

“Increasing Heavy Oil Reserves in The Wilmington Oil Field
Through Advanced Reservoir Characterization
And Thermal Production Technologies”
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ABSTRACT

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California through the testing and application of advanced reservoir characterization and thermal production technologies. The successful application of these technologies will result in expanding their implementation throughout the Wilmington Field and, through technology transfer, to other slope and basin clastic (SBC) reservoirs.

The existing steamflood in the Tar zone of Fault Block II-A (Tar II-A) has been relatively inefficient because of several producibility problems which are common in SBC reservoirs: inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil and non-uniform distribution of the remaining oil. This has resulted in poor sweep efficiency, high steam-oil ratios, and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

A suite of advanced reservoir characterization and thermal production technologies are being applied during the project to improve oil recovery and reduce operating costs, including:

1. Compiled a computer database of production and injection data, historical reservoir engineering data, detailed core studies, and digitized and normalized log data to enable work on the basic reservoir engineering study and 3-D deterministic and stochastic geologic models.
2. Developed a basic reservoir engineering study to evaluate the role of aquifer water influx, determine the original oil in place from gas production data to support the material balance work, and calculate the cumulative oil, gas and water recovery from the Tar zone.
3. Developed a new, cost-effective procedure to analyze new core data and correlations to revise old core analysis data.
4. Developed a neural network system and tested a procedure for correlating geologic markers in turbidite sequences.
5. *Tracer studies to track water salinity and non-radioactive chemicals provided mixed, but valuable results for future tracer work.
6. *Developed a petrophysical rock-log model that identified five rock types to describe the sands and shales within the "T" and "D" formations in Tar II-A. An associated study evaluated stress-dependent porosity and permeability in unconsolidated sand formations.
7. Developed three-dimensional (3-D) deterministic thermal reservoir simulation models to aid in steamflood and post-steamflood reservoir management and subsequent development work. The development of a 3-D stochastic thermal reservoir simulation model was completed through the geostatistical analysis of formation porosity and permeability in the Tar II-A.

8. Developed computerized three-dimensional (3-D) visualizations of the geologic and reservoir simulation models to aid analysis.
9. Performing detailed studies on the geochemical interactions between the steam, formation rock and associated fluids.
 - a. *Researching the use of steam injection to create sand consolidation well completion in unconsolidated sand formations.
 - b. Completed study on mineralogy and source of wellbore scales.
 - c. *Evaluating shale sensitivity to steam and heat.
10. Drilled three observation wells and two core hole/observation wells to monitor steam drive operations and to obtain critical log and core data for the stochastic geologic and reservoir simulation models.
11. Drilled and completed four horizontal wells in Tar II-A utilizing a new and lower cost drilling program.
12. Installed a 2100-ft, 14" insulated steam line, underneath a harbor channel to Terminal Island to service the four new horizontal wells.
13. Testing and proposed application of thermal recovery technologies to increase oil production and reserves:
 - a. Performing pilot tests of cyclic steam injection and production on new horizontal wells.
 - b. *Performing pilot tests of hot water-alternating-steam (WAS) injection in the existing steam drive area to improve thermal efficiency.
14. *Performing pilot steamfloods with the horizontal injectors and producers in the Tar II-A and Tar V using a pseudo steam-assisted gravity-drainage process.
15. *Performing advanced reservoir management through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring and evaluation.
16. *Developed and implemented a post-steamflood operational plan for Tar II-A based on the 3-D reservoir simulation model to address the loss of steam injection and apparent steamflood-related surface subsidence.
17. *Maintaining post-steamflood reservoir fill-up of steam chest using flank cold water injection.
18. *Reservoir pressure monitoring system developed for post-steamflood operations.
19. Developed a scrubber to strip H₂S from steamflood-related produced gas streams at less than half the previous cost.
20. Developed a 7ppm NO_x 50MMBtu/hr oil field steam generator for Tar V steamflood that uses the non-commercial low Btu produced gas from Tar II-A steamflood.
21. *Expanded the steamflood project to include the five well horizontal steamflood pilot in the Fault Block V Tar zone.

Note: The items listed above with asterisks (*) are activities that are addressed in this report and are either ongoing or have been completed.

The Project Team Partners include the following organizations:

1. The City of Long Beach - the operator of the field as a trustee of the State of California-granted tidelands;
2. Tidelands Oil Production Company - the contract operator of the field for the City of Long Beach, and the party in-charge of implementing the project;
3. The University of Southern California, Petroleum Engineering Program - consultants to the project, playing a key role in reservoir characterization and simulation; and
4. GeoSystems, formerly David K. Davies and Associates - consultants to the project regarding petrography, rock- based log modeling, and geochemistry of rock and fluid interactions.

EXECUTIVE SUMMARY

Introduction

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California. This is realized through the testing and application of advanced reservoir characterization and thermal production technologies. It is hoped that the successful application of these technologies will result in their implementation throughout the Wilmington Field and, through technology transfer, will be extended to increase the recoverable oil reserves in other slope and basin clastic (SBC) reservoirs.

The project involves the implementation of thermal recovery in the Tar zone of Fault Blocks II-A (Tar II-A) and V (Tar V). The more mature Tar II-A steamflood has been relatively inefficient due to several producibility problems commonly associated with SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and non-uniform distribution of the remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

The first two years of the project, from March 30, 1995 to March 31, 1997, began with the application of advanced reservoir characterization methods to enable improved design and application of thermal recovery methods, including the drilling of four horizontal steamflood wells and five observation wells. Historical data was compiled and new data was acquired to perform basic reservoir engineering and to develop advanced geologic and rock-log models. A state-of-the-art 2100 ft steam line was installed under a harbor channel to provide steam to the horizontal wells on Terminal Island. The horizontal wells underwent a new completion technique that controls sand production by injecting steam through limited-entry perforations. The injected steam also resulted in high peak oil production rates of 200-300 BOPD per well. Other completed work included a neural network analyzer that can recognize key log traits for correlating sand sequences and a study on the comparative thermal recovery efficiencies of vertical and horizontal wells.

This report is a compilation of studies completed since April 1, 1997. Members of all four project partners performed the studies and the topics encompass the entire range of upstream petroleum technology including reservoir characterization, reservoir simulation, rock mechanics, reservoir surveillance, sub-surface and facility engineering, and operations. The objective of this report is to show the relationship between the various studies and how the synergy of technical transfer between team members with diverse backgrounds can significantly improve the performance of a project.

Work Completed Prior to Reporting Period

Compilation and Analysis of Existing Data

A computer database of production and injection data, historical reservoir engineering data, detailed core studies, and digitized and normalized log data was completed to start work on the basic reservoir engineering study and 3-D deterministic and stochastic geologic models. Logs from 171 wells were digitized and normalized for use in the rock-log and geologic models. The digitized logs included the electric or induction and the spontaneous potential (SP) and/or gamma ray (GR) for all of the wells and the formation density and compensated neutron logs for the nine cored wells used for the rock-log model. The 171 wells (of over 600 wells penetrating the Tar zone in the area) are distributed throughout the fault block. New data acquired included Measurement While Drilling (MWD) and Logging While Drilling (LWD) data from the installation of four new horizontal wells, open hole logs and conventional cores from five new observation wells and a tracer study.

Advanced Reservoir Characterization

A basic reservoir engineering study was conducted and a report generated that evaluated the role of aquifer water influx, determined the original oil in place from gas production data to support the material balance work, and calculated the cumulative oil, gas and water recovery from the Tar zone. Allocating oil, gas, and water production to each well and to each zone completed in the wells was a problem because multiple sands were commingled in most of the wells. This was evident from using this data in the analysis of primary and waterflood recoveries and material balance. For this reason, multiple approaches were used to calculate original oil in place (OOIP) and cumulative oil, gas and water recoveries from the Tar sands. The study included permeability estimates from performance data, compared water injection profile surveys to the allocated injection volumes for each sub-zone, determined vertical communication between sands, evaluated the aquifer for water influx and determined original oil in place from gas saturations to support the material balance work. The quality of the new and old well logs was evaluated for determining log-derived OOIP, oil saturations over time, and the validity of geologic marker picks. The calculated OOIP using the different methods ranged from 98-100 million stock tank barrels of oil, a surprisingly tight range that provided more confidence of the methodologies used and OOIP estimates.

A study was also completed on the projected steam drive recoveries from vertical and horizontal wells and the diagnostic methods for evaluation of steam displacement between horizontal injectors and producers. The study utilized the TETRAD™ thermal reservoir simulator program, a product of Dyad 88 Software Inc. The aim of the study is to compare recovery from vertical and horizontal well completions as a function of reservoir properties, crude oil characteristics, and injection strategies.

A field pilot study demonstrated a low cost and operationally simple reservoir tracer alternative to obtain information about reservoir rock anisotropy from produced water chemistry data. Normally, reservoir tracer work is expensive and generally performed in one batch treatment that can lead to inconclusive results. This study periodically acquired inexpensive water chemistry data from producers to measure naturally existing cations and anions (salinity) in the produced formation water as affected by dilution from the condensed fresh water in the steam in the Tar II-a steamflood project. The project was conducted over a three-month period on two 7.5-acre inverted seven-spot well patterns with two steamflood injectors per pattern and ten producers. The correlation study showed that the reservoir sand connectivity or preferential permeability path of the steam condensate front trended in a northeast to southwest direction, which is consistent with the geological description of interpreted sand deposition.

On February 14, 1997 the reservoir tracers, ammonium thiocyanate (AT) and lithium chloride (LC), were injected into two hot water-alternating-steam pilot injectors. The tracer work included the issues related to tracer selection, concentrations and volumes and to field sampling, laboratory analyses and interpretation of the produced water results for tracer hits. Samples of produced fluids collected from the first and second rows of producers were analyzed for the ammonium and lithium tracers. The tracer analysis work recorded very few tracer hits above background levels. Upon further review of the tracer selection criteria and steamflood pattern wells used, the project team believes that the disappointing results occurred because the tracers possibly broke down in the very high temperature reservoir environment and because of operational changes related to the rapid conversion of steam injectors to hot water injectors.

Three observation wells and two core hole/observation wells were drilled to monitor steam drive operations and to obtain critical log, core and reservoir pressure data for the stochastic geologic and reservoir simulation models.

A three-dimensional (3-D) deterministic geologic model was completed using the EarthVision™ 3-D imaging software by Dynamic Graphics, Inc. The geologic model was initially completed in June 1995 with ten defined sand tops in the Tar zone. The geologic model was used to drill four horizontal steamflood wells and five observation wells, two of which were conventionally cored throughout the two steamflood formations in the "T" and "D" sands. The geologic model was also used to develop the framework of the 3-D deterministic reservoir simulation model to optimize reservoir management and thermal recovery methods. Since then, the fault picks were re-evaluated and the defined sand tops were increased from ten to eighteen. The model and newly acquired data have identified the existence of a northeast-southwest gradient of sand quality, the presence of a major channel sand cutting through the upper "T" sands, and the existence of previously unmapped faults.

A petrophysical rock-log model was completed that identified five rock types to describe the sands and shales within the "T" and "D" formations. Building the model required the development of empirical relationships between the core and log data and the

porosity and permeability data. The study was performed on the seven wells drilled from 1988-89 that had modern log suites (gamma ray [GR], resistivity, formation density and compensated neutron) and conventional cores through the Tar sands. Defining the five rock types with similar log and reservoir characteristics is critical for the stochastic geologic modeling as it provides an objective means of predicting petrophysical rock types and permeability profiles for "T" and "D" sands in locations where only minimum log data and no core data are available. The model has been applied to uncored wells within the area to aid in reservoir description and permeability modeling for the stochastic and reservoir simulation models. Another important outcome of this study is that traditional log analysis techniques can significantly overestimate shale content and consequently underestimate oil saturation and net oil sand picks in thin-bedded sands. This modeling technique corrects for that problem.

For the stochastic geologic model, a neural network analyzer was developed to analyze the similarities of various zones and sub-zones in terms of sequence stratigraphy using GR logs. Sample stochastic grid block models were test run on the 3-D EarthVision™ visualization software to ensure compatibility. A neural network analyzer can identify the unique well log characteristics of geologic markers in turbidite sequences and quickly correlate hundreds of digitized well logs. The required changes in the character of lithology logs / sand-shale, makes the visual correlation often a very difficult task. With over 600 penetrating well logs through the Tar II-A sands, the need for developing a neural network analyzer to expedite the stochastic geologic modeling was evident.

Following development of the 3-D deterministic geologic model, work began on a 3-D stochastic geologic model to describe the heterogeneous turbidite geology of the Fault Block II-A Tar zone. The reservoir characterization work was first partitioned into sand modeling and shale description projects. Determining sand continuity is of particular importance for turbidite sands, because sand sequences in adjacent wells may look similar but in fact may not be connected because of the lobated nature of the sand sequences. The detailed core analyses work on eleven cored wells located throughout the Tar II-A zone provided the backbone of the stochastic model. The core analysis work on the two wells cored in 1995, OB2-3 and OB2-5, were performed under both in situ overburden pressure of 1800 psi and "routine" minimum pressure of about 300 psi. Most core analysis work performed on unconsolidated sands, including the nine Tar II-A wells cored from 1981-88, use the routine minimum pressure to hold the core sample together. Performing core analysis at higher in situ overburden pressure is cost-effective because the results give lower porosity and permeability measurements that more closely match log porosity data. By analyzing the differences in formation characteristics between the core samples measured under the two pressures, the older core data could be normalized for the stochastic geologic model. Shaliness indicators were identified from density and neutron logs and correlated with the corrected core permeability. The vertical and horizontal geostatistical spatial correlation studies applied the core data work to develop variograms models for the stochastic geologic model.

The stochastic model was created by the sequential gaussian simulator. For input, the simulator used the variogram models of the porosity and permeability fields, density log porosity data, permeability cloud transforms, and permeability-normalized neutron log porosity data. Stochastic simulations were conducted on porosity and shaliness indicators. Permeability fields were generated from shaliness indicator results through cloud-transforms. Detailed shale mapping was partially created based on resistivity and density log responses to define the shale streaks accurately. The shale streaks control the effective vertical permeability. A method for upscaling the model is discussed for porosity, sand permeability and the combination of the shale spatial continuity information and the sand permeability.

The original intent of the 3-D stochastic geologic modeling work was to address the lateral variations in rock geology using geostatistical correlation methods. Upon completion of the geostatistical work, the plan was to convert the 3-D deterministic geologic model and examine various stochastic realizations of reservoir conceptual models for simulation purposes. With the extended time to complete the core analysis work and the unexpected shutdown in January 1999 of the steam injection process in the Tar II-A zone, the project priorities were modified by the City of Long Beach to address their concerns about steamflood-related surface subsidence and how to safely operate the Tar II-A wells during the post-steamflood phase. In mid-1998, stochastic geologic modeling work was discontinued so the project team could concentrate on developing a post-steamflood operating plan using the 3-D deterministic thermal reservoir simulation model.

Reservoir Simulation

For reservoir simulation work, benchmark tests were conducted on several advanced thermal reservoir simulation packages and computer workstations. The project team selected the STARS™ thermal reservoir simulation software by the Computer Modelling Group (CMG) of Calgary. The software was installed on a R10,000 Onyx RE2 work station by Silicon Graphics Incorporated (SGI) for modeling purposes.

The 3-D deterministic reservoir simulation model incorporated the 3-D deterministic geologic model for the Fault Block II-A Tar Zone created for this project. The reservoir simulation study started in January 1997. The model consisted of 26,660 grid blocks (43 X 155 X 4 grids), with aquifers on the north and south flanks. The model successfully history-matched primary production in the Tar II-A sands starting in 1938, waterflood operations starting in 1960, and the steamflood pilot and expansion operations starting in 1981. Development work included how the model was built, the key reservoir and modeling assumptions used, the testing of the model to predict waterflood and steamflood performance versus actual rates, and the development of a rock compaction subroutine that was incorporated into the CMG STARS™ thermal reservoir simulation software. During the preliminary runs, the single component oil (dead oil) feature of STARS was applied in simulations to speed up the modeling work. The project team identified two dynamic reservoir processes that significantly affected the history matches: compaction-related deformation of the rock and gas liberation. The

formation compaction / rebound irreversibility was quantitatively determined and the contribution of the Tar Zone to the total surface subsidence was also estimated. The model's four layers were expanded to 13 layers to account for steam gravity override to simulate the 20-acre steamflood pilot and 150 acres of steamflood expansions. This increased the number of grid blocks to 86,645. The model was validated when a seven-year projection of oil and water production for the 20-acre steamflood pilot compared favorably with actual total project production data. The model subsequently was able to closely match ten years of production from the 150 acres of steamflood expansions.

The USC and Tidelands project members used the 3-D deterministic thermal reservoir simulation model to develop the post-steamflood plan. The objective was to use the model as a reservoir management tool to convert the high pressure - high temperature Tar II-A steamflood to a cold waterflood in a stress sensitive formation without any surface subsidence. The model was used to create multiple sensitivity cases to optimize oil production while accelerating steam chest fill-up within the reservoir by measuring the mass fluid and heat balance effects as they pertained to reservoir pressure. Reservoir pressures in the target area are affected by the following occurrences: mixing of the hot and cold fluids at the water injection sites; continuous heat loss in the mature steamflood area to the overburden and underburden formations; steam chest collapse and expansion in the structurally updip areas; and the movement and production of hot fluids throughout the steamflood project area. Taken together, these parameters make the prediction of reservoir pressures too difficult without a viable reservoir model. The model results demonstrated the importance of carefully monitoring and managing the reservoir pressure.

Model sensitivity cases were developed assuming the conversion of various wells to water injection at various rates. The model confirmed the project team's plan to convert structurally downdip wells to create a flank water injection strategy. Whereas the City's initial plan was to idle all producing wells until steam chest fillup occurred from flank water injection, the simulation model successfully provided for limited oil production while filling the steam chest before it could collapse from heat loss to the overburden formation. Oil production in August 1998 averaged 2253 BOPD. Following termination of steamflooding in January 1999, oil production in February was reduced to 781 BOPD, bad but much better than no oil production. The model accurately predicted steam chest fillup in October 1999 due in part to operations successfully meeting the model's gross production and water injection rate projections.

A study was performed to quantify the heating of over and underburden shales and sands in a typical Tar II steamflood pattern over a ten year period subsequent to steamflooding. The purpose was to determine the potential for thermal-related shale compaction over time. The CMG STARS thermal reservoir simulator was used to develop a 1/12 of a seven-spot, 2025 grid block (5 x 5 x 81 grids) model to determine how much, how far vertically, and for what length of time the reservoir heat is thermally conducted from the Fault Block II-A Tar Zone steamflood to the overburden and underburden sands and shales. The model mimicked an area in the middle of the steamflood project and had two injectors (one for the T Sand & one for the D Sand), one

producer, and an observation well halfway between the injectors and the producer. Two basic scenarios were run, one with continual 500°F hot water injection and one with 135°F cold water injection. Injecting 500°F water for ten years after steam injection only cooled off the steam zone by 53 – 67°F while the shale layers above and below continued to heat up. Injecting 135°F cold water to maintain a 90% hydrostatic reservoir pressure in the T and D sands would cool the reservoirs to 135°F within five years after the steam was shut-in.

Reservoir Management

Four horizontal wells (two producers and two steam injectors) were drilled in late 1995 utilizing a new and lower cost drilling program. The four wells were drilled with measured depths of 4380-4820 ft and 1700-2075 ft of section in the target "D2" sands at a true vertical subsea depth ranging from 2410-2660 ft. The two steam injectors were completed with eleven 0.25" limited-entry perforations over an interval range of 330-465 ft at the end of the wells. Both wells underwent cyclic steam injection to consolidate the sand grains in the perforation tunnels to control sand movement into the wellbore and to thermally stimulate oil production. The two producers were completed across the same correlatable interval as the injectors but with 36-48 quarter inch perforations to increase productivity. Both producers were cyclically steamed after the injectors.

A 2100 ft steam line was installed under the Cerritos Channel and placed in service in December 1995 to provide steam to Terminal Island for the four horizontal steamflood wells. The steam line operated without problems until it was idled in January 1999 with the loss of the Harbor Cogeneration Plant steam source.

Two pilot projects were envisioned for the horizontal wells, one for cyclic steam stimulation and the other for steamflooding. Cyclic steam stimulation was initiated in injection wells 2AT-61 and 2AT-63 (146,000 and 186,000 bbls steam, respectively) during the first half of 1996 and production commenced in early summer. Gross production ranged from 1200-1500 BPD/well compared to projected production rates of 1500 BPD/well. Peak oil production rates ranged from 41-60 BPD/well compared to projected rates of 300 BPD/well. Production wells UP-955 and UP-956 underwent cyclic steam stimulation (114,000 and 183,000 bbls steam, respectively) during the second half of 1996. UP-955 achieved cyclic peak production rates of 1450 BPD gross and 80 BPD oil, while UP-956 achieved cyclic peak production rates of 1570 BPD gross and 103 BPD oil. The four wells initially would accept only low rates of about 300-500 barrels of cold water equivalent steam per day (BCWESPD) at 1300 psi injection pressure and 900 psi reservoir pressure. This would increase to the desired rate of 1500 BCWESPD per well gradually over two months (process accelerated in two wells by breaking down the perforations with high pressure water). Each well was given a one-month steam soak period prior to initiating production. These rates were lower than the projected rates of 2100 BPD gross and 300 BPD oil. At the close of the previous work period in March 1997, UP-956 reported a gradual increase in gross and oil production rates, however, UP-955 oil production experienced a decrease in oil production and an increase in gross production. It was hoped that UP-955 would exhibit a favorable response to steam drive

injection from the two offset horizontal injectors. Of note is that all four horizontal wells had no sand fill during well pulling operations, indicating successful sand consolidation jobs.

Injection wells 2AT-61 and 2AT-63 were converted to permanent steam injection in November 1996 and January 1997, respectively, at rates ranging from 1700-2000 BCWESPD. The horizontal steam drive wells have been operated based on a pseudo "steam assisted gravity drainage (SAGD)" technique. The SAGD technique was designed by Butler^{D2, D4} and has been tested extensively in the heavy oil fields in Canada. Several articles have been written on the SAGD technique in the Canadian Journal of Petroleum Technology. A good article summarizing the heavy oil recovery techniques used in Canada was written by Polikar and Redford^{D5}. The pseudo SAGD method involved completing the last 400-500 ft of the horizontal wells in the most updip section of the reservoir. The horizontal segments of the wells average 1300 ft and were drilled going west to east at a 96-99° angle (going uphill) to compensate for the reservoir dip. The concept is to concentrate the steam updip in a smaller area to take advantage of gravity segregation of the steam in order to promote earlier development of a steam chest. As the steam chest grows to envelop the producer completion intervals, more perforations will be opened downdip and the updip perforations will be plugged off, if necessary. The pseudo SAGD technique is preferred over a conventional SAGD technique because the Tar zone has more mobile oil (13° API gravity) than the bitumen in Canada and has very mobile free water located primarily downdip and along the bottom of the sands caused by prior waterflooding.

A hot water-alternating-steam (WAS) drive pilot project was initiated in 1995 in four mature vertical well steamflood patterns. Four steam injection wells (wells 2AT-32, 2AT-33, 2AT-40, and 2AT-41) were converted to hot water injection from March 1995 to February 1996. Injection rates ranged from 500-3000 barrels of water per day (BWPD). Steam injection was resumed from February to November 1996 and hot water injection resumed in November at 4400 BWPD. No significant beneficial or adverse production response was observed that could be attributed to the hot waterflood injection. One major difficulty in observing response is scale buildup in the producers which reduces productivity until the wells are acidized. Four additional steam injectors (wells 2AT-36, 2AT-37, 2AT-44, and 2AT-45) were converted to hot waterflood injection in February 1997. Reservoir tracers were injected into wells 2AT-32 ("T" sand) and 2AT-33 ("D" sand) on February 14, 1997 as described in the Reservoir Characterization section.

Reservoir management focused on the end of the steamflood phase for the Tar II-A project and developing and implementing a post-steamflood plan. The availability of a history-matched simulator for the Tar II-A was quite timely and it became the basis for a reservoir management study of the conversion process.

Thermal-related formation compaction is a concern of the project team due to observed surface subsidence in the local area above the steamflood project. On January 12, 1999, the steamflood project lost its inexpensive steam source from the Harbor Cogeneration Plant as a result of the recent deregulation of electrical power

rates in California. A post-steamflood operational plan was developed and implemented to mitigate the effects of the two situations by injecting cold water into the flanks of the steamflood. The purpose of flank injection is to increase and subsequently maintain reservoir pressures at a level which would fill-up the steam chests in the "T" and "D" sands before they can collapse and cause formation compaction and prevent the steam chests from reoccurring. Intensive reservoir engineering and geomechanics studies have been performed to determine the possible causes of formation compaction and the best ways to operate the Tar II-A zone in post-steamflood mode while minimizing any future surface subsidence.

The new 3-D deterministic thermal reservoir simulation model was used to provide sensitivity cases to optimize production, steam injection, flank cold water injection and reservoir temperature and pressure. The model has provided operations with the necessary injection rates and allowable production rates by well in order to operate the reservoir safely. The model accurately projected reservoir steam chest fill-up by October 1999. Fill-up occurred in the "D" sands in August 1999 and in the "T" sands in October. Steam chest fill-up was accompanied by steeply rising reservoir pressures, as would be expected in a fully liquid, relatively incompressible fluid situation.

Following steam chest fill-up, it was believed that the reservoir would act more like a waterflood and production and cold water injection could be operated at lower I/P ratios and net injection rates. In mid-September 1999, net water injection was reduced substantially in the "D" sands. This caused reservoir pressures to plummet about 100 psi within six weeks. Starting in late-October 1999, net "D" sand injection was increased and reservoir pressures increased back to steam chest fill-up pressures as of March 2000. When the "T" sands reached fill-up, net "T" sand injection was lowered only slightly and reservoir pressures stabilized.

A reservoir pressure-monitoring program was developed as part of the post-steamflood reservoir management plan. This bi-monthly sonic fluid level program measures the static fluid levels in all idle wells an average of once a month. The fluid levels have been calibrated for liquid and gas density gradients by comparing a number of them with Amerada bomb pressures taken within a few days. This data allows engineering to respond quickly to rises or declines in reservoir pressure by either increasing injection or production or idling production.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field is a critical part of the City of Long Beach and Tidelands Oil Production Company's development strategy for the field. The current thermal operations in the Wilmington Field are economical with today's oil prices due to the availability of inexpensive steam from an existing a 50 MMBTU/hr steam generator that can utilize non-commercial low Btu produced gas. Such favorable terms for obtaining steam are not expected to be available in the future. Future expansion of thermal recovery to other parts of the Wilmington Field and other SBC reservoirs will depend on improving the efficiency and economics of heavy oil recovery, as is the intent of the project.

Operational Management

A novel well completion technique tailored towards stabilizing unconsolidated, porous and permeable sands has been successfully applied in the Tar Zone of the Wilmington Field. This well completion technique, which involves the application of steam, has been applied in 12 horizontal wells and 22 vertical wells with over 90% of the wells capable of production or injection after two years. This completion has been used in place of the more expensive gravel-packed slotted liner completions. Sand control was achieved without any adverse effects on well productivity. The successful application of this technique has resulted in significantly lower drilling and completion costs, better control of fluid profiles into the well-bore, interchangeability of production and injection wells as they now share common drilling and completion methods, and more workover flexibility.

A geochemical study of the scale minerals being created in the steamflood producing wells was completed that determines the mineralogy and source of the scales and how to prevent their occurrence. Wellbore fill samples (sand, scale, gravel pack) from the existing steamflood wells were analyzed and found to contain several types of scale, including calcites, dolomites, barites, anhydrites, and magnesium-silicates. Although only the carbonate scales are soluble in hydrochloric acid (HCl), performing HCl jobs appear to eliminate most of the wellbore scale damage and increase production to typical Tar zone rates. The problem occurs mostly in wells that produce very hot fluids. To minimize the problem, most of the hot wells are produced with more backpressure on the formation. This initial geochemical study points to the importance of performing more thorough high temperature lab work on the cores and formation fluids before initiating a steamflood.

Operational management focused on the apparent steamflood-related surface subsidence for the Tar II-A project due to shale compaction above the "D" sands. A study was performed to confirm steamflood-related shale compaction, to determine where this phenomenon is occurring, to measure the extent of shale failure and identify the critical temperatures and reactions that occur during shale failure.

The study suggests that the shale compaction process occurs in two stages, an early compaction stage and a late compaction stage. The early compaction stage is a result of a relatively gradual expulsion of fluids from the shales through the matrix pore system into the surrounding sand laminations and its overall subsidence effect is minor. The late compaction stage is a result of fluid expansion causing pore pressures to build up high enough to cause hydraulic microfracturing throughout the shale matrix and its overall subsidence effect can be severe.

The temperature ranges for the early and late compaction stages have not been clearly defined, but evidence uncovered to date can place some temperature limits on the processes. For early stage compaction, clay dewatering is known to start at 60°C or 140°F. Based on paleo-thermometry, a sample of post-steamflooded core in well OB2-

5 experienced mineral transformations (chlorites and vitrinite reflectance values) indicative of late stage compaction. The core underwent minimum temperatures of 192-202°C (398-416°F) to create chlorites and could not have experienced temperatures above 280°C or 536°F or else the chlorites would have dissolved. Vitrinite is a kerogen-based hydrocarbon that provides reflectance values of the highest temperatures it encounters. The vitrinite reflectance values further reduced the upper range to 250°C or 482°F. Yet as mentioned above, the crude oil tends to coke at approximately 285°C or 545°F and epidotes commonly form at 260-270°C or 500-518°F, so discrepancies still exist. Therefore, it is safe to conclude that early stage compaction starts at 60°C or 140°F and late stage compaction starts between 135-192°C or 275-398°F. The upper temperature limits cannot be determined, other than to conclude it is below the steam injection temperature of 316°C or 600°F or to assume the maximum thermal reservoir simulation model temperature of 273°C or 523°F in the shales at the end of steamflood injection. These findings indicate that more ReSpec-type "open" shale compaction tests should be performed, perhaps at 177°C and 218°C (350°F and 425°F, respectively), to determine the critical microfracture temperature and measure the physical expansion and contraction of the samples.

An improved H₂S caustic scrubber was designed and implemented by a joint team of engineers from T.J. Cross Engineers and Tidelands Oil Production Company, adapting the H₂S caustic scrubber principle proposed by Dow Chemical (Patent No. 2,747, 962). The scrubber would be utilized for stripping H₂S from steamflood related produced gas streams at less than half the previous cost. The new scrubber process (entitled Lo-CoSTSM) improves the caustic mixing system by gas contact by way of an ejector-venturi contactor, followed by gas separation. The added efficiency allows for a lower caustic concentration. A more effective caustic substitute called SulfaTreatTM removes lower H₂S concentrations to < 4 ppm in the latter of a two-stage process. The net cost of removal of a pound of sulfur is \$0.43, which translates into a yearly operating cost of \$226,000. This is significantly lower than the original four-stage process, which cost \$0.74 per pound of sulfur and a yearly operating cost of \$393,000.

A 7ppm NO_x 50MMBtu/hr oil field steam generator utilizing the non-commercial low Btu produced gas from Tidelands Operations was installed in the Fault Block V area. The lowest quality gas is produced from the Fault Block II-A, Tar zone. A pilot steamflood was initiated in the Fault Block V, Tar zone in 1996 based on drilling and operating lessons learned in this project and by turning a negative situation (waste gas) into a growth opportunity. The unit was the first 50 MMbtu/hr-steam generator permitted in the Los Angeles Basin since the 1980s. The steam generator, by Struthers, was delivered in February 1996 and system check out started in June 1996. The burner was designed and built by North American Manufacturing Company and guaranteed to emit under 9ppm NO_x without selective catalytic reduction (SCR). NO_x control was dictated by maintaining the air-fuel mix at lean condition. The SCAQMD (South Coast Air Quality Management District) requires that stack emissions data be sent to the SCAQMD via a modem using a Continuous Emissions Monitoring System (CEMS). Stack emissions were in compliance with the SCAQMD guidelines, with stack emissions tested at 5.44ppm without FGR (Flue

Gas Recirculation) and a burner not equipped with SCR. A third party stack-testing laboratory, World Environmental, verified this.

Work Completed This Reporting Period

Advanced Reservoir Characterization

In 1995, five horizontal wells were drilled into the Fault Block V Tar zone as part of a steamflood pilot operation. The wells were drilled on average 1500 feet horizontally within the S₄ sand. Three-dimensional (3-D) geologic modeling and visualization were used from planning through completion of the wells.

A deterministic geological model was created from which the maps and cross-sections were extracted and used to geosteer the horizontal wells. The modeling was much more straightforward than in the earlier Tar II-A project, as the lateral sections of the horizontal wells were in unfaulted areas with relatively little structural relief. Customized 2-D and 3-D visualizations were used during drilling for interpreting the Logging-While-Drilling (LWD) resistivity, gamma ray and well survey data and for monitoring well progress. Map and section plots brought to the rig site allowed the drilling team to correlate real-time drilling to the geologic maps, thus providing a strong confidence factor that drilling operations were on target. Accurate and rapid post-drilling analysis for completion interval selection and LWD analysis completed the process.

Overall, the Tar V drilling project was a major technical and economic success. Based on what was learned in the Tar II-A project and the accuracy of the 3-D model, the drilling team was able to plan and drill with confidence. No wells were plugged back for geological reasons and drilling time was reduced by spreading out survey lengths, using less time for correctional sets, and rotating the tool string while drilling a large percentage of the horizontal section. Roller reaming prior to running casing was eliminated as shales were avoided, allowing reaming with the bit already in the hole. In addition, only one pilot hole in FJ-204 was necessary. As a result, time and money were saved. Well J-203 took only six days from rig up to rig down to drill and case the 4,661 ft measured depth hole.

For the drilling team, having 2-D and 3-D visuals at the rig site stimulated better feedback and established a clearer understanding of how the geology affected drilling performance. Drilling efficiency was improved because 2-D and 3-D visuals provided the ability to see quickly what a particular directional tool set accomplished. Previously, the drillers only had numbers to look at which were much less intuitive and informative.

The Tar V horizontal well drilling budget was based on the Tar II-A horizontal wells. The average savings per well was US\$12,400 on directional costs and US\$18,000 due to fewer drilling days. In total, US\$152,000 was saved on the five horizontal wells drilled. The monetary savings and management's confidence in the 3-D model allowed all five laterals to be extended an extra 12%, on average, effectively

increasing the producible area and adding 382, 000 stock tank barrels (STB) or 60,734 stock tank m³ (STCM) of oil.

Reservoir Simulation

The plan is to update the Tar II-A post-steamflood model to provide a comparison of model projections to actual reservoir temperatures and pressures for the past two years. The actual temperature data are from gross fluid production from individual wells and temperature profile surveys. The pressure data are from the bimonthly fluid level surveys and periodic Amerada bomb pressure recordings on idle wells. Once the model is adapted for actual temperature and pressure conditions, using it can help optimize the post-steamflood operations about maximizing production while minimizing injection volumes, heat loss and surface subsidence.

A new 3-D deterministic reservoir simulation model is planned for the Tar V steamflood pilot, similar to the Tar II-A model, to determine the status of reservoir heating from steam injection. The model will estimate the temperatures and pressures throughout the reservoir over time and forecast gross fluid production and injection rates to prevent formation compaction. The Tar V project, unlike the Tar II-A project, has only a few temperature observation wells that provide an indication of reservoir heating, but not a comprehensive three-dimensional estimate over the entire project area. Optimizing steamflood operations and oil recovery will require a 3-D deterministic model.

Reservoir Management

Tar II-A Project

The Tar II-A post-steamflood operational plan was successful in filling the steam chests in the "T" and "D" sands and mitigating further surface subsidence in the steamflood area. The plan during the past year and in the future is to closely monitor reservoir pressures and carefully manage water injection and gross fluid production rates. Both the "T" and "D" sand reservoirs are in good shape with oil production increasing coupled with stable reservoir pressures that are at or above desired levels. In short the reservoirs are in maintenance mode.

The Tar II-A "D" sands have had reservoir pressures ranging from 90% \pm 1% hydrostatic levels (approximately 1000 psi) for the past year, compared to the desired hydrostatic pressure levels of 90% \pm 5%. The "T" sands pressures started the reporting period in April 2000 at 98% hydrostatic and were gradually reduced to 95% hydrostatic by March 2001. The plan is to further reduce reservoir pressures gradually to 90% hydrostatic (approximately 920 psi) over the next year.

Once good reservoir pressure control is maintained in both the "T" and "D" sands at 90% \pm 5% for a year, then reservoir pressures should be allowed to gradually decline about 2% hydrostatic pressure per year until overall reservoir pressures approach the 80%

hydrostatic pressure level, as this is the pressure theoretically necessary to keep the saturated steam in the reservoir in solution (approximately 900 psi steam is at 532°F).

The reservoir pressure monitoring program is ongoing and a key part of the Tar II-A post-steamflood management plan. This bi-monthly sonic fluid level program measures the static fluid levels in all idle wells an average of once a month. The program utilizes old technology, sonic fluid levels and wireline Amerada temperature and pressure bombs, and is relatively low cost compared to other pressure and temperature survey methods. The program not only provides the efficiency of the well pumping equipment, it also provides indications of reservoir connectivity between producers and injectors. The fluid levels have been calibrated for liquid and gas density gradients by comparing a number of them with Amerada bomb pressures taken within a few days. This data allows engineering to respond quickly to rises or declines in reservoir pressure by either increasing injection or production or idling production. Our confidence level with this technique is allowing us to currently ramp up Tar II-A production and injection, the results of which will be provided in subsequent reports.

Tar V Steamflood Pilot Project

Expanding the project to the Tar V steamflood has allowed the project team to continue ongoing thermal operations in a pilot horizontal well steamflood that was based on the Tar II-A horizontal well pilot. Two of the three Tar V horizontal producers have experienced sand inflow problems and required the wells to be re-treated with steam to reconsolidate the formation sands. Well J-205 was returned to production in September 1999 and J-201 was returned to production in March 2000. Both wells have been on production through March 2001 with no further sand problems, however, they both have had producing fluid levels over 1300 ft over the pump (FOP). Tidelands has been cautious about pumping the wells too hard to prevent them from sanding up again. Each well has the potential to produce over 125 BOPD or twice as much as their March 2001 rate by pumping the wells down to about 750 FOP. The plan is to speed up the wells in small increments and observe the corresponding oil and gross fluid rate increases and drops in FOP. A flank producer well, A-29, was converted to water injection and renamed FRA-29 in November 2000 to supplement injection so the horizontal producer rates can be increased. The well is located to the northwest of the pilot and provides more reservoir pressure support for surface subsidence control similar the flank water injection in the Tar II-A project. A new horizontal producer, J-206, is being proposed to drill in 2001 along with converting a south flank well to water injection for additional pressure support

Expanding thermal recovery operations to other sections of the Wilmington Oil Field is a critical part of the City of Long Beach and Tidelands Oil Production Company's development strategy for the field. The current thermal operations in the Wilmington Field are economical with today's oil prices due to the availability of inexpensive steam from an existing a 50 MMBTU/hr steam generator that can utilize non-commercial low Btu produced gas. Such favorable terms for obtaining steam are not expected to be available in the future. Future expansion of thermal recovery to other parts of the Wilmington Field

and other SBC reservoirs will depend on improving the efficiency and economics of heavy oil recovery, as is the intent of the project.

Operational Management

Further research is planned on the novel steam-induced sand consolidation well completion technique to see if the process can be duplicated in the laboratory. If so, then the objective will be to optimize and possibly commercialize the process. The sand consolidation well completion technique has been field tested on an empirical basis on over two dozen wells and proven to be a superior method that offers higher productivity, more operating flexibility, and significantly lower costs than the conventional open-hole, gravel-packed, wire mesh screen completions used to control unconsolidated sands.

In the past two years, several of the sand-consolidation completed wells have sanded up. Upon restreaming the wells to reconsolidate the completions, a few of the wells have produced successfully for over a year and a few have sanded up again. This problem will be evaluated to determine the weaknesses of the completion and whether any completion procedures can be changed to minimize the problem. A possible plan for two of the Tar V horizontal producers is to improve their productivity by installing an inner liner gravel-pack completion to back up the current sand consolidation completions. The sand consolidation completions probably failed because the wells were pumped too hard and the high differential pressures pulled formation sand into the wellbores. Because of this, each of the wells are produced at a low average rate of 58 barrels of oil per day (BOPD) and 1300 barrels of gross fluid per day (BGFPD) with high producing fluid levels of 1360 feet over the pump. Theoretically, the wells could produce at 500-600% higher rates. The proposed inner liners will allow the wells to be pumped at rates up to 3000 BGFPD, which is the limit for the pumping units. The goal is to increase oil production to over 150 BOPD per horizontal well.

In light of the problems encountered with the sand consolidation completion, Tidelands is researching the state of the art of gravel-packed, slotted-liner completions for horizontal wells to maintain operating flexibility.

With the steam chest filled and reservoir pressured stabilized at about 90% hydrostatic or higher for over a year, the plan is to increase well work activity to increase production and injection. Acid stimulation jobs are planned on selected producers to remove wellbore scale and increase oil cuts. Oil production has continued to increase during the first quarter 2001 without a change in gross fluid production because of two very successful acid stimulation jobs in wells UP-903 and UP-913. UP-903 tested 40 BOPD / 340 BPD gross prior to the December 2000 acid job and 150 BOPD / 1157 BPD gross after the job. The well was still producing 107 BOPD / 1010 BPD gross with a 1550 ft producing fluid level at the end of March 2001. Well UP-913 tested 22 BOPD / 495 BPD gross prior to the February 2001 acid job and 78 BOPD / 1384 BPD gross after the job. The well was still producing 61 BOPD / 1368 BPD gross with a 2200 ft producing fluid level at the end of March 2001.

During the past two years, thermal-related compaction of sands and shales in the Tar zone were studied in an effort to confirm one of the causes of surface subsidence in the Tar II-A steamflood area. This study showed that the shales immediately above the steamflood sands were the most susceptible to thermal compaction. More laboratory tests are planned to determine the critical maximum reservoir temperature we can reach before causing appreciable shale compaction. This information will help determine whether a profitable thermal enhanced oil recovery project can be designed. This study is critically important to the future of urban steamflood projects.

Project Expansion

The plan is to expand the S sand steamflood in the Tar V zone in Budget Period 2. The current Tar V steamflood pilot is based on the knowledge gained from the Tar II-A steamflood project, including horizontal well drilling and completion technology, reservoir characterization, pilot testing, reservoir modeling and reservoir management techniques. The plan is to add four horizontal producers, four horizontal injectors, and three observation wells to the existing pilot project. The total funds allocated to Budget Period 2 are \$6,701,988, of which the DOE share is 18% or \$1,206,355. The original Budget Period 2 plan to expand the Tar II-A steamflood project was revised because of the loss of the Tar II-A steam source from the Harbor Cogeneration Plant.

The expansion project has a drainage area of approximately 88 acres and a net oil sand thickness of 50 ft. The estimated remaining oil saturation after waterflooding is 50%. The estimated remaining oil in place is 4,850,000 barrels of oil. Projected recovery from the expansion project is 1,940,000 barrels of oil. The expansion project has an expected life of eleven years and is scheduled to start within a year after the end of Budget Period 1.

Future thermal recovery work at Wilmington must consider potential oil rates and reserves, the cost-effectiveness of the sand consolidation or other completions over the life of the wells, and the sensitivity of the sands and shales to thermal-related formation compaction. The work remaining in Budget Period 1 addresses these concerns.

Technology Transfer

The project team remained very active during this reporting period by organizing technology transfer events for both industry and non-industry organizations. Of particular note is the project team's key involvement in the 2000 First Joint Convention of the American Association of Petroleum Geologists (AAPG) Pacific Section Annual Meeting and the Society of Petroleum Engineers (SPE) Western Regional Meeting. Don Clarke of the City of Long Beach and Scott Hara of Tidelands were the Co-General Chairperson and Co-Technical Program Chairperson, respectively, for the convention, held in Long Beach, CA on June 17-24. Iraj Ershaghi and his USC staff and students organized several topical workshops targeted for oil and gas operators in California and Alaska through the West Coast Petroleum Technology Transfer Council.

The project team published and presented two original professional society papers^{A34, A36} and prepared one original technical report^{A35} this period. The project team members gave two oral technical presentations and taught a class at professional society and industry meetings given in California and promoted the industry by organizing field trips and presentations for teachers, students and government agency representatives.

Non-project team members published three papers this period that refer to or are based on the sand consolidation well completion technique developed in this project.^{B14, B15 and B16} This confirms the interest level in the sand consolidation technology and the value of technology transfer, which is the primary objective of the DOE Class projects.

The project team spent much of the past reporting period preparing a special three-year DOE Annual Report for the period April 1, 1997 - March 31, 2000.^{E27} This special report presented the results of an extremely active period of technology transfer for the project team. Twenty-two original technical papers and six articles related to original project technical work were published for industry professional societies and prestigious industry magazines and journals. At USC, one student did her doctoral thesis on the project, a multi-media CD-Rom of the project was developed, and the project web page was updated. The project team was heavily involved in the 1997 Western Regional Meeting of the Society of Petroleum Engineers in Long Beach and in the activities of the West Coast Petroleum Technology Transfer Council. Project team members gave 24 technical presentations at professional society and industry meetings given throughout California, in Texas, and even internationally in China, Spain and Finland.

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INTRODUCTION

Report Overview

This is the fourth "annual" technical progress report for the project covering the period from April 1, 2000 to March 31, 2001. The contract, awarded on March 30, 1995 and Pre-Award Approval given on January 26, 1995, work began on October 1, 1994. The first two annual reports submitted covered the period from project initiation to March 31, 1997 and the third report actually covered a three-year period from April 1, 1997 to March 31, 2000.

The remainder of this chapter provides an overview of the project implemented in the Wilmington Oil Field. Subsequent chapters conform to the manner consistent with the Activities, Tasks, and Sub-tasks of the project as originally provided in Exhibit C1 in the Project Management Plan dated May 5, 1995. These chapters summarize the objectives, status and conclusions to date of the major project activities performed during the reporting period. The report concludes by describing technology transfer activities stemming from the project and providing a reference list of all publications of original research work generated by the project team or by others regarding this project.

Project Overview

The objective of this project is to increase the recoverable heavy oil reserves within sections of the Wilmington Oil Field, near Long Beach, California through the testing and application of advanced reservoir characterization and thermal production technologies. It is hoped that the successful application of these technologies will result in their implementation throughout the Wilmington Field and, through technology transfer, will be extended to increase the recoverable oil reserves in other slope and basin clastic (SBC) reservoirs.

The project has primarily involved the implementation of thermal recovery in the Tar zone of Fault Block II-A (Tar II-A) and in 1999, the project expanded to include the Tar zone of Fault Block V (Tar V). The existing steamflood has been relatively inefficient due to several producibility problems commonly associated with SBC reservoirs. Inadequate characterization of the heterogeneous turbidite sands, high permeability thief zones, low gravity oil, and non-uniform distribution of the remaining oil have all contributed to poor sweep efficiency, high steam-oil ratios and early steam breakthrough. Operational problems related to steam breakthrough, high reservoir pressure, and unconsolidated formation sands have caused premature well and downhole equipment failures. In aggregate, these reservoir and operational constraints have resulted in increased operating costs and decreased recoverable reserves.

A suite of advanced reservoir characterization and thermal production technologies are being applied during the project to improve oil recovery and reduce operating costs, including:

1. Compiled a computer database of production and injection data, historical reservoir engineering data, detailed core studies, and digitized and normalized log data to enable work on the basic reservoir engineering study and 3-D deterministic and stochastic geologic models.
2. Developed a basic reservoir engineering study to evaluate the role of aquifer water influx, determine the original oil in place from gas production data to support the material balance work, and calculate the cumulative oil, gas and water recovery from the Tar zone.
3. Developed a new, cost-effective procedure to analyze new core data and correlations to revise old core analysis data.
4. Developed a neural network system and tested a procedure for correlating geologic markers in turbidite sequences.
5. *Tracer studies to track water salinity and non-radioactive chemicals provided mixed, but valuable results for future tracer work.
6. *Developed a petrophysical rock-log model that identified five rock types to describe the sands and shales within the "T" and "D" formations in Tar II-A. An associated study evaluated stress-dependent porosity and permeability in unconsolidated sand formations.
7. Developed three-dimensional (3-D) deterministic thermal reservoir simulation models to aid in steamflood and post-steamflood reservoir management and subsequent development work. The development of a 3-D stochastic thermal reservoir simulation model was completed through the geostatistical analysis of formation porosity and permeability in the Tar II-A.
8. Developed computerized three-dimensional (3-D) visualizations of the geologic and reservoir simulation models to aid analysis.
9. Performing detailed studies on the geochemical interactions between the steam, formation rock and associated fluids.
 - a. *Researching the use of steam injection to create sand consolidation well completion in unconsolidated sand formations.
 - b. Completed study on mineralogy and source of wellbore scales.
 - c. *Evaluating shale sensitivity to steam and heat.
10. Drilled three observation wells and two core hole/observation wells to monitor steam drive operations and to obtain critical log and core data for the stochastic geologic and reservoir simulation models.
11. Drilled and completed four horizontal wells in Tar II-A utilizing a new and lower cost drilling program.
12. Installed a 2100-ft, 14" insulated steam line, underneath a harbor channel to Terminal Island to service the four new horizontal wells.
13. Testing and proposed application of thermal recovery technologies to increase oil production and reserves:
 - a. Performing pilot tests of cyclic steam injection and production on new horizontal wells.

- b. *Performing pilot tests of hot water-alternating-steam (WAS) injection in the existing steam drive area to improve thermal efficiency.
- 14. *Performing pilot steamfloods with the horizontal injectors and producers in the Tar II-A and Tar V using a pseudo steam-assisted gravity-drainage process.
- 15. *Performing advanced reservoir management through computer-aided access to production and geologic data to integrate reservoir characterization, engineering, monitoring and evaluation.
- 16. *Developed and implemented a post-steamflood operational plan for Tar II-A based on the 3-D reservoir simulation model to address the loss of steam injection and apparent steamflood-related surface subsidence.
- 17. *Maintaining post-steamflood reservoir fill-up of steam chest using flank cold water injection.
- 18. *Reservoir pressure monitoring system developed for post-steamflood operations.
- 19. Developed a scrubber to strip H₂S from steamflood-related produced gas streams at less than half the previous cost.
- 20. Developed a 7ppm NO_x 50MMBtu/hr oil field steam generator for Tar V steamflood that uses the non-commercial low Btu produced gas from Tar II-A steamflood.
- 21. *Expanded the steamflood project to include the five well horizontal steamflood pilot in the Fault Block V Tar zone.

Note: The items listed above with asterisks (*) are activities that are addressed in this report and are either ongoing or have been completed.

The project consists of two budget periods including a research and testing period and an implementation period.

The Budget Period 1 has been applying advanced reservoir characterization techniques and testing thermal production methods as described above to reduce the capital and operating costs of the Tar II-A and Tar V steamfloods. The objective is to justify thermal operations in other SBC reservoirs with similar reservoir characteristics. The papers and presentations as listed in Section 7 on Technology Transfers and in the References section describe all of the technologies applied to this project to date.

The Budget Period 2 plan is to expand the “S” sand steamflood in the Fault Block V Tar Zone. The current Tar V steamflood pilot is based on the knowledge gained from the Tar II-A steamflood project, including horizontal well drilling and completion technology, reservoir characterization, pilot testing, and reservoir management techniques. The plan is to add four horizontal producers, four horizontal injectors, and three observation wells to the existing pilot project. The original Budget Period 2 plan to expand the Tar II-A steamflood project was revised because of the loss of the Tar II-A steam source from the Harbor Cogeneration Plant.

The expansion project has a drainage area of approximately 88 acres and a net oil sand thickness of 50 ft. The estimated remaining oil saturation after waterflooding is

50%. The estimated remaining oil in place is 4,850,000 barrels of oil. Projected recovery from the expansion project is 1,940,000 barrels of oil.

The project is being implemented by a team including:

1. The City of Long Beach - the operator of the field as a trustee of the State of California-granted tidelands;
2. Tidelands Oil Production Company - the contract operator of the field for the City of Long Beach, and the party in-charge of implementing the project;
3. The University of Southern California, Petroleum Engineering Program - consultants to the project, playing a key role in reservoir characterization and simulation; and
4. GeoSystems, formerly David K. Davies and Associates - consultants to the project regarding petrography, rock- based log modeling, and geochemistry of rock and fluid interactions.

Development and Production History

The Wilmington Oil Field is the fourth largest oil field in the United States, based on the total oil recovered. Over 2.5 billion barrels of oil have been produced to date, from an original oil in place of 8.8 billion barrels.

The field is located in and around the City of Long Beach, in Southern California. Location maps of the field are in Figures 1 and 2. Figure 3 shows an aerial view of Fault Blocks I-VI. Divided into ten fault blocks (Figure 4), the field has seven major producing zones (Figure 5). Heavy oil occurs in the Tar, Ranger and Upper Terminal zones. This project is being conducted in the Tar zone within Fault Blocks II-A and V as shown in Figures 3, 4, 5 and 6.

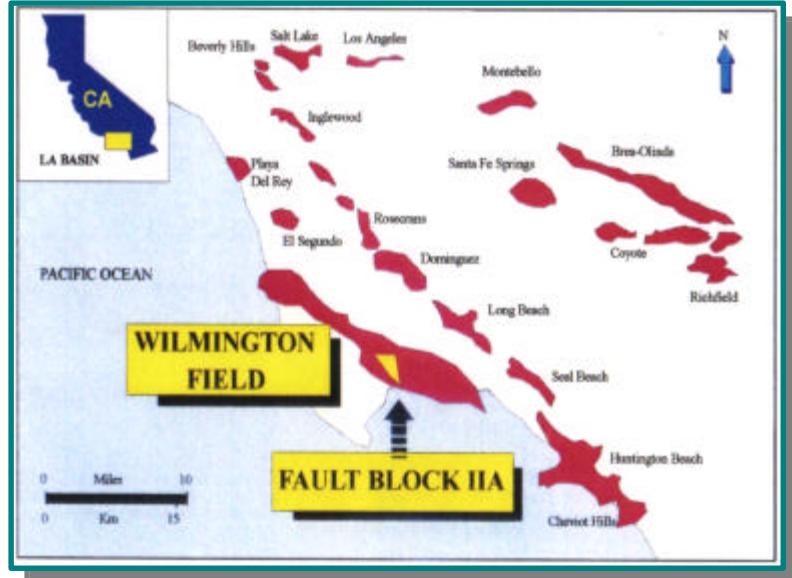


Figure 1: Map showing the geographical location of the Wilmington Field in Southern California.

Primary production from the field began in 1936. Large-scale waterflooding was introduced during the 1950-60s to increase oil recovery and control surface subsidence. Various tertiary recovery projects have been tried, but with only limited success. For most of the producing zones, the dominant form of economic oil recovery remains waterflooding. The current water cut is approximately 96.5%. Recoveries in the waterflood and tertiary recovery projects have been hindered by poor sweep efficiency, as is typical of heterogeneous reservoirs with turbidite geology.

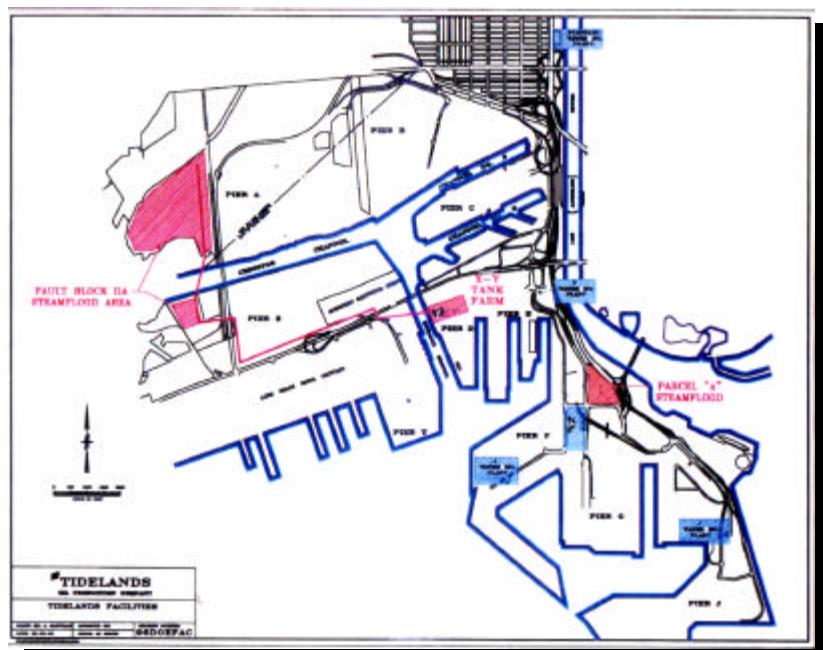


Figure 2: Plan view of Tidelands facilities showing the steamflood zone of Fault Block II-A Wilmington Field.

