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REPORT OF EVALUATION OF INJECTION TESTING FOR PARADOX VALLEY INJECTION TEST NO. 1

BUREAU OF RECLAMATION
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Envirocorp Project No. 10Y673

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EXECUTIVE SUMMARY

This report is a synopsis of injection testing operations which have been carried out on the Bureau of Reclamation (Reclamation) Paradox Valley Injection Test Well No. 1 located in Southwestern Colorado.

A total of seven injection periods were conducted between July 1991 and April 1995. The injectate began with fresh water with increases to 1/3 Paradox Valley Brine (PVB), 2/3 PVB, and finally 70% PVB. Flow distribution into the Mississippian Leadville Formation (Leadville Formation) was periodically evaluated using both radioactive tracer (RAT) surveys and temperature regression surveys. An acid stimulation was conducted in 1993 with partial success in opening additional perforations in the lower 1/3 of the Leadville Formation.

Surface equipment problems required several major shutdown periods to repair high-pressure pumps and flow lines and electrical supply equipment. The actual surface injection pressure required to inject fluid into the low permeability reservoir was greater than anticipated during the design phases of the project. Consequently, the working pressure of the system remained within a few hundred pounds per square inch gauge (psi) of the maximum pressure capabilities of the surface facility.

PVB was diluted with fresh water prior to injection as a precaution against the potential precipitation of calcium sulfate in the reservoir. The additional volume of injectate created by the addition of fresh water and the resulting loss of hydrostatic pressure of the lower density fluid column compounded the surface pressure limitations.

Reclamation has gathered operating data throughout the injection test period and has monitored seismic activity around the wellbore. These data were transmitted to Envirocorp Services & Technology, Inc. (Envirocorp) for analysis. Envirocorp created two computer simulator models of the injection reservoir from the data provided.

This report discusses the injection history of the well, the methodology of the computer models, and predictions of future reservoir performance. The cumulative injection time into the reservoir is approximately one year and the predictions are limited to 10 years. Longer predictions are possible, but the reliability of extrapolation of data beyond one order of magnitude in time is highly suspect.

Computer modeling predicts that the reservoir is capable of accepting significant quantities of PVB at a sustained injection rate of 200 to 300 gallons per minute (gpm). This could result in the disposal of approximately 80,000 to 180,000 tons of salt per year, depending on the injection rate and PVB concentration.

1.0 INTRODUCTION AND OBJECTIVES

The Paradox Valley Injection Test Well No. 1 was drilled and completed during the time period from November 1986 through December 1988. Surface treatment and injection facilities were completed in 1990. The well was acid/fracture stimulated in July and August of 1990 and injection testing began in July 1991.

A "Two-Year Injection Test" plan for the evaluation of the reservoir capacity and injectivity was submitted to Reclamation in October 1988. A specific schedule was prepared for sequences of injection and pressure falloff to gain data and construct a computer model of the reservoir. The computer model would be programmed to predict the long-term performance of the reservoir for up to the 100-year life expectancy of the well. The original schedule for the evaluation period is attached as Figure 1.0.1. The schedule was developed on information derived prior to the initial completion of the well. Permeabilities and porosities in the injection interval were estimated to be higher than the actual values which were measured. Consequently, the sequence of events was controlled by the reservoir characteristics and by surface injection facility equipment problems.

Between July 1991 and March 1995, there were seven injection periods. Geochemistry tests performed by Reclamation indicated the possibility of calcium sulfate precipitation occurring in the injection interval when Paradox Valley Brine (PVB) was exposed to the formation rock. As a result of this potential, there has been no attempt to inject 100% PVB at any time. A freshwater treatment plant with 150 gpm capability was installed. PVB was diluted with a minimum of 30% fresh water for injection. Data acquisition has been accomplished by the monitoring and recording equipment installed by Reclamation. Downhole pressure measurement has been limited by well conditions and cost considerations. All evaluation is being made using surface pressure recordings which are converted mathematically to bottom-hole conditions.

Envirocorp has prepared two separate computer models of the reservoir. One (1) model is a very complex commercially available groundwater transport numerical model which inputs individual reservoir values into grid blocks and calculates pressure response as a function of injection. Once a historical match is achieved, the model predicts reservoir behavior based on future injection of fluid. The second model is also a grid block model which has been specifically designed for the Paradox Valley injection system. The simulation uses input reservoir parameters, actual rate and pressure data, and predicts future performance. Each model is discussed in detail in the following sections.

This project is one of very few ever attempted where the long-term injection of fluid at fracture propagation pressure is the vehicle for disposal. Hydraulic fracture models which have been developed for oil and gas reservoir stimulation are designed for relatively short-term stimulation to open and mechanically prop a fracture to expose additional rock face to a conduit for production into the wellbore. In these models, a total volume of 500,000 to 1,000,000 gallons is termed a "massive hydraulic fracture stimulation". At Paradox Valley, this volume is injected on almost a daily basis. Since no commercial models were readily available for the reservoir simulation, Envirocorp began to reprogram two models which were capable of analyzing this magnitude of fracture injection. Since these are prototype models, Envirocorp elected to run the two simulations independently and compare the results of the predictions to provide a higher level of quality assurance and confidence than could be expected with only one model.

Reclamation installed several surface seismic recorders to monitor the potential for earthquakes to occur while injecting at pressures above the hydraulic fracture gradient. The data have been processed in Denver and the report of the seismic activity is being prepared separately by Reclamation. Portions of the data were supplied to Envirocorp for incorporation into the reservoir pressure analysis. Correlations of seismic activity to injection pressure responses have been made on a qualitative basis only. The correlation to bottom-hole injection pressure and the first seismic event of each injection period have been beneficial in the programming of fracture extension into the SWIFT/486 reservoir model.

During the past four years of testing, it has become apparent that this well alone will not sustain injection of fluid at the originally anticipated 800 to 1000 gpm rate. Surface injection pressures are approximately 30% higher than originally anticipated. Consequently, the 5000 psi working pressure limitations for the surface equipment have necessitated a reduction of injection rate. This is further restricted by the loss of fluid density created by the dilution of PVB with fresh water. The combined effects of increased surface injection pressure and increased injectate volume created by the dilution of the brine reduces the tonnage of salt disposal by more than 30% at any given injection rate and increases the tonnage cost of salt disposal by an equal factor.

This report will provide Reclamation with a brief history of the injection test period, a discussion of the reservoir modeling methodology, and predictions of the well performance based upon the data available and results of the two computer simulation models of the reservoir. Several scenarios have been prepared and will be discussed individually in the following text.

2.0 INJECTION TEST HISTORY

2.1 Injection Period No. 1 (July 11, 1991 to July 24, 1991)

Refer to Figure 2.1.1. The first injection sequence consisted of freshwater injection at a rate of 150 gpm for a period of 14 days. The maximum pressure reached during injection was 3828 pounds per square inch absolute (psia). Analysis of the time/pressure data obtained during this test indicated a permeability between four and five millidarcies (md). This is combined formation and fracture permeability. The fracture length was estimated to extend approximately 35 feet from the wellbore at the time injection was stopped. Plots of the data do not indicate that the fracture was growing at the time the well was shut in for the falloff. Reclamation recorded the first seismic event on July 15, 1991 at a calculated bottom-hole pressure of approximately 9500 psi. The individual seismic events are indicated by tick marks at the upper axis of the figure. Events occurred at decreasing frequency throughout the remainder of this injection period.

2.2 Falloff Period No. 1 (July 24, 1991 to August 15, 1991)

Refer again to Figure 2.1.1. The first falloff sequence was maintained for slightly more than 21 days and was terminated when the surface pressure approached zero psi. The technique for evaluating pressure falloff involves a semilogarithmic plot of pressure change known as a Horner Plot. The part of the falloff curve used in the evaluation is known as the "straight-line" portion of the curve. It became apparent during this first falloff period that the permeability of the reservoir was much less than anticipated. As a result, the time required for the pressure falloff to reach the straight-line portion was much longer than anticipated and the time allotted for the pressure falloff was insufficient and had to be extended in an effort to recover useable data. A permeability of 2 md was determined from these data. No indication of fracture closure was observed from the data. Since all pressure measurements were recorded at the surface, any indication of fracture closure, if it did exist, was disguised by the fluid column in the wellbore. Since the permeability determined during the falloff was lower than that during injection, it is presumed that the fracture did close. No seismic events were recorded during the pressure falloff period.

2.3 Injection Period No. 2 (August 15, 1991 to August 28, 1991)

Refer to Figure 2.3.1. The second injection period consisted of injection of a mixture of fresh water and PVB in the proportion of 2/3 fresh water to 1/3 PVB. This mixture was injected at 225 gpm for 13 days. The maximum surface injection pressure during injection was 4156 psia. Analysis of the data from this injection sequence resulted in a permeability between 7 and 8 md. Fracture growth was not readily apparent from the data recorded during the test; however, upon analysis, the fracture was calculated to extend 128 feet from the wellbore. A growth of the fracture is also supported by the increase in permeability between the first and second injection sequences. Only six seismic events were recorded during the second injection period, with the first event occurring at a bottom-hole injection pressure of approximately 10,300 psi.

2.4 Falloff Period No. 2 (August 28, 1991 to September 18, 1991)

Refer again to Figure 2.3.1. The second falloff period extended for 16 days. This test was also terminated when the surface pressure went to zero. The permeability was determined to be 2.2 md for this test. This value is slightly higher than the permeability from the first falloff, which indicates that the fracture remained open longer than it did during the first falloff. No seismic events were recorded during the pressure falloff period.

2.5 Injection Period No. 3 (November 5, 1991 to November 22, 1991 and April 22, 1992 to May 29, 1992)

Refer to Figures 2.5.1 and 2.5.2. The third injection period consisted of injection of 1/3 fresh water and 2/3 PVB. The initial injection rate was 450 gpm. Operational problems led to an interruption in injection at one point during the test. Loss of diesel from the annulus into the injection tubing and ultimately into the injection zone resulted in formation and/or fracture plugging and necessitated a reduction in the initial rate. The injection rate was compromised by the reduced maximum pressure of the surface equipment of 4000 psi. The injection rate was constantly reduced and reached a final rate 200 gpm. The information obtained during this injection sequence was deemed unanalyzable due to the constantly fluctuating rate. The first of 14 seismic events occurred at a bottom-hole pressure of approximately 10,900 psi.

2.6 Falloff Period No. 3 (May 29, 1992 to June 18, 1992)

Refer to Figure 2.5.2. An attempt was made to run bottom-hole pressure gauges on a corrosion resistant electric line. Downhole problems precluded the use of the downhole pressure monitoring equipment because of the risk and expense of the corrosion-resistant line. The surface pressure data obtained during the third falloff sequence, which lasted 16.5 days, indicated the permeability to be approximately 1.6 md. This is a reduction of 30% from the value determined from the second falloff test and was attributed to the damage caused by loss of diesel into the formation. At the end of the falloff period, an electric line was run into the well with a four inch gauge ring and six-arm caliper tool to define the restriction which prevented the use of downhole pressure gauges. The gauge ring and caliper did not detect any restriction in the injection tubing or the liner above 13,000 feet. An RAT tool was run into the well on the electric line to a depth of 14,770 feet. The tool became stuck on the bottom and was subsequently worked free and pulled out of the well.

On June 29, 1993, a sample bailer was run into the well on steel line. The bailer was sticking at 14,787 feet. After working the bailer free, it was pulled out of the well and sampling was abandoned. A status meeting was held in Durango, Colorado on July 15, 1992. A plan was devised to flow the well back and sample any residual material which was floating on the surface of the fluid, and then flush the well with 20,000 gallons of PVB. In theory, the material which was present on the bottom in the low-density fluid (fresh water) may float to the top of a higher density fluid (PVB).

The well was backflowed and sampled on November 16, 1992 and flushed with PVB on November 17, 1992. After allowing two weeks for the material to float to the top, a sample was recovered on December 1, 1992. The sample was analyzed and determined to be primarily organic material (diesel fuel from the annular leak) and iron sulfide and iron hydroxide. Surface equipment repairs and replacement were carried out until June 1993.

Reclamation requested that Envirocorp conduct a Feasibility Study to determine if a remediation could be performed to enhance the injectivity of the reservoir. Envirocorp submitted the Feasibility Study on July 2, 1993. The study recommended that an attempt be made to stimulate the lower set of perforations in the Leadville Formation.

2.7 Injection Period No. 4 (June 6, 1993 to July 23, 1993)

Refer to Figure 2.7.1. Fresh water was injected at 166 gpm with a maximum surface injection pressure of 4300 psi. Fresh water was chosen to clean up potential damage from the loss of annular diesel fuel during Injection Period No. 3. The rate was controlled by the capacity of the freshwater plant. No seismic events were recorded during the injection period, which was due in part to the lower injection rate and a bottom-hole pressure which was less than the pressure required to initiate the seismic activity observed in previous injection periods. A temperature survey was attempted at the end of the injection period to evaluate the distribution of the fluid into the formation. The same resistance to the wireline experienced previously was encountered at high injection pressures and the temperature survey was discontinued.

2.8 Falloff Period No. 4 (July 23, 1993 to August 9, 1993)

Refer again to Figure 2.7.1. The surface pressure falloff information did not yield data which could be evaluated for reservoir parameters.

2.9 Acid Stimulation

As a result of the Feasibility Study submitted July 2, 1993, Reclamation authorized Envirocorp to perform an isolation and stimulation of the lower perforations in the Leadville Formation. The acid stimulation was conducted from September 20, 1993 to October 3, 1993, followed immediately by a four-week injection period. The results of the acid stimulation were evaluated with a RAT survey flow profile. Figure 2.9.1 is a composite of four flow profiles conducted during the history of the well.

Flow profiles in 1989 and 1990 indicated that all of the injected fluid was entering the upper Leadville perforations and the top half of the middle Leadville perforations with no flow into the lower Leadville/Ouray perforations.

The 1992 flow profile indicated a minor amount of flow was beginning to enter the lower perforations and the bottom half of the middle perforations.

The October 1993 flow profile indicates a fairly even distribution of flow across the lower perforations with approximately 41% flow in the upper perforations, 37% flow into the middle perforations, and 22% into and below the lower perforations. The acid stimulation was successful in opening more entry holes into the Leadville Formation.

2.10 Injection Period No. 5 (October 3, 1993 to November 1, 1993)

Refer to Figure 2.10.1. Injection of 70% PVB was initiated on October 3, 1993 at 300 gpm. The injection rate remained nearly constant throughout the test with no reduction of rate required to keep injection pressure under the 4500 psi surface pressure limitation. The first seismic event occurred at a bottom-hole pressure of approximately 11,000 psi. Numerous events occurred throughout the injection period, with decreasing frequency during the final week of the injection period.

2.11 Falloff Period No. 5 (November 1, 1993 to January 18, 1994)

The pressure falloff information for Falloff Period No. 5 was not evaluated.

2.12 Injection Period No. 6 (January 18, 1994 to March 1, 1994)

Refer to Figure 2.12.1. The sixth injection period was targeted to increase the rate from 300 gpm to 400 gpm. The maximum allowable surface pressure was limited to 4500 psi and was reached within 27 days of start-up. The rate was reduced to 300 gpm to sustain continuous injection. Seismic activity was first recorded at a bottom-hole pressure of approximately 11,200 psi and continued throughout the injection period at pressures ranging from 11,100 to 11,300 psi. At the end of Injection Period No. 6, a temperature-regression logging sequence was planned to evaluate the distribution of fluid into the Leadville Formation. Figure 2.12.2 is a recreation of the temperature regression survey. For reference, the baseline temperature survey conducted on October 19, 1989 is shown. Log Run No. 1 was conducted immediately upon shutdown. The log characteristically shows the top of the cemented Hastelloy liner at 13,200 feet. Higher residual temperature exists through the cemented liner as a result of the lack of convective heat transfer through the liner, cement, casing, and outer cement sheath. Cooling is reflected in the Leadville Formation from 14,100 to 14,500 feet, which is near the bottom of the perforated interval. Log Run Nos. 2 and 3 indicate the warming which occurred 24 and 36 hours, respectively, after shutdown. The temperature logging tool became stuck at 14,582 feet on the third log run on March 3, 1994. Several attempts were made to free the tool and on March 9, 1994, the electric line was pulled out of the rope socket on the top of the tool, leaving the logging tool in the well. Downhole logging was discontinued as a result. A pressure falloff measurement was not made due to the electric logging difficulties and the lack of useful information provided during the last few pressure falloff periods.

Reclamation and Envirocorp agreed that the best chance for quality data was to initiate a long-term injection period at a constant rate. Surface equipment modifications were made to allow a maximum surface pressure of 5000 psi to be sustained.

2.13 Injection No. Period 7 (August 14, 1994 to April 3, 1995)

Refer to Figure 2.13.1. Injection began at 400 gpm of 70% PVB. Minimal seismic activity was observed until September 14, 1994. As the previously fractured reservoir was re-pressured with fluid and the bottom-hole injection pressure increased to approximately 11,500 psi, seismic events began to increase in frequency on September 14, 1994, and continued until a three-day shutdown occurred on September 29, 1994. Upon restart, there was a time lag before seismic activity was observed. At the surface, the pressure approached 5000 psi in mid-October and the fractures extended. There was a high frequency of seismic activity recorded. The 5000 psi maximum was reached on November 14, 1994, and injection was ceased to allow the pressure to bleed off. A decision was reached to reduce the injection rate to 300 gpm and lower the maximum surface injection pressure to 4500 psi. Injection resumed on November 18, 1994 at 300 gpm. With the exception of one four-day shutdown period from November 30, 1994 to December 4, 1994, injection was reasonably constant until January 25, 1995. Seismic activity continued, but at a lower frequency than at the higher pressure. When the 4500-psi surface pressure limitation was reached on January 25, 1995, a decision was made to shut down for eight hours to allow pressure to bleed off. This occurred again on January 29, 1995, resulting in an additional four days operating time before reaching the 4500-psi limit on February 2, 1995. Following a 24-hour shutdown, injection resumed for 10 days, from February 3, 1995 to February 13, 1995, followed by another 24-hour shutdown. During March 1995, a series of intermittent injection periods with 24- to 48-hour shutdowns were conducted. A decision was made to continue operations through March 1995 on a regular five-day injection/two-day shutdown schedule at 300 gpm. Injection operations were discontinued on April 3, 1995, for a 30-day pressure falloff period. The injection tubing was flushed with fresh water in order to maintain a positive surface pressure during the falloff period.

3.0 CONCEPT OF FRACTURE GROWTH

The Leadville Formation, into which the injection is occurring, is a dolomitized limestone. The leaching and karsting, which caused the limestone to change to dolomite, has left certain areas within the Leadville with small amounts of porosity.

Tectonic movement of the rock has fractured the formation in and around the fault blocks. This fracturing was defined during the drilling, logging, and testing of the well. The natural porosity of the rock is less than that anticipated prior to drilling the well. Injection is occurring into the voids created by the natural fractures and voids in the porous rock. As fluid pressure is applied to the reservoir, the fractures are spread apart hydraulically, exposing a slightly porous rock face to the fluid. Fluid leaks slowly into the pore spaces of the rock. When the rock's ability to absorb fluid is exceeded by injection rate, the pressure increases and the fracture extends to expose more rock face.

The concept that only one fracture is growing within the reservoir is most likely too simplistic. More probably, there is a network of fractures or fragmented rock which allows the fluid multiple paths. Seismic events are recorded as the rock fractures or moves along natural fractures. Reclamation's seismic monitoring during the injection test period indicates events are migrating away from the wellbore with time, generally along a northwest/southeast trending axis, which is approximately 15,000 feet long (see Figure 3.0.1). The cluster of black circles shown surrounding the wellsite represent individual seismic events in plan view. The events which were provided by Reclamation have been superimposed on a portion of the 1988 Harr-Bremkamp Structure Contour Map of the Leadville Formation. The complete map is included in this report as Attachment 1. Events are occurring generally less than 3000 feet from the axis on both the northeast and southwest sides.

Reclamation's three-dimensional seismic data indicate that the fault (mapped by Harr and Bremkamp), which trends northwest to southeast and passes generally southwest of the wellsite, may actually intersect the wellbore in and below the Leadville Formation. Three-dimensional presentations developed by Reclamation and provided to Envirocorp support this possibility. Those presentations are not included in this report since they are to be provided in a report generated separately by Reclamation.

4.0 BORFRAC RESERVOIR SIMULATION

4.1 Overview

BORFRAC is an aquifer simulation model designed specifically to model the performance of the Paradox Valley Injection Test Well No. 1 and the Leadville aquifer. The model simulates the isothermal flow of a single liquid in a three-dimensional fractured aquifer. The fractures can be both natural and injection-induced.

BORFRAC is a finite-difference, implicit-pressure numerical simulator. It uses an iterative solution method for solving the huge array of algebraic equations resulting from the modeling of fluid flow in the aquifer. Some aquifer properties such as compressibility, can vary with pressure. Others, such as depth, porosity and permeability, can vary on a grid-block by grid-block basis. Fluid properties such as viscosity and density, can vary with pressure. The model has an automatic time-step control that ensures reasonable numerical accuracy. The model currently runs on a Pentium-processor-based personal computer with 16 megabytes of memory.

The original concept for developing BORFRAC considered the induced fracture system as consisting of a single vertical fracture extending as two wings, 180° apart, from the well. The first operational version of BORFRAC using this concept did a reasonably good job of describing the well's observed performance. Subsequent evaluation of the extensive seismic monitoring in the vicinity of the wellsite revealed that this concept was not correct and that a more realistic concept was that of a natural network of sealed fractures extending throughout the Leadville. Injection pressures can cause the natural fracture network to re-open. The fracture re-opening extends farther and farther from the well when bottom-hole injection pressure reaches the propagation pressure. The current version of BORFRAC models the system using this revised concept of the fracture network.

