CO #195

PRUDHOE BAY
MISCIBLE GAS PROJECT

APPLICATION FOR APPROVAL
AS A QUALIFIED TERTIARY RECOVERY PROJECT
FOR PURPOSES OF
THE CRUDE OIL WINDFALL PROFIT TAX ACT OF 1980

DECEMBER, 1983

PRUDHOE BAY
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Application for Approval as a Qualified Tertiary Recovery Project for Purposes of the Crude Oil Windfall Profit Tax Act of 1980

December 1983

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PART I

PART I - INTRODUCTION

The Working Interest Owners of the Prudhoe Bay Unit (the Working Interest Owners are listed in Exhibit I-1) respectfully request that the Alaska Oil and Gas Conservation Commission (AOGCC) in its capacity as a designated jurisdictional agency within the meaning of I.R.C.§ 4993(d)(5)(A)(i), approve a proposed miscible fluid displacement project, hereinafter referred to as the Prudhoe Bay Miscible Gas Project (PBMGP). The PBMGP will be an enriched miscible gas project very similar in its operation to the Flow Station 3 Injection Project, which is a certified tertiary recovery project. The central gas processing facilities to be developed for the PBMGP will provide miscible solvent for enhanced oil recovery. The PBMGP will be located within two separate regions of the Prudhoe Bay Field, to be designated as the Eastern Miscible Region in the Eastern Operating Area (EOA), and the Western Miscible Region in the Western Operating Area (WOA). Both regions lie within larger areas for which waterflood is to be commenced in mid-1984. Injection of miscible gas for the PBMGP start-up is expected to commence in both regions during the last half of 1987.

The Alaska Oil and Gas Conservation Commission has been designated by the Governor in accordance with I.R.C. § 4993(d)(5)(A)(i) as the jurisdictional agency responsible for approving tertiary recovery projects located on non-federal lands in the State of Alaska for purposes of the "Crude Oil Windfall Profit Tax Act of 1980" (WPT Act). Attached as Exhibit I-2 is a copy of the designation letter. The Owners specifically request that the AOGCC approve the Prudhoe Bay Miscible Gas Project as meeting the requirements that:

A. The project involves the application (in accordance with sound engineering principles) of one or more tertiary recovery methods which can reasonably be expected to result in more than an insignificant increase in the amount of crude oil which will ultimately be recovered,

B. The date on which the injection of liquids, gases, or other matter begins is after May 1979, and

C. The portion of the property to be affected by the project is adequately delineated.

Part II of this Application, BACKGROUND, contains information on location, history of Unit operations, projected Five-Year Plan development, and projected Field status in 1987. A review of the FS-3 Injection Project and an update on current screening of the suitability of alternative EOR processes are included.

Part III, PROJECT LOCATION, contains a discussion of the evaluation criteria used for selecting the best areas for implementation of an expanded project, a delineation of the Eastern and Western Miscible Regions, and a summary of the production history from these regions.

Part IV, PROJECT DESIGN AND OPERATION, contains an overview of factors influencing Project scope and boundaries, a description of the gas processing plant facilities and injectant distribution system, and plans for Project implementation.

Part V, RESERVOIR ANALYSIS AND EXPECTED PERFORMANCE, gives reservoir performance predictions for the Project, reviews resulting revenue and expense projections, and examines implications of the timing of miscible flood implementation.

Part VI, WINDFALL PROFIT TAX QUALIFICATION REQUIREMENTS, discusses how the PBMGP meets the requirements of a qualified tertiary recovery project as defined in the WPT Act.

Part VII contains the SUMMARY.

EXHIBIT I-1
PRUDHOE BAY UNIT
WORKING INTEREST OWNERS

Amerada Hess Corporation

ARCO Alaska, Inc.

BP Alaska Exploration, Inc.

Chevron U.S.A. Inc.

Exxon Corporation

Getty Oil Company

The Louisiana Land and Exploration Company

Marathon Oil Company

Mobil Oil Corporation

Sohio Alaska Petroleum Company

Phillips Petroleum Company

Petro-Lewis Corporation

JAY S. HAMMOND
GOVERNOR

Exhibit I-2

STATE OF ALASKA
OFFICE OF THE GOVERNOR
JUNEAU

September 23, 1980

The Honorable W. Michael Blumenthal
Secretary of the Treasury
15th Street and Pennsylvania Avenue
Washington, D.C. 20220

Dear Mr. Secretary:

Pursuant to the requirements of Section 4993 (d)(5)(A) of the recently enacted Crude Oil Windfall Profits Tax Act of 1980, I have appointed the Alaska Oil and Gas Conservation Commission (AOGCC) as the jurisdictional agency over applications involving tertiary recovery projects on lands in Alaska not under federal jurisdiction. The AOGCC will review and take suitable action on any application for a tertiary recovery project within the stipulations of the Crude Oil Windfall Profits Tax Act of 1980, and applicable regulations.

This notification fulfills the responsibilities of the Governor of Alaska to provide a written submittal of agency designation in accordance with Section 4993 (d)(5)(A) of the Act.

Acknowledgement of receipt of this letter is requested.

Sincerely,

Jay S. Hammond
Governor

cc: Hoyle H. Hamilton, Chairman/Commissioner
Alaska Oil and Gas Conservation Commission

The Honorable William P. Clements, Governor of Texas
Interstate Oil Compact Commission

William W. Hopkins
Alaska Oil and Gas Association

The Honorable Robert E. LeResche, Commissioner
Department of Natural Resources

PART II

PART II - BACKGROUND

GEOGRAPHICAL LOCATION OF UNIT

The Prudhoe Bay Sadlerochit (Permo-Triassic) Reservoir, located in the North Slope Borough of Alaska, was discovered in February 1968 with the drilling of Prudhoe Bay State No. 1. Subsequent drilling confirmed the Sadlerochit Reservoir to be a major oil and gas pool with approximately 22 billion barrels of oil and 26 trillion cubic feet of gas in place. To ensure greater ultimate recovery of oil and gas, to prevent waste and to protect the correlative rights of interest owners, the Prudhoe Bay Field was unitized on April 1, 1977. As shown in Exhibit II-1, the Unit is located within Townships 10, 11, and 12 North and Ranges 10, 11, 12, 13, 14, 15, and 16 East. The Unit is divided into two Operating Areas with Sohio Alaska Petroleum Company operating the Western portion and ARCO Alaska, Inc. operating the Eastern portion.

HISTORY OF UNIT OPERATIONS

A Plan of Development and Operations for the Prudhoe Bay Permo-Triassic Reservoir was presented to the Alaska Oil and Gas Conservation Commission at a public hearing in May 1977. The Plan called for timely development of the Field on 160-acre spacing and expansion of production facilities to support an ultimate oil offtake of 1.5 MMBOPD. Possible long-term reservoir management options were also discussed and included: 1) development of the field on closer spacing; 2) injection of produced water; 3) injection of external source water; and 4) installation of low pressure separation and artificial lift facilities. It was stressed that the long-term options were not fixed and would be better defined as knowledge of the reservoir and its performance increased.

Pool rules consistent with the Plan were issued via Conservation Order No. 145 (Exhibit II-2) on June 1, 1977, and the Unit Agreement along with the Plan of Development and Operations was approved by the Commissioner of the Department of Natural Resources on June 2, 1977.

In May 1980, the Unit Owners presented a status of the Field development to the AOGCC and proposed amendment of Rules 6, 9, 10, and 11 of Conservation Order No. 145 regarding reservoir surveillance. Also, plans for injecting produced and Beaufort Sea water into the Sadlerochit formation were addressed. These plans entailed commencement of produced water injection when sufficient water volumes were available and of source water injection in mid-1984. Analysis using sophisticated reservoir simulation models indicated that the overall recovery from the Field could be increased by an additional four to seven percent of oil originally in place if waterflooding was implemented in certain areas of the Field. The primary areas which were seen to benefit from waterflooding included the Flow Station 2 (FS-2) area, the Northwest Fault Block (NWFB) area, and the Peripheral Wedge Zone (PWZ), as shown in Exhibit II-3. As a result of this hearing, Conservation Order No. 145 was amended with the issuance of Conservation Order No. 165 (Exhibit II-4). The Unit Owners submitted to the AOGCC an Application for Additional Recovery by Waterflood in December 1980. The Commission approved the Application in March 1981.

In June 1981, the Unit Owners requested that the AOGCC amend Rule 2, Well Spacing, of Conservation Order No. 145. The proposed changes included deletion of the rule requiring a minimum distance of 2,000 feet between wellbores and amendment of the allowable wellbore distance to the Unit boundary from 1,000 feet to 500 feet. Reservoir simulation studies indicated that closer well spacing would increase the ultimate recovery of oil. This request was approved in July 1981 with the issuance of Conservation Order No. 174 (Exhibit II-5).

At Field start-up in 1977, 104 oil wells and facilities designed to support production of 1.2 MMBOPD were available. As of September 1983, 501 additional wells have been drilled and production facilities have been expanded to maintain an offtake of 1.5 MMBOPD. Through September 1983, 3.01 billion barrels of oil, including condensate, have been produced. Exhibit II-6 depicts the location of production facilities currently available. Wells have been drilled from 33 drill sites/well pads which are connected to six separation centers (Gathering Centers 1, 2, and 3 in the Western Operating Area and Flow Stations 1, 2, and 3 in the Eastern Operating Area). The oil from these facilities is transported to Alyeska Pump Station 1, the beginning of TAPS.

All produced gas is routed from the separation centers to the Central Compressor Plant (CCP). Current annual average CCP gas handling capacity is 2.25 BSCF/D. Most of this gas is compressed from about 600 psia to 4100 psia and is then routed to the North and West Gas Injection Pads where it is reinjected into the Sadlerochit gas cap. The remainder of the gas is piped, after the first stage of compression, to the Field Fuel Gas Unit (FFGU) where it is conditioned for Field and TAPS fuel use. In the process of conditioning the separator gas, high molecular weight hydrocarbons are recovered as liquids. Currently, while operation of FS-3 Injection Project is interrupted, all of these liquids are sent to Flow Station 3 via a pipeline from the FFGU. A portion of these liquids is stabilized in the crude oil and shipped to TAPS. Normally the majority of these liquids is utilized in the FS-3 Injection Project.

Water production from the Field has been reinjected into the Sadlerochit formation, with the exception of water produced at Gathering Centers 1 and 3. Water produced from these two gathering centers is currently being injected into the Tertiary and Cretaceous sands. Since July 1979, the produced water at Flow Station 1 has been reinjected into the Sadlerochit formation as part of a long-term water injectivity test at Drill Site 5-17. Water production at Flow Stations 2 and 3 has been reinjected into the Sadlerochit formation since the end of 1982. Water from Gathering Center 2 has been reinjected since May 1983.

In August 1982 ARCO Alaska, Inc., on behalf of all the Owners of the Prudhoe Bay Unit, submitted to the AOGCC an application for approval of Flow Station 3 Injection Project as a qualified tertiary recovery project (Reference 1) for the purpose of the WPT Act. The Project was approved by the AOGCC in December 1982 (Exhibit II-7) and subsequently the Operator certified the Project to the IRS (Exhibit II-8). The FS-3 Injection Project uses the enhanced oil recovery technique of miscible gas displacement to increase the recoverable oil reserves in all, or portions of, Drill Sites 1, 6, 12, 13, and 14 in the Eastern Operating Area of the Prudhoe Bay Unit.

As a result of the harsh Arctic environment and the remote location of the Prudhoe Bay Field, development of the Field has entailed significantly higher capital expenditures than are required in a typical oil field. By year-end 1983, capital commitments for the Field will have totaled $13.3 billion. The current planned development through 1987 will require additional commitments of approximately $3.7 billion. In addition, the operating and maintenance costs at Prudhoe Bay are much higher than those found in onshore fields in the continental United States.

PROJECTED FIVE-YEAR PLAN DEVELOPMENT

The Field will undergo continuing development in the coming years for the purpose of optimizing recovery from the Prudhoe Bay Unit. Main Field production will be obtained from 568 160-acre wells and from 350 to 400 infill wells. These wells will be drilled from 36 drill sites/well pads connected to the six separation centers (Gathering Centers 1, 2, and 3 in the WOA and Flow Stations 1, 2, and 3 in the EOA). The oil from these facilities will continue to be transported to Alyeska Pump Station 1, the beginning of the Trans-Alaska Pipeline System. Several major projects aimed at maintaining the Field off-take will be implemented in the period 1983 to 1987. These projects are water injection, artificial lift, and low pressure separation facilities.

Facilities are planned for reinjection of up to 1.3 MMBPD produced water with additional pressure maintenance being provided by the injection of up to 2.0 MMBPD of treated Beaufort Sea water. Initial produced water injection is planned for Drill Sites 4, 12, 13, and 14 in the EOA and Well Pads F, R, and X in the WOA. Initially treated Beaufort Sea water injection is planned for Drill Sites 1, 4, 9, 11, 12, 13, 14, 16, and 17 in the EOA and Well Pads A, F, H, M, N, R, S, U, X, and Y in the WOA. Produced water injection will replace Beaufort Sea water injection as additional produced water becomes available. As shown previously, Exhibit II-3 outlines the areas initially targeted for waterflood operations.

The first major increment of the field-wide artificial lift system will be operational in early 1984, with the installation of compression at FS-3. Two additional compressors will be installed in late 1985 at GC-1, and a fourth compressor at FS-2 is under review for 1987. Ultimately, the system will provide 1.3-1.6 BSCF/D of gas-lift gas.

Low pressure separation facilities have recently been installed at each separation center to maintain production capacity. The currently planned compressor capacity for low pressure produced gas and artificial lift return gas should eventually be capable of handling a total gas production of 3.9 BSCF/D.

Development of the Eileen West End area is currently planned for production start-up in 1987 at the earliest. Pending further delineation drilling and production testing, partial 80-acre development from two to four well pads is tentatively planned. Production, injection, and gas lift capacities of GC-2 will be expanded accordingly to support West End development.

The planned development described above will necessitate expansion of currently existing support facilities. Expansion of the Central Power Station to 182 megawatts is under consideration for 1987. Gas dehydration expansions are planned at GC-2 and GC-3 in 1986, and GC-1 in 1987.

The Field development outlined above is subject to revision as more experience becomes available. Final implementation will be dependent upon the results of ongoing development studies and production performance.

PROJECTED FIELD STATUS IN 1987

By mid-1987, the daily production rate will be close to or have begun its decline from the Field offtake limit of 1.5 MMBOPD. As described in the previous section, waterflood, gas lift operations, and low pressure separation will have been implemented in stages during the preceding five years. As a result of a field-wide surveillance program and development drilling to 80-acre spacing over a large part of the Field, much more will be known about the geology and performance of the Sadlerochit reservoir. Exhibit II-9 outlines current projections for injection/production rates and cumulative volumes at mid-1987. The average field pressure is expected to be 3850 psia.

The three principal waterflood areas where enhanced oil recovery (EOR) has been under active consideration are the Northwest Fault Block, Flow Station 2 Area, and the Peripheral Wedge Zone (see Exhibit II-3). The expected cumulative water injection and oil production in these three areas by mid-1987 are also summarized in Exhibit II-9.

FLOW STATION 3 INJECTION PROJECT

The Flow Station 3 Injection Project has offered the Prudhoe Bay Unit the opportunity to test the technical feasibility of a miscible water-alternating-gas (WAG) flood in the Sadlerochit and to gain operational, facility, and reservoir experience prior to the start of PBMGP (Exhibit II-10).

Because the miscible flood projects will operate similarly, experience gained over the next three years will be invaluable. Techniques for freeze protection, wireline work, and general surveillance will be optimized before the larger Project is implemented. A major portion of the reservoir rock to be flooded in the PBMGP is geologically similar to rock within the Flow Station 3 Injection Project. Injectivity and conformance experience gained from the Flow Station 3 Injection Project will lend insight to the larger Project.

The last Flow Station 3 Injection Project well was drilled and completed in June 1983. As of December 1983, six producers remain to be perforated. The average watercut and gas-oil ratio in the Project Area are 18 percent and 720 SCF/STB, respectively.

The May 26 explosion and fire in the Injection Module after five months of miscible gas injection has postponed an evaluation of potential long-term benefits and problems associated with WAG flooding. But data collected since start-up will continue to significantly influence design and implementation of the PBMGP.

The experience in the Flow Station 3 Injection Project can be divided into two time periods on the basis of injection fluid availability and operational strategy.

December 30, 1983, to May 26, 1983

The Project was brought on stream December 30, 1982. From that time until the interruption in May, a total of eight WAG wells and five upstructure water injectors received injection. Miscible gas was injected in five WAG wells (13-6, 13-19, 13-22, 13-23A, and 13-25) and water was injected into eight WAG wells (13-6, 13-19, 13-21, 13-22, 13-23A, 13-24, 13-25, and 13-32).

The percent total pore volume of miscible gas injected in the five wells ranged from 0.2 percent to 1.1 percent. The available produced water was divided two ways. Almost 40 percent of the available water was pre-injected into seven of the WAG wells (only 13-19 did not receive pre-injection) to remove free gas saturations and improve the injection profile. The other 60 percent of the available water was injected into five upstructure water injectors to prevent gas tongue movement into the Project Area. Over 60,000 BWPD and 45 MMSCF/D gas were injected in the Project Area at peak injection.

By the end of May, Project production and injection volumes were virtually in balance. However, average pressure decline during the December-May time frame closely followed the Field pressure decline of 6-8 psi/month. This was thought to be caused by a pressure sink in the area east of the Project (i.e. DS 12, 16, and 17). This decline should be mitigated by start-up of produced water injection in the northern part of Drill Site 12 in early 1984 and by the start-up of the Eastern PWZ source waterflood in mid-1984. The reservoir pressure is expected to remain at least 100 psi above the design minimum miscibility pressure (MMP).

Pattern 13-6, containing Observation Well 13-98, received initial water injection on February 17, 1983. Well 13-6 had 0.5 percent pore volume pre-injection of water prior to miscible gas injection on May 1, 1983, and 0.4 percent pore volume miscible gas prior to the end of May.

The Project was interrupted by an explosion and fire on May 26, 1983. Miscible gas injection is scheduled to resume in the first quarter of 1984.

May 26, 1983, to Present

During this interim period, the Unit has focused on three objectives: 1) minimizing Project Area production to ensure that sufficiently high reservoir pressure is maintained; 2) prioritizing the available water injection such that WAG wells are given preference over upstructure water injectors; and 3) assigning the 13-6 pattern as a priority for injection and production to ensure validity of 13-98 time-lapsed logging and tracer results. A nine-well pressure surveillance program was implemented to monitor the pressure decline throughout the Project Area. Pressure data in these wells have been obtained every two or three months. Results to date indicate that the pressure decline has decreased to 2-3 psi/month.

From May to November the produced water gas lift module was under repair, and only 8-14 MBWPD of produced water was available. A major portion of this water was injected into 13-6. The gas lift module was brought back on-stream in November 1983 and available water increased to 60 MBWPD. Cumulative production/injection balance will be restored prior to increasing production from the Project.

Surveillance and Operational Experience

An extensive surveillance program was designed for the Flow Station 3 Injection Project. It includes a comprehensive cased hole logging package to adequately monitor gas and water movement, radioactive tracers, extra cores, and a fiberglass lined observation well.

Over 100 wireline surveys have been run for diagnostic surveillance since start-up in December 1982. This includes gas and water monitoring logs, profile, directional, and pressure surveys and cement channel detection logs. Over 20 of these surveys have been run in 13-6 and 13-98.

The radioactive tracer program was initiated May 12, 1983, with tracer injection during the gas cycle in WAG injectors 13-6, 13-22, 13-23A, and 13-25. Krypton 85 was injected in all but the 13-22 pattern; tritiated ethane was injected into 13-22. To date, produced fluid sampling has shown no evidence of tracer.

Observation Well 13-98 was completed in early 1983. Directional survey data have shown it to be 500-550' north and slightly west of 13-6 at the top of the Sadlerochit (see Exhibit II-11). Well 13-98 has been logged eight times since Project start-up with dual induction and/or compensated neutron logs. Saturation response has been noted on the dual induction log only (see Exhibit II-12). Water has appeared at the very top of the well in what appears to be a high permeability streak. Over time, the 13-98 data will provide a better understanding of fluid movement in the 13-6 pattern.

The Flow Station 3 Injection Project has provided, and will continue to provide, an excellent opportunity to gain operational experience prior to the start-up of the PBMGP. Experience to date has centered around three areas: profile improvement, injectivity problems, and scale prevention.

Seven WAG injector profiles have been performed to date: two on gas, five on water. The profile data in general shows that adequate injection profiles (fluid entry in proportion to feet perforated) can be obtained. Some of the injectors have exhibited a disproportionate amount of fluid exiting the top sets of perforations. However, a coiled tubing unit has successfully been used to stimulate the bottom intervals. Except where large permeability contrasts dominate, this technique should be successful in correcting future injection profiles.

Some WAG projects have experienced decreases in injectivity as a result of relative permeability problems. Because of equipment upsets during start-up and early metering problems, data gathered to date is inconclusive as to whether decreases in injectivity should be expected for the Flow Station 3 Injection Project. While an important consideration, its effect should be lessened by the high permeability levels found in the Sadlerochit.

One problem has been encountered which will equally affect the waterflood and WAG areas. Calcium carbonate scale was found in the upper tubulars and surface flowlines in the four water source wells. Also, several of the high watercut wells have shown evidence of scaling in the surface equipment. Recently initiated scale inhibition techniques have been very successful in solving these scaling problems.

Overall, the Flow Station 3 Injection Project has confirmed that a miscible water-alternating-gas (WAG) flood can be conducted in the Sadlerochit. The mechanisms associated with this and other tertiary methods that have been considered for the Prudhoe Bay Field are discussed in the next section.

SELECTION OF EOR PROCESS

The planned execution of primary and secondary operations at Prudhoe Bay is projected to yield an ultimate recovery of 9-10 billion barrels of oil, leaving more than 10 billion barrels of oil untapped in the Sadlerochit Reservoir. With such a large volume of oil at stake, the Unit Owners recognized the potential of increasing recovery through the application of tertiary recovery methods. Hence, screening studies were conducted to better define the applicability of the leading enhanced recovery methods at Prudhoe Bay. The processes considered fall into four categories: a) miscible gas displacement processes, b) surfactant flooding, c) enhanced waterflood techniques, and d) thermal processes. Much of the Unit's process screening work is documented in the Flow Station 3 Injection Project WPT Approval Application. A similar, updated discussion is included herein for background and completeness.

Miscible Fluid Displacement

Miscible gas displacement processes involve the injection of a gaseous mixture which is usually not miscible with crude oil initially, but develops into a miscible solvent-oil bank through the exchange of hydrocarbon components between the gaseous mixture and crude oil within the reservoir (References 2-7). Because of the miscible transitions from oil to oil-solvent to the gaseous mixture, entrapment of oil does not occur, and the miscible bank effectively displaces nearly all of the oil from the fraction of the reservoir contacted. There are two effects that govern the overall efficiency of this process. The density of the miscible injectant is lower than that of the reservoir oil leading to gravity segregation of the fluids, and the miscible injectant's viscosity is lower than that of reservoir oil with the result that conditions are conducive for viscous fingering of injectant through the oil. Water is often injected alternately with the gas (WAG process) to help control the gravity segregation and fingering problems (References 8-14). Water injection also contributes to maintaining reservoir pressure.

Two main categories of miscible gas processes exist: (1) high pressure lean gas (vaporizing) drive and (2) enriched gas (condensing) drive. High pressure lean gas drive involves the injection of methane, carbon dioxide, or inert gases at high pressures. The high pressure gas forms a miscible bank through evaporation of mainly intermediate hydrocarbon components (C_2-C_6) from the oil into the solvent. The effective use of this process requires a volatile oil with high concentrations of C_2-C_6 components in combination with high reservoir pressures. Where these conditions cannot be met, enriched gas processes can sometimes be applied. In enriched gas processes, a gas such as methane, field gas or CO_2 is enriched with intermediate hydrocarbon components and is injected into the reservoir. The enriched gas forms a miscible bank as the intermediates from the gas are absorbed into the oil.

High pressure lean gas processes are not applicable at Prudhoe Bay since Sadlerochit crude is relatively low in intermediates and the critical pressure at which methane and Sadlerochit oil become miscible is well above pressure levels existing in the reservoir. It is possible, however, to enrich either carbon dioxide or field gas by adding intermediate hydrocarbons and obtain a miscible injectant at reasonable reservoir pressures.

Surfactant Flooding

In a surfactant flood, the composition of the injected fluids is designed to reduce oil-water interfacial tension through the formation of oil-water-surfactant microemulsions, thereby mobilizing more oil than by waterflooding. With present surfactant chemicals, the formulations to reduce oil-water-surfactant interfacial tensions to low levels are sensitive to reservoir temperature and water salinity. Formulations are specific to individual reservoir conditions and are not effective at temperatures or water salinities which differ from design conditions. The planned injection of low temperature Beaufort Sea water into the Sadlerochit reservoir will introduce temperature and salinity gradients that will seriously hinder the use of currently available surfactants.

A typical surfactant flooding process might involve the injection of a surfactant bank followed by a larger bank of thickened water or brine. Polymers are usually added to both the surfactant solution and to the drive water to reduce the mobility of the injectants. With this process, a larger portion of the reservoir could be contacted than with miscible gas injection.

Most applications of polymer flooding to date have been in reservoirs with lower temperatures than the Sadlerochit. Availability of a polymer for large scale use at Prudhoe is questionable.

For reasons discussed above, development of new chemicals is a prerequisite to surfactant flooding at Prudhoe Bay. The cost of making surfactant and polymer chemicals available at the remote Prudhoe Bay location currently yields unfavorable screening economics.

Enhanced Waterflooding

Enhanced waterflood techniques such as Carbonated, Caustic, or Polymer Waterflooding attempt to improve sweep efficiency and/or reduce the residual oil left in the reservoir over what would be possible with conventional waterflooding.

The injection of water saturated with CO_2 improves recovery through the diffusion of CO_2 from the saturated water into the contacted reservoir oil. This swells the stock tank oil and reduces its viscosity, thus improving reservoir sweep and reducing the amount of oil trapped. Reservoir simulation studies have shown that carbonated waterflooding would be a less efficient EOR technique at Prudhoe than miscible displacement processes. Simulation has also shown that with the alternating injection of water and an injectant containing CO_2, carbonation of the water will occur naturally and carbonated waterflooding benefits will accrue along with the miscible displacement benefits.

Caustic waterflooding involves the injection of water containing sodium hydroxide or other pH increasing chemicals. Reduction of interfacial tension results from the in situ generation of surfactants through chemical reactions between the high pH water and organic acids in the oil. Residual oil saturations in the swept regions are reduced as a result of the generated surfactants. Successful caustic flooding is very dependent upon suitable reservoir oil and rock characteristics. Attempted field applications of caustic waterflooding are not promising.

Addition of polymer increases the viscosity of injected water and improves the mobility ratio between the oil and flood water. Polymer waterflooding may be applied at Prudhoe Bay to improve the water/oil mobility ratio and to reduce slumping of injected water in thick sand intervals. However, since a favorable mobility ratio exists between water and Sadlerochit crude, the use of polymers as a mobility control agent would yield limited benefits. At present, polymers which would be effective at the high Sadlerochit temperatures are not commercially available. Finally, with both polymer and caustic waterflooding, the logistics of supplying large quantities of chemicals to this remote Arctic location may entail prohibitive costs.

Thermal Processes

The use of thermal processes improves recovery by reducing the oil viscosity and by expansion and distillation of the crude. Two thermal methods were analyzed for possible application at Prudhoe Bay. The first involves injection of steam into the reservoir to change the flow characteristics of the oil. In the second process, in situ combustion, oil in the reservoir is ignited and combustion is sustained through air injection. Neither process appears applicable at Prudhoe Bay. Steam injection has been eliminated from consideration because the high pressure and depth of the Sadlerochit Reservoir would significantly reduce process effectiveness, as compared with use in low pressure shallow reservoirs. In situ combustion is not economically feasible since high air injection pressures and close well spacing (possibly as close as 10 to 20 acres) would be required for efficiency.

Summary

In summary, the miscible gas displacement process is the most technically feasible and practicable enhanced recovery technique which can be applied at Prudhoe Bay at this time. The process has been used with success by the industry for several years. Practical surfactant, caustic, and polymer flooding systems that can be used in the Sadlerochit Reservoir have not been developed. This assessment is consistent with conclusions reached by van Poollen after study of applicability of EOR methods at Prudhoe. He concluded that injection of CO_2 or field gas enriched with LPG's is the most promising approach for effecting EOR. (Reference 15)

Methane, carbon dioxide, and combinations of the two have been studied by the Unit Owners as base gases for obtaining miscible injectant for use at Prudhoe. Methane and carbon dioxide are both present in gas from the Field. Neither gas is miscible with Sadlerochit oil in the reservoir unless appreciable intermediate hydrocarbons have been added. Carbon dioxide is slightly preferable to methane because 1) less enrichment is required, 2) its viscosity is higher, and 3) its density is nearer the densities of oil and water. These advantages are partially offset by a higher formation volume factor. The cost of extracting and handling a high CO_2 content stream from the Field gas stream would be high. After careful study, the Unit Owners have determined that a miscible injectant comprised of about 50 percent intermediate hydrocarbons and equal parts methane and CO_2 is desirable for use at Prudhoe. This injectant can be supplied with significantly less processing than would be required for a high CO_2 content injectant, and it will have better characteristics than would an injectant which contained no carbon dioxide.

The above comments are relative to application of EOR processes to the light oil column in the Sadlerochit reservoir. None of the EOR processes are promising for application in the heavy oil/tar zone which underlies the light oil column.

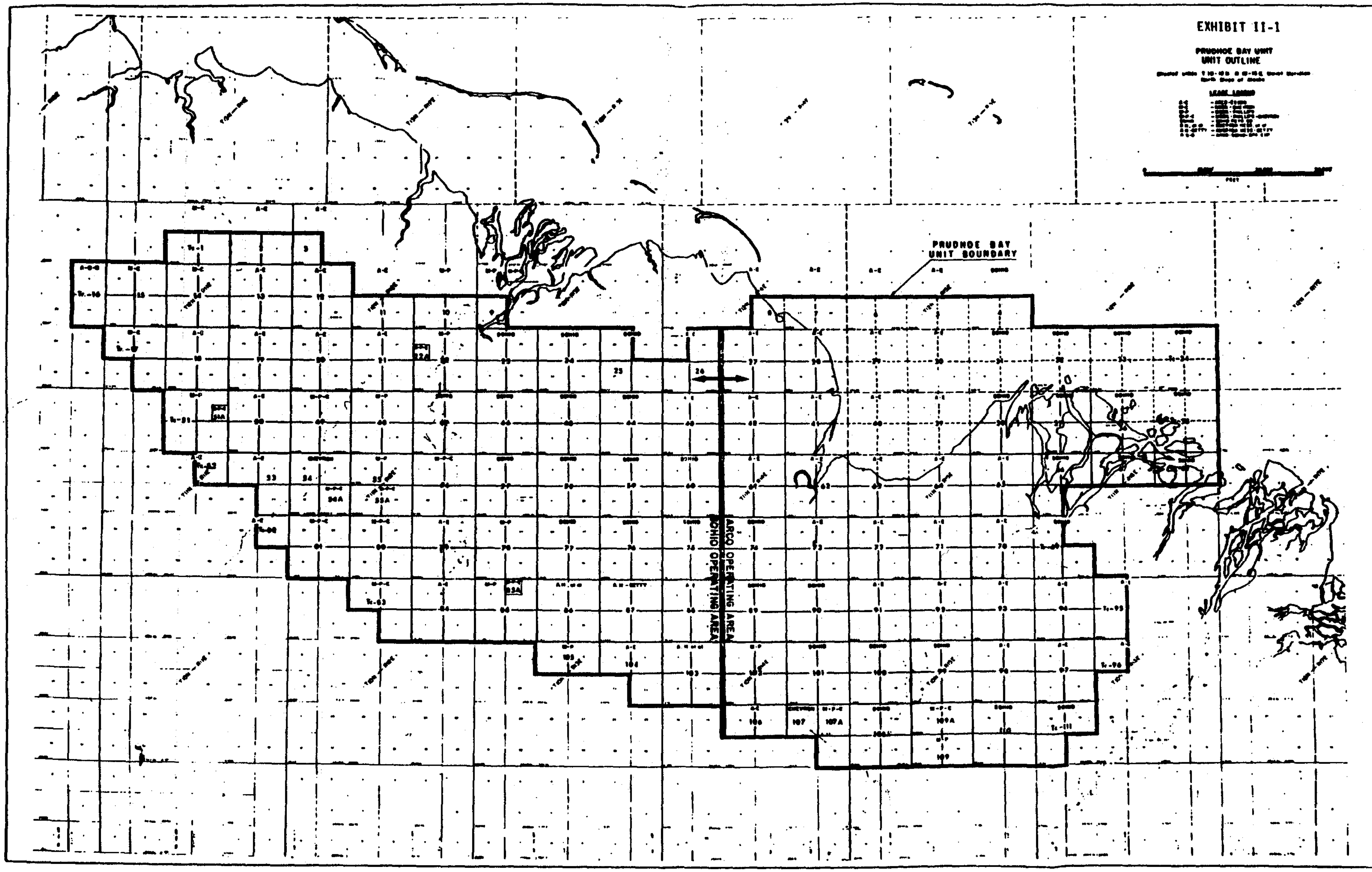


EXHIBIT II-1
PRUDHOE BAY UNIT
UNIT OUTLINE
LEASE LEGEND
PRUDHOE BAY
UNIT BOUNDARY
ARCO OPERATING AREA
SOHIO OPERATING AREA

EXHIBIT II-2

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 a 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.

