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Blade Supplemental Report (Vol. 4: Aliso Canyon Casing Integrity)

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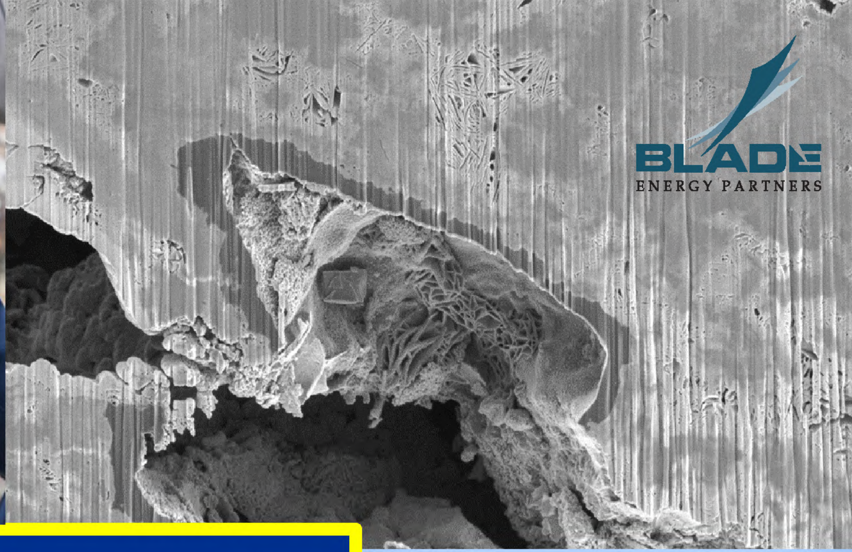

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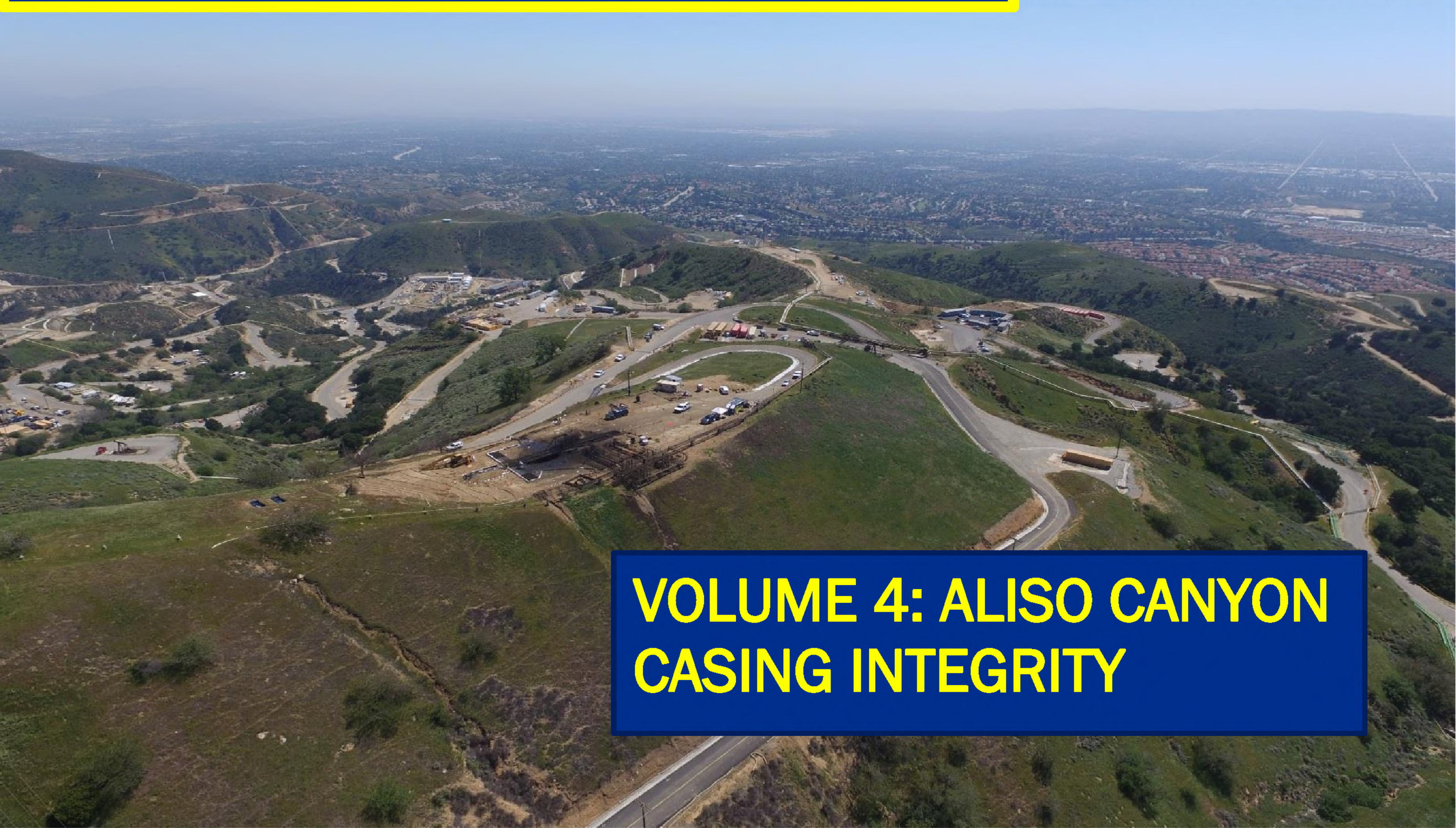
Root Cause Analysis of the Uncontrolled Hydrocarbon Release from Aliso Canyon SS-25

SUPPLEMENTARY REPORTS

May 31, 2019



VOLUME 4: ALISO CANYON CASING INTEGRITY

This RCA work necessitated a substantial amount of testing, analyses, and modeling. The integrated work is reflected in the overall RCA report. Additionally, all the technical details and discussions are provided in supplementary reports—the source documents for the RCA report—in four volumes. This is Volume 4.

MAIN REPORT

Root Cause Analysis of the Uncontrolled Hydrocarbon Release from Aliso Canyon SS-25

SUPPLEMENTARY REPORTS

Volume 1: Approach

Volume 2: SS-25 Well Failure Causes

Volume 3: Post-SS-25 Leak Events

Volume 4: Aliso Canyon Casing Integrity

Analysis of Aliso Canyon Wells with Casing Failures

Aliso Canyon Shallow Corrosion Analysis

Aliso Canyon Surface Casing Evaluation

Review of the 1988 Candidate Wells for Casing Inspection

Gas Storage Well Regulations Review

Aliso Canyon Field Withdrawal/Injection Analysis

Aliso Canyon: Regional and Local Seismic Events Analysis

SS-25 RCA Supplementary Report

Analysis of Aliso Canyon Gas Storage Wells with Casing Failures

Purpose:
Analyze casing failures in Aliso Canyon gas storage wells and summarize kill operations for wells with leaks and underground flow.

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May 31, 2019

Abstract

The gas storage well Standard Sesnon 25 (SS-25) in the Aliso Canyon Gas Storage Field located in Los Angeles County, California started leaking gas in October 2015. A relief well was drilled, and SS-25 was brought under control. The leak stopped in February 2016.

In January 2016, as part of their investigation of the leak, the California Public Utilities Commission (CPUC) and the Division of Oil, Gas, and Geothermal Resources (DOGGR) selected and gave provisional authority to Blade Energy Partners (Blade) to perform an independent Root Cause Analysis (RCA). The Blade Team and parties under Blade's direction were responsible for directing the work of subcontractors who performed the extraction of the SS-25's wellhead, tubing, casing, and the preservation and protection of associated evidence. Blade's RCA Reports, including this report, document and describe the key activities undertaken in support of the RCA effort.

A review of the Aliso Canyon wells shows a history of casing failures. The casing failures were distributed in wells throughout the field, and the depth range of failures is from the wellhead to below 8,000 ft. A general pattern regarding failure location in the field or failure depth is not apparent.

Most of the failed wells with 7 in. production casings were drilled from 1939 to the mid-1950s as conventional oil and gas wells. The failed wells with 8 5/8 in. production casings—in which many of the stage collars leaked—were drilled in the 1970s. No correlations are apparent relating casing failures and well age. Approximately 50% of the failures and casing leaks happened in the original oil and gas wells and 50% happened in the gas storage wells.

The serious consequences of casing failures were apparent when the well histories of Frew 3, FF-34A, and SS-25 were reviewed. Frew 3 and FF-34A had casing leaks that resulted in underground blowouts, and SS-25 had a casing leak that resulted in a gas blowout at surface. The underground flow wells were killed by pumping down the tubing, and SS-25 required a relief well to stop the flow. The leak in SS-25 was at 892 ft compared to leaks in FF-34A at 2,093 ft and Frew 3 at 3,240 ft. Analysis of production data shows SS-25 had a much higher leak flow rate than the other two wells, which made it more difficult to kill SS-25.

Casing connections exposed to gas are a concern when they are not designed for gas service. The majority of the casing connections in Aliso Canyon wells are either reduced outside diameter (OD) or American Petroleum Institute (API) connections. API connections are not considered to be gas-tight. Research in the 1980s showed reduced OD connections were subject to leaks and structural failures. Most of the Aliso Canyon reduced OD connections were run pre-1980. Connection leaks were reported in two wells, P-50A and Frew 4, and connection testing confirmed leaks in the SS-25 connections recovered from the well.

No documentation or analysis was found in the well files as to what caused the casing failures, making it difficult to evaluate and mitigate well integrity risks in other wells. The apparent approach prior to the SS-25 leak was to repair casing leaks as they happened to get the well back in service.

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1 Introduction

The purpose of this document is to analyze the historical production casing failures in the Aliso Canyon Field gas storage wells. The sizes of the production casings and liners that failed in Aliso Canyon include 9 5/8 in., 8 5/8 in., 7 in., 6 5/8 in., 5 1/2 in., and 5 in. OD.

A list of the Aliso Canyon wells designated as gas storage or gas storage/oil and gas well types was downloaded from the DOGGR website on May 9, 2018. The condition of the wells on this list of wells should be representative of gas storage wells in the Aliso Canyon Field. The list of wells is included in Appendix A. The 124 wells on this list were reviewed for casing failures. The well data reviewed are from the DOGGR website and SoCalGas reports and files provided to Blade.

Production casing failure[i] and/or liner failure[ii], the main focus of this document, is a condition or defect where a casing fails to perform in the manner they were designed for. In many cases, the well reports do not include enough information to determine if the leak or failure occurred in a connection or the pipe body. Unless the failed casing is recovered, it is difficult to confirm the failure details or cause of the failure in most cases. Therefore, it was not possible to categorize the Aliso Canyon failures as either connection or pipe body failures, except where the reports specifically stated the failure was in the pipe body or connection, or an inspection log confirms specific issues, such as a hole in the pipe body.

Other failures included collapsed casing, tight spots, split casing, damage due to earthquakes, and the like. While some failures, such as tight spots, may not cause loss of pressure containment, they can limit the serviceability of a well because they prevent running full gauge downhole tools. Tight spots are not normal and lead to other problems when they are swaged or reamed with a mill. A tight spot in the 7 in. casing in P-44 was milled in 1977 and 1978, and it became a casing leak [1]. Care was taken to not double-count failures. For example, if a reamed tight spot became a casing leak, it was counted as one failure, not two.

A well that has a casing failure as part of its history is considered a failed well. A well can have one or multiple casing failures, with multiple failures in the same casing, or failures in more than one casing or liner in the same well. A count of failed wells, casing failures, and the types of failures are included in this report.

Figure 1 shows a wellbore schematic of the below-ground components of a typical gas storage well. The surface casing is set and cemented to surface to protect fresh water and for well control while drilling. The production casing is then set and cemented into the cap-rock or through the gas reservoir. A production liner—optional—is run if the production casing is set above the reservoir. The typical completion is a packer set above the perforations with the tubing to the surface. The gas is injected and withdrawn through the tubing. This design concept has two barriers for pressure containment. The tubing is the primary barrier, and the production casing is the secondary barrier. If the tubing leaks, the casing contains the gas and pressure within the wellbore. A series of valves on the wellhead and tree is used to shut in and control the flow to and from the well.

[i] Production casing is the term used to define the casing outside the production tubing.

[ii] A liner is a casing that is set below a previously set casing, and the top of the liner is below the wellhead.

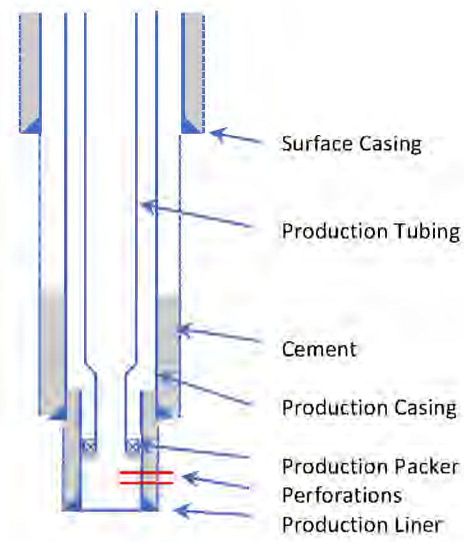

Figure 1: Gas Storage Wellbore Schematic

1.1 Abbreviations and Acronyms

Term	Definition
AB FL4S	Atlas Bradford Flushline Quadraseal
API	American Petroleum Institute
BBL	Barrels
BCF	Billion Cubic Feet
BHP	Bottomhole Pressure
BTC	Buttress Thread Casing
CP	Casing Pressure
CPET	Corrosion Protection Evaluation Tool
CPUC	California Public Utilities Commission
DOG	Division of Oil and Gas
DOGGR	Division of Oil, Gas, and Geothermal Resources
FF	Fernando Fee
FJ	Flush Joint
FP	Free Point
FWHP	Flowing Wellhead Pressure
GS	Gas Storage
ID	Internal Diameter
IPR	Inflow Performance Relationship

Term	Definition
lbf	Pounds of Force
LTC	Long Thread Casing
MA	Mission Adrian
Mcf/D	Thousand Cubic Feet per Day
MD	Measured Depth
METT	Multi-Frequency Electromagnetic Thickness
MMscf/D	Million Standard Cubic Feet per Day
OD	Outside Diameter
OG	Oil and Gas
P	Porter
P&A	Plug and Abandon
P-39A	Relief well Porter 39-A
ppf	Pounds per Foot
ppg	Pounds per Gallon
PT	Pressure Test
RBP	Retrievable Bridge Plug
RCA	Root Cause Analysis
scf/D	Standard Cubic Feet per Day
SF	Sesnon Fee
SIMP	Storage Integrity Management Program
SLB	Schlumberger
SoCalGas	Southern California Gas Company
SS	Standard Sesnon
SSSV	Subsurface Safety Valve
SSV	Surface Safety Valve
STC	Short Thread Casing
T&C	Threaded and Coupled
TOC	Top of Cement
TOF	Top of Fish
TP	Tubing Pressure
WLM	Wireline Measurement
XL	Extreme Line

2 Analysis and Discussion – Wells with Casing Failures

2.1 Gas Storage Well Design

Natural gas storage is a common practice to maintain large volumes of gas near areas where there is high demand for gas on short notice. Changing weather conditions require utilities to provide gas for residential use and short-term electricity generation. Gas is injected into depleted oil and gas fields in low demand seasons and withdrawn when required. Gas storage wells are similar in design to conventional gas wells in some respects but differ due to the cyclic nature of the pressure loads.

In conventional oil and gas wells, casing pressure loads reduce with time. This is because production of oil and gas reduce the reservoir pressure. On the other hand, the casing pressure loads for gas storage wells do not reduce with time because of the injection and withdrawal seasonal cycles. Typical gas storage wells are exposed to increased pressure during injection and reduced pressure during withdrawal. Normally, the wells have pressure cycles that are similar in magnitude, season after season, and the loads do not reduce over the years. As long as the loads and stresses remain within the elastic limit of the tubing and casing material, there should be no damage to the pipe body. There may be some plastic deformation at some thread locations, depending on the thread design and stresses caused by makeup in the connection.

SoCalGas expressed concern regarding pressure cycles related to well leaks in a 1985 Interoffice Correspondence dated April 2, 1985 [2]. A paragraph of the correspondence follows.

> . . . The number of well leakage problems in a storage field during a given year seems to be somewhat proportional to the magnitude of the pressure reversal that year. Reservoir pressure at Aliso Canyon is the lowest it has been in 12 years. If inventory goes up to 50 Bcf or higher, I would expect to find a number of leaks this year. If we lose 3 good wells or 4 mediocre wells, will be down to 80% capacity. . . .

2.2 Aliso Canyon Casing Failure Overview

Table 1 shows the details of the number of wells and production casing sizes for the 124 Aliso Canyon gas storage wells.

Table 1: Breakdown of the Production Casing Size for the Gas Storage Wells Reviewed

Casing OD	9.625 in.	8.625 in.	7 in.	6.625 in.	Total
Well Count of Wells Reviewed	26	35	61	2	124

Table 2 shows the overall numbers of wells reviewed, number of well failures, and the number of casing failures for the Aliso Canyon gas storage wells. Forty-nine of the 124 gas storage wells (40%) had at least one casing failure. There were 99 failures in the 49 wells with an average of 2 failures per well.

Table 2: Count of Wells with Casing Failures

No. Wells Reviewed	No. Wells with Casing Failures	No. Casing Failures
124	49	99

Casing leaks and tight spots make up the majority of the casing failures (Table 3). While tight spots can lead to casing leaks, the greater concern is the number of casing leaks and parted casing that cause loss of casing integrity. In many cases we were not able to discern if the failure occurred in the pipe body or in a connection based on a review of the well records because no determination or reporting had been made by SoCalGas. Casing leaks and parted casing make up 68% of the casing failures.

Table 3: Breakdown of the Types of Casing Failures

Well Type	No. Wells with Failed Casing	Failure Type and Count				
		No. Casing Leaks	No. Tight Spots	No. Parted Casing	Other[a]	Total Failures
Well and Failure Count	49	63	29	4	3	99

[a] Other types of failures include split casing in wellhead, earthquake damage, and deformed casing.

Figure 2 shows a breakdown of the number of wells reviewed, wells with casing problems, and casing failures by decade of the spud date (start date of drilling). As the plot shows, most of the drilling activity was in two groups: from 1939 to 1959, when the field was developed for oil and gas production, and from 1970 to 1979, when many of the gas storage wells were drilled.

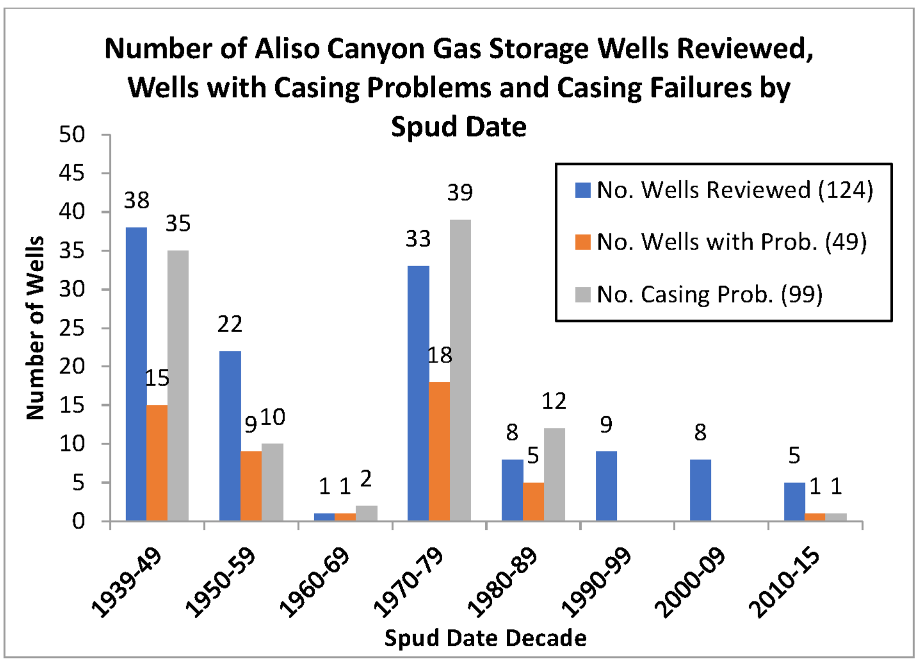

Figure 2: Number of Wells Reviewed, Wells with Failures, and Casing Failures

Table 4 shows the number and types of casing failures for the 99 failures by decade of spud date. As the data shows, many failures were in the wells drilled in the 1930s and 1940s, which were the oil and gas wells that were converted to gas storage. Many failures also occurred in the gas storage wells drilled in the 1970s after the field had been converted to gas storage. One tight spot was reported in the 22 wells drilled from 1990 to 2015.

The following summarizes the data in the table:

- 48% of casing leaks were in the 1939 to 1969 wells.
- 52% of the casing leaks were in the 1970 to 2015 wells.
- 47% of all failures were in the 1939 to 1969 wells.
- 53% of all failures were in the 1970 to 2015 wells.
- 13 of the 99 failures were reported between surface and 1,000 ft (8 casing leaks, 2 parted casing, 2 tight spots, and 1 other).

The data shows there is not a correlation between well age and casing failures. The Table 4 data is plotted in Figure 3.

Table 4: Number and Types of Casing Failures by Spud Date

Spud Date Decade	Casing Leaks	Tight Spots	Parted Casing	Other
1939–1949	22	11	1	1
1950–1959	7	1	1	1
1960–1969	1	1	-	-
1970–1979	28	10	1	-
1980–1989	5	5	1	1
1990–1999	-	-	-	-
2000–2009	-	-	-	-
2010–2015	-	1	-	-

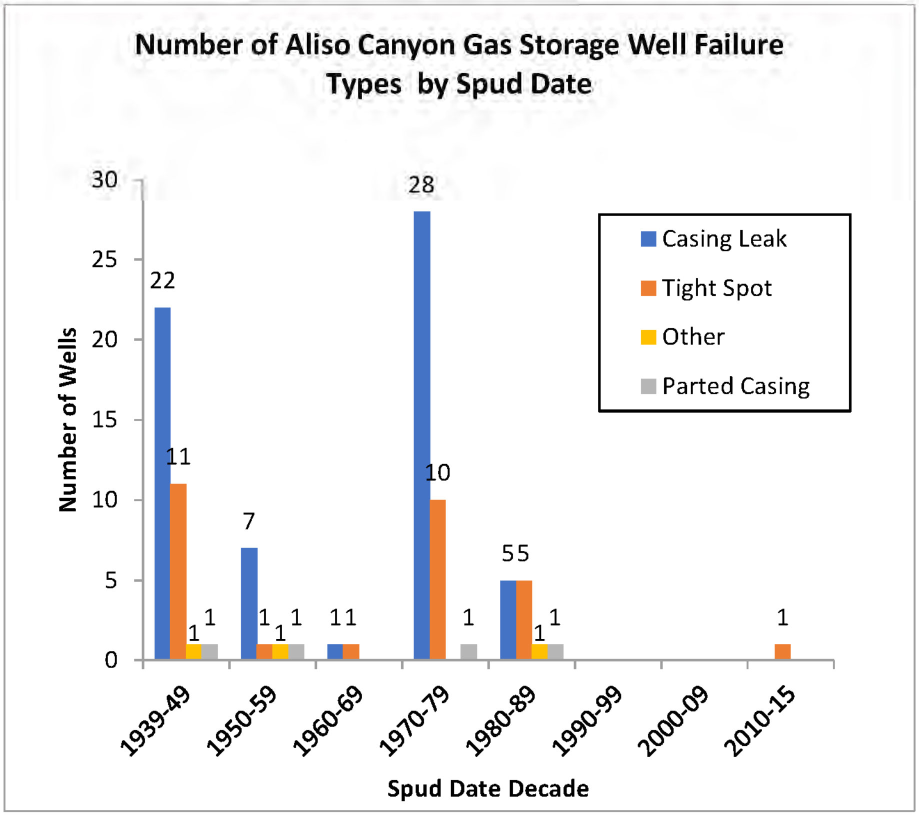

Figure 3: Number and Types of Casing Failures by Spud Date

2.2.1 Casing Leaks and Parted Casings Identified by Year

Figure 4 shows the number of casing leaks and parted casings identified by year. Thirty-four were identified from 1972 to 1982 when Aliso Canyon was converted to gas storage and began operating. The peak in 2016 was from the Storage Integrity and Management Program (SIMP) and Division Order 1109 titled *Order to Take Specific Actions Re: Aliso Canyon Gas Storage Facility* [3] operations.

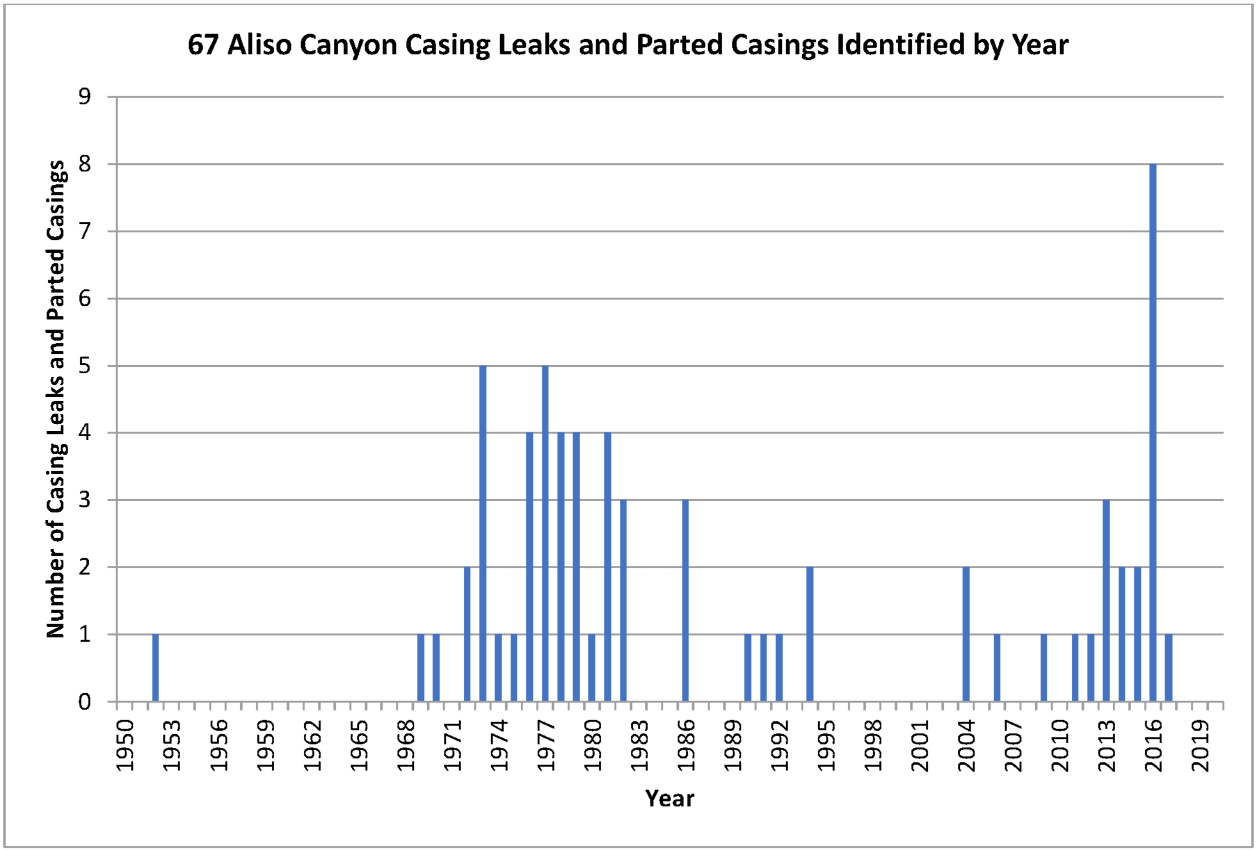

Figure 4: Casing Leaks and Parted Casing Identified by Year

Thirty-seven percent (37 of 99) of the failures occurred in 7 in. casing and 34% (34 of 99) in 8 5/8 in. casing (Table 5). These two casing sizes are the most common production casing sizes in the Aliso Canyon field.

Table 5: Breakdown of Gas Storage Wells Casing and Liner Failures by Size

Casing OD	9.625 in.	8.625 in.	7 in.	6.625 in.	5.5 in.	5 in.	Total Failures
No. of casing Failures by OD	7	34	37	7	3	11	99

2.2.2 Casing Failures in 7 in. Casing in Gas Storage Wells

Since a high number of failures occurred in 7 in. 23 ppf casings, and this size and weight match the size and weight of the casing that failed in SS-25, the wells with failed 7 in. 23 ppf casings were reviewed in more detail[iii].

Thirty-five casing failures occurred in 22 SoCalGas wells with 7 in. 23 ppf casings (Table 6). The majority of the failures were casing leaks.

Table 6: Breakdown of the 7 in. 23 ppf Casing Failure Types

	No. 7 in. Wells Failed	Failure Types and Count				
		No. Casing Leaks	No. Tight Spots	No. Parted Casing	Other	Total No. Failures
Well and Failure Count	22	21	8	3	3	35

2.2.3 Casing Failures in 8 5/8 in. Casing in Gas Storage Wells

A significant number of failures occurred in 8 5/8 in. casings. Gas storage wells with 8 5/8 in. casings were drilled starting in the early 1970s. The well design included a cement stage collar to pump a two-stage cement job. The stage collar was opened after the lower cement stage was in place, and the upper cement job was pumped in an attempt to get cement to surface. The stage collar was then closed to achieve casing pressure integrity. A stage collar has elastomer seals that can leak, and expandable casing patches were run as mitigation for the casing patch leaks.

Thirty-four casing failures were reported in 16 gas storage wells with 8 5/8 in. casings (Table 7). Similar to the 7 in. casing failures, the majority of the failures were casing leaks.

Table 7: Breakdown of the 8 5/8 in. Casing Failure Types

	No. 8 5/8 in. Wells Failed	Failure Types and Count				
		No. Casing Leaks	No. Tight Spots	No. Parted Casing	Other	Total No. Failures
Well and Failure Count	16	25	8	1	0	34

2.2.4 Parted Casing Analysis

Parted casings were reported in four wells from 1969 to 1994 (Table 8). The daily reports and log data show the casings parted in one of the connections in three of the four wells. No records were found regarding whether the parted casing in P-45 was in the connection or pipe body. The P-45 reported connection type was T&C. The comments in the table are paraphrased from each well's daily reports.

A parted casing was recovered from SS-12 in 1977. A Speedtite pin had been damaged and jumped out of a damaged box. Two more Speedtite connections had parted while being pressure tested, after tying back the casing. (All Speedtite casing was pulled and replaced during the workover in 1977.)

[iii] The SS-25 7 in. casing design consisted of 2,398 ft of 7 in. 23 ppf J55 on top, 3,910 ft of 7 in. 23 ppf N80, 1,974 ft of 7 in. 26 ppf N80 and 303 ft of 7 in. 29 ppf N80 casing on bottom. This was a fairly typical casing design used in the Aliso Canyon field in the 1940s and 1950s for oil producer wells and includes multiple weights and grades of 7 in. casing.

The typical repair for shallow parted casings was to pull the upper parted casing then cut and recover a section of the lower casing. The casing was then tied back to the surface with a new casing by using a bowl-type casing patch to connect to the top of the existing casing.

No records of failure analysis were found for any of the parted casing in the four wells.

Table 8: Details of the Parted Casing Failures

Well	Casing OD (in.)	Connection Type	Parted Casing Depth (ft)	Repair Year	Comments
P-45	7	T&C	177	1969	Recovered parted casing.
SS-12	7	Speedtite	553	1977	Recovered parted casing. Connections parted 2 more times during the workover. Pulled all casing with Speedtite connections.
P-42B	8.625	BTC	7,488	1992	Connection parted. USIT log indication of a gap in the casing.
SS-4-0	7	LTC	1,445	1994	Earthquake related. Caliper log indication of a gap in the casing. Recovered parted casing.

2.2.5 Casing Leak Analysis by Depth

Figure 5 shows the number of casing leaks by depth range. Eight of 61 (13%) casing leaks occurred above 1,000 ft. This includes the SS-25 leak. Fifty-two percent of the leaks were between surface and 4,000 ft with no trend of leak count vs. depth. Leaks in the lower part of the well were more numerous from 7,000 ft to 8,000 ft. The 63 casing leaks occurred in 41 wells with an average of 1.5 leaks per well.

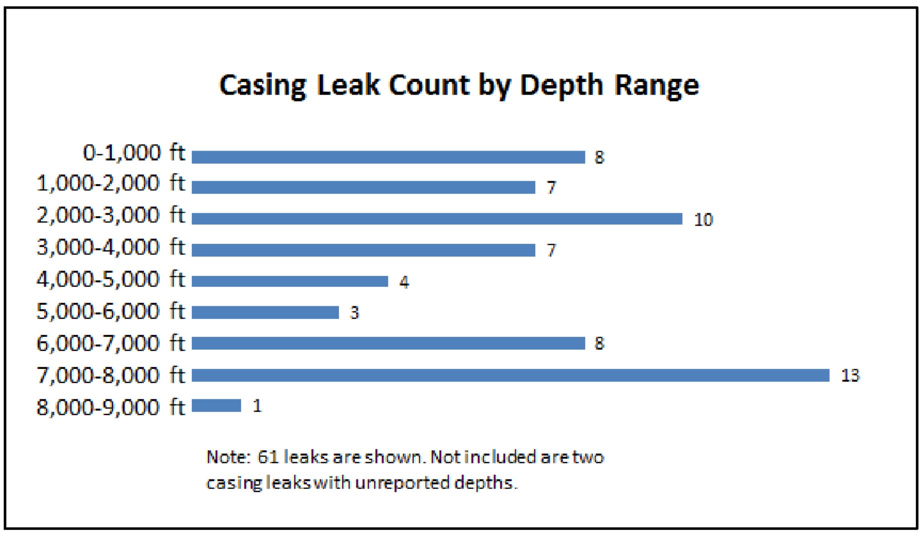

Figure 5: Casing Leak Count by Depth Range

2.2.6 Analysis of SoCalGas Casing Failures by Well Age

Sixty of the wells reviewed that were drilled in the 1930s, 1940s, and 1950s had 45 casing failures.

Two wells stand out with multiple failures:

- P-25R accounted for 9 of the 35 failures in the 1940s wells.
- P-69A had 6 of the 12 failures in the 1980s wells.

One casing failure occurred in the 22 wells reviewed that spudded after 1990 (Figure 2).

There was a natural break between 1955 and 1972 when only 1 well was drilled (Frew 9) of the 124 gas storage wells reviewed (Figure 2).

2.2.7 Service Life

There is a wide range of number of years the failed wells were in service before casing failures occurred. Frew 2 and P-35 had 70 years of service life, and SS-7 had 66 years of service life before casing failures were identified. This is compared to the following wells that had casing failures identified while drilling:

- Well SS-17 had a 7 in. casing leak while drilling in 1952.
- Well FF-35E had a leak in the 8 5/8 in. stage collar and an 8 5/8 in. casing leak in 1972.
- Well MA-1B had a leak in the 8 5/8 in. casing in 1979 while drilling.
- Well SS-4B had a tight spot in the 9 5/8 in. casing while drilling in 2015.

Figure 6 (older wells) and Figure 7 (newer wells) show the years of service life for the failed casings and liners for each failure. The service life is considered to start when the casing is run and ends when the failure is identified. The casing size, weight (wall thickness), and connection are color-coded for comparison across wells. For example, the red bars represent 7 in. 23 ppf Speedtite casings. The liners are color-coded identically to show the service life of the liners. Leaks in production casings are more of a concern than liners because of the risk of a surface blowout if a casing fails and the difficulty of killing a well with a shallow leak.

Figure 6 shows that the majority of the failures in the older wells had 7 in. 23 ppf Speedtite casings, as shown in red. Connections are discussed in more detail in Section 2.5. Most of the older wells had 7 in. production casings and were drilled as conventional oil and gas wells.

Figure 7 shows that the failed casings were mostly 8 5/8 in. casings in wells drilled as gas storage wells in the 1970s, as shown in gold color.

Gas injection started in 1973 and exposed casings to storage well loads. Figure 7 shows that well designs changed to 8 5/8 in. and 9 5/8 in. production casings in 1972, except for MA-5A and SS-4-0, which have 7 in. production casings.

The casing failures in well SS-4-0 were attributed to the 1994 Northridge earthquake. The 7 in. casing was parted at 1,445 ft and collapsed at 7,012 ft, and a split was found in the 10 3/4 in. intermediate casing from 3,116 to 3,130 ft.

Well Name	Year Casing Run	Year Failure Identified	Years of Service	Failed Casing OD, Wt, Conn.
P-12	1940	1970	30	6-5/8 in. 26 FJ
Frew-2 (1)	1944	2014	70	7 in. 23 STC
Frew-2 (2)	1944	2014	70	7 in. 30 STC
Frew-2 (3)	1944	2014	70	7 in. 23 STC
P-32 (1)	1944	1974	30	7 in. 23 Speedtite
P-32 (2)	1944	2016	72	7 in. 23 Speedtite
P-32 (3)	1944	2016	72	7 in. 23 Speedtite
SS-5	1945	1977	32	7 in. 23 Speedtite
Frew-3 (1)	1945	1986	41	7 in. 23 STC
Frew-3 (2)	1986	2013	27	5.5 in. Liner
Frew-3 (3)	1945	2013	68	7 in. 26 LTC
Frew-3 (4)	1945	2013	68	7 in. 23 STC
SS-7	1946	2012	66	7 in. 23 Speedtite
P-35	1946	2016	70	7 in. 23 Speedtite
SS-11	1947	1978	31	7 in. 23 Speedtite
SS-10	1947	1978	31	7 in. 23 Speedtite
P-38	1947	1975	28	7 in. 23 Speedtite
FF-33 (1)	1949	1981	32	7 in. 26 Speedtite
FF-33 (2)	1949	1994	45	7 in. 23 Speedtite
SS-14 (1)	1949	1969	20	7 in. 23 Speedtite
SS-14 (2)	1949	1976	27	7 in. 23 Speedtite
SS-14 (3)	1976	1998	22	7 in. 29 LTC
MA-3	1951	1977	26	7 in. 26 LTC
FF-34 (1)	1951	1991	40	7 in. 23 Speedtite
FF-34 (2)	1951	1991	40	7 in. 23 Speedtite
SS-17	1952	1952	0	7 in. 26 T&C
SF-1	1953	1976	23	7 in. 23 Not Rpt'd
P-43	1953	1977	24	7 in. 23 Speedtite
SF-2	1953	1976	23	7 in. 23 LTC
SS-25	1954	2015	61	7 in. 23 Speedtite
P-47 (1)	1954	1973	19	5 in. Liner
P-47 (2)	1954	1977	23	5 in. Liner
SS-12 (1)	1954	1975	21	6-5/8 in. Liner
SS-12 (2)	1954	1977	23	7 in. 23 Speedtite
P-45	1955	1969	14	7 in. 23 T&C
P-44	1955	1978	23	7 in. 23 STC
P-25R (1)	1962	1973	11	5 in. Liner
P-25R (2)	1962	1973	11	5 in. Liner
P-25R (3)	1962	1973	11	5 in. Liner
P-25R (4)	1962	1973	11	5 in. Liner
P-25R (5)	1962	1973	11	5 in. Liner
P-25R (6)	1962	1973	11	5 in. Liner
P-25R (7)	1962	1973	11	5 in. Liner
P-25R (8)	1962	1979	17	5 in. Liner
P-25R (9)	1962	1980	18	5 in. Liner
Frew-9 (1)	1963	2009	46	7 in. 23 BTC
Frew-9 (2)	1963	2015	52	7 in. 23 BTC
P-32B (1)	1972	1982	10	8-5/8 in. 36 BTC
P-32B (2)	1972	1982	10	8-5/8 in. 36 BTC
P-32B (3)	1972	1982	10	8-5/8 in. 36 BTC

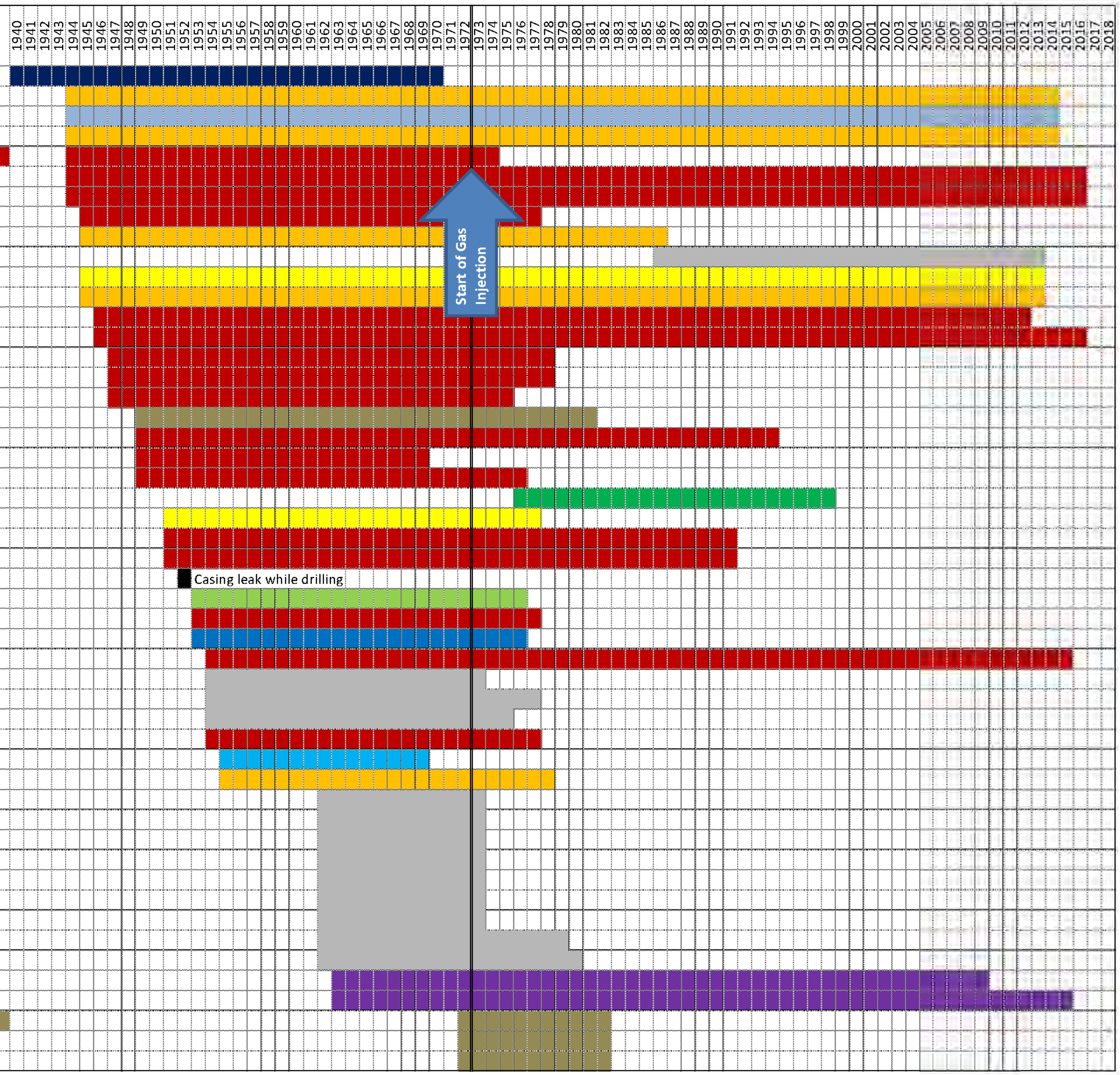

Figure 6: Service Life for Casings and Liners in Failed Wells (Older Wells)

Well Name	Year Casing Run	Year Failure Identified	Years of Service	Failed Casing & Connection
FF-32F (1)	1972	1986	14	8-5/8 in. 36 BTC
FF-32F (2)	1972	2010	38	8-5/8 in. 36 BTC
FF-35E (1)	1972	1972	0	8-5/8 in. 36 BTC
FF-35E (2)	1972	1972	0	8-5/8 in. 36 BTC
FF-35E (3)	1972	1975	3	8-5/8 in. 36 BTC
FF-35E (4)	1972	1977	5	8-5/8 in. 36 BTC
FF-35E (5)	1972	1977	5	8-5/8 in. 36 BTC
FF-35E (6)	1972	2017	45	8-5/8 in. 36 BTC
SS-25A (1)	1972	1981	9	8-5/8 in. 36 BTC
SS-25A (2)	1972	2010	38	8-5/8 in. 36 BTC
FF-32E (2)	1972	1976	4	8-5/8 in. 36 BTC
FF-32E (2)	1972	2013	41	8-5/8 in. 36 BTC
FF-35C	1972	1990	18	8-5/8 in. 36 Not Rpt'd
P-26B	1973	1981	8	8-5/8 in. 36 BTC
P-26D	1973	1975	2	6-5/8 in. Liner
SS-25B (1)	1973	1976	3	8-5/8 in. 36 BTC
SS-25B (2)	1973	1976	3	8-5/8 in. 36 BTC
P-26C (1)	1973	1980	7	8-5/8 in. 36 BTC
P-26C (2)	1973	2006	33	8-5/8 in. 36 BTC
P-26C (3)	1973	2010	37	8-5/8 in. 36 BTC
FF-32D (1)	1973	2014	41	8-5/8 in. 36 BTC
FF-32D (2)	1973	2017	44	8-5/8 in. 36 BTC
FF-32D (3)	1973	2017	44	8-5/8 in. 36 BTC
FF-32D (4)	1973	2017	44	8-5/8 in. 36 BTC
FF-35B	1974	1978	4	8-5/8 in. 36 BTC
SS-44A (1)	1974	1978	4	8-5/8 in. 36 BTC
SS-44A (2)	1974	2016	42	8-5/8 in. 36 BTC
SS-4A (1)	1975	1979	4	6-5/8 in. Liner
SS-4A (2)	1975	1979	4	6-5/8 in. Liner
SS-4A (3)	1974	2017	43	8-5/8 in. 36 BTC
P-42B (1)	1979	1992	13	8-5/8 in. 36 BTC
P-42B (2)	1979	2016	37	8-5/8 in. 36 BTC
MA-1B	1979	1979	0	8-5/8 in. 36 BTC
FF-34A (1)	1979	1991	12	8-5/8 in. 36 BTC
FF-34A (2)	1991	2009	18	6-5/8 in. Inner Csg
P-42C	1979	2016	37	9-5/8 in. 53.5 LTC
SS-4-0 (1)	1980	1994	14	7 in. 23 BTC
SS-4-0 (2)	1980	1994	14	7 in. 26 BTC
P-69A (1)	1980	1981	1	9-5/8 in. 47 LTC
P-69A (2)	1980	2004	24	5-1/2 in. Liner
P-69A (3)	1980	2004	24	5-1/2 in. Liner
P-69A (4)	1980	2004	24	9-5/8 in. 47 LTC
P-69A (5)	1980	2004	24	9-5/8 in. 47 LTC
P-69A (6)	1980	2004	24	9-5/8 in. 47 LTC
Ward-3A	1981	2016	35	8-5/8 in. 36 BTC
MA-5A (1)	1982	2001	22	7 in. 23 BTC
MA-5A (2)	1982	2001	22	7 in. 23 BTC
P-50A (1)	1983	1984	1	9-5/8 in. 43 BTC
SS-4B	2015	2015	0	9-5/8 in. 47 H 563

Figure 7: Service Life for Casings and Liners in Failed Wells (Newer Wells)

2.3 Casing Failures by Depth

Figure 8 shows an overview of the 49 casing failures with the wells' ages decreasing from left to right. The type and depth of casing failures are shown for each well. There is no apparent depth or failure-type pattern for the casing failures. The majority of the failures were casing leaks and tight spots and ranged in depth from surface to >8,000 ft.

P-25R and P-69A had multiple failures in the lower part of the well. P-25R had tight spots and leaks in a 5 in. flush joint liner, and P-69A had tight spots and leaks in the 9 5/8 in. long thread casing (LTC) and the 5 1/2 in. LTC liner.

The production casings and liners of the failed wells were run and set between 1940 and 2015. The SS-25 7 in. production casing was run in 1954.

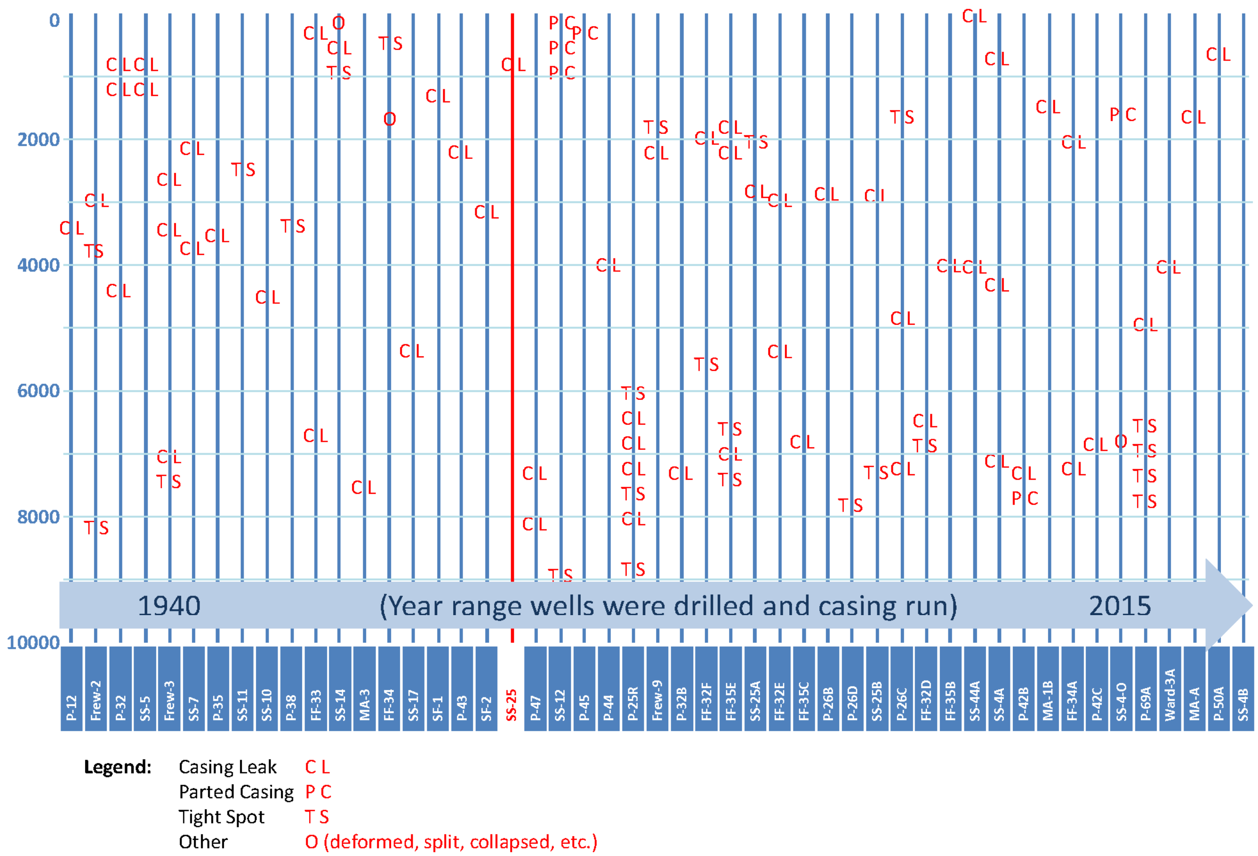

Figure 8: Casing Failures Types vs. Depth

2.4 Summary of Production Casing Failures

Table 9 summarizes and paraphrases the key parameters for wells that failed and includes the data used in the casing failure analysis. The data and well records are from the DOGGR website and SoCalGas. Wells are listed in ascending order according to the year production casings or liners were run (see the Year Casing Run column). Because some wells had more than one failure, there is a line item for each failure, designated by (1), (2), . . . (n) following the well name, e.g., the three failures listed for Frew 2 in Table 9.

Table 9: Summary of Production Casing Failures

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
P-12	6.625 in. 26 ppf Gr D-Used FJ	1,971	1940	1970	30	Casing leak	3,634	Squeezed cement.
Frew 2 (1)	7 in. 23 ppf J55 STC	2,804	1944	2014	70	Tight spot	3,872	Swaged casing.
Frew 2 (2)	7 in. 30 ppf J55 LTC	2,804	1944	2014	70	Tight spot	8,130	Worked through.
Frew 2 (3)	7 in. 23 ppf J55 STC	2,804	1944	2014	70	Casing leak	2,955–2,971	Squeezed cement.
P-32 (1)	7 in. 23 ppf N80 Speedtite	2,086	1944	1974	30	Casing leak	4,510–4,590	Squeezed cement, and ran 5 1/2 in. inner casing.
P-32 (2)	7 in. 23 ppf N80 Speedtite	2,086	1944	2016	72	Casing leak	654–845	Squeezed cement. Run and cement inner casing.
P-32 (3)	7 in. 23 ppf N80 Speedtite	2,086	1944	2016	72	Casing leak	1,300–1,323	Squeezed cement. Run and cement inner casing.
SS-5	7 in. 23 ppf J55 Speedtite	2,651	1945	1977	32	Casing leak	800–1,200	Ran 5 1/2 in. inner casing.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
Frew 3 (1)	7 in. 23 ppf J55 STC	2,419	1945	1986	41	Casing leak	3,240	Underground flow Jun 1984. Killed well. Welex inspection log showed a large hole in the pipe body. Squeezed cement and ran 5 1/2 in. inner casing.
Frew 3 (2)	5.5 in. 17 ppf J55 Hydril FJ	2,419	1986	2013	27	Casing leak	7,500	Pulled 5 1/2 in. inner casing.
Frew 3 (3)	7 in. 26 ppf N80 LTC	2,419	1945	2013	68	Tight spot	7,543	Could not pass 7 in. casing scraper. P&A'd well.
Frew 3 (4)	7 in. 23 ppf J55 STC	2,419	1945	2013	68	Casing leak	2,643–2,658	Identified during P&A USIT log.
SS-7	7 in. 23 ppf J55, N80 Speedtite	2,960	1946	2012	66	Casing leak	Between surface and 8,467	Pressure test failed. Set cement plug 8,540–8,235 ft.
P-35	7 in. 23 ppf N80 Speedtite	2,101	1946	2016	70	Casing leak	3,396 3,420 3,464	Vertilog indications; 85%, 86%, 81% penetration respectively.
SS-11	7 in. 23 ppf J55 Speedtite	2,512	1947	1978	31	Tight spot	2,359	Baker packer would not pass. Otis packer did pass the tight spot.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
SS-10	7 in. 23 ppf N80 Speedtite	2,622	1947	1978	31	Casing leak	4,492	Set expandable casing patch.
P-38	7 in. 23 ppf J55 Speedtite	2,626	1947	1975	28	Tight spot	3,289	Tight spot in the casing. Milled out 3,289–3,291 ft.
FF-33 (1)	7 in. 26 ppf N80 Speedtite	2,060	1949	1981	32	Casing leak	6,302–6,307	Squeezed cement and expandable casing patch.
FF-33 (2)	7 in. 23 ppf J55 Speedtite	2,060	1949	1994	45	Casing leak	115	Set expandable casing patch.
SS-14 (1)	7 in. 23 ppf J55 Speedtite	2,335	1949	1969	20	Split casing	Wellhead	Cut casing at 105 ft. Ran overshot type patch.
SS-14 (2)	7 in. 23 ppf J55 Speedtite	2,335	1949	1976	27	Casing leak	156	Cut casing at 625 ft. Ran overshot type patch.
SS-14 (3)	7 in. 29 ppf N80 LTC	2,335	1976	1998	22	Tight spot	626	Released casing patch bowl. POH. LD casing. Ran overshot type casing patch.
MA-3	7 in. 26 ppf N80 LTC	2,062	1951	1977	26	Casing leak	7,545–7,570	Squeezed cement.
FF-34 (1)	7 in. 23 ppf J55 Speedtite	2,212	1951	1991	40	Tight spot	575	Swaged casing.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
FF-34 (2)	7 in. 23 ppf J55 Speedtite	2,212	1951	1991	40	Deformed	1,475	P&A'd well.
SS-17	7 in. 26 ppf J55 T&C	2,600	1952	1952	0	Casing leak while drilling	5,238	Squeezed cement. Covered with liner lap.
SF-1	7 in. 23 ppf N80 Not Reported	2,520	1953	1976	23	Casing leak	1,380	Squeezed cement and ran 5 1/2 in. inner casing.
P-43	7 in. 23 ppf J55 Speedtite	2,269	1953	1977	24	Casing leak	2,220	Set expandable casing patch.
SF-2	7 in. 23 ppf N80 LTC	2,439	1953	1976	23	Casing leak	3,242	Squeezed cement and expandable patch.
SS-25	7 in. 23 ppf J55 Speedtite	2,927	1954	2015	61	Casing leak	892	Casing leak lead to parted casing.
P-47 (1)	5 in. 18 ppf J55 FJ	2,496	1954	1973	19	Casing leak	8,038–8,056	Squeezed cement.
P-47 (2)	5 in. 18 ppf J55 FJ	2,496	1954	1977	23	Casing leak	7,328	Squeezed cement.
SS-12 (1)	6 5/8 in. 28 ppf N80 T&C	2,276	1954	1975	21	Tight spot	8,590	Milled. Set 5 in. scab liner.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
SS-12 (2)	7 in. 23 ppf J55 Speedtite	2,276	1954	1977	23	Parted casing	553 889 1,224	Repaired parted connection at 553 ft, parted connections at 889 ft and 1,224 ft occurred during the workover.
P-45	7 in. 23 ppf J55 T&C	1,896	1955	1969	14	Parted casing	177	Cut casing. Ran casing patch.
P-44	7 in. 23 ppf J55 STC	2,195	1955	1978	23	Casing leak	3,983–4,014	Milled tight spot 3,983–4,014 ft. Casing leak at 3,990 ft, squeezed cement and set expandable casing patch.
P-25R (1)	5 in. 18 ppf J55 FJ	2,680	1962	1973	11	Tight spot	6,042	Swaged tight spots.
P-25R (2)	5 in. 18 ppf J55 FJ	2,680	1962	1973	11	Tight spot	7,618	Swaged tight spots.
P-25R (3)	5 in. 18 ppf J55 FJ	2,680	1962	1973	11	Tight spot	8,455	Swaged tight spots.
P-25R (4)	5 in. 18 ppf J55 FJ	2,680	1962	1973	11	Casing leak	7,618	Squeezed cement.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
P-25R (5)	5 in. 18 ppf J55 FJ	2,680	1962	1973	11	Casing leak	6,588	Shot holes, squeezed cement.
P-25R (6)	5 in. 18 ppf J55 FJ	2,680	1962	1973	11	Casing leak	6,345–6,376	Shot holes, squeezed cement.
P-25R (7)	5 in. 18 ppf J55 FJ	2,680	1962	1973	11	Casing leak	6,907–6938	Shot holes, squeezed cement.
P-25R (8)	5 in. 18 ppf J55 FJ	2,680	1962	1979	17	Casing leak	7,627–7,632	Squeezed cement.
P-25R (9)	5 in. 18 ppf J55 FJ	2,680	1962	1980	18	Tight spot	7,616	Scraped casing, ran reduced OD packer.
Frew 9 (1)	7 in. 23 ppf N80 BTC	2,089	1963	2009	46	Tight spot	2,060	Swaged casing. Ran Multi-Finger caliper. Severe deformation in 2 joints at 2,044 ft and 2,081 ft.
Frew 9 (2)	7 in. 23 ppf N80 BTC	2,089	1963	2015	52	Casing leak	Between 1,878 and 2,478 ft	P&A well
P-32B (1)	8.625 in. 36 ppf N80 BTC	2,075	1972	1982	10	Casing leak	7,207	Set cement plug. Cut section. Set 7 in. liner.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
P-32B (2)	8.625 in. 36 ppf N80 BTC	2,075	1972	1982	10	Casing leak	7,250	Set cement plug. Cut section. Set 7 in. liner.
P-32B (3)	8.625 in. 36 ppf N80 BTC	2,075	1972	1982	10	Casing leak	7,278	Set cement plug. Cut section. Set 7 in. liner.
FF-32F (1)	8.625 in. 36 ppf K55 BTC	1,993	1972	1986	14	Casing leak in stage collar	2,001	Set casing patch. Ran and cemented 6 5/8 in. inner casing in 2017.
FF-32F (2)	8.625 in. 36 ppf K55 BTC	1,993	1972	2010	38	Tight spot	5,523	Milled. Ran and cemented 6 5/8 in. inner casing in 2017.
FF-35E (1)	8.625 in. 36 ppf K55 BTC	1,674	1972	1972	0	Casing leak in stage collar	1,919	Squeezed cement.
FF-35E (2)	8.625 in. 36 ppf K55 BTC	1,674	1972	1972	0	Casing leak	2,344	Squeezed cement.
FF-35E (3)	6.625 in. 27.65 ppf K55 FJ	1,674	1972	1975	3	Tight spot	7,253–7,262	Worked through spot with bit and scraper.
FF-35E (4)	8.625 in. 36 ppf K55 BTC	1,674	1972	1977	5	Casing leak	7,121–7,126	Milled and squeezed cement. Isolated with 7 in. liner.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
FF-35E (5)	8.625 in. 36 ppf K55 BTC	1,674	1972	1977	5	Tight spot	6,930–6,937	Reamed.
FF-35E (6)	8.625 in. 36 ppf K55 BTC	1,674	1972	2017	45	Tight spot	6,889	Reamed. Ran and cemented 7 in. inner casing.
SS-25A (1)	8.625 in. 36 ppf K55 BTC	2,927	1972	1981	9	Casing leak in stage collar	2,990	Set expandable casing patch.
SS-25A (2)	8.625 in. 36 ppf K55 BTC	2,927	1972	2010	38	Tight spot	2,119 2,157	Pulled casing patch. Tight spot in casing at 2,119 ft and 2,157 ft. Set new casing patch at 2,970 ft. PT to 1,870 psi; lost 100 psi in 20 minutes.
FF-32E (1)	8.625 in. 36 ppf K55 BTC	1,993	1972	1975	3	Casing leak in stage collar	2,968–3,009	Squeezed cement.
FF-32E (2)	8.625 in. 36 ppf K55 BTC	1,993	1972	2013	41	Casing leak	5,741–5,780	Squeezed cement.
FF-35C	8.625 in. 36 ppf Not Rpt'd Not Rpt'd	1,674	1972	1990	18	Casing leak	6,832	Vertilog showed possible penetration. Ran 6 5/8 in. inner casing.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
P-26B	8.625 in. 36 ppf K55 BTC	2,505	1973	1981	8	Casing leak in stage collar	2,793	Set casing patch. Ran and cemented 6 5/8 in. inner casing in 2017.
P-26D	6.625 in. 27.65 ppf K55 FJ	2,505	1973	1975	2	Tight spot	7,826–7,831	Milled tight spot.
SS-25B (1)	8.625 in. 36 ppf N80 BTC	2,927	1973	1976	3	Tight spot Casing leak	7,445 7,462	Milled tight spot. Squeezed cement and ran 6 5/8 in. scab liner.
SS-25B (2)	8.625 in. 36 ppf K55 BTC	2,927	1973	1976	3	Stage collar leak	2,918	Set expandable casing patch.
P-26C (1)	8.625 in. 36 ppf K55 BTC	2,505	1973	1980	7	Casing leak	6,554–7,574	Shot holes at 6,606 ft and squeezed cement.
P-26C (2)	8.625 in. 36 ppf K55 BTC	2,505	1973	2006	33	Casing leak	5,026–5,161	Squeezed cement.
P-26C (3)	8.625 in. 36 ppf K55 BTC	2,505	1973	2010	37	Tight spot	1,690	Reamed 1,665–1,715 ft. Set expandable patch.
FF-32D (1)	8.625 in. 36 ppf N80 BTC	1,995	1973	2014	41	Casing leak	6,314–6,319	Squeezed cement.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
FF-32D (2)	8.625 in. 36 ppf N80 BTC	1,995	1973	2017	44	Tight spot	6,193–6,196	Ran and cemented 6 5/8 in. inner casing
FF-32D (3)	8.625 in. 36 ppf N80 BTC	1,995	1973	2017	44	Tight spot	6,233–6,236	Ran and cemented 6 5/8 in. inner casing
FF-32D (4)	8.625 in. 36 ppf N80 BTC	1,995	1973	2017	44	Tight spot	6,350–6,354	Ran and cemented 6 5/8 in. inner casing
FF-35B	8.625 in. 36 ppf K55 BTC	1,674	1974	1978	4	Casing leak	3,997	Set expandable patch
SS-44A (1)	8.625 in. 36 ppf K55 BTC	2,682	1974	1978	4	Casing leak in stage collar	3,958	Set expandable casing patch.
SS-44A (2)	8.625 in. 36 ppf K55 BTC	2,682	1974	2016	42	Casing leak	4–5	P&A well. Recovered casing with leak.
SS-4A (1)	6.625 in. 24 ppf K55 FJ	2,886	1975	1979	4	Casing leak	4,291–4,296	Squeezed cement. Ran and cemented 4 1/2 in. inner liner in 2017.
SS-4A (2)	6.625 in. 24 ppf K55 FJ	2,886	1975	1979	4	Casing leak	7,488–7,518	Squeezed cement. Ran and cemented 4 1/2 in. inner liner in 2017.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
SS-4A (3)	8.625 in. 36 ppf K55 LTC	2,886	1974	2017	43	Casing leak	753–860	Squeezed cement. Ran and cemented 6 5/8 inner casing.
P-42B (1)	8.625 in. 36 ppf N80 BTC	1,963	1979	1992	13	Parted casing	7,488–7,490	Possible parted connection per USIT log. Ran 5 1/2 in. scab liner.
P-42B (2)	8.625 in. 36 ppf N80 BTC	1,963	1979	2016	37	Casing leak	7,234–7,244	Set RBP.
MA-1B	8.625 in. 36 ppf N80 BTC	1,725	1979	1979	0	Casing leak	1,597–1,605	Squeezed cement. Identified while drilling.
FF-34A (1)	8.625 in. 36 ppf N80 BTC	2,212	1979	1991	12	Casing leak	2,093–2,098	Underground flow in Sep 1990. Killed well. Ran SLB METT and CPET logs. The inspection log showed a hole in the pipe body. Squeezed cement and expandable casing patch. Ran 6 5/8 in. inner casing.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
FF-34A (2)	6.625 in. 24 ppf Not Rptd AB FL4S	2,212	1991	2009	18	Casing leak	7,380	Pulled 6 5/8 in. inner casing. Found hole in 4th joint from bottom across from sliding sleeve.
P-42C	9.625 in. 53.5 ppf N80 LTC	1,980	1979	2016	37	Casing leak	6,753–6,784	Squeezed cement.
SS-4-0 (1)	7 in. 23 ppf N80 BTC	2,885	1980	1994	14	Parted casing	1,445	Casing parted due to 1994 earthquake. Cut and pulled casing. Ran overshot type patch.
SS-4-0 (2)	7 in. 26 ppf N80 BTC	2,885	1980	1994	14	Casing collapsed	7,012	Casing collapsed due to 1994 earthquake. Sidetracked around collapsed casing.
P-69A (1)	9.625 in. 47 ppf N80 LTC	2,368	1980	1981	1	Casing leak	4,913–4,923	Squeezed cement. Set expandable patch.
P-69A (2)	5.5 in. 20 ppf K55 LTC	2,368	1980	2004	24	Tight spot	7,655	Reamed.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
P-69A (3)	5.5 in. 20 ppf K55 LTC	2,368	1980	2004	24	Tight spot	7,809	Reamed. Pulled 5.5 in. liner. Ran new 5 in. liner. Ran 7 in. inner casing.
P-69A (4)	9.625 in. 47 ppf N80 LTC	2,368	1980	2004	24	Tight spot	6,652	Reamed.
P-69A (5)	9.625 in. 47 ppf N80 LTC	2,368	1980	2004	24	Tight spot	6,931	Reamed.
P-69A (6)	9.625 in. 47 ppf N80 LTC	2,368	1980	2004	24	Tight spot	7,278	Reamed. Ran 7 in. inner casing.
Ward-3A	8.625 in. 36 & 40 K55 & N80 BTC	2,226	1981	2016	35	Casing leak	Between surface and 7,218	Perf 2530–2550 ft, 2510–2530 ft, 2055–2560 ft and squeezed cement. Ran and cemented 6 5/8 in. inner casing.
MA-5A (1)	7 in. 23 ppf N80 BTC	2,210	1982	2001	22	Casing leak	Between 1,955 and 2,490	Squeezed cement.
MA-5A (2)	7 in. 23 ppf N80 BTC	2,210	1982	2001	22	Casing leak	Between 1,600 and 1,955	Squeezed cement.

Well Name	Casing OD wt. Grade Conn.	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments
P-50A	9.625 in. 43.5 ppf N80 BTC	1,935	1983	1984	1	Casing leak (conn.)	727, 770, 814, 856, 898	Noted on noise and RA survey. Squeezed cement and ran 7 in. inner casing in 2011.
SS-4B	9.625 in. 47 ppf L80 Hydril 563	2,888	2015	2015	0	Tight spot while drilling	8,747–8,756	Reamed and milled. Covered with liner lap.

2.5 Casing and Liner Connections

A review of the literature reveals several industry studies that show that the reliability of tubulars is dependent on the integrity and reliability of the connections. It is estimated that connection failures account for between 85% and 95% of oilfield tubular failures [4]. Schwind [5] reported that two-thirds of casing failures are due to connection failures. Schwind further states that 55% of connection failures occur in API connections, and the remaining 45% involve unqualified premium connections. Unqualified connections are those that have not been tested or qualified according to industry standards, such as API RP 5C5/ISO 13679 [6]. Studies from the 1960s indicate that 86% of casing failures occurred in the connection [7].

2.5.1 Reduced OD Connections and API Connections Performance

Standards for connection testing were developed in the mid-1980s because of failures with reduced OD and flush joint connections. Testing found that failures in connections occurred at much lower loads than the ones predicted. This included tension loads and internal pressure loads.

Most of the reduced OD connections that failed in SoCalGas wells were run before 1980 and were manufactured before testing standards were in place; therefore, the connection design and manufacturing quality are suspect. Reduced OD connections are, by definition, of lower strength, regardless of the quality. During this time period, some manufacturers claimed to have connections with multiple seals. One of the problems with multiple seals is that excess thread compound can be trapped between them during makeup. This can lead to excess pressure buildup of the thread compound, which can yield the connection and seal areas during makeup. This yielding results in connections leaks caused by the connection makeup.

Based on the above discussion, using reduced OD connections where gas-tight connections are required is a concern. Reduced OD connections are normally used for casing and liners where clearance is an issue. The connections are exposed to drilling fluid (mud), and the leak resistance to mud is adequate for drilling purposes. Production casing in gas wells normally has connections that are designed for gas exposure and are gas-leak-resistant, such as metal-to-metal or gas-tight connections. Sealing connections and design limitations of reduced OD and API connections are discussed in the literature by Bollfrass [8].

The assertion that API connections leak gas is supported by SoCalGas data and documentation. Interoffice correspondence [9] dated January 9, 1984 discusses a tracer survey showing connection leaks in 9 5/8 in. 43.5 ppf N80 buttress thread casing (BTC) less than a year after the Porter 50A well was drilled. Leaks correlated with the casing tally connection depths were noted at 727 ft, 770 ft, 814 ft, 856 ft, and 898 ft. A leak rate of about 2 Mcf/D was noted in another document [10] for P-50A.

A Frew 4 workover daily report [11] dated September 8, 1988, reported a leak in a 7 in. collar at 32 ft when testing the casing with nitrogen gas to 875 psi. A noise log was used to detect the leak. The reported casing connection was an 8-round thread, which is an API connection. This leak was not confirmed with a pressure test, and the noise log was not located; therefore, this leak is not counted in this analysis. However, the leak with nitrogen suggests that the research showing API connections are prone to leak gas is valid.

Problems with 7 in. Speedtite connections were discussed in a SoCalGas interoffice correspondence [12] dated November 25, 1977. A temperature survey run in SS-5 on September 28, 1977, showed several 8°F cooling anomalies at 150 ft, 300 ft, and 1,300 ft with smaller anomalies in between. The cooling suggested that the connections leaked and the pressure bled off after the bottom-hole safety valve was closed as discussed in the Interoffice Correspondence. The problems with Speedtite connections were in reference to a parted Speedtite connection in SS-12 and the subsequent parting of two additional connections during the workover while pressure testing. The cooling anomalies observed indicate that the Speedtite connection leaked when the reported casing pressure was 2,930 psi.

API connections include BTC, LTC, and STC (Short Thread Casing). API connections are manufactured in such a way that there is a gap between the thread root and crest. Figure 9 and Figure 10 show the LTC and BTC thread forms, respectively, with the gaps circled. The gap is plugged with thread compound to provide a seal when the connection is made up. The gaps are sealed as long as the thread compound is trapped in the gap. Exposure to gas or elevated temperature will dry out the thread compound, and this will result in a leak path through the gap in the threads. API connections provide adequate leak resistance for exposure to the drilling fluid during the drilling phase of the well. As discussed above, production casings and tubings for gas wells where pressure integrity is required usually have metal-to-metal or gas-tight connections for long-term leak resistance.

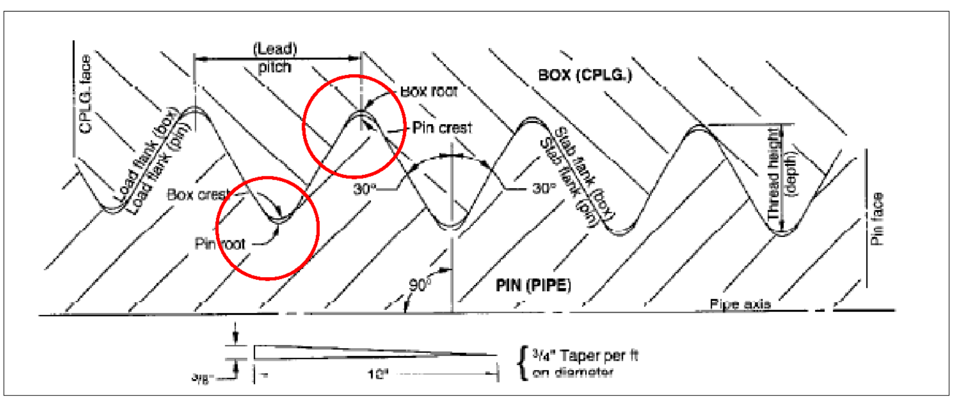

Figure 9: API LTC Thread Form and Gap between the Root and Crest

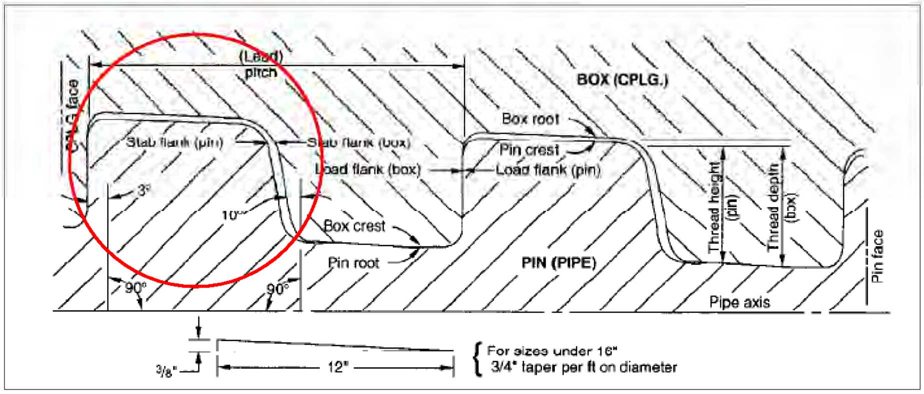

Figure 10: API BTC Thread Form and Gap between the Root and Crest

2.5.2 Use of Reduced OD Connections and API Connections in Aliso Canyon

Forty-nine out of the 124 gas storage wells reviewed had some type of casing failure. All but one of the 49 wells that failed had a reduced OD or an API connection in the production casings or liners that failed[iv]. Reduced OD connections on the failed casings and liners included 7 in. Speedtite, 6 5/8 in. FJ (flush joint), 6 5/8 in. AB FL4S, 5 1/2 in. FJ, and 5 in. FJ. The connection type was not reported in some well files. The remaining failed casings and liners had API connections.

Table 10 shows a breakdown of the production casing connection types used in the 124 SoCalGas wells reviewed. Speedtite and BTC connections were used in half of the wells. T&C are assumed to be API connections (BTC, LTC, or STC). Some wells used more than one connection type for a given casing size.

Table 10: Breakdown of the Production Casing Connection Types in Gas Storage Wells

Casing Connection Type	Speedtite	BTC	LTC	T&C	Not Reported	BTC & LTC	LTC & STC	Hydril 563[a]	Hunting SLGS[a]	Total
Well Count	33	29	20	13	10	8	6	3	2	124

[a] The 5 wells drilled from 2010-2015 used Hunting SLGS and Tenaris Hydril 563 connections on the 9 5/8 in. casing. These connections have a metal-to-metal seal and are suitable for gas service.

Table 11 shows a breakdown of the production liner connections used in 102 of the 124 reviewed SoCalGas wells. The remaining wells did not have liners. Flush joint connections were used in many of the wells. The connection type was not reported in 32 wells.

Table 11: Breakdown of the Production Liner Connection Types

Liner Connection Type	Flush Joint (FJ)	Not Reported	LTC	STC	Other[a]	Total
Well Count	39	32	16	6	9	102

[a] Other includes one each of FJ & STC, Hydril, Hydril 511, Hydril 513, T&C, TCPC, SLHT, Extreme Line (XL), BTC

[iv] A Tenaris Hydril Wedge 563 connection was used on the SS-4B 9 5/8 in. casing run in 2015. This connection would be considered a gas-tight connection with a metal-to-metal seal.

It was not possible to determine whether each of the failures occurred in the connection or pipe body from the records reviewed. Some well records specifically stated a pipe body or connection failure, while other records were not as complete. Table 12 shows the number of failures (in parentheses) for each connection type and casing size for the production casing and liners.

Table 12: Count of Connection Types for Casing Failures in Production Casing and Liners

Casing and Liner OD	9.625 in.	8.625 in.	7 in.	6.625 in.	5.5 in.	5 in.
Connection Types in Failed Casing	LTC (5 failures) BTC (1) Hydril 563 (1)	BTC (32) LTC (1) Not Reported (1)	Speedtite (18) BTC (6) LTC (5) STC (5) T&C (2) Not reported (1)	FJ (5) T&C (1) AB FL4S (1)	LTC (2) Hydril FJ (1)	FJ (11)

2.6 7 in. Speedtite Connection Discussion

Seven-inch OD casings with a Speedtite connection were commonly run in the 1940s and 1950s wells. The 7 in. casing in SS-25 had a Speedtite connection, which is an integral joint connection with a swaged-upset box on one end and a swaged-upset pin on the other end. Thirteen wells with 7 in. 23 ppf J55 Speedtite casing had a total of 19 casing failures (Table 13).

Figure 11 shows some information on the Speedtite connection from the 1960-1961 edition of the Composite Catalogue [13].

A notable instance of 7 in. 23 ppf J55 Speedtite parted casing occurred in well SS-12 in 1977. The well records show that the pin of a Speedtite connection had been damaged and jumped out of a damaged box. It would be interesting to know what kind of damage was found on the pin and box. Unfortunately, no details or description of the damage was found in the records. During the course of the workover to repair the casing, two more Speedtite connections parted, which are not included in the failure data because they occurred during the workover. The details from the report were: after cutting the casing at 615 ft, recovering the jumped Speedtite connection, and the cut casing, an external casing bowl-type patch was run at 615 ft. The casing was pressure tested to 4,000 psi with 60,000 lbf tension. The casing was landed in the wellhead with 200,000 lbf tension. A Speedtite connection was found to be parted the next day, at 889 ft. After replacing the casing to 1,070 ft, another Speedtite connection parted at 1,224 ft during a pressure test to 3,200 psi. The rest of the 7 in. Speedtite casing was replaced with 7 in. 23 ppf N80 casing as part of the workover. The 7 in. 23 ppf N80 LTC was cut and pulled in June 2018 as part of the Plug and Abandon (P&A) operations. Blade visually inspected the casing as it was pulled. No significant metal loss on the casing OD was observed.

Table 13: Breakdown of the 7 in. 23 ppf J55 Speedtite Casing Failure Types

	No. 7 in. 23 ppf Speedtite Wells Failed	Failure Type and Count				
		No. Casing Leaks	No. Tight Spots	No. Parted Casing	Other	Total No. Failures
Well and Failure Count	13	12	4	1	2	19

1470

CONTINENTAL-EMSCO COMPANY

SPEEDTITE CASING JOINT

Speedtite Casing Joint, proved by over 20 years of oil field application, gives full clearance with the extra strength needed to support heavy deep-well casing strings. Its two-step thread joint proved 100% pressure seal against both internal and external pressures.

Increased strength of Speedtite two-step joints over threaded and coupled joints will range from 30% to 70%. With this greater joint strength heavier casing can be run on the bottom of the string and lighter casing run on the top with ample tensile strength in all joints.

Speedtite casing has a joint O.D. approximately $\frac{3}{16}$" greater than the O.D. of the pipe. This smaller outside dimension provides additional assurance that the pipe will go to bottom quickly. It often makes it possible to reduce the hole size and lower drilling costs.

Speedtite is recommended for its fast make-up. It is self-stabbing and self-aligning.

Figure 11: Information on the Speedtite Connection from the 1960 Composite Catalogue

Figure 12 shows a connection recovered from the P-34 well in March 2018. The connection OD is slightly larger than the pipe body.

Figure 12: Photos of a 7 in. Speedtite Connection Showing the Box and Pin

2.6.1 SS-25 Connection Testing

Twenty-five SS-25 Speedtite connections were recovered and tested for leaks. The following is a summary of the findings:

- Sixteen connections held the test pressure of 3,300 psi.
- Nine connections leaked; the two highest leak rates were 9,967 scf/D and 57 scf/D
- Break out torques ranged from 3,614–8,708 ft-lb for the 14 connections that were backed out compared to the recommended makeup torque of 8,000 ft-lb.

The results of the testing confirmed the lack of leak resistance of reduced OD connections with pre-1980s designs.

Details of the connection testing can be found in a separate report *SS-25 7 in. Speedtite Connection Testing & 11 3/4 in. STC Assessment* [14].

2.7 Casing Failure Map

Figure 13 is a map showing the wells with casing failures. The distribution of casing failures appears to be field-wide and not concentrated in a specific area of the Aliso Canyon Field. SS-25 is located west of the middle of the field.

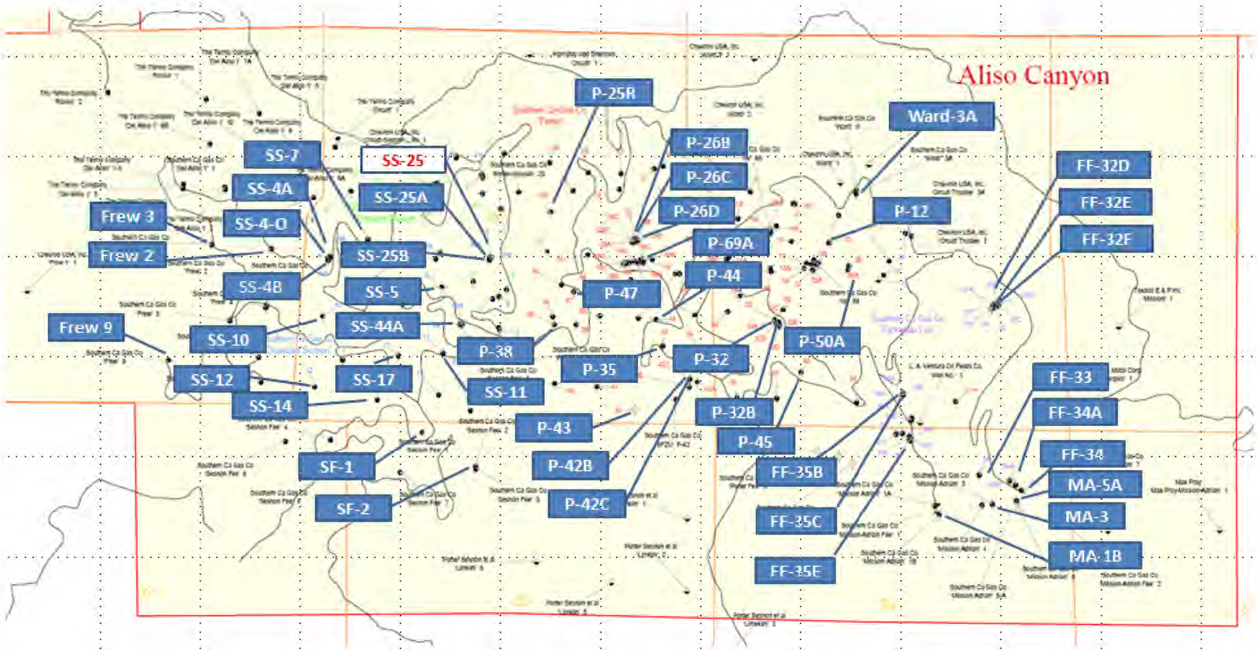

Figure 13: Field Map of Wells with Casing Failures

2.8 Casing Failures Recap by Well

Table 14 shows paraphrased details for wells with casing failures. The details and data are from well files downloaded from the DOGGR website and SoCalGas. The notes are a brief summary of the well history and notable events related to the casing failures.

Wells that were on the original SIMP list are identified in the table. The SIMP program is described in Section 3.

Table 14: Casing Failures Recap by Well

Well Name	SIMP Well	Date	Notes
FF-32D	No	Apr 1973	Set 13 3/8 in. casing at 818 ft
		May 1973	Set 8 5/8 in production casing and cemented at 7,330 ft
		Jan 2014	Casing leak in 8 5/8 in. casing 6,314-6,319 ft. Squeeze cemented. (41 years after casing run)

Well Name	SIMP Well	Date	Notes
		Jul 2017	Tight spots in 8 5/8 in. casing 6,193-6,196 ft, 6,233-6,336 ft, 6,344-6,352 ft. Milled and reamed. Ran and cemented 6 5/8 in. inner casing. (44 years after casing run)
FF-32E	No	Nov 1972	Set 13 3/8 in. casing at 717 ft
		Dec 1972	Set 8 5/8 in. production casing and cemented at 7,189 ft
		Sep 1975	Leak in 8 5/8 in. stage collar at 2,988 ft. Squeeze cement. (3 years after casing run)
		Apr 2013	Casing leak in 8 5/8 in. casing between 5,741 and 5,780 ft. Squeeze holes at 2,990 ft leaking. (41 years after casing run)
		Aug 2016	Squeeze cement two casing leaks. Set cement plugs, TOC at 6,507 ft.
FF-32F	No	Sep 1972	Set 13 3/8 in. casing at 724 ft
		Oct 1972	Set 8 5/8 in. production casing and cemented at 7,190 ft
		Jan 1986	Casing leak in 8 5/8 in. stage collar at 2,001 ft. (14 years after casing was run)
		Jun 2010	Tight spot in 8 5/8 in. casing at 5,523 ft. Milled. Ran 6 5/8 in. inner casing. (38 years after casing was run)
		Jul 2016	Ran and cemented 6 5/8 in. inner casing. (44 years after casing was run)
FF-33	Yes	Mar 1949	Set 13 3/8 in. casing at 996 ft
		Apr 1949	Set 7 in. production casing and cemented at 7,630 ft
		Mar 1981	Squeezed leak in 7 in. casing at 6,302–6,307 ft, pressure test to 1,500 psi. Set expandable casing patch 6,285–6,327 ft, pressure test not reported. (32 years after casing was run)
		May 1994	7 in. casing leak at 115 ft, set expandable patch. (45 years after casing was run)
FF-34	No	Apr 1951	Set 13 3/8 in. casing at 1,066 ft
		May 1951	Set 7 in. production casing and cemented at 7,722 ft
		Sep 1990	Perforated 7 in. casing shallow to produce gas leaked from FF-34A
		Apr 1991	RIH with bit and scraper could not get below 575 ft. Swaged casing. Dia-Log survey 574–590 ft showed *bursted* (SIC) from inside outward, casing from 1,475–1,515 ft deformed. (40 years after casing was run)
		May 1991	P&A well
FF-34A	No	Oct 1979	Set 13 3/8 in. casing at 1,003 ft
		Nov 1979	8 5/8 in. production casing set and cemented at 7,652 ft
		Sep 1990	Casing leak resulting in underground flow and well kill. Cooling anomalies noted in the well file.

Well Name	SIMP Well	Date	Notes
		May 1991	Leak in 8 5/8 in. casing 2,093–2,098 ft. Ran caliper log. Ran SLB CPET (corrosion protection evaluation tool), stuck and fished tool. Cathodic protection recommended by SLB. Ran SLB METT (multi-frequency electromagnetic thickness) log. Hole in casing at 2,104 ft identified by SLB. Jacked casing to 300,000 lbf, not able to pull slips. Cut off casing head, re-welded head. Squeezed cement leak, PT to 600 psi. Ran an expandable casing patch. Ran 6 5/8 in. inner casing to isolate leaks. (12 years after casing was run)
		Aug 1991	Discussion of external casing corrosion in FF-34A and other wells FF-35C, MA-1A and MA-5A [15]
		Jan 2009	Worked 6 5/8 in. casing to 240,000 lbf. Pulled and laid down casing. Found hole in the 4th joint of casing from bottom across from the sliding sleeve. Sidetracked well by cutting a section in the 8 5/8 in. casing at 7,400–7,470 ft. Set a cement plug and sidetracked the well. Ran and cemented 7 in. production casing. (18 years after inner casing was run)
FF-35B	No	Aug 1974	Set 13 3/8 in. casing at 830 ft
		Sep 1974	Set 8 5/8 in. production casing and cemented at 7,229 ft. Stage collar did not close. Squeezed cement. (0 years after casing was run)
		Sep 1978	Leak in 8 5/8 in. casing at 3,997 ft at stage collar. Set casing patch 4,016-3,974 ft.
FF-35C	No	Sep 1972	Set 13 3/8 in. casing at 728 ft
		Oct 1972	Set 8 5/8 in. production casing and cemented at 6,967 ft
		Sep 1990	8 5/8 in. Vertilog showed possible penetration at 6832 ft, 2,350 ft 40-60% penetration, 966 ft >60% penetration. Ran 6 5/8 in. inner casing. (18 years after casing was run)
FF-35E	No	Aug 1972	Set 13 3/8 in. casing at 699 ft
		Aug 1972	Set 8 5/8 in. production casing and cemented at 7,190 ft
		Aug 1972	Casing leak in 8 5/8 in. stage collar at 1,919 ft. Squeezed cement. (0 years after casing was run)
		Sep 1972	Set 6 5/8 in. production liner and cemented at 7,373 ft
		Nov 1972	Casing leak in 8 5/8 in. casing at 2,344 ft. Perforated and squeezed cement. (0 years after casing was run)
		Apr 1975	Tight spot in 6 5/8 in. liner at 7,253–7,262 ft. Worked through tight spot with bit and scraper. Stuck wash tool and rig went off the jacks and moved over. (3 years after casing was run)
		Aug 1977	Casing leak and bad casing in 8 5/8 in. at 7,121–7,126 ft. Milled and squeezed cement. Ran and cemented 7 in. liner to cover bad casing. (5 years after casing was run)
		Sep 1977	Tight spot in 8 5/8 in. casing 6,930–6,937 ft. Reamed. (5 years after casing was run)
		Jan 2017	Tight spot in 8 5/8 in. casing 6,889 ft. Ran and cemented 7 in. inner casing. (45 years after casing was run)

Well Name	SIMP Well	Date	Notes
Frew 2	No	Oct 1943	Set 13 3/8 in. casing at 501 ft
		Jan 1944	Set 7 in. production casing and cemented at 8,850 ft
		Aug 2014	Tight spot in 7 in. casing at 3,872 ft. Swaged.
		Sep 2014	Tight spot in 7 in. casing at 8,130 ft.
		Sep 2014	Casing leak in 7 in. casing between 2,955 ft and 2,971 ft. Squeeze cemented. (70 years after casing was run)
Frew 3	No	Oct 1944	Set 13 3/8 in. casing at 1,005 ft
		Jan 1945	Set 7 in. production casing and cemented at 7,799 ft
		Jul 1981	The Dames and Moore Report in 1981 [16] and the Dames and Moore Report in 1986 [17] discuss shallow ground water present
		Jun 1984	Casing leak resulting in underground flow and well kill operation. Possible hydrates all the way to SSSV ports as reported in the Well Activity Reports for Frew 3 [18]
		Jul 1984	Hydrate hypothesized in well file [19]
		Nov 1985	Possible casing parted [20]
		Dec 1985	Mention of possible corrosion zone in 1985 correspondence [21]
		Jan 1986	Ran Welex casing inspection log, confirmed hole at 3,240 ft. Squeezed leak in 7 in. casing at 3,240 ft. Ran 5 1/2 in. inner casing. (41 years after casing was run)
		Feb 1986	Ran 5 1/2 in. inner casing to isolate leak
		Aug 2013	Well P&A. Leak in 5 1/2 in. inner casing at 7,500 ft. Ran 5 1/2 in. USIT log, anomaly at 7,532–7,548 ft. (27 years after liner was run) Tight spot in 7 in. casing at 7,543 ft. Leak in 7 in. casing 2,643–2,658 ft. (68 years after casing was run) Ran 7 in. USIT log, anomaly at 3,233 ft. Cut and pulled 7 in. casing at 900 ft. Ran 13 3/8 in. USIT log, anomalies at 336-354 ft and 544–550 ft
Frew 9	No	Jul 1963	Set 10 3/4 in. casing at 1,500 ft
		Sep 1963	Set 7 in. production casing and cemented at 8,841 ft
		May 2009	RIH and tagged up at 2,060 ft. Swaged casing. Ran caliper. Casing severely deformed in 2 joints at 2,044 ft and 2,081 ft. Ran inflatable packer and completion. (46 years after casing was run)
		Mar 2015	Well P&A. Tight spot 1,999–2,059 ft. Casing leak between 1,878 ft and 2,478 ft. Ran 7 in. USIT log. Cut and pulled 7 in. casing at 1,488 ft. Ran 10 3/4 in. USIT log from 1,488 ft to surface. P&A'd well. (52 years after casing was run)
MA-1B	No	Jul 1979	Set 13 3/8 in. casing at 1,014 ft
		Aug 1979	Set 8 5/8 in. production casing and cemented at 7,347 ft
		Oct 1979	Casing leak in 8 5/8 in. casing at 1,597–1,605 ft. Squeezed cement (0 years after casing was run)
		Jul 1980	Set casing patch 1,578–1,620 ft. (1 year after casing was run)
		Aug 1981	Set casing patch 1,540–1,622 ft. (2 years after casing was run)

Well Name	SIMP Well	Date	Notes
		Jan 1982	Set casing patch 1,564–1,606 ft. (3 years after casing was run)
		Nov 1982	Removed casing patch. Ran 6 5/8 in. inner casing. (3 years after casing was run)
		Apr 2017	Pulled 6 5/8 in. inner casing. Ran and cemented 5 1/2 in. inner casing. (38 years after casing was run)
MA-3	Yes	Dec 1950	Set 11 3/4 in. casing at 549 ft
		Jan 1951	Set 7 in. production casing and cemented at 7,800 ft
		Oct 1977	Located 7 in. casing leak between 7,454–7,570 ft. Squeezed cement. (26 years after casing was run)
		Jul 2016	Well P&A. Casing leak 2,868–2,980 ft. Ran 7 in. USIT log. Cut and pulled 7 in. casing at 387 ft. (66 years after casing was run)
MA-5A	No	Dec 1981	Set 10 3/4 in. casing at 1,002 ft
		Feb 1982	Set 7 in. production casing and cemented at 7,563 ft.
		Nov 2004	Casing leak in 7 in. casing between 1,995 and 2,490 ft. Casing leak in 7 in. casing between 1,600 and 1,724 ft. Squeeze cement leaks. (24 years after casing was run)
P-12	No	Aug 1939	Set 16 in. casing at 512 ft
		Sep 1939	Set 11 3/4 in. casing at 2310 ft
		Sep 1939	Set 9 in. casing at 4721 ft
		Mar 1940	Set production casing and cemented at 6910 ft
		Jan 1970	Located casing leak in 6 5/8 in. casing at 3634 ft. Squeezed cement. (30 years after casing was run)
P-25R	No	Nov 1949	Set 13 3/8 in. casing at 808 ft
		Jan 1962	Set 5 in. liner 5,678 ft–8,600 ft and cemented
		Jan 1973	Tight spots in 5 in. liner at 6,042 ft, 7,618 ft, and 8,455 ft, swaged casing (11 years after casing was run)
		Jan 1973	Casing leak in 5 in. liner at 7,618 ft, squeezed cement (11 years after casing was run)
		Jan 1973	Casing leak in 5 in. liner at 6,588 ft, shot holes and squeezed cement (11 years after casing was run)
		Feb 1973	Casing leak in 5 in. liner between 6,345 ft and 6,376 ft, shot holes and squeezed cement (11 years after casing was run)
		Feb 1973	Casing leak in 5 in. liner between 6,907 ft and 6,938 ft, shot holes and squeezed cement (11 years after casing was run)
		Jan 1979	Casing leak in 5 in. liner between 7,627 ft and 7,632 ft, squeezed cement (17 years after casing was run)
		Jun 1980	Tight spot in 5 in. liner at 7,616 ft, scraped casing, ran reduced OD packer (18 years after casing was run)

Well Name	SIMP Well	Date	Notes
P-26B	No	Jun 1973	Set 13 3/8 in. casing at 797 ft
		Jul 1973	Set 8 5/8 in. production casing and cemented at 7,525 ft
		Aug 1981	Casing leak in 8 5/8 in. stage collar at 2,793 ft. Set casing patch. (8 years after casing was run)
		May 2017	Milled out casing patch. Ran and cemented 6 5/8 in. inner casing. (44 years after casing was run)
P-26C	No	Apr 1973	Set 13 3/8 in. casing at 801 ft
		May 1973	Set 8 5/8 in. production casing and cemented at 8,247 ft
		Jul 1980	Casing leak in 8 5/8 in. between 6,554 ft and 7,574 ft, shot holes at 6,606 ft and squeezed cement (7 years after casing was run)
		Apr 2006	Casing leak in 8 5/8 in. casing between 5,026 ft and 5,161 ft, squeezed cement (33 years after casing was run)
		Nov 2010	Tight spot in 8 5/8 in. casing at 1,690 ft, Reamed 1,665 ft to 1,715 ft and set casing patch from 1,670 ft to 1,710 ft. (37 years after casing was run)
		Jun 2016	Milled out casing patch. Set casing patch 1742–2309 ft. Set casing patch 814–890 ft. (43 years after casing was run)
P-26D	No	Dec 1972	Set 13 3/8 in. casing at 815 ft
		Jan 1973	Set 8 5/8 in. production casing and cemented at 7,658 ft
		Jan 1973	Set 6 5/8 in. liner 7,556 ft–8,106 ft and cemented
		Oct 1975	Milled tight spot in 6 5/8 in. liner from 7,826 ft–7,831 ft (2 years after casing was run)
P-32B	No	Sep 1972	Set 13 3/8 in. casing at 694 ft
		Oct 1972	Set 8 5/8 in. production casing and cemented at 7359 ft
		Jul 1982	Casing caliper showed holes in 8 5/8 in. casing at 7,207 ft, 7,250 ft, 7,278 ft. Cut section in casing and set cement plug. (10 years after casing was run)
		Mar 2006	Set whip stock, milled window, ran and cemented 7 in. liner.
P-32	No	Jun 1944	Set 13 3/8 in. casing at 522 ft
		Aug 1944	Set 7 in. production casing and cemented at 7,600 ft
		Nov 1972	Dia-Log caliper showed 59.1% original wall thickness, SLB inspection log showed 94.7% original well thickness (28 years after casing was run)
		Sep 1974	Casing leak in 7 in. at 4,510–4,590 ft. Squeezed cement. Ran 5 1/2 in. inner casing. (30 years after casing was run)
		Sep 2016	POH inner casing. Squeezed cement leaks in 7 in. casing at 654–845 ft and 1,300–1,323 ft. Ran and cemented 5 1/2 in. inner casing. (72 years after casing was run)

Well Name	SIMP Well	Date	Notes
P-35	Yes	Nov 1945	Set 13 3/8 in. casing at 505 ft
		Mar 1946	Set 7 in. production casing and cemented at 7,910 ft
		Feb 2016	Vertilog shows penetration indications 85% at 3,396 ft, 86% at 3,420 ft, 81% at 3,464 ft (70 years after casing was run)
P-38	Yes	Feb 1949	Set 13 3/8 in. casing at 500 ft
		Mar 1949	Set 7 in. production casing and cemented at 8,480 ft
		May 1973	A bridge plug hung up at 3,283 ft in the 7 in. casing (24 years after casing was run)
		Jul 1975	Milled out tight spot in 7 in. casing from 3,289–3,291 ft. Casing pressure tested ok. (26 years after casing was run)
		May 1980	Hydrate plug mentioned in Well Activities Report document [22]
P-42C	No	Feb 1979	Set 13 3/8 in. casing at 1,024 ft
		Mar 1979	Set 9 5/8 in. production casing and cemented at 6,955 ft. Derrick fell while running casing.
		Apr 1979	Set 7 5/8 in. liner and cemented 6,867-7,590 ft.
		Nov 2016	Casing leak in 9 5/8 in. casing below 6,753 ft due to milling. Set cement plugs to cover leak. (37 years after casing run)
P-42B	No	Dec 1978	Set 13 3/8 in. casing at 1,020 ft
		Jan 1979	Set 8 5/8 in. production casing and cemented at 7,610 ft
		Jan 1992	Inspection log indication of parted 8 5/8 in. connection 7,488-7,490 ft. Ran and cemented a scab liner. (13 years after casing was run)
		Jun 2016	Casing leak in 8 5/8 in. between 7,234 and 7,244 ft. Set RBP at 7,191 ft.
P-43	No	Nov 1953	Set 11 3/4 in. casing at 930 ft
		Dec 1953	7 in. production casing set and cemented at 8,982 ft
		Sep 1977	Casing leak in 7 in. casing at 2,220 ft. Ran expandable casing patch. (24 years after casing was run)
		Jul 1987	P&A well
P-44	Yes	Nov 1955	Set 11 3/4 in. casing at 530 ft
		Dec 1955	7 in. production casing set and cemented at 8,350 ft
		Jul 1977	Tight spot in 7 in. casing at 4,000 ft
		Feb 1978	Tight spot in 7 in. casing at 3,991 ft
		April 1978	Squeezed leak in 7 in. casing at 3,990–4,000 ft, pressure test to 1,500 psi. Set expandable casing patch 3,971–4,012 ft, pressure test to 2,000 psi. (23 years after casing was run)
		Feb 2016	Pulled casing patch. Caliper log shows severe damage 3,998–4,003 ft. Set casing patch 3,972–4,032 ft. Set casing patch 7,599–7,620 ft. (61 years after casing was run)

Well Name	SIMP Well	Date	Notes
P-45	No	Mar 1955	Set 10 3/4 in. casing at 505 ft
		Apr 1955	7 in. production casing set and cemented at 7,648 ft
		Jan 1969	Located break in 7 in. casing at 177 ft. Cut casing at 185 ft. Ran lead seal casing patch on 7 in. casing. (14 years after casing was run)
P-47	No	Apr 1943	Set 13 3/8 in. casing at 516 ft
		Aug 1943	Set 7 in. production casing and cemented at 8,050 ft
		Oct 1954	Set 5 in. liner 6,889 ft–8,364 ft
		Mar 1973	Casing leak between 8,038 ft and 8,056 ft in the 5 in. liner, squeezed cement. (19 years after casing was run)
		May 1977	Casing leak at 7,328 ft in the 5 in. liner, squeezed cement. (23 years after casing was run)
P-50A	No	Apr 1983	Set 13 3/8 in. casing at 1,028 ft
		May 1983	Set 9 5/8 in. production casing and cemented at 7,065 ft
		Jan 1984	Surface casing pressure noted. Noise and RA survey showed connection leaks that correlated with casing connections (1 year after casing was run). [9]
		Jan 2011	Casing leak between 1,050 ft and 930 ft in the 9 5/8 in. casing. Ran 7 in. inner casing. (28 years after casing was run)
		Mar 2015	P&A confirmed casing leak and identified a tight spot at 6,820 ft
		Feb 2016	Re-P&A to 1,370 ft. Flow test perforations 1,220–1,325 ft
		Mar 2016	USIT log showed corrosion from 432–1,026 ft and 1,325–1,805 ft. (SoCalGas documentation)
		Mar 2017	Complete well to shallow gas producer
P-69A	No	Jan 1980	Set 13 3/8 in. casing at 1,002 ft
		Feb 1980	Set 9 5/8 in. production casing and cemented at 7,700 ft
		Mar 1980	Set 5 1/2 in. liner 7,583–8,390 ft, not cemented
		Nov 1981	Squeezed leak in 9 5/8 in. casing between 4,913 ft and 4,923 ft. Set casing patch 4,888 ft–4,930 ft. (1 year after casing was run)
		Aug 2004	Reamed tight spots at 7,655 ft and 7,809 ft in the 5 1/2 in. liner, pulled liner, ran 5 in. liner, Ran 7 in. inner casing. (24 years after casing was run)
		Aug 2004	Reamed tight spots at 6,652 ft, 6,931, and 7,278 ft in the 9 5/8 in. casing, ran 7 in. inner casing. (24 years after casing was run)
SF-1	No	Nov 1952	Set 13 3/8 in. casing at 1,059 ft
		Jan 1953	Set 7 in. production casing and cemented at 9,234 ft
		May 1976	Squeezed leak in 7 in. casing at 1,380 ft. Ran 5 1/2 in. inner casing. (23 years after casing was run)
		Oct 1988	Hydrate plug in tubing is mentioned in SoCalGas well records [23]

Well Name	SIMP Well	Date	Notes
SF-2	No	Apr 1953	Set 13 3/8 in. casing at 1,594 ft
		Jul 1953	Set 7 in. production casing and cemented at 9,245 ft
		Jun 1976	Squeezed leak in 7 in. casing at 3,242 ft. Set expandable casing patch 3,226–3,258 ft. (23 years after casing was run)
SS-4A	No	Nov 1974	Set 13 3/8 in. casing at 928 ft
		Dec 1974	Set 8 5/8 in. intermediate / production casing at 4,065 ft due to lost circulation
		Jan 1975	Set 6 5/8 in. production liner and cemented at 8,248 ft
		Feb 1975	Set 4 1/2 in. WWS liner at 8,737 ft
		Jan 1979	Squeezed leak in 6 5/8 in. at 4,291–4,296 ft and tested to 1,000 psi. Squeezed leak in 6 5/8 in. at 7,488–7,518 ft and tested to 1,000 psi. (4 years after liner was run)
		Jan 2017	Squeezed leak in the 8 5/8 in. casing at 753–860 ft. Ran and cemented a 4 1/2 in. inner liner. Ran and cemented a 6 5/8 in. inner casing. (42 years after the casing was run)
SS-4B	No	Aug 2015	Set and cemented 13 3/8 in. casing at 1,436 ft. Pumped top job
		Sep 2015	Ran and cemented 9 5/8 in. casing at 8,887 ft. Pumped 2 top jobs. Tight spot 8,747-8,756 ft. Ran USIT logs. Reamed and milled tight spots. Covered tight spots with liner lap. (0 years after running casing)
SS-4-0 (Earthquake Damage)	Yes	Oct 1980	Set 10 3/4 in. casing at 4,852 ft
		Nov 1980	7 in. production casing set and cemented at 8,121 ft
		Apr 1994	7 in. casing parted at 1,445 ft and collapsed at ~7,012 ft due to the 1994 earthquake. Installed an overshot casing patch at 1,451 ft to repair parted casing. (14 years after casing was run)
		Aug 1994	Cut 7 in. casing at 5,000 ft (no free point run). Casing jacks not able to pull casing with 260,000 lbf. FP showed stuck at 4,800 ft. Cut casing at 4,802 ft. Pulled casing. Ran jars. Jarred on fish 100,000 lbf for 1.5 hours. Pulled casing fish. Set a cement plug.
		Sep 1995	Split in 10 3/4 in. casing 3,116–3,130 ft. Squeezed cement. (15 years after casing was run)
		Dec 1995	Hydrates while testing is mentioned in a SoCalGas email dated December 8, 1995 [24]
SS-5	No	Mar 1945	Set 13 3/8 in. casing run and cemented at 620 ft
		May 1945	7 in. casing run and cemented at 8,405 ft
		Jul 1977	Tested 7 in. casing. Pressure test 800 ft to surface failed at 4,000 psi. Tested casing to 400 psi ok. Tight spot in the 7 in. casing at 4,068 ft. Could not run packer on eline. Ran packer on tubing. Ran completion, pressure tested seals and packer to 2,000 psi for 15 minutes.
		Dec 1977	Ran 5 1/2 in. inner casing to isolate leaks in 7 in. casing above 1,200 ft. (32 years after 7 in. casing was run)

Well Name	SIMP Well	Date	Notes
SS-7	No	Nov 1945	Set 13 3/8 in. casing at 1,095 ft
		Jan 1946	Set 7 in. production casing and cemented at 8,590 ft
		Nov 2012	Ran USIT Log on 7 in. casing. Indications 1,914–1,925 ft and 4,012–4,030 ft. Pressure tested 7 in. casing to 1,500 psi, Bled to 100 psi in 15 minutes. Set cement plug. PT casing good. (66 years after casing was run)
		May 2014	P&A well. Ran USIT log on 7 in. casing. Indications 1,912–1,927 ft and 4,010–4,032 ft. (68 years after casing was run) Ran USIT log on 13 3/8 in. casing. Indications of wall loss in the top 2 joints. (69 years after casing was run)
SS-10	No	Apr 1947	Set 13 3/8 in. casing at 823 ft
		Jun 1947	Set 7 in. production casing and cemented at 8,612 ft
		Dec 1978	Leak in 7 in. casing at 4,492 ft. Set expandable casing patch. (31 years after casing was run)
		Sep 2012	Pulled expandable casing patch and ran a new expandable patch
SS-11	Yes	Sep 1947	Set 13 3/8 in. casing at 824 ft
		Nov 1947	Set 7 in. production casing and cemented at 8,767 ft
		Nov 1978	Baker packer would not pass 2,359 ft. Ran Otis packer. (31 years after casing was run)
SS-12	No	Feb 1948	Set 13 3/8 in. casing at 790 ft
		May 1948	Set 7 in. casing and cemented at 8,835 ft
		Dec 1954	Sidetracked well. Set 7 in. x 6 5/8 in. casing at 9,110 ft
		Apr 1975	Milled tight spots in 6 5/8 in. casing at 8,590 ft. Set 5 in. scab liner. (21 years after casing was run)
		Sep 1977	Casing leak in 7 in. casing at 553 ft. Cut casing at 615 ft. The 7 in. 23 ppf J55 Speedtite connection jumped out of damaged box at 553 ft. Ran casing bowl patch at 615 ft, pulled 60,000 lbf and pressure tested to 4,000 psi. Landed with 200,000 lbf and pressure tested to 4000 psi for 20 minutes. Tools would not pass through casing patch, POH parted casing connection at 889 ft. Cut casing at 900 ft. Ran casing bowl patch, pulled 200,000 lbf and pressured to 3,200 psi and casing connection parted. Cut 6 5/8 in. casing and ran overshot type casing patch with 7 in. casing. (23 years after casing was run)
		Sep 1977	Found 13 3/8 in. parted near the cellar floor. (23 years after casing was run)
SS-14	No	Mar 1949	Set 13 3/8 in. casing at 817 ft
		May 1949	Set 7 in. production casing and cemented at 8,896 ft
		Jun 1969	Found hole in casing bowl and split in 7 in. casing. Cut 7 in. casing at 105 ft. Ran overshot type casing patch. (20 years after casing was run)
		May 1976	Unable to test 7 in. casing at 156 ft. Cut 7 in. casing at 625 ft. Ran overshot type casing patch. (27 years after the casing was run)

Well Name	SIMP Well	Date	Notes
		June 1998	Tight spot in 7 in. casing at 626 ft. Required casing jacks to un-land casing with 250,000 lbf tension. Released casing bowl. POH. LD casing. Ran overshot type casing patch. (22 years after the casing was run)
SS-17	No	Mar 1952	Set and cemented 13 3/8 in. casing at 1,010 ft. Cement to surface.
		Jun 1952	7 in. casing run and cemented at 9,502 ft
		Jul 1952	Leak in 7 in. casing at 5,238 ft while drilling sidetrack hole using a whipstock. Squeezed cement 2 times. Covered leak with liner lap. (0 years after casing was run)
SS-25	No	Oct 1953	11 3/4 in. casing run and cemented at 990 ft. Top cement jobs 75sx and 60sx.
		Feb 1954	7 in. casing run and cemented at 8,585 ft
		May 1973	Converted to gas storage. Changed wellheads. Casing jacks pulled 196,000 lbf on 7 in. casing to pull slips. Changed out heads. Casing jacks pulled 196,000 lbf to land the 7 in. casing.
		Jan 1980	Problem with Annulus Pressure Controlled Flow Safety System reported 1979. Removed valve 1980-01-28 [25]
		Oct 2015	A leak occurred resulting in a release of gas to the atmosphere. The well was killed in February 2016 from a relief well. A Root Cause Analysis (RCA) was conducted to determine the cause of the well failure. (61 years after 7 in. casing was run)
		Aug 2017	Parted 7 in. casing at 887 ft wireline measurement (WLM), 892 ft measured depth (MD) was confirmed using a video camera.
SS-25A	No	Nov 1972	Set 13 3/8 in. casing and cemented at 808 ft. No cement to surface.
		Nov 1972	8 5/8 in. casing run and cemented at 8,075 ft
		Oct 1981	Set casing patch over leaking stage collar at 2,990 ft. (9 years after casing was run)
		Aug 2010	Pulled casing patch. Ran USIT log. Tight spot in casing at 2,117 ft. Ran and set casing patch. Pressure tested casing patch to 1,870 psi, 100 psi loss in 20 minutes. (38 years after casing was run)
SS-25B	No	Jan 1973	Set 13 3/8 in. casing at 900 ft
		Feb 1973	8 5/8 in. production casing run and cemented at 7,642 ft
		Oct 1976	Tight spot in 8 5/8 in. casing at 7,445 ft. Leak in 8 5/8 in. casing at 7,462 ft. Cement squeezed leak 2 times. Pressure test to 1,200 psi. Cemented 6 5/8 in. scab liner across leak. (3 years after casing was run)
		Oct 1976	Set casing patch across the stage collar (3 years after casing was run)
		Nov 1986	Remove casing patch
		Dec 1986	Set casing patch across the stage collar at 2,918 ft WLM. Patch from 2,907 ft to 2,929 ft. Pressure tested casing patch to 1500 psi. (13 years after casing was run)

Well Name	SIMP Well	Date	Notes
SS-44A	No	Sep 1974	Set 13 3/8 in. casing at 854 ft
		Oct 1974	Set 8 5/8 in. production casing and cemented at 8,864 ft
		Jul 1978	Leak in 8 5/8 in. stage collar at 3,958 ft. Set a casing patch. (4 years after casing was run)
		May 2017	Casing leak in 8 5/8 in. casing just below the wellhead. Recovered casing during P&A. (43 years after casing was run)
Ward-3A	No	Oct 1981	Set 13 3/8 in. casing at 1,005 ft
		Nov 1981	8 5/8 in. production casing run and cemented at 7,401 ft
		Dec 2016	Casing leak in the 8 5/8 in. casing between 7,218 ft and surface. Perf 2530–2550 ft, 2510–2530 ft, 2055–2560 ft and squeezed cement. Ran and cemented 6 5/8 in. inner casing. (35 years after casing was run)

3 Storage Integrity Management Program

SIMP is a program SoCalGas proposed in November 2014 to proactively identify and mitigate potential storage well safety and/or integrity issues before they result in unsafe conditions [26]. According to the program proposal, the primary threats were internal and external corrosion and erosion. SoCalGas developed a prioritized list of 18 SIMP wells [27]. The priority was based on an enhanced storage well integrity assessment program for each well using the following criteria:

- Age of well
- Proximity to sensitive areas or populations
- Workover history
- Inspection data
- Historical withdrawal rates (energy release potential)
- Known reservoir and geologic conditions
- Surrounding geologic conditions (fault lines, landslide potential, etc.)

Table 15 shows the list of prioritized wells, including the spud date and the type of casing failure reported. A total of seven failures were identified in six wells. Five casing leaks and two tight spots makeup the seven failures.

Table 15: List of Prioritized SIMP Wells

Rank	Priority	Well Name	Spud Date	Casing Failure Reported
1	A	P 36	09/04/46	–
2	A	P 35	11/08/45	Vertilog indication casing leak
3	A	FREW 7	11/27/54	–
4	A	PS 42	09/14/54	–
5	A	P 44	11/11/55	Casing leak
6	A	SS 31	09/14/53	–
7	A	P 38	02/03/47	Tight spot
8	B	FF 33	03/04/49	2 Casing leaks
9	B	SS 11	09/14/47	Tight spot
10	B	P 40	05/25/48	–
11	B	SS 04	07/26/44	–
12	B	SS 03H (SS-3)	11/29/44	–
13	B	P 46	11/02/43	–
14	B	SS 02	03/11/43	–
15	B	MA 03	12/06/50	Casing leak
16	B	SS 29	04/26/53	–
17	B	FREW 5	05/16/48	–

Rank	Priority	Well Name	Spud Date	Casing Failure Reported
18	B	SS 24	02/07/53	–

4 Analysis Summary – Wells with Underground Flow and Well Kill Operations

The SS-25 blowout of October 2015 is an example of the serious consequences of a casing failure. Blade reviewed Aliso Canyon well records and identified two wells with casing leaks and underground flow: Frew 3 in 1984 and FF-34A in 1990. SoCalGas killed Frew 3 and FF-34A within days of discovering the casing leak by pumping down the tubing. SoCalGas and Boots & Coots made seven unsuccessful kill attempts, by pumping down the tubing and casing followed by drilling P-39A, to successfully kill SS-25 in February 2016, four months after the leak had started.

A significant difference between SS-25 and the other two wells appears to be the estimated flow rate. Add Energy's estimated flow was 80 MMscf/D [28] and Blade's estimated flow was 93 MMscf/D [29] in SS-25 compared to the SoCalGas' estimated flow of 35-44 MMscf/D in FF-34A [30] and 24-50 MMscf/D in Frew 3 [20]. The leak in SS-25 was at 892 ft compared to 3,240 ft in Frew 3 and 2,093 ft in FF-34A. Furthermore, Frew 3 and FF-34A had pipe body leaks. The leak in SS-25 resulted in a parted joint of the 7 in. casing, with minimal restriction to flow when compared to the leaks through holes in the pipe body in the other two wells. The shallow parted casing, minimum restriction to flow, and high flow rate likely contributed to the difficulty in killing SS-25.

The completion designs for the three wells were similar—they consisted of a packer, an annular flow safety system above the packer, and tubing to surface. The Camco annular flow safety system was disabled in SS-25. Frew 3 and FF-34A were completed with Otis annular flow safety systems. The well records show that the internal components of the Frew 3 safety system were removed prior to the leak. We found no records showing that the internal components of the FF-34A safety system were installed. Additional information on the annular flow safety system in SS-25 can be found in a separate report [25].

Frew 3 and FF-34A had casing leaks and underground flow and were killed by pumping down the tubing. SS-25 was killed by drilling the relief well P-39A after several unsuccessful attempts to kill SS-25 by pumping down the tubing and casing.

The leaks in Frew 3 and FF-34A were in the pipe body according to casing inspection logs. Table 16 shows a comparison of leak details paraphrased from well records. Video camera and casing recovery in 2017 confirmed the casing leak and parted casing at 892 ft in SS-25.

Table 16: Comparison of Well Details

Well	Injection at Time of Leak	Date Leak Discovered	Date Well Killed	Leak Depth (ft)	Estimated Flow Rate (MMscf/D)	Leak FWHP (psi)
Frew 3	Yes	Jun 10, 1984	Jun 14, 1984	3,240 (pipe body leak)	24 (SoCalGas Low Inv.) 50 (SoCalGas High Inv.)	TP 1,285 CP 1,235
FF-34A	Yes (assumed)	Sep 10, 1990	Sep 11, 1990	2,093 (pipe body leak)	35–44 (SoCalGas)	CP 2,460

Well	Injection at Time of Leak	Date Leak Discovered	Date Well Killed	Leak Depth (ft)	Estimated Flow Rate (MMscf/D)	Leak FWHP (psi)
SS-25	Yes	Oct 23, 2015	Feb 11, 2016	892 (casing leak and parted casing)	30 (SoCalGas) 80 (Add Energy) 93 (Blade)	TP 1,700 CP 270

Each of the three wells had a similar completion design: a packer, an annular flow safety system, and tubing to surface. The safety system consisted of the body that was run with the tubing and completion and internal components that were run and pulled using a slick line unit. The well records show the internal components of the annular safety systems in Frew 3 were pulled prior to the leak. The internal components were not installed in FF-34A according to the records. FF-34A was completed with 3 1/2 in. tubing, while Frew 3 and SS-25 had 2 7/8 in. tubing. Table 17 shows the completion design comparison paraphrased from each well's records. The casing sections in red correspond to the casing that failed.

Table 17: Comparison of Well Completion Designs

Well	Production Casing	Casing Connection	Casing Shoe Depth (ft)	Tubing OD (in.)	Packer Depth (ft)	Annular Flow Safety System
Frew 3	7 in. 23 ppf N80 7 in. 23 ppf J55[a] 7 in. 23 ppf N80 7 in. 26 ppf N80	LTC STC LTC LTC	7,799	2 7/8	7,650	Otis Installed the body Sep 17, 1977. Installed the internal components Dec 4, 1981. Pulled the internal components Jan 11, 1982. Removed the body Feb 6, 1986.
FF-34A	8 5/8 in. 40 ppf N80 8 5/8 in. 36 ppf N80[a] 8 5/8 in. 40 ppf N80	BTC BTC BTC	7,652	3 1/2	7,500	Otis Installed the body Dec 18, 1970. Internal components were not run. Removed the body May 8, 1991.
SS-25	7 in. 23 ppf J55[a] 7 in. 23 ppf N80 7 in. 26 ppf J55 7 in. 29 ppf N80	Speedtite Speedtite Speedtite Speedtite	8,585	2 7/8	8,486	Camco Installed the body Feb 19, 1991. Installed internal components Jan 7, 1980. Pulled the internal components Jan 28, 1980. Body left in the P&A'd well Sep 13, 2018.

[a] Casing section and connection type that failed are shown in red.

All three wells showed cooling anomalies related to the leak and flow events. Table 18 shows wellbore temperature and kill details for the three wells paraphrased from well records.

Table 18: Comparison of Well Temperature and Kill Details

Well	Leak Wellbore Temperature Profile	Completion Interval	Kill Details	Wellbore Volumes (bbl)
Frew 3	38°F at Surf 74.5°F at 1,170 ft 82°F at 7,750 ft	7,792–8,025 ft 7,870–7,780 ft 7,850–7,856 ft 7,845–7,846 ft 7,840–7,842 ft 7,818–7,836 ft 7,766–7,790 ft 7,755–7,758 ft 7,715–7,730 ft	• 8.9 ppg polymer mud. • 100 bbl high-vis pill. • Total of 580 bbl pumped with no returns. • Bled casing pressure to zero. Well dead.	Tubing 44 bbl Annulus 302 bbl
FF-34A	Cooling anomaly 71°F at 1,470 ft	S-4 Open hole gravel pack	• Pumped approximately 450 bbl of kill fluid. • Well dead.	Tubing 67 bbl Annulus 361 bbl
SS-25	Shallow cooling anomalies 66°F at 208 ft (Temp. log February 2016) 67°F at 383 ft (Temp. log February 2016) 46°F at 140 ft (HPT April 2016) 46°F at 340 ft (HPT April 2016) 32°F at 74 ft (DTS December 2016) 50°F at 289 ft (DTS December 2016)	8,510–8,538 ft 8,542–8,559 ft Slotted liner to 8,748 ft	• Pumped 7 kill attempts and none were successful. • Drilled relief well and successfully killed the well.	Tubing 49 bbl Annulus 263 bbl

Notable differences in the well control efforts of the three wells include the time required to kill the wells. Frew 3 and FF-34A were killed within a few days of the discovery of the leak. It took almost four months to successfully kill SS-25, and it included drilling the relief well P-39A despite the multiple kill attempts made from October to December 2015. Kill Attempt #2 broached to surface and created a crater around the wellhead. The crater enlarged with subsequent kill attempts. Surface kill attempts stopped after Kill Attempt #7 on December 22, 2015. Various techniques and fluids were tried and pumped, including viscous pills followed by large volumes of brine and water, barite pills, and 15 ppg mud. Bridging material was pumped down the annulus in attempts to plug the leak in the 7 in. production casing.

The leak depths were 3,240 ft in Frew 3 and 2,093 ft in FF-34A as compared to 892 ft in SS-25. The deeper leaks had additional back pressure, which aided in killing the two wells.

The leaks in Frew 3 and FF-34A were located in the pipe body. The 7 in. casing leaked and parted in SS-25. The parted casing in SS-25 resulted in minimal restriction to flow.

The estimated leak rate or well capability to produce shows significant differences. The estimated flow rate for Frew 3 was 24 MMscf/D at low inventory to 50 MMscf/D at high inventory. The estimated leak rate for FF-34A ranged from 35 to 44 MMscf/D based on well file documentation. SoCalGas sent an IPR curve to the DOGGR District for SS-25 showing 30 MMscf/D with 2,400 psi bottomhole pressure (BHP) assuming zero back pressure [31]. The estimated flow rate with an adjusted BHP based on October 2015 data would be around 28 MMscf/D assuming the IPR curve was correct. However, analyses by Add Energy [28] and Blade Energy [29] show the flow rate for SS-25 could have been in the range of 80 to 93 MMscf/D, respectively—a significant increase in the estimated underground flow rate in SS-25 compared to Frew 3 and FF-34A. The much higher flow rate, shallow leak depth, and parted casing are contributing factors to why SS-25 could not be killed by pumping down the tubing.

4.1 SS-25 Kill Simulations

Detailed kill simulation modeling was done to determine if the kill attempts that were pumped were likely to be successful or not. The Drillbench Blowout Control model was used to model each of the SS-25 kill attempts. Flow rate and BHP were estimated using documented field data for the specific date of the kill attempt.

The conclusion of the modeling was that while pumping the kill fluid for Kill Attempts #2 through #6, the BHP was lower than the reservoir pressure and, therefore, predicted an unsuccessful kill. The simulation for Kill Attempt #7 with 15 ppg mud indicated the BHP had been exceeded, predicting a possible successful kill. However, Kill Attempt #7 was terminated early because of the wellhead movement and failed injection lines, and, therefore, was not successful. Kill Attempt #1 was terminated early by a plug forming in the tubing after pumping 11 bbl of kill fluid. Details of the kill modeling and analysis are included in a separate report [32].

4.2 Summary of Kill Events

Table 19, Table 20, and Table 21 paraphrase the kill events for Frew 3, FF-34A, and SS-25, from the well's respective well file.

Table 19: Frew 3 Summary of Kill Events

Date	Event Description	Reference
4/10/1984	Ran detailed temperature survey, confirms cooling from 6,750–7,791 ft at shoe. A noise log will be run at high inventory due to low structural position of well.	[33]
6/10/1984	Well on injection. Operations noted sudden jump in surface annulus pressure to 550 psi; repeated attempts to blow down annulus were unsuccessful.	[33]
6/11/1984	Ran temperature survey which looked very abnormal, hottest temperature noted was around 80°F so assumed temperature bomb had malfunctioned.	[33]
6/13/1984	Check seals on wellhead. Seals good. Ran temperature survey which showed extreme cooling. Surface temperature was 38°F and temperature at 7,750 ft was only 82°F. Last 2 surveys would not go through SSSV ports. Possible hydrates all the way to SSSV ports Trying to blow down annulus, but it will rise back to 460 psi from 250 psi in minutes.	[33]
6/13/1984	Tubing pressure 1,285 psi (flowing) from temperature log. Casing pressure 1,235 psi (flowing) from temperature log.	[34]
6/14/1984	Discussion with Shift Supervisor said the well was taking far more gas than normal. It sounded like as if twice the volume of gas was being injected.	[35]

Date	Event Description	Reference
86/14/1984	Gas sample showed to be Aliso gas. Confirmed the well was taking far more gas than normal. Noise log description of sounds like crackling or popping. Ran 3 noise tools. Hypothesis: the well has a hole around 1,100 ft causing hydrates to form and backup all the way to the SSSV ports. Killed the well with 67# (8.9 ppg) polymer. Pumped 100 bbl high vis (100+ cp) followed by regular polymer using constant tubing pressure method. Indications of tubing leak. Pumped a total of 580 bbl with no returns. Bled casing pressure to zero. Shut in with zero casing and tubing pressure.	[35]
6/15/1984	CP and TP zero. Blowing down surface casing pressure ~200 psi. Casing FL 661 ft. Tubing FL 598 ft.	[36]
7/5/1984	Memo: Workover recommendation: A jump in Frew 3 annulus pressure from zero to 588 psi. A jump in Frew 4 annulus pressure from zero to 140 psi (~1,200 ft south of Frew 3). A massive hydrate plug formed from the suspected leak down the annulus to the flow ports was hypothesized.	[37]
9/13/1984	Ran temperature survey, no anomaly. Waiting for workover.	[36]
4/2/1985	Memo: 1985 Aliso Canyon Well Repair Activity, dated April 2, 1985. Includes discussion that "The number of well leakage problems in a storage field during a given year seems to be somewhat proportional to the magnitude of the pressure reversal that year."	[2]
11/20/1985	Memo: Workover recommendation: Possible casing parted. Run 5 1/2 in. large tubing. Capable of producing 50 MMscf/D at high inventory and 24 MMscf/D at low inventory.	[20]
12/20/1985	Memo: Workover recommendation: Frew 3 in an important injection/withdrawal well that is capable of producing 50 MMscf/D at high storage inventory. Run casing inner string to isolate casing leaks. The well has been killed over a year awaiting workover operations.	[38]
1/31/1986	Workover to repair casing. Ran 60 arm caliper. Found large hole in 7 in. casing at 3,240 ft in the pipe body. Ran Segmented Electronic Casing Inspection log. Showed hole in casing at 3240 ft.	[39]

Table 20: FF-34A Summary of Kill Events

Date	Event Description	Reference
9/10/1990	Underground flowing condition discovered.	[40]
9/11/1990	Well killed.	[40]
9/11/1990	Kill well. Set RN tubing plug.	[41]
9/11/1990	Set tubing plug in 2.329 in. RN no-go nipple (7,489 ft). Well killed due to shallow casing leak, approx. 450bbl of kill fluid used.	[41]
9/11/1990	A cooling anomaly and high noise levels were observed from 1,440–2,060 ft (620 ft). Peak cooling in 10 ft interval 1,580– 1,590 ft.	[42]
9/12/1990	Ran temperature and noise log. Remarks: Tubing plugged at no-go at 7,489 ft. Well was killed 31 hours prior to logging.	[43]

Date	Event Description	Reference
9/12/1990	Ran noise log with spinner and temperature surveys, probable leakage at 2,100 ft.	[41]
9/14/1990	Ran TDT-K (500 ft–3,150 ft) to investigate shallow gas leakage and migration. Perforated 3 1/2 in. tubing (5 holes) at 1,700 ft.	[41]
9/26/1990	Memo discussing estimated flow 44 MMscf/D. Flowing WHP 2,460 psi (annulus pressure).	[30]
10/23/1990	Ran temperature survey, warming at 7,250 ft (WSO), fluid level at 1,850 ft, workover planned to repair shallow casing leak (Sept 1990)	[41]
10/24/1990	Memo discussing estimated flow 35 MMscf/D.	[44]
10/31/1990	Memo: Workover Recommendation Workover the well and run a new innerstring. Casing failure comments. The production casing SIWHP in FF-34A was also 140 psi lower than it should have been. Surface casing pressure in nearby wells FF-34B and MA-5A had respectively increased to 580 psi and 760 psi; and arrangements were made to bleed off gas and reduce the pressures.	[40]
11/30/1990	Memo: Nov. 30, 1990. Workover Recommendation On Sept 10, 1990, a downhole flowing condition was discovered in FF-34A. Strong vibrations and noise at the wellhead. Well was killed the next day. A cooling anomaly and high noise levels were observed from 1,440 ft to 2,060 ft. Peak cooling occurred in a 10 ft interval from 1,580 ft to 1,590 ft. Completed in the S-4 with open-hole gravel pack. (A casing leak at 2,093 ft was confirmed in May 1991)	[42]
12/27/1990	Letter from DOG RE: Perforating FF-34 at a shallow depth meeting request.	[45]
1/23/1991	SoCalGas Meeting Notes.	[46]
4/17/1991	Ran temperature survey, well killed (9/90), awaiting workover.	[41]
5/8/1991	Workover located leaks in 8 5/8 in. casing 2,093–2,098 ft.	[47]
8/20/1991	Memo: August 20, 1991. FF-34A Casing Corrosion Casing inspection showed severe metal loss at 2,104 ft and shallow (1,000 ft to 3,000 ft) metal loss averaging 15%.	[15]
2/20/1992	Memo: Casing cathodic protection recommendation for FF-34A.	[48]

Table 21: SS-25 Summary of Kill Events

Date	Event Description from the Reference	Reference
10/23/2015	Normal operations CP 2,700 psi. TP 2,700 psi. SCP should be 0 psi. Normal operates on casing injection and casing WD. It may be operated on dual flow. Well on injection - heard noise in wellhead.	[49]

Date	Event Description from the Reference	Reference
10/23/15 4:00 PM	CP 270 psi. TP 1,700 psi. SCP 140 psi. Ops noticed leaking annulus on well. They responded by closing 2 in. surface annulus valve and noticed 140 psi on gauge. When Ops closed injection header valve, the WKM SSV on casing closed almost immediately by low pressure pilot (setpoint is 270–300 psi). It was at that time Ops noticed sound of gas flow in wellhead.	[49]
10/23/15 4:10 PM	CP 270 psi. TP 1,700 psi. SCP 140 psi. Well shut in by Ops. We initially suspected an up/down wellhead seal leak between the 7 in. casing and the 11 3/4 in. surface casing. Called Cameron.	[49]
10/24/15 6:00 AM	CP 270 psi. TP 1,700 psi. SCP 140 psi. Cameron began repairing wellhead seals. Cameron initially tested both seals to 1,200 psi, both bled down to 600 psi. They then pumped 14 tubes of plastic into primary seal cavity.	[49]
10/24/15 12:27 PM	CP 290 psi. TP 1,700 psi. SCP 140 psi. Kill Attempt 1 Halliburton circulated down tubing. Pumped 11.8 bbl of 10 ppg polymer brine. Pressure tubing rose to 3,500 psi. Shut down. 7 in. casing pressure remained at 290 psi. Surface casing pressure remained at 140 psi. Monitored tubing pressure for 20 minutes. Tubing pressure bled to 2,700 psi.	[49]
10/24/15 1:20 PM	Shut well in with 2,700 psi TP.	[49]
10/24/15 1:30 PM	TP 50 psi. Put well on tubing flow to frac tank for few minutes and bled tubing down to 50 psi.	[49]
10/24/15 2:00 PM	CP 290 psi. TP 2,700 psi. Decided to pump and bleed down 7 in. casing to fill casing using 8.6 ppg lease water.	[49]
10/24/15 2:07 PM	CP 290 psi. TP 50 psi. SCP 140 psi. Halliburton began pumping 8.6 ppg lease water down 7 in. casing. Started pumping 8.6 ppg lease water at 1.5 bpm. At 20 bbl increased rate to 2.5 bpm, at 33 bbl increased to 3.5 bpm. Began monitoring location for gas. Inspected wellhead, noticed noise and vibration had subsided. Continued pumping. At 89 bbl, gas broke through surface at location and surrounding location. Continued monitoring.	[49]
10/24/15 2:30 PM	CP 400 psi. When we shut down after 89 bbl and gas came to surface, the 7 in. CP increased to 400 psi.	[49]
11/13/2015	Kill Attempt 2 not successful	[50]
11/15/2015	Kill Attempt 3 not successful	[50]
11/18/2015	Kill Attempt 4 not successful	[50]
11/24/2015	Kill Attempt 5 not successful	[50]

Date	Event Description from the Reference	Reference
11/25/2015	Kill Attempt 6 not successful	[50]
12/22/2015	Kill Attempt 7 not successful	[50]
02/11/2016	Relief well Porter 39A successful kill. SS-25 sealed.	[51]

5 Conclusions

The main conclusions are summarized here. Details and discussion can be found in the body of the report.