BORFRAC is based on a public-domain oil, gas, and water reservoir simulator named BOAST (Black Oil Applied Simulation Tool) which was developed by the U. S. Department of Energy. It was extensively modified for the Reclamation project to remove the code pertaining to oil and gas and to account for the fractured nature of the Leadville Formation.

The model has the capability of modeling three stages of the fracture network:

1. Non-Propagating Fractures:

   Whenever the bottom-hole injection pressure is less than the fracture propagation pressure, the injected brine travels through a three-dimensional network of fractures that was either present initially in the Leadville or was induced and propped open by the prior testing and stimulation of the well. The flow of the injected brine from the fracture system into the matrix of the Leadville is described by Darcy's Law for the laminar flow of fluid in porous media and is basically controlled by the matrix permeability and the pressure difference between the fracture and the matrix.

2. Propagating Fractures:

   As the Leadville matrix accepts fluid, the matrix fluid pressure increases and the fluid pressure in the fractures correspondingly increases. When the pressure in the fractures reaches the propagation level, continued injection causes the network of opened fractures to extend sufficiently to reach "fresh" matrix. Currently, BORFRAC allows propagation pressure to increase as the average aquifer pressure increases.

3. Closing Fractures:

   When injection slows or stops, such that fractures are no longer propagating, the brine existing in the fractures bleeds off into the Leadville matrix until the induced fracture system closes. This phenomenon controls the short-term pressure loss when the well is shut in. The long-term pressure loss during extended shutin periods is controlled by the rate at which the matrix pressures are dissipated throughout the aquifer.

Input required for BORFRAC includes the following:

a. number and size of the grid blocks;
b. porosity, permeability, and depth of each grid block;
c. viscosity and compressibility of brine;
d. rock compressibility;
e. original aquifer pressure;
f. fracture propagation pressure;
g. area containing the original network of open fractures;
h. formation thickness;
i. coefficients for calculating friction in fractures and near-wellbore losses;
j. coefficient for calculating volume of fluid contained in the open fractures; and
k. injection rate, as a function of time.

The principal output includes the surface injection pressure and the pressure at each grid block at specified times. This output can be imported into a spreadsheet program or a contouring program for generating graphical output.

4.2 History Matching

A necessary step in validation and verification of a model such as BORFRAC is to simulate what has already occurred. Only by achieving a valid history match or calibration can any degree of confidence be placed in the model. Only Test No. 7 data, which lasted from August 14, 1994 until April 3, 1995, was used in the BORFRAC history match. This was an ideal test for a history match because the test consisted of numerous rate changes which gave BORFRAC a wide range of operating parameters to model.

The Leadville aquifer was mapped for the Reclamation by Harr and Bremkamp in March 1988. Refer to Attachment No. 1. The aquifer is compartmentalized by major faults. The faulted compartment into which the Paradox Valley Injection Test Well No. 1 injects is very elongated and extends in a northwest-southeast direction. The northwest-southeast dimensions extend over 385,000 feet (73 miles) and the northeast-southwest dimensions near the well are only about 16,000 feet (three miles), but increase away from the well. The areal extent of the mapped compartment exceeds 1×10^{10} square feet (360 square miles). To model the aquifer, a rectangular-shaped grid system of 371,800 feet (X direction) by 24,850 feet (Y direction) was used. While not an exact replica of the mapped aquifer, the grid system has the correct area and the more-or-less similar highly-elongated shape. The grid consisted of 90 blocks in the X-direction, 70 blocks in the Y-direction, and one block in the Z-direction (the thickness of the aquifer). The X,Y dimensions of the individual grid blocks varied in size from 100' x 75' near the well to 30,000' x 2,000' at the aquifer extremity.

For history matching, the principal parameters affecting the process were varied within reasonable limits until the calculated results (i.e., surface injection pressure) reasonably matched the actual values. For Test No. 7, about 2800 observed values of injection rates and pressures were used for the match. The parameters that were varied were matrix permeability, fracture propagation pressure, and the area of the aquifer that contained the initial network of open fractures. All other parameters were fixed at reasonable values. Table I shows the parameters that resulted in the best match of Test No. 7. Figure 4.2.1 shows the match for the entire Test No. 7. Figure 4.2.2 shows the match for the last 60 days of Test No. 7, when operations had gone to a five-day on/ two-day off schedule. Figure 4.2.2 indicates that the model does a good job of calculating the injection pressures, but tends to over-estimate the rate at which the pressure falls when the well is shut in. Additional model calibration during the operations and maintenance phase of the project should remedy this problem.

TABLE I
Parameters Used in the History Match

Porosity, fraction	0.05
Permeability in X-direction, md	3.0
Permeability in Y-direction, md	3.0
Aquifer Fluid Viscosity, cp	0.4
Rock Compressibility, 1/psi	5.0×10^{-6}
Initial Aquifer Pressure, psi	6,330
Fracture Prop. Pressure, psi	10,000
Area of Initial Open Fractures	200' x 150'
Aquifer Thickness, ft	280

4.3 Analysis of Test No. 7

According to BORFRAC, during the initial phases of injection, fluid flows into the rock matrix via an existing network of open fractures. These fractures are probably the result of the earlier injection tests and stimulation treatments. Model calibration suggests that the network is approximately 200' x 150' in size, with the well in the center. This network of propped fractures results in the type of injection pressure buildup evident when the well is first put into operation or is returned to operation after a few days of shutin. In Figure 4.2.1, this can be seen at several time periods; for example at start-up, near the end of August, mid-November, early December, and each of the five-day injection cycles.

The flattening-out or breakover of the injection pressure at about 5000 psi at 400 gpm in the September-November period is an indication that the fracture network is being extended. The breakover at about 4400 psi at 300 gpm during January also indicates breakover. The difference in the magnitude of the breakover pressures at the two rates is caused by increased friction at the higher rate, primarily in the form of friction in the fractures, friction near the wellbore, and friction in the tubing.

During the series of five-on/two-off tests, the model suggests that fracture propagation is not occurring. During the two-day shutin, matrix pressures have a chance to dissipate sufficiently so that the matrix becomes capable of accepting five days of 300 gpm without additional fracture creation.

4.4 Pressure Buildup Predictions

Using the parameters obtained from the best history match, BORFRAC was then used to predict the long-term behavior of the well for the operating strategies listed below. Each prediction begins after an assumed 30-day shutin period following Test No. 7.

1. Five (5) days on at 300 gpm followed by two days at zero gpm. This is the operating strategy used at the end of Test No. 7. The injectate consists of 70% PVB and 30% fresh water. At a PVB sodium chloride content of 205,000 mg/kg, this is equivalent to the disposal of 79,100 tons of salt per year.

2. A steady injection rate of 300 gpm using the 70-30 mix (equivalent to 110,000 tons of salt per year).

3. A steady injection rate of 215 gpm using the 70-30 mix. This will dispose of the same volume as the five-day on (300 gpm)/two-day off schedule (equivalent to 79,100 tons of salt per year).

4. Five (5) days on at 300 gpm followed by two days at zero gpm with pure PVB (equivalent to 113,000 tons of salt per year).

5. A steady injection rate of 300 gpm using pure PVB (equivalent to 158,000 tons of salt per year).

6. A steady injection rate of 215 gpm using pure PVB (equivalent to 113,000 tons of salt per year).

Plots of the injection pressures for each of these six are shown in Figures 4.4.1 through 4.4.6.

Figure 4.4.1 predicts the behavior if the five-on/two-off schedule is maintained for 10 additional years. The broad smear of pressures is caused by the rapidly alternating injection-shutin periods. It appears that after a year and a half, injection pressures during the 300 gpm injection cycles will once again reach the fracture propagation level of 4400 psi to 4500 psi, as evidenced by the pressure breakover.

Figure 4.4.2 predicts the behavior if 300 gpm of 70% PVB is maintained for 10 additional years. The injection pressure can be expected to remain at the fracture propagation level of 4400 psi to 4500 psi.

Figure 4.4.3 predicts the behavior if 215 gpm of 70% PVB is maintained for 10 additional years. A continuous rate of 215 gpm will dispose of the same salt as the five-on/two-off cycles at 300 gpm. BORFRAC suggests that the injection pressures will be below fracture propagation levels for about seven years. The injection pressure will gradually rise from about 3300 psi to the propagation level of about 4200 psi.

The results presented in Figure 4.4.3 appear to be at odds with the observed behavior of the well during Injection Period No. 2 (Figure 2.3.1) that began on August 15, 1991. In this test, a rate of 225 gpm was maintained for roughly two weeks and the injection pressure went to 4000 psi. BORFRAC suggests a comparable injection pressure of only 3300 psi. It is, of course, possible that the model is wrong; however, we believe that a more logical explanation is that the fracture network induced by the testing and simulation treatments subsequent to the earlier test have significantly improved the ability of the well to accept fluid. Also, the injectate used in Injection Period No. 2 contained 2/3 fresh water and was less dense than the 70-30 mix used in the prediction.

Figures 4.4.4, 4.4.5, and 4.4.6 show predictions for the three strategies mentioned above, except that pure PVB is injected. The benefit of injecting pure PVB is lower injection pressures because of the increased hydrostatic head of the denser injectate and more salt disposed per gallon of injectate. However, the model does not take into account the possibility of formation plugging caused by the injection of pure PVB.

As brine is injected into the Leadville, the average aquifer pressure will increase. The variables controlling the magnitude of the increase are the aquifer size, thickness, porosity, and system compressibility. Ten (10) years of injection at an average rate of 215 gpm and 300 gpm will cause the aquifer pressure to increase by 146 psi and 204 psi, respectively. Figure 4.4.7 shows the aquifer pressure distribution at the end of Test No. 7. Figure 4.4.8 shows the pressure distribution after 10 years of injection at 300 gpm.

4.5 Future Modeling Work

Envirocorp recommends that the modeling effort continue into the operations and maintenance (O&M) phase of the project. Periodically the model should be checked for calibration by history matching past performance. This will provide added confidence to the use of the model for prediction of future well behavior. Some of the uses of a well-calibrated model are:

1. Equipment Design:

   BORFRAC predicts the surface injection pressure for any injection rate schedule. With the rate-pressure information supplied by the model, injection facilities can be re-designed, if need be, with a higher degree of confidence.

2. Stimulation Design:

   The model can be used to help forecast the behavior of the well if additional stimulation treatments are performed. This should result in more informed cost-benefit analyses for such treatments.

3. Evaluation of Operating Schedules:

   The model can predict injection pressures for any injection sequence. This will aid the O&M personnel with implementing new operating procedures.

4. Evaluation of Test Results:

   Pressure testing of the well, such as injectivity tests and falloff tests, can be analyzed with the model. Indeed, this may be the only method of analysis. There is no known method in the literature for analyzing pressure tests on an ever-growing areal network of natural fractures.

5. Evaluation of New Well Sites:

   Should a new well be drilled into the aquifer, the model can help with choosing the location.

4.6 Future Model Development

Little additional development work is needed for the model. The concept of a growing area of opened natural fractures is believed to be correct. As the project moves into the O&M phase, the model should be recalibrated from time-to-time to increase the confidence level in the results. Consideration should also be given to re-designing the grid system to more closely match the mapped aquifer. Recent seismic information may call for a revision of the existing map.

New development work, if necessary, includes provisions to model multiple wells (BORFRAC currently can handle only a single well). Provisions to predict injection rates for specified injection pressures might also be useful (currently the model predicts injection pressures for specified rates). Each of these modifications are relatively minor.

5.0 SWIFT/486 RESERVOIR SIMULATION

The objectives of this modeling effort are to:

- Demonstrate that the SWIFT/486 reservoir simulator can be used to produce results which match measured reservoir pressures.

- Use information from history matching to predict future reservoir pressures during injection.

The SWIFT/486 code is a transient, three-dimensional, finite difference model which simulates flow and transport (diffusion/kinematic dispersion) of fluid, solute, and (thermal) energy in porous or fractured media. The "solute" in this case, is the injected mixture of fluid which is composed of PVB and fresh water. With respect to deep well applications, SWIFT/486 is ideally suited to treat issues involving spatial variation of reservoir properties and confinement, as well as temperature/concentration dependence of fluid properties (e.g., density and viscosity). The final system(s) of matrix equations, which characterize the explicit finite difference operators, are derivable from the classical field conservation equations (solute, fluid, energy), Darcy's law, and the assumption that solute transport processes (dispersion and diffusion) are mathematically expressible as Fickean processes. For isothermal fluid flow and solute transport in a porous media, the principal conservation and constitutive equations (neglecting decay mechanisms) are summarized by:

1. Fluid conservation:

$$-\nabla\cdot(\rho v) - q = \frac{\partial(\phi\rho)}{\partial t}$$ Equation 5-1

2. Solute conservation with advective and dispersive transport:

$$\nabla\cdot(\rho \underline{D}\cdot\nabla C) - Cq - \nabla\cdot(\rho C v) = \frac{\partial(\phi\rho C)}{\partial t}$$ Equation 5-2

3. Darcy's law:

$$v = -\left(\frac{k}{\mu}\right)\cdot(\nabla p + \rho g \nabla z)$$ Equation 5-3

4. Viscosity (concentration dependent):

$$\mu = \mu(C)$$ Equation 5-4

5. Porosity (pressure dependent):

$$\phi = \phi_o\,[1 + c_R\,(p - p_o)]$$ Equation 5-5

6. Fluid density (concentration/pressure dependent):

$$\rho = \rho_o\,[1 + c_w\,(p - p_o) + c_C\,C]$$ Equation 5-6

In these expressions, pressure, concentration, and time are denoted by p, C, and t, respectively; v is the Darcy velocity vector; and ϕ, ρ, μ refer to porosity, density, and viscosity. The combined molecular diffusion/kinematic dispersion tensor is represented by D, and k is the permeability tensor. The pore and fluid compressibilities are denoted by c_R and c_w, respectively, and c_C is a prescribed constant depicting the assumed linear dependence of concentration on density. The zero subscript in Equations 5-5 and 5-6 indicates parameter evaluation at a prescribed reference state. Finally, the quantities q and g represent the generalized fluid injection rate and gravitational acceleration constant.

It is apparent that the fluid and solute field equations, cited above, each contain terms containing density and viscosity, both of which are related to pressure and concentration by virtue of Darcy's law and the prescribed variation in properties ρ, μ, and ϕ. Thus, Equations 5-1 and 5-2 constitute a coupled system which must be solved simultaneously.

5.1 History Matching

The reservoir geometry set up in the simulation model was comprised of two superimposed radial layers consisting of 200 blocks each. The radius of the model is two miles. The first layer represents the fracture(s) which are created and enlarged during the injection period and can shrink in size during the shutin period.

The second layer represents the naturally fractured matrix. SWIFT/486 was modified to allow changes in the rock properties (permeability, pore volume, and porosity) of the individual simulator grid blocks to enable fracture growth and shrinkage through time. The viscosity and density of the injected fluid were allowed to vary according to the composition of PVB and fresh water.

During the simulation of historical pressures, fracture growth was initiated at the time that seismic events were recorded. An accurate history match of the actual pressure measurements allowed development of a strategy to predict future fracture growth and, thus, injection pressure.

Seven (7) injection periods were historically matched with measured pressures and simulated pressures. The results of the comparison are depicted in Figures 5.5.1 through 5.1.8. The measured pressures are shown as a solid line, while the simulated pressures are represented by triangles.

Figure 5.1.1 is Injection/Falloff Period No. 1 and the simulated pressure is a direct overlay of the measured pressure. The departure of the curves on August 6, 1991 occurred as the surface pressure became unstable as it fell below 100 psig.

Figure 5.1.2 is Injection/Falloff Period No. 2. Again, there is very close agreement between the curves with departure occurring as surface pressure approached zero psig.

Figure 5.1.3 is the first part of Injection/Falloff Period 3. The erratic injection rate and pressure is closely matched until the falloff period. The departure of the curves on November 27, 1991 are created by the difference in hydrostatic head of a freshwater flush. The SWIFT/486 simulator was still using the dilute PVB density to calculate pressure falloff response.

Figure 5.1.4 is the repeat run of Injection/Falloff Period No. 3 with very close agreement of the two curves. Pressure falloff data were not collected after June 9, 1992.

Figure 5.1.5 is Injection/Falloff Period No. 4. There is a small difference in the breakover portion of the curve from June 14 to 22, 1993, and again in the buildup and breakover from July 15 to 20, 1993, where predicted pressures were slightly higher than measured pressures.

Figure 5.1.6 is Injection/Falloff Period No. 5. The continuous steady rate injection, which was accomplished during this period, produced an almost perfect comparison between simulated and measured pressure.

Figure 5.1.7 is Injection/Falloff Period No. 6. The comparison again is very close and the adjustment in injection rate from 400 gpm to 350 gpm on February 13, 1994, was simulated perfectly.

Figure 5.1.8 is Injection/Falloff Period No. 7. This was the first long-term sustained injection run accomplished during the injection test period. Rate reduction from 400 gpm to 300 gpm was necessitated by surface pressure limitations and the latter portion of the injection period was scheduled with five days at 300 gpm and two days shutdown.

5.2 Pressure Buildup Predictions

The reservoir pressure predictions were based upon the fracture geometry determined during the history match of injection periods 1-6 and 7 up to January 25, 1995. The fracture size was not increased during the 10-year predictive runs. By not increasing the fracture size, the predicted pressures will be higher than actual pressures.

A total of six predictive runs were conducted. The first two runs were configured to inject 70% PVB for 10 years at rates of 215 gpm and 300 gpm. The surface pressure following 10 years of injection are shown to be 3900 psi and 5700 psi, respectively. These results indicate a rate of 265 gpm would yield a surface pressure approaching 5000 psi; therefore, a third run was conducted in which 70% PVB was injected at 265 gpm for 10 years. The results of the runs using 70% PVB are presented in Figure 5.2.1.

Predictive runs 4 and 5 were conducted with 100% PVB at injection rates of 215 gpm and 300 gpm for 10 years. The surface pressure following 10 years of injection are shown to be 3600 psi and 5350 psi, respectively. These results indicate a rate of 280 gpm would yield a surface pressure approaching 5000 psi following 10 years of injection. The sixth run used an injection rate of 280 gpm of 100% PVB for a 10-year period. The results of the 100% PVB runs are presented in Figure 5.2.2.

5.3 Future Modeling Work

The predictive results from SWIFT/486, as presented in this document, show pressures which are elevated because the fracture geometry is static for the 10-year period. It is still necessary to develop an algorithm to determine the pressure at which the fracture(s) will reopen when injection resumes following a shutin and also the long-term growth behavior of the fracture. To date, the longest sustained injection period in which fracture growth was observed has been about 30 days. In order to develop an algorithm to predict long-term fracture growth, additional data will be necessary.

6.0 COMPARISON OF SIMULATOR HISTORY MATCH AND PREDICTIONS

The two reservoir simulation models which were constructed for this project operate similarly, but there are several areas within the models which are somewhat different in methodology. The methodology of each simulator is discussed in each respective section, and the direct comparisons are included in this section.

Both BORFRAC and SWIFT/486 are finite-difference grid block models. Each model calculates the flow through an individual grid block and determines the pressure and flow parameters that exist at the outer boundaries. These parameters are then entered into the adjacent grid block and the flow is calculated through that grid block. Reservoir parameters are input into each grid block and fracture geometry is input and varied to produce the simulated pressure-rate response. Adjustments to input values are made, after comparison to measured pressures, until the history match is complete.

The primary difference in the setup of the two simulators is in the grid block geometry. BORFRAC was programmed with a rectangular grid block similar to the fault block geometry mapped by Harr and Bremkamp with grid blocks increasing in size with distance from the wellbore. SWIFT/486 uses a cylindrical or radial grid block geometry with two layers which contain primary reservoir parameters in one layer and secondary (fracture) reservoir parameters in the second layer.

The history match outputs and prediction outputs in BORFRAC are expressed in surface pressure values which are adjusted for friction pressure loss and fluid density.

SWIFT/486 utilizes surface pressure information, which has converted to bottom-hole pressure information adjusting for frictional pressure loss, fluid density, and thermal and pressure effects on fluid density and viscosity. The SWIFT/486 outputs are not reconverted to surface pressures, but are expressed in bottom-hole pressure values. Consequently, the pressure values presented on the output curves will differ by approximately 6000 psig. There are advantages of both presentations. If the fracture propagation pressure and fracture gradient is the focus, it is easily observed in the SWIFT/486 outputs. If surface pressure is the area of interest, it is more quickly observed in the BORFRAC outputs. The conversion of either output is simple:

$$p_{BHP} = p_{surf} + \Delta p_{head} - \Delta p_{fric}$$

$$\Delta p_{head} = 0.433\, \rho_{inj}\, D$$

$$\Delta p_{fric} = 0.433\, \rho_{inj}\, f\, \frac{0.03112\, L q^2}{d^5}$$

$$\frac{1}{\sqrt{f}} = -2 \log_{10} \left[\frac{\epsilon}{\frac{3.7\,d}{12}} + \frac{2.51}{R\sqrt{f}} \right] \quad \text{interactive solution}$$

$$R = \frac{3162\,q}{d\mu / \rho_{inj}}$$

where,

p_{BHP} = bottom-hole pressure, psi
p_{surf} = surface pressure, psi
Δp_{head} = pressure exerted by fluid column, psi
Δp_{fric} = friction pressure in tubing, psi
ρ_{inj} = density of injection fluid g/cc
D = vertical depth, feet
f = friction factor, dimensionless
L = length of tubing, feet
q = injection rate, gpm
d = inside diameter of tubing, inches
ϵ = pipe roughness, feet

R = Reynolds Number, dimensionless
μ = fluid viscosity, centipoise

The entire injection history was modeled with the SWIFT/486 simulator. Those historical matches were discussed previously in Section 5.1. Only Injection Period No. 7 was modeled with BORFRAC. As a result, the quality of the history match can only be compared in Injection Period No. 7. The results of the history match in SWIFT/486 for Injection Period Nos. 1 through 6 are excellent. There is very little departure in the curves of measured and simulated pressure. This leads to the conclusion that the SWIFT/486 simulation of the reservoir very closely represents the response of the reservoir. Consequently, the predictive computer runs for future injection should have a reasonable reliability. The BORFRAC history match of Injection Period No. 7 compares very closely to measured pressures. There is some difference in the slope of the pressure falloff curves and in the overall slope of the buildup portions of the staged injection; however, the overall match is good and the predictability of BORFRAC is deemed to be acceptable.