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

Concurrence:

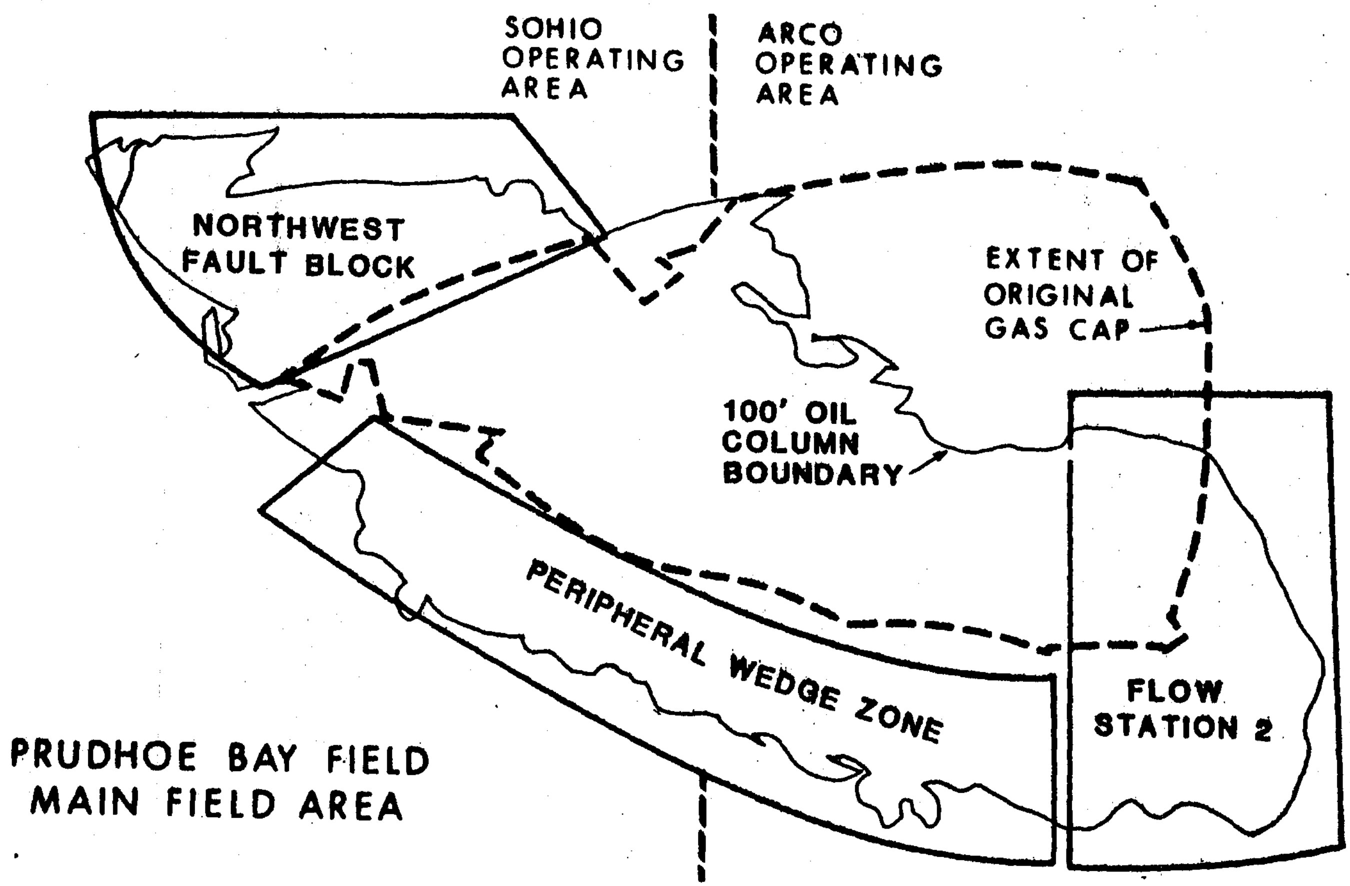
Hoyle H. Hamilton, Chairman
Alaska Oil and Gas Conservation Committee

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

EXHIBIT II-3

PRUDHOE BAY UNIT

MAJOR WATERFLOOD AREAS



DWG. # PE-1-NS-8-1846

EXHIBIT II-4

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

Re: The ALASKA OIL AND GAS CONSERVATION COMMISSION, upon its own motion, to hear plans of the Prudhoe Bay Unit operators for water injection, to present the results of recent model studies, and to consider changes to certain rules of Conservation Order No. 145	Conservation Order No. 165 Prudhoe Bay Field Prudhoe Oil Pool June 6, 1980

IT APPEARING THAT:

1. The Alaska Oil and Gas Conservation Commission, upon its own motion, called for a public hearing to hear water injection plans of the Prudhoe Bay Unit operators, to present the results of the Commission's model study of the Prudhoe Oil Pool and to consider changes to Rules 6, 9, 10, and 11 of Conservation Order No. 145.

2. Notice of public hearing was published in the Anchorage Daily News on March 21, 1980

3. A public hearing was held in the Municipality of Anchorage Assembly Room, Anchorage, Alaska on May 7 and 8, 1980.

FINDINGS:

1. During the period from June 1977 through April 1980 the following down-hole surveys were run: 898 reservoir pressures, 407 productivity profiles, 285 gas-oil contact logs and 110 water-oil contact logs.

2. The operators have requested an additional 15 days in which to file the data required in Rules 6, 9, 10, and 11 because of the time required to handle the increased volume of data.

3. The operators have requested that the frequency of pressure surveys be reduced.

4. The operators have recommended key wells for repetitive pressure surveys and gas-oil contact monitoring.

FINDINGS: (cont.)

5. Neutron logs which have been run in the same well at various time intervals have proven effective in monitoring movement of the gas-oil contact.

6. A capable method for oil-water contact monitoring has not been demonstrated.

7. Spinner and tracer surveys have yielded comparable results in determining production profiles in most wells and tracer surveys have been found to be more accurate at low producing rates.

CONCLUSIONS:

1. An additional 15 days in which to file the data required in Rules 6, 9, 10, and 11 as requested by the operators is reasonable and will not be a hardship on the Commission.

2. Sufficient pressure surveys have been run so that the frequency of the surveys can be reduced if the same density is maintained.

3. Key well programs for long term monitoring of the pressure changes and the gas-oil contact movement should be initiated.

4. The key well programs recommended by the operators are acceptable.

5. A key well program for oil-water contact monitoring is inappropriate at this time but investigation of a monitoring tool should continue.

6. Tracer surveys should be permitted as an alternate method to spinner surveys in determining productivity profiles.

NOW, THEREFORE, IT IS ORDERED THAT the following rules of Conservation Order No. 145 are changed to read as follows:

<u>Rule 6 Pressure Surveys</u>

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

(b) Within the first six months following the initial sustained production from each well, a transient pressure survey shall be taken.

(c) One specific well on each producing pad or drill site shall be designated as a key well. Semi-annual bottomhole transient pressure surveys shall be conducted on each key well and the following wells are currently designated as key wells:

Western Operating Area Sohio Alaska Petroleum Company Operator	Eastern Operating Area Atlantic Richfield Company Operator
Prudhoe Bay Unit Well Numbers	Prudhoe Bay Unit Well Numbers
A-5	DS 1-4
B-2	DS 2-1
C-2	DS 3-7
D-6	DS 4-5
E-1	DS 5-11
F-4	DS 6-4
G-3	DS 7-6
H-8	DS 9-6
J-6	DS 12-3
M-5	DS 13-4
N-7	DS 14-5
Q-3	

(d) An annual transient pressure survey shall be conducted on one well in each governmental section from which oil is being produced. The surveys required in either (b) or (c) of this rule can be used to fulfill this requirement.

(e) Data from the surveys required in (a), (b), (c) and (d) of this rule shall be filed with the Commission by the last 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 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 8800 feet subsea. Bottomhole transient pressures obtained by a 24 hour buildup or multiple flow rate test will be acceptable.

(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) When new pads or drill sites are developed, the operator shall designate a key well for each and, upon commission approval, these wells will become part of the key well program in (c) of this rule.

(h) By administrative order the Commission may require additional pressure surveys or modify the key wells designated in (c) of this rule.

Rule 9 Gas-Oil Contact Monitoring

(a) Prior to initial sustained production, a cased or open hole neutron log shall be run in each well.

(b) Semi-annual neutron log surveys shall be run in the following wells designated as key wells:

Western Operating Area Sohio Alaska Petroleum Company Operator	Eastern Operating Area Atlantic Richfield Company Operator
Prudhoe Bay Unit Well Numbers	Prudhoe Bay Unit Well Numbers
A-4	DS 1-8
B-8	DS 2-1
C-8	DS 4-7
D-4	DS 5-5
E-2	DS 5-7
F-3	DS 5-12
H-7	DS 6-3
J-5	DS 7-11
N-6	DS 7-14
Q-2	DS 9-4

(c) An annual report shall be submitted to the Commission by July 1 of each year which shall include a summary of the wells surveyed, an analysis of the surveys, and an analysis of the gas-oil contact behavior.

(d) The neutron logs run on any well and those required in (a) and (b) of this rule shall be filed with the Commission by the last day of the month following the month in which the logs were run.

(e) The operators may at anytime designate additions or changes to the key wells and, if approved by the Commission, they would become part of the key well program under (b) of this rule.

(f) By administrative order, the Commission may require additional wells to be logged or modify the key wells designated in (b) of this rule.

Rule 10 Oil-Water Contact Monitoring

(a) The operators shall continue an evaluation program to determine the oil-water contact monitoring capability of various cased hole logs. An annual report shall be submitted to the Commission by July 1 of each year on the evaluation program.

(b) All cased hole logs run for this purpose shall be filed with the Commission by the last day of the month following the month in which each log was run.

(c) If the capability of monitoring the change in the oil-water contact movement can be demonstrated by a cased hole logging method, a key well program shall be set up by the operators subject to the approval of the Commission.

Rule 11 Productivity Profiles

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

(b) Follow up surveys 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 flow meter or tracer survey data and results shall be recorded and filed with the Commission by the last day of the month following the month in which each survey is taken.

(d) By administrative order the Commission may specify additional surveys other than the surveys submitted under (a), (b), and (c) of this rule.

DONE at Anchorage, Alaska and dated June 6, 1980.

Hoyle H. Hamilton
Chairman/Commissioner
Alaska Oil and Gas Conservation Commission

Lonnie C. Smith
Commissioner
Alaska Oil and Gas Conservation Commission

Harry W. Kugler
Commissioner
Alaska Oil and Gas Conservation Commission

EXHIBIT II-5

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

Re: THE APPLICATION OF ARCO ALASKA, INC. and SOHIO ALASKA PETROLEUM COMPANY requesting the amendment of Rule 2 of Conservation Order No. 145, which pertains to well spacing in the Prudhoe Oil Pool, Prudhoe Bay Field.	Conservation Order No. 174 Prudhoe Bay Field Prudhoe Oil Pool July 1, 1981

IT APPEARING THAT:

1. ARCO Alaska, Inc. and Sohio Alaska Petroleum Company, operators of the Prudhoe Bay Unit, by letter dated June 15, 1981, requested the Alaska Oil and Gas Conservation Commission to amend Rule 2 of Conservation Order No. 145 which sets out well spacing requirements for the Prudhoe Oil Pool.

2. Notice of public hearing was published in the Anchorage Times on June 19, 1981.

3. The notice of public hearing indicated only ARCO Alaska, Inc. to be the applicant when in fact Sohio Alaska Petroleum Company was a joint applicant.

4. There were no protests to the application.

FINDINGS:

1. Rule 2 of Conservation Order No. 145 states "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."

2. The Prudhoe Oil Pool, as defined in Conservation Order No. 145, exists in an area that is part of the Prudhoe Bay Unit.

3. Based on current data, the Prudhoe Oil Pool is completely within the Prudhoe Bay Unit and correlative rights of all owners are protected.

4. Evidence indicates that a closer spacing of wells could result in increased recoveries in waterflood areas where multiple sand intervals of contrasting permeability are separated by shales.

5. Evidence indicates that a closer spacing of wells could also result in increased recoveries in areas which are cut by major faults.

6. Evidence further indicates that a closer spacing of wells in the areas of a thicker oil column could increase recoveries.

7. The flexibility to vary well spacing at this stage of pool development will facilitate the best use of rigs by minimizing rig moves.

8. Since statewide rules allows a well to be drilled no closer than 500 feet to a unit boundary, the operators of a unit should have the same minimum distance restriction at the boundary of the affected area.

NOW, THEREFORE, it is ordered that:

Rule 2 of Conservation Order No. 145 is hereby amended to read as follows:

RULE 2 Well Spacing

There shall be no restrictions as to well spacing except that no pay shall be opened in a well closer than 500 feet to the boundary of the affected area.

DONE at Anchorage, Alaska and dated July 1, 1981.

Hoyle H. Hamilton
Chairman/Commissioner
Alaska Oil and Gas Conservation Commission

Harry W. Kugler
Commissioner
Alaska Oil and Gas Conservation Commission

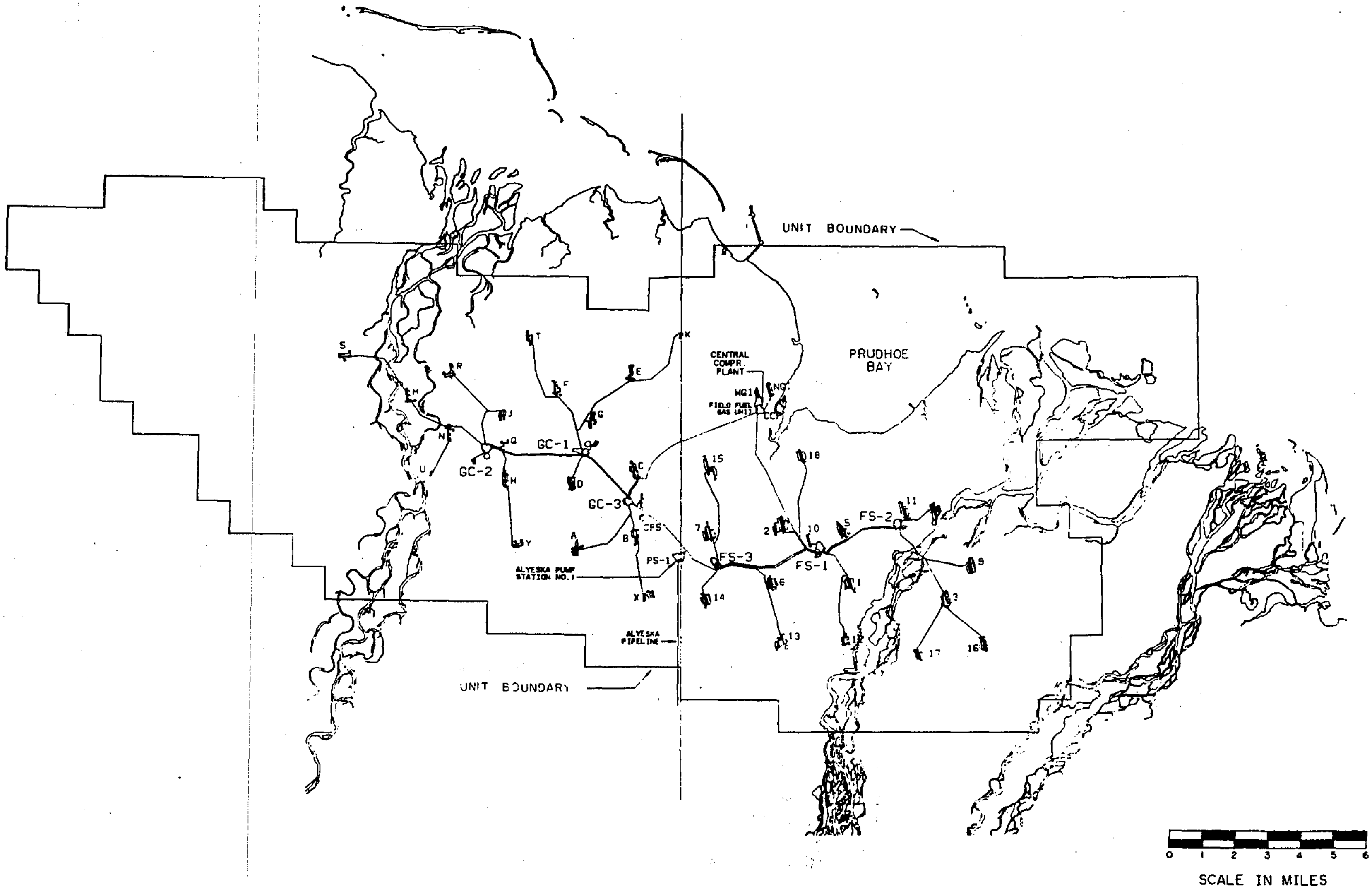


EXHIBIT- II-6
PRUDHOE BAY FIELD
PRODUCTION FACILITIES

2CC482C2

EXHIBIT II-7

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

Re: THE APPLICATION OF ARCO, ALASKA, INC. on behalf of the Prudhoe Bay Unit Working Interest Owners, for (1) additional recovery by miscible enriched hydrocarbon gas injection and (2) approval as a qualified tertiary recovery project for purposes of the Crude Oil Windfall Profit Tax Act of 1980.	Conservation Order No. 186 Prudhoe Bay Field Prudhoe Oil Pool November 29, 1982

IT APPEARING THAT:

1. ARCO Alaska, Inc., by letter dated August 31, 1982, requested the Alaska Oil and Gas Conservation Commission to hold a public hearing to provide an opportunity for the Prudhoe Bay Unit Working Interest Owners to enter testimony into the public record in support of their request for approval of the Flow Station 3 Injection Project under Section 20 AAC 25.400 and approval as a qualified tertiary recovery project according to paragraphs (A), (B), and (C) of IRC Section 4993(C)(2).

2. Notice of public hearing was published in the Anchorage Times on November 3, 1982.

3. A public hearing was held in the Captain Cook Hotel, Anchorage, Alaska on November 19, 1982.

FINDINGS:

1. An additional recovery project to waterflood the Prudhoe Oil Pool was approved on March 20, 1981.

2. The Flow Station 3 Injection Project involves 3650 acres and is a portion of the Sadlerochit sandstone reservoir of the Prudhoe Oil Pool and effects about 2% of the total reservoir.

3. The Flow Station 3 Injection Project compliments the additional recovery project approved in March 1981 by offering additional crude oil recovery to be obtained by the injection of miscible enriched hydrocarbon gas alternating with the injection of water (WAG).

4. Reservoir simulation model studies indicate that about 5.5% of the original oil in place, or 24 MMbbls, may be recovered over and above that projected by primary and conventional waterflood as a result of the Flow Station 3 Injection Project.

5. The gas, natural gas liquids and water to be injected are compatible with reservoir fluids since they are indigenous to the reservoir.

6. The approval of the Flow Station 3 Injection Project as a qualified tertiary recovery project for purposes of the Crude Oil Windfall Profit Tax Act of 1980 should be covered in a separate decision.

CONCLUSION:

1. The Flow Station 3 Injection Project will not cause waste and correlative rights will be protected.

2. The Flow Station 3 Injection Project could increase recovery from the specific area by up to 24 million barrels of oil beyond that predicted by primary and conventional waterflood.

3. There will be no impairment of the reservior from the WAG project and other Enhanced Oil Recovery methods could be employed in the future.

NOW THEREFORE, IT IS ORDERED THAT:

The Flow Station 3 Injection Project is approved as an additional recovery method for the 3650 acre portion of the Sadlerochit Reservoir, defined in the record as the Flow Station 3 Injection Project Area.

Semiannual reports, in January and July of each year, beginning in January, 1983, shall be submitted and will include the following:

1. Reservoir pressure.
2. Volumes (by month and well) of injected gas, injected water, injected low molecular weight liquids, and produced fluids (oil, water, and gas).
3. Results of production logging surveys.
4. Results of radioactive tracer tests.
5. Results of observation well surveys.

Additional information concerning the Flow Station 3 Injection Project may be requested by the Commission.

These reports are in addition to present reporting requirements required by Conservation Order 165 and the waterflood program.

DONE at Anchorage, Alaska and dated November 29, 1982.

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

ARCO Alaska, Inc.
Post Office Box 360
Anchorage, Alaska 99510
Telephone 907 265 6511
Paul B. Norgaard
President

EXHIBIT II-8

December 3, 1982

District Director
Internal Revenue Service Center
300 E. 8th St.
Austin, Texas 78701

Attention: Windfall Profit Tax Division

Re: Jurisdictional Agency Certification of Tertiary Recovery Project at Prudhoe Bay Unit Flow Station 3

Dear Director:

Pursuant to Section 4993(c)(2)(D)(ii) of the Internal Revenue Code of 1954, as amended, (hereinafter referred to as the "Code") and Treasury Regulation Section 51.4993-3(a), ARCO Alaska, Inc., as operator, hereby certifies that the Alaska Oil and Gas Conservation Commission, a duly designated jurisdictional agency pursuant to Section 4993(d)(5)(A)(i) of the Code, has approved the Prudhoe Bay Unit Flow Station 3 Injection Project as meeting the requirements of subparagraphs (A), (B) and (C) of Section 4993(c)(2) of the Code. Enclosed is a certified copy of the approval document from the Alaska Oil and Gas Conservation Commission and a completed Form 6458. ARCO Alaska, Inc., does also hereby certify that the approval by the Alaska Oil and Gas Conservation Commission is still in effect.

If you have any questions regarding this matter, please contact Ms. Judee Wells at (214) 651-2165.

Sincerely yours,

Paul B. Norgaard

PBN:JAW:clm

Enclosures

STATE OF ALASKA

ALASKA OIL AND GAS CONSERVATION COMMISSION

Re: IN THE MATTER OF APPLICATION BY ARCO ALASKA, INC. on behalf of the Prudhoe Bay Unit working interest owners for the approval of the Prudhoe Bay Unit Flow Station 3 Injection Project as a Qualified Tertiary Recovery Project for purposes of the Crude Oil Windfall Profit Tax Act of 1980.	Conservation File No. 187

DECISION IN THE MATTER
OF SUBJECT APPLICATION

DATED: November 29, 1982

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

INTRODUCTION

By letter dated September 23, 1980, the Honorable Jay S. Hammond, Governor, advised the Honorable W. Michael Blumenthal, Secretary of the Treasury, of his appointment of the Alaska Oil and Gas Conservation Commission as the jurisdictional agency over applications involving tertiary recovery projects on land within Alaska not under federal jurisdiction. The letter notification fulfilled the responsibility of the Governor of Alaska to provide a written submittal of agency designation in accordance with Section 4993(d)(5)(A) of the Internal Revenue Code promulgated from the Crude Oil Windfall Profits Tax Act of 1980.

August 31, 1982 the Alaska Oil and Gas Conservation Commission in its capacity as the designated jurisdictional agency received from ARCO Alaska, Inc. on behalf of the Prudhoe Bay Unit working interest owners an application for approval of their Prudhoe Bay Unit Flow Station 3 Injection Project as a qualified tertiary recovery project for purposes of the Crude Oil Windfall Profit Tax Act of 1980. ARCO Alaska, Inc. further requested under AS 31.05.060 that a public hearing be held on their application.

Notice of public hearing was published in the Anchorage Times on November 3, 1982. A public hearing was held in the Quadrant Room of the Captain Cook Hotel in Anchorage on November 19, 1982. The applicants testified in support of their application. There was no testimony offered in opposition to application.

Hearing proceedings are a matter of public record. The application and supporting engineering data are part of the record. The record on this matter was closed 11:45 AM AST November 19, 1982. The record is available for review by the public at the Commission's library, 3001 Porcupine Drive, Anchorage, Alaska.

FINDINGS

1. The Prudhoe Bay Unit Flow Station 3 Injection Project is confined to 3650 acres overlying a portion of the Prudhoe Oil Pool and contained 440,000,000 STB of original oil in-place or approximately 2% of the original oil in-place for the entire Prudhoe Oil Pool of the Prudhoe Bay Unit, a Department of Energy property.

2. The boundaries of the 3650 acre project area in the plan view are defined by the outer producing wells of inverted nine spot injection patterns to the east and west (strike direction of the Prudhoe Oil Pool); by the limit of development wells to the south (downstructure) and by the seven water injection wells to the north (upstructure).

3. The project boundaries in a vertical or cross-sectional view are provided by the Shublik formation (caprock) at the top and the immobile Heavy Oil/Tar Zone at the base thus subjecting to the project the entire light oil column of that portion of the Sadlerochit Reservoir which lies within the boundaries of the project area.

4. The Prudhoe Bay Unit Flow Station 3 Injection Project involves the alternating injection of enriched natural gas and water (WAC process) into eleven (11) inverted nine spot injection wells, all within the project area. Further the project involves forty-two (42) producing wells within or on the perimeter of the project area and seven (7) upstructure water injection wells along the northern perimeter of the project area.

5. Produced natural gas will be enriched with intermediate hydrocarbons to achieve an injectant fluid with a mole percent composition which approximates 42½% methane, 12½% carbon dioxide, 42½% intermediate hydrocarbons (C_2-C_6) and 2½% heavier hydrocarbons.

6. Theory indicates and laboratory bench tests confirm that the planned injectant fluid will be miscible with Sadlerochit crude at reservoir temperature and pressures greater than 3700 psi.

7. Reservoir pressure within the project area exceeds 3900 psi. Production and injection rates shall be controlled during the project life to offset reservoir voidage by injected volumes thus insuring that miscible pressures are maintained within the project area.

8. The projected Prudhoe Bay Unit crude oil production rates insure an adequate supply of intermediate hydrocarbons for gas enrichment to provide sufficient volumes of miscible fluid injectant to excede 10% of the reservoir pore volume within the project area.

9. Delay of miscible fluid injection until later in the field's productive life or following a conventional waterflood (secondary) program will jeopordize realization of additional oil recovery due to declining supply of intermediate hydrocarbon production necessary for adequate gas enrichment to achieve miscibility.

10. Testimony by the major working interest owners discloses that reservoir simulation model predictions indicate an additional 24,000,000 STB of crude oil will be recovered from the project area than other wise would be recovered by 80 acre well spacing and conventional (secondary) waterflooding. The 24 million barrels represents approximately 5.5% of the original oil in-place within the project area.

11. ARCO Alaska, Inc. as operator plans to commence injection of enriched natural gas into the project area around January 1, 1983.

CONCLUSIONS

1. The Prudhoe Bay Unit Flow Station 3 Injection Project qualifies as a qualified tertiary enhanced recovery project

within the meaning of Section 212.78(c)(1) of the Department of Energy (DOE) regulations in effect on June 1, 1979 and as amended August 30, 1979.

2. The delineation and planned operations for the Prudhoe Bay Unit Flow Station 3 Injection Project area ensure that the project area can effectively be treated as a separate property within an established DOE property for incremental oil purposes (IRC § 4993 (c)(2)(C) and (d)(3)).

3. The project beginning date is after May 1979 (IRC § 4993 (c)(2)(B)).

4. The Prudhoe Bay Unit Flow Station 3 Injection Project involves the application of a tertiary recovery method that is in accordance with sound engineering principles and is expected to result in more than an insignificant increase in the amount of crude oil than otherwise would be ultimately recovered. (IRC § 4993(c)(2)(A))

5. The Alaska Oil and Gas Conservation Commission is the appropriate jurisdictional agency (IRC § 4993 (d)(5)(A)(i)) to determine whether the Prudhoe Bay Unit Flow Station 3 Injection Projection qualifies as a qualified tertiary recovery project.

DECISION

The Alaska Oil and Gas Conservation Commission approves the Prudhoe Bay Unit Flow Station 3 Injection Project as a qualified tertiary recovery method meeting the requirements of subparagraphs (A), (B), and (C) of IRC § 4993(c)(2) for purposes of the Crude Oil Windfall Profit Tax Act of 1980.

DONE at Anchorage, Alaska and dated November 29, 1982.

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

ALASKA OIL AND GAS CONSERVATION COMMISSION

SUBSCRIBED and SWORN to before me this 30 day of November, 1982.

Notary Public, State of Alaska
My commission expires:

I, Bettyjane Ehrlich, Executive Secretary of the Alaska Oil & Gas Conservation Commission, swear that this is a true unaltered copy of the orginal Conservation File No. 187.

Bettyjane Ehrlich 11/30/82

EXHIBIT II-9

PROJECTED PRUDHOE BAY FIELD STATUS
ESTIMATED MID-1987 PRODUCTION AND INJECTION VOLUMES

A. Full Field Production and Injection Volumes:

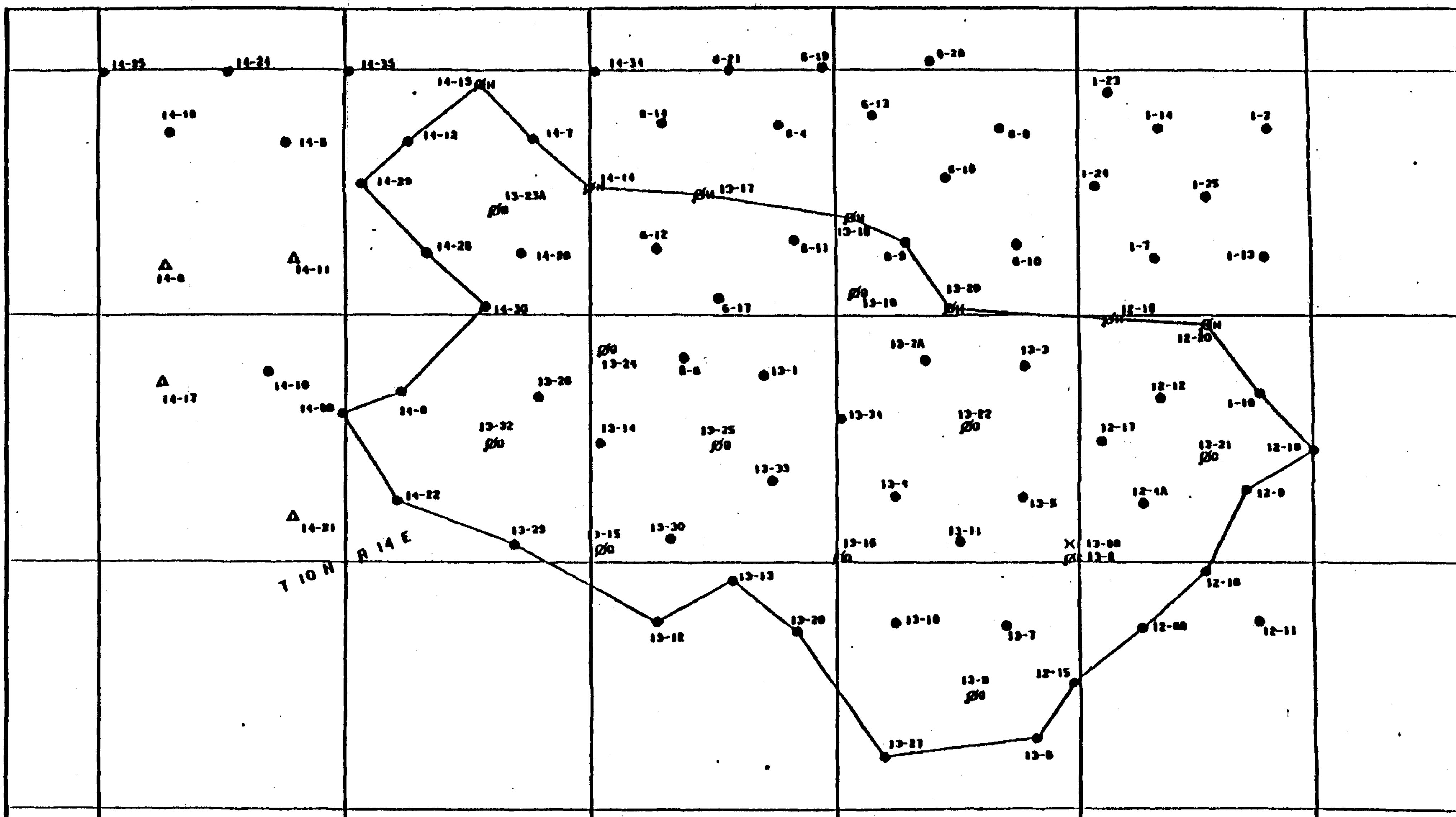
Production:				
	Oil			
		Rate :	1.2 to 1.5	MMBOPD
		Cumulative:	5.0	MMM STB
	Gas			
		Rate :	2.4	BSCF/D
		Cumulative:	6250	BSCF
	Water			
		Rate :	0.8 to 1.1	MMBWPD
		Cumulative:	0.6	MMMSTB
Injection:				
	Gas			
		Rate :	2.25	BSCF/D
		Cumulative:	5610	BSCF
	Water (Total)			
		Rate :	2.40	MMBWPD
		Cumulative:	2.03	MMMB

Average Field Pressure: 3850 psig

B. Waterflood Areas Production and Injection Volumes:

	NWFB	FS2	WPWZ
Cum Water Inj. (MMB)	600	880	430
Cum. Oil Rec (MMB)	500	1190	720

EXHIBIT II-10



LEGEND:

- ● OIL PRODUCER
- Δ WATER PRODUCER
- ØG GAS INJECTOR
- ØW WATER INJECTOR
- OBSERVATION WELL

WELL STATUS AT
TOP OF SADLEROCHIT
FORMATION

ARCO Alaska, Inc.

