consideration will be met from the BP group's own cash resources. The balance will be met by new borrowings, partly from a number of commercial banks under a four-year committed revolving credit facility and partly under a new US Dollar commercial paper programme backed up by the revolving credit facility. BP is in the course of arranging these facilities.

Standard Oil is an integrated US petroleum company with interests in coal, metals mining, chemicals and other industrial businesses. The Cleveland-based company is a major producer of oil on the Alaskan North Slope.

Net assets of Standard Oil at December 31, 1986, as shown by its balance sheet as at that date and prepared in accordance with US generally accepted accounting principles, were US$7,020 million. In the year to December 31, 1986, Standard Oil reported a loss before tax and extraordinary item of US$608 million, after deduction of unusual items of US$1,079 million.

The tender offer and withdrawal rights will expire 20 business days from commencement, unless extended. Goldman, Sachs & Co. will act as dealer managers for the tender offer.

# # # #

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EXHIBIT (a)(9)

The British Petroleum Company p.l.c.

c/o BP North America Inc.
620 Fifth Avenue
New York, NY 10020

Press Contact:
Mike McDermott
(212) 887-9372

Investment Analyst Contact:
Peter Aslet
(212) 887-9385

BP NEWS

FOR IMMEDIATE RELEASE

Contact: Jonathan Rinehart
or David Duffy
Adams & Rinehart, Inc.
(212) 557-0100

BP COMMENCES CASH TENDER OFFER FOR ANY AND ALL STANDARD OIL SHARES AT $70.00 PER SHARE

LONDON, April 1, 1987 — The British Petroleum Company p.l.c. announced that its wholly owned subsidiary, BP North America Inc. (BPNA), has commenced today its previously announced tender offer for any and all outstanding shares of common stock of The Standard Oil Company at US$70 per share in cash. The BP group already owns approximately 55 percent of Standard Oil's common stock.

Approval of BP's shareholders will be required and will be sought at a special meeting of shareholders scheduled for April 22, 1987. The offer is not conditioned upon any minimum number of shares being tendered.

The offer and withdrawal rights will expire at 12:00 midnight, New York City time, on Tuesday, April 28, 1987, unless extended.

Following completion of the offer, BPNA intends to effect a merger of a wholly owned subsidiary into Standard Oil whereby any remaining public shareholders will receive US$70 per share.

Goldman, Sachs & Co. are acting as dealer managers for the tender offer. The information agent is D.F. King & Co., Inc. BPNA said that definitive offering materials are being filed with the Securities and Exchange Commission today and will be mailed to Standard Oil shareholders promptly.

# # # #

[4714d]

EXHIBIT (b)

BP INTERNATIONAL LIMITED
Britannic House
Moor Lane
London, England EC2Y9BU

and

BP NORTH AMERICA, INC.
650 Fifth Avenue
New York, New York

and

ROBERT B. HORTON
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

E. JOHN P. BROWNE
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

J. COLIN WEBSTER
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

BASIL R. R. BUTLER
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

IAN G. S. HARTIGAN
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

KENNETH R. KEEP
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and)
)
FRANK E. MOSIER)
200 Standard Oil Bldg.)
& Public Square)
Cleveland, Ohio 44114)
)
and)
)
RICHARD A. BRAY)
200 Standard Oil Bldg.)
& Public Square)
Cleveland, Ohio 44114)
)
Defendants.)

Now come the plaintiffs, and for their Complaint against defendants, states the following upon information and belief, except as to paragraph 1 which is alleged upon knowledge:

1. Plaintiffs John and Marjorie Moore, Louis H. Goldman and David Grobow are each the owner of the common stock of defendant The Standard Oil Company ("Standard Oil") and have held said common stock since prior to the announcement of the proposed tender-offer/freeze-out transaction described herein.

2. Defendant Standard Oil is an Ohio corporation with its principal place of business in Cleveland, Ohio. Standard Oil is engaged in all phases of the petroleum business, primarily in the United States, including the exploration for and production of crude oil and natural gas and the transportation, refining and marketing of crude oil and petroleum products. In addition (as a result of Standard Oil's purchase, in 1981, of Kennecott Corp.), Standard Oil is a major producer and marketer of copper, gold, silver and coal, and a leading supplier of refractories, copper,

brass, mill products and process systems and equipment. Standard Oil also manufactures and markets certain chemical products and products produced from ilmenite (an ore used to produce products for the pigment industry).

3. Standard Oil's oil and gas reserves and production facilities are located primarily in Alaska, Texas, Oklahoma, Louisiana and the Gulf of Mexico; its principal coal reserves and mines are located in Illinois, Indiana, Kentucky, Pennsylvania and West Virginia; and its ilmenite mine and processing facilities are located in Quebec, Canada. Standard Oil also has interests in oil shale and tar sands properties located in Colorado and Utah.

4. Standard Oil's most important assets are its petroleum reserves and exploration properties, which are located chiefly in Alaska and the Gulf Coast region, and its petroleum refining and marketing facilities. Standard Oil produces approximately one fifth of this country's oil output. As of the end of Standard Oil's most recent fiscal year, December 31, 1986, Standard Oil had reserves in approximately the following amounts: petroleum liquids, 2.41 billion barrels; and natural gas, 7.30 trillion cubic feet. Standard Oil also had reserves of 7.06 billion tons of coal; 100 million troy ounces of silver; 10.4 million troy ounces of gold; and 7.3 million tons of copper. These reserves have generated strong cash flow. For example, on or about January 22, 1987 defendants announced that Standard Oil would continue its quarterly dividend of $.70 per share, and retire debt early, citing strong cash flow from operations.

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5. Standard Oil has the equivalent of approximately 239 million shares of common stock outstanding. Standard Oil's common stock is traded on the New York and Midwest Stock Exchanges and, as of February 28, 1986, was held by approximately 55,760 shareholders of record. Approximately 130,160,000 shares of Standard Oil's common stock, or 55% of all such shares, are owned by defendant The British Petroleum Company p.l.c., through its wholly owned subsidiary, defendant BP International Limited.

6. Defendant the British Petroleum Company p.l.c. is a corporation organized under the laws of England. The British Petroleum Company and its subsidiaries (including its subsidiaries, defendants BP North America, Inc. and BP International Limited, collectively referred to hereinafter as "BP"), is the largest industrial concern in the United Kingdom, the second largest in Europe, and the fifth largest in the non-communist world. For the year ended December 31, 1985, (the most recent year for which BP has published audited financial results), BP had revenues of more than 59 billion dollars and profits of more than 2.3 billion dollars. In 1970, BP acquired 1,000 shares of Special Stock of Standard Oil, each such share equivalent to 125,840 shares of Standard Oil's common stock. BP also owns 4,320,000 shares of Standard Oil's common stock. As a result of BP's ownership of a majority of Standard Oil's voting shares (as well as BP's other relationships with Standard Oil), BP controls Standard Oil.

7. Defendant Robert B. Horton ("Horton") is Chairman of the Board and Chief Executive Officer of Standard Oil. In February, 1986, BP ousted Standard Oil's former Chairman and Chief Executive Officer, Alton W. Whitehouse, and installed Horton in those positions. Prior to February, 1986, Horton was a Managing Director of BP, in charge of BP's corporate finance and planning and its operations in the Western Hemisphere.

8. Defendant E. John P. Browne ("Browne") is Executive Vice President, Chief Financial Officer and a director of Standard Oil. In February, 1986, BP installed Browne in the position of Standard Oil's Executive Vice President and Chief Financial Officer; in April, 1986 BP placed him on Standard Oil's Board. Prior to February, 1986, Browne was Group Treasurer of BP and Chief Executive of BP Finance International.

9. Defendant J. Colin Webster ("Webster") is Executive Vice President and a director of Standard Oil. In 1985, BP placed him on Standard Oil's Board; in February, 1986, BP installed Webster as Executive Vice President of Standard Oil. Prior to February, 1986, Webster was President of BP North America. In July, 1986, Barron's reported with regard to defendants Horton, Browne and Webster: "All three have formally left BP, but few people doubt that Standard Oil is being seen as their proving ground. Turn Standard Oil around, and plum jobs await them back at Britannic House [BP's headquarters] should they wish to return."

10. Defendant Basil R.R. Butler ("Butler") is a Managing Director of BP and Chairman of BP Exploration Company Limited and

of BP Gas International Limited. BP placed Butler on the Board of Standard Oil in April, 1986.

11. Defendant Ian G.S. Hartigan ("Hartigan") is President of BP North America, a position he has held since April, 1986. Prior to then, he was Managing Director of BP Shipping. Also in April, 1986, BP installed Hartigan on the Board of Standard Oil.

12. Defendant Kenneth R. Keep ("Keep") is Technical Director of BP Exploration. BP installed him on the Board of Standard Oil in April 1986.

13. Defendant Frank E. Mosier ("Mosier") is President and Chief Operating Officer of Standard Oil. In February, 1986, BP ousted the former President and Chief Operating Officer of Standard Oil, John R. Miller, and installed Mosier in those positions. Mosier is a director of Standard Oil (since 1980). Mosier joined Standard Oil in 1953.

14. Defendant Richard A. Bray ("Bray") is Executive Vice President of Standard Oil and a director (since January, 1985). He joined Standard Oil in 1982. Prior to then, he was Managing Director of an oil exploration company in the United Kingdom.

15. The individual defendants constitute a majority of Standard Oil's directors. By reason of defendants' stock ownership and/or their positions with Standard Oil, defendants occupy a fiduciary relationship with the plaintiff and other public stockholders of Standard Oil and owe the plaintiff and the other members of the Class the highest obligations of good faith and fair dealing.

Class Action Allegations

16. Plaintiffs bring this action on their own behalf and as a class action, pursuant to Rule 23 of the Ohio Rules of Civil Procedure, on behalf of all common stockholders of Standard Oil (except the defendants herein and the members of the immediate families of the individual defendants), and their successors in interest, who are or will be threatened with the deprivation of their equity interest in Standard Oil by reason of the proposed elimination of the public stockholders of Standard Oil through the transactions hereinafter described.

17. This action is properly maintainable as a class action for the following reasons:

(a) The class of stockholders for whose benefit this action is brought is so numerous that joinder of all class members is impracticable. As of October 31, 1986, there were approximately 109 million common shares of Standard Oil outstanding (other than those owned by BP), owned by approximately 56,000 shareholders of record. Members of the class are scattered throughout the United States.

(b) There are questions of law and fact which are common to members of the class and which predominate over any questions affecting any individual members. The common questions include, inter alia, the following:

(i) whether the defendants have engaged in a plan and scheme to defraud the members of the class;

(ii) whether the defendants have engaged in a plan and scheme to unlawfully "freeze-out" the public stockholders of Standard Oil;

(iii) whether the proposed tender offer/freeze-out is so grossly unfair to the public stockholders of Standard Oil as to constitute a fraud upon them;

(iv) whether defendants have failed to disclose potential and expected positive future financial benefits to Standard Oil in order to depress the market price for Standard Oil to enable defendants to take Standard Oil private at a fraudulently low and unfair price;

(v) whether defendants have breached their fiduciary and the other common law duties owed by them to plaintiff and the members of the class; and

(vi) whether defendants are pursuing a course of business designated to eliminate the public shareholders of Standard Oil in violation of the laws of the State of Ohio.

(c) The claims of the plaintiffs are typical of the claims of the members of the class, and plaintiffs will fairly and adequately protect the interests of the class. Plaintiffs have retained attorneys who are thoroughly experienced in shareholder litigation.

(d) A class action is superior to other available methods for the fair and efficient adjudication of the claims which are asserted, and no unusual difficulties are likely to be encountered in the management of this class action. The likeli-

hood of the individual class members prosecuting separate claims is remote.

Cause of Action Against All Defendants

18. By virtue of the acts and conduct alleged herein, the defendants have carried out a preconceived plan and scheme to eliminate the public common stockholders of Standard Oil and wrongfully to permit defendants to appropriate the benefit of the ownership of Standard Oil, including its potential and continuing growth and profitability, while at the same time the public common stockholders of Standard Oil would be wrongfully deprived of their investment in Standard Oil and all of its present and continuing profitability and growth and would receive in return for their investment grossly inadequate consideration.

19. The sole and primary objective of that plan and scheme is to permit defendants to acquire the equity ownership of Standard Oil for a fraudulently low and unfair price. The plan and scheme constitutes an improper and unlawful attempt by defendants to freeze-out the public stockholders of Standard Oil.

20. In furtherance of this plan and scheme, on or about February 24, 1986, BP announced that it had peremptorily ousted Standard Oil's former Chairman of the Board and Chief Executive Officer and former President and Chief Operating Officer, and had installed its own handpicked officers, the individual defendants, as the management of Standard Oil. At the same time, BP "packed" the Board of Directors of Standard Oil so that, for the

first time, a majority of the Standard Oil Board consisted of executives appointed by BP. By those acts, BP made clear that it intended to operate Standard Oil for its own benefit, and that anyone who challenged BP's domination and control of Standard Oil would be instantly dismissed.

21. Pursuant to the plan and scheme of the defendants, on or about March 26, 1986, defendant BP announced a proposal to acquire the approximately 45% of Standard Oil's common stock that was not already owned by it. Under said plan, the common stockholders of Standard Oil would receive only Seventy Dollars ($70.00) per share.

22. Defendants' plan and scheme is an attempt to force out the public common stockholders of Standard Oil at a price which is far less than the common stock is worth, for the sole purpose of enriching the defendants. The Seventy Dollars ($70.00) per share price proposed to be paid to the public stockholders is so grossly inadequate and unfair as to constitute a fraud upon the shareholders of Standard Oil. The intrinsic value of the stock of Standard Oil is materially in excess of Seventy Dollars ($70.00) per share, giving due consideration to its assets, its growth and profitability, the underlying strength of its business, its earnings and earnings power, present and projected. The proposed price of Seventy Dollars ($70.00) per share is a fraudulent and unfair effort by the defendants to take advantage of current market conditions with respect to Standard Oil and deprive plaintiffs and the members of the public of the benefits

which defendants expect to obtain from the projected growth of Standard Oil's earnings.

23. The proposed tender offer/freeze-out price of Seventy Dollars ($70.00) per share is not the result of arm's-length negotiations and was not based upon any independent appraisal of the current value of Standard Oil's shares, assets, or business, but was fixed arbitrarily by the defendants themselves as part of their plan to obtain ownership of Standard Oil's assets and businesses at the lowest possible price and to obtain for themselves benefits disproportionate with those to be received by the public shareholders, which facts were not disclosed.

24. In proposing the freeze-out of Standard Oil's minority shareholders, defendants are seeking to appropriate for their own benefit, to the detriment of Standard Oil's public shareholders, Standard Oil's extraordinary potential for profitability and growth. For example:

(a) Defendants have timed the tender offer/freeze out to take advantage of the imminent surge in oil prices and recovery in the oil industry. Accordingly, securities analysts have estimated mean earnings per share for standard oil of $3.63 per share in 1987 and $4.79 in 1988, compared to a loss of $1.32 per share in 1986 and earnings of only $1.31 per share in 1985.

(b) Standard Oil has taken action in 1986 "to reposition the company so that it will perform well in an environment of low and volatile or due oil prices, based on the assumption that prices will average $15 per barrel Mreal terms

for the next few years." 1986 Standard Oil Annual Report. In fact, the price for crude oil on the spot market is already substantially in excess of $15 per barrel, closing on the New York Mercantile Exchange on March 25, 1987 at a price of $18.71 per barrel. Based on Standard Oil's current production levels, that increase in oil prices will increase Standard Oil's revenues and income by a material amount.

(c) Only last year, Standard Oil's former Chief Executive Officer (who defendants ousted) represented to Standard Oil's shareholders:

> Sohio Goal is Long-Term Value
>
> * * *
>
> Standard Oil's ability to create a competitive advantage is made easier by these factors:
>
> Financial stability is provided by cash flow generated by our large domestic hydrocarbon base.
>
> ***
>
> Investment Emphasis Shifts
>
> We have come a long way toward creating a strong, integrated energy company that is well positioned for the future.
>
> When Prudhoe Bay [Alaska reserves] was brought on stream, Standard Oil's business was small and narrow. Since then, we have made substantial investments in oil and gas exploration, coal reserves, metals mining, chemicals and most recently, petroleum refining and marketing.
>
> Our major positioning investments are behind us,...the major role of our investments now ill be...on translating our non-income pro-

ducing assets -- such as idle coal reserves and undeveloped exploration acreage -- into income producing assets.

***

We have witnessed large oil companies being acquired by other large companies, at prices well in excess of the previously prevailing stock market valuation....

These actions imply that the acquiring companies, while paying a premium over the stock market valuations, believe they are acquiring reserves and other assets cheaper and with less risk than they could by exploration and direct investment.

***

Reserves Increased

In 1984, we announced three production development projects in Alaska -- the endicott field, the Lisburne pool of the Prudhoe Bay field, and the Prudhoe Bay Miscible Gas Project.

In total, those three projects added 310 million barrels to our proved reserves. As a result [Standard Oil's] reserves at year-end 1984 exceeded those at year-end 1983 and 1982 as well (emphasis added and in the original).

(d) Then, shortly before his dismissal, he similarly represented to Standard Oil's shareholders:

In Alaska, our major oil and gas production projects are ahead of schedule and under budget. Also, the production plateau of the Prudhoe Bay field was extended into 1988 by continued development efforts.

We accelerated our evaluation of the substantial portfolio of exploration acreage acquired since 1981, particularly in Lower 48 States prospects.

In the Gulf of Mexico, we made significant discoveries on East Breaks Block 165 and Ewing Bank Block 826, and we have

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commenced construction of a production platform for the East Breaks discovery.

On the international front, where there is the opportunity to be exposed to sizable investment opportunities at higher rates of return, we acquired a three-million-acre concession offshore Qatar and entered into a Canadian exploration joint venture.

In refining and marketing, the newly acquired Gulf Oil Corporation properties contributed importantly to that business's improved income (emphasis added).

(e) Worldwide economic and political conditions at the present time have resulted in the recognition of the value of oil and gas reserves in the United States, coupled with industry recognition that long term oil and gas prices will substantially increase. For example, BP's Chairman, Sir Peter Walters was quoted in July 1986 as stating that, "The lower the oil price goes now, the more likely it is to bounce back in the 1990's." Also, in July, 1986, Sir Peter Walters admitted that BP was "always looking at it [the publicly held portion of Standard Oil." He conceded then: "Although it may be cheaper to make the bid now, cheap is not cheap if it is not in the right shape. Better to pay higher prices for more valuable objects when you're sure of the value" (emphasis added).

(f) During 1986, Standard Oil recently announced that it was disposing, modernizing and writing off certain assets, including portions of Kennecott's mining and metals business it acquired in 1981. Since their acquisition by Standard Oil, those operations have consistently been unprofitable. Disposition and

modernization of these assets and associated tax benefits will not only provide defendants with substantial funds to pay for the freeze-out of Standard Oil's public shareholders, but also will very materially increase Standard Oil's cash flow and profitability. Standard Oil stated that it expected this program to provide more than $500 million of net cash inflows and provide additional income in future years. BP has conceded that, although "[t]he immediate result [of these changes] is very large write-offs in copper and coal mining, oil and gas exploration and stiff redundancy payments [, i]n the long run, of course, Standard Oil will be operating from a stronger base (emphasis added)."

(g) The proposed tender offer/freeze-out of Seventy Dollars ($70.00) for each share of Standard Oil stock translates into a total value of approximately $7.4 billion assigned by BP to all of Standard Oil's reserves, undeveloped acreage, refining and marketing operations and other businesses, less Standard Oil's debt. Based upon evaluations of oil and gas reserves by recognized appraisers and geologists and prices paid and offered in other recent acquisitions and mergers in the oil industry, the true value of Standard Oil's net assets is substantially in excess of the Seventy Dollars ($70.00) tender offer/freeze-out price.

(h) The price of Seventy Dollars ($70.00) per share represents a discount from the true net asset value of Standard Oil far exceeding the discount in comparable transactions, in-

cluding the acquisition price offered by Texaco, Inc. for the Getty Oil Company, and the damages recently awarded to Pennzoil, Inc., for the loss of Getty's oil reserves.

(i) Standard Oil recently purchased from Gulf Oil Corp. a refinery in Louisiana with a capacity of 200,000 barrels per day, for a price of approximately $583 million (including $268 million of inventories), at a time when refining and marketing margins were recovering dramatically, so that, for the year ended December 31, 1985, Standard Oil's refining and marketing earnings increased more than 100%, to $424 million. In July, 1986, Barron's reported that Standard Oil's "downstream operations are among the most profitable of any oil major, and [Sir Peter] Walters describes the recent $613 million purchase of Gulf Oil's refining and marketing operations in the Southeast as 'a super buy'."

(j) Standard Oil recently eliminated approximately 1,300 staff positions, which will enable Standard Oil to enjoy dramatic future cost savings.

(k) In preparation for this unlawful and grossly unfair tender offer/freeze out, management of Standard Oil, which are controlled by B.P., implemented a plan to effectuate early retirement of $1.3 billion of debt associated with nine separate debt issues through early redemption, tender offers and purchase in the open market. The early retirement of certain of the high-coupon debt will produce a substantial pre-tax interest savings to Standard Oil.

25. Although defendants are now sure that Standard Oil, its assets and its business, are extremely valuable, they are attempting to violate their own admonition to pay "higher prices" for that business and those assets.

26. Prior to announcing the proposed freeze-out, defendants did not (i) undertake an adequate evaluation of Standard Oil's worth as potential merger or acquisition candidate or take adequate steps to enhance Standard Oil's value or attractiveness as a merger or acquisition candidate; (ii) effectively attempt to dispose of Standard Oil's assets; (iii) act so that the interests of the public security holders were protected.

27. The marketplace has already determined that the Seventy Dollars ($70.00) per share is unfair. Within several hours of the announcement of the tender offer/freeze out on March 26, Standard oil stock was trading at Seventy-Two Dollars ($72.00) on the New York Stock Exchange. Additionally, BP stock has also risen $2.6125 within hours of the announcement, as the marketplace has recognized the synergistic value of the combination of the companies.

28. The tender offer/freeze-out serves no legitimate business purpose of Standard Oil, and is an attempt by the defendants to aggrandize their own interests and finances at the expense and to the detriment of the public stockholders of Standard Oil. The proposed freeze-out will deny class members their right to share proportionately in the true value of Standard Oil's valuable assets, profitable businesses, and future growth in profits,

earnings, and profitable businesses, while usurping the same for the benefit of the defendants at a fraudulently unfair and inadequate price. Because defendants control the business and corporate affairs of Standard Oil (and because they are in possession of corporate information concerning Standard Oil's assets, businesses, and future financial prospects), the knowledge and economic power between defendants and the common stockholders of Standard Oil is unequal which makes it grossly and inherently unfair for the defendants to obtain ownership of Standard Oil's assets from the public security holders at the unfair and inadequate price which defendants (and those acting in concert with them) have set.

29. Moreover, defendants have timed the announcement of the proposed tender offer/freeze-out transaction to take unfair advantage of foreign currency fluctuations and adjustments, which, at present, provide defendants with an unfair, short-term advantage.

30. In addition, Standard Oil's business is especially valuable to BP because, (a) Standard Oil's large domestic reserves provide BP with the assurance of a steady flow of petroleum products necessary to supply BP's huge refining capacity; and (b) pursuant to BP's accounting policies, BP can reduce Standard Oil's deferred taxation charge to a restricted liability basis and increases the value of Standard Oil's inventory to an amount calculated using a first-in, first-out method.

31. As a result of the foregoing, defendants herein have willfully participated in the perpetuation of a fraud upon the members of the class and have engaged in, knowingly and substantially assisted in, and aided and abetted each other in a breach of their fiduciary duty to the class.

32. The plaintiffs and the other class members are imminently threatened by the acts and transactions complained of herein, which if effectuated, would cause irreparable injury to them.

33. The plaintiffs and members of the class have no adequate remedy at law.

WHEREFORE, the plaintiffs demand judgment, as follows:

A. Enjoining, preliminarily and permanently, the consummation of the proposed transaction and freeze-out of the class members and their equity interest in Standard Oil;

B. In the event that the proposed acquisition of Standard Oil is consummated, rescinding it and setting it aside;

C. Requiring that the defendants account to the plaintiffs and other class members for all damages, including rescissory damages, and injuries sustained by the class as a result of the acts and transactions complained of herein;

D. Awarding to plaintiffs the costs and disbursements of this action, including a reasonable allowance for the fees and expenses of their attorneys, experts and accountants; and

TOTAL P.23

E. Granting such other and further relief as may be just and proper in the premises.

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EXHIBIT (h)

Statement of Income

Millions of Dollars, Except Per-Share Amounts—Year Ended December 31	1986	1985	1984
Revenues			
Sales and operating revenue	$ 9,219	$13,002	$11,692
Excise taxes	803	816	559
	10,022	13,818	12,251
Costs and Expenses			
Costs of products sold and operating expenses	4,903	6,156	5,406
Taxes other than income taxes	1,368	1,817	1,579
Depreciation, depletion and amortization	1,158	927	796
Oil and gas exploration expenses, including amortization of unproved properties	926	1,101	704
Selling, general and administrative expenses	954	943	728
Unusual items (Note B)	1,079	1,699	90
	10,388	12,643	9,303
Income (Loss) Before Interest, Income Taxes and Extraordinary Item	(366)	1,175	2,948
Interest expense	(335)	(396)	(374)
Interest income	93	97	132
Income (Loss) Before Income Taxes and Extraordinary Item	(608)	876	2,706
Income taxes (Note G)	297	(568)	(1,218)
Income (Loss) Before Extraordinary Item	(311)	308	1,488
Extraordinary item—loss on extinguishment of debt, net of income taxes (Note F)	(34)	—	—
Net Income (Loss)	$ (345)	$ 308	$ 1,488
Per Share of Common Stock			
Income (loss) before extraordinary item	$ (1.32)	$ 1.31	$ 6.14
Extraordinary item	$ (.15)	—	—
Net income (loss)	$ (1.47)	$ 1.31	$ 6.14
Cash dividends	$ 2.80	$ 2.80	$ 2.65
Average Number of Common and Equivalent Shares Outstanding (millions)	235	235	242

Statement of Retained Earnings

Balance at beginning of year	$ 7,628	$ 7,977	$ 7,128
Net income (loss)	(345)	308	1,488
Cash dividends			
Common	(305)	(305)	(306)
Special	(352)	(352)	(333)
Balance at end of year	$ 6,626	$ 7,628	$ 7,977

The Notes to Financial Statements are an integral part of these statements.

Balance Sheet

Millions of Dollars—December 31	1986	1985
Assets		
Current Assets		
Cash, including time deposits of $6 and $37	$ 138	$ 120
Marketable securities at cost, which approximates market	275	235
Accounts receivable, less allowances of $20 and $17	861	1,611
Refundable Federal income taxes	771	—
Inventories (current cost—$1,429 and $2,247)	1,200	1,437
Net investment in operations to be divested	127	—
Prepaid expenses and deferred charges	83	92
	3,455	3,495
Property, Plant and Equipment		
Petroleum		
Exploration and production (successful efforts accounting method)	13,733	13,502
Refining and marketing	2,130	1,998
Coal	501	962
Metals mining	1,396	2,114
Chemicals	468	461
QIT	279	219
Other businesses	290	420
Corporate and other	454	460
	19,251	20,136
Less accumulated depreciation, depletion and amortization	7,434	7,001
	11,817	13,135
Other Noncurrent Assets		
Investments in unconsolidated affiliates	218	291
Receivables	333	390
Prepaid expenses and deferred charges	132	197
	683	878
	$15,955	$17,508

Millions of Dollars—December 31	1986	1985
Liabilities and Shareholders' Equity		
Current Liabilities		
Notes payable	$ 318	$ 72
Current maturities of long-term obligations	101	328
Accounts payable	974	1,568
Accrued income and other taxes	365	413
Accrued interest	134	113
Other	554	733
	2,446	3,227
Long-Term Obligations and Accruals		
Long-term debt	2,951	2,962
Capital lease obligations	325	343
Accruals and reserves	1,152	1,300
	4,428	4,605
Deferred Income Taxes	2,061	1,658
Shareholders' Equity		
Capital stock		
Common—$1.25 stated value, 300 million shares authorized, shares issued—122,498,893 and 122,337,553	154	154
Special—stated value, 1,000 shares authorized and issued	25	25
	179	179
Additional paid-in capital	822	818
Retained earnings	6,626	7,628
Common stock in treasury, at cost—13,626,248 shares and 13,623,050 shares	(607)	(607)
	7,020	8,018
	$15,955	$17,308

The Notes to Financial Statements are an integral part of these statements.

Statement of Changes in Financial Position

Millions of Dollars – Year Ended December 31	1986	1985	1984
Cash Was Provided From (Used For)			
Operations			
Income (loss) before extraordinary item	$ (311)	$ 308	$1,488
Noncash charges			
Depreciation, depletion and amortization	1,158	927	796
Amortization and impairment of unproved oil and gas properties	558	459	266
Dry hole costs expended in prior year	89	131	21
Deferred income taxes	389	119	447
Unusual items	647	1,550	90
Other—net	44	77	(89)
Working capital provided from operations	2,574	3,571	3,019
(Increase) decrease in operating working capital (Note R)	(770)	(97)	164
Cash provided from operations	1,804	3,474	3,183
Dividends	(657)	(657)	(639)
Investment Activities			
Capital expenditures	(1,618)	(2,144)	(2,329)
Less dry hole costs expended in current year	104	202	116
	(1,514)	(1,942)	(2,213)
Acquisition of certain Gulf refining and marketing operations, including inventories of $273	–	(613)	–
Net book value of property, plant and equipment sold	289	105	67
Sale of long-term marketable securities	8	462	6
Change in investment working capital	100	(7)	(26)
Other	(49)	(43)	5
Cash used for investments	(1,166)	(2,038)	(2,161)
Financing Activities			
Issuance of long-term debt	1,189	408	–
Reduction of long-term debt	(1,200)	(668)	(259)
Extraordinary item—loss on extinguishment of debt	(34)	–	–
Purchase of common stock for treasury	–	(32)	(561)
Changes in financing working capital			
Sale of accounts receivable to finance subsidiary	(32)	(411)	376
Increase (decrease) in short-term notes payable	246	(265)	312
(Decrease) increase in current maturities of long-term obligations	(227)	203	(3)
Other	135	4	(2)
Cash provided from (used for) financing	77	(761)	(137)
Increase in Cash and Short-Term Marketable Securities	$ 58	$ 13	$ 246

The Notes to Financial Statements are an integral part of these statements.

Note A: Major Accounting and Financial Reporting Policies

Reclassification: The December 31, 1985, Balance Sheet reflects the reclassification of certain reserves, which were established for losses on disposition, shutdown and modification of operations, from long-term obligations to net property, plant and equipment. Certain other amounts in previously issued financial statements have been reclassified to conform to 1986 presentations.

Consolidation: Majority-owned joint-venture financing and mining companies and the Company's 33.34% undivided interest in the trans-Alaska pipeline are consolidated on a pro rata basis. The Company's investment in Standard Oil Finance Company, a wholly-owned finance subsidiary, and operations which it has decided to divest are accounted for using the equity method. The Company fully consolidates in its financial statements the accounts of all other significant subsidiaries in which it owns more than 50% of the voting stock.

Inventories: Inventories are stated at cost, but not in excess of net realizable value. The cost of inventories is determined primarily on the last-in, first-out method, except for foreign product inventories and materials and supplies for which cost is determined using the first-in, first-out or average cost method.

Exploration and Development

Petroleum: The successful efforts method of accounting is followed for costs incurred in oil and gas exploration and development operations.