The SWIFT/486 simulator is much more complex than the BORFRAC simulator. There are more ways to fine tune the SWIFT/486 simulation, making SWIFT/486 more input intensive than BORFRAC. As a result, the history match is better in SWIFT/486 than in BORFRAC. This does not necessarily make SWIFT/486 a more reliable model. It must be remembered that prediction of future reservoir response to injection by either model is based solely on the assumption that the reservoir, which has not been injected into at this time, will behave similarly to the reservoir which has been effected by injection and upon which the simulations are based.

6.1 Pressure Buildup Predictions

Direct comparisons of 10-year pressure buildup predictions between BORFRAC AND SWIFT/486 have been made for the following four cases:

1. 70% PVB at 300 gpm
2. 70% PVB at 215 gpm
3. 100% PVB at 300 gpm
4. 100% PVB at 215 gpm

Case I

BORFRAC predicted a surface injection pressure of 4500 psi in 10 years with minimal pressure buildup after the first year. SWIFT/486 predicted 5700 psig surface injection pressure in 10 years. The SWIFT/486 does not extend the fracture and uses the current fracture area; whereas, BORFRAC is extending the fracture. As a result, the SWIFT/486 predictions are approximately 1200 psi higher than BORFRAC.

Case II

BORFRAC predicted a surface injection pressure of 4200 psi, while SWIFT/486 predicted 3900 psig. At the lower rates and below fracture propagation pressure, the two independent models are within 10%.

Case III

BORFRAC predicted a surface injection pressure of 4200 psig; whereas, SWIFT/486 predicted 5350 psig with no fracture extension.

Case IV

BORFRAC predicted 3900 psig surface injection pressure compared to the SWIFT/486 prediction of 3600 psig. Again, the injection at pressures below propagation pressure are within 10%.

Since fracture propagation prediction is somewhat arbitrary, there remains some reservations about the BORFRAC predictions at higher rates above propagation pressure. There is encouragement that the higher rates may be achievable. The SWIFT/486 predictions are deemed to be somewhat higher than will be actually seen since it uses a fracture extension and area which we know is currently open. SWIFT/486 also incorporates injectate density and viscosity which will cause predictions of higher pressure than BORFRAC, which does not include these parameters.

7.0 CONCLUSIONS AND RECOMMENDATIONS

- The first three pressure falloff periods were analyzed according to accepted pressure transient analysis theory. These analyses provided a preliminary estimate of the matrix permeability. The analyses also indicated a fracture or fractures in communication with the wellbore. The extent of these fractures were not consistent when the individual analyses were compared to each other. This is not surprising since fractures are being propagated and extended continuously during injection periods. Open fractures expose a larger area of rock face with natural porosity and permeability to the injectate. When injection ceases and the pressure begins to bleed off into the natural matrix of the reservoir, the force necessary to overcome tectonic forces and keep the fracture open is reduced. This reduction in force allows the fracture to close; thus, reducing effective area of the exposed formation matrix. Therefore, pressure falloff analysis does not reflect the entire reservoir after fracture closure, but only the near-wellbore area. This results in a lower transmissivity value and also shorter fracture length than is indicated during injection when the fractures are open. After establishing this to be true and evaluating the value of the calculated data against the cost and risk of gathering and analyzing downhole data, a pressure falloff analysis was not performed on the latter injection periods.

- The well is capable of sustained injection at rates of 200 gpm to 300 gpm using 70/30 mix of PVB and fresh water.
- Near-wellbore reservoir resistance to injection may be reduced by periodic high-rate acid/fracture treatments. Treatments should be designed utilizing operating data that have been collected. Envirocorp recommends that continuing computer modeling in conjunction with acid/fracture design models be used to evaluate the possible benefits.
- At some point in the future, remedial work will be required to repair the seal assembly at the top of the liner to restore mechanical integrity.
- Thought should be given to testing the well with 100% PVB. BORFRAC or SWIFT/486 can be used to design a short-term test such that the possibility of harming the reservoir will be kept at a minimum. A successful test could lead to substantial improvement in the disposed rate of salt at reduced levels of injection pressure.
- Computer simulation has been shown to do a good job of modeling the injection system and should be continued. Modeling can be used for equipment design, stimulation design, operating schedule evaluation, well test analysis, and new site evaluation.
- Although two computer models have been used for the test phase of this project, we recommend for cost containment that only one of them be maintained for the O&M phase of the project. The decision as to which model is kept can be made at a later date. Consideration should be given to both models since the SWIFT/486 history

match is of such high quality and is more versatile; while BORFRAC is less operator intensive.

- The two independent models have predicted pressures over a 10-year period that are within 10% of each other.

FIGURES

TABLE 1

PRELIMINARY TWO-YEAR TEST SCHEDULE

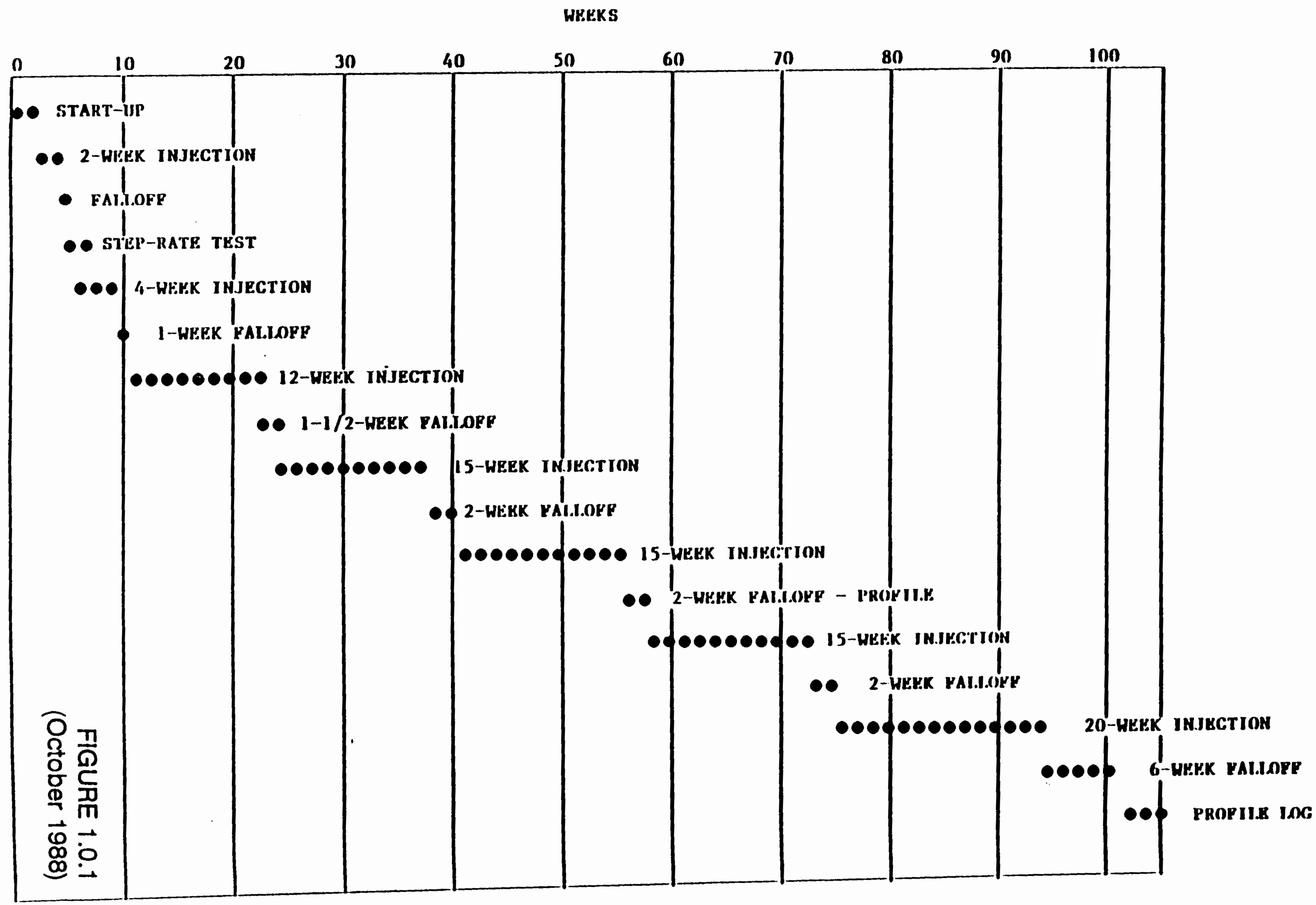
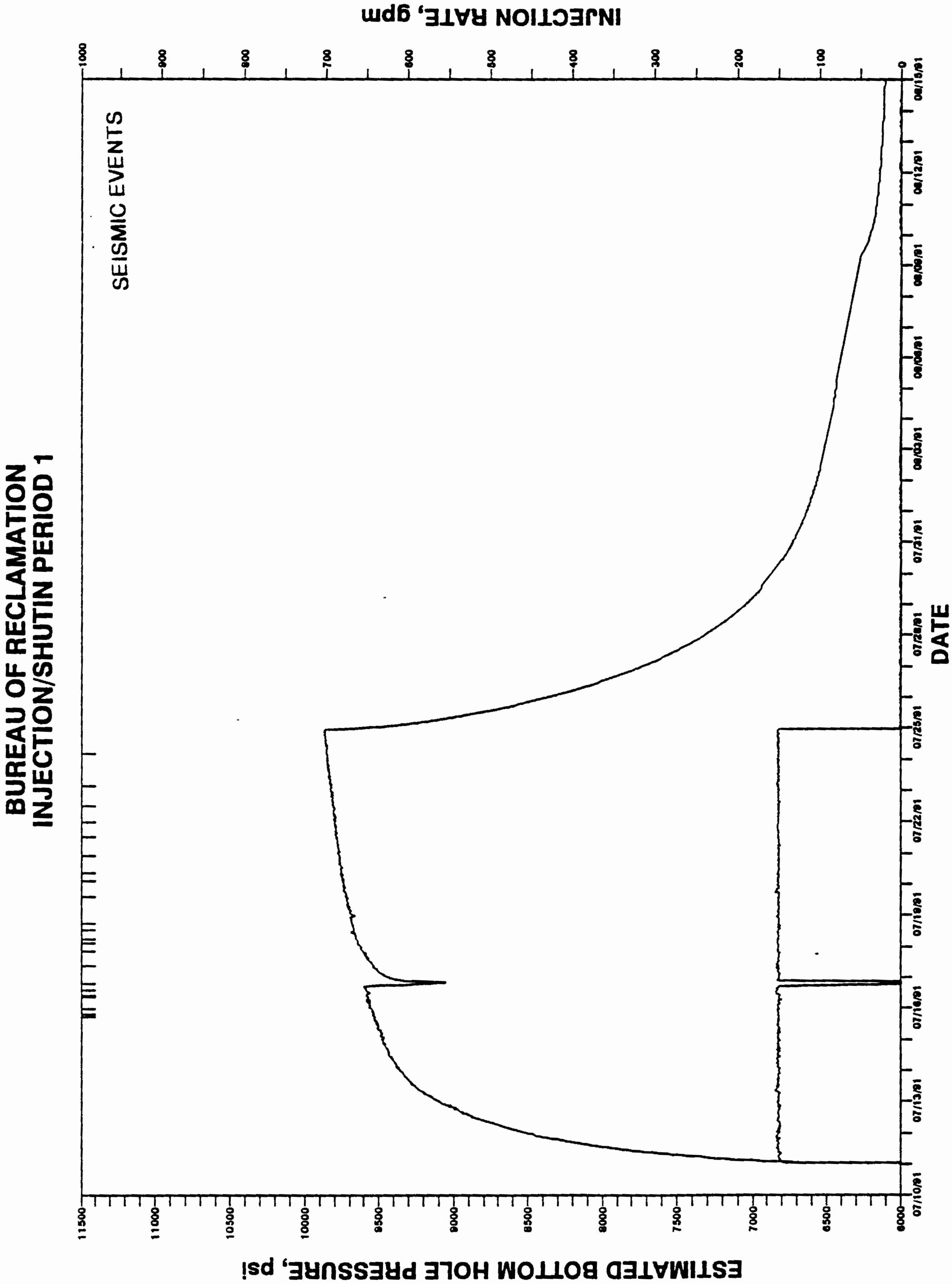


FIGURE 1.0.1
(October 1988)

FIGURE 2.1.1



BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 1
SEISMIC EVENTS
INJECTION RATE, gpm
0
100
200
300
400
500
600
700
800
900
1000
ESTIMATED BOTTOM HOLE PRESSURE, psi
6000
6500
7000
7500
8000
8500
9000
9500
10000
10500
11000
11500
DATE
07/10/91
07/13/91
07/16/91
07/19/91
07/22/91
07/25/91
07/28/91
07/31/91
08/03/91
08/06/91
08/09/91
08/12/91
08/15/91

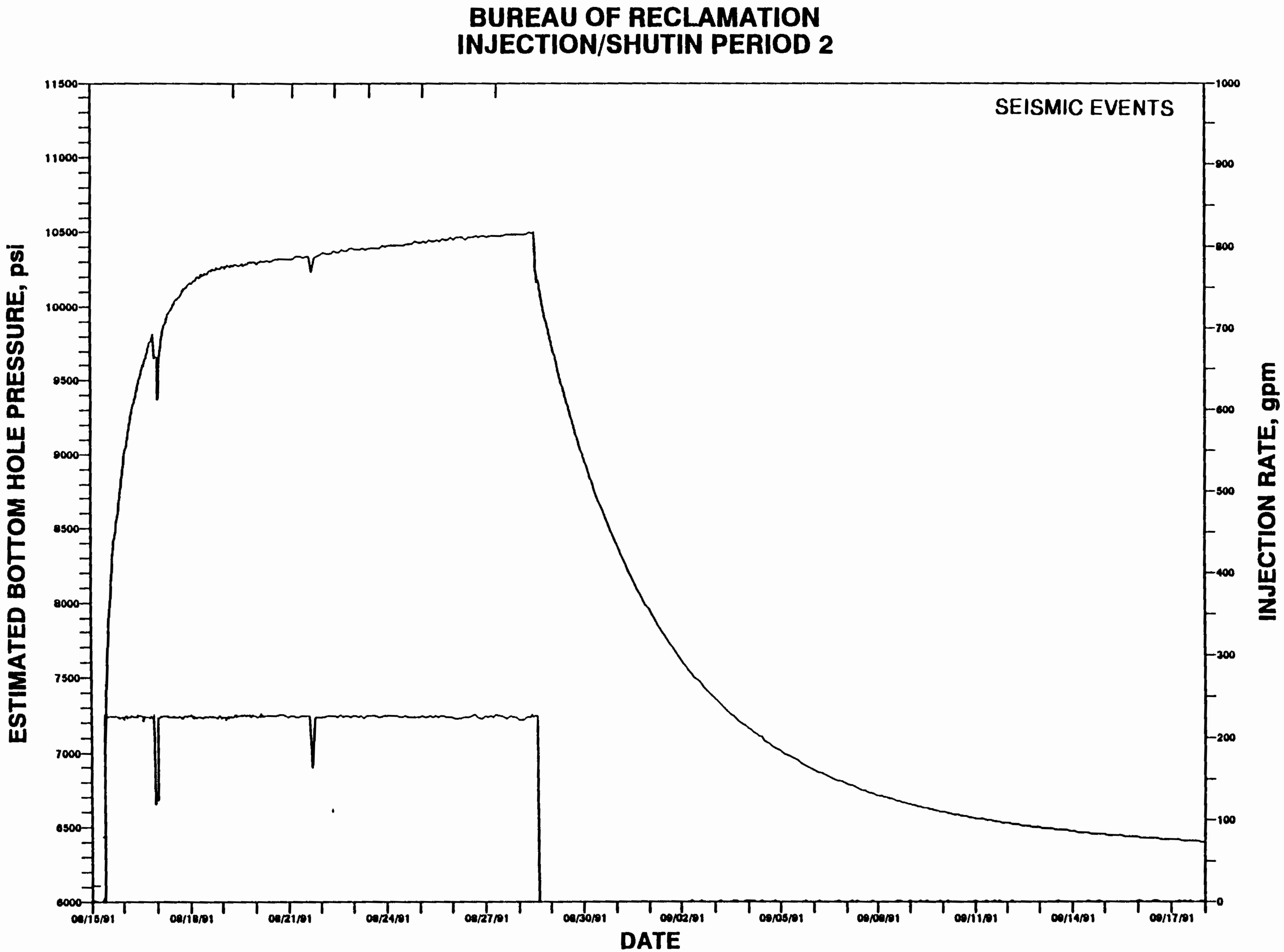
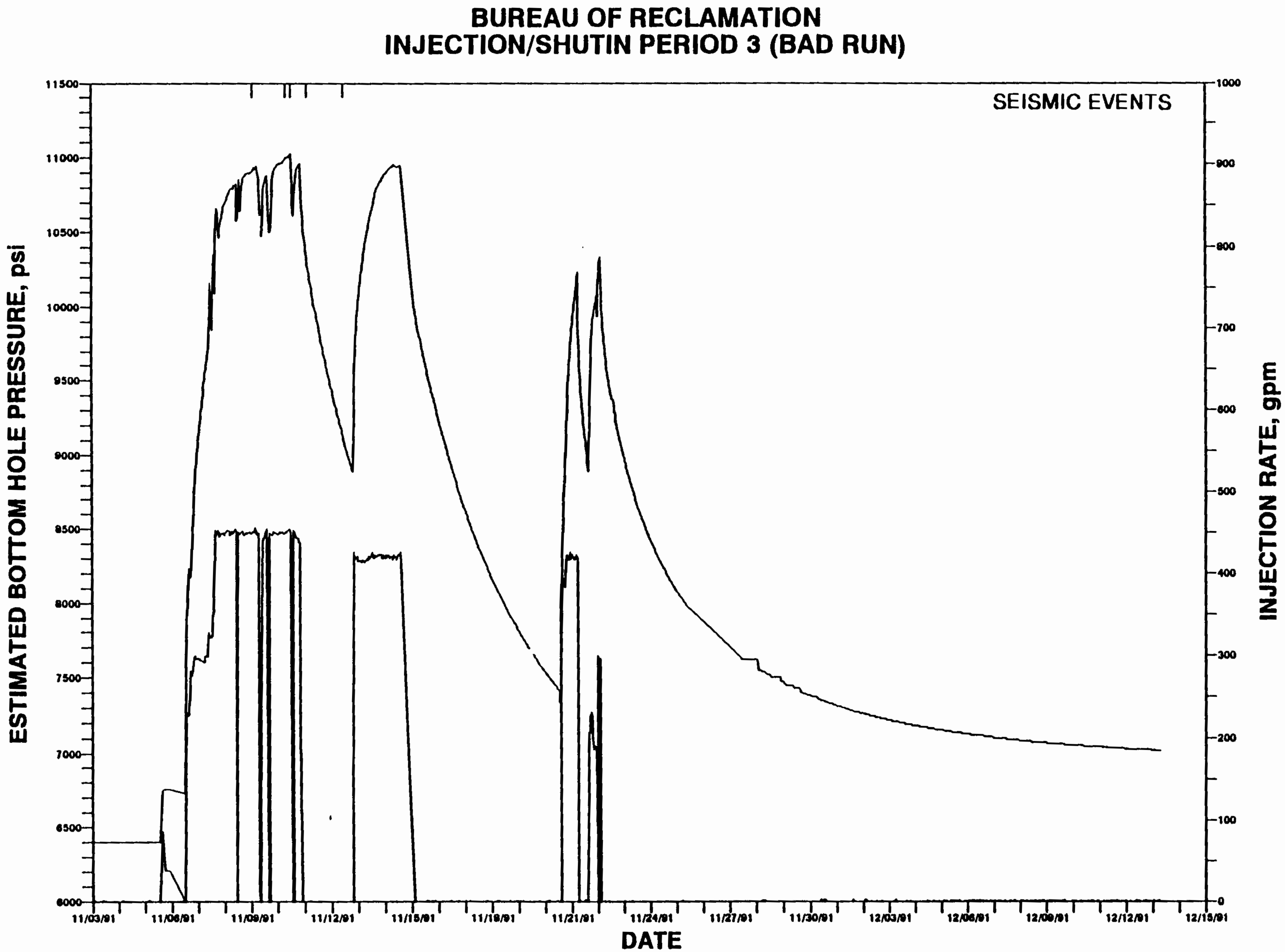

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 2
SEISMIC EVENTS
ESTIMATED BOTTOM HOLE PRESSURE, psi
INJECTION RATE, gpm
DATE
11500
11000
10500
10000
9500
9000
8500
8000
7500
7000
6500
6000
1000
900
800
700
600
500
400
300
200
100
0
08/15/91
08/18/91
08/21/91
08/24/91
08/27/91
08/30/91
09/02/91
09/05/91
09/08/91
09/11/91
09/14/91
09/17/91