FLOW STATION #3
INJECTION PROJECT AREA

7/83	1"=2000'	20065J0201	KMJ	2

EXHIBIT II-11

DIRECTIONAL SURVEY DATA

(WELL 13-98)

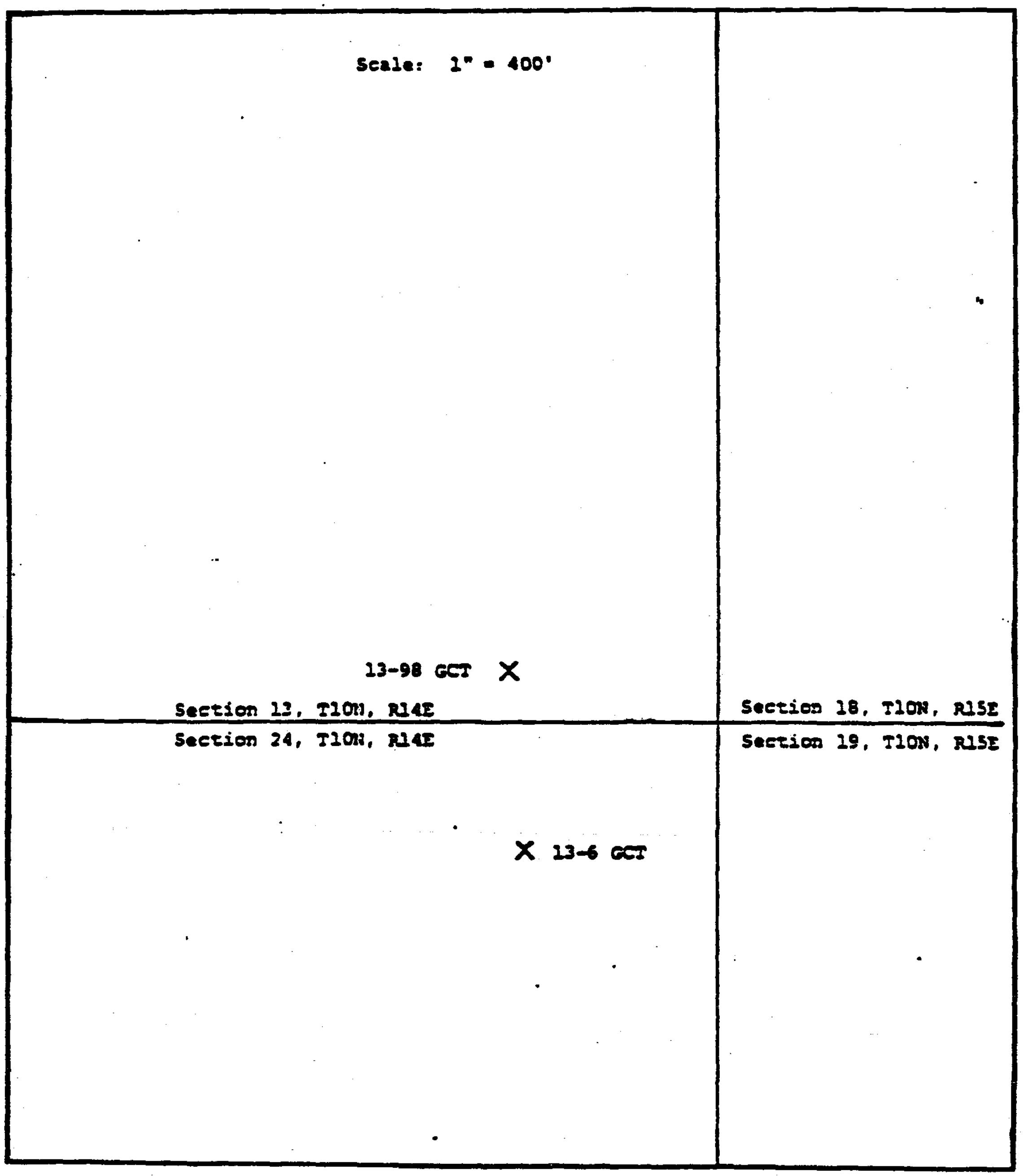
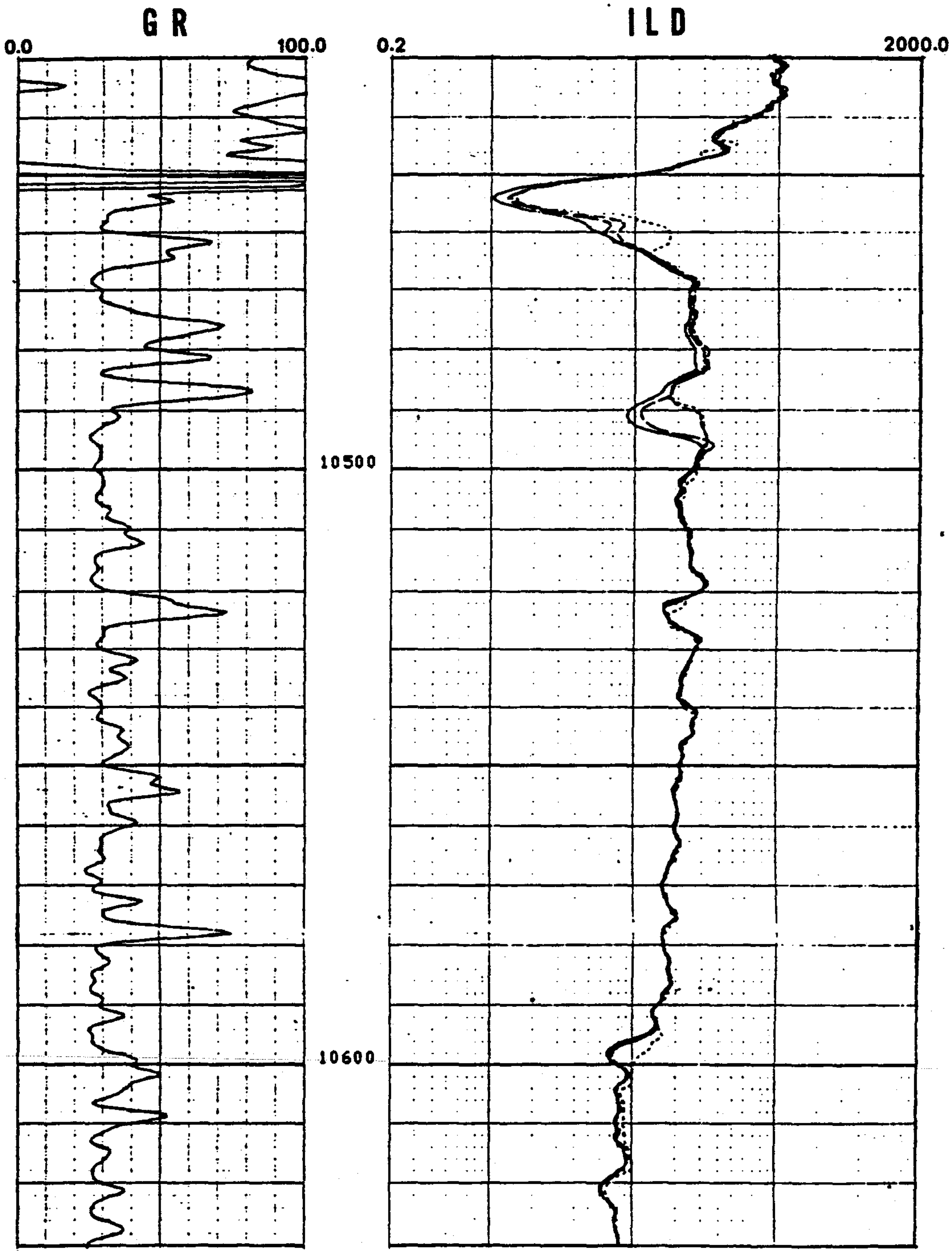


EXHIBIT II-12

DIL RESPONSE



LEGEND

9 · 30 · 83	———————
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1 · 14 · 83	----------------

WELL

13—98

PART III

PART III - PROJECT LOCATION

OVERVIEW

The PBMGP will provide miscible solvent for injection into the Sadlerochit reservoir. A ten-year average of approximately 200 MMSCF/D of miscible gas will be compressed for injection and distributed to the EOR target drill sites/pads. Because of the long lead times for Prudhoe Bay projects, the earliest possible start-up of miscible gas injection is 1987. AOGCC approval of the Project is one of many steps which will significantly enhance the chances of Project implementation.

In accordance with the screening criteria discussed in the following section, the EOR Project will be applied incrementally to the existing waterflood plans. The two processes are compatible and no major changes in waterflood implementation appear to be required based on our work to date. The waterflood areas were further studied to select the most attractive areas given a limited volume of injectant. About 10 percent of the reservoir light oil pore volume will be affected by the EOR process as planned. Most of the patterns will be the inverted nine-spots used for the waterflood.

Designing a process three years prior to start-up requires significant flexibility in planning. Performance data from the waterflood and the Flow Station 3 Injection Project may provide guidance for adjustments in implementation. The information in the following sections describes the Project as currently planned.

SCREENING CRITERIA FOR EOR TARGET AREAS

The implementation of PBMGP has been considered from the standpoint of applying the available miscible solvent volume in the most advantageous manner. The proposed average solvent injection rate of 200 MMSCF/D will be utilized to flood a reservoir volume of 4.9 billion reservoir barrels (RB). This is consistent with an average injection rate of 1 percent pore volume per year, taking into account a solvent formation volume factor of approximately 1500 SCF/RB.

The Project will encompass about one-third of the currently estimated waterflood pore volume. The Owners used several screening criteria to choose the most advantageous portions of the reservoir which would maximize the benefits within the target volume. The four principal factors considered are as follow:

a) Remoteness from regions with high gas saturation.
b) Light oil column at least 100 feet thick.
c) Most advantageous geological characteristics to maximize areal and vertical sweep efficiency.
d) Interference with or by processes in adjacent areas.

The first factor excludes regions under the original gas/oil contact, which combined with the second factor, implies selection within regions where waterflood is being implemented.

In order to evaluate the relative merits of the third factor, a variety of numerical approaches to modeling miscible displacement have been used, as well as analytical methods. The steady state theory developed by H. L. Stone (Reference 16) has been used for guidance. This theory shows that a dimensionless parameter, viscous to gravity ratio (VGR), is critical in determining vertical sweep efficiency. Better sweep efficiencies are provided by thick oil columns and low, but finite, effective vertical permeabilities. Thin discontinuous shales can provide a desirable reduction in effective vertical permeability. It is also advantageous to have a high permeability zone transmitting solvent horizontally below a communicating lower permeability zone.

The fourth factor is concerned with the possible effects that movement of free gas from the gravity drainage area may have on miscibility behavior, or alternatively, possible adverse effects that water or solvent movement into the main area may have on the efficient gravity drainage process in that area. A related possible influence is the directness of communication with the aquifer, which could result in high water/oil ratios at production wells and longer time intervals for producing additional oil.

Application of the above screening criteria has led to the potential choice of the regions shown in Exhibit III-1. Miscible flooding of all these regions would require more solvent than will be available (see Part IV). Further optimization then led to the selection of the Eastern and Western Miscible Regions delineated in the next section. The choice of these two regions was based on results from numerical simulation and a detailed review of the geology present in the target areas. These model results will be discussed in Part V. The two areas chosen represent our best estimate of the regions where miscible gas injection will be the most beneficial.

PROJECT AREA DELINEATION

Based upon the above considerations, two regions of the Field were identified as the best candidates for a miscible gas injection project. In the eastern portion of the Field, the chosen area (Eastern Miscible Region) encompasses all, or portions of, the following: Sections 1-3 and 9-24 in Township 10N, Range 15E; Sections 6, 7, 18 and 19 in Township 10N, Range 16E. In the western portion of the Field, the target area chosen (Western Miscible Region) encompasses all or portions of the following: Sections 1, 2, and 12 in Township 11N, Range 12E; Sections 5, 6, 7, and 8 in Township 11N, Range 13E; Sections 35 and 36 in Township 12N, Range 12E; and Sections 29 through 33 in Township 12N, Range 13E (Exhibit III-2).

In the Eastern Miscible Region, an inverted nine-spot pattern development is currently planned, with the possible exception of the southern and eastern edges where some modifications may be utilized. As indicated in Exhibit III-3, wells are currently planned to be drilled on 80-acre spacing. The Eastern Miscible Region will affect all or portions of Drill Sites 1, 3, 9, 12, 16, and 17 and the associated separation centers FS-1 and FS-2. Injection of miscible gas into 25 WAG injectors is expected to increase the oil recovery from the associated 107 producers. The actual development of the Eastern Miscible Region may be different as a result of further performance evaluation prior to the Project start-up. While not a part of this Project, the ongoing pattern waterflood to the north and west will serve to confine the miscible gas within the Project region, prevent contamination of the miscible fluid by encroaching gas tongues, and help maintain pressure above minimum miscibility conditions. Further confinement is provided by the sealing Lower Cretaceous Unconformity to the east and the downdip productive limit of the reservoir to the south. Region boundaries are defined by the outermost WAG affected production wells as shown in Exhibit III-4. The Eastern Miscible Region covers approximately 8,100 surface acres.

Much of the Eastern Miscible Region is characterized by massive, continuous shales which effectively separate the Sadlerochit into three productive zones: the Romeo, the Victor, and the Zulu. The Project is defined to vertically encompass the light oil column of the Sadlerochit as illustrated by the type logs of Exhibit III-5. Exhibit III-6 describes the method for determining the lower limit of the light oil column as determined by the heavy oil/tar (HOT) zone contact. The HOT zone will not be affected by the miscible gas injection because the oil is nearly immobile at reservoir conditions and solvent will be injected above it.

In the Western Miscible Region, an inverted nine-spot development is planned as depicted in Exhibit III-7. Skewed patterns will be based on an average 80-acre well spacing and the Project will affect all or portions of Well Pads M, N, R, and S and the associated GC-2. Injection of miscible gas and water into 17 WAG injectors is expected to increase oil recovery from 47 producers. The actual development of the Western Miscible Region may change as a result of waterflood performance evaluation prior to Project start-up. While not a part of this Project, the ongoing waterflood to the east will confine miscible gas within the Western Miscible Region, reduce contamination of the miscible gas by an expanding secondary gas cap, and help maintain the area pressure above minimum miscibility conditions. The Project is bounded on the north and west due to faulting. These same faults serve to define the Project boundaries to the north and west. The eastern boundary is defined as the outermost affected production wells, as shown in Exhibit III-8. The Western Miscible Region covers approximately 4,800 surface acres.

The Western Miscible Region vertically encompasses the light oil column of the Sadlerochit; that is the interval from the top of the Sadlerochit formation to the top of the heavy oil/tar zone. This delineation is illustrated by the sample log shown in Exhibit III-9.

PRODUCTION HISTORY WITHIN PROJECT AREA

For the Eastern Miscible Region, production began in June 1977 when eight wells from the DS-3 area came on stream. To date, 78 160-acre and one 80-acre wells are drilled for oil production as shown in Exhibit III-4. Through September 1983, 250 million barrels of oil, 13 million barrels of water, and 392 billion SCF of gas have been produced. Exhibit III-10 shows the production history of the area.

The Western Miscible Region consists of portions of Well Pads M, N, R, and S. Production from the area began in June 1977 when N-5 and N-8 came on stream. To date, 42 160-acre wells and 13 infill wells have been drilled (Exhibit III-8). Through September 1983, 112 million barrels of oil, 4 million barrels of water, and 75 billion SCF of gas have been produced. Exhibit III-11 shows the production history of the area.

GEOLOGIC AND RESERVOIR CHARACTERISTICS

General

The Sadlerochit Formation is subdivided into eight zones on the basis of petrophysical characteristics and shale distribution. Zones 1A, 1B, 2, 3, and 4 are defined by log characteristics and are subdivided by depositional time correlative horizons: Zulu, X-ray, Victor, Tango, and Romeo. The resulting eight zones (1A, 1B, 2A, 2B, 2C, 3, 4A, and 4B) are illustrated by the type logs in Exhibits III-12 and III-13 for the FS-2 and NWFB areas, respectively.

Zones 1A and 1B consist of mostly fine to very fine grained sandstones and thin interbedded shales deposited in a deltaic environment. Zone 1A is defined as a gradually coarsening upward transition at the base of this sequence; throughout most of the NWFB and FS-2 areas , the transition is more abrupt and Zone 1A is not present. Shales in Zones 1A and 1B are generally thin and appear to exhibit low to moderate continuity.

Zone 2A consists of mostly fine to medium grained sandstones with infrequent, thin, discontinuous interbedded shales. This sequence was deposited in a delta plain to fluvial environment.

Zone 2B consists of very fine to coarse grained sandstones and interbedded shales. The sandstones are probably representative of active channel fill and the shales are of flood plain deposition, all within a fluvial environment. The thick shale seen at the base of zone 2B in the type log appears to extend continuously over most of the NWFB area and the entire FS 2 area.

Zones 2C and 3 consist of predominately medium to course-grained sandstone and conglomerate with the percentage of conglomerate increasing upwards within the interval. These deposits were probably formed in a more proximal fluvial environment. Occasional shales in these zones are thin and discontinuous.

Zones 4A and 4B consist of very fine to medium grained sandstones with interbedding of thin shales deposited in a fluvial environment. The shales in these zones appear to exhibit low to moderate continuity.

Eastern Miscible Region

The Eastern Miscible Region occupies the south dipping peripheral and midfield portions of the FS-2 and southern portion of the FS-1 area. The gently dipping character is interrupted in the DS-12 to DS-16 peripheral area by a number of west-northwest/east-southeast trending faults which throw down both to the north and to the south. The displacements across these faults range up to 100 feet. The faults are generally believed to be nonsealing with the possible exception of the fault between 3-11 and 3-8 which, based upon pressure drawdown differentials, may be considered to be sealing over at least part of its length. The eastern limit of the Field, around DS-9 and DS-16, is defined by the progressive truncation of the Sadlerochit reservoir zones by the Lower Cretaceous Unconformity (LCU) which dips towards the southeast. These aspects are illustrated in the structure map, Exhibit III-14.

The original GOC at 8575 feet s.s. intersects the top of the Sadlerochit in the northern portion of the region. The OWC varies in depth from 9,000 to 9,080 feet s.s., generally being deeper towards the north-east, towards the LCU truncation area. Over most of the region, however, this surface lies between 9,010 and 9,040 feet s.s. The HOT isopach varies in thickness up to

80 feet but for the most part lies in the 20 to 50 foot range with no obvious areal thickening trends.

In this portion of the Field, Zone 3 is much more permeable than other zones as illustrated by the zonal averages in the following tabulation:

	Permeability (md)	Porosity (%)
Zone 4	300	23.2
Zone 3	1010	20.0
Zone 2	600	22.6
Zone 1	120	16.0

Although faulting is limited to the most down flank portions of the region, the faults do result in the juxtaposition of parts of zones which have differing average permeabilities.

Western Miscible Region

The NWFB is characterized by nonsealing faults which trend east-northeast/ west-southwest, and northwest/southeast. The east-northeast/west-southwest fault system is related to the regional Niakuk Fault System and is represented by three major fault zones which bound and divide the NWFB into northern and southern blocks. The vertical displacement of these faults ranges from less than 25 feet to 385 feet. The northwest/southeast fault system forms the effective western limit to this area. The interplay of these two fault systems form a complicated arrangement of fault blocks in the area west of M and N pads.

The Top Sadlerochit depth in the northern fault block varies from 8,650 feet s.s. in the west, to 8,900 feet s.s. in the east. In contrast, the southern block dips towards the southeast from an elevation of 8,500 feet s.s. at the central fault zone, to 8,700 feet s.s. along the southern fault zone. Exhibit III-15 depicts these relationships.

An original gas cap is present in the southern fault block with the gas/oil contact (GOC) at 8,575 feet s.s. No gas cap is present in the northern fault block, however. Generally the oil/water contact (OWC) dips gradually to the northeast, from about 8,990 feet s.s. in the west, to 9,050 feet s.s. in the northern part of the R pad area. The heavy oil/tar zone follows a trend similar to the OWC. The HOT thickens from 20 feet in the west to over 70 feet north of the R pad. The zonal distribution of the HOT depends upon its thickness and the structural relief. It ranges from occupying Zone 1B to Zone 3 in the north R pad area.

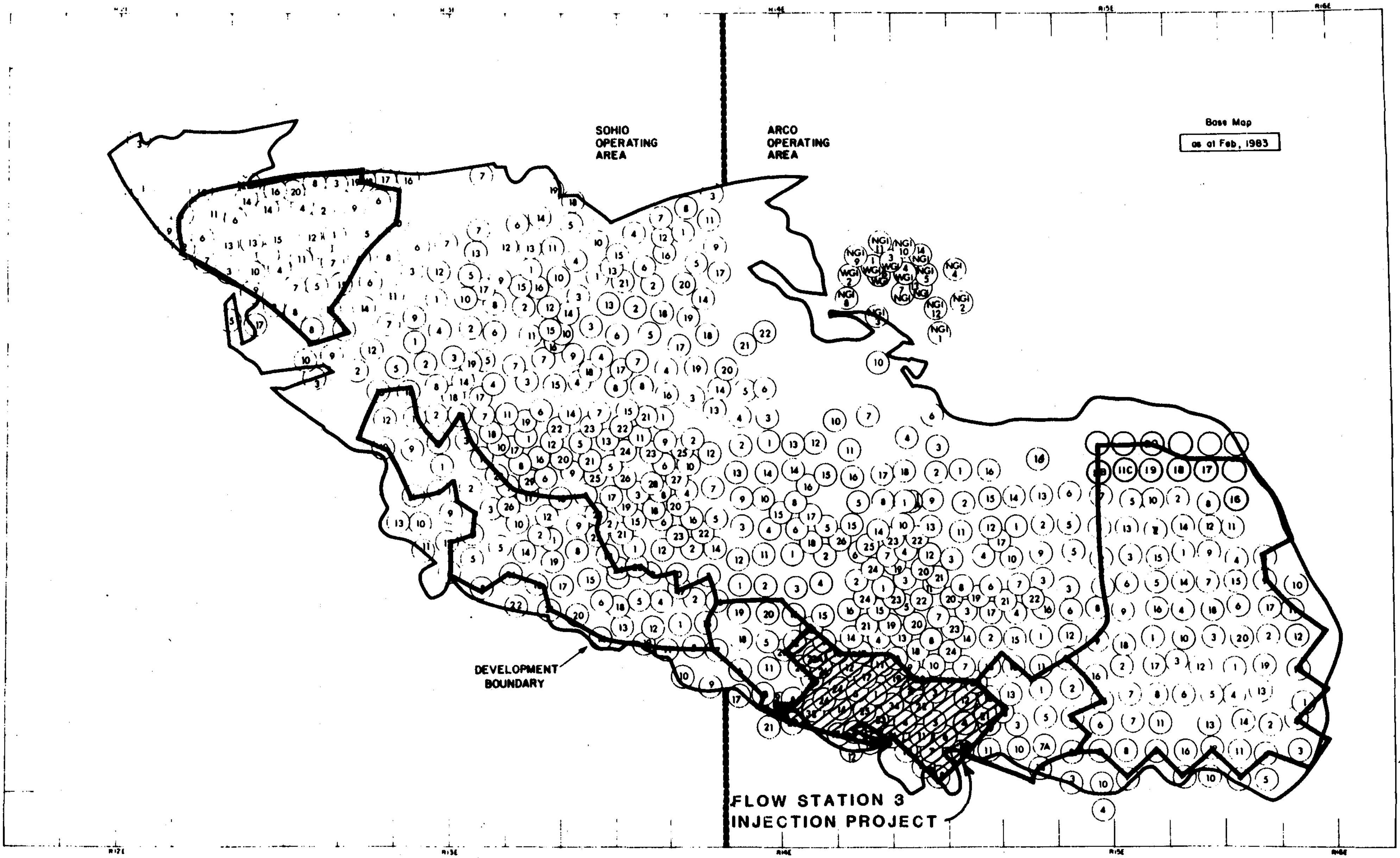
The top of the Sadlerochit structural configuration and the aforementioned fluid distributions, within the Project area, result in an original light oil column variation of 100 to 325 feet in the northern fault block and 300 to 400 feet in the southern fault block.

Based upon core analyses, average permeability and average porosity of the zones in the NWFB, excluding non-pay intervals, is as follows:

	Permeability (md)	Porosity (%)
Zone 4	250	23.3
Zone 3	1100	15.5
Zone 2	500	21.6
Zone 1	100	16.5