Property acquisition costs for unproved oil and gas properties are initially capitalized. The acquisition costs for individually significant unproved properties are assessed at least annually on a property-by-property basis, and any impairment in value is recognized currently. The acquisition costs of all other unproved properties that are not individually significant ("pooled properties") are aggregated, and the portion of such properties estimated to be nonproductive based on past experience are amortized over their weighted average expected holding period. Revisions of estimates that affect pooled properties are generally accounted for prospectively using revised amortization rates. However, current period income may be charged if a material, unusual event results in a significant change in expected exploration activities. Costs of properties surrendered are charged against the applicable valuation allowance.

Exploratory drilling costs are initially capitalized. If and when exploratory wells are determined to be nonproductive, the related costs are charged to expense. Other exploration costs, including geological, geophysical and carrying costs, are charged to expense as incurred.

When a property is determined to contain proved reserves, property acquisition costs and related exploratory drilling costs of successful wells are transferred to proved properties.

Development costs of proved properties, including producing wells and related facilities and any development dry holes, are capitalized.

Coal and Metals Mining: Exploration and development expenditures are generally charged to expense as incurred until a decision is made to develop a mineral reserve. Expenditures to bring new properties into production and major expenditures of a nonrecurring nature are deferred and amortized ratably over the production benefited. Expenditures for continuing development required to maintain production are charged to expense as incurred.

Property, Plant and Equipment

Depreciation, Depletion and Amortization Costs: Depreciation of the trans-Alaska pipeline is computed by the unit-of-throughput method based on estimated applicable proved crude oil reserves. Depletion and depreciation of proved oil and gas properties and depletion of mine development costs, mineral lands and leaseholds are computed for each oil and/or gas reservoir or mine using the unit-of-production method based on applicable reserves. Other property, plant and equipment is depreciated principally by the straight-line method over estimated useful lives which are revised periodically based on experience.

Dismantlement, Restoration and Reclamation Costs: The estimated future costs of dismantling, restoring and reclaiming certain major properties and facilities, less estimated residual values, are accrued during operations.

Capitalized Interest: Interest costs incurred in connection with significant expenditures for the construction or acquisition of property, plant and equipment are capitalized.

Property Dispositions: Upon disposition of property, plant and equipment, the asset cost and related accumulated depreciation are eliminated from the respective accounts. Any gain or loss is included in current operations, except those related to dispositions of pipeline property and partial dispositions of oil and gas properties which are normally recorded as adjustments to the accumulated depreciation account.

Impairment: Except for impairment of unproved oil and gas properties discussed above, reductions in the utility of major units of property, plant and equipment, which the Company intends to hold and operate, caused by obsolescence due to technological, economic or other

changes are generally recognized over the remaining productive lives of the assets. However, if it is determined that the book value of property, plant and equipment exceeds future estimated cash flows (undiscounted) over the remaining productive life of the asset, such excess is charged to expense in the period of determination. Property, plant and equipment held for divestment is written down to estimated net realizable value to the extent it is less than net book value.

Warrants and Indexed Debt Instruments: Proceeds from the issuance of warrants and the contingent payment portion of indexed debt instruments are deferred and recorded as long-term liabilities. Subsequently, the deferred liability is valued at the higher of premium received or market (the difference between the applicable commodity or other market value and the exercise price of the warrant or indexed debt instrument) until the warrant or indexed instrument is either exercised or expires.

Earnings Per Share: Earnings per share of common stock is based on the weighted average number of common shares outstanding and shares to which the special stock is equivalent.

Note B: Unusual Items

During 1986 the Company recorded special charges of $1.08 billion pretax ($588 million after tax) which are classified as unusual items in the Statement of Income. These unusual items provided for the following by business segment:

- $283 million in exploration and production, of which $200 million was to write down the Eugene Island and Mississippi Canyon high-cost, short-lived oil and gas producing properties, because estimated future cash flows were no longer expected to recover current book values. Additionally, the charges included $65 million that represented the excess of the Company's settlement with the Internal Revenue Service of the windfall profit tax valuation of Alaskan crude oil for the period 1980-1983 over amounts previously provided. The balance of the charges related to staff reduction and restructuring.
- $300 million in coal, of which $271 million was related to the disposal of nonoperating properties. Other charges related to a variety of issues.
- $353 million in metals mining, of which $334 million provided for disposal of the Ray and Chino copper mines, which did not fit the Company's long-term business plans. Other charges related to a variety of issues.
- $140 million in other businesses, $124 million of which related to the disposal of assets that did not fit the Company's long-term business plans. The balance of the charges related to a variety of issues.
- $3 million in corporate and other.

The 1985 unusual items charges of $1.70 billion pretax ($1.07 billion after tax) provided for the following by business segment:

- $284 million in exploration and production. This included $140 million related to various regulatory issues associated with Alaskan operations and $144 million for staff reductions and restructuring, including the cost of closing offices in San Francisco and Denver and relocating personnel.
- $47 million in refining and marketing for staff restructuring.
- $526 million in coal related to the disposal of certain undeveloped coal properties; the partial write-down of equipment and mine development costs at certain high-cost operating mines to the extent that estimated cash flows subsequent to 1985 would not recover then existing book values; a write-down of the value of certain coal reserves because of current and foreseeable economic conditions; and a variety of other issues.
- $686 million in metals mining related to certain assets made excess or obsolete by the Bingham Canyon modernization; a provision for shutdown costs subsequent to 1985 which are being incurred during the period Bingham Canyon operations are suspended; a write-down of the value of certain copper reserves because of current and foreseeable economic conditions; the disposal of the uranium operations; and a reassessment of other aspects of the metals mining business.
- $14 million in chemicals related to staff restructuring and a variety of other issues.
- $8 million in QIT related to the anticipated disposal of a division.
- $54 million in other businesses, primarily related to costs for various facilities consolidation and modification of operations.
- $80 million in corporate and other, of which $54 million related to the write-down of the value of shale oil properties due to current and foreseeable economic conditions, with the balance related to staff reduction and restructuring costs.

The 1984 exploration and production unusual item of $90 million pretax ($50 million after tax) was provided to cover various regulatory issues associated with Alaskan operations.

In addition to these unusual items, the exploration and production business recorded pretax charges of $410 million and $165 million in 1986 and 1985, respectively, for the impairment of leases held in the oil and gas prospect inventory, over and above normal lease amortization expense. These charges were included in exploration expenses in the Statement of Income and resulted from technical reassessment and lower expected future oil prices.

Note C: Major Acquisitions and Divestitures

On February 1, 1985, the Company acquired from Gulf Oil Corporation (Gulf) its 200,000 barrel-per-day refinery in Belle Chasse, Louisiana, and most of its Southeastern United States petroleum marketing operations, including certain inventories, for $583 million. Following Federal Trade Commission approval, the Company acquired on July 1, 1985, Gulf's Lake Charles, Louisiana, coke calciner and related inventories for $30 million.

The Gulf operations have been included in the Company's financial statements since acquisition dates. Pro forma effects, assuming the acquisition had taken place on January 1, 1984, are not presented as they would not materially change reported consolidated results of operations.

During 1986 the Company completed major asset disposals, primarily in the metals mining, coal and other businesses segments. Proceeds from asset sales totalled $387 million in 1986.

Metals Mining: The Ray and Chino copper mines were sold for approximately $160 million, excluding finished goods inventories to be sold in 1987. The Ray Mines Division was sold to Asarco Incorporated. The Company's two-thirds interest in Chino Mines Company was sold to Phelps Dodge Corporation at the close of business on December 31, 1986. The agreements provide that the Company may receive additional amounts based on future increases in copper prices. The Company sold its interest in the Crixas (Brazil) gold property for $30 million. Certain other nonoperating properties, including the Baltimore copper refinery and rod mill and the Ozark lead mine and concentrator, were also sold.

Coal: The Company relinquished 615 million tons of reserves in West Virginia, Pennsylvania and Illinois. This reserve reduction included the permanent closure of the Kitt coal mine, the sale of company-owned undeveloped reserves, and the termination of a lease on certain undeveloped coal reserves. This lease required the payment of minimum coal royalties over the next fifteen years.

Other Businesses: Certain electro minerals operations were sold to a group of private investors. The Pangborn business, targeted for divestiture in a previous year, was also sold. In addition, the Company announced its intention to sell other industrial products businesses including Dorr-Oliver and Pfaudler.

Except for the Crixas sale, the financial effects of the above divestitures were included in the 1985 and 1986 charges for unusual items. The Company also sold sundry assets and real estate for $88 million in 1986.

In 1985 and 1984 proceeds from asset disposals totalled $222 million, the largest of which was the sale of the retail agricultural chemicals business in 1985. Included in the 1985 disposals were 362 million tons of undeveloped coal reserves.

Note D: Business Segment Information

Millions of Dollars	1986 Operating Income (Loss) (Before Interest, Income Taxes and Extraordinary Item)	1986 Charges for Unusual Items Included in Operating Income	1985 Operating Income (Loss) (Before Interest, Income Taxes and Extraordinary Item)	1985 Charges for Unusual Items Included in Operating Income	1984 Operating Income (Loss) (Before Interest, Income Taxes and Extraordinary Item)	1984 Charges for Unusual Items Included in Operating Income
Petroleum						
Exploration and production	$ 13	$ 283	$2,442	$ 284	$2,954	$ 90
Refining and marketing	436	–	351	47	200	–
	449	283	2,793	331	3,154	90
Coal	(255)	300	(518)	526	61	–
Metals mining	(342)	353	(851)	686	(160)	–
Chemicals	57	–	39	14	45	–
Oil	110	–	80	8	41	–
Other businesses	(151)	140	(98)	54	(33)	–
Corporate and other						
Research and development/ventures	(76)	–	(93)	–	(63)	–
Central functions	(77)	–	(78)	–	(74)	–
Other	(81)	7	(99)	80	(23)	–
Total corporate and other	(234)	7	(270)	80	(160)	–
	$ (366)	$1,079	$1,175	$1,699	$2,948	$ 90

Millions of Dollars	1986	1985	1984
Revenues			
Petroleum	$ 7,959	$11,425	$ 9,480
Coal	465	437	465
Metals mining	178	270	482
Chemicals	475	551	643
QIT	337	303	257
Other businesses	708	857	909
Corporate and other	(28)	23	15
Intersegment eliminations	(72)	(48)	–
	$10,022	$13,818	$12,251
Assets			
Petroleum			
Exploration and production	$ 9,677	$ 9,608	$ 9,366
Refining and marketing	2,469	2,949	2,079
	11,146	12,557	11,445
Coal	376	679	1,131
Metals mining	1,289	1,729	2,317
Chemicals	347	402	495
QIT	458	365	318
Other businesses	390	736	715
Corporate and other	1,949	1,040	1,066
	$15,955	$17,508	$17,487
Capital expenditures			
Petroleum			
Exploration and production	$ 1,121	$ 1,535	$ 1,633
Refining and marketing	185	489	247
	1,306	2,024	1,880
Coal	53	74	51
Metals mining	101	98	176
Chemicals	10	13	23
QIT	68	80	19
Other businesses	42	81	58
Corporate and other	38	114	122
	$ 1,618	$ 2,484	$ 2,329
Depreciation, depletion and amortization expense			
Petroleum			
Exploration and production	$ 904	$ 671	$ 548
Refining and marketing	110	98	65
	1,014	769	613
Coal	44	45	42
Metals mining	15	32	50
Chemicals	23	22	38
QIT	14	12	11
Other businesses	23	24	23
Corporate and other	25	23	19
	$ 1,156	$ 927	$ 796

Exploration and production includes the trans-Alaska pipeline and tankers used to transport Alaskan crude oil. Metals mining includes the mining and production of copper, gold, silver and molybdenum. QIT consists of the mining and production of low-manganese iron and titanium dioxide slag. Other businesses includes the fabricating and manufacturing of metal products, process equipment and engineered materials.

Net operating results and net assets for the Company's business operations that were identified for divestment have been included in corporate and other since the decision to divest was made in mid-1986.

Petroleum revenues include certain sales of crude oil, sales of natural gas and refined products, and revenues from the transportation of crude oil and refined products. Only sales of company-owned crude oil production that is surplus to refinery supply requirements are reported as revenues. Other sales of crude oil and the net effect of crude oil and refined products exchange transactions are included in costs of products sold.

Business segment assets are those used directly in the operations of each segment and consist primarily of net property, plant and equipment, inventories and accounts receivable. Corporate and other assets consist primarily of cash and marketable securities, investments in certain unconsolidated affiliates, net property, plant and equipment related to corporate headquarters and corporate research facilities and, in 1986, refundable Federal income taxes and net assets of businesses intended to be divested.

Capital expenditures for refining and marketing include $340 million for the acquisition of certain Gulf Oil Corporation properties in 1985 and $84 million for the acquisition of Truckstops Corporation of America in 1984.

Note E: Major Credit Arrangements and Shelf Registration Statements

Effective December 1, 1986, the Company entered into agreements with 45 domestic and foreign banks for committed lines of credit totalling $2 billion and uncommitted lines of credit totalling $3.5 billion.

The committed lines of credit, which extend for a period of seven years, require the Company to pay commitment fees on the unused portion of the lines of credit. Borrowings will be at prevailing money market rates.

No borrowings were outstanding at December 31, 1986, under the committed lines; however, a portion was committed by management as back-up for outstanding commercial paper borrowings of the Company and its finance subsidiary ($398 million outstanding at December 31, 1986). Additionally, these lines of credit are available to finance the $239 million of variable rate demand revenue bonds (Note F) and for other corporate purposes.

The uncommitted lines are promises by banks to make reasonable endeavors to lend the Company money, should it be needed. These lines will be reviewed periodically. No borrowings were outstanding at December 31, 1986, under these lines.

At December 31, 1986, the Company had on file shelf registration statements with the Securities and Exchange Commission enabling the issuance of up to $344 million in debt securities.

Note F: Long-Term Debt—Excluding Current Maturities

Millions of Dollars—December 31	1986	1985
13¾% notes due 1992	$ 128	$ 150
10⅞% debentures due 1994-2017	–	150
10⅝% notes due 1988-1998	11	673
10½% notes due 1989	150	150
10% notes due 1992	95	11
9¾% notes due 1988-1998	–	179
9¾% debentures due 1988-1999	34	144
8¾% debentures due 1988-2001	227	235
8½% debentures due 1988-2000	101	101
8¼% debentures due 1988-2007	244	250
8% notes due 1993	150	–
8% notes due 1996	90	–
7⅞% debentures due 1988-2001	120	120
7¾% notes due 1991	150	–
7½% Swiss franc foreign interest payment bonds (issued 1986)	100	–
7% notes due 1991	150	–
6½%–7½% pollution control revenue bonds due 1993-2007	120	120
6.3% debentures due 2001	300	–
6.05% marine terminal revenue bonds due 1998-2007	161	161
6% marine terminal revenue bonds due 1998-2007	180	180
3⅛% Swiss franc bonds due 1993	93	–
Oil indexed notes due 1990 and 1992	75	–
Variable rate demand marine terminal revenue refunding bonds due 2025	94	94
Floating rate monthly demand revenue bonds due 2012	12	124
Variable rate demand revenue bonds due 2009-2020	145	145
Other(1)	213	178
	3,141	3,165
Unamortized debt discount	(190)	(91)
Funds held in trust(2)	–	(112)
	$2,951	$2,962

(1) Includes $4 million (40,537 shares) and $4 million (42,548 shares) of Series A redeemable preferred stock outstanding at December 31, 1986 and 1985, respectively.
(2) Represents funds held in trust for the redemption at par in early 1986 of $112 million of floating rate monthly demand revenue bonds.

During 1986 the Company used proceeds from the sale of assets to repay the $150 million 10⅞% debentures. The Company also repaid $612 million of the 10⅝% notes, $167 million of the 9¾% notes and other debt before scheduled maturity. Some of this debt was repaid at prices reflecting a premium to the par amount. The loss from these debt extinguishments, which totalled $34 million after tax, has been classified as an extraordinary item on the Statement of Income.

The Company has an option every ten years to redeem all but not part of the then outstanding Swiss franc 200 million 7½% foreign interest payment bonds at a redemption price equal to 100% of the Swiss franc par value. Every ten years the bondholders will also be entitled to redeem their holdings. The redemption value available to the bondholder will be 100% of the Swiss franc par value unless the exchange rate of U.S. dollars to Swiss francs is less than 1 to 2.01, in which case bondholders would receive the Swiss franc equivalent of $99.5 million. The interest rate for the first ten years will be 7½% per annum payable in U.S. dollars. If the bonds are not redeemed, the interest rate will be adjusted every ten years to equal the yield of current 10-year U.S. Treasury obligations minus ½%. The Company also entered into an interest rate swap agreement which effectively converts the fixed rate for this debt issue to a floating U.S. dollar interest rate.

The oil indexed notes, issued in $1,000 denominations, are comprised of 37,500 notes due in 1990 and 37,500 notes due in 1992. Interest on the notes will be paid only upon maturity or redemption based on the spot price of West Texas Intermediate (WTI) crude oil. Notes can be redeemed at the end of each month for one year preceding the date of maturity. An average price will be calculated semimonthly commencing on January 1, 1990, for the 1990 notes and on April 1, 1991, for the 1992 notes based on the spot prices of WTI over approximately 20 trading days. The excess of that indexed price above $25 per barrel, up to a maximum indexed price of $40 per barrel, will be multiplied by 170 barrels for each 1990 note and 200 barrels for each 1992 note to determine the interest on the notes. The amount allocated to the contingent interest rights is included in accruals and reserves on the Balance Sheet.

The Swiss franc 150 million bonds with an annual coupon of 3⅛% will mature on November 6, 1993, and will not be redeemable prior to maturity. Concurrent with the issuance of these notes, the Company entered into a cross-currency interest rate swap which effectively eliminates the Company's exposure to currency exchange rate fluctuations and converts the 3⅛% Swiss franc fixed interest rate to a floating U.S. dollar interest rate. Each Swiss franc 5,000 bond includes one detachable gold warrant representing 3.3 ounces of gold exercisable at the holder's option monthly beginning November 6, 1987, and expiring November 6, 1991. Upon exercise the holder may purchase gold at the exercise price of $565.20 per troy ounce or receive in U.S. dollars the excess, if any, of the spot price of gold over the exercise price. The amount allocated to the gold warrants is included in accruals and reserves on the Balance Sheet.

Demand revenue bonds bear interest at rates that reflect prevailing market interest rates for short-term tax-exempt securities. The bonds may be converted to a fixed rate under specified conditions.

The Company intends to finance the $239 million of variable rate demand revenue bonds on a long-term basis and has lines of credit which enable it to borrow for a period in excess of one year (Note E).

The Company uses interest rate swap agreements as a debt management tool. In addition to the agreements noted above, during 1986 the Company entered into interest rate swap agreements which effectively provide for fixed rate refinancing of certain debt that is not currently callable.

Scheduled maturities of long-term debt (in millions) for the five years from December 31, 1986, are: 1987-$83; 1988-$98; 1989-$206; 1990-$109; 1991-$364.

In 1987 the Company issued debt securities in the Japanese market which included $50 million of U.S. dollar denominated 7⅞% notes due in 1997 and 8 billion yen (approximately $48 million net proceeds) of 7⅞% dual currency notes due in 1994. In 1987 the Company also issued Swiss franc 108 million (approximately $68 million net proceeds) of 4¾% bonds at par due in 2000.

Note 6: Taxes

Millions of Dollars – Year Ended December 31	1986	1985	1984
Income (loss) before income taxes and extraordinary item			
Domestic	$ (729)	$ 805	$2,662
Foreign	121	71	44
	$ (608)	$ 876	$2,706
Income taxes			
Federal			
Current	$ (738)	$ 331	$ 681
Deferred	365	110	441
Foreign			
Current	15	24	15
Deferred	24	9	6
State	37	94	74
	$ (297)	$ 568	$1,218
Tax effect of extraordinary loss on extinguishment of debt	$ (33)	–	–
Taxes other than income taxes			
Excise	$ 803	$ 816	$ 559
Production and severance	284	671	630
Windfall profit	–	18	87
Real estate and personal property	195	194	183
Payroll	60	79	86
Other	26	39	34
	$1,368	$1,817	$1,579

Investment tax credits are recognized using the flow through method and include credits on qualified progress expenditures.

Deferred taxes reflect the differences in timing of recognition of certain revenues and expenses for financial and tax reporting. Deferred income taxes were provided for the following items:

Millions of Dollars – Year Ended December 31	1986	1985	1984
Depreciation	$370	$372	$350
Intangible drilling costs	24	91	90
Lease amortization and other exploration expenses	71	24	(66)
Unusual items – loss provisions deductible in different periods for financial and tax reporting	(112)	(428)	(40)
Dismantlement, restoration and reclamation	(53)	(24)	(30)
Inventories	65	–	–
Pensions	40	4	4
Other	(16)	80	139
Deferred income taxes	$389	$119	$147

The following summarizes the difference between the Company's effective income tax rate and the statutory Federal income tax rate:

Millions of Dollars – Year Ended December 31	1986		1985		1984	
Income (loss) before income taxes and extraordinary item	$ (608)	(100.0)%	$ 876	100.0%	$2,706	100.0%
Statutory Federal income tax	$ (280)	(46.0)%	$ 403	46.0%	$1,245	46.0%
Effect of:						
State income taxes	20	3.3	51	5.8	40	1.5
Investment tax credit	(47)	(7.7)	(63)	(7.2)	(71)	(2.6)
Unusual items*	5	.8	150	17.1	–	–
Other	5	.8	27	3.1	4	.1
Income tax expense and effective rate	$ (297)	(48.8)%	$ 568	64.8%	$1,218	45.0%

*Primarily differences in book and tax bases of assets and liabilities as a result of the application of purchase accounting principles in business acquisitions.

Note 11: Redetermination

The unit operating agreement under which the Prudhoe Bay oil field is operated required a final redetermination of participating interests, based upon improved technical knowledge of the reservoir as a result of field operations.

In 1982 the Company, the Atlantic Richfield Company and Exxon Corporation (the three major interest owners holding a total of almost 94% in the Prudhoe Bay oil field) reached an agreement regarding final redetermination of participating interests in the Prudhoe Bay field.

Under the agreement, which was not binding on the other participants in the field, the Company's participating interest in the oil reservoir decreased from 53.0% to 50.4%. At the current maximum allowable production rate of 1,500,000 gross barrels per day, this resulted in the Company's interest decreasing to 661,700 net barrels per day from 695,200 net barrels per day. Furthermore, to adjust its share of cumulative total production since the inception of commercial production, the Company underlifted about 76,000 net barrels per day for a two-year period which ended September 30, 1984. The Company recovered approximately $400 million of excess contributions to field development expenditures and operating costs by bearing a reduced share of ongoing costs.

As a result of arbitration proceedings concluded in 1985 among the owners of the field, the Company's participating interest in the oil reservoir increased to 50.7%. At the current maximum allowable production rate, this resulted in the Company's interest increasing to 665,200 net barrels per day. Also, to adjust its share of cumulative total production since the inception of commercial production, the Company began an overlift of about 13,500 net barrels per day for a two-year period commencing September 1, 1985. The arbitration award is subject to judicial review by two courts.

Note I: Defined Benefit Retirement Plans

The Company and certain subsidiaries have defined benefit retirement plans covering substantially all domestic employees except certain union employees covered by multiemployer pension plans (Note J). Certain foreign subsidiaries sponsor pension plans with benefit and vesting provisions which vary among different countries, often supplementing local social law arrangements.

The Company's defined benefit plans are of two general types—fixed benefit and final pay. Fixed benefit plans, which are often negotiated with unions, pay specified benefits based on the number of years of employee service. Final pay or career average plans (salary plans) pay benefits that are computed based on an employee's career average or final average salary. The Company makes annual contributions to the defined benefit plans which at least equal the amounts required by law. Contribution amounts are determined by independent actuaries using an actuarial cost method that has an objective of providing an adequate fund to meet pension obligations as they mature over the long-term future. As of December 31, 1986, the assets of the plans were held in U.S. and foreign equity securities, fixed income securities, cash and real estate.

The Company adopted Statement of Financial Accounting Standards No. 87 (FASB 87), "Employers' Accounting for Pensions," for the purpose of determining net pension cost effective January 1, 1986. In contrast to prior years where net pension cost was determined using primarily the entry age normal actuarial method, the FASB requires that the projected unit credit method be used. The Statement also sets forth specific rules for determining net pension cost, the effect of which was to reduce net pension cost in 1986 by approximately $52 million ($28 million after tax, or $.12 per share).

Net pension cost for defined benefit retirement plans was $11 million, $148 million and $60 million in 1986, 1985 and 1984, respectively. In addition to the effects of the adoption, the decrease in 1986 net pension cost was due primarily to the absence of both the enhanced retirement benefits incurred because of the 1985 staff reorganization and the 1985 actuarial losses related to the complete shutdown of the Bingham Canyon mine.

The following table summarizes the components of net pension cost for 1986:

Millions of Dollars	1986
Service cost-benefits earned during period	$ 27
Interest accrued on benefits earned in prior years	97
Actual return on plan assets	(142)
Net amortization and deferral*	29
Net pension cost	$ 11

*FASB 87 requires the disclosure of the actual return on plan assets although the estimated return on plan assets is used to determine pension expense for the period. The difference between the actual return and the estimated return is included in net amortization and deferral.

The following table presents the funded status of the plans and amounts recognized in the Company's Balance Sheet. The projected benefit obligation is based on discount rates of 9% and 10% at December 31, 1986 and December 31, 1985, respectively. The expected long-term rate of return on plan assets was 10% in 1986.

	Plans Whose Assets Exceed Accumulated Benefits		Plans Whose Accumulated Benefits Exceed Assets	
Millions of Dollars—December 31	1986		1986	1985
Projected benefits based on employment service to date and present pay levels				
Vested	$480	$443	$447	$361
Nonvested	45	41	33	26
Accumulated benefit obligation	525	484	480	387
Projected benefits related to projected salary increases*	121	92	8	5
Projected benefit obligation	646	576	488	392
Plan assets at fair value	768	702	345	300
Plan assets (in excess of) less than projected benefit obligation	(122)	(126)	143	92
Unrecognized net loss	(64)	–	(60)	–
Unrecognized net assets at January 1, 1986, net of amortization	233	241	40	53
Net accrued pension liability	$ 47	$115	$123	$145

*Based on projected long-term compensation growth of 6% per annum.

Note J: Multiemployer Pension Plans and Other Postemployment Benefits

Company subsidiaries under contract with the United Mine Workers of America participate in multiemployer pension plans which provide defined benefits to union employees. Contributions, which are based on coal production and hours worked, were $21 million, $20 million and $22 million in 1986, 1985 and 1984, respectively.

The Company is liable under federal law and various state statutes for the payment of benefits to disabled workers and their dependents resulting from occurrences of coal workers' pneumoconiosis disease (black lung). Provisions for estimated benefit costs are accrued based on production and aggregated $77 million at December 31, 1986.

The Company and certain domestic and foreign subsidiaries provide certain health care and life insurance benefits for retired employees who meet eligibility requirements. Those benefits are provided through self-insurance arrangements for which annual expense is based on the amount of actual claims incurred and through insurance arrangements for which annual expense is based on the amount of premiums paid. The annual expense attributable to retired employees is not material to the results of operations.

Note K: Transactions with The British Petroleum Company p.l.c. and Subsidiaries (BP)

BP owns 1,000 shares of special stock which is equivalent to 125,840,000 shares of common stock of the Company. The special stock, together with 4,320,000 shares of common stock owned by BP, results in a total BP ownership of approximately 55% of the voting rights of shares of common stock outstanding and common stock equivalents at December 31, 1986.

In April 1986 the Board of Directors of the Company established a Special Committee composed of all the non-management directors, other than those employed by BP. The Committee has the responsibility to monitor compliance with the Company's policy statement concerning the relationship with BP and to advise the Board as to whether the Company is in compliance with that policy. The Committee also has responsibility to review significant commercial transactions, joint programs, joint ventures and other working relationships between the Company and BP.

The Company's Prudhoe Bay reserves are subject to a BP net profits royalty interest (NPRI) equal to 75% of the net profits from oil and gas production from Prudhoe Bay leases multiplied by a fraction, of which the numerator is the number of net barrels per day of crude oil production from the Company's Prudhoe Bay leases between 600,000 net barrels per day and 1,050,000 net barrels per day, and the denominator is the total number of net barrels per day of crude oil production from such leases. Included in costs of products sold and operating expenses are charges of $44 million in 1986, $108 million in 1985 and $36 million in 1984 for the NPRI which are payable as dividends on a subsidiary's preferred stock, which preferred stock is owned by BP. There was no NPRI expense during the two-year redetermination underlift period ended September 30, 1984, since the Company's Prudhoe Bay production was below 600,000 net barrels per day. Also, there is no NPRI on most of the barrels being overlifted as a result of the 1985 arbitration decision (Note H).

The Company (or subsidiaries): (1) makes payments to BP ($197 million in 1986, $309 million in 1985 and $260 million in 1984) and receives payments from BP ($34 million in 1986, $33 million in 1985 and $24 million in 1984) for pipeline transportation of Alaskan crude oil at rates governed by the Federal Energy Regulatory Commission. In addition, a refund of $69 million was received from BP in 1985 related to the TAPS Agreement (Note L); (2) purchases from BP ($44 million in 1986, $84 million in 1985 and $67 million in 1984) and sells to BP ($124 million in 1986, $187 million in 1985 and $116 million in 1984) petroleum and chemicals in the ordinary course of business at prevailing competitive prices; (3) is a party to an agreement which provides that, whenever the Trans Alaska Pipeline System (TAPS) operates at less than design capacity, the crude oil produced by Standard Oil or BP from the North Slope will be shipped through the interests of their pipeline subsidiaries in TAPS in the approximate proportions that such ownership interests in TAPS bear to one another, so long as the pipeline subsidiary requesting such throughput protection maintains a competitive tariff rate; (4) contracts with BP for services related to marine operation and exploration and production; (5) is a party with BP in a number of other transactions and arrangements in the ordinary course of business.

Note L: Litigation, Other Proceedings and Contingencies

The Company's pipeline subsidiary and the other owners of the Trans Alaska Pipeline System (TAPS) have reached agreement with the State of Alaska as to the methodology for determining their interstate TAPS tariff rates, both for the past and in the future. The methodology has been approved by the Federal Energy Regulatory Commission, but the approval has been appealed to Federal court. The net effect of the agreement on the Company's earnings through 1986 was not material and has been recognized in the financial statements.

The Company is engaged in judicial and administrative proceedings in which the State of Alaska is challenging the valuation of crude oil reported by the Company since 1977 for royalty and 1978 for tax purposes. The Company believes it has complied with applicable tax legislation and provisions for royalty contained in its Prudhoe Bay leases, and is disputing the State's claims. While the amounts claimed and subject to claim are substantial, the Company believes the ultimate resolution of these disputes will not have a material impact on its financial position.

The Company also is engaged in various litigation and other proceedings with private parties and governmental authorities and has a number of unresolved claims pending. While the amounts claimed in the aggregate are substantial and the ultimate liability in respect of such litigation, proceedings and claims cannot be determined at this time, the Company is of the opinion that the aggregate amount of any such liabilities will not have a material impact on its financial position.

Note M: Stock Plans

The 1967 and 1977 Standard Oil Stock Option Plans for Key Employees authorized issuance of common stock to executives and other key employees. Under the 1977 plan, options granted prior to 1982 included stock appreciation rights. Authorization to grant options under both the 1967 and 1977 plans has been terminated.

The 1983 Standard Oil Stock Plan authorizes issuance of 5,000,000 shares of common stock for incentive and nonqualified stock options, restricted stock awards and performance awards to executives and other key employees. The options may be awarded with or without surrender rights. Grants made as incentive stock options did not include surrender rights. Performance awards are payable at the discretion of the Board of Directors subject to the accomplishment of specific performance objectives over a period of three years. No more than 500,000 of the total number of available shares may be used for restricted stock awards and performance awards.

The 1980 Kennecott Employees' Stock Plan (assumed in 1981) provides for the granting of options to Kennecott executives and other key employees to purchase shares of Standard Oil common stock, stock appreciation rights and restricted Standard Oil common stock.