- Ninety-nine casing failures were identified in the 124 Aliso Canyon gas storage wells reviewed. This includes 63 casing leaks, 29 tight spots, 4 parted casings, and 3 other failures. Casing leaks include both connection leaks and pipe body leaks.
- The casing integrity of the Aliso Canyon gas storage wells is a concern based on the high percentage of casing failures in the 124 gas storage wells reviewed. Forty percent of the gas storage wells we reviewed had a casing failure with an average of 2 casing failures per well (99 failures in 49 wells). There are no details regarding the nature and cause of these leaks and failures. No failure analyses were done, based on the data made available to Blade. The apparent approach was to repair the leaks as they occurred to get the well back in service.
- Most of the casing connections used in the wells that failed are reduced OD or API connections[v]. However, it was not possible to determine if the failure in most wells occurred in the pipe body or in the connection, based on the well reports. There are exceptions where the reports clearly stated parted connections, i.e., in well SS-12, the 7 in. 23 ppf J55 Speedtite connection parted, and in well P-50A, the connections leaked in the 9 5/8 in. BTC casing less than a year after drilling. A noise log run in 1988 detected a 7 in. 8-round collar leak in Frew 4 with the casing pressured to 875 psi with nitrogen. Many of the reduced OD connections used in Aliso Canyon wells were run prior to 1980. Testing in the mid-1980s showed that reduced OD connections were prone to structural failures and internal and external leaks. A temperature survey run in SS-5 in 1977 showed cooling anomalies, which indicated the presence of leaks in the 7 in. Speedtite connection between 150 ft and 1,300 ft. Nine of the Speedtite connections recovered from SS-25 leaked. A discussion on connections is included in Section 2.5.
- Seven casing failures were reported in the 18 original SIMP wells consisting of 5 casing leaks and 2 tight spots in 6 of the 18 wells.
- Serious consequences can result from casing leaks. Underground flow was reported in Frew 3 and FF-34A. The wells were killed by pumping down the tubing. SS-25 was a more serious event where a shallow casing leak broached to surface and a relief well was required to kill the well after several kill attempts were made by pumping down the tubing. This resulted in several billion cubic feet (BCF) of gas escaping into the atmosphere.
- Many of the Aliso Canyon gas storage wells were designed and drilled as oil producers, and the casing and connection designs were not intended for gas exposure and gas storage well loads. The production casing loads for oil and gas wells normally decrease with time due to depletion and reduced reservoir pressure when compared to gas storage wells where the pressure is cyclic depending on the injection and withdrawal cycles. Gas storage wells are pressured up to field operating pressure while injecting gas, and then the gas is withdrawn (produced) usually on an annual cycle. The well pressure is reduced under withdrawal conditions, and the cycle repeats year after year. These pressure reversals are suspected of having contributed to casing and well leaks.

[v] Wells drilled from 2010 to 2015 did have casing connections that would be considered a gas-tight connection with a metal-to-metal seal.

- Wells with casing failures were distributed throughout the Aliso Canyon Field. A map showing the distribution is included in Section 2.6. Nothing seems unusual regarding the casing failures near SS-25 when comparing them to the casing failures in the rest of the field.
- Most of the failed wells with 7 in. production casings were drilled from 1939 to the mid-1950s as conventional oil and gas wells. The data shows that casing failures and casing leaks happened in approximately 50% of these wells. The failed wells with 8 5/8 in. production casings were drilled in the 1970s, and a cement stage collar was run to cement to surface and many of the stage collars leaked. The failure and casing leak rate for the gas storage wells is also around 50%, implying that well age does not correlate with casing failures.
- The depths of casing failures ranged from the wellhead to below 8,000 ft, and no general pattern is apparent. Thirteen of the 99 failures were reported between surface and 1,000 ft (8 casing leaks, 2 parted casings, 2 tight spots, and 1 other). Refer to Section 2.3.
- The time of service before a well failed due to a casing problem was evaluated, and the time of service ranges from failures while drilling to 70 years. Section 2.4 summarizes the casing failures in a tabular format. No general conclusions could be drawn from an analysis of average time before a failure was identified or similar metrics.

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Appendix A List of 124 Wells Evaluated

Table 22 is a list of the 124 Aliso Canyon wells downloaded from the DOGGR website on May 9, 2018. These wells were designated as Well Types Gas Storage (GS) and GS, Oil and Gas (OG). Some wells are designated as GS and the remainder as GS, OG.

Table 22: List of Wells Evaluated

Row	Lease	Well	Well Type	Spud Date
1	Fernando Fee	31	GS, OG	5/17/1945
2	Fernando Fee	32	GS	6/10/1948
3	Fernando Fee	33	GS	3/4/1949
4	Fernando Fee	34	GS, OG	3/28/1951
5	Fernando Fee	35	GS, OG	9/19/1951
6	Fernando Fee	32A	GS	7/6/1978
7	Fernando Fee	32B	GS	6/29/1973
8	Fernando Fee	32C	GS	5/16/1973
9	Fernando Fee	32D	GS	4/5/1973
10	Fernando Fee	32E	GS	11/11/1972
11	Fernando Fee	32F	GS	9/23/1972
12	Fernando Fee	32G	GS	8/13/2014
13	Fernando Fee	32H	GS	6/30/2015
14	Fernando Fee	34A	GS	10/5/1979
15	Fernando Fee	34BR	GS	12/19/1980
16	Fernando Fee	35A	GS	7/16/1974
17	Fernando Fee	35B	GS	8/20/1974
18	Fernando Fee	35C	GS	9/19/1972
19	Fernando Fee	35D	GS	4/16/1974
20	Fernando Fee	35E	GS	7/10/1972
21	Fernando Fee	38A	GS	10/7/2001
22	Fernando Fee	38B	GS	11/1/2001
23	Fernando Fee	38C	GS	11/19/2001
24	Frew	2	GS	10/19/1943
25	Frew	3	GS, OG	9/21/1944
26	Frew	4	GS	9/20/1947
27	Frew	5	GS	5/16/1948
28	Frew	6	GS	9/20/1948
29	Frew	7	GS	11/27/1954
30	Frew	8	GS	4/4/1955
31	Frew	9	GS	7/26/1963

Row	Lease	Well	Well Type	Spud Date
32	Mission Adrian	3	GS	12/6/1950
33	Mission Adrian	1A	GS	10/28/1979
34	Mission Adrian	1B	GS	6/30/1979
35	Mission Adrian	5A	GS	12/5/1981
36	Porter	12	GS	8/23/1939
37	Porter	26	GS	8/8/1941
38	Porter	30	GS	5/12/1945
39	Porter	32	GS	6/8/1944
40	Porter	34	GS	12/24/1944
41	Porter	35	GS	11/8/1945
42	Porter	36	GS	9/4/1946
43	Porter	37	GS	6/12/1946
44	Porter	38	GS	2/3/1946
45	Porter	39	GS	6/29/1947
46	Porter	40	GS	4/6/1948
47	Porter	41	GS, OG	11/23/1948
48	Porter	42	GS, OG	5/18/1949
49	Porter	43	GS, OG	11/4/1953
50	Porter	44	GS	11/11/1955
51	Porter	45	GS	3/27/1955
52	Porter	46	GS	11/2/1943
53	Porter	47	GS	4/20/1945
54	Porter	24A	GS	8/5/1993
55	Porter	24B	GS	7/17/1993
56	Porter	25R	GS	11/12/1949
57	Porter	26A	GS	7/17/1973
58	Porter	26B	GS	6/6/1973
59	Porter	26C	GS	4/8/1973
60	Porter	26D	GS	12/18/1972
61	Porter	26E	GS	10/26/1972
62	Porter	32A	GS	8/3/1972
63	Porter	32B	GS	9/12/1972
64	Porter	32C	GS	11/10/1973
65	Porter	32D	GS	9/26/1973
66	Porter	32E	GS	8/26/1973
67	Porter	32F	GS	7/15/1973
68	Porter	37A	GS	3/28/1980

Row	Lease	Well	Well Type	Spud Date
69	Porter	42A	GS	9/22/1978
70	Porter	42B	GS	12/9/1978
71	Porter	42C	GS	2/18/1979
72	Porter	50A	GS	4/15/1983
73	Porter	50B	GS	7/2/2010
74	Porter	50C	GS	6/7/2014
75	Porter	68A	GS	5/23/1983
76	Porter	68B	GS	5/21/1993
77	Porter	69A	GS	1/3/1980
78	Porter	69B	GS	1/28/1992
79	Porter	69C	GS	3/19/1992
80	Porter	69D	GS	4/28/1992
81	Porter	69E	GS	6/23/1993
82	Porter	69F	GS	10/7/2001
83	Porter	69G	GS	10/28/2001
84	Porter	69H	GS	11/23/2001
85	Porter	69J	GS	12/12/2001
86	Porter	69K	GS	1/3/2002
87	Porter	72A	GS	9/20/1993
88	Porter	72B	GS	9/1/1993
89	Porter Sesnon	42	GS	9/14/1954
90	Sesnon Fee	1	GS	11/6/1952
91	Sesnon Fee	2	GS	4/21/1953
92	Sesnon Fee	3	GS	11/26/1953
93	Sesnon Fee	4	GS	2/5/1954
94	Sesnon Fee	5	GS	4/22/1954
95	Sesnon Fee	6	GS	7/24/1954
96	Sesnon Fee	8	GS	12/13/1956
97	Standard Sesnon	1	GS	12/25/1941
98	Standard Sesnon	2	GS	3/11/1943
99	Standard Sesnon	3	GS	11/1/1943
100	Standard Sesnon	4	GS	11/1/1943
101	Standard Sesnon	5	GS	2/5/1945
102	Standard Sesnon	6	GS	6/6/1945
103	Standard Sesnon	7	GS	10/14/1945
104	Standard Sesnon	9	GS	11/13/1946
105	Standard Sesnon	10	GS	4/20/1947

Row	Lease	Well	Well Type	Spud Date
106	Standard Sesnon	11	GS	9/14/1947
107	Standard Sesnon	12	GS	2/12/1948
108	Standard Sesnon	13	GS	10/5/1948
109	Standard Sesnon	14	GS	3/23/1949
110	Standard Sesnon	16	GS	9/3/1949
111	Standard Sesnon	17	GS	3/5/1952
112	Standard Sesnon	24	GS	2/7/1953
113	Standard Sesnon	25	GS	10/1/1953
114	Standard Sesnon	29	GS	4/26/1953
115	Standard Sesnon	30	GS	8/1/1953
116	Standard Sesnon	31	GS	9/14/1953
117	Standard Sesnon	25A	GS	11/2/1972
118	Standard Sesnon	25B	GS	1/13/1973
119	Standard Sesnon	44A	GS	9/3/1974
120	Standard Sesnon	44B	GS	7/5/1974
121	Standard Sesnon	4A	GS	11/12/1974
122	Standard Sesnon	4B	GS	8/17/2015
123	Standard Sesnon	4-0	GS	8/11/1980
124	Ward	3A	GS	10/10/1981

SS-25 RCA Supplementary Report

Aliso Canyon Shallow Corrosion Analysis

Purpose:
To investigate if the shallow external corrosion on the SS-25 7 in. casing was a unique situation.

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Abstract

The gas storage well Standard Sesnon 25 (SS-25) in the Aliso Canyon Gas Storage Field located in Los Angeles County, California started leaking gas in October 2015. A relief well was drilled, and SS-25 was brought under control. The leak stopped in February 2016.

In January 2016, as part of their investigation of the leak, the California Public Utilities Commission (CPUC) and the Division of Oil, Gas, and Geothermal Resources (DOGGR) selected and gave provisional authority to Blade Energy Partners (Blade) to perform an independent Root Cause Analysis (RCA). The Blade Team and parties under Blade's direction were responsible for directing the work of subcontractors who performed the extraction of the SS-25's wellhead, tubing and casing, and the preservation and protection of associated evidence. Blade RCA Reports, including this report, document and describe the key activities undertaken in support of the RCA effort.

Corrosion was found visually, by laser scanning, and by running casing inspection logs on the SS-25 7 in. production casing. The data sources used were reports provided by SoCalGas, Blade reports, and publicly available log data. This report answers the question: To what degree was the SS-25 7 in. casing corrosion an isolated event?

The key findings were:

- Out of 116 wells evaluated, logs were available for 76 wells, 27 of which (including SS-25) showed external corrosion on the production casing.
- In almost all wells, the shallow corrosion was observed on the production casing just below the depth of the surface casing shoe. Exceptions included F-4 and P-50A, which showed external corrosion above the depth of the surface casing like SS-25.
- Ten wells had shallow production casing leaks with depths ranging from surface to 1,500 ft. Three of the casing leaks can be attributed to shallow corrosion, namely SS-25, P-50A, and P-32. Three of these casing leaks were not attributed to shallow corrosion, namely SS-5, SS-12, and SS-4A. There was not enough information to determine if the remaining casing leaks were related to shallow corrosion.
- Although not one well was found with the exact placement and pattern of corrosion as that of SS-25, Blade concluded that shallow corrosion was not an isolated event; it was common, found field-wide and in close proximity to the surface casing shoe. Both the occurrence of shallow corrosion and shallow casing leaks related to corrosion were not unique to SS-25.

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1 Introduction

On October 23, 2015, the SS-25 7 in. casing ruptured at 892 ft as a result of diminished pressure capacity that was caused by Outside Diameter (OD) corrosion. As detailed in the Phase 3 Summary Report [1], the 7 in. casing was recovered to a depth of 1,025 ft. Corrosion was observed on the OD; it was typically less than 40% penetration, except at 892 ft, which had approximately 85% penetration. The location of the 7 in. casing external corrosion was primarily from 700 ft to 1,015 ft and was close to the 11 3/4 in. surface casing shoe, which was at 990 ft. The focus of this work was to study production casing corrosion, using casing inspection logs from surface to 500 ft beyond the surface casing shoe. This range of depths was considered shallow compared to the depths of the wells. The following were the data sources used:

- SoCalGas's Casing Leak Summary [2]
- Blade's Analysis of Aliso Canyon Gas Storage Wells with Casing Failures [3]
- Blade's Review of the 1988 Candidate Wells for Casing Inspection [4]
- SoCalGas's Response to Blade's Data Request regarding the 2014 Testimony related to the 2016 General Rate Case [5]
- SoCalGas's Casing Inspection Logs per Order 1109 [6]

1.1 Abbreviations and Acronyms

Term	Definition
CHDT	Cased Hole Dynamics Tester
CPUC	California Public Utilities Commission
DOGGR	Division of Oil, Gas, and Geothermal Resources
F	Frew
FF	Fernando Fee
GRC	General Rate Case
HRVRT	High-Resolution Vertilog
IBC	Isolation Scanner
ID	Internal Diameter
OD	Outside Diameter
P	Porter
P&A	Plug and Abandon
RCA	Root Cause Analysis
SF	Sesnon Fee
SoCalGas	Southern California Gas Company
SS	Standard Sesnon
TBD	To Be Decided
UCI	Ultrasonic Corrosion Imager
USIT	UltraSonic Imaging Tool

Term	Definition
WL	Wireline

2 SS-25 7 in. Casing Corrosion

The location and severity of the corrosion on the 7 in. casing from the surface to 939 ft was observed and photo-documented during the Phase 3 operations [1]. Additional analysis was performed and documented in the SS-25 Casing Failure Analysis report [7]. After the 7 in. tieback was run to 939 ft, the casing inspection logs were run. The SS-25 Inspection Log Analysis report [8] details all logging observations. The 7 in. casing from 939–1,025 ft was logged and extracted. Below 1,025 ft, the 7 in. casing was logged but not extracted.

Figure 1 to Figure 5, and Table 1 show the extent and dimensions of the SS-25 7 in. casing corrosion. In Section 4, Shallow External Corrosion Log Analysis, logs from other wells were compared to SS-25.

Figure 1 shows the High-Resolution Vertilog (HRVRT) log of the 7 in. tieback and original casing [9]. This log was post-extraction of the upper 939 ft of 7 in. casing, so the area above 939 ft is the 7 in. tieback. It shows the region of external corrosion in green brackets. In some areas, the corrosion is on one side of the pipe; in other areas, the corrosion is around the circumference of the pipe.

Table 1 shows the depths and defect dimensions that are in Figure 1's HRVRT log. The highest penetration was 51% at 985.85 ft. Only defects exceeding 15 % penetration are reported.

Figure 2 shows the Ultrasonic Corrosion Imager (UCI) log in a similar depth range as Figure 1's HRVRT log. The UCI log shows the same pattern of external corrosion on the joint that begins at 939 ft, as the HRVRT, but does not show the external corrosion on the joint that begins at 982 ft. The ultrasonic logs, namely UCI and Isolation Scanner (IBC), generally agree very well with the HRVRT in terms of position and severity of metal loss features.

Figure 3 shows the laser scan data of section C026A2, which is Joint 24 in the HRVRT log for the depth range of 939 to 980 ft. The range of defect penetration is from 0 to 20%. One exception is at 40%, which is associated with a Cased Hole Dynamics Tester (CHDT) plug and not corrosion. Almost all defects are above 1,015 ft.

Figure 4 shows the histogram of laser scan data of joints 1–25. Features less than than 10% penetration are not shown for clarity. There is a notable difference at joint 18, where the feature count dramatically increases. This is at a depth of approximately 700 ft.

Figure 5 shows the SS-25 wellbore schematic with the location of the 7 in. external corrosion denoted by orange brackets. The 7 in. external corrosion is most extensively observed between 700 ft and 1,015 ft. This interval extends above and below the depth of the surface casing shoe, which is 990 ft.

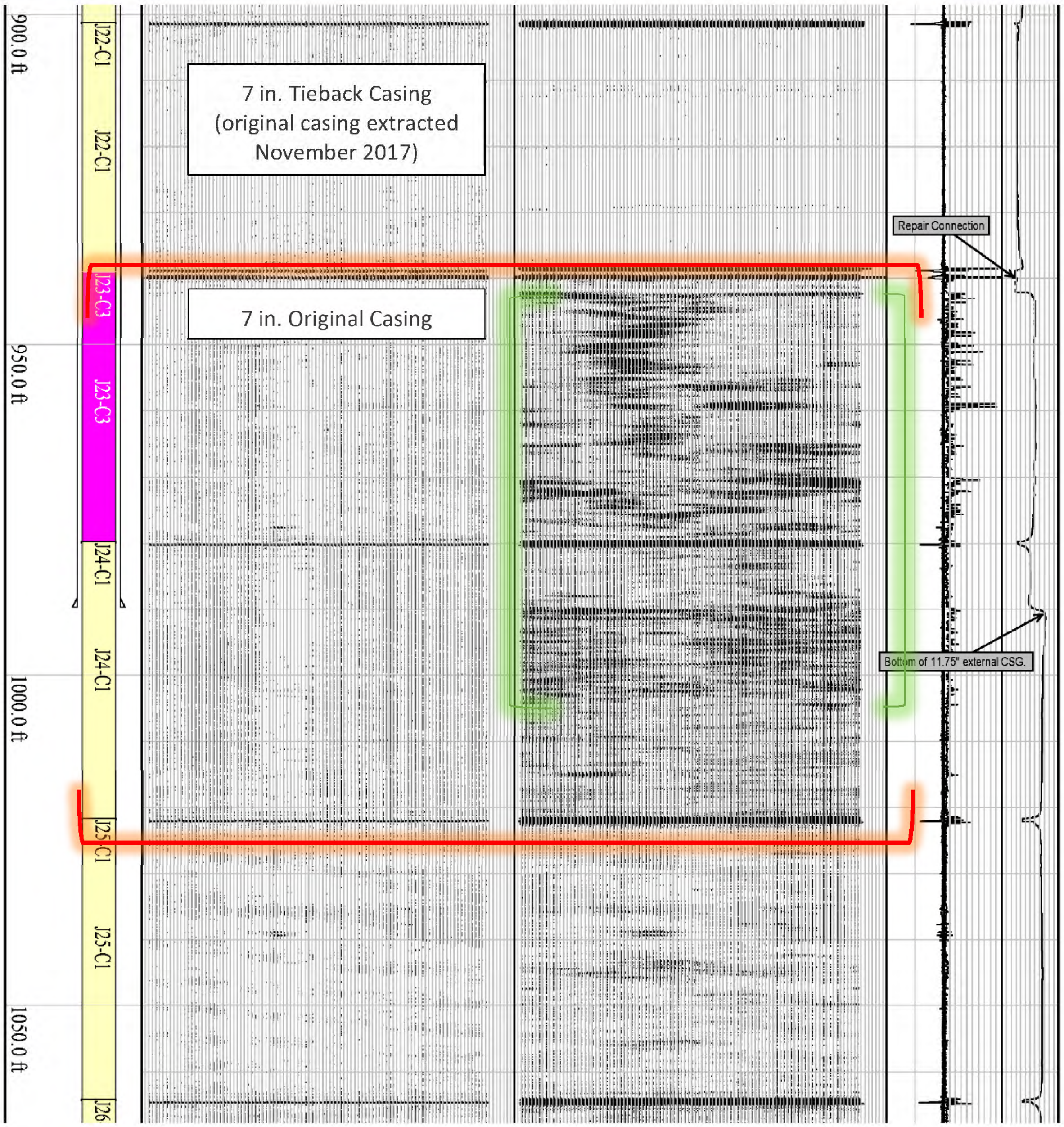


Figure 1: 7 in. HRVRT Log [9], December 2, 2017, External Corrosion at 939–1,015 ft (Green Brackets). Extracted August 8, 2018 (Red Brackets)

Table 1: HRVRT Log Feature Listing [9] for Joints in Figure 1

Log Depth ft	Dist UHC ft	Joint Length ft	Identifier	Class	Description	Surface Indication	Length in	Width in	Depth %	Dim Class
939.14	37.78	40.73	C-23	Collar						
942.22	3.08	40.73	MLCB-23-1	Metal Loss Call Box		External	1.8	3.7	18	GENE
942.47	3.33	40.73	MLCB-23-2	Metal Loss Call Box		External	1.0	1.5	16	PITT
942.82	3.68	40.73	MLCB-23-3	Metal Loss Call Box		External	1.3	1.9	29	GENE
945.98	6.85	40.73	MLCB-23-4	Metal Loss Call Box		Internal	1.9	3.8	17	GENE
947.99	8.85	40.73	MLCB-23-5	Metal Loss Call Box		External	1.1	1.4	24	PITT
948.49	9.35	40.73	MLCB-23-6	Metal Loss Call Box		External	1.2	1.8	17	PITT
949.66	10.52	40.73	MLCB-23-7	Metal Loss Call Box		External	1.2	1.6	16	PITT
949.98	10.84	40.73	MLCB-23-8	Metal Loss Call Box		External	1.6	2.0	34	GENE
950.26	11.12	40.73	MLCB-23-9	Metal Loss Call Box		External	2.5	2.8	23	GENE
950.95	11.82	40.73	MLCB-23-10	Metal Loss Call Box		External	1.2	1.5	32	PITT
952.08	12.95	40.73	MLCB-23-11	Metal Loss Call Box		External	1.4	1.3	16	GENE
952.87	13.73	40.73	MLCB-23-12	Metal Loss Call Box		External	1.1	1.4	22	PITT
958.85	19.71	40.73	MLCB-23-13	Metal Loss Call Box		External	1.2	1.3	51	PITT
959.05	19.91	40.73	MLCB-23-14	Metal Loss Call Box		External	1.4	1.4	19	GENE
959.20	20.06	40.73	MLCB-23-15	Metal Loss Call Box		External	1.2	1.5	48	PITT
970.21	31.07	40.73	MLCB-23-16	Metal Loss Call Box		External	2.4	1.3	33	GENE
970.57	31.44	40.73	MLCB-23-17	Metal Loss Call Box		External	0.9	1.1	15	PITT
972.70	33.57	40.73	MLCB-23-18	Metal Loss Call Box		External	1.1	1.1	17	PITT
974.01	34.87	40.73	MLCB-23-19	Metal Loss Call Box		External	0.8	1.0	16	PITT
974.92	35.78	40.73	MLCB-23-20	Metal Loss Call Box		External	1.0	1.2	17	PITT
979.87	40.73	41.92	C-24	Collar						
989.77	9.90	41.92		End External Casing						
989.79	9.92	41.92	H-24-1	Hardware	Bottom Of External Casing					
990.61	10.74	41.92	MLCB-24-1	Metal Loss Call Box		External	1.1	1.1	17	PITT
991.22	11.35	41.92	MLCB-24-2	Metal Loss Call Box		External	1.6	1.3	18	GENE
991.51	11.64	41.92	MLCB-24-3	Metal Loss Call Box		External	1.5	0.9	16	PITT
1021.79	41.92	41.92	C-25	Collar						

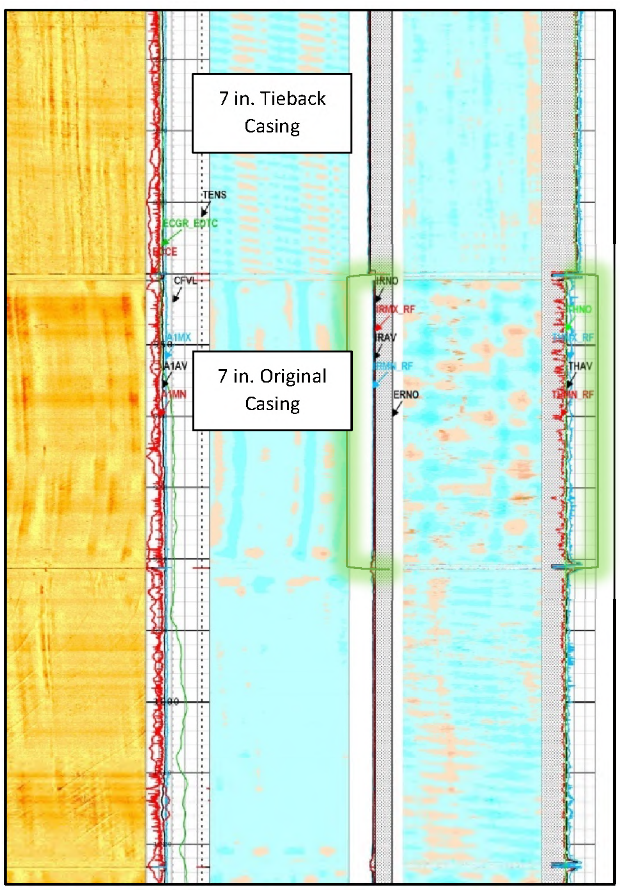


Figure 2: 7 in. UCI Log [10], December 2, 2017, External Corrosion at 939–980 ft (Green Brackets)

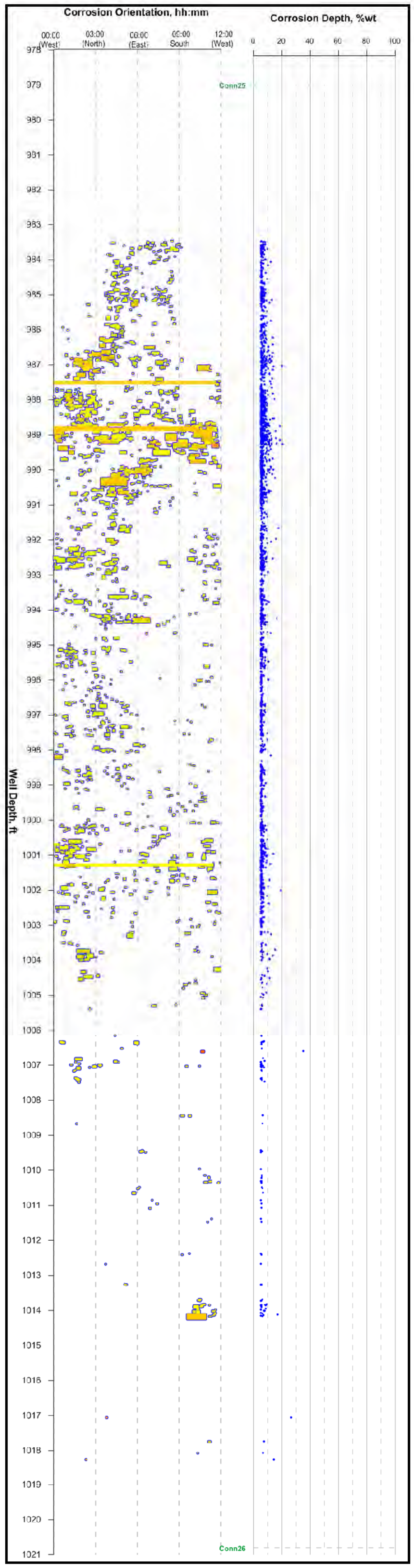
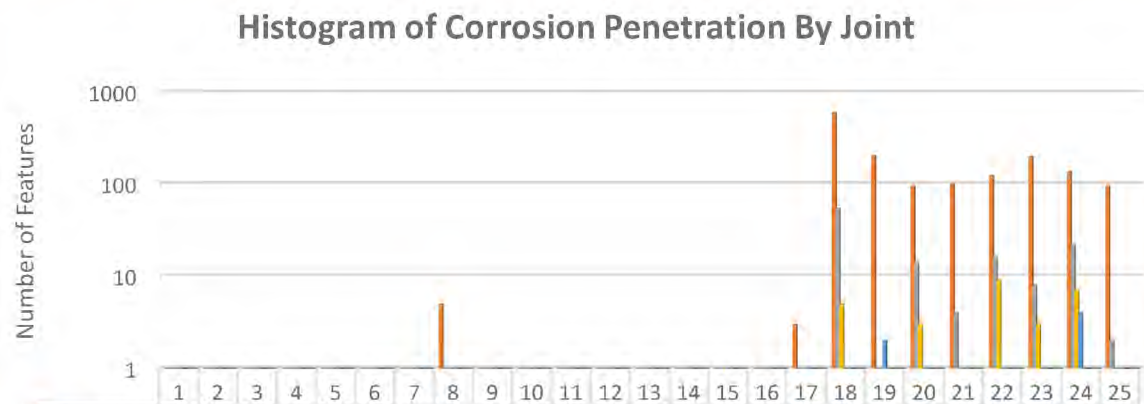


Figure 3: Laser Scan Data of 7 in. Casing Section C026A2



	1	2	3	4	5	6	7	8	9	10	11	12	13	14	15	16	17	18	19	20	21	22	23	24	25
10%-20%	0	0	0	0	0	0	0	5	0	0	0	0	0	0	1	0	3	605	206	94	99	126	202	138	95
20%-30%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	54	0	14	4	16	8	22	2
30%-40%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	5	1	3	1	9	3	7	1
40%-50%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	2	0	0	1	0	4	0
50%-60%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0	1	0
60%-70%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	1	0
70%-80%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0
80%-90%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1	0	0	0
90%-100%	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0

Figure 4: Histogram of 7 in. Laser Scan Data of Joint 1–25, Log Scale, Greater Than 10%

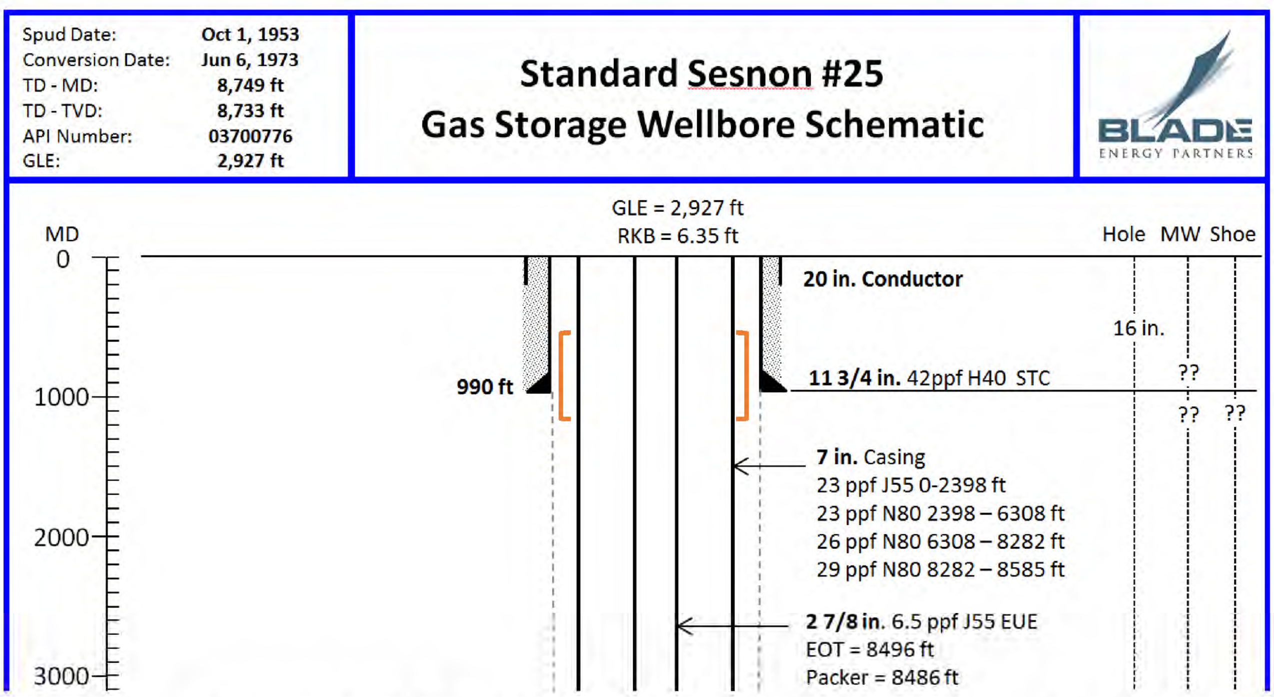


Figure 5: Upper Portion of the SS-25 Well Schematic, 7 in. External Corrosion (Orange Brackets) Located Above and Below the Surface Casing Shoe

3 Discussion

3.1 Casing Leaks per SoCalGas

During a data clarifications meeting on August 24, 2018, Blade learned of a CPUC request to SoCalGas to summarize all the casing leaks associated with gas storage wells at Aliso Canyon. SoCalGas provided this summary [2] to Blade on September 17, 2018, and it is summarized in Appendix B. Figure 6, Figure 7 and Table 3 are related to this summary.

Figure 6 shows this summary graphically by leak discovery date on the x-axis and depth of leak on the y-axis. Two legends are present: one for the leak type and a second one for the leak cause. Most relevant to this report are the casing leaks denoted by red circles.

Figure 7 shows two pie charts. The left pie chart is the casing leak type. Of the 81 leaks, 27 of those are casing leaks, which are of interest to this report. The rest of the leak types are stage collar, casing shoe, water shut off (WSO), casing patch and inner string, but these are not of interest to this report. The right pie chart shows the casing leak causes. Of the 27 casing leaks, 22 of them are for unknown reasons. Three casing leaks are stated to relate to corrosion, and two casing leaks are to be determined (TBD).

Table 3 shows just the eight wells with shallow casing leaks, i.e., above 1,500 ft. Only one of these wells has a reason for the leak cause: Porter 50A (P-50A) was stated as "Casing inspection log indicates corrosion". Shallow corrosion was not observed in the logs of two wells, SS-5 and SS-14. Four wells did not have logs. Shallow corrosion was observed in the logs of two wells, namely, P-50A and Frew 4 (F-4); these wells will be discussed in the Shallow External Corrosion Log Analysis (Section 4).

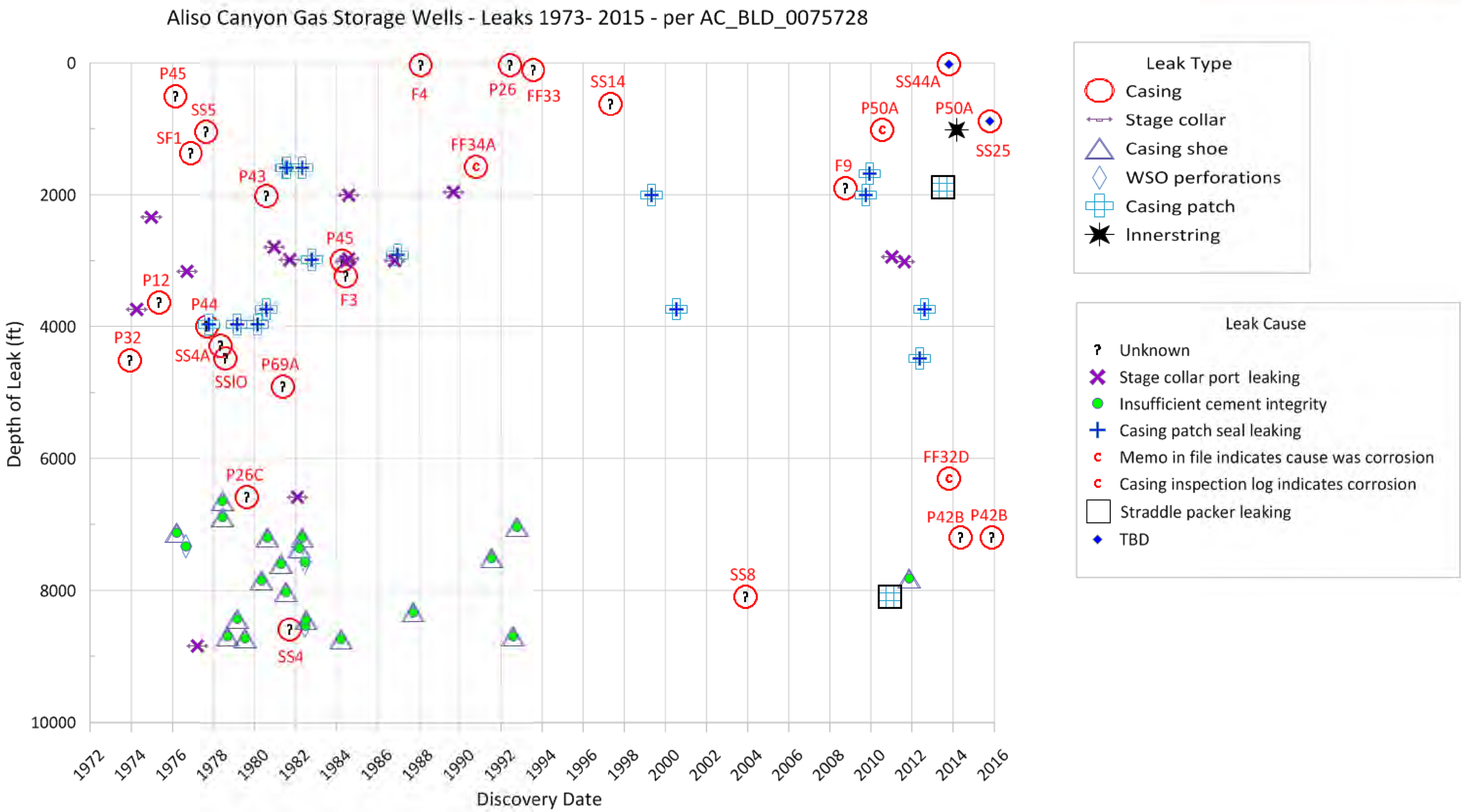


Figure 6: Leaks Reported by SoCalGas [11]

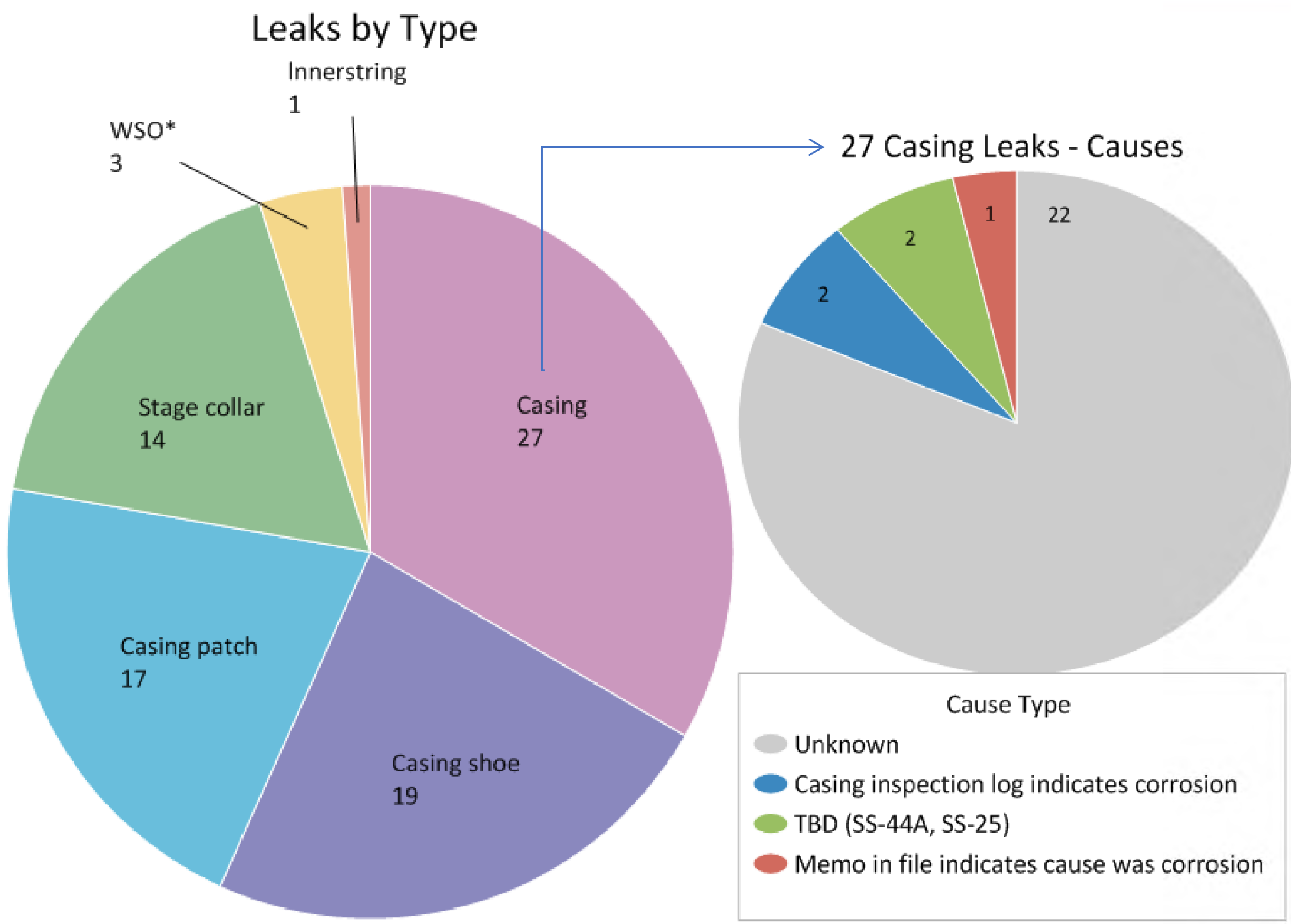


Figure 7: Leak Types and Causes Reported by SoCalGas [11], (*- Water Shut Off Perforations)

3.2 Analysis of Aliso Canyon Gas Storage Wells with Casing Failures [3]

Blade examined the well records of 124 wells in Aliso Canyon and identified 99 failures in 49 wells. The failures were 63 casing leaks, 29 tight spots, 4 parted casings, and 3 other failures.

Table 4 shows just the shallow casing leaks, i.e., above 1,500 ft. In some instances, the well names in the table are suffixed with a number in brackets. This is because some wells had more than one failure and are detailed in a separate report titled *Analysis of Aliso Canyon Gas Storage Wells with Casing Failures* [3]. There are 11 entries for 10 different wells of which 7 wells are common to Table 3. The unique wells are SS-12, SS-4A, and P-32. Shallow corrosion was not observed in the logs of three wells, namely SS-5, SS-12, and SS-4A. Shallow corrosion was observed in the logs of three wells, namely, SS-25, P-50A, and P-32; these wells will be discussed in the Shallow External Corrosion Log Analysis Section.

3.3 Review of the 1988 Candidate Wells for Casing Inspection

A recommendation was made in a SoCalGas Interoffice Correspondence document [12], dated August 30, 1988, to run casing inspection logs in 20 wells and pressure test each well; SS-25 was on this list. Blade reviewed the well records of the 20 wells to understand what was done in each well with respect to casing inspection, pressure tests, and operations related to casing problems since 1988. This work is documented in a separate report [4]. Table 5 shows the only wells that had indications of shallow corrosion on inspection logs; from the original listing of 20 wells, 8 wells are listed. Casing leaks were identified in two wells during workovers, namely Porter 44 (P-44) and Frew 2 (F-2); these were not related to shallow corrosion above 1,500 ft. Four of the wells had been logged with the Vertilog during 1988–1990 and showed corrosion greater than 20% penetration.

3.4 SoCalGas General Rate Cases

Various SoCalGas general rate case (GRC) documents describe their gas storage wells as being affected by aging and deterioration due to the combined effects of corrosion, erosion, and wide variations of pressure and temperature. SoCalGas presented the 2016 GRC before the CPUC in November 2014 [5] and provided details about the required operations and maintenance expenses and capital investments for their underground storage facilities and proposed a new six-year Storage Integrity Management Program (SIMP). The intent was to “proactively identify and mitigate potential storage well safety and/or integrity issues before they result in unsafe conditions for the public or employees.” SoCalGas noted an increasing trend in well integrity repairs and that without the SIMP, they would continue to operate in a reactive mode to address sudden and major failures and service interruptions. As part of the well repair work from 2008 to 2013, SoCalGas explained that mechanical damage and internal and external corrosion were identified in 15 wells with the use of ultrasonic logs. Also, the external corrosion had been observed at relatively shallow depths in the production casing. SoCalGas cited P-50A, where 400 psi was observed in the casing annulus during routine weekly pressure surveillance in 2008; a footnote provided additional information that a subsequent ultrasonic inspection revealed external production casing corrosion from 450 to 1,050 ft.

The proposed SIMP program in the 2014 testimony included identifying threats and risk assessments for all wells. The baseline assessments would determine the priority of casing inspections and pressure testing. Risk assessments, casing inspection, and pressure testing are all tenets of the 2019 California regulatory requirements for gas storage wells. The risk management approach indicated a shift toward the management of SoCalGas’ below-ground facilities.

Specifically, SoCalGas noted that ". . . two wells were found to have leaks in the production casing at depths adjacent to the shallower oil production sands." and "Ultrasonic surveys conducted in storage wells as part of well repair work from 2008 to 2013 identified internal/external casing corrosion, or mechanical damage in 15 wells." On February 18, 2018, Blade requested the names of the wells in the November 2014 testimony; SoCalGas provided a list with the 17 well names [13]. Six wells in the list were from other SoCalGas gas storage fields (i.e., not from Aliso Canyon). Including P-50A, there were 12 Aliso Canyon wells.

Table 6 shows the 12 Aliso Canyon wells provided by SoCalGas that are related to the 2014 Testimony. Five of the wells have shallow corrosion indications and are shown in the Shallow External Corrosion Log Analysis.

3.5 Casing Inspection Logs from the Comprehensive Safety Review

On March 4, 2016, Order No. 1109 [6] was issued from DOGGR to SoCalGas for the Aliso Canyon wells. Among other operations, the order stated that SoCalGas must run a casing inspection log for all wells that were intended for future operations; otherwise, they must be plugged and abandoned. Order No. 1109, within the document itself, is referred to as the Comprehensive Safety Review.

Status reports for the Aliso Canyon wells were issued by SoCalGas as part of their compliance to Order 1109; 114 wells were listed in the status reports. The status report dated February 15, 2019 [14] was used for this work. Table 7 shows the list of 114 wells and the dates of the casing inspection logs. These casing inspection logs were downloaded from the DOGGR website [15]. Twenty-five wells were identified from the Comprehensive Safety Review listing that showed shallow corrosion and are shown in Shallow External Corrosion Log Analysis.

4 Shallow External Corrosion Log Analysis

A total of 116 unique wells were included in the Discussion section (Section 3). Casing inspection logs were available for 76 wells. Some logs were not available because the installation of an inner casing string had covered the production casing. Table 2 shows a list of wells that have shallow external corrosion indications on casing inspection logs from the various data sources presented in Section 3. The 27 wells are:

- Frew, 2 wells:
  - F-2 and F-4
- Standard Sesnon, 4 wells:
  - SS-8, SS-9, SS-24, and SS-25
- Porter, 14 wells:
  - P-32, P-32B, P-32D, P-32E, P-32F, P-35, P-36, P-37, P-37A, P-46, P-50A, P-68A, P-69A, and P-72A
- Sesnon Fee, 1 well:
  - SF-5
- Ward, 1 well:
  - W-3
- Fernando Fee, 3 wells:
  - FF-32A, FF-32E, and FF-32F
- Mission Adrian, 2 wells:
  - MA-1A and MA-3

Table 2 shows different columns, and some of them are detailed as follows:

- Column 3 shows the spud dates of the wells ranging from October 19, 1943, to September 20, 1993, a span of nearly 50 years. Figure 8 shows the spud dates of these wells. The two major groups were: first, wells drilled in the 1940s and 1950s by Tidewater, et. al., and second, wells drilled by SoCalGas, about an equal number of wells were from each group; this suggests that the company that drilled the wells was not a factor for shallow corrosion. Although not investigated in detail, the drilling techniques would have been different from 1943 to 1993; this suggests that drilling techniques were not a factor for shallow corrosion either.

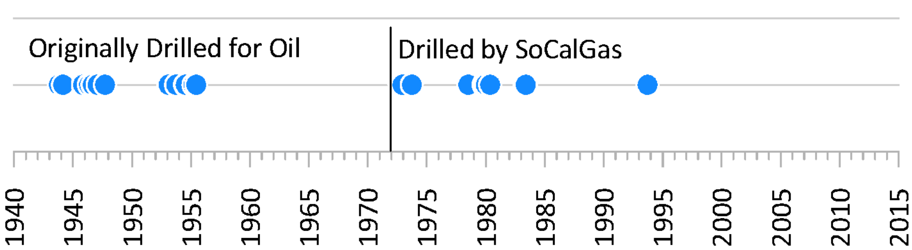


Figure 8: Range of Spud Dates for Wells with Shallow Corrosion on Production Casing

- Columns 5 and 6 show the wells that had a casing leak. This information was compiled by using SoCalGas data and Blade analysis, respectively. Aside from SS-25, shallow corrosion was identified on casing inspection logs that were run in three wells with shallow casing leaks: F-4, P-32, P-50A. Blade reviewed these wells' history. F-4 was identified as having a 7 in. Speedtite connection leak[i]. P-32 was pressure tested October 27–28, 2016, and at the 654 to 845 ft interval, it was unable to hold pressure; this interval was subsequently cement squeezed and pressure tested. We presumed that the reason for this was the well not being able to hold pressure due to extensive deep external corrosion. P-50A was reported by SoCalGas to have a casing leak at 1,020 ft on July 16, 2010 [2]. This was not the first time SoCalGas reported leaks for this well; P-50A has a complicated history of multiple possible leaks that were determined by noise anomalies, radioactive tracer surveys, shallow gas flow in the surface casing, helium analyses, and anomalous surface casing pressures. The well's reports are from 1983, its completion date. SoCalGas indicated that corrosion was the cause for the casing leak, based on casing inspection logs [2], but no record was found regarding the corrosion mechanism. The gas flowing into the surface casing was analyzed in various years for flow rate and composition. SoCalGas determined that the gas was not storage gas—it was instead from a shallow gas zone; this was determined by low levels of helium [16]. Gas analysis also showed a slightly elevated level of carbon dioxide: around 2 mol% when it was compared to the storage gas of less than 1 mol%. Blade interpreted the presence of shallow gas flow containing an elevated level of carbon dioxide plus an aqueous environment as the cause for the corrosion in P-50A. As with P-32, confirmation of the corrosion mechanism was not possible because the casing was cement squeezed and not recovered.
- Column 7 shows seven wells with shallow external corrosion on the production casing from the wells in the 1988 interoffice correspondence [12]. Of the seven wells, three wells had logs from 1988–1990 that showed shallow external corrosion on the production casing; this suggests that shallow corrosion had not been a recent phenomenon.
- Column 8 shows five wells that had shallow external corrosion and were referenced in the 2014 Testimony (related to the 2016 GRC) or subsequent data request, which included 12 Aliso Canyon gas storage wells. When considering only the casing inspection logs from these five wells, the SIMP plan proposed by the 2014 Testimony was reasonable.
- Columns 9–11 show the production casing details in terms of size, connection, and grade: three casing sizes (7, 8 5/8, and 9 5/8 in.), four connection types (LTC, Speedtite, Buttress, and 8 Round), and three grades (J55, K55, and N80). This variability suggests that the corrosion mechanism was not specific to a single size, connection, or grade.
- Columns 12 and 13 show the depth of the surface casing shoe and the surface elevation of the well. The range of surface casing shoe depths was 501–1660 ft. The average surface casing shoe depth was 812 ft. The average surface elevation was 2,193 ft. SS-25 had the highest elevation: 2,927 ft.

[i] Blade did not count F-4 as a leak because the noise log was not located for evaluation and the reported leak with nitrogen was not confirmed with a pressure test.

Table 2: Wells with Shallow Corrosion Indications Compiled from Table 3–Table 7

Column 1	2	3	4	5	6	7	8	9	10	11	12	13
Lease Name	Well #	Spud Date	Years from Spud	Shallow Leak Well [a]	Shallow Leak Well [b]	1988 Memo Well[c]	2016 GRC Well[d]	Prod. Casing Size (in.)	Prod. Casing Conn.	Prod. Casing Grade	Surface Casing Depth (ft)	Surface Elevation (ft)
Frew	2	October 19, 1943	76	No	No	Yes	No	7	LTC	N80	501	2,796
Porter	46	February 27, 1944	75	No	No	No	No	7	Speedtite	J55	533	2,255
Porter	35	November 8, 1945	74	No	No	No	No	7	Speedtite	J55	505	2,094
Standard Sesnon	8	May 14, 1946	73	No	No	Yes	Yes	7	Speedtite	J55	812	2,697
Porter	37	August 26, 1946	73	No	No	Yes	Yes	7	Speedtite	J55	520	1,900
Porter	36	September 4, 1946	73	No	No	No	No	7	Speedtite	J55	517	1,924
Standard Sesnon	9	February 4, 1947	72	No	No	Yes	No	7	Speedtite	J55	598	2,836
Frew	4	September 20, 1947	72	Yes	No	Yes	No	7	8 Round	N80	770	2,420
Standard Sesnon	24	February 7, 1953	66	No	No	Yes	No	7	LTC	N80	1,134	2,539
Standard Sesnon	25	October 1, 1953	66	Yes	Yes	Yes	No	7	Speedtite	J55	990	2,927
Ward	3	July 7, 1954	65	No	No	No	No	7	8 Round	J55	1,660	2,226
Sesnon Fee	5	July 19, 1954	65	No	No	No	No	7	LTC	N80	837	2,439
Porter	32	March 21, 1955	64	No	Yes	No	No	7	Speedtite	J55	522	2,079
Mission Adrian	3	June 15, 1955	64	No	No	No	No	7	8 Round	N80	549	2,053
Porter	32B	September 12, 1972	47	No	No	No	No	8 5/8	Buttress	K55	694	1,995
Fernando Fee	32F	September 23, 1972	47	No	No	No	Yes	8 5/8	Buttress	K55	799	1,995
Porter	32F	September 23, 1972	47	No	No	No	No	8 5/8	Buttress	K55	799	1,995
Fernando Fee	32E	December 6, 1972	47	No	No	No	Yes	8 5/8	Buttress	K55	717	1,995
Porter	32E	September 25, 1973	46	No	No	No	No	8 5/8	Buttress	K55	791	2,075
Porter	32D	September 26, 1973	46	No	No	No	No	8 5/8	Buttress	K55	806	2,075
Fernando Fee	32A	July 6, 1978	41	No	No	No	No	8 5/8	LTC	K55	990	1,995
Mission Adrian	1A	October 28, 1979	40	No	No	No	No	8 5/8	Buttress	N80	1,000	1,725

Column 1	2	3	4	5	6	7	8	9	10	11	12	13
Lease Name	Well #	Spud Date	Years from Spud	Shallow Leak Well [a]	Shallow Leak Well [b]	1988 Memo Well[c]	2016 GRC Well[d]	Prod. Casing Size (in.)	Prod. Casing Conn.	Prod. Casing Grade	Surface Casing Depth (ft)	Surface Elevation (ft)
Porter	69A	January 3, 1980	39	No	No	No	No	9 5/8	Buttress	N80	1,002	2,365
Porter	37A	May 17, 1980	39	No	No	No	No	8 5/8	Buttress	N80	1,024	1,898
Porter	50A	April 15, 1983	36	Yes	Yes	No	Yes	9 5/8	Buttress	N80	1,025	1,936
Porter	68A	May 23, 1983	36	No	No	No	No	9 5/8	Buttress	N80	1,015	2,080
Porter	72A	September 20, 1993	26	No	No	No	No	9 5/8	LTC	N80	814	1,909
Total Wells			Average	Total	Total	Total	Total				Average	Average
27			56.1	3	3	7	5				812.0	2,193.4

a – shallow casing leaks identified by SoCalGas [2]
b – shallow casing leaks identified by Blade [3]
c – wells listed in the 1988 Casing Inspection Interoffice Memo [17]
d – wells listed in the SoCalGas response dated March 12, 2018 [13]

4.1 External Corrosion Below the Surface Casing Shoe

Appendix A shows a large format compilation of 15 wells. The logs have been shifted so that the surface casing shoe is in the same location for each well. Figure 9 shows a screenshot of the composite log, showing logs from Porter 69A (P-69A), Porter 32 (P-32) and Porter 32D (P-32D) side by side. The surface casing shoe is at a different depth for each well. The composite log has been arranged so that the surface casing shoe is shown at the same location; this is denoted by the label Surface Casing Shoe and a faint blue line. A distinctive trend is obvious on the compilation log: almost all of the displayed wells have external corrosion just below the depth of the surface casing shoe (and absent above this depth).

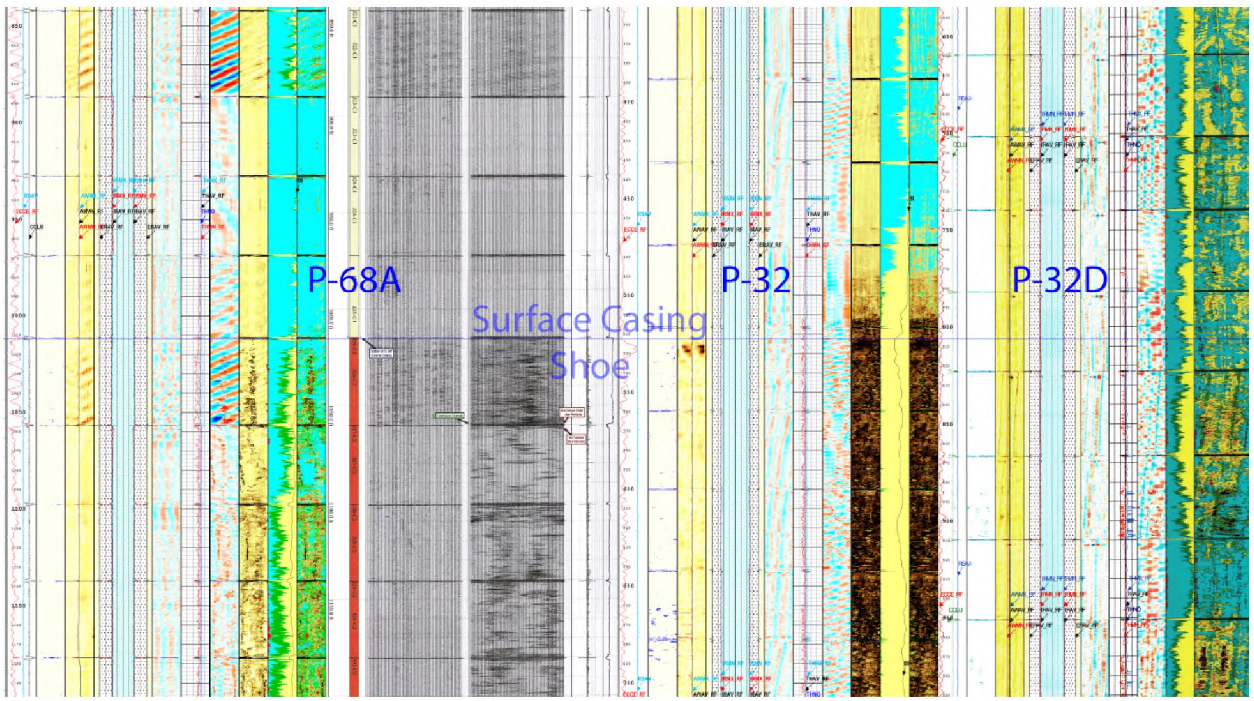


Figure 9: Screenshot of Composite Log Showing the Surface Casing Shoe

Figure 10 shows the March 31, 2016, USIT log on the left and April 1, 2016, HRVRT log on the right for FF-32A 8-5/8 in. production casing. The tracks are labelled. External corrosion is best interpreted using the tracks titled Casing Thickness, Flux Leakage Axial, and Maximum Flux Leakage. The depth of the surface casing shoe is denoted by a green arrow at an approximate depth of 977 ft and is denoted by a faint blue line. The Casing Thickness track shows a red line, which is the minimum thickness measured in inches observed by the USIT. This track scale is from 0.1–0.6 in. Where the red line moves to the left indicates that the casing wall thickness is reduced. The black line on the Maximum Flux Leakage shows the same character as the red line on the Casing Thickness track; both lines are indicating metal loss at the same depth. There are no internal metal loss features, ovality, nor any other types of deformation; this is denoted by blue arrows in the Casing Cross Section, Internal Radius Map, and the Discriminator tracks.

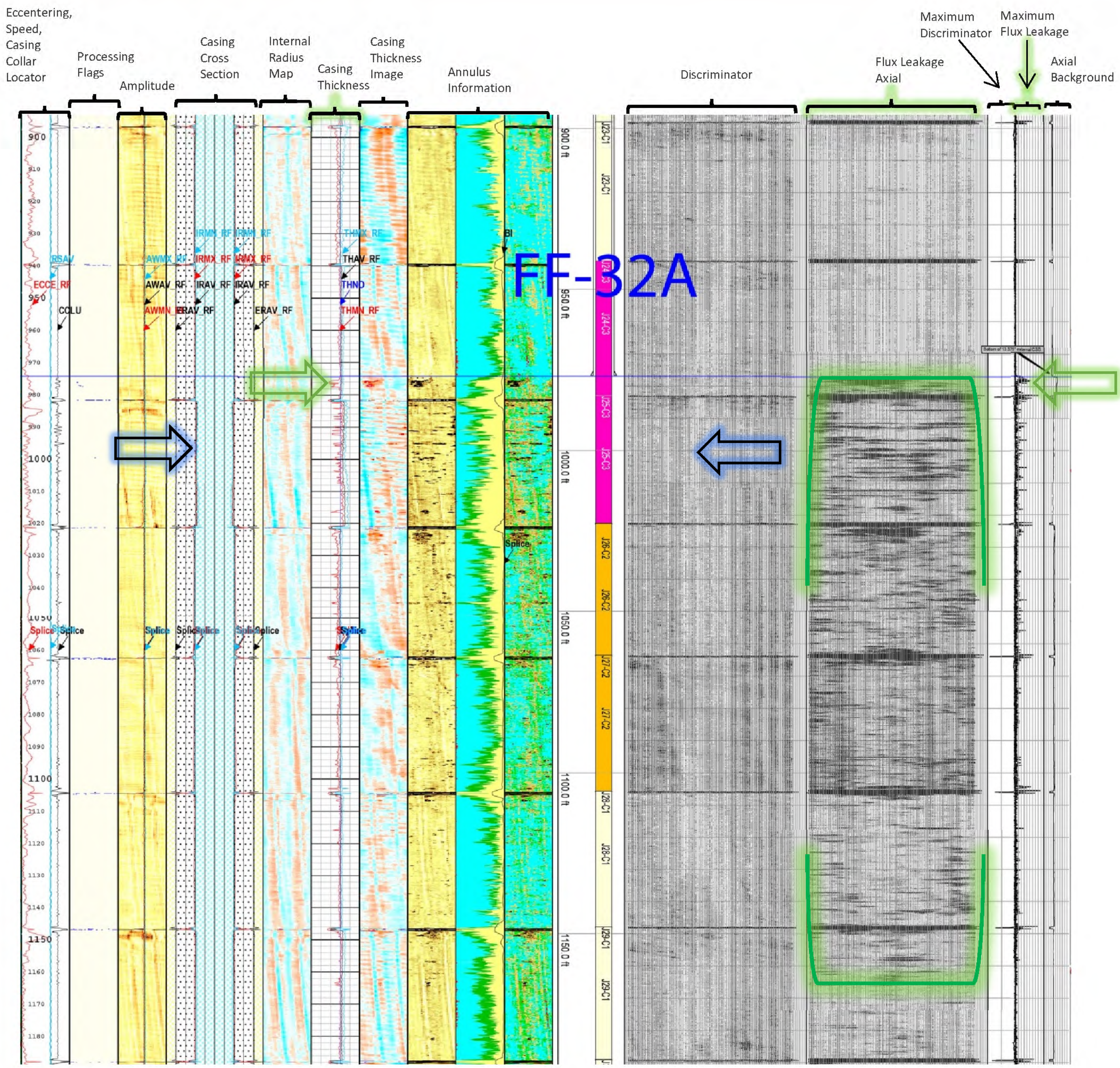


Figure 10: FF-32A, USIT Log (Left), HRVRT (Right), External Corrosion (Green Brackets)

Baker Hughes GE interpreted the FF-32A casing joints to have OD metal loss. Figure 11 shows this interpretation where four joints have OD defects ranging from 25–40 %; this is denoted by the green highlights. The depth of the surface casing shoe was observed at approximately 977 ft and is highlighted blue. This OD metal loss was interpreted as corrosion and not some other form of mechanical metal loss, such as manufacturing defects or handling damage. This is because the pattern is non-uniform, is prevalent on 4–5 casing joints at varying penetrations, and the placement below the surface casing shoe does not seem random.

Interpretation

HRVRT analysis depth correlated to caliper log dated 01-Apr-2016.
10.64 ft Hardware - External CSG head response.
976.77 ft Hardware - Bottom of 13.375" external CSG.
Numerous centralizers installed from interval 2195' to 6462'

Joint Interpretation Summary

Joint	From	To	Length	Class	Max Depth	Position	ID/OD
1	9.64	29.47	19.83	Class 1	-	-	-
2	29.47	71.93	42.46	Class 1	-	-	-
3	71.93	113.60	41.67	Class 1	-	-	-
4	113.60	154.46	40.86	Class 1	-	-	-
5	154.46	196.08	41.62	Class 1	-	-	-
6	196.08	238.08	42.00	Class 1	-	-	-
7	238.08	278.70	40.62	Class 1	-	-	-
8	278.70	320.35	41.65	Class 1	-	-	-
9	320.35	362.46	42.11	Class 1	-	-	-
10	362.46	404.04	41.58	Class 1	-	-	-
11	404.04	445.52	41.48	Class 1	-	-	-
12	445.52	487.85	42.33	Class 1	-	-	-
13	487.85	529.02	41.17	Class 1	-	-	-
14	529.02	569.70	40.68	Class 1	-	-	-
15	569.70	611.84	42.14	Class 1	-	-	-
16	611.84	651.77	39.93	Class 1	-	-	-
17	651.77	693.30	41.53	Class 1	-	-	-
18	693.30	731.92	38.62	Class 1	-	-	-
19	731.92	774.85	42.93	Class 1	-	-	-
20	774.85	817.26	42.41	Class 1	-	-	-
21	817.26	859.30	42.04	Class 1	-	-	-
22	859.30	898.03	38.73	Class 1	-	-	-
23	898.03	941.15	43.12	Class 1	-	-	-
24	941.15	982.99	41.84	Class 3	40.0%	978.79	OD
25	982.99	1022.79	39.80	Class 3	40.0%	991.35	OD
26	1022.79	1063.71	40.92	Class 2	25.0%	1055.72	OD
27	1063.71	1105.84	42.13	Class 2	39.0%	1104.52	OD
28	1105.84	1148.05	42.21	Class 1	-	-	-
29	1148.05	1189.19	41.14	Class 1	-	-	-
30	1189.19	1231.51	42.32	Class 1	-	-	-

Figure 11: FF-32A, HRVRT Joint Interpretation Summary, External Corrosion (Highlighted Green)

Figure 12, and Figure 13 show examples of the same shallow corrosion trend. Each figure shows the USIT log on the left and the HRVRT on the right. The external corrosion is denoted by the green brackets on the HRVRT log. The USIT log shows agreement with the HRVRT for the same internal pattern. The severity of the corrosion (in terms of wall thickness penetration) varies from well to well, but the pattern is clear. See the composite log for the log headers and for additional log footage not shown.

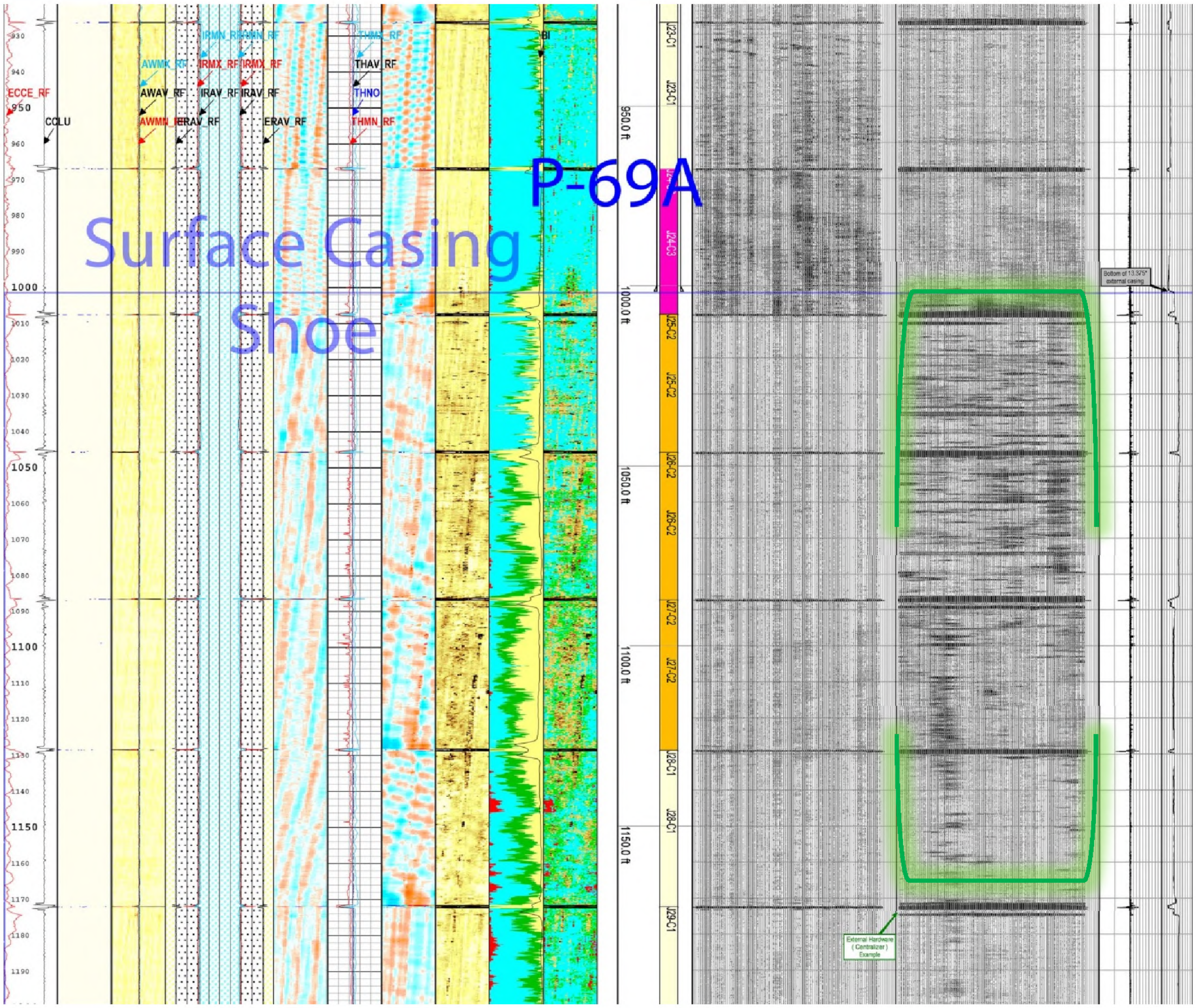


Figure 12: P-69A, External Corrosion (Green Brackets on HRVRT Log)

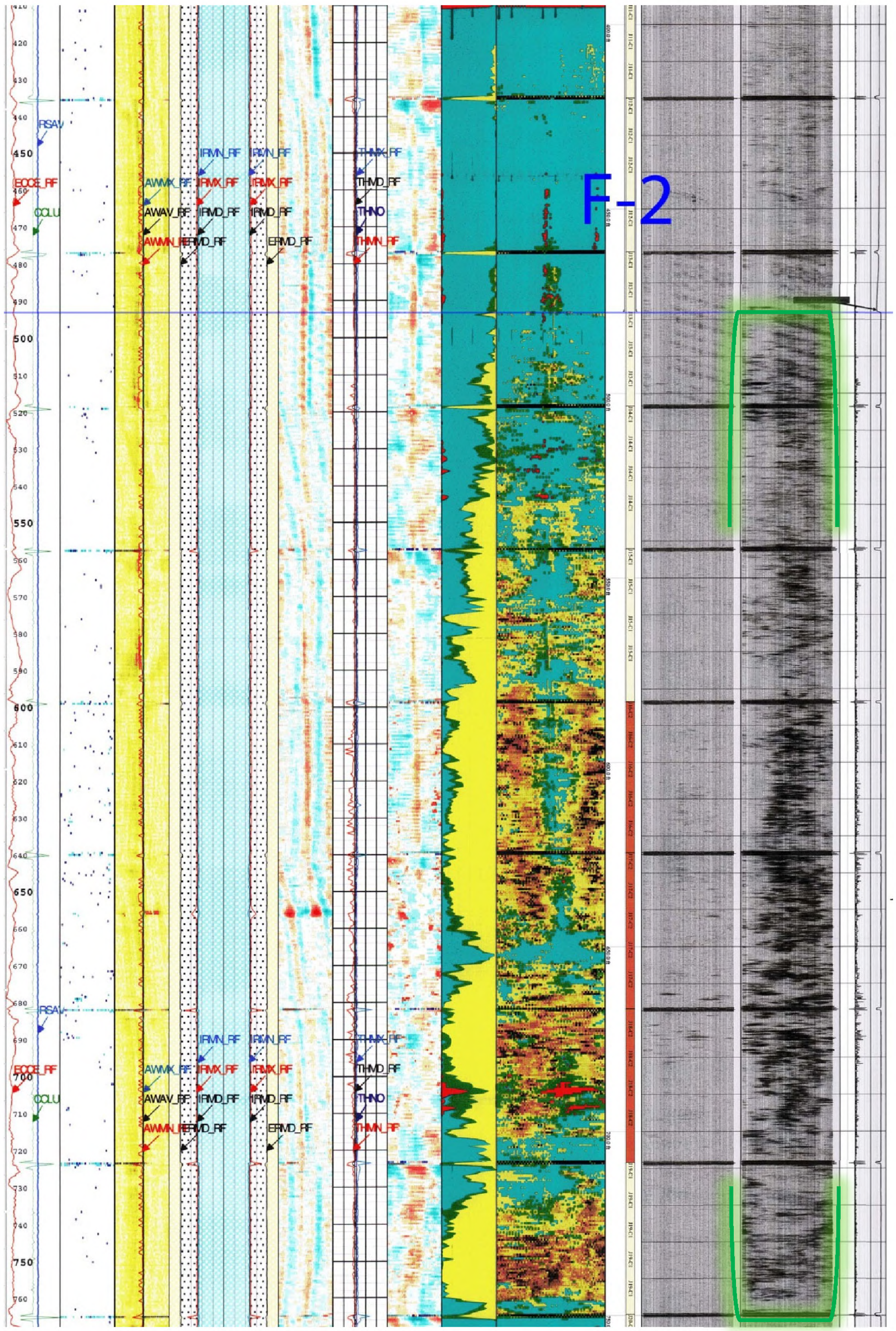


Figure 13: F-2, External Corrosion (Green Brackets)

4.2 Frew 4 and Porter 50A

Apart from SS-25, only two wells have external corrosion above the depth of the surface casing shoe, namely F-4 and P-50A. F-4 will be discussed first.

Figure 14–Figure 16 show the F-4 Vertilog from September 6, 1988 and the USIT log from October 19, 2016 for various depth intervals. Figure 14 shows the interval of approximately 100–200 ft, which is about 500 ft above the depth of the surface casing shoe. A class 2 defect (20–40% penetration) was found at about 3 ft below a connection on the Vertilog. This depth is denoted by the green arrow on the USIT log; the defect is absent. Additionally, the pattern of corrosion in this location of F-4 does not appear to be similar to that of SS-25. Blade interprets that the defect found by the Vertilog did not exist and no shallow external corrosion existed above the shoe. Therefore, P-50A was the only well that showed external corrosion above the surface casing shoe.

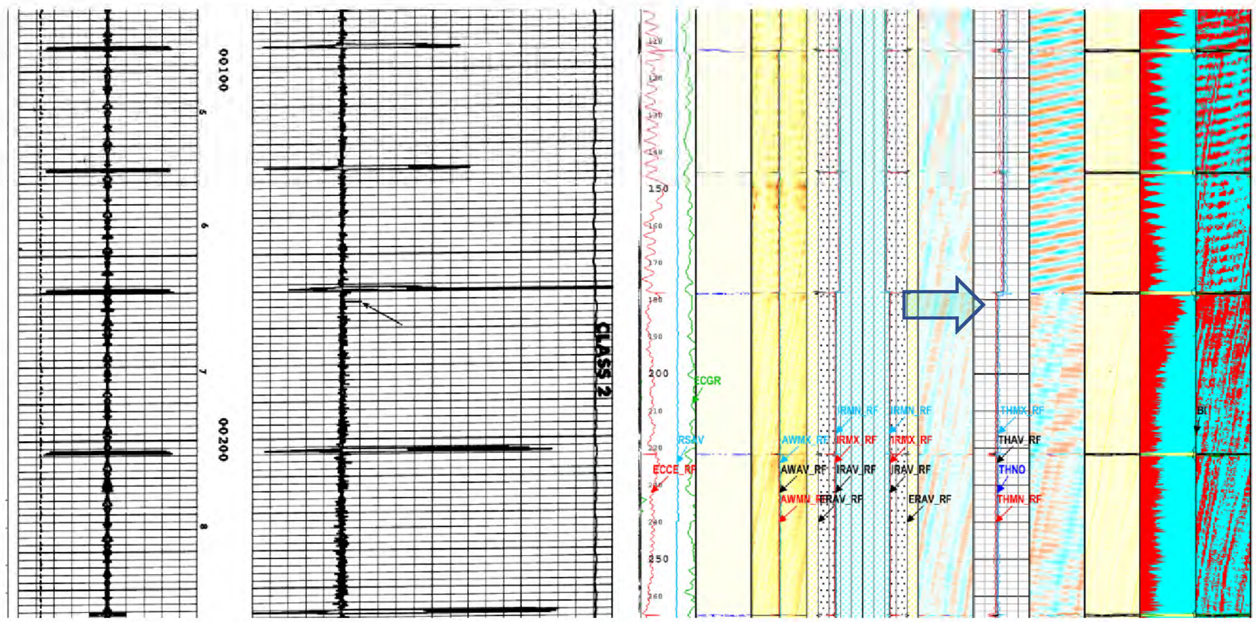


Figure 14: Screenshot of Composite Log F-4 Joint 7, Vertilog (Left) Class 2 Defect, USIT (Right) - No Defect at Arrow

F-4 was reported to have a casing leak at 32 ft on January 2, 1988 [2]. An inner string was installed to isolate the leak. The well records stated that that the leak was detected by a noise anomaly at the first casing connection while nitrogen pressure was applied [Table 8]. Figure 15 shows the F-4 casing inspection logs near surface; they did not show any indications of corrosion near the first connection, which is denoted by an arrow. Blade interprets that the connection leak is unrelated to shallow corrosion.

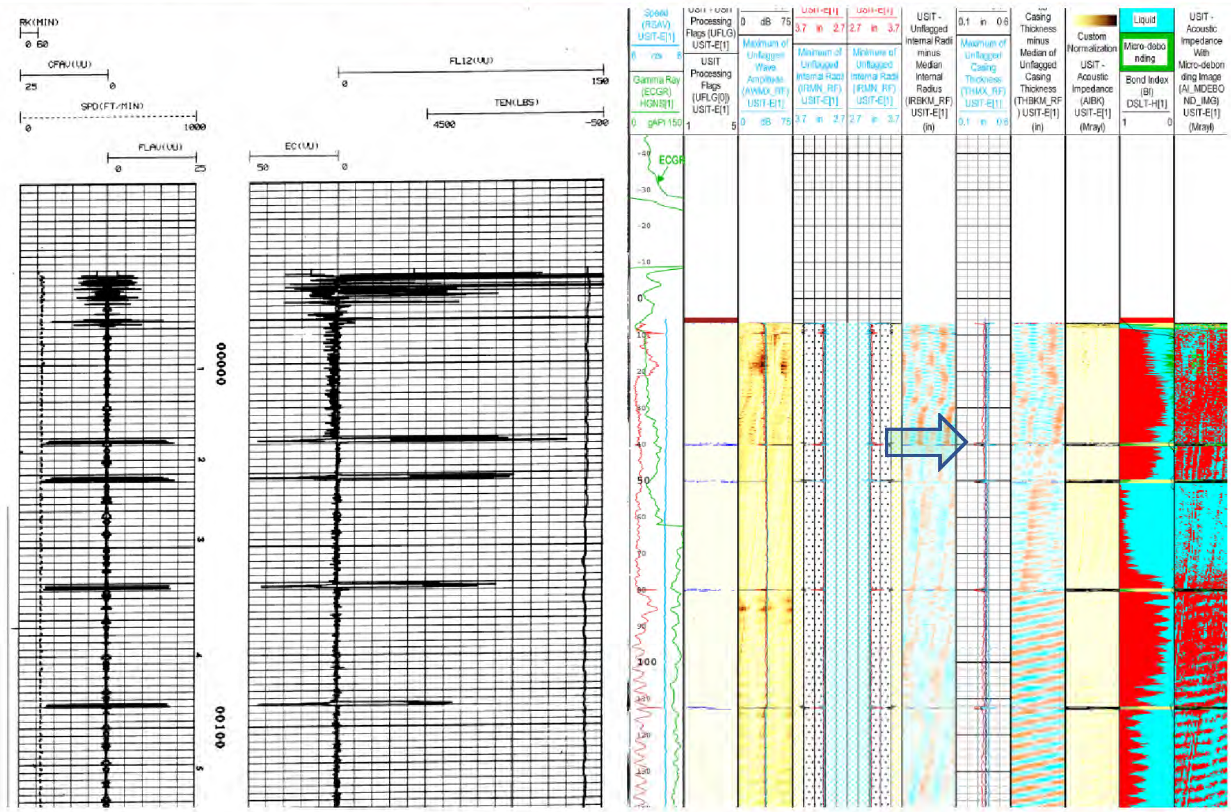


Figure 15: Screenshot of Composite Log, F-4, Vertilog (Left), USIT (Right), No Corrosion Indications at First Connection (Arrow)

Figure 16 shows the F-4 logs for the depths near the surface casing shoe, which is at approximately 770 ft. There is good agreement between the logs, despite the different technologies used and a separation of 28 years. The figure shows corrosion starting at the depth of the surface casing shoe (denoted by the blue line) and extending several joints below. This continues the trend that is common to wells in the composite log except for P-50A, which is discussed in Figure 17.

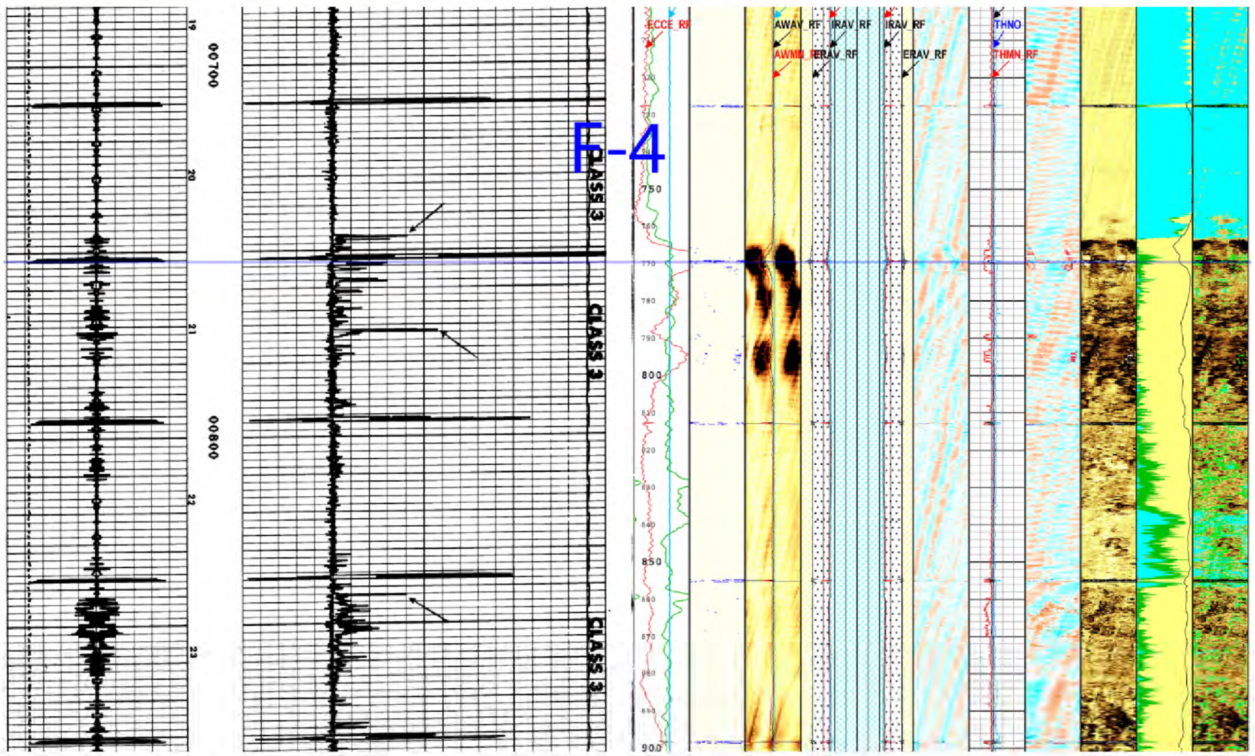


Figure 16: Screenshot of Composite Log F-4 Joint 21, Vertilog (Left), USIT (Right)

Figure 17 shows a screenshot of P-50A USIT logs from 2011 and 2016. The logs have very good agreement. The external corrosion is denoted by green brackets on the wall thickness track. Numerous occurrences of external corrosion are observed above the shoe, but it appears to be completely absent immediately below the shoe. P-50A is the only well observed that has this corrosion pattern.

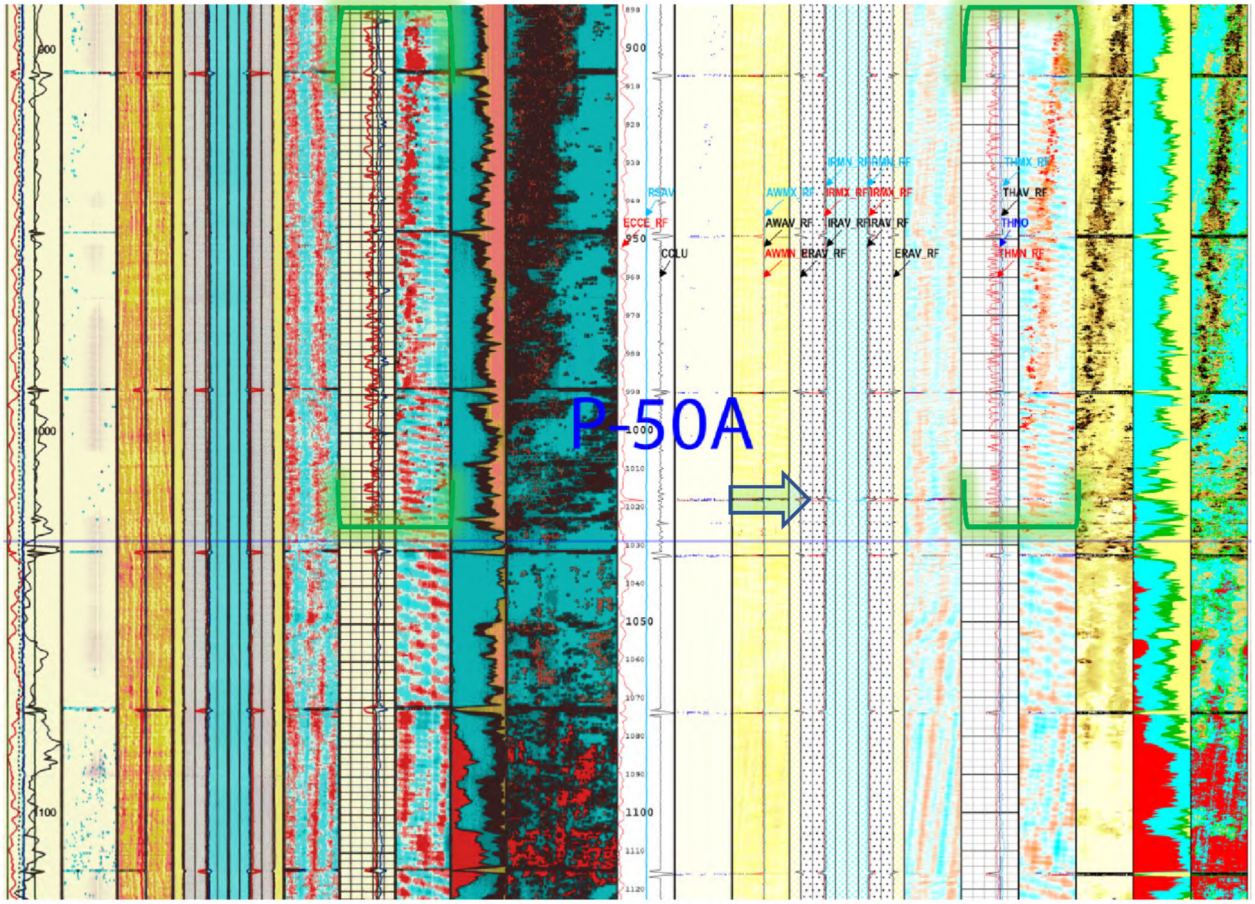


Figure 17: Screenshot of Composite Log P-50A USIT Logs, 2011 (Left), 2015 (Right), Surface Casing Shoe (Blue Line), Cut Attempt (Arrow), External Corrosion (Green Brackets)

P-50A was reported by SoCalGas to have a casing leak at 1,020 ft on July 16, 2010 [2]. This was not the first time SoCalGas reported leaks for this well, but rather part of a complicated history of multiple possible leaks determined by noise anomalies, radioactive tracer survey, shallow gas flow in the surface casing, helium analyses, and anomalous surface casing pressures. These reports stretched back to its completion date in 1983. SoCalGas indicated corrosion was the cause for the casing leak, based on casing inspection logs [2], but no record was found regarding the reason for the corrosion. The gas flowing into the surface casing was analyzed, in various years, in terms of flow rate and composition. SoCalGas determined the gas was not storage gas but instead was from a shallow gas zone; this was determined by low levels of helium [16]. Gas analysis also showed slightly elevated carbon dioxide around 2 mol. % as compared to the storage gas. Blade interprets the presence of flowing gas with elevated carbon dioxide in a wet environment as the reason for the corrosion in P-50A.

The well records [18] showed a hole in the production casing; this was confirmed by packer testing at a depth between 997 ft and 1,018 ft. An attempt was made to cut and pull the 9 5/8 in. casing on June 9, 2015, which is denoted by the green arrow in Figure 17. The casing did not pull free. Blade's interpretation was that this was most likely related to previous cementing operations on January 6, 2011.

4.3 Porter 32

A 5 1/2 in. inner string was originally run on October 20, 1979, to isolate 7 in. casing leaks at 4,510–4,590 ft. It was removed from P-32 on October 10, 2016, as part of the Comprehensive Safety Review. A USIT log was run in the 7 in. production casing on October 18, 2016. Figure 18 shows this USIT log for the interval of 490–720 ft. The external corrosion is denoted by green brackets in the figure but extends much further than what is shown–beyond 4,000 ft. A deep isolated internal defect is present at 670 ft and is marked by the arrow. Figure 19 shows the USIT summary spreadsheet [19] for the top 25 joints, which are at approximately 1,000 ft. The largest internal penetration is 70%, at 670 ft (and is the same defect shown by the arrow in Figure 18). The row is denoted by red text. The penetration of external corrosion is represented by green brackets and ranges from 7–48%. This well was pressure tested October 27–28, 2016, and an interval of 654–845 ft was unable to hold pressure; this interval was subsequently cement squeezed and pressure tested. Blade speculated that the reason this 654–845 ft interval could not hold pressure was because of the extensive deep external corrosion. Confirmation is not possible because this interval was cemented and the casing was not recovered.

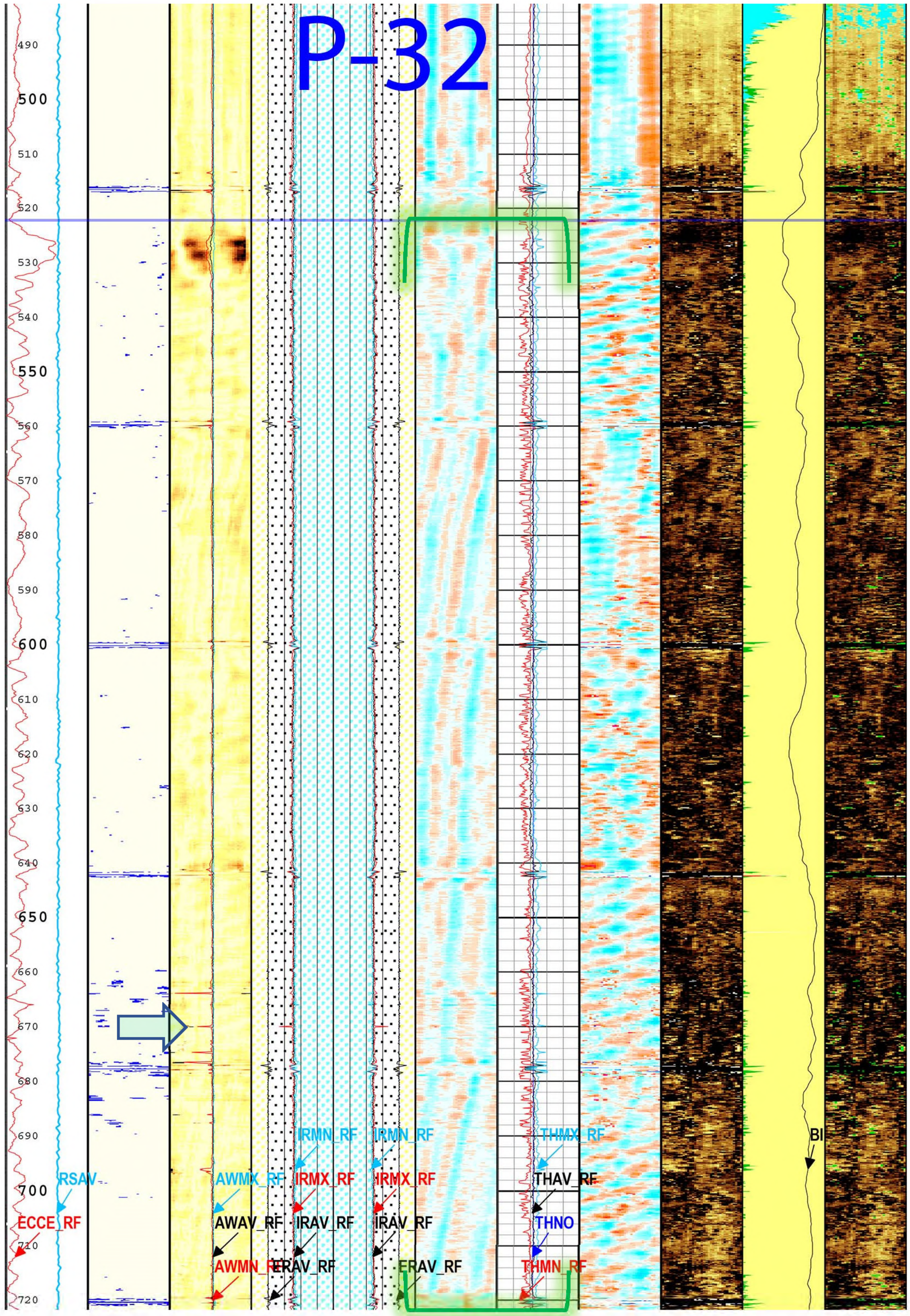


Figure 18: Screenshot of Composite Log P-32, USIT Log, 2016, Surface Casing Shoe (Blue Line), Near Through Wall Defect (Arrow), External Corrosion (Green Brackets)

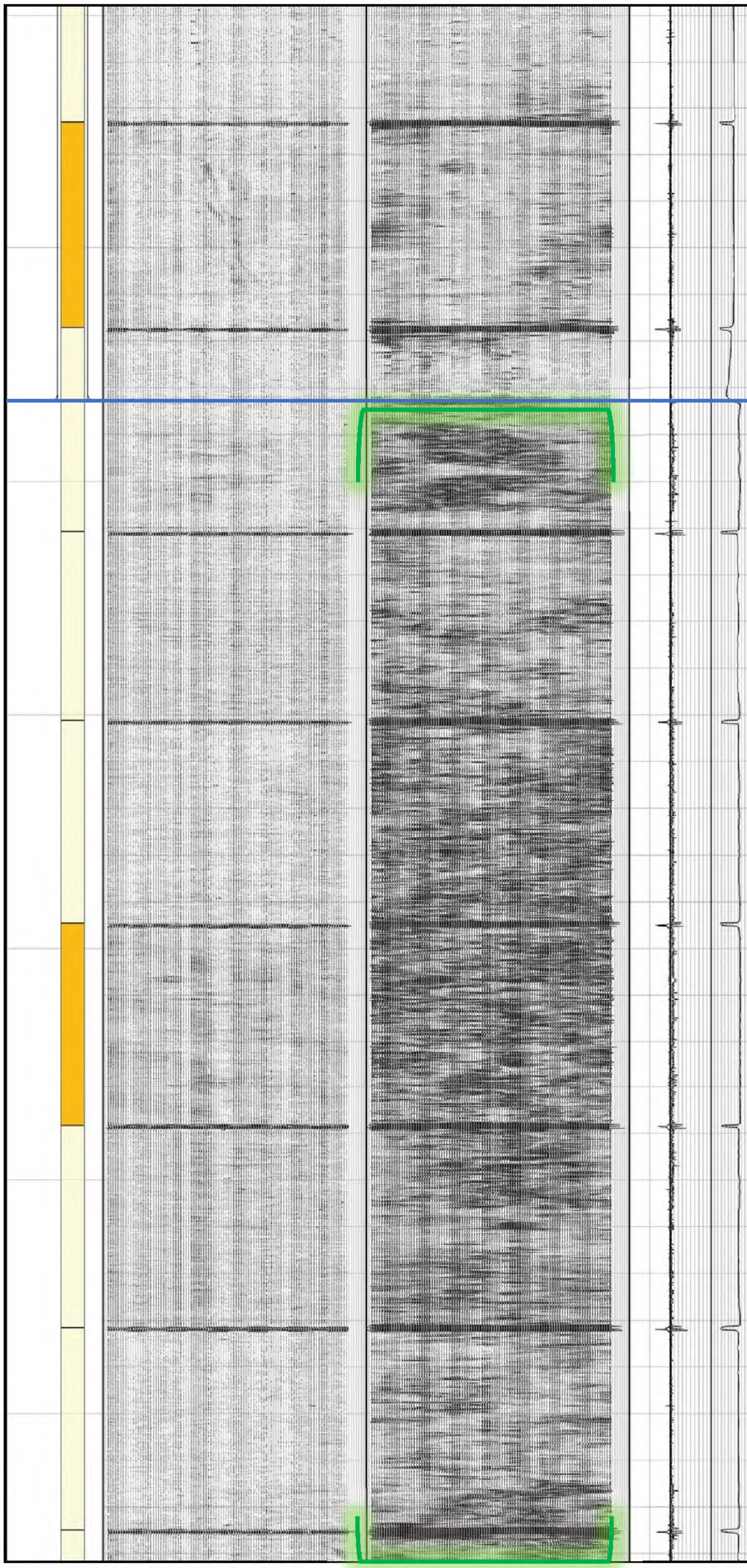
Company SocalGas
Well Nam Porter 32
Log Date 18-Oct-2016

Joint No	Joint_Top	Joint_Length	CWEI_Joint	YIELD_Joint	IRAV_Joint	IRMN_Joint	IRMN_Joint_Depth	IRMX_Joint	IRMX_Joint_Depth	THAV_Joint	THMN_Joint	THMN_Joint_Depth	IDMN_Joint	IDMN_Joint_Depth	PENMX_Radius_Joint	PENMX_Joint
	ft	ft	lbf/ft	psi	in	in	ft	in	ft	in	in	ft	in	ft	%	%
1	8.730	25.402	23.000	80000.000	3.194	3.154	32.605	3.254	10.230	0.305	0.269	14.105	6.312	32.605	22.504	15.136
2	34.132	36.368	23.000	80000.000	3.185	3.150	35.632	3.207	54.882	0.317	0.277	45.007	6.303	35.632	7.512	12.702
3	70.500	41.375	23.000	80000.000	3.182	3.129	110.250	3.207	104.875	0.318	0.276	107.625	6.262	110.250	7.427	12.965
4	111.875	35.875	23.000	80000.000	3.184	3.131	146.125	3.220	121.250	0.317	0.276	141.625	6.270	146.125	11.603	12.867
5	147.750	34.750	23.000	80000.000	3.191	3.132	178.375	3.228	175.375	0.308	0.271	179.000	6.272	180.625	14.137	14.377
6	182.500	37.750	23.000	80000.000	3.185	3.136	218.500	3.208	191.000	0.316	0.278	211.375	6.279	218.250	7.863	12.318
7	220.250	43.500	23.000	80000.000	3.184	3.139	262.000	3.207	252.250	0.315	0.289	260.750	6.282	262.000	7.639	8.831
8	263.750	41.375	23.000	80000.000	3.179	3.134	303.125	3.203	272.875	0.321	0.299	303.000	6.277	303.375	6.212	5.536
9	305.125	42.000	23.000	80000.000	3.183	3.149	314.625	3.210	338.125	0.318	0.265	344.750	6.309	307.625	8.563	10.324
10	347.125	41.375	23.000	80000.000	3.182	3.123	386.625	3.214	363.250	0.318	0.284	367.250	6.260	386.625	9.888	10.336
11	388.500	43.000	23.000	80000.000	3.183	3.136	429.875	3.209	401.125	0.317	0.278	406.250	6.292	429.750	8.254	12.376
12	431.500	42.625	23.000	80000.000	3.181	3.137	472.500	3.204	467.875	0.319	0.293	465.375	6.293	472.500	6.556	7.553
13	474.125	42.125	23.000	80000.000	3.182	3.134	513.625	3.216	507.250	0.316	0.232	513.875	6.296	482.375	10.356	26.675
14	516.250	43.500	23.000	80000.000	3.190	3.145	517.875	3.224	544.750	0.309	0.227	546.875	6.297	517.875	12.893	28.312
15	559.750	40.375	23.000	80000.000	3.190	3.153	598.500	3.218	562.600	0.311	0.228	591.500	6.310	598.375	11.134	27.935
16	600.125	42.125	23.000	80000.000	3.192	3.145	640.500	3.210	611.375	0.307	0.229	627.750	6.290	640.500	10.996	27.700
17	642.250	35.500	23.000	80000.000	3.183	3.110	[illegible]	[illegible]	[illegible]	0.315	0.229	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
18	677.750	42.125	23.000	80000.000	3.183	3.138	679.250	3.228	688.500	0.318	0.229	698.975	6.286	679.250	14.219	27.606
19	719.875	43.875	23.000	80000.000	3.193	3.139	721.625	3.235	724.500	0.305	0.214	756.000	6.292	721.625	16.272	32.506
20	763.750	44.250	23.000	80000.000	3.190	3.132	806.375	3.218	782.125	0.310	0.191	797.500	6.290	806.250	10.986	39.600
21	808.000	43.375	23.000	80000.000	3.192	3.130	849.750	3.229	840.750	0.308	0.221	827.125	6.284	849.750	14.429	30.378
22	851.375	42.500	23.000	80000.000	3.191	3.106	892.250	3.221	863.750	0.309	0.164	859.375	6.247	892.250	12.025	48.213
23	893.875	42.000	23.000	80000.000	3.191	3.114	934.125	3.234	909.875	0.308	0.228	908.375	6.251	934.125	16.217	28.062
24	935.875	40.250	23.000	80000.000	3.185	3.130	939.500	3.210	939.375	0.316	0.236	946.125	6.285	974.375	8.408	25.594
25	976.125	42.500	23.000	80000.000	3.187	3.133	1017.000	3.212	981.000	0.312	0.178	1016.250	6.277	1017.000	9.027	43.797

Figure 19: P-32 USIT Log Data [19], External Corrosion (Green Brackets), Interval 654–845ft: Could Not Hold Pressure

4.4 Sesnon Wells: SS-8, SS-9, and SS-24

The Sesnon wells were investigated further due to their proximity to SS-25. Appendix E shows the location of these wells. The SS-24 shallow external corrosion was much more prevalent compared to SS-8 and SS-9. Figure 20 shows the HRVRT [20] log from SS-24. The depth of the collars and features are on the right side. External corrosion was observed at the depth of the surface casing shoe, which was 1,113.33 ft. There appeared to be external corrosion above the surface casing shoe, but Baker Hughes GE interpreted that to be related to internal corrosion.



Log Depth	Dist UHC	Joint Length	Identifier	Class	Description	Surface Indication	Length	Width	Depth
ft	ft	ft					in	in	%
1073.11	44.17	44.17	C-26	Collar	Anomalous				
1096.96	23.85	44.09	MLCB-26-1	Metal Loss Call Box		Internal	0.8	0.8	21
1117.21	44.09	44.09	C-27	Collar					
1133.13	15.93	43.59	H-27-1	Hardware	Bottom Of External Casing				
1133.17	15.96	43.59		End External Casing					
1142.31	25.10	43.59	MLCB-27-1	Metal Loss Call Box		External	0.8	0.8	16
1149.37	32.16	43.59	MLCB-27-2	Metal Loss Call Box		External	0.7	1.0	16
1150.57	33.36	43.59	MLCB-27-3	Metal Loss Call Box		External	0.6	0.7	18
1153.26	36.05	43.59	MLCB-27-4	Metal Loss Call Box		External	1.1	1.2	16
1160.79	43.59	43.59	C-28	Collar					
1201.34	40.54	40.54	C-29	Collar					
1231.38	30.04	43.33	MLCB-29-1	Metal Loss Call Box		External	0.5	0.9	16
1243.34	42.00	43.33	MLCB-29-2	Metal Loss Call Box		External	0.6	0.4	15
1244.67	43.33	43.33	C-30	Collar					
1260.71	16.04	43.79	MLCB-30-1	Metal Loss Call Box		External	1.5	2.3	20
1264.71	20.04	43.79	MLCB-30-2	Metal Loss Call Box		External	1.3	3.7	15
1265.11	20.44	43.79	MLCB-30-3	Metal Loss Call Box		External	0.7	1.1	18
1270.99	26.32	43.79	MLCB-30-4	Metal Loss Call Box		External	1.0	1.2	16
1276.96	32.30	43.79	MLCB-30-5	Metal Loss Call Box		External	0.8	1.2	17
1277.32	32.65	43.79	MLCB-30-6	Metal Loss Call Box		External	0.7	1.0	17
1278.53	33.86	43.79	MLCB-30-7	Metal Loss Call Box		External	2.1	1.9	20
1288.46	43.79	43.79	C-31	Collar					
1296.85	8.39	43.25	MLCB-31-1	Metal Loss Call Box		External	1.4	1.8	19
1331.71	43.25	43.25	C-32	Collar					
1375.09	43.37	43.37	C-33	Collar					

Figure 20: SS-24 HRVRT Log [20], External Corrosion (Green Brackets), Surface Casing Shoe (Blue Line)

In SS-8, the Vertilog casing inspection log was run on January 17, 1989; subsequently, the USIT was run on April 24, 2013 (Figure 21). The Vertilog shows Class 2 and Class 3 defects corresponding to external defects ranging from 20–40% and 40–60%, respectively; this is denoted by the green brackets. The USIT does not show these defects. Blade concluded that these external defects may be present, but the depth of penetration is likely overstated in the Vertilog. Blade included SS-8 as a well with shallow external corrosion because the location and pattern of this corrosion on the Vertilog seemed akin to that of the other wells with shallow corrosion. Confirmation of these defects would be best made with the HRVRT, which is a modern version of the Vertilog.

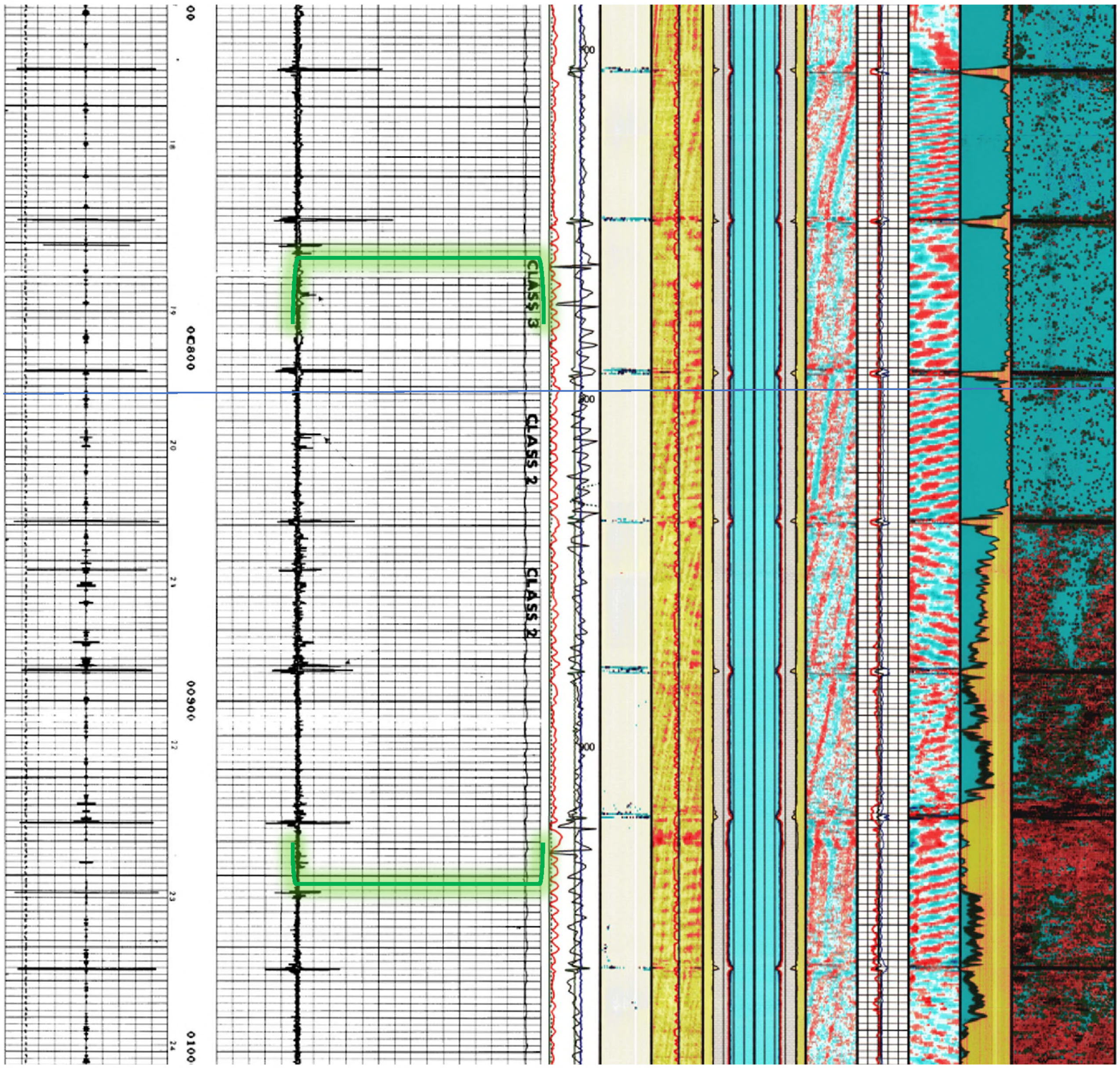


Figure 21: SS-8 Vertilog (Left) and USIT (Right), External Corrosion (Green Brackets), Surface Casing Shoe (Blue Line)

The Vertilog was run in SS-9 on December 16, 1988. Subsequently it was logged with the HRVRT and USIT on September 6, 2018, and September 7, 2018. Only the HRVRT showed shallow external corrosion, just below the depth of the surface casing shoe. Figure 22 shows the SS-9 HRVRT in the region at and below the surface casing shoe. The corrosion pattern is not as pronounced as in SS-24.

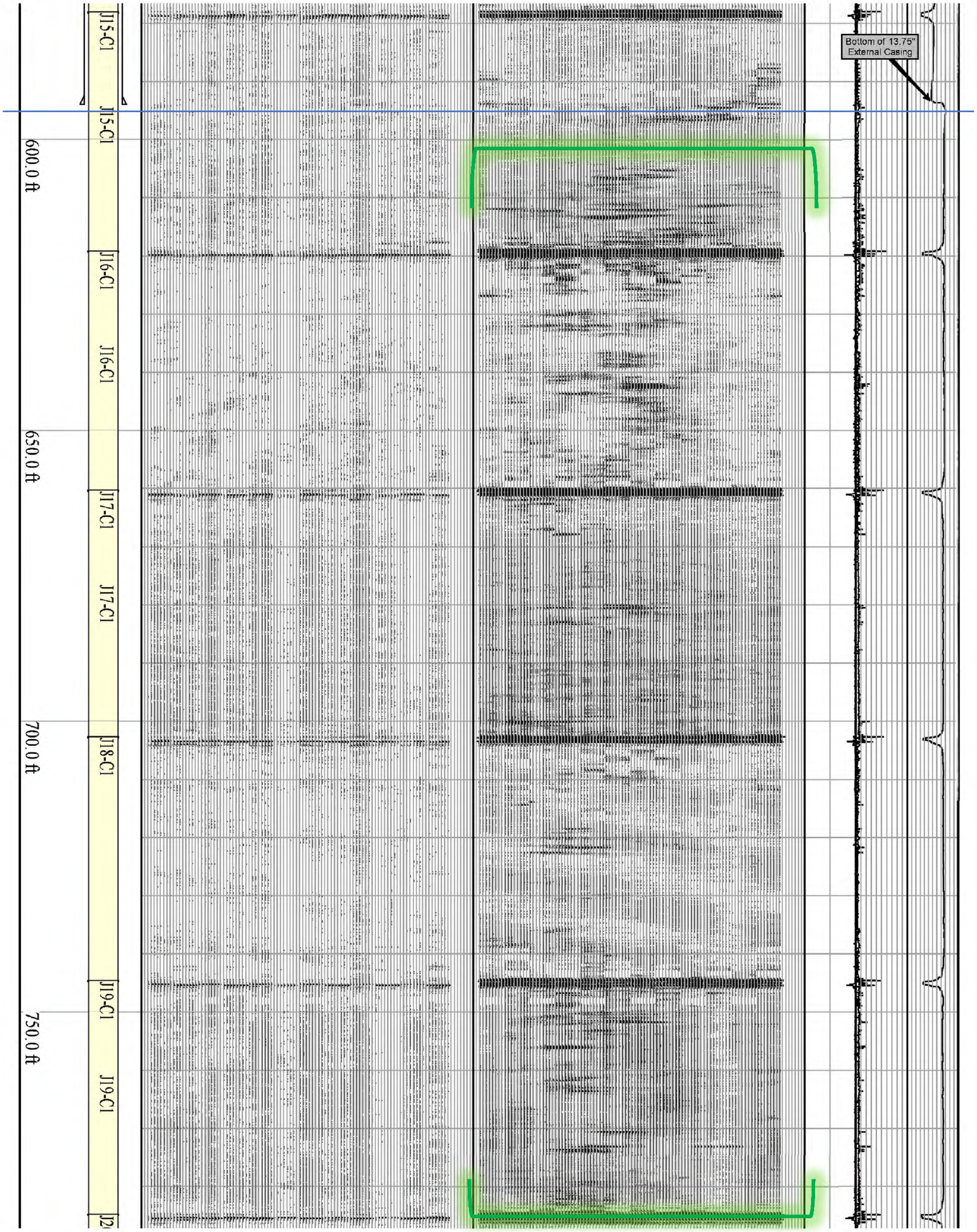


Figure 22: SS-9 HRVRT, External Corrosion (Green Brackets), Surface Casing Shoe (Blue Line)

4.5 Location and Other Trends

Figure 23 shows the locations of the 114 comprehensive safety review wells, also known as the SIMP wells, (upper graphic), and the 27 wells with shallow external corrosion on the production casing (lower graphic). The wells are spread out throughout Aliso Canyon showing the wide variability in well elevations; with no apparent trends. Additional maps are found in Appendix E.

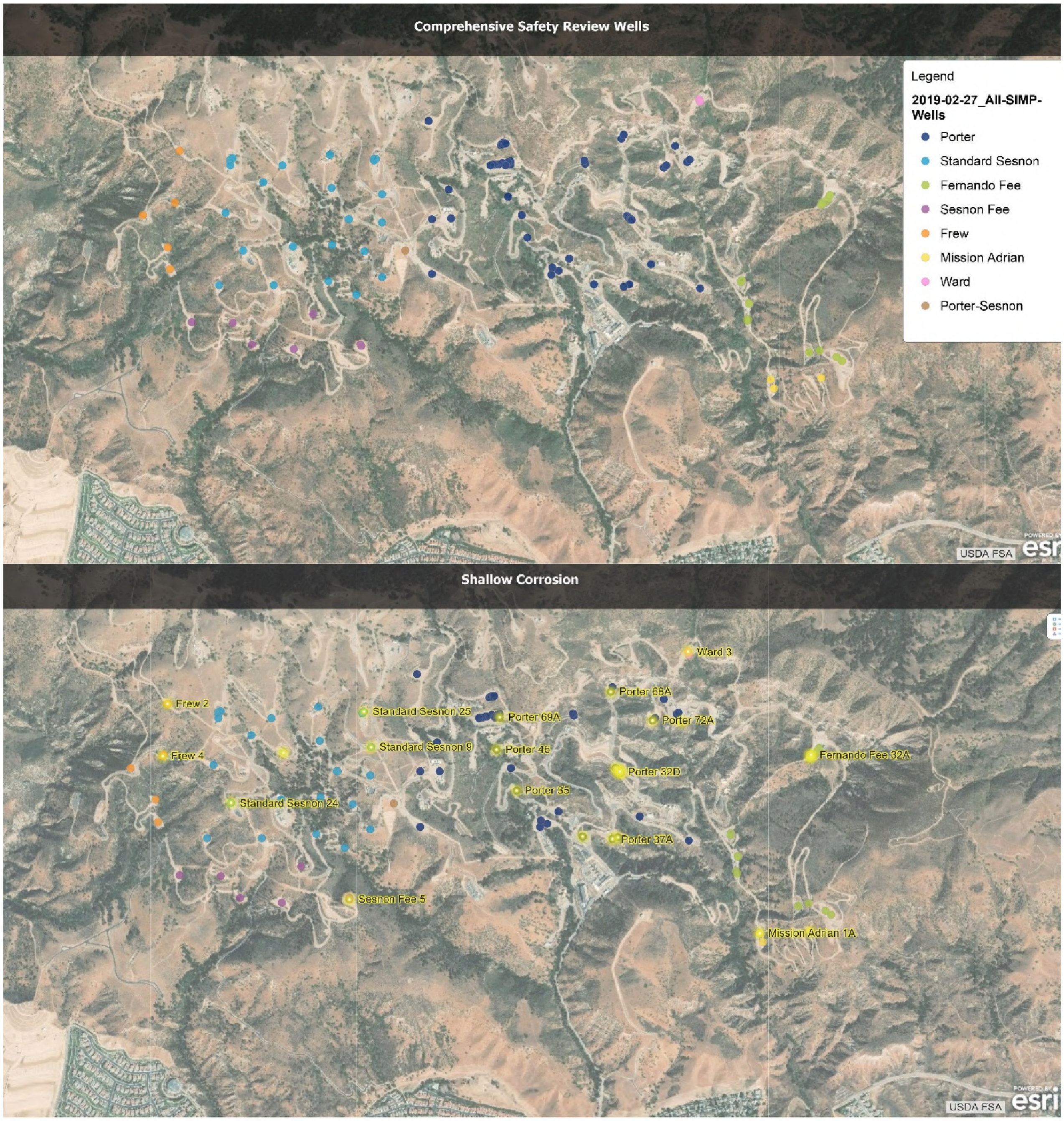


Figure 23: Well Locations with Shallow External Corrosion on Production Casing

Figure 24 shows the location of the shallow external corrosion on the production casing for 26 wells. Almost all of the wells had production casing external corrosion present just below the depth of the surface casing shoe. One well, P-50A, had external corrosion above the depth of the surface casing shoe. SS-25 was not included, but it was the only well that showed shallow corrosion above *and* below the surface casing shoe.

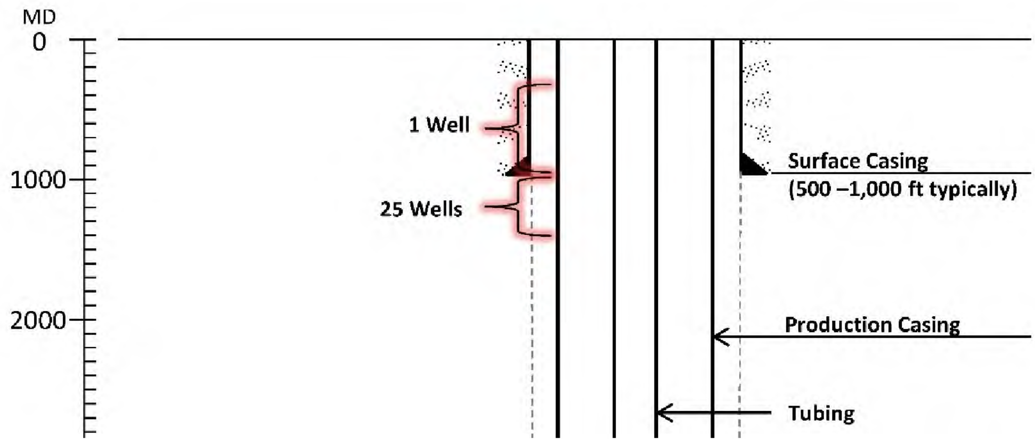


Figure 24: Location of Shallow External Corrosion on Production Casing Not Including SS-25

Figure 25 shows a production casing USIT log from SF-5 which is a well in the West section of Aliso Canyon. The production casing is 7 in. 23 ppf (0.317 in. wall thickness) N80 LTC. The track titled Minimum of Unflagged Thickness (THMN_RF) is the minimum wall thickness of the production casing measured by the USIT. THMN_RF is denoted by a red line and labeled in red. Above the depth of the surface casing shoe, THMN_RF shows no variability; the production casing has no issues here. Below the depth of the surface casing shoe, THMN_RF drops erratically down as low as ~0.23 in. wall thickness or 27% penetration. Note each division on the THM_RF track is 0.1 in. Blade interprets this production casing metal loss as external corrosion. Some additional observations were evident. The 13 3/8 in. x 7 in. casing annulus is liquid filled to a depth of ~400 ft and is labeled "Top of Liquid Column"; this observation of a deep annulus liquid level with gas on top is common to most of the wells reviewed. At the depth of the shoe, the percentage of solids increases; this is also common to most of the wells reviewed. This is denoted by a yellow shading in the second from the right track. In some of the wells reviewed, behind the 7 in. casing, there is gas present adjacent to the casing OD. This is denoted by red shading in the second from the right track.

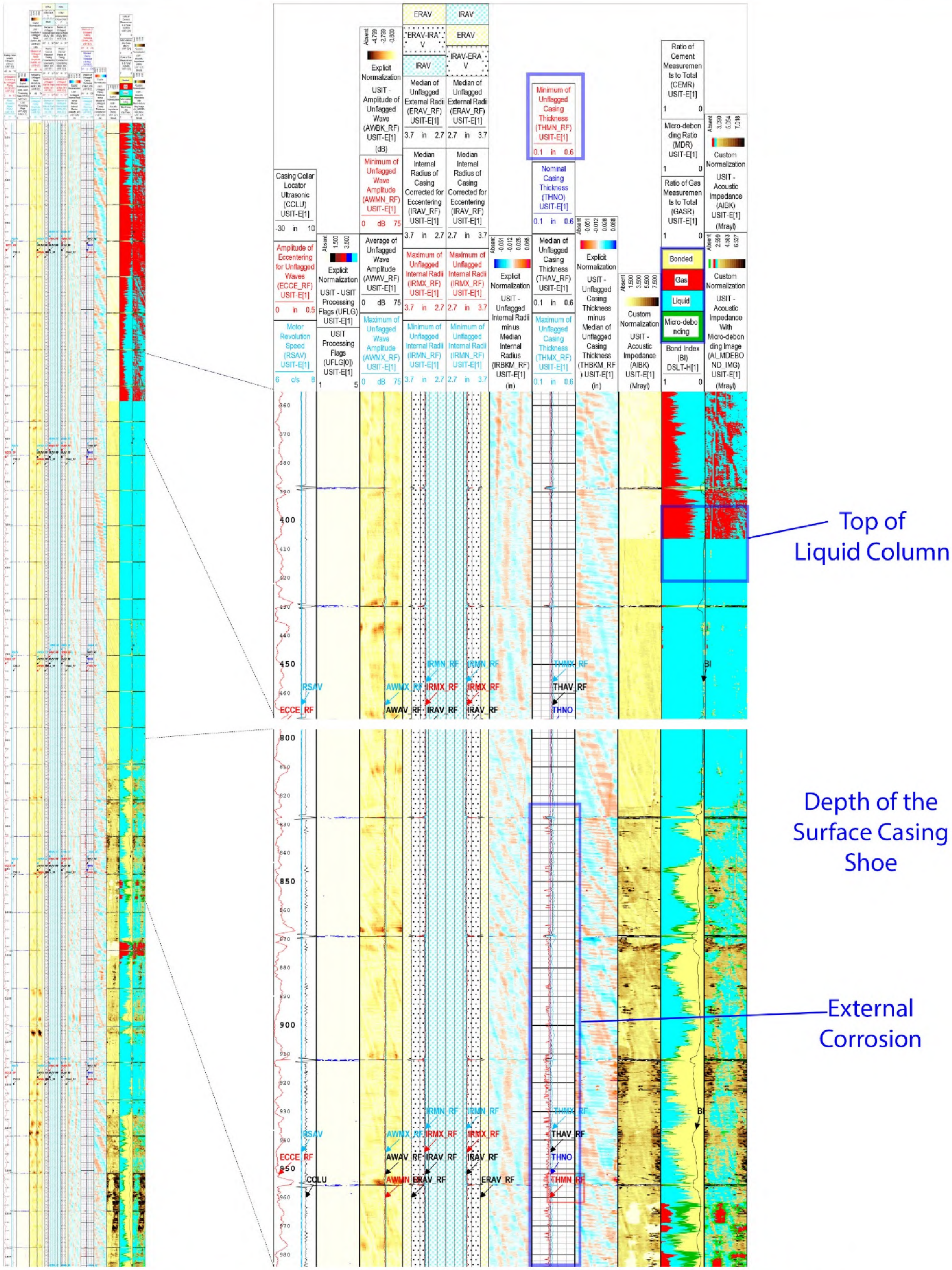


Figure 25: SF-5 Production Casing USIT Log Example of External Corrosion

4.6 Possible Corrosion Mechanism

The location and nature of the corrosion in SS-25 including what components lead to the corrosive environment have been detailed in this report. But it is not clear how similar the corrosion mechanisms of SS-25's surface and production casing are to the rest of the Aliso Canyon field. What is clear is that a corrosive environment is present in a number of wells that has affected the production casing at similar depths. Complex systems have interacted to create this environment. The casing inspection logs only provide a snapshot of the deterioration of the casings but does little to quantify the corrodents (i.e., logs do not identify the corrosion mechanism). Of 76 casing inspection logs reviewed, 27 showed shallow external corrosion but 49 did not. Furthermore, in many cases, wells directly next to each other on the same site showed entirely different corrosion patterns. Although important trends have been identified in this section, additional work, beyond the scope of the RCA, is recommended to investigate if the corrosion mechanisms of SS-25 are present elsewhere in the field.

One area of investigation focuses on the location of corrosion near the surface casing shoe. This is common in a number of wells; this suggests a common corrosion mechanism. Figure 26 shows a possible corrosion mechanism supported by some of the observations discussed previously. Using the numbered inset images, the hypothesis is as follows:

1. During the initial cementing operations of the production casing, drilling mud was circulated and left in the production casing annulus above the cement. Drilling mud typically has a high pH and is not likely to cause corrosion.
2. Over time, the drilling mud in the production casing by surface casing annulus leaked off into the formations below the surface casing shoe. Solids within the mud settled out, and bridges formed between the production casing OD and the surface casing ID, trapping the drilling mud. Additionally, the formations below the surface casing shoe may have collapsed and formed a barrier.
3. Over time, ground water channels through poor cement behind the surface casing. Ground water mixed with and displaced the remaining drilling mud behind the production casing.
4. Over time, gas from weeping production casing connections or gas from a shallow gas formation (e.g., Pliocene Gas Sand) percolated upwards. This gas contained carbon dioxide.
5. Corrosion initiated and grew in the aqueous carbon dioxide environment. This process may have been assisted by microbes residing in the ground water.

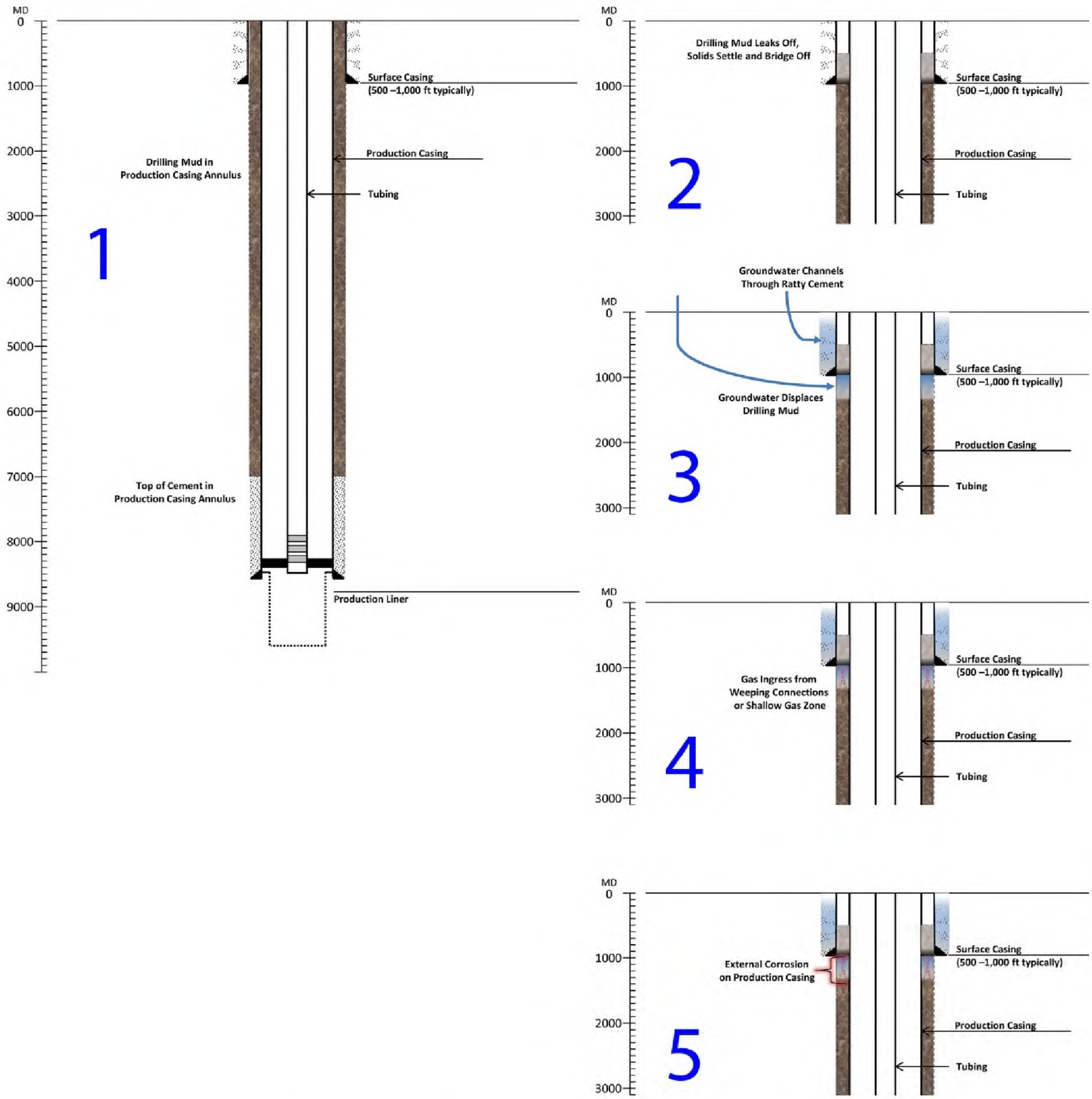


Figure 26: Hypothesis for the Shallow External Corrosion Mechanism

5 Conclusions

Blade reviewed 116 wells as part of this work; 76 wells had casing inspection logs available, of which, 27 wells showed indications of shallow external corrosion on the production casing. In almost all of these 27 wells, the external corrosion was below the depth of the surface casing shoe. There were two exceptions, F-4 and P-50A. The corrosion above the shoe in F-4 was not found in a subsequent log. The shallow corrosion in P-50A was found above the shoe and abruptly stops at the depth of the casing shoe.