EXHIBIT III-1

POTENTIAL EOR TARGET AREAS



DWG. # PE-1-NS-S-1813

EXHIBIT III-2

PBMGP AREA

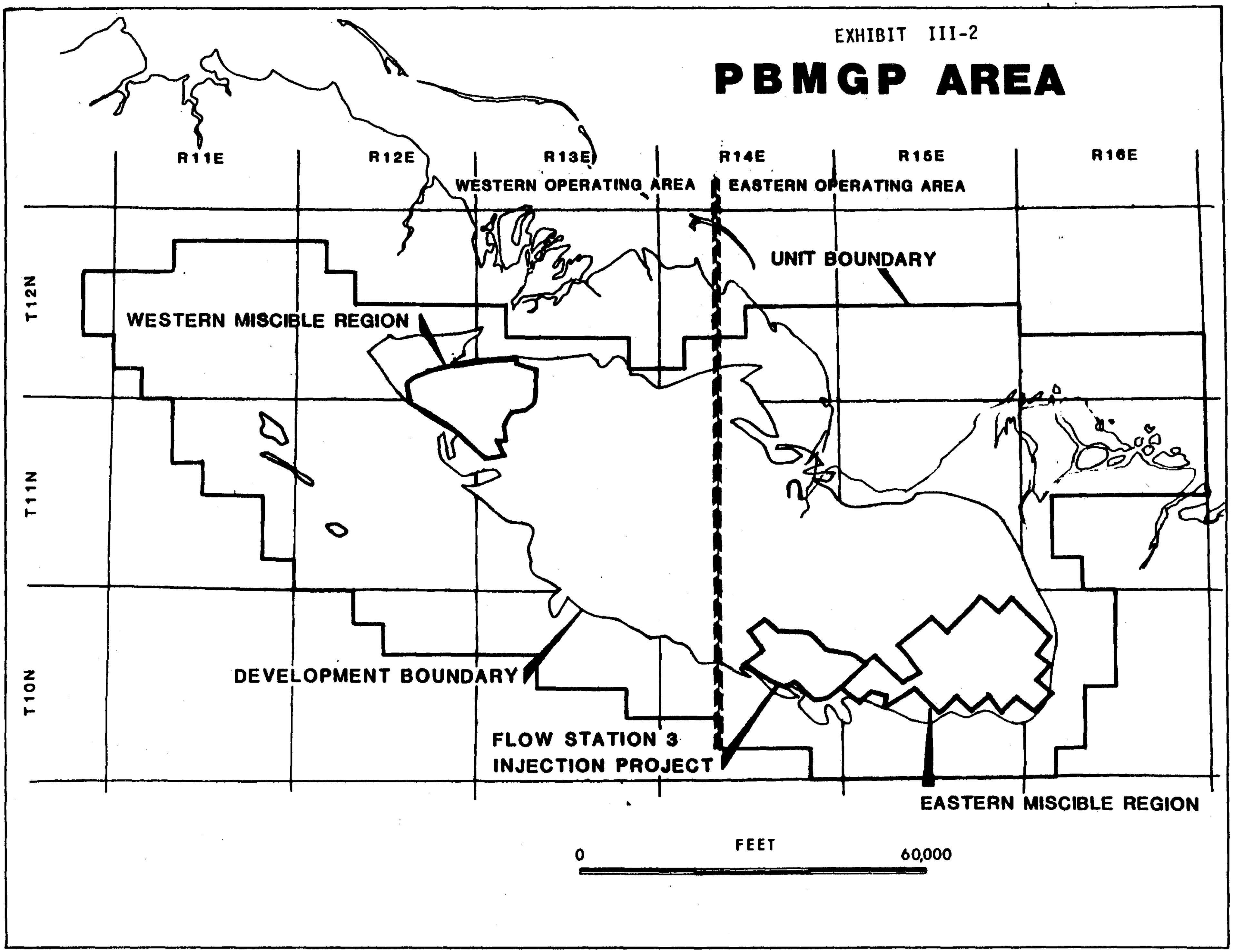


EXHIBIT III-3

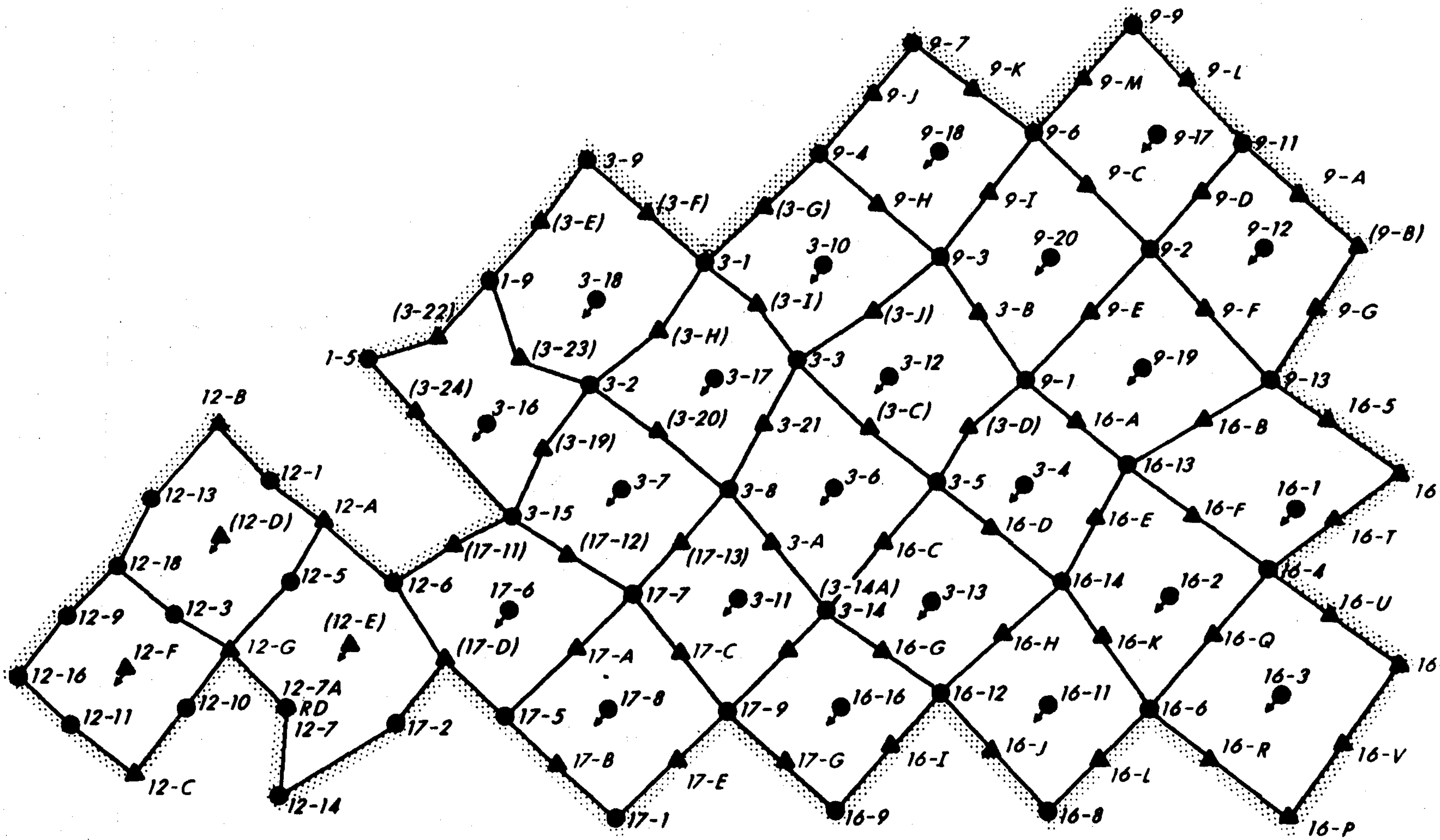
EASTERN MISCIBLE REGION DEVELOPMENT

Legend

● 160-ACRE WELL

▲ 80-ACRE WELL

INJECTORS



DWG. No. PE-1-NS-S-172

EXHIBIT III-4

EASTERN MISCIBLE REGION BOUNDARY

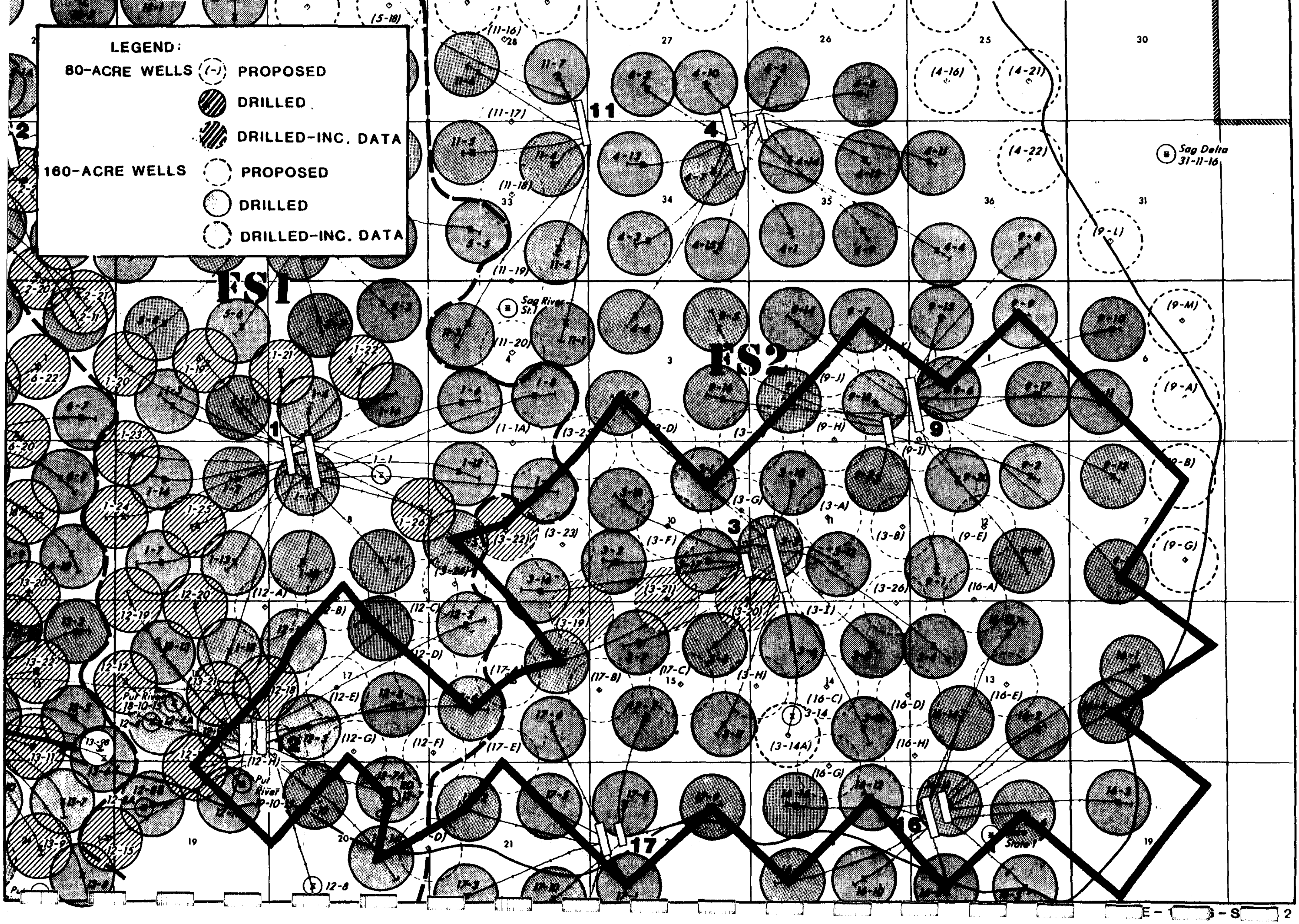


EXHIBIT III- 5

SAMPLE LOGS SHOWING VERTICAL DELINEATION OF PROJECT

Eastern Miscible Region

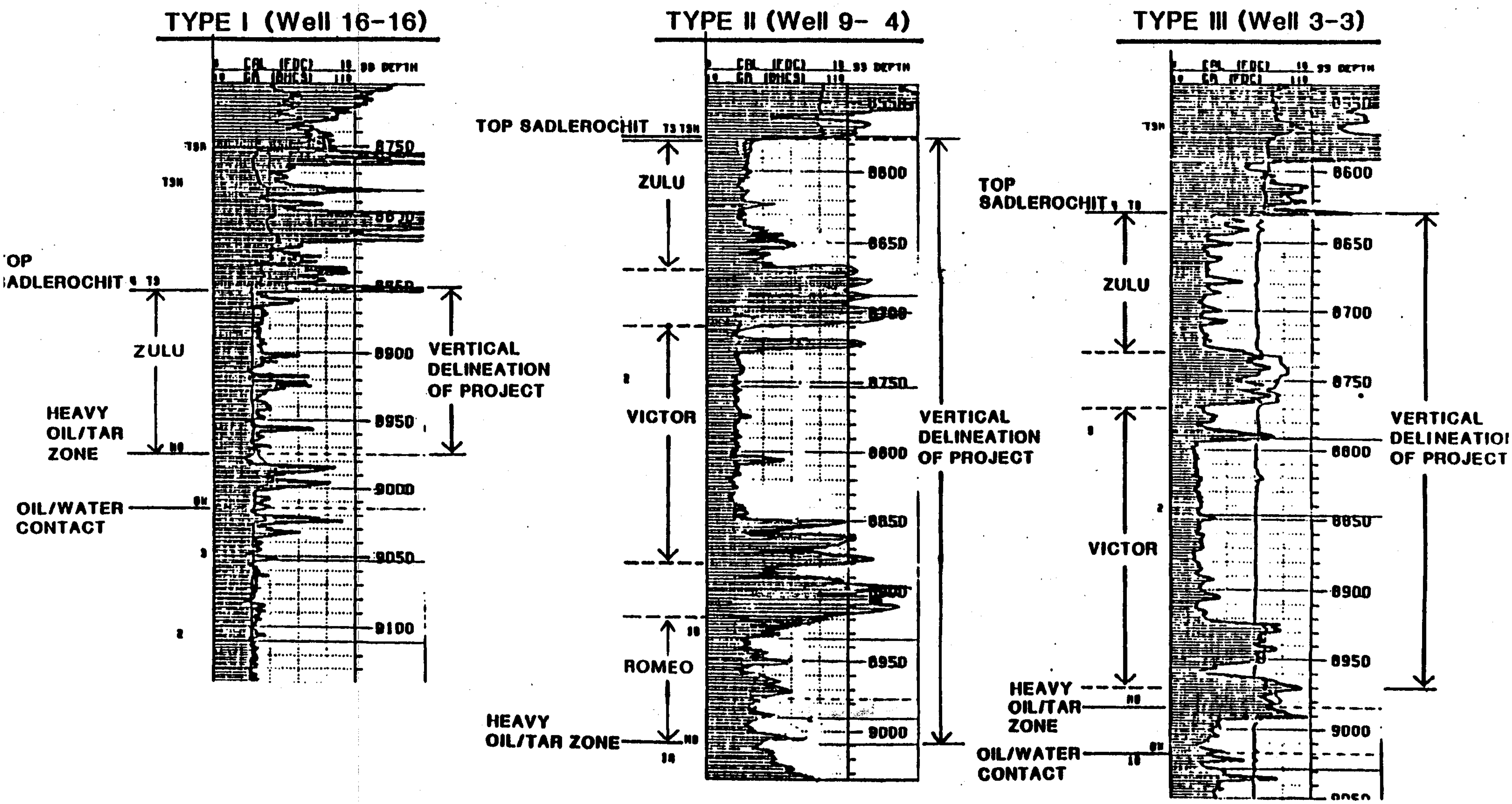


EXHIBIT III-6

PRUDHOE BAY UNIT

DESCRIPTION OF HEAVY OIL/TAR

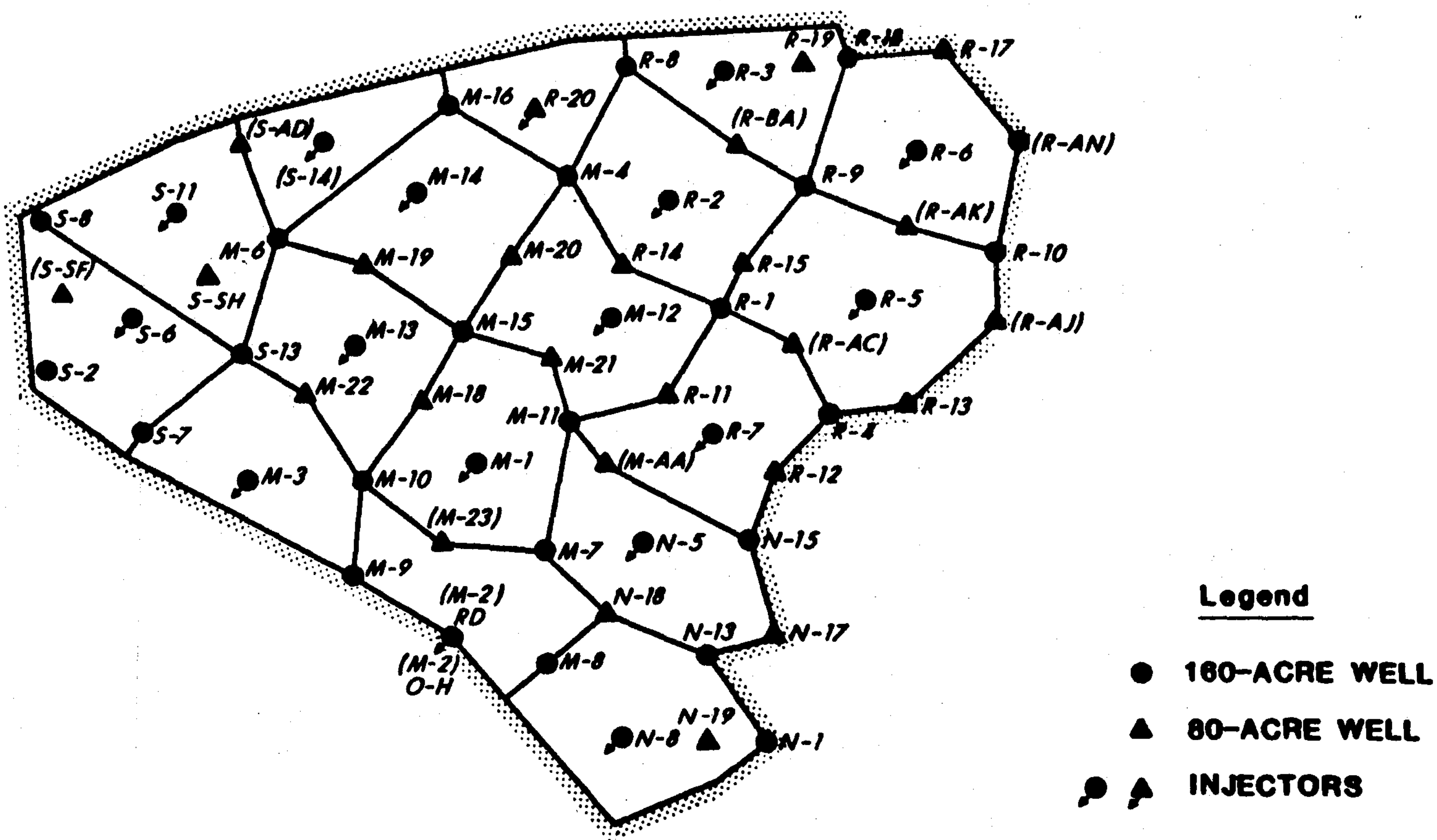
ZONE AND METHOD OF PICKING ZONE

The heavy oil/tar zone is a deposit of low gravity oil directly overlying the oil/water contact. Where a well is cored the zone is recognized by a dark brown or black color and has a marked increase in residual oil saturation compared to the overlying light oil zone.

In an uncored well there is an often coincident marked increase in the Laterlog 8 resistivity response compared to the Induction resistivity response. The increased LL-8 resistivity in the HO/T zone compared to the light oil zone above it is caused by the increased residual oil saturation (assuming that the conductive phase is mud filtrate in both cases).

EXHIBIT III-7

WESTERN MISCIBLE REGION DEVELOPMENT



DWG. No. PE-1-NS-8-172

EXHIBIT III-8

WESTERN MISCIBLE REGION BOUNDARY

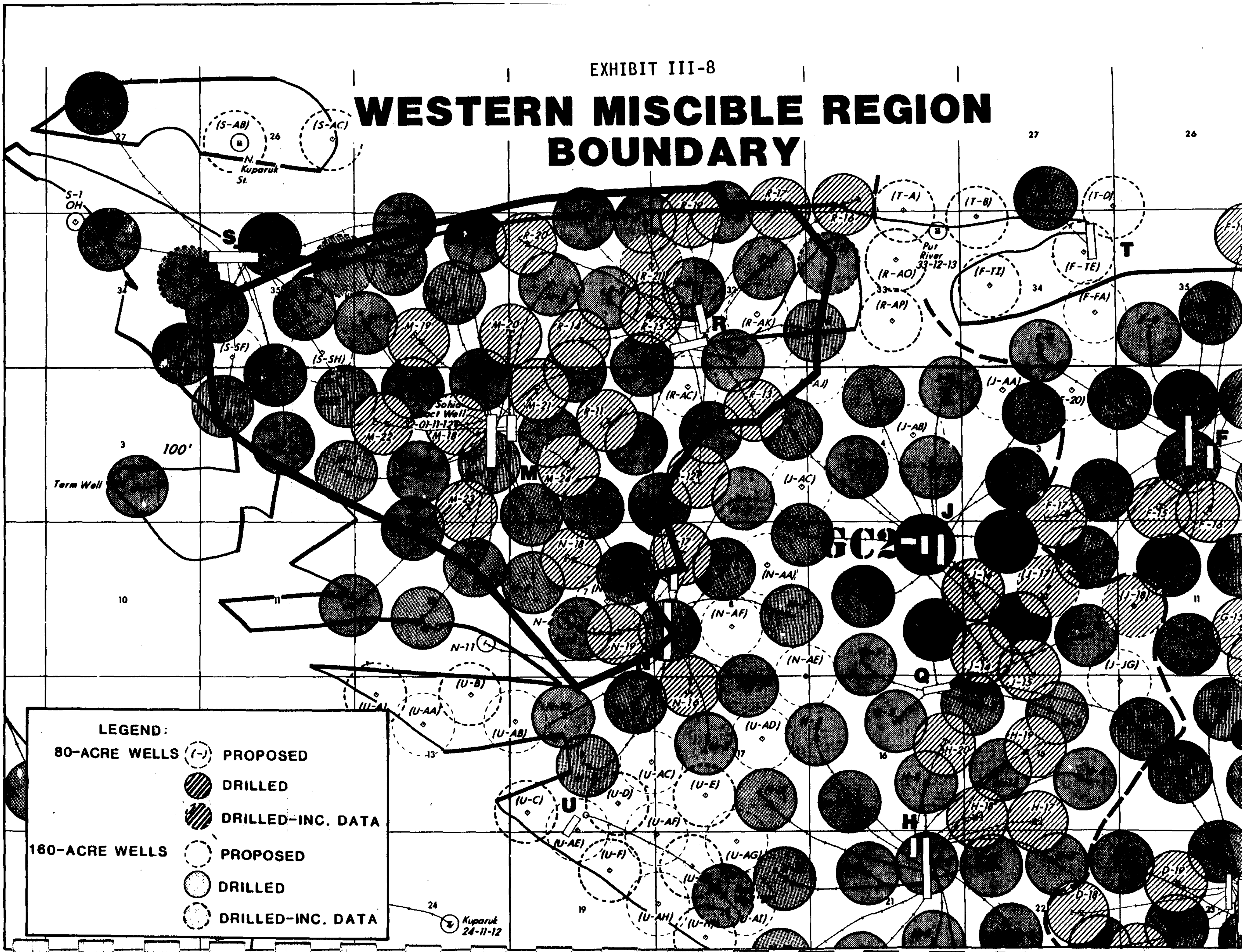
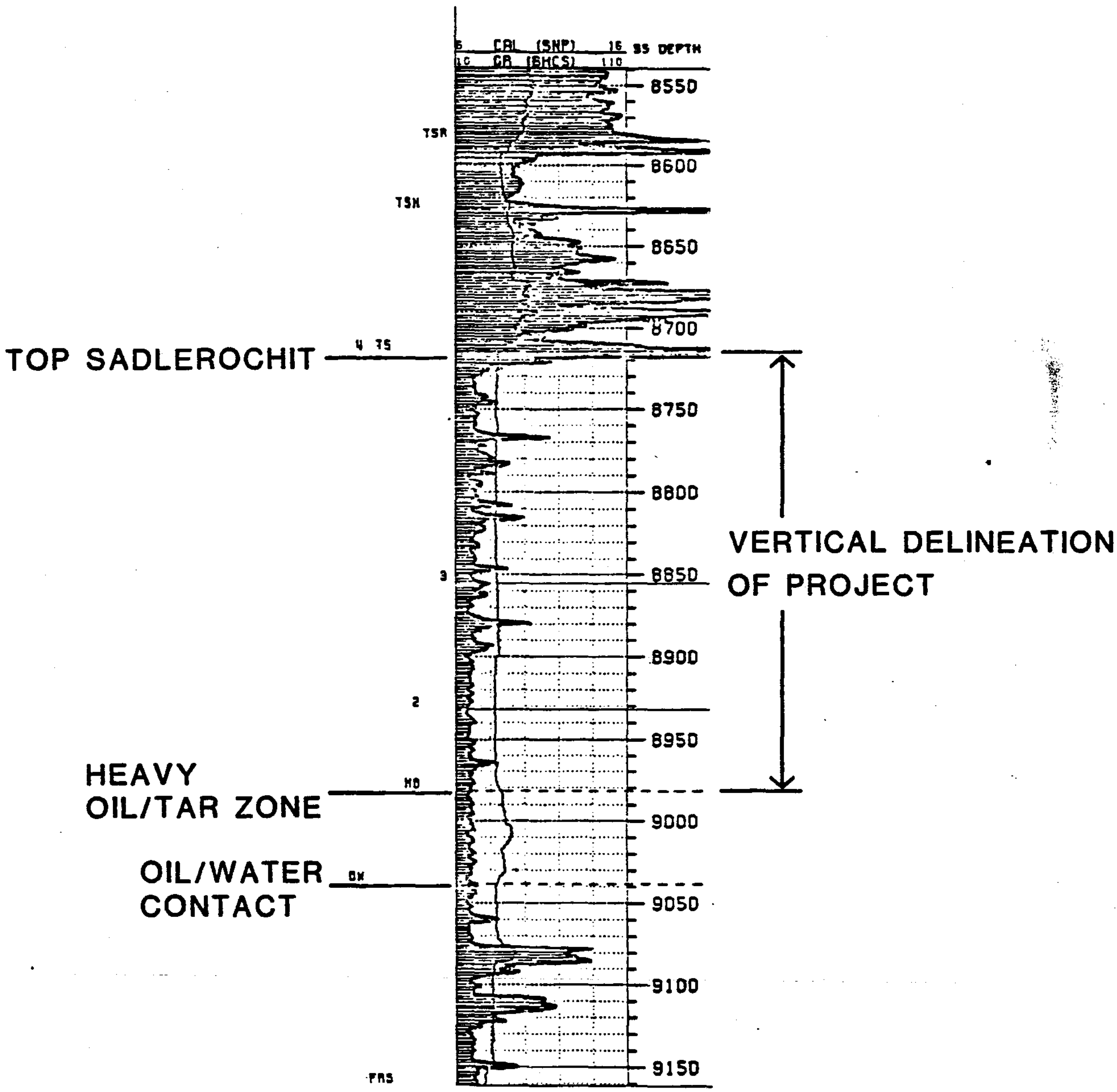


EXHIBIT III-9

SAMPLE LOG SHOWING VERTICAL DELINEATION OF PROJECT

Western Miscible Region

(WELL M-4)



DWG. Nº PE-I-NS-S-1721

EXHIBIT III-10

EASTERN MISCIBLE REGION

OIL, GAS, AND WATER PRODUCTIONS

JUNE 1977 - SEPTEMBER 1983

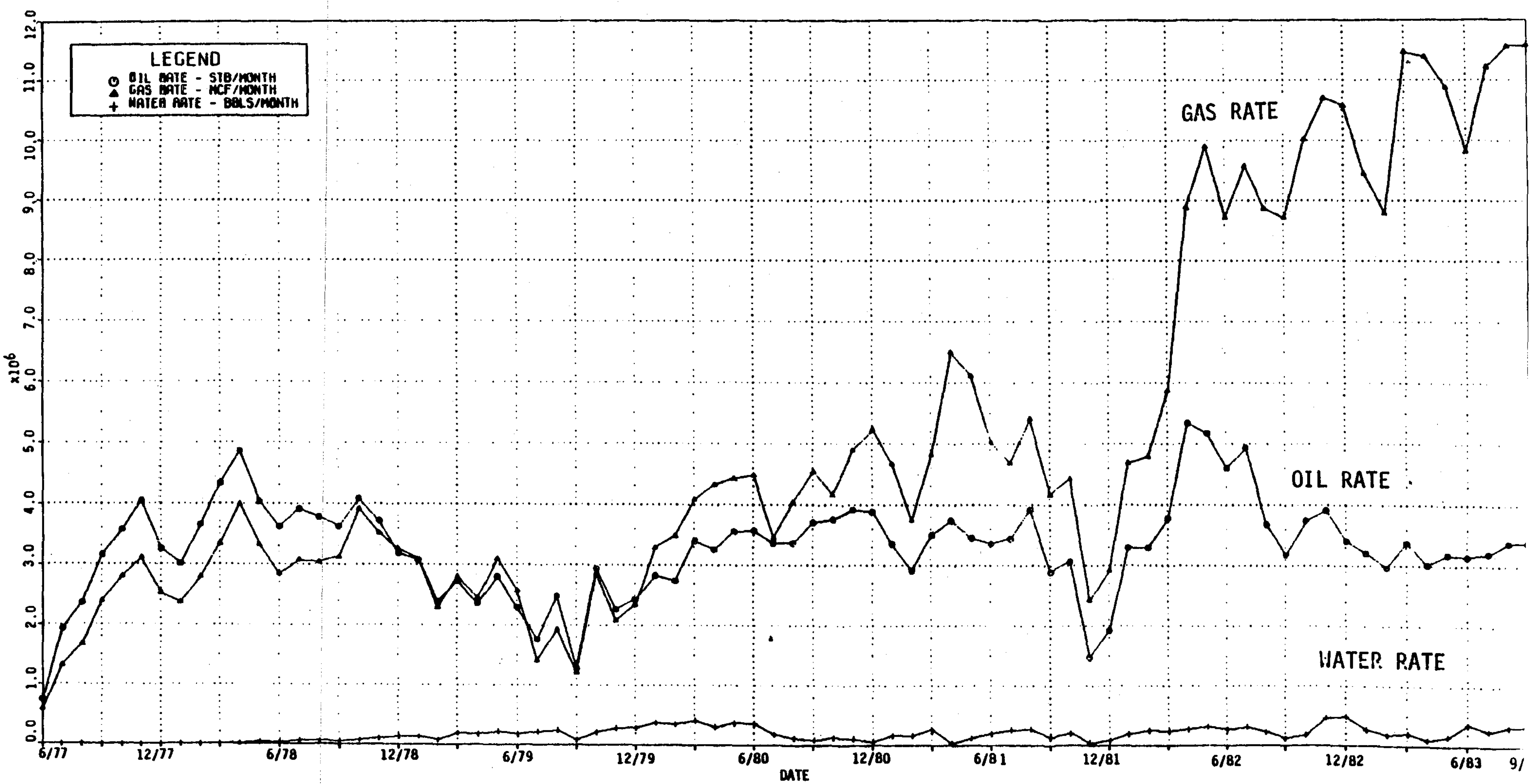


EXHIBIT III-11

WESTERN MISCIBLE REGION
OIL, GAS, AND WATER PRODUCTIONS
JUNE 1977- SEPTEMBER 1983

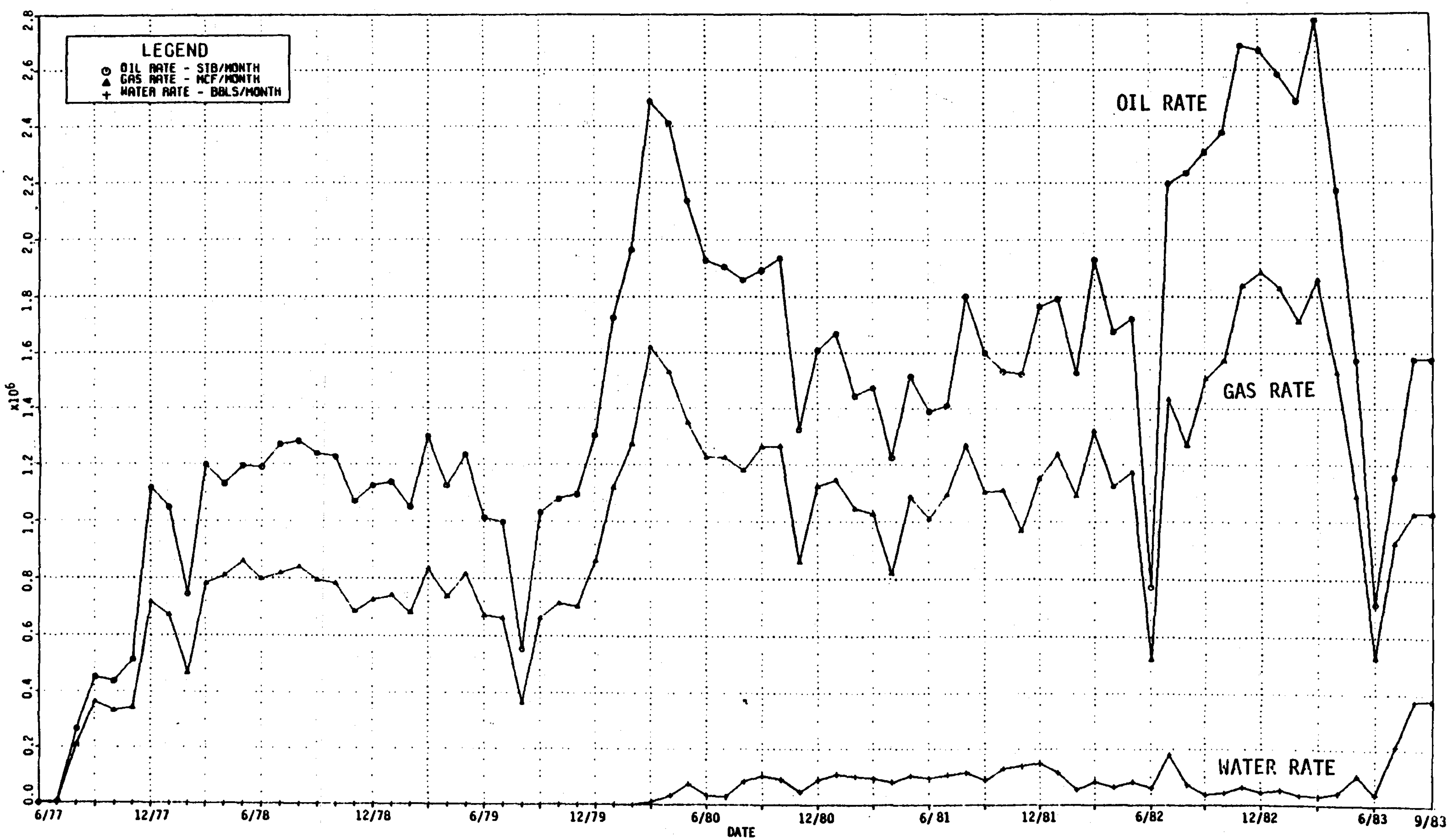
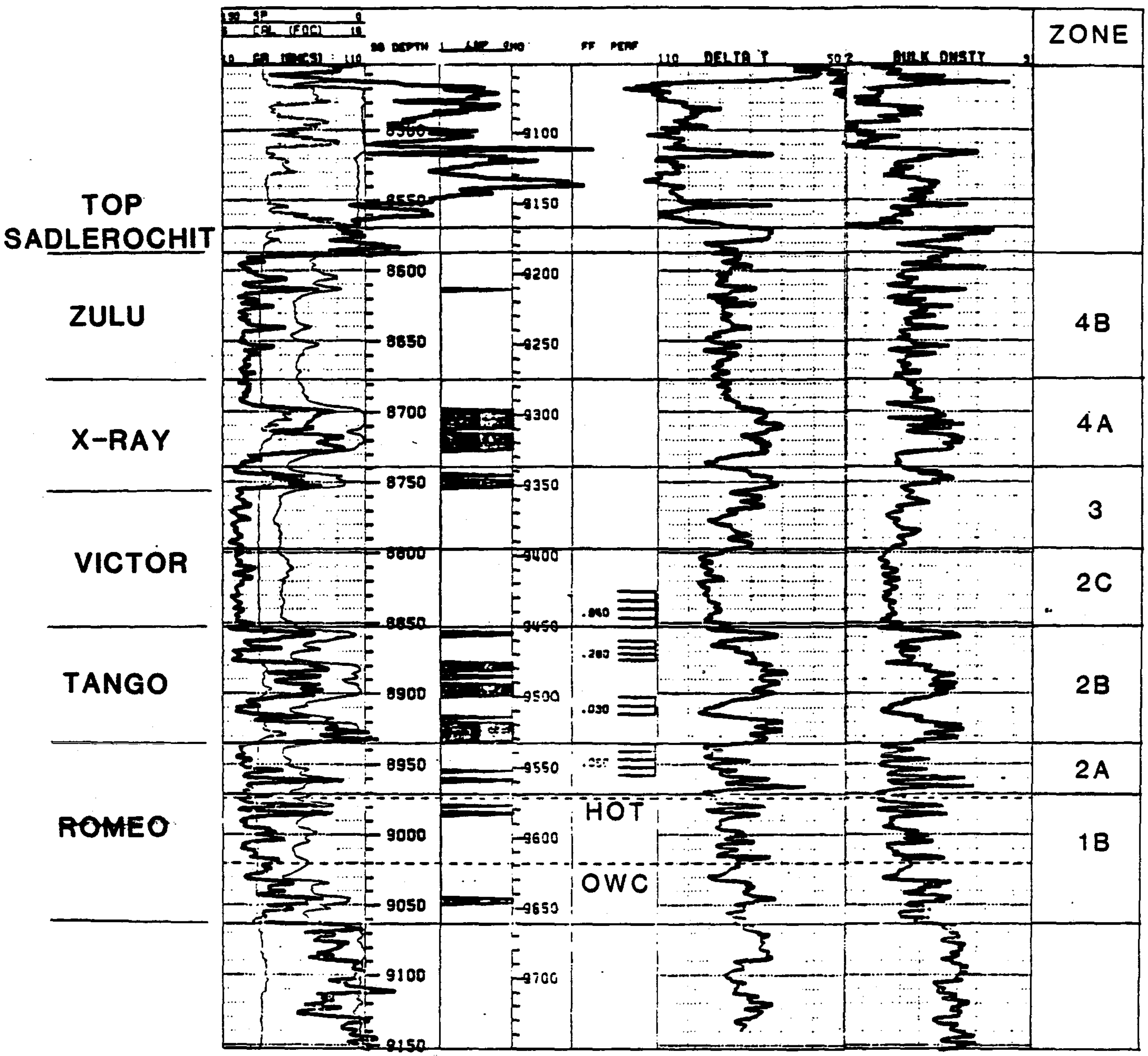


EXHIBIT III-12

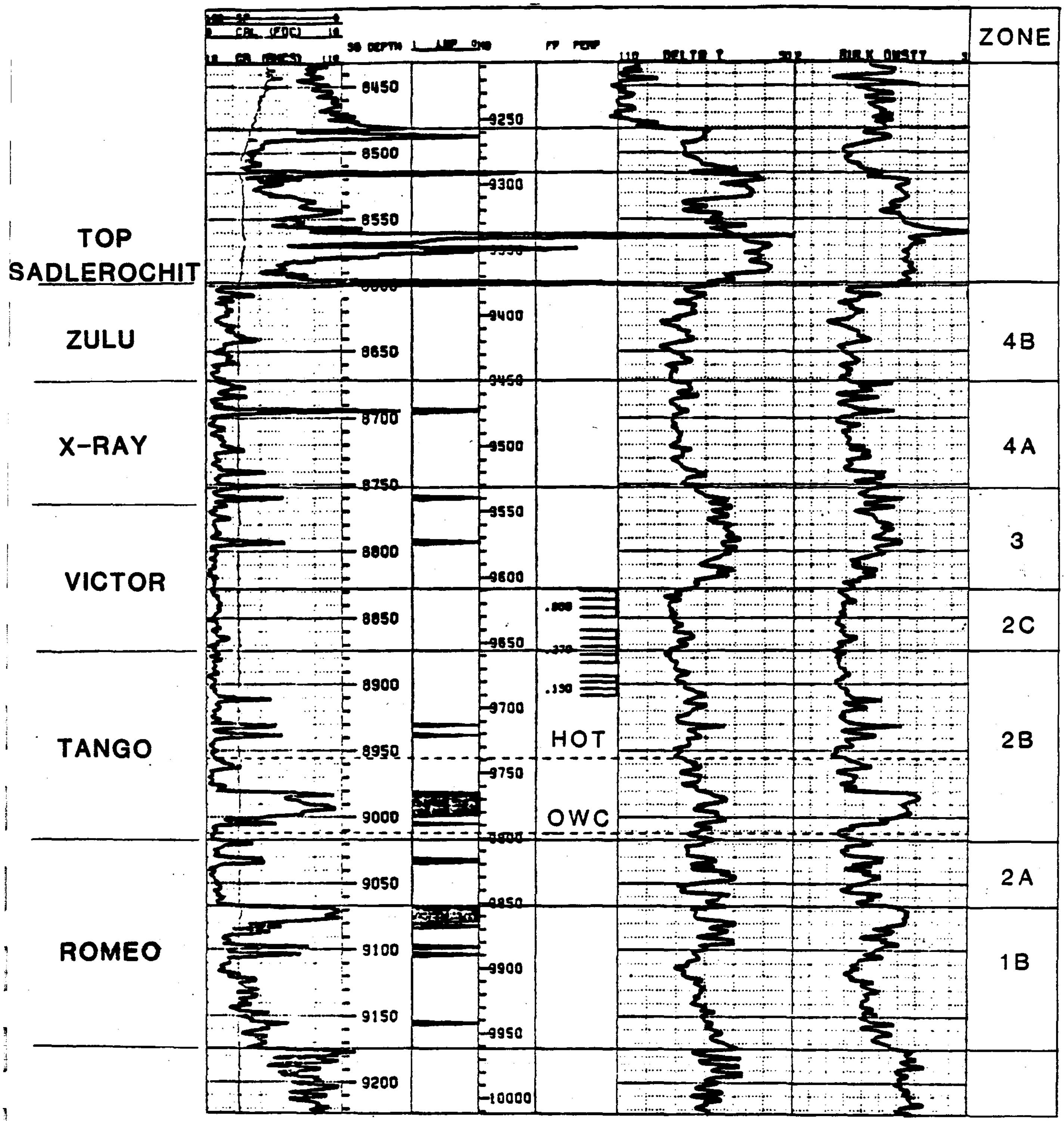


PERFORATION INTERVAL

MD		SS		FF	DATE	TYPE
9425.00-	9450.00	8827.37-	8852.37	.840	04/12/80	
9460.00-	9474.00	8862.37-	8876.37	.280	04/12/80	
9500.00-	9512.00	8902.36-	8914.36	.030	04/12/80	
9533.00-	9555.00	8935.36-	8957.36	.050	04/12/80	

PRUDHOE BAY UNIT
FLOW STATION 2
TYPE LOG
(DS 3-10)

EXHIBIT III-13



PERFORATION INTERVAL

MD		SS		FF	DATE	TYPE
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9640.00-	9655.00	8858.71-	8883.28	.270	04/14/80	
9675.00-	9690.00	8893.08-	8907.81	.130	04/14/80	

PRUDHOE BAY UNIT
NORTH WEST
FAULT BLOCK
TYPE LOG (W P M-7)