Options generally become exercisable in approximately equal annual installments over a three- or five-year period beginning one year from date of grant, and expire after ten years. The option price will not be less than the market price on the date of grant. At December 31, 1986, Company employees held options to purchase 3,150,714 common shares at an average price of $46.25 per share. These options expire on various dates ranging from 1987 to 1996.

Limitations on restricted stock are in effect for at least three years from the date of grant and then lapse in installments or in full. At December 31, 1986, 11,225 shares were outstanding as restricted stock awards.

Stock option transactions during 1986, 1985 and 1984 are summarized as follows:

	1986		1985		1984	
	Shares	Option Prices	Shares	Option Prices	Shares	Option Prices
Outstanding—January 1	2,952,244	$15.63-52.00	2,976,517	$15.63-52.00	2,685,745	$13.29-52.00
Granted	716,800	—46.94—	737,800	—47.56—	715,700	—45.75—
Exercised	(175,928)	15.63-52.00	(322,462)	15.63-52.00	(276,911)	13.29-47.50
Cancelled(1)	(342,402)	15.63-52.00	(459,611)	15.63-52.00	(148,017)	13.29-52.00
Outstanding—December 31	3,150,714	15.63-52.00	2,952,244	15.63-52.00	2,976,517	15.63-52.00
Exercisable—December 31(2)	1,915,336		1,673,204		1,403,302	
Available for grant—December 31	2,655,056		3,179,261		3,647,350	

(1) Includes options surrendered in connection with the exercise of 63,399, 86,660 and 20,356 stock appreciation and surrender rights in 1986, 1985 and 1984, respectively.
(2) Subject to sequential exercise requirements.

Note N: Inventories

As a result of the Company's extensive use of the last-in, first-out (LIFO) method, inventories are reported in the balance sheet at less than current cost. Inventories valued under the LIFO method were approximately 83% and 81% of total inventories (exclusive of materials and supplies) at December 31, 1986 and 1985, respectively.

The following is information about the current cost of inventories (determined primarily using the first-in, first-out method):

Millions of Dollars—December 31	1986	1985
Inventories at current cost		
Crude oil and petroleum products	$ 813	$1,407
Metals and coal	122	156
Chemicals	31	46
OIT	84	66
Other businesses	81	167
Materials and supplies	298	405
	1,429	2,247
Excess of current cost over reported balance sheet amounts	(229)	(810)
Reported balance sheet amounts	$1,200	$1,437

Note O: Standard Oil Finance Company

Under the terms of an agreement, Standard Oil Finance Company (Finance), a wholly-owned unconsolidated subsidiary, utilizes commercial paper borrowings to purchase accounts receivable from the Company at a discount which provides earnings (before fixed charges and income taxes) of at least 1.25 times Finance's fixed charges. Summarized financial information of Finance is as follows:

Millions of Dollars	1986	1985	1984
Purchased accounts receivable outstanding at December 31	$156	$188	$599
Commercial paper borrowings outstanding at December 31	105	13	429
Interest expense on commercial paper borrowings	3	22	23
Income before income taxes	1	9	11
Net income	2	5	6

Note P: Lease Commitments and Rentals

The Company has lease commitments for tankers, refinery facilities, mining equipment, service stations, offices and other equipment.

Millions of Dollars – December 31	1986	1985
Capital leases included in property, plant and equipment		
Tankers	$376	$376
Refinery facilities	40	40
Other	16	19
	432	435
Less accumulated amortization	193	172
	$239	$263

	Capital Leases	Operating Leases
Future minimum annual rentals		
1987	$ 47	$201
1988	44	106
1989	42	93
1990	40	90
1991	41	47
Thereafter	399	116
Total minimum lease payments	613	$653
Less amounts representing interest	270	
Present value of net minimum lease payments	$343	
Current	$ 18	
Long-term	325	
	$343	

	1986	1985	1984
Rental expense under operating leases			
Minimum rentals	$360	$375	$306
Sublease rentals	(24)	(33)	(12)
	$336	$342	$294

The higher level of rental expense in 1986 and 1985 compared with 1984 is primarily due to increased tanker requirements caused by the end of Prudhoe Bay underlifting on September 30, 1984.

Note Q: Accruals and Reserves

Millions of Dollars – December 31	1986	1985
Accrued dismantlement, restoration and reclamation costs	$ 372	$ 340
Reserve for employee benefits	239	318
Reserve for shutdown and modification of operations	123	226
Reserve for regulatory issues and other	218	316
	$1,152	$1,300

Note R: Statement of Changes in Financial Position

The Statement of Changes in Financial Position presents the Company's principal sources and uses of cash related to four primary activities: operations, dividends, investment activities and financing activities. Similarly, cash inflows and outflows related to changes in working capital (other than cash and short-term marketable securities) are segregated among those activities as follows:

Millions of Dollars	1986	1985	1984
Operating working capital			
Accounts receivable	$ 571	$(247)	$ (52)
Refundable Federal income taxes	(771)	–	–
Inventories	47	64	(17)
Prepaid expenses and deferred charges	9	(15)	(5)
Accounts payable	(558)	93	122
Accrued income and other taxes	(48)	(34)	151
Accrued interest	21	4	(11)
Other current liabilities	(41)	38	(24)
	(770)	(97)	164
Investment working capital	100	(280)*	(26)
Financing working capital	(13)	(473)	685
Cash (outflow) inflow due to change in working capital	$(683)	$(850)	$823

*Includes $273 million of inventories from the acquisition of certain Gulf Oil Corporation refining and marketing properties in 1985.

Investment working capital consists primarily of accounts payable related to expenditures for capital assets and related materials and supplies inventories, working capital associated with acquisitions and divestitures, and joint-venture receivables and payables. Financing working capital includes all short-term notes payable, current maturities of long-term debt, and the effect on working capital from the sale of accounts receivable to the Company's unconsolidated finance subsidiary.

Note S: Supplemental Statement of Income Information

Millions of Dollars – Year Ended December 31	1986	1985	1984
Interest expense			
Notes payable and other*	$ 50	$ 69	$ 70
Long-term obligations	356	356	364
	406	425	434
Capitalized interest	(71)	(29)	(60)
Total interest expense	$335	$396	$374
Research and development expense	$125	$158	$148
Maintenance and repairs expense	$426	$461	$552

*Includes the net results of Standard Oil Finance Company.

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Company Report on Financial Statements

The Company is responsible for the information included in its consolidated financial statements, and it believes those statements have been prepared in accordance with generally accepted accounting principles. A system of internal accounting controls has been developed and maintained which is designed to provide reasonable assurance that assets are safeguarded from loss or unauthorized use and that the financial records are reliable for preparing the financial statements. In establishing and maintaining internal controls, the Company exercises judgment in determining that the costs of such controls do not exceed the benefits to be derived.

The Board of Directors of the Company is responsible for assuring that the Company fulfills its responsibilities in the preparation of the consolidated financial statements. The Board, on the recommendation of the Audit Committee and subject to shareholder ratification, selects and engages the independent auditors. The Audit Committee, comprised exclusively of nonmanagement members of the Board, meets with representatives of the Company, internal auditors and independent auditors to review the scope of and any recommendations for improvements in the Company's internal accounting controls. The Audit Committee reports its conclusions and recommendations to the Board of Directors. The independent auditors issue a report, upon completion of their audit, as to whether the consolidated financial statements present fairly the financial position, operating results and changes in financial position in accordance with generally accepted accounting principles.

Robert B. Horton
Chairman of the Board
and Chief Executive Officer

E. John P. Browne
Executive Vice President
and Chief Financial Officer

February 17, 1987

Report of Ernst & Whinney, Independent Auditors

Shareholders and Board of Directors
The Standard Oil Company

We have examined the consolidated balance sheet of The Standard Oil Company and subsidiaries as of December 31, 1986 and 1985, and the related consolidated statements of income, retained earnings and changes in financial position for each of the three years in the period ended December 31, 1986. Our examinations were made in accordance with generally accepted auditing standards and, accordingly, included such tests of the accounting records and such other auditing procedures as we considered necessary in the circumstances.

In our opinion, the financial statements referred to above present fairly the consolidated financial position of The Standard Oil Company and subsidiaries at December 31, 1986 and 1985, and the consolidated results of their operations and the changes in their financial position for each of the three years in the period ended December 31, 1986, in conformity with generally accepted accounting principles applied on a consistent basis.

Ernst & Whinney
Cleveland, Ohio
February 17, 1987

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did assign any value?
who were plaintiffs - how much stock etc.
why settle - fear of loss, any opp'y to merge - what kind of signals fr. def's?

MAR 26 4 2 1 1 37

IN THE COURT OF COMMON PLEAS
CUYAHOGA COUNTY, OHIO

JOHN and MARJORIE MOORE
32 Golden Gate Avenue
Belvedere, California 94920

and

LOUIS H. GOLDMAN
12 East 49th Street
New York, New York 10017

and

DAVID GROBOW
86 Davison Place
Englewood, New Jersey 07631

Plaintiffs,

v.

THE STANDARD OIL COMPANY
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

THE BRITISH PETROLEUM COMPANY
p.l.c.
Britannic House
Moor Lane
London, England EC2Y9BU

and

Case No. 126760

Judge:
090 THOMAS J. POKORNY

SHAREHOLDERS' CLASS ACTION COMPLAINT FOR PRELIMINARY AND INJUNCTIVE RELIEF

BP INTERNATIONAL LIMITED
Britannic House
Moor Lane
London, England EC2Y9BU

and

BP NORTH AMERICA, INC.
650 Fifth Avenue
New York, New York

and

ROBERT B. HORTON
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

E. JOHN P. BROWNE
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

J. COLIN WEBSTER
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

BASIL R. R. BUTLER
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

IAN G. S. HARTIGAN
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and

KENNETH R. KEEP
200 Standard Oil Bldg.
& Public Square
Cleveland, Ohio 44114

and)
)
FRANK E. MOSIER)
200 Standard Oil Bldg.)
& Public Square)
Cleveland, Ohio 44114)
)
and)
)
RICHARD A. BRAY)
200 Standard Oil Bldg.)
& Public Square)
Cleveland, Ohio 44114)
)
Defendants.)

Now come the plaintiffs, and for their Complaint against defendants, states the following upon information and belief, except as to paragraph 1 which is alleged upon knowledge:

1. Plaintiffs John and Marjorie Moore, Louis H. Goldman and David Grobow are each the owner of the common stock of defendant The Standard Oil Company ("Standard Oil") and have held said common stock since prior to the announcement of the proposed tender-offer/freeze-out transaction described herein.

2. Defendant Standard Oil is an Ohio corporation with its principal place of business in Cleveland, Ohio. Standard Oil is engaged in all phases of the petroleum business, primarily in the United States, including the exploration for and production of crude oil and natural gas and the transportation, refining and marketing of crude oil and petroleum products. In addition (as a result of Standard Oil's purchase, in 1981, of Kennecott Corp.), Standard Oil is a major producer and marketer of copper, gold, silver and coal, and a leading supplier of refractories, copper,

brass, mill products and process systems and equipment. Standard Oil also manufactures and markets certain chemical products and products produced from ilmenite (an ore used to produce products for the pigment industry).

3. Standard Oil's oil and gas reserves and production facilities are located primarily in Alaska, Texas, Oklahoma, Louisiana and the Gulf of Mexico; its principal coal reserves and mines are located in Illinois, Indiana, Kentucky, Pennsylvania and West Virginia; and its ilmenite mine and processing facilities are located in Quebec, Canada. Standard Oil also has interests in oil shale and tar sands properties located in Colorado and Utah.

4. Standard Oil's most important assets are its petroleum reserves and exploration properties, which are located chiefly in Alaska and the Gulf Coast region, and its petroleum refining and marketing facilities. Standard Oil produces approximately one fifth of this country's oil output. As of the end of Standard Oil's most recent fiscal year, December 31, 1986, Standard Oil had reserves in approximately the following amounts: petroleum liquids, 2.41 billion barrels; and natural gas, 7.30 trillion cubic feet. Standard Oil also had reserves of 7.06 billion tons of coal; 100 million troy ounces of silver; 10.4 million troy ounces of gold; and 7.3 million tons of copper. These reserves have generated strong cash flow. For example, on or about January 22, 1987 defendants announced that Standard Oil would continue its quarterly dividend of $.70 per share, and retire debt early, citing strong cash flow from operations.

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5. Standard Oil has the equivalent of approximately 239 million shares of common stock outstanding. Standard Oil's common stock is traded on the New York and Midwest Stock Exchanges and, as of February 28, 1986, was held by approximately 55,760 shareholders of record. Approximately 130,160,000 shares of Standard Oil's common stock, or 55% of all such shares, are owned by defendant The British Petroleum Company p.l.c., through its wholly owned subsidiary, defendant BP International Limited.

6. Defendant the British Petroleum Company p.l.c. is a corporation organized under the laws of England. The British Petroleum Company and its subsidiaries (including its subsidiaries, defendants BP North America, Inc. and BP International Limited, collectively referred to hereinafter as "BP"), is the largest industrial concern in the United Kingdom, the second largest in Europe, and the fifth largest in the non-communist world. For the year ended December 31, 1985, (the most recent year for which BP has published audited financial results), BP had revenues of more than 59 billion dollars and profits of more than 2.3 billion dollars. In 1970, BP acquired 1,000 shares of Special Stock of Standard Oil, each such share equivalent to 125,840 shares of Standard Oil's common stock. BP also owns 4,320,000 shares of Standard Oil's common stock. As a result of BP's ownership of a majority of Standard Oil's voting shares (as well as BP's other relationships with Standard Oil), BP controls Standard Oil.

7. Defendant Robert B. Horton ("Horton") is Chairman of the Board and Chief Executive Officer of Standard Oil. In February, 1986, BP ousted Standard Oil's former Chairman and Chief Executive Officer, Alton W. Whitehouse, and installed Horton in those positions. Prior to February, 1986, Horton was a Managing Director of BP, in charge of BP's corporate finance and planning and its operations in the Western Hemisphere.

8. Defendant E. John P. Browne ("Browne") is Executive Vice President, Chief Financial Officer and a director of Standard Oil. In February, 1986, BP installed Browne in the position of Standard Oil's Executive Vice President and Chief Financial Officer; in April, 1986 BP placed him on Standard Oil's Board. Prior to February, 1986, Browne was Group Treasurer of BP and Chief Executive of BP Finance International.

9. Defendant J. Colin Webster ("Webster") is Executive Vice President and a director of Standard Oil. In 1985, BP placed him on Standard Oil's Board; in February, 1986, BP installed Webster as Executive Vice President of Standard Oil. Prior to February, 1986, Webster was President of BP North America. In July, 1986, Barron's reported with regard to defendants Horton, Browne and Webster: "All three have formally left BP, but few people doubt that Standard Oil is being seen as their proving ground. Turn Standard Oil around, and plum jobs await them back at Britannic House [BP's headquarters] should they wish to return."

10. Defendant Basil R.R. Butler ("Butler") is a Managing Director of BP and Chairman of BP Exploration Company Limited and

of BP Gas International Limited. BP placed Butler on the Board of Standard Oil in April, 1986.

11. Defendant Ian G.S. Hartigan ("Hartigan") is President of BP North America, a position he has held since April, 1986. Prior to then, he was Managing Director of BP Shipping. Also in April, 1986, BP installed Hartigan on the Board of Standard Oil.

12. Defendant Kenneth R. Keep ("Keep") is Technical Director of BP Exploration. BP installed him on the Board of Standard Oil in April 1986.

13. Defendant Frank E. Mosier ("Mosier") is President and Chief Operating Officer of Standard Oil. In February, 1986, BP ousted the former President and Chief Operating Officer of Standard Oil, John R. Miller, and installed Mosier in those positions. Mosier is a director of Standard Oil (since 1980). Mosier joined Standard Oil in 1953.

14. Defendant Richard A. Bray ("Bray") is Executive Vice President of Standard Oil and a director (since January, 1985). He joined Standard Oil in 1982. Prior to then, he was Managing Director of an oil exploration company in the United Kingdom.

15. The individual defendants constitute a majority of Standard Oil's directors. By reason of defendants' stock ownership and/or their positions with Standard Oil, defendants occupy a fiduciary relationship with the plaintiff and other public stockholders of Standard Oil and owe the plaintiff and the other members of the Class the highest obligations of good faith and fair dealing.

Class Action Allegations

16. Plaintiffs bring this action on their own behalf and as a class action, pursuant to Rule 23 of the Ohio Rules of Civil Procedure, on behalf of all common stockholders of Standard Oil (except the defendants herein and the members of the immediate families of the individual defendants), and their successors in interest, who are or will be threatened with the deprivation of their equity interest in Standard Oil by reason of the proposed elimination of the public stockholders of Standard Oil through the transactions hereinafter described.

17. This action is properly maintainable as a class action for the following reasons:

(a) The class of stockholders for whose benefit this action is brought is so numerous that joinder of all class members is impracticable. As of October 31, 1986, there were approximately 109 million common shares of Standard Oil outstanding (other than those owned by BP), owned by approximately 56,000 shareholders of record. Members of the class are scattered throughout the United States.

(b) There are questions of law and fact which are common to members of the class and which predominate over any questions affecting any individual members. The common questions include, inter alia, the following:

(i) whether the defendants have engaged in a plan and scheme to defraud the members of the class;

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(ii) whether the defendants have engaged in a plan and scheme to unlawfully "freeze-out" the public stockholders of Standard Oil;

(iii) whether the proposed tender offer/freeze-out is so grossly unfair to the public stockholders of Standard Oil as to constitute a fraud upon them;

(iv) whether defendants have failed to disclose potential and expected positive future financial benefits to Standard Oil in order to depress the market price for Standard Oil to enable defendants to take Standard Oil private at a fraudulently low and unfair price;

(v) whether defendants have breached their fiduciary and the other common law duties owed by them to plaintiff and the members of the class; and

(vi) whether defendants are pursuing a course of business designated to eliminate the public shareholders of Standard Oil in violation of the laws of the State of Ohio.

(c) The claims of the plaintiffs are typical of the claims of the members of the class, and plaintiffs will fairly and adequately protect the interests of the class. Plaintiffs have retained attorneys who are thoroughly experienced in shareholder litigation.

(d) A class action is superior to other available methods for the fair and efficient adjudication of the claims which are asserted, and no unusual difficulties are likely to be encountered in the management of this class action. The likeli-

hood of the individual class members prosecuting separate claims is remote.

Cause of Action Against All Defendants

18. By virtue of the acts and conduct alleged herein, the defendants have carried out a preconceived plan and scheme to eliminate the public common stockholders of Standard Oil and wrongfully to permit defendants to appropriate the benefit of the ownership of Standard Oil, including its potential and continuing growth and profitability, while at the same time the public common stockholders of Standard Oil would be wrongfully deprived of their investment in Standard Oil and all of its present and continuing profitability and growth and would receive in return for their investment grossly inadequate consideration.

19. The sole and primary objective of that plan and scheme is to permit defendants to acquire the equity ownership of Standard Oil for a fraudulently low and unfair price. The plan and scheme constitutes an improper and unlawful attempt by defendants to freeze-out the public stockholders of Standard Oil.

20. In furtherance of this plan and scheme, on or about February 24, 1986, BP announced that it had peremptorily ousted Standard Oil's former Chairman of the Board and Chief Executive Officer and former President and Chief Operating Officer, and had installed its own handpicked officers, the individual defendants, as the management of Standard Oil. At the same time, BP "packed" the Board of Directors of Standard Oil so that, for the

first time, a majority of the Standard Oil Board consisted of executives appointed by BP. By those acts, BP made clear that it intended to operate Standard Oil for its own benefit, and that anyone who challenged BP's domination and control of Standard Oil would be instantly dismissed.

21. Pursuant to the plan and scheme of the defendants, on or about March 26, 1986, defendant BP announced a proposal to acquire the approximately 45% of Standard Oil's common stock that was not already owned by it. Under said plan, the common stockholders of Standard Oil would receive only Seventy Dollars ($70.00) per share.

22. Defendants' plan and scheme is an attempt to force out the public common stockholders of Standard Oil at a price which is far less than the common stock is worth, for the sole purpose of enriching the defendants. The Seventy Dollars ($70.00) per share price proposed to be paid to the public stockholders is so grossly inadequate and unfair as to constitute a fraud upon the shareholders of Standard Oil. The intrinsic value of the stock of Standard Oil is materially in excess of Seventy Dollars ($70.00) per share, giving due consideration to its assets, its growth and profitability, the underlying strength of its business, its earnings and earnings power, present and projected. The proposed price of Seventy Dollars ($70.00) per share is a fraudulent and unfair effort by the defendants to take advantage of current market conditions with respect to Standard Oil and to deprive plaintiffs and the members of the public of the benefits

which defendants expect to obtain from the projected growth of Standard Oil's earnings.

23. The proposed tender offer/freeze-out price of Seventy Dollars ($70.00) per share is not the result of arm's-length negotiations and was not based upon any independent appraisal of the current value of Standard Oil's shares, assets, or business, but was fixed arbitrarily by the defendants themselves as part of their plan to obtain ownership of Standard Oil's assets and businesses at the lowest possible price and to obtain for themselves benefits disproportionate with those to be received by the public shareholders, which facts were not disclosed.

24. In proposing the freeze-out of Standard Oil's minority shareholders, defendants are seeking to appropriate for their own benefit, to the detriment of Standard Oil's public shareholders, Standard Oil's extraordinary potential for profitability and growth. For example:

(a) Defendants have timed the tender offer/freeze out to take advantage of the imminent surge in oil prices and recovery in the oil industry. Accordingly, securities analysts have estimated mean earnings per share for standard oil of $3.63 per share in 1987 and $4.79 in 1988, compared to a loss of $1.32 per share in 1986 and earnings of only $1.31 per share in 1985.

(b) Standard Oil has taken action in 1986 "to reposition the company so that it will perform well in an environment of low and volatile or due oil prices, based on the assumption that prices will average $15 per barrel Mreal terms

for the next few years." 1986 Standard Oil Annual Report. In fact, the price for crude oil on the spot market is already substantially in excess of $15 per barrel, closing on the New York Mercantile Exchange on March 25, 1987 at a price of $18.71 per barrel. Based on Standard Oil's current production levels, that increase in oil prices will increase Standard Oil's revenues and income by a material amount.

(c) Only last year, Standard Oil's former Chief Executive Officer (who defendants ousted) represented to Standard Oil's shareholders:

> Sohio Goal is Long-Term Value
>
> * * *
>
> Standard Oil's ability to create a competitive advantage is made easier by these factors:
>
> Financial stability is provided by cash flow generated by our large domestic hydrocarbon base.
>
> ***
>
> Investment Emphasis Shifts
>
> We have come a long way toward creating a strong, integrated energy company that is well positioned for the future.
>
> When Prudhoe Bay [Alaska reserves] was brought on stream, Standard Oil's business was small and narrow. Since then, we have made substantial investments in oil and gas exploration, coal reserves, metals mining, chemicals and most recently, petroleum refining and marketing.
>
> Our major positioning investments are behind us,...the major role of our investments now will be ..on translating our non-income pro-

ducing assets -- such as idle coal reserves and undeveloped exploration acreage -- into income producing assets.

***

We have witnessed large oil companies being acquired by other large companies, at prices well in excess of the previously prevailing stock market valuation....

These actions imply that the acquiring companies, while paying a premium over the stock market valuations, believe they are acquiring reserves and other assets cheaper and with less risk than they could by exploration and direct investment.

***

Reserves Increased

In 1984, we announced three production development projects in Alaska -- the endicott field, the Lisburne pool of the Prudhoe Bay field, and the Prudhoe Bay Miscible Gas Project.

In total, those three projects added 310 million barrels to our proved reserves. As a result [Standard Oil's] reserves at year-end 1984 exceeded those at year-end 1983 and 1982 as well (emphasis added and in the original).

(d) Then, shortly before his dismissal, he similarly represented to Standard Oil's shareholders:

In Alaska, our major oil and gas production projects are ahead of schedule and under budget. Also, the production plateau of the Prudhoe Bay field was extended into 1988 by continued development efforts.

We accelerated our evaluation of the substantial portfolio of exploration acreage acquired since 1981, particularly in Lower 48 States prospects.

In the Gulf of Mexico, we made significant discoveries on East Breaks Block 165 and Ewing Bank Block 826, and we have

commenced construction of a production platform for the East Breaks discovery.

On the international front, where there is the opportunity to be exposed to sizable investment opportunities at higher rates of return, we acquired a three-million-acre concession offshore Qatar and entered into a Canadian exploration joint venture.

In refining and marketing, the newly acquired Gulf Oil Corporation properties contributed importantly to that business's improved income (emphasis added).

(e) Worldwide economic and political conditions at the present time have resulted in the recognition of the value of oil and gas reserves in the United States, coupled with industry recognition that long term oil and gas prices will substantially increase. For example, BP's Chairman, Sir Peter Walters was quoted in July 1986 as stating that, "The lower the oil price goes now, the more likely it is to bounce back in the 1990's." Also, in July, 1986, Sir Peter Walters admitted that BP was "always looking at it (the publicly held portion of Standard Oil." He conceded then: "Although it may be cheaper to make the bid now, cheap is not cheap if it is not in the right shape. Better to pay higher prices for more valuable objects when you're sure of the value" (emphasis added).

(f) During 1986, Standard Oil recently announced that it was disposing, modernizing and writing off certain assets, including portions of Kennecott's mining and metals business it acquired in 1981. Since their acquisition by Standard Oil, those operations have consistently been unprofitable. Disposition and

modernization of these assets and associated tax benefits will not only provide defendants with substantial funds to pay for the freeze-out of Standard Oil's public shareholders, but also will very materially increase Standard Oil's cash flow and profitability. Standard Oil stated that it expected this program to provide more than $500 million of net cash inflows and provide additional income in future years. BP has conceded that, although "[t]he immediate result [of these changes] is very large write-offs in copper and coal mining, oil and gas exploration and stiff redundancy payments [, i]n the long run, of course, Standard Oil will be operating from a stronger base (emphasis added)."

(g) The proposed tender offer/freeze-out of Seventy Dollars ($70.00) for each share of Standard Oil stock translates into a total value of approximately $7.4 billion assigned by BP to all of Standard Oil's reserves, undeveloped acreage, refining and marketing operations and other businesses, less Standard Oil's debt. Based upon evaluations of oil and gas reserves by recognized appraisers and geologists and prices paid and offered in other recent acquisitions and mergers in the oil industry, the true value of Standard Oil's net assets is substantially in excess of the Seventy Dollars ($70.00) tender offer/freeze-out price.

(h) The price of Seventy Dollars ($70.00) per share represents a discount from the true net asset value of Standard Oil far exceeding the discount in comparable transactions, in-

cluding the acquisition price offered by Texaco, Inc. for the Getty Oil Company, and the damages recently awarded to Pennzoil, Inc., for the loss of Getty's oil reserves.

(i) Standard Oil recently purchased from Gulf Oil Corp. a refinery in Louisiana with a capacity of 200,000 barrels per day, for a price of approximately $583 million (including $268 million of inventories), at a time when refining and marketing margins were recovering dramatically, so that, for the year ended December 31, 1985, Standard Oil's refining and marketing earnings increased more than 100%, to $424 million. In July, 1986, Barron's reported that Standard Oil's "downstream operations are among the most profitable of any oil major, and [Sir Peter] Walters describes the recent $613 million purchase of Gulf Oil's refining and marketing operations in the Southeast as 'a super buy'."

(j) Standard Oil recently eliminated approximately 1,300 staff positions, which will enable Standard Oil to enjoy dramatic future cost savings.

(k) In preparation for this unlawful and grossly unfair tender offer/freeze out, management of Standard Oil, which are controlled by B.P., implemented a plan to effectuate early retirement of $1.3 billion of debt associated with nine separate debt issues through early redemption, tender offers and purchase in the open market. The early retirement of certain of the high-coupon debt will produce a substantial pre-tax interest savings to Standard Oil.

25. Although defendants are now sure that Standard Oil, its assets and its business, are extremely valuable, they are attempting to violate their own admonition to pay "higher prices" for that business and those assets.

26. Prior to announcing the proposed freeze-out, defendants did not (i) undertake an adequate evaluation of Standard Oil's worth as potential merger or acquisition candidate or take adequate steps to enhance Standard Oil's value or attractiveness as a merger or acquisition candidate; (ii) effectively attempt to dispose of Standard Oil's assets; (iii) act so that the interests of the public security holders were protected.

27. The marketplace has already determined that the Seventy Dollars ($70.00) per share is unfair. Within several hours of the announcement of the tender offer/freeze out on March 26, Standard oil stock was trading at Seventy-Two Dollars ($72.00) on the New York Stock Exchange. Additionally, BP stock has also risen $2.6125 within hours of the announcement, as the marketplace has recognized the synergistic value of the combination of the companies.

28. The tender offer/freeze-out serves no legitimate business purpose of Standard Oil, and is an attempt by the defendants to aggrandize their own interests and finances at the expense and to the detriment of the public stockholders of Standard Oil. The proposed freeze-out will deny class members their right to share proportionately in the true value of Standard Oil's valuable assets, profitable businesses, and future growth in profits,

earnings, and profitable businesses, while usurping the same for the benefit of the defendants at a fraudulently unfair and inadequate price. Because defendants control the business and corporate affairs of Standard Oil (and because they are in possession of corporate information concerning Standard Oil's assets, businesses, and future financial prospects), the knowledge and economic power between defendants and the common stockholders of Standard Oil is unequal which makes it grossly and inherently unfair for the defendants to obtain ownership of Standard Oil's assets from the public security holders at the unfair and inadequate price which defendants (and those acting in concert with them) have set.

29. Moreover, defendants have timed the announcement of the proposed tender offer/freeze-out transaction to take unfair advantage of foreign currency fluctuations and adjustments, which, at present, provide defendants with an unfair, short-term advantage.

30. In addition, Standard Oil's business is especially valuable to BP because, (a) Standard Oil's large domestic reserves provide BP with the assurance of a steady flow of petroleum products necessary to supply BP's huge refining capacity; and (b) pursuant to BP's accounting policies, BP can reduce Standard Oil's deferred taxation charge to a restricted liability basis and increases the value of Standard Oil's inventory to an amount calculated using a first-in, first-out method.

31. As a result of the foregoing, defendants herein have willfully participated in the perpetuation of a fraud upon the members of the class and have engaged in, knowingly and substantially assisted in, and aided and abetted each other in a breach of their fiduciary duty to the class.

32. The plaintiffs and the other class members are imminently threatened by the acts and transactions complained of herein, which if effectuated, would cause irreparable injury to them.

33. The plaintiffs and members of the class have no adequate remedy at law.

WHEREFORE, the plaintiffs demand judgment, as follows:

A. Enjoining, preliminarily and permanently, the consummation of the proposed transaction and freeze-out of the class members and their equity interest in Standard Oil;

B. In the event that the proposed acquisition of Standard Oil is consummated, rescinding it and setting it aside;

C. Requiring that the defendants account to the plaintiffs and other class members for all damages, including rescissory damages, and injuries sustained by the class as a result of the acts and transactions complained of herein;

D. Awarding to plaintiffs the costs and disbursements of this action, including a reasonable allowance for the fees and expenses of their attorneys, experts and accountants; and

E. Granting such other and further relief as may be just and proper in the premises.

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IN THE COURT OF COMMON PLEAS
CUYAHOGA COUNTY, OHIO

IN RE THE STANDARD OIL COMPANY/ BRITISH PETROLEUM LITIGATION	))	CONSOLIDATED CASE NO. 126760

STIPULATION OF SETTLEMENT

WHEREAS:

A. The British Petroleum Company p.l.c. ("BP"), through its wholly-owned subsidiary BP International Limited ("BPI"), owns 1,000 shares of Special Stock, without par value, of the Standard Oil Company ("Standard"), equivalent to 125,840,000 shares of Common Stock, without par value, of Standard ("Shares"), and 4,320,000 Shares, constituting an aggregate of 130,160,000 Shares and Share-equivalents (or approximately 55.4% of the outstanding Shares and Share-equivalents). As of March 27, 1987, there were 109,193,816 Shares of Standard issued and outstanding of which 104,873,816 Shares were owned by common Shareholders other than BP.