Tar II-A Production

The Union Pacific Railroad Company first produced the Tar II-A in 1937. The Fault Block II oil operations were unitized for secondary recovery operations (waterflooding) in 1960 to maintain reservoir pressures. Water injection began later that year. The Tar II-A cumulative oil production through 1979, after 19 years of waterflooding, was 20 million barrels; equivalent to a recovery factor of only 20% of the original oil in place (OOIP). These low recovery factors are due to adverse mobility ratio and sand heterogeneity, which have resulted in low areal and vertical sweep efficiencies. Because of the poor waterflood performance, applying steam injection was ev-

applying steam injection was evaluated to improve heavy oil recovery (13° API) oil. A1, D3

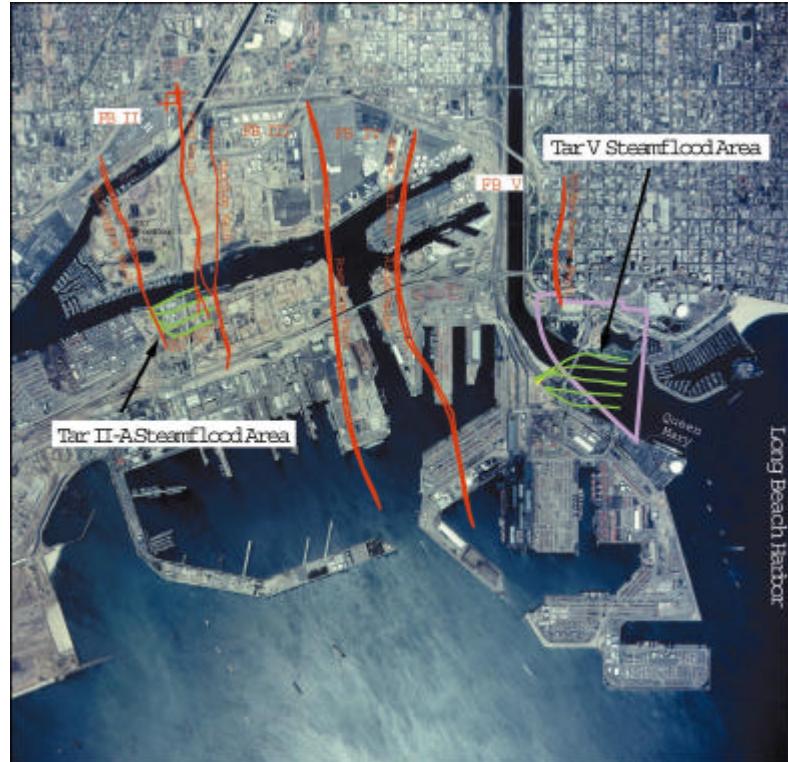


Figure 3: Aerial view of the Wilmington Field shows locations of FB II-A and V steamflood projects.

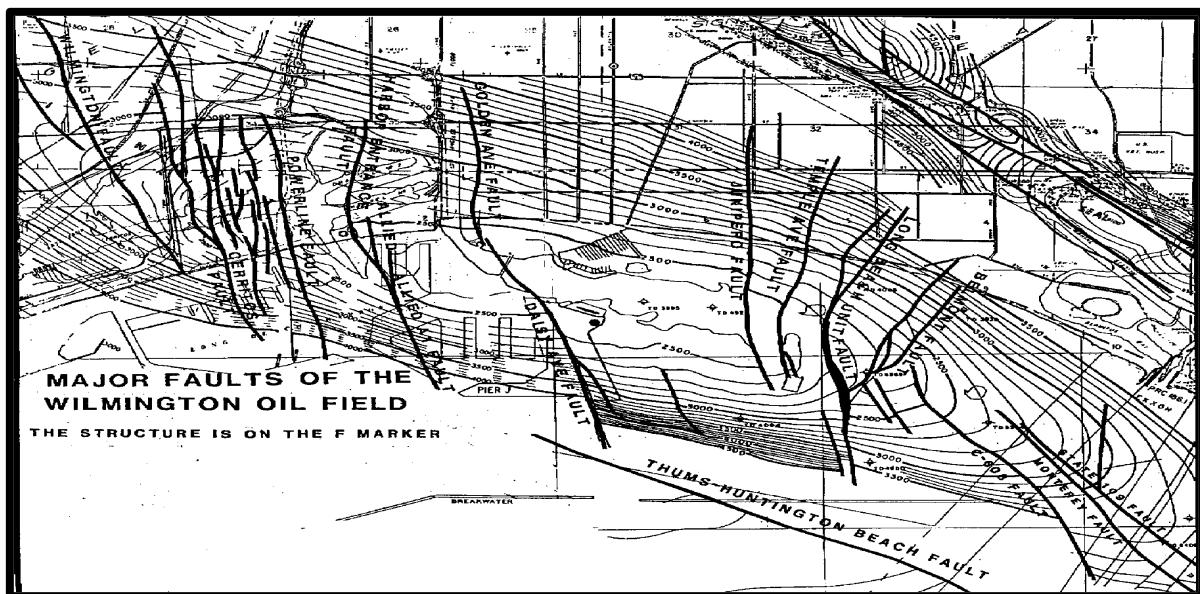
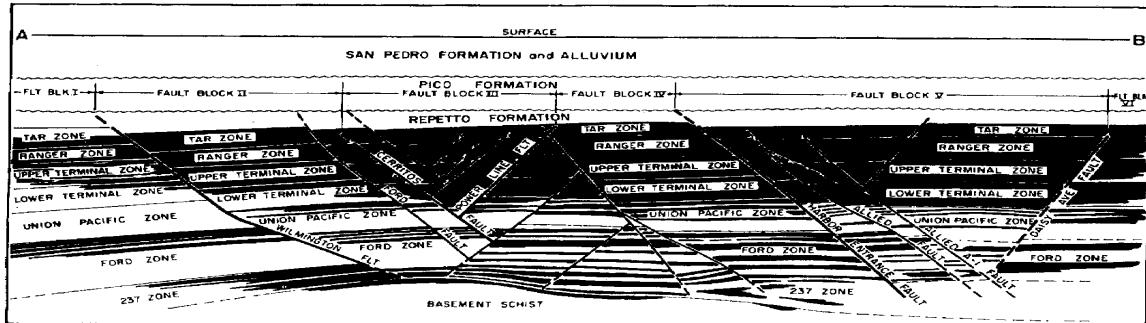


Figure 4: Geologic representation of the Wilmington Oil Field detailing fault line layout.



Northwest-southeast cross section, Wilmington field, showing producing zones. Trace of section is A-B on Fig. 1. Source—*California Oil and Gas Fields*, Pt. 2; courtesy California Division of Oil and Gas.

Figure 5: Cross section of a representative sector of the Wilmington field detailing producing zones.

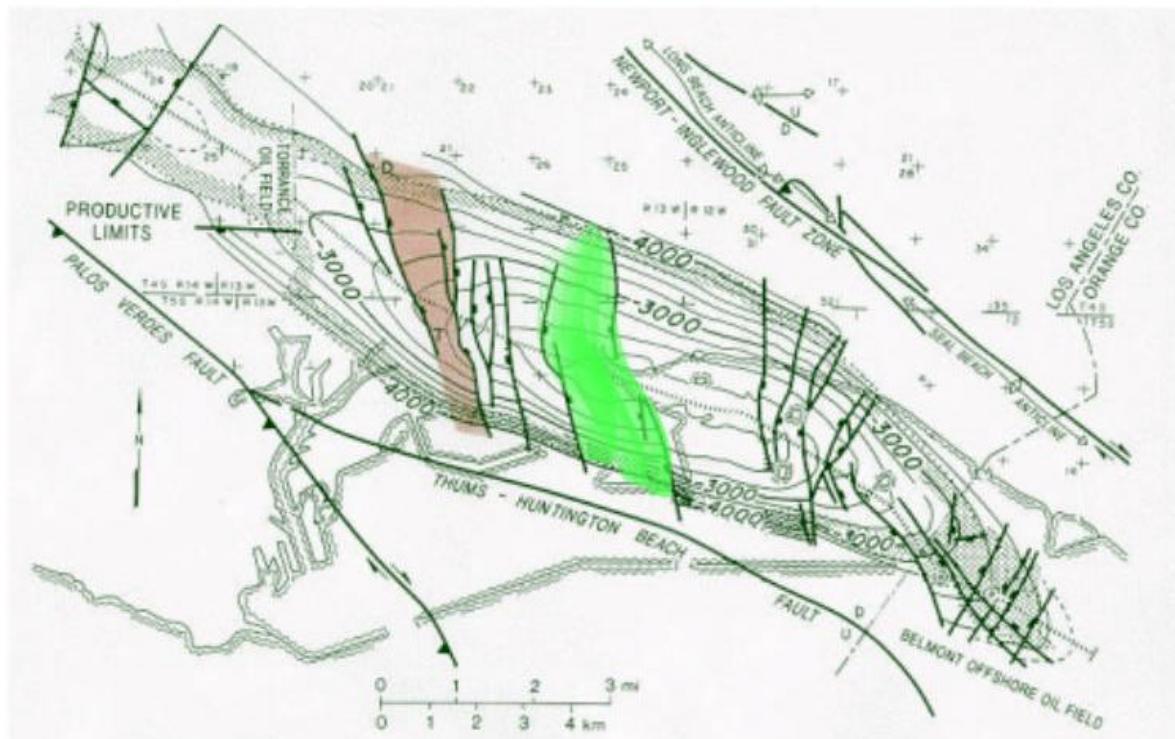
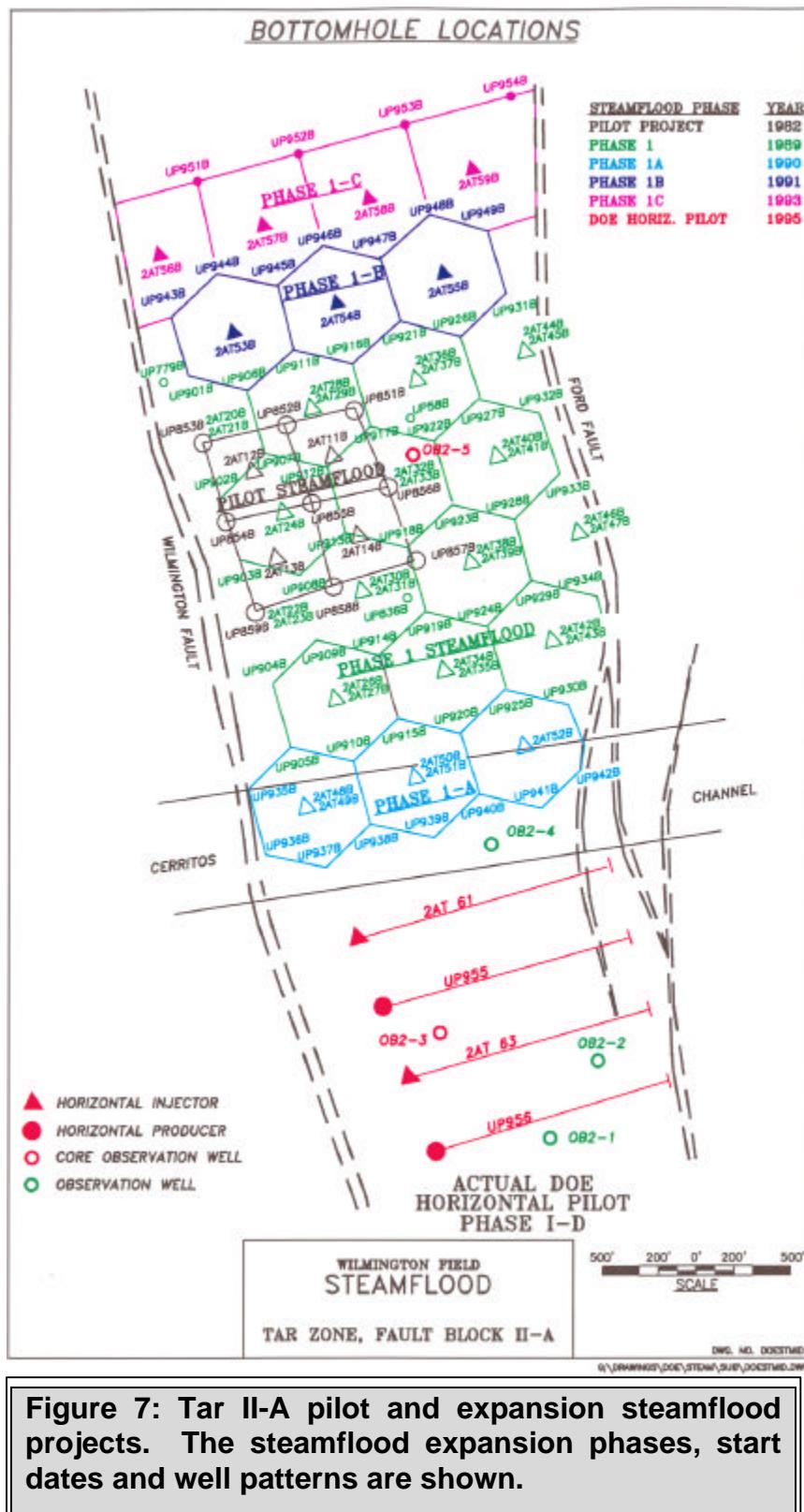


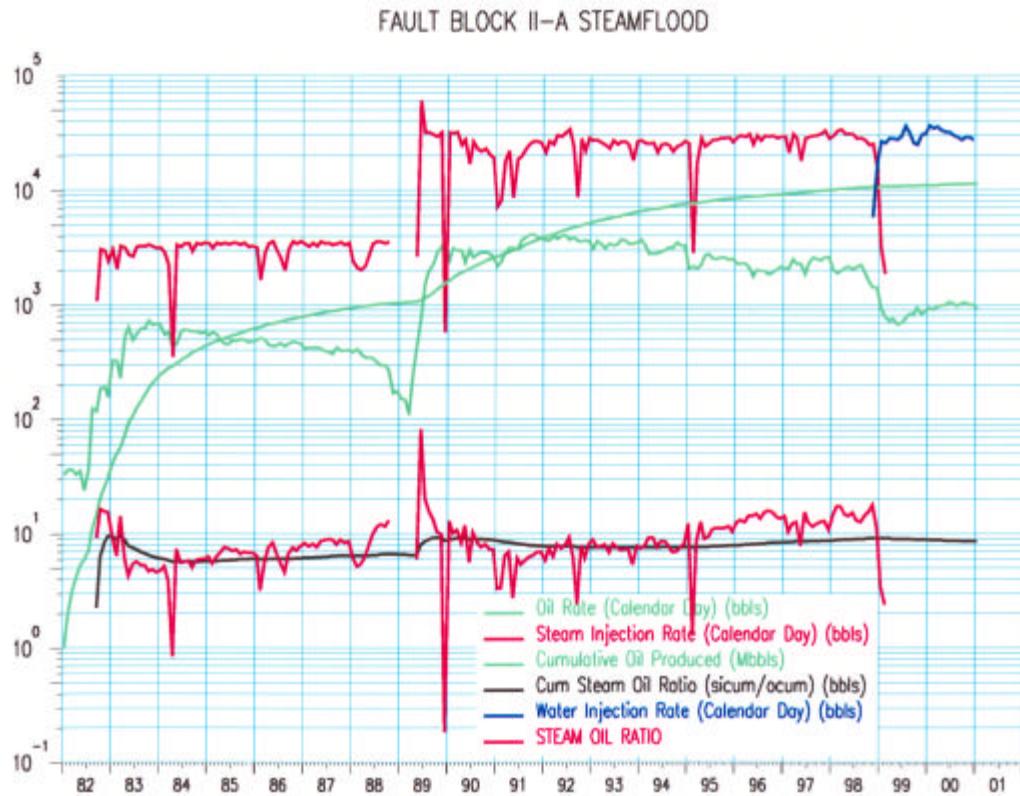
Figure 6: Fault Blocks II-A (red) and V (green), Wilmington Field. Structural contours on Ranger Zone.

Champlin Petroleum, later called Union Pacific Resources Company, performed a successful steam injection pilot test in the Tar zone of Fault Block II-A from 1982-1989.^{D3} The pilot project comprised of four inverted 5-acre five-spot patterns and recovered 1.1 million barrels of oil for a recovery factor of 75% OOIP or an incremental recovery of 55% OOIP over waterflooding. The pilot had a reasonable cumulative steam/oil ratio (SOR) of 6.4 barrels of cold water equivalent steam (BCWES) per barrel of oil recovered, with the lowest annual SOR of 5.5 occurring in 1984. Steamflood expansion potential was

considered to be better than the pilot because most of the production wells would be backed up with steam injection from all directions.

The Tar II-A pilot was expanded to 98 acres using an inverted 7-spot pattern in the northern half of the fault block in 1989 (Figure 7). Subsequent phases were added from 1990 through 1995 for a total area under steamflood of 194 acres. The expanded steamflood project did not meet with the same degree of success as the pilot. Although the steamflood achieved peak oil rates exceeding 3,000 BOPD in 1991, the best instantaneous SOR for a month only went as low as 5.5. From 1991 to the end of steam injection in January 1999, steam injection rates maintained an average of 25-32,000 BCWESPD while oil production rates gradually declined to 2,000 BOPD. This resulted in a very high instantaneous SOR in 1998 averaging about 15 and a high cumulative SOR of 9 for the project (Figure 8). The project experienced several downhole and surface operational problems. Well problems included scaling of the slotted liners and downhole pumps and premature equipment failure due to the high produced fluid





temperatures accompanying steam breakthrough. Costly and inflexible completion practices were utilized to control sanding problems that have occurred elsewhere in the field. Surface facility problems included handling the hydrogen sulphide, mercaptans, and carbon dioxide gases created in the reservoir by the steam heat, controlling steam breakout in the production gathering lines, and monitoring tank farm fluid temperatures and pressures for safety and to prevent damage to vessels and pipelines. Many of these types of problems could have been anticipated with a better understanding of the mineralogy of the formation sands and water and the complex turbidite geology of SBC reservoirs in the Tar zone. The steamflood was primarily profitable because of a favorable steam purchase contract with the Harbor Electric Cogeneration plant. Harbor Cogen discontinued supplying steam in January 1999 after Southern California Edison Company purchased its favorable electric power contract through an electric deregulation incentive program.

The Tar II-A project area began experiencing severe surface subsidence just prior to the cessation of steam injection. There were several possible causes, including grading work by the Port of Long Beach that added several tens of millions of tons of compacted fill to the area to expand port facilities, the wholesale abandonment of adjacent waterflood wells for port expansion that terminated water injection, and heat-related formation compaction in the steamflood sands. The last possibility jumpstarted the development of a post-steamflood operation plan to mitigate the problem. Strategically placed water injection wells along the structural flanks of the reservoir replaced steam injection and gross production was curtailed by 75% to allow reservoir pressure to increase. This

caused oil production to decline from 2,000 BOPD in late 1998 to 700 BOPD in early 1999. The post-steamflood plan has been successful in stopping surface subsidence and oil production (and gross production) has increased to 1162 BOPD in March 2001. The Tar II-A cumulative oil production through December 2000 is about 39 million barrels for a recovery factor of 39% OOIP.

Tar V Production

The Long Beach Oil Development Company (LBOD), as contract operator for the City of Long Beach, began Tar V production in 1951. Similar to Tar II-A, LBOD and the City of Long Beach implemented a non-unitized waterflood project in the Tar V in 1960 to increase and maintain reservoir pressure at about 80% of hydrostatic pressure or 800 psi to prevent further surface subsidence. The Tar V cumulative oil production through 1960 was 9.8 million barrels or about 5% OOIP. Reservoir pressure in 1960 averaged about 460 psig. After 36 years of waterflood and just prior to the steamflood pilot, cumulative oil production through 1996 was 50 million barrels for a waterflood recovery factor of 25% OOIP. Waterflood operations in 2001 still represent 55-75% of the oil production from the Tar V sands. Tar V oil production in March 2001 was 717 BOPD, of which pilot steamflood production was 199 BOPD or 28%. Tar V total water injection in March 2001 was 21,825 BWPD, of which steam was 3,304 BCWESPD or 15%.

Tar V S4 Structure Map. Scale: 1" = 500'

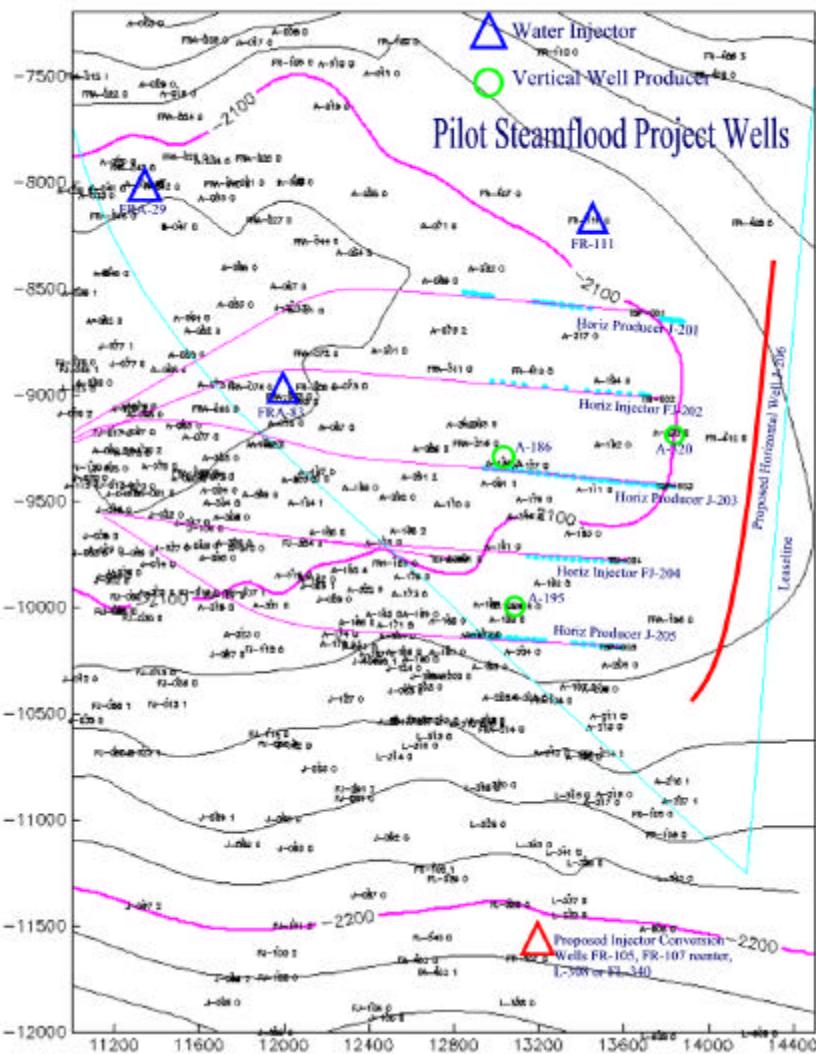
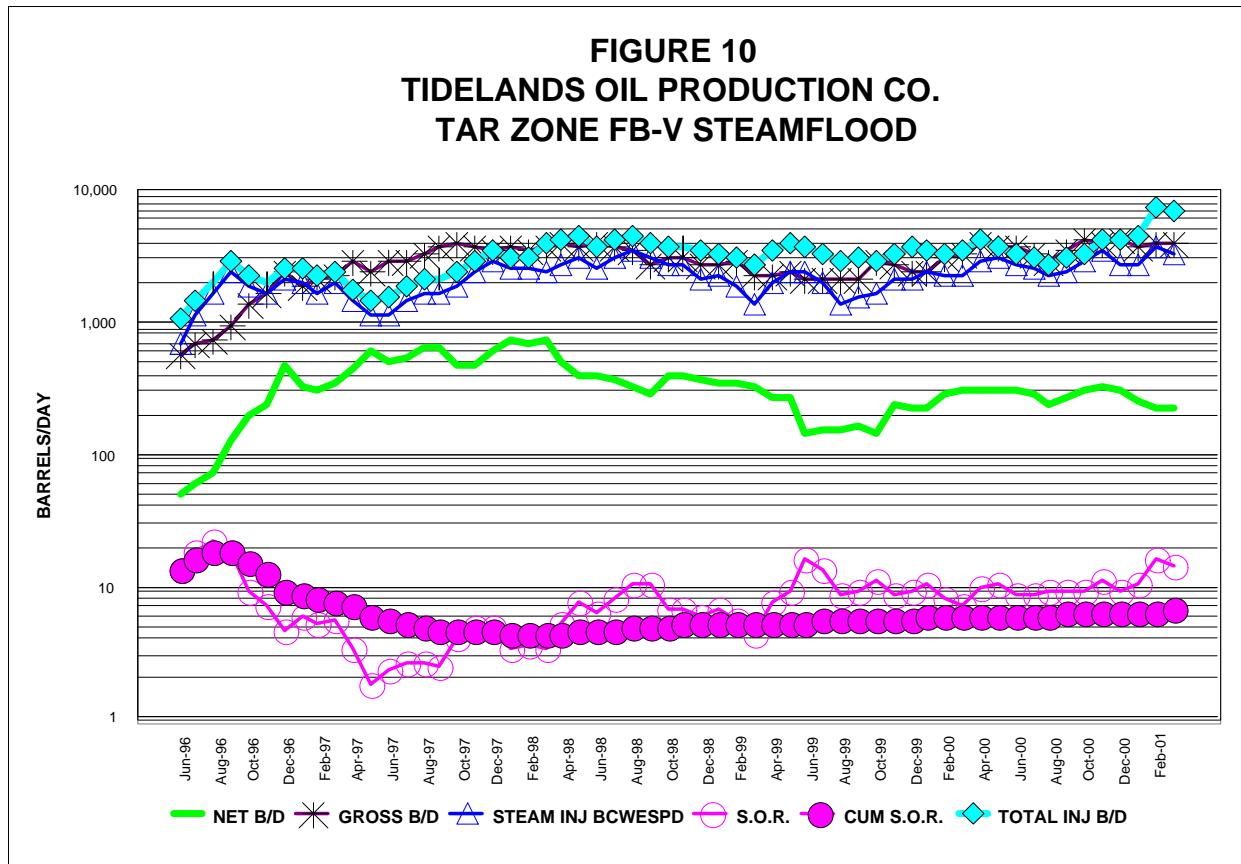


Figure 9: Tar V steamflood project wells, including three horizontal producers (light blue "J" wells), two horizontal steam injectors (light blue "FJ" wells), three vertical infill producers (green circles) and three flank water injectors. (blue triangles)

Tidelands drilled five Tar V horizontal well steamflood pilot wells in late 1995 to early 1996 and production began in late 1996. Figure 9 shows the locations of the wells. The pilot steamflood project was developed based on the Tar II-A horizontal well steamflood pilot. Cumulative steamflood oil production from June 1996 through March 2001 is 607,272 barrels. The project is estimated to ultimately recover 1.7 million incremental barrels from the steamflood pilot area. Total steam injection rates into Tar V have ranged from 1100 – 3700 BCWESPD, averaging 2871 BCWESPD from June 1996 through March 2001. The project initially had several months when the steam/oil ratio was below 5. The cumulative SOR through March 2001 is a reasonable 6.6. The steamflood project currently has flank water injection averaging 910 BWIPD to the north and west to assure reservoir pressure is maintained. The water injection rate was recently increased in February 2001 to 3800 BWIPD. Figure 10 is a production and injection graph for the Tar V steamflood project from June 1996 through March 2001.



Each horizontal well received a cyclic steam-stimulation job to provide a sand consolidation well completion and to accelerate oil production. All five wells had early peak oil rates ranging from 223 - 328 BOPD. Two of the horizontal wells, wells FJ-202 and FJ-204, were converted to permanent steam injection following cyclic steam production. Steam drive response for each of the three horizontal producers (wells J-201, J-203 and J-205) peaked at 91 - 151 BOPD. The three producers have had

continuously high producing fluid levels and should be capable of producing at higher peak rates. Water injection was increased to allow for higher gross fluid production rates. This should favorably affect the instantaneous SOR of the project, which has averaged 10.15 since May 1999 primarily because of this problem. Significant oil production is recovered from three pre-steamflood vertical producers (wells A-186, A-195 and A-320) located within the steamflood area that have recovered 209,486 barrels of oil since June 1996 or 34% of the cumulative steamflood recovery. Flank water injection is from three wells, FRA-29, FRA-83 and FR-111 (Figure 9).

Geologic Setting

The Wilmington Oil Field is an asymmetrical, highly faulted, doubly plunging anticline, eleven miles long and three miles wide (Figures 4 and 6). The productive area consists of approximately 13,500 acres. Fault Block II-A is located near the western edge of the field and is bounded on the east by the Cerritos Fault and on the west by the Wilmington Fault. Fault Block V is located just west of the center of the field and is bounded on the west by the Harbor Entrance and Allied faults and on the east by the Daisy Avenue and Golden Avenue faults. Neither the Daisy Avenue nor the Golden Avenue faults penetrate the Tar zone. The Tar sands stratigraphically thin and pinch out to the east before reaching the Junipero Fault. From the surface, Fault Block V lies within the eastern-most portion of the Port of Long Beach shipping operations. The north and south production limits of both fault blocks are governed by water-oil contacts within the individual sand members of the various zones (Figures 4 and 6). The seven zones within each fault block listed in order of increasing depth are: Tar, Ranger, Upper Terminal, Lower Terminal, Union Pacific, Ford and "237" (Figure 5).

Oil from the Wilmington Field and from throughout the Los Angeles Basin is produced mainly from Lower Pliocene (8 –11 million years ago [mya]) and Upper Miocene (11 – 16 mya) age deposits. The Tar zone has the shallowest oil producing sands in the Wilmington Field. These sands are lower Pliocene, middle Repetto formation lobe deposits. The Pliocene age deposits go as deep as the "X" sands in the Ranger zone. The upper Miocene age Puente formations begin with the "G" sands in the Ranger zone and continue through the other five zones mentioned above. The "237" zone overlays a basement schist occasionally capped with a basal conglomerate. The schist is considered Jurassic age (130 – 180 mya), although it has similarities with local Cretaceous (65 – 130 mya) age formations. Wells have been completed into the Schist zone and are oil productive along the anticlinal axis at localized structural highs where the schist is fractured.

During the late Miocene, the Los Angeles Basin experienced a phase of accelerated subsidence during which the Puente Formation and Pliocene age sands were deposited. Structurally, the late Miocene Puente Formation deposits in the Wilmington Field appear to be drape-folded over a relative basement high, with generally thinner beds at the crest of the structure and thicker beds on the flanks. Starting in the middle Pliocene age to the current time, the Los Angeles Basin has experienced significant tectonic activity that has resulted in a major syncline within the central portion of the basin and uplift along

the margins, as in the Wilmington – Palos Verdes area. For example, the basement schist top is found at 10,000 ft subsea depth in the Thums area and at 600 ft above sea level in Palos Verdes, a two-mile vertical change within a ten-mile distance! During the mid-Pliocene to Pleistocene ages is when the Wilmington Field developed its anticlinal structure. The Pliocene age sands were divided into two units, the Repetto Formation for the early Pliocene sands and the Pico Formation which unconformably overlies the Repetto formation. Both the Repetto and Pico formations contain prolific oil deposits within the Los Angeles Basin. In the Wilmington Field, the top of the Repetto Formation was eroded away, probably by the Pico Formation, which is relatively thin and probably also eroded away. The Pleistocene (<1 mya) and Holocene (recent) age sediments cover the flat erosional surface of the upper Repetto - Pico sands. They buried the Wilmington anticline under 1,800 – 2,000 ft of horizontal younger beds. The Pleistocene and Holocene sands originally contained fresh water, but now contain filtered, low oxygen-filled seawater because of rapid fresh water removal for domestic and agricultural use in the early-mid 20th century. The Pleistocene Gaspar zone was the prime injection source water for the waterflood projects. ^{A36, D8, D9}

The upper Miocene Puente and lower Pliocene Repetto formations within the Wilmington Field consist of interbedded sand/shale sequences belonging to submarine fan facies. These are considered to be bathyal, slope and base-of-slope deposits. The upper Miocene sands are

intercalated with shales and siltstones in the form of widespread thin turbidites. Large lobate fans dominate the Pliocene section.

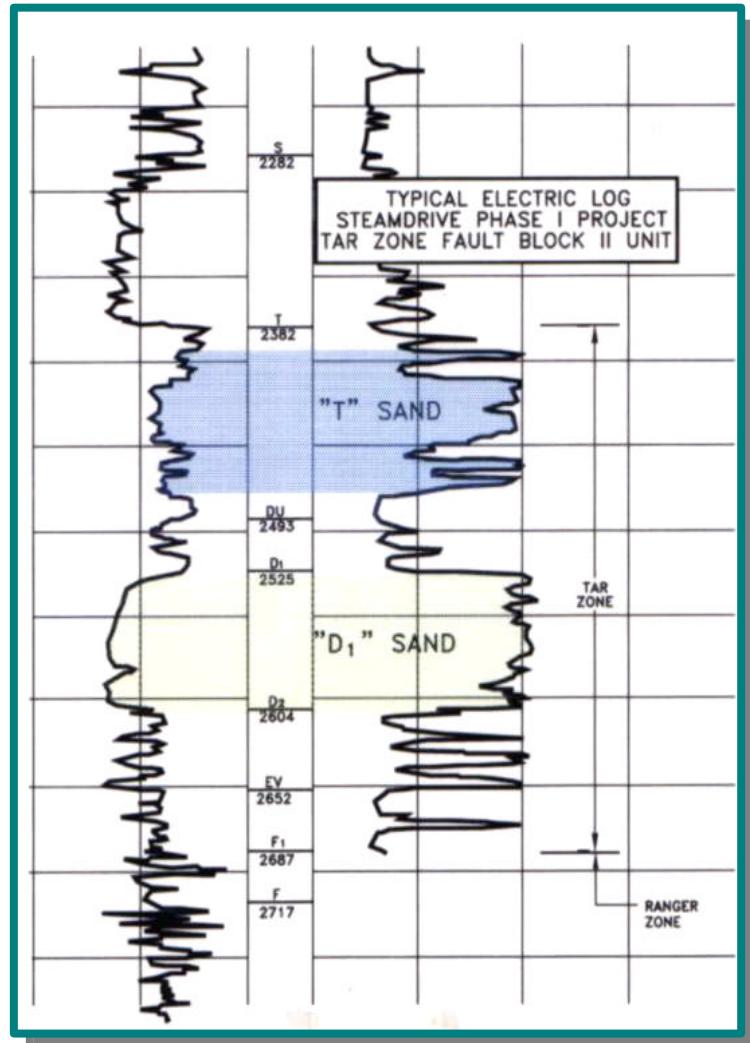


Figure 11: Type Log, Fault Block II-A Tar Zone, illustrating "T" and "D1" sands.

Tar Zone Geology

The Tar zone consists of four major producing intervals, the "S", "T", "D" and occasionally "F₁/F₀" sands. The Tar II-A waterflood and steamflood wells produce from the "T" and "D" sands. The "S" sand has a relatively small oil productive area in Tar II-A that is completely underlain by water, therefore, only a few wells have been completed. The Tar V waterflood produces from the "S", "T", and "F₁/F₀" sands and the steamflood pilot is in the "S" sands. The "F₁/F₀" sands are defined as being in the Tar zone in most of Fault Block V, however, they are defined as in the Ranger zone throughout the rest of the field. Each subzone exhibits typical California-type

alternation of sand and shale layers as illustrated by the type logs in Figure 11 for Tar II-A and Figure 12 for Tar V.

The Tar zone sands tend to be unconsolidated, friable, fine to medium-grained and contain varying amounts of silt. The thickness of the sand layers varies from a few inches to several tens of feet. Shales and siltstones are generally massive, with abundant foraminifera, mica, and some carbonaceous material. The shales are generally soft and poorly indurated, although there are thin beds of fairly firm to hard shale. The oil is of low gravity, ranging from 12-15° API with a viscosity of 360 cp and an initial formation volume factor of 1.057 RB/STB. Based on available information, the Tar zone sands have an average porosity ranging from 30-35% and permeabilities ranging from 500-8,000 millidarcies with a weighted average of 1,000 millidarcies. Approximate zone thickness ranges from 250-300 ft. The top of the structure appears at a depth of 2,330 ft below sea level in Fault Block II.

Sedimentological analyses of the textures, sedimentary structures and fossils preserved in the Tar II-A conventional cores reveal that the Tar zone sediments were deposited in several related environments of a deep sea submarine fan system (Figure 13A). The sediments that compose the fan were supplied by gravity-induced flows that transported sands from the northeast (sediment source) towards the southwest (basin

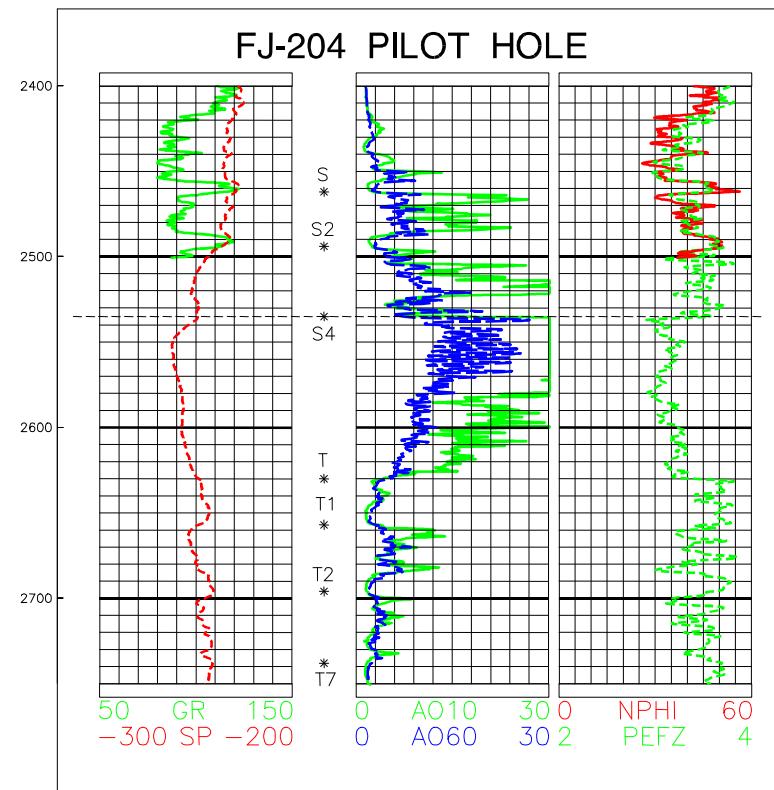


Figure 12: Type Log, Fault Block V Tar Zone, illustrating "S" and "T" sands.

of deposition). Sand deposition occurred basinward of a slope break that lay to the east of the present field location. Shales were deposited by differential pelagic settling of fine particles from the overlying water column. The Tar II-A “T” and “D” sand reservoirs represent two unrelated submarine fan systems, as evidenced by the thick, basinal shale that separates them (Figure 11). The “S” sands in Tar II-A and Tar V represent

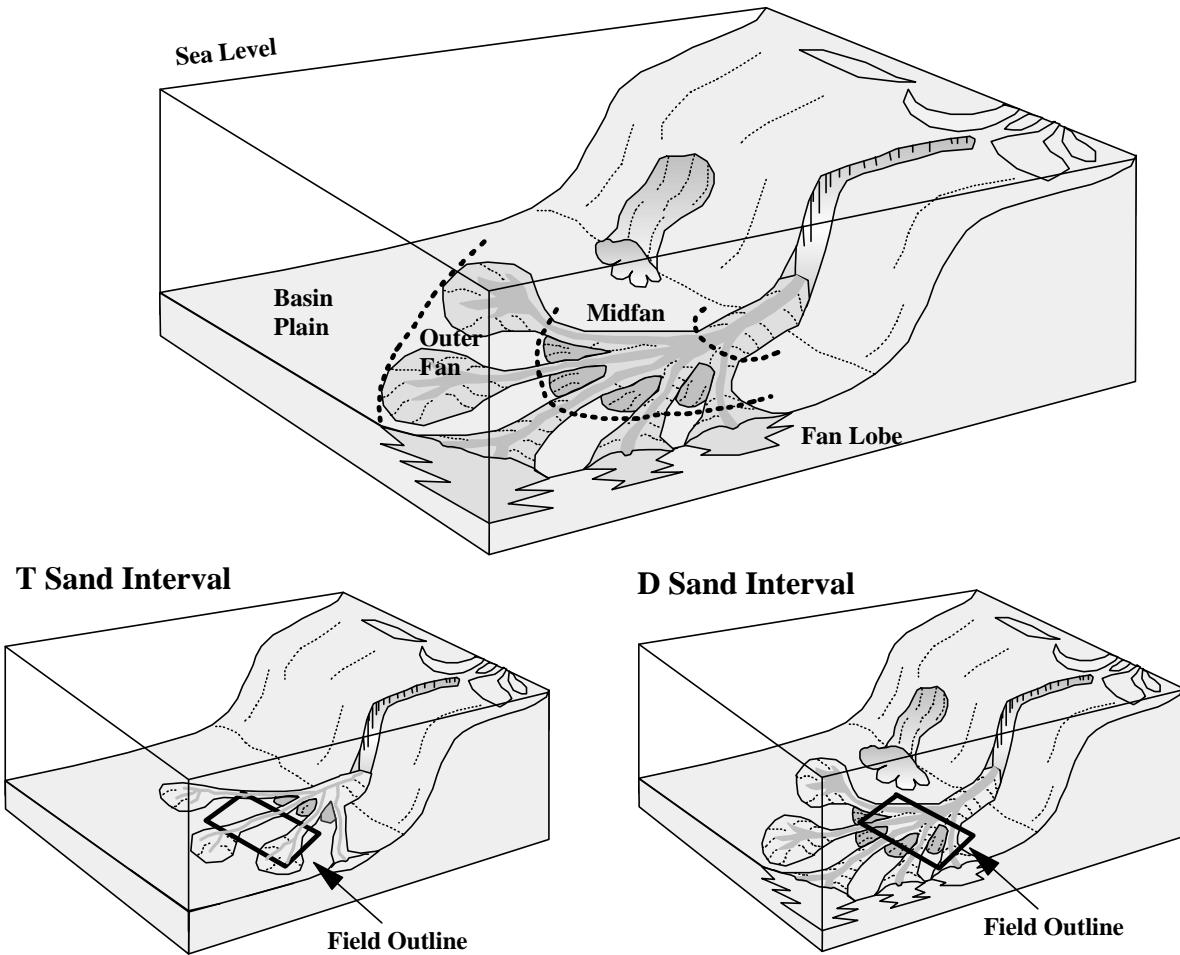


Figure 13: Diagrammatic reconstruction of submarine fan system.

another separate, unrelated submarine fan system that appears similar in description to the “D” sands (Figures 11 and 12).^{A32}

Growth of a submarine fan system involves the repeated supply of coarse-grained detritus (sand) by individual gravity flows. The architecture of the reservoir is the result of this growth. Fan growth is accomplished in three ways:

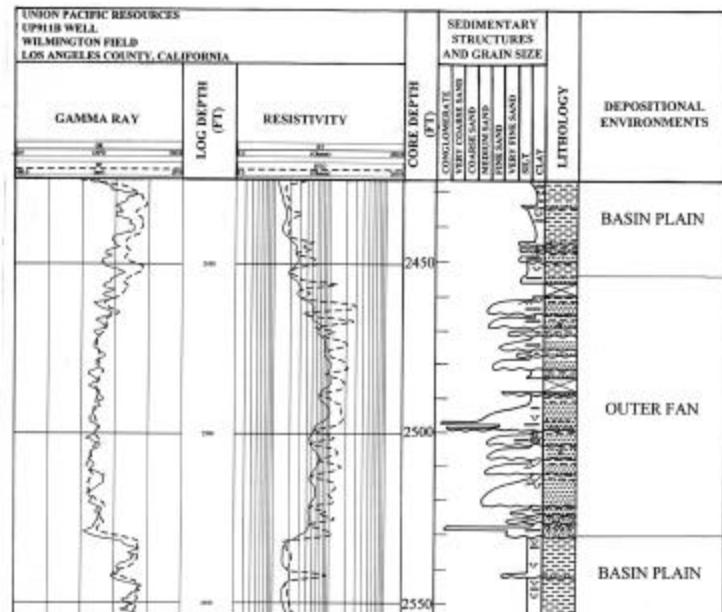
1. Progradation: Sands are deposited basinward of the break-in-slope due to a decrease in flow velocity. Continued supply of sands to the basin floor results

in the gradual basinward growth (progradation) of the sand-rich fan system out over previously deposited basin shales.

2. Avulsion and Lobe Switching: As the fan system progrades into the basin, individual feeder channels are avulsed (abandoned) and the feeder channels are re-directed into the topographically low areas adjacent to the existing lobes. As a result, new sand lobes are developed in these inter-lobe areas and the old lobes are abandoned.
3. Aggradation: Continued supply of sands over time results in the overall vertical growth (aggradation) of the reservoir sand bodies.

The model presented in Fig. 13 represents a submarine fan at one instant of time. The simultaneous operation of progradation, avulsion and aggradation over a period of time results in the random, vertical stacking of the various fan elements. This produces reservoirs that are internally complex and heterogeneous, such as those in the Wilmington Tar zones.

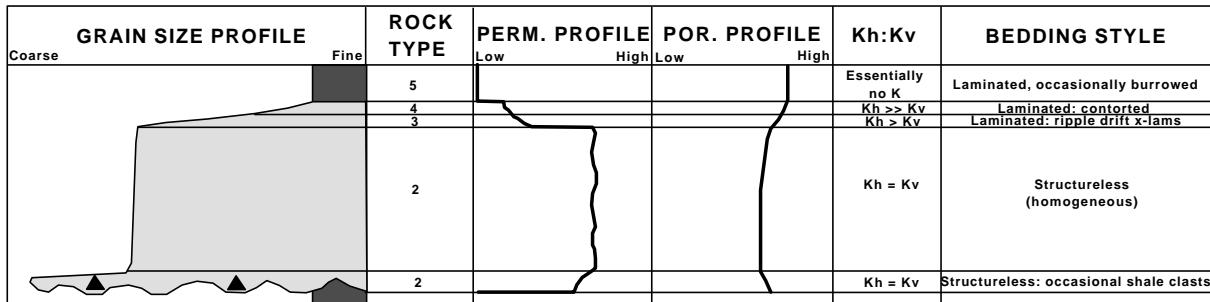
T Sand. The T Sand interval is approximately 85 ft thick (Figure 11). It was deposited in the outer fan environment, specifically in feeder channels and fan lobes (Figure 13B). The reservoir interval has a high degree of internal complexity, much higher than is indicated by a cursory evaluation of the wireline logs. In all conventional cores, the T Sand consists of numerous, thin (2 ft), porous and permeable sand beds each of which is capped by an impermeable shale (see the geological core description, Figure 14).



Each sand bed was deposited from a single, gravity- driven turbidity current that carried coarse detritus (sand) from the nearby slope out onto the basin plain. Geological and petrophysical characteristics of these sand beds are presented in Figure 15A. The basal contact of individual sand beds with underlying shale is erosive, indicating high energy during sand transportation and deposition. Within each sand bed, grain size fines upwards – a characteristic of many turbidites. This internal, upwards fining of grain size reflects a reduction of current energy (flow velocity and turbulence) with time. The sands

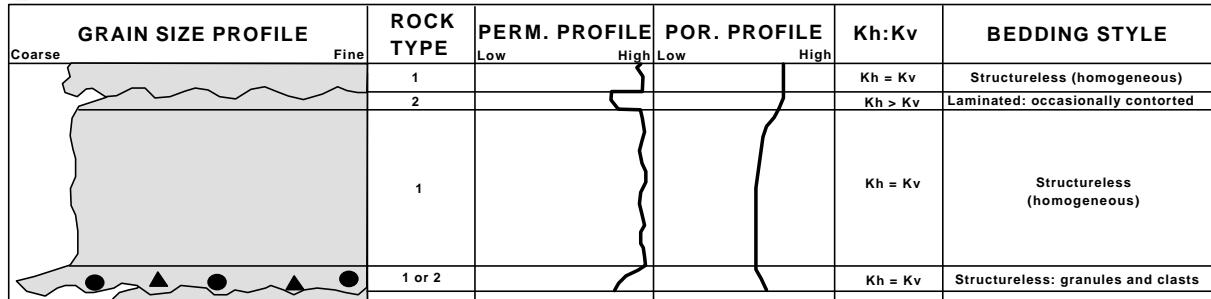
Figure 14: Log response and geological core description, outer fan environment, T Sand interval

A



LATERAL EXTENT OF INDIVIDUAL SAND BEDS: >3,000ft parallel to depositional dip, <1,000ft perpendicular to dip

B



INDIVIDUAL SAND BEDS LATERALLY EXTENSIVE IN ALL DIRECTIONS DUE TO ABSENCE OF SHALES

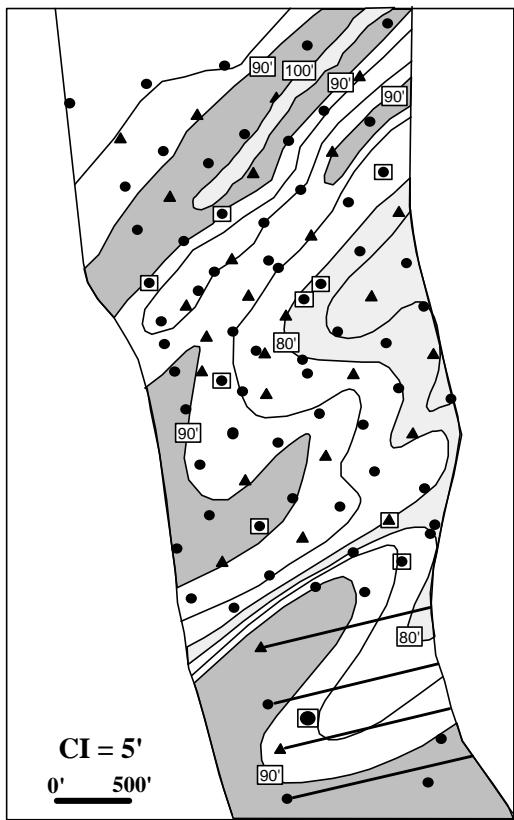
Figure 15: Geological and petrophysical characteristics of individual sand beds:
A: T Sand interval; B: D Sand interval. (Not to scale).

that make up most of the thickness (>90%) of any bed (central portion in Figure 15A) are homogeneous; they

show little or no vertical change in grain size and they contain <1% shale, based on thin section and X-ray diffraction analysis.

Shale beds cap virtually all of the numerous sand beds that comprise the T Sand reservoir. The shale beds are thin (0.5ft) but are known to be laterally very extensive in outer fan environments. The shales form effective barriers to vertical flow and therefore impact significantly the vertical sweep efficiency. In this field, this is demonstrated by the fact that post-steam cores (cores taken in areas of the field that have been swept by steam) show no change of oil saturation in thin (<1inch thick) sand layers that occasionally occur within the shale beds.

The presence of numerous interbeds of pelagic shale causes the T Sand reservoir to be strongly laminated (bedded). The Spontaneous Potential (SP), Gamma Ray (GR) and true Resistivity (R_T) responses do not effectively reveal the highly laminated nature of this reservoir. On the other hand, the flushed zone resistivity (R_{x0}) response gives an improved indication of the high degree of reservoir lamination (Figure 14). High GR response in the T (and D) Sand is the result of the presence of abundant radioactive sand grains (orthoclase feldspar and micas).



feeder channels (axes of the “thicks”) into the basin. Overbank flow resulted in deposition of sands along the sides of the principal avenues of sand transport.

Figure 16: Isopach map of gross thickness, T Sand interval

outer fan feeder channels and lobes during the sedimentation of the entire interval. This map shows the presence of a major feeder channel in the NW portion of the field, and the proximal portions of several lobes in the rest of the field. Not all of these channels and lobes were active at the same time. As a result, reservoir continuity is anisotropic. Individual sand beds are continuous in a NE-SW direction (>3,000ft) and discontinuous in a NW-SE direction (<1,000ft) based on a consideration of log responses and maps of sand distribution.

D Sand. The D Sand interval is approximately 60ft thick. It was deposited in the Middle Fan (midfan) environment (Figure 13C) as indicated by the characteristics of the sand beds and the general absence of shale interbeds. Sand bed thickness is a function of relative position on the fan surface (Figures 17 and 18). Sand beds are thick in the proximal (inner) portion of the midfan and they thin gradually towards the distal portion of the midfan (outer midfan). Shale beds occur only in cores from the outer midfan sub-environment, where they are very thin (<0.2ft) and discontinuous due to minimal deposition and subsequent erosion of the thin shale beds during transportation and deposition of the overlying sand beds.

A map of the gross thickness of the T Sand interval (Figure 16) reveals a characteristic NE-SW trending pattern of alternately thick and thin deposits. Long, narrow “thicks” (such as in the northern area of the field) are characterized by increased sand content (relative to shale), and they represent the locations of the outer fan submarine feeders that were the main avenue of transport of the sands to the distal lobes. In a general sense, these can be regarded as channels, but it is important to stress that they are not characterized by significant down cutting (basal incision). The system was strongly aggradational: deposition dominated over erosion. While erosion surfaces are common at the base of most sand beds, the amount of vertical downcutting at the base of any sand bed is less than one or two inches. The sands do not completely erode the underlying shale beds. This fact is important because it means that the laminated nature of the reservoir is preserved even in areas where feeder channels are dominant. Sands were transported along the

The map of the distribution of T interval thickness (Figure 16) displays the result of the growth and abandonment of several individual

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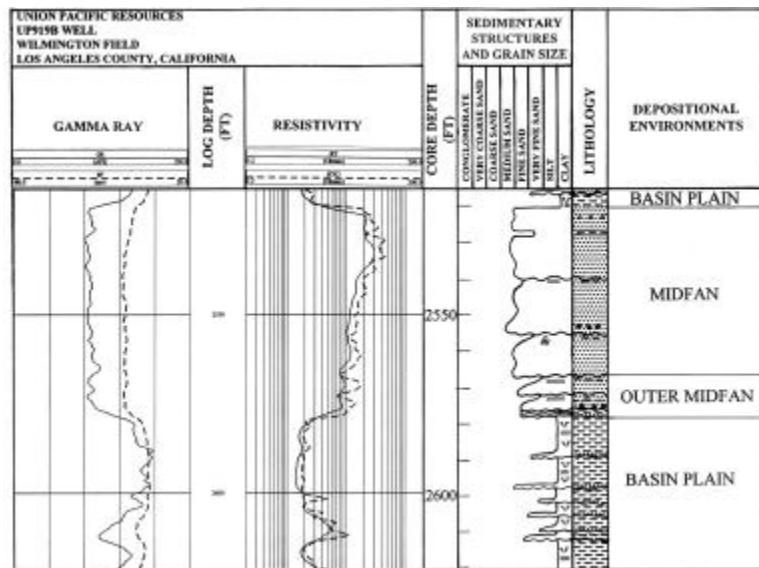
thickness (Figure 16) displays the result of the growth and abandonment of several individual

thickness (Figure 16) displays the result of the growth and abandonment of several individual

The D Sand interval is characterized by a vertical stacking of numerous porous and permeable sand beds. In the outer portions of the midfan sub-environment, grain size fines upwards within individual sand beds (Figure 18). Sand beds deposited in this environment have similar geological and petrophysical characteristics to those of the outer fan environment.

Sand beds deposited in the central portion of the midfan environment exhibit no consistent vertical change in grain size (Figures 15B and 17) because here 1) deposition occurs from debris flows as well as from turbidity currents, and 2) bed contacts are erosive, sand-on-sand (shale interbeds are absent), making it difficult to separate deposits of individual gravity flows. The SP, GR and R_T responses do not effectively respond to the internal bedding characteristics of the D Sand interval. This is to be expected given the presence of sand-on-sand contacts between adjacent beds in this reservoir.

A map of the gross interval thickness of the D Sand interval (Figure 19) reveals that NE-SW trending areas that are alternately thick and thin dominate sediment distribution patterns. However, the rate of change of thickness is less pronounced than in the T Sand interval (compare Figures 16 and 19). These differences reflect the differences in detailed depositional environments between the two intervals. The D Sand interval was deposited in the center of a submarine fan system where rapid changes in sediment thickness are not common. The T Sand interval was deposited towards the outer edges of a submarine fan system where lateral changes in thickness and lithology (sand to shale) are common (Figures 13B and 13C).



environment exhibit no consistent vertical change in

Figure 17: Log response and geological core description, central mid-fan environment, D Sand interval

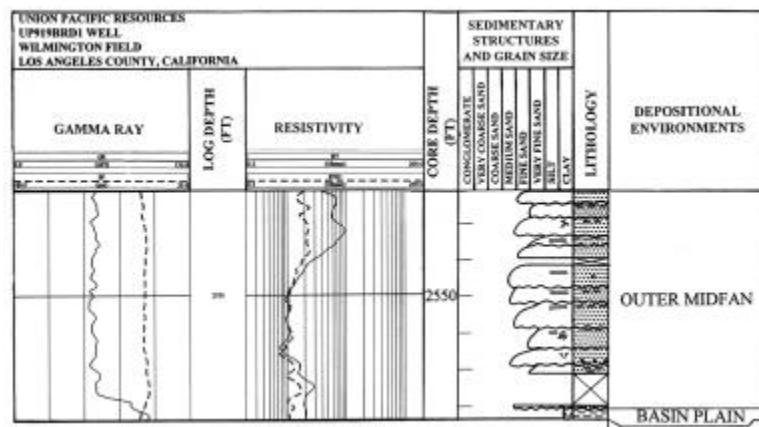


Figure 18: Log response and geological core description, outer mid-fan environment, D Sand interval.

In this field, the D Sand was deposited in a submarine fan system that received sediment along several, NE-SW oriented feeders (the apexes of the sand thick, Figure 19. Sand quality in the D interval increases towards the northeast (towards the sediment source) along the directions of the feeders.

Vertical permeability, vertical sweep efficiency and sand continuity are very high, as indicated by efficient oil displacement during steamflood operations. Finer grained portions of sand beds act only as permeability baffles, not as permeability barriers. The D Sand is the most homogeneous and most productive interval of the Tar Zone in Fault Block II.

Despite the overall homogeneity of this interval, production history reveals that the most productive wells occur along a northeast-southwest trend that parallels the depositional trend. Analyses of water salinity variations over time likewise reveal that the reservoir sweep has a preferred anisotropy in a NE-SW direction.

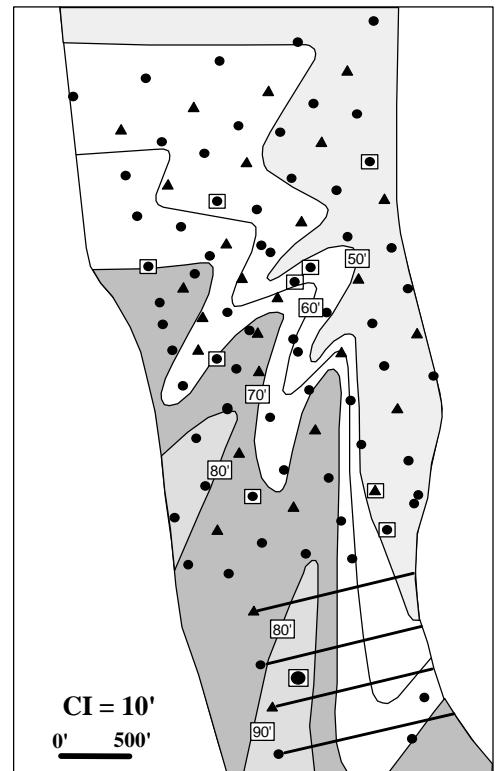


Figure 19: Isopach map of gross thickness, D Sand interval

ACTIVITY 1 - COMPILED AND ANALYSIS OF EXISTING DATA

Introduction

Previous to this reporting period, existing field production and injection data for Tar II-A were compiled, evaluated for reliability, and analyzed in terms of production response and constraints to provide a foundation for creating geologic and reservoir simulation models. The data were incorporated into Production Analyst™ (PA), a computer-aided data retrieval system by Schlumberger Geoquest, to facilitate simulation-based reservoir management.