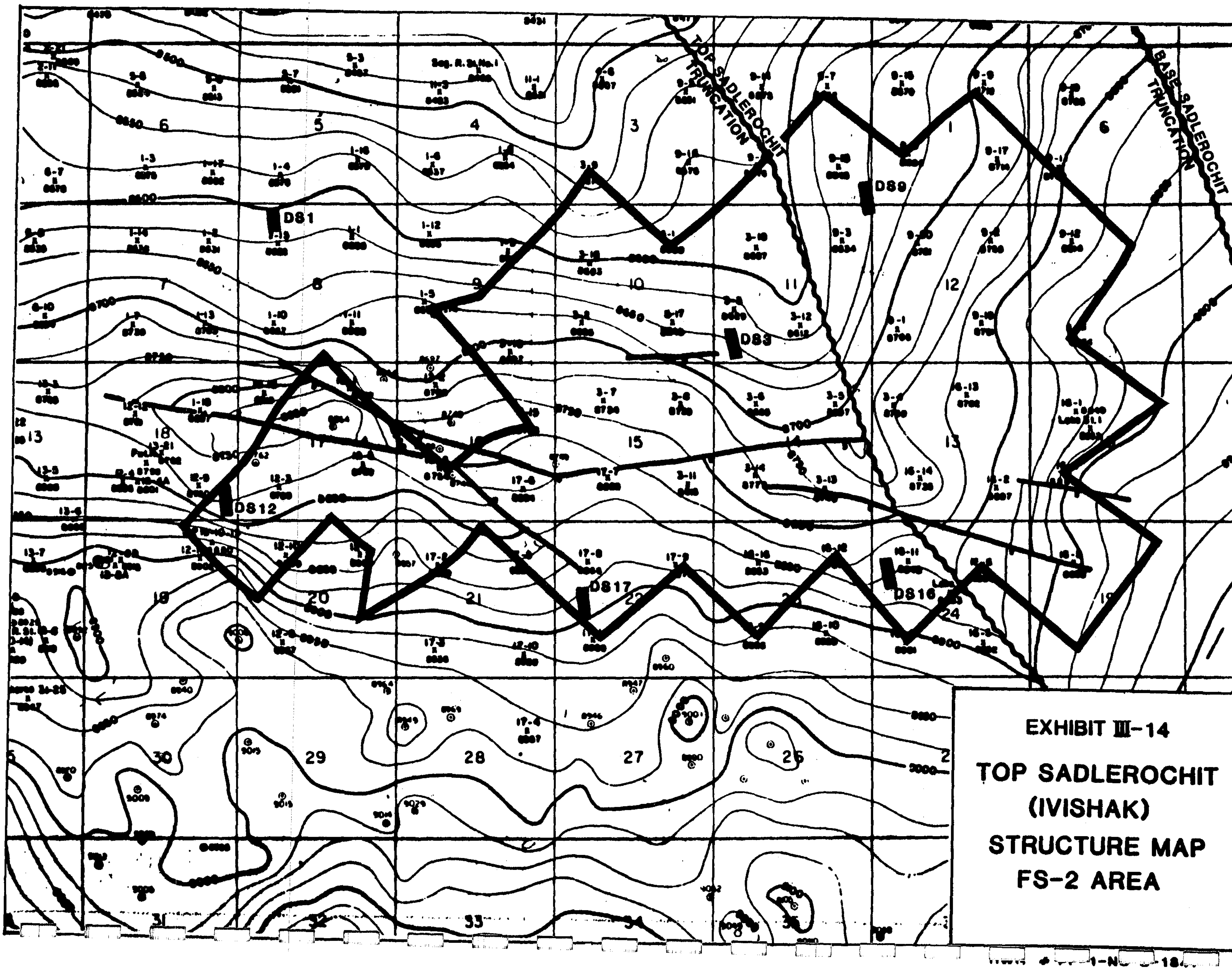


EXHIBIT III-14

TOP SADLEROCHIT (IVISHAK) STRUCTURE MAP FS-2 AREA

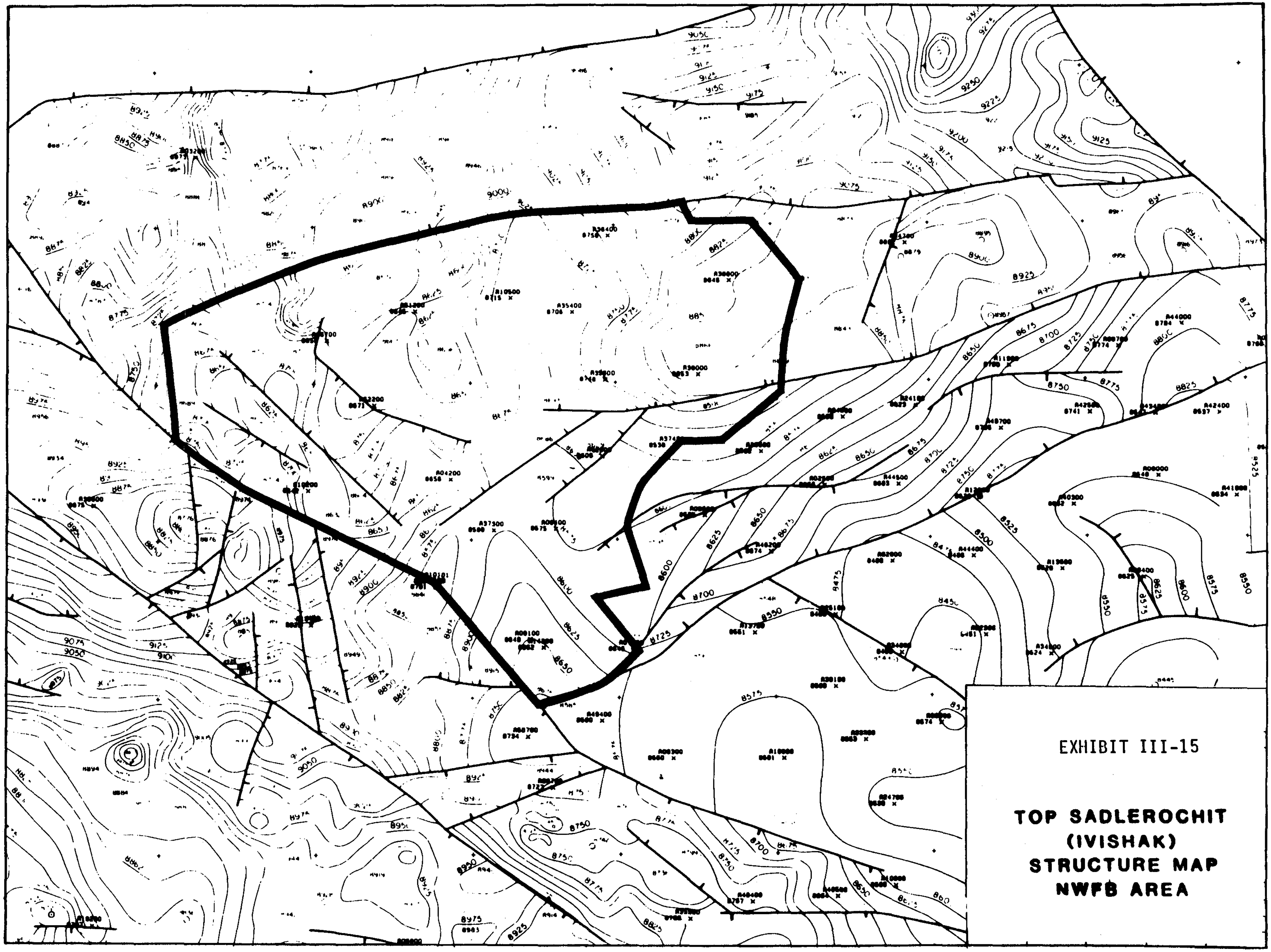


EXHIBIT III-15

TOP SADLEROCHIT (IVISHAK) STRUCTURE MAP NWFB AREA

PART IV

PART IV - PROJECT DESIGN AND OPERATION

PROJECT DESIGN PHILOSOPHY

The PBMGP design objectives are to (1) inject an enriched gas that will miscibly displace crude oil, (2) make maximum effective use of available solvent volumes, (3) maintain operational flexibility, and (4) minimize impact on non-EOR portions of the Field. Part III described the screening criteria used to define target patterns within the constraints of solvent availability and an average injection rate of 1 percent PV/yr. The most efficient use of solvent within this target area depends primarily on controlling volumetric sweep efficiency and maintaining flexibility to react to variations in performance history. The primary considerations in achieving these goals are the enrichment required to maintain miscibility, viscous-to-gravity ratio, water-alternating-gas (WAG) ratio, and pattern development.

Minimum Miscibility Pressure

The solvent enrichment requirements to achieve miscibility have been determined by equation-of-state calculations and by correlations derived from experiments. The primary data used were nine slim tube experiments performed with Sadlerochit crude displaced by various mixtures of enriched methane gas at 195-200^{o}F. Corresponding to the anticipated solvent composition, an MMP of 3600 psia was derived from these data and was used for Project design studies. The Field average pressure at mid-1987 is expected to be 3850 psia, thus the MMP margin is approximately 250 psia.

Additional slim tube experiments have recently been performed with enriched methane injectants specific to our current plant design. Two sets of crude samples were taken from the NWFB and FS-2 areas. Duplicate MMP slim tube experiments with NWFB and FS-2 area crudes have been conducted at respective reservoir conditions by both Sohio Alaska Petroleum Company (SAPC) through BRTR Petroleum Consultants, Ltd., and ARCO Alaska, Inc., through Core Laboratories. Preliminary results indicate that the design solvent MMP may be 400 psi lower than previous estimates. Thus the margin may be somewhat greater than indicated above.

Viscous-to-Gravity Ratio (VGR)

Oil recovery by WAG flooding often is limited by gravity segregation which causes the injected gas to rise to the top of the formation and water to migrate to the bottom. This results in a relatively thin layer at the top of the reservoir and a region immediately adjacent to the wellbore where the miscible gas will be effective in displacing oil. The size of the miscibly swept zone around the wellbore can be correlated with a dimensionless parameter constituting the ratio of viscous flow forces to gravity forces (Reference 16):

$$VGR = \frac{Q}{k_V \; M_W \; \Delta\rho \; A}$$

where Q = Total injection rate

k_V = Vertical permeability

M_W = Total mobility of WAG fluids

$\Delta\rho$ = Density difference between water and gas

A = Pattern area.

For operating conditions typical of the range anticipated at Prudhoe Bay, recovery is approximately a linear function of VGR; that is, higher values of VGR correlated with improved volumetric sweep.

Operationally, the only parameters appearing in the VGR that can be controlled are injection rate (Q), injection fluid mobility (M) and pattern area (A). Actually over the range of potential WAG ratios, mobility is relatively constant and therefore, recovery is most influenced by pattern area, i.e. well spacing, and total fluid injection rate. On the basis of these considerations, a maximum nominal pattern size of 320 acres was selected. The viscous-to-gravity ratio formulation also indicates fluid injection rate should be maximized. This is consistent with maintaining reservoir pressure and as discussed below, optimizing volumetric sweep for a given solvent injection rate.

Water Alternating Gas Ratio

Present plans are to use the Water Alternating Gas method for PBMGP injection. This method has been effective for improving sweep efficiency in other field applications. In this method injected water maintains a high water saturation behind the flood front, and therefore the total mobility of the injected fluids is less than if only gas were being injected. In general, higher WAG ratios lead to lower mobility ratios. The resulting decrease in mobility ratio tends to increase areal and vertical conformance.

Water Alternating Gas injection has been used with the objective of achieving simultaneous water and gas flow in the reservoir outside the small volume surrounding the injection wells. Attempts to inject water and gas simultaneously have been unsatisfactory because of gravity segregation of the fluids in injection wellbores with the result that gas was injected into the top of perforated intervals and water into the bottom. Core flood results show that low residual oil saturations of 2 percent or less are obtained when the miscible gas and water are flowed alternately through cores (Reference 17-23). Conceptually, a desirable arrangement would be to inject gas into the bottom and water into the top of each vertically continuous oil zone. The PBU owners are considering the feasibility of equipping injection wells so that water and gas can be maintained as separate streams and injected simultaneously into separate perforated intervals, with the gas injection perforations located below the water injection perforations. Segregated simultaneous injection may be tried in a Flow Station 3 Injection Project well. If found to be beneficial, the method may then be used in PBMGP wells which have characteristics favorable for segregated simultaneous injection.

Solvent will be injected into each pattern at an average rate of 1 percent PV/year. In general, water will be injected to the extent necessary to offset pattern voidage, provide pressure support, and minimize the impact on adjacent non-EOR patterns. Over the Project life certain operational considerations (e.g., premature solvent breakthrough) may dictate adjustments to WAG ratio for a particular pattern. Laboratory core floods using Sadlerochit core have shown no decrease in incremental recovery for WAG ratios exceeding 10 (Reference 24). Although an upper limit of 5 will be imposed as a general operating guideline on the Field-wide WAG ratio, actual performance may dictate utilizing a higher WAG ratio in individual patterns for short time periods.

Pattern Development

Large strip model simulations have indicated that a pattern flood is superior to line drive for Prudhoe Bay applications. As stated above, viscous-to-gravity ratio analysis indicates significant recovery can be obtained with a pattern size as large as 320 acres. These considerations, plus the requirement for maximum flexibility and process control, led to the selection of 320-acre inverted 9-spot patterns for implementing the PBMGP. The inverted 9-spot pattern was selected because of its flexibility in conversion to other pattern configurations should conditions warrant after Project startup. This flexibility is desirable due to the sensitivity of the WAG process to geological uncertainties. Alternate configurations which may be developed from the inverted 9-spot include a line drive pattern capable of being oriented in four different directions to overcome adverse directional permeability and a 5-spot pattern should it become attractive to reduce pattern area. Initial development with the inverted 9-spot is also preferred for its 3-to-1 producer to injector ratio. This will allow more versatility in maintaining the balance of injection and withdrawals required to sustain reservoir pressure within any particular pattern, and to control fluid movements across pattern boundaries. Thus, the Project design includes flexibility for controlling flood performance.

INJECTION PLAN INTERFACE WITH WATERFLOOD

The impact of EOR on waterflood plans was evaluated for the following aspects: zonal control, ultimate injection well count, conversion timing, ultimate water injection volumes, waterflood implementation/operating strategies, and perforating and well completion.

While zonal control is not initially planned for waterflood or EOR, it is recognized as a potential requirement, especially in the FS-2 area where continuous shales are prevalent. Means for zonal control currently under consideration include selective perforations, downhole chokes, polymers to restrict fluid entry, and twin injectors. If field performance dictates, careful consideration will be given to the use of these or other methods.

The Project encompasses 42 patterns and affects 196 wells of which 154 are planned as producers. Only patterns targeted for waterflooding were considered for possible miscible flooding. If mechanical profile control is desired in an injector, an additional injector may be used to achieve effective control. Most injectors will be converted 160-acre producers (38), although some 80's may become injectors. Some nine-spot patterns may not have their full complement of 80-acre side wells. Along the southern border of FS-2 where the zones have been truncated, the reduced oil column thickness makes infill drilling marginal.

No significant conversion efforts will be required once the gas manifold is linked to the well. Each well will begin injection as the WAG cycle permits.

Preliminary EOR plans have not affected forecasted water injection volumes. Water volumes will undergo further optimization for waterflood effectiveness; and after EOR start-up, water and gas volumes will be optimized together to achieve cost effective displacement at reasonable WAG ratios.

Both waterflood and EOR processes will be applied on a pattern basis. Each pattern's production and injection will be examined to provide efficient displacement and to maintain a reasonably balanced system. Each area will be similarly examined to balance the system and maintain the pressure.

Current waterflood plans include only simple single tubing completions with most of the zone perforated. Minor changes in perforating philosophy may accompany Project implementation. For water injection, perforating to the top of the zone is optimum; while for miscible gas injection, the top of the zone should be avoided.

PROJECT OPERATION

As mentioned previously, waterflood injection will have been in progress for approximately three years prior to PBMGP startup in the second half of 1987. Thus, all the proposed WAG injection wells will have received substantial amounts of water injection during 1985 to 1987. The water injected into the Project Area before startup will dissipate local areas of high gas saturation and create a safety margin between average pressure and minimum miscibility pressure of the enriched gas. Waterflood surveillance by pressure tests, production logging, and neutron logs will be used to confirm these conditions, and history-matched reservoir simulation studies will also be used to confirm the reservoir conditions. The results of such studies will be used with detailed miscible WAG predictions to select an optimum startup schedule.

At Project startup, a selected set of water injectors will be converted to enriched gas injection for a period of one to three months. After this period, source water will be injected into these initial wells, thus beginning the normal water-alternating-gas process, and another set of injectors will be converted from water to miscible gas injection. It is anticipated that several periods or sequences will be required before all the WAG injectors in the Project Area have received their first cycle of miscible gas.

Maintenance of the MMP for the planned injection period is not expected to be a problem. The expected gradual decline in reservoir pressure is one of the incentives for early EOR start-up. Continued injection beyond 10 percent pore volume will be predicated on our ability to maintain miscibility in the reservoir. If economically justifiable, miscibility may be maintained through increasing enrichment of the injectant to compensate for declining reservoir pressure.

Current waterflood plans call for the injectors in the NWFB to be completed in Zone 4 only, to maximize waterflood recovery. The existing production wells are perforated primarily in Zones 4 and 2, with appropriate levels of standoff from the top of Sadlerochit and Heavy Oil/Tar mat. Infill wells will be completed in the same manner. Injection and production profile measurements during the first few years of operation of the waterflood will be used to evaluate the need to reperforate intervals to optimize the WAG injection strategy.

Waterflood injectors and producers in the Eastern Miscible Region will be completed in the Zulu, Victor, and Romeo zones as appropriate to maximize waterflood recovery. On the basis of waterflood performance, injectors will be reperforated for optimum WAG injection. The basic strategy is to superimpose EOR over the waterflood causing as little change to the ongoing waterflood operation as possible. Any major changes in waterflood operations, such as pattern conversion to five-spot or line drive or zonal control, would dictate operation of EOR on a similar basis.

PROJECT SURVEILLANCE

An extensive reservoir surveillance program is being carried out for the FS-3 Injection Project to monitor and optimize the enriched gas drive process. The existing field-wide reservoir surveillance program is supplemented by the use of an observation well with special DIL and neutron logging, extensive coring, more frequent well surveys, and radioactive tracers. It is anticipated that the results of this surveillance program when utilized in conjunction with a history-matched simulation of the FS-3 Injection Project will result in a comprehensive confirmation of the mechanisms of miscible flooding at Prudhoe. This information will be taken into account in designing a cost effective surveillance program for the PBMGP.

The PBMGP surveillance program will be designed as an addition to the surveillance proposals being developed for the waterflood project. Prior to the start of miscible gas injection, a comprehensive surveillance program specifically developed for this Project will be submitted to the AOGCC.

FACILITY DESCRIPTION

Several processes were examined to determine the most cost effective miscible gas plant. Conceptual design involved screening all major facility options such as the basic plant process, size and location of the plant, impact on existing facilities and benefit versus cost analysis. The following design criteria were assumed for conceptual process design:

1. Feed gas volume limited by CCP reinjection capacity of the residue gas.
2. A nominal initial minimum miscibility pressure of 3600 psia (conceptual design allows for a 200 psi safety factor).
3. Flow Station 3 Injection Project continues operation.
4. Wellhead delivery pressure of 4000 psia for miscible injectant.
5. Minimum wellhead temperature of 80°F.
6. Field fuel is supplied by the new plant and the existing Field Fuel Gas Unit is shut down.
7. Water available at each drill site/well pad for waterflood plans will be sufficient for WAG flooding.

Refrigerated condensation/stabilization was selected over Selexol, refrigerated lean oil, and Ryan/Holmes. Although the high CO_2 content processes provided some reservoir advantages, these did not outweigh the significantly higher costs required. Once the basic process was selected, further studies examined optimum operating temperatures, plant location, and plant size.

This Project requires a substantial investment in surface facilities and pipelines for processing, distribution and injection of miscible fluids. Design and construction of the facilities are compatible with existing and future facilities and projects. A description of proposed facilities with implementation plans and operational philosophy are discussed in this section. Final design may slightly alter the facilities described below.

Gas Processing Plant

A centrally located refrigerated condensation/stabilization plant using vapor compression propane refrigeration to -35°F will produce the miscible injectant for enhanced oil recovery. In the following discussion of the EOR plant process design, reference is made to Exhibit IV-1. A nominal 2.7 BSCF/D of feed gas is split into two refrigerated condensation trains. Chilling and condensation of feed in the Low Temperature Section (LTS) is accomplished by back-exchange of feed gas against chilled products and propane refrigerant chilling to -35°F.

Condensed liquids from the refrigerated condensation trains are combined and fed to a single stabilization section. Recovery of light NGLs and CO_2 for use as injectant is improved by recycling NGL liquid from the stabilizer. Cold residue gas is back-exchanged against inlet feed in the LTS Gas/Feed Gas Exchanger. Following back-exchange, residue gas from the parallel trains is combined and sent to the CCP after satisfying fuel gas requirements. After further warming in the Feed Gas/LTS Liquid Exchanger, two phase feed enters the Stabilizer Feed Flash Drum.

Gas from the flash drum is fed directly to the stabilizer. The liquid part of the feed is heated by exchange against hot stabilizer bottoms (NGL product) in the Stabilizer Feed/Bottoms Exchanger. Bottoms product NGL is cooled against stabilizer feed and after taking a slip stream for recycle to the refrigeration condensation section, is sent to TAPS for crude blending.

Stabilizer overhead is air-cooled in the stabilizer condenser. Liquids are collected in the stabilizer overhead drum and returned as reflux to the stabilizer. Uncondensed stabilizer overhead is miscible injectant which is compressed in two stages to 4500 psia and after-cooled to 165°F. The estimated initial composition is outlined in Exhibit IV-2. Optimization of the process design and daily operation will determine the ultimate composition of this stream. Stream composition will be monitored to maintain miscibility.

Miscible Gas and Water Distribution

Miscible injectant is distributed via high pressure pipelines to drill sites and well pads. Pipelines are routed along existing pipeways and use available supports where possible. A trunk line approach was taken to eliminate multiple pipelines on the same right-of way. Exhibit IV-3 provides a plan view of the distribution system. A small injectant module will be added to each drill site/ well pad where revamp of existing facilities cannot be economically justified. Miscible injectant will be distributed through a header with a branch system to selected wellheads.

Miscible injectant is distributed to injection wells at Drill Sites 3, 9, 12, 13, 16, and 17 and Well Pads M, R, and S. Two injection wells for the N Pad area will be drilled from M Pad. Make-up miscible injectant to Drill Site 13 is supplied via a tie-in to the existing FS-3 Injection Project distribution pipeline. The injection facility discharge pressure design basis is 4500 psia or 4000 psia at the wellhead with 500 psi distribution system loss.

Switch over from gas to water and vice versa will be accomplished through use of the existing waterflood freeze protection system employing methanol displacement and corrosion inhibitor injection as needed.

The Seawater Treatment Plant (STP), which will provide the source water, arrived at Prudhoe Bay in August 1983 and is already in place at the extension of the west dock. Seawater Injection Plants (SIP) near Gathering Center 3 and Flow Station 1 are in place. Pipelines and manifolds are installed, and the STP and SIPs are being tied-in. Source water injection will begin in both the Eastern and Western Miscible Regions in mid-1984.

<u>Volume Forecast</u>

The amount of injectant available to the Project is a direct function of the composition of the produced gas in the Field and the volume of available NGLs. In later Project life, Field off gas will become leaner, thereby reducing the NGLs available for removal as miscible injectant or blendable NGL product. As the NGL blending rate decreases with crude oil volume, the proportion of NGLs removed as miscible injectant will increase.

Additional volumes of miscible injectant can be realized from injectant returning from the reservoir. An estimated returned injection profile is shown on Exhibit IV-4 for a mid-1987 start-up. This profile reflects both areal and vertical sweep efficiency and breakthrough times as defined by reservoir models and previous Field experience with miscible gas processes. The chromatographic effect of the dynamic miscible process on individual components is minor as revealed by compositional simulation.

The plant is expected to produce miscible injectant at rates ranging from 180 MMSCF/D in 1987 to 266 MMSCF/D in the year 1996. Residue gas, including fuel gas produced during Project life is about 2.4 BSCF/D for a nominal 2.7 BSCF/D plant inlet rate. Continued operation of the FS-3 Injection Project process module provides approximately 35 MMSCF/D of injectant. As needed, additional FS-3 Injection Project requirements will be supplied by the new facility. Predicted miscible injectant rates with time are shown in Exhibit IV-5. The ten-year average rate of 200 MMSCF/D was calculated using a field-wide process model, forecast reservoir production data, and expected Flow Station/Gathering Center conditions.

No difficulty is anticipated in providing the injectant volume required to achieve more than a 10 percent pore volume slug. Current plans are to continue injection beyond this point as long as economically justifiable.

An additional effect of the Project is to increase Field gas handling capacity which results in improved oil and condensate recovery. Since the current limit to gas handling is the CCP, by shutting down the existing Field Fuel Gas Unit and by removing saleable NGL's and fuel upstream of the CCP, more total gas can be handled in the Field. Total gas offtake capacity will increase from 2.40 to 2.85 BSCF/D.

IMPACT ON EXISTING FACILITIES

Central Compression Plant (CCP)

The Central Compression Plant (CCP) currently consists of 13 General Electric MS 5001 Single Shaft Gas Turbines driving Dresser-Clark Centrifugal Compressors. Nine units are in first stage service, with four units in second stage service. The CCP is currently compressing separator off gas which has a molecular weight of approximately 23.0. Field fuel gas is withdrawn from the second stage suction as feed to the FFGU. With the Gas Plant in operation, the CCP will be required to compress a lower molecular weight residue gas. Since the FFGU will be shut down, no interstage withdrawal of gas will be required. The net results of these two effects will be a small overall reduction in CCP gas handling capacity. Studies have also evaluated increasing the capacity of CCP equipment under new operating conditions with several options for restaging the existing machines when compressing the residue gas from the Gas Plant. The effects of gas transit line looping and boost compression were examined. Current plans are to add boost compression upstream of the Gas Plant and to rewheel the first stage CCP compressors.

Flow Station 3 Injection Project

The FS-3 Injection Project will remain an independently certified project. The primary impact of the PBMGP on the existing Project at FS-3 is to supplement the source of miscible injectant. The injectant composition is similar (Exhibit IV-6) and no change in recovery is expected. The pipelines required for the distribution of miscible injectant to FS-3 drill sites will remain the same regardless of injectant source.

Separation Facilities

An extensive study of separation facility impacts due to EOR has been undertaken. The study has evaluated the range of expected wellhead fluid compositions over the Project life. The effects of increased oil and gas production, as well as produced injectant impacts, have been examined. Separator performance models based upon Peng-Robinson equations-of-state have been utilized to predict the required capabilities.

The Project does not introduce any significant increases in liquid handling requirements. Potential produced water handling equipment overloads, predicted under present water production forecasts, are under continuous evaluation in the PBU produced water expansion studies. Included in these studies are plans for possible expansion or debottlenecking of existing produced water handling facilities. Decisions are reviewed yearly to ensure the Gathering Centers and Flow Stations are upgraded to meet predicted loads.

Gas handling requirements are eventually increased due to the reproduced solvent and are the main cause of some facility impacts. Appropriate modifications of Gathering Centers and Flow Stations are planned to meet the additional load.

FS-2 is the only Eastern Operating Area facility that is significantly impacted by the EOR Project. Gas handling suction coolers, suction scrubbers, compressors, and discharge coolers could be overloaded in 1990 based on current reservoir predictions. These impacts are under review and will be studied more thoroughly as part of the final design.

The remaining equipment (high pressure separators, intermediate pressure oil separators, treaters, treater flash drums, oil surge tank, STV suction scrubber, IP suction scrubber, and the STV and LP compressors) is expected to operate satisfactorily during the life of the EOR Project.

All three Gathering Centers in the Western Operating Area experience some gas handling overloading after 1990. In all cases the overloads are confined to specific portions of the production facilities. Equipment impacted are the low pressure knock-out drum, intermediate pressure gas scrubber, high pressure first stage separators, high and low pressure train third stage production separators, and slug catchers. Operational procedure changes or minor equipment modification/additions are expected to accommodate any EOR related overloads without the need for installation of new process trains. In some years equipment overloads are experienced with oil and water production rates expected from the waterflood. Additional production associated with EOR does not significantly compound those equipment overloads. Resolution of these non-EOR related facility overloads will be incorporated in future engineering studies. Facilities impacted are the high pressure train second stage separator and water settlers in LPS trains.

Waterflood

Waterflood facilities were designed with flexibility in mind. The current waterflood plans are compatible with envisioned EOR plans, and no change in water source facilities is anticipated. Water injection volumes for EOR are similar to those for waterflood and no major change in water handling requirements is expected.

IMPACT OF FUTURE GAS SALES

Implementation of the PBMGP will not significantly affect the volume of gas available for gas sales. The additional facilities are designed to maintain the residue gas to the CCP at the level prior to Project implementation. The reinjection of enriched residue gas as miscible injectant will result in a small reduction in the heating value of the conditioned sales gas in the early years of the Project.

PROJECT INVESTMENT COSTS

The PBMGP is a capital intensive Project requiring a 750 MM$ (1983$) investment. This order of magnitude cost estimate was generated during conceptual design. Costs will be refined as engineering design progresses. Five primary expenditure areas have been identified:

- Gas Processing Plant — 430 MM$

  Costs include feed exchangers/chillers, refrigeration, process equipment, utilidors, utilities, CCP revamp and tie-ins, engineering, transportation, construction, and installation.

- Injectant Compression and Distribution — 190 MM$

  Costs include distribution lines, modules at designated drill sites and well pads, and the injectant compression.

- Pipelines and Miscellaneous — 100 MM$

  Costs include boost compression upstream of the Gas Plant, crude cooling, and the NGL Sales Line.

- Workover/Completion Costs — 10 MM$

- Start-up Costs — 20 MM$

Total 750 MM$

Operating and maintenance (O&M) costs are also a major consideration in the PBMGP. The geographic location of the Prudhoe Bay Field, some 350 miles above the Arctic Circle, increases transportation costs, lengthens equipment lead times, and results in premium labor costs. Harsh weather conditions and operation on the ecologically sensitive tundra often create a need for special equipment and operating procedures not encountered in routine oil field operation.

Corrosion control has been and continues to be a significant program. The tendency of Sadlerochit crude oil not to wet steel surfaces has resulted in initiation of corrosion inhibition treatments and the use of plastic coated tubulars, thus increasing O&M expenses. However, the EOR process does not add significantly to corrosion problems and incremental corrosion-related costs are not expected.

While incremental workovers cannot be specifically identified for this Project, some incremental cost for workovers over and above those normally anticipated is included. A nominal 20% increase in workovers was assumed for estimating purposes.

The WAG process itself requires some additional O&M costs relating to change from injection of one fluid to another. For the Flow Station 3 Injection Project, special precautions are being used to ensure complete isolation of the water and gas injection systems. These special precautions involve manual changeover at the wellhead and are time consuming and expensive, but provide positive control of the process. Improvements in manifold design may eliminate the need for manual operations when the PBMGP is started up.

Anticipated costs for O&M based on the above discussion are detailed in Exhibit IV-7.

EXHIBIT IV-1

EOR PROCESS PLANT SCHEMATIC FLOW

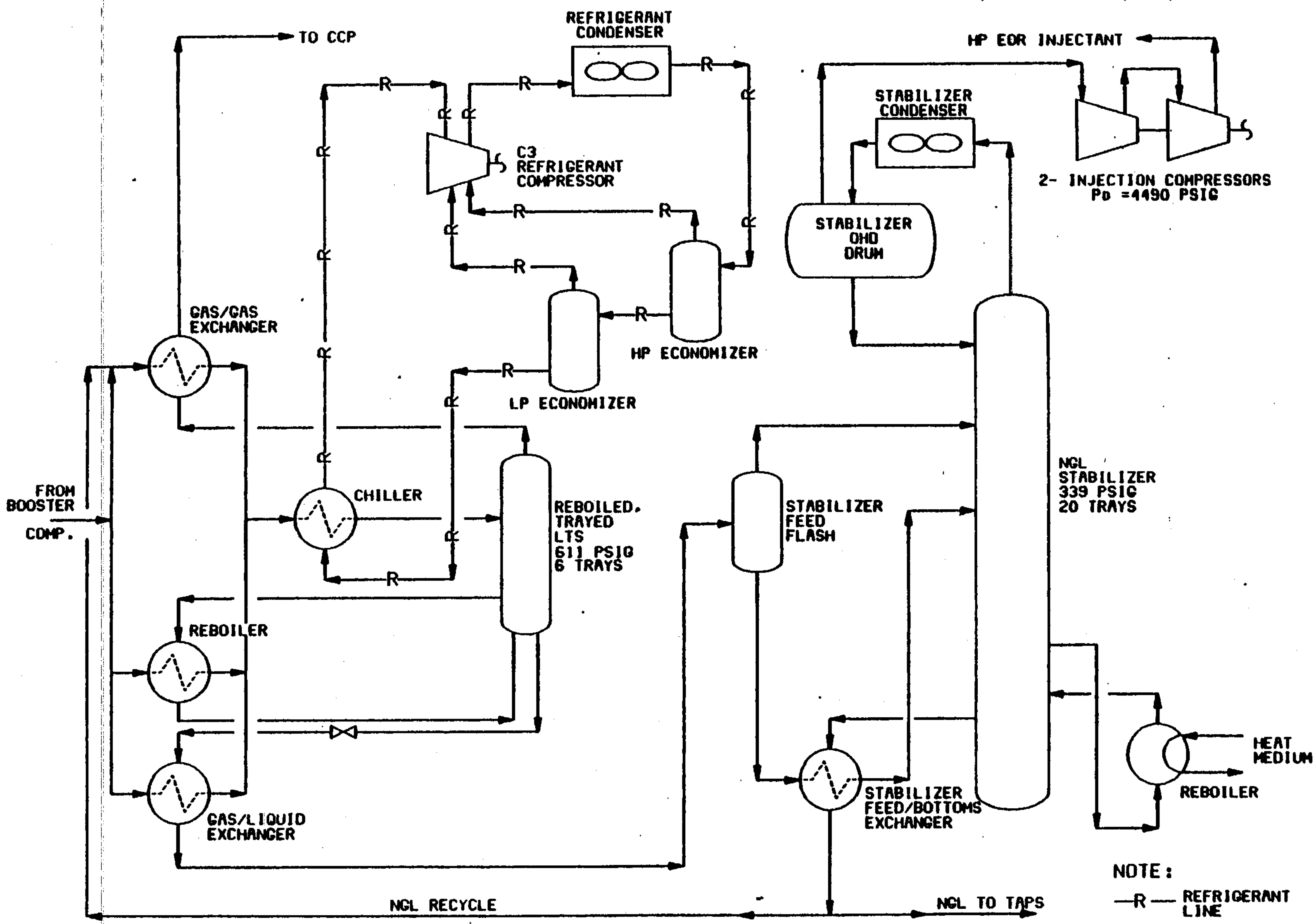


Exhibit IV-2

INITIAL MISCIBLE INJECTANT

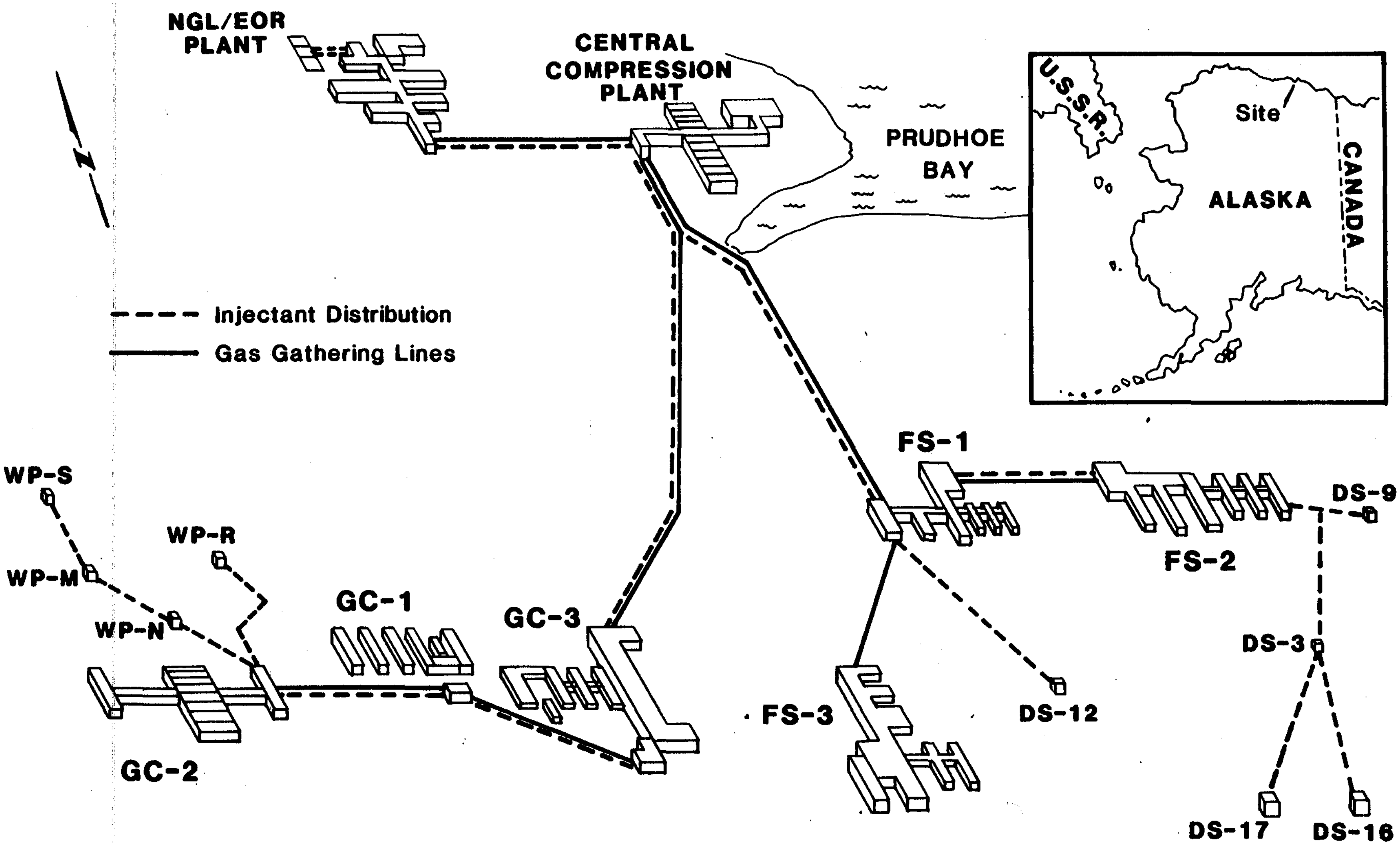
COMPOSITION

Component	Mole %
H_2O	Trace
N_2	0.01
CO_2	21.60
C_1	23.50
C_2	24.03
C_3	28.43
$i\text{-}C_4$	1.22
$n\text{-}C_4$	1.19
$i\text{-}C_5$	0.01
$n\text{-}C_5$	0.01
C_6	Trace
C_7	Trace
C_8	---
C_9	---
C_{10}	---
C_{11}	---
	100.00