B. On March 9, 1987, Sir Peter Walters, Chairman of BP, and several other representatives of BP, met with a special committee of the Board of Directors of Standard (the "Special Committee"), which had been established in 1986 and was charged with monitoring the relationship between BP and Standard, as well as certain other representatives of

Standard, and stated that BP was giving serious consideration to the possibility of making a tender offer for the outstanding Shares that it did not own.

C. The Special Committee informed BP that it had decided to retain The First Boston Corporation ("First Boston") as its independent financial advisor and to retain independent counsel for advice with respect to any offer which BP might make.

D. On March 26, 1987, BP North America Inc. ("BPNA"), an indirect wholly-owned subsidiary of BP, announced that on April 1, 1987 it would commence a tender offer for any and all of the outstanding Shares of Standard for $70 per Share, net to the seller in cash (the "Offer"). Goldman, Sachs & Co. acted as financial advisor to BP and as dealer-manager in connection with the Offer.

E. On April 1, 1987 BPNA issued an offer to purchase (the "Offer to Purchase"), which was mailed to all holders of Shares and which disclosed that if BPNA acquired 60 million or more Shares pursuant to the Offer or otherwise, BPNA would effect a merger of a wholly-owned subsidiary of BPNA into Standard, pursuant to which the remaining holders of Shares, other than BP, its subsidiaries, and holders of Shares who perfected their dissenters' rights under Section 1701.85 of the Ohio General Corporation Law, would become entitled to receive $70 in cash per Share (the "Merger").

F. On March 26, 1987, a class action was filed in this Court entitled John and Marjorie Moore, et al. v. The Standard Oil Company, et al., Case No. 126760. Plaintiffs in that action, claiming to represent all stockholders of Standard (other than defendants), whose Shares were sought to be purchased pursuant to the Offer or cashed out in the Merger, alleged, in substance: (i) that BP, BPNA, BPI and certain individual defendants (together, the "BP Defendants") engaged in a plan and scheme to eliminate the interests of the minority shareholders in Standard at an inadequate price; (ii) that the Offer and Merger were part of a scheme on the part of the BP Defendants to appropriate disclosed and undisclosed potential future benefits to Standard for themselves; and (iii) whether defendants breached their fiduciary duties owed by them to the Standard Oil minority Shareholders. Plaintiffs sought, among other things, preliminary and permanent injunctions against consummation of the Offer and the Merger.

G. Additional actions raising claims and seeking relief substantially similar to the Moore action were filed with this Court between March 26, 1987 and April 10, 1987: Freeman v. The Standard Oil Company, et al., Case No. 126785; Kassel v. The Standard Oil Company, et al., Case No. 126824; Stepak v. The Standard Oil Company, et al., Case No. 126872; Friedman v. The Standard Oil Company, Case No. 126896;

Trief v. The Standard Oil Company, et al., Case No. 127045; Decker v. The Standard Oil Company, et al., Case No. 127242; Cummings v. The British Petroleum Company, et al., Case No. 127139; and Jewish Foundation for Education of Women v. The Standard Oil Company, et al., Case No. 127540.

H. On April 8, 1987, plaintiffs in the Moore action filed a First Amended and Supplemental Complaint (the "Amended Complaint"). The Amended Complaint contained, in addition to the allegations in the original complaint, the further allegations that: (i) the BP Defendants breached fiduciary duties owed to Standard's minority shareholders by failing to request Goldman Sachs to render an opinion as to the fairness of the $70 Offer price, and by failing to ensure that Goldman Sachs possessed material information necessary to render an accurate valuation; (ii) despite the Special Committee's two requests for additional time to consider the Offer and their request to proceed initially by merger rather than tender offer, BP refused such requests and determined to proceed by tender offer to minimize the time of the Special Committee to consider such Offer; (iii) despite the offer by the Special Committee to provide BP with whatever information might be useful to make a complete and informed valuation, BP declined such offer and instead disseminated the Offer to Purchase without the benefit of such material information; and (iv) by taking the

position that $70 per share is fair to the Standard Oil minority Shareholders and disseminating Goldman Sachs' range of values which was substantially less than $70 per share, BP was attempting to cap the market for Standard Oil.

I. Also on April 8, 1987, plaintiffs in the Moore action filed a complaint in the United States District Court for the Northern District of Ohio, Moore v. The Standard Oil Company, et al., Civil Action No. 87-848 (the "Federal Action"), setting forth claims similar to those asserted by the actions in this Court and seeking substantially similar relief under Federal law.

J. On April 10, 1987, this Court ordered that the nine actions filed in this Court be consolidated for all purposes and directed that the Amended Complaint in Case No. 126760 be designated the Consolidated Complaint, under the caption "In Re the Standard Oil Company/British Petroleum Litigation" (as consolidated, the "Action"). The consolidation order also appointed three law firms representing plaintiffs (Messrs. Abbey & Ellis; Lowey Dannenberg & Knapp, P.C.; and Wolf Popper Ross Wolf & Jones) as lead counsel for plaintiffs, who "shall set policy for the plaintiffs in prosecution of this litigation . . . ," and liason counsel for plaintiffs (Arter & Hadden). A subsequent order dated April 21, 1987 further appointed Messrs. Coudert Brothers and Silverman & Harnes as additional co-lead counsel for plaintiffs.

K. On April 8, 1987, plaintiffs filed a motion, and on April 19, 1987 an Amended Motion, for a preliminary injunction with this Court. In their Amended Motion plaintiffs sought an order enjoining the consummation of the BPNA tender offer for such additional time after April 28, 1987, (1) until Standard's minority shareholders were provided with additional information clarifying and correcting the allegedly misleading opinions and incomplete and erroneous data contained in the Offer to Purchase, (2) until BPNA disseminated such corrective information in a supplement or amendment to the Offer to Purchase; and (3) until an allegedly fair price under the tender offer was determined and offered to the public stockholders of Standard.

L. The BP Defendants have, throughout these proceedings, maintained and continue to maintain that there is no merit to any of the claims alleged in any of the Consolidated Actions, and that all actions taken by the BP Defendants or any of them have been and are fair to the public stockholders of Standard.

M. Having coordinated the efforts of Ohio, Pennsylvania and New York counsel, lead counsel for the plaintiffs in the Action, with the substantial assistance of all plaintiffs' counsel, have conducted prior to and in

preparation for the preliminary injunction hearing originally scheduled for April 23, and subsequently adjourned to April 29, an intensive investigation into the background and history of Standard Oil, BP and the relationship between them and have, in connection with the expedited discovery had herein, conducted substantial research into the facts and research of the law, including the review of thousands of documents relating to the acts and transactions complained of, documents relating to Standard's past and expected financial performance in all its various business segments, financial analyses of such segments and Standard as a whole using a wide variety of methodologies, crude oil and natural gas price forecasts and scenarios, and the various materials which formed the bases for the valuations of Standard by BP and its financial advisors Goldman Sachs and by First Boston. In addition, counsel for plaintiffs conducted the depositions of five individuals, including the Chairmen, respectively, of BP and of Standard, a partner of Goldman Sachs and an officer of First Boston, and the Senior Vice President in charge of production of Standard Oil Production Company. Counsel for plaintiffs also retained and worked with their financial advisors, Bear, Stearns & Co. Inc., and with their independent petroleum engineers, Huddleston & Co. Inc. and Geoffrey M. Hertel.

N. Lead counsel for plaintiffs herein engaged in intensive arms'-length negotiations with counsel for BP in

order to achieve for the public shareholders of Standard the substantial benefits provided for in this Stipulation. Plaintiffs and their counsel have concluded, after taking into account the many sharply contested legal and factual issues involved, the risks attendant upon further prosecution of this litigation and the substantial benefits to be received by the public shareholders of Standard pursuant to the proposed settlement, that settlement of this litigation upon the terms provided herein is fair, reasonable and adequate and in the best interest of the Class, as defined below.

O. The intensive expedited discovery conducted by counsel for plaintiffs in this Action and the negotiations conducted on behalf of the Class by plaintiff's lead counsel were critical factors in achieving the substantial benefits to be provided pursuant to the proposed settlement. The BP Defendants categorically deny, however, all allegations of wrongdoing in the Amended Complaint and continue to assert that the claims are without merit and that none of the BP Defendants is liable for any of the acts alleged therein. Defendants consider it desirable that the claims asserted against them be settled in order to permit a prompt resolution of all disputes, thereby facilitating the early completion by BPNA of the Offer and the Merger, and so as to terminate the uncertainties associated with this litigation.

The Special Committee has unanimously concluded that, in light of the increase by BP in the tender offer price, the agreement by BP to issue the warrants subject to court approval of the settlement, and the approval of the Board of quarterly cash dividend, the transaction as a whole is acceptable and recommended that the full Board concur in this conclusion and take the proposed dividend action. The full Board unanimously approved this recommendation.

NOW, THEREFORE, IT IS STIPULATED AND AGREED, subject to the approval of this Court pursuant to Rule 23(E) of the Rules of this Court, that this Action and all claims which the plaintiffs or the members of the Class, as defined in paragraph 1 below, or any of them ever had, now has or hereafter can, shall or may have by reason of or arising out of or relating to any of the facts, transactions, actions or conduct, actual or purported, alleged or which could have been alleged in the Action or in any of the complaints in the actions consolidated herein or in any other forum, including without limitation, the Offer, the Offer to Purchase, including any supplements thereto, or the acquisition by BPNA of Shares pursuant to the Offer or in the Merger, all as described herein (the "Settled Claims"), including dissenters' rights under Section 1701.85 of the Ohio General Corporation Law, shall be released and dismissed with prejudice with respect to each and every defendant named in the Action and each of their respective officers, directors, employees, agents, advisors, attorneys,

representatives, predecessors, affiliates, parents, subsidiaries and the general or limited partners, successors, heirs, administrators, executors and assigns of any of the foregoing, upon the following terms and conditions:

1. The parties agree that, for purposes of this Stipulation only, this Action be certified as a class action under Ohio R. Civ. P. 23(B)(3) on behalf of a class (the "Class") consisting of all common stockholders of Standard or their successors in interest from and including March 26, 1987 to and including the date of the Merger except for corporate defendants BP, BPI and BPNA and any of their wholly-owned subsidiaries. Excluded from the Class is any person who requests exclusion from the Class in writing received by the Court or any person who perfects his dissenter's rights with respect to the Merger in accordance with Section 1701.85 of the Ohio General Corporation Law.

2. In consideration of the compromise, dismissal and release of all the Settled Claims against all the defendants:

(a) BPNA shall increase the price per Share it will pay pursuant to the Offer and in the Merger by $1.50 so that all Shareholders who tender or are cashed out in the Merger will receive $71.50 per Share, net to the seller in cash.

(b) BPNA shall amend its Offer to provide that the purchase price paid by BPNA will not be reduced by the value of Standard's quarterly dividend payable to record holders of Shares on May 8, 1987, and that recipients of such dividend who tender their Shares will be entitled to retain it.

(c) Promptly after the Effective Date, as hereinafter defined, BP shall issue to all members of the Class who tender their Shares pursuant to the Offer or are cashed out in the Merger (but not to Shareholders who request exclusion from the Class or perfect dissenters' rights as provided above): for every five Shares a warrant exercisable from the date of issuance through December 31, 1992, entitling the holder to purchase one BP American Depositary Receipt ("ADR") at an exercise price of $80 per ADR. For each month or part of a month that the Effective Date is delayed beyond June 30, 1987, the expiration of the warrant shall be extended by one month. Fractional warrants will be settled in cash.

3. As soon as practicable, the parties shall jointly move the Court for the approval of this Stipulation

and for entry of the Order and Final Judgment referred to in Paragraph 4 hereof. As part of that motion, the parties shall apply jointly for an Order in the form set forth as Exhibit A to this Stipulation.

4. If the Stipulation (including any modification thereto made with the consent of the parties as provided for herein) shall be approved by the Court following a hearing, the parties shall jointly request the Court to enter an Order and Final Judgment in the form annexed hereto as Exhibit B:

(a) approving the Stipulation;

(b) dismissing the complaints in the Action on the merits and as to all defendants with prejudice as against plaintiffs and all members of the Class, and discharging all defendants from any and all liability arising out of the Settled Claims, such dismissal to be without costs except as hereinafter provided;

(c) permanently barring and enjoining the institution by any of the plaintiffs and any member of the Class, either directly, representatively, derivatively, or in any other capacity, of any other actions asserting claims which are Settled Claims as heretofore defined; and

(d) awarding attorneys' fees and expenses, or reserving jurisdiction with respect thereto.

5. The Effective Date for purposes of this Stipulation shall, if an appeal shall not have been taken from the Order and Final Judgment, be the date 31 days after entry of such Order and Final Judgment or, if an appeal therefrom shall have been taken, five days after all appeals shall have been resolved so that the Settlement contemplated by this Stipulation shall have been finally approved; provided, however, that if an appeal therefrom shall have been taken, BP and BPNA shall have the right to accelerate the Effective Date; and provided that, if an appeal therefrom shall have been taken, the parties hereto agree to use their best efforts to obtain expedited disposition of such appeal.

6. After the Effective Date, no claim on behalf of the Class shall survive against defendants, and BPNA shall be free and clear of all claims to cause a merger of Standard with BP or an affilate of BP at a merger price of $71.50 per share. Nothing in this Stipulation shall be construed as implying, or otherwise be deemed to imply, any commitment by BP to cause a merger prior to the Effective Date.

7. Lead counsel for the plaintiffs in the Action shall, within 10 days after the Effective Date, in connection

with the consummation of the transactions described in Paragraph 2, on behalf of all members of the Class, execute and deliver to each of the defendants a release substantially in the form annexed hereto as Exhibit C.

8. Lead counsel, on behalf of all counsel for plaintiffs, may apply to this Court for an award of attorneys' fees, including reimbursement of expenses, in an aggregate amount not to exceed $22 million, to be paid by BP, BPI or BPNA upon final approval of the Settlement. BP, BPI and BPNA have agreed not oppose such a fee request up to the amount of $22 million (including all expenses). In the event the attorneys' fees awarded by the Court are not paid within 41 days of the date of the award of such sum, interest thereon shall accrue at a rate of 10% per annum. Subject to the conditions set forth in this paragraph, all such attorneys' fees and expenses awarded by the Court to plaintiffs' attorneys shall be paid by wire transfer to a separate special joint account of Wolf Popper Ross Wolf & Jones and Lowey Dannenberg & Knapp, within ten days after the Effective Date, or as may otherwise be ordered by the Court. BP, BPI or BPNA will pay the costs of notice and settlement administration; plaintiffs shall have no responsibility for any such costs regardless whether the settlement is consummated. Except as provided in this Stipulation,

defendants shall bear no other expenses, costs, damages or fees of any of the plaintiffs or any of their attorneys, experts, advisors, agents or representatives, or of any other members of the Class.

9. The undersigned parties shall use their best efforts to secure Court approval of the Settlement.

10. Counsel for plaintiffs in the Federal Action undertake to take such action as is necessary to discontinue voluntarily the Federal Action and, if necessary, to seek the approval of the Federal Court to dismiss the action and to provide notice to the putative class on whose behalf the action was brought should the Federal Court require such notice as a condition to the dismissal. Should such notice be required, such notice shall be given by BP at its cost and expense. The dismissal of the Federal Action shall be a condition to this Stipulation becoming effective pursuant to paragraph 5.

11. If this Settlement is not approved by the Court or is approved by the Court but such approval is reversed or substantially modified on appeal, the Settlement proposed herein and any actions to be taken in connection therewith (including the Order, and the Order and Final Judgment, to be entered pursuant to Paragraphs 3, and 4 herein, respectively) shall be vacated and terminated and shall become null and void for all purposes, except as contained in this paragraph and so much of Paragraph 8 as

relates to BPNA's obligation to pay the costs of notice and settlement administration, and all negotiations, transactions and proceedings connected with it (a) shall be without prejudice to the rights of any party, including the right of any party who has not heretofore entered an appearance to contest the jurisdiction of the court over his person, (b) shall not be deemed or construed as evidence or an admission by any party of any fact, matter or thing, and (c) shall not be admissible in evidence or used for any purpose in any subsequent proceedings in the Action or any other action or proceeding.

12. BP's obligation to issue the warrants specified in Paragraph 2(c) is subject to the effectiveness of a registration statement for such securities under the Securities Act of 1933 and to approval of BP's shareholders at an Extraordinary General Meeting ("EGM"). BP undertakes to file such a registration statement and seek to have it made effective promptly and to convene an EGM as promptly as possible and to use its best efforts to obtain shareholder approval at that meeting. Should BP be unable to obtain effectiveness of a registration statement or shareholder approval, and therefore be unable to perform its obligation to issue warrants, this Stipulation and the Settlement proposed herein shall become null and void as provided in the event of judicial disapproval by Paragraph 11.

13. This Stipulation may be amended or any of its provisions waived only by a writing executed by or on behalf of all signatories hereto.

14. This Stipulation may be executed in two or more counterparts.

15. The administration of the Stipulation and determination of all disputed questions of law and fact relating to the Stipulation shall be under the authority of this Court and the laws of the State of Ohio.

Dated: April 27, 1987

ARTER & HADDEN
Stanley M. Fisher
Mark F. McCarthy
1100 Huntington Building
Cleveland, Ohio 44115

Liaison Counsel for Plaintiffs

and

WOLF POPPER ROSS WOLF & JONES

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Stephen D. Oestreich
Jeffrey H. Squire
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New York, New York 10022

and

LOWEY, DANNENBERG & KNAPP,
P.C.

By _____
Stephen Lowey
Burton L. Knapp
747 Third Avenue
New York, New York 10017

and

ABBEY & ELLIS

By _____
Arthur Abbey
Jill Abrams
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New York, New York 10017

and

COUDERT BROTHERS

By _____
William Rand
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New York, New York 10166

and

SILVERMAN & HARNES

By _____
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New York, New York 10017

Counsel for Plaintiffs

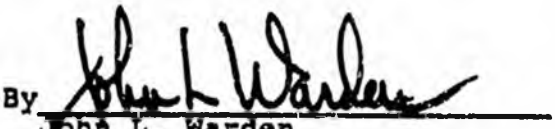
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and

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BP North America Inc.,
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and Sir Peter Walters

SQUIRE, SANDERS & DEMPSEY

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Browne, Frank E. Mosier,
Richard A. Bray, and J. Colin
Webster

EXHIBIT A

IN THE COURT OF COMMON PLEAS
CUYAHOGA COUNTY, OHIO

IN RE THE STANDARD OIL COMPANY/ BRITISH PETROLEUM LITIGATION	))	CONSOLIDATED CASE NO. 126760

ORDER

The above-captioned consolidated action (the "Action") having been commenced by shareholders of The Standard Oil Company ("Standard" or the "Company"), individually and on behalf of a class of the Company's shareholders against the Company, The British Petroleum Company p.l.c. ("BP"), BP International Limited ("BPI"), BP North America Inc. ("BPNA"), and certain individuals (the "Individual Defendants"), and the parties having entered into a Stipulation of Settlement (the "Stipulation") dated April 27, 1987, for the settlement of the Action upon the terms and conditions set forth in the Stipulation,

Now, upon the consent of the parties, after consideration of the Stipulation and the exhibits annexed thereto, and after due deliberation,

IT IS HEREBY ORDERED that:

1. For purposes of settlement only, this Action is hereby certified as a class action under Ohio R. Civ. P. 23(b)(3) on behalf of a class (the "Class") consisting of all common stockholders of Standard or their successors in interest from and including March 26, 1987 to and including the date of the Merger (as defined in the Stipulation) except for corporate defendants BP, BPI and BPNA and any of their wholly-owned subsidiaries. Excluded from the Class is any person who requests exclusion from the Class in a writing received by this Court or any person who perfects his dissenters' rights with respect to the Merger in accordance with Section 1701.85 of the Ohio General Corporation Law.

2. A hearing shall be held on _____, 1987 at _____, _.m. (the "Hearing") to determine the fairness, reasonableness and adequacy of the terms and conditions of the settlement (the "Settlement") proposed in the Stipulation and whether the Settlement should be approved by the Court and judgment entered thereon. At the Hearing or such adjourned date as the Court deems appropriate, lead counsel, on behalf of all attorneys for plaintiffs, may apply for an award of attorneys' fees and reimbursement of expenses as set forth in Paragraph 8 of the Stipulation.

3. The Court reserves the right to adjourn the Hearing, including consideration of the application for attorneys' fees and costs, without further notice other than announcement at the Hearing or any adjournment thereof.

4. The Court reserves the right to approve the Stipulation and the Settlement with or without modification and with or without further notice to the Class.

5. A notice of the Hearing in a form to be approved by the Court (the "Notice") shall be mailed by any one of the corporate defendants by United States mail, postage prepaid, no later than _____, 1987 to all persons shown on the stock records maintained by or on behalf of the Company to be eligible to participate as a member of the Class and shall make available additional copies of the Notice to any record holder requesting the same for the purpose of distribution to beneficial owners. In addition, a summary of the Notice to be approved by the Court shall be published twice in the National Edition of the Wall Street Journal at least fifteen days before the Hearing.

6. The form and method of notice specified herein is the best notice practicable and shall constitute due and sufficient notice of the Hearing to all persons entitled to receive such notice. The Company shall, on or before the date of the Hearing, file proof of mailing of the Notice.

7. Any member of the Class who objects to the Stipulation, the Settlement, the judgment to be entered

thereon, and/or the application for attorneys' fees and reimbursement of expenses, or who otherwise wishes to be heard, may appear in person or by his attorney at the Hearing and present any evidence or argument that may be proper and relevant; provided, however, that no person other than the named plaintiffs and defendants in this Action shall be heard, and no papers, briefs, pleadings or other documents submitted by any such person shall be received and considered by the Court (unless the Court in its discretion shall thereafter otherwise direct) unless no later than ten days prior to the Hearing (i) notice of the intention to appear, (ii) a statement of such person's objections to any matter before the Court, and (iii) the grounds for such objections or the reasons for such person's desiring to appear and to be heard, as well as all documents and writings which such person desires the Court to consider, shall be filed by such person with the Clerk of the Court and, on or before such filing, shall be served upon the following counsel of record:

Stanley M. Fisher, Esq.
Arter & Hadden
1100 Huntington Boulevard
Cleveland, Ohio 44115

Richard Cusick, Esq.
Calfee, Halter & Griswold
1800 Society Building
Cleveland, Ohio 44114-2688

James A. Smith, Esq.
Squire, Sanders & Dempsey
1800 Huntington Building
Cleveland, Ohio 44115

Patrick F. McCartan, Esq.
Jones, Day, Reavis & Pogue
1700 Huntington Building
Cleveland, Ohio 44105

8. Unless the Court otherwise directs, no person shall be entitled to object to the approval of any of the Settlement, the judgment to be entered thereon, or the award of attorneys' fees and reimbursement of expenses to plaintiffs' counsel, or otherwise be heard, except by serving and filing his written objection, notice of intention to appear, and supporting papers and documents as described in Paragraph 7. Any person who fails to object in the manner prescribed in paragraph 7 shall be deemed to have waived his objection and shall be forever barred from raising such objection in this or any other action or proceeding.

9. Pending final determination of whether the Settlement should be approved, plaintiffs, members of the Class, or any of them, shall not commence or prosecute any action asserting claims against any defendant herein which have been or could have been asserted, or arise from or relate to, any of the matters or transactions referred to in any of the complaints consolidated into this Action, or the Stipulation.

10. If the Settlement (including any modification thereof with the consent of the parties made as provided for

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in the Stipulation) should be approved by the Court following the Hearing, an Order and Final Judgment shall be entered as described in Paragraph 4 of the Stipulation.

11. If the Settlement is not approved by the Court or shall not become final for any reason whatsoever, this Action shall proceed, completely without prejudice to any party as to any matter of law or fact, including the rights of any party who has not heretofore entered an appearance to contest the jurisdiction of the Court over his or its person, as if the Stipulation had not been made and had not been submitted to the Court, except that all costs and expenses incurred in connection with provision of notice and the Settlement herein shall be borne by BPNA.

_____

Dated: _____

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EXHIBIT B

IN THE COURT OF COMMON PLEAS
CUYAHOGA COUNTY, OHIO

IN RE THE STANDARD OIL COMPANY/ BRITISH PETROLEUM LITIGATION	))	CONSOLIDATED CASE NO. 126760

ORDER AND FINAL JUDGMENT

A hearing having been held before this Court on _____, 1987, pursuant to this Court's Order of _____, 1987 (the "Hearing Order"), upon the Stipulation of Settlement dated April 27, 1987 (the "Stipulation") in the above-entitled consolidated action (the "Action"); and it appearing that due notice of the hearing was given in accordance with the Hearing Order to all persons eligible to participate as members of the class certified pursuant to the Hearing Order (the "Class"); and the respective parties having appeared by their respective attorneys; and said attorneys having been heard; and an opportunity to be heard having been given to all other persons desiring to be heard or to object to the proposed settlement; and the proposed settlement having been considered by the Court:

IT IS ORDERED, ADJUDGED AND DECREED AS FOLLOWS:

1. The Court hereby approves and adjudges the terms and conditions of the Stipulation and the Settlement for which provision is made therein to be fair, reasonable and adequate.

2. This Action is hereby dismissed with prejudice, and all claims which the plaintiffs or the members of the Class, as defined in the Hearing Order, or any of them ever had, now has or hereafter can, shall or may have by reason of or arising out of or relating to any of the facts, transactions, actions or conduct, actual or purported, alleged or which could have been alleged in the Action or in any other forum, including without limitation, the Offer, the Offer to Purchase, including any supplements thereto, or the acquisition by BPNA of Shares pursuant to the Offer or in the Merger, all as described in the Stipulation (the "Settled Claims"), including dissenters' rights under Section 1701.85 of the Ohio General Corporation Law, shall be released and dismissed with prejudice with respect to each and every defendant named in the Action and each of their respective officers, directors, employees, agents, advisors, attorneys, representatives, predecessors, affiliates, parents, subsidiaries, and the general or limited partners, successors, heirs, administrators, executors and assigns of any of the foregoing.

3. Plaintiffs and all members of the Class are hereby permanently barred and enjoined from instituting or prosecuting, whether directly, representatively, derivatively or in any other capacity, any action asserting claims which are, relate to or arise out of Settled Claims.

4. Plaintiffs' attorneys are hereby awarded the sum of $ _____ for legal fees and reimbursement of expenses incurred in the prosecution of the Action, which award the Court finds to be fair and reasonable. Such sum shall be paid by BPNA in accordance with the Stipulation. No other costs shall be taxed in connection with this Action, except as otherwise provided by paragraph 8 of the Stipulation.

5. Without affecting the finality of this Order and Final Judgment in any way, the Court hereby reserves jurisdiction over all matters relating to the administration and effectuation of the Stipulation.

_____

Dated: _____, 1987

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EXHIBIT C

RELEASE

TO ALL TO WHOM THESE PRESENTS MAY COME OR MAY CONCERN,

WHEREAS, the undersigned are co-lead counsel for and on behalf of the members of the Class (the "Releasors") referred to in the Stipulation of Settlement in the consolidated class action entitled _____, Consolidated Civil Action No. _____, dated _____, 1987, and filed with the Court of Common Pleas for Cuyahoga County, Ohio on _____, 1987 (the "Stipulation"); and

WHEREAS, the Court, following a hearing held on _____, approved the settlement provided for by the Stipulation and the Effective Date has occurred:

NOW, THEREFORE,

1. As provided in the Stipulation, Releasors, for good and valuable consideration, the receipt of which is hereby acknowledged, have remised, released and forever discharged and by these presents for their predecessors, successors and assigns and any of their past or present officers, directors, employees, agents (and any of their heirs, executors or administrators, successors and assigns) do hereby remise, release and forever discharge each and all of the defendants in any of and all the actions referred to above, such defendants' officers, directors, employees, agents, advisors, attorneys, representatives, affiliates, or subsidiaries, and the general or limited partners, heirs, successors and assigns of any of the foregoing (the "Releasees"), of and from all manner of actions, causes of action, suits, debts, dues, sums of money, accounts, reckonings, bonds, bills, specialties, covenants, contracts, controversies, agreements, promises, variances, trespasses, damages, judgments, extents, executions, rights, claims and demands whatsoever, in law, in admiralty or in equity (hereinafter collectively referred to as "Claims"), which against the Releasees, or any of them, Releasors or Releasors' predecessors, subsidiaries, successors and assigns and any of their past or present officers, directors, employees or agents and any of their heirs, executors or administrators, successors and assigns ever had or now has or hereafter can, shall or may have by reason of or arising out of any of the facts, transactions, actions or conduct, actual or purported, from the beginning of the world to the date of this Release, alleged in the pleadings in the foregoing Consolidated Civil Action or any of them, or which might have been alleged in the Court or in any other court, administrative body or tribunal or arbitration panel of any state, federal or other jurisdiction, domestic or foreign, with respect of or relating to the Offer, or any supplements thereto, the Merger or possible Merger or otherwise in connection with the acquisition of the Shares.

2. Nothing in this Release shall be deemed to be construed as an admission of any liability of any Releasee, which liability is expressly denied.

3. Nothing in this Release shall relieve the Releasees from any and all of their obligations under the Stipulation and the order and judgment of the Court in connection therewith.

4. This Release shall inure to the benefit of and shall be binding upon the heirs, executors, administrators, successors and assigns of the parties hereto and it shall be governed and construed in accordance with the laws of the State of Ohio.

IN WITNESS WHEREOF, the undersigned have for and on behalf of the members of the Class executed these presents this ___ day of _____, 1987.

ABBEY & ELLIS

By_____

LOWEY, DANNENBERG & KNAPP, P.C.

By_____

WOLF POPPER ROSS WOLF & JONES

By_____

COUDERT BROTHERS

By_____

SILVERMAN AND HARNES

By_____

12-10-87

Wed.,

Counter to what Jon Faiks says, her office did not submit an incentives package to the Division of Oil & Gas. To my knowledge, this report represents an up to date review of the legislation that was enacted by the States Congress in the last few years.

Mike Kotowski

To Nedt

LOUISIANA ECONOMIC ACCELERATION PROGRAM

(LEAP)

PROPOSAL

a rig = 172 jobs direct/yr (3)

largely oriented tow. gas problem + conservation - gas seen as much > difficult problem than oil (p 6, 7)

does not affect existing produc or existing non-producing fields - only new explor wells (p. 9)

"minimizing cost to the state" a stated goal (p. 10)

foresees supply only on gas; servic focuses on oil + gas; (p 10)

local hire requirements (p 13)

legislative oversight committee for implementation of LEAP. (p 14)

3 yr. suspension only

80% of offd "wildcat" wells are drilled by indepes (p 15)

will produce ~~don~~ cap producing wells + drill new ones to offset serv/supply ? need readiness regs (16)

→ 3 yr. limit (22)

Louisiana employment multiplier is much different from Alaska's - (3, 23)

BY

SENATOR SAMUEL B. NUNEZ, JR.
PRESIDENT
LOUISIANA SENATE

PROPOSAL PAPER PREPARED BY

LORI CAMERON
COUNSEL TO THE PRESIDENT

NOVEMBER 25, 1985

Senate
State of Louisiana

P. O. Box 94183
Baton Rouge, Louisiana 70804
(504) 342-2040

February 18, 1988

Rep. Sam Cotten, Chairman
House Natural Resources Committee
Room 124, P.O. Box V
Juneau, AK 99811

Dear Rep. Cotten:

Pat Raffaniello asked me to send you any available information on the Louisiana Economic Acceleration Program or LEAP, as it is commonly known. Enclosed you will find:

- A LEAP Proposal Paper which preceded the legislation,
- The LEAP legislation, passed during the 1986 Regular Session,
- Legislation from the 1986 Extraordinary Session which exempted oil and gas development in certain wildlife refuges from the severance and royalty provisions of LEAP,
- Legislation from the 1987 Regular Session amending LEAP to include women-owned businesses and setting a certain date for spudding LEAP wells (we found applicants reworking old wells to take advantage of the tax benefits),
- Regulations issued by the Commissioner of Conservation implementing LEAP, and
- A report from the Department of Natural Resources the direct revenue impacts of LEAP.