Although not one well was found with the exact placement and pattern of corrosion as that of SS-25, Blade concluded that shallow corrosion was not an isolated event; it was common, found field wide, and close to the surface casing shoe. Shallow casing leaks occurred. We found 10 shallow casing leaks in a review of 116 wells. Blade interpreted that three of these shallow casing leaks could be attributed to shallow corrosion; three were not. There was not enough information to determine if the remaining shallow casing leaks were corrosion related. The key finding is that both the occurrence of shallow corrosion and shallow casing leaks related to corrosion were not unique to SS-25.

6 References

[1] Blade Energy Partners, "Phase 3 Summary," Houston, 2019.

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[3] Blade Energy Partners, "Analysis of Aliso Canyon Gas Storage Wells with Casing Failures," Houston, 2019.

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[7] Blade Energy Partners, "SS-25 Casing Failure Analysis," 2019.

[8] Blade Energy Partners, "SS-25 Inspection Logs Analysis," Houston, 2019.

[9] Baker Hughes GE, "7_Baker_Hughes_GE_Logs.pdf," Houston, 2019.

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[11] Southern California Gas Company, "AC_BLD_0075728.pdf," Chatsworth, 2018.

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[14] Southern California Gas Company, "Southern CA Gas Report 02.15.19.pdf," Chatsworth, 2019.

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[17] Southern California Gas Company, "SoCalGas Response Dated April 19, 2019 (Blade-37.pdf)".

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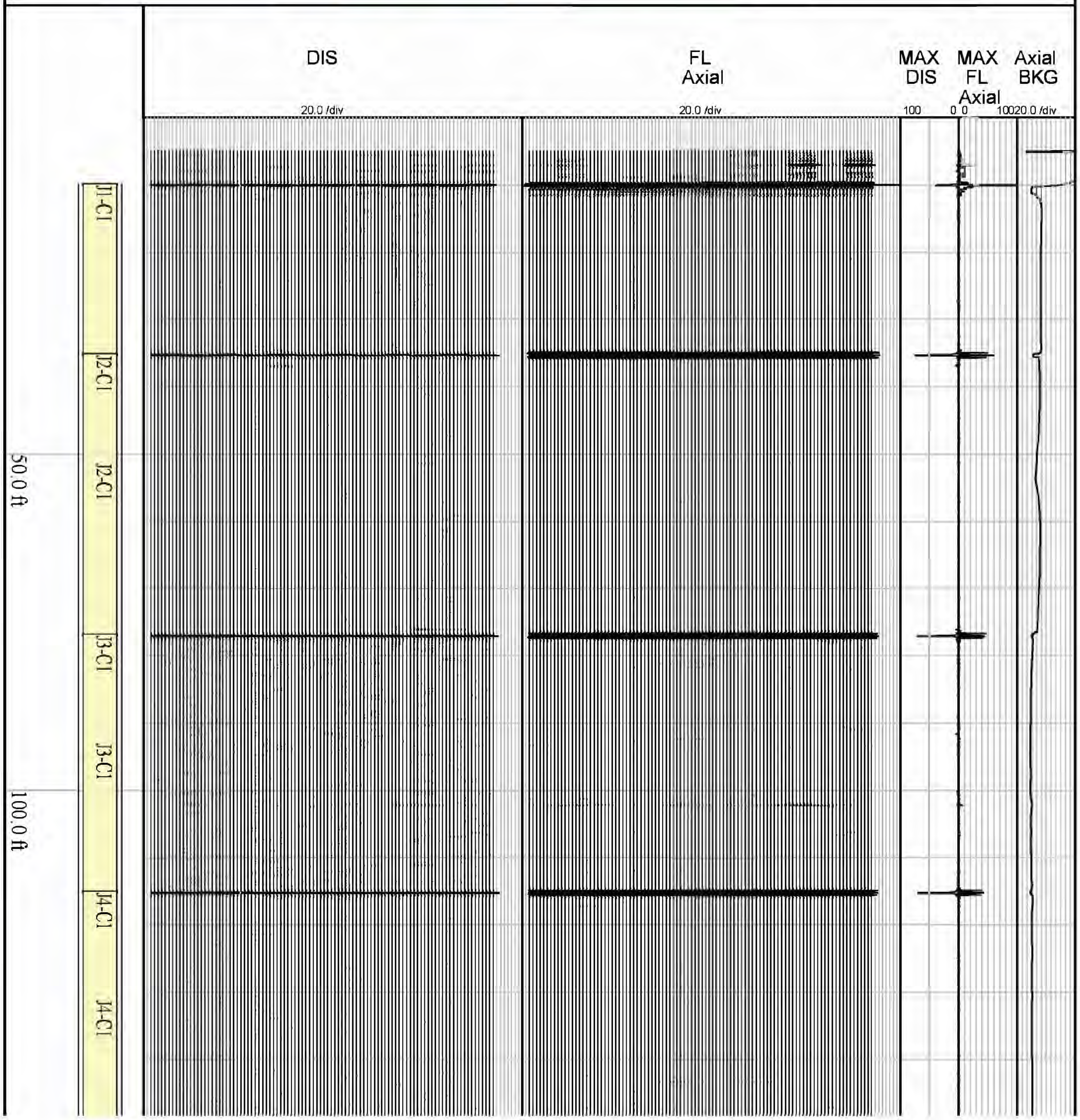
[19] Southern California Gas Company, "AC_BLD_0067627.xls, Porter 32_Failure Reports_Blade-29.pdf," Chatsworth, 2018.

[20] Southern California Gas Company, ""AC_BLD_0063691.meta", "AC_BLD_0063814.xlsx," Chatsworth, 2017.

Appendix A Log Headers

Main Log
5"/100'

Class 1	Class 2	Class 3	Class 4
0 - 20%	20 - 40%	40 - 60%	60 - 100%



SS-IBC

Main Pass

Software Version

Acquisition System	Version
Maxwell 2017 SP3	7.3.92069.3100

Pass Summary

Run Name	Pass Objective	Direction	Top	Bottom	Start	Stop	DSC Mode	Depth Shift	Include Parallel Data
SS-IBC	Log[6]:Up	Up	26.73 ft	7551.80 ft	04-Dec-2017 6:13:20 PM	05-Dec-2017 10:19:25 AM	ON	3.31 ft	No

All depths are referenced to toolstring zero

Log

Company:Southern California Gas Company Well:Standard Sesnon 25

SS-IBC: Log[6]:Up:S004

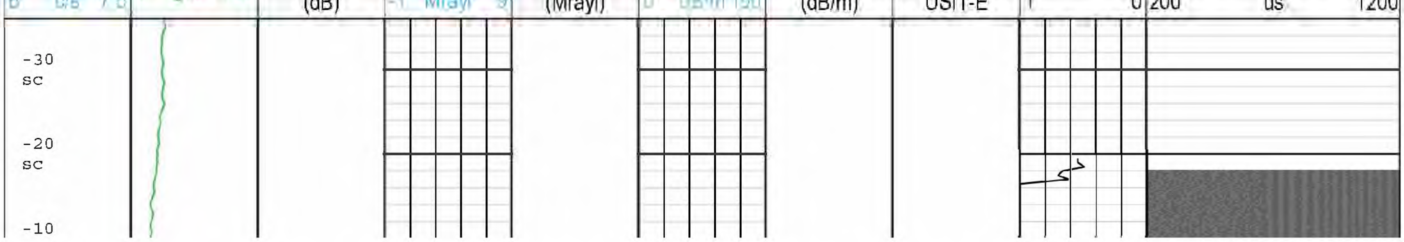
Description: USI IBC SLG Format: Log (IBC SLG VDLCBL) Index Scale: 5 in per 100 ft Index Unit: ft Index Type: Measured Depth Creation Date: 06-Dec-2017 18:09:22

TIME_1900 - Time Marked every 60.00 (s)

USIT Processing Flags (UFLG[0]) USIT-E

1 - UFLG 1 Value within [0.0 - 1.5] - : UTIM Error
2 - UFLG 2 Value within [1.5 - 2.5] - : Pulse Origin Not Detected
3 - UFLG 3 Value within [2.5 - 3.5] - : WINLEN Error
4 - UFLG 4 UFLG 5 UFLG 6 Value within [3.5 - 6.5] - : Casing Thickness Error
5 - UFLG 7 UFLG 8 UFLG 9 Value within [6.5 - 10] - : Loop Processing Error

Track 1	Track 2	Track 3	Track 4	Track 5	Track 6	Track 7	Track 8	Track 9	Track 10	Track 11
	Absent 1.500 3.500 Explicit Normalization USIT - USIT Processing Flags (UFLG) USIT-E		Acoustic Impedance Minimum (AIMN) USIT-E -1 Mrayl 9		Average Flexural Attenuation (U-USIT_UFAV) USIT-E 0 dB/m 150				SLG Solid Index; SLG Liquid Index; SLG Gas Index; SLG White Point Index	
Casing Collar Locator Ultrasonic (CCLU) USIT-E -20 in 20	USIT Processing Flags (UFLG[0]) USIT-E 1 5	Absent -5.200 -3.600 -2.000 -0.400 Explicit Normalization USIT - Amplitude of Wave (AWBK) USIT-E (dB)	Acoustic Impedance Average (AIAV) USIT-E -1 Mrayl 9	Absent 1.500 3.500 5.500 7.500 Custom Normalization USIT - Acoustic Impedance (AIBK) USIT-E (Mrayl)	Minimum Flexural Attenuation (U-USIT_UFAN) USIT-E 0 dB/m 150	Absent 42.000 66.000 90.000 114.000 Custom Normalization USIT - Flexural Attenuation (UFAK) USIT-E (dB/m)	Absent 1.500 3.500 Explicit Normalization USIT - Solid Liquid Gas Sorted Color Map (USLP) USIT-E	Synthetic CBL from Discriminated Attenuation (DCBL) MAST-B 0 mV 100		
Amplitude of Eccentering (ECCE) USIT-E 0 in 0.5	Gamma Ray (ECGR_EDTC) EDTC-B 0 gAPI 150		Acoustic Impedance Maximum (AIMX) USIT-E -1 Mrayl 9		Maximum Flexural Attenuation (U-USIT_UFAX) USIT-E 0 dB/m 150			Bond Index From Near Attenuation (NBI) MAST-B 1 0	Min Amplitude Max VDL VariableDensity - Color (VDL) MAST-B 200 us 1200	
Motor Revolution Speed (RSAV) USIT-E 6 c/s 7.5										



SS-IBC

CORROSION Main Pass

Software Version

Acquisition System	Version
Maxwell 2017 SP3	7.3.92069.3100

Pass Summary

Run Name	Pass Objective	Direction	Top	Bottom	Start	Stop	DSC Mode	Depth Shift	Include Parallel Data
SS-IBC	Log[6]:Up	Up	26.73 ft	7551.80 ft	04-Dec-2017 6:13:20 PM	05-Dec-2017 10:19:25 AM	ON	3.31 ft	No

All depths are referenced to toolstring zero

Log

Company:Southern California Gas Company Well:Standard Sesnon 25

SS-IBC: Log[6]:Up:S004

Description: USI Corrosion Format: Log (USI Corrosion 7inch) Index Scale: 5 in per 100 ft Index Unit: ft Index Type: Measured Depth Creation Date: 06-Dec-2017 18:09:07

TIME_1900 - Time Marked every 60.00 (s)

USIT Processing Flags (UFLG[0]) USIT-E

1 - UFLG 1 Value within [0.0 - 1.5] - :	UTIM Error
2 - UFLG 2 Value within [1.5 - 2.44] - :	Pulse Origin Not Detected
3 - UFLG 2 Value within [2.44 - 2.5] - :	Spiky Waveform
4 - UFLG 3 Value within [2.5 - 3.5] - :	WINLEN Error
5 - UFLG 4 UFLG 5 UFLG 6 Value within [3.5 - 6.5] - :	Casing Thickness Error
6 - UFLG 7 UFLG 8 UFLG 9 Value within [6.5 - 10] - :	Loop Processing Error

Amplitude of Eccentering (ECCE) USIT-E
0 in 0.5

Cable Speed (CS)
0 ft/h 50000

Absent 1.500 2.500 6.500
Explicit Normalization
USIT - USIT Processing Flags (UFLG) USIT-E

USIT Processing Flags (UFLG[0]) USIT-E
1 6

Absent -5.200 -3.600 -2.000 -0.400
Explicit Normalization
USIT - Amplitude of Wave (AWBK) USIT-E (dB)

Amplitude of Wave Minimum (AWMN) USIT-E
0 dB 75

Amplitude of Wave Average (AWAV) USIT-E
0 dB 75

Amplitude of Wave Maximum (AWMX) USIT-E
0 dB 75

Absent -0.059 -0.028 0.004 0.035 0.068
Explicit Normalization
USIT - Internal Radii Normalized (IRBK) USIT-E (in)

Internal Radius Minimum Value (IRMN) USIT-E
2.7 in 3.7

Internal Radius Averaged Value (IRAV) USIT-E
2.7 in 3.7

Internal Radius Maximum Value (IRMX) USIT-E
2.7 in 3.7

ERAV-IRAV
ERAV
IRAV

External Radii Average (ERAV) USIT-E
3.7 in 2.7

Internal Radius Averaged Value (IRAV) USIT-E
3.7 in 2.7

Internal Radius Maximum Value (IRMX) USIT-E
3.7 in 2.7

Internal Radius Minimum Value (IRMN) USIT-E
3.7 in 2.7

ERAV
IRAV
IRAV-ERAV

External Radii Average (ERAV) USIT-E
2.7 in 3.7

Internal Radius Averaged Value (IRAV) USIT-E
2.7 in 3.7

Internal Radius Maximum Value (IRMX) USIT-E
2.7 in 3.7

Internal Radius Minimum Value (IRMN) USIT-E
2.7 in 3.7

Absent -0.059 -0.028 0.004 0.035 0.068
Explicit Normalization
USIT - Casing Thickness Normalized (THBK) USIT-E (in)

Thickness Minimum Value (THMN) USIT-E
0.1 in 0.6

Nominal Casing Thickness (THNO) USIT-E
0.1 in 0.6

Thickness Average Value (THAV) USIT-E
0.1 in 0.6

Thickness Maximum Value (THMX) USIT-E
0.1 in 0.6

SC

10
SC

20
SC

NEXT-HNGS-UCI

Main Pass 12 in = 100 ft

Log

Company:Southern California Gas Company   Well:Standard Sesnon 25

NEXT-HNGS-UCI: Log[5]:Up:S006

Description: UCI MAIN Format: UCI MAIN Index Scale: 10 in per 100 ft Index Unit: ft Index Type: Measured Depth Creation Date: 07-Dec-2017 12:27:53

TIME_1900 - Time Marked every 60.00 (s)

Absent -16.800 -14.400 -12.000 -9.599 -7.200 -4.799 -2.399

Explicit Normalization

USIT - Amplitude of Unflagged Wave (AWBK_RF) USIT-D (dB)

Ultrasonic Azimuth (UCAZ) USIT-D

0 deg 360

Minimum of First Echo Amplitude (A1MN) USIT-D

0 dB 50

Average of First Echo Amplitude (A1AV) USIT-D

0 dB 50

Maximum of First Echo Amplitude (A1MX) USIT-D

0 dB 50

Memorized Fluid Acoustic Slowness (CFVL) USIT-D

150 us/ft 250

Amplitude of Eccentering (ECCE) USIT-D

0 in 0.5

Gamma Ray (ECGR_EDTC) EDTC-B

0 gAPI 150

Cable Tension (TENS)

10000 lbf 0

Absent -0.190 -0.149 -0.110 -0.070 -0.029 0.010 0.050 0.089 0.130 0.170

Explicit Normalization

USIT - Unflagged Internal Radii of Casing (IRBK_RF) USIT-D (in)

Ultrasonic Azimuth (UCAZ) USIT-D

0 deg 360

Nominal Casing External Radius (ERNO) USIT-D

2.7 in 3.7

Minimum of Unflagged Internal Radii (IRMN_RF) USIT-D

2.7 in 3.7

Median Internal Radius of Casing for Unflagged Waves (IRAV) USIT-D

2.7 in 3.7

Maximum of Unflagged Internal Radii (IRMX_RF) USIT-D

2.7 in 3.7

Nominal Casing Internal Radius (IRNO) USIT-D

2.7 in 3.7

Absent -0.190 -0.149 -0.110 -0.070 -0.029 0.010 0.050 0.089 0.130 0.170

Explicit Normalization

USIT - Image of Unflagged Thickness of Casing (THBK_RF) USIT-D (in)

Ultrasonic Azimuth (UCAZ) USIT-D

0 deg 360

Minimum of Unflagged Casing Thickness (THMN_RF) USIT-D

0.1 in 0.6

Average of Unflagged Casing Thickness (THAV) USIT-D

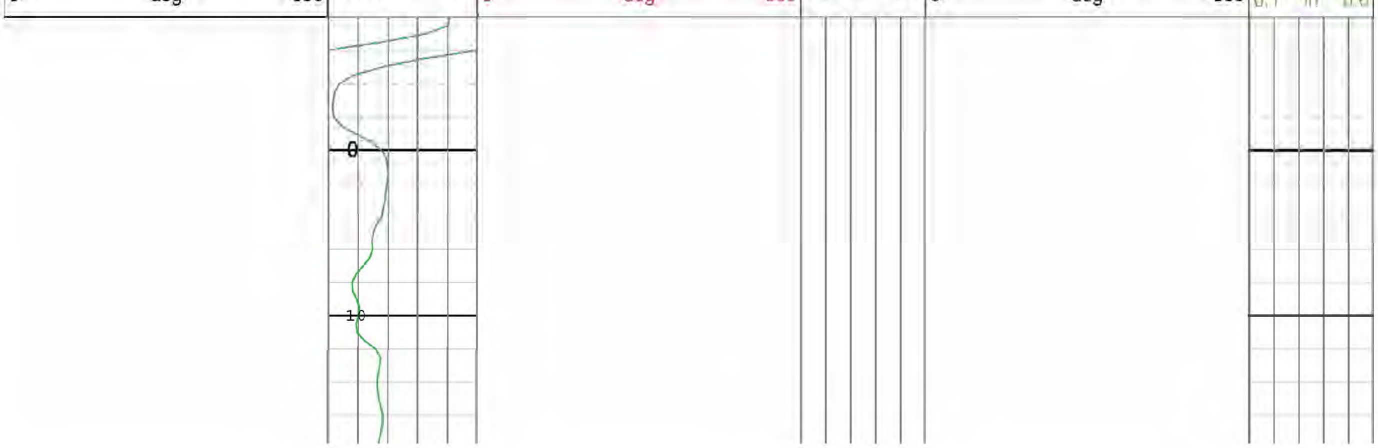
0.1 in 0.6

Maximum of Unflagged Casing Thickness (THMX_RF) USIT-D

0.1 in 0.6

Nominal Casing Thickness (THNO) USIT-D

0.1 in 0.6



Appendix B SoCalGas Casing Leak Summary [2]

Well	Discovery Date	Stop Date	Type	Depth, ft	Method of Mitigation	Method of Repair	Cause of Leak
P32	12/13/1973	8/6/1975	Casing	4510	Killed well	Innerstring installation	Unknown
FF32C	4/4/1974	6/17/1976	Stage collar	3738	Killed well	Casing patch installation	Stage collar port leaking
FF35E	12/14/1974	11/13/1976	Stage collar	2344	Killed well	Innerstring installation	Stage collar port leaking
P12	4/30/1975	12/4/1975	Casing	3634	Killed well	Cement squeeze, casing patch, and convert to tubing flow	Unknown
P45	2/26/1976	4/25/1977	Casing	500	Killed well	Innerstring installation	Unknown
FF32E	3/15/1976	11/2/1976	Casing shoe	7122	Killed well	Cement squeeze	Insufficient cement integrity
P47	8/27/1976	9/9/1976	WSO perforations	7328	Closed sliding sleeve	Cement squeeze	Insufficient cement integrity
P32C	9/21/1976	10/6/1976	Stage collar	3165	Killed well	Cement squeeze & casing patch	Stage collar port leaking
SF1	11/24/1976	12/23/1977	Casing	1378	Killed well	Innerstring installation	Unknown
SS44A	4/4/1977	6/2/1977	Stage collar	8850	Set tubing plug at 8790'	Cement squeeze & casing patch installation	Stage collar port leaking
SS5	8/30/1977	11/23/1977	Casing	1050	Killed well	Innerstring installation	Unknown
FF35B	10/14/1977	7/25/1978	Casing patch	3978	Killed well	Casing patch replacement	Casing patch seal leaking
P44	12/9/1977	1/24/1978	Casing	4000	Killed well	Cement squeeze & casing patch	Unknown
FF35	6/15/1978	6/22/1978	Casing shoe	6900	Killed well	Cement squeeze, plugged and abandoned	Insufficient cement integrity
FF35A	6/15/1978	7/25/1978	Casing shoe	6640	Killed well	Cement squeeze	Insufficient cement integrity
SS11	9/19/1978	11/8/1978	Casing shoe	8692	Killed well	Cement squeeze	Insufficient cement integrity
SS4A	10/5/1978	12/15/1978	Casing	4291	Killed well	Cement squeeze and set straddle packers	Unknown
SS10	11/8/1978	12/9/1978	Casing	4492	Killed well	Casing patch installation	Unknown
SS11	7/24/1979	3/24/1980	Casing shoe	8730	Set tubing plug at 8659'	Cement squeeze	Insufficient cement integrity
SS25B	8/3/1979	10/18/1979	Casing shoe	8434	Set tubing plug at 8395'	Cement squeeze	Insufficient cement integrity
SS44A	8/3/1979	9/5/1979	Casing patch	3977	Killed well	Casing patch replacement	Casing patch seal leaking
P26C	8/27/1979	7/16/1980	Casing	6586	Killed well	Cement squeeze and casing patch	Unknown
FF35B	2/27/1980	4/17/1980	Casing patch	3978	Killed well	Cement squeeze & casing patch replacement	Casing patch seal leaking
P26C	5/13/1980	7/16/1980	Casing shoe	7850	Killed well	Cement squeeze & casing patch	Insufficient cement integrity
FF32C	7/24/1980	7/29/1981	Casing patch	3738	Killed well	Casing patch replacement	Casing patch seal leaking
FF35B	8/13/1980	10/29/1980	Casing shoe	7200	Killed well	Cement squeeze & casing patch replacement	Insufficient cement integrity
P43	10/8/1980	4/23/1981	Casing	2020	Killed well	Casing patch installation	Unknown
P26B	12/15/1980	8/7/1981	Stage collar	2793	Killed well	Installed casing patch	Stage collar port leaking
P4	4/23/1981	6/6/1982	Casing shoe	7600	Killed well	Cement squeeze, plugged and abandoned	Insufficient cement integrity
MA1B	5/8/1981	8/14/1981	Casing patch	1594	Killed well	Casing patch replacement	Casing patch seal leaking
P69A	5/19/1981	10/30/1981	Casing	4913	Killed well	Cement squeeze & casing patch installation	Unknown
P42	7/13/1981	7/13/1982	Casing shoe	8020	Killed well	Cement squeeze, plugged and abandoned	Insufficient cement integrity
SS25A	9/22/1981	10/2/1981	Stage collar	2990	Set tubing plug at 8190'	Casing patch installation	Stage collar port leaking
SS4	9/24/1981	12/1/1981	Casing	8600	Killed well	Cement squeeze	Unknown
MA1B	10/7/1981	1/5/1982	Casing patch	1594	Killed well	Cement squeeze & casing patch replacement	Casing patch seal leaking
SS6	2/7/1982	8/12/1982	Casing shoe	8444	Killed well	Cement squeeze	Insufficient cement integrity
P26C	4/2/1982	7/6/1982	Stage collar	6586	Killed well	Cement plug back	Stage collar port leaking
MA1B	4/30/1982	11/18/1982	Casing patch	1594	Killed well	Innerstring installation	Casing patch seal leaking
MA1B	4/30/1982	11/18/1982	Casing shoe	7200	Killed well	Cement squeeze	Insufficient cement integrity
P69A	6/18/1982	1/7/1983	WSO perforations	7572	Killed well	Cement squeeze and innerstring installation	Insufficient cement integrity
SS2	6/25/1982	12/8/1982	WSO perforations	8540	Killed well	Cement squeeze	Insufficient cement integrity
SS25A	10/18/1982	10/23/1982	Casing patch	2990	Set tubing plug at 8190'	Convert to tubing flow	Casing patch seal leaking
P26E	12/3/1982	1/6/1983	Casing shoe	7360	Killed well	Cement squeeze	Insufficient cement integrity
SS24	3/29/1984	1/11/1985	Casing shoe	8750	Killed well	Cement squeeze	Insufficient cement integrity
P45	4/15/1984	6/5/1985	Casing	3000	Killed well	Innerstring replacement	Unknown
F3	6/13/1984	6/14/1984	Casing	3240	Killed well	Cement squeeze & innerstring installation	Unknown
P32E	7/6/1984	7/16/1984	Stage collar	3014	Set tubing plug at 7397'	Casing patch installation	Stage collar port leaking
FF32F	7/30/1984	8/20/1984	Stage collar	2001	Set tubing plug at 7050'	Casing patch installation	Stage collar port leaking
FF32B	8/13/1984	8/30/1984	Stage collar	2980	Set tubing plug at 7329'	Casing patch installation	Stage collar port leaking
SS25B	8/12/1986	11/21/1986	Casing patch	2918	Set tubing plug at 8380'	Casing patch replacement	Casing patch seal leaking
FF32E	10/29/1986	11/10/1986	Stage collar	3000	Closed sliding sleeve	Convert to tubing flow	Stage collar port leaking
SS29	9/24/1987	9/20/1991	Casing shoe	8330	Killed well	Cement squeeze	Insufficient cement integrity
F4	1/2/1988	1/29/1988	Casing	32	Set tubing plug at 8212'	Innerstring installation	Unknown
FF35C	9/15/1989	6/6/1990	Stage collar	1955	Killed well	Innerstring installation	Stage collar port leaking
FF34A	9/10/1990	9/11/1990	Casing	1580	Set tubing plug at 7489'	Cement squeeze, casing patch & innerstring installation	Memo in file indicates cause was corrosion
P26	7/21/1991	8/30/1991	Casing shoe	7513	Killed well	Cement squeeze and innerstring installation	Insufficient cement integrity
P26	6/14/1992	8/11/1992	Casing	40	Closed sliding sleeve	Replaced top two joints of innerstring	Unknown

SS11	7/28/1992	4/19/1993	Casing shoe	8700	Killed well	Cement squeeze	Insufficient cement integrity
FF32	9/10/1992	12/14/1992	Casing shoe	7040	Killed well	Cement squeeze	Insufficient cement integrity
FF33	7/28/1993	4/27/1994	Casing	115	Killed well	Casing patch installation	Unknown
SS14	4/30/1997	5/31/1997	Casing	622	Closed sliding sleeve	Replaced top section of casing	Unknown
FF32F	1/5/1999	1/6/1999	Casing patch	2001	Set tubing plug at 7050'	Casing patch replacement	Casing patch seal leaking
FF32C	7/25/2000	8/31/2010	Casing patch	3738	Set tubing plug at 7151'	Casing patch replacement	Casing patch seal leaking
SS8	11/17/2003	8/31/2006	Casing	8100	Set tubing plug at 8542'	Set straddle packer casing patch	Unknown
F9	7/10/2008	5/7/2009	Casing	1900	Killed well	Plugged and abandoned	Unknown
FF32F	9/23/2009	11/6/2009	Casing patch	2001	Set tubing plug at 7050'	Innerstring installation	Casing patch seal leaking
P26C	10/12/2009	11/6/2009	Casing patch	1684	Killed well	Casing patch replacement	Casing patch seal leaking
P50A	7/16/2010	7/16/2010	Casing	1020	Closed sliding sleeve	Cement squeeze & innerstring installation	Casing inspection log indicates corrosior
SS8	8/12/2010	10/29/2010	Casing patch	8100	Killed well	Cement plugback	Straddle packer leaking
P26E	8/1/2011	11/4/2013	Stage collar	2943	Killed well	Plugged and isolated, repair tbd	Stage collar port leaking
P26C	8/11/2011	9/29/2011	Casing shoe	7819	Killed well	Cement squeeze	Insufficient cement integrity
P32D	8/16/2011	6/26/2012	Stage collar	3011	Closed sliding sleeve	Convert to tubing flow	Stage collar port leaking
SS10	5/26/2012	6/26/2012	Casing patch	4492	Set tubing plug at 7916'	Casing patch replacement	Casing patch seal leaking
FF32C	10/8/2012	4/20/2016	Casing patch	3738	Killed well	Cemented innerstring installation	Casing patch seal leaking
MA5A	5/7/2013	5/7/2013	Casing patch	1880	Set tubing plug at 7176'	Plugged and abandoned	Straddle packer leaking
FF32D	10/14/2013	10/16/2013	Casing	6313	Set tubing plug at 7010'	Cement squeeze & plugback	Casing inspection log indicates corrosion
SS44A	10/15/2013	10/16/2013	Casing	17	Killed well	Plugged and isolated, repair tbd	TBD
P50A	5/3/2014	5/7/2014	Innerstring	1020	Set tubing plug at 6848'	Plugged and abandoned	Unknown
P42B	5/19/2014	6/19/2014	Casing	7200	Killed well	Patched by liner top extension	Unknown
SS25	10/23/2015	2/18/2016	TBD	TBD	Relief well	TBD	TBD
P42B	11/10/2015	1/21/2016	Casing	7200	Killed well	Plugged and isolated	Unknown

WSO - Water Shut Off

AC_CPUC_0036139

AC_BLD_0075729

Appendix C Tables

Table 3: Shallow Casing Leaks per AC_BLD_0075728 [11]

Well	Discovery Date	Stop Date	Type	Depth, (ft)	Method of Mitigation	Method of Repair	Cause of Leak	Surface Casing Shoe Depth (ft)	Shallow Corrosion on Log
P-45	February 26, 1976	April 25, 1977	Casing	500	Killed well	Innerstring installation	Unknown	505	No log
SF-1	November 24, 1976	December 23, 1977	Casing	1378	Killed well	Innerstring installation	Unknown	1059	No log
SS-5	August 30, 1977	November 23, 1977	Casing	1050	Killed well	Innerstring installation	Unknown	620	No
F-4	February 1, 1988	January 29, 1988	Casing	32	Set tubing plug at 8212'	Innerstring installation	Unknown	770	Yes
FF-33	July 28, 1993	April 27, 1994	Casing	115	Killed well	Casing patch installation	Unknown	996	No log
SS-14	April 30, 1997	May 31, 1997	Casing	622	Closed sliding sleeve	Replaced top section of casing	Unknown	817	No
P-50A	July 16, 2010	July 16, 2010	Casing	1020	Closed sliding sleeve	Cement squeeze & innerstring installation	Casing inspection log indicates corrosion	1025	Yes
SS-44A	October 15, 2013	October 16, 2013	Casing	17	Killed well	Plugged and isolated, repair tbd	TBD	854	No log

Table 4: Shallow Casing Leaks [3]

Well Name	Elevation (ft)	Year Casing Run	Year Failure Identified	Years of Service	Failure Type	Approx. Failure Depth (ft)	Comments	Casing OD	Weight	Grade	Connection	Shallow Corrosion on Log?
SS-14 (1)	2,335	1949	1969	20	Split casing	Wellhead	Cut casing at 105 ft. Ran overshot type patch.	7 in.	23 ppf	J55	Speedtite	No log
P-45	1,896	1955	1969	14	Parted casing	177	Cut casing. Ran casing patch.	7 in.	23 ppf	J55	T&C	No log
SS-14 (2)	2,335	1949	1976	27	Casing leak	156	Cut casing at 625 ft. Ran overshot type patch.	7 in.	23 ppf	J55	Speedtite	No log
SF-1	2,520	1953	1976	23	Casing leak	1,380	Squeezed cement and ran 5 1/2 in. inner casing.	7 in.	23 ppf	N80	Not Reported	No log
SS-5	2,651	1945	1977	32	Casing leak	800–1,200	Ran 5 1/2 in. inner casing.	7 in.	23 ppf	J55	Speedtite	No
SS-12 (2)	2,276	1954	1977	23	Parted casing	553	Repaired parted connection at 553 ft, parted connections at 889 ft and 1,224 ft occurred during the workover.	7 in.	23 ppf	J55	Speedtite	No
P-50A	1,935	1983	1984	1	Casing leak (conn.)	727, 770, 814, 856, 898	Noted on noise and radioactive survey. Squeezed cement and ran 7 in. inner casing in 2011.	9.625 in.	43.5 ppf	N80	BTC	Yes
FF-33 (2)	2,060	1949	1994	45	Casing leak	115	Set expandable casing patch.	7 in.	23 ppf	J55	Speedtite	No log
P-32 (2)	2,086	1944	2016	72	Casing leak	654–845	Squeezed cemented. Run and cement inner casing.	7 in.	23 ppf	N80	Speedtite	Yes
SS-44A (2)	2,682	1974	2016	42	Casing leak	4–5	P&A well. Recovered casing with leak.	8.625 in.	36 ppf	K55	BTC	No log
SS-4A (3)	2,886	1974	2017	43	Casing leak	753–860	Squeezed cement. Ran and cemented 6 5/8 inner casing.	8.625 in.	36 ppf	K55	LTC	No

Table 5: Wells from 1988 Memo with Shallow Corrosion on Logs

Well Name	Priority	Vertilog Date	Vertilog Available	Vertilog Summary	Subsequent Casing Inspection Log Date	Subsequent Casing Inspection Log Summary	Notes	Shallow Corrosion on Logs
P-37	High	October 11, 1988	Yes	4 jts >20% OD Penetration and 1 jt > 60% OD Penetration	-	-	Ran 5 1/2 in. inner casing May 12, 1989. Ran and cemented 5 1/2 in. inner casing Nov 14, 2017.	Yes
P-44	Low	-	-	-	HRVRT Feb 15, 2016. USIT Feb 29, 2016	1 jt >20% OD Penetration. 1 jt >80% OD Penetration. External corrosion on multiple joints and potential casing hole at 4,000 ft	Casing leak between 3,961 ft and 4,010 ft Feb 18, 2016. Set casing patch Mar 4, 2016. Set casing patch Mar 5, 2016.	No
SS-8	High	January 17, 1989	Yes	28 jts >20% OD Penetration. 5 jts > 40% OD Penetration	Cast V Apr 28, 2007. USIT Apr 24, 2013	Indications 955–1,080 ft. 2,276–2,482 ft. 3,287–3,289 ft. 8,479–8,482 ft	-	Yes
SS-9	High	December 16, 1988	Yes	6 jts >20% OD Penetration	HRVRT Sep 6, 2018 USIT Sep 7, 2018	Indications 773 ft.		Yes
SS-24	Low	-	-	-	HRVRT Feb 11, 2017. USIT Feb 15, 2017	4 jts >20% OD Penetration. 4 jts >20% ID Penetration. Daily report USIT comments; External Anomalies 8,406–8,414 ft 2,250–2,920 ft 1,100–1,620 ft. 8 jts >20% Penetration	-	Yes
SS-25	Low	-	-	-	December 2017 (RCA)		Casing parted at 892 ft Oct 23, 2015.	Yes
F-2	Medium	January 11, 1990	No	-	USIT Sep 11, 2014. Vertilog Oct 20, 2014	Indications 600–3,220 ft. 15 jts >20% OD Penetration. 3 jts >40% OD Penetration. 5 jts >60% OD Penetration. 2 jts >80% OD Penetration. Possible penetration around 2835'	Tight Spot 3,872 ft. Tight Spot 8,130 ft. Casing leak between 2,949 and 2,969 ft. Workover in 2014	Yes
F-4	-	Septembe r 6, 1988	Yes	12 jts >20% OD Penetration. 12 jts > 40% OD Penetration. 2 jts > 60% OD Penetration	USIT Oct 20, 2016	Indications 764–5,085 ft. 5,708–5,911 ft. 6,782–6,788 ft. 6,908–6,911 ft	-	Yes

Table 6: Wells from 2014 General Rate Case Testimony [5] with Shallow Corrosion Indications

Lease Name	Well #	Spud Date	Log Type, Log Date	Shallow Corrosion on Log
Standard Sesnon	6	June 6, 1945	USIT, August 8, 2012	No
Standard Sesnon	8	May 14, 1946	USIT, April 24, 2013	Yes
Porter	37	June 12, 1946	Vertilog, October 11, 1988	Yes
Standard Sesnon	10	April 20, 1947	USIT, September 24, 2012	No
Fernando Fee	32F	September 23, 1972	USIT, June 23, 2010	Yes
Standard Sesnon	25A	November 2, 1972	USIT, August 18, 2010	No
Fernando Fee	32E	December 6, 1972	USIT, June 2, 2007	Yes
Fernando Fee	32D	April 5, 1973	USIT, January 9, 2014	No
Porter	26C	April 18, 1973	USIT, November 15, 2010	No
Porter	42B	December 9, 1978	USIT, December 11, 2012	No
Fernando Fee	34BR	December 19, 1980	USIT, July 13, 2012	No
Porter	50A	April 15, 1983	USIT, January 4, 2011	Yes

Table 7: Wells from Comprehensive Safety Review [14]

Well Name	API Number	Current Status	Legacy Production Casing Log Date	Production Casing MFLLog Date	Production Casing Ultrasonic Log Date	Safety Review Production Casing Inspection Log Available?	Shallow Corrosion on Safety Review or Historic Casing Inspection Log
Fernando Fee 32	03700686	Passed All Tests	-	-	-	no	no
Fernando Fee 32A	03721872	Passed All Tests	-	April 1, 2016	March 30, 2016	yes	yes
Fernando Fee 32B	03721358	Passed All Tests	-	December 29, 2016	January 3, 2017	yes	no
Fernando Fee 32C	03721359	Passed All Tests	-	May 26, 2016	May 25, 2016	yes	no
Fernando Fee 32D	03721356	Passed All Tests	-	-	January 9, 2014	yes	no
Fernando Fee 32E	03721321	Subsurface P/A in Progress	-	-	June 2, 2007	yes	yes
Fernando Fee 32F	03721313	Passed All Tests	-	-	June 23, 2010	yes	yes
Fernando Fee 32G	03730374	Passed All Tests	-	-	September 18, 2014	yes	no

Well Name	API Number	Current Status	Legacy Production Casing Log Date	Production Casing MFLLog Date	Production Casing Ultrasonic Log Date	Safety Review Production Casing Inspection Log Available?	Shallow Corrosion on Safety Review or Historic Casing Inspection Log
Fernando Fee 32H	03730456	Passed All Tests	-	-	August 3, 2015	yes	no
Fernando Fee 33	03700687	Passed All Tests	-	-	-	no	no
Fernando Fee 34A	03722044	Passed All Tests	-	-	-	no	no
Fernando Fee 34BR	03722302	Passed All Tests	-	January 4, 2017	December 29, 2016	yes	no
Fernando Fee 35A	03721457	Passed All Tests	-	August 12, 2016	August 18, 2016	yes	no
Fernando Fee 35B	03721458	Passed All Tests	-	July 14, 2016	June 1, 2017	yes	no
Fernando Fee 35C	03721279	Passed All Tests	September 18, 1990	-	-	no	no
Fernando Fee 35D	03721453	Passed All Tests	-	April 6, 2017	-	no	no
Fernando Fee 35E	03721278	Passed All Tests	-	March 2, 2017	-	no	no
Fernando Fee 38A	03724230	Passed All Tests	-	May 4, 2016	May 11, 2016	yes	no
Fernando Fee 38B	03724231	Passed All Tests	-	April 18, 2016	April 16, 2016	yes	no
Fernando Fee 38C	03724232	Passed All Tests	-	March 23, 2016	March 22, 2016	yes	no
Frew 2	03700665	Subsurface P/A in Progress	-	October 20, 2014	October 3, 2014	yes	yes
Frew 4	03700667	P/A Site Restoration in Progress	September 6, 1988	-	October 19, 2016	yes	yes
Frew 5	03700668	P/A Site Restoration in Progress	-	-	-	no	no
Frew 6	03700669	P/A Site Restoration in Progress	-	-	-	no	no
Frew 7	03700670	P/A Site Restoration in Progress	-	-	-	no	no
Frew 8	03700671	P/A Site Restoration in Progress	-	-	-	no	no
Mission Adrian 1A	03721891	P/A Site Restoration in Progress	December 27, 1989	-	September 12, 2017	yes	yes
Mission Adrian 1B	03721892	Passed All Tests	-	-	May 15, 2017	yes	no
Mission Adrian 3	03700693	Plugged and Abandoned	-	-	August 17, 2016	yes	yes
Porter 12	03700701	Taken Out of Operation (Plugged & Isolated)	-	-	-	no	no
Porter 24A	03724143	Passed All Tests	-	September 21, 2016	September 23, 2016	yes	no

Well Name	API Number	Current Status	Legacy Production Casing Log Date	Production Casing MFLLog Date	Production Casing Ultrasonic Log Date	Safety Review Production Casing Inspection Log Available?	Shallow Corrosion on Safety Review or Historic Casing Inspection Log
Porter 24B	03724144	Passed All Tests	-	May 16, 2016	May 19, 2016	yes	no
Porter 25R	03700712	Passed All Tests	-	April 28, 2016	April 29, 2016	yes	no
Porter 26	03700713	Passed All Tests	-	-	-	no	no
Porter 26A	03721362	Passed All Tests	-	August 5, 2016	August 10, 2016	yes	no
Porter 26B	03721357	Passed All Tests	-	-	-	no	no
Porter 26C	03721353	Passed All Tests	November 15, 2010	July 11, 2016	October 25, 2016	yes	no
Porter 26D	03721320	Passed All Tests	-	-	-	no	no
Porter 26E	03721319	Passed All Tests	October 21, 2010	-	March 10, 2014	yes	no
Porter 30	03700717	P/A Site Restoration in Progress	-	-	-	no	no
Porter 32	03700719	Passed All Tests	October 26, 1979	-	October 18, 2016	yes	yes
Porter 32A	03721277	Taken Out of Operation (Plugged & Isolated)	-	-	-	no	no
Porter 32B	03721276	Passed All Tests	-	February 9, 2017	February 7, 2017	yes	yes
Porter 32C	03721360	Passed All Tests	July 26, 1989	-	-	no	no
Porter 32D	03721355	Passed All Tests	-	-	January 19, 2014	yes	yes
Porter 32E	03721363	P/A Site Restoration in Progress	-	June 22, 2018	June 20, 2018	yes	yes
Porter 32F	03721354	Pending Test Results	-	January 28, 2019	January 25, 2019	yes	yes
Porter 34	03700721	P/A Site Restoration in Progress	-	-	-	no	no
Porter 35	03700722	P/A Site Restoration in Progress	-	February 26, 2016	January 23, 2016	yes	yes
Porter 36	03700723	Plugged and Abandoned	-	-	February 19, 2016	yes	yes
Porter 37	03700724	Passed All Tests	October 11, 1988	-	-	no	yes
Porter 37A	03722046	Taken Out of Operation (Plugged & Isolated)	-	November 9, 2016	November 5, 2016	yes	yes
Porter 38	03700725	Subsurface P/A in Progress	-	-	-	no	no

Well Name	API Number	Current Status	Legacy Production Casing Log Date	Production Casing MFLLog Date	Production Casing Ultrasonic Log Date	Safety Review Production Casing Inspection Log Available?	Shallow Corrosion on Safety Review or Historic Casing Inspection Log
Porter 39	03700726	Subsurface P/A in Progress	-	-	-	no	no
Porter 40	03700727	Subsurface P/A in Progress	-	-	-	no	no
Porter 42A	03721876	Passed All Tests	-	December 16, 2016	December 12, 2016	yes	no
Porter 42B	03721877	Passed All Tests	-	May 25, 2016	May 26, 2016	yes	no
Porter 42C	03721878	Subsurface P/A in Progress	-	November 8, 2016	November 8, 2016	yes	no
Porter 44	03700731	Passed All Tests	-	February 15, 2016	February 29, 2016	yes	no
Porter 45	03700732	Subsurface P/A in Progress	-	-	-	no	no
Porter 46	03700733	Passed All Tests	October 19, 1988	-	August 16, 2017	yes	yes
Porter 47	03700734	Plugged and Abandoned	-	-	-	no	no
Porter 50B	03724336	Passed All Tests	-	April 16, 2016	April 14, 2016	yes	no
Porter 50C	03724337	Passed All Tests	-	March 17, 2016	March 16, 2016	yes	no
Porter 68A	03722742	Passed All Tests	-	May 26, 2016	May 24, 2016	yes	yes
Porter 68B	03724136	Passed All Tests	-	April 14, 2016	April 13, 2016	yes	no
Porter 69A	03722051	Passed All Tests	-	January 25, 2017	January 23, 2017	yes	yes
Porter 69B	03724127	Passed All Tests	-	April 4, 2016	April 5, 2016	yes	no
Porter 69C	03724128	Passed All Tests	-	July 9, 2016	July 15, 2016	yes	no
Porter 69D	03724130	Passed All Tests	-	May 21, 2016	May 24, 2016	yes	no
Porter 69E	03724138	Passed All Tests	-	September 7, 2016	August 31, 2016	yes	no
Porter 69F	03724226	Passed All Tests	-	April 6, 2016	May 7, 2016	yes	no
Porter 69G	03724225	Passed All Tests	-	August 3, 2016	August 8, 2016	yes	no
Porter 69H	03724223	Passed All Tests	-	June 17, 2016	June 11, 2016	yes	no
Porter 69J	03724224	Passed All Tests	-	March 31, 2016	March 31, 2016	yes	no
Porter 69K	03724236	Passed All Tests	-	May 24, 2016	May 23, 2016	yes	no
Porter 72A	03724145	Passed All Tests	-	May 19, 2016	May 18, 2016	yes	yes

Well Name	API Number	Current Status	Legacy Production Casing Log Date	Production Casing MFLLog Date	Production Casing Ultrasonic Log Date	Safety Review Production Casing Inspection Log Available?	Shallow Corrosion on Safety Review or Historic Casing Inspection Log
Porter 72B	03724146	Passed All Tests	-	June 29, 2016	June 28, 2016	yes	no
Porter Sesnon 42	03700753	P/A Site Restoration in Progress	-	-	-	no	no
Sesnon Fee 1	03700647	P/A Site Restoration in Progress	-	-	-	no	no
Sesnon Fee 2	03700648	P/A Site Restoration in Progress	November 19, 1999	-	-	no	no
Sesnon Fee 3	03700649	P/A Site Restoration in Progress	-	-	-	no	no
Sesnon Fee 4	03700650	P/A Site Restoration in Progress	-	-	August 14, 2017	yes	no
Sesnon Fee 5	03700651	P/A Site Restoration in Progress	-	-	March 22, 2018	yes	yes
Sesnon Fee 6	03700652	P/A Site Restoration in Progress	-	-	June 6, 2017	yes	no
Sesnon Fee 7	03700653	Subsurface P/A in Progress	-	-	-	no	no
Sesnon Fee 8	03700654	P/A Site Restoration in Progress	-	-	-	no	no
Standard Sesnon 02	03700755	Plugged and Abandoned	-	-	-	no	no
Standard Sesnon 03H	03700756	Subsurface P/A in Progress	-	-	-	no	no
Standard Sesnon 04	03700757	Subsurface P/A in Progress	-	-	-	no	no
Standard Sesnon 04A	03721375	Passed All Tests	-	September 17, 2016	September 21, 2016	yes	no
Standard Sesnon 04B	03730460	Passed All Tests	-	August 19, 2016	August 15, 2016	yes	no
Standard Sesnon 04-O	03722063	Passed All Tests	April 21, 1994	December 14, 2016	December 12, 2016	yes	no
Standard Sesnon 05	03700758	Passed All Tests	-	November 3, 2016	October 3, 2016	yes	no
Standard Sesnon 06	03700759	Passed All Tests	-	-	August 8, 2012	yes	no
Standard Sesnon 09	03700762	Passed All Tests	December 16, 1988	September 6, 2018	September 7, 2018	yes	yes
Standard Sesnon 10	03700040	Passed All Tests	-	-	September 24, 2012	yes	no
Standard Sesnon 11	03700763	Subsurface P/A in Progress	-	-	-	no	no
Standard Sesnon 12	03700764	P/A Site Restoration in Progress	-	-	-	no	no
Standard Sesnon 13	03700765	P/A Site Restoration in Progress	-	-	-	no	no
Standard Sesnon 14	03700766	P/A Site Restoration in Progress	May 26, 1998	-	-	no	no

Well Name	API Number	Current Status	Legacy Production Casing Log Date	Production Casing MFLLog Date	Production Casing Ultrasonic Log Date	Safety Review Production Casing Inspection Log Available?	Shallow Corrosion on Safety Review or Historic Casing Inspection Log
Standard Sesnon 16	03700768	Subsurface P/A in Progress	-	-	-	no	no
Standard Sesnon 17	03700769	P/A Site Restoration in Progress	-	-	-	no	no
Standard Sesnon 24	03700775	P/A Site Restoration in Progress	-	February 11, 2017	-	no	yes
Standard Sesnon 25	03700776	P/A Site Restoration in Progress	-	December 2, 2017	December 2, 2017	yes	yes
Standard Sesnon 25A	03721322	Taken Out of Operation (Plugged & Isolated)	August 18, 2010	June 7, 2017	June 3, 2017	yes	no
Standard Sesnon 25B	03721323	Subsurface P/A in Progress	-	December 10, 2018	December 11, 2018	yes	no
Standard Sesnon 29	03700041	Passed All Tests	-	October 13, 2017	October 10, 2017	yes	no
Standard Sesnon 30	03700780	P/A Site Restoration in Progress	-	-	-	no	no
Standard Sesnon 31	03700781	Passed All Tests	-	-	-	no	no
Standard Sesnon 44A	03721455	P/A Site Restoration in Progress	-	-	-	no	no
Standard Sesnon 44B	03721361	Pending Test Results	-	-	-	no	no
Ward 3	03700192	Taken Out of Operation (Plugged & Isolated)	-	-	September 2, 2016	yes	yes
Ward 3A	03722306	Passed All Tests	-	-	-	no	no
Total Wells			**Number of Wells**	**Number of Wells**	**Number of Wells**	**Number of Wells**	**Number of Wells**
114			14	52	69	69	25

Table 8: List of Wells and Web Links

Well Name	API Number	Web Link to Well - URL
Fernando Fee 32	03700686	https://secure.conservation.ca.gov/WellSearch/Details?api=03700686
Fernando Fee 32A	03721872	https://secure.conservation.ca.gov/WellSearch/Details?api=03721872
Fernando Fee 32B	03721358	https://secure.conservation.ca.gov/WellSearch/Details?api=03721358
Fernando Fee 32C	03721359	https://secure.conservation.ca.gov/WellSearch/Details?api=03721359
Fernando Fee 32D	03721356	https://secure.conservation.ca.gov/WellSearch/Details?api=03721356
Fernando Fee 32E	03721321	https://secure.conservation.ca.gov/WellSearch/Details?api=03721321
Fernando Fee 32F	03721313	https://secure.conservation.ca.gov/WellSearch/Details?api=03721313
Fernando Fee 32G	03730374	https://secure.conservation.ca.gov/WellSearch/Details?api=03730374
Fernando Fee 32H	03730456	https://secure.conservation.ca.gov/WellSearch/Details?api=03730456
Fernando Fee 33	03700687	https://secure.conservation.ca.gov/WellSearch/Details?api=03700687
Fernando Fee 34A	03722044	https://secure.conservation.ca.gov/WellSearch/Details?api=03722044
Fernando Fee 34BR	03722302	https://secure.conservation.ca.gov/WellSearch/Details?api=03722302
Fernando Fee 35A	03721457	https://secure.conservation.ca.gov/WellSearch/Details?api=03721457
Fernando Fee 35B	03721458	https://secure.conservation.ca.gov/WellSearch/Details?api=03721458
Fernando Fee 35C	03721279	https://secure.conservation.ca.gov/WellSearch/Details?api=03721279
Fernando Fee 35D	03721453	https://secure.conservation.ca.gov/WellSearch/Details?api=03721453
Fernando Fee 35E	03721278	https://secure.conservation.ca.gov/WellSearch/Details?api=03721278
Fernando Fee 38A	03724230	https://secure.conservation.ca.gov/WellSearch/Details?api=03724230
Fernando Fee 38B	03724231	https://secure.conservation.ca.gov/WellSearch/Details?api=03724231
Fernando Fee 38C	03724232	https://secure.conservation.ca.gov/WellSearch/Details?api=03724232
Frew 2	03700665	https://secure.conservation.ca.gov/WellSearch/Details?api=03700665
Frew 4	03700667	https://secure.conservation.ca.gov/WellSearch/Details?api=03700667
Frew 5	03700668	https://secure.conservation.ca.gov/WellSearch/Details?api=03700668

Well Name	API Number	Web Link to Well - URL
Frew 6	03700669	https://secure.conservation.ca.gov/WellSearch/Details?api=03700669
Frew 7	03700670	https://secure.conservation.ca.gov/WellSearch/Details?api=03700670
Frew 8	03700671	https://secure.conservation.ca.gov/WellSearch/Details?api=03700671
Mission Adrian 1A	03721891	https://secure.conservation.ca.gov/WellSearch/Details?api=03721891
Mission Adrian 1B	03721892	https://secure.conservation.ca.gov/WellSearch/Details?api=03721892
Mission Adrian 3	03700693	https://secure.conservation.ca.gov/WellSearch/Details?api=03700693
Porter 12	03700701	https://secure.conservation.ca.gov/WellSearch/Details?api=03700701
Porter 24A	03724143	https://secure.conservation.ca.gov/WellSearch/Details?api=03724143
Porter 24B	03724144	https://secure.conservation.ca.gov/WellSearch/Details?api=03724144
Porter 25R	03700712	https://secure.conservation.ca.gov/WellSearch/Details?api=03700712
Porter 26	03700713	https://secure.conservation.ca.gov/WellSearch/Details?api=03700713
Porter 26A	03721362	https://secure.conservation.ca.gov/WellSearch/Details?api=03721362
Porter 26B	03721357	https://secure.conservation.ca.gov/WellSearch/Details?api=03721357
Porter 26C	03721353	https://secure.conservation.ca.gov/WellSearch/Details?api=03721353
Porter 26D	03721320	https://secure.conservation.ca.gov/WellSearch/Details?api=03721320
Porter 26E	03721319	https://secure.conservation.ca.gov/WellSearch/Details?api=03721319
Porter 30	03700717	https://secure.conservation.ca.gov/WellSearch/Details?api=03700717
Porter 32	03700719	https://secure.conservation.ca.gov/WellSearch/Details?api=03700719
Porter 32A	03721277	https://secure.conservation.ca.gov/WellSearch/Details?api=03721277
Porter 32B	03721276	https://secure.conservation.ca.gov/WellSearch/Details?api=03721276
Porter 32C	03721360	https://secure.conservation.ca.gov/WellSearch/Details?api=03721360
Porter 32D	03721355	https://secure.conservation.ca.gov/WellSearch/Details?api=03721355
Porter 32E	03721363	https://secure.conservation.ca.gov/WellSearch/Details?api=03721363

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Porter 34	03700721	https://secure.conservation.ca.gov/WellSearch/Details?api=03700721
Porter 35	03700722	https://secure.conservation.ca.gov/WellSearch/Details?api=03700722
Porter 36	03700723	https://secure.conservation.ca.gov/WellSearch/Details?api=03700723
Porter 37	03700724	https://secure.conservation.ca.gov/WellSearch/Details?api=03700724
Porter 37A	03722046	https://secure.conservation.ca.gov/WellSearch/Details?api=03722046
Porter 38	03700725	https://secure.conservation.ca.gov/WellSearch/Details?api=03700725
Porter 39	03700726	https://secure.conservation.ca.gov/WellSearch/Details?api=03700726
Porter 40	03700727	https://secure.conservation.ca.gov/WellSearch/Details?api=03700727
Porter 42A	03721876	https://secure.conservation.ca.gov/WellSearch/Details?api=03721876
Porter 42B	03721877	https://secure.conservation.ca.gov/WellSearch/Details?api=03721877
Porter 42C	03721878	https://secure.conservation.ca.gov/WellSearch/Details?api=03721878
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Porter 47	03700734	https://secure.conservation.ca.gov/WellSearch/Details?api=03700734
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Porter 50C	03724337	https://secure.conservation.ca.gov/WellSearch/Details?api=03724337
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Porter 69C	03724128	https://secure.conservation.ca.gov/WellSearch/Details?api=03724128
Porter 69D	03724130	https://secure.conservation.ca.gov/WellSearch/Details?api=03724130
Porter 69E	03724138	https://secure.conservation.ca.gov/WellSearch/Details?api=03724138

Well Name	API Number	Web Link to Well - URL
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Porter 69G	03724225	https://secure.conservation.ca.gov/WellSearch/Details?api=03724225
Porter 69H	03724223	https://secure.conservation.ca.gov/WellSearch/Details?api=03724223
Porter 69J	03724224	https://secure.conservation.ca.gov/WellSearch/Details?api=03724224
Porter 69K	03724236	https://secure.conservation.ca.gov/WellSearch/Details?api=03724236
Porter 72A	03724145	https://secure.conservation.ca.gov/WellSearch/Details?api=03724145
Porter 72B	03724146	https://secure.conservation.ca.gov/WellSearch/Details?api=03724146
Porter Sesnon 42	03700753	https://secure.conservation.ca.gov/WellSearch/Details?api=03700753
Sesnon Fee 1	03700647	https://secure.conservation.ca.gov/WellSearch/Details?api=03700647
Sesnon Fee 2	03700648	https://secure.conservation.ca.gov/WellSearch/Details?api=03700648
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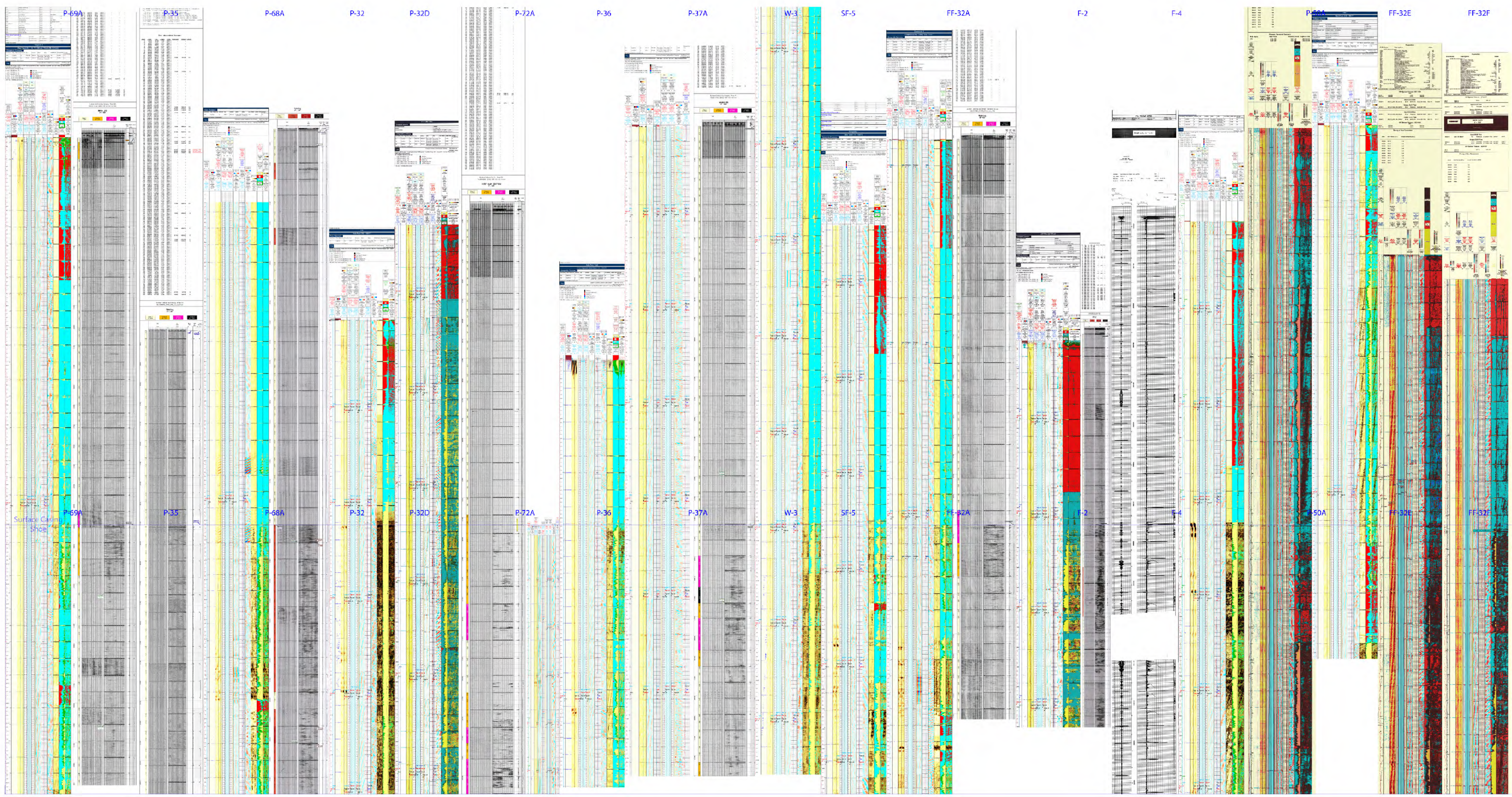
Sesnon Fee 7	03700653	https://secure.conservation.ca.gov/WellSearch/Details?api=03700653
Sesnon Fee 8	03700654	https://secure.conservation.ca.gov/WellSearch/Details?api=03700654
Standard Sesnon 02	03700755	https://secure.conservation.ca.gov/WellSearch/Details?api=03700755
Standard Sesnon 03H	03700756	https://secure.conservation.ca.gov/WellSearch/Details?api=03700756
Standard Sesnon 04	03700757	https://secure.conservation.ca.gov/WellSearch/Details?api=03700757
Standard Sesnon 04A	03721375	https://secure.conservation.ca.gov/WellSearch/Details?api=03721375
Standard Sesnon 04B	03730460	https://secure.conservation.ca.gov/WellSearch/Details?api=03730460
Standard Sesnon 04-O	03722063	https://secure.conservation.ca.gov/WellSearch/Details?api=03722063
Standard Sesnon 05	03700758	https://secure.conservation.ca.gov/WellSearch/Details?api=03700758
Standard Sesnon 06	03700759	https://secure.conservation.ca.gov/WellSearch/Details?api=03700759
Standard Sesnon 09	03700762	https://secure.conservation.ca.gov/WellSearch/Details?api=03700762

Well Name	API Number	Web Link to Well - URL
Standard Sesnon 10	03700040	https://secure.conservation.ca.gov/WellSearch/Details?api=03700040
Standard Sesnon 11	03700763	https://secure.conservation.ca.gov/WellSearch/Details?api=03700763
Standard Sesnon 12	03700764	https://secure.conservation.ca.gov/WellSearch/Details?api=03700764
Standard Sesnon 13	03700765	https://secure.conservation.ca.gov/WellSearch/Details?api=03700765
Standard Sesnon 14	03700766	https://secure.conservation.ca.gov/WellSearch/Details?api=03700766
Standard Sesnon 16	03700768	https://secure.conservation.ca.gov/WellSearch/Details?api=03700768
Standard Sesnon 17	03700769	https://secure.conservation.ca.gov/WellSearch/Details?api=03700769
Standard Sesnon 24	03700775	https://secure.conservation.ca.gov/WellSearch/Details?api=03700775
Standard Sesnon 25	03700776	https://secure.conservation.ca.gov/WellSearch/Details?api=03700776

Well Name	API Number	Web Link to Well - URL
Standard Sesnon 25A	03721322	https://secure.conservation.ca.gov/WellSearch/Details?api=03721322
Standard Sesnon 25B	03721323	https://secure.conservation.ca.gov/WellSearch/Details?api=03721323
Standard Sesnon 29	03700041	https://secure.conservation.ca.gov/WellSearch/Details?api=03700041
Standard Sesnon 30	03700780	https://secure.conservation.ca.gov/WellSearch/Details?api=03700780
Standard Sesnon 31	03700781	https://secure.conservation.ca.gov/WellSearch/Details?api=03700781
Standard Sesnon 44A	03721455	https://secure.conservation.ca.gov/WellSearch/Details?api=03721455
Standard Sesnon 44B	03721361	https://secure.conservation.ca.gov/WellSearch/Details?api=03721361
Ward 3	03700192	https://secure.conservation.ca.gov/WellSearch/Details?api=03700192
Ward 3A	03722306	https://secure.conservation.ca.gov/WellSearch/Details?api=03722306

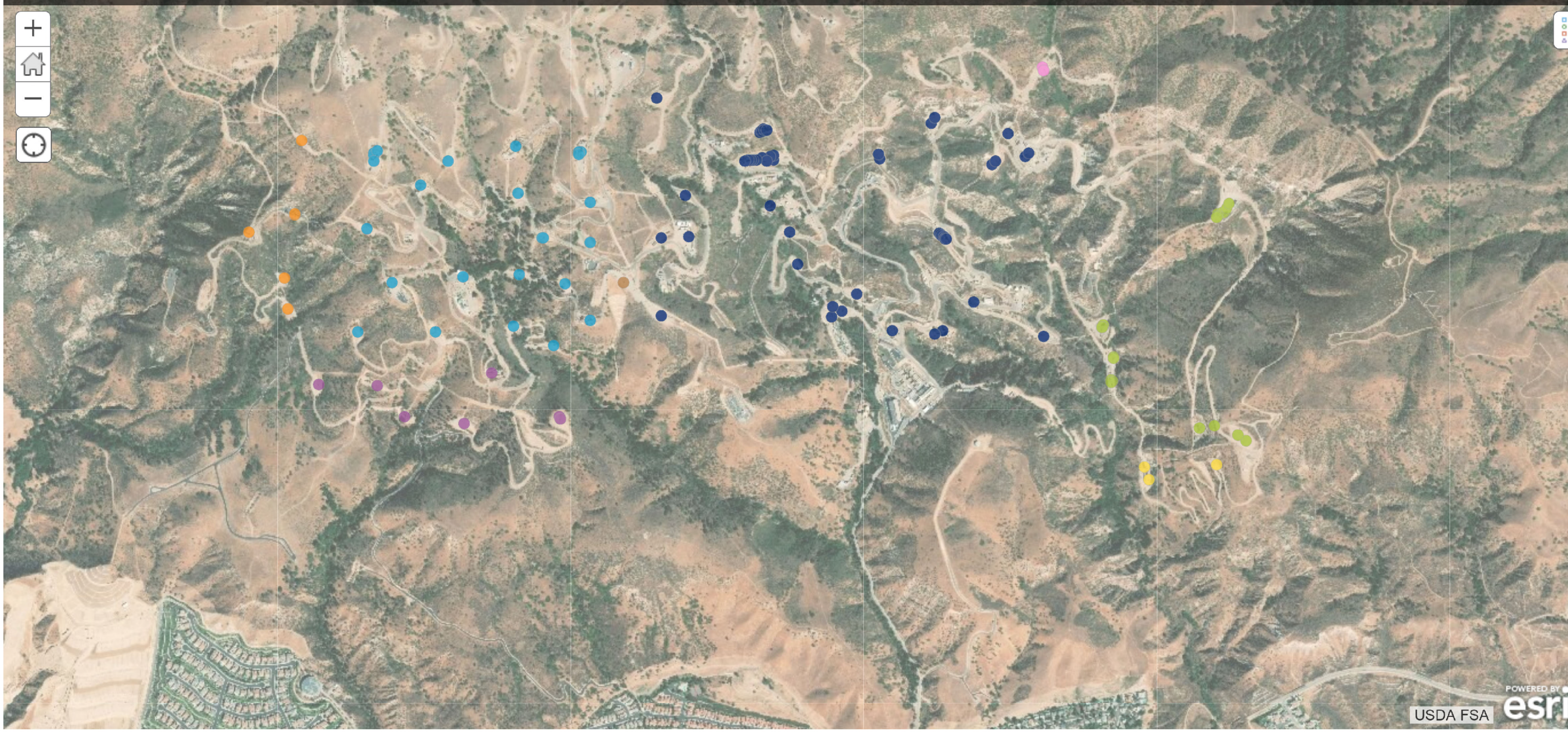
Appendix D Log Compilation



P-69A
P-35
P-68A
P-32
P-32D
P-72A
P-36
P-37A
W-3
SF-5
FF-32A
F-2
F-4
P-50A
FF-32E
FF-32F
Surface Casing Shoe

Appendix E Maps of Casing Failures and Shallow Corrosion

Comprehensive Safety Review Wells



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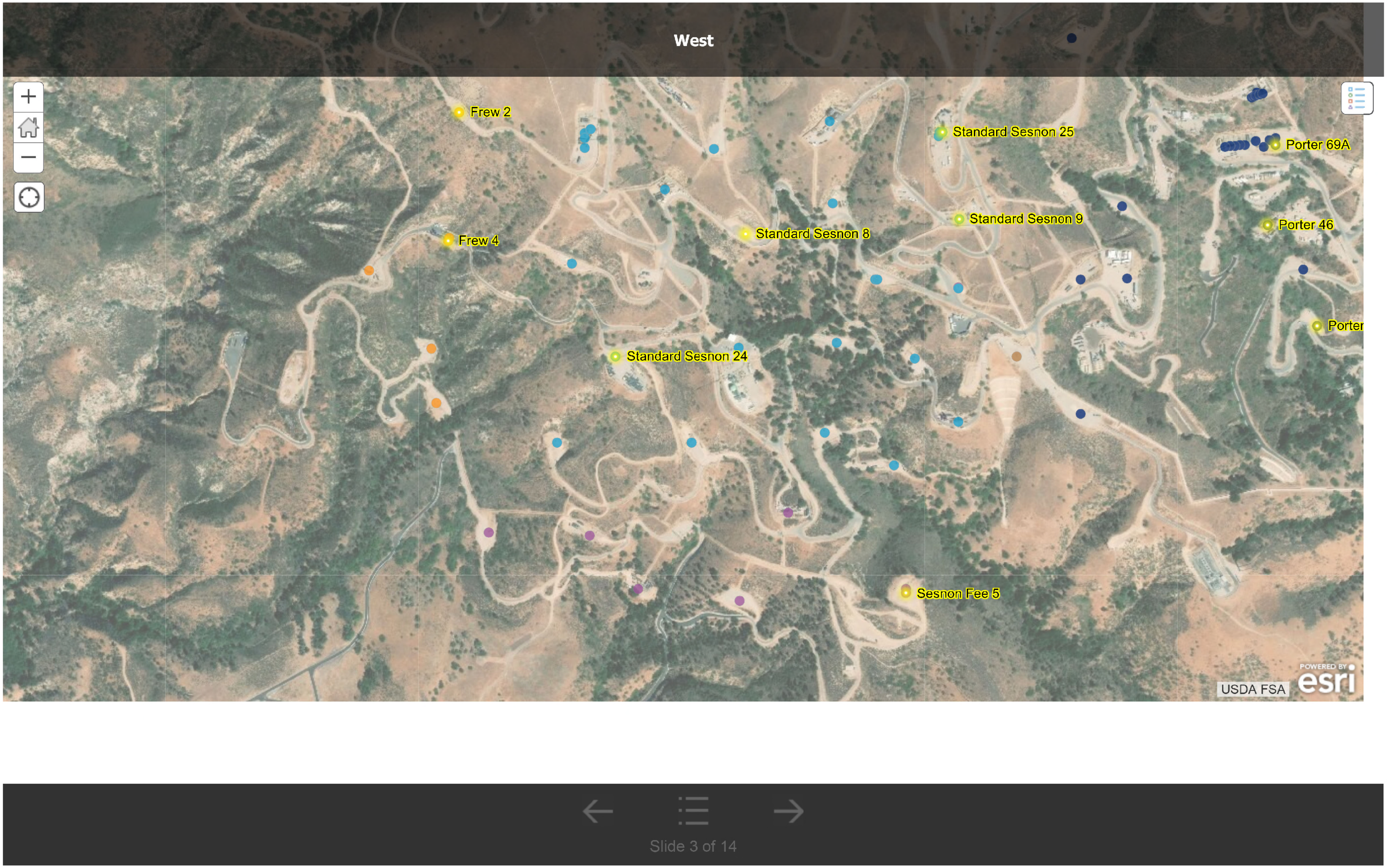
Shallow Corrosion

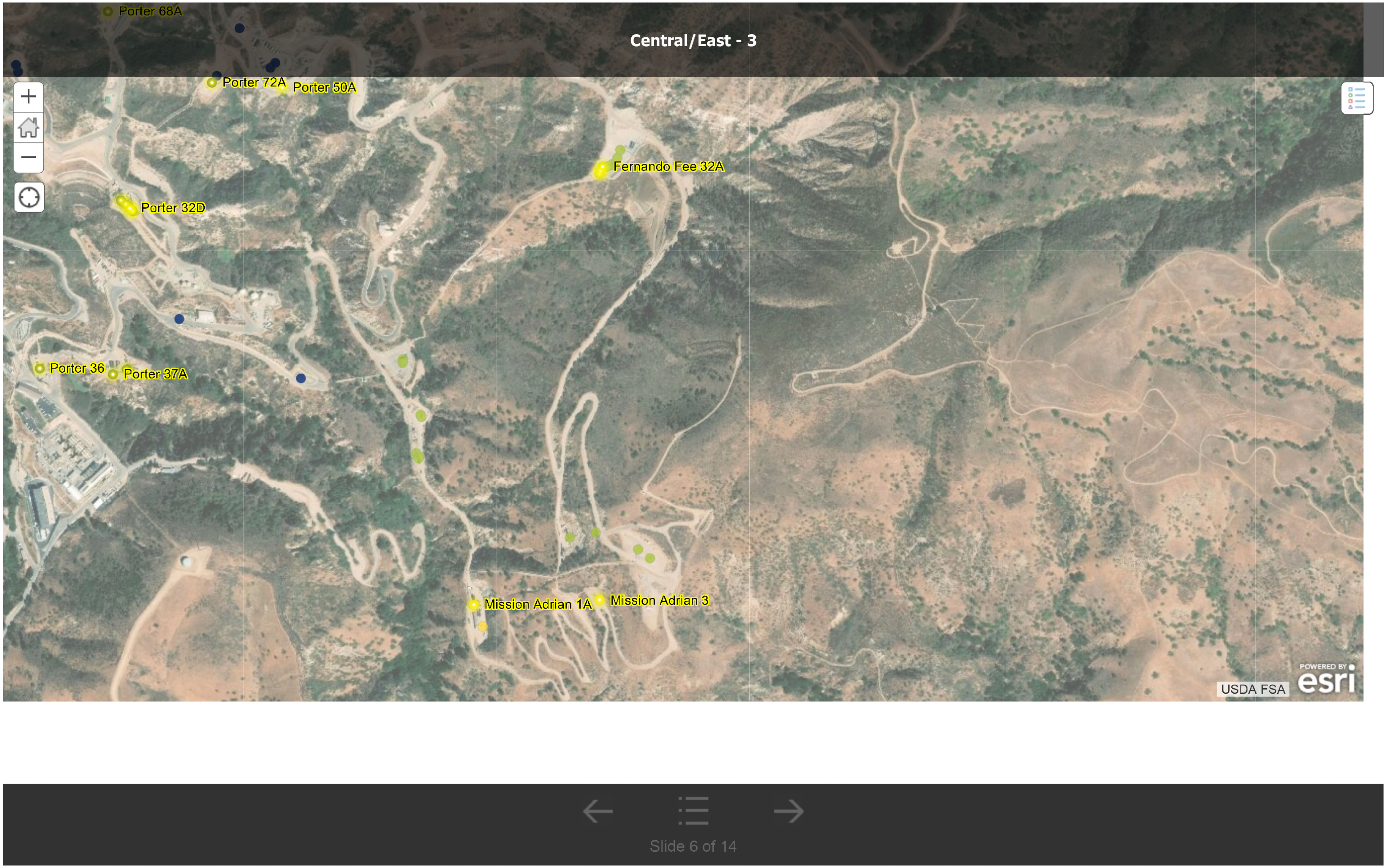
Slide 2 of 14


West
Frew 2
Frew 4
Standard Sesnon 25
Standard Sesnon 9
Standard Sesnon 8
Standard Sesnon 24
Sesnon Fee 5
Porter 69A
Porter 46
Porter
USDA FSA
POWERED BY esri
Slide 3 of 14

Central/East - 1

Slide 4 of 14

Central/East - 2


Central/East - 3
Porter 68A
Porter 72A
Porter 50A
Fernando Fee 32A
Porter 32D
Porter 36
Porter 37A
Mission Adrian 1A
Mission Adrian 3
USDA FSA
POWERED BY esri
Slide 6 of 14

Central/East - 4

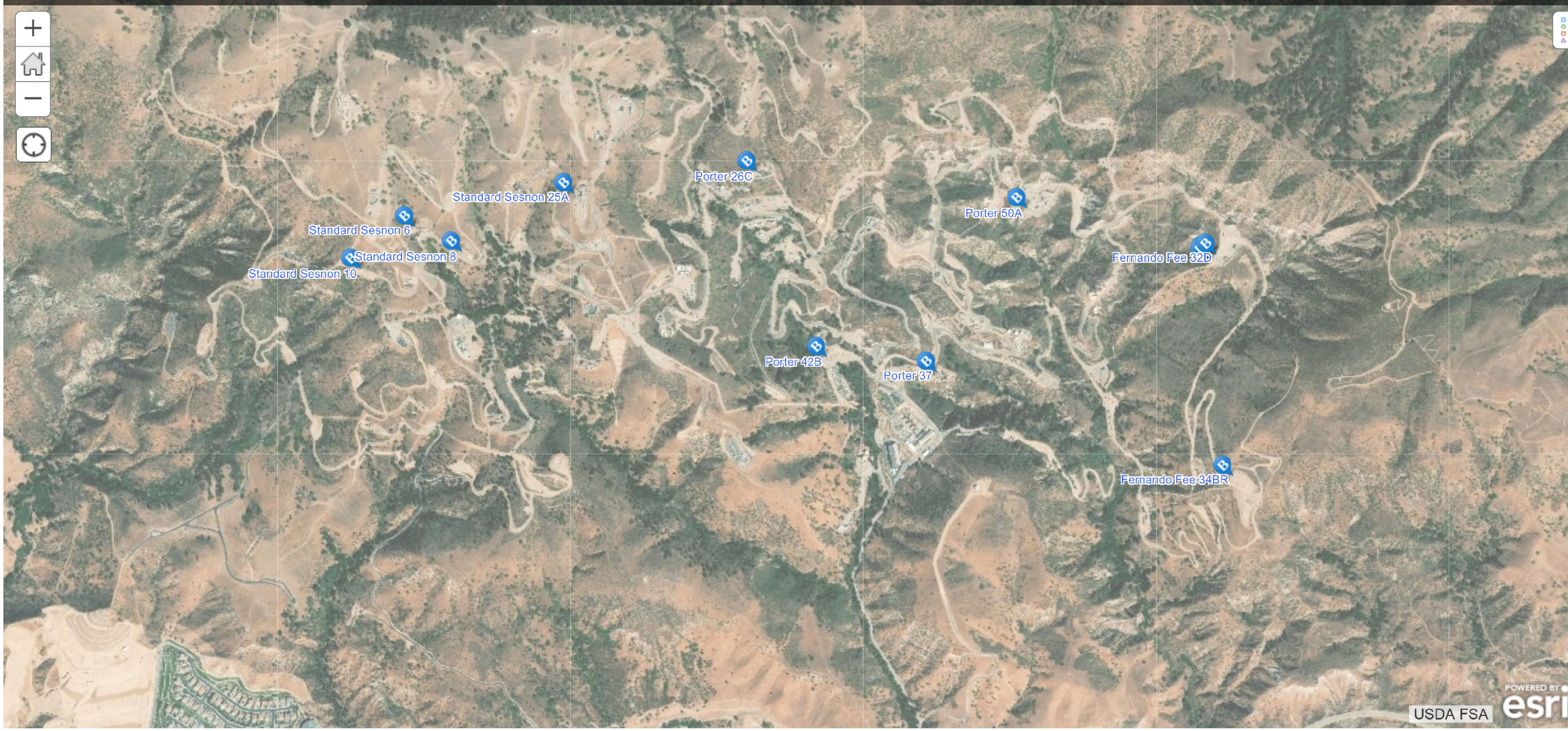
Slide 7 of 14

Shallow Corrosion

Slide 8 of 14

1988 Memo Wells for Casing Inspection

2014 Testimony Wells (2016 General Rate Case)



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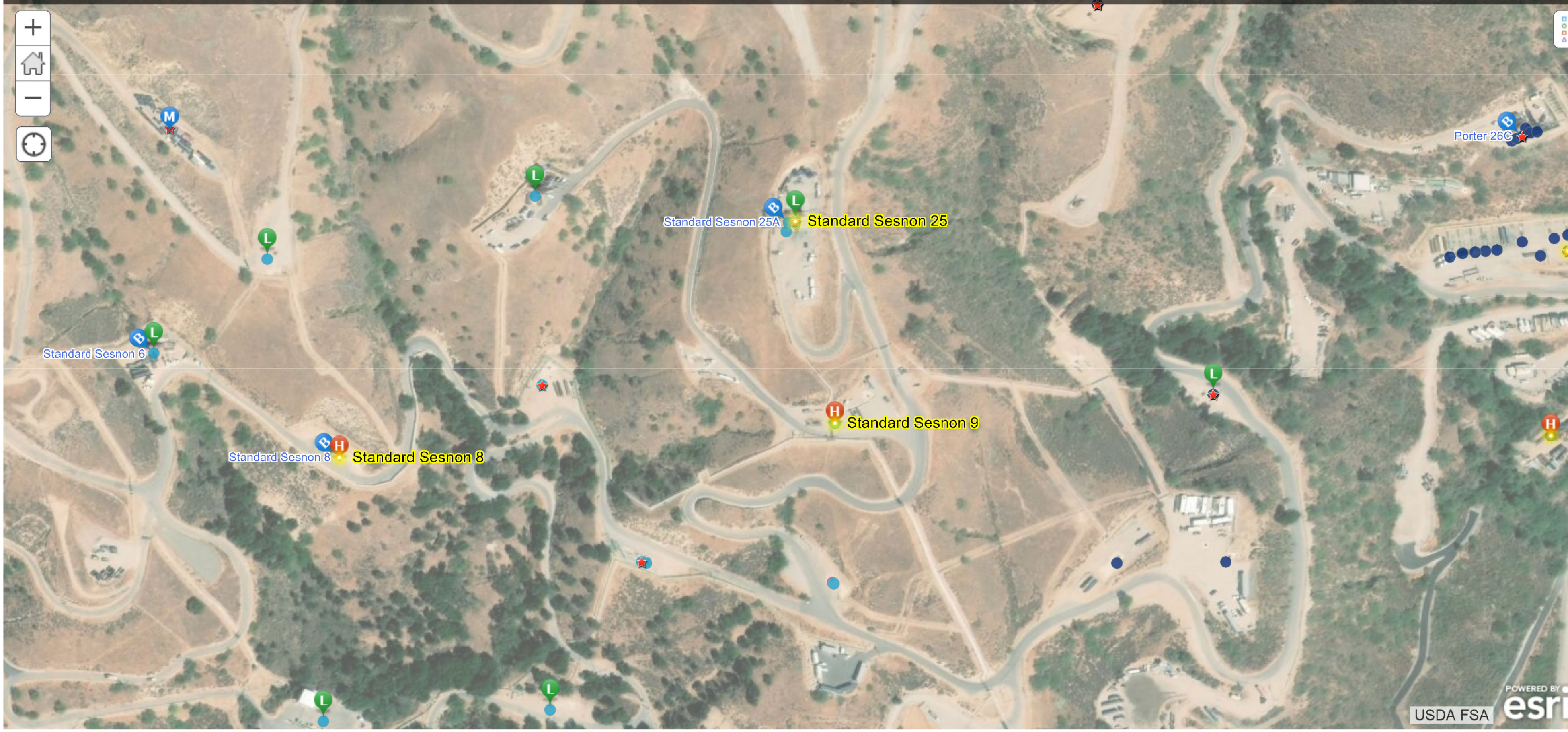
Casing Leaks Per Blade Report

1988 Wells, 2014 Testimony, Casing Leak Wells



Slide 12 of 14

1988 Wells, 2014 Testimony, Casing Leak Wells -2

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1988 Wells, 2014 Testimony, Casing Leak Wells - 3

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SS-25 RCA Supplementary Report

Aliso Canyon Surface Casing Evaluation

Purpose:

Report on the analysis and results of the evaluation of the surface casing condition for eight Aliso Canyon wells.

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Date:

May 31, 2019

Abstract

The gas storage well Standard Sesnon 25 (SS-25) in the Aliso Canyon Gas Storage Field located in Los Angeles County, California started leaking gas in October 2015. A relief well was drilled, and SS-25 was brought under control. The leak stopped in February 2016.

In January 2016, as part of their investigation of the leak, the California Public Utilities Commission (CPUC) and the Division of Oil, Gas, and Geothermal Resources (DOGGR) selected and gave provisional authority to Blade Energy Partners (Blade) to perform an independent Root Cause Analysis (RCA). The Blade Team and parties under Blade's direction were responsible for directing the work of subcontractors who performed the extraction of the SS-25's wellhead, tubing, and casings and the preservation and protection of associated evidence. Blade's RCA Reports, including this report, document and describe the key activities undertaken in support of the RCA effort.

Blade evaluated the condition of the surface casing in several Aliso Canyon wells for comparison with the surface casing in SS-25. We found significant corrosion in the SS-25 surface casing based on casing evaluation logs run as part of the RCA. The number of wells with surface casing information is limited because inspection logs are run only in some wells on an as-needed basis during the plug and abandonment (P&A) phase of a well's life. Surface casing inspection logs were available on four other wells in addition to SS-25: Frew 3 (F-3), Frew 9 (F-9), Sesnon Fee 2 (SF-2), and Standard Sesnon 7 (SS-7).

Caliper logs and daily report information for three additional wells (Porter 30 [P-30], Standard Sesnon 17 [SS-17], and Standard Sesnon 44A [SS-44A]) indicated possible problems with the surface casings. All eight wells evaluated were P&A'd between 2013 and 2018.

Internal and external corrosion was indicated on logs from the four wells (F-3, F-9, SF-2, and SS-7), albeit not as bad as the corrosion in SS-25. One of the other three wells (SS-17) reported a split in the top joint of the 13 3/8 in. casing, and another well (SS-44A) reported wellbore fluid flowing from a fissure in the ground while P&A operations were ongoing. The third of the three wells (P-30) had a caliper log that showed an anomaly at 22.5 ft. The daily reports for P-30 when the caliper log was run were not available; therefore, the information is limited to the caliper log.

SS-25 has the poorest surface casing condition and cement integrity based on the casing evaluation logs of the wells evaluated. A likely reason for the poor casing condition is the poor cement job, which allows the casing to be exposed to alternating ground water and air in the vadose zone depending on the seasonal rainfall. Another difference is the SS-25's surface casing grade is H40 whereas the casing grade for the other wells is J55.

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1 Introduction

The purpose of this evaluation was to review and analyze the condition of the surface casing of the Aliso Canyon wells. We found significant corrosion in the SS-25 surface casing based on casing evaluation logs run as part of the RCA. The number of wells with surface casing information is limited because inspection logs are only run in some wells on an as-needed basis during the P&A phase of a well's life. UltraSonic Imaging Tool (USIT) logs are available on four of the eight wells. SS-25 surface casing inspection logs include a High-Resolution Vertilog (HRVRT) and an Isolation Scanner Corrosion (IBC) log.

We identified caliper logs and daily report information for three other wells indicating possible problems with the surface casing. The eight wells evaluated (including SS-25) were P&A'd between 2013 and 2018. The spud dates for the wells ranged from 1944 to 1974.

Casing depths are reported as measured depth (MD) unless stated otherwise, and log depths are reported as wireline measurement (WLM) in this document. Each well has a permanent datum for zero depth, usually the original rig floor. The difference in MD and WLM is normally small (a few feet) and can be ignored for the discussion of the topics in this report.

1.1 Abbreviations and Acronyms

Term	Definition
BBL	Barrel
CBL-VDL	Cement Bond Log-Variable Density Log
CPUC	California Public Utilities Commission
Cmt	Cement
DOGGR	Division of Oil, Gas, and Geothermal Resources
F	Frew
HRVRT	High-Resolution Vertilog
IBC	Isolation Scanner Corrosion
ID	Inside Diameter
MD	Measured Depth
MU	Make Up
OD	Outside Diameter
P	Porter
PPF	Pounds Mass per Foot
P&A	Plug and Abandon
RCA	Root Cause Analysis
RIH	Run In Hole
SoCalGas	Southern California Gas Company
SF	Sesnon Fee
SS	Standard Sesnon
STC	Short Thread Casing

Term	Definition
sx	Sacks of cement
T&C	Threaded and Coupled
USIT	UltraSonic Imager Tool
WLM	Wireline Measurement

2 Wells with Surface Casing Inspection Logs

When Aliso Canyon wells are P&A'd, a common practice is to cut the production casing above the surface casing shoe and recover the production casing. The surface casing is then exposed to the wellbore. A casing inspection log is run in the surface casing in some wells before setting cement plugs to the surface. Blade presumes that the reason for running the log is to ensure compliance with regulatory requirements related to the protection of fresh water and cement quality behind the surface casing.

Figure 1 shows a map of the Aliso Canyon Field with wells flagged that have surface casing inspection logs. The wells identified are located in the western part of the field.

Table 1 shows the list of wells, a summary of surface casing inspection log results, and paraphrased notes related to the wells. SoCalGas ran USIT logs in the first four wells (F-3, F-9, SF-2, and SS-7) and HRVRT and IBC logs in SS-25 at the request of Blade. This report includes a summary of the inspection log results and additional details about each well.

Three different casing sizes were used as surface casing among the compared wells: 13 3/8 in., 11 3/4 in., and 10 3/4 in. outside diameter (OD). We found indications of internal and external corrosion on the USIT logs for the four wells with 13 3/8 in. and 10 3/4 in. surface casing. The log for F-3 showed anomalies at approximately 350 ft and 550 ft. SoCalGas attempted to run a cement retainer as part of the P&A in August 2013. The run was aborted after the tool stopped at 550 ft, and the retainer was pulled and laid down. Appendix A includes sections of the logs.

The SS-25 11 3/4 in. surface casing had numerous holes between 134 ft and 300 ft and external corrosion. The condition of the SS-25 surface casing appears to be the poorest of the wells we reviewed. It should be noted that we evaluated SS-25 in great detail because of the well failure and the RCA. Also, we used different casing evaluation tools in SS-25, namely, a camera run and HRVRT and IBC logs. The HRVRT is a magnetic flux leakage tool used to identify defects in the casing and determine if the wall loss is internal or external. The IBC is an ultrasonic tool similar to the USIT log, but more sophisticated. The camera run provided direct evidence showing multiple holes in the SS-25 surface casing.

The definitive reason for more severe corrosion in SS-25 is not clear. The wall thicknesses for 13 3/8 in. 54.5 ppf, 11 3/4 in. 42 ppf, and 10 3/4 in. 40.5 ppf casing are similar, at 0.380 in., 0.333 in., and 0.350 in., respectively. A possible reason for the more severe corrosion is a poor surface casing cement job in SS-25, as discussed in Section 4. It is noted that the SS-25's 11 3/4 in. casing grade is H40 whereas the casing grade used in the other wells was J55.

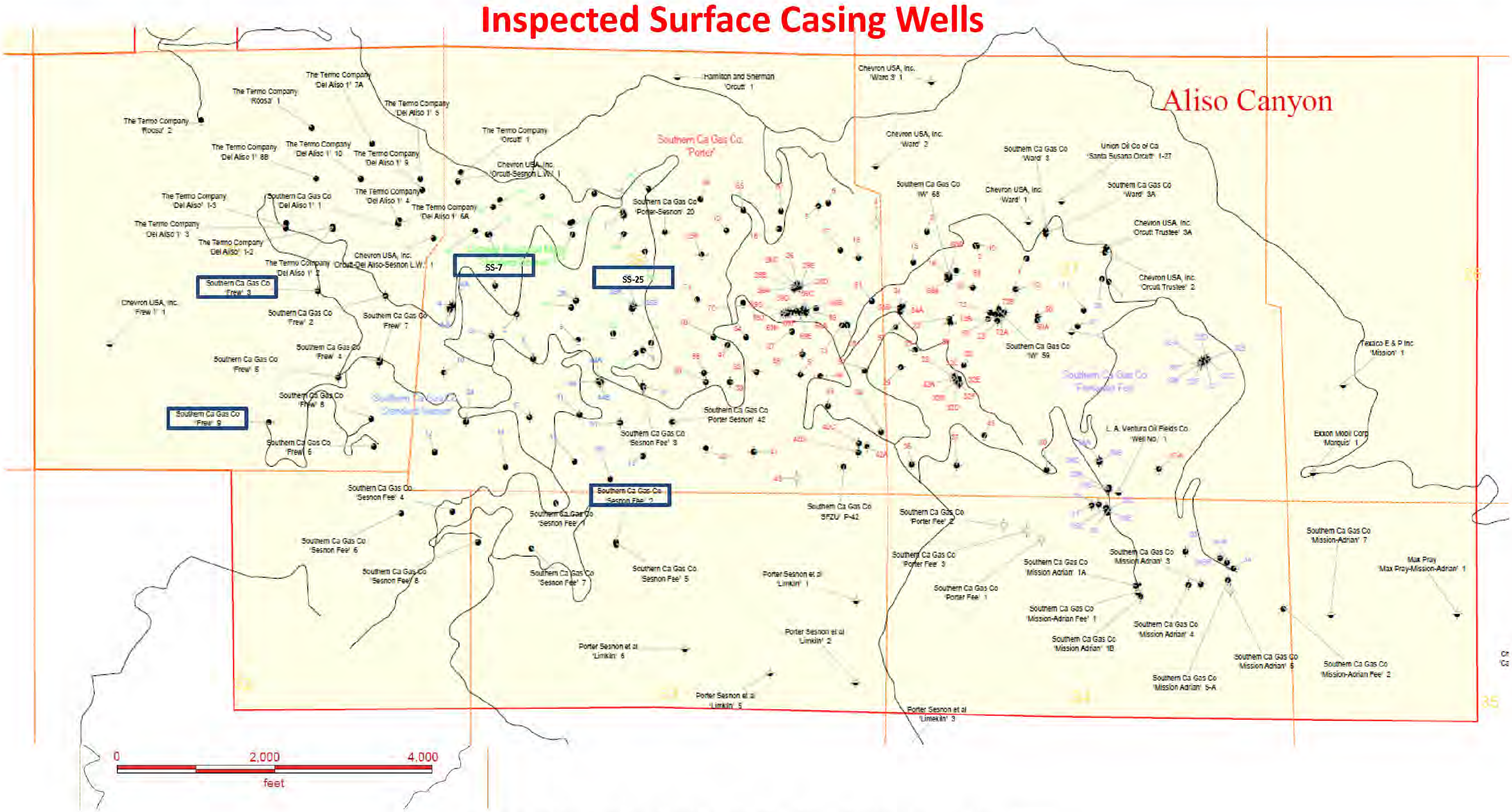

Figure 1: Map of the Wells with Surface Casing Inspection Logs

Table 1: List of Wells and a Summary of Surface Casing Inspection Log Results

Lease	Well	Spud Date	Surface Casing OD (in.)	Grade	Wall Thickness (in.)	Surface Casing Depth (ft)	Inspection Log	Inspection Log Date	Log Summary	Notes	Current Status
Frew	3	September 21, 1944	13.375	J55	0.380	1,005	USIT	August 15, 2013	Log anomalies at approximately 350 ft and 550 ft	A cement retainer stopped at 555 ft and was pulled out	P&A 2013
Frew	9	July 26, 1963	10.750	J55	0.350	1,500	USIT	May 12, 2015	Indications of internal and external corrosion	N/A	P&A 2015
Sesnon Fee	2	April 21, 1953	13.375	J55	0.380 0.430	1,594	USIT	December 13, 2017	Indications of internal and external corrosion	61 ppf casing, the second joint and 570–1,594 ft	P&A 2018
Standard Sesnon	7	October 14, 1945	13.375	J55	0.380	1,095	USIT	May 27, 2014	Indications of external corrosion	Processing flags indicating possible aerated fluid near surface Log data may be questionable	P&A 2014

Lease	Well	Spud Date	Surface Casing OD (in.)	Grade	Wall Thickness (in.)	Surface Casing Depth (ft)	Inspection Log	Inspection Log Date	Log Summary	Notes	Current Status
Standard Sesnon	25	October 01, 1953	11.750	H40	0.333	990	Two camera runs	November 07, 2017 August 18, 2018	Camera showed numerous holes in the 11 3/4 in. casing	A mechanical caliper log confirmed holes in the casing	P&A 2018
							HRVRT	August 12, 2018	External corrosion and holes 134–300 ft Some internal corrosion 700–950 ft		
							IBC	August 14, 2018	IBC confirms external corrosion 200–540 ft, 625–660 ft, 700–825 ft, and 865–990 ft internal corrosion 200–990 ft	The IBC log starts at 200 ft due to the low fluid level	

3 Wells Without Surface Casing Inspection Logs

We identified three wells with indications of problems with the surface casing (Table 2). They do not have casing inspection logs other than a caliper log that measures the inside diameter (ID) of the casing. The Notes in Table 2 were paraphrased from various well reports to summarize the well operations that are relevant to the surface casing evaluation.

P-30 has a 56-arm caliper log that shows an anomaly at 22.5 ft. The daily reports for P-30 are not available; therefore, the background and operations details are unknown. The caliper log is included in Appendix A.

The SS-17 P&A reports indicate a leak in the 13 3/8 in. casing detected during the P&A. The SoCalGas daily report for June 28, 2017 [1] includes the following statement:

> MU 13 3/8 Baker fullbore packer RIH to isolate hole in 13 3/8 casing, 13 3/8 tested good from 45' to 838', 45' to surface would not test, split top jt in 13 3/8 casing.

A bridge plug was set at 112 ft, and a cement plug was set from 112 ft to surface. The P&A was completed in 2017.

SS-44A was in the process of being P&A'd when a fissure opened at surface with wellbore fluid flowing from it. The 8 5/8 in. casing was pulled and milled out to 405 ft. After the casing was milled from 400 to 405 ft, the following comment was included in the August 2, 2017, SoCalGas daily report [2]:

> Noticed that a fissure opened with polymer circulating fluid flowing from it. Amount flowed on ground less than 1/4 of a bbl.

SoCalGas ran a Schlumberger four-arm caliper log from 500 ft to surface. Work was suspended on August 4, 2017. The SS-44A caliper log showed a change in ID at 90 ft and 225 ft. The caliper was run after cutting the 8 5/8 in. casing a number of times between 17 ft and 830 ft and extensive milling to remove the 8 5/8 in. casing from 80 to 82 ft, 211 to 375 ft, and 400 to 405 ft. The indications on the log could have been caused by the casing cutting and milling operations. The well was successfully P&A'd in 2018. Appendix A includes the caliper log.

Table 2: List of Wells with Surface Casing Indications Based on Operations Records and/or Caliper Logs

Lease	Well	Spud Date	Surface Casing OD (in.)	Wall Thick. (in.)	Surface Casing Depth (ft)	Notes	Current Status
Porter	30	May 12, 1945	13.375	0.380	565	A 56-arm caliper showed an anomaly at 22.5 ft. The daily reports related to this work are not available on the DOGGR website as of February 11, 2019.	P&A 2018
Standard Sesnon	17	March 05, 1952	13.375	0.380	1,010	Indication of a leak in the 13 3/8 in. surface casing during the P&A. The daily report for June 28, 2017, includes the following statement: MU 13 3/8 Baker fullbore packer RIH to isolate hole in 13 3/8 casing, 13 3/8 tested good from 45' to 838', 45' to surface would not test, split top jt in 13 3/8 casing. A bridge plug was set at 112 ft and a cement plug was set from 112 ft to surface.	P&A 2017
Standard Sesnon	44A	September 03, 1974	13.375	0.380	854	Indication of a leak in the 13 3/8 in. surface casing during the P&A. A caliper log showed a change in ID at 90 ft and 225 ft. The caliper log was run after cutting the 8 5/8 in. casing a number of times between 17 ft and 830 ft and extensive milling to remove the 8 5/8 in. casing at 80–82 ft, 211–375 ft, and 400–405 ft. The 8 5/8 in. production casing was pulled and milled out to 405 ft. While milling the casing from 400–405 ft, the daily report includes the following statement. Noticed that a fissure opened with polymer circulating fluid flowing from it. Amount flowed on ground less than 1/4 of a bbl. Ran a Schlumberger four-arm caliper log. Work was suspended on August 4, 2017 [2].	P&A 2018

4 Summary of Surface Casing Cement Jobs

Table 3 is a summary of the surface casing cement jobs for the wells evaluated. The data in Table 3 are paraphrased from various reports and cement evaluation logs. The details for each well include the surface casing description, setting depth, a summary of the cement job for each well, and a summary of the cement evaluation. The cement evaluation was a visual, subjective analysis from available USIT and cement bond logs (CBL). Appendix A includes selected sections of the logs for reference.

Most of the wells have poor cement in the upper part of the well according to the logs. This is not unexpected because in this mountainous terrain it is common to lose circulation while drilling the surface casing hole section. Four of the eight wells reported cement to surface. However, reported cement to surface does not ensure that all of the drilling fluid in the annulus was displaced, as indicated by the cement evaluation logs showing poor cement near surface.

The main observation regarding the cement jobs and condition is that the cement job for the SS-25 11 3/4 in. surface casing appears to be the worst one when we compare it to the other wells' cement jobs. There are only two short sections of fair cement, 54 ft from 606 to 660 ft and 35 ft from 950 to 985 ft, whereas the other wells have longer sections of fair to good cement.

Table 3: Summary of Surface Casing Cement Jobs

Lease	Well	Surface Casing Description	Setting Depth (ft)	Casing Set Date	Cement Job Comments	Cement to Surface	Cement Evaluation
Frew	3	13 3/8 in. 54.5 ppf J55 8 round	1,005	October 4, 1944	400 sx construction cmt Good circulation	Not reported Top job at 80 ft	Poor cement Surface–200 ft Fair cement 200–350 ft Poor cement 350–450 ft Fair cement 450–1,005 ft
Frew	9	10 3/4 in. 40.5 ppf J55 STC	1,500	July 30, 1963	1,200 sx Class A	Not reported	Poor cement Surface–400 ft Good cement 400–1,500 ft
Sesnon Fee	2	13 3/8 in. 54.5 ppf J55 from surface to 570 ft except the second joint 13 3/8 in. 61 ppf J55 for the second joint and remainder	1,594	May 5, 1953	670 sx construction cmt, 27 sx gel, 1008 ft^3 Sealite + 100 sx construction cmt with $CaCl_2$	Yes, 250 ft^3	Poor cement Surface–350 ft Good cement 350–1,594 ft
Standard Sesnon	7	13 3/8 in. 54.5 ppf J55 T&C	1,095	November 10, 1945	675 sx construction cmt	No, lost circulation after 600 sx pumped	Fair cement Surface–150 ft Good cement 150–200 ft Fair cement 200–350 ft Good cement 350–550 ft Poor cement 550–610 ft Good cement 610–1,095 ft
Standard Sesnon	25	11 3/4 in. 42 ppf H40 Short Thread Casing (STC)	990	October 18, 1953	600 sx 1:1 Diamix + 100 sx neat cmt	No, lost circulation with 114 ft^3 of slurry to displace Top job #1 75 sx neat cmt Top job #2 60 sx neat cmt	Poor cement Surface–606 ft Fair cement 606–660 ft Poor cement 660–950 ft Fair cement 950–985 ft
Porter	30	13 3/8 in. 54.5 ppf J55 T&C	565	May 21, 1945	400 sx construction cmt	Yes	CBL or USIT not run

Lease	Well	Surface Casing Description	Setting Depth (ft)	Casing Set Date	Cement Job Comments	Cement to Surface	Cement Evaluation
Standard Sesnon	17	13 3/8 in. 54.5 ppf T&C	1,010	March 19, 1952	435 sx construction cmt	Yes	Poor cement Surface–150 ft Fair cement 150–375 ft Poor cement 375–480 ft Fair cement 480–1,010 ft
Standard Sesnon	44A	13 3/8 in. 54.5 ppf K55	830	September 6, 1974	185 sx Class G with 185 ft^3 Pozmix with 2% gel + 148 sx Class G with 2% $CaCl_2$	Yes	CBL or USIT not run

5 Discussion

Although it is not clear what caused the severe corrosion and reduced wall thickness of the SS-25 surface casing, we discuss in this section some possible contributing factors.

The SS-25 well site is located in the mountains, and the surface slopes downward on three sides of the well site: east, south, and west. An undersaturated or vadose zone is present from the surface to the ground water table. The vadose depth in SS-25 was logged at 305 ft according to the formation log data [3]. This depth was confirmed in SS-25 during the casing extraction and P&A operations by shooting the fluid level many times.

A possible cause of the SS-25 11 3/4 in. casing corrosion includes exposure to fluctuating levels of ground water. The poor cement job allowed the casing to be exposed to alternating cycles of water and air (oxygen) in the vadose zone because of the seasonal changes in the water level. Groundwater was confirmed at 382 ft in Test Hole #1 located at well site SS-9. Test Hole #1 is approximately 630 ft south-south-east of SS-25 and 85 ft lower in surface elevation [4]. The presence, source, and properties of groundwater in Aliso Canyon are the subjects of a separate Blade report *Aliso Canyon Field: Hydrology* [5].

The SS-25's 11 3/4 in. surface casing is grade H40 compared to the casing grade J55 in the other four wells (F-3, F-9, SF-2, and SS-7) with casing inspection logs. The 11 3/4 in. casing has the thinnest wall, 0.333 in., compared to wall thicknesses of 0.380 in. and 0.350 in. for the 13 3/8 in. and 10 3/4 in. casing, respectively, in the other wells.

6 Conclusions

The main conclusions from the evaluation are the following:

- The casing inspection logs in the four wells with casing inspection logs and SS-25 indicated internal and external corrosion. The SS-25 surface casing had holes from 134 to 300 ft, as confirmed by a camera run.
- The reasons for the apparent more severe corrosion of the SS-25 11 3/4 in. surface casing are not definitive from this analysis. The wall thickness for 13 3/8 in. 54.5 ppf, 11 3/4 in. 42 ppf, and 10 3/4 in. 40.5 ppf casing are similar at 0.380 in., 0.333 in., and 0.350 in., respectively. SS-25 had grade H40 surface casing compared to J55 casing used in the other four wells (F-3, F-9, SF-2, and SS-7). The spud dates of the five wells with casing inspection logs evaluated ranged from 1944 to 1963.
- The IBC log indicated the cement job on the SS-25's surface casing was the poorest of the wells evaluated. Only two short intervals in SS-25 had fair cement: 35 ft near the shoe and 54 ft from 606 to 660 ft. Other wells had longer sections of fair to good cement. Poor cement was common in the upper section of the wells.
- The contributing factors to the corrosion of the SS-25's surface casing include extensive intervals of poor cement providing no protection to fluctuating levels of ground water. The fluctuating water levels exposed the surface casing OD to alternating cycles of ground water and air in the vadose zone from approximately 300 ft to surface in SS-25.

7 References

[1] SoCalGas, "History of Oil or Gas Well, AC_BLD_0060628-AC_BLD_0060632 (SS-17 P&A 2017-04-21 AC_BLD_0060628.pdf, pages 1-5)".

[2] SoCalGas, "History of Oil or Gas Well, AC_BLD_0067777-AC_BLD_0067783 (SS-44A P&A Reports 2017-03-22.pdf, pages 1-7)".

[3] Schlumberger, "Log Review Southern California Gas Aliso Canyon Sesnon 25 (Schlumberger 2018-01-31_Log_Review_Socal_SS-25.pptx)".

[4] Geosyntec, "Subsurface Assessment Report, Investigative Order R-4-2016-0035 (T10000008175.pdf, pages 8-9)".

[5] Blade, "Aliso Canyon Field: Hydrology," 2019.

[6] DOGGR, "Division of Oil, Gas, and Geothermal Resources - Well Search," [Online]. Available: https://secure.conservation.ca.gov/WellSearch/. [Accessed 31 January 2019].

[7] Schlumberger, "SF-2 USIT 13_375 December 13, 2017 (SF-2 USIT 13_375 2017-12-13 AC_BLD_0067804.pdf)".

[8] Baker Hughes, "SS-25 HRVRT 11_75 August 14, 2018 (SCG_SS-25_11.75_HRVRT_Final_2018-08-14.pdf)".

[9] Schlumberger, "SS-25 IBC_Corrosion 13_375 August 15, 2018 (0403700776_SS25_IBC_Corrosion_15Aug18_corrected.Pdf)".

[10] Schlumberger, "SS-44A Caliper 13_375 August 3, 2017 (SS-44A SLB 4-Arm Caliper 13_375 AC_BLD_0067785.pdf)".

Appendix A Log Summary

Relevant and example sections of the inspection and CBL logs for the wells discussed in this report are included for reference. The logs are from SoCalGas and the DOGGR Well Search website [6] where public information on wells is available. Well logs not referenced in this document can be downloaded from the Well Search website.

A.1 Frew 3

F-3 has a 13 3/8 in. surface casing at 1,005 ft. Top cement job at 80 ft.

A.1.1 F-3 USIT Log August 15, 2013

Figure 2 is the USIT log header, and Figure 3 shows the log legend. The 13 3/8 in. casing weight is 54.5 ppf (not 64.5 ppf as the log header shows).

Figure 4 through Figure 8 show log sections and anomalies at approximately 350 ft and 550 ft. As part of the P&A operations, a cement retainer run stopped at 555 ft, indicating the presence of a parted or collapsed casing, and the cement retainer was pulled out and laid down.

Schlumberger

Company: **Southern California Gas Company**

Well: **Frew 3**
Field: **Aliso Canyon**
County: **Los Angeles** State: **California**

County: Los Angeles
Field: Aliso Canyon
Location: LAT: 34.313137
Well: Frew 3
Company: Southern California Gas Compa

UltraSonic Imaging Tool
Gamma Ray Tie-In

LOCATION

LAT: 34.313137
LONG: -118.574798

Elev.: K.B. 2473.00 ft
G.L. 2465.00 ft
D.F.

Permanent Datum: GROUND LEVEL — Elev.: 2465.00 ft
Log Measured From: GROUND LEVEL — 0.00 ft above Perm. Datum
Drilling Measured From: GROUND LEVEL

API Serial No.	Section	Township	Range
03700666	19	3N	16W

Logging Date		15-Aug-2013			
Run Number		THREE			
Depth Driller		890 ft			
Schlumberger Depth		887 ft			
Bottom Log Interval		887 ft			
Top Log Interval		15 ft			
Casing Fluid Type		BRINE			
Salinity					
Density		8.4 lbm/gal			
Fluid Level					
BIT/CASING/TUBING STRING					
Bit Size		16.000 in			
From					
To					
Casing/Tubing Size		13.375 in			
Weight		64.5 lbm/ft			
Grade		N/A			
From		0 ft			
To		890 ft			
Maximum Recorded Temperatures		81 degF			
Logger On Bottom	Time	15-Aug-2013	10:31		
Unit Number	Location	2363	BAKERSFIELD		
Recorded By		PCHYBOWSKI			
Witnessed By		MIKE VOLKMAR			

Figure 2: F-3 USIT Log Header

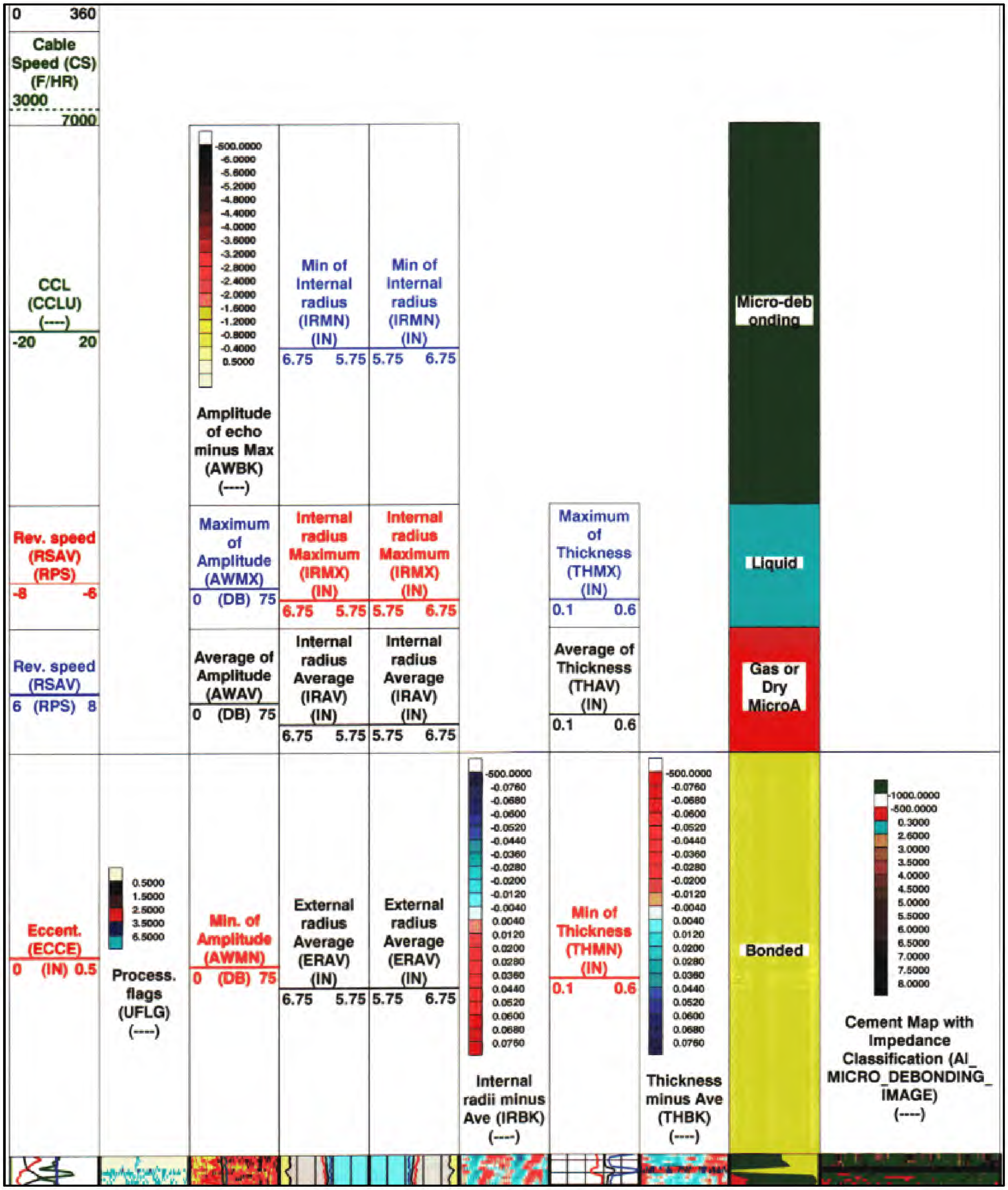

Figure 3: F-3 USIT Log Legend

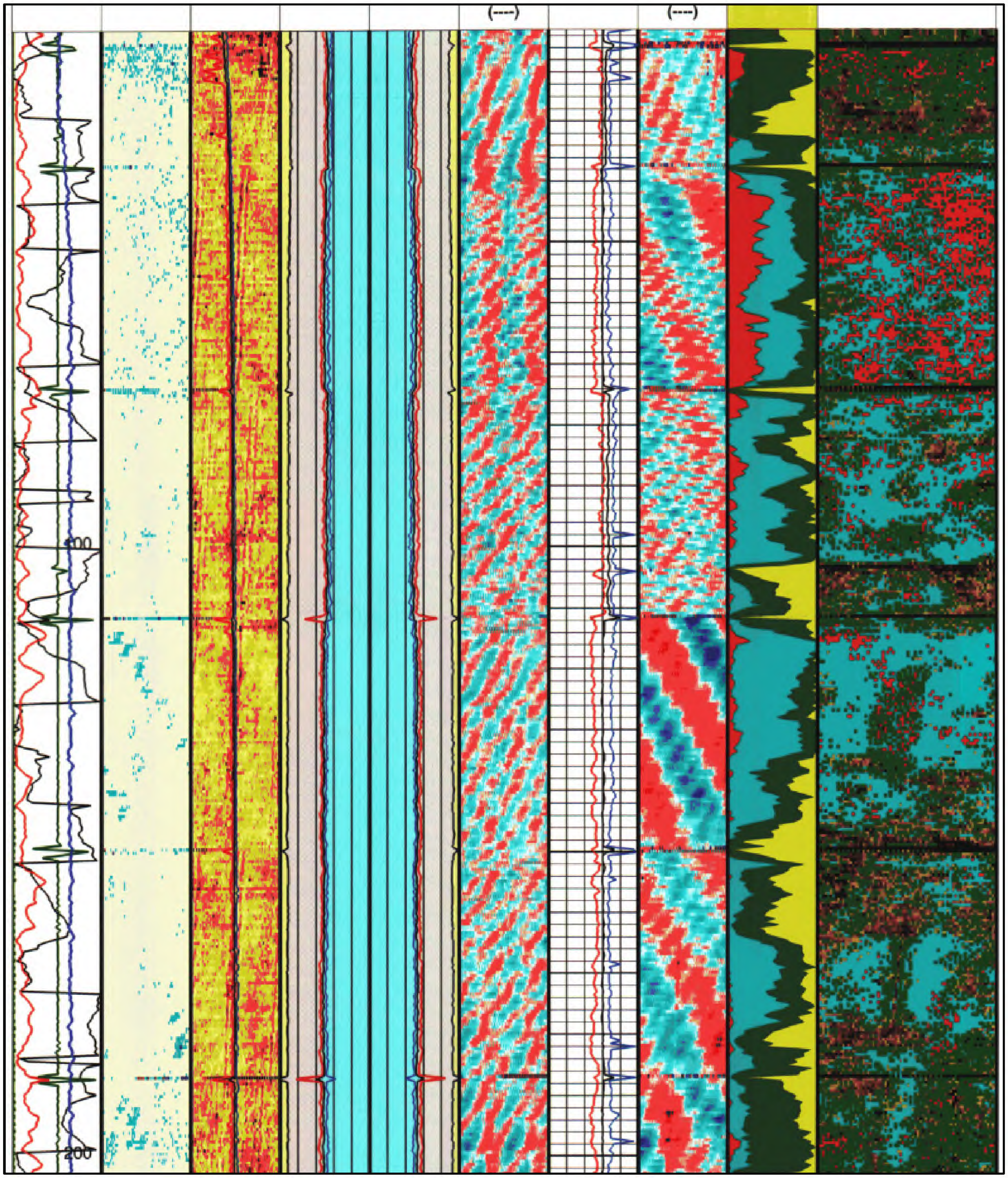

Figure 4: F-3 USIT Log Section

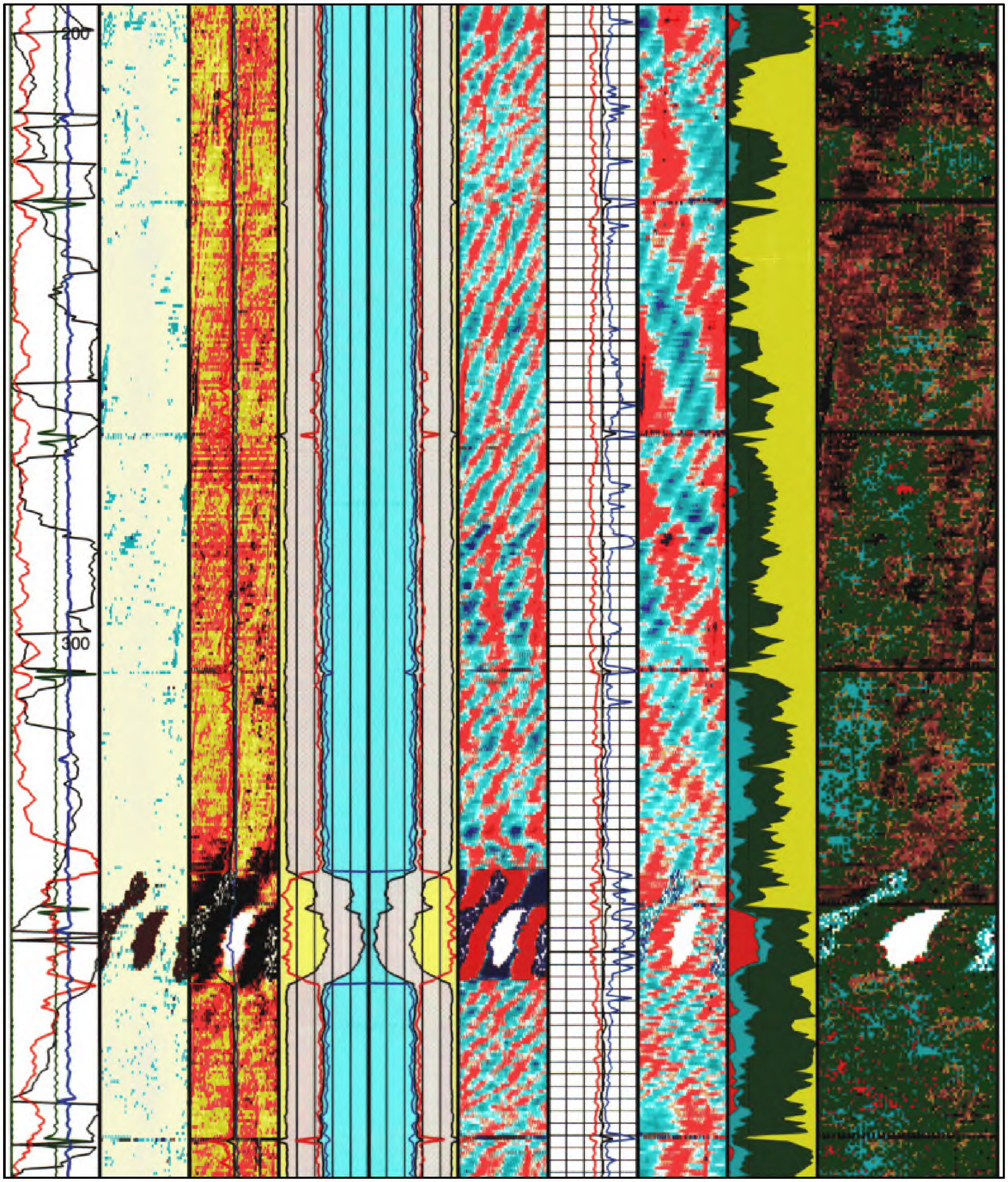

Figure 5: F-3 USIT Log Anomaly at Approximately 350 ft

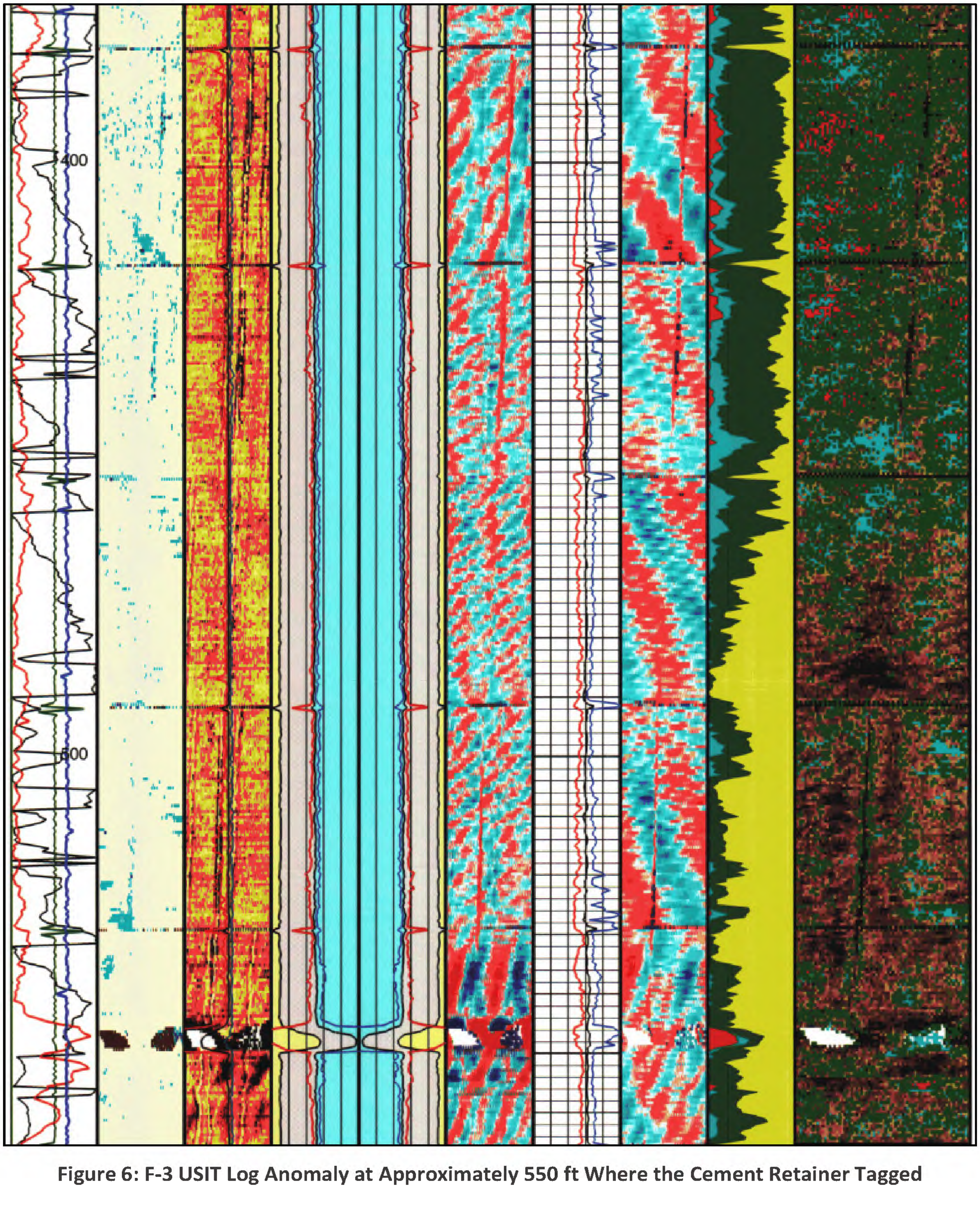

Figure 6: F-3 USIT Log Anomaly at Approximately 550 ft Where the Cement Retainer Tagged

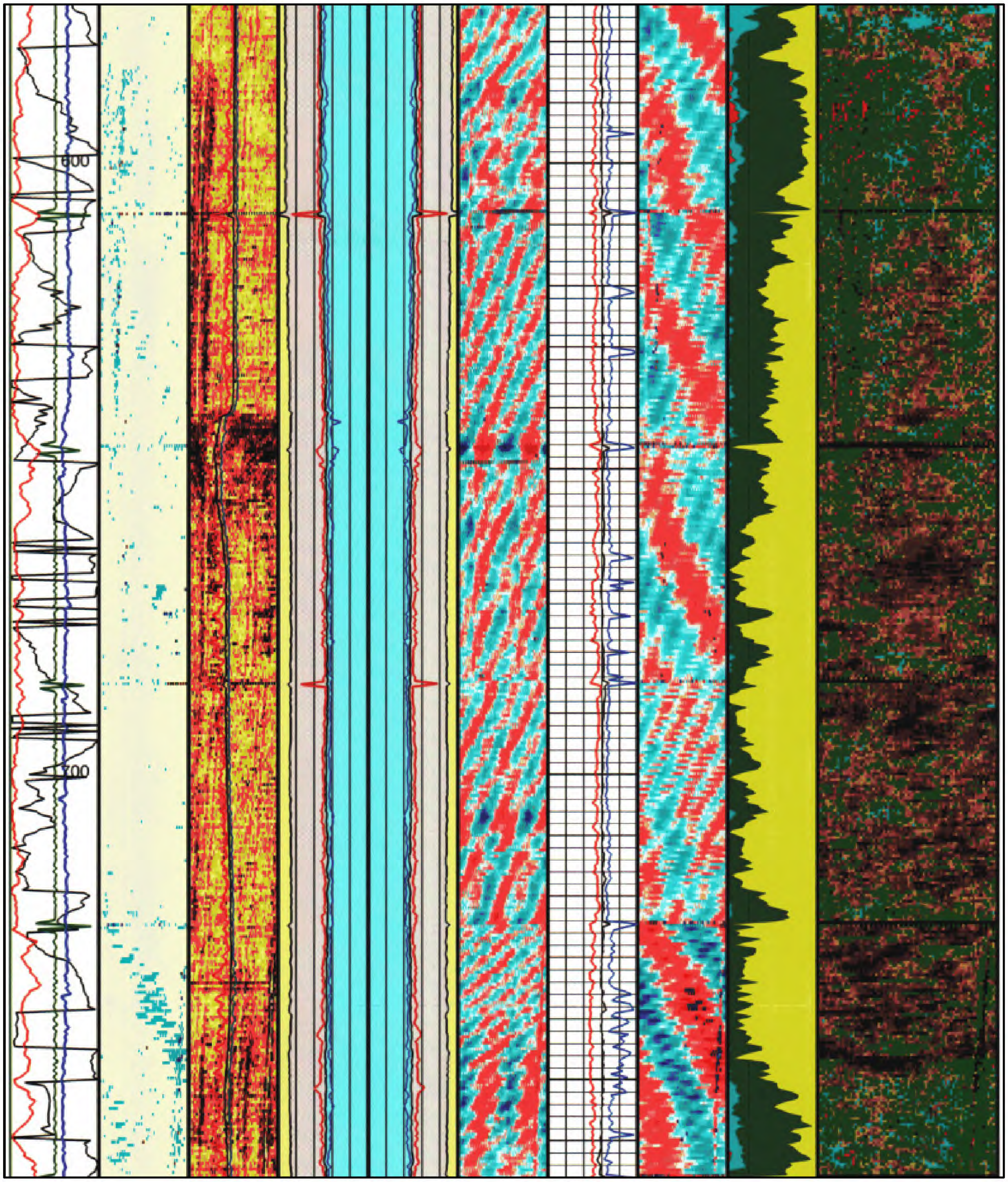

Figure 7: F-3 USIT Log Section

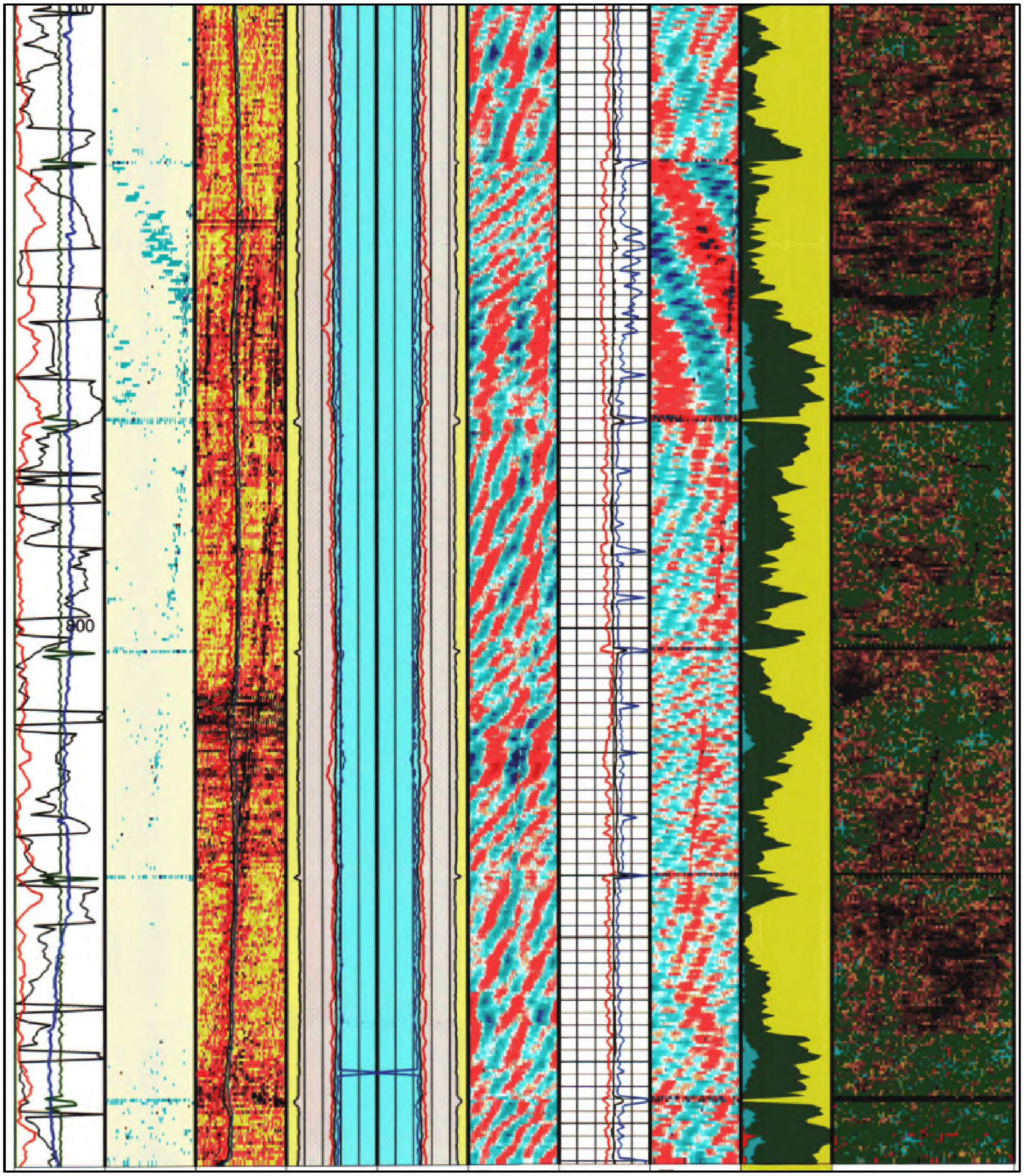

Figure 8: F-3 USIT Log Section

A.2 Frew 9

F-9 has a 10 3/4 in. surface casing at 1,500 ft. Cement to surface not reported.