FIGURE 2.3.1



BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 3 (BAD RUN)
SEISMIC EVENTS
ESTIMATED BOTTOM HOLE PRESSURE, psi
INJECTION RATE, gpm
DATE
11500
11000
10500
10000
9500
9000
8500
8000
7500
7000
6500
6000
1000
900
800
700
600
500
400
300
200
100
0
11/03/91
11/06/91
11/09/91
11/12/91
11/15/91
11/18/91
11/21/91
11/24/91
11/27/91
11/30/91
12/03/91
12/06/91
12/09/91
12/12/91
12/15/91

FIGURE 2.5.1

FIGURE 2.5.2

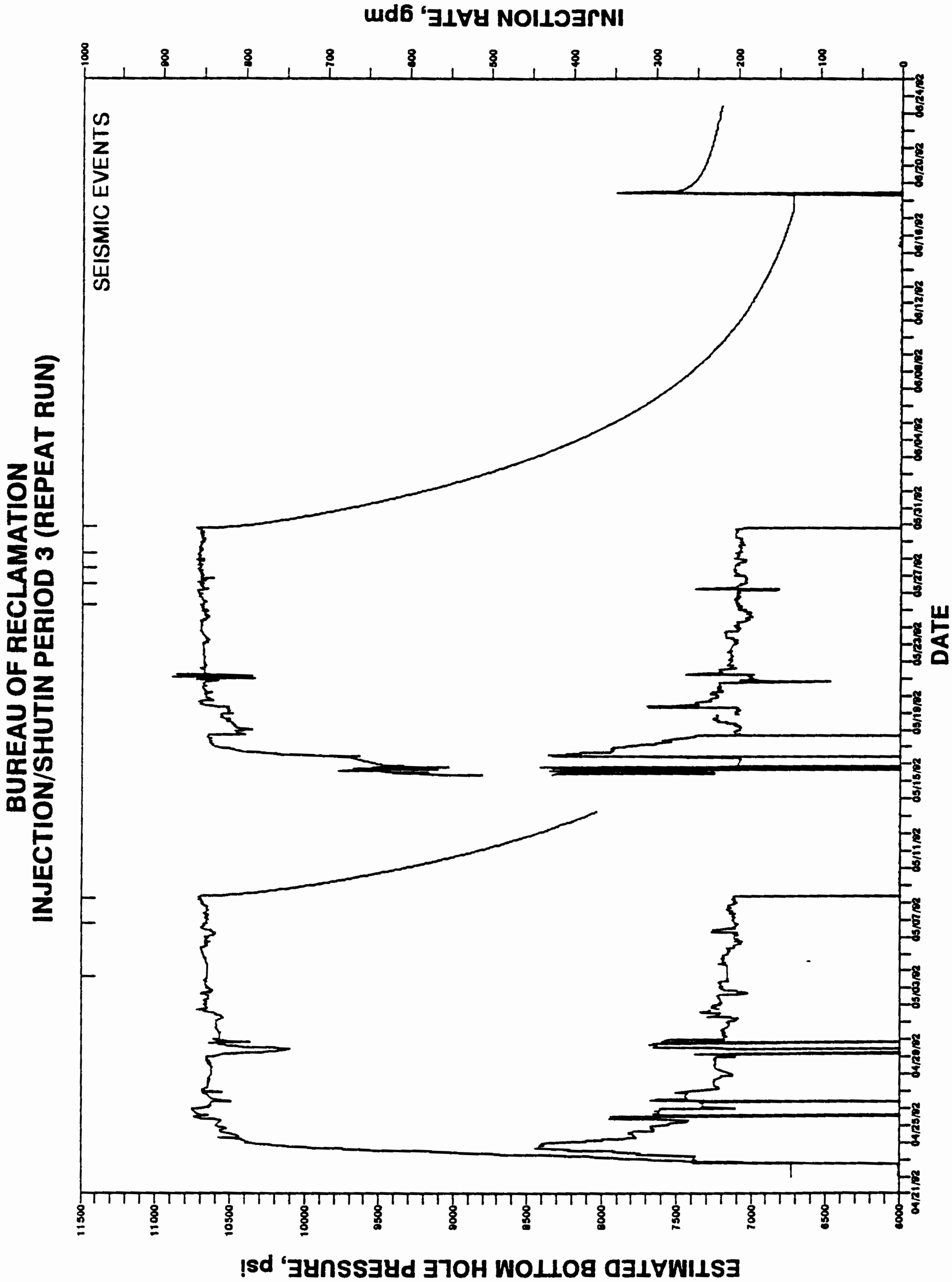
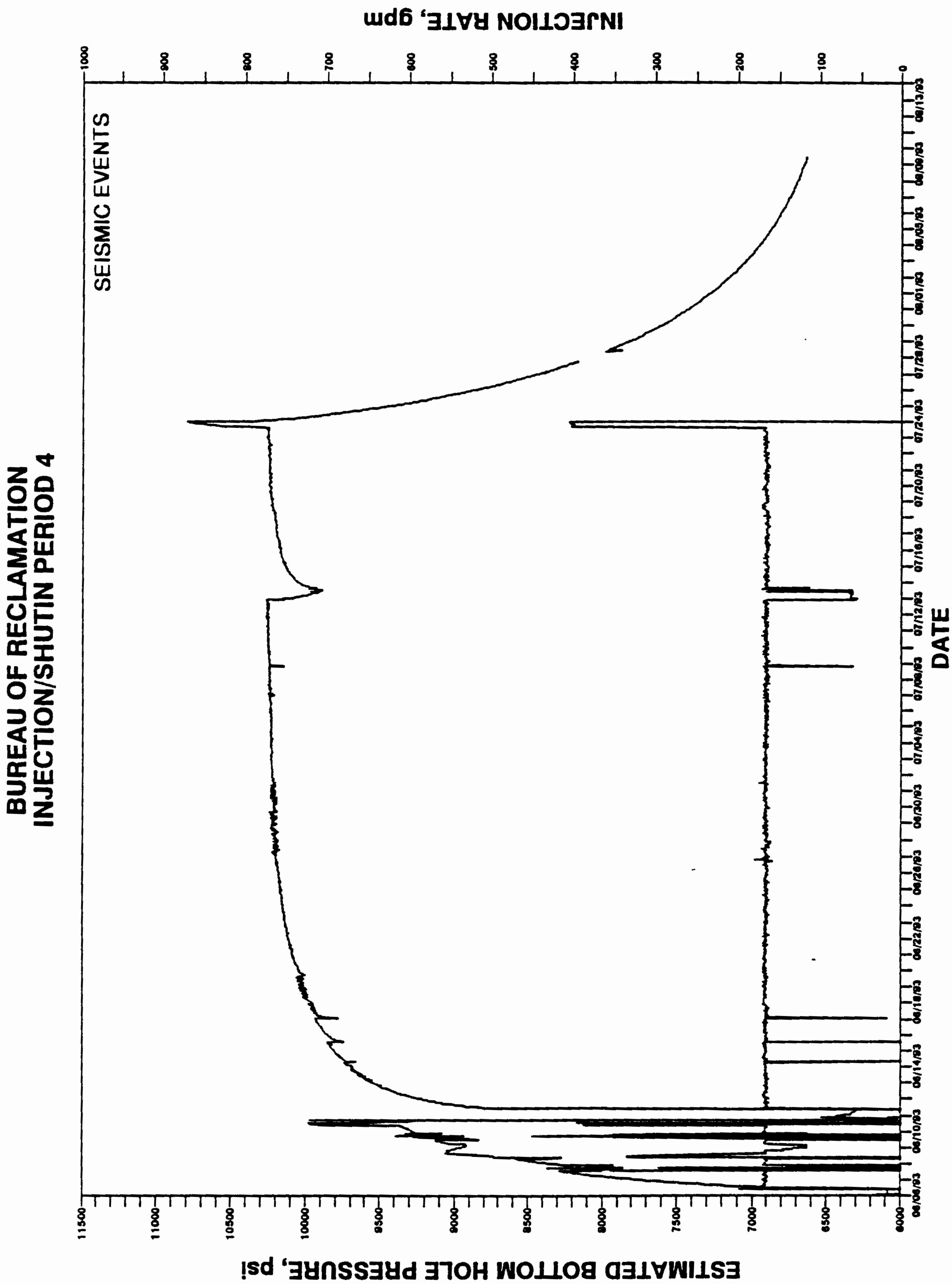
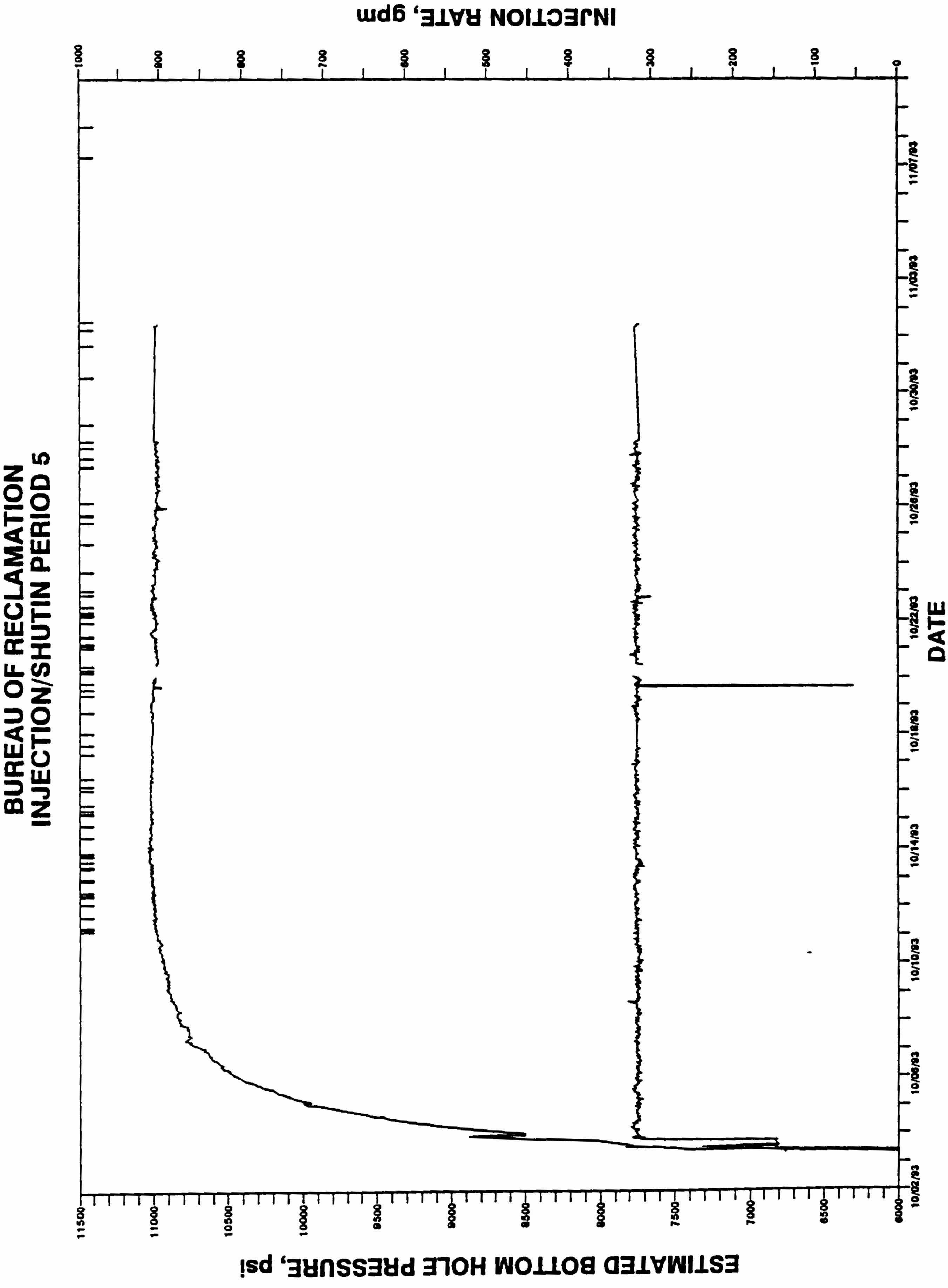

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 3 (REPEAT RUN)
SEISMIC EVENTS
INJECTION RATE, gpm
DATE
ESTIMATED BOTTOM HOLE PRESSURE, psi

FIGURE 2.7.1



BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 4
SEISMIC EVENTS
INJECTION RATE, gpm
0
100
200
300
400
500
600
700
800
900
1000
ESTIMATED BOTTOM HOLE PRESSURE, psi
6000
6500
7000
7500
8000
8500
9000
9500
10000
10500
11000
11500
DATE
06/06/93
06/10/93
06/14/93
06/18/93
06/22/93
06/26/93
06/30/93
07/04/93
07/08/93
07/12/93
07/16/93
07/20/93
07/24/93
07/28/93
08/01/93
08/05/93
08/09/93
08/13/93

FIGURE 2.10.1


BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 5
INJECTION RATE, gpm
ESTIMATED BOTTOM HOLE PRESSURE, psi
DATE
10/02/93
10/06/93
10/10/93
10/14/93
10/18/93
10/22/93
10/26/93
10/30/93
11/03/93
11/07/93
0
100
200
300
400
500
600
700
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6000
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9000
9500
10000
10500
11000
11500

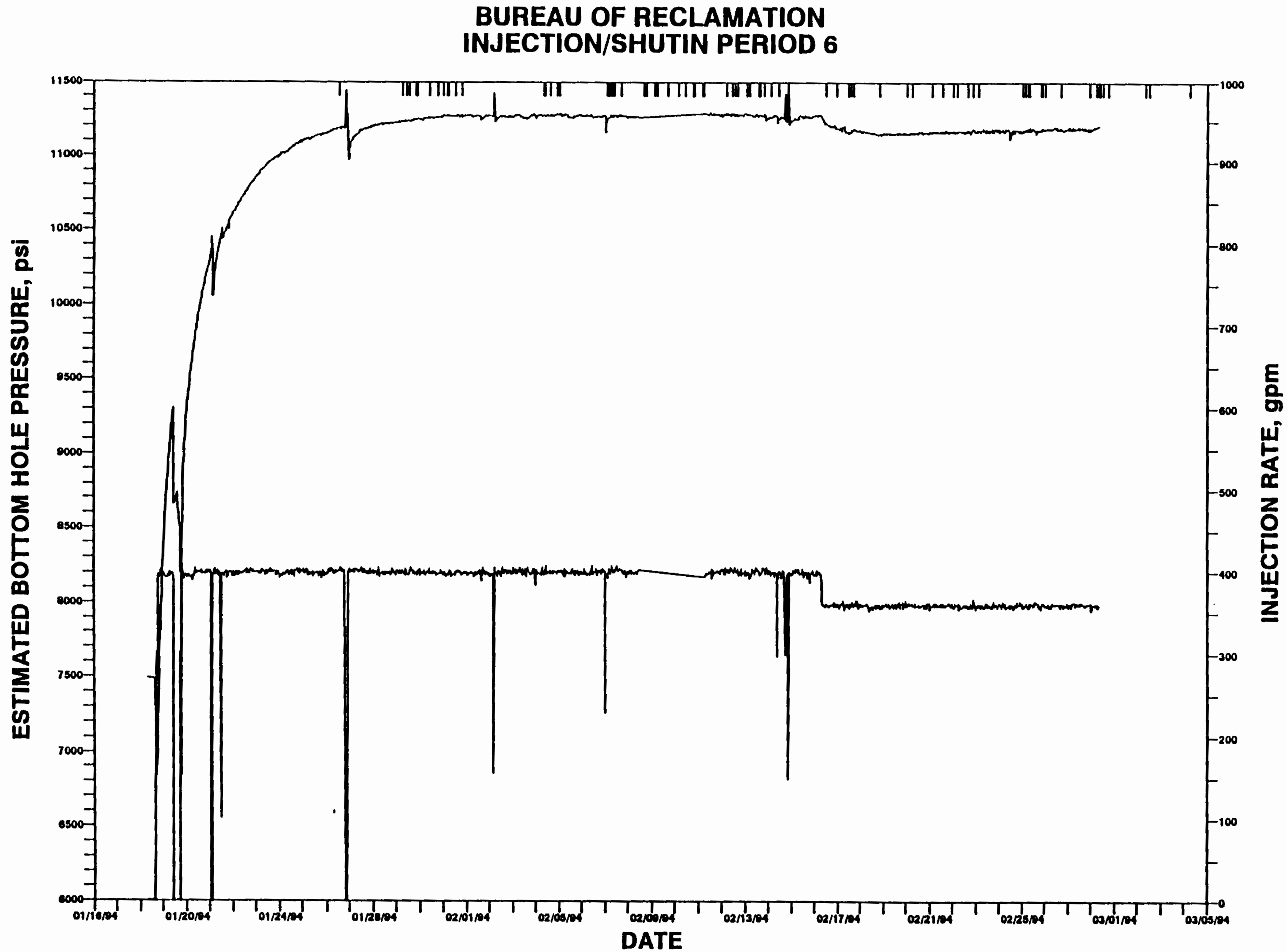
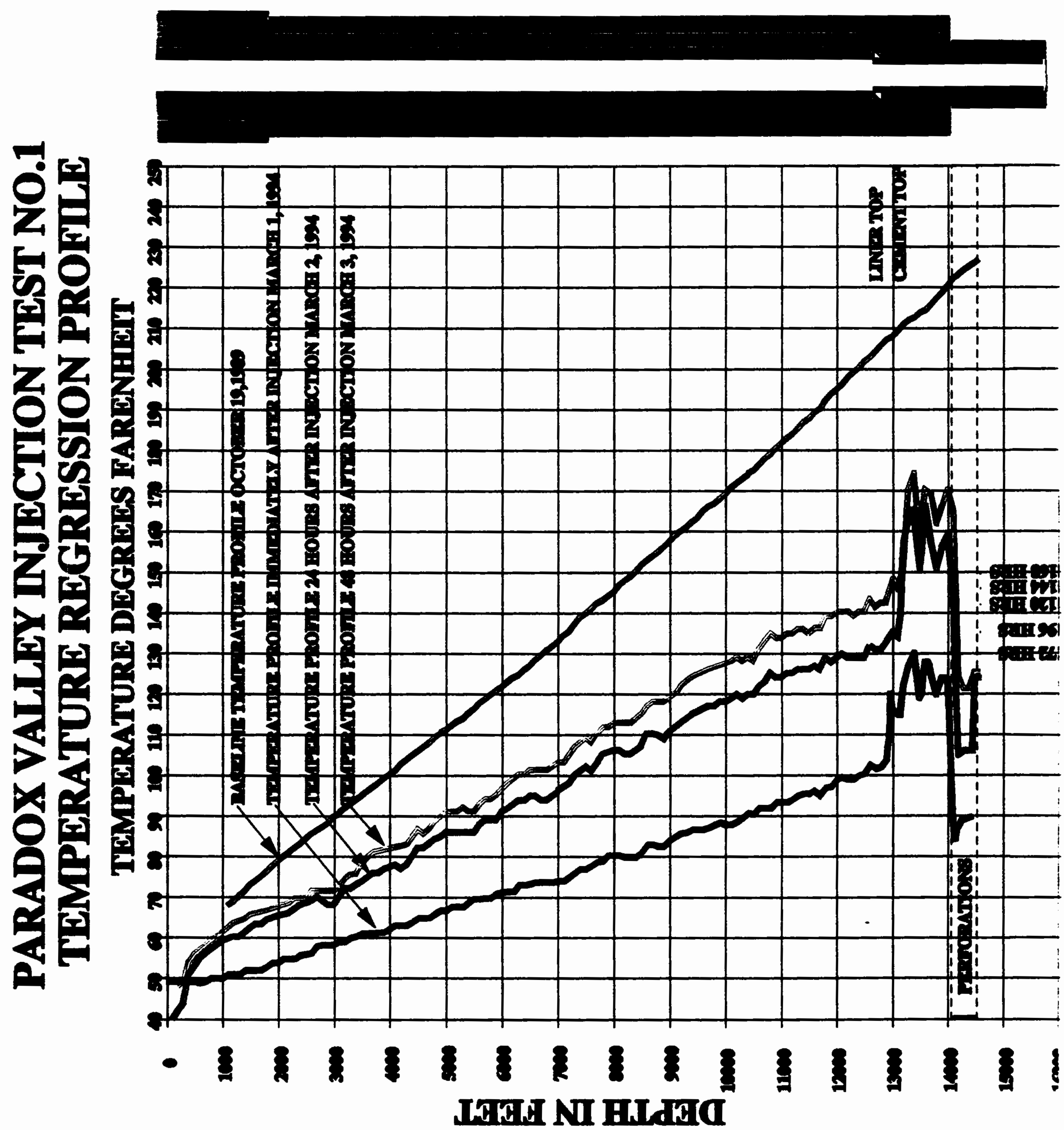

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 6
ESTIMATED BOTTOM HOLE PRESSURE, psi
INJECTION RATE, gpm
DATE
11500
11000
10500
10000
9500
9000
8500
8000
7500
7000
6500
6000
1000
900
800
700
600
500
400
300
200
100
0
01/16/94
01/20/94
01/24/94
01/28/94
02/01/94
02/05/94
02/09/94
02/13/94
02/17/94
02/21/94
02/25/94
03/01/94
03/05/94

FIGURE 2.12.1

FIGURE 2.12.2


PARADOX VALLEY INJECTION TEST NO.1
TEMPERATURE REGRESSION PROFILE
TEMPERATURE DEGREES FARENHEIT
BASELINE TEMPERATURE PROFILE OCTOBER 19,1989
TEMPERATURE PROFILE IMMEDIATELY AFTER INJECTION MARCH 1, 1994
TEMPERATURE PROFILE 24 HOURS AFTER INJECTION MARCH 2, 1994
TEMPERATURE PROFILE 48 HOURS AFTER INJECTION MARCH 3, 1994
LINER TOP
CEMENT TOP
PERFORATIONS
DEPTH IN FEET