I'm not sure that the DNR report was specific enough to give a true picture of the impact of LEAP. I'm trying to get a report done now that would compare wildcat drilling on a month by month basis to more clearly illustrate LEAP's impact.

Please do not hesitate to contact me if I can be of further assistance on this matter.

Sincerely yours,

Lori

Lori Cameron

LOUISIANA ECONOMIC ACCELERATION PROGRAM

(LEAP)

PROPOSAL

BY

SENATOR SAMUEL B. NUNEZ, JR.
PRESIDENT
LOUISIANA SENATE

PROPOSAL PAPER PREPARED BY

LORI CAMERON
COUNSEL TO THE PRESIDENT

NOVEMBER 25, 1985

ACKNOWLEDGEMENTS

This background paper was prepared with the valuable assistance of Renwick DeVille, Louisiana Geological Survey; Robert Keaton, Senate Budget Analyst; Donald J. Vandal, Senate Budget Analyst; and John Rombach, Senate Economist.

PREFACE

The Louisiana Economic Acceleration Program (LEAP) proposal is an organized approach to easing Louisiana's unemployment and fiscal problems while beginning work on the diversification of the state's economy.

It is presented as such, in the belief that public discussion and recommendations can only strengthen the proposal. Constructive criticism and suggestions are, by means of this proposal paper, actively solicited from the citizens of Louisiana, as well as those who presently, or may in the future, do business in our state.

LOUISIANA ECONOMIC ACCELERATION PROGRAM

(LEAP)

PROPOSAL SYNOPSIS

SITUATION: Louisiana is second only to West Virginia in unemployment and is facing a state deficit despite budget cuts and increased taxes. These crisis conditions are indicative of a weak state economy.

PURPOSE: LEAP is designed to accelerate Louisiana's economic recovery, easing unemployment and fiscal problems, while providing planning and funding mechanisms for long-term economic diversification.

PROGRAM ELEMENTS: LEAP is a three year program. During the program period, exploratory oil and gas wells drilled in new fields, and all subsequent developmental wells in the same field, will qualify as LEAP wells.

Oil and gas severance taxes and the state's natural gas royalties on LEAP wells will be forgone for the program period.

Louisiana's natural gas consumers will receive an incentive from the state of X cents per Mcf for consumption of gas from LEAP wells consumed in excess of 1985 consumption levels.

The Economic Diversification Fund will be established to pay for the natural gas consumer incentive during the program period and to provide revenues for long-term economic diversification programs at LEAP's conclusion.

State oil royalties from LEAP wells will be dedicated to the Fund immediately. At the end of the program period all LEAP well severance taxes and royalties would accrue to the Fund.

Existing production and related revenues are unaffected by LEAP.

IMPACTS: Preliminary calculations indicate that for every 200 new wells that are attributable to LEAP during a program year, 10,000 jobs will be created, net state revenues will increase by $15.2 million, and there will be $360 million in increased personal income in Louisiana.

LOUISIANA ECONOMIC ACCELERATION PROGRAM

(LEAP)

PROPOSAL PAPER

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III. Analysis of Impacts of the LEAP Proposal

IV. LEAP, State Policy and The Industry

V. Questions and Answers on the LEAP Proposal

MEETING THE CHALLENGE OF LOUISIANA'S ECONOMIC CRISIS

The close of 1985 finds Louisiana in economic crisis. The state's staggering unemployment rate, which is second only to West Virginia's, and the chronic deficit posture of state government, are indicators of its condition.

The crisis is an immediate problem. The crisis must be considered however, in the context of Louisiana's limited, and weakened, economic base. Future crises may only be averted by directing the state's attention to creating a stronger, diversified economy.

The Louisiana Economic Acceleration Program (LEAP) proposes to create immediate employment opportunities, accelerate the state's economic recovery, and begin work on long-term economic diversification.

There are a multitude of statistics quantifying the extent and cost of unemployment to the state's economy. It is impossible however to quantify the effect on Louisiana's citizens and their families. The cost to the state's spirit is as unacceptable as the cost to the economy.

Unemployment is a double burden on the state's economy. People without jobs drain the state's coffers directly in the form of unemployment, health, and medical benefits. During 1985 unemployment benefits will cost the state's economy about 450 million dollars. That figure does not include amounts spent on social services for the unemployed.

However, the greater burden to the economy relates to the fact that the unemployed cannot pay taxes or spend money to support expanding economic activity. No jobs, no tax revenues, no economic growth.

There are more than 215,000 unemployed people in Louisiana today. That is more than the population of Shreveport. It is about three times the population of Lake Charles.

Unemployment in Louisiana over the first eight months of 1985 averaged 11.6 percent. This is in contrast to the national average of 7.4 percent for that same period. Three-fourths of Louisiana's parishes (48 parishes) had unemployment rates in excess of 10 percent. One in five of the parishes (13 parishes) had unemployment rates over 15 percent.

Especially troubling is the state's inability to break out of the highest unemployment ranks. Over an 18 month period from the beginning of 1983, the national unemployment rate fell steadily from 10.4 percent to about 7 percent where it has remained through mid-1985.

Louisiana has shown no sign of sharing in this national recovery. The state's unemployment rate remains stubbornly at more than 50 percent above the national average.

The second indicator of economic crisis is the perilous fiscal situation of state and local governments. Since 1983, the state has cut 277.6 million dollars in expenditures. In 1984 over 900 million dollars of new taxes were levied.

In spite of the cuts and the increased tax rates, the state faces a deficit of up to 177 million dollars this fiscal year. Parochial and local governments face similar dilemmas.

Tax increases are not the answer. Raising tax levels has a chilling effect on the economy. The purpose of the State must be to increase economic acitivity in Louisiana, to get money moving again, rather than taking it out of circulation in the form of increased taxes.

Louisiana must put her people to work, and encourage investors to put their money to work in Louisiana. An economic recovery, sparked by new jobs and investments will increase revenues for the state and restore Louisiana's sense of purpose.

LEAP is a three year program to create new jobs and revenue while accelerating Louisiana's economic recovery. LEAP establishes an Economic Diversification Fund within the State Treasury, the proceeds of which will fund economic diversification programs.

LEAP utilizes Louisiana's strongest natural resource, oil and gas, as a tool. Historically, Louisiana's state government has viewed oil and gas development as a source of direct tax revenues.

LEAP views oil and gas development as an engine to accelerate the state's economic recovery by providing cash and jobs to the state. Direct tax revenues are forgone in favor of jobs, economic activity and indirect tax revenues.

Oil and gas drilling creates jobs and cash flow throughout the economy. Initial analyses indicate that a single rig, running throughout the year, means jobs for 516 people in Louisiana.

The rig represents 172 jobs in the oil and gas exploration and production sector. Further, for every job in the oil and gas exploration and production sector there are two others created elsewhere in the economy.

Relative to cash flow, it has been estimated that an average well drilled in Louisiana costs more than a million dollars, (i.e. $1,023,079). Other studies demonstrate that for every million dollars expended in the oil and gas exploration and production sector, three quarters of a million dollars in sales occur elsewhere in the economy.

One of the most attractive aspects of LEAP is the fact that Louisiana has a knowledgeable work force ready to walk back onto the drilling sites and start operations.

There will be no lag-time training computer specialists or high tech machinery operators. Louisiana's people know how to work the oil rigs, run the seismic tests, prepare the mud, and operate the related service industries.

Anyone familiar with Louisiana's economy recognizes that overdependence on an ailing oil and gas industry is a major contributing factor to the state's current economic problems. How then can LEAP expect to improve the state's position using that same industry?

The answer lies in coaxing the entire U.S. oil and gas industry to give its best performance over the next three years in Louisiana. Although drilling activity nationally may be limited, Louisiana will distinguish itself from other producing areas and attempt to pull as much activity as possible into the state for the three year period.

The state will give producers a reason to drill in Louisiana rather than Texas, Oklahoma, or Alberta. The state will provide oil and gas investors with an alternative to "sitting next year out", and instead, encourage the investor to risk drilling capital in Louisiana.

In order to understand the elements of the LEAP proposal, it is important to understand the status of the oil and gas industry. It is not a healthy industry. In the closing days of October 1985, drilling activity was down 27 percent nationally, from the year before. Dismally, Louisiana's drilling was down 31 percent for the same period. Industry forecasts indicate further declines in drilling activities for 1986.

Similar drilling declines over the last five years have affected Louisiana tremendously. Since 1981 the state has lost over 19,000 jobs in oil and gas exploration and production. The multiplier would suggest that another 38,000 jobs were lost throughout the economy, for a total of 57,000 jobs.

Severance taxes in Louisiana have also decreased every year since 1981. Severance tax revenues this year are expected to be down more than 25 percent or 250 million dollars from five years earlier. The downward revenue trend is expected to continue.

The reasons for the drilling declines are varied. Basic to an understanding of the problem is a recognition that the oil market is distinct from the gas market and they face differing market situations.

The market for oil is a world market, tied together by tankers transporting crude from producing nations to consuming ones. Despite internal problems, OPEC maintained its power to influence the world price for crude oil throughout 1985. A premium commodity, Louisiana sweet crude has sold at about $28 per barrel all year.

The demand for crude has likewise remained stable. Louisiana producers report that they can sell crude oil, if they are willing to take the world-dictated price. The lower price has caused a decrease in drilling activity throughout the nation, as investors opt for alternative investments or wait out the lower price.

Unlike the relatively stable, though depressed, crude oil market, the market for natural gas is in shambles. Despite prices at a fraction of what they were three year ago, an excess of supply exists.

The market for natural gas is limited to North American producers and primarily American consumers. The market's geographical boundaries are defined by pipelines, since pipelines are the only economical means of transporting natural gas.

Over the last few years, the price of natural gas has plummeted. Some Louisianians recall Tuscaloosa Trend gas contracts signed in the early 1980's for $8 per Mcf and more. In contrast, the November 1985 spot market price for Louisiana natural gas was $2.03 per Mcf.

Higher natural gas prices in the early 1980's led to more production at the very time consumers began to implement serious conservation efforts. Increased production led to increased supply while conservation led to decreased demand.

These factors combined to spawn an oversupply of natural gas, originally referred to as a "bubble" of excess deliverability. The excess supply of natural gas causes producers to fear that even if they find gas at competitive prices (i.e. in the $2 per Mcf range) there will be no buyers for the new gas.

Producers see the consuming end of the market as saturated with gas. Unless market demand can be expanded, there is no reason to drill for gas not expected to sell. This is particularly true given today's extremely competitive price structure where profit margins have been shaved thin.

The differing market situations facing crude oil and natural gas require a different combinations of incentives to promote increased drilling activity in Louisiana. Oil producers need to see an improved bottom line to entice them to move drilling activites to Louisiana, or indeed to commit investment dollars to drilling anywhere.

Natural gas producers need encouragement at both ends of their market before they will commit to drill. On the producing end they need to feel that there is an opportunity to be competitive in the cutthroat national price battle.

On the consuming end, they need to see expansion of demand for natural gas, either from new consumers or increased takes by present consumers. Expanded demand will assure producers that there will be buyers for gas from new wells.

In addition to the market pressures described, there are a number of factors outside of the market framework, each of which has the potential to profoundly affect drilling activity in the United States. They are declines in the world price of oil; changes in federal laws, (e.g. an abandonment of tax credits for oil and gas operations under the Tax Simplification Plan); and federal regulatory changes, (e.g. the Federal Energy Regulatory Commission's (FERC) proposed block billing regulations).

These factors are largely outside of Louisiana's control although pressure may be exerted on the congressional and regulatory fronts. However, these factors should affect all producing states uniformly. Therefore, if Louisiana distinguishes itself through a state incentive program, it will maintain an advantage.

It should be noted that Outer Continental Shelf (OCS) activity is unrelated to onshore Louisiana. At present, OCS development is driven largely by federal lease considerations. In 1983 the federal government held its first, record-breaking, area-wide lease sale. Blocks of OCS acreage were leased by the federal government for millions of dollars.

Recently there has been minimal activity on these leased blocks because of depressed market conditions. However, under the terms of the lease, if exploratory activities are not underway by the conclusion of the lease period, all rights under the lease will be lost.

Since the normal term of these leases is five years, increased OCS activity may be expected in 1987 and 1988 due to lease pressure. This activity is independent and outside of state influence.

The following section presents the elements of the LEAP proposal. The third section discusses estimated impacts attributable to the proposal and the fourth section deals with state policy, the industry, and LEAP.

ELEMENTS OF THE LOUISIANA ECONOMIC ACCELERATION PROGRAM PROPOSAL

The LEAP proposal ties short-term economic acceleration to long-term economic diversification in a comprehensive package. The LEAP proposal is for a three year period, which is assumed to begin upon the enactment of the enabling legislation. During the program period, exploratory oil and gas wells drilled in new fields, and all subsequent developmental wells in the same field, will qualify as LEAP wells. There are three major elements of the LEAP proposal.

The first deals with the suspension of oil and gas severance taxes, as well as the state's natural gas royalty, on production from LEAP wells. Producers applying for such benefits would be required to certify that Lousiana labor would be utilized to the maximum extent possible. The severance tax provisions would be administered by the Department of Revenue and Taxation. The royalty provision would be administered by the Mineral Board.

The second element deals with state incentives for the consumption of natural gas produced from LEAP wells. The state would provide an incentive of X cents per MCF for such gas consumed in excess of the consumer's 1985 baseline consumption. This incentive will assure a market for natural gas produced from LEAP wells.

The amount of the consumer natural gas incentive remains to be determined. It will be established prior to drafting of enabling legislation, based on discussions with market participants.

The incentive would be paid to qualified consumers at the end of the program year. Applicants for the incentive would certify as to their 1985 baselevel of natural gas consumption, as well as their increased consumption during the program year. Further, documentation would be required as to the origin of the LEAP gas.

The natural gas incentive aspect of LEAP will be structured so that Louisiana industrials and utilities are qualified applicants. LEAP will further provide that all incentives received by a utility serving end-users (i.e. residential and commercial customers) be passed through to those end-users. The natural gas incentive element of the program will be administered by the Department of Revenue and Taxation.

The third element deals with an Economic Diversification Fund, which would be established within the state treasury. During the program period, the Fund would receive all state oil royalties from LEAP wells. At the conclusion of the program period, all future severance taxes and royalties from LEAP wells would accrue to the Fund.

The Fund would be the source of revenue for natural gas incentive payments during the program period; remaining revenue in the Fund could be appropriated to economic development programs. At the conclusion of the program period, the Fund would be utilized to support long term economic diversification program plans developed over the three year period.

All appropriations from the Economic Diversification Fund will be designated as such in the state budget. Long term economic diversification program plans will be developed during the three year program period and defined in legislation. Once codified in the statutes, long term economic diversification programs will be eligible for appropriations from the Fund.

Existing production, as well as severance and royalties accruing from existing production (approximately 1.2 billion dollars) would be unaffected by LEAP.

ANALYSIS OF IMPACTS OF THE LEAP PROPOSAL

The LEAP proposal is designed to maximize speedy employment and investment response. Although more thorough studies are underway, initial calculations approximate the impact of the program.

Pending verification with econometric models, the state may expect that an increase of 200 exploratory wells as a result of LEAP, over one program year, may provide 10,000 new jobs, $15.2 million in increased revenues to the state and $360 million in increased personal income in Louisiana in the program year.

Suspension of the severance tax on LEAP wells for the three year program period is an ideal incentive to encourage speedy response. Suspension of severance tax offers producers immediate price relief on oil and gas from new Louisiana wells, improving the producer's cash flow situation from earliest production.

Since virtually all producing states have severance taxes, suspension of the tax on new production is a clear means of distinguishing Louisiana as the state of choice for drilling activities. Severance taxes are built into the producer's economic analyses of nationwide drilling prospects. Suspension of the tax in Louisiana will have a decided impact on the bottom line, drawing drilling capital from around the country.

The severance tax provisions of the proposal are also in line with the Program's goal of minimizing cost to the state. Realistically, the current oil and gas markets go a long way toward minimizing the cost of severance forgone. If producers don't drill there will be no new severance tax revenues to forego.

Severance tax and royalty revenues from production existing prior to LEAP's start would continue to be collected by the state. The only tax revenues foregone would be those from LEAP wells.

Revenue losses from wells that might have been drilled without LEAP's encouragement will be offset by increased revenues attributable to economic activity generated by LEAP. Drilling investments will have expansive affects on the economy. The re-employed will be paying income taxes, sales taxes as well as other taxes. Further, they will no longer be draining state coffers but rather, contibuting to them.

Natural gas royalties on state-owned production from LEAP wells will also be foregone by the state. This additional incentive is offered to natural gas producers in recognition of the more depressed natural gas market.

There is a cost of LEAP not mentioned in the impact analysis. That is the long-term cost of encouraging present use of Louisiana's finite natural resources. This cost is incurred by the LEAP in consideration of the state's present economic crisis. Certainly Louisiana does not have to wait until it is dead last, rather than 49th in unemployment before utilizing its strongest assets.

In order to assure maximum employment, each application for severance tax and royalty forgiveness will include a labor certification. The producer will certify that Louisiana labor has been used to the maximum extent possible in exploration and production of the oil or gas.

The second major element of the program is an incentive payment to encourage additional consumption of natural gas by Louisiana consumers. Revenue for the incentive payments will come from state crude oil royalties accrued from new production activities spurred by LEAP.

In other words, if LEAP works, it will pay for the natural gas incentive itself. If LEAP does not work, there will be no additional gas to be consumed, no incentives to be paid, and so, no cost to the state.

The incentives are necessary because of economic disorder in the natural gas market, nationally as well as in Louisiana. Even at nationally competitive prices, Louisiana producers cannot find markets for new natural gas.

In order to assure that producers of natural gas drill in Louisiana, creating the jobs and attendant economic benefits to the state, the state will endeavor to provide additional markets for natural gas. Market expansion will be encouraged by offering incentives to Louisiana consumers to buy additional amounts of natural gas from new wells in the state. Utilities will be required to pass through benefits to residential and commercial customers.

In addition to assuring a market for new Louisiana gas, the incentive program will assure that Louisiana's natural gas-consuming industrials remain competitive in fierce national and international markets. Those Louisiana jobs will be protected as well.

In order to qualify for incentives at the end of the year, the natural gas consumer (industrial or utility) will apply to the Department of Revenue and Taxation. The application will certify the consumer's 1985 baseline consumption, the amount of natural gas used in excess of the baseline during the program year, and provide documentation as to the purchase of gas from LEAP wells in an amount equal, at least, to the excess consumption.

The third major component of the program is proposed in recognition to the state's critical need to develop a diversified economy as part of a long-term economic development plan. LEAP addresses the crisis as well as the underlying weakness, by providing a planning and funding mechanism with which state may implement long-term economic diversification plans.

At the conclusion of the three year program period, severance taxes and natural gas royalties will be levied on future production from wells drilled under the auspices of the program.

These severances and royalties from increased production attributable to program incentives will accrue to the Economic Diversification Fund and be dedicated implementing long range economic diversification plans.

The three year LEAP period may be utilitzed for developing economic diversification programs. The plans should be developed as legislatively-approved programs, their purpose and approach set down in the statutes.

At LEAP's conclusion the Economic Diversification Fund will receive the revenue benefits of increased production. At that time, appropriations may be made, and identified as such, to the economic diversification programs.

If, during the program period, the Fund has revenues remaining after the payment of natural gas consumer incentives those monies may be appropriated to existing economic development programs. For example, the Small Business Development Act of 1984 would be an excellent candidate for an appropriation from the Economic Diversification Fund.

LEAP is limited to three years for a number of reasons. Foremost among the reasons is that the state of Louisiana cannot afford to continue its economic dependency on oil and gas.

The second reason for the Program's three-year term is that it will take at least that long for Louisiana to take its place among its economically active sister states. A recovery from 49th in unemployment will take longer than a few months.

The third reason or set of reasons concerns the oil and gas industry. A three year period is long enough to fully attract the attention of producers nationwide. Also, many experts feel that a revival of the oil and gas industry may be expected in three year to five years. If this is the case, Louisiana will be poised and ready to take full advantage of the industry's comeback.

LEAP has a number of program requirements to assure that employment and revenue benefits are safeguarded. First, producers applying for severance tax and natural gas royalty relief will have to prove that the well in question was drilled and completed during the program period. This may be done with the Office of Conservation permits which are required prior to drilling.

The producer will also certify that Louisiana labor was utilized during exploration and production activities to the maximum extent possible. This certification will be similar to one required by the state's bonding authority with regards to state funded projects.

Second, industrial and utility consumers of natural gas will have three tests to meet in applying for consumption incentives. They will have to certify 1985 baseline consumption of natural gas, certify the amount they use in excess of the 1985 baseline, and show with purchase certificates that the excess amount for which the incentive is sought was purchased from LEAP wells.

Producers will certify LEAP well sales to pipelines, who will certify the same to consumers. Since well production figures and transportation data are currently kept by the Office of Conservation, the Program's impacts will be easily verified.

Residential and commercial consumers will not be troubled by the verification procedure. Utilities, both private and public, which supply residential and commercial consumers will meet the program certification requirements and be required by statute to automatically pass through benefits to the end-user.

As a final safeguard, a legislative committee appointed by the Speaker of the House and the President of the Senate would be give legislative oversight authority for the program. The committee would be authorized to order program audits where indicated.

LEAP, STATE POLICY AND THE INDUSTRY

LEAP will help reshape Louisiana's business image nationally. It sends a clear message: Louisiana wants you and your dollars doing business in Louisiana.

Equally important, it will send a message to the citizens of this state that Louisiana has the willpower and the ingenuity to deal with problems facing the state. This is a state of people wanting and ready to work and a government prepared to give them that opportunity.

Given the critical nature of Louisiana's employment and fiscal situation, LEAP is designed to encourage quick response from the oil and gas industry. Because severance taxes and natural gas royalties will be suspended only for the three year program period, wells drilled early in the program period will reap the most benefit.

Industry conditions also assure quick response. About 80% of "wildcat" or exploratory wells are drilled by "independents", small oil and gas producers. Major oil and gas companies like Exxon, Texaco and others are responsible for the remaining 20 percent.

Today, like many other relatively small businesses, a number of independents facing severe cash flow problems. Drilling under LEAP's terms will offer some immediate relief to their cash flow situtation.

Banks, and other leading institutions to whom Louisiana independents are indebted, may also be interested in LEAP. If banks foreclose, they get little besides equipment. If they give the producer "another chance" there may be an improvement in his overall financial condition.

Loans to finance new wells with guaranteed lower costs (e.g. severance tax forgiveness) are relatively attractive risks. LEAP should be welcomed by lenders, as well as by independents.

The majors find themselves in a different situation. Majors generally have investment capital but may, because of corporate diversification, may have better alternative investments. LEAP may provide the majors with the incentive necessary to invest in drilling in Louisiana.

Finally, because drilling is off, drilling equipment and services are readily available at very reasonable costs. Given incentives beyond those available in the market place, it's a good time to drill for oil and gas.

Further, with regard to the oil and gas industry nationally, LEAP will leave Louisiana well-positioned. The state's oil and gas producers will be activated and able to quickly and easily increase production to meet demand as the market recovers nationally.

It is expected that both shallow and deep wells will be drilled under the auspices of LEAP. In terms of employment benefits to the state, it doe. not appear that either shallow or deep wells are markedly more advantageous. A number of shallow wells, each employing a drilling crew, can be drilled over the same time period it takes to drill a single deep well. In addition to a longer employment term for the crew, a deep well will require more equipment and services (and related employment) like specialized mud, pipe, and drill bits.

From the producer's standpoint, the program should be attractive for either type of well. Shallow wells cost less to drill and so an incentive (a 7 cent per Mcf cost reduction) may have a dramatic affect on the "bottom line." On the other hand, deep wells generally produce more, multiplying the impact of an incentive.

LEAP should have little impact on existing oil and gas production in the state. This largely because drilling activity is financed by lenders who are repaid with proceeds from the well's production. In order to pay for a well, it must be kept in production.

In the case of an older well that has already paid out, it is likely to be producing oil or gas the producer can afford to sell cheaply. The producer will want to maintain that production in order to lower his average sale price. Further, impacts on existing natural gas production should be minimized by the market expansion generated in Louisiana for new gas by the state's consumer incentive. Similarly, there should be little impact on the national oversupply situation.

There may be concern that producers might cap existing wells and drill new wells into presently producing pools in order to avoid severance taxes. This concern may be addressed on regulatory and economic grounds.

First, the State's Office of Conservation keeps track of all wells drilled in Louisiana. Attempts to drill in presently productive pools will be quickly recognized.

Second, it is unlikely that a producer would expend the capital, on average of a million dollars, to drill a new well in a producing field just to get a severance break. There are no geophysical guarantees that production will be resumed with the second well.

No other state has undertaken an initiative similar to LEAP. Other states do not have Louisiana's combination of economic problems and geological conditions that favor the response expected in Louisiana.

However, the Canadian government, along with its oil and gas producing provinces, have embarked on a related program. Changes in Canadian energy policies brought about a 21 percent increase in oil sales to the U.S. and a 27 percent increase in gas sales over a six month period.

Canada's situation differs from Louisiana's; Canadian provinces own the mineral resources within their boundaries. Not surprisingly, Alberta which produces 85 percent of Canada's oil and gas, is anxious to take advantage of the employment and revenue advantages of increased production.

In the spring of 1985, the Canadian federal government reached an agreement with the oil and gas producing provinces of Alberta, Saskatchewan and British Columbia termed the Western Accord. The Western Accord called for increasing energy investments and creating additional jobs through decontrol of crude oil prices, a policy of deregulation of natural gas, and a phase-out of the petroleum and gas revenue taxes. The province of Alberta has also lowered its royalty substantially to increase employment and investment.

Given the Canadian's recent policy stance, Louisiana competes even for dollars that might otherwise go to Alberta or Saskatchewan. In order to achieve its employment and fiscal purpose, the state must distinguish itself as the premier location for drilling investment in the Northern Hemisphere. Louisiana is indeed fortunate that the most critical factor, the excellent natural resource base has preceded the state by millions of years.

The state needs only to create an economic atmosphere. LEAP sets the tone. Louisiana wants the jobs and the dollars and is willing to sharing the risk to get them.

QUESTIONS AND ANSWERS ON THE LOUISIANA ECONOMIC ACCELERATION PROGRAM (LEAP) PROPOSAL

1. Why does Louisiana need LEAP? Louisiana is second only to West Virginia in unemployment and is facing a state deficit despite budget cuts and increased taxes. These crisis conditions are indicative of a weak state economy.

2. What is LEAP's purpose? LEAP is designed to accelerate Louisiana's economic recovery, easing unemployment and fiscal problems, while providing planning and funding mechanisms for long-term economic diversification.

3. Why utilize Louisiana's oil and gas resources, especially in light of the weakened condition of the oil and gas industry? In order to work, LEAP needs an industry that can quickly provide jobs and investments in exchange for state incentives. LEAP targets oil and gas drilling because Louisiana's resource base is proven and there is a knowledgeable, trained workforce ready to walk back onto drilling sites and start operations. There will be no lag-time training computer specialists or high tech machinery operators. Louisiana's people know how to work the oil rigs, run the seismic tests, prepare the mud, and operate the related service industries. There is also an abundance of idle drilling rigs, equipment, and service companies.

4. What are the elements of LEAP? LEAP is a three year program. During the program period exploratory oil and gas wells drilled in new fields, and all subsequent wells in the same field, will quality as LEAP wells.

First, severance taxes and the state's natural gas royalties on LEAP wells will be forgone for the program period.

Second, Louisiana's natural gas consumers will receive an incentive from the state of X cents per Mcf for consumption of gas from LEAP wells consumed in excess of 1985 consumption levels.

Third, the Economic Diversification Fund will be established to pay for the natural gas consumer incentive during the program period and to provide revenues for long-term economic diversification programs at LEAP's conclusion. State oil royalties from LEAP wells will be dedicated to the Fund immediately. At the end of the program period all severance taxes and royalties from LEAP wells would accrue to the Fund. Existing production and related revenues are unaffected by LEAP.

5. Why suspend the severance tax? Suspension of severance tax is the one area that the State controls which can have an immediate positive impact on the marketability of Louisiana oil and gas. The suspension of severance allows the "bottom line" on many wells to shift from marginal to positive, thus spurring drilling activity. It also improves the producer's cash flow situation from earliest production, when such relief is needed most.

6. Why suspend natural gas royalties and offer additional incentives on the natural gas marketing end? The incentives are necessary because of the current economic disorder in the natural gas market, nationally as well as in Louisiana. Suspension of the severance tax and gas royalties from state lands on natural gas will encourage producers to drill. However, further incentives will assure that there are buyers for LEAP gas.

7. How is Louisiana assured of long-term benefits from LEAP? The Economic Diversification Fund will provide revenues dedicated to the implementation of long-term economic diversification plans. Such plans will be developed over LEAP's three year period and defined in the statutes in order to be eligible for appropriations from the Economic Diversification Fund. The Fund is the State's way of announcing that all revenues generated from LEAP wells are forever dedicated to the diversification and expansion of Lousiana's economy.

8. What safeguards will be built into this program to ensure that employment and revenue benefits are realized? First, producers applying for severance and royalty relief will have to prove that the well in question was drilled and completed during the program period and is in a new field. This may be done with the Office of Conservation permits which are required prior to drilling. Secondly, the producer will certify that Louisiana labor was utilized during exploration and production activities to the maximum extent possible. This certification will be similar to one required by the state's bonding authority with regards to state funded projects. Applicants for consumer natural gas incentives will certify 1985 baseline consumption, excess consumption for the program year, and document that excess consumption amounts come from LEAP wells. Finally, a legislative committee will be appointed to give legislative oversight of the program, with authoriztion to order program audits where indicated.

9. Will there be a quick response to the program? Industry conditions assure a quick response. Because severance taxes and natural gas royalties will be suspended for only a three year period, wells drilled early will benefit the most. Additionally, many independent producers (the group responsible for the vast majority of exploratory drilling) are facing severe cash flow problems. Immediate drilling and production will provide some relief to this situation. Also, drilling equipment, and service costs are currently very low, thus creating additonal incentives to drill now.

10. Why limit the program to three years? First and foremost the state cannot afford to continue its economic dependence on oil and gas. Second, it will take at least that long for Louisiana to become competitive with its economically-active sister states. Third, three years is sufficient time to attract the attention of producers nationwide. Also, many forecasters predict the revitalization of the oil and gas industry in the next three to five years. In this case, Louisiana will be poised and ready to take full advantage of the industry's comeback.

11. What will LEAP cost the state? The cost of LEAP will be the long-term cost of encouraging present use of Louisiana's finite natural resources. This cost is incurred by the LEAP in consideration of the state's present economic crisis. Certainly Louisiana does not have to wait until it is dead last, rather than 49th in unemployment before utilizing its strongest assets.

12. What employment and revenue impacts may be generated by LEAP? Pending verification with econometric models, the state may expect that for every increase of 200 exploratory wells as a result of LEAP, over one program year, may provide 10,000 new jobs, $15.2 million in increased revenues to the state and $360 million in increased personal income in Louisiana during the program year.

13. How will the proposed program affect the state's business image? It will send a clear message that "Louisiana wants you and your dollars doing business in Louisiana". Equally important, it will send a message that Louisiana has the willpower and the ingenuity to effectively deal with its problems.