Historical Tar II-A reservoir engineering data such as pressure, volume, and temperature (PVT) test results on crude, annual isobaric data, water injection profile surveys, and past reservoir engineering studies were retrieved and analyzed to perform material balance calculations.

A database of available well logs was compiled. Digitization and normalization of log data from 178 wells distributed throughout the Fault Block II-A Tar Zone were completed for use in the 3-D deterministic and stochastic geologic models and rock-log models.

No data compilation work was performed this reporting period.

During the next year, the project team will complete the production and injection data compilation work for the Tar V wells. This data, along with the Tar V geologic model, will be used for history-matching and material balance calculations in developing a 3-D deterministic thermal reservoir simulation model. Reservoir temperature and pressure surveys will be run periodically as described in Section 4.7 Reservoir Surveillance.

1.1. Data Compilation

No activity reported this period.

1.2. Log Digitization and Normalization

No activity reported this period.

ACTIVITY 2 – ADVANCED RESERVOIR CHARACTERIZATION

2.1 Basic Reservoir Engineering

No activity reported this period.

2.2 Obtaining New Characterization Data

2.2.1 Measurement While Drilling Data

No activity reported this period.

2.2.2 Tracer Surveys

Introduction

On February 14, 1997 the reservoir tracers, ammonium thiocyanate (AT) and lithium chloride (LC), were injected into two hot water-alternating-steam pilot injectors. The tracer work included the issues related to tracer selection, concentrations and volumes and to field sampling, laboratory analyses and interpretation of the produced water results for tracer hits. Samples of produced fluids collected from the first and second rows of producers were analyzed for the ammonium and lithium tracers. The tracer analysis work recorded very few tracer hits above background levels. Upon further review of the tracer selection criteria and steamflood pattern wells used, the project team believes that the disappointing results occurred because the tracers possibly broke down in the very high temperature reservoir environment and because of operational changes related to the rapid conversion of steam injectors to hot water injectors. In spite of its mixed results, the technology transfer value of the findings is substantial for other similar thermal operations and an upgraded report will be included in the next Annual Report.

2.2.3 Water Composition Tests

No activity reported this period.

2.2.4 Oil Finger Printing

No activity reported this period.

2.2.5 Drill 3 Observation and 2 Core Hole / Observation Wells

No activity reported this period.

2.3 Deterministic 3-D Geologic Model

2.3.1 Three-Dimensional EarthVision™ Structure

In 1995, five horizontal wells were drilled into the Fault Block V Tar zone as part of a steamflood pilot operation. The wells were drilled on average 1500 feet horizontally within the S₄ sand. Three-dimensional (3-D) geologic modeling and visualization were used from planning through completion of the wells. The modeling work was the subject of a paper by Clarke and Phillips entitled "3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year Old Wilmington Oil Field of Southern California."^{A36}

Horizontal wells require precision placement to be effective. The studied areas required significant geological evaluation and characterization. The area was modeled with Dynamic Graphic's EarthVision™ software that provided 3-D visual displays of stratigraphic and structural relationships and also enabled excellent error checking of data and grids in 3-D space. The 3-D model provided a visual reference for well planning and communicating the spatial relationships contained within the reservoir.

The technologies developed in the Tar II-A steamflood project were applied to the Tar V steamflood project where five horizontal wells were drilled. The excellent accuracy of the 3-D geological model generated, and the usefulness of the computerized tools used to extract information from the model, greatly enhanced the success of the project.

As with the Tar II-A project, the 60+ year-old electric logs were reviewed and recorrelated dividing the Tar V zone into 14 sub-subzones. The log (Figure 2.3.1-1) shows a portion of the stratigraphic section from the probe hole drilled prior to the horizontal section in well FJ-204. The "S₄" sand has the highest resistivity (oil saturation) and is the most thick, continuous, and clean Tar V sand across the fault block. The FJ-204 probe hole verified the oil saturations and reservoir pressures in the individual Tar sands and confirmed the subsidence-corrected vertical depths used in generating the maps for horizontal well placement.

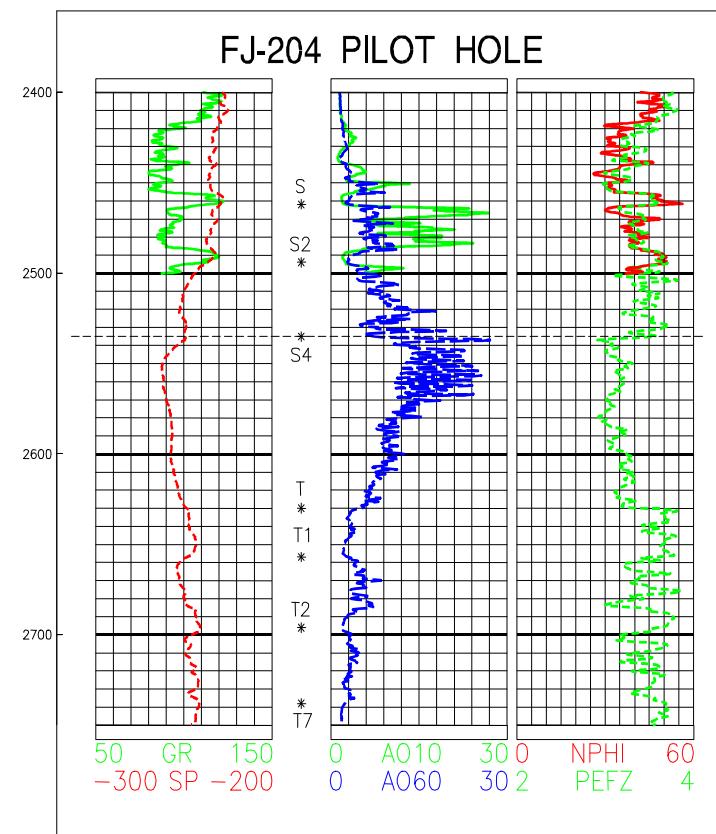


Figure 2.3.1 -1: Well log for FJ-204 pilot hole in FB V Tar zone. Shown are the S and T sands. The S₄ is the sand completed in pilot steamflood.

A deterministic geological model was created from which the maps and cross-sections were extracted and used to geosteer the horizontal wells. The modeling was much more straightforward than in the earlier Tar II-A project, as the lateral sections of the horizontal wells are in unfaulted areas with relatively little structural relief (Figure 14). Customized 2-D and 3-D visualizations were used during drilling for interpreting the Logging-While-Drilling (LWD) resistivity, gamma ray and well survey data and for monitoring well progress. Map and section plots brought to the rig site allowed the drilling team to correlate real-time drilling to the geologic maps, thus providing a strong confidence factor that drilling operations were on target. Accurate and rapid post-drilling analysis for completion interval selection and LWD analysis completed the process.

The experience gained in the Tar II-A project and improvements to the EarthVision™ software made modeling even easier. Adding interpretive “ghost” points through the EarthVision 3-D viewer and then reconstructing the model controlled the mapped areas with “no data”. This interpretative technique cut modeling time significantly.

During drilling, the LWD data provided near real-time data as the recorder was 60 ft behind the bit. This current data stream allowed the drilling team to adapt quickly when the penetrated formations did not correlate to the geologic maps. For example, one area of the geologic model indicated an anomalous structural low. The survey and log picks appeared to be correct for a well located in this “low” area. The datum point was honored and horizontal well J-201 was drilled into the area. It was apparent from the LWD curve separation and bed boundary intersections that the “T” shale below the “S₄” sand was shallower than the model indicated. The well course was changed during drilling of the horizontal section to point the bit up. Unfortunately, the new drilling course overcorrected for the problem and the well exited the top of the “S₄” sands for 200 ft before the reentering the sand. Still, the well course was placed into the “S₄” and “S₂” sands rather than in the “T” shale or below. Afterwards, the offending well datum was removed and the model was revised based on the multiple horizon picks from well J-201. Because this remodeling can now

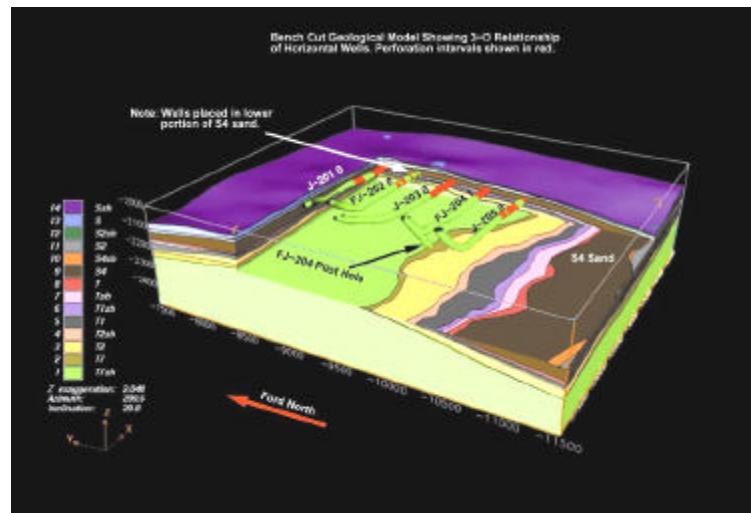


Figure 2.3.1-2: Three-dimensional bench cut of FB V Tar Zone showing steamflood project in S4 sand. “J” wells are producers and “FJ” wells are injectors. Well completions shown in red. This structurally flat area has 2X vertical exaggeration.

be done in almost real-time, the geologist can revise the model as drilling proceeds or after each new well is drilled.

The 3-D model in Figure 2.3.1-2 is “bench cut” and shows the five horizontal wells and their perforations. The goal was to keep the wells parallel to and within five feet above the top of the “T” shale to maximize recoverable reserves from the superjacent “S₄” sand. The maps, cross-sections and geological model were all used to place the horizontal wells accurately. Figure 2.3.1-3 shows the cross-section for well J-203, which was drilled near perfect along the bottom of the “S₄” sands.

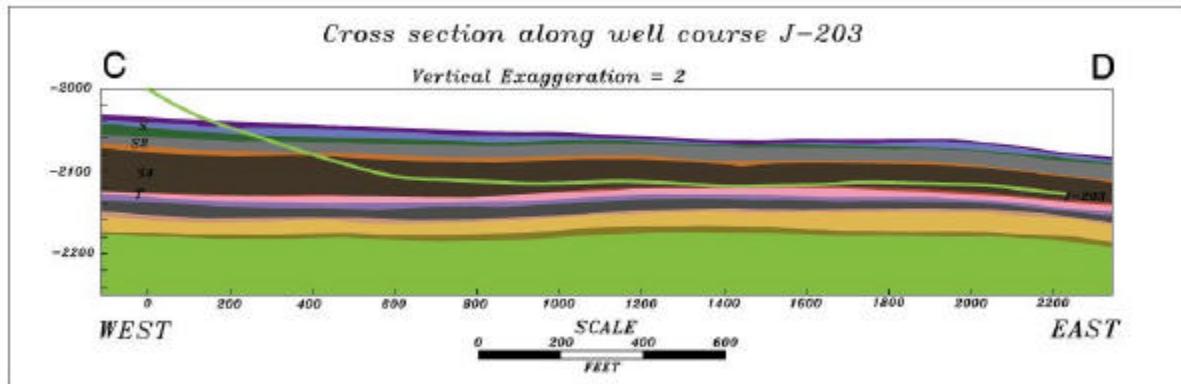


Figure 2.3.1-3: Cross-section along well course of J-203. Placing the well as close to the bottom of the S₄ sand as possible to increase oil recovery.

Overall, the Tar V drilling project (case history 3) was a major technical and economic success. Based on what was learned in the Tar II-A project and the accuracy of the 3-D model, the drilling team was able to plan and drill with confidence. No wells were plugged back for geological reasons and drilling time was reduced by spreading out survey lengths, using less time for correctional sets, and rotating the tool string while drilling a large percentage of the horizontal section. Roller reaming prior to running casing was eliminated as shales were avoided, allowing reaming with the bit already in the hole. In addition, only one pilot hole in FJ-204 was necessary. As a result, time and money were saved. Well J-203 took only six days from rig up to rig down to drill and case the 4,661 ft measured depth hole.

For the drilling team, having 2-D and 3-D visuals at the rig site stimulated better feedback and established a clearer understanding of how the geology affected drilling performance. Drilling efficiency was improved because 2-D and 3-D visuals provided the ability to see quickly what a particular directional tool set accomplished. Previously, the drillers only had numbers to look at which were much less intuitive and informative.

The Tar V horizontal well drilling budget was based on the Tar II-A horizontal wells. The average savings per well was US\$12,400 on directional costs and US\$18,000 due to fewer drilling days. In total, US\$152,000 was saved on the five horizontal wells drilled. The monetary savings and management's confidence in the 3-D

model allowed all five laterals to be extended an extra 12%, on average, effectively increasing the producible area and adding 382, 000 stock tank barrels (STB) or 60,734 stock tank m³ (STCM) of oil.

CONCLUSIONS

The geologist who can carefully characterize rock data and apply 3-D modeling and visualization techniques adds greatly to the horizontal well drilling team. The highly accurate 3-D visualizations of the reservoir greatly increase the confidence factor of the team by reducing drilling risks and costs, thus enabling Wilmington Field oil reserves to be maximized.

To be effective, horizontal wells require precision placement. Three-dimensional models help isolate data inconsistencies, while 3-D viewers are good for adding data to correct the geological model. Once the final geological model is created, the drilling team can use the resulting 3-D visuals with confidence to improve drilling techniques and directional control. Post-well analysis of the LWD data also is facilitated using 3-D geological models.

The 3-D techniques contributed significantly to the economic success of the Tar Zone horizontal project. Assuming a 50% oil recovery factor, every foot the well is drilled above the target is equivalent to 15,876 STB (2,524 STCM) in lost reserves.^{A37} At US\$14/ bbl oil, being off as much as five feet vertically would equate to U.S.\$1.1 million in lost revenue.

2.3.2 Core Based Log Model

No activity reported this period.

2.3.3 Porosity-Permeability Model

No activity reported this period.

2.3.4 Rock-Log Model

No activity reported this period.

2.3.5 V-Shale Model

No activity reported this period.

2.3.6 Qualitative Conditioning

No activity reported this period.

2.3.7 Basin Modeling

No activity reported this period.

2.3.8 Updating

No activity reported this period.

2.4 Stochastic 3-D Geologic Modeling

No activity reported this period.

ACTIVITY 3 – ACTIVITY RESERVOIR SIMULATION

3.1 Deterministic 3-D thermal Reservoir Modeling

Introduction

The original intent of the 3-D advanced reservoir modeling work was to address the lateral variations in rock geology using geostatistical correlation methods. Upon completion of the geostatistical work, the plan was to rebuild the 3-D deterministic geologic model and examine various stochastic realizations of reservoir conceptual models for simulation purposes. The STARS™ thermal reservoir simulation program by the Computer Modeling Group (CMG) of Calgary and the R10,000 Onyx RE2 work station by Silicon Graphics Incorporated (SGI) were selected for the reservoir simulation modeling which began in October 1996. History matches covering the primary depletion, waterflood, and steamflood periods were completed for the 3-D deterministic thermal reservoir simulation model in June 1998.^{A22, A25, A27}

The City of Long Beach modified the project priorities in the third quarter 1998 to address their concerns about steamflood-related surface subsidence and how to safely operate the Tar II-A wells during the post-steamflood phase. The 3-D deterministic reservoir simulation model was immediately used to optimize oil production while accelerating steam chest fill-up with flank water injection by measuring the mass fluid and heat balance effects as they pertained to reservoir pressure. Affecting reservoir pressures in the target area are the following four occurrences: (1) Mixing of the hot and cold fluids at the flank-water injection sites. (2) Continuous heat loss occurring in developed steamflood areas to the overburden and underburden formations. (3) Steam chest collapse and expansion in the structurally updip areas. (4) The movement and production of hot fluids throughout the steamflood project area. Taken together, these parameters make the prediction of reservoir pressures too difficult without a viable reservoir model. The post-steamflood reservoir simulation modeling study was the basis for a technical paper presented at the AAPG / SPE Western Regional Meeting in June 2000.^{A34}

The real-time response capability of the reservoir simulation model has made it an indispensable tool for day-to-day reservoir management purposes. The model successfully performed its primary function of mitigating further surface subsidence by setting injection and production rates and predicting when steam chest fill-up would occur. The model can effectively predict overall mass and heat balance of the injected and produced fluids, provided its updated with actual data. The model cannot predict net oil production and did not provide the correct steam chest fill-up pressure or the short-term injection to production ratio to use following steam chest fill-up. These model weaknesses will probably require a stochastic 3-D model to correct.

The plan is to update the Tar II-A post-steamflood model to provide a comparison of model projections to actual reservoir temperatures and pressures for the past two

years. The actual temperature data are from gross fluid production from individual wells and temperature profile surveys. The pressure data are from the bimonthly fluid level surveys and periodic Amerada bomb pressure recordings on idle wells. Once the model is adapted for actual temperature and pressure conditions, using it can help optimize the post-steamflood operations about maximizing production while minimizing injection volumes, heat loss and surface subsidence.

The five horizontal well steamflood pilot installed in the Tar V zone in late 1995 is based upon the three dimensional (3-D) deterministic geologic modeling and horizontal drilling technologies derived from the Tar II-A project. The Tar V steamflood pilot began operating in mid-1996 and has injected over 3.8 million barrels of steam and recovered about 607,000 barrels of oil from the S2 and S4 sands. Both modeling and operational tasks are planned for the Tar V Zone.

A simplified 3-D deterministic thermal reservoir simulation model was developed to predict thermal heating of the overburden and underburden shales in the Tar II-A post-steamflood phase. The model consisted of one partial steamflood pattern using actual injected steam temperatures for the steam injectors and produced fluid temperatures for the producers. The model estimated the current reservoir temperatures at infill locations within the pattern and forecasted pattern areal and vertical temperatures over several years assuming different production and water injection scenarios.

Tar V Model

Plans are for development of a 3-D deterministic reservoir simulation model for the Tar V steamflood pilot, similar to the Tar II-A model, to determine the status of reservoir heating from steam injection. The model will estimate the temperatures and pressures throughout the reservoir over time and forecast gross fluid production and injection rates to prevent formation compaction. The Tar V project, unlike the Tar II-A project, has only a few temperature observation wells that provide an indication of reservoir heating, but not a comprehensive three-dimensional estimate over the entire project area. Optimizing steamflood operations and oil recovery will require a 3-D deterministic model.

The pilot currently has eleven wells, including three horizontal producers and two horizontal injectors completed at the bottom of the S4 sands and three vertical producers and three vertical flank water injectors completed in the S2 and S4 sands. The model will provide a better conceptual picture of where the injected water is going, where and how quickly the reservoir is heating up or cooling, and the supplemental flank water injection rates necessary to maintain reservoir pressure, all assuming several water injection and gross fluid production rate scenarios. The model will also help determine when to convert the pilot to post-steamflood operations.

Similarities and differences between the Tar II-A and Tar V geologic models and oil recovery histories will be highlighted and methodologies will be developed to handle

the differences. The objective is to demonstrate how an independent producer can properly adapt and utilize the FB II-A Tar Zone geologic and reservoir simulation models in their reservoirs where they do not have the same amount of quality reservoir data.

Simulating Thermal Heating of Overburden and Underburden Shales

In the fourth quarter 1999, reservoir simulation modeling efforts were directed towards determining the amount of reservoir heat that is thermally conducted from the Tar II-A steamflood sands to the overburden and underburden shales. The model was based on a 1/12 of a seven-spot 5 x 5 x 81 grid (2025 grid blocks) using the CMG STARS™ thermal reservoir simulation software. The grid dimensions were 48 feet by 83 feet with the thickness of the vertical layers varying from 3 feet to 35 feet depending on whether the layer was part of a sand or shale. The model had 60 feet of non-steamflooded sands and shales below the steam zone and 200 feet of non-steamflooded sands and shales above the steam zone. The steam zone consisted of 50 feet of the "T" sands with three 3 foot interbedded shales and 50 feet of the "D" sands. There were 51 feet of non-steamflooded sands and shales between the "T" and the "D" sands. The model mimicked two injection wells (one for the "T" sand and one for the "D" sand) and one production well in a specific seven-spot pattern in the middle of the Tar Zone steamflood. The distance between the injection wells, 2AT-032 ("T" sand) and 2AT-033 ("D" sand), and the production well, UP-922 ("T" & "D" sands), was 384 feet. This is equivalent to an 8.8-acre pattern, although the average pattern size was 7.5 acres. The three wells were selected as the model pattern because observation well OB2-5 is located halfway between the injectors and the producer so reservoir temperatures in the model could be compared to actual data.

The first scenario was to inject 1,000 BPD of cold water equivalent steam (CWES) at 580°F and 80% quality into wells 2AT-032 and 2AT-033 and produce well UP-922 at 1200 B/D of gross production from June 1989 to January 1, 1999. The model's predicted temperature profile of the steamflood zones and the adjacent non-steamflood layers in the observation well for January 1, 1999 was compared to an actual temperature profile in observation well OB2-5 for the same time period and had a very good match. The producer was shut-in on January 1, 1999. The injectors stopped injecting steam and started injecting only enough 500°F hot water to maintain reservoir pressures at 90% of the hydrostatic pressures, 930 psi in the "T" sand and 980 psi in the "D" sand. Without some form of injection, reservoir pressures would decline due to steam chest collapse from overburden and underburden heat losses and fluid losses to the lower pressured aquifers. In actuality, flank cold water injection is maintaining the reservoir pressures in the steamflood area. Hydrostatic pressure is the pressure at a specific depth equivalent to the weight of a column of water from that specific depth to the surface. The model continued to run an additional ten years to determine the heating and cooling effects after steam injection. The heating and cooling data of the layers above and below the steam zone were recorded and analyzed. The normal reservoir temperature before steamflooding was 123°F. The model predicted that the average temperature of the steam zone cooled off from 523°F in January 1999 to 470°F by January 2009 at the injection wells, 520°F to 448°F at the observation well, and

515°F to 448°F at UP-922. The model showed that after steam injection the steam zone and shale immediately adjacent to the sands cooled off by 60-70 degrees while the remaining shale layers above and below continued to heat up slightly.

The second scenario was to restart the model on January 1, 1999 and inject only enough 135°F water into the injectors to maintain 90% hydrostatic reservoir pressures in the "T" and "D" sands. The producer was shut-in on January 1, 1999 and returned to production on October 1, 1999 following the model's projected reservoir steam chest fill-up. This simplified 1/12 of a seven-spot model predicted the same reservoir steam chest fill-up time as the full reservoir 3-D deterministic thermal model. The model continued to run an additional ten years and the heating and cooling data of the layers above and below the steamflood zone were recorded and analyzed. The model predicted that the steamflood zone cooled off from 523°F in January 1999 to 135°F by January 2009 at the injectors, 520°F to 160°F at the observation well, and 515°F to 214°F at the producer. Ten years after the steamflood was shut-in, the layers above and below the steamflood zone continued to heat up proportionally to how the steamflood zones were cooling off.

No case occurred that simulated the actual Tar II-A flank-water injection strategy because of the limitations of the one-pattern model. The actual reservoir heating and cooling situation is probably in between the two scenarios but closer to the first scenario because injection of cold water is not directly within the steamflood area.

ACTIVITY 4 – RESERVOIR MANAGEMENT

4.1 Horizontal Wells and Surface Locations

No activity reported this period.

4.2 Horizontal Well Cyclic Steam Stimulation Pilot (4 Wells-2 Prod. & 2 Injection)

No activity reported this period.

4.3 Horizontal Well Steam Drive

Introduction

The original DOE horizontal well steamflood pilot, drilled and operated as an expansion phase within the Tar II-A steamflood project, included two producers and two injectors. Upon the cessation of Tar II-A steamflood injection in January 1999 because of loss of the steam source from Harbor Cogeneration Plant, the DOE approved continuing this segment of the project by replacing the Tar II-A pilot with the existing five-well horizontal steamflood pilot in Tar V in late 1998.

Tar V Production History Summary

The Long Beach Oil Development Company (LBOD), as contract operator for the City of Long Beach, began Tar V production in 1951. Similar to Tar II-A, LBOD and the City of Long Beach implemented a non-unitized waterflood project in the Tar V in 1960 to increase and maintain reservoir pressure at about 80% of hydrostatic pressure or 800 psi to prevent further surface subsidence. The Tar V cumulative oil production through 1960 was 9.8 million barrels or about 5% OOIP. Reservoir pressure in 1960 averaged about 460 psig. After 36 years of waterflooding and just prior to the steamflood pilot, cumulative oil production through 1996 was 50 million barrels for a waterflood recovery factor of 25% OOIP. Waterflood operations in 2001 still represent 55-75% of the oil production from the Tar V sands. Tar V oil production in March 2001 was 717 barrels of oil per day (BOPD), of which pilot steamflood production was 199 BOPD or 28%. Tar V total water injection in March 2001 was 21,825 BWPD, of which steam was 3,304 BCWESPD or 15%.

Tar V Horizontal Well Steam Drive Pilot

The Tar V Horizontal Well Steam Drive Pilot project consists of eleven wells. In late 1995 to early 1996, Tidelands drilled five of these wells (three producers and two injectors) at the bottom of the S4 sands. Production of these wells began in late 1996. The existing wells (three vertical producers and three vertical flank water injectors) are completed in the S2 and S4 sands. Figure 4.3-1 shows the locations of these wells. Figure 4.3-2 is a type log of the Tar zone showing the "S" and "T" sands. The Tar V Horizontal Well Steam Drive Pilot projects development based on the Tar II-A horizontal

well steamflood pilot. Tar V cumulative steamflood oil production from June 1996 through March 2001 is 607,272 barrels. The project estimated to ultimately recover 1.7 million incremental barrels from the steamflood pilot area. The project initially had several months when the steam/oil ratio was below five. The cumulative SOR through March 2001 is a reasonable 6.6. Figure 4.3-3 is a production and injection graph for the Tar V steamflood project from June 1996 through March 2001. The production and injection graphs for each of the individual wells are located in the Appendix.

Each horizontal well received a cyclic steam-stimulation job to provide a completed sand consolidation well and to accelerate oil production. Initial production performance was very encouraging. All five wells had early peak oil rates ranging from 223 - 328 BOPD. For the first four months of 1998, while the wells were still stimulated from cyclic steam and starting to respond to steamflood injection, the average oil production was 698 BOPD compared to the forecasted rate of 590 BOPD.

Two horizontal wells, FJ-202 and FJ-204, were converted to permanent steam injection in June 1997 and October 1997, respectively, following cyclic steam production. Total steam injection rates into Tar V have ranged from 1100 – 3700 barrels of cold water equivalent steam per day (BCWESPD), averaging 2871

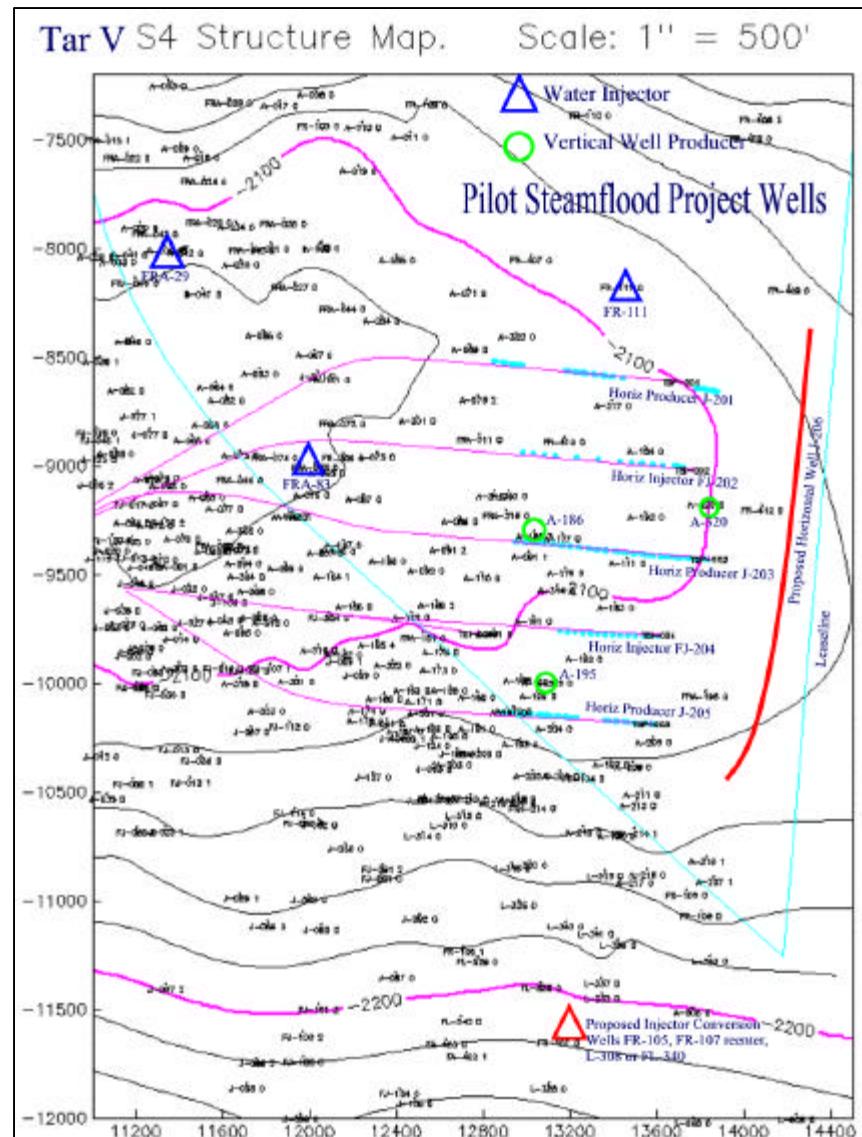


Figure 4.3-1: Tar V steamflood project wells, including three horizontal producers (light blue "J" wells), two horizontal steam injectors (light blue "FJ" wells), three vertical infill producers (green circles) and three flank water injectors (blue triangles).

BCWESPD from June 1996 through March 2001. Cumulative cyclic and steamflood steam injected through March 2001 was 4.0 million barrels.

Steam drive response a year or more after the start of steamflood injection peaked at 91 - 151 BOPD for each of the three horizontal producers (wells J-201, J-203 and J-205). The three producers have had continuously high producing fluid levels over 1300 ft above the pump and should be capable of producing at higher peak rates. Increasing water injection in February 2001 allowed for higher gross fluid production rates. This should favorably affect the instantaneous SOR of the project, which has averaged 10.15 since May 1999 primarily because of the high fluid level problem.

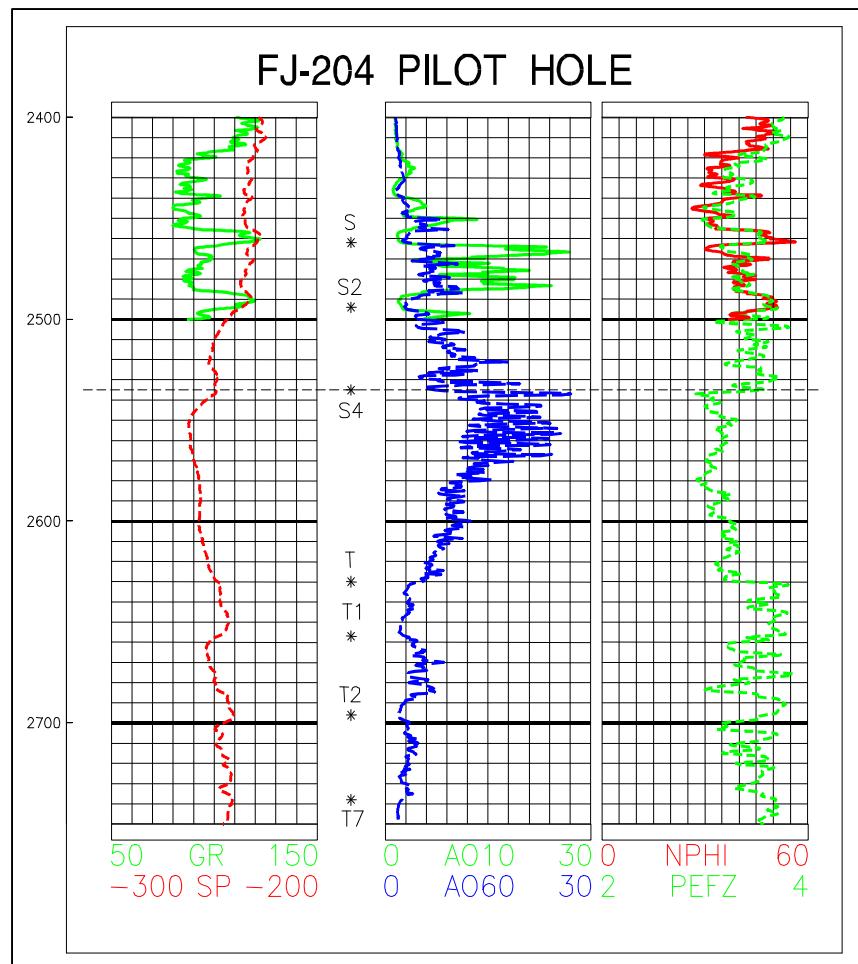
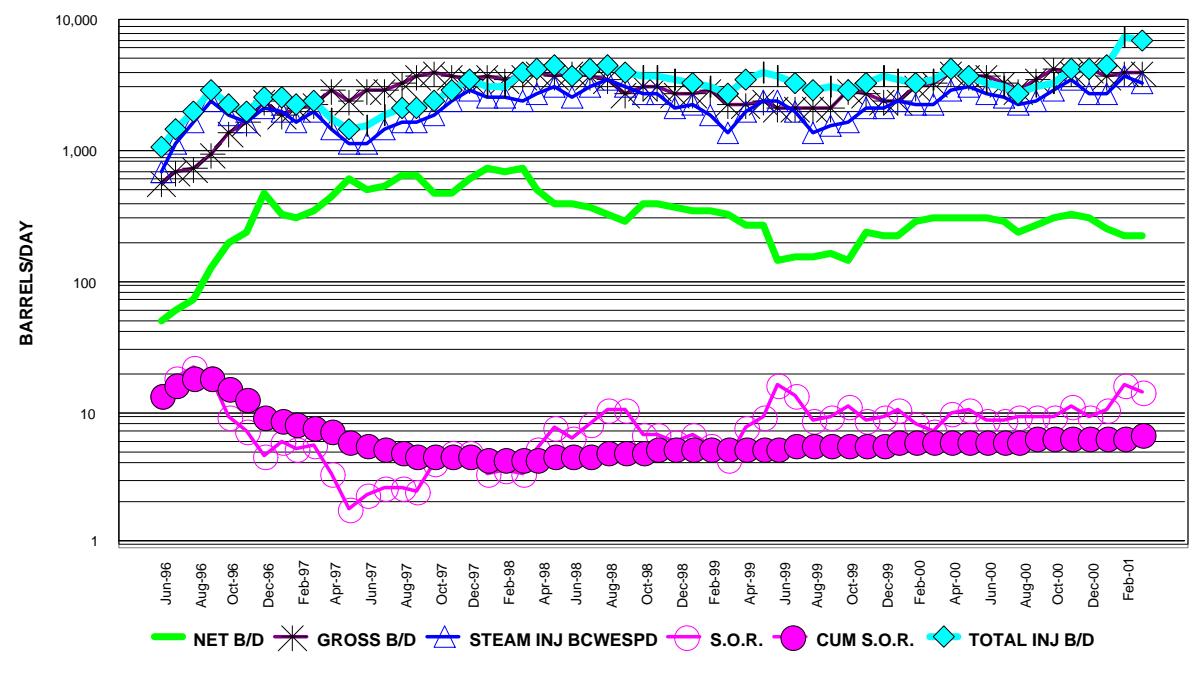


Figure 4.3-2: Type Log, Fault Block V Tar Zone, illustrating "S" and "T" sands.

Significant oil production is recovered from three pre-steamflood vertical producers (wells A-186, A-195 and A-320) located within the steamflood area that have recovered 209,486 barrels of oil since June 1996 or 34% of the cumulative steamflood recovery. All three wells are over 30 years old and responded to offset steam injection. Before steaming, the wells averaged 16 bbl/day (2.5 m³/day) net with 200 bbl/day (31.8 m³/day) gross, at an average water cut of 92%. Figure 4.3-4 shows the pre-steamflood production rates from the existing waterflood producers in March 1996. Figure 4.3-5 shows the production well tests and steam and water injection rates in January 1998 for the horizontal and existing waterflood wells following the initiation of steamflood-related steam injection in October 1997. Figure 4.3-6 shows more recent production well tests and water injection rates for the mature steamflood wells in August 2000.^{A36}

Flank water injection is currently from three wells (FRA-29, FRA-83 and FR-111) located to the north and west of the horizontal wells (Figure 4.3-1). At the start of the

FIGURE 4.3-3
TIDELANDS OIL PRODUCTION CO.
TAR ZONE FB-V STEAMFLOOD



steamflood, FR-111 was the only well injecting water. Because of its proximity to the horizontal well completions during both the drilling and cyclic work, Well FRA-83 was idled in November 1995. Injection resumed in February 1998. In November 2000, converting Well FRA-29 to water injection ensured reservoir pressure maintenance to the north and allowed the horizontal wells to be produced at higher rates. From June 1996 through March 2001, flank water injection averaged 910 BWIPD increasing to 3800 BWIPD in February 2001.

A new horizontal well, J-206, will be drilled and completed in late 2001 to improve drainage of the pilot area reserves and to capture new oil reserves in the adjacent area between the steamflood pilot and the THUMS lease line to the east. The well will be drilled parallel to the lease line as shown on the formation structure map of the Tar V "S4" sands in Figure 4.3-1. Available horizontal well completion technology will be reviewed to determine the best application for this new well. Engineering needs to consider whether to place the horizontal section at the bottom, middle or top of the S4 sands.

Current production rates are below expectations because of self-imposed production limitations to prevent well completion failures. To improve productivity, two of the horizontal wells will have inner liner gravel-pack completions installed to back up the current sand consolidation completions. Two of the three horizontal well pilot producers

Figure 4.3-4: FB V Tar zone waterflood wells in future steamflood area. Producers are in green and injectors in red. Producers show gross fluid and oil production rates and water cut and injectors show water injection rate and pressure. All data in March 1996 is prior to steamflood operations. Structure contours on top T sand (bottom S4).

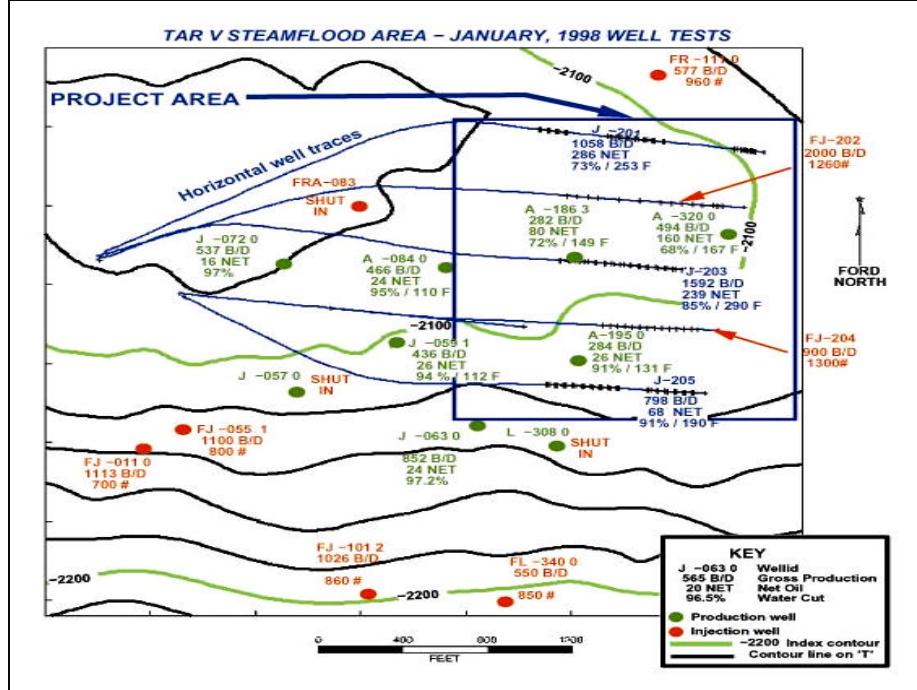
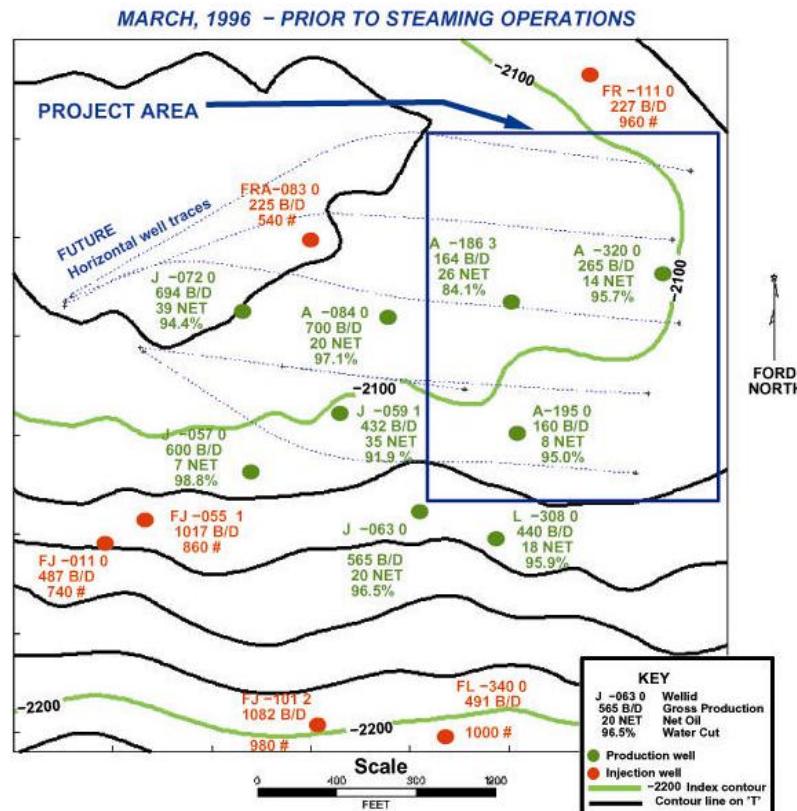


Figure 4.3-5: FB V Tar zone steamflood and offset waterflood wells. Initial steamflood production and injection data and effect on offset producers in January 1998. Structure contours on top T sand (bottom S4).

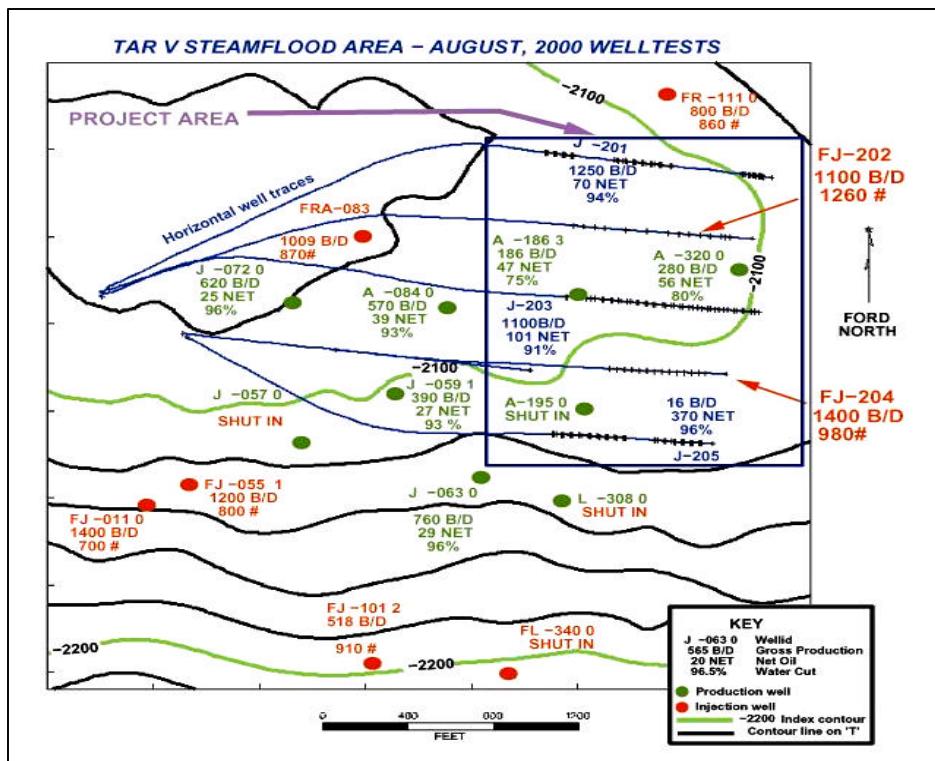


Figure 4.3-6: FB V Tar zone steamflood and offset waterflood wells. Stabilized steamflood production and injection performance in August 2000. Structure contours on top T sand (bottom S4).

have experienced sand production and required second sand consolidation well completion jobs to return them to production. The sand consolidation completions probable failure was due to pumping the wells too hard during the cyclic stimulation phase and the high differential pressures pulling formation sand into the wellbores. Because of this, each well has produced a low average rate of 58 BOPD and 1300 barrels of gross fluid per day (BGFPD) with high producing fluid levels of 1360 feet over the pump. Theoretically, the wells could produce at 500-600% higher rates. The proposed inner liners will allow us to pump the wells at rates up to 3000 BGFPD, which is the limit for our pumping units. The goal is to increase oil production to over 150 BOPD per horizontal well.

To support the additional production from installing inner liners and pumping down the existing horizontal wells and drilling a new one, the plan is to convert one well to water injection in the southeast flank of the pilot.

Plans are for a 3-D deterministic reservoir simulation model for the Tar V steamflood pilot. The model will provide a better conceptual picture of where the injected steam and water are going, where and how quickly the reservoir is heating up, the production rates necessary to pump the wells off, and the supplemental flank water injection rates needed to maintain reservoir pressure (assuming steam injection rates are constant). The model will also help determine when to convert the pilot to post-steamflood operations.

4.4 Hot Water Alternating Steam (WAS) Drive Pilot

See Section 4.7

4.5 Geochemistry of Rock / Fluid / Interactions

Research will continue on the geochemical and petrophysical changes to the reservoir rock due to steam injection. Further research will be performed on the novel steam-induced sand consolidation well completion technique to see if the process can be duplicated in the laboratory and to confirm the mineralogy of the cement precipitates. If successful, the objective will be to optimize and possibly commercialize the process. The sand consolidation well completion technique has been field tested on an empirical basis on over two dozen wells and proven to be a superior method that offers higher productivity, more operating flexibility, and significantly lower costs than the conventional open-hole, gravel-packed, wire mesh screen completions used to control unconsolidated sands. Recent sanding problems will also be studied to determine the robustness of the completion. See Sections 5.1 and 5.2 for more details.

During the past two years, research has been performed on the thermal-related compaction of sands and shales in the Tar zone to confirm whether these are causes of observed surface subsidence in the Tar II-A steamflood area. This study showed that the shales immediately above the steamflood sands were the most susceptible to thermal compaction. More laboratory tests are needed to determine the critical maximum reservoir temperature attainable before causing appreciable shale compaction. This information will determine whether a profitable thermal enhanced oil recovery project can be designed. This study is critically important to the future of urban steamflood projects. See Section 5.5 for more details

4.6 Steam Drive Mechanisms

See Sections 4.3 and 4.7.

4.7 Reservoir Surveillance

The Tar II-A steamflood reservoirs have been operated over a year at relatively stable pressures, due in large part to the bimonthly pressure-monitoring program enacted at the start of the post-steamflood phase. Starting in the fourth quarter 2000, operational activity has been ramped up to increase production and injection. This work will continue through 2001 as described in this section and in the Operational Management sections 5.1, 5.3 and 5.4.

The reservoir pressure-monitoring program was developed as part of the post-steamflood reservoir management plan. This bi-monthly sonic fluid level program measures the static fluid levels in all idle wells an average of once a month. The fluid levels have been calibrated for liquid and gas density gradients by comparing a number

of them with Amerada bomb pressures taken within a few days. This data allows engineering to respond quickly to rises or declines in reservoir pressure by either increasing injection or production or idling production.

Expanding thermal recovery operations to other sections of the Wilmington Oil Field, including the Tar V horizontal well pilot steamflood project, is a critical part of the City of Long Beach and Tidelands Oil Production Company's development strategy for the field. The current steamflood operations in the Tar V pilot are economical, but recent performance is below projections because of wellbore mechanical limitations that will be addressed in 2001. See Operational Management for more details.

Introduction

A post-steamflood operating plan was developed during the third quarter 1998 and implemented in the fourth quarter 1998 to mitigate problems associated with the January 1999 shutdown of steam injection and the possibility of thermal-related surface subsidence. The plan was to inject cold water into the flanks of the steamflood to increase and subsequently maintain reservoir pressures in the "T" and "D" sands at a high enough level that the steam vapor phase (steam chest) goes back into solution before it can cool through overburden heat loss and collapse, causing possible formation compaction. The flank water injection fills up the steam chests that exist without introducing cold water into the interior of the mature steamflood area. Thirteen water injection wells are in service on the northern and southern flanks of the steamflood area. The wells include two existing injectors (wells FW-101 and FW-103), seven wells that were added in the fourth quarter 1998 (wells FW-88, 901-UP, 935-UP, 937-UP, 943-UP, 951-UP, and 2AT-56), two wells added in the second quarter 1999 (2AT-48 and 953-UP), one well (2AT-20) added in the fourth quarter 1999 and one well added in the first quarter 2001 (2AT-49).

A new 3-D deterministic thermal reservoir simulation model was used to provide sensitivity cases to optimize production, steam injection, flank cold water injection and reservoir temperature and pressure. According to the model, reservoir fill up of the steam chest would occur in October 1999 at a constant injection rate of 28,000 BPD and gross fluid production rate of 7,700 BPD (injection to production (I/P) ratio of 3.6, net injection of 20,300 BPD). Actual operations followed the model's recommendations during the first six months of 1999, as water injection averaged 28,600 BPD and gross fluid production averaged 7,800 BPD. The number of active producers during the steam chest fill-up phase ranged from 8-11 wells, of which 6-8 were dual "T" and "D" completions, 1-2 were "D" completions and 0-1 was a "T" sand completion.

Further modeling runs found that varying individual well injection rates was better for addressing localized sub-zone pressure problems caused by added production and could reduce steam chest fill-up by up to one month. Based on this information, Tidelands increased water injection in July and August to an average of 36,000 BPD while only increasing gross fluid production to 9,500 BPD (I/P ratio of 3.8, net injection of 26,500 BPD). This operational change accelerated overall reservoir steam chest fill-

up in the "D" sands to August 1999 because most of the increased net injection went to those sands. Reservoir pressures in the "D" sands at fill-up ranged from 960-1180 psi with a rough average of 1080 psi (89-106% hydrostatic pressure, 98% avg). Steam chest fill-up in the "D" sands was accompanied by steeply rising reservoir pressures, as would be expected in a fully liquid, relatively incompressible fluid situation.

It was believed that once steam chest fill-up occurred, the reservoir would act more like a waterflood and production and cold water injection could be operated at lower injection to production ratios (I/P) and net injection rates. The City and Tidelands decided to maintain reservoir pressures at about 90% 5% hydrostatic as ideal in the short term and to possibly lower reservoir pressures to 80% hydrostatic over time provided no steam chest development reoccurred. The model predicted steam chest fill-up at about 78% hydrostatic pressure. The City and Tidelands felt that production rates could be increased as long as water injection rates were kept at relatively high injection to production ratios (I/P).

In September 1999, "D" sand gross fluid production was increased from 6200 BPD to 7800 BPD and water injection was reduced substantially from 24,200 BPD to 14,500 BPD (net injection from 18,000 BPD to 6700 BPD). Injection was increased slightly in the "T" sands from 10,700 BPD to 12,700 BPD (net injection from 7100 BPD to 9000 BPD). The "T" sands reached steam chest fill-up on schedule in mid-October 1999 with reservoir pressures ranging from 930-1070 psi with an average of 980 psi (91-103% hydrostatic pressure, 95% avg). Following steam chest fill-up of the "T" sands in October 1999, gross fluid production was increased from 10,500 BPD in September to 14,500 BPD in November. In September and October, nine production wells were activated for a total of 19 producers, of which 15 were dual "T" and "D" completions, three were "D" completions and one was a "T" sand completion. The number of active producers thereafter through March 2001 has ranged from 16-19 wells, with high water cut wells being idled to allow for the activation and testing of other wells. Two of the best oil producing wells, UP-941 and UP-942, were idled from November 1999 to September 2000 to accommodate the surface owner.

The significant decrease in "D" sand net injection rates caused reservoir pressures to plummet about 100 psi to an average of 980 psi and 89% hydrostatic pressure (range 930-1050 psi) within six weeks. This happened even though the I/P was 1.85. Starting in late-October, gross fluid production in the "D" sands was further increased to 8800 BPD, but net injection still increased to 10,200 BPD to an I/P of 2.20. "D" sand reservoir pressures stopped falling and stabilized by the end of December to an average of 960 psi and 88% hydrostatic pressure (890-1030 psi range). By March 2000, "D" sand reservoir pressures increased back to steam chest fill-up pressures of 90% hydrostatic pressure and have been maintained within $90\% \pm 1\%$ through March 2001. Table 4.7-1 lists the reservoir pressures of the "D" sands in pounds per square inch (psi) and in percent hydrostatic pressure, both before pressure response from the post-steamflood water injection (March 1999 and before) and after response. Note how the pressures have stabilized at close to 90% hydrostatic since March 2000. Figure 4.7-1 shows a color contour presentation of the "D" sand hydrostatic pressures in five

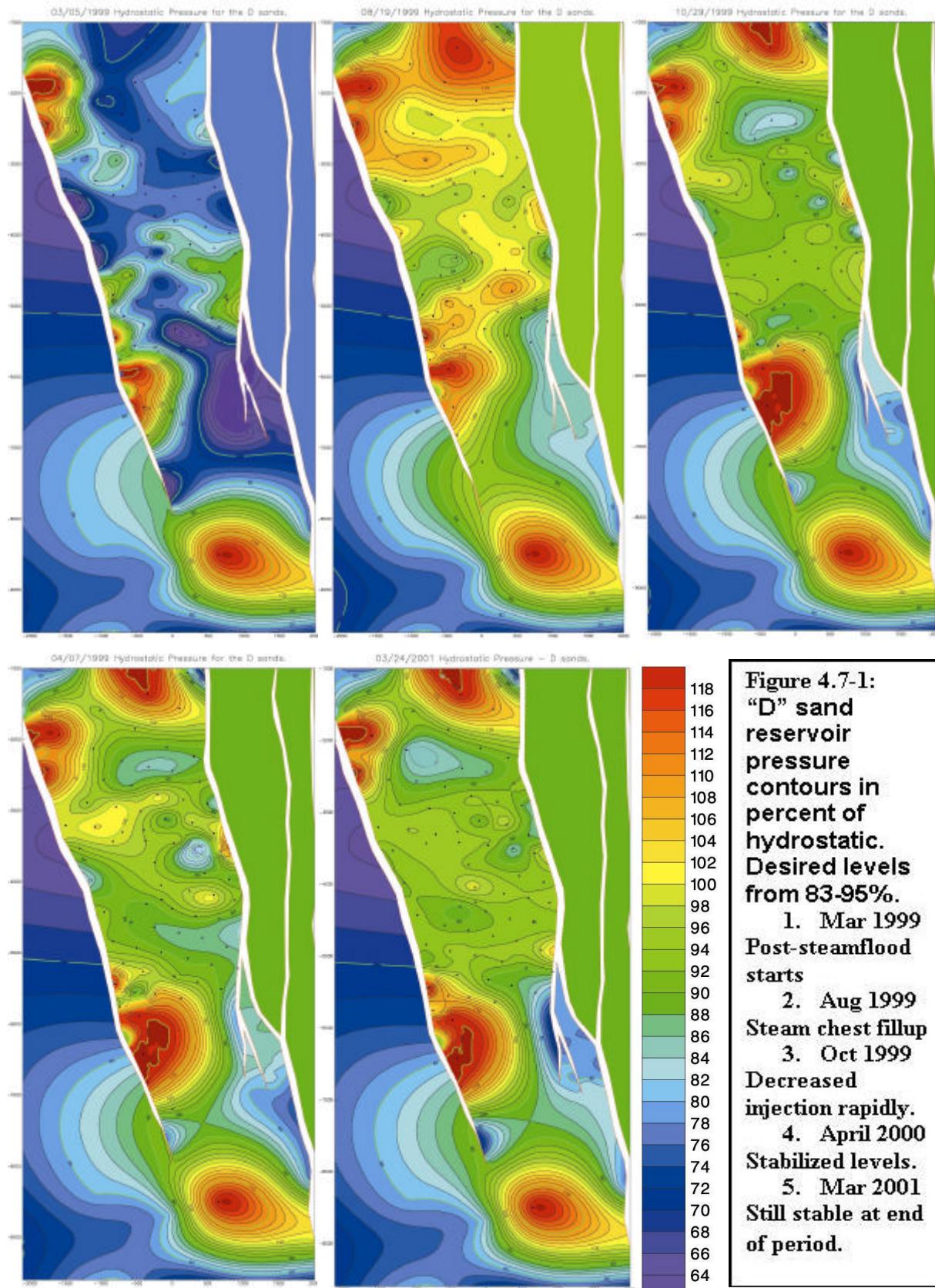
time sequences from March 1999 to March 2001. The five sequences show reservoir pressure prior to post-steamflood water injection response (March 1999), at steam chest fillup (August 1999), two months after fillup following a large net injection decrease (October 1999), five months later when pressures are stabilized (April 2000) and one year later when pressures are still stable (March 2001).