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 7

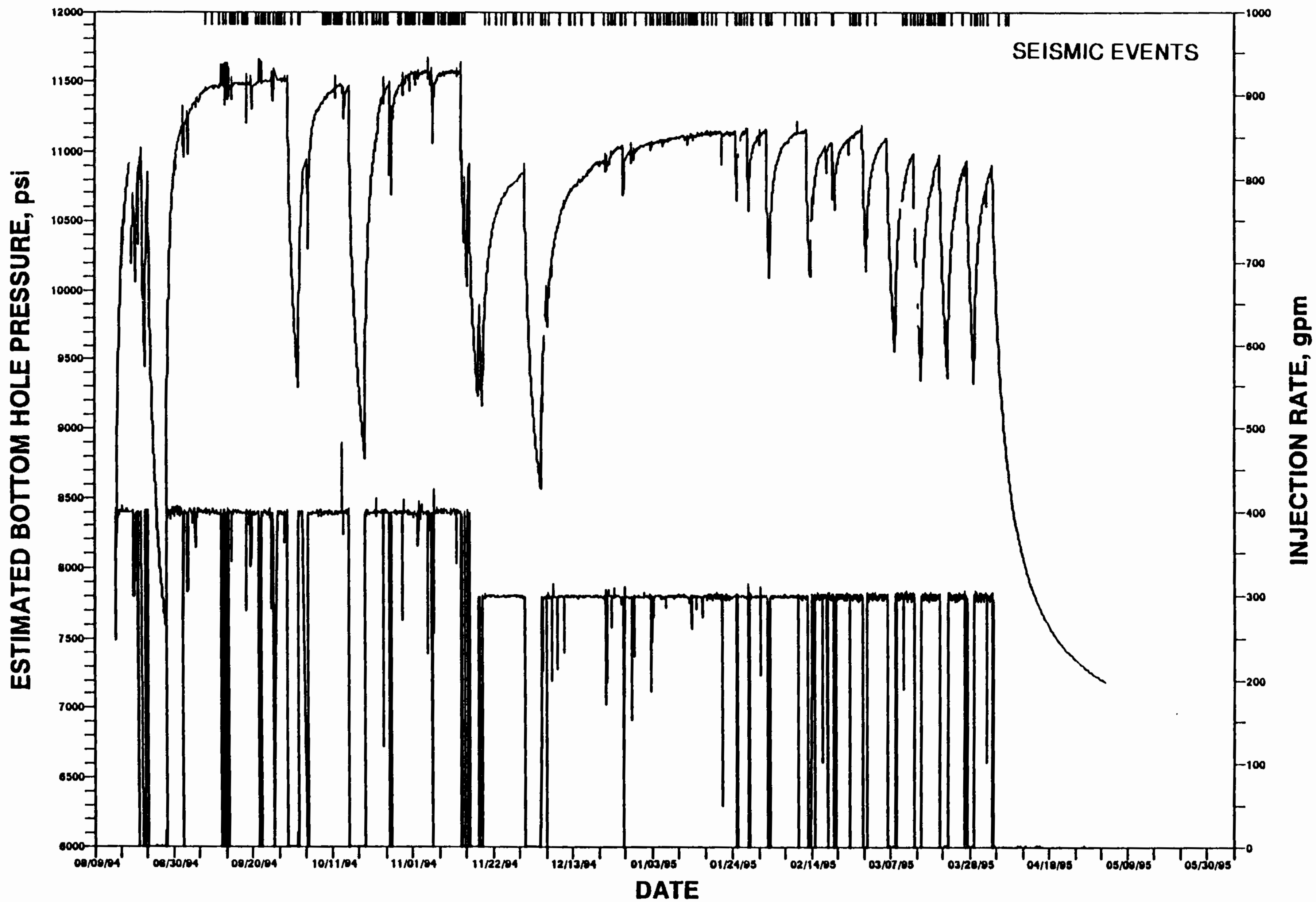
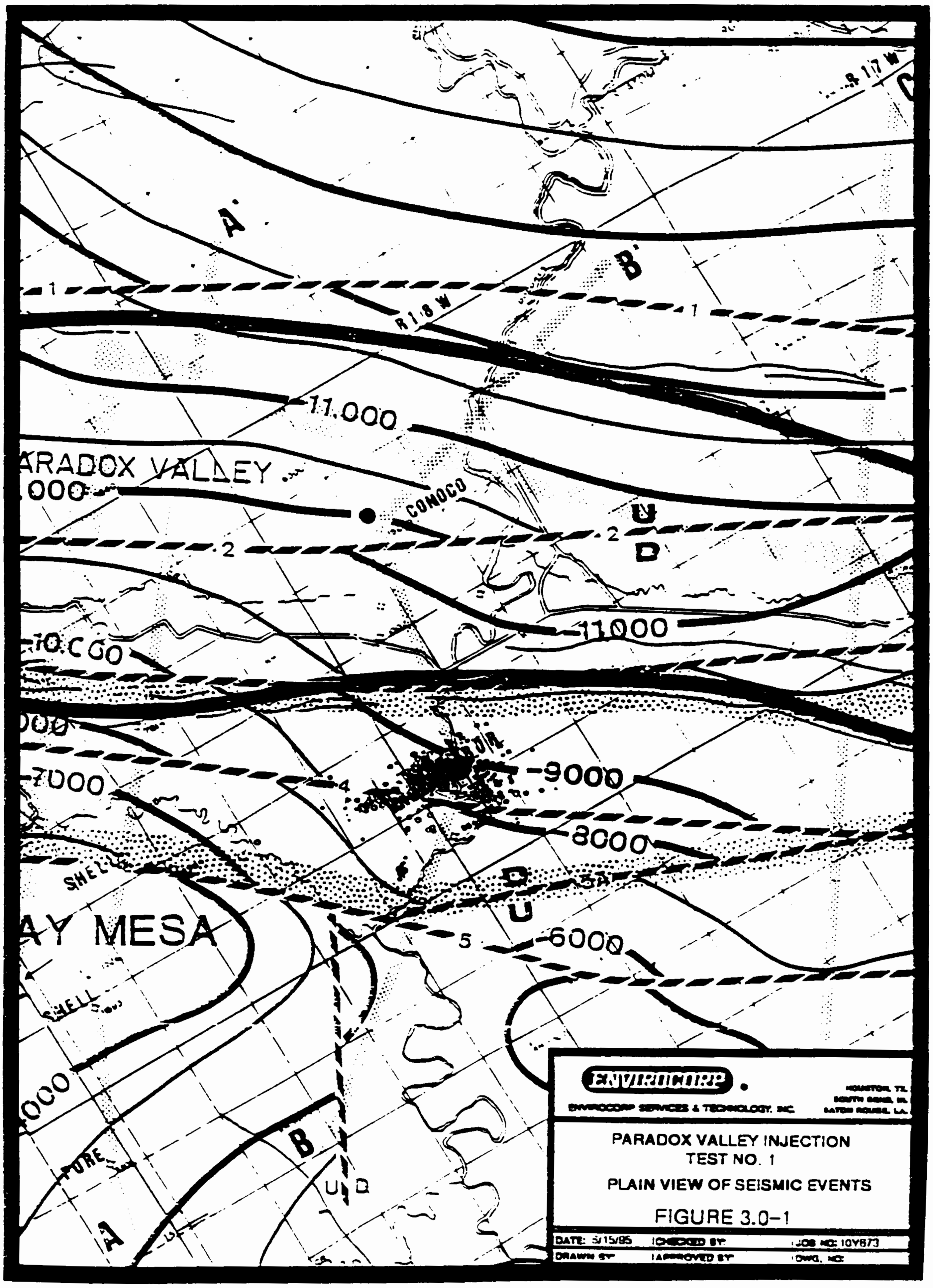


FIGURE 2.13.1



PARADOX VALLEY INJECTION
TEST NO. 1
PLAIN VIEW OF SEISMIC EVENTS
FIGURE 3.0-1

FIGURE 4.2.1

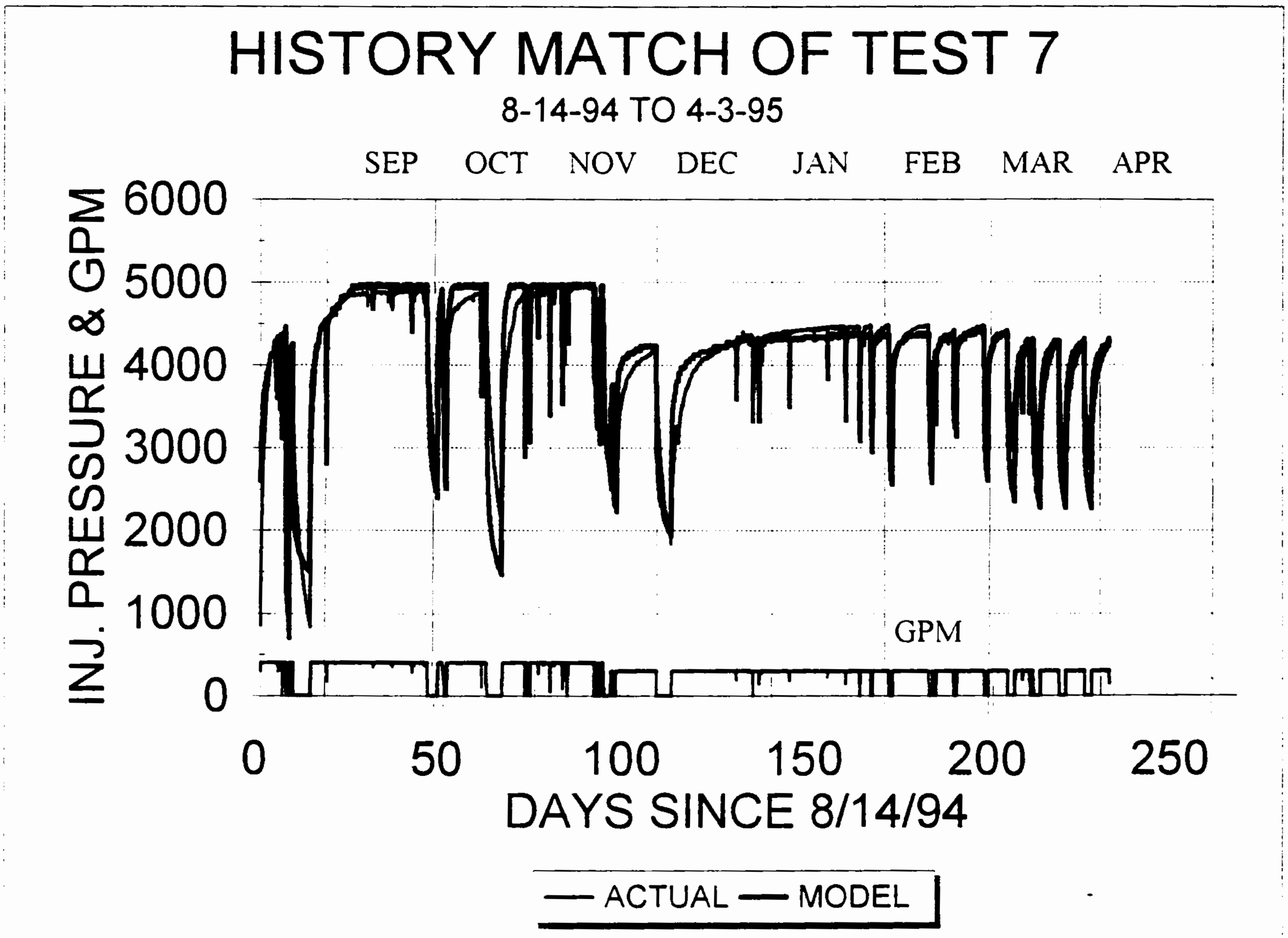

HISTORY MATCH OF TEST 7
8-14-94 TO 4-3-95
SEP
OCT
NOV
DEC
JAN
FEB
MAR
APR
INJ. PRESSURE & GPM
6000
5000
4000
3000
2000
1000
0
GPM
0
50
100
150
200
250
DAYS SINCE 8/14/94
ACTUAL
MODEL

FIGURE 4.2.2

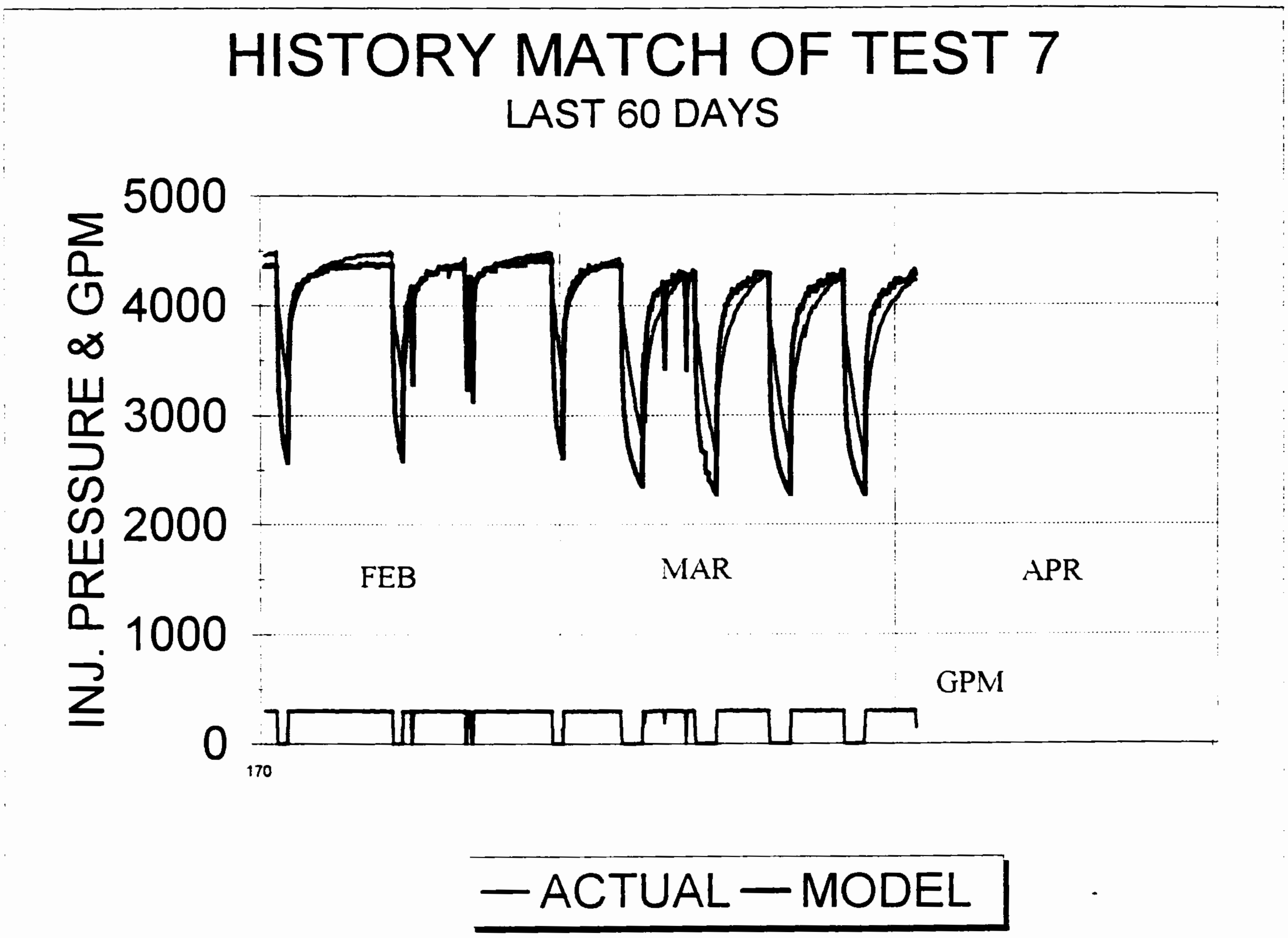
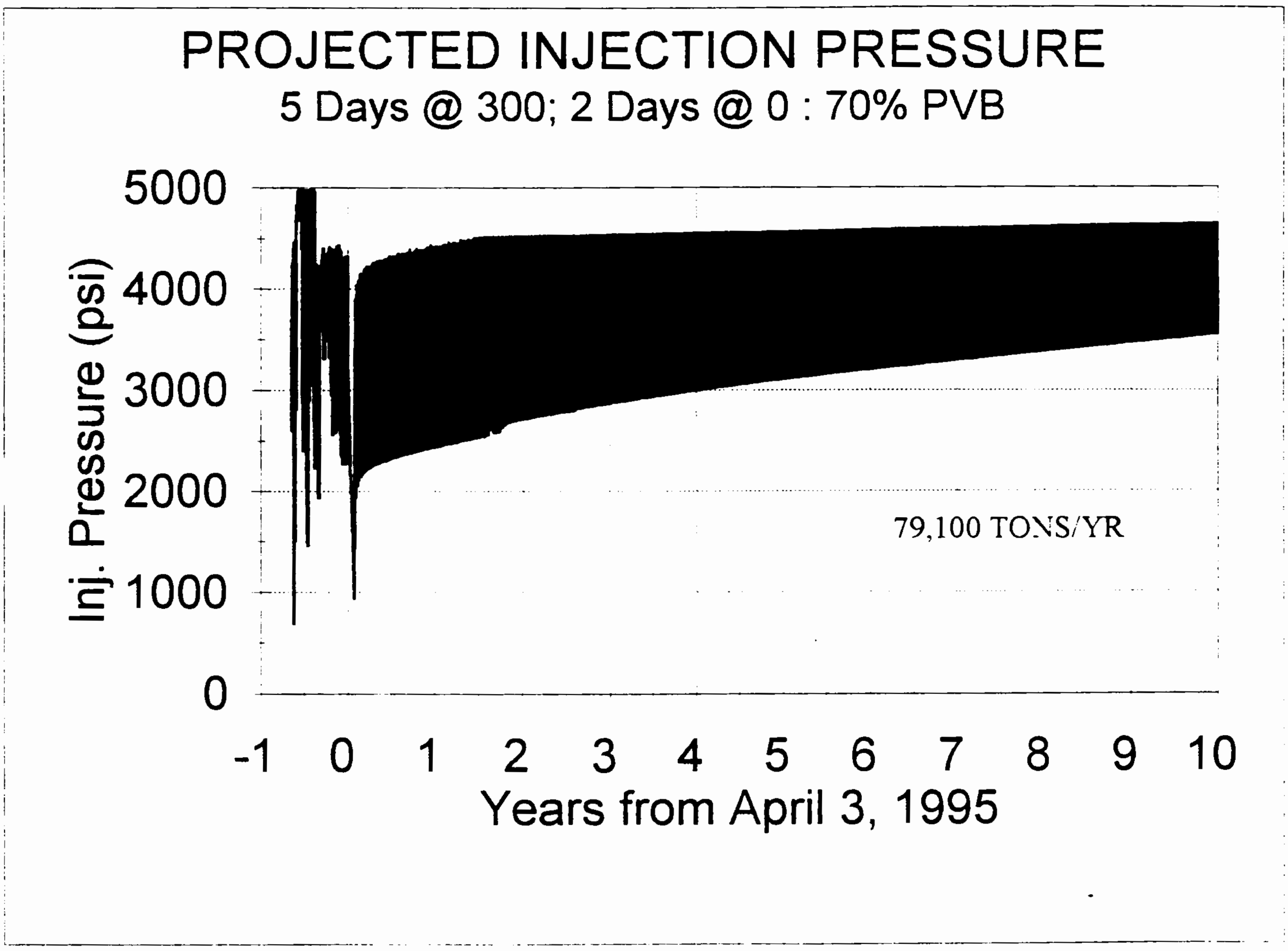

HISTORY MATCH OF TEST 7
LAST 60 DAYS
INJ. PRESSURE & GPM
5000
4000
3000
2000
1000
0
170
FEB
MAR
APR
GPM
— ACTUAL — MODEL

FIGURE 4.4.1



PROJECTED INJECTION PRESSURE
5 Days @ 300; 2 Days @ 0 : 70% PVB
Inj. Pressure (psi)
5000
4000
3000
2000
1000
0
79,100 TONS/YR
-1
0
1
2
3
4
5
6
7
8
9
10
Years from April 3, 1995