14. Have other governments taken similar steps? No other state has undertaken a program similar to LEAP. However, the Canadian government, along with its oil and gas producing provinces, has embarked on a related program. Changes in Canadian energy policies brought about a 21 percent increase in oil sales to the U.S. and a 27 percent increase in gas sales over a six month period. Additionally, active rig counts have increased markedly.

15. What can Louisiana do about national and international factors influencing the oil and gas market? There is nothing Louisiana can do to affect the world market. Other factors, like FERC regulatory controls and proposed congressional tax law changes, are subject to state pressure. Louisiana's story must be told at every opportunity.

16. Is this proposal a final one? This proposal is by no means a final one. This proposal is presented as such, in the belief that public discussion and recommendations can only strengthen it. Construtive criticism and suggestions are, by means of this proposal paper, actively solicited from the citizens of Louisiana, as well as those who presently, or may in the future, do business in our state.

total foregone revenue - oil - $6.3m - 1

Buck & Neff

REVIEW OF DIRECT REVENUE IMPACT OF LEAP AND STEP FOR FISCAL YEAR 1986-87

PREPARED FOR

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Baton Rouge
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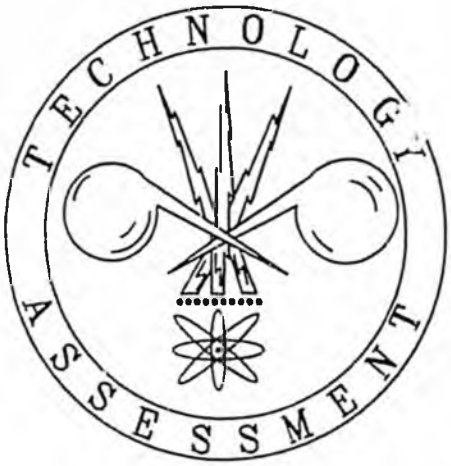
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EXECUTIVE SUMMARY

This report presents the results of an analysis of the impact on drilling activity and on the direct revenue foregone by the state of Louisiana from the implementation of the "Severance Tax Exemption Plan" (STEP), the 1987 amendment to STEP and the "Louisiana Economic Acceleration Plan" (LEAP) bills enacted by the Louisiana Legislature. The theory behind LEAP and STEP is that an economic incentive created by not collecting certain oil and gas revenue will stimulate new oil and gas industry exploration and drilling activity; and that will stimulate the state's economy and generate greater revenue than the direct mineral revenue foregone.

This report does not address the potential indirect revenue generated. However, an analysis of the drilling activity is provided in an attempt to indicate to what extent any indirect revenue may have been stimulated. Recent developments in drilling suggest that statistical treatment of Louisiana historical data may be inadequate for predicting the effect of STEP and LEAP beyond the period for which reported data exists. If the long term trend in drilling changes, as could be expected, the drilling results and projected revenue effects may be significantly higher than now shown for fiscal year 1987/88 and beyond.

The initial STEP act, discussed in Chapter 1, involved 646 wells producing 4,650,622 barrels of crude oil of which 3,693,610 barrels were exempted from severance taxes. It forgave 2.6 million dollars in severance taxes in fiscal year 1986/87 and over the life of this act is estimated to forgive state revenues of 16.2 to 21.6 million dollars, depending on the price of oil.

The STEP Amendment, discussed in Chapter 2, enacted during the 1987 Regular Session extends the period for STEP qualification by one year. It will forego additional state revenues at least equal to that mentioned above, but it is expected to be even more since drilling activity is higher this year than last.

The LEAP Act, examined in Chapter 3, to date encompasses 72 wells, 269,515 barrels of crude oil and 1,536,308 MCF of natural gas. In its lifetime, LEAP is projected to forgo 2.5 to 6.3 million dollars in crude oil severance, and 4.9 to 10.5 million dollars in natural gas severance and royalty. The total potential revenue forgiven by the state by this Act is estimated between 7.4 and 16.8 million dollars over its lifetime, depending on the prices of oil and gas, drilling activities, and production restrictions.

The effects of LEAP, STEP and the STEP Amendment are difficult to demonstrate conclusively because of time lags in data reporting and an overall shortage of data. However comparisons of Louisiana's performance with that of Texas, a major oil producing state without comparable STEP and LEAP programs in place, so far shows little measurable direct STEP and LEAP induced drilling of extra wells. Additional historical and projected data is shown in Chapter 4.

Oil and gas prices, which are key determinant factors in today's energy market, are discussed in Chapter 5.

CHAPTER 1

REVENUE IMPACT OF SEVERANCE TAX EXEMPTION PLAN (STEP) FOR FISCAL YEAR 1986/87

The Severance Tax Exemption Plan, Act 673 of the 1986 Regular Session (House Bill 1083) is also known as STEP. This Act exempts from the collection of severance tax, oil produced from a well drilled between July 15, 1986 and July 15, 1987. The 1987 Legislature extended this period to July 15, 1988. The following discussion addresses the initial STEP period. The extension period is addressed in Chapter 2 of this report.

Oil Severance Tax Exemption

STEP exempts severance tax for the first 50 barrels per day during the production of the first 10,000 barrels of oil removed from the ground annually for a well drilled between July 15, 1986 and July 15, 1987.

The exemption may be claimed from the date of first production from each well until July 15, 1990, except for months when the value of oil, as reported to the Department of Revenue and Taxation under R.S. 47:633(7), exceeds $21 per barrel.

Definitions Limiting Qualifying Wells

Since initial passage of the STEP legislation, the Department of Natural Resources has promulgated regulations clarifying when a well qualifies for the STEP incentives as follows:

The tax exemption does not apply to:

(1) Condensate, distillate, or similar natural resources produced from a well classified as a gas well by the Assistant Secretary of the Office of Conservation.
(2) Casinghead gas produced with oil, from a well drilled between July 15, 1986 and July 15, 1987.
(3) Oil from a well on which drilling began prior to July 15, 1986.
(4) Oil from a well on which drilling is done after July 15, 1987.
(5) Oil from a well with a price per barrel greater than $21 as reported under R.S. 47:633(7).

(6) Oil from a well following, or in excess of, the first fifty barrels produced on any day.
(7) Oil from a well following, or in excess of, the first ten thousand barrels produced in any year.

Severance Tax Rates

The various Louisiana severance tax rates are provided in the Appendix.

Total crude oil production from all STEP classified wells for fiscal year 1986/87 was approximately 3.7 million barrels. The average monthly number of drilling permits issued in fiscal year 1986/87 was 161. From the 3.7 million barrels of crude oil produced, only 1.8 million barrels are expected to be exempted from severance tax, based on data reported by Department of Natural Resources (DNR), Office of Conservation. As a back-up check of the validity of this exempted production figure, we used our new well production model to project the volume of exempted production that would be expected to be obtained from extension wells evolving from an average of 161 drilling permits per month (assuming successful wildcats would preferentially produce under LEAP and only extension wells would produce under STEP). The resulting projection indeed showed that exempted STEP production should be 1.8 million barrels. Projected production volumes exempted from severance tax for the other years covered by the Act are shown in Table I, a comparison of actual versus projected is shown in Figure 1, and Table II shows projected revenue losses at different crude oil prices.

The Department of Revenue and Taxation (DRT) reported 1.4 million barrels of crude oil claimed exemption, totaling 2.6 million dollars in taxes exempted. The difference between DNR and DRT reported volumes is due to the lead time between dates of production reports submitted to DNR and dates of sales and tax reports submitted to DRT. If time had allowed for us to delay this analysis until the time lag for the DRT data had past, it is expected that the DNR and DRT data would be in close agreement. This is a point that will need examination in the future.

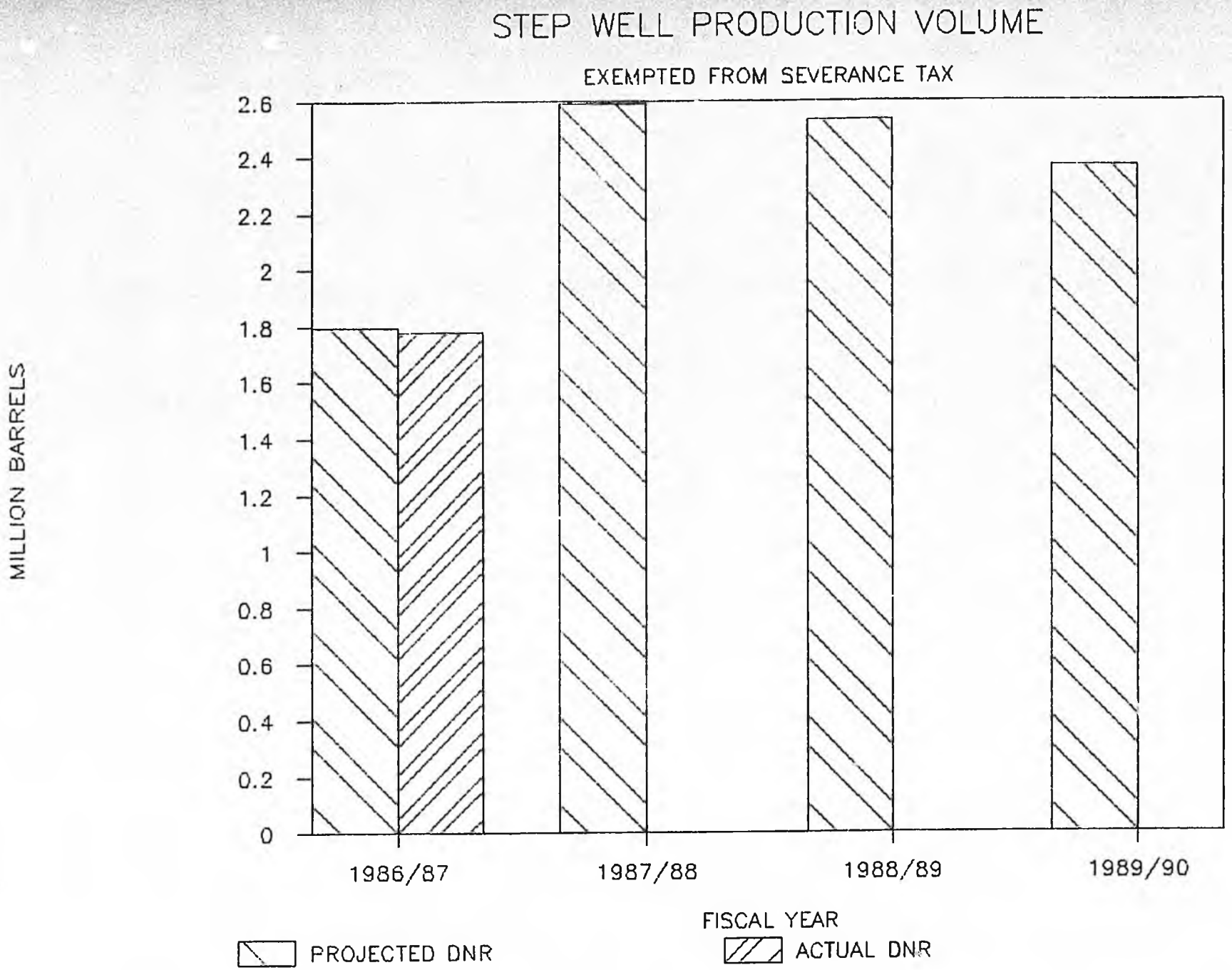

STEP WELL PRODUCTION VOLUME
EXEMPTED FROM SEVERANCE TAX
MILLION BARRELS
2.6
2.4
2.2
2
1.8
1.6
1.4
1.2
1
0.8
0.6
0.4
0.2
0
1986/87
1987/88
1988/89
1989/90
FISCAL YEAR
PROJECTED DNR
ACTUAL DNR

FIGURE 1

TABLE I

PROJECTIONS OF EXEMPTED CRUDE OIL PRODUCTION FROM NEW EXTENSION WELLS, DRILLED BETWEEN JULY 15, 1986 AND JULY 15, 1987 AS DEFINED UNDER STEP (Act 573)

EXEMPTED CRUDE OIL PRODUCTION[2]
(Barrels)

Fiscal Year	NORTH	SOUTH	OFFSHORE	TOTAL
1986/87	1,008,102	707,022	79,698	1,794,823
1987/88	1,373,383	1,088,938	130,956	2,593,277
1988/89	1,324,390	1,077,317	129,803	2,531,510
1989/90	1,240,852	1,005,789	121,747	2,368,388
1990/91[1]	101,457	82,179	9,962	193,598

[1] The 1990/91 revenues account for the 15 day period, July 1 through July 15, 1990 that the STEP program extends beyond the 1989/90 fiscal year. A fiscal year runs from July 1 through June 30.

[2] Volumes shown are only the portions that fall under the 50 barrels per day / 10,000 barrels per year exemption limit.

The formula used to calculate the loss of revenues from crude oil severance taxes is as follow:

Oil Severance = (Full Oil Tax Rate x Its Average % Oil Production Volume + Incapable Tax Rate x Its Average % Oil Production Volume + Stripper Tax Rate x Its Average % Oil Production Volume) x Average Oil Price x Total State Oil Production Volume.

TABLE II

PROJECTED REVENUE LOSS DEPENDING ON THE PRICE OF CRUDE OIL FROM PRODUCTION OF NEW EXTENSION WELLS, DRILLED BETWEEN JULY 15, 1986 AND JULY 15, 1987 UNDER STEP (Act 673)

REVENUE LOST
(Million Dollars)

PRICE	FISCAL YEAR					TOTAL[2] REVENUE
$/BBL	1986/87*	1987/88	1988/89	1989/90	1990/91[1]	LOSSES
8.00	2.63	2.47	2.41	2.25	0.09	9.85
9.00	2.63	2.78	2.71	2.53	0.10	10.75
10.00	2.63	3.08	3.01	2.82	0.12	11.65
11.00	2.63	3.39	3.31	3.10	0.13	12.56
12.00	2.63	3.70	3.61	3.38	0.14	13.46
13.00	2.63	4.01	3.91	3.66	0.15	14.36
14.00	2.63	4.32	4.21	3.94	0.16	15.26
15.00	2.63	4.63	4.51	4.22	0.17	16.17
16.00	2.63	4.93	4.82	4.51	0.18	17.07
17.00	2.63	5.24	5.12	4.79	0.20	17.97
18.00	2.63	5.55	5.42	5.07	0.21	18.87
19.00	2.63	5.86	5.72	5.35	0.22	19.78
20.00	2.63	6.17	6.02	5.63	0.23	20.68
21.00	2.63	6.48	6.32	5.91	0.24	21.58
22.00	2.63	0.00	0.00	0.00	0.00	2.63

NOTE: * Actual Data

[1] The 1990/91 revenues account for the 15 day period, July 1 through July 15, 1990 that the STEP program extends beyond the 1989/90 fiscal year. A fiscal year runs from July 1 through June 30.

[2] For the entire life of the STEP program July 15, 1986 to July 15, 1990.

CHAPTER 2

SEVERANCE TAX EXEMPTION PLAN AMENDMENT (STEP AMENDMENT)

The Severance Tax Exemption Plan Amendment, Act 430 of the 1987 Regular Session (Senate Bill 274) is also known as "STEP Amendment" extends the STEP drilling period by one year, thereby exempting from the collection of severance tax oil produced from a qualified well drilled between July 15, 1986 and July 15, 1988.

This Act carries all the restrictions mentioned in the preceding STEP chapter but additionally requires a certification that at least ten percent of the service contracts related to the well drilling have been made available to minority-owned businesses and at least five percent of the service contracts have been made available to women-owned businesses.

Whereas the analysis of STEP production in the preceding chapter was based on a known number of qualified STEP wells that were drilled during the first year of STEP, this chapter estimates the impact of an unknown number of wells that are currently or are yet to be drilled under the second year of STEP. The STEP Amendment (Act 430) production volume is projected, therefore, using the following assumptions:

1 Eighty five percent (85%) of the new wells drilled will meet the requirement of minority- and women-owned business participation.

2 The producing life of an oil and gas well in Louisiana ranges from 3 to 50 years. In this study all new permitted wells are assigned a producing life of 20 years, and have a straight line decay.

3 The mean average day for issuing permits from July 15, 1986 through July 15, 1988 is the 30th of each month.

4 The historical drilling success rate, production average, and lead time between permit issue to first production is representative of the future.

5 The monthly average number of drilling permits issued in fiscal year 1987/88 is going to be 250 permits for the calculation of revenue loss.

Projections of STEP Amendment production volumes of crude oil that will be exempted from severance taxes are shown in Table III for the

average of 250 drilling permits per month assumed in this report as well as at several other drilling permit issue rates. Table IV shows possible revenue losses at different crude oil prices. The revenues loss was calculated using the formula listed in previous chapter.

TABLE III

CRUDE OIL PRODUCTION FROM NEW EXTENSION WELLS, DRILLED AFTER JULY 1, 1987 AS DEFINED UNDER THE STEP AMENDMENT

	FISCAL YEAR	ASSUMED MONTHLY AVERAGE DRILLING PERMITS ISSUED 150	200	250	300	350
		CRUDE OIL PRODUCTION (Barrels)				
N	1987/88	737,752	983,670	1,229,587	1,475,505	1,721,422
O	1988/89	977,987	1,303,983	1,629,979	1,955,974	2,281,970
R	1989/90	905,562	1,207,416	1,509,269	1,811,183	2,112,977
T	JULY 90	90,965	121,287	151,608	181,930	212,252
H		---	---	---	---	---
	SUM	2,712,266	3,616,355	4,520,444	5,424,532	6,328,621
S	1987/88	559,934	746,579	933,224	1,119,868	1,306,513
O	1988/89	866,153	1,154,871	1,443,589	1,732,307	2,021,025
U	1989/90	826,479	1,102,238	1,377,798	1,653,358	1,920,917
T	JULY 90	83,088	110,783	138,479	166,175	193,871
H		---	---	---	---	---
	SUM	2,335,854	3,114,472	3,893,090	4,671,708	5,450,326
S	1987/88	63,115	84,153	105,191	126,230	147,268
OH	1988/89	104,154	138,872	173,590	208,308	243,026
FO	1989/90	99,593	132,791	165,989	179,187	232,385
FR	JULY 90	10,011	13,348	16,685	20,022	23,359
E		---	---	---	---	---
	SUM	276,873	365,827	461,455	553,746	646,037
		=========	=========	=========	=========	=========
T	1987/88	1,360,801	1,814,402	2,268,002	2,721,603	3,175,203
O	1988/89	1,948,295	2,597,726	3,247,158	3,896,589	4,546,021
T	1989/90	1,831,834	2,442,445	3,053,056	3,663,668	4,274,269
A	JULY 90	184,063	245,417	306,772	368,127	429,481
L		---	---	---	---	---
	SUM	5,324,993	7,096,654	8,874,989	10,649,986	12,424,984

TABLE IV

PROJECTED REVENUE LOSSES DEPENDING ON THE PRICE OF CRUDE OIL FROM PRODUCTION OF NEW EXTENSION WELLS, DRILLED BETWEEN JULY 1, 1987 AND JULY 15, 1988 UNDER STEP AMENDMENT (Act 430) (ASSUMING THAT THE AVERAGE MONTHLY PERMIT RATE IS 250)

REVENUE LOST
(Million Dollars)

PRICE	FISCAL YEAR				TOTAL[2] REVENUE
$/BBL	1987/88	1988/89	1989/90	1990/91[1]	LOSSES
8.00	2.16	3.09	2.93	0.15	8.32
9.00	2.43	3.47	3.32	0.16	9.39
10.00	2.70	3.86	3.71	0.18	10.45
11.00	2.97	4.25	4.04	0.20	11.45
12.00	3.24	4.63	4.43	0.22	12.32
13.00	3.51	5.02	4.76	0.24	13.52
14.00	3.78	5.41	5.15	0.26	14.58
15.00	4.04	5.79	5.53	0.27	15.54
16.00	4.31	6.18	5.86	0.29	16.65
17.00	4.58	6.56	6.25	0.31	17.71
18.00	4.85	6.95	6.58	0.33	18.71
19.00	5.12	7.34	6.97	0.35	19.78
20.00	5.39	7.72	7.36	0.36	20.84
21.00	5.66	8.11	7.69	0.38	21.84
22.00	0.00	0.00	0.00	0.00	0.00

[1] The 1990/91 revenues account for the 15 day period, July 1 through July 15, 1990 that the STEP program extends beyond the 1989/90 fiscal year. A fiscal year runs from July 1 through June 30.

[2] For the entire life of the STEP program July 15, 1986 to July 15, 1990.

CHAPTER 3

LOUISIANA ECONOMIC ACCELERATION PLAN (LEAP)

The Louisiana Economic Acceleration Plan, Act 763 from 1986 Regular Session (Senate Bill 590) is also known as LEAP. This Act exempts the collection of oil and natural gas severance tax and natural gas royalties under the following constraints and definitions:

Oil and Gas Severance Tax Exemption and Forgiveness of Gas Royalty

LEAP exempts total production from severance tax for oil and gas produced from qualified wildcat and developmental wells completed between July 1, 1986 and January 1, 1990 from the date of first production through January 1, 1990, or until the date on which the posted price of West Texas Intermediate equals or exceeds $29.50 per barrel, whichever occur first.

Additionally for natural gas wells drilled on state leases, royalty payments are forgiven under the same qualifying requirements as the severance tax exemption.

Definitions of Wildcat and Developmental Wells

Since initial passage of the LEAP legislation, the Department of Natural Resources has promulgated regulations clarifying the definitions of wildcat well and developmental well as follow:

> A "wildcat well" is a well that is drilled, completed, and produced during the time period provided for herein from a pool which has not produced or known to have been capable of producing hydrocarbons in commercial quantities. A well drilled in a contiguous fault segment of a sand that was either producing or capable of production prior to July 1, 1986, or which is subsequently recompleted in a sand previously penetrated from a well that was drilled, completed, and/or produced prior to July 1, 1986, is not considered a wildcat well. Upon successful completion, the "wildcat well" is then recognized as a "discovery well."
>
> A "developmental well" must be drilled and completed to a pool previously discovered by a "wildcat well."

Table V shows projected gas production for the first four years from wells drilled each year in areas that do not have a previous history

of production. Table VI shows projected oil production for the first four years from wells drilled each year in areas that do not have a previous history of production. Since there is very little available data for production of wildcat wells from a new sand level under existing producing fields, extrapolations were used to calculate the oil and gas production for LEAP wells in this category. The results of these extrapolations are shown on Table VII for wells drilled in a year's time, and on Table VIII the total production of all classified LEAP wells drilled in a year's time.

To calculate approximate revenues foregone, in dollars, to the state treasury caused by LEAP, the following empirical equations can be used:

a) Oil Severance = 0.1189 x Total State Oil Production (barrels) x Average State Oil Wellhead Price.

b) Gas Severance = 0.0680 x Gas Production (MCF)

c) Gas Royalty = 0.1402 x Gas Production (MCF) x Average State Gas Wellhead Price.

The above empirical equations are generated using historical data, statistic approximations and assuming that future production patterns will be similar to the past.

FISCAL YEAR 1986/87 LEAP STATISTICS

- Fifty five (55) producing wells were classified as LEAP wells.
- LEAP wells produced around 1.0 billion cubic feet of natural gas and 170 thousand barrels of crude oil.
- LEAP, Act 763, exempted around $300,000 in oil severance tax and another $300,000 in royalty and severance tax from natural gas production.

TABLE V

PROJECTED ANNUAL CRUDE OIL PRODUCTION FROM NEW WELLS, DRILLED IN YEAR 1 IN AREAS THAT DO NOT HAVE A PREVIOUS HISTORY OF OIL PRODUCTION

		ASSUMED MONTHLY AVERAGE DRILLING PERMITS ISSUED				
		150	200	250	300	350
	YEAR	CRUDE OIL PRODUCTION (Barrels)				
N	YR #1	9,324	12,432	15,540	18,648	21,756
O	YR #2	10,519	14,025	17,531	21,038	24,544
R	YR #3	9,781	13,042	16,302	19,563	22,823
T	YR #4	8,658	11,544	14,430	17,316	20,202
H						
	SUM	32,737	43,649	54,561	65,474	76,386
S	YR #1	6,311	8,415	10,519	12,623	14,727
O	YR #2	9,557	12,742	15,928	19,114	22,299
U	YR #3	9,791	13,055	16,319	19,583	22,847
T	YR #4	8,683	11,577	14,471	17,365	20,260
H						
	SUM	30,808	41,078	51,347	61,617	71,886
S	YR #1	69,518	92,690	115,863	139,035	162,208
OH	YR #2	79,710	106,280	132,850	159,420	185,990
FO	YR #3	80,098	106,797	133,497	160,196	186,896
FR	YR #4	71,073	94,764	118,455	142,146	165,837
E						
	SUM	250,300	333,733	417,166	500,600	584,033
T	YR #1	85,153	113,538	141,922	170,307	198,691
O	YR #2	99,786	133,047	166,309	199,571	232,833
T	YR #3	99,671	132,894	166,118	199,342	232,565
A	YR #4	95,273	127,031	158,788	190,546	222,304
L						
	SUM	313,845	418,460	523,075	627,690	732,305

TABLE VI

PROJECTED ANNUAL NATURAL GAS PRODUCTION FROM NEW WELLS, DRILLED IN YEAR 1 IN AREAS THAT DO NOT HAVE A PREVIOUS HISTORY OF GAS PRODUCTION

		ASSUMED MONTHLY AVERAGE DRILLING PERMITS ISSUED				
		150	200	250	300	350
	YEAR	NATURAL GAS PRODUCTION (MCF)				
NORTH	YR #1	137,749	183,665	229,581	275,498	321,414
	YR #2	186,404	248,539	310,674	372,809	434,944
	YR #3	175,801	234,401	293,001	351,601	410,202
	YR #4	154,762	206,349	257,937	309,524	361,111
	SUM	654,716	872,955	1,091,193	1,309,432	1,527,671
SOUTH	YR #1	67,448	89,931	112,414	134,897	157,379
	YR #2	151,570	202,093	252,616	303,139	353,663
	YR #3	163,814	218,419	273,024	327,629	382,234
	YR #4	144,868	193,157	241,447	289,736	338,035
	SUM	527,700	703,600	879,501	1,055,401	1,231,301
SOHFOFRE	YR #1	823,081	1,097,441	1,371,801	1,646,162	1,920,522
	YR #2	1,798,796	2,398,395	2,997,994	3,597,593	4,197,191
	YR #3	1,833,883	2,445,178	3,056,472	3,667,767	4,279,061
	YR #4	1,627,249	2,169,665	2,712,081	3,254,497	3,796,914
	SUM	6,083,009	8,110,679	10,138,349	12,166,019	14,193,689
TOTAL	YR #1	1,028,278	1,371,037	1,713,797	2,056,556	2,399,315
	YR #2	2,136,770	2,849,027	3,561,284	4,273,541	4,985,798
	YR #3	2,173,499	2,897,998	3,622,498	4,346,997	5,071,497
	YR #4	1,926,879	2,569,172	3,211,465	3,853,758	4,496,050
	SUM	7,265,426	9,687,234	12,109,043	14,530,851	16,952,660

TABLE VII

PROJECTED ANNUAL LEAP WELLS PRODUCTION FROM NEW SAND LEVEL, DRILLED IN YEAR 1 IN EXISTING PRODUCTION FIELDS

	ASSUMED MONTHLY AVERAGE DRILLING PERMITS ISSUED				
	150	200	250	300	350
YEAR	CRUDE OIL PRODUCTION (Barrels)				
YR #1	127,730	170,307	212,883	255,460	298,037
YR #2	139,700	186,266	232,833	279,400	325,966
YR #3	129,572	172,763	215,953	259,144	302,335
YR #4	114,328	152,437	190,546	228,655	266,765
SUM	511,330	681,773	852,216	1,022,659	1,193,102
	NATURAL GAS PRODUCTION (MCF)				
YR #1	308,483	411,311	514,139	616,967	719,795
YR #2	641,031	854.708	1,068,385	1,282,062	1,495,739
YR #3	652,050	869,399	1,086,749	1,304,099	1,521,449
YR #4	578,064	770,752	963,439	1,156,127	1,348,815
SUM	2,179,628	2,906,170	3,632,713	4,359,255	5,085,798

TABLE VIII

PROJECTED TOTAL ANNUAL LEAP WELLS PRODUCTION FROM WELLS DRILLED IN YEAR 1 IN ALL FIELDS

YEAR	ASSUMED MONTHLY AVERAGE DRILLING PERMITS ISSUED				
	150	200	250	300	350
	CRUDE OIL PRODUCTION (Barrels)				
YR #1	212,883	283,845	354,806	425,767	496,728
YR #2	239,485	319,314	399,142	478,971	558,798
YR #3	229,243	305,657	382,071	458,486	534,900
YR #4	209,601	279,468	349,335	419,201	489,068
SUM	825,175	1,100,233	1,375,291	1,650,349	1,925,407
	NATURAL GAS PRODUCTION (MCF)				
YR #1	1,336,761	1,782,348	2,227,935	2,673,523	3,119,110
YR #2	2,777,802	3,703,735	4,629,669	5,555,603	6,481,537
YR #3	2,825,548	3,767,398	4,709,247	5,651,096	6,592,946
YR #4	2,504,942	3,339,923	4,174,904	5,009,885	5,844,866
SUM	9,445,053	12,593,405	15,741,756	18,890,107	22,038,458

CHAPTER 4

DRILLING IMPACT ANALYSIS

We analyzed the effects of STEP and LEAP on drilling, but no demonstratively conclusive results were possible. There are several possible reasons for this. Most of these causes were beyond the control of the state incentive programs as well as beyond the scope of this study. One major reason was a lack of statistically significant data for that time period. Another possible reason was that one fundamental basis for drilling investment decisions was a stable or increasing price for oil. Price stability currently appears to be a more significant factor in making drilling decisions and in raising capital than the current price of price of oil, with or without incentives.

The incentives provided in STEP and LEAP were designed to provide roughly a 12 1/2% price increase to the price of oil to encourage drilling. With a stable price for oil at $14 for example this means an investor could make a profit if, before STEP or LEAP, a project took $15.25 per barrel oil to pay out. With oil prices falling, however the investors just stayed out of the market until the price, supply and demand stabilized enough so they could make reasonable investment decisions and make a profit. If the financial community was relatively confident that the price of oil would remain at or above the example $14 per barrel they would be willing to invest in projects which would not have been economic without the incentives of STEP and LEAP. If on the other hand the prevailing reasoning was that oil is $14 per barrel and the price will possibly drop to $12 or $10 per barrel next week, or next month, the investor would decide to not participate in the project.

Drilling activity by its nature is cyclic; therefore, the most promising approach to detect a change in drilling trend (resulting from the incentive programs) in noisy short term data is to compare Louisiana data to that of other areas that do not have the incentive (i.e. Texas and rest of U.S.). Using preliminary data and projected values from World Oil magazine and Oil and Gas Journal, such as projected wells to be drilled, active rigs, and prices for oil and gas, and if we assume Texas is a control group that did not have equivalent STEP and LEAP acts in effect, and that their drilling activity is similar to Louisiana, one might conclude:

a) There was little measurable direct STEP and LEAP induced drilling of extra wells, based on data available for the past fiscal year.

b) Future effects for the second and subsequent years of drilling under STEP Amendment or LEAP cannot be accurately predicted from the available data.

There were 590 producing wells classified as STEP wells and 55 producing wells classified as LEAP wells in fiscal year 1986/87. This level of drilling is consistent with what would have been expected in Louisiana without incentives based on (a) recent Louisiana trends, (b) drilling projections as a function of oil price prior to incentives passage and (c) direct comparison to actual drilling without incentives in Texas and the rest of the U.S.