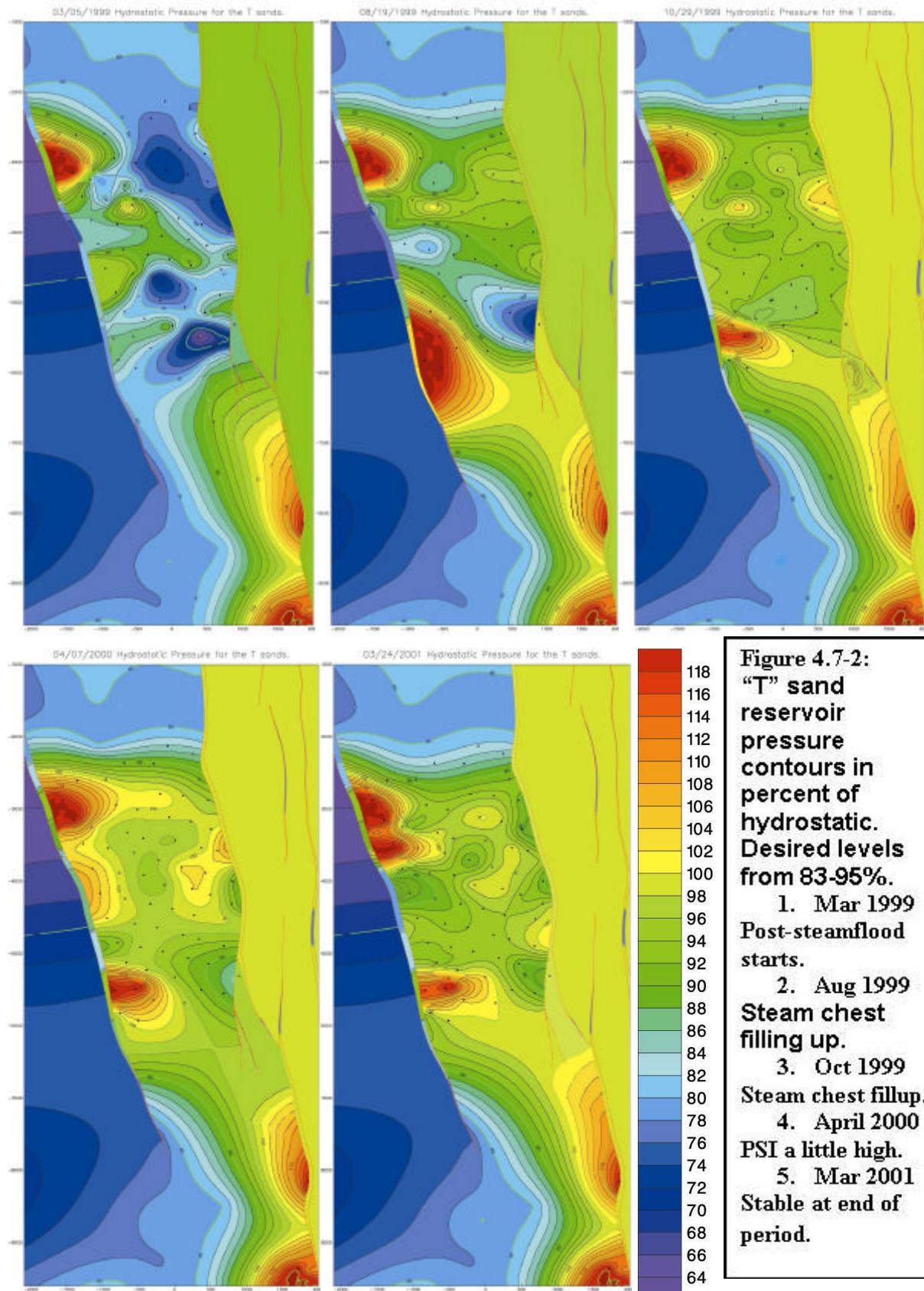
TAR II-A STEAMFLOOD PROJECT - RESERVOIR PRESSURE

"T" Sands			"D" Sands - Phase 1-1C Wells		
<u>Reservoir Pressure</u>			<u>Reservoir Pressure</u>		
	psi	hydrostatic %		psi	hydrostatic %
Jun-97	818	79	May-96	594	54
			Aug-98	748	68
Mar-99	888	85	Mar-99	881	79
Jun-99	925	89	Jun-99	1026	92
Sep-99	976	94	Sep-99	1056	95
Dec-99	1002	96	Dec-99	954	86
Mar-00	1008	97	Mar-00	1009	91
Jun-00	1011	97	Jun-00	991	90
Sep-00	1000	96	Sep-00	995	90
Dec-00	1003	96	Dec-00	999	90
Mar-01	992	95	Mar-01	1005	91

Table 4.7-1: Tar II-A Steamflood Project reservoir pressures for the "T" and "D" sands.

Following "T" sand fill-up in October 1999, gross fluid production was increased from 3700 BPD to 5600 BPD by activating an additional four "T" only completions and net injection was lowered only slightly to 7400 BPD (I/P of 2.4) through December 1999 to avoid the pressure drops experienced in the "D" sands. "T" sand reservoir pressures continued to rise until December 1999 when it stabilized to an average of 1010 psi and 98% hydrostatic pressure (950-1060 psi range). The objective is to lower "T" sand pressure slowly to 90% hydrostatic. Net injection was reduced to 5500 BPD in June 2000 and "T" sand reservoir pressure slowly declined to 97% hydrostatic in September 2000, 96% in December 2000 and 95% in March 2001. Table 4.7-1 lists the reservoir pressures for the "T" sands both before and after post-steamflood water injection response. Note how the pressures stabilized at about 97% hydrostatic in March 2000 and have been gradually declining since then. Figure 4.7-2 shows a color contour presentation of the "T" sand hydrostatic pressures in five time sequences from March 1999 to March 2001. The five sequences show reservoir pressure prior to post-steamflood water injection response (March 1999), almost at steam chest fillup (August 1999), at steam chest fillup (October 1999), five months later when pressures are stabilized at a relatively high level (April 2000) and one year later when pressures have declined to approach desirable levels (March 2001).





In summary, reservoir pressures in the mature Phase 1 area have increased during the last three years to eliminate the steam chests in the "T" and "D" sands. The current objective is to gradually lower the "T" sand pressure to about 920 psi 50 psi or 90% 5% hydrostatic pressure and to maintain the "D" sand pressure at about 1000 psi 50 psi or 90% 5% hydrostatic pressure. The average "T" sand pressure has risen from 818 psi in June 1997, to 889 psi in March 1999, to 979 psi in September 1999, to 1020 psi in June 2000, and to 1000 psi or 97% hydrostatic pressure in September 2000. The average "D" sand pressure has gone from 594 psi in May 1996, to 748 psi in August 1998, to 874 psi in March 1999, to 1080 psi in September 1999, to 960 psi in December 1999 and has been maintained at about 1000 psi or 90% hydrostatic pressure from March to September 2000.

ACTIVITY 5 – OPERATIONAL MANAGEMENT

5.1 Alkaline Water/ Steam Injection Sand Control

Further research is planned on the novel steam-induced sand consolidation well completion technique to see if the process can be duplicated in the laboratory. If so, then the objective will be to optimize and possibly commercialize the process. The sand consolidation well completion technique has been field tested on an empirical basis on over two dozen wells and proven to be a superior method that offers higher productivity, more operating flexibility, and significantly lower costs than the conventional open-hole, gravel-packed, wire mesh screen completions used to control unconsolidated sands.

In the past two years, several of the sand-consolidation completed wells have sanded up. Upon restreaming the wells to reconsolidate the completions, a few of the wells have produced successfully for over a year and a few have sanded up again. This problem will be evaluated to determine the weaknesses of the completion and whether any completion procedures can be changed to minimize the problem. A possible plan for two of the Tar V horizontal producers is to improve their productivity by installing an inner liner gravel-pack completion to back up the current sand consolidation completions. The sand consolidation completions probably failed because the wells were pumped too hard and the high differential pressures pulled formation sand into the wellbores. Because of this, each of the wells are produced at a low average rate of 58 barrels of oil per day (BOPD) and 1300 barrels of gross fluid per day (BGFPD) with high producing fluid levels of 1360 feet over the pump. Theoretically, the wells could produce at 500-600% higher rates. The proposed inner liners will allow the wells to be pumped at rates up to 3000 BGFPD, which is the limit for the pumping units. The goal is to increase oil production to over 150 BOPD per horizontal well.

In light of the problems encountered with the sand consolidation completion, Tidelands is researching the state of the art of gravel-packed, slotted-liner completions for horizontal wells to maintain operating flexibility.

5.2 Horizontal Well Completion Techniques

See Section 5.1.

5.3 Profile Control in Horizontal Injectors

No activity this period.

5.4 Minimize Carbonate Scale Problems

With the steam chest filled and reservoir pressured stabilized at about 90% hydrostatic or higher for over a year, the plan is to increase well work activity to increase production and injection. Acid stimulation jobs are planned on selected producers to

remove wellbore scale and increase oil cuts. Oil production has continued to increase during the first quarter 2001 without a change in gross fluid production because of two very successful acid stimulation jobs in wells UP-903 and UP-913. UP-903 tested 40 BOPD / 340 BPD gross prior to the December 2000 acid job and 150 BOPD / 1157 BPD gross after the job. The well was still producing 107 BOPD / 1010 BPD gross with a 1550 ft producing fluid level at the end of March 2001. Well UP-913 tested 22 BOPD / 495 BPD gross prior to the February 2001 acid job and 78 BOPD / 1384 BPD gross after the job. The well was still producing 61 BOPD / 1368 BPD gross with a 2200 ft producing fluid level at the end of March 2001.

5.5 Determine Temperature Limits to Minimize Operating Problems

During the past two years, thermal-related compaction of sands and shales in the Tar zone were studied in an effort to confirm one of the causes of surface subsidence in the Tar II-A steamflood area. This study showed that the shales immediately above the steamflood sands were the most susceptible to thermal compaction. More laboratory tests are planned to determine the critical maximum reservoir temperature we can reach before causing appreciable shale compaction. This information will help determine whether a profitable thermal enhanced oil recovery project can be designed. This study is critically important to the future of urban steamflood projects.

ACTIVITY 6 – EXPANSION PROGRAM

Recent thermal recovery methods in the Wilmington Field have been expanded from the Tar II-A steamflood project to include a pilot steamflood in the Tar V “S” sands and cyclic steam injection into the Ranger V zone, the Upper Terminal V zone and other areas of the Tar V zone. Some of the Ranger V and Upper Terminal V cyclic steam injection work were included in the DOE Class III Short-term Wilmington Field Waterflood Project under contract #DE-FC22-95BC14934. Cyclic steam jobs applied to the wells gave them sand-consolidated, limited-entry perforated completions and provided a boost to initial oil production rates by reducing the oil viscosity in the near-wellbore region.

Future thermal recovery work at Wilmington must consider potential oil rates and reserves, the cost-effectiveness of the sand consolidation or other completions over the life of the wells, and the sensitivity of the sands and shales to thermal-related formation compaction. The work remaining in Budget Period 1 addresses these concerns.

The plan is to expand the S sand steamflood in the Tar V zone in Budget Period 2. The current Tar V steamflood pilot is based on the knowledge gained from the Tar II-A steamflood project, including horizontal well drilling and completion technology, reservoir characterization, pilot testing, reservoir modeling and reservoir management techniques. The plan is to add four horizontal producers, four horizontal injectors, and three observation wells to the existing pilot project. The total funds allocated to Budget Period 2 are \$6,701,988, of which the DOE share is 18% or \$1,206,355. The original Budget Period 2 plan to expand the Tar II-A steamflood project was revised because of the loss of the Tar II-A steam source from the Harbor Cogeneration Plant.

The expansion project has a drainage area of approximately 88 acres and a net oil sand thickness of 50 ft. The estimated remaining oil saturation after waterflooding is 50%. The estimated remaining oil in place is 4,850,000 barrels of oil. Projected recovery from the expansion project is 1,940,000 barrels of oil.

The expansion project has an expected life of eleven years and is scheduled to start within a year after the end of Budget Period 1.

ACTIVITY 7 – TECHNOLOGY TRANSFER

Introduction

The project team remained very active during this reporting period by organizing technology transfer events for both industry and non-industry organizations. Of particular note is the project team's key involvement in the 2000 First Joint Convention of the American Association of Petroleum Geologists (AAPG) Pacific Section Annual Meeting and the Society of Petroleum Engineers (SPE) Western Regional Meeting. Don Clarke of the City of Long Beach and Scott Hara of Tidelands were the Co-General Chairperson and Co-Technical Program Chairperson, respectively, for the convention, held in Long Beach, CA on June 17-24. Iraj Ershaghi and his USC staff and students organized several topical workshops targeted for oil and gas operators in California and Alaska through the West Coast Petroleum Technology Transfer Council.

The project team published and presented two professional society papers^{A34, A36} and prepared one technical report^{A35} this period. In addition, significant time was spent this period preparing a special three-year DOE "Annual" report that covered the period April 1997 to March 2000.^{E27} Many new technical reports were incorporated into that Annual Report which will provide the basis for several papers to be presented to industry professional societies and published in industry magazines and journals during the next two years. The project team members gave two oral technical presentations and taught a class at professional society and industry meetings given in California and promoted the industry by organizing field trips and presentations for teachers, students and government agency representatives.

Non-project team members published three papers this period that refer to or are based on the sand consolidation well completion technique developed in this project.^{B14, B15 and B16} This confirms the interest level in the sand consolidation technology and the value of technology transfer, which is the primary objective of the DOE Class projects.

7.1 DOE Reports

The project team is current on quarterly and annual reports from project inception on March 30, 1995 through this reporting period, which total 24 quarterly reports and 4 annual reports. The three prior "annual" reports cover the periods 1995-96, 1996-97, and 1997-2000. This "annual report" covers the period from April 1, 2000 to March 31, 2001.

7.2 Publications

Project team publications written during the reporting period have been categorized by professional society, DOE, or other organizations for which original technical work has been prepared.

7.2.1 Professional Societies

Julius Mondragon, Iraj Ershaghi, and Zhengming Yang of USC presented an SPE paper entitled “Post Steamflood Reservoir Management Using a Full-Scale Three-Dimensional Deterministic Thermal Reservoir Simulation Model, Wilmington Field, California” at the 2000 AAPG / SPE Western Regional Meeting held in Long Beach, CA, June 17-24^{A34}.

F. E. Moreno and D. D. Mamora of Texas A&M University presented papers; the first one presented at the 2000 SPE Annual Technical Conference and Exhibition in Dallas, TX from October 1-3^{B15} entitled “Sand Consolidation Using High-Temperature Alkaline Solution.” The second one presented at the 2001 SPE Western Regional Meeting held in Bakersfield, CA from March 26-30^{B16} similarly entitled “Sand Consolidation Using High -Temperature Alkaline Solution – Analysis of Reaction Parameters.” This paper is based on lab work performed on Wilmington Field cores in an effort to duplicate in the laboratory the sand consolidation well completion process developed in this project. These papers reference the DOE project.

Don Clarke of the City of Long Beach presented a paper entitled “3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year Old Wilmington Oil Field of Southern California,” at the GCSSEPM Foundation 20th Annual Research Conference – Deep-Water Reservoirs of the World Conference in Houston, TX on December 3-6, 2000.^{A36}

7.2.2 Industry Trade Journals and Newspapers

Ron Bowman of Case Engineering and Laboratory, Inc., L. C. Gramms of Separ Systems and Research Ltd., and R. R. Craycraft of Union Pacific Resources Inc. wrote a paper entitled “High-Silica Waters in Steamflood Operations” that was published in the May 2000 issue of *SPE Production and Facility Engineering Magazine* (pages 123-125)^{B14}. This paper refers to the sand consolidation well completion technique work developed in this project and specifically to the operational problems associated with silica dissolution by highly alkaline steam condensate.

7.2.3 DOE Symposium Proceedings

No activity reported this period.

7.2.4 Professional Society Newsletters / Mailing List

No activity reported this period.

7.2.5 Database Files

No activity reported this period.

7.3 Presentations

Presentations on project-related technical work given during the current reporting period are categorized by PTTC, professional society, DOE, or other organizations.

7.3.1 Professional Societies

SPE/AAPG-organized Oral Presentations

Scott Hara reprised his presentation entitled "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam" at the 2000 IPAA Mid-year Meeting, San Francisco, CA, May 18-20^{C23}.

Don Clarke of the City reprised his oral presentation entitled "At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field" at the 2000 AAPG / SPE Western Regional Meeting held in Long Beach, CA, June 17-24^{C24}.

David Davies of David K. Davies and Associates taught a class on Formation Damage and Well Stimulation - Identification & Prevention of Formation Damage Through Detailed Rock Analysis", at the 2000 AAPG / SPE Western Regional Meeting held in Long Beach, CA, June 17. Most of the material for this class based on research from this DOE project³.

7.3.2 Industry Organizations

No activity reported this period.

7.3.3 Non-oil Industry Organizations

Scott Hara of Tidelands and Don Clarke of the City organized the first annual "Petroleum Operations Day for Teachers and Community Leaders" held on November 10, 2000 in Long Beach². This event was open to all teachers and community leaders in Los Angeles and Orange Counties and the purpose was to introduce them to oil production and refinery operations. The whole day event included several oral presentations (Scott, Don and Mark Shemaria each made a presentation along with others), two field trips to one of the THUMS oil operating islands and to the Tosco Oil Refinery in Carson, and a large packet of oil and gas industry information and gifts. Thirty-eight teachers and community leaders welcomed the event.

On February 20, 2001, Scott Hara of Tidelands made a presentation entitled "World Oil Reserves and Prices" to the AP Geology Class at Long Beach Polytechnic High School in Long Beach, CA.

Scott Hara also nominated and helped prepare the application for the 2001 Pacific Section AAPG Teacher of the Year Award Winner, Mr. John Jackson, of Monterey Highlands Elementary School, Monterey Park, CA. Mr. Jackson to be given the award at the 2001 PSAAPG Annual Meeting in Universal City, CA on April 10, 2001.

7.4 Technology Awards

No activity reported this period.

7.5 Web Site and CD-ROM Projects

A home page on the USC service provider has been set up in conjunction with the existing account for the Petroleum Engineering Program at USC. The ongoing DOE projects on the West Coast are comprehensively summarized and can be accessed at:

<http://www.usc.edu/dept/peteng/topko.html>

The web site is also linked to a significant number of petroleum related sites both in industry and in academia, which includes the national PTTC site.

A CD-ROM of the project has been completed and was presented at the DOE and PTTC exhibit booths at the 1997 SPE Western Regional Meeting. The CD-ROM is available on IBM PC format and is distributed free to interested operators and organizations by contacting Scott Hara by phone at 562-436-9918 or through email at scott.hara@tidelandsoil.com. The CD-ROM project is essentially a collection of interviews and presentations saved as brief movie clips detailing the scope of operations at Tidelands Oil production related to the Class III DOE project.

A new CD-Rom will be created this year that will include the library of papers, articles and publications developed through this project.

7.6 Field Tours

Don Clarke of the City lead a Field Trip for Teachers on "Geology and Exploitation of Los Angeles Oil Fields", at the 2000 AAPG / SPE Western Regional Meeting held in Long Beach, CA, June 24.

ACTIVITY 8 – PROJECT MANAGEMENT

Executive Committee and Steering Committee

The Executive and Steering Committees are active in supporting the operation of the Tar II-A and Tar V thermal projects and committing to the technology transfer aspects of this DOE project. In fact, as of the end of the reporting period, the Project Team partners have published more original papers and given more presentations to industry and non-industry groups than any other DOE Class Project.

REFERENCES

References in "A", "B", and "E" below provide all of the papers and publications of original technical work completed throughout the project or in progress. References in "C" below are poster and oral presentations that were given throughout the current reporting period only. References in "D" below were cited in this report, but were not specifically part of this project.

A. Papers, Articles, Reports, CD-ROMs, Web Sites, and Other Original Technical Work Generated by DOE Project Team

- A¹ Sameer Joshi, L.M. Castanier and W.E. Brigham (Stanford University), Mike C. Wood (Union Pacific Resources Co.), "Steamflooding a Waterflooded Reservoir - Performance Evaluation Prediction", SPE Paper 29669 presented at the 1995 Western Regional Meeting of the Society of Petroleum Engineers in Bakersfield, CA, 8-10 March 1995.
- A² Mike C. Wood, Bruce Laughlin, Doug Fuller and Robert Fickes (Tidelands Oil Production), "The Use of Downhole Submersible Pumps in a High Temperature Steamflood", SPE paper 29507, presented at the 1995 Society of Petroleum Engineers Production Operations Symposium in Tulsa, OK, April 1995.
- A³ David Crane, William R. Barry II (Digital Petrophysics Inc.), "Database preparation for Wilmington Field, Fault Block II-A - Tar Zone" dated 15 June 1995.
- A⁴ Herman E. Schaller, "Study of Water Injection Surveys, Tar Zone, Fault Block II, Wilmington Field" dated 8 November 1995.
- A⁵ David Crane (Digital Petrophysics Inc.), report dated 12 March 1996 detailing list of well data that had undergone checking and processing.
- A⁶ David K. Davies, Richard K. Vessel (David K. Davies and Associates), "Nature, Origin, Treatment and Control of Well-Bore Scales in an Active Steamflood, Wilmington Field, California", SPE Paper No. 35418, 1996 Society of Petroleum Engineers/Department of Energy Tenth Symposium on Improved Oil Recovery in Tulsa, OK, 21-14 April.
- A⁷ Donald Clarke (City of Long Beach), Chris Phillips (Tidelands Oil production), "Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin", field trip and guidebook of 14 papers, given at the 1996 Annual Meeting of the American Association of Petroleum Geologists (AAPG) in San Diego, California, May 1996. The guidebook was revised for a tour given at the 1997 Western Regional Meeting of the Society of Petroleum Engineers and subsequently reprised each year for industry professionals and public school teachers.

A8 Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), and Linji An (University of Southern California), "3-D Modeling, Horizontal Drilling... Give New Life to Aging Fields", *American Oil & Gas Reporter*, September 1996 issue, pages 106-115.

A9 Iraj Ershaghi, M. Hassibi (University of Southern California), "A Neural Network Approach for Correlation Studies in a Complex Turbidite Sequence", SPE Paper No. 36720, 1996 Society of Petroleum Engineers Annual Technical Conference and Exhibition in Denver, CO, 6-9th October.

A10 Rick Cassinis (Tidelands Oil Production), "2100-foot, 14-inch Steam Line Under a Ship Channel", SPE Paper No. 37530, 1997 SPE International Thermal Operations and Heavy Oil Symposium in Bakersfield, CA, 10-12 February 1997.

A11 Al-Qahtani, M., Ershaghi, I., University of Southern California: "Characterization and Estimation of Permeability Correlation Structure from Performance Data", Paper presented at Fourth International Reservoir Characterization Technical Conference sponsored by DOE, BDM, and AAPG, 2-4 March 1997.

A12 Iraj Ershaghi, Lyman L. Handy, Yucel I. Akkutlu (University of Southern California), Julius J. Mondragon III (Tidelands Oil Production), "Conceptual Model of Fault Block II-A, Wilmington Field, from Field Performance Data", SPE Paper No. 38309, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

A13 Iraj Ershaghi, Pouya Amili (University of Southern California), "Correlations for Prediction of Steamflood Oil Recovery in Steam-Assisted Gravity Drainage (SAGD) Process Using Horizontal Injectors and Producers", SPE Paper No. 38297, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

A14 Walt Whitaker II (Tidelands Oil Production), "7-ppm No. 50 MM BTU/hr Oilfield Steam Generator Operating on Low-Btu Produced Gas", SPE Paper No. 38277, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

A15 F. Scott Walker (Tidelands Oil Production), "Locating and Producing Bypassed Oil: A DOE Project Update", SPE Paper No. 38283, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June. This DOE waterflood project for Wilmington describes new application of well completion technology using steam to consolidate sand developed in this project.

A16 Richard Cassinis (Tidelands Oil Production), William A. Farone (Applied Power Concepts, Inc.), "Improved H₂S Caustic Scrubber", SPE Paper No. 38273, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

A17 David K. Davies, Richard K. Vessel (David K. Davies and Associates), "Improved Prediction of Permeability and Reservoir Quality through Integrated Analysis of Pore

Geometry and Open-hole Logs: Tar Zone, Wilmington Field, California", SPE Paper No. 38262, 1997 Western Regional Meeting in Long Beach, CA, 23-27 June.

A¹⁸ Donald Clarke, (City of Long Beach), Chris Phillips, (Tidelands Oil Production Company), "Horizontal Drilling for Thermal Recovery in the Wilmington Field, California", Article for Summer 1997 edition of U. S. DOE *The Class Act*.

A¹⁹ David K. Davies (David K. Davies and Associates), Julius J. Mondragon III, P. Scott Hara (Tidelands Oil Production), "A Novel Low-Cost Well Completion Technique Using Steam for Formations with Unconsolidated Sands, Wilmington Field, California", SPE Paper No. 38793, 1997 Society of Petroleum Engineers Annual Technical Conference and Exhibition in San Antonio, TX, 6-8 October.

A²⁰ David K. Davies, John Aumon, Richard K. Vessel (David K. Davies and Associates), "Improved Prediction of Reservoir Behavior through Integration of Quantitative Geological and Petrophysical Data", SPE Paper No. 38914, 1997 Society of Petroleum Engineers Annual Technical Conference and Exhibition in San Antonio, TX, 6-8 October.

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A²² Zhengming Yang, Linji An (University of Southern California): Developed COMPACT software program was incorporated as module into Computer Modeling Group's STARS 97.2 thermal simulator program. COMPACT is an algorithm that can mimic local and dynamic features of rock compaction and rebound as a function of reservoir pressure.

A²³ Montgomery, Scott (Consultant Technical Writer), "Increasing Reserves in a Mature Giant: Wilmington Field, Los Angeles Basin, Part I: Reservoir Characterization to Identify By-passed Oil", *AAPG Bulletin*, March 1998, pages 367-385.

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A29 Hassibi, Mahnaz, (USC), "A Method For Automating Delineation of Reservoir Compartments and Lateral Connectivity From Subsurface Geophysical Logs", Doctoral Thesis, USC Department of Chemical Engineering - Petroleum Engineering Program, May 1999.

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A31 Davies, David K., (DKD), Davies, John P., (Chevron), "Stress-Dependent Permeability: Characterization and Modeling", SPE Paper #56813, 1999 SPE Annual Technical Conference and Exhibition (ATCE), Houston, TX, October 3-6.

A32 Davies, David K., (DKD), Hara, P. Scott and Mondragon, Julius J. III, (Tidelands), "Geometry, Internal Heterogeneity and Permeability Distribution in Turbidite Reservoirs, Pliocene California", SPE Paper #56819, 1999 SPE Annual Technical Conference and Exhibition (ATCE), Houston, TX, October 3-6.

A33 Ershaghi, Iraj and Hassibi, Mahnaz, (USC), "Reservoir Heterogeneity Mapping Using an Artificial Intelligence Approach", SPE Paper #56818, 1999 SPE Annual Technical Conference and Exhibition (ATCE), Houston, TX, October 3-6.

A34 Mondragon, Julius J. III, Yang, Zhengming, Ershaghi, Iraj, U. of Southern California, Hara, P. Scott, Tidelands Oil Production Co., Bailey, Scott, Koerner, Roy, City of Long Beach, "Post Steamflood Reservoir Management Using a Full-Scale Three-Dimensional Deterministic Thermal Reservoir Simulation Model, Wilmington Field, California", SPE Paper #62571, 2000 AAPG/SPE Western Regional Meeting, Long Beach, CA, June 19-22.

A35 Changan Du, Iraj Ershaghi, (USC), "Reservoir Characterization and Stochastic Modeling of Fault Block II-A Turbidite Sand Formation of Wilmington Oil Field, Long Beach, California", technical report, USC Department of Chemical Engineering –

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A36. Donald D. Clarke, City of Long Beach, Christopher C. Phillips, Tidelands, "3-D Geological Modeling and Horizontal Drilling Bring More Oil Out of the 68-Year Old Wilmington Oil Field of Southern California," GCSSEPM Foundation 20th Annual Research Conference – Deep-Water Reservoirs of the World, Houston, TX, December 3-6, 2000

A37. Christopher C. Phillips, Tidelands, "Enhanced Thermal Recovery and Reservoir Characterization", in Field Guide prepared by Don D. Clarke, City of Long Beach George E. Otott, Jr., THUMS, and Christopher C. Phillips, "Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin: Pacific Section AAPG, 1996 AAPG Annual Meeting, May 18-22, p. 65-82.

B. Publications Related to Original DOE Project Technical Work and Articles of Interest

B1 Steve Bell, "Extraction Technologies May Increase Recoverable Reserves by Billions", *Hart's Petroleum Engineer*, Tech Trends, page 9, March 1995.

B2 Donald D. Clarke, Xen Colazas (City of Long Beach), Janet Wiscombe (Los Angeles Times), "Drilling in Disguise", *Los Angeles Times*, Metro Section, page B2, 15 November 1996.

B3 Chris C. Phillips (Tidelands Oil Production), Pat Prince Rose (Los Angeles Times), "In Geological Time, He's Ancient", *Los Angeles Times*, Business Section, Trends, page D5, 9 December 1996.

B4 Iraj Ershaghi (University of Southern California), Frank Clifford (Los Angeles Times), "A New Oil Boom", *Los Angeles Times*, Metro Section, Next L.A., page B2, 24 December 1996.

B5 Richard Cassinis, Sean Massey (Tidelands Oil Production), Stuart M. Heisler (TJ Cross Engineers Inc.), for the Sulfatreat Company "The Story Behind Lo-CoSTSM", *Oil, Gas and Petrochem Equipment Magazine*, back cover page, March 1997. Advertisement by the Sulfatreat Company on product developed through the DOE project work related to "Improved H₂S Caustic Scrubber" technology. Also refer to, <http://www.ingersoll-rand.com/compair>

B6 Iraj Ershaghi (University of Southern California), Herb Tiderman (DOE), Gail Dutton (Compressed Air Magazine), "Coaxing Crude From The Ground", *Compressed Air Magazine*, pages 22-26, March 1997.

B7 Jeff Schwalm (Dynamic Graphics Inc.), Chris C. Phillips (Tidelands Oil Production), "Earth Vision Software Solutions for Structurally Consistent 3-D Geologic Modeling,

3-D Well Placement Planning", Advertisement Mailer sent to the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting attendees, conducted 7-9 April 1997. Mailer contains copy of "3-D Modeling, Horizontal Drilling... Gives New Life to Aging Fields", Wilmington DOE projects featured in Dynamic Graphics' exhibit booth at convention and in Internet homepages: (info@dgi.com and <http://www.dgi.com/topko.html>)

- B8 University of Southern California, West Coast DOE projects comprehensively summarized and can be accessed at: <http://www.usc.edu/dept/peteng/doe.html>. Summarized content of the previous year's annual report is located at: <http://www.usc.edu/dept/peteng/topko.html>
- B9 University of Southern California, A collection of interviews and presentations saved as brief movie clips detailing the scope of operations at Tidelands Oil production related to the Class III DOE project on CD-ROM.
- B10 Davies, David K., David K. Davies and Assoc. Inc., Mondragon, Julius J. III and Hara, P. Scott, Tidelands Oil Production Co., SPE Paper #38793 "Well-Completion Technique Using Steam For Formations With Unconsolidated Sands", *SPE Journal of Petroleum Technology*, September 1998, pages 46-52, an abridged version of the paper.
- B11 Clark, Donald D., City of Long Beach, Phillips, Christopher C., Tidelands Oil Production Company, "Successful Horizontal Well Program In Wilmington Field", *DGInsider, the EarthVision Newsletter*, First Quarter 1999.
- B12 Davies, David K., Vessel, Richard K., Aumon, John P., DKD, "An Improved Prediction of Reservoir Behavior Through Integration of Quantitative Geological and Petrophysical Data", SPE Paper #38914 peer-reviewed and assigned SPE Paper #55881, *SPE Reservoir Evaluation and Engineering Magazine*, April 1999.
- B13 Davies, David K., DKD, Davies, John P., Chevron wrote an article entitled "Stress-dependent Permeability in Unconsolidated Sand Reservoirs", *Offshore Magazine*, February 2000, pp 82-84, a summary of SPE Paper 56813, "Stress-Dependent Permeability: Characterization and Modeling" in ref. A31 above.
- B14 Ron Bowman (Case Engineering and Laboratory, Inc.), L. C. Gramms (Separ Systems and Research Ltd.), R. R. Craycraft (Union Pacific Resources Inc.), "High-Silica Waters in Steamflood Operations", SPE Paper #37528 peer-reviewed and assigned SPE #63015, *SPE Production and Facility Engineering Magazine* (pages 123-125) May 2000.
- B15 D. D. Mamora, F. E. Moreno, Guillemette R. (Texas A&M University), "Sand Consolidation Using High-Temperature Alkaline Solution", SPE Paper #62943, 2000 SPE Annual Technical Conference and Exhibition, Dallas, TX, October 1-3.

B¹⁶ F. E. Moreno, D. D. Mamora, (Texas A&M University), "Sand Consolidation Using High-Temperature Alkaline Solution – Analysis of Reaction Parameters", SPE Paper #68847, 2001 SPE Western Regional Meeting, Bakersfield, CA, March 26-30.

C. Presentations, Poster Sessions, Tours, and Other Activities from which No New Reference Materials were Generated

C¹ Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), "Horizontal Wells in a Clastic Oil Field with Intraformational Compaction", poster session presentation at the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting in Dallas, TX, 7-9 April.

C² Iraj Ershaghi, Linji An (University of Southern California), Donald D. Clarke (City of Long Beach), Chris Phillips (Tidelands Oil Production), "Sealing Behavior of Normal Faults in Fault Block II, Wilmington Oil Field, California", poster session presentation at the 1997 American Association of Petroleum Geologists (AAPG) Annual Meeting in Dallas, TX, 7-9 April.

C³ Jeff Schwalm, John Perry (Dynamic Graphics Inc.), :"3-D Geologic Modeling: Theory and Application", a half day workshop sponsored by the PTTC at USC Campus, Los Angeles, CA on 2 May 1997. Presentation utilizes 3-D Deterministic Geologic Model from this project to explain fundamentals of 3-D Geologic Modeling.

C⁴ Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), "Tertiary Development of Heavy Oil Sands through Thermal Recovery in the Wilmington Oil Field, California: An Update and Some New Challenges", Oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, on 14-16 May.

C⁵ Donald D. Clarke (City of Long Beach), Chris C. Phillips (Tidelands Oil Production), Linji An (University of Southern California), "Reservoir Characterization Using Advanced 3-D Computer Modeling Technology: A Case Study of the Fault Block II in Wilmington Field, California", Electronic poster session at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May.

C⁶ M. Hassibi, Iraj Ershaghi (University of Southern California), "Characterization of Lithological Log Responses in Turbidite Series using Neural Networks", oral presentation at the 1997 American Association of Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May 1997.

C⁷ David K. Davies, Richard K. Vessel (David K. Davies and Associates), "Geological Controls on Permeability Distribution and Sand Distribution: Tar Zone, Fault Block II-A, Wilmington Field", oral presentation at the 1997 American Association of

Petroleum Geologists (AAPG) Pacific Section Convention in Bakersfield, CA, 14-16 May.

- C8 Donald D. Clarke (City of Long Beach): Project status presentation for DOE/BDM conference regarding status of all DOE contracted projects, Houston, TX, 16-20 June 1997.
- C9 Julius Mondragon III, Scott Hara (Tidelands Oil Production), "Novel Sand Consolidation Completion Technique Using Alkaline-Steam Injection in the Tar Zone, Wilmington Field", SPE GEM Presentation WR GEM 29, 1997 Western Regional Meeting in Long Beach, CA 23-27 June.
- C10 Chris Phillips, Scott Hara (Tidelands Oil Production), "Three-Dimensional Geological Modeling as a Cost-Effective Tool for Horizontal Drilling", SPE GEM Presentation WR GEM 6, 1997 Western Regional Meeting in Long Beach, CA 23-27 June.
- C11 Mark Kapelke (Tidelands Oil Production), "How to Work With the DOE" and "Multimedia and Technical Transfer", National Petroleum Technology Resource Center sponsored by the DOE, 1997 Western Regional Meeting in Long Beach, CA 23-27 June.
- C12 Du, C., University of Southern California, West Coast PTTC staff, organized short course entitled "GOCAD⁺⁺ Training" and made a presentation during the course, November 14, 1997 at USC campus.
- C13 Hara, S., Tidelands Oil Production Company, reprised sand consolidation well completion presentation - SPE paper 38793, SPE Los Angeles Basin Section New Technology and Environmental Forum meeting, November 19, 1997, Long Beach Petroleum Club.
- C14 Ershaghi, I., University of Southern California, Clarke, D., City of Long Beach, West Coast PTTC staff: Organized geologic short course and field trip on "Turbidite Reservoirs in California", November 24, 1997, Ventura, CA.
- C15 Tidelands Oil Production Company gave a short presentation of the two Wilmington Class III projects to Guido DeHoratiis of the DOE on December 4, 1997 in Tidelands' office.
- C16 Clark, D., City of Long Beach, Phillips, C., Tidelands Oil Production Company, "Subsidence and Old Data Present Unique Challenges in Aging Turbidite Oil Fields. Examples of Successful Technologies Solutions from the Wilmington Oil Field, California, USA", 3rd AAPG / EAGE Joint Research Conference on Developing and Managing Turbidite Reservoirs: Case Histories and Experiences, Almeria, Spain, 4-9 October 1998.

C¹⁷ Scott Hara gave an oral presentation entitled "Steamflooding Recovery of a Class 3 Reservoir – DOE's Cooperative Efforts with Independent Producers to Enhance Production While Maintaining Safe and Environmentally Compatible Operations" at the Technology Assessment & Research Program's Technology Seminar held on May 19, 1999 at the office of the U. S. Minerals Management Service in Camarillo, CA.

C¹⁸ Same as (C18), but given at 1999 EAGE Conference and Technical Exhibition, Helsinki, Finland, June 7-11.

C¹⁹ Same as (C18), but given at 1999 AAPG/SPWLA Hedberg Research Symposium, The Woodlands, TX, October 10-13.

C²⁰ Clarke, Donald D., City of Long Beach, "At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field", 1999 AAPG/SPWLA Hedberg Research Symposium, The Woodlands, TX, October 10-13.

C²¹ Scott Hara reprised his presentation entitled "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam" at two West Coast Petroleum Technology Transfer Council (PTTC) workshops on "Sand Control for California Oilfield Operations" given in Long Beach, CA on November 18, 1999 and in Bakersfield, CA on November 19, 1999.

C²² Scott Hara made an oral presentation summarizing this DOE project's achievements related to reservoir and operational management and technical transfer of steamflood experience to the Wilmington Fault Block V Tar zone. The presentation was given at the West Coast PTTC Annual Forum held on the USC campus on December 10, 1999.

C²³ Scott Hara, Tidelands, reprised presentation "A Well Completion Technique for Controlling Unconsolidated Sand Formations by Using Steam", 2000 IPAA Mid-year Meeting, San Francisco, CA, May 18-20.

C²⁴ Don Clarke, City of Long Beach, reprised oral presentation "At 68, Wilmington Still Has Life: New Technology Revitalizes the Old Field", 2000 Pacific Section AAPG/SPE Western Regional Meeting, Long Beach, CA, June 19-22.

D. Outside References Cited in Report

D¹ Small, G.P., Shell California Production Inc. "Steam-Injection Profile Control Using Limited-Entry Perforations", SPE Paper 13607, presented at the 1985 California Regional Meeting in Bakersfield, CA, March 27-29 1985.

D² R.M. Butler, "Gravity Drainage to Horizontal Wells", *Journal of Canadian Petroleum Technology*, Volume 31, No. 4, pages 31-37, April 1992.

D3 F.H. Lim, W.B. Saner and W.H. Stillwell (Union Pacific Resources Co.) and J.T. Patton (New Mexico State University), "Steamflood Pilot Test in Waterflooded, 2500 ft. Tar Zone Reservoir, Fault Block II Unit, Wilmington Field, California", presented at the 1993 Society of Petroleum Engineers Annual Technical Conference and Exhibition in Houston, TX, 3-6 October 1993.

D4 R.M. Butler, "*Horizontal Wells for the Recovery of Oil, Gas and Bitumen; Monograph 2*", Petroleum Society of CIM, Calgary 1994.

D5 M. Polikar, D.A. Redford, "Evolution of Steam-Based Technology for the Recovery of Canadian Heavy Oil Reservoirs", *Journal of Petroleum Technology*, Volume 34, No. 5, pages 33-40, May 1995.

D6 Ershaghi, I., Omoregie, O., University of Southern California, "A Method for Extrapolation of Cut Vs. Recovery Curves," *Journal of Petroleum Technology*, pages 203-04, February 1978.

D7 Ershaghi, I., Abdassah, D., University of Southern California, "A Prediction Technique for Immiscible Processes Using Field Performance Data," *Journal of Petroleum Technology*, pages 664-70, April 1984.

D8 George E. Ottot, Tom F. Norton, Thums Long Beach Company, "The Stratigraphy of the Wilmington Field", Pacific Section American Association of Petroleum Geologists, Field Guide Book entitled "Old Oil Fields and New Life: A Visit to the Giants of the Los Angeles Basin"^{A7}, 1996 AAPG Annual Meeting, San Diego, CA, May 18-22

D9 M. N. Mayuga, City of Long Beach, "Geology and Development of California's Giant - Wilmington Oil Field", American Association of Petroleum Geologists Memoir No. 14, 1970.

E. Required Reports Generated for the Department of Energy

E1 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (30 March 1995 - 30 June 1995).

E2 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 July 1995 - 30 September 1995).

E3 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil

Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 October 1995 - 31 December 1995).

- E4 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 1996 - 31 March 1996).
- E5 Project Team, Annual Report entitled "Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (30 March 1995 - 31 March 1996).
- E6 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 1996 - 30 June 1996).
- E7 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 July 1996 - 30 September 1996).
- E8 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 October 1996 - 31 December 1996).
- E9 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 1997 - 31 March 1997).
- E10 Project Team, Annual Report entitled "Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 1996 - 31 March 1997).
- E11 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 1997 - 30 June 1997).
- E12 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 July 1997 - 30 September 1997).

E13 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 October 1997 - 31 December 1997).

E14 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 1998 - 31 March 1998).

E15 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 1998 - 30 June 1998).

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E17 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 October 1998 - 31 December 1998).

E18 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 1999 - 31 March 1999).

E19 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 1999 - 30 June 1999).

E20 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 July 1999 - 30 September 1999).

E21 P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 October 1999 - 31 December 1999).

E²² P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 2000 - 31 March 2000).

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E²⁷ P. Scott Hara (Tidelands Oil Production), Quarterly Technical Progress Report - Class III Mid-Term Project, "Increasing Heavy Oil Reserves in the Wilmington Oil Field Through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 January 2001 - 31 March 2001).

E²⁸ Project Team, Annual Report entitled "Increasing Heavy Oil Reserves in the Wilmington Oil Field through Advanced Reservoir Characterization and Thermal Production Technologies", DE-FC22-95BC14939, (1 April 2000 - 31 March 2001).

F. References for Section 2.2.2

F¹ Norton, T.F., Otott, G.E.: "The Stratigraphy of the Wilmington Oil Field, Thums Long Beach Company".

F² Ershaghi, I. and Omoregie, O.: "A Method for Extrapolation of Cut vs. Recovery Plots," JPT (Feb. 1978) 203-04.

F³ Ershaghi, I., and Abdassah, D.: "A Prediction Technique for Immiscible Processes Using Field Performance Data," JPT (April 1984) 664-70.

F⁴ Ershaghi, I., Handy, L.L., and Hamdi, M.: "Application of the X-Plot Technique to the Study of Water Influx in the Sidi El_Itayem Reservoir, Tunisia," JPT (Sept. 1987) 1127-36.

G. References for Section 2.3.2.1 and 2.4.1

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G² Zeito, G. A., "Interbedding of Shale Breaks and Reservoir Heterogeneities", JPT, Oct. 1965. 1223 - 1228.

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G14 Slatt, R. M., S. Phillips, J. M. Boak and M. B. Lagoe, ``Scales of Geologic Heterogeneity of a Deep-Water Sand Giant Oil Field, Long Beach Unit, Wilmington Field, California", in E. G. Rhodes and T. F. Moslow (eds.), *Frontiers in Sedimentary Geology: Marine Clastic Reservoirs: Example and Analogues*, Springer-Verlag, 1993.

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APPENDIX

A. TAR II-A Steamflood Performance: January 1982 – December 2000

B. TAR II-A Post-Steamflood Wells: January 1999 – May 2001

Total Production

Total Injection

Individual Producers	Post-Steamflood Individual Injectors
AT-058	UP-928
AT-059	UP-930
AT-061	UP-939
AT-063	UP-940
UP-907	UP-941
UP-908	UP-942
UP-910	UP-944
UP-912	UP-945
UP-013	UP-946
UP-914	UP-947
UP-915	UP-948
UP-916	UP-949
UP-918	UP-955
UP-920	UP-956
UP-924	

C. TAR V Steamflood Pilot Wells – January 1996 – May 2001

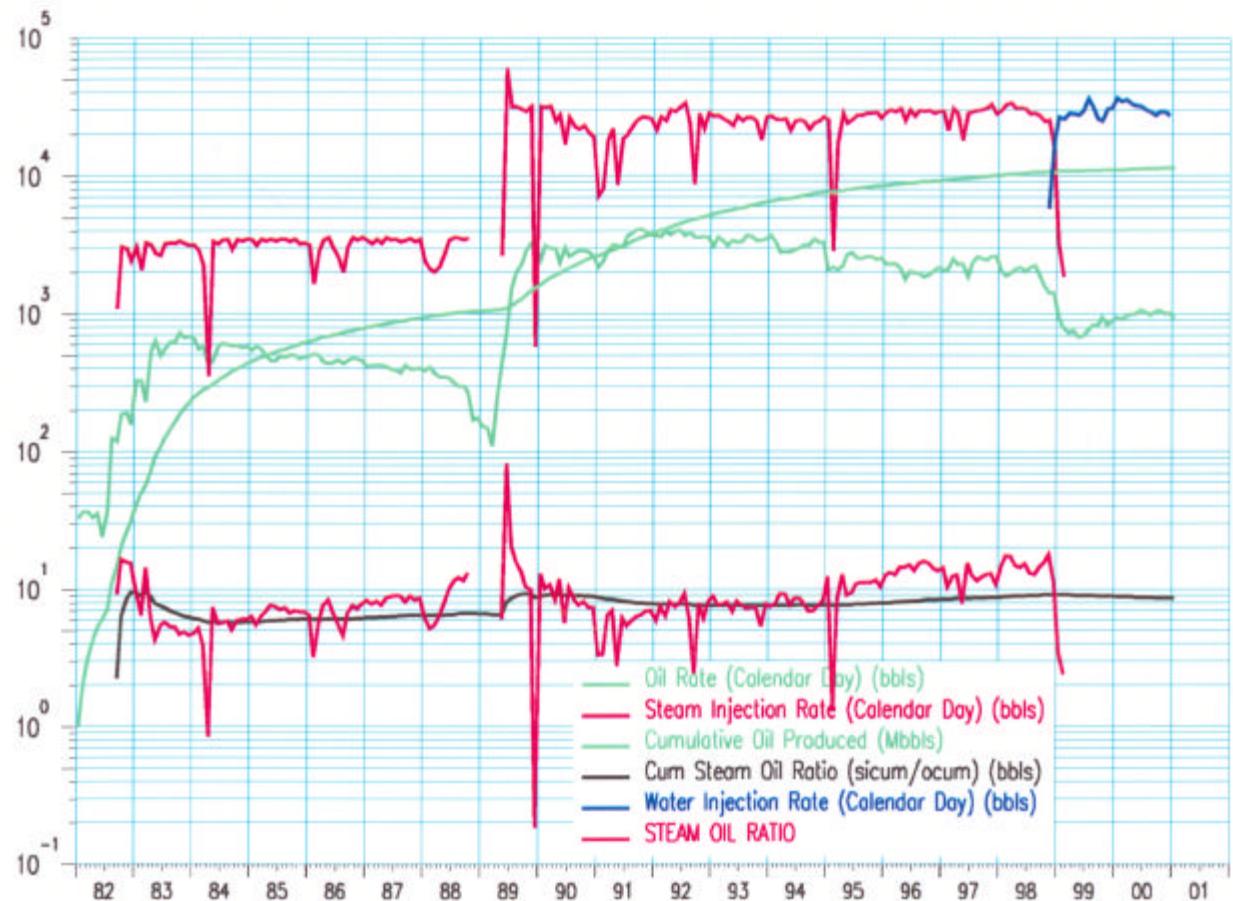
Total Production

Total Steam

Total Injection

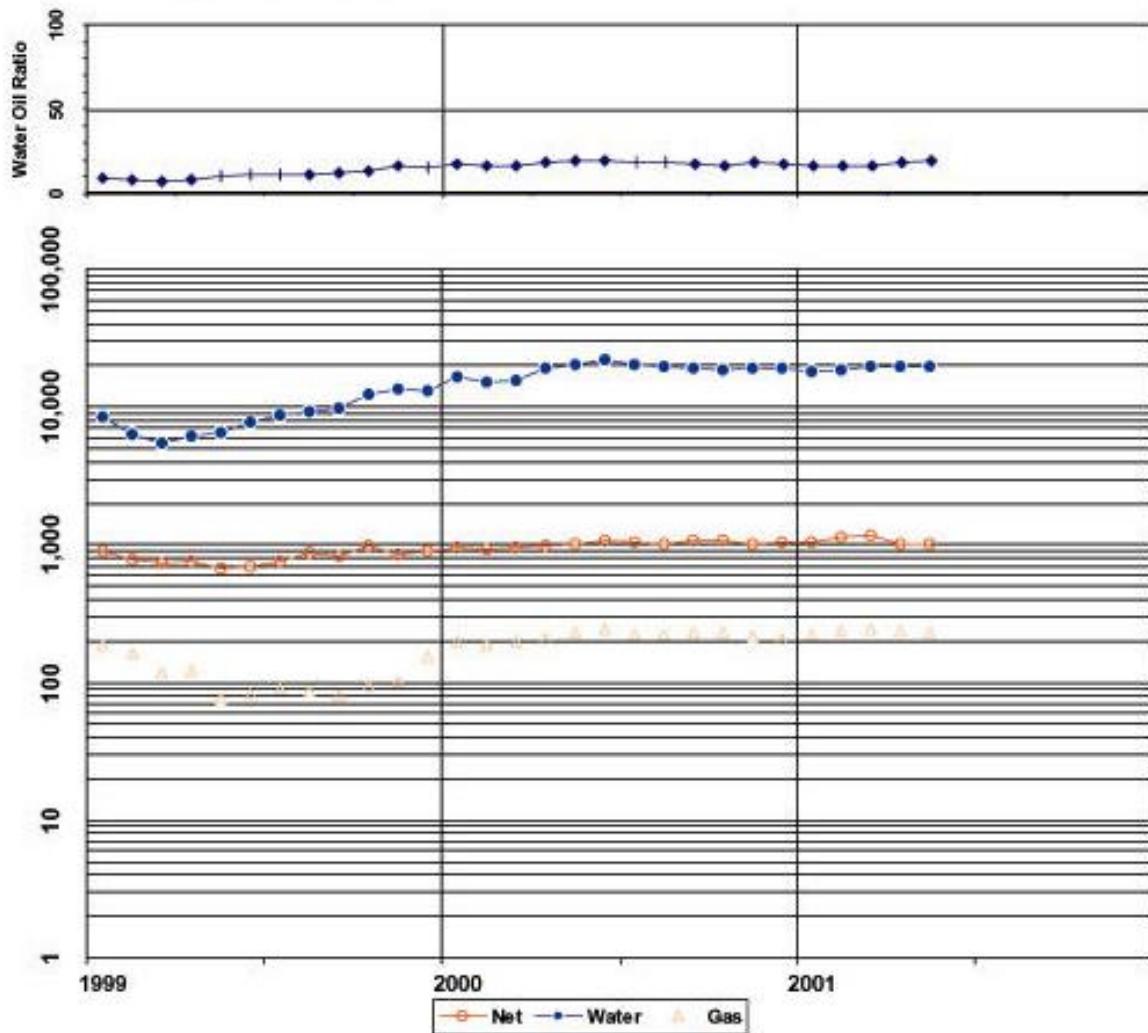
Individual Producers	Individual Steam Injectors	Individual Water Injectors
A-186	FJ-201	FR-111
A-195	FJ-202	FRA-029
A-320	FJ-203	FRA-083
J-201	FJ-204	
J-202	FJ-205	
J-203		
J-204		
J-205		

FAULT BLOCK II-A STEAMFLOOD



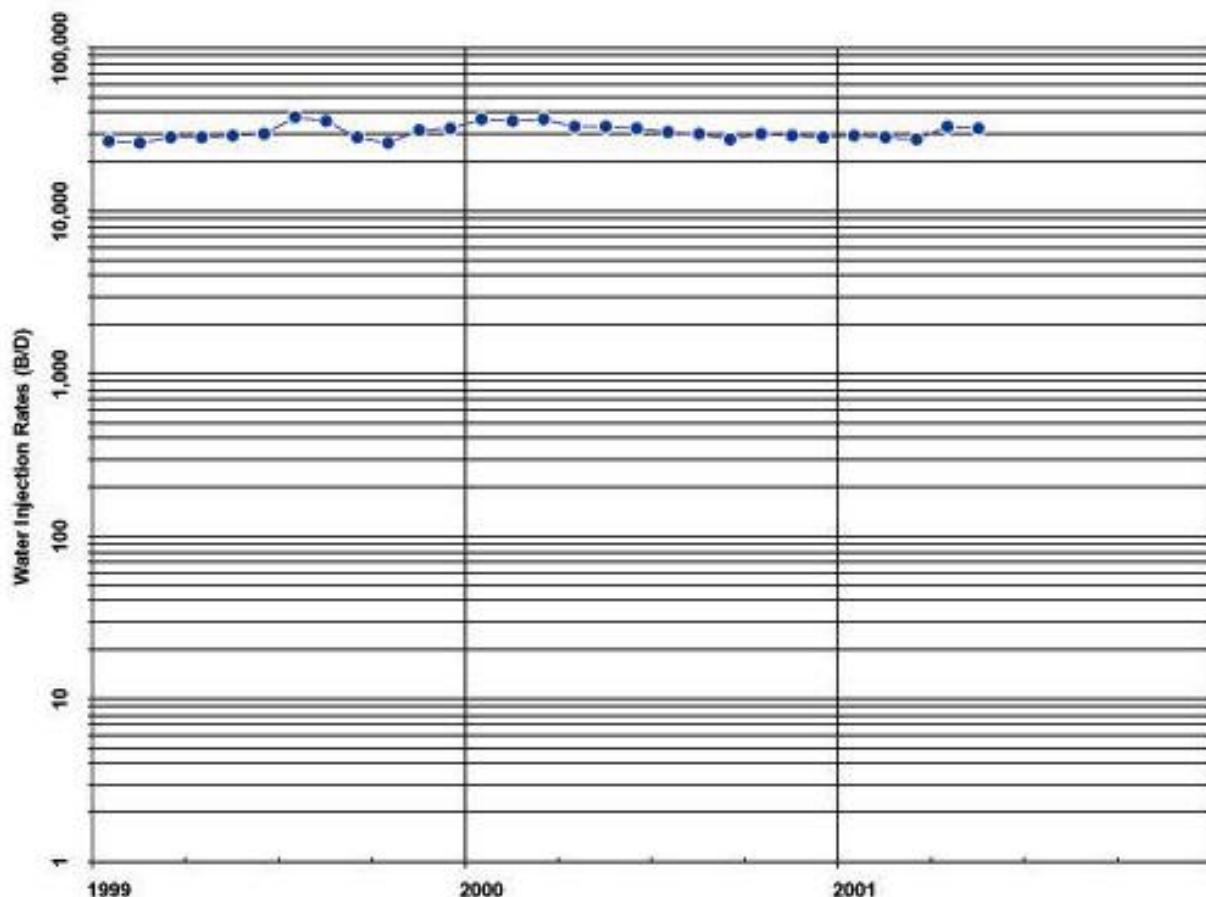
Tar II-A Post-Steamflood Production January 1999 - May 2001