FIGURE 4.4.2

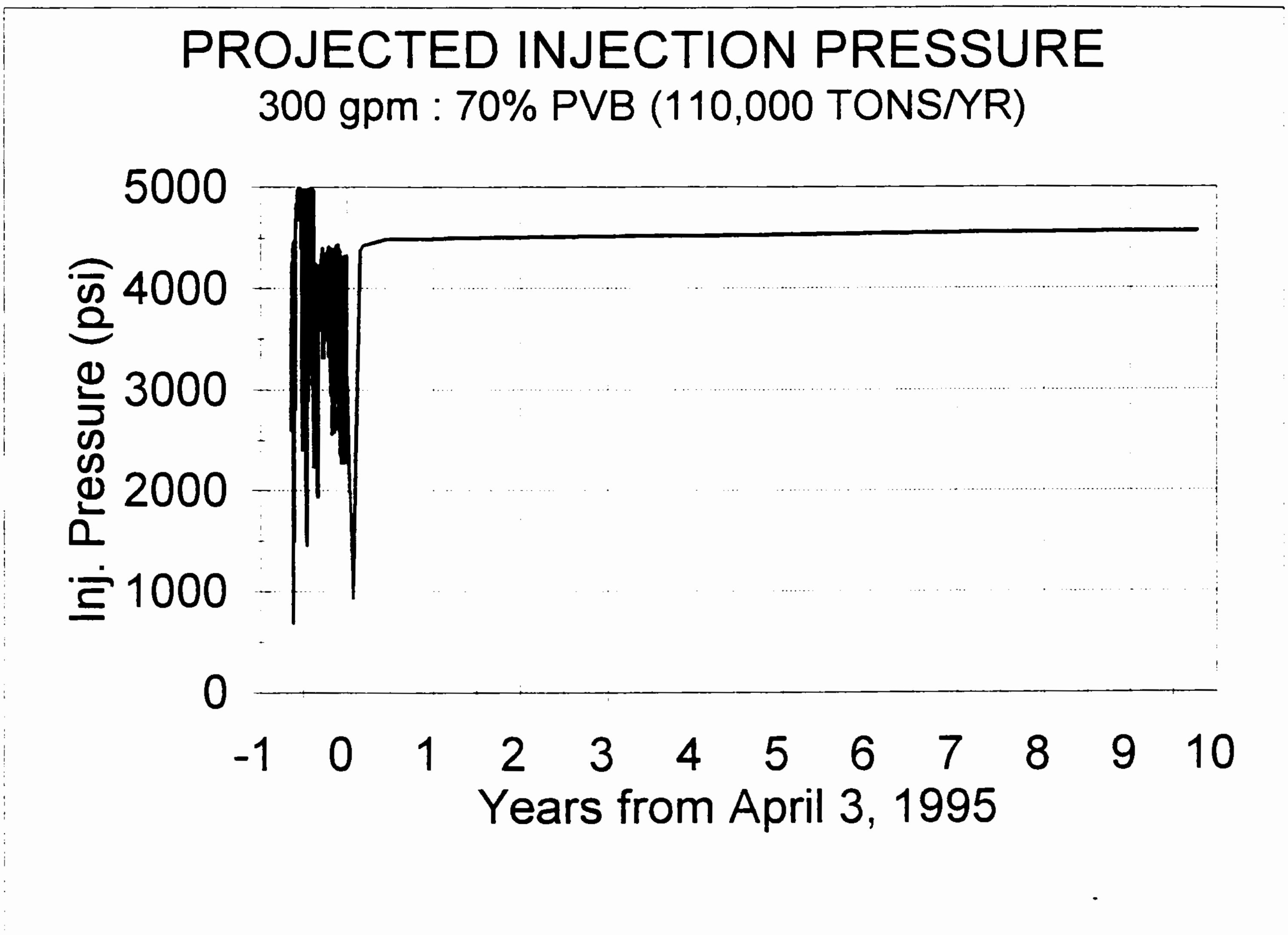
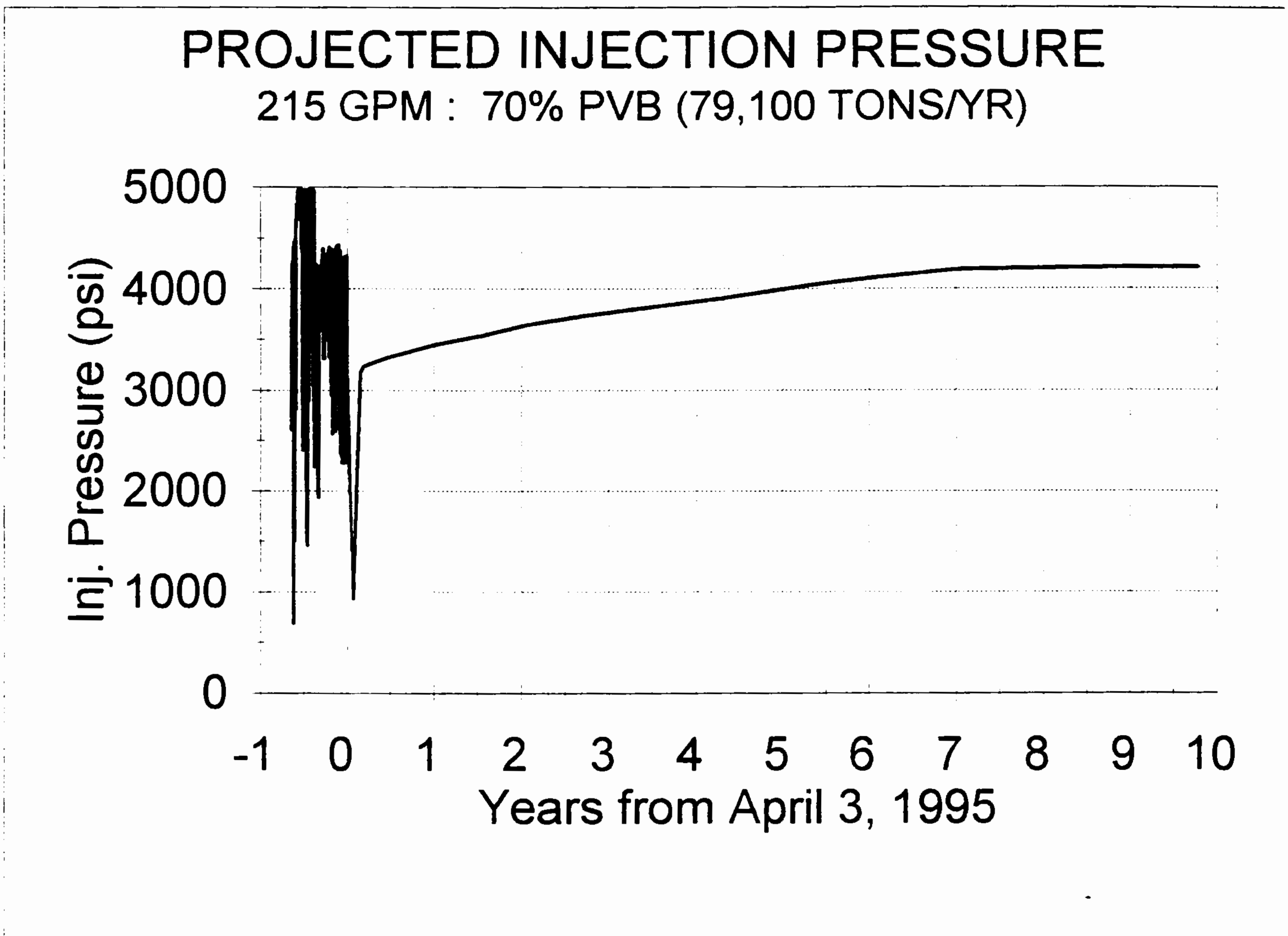

PROJECTED INJECTION PRESSURE
300 gpm : 70% PVB (110,000 TONS/YR)
5000
4000
3000
2000
1000
0
Inj. Pressure (psi)
-1
0
1
2
3
4
5
6
7
8
9
10
Years from April 3, 1995

FIGURE 4.4.3



PROJECTED INJECTION PRESSURE
215 GPM : 70% PVB (79,100 TONS/YR)
Inj. Pressure (psi)
5000
4000
3000
2000
1000
0
-1
0
1
2
3
4
5
6
7
8
9
10
Years from April 3, 1995

FIGURE 4.4.4

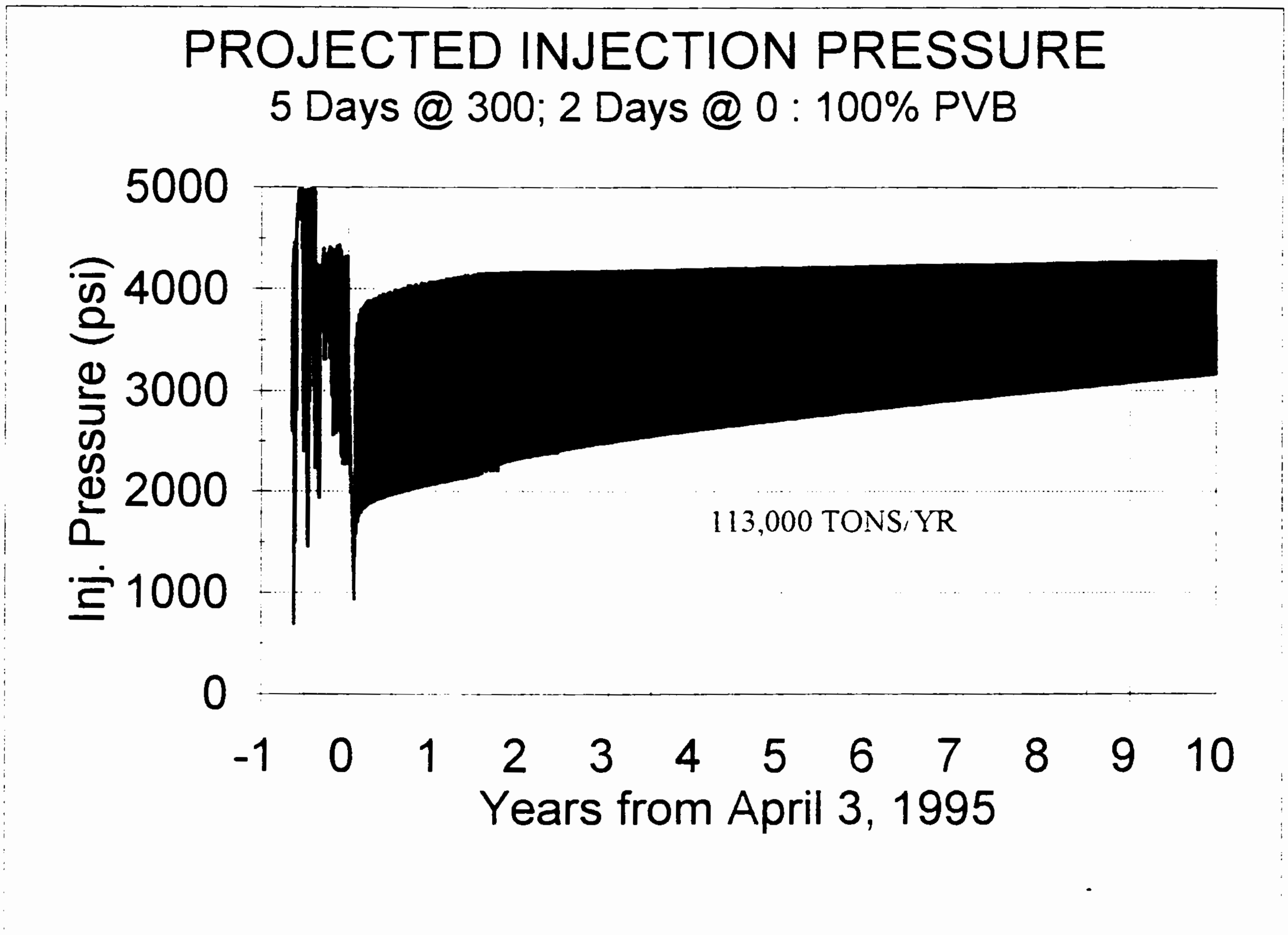

PROJECTED INJECTION PRESSURE
5 Days @ 300; 2 Days @ 0 : 100% PVB
Inj. Pressure (psi)
5000
4000
3000
2000
1000
0
113,000 TONS/YR
-1
0
1
2
3
4
5
6
7
8
9
10
Years from April 3, 1995

FIGURE 4.4.5

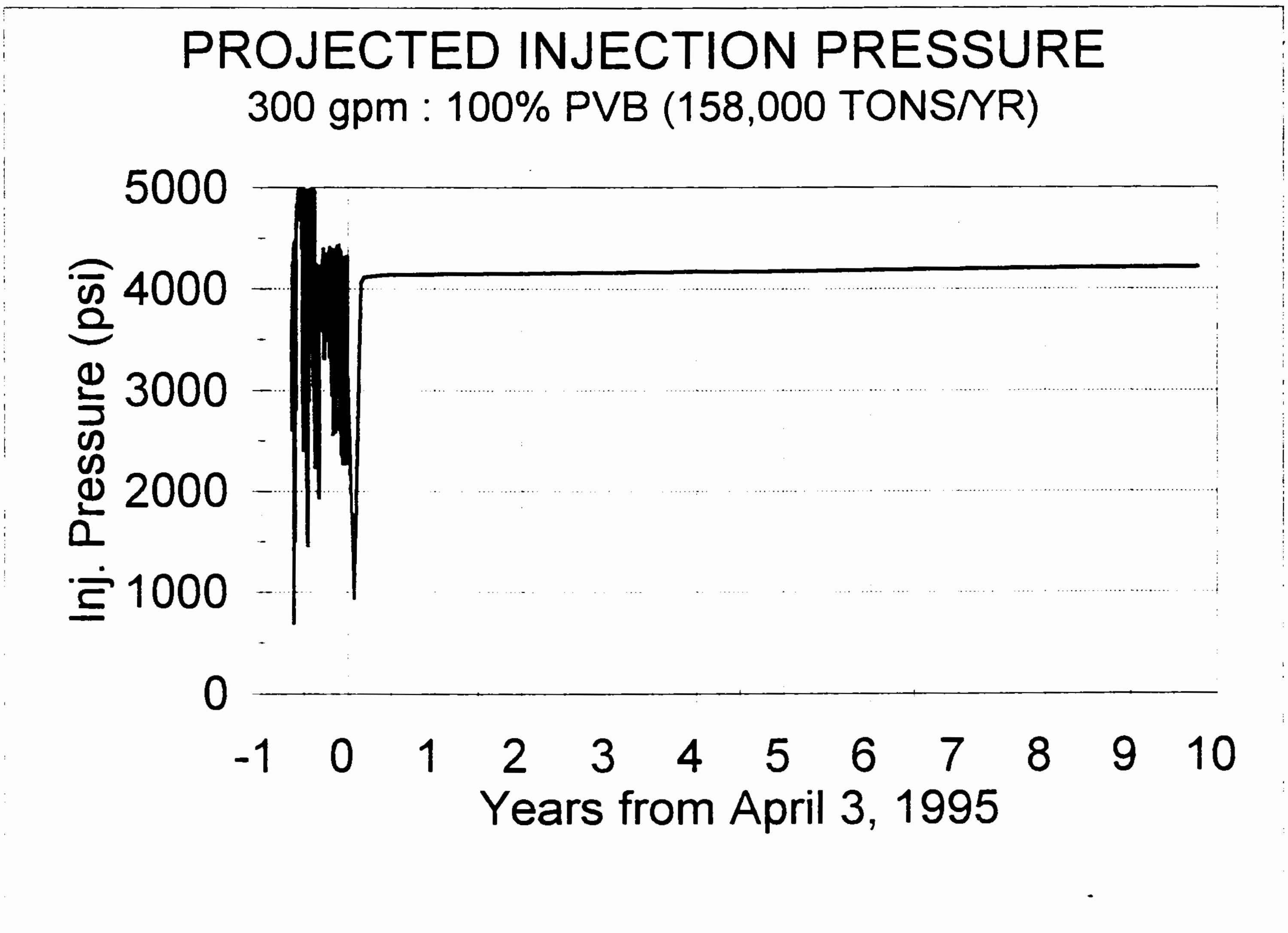

PROJECTED INJECTION PRESSURE
300 gpm : 100% PVB (158,000 TONS/YR)
5000
4000
3000
2000
1000
0
Inj. Pressure (psi)
-1
0
1
2
3
4
5
6
7
8
9
10
Years from April 3, 1995

FIGURE 4.4.6

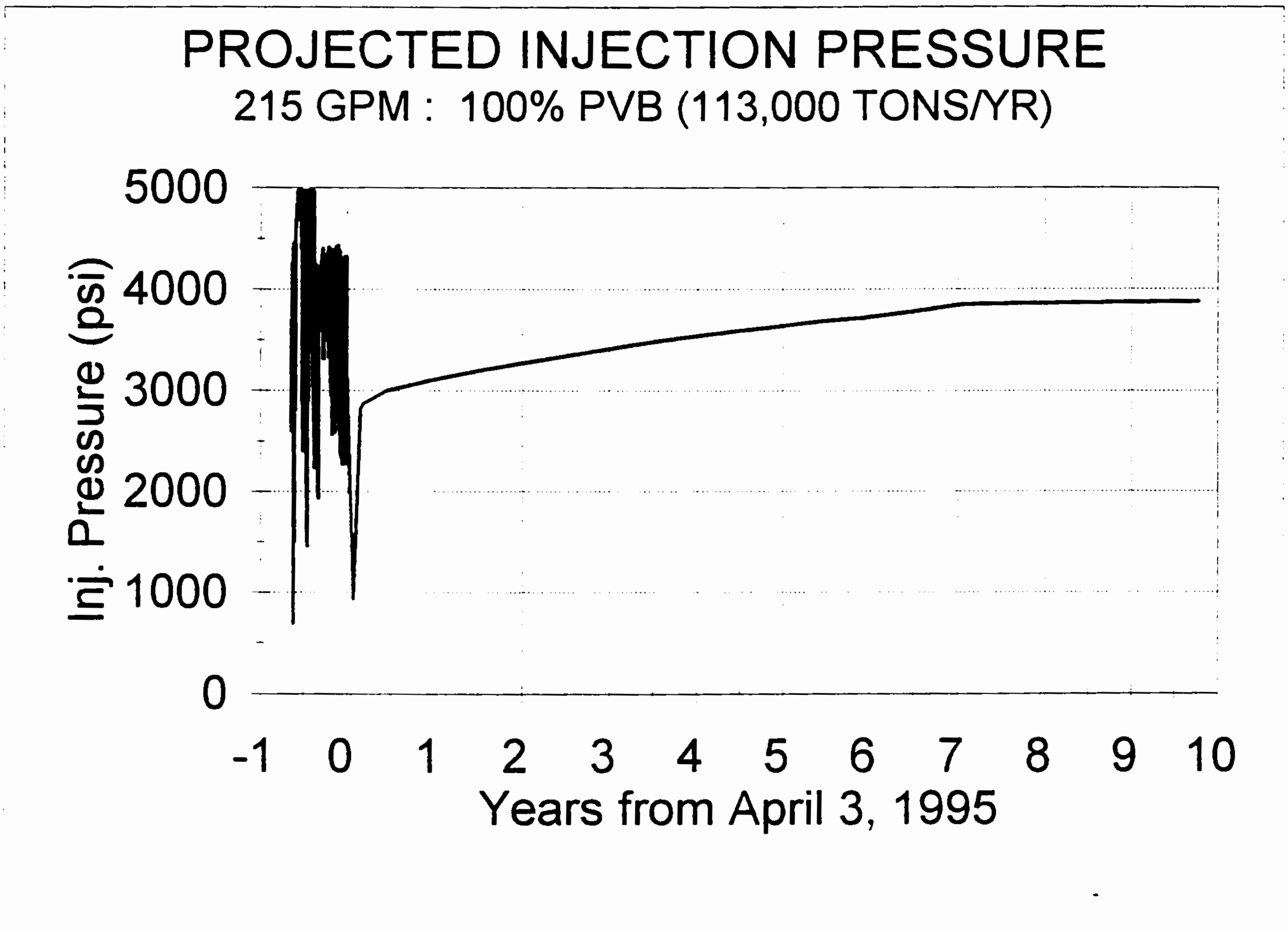

PROJECTED INJECTION PRESSURE
215 GPM : 100% PVB (113,000 TONS/YR)
Inj. Pressure (psi)
5000
4000
3000
2000
1000
0
-1
0
1
2
3
4
5
6
7
8
9
10
Years from April 3, 1995

FIGURE 4.4.8

PRESSURES FOR A 12.6 MILE X 4.3 MILE
PORTION OF THE AQUIFER

300 GPM - APRIL 3, 2005

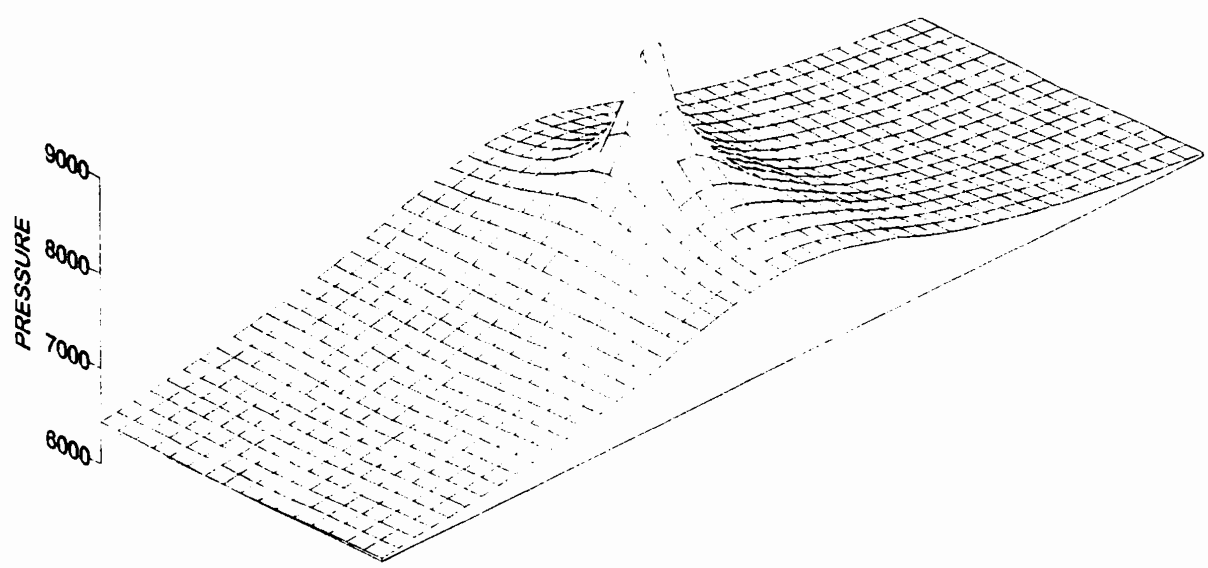
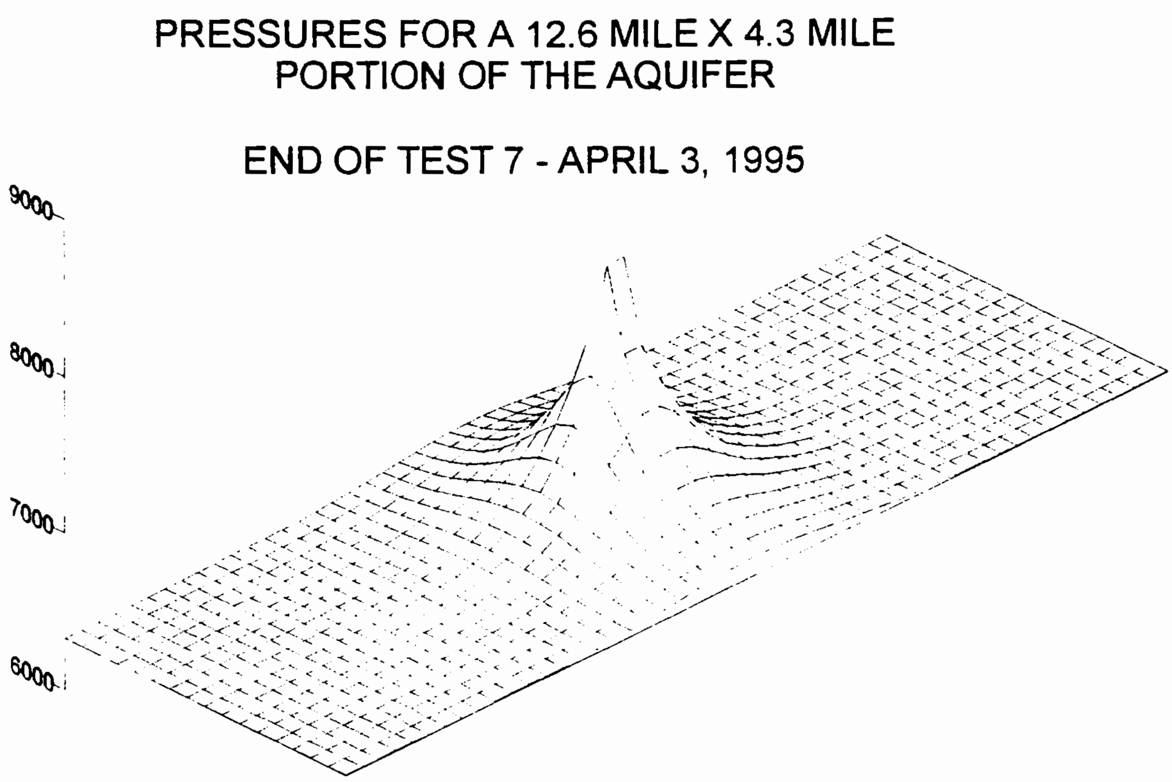