For fiscal year 1986/87 the oil wells from STEP and LEAP were forgiven $2.0 million dollars from severance, and the LEAP gas wells were forgiven around $0.3 million dollars in severance tax and royalties

Historical wells drilled and drilled-percentage changes for Louisiana, Texas and the other states are shown in Figures 2 to 7. Figure 8 shows a comparison of wildcat wells drilled in the United States to the average wellhead price of crude oil in the United States. Figure 9 shows a comparison of extension wells drilled in the United States to the United States average wellhead price for crude oil. Figure 10 shows a comparison of total wells drilled in Louisiana compared to the average wellhead price in Louisiana. Figure 11 shows a comparison of total wells drilled in Texas compared to the average wellhead price in Texas.

FIGURE 2

TOTAL WILDCAT WELLS DRILLED

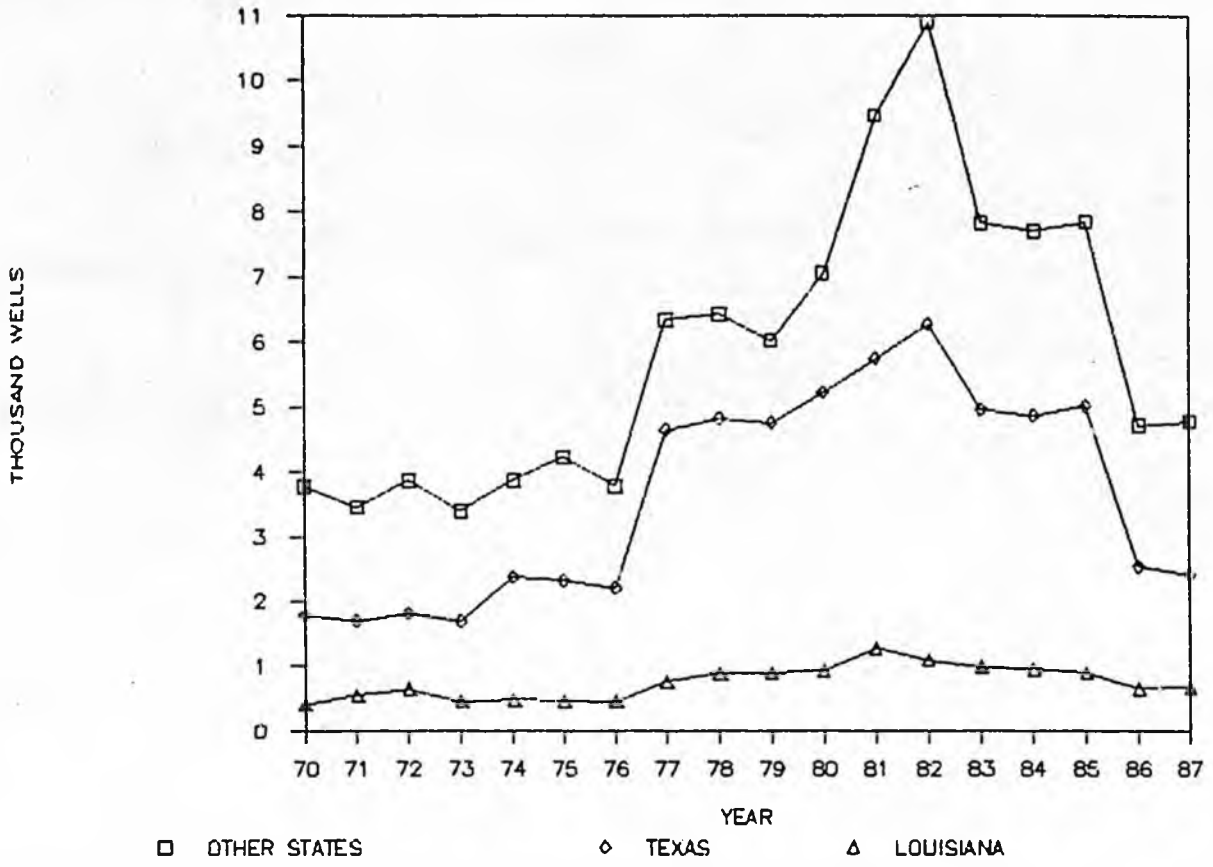


FIGURE 3

WILDCAT WELLS DRILLED—PERCENTAGE CHANGES

FROM YEAR TO YEAR

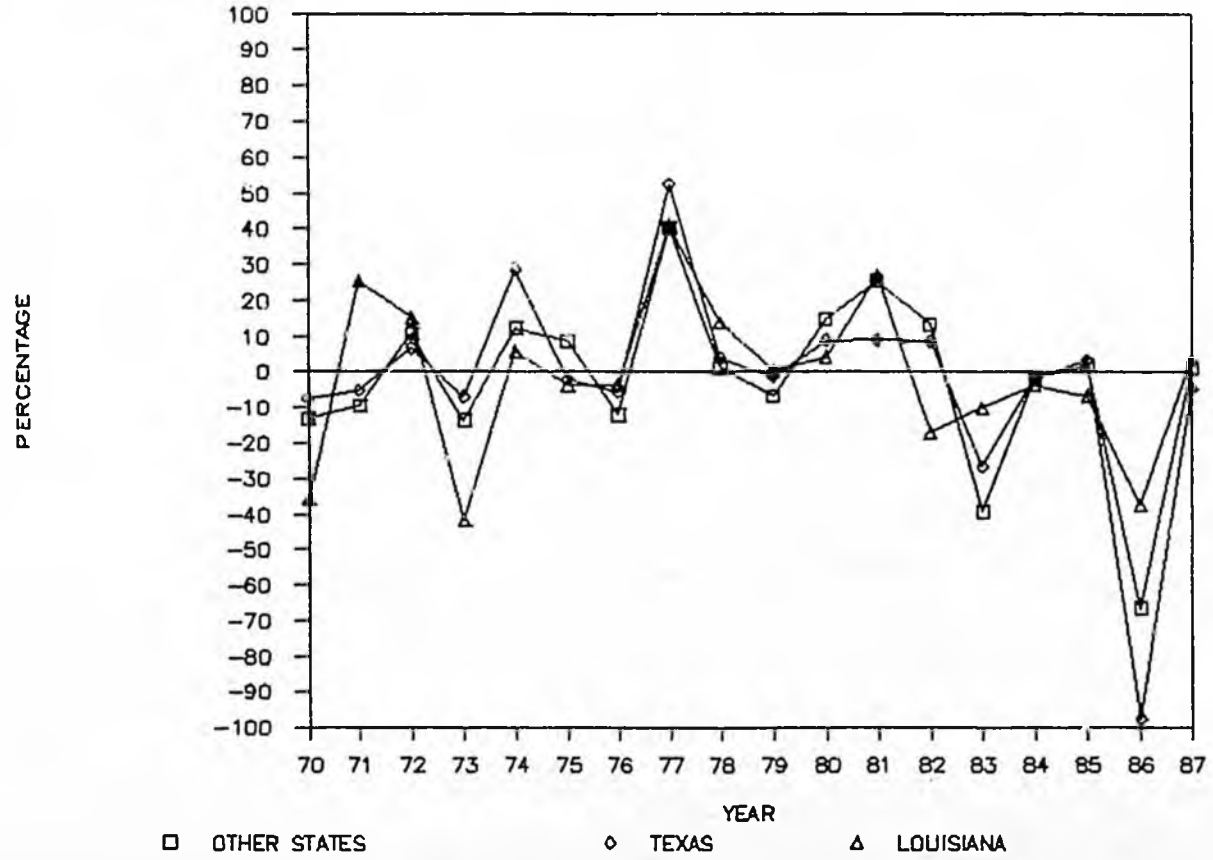


FIGURE 4

TOTAL WELLS DRILLED

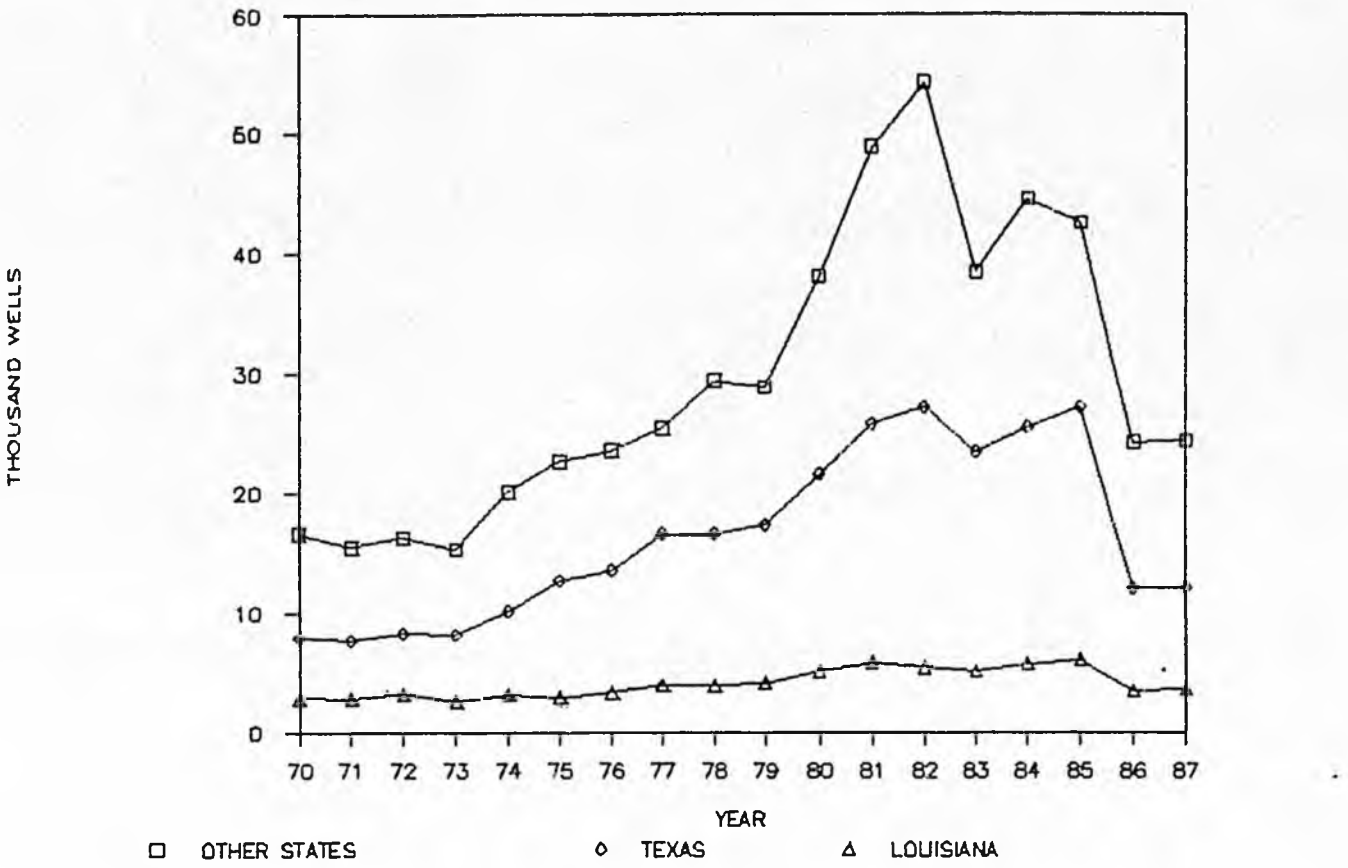


FIGURE 5

WELL COMPLETIONS—PERCENTAGE CHANGES

FROM YEAR TO YEAR

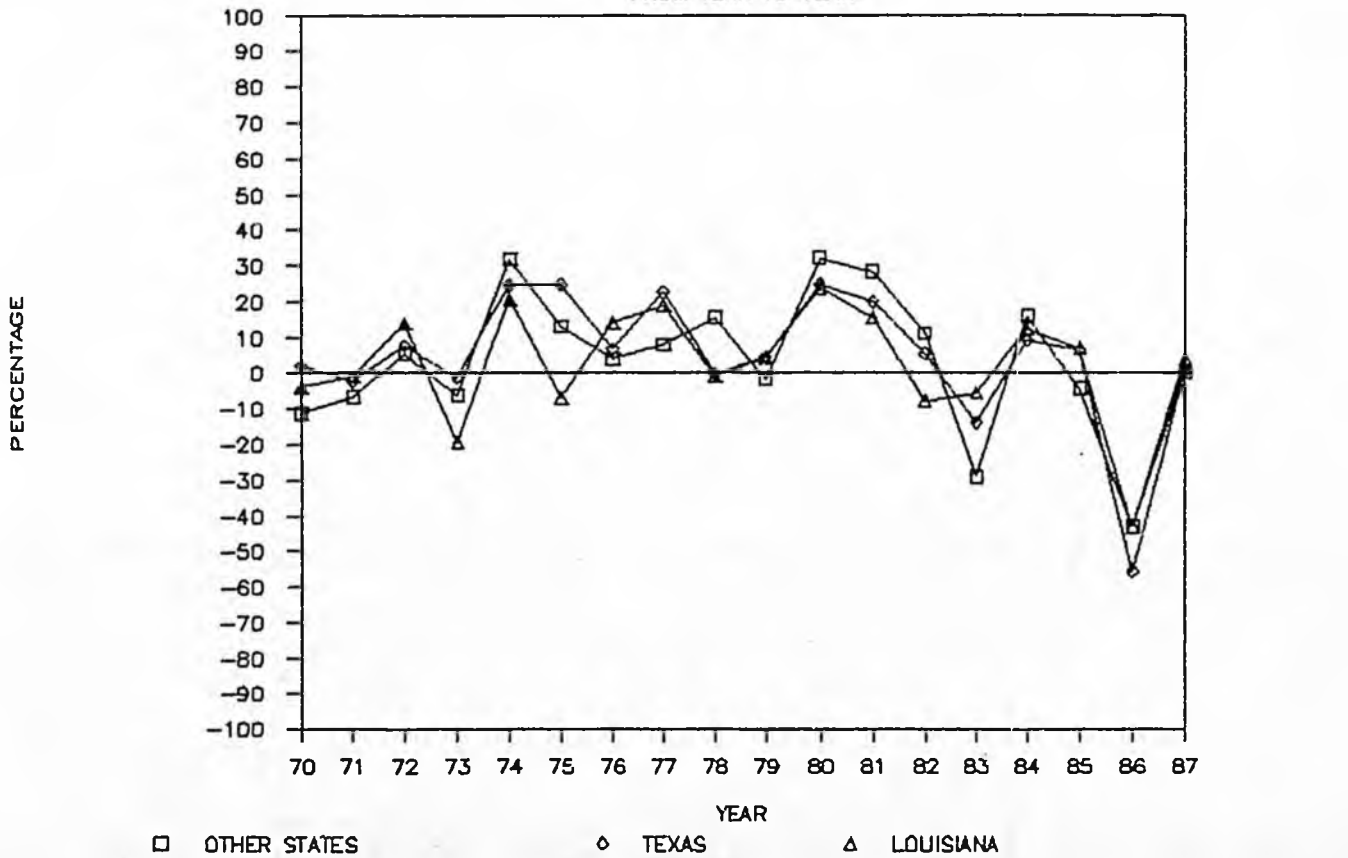


FIGURE 6

TOTAL FOOTAGE DRILLED

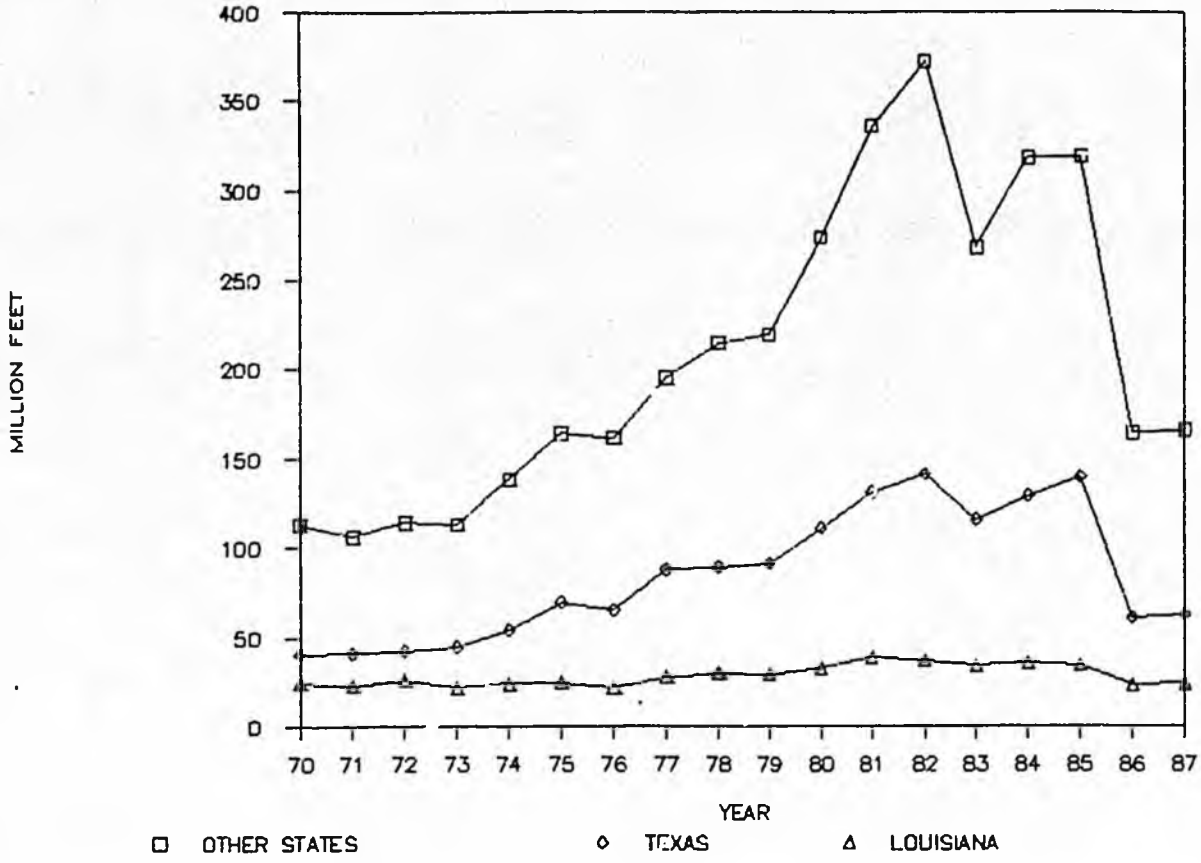


FIGURE 7

TOTAL FOOTAGE DRILLED—PERCENTAGE CHANGES

FROM YEAR TO YEAR

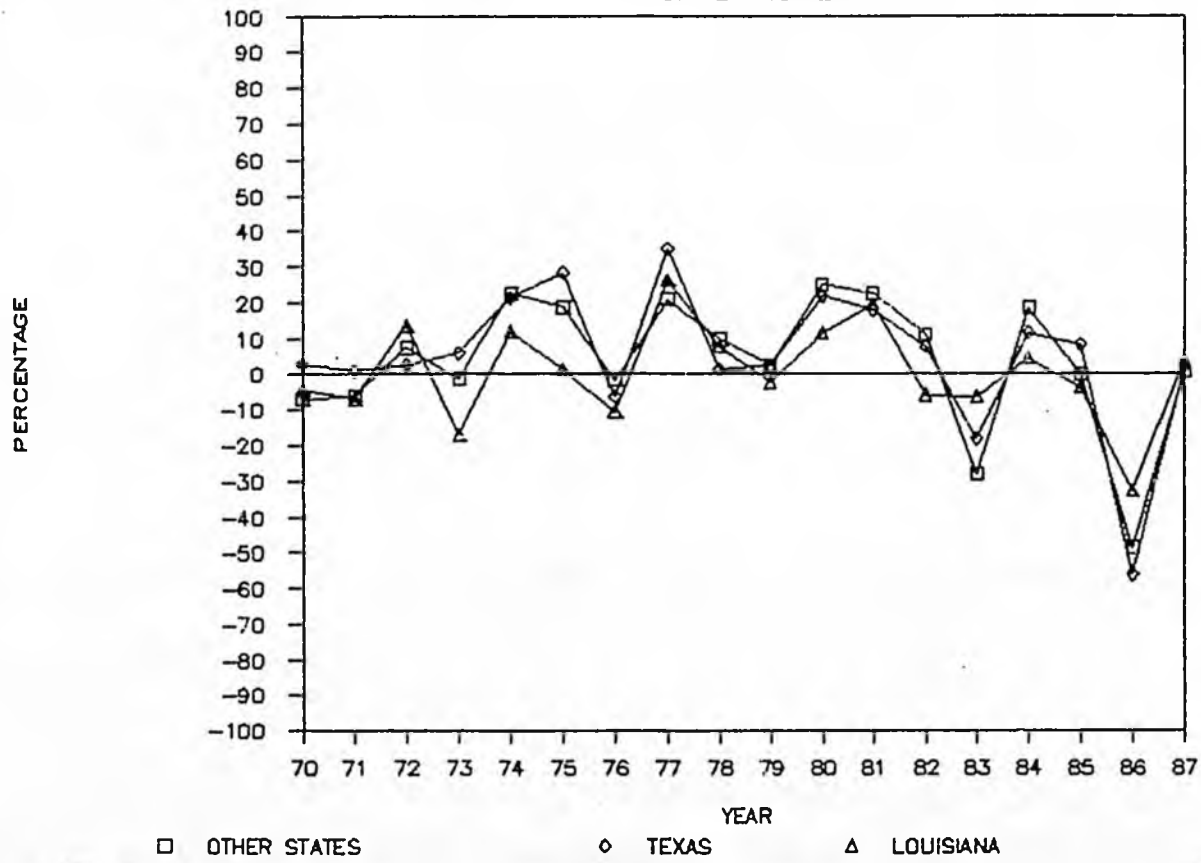


FIGURE 8

UNITED STATES WILDCAT WELLS

WELLS DRILLED & OIL WELLHEAD PRICES

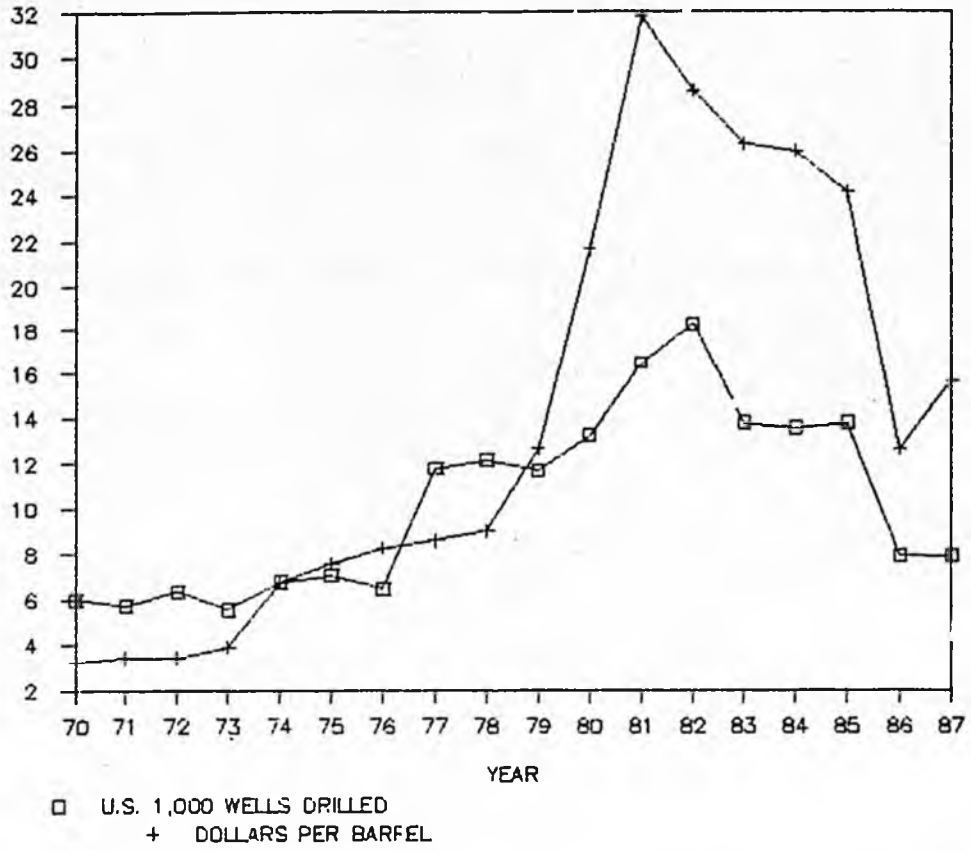


FIGURE 9

UNITED STATES EXTENSION WELLS

WELLS DRILLED & OIL WELLHEAD PRICES

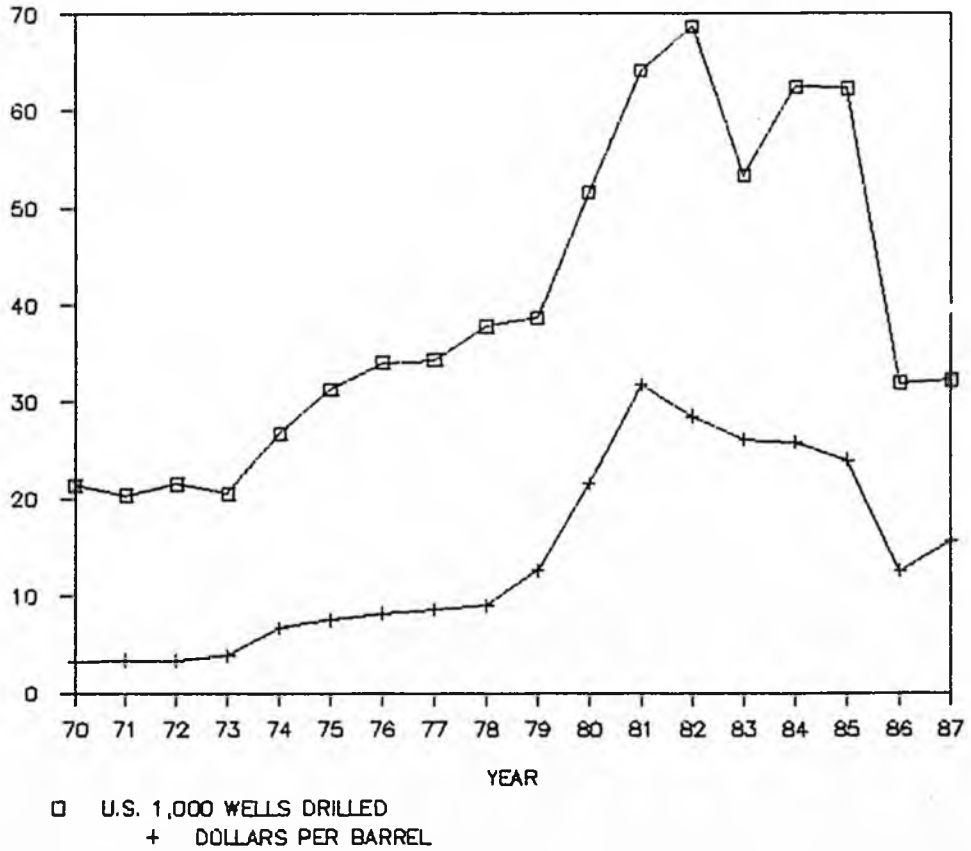


FIGURE 10

LOUISIANA

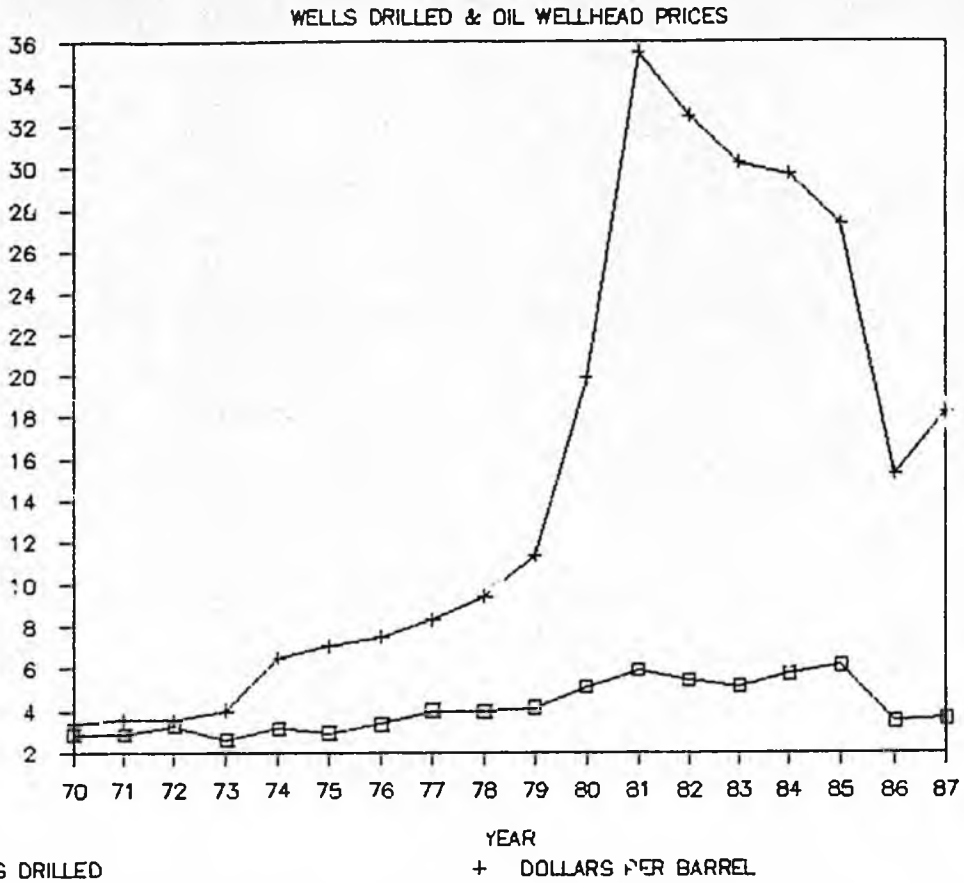
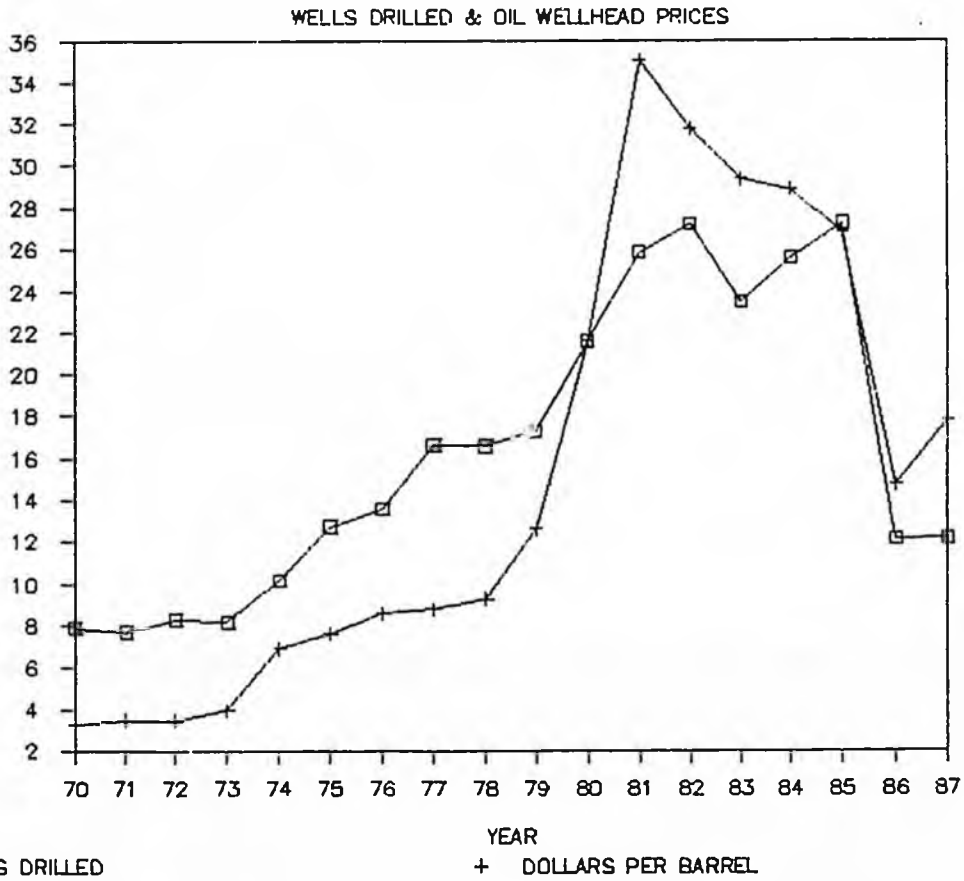


FIGURE 11

TEXAS



CHAPTER 5

PRICES

CRUDE OIL PRICES

Crude oil prices stabilized in recent months between $17 to $20 per barrel, due to OPEC production restraint balancing moderate consumption demand after a high in the Summer months, and high inventories of crude oil. The weak accord signed in Vienna this December, however, should push the price of oil lower to between $15 and $18 per barrel for the next year.