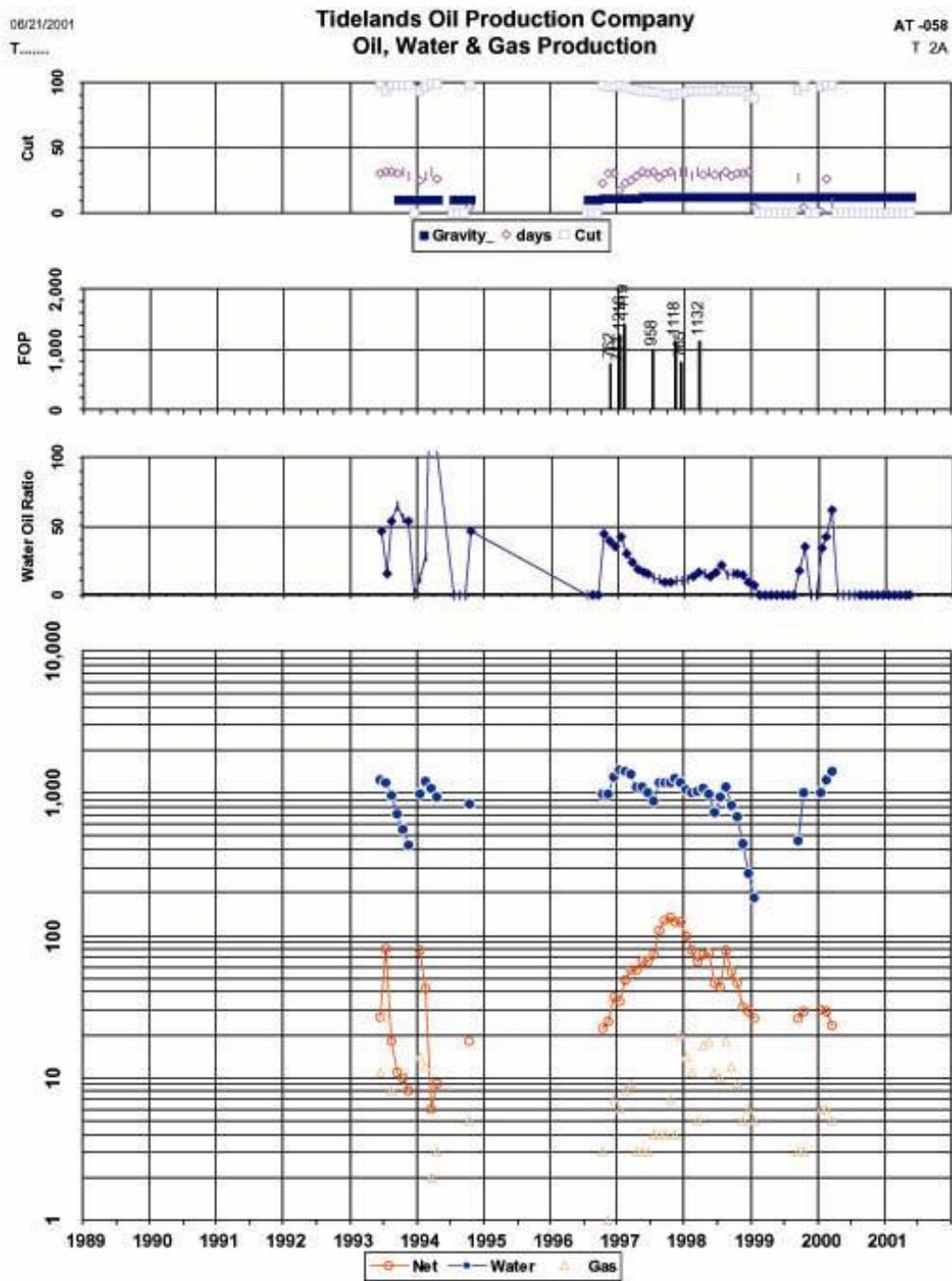
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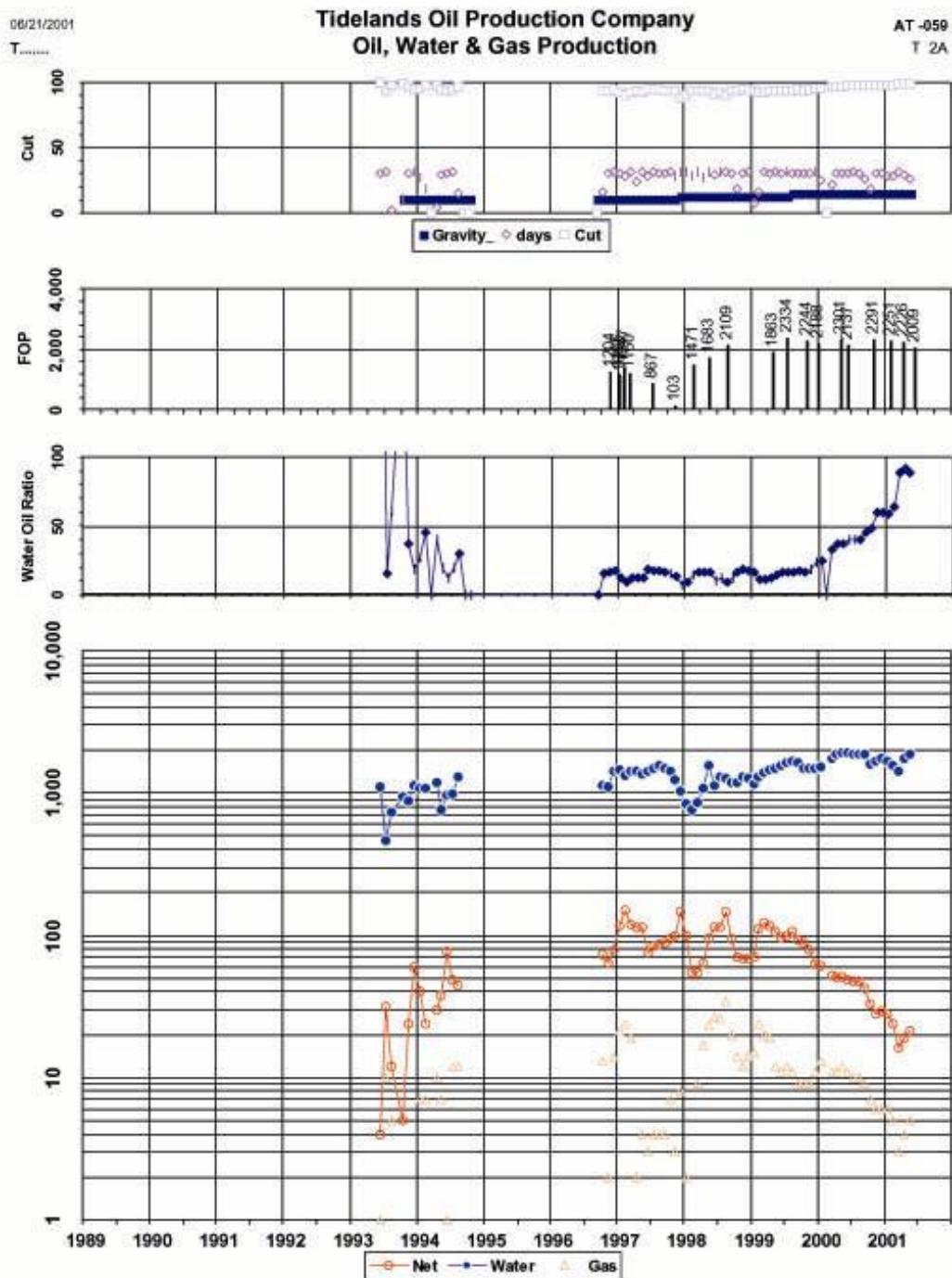


Tar II-A Post-Steamflood Water Injection January 1999 - May 2001

2AT-020, 2AT-048, 2AT-049, 2AT-056, 901-UP, 935-UP, 937-UP, 943-UP, 951-UP, 953-
UP, FW -088, FW -101, FW -103



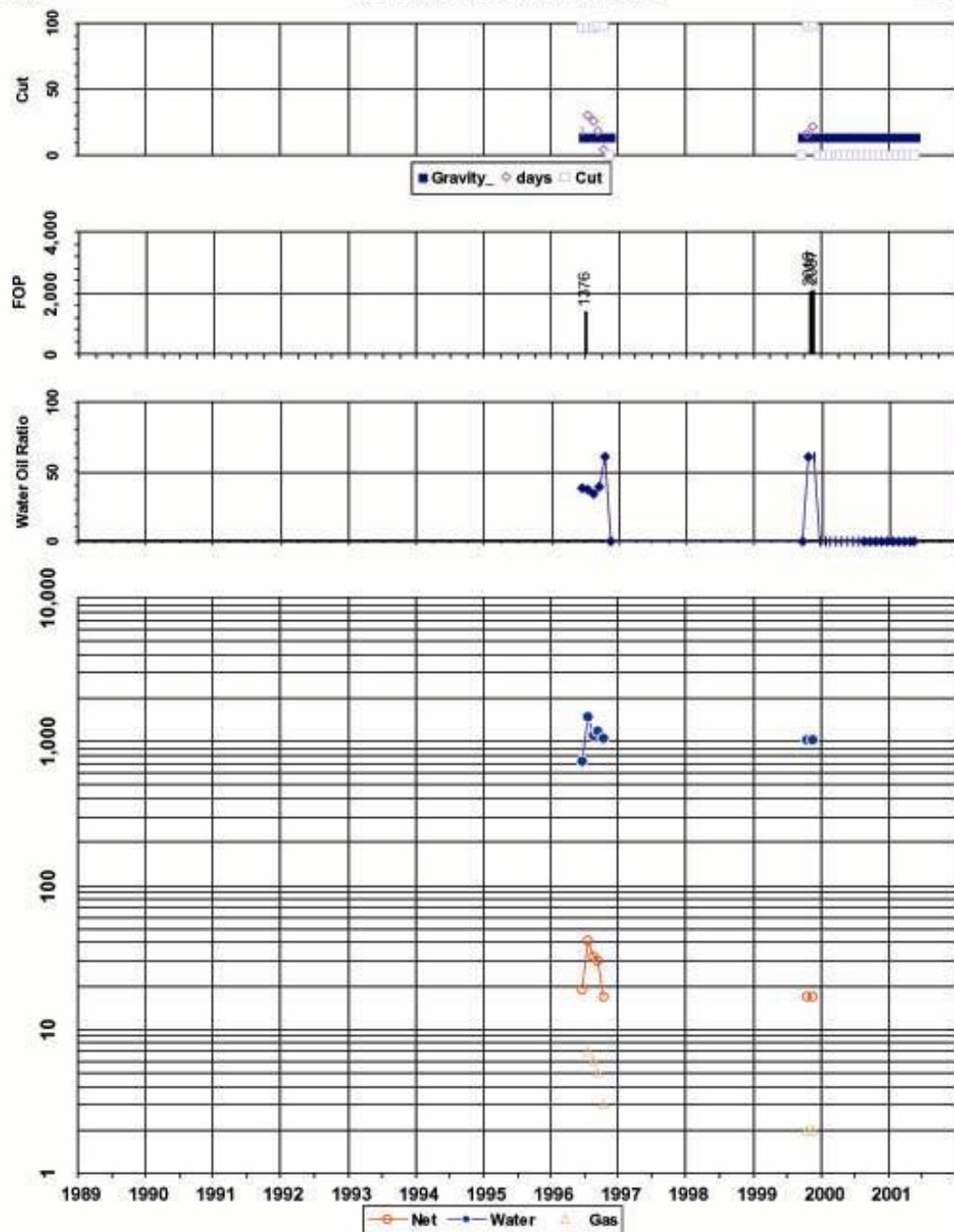




06/21/2001
T.....

Tidelands Oil Production Company
Oil, Water & Gas Production

AT-061
T 2A

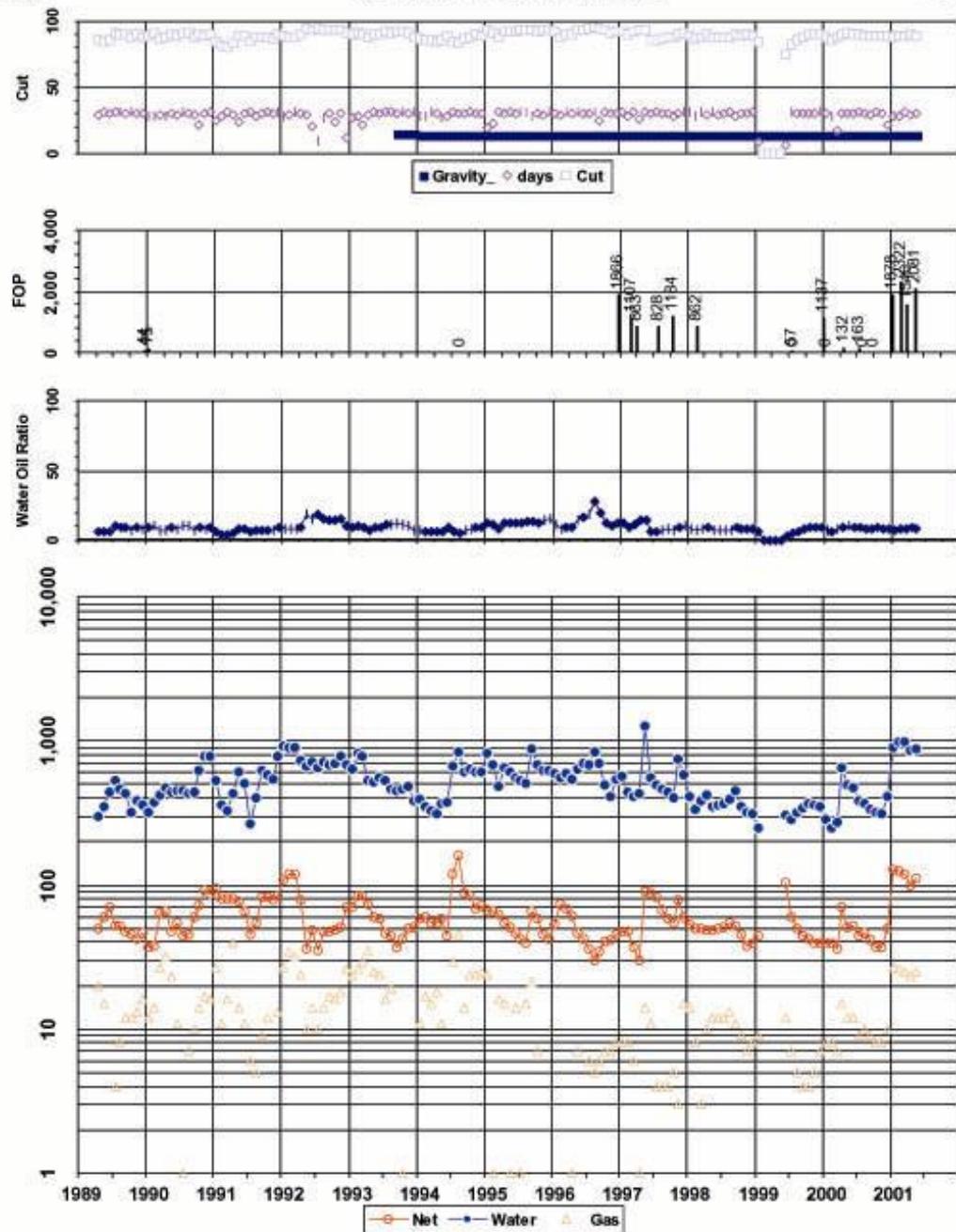


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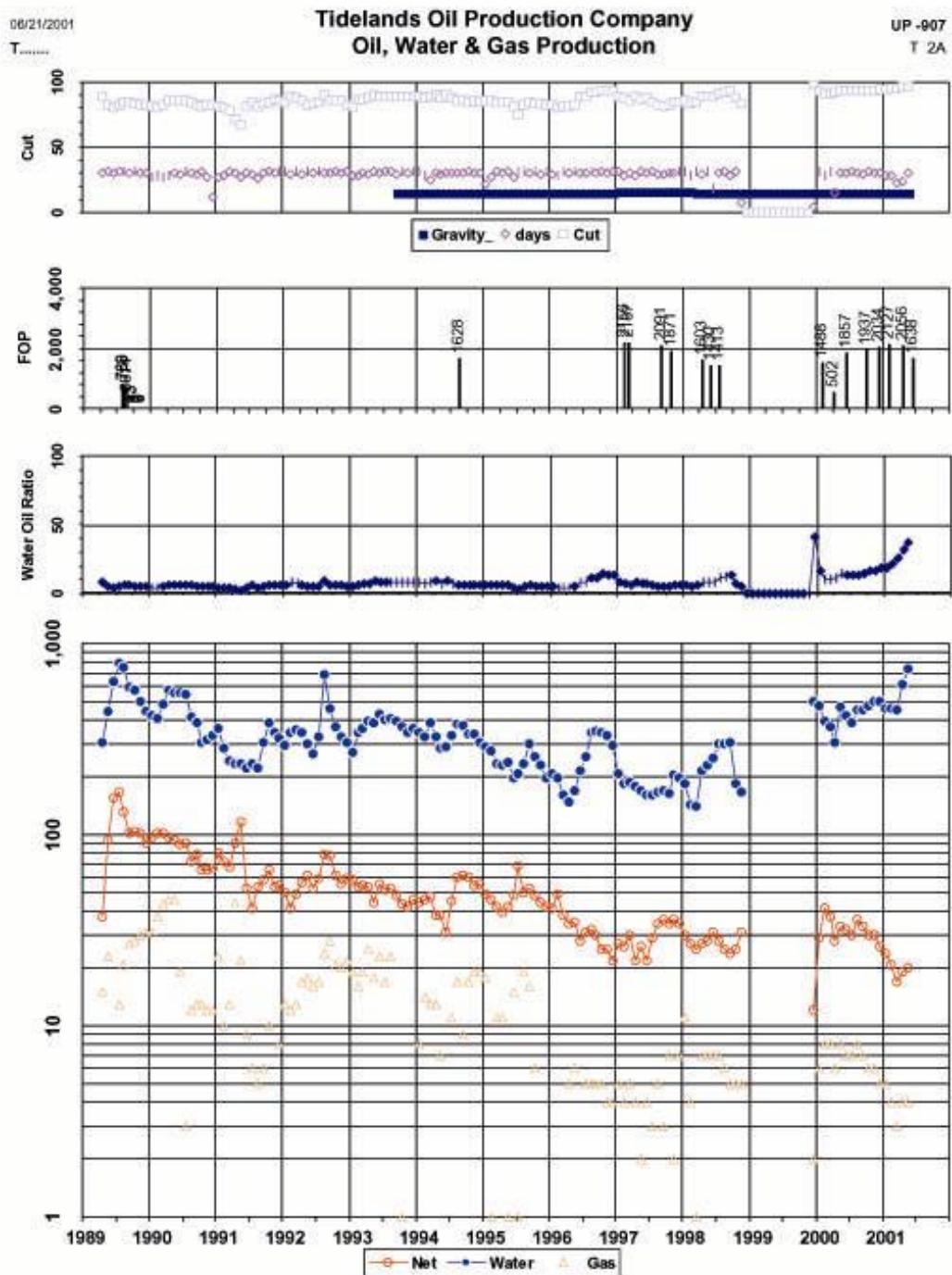
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T.....

Tidelands Oil Production Company
Oil, Water & Gas Production

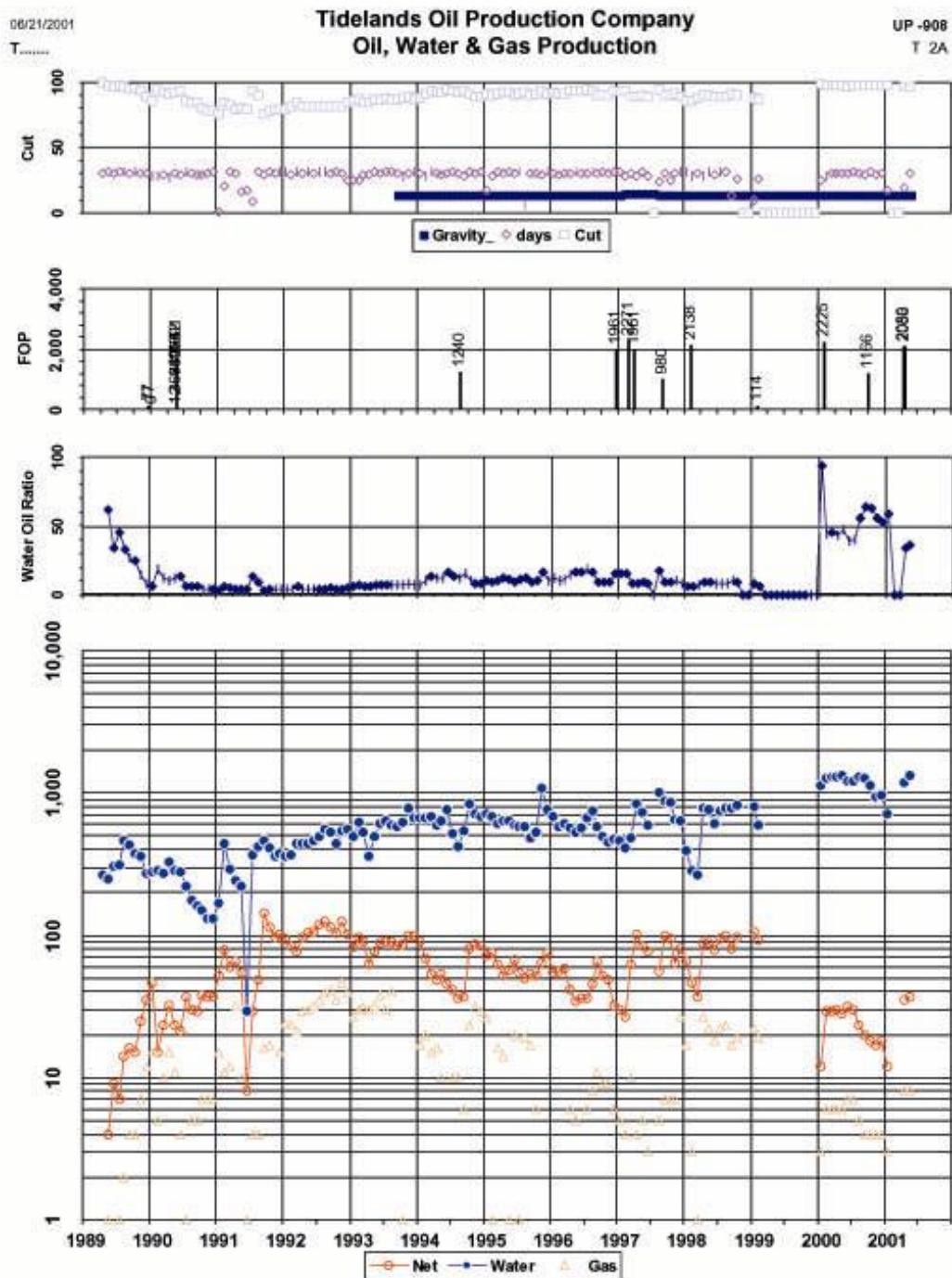
UP -903
T 2A



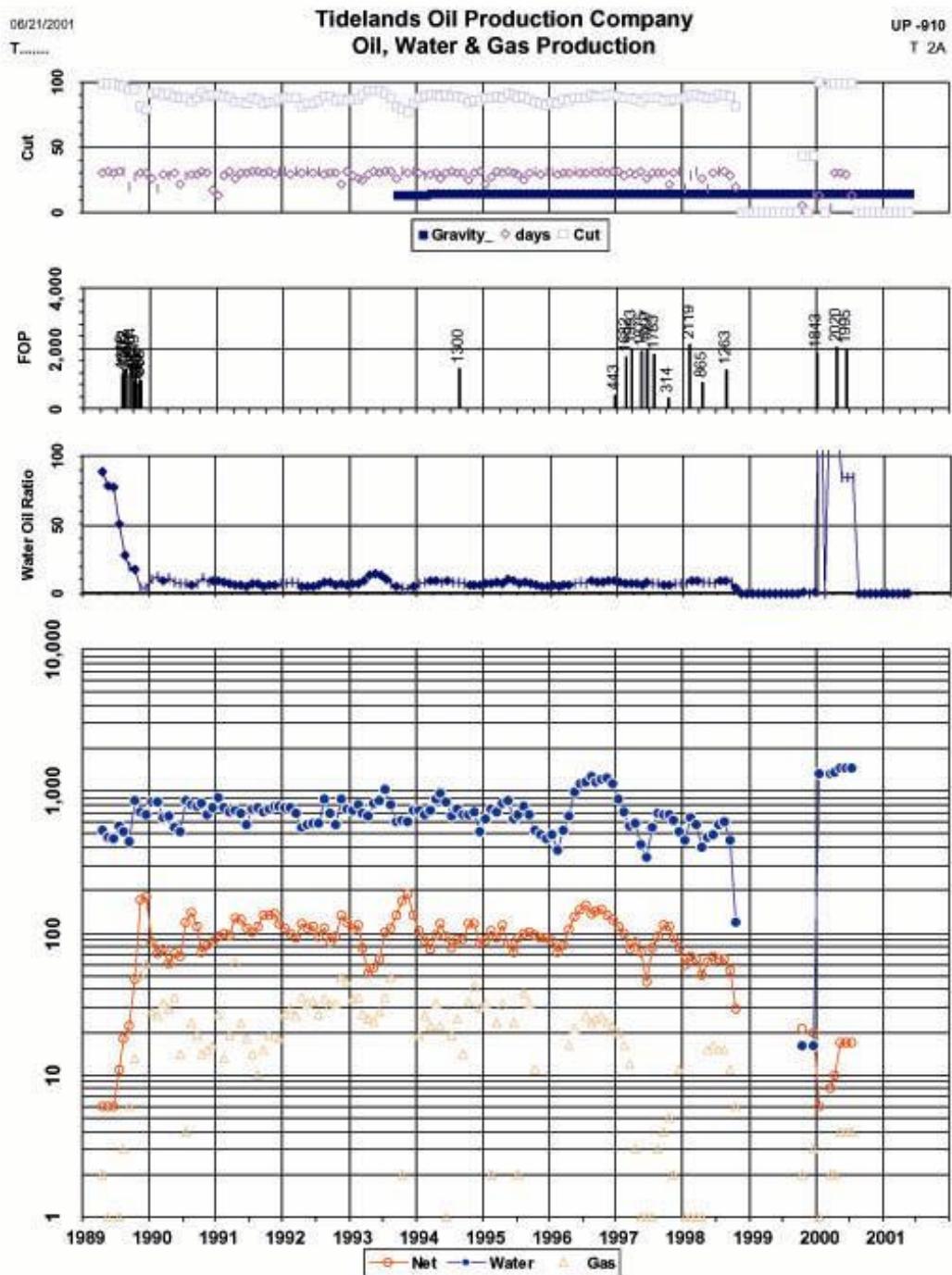
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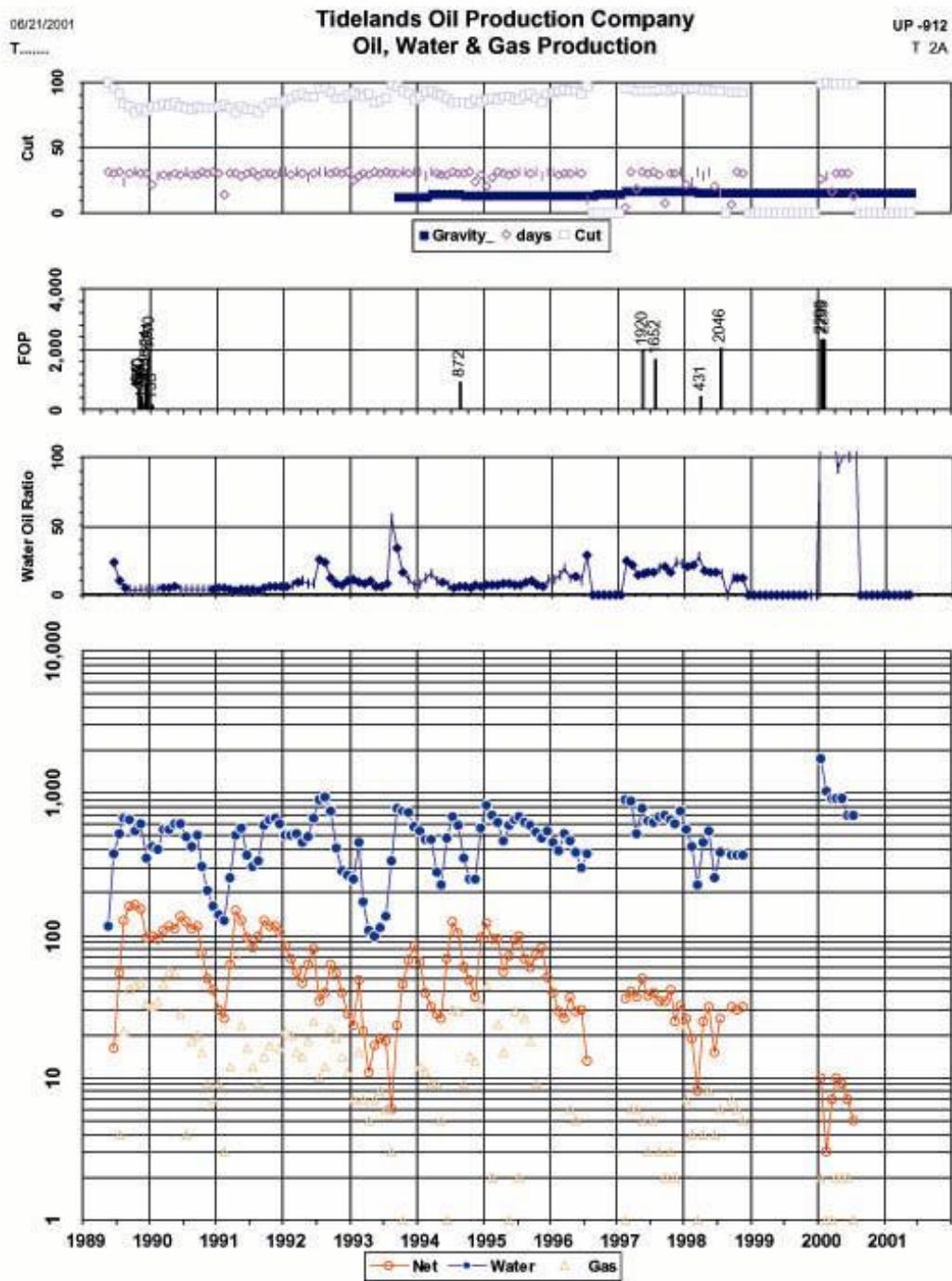
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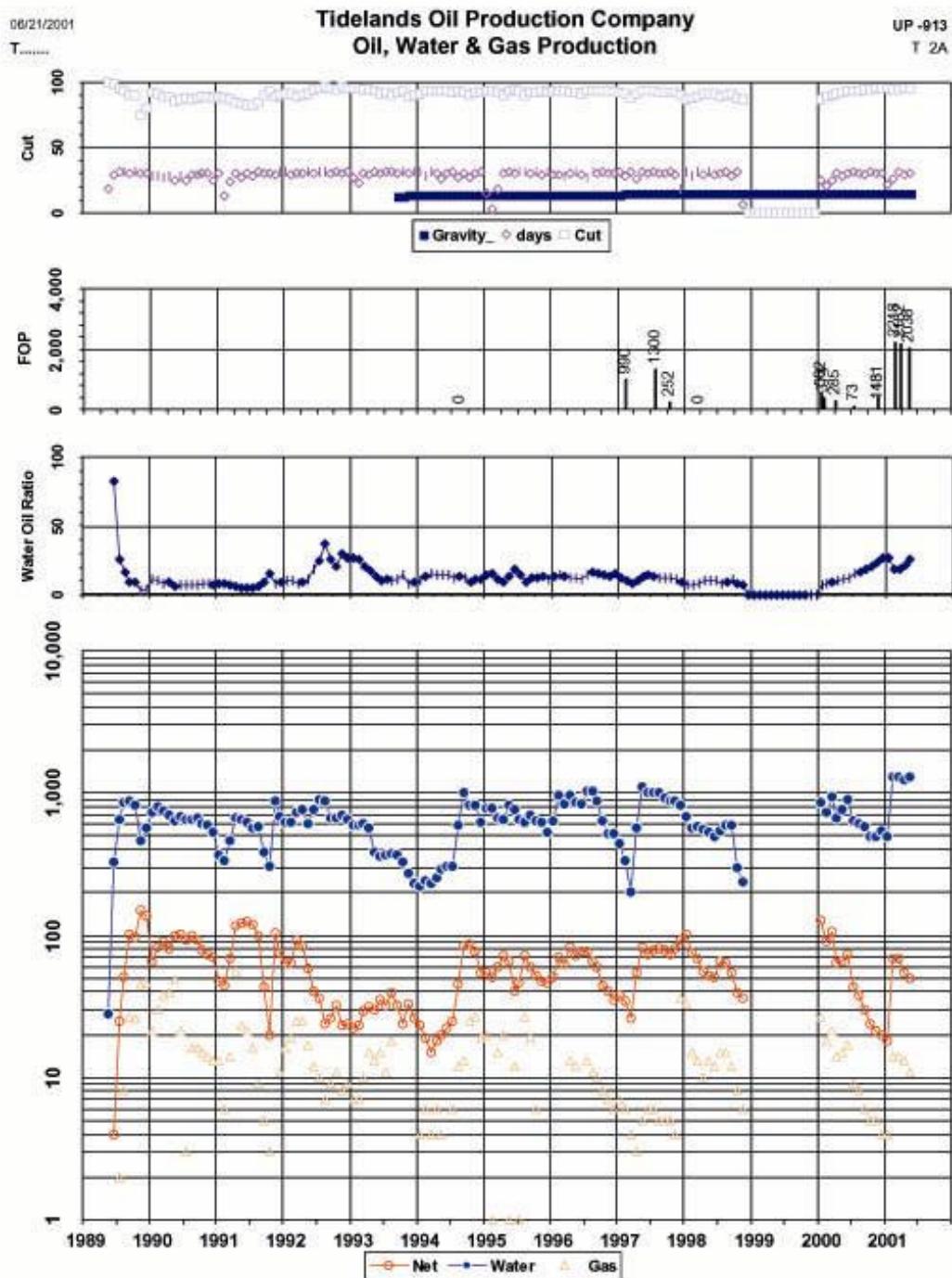
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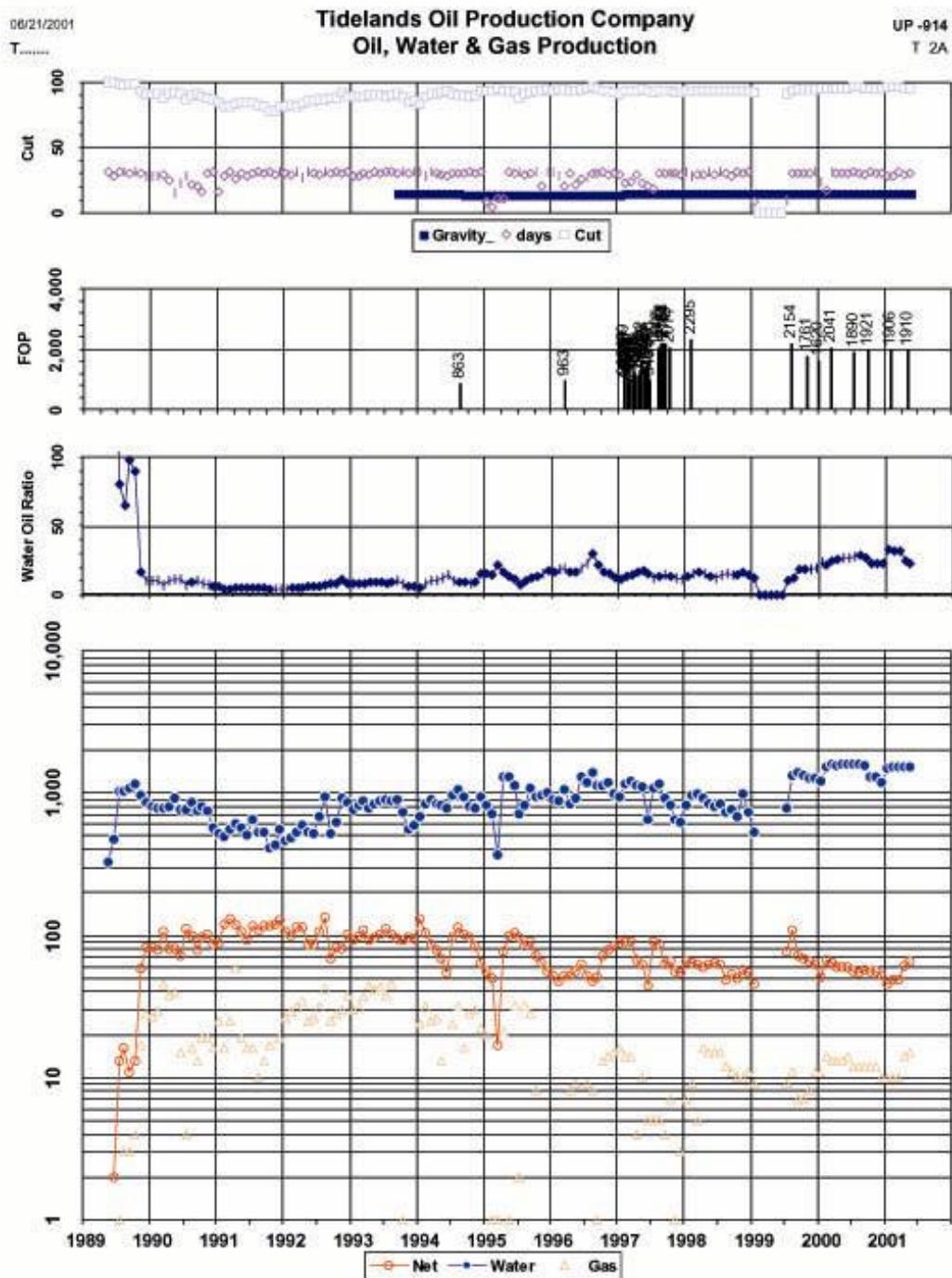
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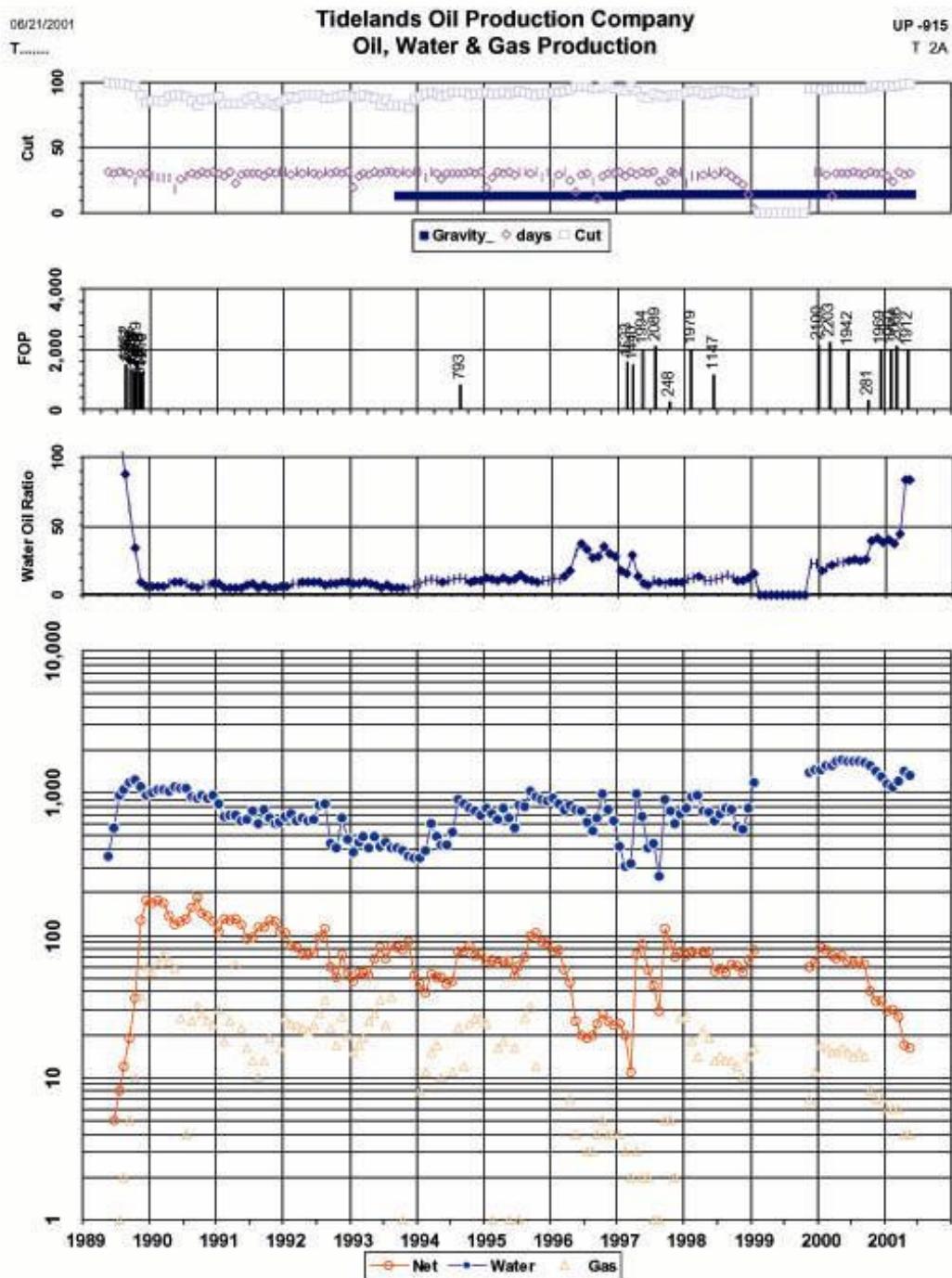


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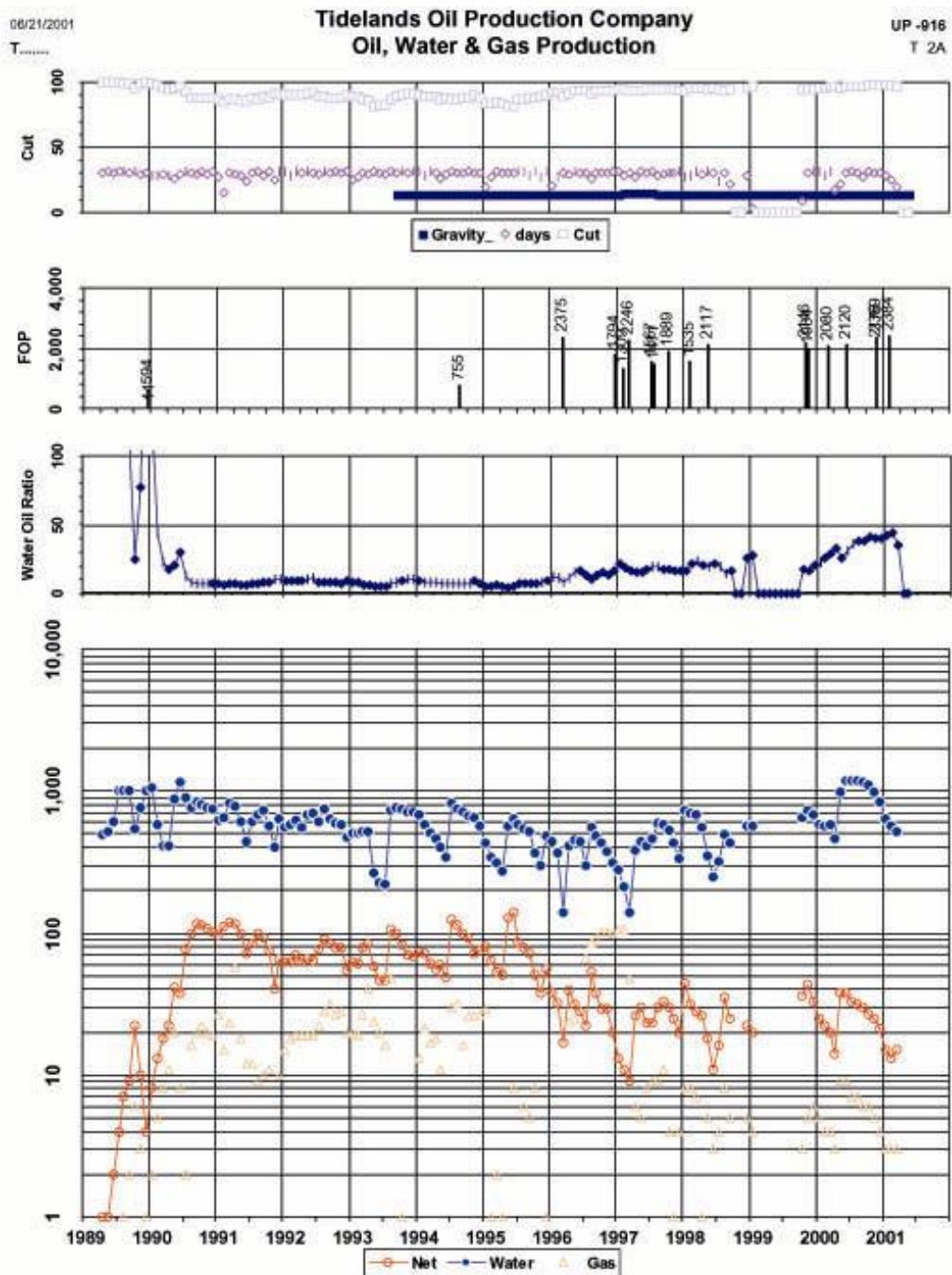


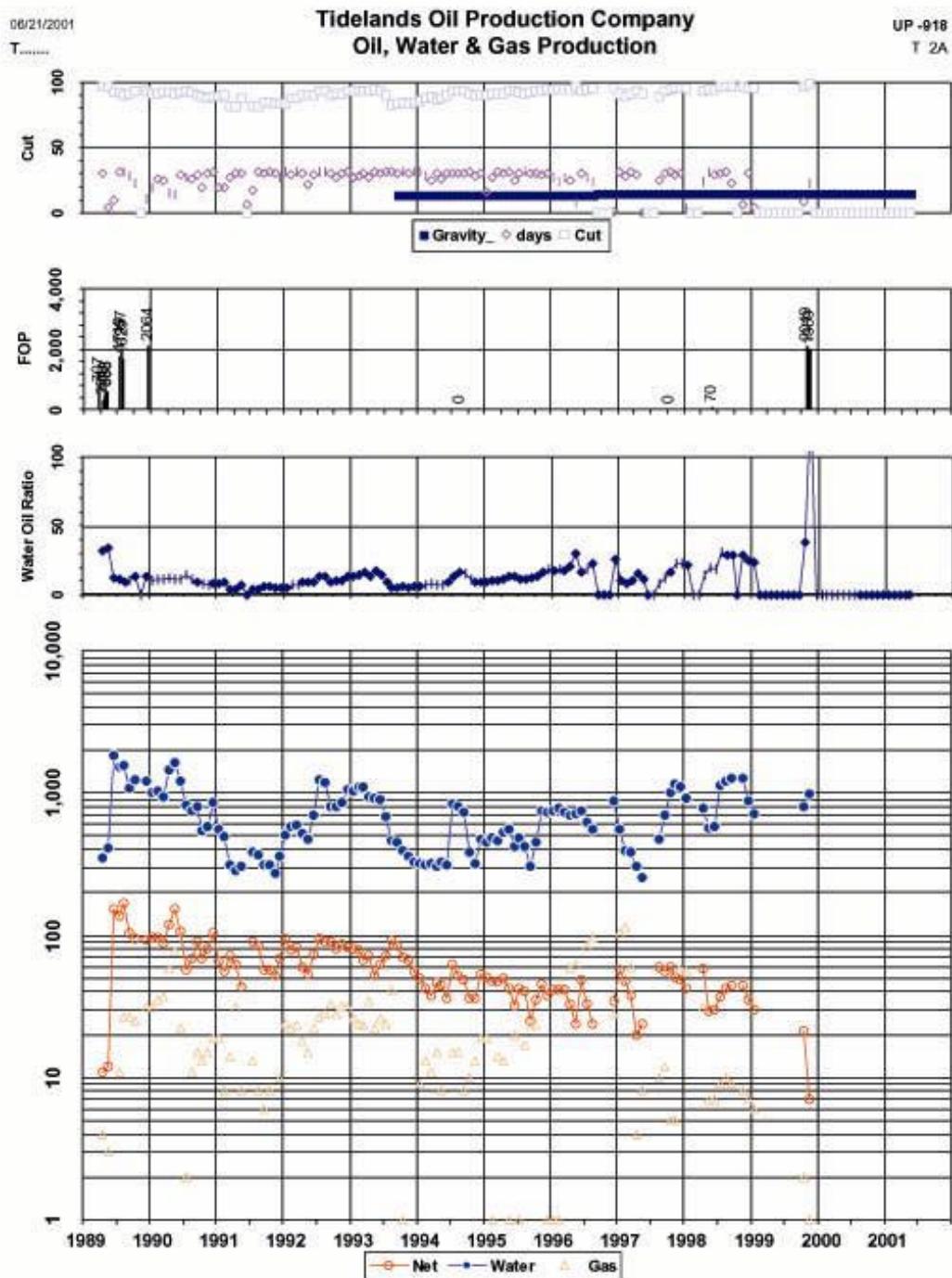
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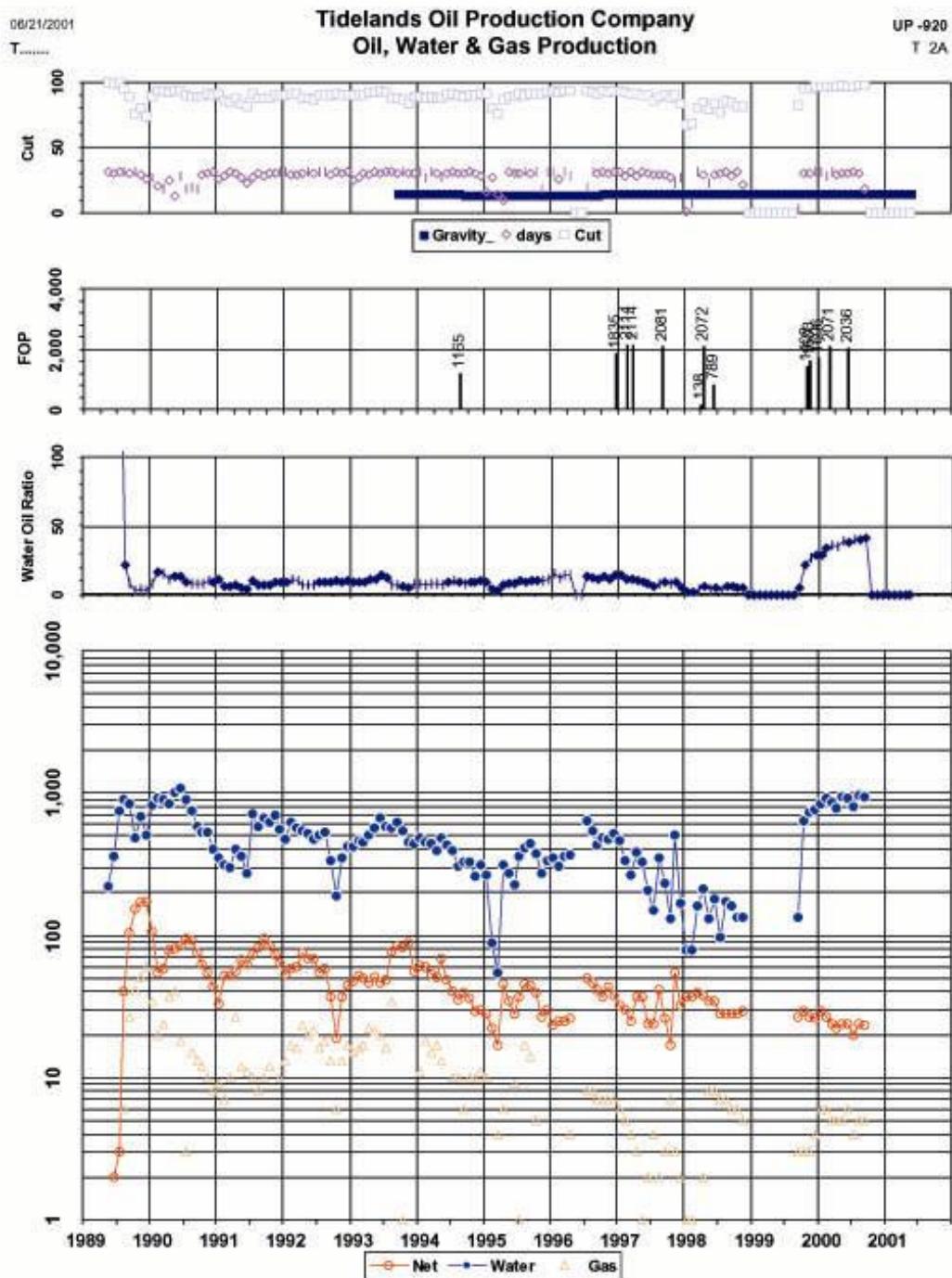


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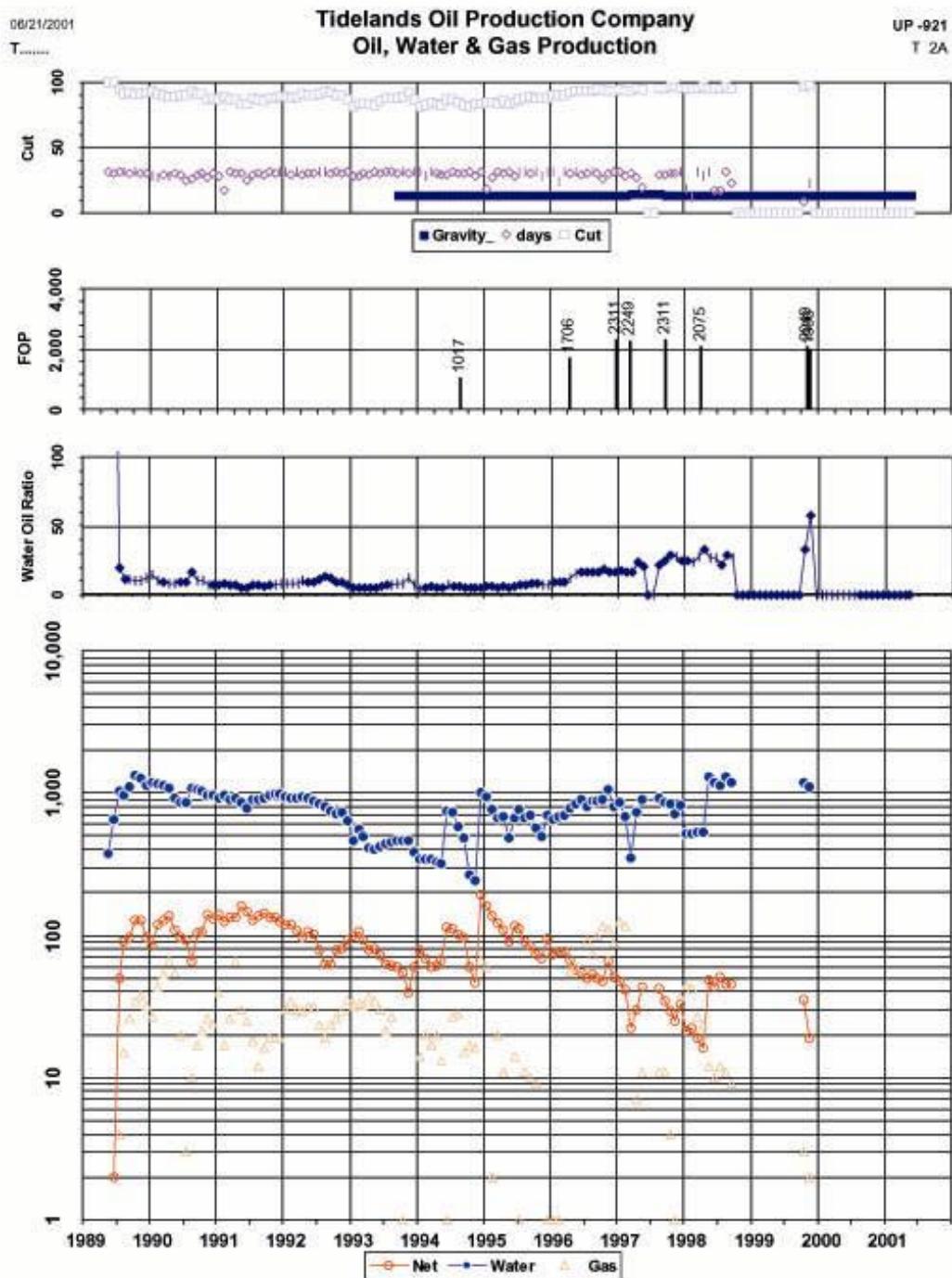