83/573

EXHIBIT IV-3

PBMGP DISTRIBUTION SYSTEM



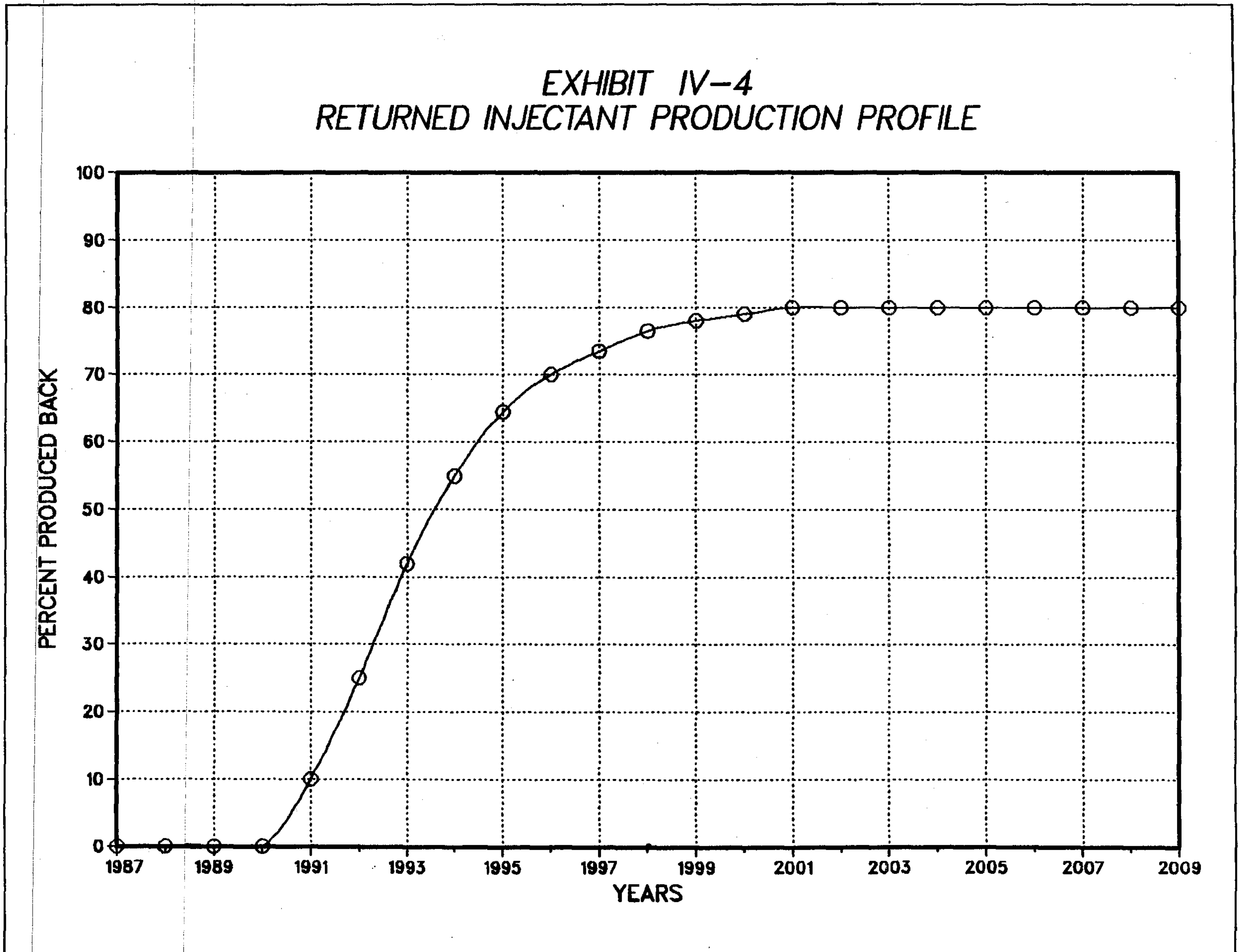


EXHIBIT IV-4
RETURNED INJECTANT PRODUCTION PROFILE
PERCENT PRODUCED BACK
YEARS
0
10
20
30
40
50
60
70
80
90
100
1987
1989
1991
1993
1995
1997
1999
2001
2003
2005
2007
2009

EXHIBIT IV-5
INJECTANT AVAILABILITY vs TIME

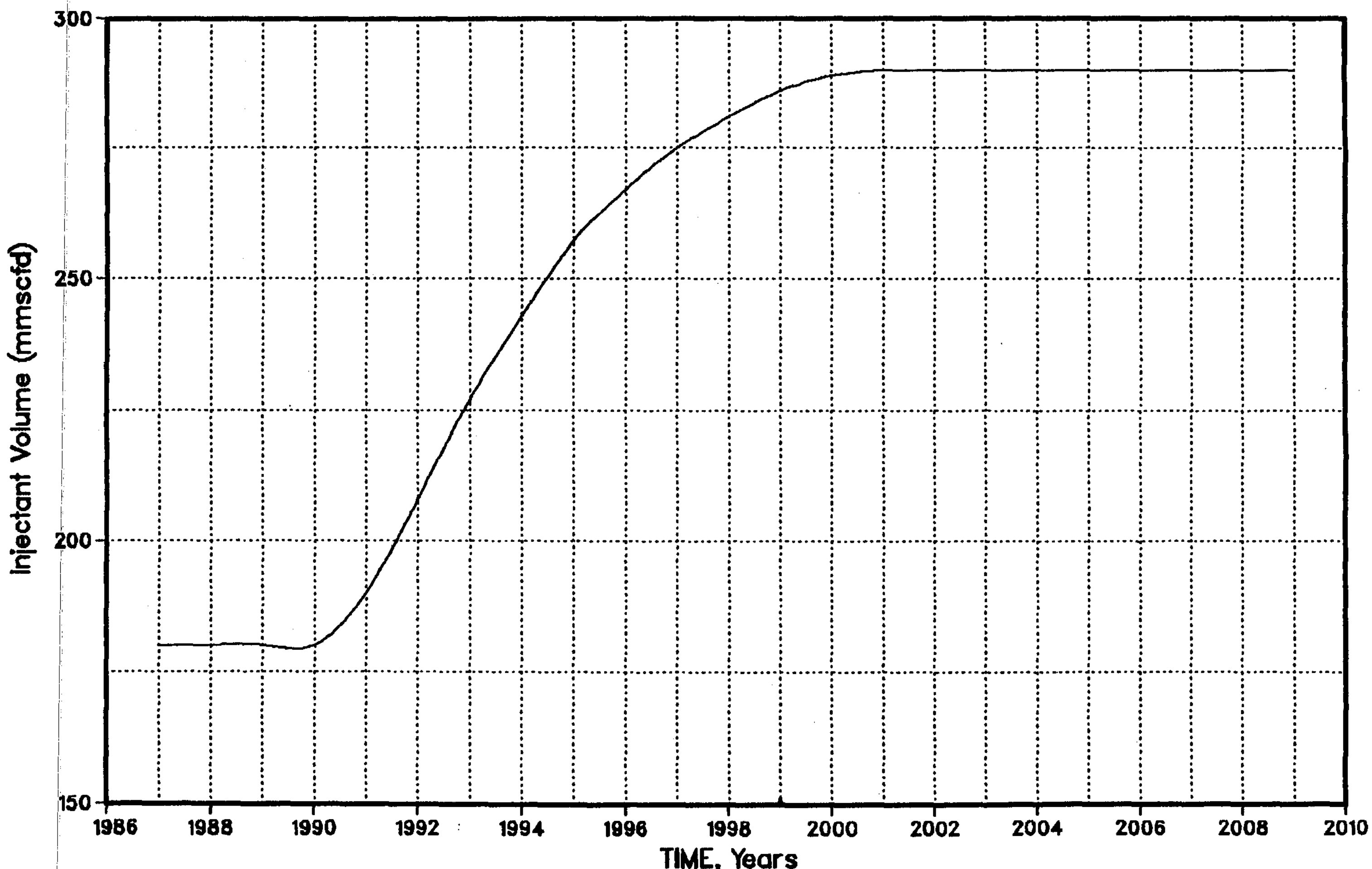


Exhibit IV-6

COMPARISON OF INJECTANT COMPOSITION

Component	FS3IP Mole %	PBMGP Mole %
N_2	0.13	0.01
CO_2	12.41	21.60
C_1	42.50	23.50
C_2	12.77	24.03
C_3	13.59	28.43
$i\text{-}C_4$	2.49	1.22
$n\text{-}C_4$	6.76	1.19
$i\text{-}C_5$	1.86	0.01
$n\text{-}C_5$	3.07	0.01
C_6	1.97	Trace
C_7	1.10	Trace
C_8	0.79	---
C_9	0.41	---
C_{10}	0.15	---
	100.00	100.00

Exhibit IV-7

OPERATING & MAINTENANCE COSTS

Expenditure Area	Gross Capital Cost	O&M Portion (MM$/Yr.)
EOR/NGL Plant Costs	430	34.40
Injection Plant	72	5.76
Distribution System	118	5.90
Pipelines & Miscellaneous	100	5.00
Workover/Completion Costs	10	4.0
Start-up Costs	20	1.60
Total	750	56.66

PART V

PART V - RESERVOIR ANALYSIS AND EXPECTED PERFORMANCE

Project design and anticipated performance are based on extensive reservoir simulation studies conducted by ARCO, Sohio and Exxon. These studies have addressed incremental recovery, Project sensitivities, and Project implementation strategies. State-of-the-art miscible simulation techniques were used to simulate this complex process. Model size and simulator complexity varied over a wide range depending on application.

Although each of the Owner Companies took independent approaches to reservoir modeling and interpretation, each arrived at comparable design bases and recovery estimates that are considered to be significant amounts. The following paragraphs describe the analyses performed by each company and summarize their results.

ARCO PERFORMANCE PROJECTIONS

ARCO has relied primarily on numerical simulation techniques in its studies of miscible displacement processes at Prudhoe Bay. Incremental recoveries and regional effects were predicted with large three-dimensional area-wide and strip models. Finely-gridded three-dimensional pattern models were used to investigate mechanistic results and compare individual geologies. Sensitivity analyses were performed with two-dimensional cross-sectional models. ARCO's sequential four-component simulator was used in these studies (Reference 25). Additional compositional simulator studies were used to validate the four-component results.

Reservoir simulation results were found to be very sensitive to reservoir description due to the dominant importance of gravity segregation of miscible gas relative to reservoir oil and water. The presence of high permeability layers and/or shale layers strongly affects the volume of reservoir contacted by miscible gas. In addition, lateral continuity of shale layers was found to be very important. This recognized sensitivity coupled with imperfect knowledge of how the Sadlerochit reservoir is stratified/faulted introduces uncertainty in interpreting simulation results. These reservoir heterogeneities can serve to either improve or limit miscible flood over waterflood incremental recoveries. These facts, combined with the as yet unquantified relationship of numerical dispersion effects to physical dispersion, have led ARCO to treat its simulation results conservatively in arriving at estimates of incremental recoveries.

In the course of analyzing miscible displacement processes for Prudhoe Bay, ARCO performed major studies of the NWFB, PWZ, and FS-2 areas, the three targeted regions for miscible flooding. Results from these studies, along with those from small pattern models used in the evaluation of the areal studies, are presented in the following sections. In summary, injection of a 10 percent pore volume slug of miscible gas resulted in incremental recoveries over waterflood of 6.1 percent, 5.5 percent, and 6.9 percent for the NWFB, PWZ, and FS-2 areas, respectively based on large area 3-D models. On a pore volume basis, the NWFB region is 44 percent of the proposed floodable area, the PWZ is 6 percent, and the FS-2 area is 50 percent. Tempering these results with finely gridded pattern models, this breakdown results in a pore volume weighted incremental recovery over waterflood of approximately 6.0 percent of the original-oil-in place (OOIP) in the Project Area for a 10 percent PV miscible gas flood. Also, from these studies a pore volume weighted incremental recovery of 8.5 percent OOIP is predicted for a 20 percent pore volume slug.

ARCO Northwest Fault Block Study

To study the NWFB, a four-component version of ARCO's three-dimensional, reservoir simulator was utilized. The overall model grid was 37 x 26 x 11 (10,582 cells). Exhibit V-1 shows the areal grid overlain on a structure map of the region. The areal grid size was 20 acres and cell column thickness was calculated from the most recently available structure map using gross thickness values. Net to gross reductions were applied to the porosity and permeability properties, rather than to gross thickness. Horizontal permeabilities were determined by contour mapping all available measured core permeabilities. Initial vertical permeabilities were calculated from fixed K_v/K_h ratios for each of the geologic zones.

The effects of shales were modeled through the use of vertical transmissibility modifiers. Cross-sections were plotted using logs from all currently drilled wells. Correlatable shales greater than 5 feet in thickness were assigned a vertical transmissibility of zero. Less continuous and thinner shales were represented as partial vertical flow barriers.

Production history matched in the model covered approximately the first five years of Prudhoe Bay operations. Boundary wells representing the gravity drainage area were used to history match reservoir behavior in the NWFB. In addition to the miscible gas injection cases, five waterflood cases and a natural depletion case were investigated. Water injection began in mid-1984 for both the waterflood and miscible gas injection cases. Beginning in mid-1987, miscible gas was injected alternately with water at a 5:1 WAG ratio until a 10 percent pore volume slug of gas was injected. This was followed by water injection and compared to a waterflood base case. The simulated incremental recovery for the miscibly flooded region was 6.1 percent. For a 15 percent pore volume slug size the recovery increased to 7.1 percent, and for a 20 percent pore volume slug the recovery increased to 8.4 percent.

From this study a better understanding of miscible gas displacement was obtained. Results indicated that a pattern flood was the most attractive approach to a WAG type project. Water slumping was observed to be more severe with peripheral development than with a pattern waterflood. A gravity stabilized miscible injection scenario involving the secondary gas cap in the south fault block was found to be infeasible because sufficient injectant volumes are not available to maintain pressure within the NWFB. ARCO's results also showed that significant fluid movement could occur from the NWFB toward the main gravity drainage area of the Field.

ARCO Peripheral Wedge Zone Study

ARCO's modeling efforts of the Peripheral Wedge Zone concentrated on a section of the Flow Station 3 Injection Project area and evaluated an enriched methane flood employing an inverted nine-spot pattern with 80 acre spacing. These results were documented previously in the Flow Station 3 Injection Project WPT Approval Application (see Reference 1). A three-dimensional symmetrical strip of the area was modeled. This strip extended north into the gas cap and south to the aquifer to correctly incorporate pressure boundary effects. The model gridding was 36 x 7 x 10 (2520 cells), with areal cell sizes ranging between 2 and 40 acres. Exhibit V-2 is a representation of the model geometry. The top two layers were 10 feet and 25 feet thick, respectively, to adequately model solvent overriding. The model was matched to existing actual Project Area performance and to the predicted future pressure performance of the area generated with ARCO's full field three-dimensional simulator. Small area models were used to quantify gas overriding, determine coning behavior and investigate well completion philosophy. Incremental recovery over waterflooding was approximately 5.5 percent OOIP for a miscible WAG process employing a 10 percent pore volume slug (1 percent pore volume per year) of enriched methane injected at a 3:1 WAG ratio. Increasing the slug size to 15 percent pore volume (1 percent pore volume per year) resulted in approximately 8.1 percent OOIP incremental recovery over waterflooding. A 20 percent pore volume slug resulted in approximately 9.7 percent incremental recovery.

ARCO Flow Station 2 Study

ARCO modeled the entire Flow Station 2 area on 160 acre spacing and a portion of the area on 80 acre spacing. The simulator used in the 160 acre areal model was a four-component model adaptation of a simulator previously built to study waterflood patterns for the FS-2 area. The model gridding was 34 x 21 x 10 (7140 cells) and is shown in Exhibit V-3 overlaying a geographical map of the FS-2 area. Areal cell size is 40 acres. Cell columns 20 and 21 were part of the FS-1 area, but were included during the history match to represent the western boundary.

The X-Ray and Tango shale complexes divide the reservoir in the FS-2 Area into three vertical zones known as the Zulu, Victor, and Romeo. Exhibit V-4 illustrates this vertical zonation and the corresponding model layers. The shale complexes were represented by zero or reduced vertical transmissibilities. The layers immediately below the shales and at the top of the formation were each 10 feet thick, in order that gas overriding could be modeled.

A 5:1 WAG ratio and inverted nine-spot pattern were found to be the preferred operating scenario due to greater initial pressure support, earlier oil production, and best overall recovery. With a 20 percent pore volume slug injected in twenty years, incremental recovery over waterflood was 9.0 percent OOIP. An incremental 6.9 percent OOIP was recovered for a 10 percent pore volume slug followed by waterflood.

The study showed pronounced gas override with efficient sweep near injection wells and immediately below major shales. A 5:1 WAG ratio flood was more efficient than a 3:1 WAG, and achieved a higher incremental recovery. In addition, limiting WAG ratios below 5:1 would require that withdrawal rates be restricted in order to maintain reservoir pressure. This study also indicated that miscible gas flooding had the potential to slightly extend Field life, due to higher oil production rates later in time.

ARCO Small Model Comparisons

Small three-dimensional pattern models were constructed for each of the areas targeted for miscible injection. The small model studies utilized ARCO's sequential four-component simulator. Quarter and 1/8 nine-spot patterns were constructed, with areal cell dimensions of approximately one acre, and light oil column layers between 10 and 35 feet in thickness. Enriched methane was injected at the rate of 1 percent pore volume per year for ten years in various WAG ratios, and followed by water injection.

The goal of these studies was to look at the mechanistic effects of miscible gas injection and to calibrate the large area-wide 3-D models. Simulations examined gravity segregation effects, water and gas coning, WAG ratios, injectant composition, injection/production strategies, simultaneous injection of water and gas, and influences of various reservoir descriptions (permeability variations and concentration of shales).

The pattern models indicated that reservoir geology variations between the three targeted areas would be a source of incremental recovery variations. Sensitivities performed also indicated that various operational schemes could provide additional incremental recovery over that reported in this document. Among these was a study of simultaneous injection of water and miscible gas (maintaining isolated fluid streams, and injecting the gas beneath the water), which utilized a 1/4 nine-spot model. Simulations indicated that for particular reservoir descriptions, split-stream simultaneous injection has the potential for additional incremental recovery.

SOHIO PERFORMANCE PROJECTIONS

Sohio performed several detailed reservoir model studies to: 1) gain a better understanding of the reservoir mechanisms involved; 2) estimate potential recovery benefits of miscible gas injection; and 3) aid in the development of Project implementation plans. Two independent studies employing large scale, finely gridded strip models of the NWFB and the Flow Station 2 Areas were performed in parallel. Both studies employed a modified version of the Intercomp COMP-II compositional simulator which was designed to model three-phase, multi-component flow in hydrocarbon reservoirs. The three phases represented in the simulator were a hydrocarbon liquid phase, a hydrocarbon gaseous phase, and the aqueous phase. The simulator calculated volumetric and phase behavior of the reservoir fluid mixtures by means of a tuned Peng-Robinson equation of state. For the cases modeled, the reservoir fluids were described with five components: carbon dioxide, methane, two hydrocarbon pseudo-components, and water. Special calibration of the simulator was performed by comparing water, dry gas, and miscible flood results obtained in coarse (10-acre) and fine (1.6-acre) grid representations. These calibration studies, undertaken with representative geological models in repeated nine-spot elements, allow the strip model results to be normalized to a more conservative basis.

Sohio Northwest Fault Block Model

The strip shown in Exhibit V-5 was employed in the study of the Western Miscible Region. The strip was positioned so as to take into account the effects of faulting, the presence of shales with large areal extent, and gas and water influx into the Project Area. The fine vertical gridding represented in Exhibit V-6 was used to provide as much vertical resolution of reservoir heterogeneity and fluid segregation as was practical. The overall grid was 36 x 9 x 24 with a total of 5,148 active cells. Reservoir properties (top sand, porosity, and net-to-gross ratio) were assigned cell-by-cell on the basis of the latest data available as a result of the ongoing 80-acre infill drilling program. Permeabilities used were based upon core analysis in conjunction with pressure buildup evaluations in the area. Vertical permeability was deduced based upon net-to-gross ratio to take into account the effects of discontinuous shales and the massive shale underlying the light oil column. The heavy oil/tar was accounted for by reducing oil mobility in the model layers where it existed. The model was initialized to capillary pressure equilibrium and was consistent with agreed in-place fluid volumes.

Since it is difficult to account for field-wide effects in a strip model, a full history match was beyond the scope of this work, but a broad match was obtained on Field pressure history and produced fluid volumes. Historical and predicted main-Field pressures were used as the boundary condition at the eastern (original gas cap) end of the strip.

Both waterflood and miscible gas injection performance predictions were based upon a pattern arrangement which approximates an inverted nine-spot with average 80-acre well spacing as shown in Exhibit V-7. Consistent with current development plans, water injection in mid-1984 and continued until mid-1987 and was proportioned to the pattern injectors in the model based upon a total NWFB injection rate of 570 MBWPD.

At mid-1987 either waterflooding was continued or miscible gas/water was injected at an approximate 5:1 WAG ratio. Volumes were allocated to the injectors based upon light oil in place per pattern and total Western Miscible Region area rates of 250 MBWPD of water and 72 MMSCF/D of solvent. For the WAG prediction case, miscible gas injection at approximately one percent (light oil column) total pore volume per year was continued for 10 years until mid-1997 at which time the project reverted to waterflood. All simulator runs were terminated in the year 2009 corresponding to Sohio's currently estimated full field oil rim depletion date. WAG injection of a 10 percent PV slug of miscible gas followed by twelve years of further waterflood is expected to provide a 6.9 percent OOIP increase in oil recovery over a corresponding pattern waterflood.

Sohio Flow Station 2 Model

In a parallel manner, the strip shown in Exhibit V-8 was employed in the study of the Eastern Miscible Region. This region is characterized by two massive, continuous shales and a single fault to the south. The X-ray shale separates the Zulu region from the Victor, and the Tango shale isolates the Victor from the Romeo. Both shales are assumed to be completely sealing along the length of the strip model. The single fault to the south, with a throw of approximately 50 feet also appears to be sealing. The Romeo and Zulu zones are characterized by small, discontinuous shales, whereas the Victor is a relatively clean sand with correspondingly higher permeabilities. Appropriate vertical permeabilities were chosen based upon net-to-gross ratios for each layer.

The overall model grid is 9 x 41 x 26 with a total of 5330 active cells. Fine vertical model layering adjacent to the underside of the major shales was employed to realistically model gas movement (Exhibit V-9). Gas influx to the north from the original gas cap was modelled by defining historical and predicted main-Field pressure. Water influx to the south from the aquifer was represented by including an appropriate aquifer model.

Exhibit V-10 shows the regular nine-spot development proposed for both water and miscible gas injection. Water injection was begun in mid-1984 and continued until mid-1987. During this period the waterflood operation was developed progressively from the south to the north. By mid-1987 the total water injection rate was 860 MBWPD in the eastern waterflood area, which is appropriately scaled to the strip model. At that time, either waterflood was continued, or pattern injectors in the EOR target area were converted to miscible gas/water injection at a 5:1 WAG ratio (378 MBWPD water, 116 MMSCF/D solvent for the project area). For the WAG prediction case, miscible gas injection at approximately one percent (light oil column) total pore volume per year was continued for 10 years until mid-1997 at which time the project reverted to 12 years of waterflood. Again, all simulation runs were terminated by the year 2009 corresponding to Sohio's estimated full field oil rim depletion date. WAG injection of a 10 percent PV slug of miscible gas followed by twelve years of further waterflood is expected to provide an increase in oil recovery of 4.5 percent OOIP.

Sohio Average Recovery Predictions

Taking account of the pore volumes of light oil originally in place in the two miscible regions, the average Sohio additional recovery estimate is 5.5 percent OOIP, relative to waterflood. Sohio's estimates of the benefit of extended solvent injection are based on simple strip model studies. For a Project life of 20 percent PV injection of solvent, the expected additional recovery would be about 8.3 percent OOIP.

EXXON PERFORMANCE PROJECTIONS

Exxon used finely gridded 2-D and 3-D numerical models in conjunction with the previously defined analytical model to study process physics and to make recovery estimates. Project implementation strategies were assessed using large strip models.

Exxon Recovery Estimates

In developing recovery estimates, Exxon used a somewhat different, and more conservative, approach than ARCO and Sohio. Based on studies which quantified the effects of numerical dispersion on incremental recoveries, Exxon adopted a 2-D simulator, PRSIM (see Reference 26), which uses the method of characteristics. Although the method of characteristics is inherently less affected by numerical dispersion than finite difference techniques, it was still necessary to adjust PRSIM simulator results at low viscous-to-gravity ratios typical of Prudhoe Bay using the analytical model. The need for adjustment is reflected in Exhibit V-11 which show solvent concentration profiles at steady state as predicted by the analytical model and PRSIM, respectively. These profiles indicate that recovery predicted by PRSIM is greater than that predicted using the analytical model. This difference is attributed to numerical dispersion.

An approach was developed to generate pattern-by-pattern recovery estimates by adjusting PRSIM numerical simulations on the basis of the dimensionless parameters defined by the analytical model. This procedure is briefly outlined below.

1. A comprehensive statistical analysis of available core and log data from each pattern was used to identify probable combinations of the key parameters - oil column thickness, vertical permeability, and horizontal permeability. On the basis of these statistical studies and simulator studies to determine the sensitivity of incremental recovery to these parameters, it was determined that production response of all target patterns could adequately be represented by five "typical" cross sections.

2. Finely gridded models (Exhibit V-12) were constructed for each of the "typical" cross-sections assuming 320 acre inverted 9-spot patterns. Grid block size in these models was approximately 100 ft. in the horizontal direction and 20 ft. in the vertical direction.

3. PRSIM waterflood and miscible gas flood simulations were performed for each of the five "typical" cross-sections to determine incremental production profiles. Each simulation was continued for a 60 year period to arrive at a steady state recovery that could be compared with steady state recoveries predicted by the analytical model.

4. Recovery curves for each pattern were determined by adjusting the appropriate "typical" recovery profile for thickness, vertical permeability and injection rate. The analytical model served as the basis for making these adjustments.

Exxon's primary effort has focused on estimating incremental EOR over recovery obtainable by waterflooding from twenty years of WAG injection. All simulations were based on continuous 1 percent PV/yr solvent injection and a WAG ratio of 5:1. The first twenty years of the adjusted heterogeneous recovery curves were used to estimate EOR recovery for each pattern. The twenty year WAG flood life generally corresponds to waterflood life and is a plausible operating scenario. The predicted incremental recovery is approximately 6 percent of OOIP. Recovery from a project consisting of ten years of WAG injection followed by waterflooding to depletion was also considered. The predicted incremental recovery from a project of this nature carried out by injecting 10 percent PV solvent is 4 percent of OOIP.

Exxon Large Model Studies

Two large strip models representing the NWFB and WPWZ were constructed. The reservoir description incorporated in these models was selected to represent "typical" cross sections through their respective areas of the Field. The NWFB model (Exhibit V-13) was 2 1/2 miles long by 1/2 mile wide containing 5,586 blocks and 17 wells. It straddled the centrally located east-west trending major fault. Water potential wells were located across the northern end of the NWFB to account for water migration across the fault from the aquifer. The model also used potential wells to account for communication with the gravity drainage area under the main gas cap, and gas potential wells to model tonguing from the gas cap.

The WPWZ model (Exhibit V-14) was 2 miles long by 1/2 mile wide containing 3,003 reservoir grid blocks and 14 wells. The model straddled a minor fault. In addition to the reservoir grid blocks, the underlying aquifer to the south was represented by several grid blocks. The WPWZ model also used potential wells to account for communication with the gravity drainage area.

Both strip models were more finely gridded at the well locations (1-acre grid blocks) and at the top of the sand to provide a better representation of coning and solvent override. Both models also included a HOT zone and underlying water where appropriate.

All simulations were initialized to original reservoir conditions and included primary, secondary and tertiary depletion. The primary and waterflood portions of the simulation used Exxon's 3-phase black oil simulator, GPSIM. A well management program was incorporated to determine well rates and simulate workovers. Simulations of the miscible flood were performed with Exxon's 3-phase, 4-component simulator. This simulator partitions three hydrocarbon components (oil, gas, solvent) into two phases. These simulations also used a well management routine.

From the strip model studies it is generally concluded that a miscible project can be effectively implemented in the waterflood areas. Recovery estimates, adjusted on the basis of small model studies, indicate incremental reserves in the range of 4-6 percent can be expected from miscible flooding over waterflood. Also, it was shown that a pattern process is superior to line drive because of water slumping, oil entrapment on the upthrown side of faults, and viscous to gravity effects.

SUMMARY OF PERFORMANCE PREDICTIONS

The WAG miscible flood is a relatively new and complicated enhanced oil recovery process. Only limited field experience is available for comparative studies. As described in previous sections, performance predictions require careful use of modeling techniques to obtain accurate forecasts.

In light of these difficulties, the Owners employed the variety of different modeling techniques described previously. These alternative methods result in different recovery estimates. Furthermore, the assignment of permeabilities and shales (commonly referred to as the reservoir description) profoundly affects model results. The interpretation of cores, well logs, and well test results for this type of reservoir data involves considerable uncertainty; and this also contributes to different recovery estimates.

The table shown below indicates the incremental enhanced oil recovery (percent OOIP) estimates obtained from model studies by ARCO, Sohio, and Exxon.

	10% PV Miscible Gas	20% PV Miscible Gas
ARCO	6.0	8.5
Sohio	5.5	8.3
Exxon	4.0	6.0

Considering the uncertainties in performance forecasts, these EOR estimates are in reasonable agreement, and are generally in line with performance expectations for the FS-3 Injection Project. The mean value corresponding to a 10 percent PV miscible gas slug has been chosen as a single EOR estimate for the Project. This amounts to some 5.2 percent OOIP or 115 MMSTB. Exhibit V-15 shows an oil rate projection for the base waterflood performance and the EOR recovery with initiation of the Project.

The final recovery predictions for the PBMGP project may be summarized as follows:

Original Oil-In-Place	-	2213 MMSTB	
Primary Plus Waterflood Recovery	-	900-1000 MMSTB	(40.7% to 45.2%)
Additional Recovery by WAG for 10 Percent PV Injection	-	115 MMSTB	(5.2%)
Additional Recovery by WAG for 20 Percent PV Injection	-	170 MMSTB	(7.7%)

The additional recovery of 115 MMSTB is substantial and represents an addition of some 27 percent to the remaining oil which can be recovered by waterflood in the Project areas at WAG start-up in the second half of 1987.

The above table also shows that model results indicate increased recovery for extended miscible gas injection. However, the ultimate Project life beyond the planned 10 percent PV slug injection must be based on actual performance at the time. Project life also depends on a favorable economic climate and an adequate supply of miscible injectant.

ESTIMATED PROJECT REVENUE AND EXPENSES

It is estimated that the PBMGP will generate $1999 MM in gross revenues, representing the uninflated and undiscounted worth of the 115 MMSTB of incremental oil before Federal excise and income tax as well as state tax. This incremental oil is estimated to be recoverable with the 10 percent PV enriched gas slug over the pattern waterflood. These revenues are based on a constant oil price of $17.38 per barrel (May 1983 average wellhead price for Alaska royalty oil). The expected incremental costs for operation and maintenance of the Project over the normal pattern waterflood, as well as injectant expense, were detailed in Exhibit IV-7.

IMPLEMENTATION TIMING

With the extensive lead times for implementing a major project at Prudhoe Bay, the earliest date at which the PBMGP could be implemented is 1987. A start-up in 1987 would maximize the available time frame for Project operation and therefore maximize the opportunity for incremental oil production. It is evident that this course of action will lead to implementation of enhanced oil recovery while secondary recovery is still underway. There are several compelling reasons for proceeding expeditiously.

First, current studies indicate that, under waterflood, the majority of the wells in the Project Area would water-out and be abandoned before the year 2010. Because of the timing of incremental oil production, the miscible flood is unlikely to greatly prolong the economic Field life. Deferral of Project implementation would therefore reduce the approximately twenty year time window within which the Project must operate. At a basic level this means that the cumulative miscible gas injection and the incremental oil recovery could be reduced by deferring implementation.