FIGURE 4.4.7


PRESSURES FOR A 12.6 MILE X 4.3 MILE
PORTION OF THE AQUIFER
END OF TEST 7 - APRIL 3, 1995
9000
8000
7000
6000

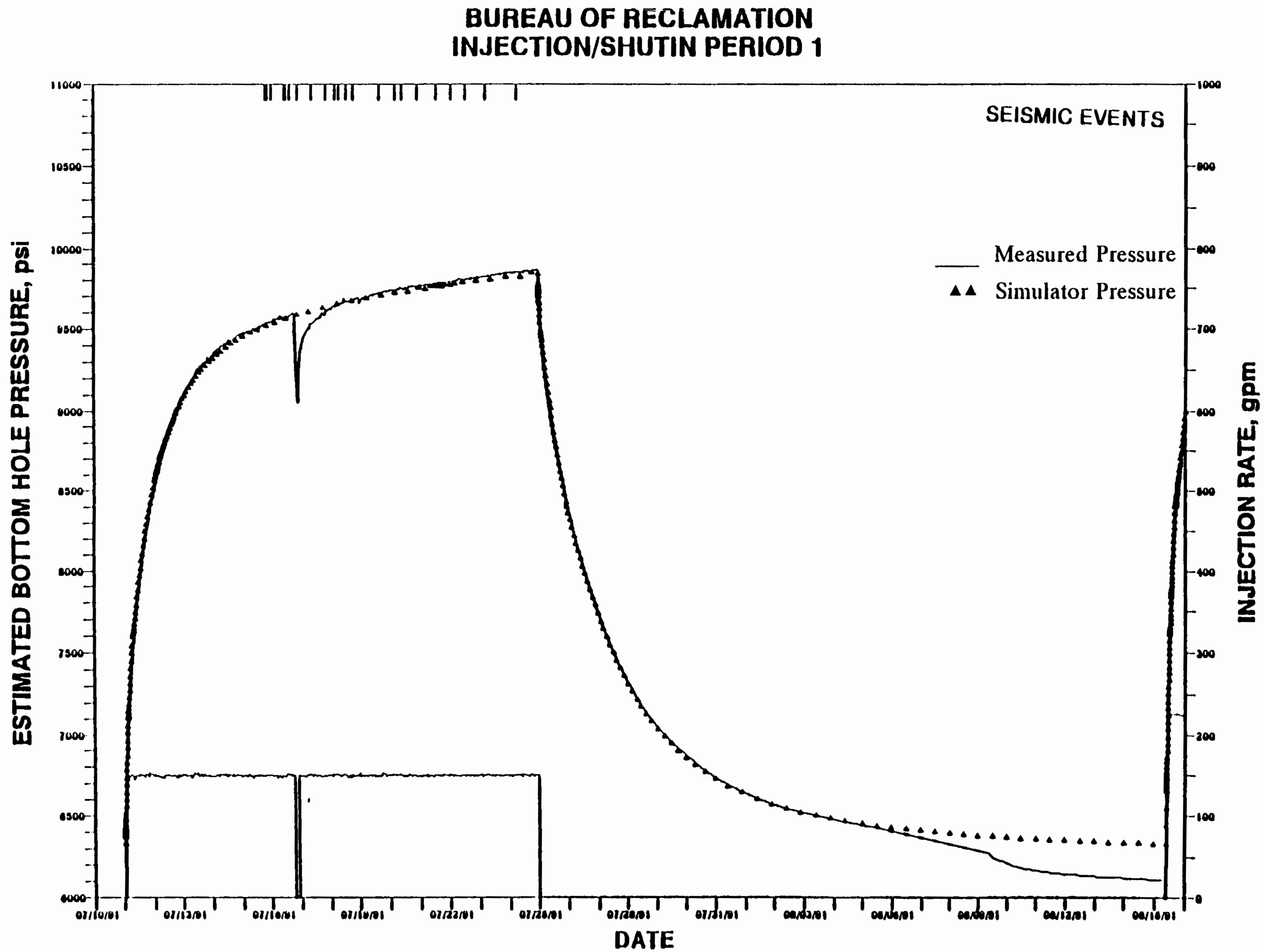

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 1
SEISMIC EVENTS
Measured Pressure
Simulator Pressure
ESTIMATED BOTTOM HOLE PRESSURE, psi
INJECTION RATE, gpm
DATE

FIGURE 5.1.1

FIGURE 5.1.2

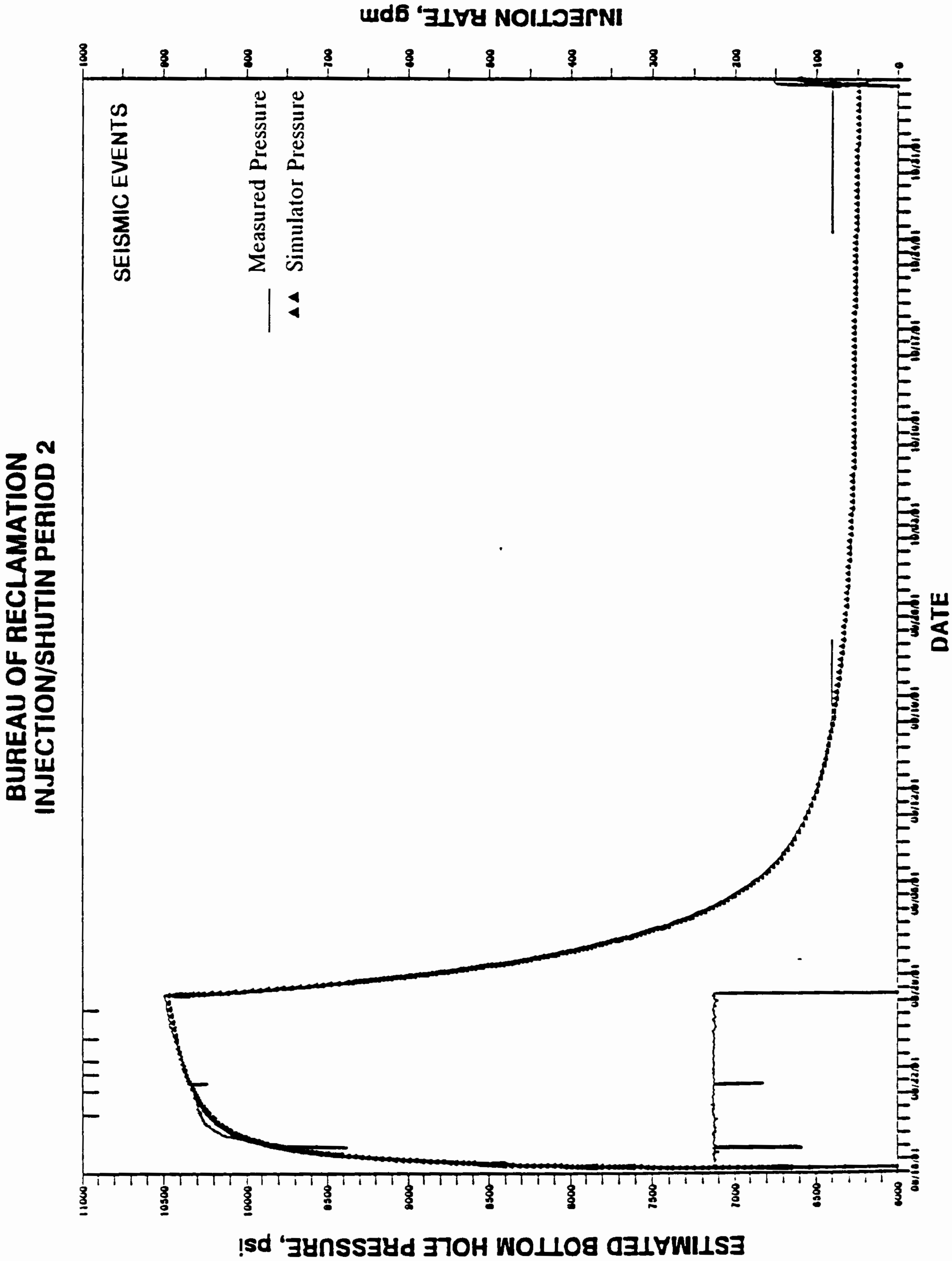

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 2
SEISMIC EVENTS
Measured Pressure
Simulator Pressure
INJECTION RATE, gpm
ESTIMATED BOTTOM HOLE PRESSURE, psi
DATE

FIGURE 5.1.3

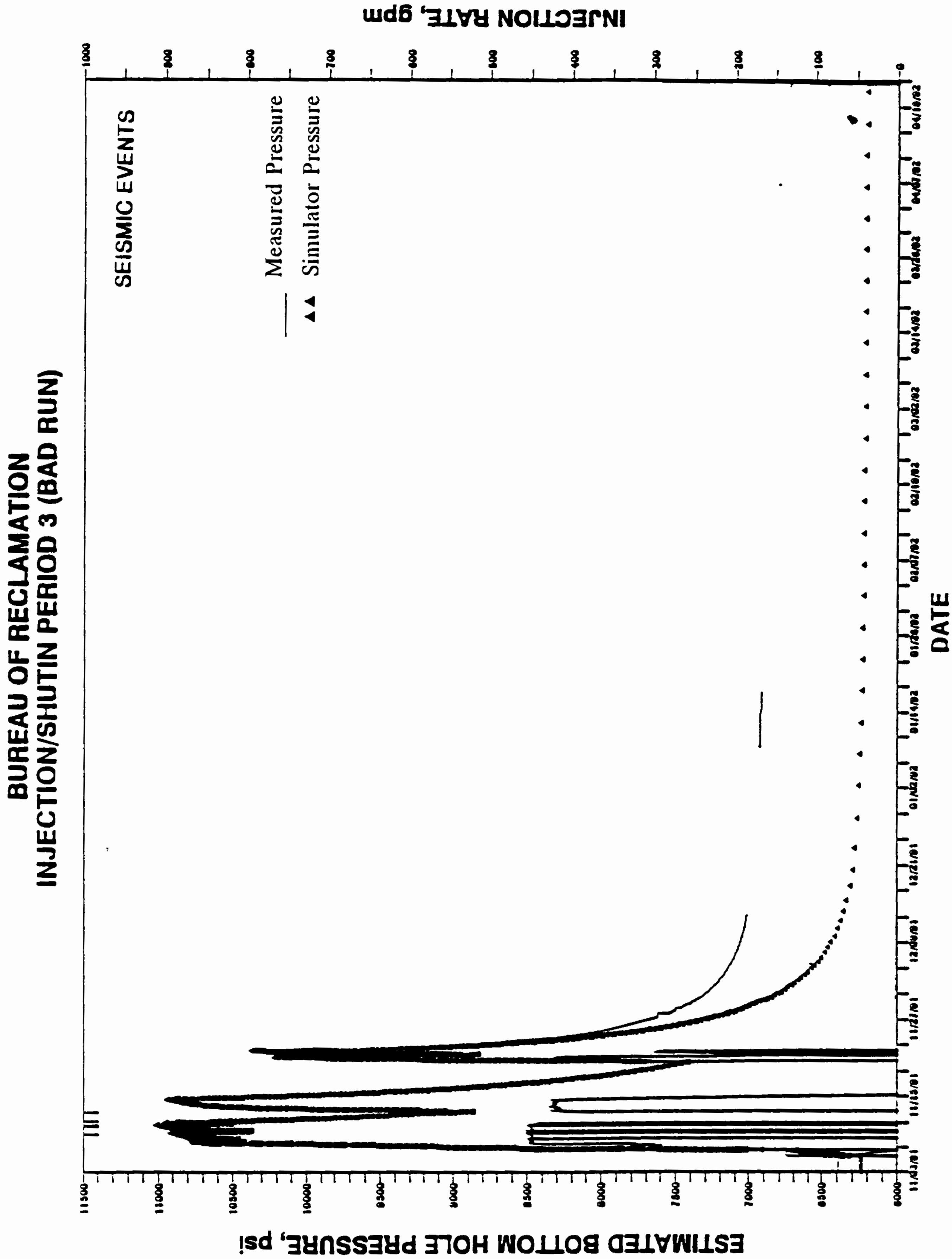

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 3 (BAD RUN)
SEISMIC EVENTS
Measured Pressure
Simulator Pressure
INJECTION RATE, gpm
ESTIMATED BOTTOM HOLE PRESSURE, psi
DATE

FIGURE 5.1.4

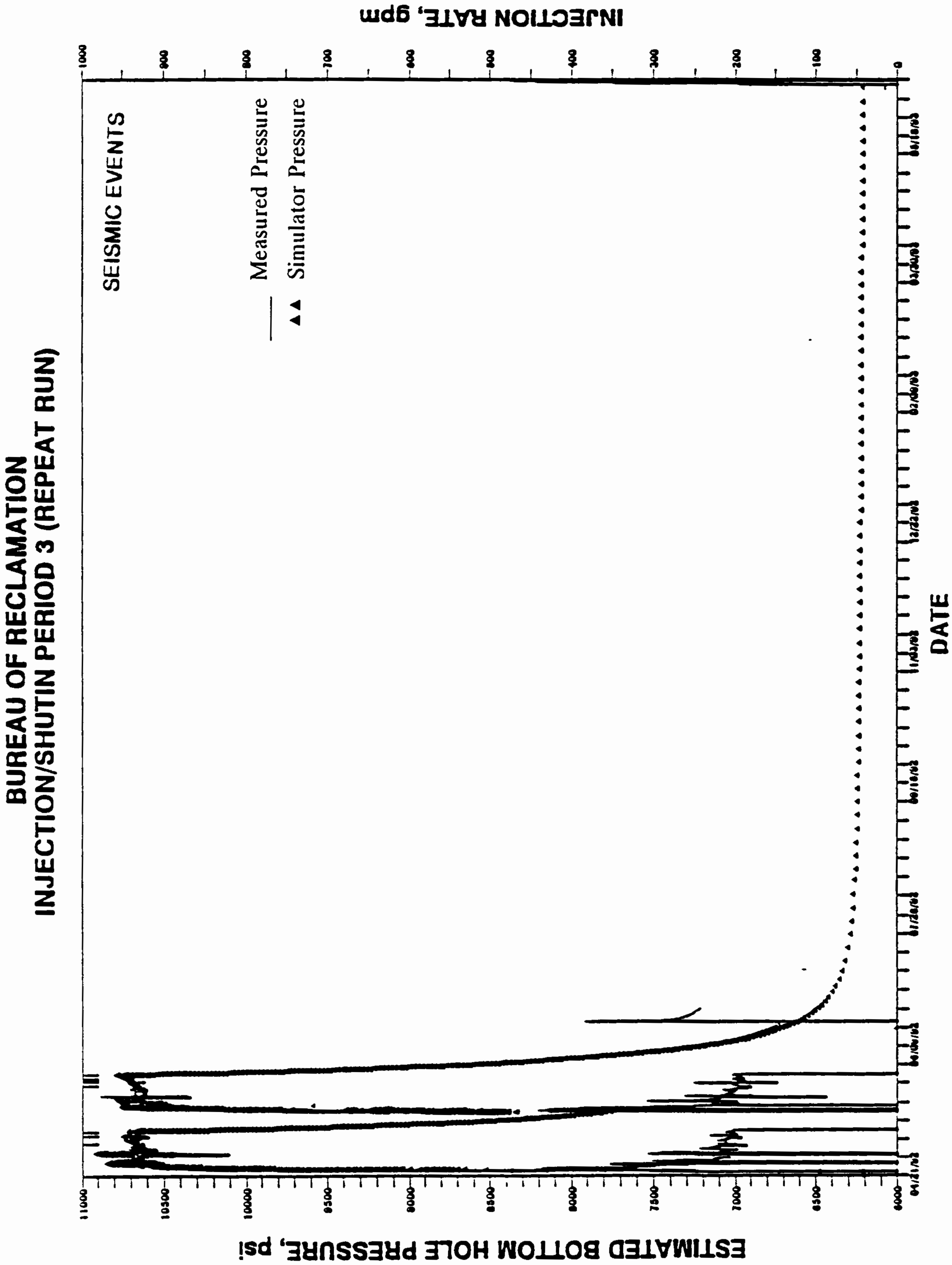
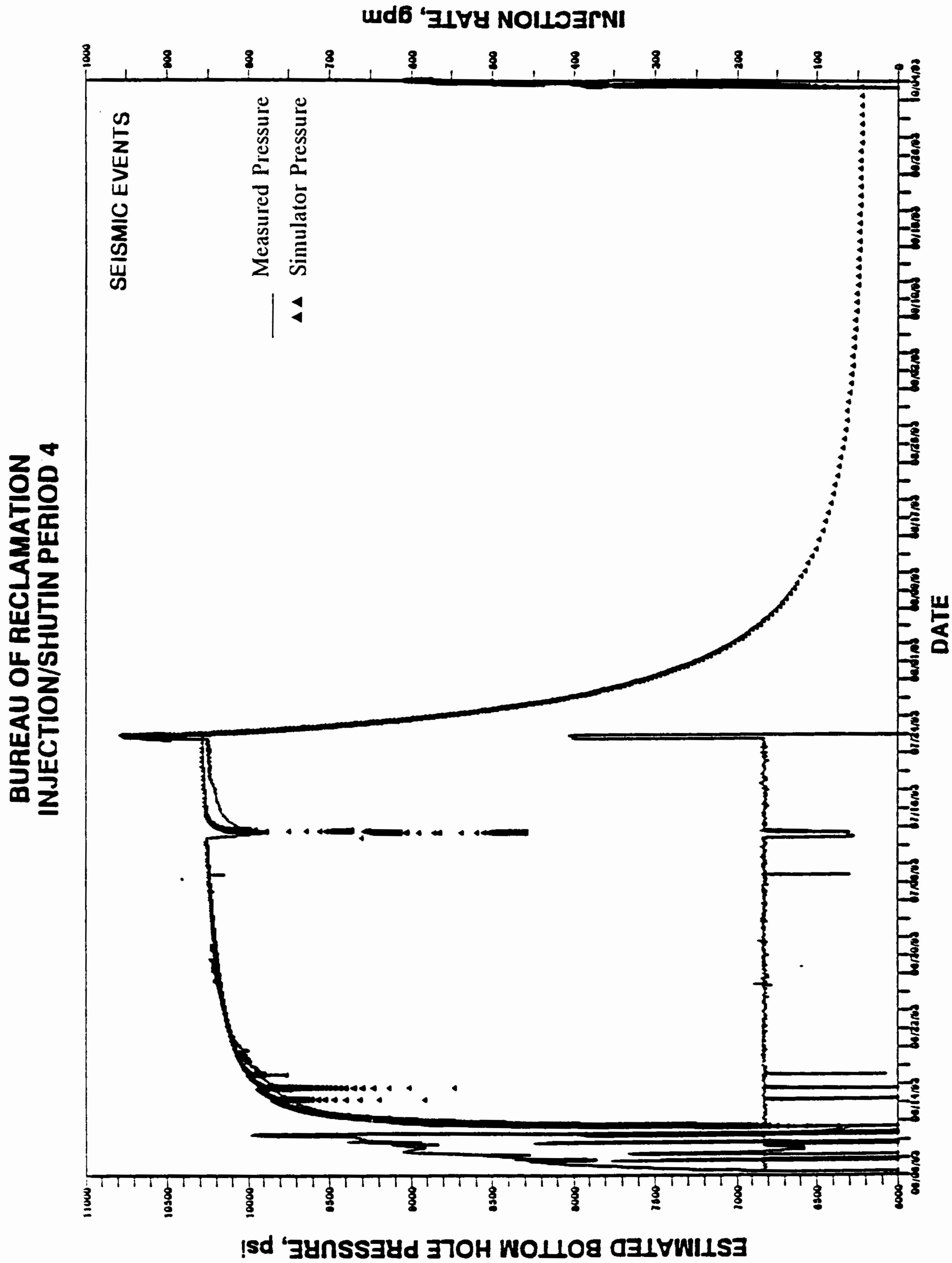