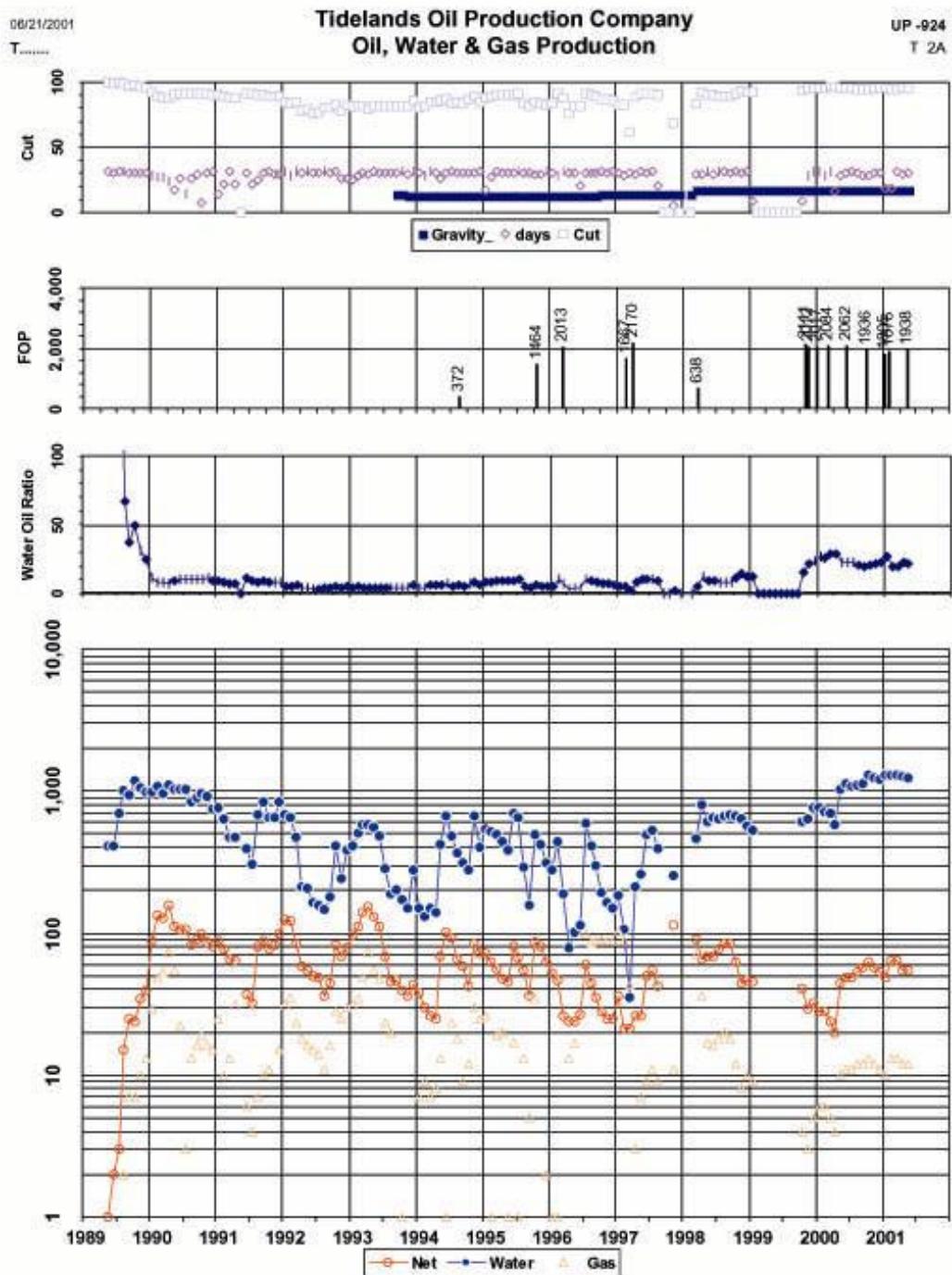
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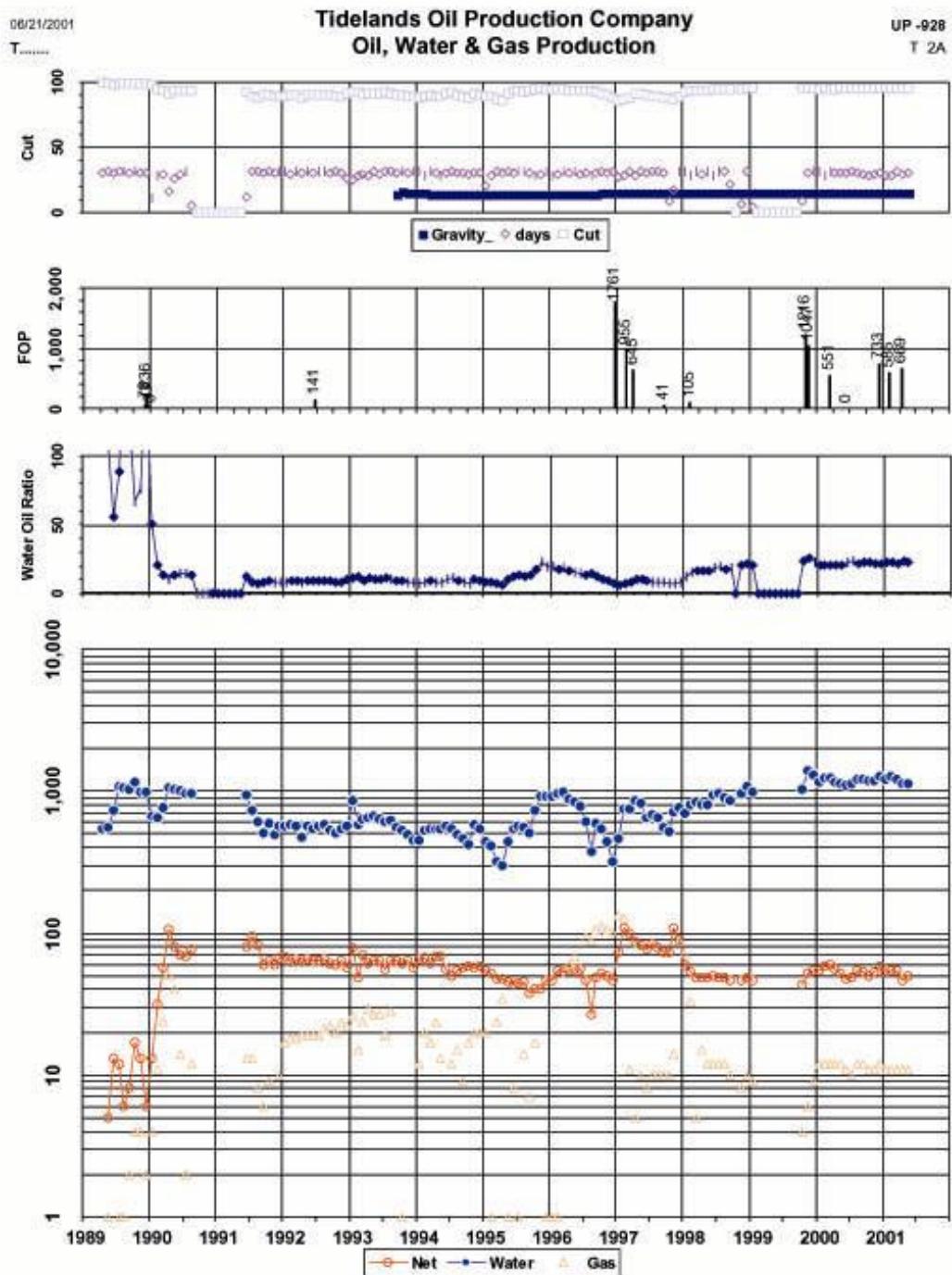
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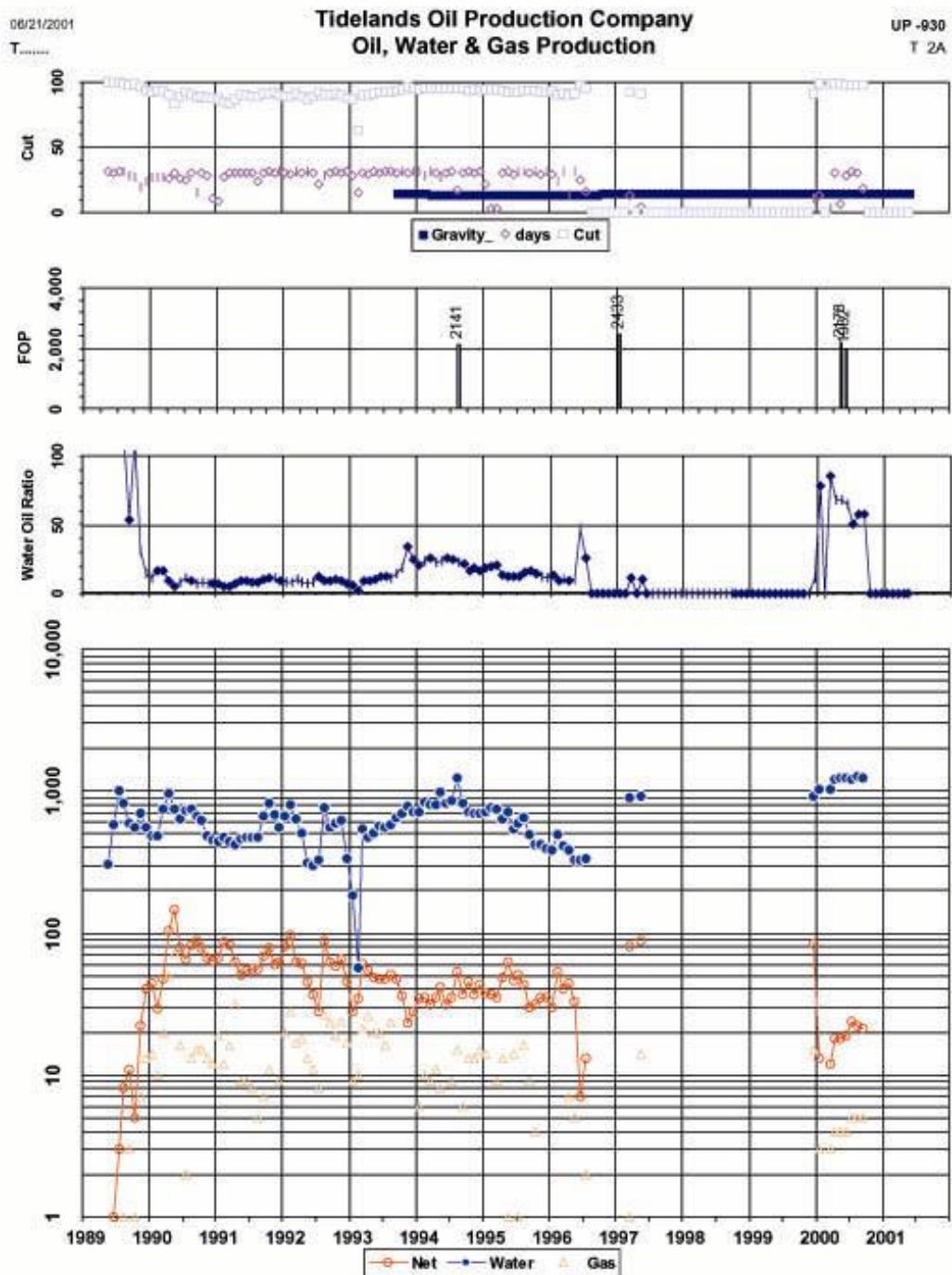
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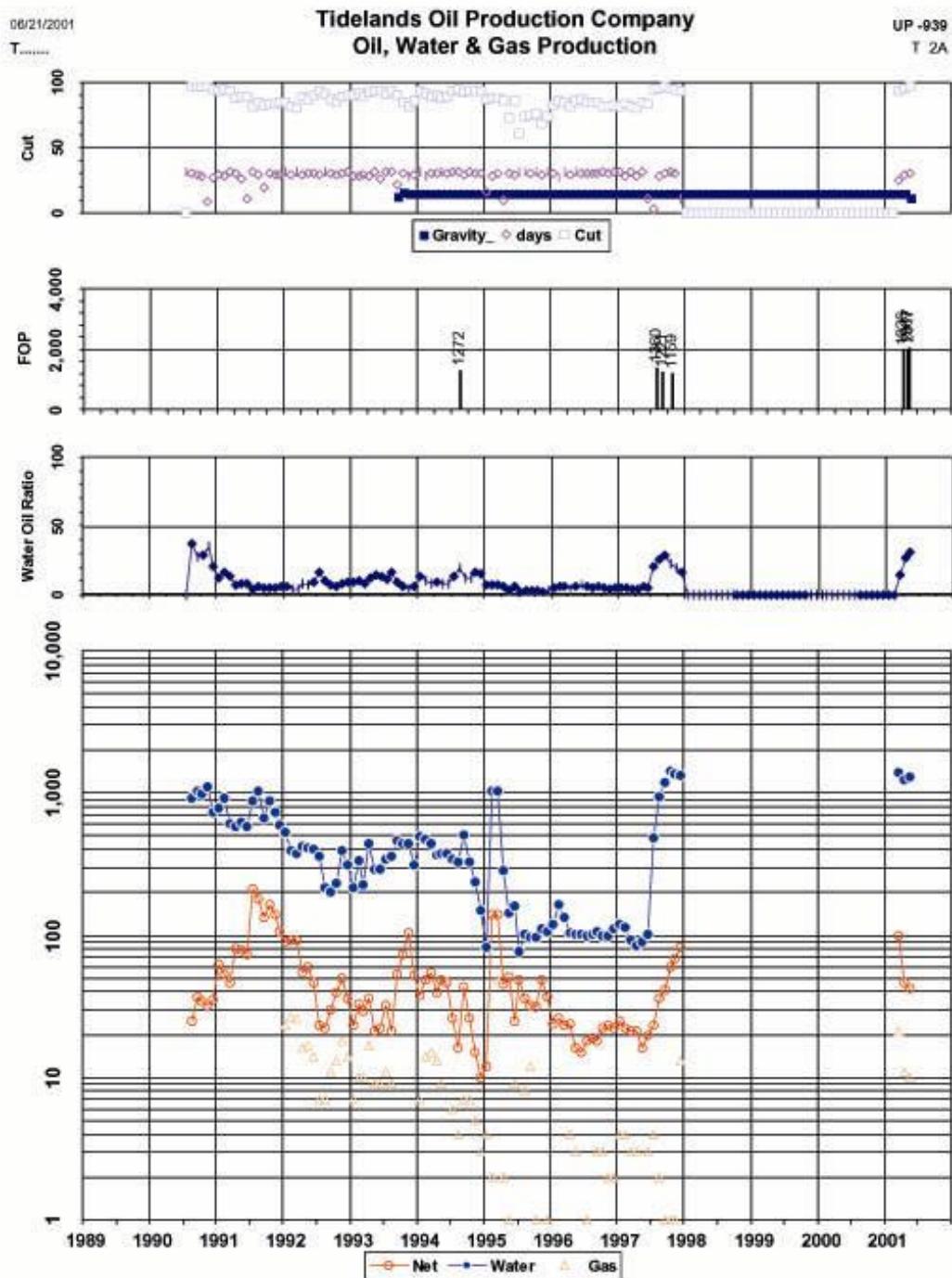
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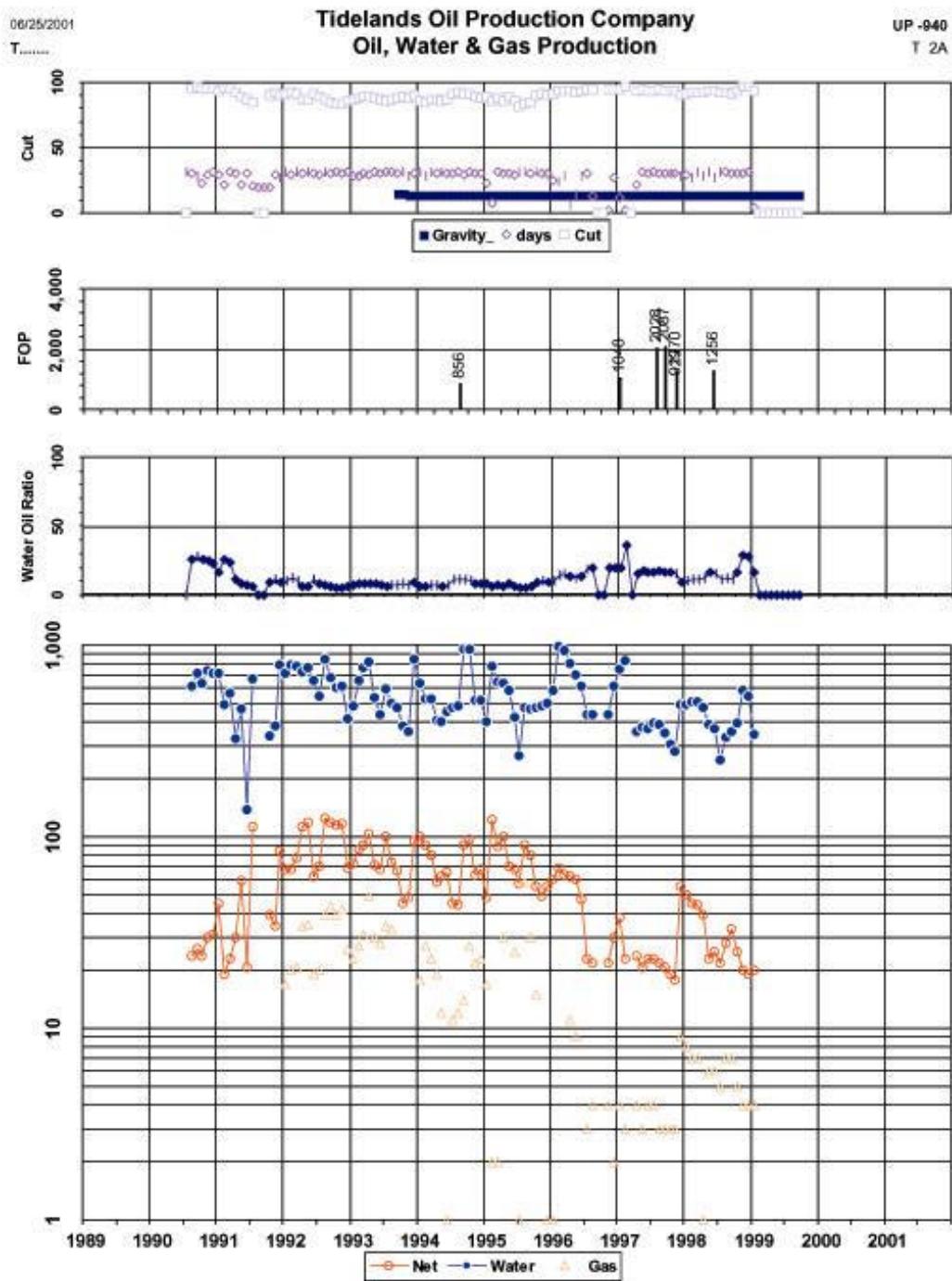
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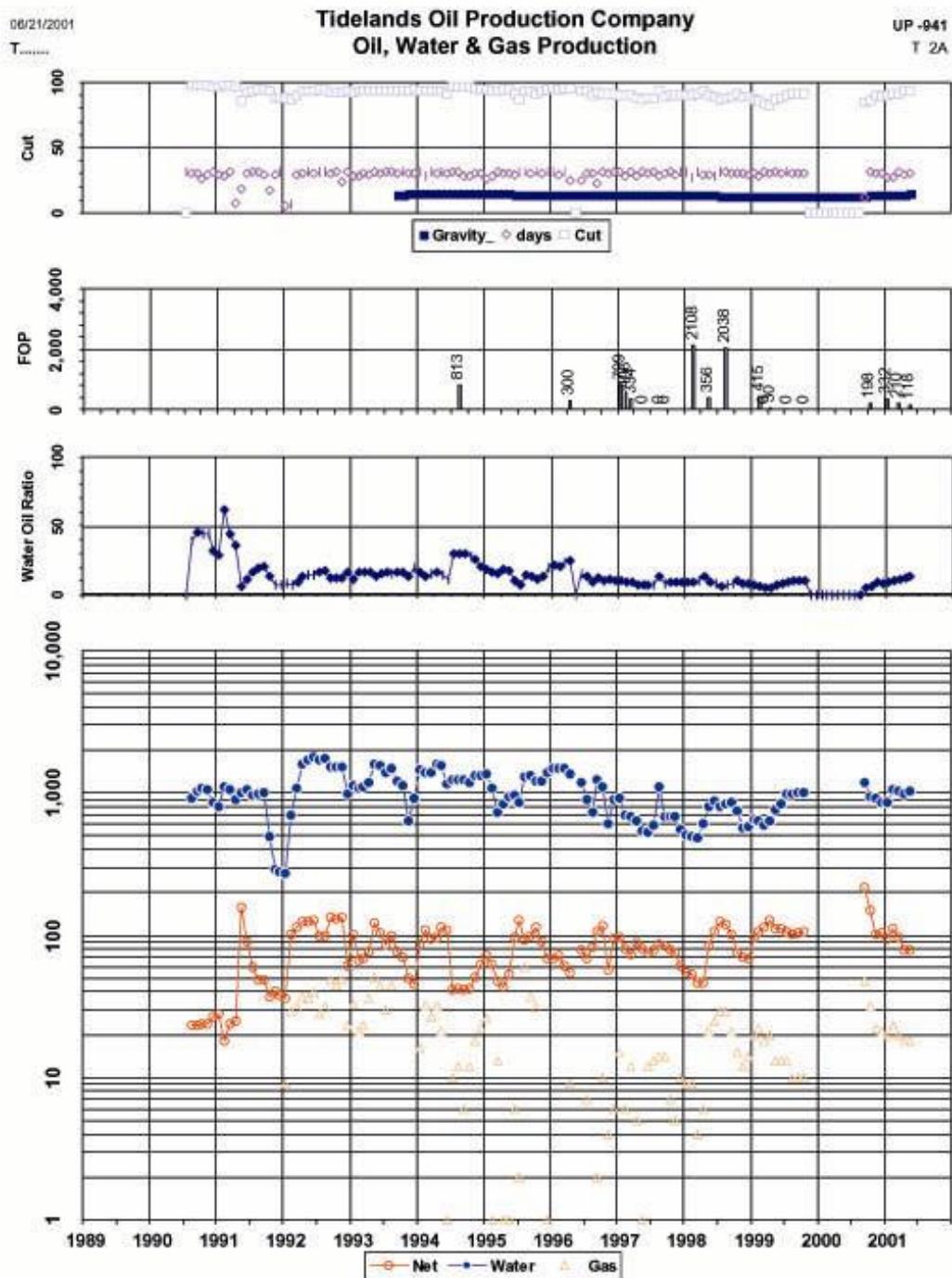


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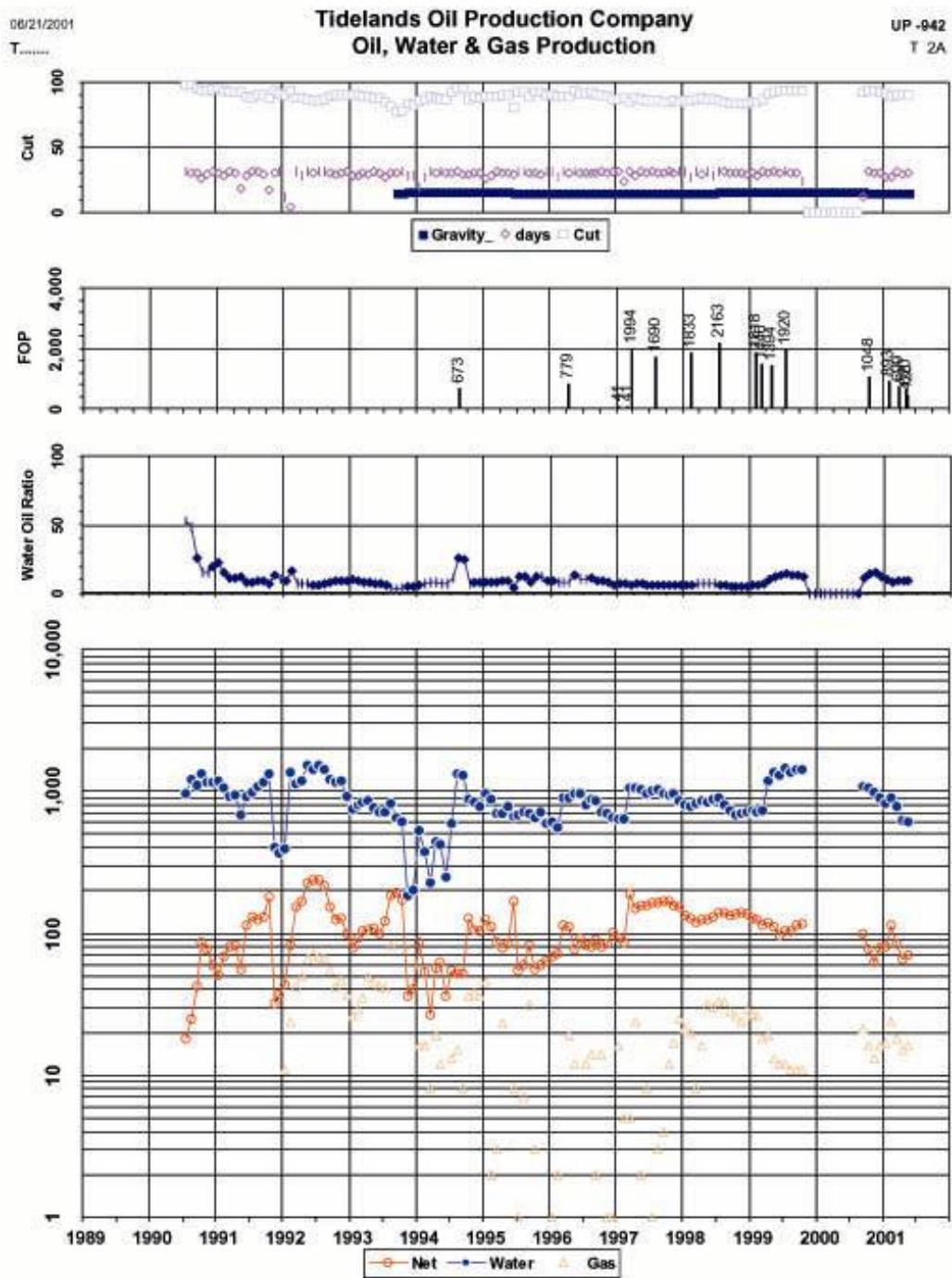


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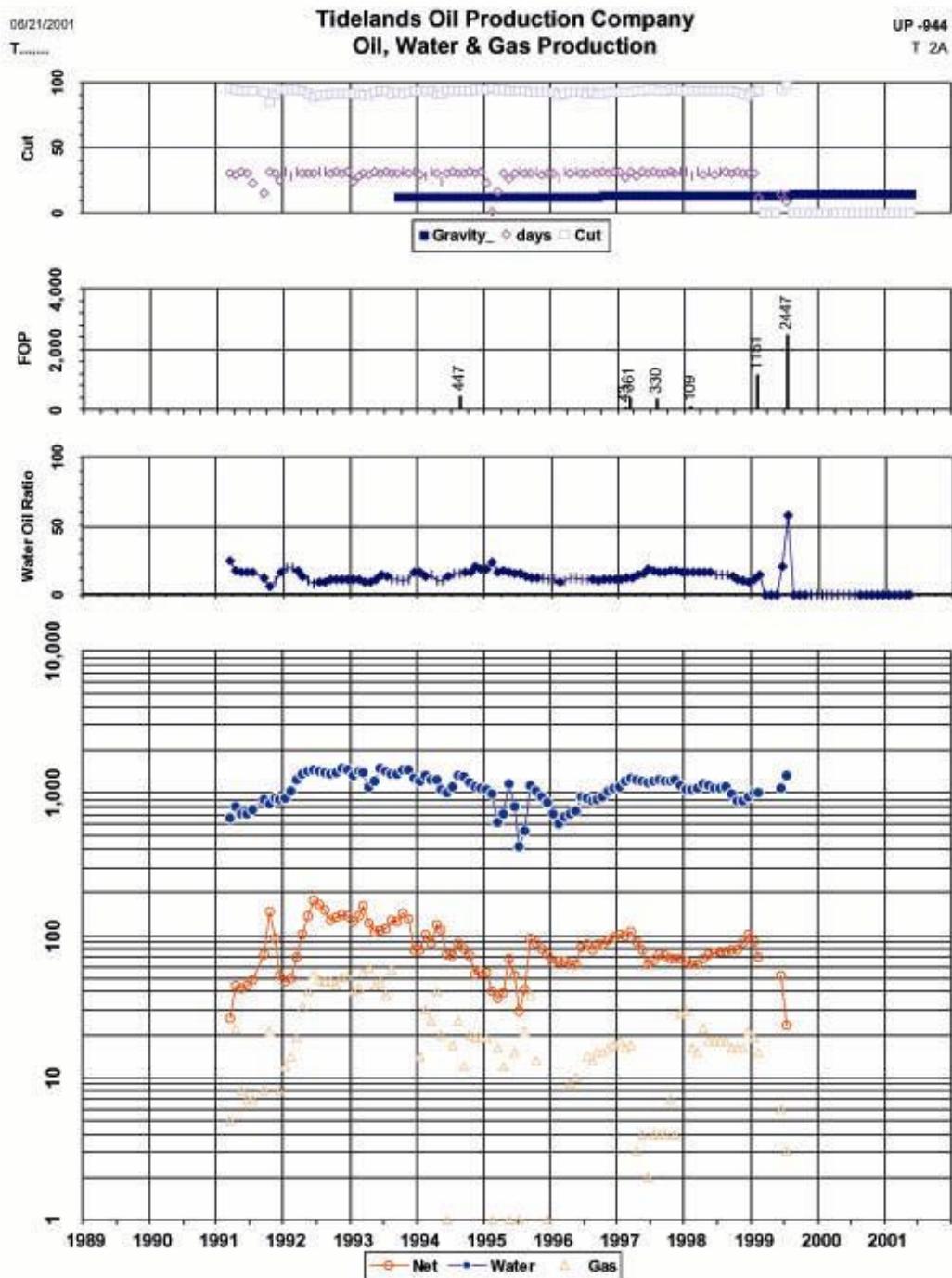




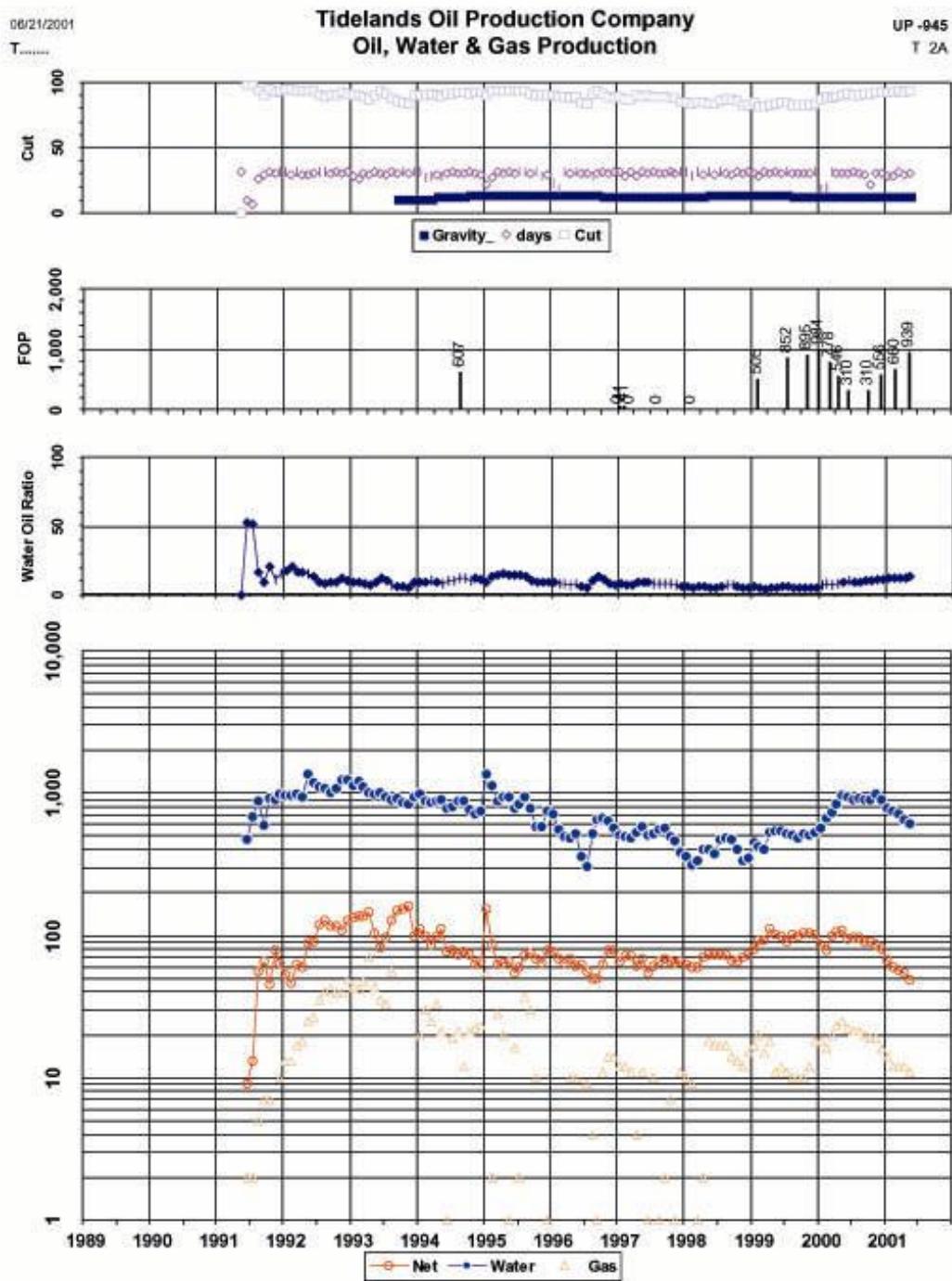
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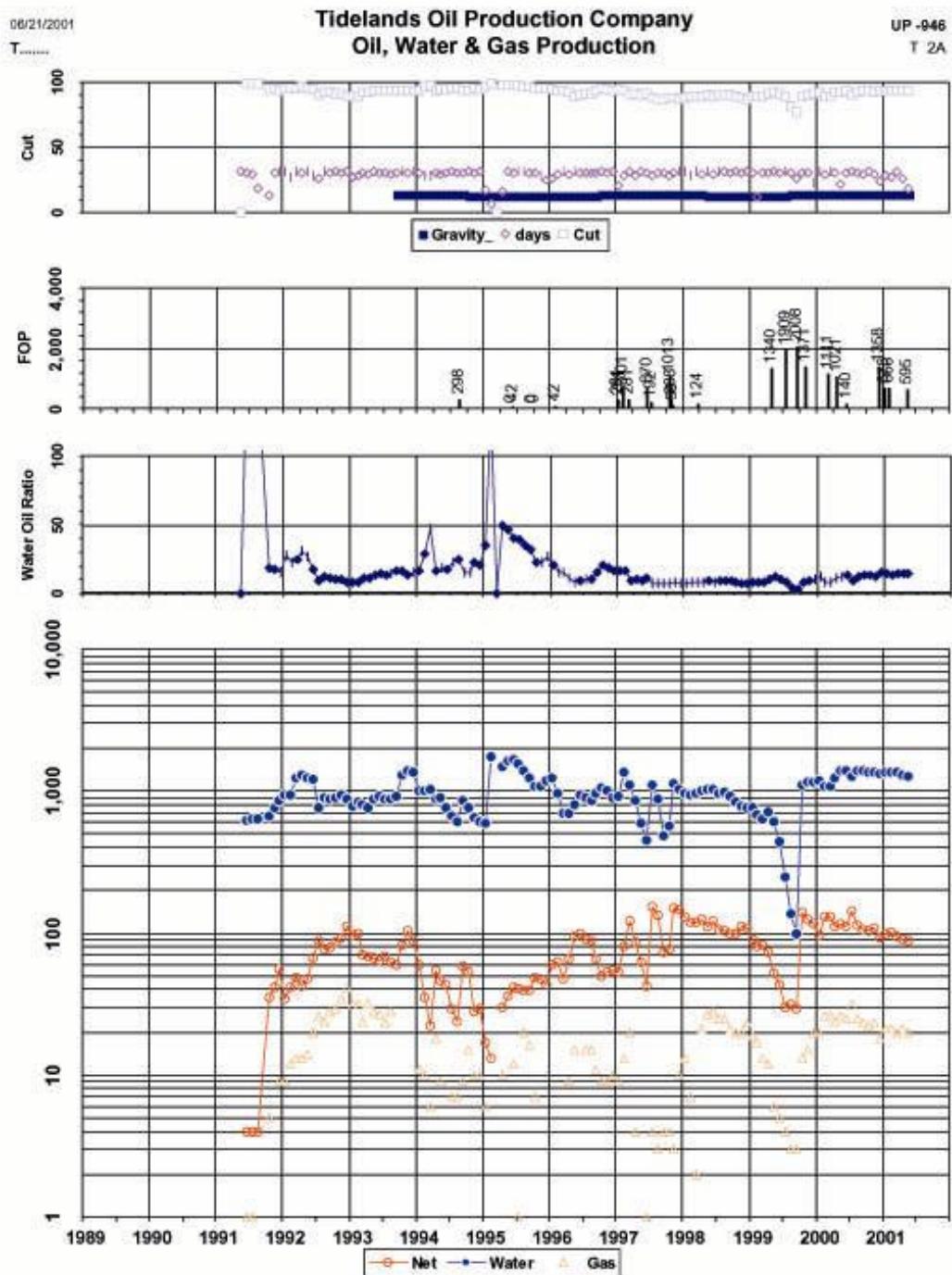
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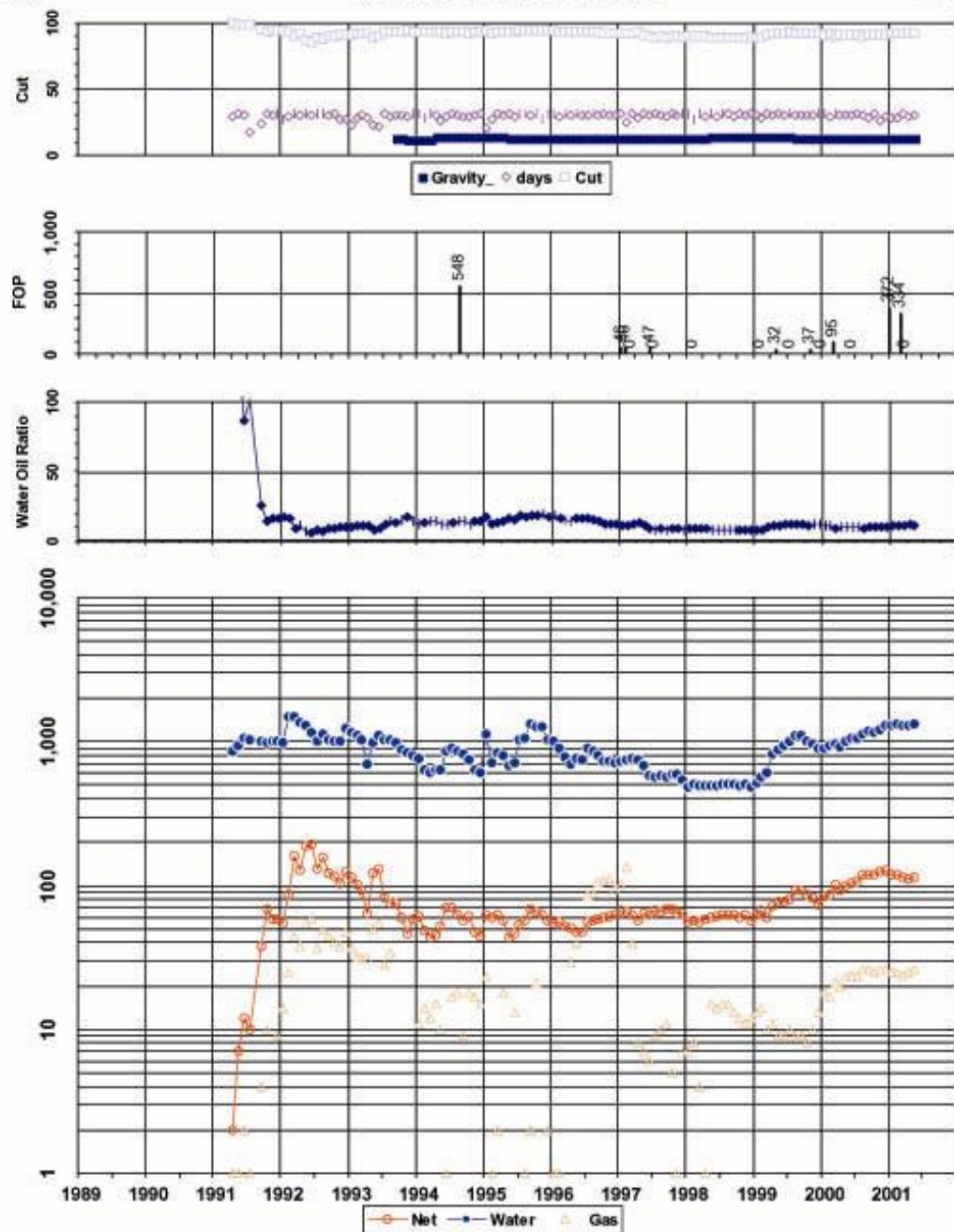


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06/21/2001
T.....

Tidelands Oil Production Company
Oil, Water & Gas Production

UP -947
T 2A

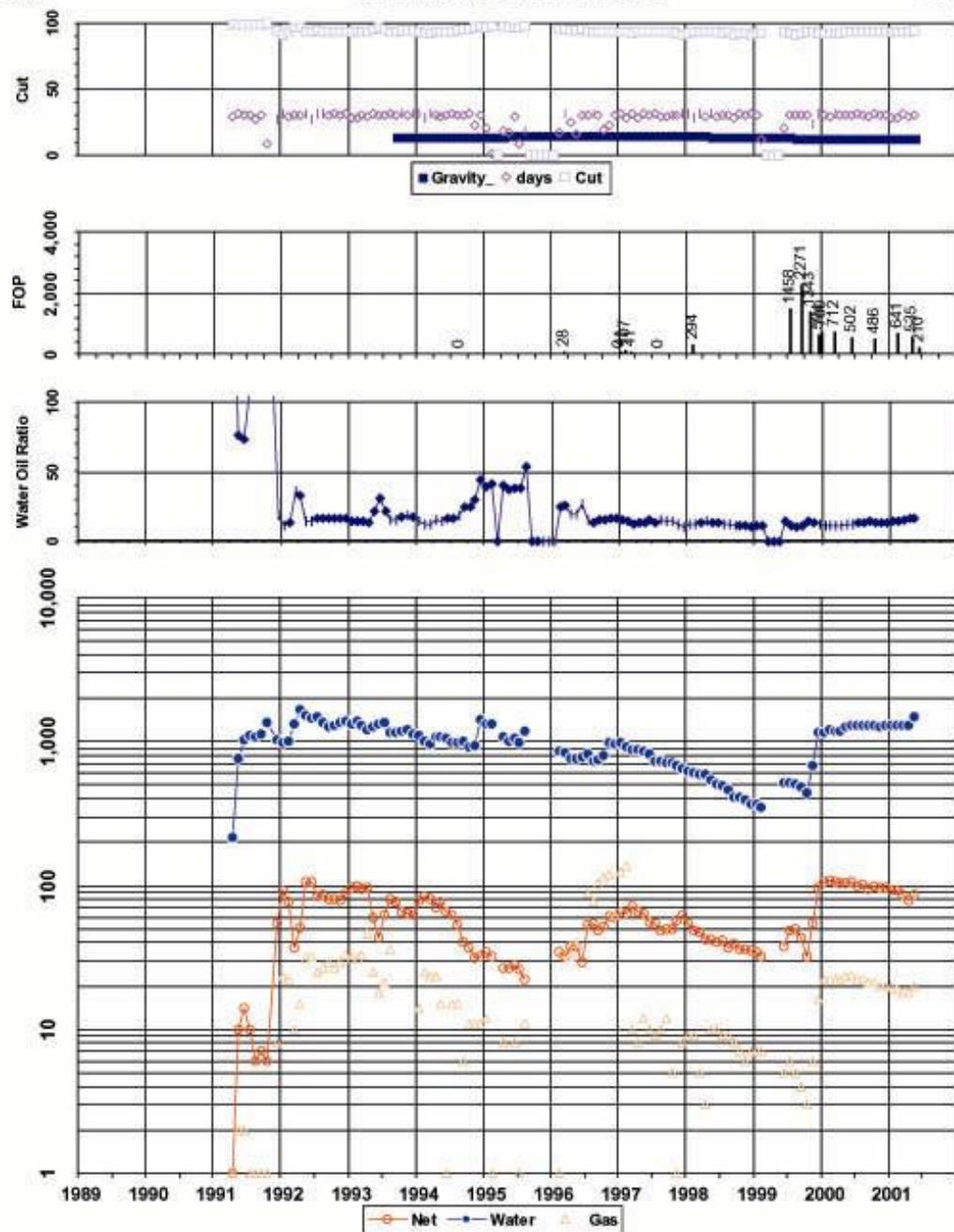


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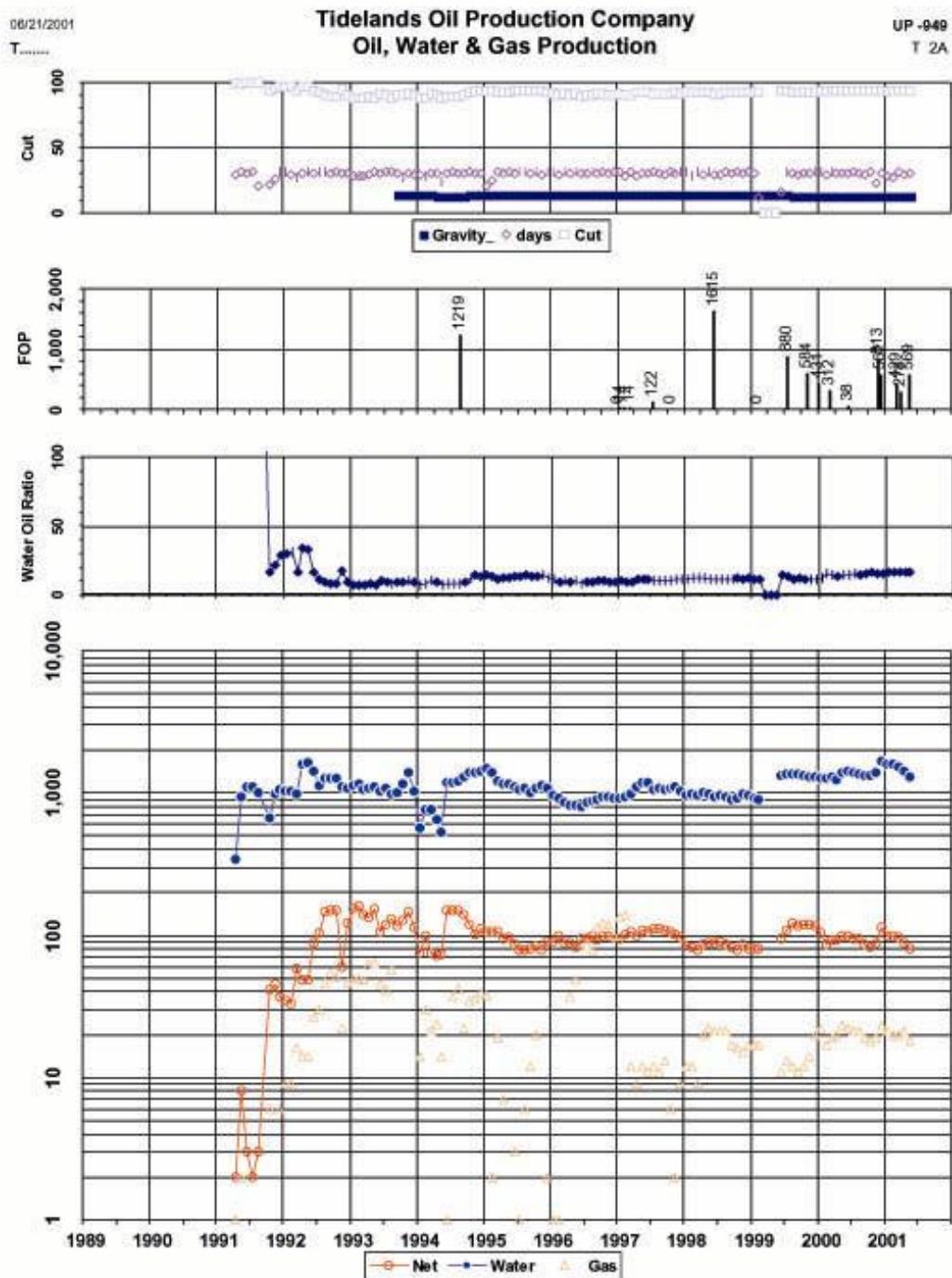
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T.....

Tidelands Oil Production Company
Oil, Water & Gas Production

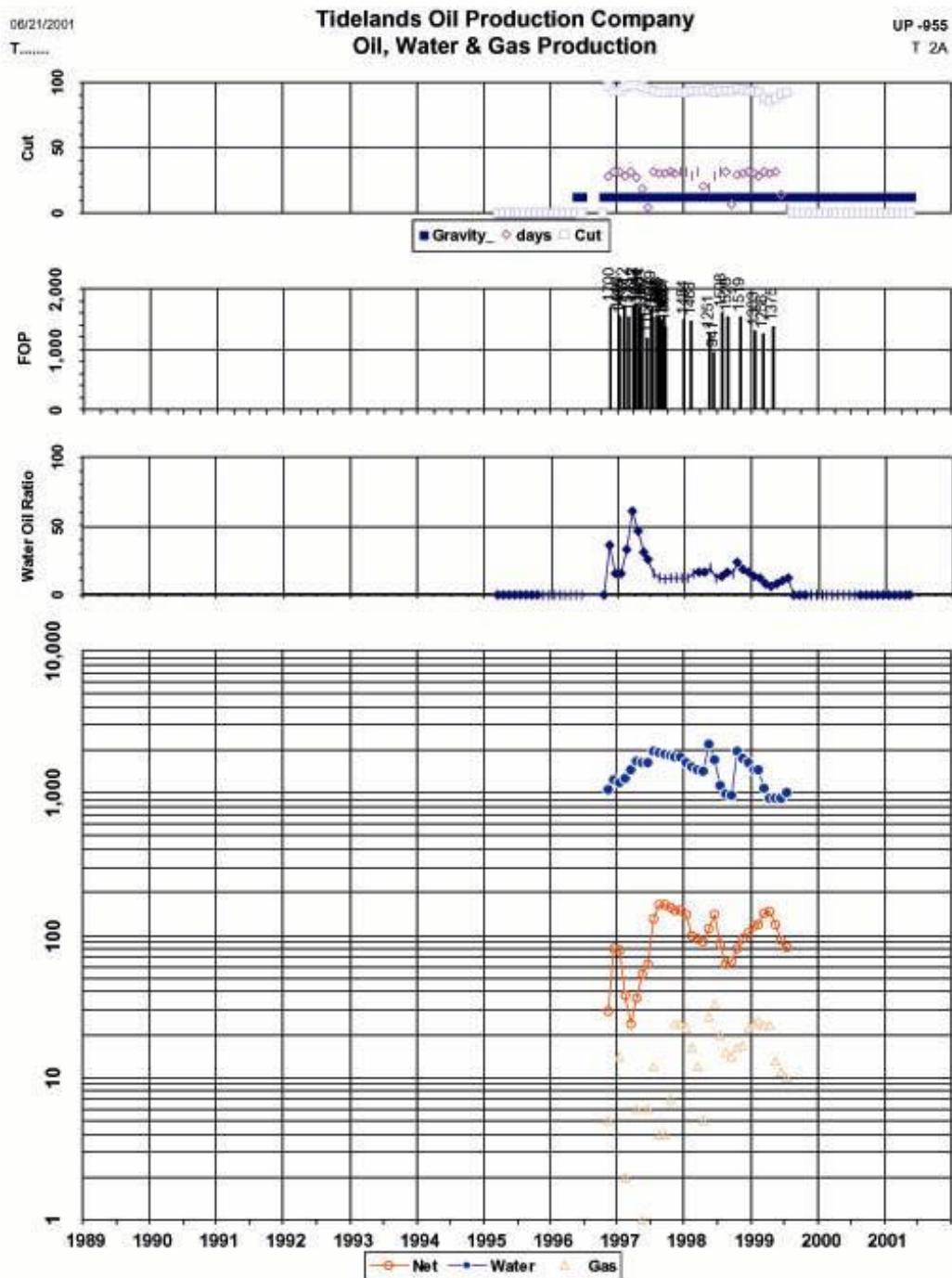
UP -948
T 2A

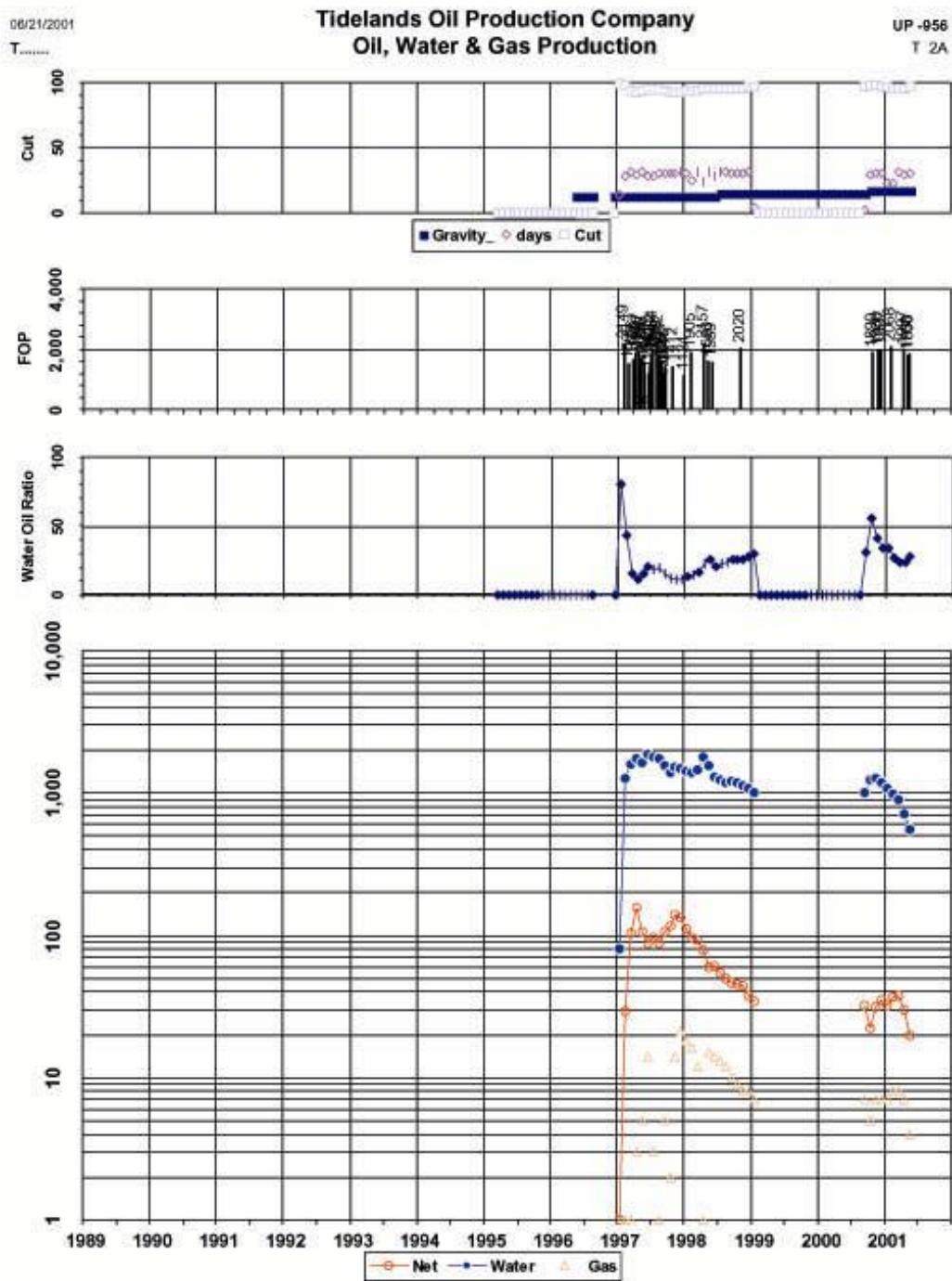


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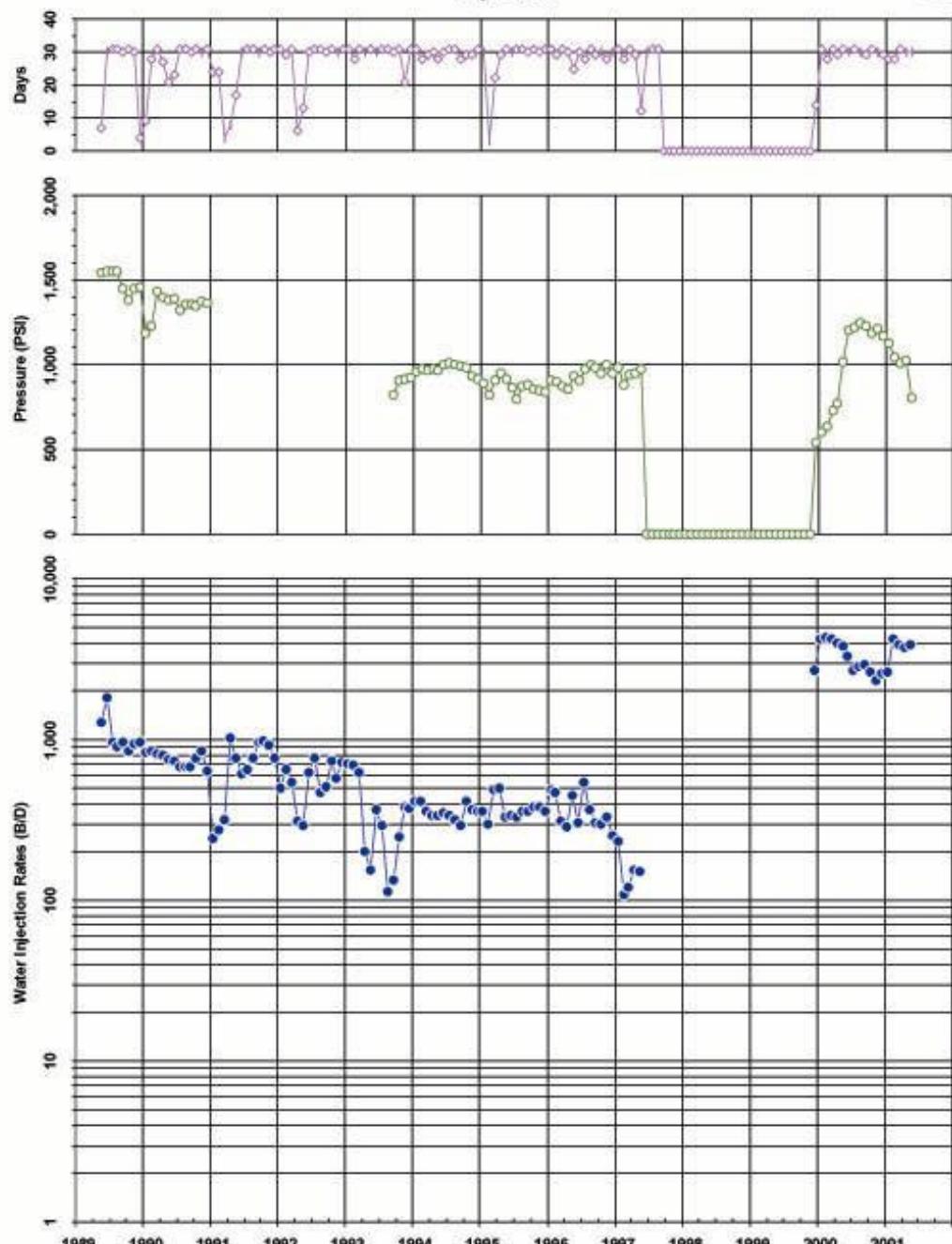