A.2.1 F-9 USIT Log July 26, 1963

Figure 9 is the USIT log header, and Figure 10 shows the log legend. Figure 11 through Figure 18 show indications of internal and external corrosion.

Schlumberger

Company: Southern California Gas Company

Well: Frew 9

Field: Aliso Canyon

County: Los Angeles State: California

Ultrasonic Imaging Tool

Gamma Ray / CCL / Neutron

REVISED

SCANNED

County: Los Angeles
Field: Aliso Canyon
Location: From Rancho Corner SF 19
Well: Frew 9
Company: Southern California Gas Company

Location: From Rancho Corner SF 19
2262.46' S & 1756.44' W
Lat 34.310978 Long: -118.579439

Elev.:	K.B.	2098.00 ft	
	G.L.	2089.00 ft	
	D.F.		
Permanent Datum:	Ground Level	Elev.:	2089.00 f
Log Measured From:	Kelly Bushing	9.00 ft	above Perm.Datum
Drilling Measured From:	Kelly Bushing		

API Serial No.	Section:	Township:	Range:
037-00642 672	29	3N	16W

Logging Date	12-May-2015		
Run Number	Two		
Depth Driller	1488.00 ft		
Schlumberger Depth	1490.00 ft		
Bottom Log Interval	1490.00 ft		
Top Log Interval	50.00 ft		
Casing Fluid Type	3% KCL		
Salinity			
Density	8.6 lbm/gal		
Fluid Level	8.00 ft		
BIT/CASING/TUBING STRING			
Bit Size	9.63 in		
From	1500.00 ft		
To	8841.00 ft		
Casing/Tubing Size	7 in		
Weight	26 lbm/ft		
Grade	N/A		
From	7378.00 ft		
To	8841.00 ft		
Max Recorded Temperatures			
Logger on Bottom Time	12-May-2015	11:42:00	
Unit Number / Location:	2222	Long Beach	
Recorded By	Benjamin Kohner		
Witnessed By	Alan Fortenberry		

RECEIVED
JUN 0 2 2015
DIV. of OIL, Gas & Geothermal Resources Ventura

Figure 9: F-9 USIT Log Header

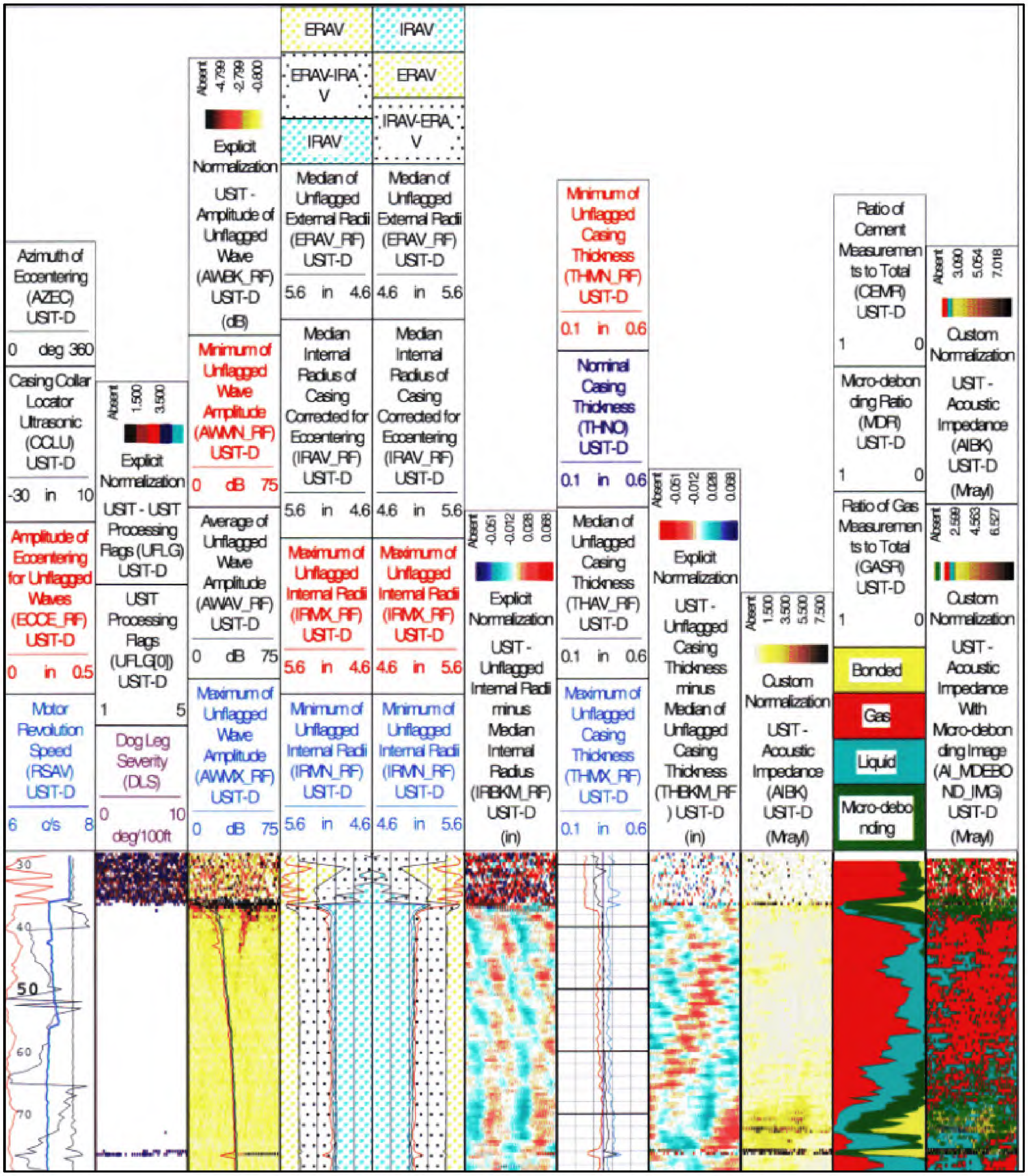

Figure 10: F-9 USIT Log Legend

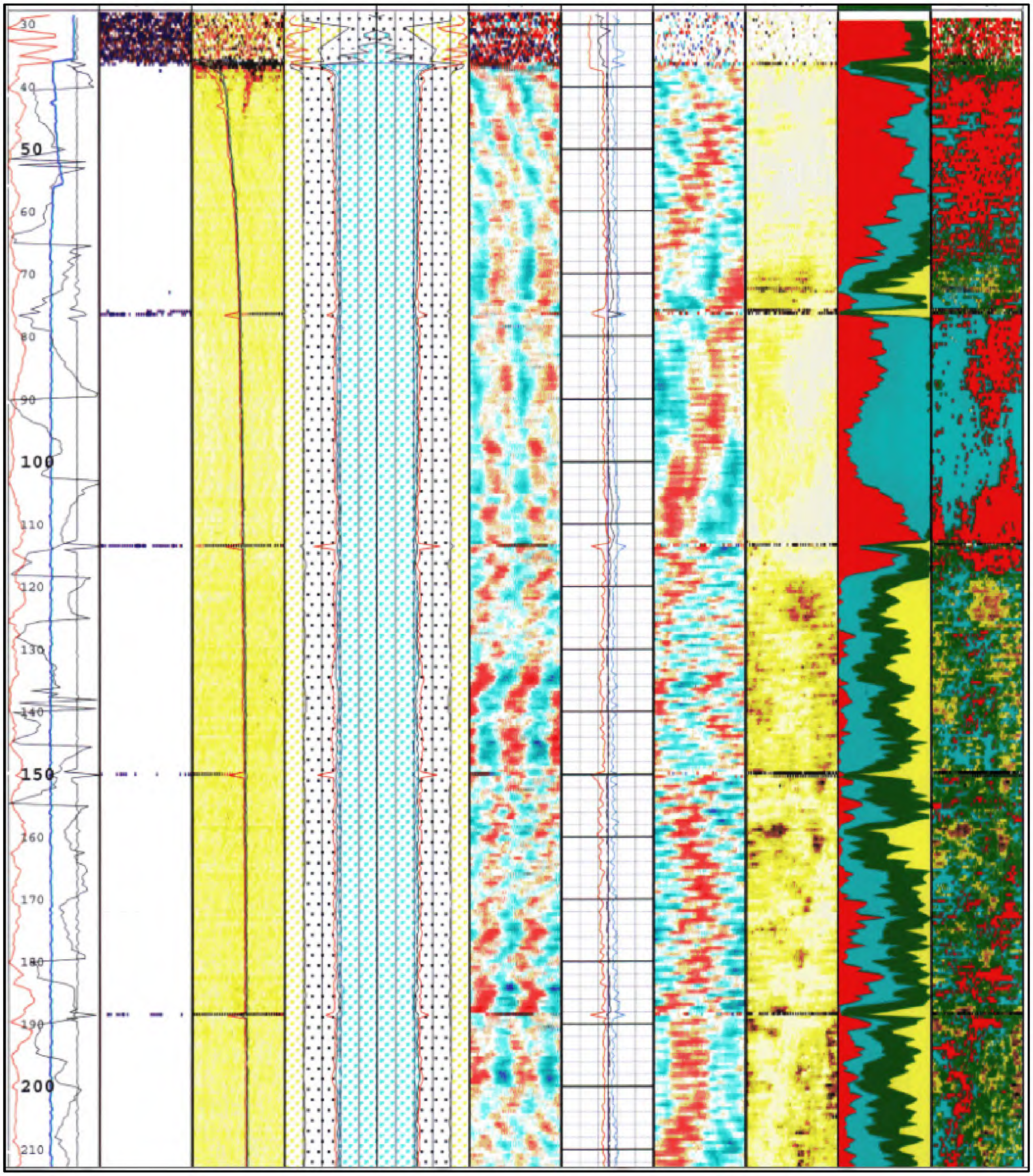

Figure 11: F-9 USIT Log Section

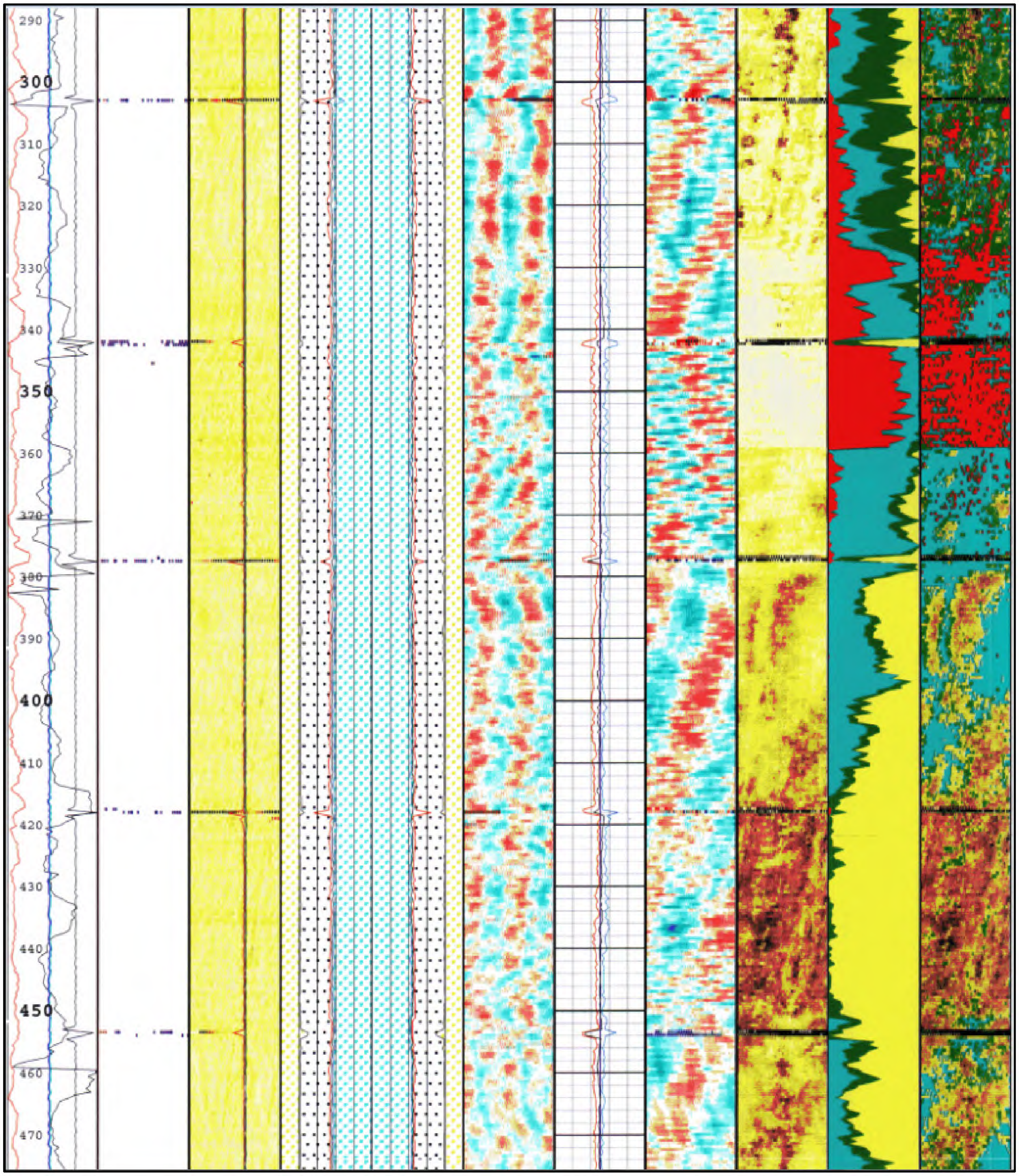

Figure 12: F-9 USIT Log Section

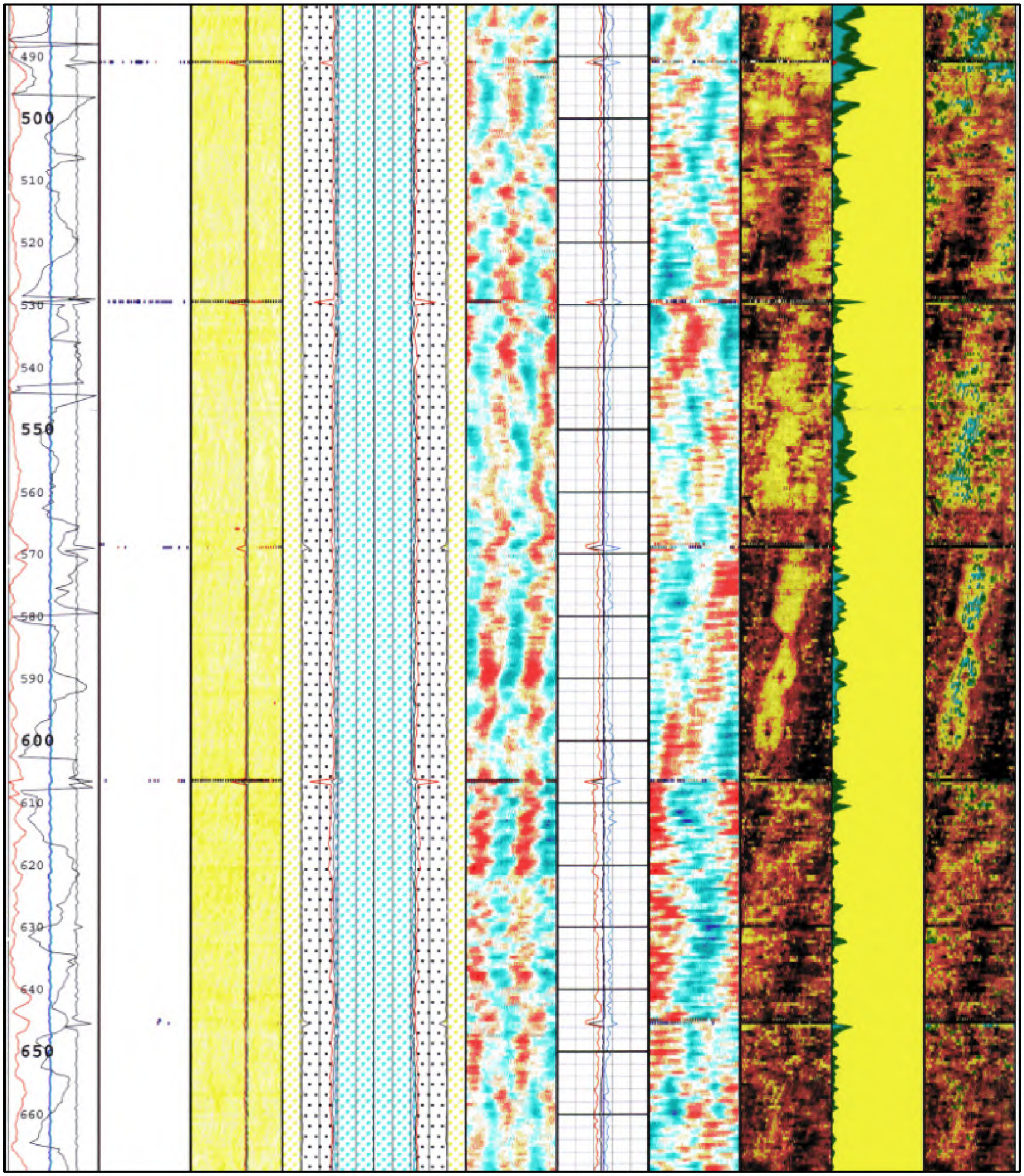

Figure 13: F-9 USIT Log Section

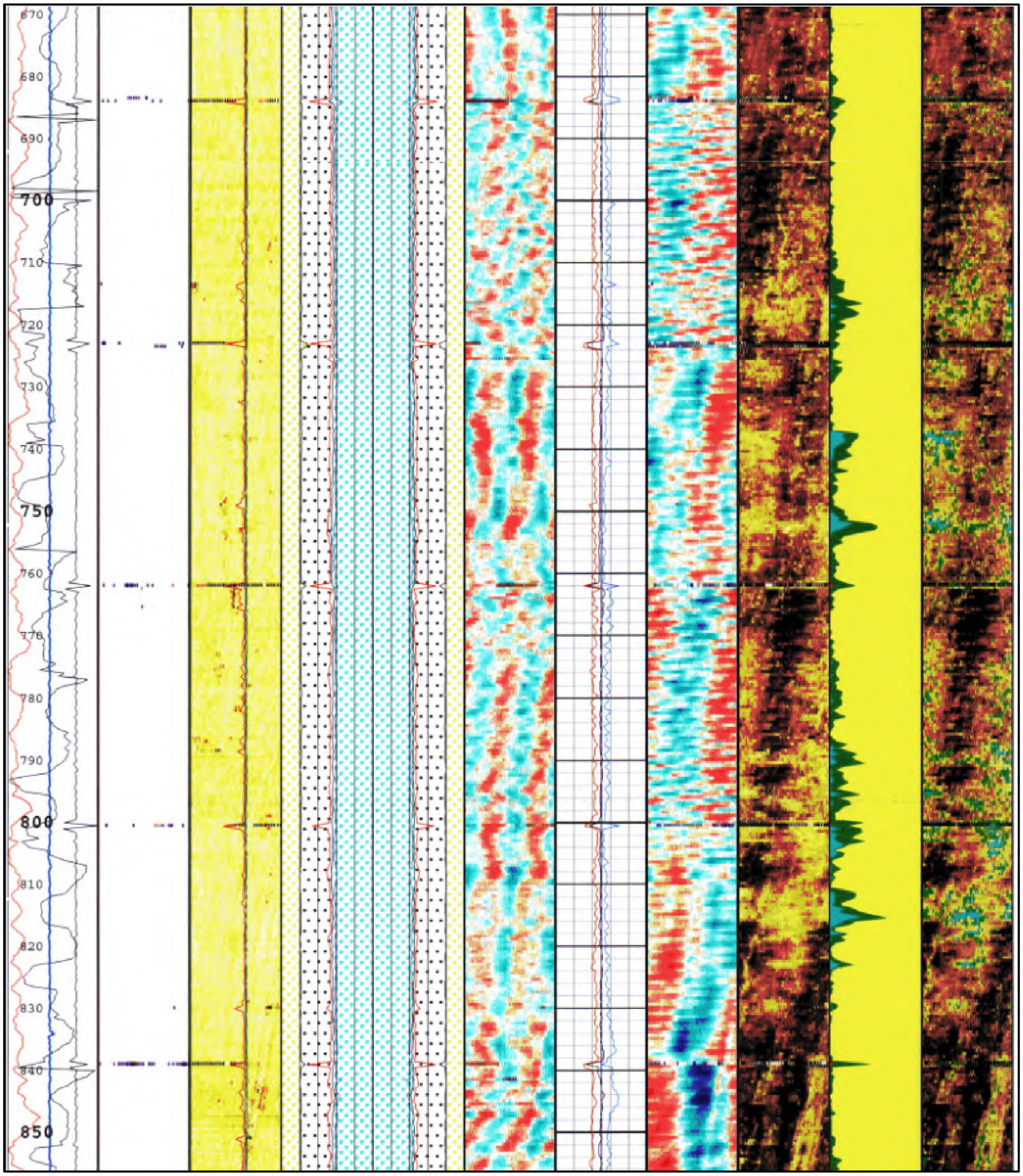

Figure 14: F-9 USIT Log Section

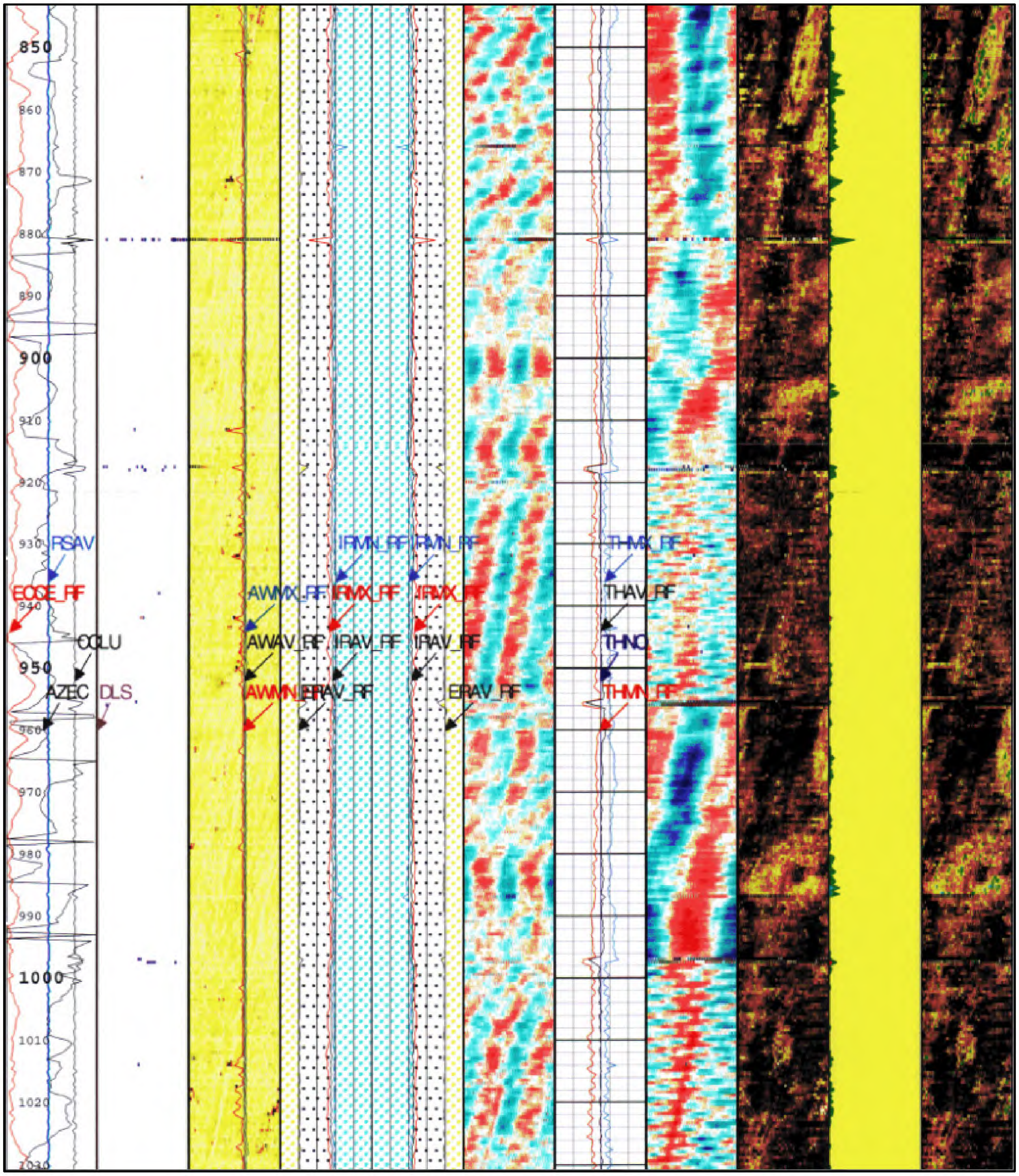

Figure 15: F-9 USIT Log Section

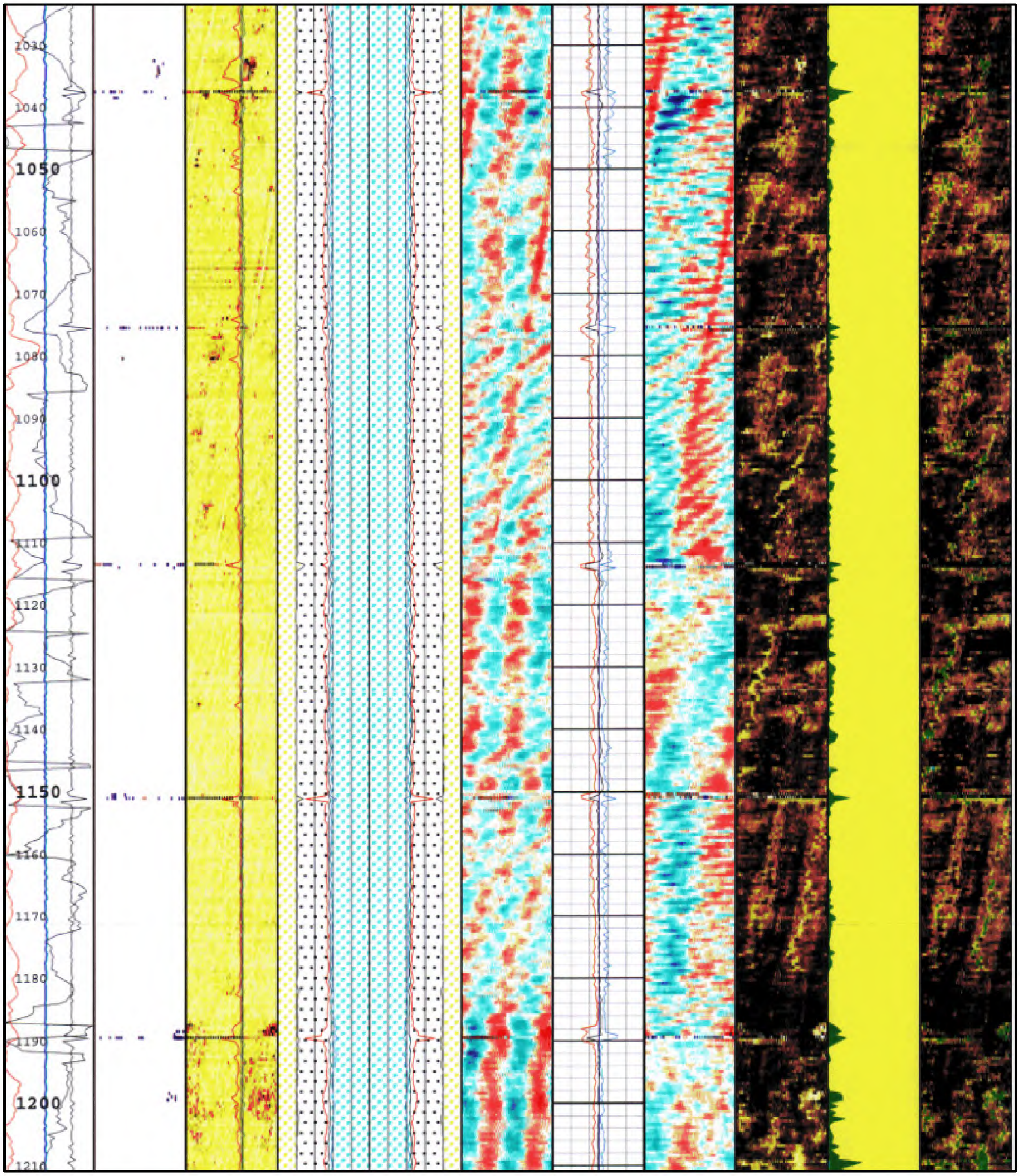

Figure 16: F-9 USIT Log Section

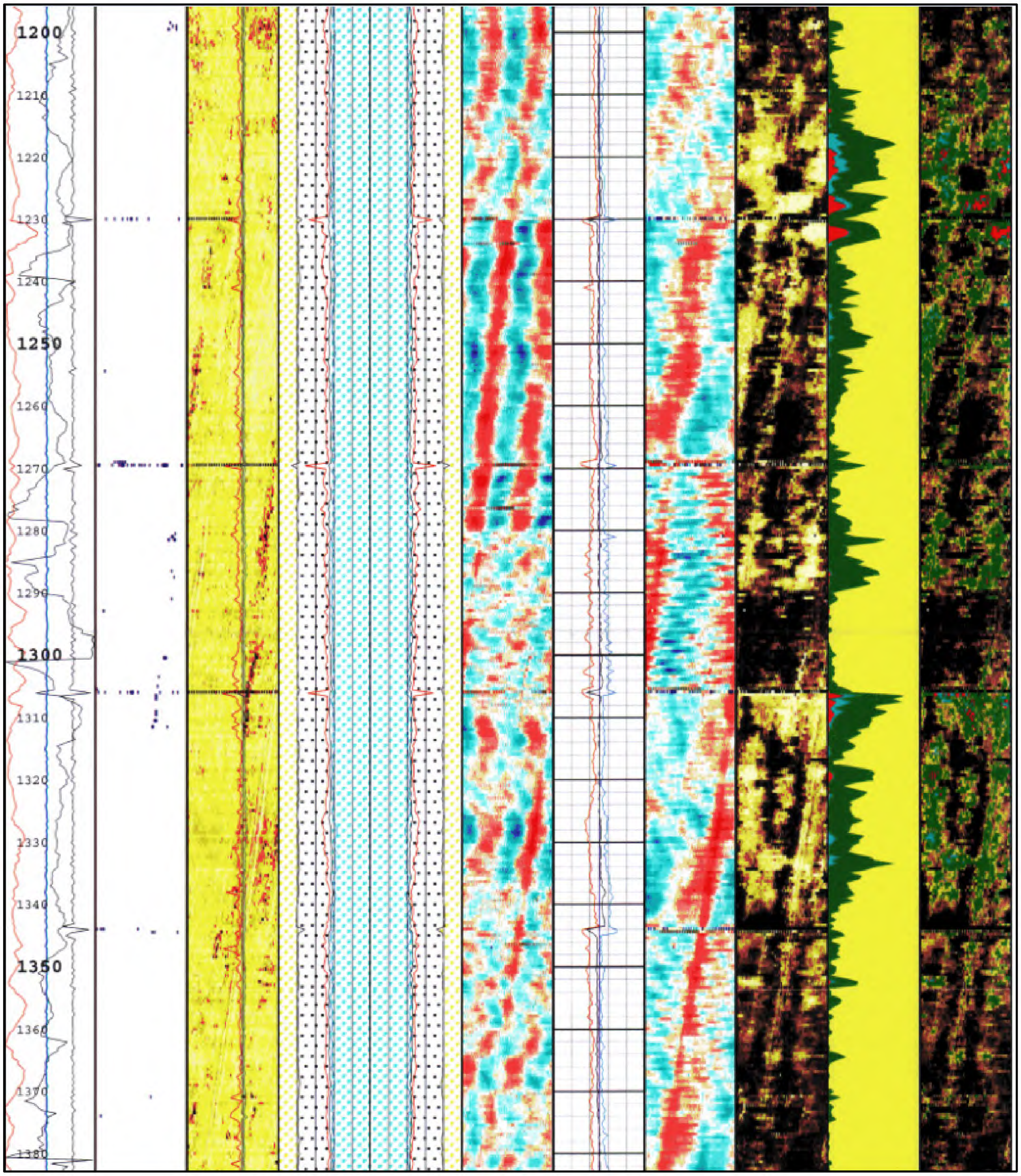

Figure 17: F-9 USIT Log Section

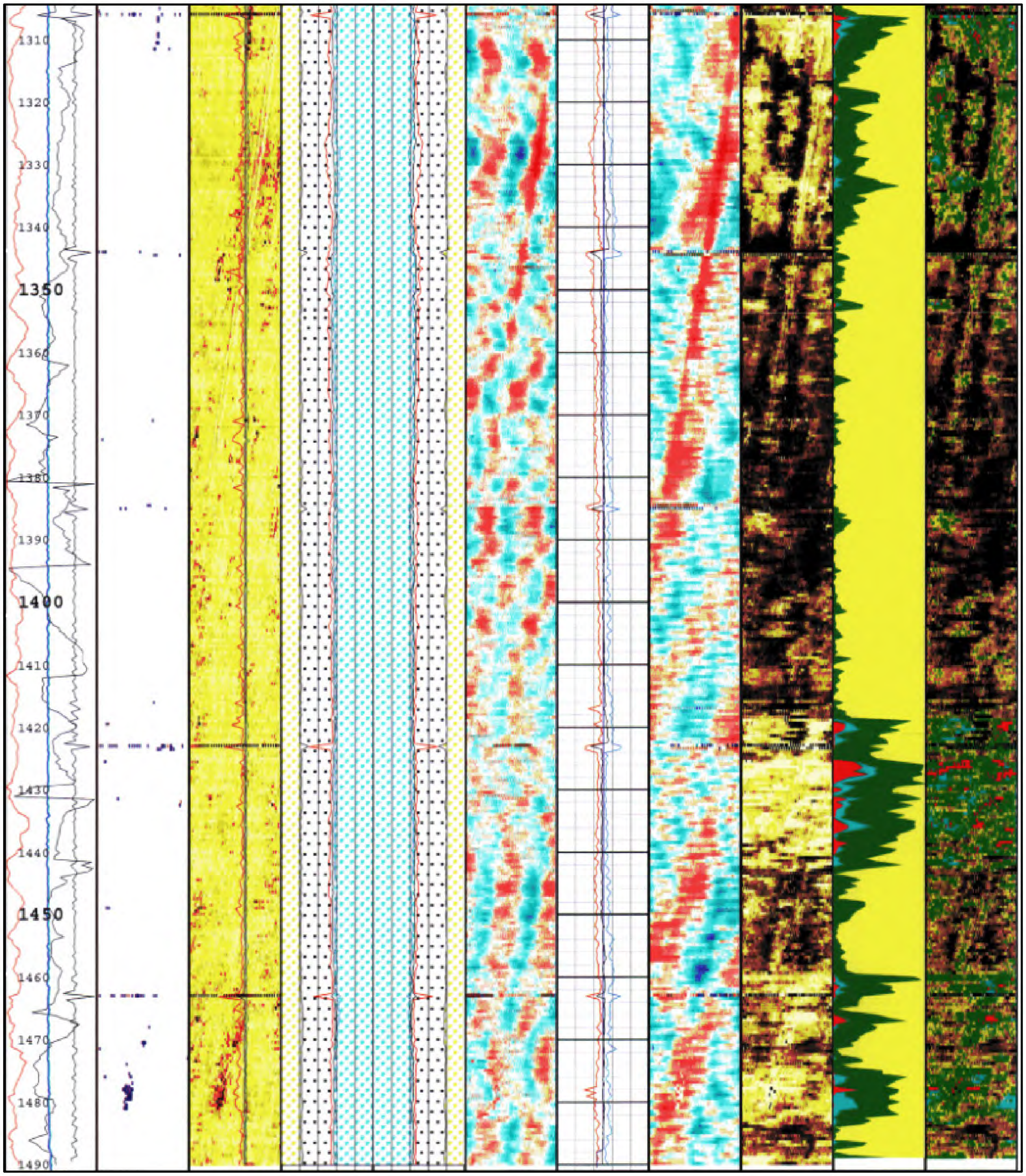

Figure 18: F-9 USIT Log Section

A.3 Sesnon Fee 2

SF-2 has a 13 3/8 in. surface casing at 1,594 ft. Reported cement to surface.

A.3.1 SF-2 USIT Log December 13, 2017

Figure 19 is the USIT log header, and Figure 20 shows the log legend. Figure 21 through Figure 24 show indications of internal and external corrosion.

Schlumberger

Company: Southern California Gas Company

Well: Sesnon Fee 2
Field: Aliso Canyon
County: Los Angeles State: California

County: Los Angeles
Field: Aliso Canyon
Location: 3797.72' S. & 5598.94' W from Station 84
Well: Sesnon Fee 2
Company: Southern California Gas Company

Ultrasonic Imager

Gamma Ray - CCL

13-3/8" 54.5# and 61# surface casing

Location: 3797.72' S. & 5598.94' W from Station 84

Elev.: K.B. 2453.00 ft; G.L. 2439.40 ft; D.F.

Permanent Datum:	Ground Level	Elev.:	2439.40 f
Log Measured From:	Kelly Bushing	13.60 ft	above Perm.Datum
Drilling Measured From:	Kelly Bushing		

API Serial No.	Section:	Township:	Range:
04-037-00648	33	3N	16W

Logging Date	13-Dec-2017		
Run Number	One		
Depth Driller	1584.00 ft		
Schlumberger Depth	1520.00 ft		
Bottom Log Interval	1520.00 ft		
Top Log Interval	15.00 ft		
Casing Fluid Type	Water		
Salinity			
Density	9.1 lbm/gal		
Fluid Level	0.00 ft		
BIT/CASING/TUBING STRING			
Bit Size	18.63 in		
From	0.00 ft		
To	1594.00 ft		
Casing/Tubing Size	13.375 in		
Weight	61 lbm/ft		
Grade	N/A		
From	1024.00 ft		
To	1594.00 ft		
Max Recorded Temperatures			
Logger on Bottom Time	13-Dec-2017	08:45:00	
Unit Number Location:	3079	Ventura	
Recorded By	T.Savoie / J.Lopez		
Witnessed By	Mr. Tom McMahon		

Figure 19: SF-2 USIT Log Header [7]

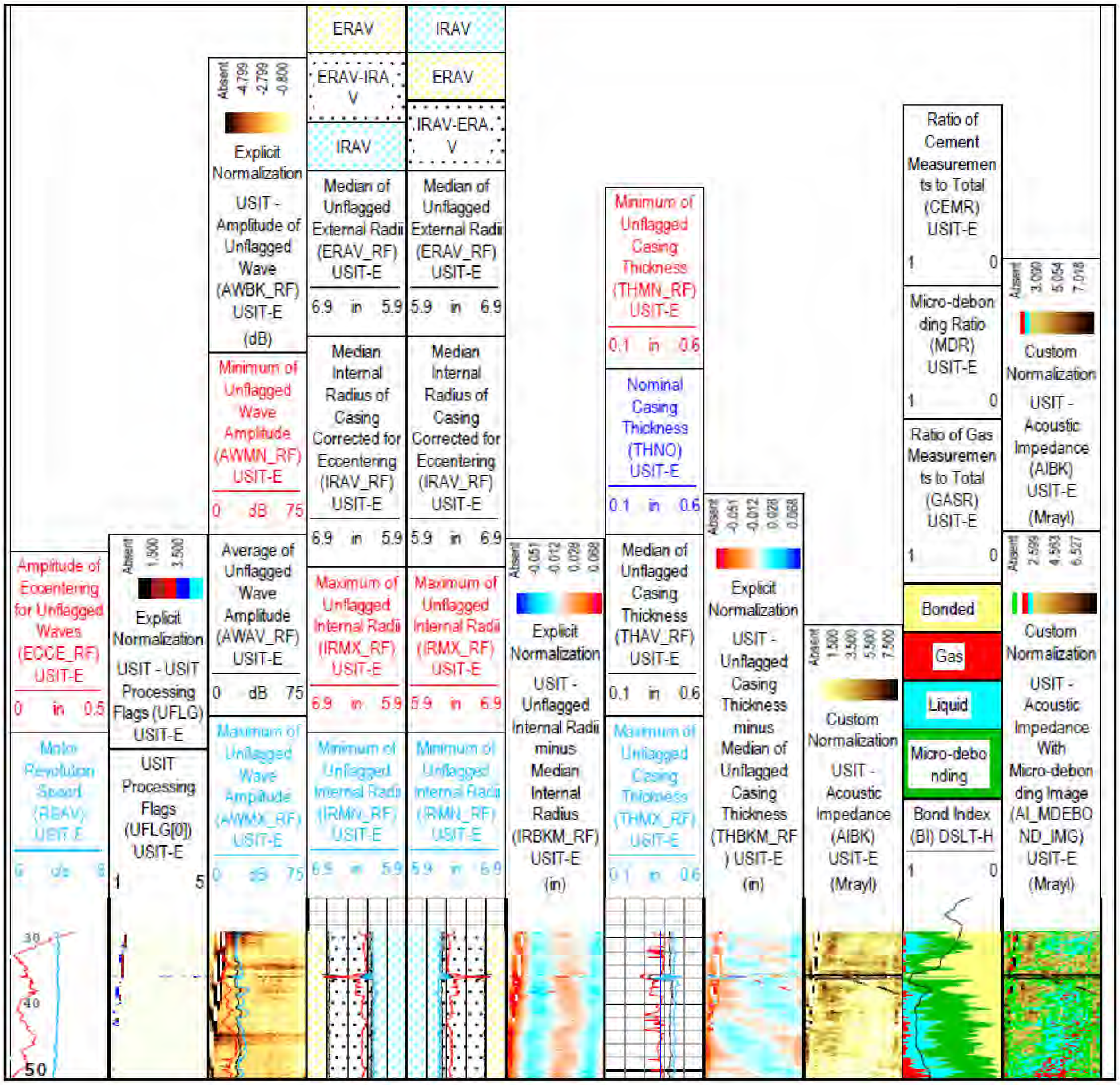

Figure 20: SF-2 USIT Log Legend

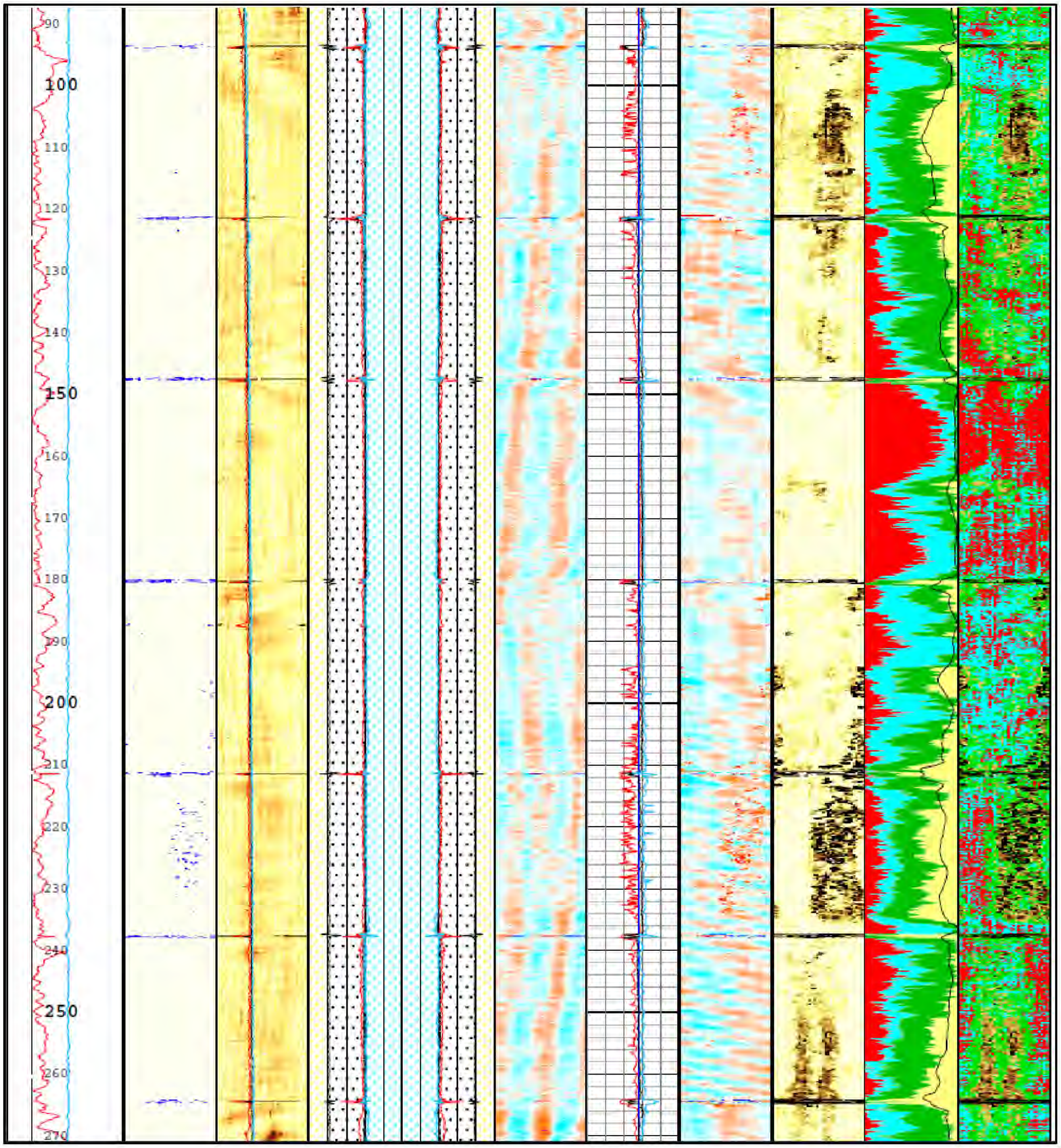

Figure 21: SF-2 USIT Log Section

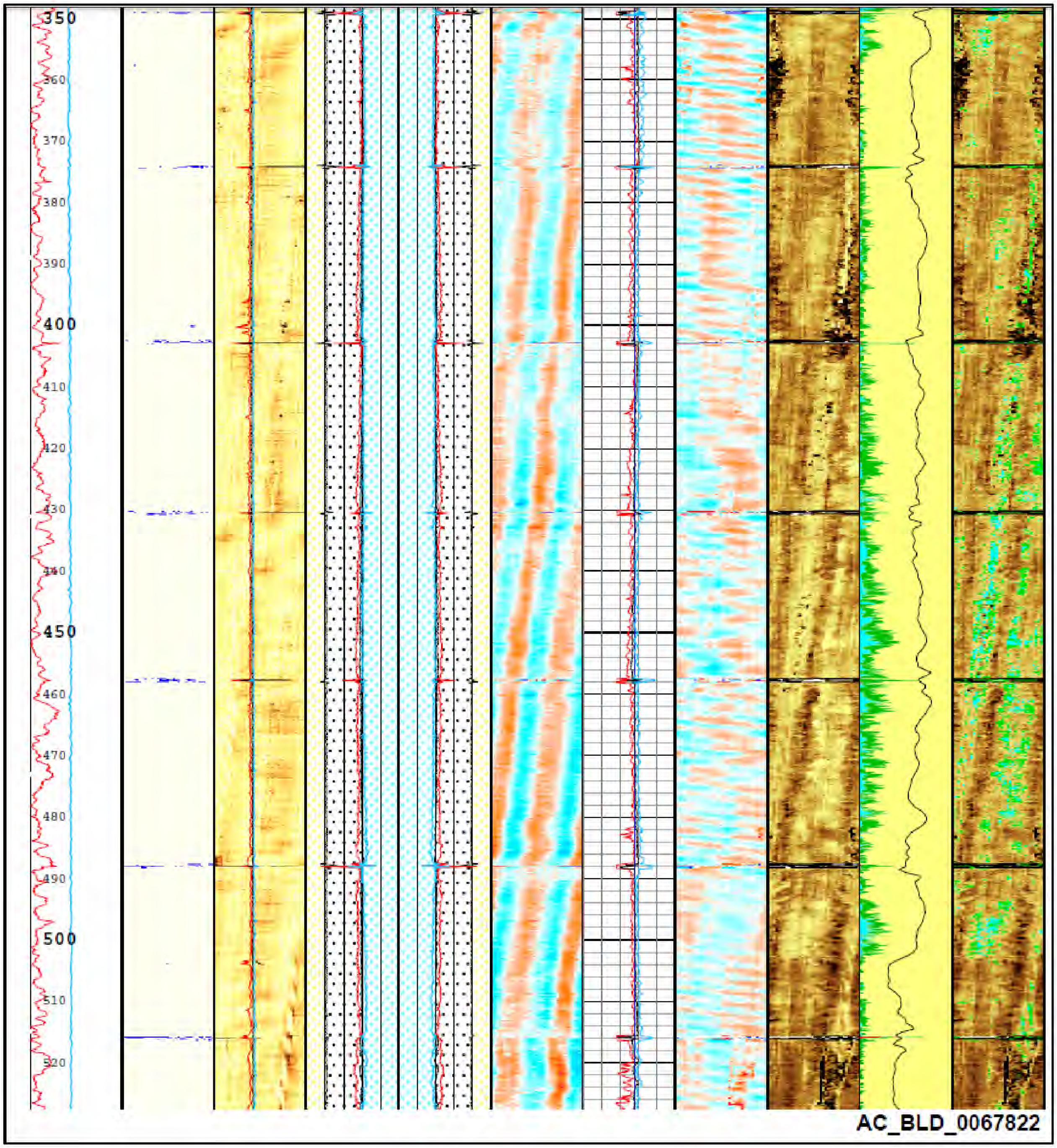

Figure 22: SF-2 USIT Log Section

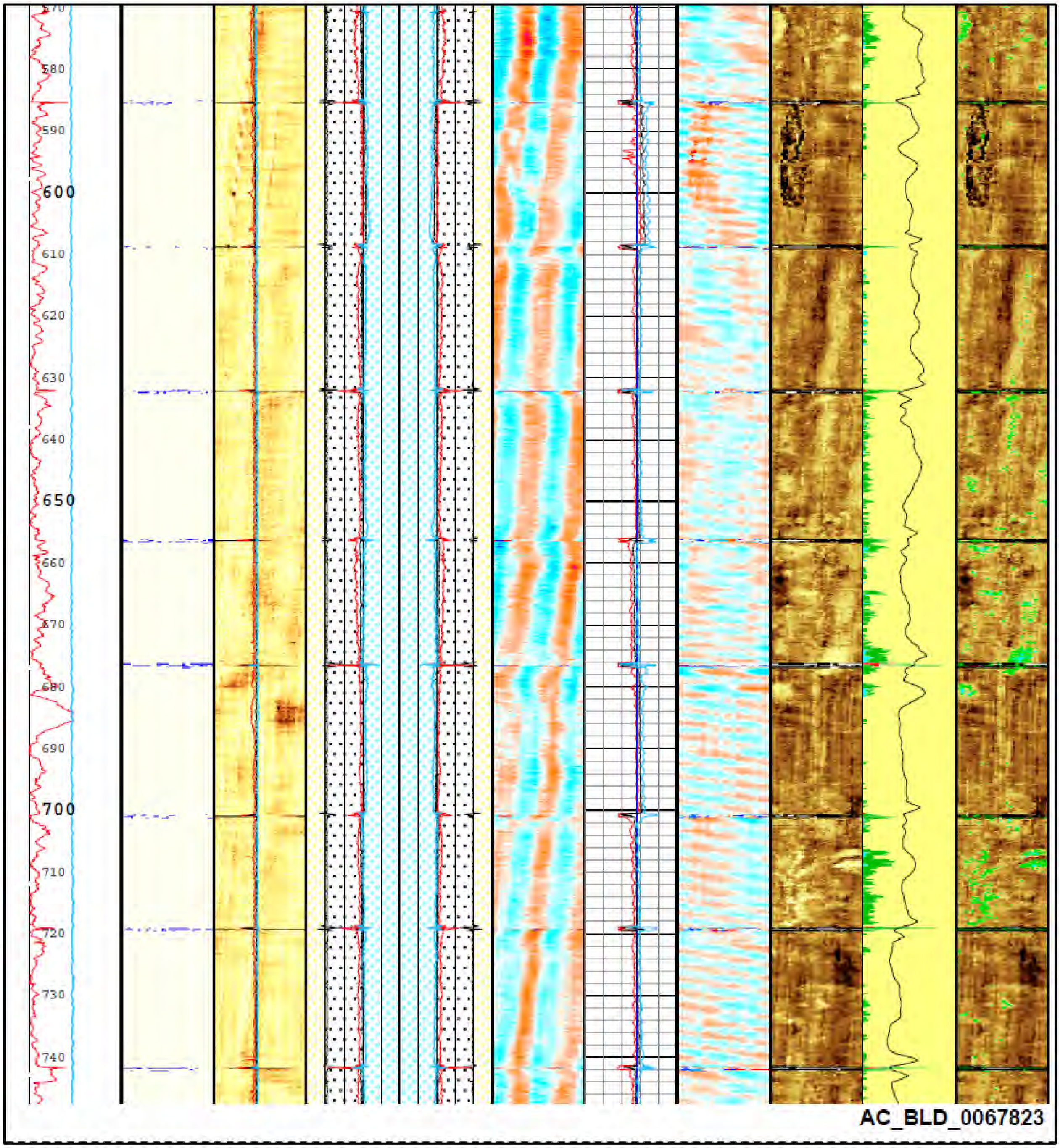

Figure 23: SF-2 USIT Log Section

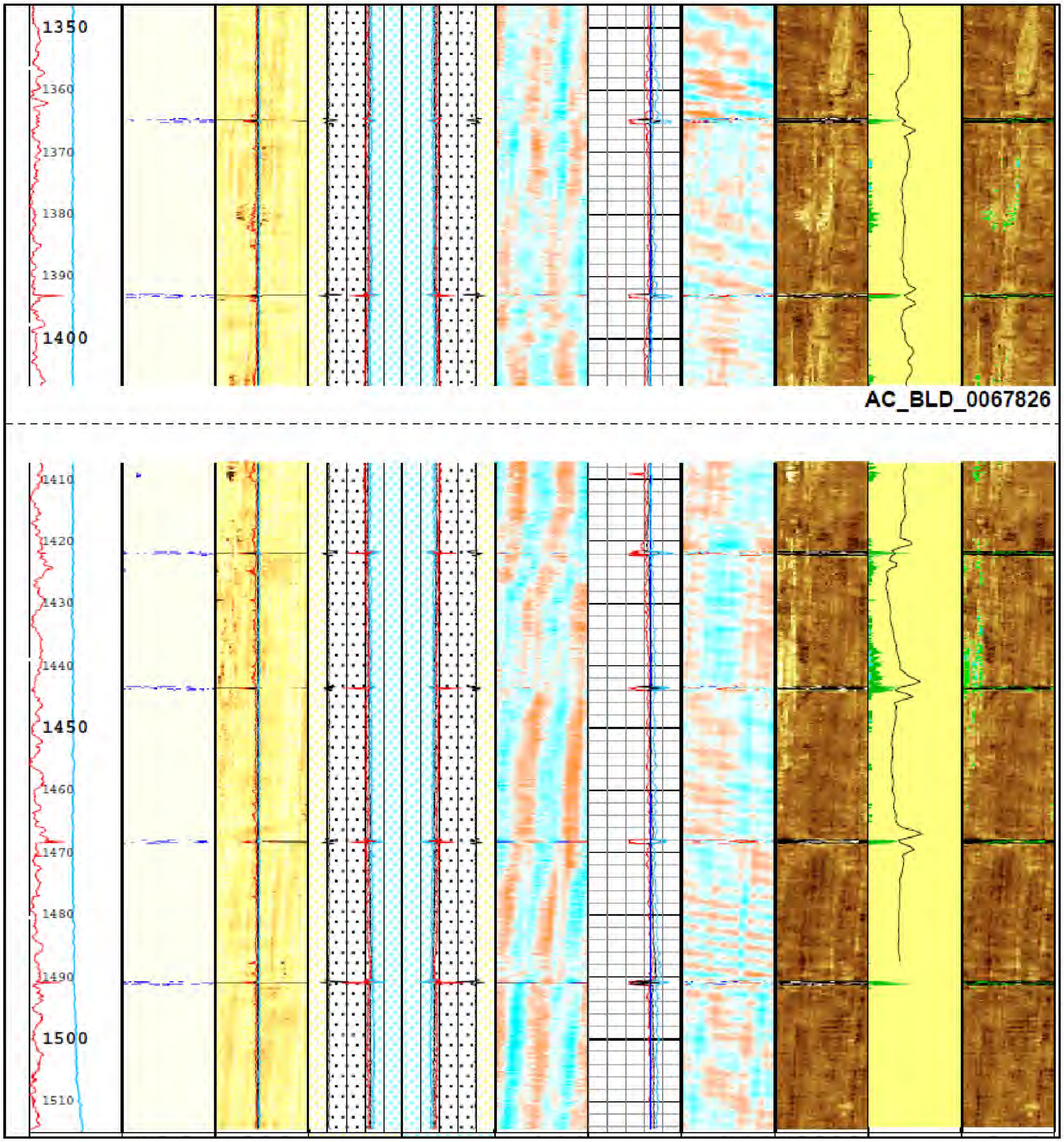

Figure 24: SF-2 USIT Log Section

A.4 Standard Sesnon 7

SS-7 has a 13 3/8 in. surface casing at 1,095 ft. No cement to surface.

A.4.1 SS-7 USIT Log August 13, 2014

Figure 25 is the USIT log header, and Figure 26 shows the log legend. Figure 27 through Figure 29 show indications of internal and external corrosion.

Schlumberger

Company: Southern California Gas Company

Well: Standard Sesnon 7

Field: Aliso Canyon

County: Los Angeles State: California

County: Los Angeles
Field: Aliso Canyon
Location: 552' S AND 7129' W
Well: Standard Sesnon 7
Company: Southern California Gas Company

Ultrasonic Imaging Tool

Gamma Ray - CCL

Location:	552' S AND 7129' W FROM STA 84	Elev.:	K.B.	
			G.L.	2960.00 ft
			D.F.	2967.00 ft
Permanent Datum:	Ground Level	Elev.:	2960.00 f	
Log Measured From:	Drill Floor	7.00 ft	above Perm.Datum	
Drilling Measured From:	Drill Floor			

API Serial No.	Section:	Township:	Range:
04-037-00760	28	3N	16W

Logging Date	27-May-2014		
Run Number	one		
Depth Driller	1000.00 ft		
Schlumberger Depth	930.00 ft		
Bottom Log Interval	930.00 ft		
Top Log Interval	33.00 ft		
Casing Fluid Type	3% KCL		
Salinity			
Density	8.5 lbm/gal		
Fluid Level	8.00 ft		
BIT/CASING/TUBING STRING			
Bit Size	15.00 in		
From	0.00 ft		
To	1000.00 ft		
Casing/Tubing Size	13.375 in		
Weight	54.5 lbm/ft		
Grade	JK60		
From	0.00 ft		
To	1000.00 ft		
Max Recorded Temperatures			
Logger on Bottom Time	27-May-2014	14:02:57	
Unit Number / Location:	362	Long Beach	
Recorded By	Kevin Michal		
Witnessed By	Mike Volkmar		

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Figure 25: SS-7 USIT Log Header

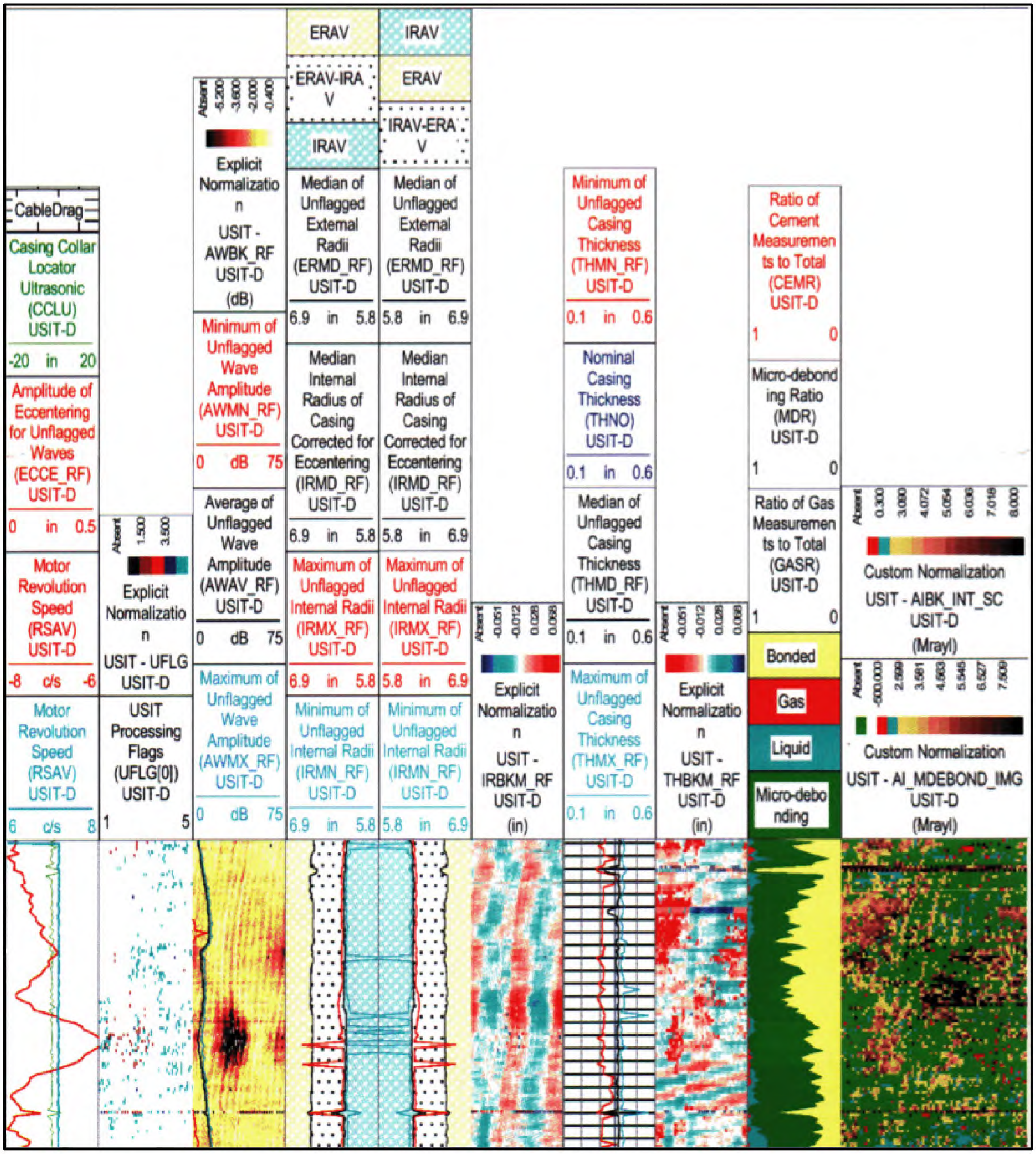

Figure 26: SS-7 USIT Log Legend

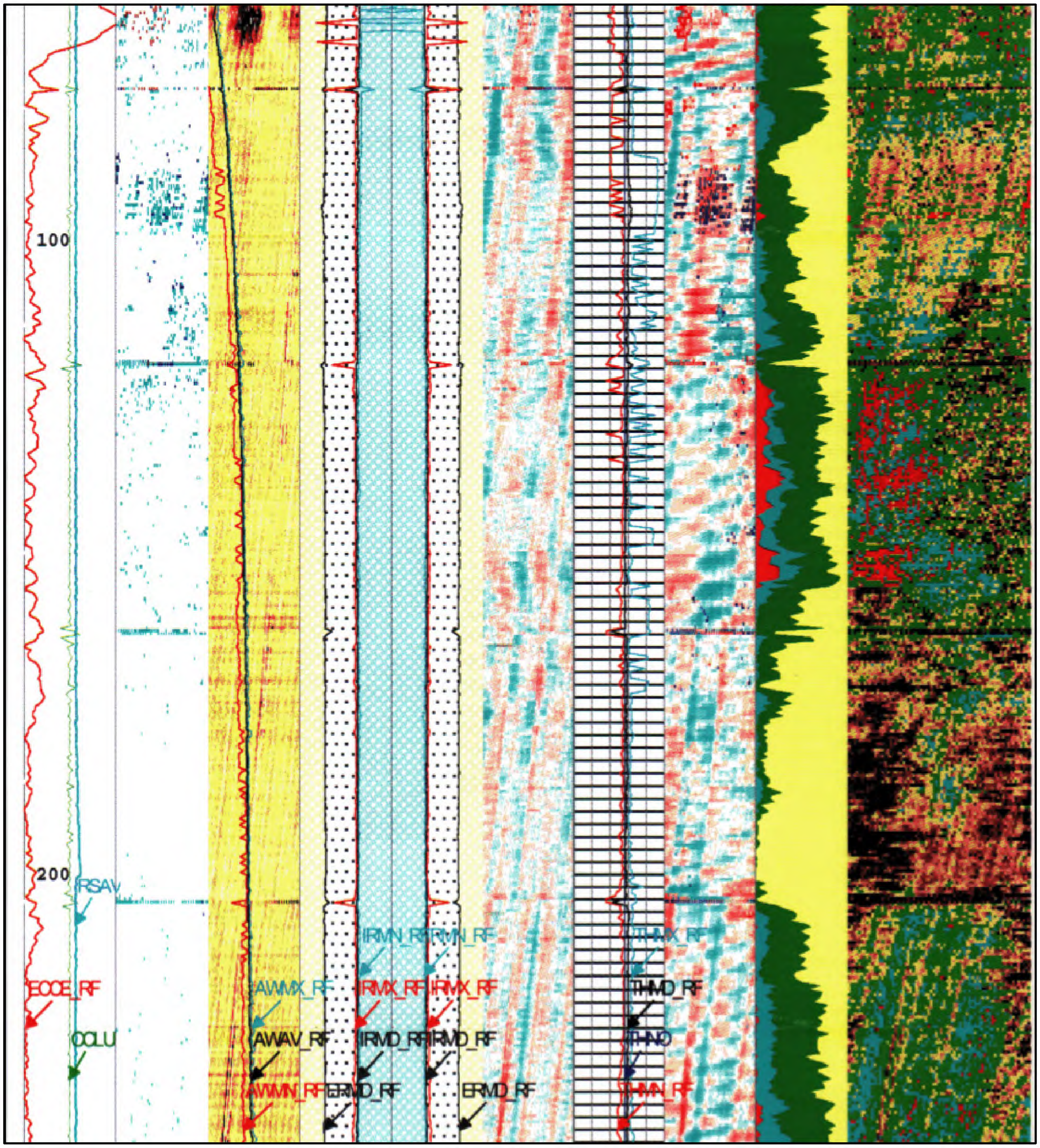

Figure 27: SS-7 USIT Log Section

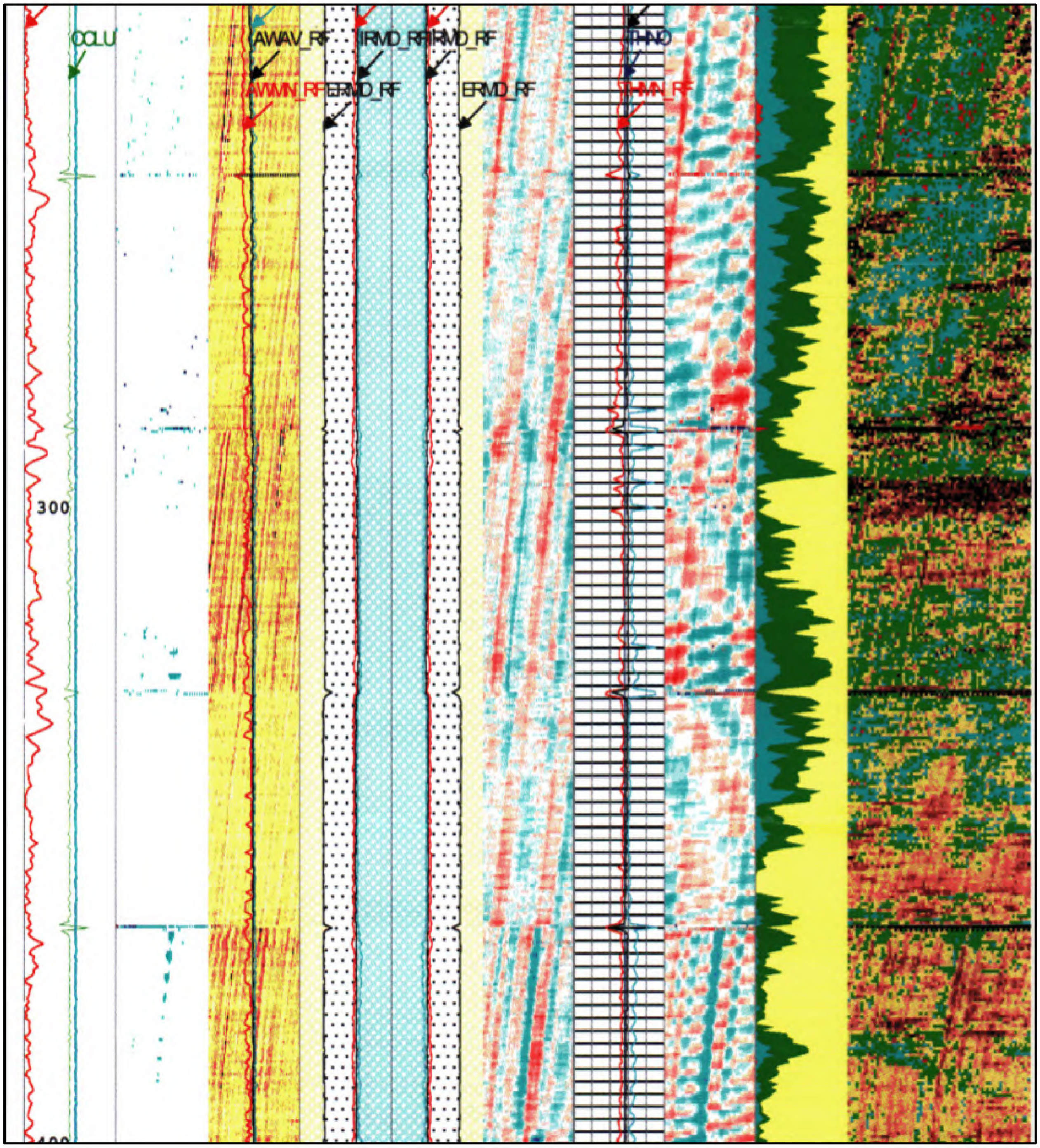

Figure 28: SS-7 USIT Log Section

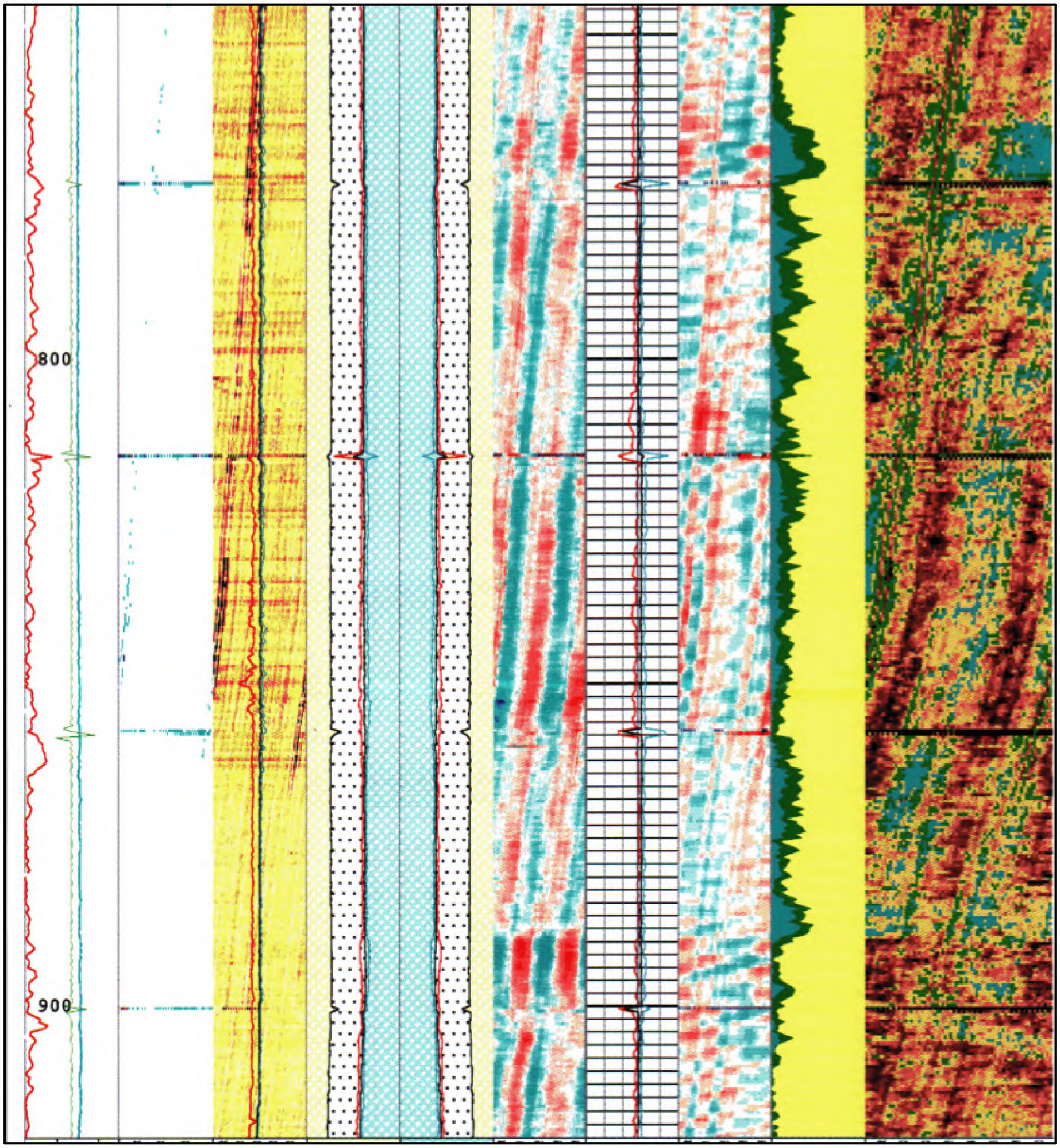

Figure 29: SS-7 USIT Log Section

A.5 Standard Sesnon 25

SS-25 has an 11 3/4 in. surface casing at 990 ft. No cement to surface, two top cement jobs.

A.5.1 SS-25 Camera Run November 7, 2017

Figure 30 and Figure 31 show camera images of holes in the 11 3/4 in. casing. This camera run was made prior to running a casing scraper. The camera depths have not been correlated so there can be a depth difference compared to the casing inspection log depths.

Figure 30: SS-25 Camera Image of a Hole in 11 3/4 in. Casing at Approximately 145 ft WLM

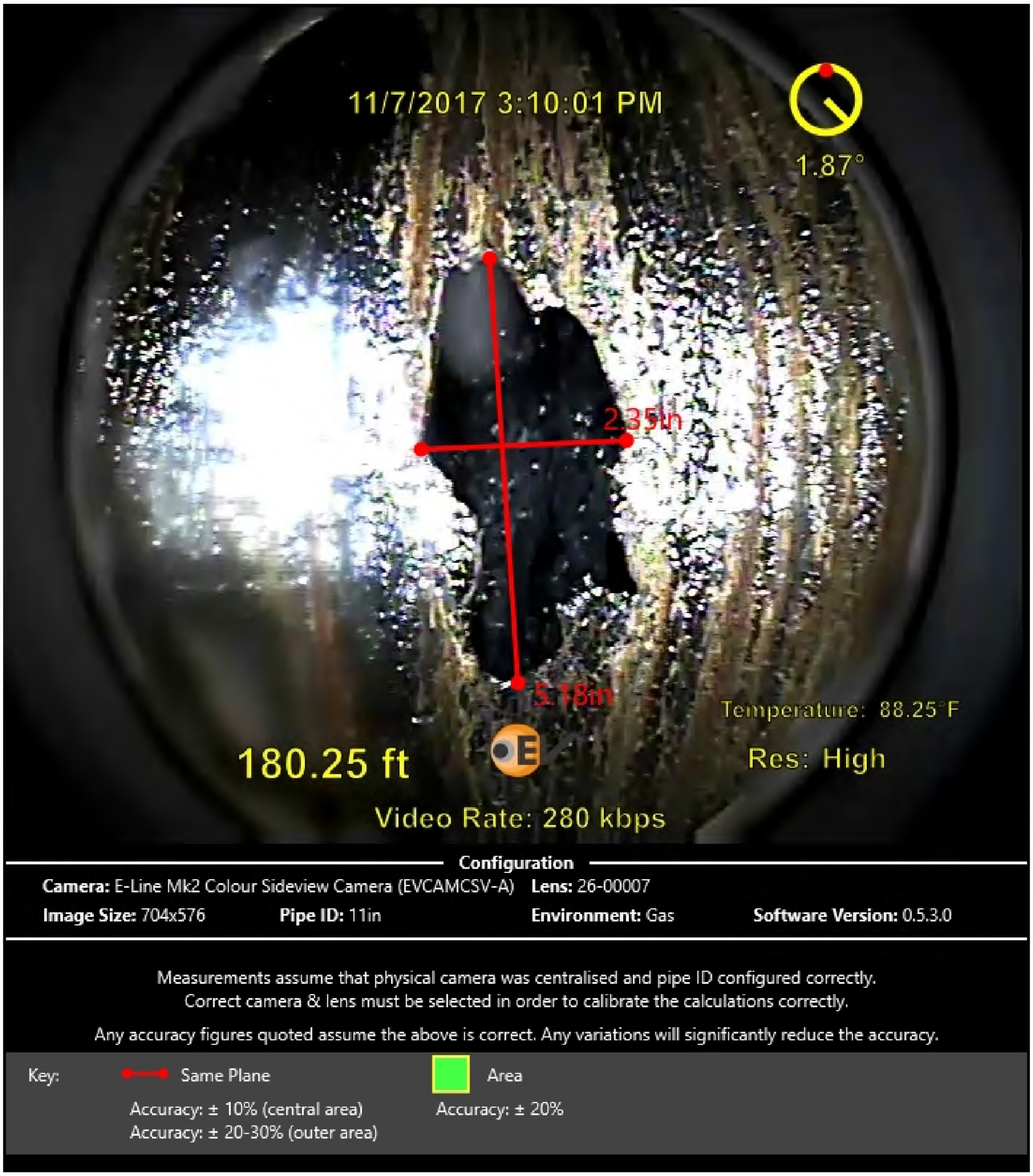

Figure 31: SS-25 Camera Image of a Hole in 11 3/4 in. Casing at Approximately 180 ft WLM

Figure 32 is the HRVRT log header, and Figure 33 shows the log legend and a section of the log showing external corrosion in the FL Axial track. Figure 34 shows external corrosion, and Figure 35 shows some internal corrosion in the DIS track. The MAX FL Axial track indicates holes in the casing from approximately 134–300 ft. Figure 36 and Figure 37 show some internal corrosion.

BAKER HUGHES a GE company

HR Vertilog

Magnetic Flux Leakage Inspection

Qualitative Analysis

Company	Southern California Gas Company
Well	Standard Sesnon 25
Field	Aliso Canyon
County	Los Angeles
State	California
Location:	

Section 28	Township 3N	Range 16W	

Date	Aug. 12, 2018
Service Order	US138251J
Recorded by	Sid Gornto
Witnessed by	Blade Energy Partners /
API Serial No.	

Permanent Datum:	GL	Elevation: 2927.000 ft.	Depth	1016.000
Log Measured From:	KB	6.350 ft. above Perm. Datum	Btm. Log Interval	0.000
Drilling Measured From:	KB	6.350 ft. above Perm. Datum	Top Log Interval	0.000
			Fluid Type	FLOZAN

Casing Data

Size	Weight	Grade	From	To	Length
11-3/4 inch	42 lb/ft	H-40	0	990	990.0

Figure 32: SS-25 HRVRT Log Header [8]

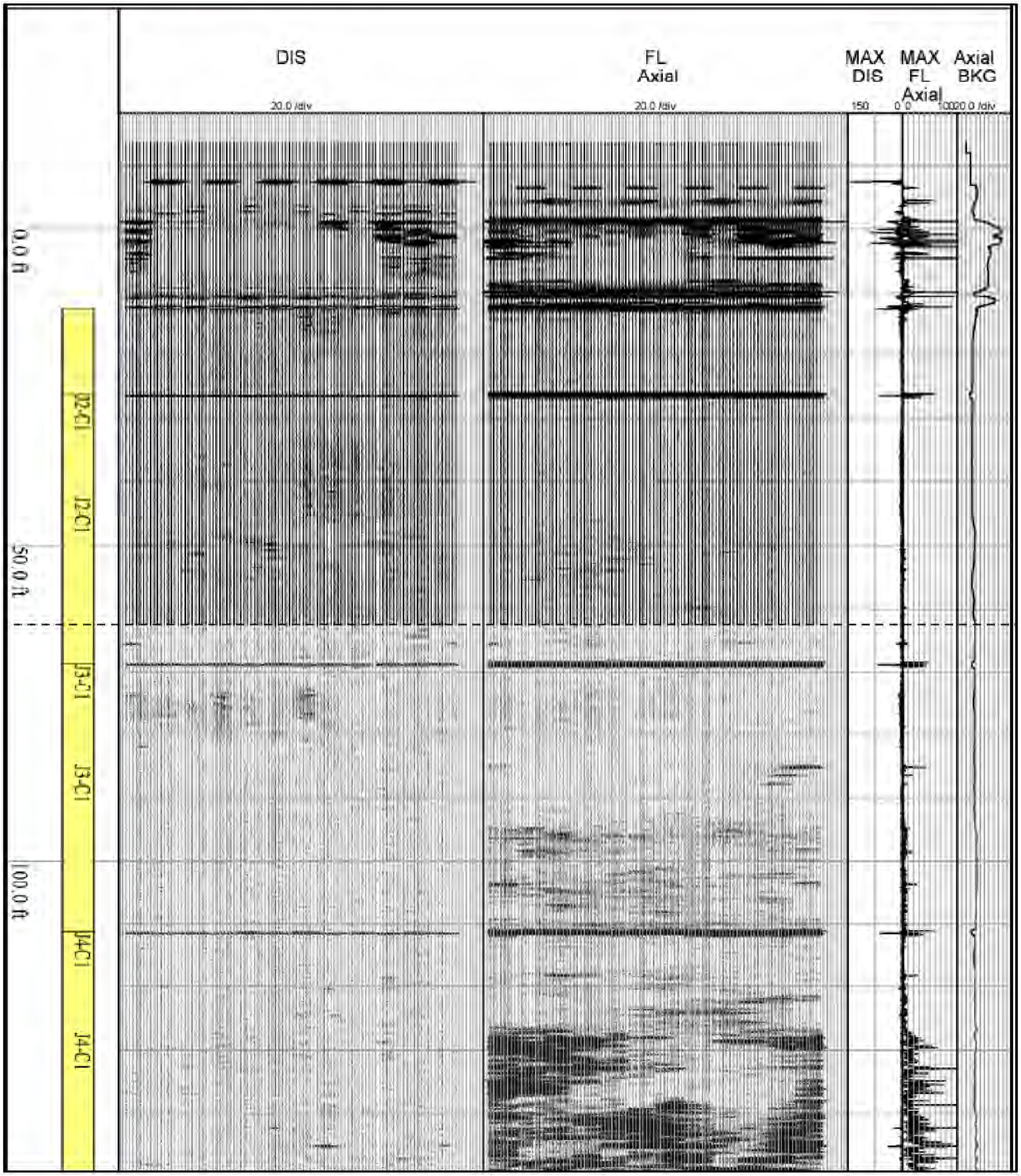

Figure 33: SS-25 HRVRT Log Legend and Log Section

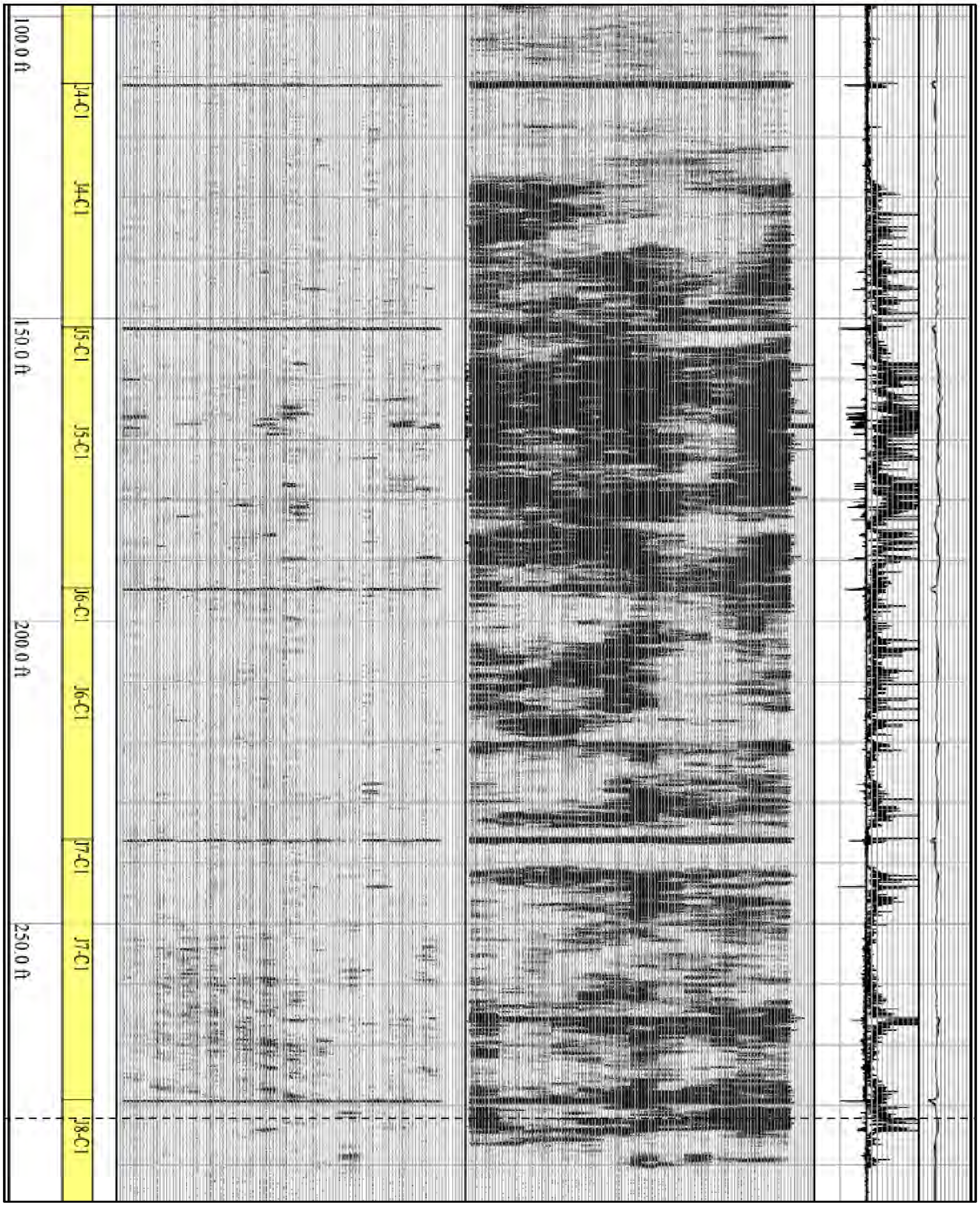

Figure 34: SS-25 HRVRT Log Section

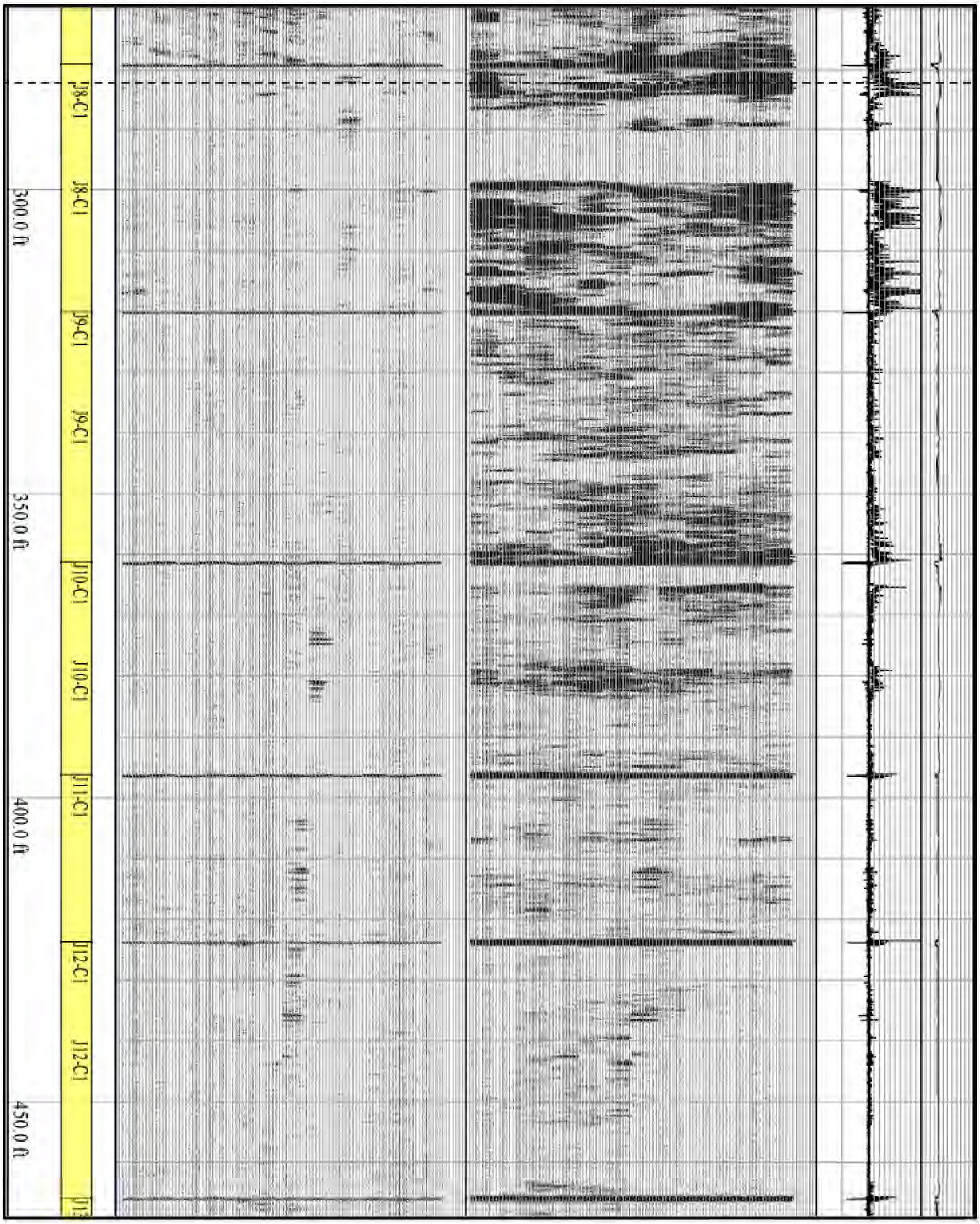

Figure 35: SS-25 HRVRT Log Section

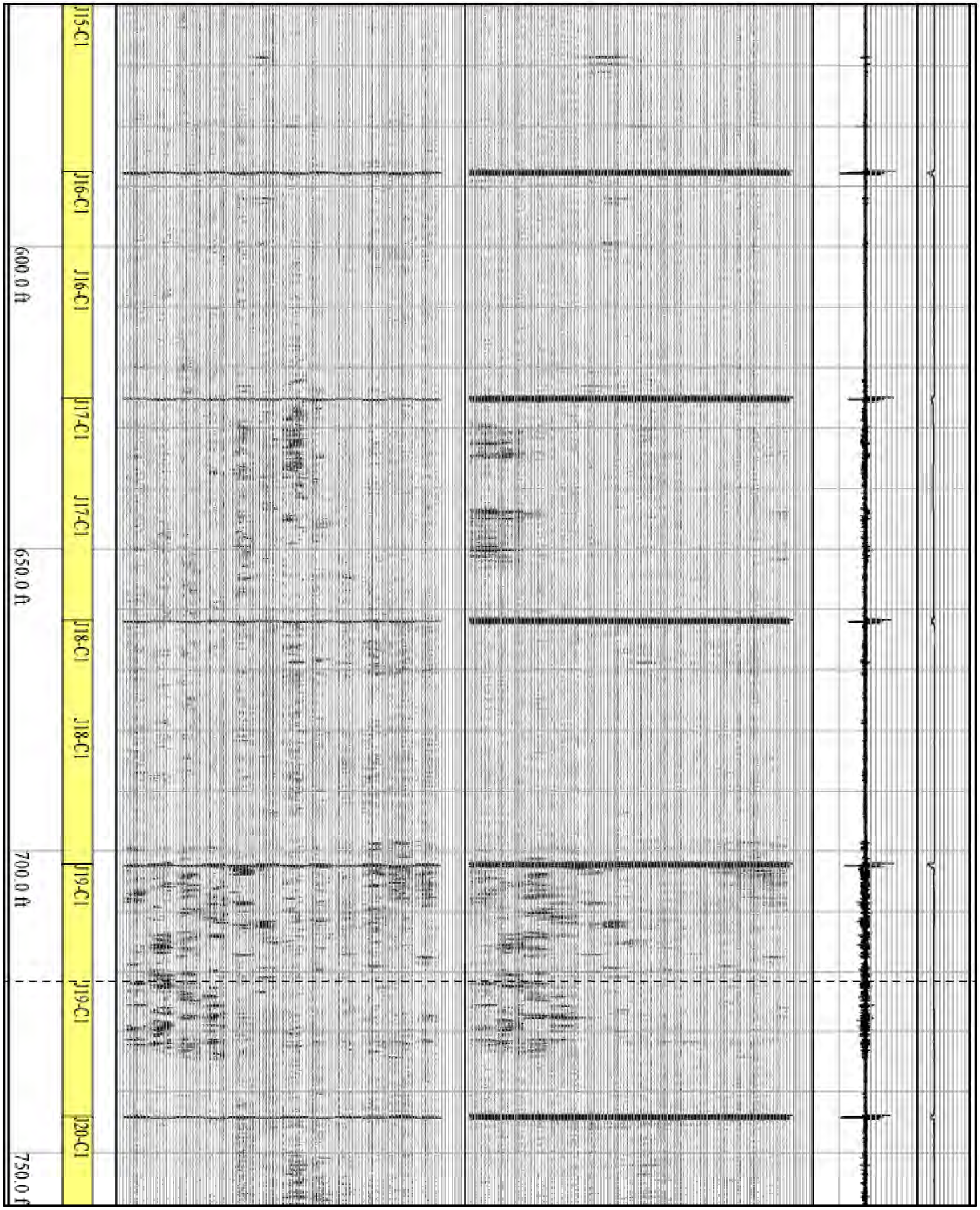

Figure 36: SS-25 HRVRT Log Section

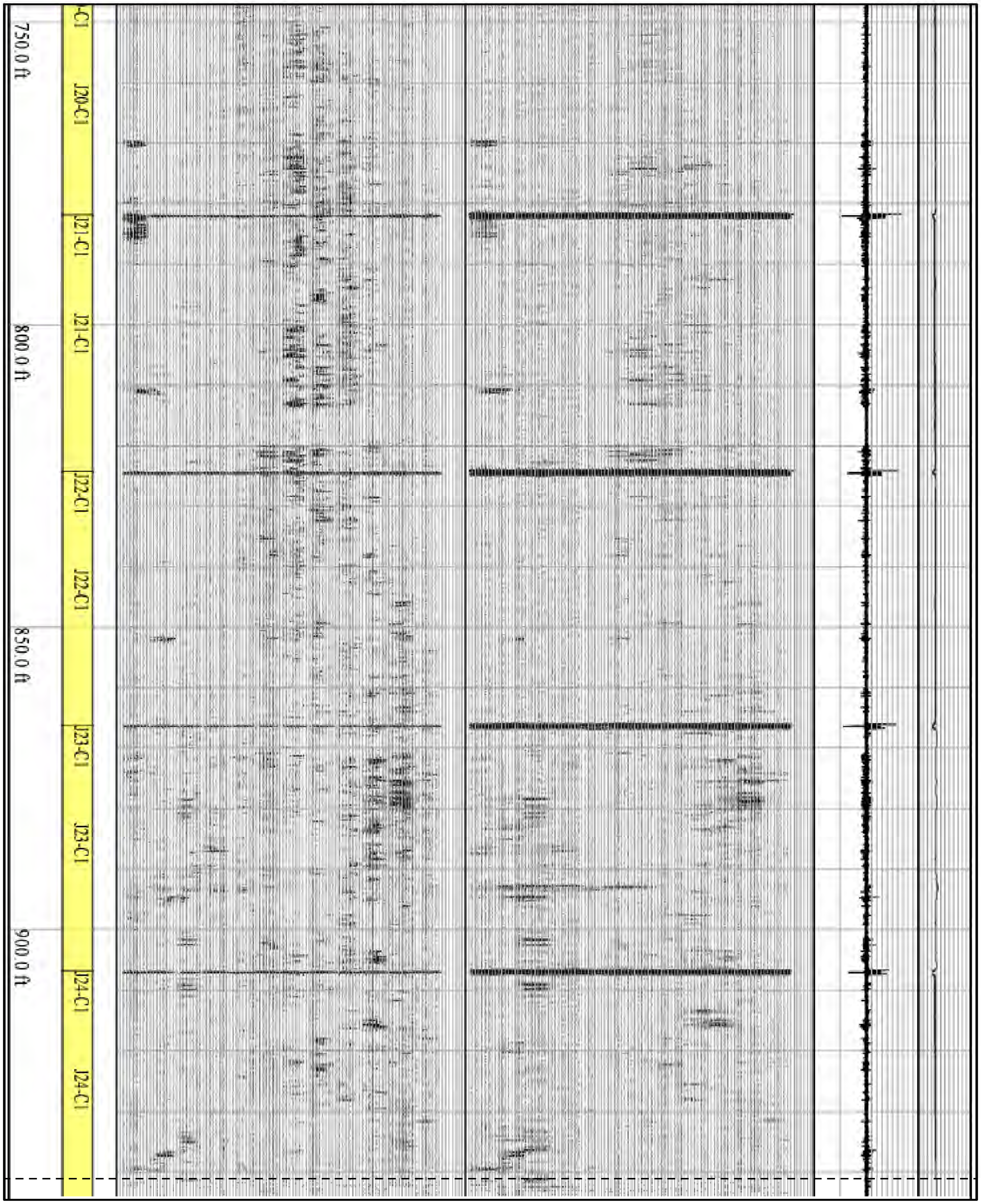

Figure 37: SS-25 HRVRT Log Section

A.5.2 SS-25 IBC Log August 14, 2018

Figure 38 is the IBC log header, and Figure 39 shows the log legend and a section of the log indicating internal and external corrosion. Figure 40 shows mostly external corrosion and an example of casing ovality at 386–396 ft. Figure 41 through Figure 43 show internal and external corrosion.

The log starts at 196 ft because the fluid level was at 170 ft. The well would not stand full of fluid.

Schlumberger

Company:	Southern California Gas Company		
Well:	Standard Sesnon 25		
Field:	Aliso Canyon		
County:	Los Angeles	State:	California

County: Los Angeles
Field: Aliso Canyon
Location: 820 Ft South & 5360 Ft West Fr Station 84
Well: Standard Sesnon 25
Company: Southern California Gas Company

Isolation Scanner

Casing Evaluation

Gamma Ray - CCL

Location: 820 Ft South & 5360 Ft West Fr Station 84	Elev.:	K.B.	2933.35 ft
		G.L.	2927.00 ft
		D.F.	
Permanent Datum:	Ground Level	Elev.:	2927.00 f
Log Measured From:	Kelly Bushing	6.35 ft	above Perm.Datum
Drilling Measured From:	Kelly Bushing		

API Serial No.	Section:	Township:	Range:
04-037-00776	28	3N	16W

Logging Date	14-Aug-2018	
Run Number	Surface IBC 11 3/4	
Depth Driller	1000.00 ft	
Schlumberger Depth	1000.00 ft	
Bottom Log Interval	995.00 ft	
Top Log Interval	196.00 ft	
Casing Fluid Type	Salt Brine	
Salinity		
Density	9.1 lbm/gal	
Fluid Level	170.00 ft	
BIT/CASING/TUBING STRING		
Bit Size	16.00 in	
From	0.00 ft	
To	1000.00 ft	
Casing/Tubing Size	11.75 in	
Weight	42 lbm/ft	
Grade	H40	
From	0.00 ft	
To	1000.00 ft	
Max Recorded Temperatures		
Logger on Bottom Time	14-Aug-2018 15:54:00	
Unit Number Location:	3017 Ventura Ca	
Recorded By	John Lopez	
Witnessed By	Blade Energy Partners/ T. MacMahon	

Figure 38: SS-25 IBC Log Header [9]

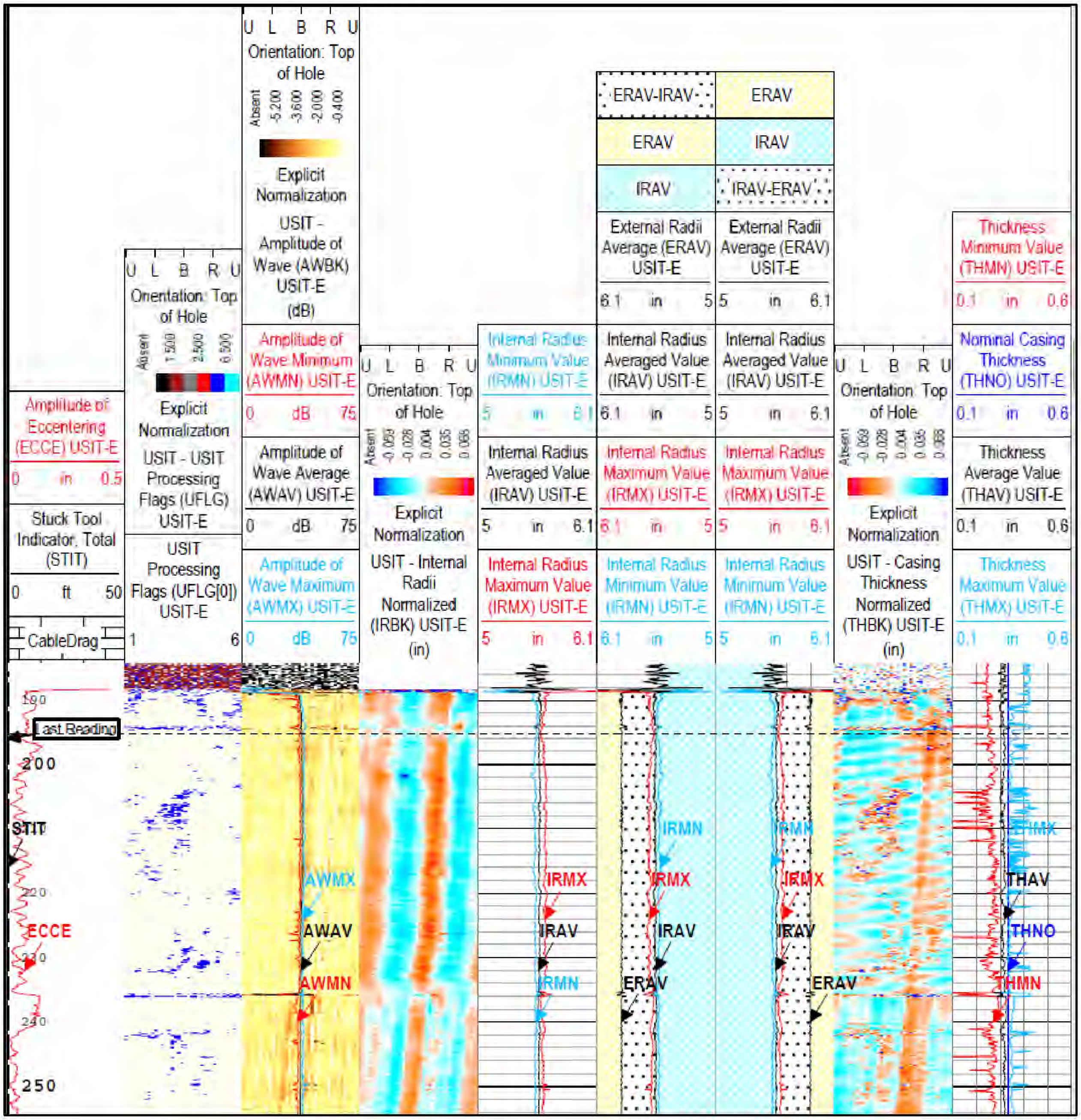

Figure 39: SS-25 IBC Log Legend and Log Section

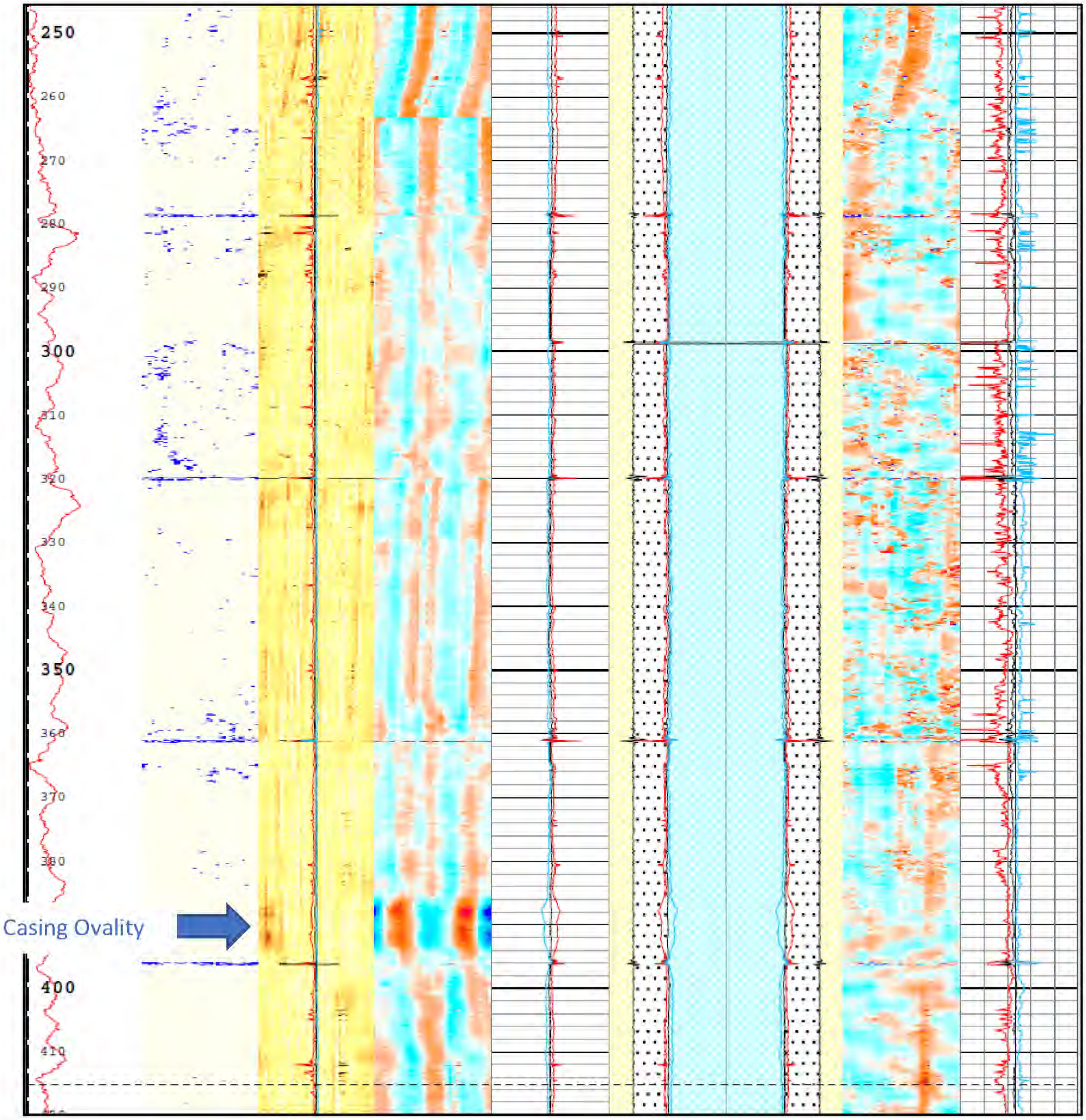

Figure 40: SS-25 IBC Log Section Showing External Corrosion and Casing Ovality

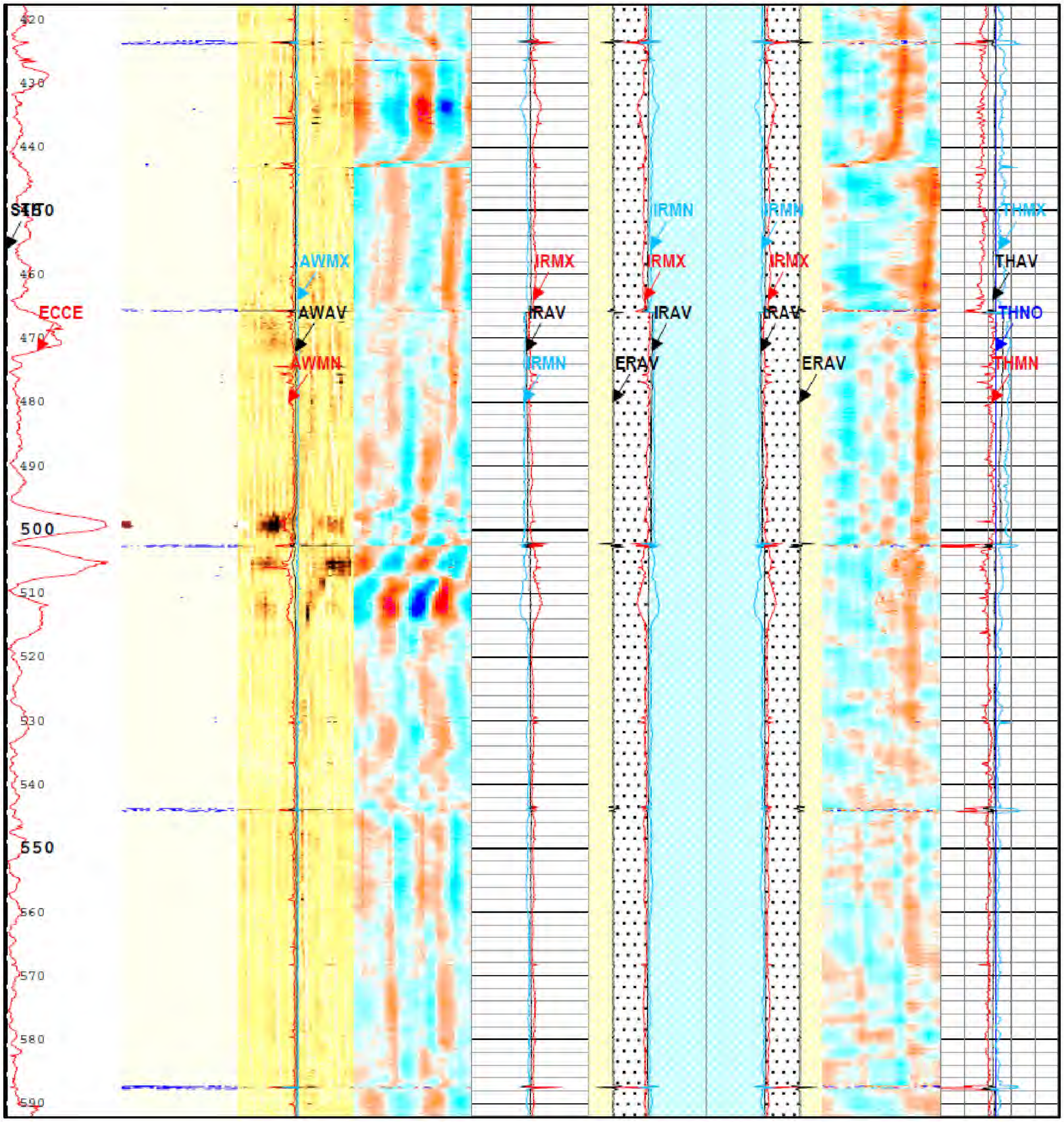

Figure 41: SS-25 IBC Log Section

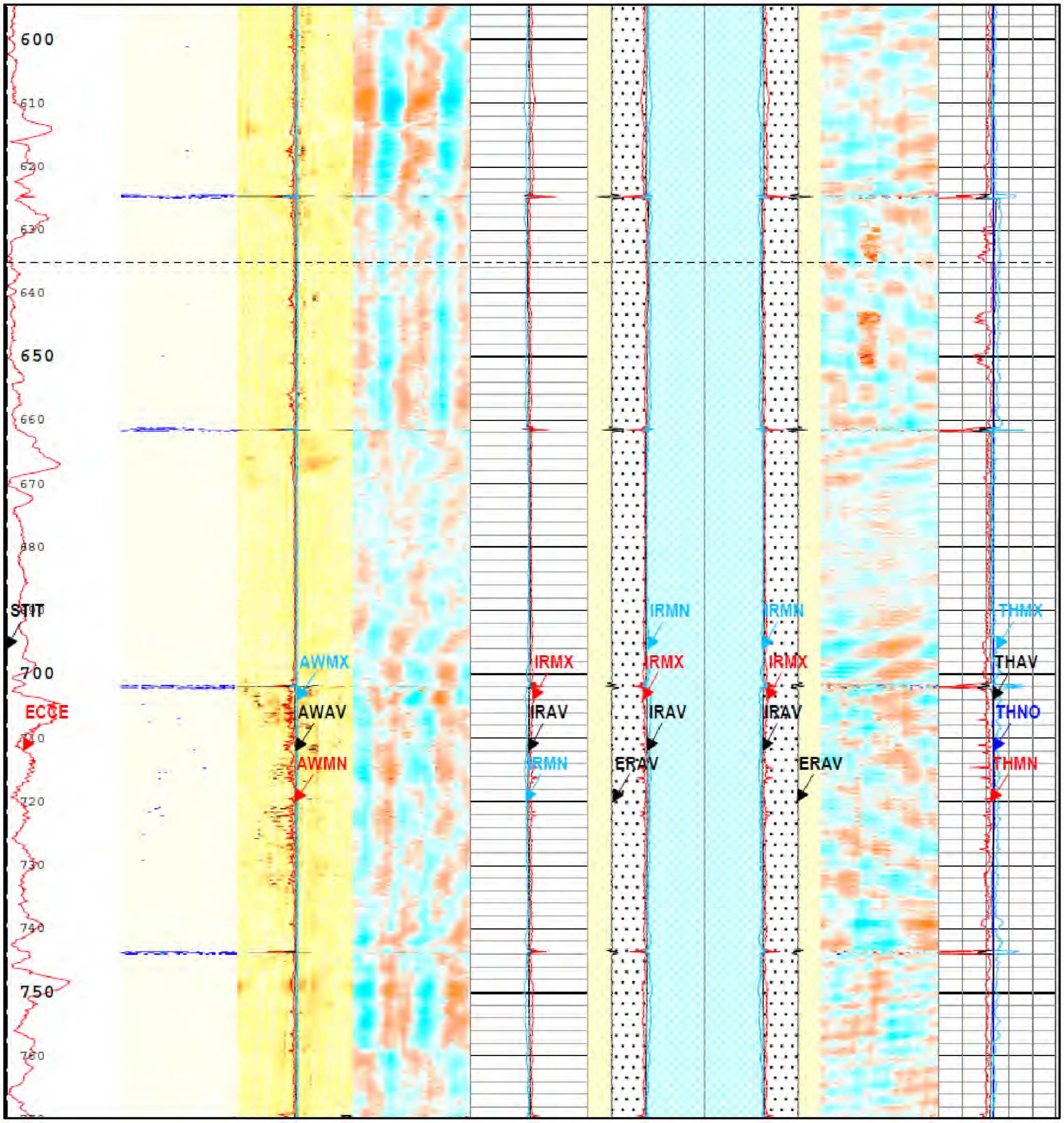

Figure 42: SS-25 IBC Log Section

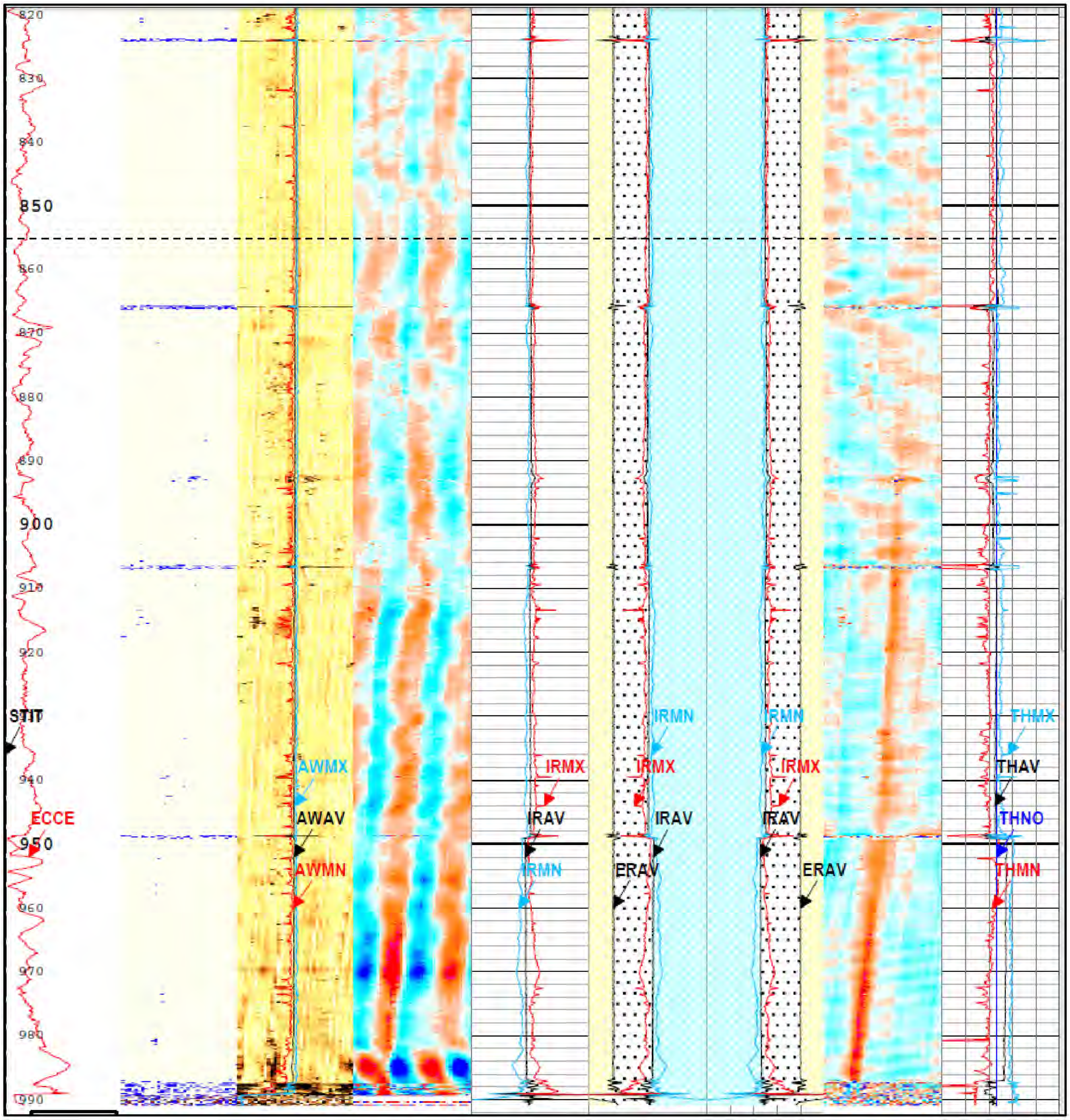

Figure 43: SS-25 IBC Log Section

A.6 Porter 30

P-30 has a 13 3/8 in. surface casing at 565 ft. Reported cement to surface.

A.6.1 P-30 56 Arm Caliper Log July 12, 2018

Figure 44 is the 56 arm caliper log header, and Figure 45 shows the log legend and a section of the log. The caliper log shows an internal indication at 22.5 ft.

BAKER HUGHES a GE company

56 ARM CALIPER

Company SOUTHERN CALIFORNIA GAS CO
Well PORTER 30
Field ALISO CANYON
County LOS ANGELES

Company SOUTHERN CALIFORNIA GAS CO

Well PORTER 30

Field ALISO CANYON

County LOS ANGELES State CALIFORNIA

Location: API # : 04-037-00717-00

SEC 27 TWP 3N RGE 16W

Other Services: HRVRT

Permanent Datum GL Elevation 1799.15

Log Measured From KB

Drilling Measured From KB

Elevation: K.B. 1809.15' D.F. G.L. 1799.15'

Date	12 JULY 2018		
Run Number	1		
Service Order	US139958		
Depth Driller	440		
Depth Logger	440		
Bottom Logged Interval	432		
Top Log Interval	0		
Type Fluid	KCL		
Density / Viscosity	8.5		
Max. Recorded Temp.	84.1		
Estimated Cement Top	N/A		
Time Well Ready	0630		
Time Logger on Bottom	0730		
Equipment Number	4256		
Location	SHAFTER		
Recorded By	GORNTO/REYNOLDS		
Witnessed By	JOHN HERRON		

Borehole Record				Tubing Record			
Run Number	Bit	From	To	Size	Weight	From	To

Casing Record	Size	Wgt/Ft	Top	Bottom
Surface String	13 3/8	54.5	0	565
Prot. String				
Production String	7	23	440	7230
Liner				

Figure 44: P-30 Caliper Log Header

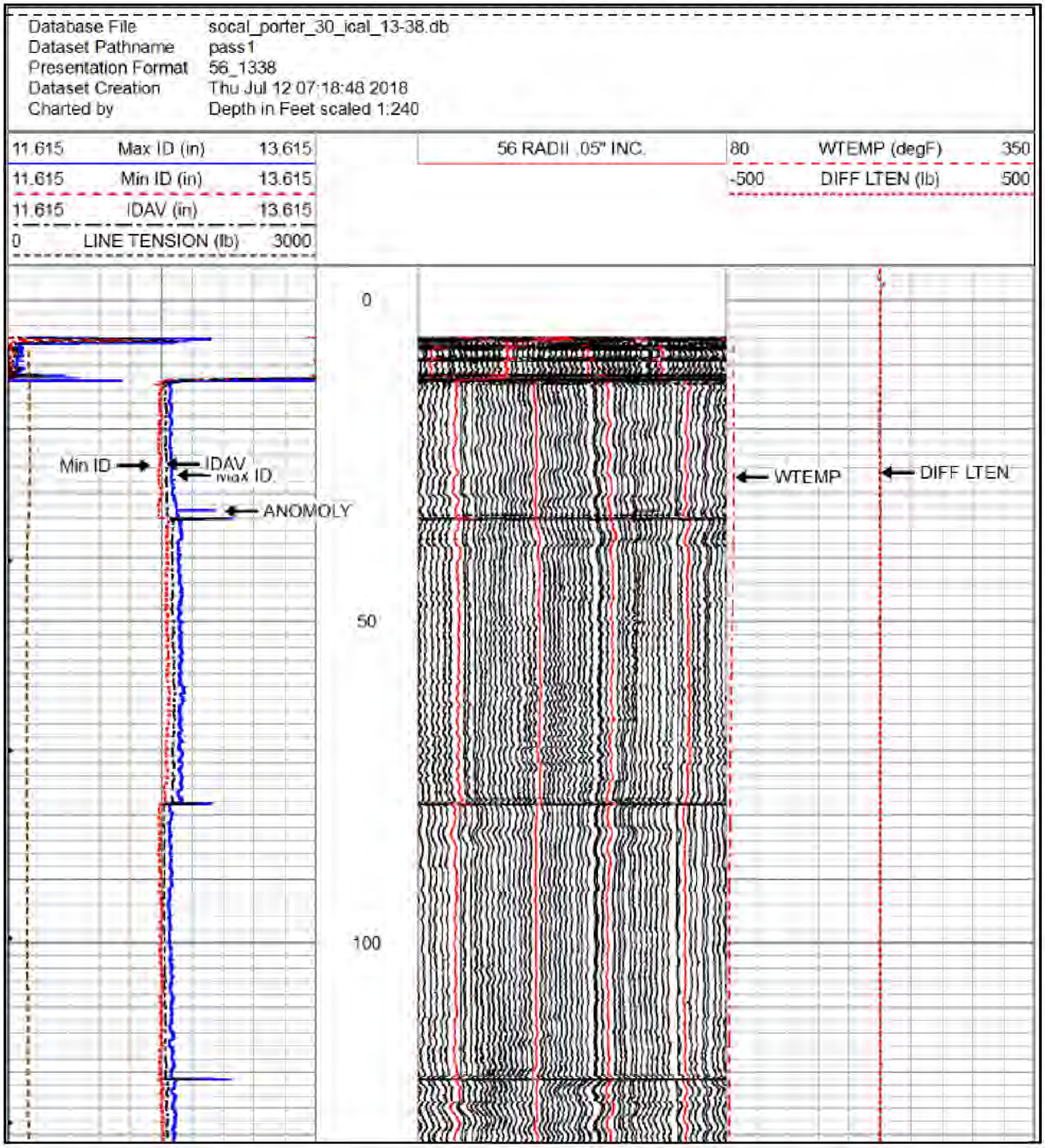

Figure 45: P-30 Caliper Log Legend and Log Section with Anomaly at 22.5 ft

A.7 Standard Sesnon 17

SS-17 has a 13 3/8 in. surface casing at 1,010 ft. Reported cement to surface.

A.7.1 SS-17 CBL-VDL Log June 26, 2017

Figure 46 is the CBL-VDL log header, and Figure 47 shows the log legend and a section of the log. Figure 48 through Figure 51 show the remainder of the log.