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 3 (REPEAT RUN)
SEISMIC EVENTS
Measured Pressure
Simulator Pressure
INJECTION RATE, gpm
ESTIMATED BOTTOM HOLE PRESSURE, psi
DATE

FIGURE 5.1.5



BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 4
SEISMIC EVENTS
Measured Pressure
Simulator Pressure
INJECTION RATE, gpm
ESTIMATED BOTTOM HOLE PRESSURE, psi
DATE

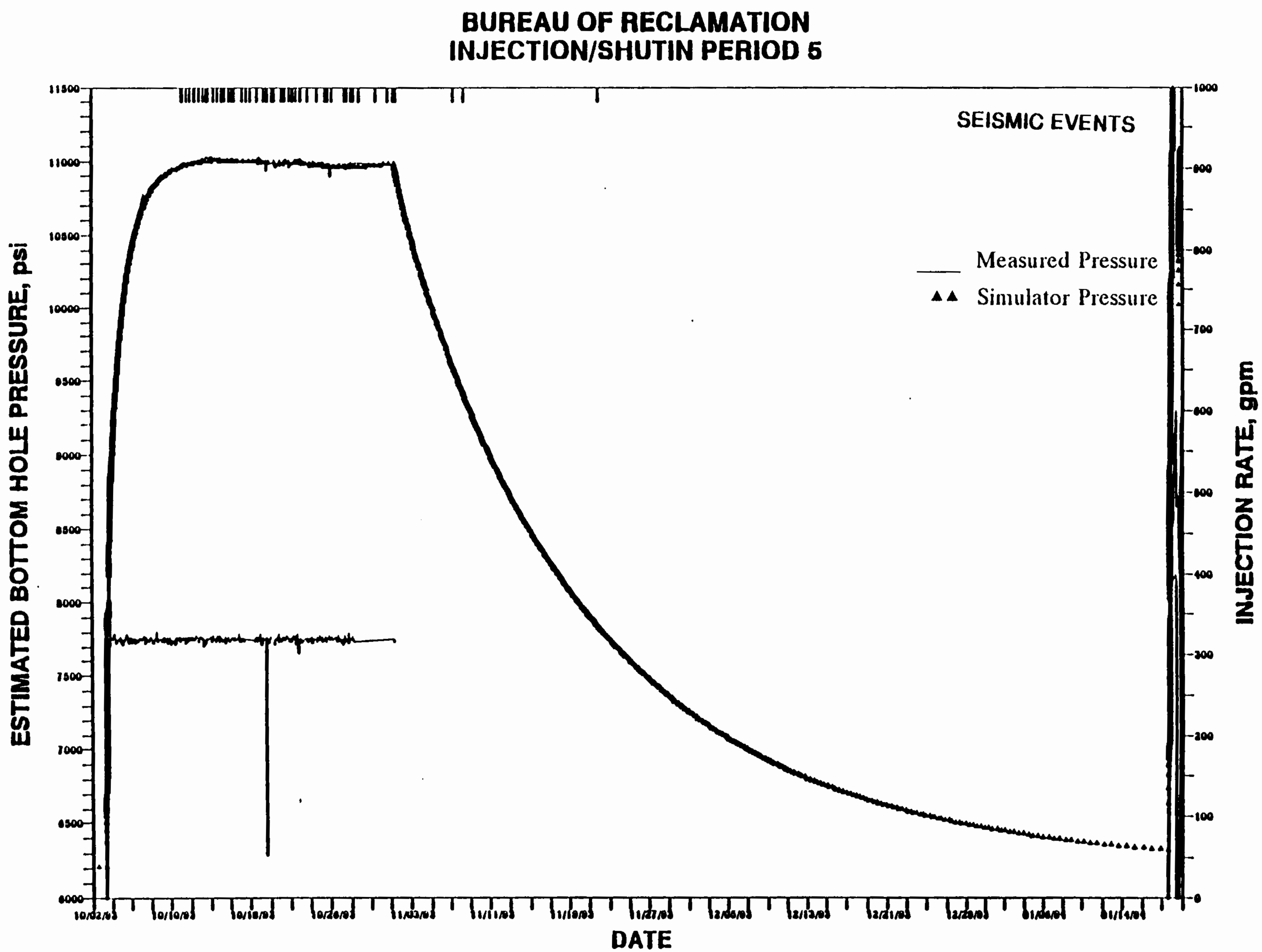
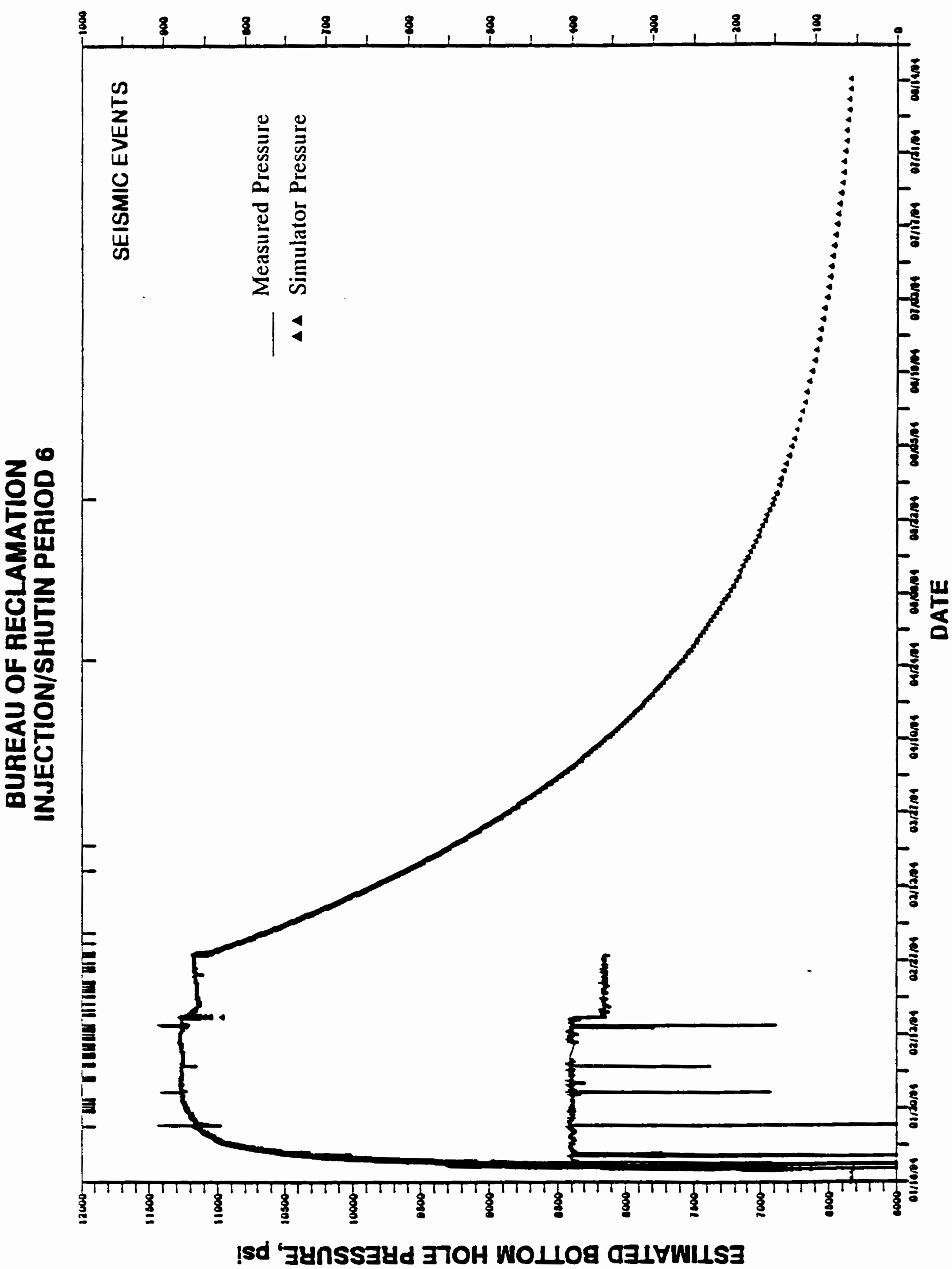
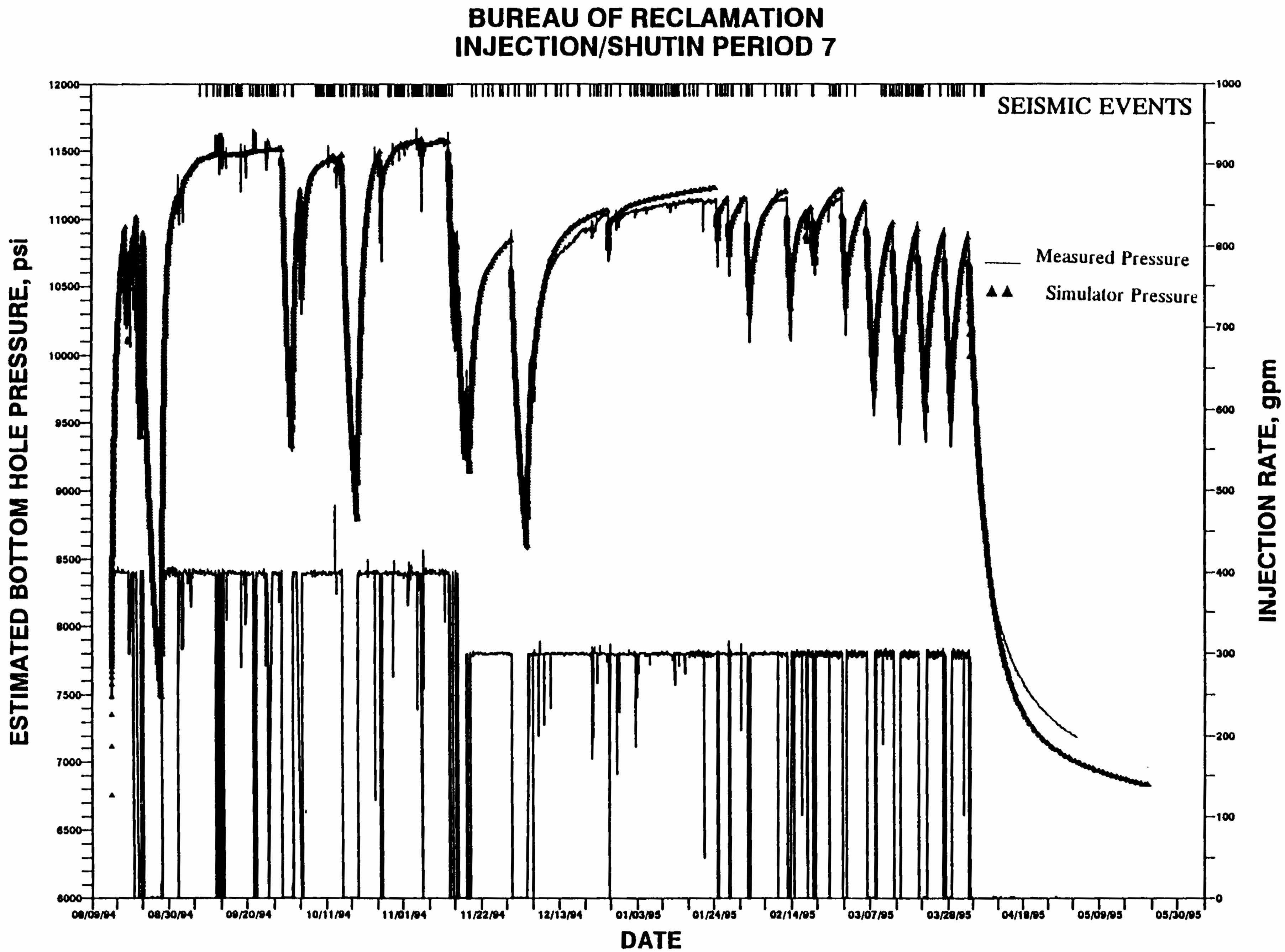

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 5
SEISMIC EVENTS
Measured Pressure
Simulator Pressure
ESTIMATED BOTTOM HOLE PRESSURE, psi
INJECTION RATE, gpm
DATE

FIGURE 5.1.6

FIGURE 5.1.7

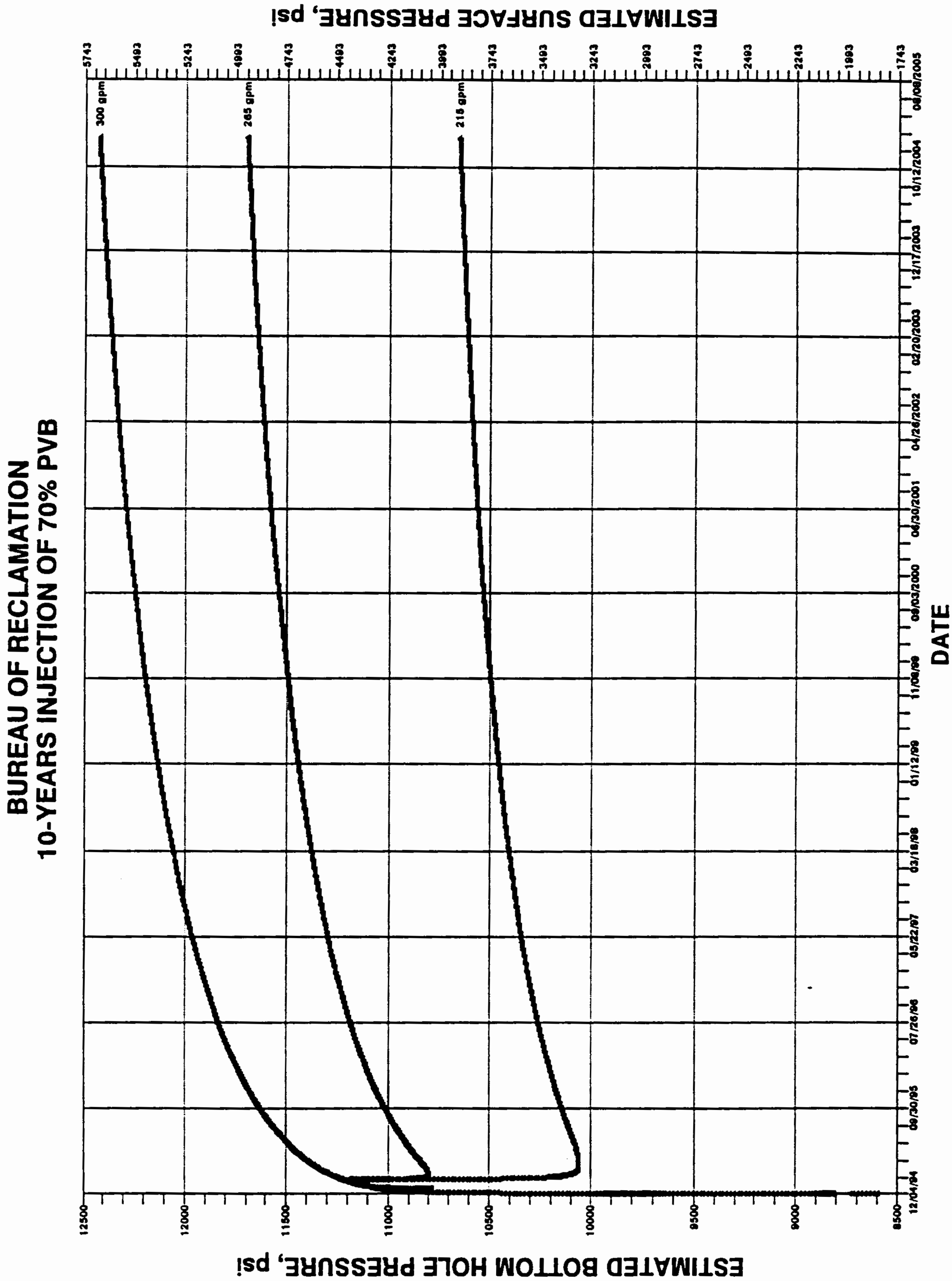

BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 6
SEISMIC EVENTS
Measured Pressure
Simulator Pressure
DATE
ESTIMATED BOTTOM HOLE PRESSURE, psi



BUREAU OF RECLAMATION
INJECTION/SHUTIN PERIOD 7
SEISMIC EVENTS
Measured Pressure
Simulator Pressure
ESTIMATED BOTTOM HOLE PRESSURE, psi
INJECTION RATE, gpm
DATE
12000
11500
11000
10500
10000
9500
9000
8500
8000
7500
7000
6500
6000
1000
900
800
700
600
500
400
300
200
100
0
08/09/94
08/30/94
09/20/94
10/11/94
11/01/94
11/22/94
12/13/94
01/03/95
01/24/95
02/14/95
03/07/95
03/28/95
04/18/95
05/09/95
05/30/95

FIGURE 5.1.8

FIGURE 5.2.1


BUREAU OF RECLAMATION
10-YEARS INJECTION OF 70% PVB
ESTIMATED SURFACE PRESSURE, psi
ESTIMATED BOTTOM HOLE PRESSURE, psi
DATE
300 gpm
265 gpm
215 gpm
12500
12000
11500
11000
10500
10000
9500
9000
8500

BUREAU OF RECLAMATION
10-YEARS INJECTION OF 100% PVB

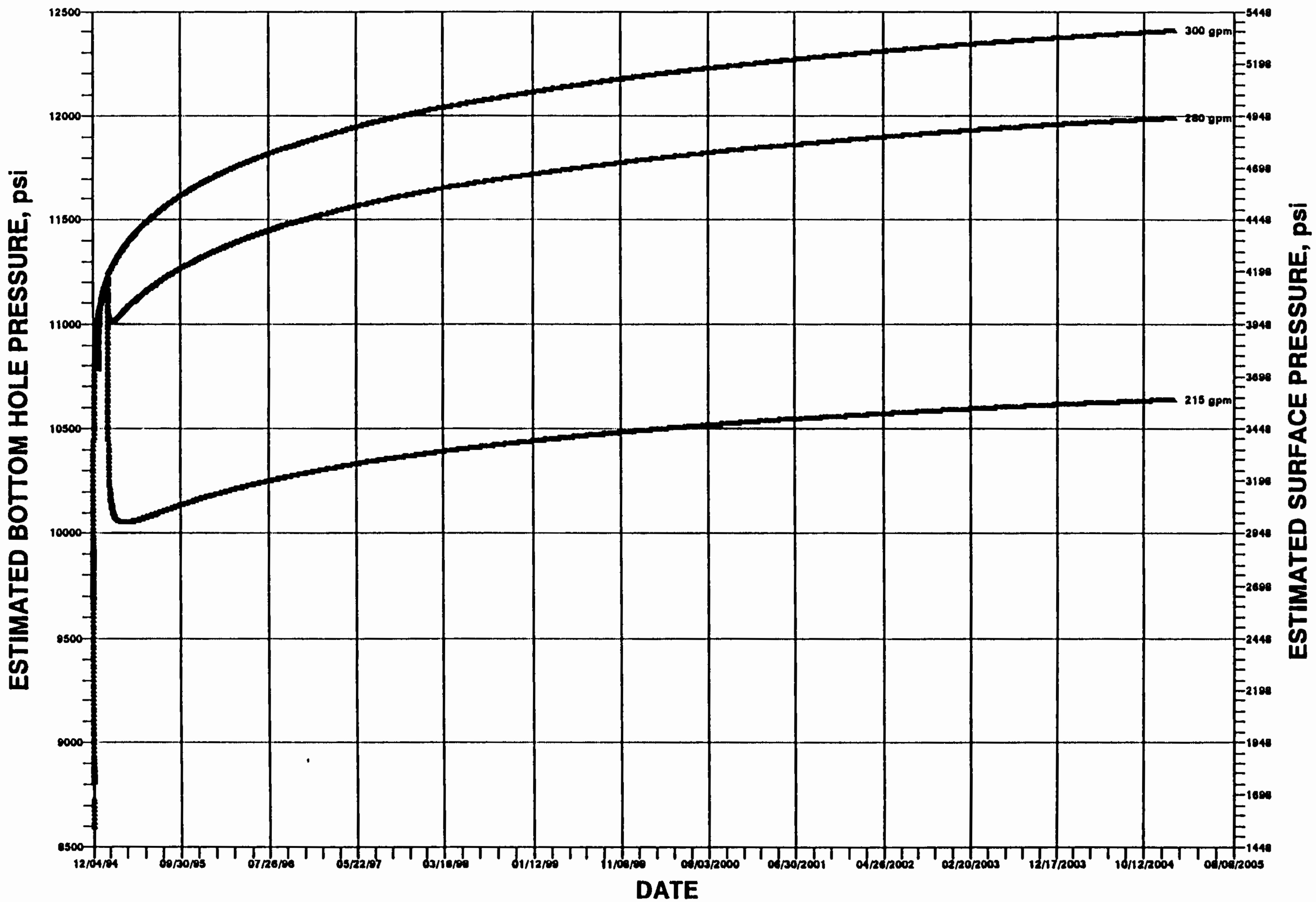


FIGURE 5.2.2

ATTACHMENTS

ATTACHMENT 1

ISOPACH MAP OF LOWER LEADVILLE FORMATION