The spot price of West Texas Intermediate (WTI) began to drop slowly from the late Summer high even though most OPEC member countries appeared to be abiding by their new interim output quotas, the war between Iraq and Iran has intensified from time to time, and some non-OPEC producing countries have cut down their production. WTI was over $20 per barrel in August, it decreased to around $18 per barrel on November 1987 on the spot market and, during the past week, the majority of U.S. refiners' posted price for WTI crude oil was $18.15 per barrel. Even though $18 per barrel is almost half of its early 80's prices, it is better than the $11 to $ 13 per barrel in the Summer of 1986.

TABLE IX

AVERAGE CRUDE OIL PRICES
(Dollars per Barrel)

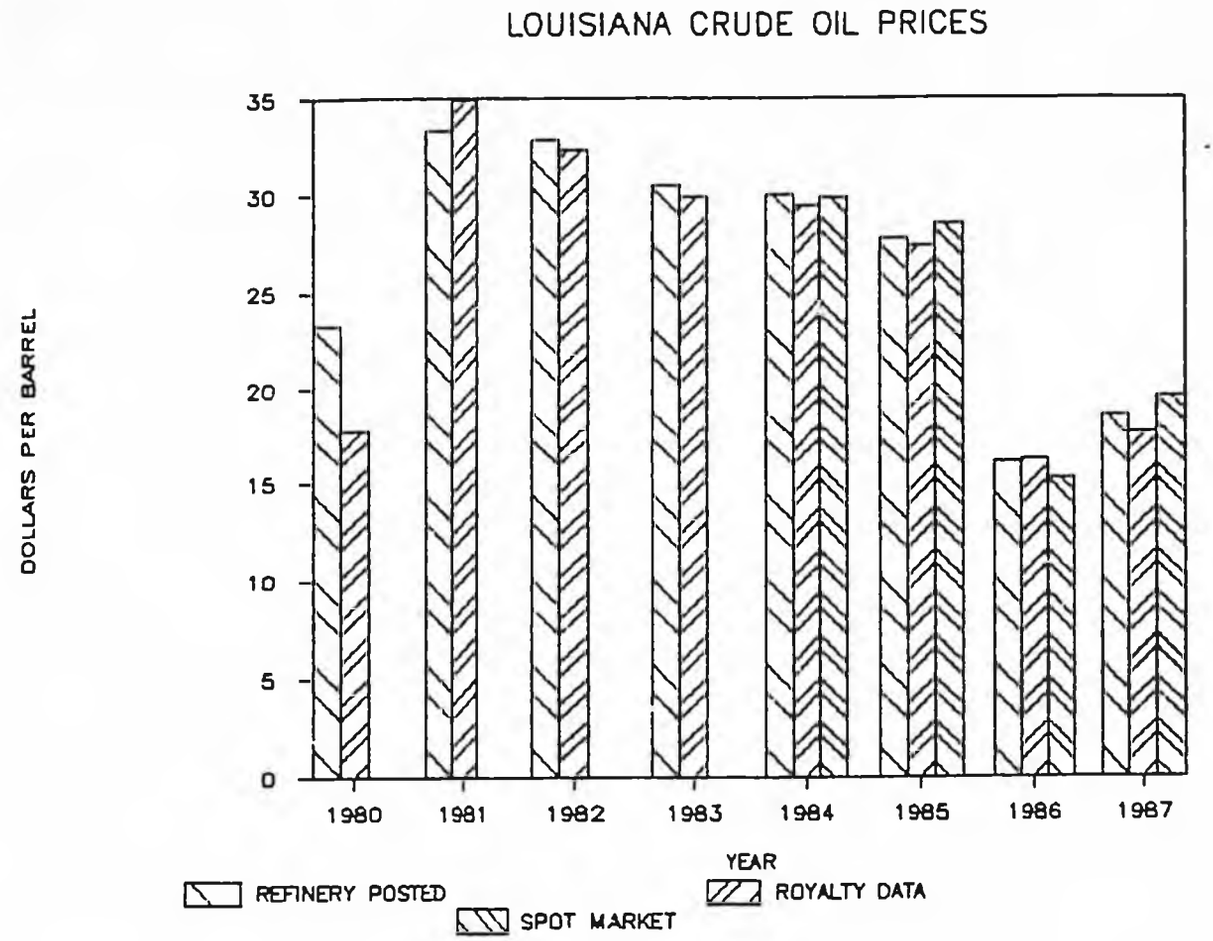
	LOUISIANA		UNITED STATES		
	ROYALTY			REFINERY	
YEAR	PAYMENT	WELLHEAD	WELLHEAD	IMPORTS	DOMESTIC ACQUISITION
1977	7.46	8.33	8.57	13.24	9.55
1978	9.85	9.42	9.00	13.30	10.61
1979	10.03	11.40	12.64	20.19	14.27
1980	17.80	19.87	21.59	32.27	24.23
1981	34.94	35.45	31.77	35.10	34.33
1982	32.38	32.44	28.52	32.11	31.22
1983	29.95	30.20	26.19	27.73	28.87
1984	29.42	29.67	25.88	27.44	28.53
1985	27.41	27.24	24.08	25.83	26.66
1986*	16.73	15.29	12.60	14.31	14.81
1987*	17.25	17.42	14.85	17.58	17.15

* Preliminary
Data source: U.S. Department of Energy and Louisiana Department of Natural Resources.

Louisiana refiners' crude oil average posted price for the South Louisiana Sweet (SLS) in July 1986 was around $12 per barrel, and a year later in July 1987, the posted price recovered to around $21 per barrel. After the Summer's peak demand the posted price has been dropping to around $18 per barrel in recent months. The expected SLS crude oil price for the next year is between $16 and $19 per barrel, if the sea lanes in the Persian Gulf are kept open, and producing countries do not flood the market.

Some historical oil prices for the United States and Louisiana are listed in Table IX and a comparison of the different sources for Louisiana crude oil reference prices is plotted in Figure 12.

FIGURE 12



NATURAL GAS PRICES

The spot price for natural gas has also been weak, due to the low price of competitive fuels and a gas surplus in the market. The price of Louisiana gas is on a continuous decline trend that started in 1985 but seems to have reversed this past month, because of the expectation of a high demand during the Winter months and market disruption caused by the recent Federal Energy Regulatory Commission (FERC) Order 500. The November average spot price for Louisiana gas, published by U.S. Natural Gas Clearing House in Houston indicated $1.50 per MCF. The price calculated from the royalty data is around $1.65 per MCF on the average from the 1987 reported data.

FERC Order 500, however, has unintentionally driven spot prices into the $1.75 to $1.85 per MCF range recently as some producers have begun to withhold less expensive gas from the spot market. Order 500 allows pipelines to be relieved of some of their high price take-or-pay obligations to a producer on a cubic foot for cubic foot basis for every cubic foot of less expensive gas the pipeline transports for that producer on a direct sale to a third party. Huge sums are involved, and many producers are simply not willing to comply with this crediting provision for the higher price gas the pipeline had previously contracted to buy, causing these producers to withhold low price gas otherwise available for sale.

TABLE X

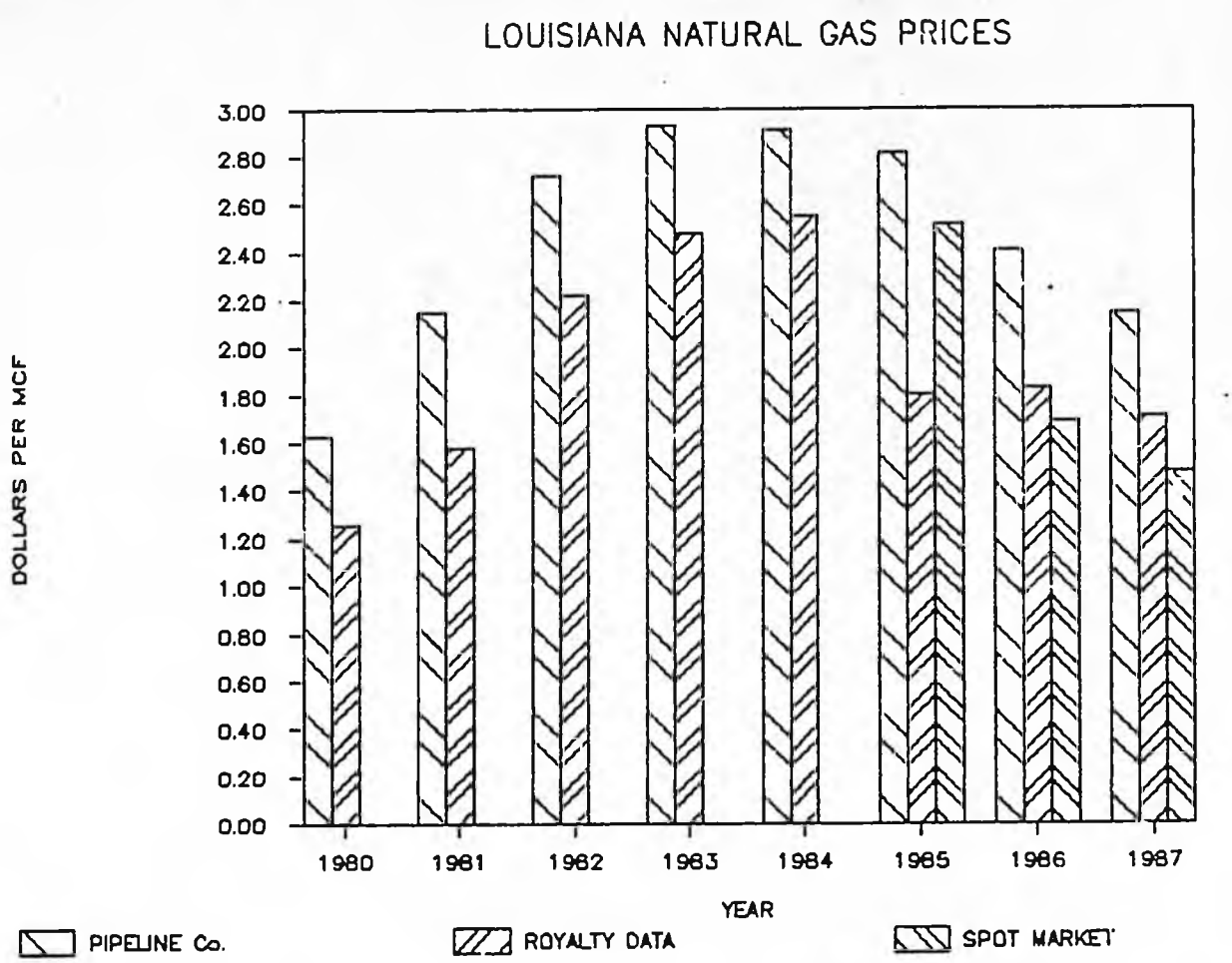
AVERAGE NATURAL GAS PRICES
(Dollars per MCF)

	UNITED STATES			LOUISIANA	
YEAR	WELLHEAD	PIPELINE IMPORTS	PIPELINE DOMESTIC ACQUISITION	ROYALTY PAYMENT	WELLHEAD
1979	1.18	2.60	1.22	0.99	1.11
1980	1.59	4.42	1.63	1.26	1.61
1981	1.98	4.84	2.15	1.58	2.07
1982	2.46	4.94	2.72	2.22	2.60
1983	2.59	4.51	2.93	2.48	2.67
1984	2.66	4.08	2.91	2.55	2.73
1985	2.51	3.18	2.81	1.80	2.16
1986*	1.86	2.53	2.39	1.75	1.84
1987*	1.65	2.19	2.14	1.41	1.69

* Preliminary
Data source: U.S. Department of Energy and Louisiana Department of Natural Resources.

Some historical natural gas prices for the United States and Louisiana are listed in Table X and a comparison of the different Louisiana natural gas reference prices is plotted in Figure 13.

FIGURE 13



APPENDIX A

SEVERANCE TAX

Legal Citation: LSA R.S. 47:631 through 47:646

Oil/Condensate/Similar Natural Resources
(Per Barrel of 42 Gallons)

a) Full rate - Oil/Condensate	12 1/2% of value
b) Incapable oil rate	6 1/4% of value
c) Stripper oil rate	3 1/8% of value

Gas
(Per MCF at 15.025 psia)

a) Full rate	$00.07
b) Incapable oil well gas *	$00.03
c) Incapable gas well gas **	$00.01 3/10
d) Reduced rate ***	$00.04
e) Special rate ****	$00.03

* Gas produced from an oil well with wellhead pressure of fifty pounds per square inch gauge or less under operating conditions.

** Gas produced from a gas well which has been determined by the Secretary to be incapable of producing an average of 250,000 cubic feet of gas per day during the entire taxable month.

*** Gas sold under a contract, in existence prior to November 15, 1973, at a price less than the rate authorized by the FPC in Opinion #597 and #607 which require seller to pay and bear more than 50% of any increase in severance tax levied since date of contract.

**** Gas sold under a contract, in existence prior to May 1, 1972, at a price less than the FPC authorized area rate which requires seller to pay and bear all of the severance tax without reimbursement of any portion thereof.

Exemptions

1. Gas which is subsequently injected into a formation for purposes of recycling, repressuring or pressure maintenance or for any other purpose which increases the ultimate recovery of oil or other hydrocarbons, or for the purpose of storing.

2. Gas when produced from oil wells and vented of flared directly into the atmosphere, unless otherwise sold.

3. Gas used as drilling fuel in the field where produced or used by operators for fuel in connection with the operation and development for, or production of, oil and gas in the field where produced.

4. Gas used in the manufacture of carbon black.

5. Gas consumed in the production of natural resources in the state of Louisiana.

6. United States Government Royalties.

7. The working interest owners in an oil or gas well that discover a new field shall be exempted from fifty percent (50%) of all severance taxes on oil or gas produced from that well for a period of twenty-four (24) months from the date regular production is begun.

Percentage of crude oil production that paid severance tax.

YEAR	FULL RATE	INCAPABLE RATE	STRIPER RATE
1979	95.37%	1.22%	3.41%
1980	94.96%	1.25%	3.79%
1981	94.33%	1.26%	4.42%
1982	93.71%	1.54%	4.73%
1983	93.17%	1.56%	5.27%
1984	92.99%	1.68%	5.33%
1985	92.72%	1.66%	5.62%
1986	92.55%	1.76%	5.69%

Percentage of natural gas production that paid severance tax.

YEAR	FULL	INCAPABLE		REDUCED	SPECIAL
		OIL	GAS		
	RATE	RATE	RATE	RATE	RATE
1979	96.74%	0.79%	2.24%	0.08%	0.15%
1980	96.21%	0.83%	2.70%	0.07%	0.18%
1981	95.89%	0.82%	2.93%	0.06%	0.30%
1982	95.72%	1.39%	3.16%	0.10%	0.19%
1983	95.47%	0.79%	3.44%	0.07%	0.22%
1984	95.66%	0.75%	3.18%	0.08%	0.33%
1985	95.61%	0.86%	3.16%	0.12%	0.26%
1986	95.63%	0.80%	3.18%	0.11%	0.29%

Percentage of state production that is royalty and percentage deductions from royalty payments.

	CRUDE OIL		NATURAL GAS	
YEAR	ROYALTY	DEDUCTION	ROYALTY	DEDUCTION
1979	4.93%	12.05%	4.17%	8.00%
1980	4.80%	12.15%	4.07%	6.05%
1981	4.68%	12.10%	3.91%	5.04%
1982	4.63%	12.26%	4.16%	3.37%
1983	4.66%	12.31%	4.21%	3.04%
1984	4.71%	12.37%	4.05%	3.27%
1985	4.47%	12.41%	4.03%	3.78%
1986	4.52%	12.80%	4.09%	3.85%

STATE OF ALASKA
ALASKA OIL AND GAS CONSERVATION COMMISSION
3001 Porcupine Drive
Anchorage, Alaska 99501

Re: THE APPLICATION OF ATLANTIC RICHFIELD COMPANY for a hearing to present testimony to determine the pool rules for the development and production of the Kuparuk River Formation west of the Prudhoe Bay Field. The contraction of the Prudhoe Bay Kuparuk River Oil Pool and the naming of the field is considered as part of the application.	Conservation Order No. 173 Kuparuk River Field Kuparuk River Oil Pool. Prudhoe Bay Field Prudhoe Bay Kuparuk River Oil Pool. May 6, 1981

IT APPEARING THAT:

1. Atlantic Richfield Company by letter dated November 25, 1980, requested the Alaska Oil and Gas Conservation Commission to take the necessary steps to adopt pool rules for the development and production of the Kuparuk River Formation west and north of the Prudhoe Bay Field.

2. Notice of a public hearing was published in the Anchorage Times on February 5, 1981.

3. A public hearing was held on March 25, 1981 at the Municipality of Anchorage Assembly Room, 3500 East Tudor Road, Anchorage, Alaska. Testimony was presented and oral and written statements were accepted.

4. The hearing was continued until April 8, 1981 at 4:30 PM. Additional written statements and maps were received.

FINDINGS:

1. Oil was first discovered in the Kuparuk area when Sinclair Oil Company tested oil from the Kuparuk River Formation at their Ugnu No. 1 well in 1969.

2. Since 1969, more than 25 wells have been drilled and hundreds of miles of multi-fold seismic data have been acquired in an attempt to define the limits of the Kuparuk River oil accumulation.

3. The area for the Prudhoe Bay Kuparuk River Oil Pool Rules was initially described on January 12, 1970 in Conservation Order No. 83-A and the area has not been changed since that date.

4. A fault, labeled the Eileen fault, exists in the western part of the Prudhoe Bay Field and the evidence indicates that this fault marks the western boundary of the oil accumulation defined as the Prudhoe Bay Kuparuk River Oil Pool.

5. There is doubt about the existence of the Eileen Fault north of the Prudhoe Bay Field and this area may have several faults.

6. Some of the area west and north of the Prudhoe Bay Field should be included within the area where a common accumulation is possible and not covered by the Prudhoe Bay Kuparuk River Oil Pool rules.

7. The Kuparuk River Formation interval in the Atlantic Richfield Company West Oak River State #1 well appears adequate for defining the pool.

8. The area of oil accumulation appears to be controlled by structural dip and truncation to the south, truncation of the formation to the west, northeast dip and possible faulting to the north and east, and a fault, the Eileen Fault, to the east.

9. The Kuparuk River formation consists of very fine to medium grained marine sandstone, usually occurring as three sand members separated by mudstones, siltstones and thinly bedded sandstones.

10. Sand members of the Kuparuk River Formation west of the Eileen Fault could be a common pool and share the same fluid contact.

11. To date, no wells have established the existence of a gas cap in the Kuparuk River Formation.

12. Although water has been found in the Kuparuk River Formation, no oil-water contacts have been substantiated in any individual sand members.

13. The aquifer underlying the Kuparuk River oil accumlation appears to be small in volume and the influx into the oil column is expected to be insignificant.

14. Preliminary development plans cover an area of 210 squares miles.

15. Initial reservoir pressure is estimated to average 3100 psia. with a bubble point pressure of 3000 psia.

16. Solution gas drive is expected to be the primary recovery mechanism.

17. All gas produced will be utilized, in accordance with 20 AAC 25.035 GAS UTILIZATION, for use as fuel, safety flaring, artifical lifting of oil, and injection into the reservoir for storage until a gas sales pipeline is available.

18. It is proposed that when gas sales facilities become available, the injected gas will be produced from the injected area for fuel and for sale.

19. Waterflooding plans are being formulated for the reservoir.

20. The blowout prevention equipment and its use should be in accordance with 20 AAC 25.035 BLOWOUT PREVENTION EQUIPMENT.

21. The Kuparuk River Field, the name proposed by the operator for the area to be covered by these rules, is considered an appropriate name since it meets the required criteria.

22. Development is planned under state-wide spacing regulations.

23. In the northern latitudes, the convergence of governmental survey lines toward true north results in some governmental quarter sections of less than 150 acres.

24. The drilling, completion and production from a well located in a governmental quarter section of no less than 125 acres will not adversely affect correlative rights.

25. Surface casing setting depths between 500 feet below the base of the permafrost and 2700 feet TVD will allow flexibility in the complex directional well programs.

26. Slotted liners, wire wrapped screen liners with and without gravel packing, and open hole completions may offer a means to reduce formation damage and improve oil recovery.

27. The casing design criteria being used has effectively eliminated casing collapse.

28. Installation of downhole and surface automatic shut-in valves could prevent an uncontrolled flow of oil or gas.

29. A minimum subsurface safety valve setting depth of 500 feet should provide adequate protection from an uncontrolled flow and should reduce the risk of damaging both the valve and the control line while running in the hole.

30. To properly regulate and operate the reservoir, performance must be carefully monitored and bottomhole pressure and gas-oil ratio test data must be obtained soon after production commences.

31. The contribution of each of the various perforated intervals in each producing well may be determined by running productivity profile surveys.

NOW THEREFORE, IT IS ORDERED THAT Conservation Order No. 98-A is hereby amended by removing the following described area from the area covered by the Prudhoe Bay Kuparuk River Oil Pool Rules.

T 11 N, R 10 E, U.M.	T 12 N, R 10 E, U.M.
Secs. 1,2,11,12,13,14,23, 24,25,26,35,and 36.	Secs. 1,2,11,12,13,14,23, 24,25,26,35 and 36.
T 11 N, R 11 E,U.M.	T 12 N, R 11 E, U.M.
Secs. 3,4,5,6,7,8,9,10, 11,14,15,16,17,18, 19,20,21,22,23,24, 25,26,27,28,29,30, 31,32,33,34,35 and 36.	Secs. 3,4,5,6,7,8,18,19, 20,29,30,31,32 and 33.
T 13 N, R 10 E, U.M.	T 13 N, R 11 E, U.M.
Secs. 13,14,15,16,21,22, 23,24,25,26,27,28, 33,34,35 and 36.	Secs. 17,18,19,20,28,29, 30,31,32 and 33.

NOW THEREFORE IT IS FURTHER ORDERED THAT the rules hereinafter set forth apply to the following described area:

T 9 N, R 6 E, U.M.
Secs. 1,2,11,12,13 and 14.

T 9 N, R 7 E, U.M.
Secs. 1,2,3,4,5,6,7,8,9, 10,11,12,13,14,15, 16,17 and 18.

T 9 N, R 8 E, U.M.
Secs. 1,2,3,4,5,6,7,8,9, 10,11,12,13,14,15, 16,17 and 18.

T 9 N, R 9 E, U.M.
Secs. 1,2,3,4,5,6,7,8,9, 10,11,12,15,16,17 and 18.

T 9 N, R 10 E, U.M.
Secs. 1,2,3,4,5,6,7,8,9, 10,11 and 12.

T 10 N, R 6 E, U.M.
Secs. 1,2,3,4,9,10,11,12,13, 14,15,16,21,22,23,24, 25,26,35 and 36.

T 10 N, R 7 E, U.M.
ALL

T 10 N, R 8 E, U.M.
ALL

T 10 N, R 9 E, U.M.
ALL

T 10 N, R 10 E, U.M.
ALL

T 10 N, R 11 E, U.M.
Secs. 5,6,7,8,17,18,19 and 20.

T 11 N, R 6 E, U.M.
Secs. 25,26,35 and 36.

T 11 N, R 7 E, U.M.
Secs. 1,2,3,4,9,10,11,12, 13,14,15,16,17,18,19, 20,21,22,23,24,25,26, 27,28,29,30,31,32,33, 34,35 and 36.

T 11 N, R 8 E, U.M.
ALL

T 11 N, R 9 E, U.M.
ALL

T 11 N, R 10 E, U.M.
ALL

T 11 N, R 11 E, U.M.
Secs. 3,4,5,6,7,8,9,10,11, 14,15,16,17,18,19,20, 21,22,23,24,25,26,27, 28,29,30,31,32,33,34, 35 and 36.

T 12 N, R 7 E, U.M.
Secs. 25,26,35 and 36.

T 12 N, R 8 E, U.M.
ALL

T 12 N, R 9 E, U.M.
ALL

T 12 N, R 10 E, U.M.
ALL

T 12 N, R 11 E, U.M.
Secs. 3,4,5,6,7,8,18,19,20, 29,30,31,32 and 33.

T 13 N, R 8 E, U.M.
Secs. 13,14,23,24,25,26, 27,28,33,34,35 and 36.

T 13 N, R 9 E, U.M.
ALL

T 13 N, R 10 E, U.M.
ALL

T 13 N, R 11 E, U.M.
Secs. 7,8,16,17,18,19,20,21, 28,29,30,31,32 and 33.

Rule 1. Name of Field

The name of the field shall be the Kuparuk River Field.

Rule 2. Definition of Pool

The name of the Pool in the Kuparuk River Field shall be the Kuparuk River Oil Pool and is defined as the accumulation of oil that is common to and correlates with the accumulation found in the Atlantic Richfield Company West Sak River State No. 1 well between the depths of 6,474 and 6,880 feet.

Rule 3. Well Spacing

Not more than one well may be drilled on any governmental quarter section or governmental lot corresponding to it nor may any well be drilled on a governmental quarter section or governmental lot corresponding to it which contains less than 125 acres, nor may the Pool be opened in a well bore that is closer than 500 feet to any property line nor closer than 1,000 feet to the Pool opened to the well bore in another well.

Rule 4. Casing and Cementing Requirements

(a) Casing and cementing requirements are as specified in 20 AAC 25.030. CASING AND CEMENTING. except as modified below.

(b) For proper anchorage and to prevent an uncontrolled flow, a conductor casing shall be set at least 75 feet below the surface and sufficient cement shall be used to fill the annulus behind the pipe to the surface.

(c) For proper anchorage, to prevent an uncontrolled flow, and to protect the well from the effects of permafrost thaw-subsidence and freeze back, a string of surface casing shall be set at least 500 measured feet below the base of the permafrost section but not below 2700 feet true vertical depth. Sufficient cement shall be used to fill the annulus behind the casing to the surface.

(d) The surface casing, including connections, shall have minimum post-yield strain properties of 0.9% in tension and 1.26% in compression.

(1) The only types and grades of casing, with threaded connections, that have been shown to meet the requirements in (d) above and have been approved for use as surface casing are the following:

(A) 13-3/8 inch, 72 pounds/foot, L-80, Buttress;

(B) 13-3/8 inch, 72 pounds/foot, N-80, Buttress;

(C) 10-3/4 inch, 45.5 pounds/foot, K-55, Buttress;

(2) The Commission may approve other types and grades of surface casing upon a showing that the proposed casing and connection can meet the post-yield strain requirements in (d) above. This evidence shall consist of one of the following:

(A) full scale tensile and compressive tests;

(B) finite element model studies; or,

(C) other types of axial strain data acceptable to the Commission.

(e) Other means for maintaining the integrity of the well from the effects of permafrost thaw-subsidence and freeze back may be approved by the Commission upon application.

(f) The Commission may approve alternative completion methods (to 20 AAC 25.030 (b) (4) and (5)) upon application and presentation of data which shows the alternatives are based on accepted engineering principles. Such alternative designs may include:

(1) slotted liners, wire wrapped screen liners, or combinations thereof, landed inside of open hole and may be gravel packed;

(2) open hole completions provided that the casing is set not more than 200 feet above the productive zone.

Rule 5. Automatic Shut-In Equipment

(a) Upon completion, each well which is capable of unassisted flow of hydrocarbons must be equipped with a commission-approved

(1) fail-safe automatic surface safety valve (SSV) capable of preventing an uncontrolled flow by automatically closing if such a flow should occur; and

(2) fail-safe automatic surface controlled subsurface safety valve (SSSV), unless another type of subsurface valve is approved by the Commission; this valve must be in the tubing string located at a depth of 500 feet or greater below ground level; the valve must be capable of preventing an uncontrolled flow by automatically closing if such a flow should occur.

(b) A representative of the Commission will witness operation and performance tests at intervals and times as prescribed by the Commission to confirm that the SSV, SSSV, and all associated equipment are in proper working condition; and

(c) A well that is not capable of unassisted flow of hydrocarbons as determined by a "no flow" performance test witnessed by a commission representative is not required to have fail-safe automatic SSV or SSSV valves.

Rule 6. Safety Flares

(a) The daily average volume of 250 MCF/day is permitted for a safety flare in the Central Production Facility operated by Atlantic Richfield Company.

(b) Safety flare volumes for additional facilities may be approved administratively upon application.

(c) Safety flare volumes may be increased or decreased administratively.

Rule 7. Gas-Oil Ratio Tests

Between 90 and 120 days after continuous production and each six months thereafter a gas-oil ratio test shall be taken on each producing well. The test shall be of at least 12 hours duration and shall be conducted at the normal producing rate of the well. Test results shall be reported on Gas-Oil Ratio Test, Form 10-409. All tests run in a calendar month shall be reported by the 15th of the following month.

Rule 8. Pressure Surveys

(a) A static bottomhole pressure survey shall be taken on each well prior to initial sustained production.

(b) Following initial sustained production from each governmental section, a transient pressure survey shall be taken on one well in the section after six months and after 18 months.

(c) One of the wells from (b) above on each lease will be designated a key well and a transient pressure survey on this well shall be taken after 30 months production and annually thereafter.

(d) Bottomhole pressures obtained by a static buildup pressure survey, a 24 hour shut-in instantaneous test or a multiple flow rate test will be acceptable.

(e) Data from the surveys required in this rule shall be filed with the Commission by the last day of the month following the month in which each survey is taken. Reservoir Pressure Report, Form 10-412 shall be utilized for all surveys with attachments for complete additional data. Data submitted shall include, but are not limited to, rate, pressure, time, depths, temperature, and other well conditions necessary for complete analysis of each survey being conducted. The Pool pressure datum plane shall be 6,200 feet subsea.

(f) Results and data from any special reservoir pressure monitoring techniques, tests, or surveys shall also be submitted as prescribed in (e) of this rule.

(g) By administrative order, the Commission may require additional pressure surveys or modify the key wells designated in (c) of this rule.

Rule 9. Productivity Profiles

(a) During the first year of production, a production survey shall be run in each well which has multiple sand intervals open to the well bore.

(b) Subsequent surveys shall be run in wells which exhibit rapid changes in gas-oil ratio, water-oil ratio, or productivity. Subsequent surveys shall also be required in wells which have had remedial work performed to change the production profile unless the remedial work results in only one sand interval being open to the well bore.

(c) Complete production survey data and results shall be recorded and filed with the Commission by the 15th day of the month following the month in which each survey is taken.

(d) By administrative order, the Commission shall specify additional surveys should it be determined that the surveys submitted under (a) and (b) are inadequate.

Done at Anchorage, Alaska and dated May 6, 1981.

Hoyle H. Hamilton, Chairman
Alaska Oil and Gas Conservation Commission

ALASKA OIL AND GAS CONSERVATION COMMISSION

Harry W. Kugler, Commissioner
Alaska Oil and Gas Conservation Commission

Lonnie C. Smith, Commissioner
Alaska Oil and Gas Conservation Commission