Schlumberger

Company: Southern California Gas Company

Well: Standard Sesnon 17

Field: Aliso Canyon

County: Los Angeles State: California

County: Los Angeles
Field: Aliso Canyon
Location:
Well: Standard Sesnon 17
Company: Southern California Gas Company

Cement Bond Log

Variable Density Log

Gamma Ray (13 3/8" Casing)

Location: 03700769

Elev.:	K.B.	2600.36 ft	
	G.L.	2592.04 ft	
	D.F.		
Permanent Datum:	Ground Level	Elev.:	2592.04 f
Log Measured From:	Kelly Bushing	8.32 ft	above Perm.Datum
Drilling Measured From:	Kelly Bushing		

API Serial No.	Section:	Township:	Range:
040370076901	28	3N	16W

Logging Date	26-Jun-2017	
Run Number	Two	
Depth Driller	990.00 ft	
Schlumberger Depth	990.00 ft	
Bottom Log Interval	981.00 ft	
Top Log Interval	30.00 ft	
Casing Fluid Type	Water	RECEIVED
Salinity		
Density	8.4 lbm/gal	
Fluid Level	8.00 ft	AUG 21 2017
BIT/CASING/TUBING STRING		
Bit Size	7.88 in	Div. of Oil, Gas &
From	1010.00 ft	Geothermal Resources
To	9140.00 ft	Ventura
Casing/Tubing Size	13.375 in	
Weight	54.5 lbm/ft	
Grade	J55	
From	0.00 ft	
To	1010.00 ft	
Max Recorded Temperatures	161 degF	
Logger on Bottom Time	26-Jun-2017 15:00:00	
Unit Number Location:	3017 Ventura	
Recorded By	John Lopez	
Witnessed By	Mr Tom McMahon	

Figure 46: SS-17 CBL-VDL Log Header

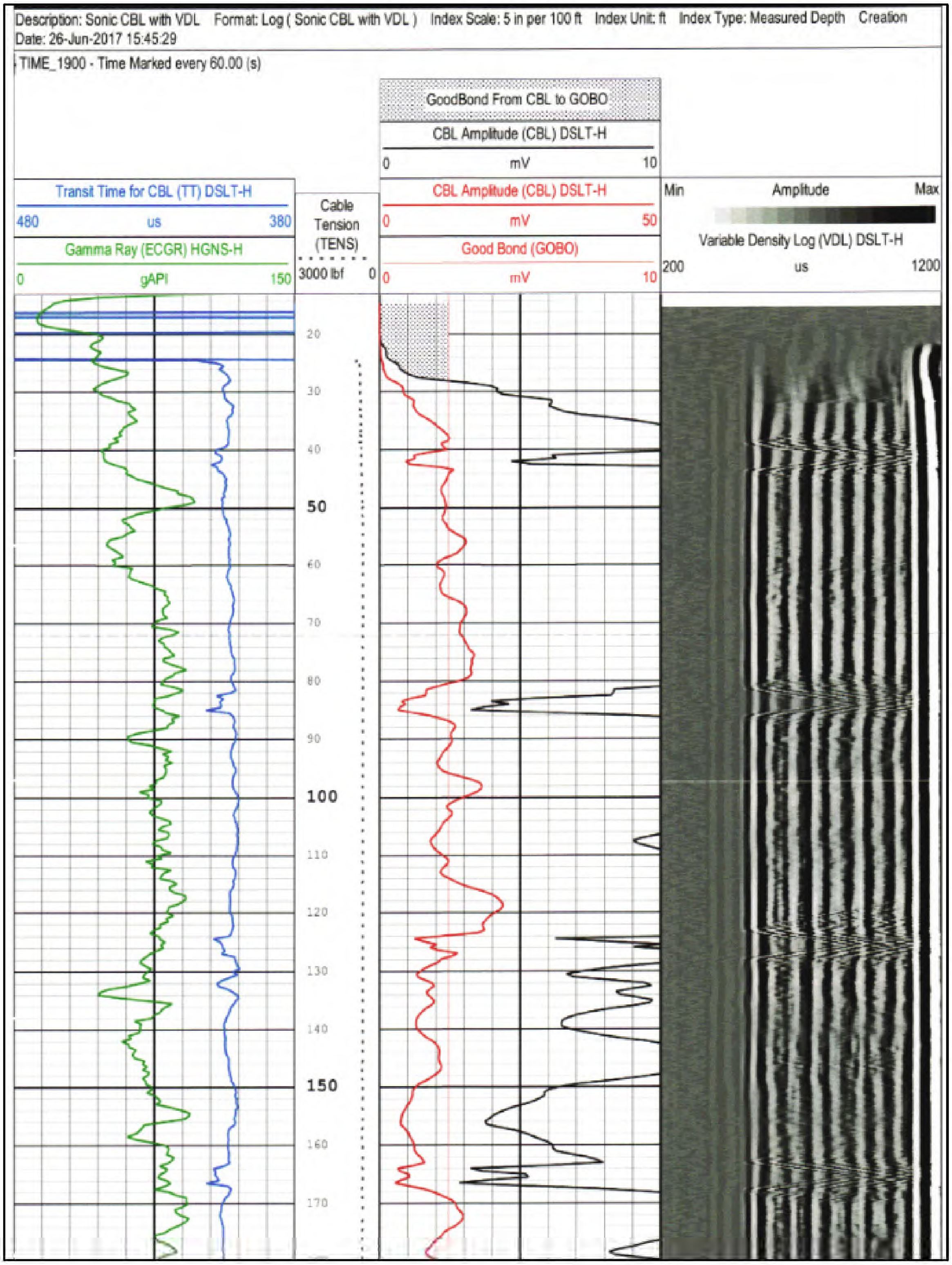

Figure 47: SS-17 CBL-VDL Log Legend and Section

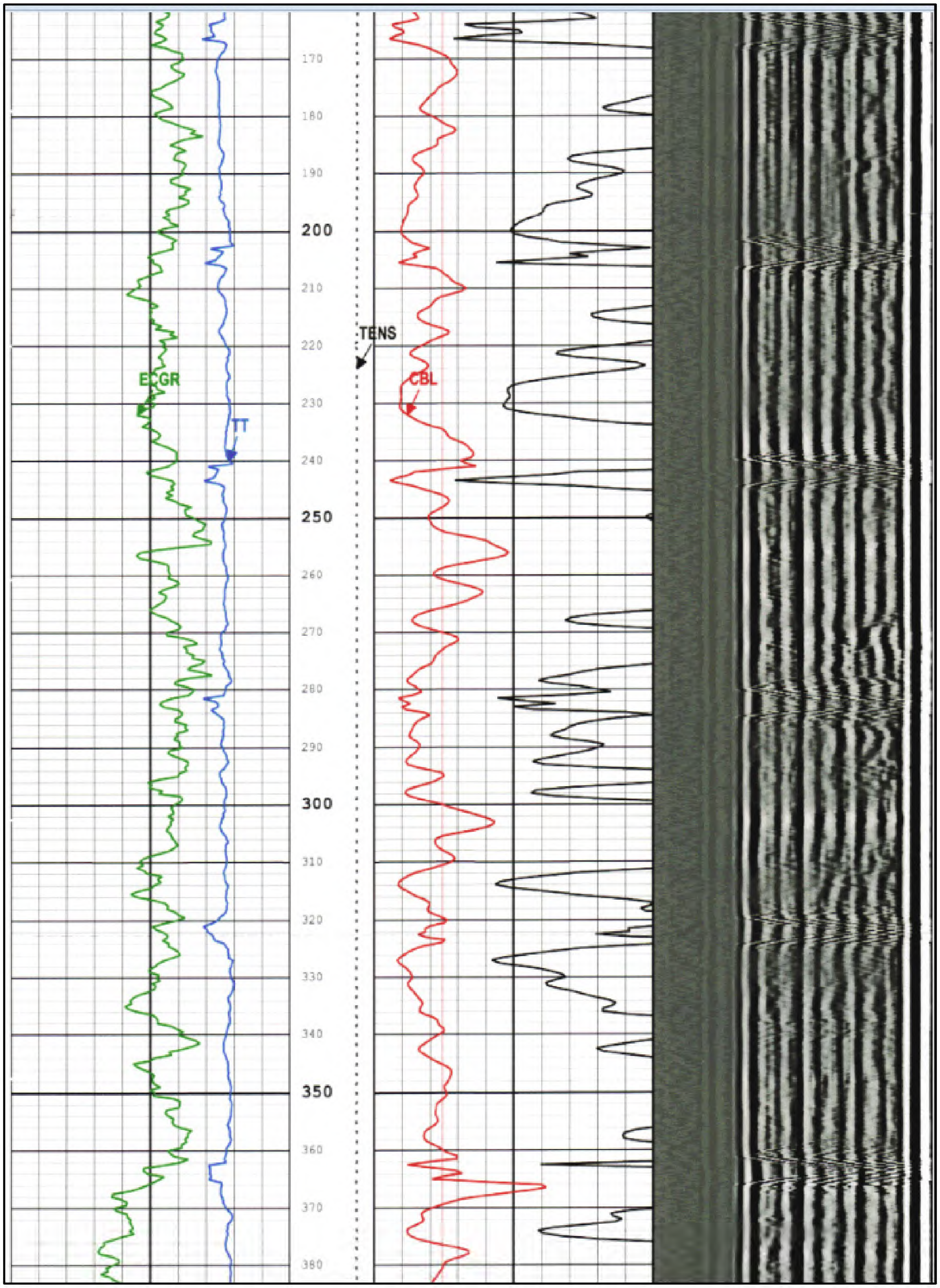

Figure 48: SS-17 CBL-VDL Log Section

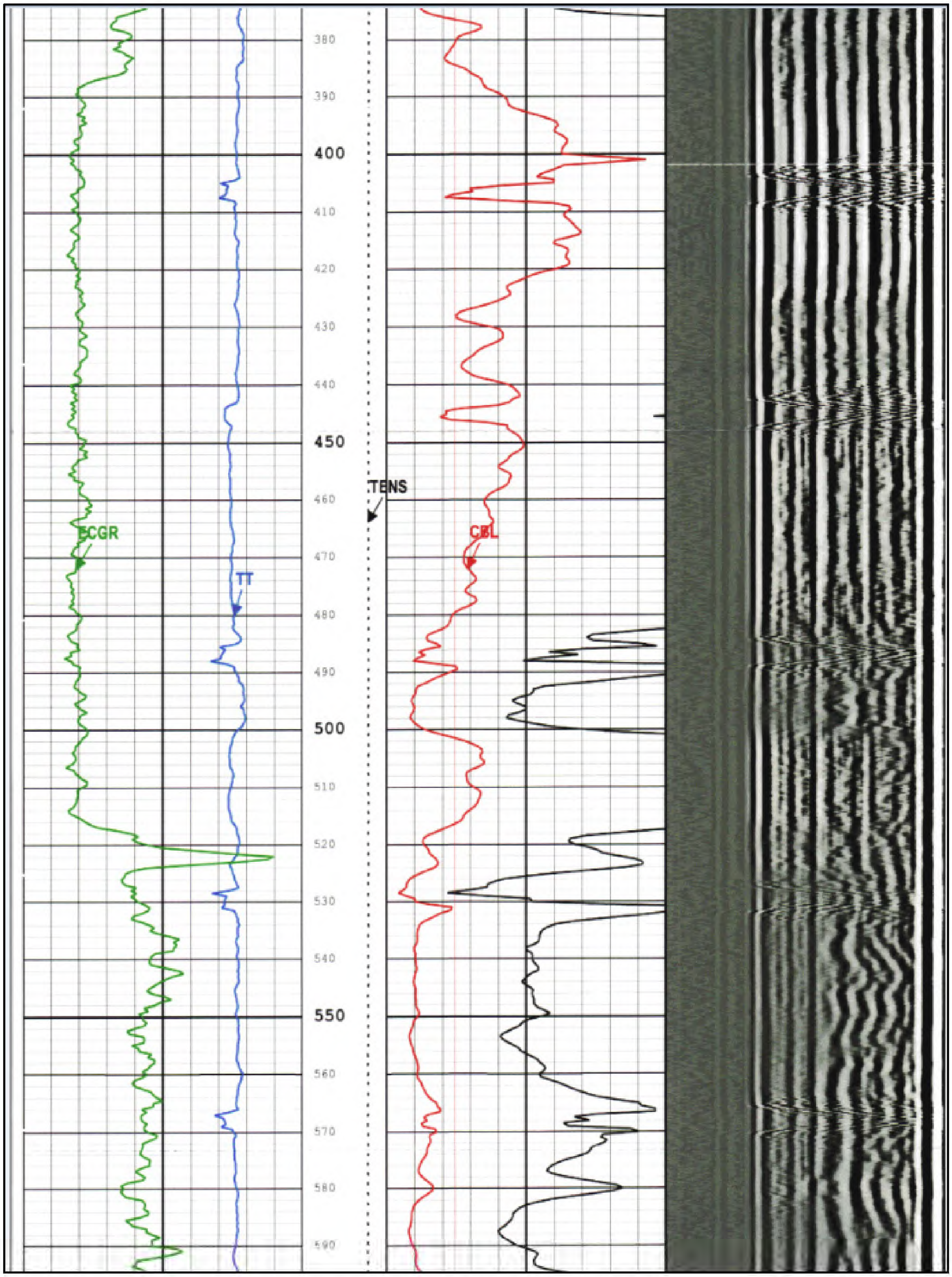

Figure 49: SS-17 CBL-VDL Log Section

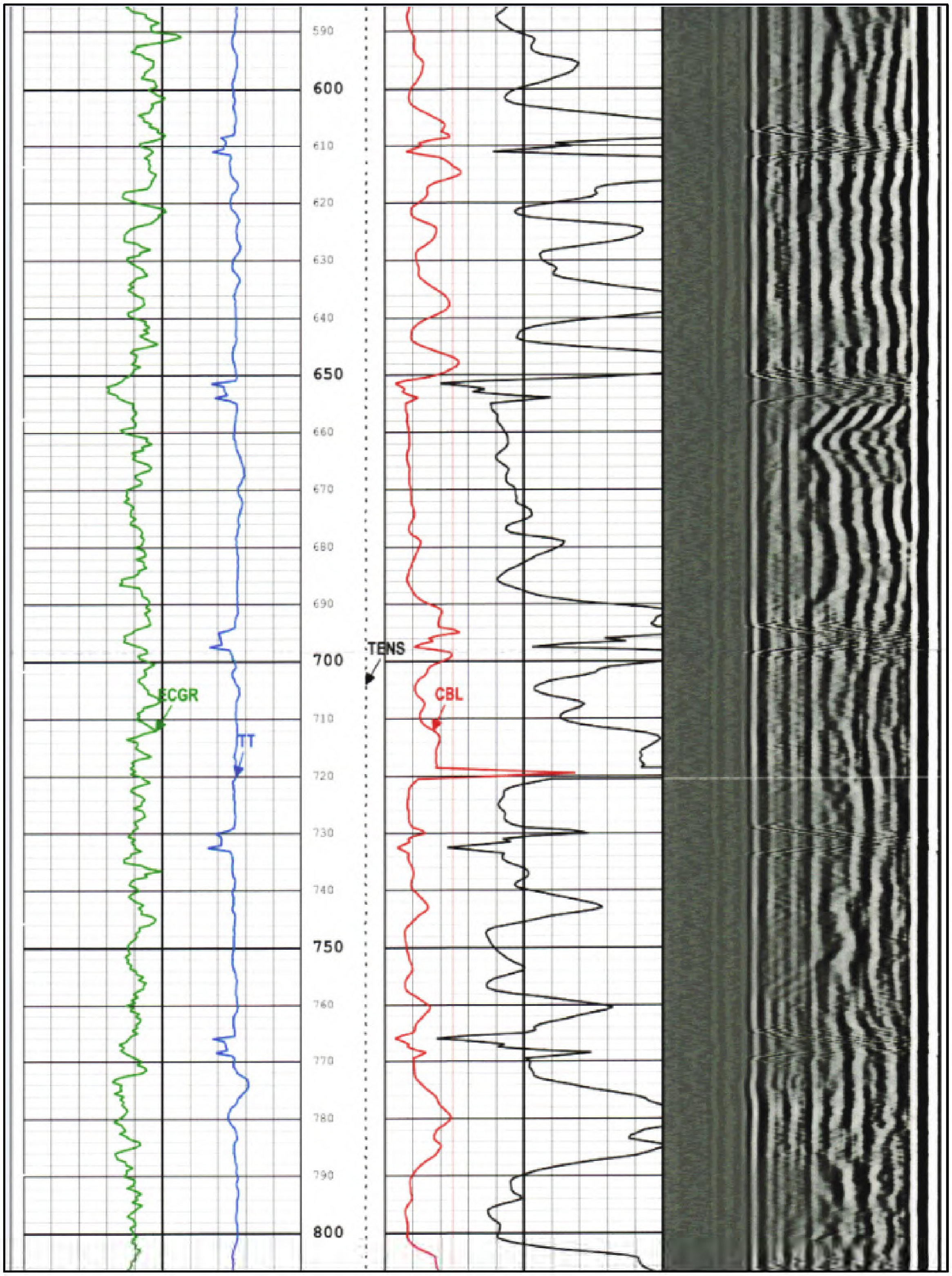

Figure 50: SS-17 CBL-VDL Log Section

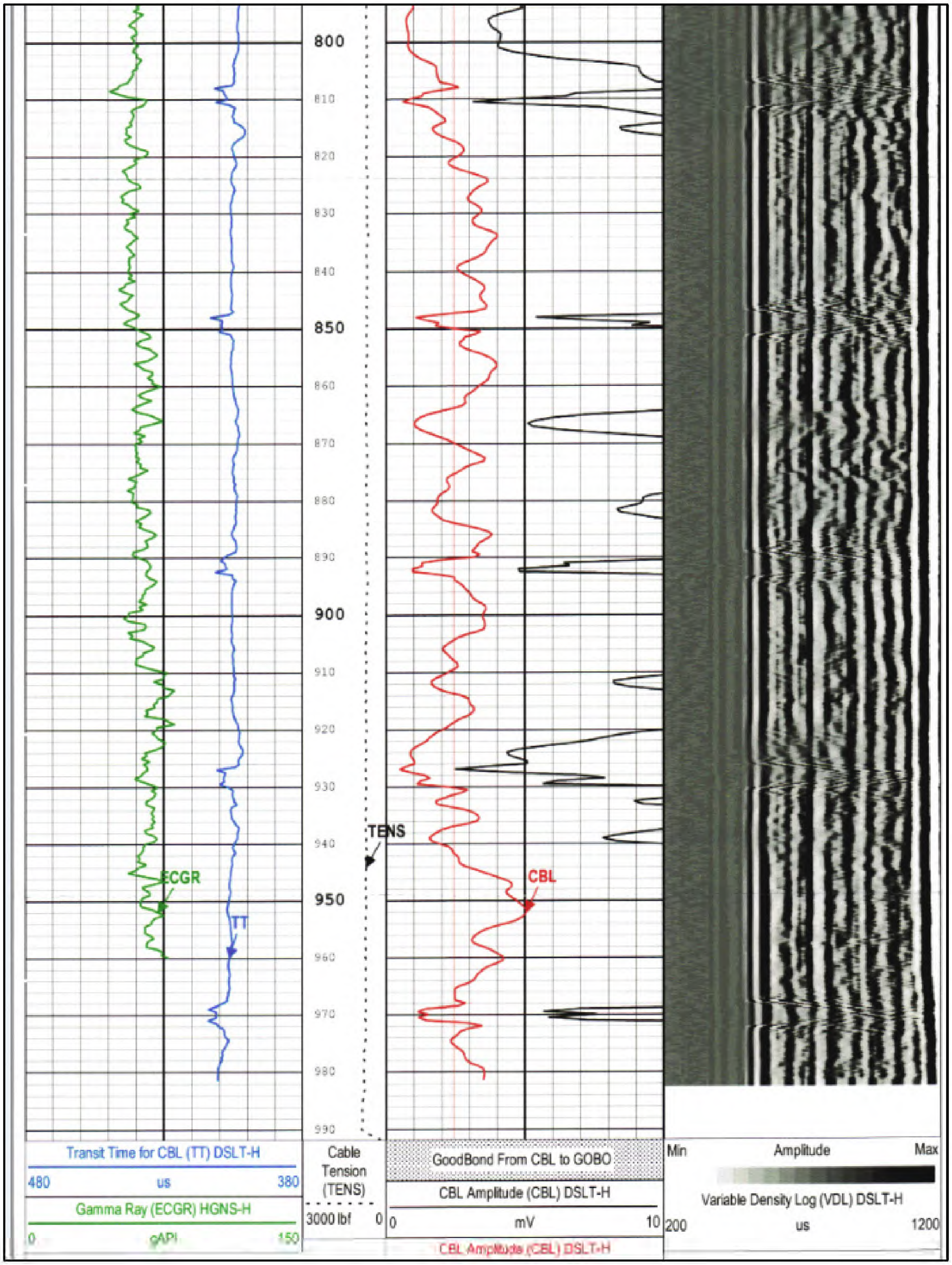

Figure 51: SS-17 CBL-VDL Log Section

A.8 Standard Sesnon 44A

SS-44A has a 13 3/8 in. surface casing at 854 ft. Reported cement to surface.

A.8.1 SS-44A Four-Arm Caliper Log August 3, 2017

Figure 52 is the four-arm caliper log header, and Figure 53 shows the log legend and a section of the log. The caliper log shows the internal indications at 90 ft and 225 ft. The indications on the log were likely caused by the extensive casing cutting and milling on the 8-5/8" production casing.

Schlumberger

Company:	Southern California Gas Company		
Well:	Standard Sesnon 44A		
Field:	Aliso Canyon		
County:	Los Angeles	State:	California

County: Los Angeles
Field: Aliso Canyon
Location:
Well: Standard Sesnon 44A
Company: Southern California Gas Company

Four-Arm Caliper

Location:

		Elev.:	K.B.	2691.00 ft
			G.L.	2674.00 ft
			D.F.	
Permanent Datum:	Ground Level	Elev.:	2674.00 f	
Log Measured From:	Kelly Bushing	17.00 ft	above Perm.Datum	
Drilling Measured From:	Kelly Bushing			

API Serial No.	Section:	Township:	Range:
04-037-21455-00	28	3N	16W

Logging Date	03-Aug-2017		
Run Number			
Depth Driller	500.00 ft		
Schlumberger Depth	500.00 ft		
Bottom Log Interval	395.00 ft		
Top Log Interval			
Casing Fluid Type	Water		
Salinity			
Density	8.5 lbm/gal		
Fluid Level	8.00 ft		
BIT/CASING/TUBING STRING			
Bit Size	17.50 in		
From	0.00 ft		
To	500.00 ft		
Casing/Tubing Size	13.375 in		
Weight	54.5 lbm/ft		
Grade	K55		
From	0.00 ft		
To	500.00 ft		
Max Recorded Temperatures			
Logger on Bottom Time	03-Aug-2017	07:15:00	
Unit Number Location:	3189	Ventura	
Recorded By	I. Kartawidjaja		
Witnessed By	Mr. Tom McMahon		

Figure 52: SS-44A Caliper Log Header [10]

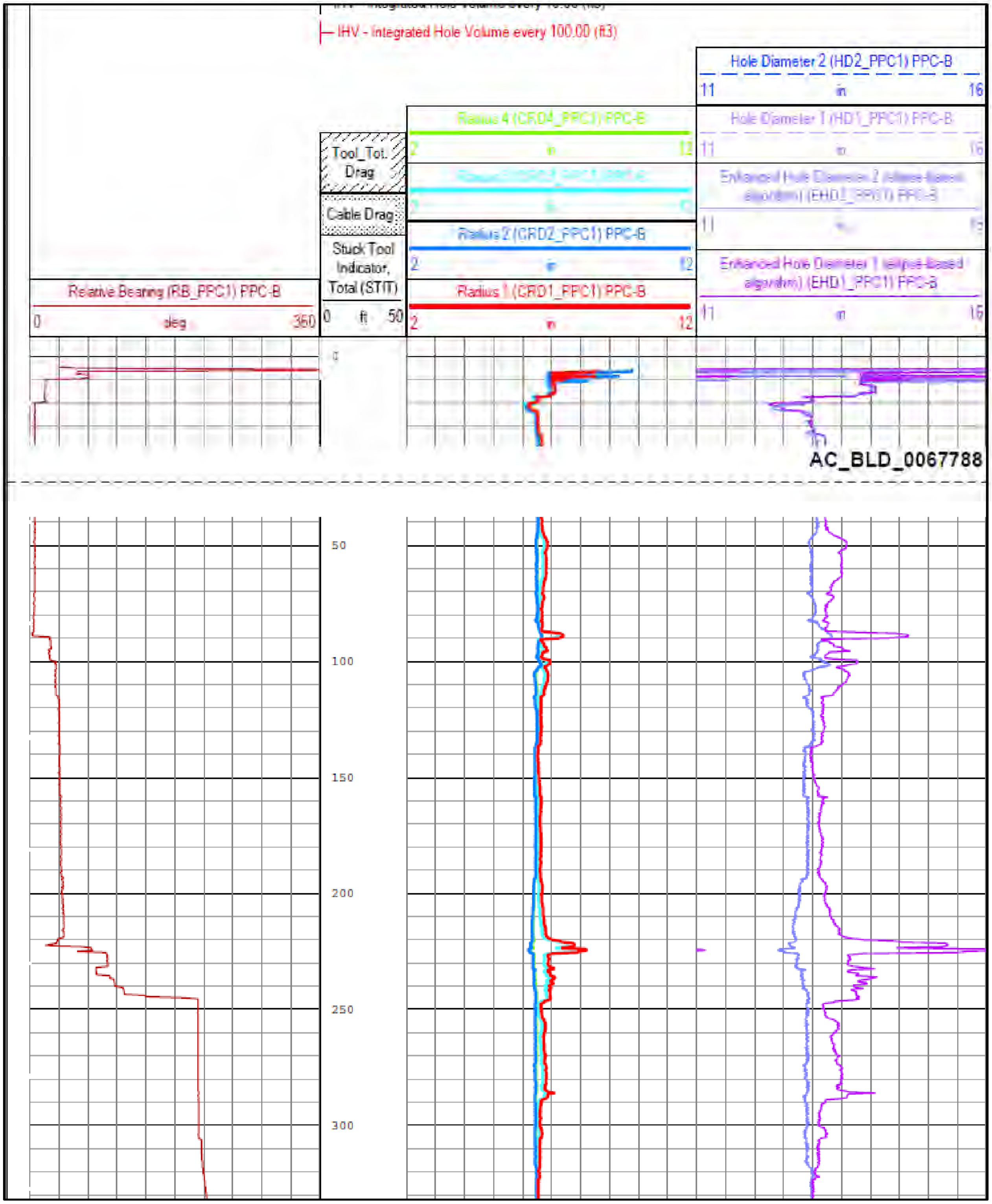

Figure 53: SS-44A Caliper Log Legend and Log Section

SS-25 RCA Supplementary Report

Review of the 1988 Candidate Wells for Casing Inspection

Purpose:
Report on the review, analysis, and results of an August 1988 recommendation to inspect and pressure test Aliso Canyon casing flow wells.

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www.blade-energy.com

Date:
May 31, 2019

Abstract

The gas storage well Standard Sesnon 25 (SS-25) in the Aliso Canyon Gas Storage Field located in Los Angeles County, California started leaking gas in October 2015. A relief well was drilled, and SS-25 was brought under control. The leak stopped in February 2016.

In January 2016, as part of their investigation of the leak, the California Public Utilities Commission (CPUC) and the Division of Oil, Gas, and Geothermal Resources (DOGGR) selected and gave provisional authority to Blade Energy Partners (Blade) to perform an independent Root Cause Analysis (RCA). The Blade Team and parties under Blade's direction were responsible for directing the work of subcontractors who performed the extraction of the SS-25's wellhead and tubing and casing and the preservation and protection of associated evidence. Blade RCA Reports, including this report, document and describe the key activities undertaken in support of the RCA effort.

Southern California Gas Company (SoCalGas) made a recommendation in August 1988 to run casing inspection surveys and pressure test the casing in specific Aliso Canyon wells used as casing flow wells. SS-25 was on the list of wells as a Low Priority well. Inspection surveys were run in seven of the 20 wells and included all five High Priority wells. The surveys showed penetration (wall loss) up to 60% in five of the seven wells. The logs on two of the seven wells have not been located for review. Four of the five wells showed numerous indications of wall loss above the surface casing shoe. Based on the high percentage of wells with significant penetration, the question remains as to why the remaining 13 wells were not inspected in the 2-year period as recommended.

Blade reviewed the records of all 20 wells to evaluate subsequent casing inspections and the casing problems that occurred in the following years. A number of casing problems were identified. Mitigation for casing problems included running inner casing in some wells in the late 1980s with a packer. Inner casing was run and cemented in some of the 20 wells in 2016–2017. Twelve of the 20 wells are now plugged and abandoned (P&A'd); the remaining 8 wells had workovers to mitigate the production casing problems and have passed the required integrity tests.

The conclusion of this analysis is that SoCalGas made a recommendation to run casing inspection logs in 20 wells that concerned them at the time, and the opportunity to inspect the casing in SS-25 was missed. There is no way to know what an inspection of the SS-25 casing would have shown in 1988, but it is possible that corrosion was present and detectable, and steps could have been taken to avoid the leak in 2015.

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1 Introduction

The purpose of this document is to review and analyze a recommendation made in a SoCalGas Interoffice Correspondence document dated August 30, 1988 [1]. The recommendation was to run casing inspection surveys in 20 wells and pressure test each well. Blade reviewed the well records of these 20 wells to understand what was done in each well with respect to casing inspection, pressure tests, and operations related to casing problems since 1988. The results of the casing inspections are reviewed and summarized in this report.

Sections of the casing inspection logs and the results of the casing inspection are included. The term *penetration* is used in some of the casing inspection logs reports and has the same meaning as wall loss or defect depth.

1.1 Abbreviations and Acronyms

Term	Definition
BOP	Blowout Preventer
CBL	Cement Bond Log
CIT	Casing Inspection Tool
CPUC	California Public Utilities Commission
DFE	Derrick Floor Elevation
DOGGR	Division of Oil, Gas, and Geothermal Resources
E-log	Electric Log
F	Frew
HR	High Resolution
HRVRT	High Resolution Vertilog
IBC	Isolation Scanner
MMscf/D	Million Standard Cubic Feet per Day
P	Porter
P&A	Plug and Abandon
PSI	Gauge pressure units of Pounds Force per Square Inch
SLB	Schlumberger
SoCalGas	Southern California Gas Company
SS	Standard Sesnon
TCP	Tubing Conveyed Perforating
USIT	UltraSonic Imager Tool
WSO	Water Shut-Off

2 Candidate Wells for Casing Inspection

Figure 1 shows a scan of the Interoffice Correspondence document that recommended running casing inspection surveys (Vertilogs[i]) in all casing flow wells[ii] of 1940s and 1950s vintage Aliso Canyon wells and pressure testing the casings. Appendix B includes the attachment listing the wells and parameters.

INTEROFFICE SOUTHERN CALIFORNIA gas COMPANY CORRESPONDENCE

TO [redacted] FROM [redacted] DATE August 30, 1988

SUBJECT Candidate Wells for Casing Inspection, Aliso Canyon Field

Attached is a listing of all casing flow wells of 1940's and 1950's vintage currently in operation at the subject field. It is recommended that casing inspection surveys (vertilogs) be run to determine the mechanical condition of each well casing. In addition, each well should be pressure tested to identify any leaks at the casing collars.

The wells included on the attached list are prioritized based upon deliverability, operational history, and the length of time since their last workover. Please advise should you have any questions or require additional information.

[redacted]

Attachments

AC_CPUC_0000064

Figure 1: Scan of the August 30, 1988 Interoffice Correspondence
Nonessential Information was Redacted

Blade's interpretation of the recommendation was to run a Vertilog casing inspection log to identify damaged intervals and the severity of corrosion. The log analysis and report provided a listing of percent wall penetration by casing joint, depth in the well, and if the defect is internal or external. The casing body can be evaluated using the inspection data to determine if it has the pressure capacity for the expected pressure load. However, the Vertilog inspection does not ensure there are no casing leaks. The inspection only covers the casing body and not the connection. The casing connection interferes with the inspection magnetic field imposed on the casing to identify defects.

In addition to the recommendation to run the Vertilog survey, a pressure test was recommended to identify any leaks at the casing collars. The pressure test would also confirm the integrity of the casing body and check for small through-wall defects that the inspection tool can miss.

[i] Vertilog services were provided by Western Atlas in the 1988–1990 time period. Baker Hughes acquired Atlas and now provides Vertilog services. Vertilog technology uses magnetic flux leakage measurements to determine the corrosion caused casing wall penetration and if the corrosion damage is internal or external. Additional information on the Vertilog technology and survey reporting in the 1980s is discussed by Haire and Heflin [8].

[ii] Casing flow refers to wells that are completed such that the injected and withdrawn gas is exposed to the casing. A reason for casing flow is to operate wells at higher rates because of the larger flow area in the casing-tubing annulus. The risk with casing flow wells is the inexistence of a secondary barrier in case of a casing leak.

A second Interoffice Correspondence was prepared to recommend that all wells listed be logged and pressure tested over the next two-year period [2]. Figure 2 shows a scan of the September 2, 1988 document, which states that 19 wells are listed; however, the document's attachment shows 20 wells.

SOUTHERN CALIFORNIA gas COMPANY

INTEROFFICE CORRESPONDENCE

XC: [redacted]

TO [redacted] FROM [redacted] DATE Sept. 2, 1988

SUBJECT Candidate Wells for Casing Inspection, Aliso Canyon Field

Attached is [redacted] recommendations and priorities for inspection of casing flow wells originally completed in the 1940's and 50's.

I agree with [redacted] priorities and recommend that all 19 wells listed be logged and pressure tested over the next two year period.

[redacted]

Attachments

cc: [redacted]

AC_CPUC_0000053

Figure 2: Scan of the September 2, 1988 Interoffice Correspondence Nonessential Information was Redacted

Figure 3 shows a map of the Aliso Canyon Field with the 20 casing inspection wells flagged.

Table 1 shows a summary of the list of wells taken from the Interoffice Correspondence attachment. The priority was based on deliverability, operational history, and the time since the last workover. SS-25 was included in the list as Low Priority.

Seven of the 20 wells were logged within the 2-year period specified in the recommendation. The five High Priority wells, one medium priority, and the Frew 4 well were logged. The wells logged are indicated by the dates shown in the table. A summary of the Vertilog results for 5 of the 7 wells logged show that all 5 wells had wall penetration ranging from greater than 20% to greater than 60%. Logs from the remaining 2 wells have not been located (Porter 34 and Frew 2). The remaining 13 wells were not logged during the 2-year window. The log for P-34 was not located; however, a 5 1/2 in. inner casing was run immediately following the inspection log, suggesting the log showed the 7 in. casing's condition was a concern.

The table column titled Date Logged (Post 2 yrs.) shows the casing inspection logs and a summary of the results of those logs run from 2007 through 2017. As the table shows, penetrations ranged from greater than 20% to greater than 80%.

The column labeled Notes shows numerous wells with casing problems, such as leaks and tight spots. Inner casings were installed to remediate casing problems. Some wells had inner casings installed in 1989 and were set with a packer, unlike recent inner casing strings (2016–2017), which were cemented in place.

The Current Status column indicates the well status as of March 2019, based on a review of the Test Results of Aliso Canyon Wells that SoCalGas files with the California Department of Conservation twice a month [3]. Twelve of the 20 wells are P&A'd and the remaining 8 wells have passed the required integrity tests.

Appendix A includes additional details related to casing inspection logging, pressure testing, remedial work for each well, and relevant sections of the casing inspection logs.

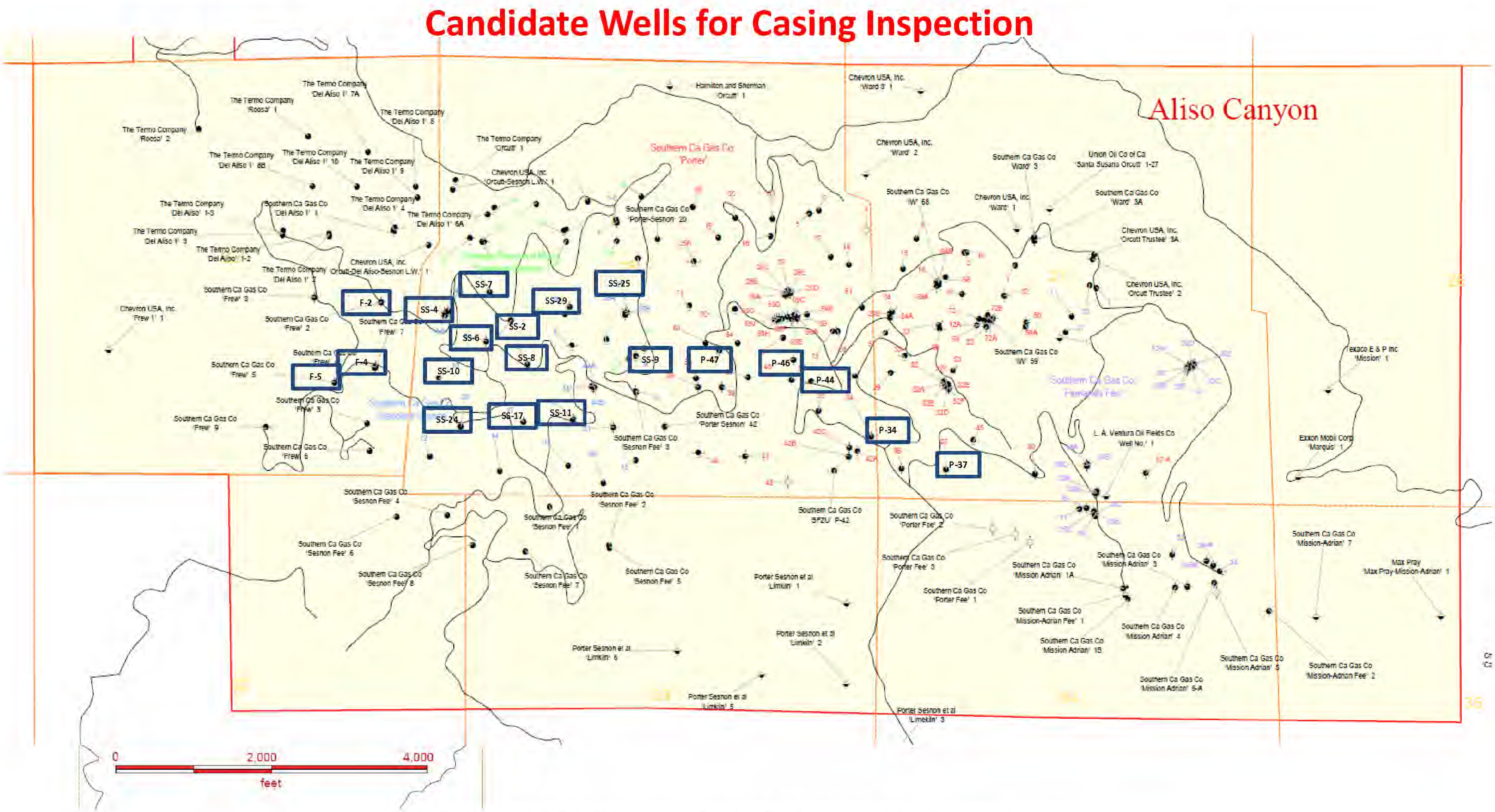


Figure 3: Aliso Canyon of the 20 Candidate Wells for Casing Inspection

Table 1: List of 1988 Casing Flow Wells

Lease	Well	Deliverability (MMscf/D)	Priority	Date Logged (within 2 yrs.)	Vertilog Available	Vertilog Summary	Date Logged (Post 2 yrs.)	Log Summary	Notes	Current Status
Porter	34	9	High	Vertilog Nov 2, 1989	No	N/A	N/A	N/A	Ran 5 1/2 in. inner casing Dec 20, 1989	P&A 2018
Porter	37	24	High	Vertilog Oct 11, 1988	Yes	4 jts >20% OD Penetration 1 jt > 60% OD Penetration	N/A	N/A	Ran 5 1/2 in. inner casing May 12, 1989. Ran and cemented 5 1/2 in. inner casing Nov 14, 2017.	Passed All Tests
Porter	44	26	Low	Not logged within 2 years	N/A	N/A	High Resolution Vertilog (HRVRT) Feb 15, 2016 UltraSonic Imager Tool (USIT) Feb 29, 2016	1 jt >20% OD Penetration 1 jt >80% OD Penetration External corrosion on multiple joints and potential casing hole at 4,000 ft	Casing leak between 3,961 ft and 4,010 ft Feb 18, 2016 Set casing patch Mar 4, 2016. Set casing patch Mar 5, 2016.	Passed All Tests
Porter	46	35	High	Vertilog Oct 19, 1988	Yes	10 jts >20% OD Penetration	USIT Aug 16, 2017	Indications 3,970–3,984 ft	Ran and cemented 5 1/2 in. inner casing Oct 4, 2017	Passed All Tests
Porter	47	21	Low	Not logged within 2 years	N/A	N/A	No casing inspection logs found as of Feb 4, 2019	N/A	Pressure tested 7 in. casing to 1,200 psi for 1 hour, Sep 19, 2016	P&A 2017
Standard Sesnon	2	16	Low	Not logged within 2 years	N/A	N/A	No casing inspection logs found as of Feb 4, 2019	N/A	Pressure tested 7 in. casing to 1000 psi for 1 hour, Jul 26, 2016	P&A 2017

Lease	Well	Deliverability (MMscf/D)	Priority	Date Logged (within 2 yrs.)	Vertilog Available	Vertilog Summary	Date Logged (Post 2 yrs.)	Log Summary	Notes	Current Status
Standard Sesnon	4	0	Low	Not logged within 2 years	N/A	N/A	No casing inspection logs found as of Feb 4, 2019	N/A	N/A	P&A in progress
Standard Sesnon	6	10	Low	Not logged within 2 years	N/A	N/A	USIT Aug 8, 2012	Questionable log data	Ran and cemented 5 1/2 in. inner casing Jul 17, 2017	Passed All Tests
Standard Sesnon	7	1	Medium	Not logged within 2 years	N/A	N/A	USIT Nov 1, 2012 Noise Jul 6, 2012 USIT May 5, 2014	Indications 1,912–1,927 ft 4,012–4,030 ft Above normal noise activity 3,600–4,200 ft Indications 1,912–1,927 ft 4,010–4,032 ft	N/A	P&A 2014
Standard Sesnon	8	15	High	Vertilog Jan 17, 1989	Yes	28 jts >20% OD Penetration 5 jts > 40% OD Penetration	Cast V Apr 28, 2007 USIT Apr 24, 2013	Indications 955–1,080 ft 2,276–2,482 ft 3,287–3,289 ft 8,479–8,482 ft	N/A	Passed All Tests Observation Well
Standard Sesnon	9	15	High	Vertilog Dec 16, 1988	Yes	6 jts >20% OD Penetration	N/A	N/A	5 1/2 in. inner casing 0–8,599 ft (5 1/2 in. USIT log Oct 24, 2018)	Passed All Tests
Standard Sesnon	10	25	Low	Not logged within 2 years	N/A	N/A	USIT Sep 24, 2012	Indications 2,294–3,246 ft	Ran 7 in. casing patch 4,462–4,524 ft Sep 27, 2012. Ran and cemented 5 1/2 in. inner casing May 17, 2017.	Passed All Tests

Lease	Well	Deliverability (MMscf/D)	Priority	Date Logged (within 2 yrs.)	Vertilog Available	Vertilog Summary	Date Logged (Post 2 yrs.)	Log Summary	Notes	Current Status
Standard Sesnon	11	9	Low	Not logged within 2 years	N/A	N/A	No casing inspection logs found as of Feb 4, 2019	N/A	N/A	P&A in Progress
Standard Sesnon	17	7	Low	Not logged within 2 years	N/A	N/A	No casing inspection logs found as of Feb 4, 2019	N/A	N/A	P&A 2017
Standard Sesnon	24	11	Low	Not logged within 2 years	N/A	N/A	HRVRT Feb 11, 2017 USIT Feb 15, 2017	4 jts >20% OD Penetration 4 jts >20% ID Penetration Daily report USIT comments; External Anomalies 8,406–8,414 ft 2,250–2,920 ft 1,100–1,620 ft 8 jts >20% Penetration	N/A	P&A 2017

Lease	Well	Deliverability (MMscf/D)	Priority	Date Logged (within 2 yrs.)	Vertilog Available	Vertilog Summary	Date Logged (Post 2 yrs.)	Log Summary	Notes	Current Status
Standard Sesnon	25	38	Low	Not logged within 2 years	N/A	N/A	HRVRT Dec 2, 2017 Isolation Scanner (IBC) Corrosion Dec 4, 2017	4 jts >20% OD Penetration 1 Jt > 40% OD Penetration Indications of external corrosion 940–980 ft 1,525–2,400 ft 2,525–2,570 ft	Casing parted at 892 ft Oct 23, 2015. The inspection logs were run in the 7 in. casing below 892 ft	P&A 2018
Standard Sesnon	29	22	Low	Not logged within 2 years	N/A	N/A	USIT Oct 10, 2017 HRVRT Oct 13, 2017	4 jts >20% Penetration 1 jt >20% OD Penetration 3 jts >20% ID Penetration 1 jt > 40% ID Penetration	5 1/2 in. inner casing 0–8,076 ft (5 1/2 in. HRVRT log Dec 26, 2018)	Passed All Tests

Lease	Well	Deliverability (MMscf/D)	Priority	Date Logged (within 2 yrs.)	Vertilog Available	Vertilog Summary	Date Logged (Post 2 yrs.)	Log Summary	Notes	Current Status
Frew	2	1	Medium	Vertilog Jan 11, 1990	No	N/A	USIT Sep 11, 2014 Vertilog Oct 20, 2014	Indications 600–3,220 ft 15 jts >20% OD Penetration 3 jts >40% OD Penetration 5 jts >60% OD Penetration 2 jts >80% OD Penetration Possible penetration around 2835'	Tight Spot 3,872 ft Tight Spot 8,130 ft Casing leak between 2,949 and 2,969 ft Workover in 2014	P&A 2017
Frew	4	12	-	Vertilog Sep 6, 1988	Yes	12 jts >20% OD Penetration 12 jts > 40% OD Penetration 2 jts > 60% OD Penetration	USIT Oct 20, 2016	Indications 764–5,085 ft 5,708–5,911 ft 6,782–6,788 ft 6,908–6,911 ft	N/A	P&A 2018
Frew	5	2	Medium	Not logged within 2 years	N/A	N/A	Noise Apr 8, 2016	No casing inspection logs found as of Feb 4, 2019	Noise detected 1,100-2,200 ft.	P&A 2017

2.1 Vertilog Production Casing Penetration above the Surface Casing Shoe

Figure 4 summarizes the percent penetration and depths from the Vertilog results for P-37, P-46, F-4 and SS-8 production casings above and immediately below the surface casing shoe. The four wells were logged in 1988 and 1989. The derrick floor elevation (DFE) above sea level is included and shows the significant change in elevations among the wells.

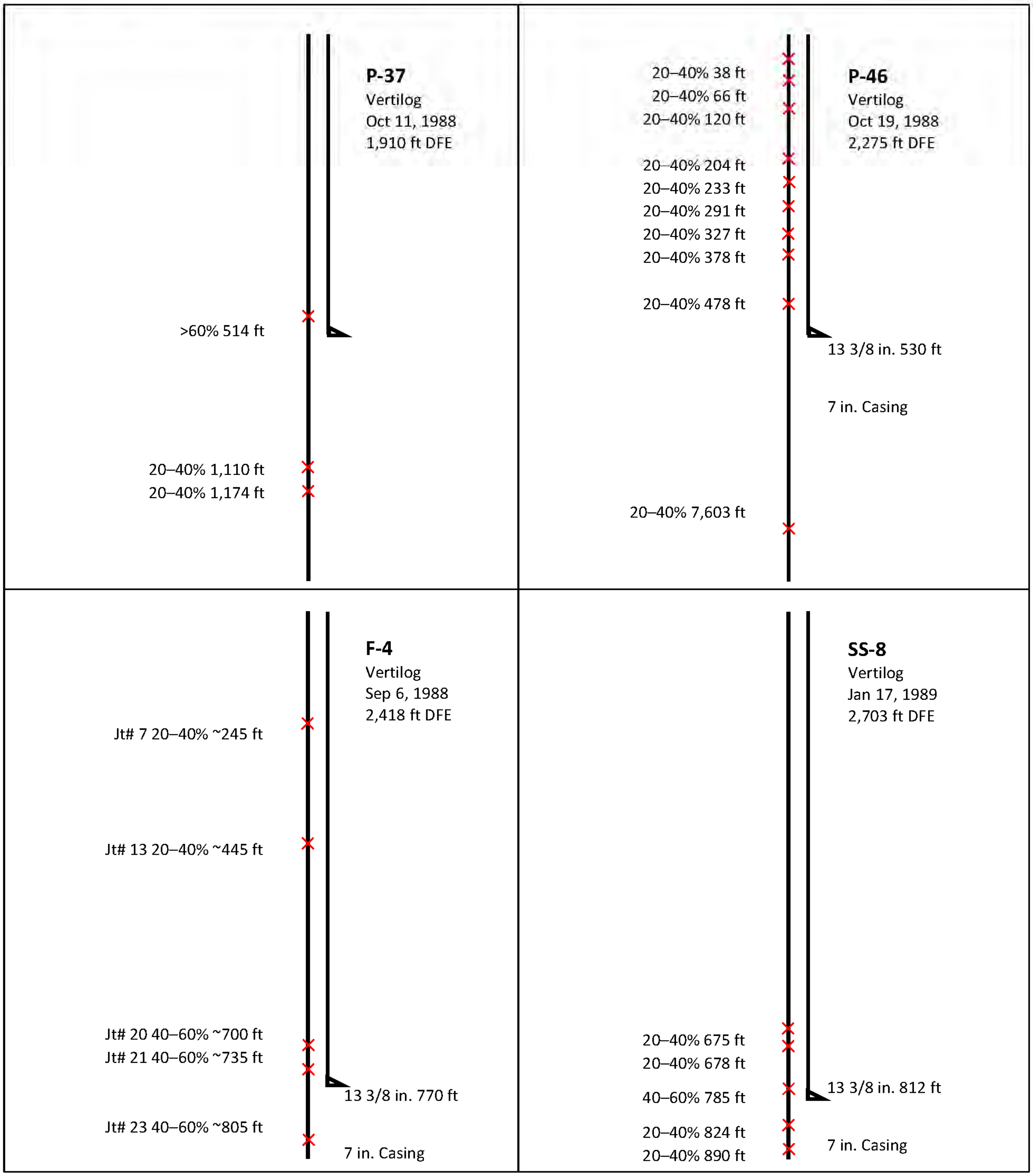


Figure 4: Wellbore Schematics Showing Vertilog Penetration Data

Table 2 shows the same data as Figure 4 in tabular form. The log data shows numerous indications of wall loss on the production casing above the surface casing shoe in all four wells and immediately below the shoe in two wells (F-4 and SS-8).

Table 2: Production Casing Vertilog Penetrations Summary

Well	Spud Date	Vertilog Date	DFE (ft)	Vertilog Penetrations, Depths, and Surface Casing Depths
P-37	Jun 12,1946	Oct 11, 1988	1,910	>60% 514 ft 13 3/8 in. Surface Casing 520 ft
P-46	Nov 2, 1943	Oct 19, 1988	2,275	20–40% 38 ft 20–40% 66 ft 20–40% 120 ft 20–40% 204 ft 20–40% 233 ft 20–40% 291 ft 20–40% 327 ft 20–40% 378 ft 20–40% 478 ft 13 3/8 in. Surface Casing 530 ft 20–40% 7,603 ft
F-4	Sep 20, 1947	Sep 6, 1988	2,418	Jt# 7 20–40% ~245 ft Jt# 13 20–40% ~445 ft Jt# 20 40–60% ~700 ft Jt# 21 40–60% ~735 ft 13 3/8 in. Surface Casing 770 ft Jt# 23 40–60% ~805 ft
SS-8	May 14, 1946	Jan 17, 1989	2,703	20–40% 675 ft 20–40% 678 ft 40–60% 785 ft 13 3/8 in. Surface Casing 812 ft 20–40% 824 ft 20–40% 890 ft

2.2 Casing Inspection Recommendation Analysis

Based on the Interoffice Correspondence of August 1988 (Figure 1), there was a reason that the recommendation was made to inspect the casing and pressure test the 20 wells listed. Blade was not able to locate documented reasons for the recommendation, other than the list included all of the casing flow wells, as stated in the recommendation.

The log results from five of seven inspected wells shows the recommendation to run casing inspection logs was prudent. An inner casing was run in one of the remaining two wells at the time of the inspection, suggesting the log identified wall loss. The log results for the remaining well may or may not show significant penetration or wall loss. However, the question of why the remaining 13 wells were not logged within the 2-year period has not been fully answered.

Blade asked SoCalGas the paraphrased question "Was the recommended casing inspection run in SS-25?" in an information request on December 18, 2018. The paraphrased follow-up question, to which SoCalGas responded on January 11, 2019, was "If the inspection was not run, what was the reason for not running the survey?" Figure 5 shows a scan of the questions from Blade and the response from SoCalGas.

Question 2:

Refer to documents AC_CPUC_0000064 through AC_CPUC_0000066 and AC_CPUC_0000063 regarding Interoffice Correspondence recommending casing inspections for a list of casing flow wells of 1940s and 1950s vintage to determine the mechanical condition of each well casing. SS-25 was included in the list of wells recommended for casing inspection.

a. Please advise if the recommended casing inspection (Vertilog) was run in SS-25. If so, provide the inspection survey. If not, what was the reason for not running the inspection survey in SS-25?

Response 2:

Consistent with the recommendations set forth in AC_CPUC_0000064 through AC_CPUC_0000066, the casing inspection (Vertilog) was run on the wells identified to be "high priority" on the following dates:

Porter 34	11/2/89
Porter 37	10/11/88
Porter 46	10/19/88
Standard Sesnon 8	1/17/89
Standard Sesnon 9	12/16/88
Frew 4	9/6/88

The Vertilog was not run on SS-25. The Vertilog technology in 1988 that was recommended in this memo, proved to be less effective at identifying casing leaks than the well diagnostic tests that SoCalGas routinely performed on its underground gas storage wells (e.g., annual temperature surveys, noise logs, etc.).

Figure 5: Information Request and Response

As stated in the SoCalGas response, the wells with High Priority were inspected. However, at least six of seven wells showed significant wall loss (penetration). SoCalGas' response that the Vertilog was less effective at identifying casing leaks seems to miss the objective of the recommendation. Since significant wall loss was found in a high percentage of wells, it would seem prudent to continue with the inspection program to collect inspection data on other wells on the list to see if this was an isolated problem or a pervasive problem in multiple wells.

The purpose of the inspection according to the August 30, 1988 Interoffice Correspondence (Figure 1) was to determine the mechanical condition of the casing. Blade's interpretation of mechanical condition in this context is to detect metal loss, quantify the depth of penetration, and confirm casing pressure integrity.

Vertilog casing inspection surveys cover the pipe body and not casing connections. As stated in the Interoffice Correspondence, the second part of the recommendation was to pressure test the casing to identify leaks at the casing collar (and pipe body by default). A Vertilog survey showing all casing with less than 20% penetration does not ensure the casing has pressure integrity. A defect (hole) can be too small to be reliably detected by a Vertilog survey. Therefore, casing inspection for wall thickness measurement *and* a pressure test for casing integrity is a requirement. This is consistent with the current (January 2019) California DOGGR regulations [4].

Each of the 20 wells' production casings was pressure tested multiple times during the life of the well. Most of the wells were pressure tested up to 4,000 psi in stages with the highest pressure in the upper part of the well. Reported pressure tests for each well are documented in Appendix A.

2.3 Current Status

SoCalGas P&A'd 12 of the 20 wells and worked over the remaining 8 wells. The eight wells passed the required integrity tests. The following is a summary of the eight wells:

- Six have a 5 1/2 in. inner casing to isolate the 7 in. casing.
- One has a casing patch to isolate a zone with indications on the inspection logs (P-44).
- One is plugged back with cement to 8,290 ft and was converted to an observation well (SS-8).

3 Conclusions

- SoCalGas had a two-year plan to determine the mechanical condition of the casing in 20 casing flow wells originally completed in the 1940s and 1950s. They prioritized the wells based on gas deliverability, operational history, and length of time since their last workover. This was according to two Interoffice Correspondence documents on August 30, 1988 (Figure 1) and September 2, 1988 (Figure 2). SoCalGas logged 7 of the 20 wells within 2 years of the recommendation.
- Inspection logs showed penetrations of greater than 20% to greater than 60% in five of the seven wells logged from 1988–1990. Logs in two of the seven wells have not been located; however, a 5 1/2 in. inner casing was run in one of the two wells at the time of the inspection indicating significant penetration. An inner casing string was run in two of the seven wells in 1989. The logs showed numerous indications above the surface casing shoe in four of five wells (Table 2) and immediately below the shoe in two of the four wells (F-4 and SS-8).
- SoCalGas made a recommendation to run casing inspection logs in the 20 wells that concerned them at the time, and the opportunity to inspect the casing in SS-25 was missed. There is no way to know what an inspection of the SS-25 casing would have shown in 1988, but it is possible that the corrosion was present and detectable, and steps could have been taken to avoid the leak in 2015.
- SoCalGas logged some of the 13 remaining wells starting in 2007, resulting in a gap from 1990 to 2007 when no inspection logs were run in the 20 wells, according to the available well records.
- Blade's review of the available well records indicates that no casing inspection logs were run in seven of the 20 wells. SS-25 is included in the seven wells since no inspection logs were run prior to the leak in October 2015.
- SoCalGas logged the High Priority wells and found significant penetration (wall loss). No documentation was found that explained why the remaining wells were not inspected as per the recommendation in 1988. Blade inquired if SS-25 was inspected based on the 1988 recommendation since it was on the list of 20 wells as Low Priority. SoCalGas responded that SS-25 was not inspected because the Vertilog technology was less effective at identifying casing leaks than the well diagnostic tests that SoCalGas routinely performed on its underground gas storage wells. As discussed, the 1988 objective was to determine the mechanical condition of the casing, not to identity casing leaks.

4 References

[1] SoCalGas, "Interoffice Correspondence, Candidate Wells for Casing Inspection, Aliso Canyon Field, August 30, 1988 AC_CPUC_0000064-AC_CPUC_0000066 (SS-25 Well Documentation (from SoCalGas)_N.pdf, pages 42-44)".

[2] SoCalGas, "Interoffice Correspondence, Candidate Wells for Casing Inspection, Aliso Canyon Field, September 2, 1988, AC_CPUC_0000063 (SS-25 Well Documentation (from SoCalGas)_N.pdf, page 41)".

[3] SoCalGas, "California Department of Conservation, Test Results of Aliso Canyon Wells," [Online]. Available: https://www.conservation.ca.gov/dog/AlisoCanyon. [Accessed 29 January 2019].

[4] California Department of Conservation, *Statutes & Regulations,* January 2019.

[5] DOGGR, "Division of Oil, Gas, and Geothermal Resources - Well Search," [Online]. Available: https://secure.conservation.ca.gov/WellSearch/. [Accessed 31 January 2019].

[6] Baker Hughes, "SS-24 HRVRT 7 in Feb 11 2017 AC_BLD_0063764.pdf," 2017.

[7] Blade, "SS-25 Inspection Log Analysis," 2019.

[8] J. N. Haire and J. D. Heflin, "Vertilog - A Down-hole Casing Inspection Service," in *47th Annual California Regional Meeting of the Society of Petroleum Engineers of AIME*, Bakersfield, 1977.

Appendix A Pressure Test and Log Summary

Additional production casing integrity details on the 20 wells are included in this section, including relevant sections of inspection logs, pressure tests, and operations related to casing problems and mitigation. The summaries are paraphrased from well records from SoCalGas and the DOGGR Well Search website [5] where public information on wells is available. Well logs not referenced in this document can be downloaded from the Well Search website.

A.1 Porter 34

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 497 ft
2. Gap in 13 3/8 in. casing from 445 ft to 477 ft by E-log. April 13, 1946
3. Pressure test 7 in. casing in stages 2,400–3,400 psi for 20 minutes. November 25, 1974
4. Pressure test 7 in. casing in stages 2,700–4,000 psi for 60 minutes. October 13, 1977
5. Ran 7 in. Vertilog 7,694 ft–Surface. November 2, 1989. (Vertilog not available. Not on DOGGR website as of February 7, 2019)
6. Pressure test seals, packer and 7 in. casing 1,500 psi for 20 minutes. December 20, 1989
7. Ran 5 1/2 in. inner casing 7,640 ft–Surface. December 26, 1989
8. Pressure test 7 in. x 5 1/2 in. annulus to 1,107 psi for 1 hour. October 10, 2016
9. Pull 5 1/2 in. inner casing. January 17, 2017
10. Pressure test 7 in. casing 1,061 psi for 20 minutes. January 18, 2017
11. Pressure test 7 in. casing 1,080 psi for 20 minutes. January 24, 2017
12. Pressure test 7 in. casing 1,140 psi for 15 minutes. January 25, 2017
13. Blade collected 7 each of the 7 in. Speedtite connections during the P&A. March 23, 2018
14. P&A'd in 2018

A.1.1 P-34 Vertilog November 2, 1989

The Vertilog was run according to the well records. The log was not available on the DOGGR website as of February 7, 2019.

A.2 Porter 37

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 520 ft
2. Pressure test 7 in. casing in stages 2,500–3,200 psi for 15 minutes. November 8, 1972
3. Pressure test 7 in. casing in stages 2,800–4,000 psi for 60 minutes. September 24, 1977
4. Ran 7 in. Vertilog 7,460 ft–surface. October 11, 1988
   - 4 joints >20% OD penetration. 1,110–1,174 ft, 3,152, 3,488 ft
   - 1 joint >60% OD penetration. 514 ft
5. Pressure test 7 in. casing in stages 2,300–3,200 psi. October 12, 1988
6. Ran 5 1/2 in. inner casing 7,434 ft to surface. May 12, 1989
7. SIMP Well Operations Procedure to pull 5 1/2 in. inner casing. Run new 5 1/2 in. inner casing and cement to surface dated August 4, 2017
8. Pressure integrity test 5 1/2 in. casing 3,752 psi for 60 minutes. November 14, 2017
9. Passed all tests

A.2.1 P-37 Vertilog Sections October 11, 1988

Class 2 is 20–40% penetration.

Class 4 is >60% penetration.

Figure 6 is the Vertilog log header, and Figure 7 and Figure 8 show Vertilog sections with penetrations flagged by arrows.

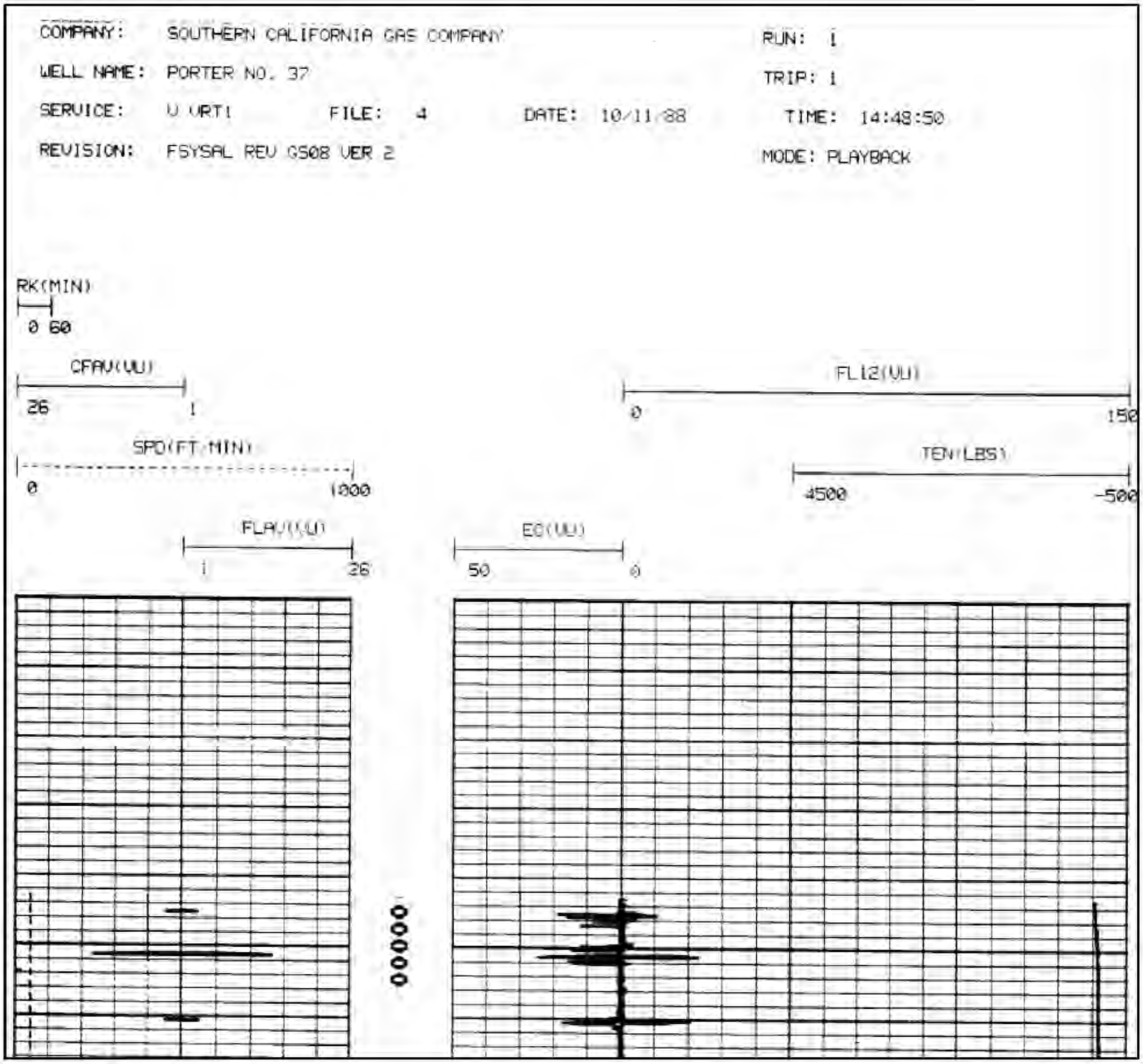


Figure 6: P-37 Vertilog Header

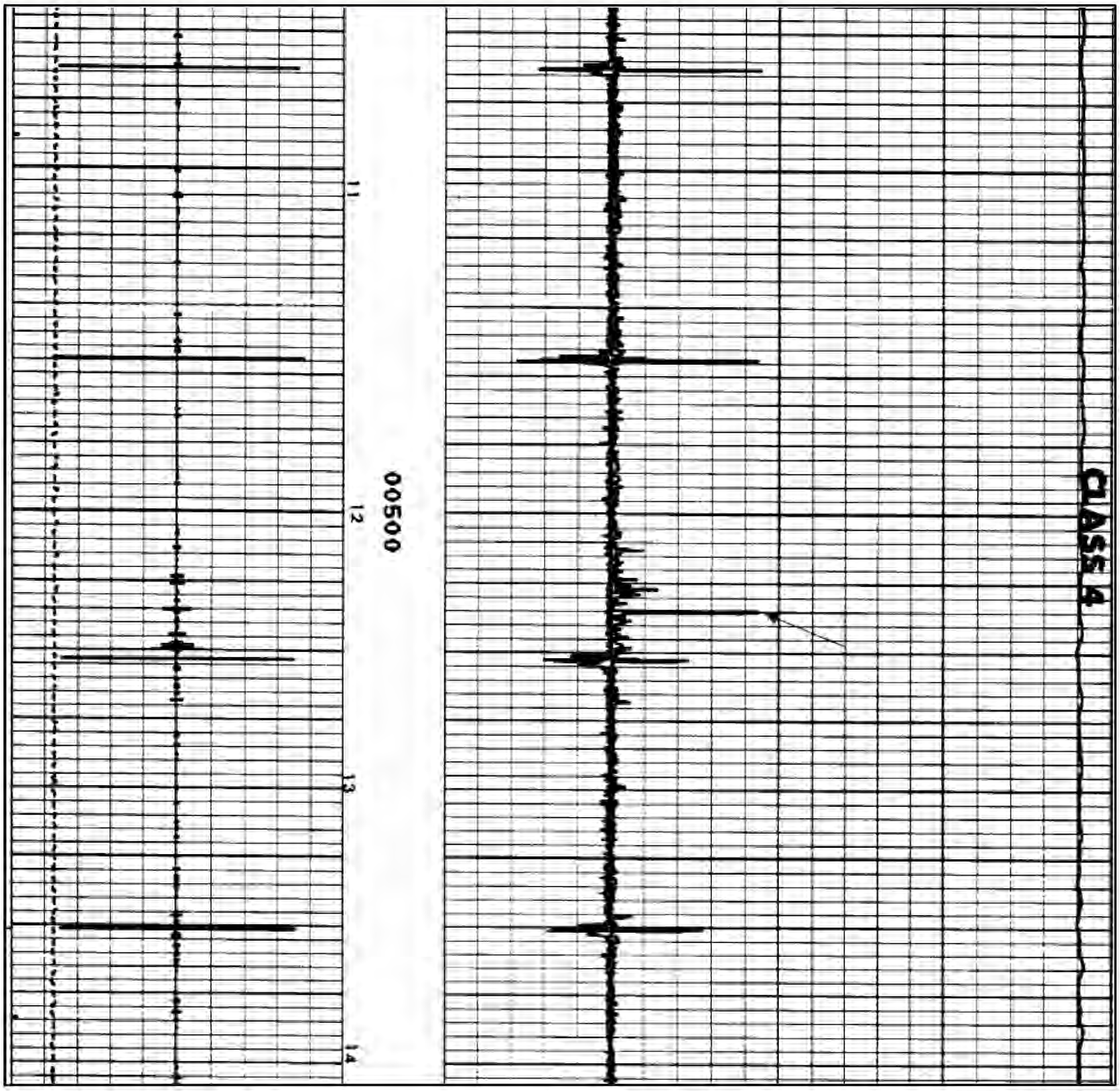


Figure 7: P-37 Vertilog Section

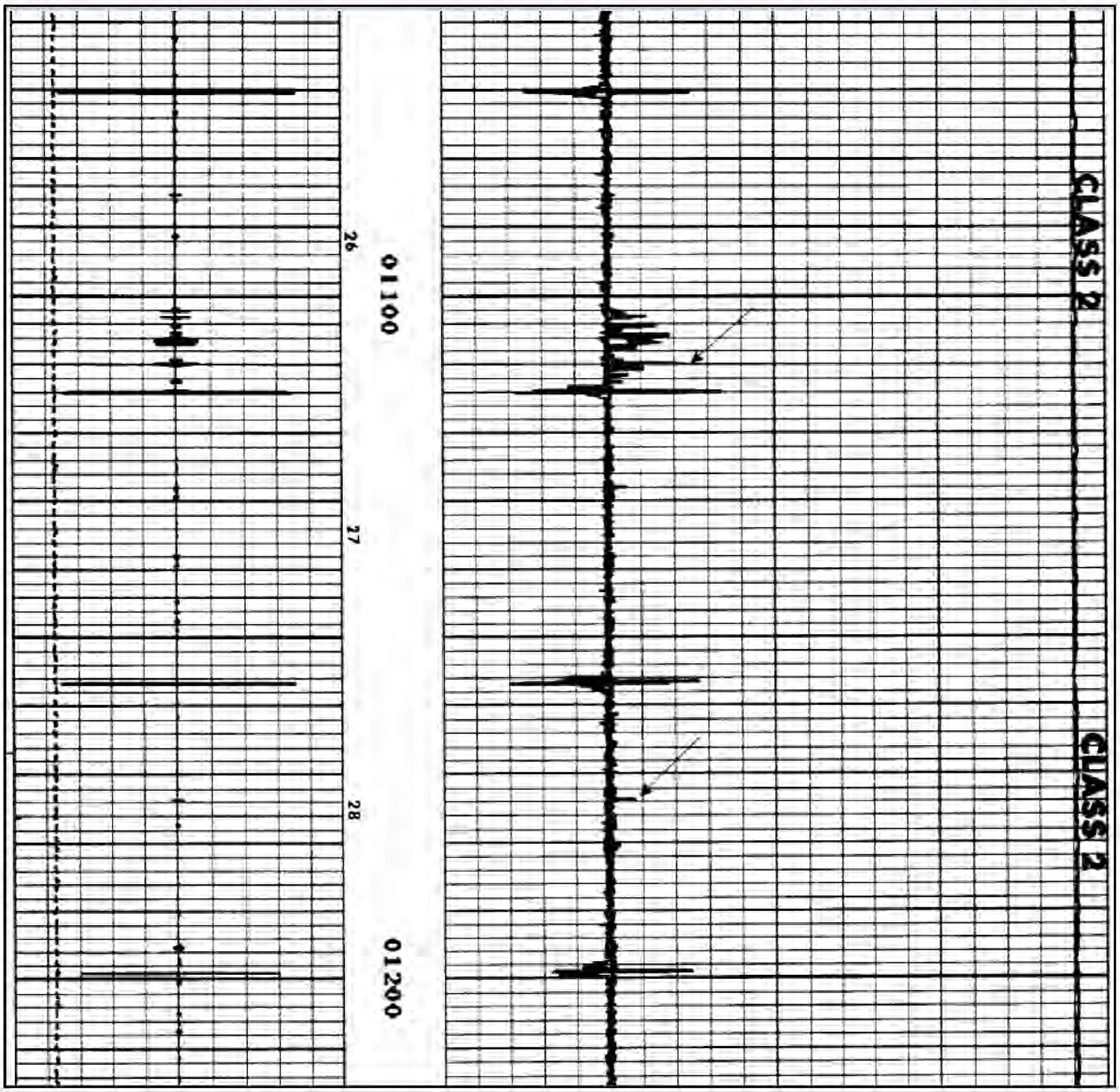


Figure 8: P-37 Vertilog Section

A.3 Porter 44

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 11 3/4 in. Surface casing at 530 ft
2. Fracked in 1956
3. Pressure test 7 in. casing in stages 2,000–3,050 psi for 20 minutes. January 12, 1973
4. Tight spot in 7 in. casing at 4,000 ft, milled tight spot. July 5, 1977
5. Pressure test casing in stages 2,300–4,000 psi. July 16, 1977
6. Milled tight casing 3,984–4,003 ft. November 7, 1977
7. Pressure test packer and seals 2,000 psi for 20 minutes. November 11, 1977
8. Tight spot in 7 in. casing 3,991–3,993 ft. Reamed. February 11, 1978
9. Casing leak at 3,990–4,000 ft, squeezed cement. April 7, 1978
10. Pressure test 7 in. casing in stages 2,300–4,000 psi for 60 minutes. April 11, 1978
11. Set expandable patch. April 14, 1978
12. Pressure test seals, packer and casing patch to 2,000 psi. April 18, 1978
13. Coiled tubing solvent job attempted when the stuffing box leaked and the blowout preventer (BOP) failed to close. BOP was on up-side-down. December 14, 1988
14. Ran Tiger 7 in. caliper log 7,639 ft–Surface. February 13, 2016
15. Ran HRVRT 3,639 ft–Surface. February 15, 2016
    - 1 joint >20% OD penetration. 3,261 ft
    - 1 joint >80% OD penetration. 4,000 ft
16. Ran CBT 7,630–3,800 ft. February 16, 2016
17. 7 in. Casing leak between 3,970 ft and 4,010 ft. February 18, 2016
18. Ran 7 in. Tiger Multi-finger caliper 7,639 ft–Surface. February 25, 2016
19. Ran 7 in. USIT 7,639 ft–Surface. February 29, 2016
    - External corrosion on joints 1–3, 26–32, 34–35, 51–53, 58, 80, 85, 96
    - Potential casing hole in joint 91 at 4,000 ft.
20. Set casing patch 7,599–7,620 ft. March 4, 2016
21. Set casing patch 3,972–4,032 ft. March 5, 2016
22. Pressure test 7 in. casing from 3,961–7,609 ft to 2,435 psi for 60 minutes. March 8, 2016
23. Pressure test casing to 2,050 psi for 1 hr. March 14, 2016
24. Passed all tests

A.3.1 P-44 HRVRT Log February 15, 2016

Figure 9 shows the HRVRT log header, and Figure 10 and Figure 11 show the log summary.

BAKER HUGHES

HR Vertilog

Magnetic Flux Leakage Inspection

Advanced Analysis

Company	Southern California Gas Company
Well	Porter 44
Field	Aliso Canyon
County	Los Angeles
State	California
Location:	1720' S & 2994' W, From Station 84

RECEIVED
JUL 0 5 2016
Div. of Oil, Gas & Geothermal Resources Ventura

Section 28	Township 3N	Range 16W

Date	Feb. 15, 2016
Service Order	US105596J
Recorded by	Sid Gornto
Witnessed by	Tom McMahon
API Serial No.	04-037-00731

Permanent Datum:	GL	Elevation: 2193.500 ft.	Depth	7639.000
Log Measured From:	K.B.	11.000 ft. above Perm. Datum	Btm. Log Interval	7634.480
Drilling Measured From:	K.B.	0.000 ft. above Perm. Datum	Top Log Interval	16.170
			Fluid Type	HEC POLYMER

Casing Data

Size	Weight	Grade	From	To	Length
7 inch	23.0 lb/ft	N-80	0	673	673.0
7 inch	23.0 lb/ft	J-55	673	4615	3942.0
7 inch	23.0 lb/ft	S-95	4615	5019	404.0
7 inch	23.0 lb/ft	N-80	5019	6798	1779.0
7 inch	26.0 lb/ft	N-80	6798	7805	1007.0
5	15.5 lb/ft	N/A	7639	8039	400.0
11 3/4 inch	42.0 lb/ft	H-40	0	530	530.0

Figure 9: P-44 Vertilog Header

Joint Interpretation Summary

Joint	From	To	Length	Class	Max Depth	Position	ID/OD
1	16.17	18.89	2.72	Class 1	-	-	-
2	18.89	28.30	9.41	Class 1	-	-	-
3	28.30	70.22	41.92	Class 1	-	-	-
4	70.22	113.46	43.24	Class 1	-	-	-
5	113.46	155.01	41.55	Class 1	-	-	-
6	155.01	196.49	41.48	Class 1	-	-	-
7	196.49	239.80	43.31	Class 1	-	-	-
8	239.80	283.97	44.17	Class 1	-	-	-
9	283.97	326.79	42.82	Class 1	-	-	-
10	326.79	370.13	43.34	Class 1	-	-	-
11	370.13	414.42	44.29	Class 1	-	-	-
12	414.42	457.70	43.28	Class 1	-	-	-
13	457.70	501.47	43.77	Class 1	-	-	-
14	501.47	544.12	42.65	Class 1	-	-	-
15	544.12	586.69	42.57	Class 1	-	-	-
16	586.69	629.28	42.59	Class 1	-	-	-
17	629.28	673.26	43.98	Class 1	-	-	-
18	673.26	711.87	38.61	Class 1	-	-	-
19	711.87	755.17	43.30	Class 1	19.0%	750.84	OD
20	755.17	792.12	36.95	Class 1	-	-	-
21	792.12	834.51	42.39	Class 1	-	-	-
22	834.51	876.99	42.48	Class 1	-	-	-
23	876.99	919.12	42.13	Class 1	-	-	-
24	919.12	962.37	43.25	Class 1	-	-	-
25	962.37	1005.40	43.03	Class 1	-	-	-
26	1005.40	1049.67	44.27	Class 1	-	-	-
27	1049.67	1093.23	43.56	Class 1	-	-	-
28	1093.23	1136.54	43.31	Class 1	-	-	-
29	1136.54	1178.97	42.43	Class 1	-	-	-
30	1178.97	1222.88	43.91	Class 1	-	-	-
31	1222.88	1267.38	44.50	Class 1	18.0%	1265.06	OD
32	1267.38	1311.74	44.36	Class 1	-	-	-
33	1311.74	1354.82	43.08	Class 1	-	-	-
34	1354.82	1398.24	43.42	Class 1	-	-	-
35	1398.24	1443.00	44.76	Class 1	-	-	-
36	1443.00	1486.51	43.51	Class 1	-	-	-
37	1486.51	1529.18	42.67	Class 1	-	-	-
38	1529.18	1573.24	44.06	Class 1	-	-	-
39	1573.24	1616.09	42.85	Class 1	-	-	-
40	1616.09	1657.62	41.53	Class 1	-	-	-
41	1657.62	1699.45	41.83	Class 1	-	-	-
42	1699.45	1743.21	43.76	Class 1	-	-	-
43	1743.21	1786.47	43.26	Class 1	-	-	-
44	1786.47	1830.02	43.55	Class 1	-	-	-
45	1830.02	1873.23	43.21	Class 1	-	-	-
46	1873.23	1916.10	42.87	Class 1	-	-	-
47	1916.10	1958.72	42.62	Class 1	-	-	-
48	1958.72	2002.83	44.11	Class 1	-	-	-
49	2002.83	2045.58	42.75	Class 1	-	-	-
50	2045.58	2088.79	43.21	Class 1	-	-	-
51	2088.79	2132.51	43.72	Class 1	-	-	-
52	2132.51	2176.32	43.81	Class 1	-	-	-
53	2176.32	2220.54	44.22	Class 1	-	-	-
54	2220.54	2264.20	43.66	Class 1	-	-	-
55	2264.20	2305.33	41.13	Class 1	-	-	-
56	2305.33	2348.53	43.20	Class 1	-	-	-
57	2348.53	2390.14	41.61	Class 1	-	-	-
58	2390.14	2432.97	42.83	Class 1	-	-	-
59	2432.97	2473.73	40.76	Class 1	-	-	-

Figure 10: P-44 Vertilog Summary

59	2432.97	2473.73	40.76	Class 1	-	-	-
60	2473.73	2517.28	43.55	Class 1	-	-	-
61	2517.28	2559.45	42.17	Class 1	-	-	-
62	2559.45	2601.64	42.19	Class 1	-	-	-
63	2601.64	2644.91	43.27	Class 1	-	-	-
64	2644.91	2688.05	43.14	Class 1	-	-	-
65	2688.05	2732.97	44.92	Class 1	-	-	-
66	2732.97	2776.06	43.09	Class 1	-	-	-
67	2776.06	2819.59	43.53	Class 1	-	-	-
68	2819.59	2862.17	42.58	Class 1	-	-	-
69	2862.17	2905.30	43.13	Class 1	-	-	-
70	2905.30	2948.39	43.09	Class 1	-	-	-
71	2948.39	2991.67	43.28	Class 1	-	-	-
72	2991.67	3034.47	42.80	Class 1	-	-	-
73	3034.47	3078.22	43.75	Class 1	-	-	-
74	3078.22	3121.31	43.09	Class 1	-	-	-
75	3121.31	3163.59	42.28	Class 1	-	-	-
76	3163.59	3207.84	44.25	Class 1	-	-	-
77	3207.84	3251.69	43.85	Class 1	-	-	-
78	3251.69	3295.67	43.98	Class 1	20.0%	3261.39	OD
79	3295.67	3339.35	43.68	Class 1	-	-	-
80	3339.35	3382.71	43.36	Class 1	-	-	-
81	3382.71	3426.55	43.84	Class 1	-	-	-
82	3426.55	3470.35	43.80	Class 1	-	-	-
83	3470.35	3512.20	41.85	Class 1	-	-	-
84	3512.20	3553.72	41.52	Class 1	-	-	-
85	3553.72	3596.38	42.66	Class 1	-	-	-
86	3596.38	3638.92	42.54	Class 1	-	-	-
87	3638.92	3681.56	42.64	Class 1	-	-	-
88	3681.56	3725.73	44.17	Class 1	-	-	-
89	3725.73	3770.52	44.79	Class 1	-	-	-
90	3770.52	3814.85	44.33	Class 1	-	-	-
91	3814.85	3854.92	40.07	Class 1	-	-	-
92	3854.92	3897.14	42.22	Class 1	-	-	-
93	3897.14	3939.58	42.44	Class 1	-	-	-
94	3939.58	3983.15	43.57	Class 1	-	-	-
95	3983.15	4026.78	43.63	Class 4	88.0%	3999.72	OD
96	4026.78	4069.37	42.59	Class 1	-	-	-
97	4069.37	4112.40	43.03	Class 1	-	-	-
98	4112.40	4155.40	43.00	Class 1	-	-	-
99	4155.40	4196.65	41.25	Class 1	-	-	-
100	4196.65	4240.51	43.86	Class 1	-	-	-
101	4240.51	4284.25	43.74	Class 1	-	-	-
102	4284.25	4328.92	44.67	Class 1	-	-	-
103	4328.92	4372.59	43.67	Class 1	-	-	-
104	4372.59	4414.07	41.48	Class 1	-	-	-
105	4414.07	4457.05	42.98	Class 1	-	-	-
106	4457.05	4501.77	44.72	Class 1	-	-	-
107	4501.77	4539.13	37.36	Class 1	-	-	-
108	4539.13	4575.63	36.50	Class 1	-	-	-
109	4575.63	4617.95	42.32	Class 1	-	-	-
110	4617.95	4664.76	46.81	Class 1	-	-	-
111	4664.76	4711.52	46.76	Class 1	-	-	-
112	4711.52	4750.64	39.12	Class 1	-	-	-
113	4750.64	4789.54	38.90	Class 1	-	-	-
114	4789.54	4835.85	46.31	Class 1	-	-	-
115	4835.85	4882.16	46.31	Class 1	-	-	-
116	4882.16	4928.69	46.53	Class 1	-	-	-
117	4928.69	4975.12	46.43	Class 1	-	-	-
118	4975.12	5022.23	47.11	Class 1	-	-	-
119	5022.23	5066.33	44.10	Class 1	-	-	-
120	5066.33	5110.22	43.89	Class 1	-	-	-
121	5110.22	5152.24	42.02	Class 1	-	-	-
122	5152.24	5196.52	44.28	Class 1	-	-	-

Figure 11: P-44 Vertilog Summary

A.4 Porter 46

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 533 ft
1. Pressure test 7 in. casing in stages 2,100–3,050 psi for 15 minutes. December 6, 1972
2. Pressure test 7 in. casing 3,300 ft–Surface in stages 3,000–4,000 psi. July 27, 1977
3. Pressure test seals and packer to 2,000 psi. August 15, 1977
4. Ran 7 in. Vertilog 7,650 ft–Surface. October 19, 1988
    - 10 joints >20% OD penetration. 38–120 ft, 204–378 ft, 478 ft, 7,603 ft
5. Pressure annulus 1,700 psi. October 19, 1988
6. Pressure test packer, tubing plug and 7 in. casing to 1,100 psi for 1 hour. July 1, 2016
7. Ran 7 in. USIT log. August 16, 2017
8. Indications 850–865 ft, 3,970–3,984 ft
9. Run and cement 5 1/2 in. inner casing at 7,662 ft. October 4, 2017
10. Ran 5 1/2 in. USIT log October 9, 2017
11. Ran 5 1/2 in. HRVRT log October 10, 2017 (log header is misleading, it shows 7 in. 23 ppf)
12. Pressure test 5 1/2 in. casing 3,751 psi for 60 minutes. October 11, 2017
13. Passed all tests

A.4.1 P-46 Vertilog Sections October 19, 1988

Class 2 is penetration from 20–40%.

Figure 12 is the Vertilog log header, and Figure 13 through Figure 15 shows Vertilog sections with penetrations flagged.

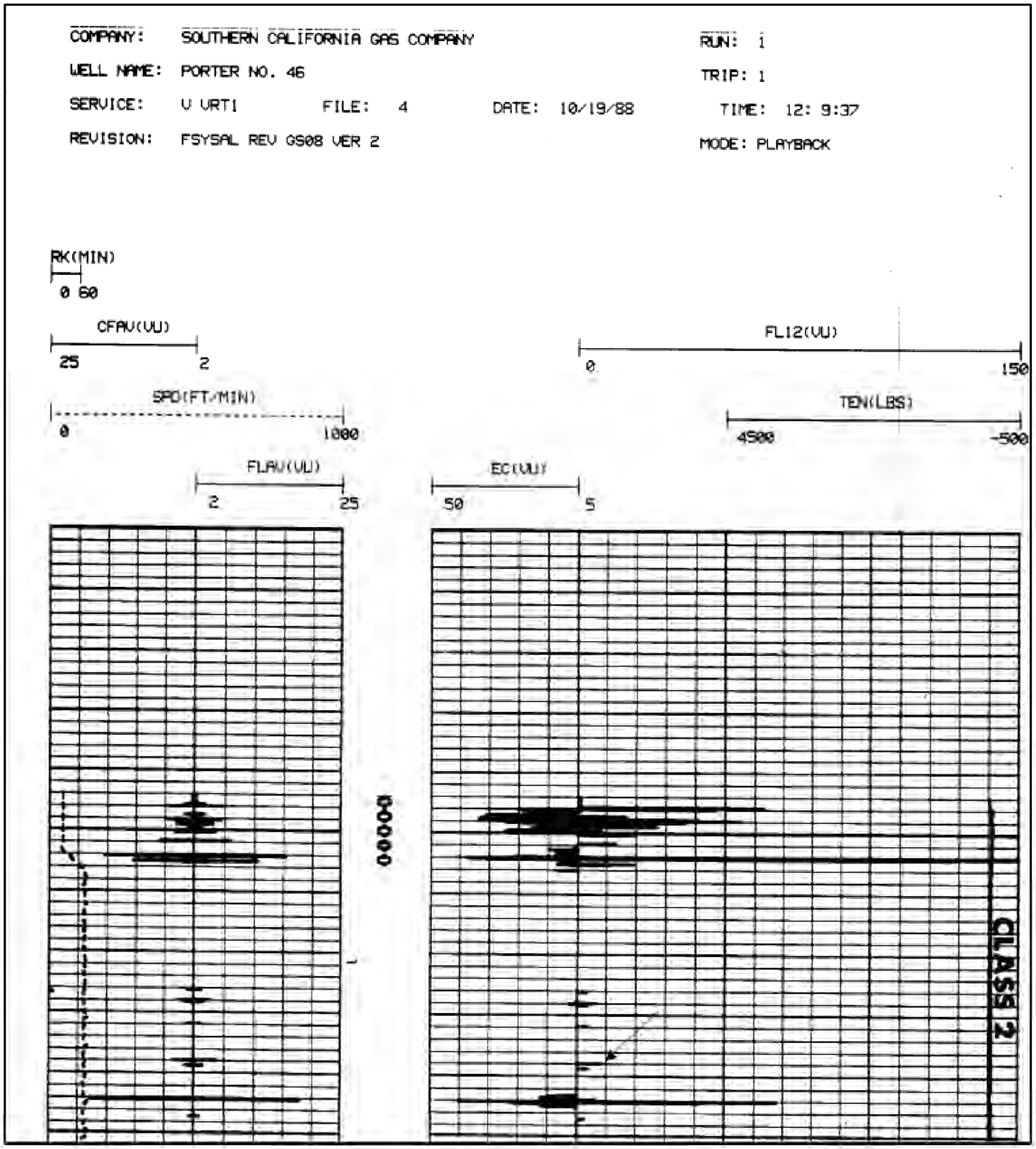


Figure 12: P-46 Vertilog Header

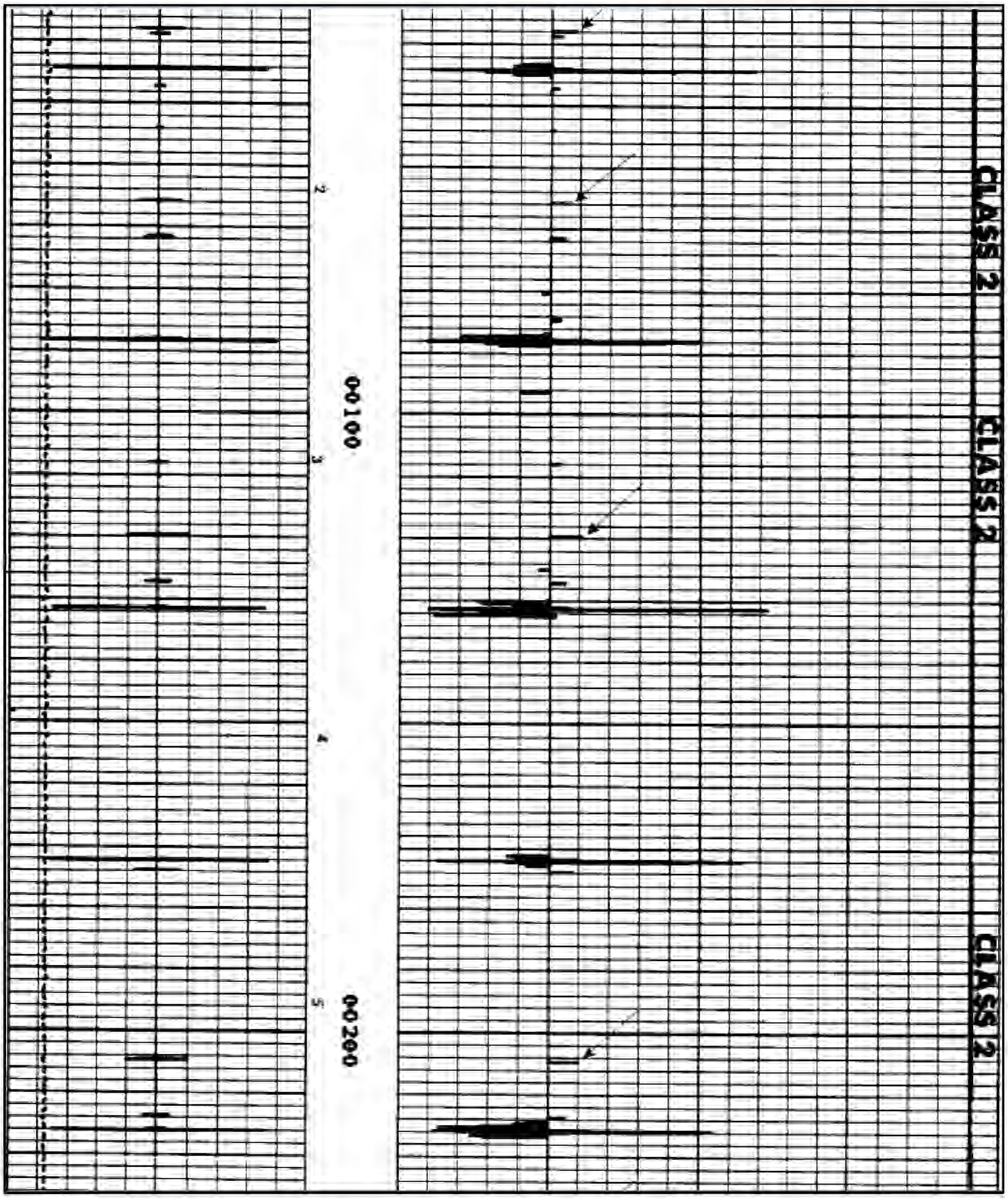


Figure 13: P-46 Vertilog Section

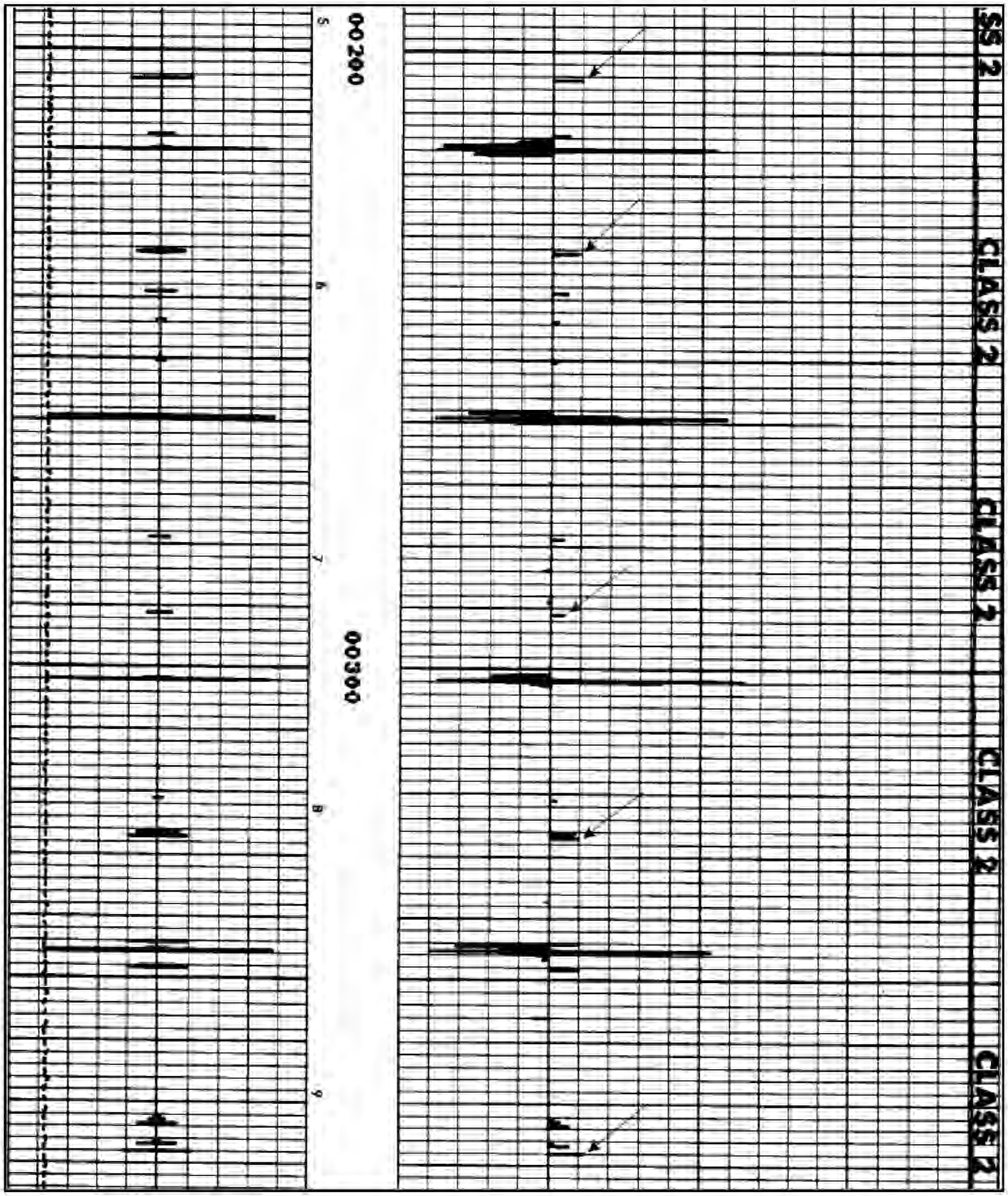


Figure 14: P-46 Vertilog Section

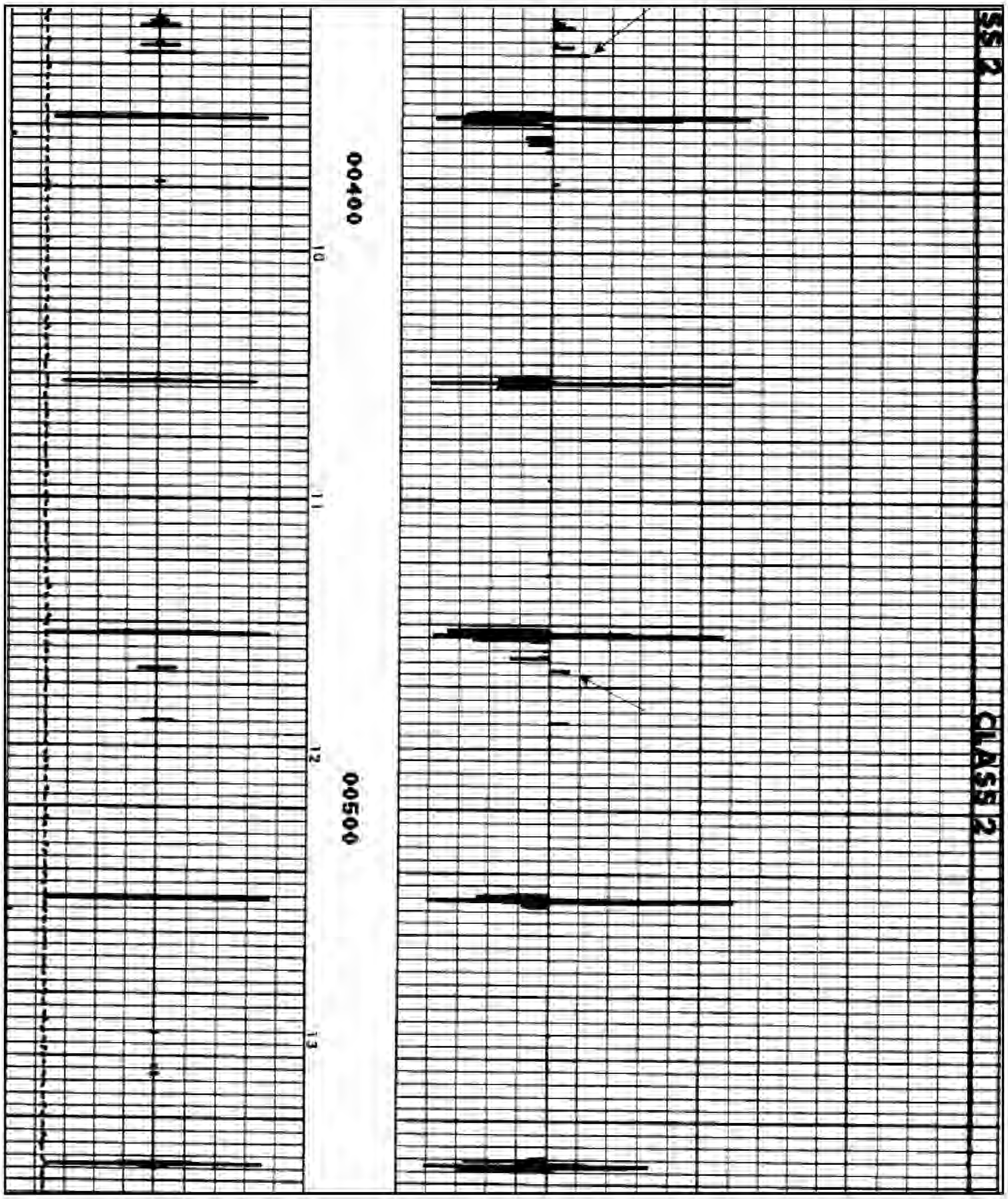


Figure 15: P-46 Vertilog Section

A.5 Porter 47

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface Casing at 498 ft
2. Pressure test 7 in. casing 1,700 psi for 15 minutes. March 17, 1973
3. Liner leak in 5 in. 8,038–8,056 ft, squeeze cement. March 21, 1973
4. Pressure test 7 in. casing 1,140 psi for 15 minutes. March 29, 1973
5. Pressure test 7 in. casing in stages (6,340 ft–Surface) 3,000–4,000 psi for 60 minutes. May 30, 1977
6. Casing leak in 5 in. at 7,328 ft, squeeze cemented. May 31, 1977
7. Pressure test 7 in. packer and seals for 20 minutes. June 14, 1977
8. Pressure test 7 in. casing 1,200 psi for 1 hr. September 19, 2016
9. P&A'd in 2017

A.6 SS-2

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 512 ft
2. Pressure test 7 in. casing in stages 2,500–3,400 psi for 20 minutes. July 19, 1973
3. Pressure test 7 in. casing in stages 2,600–4,000 psi. July 22, 1977
4. Pressure test packer 1,500 psi for 20 minutes. August 4, 1983
5. Pressure test packer, tubing plug and 7 in. casing 1,000 psi for 1 hour. July 26, 2016
6. P&A'd in 2017

A.7 SS-4

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 580 ft
2. Pressure test 7 in. casing in stages 2,050–3,075 psi. April 4, 1973
3. Pressure test 7 in. casing 1,010 psi for 15 minutes. April 9, 1973
4. Pressure test plug, packer and seals 1,500 psi for 10 minutes. August 12, 1976
5. Pressure test packer, tubing plug and 7 in. casing 1,100 psi for 1 hour. July 1, 2016
6. P&A in progress

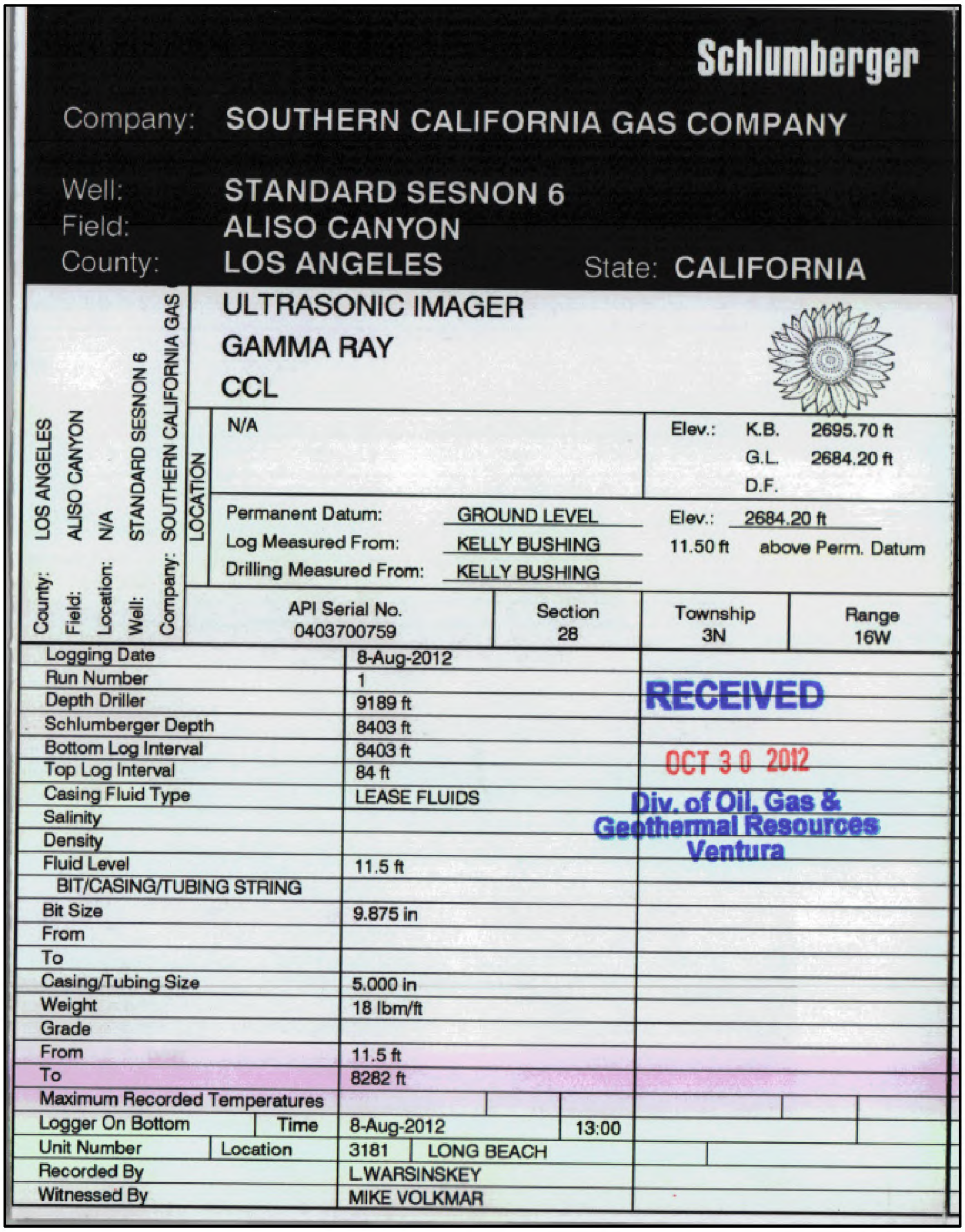
A.8 SS-6

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 955 ft
2. Pressure test 7 in. casing in stages 1,500–3,000 psi for 20 minutes. May 8, 1973
3. Pressure test 7 in. casing in stages 3,000–4,000 psi for 60 minutes. August 16, 1977
4. Pressure test seals and packer 2,000 psi for 20 minutes. August 30, 1977
5. Pressure test seals and packer 1,500 psi. August 31, 1982
6. Ran 7 in. USIT log 8,134–7,134 ft. August 24, 2012
   - Indications 80–160 ft
7. Pressure test 7 in. casing 1,500 psi for 20 minutes. August 27, 2012
8. Pressure test packer and 7 in. casing 1,100 psi for 1 hour. July 8, 2016
9. SIMP Well Operations Procedure; Run and cement 5 1/2 in. inner casing. July 17, 2017
10. Pressure test 5 1/2 in. inner casing 1,117 psi for 60 minutes. April 16, 2018
11. Passed all tests

A.8.1 SS-6 USIT Log August 8, 2012

Figure 16 shows the USIT log header and Figure 17 shows the log legend. Figure 18 shows a section of casing just below surface with the indications down to approximately 160 ft. The log shows abundant quality-control-process-flags from approximately 150 ft to surface indicating some level of aeration in the wellbore fluid which may affect the log interpretation.



Schlumberger

Company: SOUTHERN CALIFORNIA GAS COMPANY

Well: STANDARD SESNON 6
Field: ALISO CANYON
County: LOS ANGELES State: CALIFORNIA

County: LOS ANGELES
Field: ALISO CANYON
Location: N/A
Well: STANDARD SESNON 6
Company: SOUTHERN CALIFORNIA GAS

ULTRASONIC IMAGER
GAMMA RAY
CCL

LOCATION: N/A

Elev.: K.B. 2695.70 ft
G.L. 2684.20 ft
D.F.

Permanent Datum: GROUND LEVEL — Elev.: 2684.20 ft
Log Measured From: KELLY BUSHING — 11.50 ft above Perm. Datum
Drilling Measured From: KELLY BUSHING

API Serial No.	Section	Township	Range
0403700759	28	3N	16W

Logging Date	8-Aug-2012	
Run Number	1	
Depth Driller	9189 ft	
Schlumberger Depth	8403 ft	
Bottom Log Interval	8403 ft	
Top Log Interval	84 ft	
Casing Fluid Type	LEASE FLUIDS	
Salinity		
Density		
Fluid Level	11.5 ft	
BIT/CASING/TUBING STRING		
Bit Size	9.875 in	
From		
To		
Casing/Tubing Size	5.000 in	
Weight	18 lbm/ft	
Grade		
From	11.5 ft	
To	8282 ft	
Maximum Recorded Temperatures		
Logger On Bottom — Time	8-Aug-2012	13:00
Unit Number — Location	3181	LONG BEACH
Recorded By	L.WARSINSKEY	
Witnessed By	MIKE VOLKMAR	

RECEIVED
OCT 3 0 2012
Div. of Oil, Gas & Geothermal Resources
Ventura

Figure 16: SS-6 USIT Log Header

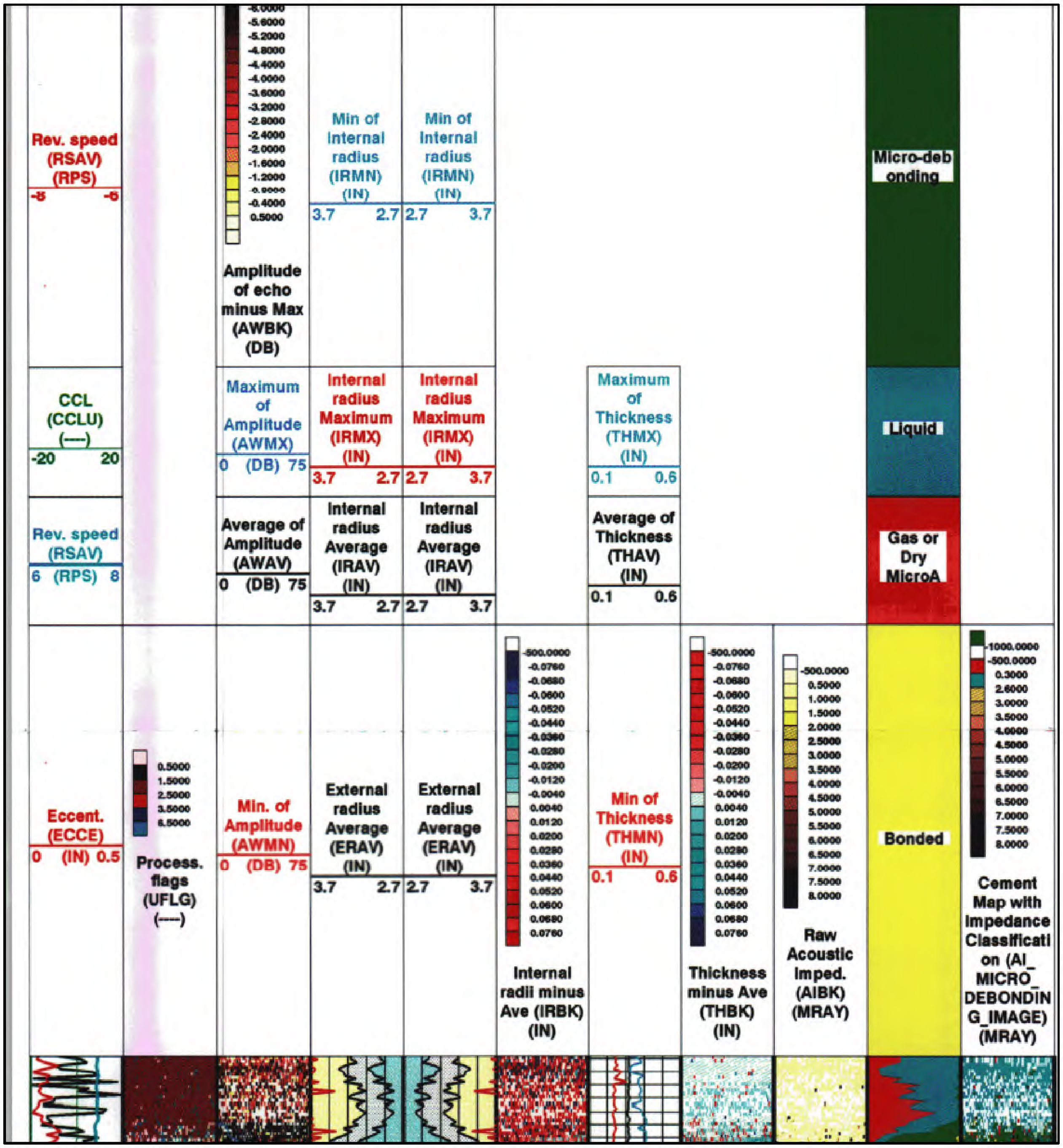


Figure 17: SS-6 USIT Log Legend

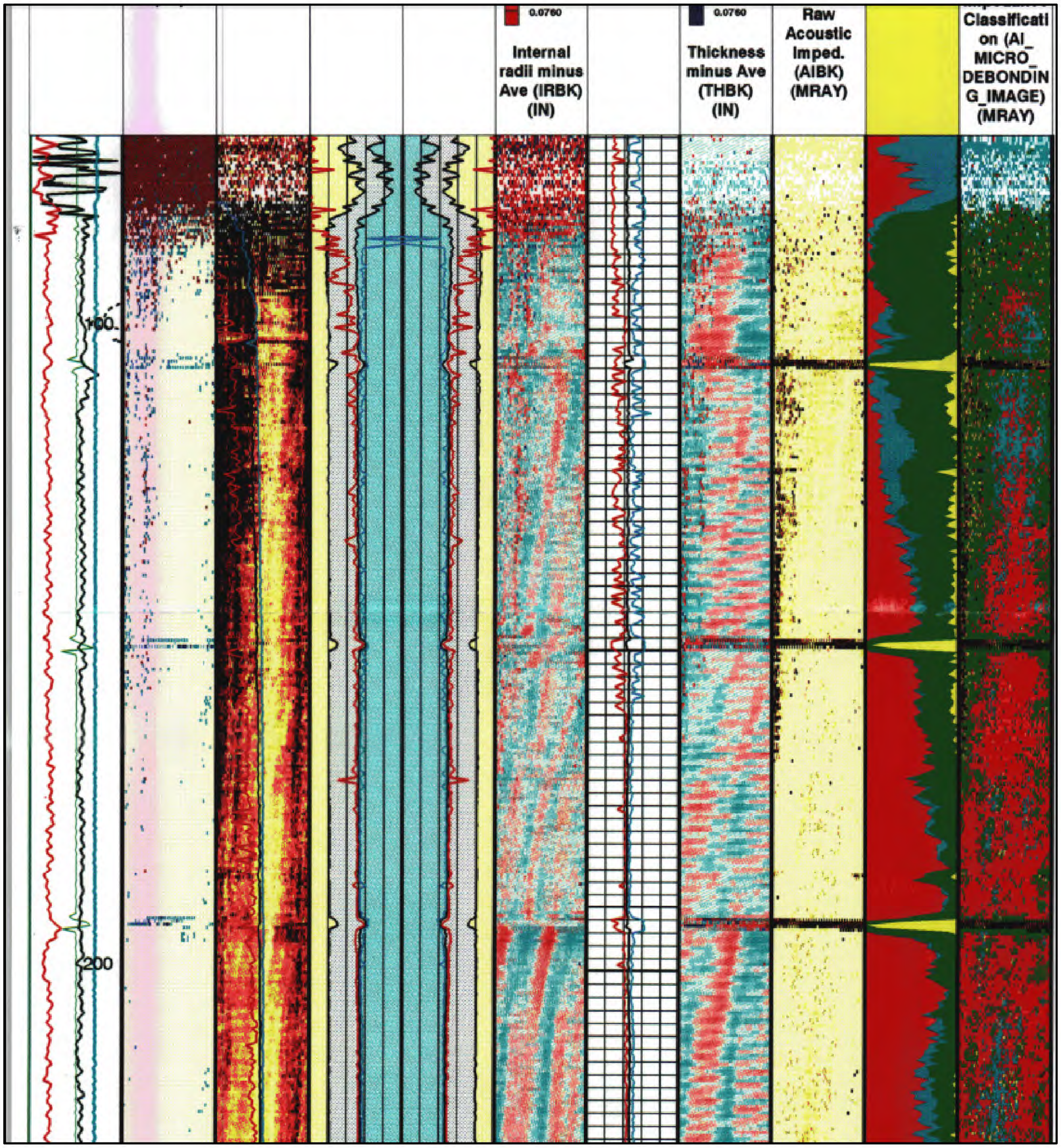


Figure 18: SS-6 USIT Log Section

A.9 SS-7

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 1,095 ft
2. Pressure test 7 in. casing 1,500 psi. April 18, 1973
3. Pressure test 7 in. casing in stages 2,700–4,000 psi. September 6, 1977
4. Ran noise survey 8,600–25 ft. Above normal activity 3,600–4,200 ft. July 6, 2012
5. Ran 7 in. USIT 8,467 ft–Surface. Indications 1,912–1,927 ft, 4,012–4,030 ft. November 1, 2012
6. Casing leak in 7 in. between surface and 8,467 ft. November 5, 2012
7. Set cement plugs 8,775–8,235 ft. November 9, 2012
8. Pressure test 7 in. casing to 1,500 psi for 20 minutes. November 12, 2012
9. Ran 7 in. USIT log 8,234 ft–Surface. Indications 1,912–1,927 ft, 4,010–4,032 ft. May 5, 2014
10. Ran 13 3/8 in. USIT log 941 ft–Surface. May 27, 2014
11. P&A'd in 2014

A.9.1 SS-7 USIT Log Sections November 1, 2012

Figure 19 shows the USIT log header and Figure 20 shows the log legend. Figure 21 and Figure 22 show the log anomalies at approximately 1,900 ft and 4,000 ft.

Schlumberger

Company: **Southern California Gas Company**

Well: **Standard Sesnon 7**
Field: **Aliso Canyon**
County: **Los Angeles** State: **California**

County: Los Angeles
Field: Aliso Canyon
Location: 552 Ft. S and 7129 Ft. W
Well: Standard Sesnon 7
Company: Southern California Gas Compa

ULTRASONIC IMAGER
GAMMA RAY
NEUTRON

LOCATION: 552 Ft. S and 7129 Ft. W From Sta 84

Elev.: K.B.
G.L. 2960.00 ft
D.F. 2967.00 ft

Permanent Datum: Ground Level — Elev.: 2960.00 ft
Log Measured From: DF — 7.00 ft above Perm. Datum
Drilling Measured From: DF

API Serial No.	Section	Township	Range
0403700760	28	3N	16W

Logging Date	1-Nov-2012	
Run Number	One	
Depth Driller		
Schlumberger Depth	TD not tagged	
Bottom Log Interval	8460 ft	
Top Log Interval	50 ft	RECEIVED
Casing Fluid Type	Water	
Salinity		
Density	8.4 lbm/gal	JAN - 7 2013
Fluid Level		
BIT/CASING/TUBING STRING		Div. of Oil, Gas &
Bit Size	8.750 in	Geothermal Resources
From		Ventura
To		
Casing/Tubing Size	7.000 in	
Weight	23 lbm/ft	
Grade		
From	6 ft	
To		
Maximum Recorded Temperatures		
Logger On Bottom / Time	1-Nov-2012 14:30	
Unit Number / Location	2220 Long Beach	
Recorded By	Eric Kroh	
Witnessed By	Mike Volkmeyer	

Figure 19: SS-7 USIT Log Header

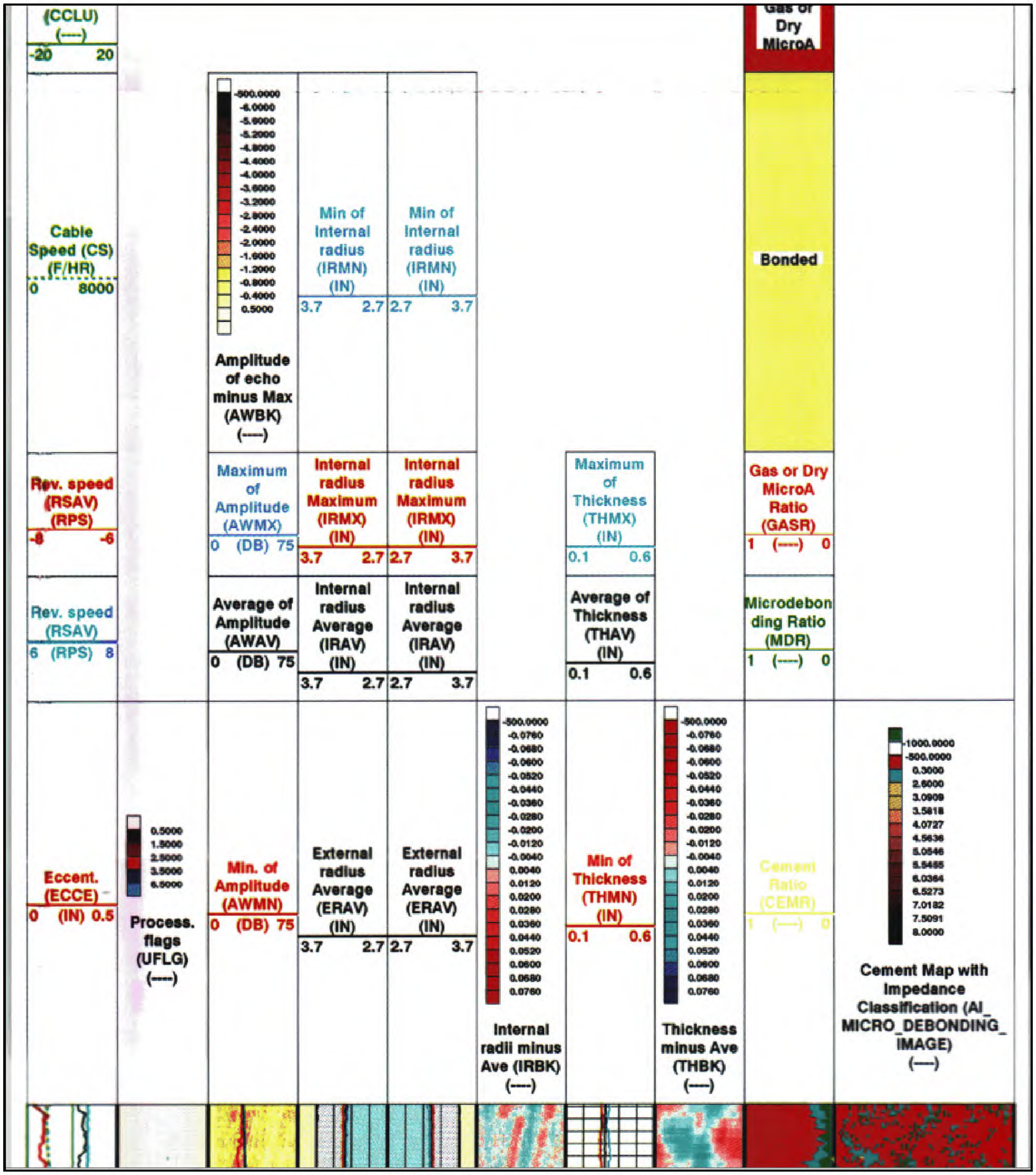


Figure 20: SS-7 USIT Log Legend

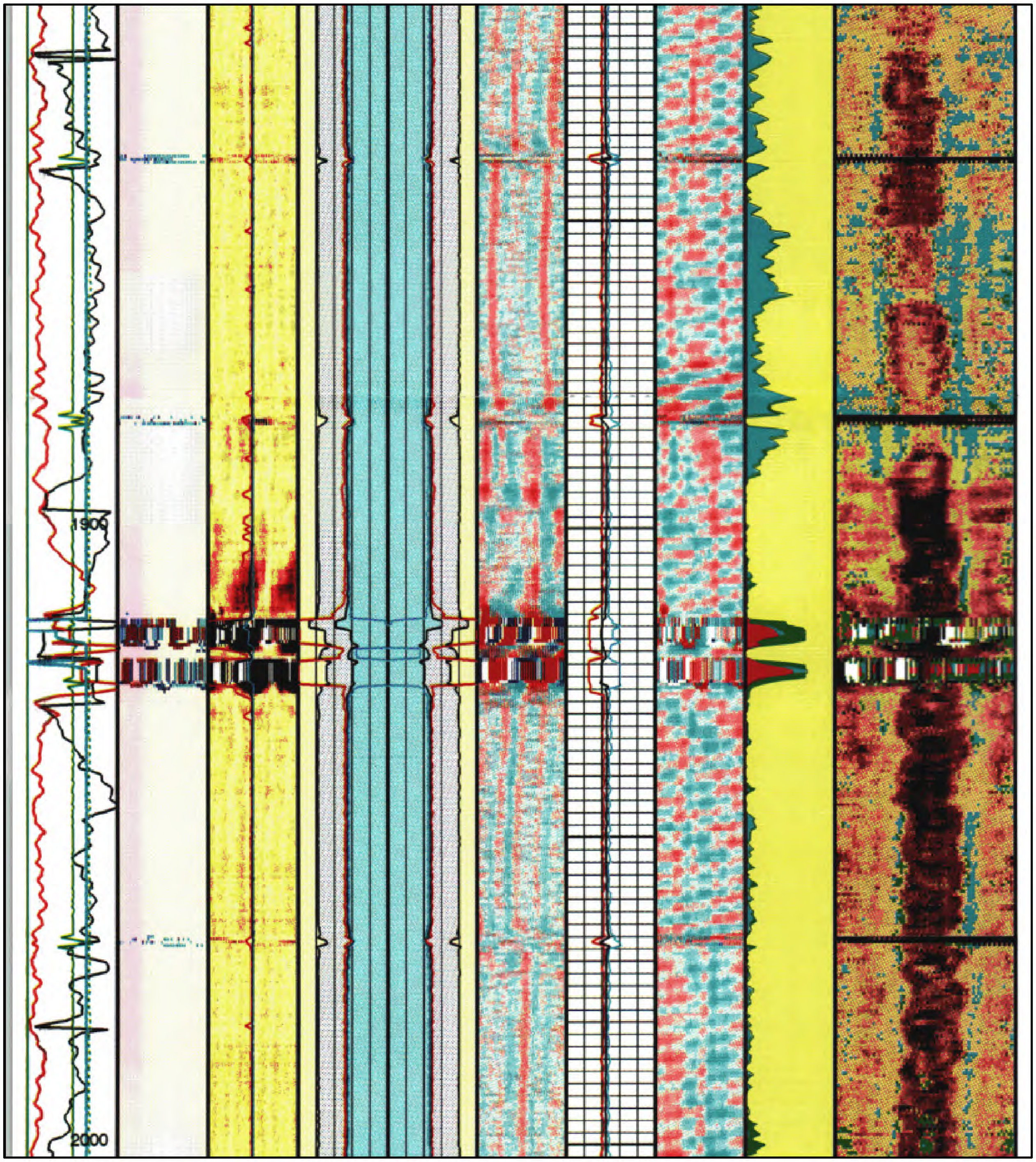


Figure 21: SS-7 USIT Log Section Anomaly at Approximately 1,900 ft

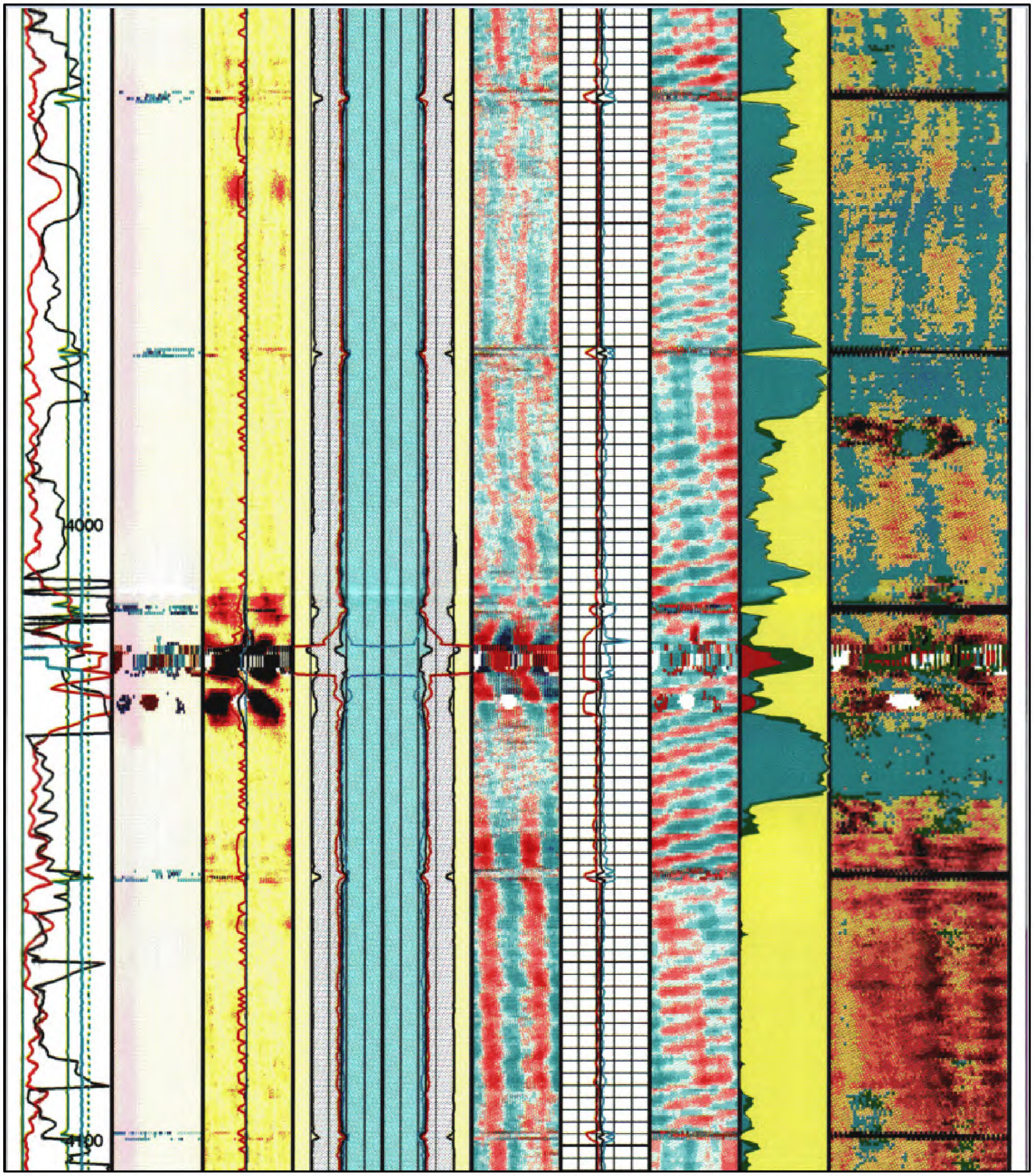


Figure 22: SS-7 USIT Log Section Anomaly at Approximately 4,000 ft

A.10 SS-8

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 812 ft
2. Pressure test 7 in. casing in stages 2,350–3,250 psi for 18 minutes. May 30, 1973
3. Squeeze cement 5 in. liner leak and clean out cement. September 30, 1977
4. Pressure test 7 in. casing 2,800 psi for 60 minutes. October 2, 1977
5. 5 in. liner leaks, cement sqz'd. Pressure test to 2,800 psi for 20 min. October 5, 1977
6. Pressure test 7 in. casing 2,850 ft to surface in stages 3,100–4,000 psi for 60 minutes. Leaks below 2,850 ft. October 7, 1977
7. Pressure test 7 in. casing 8,568 ft to surface 2,800 psi for 60 minutes. October 12, 1977
8. Pressure test packer and seals 2,000 psi for 20 minutes. October 17, 1977
9. Ran 7 in. Vertilog 7,756 ft–Surface. January 17, 1989
   - 27 joints >20% OD penetration. 675–678 ft, 824–890 ft, 1,189–1,231 ft, 1,658 ft, 2,084–2,104 ft, 2,218 ft, 2,382 ft, 2,644 ft, 2,950 ft, 3,355–3,441 ft, 3,532 ft, 4,331 ft, 4,832 ft, 5,796 ft, 5,925–6,009 ft, 6,222–6,265 ft, 6,641 ft, 6,895 ft, 7,274 ft
   - 6 joints >40% OD penetration. 785 ft, 2,257 ft, 3,018 ft, 3,253–3,314 ft
10. Pressure test seals and 7 in. casing 1,900 psi for 20 minutes. January 18, 1989
11. Pressure test 7 in. casing in stages 500–2,760 psi for 10 minutes. April 18, 2007
12. Ran 7 in. Halliburton Cast V inspection log 7,756 ft–Surface. April 28, 2007
13. Pressure test annulus to 500 psi for 20 minutes. May 16, 2007
14. Pressure test 7 in. casing to 500 psi, bled to 200 psi in 5 minutes. April 22, 2013
15. Ran 7 in. USIT log 8,475 ft to Surface. April 24, 2013
    - Indications 950–1,080 ft, 2,276–2,482 ft, 2,506–2,511 ft, 3,287–3,289 ft, 8,479–8,482 ft
16. Set cement plugs. TOC 8,290 ft. April 29, 2013
17. Leak in 5 in. liner between 8,050 ft and 8,150 ft. May 1, 2013
18. Perforate 8 each 1/2 in. holes 8,007–8,009 ft. May 3, 2013
19. Perforate tubing conveyed perforating (TCP) top shot 8,060 ft. May 7, 2013
20. Pressure test tubing-casing annulus 500 psi for 20 minutes. May 15, 2013
21. Passed all tests. Observation well

A.10.1SS-8 Vertilog Sections January 17, 1989

Class 2 is 20–40% penetration.

Class 3 is 40–60% penetration.

Figure 23 shows the Vertilog header, and Figure 24 and Figure 25 show Vertilog sections with penetrations flagged.

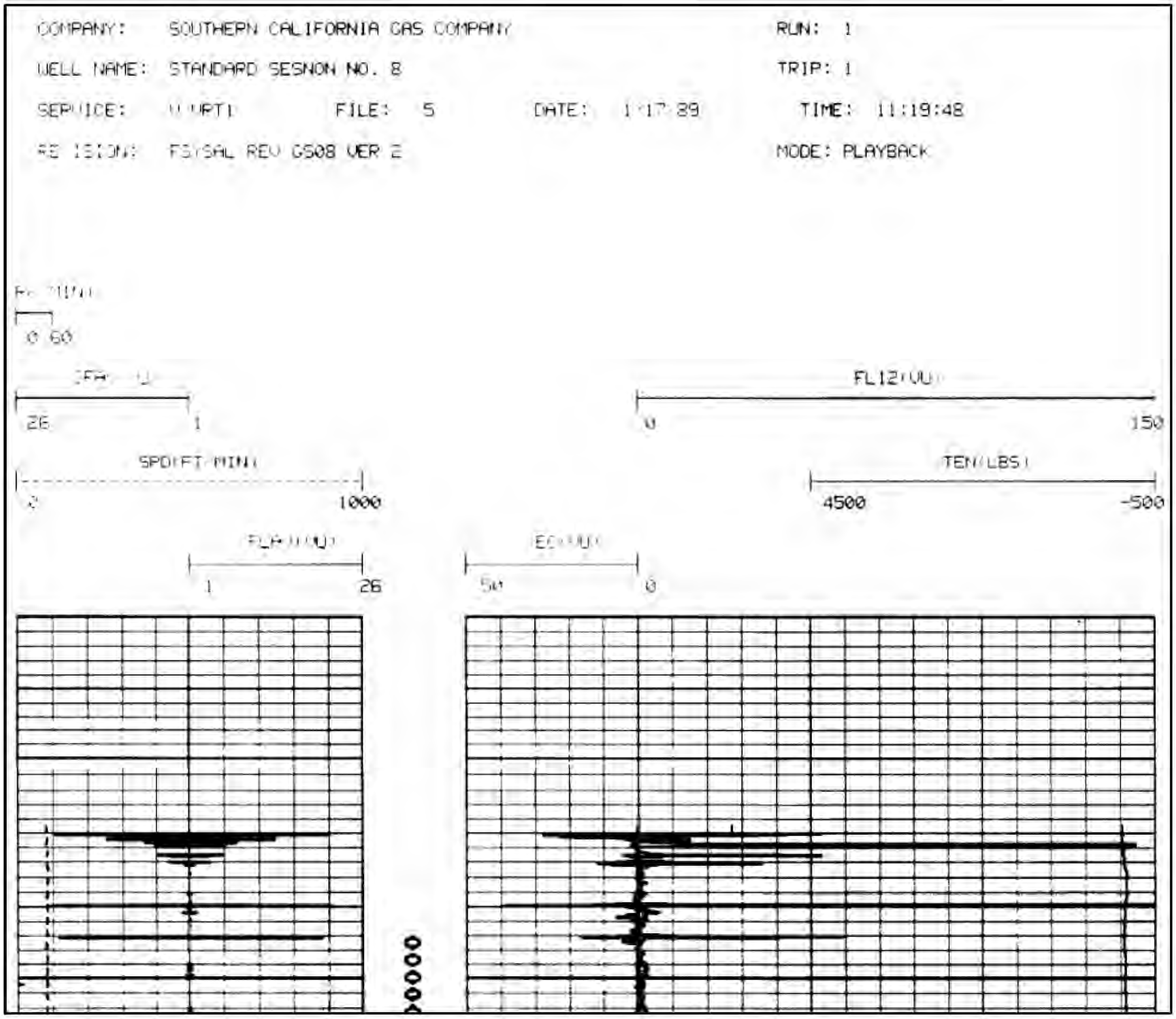


Figure 23: SS-8 Vertilog Header

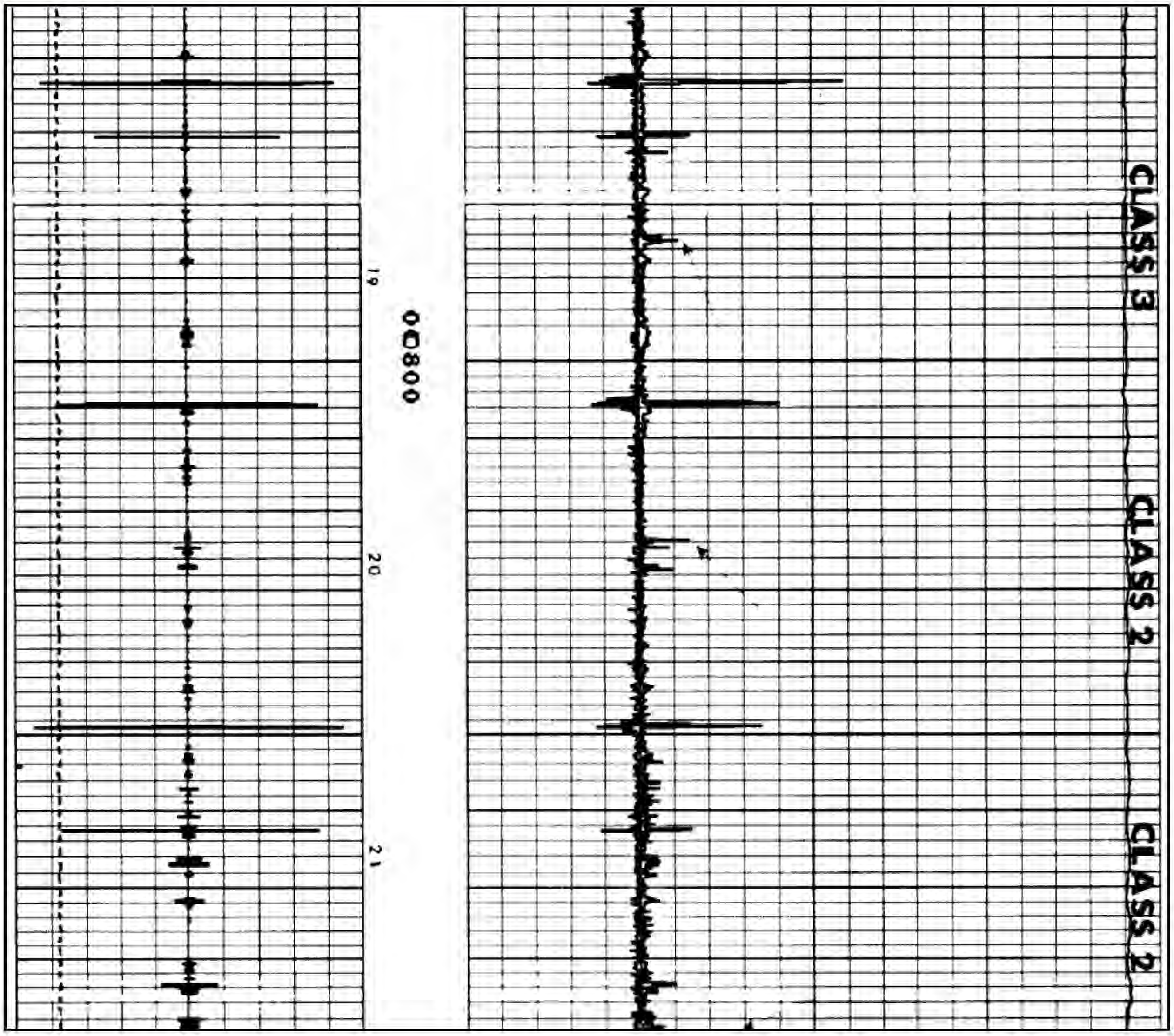


Figure 24: SS-8 Vertilog Section

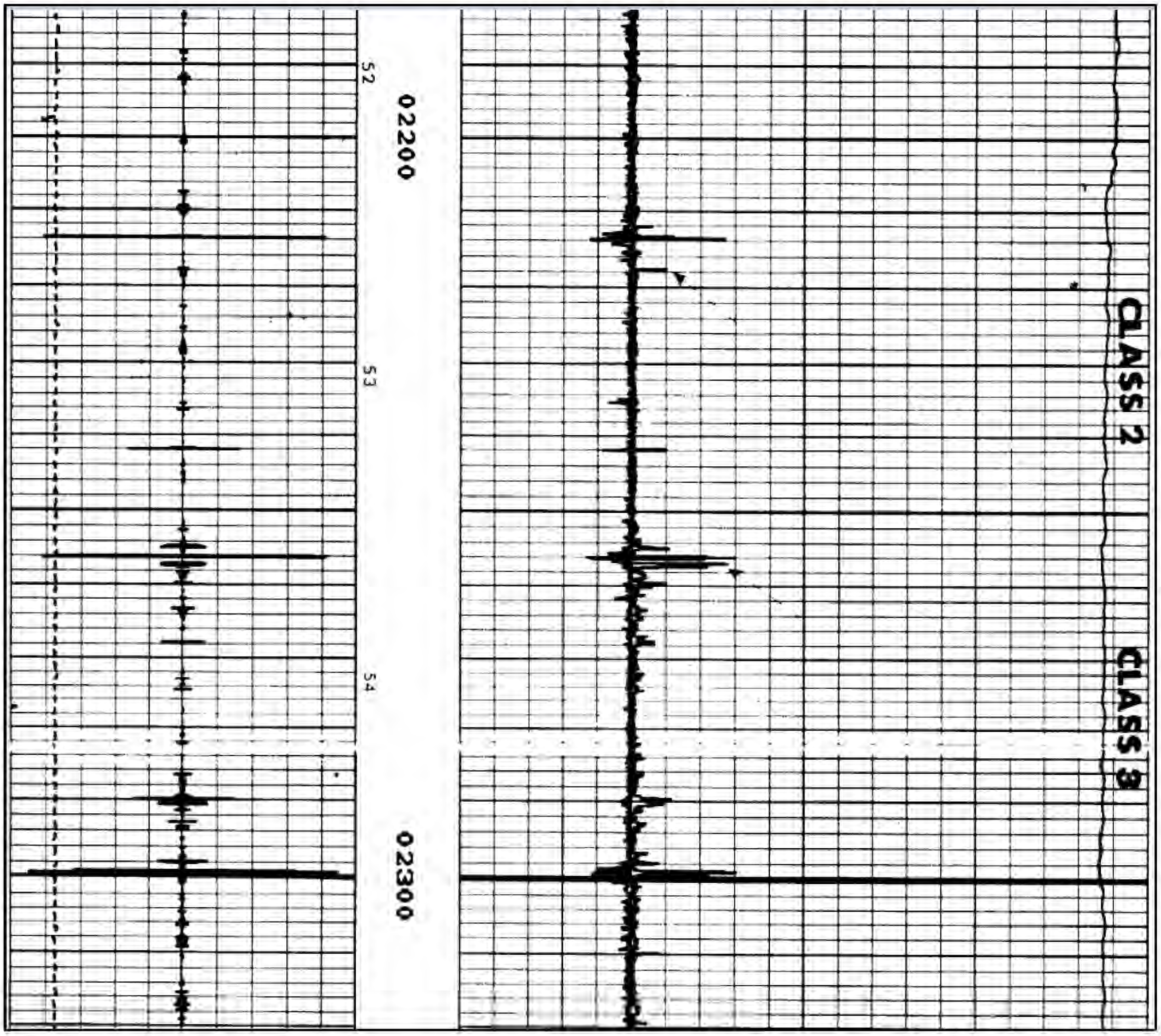


Figure 25: SS-8 Vertilog Section

A.11 SS-9

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 598 ft
2. Pressure test 7 in. casing 1,500 psi for 15 minutes. February 1, 1956
3. Pressure test 7 in. casing in stages 1,500–3,400 psi for 27 minutes. July 6, 1973
4. Pressure test 7 in. casing in stages 2,800–4,000 psi for 60 minutes. August 31, 1977
5. Pressure test seals and packer 2,000 psi for 20 minutes September 3, 1977
6. Ran 7 in. Vertilog 8,558 ft–Surface. December 16, 1988
   - 6 joints >20% OD penetration. 2,105 ft, 2,560 ft, 2,641 ft, 2,765 ft, 3,512 ft, 3,760 ft

7. Pressure test 7 in. casing, packer, tubing plug 1,100 psi for 1 hour. July 8, 2016
8. Pressure test 7 in. casing 1,221 psi for 60 minutes. February 12, 2018
9. Passed all tests

A.11.1SS-9 Vertilog Sections December 16, 1988

Class 2 is 20–40% penetration.