Second, as the general depletion of the Sadlerochit proceeds, reservoir pressure will decline. Currently the decline is 75-100 psi/year. An ongoing pressure decline, as already noted, results in liberation of solution gas. In a miscible flood the liberated solution gas would mix with and dilute the miscible injectant thus threatening the maintenance of miscibility. Miscibility can be assured by increasing the enrichment of the injectant, but an increased enrichment reduces the injectant availability. While waterflood substantially reduces the reservoir pressure decline rate over much of the early life of the Project, operational considerations in the later years of the waterflood could result in reduced injection rates. The preservation of the efficient gravity drainage oil recovery process might require controlled water injection rates to minimize water influx to the gravity drainage area. In summary, the maintenance of reservoir pressure in the period 2000 onwards becomes increasingly uncertain. An early Project implementation date would minimize the adverse impact of these uncertainties on incremental oil production.

The third reason is linked to the effect of increasing water saturation on miscible flood performance. Relative permeability considerations indicate that, with increasing water saturation, the production rate of mobilized tertiary oil decreases significantly. Laboratory data (see Reference 24) confirm this trend. Because the Project Area is under waterflood, deferral would result in generally higher water saturations during the miscible flood. Consequently, incremental oil production rates tend to decrease with progressive deferral. Given the limited reservoir lifetime, the incremental recovery realized by the Project would also decrease. Also, it should be noted that higher water-oil ratios and lifting costs would adversely affect Project operation.

In summary, it is concluded that deferral of implementation will adversely affect the incremental oil recovery from miscible flooding and the magnitude of this adverse impact increases with longer deferrals.

EXHIBIT V-1

NWFB AREAL GRID - ARCO

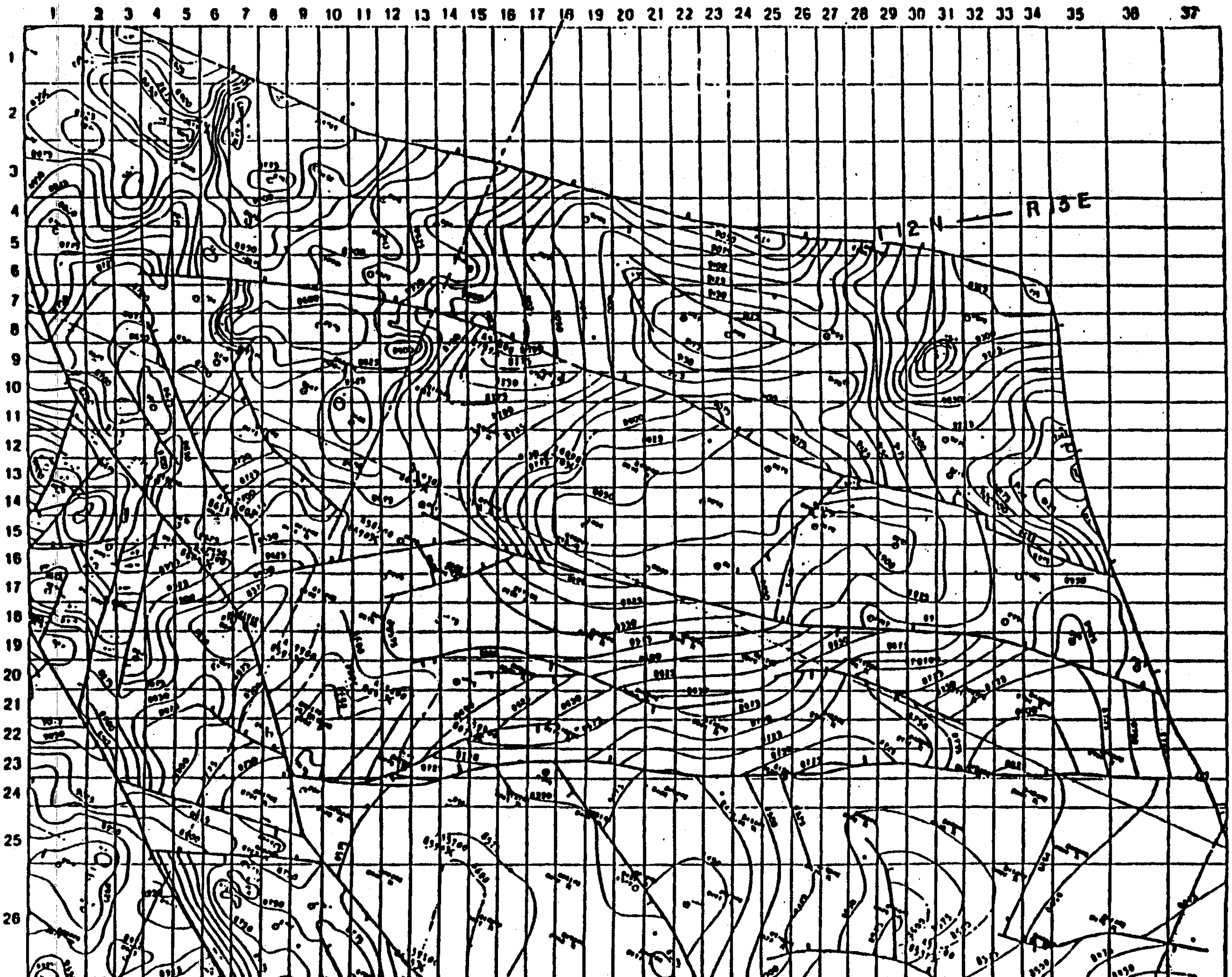


EXHIBIT V-2

PWZ MODEL GEOMETRY — ARCO

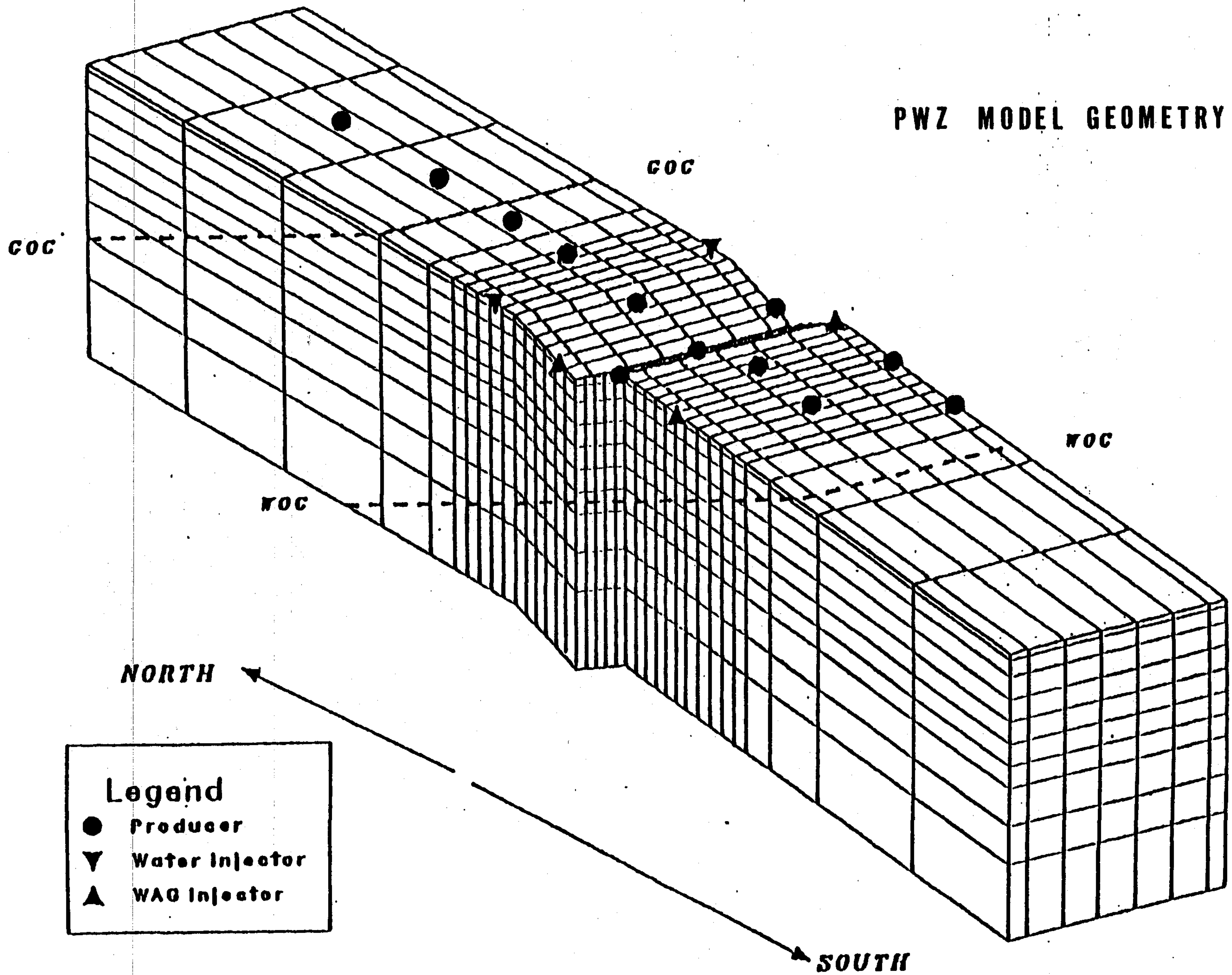


EXHIBIT V-3

FLOW STATION 2 MODEL GRID - ARCO

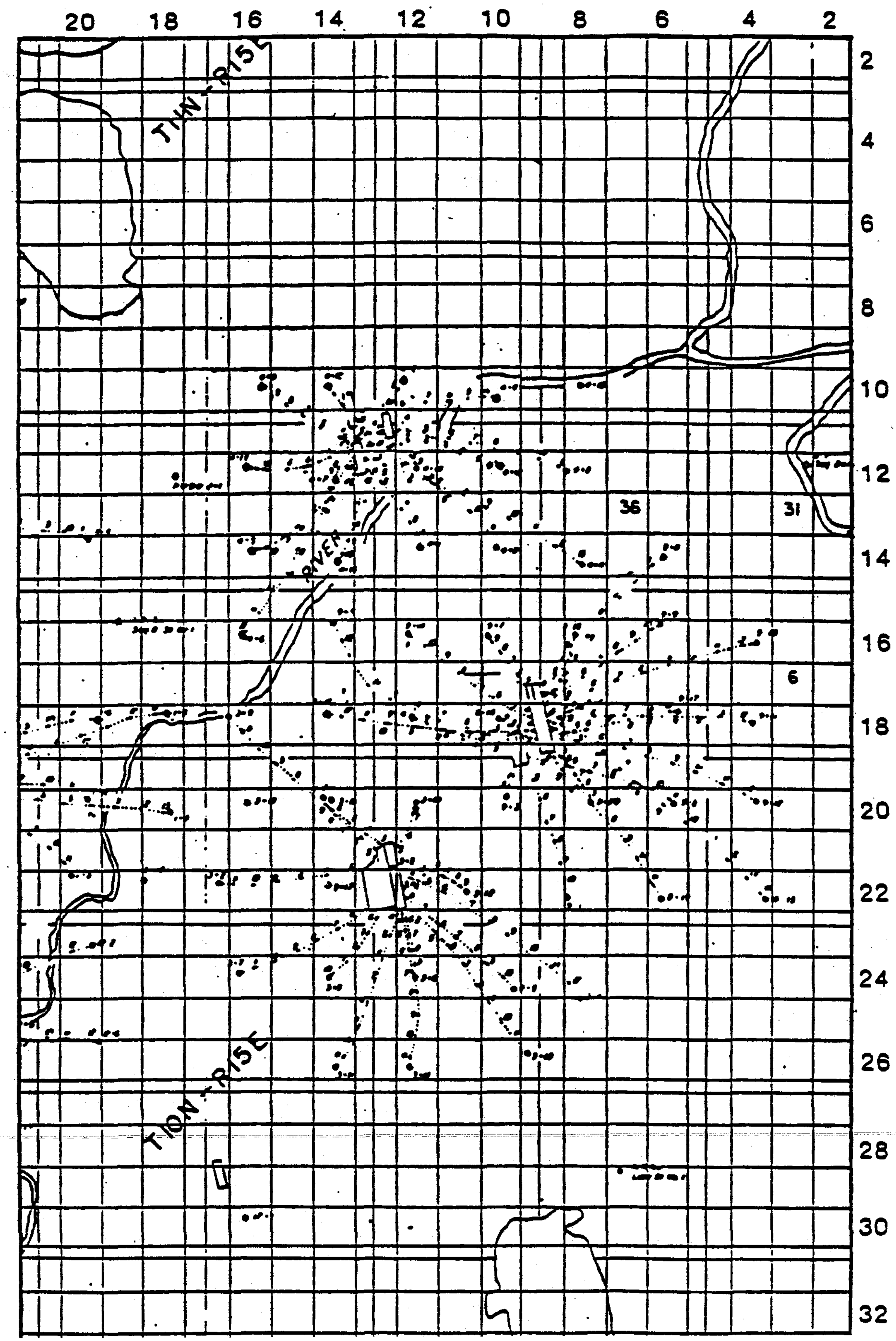


EXHIBIT V-4

FLOW STATION 2 ZONATION - ARCO

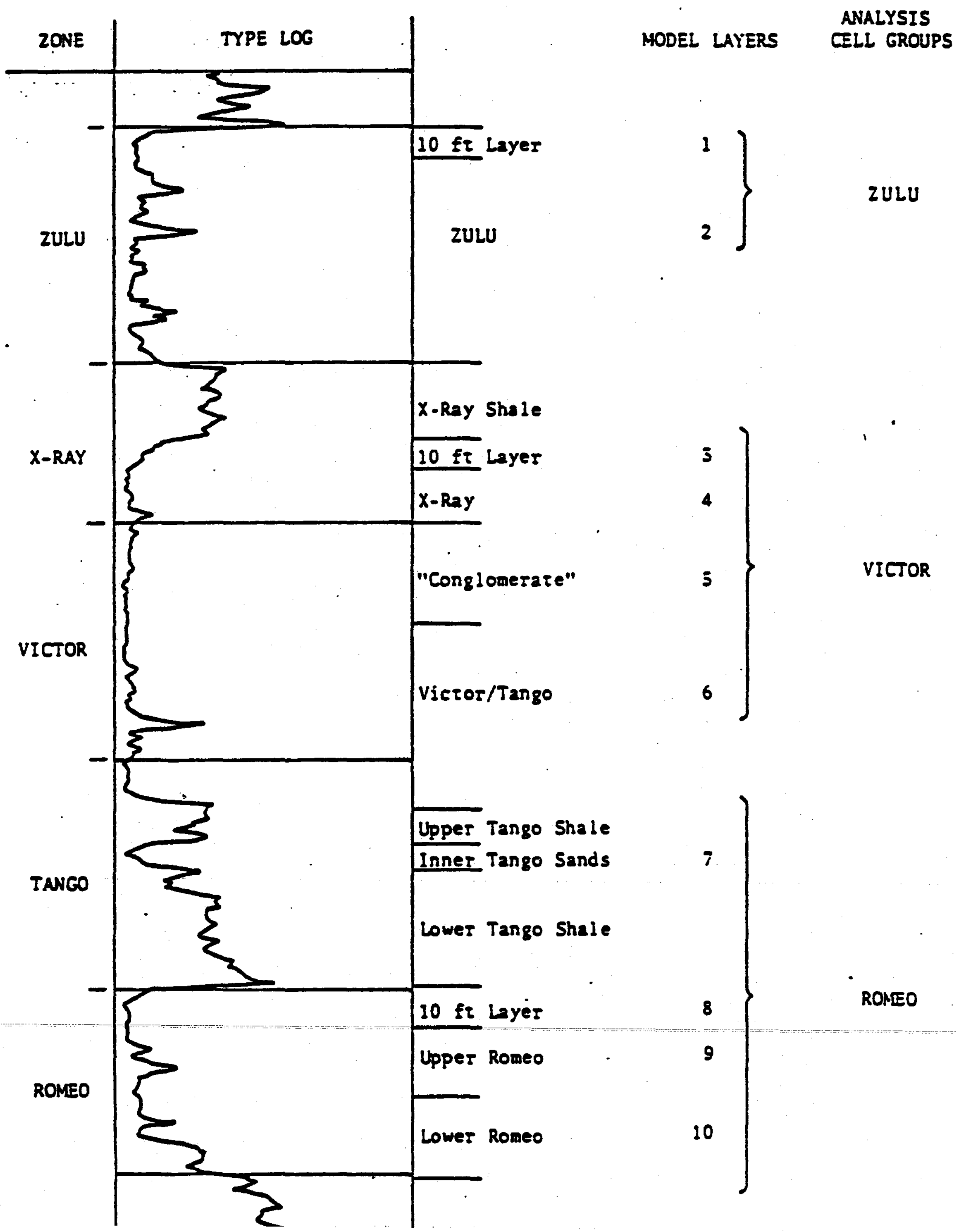
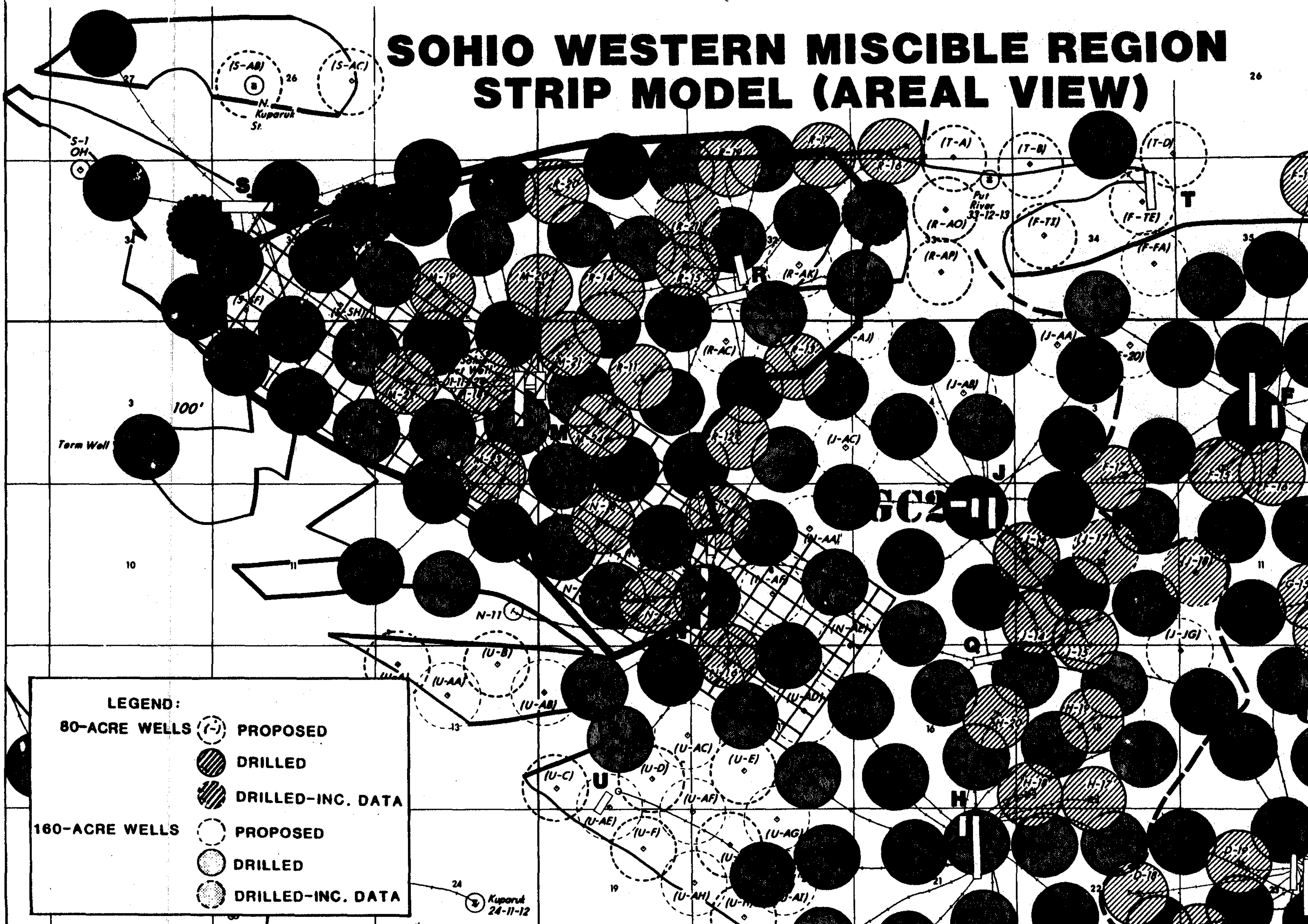


EXHIBIT V-5

SOHIO WESTERN MISCIBLE REGION STRIP MODEL (AREAL VIEW)



PE-1-NS-S-1731

EXHIBIT V-6

SOHIO WESTERN MISCIBLE REGION STRIP MODEL

NWFB CROSS SECTION

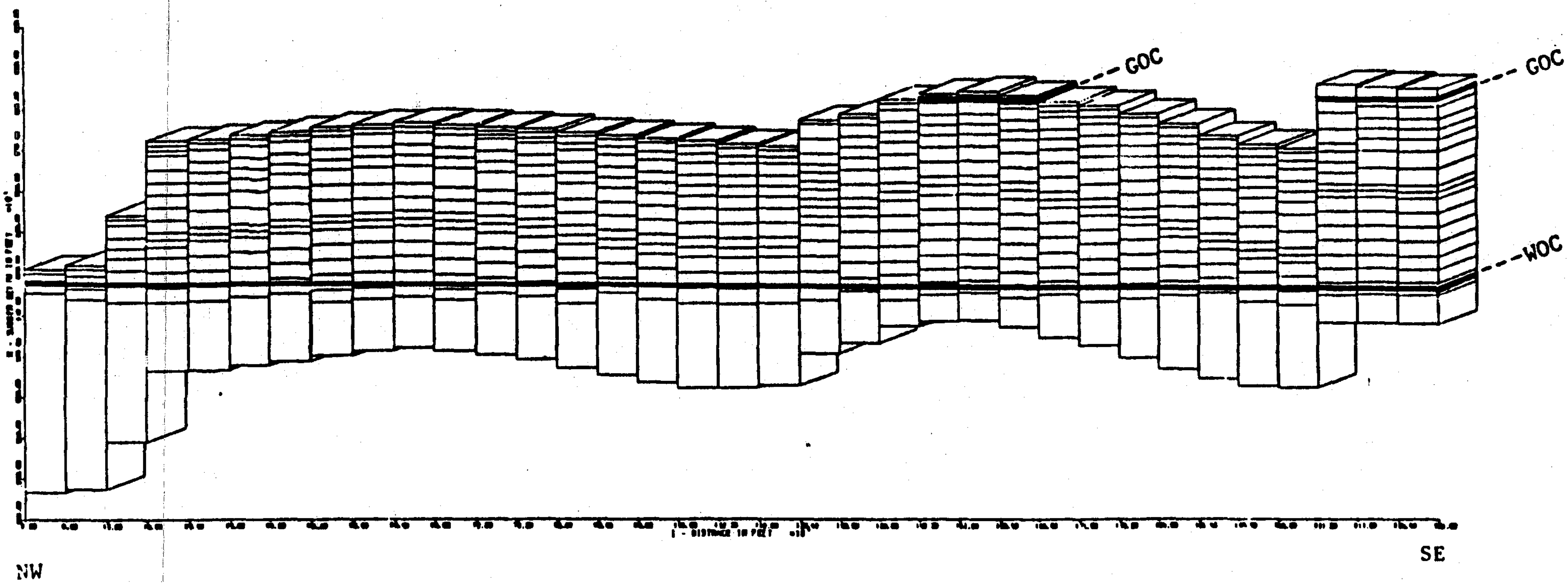
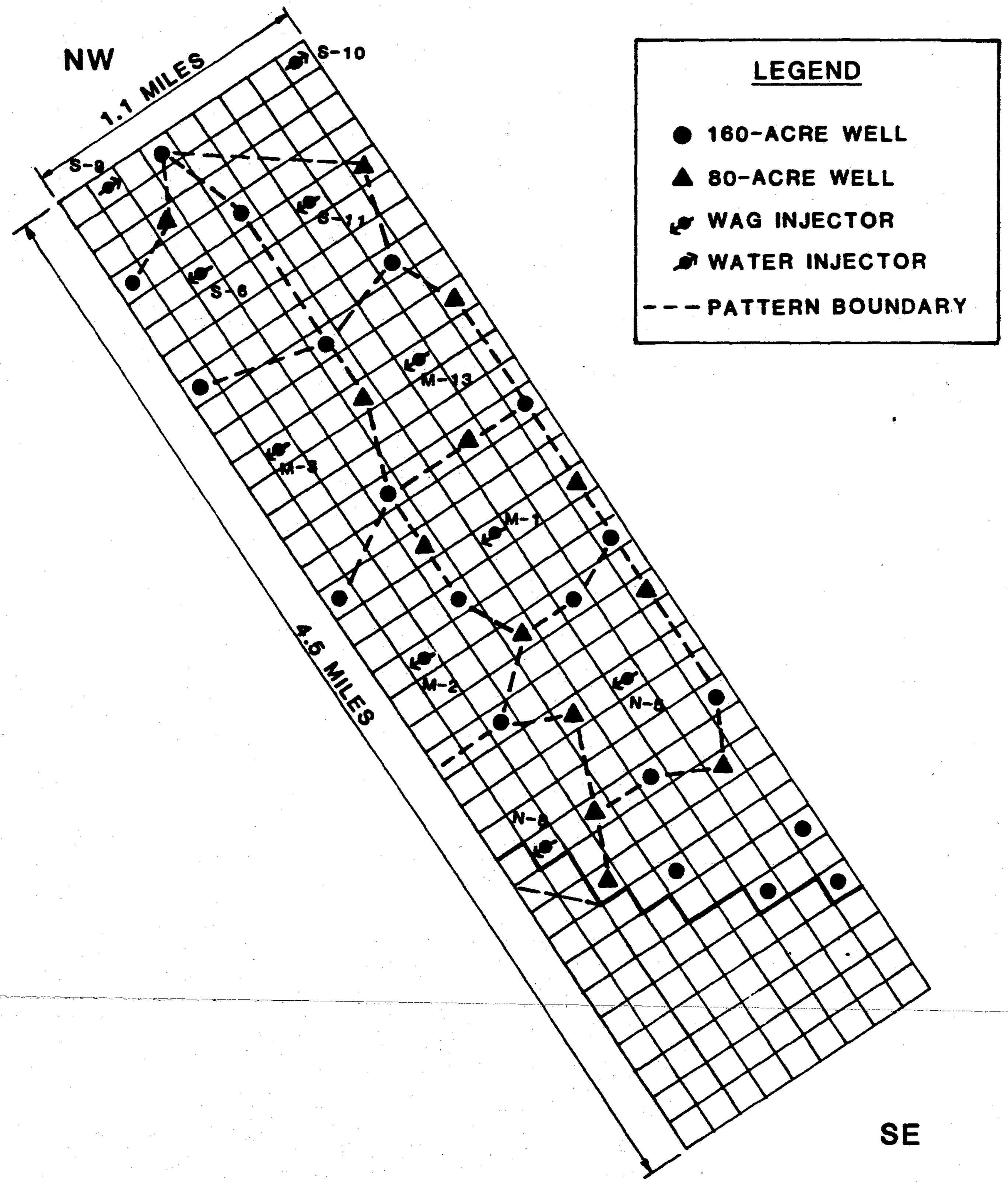


EXHIBIT V-7

SOHIO WESTERN MISCIBLE REGION STRIP MODEL

NINE SPOT PATTERN DEVELOPMENT



DWG Nº PE-1-NS-S-1729

SOHIO EASTERN MISCIBLE REGION STRIP MODEL (AREAL VIEW)

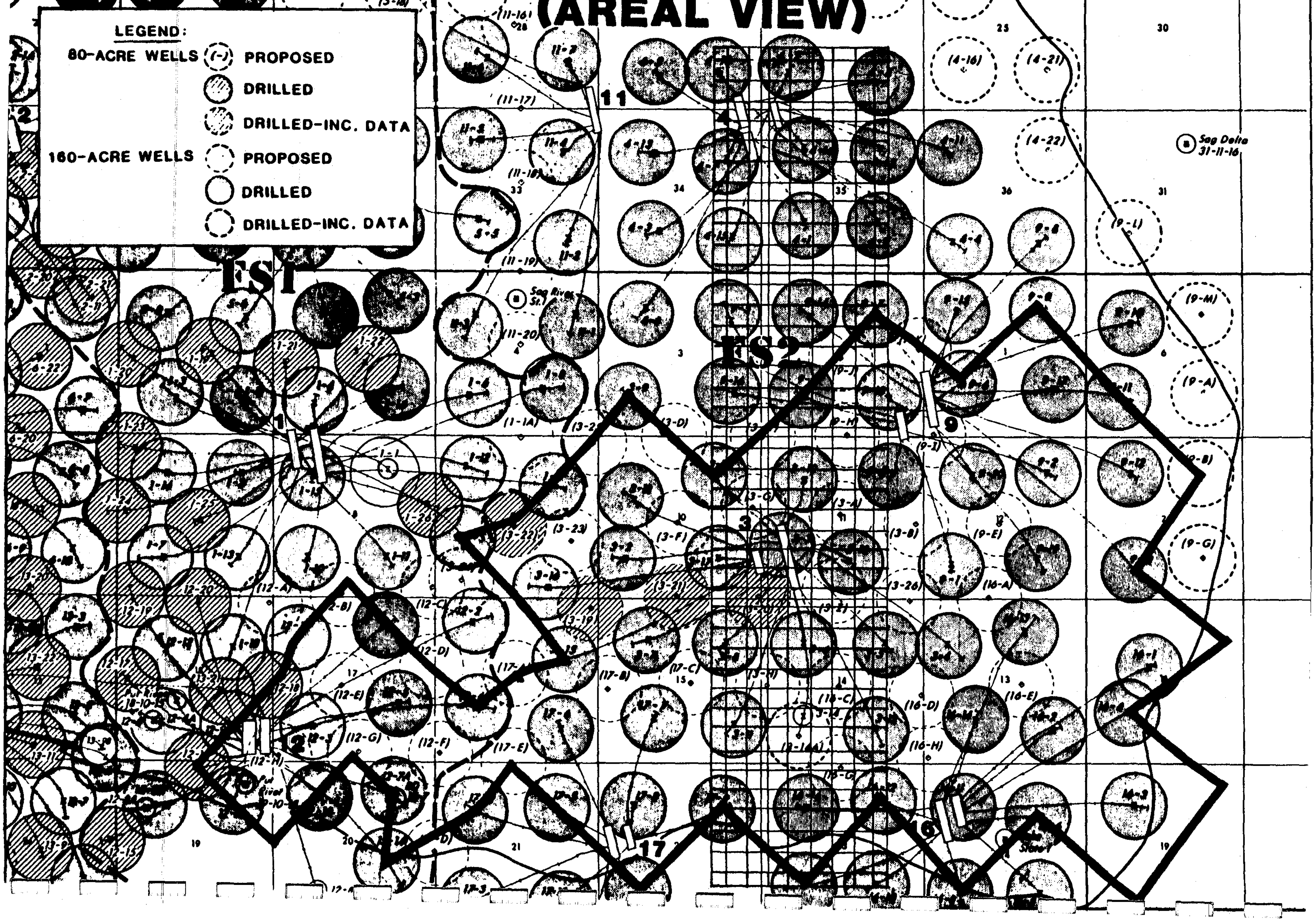


EXHIBIT V-9

SOHIO EASTERN MISCIBLE REGION STRIP MODEL

FS-2 CROSS SECTION

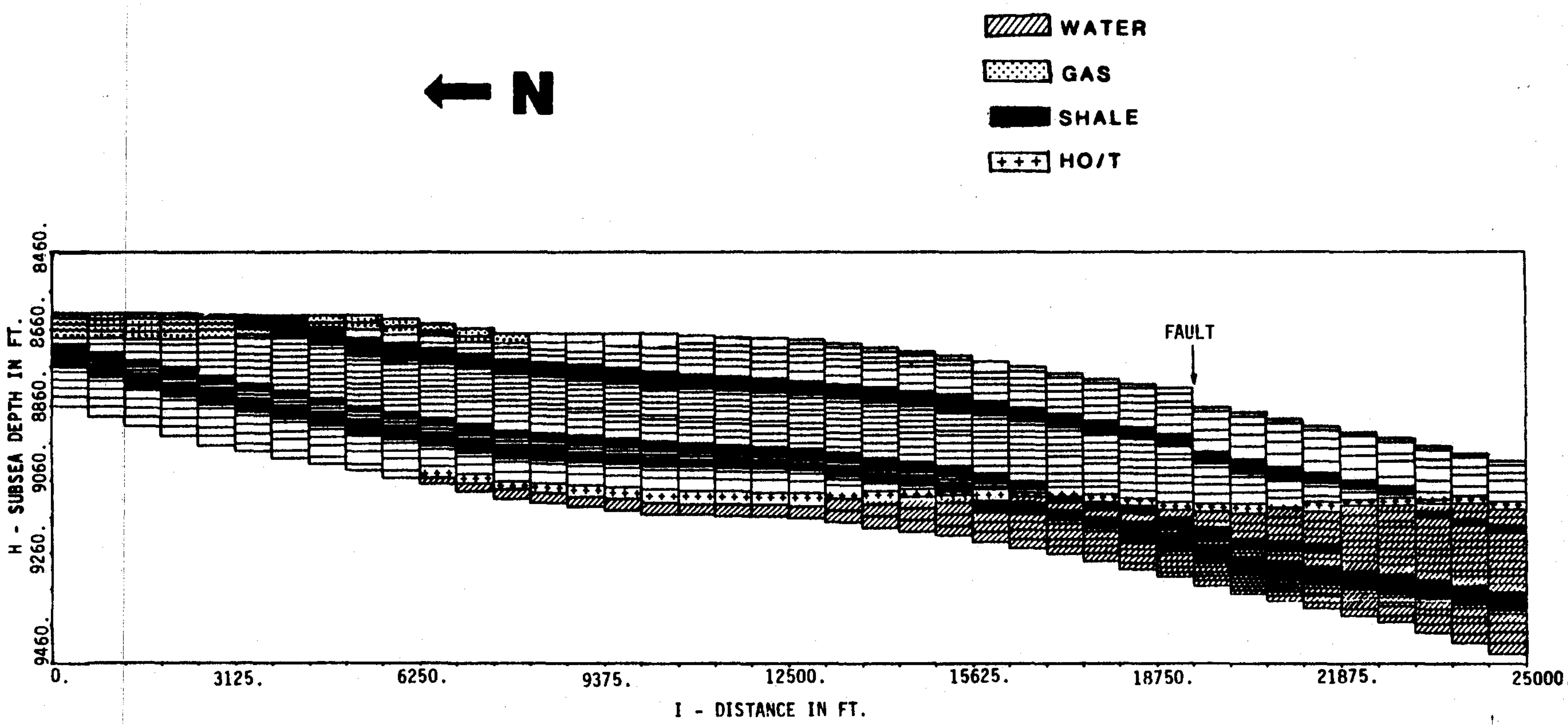
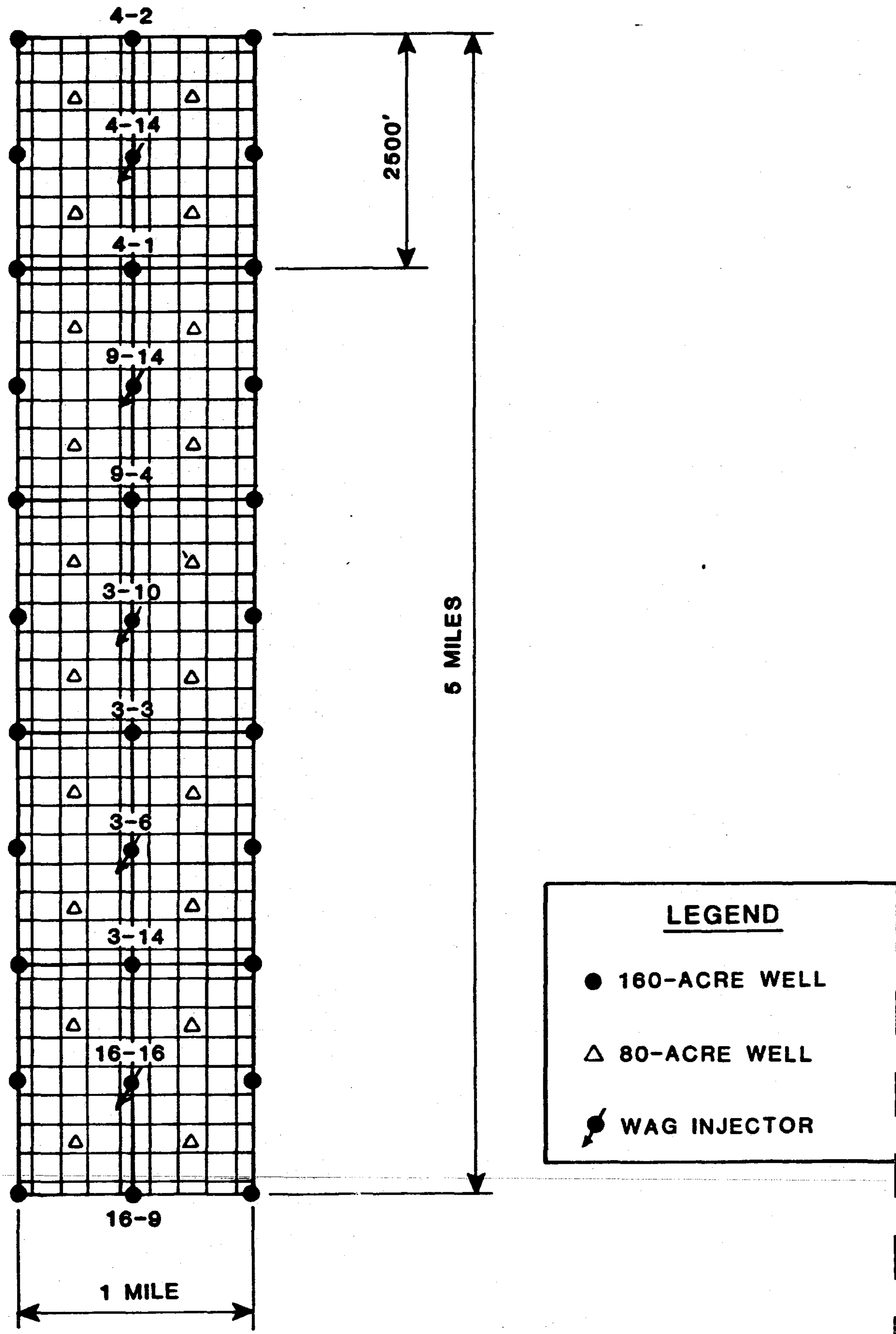