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06/21/2001
T

Tidelands Oil Production Company
Injection

2AT-020
T 2A

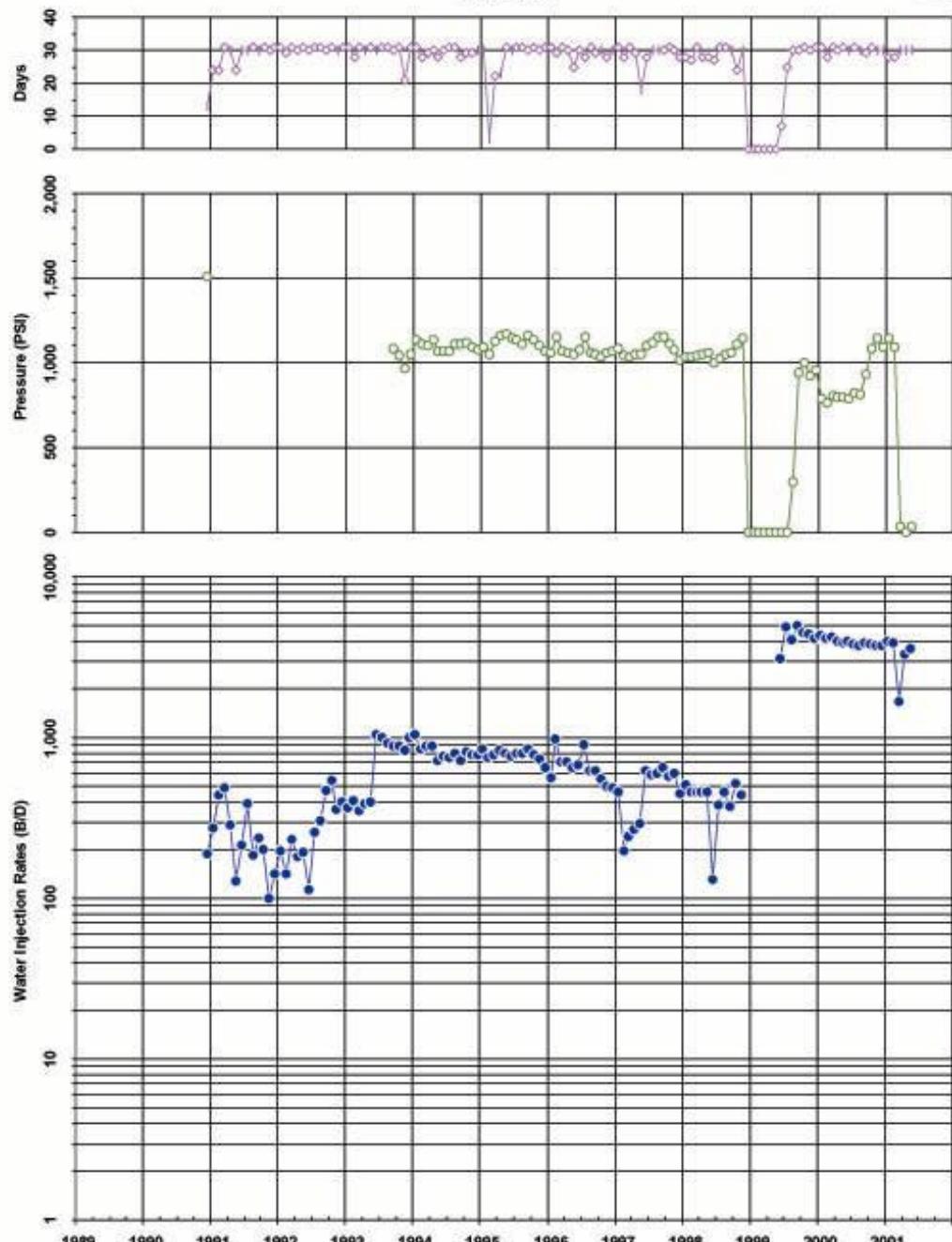


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T

Tidelands Oil Production Company
Injection

2AT-048
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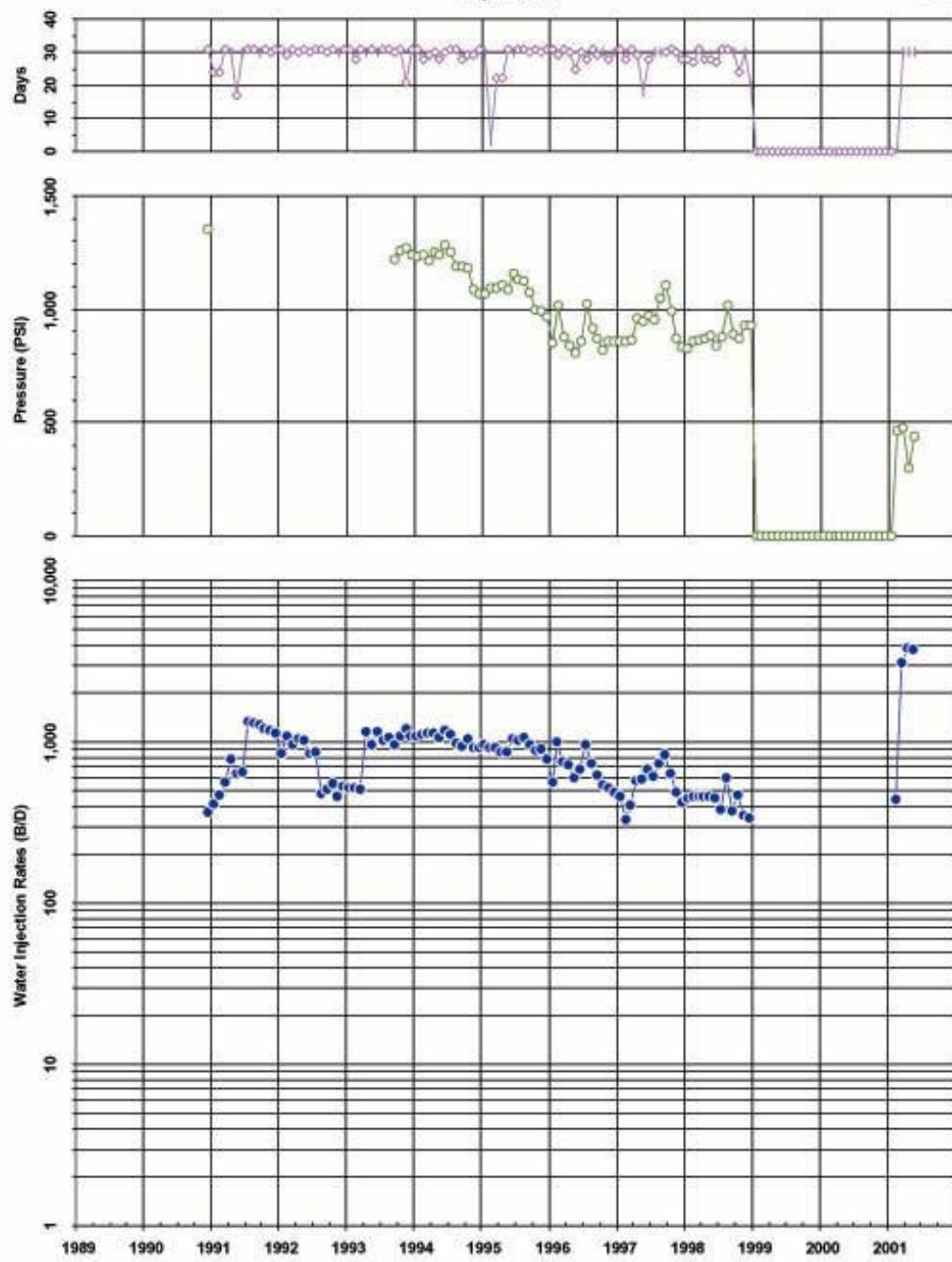


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06/21/2001
D1

Tidelands Oil Production Company
Injection

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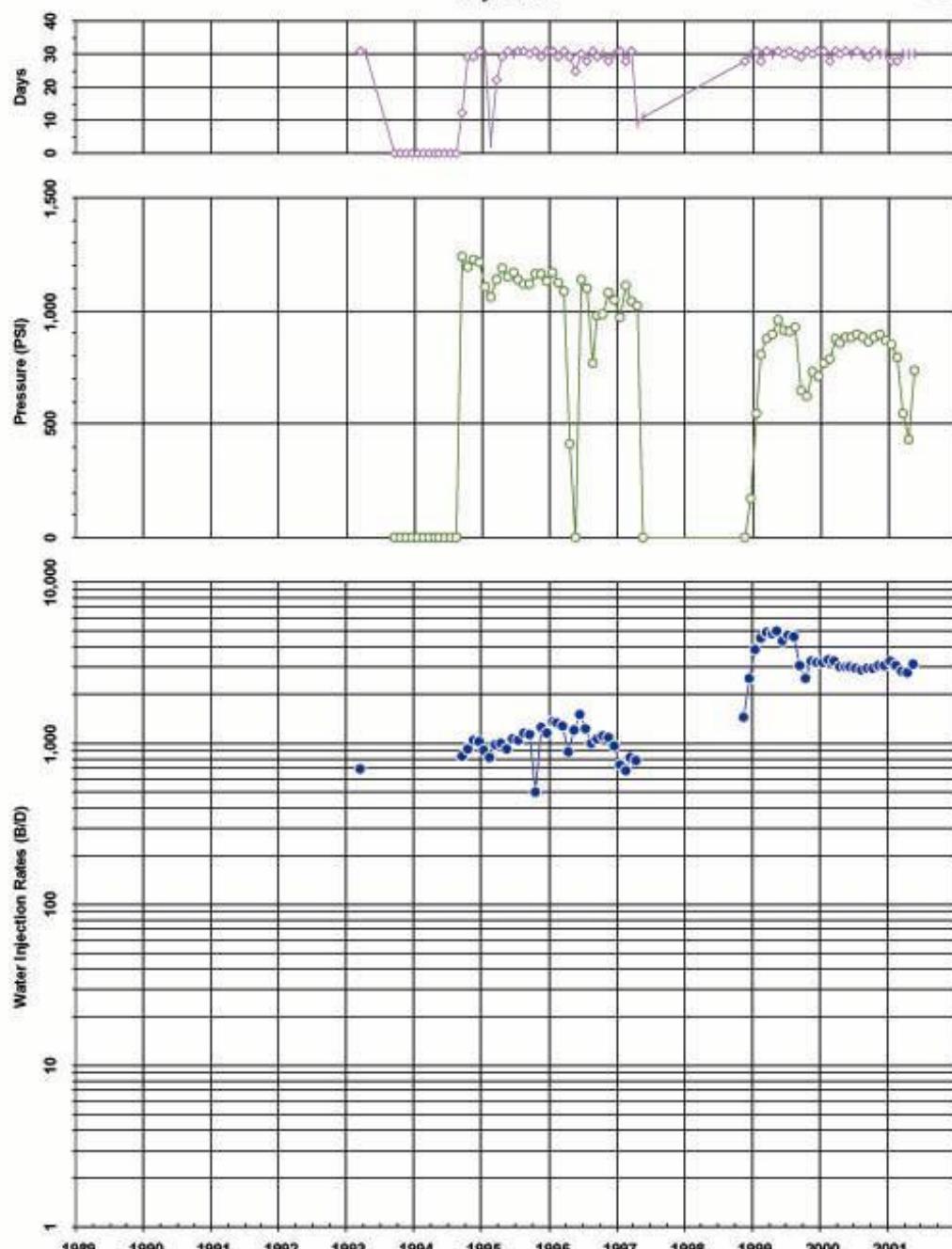


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06/21/2001
D1

Tidelands Oil Production Company
Injection

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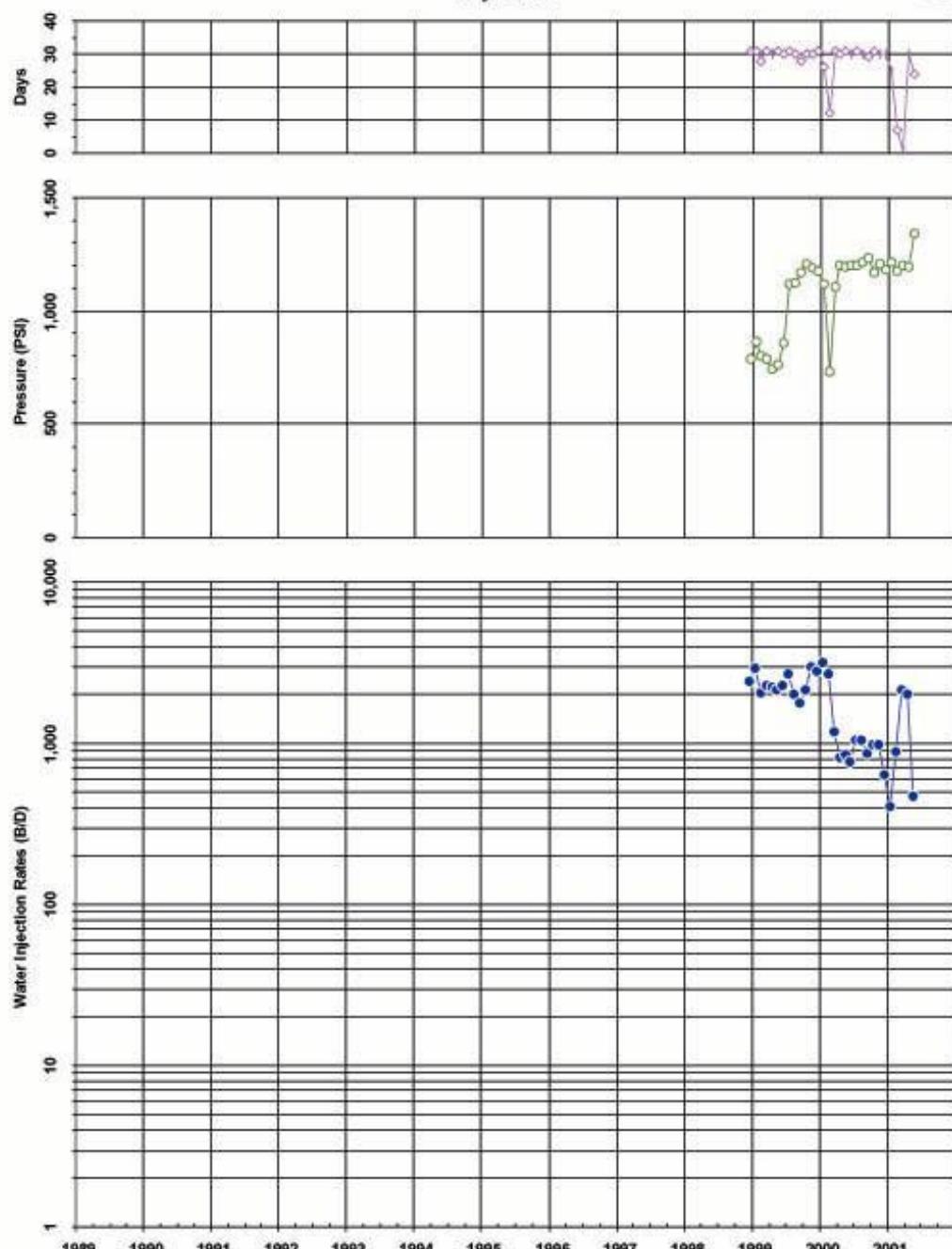


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06/21/2001
T D1 D2

**Tidelands Oil Production Company
Injection**

901-UP
T 2A

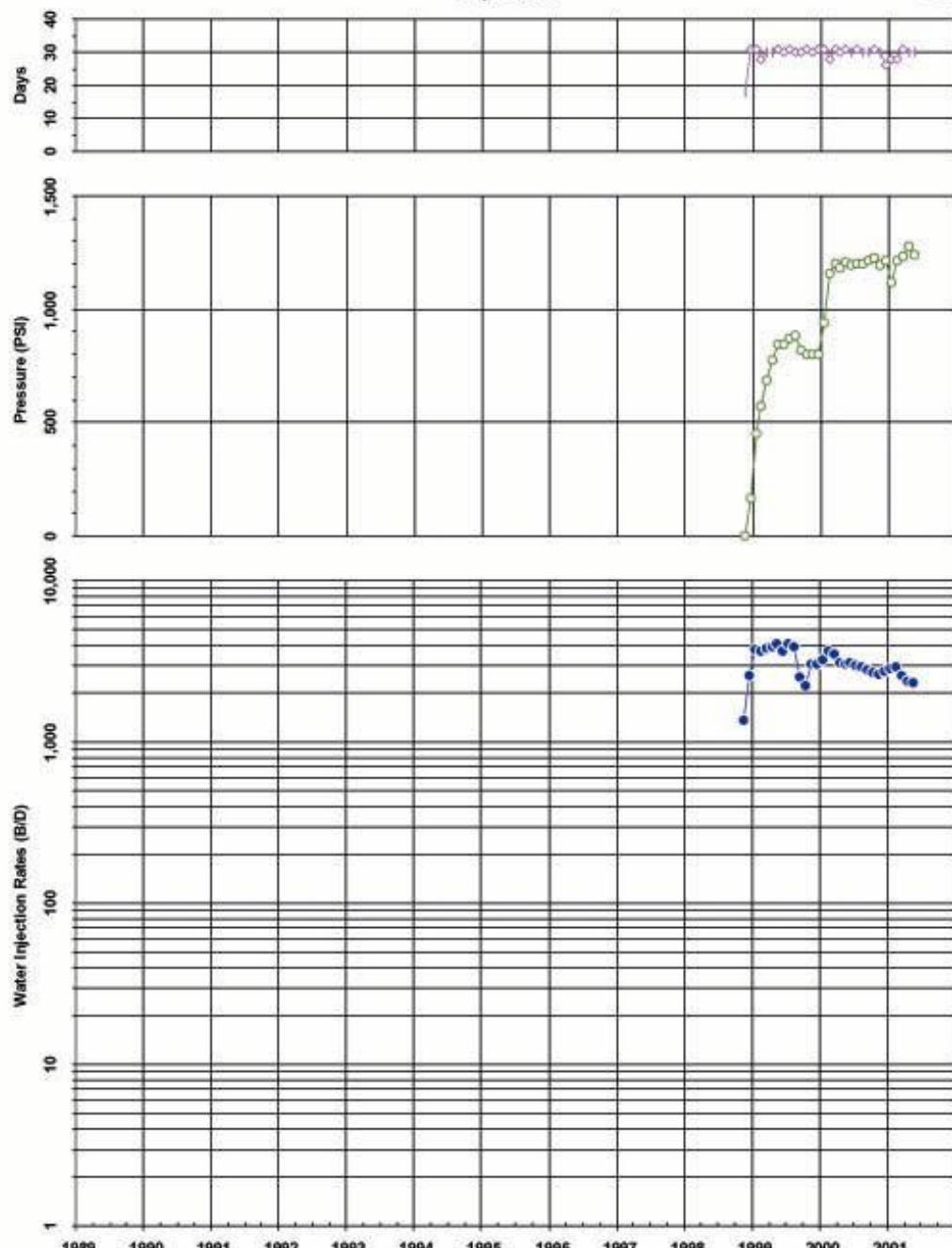


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06/21/2001
T D1 D2

Tidelands Oil Production Company
Injection

935-UP
T 2A

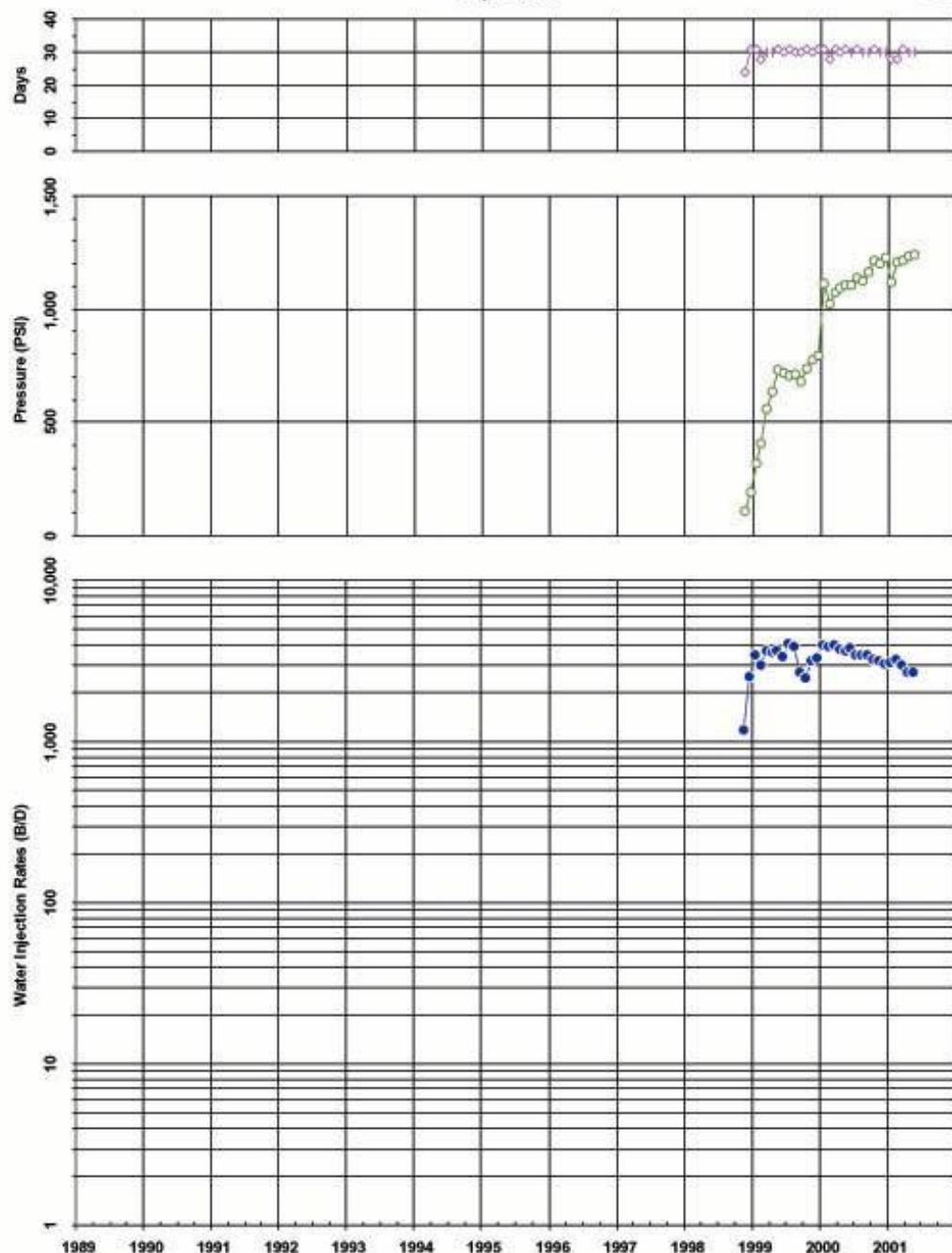


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06/21/2001
T D1 D2

Tidelands Oil Production Company
Injection

937-UP
T 2A

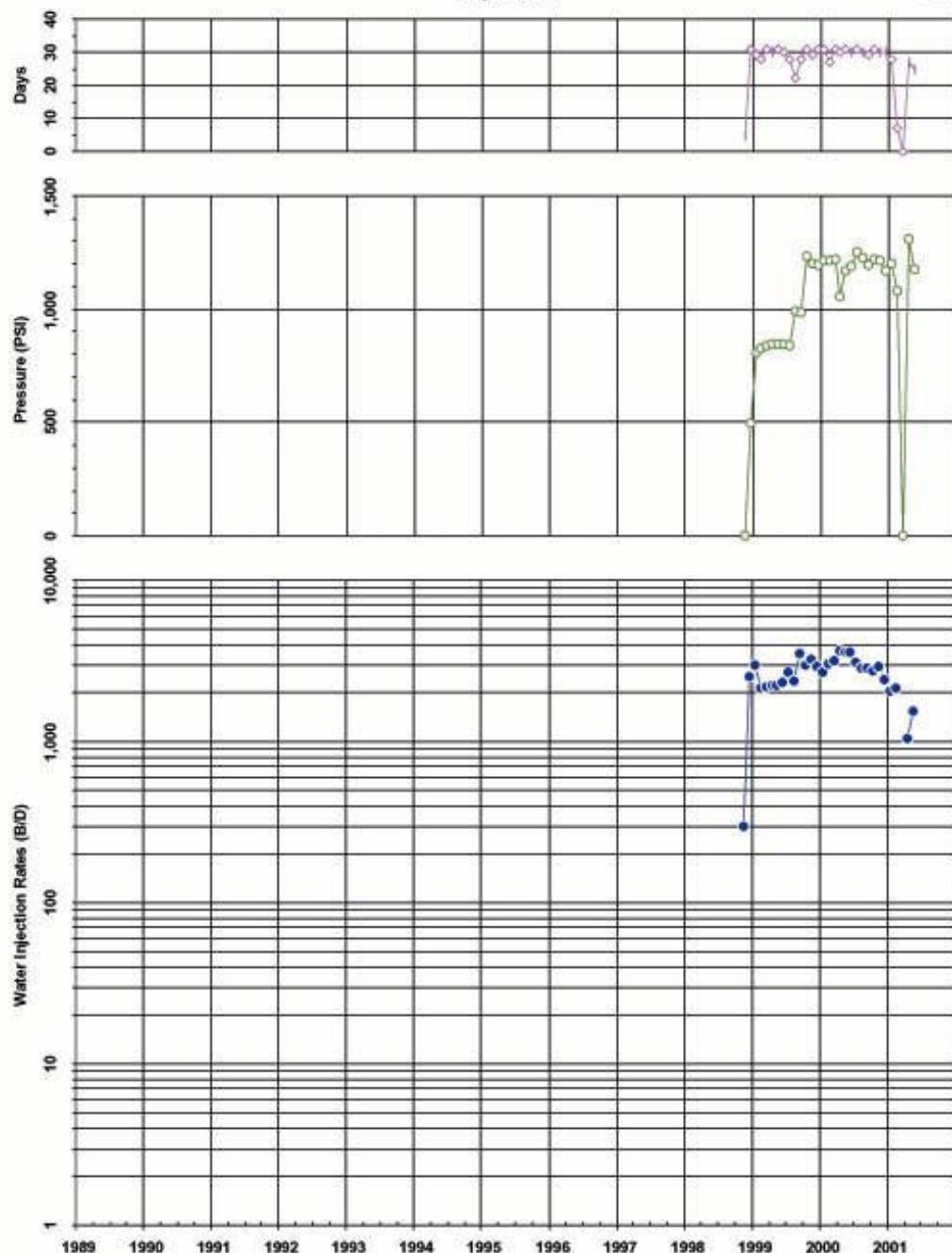


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06/21/2001
T D1

**Tidelands Oil Production Company
Injection**

943-UP
T 2A

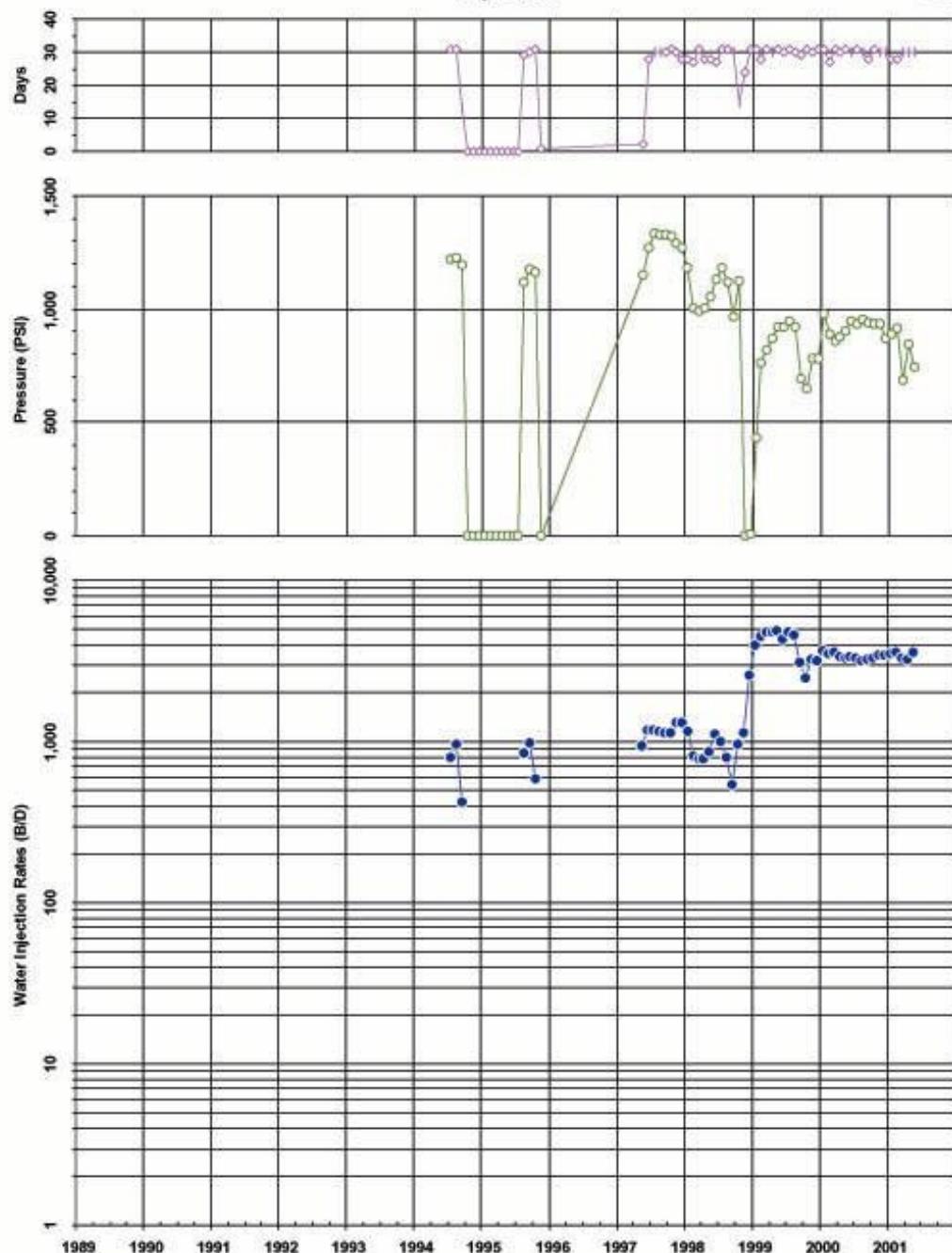


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06/21/2001
D1 D2

Tidelands Oil Production Company
Injection

951-UP
T 2A

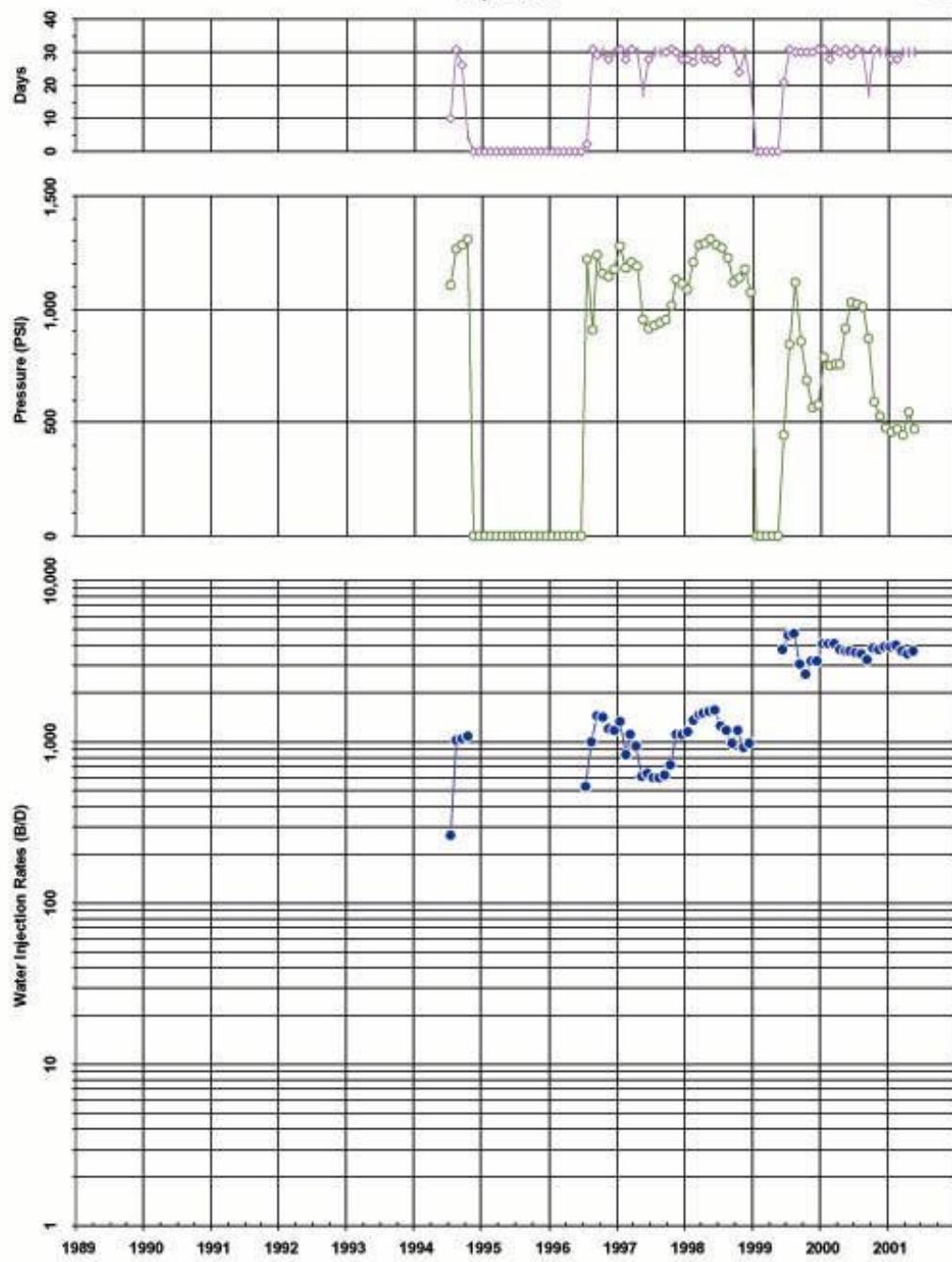


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06/21/2001
D1 D2

**Tidelands Oil Production Company
Injection**

953-UP
T 2A

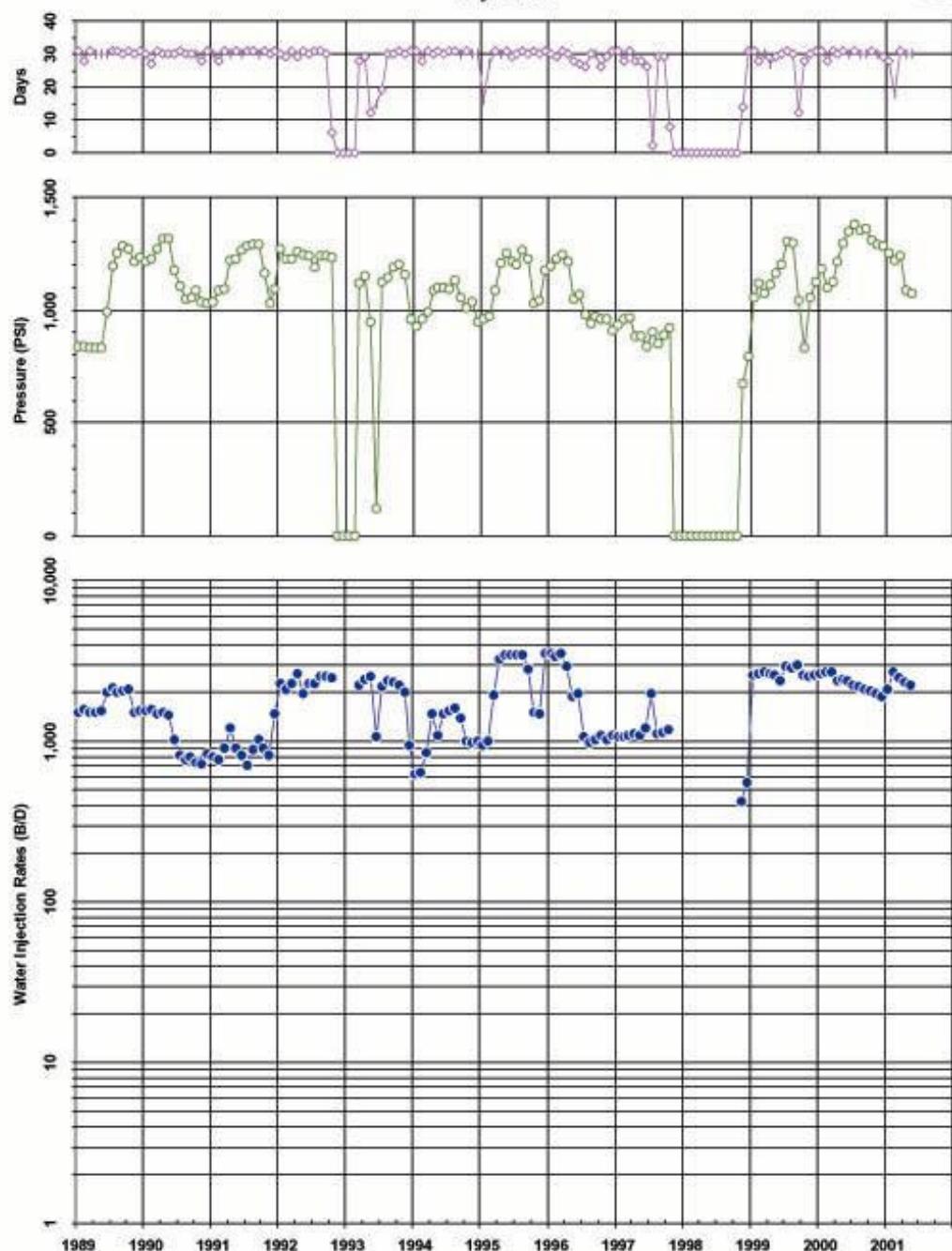


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06/21/2001
D1 F H G

Tidelands Oil Production Company
Injection

FW -088
T 2A

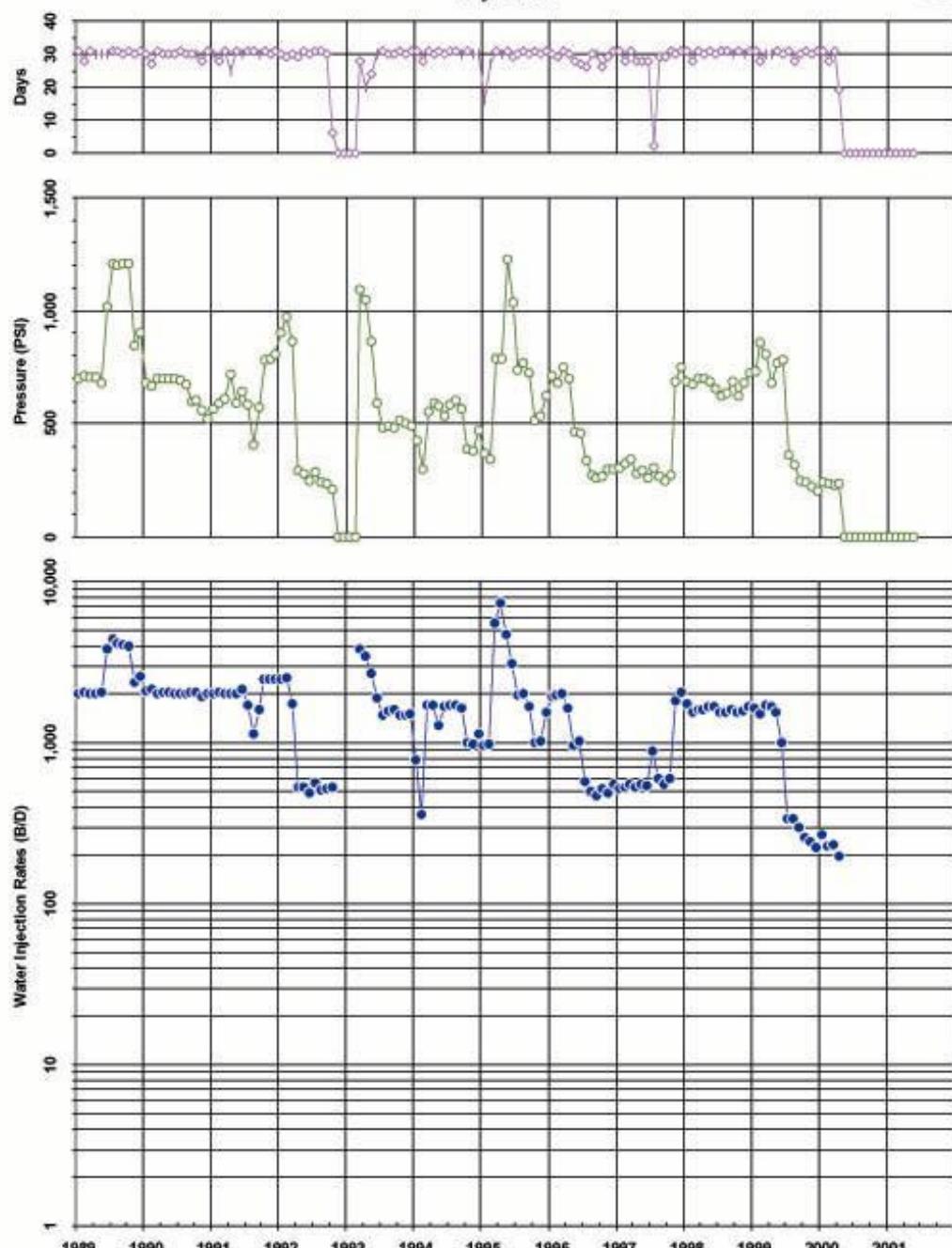


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06/21/2001
T D1 D2

Tidelands Oil Production Company
Injection

FW -101
T 2A

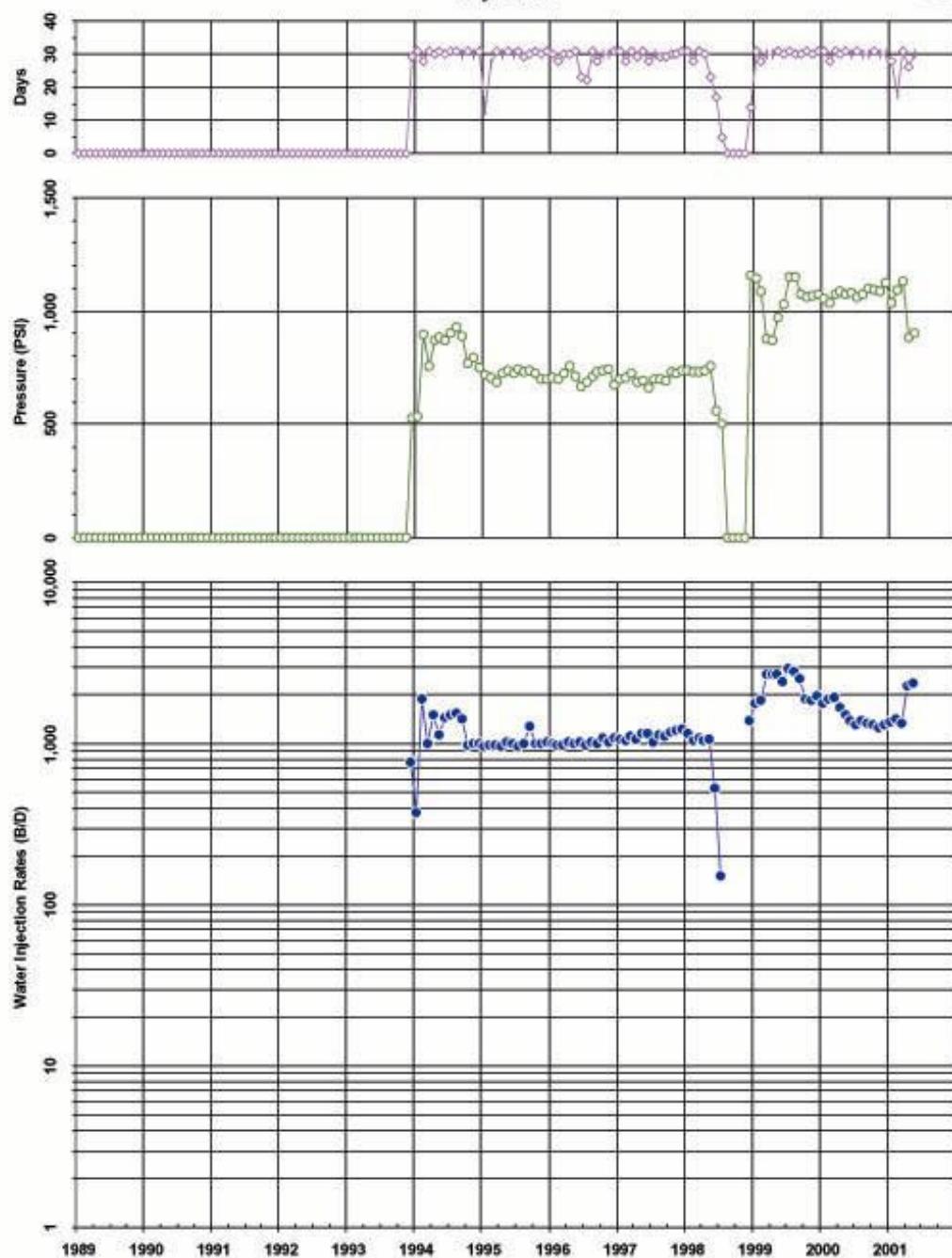


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06/21/2001
T

Tidelands Oil Production Company
Injection

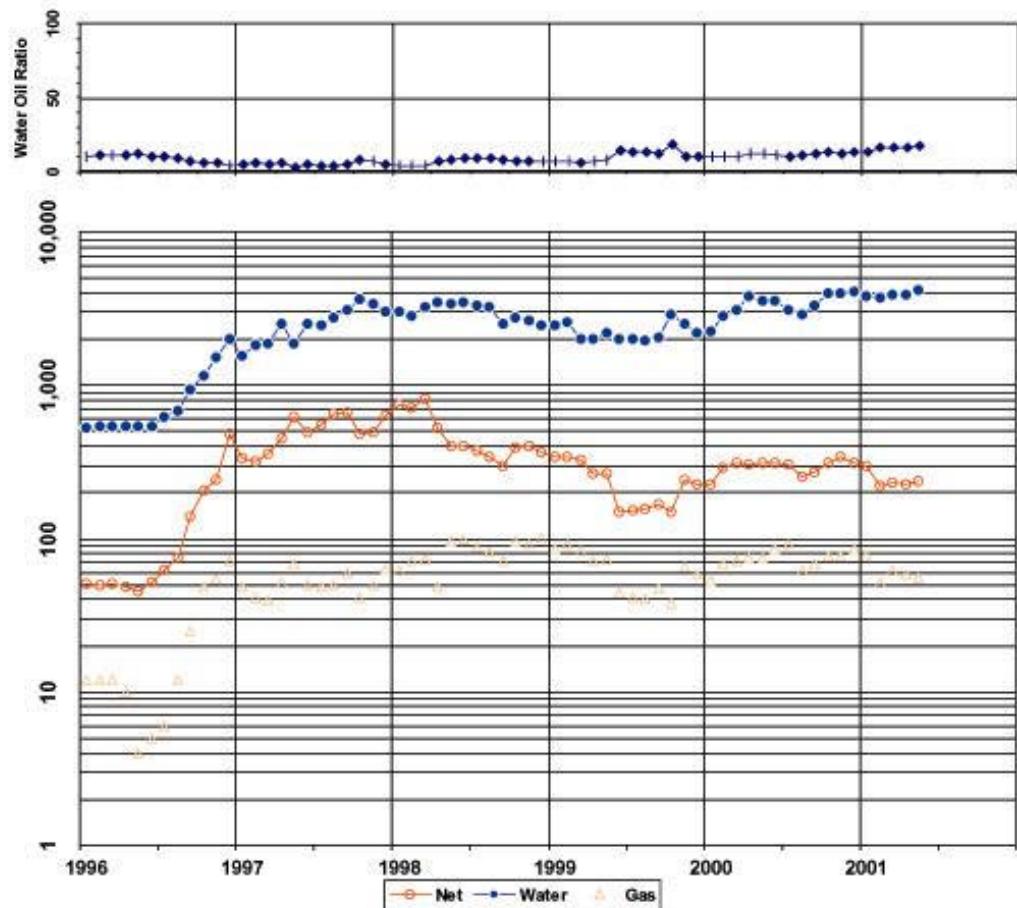
FW -103
T 2A



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**Tidelands Oil Production Company
Oil, Water & Gas Production**

A -186, A -195, A -320, J -201, J -202, J -203, J -204, J -205

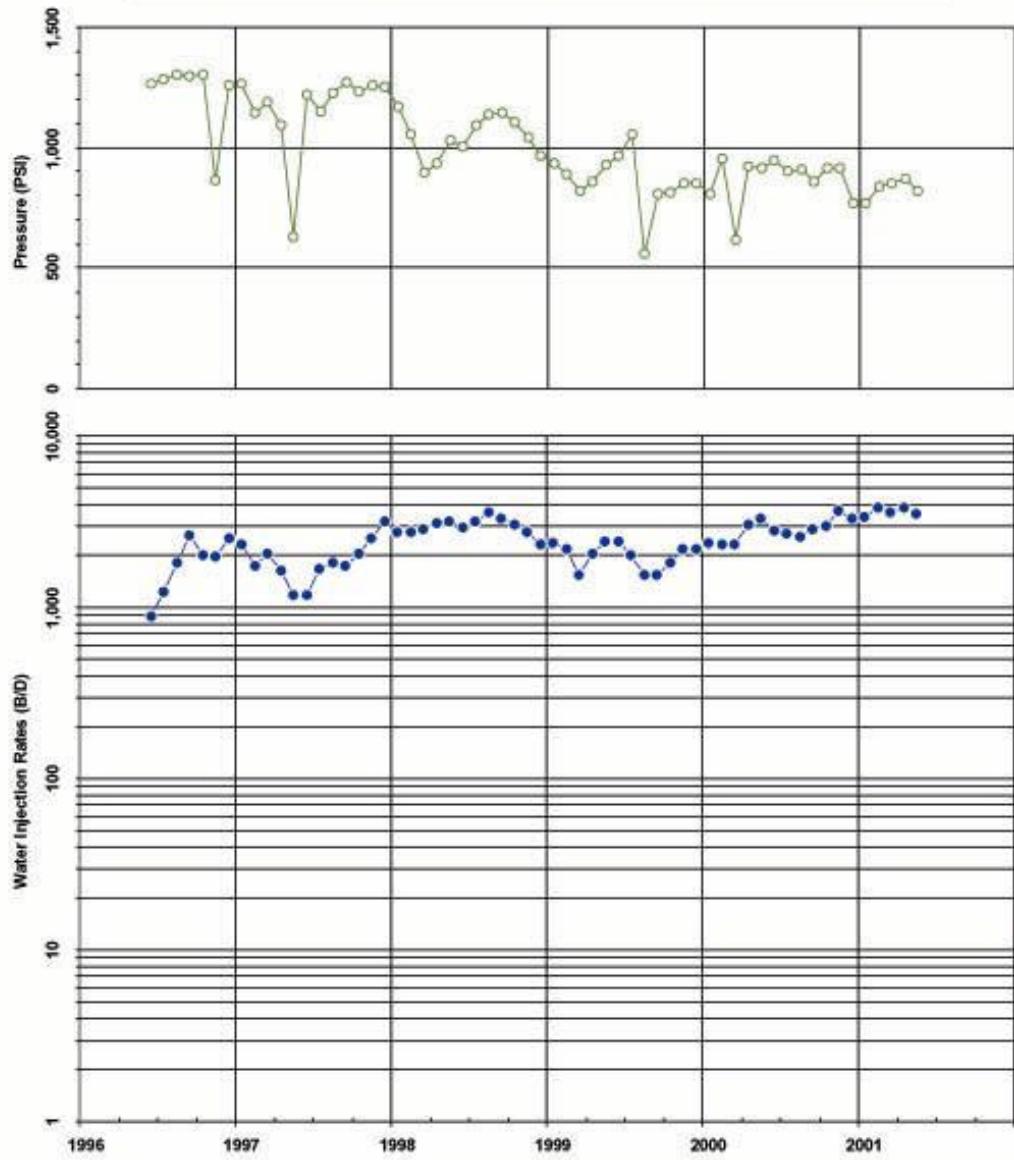


06/21/2001

**Tidelands Oil Production Company
Injection**

Wells

Well Group: PARCEL "A" STEAMFLOOD
FJ -201, FJ -202, FJ -203, FJ -204, FJ -205



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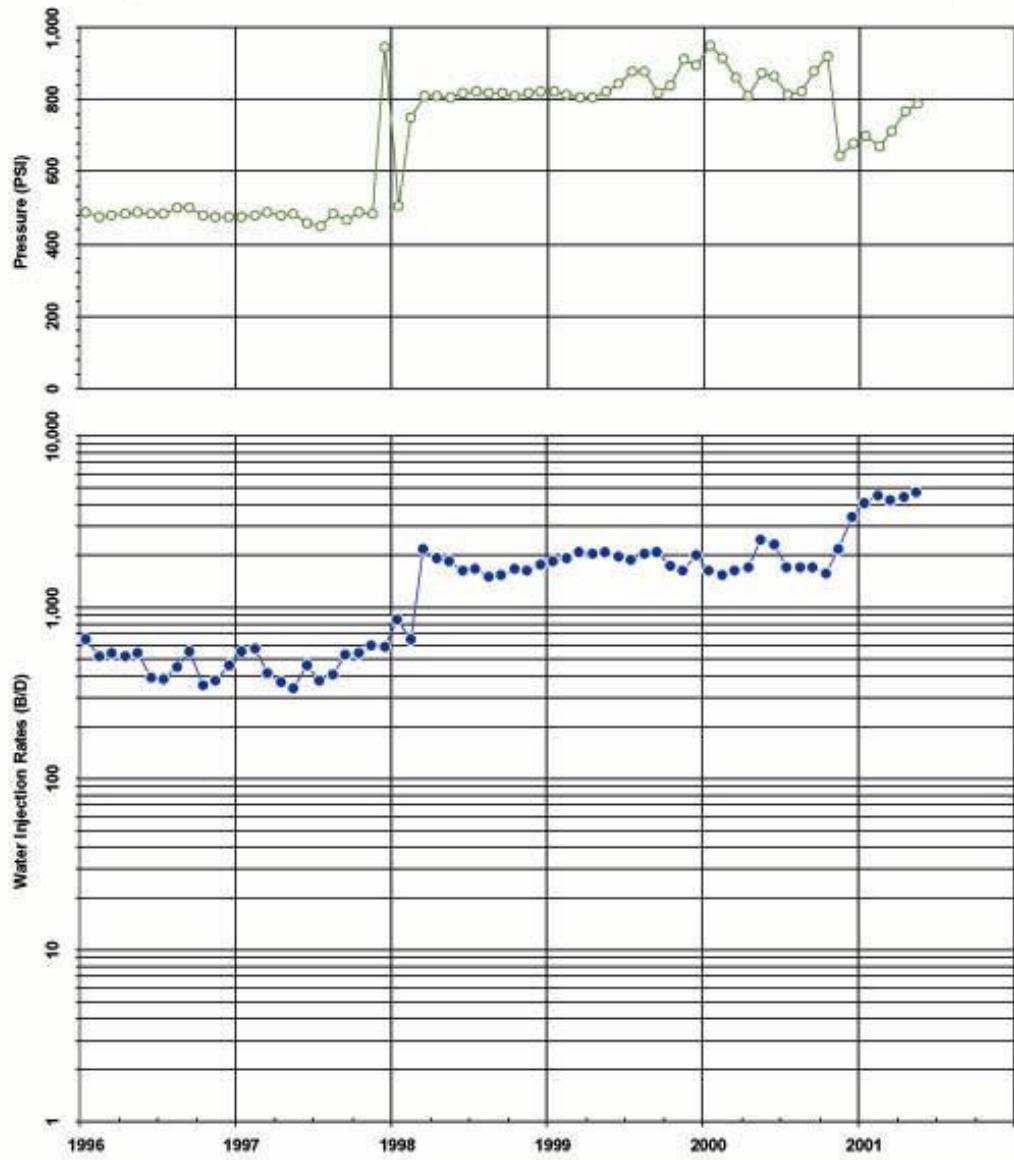
06/21/2001

Tidelands Oil Production Company
Injection

Wells

Well Group:

FR -111, FRA-029, FRA-083

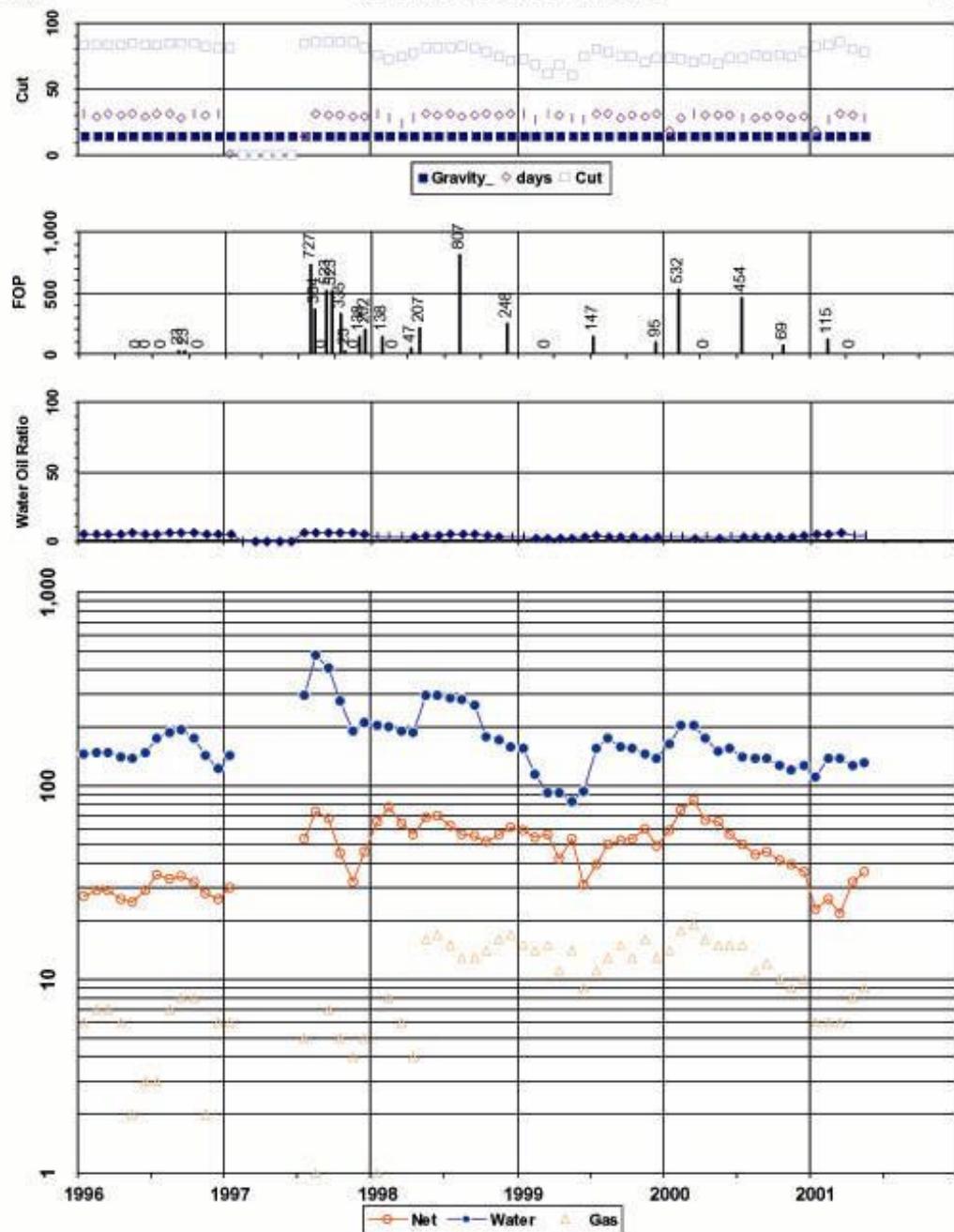


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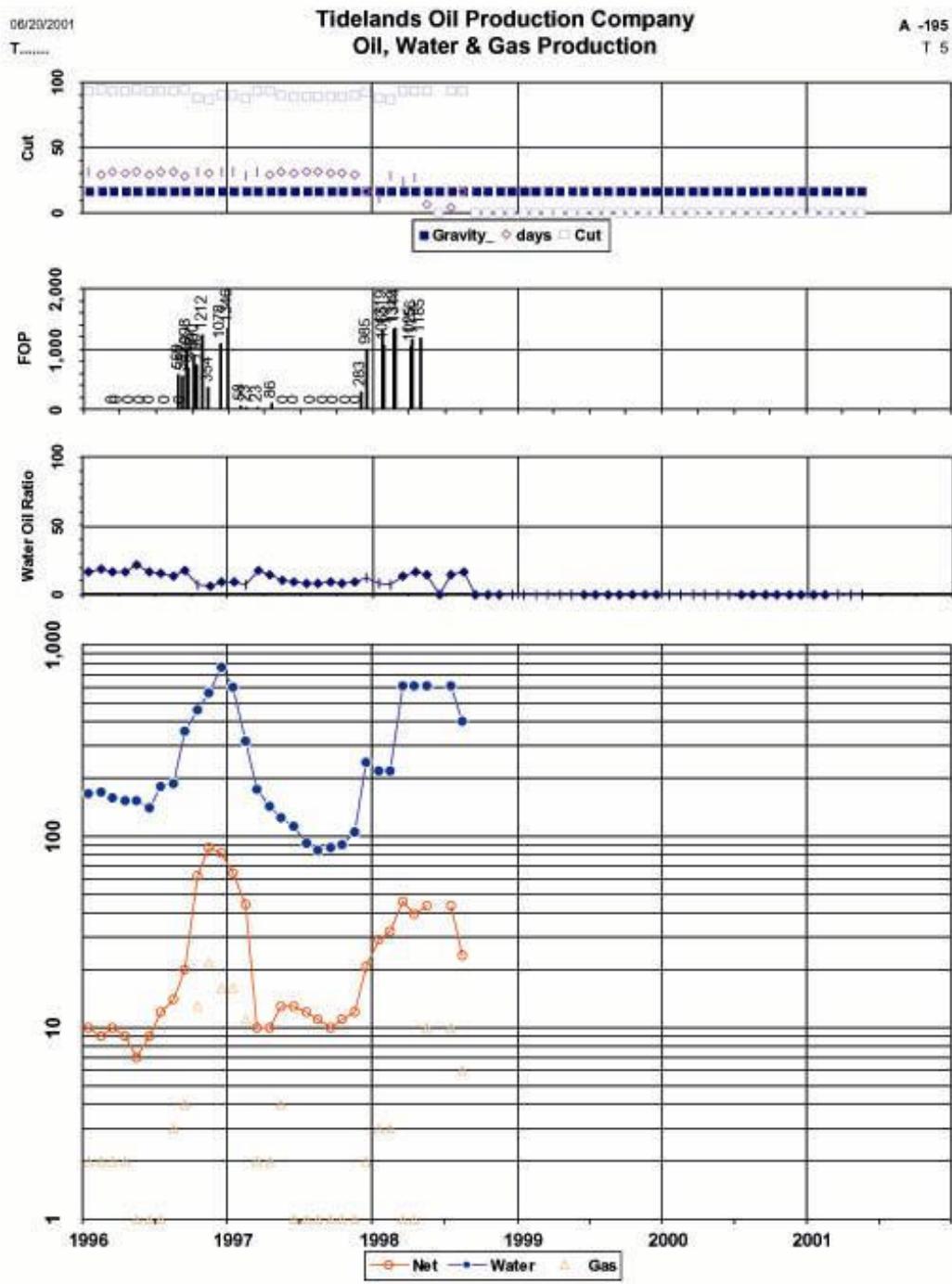
06/29/2001
T.....