Figure 26 shows the Vertilog header, and Figure 27 and Figure 28 show Vertilog sections with penetrations flagged.

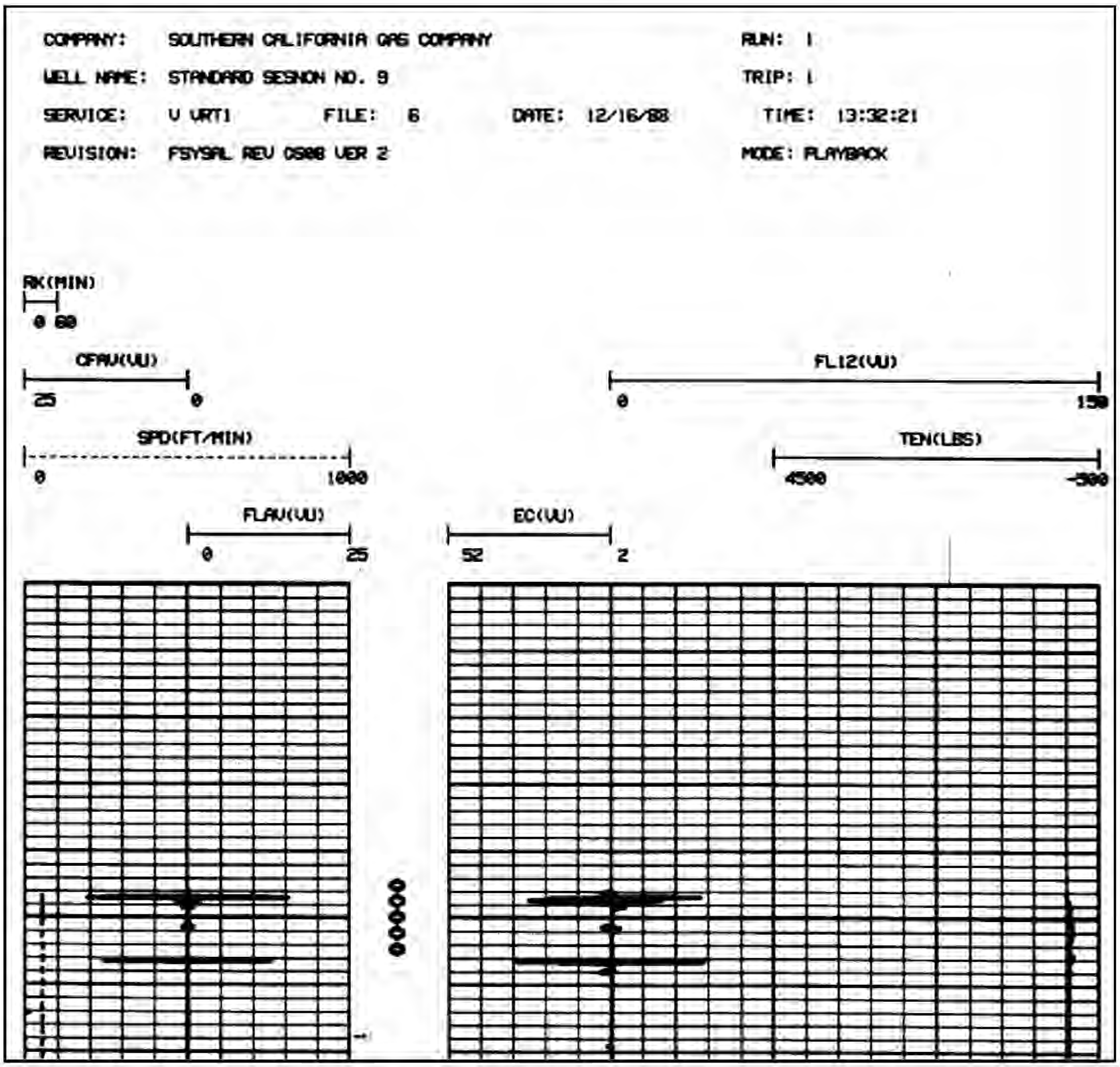


Figure 26: SS-9 Vertilog Header

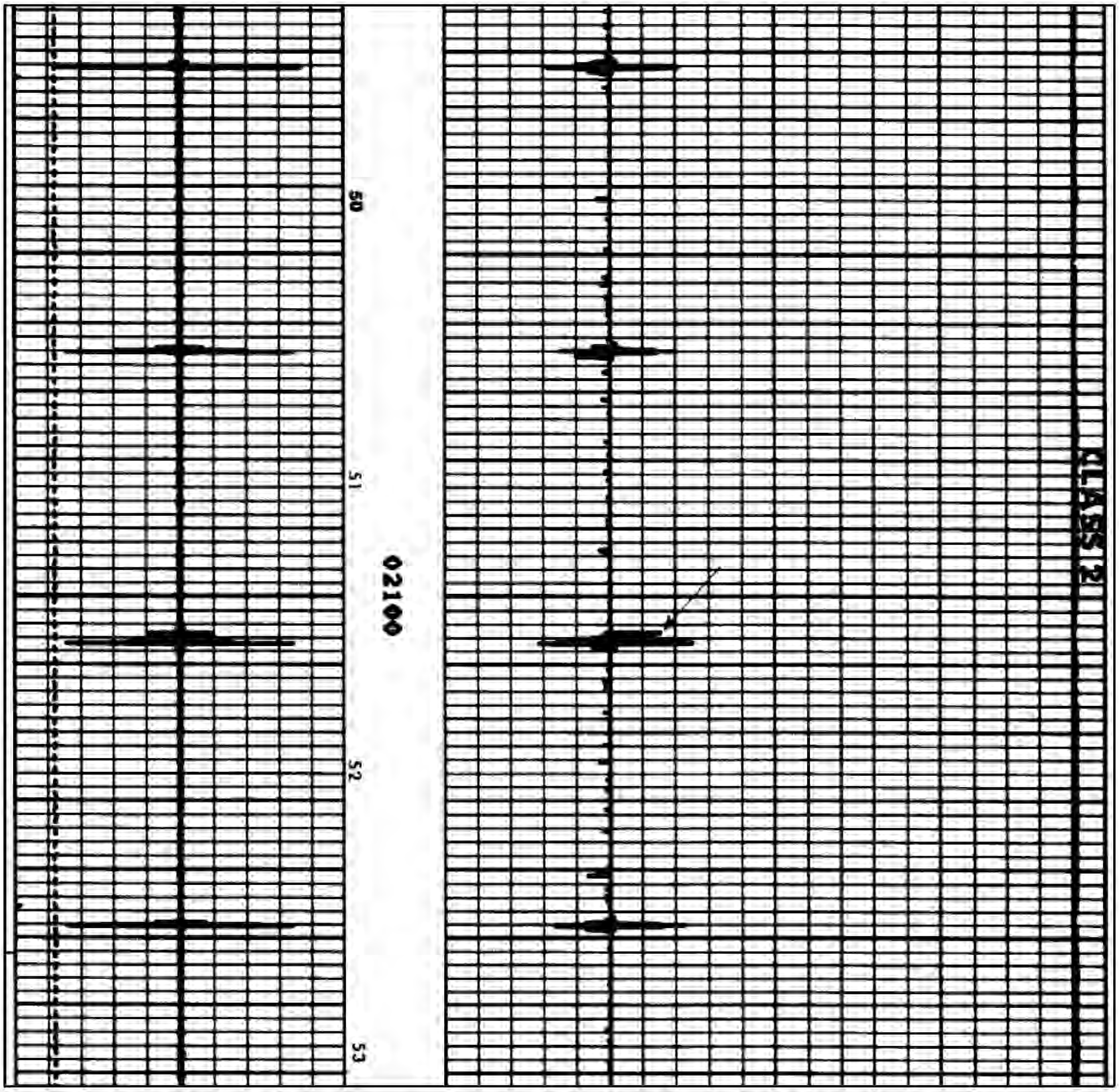


Figure 27: SS-9 Vertilog Header

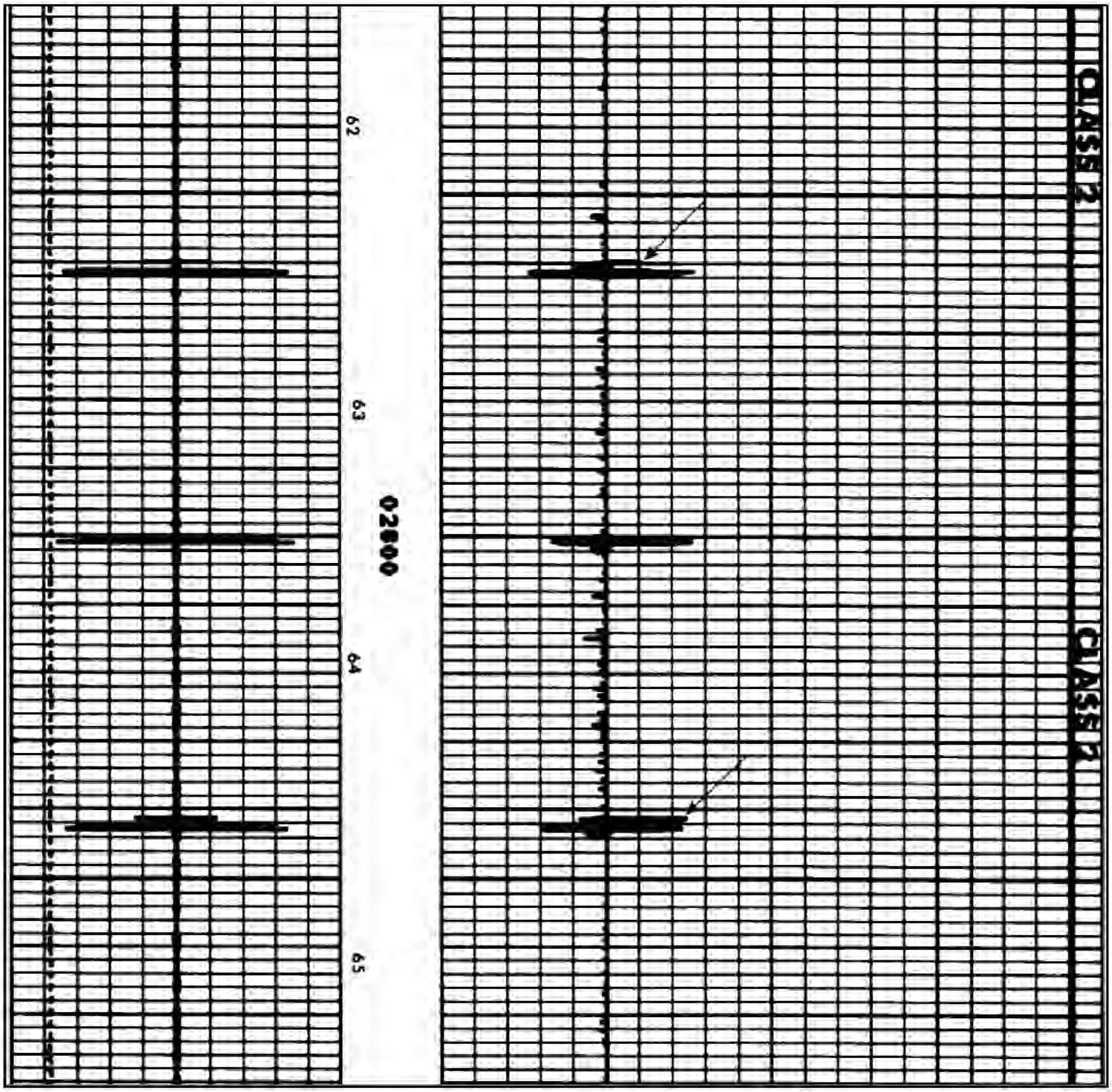


Figure 28: SS-9 Vertilog Section

A.12 SS-10

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 823 ft
2. Pressure test 7 in. casing in stages 1,525–3,075 psi. April 19, 1973
3. Pressure test 7 in. casing in stages 2,800–4,000 psi. September 14, 1977
4. Casing leak in 7 in. at 4,492 ft? (Pressure test to 2,000 psi for 20 minutes) Ran casing patch 4,474–4,516 ft. December 19, 1978
5. Pressure test packer 1,500 psi for 20 minutes. December 20, 1978
6. Pressure tested annulus to 1,000 psi for 20 minutes. September 21, 2012
7. Ran 7 in. USIT log 7,923–33. September 24, 2012
   - Indications 2,274–3,246 ft
8. Set 7 in. casing patch 4,462–4,524 ft. September 27, 2012
9. Pressure test tubing-annulus to 1,650 psi. September 28, 2012
10. Pressure tubing-casing annulus 1,000 psi for 20 minutes. October 10, 2012
11. Pressure test 7 in. casing 1,000 psi for 1 hr. June 30, 2016
12. Perforate and cement squeeze 7 in. casing. Clean out cement. May 11, 2017
13. Run and cement 5 1/2 in. inner casing. May 17, 2017
14. Passed all tests

A.12.1SS-10 USIT Log September 24, 2012

Figure 29 shows the log header and Figure 30 shows the log legend. Figure 31 shows a section of the USIT log.

Schlumberger

Company: **Southern California Gas Company**

Well: **STANDARD-SESNON 10**
Field: **ALISO CANYON**
County: **LOS ANGELES** State: **CALIFORNIA**

County: LOS ANGELES
Field: ALISO CANYON
Location: N/A
Well: STANDARD-SESNON 10
Company: Southern California Gas Compa

ULTRASONIC IMAGING TOOL
GAMMA RAY / NEUTRON / CCL

LOCATION

N/A		Elev.: K.B. 2622.00 ft G.L. 2615.00 ft D.F.
Permanent Datum:	GROUND LEVEL	Elev.: 2626.00 ft
Log Measured From:	KELLY BUSHING	7.00 ft above Perm. Datum
Drilling Measured From:		

API Serial No.	Section	Township	Range
037-00040	28	3N	16W

Logging Date	24-Sep-2012	
Run Number	ONE, TWO	
Depth Driller	7936 ft	
Schlumberger Depth	7923 ft	
Bottom Log Interval	7923 ft	
Top Log Interval	33 ft	
Casing Fluid Type	KCL	
Salinity		
Density	8.6 lbm/gal	
Fluid Level		
BIT/CASING/TUBING STRING		
Bit Size		
From		
To		
Casing/Tubing Size	7.000 in	
Weight	23 lbm/ft	
Grade	N-80	
From	0 ft	
To	8115 ft	
Maximum Recorded Temperatures		
Logger On Bottom / Time	24-Sep-2012 17:37	
Unit Number / Location	3181 Long Beach	
Recorded By	Stepan Oskin/ Sarah Corbyn	
Witnessed By	Mike Volkmar	

Figure 29: SS-10 USIT Log Header

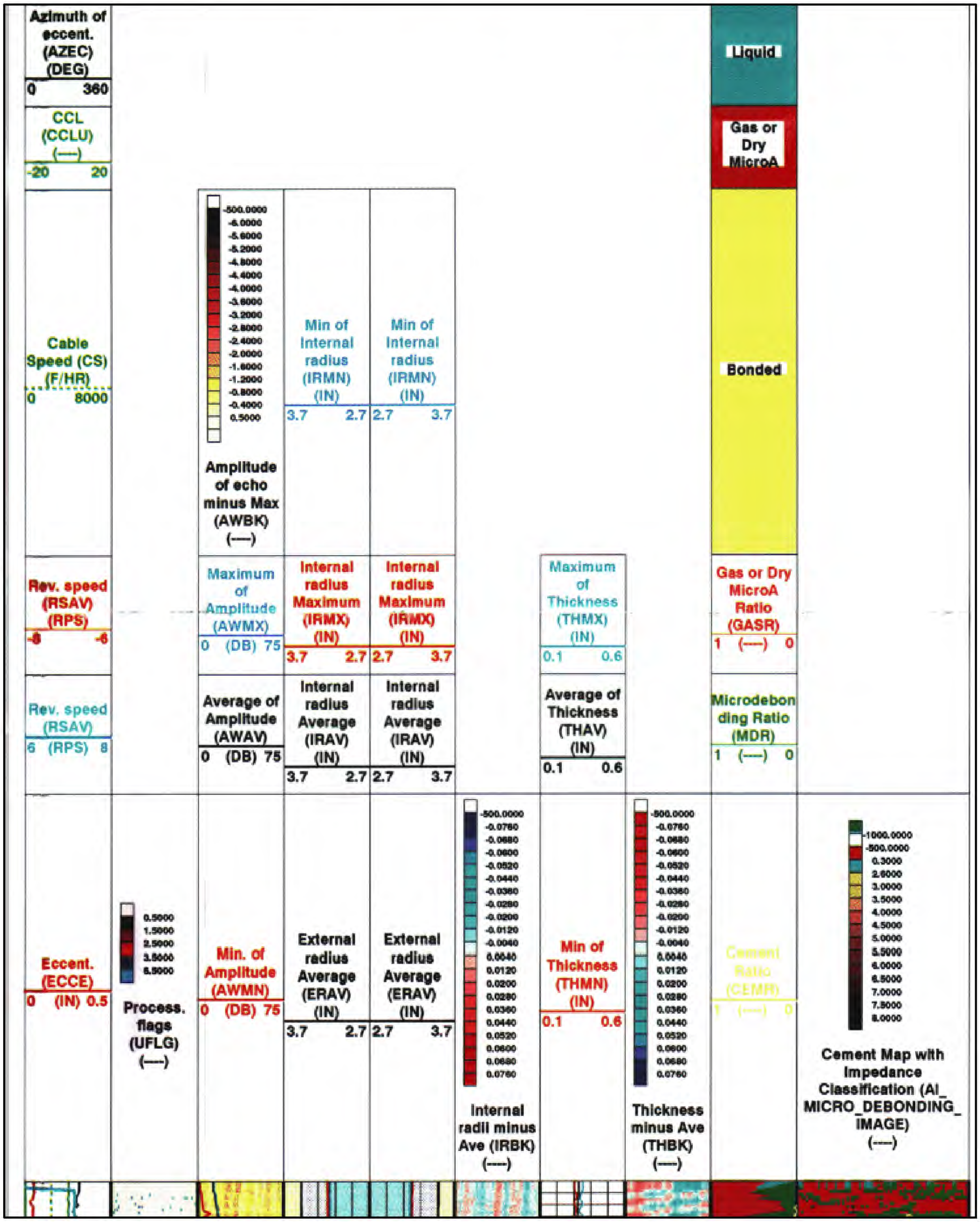


Figure 30: SS-10 USIT Log Legend

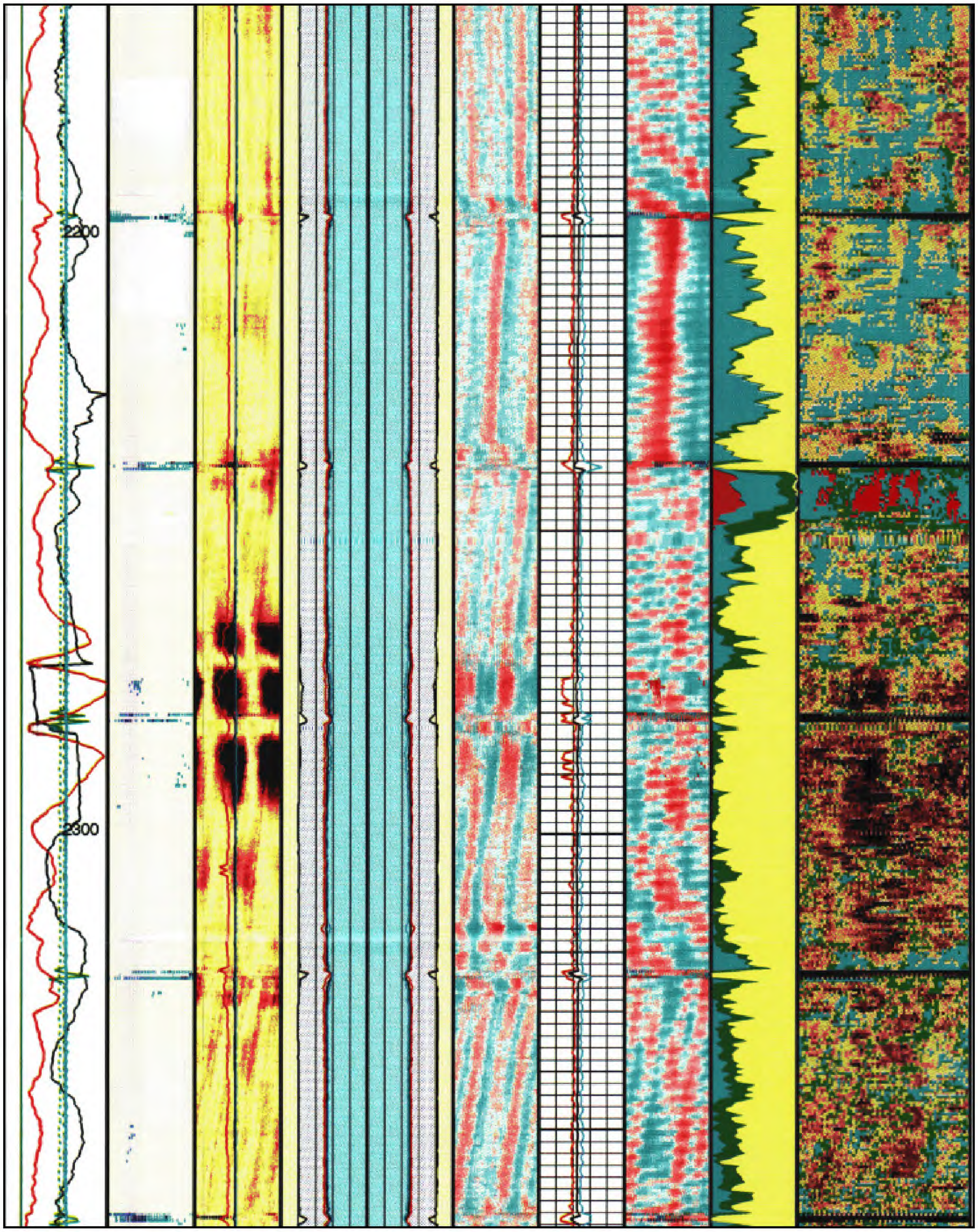


Figure 31: SS-10 USIT Log Section

A.13 SS-11

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 824 ft
2. Pressure test 7 in. casing in stages 1,700–3,000 psi for 20 minutes. June 15, 1973
3. Pressure test 7 in. casing in stages 2,700–4,000 psi for 60 minutes. September 26, 1977
4. Tight spot in 7 in. casing at 2,359 ft. Packer stopped several times. Ran a different packer. November 27, 1978
5. Tested packer to 1,500 psi for 20 minutes. November 29, 1978
6. Pressure test 7 in. casing in stages 2,700–4,000 psi for 60 minutes. March 29, 1980
7. Tested annulus to 1,500 psi for 20 minutes. June 9, 1980
8. Pressure test 7 in. casing 1,500 psi for 20 minutes. April 27, 1993
9. Pressure test 7 in. casing 3,000 psi for 20 minutes. April 29, 1993
10. Pressure test 7 in. casing, packer, seal assembly to 1,500 psi for 20 minutes. May 7, 1993
11. Pressure test 7 in. casing 1,100 psi for 1 hr. July 29, 2016
12. Pressure test 7 in. casing 1,144 psi for 1 hr. February 1, 2017
13. P&A'd in 2017

A.14 SS-17

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. at 1,010 ft
2. Casing leak in 7 in. casing at 5,238 ft while drilling. Squeeze cement 2 times. Pressure tested to 2,000 psi for 15 minutes. August 3, 1952
3. Pressure test 7 in. casing in stages 1,750–3,200 psi for 20 minutes. June 27, 1973
4. Pressure test 7 in. casing in stages 2,500–4,000 psi for 60 minutes. July 27, 1977
5. Tested packer and seals to 1,500 psi for 15 minutes. April 16, 1993
6. Found split 13 3/8 in. top joint while P&A. June 28, 2017
7. P&A'd in 2017

A.15 SS-24

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 11 3/4 in. at 1,134 ft
2. Pressure test 7 in. casing 1,500 psi for 1 hr. October 23, 1955
3. Pressure test 7 in. casing in stages 1,800–3,100 psi for 20 minutes. July 9, 1973
4. Pressure test 7 in. in stages 2,500–4,000 psi for 60 minutes. August 22, 1977
5. Pressure test packer 2,000 psi for 20 minutes. August 26, 1977
6. Pressure test 7 in. casing 1,800 psi for 20 minutes. January 28, 1985
7. Pressure test seals and packer 1,500 psi. March 20, 1985
8. Pressure test 1,100 psi for 1 hour. June 30, 2016
9. Ran 7 in. Baker multi-finger caliper log 8,904 ft–Surface. February 11, 2017
10. Ran 7 in. HRVRT log 8,800 ft–Surface. February 11, 2017
    - 4 joints >20% OD penetration 1,585 ft, 2,565 ft, 2,613 ft, 2,883 ft
    - 4 joints > 20% ID penetration 977 ft, 1,097 ft, 5,823 ft, 8,297 ft
11. Pressure test 7 in. casing 1,000 psi for 1 hour. February 13, 2017
12. Pressure test 7 in. casing 1,099 psi for 60 minutes. February 14, 2017
13. Ran 7 in. USIT 8,506 ft–Surface. Daily Report: External Anomalies, 8,406–8,414 ft, 2,250–2,920 ft, 1,100–1,620 ft. February 15, 2017
    - 8 jts >20% penetration
14. P&A'd in 2017

A.15.1SS-24 HRVRT Log February 11, 2017

Figure 32 shows the HRVRT header, and Figure 33 and Figure 34 show the log summary.

BAKER HUGHES

HR Vertilog

Magnetic Flux Leakage Inspection

Advanced Analysis

Company	Southern California Gas Company
Well	Standard Sesnon 24
Field	Aliso Canyon
County	Los Angeles
State	California
Location: 2284.11' S and 7499.16' W FROM STATION 84	
Section 29	Township 3N / Range 16W
Date	Feb. 11, 2017
Service Order	US111472J
Recorded by	Spencer
Witnessed by	J. Mosier
API Serial No.	04-037-00775-00

Permanent Datum:	G.L	Elevation: 2539.400 ft.	Depth	0.000
Log Measured From:	D.F	6.920 ft. above Perm. Datum	Btm. Log Interval	8765.000
Drilling Measured From:	D.F	0.000 ft. above Perm. Datum	Top Log Interval	0.000
			Fluid Type	KCL

Casing Data

Size	Weight	Grade	From	To	Length
11 3/4 inch	42.0 lb/ft	H-40	0	1134	1134.0
7 inch	23.0 lb/ft	N-80	0	1807	1807.0
7 inch	23.0 lb/ft	J-55	1807	4346	2539.0
7 inch	23.0 lb/ft	N-80	4346	6479	2133.0
7 inch	26.0 lb/ft	N-80	6479	8414	1935.0
7 inch	29.0 lb/ft	N-80	8414	8920	506.0
5 inch	18.0 lb/ft	N-80	8914	9064	150.0

Figure 32: SS-24 HRVRT Log Header [6]

Joint Interpretation Summary

Joint	From	To	Length	Class	Max Depth	Position	ID/OD
1	12.25	32.50	20.25	Class 1	-	-	-
2	32.50	74.32	41.82	Class 1	-	-	-
3	74.32	118.20	43.88	Class 1	-	-	-
4	118.20	161.61	43.41	Class 1	-	-	-
5	161.61	204.80	43.19	Class 1	-	-	-
6	204.80	247.41	42.61	Class 1	-	-	-
7	247.41	291.14	43.73	Class 1	-	-	-
8	291.14	333.81	42.67	Class 1	-	-	-
9	333.81	377.35	43.54	Class 1	-	-	-
10	377.35	420.61	43.26	Class 1	-	-	-
11	420.61	464.25	43.64	Class 1	-	-	-
12	464.25	507.72	43.47	Class 1	-	-	-
13	507.72	550.57	42.85	Class 1	-	-	-
14	550.57	594.57	44.00	Class 1	-	-	-
15	594.57	637.85	43.28	Class 1	-	-	-
16	637.85	679.85	42.00	Class 1	-	-	-
17	679.85	724.44	44.59	Class 1	-	-	-
18	724.44	768.47	44.03	Class 1	-	-	-
19	768.47	811.94	43.47	Class 1	-	-	-
20	811.94	855.28	43.34	Class 1	-	-	-
21	855.28	898.24	42.96	Class 1	-	-	-
22	898.24	941.99	43.75	Class 2	20.0%	929.88	ID
23	941.99	985.87	43.88	Class 2	25.0%	977.12	ID
24	985.87	1028.95	43.08	Class 1	19.0%	1022.53	ID
25	1028.95	1073.11	44.16	Class 1	-	-	-
26	1073.11	1117.21	44.10	Class 2	21.0%	1096.96	ID
27	1117.21	1160.79	43.58	Class 1	18.0%	1150.57	OD
28	1160.79	1201.34	40.55	Class 1	-	-	-
29	1201.34	1244.67	43.33	Class 1	16.0%	1231.38	OD
30	1244.67	1288.46	43.79	Class 2	20.0%	1260.71	OD
31	1288.46	1331.71	43.25	Class 1	19.0%	1296.85	OD
32	1331.71	1375.09	43.38	Class 1	-	-	-
33	1375.09	1418.29	43.20	Class 1	-	-	-
34	1418.29	1461.77	43.48	Class 1	-	-	-
35	1461.77	1504.73	42.96	Class 1	-	-	-
36	1504.73	1548.28	43.55	Class 1	-	-	-
37	1548.28	1591.83	43.55	Class 2	22.0%	1584.95	OD
38	1591.83	1635.54	43.71	Class 1	-	-	-
39	1635.54	1678.64	43.10	Class 1	-	-	-
40	1678.64	1721.80	43.16	Class 1	16.0%	1712.50	OD
41	1721.80	1764.66	42.86	Class 1	-	-	-
42	1764.66	1809.17	44.51	Class 1	-	-	-
43	1809.17	1839.62	30.45	Class 1	-	-	-
44	1839.62	1868.43	28.81	Class 1	-	-	-
45	1868.43	1896.96	28.53	Class 1	-	-	-
46	1896.96	1926.98	30.02	Class 1	-	-	-
47	1926.98	1960.58	33.60	Class 1	-	-	-

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Figure 33: SS-24 HRVRT Log Section

48	1960.58	1991.62	31.04	Class 1	-	-	-
49	1991.62	2025.15	33.53	Class 1	-	-	-
50	2025.15	2058.08	32.93	Class 1	-	-	-
51	2058.08	2090.65	32.57	Class 1	-	-	-
52	2090.65	2122.89	32.24	Class 1	-	-	-
53	2122.89	2153.43	30.54	Class 1	-	-	-
54	2153.43	2184.54	31.11	Class 1	15.0%	2168.23	ID
55	2184.54	2214.72	30.18	Class 1	-	-	-
56	2214.72	2247.53	32.81	Class 1	19.0%	2240.54	OD
57	2247.53	2277.78	30.25	Class 1	16.0%	2254.73	OD
58	2277.78	2310.49	32.71	Class 1	-	-	-
59	2310.49	2344.09	33.60	Class 1	-	-	-
60	2344.09	2375.39	31.30	Class 1	16.0%	2346.87	ID
61	2375.39	2408.72	33.33	Class 1	-	-	-
62	2408.72	2423.93	15.21	Class 1	-	-	-
63	2423.93	2440.79	16.86	Class 1	-	-	-
64	2440.79	2473.80	33.01	Class 1	-	-	-
65	2473.80	2507.35	33.55	Class 1	17.0%	2505.92	OD
66	2507.35	2538.58	31.23	Class 1	16.0%	2534.62	OD
67	2538.58	2571.88	33.30	Class 2	22.0%	2565.14	OD
68	2571.88	2605.46	33.58	Class 1	18.0%	2591.83	OD
69	2605.46	2636.98	31.52	Class 2	22.0%	2612.76	OD
70	2636.98	2670.65	33.67	Class 1	-	-	-
71	2670.65	2702.88	32.23	Class 1	-	-	-
72	2702.88	2736.43	33.55	Class 2	20.0%	2723.35	OD
73	2736.43	2769.98	33.55	Class 1	-	-	-
74	2769.98	2802.49	32.51	Class 1	-	-	-
75	2802.49	2834.47	31.98	Class 1	-	-	-
76	2834.47	2866.43	31.96	Class 1	-	-	-
77	2866.43	2898.77	32.34	Class 2	27.0%	2883.30	OD
78	2898.77	2930.89	32.12	Class 1	-	-	-
79	2930.89	2964.43	33.54	Class 1	-	-	-
80	2964.43	2993.19	28.76	Class 1	-	-	-
81	2993.19	3026.80	33.61	Class 1	-	-	-
82	3026.80	3059.26	32.46	Class 1	15.0%	3057.15	OD
83	3059.26	3087.37	28.11	Class 1	-	-	-
84	3087.37	3115.72	28.35	Class 1	-	-	-
85	3115.72	3148.73	33.01	Class 1	-	-	-
86	3148.73	3178.13	29.40	Class 1	-	-	-
87	3178.13	3210.38	32.25	Class 1	-	-	-
88	3210.38	3242.35	31.97	Class 1	-	-	-
89	3242.35	3272.26	29.91	Class 1	-	-	-
90	3272.26	3304.48	32.22	Class 1	-	-	-
91	3304.48	3336.46	31.98	Class 1	-	-	-
92	3336.46	3370.04	33.58	Class 1	-	-	-
93	3370.04	3386.16	16.12	Class 1	-	-	-
94	3386.16	3401.92	15.76	Class 1	-	-	-
95	3401.92	3430.05	28.13	Class 1	-	-	-
96	3430.05	3461.89	31.84	Class 1	-	-	-
97	3461.89	3493.32	31.43	Class 1	-	-	-
98	3493.32	3526.88	33.56	Class 1	-	-	-
99	3526.88	3558.68	31.80	Class 1	-	-	-
100	3558.68	3592.23	33.55	Class 1	-	-	-
101	3592.23	3623.87	31.64	Class 1	-	-	-
102	3623.87	3657.45	33.58	Class 1	-	-	-
103	3657.45	3690.17	32.72	Class 1	-	-	-
104	3690.17	3721.94	31.77	Class 1	-	-	-
105	3721.94	3748.36	26.42	Class 1	-	-	-
106	3748.36	3777.27	28.91	Class 1	-	-	-
107	3777.27	3810.91	33.64	Class 1	-	-	-
108	3810.91	3844.52	33.61	Class 1	-	-	-
109	3844.52	3877.09	32.57	Class 1	-	-	-
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]			

Figure 34: SS-24 HRVRT Log Section

A.16 SS-25

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 11 3/4 in. Surface casing at 990 ft
2. Pressure test 7 in. casing in stages 1,500–3,400 psi for 33 minutes. May 29, 1973
3. Pressure test seals and packer 2,500 psi for 20 minutes. July 9, 1976
4. Pressure test annulus to 1,500 psi for 20 minutes. February 19, 1979
5. Pressure 7 in. casing to 2,500 psi. January 10, 1980
6. Casing leak October 23, 2015. Confirmed parted casing at 892 ft MD
7. 7 in. and 11 3/4 in. Inspection logs run in 2017 as part of the RCA
8. Ran 7 in. HRVRT log 7,539 ft–surface, December 2, 2017
9. Ran 7 in. IBC Casing Evaluation log 7,546–990 ft, December 4, 2017
10. P&A'd in 2018

A.16.1SS-25 Inspection Logs

The inspection logs analysis for SS-25 is covered in a separate report *SS-25 Inspection Log Analysis* [7].

A.17 SS-29

The following is a SoCalGas' summary of sequential records for this well related to production casing integrity:

1. 11 3/4 in. Surface casing at 1,042 ft
2. Pressure test 7 in. casing in stages 2,060–3,000 psi for 15 minutes. February 8, 1973
3. Pressure test 7 in. casing in stages 2,500–4,000 psi for 60 minutes. September 6, 1977
4. Pressure test seals and packer 1,500 psi. November 6, 1991
5. Pressure test packer, tubing plug and 7 in. casing 1,000 psi for 1 hour. July 21, 2016
6. SIMP Well Operations Procedure to rework. September 17, 2017
7. Ran 7 in. USIT log 8,080 ft to surface. October 10, 2017
   – 4 jts >20% penetration
8. Ran 7 in. HRVRT log 8,075 ft to surface. October 13, 2017
   – 1 joint >20% OD penetration 8,050 ft
   – 3 joints >20% ID penetration 3,997 ft, 7,960 ft, 8,050 ft
   – 1 joint >40% ID penetration 8,050 ft
9. Passed all tests

A.17.1SS-29 HRVRT Log October 13, 2017

Figure 35 shows the HRVRT log header. Figure 36, Figure 37, and Figure 38 show HRVRT log sections.

BAKER HUGHES a GE company

HR Vertilog

Magnetic Flux Leakage Inspection

Advanced Analysis

Company	Southern California Gas Company				
Well	Standard Sesnon 29				
Field	Aliso Canyon				
County	Los Angeles				
State	California				
Location					
Section 28	Township T3N	Range 16W			
Date	Oct. 13, 2017				
Service Order	US128680J				
Recorded by	J Burge				
Witnessed by	P Brogdin				
API Serial No.	04-037-00041				
Permanent Datum:	GL	Elevation: 2848.770 ft.		Depth	9790.000
Log Measured From:	DF	6.920 ft. above Perm. Datum		Btm. Log Interval	8264.000
Drilling Measured From:	DF	6.920 ft. above Perm. Datum		Top Log Interval	0.000
				Fluid Type	Water

Figure 35: SS-29 HRVRT Log Header

Joint Interpretation Summary

Joint	From	To	Length	Class	Max Depth	Position	ID/OD
1	1.82	6.85	5.03	Class 1	-	-	-
2	6.85	49.26	42.41	Class 1	-	-	-
3	49.26	91.96	42.70	Class 1	-	-	-
4	91.96	135.00	43.04	Class 1	-	-	-
5	135.00	176.78	41.78	Class 1	-	-	-
6	176.78	220.40	43.62	Class 1	-	-	-
7	220.40	264.02	43.62	Class 1	-	-	-
8	264.02	307.23	43.21	Class 1	-	-	-
9	307.23	350.79	43.56	Class 1	-	-	-
10	350.79	393.37	42.58	Class 1	-	-	-
11	393.37	435.40	42.03	Class 1	-	-	-
12	435.40	478.33	42.93	Class 1	-	-	-
13	478.33	520.98	42.65	Class 1	-	-	-
14	520.98	564.26	43.28	Class 1	-	-	-
15	564.26	606.99	42.73	Class 1	-	-	-
16	606.99	649.73	42.74	Class 1	-	-	-
17	649.73	691.50	41.77	Class 1	-	-	-
18	691.50	734.04	42.54	Class 1	-	-	-
19	734.04	775.64	41.60	Class 1	-	-	-
20	775.64	816.33	40.69	Class 1	-	-	-
21	816.33	858.77	42.44	Class 1	-	-	-
22	858.77	897.52	38.75	Class 1	-	-	-
23	897.52	939.03	41.51	Class 1	-	-	-
24	939.03	981.78	42.75	Class 1	-	-	-
25	981.78	1024.45	42.67	Class 1	-	-	-
26	1024.45	1056.60	32.15	Class 1	-	-	-
27	1056.60	1092.50	35.90	Class 1	-	-	-
28	1092.50	1113.69	21.19	Class 1	-	-	-
29	1113.69	1132.32	18.63	Class 1	-	-	-
30	1132.32	1150.30	17.98	Class 1	-	-	-
31	1150.30	1170.30	20.00	Class 1	-	-	-
32	1170.30	1186.15	15.85	Class 1	-	-	-
33	1186.15	1207.95	21.80	Class 1	-	-	-
34	1207.95	1247.08	39.13	Class 1	-	-	-
35	1247.08	1286.10	39.02	Class 1	-	-	-

Figure 36: SS-29 HRVRT Log Summary

76	2961.03	3002.02	40.99	Class 1	-	-	-
77	3002.02	3040.30	38.28	Class 1	-	-	-
78	3040.30	3082.50	42.20	Class 1	-	-	-
79	3082.50	3125.42	42.92	Class 1	-	-	-
80	3125.42	3166.82	41.40	Class 1	-	-	-
81	3166.82	3204.38	37.56	Class 1	-	-	-
82	3204.38	3244.98	40.60	Class 1	-	-	-
83	3244.98	3286.20	41.22	Class 1	-	-	-
84	3286.20	3328.57	42.37	Class 1	-	-	-
85	3328.57	3371.04	42.47	Class 1	-	-	-
86	3371.04	3413.75	42.71	Class 1	-	-	-
87	3413.75	3455.98	42.23	Class 1	-	-	-
88	3455.98	3497.64	41.66	Class 1	-	-	-
89	3497.64	3540.01	42.37	Class 1	-	-	-
90	3540.01	3582.27	42.26	Class 1	-	-	-
91	3582.27	3624.35	42.08	Class 1	-	-	-
92	3624.35	3667.25	42.90	Class 1	-	-	-
93	3667.25	3709.29	42.04	Class 1	-	-	-
94	3709.29	3750.70	41.41	Class 1	-	-	-
95	3750.70	3792.03	41.33	Class 1	-	-	-
96	3792.03	3834.08	42.05	Class 1	-	-	-
97	3834.08	3876.21	42.13	Class 1	-	-	-
98	3876.21	3917.70	41.49	Class 1	-	-	-
99	3917.70	3961.20	43.50	Class 1	-	-	-
100	3961.20	4003.51	42.31	Class 2	34.0%	3996.72	ID
101	4003.51	4045.20	41.69	Class 1	-	-	-
102	4045.20	4086.49	41.29	Class 1	-	-	-
103	4086.49	4128.52	42.03	Class 1	-	-	-
104	4128.52	4171.01	42.49	Class 1	-	-	-
105	4171.01	4214.07	43.06	Class 1	-	-	-
106	4214.07	4256.77	42.70	Class 1	-	-	-
107	4256.77	4298.66	41.89	Class 1	-	-	-
108	4298.66	4341.32	42.66	Class 1	-	-	-
109	4341.32	4379.69	38.37	Class 1	-	-	-
110	4379.69	4422.32	42.63	Class 1	-	-	-
111	4422.32	4463.68	41.36	Class 1	-	-	-
112	4463.68	4506.78	43.10	Class 1	-	-	-
113	4506.78	4549.57	42.79	Class 1	-	-	-
114	4549.57	4591.38	41.81	Class 1	-	-	-

Figure 37: SS-29 HRVRT Log Summary

174	6944.26	6976.88	32.62	Class 1	-	-	-
175	6976.88	7008.59	31.71	Class 1	-	-	-
176	7008.59	7040.20	31.61	Class 1	-	-	-
177	7040.20	7073.63	33.43	Class 1	-	-	-
178	7073.63	7105.69	32.06	Class 1	-	-	-
179	7105.69	7136.96	31.27	Class 1	-	-	-
180	7136.96	7166.94	29.98	Class 1	-	-	-
181	7166.94	7198.09	31.15	Class 1	-	-	-
182	7198.09	7229.71	31.62	Class 1	-	-	-
183	7229.71	7260.95	31.24	Class 1	-	-	-
184	7260.95	7291.98	31.03	Class 1	-	-	-
185	7291.98	7323.26	31.28	Class 1	-	-	-
186	7323.26	7354.72	31.46	Class 1	-	-	-
187	7354.72	7386.17	31.45	Class 1	-	-	-
188	7386.17	7417.64	31.47	Class 1	-	-	-
189	7417.64	7448.32	30.68	Class 1	-	-	-
190	7448.32	7481.25	32.93	Class 1	-	-	-
191	7481.25	7513.36	32.11	Class 1	-	-	-
192	7513.36	7543.60	30.24	Class 1	-	-	-
193	7543.60	7574.44	30.84	Class 1	-	-	-
194	7574.44	7605.58	31.14	Class 1	-	-	-
195	7605.58	7637.33	31.75	Class 1	-	-	-
196	7637.33	7667.99	30.66	Class 1	-	-	-
197	7667.99	7700.56	32.57	Class 1	-	-	-
198	7700.56	7730.93	30.37	Class 1	-	-	-
199	7730.93	7764.00	33.07	Class 1	-	-	-
200	7764.00	7795.66	31.66	Class 1	-	-	-
201	7795.66	7827.51	31.85	Class 1	-	-	-
202	7827.51	7859.03	31.52	Class 1	-	-	-
203	7859.03	7890.33	31.30	Class 1	-	-	-
204	7890.33	7922.19	31.86	Class 1	-	-	-
205	7922.19	7954.14	31.95	Class 1	-	-	-
206	7954.14	7986.00	31.86	Class 2	27.0%	7960.47	ID
207	7986.00	8017.44	31.44	Class 2	35.0%	8003.79	ID
208	8017.44	8050.05	32.61	Class 3	43.0%	8049.55	ID
209	8050.05	8064.69	14.64	Class 2	30.0%	8050.45	OD

Figure 38: SS-29 HRVRT Log Summary

A.18 Frew 2

The following is a SoCalGas' summary of sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 501 ft
2. Pressure test 7 in. casing 1,375 psi for 20 minutes. April 6, 1973
3. Pressure test 7 in. casing in stages 2,500–4,000 psi for 60 minutes. September 7, 1977
4. Pressure test seals and packer 2,000 psi for 20 minutes. September 9, 1977
5. Ran 7 in. Vertilog 8,250 ft–Surface. January 11, 1990 (Vertilog not on DOGGR website as of February 7, 2019)
6. Tight spot 7 in. casing 3,872 ft. August 28, 2014
7. Tight spot 7 in. casing 8,130 ft. September 3, 2014
8. Ran 7 in. USIT 8,110 ft–Surface. September 11, 2014

9. Ran 7 in. USIT-CBL 2,900 ft–Surface. September 16, 2014
10. Casing leak 7 in. casing between 2,949 ft and 2,969 ft. Multiple squeeze cement jobs. September 24, 2014
11. Casing leak below 2,786 ft. October 2, 2014
12. Ran 7 in. USIT 3,500 ft–Surface. October 3, 2014
    - Indications 600–3,220 ft
13. Ran 7 in. USIT 3,200–1,000 ft. October 9, 2014
14. Ran 7 in. High Resolution (HR) Vertilog 3,872 ft–Surface. October 20, 2014
    - 15 joints >20% OD penetration. 607–674 ft, 1,129 ft, 1,469 ft, 1,570 ft, 1,875 ft, 2,315 ft, 2,692–2,726 ft, 2,823 ft
    - 3 joints >40% OD penetration. 2,506 ft, 2,974–3,233 ft
    - 5 joints >60% OD penetration. 2,565–2,566 ft, 2,943 ft
    - 2 joints >80% ID penetration. 2,611 ft, 2,837 ft
    - Possible penetration around 2,835 ft
15. Ran 7 in. Tiger multi-finger caliper 8,079 ft–Surface. October 21, 2014
16. Ran 7 in. USIT 8,117 ft–Surface. October 28, 2014
17. Ran 7 in. Schlumberger (SLB) UCI 3,700–440 ft. October 29, 2014
18. Ran 7 in. Weatherford ultrasonic radial scanner and CBL 8,177 ft–Surface. October 31, 2014
19. Ran 7 in. Weatherford multi-sensor caliper 3,872 ft–Surface, casing imaging tool 2,872 ft–Surface. November 4, 2014
20. Pressure test 7 in. casing 500 psi for 10 minutes. December 5, 2014
21. Pressure test 7 in. casing 1,000 psi for 20 minutes. May 7, 2016
22. Pressure test 7 in. casing 1,100 psi for 1 hour. July 28, 2016
23. Pressure test 7 in. casing 1,131 psi for 1 hour. September 20, 2017
24. P&A'd in 2017

A.18.1Frew 2 Vertilog January 11, 1990

Log not available. Not on DOGGR website as of February 7, 2019.

A.18.2 Frew 2 HR Vertilog October 20, 2014

Figure 39 through Figure 43 are from a HRVRT log run in 2014 showing the condition of the 7 in. casing at that time. Figure 40, Figure 41, and the upper part of Figure 42 show a summary of penetration percent by joint and depth. Figure 43 shows the HRVRT log for a section of Class 3 (40–60% penetration) and Class 4 (>60% penetration).

BAKER HUGHES

HR Vertilog

Magnetic Flux Leakage Inspection

Advanced Analysis

Company	Southern California Gas Company
Well	Frew 2
Field	Aliso Canyon
County	Los Angeles
State	California
Location:	

RECEIVED
JUN 0 2 2015
Div. of Oil, Gas & Geothermal Resources
Ventura

Section N/A	Township N/A	Range N/A

Date	Oct. 20, 2014
Service Order	US091691
Recorded by	Grant Riffle
Witnessed by	Tom Egbert
API Serial No.	

Permanent Datum:	G.L.	Elevation: 2796.000 ft.	Depth	8120.000
Log Measured From:	G.L.	0.000 ft. above Perm. Datum	Btm. Log Interval	8100.000
Drilling Measured From:	G.L.	0.000 ft. above Perm. Datum	Top Log Interval	-5.000
			Fluid Type	8.5 KCL

Casing Data

Size	Weight	Grade	From	To	Length
7 inch	26.0 lb/ft	N80 (HR Std)	0	47	47.0
7 inch	23.0 lb/ft	N80	47	1732	1685.0
7 inch	23.0 lb/ft	J55	1732	5485	3753.0

Figure 39: Frew 2 HRVRT log Header

Joint Interpretation Summary

Joint	From	To	Length	Class	Max Depth	Position	ID/OD
1	-1.90	32.48	34.38	Class 1	-	-	-
2	32.48	53.73	21.25	Class 1	-	-	-
3	53.73	94.05	40.32	Class 1	-	-	-
4	94.05	135.50	41.45	Class 1	-	-	-
5	135.50	174.54	39.04	Class 1	-	-	-
6	174.54	212.52	37.98	Class 1	-	-	-
7	212.52	254.32	41.80	Class 1	-	-	-
8	254.32	295.35	41.03	Class 1	-	-	-
9	295.35	337.16	41.81	Class 1	-	-	-
10	337.16	378.40	41.24	Class 1	-	-	-
11	378.40	419.90	41.50	Class 1	-	-	-
12	419.90	461.71	41.81	Class 1	-	-	-
13	461.71	503.40	41.69	Class 1	-	-	-
14	503.40	542.15	38.75	Class 1	-	-	-
15	542.15	583.59	41.44	Class 1	-	-	-
16	583.59	624.57	40.98	Class 2	20.0%	606.66	OD
17	624.57	666.85	42.28	Class 2	37.0%	664.21	OD
18	666.85	708.46	41.61	Class 2	32.0%	674.33	OD
19	708.46	749.81	41.35	Class 1	-	-	-
20	749.81	790.68	40.87	Class 1	-	-	-
21	790.68	832.84	42.16	Class 1	-	-	-
22	832.84	875.38	42.54	Class 1	-	-	-
23	875.38	916.61	41.23	Class 1	-	-	-
24	916.61	958.24	41.63	Class 1	-	-	-
25	958.24	996.54	38.30	Class 1	-	-	-
26	996.54	1035.65	39.11	Class 1	-	-	-
27	1035.65	1077.66	42.01	Class 1	-	-	-
28	1077.66	1115.69	38.03	Class 1	-	-	-
29	1115.69	1156.97	41.28	Class 2	30.0%	1128.89	OD
30	1156.97	1194.89	37.92	Class 1	-	-	-
31	1194.89	1237.22	42.33	Class 1	-	-	-
32	1237.22	1279.04	41.82	Class 1	-	-	-
33	1279.04	1319.14	40.10	Class 1	-	-	-
34	1319.14	1357.04	37.90	Class 1	-	-	-
35	1357.04	1398.84	41.80	Class 1	-	-	-
36	1398.84	1441.03	42.19	Class 1	-	-	-
37	1441.03	1480.23	39.20	Class 2	33.0%	1469.39	OD
38	1480.23	1521.76	41.53	Class 1	-	-	-

Figure 40: Frew 2 HRVRT Log Summary

37	1441.03	1480.23	39.20	Class 2	33.0%	1469.39	OD
38	1480.23	1521.76	41.53	Class 1	-	-	-
39	1521.76	1562.77	41.01	Class 1	-	-	-
40	1562.77	1600.01	37.24	Class 1	20.0%	1569.82	OD
41	1600.01	1640.37	40.36	Class 1	-	-	-
42	1640.37	1681.84	41.47	Class 1	-	-	-
43	1681.84	1719.74	37.90	Class 1	-	-	-
44	1719.74	1764.61	44.87	Class 1	-	-	-
45	1764.61	1809.58	44.97	Class 1	-	-	-
46	1809.58	1854.49	44.91	Class 1	-	-	-
47	1854.49	1899.46	44.97	Class 2	21.0%	1875.12	OD
48	1899.46	1940.01	40.55	Class 1	-	-	-
49	1940.01	1984.80	44.79	Class 1	-	-	-
50	1984.80	2030.11	45.31	Class 1	-	-	-
51	2030.11	2073.96	43.85	Class 1	-	-	-
52	2073.96	2118.64	44.68	Class 1	-	-	-
53	2118.64	2163.48	44.84	Class 1	-	-	-
54	2163.48	2208.46	44.98	Class 1	-	-	-
55	2208.46	2253.02	44.56	Class 1	-	-	-
56	2253.02	2297.66	44.64	Class 1	-	-	-
57	2297.66	2342.54	44.88	Class 2	28.0%	2314.74	OD
58	2342.54	2387.39	44.85	Class 1	-	-	-
59	2387.39	2431.64	44.25	Class 1	-	-	-
60	2431.64	2476.60	44.96	Class 1	-	-	-
61	2476.60	2520.43	43.83	Class 3	40.0%	2506.07	OD
62	2520.43	2565.57	45.14	Class 4	79.0%	2565.22	OD
63	2565.57	2610.31	44.74	Class 4	68.0%	2566.03	OD
64	2610.31	2654.65	44.34	Class 4	82.0%	2610.79	ID
65	2654.65	2693.53	38.88	Class 2	28.0%	2691.90	OD
66	2693.53	2738.26	44.73	Class 2	37.0%	2725.69	OD
67	2738.26	2783.60	45.34	Class 3	40.0%	2740.45	OD
68	2783.60	2828.92	45.32	Class 2	35.0%	2823.27	OD
69	2828.92	2874.14	45.22	Class 4	87.0%	2836.69	ID
70	2874.14	2918.52	44.38	Class 1	-	-	-
71	2918.52	2964.65	46.13	Class 4	61.0%	2942.59	OD
72	2964.65	3009.44	44.79	Class 3	40.0%	2974.16	OD
73	3009.44	3054.66	45.22	Class 2	31.0%	3011.07	OD
74	3054.66	3099.65	44.99	Class 1	20.0%	3099.08	OD
75	3099.65	3144.09	44.44	Class 2	29.0%	3100.12	OD
76	3144.09	3188.73	44.64	Class 2	21.0%	3180.39	OD
77	3188.73	3233.19	44.46	Class 2	38.0%	3195.83	OD
78	3233.19	3277.71	44.52	Class 2	21.0%	3233.80	OD

Figure 41: Frew 2 HRVRT Log Summary

78	3233.19	3277.71	44.52	Class 2	21.0%	3233.80	OD
79	3277.71	3322.75	45.04	Class 1	-	-	-
80	3322.75	3368.03	45.28	Class 1	-	-	-
81	3368.03	3413.14	45.11	Class 1	-	-	-
82	3413.14	3457.57	44.43	Class 1	-	-	-
83	3457.57	3500.29	42.72	Class 1	-	-	-
84	3500.29	3544.23	43.94	Class 1	-	-	-
85	3544.23	3588.93	44.70	Class 1	-	-	-
86	3588.93	3630.50	41.57	Class 1	-	-	-
87	3630.50	3675.53	45.03	Class 1	-	-	-
88	3675.53	3720.06	44.53	Class 1	-	-	-
89	3720.06	3763.47	43.41	Class 1	-	-	-
90	3763.47	3808.58	45.11	Class 1	-	-	-
91	3808.58	3853.14	44.56	Class 1	-	-	-

Southern California Gas Company Frew 2
File 20141020_174519_RSP_0_0_0_0.mvl

Main Log
10" / 100'

Class 1 0 - 20%	Class 2 20 - 40%	Class 3 40 - 60%	Class 4 60 - 100%

DIS | FL Axial | MAX DIS | MAX FL Axial | Axial

10.0 /div | 10.0 /div | 150 | 0 0 | 10020.0 /div

Figure 42: Frew 2 HRVRT Log Summary and Log Section Header

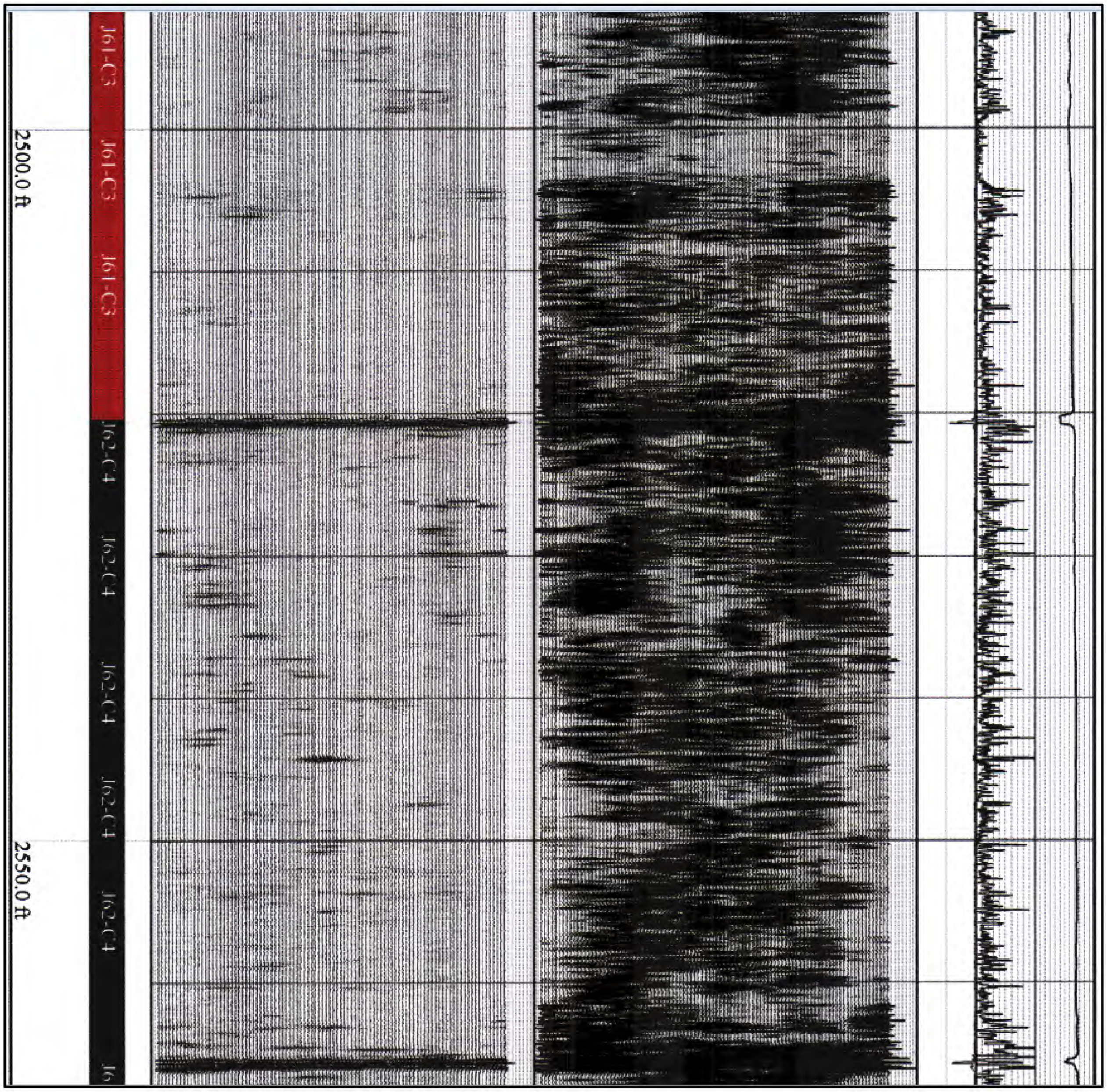

Figure 43: Frew 2 HRVRT Log Section

A.19 Frew 4

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 770 ft
2. Pressure test 7 in. casing in stages 2,200–3,400 psi. December 14, 1974
3. Pressure test 7 in. casing 1,800 psi. September 8, 1977
4. Pressure test 7 in. casing 4,300 ft–Surface in stages 2,600–4,000 psi for 60 minutes. September 10, 1977
5. Squeeze cement water shut off (WSO) holes. September 16, 1977
6. Pressure test 7 in. casing 2,560 psi for 60 minutes. September 17, 1977
7. Pressure test packer and seals 1,500 psi for 20 minutes. September 22, 1977
8. Pressure test 7 in. casing 2,000 psi for 20 minutes. September 3, 1988
9. Ran 7 in. Vertilog 8,180 ft–Surface. September 6, 1988 (log not reported on daily report)
   - 12 joints >20% OD penetration. 280 ft, 520 ft, 800–840 ft, 920 ft, 1,000–1,040 ft, 1,160–1,240 ft, 1,880 ft, 1,960 ft, 2,240 ft, 2,440 ft, 3,320 ft
   - 12 joints >40% OD penetration. 1,080–1,120 ft, 1,280 ft, 4,240–4,320 ft, 4,440–4,560 ft
   - 2 joints >60% OD penetration. 2,880 ft, 4,360 ft
10. Leak in first collar at 32 ft found with noise log. September 8, 1988 (Log not on the DOGGR website as of February 7, 2019)
11. Ran 5 1/2 in. inner casing 8,224 ft–Surface. September 15, 1988
12. Cut and pulled 5 1/2 in. inner casing. October 13, 2016
13. Pressure test 7 in. casing 1,150 psi for 15 minutes. October 18, 2016
14. Ran SLB caliper log 8,180 ft–surface. USIT 8,180–7,100 ft. October 19, 2016
15. Ran USIT 7,100 ft–Surface. October 20, 2016
    - Indications 764–5,085 ft, 5,908–5,911 ft, 6,782–6,788 ft, 6,908–6,911 ft
16. Pressure test 7 in. casing 1,122 psi for 1 hour. October 29, 2016
17. P&A'd in 2018

A.19.1F-4 Vertilog September 6, 1988

Figure 44 shows the Vertilog header and summary. Figure 45 shows the log summary.

VERTILOG®

Western Atlas International

CUSTOMER SOUTHERN CALIFORNIA GAS COMPANY

LEASE/WELL NO. FREW No. 4 WORK ORDER NO. 124201 PAGE ____ OF ____

FIELD ALISO CANYON CUSTOMER ORDER NO. DATE 9-6-88

CASING O.D. 7" WEIGHT(S) 23#, 26# COUNTY LOS ANGELES STATE CALIFORNIA

TOTAL FOOTAGE INSPECTED 8180' NOMINAL WALL THICKNESS GRADE N-80, J-55

FROM SURFACE TO 8180' DEPTH

SUBSURFACE CASING DEFECT REPORT

LENGTH NO. TYPE DEFECT PENETRATION LENGTH NO. TYPE DEFECT
INSIDE 13-3/8" CASING
7 OD IP

LENGTH NO.	TYPE DEFECT	PENETRATION	LENGTH NO.	TYPE DEFECT	PENETRATION
INSIDE 13-3/8" CASING			111	OD IP	41 - 60
7	OD IP	21 - 40	113	OD IP	41 - 60
13	OD IP	21 - 40	114	OD IP	41 - 60
20	OD IP	41 - 60			
21	OD IP	41 - 60			
OUTSIDE 13-3/8" CASING					
23	OD IP	41 - 60			
25	OD IP	21 - 40			
26	OD IP	21 - 40			
27	OD IP	41 - 60			
28	OD IP	41 - 60			
29	OD GC	21 - 40			
30	OD IP	21 - 40			
31	OD IP	21 - 40			
32	OD IP	41 - 60			
47	OD IP	21 - 40			
49	OD IP	21 - 40			
56	OD IP	21 - 40			
61	OD IP	21 - 40			
72	OD IP	61 - 80			
83	OD IP	21 - 40			
106	OD IP	41 - 60			
107	OD IP	41 - 60			
108	OD IP	41 - 60			
109	OD IP	61 - 80			

Figure 44: Frew 4 HRVRT Log Header and Summary

VERTILOG® Dresser Atlas DRESSER

037-00667

CUSTOMER SOUTHERN CALIFORNIA GAS COMPANY DATE 9-6-88

WELL FREW No. 4 SERVICE ORDER NO. 124201

FIELD ALISO CANYON COUNTY LOS ANGELES STATE CALIFORNIA

CASING SIZE 7" WEIGHT(S) 23#, 26# GRADE N-80, J-55 NOMINAL WALL THICKNESS

TOTAL FOOTAGE INSPECTED 8180' FROM SURFACE TO 8180' DEPTH

SUBSURFACE CASING INSPECTION REPORT

SUMMARY

172 LENGTHS WERE FOUND TO SHOW NO EVIDENCE OF CORROSION EXCEEDING 20 PERCENT OF THE NOMINAL BODY WALL. CLASS 1

12 LENGTHS WERE FOUND TO SHOW EVIDENCE OF CORROSION EXCEEDING 20 PERCENT BUT LESS THAN 41 PERCENT OF THE NOMINAL BODY WALL. CLASS 2

12 LENGTHS WERE FOUND TO SHOW EVIDENCE OF CORROSION EXCEEDING 40 PERCENT BUT LESS THAN 61 PERCENT OF THE NOMINAL BODY WALL. CLASS 3

2 LENGTHS WERE FOUND TO SHOW EVIDENCE OF CORROSION EXCEEDING 60 PERCENT OF THE NOMINAL BODY WALL. CLASS 4

198 TOTAL LENGTHS

8180' TOTAL FOOTAGE

REFERENCE FOR FOOTAGE MEASURE GROUND LEVEL + 8.25'

LENGTHS ARE NUMBERED FROM SURFACE

COMMENTS

DIVISION OF OIL AND GAS
RECEIVED
SEP 19 1988
VENTURA, CALIFORNIA

CHART # 7N20E
CHART # 7N1E
CHART # 7J6E

SERVICED BY

DA-1363-C (08/82)

Figure 45: Frew 4 HRVRT Log Summary

A.20 Frew 5

The following is a summary of SoCalGas' sequential records for this well related to production casing integrity:

1. 13 3/8 in. Surface casing at 1,000 ft
2. Pressure test 7 in. casing in stages 2,200–3,400 psi for 20 minutes. December 31, 1974
3. Pressure test 7 in. casing in stages 2,300–4,000 psi for 60 minutes. August 20, 1977
4. Ran Noise survey 8,260–100 ft. Activity above 2,600 ft. April 8, 2016
5. Pressure test 7 in. casing 1,000 psi for 1 hour. June 30, 2016
6. P&A operations, pressure test 7 in. casing 7,017 ft–Surface 1000 psi for 30 minutes. August 23, 2017
7. P&A'd in 2017

A.20.1F-5 Noise Log April 8, 2016

Figure 46 shows the noise log header, and Figure 47 and Figure 48 show noise log sections.

WELL ANALYSIS CORPORATION

AUDIO DETECTION SURVEY

WELL TYPE GS, OG

COMPANY: SOUTHERN CALIF. GAS CO.
WELL: FREW 5
FIELD: ALISO CANYON
COUNTY: LOS ANGELES STATE: CALIFORNIA

LOCATION:
DISTRICT 2

API NUMBER: 0403700668
SEC: 29 TWN: 3N RNG: 16W

OTHER SVC:

VS

PERMANENT DATUM: GROUND LEVEL ELEV: 2387.00 FT.
LOG MEASURED FROM KB 8' ABOVE PERM DATUM
DRILLING MEASURED FROM

-ELEVATIONS-
KB: 2395.00 Ft.
DF: Ft.
GL: 2387.00 Ft.

DATE LOG RAN	04-08-2016	PRESSURE	FLOWING	INJECTION	SHUT-IN
RUN NUMBER	ONE	TUBING PSI		0	
EFFECTIVE DEPTH	8676'	CASING PSI		0	
PICKUP DEPTH	8260'	INJECTION RATE	N/A		
BOT LOGGED INT	8260'	OBSERVED RATE	N/A		
TOP LOGGED INT	25'	R/A SOURCE	N/A		
TYPE OF INJECT	NONE	ACTIVITY	N/A		
FLUID IN WELL	OWG	HALF LIFE	N/A		
FLUID LEVEL	N/A				

WELL STATUS	STATIC			PRODUCTION DATA	
MAX TEMPERATURE	179.7 F.	OIL Gr.	N/A	OIL =	N/A
AT DEPTH	8260.0'	GAS Gr.	N/A	GAS=	N/A
TEMPERATURE SENS	1 F/DIV.	MPP	N/A	BHP =	N/A
LOGGING SPEED	100 FPM			WATER=	N/A
RECORDED BY	C. FITZPATRICK				
WITNESSED BY	N/A				
EMAIL TO	A. KARGAR				
DEPTH CORRELATION	N/A				

Figure 46: Frew 5 Noise Log Header

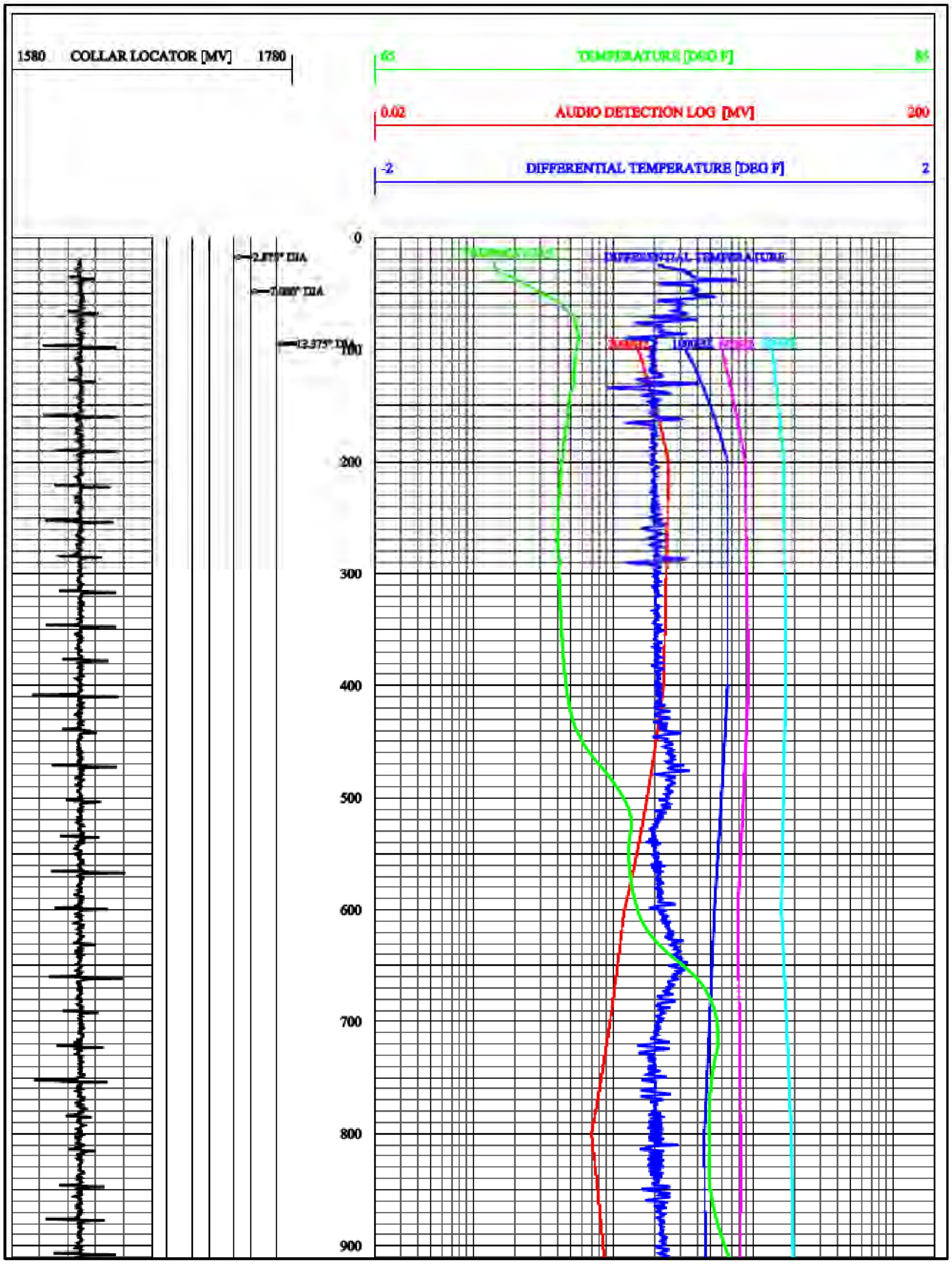

Figure 47: Frew 5 Noise Log Section

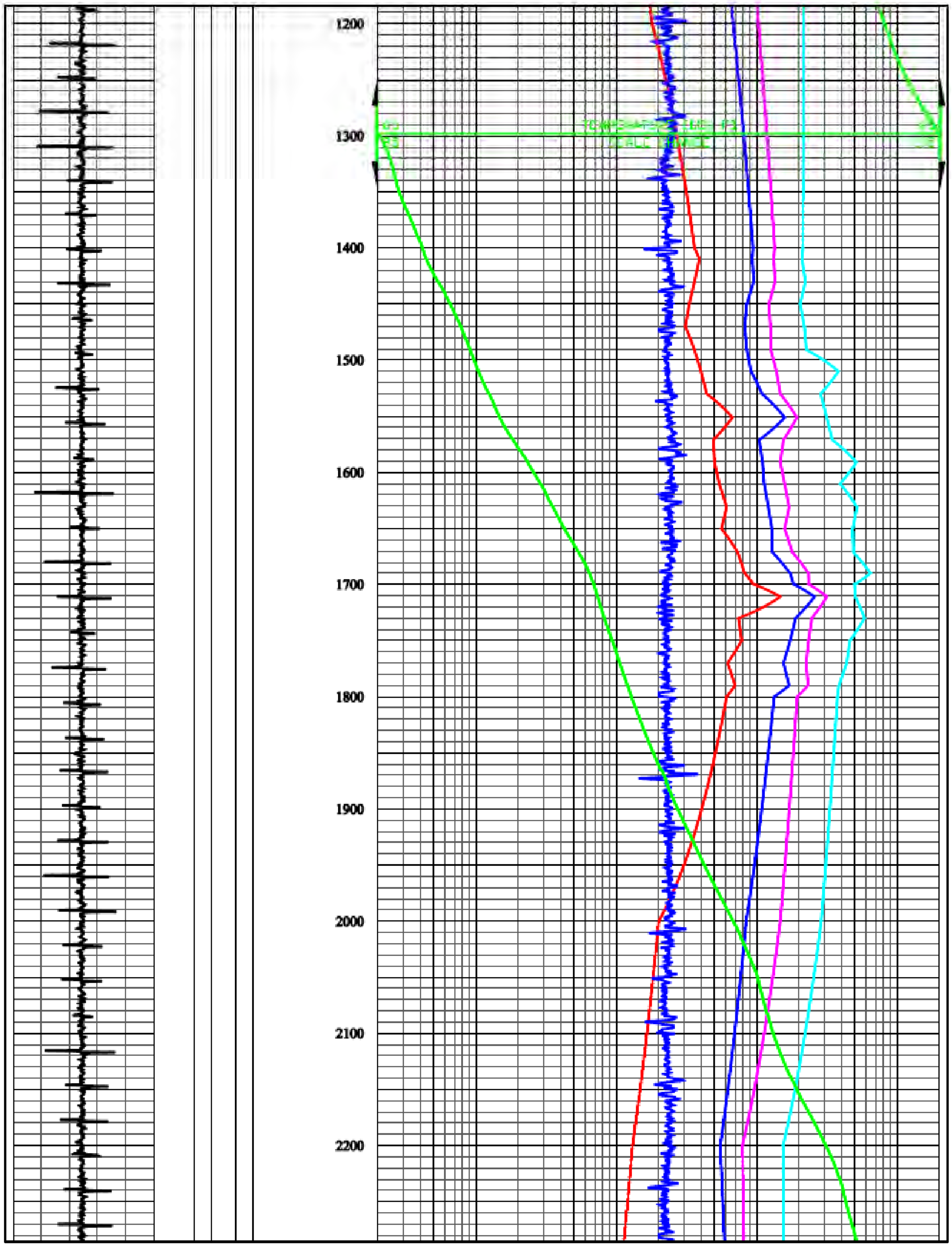

Figure 48: Frew 5 Noise Log Section

Appendix B Attachment to Interoffice Correspondence

Figure 49 and Figure 50 are scans of the August 30, 1988 Interoffice Correspondence attachment.

Aliso Canyon Casing Flow Wells of 1940's and 1950's Vintage

Well	Completed	Deliverability @ 19.8 Bcf (MMcf/d)	Most Recent Workover	Comments	Priority
P 34	5/45	9	10/77	Casing pressure tested, SSSV run.	High
P 37	8/46	24	9/77	Casing pressure tested, SSSV run.	High
P 44*	1/56	26	4/78	Redrilled from 7805', casing patch set 3971'-4012', SSSV run.	Low
P 46	2/44	35	8/77	Reperf'd 7730'-7920', SSSV run.	High
P 47	8/43	21	6/77	Pulled 2-3/8" liner, squeezed perf's @ various depths. Temp anomaly @ shoe (3/23/88).	Low
SS 2	9/43	16	8/83	Repaired shoe leak, CBL run 7/73.	Low
SS 4	1/45	0(FL)	12/81	Repaired shoe leak, CBL run 11/80.	Low
SS 6	9/45	10	9/82	Repaired shoe leak, CBL and TDT run 5/73.	Low
SS 7	2/46	1	9/77	Casing pressure tested, SSSV run.	Medium
SS 8	8/46	15	7/78	Casing pressure tested, SSSV repaired.	High
SS 9	2/47	15	2/79	Casing pressure tested, SSSV replaced.	High
SS 10*	6/47	25	12/78	Casing patch run 4474'-4516', SSSV replaced.	Low
SS 11	11/47	9	6/80	Repaired shoe leak. CBL and TDT run 7/73. New temp anomaly @ shoe (2/88).	Low
SS 17**	6/51	7	8/77	Casing pressured tested, SSSV run. Well has a shoe leak.	Low

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SS-25 Well Documentation (from SoCalGas)_N.pdf

AC_CPUC_0000065

Figure 49: Page 1 of Interoffice Correspondence Attachment

Aliso Canyon Casing Flow Wells
of 1940' & 1950's Vintage
Page 2

Well	Completed	Deliverability @ 19.8 Bcf (MMcf/d)	Most Recent Workover	Comments	Priority
SS 24	4/53	11	3/85	Repaired shoe leak. CBL run 7/73.	Low
SS 25	2/54	38	2/79	Replaced SSSV. Temp anomaly @ shoe (3/3/88).	Low
SS 29**	9/53	22	3/79	Replaced SSSV and set packer @ 8040'. Well has a shoe leak.	Low
F 2	7/44	1	9/77	Casing pressure tested, SSSV run.	Medium
F 4	1/48	12	9/77	Workover planned for 1988. Will log at that time.	-
F 5	7/48	2	8/77	SSSV run.	Medium

* Equipped with casing patch.
** Identified shoe leak. Casing will be inspected during workover.
FL - Fluid loaded

8/30/88

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SS-25 Well Documentation (from SoCalGas)_N.pdf

AC_CPUC_0000066

Figure 50: Page 2 of Interoffice Correspondence Attachment

SS-25 RCA Supplementary Report

Gas Storage Well Regulations Review

Purpose:

To review the regulations related to gas storage wells and determine if the current California (January 2019) regulations could have prevented the SS-25 casing leak. Assess SoCalGas compliance with the 2015 regulations and Aliso Canyon project approval conditions.

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www.blade-energy.com

Date:

May 31, 2019

Abstract

The gas storage well Standard Sesnon 25 (SS-25) in the Aliso Canyon Gas Storage Field located in Los Angeles County, California started leaking gas in October 2015. A relief well was drilled, and SS-25 was brought under control. The leak stopped in February 2016.

In January 2016, as part of their investigation of the leak, the California Public Utilities Commission (CPUC) and the Division of Oil, Gas, and Geothermal Resources (DOGGR) selected and gave provisional authority to Blade Energy Partners (Blade) to perform an independent Root Cause Analysis (RCA). The Blade Team and parties under Blade's direction were responsible for directing the work of subcontractors who performed the extraction of the SS-25's, wellhead, tubing and casings and the preservation and protection of associated evidence. Blade's RCA Reports, including this report, document and describe the key activities undertaken in support of the RCA effort.

Blade reviewed regulatory and Southern California Gas Company (SoCalGas) documents related to well integrity to determine how Aliso Canyon well operations and practices comply with existing regulations and policies.

This document includes Blade's review of California state regulations related to gas storage wells to determine if application of the January 2019 version of the California Statutes & Regulations for the DOGGR requirements for underground storage projects and gas storage wells could have prevented the SS-25 leak. A summary of the federal mandate to issue safety standards for underground gas storage facilities is included in addition to the Division of Oil and Gas (DOG) gas storage project approvals that specified the conditions under which the gas storage project could operate.

We compare the California state-wide gas storage well regulations to the DOGGR Division Order 1109 issued for the purpose of ensuring the integrity and safety of all wells in the Aliso Canyon field. This comparison shows that the requirements of the two documents are similar and consistent. Significant changes have been made to the November 2018 and January 2019 California Statutes and Regulations requirements regarding gas storage wellbore mechanical integrity. The changes include well construction with both primary and secondary mechanical well barriers in which the secondary barrier is able to withstand full operating pressure as demonstrated by pressure testing and casing evaluation logs. The other major requirements are a Risk Management Plan and Emergency Response Plan for each underground project.

Based on the regulation changes, a case can be made that if the 2019 requirements of (1) Risk Management Plans, (2) Well Construction Requirements, or (3) Mechanical Integrity Testing had been in place and followed in 2015, the SS-25 leak could have been prevented.

Blade reviewed compliance with the 2015 casing pressure test regulations by SoCalGas. SoCalGas provided documents to support their understanding and belief that they were in compliance by running a temperature log annually to satisfy the mechanical integrity requirement.

A review of SoCalGas operations policies and practices indicates that more attention is paid to surface assets than to wells. A document discussing the investigation of a pipeline failure was found, but none were found related to a well failure.

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1 Introduction

Blade evaluated the updated regulations issued in January 2019 for gas storage wells to determine if the current California regulations could have prevented the SS-25 casing leak if the regulations had been in place and followed in 2015 as part of the RCA.

DOGGR issued the Division Order 1109 titled *Order to Take Specific Actions Re: Aliso Canyon Gas Storage Facility* on March 04, 2016, [1] to ensure the integrity and safety of all wells in the Aliso Canyon field. The Order included a list of specified actions that SoCalGas, the Operator, must take to demonstrate well integrity before gas injection could resume.

The Securing America's Future Energy: Protecting our Infrastructure of Pipelines and Enhancing Safety (PIPES) Act of 2016 [2], passed by the US Congress, directed the Pipeline and Hazardous Materials Safety Administration (PHMSA) to issue minimum safety standards for underground gas storage facilities.

Blade reviewed the casing pressure testing regulations that were in place in 2015 to determine if the Aliso Canyon practices were in compliance with the regulations. The regulation requirements were complicated by the ambiguity regarding the exemption that gas storage wells are not required to have tubing and a packer.

The operation of the Aliso Canyon gas storage project was approved by the DOG on July 26, 1989. The project requirements related to well integrity are summarized and compared to the requirements for the water-flood and water disposal wells. The SoCalGas Operations Standards related to gas storage wells are compared to surface assets standards.

1.1 Abbreviations and Acronyms

Term	Definition
Blade	Blade Energy Partners
CP	Cathodic Protection
CPUC	California Public Utilities Commission
DOC	Department of Conservation
DOG	Division of Oil and Gas
DOGGR	Division of Oil, Gas, and Geothermal Resources
GTC	General Terms and Conditions
IFR	Interim Final Rule
MIT	Mechanical Integrity Test
OD	Outside Diameter
PAL	Project Approval Letter
PHMSA	Pipeline and Hazardous Materials Safety Administration
PIPES	Protecting our Infrastructure of Pipelines and Enhancing Safety
RBW	Remaining Body Wall
RCA	Root Cause Analysis
SS	Standard Sesnon

Term	Definition
SoCalGas	Southern California Gas Company
UIC	Underground Injection Control

2 Regulations Related to the SS-25 Casing Leak

2.1 State of California Regulations

Table 1 shows a summary of the verification methods and California regulations related to gas storage well integrity. We compared and assessed the Division Order 1109 and California state regulatory requirements for each well integrity verification method to determine if the SS-25's leak could have been prevented if the January 2019 regulatory requirements had been in place at the time of the leak.

Division order 1109 included actions that SoCalGas was required to take related to an uncontrolled flow of fluids from SS-25 in the Aliso Canyon field. A partial list and summary of Division Order 1109 actions related to well integrity included:

- Conducting a safety review of each well in the field. Requirements of the safety review are detailed in Attachment 1 of DOGGR Order 1109.
- Equipping all gas storage wells with tubing and packer completions that isolated the tubing-casing annulus.
- Equipping all gas storage wells with real-time pressure monitors.

California Statutes & Regulations, January 2019 [3], include the regulations that govern well construction and operations in the state of California. Regulations related to gas storage wells are of interest for this review. Article 4 Requirements for Underground Gas Storage, Subchapter 1 Onshore Well Regulations, Chapter 4 Development, Regulation, and Conservation of Oil and Gas Resources of the California Code of Regulations was added in the November 2018 version [4] and the same regulations are in the January 2019 version. Article 4 contains additional requirements for gas storage projects and wells as compared to the 2015 version of the California Statutes and Regulations [5].

2.2 Well Integrity Verification

Table 1 shows verification methods related to well integrity. The methods of interest are inspections and pressure testing. A casing inspection log by itself does not ensure pressure integrity—its purpose is to provide an estimate of remaining body wall (RBW) thickness of the casing. RBW is used as an indication of pipe body pressure capacity, but does not address casing connection pressure integrity or defects smaller than the inspection tool resolution. Similarly, a pressure test by itself does not imply future pressure integrity because the pressure test only confirms integrity at a moment in time under the test conditions. A casing inspection log separate from a pressure test, or vice versa, does not meet the current requirements.

When the casing inspection log and pressure test data are used in combination, it is possible to evaluate the casing pressure integrity and assess the risks associated with the well thereby meeting and continuing to meet the design and well constructing requirements and regulations.

Table 1: Verification Methods and Summary of Regulations Related to Well Integrity

Gas Storage Well Integrity Verification Methods	DOGGR Division Order 1109	California Statutes & Regulations January 2019	Could the January 2019 Requirements Have Prevented the SS-25 Leak?
Well Construction Requirements	Equip all wells to be employed in the gas storage injection project with tubing and packer that isolate the tubing-casing annulus [1] (Item (5), Page 6).	The well has been constructed with both primary and secondary mechanical barriers . . . [3] (Section 1726.5 (b) (1), Page 224). The secondary mechanical barrier shall be able to withstand full operating pressure as demonstrated by the pressure testing required . . . and casing evaluation logs as required . . . [3] (Section 1726.5 (b) (1) (b), Page 224). . . . ensure that a single point of failure does not pose an immediate threat of loss of control of fluids . . . [3] (Section 1726.5 (a), Page 223).	Yes
Risk Management Plans	Ensure the Risk Management Plan filed under section 1724.9, subdivision (g) [5] includes an effective facility-wide emergency response plan and effective geologic and geotechnical hazard mitigation protocols. [1] (Item (11), Page 7).	Risk Management Plans [3] (Section 1726.3, Page 213) includes several sub-sections related to well integrity including well construction and design standards, safety valves, verification of mechanical integrity, corrosion monitoring, changes in casing pressure, and emergency response plans.	Yes
Mechanical integrity testing	Temperature and noise log in each well [1] (Attachment 1, Item Step 1: a. and Step 1: b. Page 1 of 4). Conduct a casing inspection log that measures the thickness of the production casing [1] (Attachment 1, Item Step 4a: Page 2 of 4). The pressure test will be one hour and begin at a pressure of 115% of the maximum operating pressure [1] (Attachment 1, Item 7a: Page 3 of 4).	Temperature and noise log at least annually [3] (1726.6 (a) (1), Page 225) Casing wall thickness inspection every 24 months [3] (1726.6 (a) (2), Page 226). Pressure testing of the production casing at least every 24 months [3] (1726.6 (a) (3), Page 226). Pressure testing to at least 115% of maximum allowable injection pressure at the wellhead [3] (1726.6.1 (a) (4), Page 227).	Yes

2.3 Mandate to Update Regulations

The Federal Government formed a Task Force in April 2016 to study natural gas storage safety based on the Aliso Canyon incident and make recommendations on how to reduce the likelihood of future leaks from gas storage facilities. Congress codified the Task Force through the PIPES Act of 2016 which was signed into law on June 22, 2016. Congress directed the Task Force to perform an analysis of the Aliso Canyon events and make recommendations to reduce the occurrence of similar incidents in the future. To do so the Task Force examined three key areas: integrity of natural gas wells at storage facilities, public health and environmental efforts from natural gas leaks, and vulnerability to reduced energy reliability in the case of future leaks. The Task Force findings were published in the report titled *Ensuring Safe and Reliable Underground Natural Gas Storage* [6] issued in October 2016.

The Task Force made a number of observations and recommendations under the broad topics of Well Integrity, Health and Environment, and Reliability. A review of the well integrity recommendations indicates they are aligned with the gas storage well integrity verification methods in Table 1.

PHMSA was directed to issue minimum safety standards for underground natural gas storage facilities within two years as required by the US Congress in Section 12 of the PIPES Act.

An interim final rule (IFR) effective January 18, 2017, was issued revising the federal pipeline regulations to include new reporting requirements and API RP 1171 [7] and API RP 1170 [8] as federal requirements for the safety of underground natural gas storage facilities.

The state of California issued updated regulations for gas storage projects and wells in November 2018 [4].

3 SoCalGas Compliance to 2015 Well Integrity Regulations

Blade reviewed the 2015 California Statutes and Regulations [5] to determine the regulatory requirements for gas storage well integrity at the time of the leak. The following regulations summarize the gas storage well requirements related to well integrity:

- Section 1724.10 (g): All injection wells require tubing and a packer, except steam, air, and pipeline-quality gas injection wells.

  Gas withdrawal wells are not mentioned in this regulation. One could assume that gas storage injection and withdrawal wells would be treated the same way. SS-25 was operated as both an injection and withdrawal well. SS-25 qualified for the exemption because pipeline-quality gas was injected and therefore isolation between the tubing and production casing with a packer was not required by the regulation.

- Section 1724.10 (j): A mechanical integrity test (MIT) must be performed on all injection wells to ensure the injected fluid is confined to the approved zones. The MIT consists of two parts.

  - Section 1724.10 (j) (1): MIT Part 1. Prior to commencing injection operations, each injection well must pass a pressure test of the casing-tubing annulus to determine the absence of leaks. Thereafter, the annulus of each well must be tested at least once every five years.

    When SS-25 was converted to a gas storage well in 1973, the 7 in. production casing was pressure tested to 3,400 psi and it was tested to 2,500 psi in 1976, and 1,500 psi in 1979. The pressure tests in 1973, 1976, and 1979 were done with a well service rig on location. No 7 in. casing or 7 in. × 2 7/8 in. annulus pressure tests were reported after 1979[i].

    The pressure test in 1973 met the requirement for MIT Part 1 because it was done prior to commencing injection operations. The requirement of testing the annulus every five years was not met according to the SS-25 well records.

    The regulatory clarity regarding internal pressure testing of injection wells with regard to gas storage wells was discussed in a DOGGR meeting in May 2006 [9]. The minutes of that meeting reported that because gas storage injection wells do not fall under the federal Underground Injection Control (UIC) program, and should not be subject to federally-imposed internal mechanical integrity testing requirements. The committee considered proposing a change in the regulations to clarify Section 1724.10 (j), but decided not to because section 1724.10 (k) allows for additional requirements, gas storage injection wells were tested with a static temperature logging tool, and no DOGGR District required casing pressure tests for gas storage wells.

    Blade asked SoCalGas for their interpretation of Section 1724.10 (j)'s requirement of casing pressure testing every five years in an information request. SoCalGas responded that their belief and understanding was that the two-part pressure-testing requirement did not apply to gas storage wells based on their correspondence with DOGGR.

[i] SS-25 had a tubing and packer completion at the time of the leak in October 2015, however, there were open ports above the packer so the casing × tubing annulus was not isolated from the tubing. There was a nipple profile below the ports so a wireline plug could have been set to isolate the perforations below the packer and the casing could have been pressure tested.

SoCalGas proposed to DOGGR in 1994 ". . . the most economical and effective method to monitor casing integrity of gas storage wells is through the use of static temperature surveys." [10]. The response to SoCalGas' proposal stated [11] [12]:

> Section 1724.10. (k)(5) in the regulations currently addresses this concern since it acknowledges that additional requirements or modifications of the requirements in Section 1724.10 may be necessary to fit specific circumstances and types of projects. The subsection goes on to list examples of such additional requirements or modifications, including subsection (5), which states that a list of all injection-withdrawal wells in a gas project, showing casing-integrity test methods and dates, the types of safety valves used, may be submitted to the Division annually. Therefore, the monitoring program and static temperature surveys currently used by The Gas Company could be used to satisfy compliance of the requirements for mechanical integrity found in this section.

The casing leak in SS-25 showed that using temperature surveys to confirm mechanical integrity of casing was a flawed concept. The concept assumed that leaks would not be catastrophic, would cause a cooling anomaly, and would be detected in time to allow the well to be killed quickly and safely. A temperature survey was run in SS-25 on October 21, 2014, a year before the leak on October 23, 2015, and showed no temperature anomalies.

The use of multiple methods to assess well integrity is discussed in the Department of Energy report [6]. Noise and temperature surveys are used to identify leaks, but the sensitivity of the instruments is limited. If no leak is detected, noise and temperature data provide no indication of future integrity problems. Alternatively, casing inspection can identify defects that may be growing with time and can be used to monitor integrity deterioration.

- Section 1724.10 (j) (2): MIT Part 2. The second test of a two-part MIT shall demonstrate that there is no fluid migration behind the casing, tubing, or packer.

  Numerous temperature, noise, and pressure surveys were run in SS-25 between the years of 1974 and 2014, and no major anomalies were found indicating fluid migration.

- Section 1724.3: Well Safety Devices for Critical Wells. Certain wells that meet the definition of *critical* pursuant to Section 1720 (a) and have sufficient pressure to flow to surface shall have safety devices including surface and subsurface safety devices. The definition of a critical well includes a well within 300 ft of any building intended for human occupancy, or an airport runway or is within 100 ft of a public street, highway, railway, navigable body of water, public recreational facility or wildlife preserve.

  SS-25 did not qualify as a critical well, so a subsurface safety device was not required. SS-25 was equipped with surface safety valves on the tubing and the 7 in. × 2 7/8 in. annulus.

4 Aliso Canyon Project Approval Conditions

Table 2 shows the UIC projects for Aliso Canyon created from original content from the DOGGR ftp site [13]. We highlighted the project approval letters (PALs) in yellow and highlighted the SoCalGas Aliso Canyon Gas Storage project in blue. These three PALs will be discussed in Section 4.1.

Table 2: Aliso Canyon Underground Injection Control Projects

Inject. Type	CalWIMS	Operator	Injection Zone	Project Estab. (Year)	Date of Latest PAL	No. of Wells	Current No. of Wells Injecting	Year of Last Project Review
wd	0100007	The Termo Company	Port-Del Aliso A-36 (Pico Fm.)	2013	7/3/2013	1	0	2013
dg	0100008	The Termo Company	Port-Del Aliso A-36 (Pico Fm.)	2013	7/30/2013	1	0	2013
wd	0100001	Southern California Gas	Porter-Del Aliso 36 (Pico Fm.) fmrly Fernando Fee Zone	1954	1/16/1998	3	2	2012
wf	0100002	Southern California Gas	Aliso and Porter-Del Aliso (Pico Fm.)	1963	9/30/1996	8	7	2012
wf**	0100004	Southern California Gas	Pico Formation (Aliso only)	-	-	1	0	2001
gs	0100006	Southern California Gas	Sesnon-Frew (Modelo Fm.)	1970	7/26/1989	124	116	2009

wd = water disposal well
dg = gas disposal
wf = water flood (EOR)
gs = natural gas storage
wf** = rescinded water flood project

4.1 Project Approval Letters Review

4.1.1 Water Disposal Project 0100001

DOGGR granted approval for the Aliso Canyon Field Water Disposal Project 0100001 in the PAL dated January 16, 1998 [14]. Approval was granted provided that certain conditions were met. We paraphrased a subset of those conditions listed here:

- All injection wells shall be equipped with tubing and packer set in cemented casing.
- Precautions are taken to prevent corrosion from occurring in surface equipment, casing, tubing and packers.
- MITs are run annually.
- Static temperature surveys are run annually.

- Casing must be pressure tested prior to injection then every five years.
- Annual project review meetings must be conducted.

4.1.2 Water Flood Project 0100002

DOGGR granted approval for the Aliso Canyon Field Water Flood Project 0100002 in the PAL dated September 30, 1996 [15]. Approval was granted provided that certain conditions were met. We paraphrased a subset of those conditions listed here:

- All injection wells shall be equipped with tubing and packer set in cemented casing.
- Precautions are taken to prevent corrosion from occurring in surface equipment, casing, tubing and packers.
- MITs are run every other year.
- Casing must be pressure tested prior to injection then every five years.
- Annual project review meetings must be conducted.

4.1.3 Gas Storage Project 0100006

DOGGR granted approval for the Aliso Canyon Field Gas Storage Project 0100006 in the PAL dated July 26, 1989 [16]. Approval was granted provided that certain conditions were met. We paraphrased a subset of those conditions listed here:

- When an existing well is converted for injection, withdrawal, or observation-collection, the casing must be tested to demonstrate mechanical integrity.
- MITs are run within the first three months after injection or withdrawal has commenced and then run annually thereafter. An MIT is required if any significant anomalous rate or pressures changes are observed.
- A DOGGR-approved monitoring program plan is installed for the gas storage zone.
- The project operator is responsible for any remedial work to wells to protect life, health, property, and oil, gas, or fresh-water zones.
- Injection and withdrawal operations shall cease if any evidence of damage is observed.

4.1.4 Summary

The DOGGR PALs of the water disposal and water flood projects had requirements that differed from the gas storage project. The gas storage PAL did not have requirements regarding corrosion prevention, the use of tubing and packer, annual project review meetings, or routine casing pressure tests. The water disposal and water flood project PAL had such requirements.

On October 08, 2015, the Department of Conservation (DOC) and DOGGR released a plan titled the Renewal Plan for Oil and Gas Regulation [17] (Renewal Plan). According to the Renewal Plan website, "DOC and DOGGR's Renewal Plan is an ongoing, four-year framework to correct past problems and to create a regulatory program for oil and gas production that ensures the environment and public health are protected.". DOGGR had recognized through various audits that the regulations for the UIC Program were enforced inconsistently and, in some cases, incorrectly. One key aspect of the Renewal Plan called for a review and evaluation of all regulations administered by DOGGR and a review of all previously issued

PALs. New technologies, best practices, and updated well construction requirements were to be incorporated into the new regulations. The 2015 version of the Renewal Plan didn't specifically use the term 'gas storage'. Considering that the number of active gas storage wells was less than 1% of all injection wells in 2009 (231 out of 24,739 active injection wells), it is not surprising to us that gas storage was not specifically addressed.

Gas storage was prominent in the April 2017 version of the Renewal Plan [18]. DOGGR stated: "In response to the leak at the Aliso Canyon Storage Facility, the Division significantly strengthened oversight of natural gas storage facilities across California. The draft regulations released by the Division represent the strongest gas storage regulatory program in the nation and preparations for the formal rulemaking are underway." The draft regulations in 2017 were formalized in 2018 and again in 2019.

4.2 SoCalGas Operations Standards

Table 3 shows the SoCalGas Operations Standards related to gas storage wells. Listed are the names of the SoCalGas Operations Standards, document number, and published dates. The language is verbatim from the original content. All of the standards in this table were provided by SoCalGas to Blade, CPUC, and DOGGR through data requests; the file names are in the Reference column. Ten operations standards were related to gas storage wells. The Operations Standards in rows 2 and 10 titled, *Operation of Underground Storage Wells*, and *Gas Inventory - Monitoring, Verification and Reporting*, respectively, will be discussed in Section 4.2.1 and Section 4.2.2.

Table 3: SoCalGas Operations Standards Related to Gas Storage Wells

Row	Company Operations Standard Name	SCG Number:	Published Date	Reference
1	Testing Surface Controlled Subsurface Safety Valve	224.0000	February 21, 2014	AC_BLD_0026280.pdf
2	Operation of Underground Storage Wells	224.02	February 10, 2012	AC_BLD_0026308.pdf
3	Blowout Prevention Equipment Configuration, Installation, Testing and Operation	224.05	July 29, 2013	AC_BLD_0026335.pdf
4	Security and Accounting - Underground Storage Field Production Fluids	224.0015	February 5, 2013	AC_BLD_0026292.pdf
5	Gas Inventory Verification - Shut In	224.0020	March 5, 2014	AC_BLD_0026301.pdf
6	Wireline Operations - Wellhead Preparation, Rig-Up and Rig-Down	224.023	January 28, 2014	AC_BLD_0026315.pdf
7	Well Operations - Well Kill	224.0030	February 22, 2011	AC_BLD_0026303.pdf
8	Routine Well Kills	224.045	August 18, 2014	AC_BLD_0026325.pdf
9	Well Operations - Unload and Clean Up	224.055	February 25, 2014	AC_BLD_0026270.pdf
10	Gas Inventory - Monitoring, Verification and Reporting	224.070	November 10, 2014	AC_BLD_0026360.pdf

Table 4 shows a select listing of SoCalGas Operations Standards related to inspections, investigations, and integrity [19] [20]. The language is verbatim from the original content. This is not an exhaustive list, but rather a selection showing that SoCalGas did have policies (i.e., Operations Standards) related to inspection, investigation, and integrity. We performed a cursory review of these standards and found a robust proactive framework for pipeline integrity. One example of this is in row 8, *Investigation of Failures* *on Distribution and Transmission Pipeline Facilities* [21], where the purpose of the document was to determine the cause of the pipeline failure and prevent reoccurrence. There was specific guidance on soil and liquid samples to collect, which lab or analysis center to use, what follow-up actions were required, and how long to retain investigation reports. Such guidance was not found in our review of the Gas Storage Operations Standards listed in Table 3.

None of the Operations Standards listed in Table 4 pertain to gas storage wells but instead to pipelines and valves. Proactive procedures for pipeline integrity were clearly visible, whereas well integrity procedures were absent. Our interpretation is that SoCalGas was more focused on surface assets than on downhole assets.

Table 4: SoCalGas Operations Standards Related to Inspections, Investigations, and Integrity [19] [20]

Row	Company Operations Standard Name	SCG Number:	Published Date
1	In-Line Inspection Surveys Standard	167.022	May 23, 2012
2	Inspection of Pipelines on Bridges and Spans	184.12	December 9, 2013
3	Leak Investigation - Distribution	184.0245	November 4, 2013
4	Investigate Measurement and Regulation Problems - Medium, Large and Above - Standard Pressures MSAs	185.0342	March 18, 2014
5	Cathodic Protection - Inspection of Exposed Pipe	186.02	March 5, 2014
6	Investigation of Accidents and Pipeline Failures	191.01	November 6, 2012
7	Valve Inspections and Maintenance Self-Audit	203.017	October 12, 2012
8	Investigation of Failures on Distribution and Transmission Pipeline Facilities	223.003	October 18, 2012
9	Pressure Vessel Inspection	223.0045	September 18, 2009
10	Pipeline Patrol and Unstable Earth Inspections	223.0065	December 12, 2013
11	External and Internal Transmission Pipeline Inspection	223.0095	October 24, 2012
12	Self-Audit Guidelines - Pipeline Integrity Program	167.0125	July 27, 2012
13	Assessment of Pipeline Integrity Using Guided Wave UT	167.024	October 21, 2013
14	Leakage Surveys	223.01	January 16, 2014

4.2.1 SCG 224.070: Gas Inventory - Monitoring, Verification and Reporting

The Operations Standard titled Gas Inventory - Monitoring, Verification and Reporting [22] was a key document. It has procedures for:

- Monitoring to confirm the injected gas remained in the storage zone.
- Estimating the gas inventory in the storage zone.
- Reporting gas inventory losses.

Table 5 is a summary of our interpretation of the monitoring requirements of the Storage Zone wells. We focused on the monitoring components of this document because they are related to well integrity.

Table 5: Monitoring of Storage Zone Wells

Monitoring Component	Time Interval	Details
Storage zone wells—performance review of individual wells and the field	Not explicitly stated: interpreted to be once every two years	• Back pressure curve shifts, changes in deliverability, individual well and reservoir tests, and field performance are investigated.
Tubing, production casing × tubing annulus, surface casing × production casing annulus	Weekly readings and plots with monthly reports to DOGGR	• Surface casing × production casing annulus pressure is abnormal when it is high enough to force gas into normally pressured water sands at the shoe or other known surface casing holes or leaks. • Zero pressure is abnormal if that well had a history of annular pressure. • Take diagnostic steps to determine the source of pressure buildup. • Note blowdowns (i.e., bleeding off the annulus pressure) if they occur.
Wellhead inspections	Monthly	• Report and correct leaks from wellhead flanges and valves.
Subsurface temperature surveys	Annually	• Surveys are done in accordance with DOGGR regulations. • Wells that are killed are not exempt. • Additional surveys will be run if unusual well conditions occur, such as anomalous pressure, surface gas emissions, or other well problems. • Wireline retrievable tubing obstructions are to be removed for temperature surveys. • Ideally, surveys are conducted at high reservoir pressures when shoe leaks are most noticeable. • To investigate anomalies, additional surveys are made such as temperature surveys, noise logs, spinner surveys, and radioactive tracer surveys. • For well casing leaks above the shoe, radioactive tracer surveys are typically used to verify the location of the leak. Additional surveys are used to verify that the leak exists and quantify the leakage rate.

Figure 1 shows the summary of the Aliso Canyon Monitoring Plan for Storage Zone Wells from the SoCalGas Annual Review Meeting with DOGGR, 1989 [23]. The components and frequency of the monitoring plan are listed. Industry technology has evolved for real-time pressure, temperature, flow, and vibration (noise) monitoring but, there were no significant differences in the monitoring plan from 1989 compared to the 2014 SCG 224.070 Operation Standard.

The monitoring program was successful in identifying casing integrity issues. Most of the historical casing failures in the Aliso Canyon Field were identified by the program.

These documents fail to mention casing inspection logs, pressure testing wells, real-time pressure monitoring, investigation of leaks, and RCA.

TABLE 5
SUMMARY OF THE ALISO CANYON MONITORING PLAN

STORAGE ZONE WELLS

ITEM	MINIMUM FREQUENCY OF DATA COLLECTION	PRIMARY RESPONSIBILITY	COMMENTS
1. Flow tests	Annual	Resident Reservoir Engineer	All wells are flow tested for sand, production and back-pressure curves annually.
2. Wellhead pressures (including surface casing and annular pressures)	Weekly	Station	Copies to Staff.
3. Plot of surface casing annular pressures	Weekly	Resident Reservoir Engineer	To be reviewed twice yearly with Underground Storage Staff.
4. Wellhead inspections	Monthly	Station	To be reported to Underground Storage Staff on daily activity report whenever leakage is found.
5. Temperature surveys	Annual	Resident Reservoir Engineer	Copies to Staff.
6. Noise logs	As needed	Resident Reservoir Engineer	Copies maintained in Division and Underground Storage files.
7. Tracer surveys	As needed	Resident Reservoir Engineer Staff will normally assist	A detailed explanation of methods and results to be prepared by Resident for each well. Copy sent to Underground Storage Staff.
8. Neutron logs	As needed	Underground Storage Staff	Copy to Division.
9. Reservoir shut-ins	Annual	Senior Petroleum Engineer	Hysteresis curve and isobaric maps to be updated by Underground Storage Staff.
10. Annular blowdown	As needed	Resident Reservoir Engineer	To recommend and implement annular blowdown tests and programs to determine corrective action needed, and to prevent fracture of primary cement at surface string shoe.
11. Annular helium samples	Annual	Engineering Test Center	To monitor gas content in the annular.

Figure 1: Summary of Aliso Canyon Monitoring Plan, Storage Zone Wells, 1989 [23]

4.2.2 SCG 224.02: Operation of Underground Storage Wells

The Operations Standard SCG 224.02: Operation of Underground Storage Wells [24]details the following:

- Well signage requirements
- Semi-annual testing and inspection of the following surface safety devices:
  - Automatic fail-close valves
  - High-low pressure sensors (to shut in the well at high or low pressure conditions)
  - Fire detecting fusible plugs
  - Remote shut in controls
  - Sacrificial sand probes (to shut in the well in the case of excessive sand production)
- Wellhead valve configuration

- Critical well criteria and testing and inspection of critical well safety devices
- Recordkeeping requirements

Figure 2 shows the Well Safety Systems from the Annual Review Meeting with DOGGR, 1989 [23]. The components and frequency of the monitoring plan are listed. There are no significant differences in the monitoring plan from 1989 compared to the SCG 224.02 Operation Standard. Guidance is provided that if a sacrificial probe should fail, the cause of failure should be diagnosed and corrected prior to returning the well to service. Like the Gas Inventory – Monitoring, Verification and Reporting Operations Standard, the Operation of Underground Storage Wells Operation Standard fails to mention casing inspection logs, pressure testing wells, investigation of leaks, and RCA.

WELL SAFETY SYSTEMS

All wells at Aliso Canyon are equipped with surface safety systems that are designed to shut the well in to prevent loss of gas and oil in the event of damage to surface piping. The surface safety system consists of fail-close pneumatic operated gate valves that are closed by any of the following:

1. Low pressure pilot - shuts well in if a break in the piping causes pressure to drop below 300 psi.
2. High pressure pilot - shuts well in if pressure in withdrawal line exceeds 710 psi.
3. Sacrificial sand erosion probe - shuts well in if sand erosion wears hole in thin walled probe.
4. Fusible plug - shuts well in if a fire occurs in well cellar.
5. Remote shutdown station - allows well to be shut in manually from no closer than 150 feet away from wellhead.

All surface safety systems are tested twice a year.

Figure 2: Summary of Aliso Canyon Well Safety Systems, 1989 [23]

5 Conclusions

A review of the Division Order 1109 and the January 2019 version of the California Statutes and Regulations indicates that the requirements of these two documents are similar and consistent. Significant changes have been made to the state regulatory requirements regarding gas storage wellbore mechanical integrity because of the SS-25 leak. Major changes include requirements for two mechanical barriers, casing wall thickness inspections, casing pressure testing and a comprehensive risk management plan for each underground storage project. An emergency response plan that addresses leaks, well failure, and well control processes for well failure and full blowout scenarios is now required.

Based on these changes, a case can be made that if the 2019 regulations had been in place and were followed in 2015, the SS-25s leak could have been prevented. The area of corrosion was large enough that a casing inspection could have identified the metal loss.

The 2015 regulations regarding well integrity for gas storage wells were insufficient considering that gas storage wells are long life wells and are exposed to seasonal cyclic pressure loads from high injection pressure to low withdrawal pressure year after year. Gas storage wells are unlike typical oil and gas wells where the pressure starts out high and decreases with time as the reservoir is depleted. No regulations were found that required casing inspections to monitor casing wall defects, corrosion, and remaining wall thickness for the purpose of confirming the pressure capacity of the casing for the expected pressure loads.

SoCalGas' monitoring program and static temperature surveys, as approved by DOGGER in 1995, fulfilled the requirements for mechanical integrity found in Section 1724.10 (j) and (j)(1) of the 2015 regulations.

Allowing an annual temperature survey to meet the requirements of an MIT was inadequate for several reasons: a leak and cooling must exist to develop a temperature anomaly, lack of an anomaly does not provide any data regarding the future integrity of the casing or remaining wall thickness, temperature change must be within the sensitivity of the tool, and interpretation of the survey is subjective.

The casing leak in SS-25 showed that using temperature surveys to confirm mechanical integrity of casing was a flawed concept. The concept assumed that leaks would not be catastrophic, would cause a cooling anomaly, and would be detected in time to allow the well to be killed quickly and safely. A temperature survey was run in SS-25 on October 21, 2014, a year before the leak on October 23, 2015, and showed no temperature anomalies.

The revised regulations issued after the SS-25 leak event are much more comprehensive, requiring periodic casing inspections and pressure tests. The primary and secondary mechanical well barrier requirement is another important step in maintaining well integrity in gas storage wells.

Suggestions for improving the regulations include:

- Cementing the production casing to surface for new wells to protect the production casing from outside diameter (OD) corrosion. Cementing technology has advanced to the point that cement to surface is possible by using low-density cement slurry. Cement to surface helps protect the casing from ground water exposure resulting in long life gas storage wells.
- Requiring an analysis of casing failures that result in loss of pressure integrity, such as casing leaks and parted casing. The analysis should be documented in a report and include the following, as applicable:
  - Details of how the failure was identified and located

- Details of the casing OD, weight, grade, and connection
- Photos of the failure if recovered, or downhole camera and video as applicable
- Metallurgical analysis if the failure was recovered
- Analysis and hypothesis of the cause
- Determination if the failure was an isolated event or is related to other similar failures
- Recommendations to mitigate future failures

- Requiring a detailed well control plan for each gas storage well with the following analysis, at minimum:
  - A well-specific inflow performance relationship curve to understand the well's deliverability vs. bottomhole pressure
  - A well-specific kill plan based on transient modeling: The plan should be detailed enough to cover the callout of equipment and services.
  - A well-specific relief well plan that includes a surface location and a general overall plan

SoCalGas operating policies are found in the Company Operation Standards. Blade reviewed the Operations Standards related to gas storage wells in detail and compared them to the pipeline integrity Operations Standards. The latter contain proactive, modern, and robust procedures compared to the Gas Storage Operations Standards, which contain reactive procedures and offer no guidance for the prevention or reoccurrence of well integrity issues.

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SS-25 RCA Supplementary Report

Aliso Canyon Field Withdrawal/Injection Analysis

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Purpose:
Detail the results of the study of the historical production of Aliso Canyon Field in support of the Aliso Canyon Root Cause Analysis (AC-RCA) project.

Date:
May 31, 2019

Abstract

The gas storage well Standard Sesnon 25 (SS-25) in the Aliso Canyon Gas Storage Field located in Los Angeles County, California started leaking gas in October 2015. A relief well was drilled, and SS-25 was brought under control. The leak stopped in February 2016.

In January 2016, as part of their investigation of the leak, the California Public Utilities Commission (CPUC) and the Division of Oil, Gas, and Geothermal Resources (DOGGR) selected and gave provisional authority to Blade Energy Partners (Blade) to perform an independent Root Cause Analysis (RCA). The Blade Team and parties under Blade's direction were responsible for directing the work of subcontractors who performed the extraction of the SS-25's wellhead and tubing and casing and the preservation and protection of associated evidence. Blade RCA Reports, including this report, document and describe the key activities undertaken in support of the RCA effort.

Regulatory injection and production (withdrawal) data are analyzed for the Aliso Canyon field to develop information to guide and be used in future studies associated with the failure of well Standard Sesnon 25 (SS-25). Key findings of this analysis are:

- SS-25, 62 years old at the time of its failure, was one of the oldest wells in the field.
- The field was on injection for about 8–9 months (February/March through October/November) and on withdrawal for the remaining 3–4 months (October/November through February/March) in any given year. The field gas inventory (and therefore, pressure) was the highest in the year at the end of the injection season in October/November, which is when SS-25 failure occurred. At the time of the failure in 2015, the field gas inventory was slightly lower than the historical maximum in late 2012.
- SS-25 was used almost equally for injection (33.0 Bscf) and withdrawal (31.0 Bscf).
- The historical water-to-gas ratio (WGR) of the SS-25 well was 0.96 stb/MMscf, which was below the field-wide WGR of 2.58 stb/MMscf.
- The water injection operations occur entirely to the east of the failed SS-25. The two dominant water injection/disposal wells (Fernando Fee 36 and 37), which together account for 56% of the injected/disposed water volume, are located 7,230 and 5,340 ft, respectively, east of the SS-25.

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1 Introduction

This document details the results of the study of the historical production of Aliso Canyon field in support of the Aliso Canyon Root Cause Analysis (AC-RCA) project.

1.1 Abbreviations and Acronyms

Term	Definition
abd	Abandoned
B	Billion (e.g., 1 Bscf = 10^9 scf)
DOGGR	Division of Oil, Gas, and Geothermal Resources
GOR	Gas-to-Oil Ratio
M	Thousand (e.g., 1 Mscf = 10^3 scf)
MM	Million (e.g., 1 MMscf = 10^6 scf)
OGR	Oil-to-Gas Ratio
P&A	Plug and Abandon
scf	Standard Cubic Feet
SoCalGas	Southern California Gas Company
Stb	Standard Barrels
WGR	Water-to-Gas Ratio

2 Gas Storage Operations

Gas storage operations in Aliso Canyon are conducted only by Southern California Gas Company (SoCalGas). During injection, gas is injected into the Sesnon-Frew zone through injection wells. During withdrawal, gas is withdrawn (produced) through withdrawal wells.

SoCalGas divides the field into east, central, and west sectors based on the injection and withdrawal facility networks (Figure 1). SS-25, the incident well, is located in the west sector.

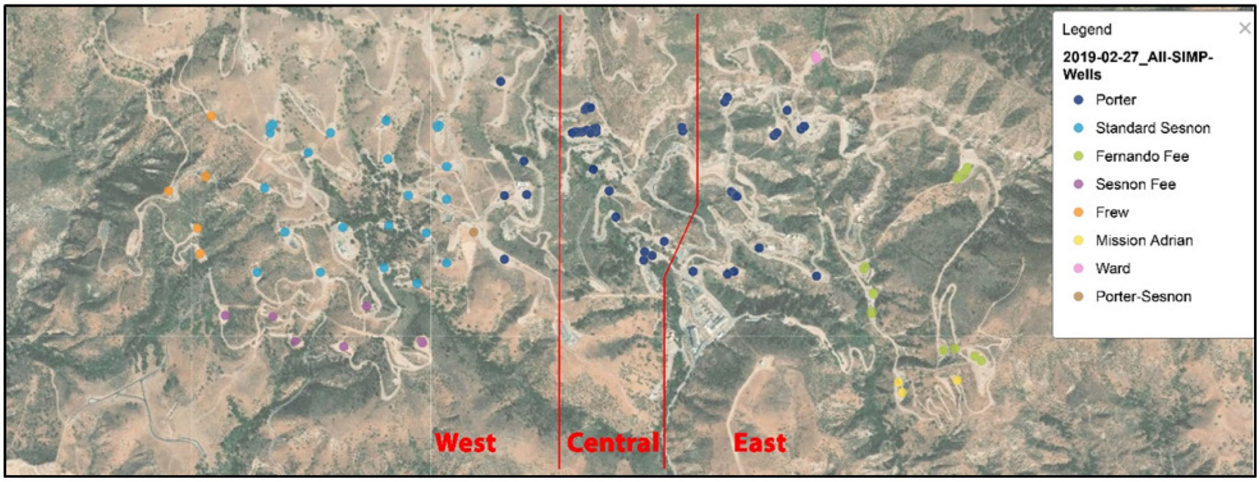


Figure 1: Aliso Canyon Field (with East, Central, and West Sectors)

There are 119 active or idle and 12 plugged and abandoned (P&A'd) gas storage wells (Table 1). The gas storage wells are mainly of two vintages:

- Wells drilled between 1938 and 1955, when the Aliso Canyon was first developed
- Wells drilled between 1971 and 1985, when the Sesnon-Frew zone was converted from conventional operation to gas storage (Figure 2)

Table 1: Ages of Wells (in Years) in the Aliso Canyon Field

Wells	Gas Storage	Conventional Production	Water Injection
Active/Idle Wells			
Count	119	65	12
Median Age	43	63	65
Oldest Age	77	78	76
P&A Wells			
Count	12	17	0
Median Age @P&A	41	41	-
Youngest Age @ P&A	33	2 months	-
Oldest Age @ P&A	48	61	-

The median age of the gas storage wells is 43 years, and the oldest gas storage well is 77 years old (Table 1). For the P&A'd wells, the age at abandonment ranged from 33 to 48 years, with a mean of 41 (Table 1,

Figure 3). The SS-25 incident well, which was spudded in October 1953, was 62 years old at the time of the incident in October 2015.

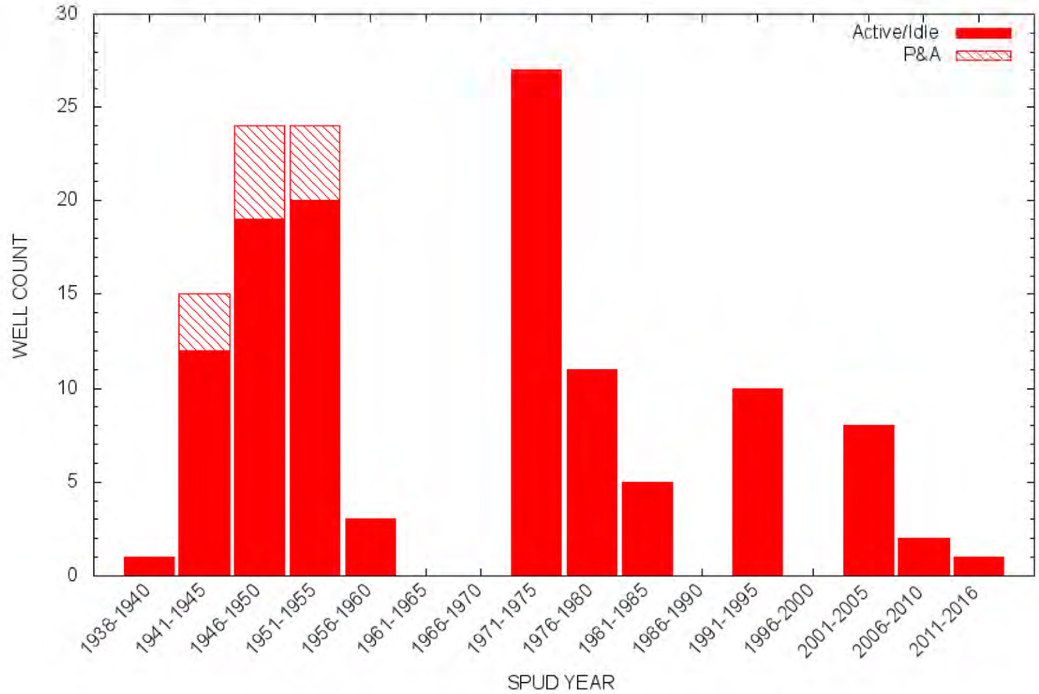


Figure 2: Drilling History of Gas Storage Wells

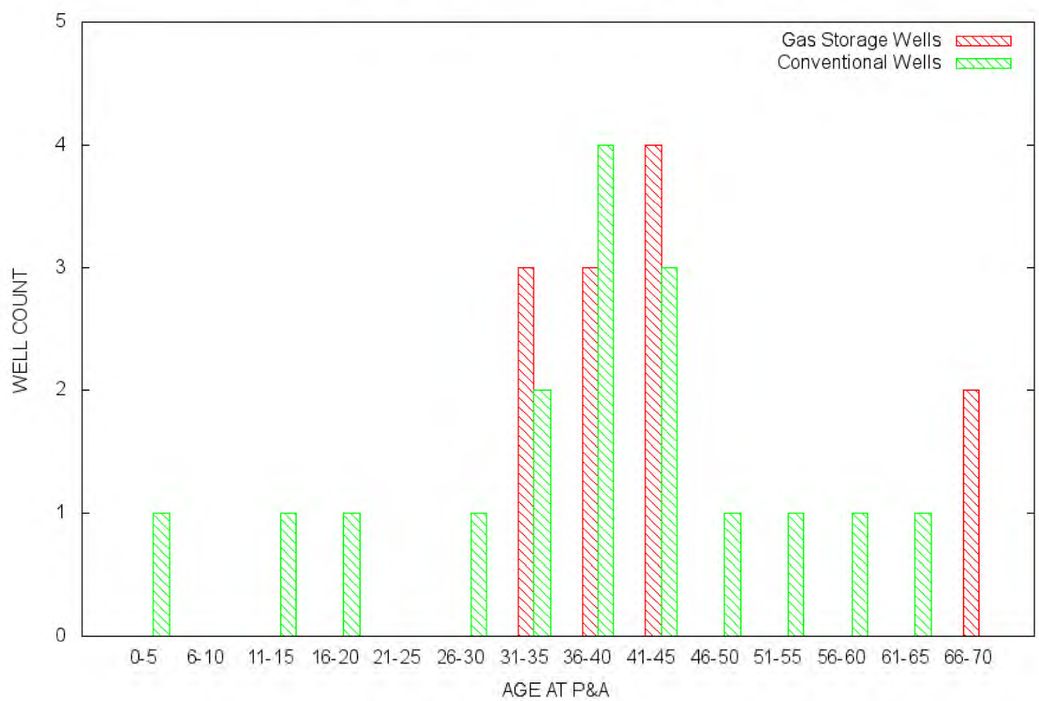


Figure 3: P&A History of Wells

Over the life of the well, the number of wells used for gas storage have varied between 83 and 108, with a median value of 99 (Figure 4). On average, about 60% of the wells were used for both injection and withdrawal and 40% were used for withdrawal only. Except for 1977, at the beginning of the gas storage operations, very few wells were dedicated to injection.

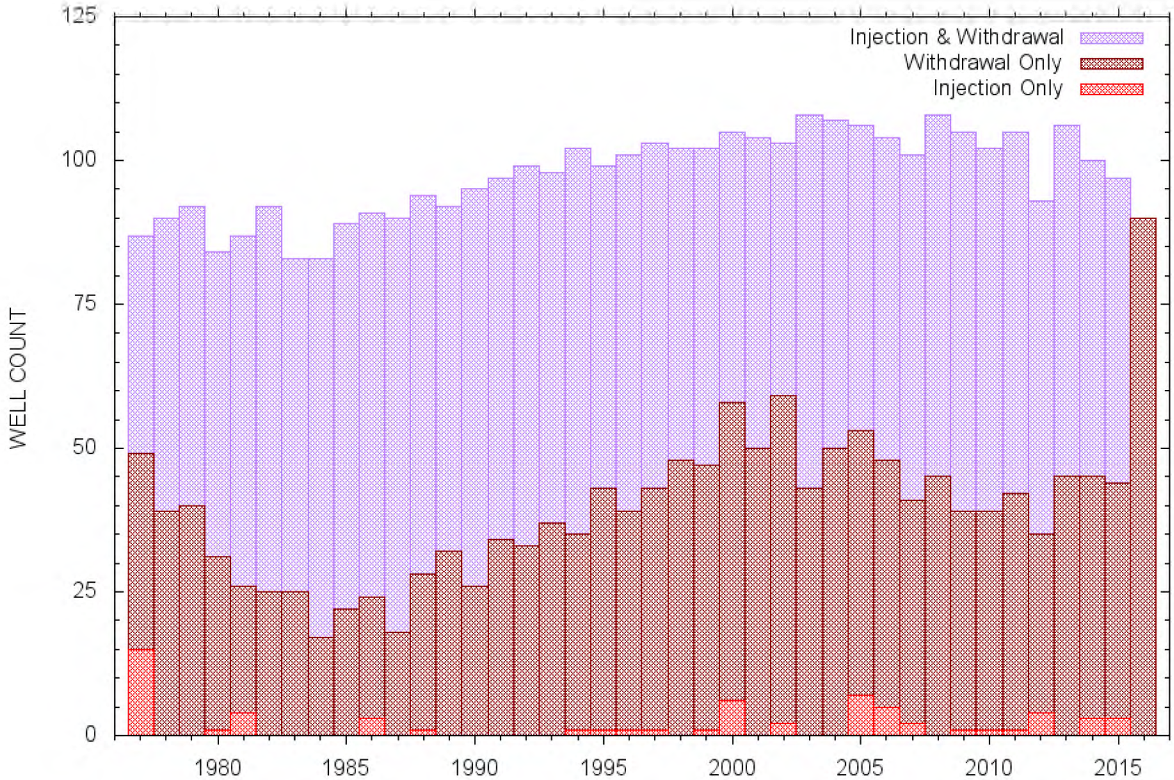


Figure 4: Gas Storage Well Types

In Figure 4, for a given year, a well is designated as:

- **Injection Only** if its injected gas volume is greater than zero, and its withdrawn gas volume is zero for that year.
- **Withdrawal Only** if its injected gas volume is zero and its withdrawn gas volume is greater than zero for that year.
- **Injection & Withdrawal** if both its injected and withdrawn gas volumes are greater than zero for that year.
- **Idle/Unused** if both its injected and withdrawn gas volumes are zero for that year (not shown in Figure 4).

In this scheme, a well's designation may change from year to year.

At the time of the incident, 1,895 Bscf of gas had been injected, and 1,805 Bscf of gas had been withdrawn from the gas storage zone since 1977 (Table 2). In addition, 4.04 MMstb of oil and 4.67 MMstb of water had been co-produced along with the withdrawn gas, resulting in an overall oil-to-gas ratio (OGR) of 2.24 stb/MMscf and an overall WGR of 2.58 stb/MMscf.

The data indicate an imbalance between the geographical distribution of injection and withdrawal volumes. The gas is mostly injected in the east and central sectors, which account for 50% and 33% of the total injection, respectively. The east, central, and west sectors account for 40%, 20%, and 40% of the withdrawn gas volumes, respectively, so gas is withdrawn more evenly. This suggests that a net migration of gas from the east to the west occurs within the storage zone.

In addition, the data indicate that OGR and WGR increase from the east to the west.

Table 2: Gas Storage Injection and Withdrawal Volumes (1/1977–10/2015)

Sector	Totals					OGR (stb/ MMscf)	WGR (stb/ MMscf)
	Injected Gas (Bscf)	Withdrawn Gas (Bscf)	Net Injection (Bscf)	Oil (MMstb)	Water (MMstb)		
East Sector	937.3	705.2	+232.1	0.89	1.19	0.76	0.84
Central Sector	639.6	393.8	+245.8	0.30	0.33	1.27	1.69
West Sector	318.5	706.2	-387.7	2.85	3.15	4.04	4.45
Field Total	**1,895.4**	**1,805.2**	**+90.2**	**4.04**	**4.67**	**2.24**	**2.58**

The review of injection and production data for the SS-25 incident well and the other two wells on the same pad (SS-25A and SS-25B) show that all three wells have been used for both injection and withdrawal; however, the injection volumes are higher than the withdrawal volumes, especially for SS-25A and SS-25B. All three wells located in the west sector have OGR lower than the field and the sector values (Table 3). Although all three wells have WGR below the sector average, SS-25A has produced more water than its two neighbors and has WGR above the field average.