EXHIBIT V-10

SOHIO EASTERN MISCIBLE REGION STRIP MODEL

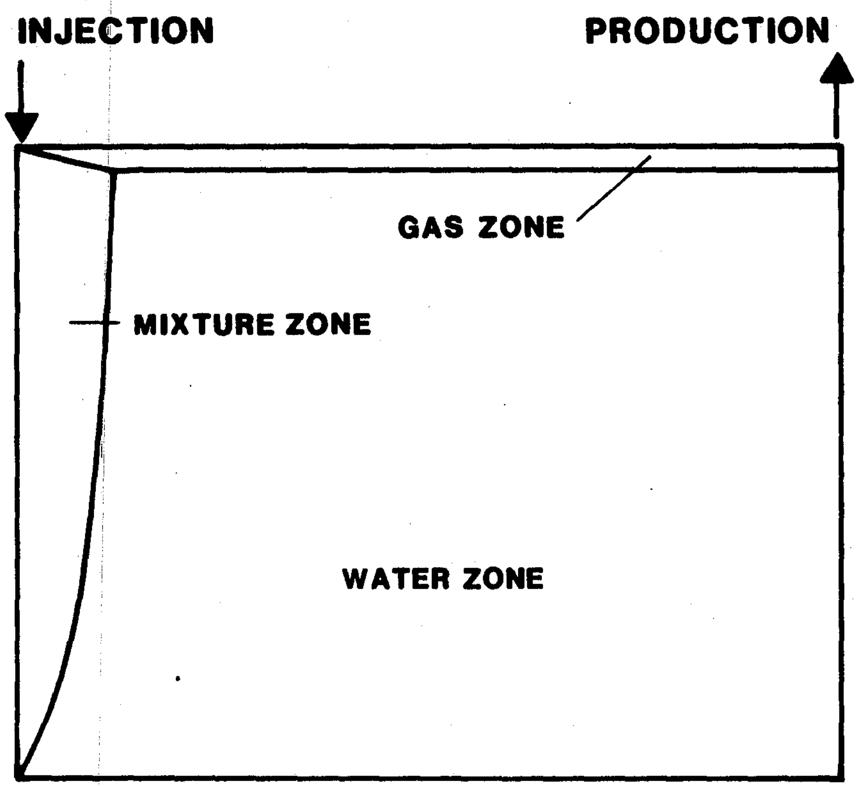
NINE SPOT PATTERN DEVELOPMENT



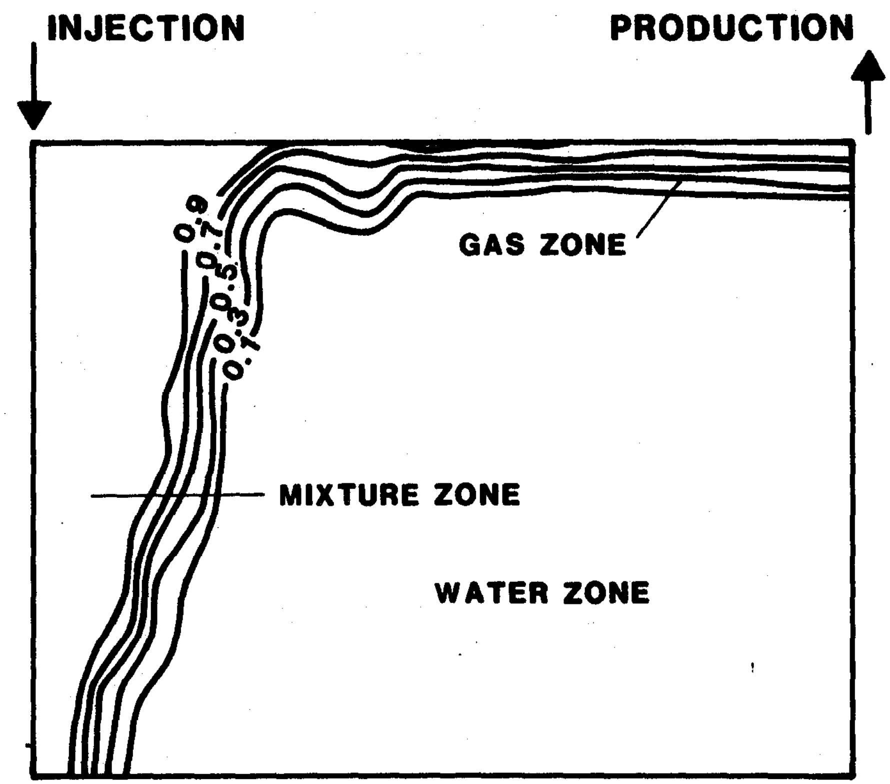
DWG. Nº PE-I-NS-S-1730

EXHIBIT V-11

EXXON SOLVENT CONCENTRATION PROFILES



ANALYTICAL MODEL



METHOD OF CHARACTERISTICS MODEL (PRSIM)

EXHIBIT V-12

EXXON 2-D MODEL

TYPICAL PRSIM CROSS-SECTION

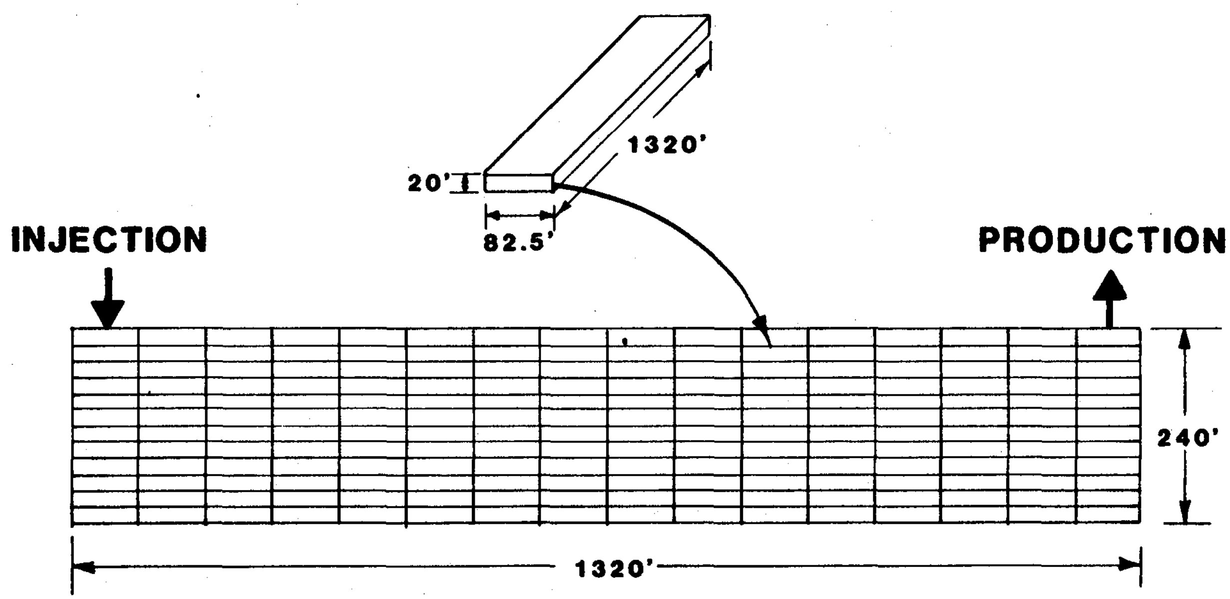


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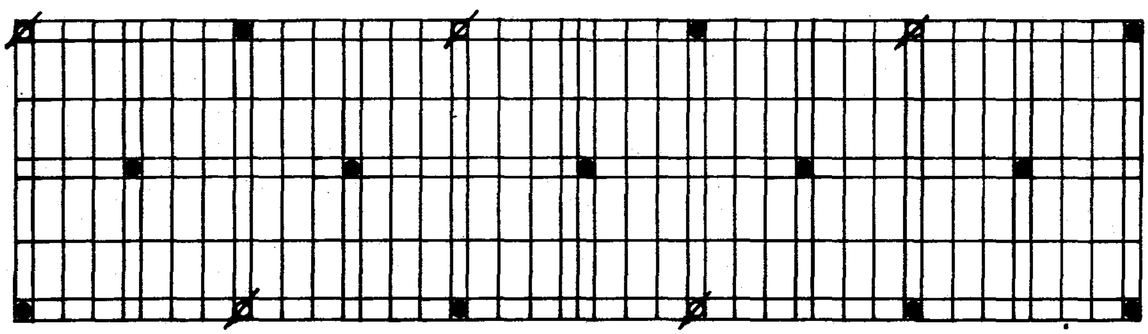
EXHIBIT V-13

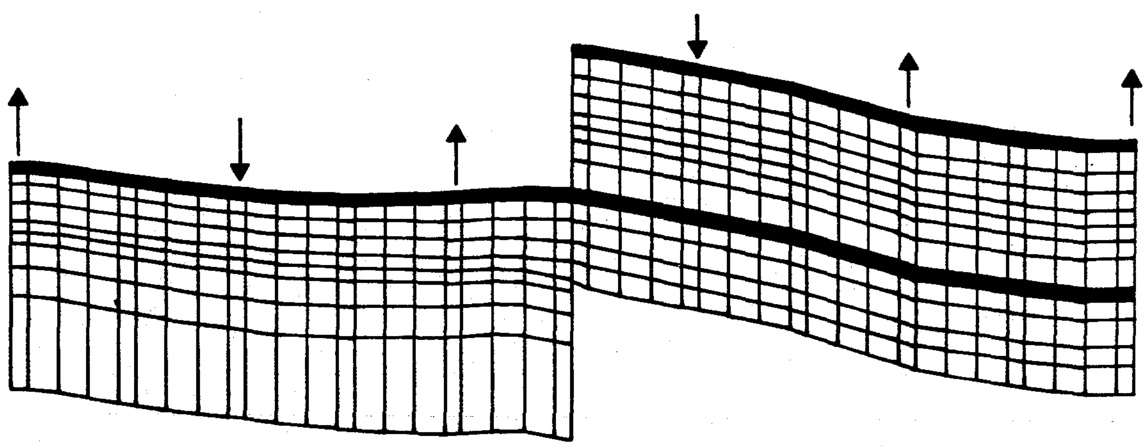
EXXON 3-D STRIP MODEL

NWFB GRID GEOMETRY

AREAL VIEW



CROSS-SECTION VIEW



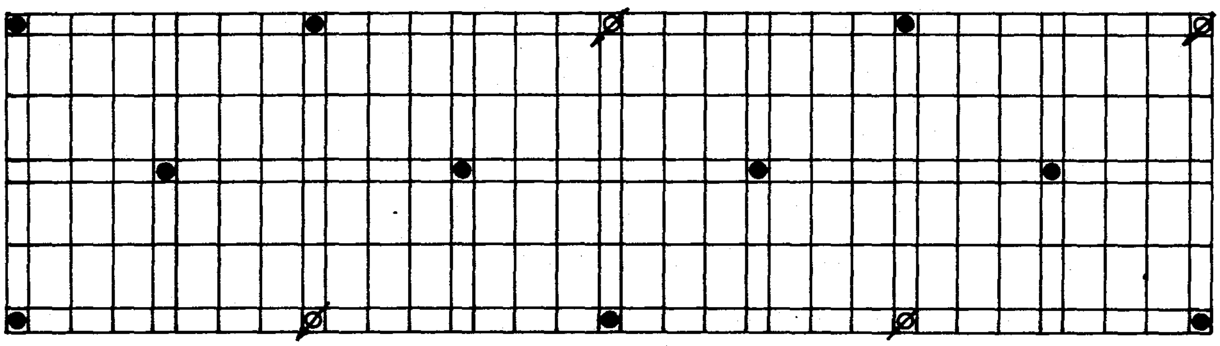
⌀ **INJECTOR**
● **PRODUCER**

EXHIBIT V-14

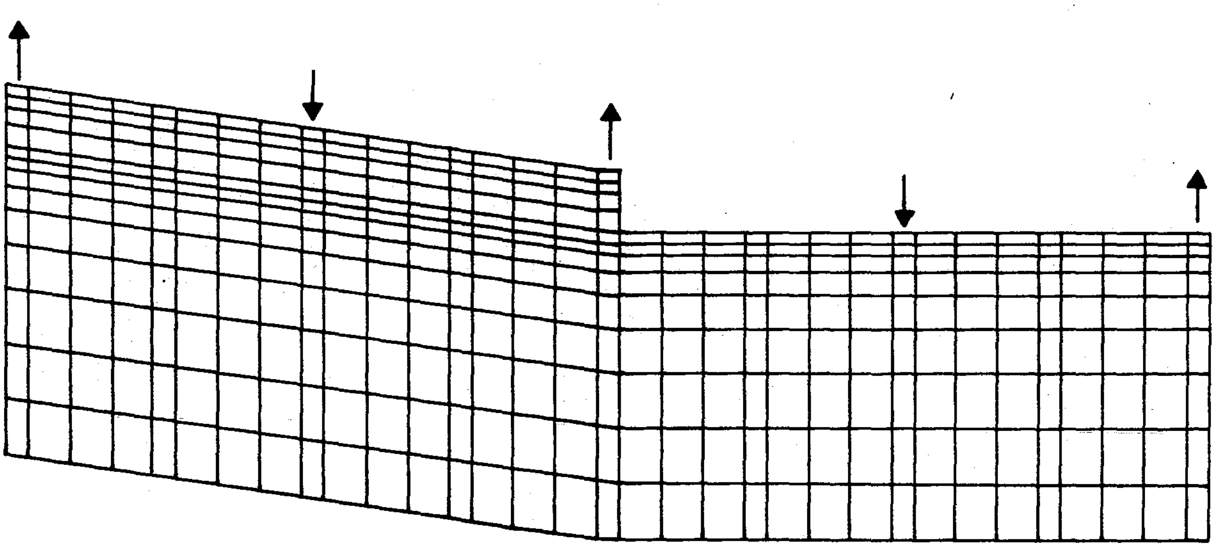
EXXON 3-D STRIP MODEL

WPWZ GRID GEOMETRY

AREAL VIEW



CROSS-SECTION VIEW



ø INJECTOR

• PRODUCER

EXHIBIT V–15
OIL RATE PROJECTIONS

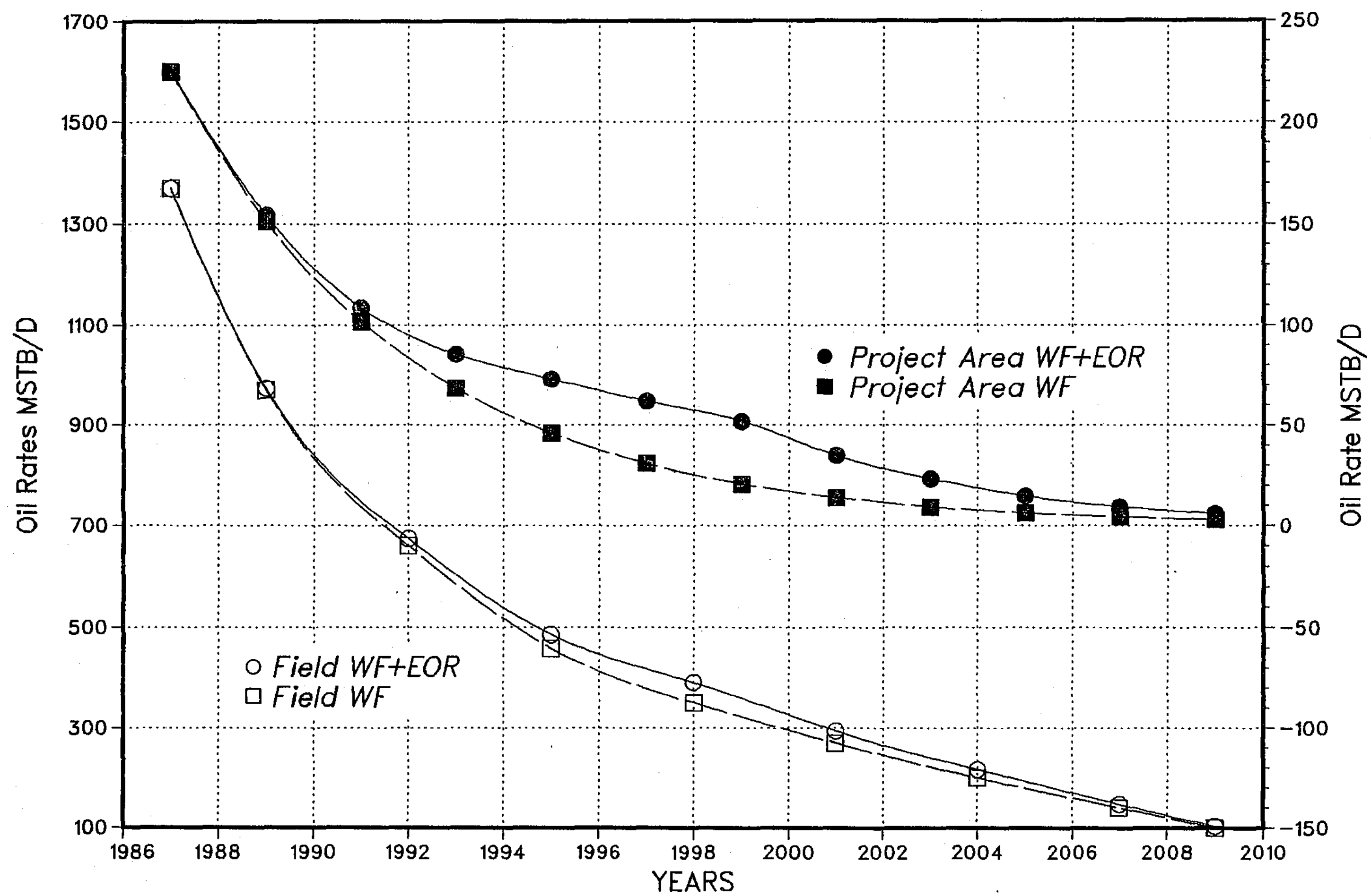
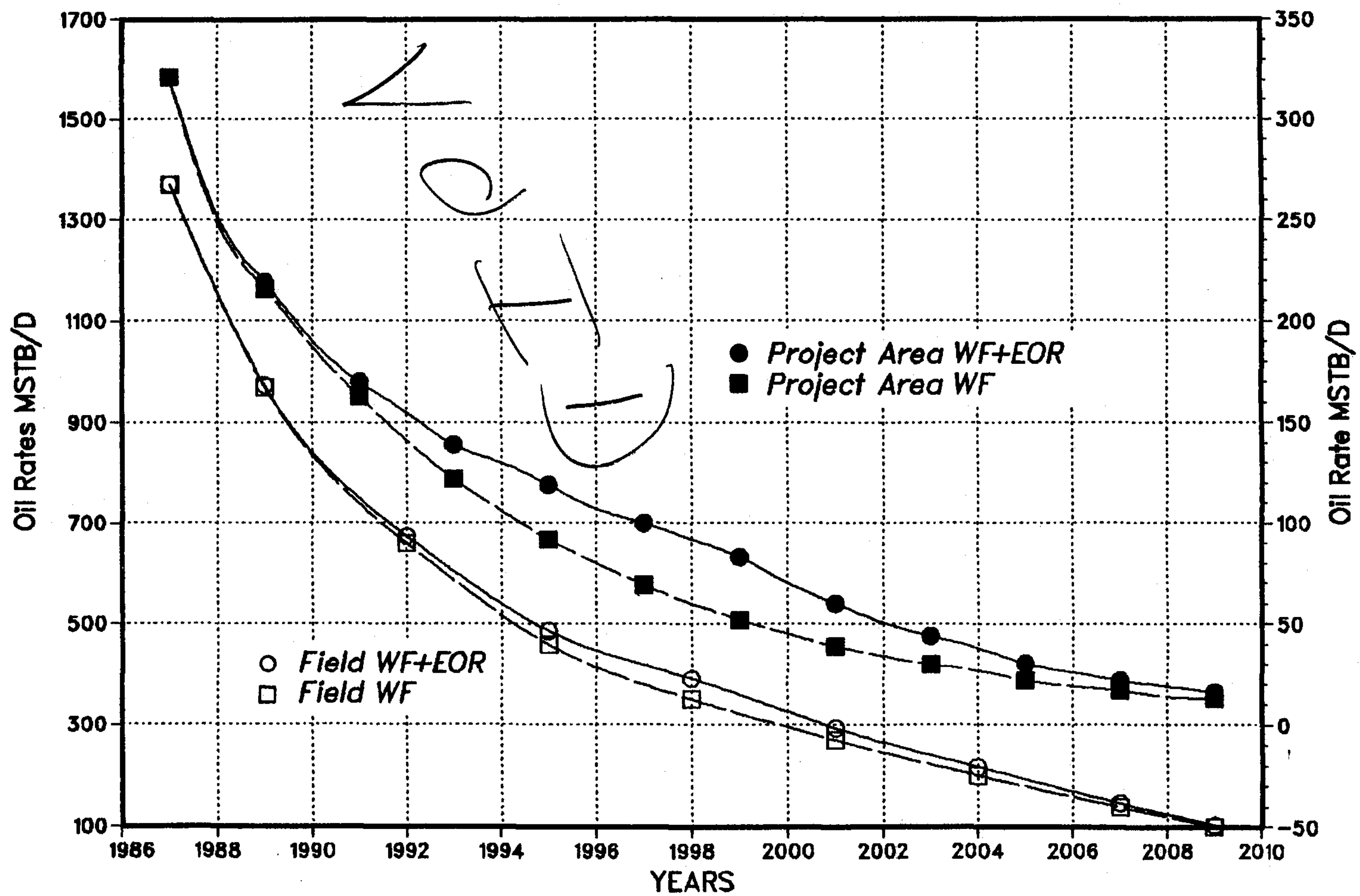


EXHIBIT V–15
OIL RATE PROJECTIONS



PART VI

PART VI - WINDFALL PROFIT TAX QUALIFICATION REQUIREMENTS

For purposes of the "Crude Oil Windfall Profit Tax Act of 1980," an enhanced oil recovery project is a "qualified tertiary recovery project" if the Operator submits a certification to the Secretary of the Treasury stating that a designated jurisdictional agency has approved the project as meeting the requirements in I.R.C. § 4993(c)(2)(A)-(C) which are:

(A) the project involves the application (in accordance with sound engineering principles) of one or more tertiary recovery methods which can reasonably be expected to result in more than an insignificant increase in the amount of crude oil which will ultimately be recovered,

(B) the date on which the injection of liquids, gases, or other matter begins is after May 1979, and

(C) the portion of the property to be affected by the project is adequately delineated.

The AOGCC has been designated by the Governor in accordance with I.R.C. § 4993(d)(5)(A)(i) as the jurisdictional agency responsible for approving tertiary recovery projects located on non-federal lands in the State of Alaska for purposes of the WPT Act. As will be discussed in the following paragraphs, the Prudhoe Bay Miscible Gas Project meets the requirements of subparagraphs (A), (B) and (C) of I.R.C. § 4993(c)(2) and should therefore be approved by the AOGCC.

QUALIFIED TERTIARY RECOVERY METHOD

The Prudhoe Bay Miscible Gas Project involves the application of a qualified tertiary recovery method. The term "tertiary recovery method" is defined in the WPT Act as:

(A) any method which is described in subparagraphs (1) through (9) of section 212.78(c) of the June 1979 energy regulations, or

(B) any other method to provide tertiary enhanced recovery which is approved by the Secretary for purposes of this chapter. [I.R.C. § 4993(d)(1)]

The term "June 1979 energy regulations" as used in the above definition is defined in I.R.C. § 4996(b)(8)(C) as Department of Energy regulations which existed on June 1, 1979 including final action taken pursuant thereto before June 1, 1979, and including action taken before, on, or after such date with respect to incremental production from qualified tertiary recovery projects.

The enriched gas WAG injection method which is planned for use in the Prudhoe Bay Miscible Gas Project is a miscible fluid displacement method. Miscible fluid displacement is listed as a tertiary recovery method in subparagraph (1) of section 212.78(c) of the June 1979 energy regulations. This definition of miscible fluid displacement was amended on August 30, 1979. These amendments added pore volume requirements to the miscible fluid definition and also changed "gas or alcohol" to "fluid." The June 1979 definition of miscible fluid displacement and the August 30, 1979 amendments thereto are in Exhibit VI-1.

The WAG injection process planned for this Project meets all the requirements in the June 1979 definition of miscible fluid displacement as well as the requirements added by the August 30, 1979 amendments. Enriched natural gas will be injected into the oil reservoir at pressure levels such that the gas at the reservoir temperature and pressure is reasonably expected to be more than 10 percent of the reservoir pore volume being served by the injection wells. The process involves the alternating and/or concurrent injection of water and gas which is specifically recognized in the energy regulations.

SOUND ENGINEERING PRINCIPLES

The Prudhoe Bay Miscible Gas Project has been planned and will be implemented and operated in accordance with sound engineering principles. The planning and implementation of the Project has been under the direct supervision of qualified and experienced reservoir and production engineers. Miscible fluid displacement using enriched hydrocarbon gas was selected as the best method to use at this time for this portion of the reservoir after a comparative examination of various methods based on formation type, injectant availability, and process costs. The various other methods which were examined for potential use in the Project were discussed in Part II of this Application.

The Project was planned after a thorough examination of the Sadlerochit formation underlying the Project Area including its geological characteristics, reservoir pressure, current and projected well productivity, statistical data relating to actual and projected well performances, viscosity, pressure build-up and sweep efficiency analyses. The Project applies the miscible fluid displacement method in a manner which is generally recognized and accepted in the professional literature of engineering as likely to increase the amount of crude oil that can economically be recovered from the Project Area.

MORE THAN AN INSIGNIFICANT INCREASE IN RECOVERY

It is reasonable to expect that the Project will result in more than an insignificant increase in the amount of crude oil which will ultimately be recovered from the Project Area. The implementation of the Prudhoe Bay Miscible Gas Project is estimated to recover 115 MMSTB of additional oil, providing an increase in ultimate recovery of 5.2 percent (OOIP) over 80 acre pattern waterflood in the affected areas. This corresponds to an increase of 12.1 percent in the recoverable reserves from the Project Area. A recovery of 115 million additional barrels of oil is clearly more than an insignificant increase in the ultimate recovery of crude oil.

INJECTION OF GAS AFTER MAY 1979

A Project will qualify under the WPT Act only if the date the injection of liquids, gases, or other matter begins is after May 1979. The PBMGP satisfies this requirement because injection of the enriched miscible gas in the Project Area will begin after this date.

ADEQUATE DELINEATION OF PROJECT AREA

If a tertiary recovery project is expected to increase the ultimate recovery of crude oil from only a portion of a D.O.E. property, that portion is required to be treated as a separate property for incremental tertiary oil purposes (I.R.C. § 4993(d)(3)). The Prudhoe Bay Miscible Gas Project will affect only a portion of the Prudhoe Bay Unit which is one D.O.E. property.

As discussed previously, two noncontiguous areas will be affected by this Project, i.e., the Eastern Miscible Region and the Western Miscible Region. The Eastern Miscible Region involves 25 injection patterns and encompasses approximately 8,100 acres.

The boundaries of the Eastern Miscible Region are defined by the outer WAG affected producing wells of the nine spot patterns (or by the five spot patterns on the southern and eastern edges, if utilized). See Exhibit III-4. Further confinement and, hence, delineation is provided by the sealing Lower Cretaceous Unconformity to the east, and by the downdip productive limit of the reservoir to the south. The Project will affect all the light oil column of the Sadlerochit Reservoir which lies within the surface boundaries of the Eastern Miscible Region (Exhibit III-5).

The Western Miscible Region involves 17 injection patterns and encompasses approximately 4,800 acres. The boundaries of the Western Miscible Region are defined by the outer WAG affected producing wells of the nine spot patterns to the east and by faulting to the north and west (Exhibit III-8). The Project will affect the light oil column of the Sadlerochit Reservoir which lies within the surface boundaries of the Western Miscible Region (Exhibit III-9).

From the above it is clear that the portion of the Prudhoe Bay Unit which will be affected by the Prudhoe Bay Miscible Gas Project has been adequately delineated. This portion of the Prudhoe Bay Unit will be treated as a separate property for purposes of calculating the WPT base level for the Project and the amount of incremental tertiary oil removed each month from the property. A reasonable allocation method will be applied to production from any peripheral well to determine appropriately the production from within the Project Area.

EXHIBIT VI-1

Definition of Miscible Fluid Displacement

June 1979 D.O.E. Regulations

- Miscible fluid displacement, i.e., an oil displacement process in which gas or alcohol is injected into an oil reservoir at pressure levels such that the injected gas or alcohol and reservoir oil are miscible. The process may include the concurrent, alternating, or subsequent injection of water. The injected gas may be natural gas, enriched natural gas, a liquefied petroleum gas slug driven by natural gas, carbon dioxide, nitrogen, or flue gas. Gas cycling, i.e., gas injection into gas condensate reservoirs, is not a miscible fluid displacement technique nor a tertiary enhanced recovery technique within the meaning of this section.

August 30, 1979, Amendments (Effective October 1, 1979)

- "Miscible fluid displacement" means an oil displacement process in which fluid is injected into an oil reservoir at pressure levels such that the injected fluid and reservoir oil are miscible. The process may include the concurrent, alternating, or subsequent injection of water. The injected fluid measured at reservoir temperature and pressure must, with reasonable expectations, be more than 10 percent of the reservoir pore volume being served by the injection well or wells. Gas cycling, i.e, gas injection into gas condensate reservoir, is not a miscible fluid displacement technique nor a tertiary enhanced recovery technique.

PART VII

PART VII - SUMMARY

In this application the Owners have presented sufficient facts and information to demonstrate that the Miscible Gas Project, which is planned for the Prudhoe Bay Unit, meets the requirements of I.R.C. § 4993(c)(2)(A), (B), and (C). Specifically, we have demonstrated that:

a) The Project involves the application of a miscible fluid displacement method which is a qualified tertiary recovery method as that term is defined in I.R.C. § 4993(d)(1).

b) The Project has been planned and will be implemented and operated in accordance with sound engineering principles.

c) The Project is reasonably expected to increase the ultimate recovery of crude oil from the Project Area by 115 million barrels, an amount which is clearly more than an insignificant increase.

d) The injection of miscible gas will begin after May 1979.

e) The portion of the Prudhoe Bay Unit which will be affected by this Project has been adequately delineated in this Application.

Based on the foregoing facts and information, the Owners respectfully request that the AOGCC, in its capacity as a designated jurisdictional agency, issue an order approving the Prudhoe Bay Miscible Gas Project as meeting the requirements of subparagraphs (A), (B), and (C) of I.R.C. § 4993(c)(2).

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TECHNICAL REFERENCES

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