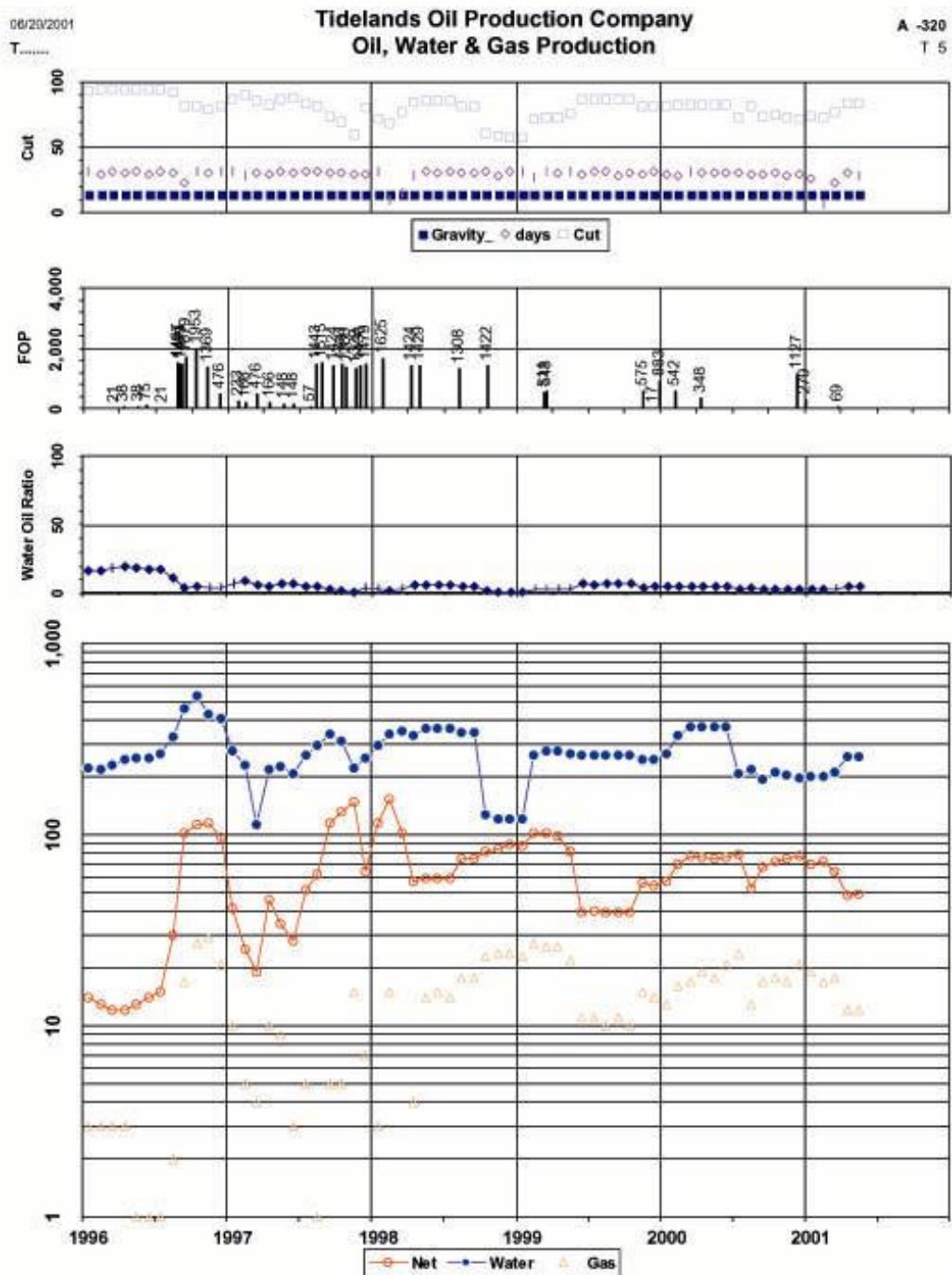
Tidelands Oil Production Company
Oil, Water & Gas Production

A -186
T 5



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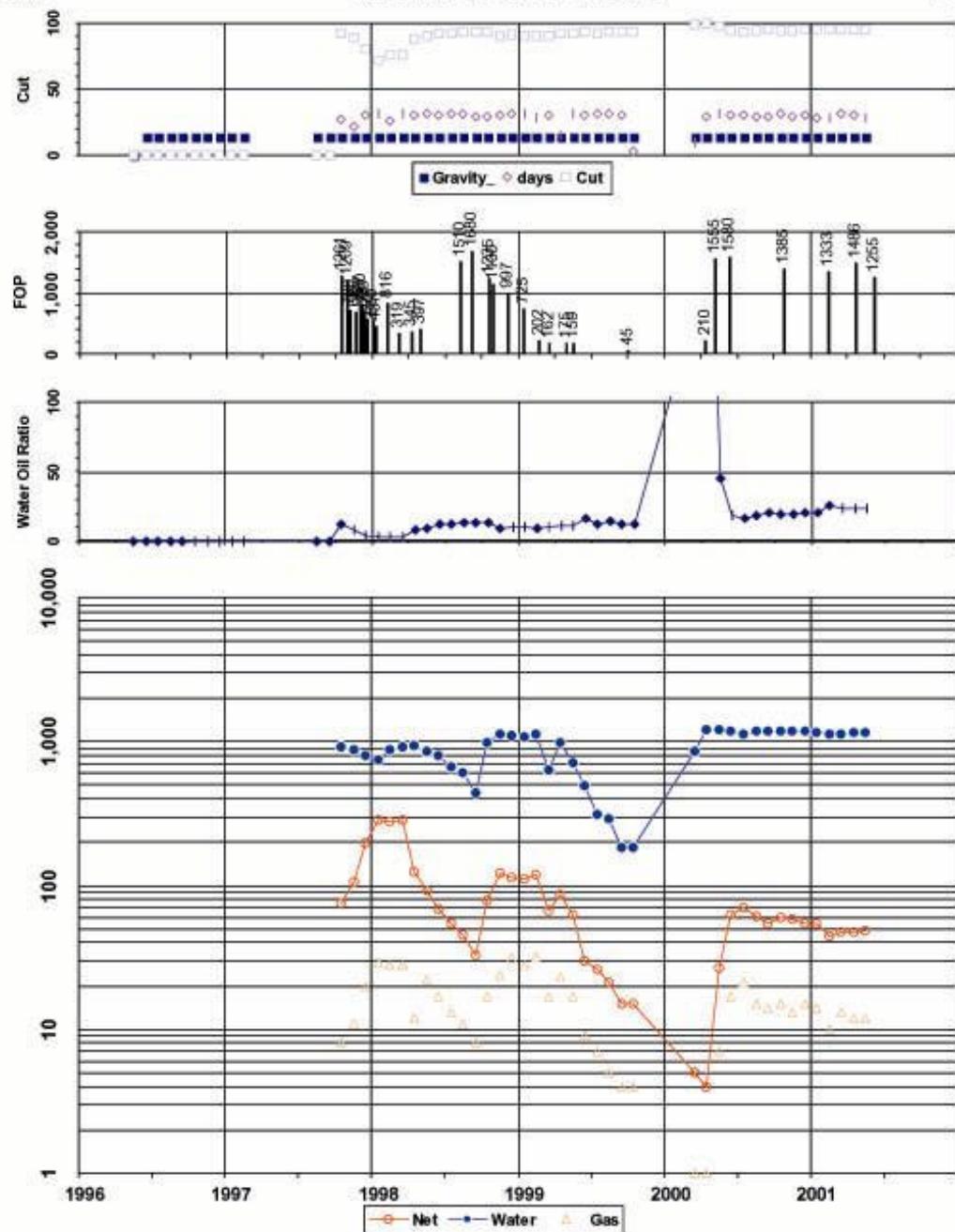


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06/29/2001
T.....

Tidelands Oil Production Company
Oil, Water & Gas Production

J -201
T 5

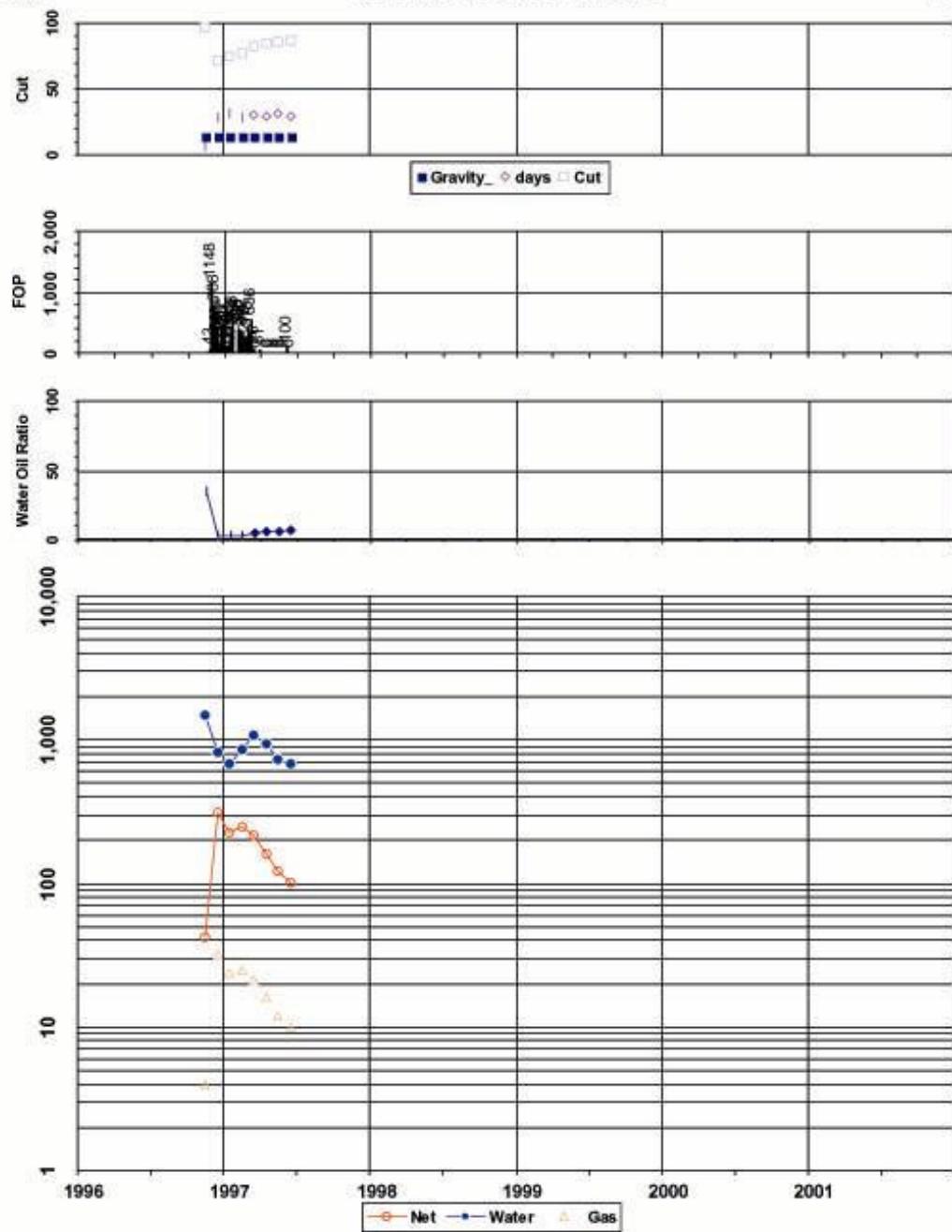


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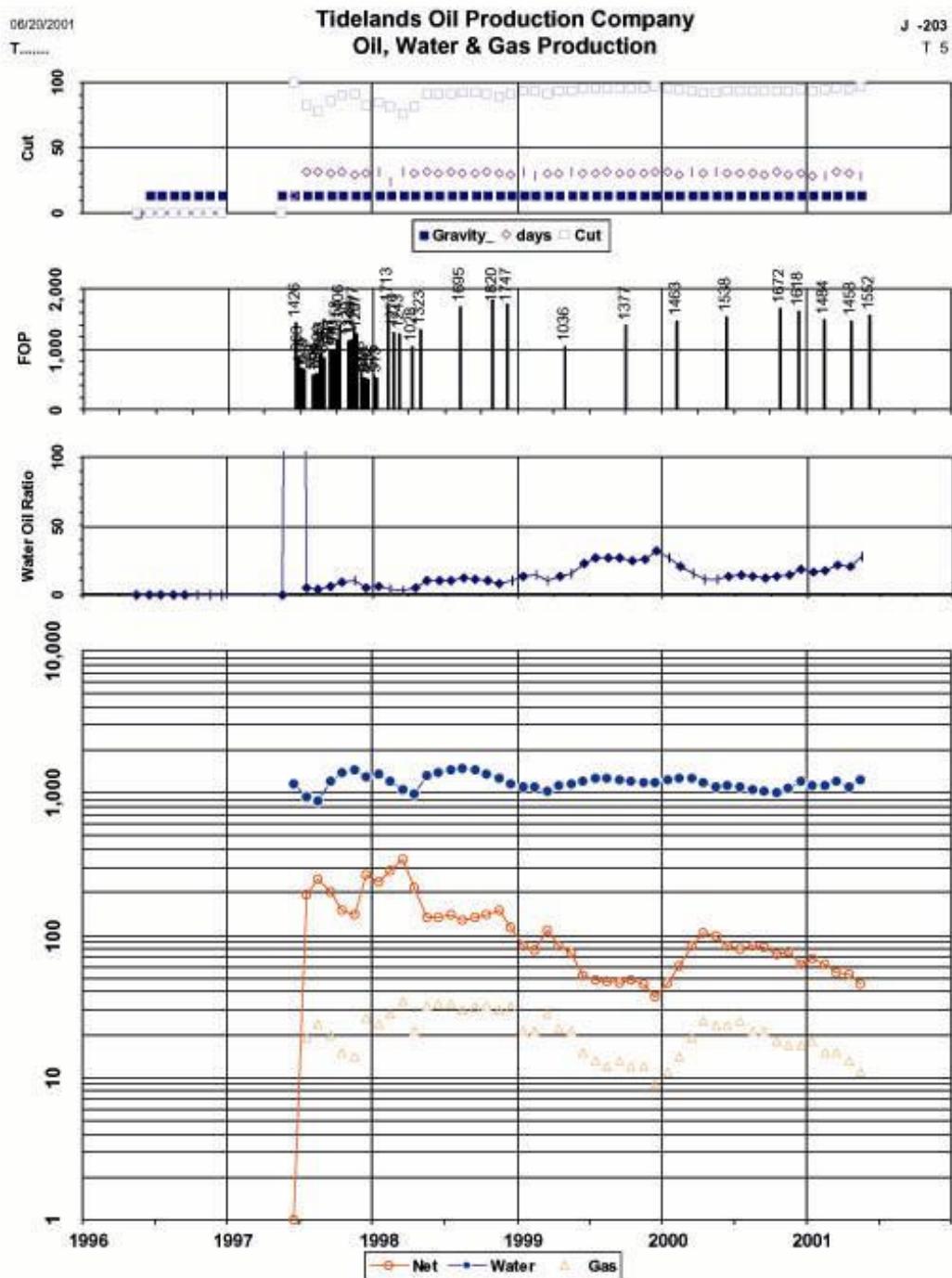
06/29/2001
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Tidelands Oil Production Company
Oil, Water & Gas Production

J -202
T 5



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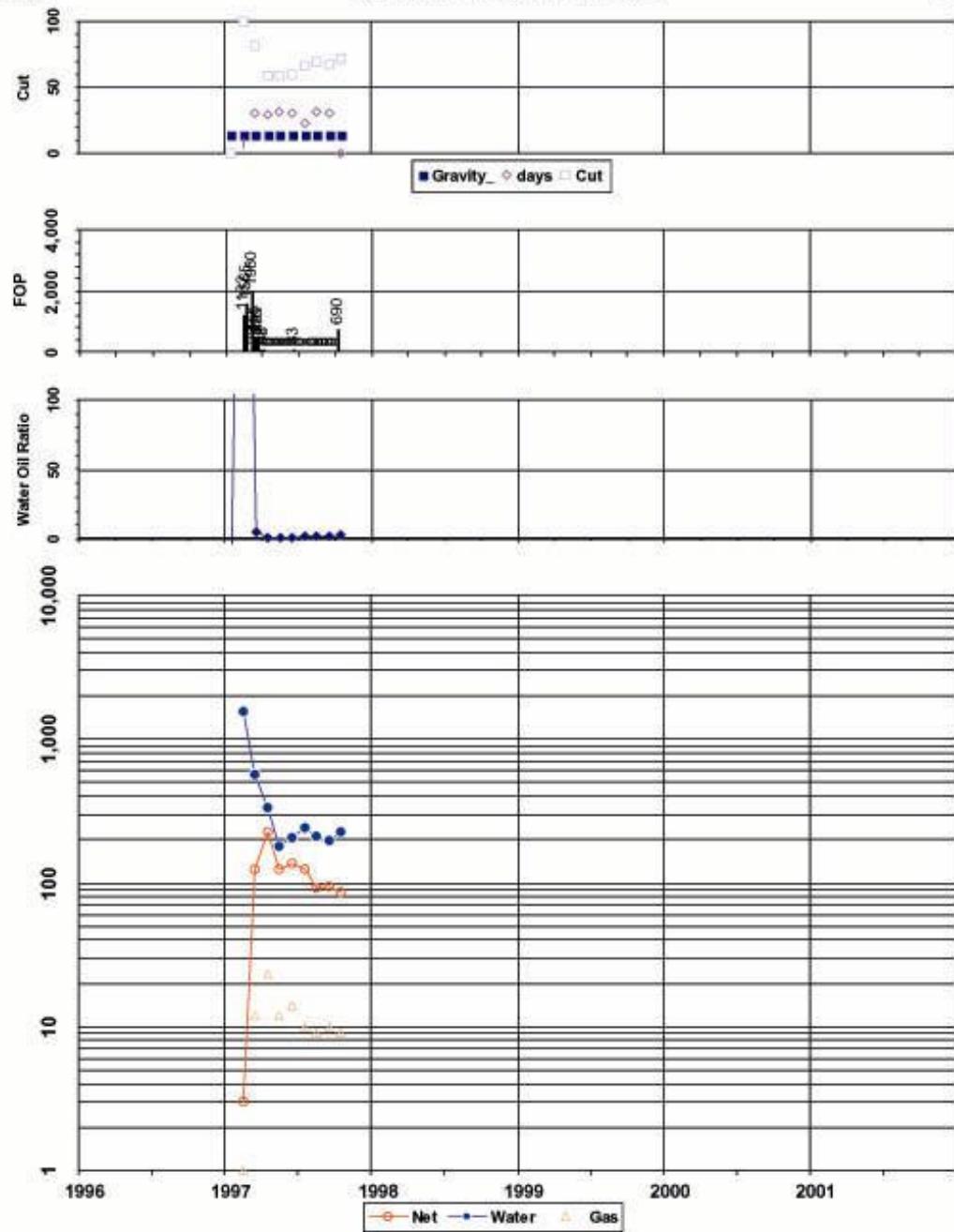


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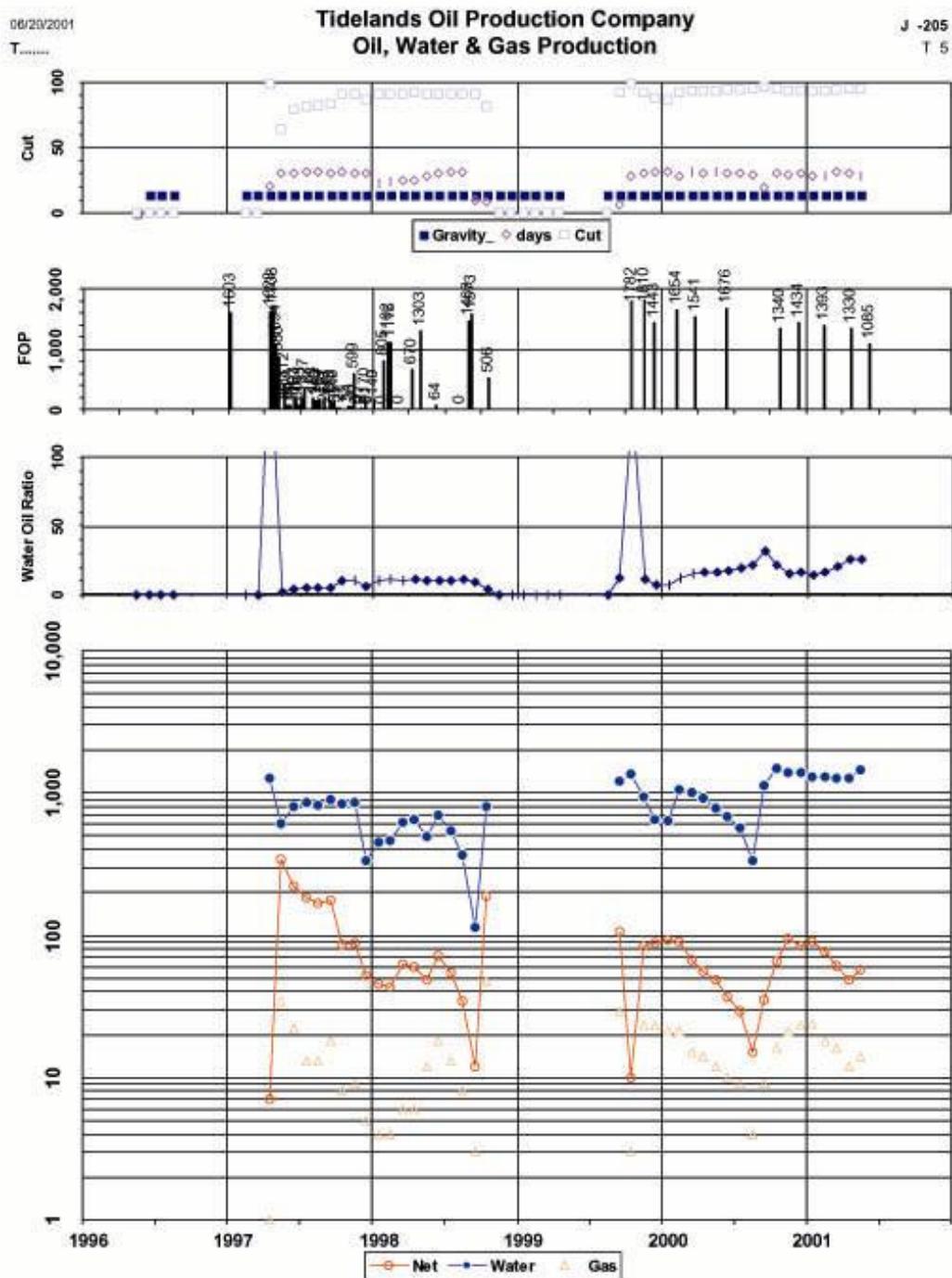
06/29/2001
T.....

Tidelands Oil Production Company
Oil, Water & Gas Production

J -204
T 5



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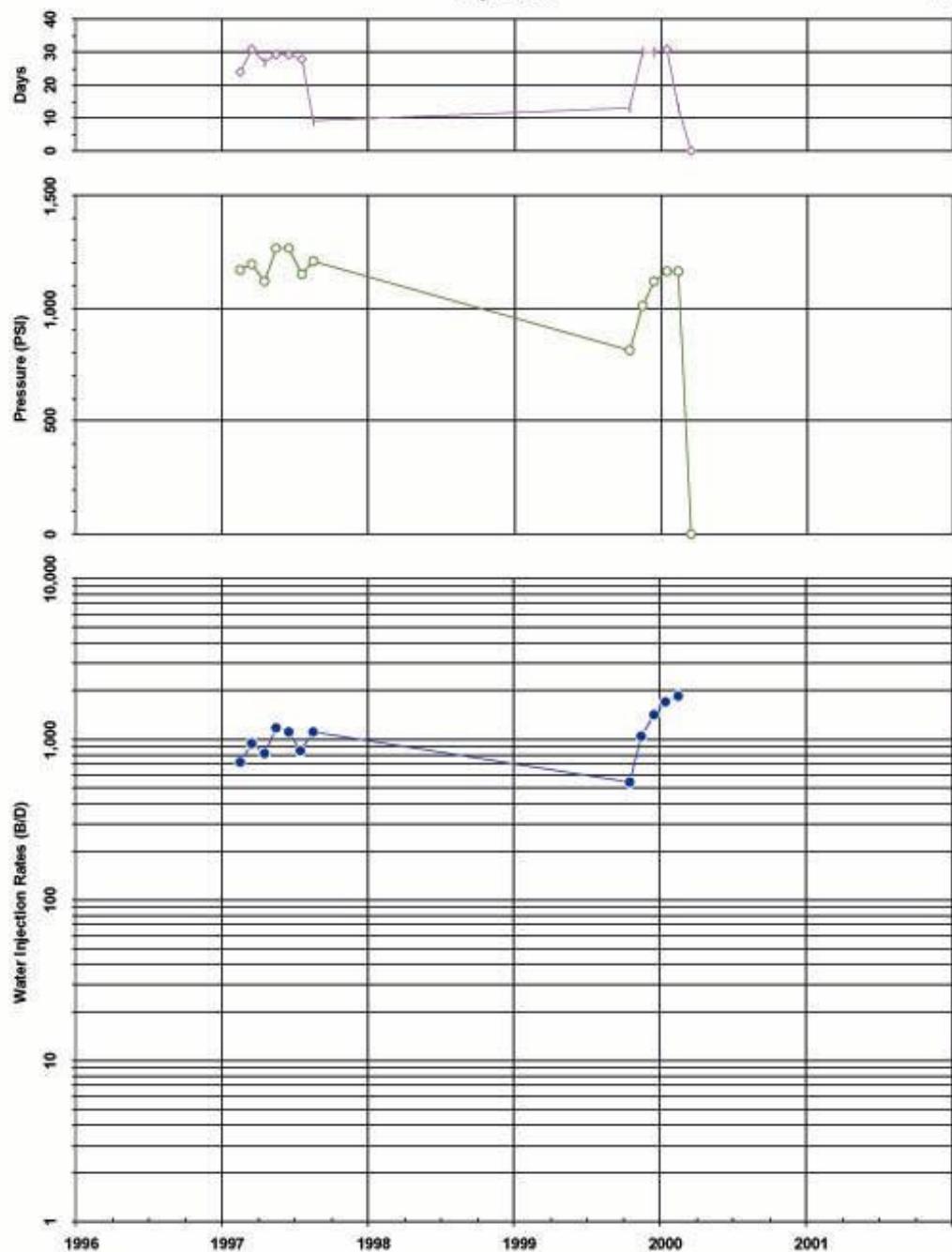


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06/20/2001
S

Tidelands Oil Production Company
Injection

FJ -201
T 5

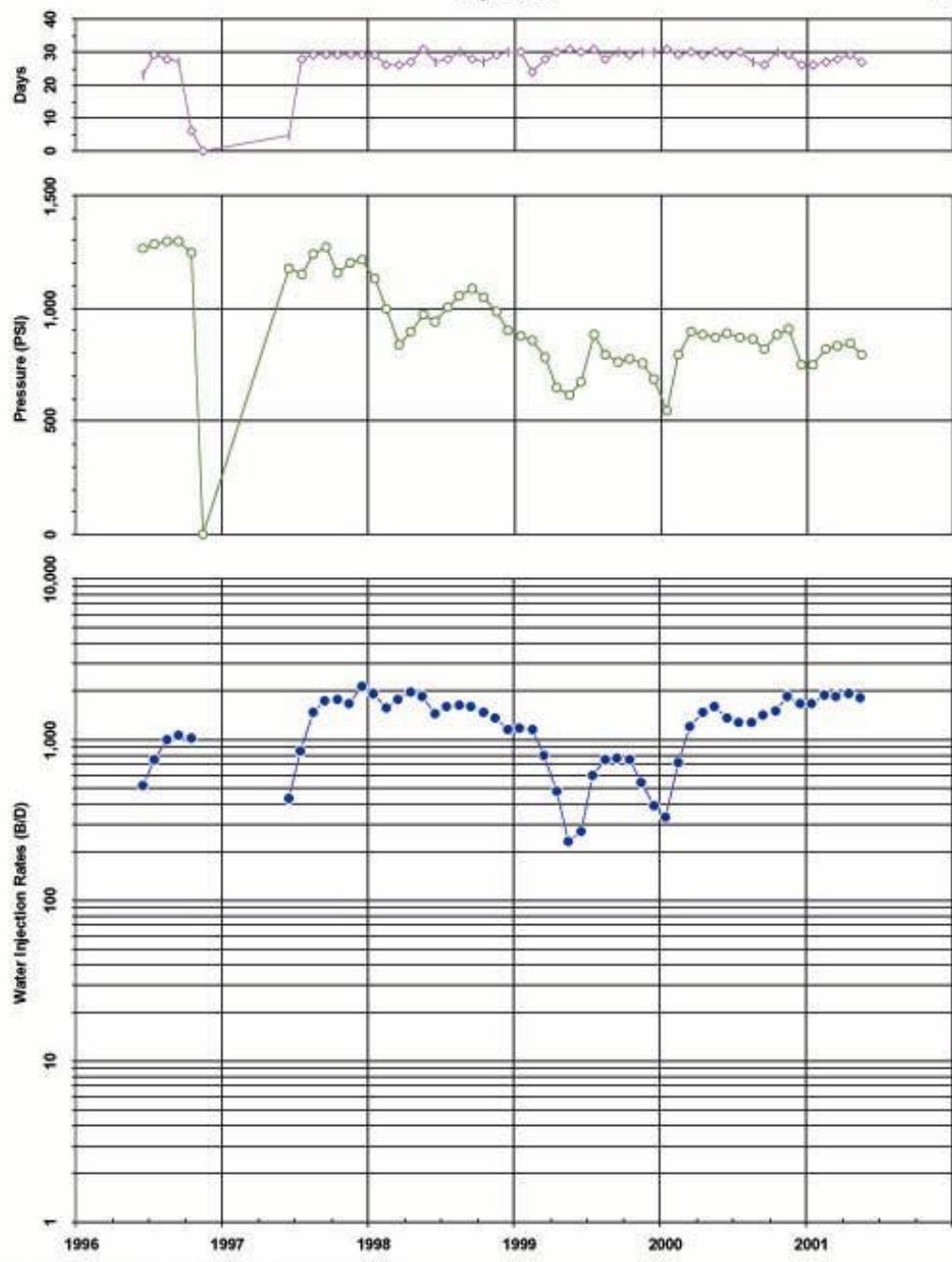


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06/20/2001
S

**Tidelands Oil Production Company
Injection**

FJ -202
T 5

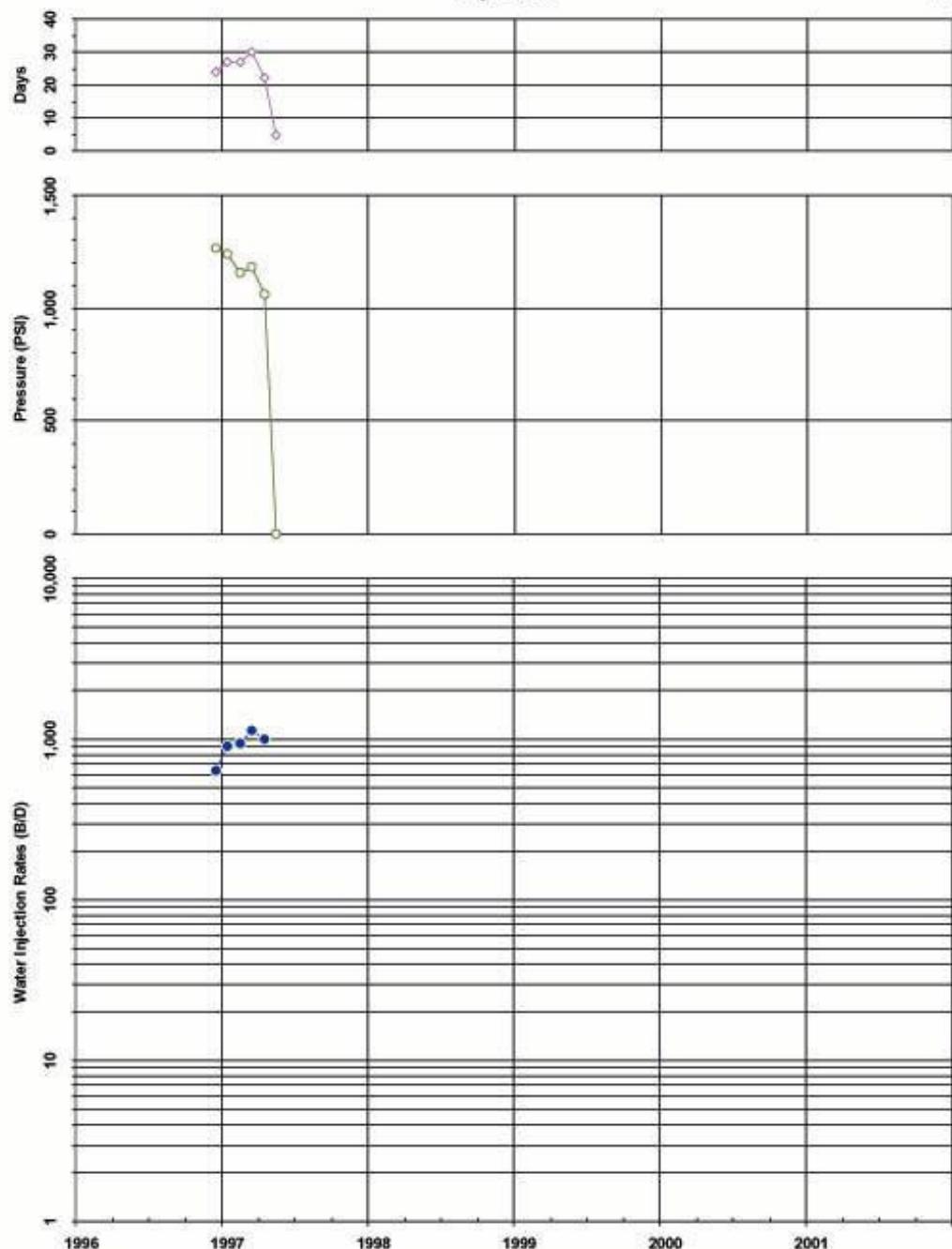


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06/20/2001
S

Tidelands Oil Production Company
Injection

FJ -203
T 5

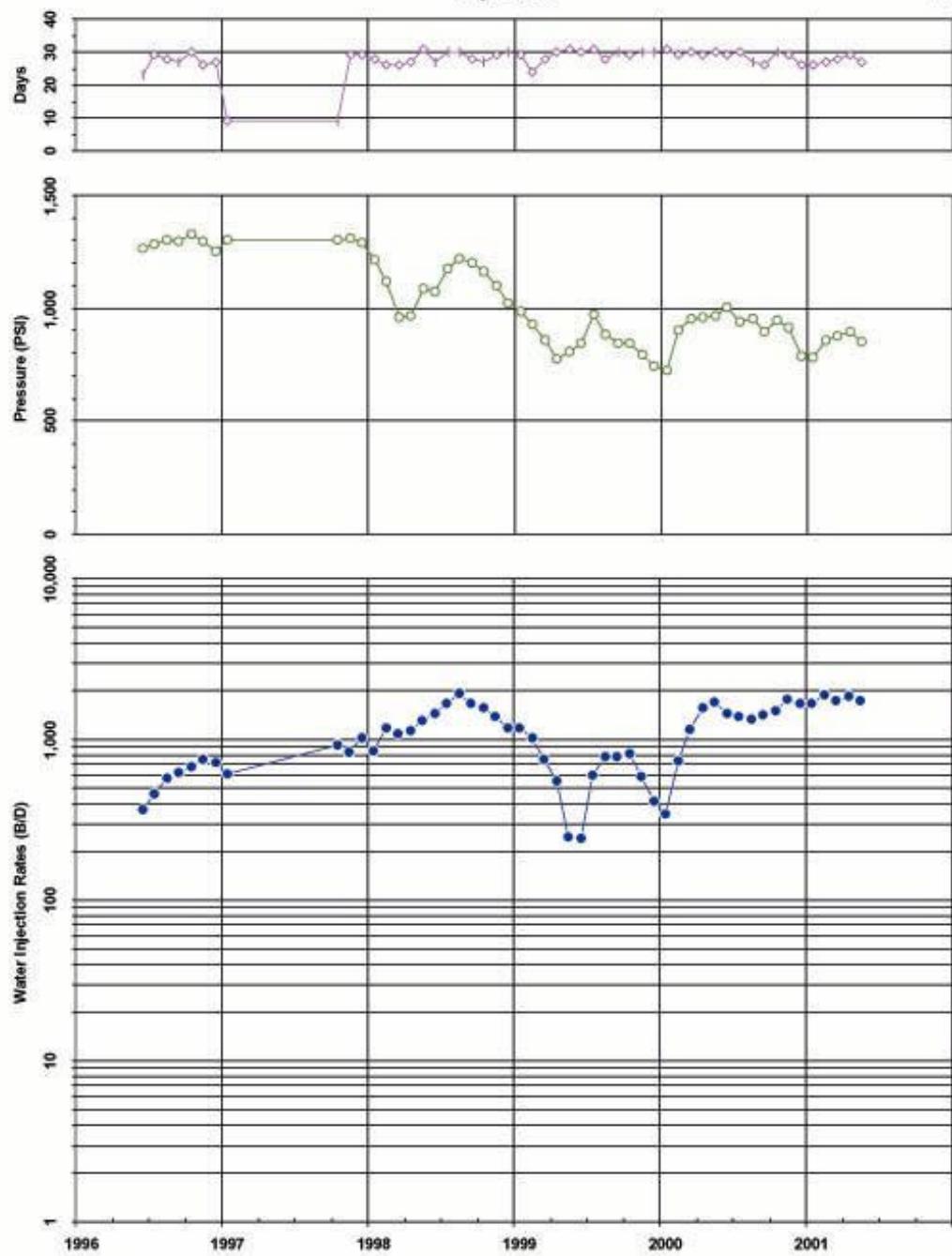


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06/20/2001
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Tidelands Oil Production Company
Injection

FJ -204
T 5

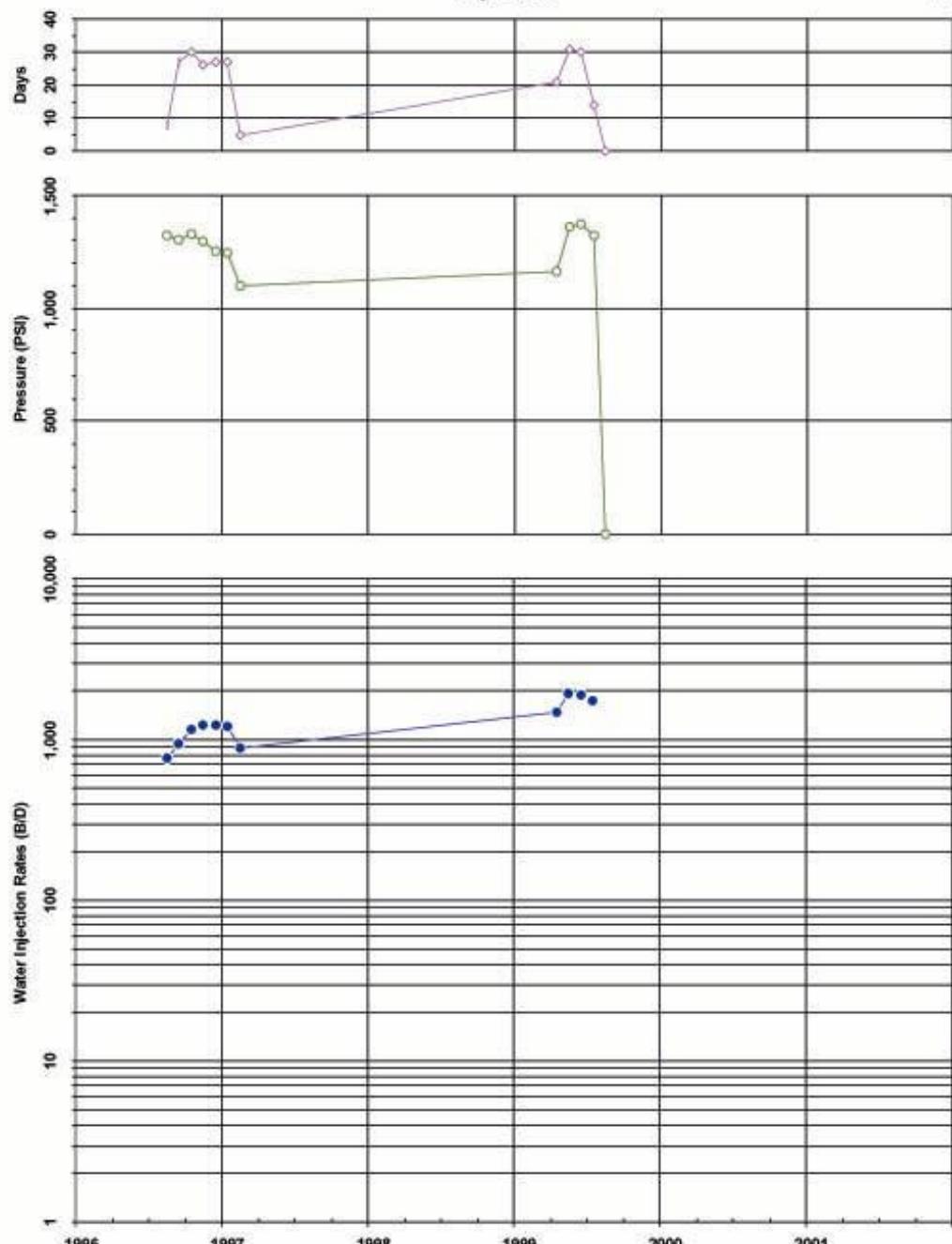


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06/20/2001
S

Tidelands Oil Production Company
Injection

FJ -205
T 5

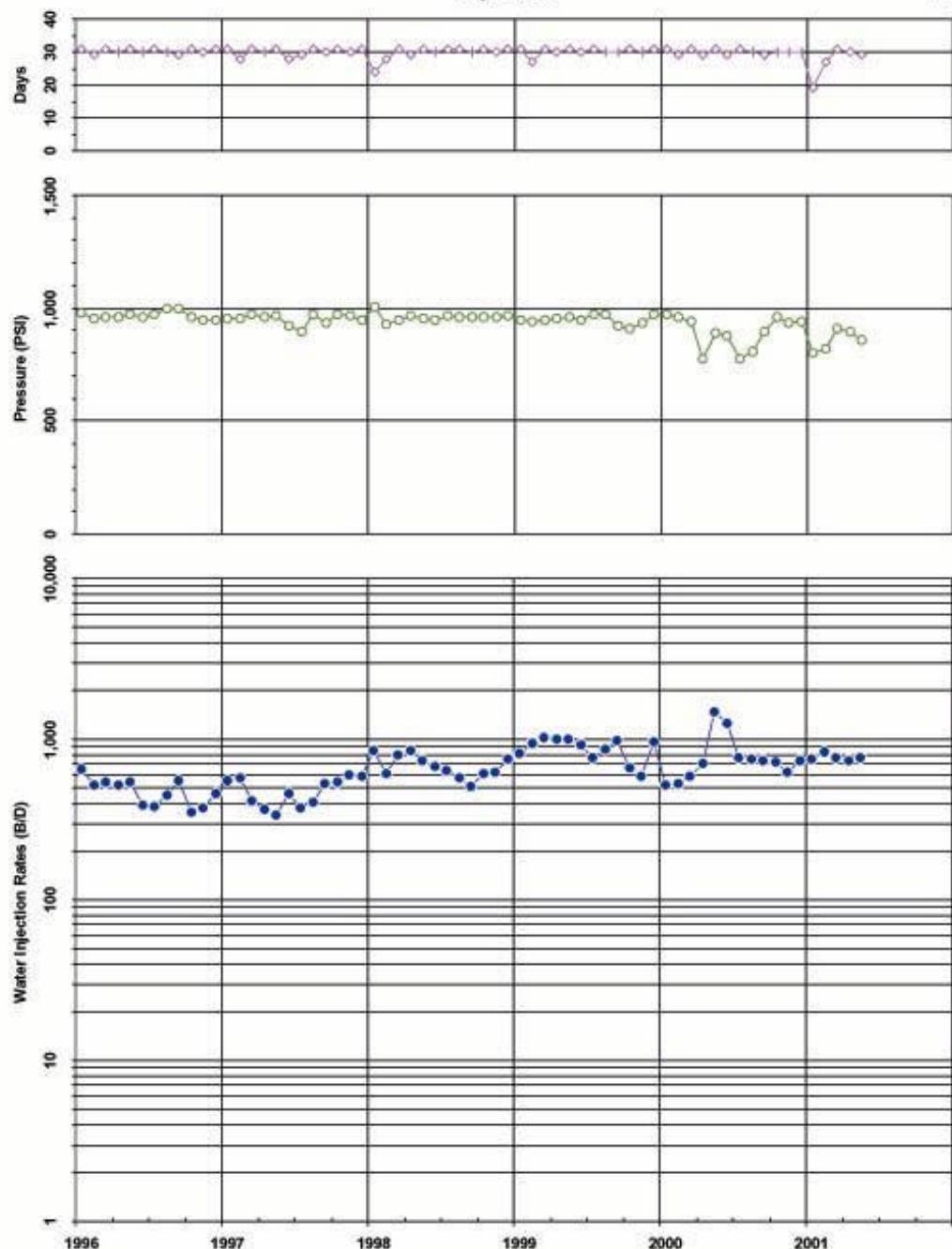


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06/20/2001
S T DU F1 FO

Tidelands Oil Production Company
Injection

FR-111
T 5

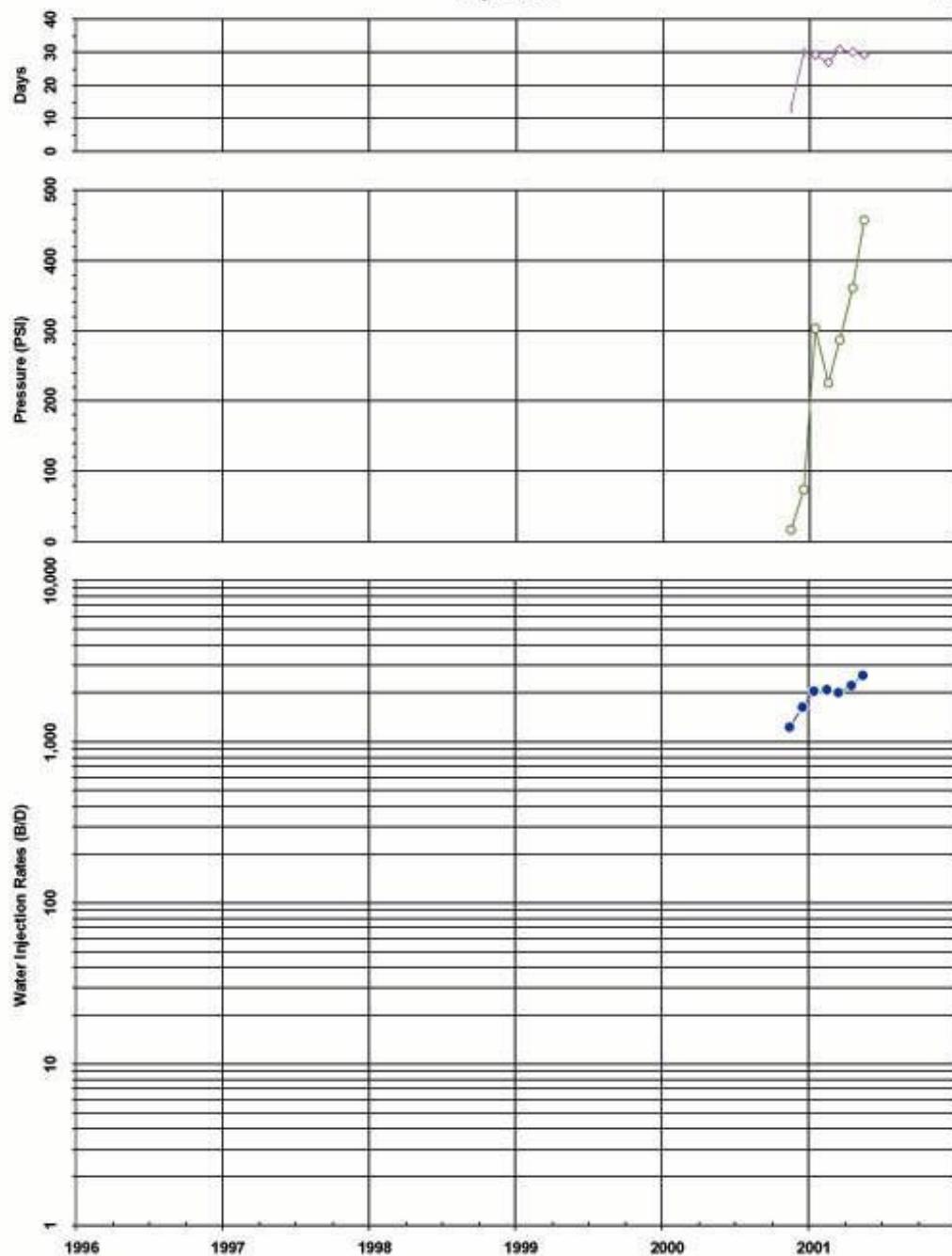


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06/20/2001
S T D U

Tidelands Oil Production Company
Injection

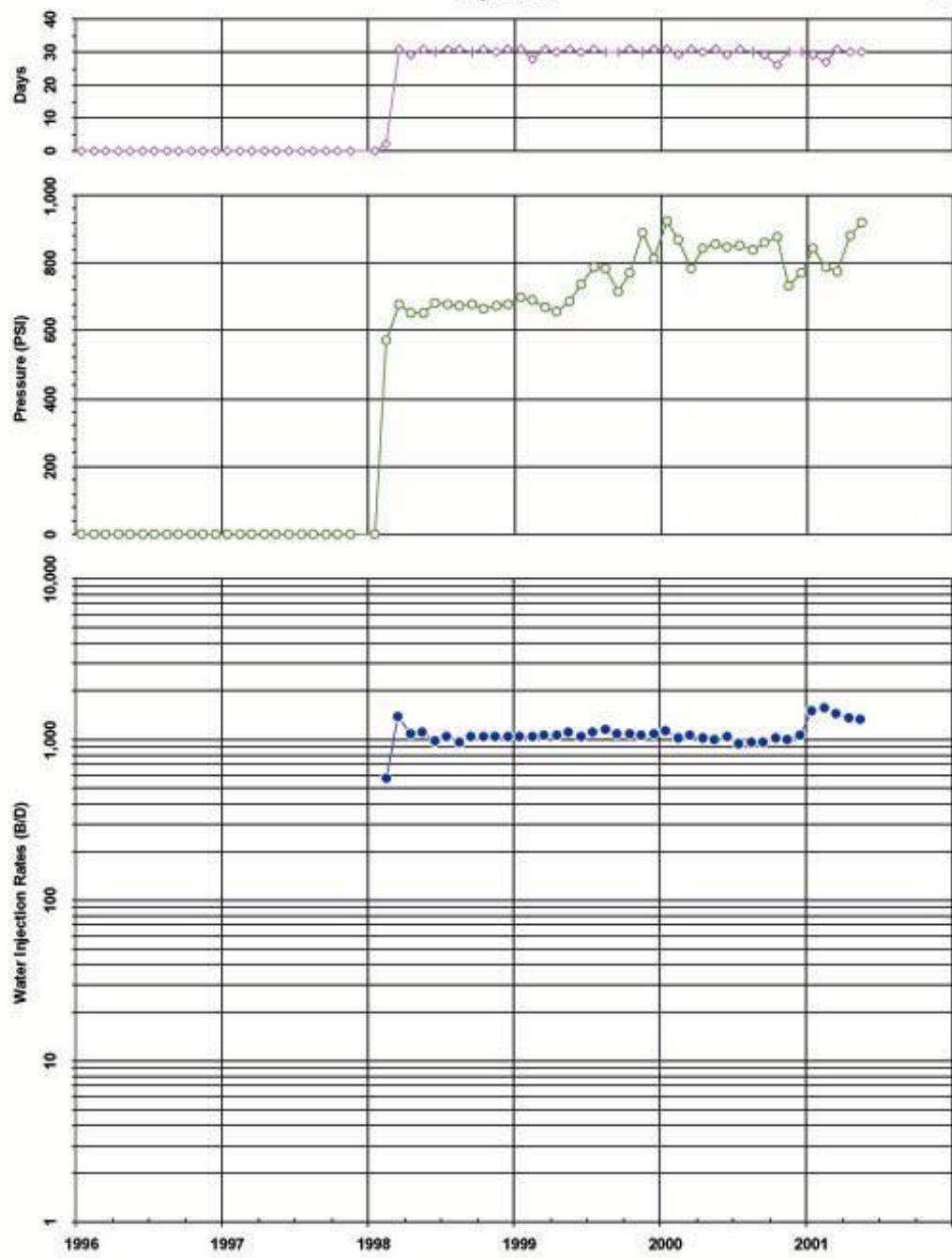
FRA-029
T 5



06/20/2001
S T DU F1 FO

Tidelands Oil Production Company
Injection

FRA-083
T 5



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