Table 3: Gas Storage Injection and Withdrawal Volumes for Incident Well and Its Neighbors (1/1977–10/2015)

Sector	Totals					OGR (stb/ MMscf)	WGR (stb/ MMscf)
	Injected Gas (Bscf)	Withdrawn Gas (Bscf)	Net Injection (Bscf)	Oil (MMstb)	Water (MMstb)		
SS-25[1]	33.0	31.0	+2.0	0.033	0.030	1.053	0.959
SS-25A	25.7	16.9	+8.8	0.019	0.053	1.110	3.134
SS-25B	45.8	24.9	+20.9	0.016	0.021	0.632	0.844
Pad Total	**104.5**	**72.8**	**+31.7**	**0.067**	**0.103**	**0.922**	**1.424**
[1] Incident well							

Figure 5 shows the annual injection-withdrawal cycle. Gas is injected for about 8–9 months (February to October) and withdrawn for 3–4 months (October to February). This pattern varies slightly from year to year, which presumably depends on the weather.

Year-to-year gas inventory increased between 1995 and 2010 and has since remained steady. Since 2005, every third winter has seen higher withdrawals than the other two.

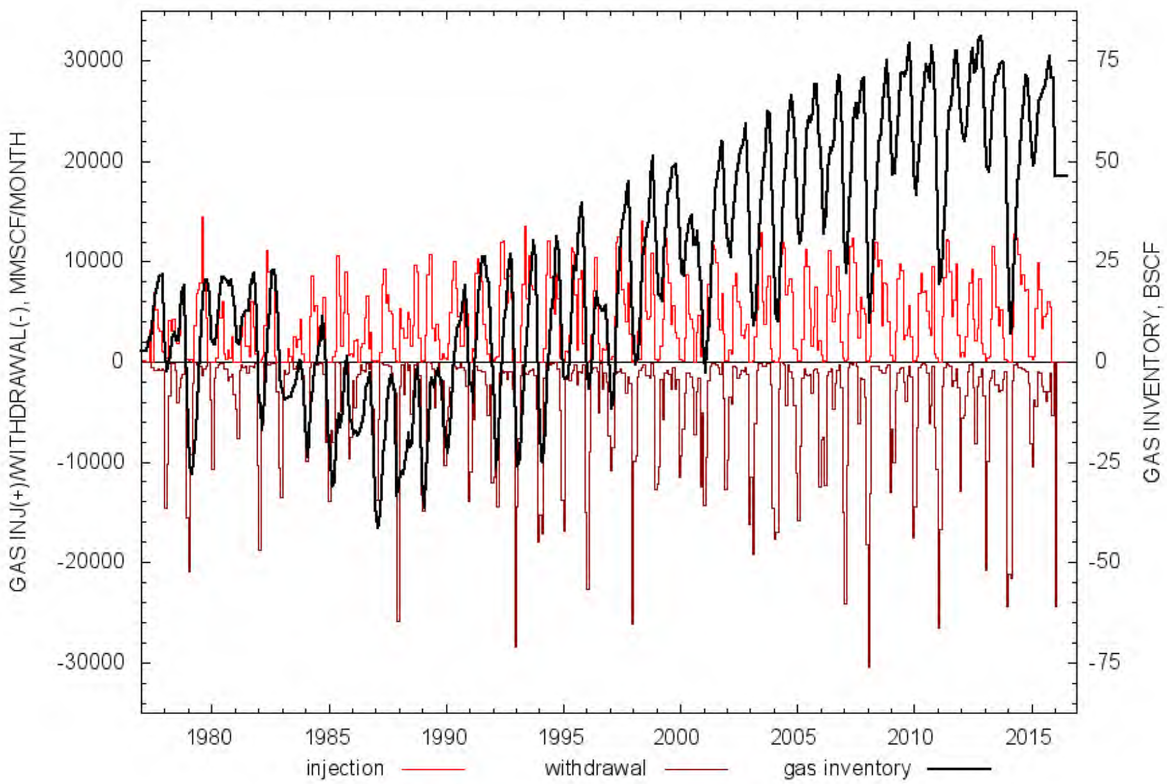


Figure 5: Gas Storage Operations (1977–2016)

The SS-25 incident occurred during the tail end of the injection season, on or about October 23, 2015. Estimated working inventory in the field was 75 Bscf (Figure 6). This was close to but below the highest historical working inventory of 81 Bscf recorded in December 2012.

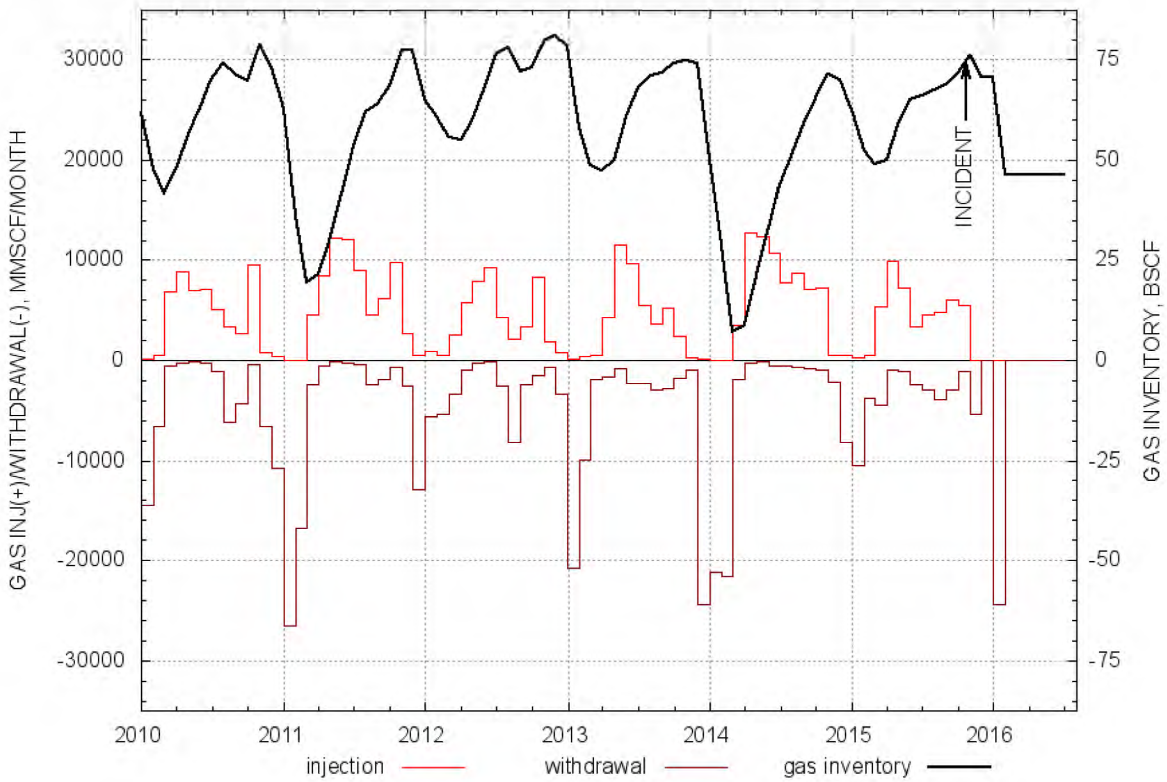


Figure 6: Gas Storage Operations (2010–2016)

Neglecting year-to-year variations, OGR shows a decline over the past 40 years. This is expected because the cyclic gas storage process (injection-withdrawal) strips the storage zone of its remaining oil while the remaining oil evaporates into the injected dry gas.

In Figure 7, WGR shows an increasing trend during the first 20 years and a decreasing trend during the last 20 years. Temporary increases in WGR occur in 1995–1996 and again in 2005.

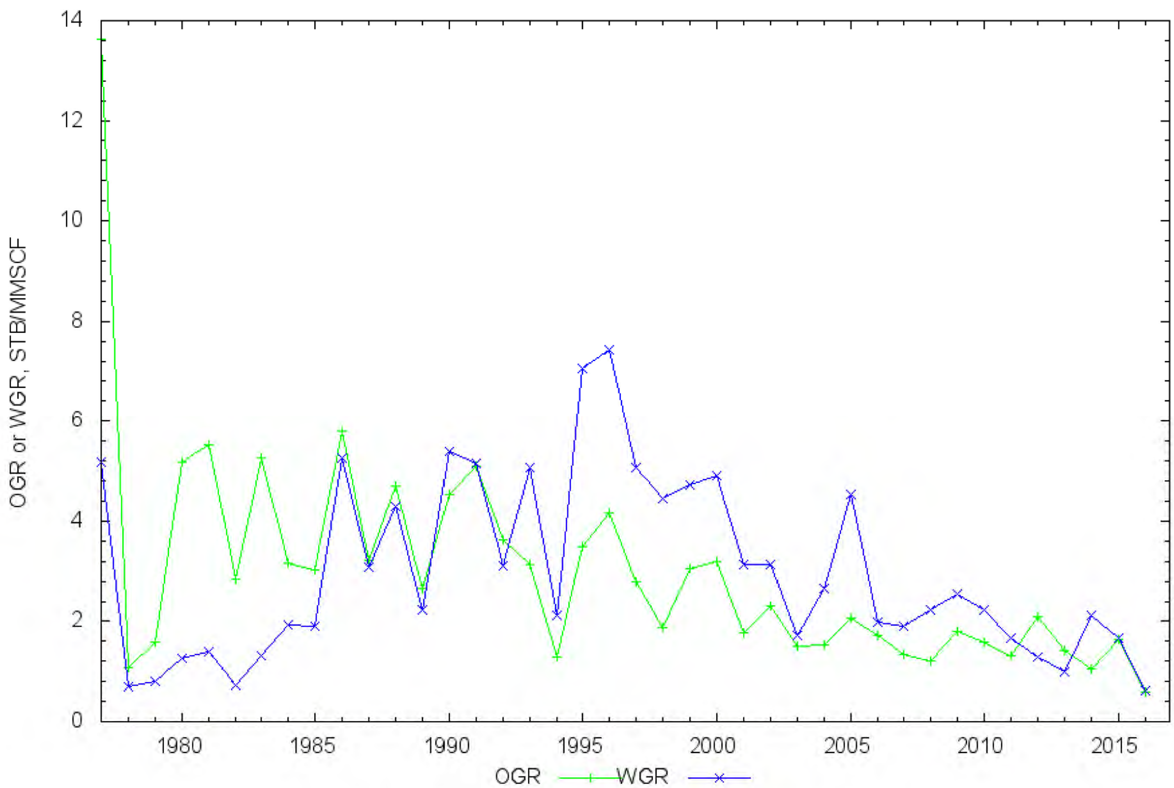


Figure 7: Gas Storage Operations: OGR and WGR

Tubing and casing pressures (for withdrawal) and surface injection pressure (for injection) are also reported monthly to the Division of Oil, Gas, and Geothermal Resources (DOGGR) and are included in the production and injection tables. In general, the pressures are expected to be correlated with the gas inventory in the Sesnon-Frew zone (Figure 8). This holds true for individual years, but a discrepancy across several years is noted. For example, between 2000 and 2010, the pressure fluctuates about the same level, although the average gas inventory is gradually increasing year to year. Similarly, the pressure trends decrease between 2010 and 2015, although the year-to-year gas inventory remains the same.

Although the reason for this discrepancy is unclear, the data quality of the pressure data is suspect. Wells' pressures are reported once a month, but the operational states of the wells during pressure measurements are not recorded. For example, if the well is withdrawing, the casing and tubing pressures will be lower than if the well is idle (shut-in) due to the frictional pressure drop. Similarly, if the well is injecting, the injection pressure will be higher than if the well is idle (shut-in) due to the frictional pressure drop.

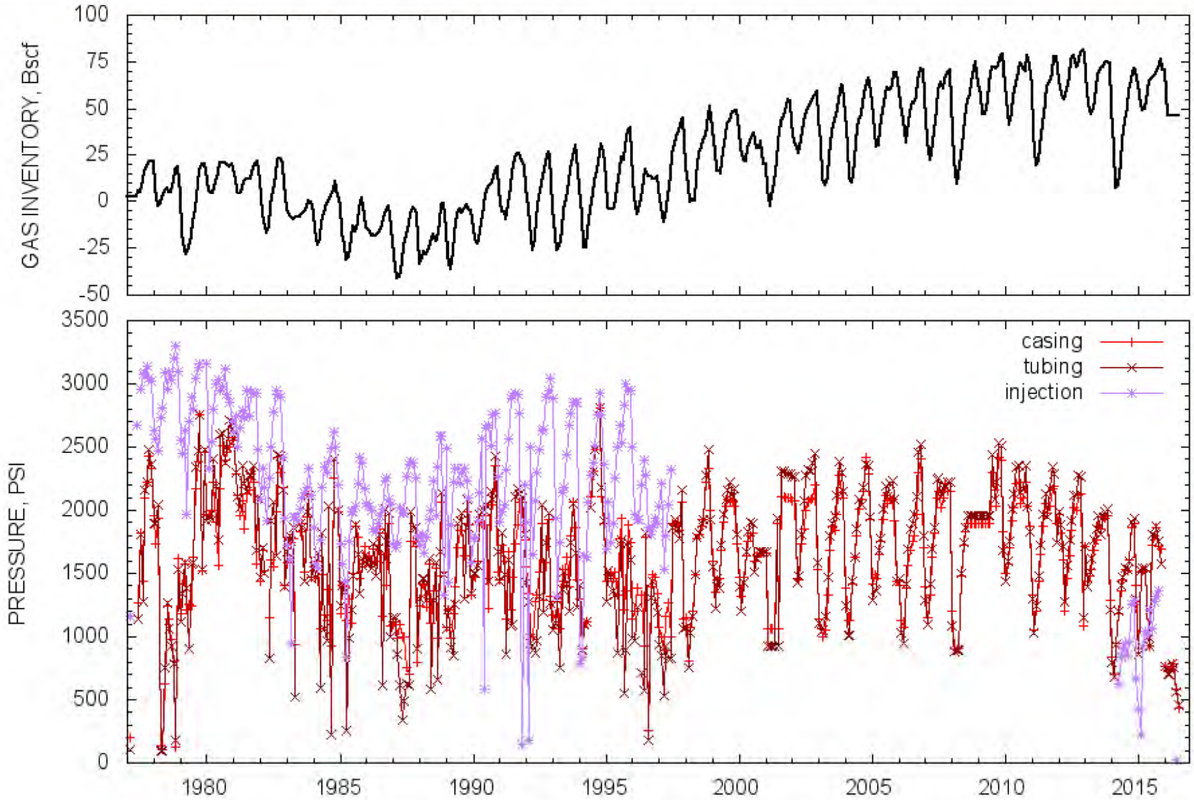


Figure 8: Gas Storage Operations: Average Pressure

Appendix A lists the gas storage wells arranged in order of increasing distance from SS-25.

Appendix D has plots of historical injection and withdrawal data for the field, for the three sectors, and for individual wells.

3 Conventional Production Operations

In addition to gas storage operations, oil is produced conventionally in the Aliso Canyon and nearby Oat Mountain fields by three operators: SoCalGas, Crimson Resource Management, and the Termo Company.

Table 1 shows the existence of 65 active or idle and 17 P&A'd conventional wells. Most conventional wells were drilled during the 1938–1955 initial development with peak drilling occurring between 1951–1955 when 26 wells were drilled (Figure 9). There were also three conventional wells drilled in the 2006–2010 period, probably in response to the high oil prices of the period.

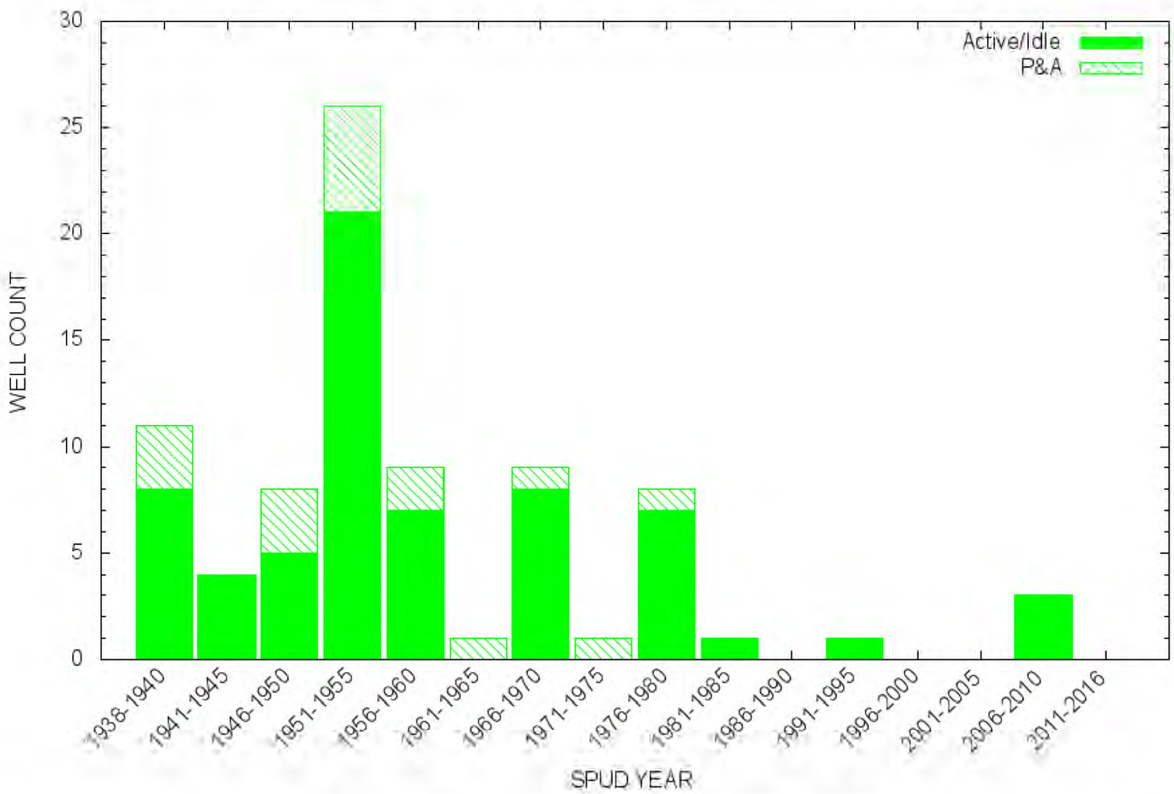


Figure 9: Drilling History of Conventional Wells

The median age of active or idle wells is 63 years, and the oldest conventional well is 78 years old (Table 1). For the P&A'd wells, the age at abandonment ranges from two months[i] to 61 years with a median value of 41 years (Figure 3).

Through 1976, Aliso Canyon/Oat Mountain fields had produced 51.6 MMstb of oil with most production originating from the Sesnon-Frew (45%) zone, which was later converted to gas storage, and Porter-Del Aliso A-36 (42%) zone.

Since 1977, 8.3 MMstb of oil has been produced (Table 4). About half of the production has originated from the Porter-Del Aliso A-36 zone, and another third has come from the Sesnon-Eocene zone. The overall watercut has been 89%, and the overall gas-to-oil ratio (GOR) has been 950 scf/stb.

[i] This well, Orcutt 1, was spudded by Hamilton & Sherman Company in May 1961 and P&A'ed in July 1961. It is the only well drilled in this field by this historical operator.

Table 4: Conventional Operations Production Volumes (1977–2016)

Zone	Oil [1] (–1976) (MMstb)	Production (1977–2016)					Injection Water[i] (MMstb)
		Totals			Watercut	GOR (scf/stb)	
		Oil (MMstb)	Gas (Bscf)	Water (MMstb)			
No Pool Breakdown	–	0.012	0.504	0.052	80.8%	41076	–
Pliocene (abd)	–	0.002	0.005	0.000	0.0%	3055	–
Aliso	5.253	0.988	1.216	20.364	95.4%	1230	9.690
Aliso, West	0.128	0.129	0.138	1.012	88.7%	1072	–
Sesnon-Eocene	–	2.690	1.315	3.912	59.3%	489	–
Porter-Del Aliso A-36	21.825	4.277	4.547	41.669	90.7%	1063	–
Porter, West (abd)	0.052	0.000	0.000	0.001	95.9%	333	66.542
Mission-Adrian (abd)	0.021	–	–	–	–	–	–
Monterey	–	0.000	0.000	0.004	96.9%	53	–
Sesnon-Frew	23.435	–	–	–	–	–	–
Faulted Sesnon	0.172	–	–	–	–	–	–
Sesnon-Wigdal	0.664	–	–	–	–	–	–
Wigdal	0.078	0.188	0.146	0.064	25.5%	774	–
Field Total	**51.629**	**8.286**	**7.873**	**67.079**	**89.0%**	**950**	**76.231**

[i] Discussed in Section 4.

Since the Aliso Canyon field was initially put on production in the early 1940s, the data analyzed in this report represent the more mature stages of its life. Data prior to 1977 are not (easily) available.

The oil production rate was initially 30–40 Mstb/month (1000–1300 bpd) and had decreased to about 10 Mstb/month (330 bpd) by the 1990s (Figure 10). Since 2005, oil production has increased to the current value of 15–20 Mstb/month (500–650 bpd), presumably stimulated by the high oil prices of the late 2000s and early 2010s. There was a temporary reduction in conventional oil production in 1994, probably in response to the nearby Northridge earthquake[ii].

[ii] The 6.7 magnitude Northridge earthquake occurred on January 17, 1994. Its epicenter was 7 miles south of the Aliso Canyon field.

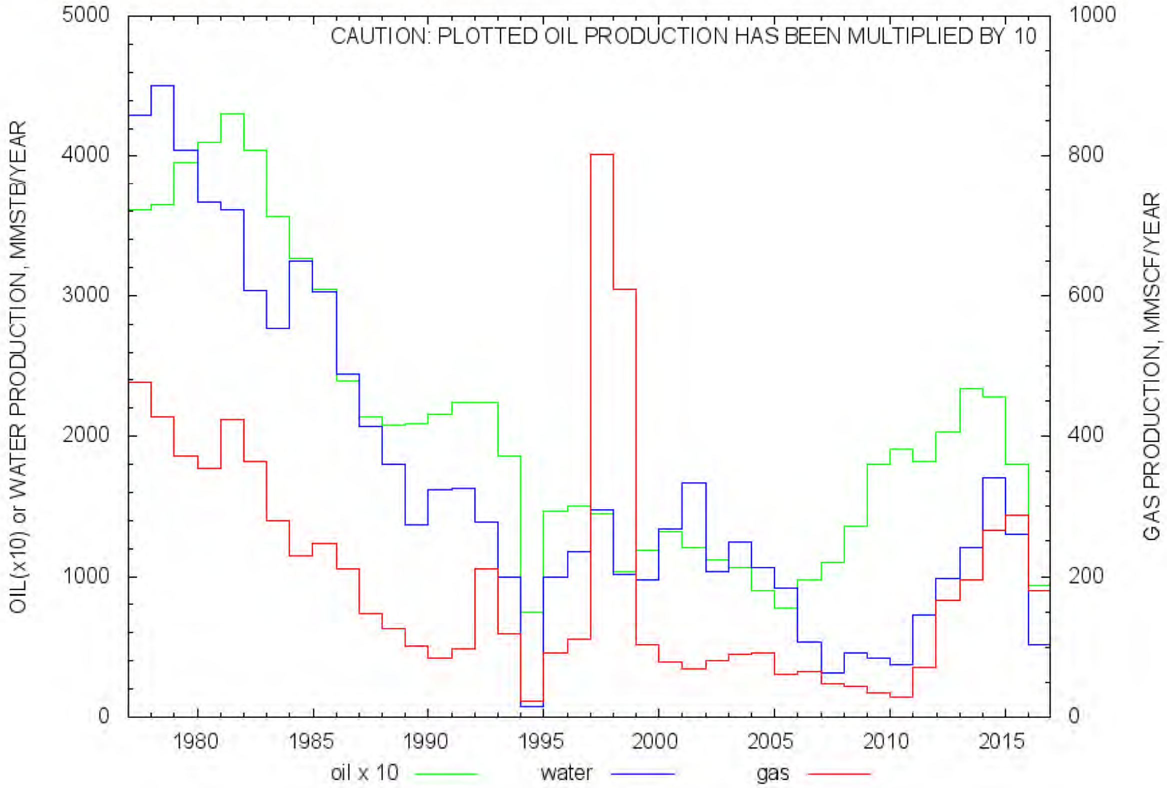


Figure 10: Conventional Operations (1977–2016)

The water cut has been steady with two exceptions (Figure 11): a period of low water cut in 1994, probably related to the reduction in conventional production after the Northridge earthquake, and a temporary decrease during the 2005–2011 period, coincident with the increased oil production. The later decrease may be due to three new oil wells being drilled in less wet areas of the reservoir.

GOR decreased from 1977 to 1990, was steady between 1990 and 2005 (except for 1997–1998), decreased slightly between 2005 and 2010, and has been increasing since 2010. When neglecting the 1997–1998 values, GOR is currently at its highest level, which is about double its cumulative average.

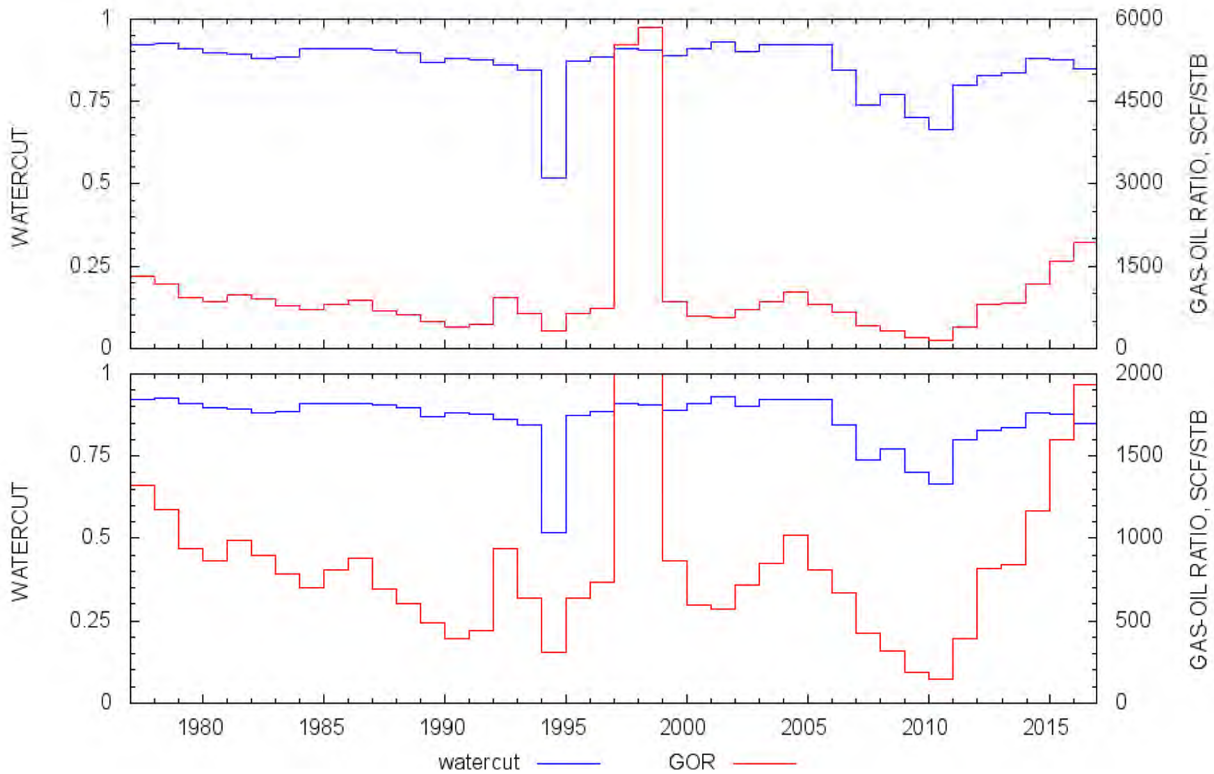
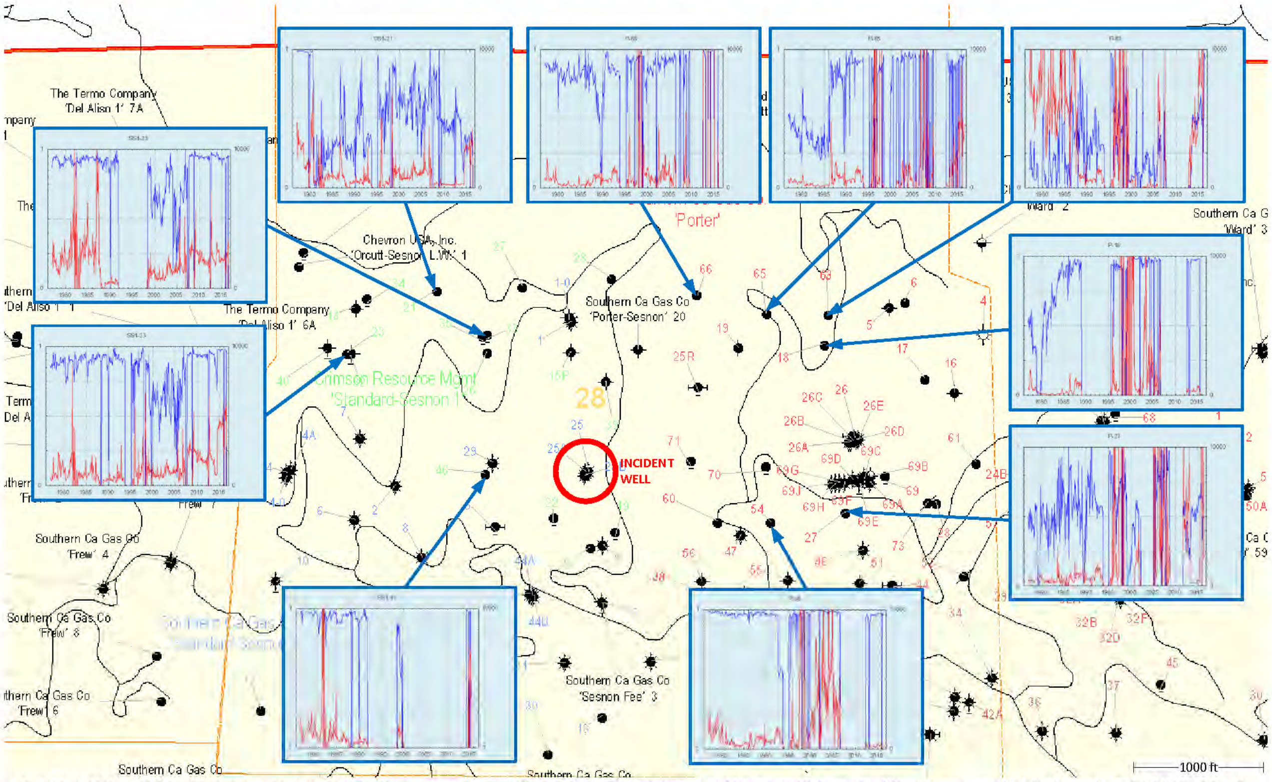


Figure 11: Conventional Operations: Watercut and GOR

The water-cut and GOR data from the ten wells closest to the SS-25 incident well with recent conventional production do not show any discernible geographic trend (Figure 12).



Base Map: State of California, Division of Oil, Gas and Geothermal Resources (DOGGR). Map 254. Obtained on May 23, 2019, from: ftp://ftp.consrv.ca.gov/pub/oil/maps/dist2/254/Map254.pdf

Figure 12: Geographic Analysis of Watercut and GOR Trends

Appendix B lists the conventional wells arranged in order of increasing distance from the SS-25 incident well. Appendix E has plots of historical production data for conventional operations.

4 Water Injection Operations

All water produced during the gas storage and conventional oil production operations are injected by SoCalGas into the Porter-Del Aliso A-36 and Aliso zones. The former zone, which is also the main zone of conventional oil production, accounts for 87% of the injection. Between 1977 and 2016 period, 76.2 MMstb of water has been injected (Table 4).

There are 12 water injection wells and all are listed as active or idle. The water injection wells were drilled between 1940 and 1968; most had been drilled by 1955 (Figure 13). The ages of water injection wells range from 48 to 76 years with a median value of 65 years old (Table 1).

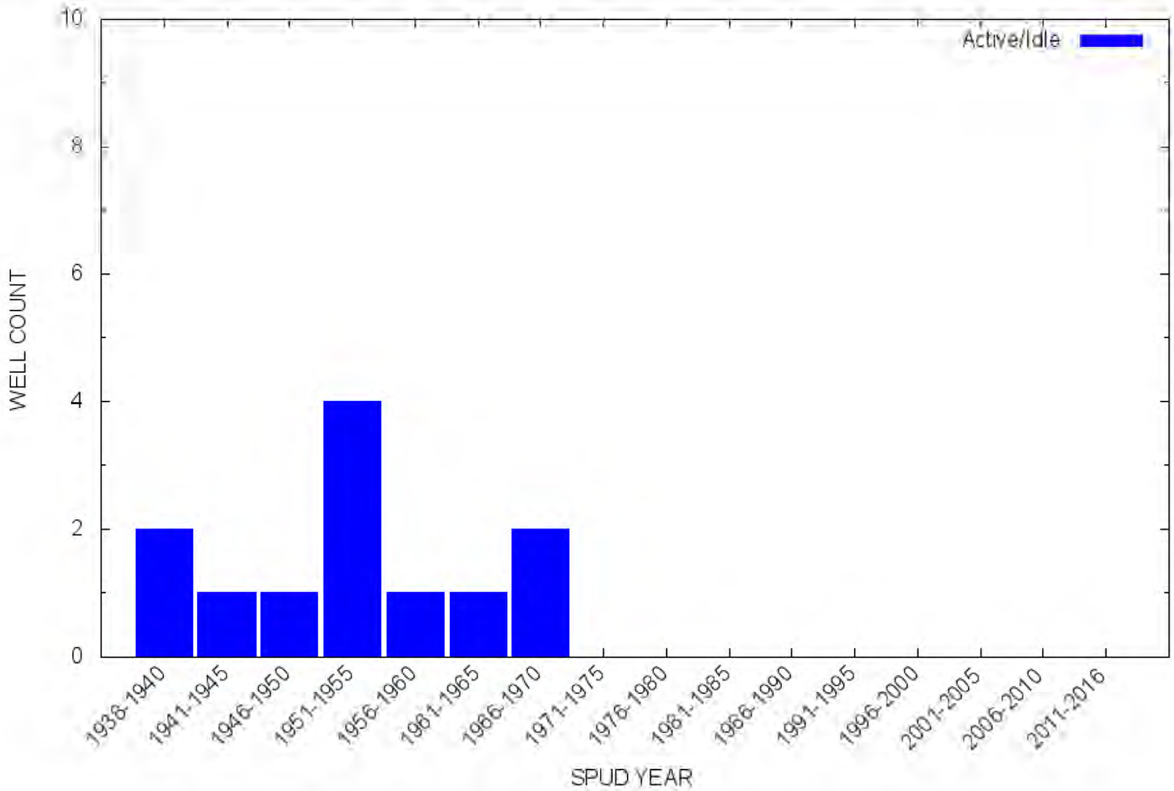
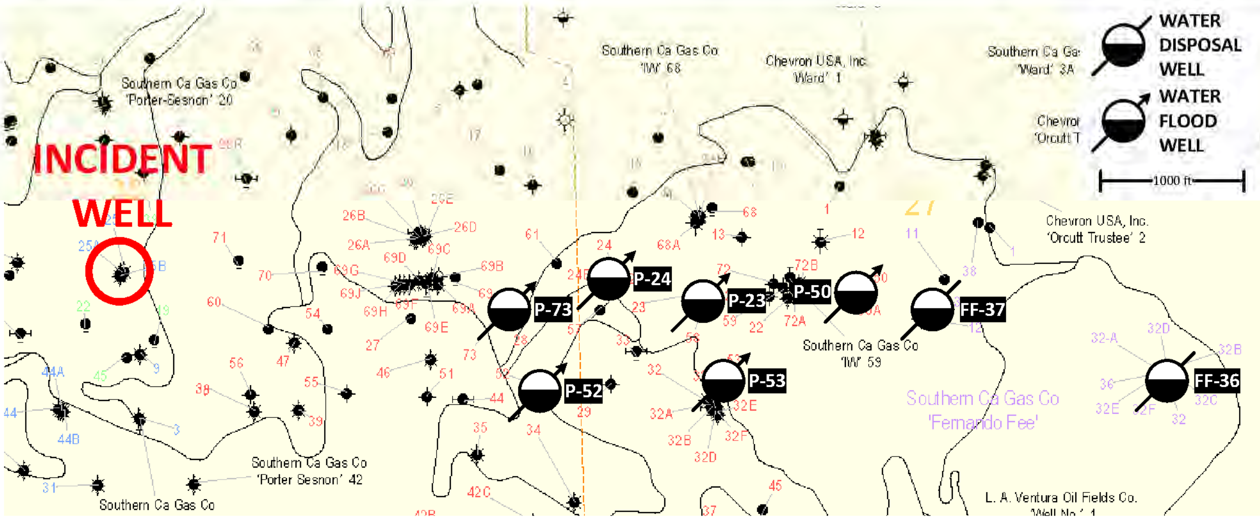


Figure 13: Drilling History of Water Injection Wells

Since the Aliso Canyon field was initially put on production in the early 1940s, the data analyzed here represent the more mature stages of its life. Data prior to 1977 are not (easily) available.

Data provided by Southern California Gas Company (SoCalGas) in January 2017 [2] indicate that only eight wells are active (Figure 14). Six of these wells are classified as "Water Flood Wells," and the remaining two are classified as "Water Disposal Wells." Table 5 lists the perforation depths and formations for these eight active wells.



Base Map: State of California, Division of Oil, Gas and Geothermal Resources (DOGGR). Map 254. Obtained on May 23, 2019, from: ftp://ftp.consrv.ca.gov/pub/oil/maps/dist2/254/Map254.pdf

Figure 14: Water Injection Wells

Table 5: Water Injection Well Functions, Formations, and Perforation Depths [2]

Well Function	Well Name	Formation	Perforation Depths
Water Disposal	Fernando Fee 36	Lower Porter	5,502–5,587 ft 5,592–5,652 ft 5,695–5,733 ft
		Upper Del Aliso	5,859–6,228 ft
	Fernando Fee 37	Aliso 1	3,764–3,800 ft 3,820–3,876 ft 3,887–4,077 ft 4,102–4,136 ft 4,160–4,261 ft 4,278–4,300 ft 4,311–4,330 ft
		Aliso 36	4,544–4,552 ft 4,579–4,590 ft 4,793–4,803 ft
		Upper Porter	4,931–4,939 ft 4,944–4,965 ft 4,973–4,997 ft 5,053–5,066 ft 5,069–5,077 ft 5,089–5,108 ft
Water Flood	Porter 23	Aliso 36	4,570–4,571 ft 4,590–4,630 ft
		Upper Porter	5,100–5,120 ft 5,140–5,150 ft 5,165–5,265 ft
	Porter 24	Aliso 36	4,611–4,612 ft
		Aliso 36/ Upper Porter	4,657–5,263 ft
	Porter 50	Upper Porter	4,748–5,078 ft
	Porter 52	Aliso 1	3,908–3,978 ft
	Porter 53	Aliso 1	3,806–3,869 ft
	Porter 73	Aliso 36	4,892–4,906 ft 4,921–4,957 ft
		Upper Porter	5,223–5,245 ft 5,253–5,280 ft

The injected water has three primary sources (Figure 15):

- Water produced by SoCalGas during gas withdrawal
- Water produced by SoCalGas during conventional oil production
- Water produced by other operators (Crimson and Termo) during conventional oil production

Almost all of the produced water originates from conventional oil production, mostly by SoCalGas. In general, there is a balance between produced water and injected water.

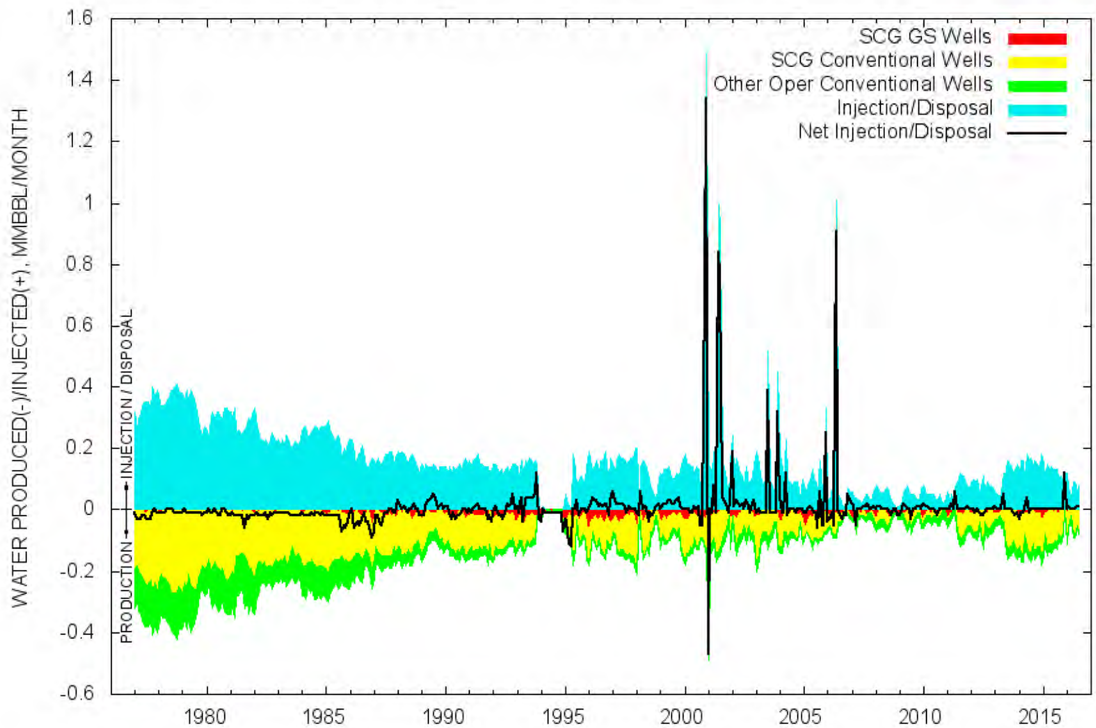


Figure 15: Water Injection Operations: Sources and Rates

Geographically, all of the water injection occurs to the east of SS-25 (Appendix G). Initially, water injection was concentrated on the eastern edge of the Aliso Canyon field. However, there has been a shift to the west during the last 20 years (1997–2016) with Porter 52, Porter 53, and Porter 24 wells becoming more active.

Appendix C lists the water injection wells, arranged in order of increasing distance from the SS-25 incident well. Appendix F has plots of historical injection data for individual wells.

5 Methodology

Except for data in Table 5, provided by SoCalGas, production analyses described in this report have been performed as follows:

1. **Obtain production and injection data.** Production (withdrawal for gas storage operations) and injection data files have been obtained from the DOGGR website [3]. Each data file contains either production or injection data for all wells in California for a given year. The files available are for production and injection operations from 1977 to present.
2. **Extract relevant data.** Data for Aliso Canyon and nearby Oat Mountain fields have been extracted from each production and injection data file.
3. **Merge extracted data.** The extracted production and injection data from Step 2 have been merged into a single Microsoft Access (MS Access) database.
4. **Create master well records**. The well-level information has been moved from individual production and injection records into a separate table in the same MS Access database. Well-level information includes well lease name, well number, well type, well coordinates, well operator, and so forth. Moving this information to a separate table allows the use of advanced analysis features, such as queries and pivot tables.
5. **Check records for quality**. Each production record must contain oil, gas, and water production data for a single well and a single calendar month, and similarly for each injection record. In other words, there should be at most one withdrawal and one injection record for a given well and a given month. However, it has been found that the original DOGGR data sometimes contains duplicate records. For example, for a given well and given month, there might be two records, one with gas volumes, and the other with oil and water volumes. Unless corrected, such duplicate records result in the well incorrectly showing zero OGR and zero WGR for the month. Therefore, these duplicate records have been identified and merged.
6. **Obtain and add missing data**. Some missing well-level data have been located by reviewing individual well files obtained from the DOGGR website and have been added to the database. Missing data have been related to spud and P&A dates and well locations.
7. **Analyze data**. Various queries and pivot tables have been generated to analyze the underlying data to answer specific questions as discussed in this report.

5.1 Data Format

Injection and production data[iii] for each well are reported monthly. Injection data are recorded in the DOGGR injection tables with one record per well per month; each injection record contains the total gas volume injected through one well during one calendar month. Production data are recorded in the DOGGR production tables with one record per well per month; each production record contains the total oil, gas, and water volumes produced from one well during one calendar month.

Oil and water volumes are recorded in stb. Gas volumes are recorded in Mscf.

[iii] For gas storage operations, the term *withdrawal* is used instead of *production*. Withdrawal data are recorded in the DOGGR production tables.

6 References

[1] California Division of Oil and Gas, "62nd Annual Report of the State Oil & Gas Supervisor," Sacramento, CA, 1977.

[2] Southern California Gas Company, *Response to Blade Energy Partners Request for Information Dated December 28, 2016,* 2017.

[3] California Division of Oil, Gas and Geothermal Resources, "FTP Site," [Online]. Available: ftp://ftp.consrv.ca.gov/pub/oil/new_database_format/. [Accessed 2016].

Appendix A Gas Storage Well List

This section lists the gas storage wells in order of increasing distance from the SS-25 incident well.

Well Name	Distance & Bearing to Incident Well (ft)	Status	Sector	Type	Total Gas Volume (Bscf) Injected	Withdrawn	Net Inj	Dates Spud	P&A	Injection Dates First	Last	Withdrawal Dates First	Last
Standard Sesnon 25	Incident Well	Active	West	GS	33.01	31.01	2.00	10/53		7/77	10/15	1/78	9/15
Standard Sesnon 25A	19 W	Active	West	GS, OG	25.66	16.86	8.80	11/72		7/77	2/11	1/78	9/15
Standard Sesnon 25B	39 SW	Active	West	GS, OG	45.84	24.92	20.92	1/73		7/77	10/15	1/78	10/15
Standard Sesnon 9	578 S	Active	West	GS, OG	18.90	28.37	-9.47	11/46		2/77	5/13	9/77	1/16
Standard Sesnon 29	739 W	Active	West	GS	24.74	28.27	-3.53	4/53		2/77	7/15	9/77	3/16
Standard Sesnon 5	853 SW	Active	West	OB	7.65	7.34	0.32	2/45		2/77	5/97	2/78	11/15
Sesnon Fee 3	1022 S	Active	West	GS	0.00	14.22	-14.22	11/53				7/77	6/15
Standard Sesnon 3	1027 S	Active	West	GS	7.54	4.91	2.63	11/44		11/77	5/96	7/77	3/16
Porter 25R	1049 NE	Active	West	GS	5.58	9.87	-4.29	10/93		7/77	10/15	12/77	4/16
Standard Sesnon 44	1049 SW	Active	*West*	OB	7.36	2.61	4.75	2/54		5/77	8/91	1/78	2/92
Standard Sesnon 44B	1051 SW	Active	West	GS, OG	12.83	23.33	-10.50	7/74		7/77	10/15	1/78	1/16
Standard Sesnon 44A	1054 SW	Active	West	GS, OG	7.90	15.44	-7.55	9/74		7/77	3/14	1/78	10/13
Standard Sesnon 1	1163 N	Idle	*West*	GS	3.20	0.96	2.24	12/41		5/77	9/79	10/77	4/80
Standard Sesnon 1-0	1179 N	Idle	*West*	GS, OG	0.00	0.61	-0.61	5/80				2/85	9/07
Porter 47	1280 SE	Idle	West	GS	8.04	30.50	-22.47	4/43		10/81	5/97	10/77	1/16
Porter 38	1324 SE	Active	West	GS, OG	5.26	21.63	-16.37	6/75		10/81	5/03	12/77	3/16
Standard Sesnon 8	1450 SW	Active	*West*	GS	10.93	18.04	-7.11	5/46		2/77	8/10	10/77	8/10
Standard Sesnon 31	1490 S	Active	West	GS	2.47	24.61	-22.15	8/53		7/81	8/09	8/77	3/16
Standard Sesnon 2	1498 W	Active	West	GS	14.75	23.65	-8.90	3/43		2/77	10/15	7/77	3/16
Standard Sesnon 11	1539 SW	Active	West	GS	7.10	22.48	-15.38	9/47		5/77	10/92	10/77	3/16
Porter Sesnon 42	1545 S	Active	West	GS	0.00	9.70	-9.70	9/54		4/83	4/83	10/77	11/15
Porter 39	1549 SE	Active	West	GS, OG	4.62	21.71	-17.09	6/47		10/81	5/03	11/77	10/15
Standard Sesnon 7	1787 W	P&A	*West*	GS, OG	12.47	6.61	5.86	10/45	9/14	2/77	9/12	9/77	10/12
Standard Sesnon 6	1853 W	Active	West	GS, OG	8.40	20.80	-12.40	6/45		2/77	10/15	9/77	1/16
Porter 69K	1856 E	Active	Central	GS	0.01	6.30	-6.29	1/02		4/04	10/15	8/03	1/16
Porter 69J	1891 E	Active	Central	GS	0.01	9.50	-9.49	12/01		4/04	10/15	8/02	4/16
Standard Sesnon 13	1894 S	Idle	West	GS	0.00	15.32	-15.32	10/48				3/78	8/15
Porter 69H	1925 E	Active	Central	GS	11.44	5.85	5.58	11/02		6/05	10/15	2/03	1/16
Standard Sesnon 17	1939 SW	Idle	West	GS	7.80	23.47	-15.67	6/51		5/77	2/93	8/77	1/16
Porter 69G	1955 E	Active	Central	GS	10.74	6.94	3.80	10/01		6/05	9/15	8/02	7/15
Porter 41	1977 SE	P&A	*West*	GS, OG	0.00	0.01	-0.01	11/48	12/87			12/77	1/81
Porter 69F	1987 E	Active	Central	GS	11.42	1.78	9.64	10/01		6/05	10/15	3/03	4/16
Porter 26A	2040 E	Active	Central	GS, OG	40.58	16.17	24.41	7/73		7/77	10/15	1/78	1/16
Porter 26B	2054 E	Active	Central	GS, OG	50.97	17.69	33.28	6/73		7/77	10/15	12/77	1/16
Porter 40	2054 SE	Active	West	GS	0.00	8.68	-8.68	5/48		5/03	5/03	7/77	3/16
Porter 69D	2057 E	Active	Central	GS, OG	13.63	11.40	2.22	3/92		8/94	10/15	12/92	1/16
Porter 26C	2069 E	Active	Central	GS	9.48	7.85	1.64	4/73		7/77	10/15	9/77	9/15
Porter 26	2082 E	Active	Central	GS	31.94	11.57	20.37	8/41		7/77	10/15	7/77	1/16
Porter 26D	2095 E	Active	Central	GS	52.98	16.06	36.92	12/72		7/77	10/15	7/77	1/16
Standard Sesnon 16	2105 S	Active	West	GS	0.00	25.52	-25.52	9/49				3/78	7/14
Porter 69E	2110 E	Active	Central	GS, OG	38.10	12.06	26.04	6/93		4/97	10/15	1/94	1/16

Well Name	Distance & Bearing to Incident Well (ft)	Status	Sector	Type	Total Gas Volume (Bscf) Injected	Withdrawn	Net Inj	Dates Spud	P&A	Injection Dates First	Last	Withdrawal Dates First	Last
Porter 26E	2114 E	Active	Central	GS	47.23	24.53	22.70	10/72		7/77	3/14	11/77	6/15
Porter 69C	2146 E	Active	Central	GS, OG	31.84	7.34	24.50	3/92		7/93	10/15	12/92	1/16
Porter 69B	2185 E	Active	Central	GS, OG	29.47	5.99	23.48	1/92		5/93	10/15	2/93	4/16
Porter 69A	2187 E	Active	Central	GS, OG	34.73	20.97	13.76	1/80		4/82	10/15	1/82	1/16
Standard Sesnon 30	2199 S	Active	West	GS	0.00	9.95	-9.95	8/53				7/77	6/15
Porter 46	2221 E	Active	Central	GS	11.04	33.90	-22.85	11/43		10/81	4/01	8/77	3/16
Standard Sesnon 4A	2305 W	Active	West	GS, OG	7.98	14.42	-6.44	11/74		7/77	4/15	10/77	1/16
Standard Sesnon 4	2343 W	Active	West	GS	10.40	7.28	3.12	7/44		2/77	4/15	1/78	3/16
Standard Sesnon 4-0	2344 W	Active	West	GS, OG	4.65	9.33	-4.67	8/80		4/87	11/14	11/82	1/16
Porter 44	2531 E	Active	Central	GS	6.51	38.74	-32.24	11/55		10/81	11/96	7/77	3/16
Standard Sesnon 10	2573 W	Active	West	GS	10.53	36.95	-26.42	4/47		5/77	6/00	9/77	1/16
Porter 43	2582 SE	P&A	*Central*	GS, OG	0.00	0.15	-0.15	11/53	7/87			10/77	2/80
Standard Sesnon 24	2593 SW	Idle	West	GS	7.65	22.21	-14.55	2/56		5/77	5/03	8/77	3/16
Standard Sesnon 14	2609 SW	Active	West	GS	0.00	10.78	-10.78	3/49				7/77	10/15
Sesnon Fee 1	2681 SW	Active	West	GS	0.00	14.89	-14.89	11/52				2/77	1/16
Porter 35	2765 SE	Active	Central	GS	1.27	10.06	-8.79	11/45		4/84	5/01	12/77	3/16
Frew 2	3166 W	Active	West	GS	5.97	14.36	-8.39	10/43		2/77	11/11	9/77	2/16
Porter 4	3213 E	P&A	*Central*	GS, OG	3.47	1.47	2.01	4/42	12/87	7/77	4/82	9/77	10/82
Standard Sesnon 12	3236 SW	Idle	*West*	GS	0.00	5.73	-5.73	2/48				6/77	6/15
Frew 7	3304 W	Active	West	GS, OG	7.22	22.83	-15.61	11/54		11/77	7/96	10/77	3/16
Frew 4	3316 W	Active	West	GS	8.91	40.51	-31.60	10/47		11/77	11/93	9/77	2/16
Porter 42C	3337 SE	Active	Central	GS, OG	49.61	27.57	22.05	2/79		8/80	10/15	12/79	1/16
Porter 24B	3376 E	Active	Central	GS, OG	25.42	6.74	18.68	7/93		3/95	4/15	1/94	4/16
Porter 24A	3385 E	Active	Central	GS, OG	26.57	9.15	17.42	8/93		4/94	10/15	1/94	1/16
Porter 42B	3391 SE	Active	Central	GS	43.23	34.30	8.93	12/78		6/80	10/15	12/79	8/15
Porter 42	3417 SE	P&A	*Central*	GS, OG	0.17	1.33	-1.16	5/49	6/89	10/81	5/82	7/77	3/82
Porter 42A	3460 SE	Active	Central	GS, OG	57.73	40.09	17.64	9/78		6/80	8/15	12/79	1/16
Porter 34	3515 SE	Active	Central	GS	3.64	21.78	-18.14	12/45		6/83	5/03	10/77	1/16
Sesnon Fee 8	3583 SW	Active	West	GS	0.00	1.61	-1.61	12/56				6/77	6/15
Frew 8	3635 W	Active	West	GS	0.00	10.97	-10.97	7/55				6/77	10/15
Frew 6	3758 SW	Idle	West	GS	0.00	13.57	-13.57	9/48				6/77	10/15
Frew 5	3864 W	Active	West	GS, OG	7.13	28.21	-21.09	5/48		11/77	5/03	10/77	3/16
Porter 68A	3986 E	Active	East	GS, OG	37.18	9.29	27.89	5/83		5/85	10/15	1/85	1/16
Frew 3	4024 W	P&A	*West*	GS, OG	7.75	18.49	-10.74	9/44	5/13	5/77	5/13	9/77	3/13
Porter 68B	4025 E	Active	East	GS, OG	4.11	0.61	3.50	5/93		6/94	10/15	1/94	1/16
Porter 36	4056 SE	Active	East	GS	0.43	14.84	-14.41	9/46		3/88	6/98	10/77	3/16
Porter 32	4162 E	Active	East	GS	25.57	29.98	-4.41	6/44		7/77	10/15	10/77	1/16
Porter 32A	4177 E	Active	East	GS, OG	45.28	23.59	21.68	8/72		10/77	10/15	11/77	1/16
Porter 32B	4196 E	Active	East	GS, OG	3.84	9.37	-5.53	9/72		10/77	10/15	10/77	1/16
Porter 32C	4218 E	Active	East	GS, OG	12.00	10.33	1.67	1/73		9/77	10/15	9/77	1/16

	Distance & Bearing to				Total Gas Volume (Bscf)			Dates		Injection Dates		Withdrawal Dates	
Well Name	Incident Well (ft)	Status	Sector	Type	Injected	Withdrawn	Net Inj	Spud	P&A	First	Last	First	Last
Porter 32D	4230 E	Active	East	GS	46.11	31.95	14.16	9/73		7/77	10/15	10/77	1/16
Porter 32E	4241 E	Active	East	GS, OG	34.12	19.05	15.08	8/73		9/77	10/15	1/78	1/16
Porter 32F	4253 E	Active	East	GS, OG	56.10	15.74	40.36	7/73		7/77	10/15	11/77	1/16
Porter 37-A	4497 SE	Active	East	GS, OG	15.40	36.00	-20.60	3/80		10/81	10/15	9/81	1/16
Porter 37	4565 SE	Active	East	GS	4.36	32.29	-27.93	6/46		8/82	10/15	10/77	1/16
Porter 72A	4659 E	Active	East	GS, OG	41.48	6.82	34.65	9/93		6/94	10/15	2/94	1/16
Porter 72B	4692 E	Active	East	GS, OG	31.41	16.28	15.13	9/93		9/95	10/15	2/94	1/16
Porter 45	4749 E	Active	East	GS	3.08	15.89	-12.81	3/55		5/82	11/94	7/77	1/16
Porter 12	4844 E	Active	East	GS, OG	0.88	4.03	-3.15	8/39		5/85	3/06	1/78	3/14
Frew 9	4875 W	P&A	*West*	GS	0.00	6.82	-6.82	11/54	Uknwn			6/77	4/09
Porter Fee 2	5029 SE	P&A	*East*	GS, OG	0.00	0.36	-0.36	7/46	6/89	7/88	7/88	2/77	7/88
Porter 50B	5036 E	Active	East	GS	0.00	2.27	-2.27	7/10		3/11	3/11	9/12	4/16
Porter 50C	5068 E	Active	East	GS	0.00	0.36	-0.36	6/14				1/16	1/16
Porter 50A	5119 E	Active	East	GS, OG	43.02	14.64	28.39	4/83		5/85	5/14	1/85	3/14
Porter Fee 3	5303 SE	P&A	*East*	GS, OG	0.00	0.01	-0.01	6/52	10/87			12/77	4/78
Ward 3A	5313 E	Active	East	GS, OG	2.97	3.22	-0.26	10/81		3/84	6/95	10/82	3/14
Porter Fee 1	5507 SE	P&A	*East*	GS, OG	0.00	4.48	-4.48	11/45	7/89	4/79	7/88	2/77	6/89
Porter 30	5635 E	Active	East	GS	19.39	29.60	-10.20	5/45		7/77	10/15	11/77	1/16
Fernando Fee 31	5855 SE	P&A	*East*	GS, OG	0.00	0.06	-0.06	5/45	6/89			11/85	1/89
Fernando Fee 35	5945 E	P&A	*East*	GS, OG	1.13	0.63	0.50	9/51	6/89	7/77	5/79	1/78	3/79
Fernando Fee 38A	6222 E	Active	East	GS	4.94	12.65	-7.71	10/01		7/03	10/15	7/02	1/16
Fernando Fee 38C	6225 E	Active	East	GS	3.91	11.37	-7.47	11/01		7/03	10/15	7/03	4/16
Fernando Fee 38B	6225 E	Active	East	GS	11.10	14.95	-3.84	10/01		7/03	10/15	2/03	4/16
Fernando Fee 35A	6452 E	Active	East	GS, OG	58.86	25.11	33.76	7/74		7/77	10/15	12/77	1/16
Fernando Fee 35B	6461 E	Active	East	GS, OG	46.68	34.75	11.92	8/74		7/77	10/15	10/77	1/16
Fernando Fee 35C	6521 SE	Active	East	GS, OG	32.16	21.62	10.54	9/72		7/77	10/15	1/78	1/16
Fernando Fee 35E	6544 SE	Active	East	GS, OG	47.41	27.19	20.22	11/72		12/77	10/15	11/77	1/16
Fernando Fee 35D	6545 SE	Active	East	GS, OG	38.68	24.72	13.96	4/74		7/77	9/15	12/78	12/13
Fernando Fee 32F	7230 E	Active	East	GS	35.77	10.25	25.51	9/72		12/77	10/15	8/77	1/16
Fernando Fee 32-A	7237 E	Active	East	GS	55.84	19.53	36.30	7/78		6/80	10/15	12/78	4/16
Fernando Fee 32E	7240 E	Active	*East*	GS	8.44	3.03	5.41	11/72		8/86	9/12	6/86	2/11
Fernando Fee 32	7270 E	Active	East	GS	40.54	23.17	17.37	6/48		9/77	10/15	9/77	2/16
Fernando Fee 32D	7290 E	Active	East	GS, OG	25.26	9.00	16.26	4/73		7/77	7/14	1/78	1/16
Mission Adrian 1A	7294 SE	Idle	East	GS, OG	6.18	14.08	-7.90	10/79		9/81	7/07	1/81	1/16
Fernando Fee 32C	7303 E	Active	East	GS, OG	57.21	24.01	33.20	5/73		7/77	10/15	1/78	4/16
Fernando Fee 32B	7317 E	Active	East	GS, OG	29.55	13.20	16.36	6/73		9/77	10/15	11/77	1/16
Mission Adrian 1B	7417 SE	Idle	East	GS	9.29	26.41	-17.13	6/79		8/81	5/95	2/81	1/16
Fernando Fee 33	7663 SE	Active	East	GS	1.29	46.74	-45.44	3/49		4/83	7/94	2/82	3/16
Mission Adrian 4	7876 SE	Idle	*East*	GS	0.00	2.30	-2.30	12/51		10/90	10/90	12/86	9/05
Mission Adrian 5	7876 SE	P&A	*East*	GS, OG	0.00	0.17	-0.17	2/52	11/87			11/77	10/85

Well Name	Distance & Bearing to Incident Well (ft)	Status	Sector	Type	Total Gas Volume (Bscf) Injected	Withdrawn	Net Inj	Dates Spud	P&A	Injection Dates First	Last	Withdrawal Dates First	Last
Mission Adrian 3	8010 SE	Idle	East	GS	0.00	1.72	-1.72	12/50		8/89	10/92	12/78	3/16
Fernando Fee 34BR	8098 SE	Idle	East	GS	0.08	7.45	-7.37	12/80		6/94	8/97	11/82	1/16
Fernando Fee 34-A	8200 SE	Active	East	GS	5.81	26.16	-20.35	10/79		10/81	8/95	1/82	1/16
Mission Adrian 5-A	8300 SE	P&A	*East*	GS	2.05	8.36	-6.31	12/81	Uknwn	7/83	5/95	11/82	5/13
The following are oil & gas producing wells producing from the gas storage zone.													
Sesnon Fee 2	2989 S	Idle	*West*	OG	0.00	0.97	-0.97	4/53				2/77	5/06
Sesnon Fee 5	3019 S	Idle	*West*	OG	0.00	0.65	-0.65	4/54				10/77	4/16
Sesnon Fee 7	3333 SW	Idle	*West*	OG	0.00	6.88	-6.88	9/55				6/77	12/06
Sesnon Fee 4	3500 SW	Idle	*West*	OG	0.00	6.46	-6.46	2/54				6/77	7/13
Del Aliso 11	3947 W	Active	*West*	OG	0.00	0.13	-0.13	9/09				11/09	4/16
Sesnon Fee 6	3957 SW	Idle	*West*	OG	0.00	1.47	-1.47	7/54				10/77	7/04

Italics indicate values that were inferred from field facility schematic diagrams.

P&A: Plugged and abandoned

GS: Gas Storage Well

OB: Observation Well

OG: Producing well

Uknwn: Unknown

Appendix B Conventional Well List

This section lists the conventional wells in order of increasing distance from the SS-25 incident well.

Well Name	Distance & Bearing to Incident Well (ft)	Field	Operator	Status	Type	Total Volumes Oil (Mstb)	Gas (MMscf)	Water (Mstb)	Watercut	GOR (scf/stb)	Dates Spud	P&A	First Production	Last Production
ALISO CANYON FIELD														
Standard-Sesnon 1 19	544 S	Aliso Canyon	Crimson	Idle	OG	0.0	0.6	11.1	100%	24077	12/51		9/78	11/78
Standard-Sesnon 1 45	586 S	Aliso Canyon	Crimson	Idle	OG	68.9	32.5	816.1	92%	472	11/66		before 1/77	12/99
Porter 71	793 E	Aliso Canyon	SCG	Idle	OG	81.8	65.1	1758.1	96%	796	10/66		before 1/77	6/03
Standard-Sesnon 1 46	803 W	Aliso Canyon	Crimson	Active	OG	41.6	33.8	734.1	95%	814	9/66		before 1/77	3/15
Standard Sesnon 5	853 SW	Aliso Canyon	SCG	Active	OB		1.6				2/45		10/99	10/99
Standard-Sesnon 1 39	936 N	Aliso Canyon	Crimson	P&A	OG	3.4	19.0	53.4	94%	5669	7/54	10/94	before 1/77	6/82
Porter 60	1072 E	Aliso Canyon	SCG	Idle	OG	43.2	56.0	1572.9	97%	1298	3/52		before 1/77	1/00
Porter-Sesnon 20	1167 N	Aliso Canyon	SCG	P&A	OG			60.1	100%		8/48	1/95	8/80	7/86
Standard-Sesnon 1 26	1213 NW	Aliso Canyon	Crimson	Idle	OG	29.2	37.3	172.0	85%	1280	4/53		before 1/77	8/09
Standard-Sesnon 1 15P	1225 NW	Aliso Canyon	Crimson	P&A	OG	27.5	29.7	967.0	97%	1079	5/49	9/94	before 1/77	9/88
Standard-Sesnon 1 33	1288 NW	Aliso Canyon	Crimson	Active	OG	73.7	111.2	636.8	90%	1509	10/53		before 1/77	6/16
Standard-Sesnon 1 35	1297 NW	Aliso Canyon	Crimson	Idle	OG	16.4	23.6	121.1	88%	1437	5/58		before 1/77	7/86
Porter 70	1375 E	Aliso Canyon	SCG	Active	OG	57.2	61.8	756.4	93%	1082	8/66		before 1/77	7/15
Porter 54	1465 E	Aliso Canyon	SCG	Active	OG	188.5	408.1	7429.6	98%	2165	7/51		before 1/77	7/16
Standard-Sesnon 1 28	1504 N	Aliso Canyon	Crimson	Idle	OG	17.6	22.3	287.3	94%	1266	12/53		before 1/77	7/86
Porter 19	1505 NE	Aliso Canyon	SCG	Idle	WF	37.6	29.8	816.8	96%	792	11/47		before 1/77	1/99
Standard-Sesnon 1 27	1517 N	Aliso Canyon	Crimson	Idle	OG	42.6	28.6	814.6	95%	672	6/53		before 1/77	5/07
Porter 66	1605 NE	Aliso Canyon	SCG	Active	OG	245.1	515.1	1737.1	88%	2101	3/52		before 1/77	10/15
Standard-Sesnon 1 21	1829 NW	Aliso Canyon	Crimson	Active	OG	358.6	295.7	1384.9	79%	825	1/53		before 1/77	6/16
Porter 65	1846 NE	Aliso Canyon	SCG	Active	OG	301.7	210.6	1075.7	78%	698	9/54		before 1/77	7/16
Porter 27	2019 E	Aliso Canyon	SCG	Active	OG	55.2	76.4	117.6	68%	1384	3/50		before 1/77	7/16
Porter 18	2081 NE	Aliso Canyon	SCG	Active	OG	149.6	131.0	1500.1	91%	876	10/43		before 1/77	6/15
Standard-Sesnon 1 23	2084 NW	Aliso Canyon	Crimson	Active	OG	105.9	106.9	856.0	89%	1009	10/52		before 1/77	6/16
Standard-Sesnon 1 34	2154 NW	Aliso Canyon	Crimson	Idle	OG	43.4	51.9	1704.0	98%	1195	12/56		before 1/77	5/87
Porter 63	2217 NE	Aliso Canyon	SCG	Active	OG	105.5	470.5	100.6	49%	4459	4/53		before 1/77	7/16
Porter 69	2298 E	Aliso Canyon	SCG	Active	OG	107.8	160.1	1382.0	93%	1486	6/66		before 1/77	7/16
Standard-Sesnon 1 32	2435 NW	Aliso Canyon	Crimson	P&A	OG	23.1	31.4	156.0	87%	1359	9/56	8/95	before 1/77	5/87
Standard-Sesnon 1 18	2613 NW	Aliso Canyon	Crimson	P&A	OG	33.9	75.0	3213.4	99%	2212	2/51	6/95	before 1/77	7/86
Standard-Sesnon 1 40	2618 NW	Aliso Canyon	Crimson	P&A	OG	24.2	26.7	105.4	81%	1100	8/54	8/95	before 1/77	5/87
Porter 17	2703 E	Aliso Canyon	SCG	Active	OG	27.8	27.3	927.3	97%	982	9/40		before 1/77	7/16
Porter 28	2705 E	Aliso Canyon	SCG	Idle	OG	16.9	20.4	50.1	75%	1206	7/50		before 1/77	9/07
Porter 16	2713 E	Aliso Canyon	SCG	P&A	OG	5.0	4.6	168.0	97%	926	9/40	8/81	before 1/77	2/80
Orcutt-Del Aliso-Sesnon L.W. 1	2778 W	Aliso Canyon	Chevron[1]	P&A	OG	14.7	23.9	71.2	83%	1620	11/54	4/90	before 1/77	7/84
Porter 6	2782 NE	Aliso Canyon	SCG	Active	OG	77.9	43.9	244.9	76%	563	6/80		10/80	11/15
Orcutt-Sesnon L.W. 1	2979 NW	Aliso Canyon	Chevron[1]	P&A	OG	9.5	10.4	337.7	97%	1093	4/59	4/90	before 1/77	10/84
Porter 61	3008 E	Aliso Canyon	SCG	Active	OG	131.0	81.6	2007.0	94%	623	12/52		before 1/77	3/16
Orcutt 1	3024 N	Aliso Canyon	H&S[1]	P&A	OG	272.1	318.8	528.3	66%	1172	5/61	7/61	before 1/77	7/16
Porter 52	3029 E	Aliso Canyon	SCG	Active	WF	19.1	10.0	491.7	96%	526	5/51		before 1/77	6/87
Del Aliso 1 9	3080 NW	Aliso Canyon	Termo	Idle	OG	120.6	103.2	323.4	73%	855	8/59		before 1/77	11/12
Del Aliso 1 5	3168 NW	Aliso Canyon	Termo	Idle	OG	95.4	200.5	201.8	68%	2103	12/69		before 1/77	8/09

						Total Volumes					Dates			
Well Name	Distance & Bearing to Incident Well (ft)	Field	Operator	Status	Type	Oil (Mstb)	Gas (MMscf)	Water (Mstb)	Watercut	GOR (scf/stb)	Spud	P&A	First Production	Last Production
Del Aliso 1 6A	3169 W	Aliso Canyon	Termo	Idle	WD	54.4	127.9	231.7	81%	2352	8/50		before 1/77	11/12
Del Aliso 1 4	3248 W	Aliso Canyon	Termo	Idle	OG	72.6	100.2	507.5	87%	1379	5/49		before 1/77	3/93
Porter 57	3325 E	Aliso Canyon	SCG	Idle	OG	17.4	9.7	112.4	87%	560	8/51		before 1/77	2/05
Porter 15	3584 E	Aliso Canyon	SCG	Idle	OG	41.1	39.3	2266.3	98%	955	4/40		before 1/77	7/10
Porter 3	3827 E	Aliso Canyon	SCG	Active	OG	35.9	64.2	827.5	96%	1789	11/39		before 1/77	1/16
Del Aliso 1 10	3839 NW	Aliso Canyon	Termo	Idle	OG	18.2	55.8	29.9	62%	3068	5/60		before 1/77	6/87
Del Aliso 1 7A	3930 NW	Aliso Canyon	Termo	Active	OG	14.6	7.8	70.6	83%	534	2/51		12/08	7/16
Del Aliso 1 2	3960 W	Aliso Canyon	Termo	P&A	OG	39.9	144.6	199.6	83%	3620	2/48	7/09	before 1/77	3/08
Porter 14	3993 E	Aliso Canyon	SCG	Active	OB	36.9	21.6	933.0	96%	587	5/40		before 1/77	2/82
Porter 58	4024 E	Aliso Canyon	SCG	Active	OB		0.1				11/51		6/87	6/87
Porter 13	4073 E	Aliso Canyon	SCG	P&A	OG	34.4	29.8	968.3	97%	866	2/40	11/94	before 1/77	6/87
Porter 68	4107 E	Aliso Canyon	SCG	Active	OG	97.5	39.3	1244.8	93%	403	5/66		before 1/77	7/16
Porter 53	4249 E	Aliso Canyon	SCG	Active	WF	12.4	10.0	1177.4	99%	810	4/51		before 1/77	6/87
Porter 12A	4279 E	Aliso Canyon	SCG	P&A	OG	1.8	4.6	52.0	97%	2580	8/80	7/93	10/80	6/87
Porter 72	4314 E	Aliso Canyon	SCG	P&A	OG	42.0	127.0	487.1	92%	3028	10/66	7/93	before 1/77	6/87
Del Aliso 1 8B	4366 NW	Aliso Canyon	Termo	Active	OG	124.1	219.2	400.7	76%	1766	11/56		before 1/77	7/16
Porter 59	4376 E	Aliso Canyon	SCG	P&A	OG	4.5	4.0	162.6	97%	892	7/52	8/93	before 1/77	6/87
Porter 2	4392 E	Aliso Canyon	SCG	Active	OG	190.2	218.0	2033.0	91%	1147	1/39		before 1/77	7/15
Porter 10	4423 E	Aliso Canyon	SCG	Active	OG	227.5	137.3	2521.9	92%	603	10/77		9/78	7/16
Porter 22	4623 E	Aliso Canyon	SCG	Idle	DG		496.2				4/40		9/96	2/07
Roosa 1	4691 NW	Aliso Canyon	Termo	Active	OG	82.1	90.8	60.8	43%	1106	12/43		before 1/77	7/16
Porter 1	5014 E	Aliso Canyon	SCG	Active	OG	210.1	163.1	1981.6	90%	777	6/38		before 1/77	7/16
Porter 11	5287 E	Aliso Canyon	SCG	P&A	OG	36.1	6.8	747.6	95%	189	5/39	11/98	before 1/77	6/87
Ward 3	5313 E	Aliso Canyon	SCG	Active	OB	0.1	1.7	0.0	36%	22429	3/54		before 1/77	7/16
Fernando Fee 11	5707 E	Aliso Canyon	SCG	Active	OG	176.8	49.9	3325.0	95%	282	8/39		before 1/77	11/15
Fernando Fee 38	5945 E	Aliso Canyon	SCG	Active	OG	197.0	53.7	3087.6	94%	272	10/66		before 1/77	7/16
Roosa 4	5978 NW	Aliso Canyon	Termo	Active	OG	188.1	145.6	64.3	25%	774	11/09		3/10	7/16
Roosa 2	5981 NW	Aliso Canyon	Termo	Active	OG	176.0	89.4	309.0	64%	508	4/60		before 1/77	7/16
Roosa 3	5992 NW	Aliso Canyon	Termo	Active	OG	152.5	81.5	53.5	26%	535	5/07		9/07	7/16
Fernando Fee 1	6031 E	Aliso Canyon	SCG	Active	OG	237.1	56.0	3619.3	94%	236	7/42		before 1/77	9/14
Mission Adrian 4	7876 SE	Aliso Canyon	SCG	Idle	GS	0.0	0.8		0%	847000	12/51		7/06	7/06
			Aliso Canyon Field Totals			**5594.1**	**6553.2**	**63166.7**	**92%**	**1171**				

Well Name	Distance & Bearing to Incident Well (ft)	Field	Operator	Status	Type	Total Volumes Oil (Mstb)	Gas (MMscf)	Water (Mstb)	Watercut	GOR (scf/stb)	Dates Spud	P&A	First Production	Last Production
OAT MOUNTAIN FIELD														
Gardett 2-20	8852 NW	Oat Mountain	Termo	Active	OG	257.9	75.9	289.2	53%	294	4/91		5/91	7/16
Gardett 1-20	8971 NW	Oat Mountain	Termo	P&A	OG	75.7	33.6	215.8	74%	444	12/74	3/91	1/77	8/90
Del Aliso 1-4	9581 NW	Oat Mountain	Termo	Active	OG	155.0	91.8	253.6	62%	592	3/07		7/07	7/16
Del Aliso 1-3	9606 NW	Oat Mountain	Termo	Active	OG	591.0	235.3	97.9	14%	398	7/76		1/77	7/16
Del Aliso 1-1	10156 NW	Oat Mountain	Termo	Active	OG	287.7	64.8	382.7	57%	225	9/52		1/77	7/16
Del Aliso 1-2	10551 NW	Oat Mountain	Termo	Active	OG, WD	209.3	51.1	203.6	49%	244	1/56		1/77	7/16
Oat Mountain 3-19	12188 NW	Oat Mountain	Termo	Active	OG	171.6	127.9	538.0	76%	746	5/80		8/80	7/16
Oat Mountain 5-19	13087 NW	Oat Mountain	Termo	Active	OG	449.4	295.9	894.4	67%	658	3/81		8/81	7/16
Oat Mountain 1-24	14141 W	Oat Mountain	Termo	Active	OG	308.0	226.9	756.2	71%	737	8/79		11/79	7/16
Oat Mountain 2-24	16271 NW	Oat Mountain	Termo	Active	OG	68.2	42.9	216.5	76%	629	3/80		5/80	5/16
Oat Mountain 4-24	16302 NW	Oat Mountain	Termo	Active	OG	118.3	73.4	64.3	35%	620	8/80		10/80	5/16
					Oat Mountain Field Totals	**2692.0**	**1319.6**	**3912.1**	**59%**	**490**				
					TOTALS	**8286.1**	**7872.8**	**67078.8**	**89%**	**950**				

[1] Former/inactive operator

DG Producing well - dry gas
GS Gas storage well
OB Observation well
OG Producing well - oil & gas
WD Water disposal injection well
WF Water flood injection well

Appendix C Water Injection Well List

This section lists the water injection wells in order of increasing distance from the SS-25 incident well.

Well Name	Distance & Bearing to Incident Well (ft)	Operator	Status	Type	Water Injected MMstb	Water Injected % of Total	Dates Spud	Dates P&A	Dates First Injection	Dates Last Injection
ALISO CANYON FIELD										
Porter 19	1505 NE	SCG	Idle	WF	0.020	0.0%	11/47		8/00	5/04
Porter 73*	2649 E	SCG	Active	WF	3.927	5.1%	9/68		before 1/77	7/16
Porter 52*	3029 E	SCG	Active	WF	2.208	2.9%	5/51		4/97	7/16
Porter 24*	3410 E	SCG	Active	WF	6.577	8.6%	9/40		before 1/77	7/16
Porter 23*	4008 E	SCG	Active	WF	4.698	6.2%	11/40		before 1/77	7/16
Porter 53*	4249 E	SCG	Active	WF	7.461	9.8%	4/51		3/97	7/16
Porter 22	4623 E	SCG	Idle	DG	2.606	3.4%	4/40		before 1/77	6/92
Porter 50*	5128 E	SCG	Active	WF	6.039	7.9%	12/50		before 1/77	12/14
Fernando Fee 37**	5638 E	SCG	Active	WD	25.647	33.6%	9/66		before 1/77	5/16
Fernando Fee 30	6548 SE	SCG	Idle	WD	0.001	0.0%	8/54		12/98	12/98
Fernando Fee 36**	7227 E	SCG	Active	WD	17.047	22.3%	9/65		before 1/77	7/16
			Aliso Canyon Field Total		**76.231**	**99.8%**				
OAT MOUNTAIN FIELD										
Del Aliso 1-2	10551 NW	Termo	Active	OG, WD	0.151	0.2%	1/56		before 1/77	12/84
			Oat Mountain Field Total		**0.151**	**0.2%**				
				TOTALS	**76.383**					

* Designated as "Water Flood Well" by SCG according to data provided by SCG in January 2017.

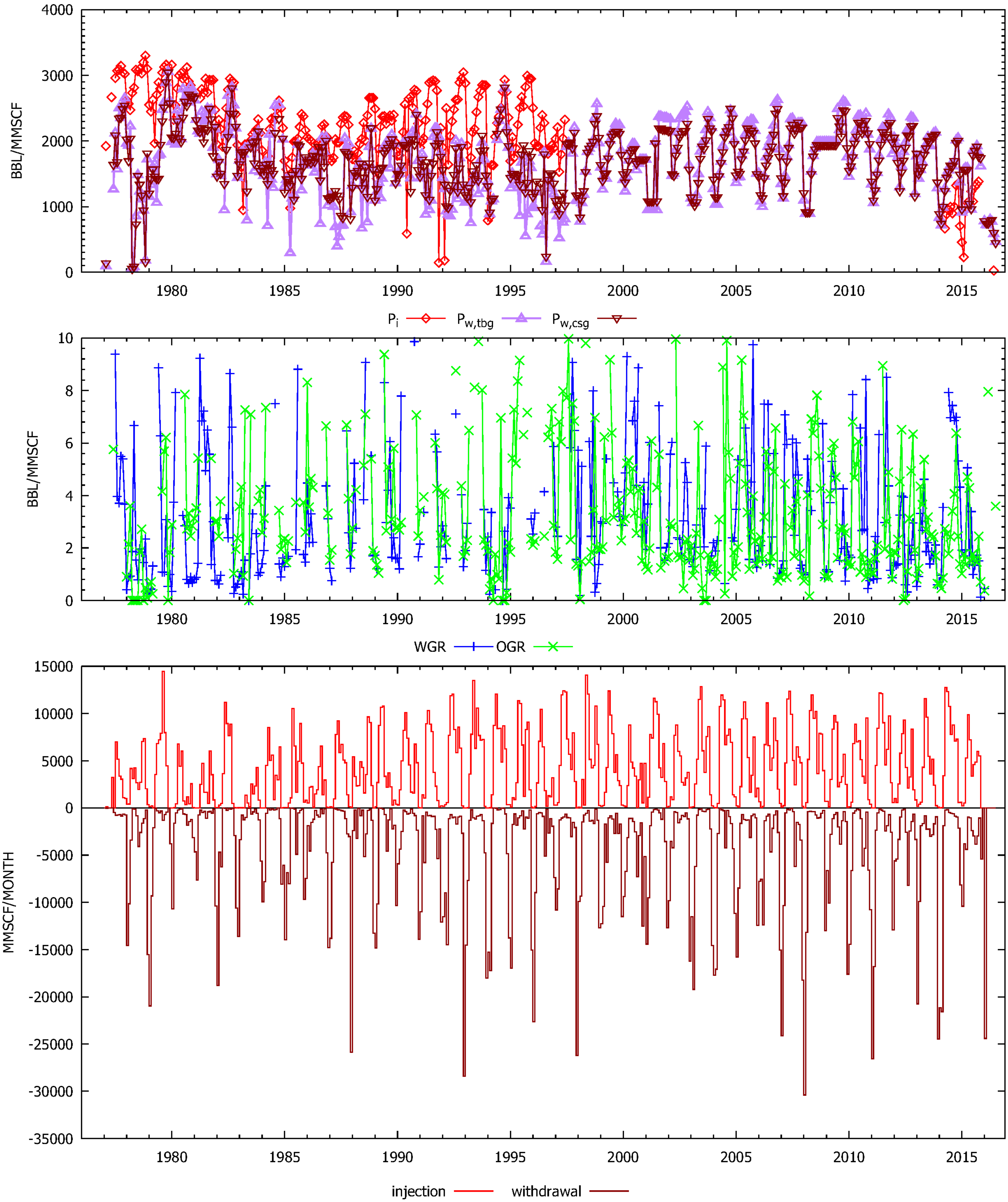
**Designated as "Water Disposal Well" by SCG according to data provided by SCG in January 2017.

Appendix D Gas Storage Field, Sector, and Well Plots

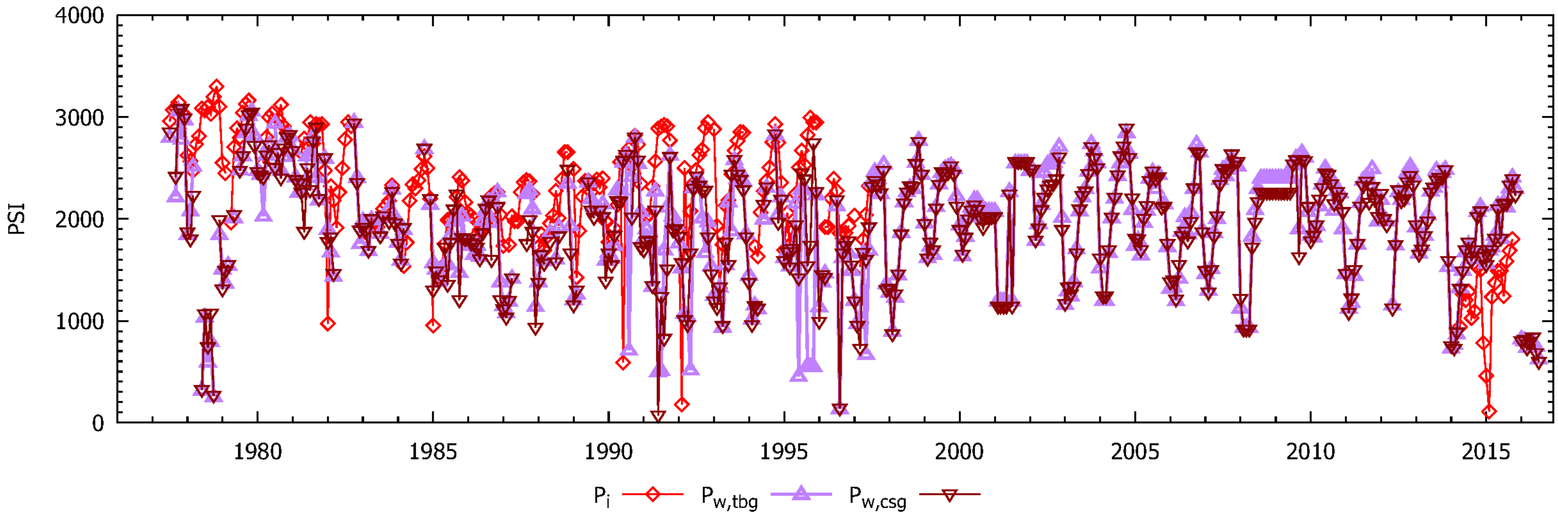
This section shows plots of historical injection and withdrawal data for:

- Aliso Canyon field.
- East, central, and west sectors.
- Individual wells.

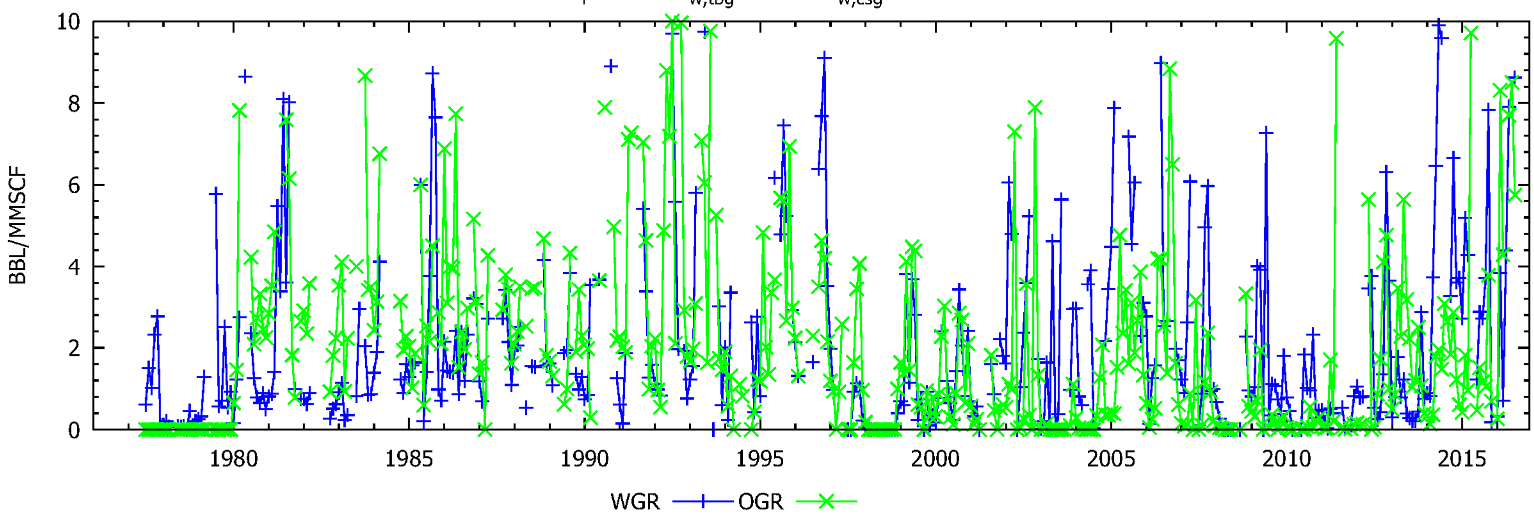
ENTIRE FIELD



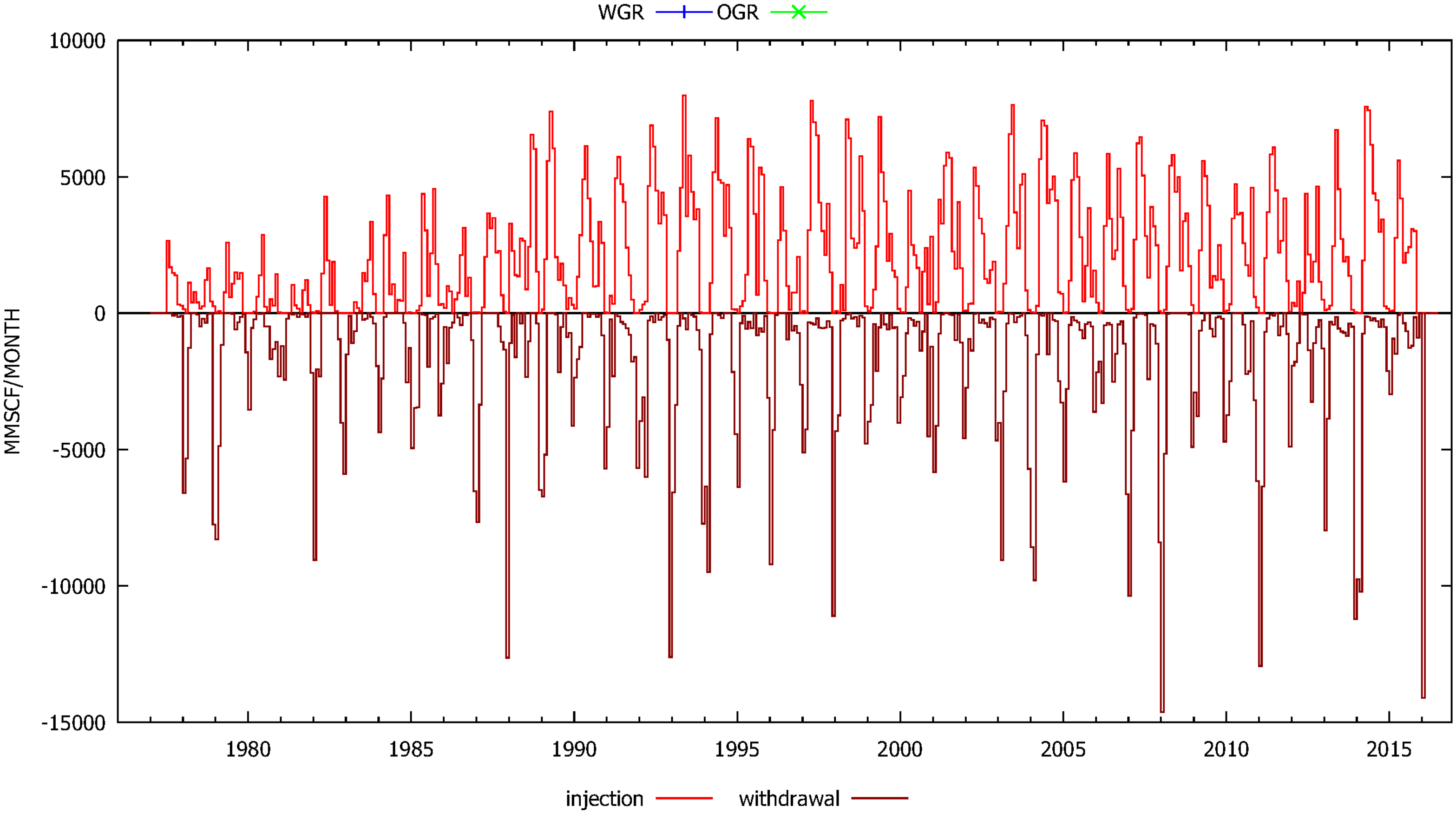
EAST SECTOR



PSI
4000
3000
2000
1000
0
1980
1985
1990
1995
2000
2005
2010
2015
P_i
$P_{w,tbg}$
$P_{w,csg}$

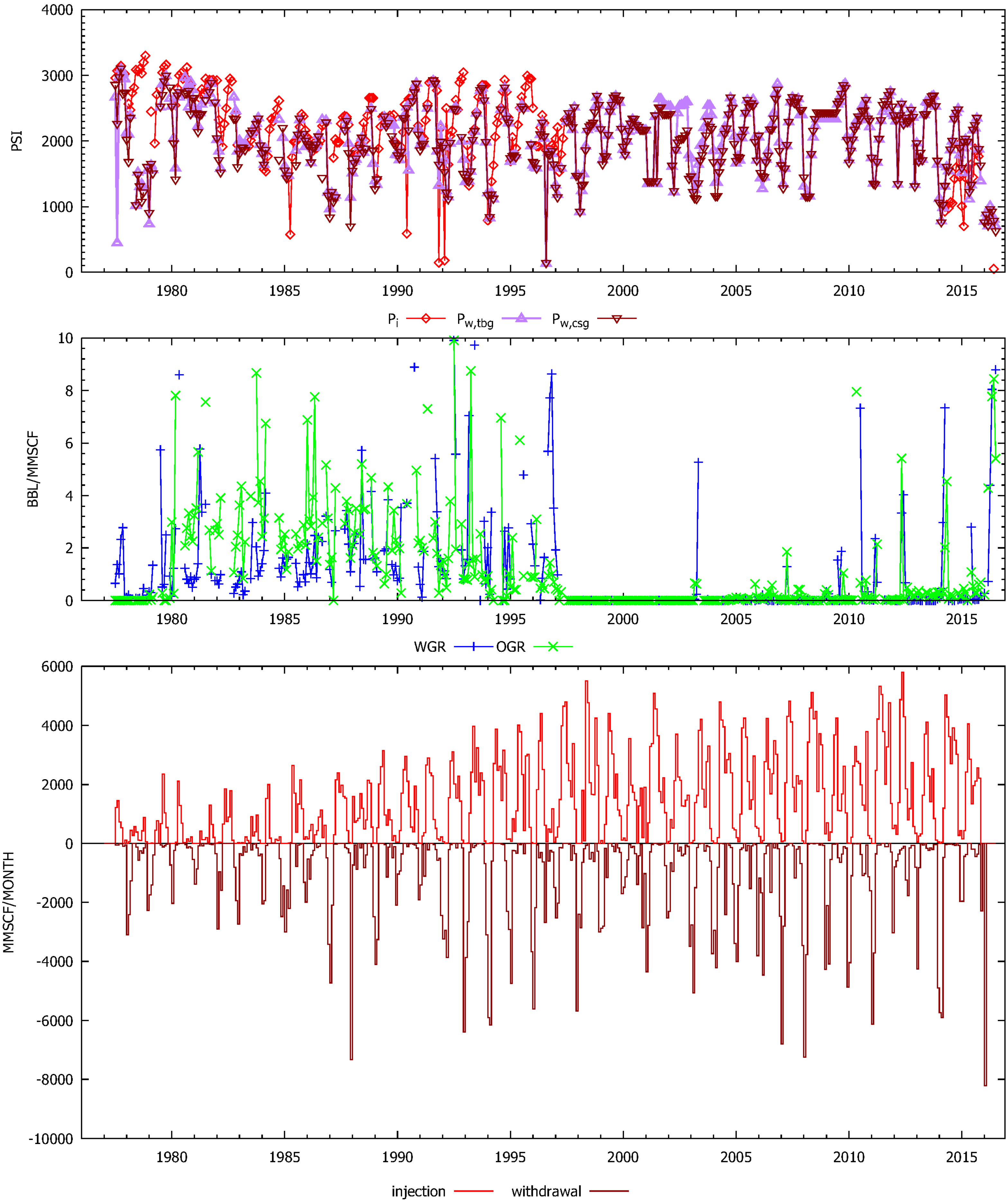


BBL/MMSCF
10
8
6
4
2
0
1980
1985
1990
1995
2000
2005
2010
2015
WGR
OGR

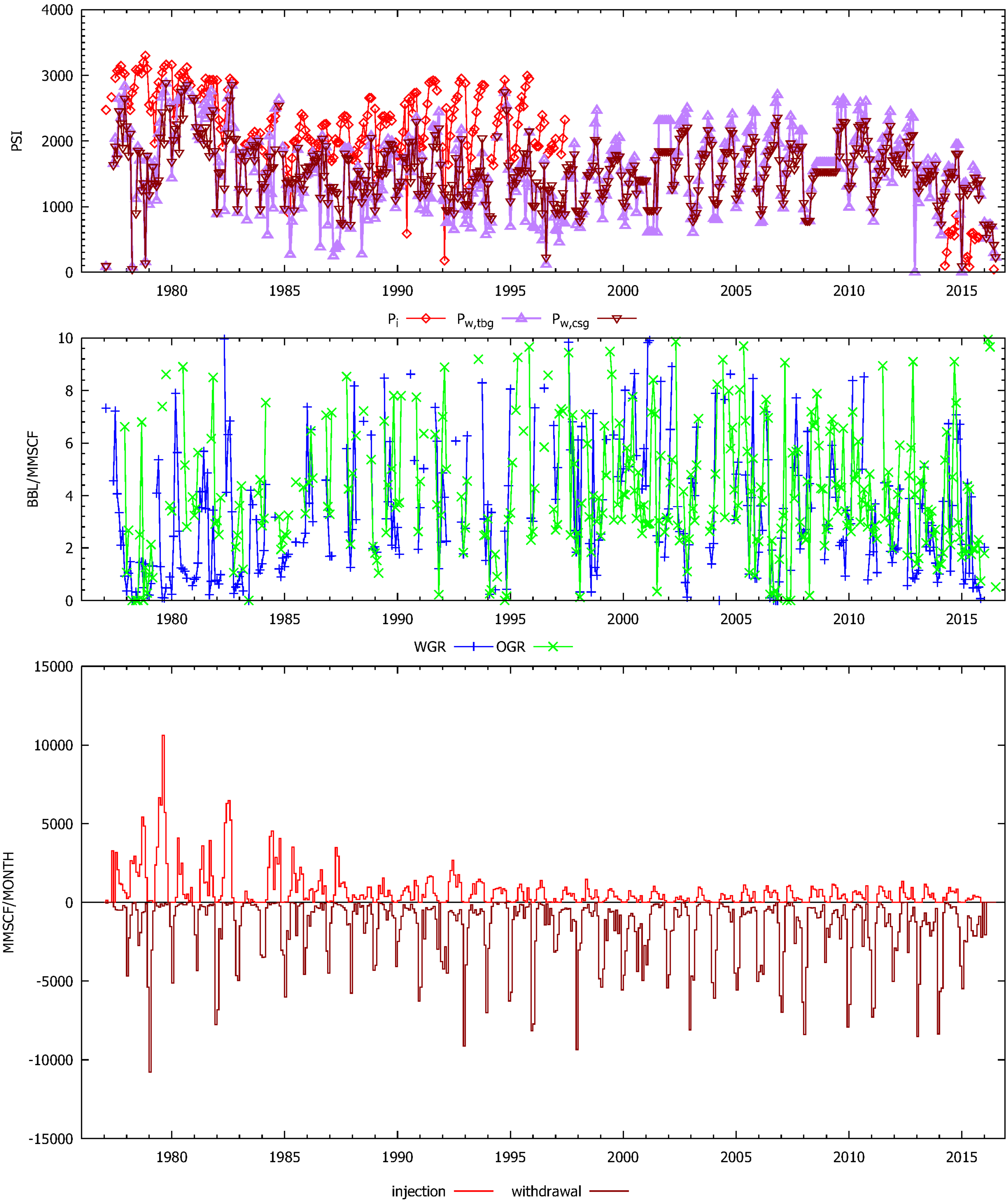


MMSCF/MONTH
10000
5000
0
-5000
-10000
-15000
1980
1985
1990
1995
2000
2005
2010
2015
injection
withdrawal

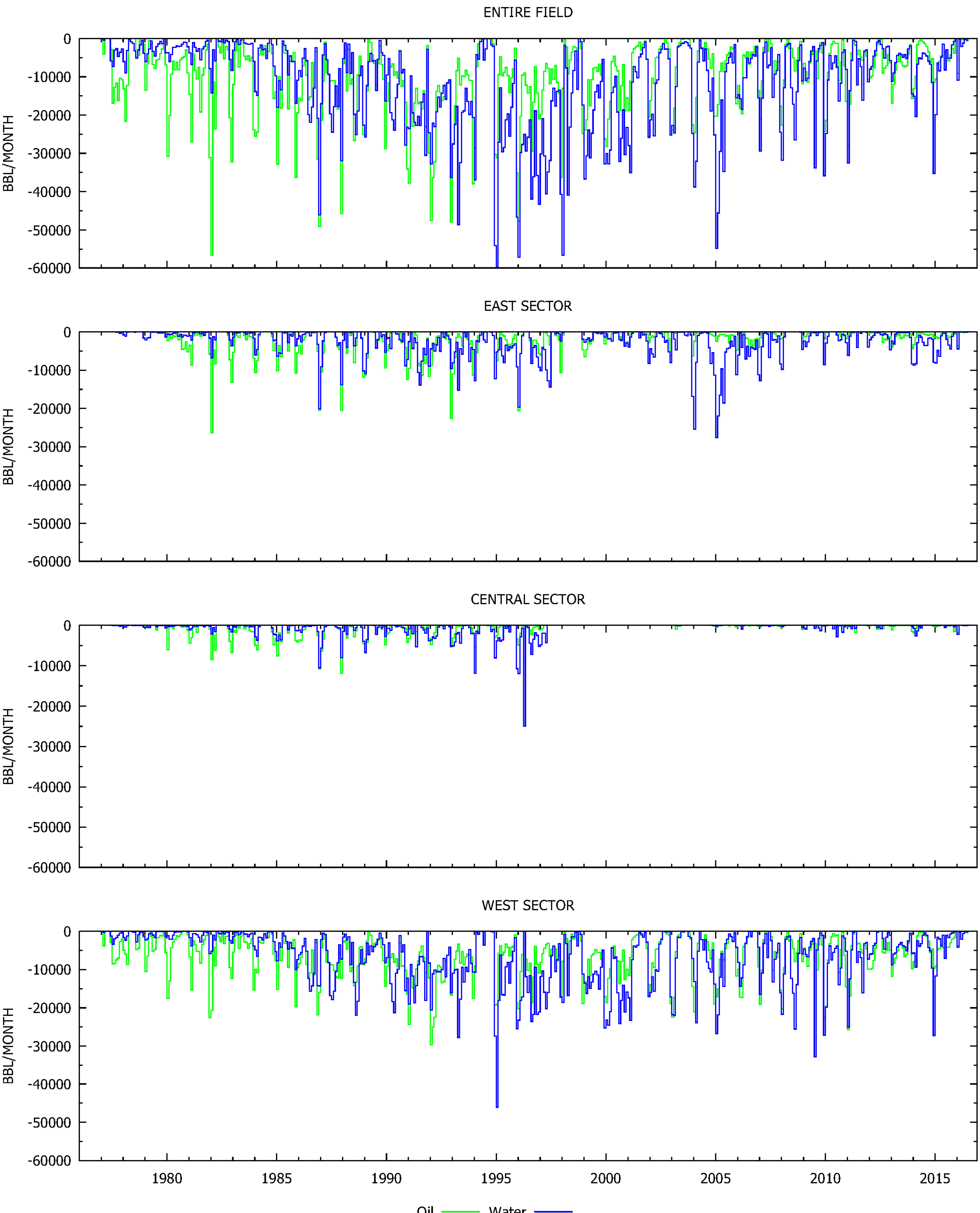
CENTRAL SECTOR

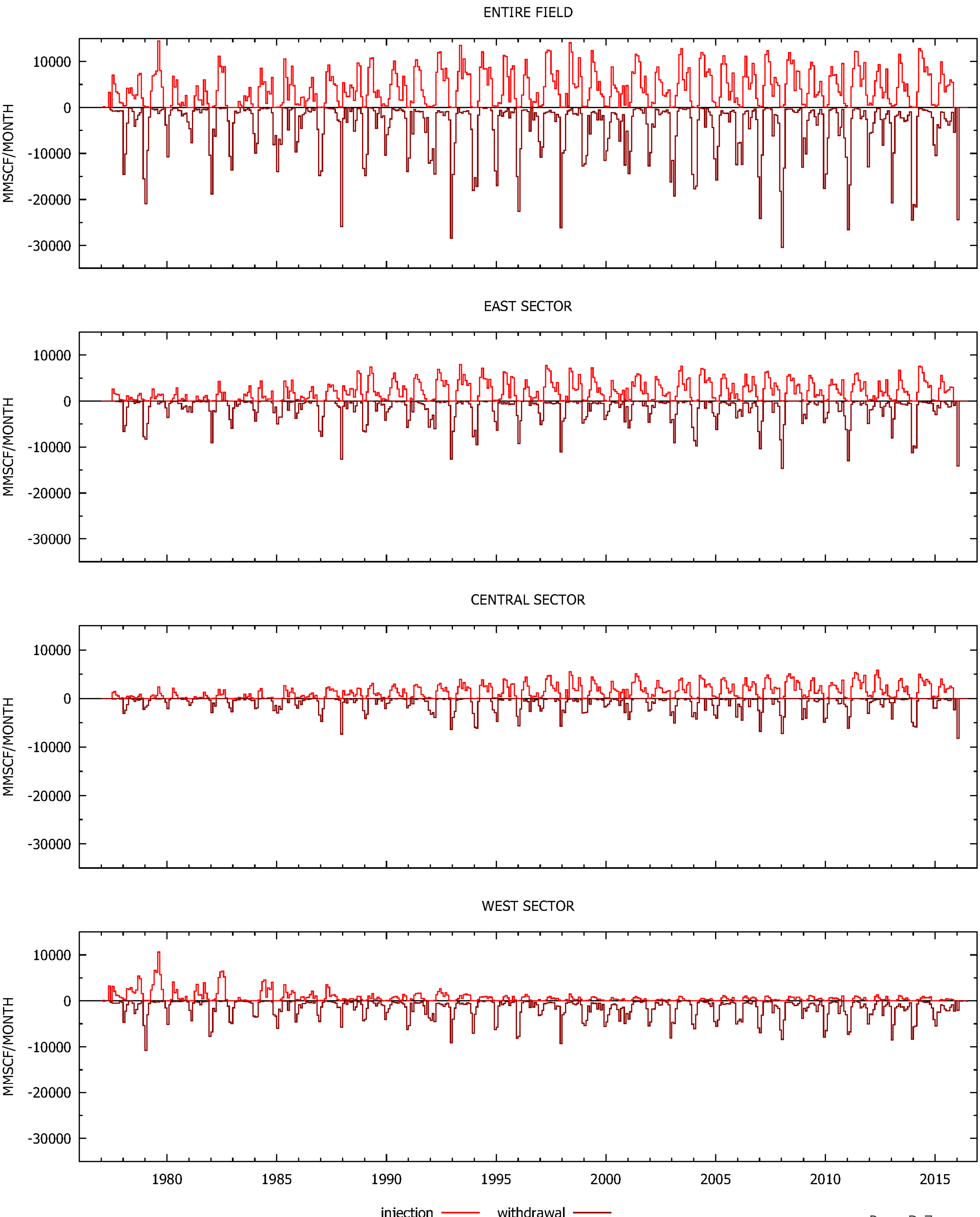


WEST SECTOR



PSI
4000
3000
2000
1000
0
1980
1985
1990
1995
2000
2005
2010
2015
P_i
$P_{w,tbg}$
$P_{w,csg}$
BBL/MMSCF
10
8
6
4
2
0
WGR
OGR
MMSCF/MONTH
15000
10000
5000
0
-5000
-10000
-15000
injection
withdrawal


ENTIRE FIELD
EAST SECTOR
CENTRAL SECTOR
WEST SECTOR
BBL/MONTH
0
-10000
-20000
-30000
-40000
-50000
-60000
1980
1985
1990
1995
2000
2005
2010
2015
Oil
Water


ENTIRE FIELD
EAST SECTOR
CENTRAL SECTOR
WEST SECTOR
MMSCF/MONTH
10000
0
-10000
-20000
-30000
1980
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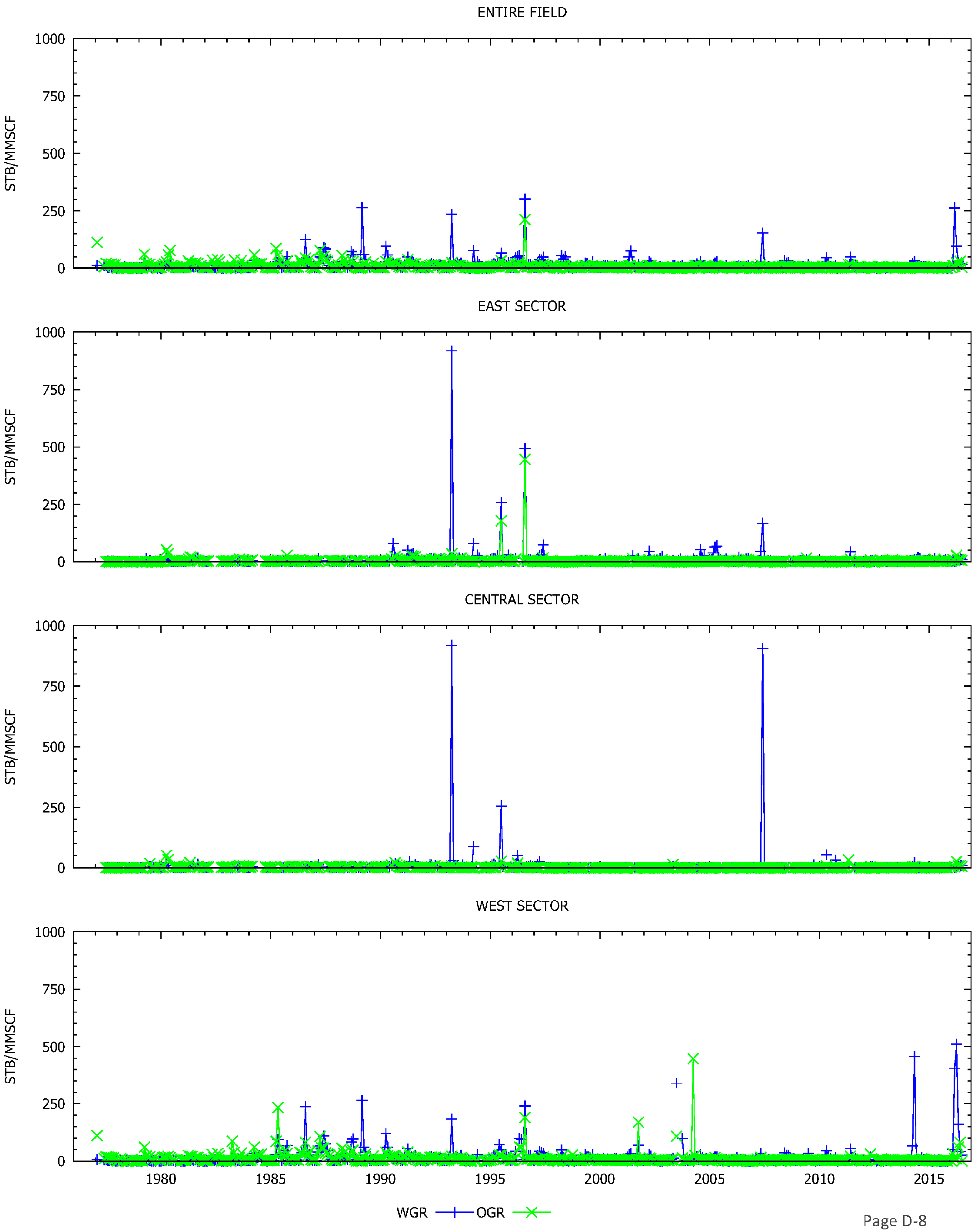
2005
2010
2015
injection
withdrawal


ENTIRE FIELD
EAST SECTOR
CENTRAL SECTOR
WEST SECTOR
STB/MMSCF
1000
750
500
250
0
1980
1985
1990
1995
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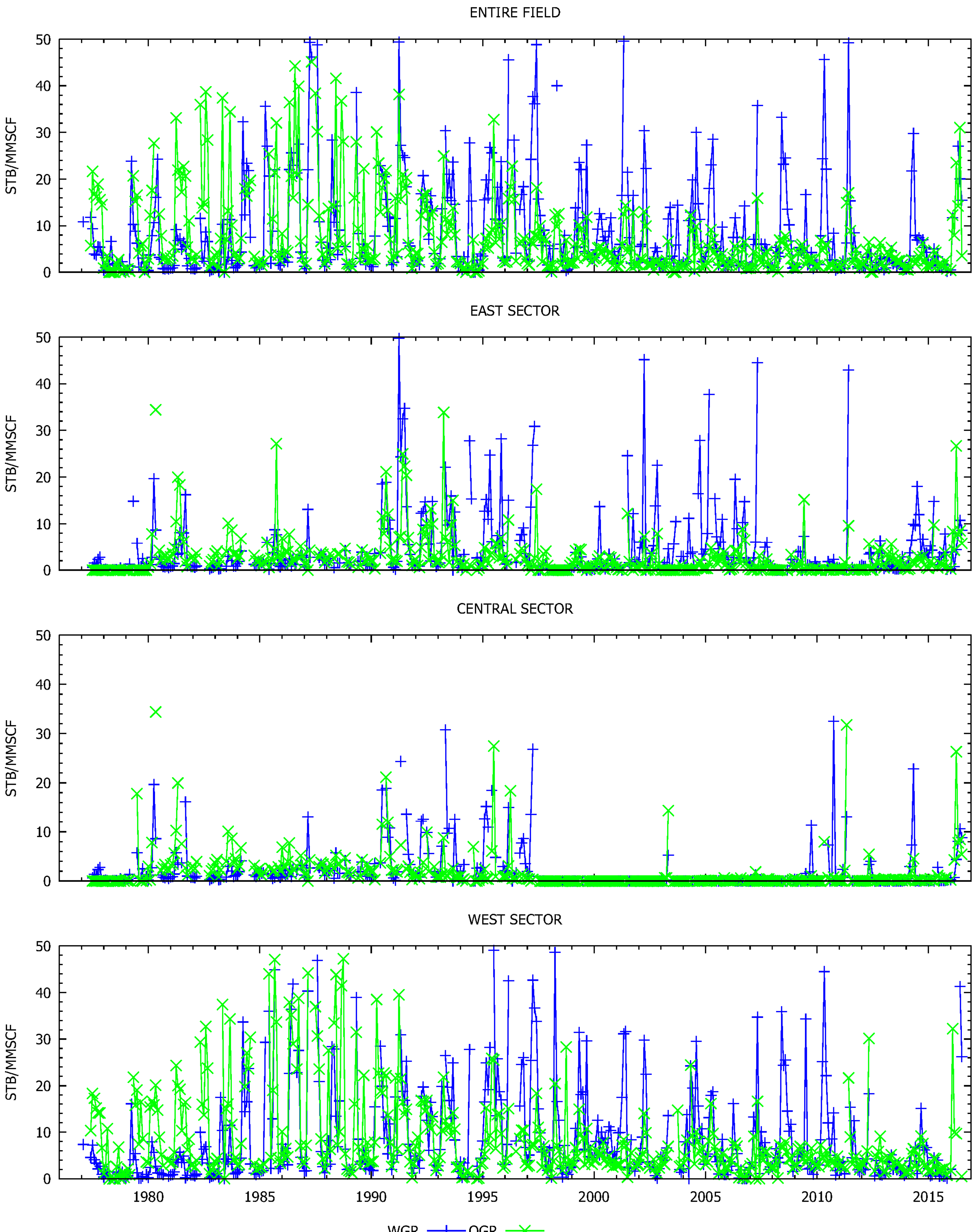
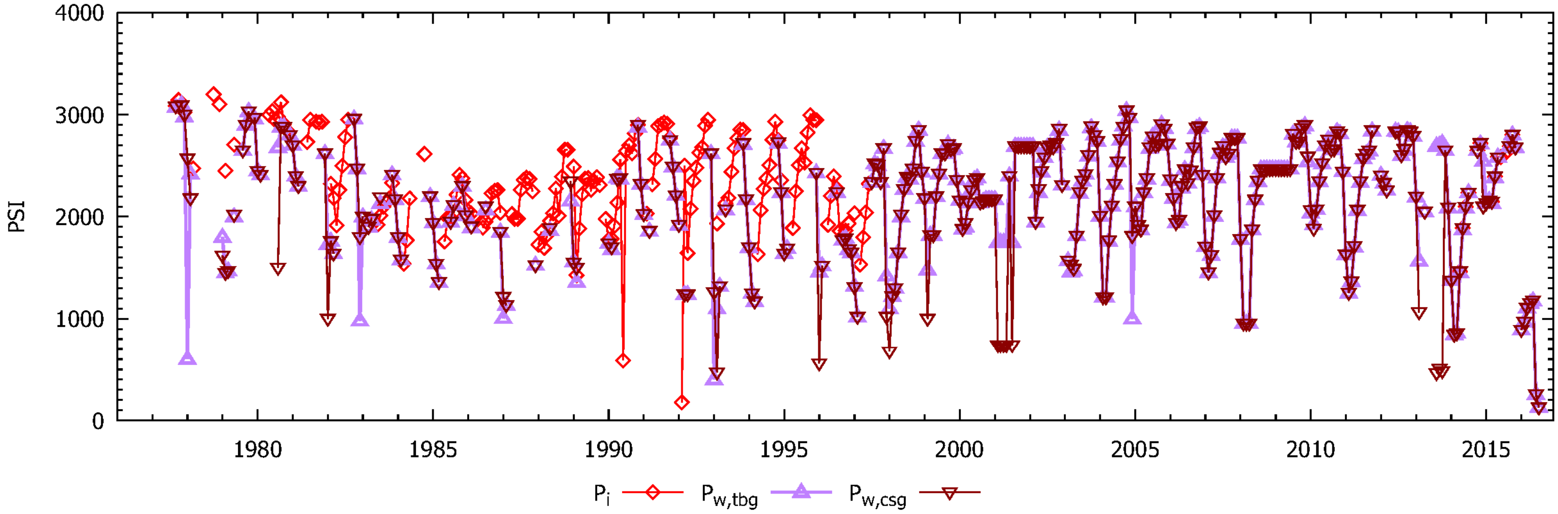
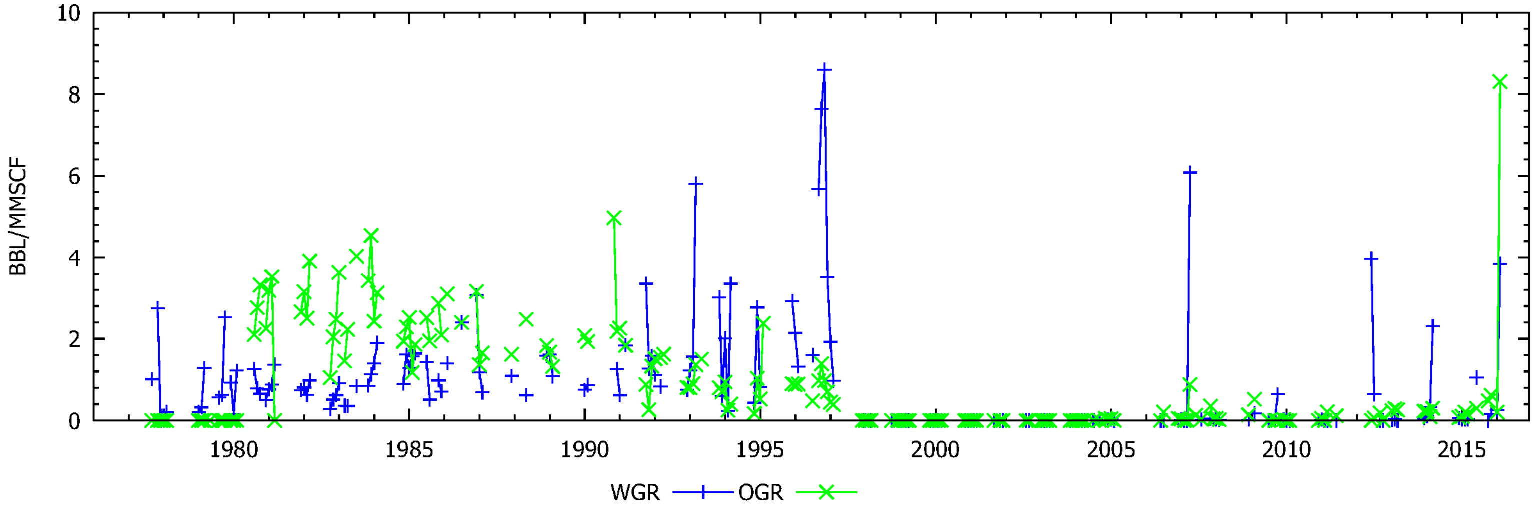
2005
2010
2015
WGR
OGR

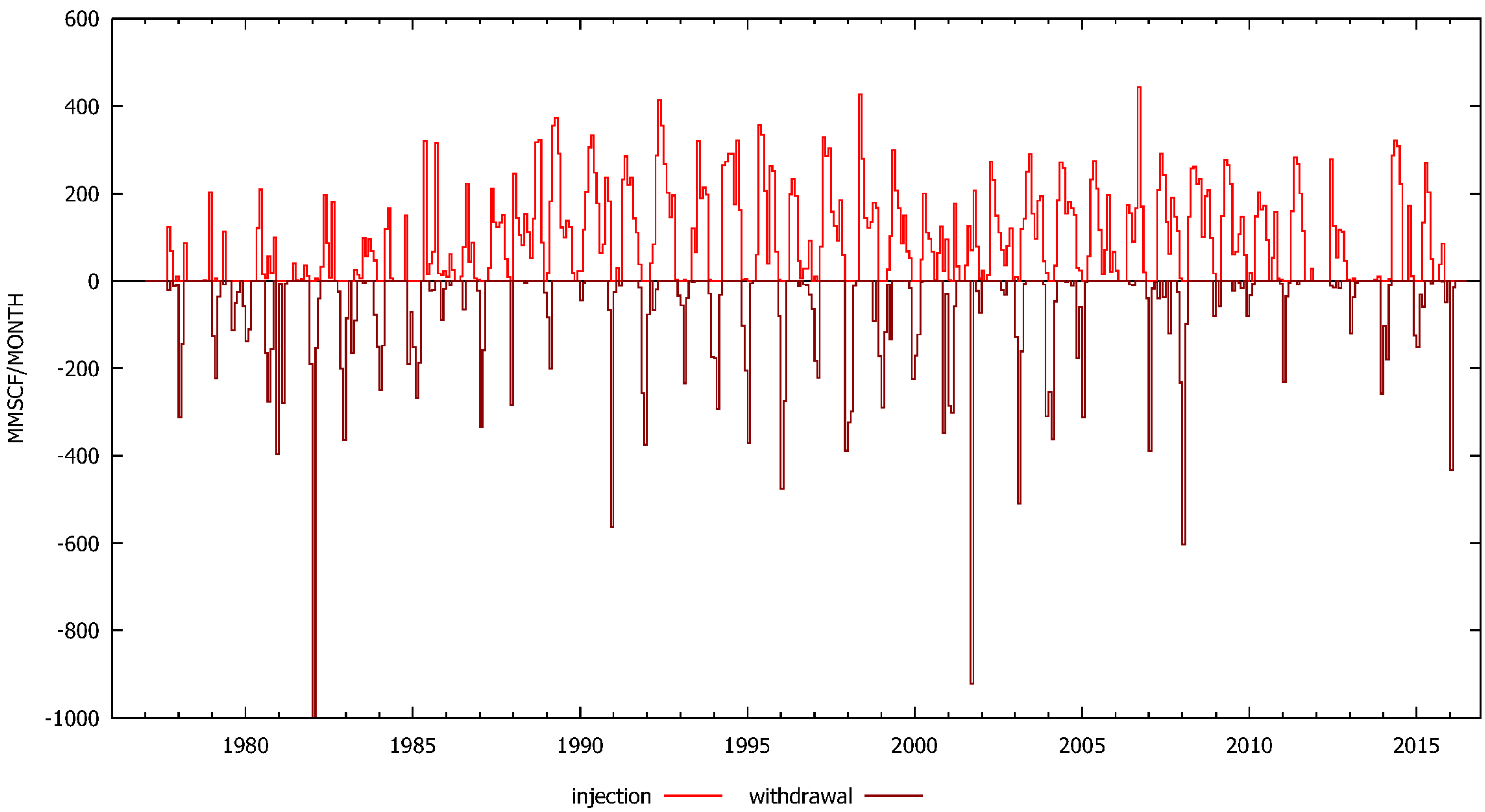


ENTIRE FIELD
EAST SECTOR
CENTRAL SECTOR
WEST SECTOR
STB/MMSCF
50
40
30
20
10
0
1980
1985
1990
1995
2000
2005
2010
2015
WGR
OGR

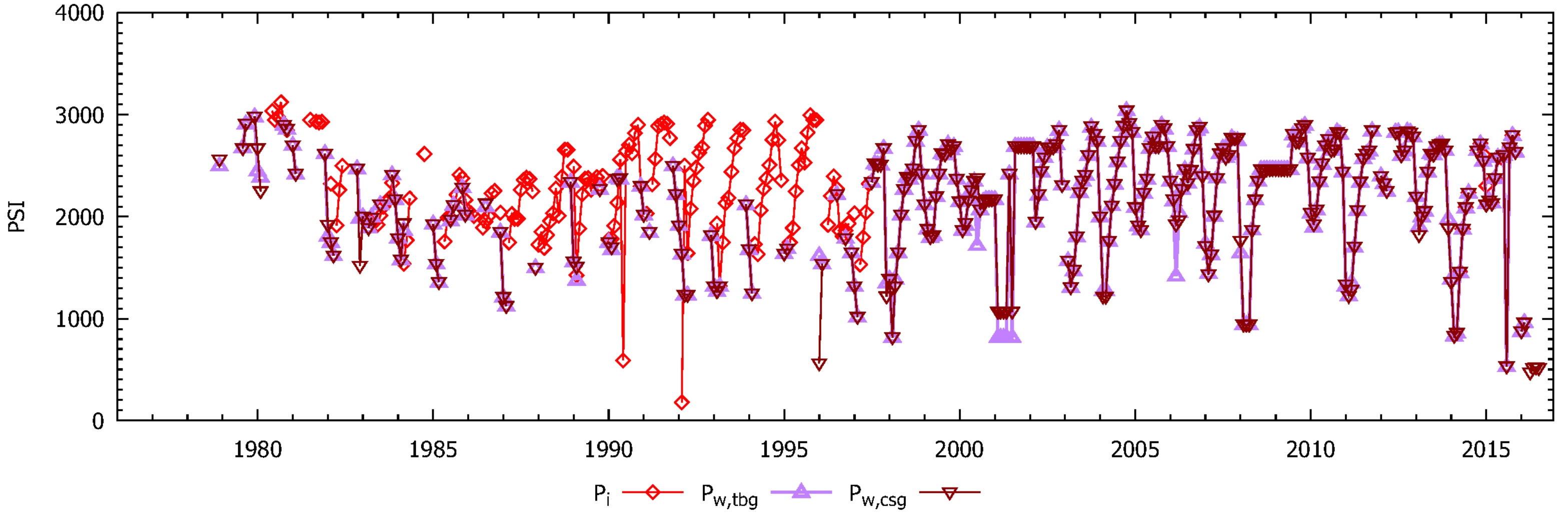
FERNANDO FEE 32 WELL

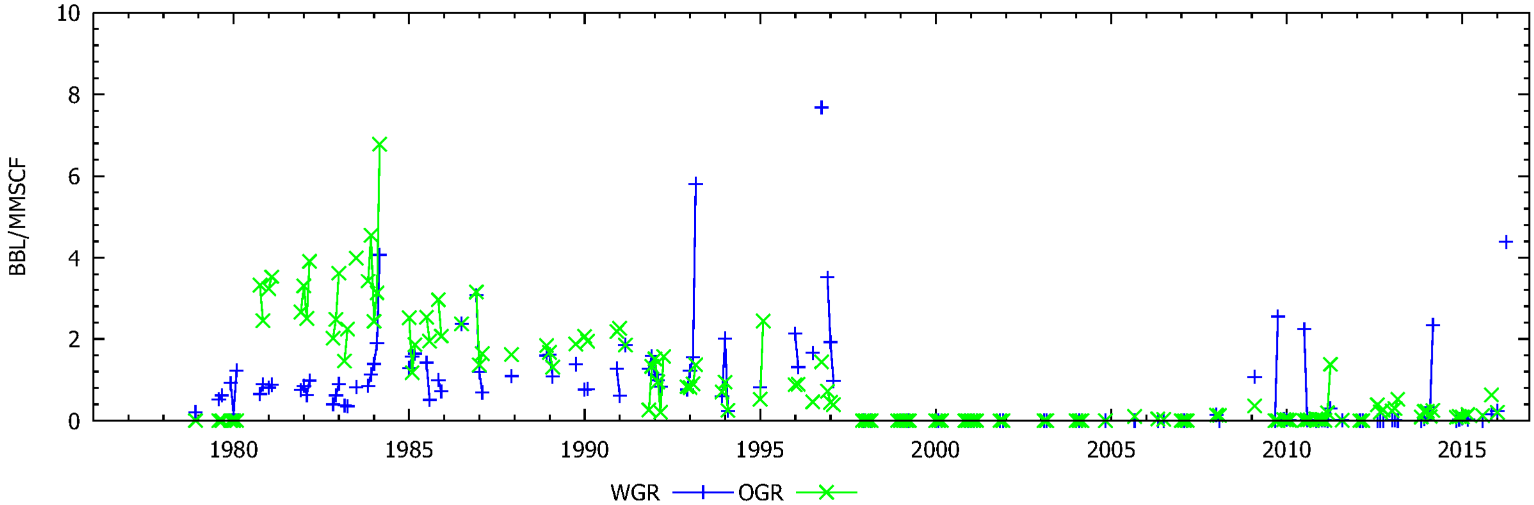


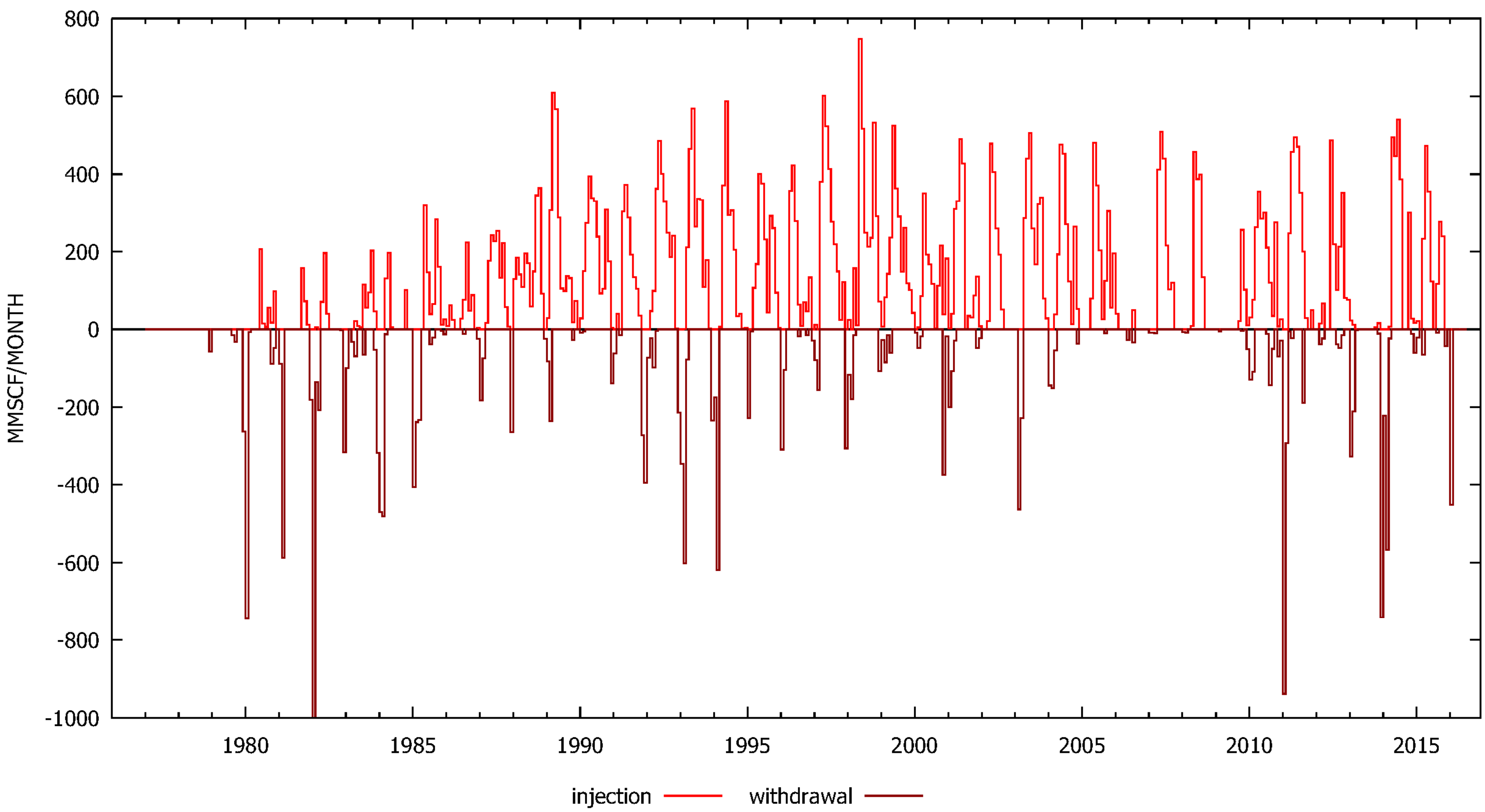




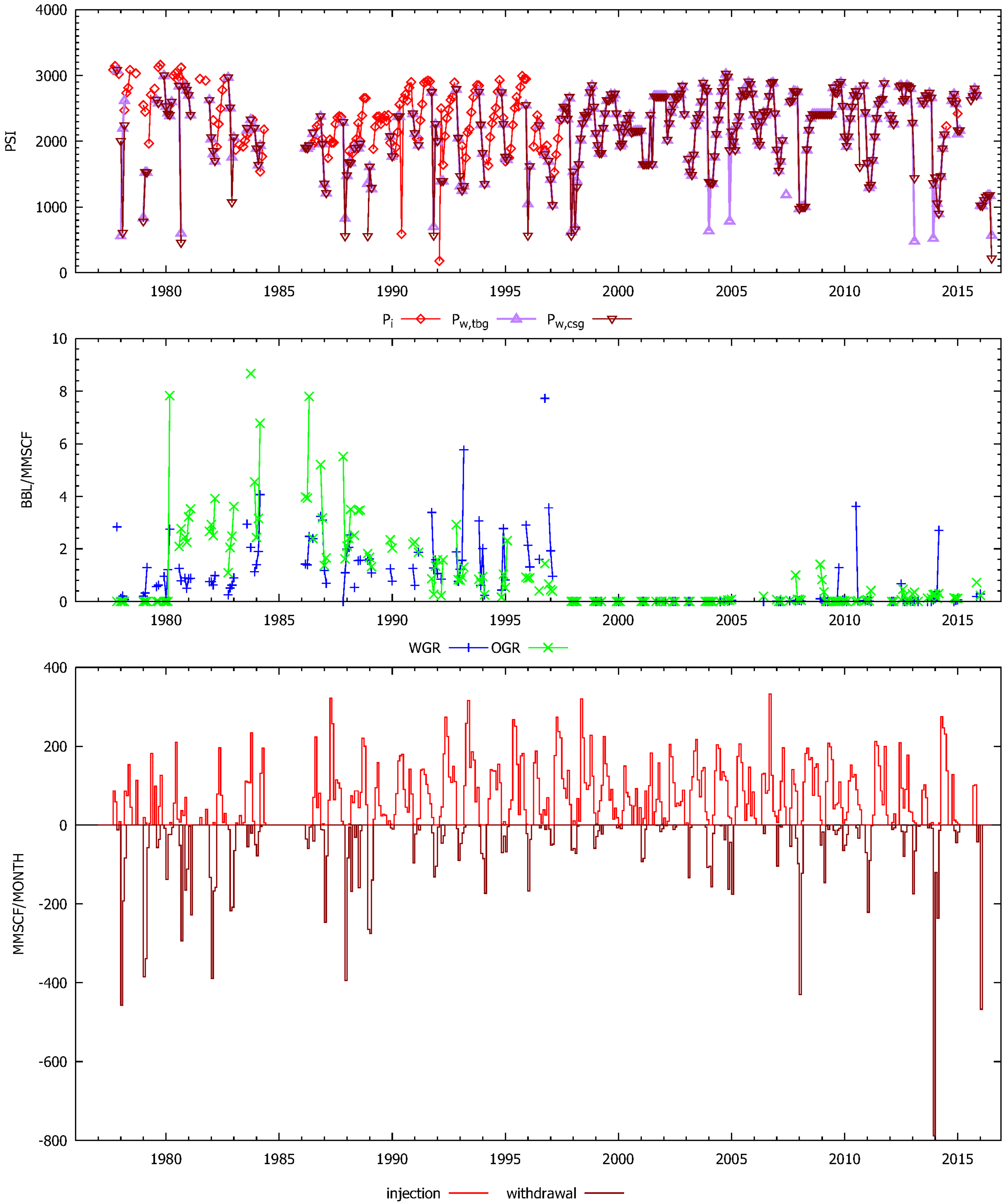
FERNANDO FEE 32-A WELL

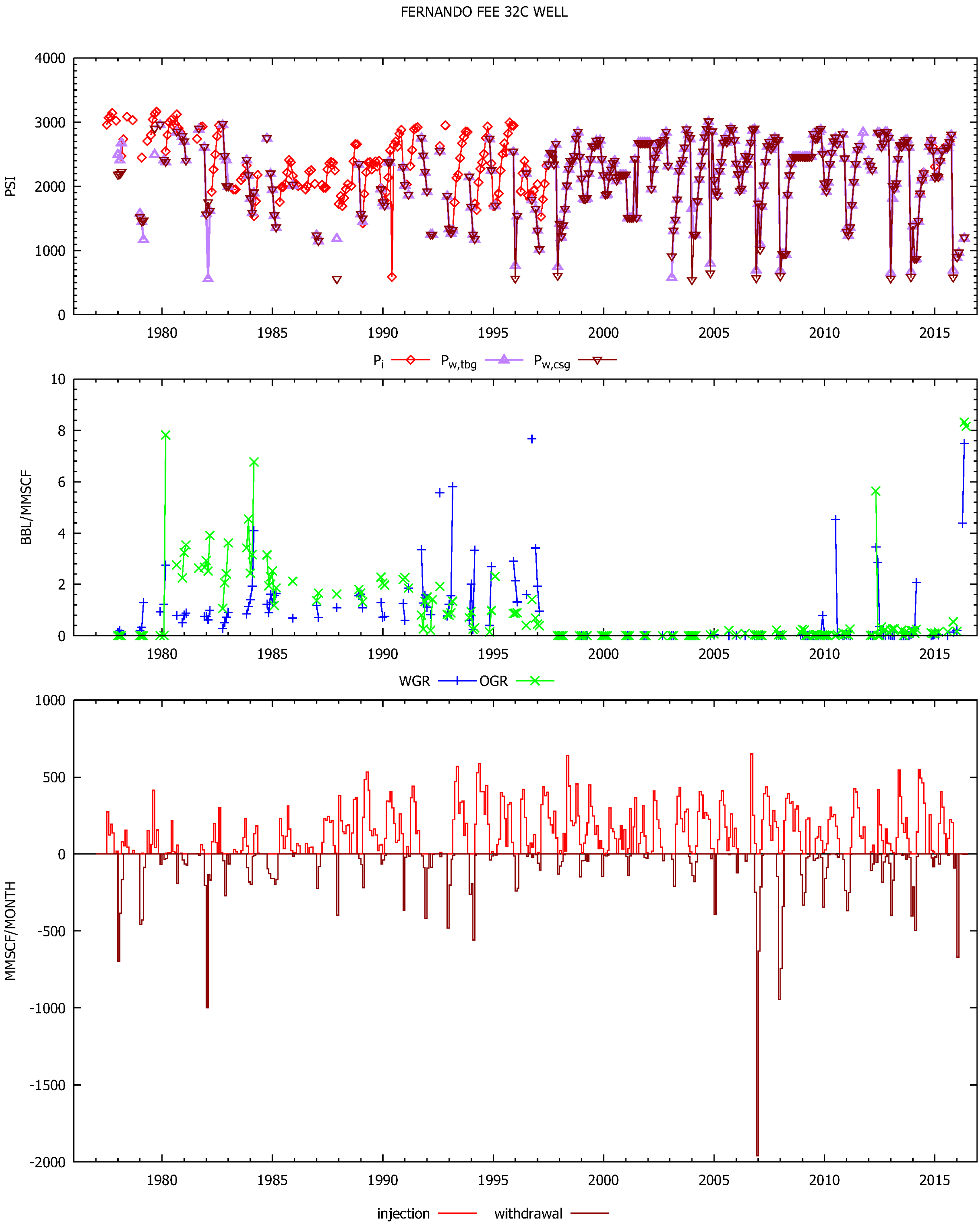






FERNANDO FEE 32B WELL





FERNANDO FEE 32C WELL
4000
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PSI
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P_i
$P_{w,tbg}$
$P_{w,csg}$
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BBL/MMSCF
WGR
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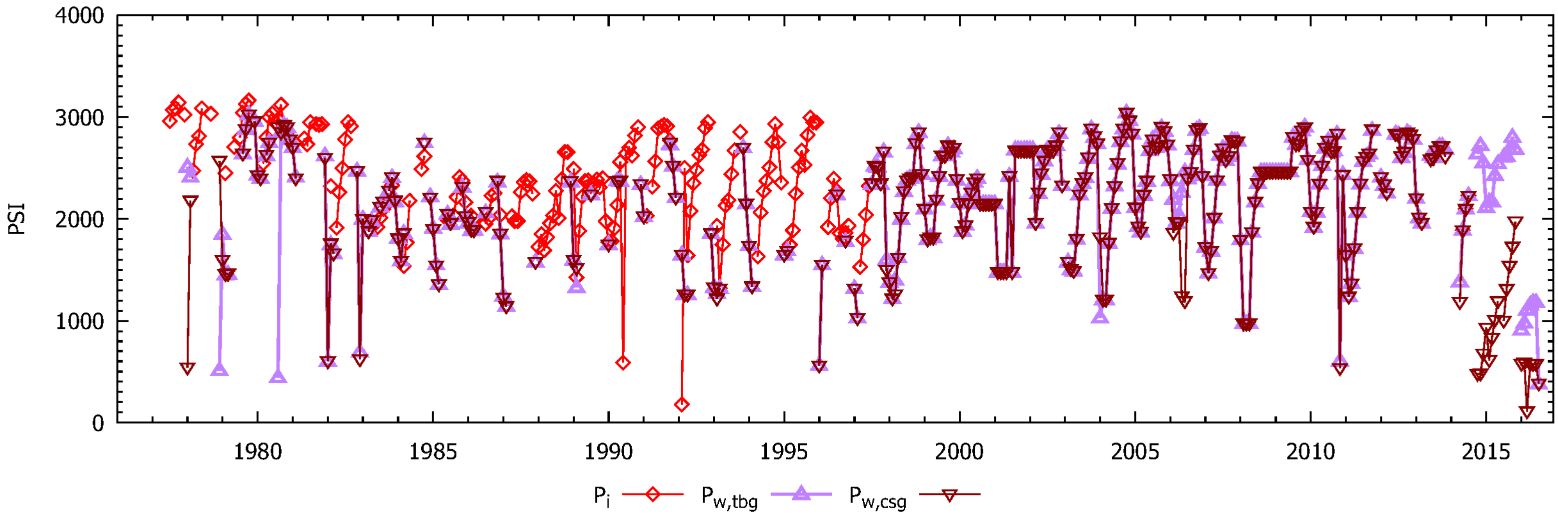
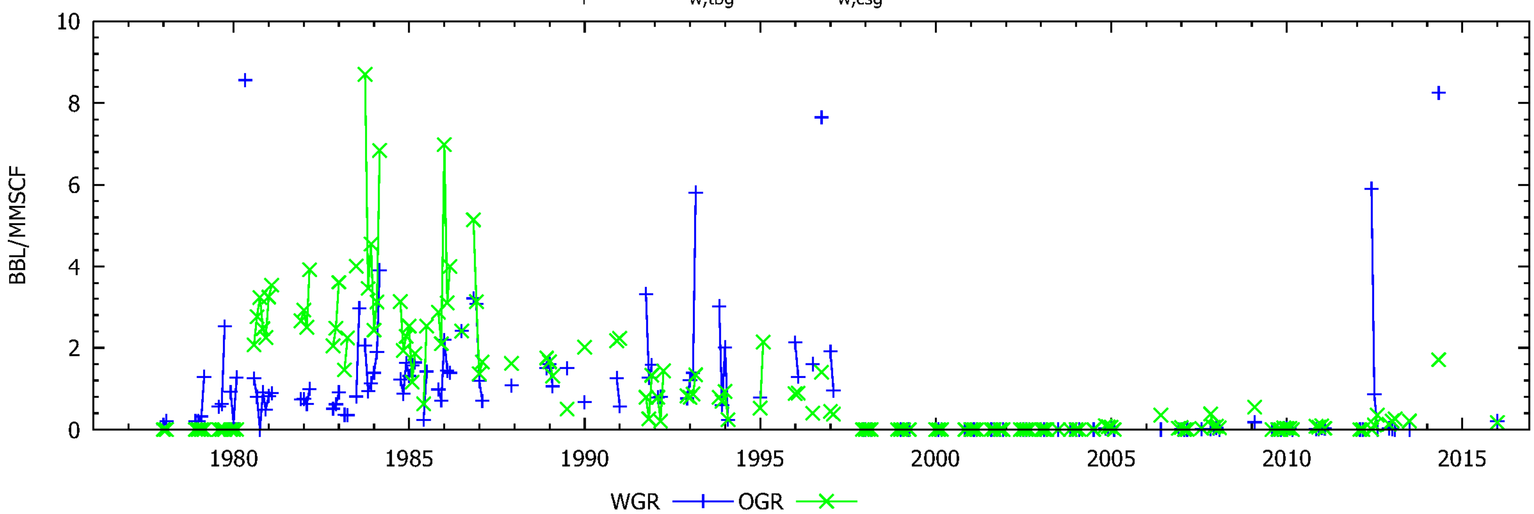
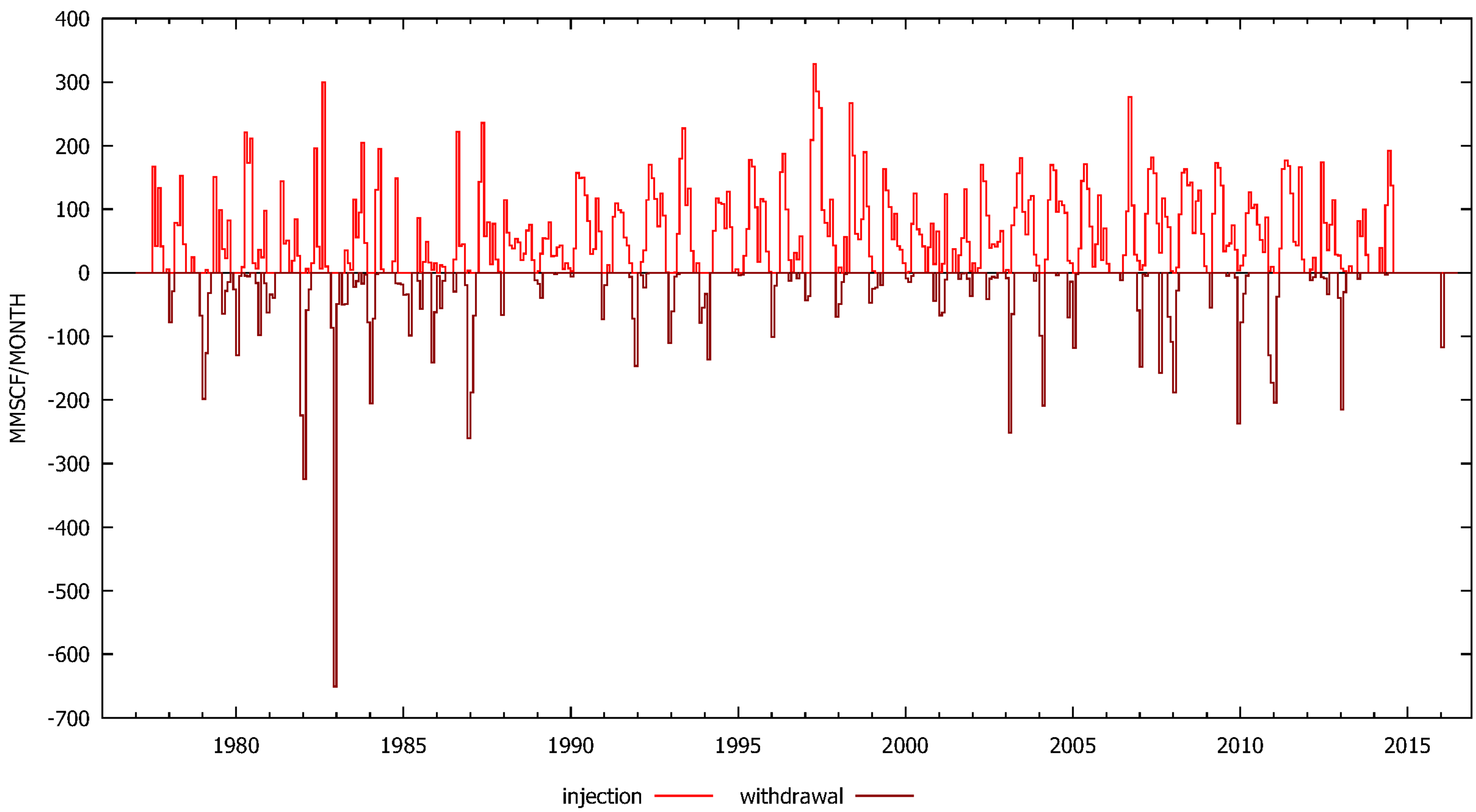
-500
-1000
-1500
-2000
MMSCF/MONTH
injection
withdrawal

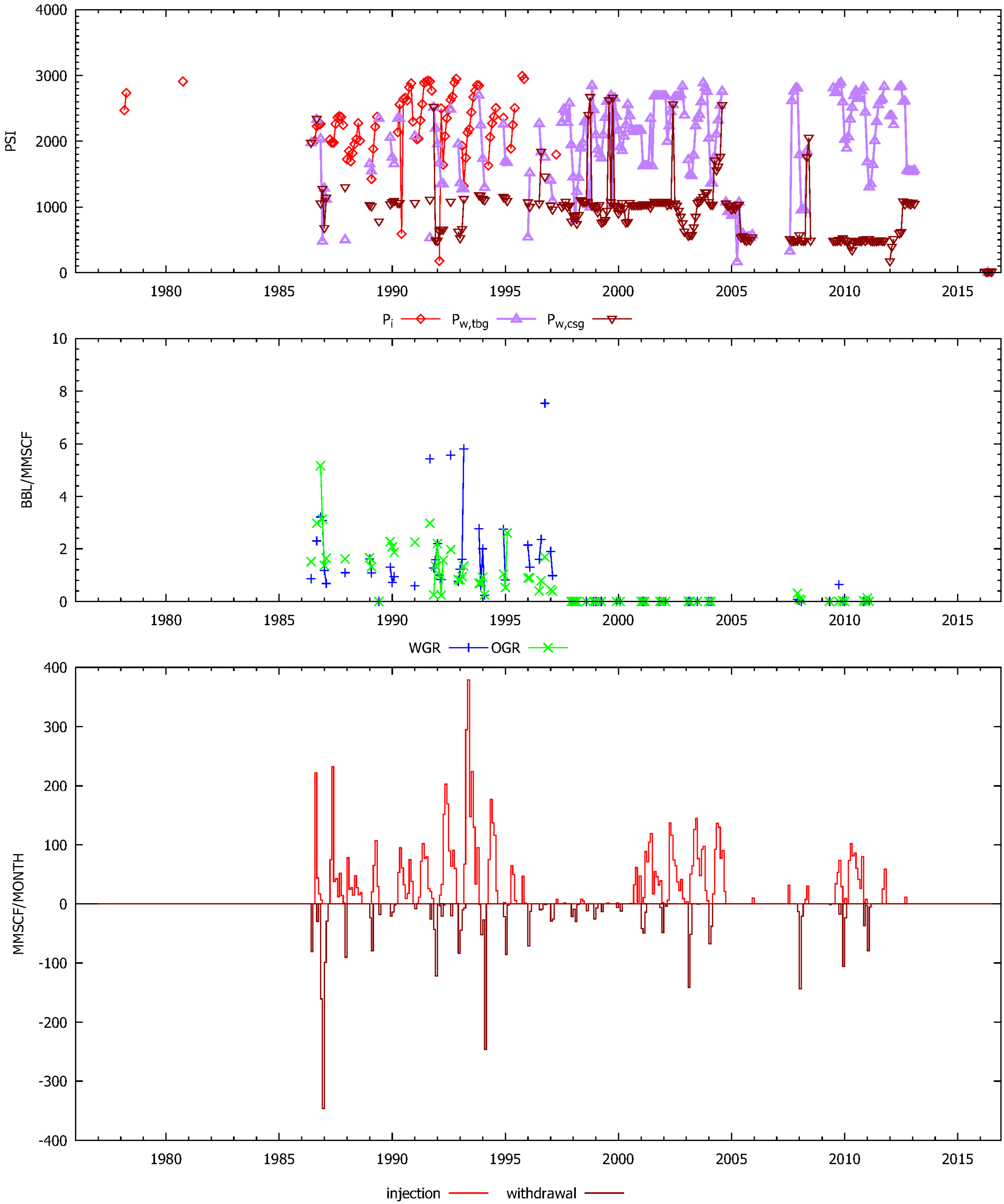
FERNANDO FEE 32D WELL



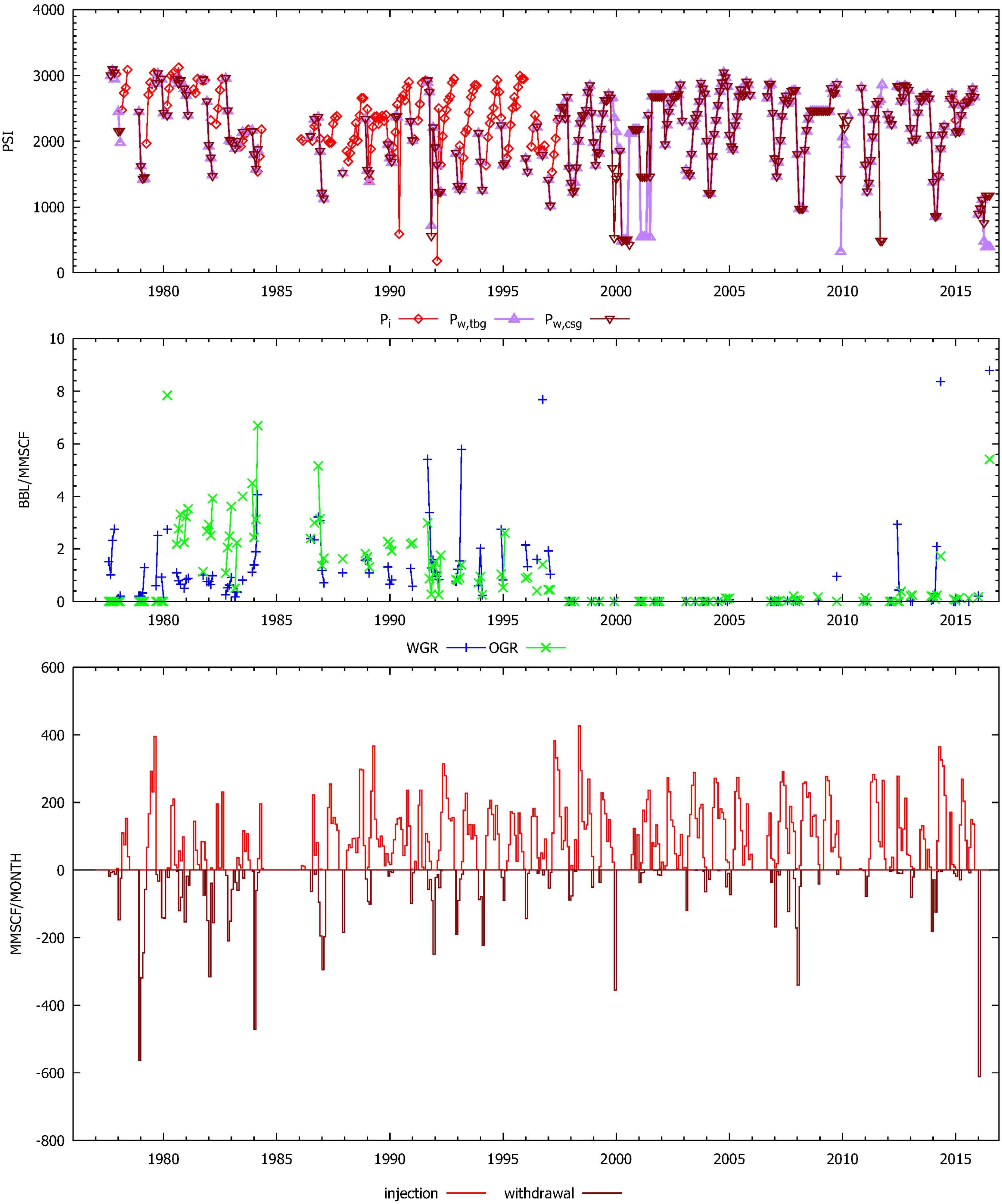


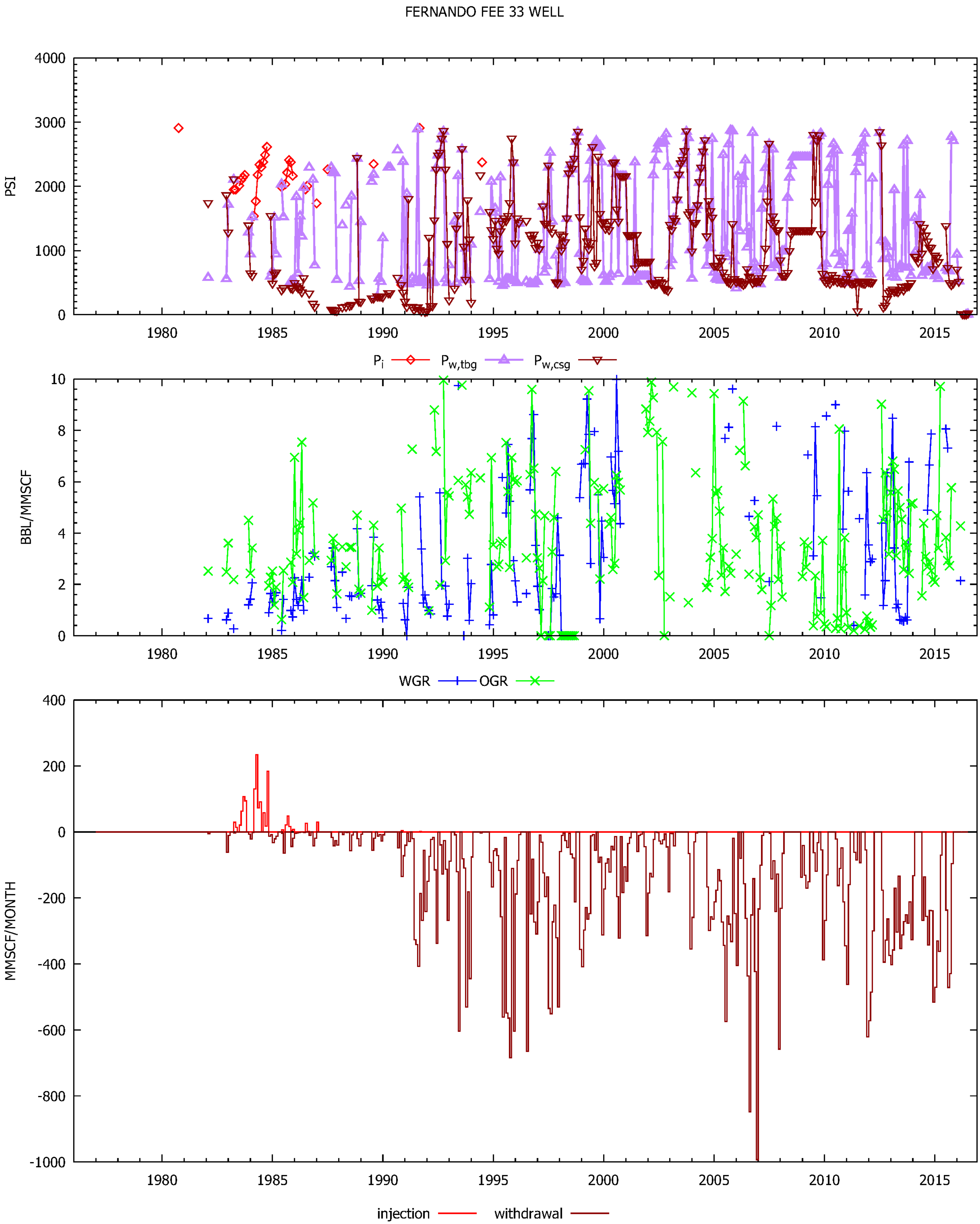


FERNANDO FEE 32E WELL



FERNANDO FEE 32F WELL




FERNANDO FEE 33 WELL
PSI
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P_i
$P_{w,tbg}$
$P_{w,csg}$
BBL/MMSCF
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WGR
OGR
MMSCF/MONTH
400
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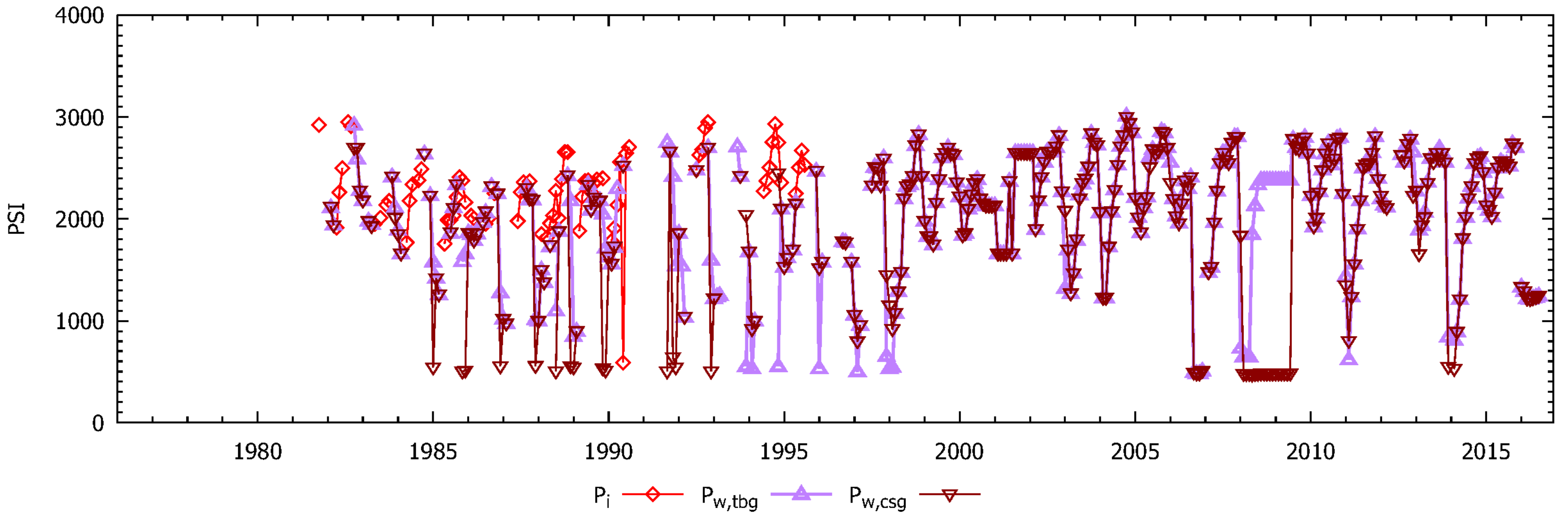
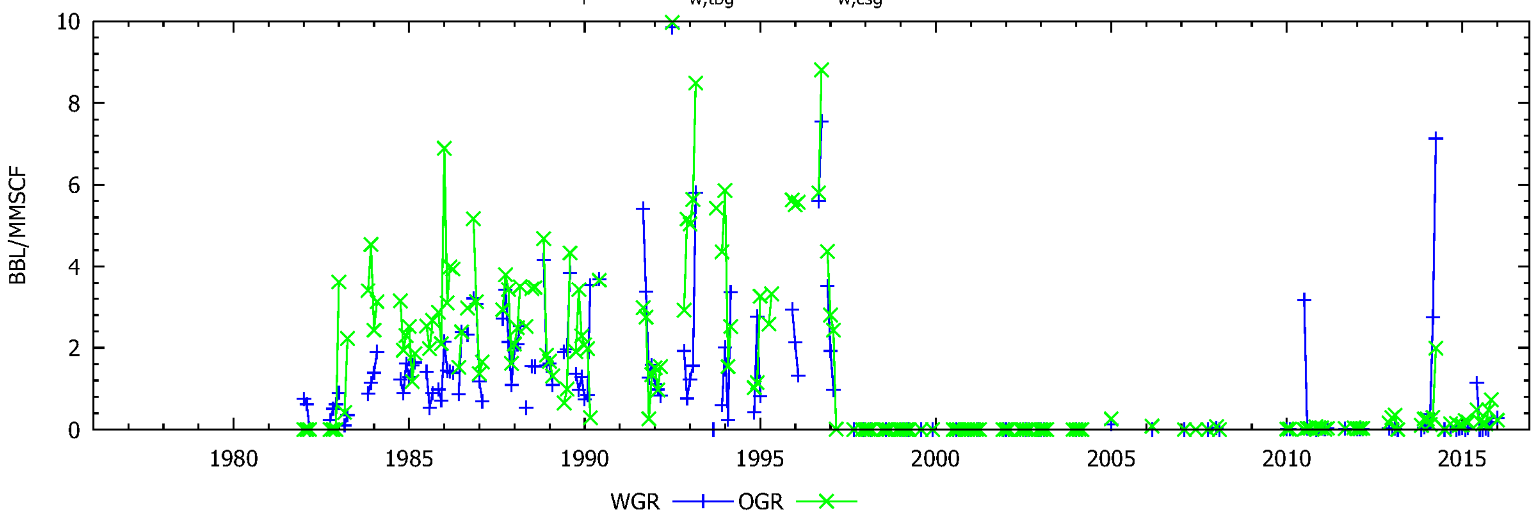
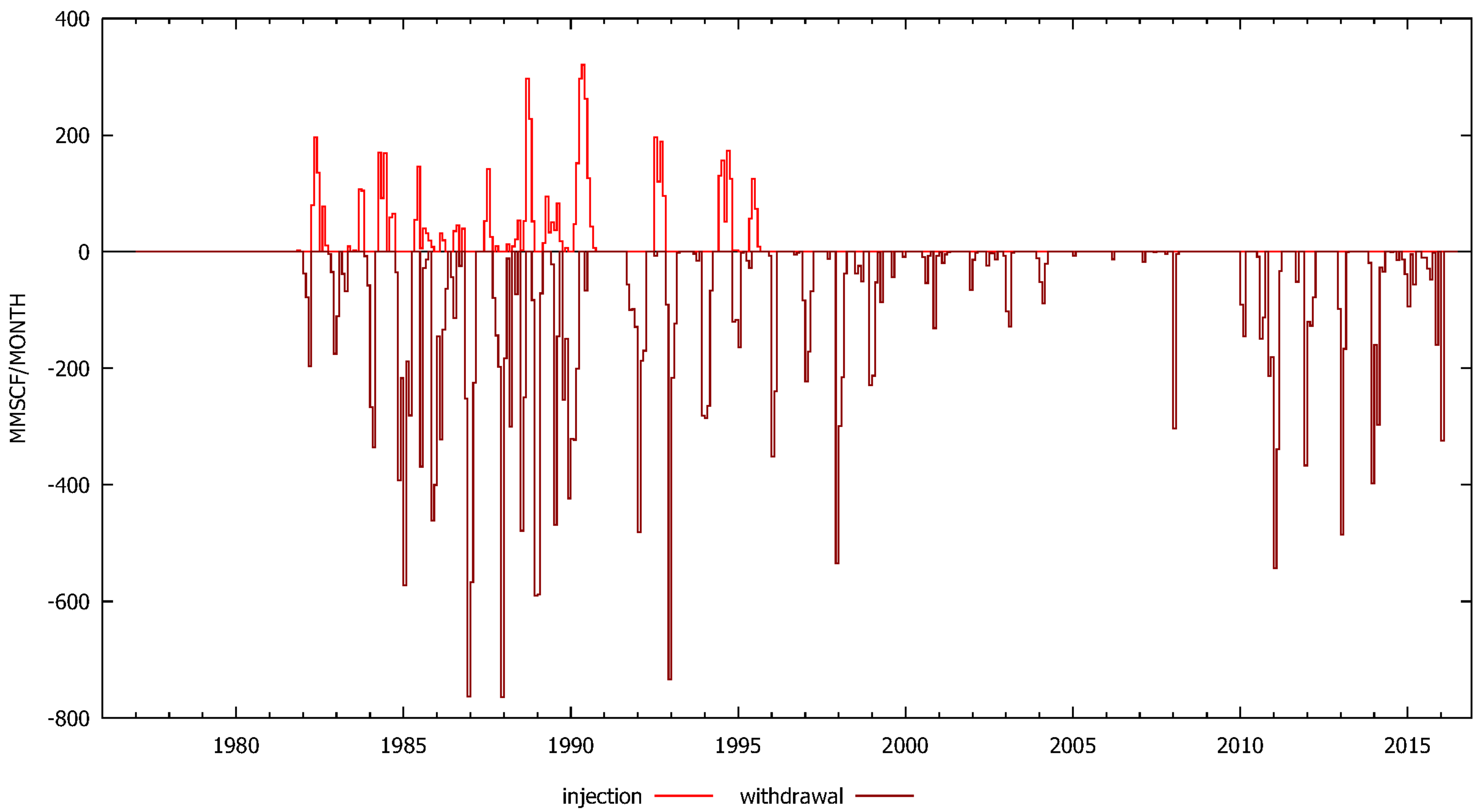
-200
-400
-600
-800
-1000
injection
withdrawal

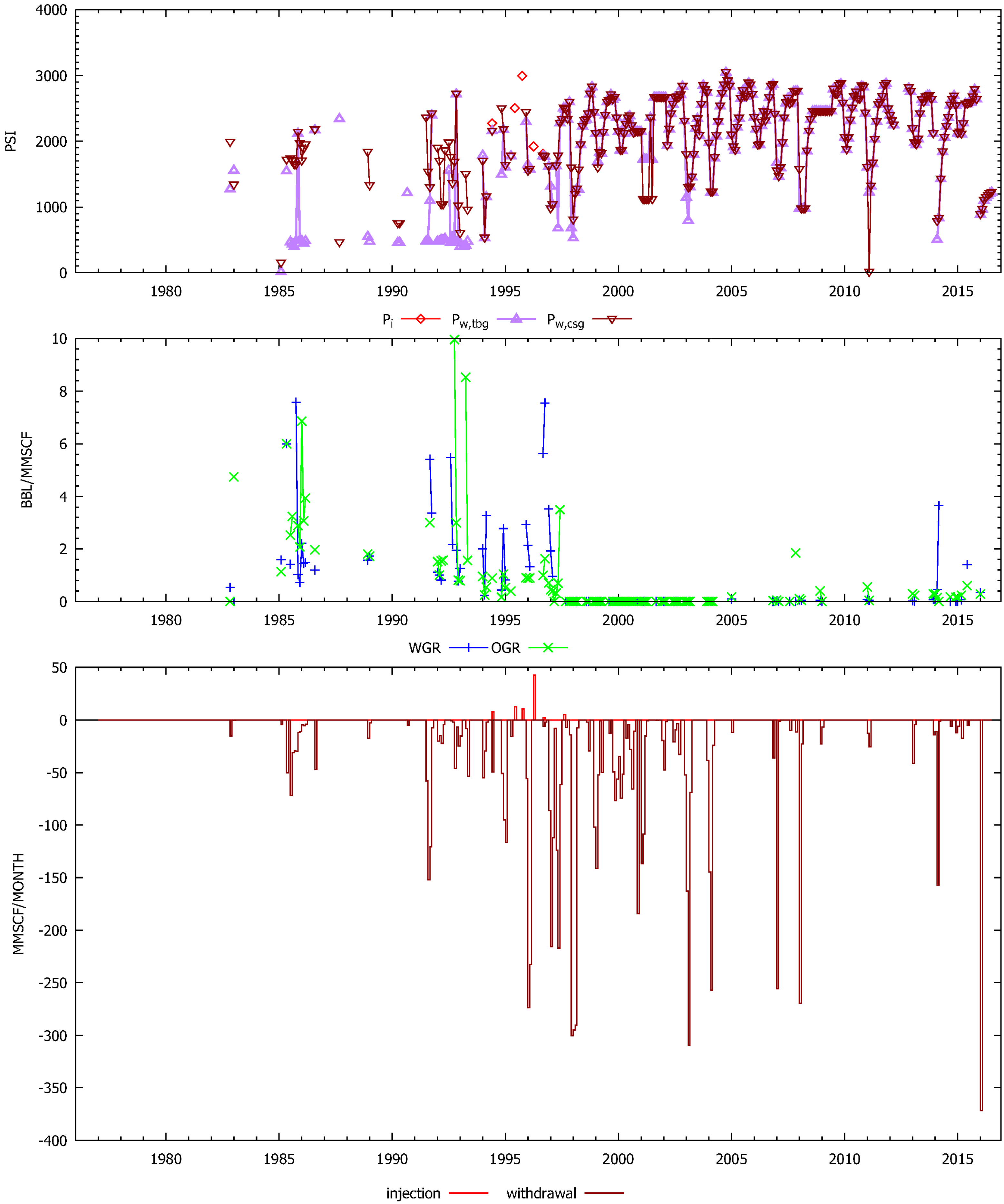
FERNANDO FEE 34-A WELL



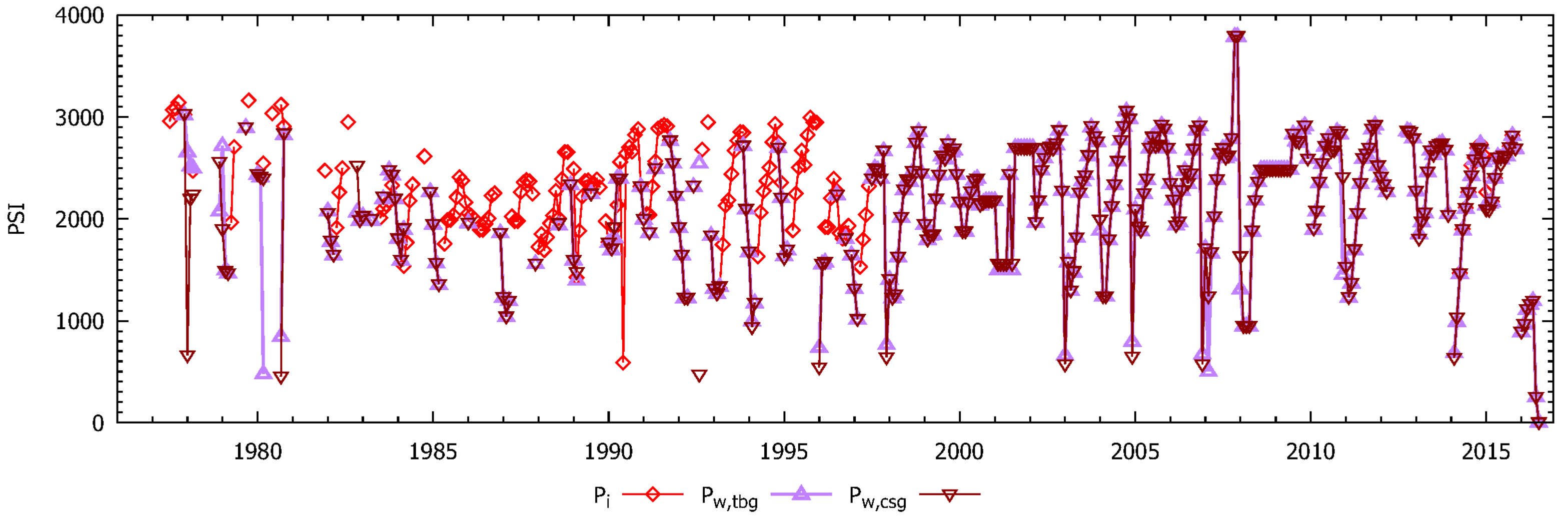


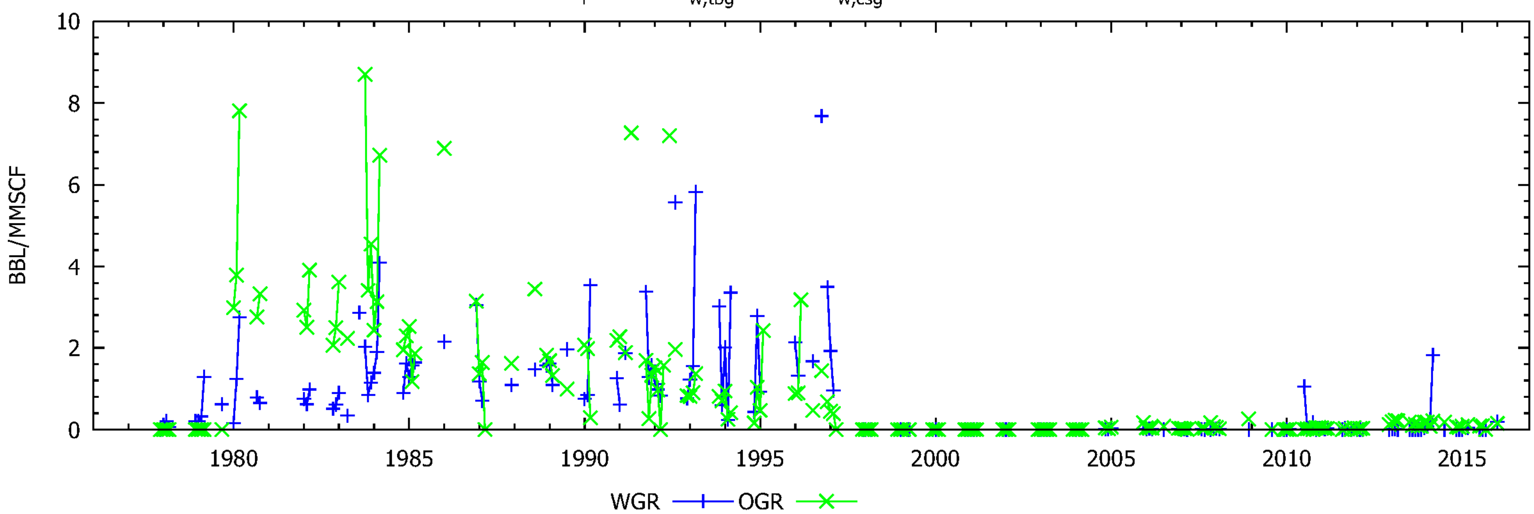


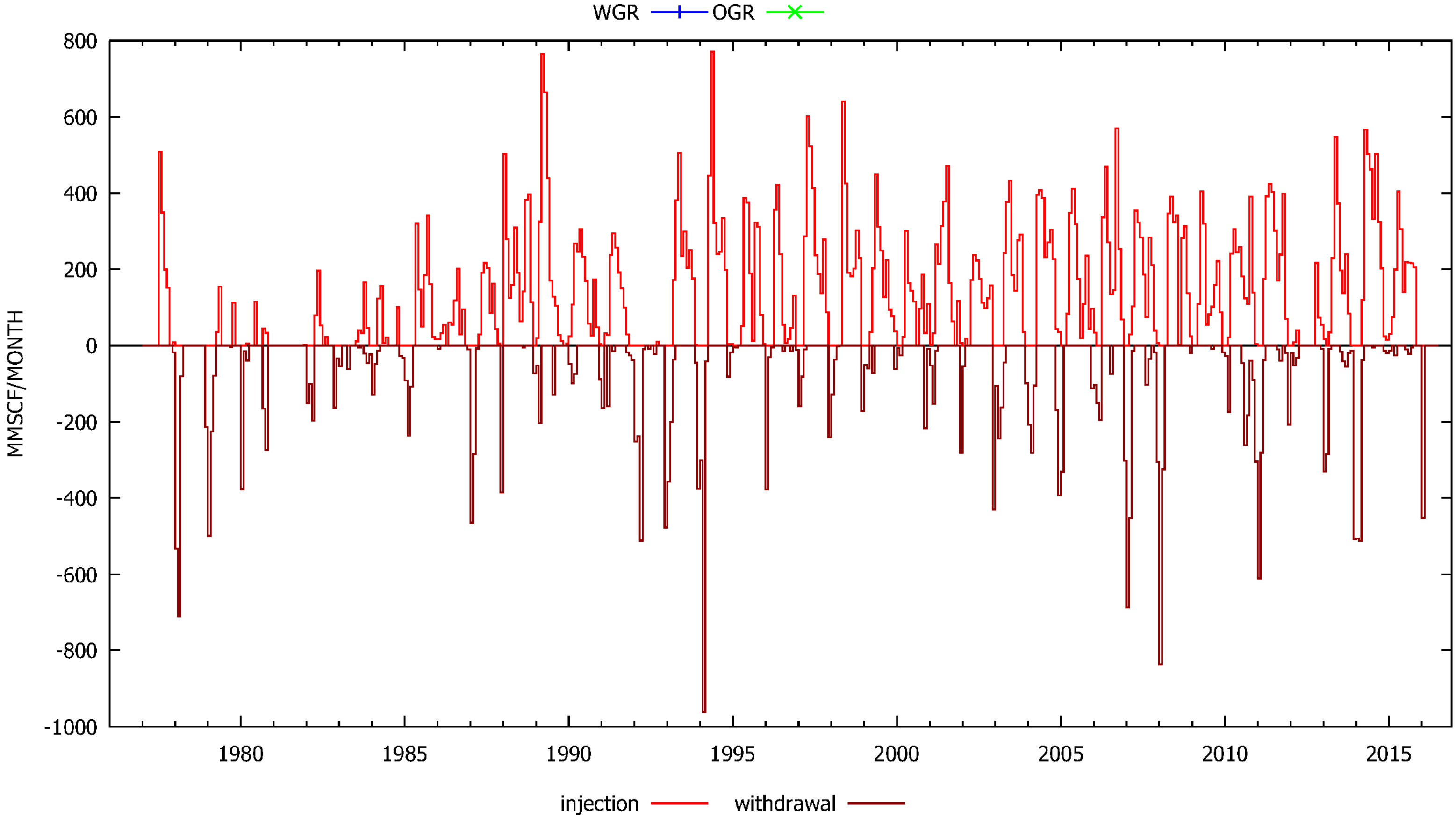
FERNANDO FEE 34BR WELL



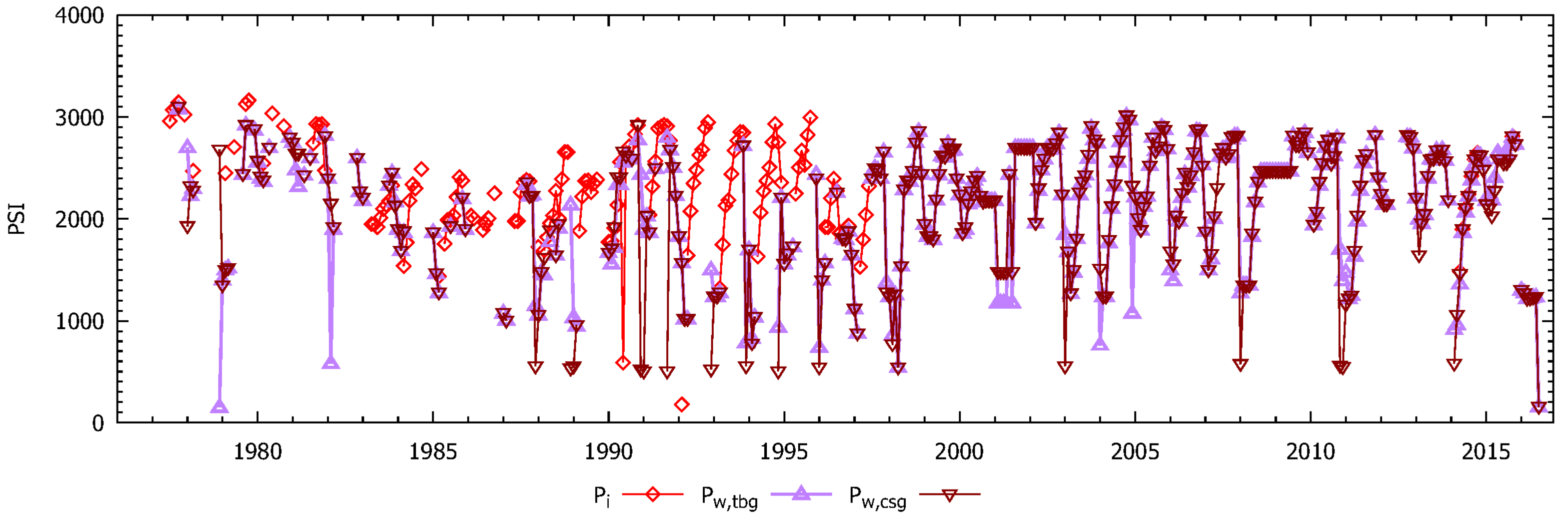
FERNANDO FEE 35A WELL

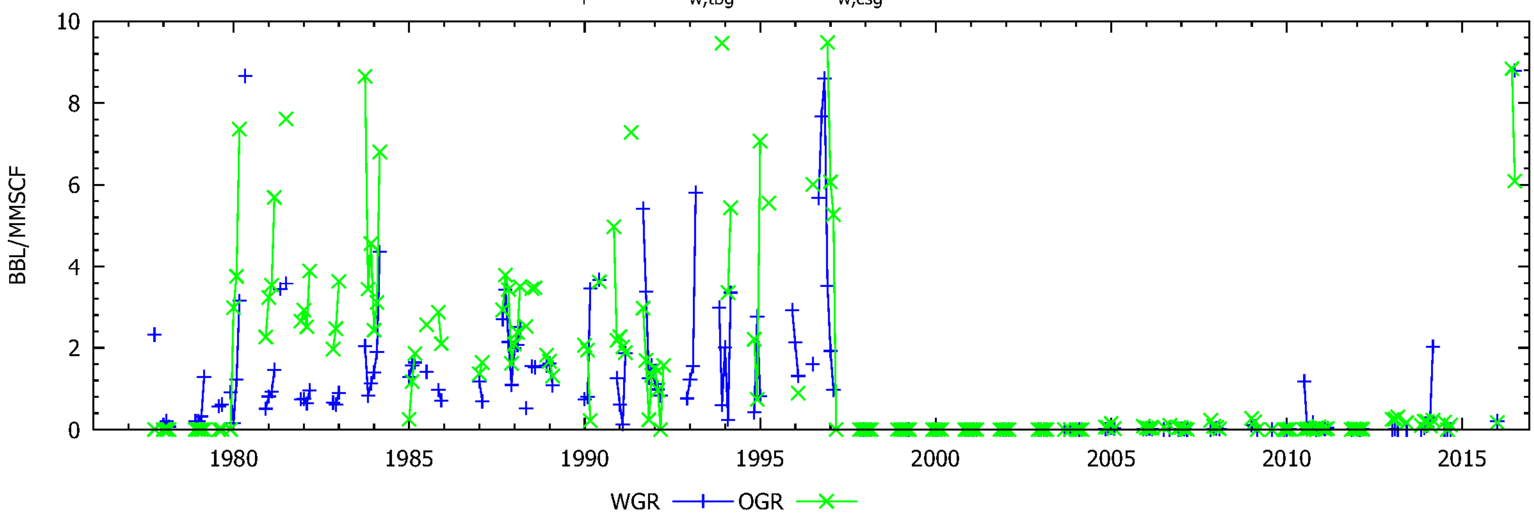


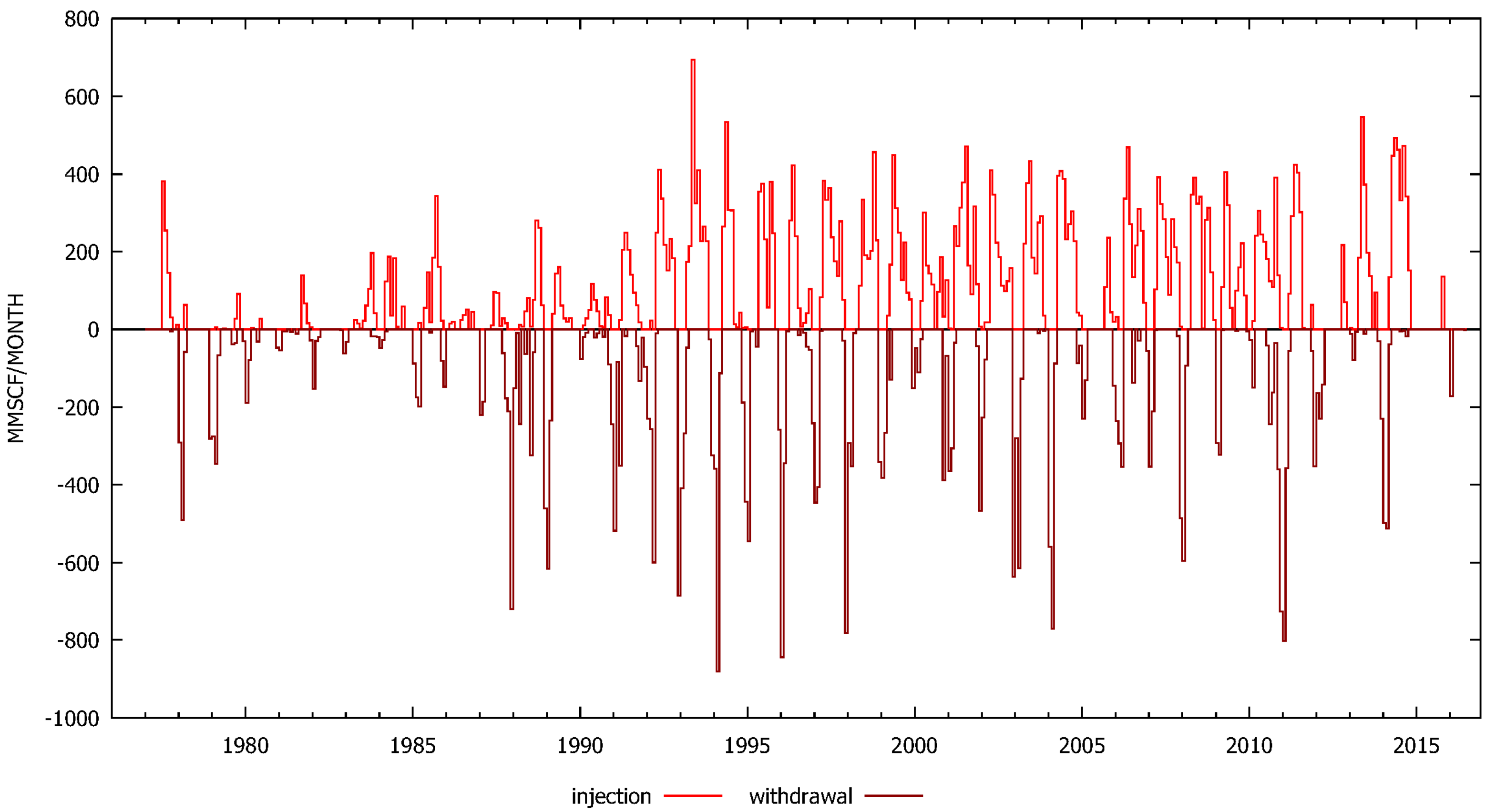


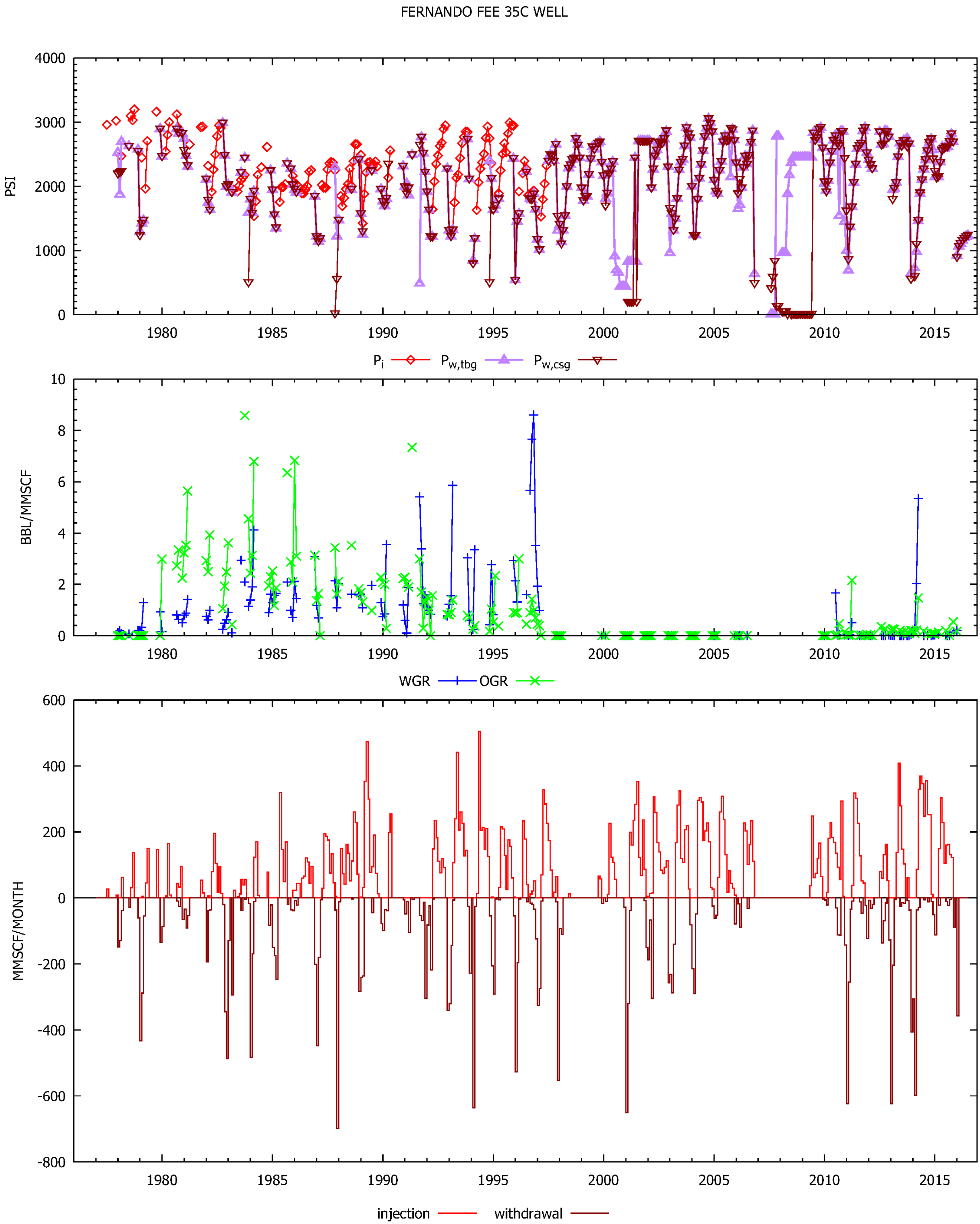


FERNANDO FEE 35B WELL








FERNANDO FEE 35C WELL
PSI
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WGR
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MMSCF/MONTH
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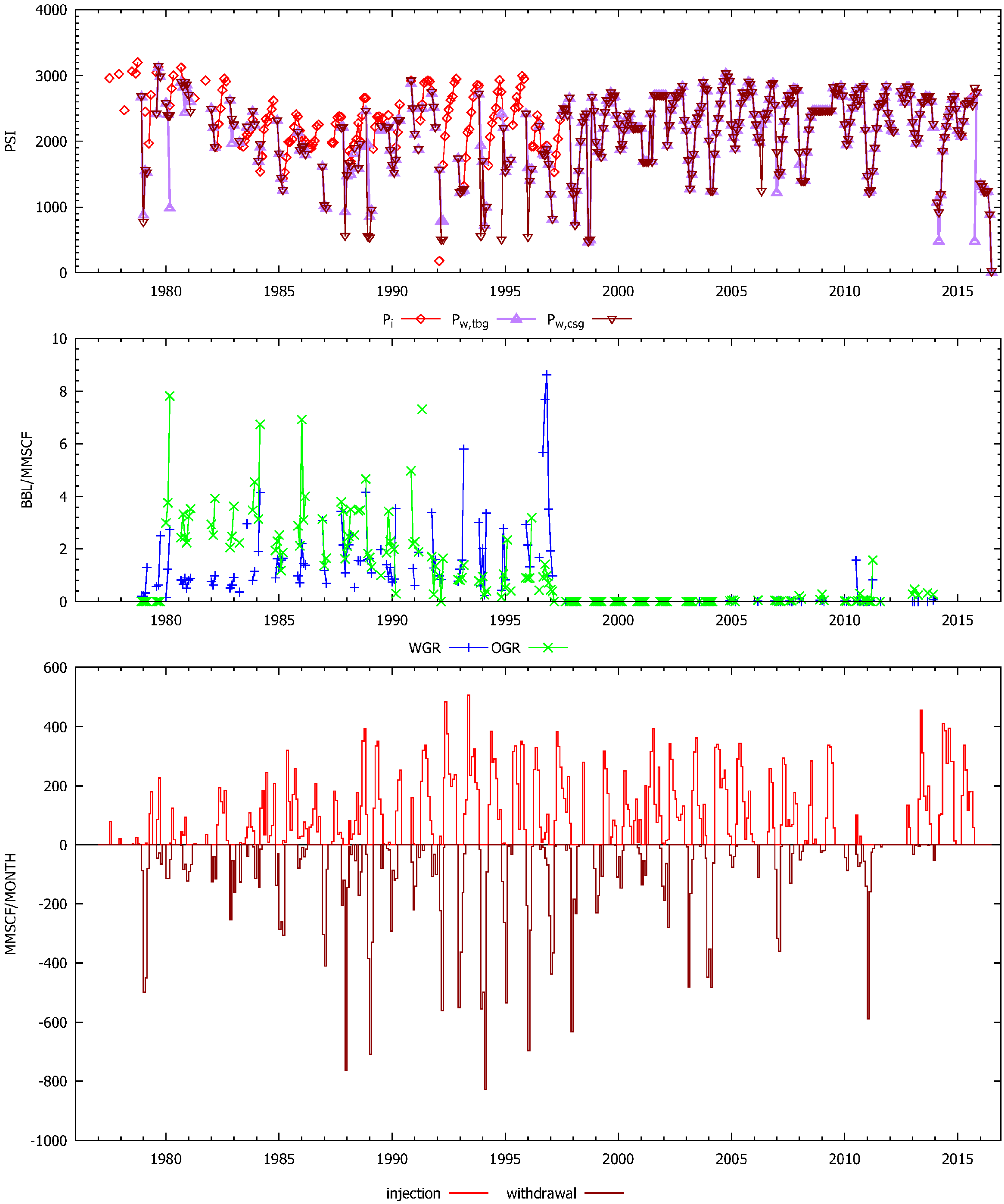
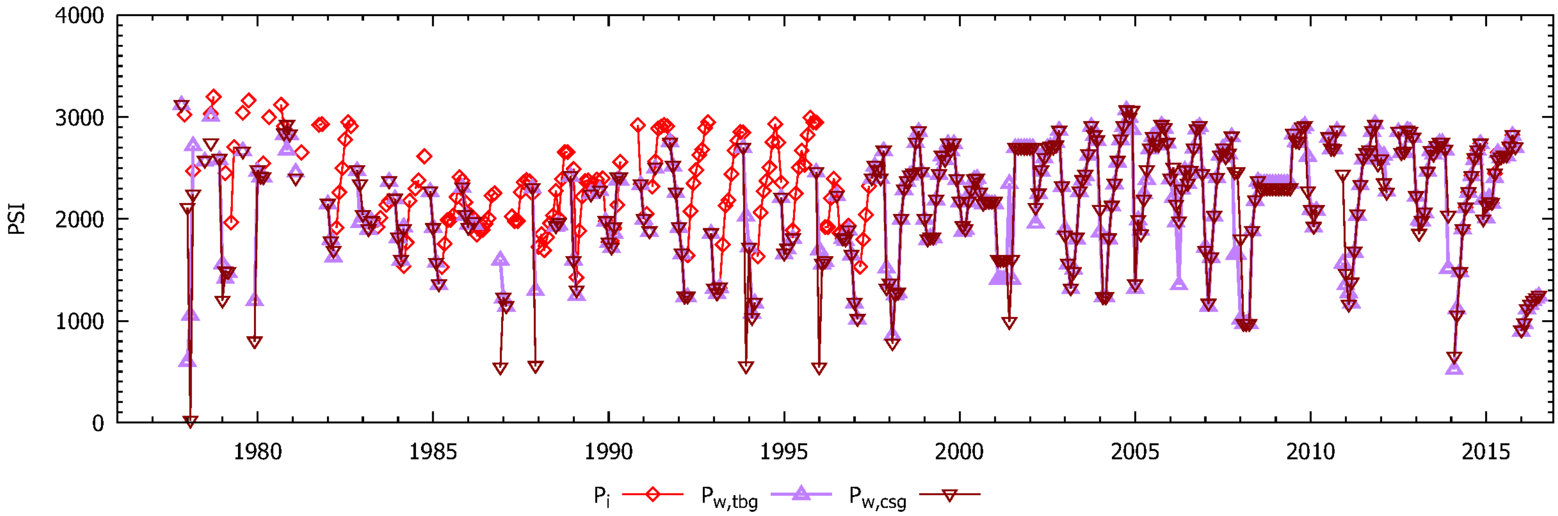
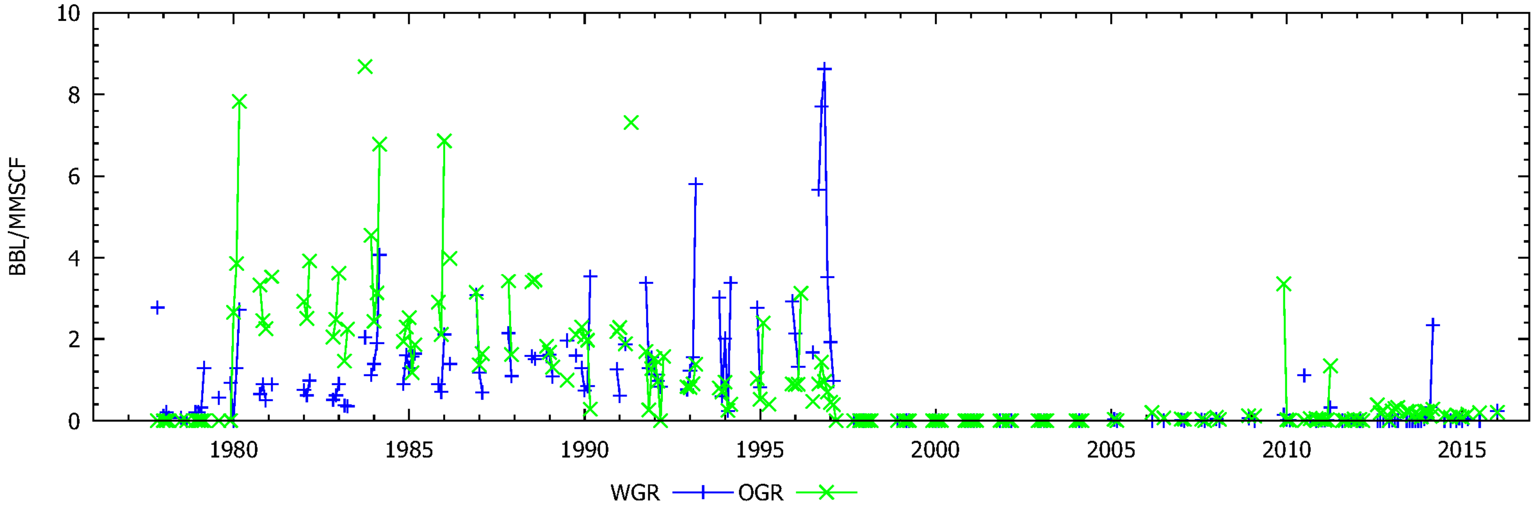
-200
-400
-600
-800
injection
withdrawal

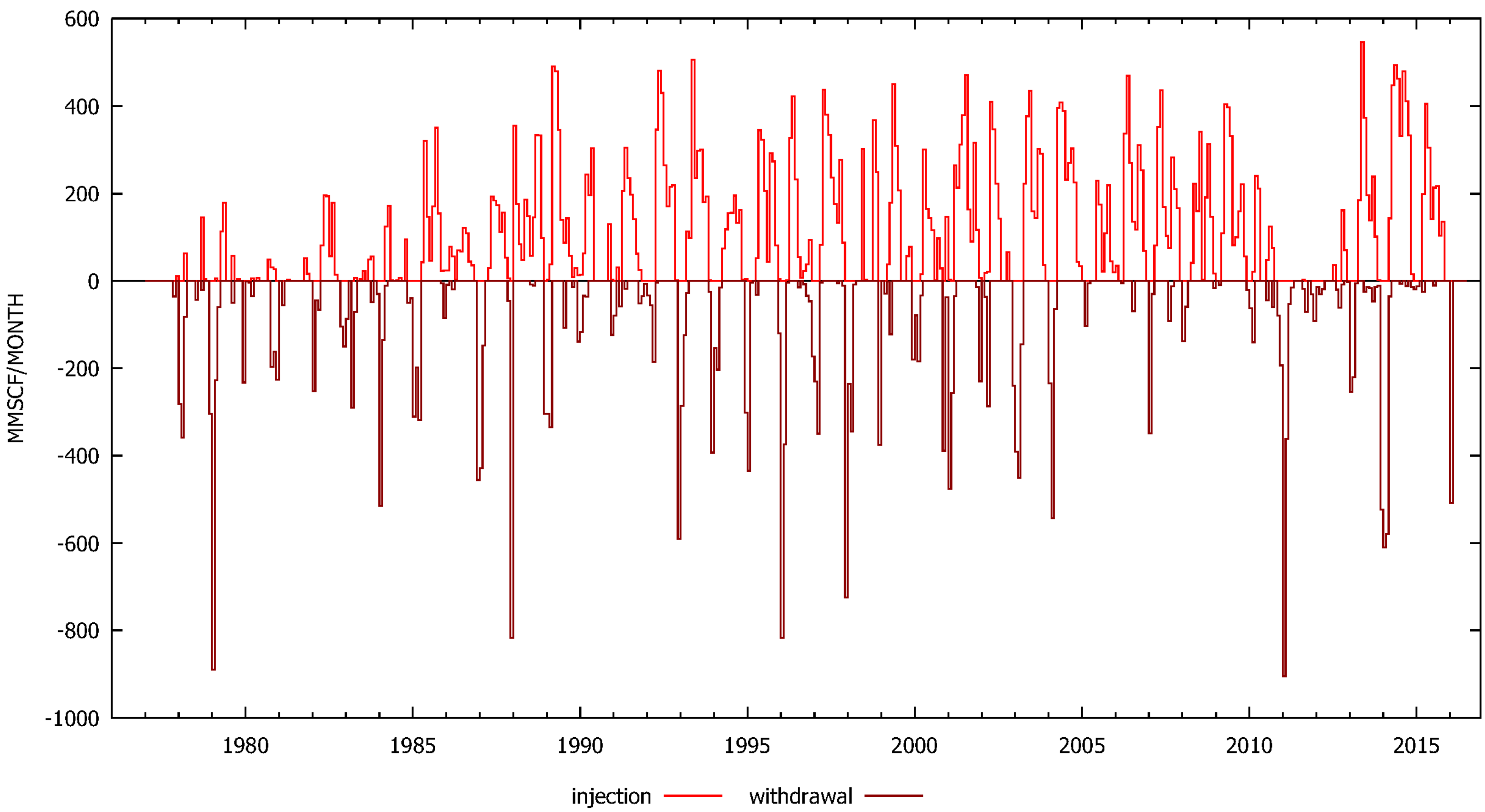
FERNANDO FEE 35D WELL



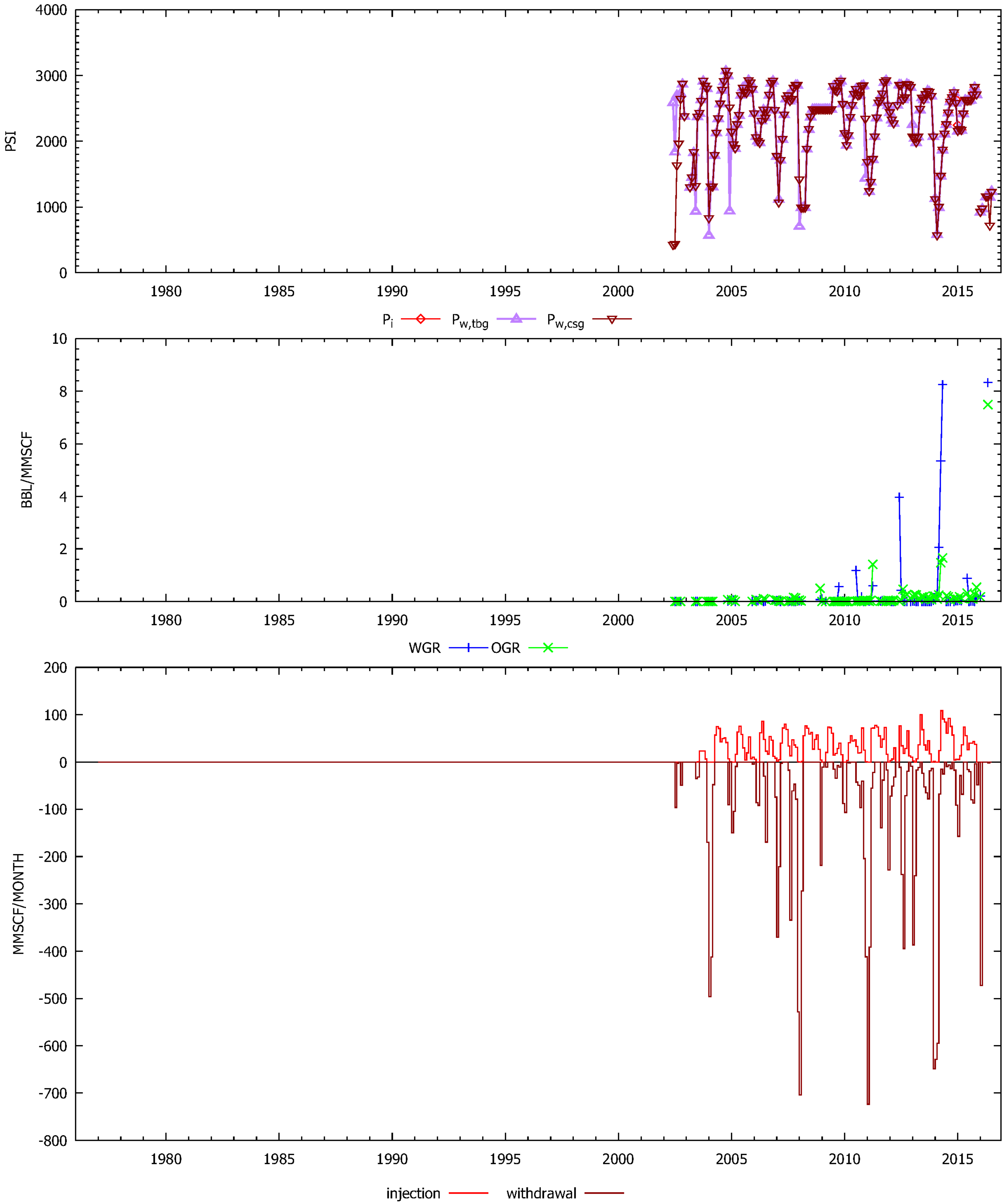
FERNANDO FEE 35E WELL



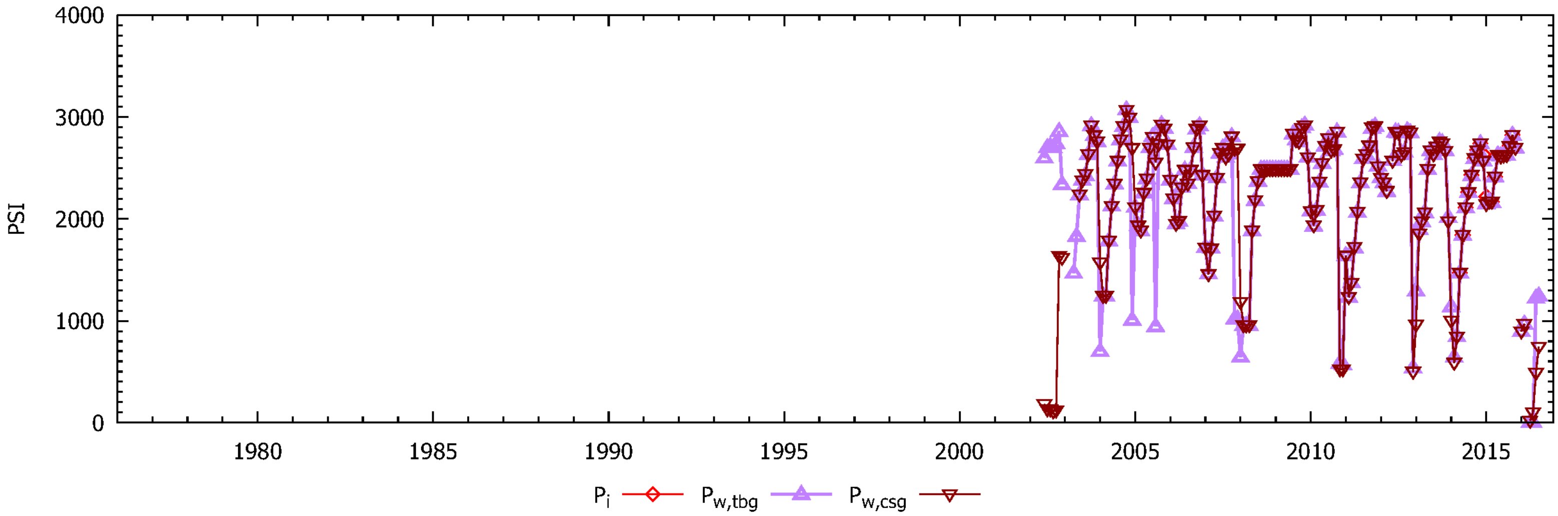


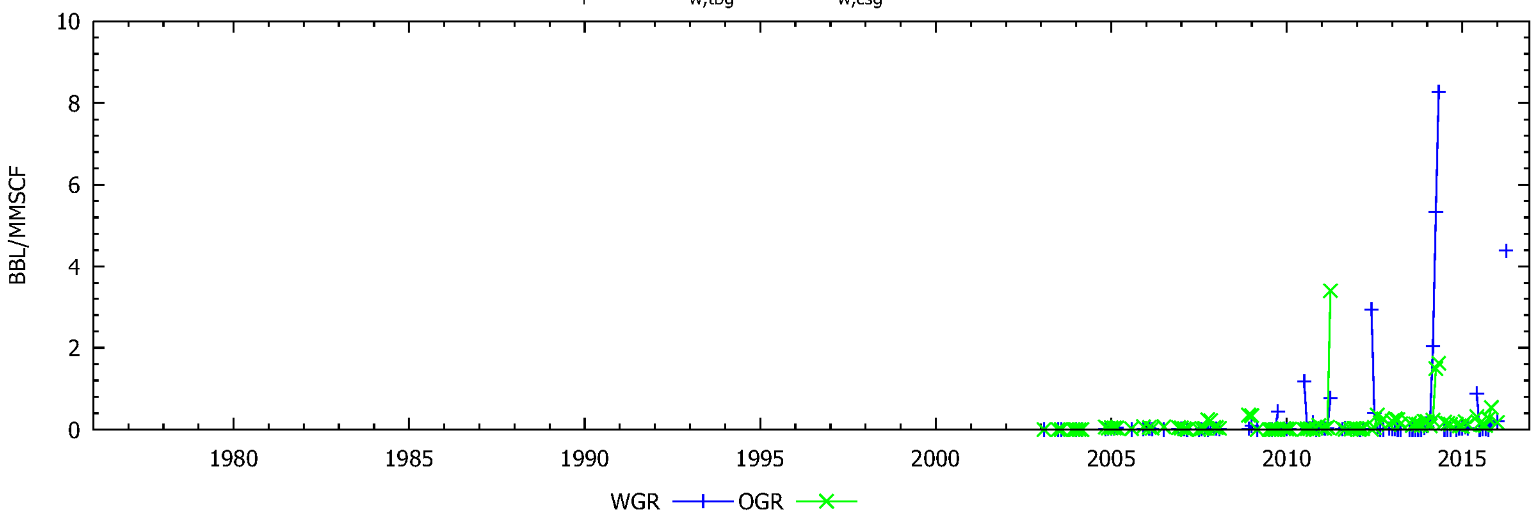


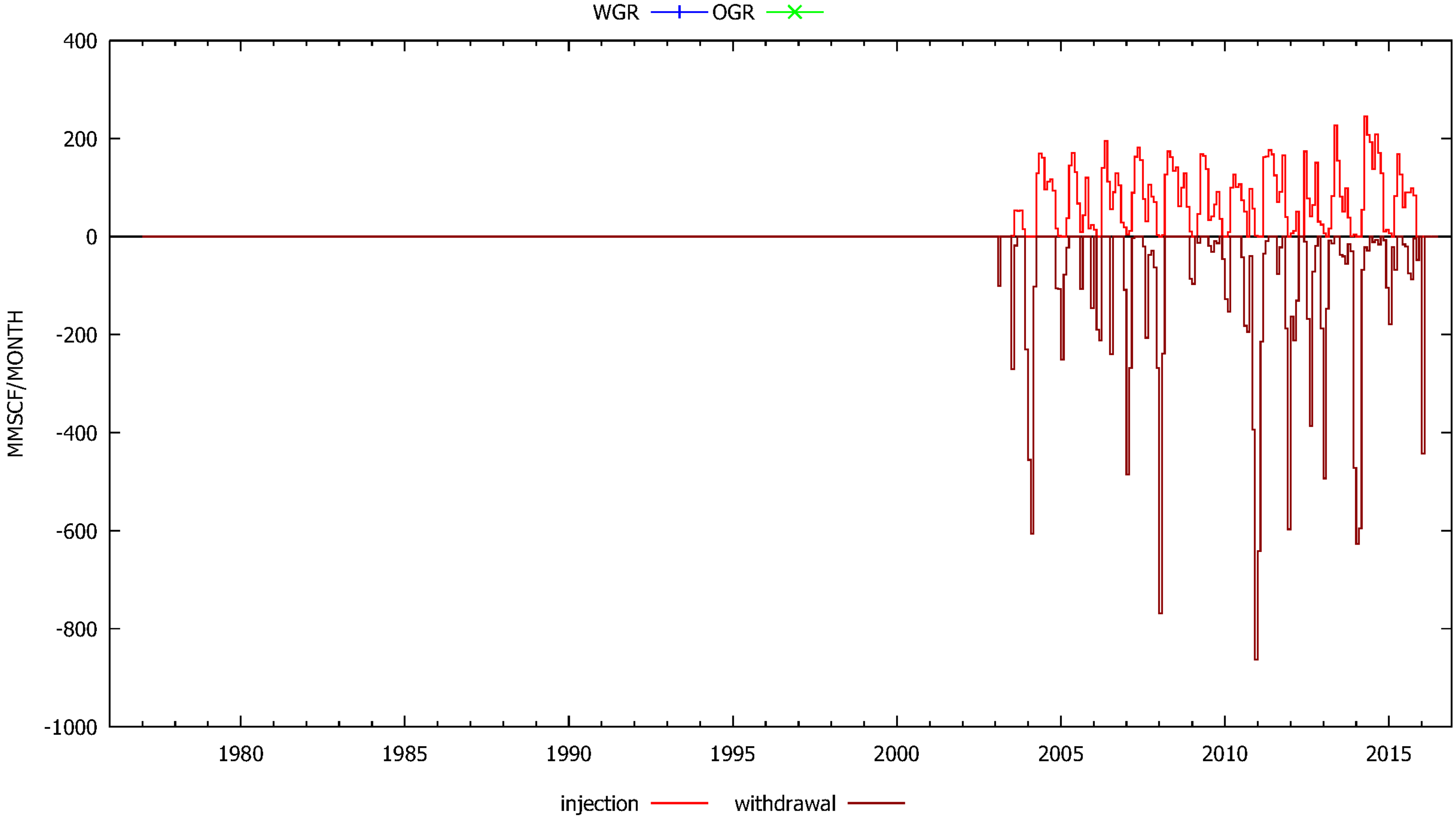
FERNANDO FEE 38A WELL



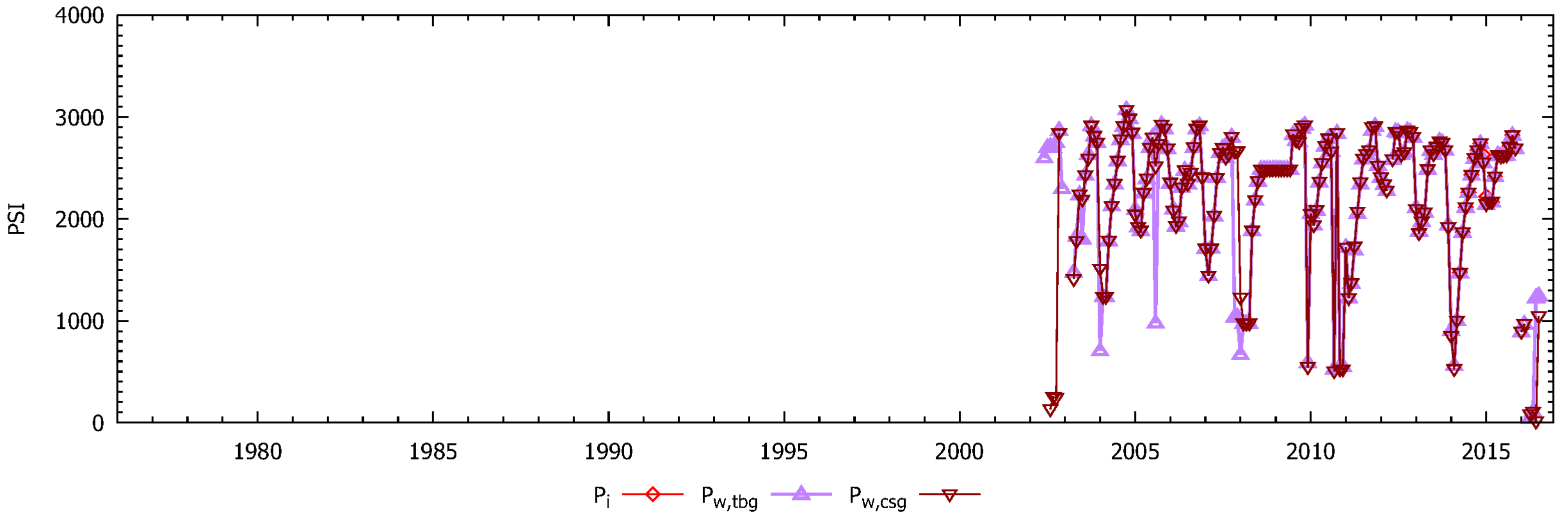
FERNANDO FEE 38B WELL

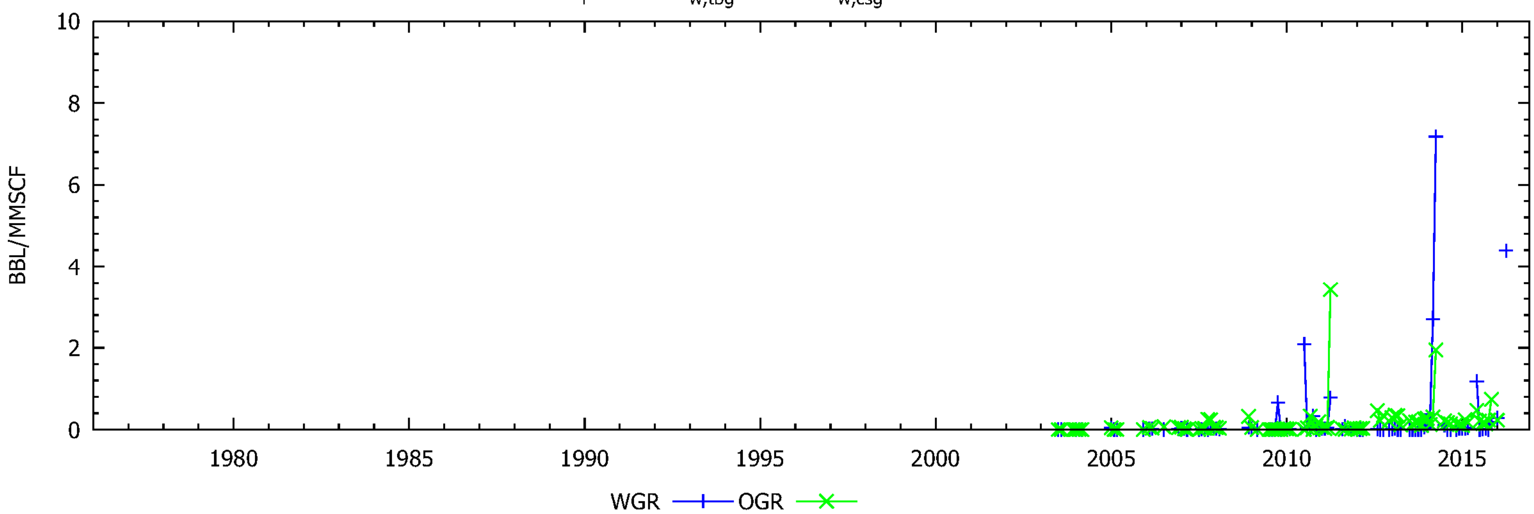


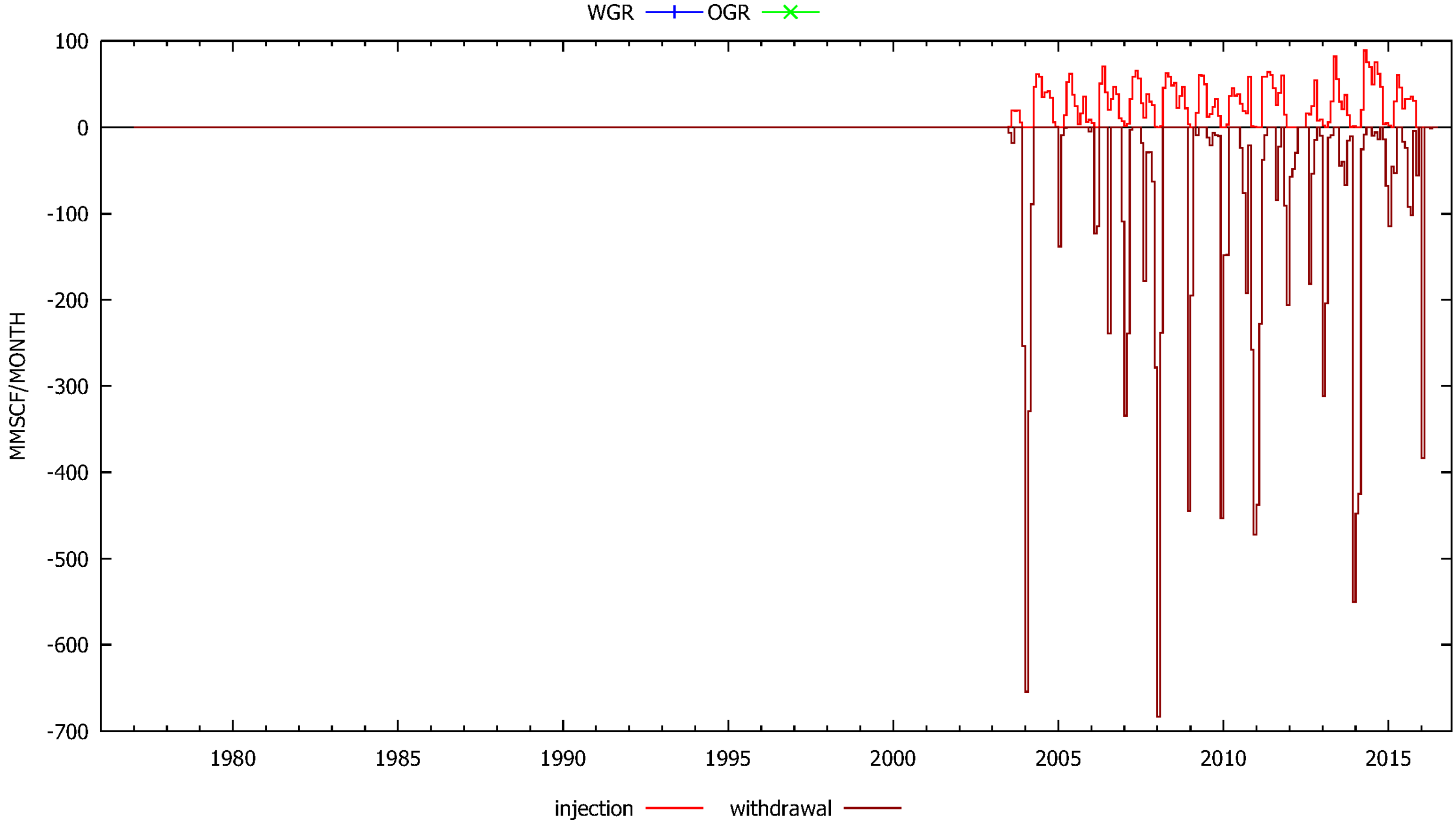




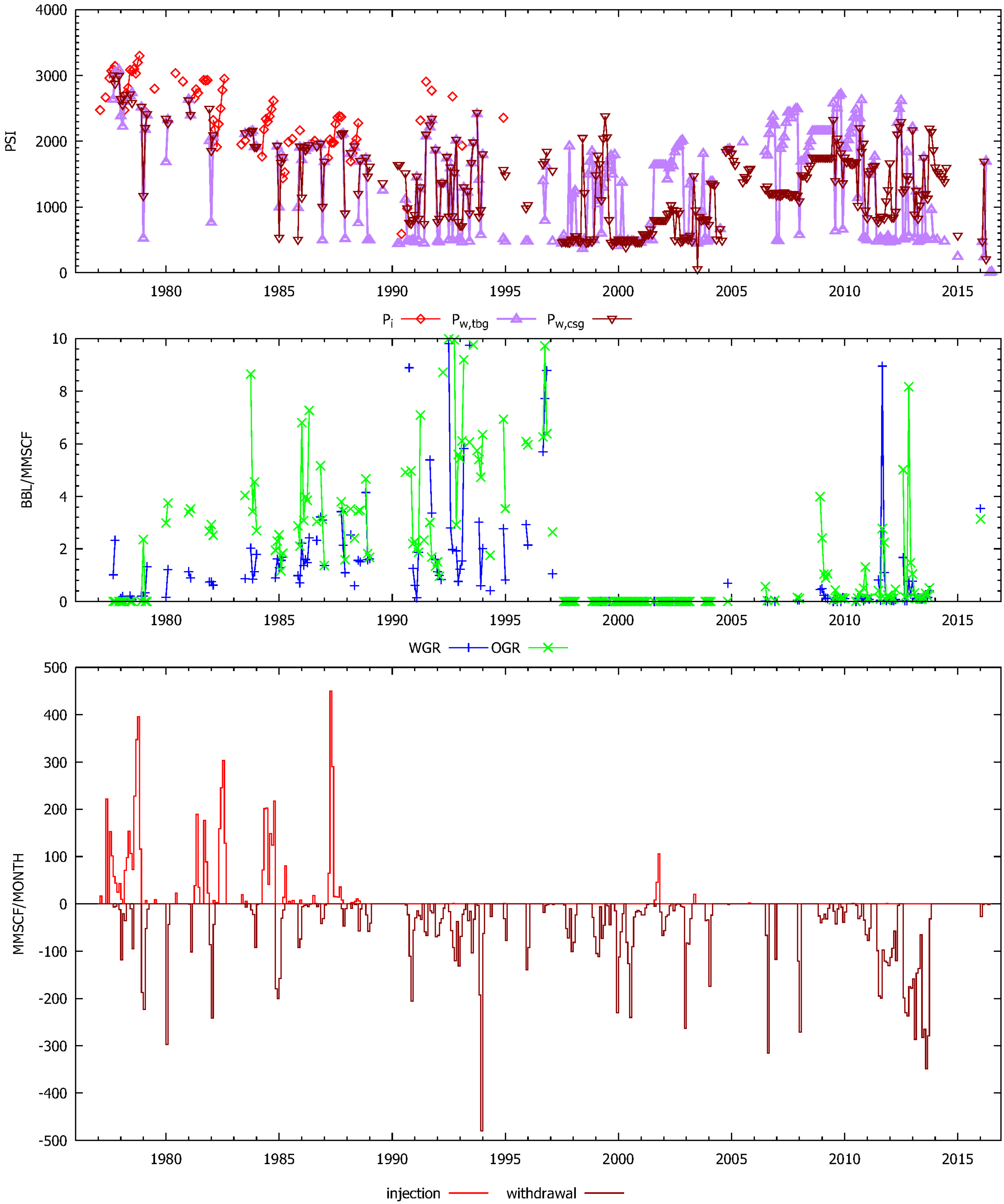
FERNANDO FEE 38C WELL







FREW 2 WELL


PSI
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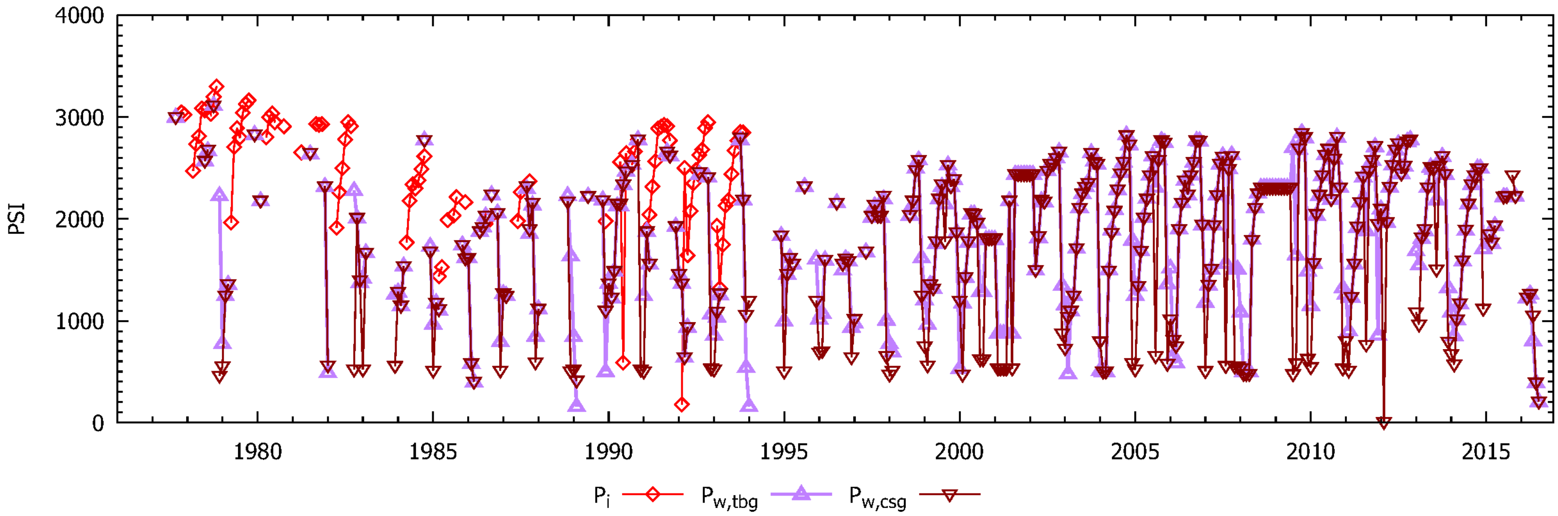
-500
injection
withdrawal

FREW 4 WELL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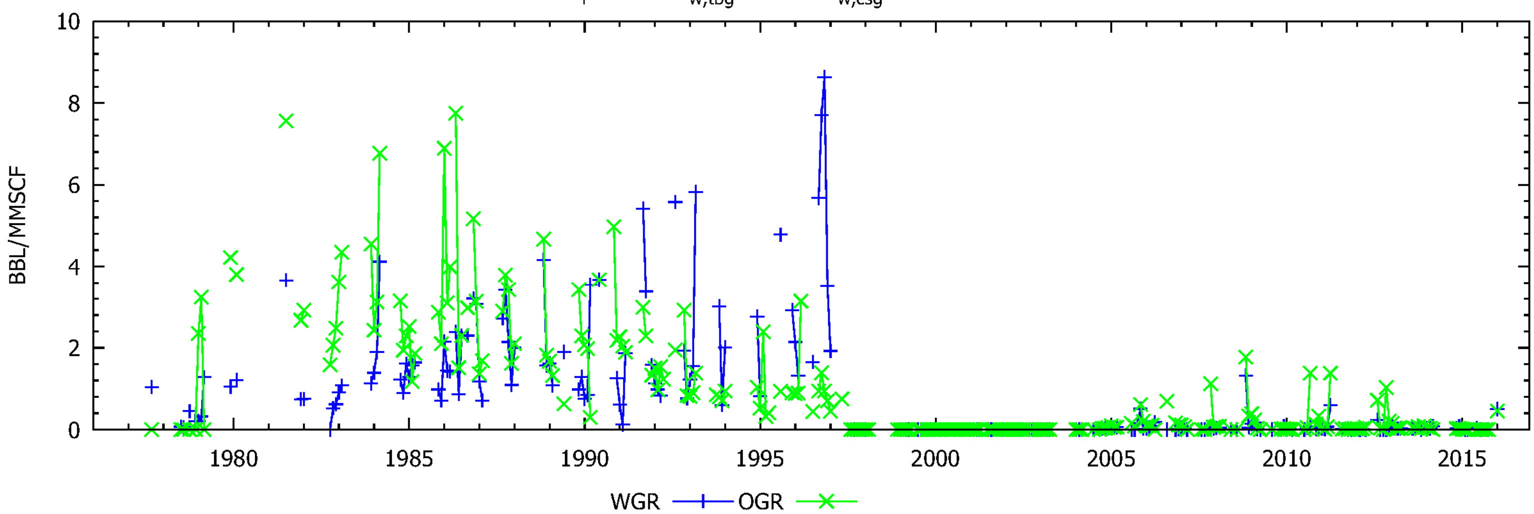
$P_{w,tbg}$
$P_{w,csg}$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WGR
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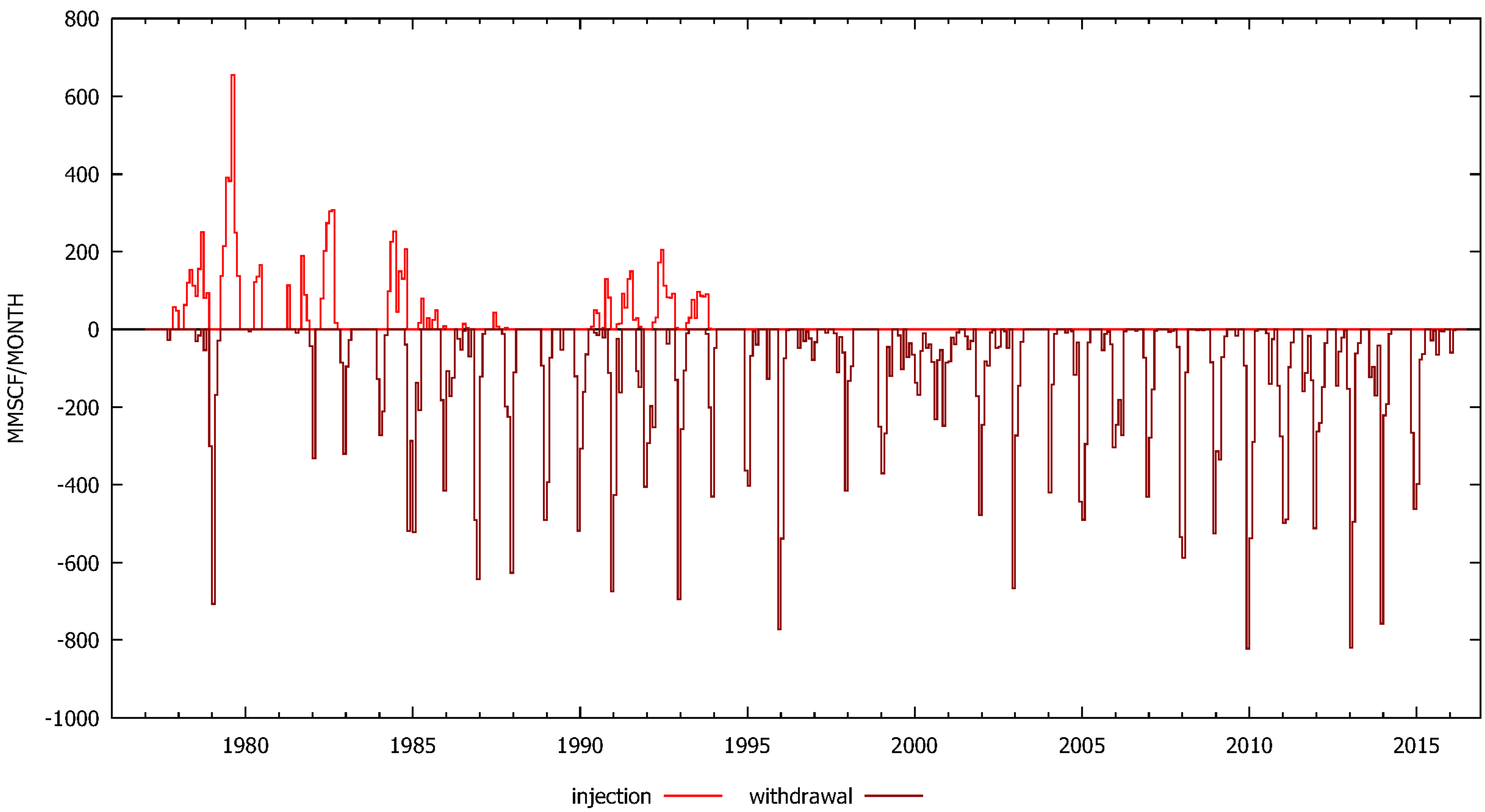
800
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MMSCF/MONTH
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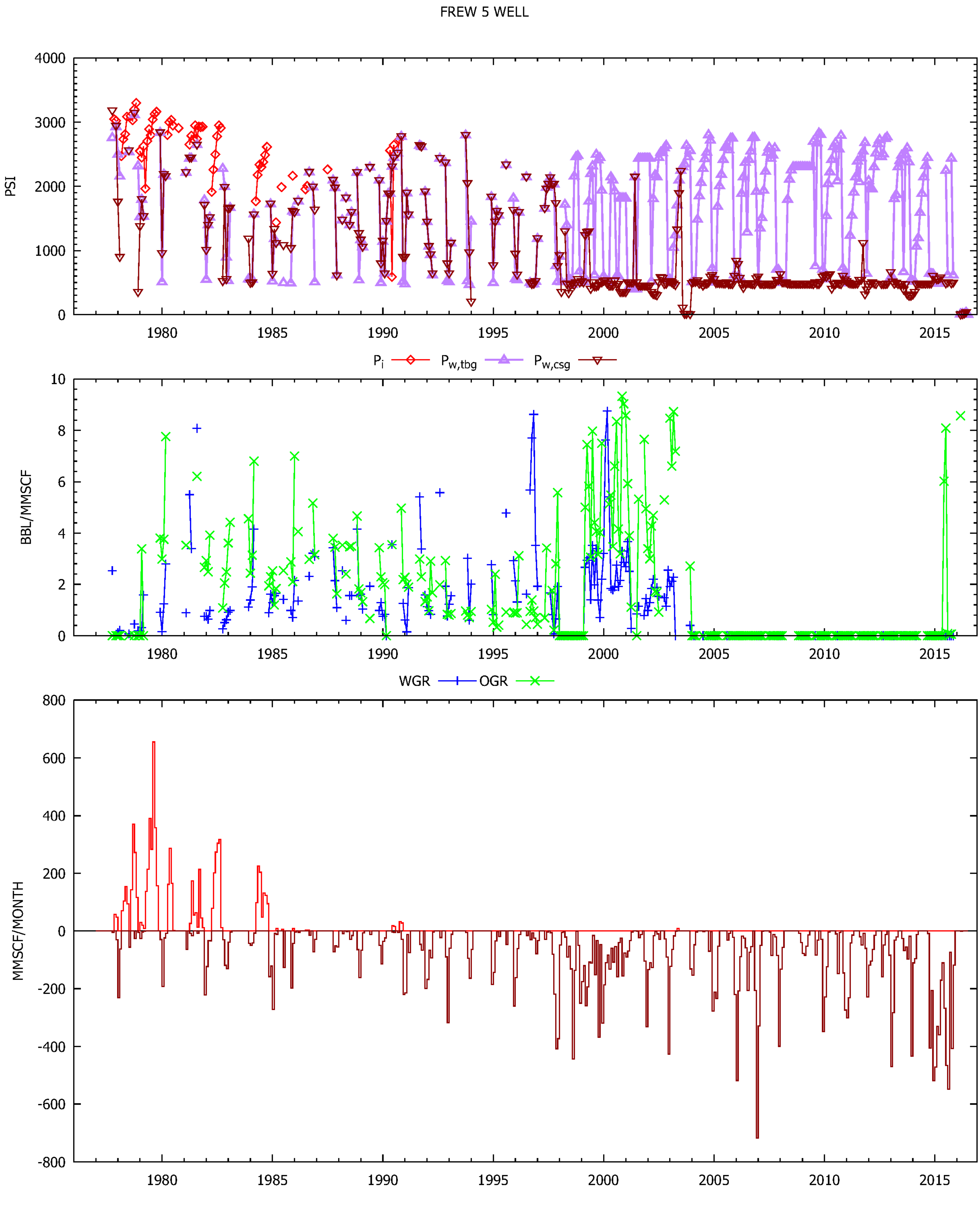
injection
withdrawal


FREW 5 WELL
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PSI
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P_w,tbg
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BBL/MMSCF
WGR
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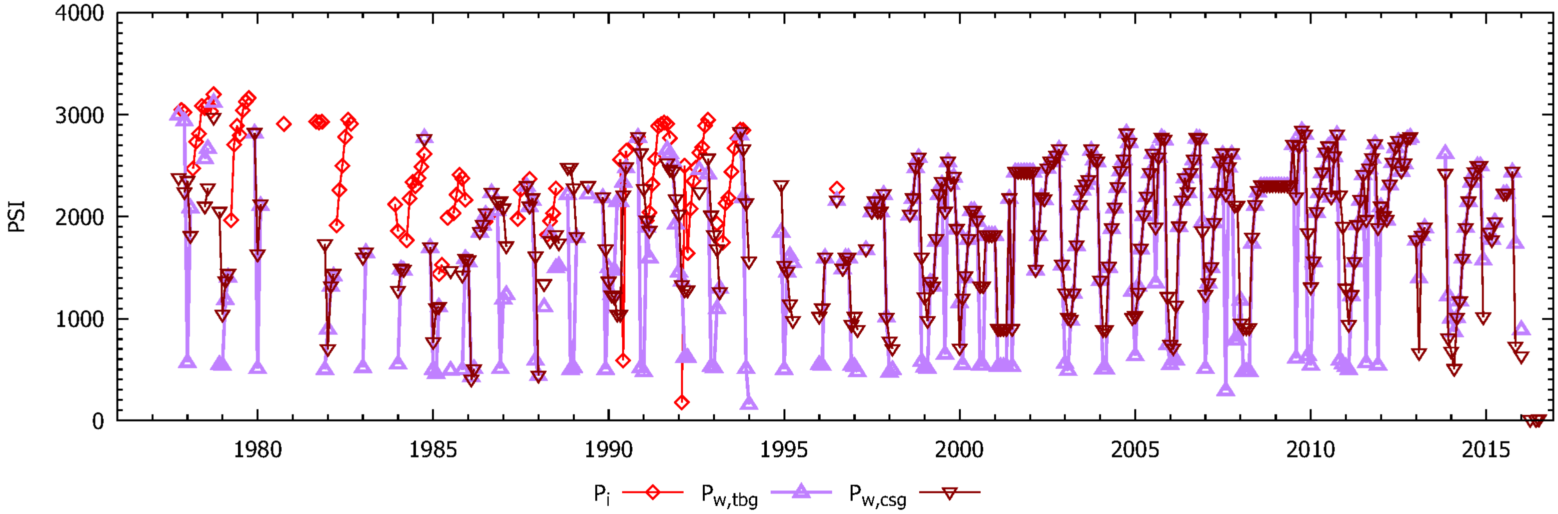
-200
-400
-600
-800
MMSCF/MONTH
injection
withdrawal

FREW 7 WELL



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PSI
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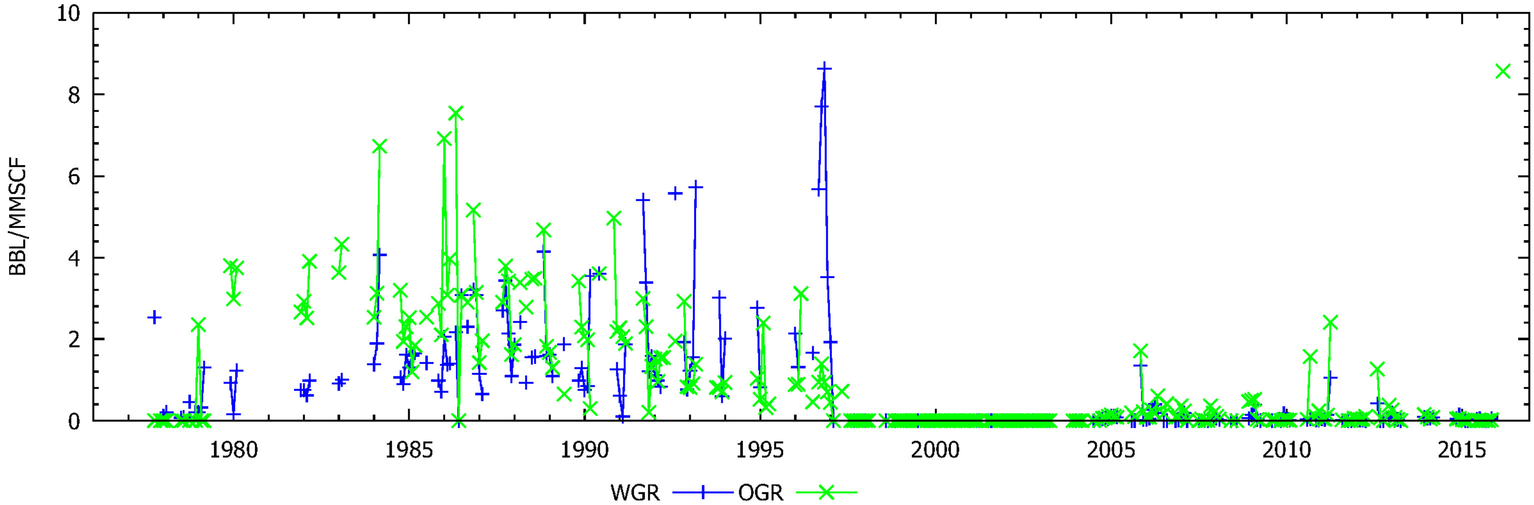
2015
P_i
$P_{w,tbg}$
$P_{w,csg}$



10
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BBL/MMSCF
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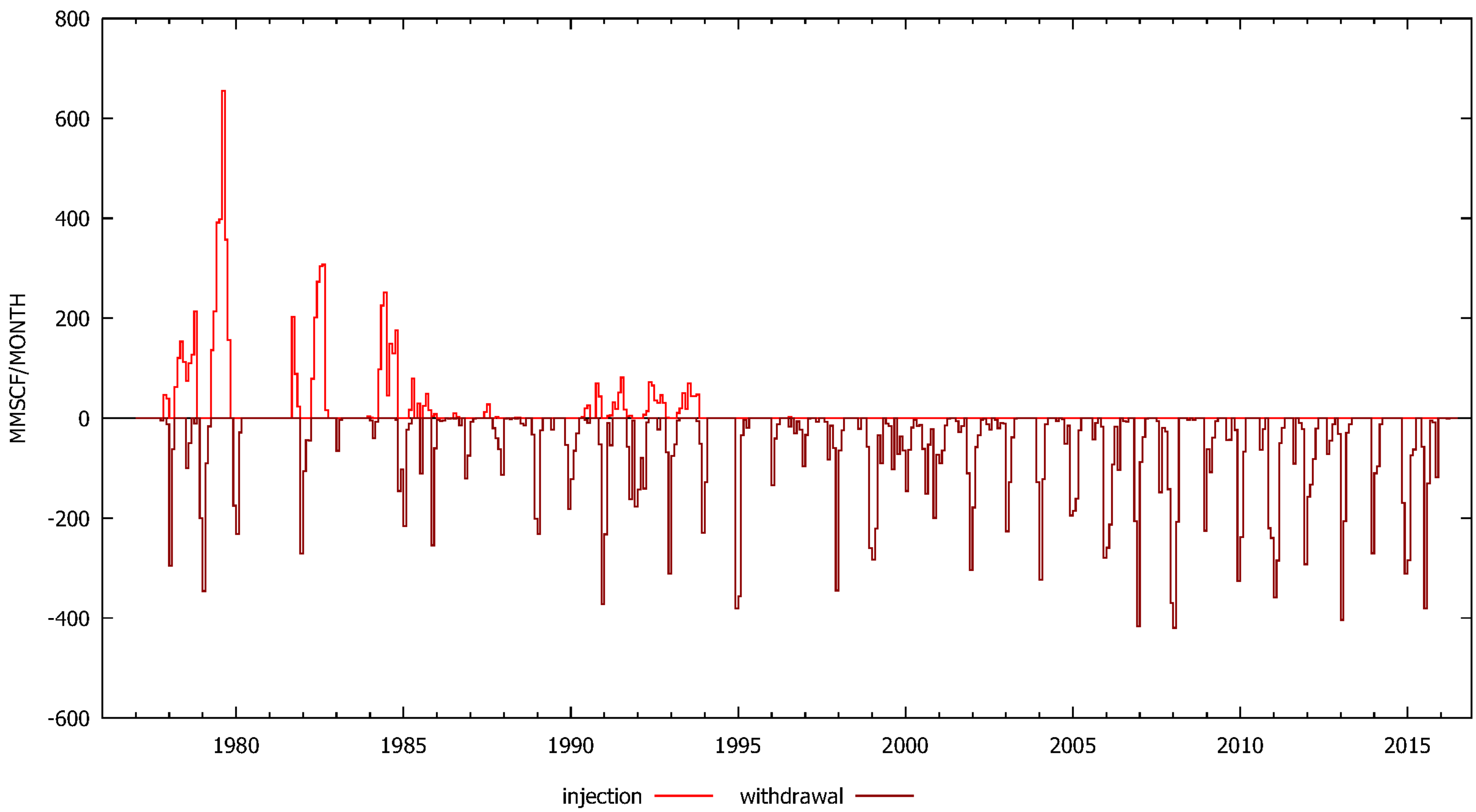

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MMSCF/MONTH
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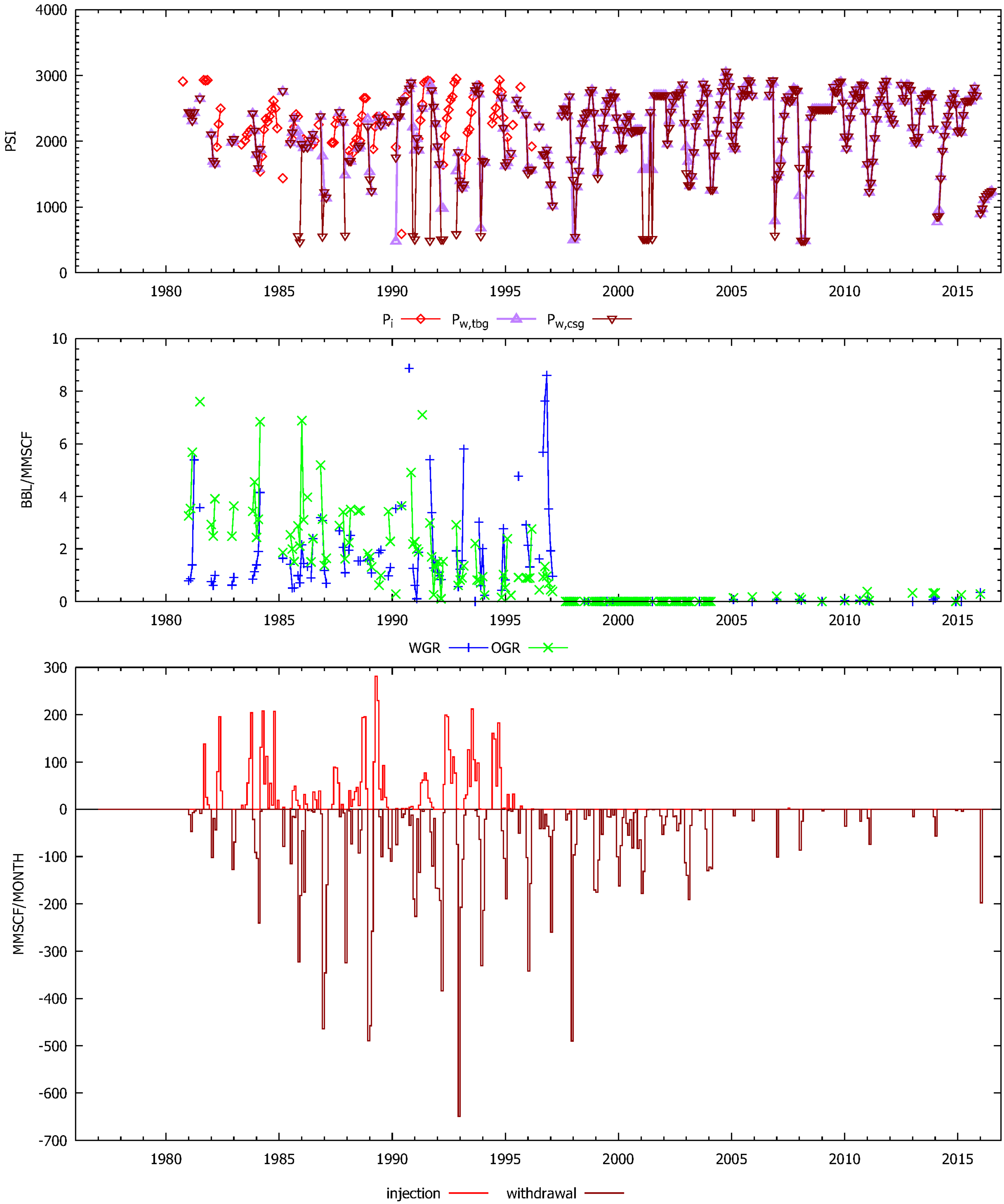
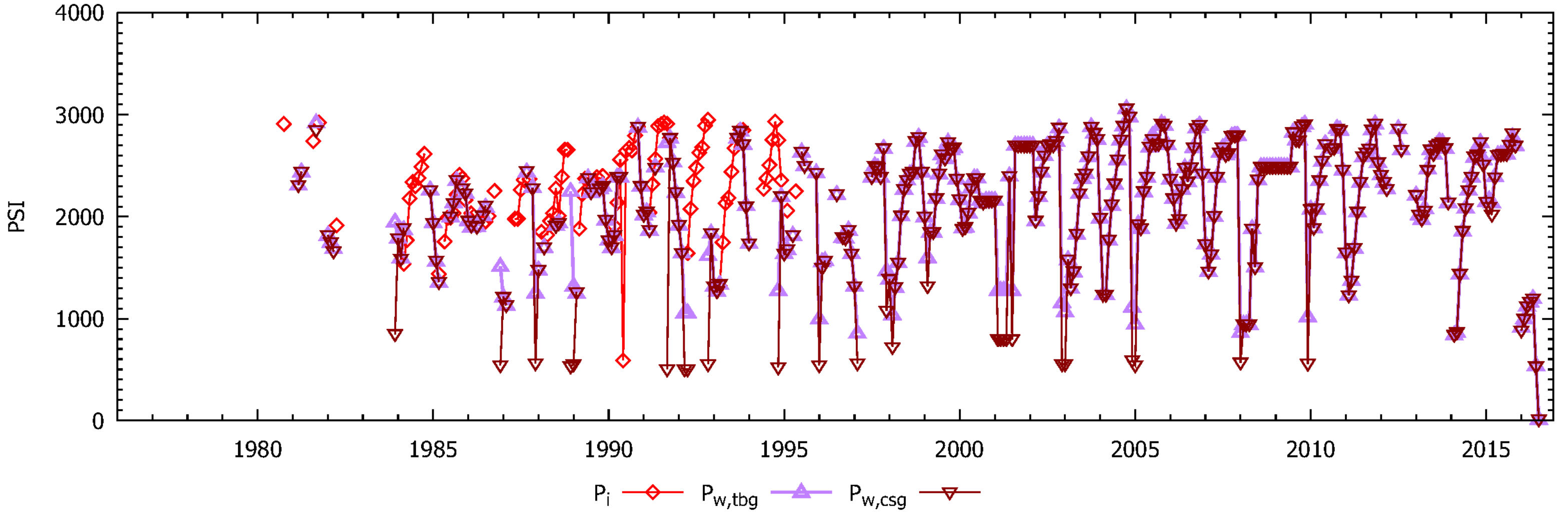
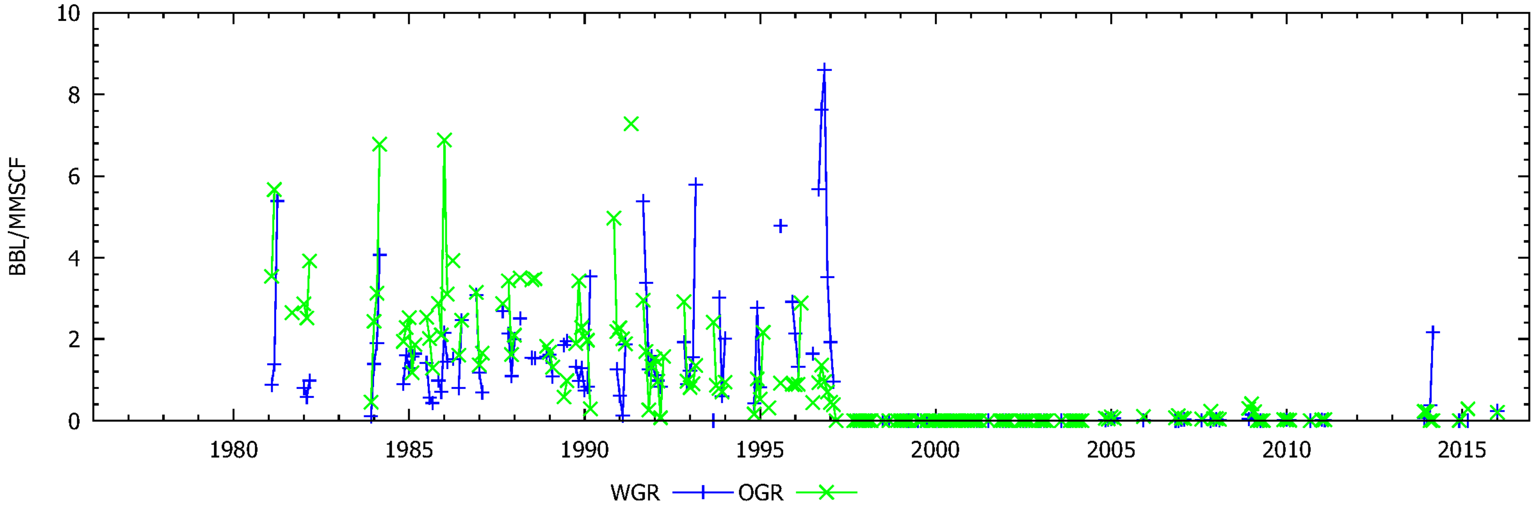
2015
injection
withdrawal

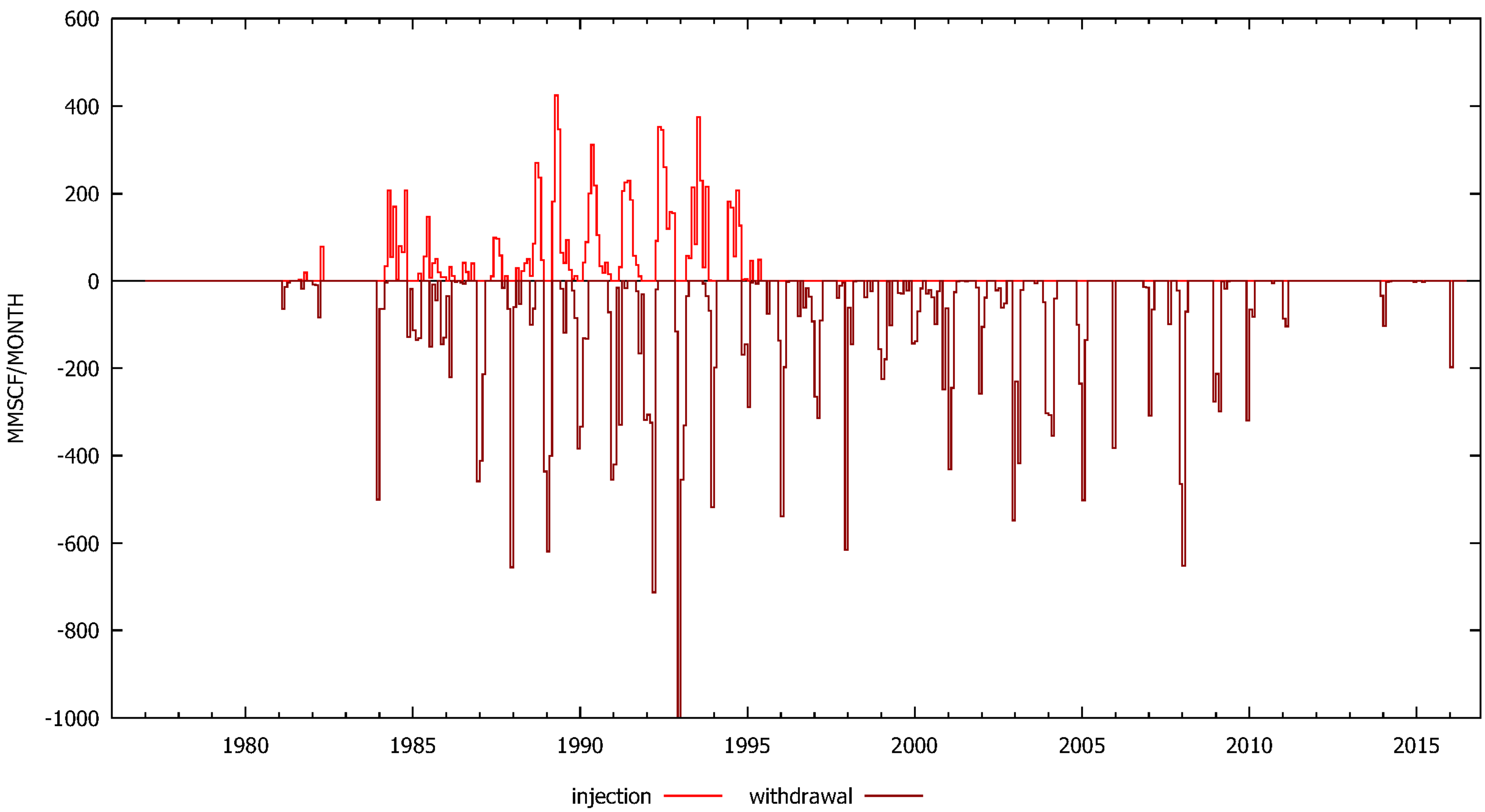
MISSION ADRIAN 1A WELL



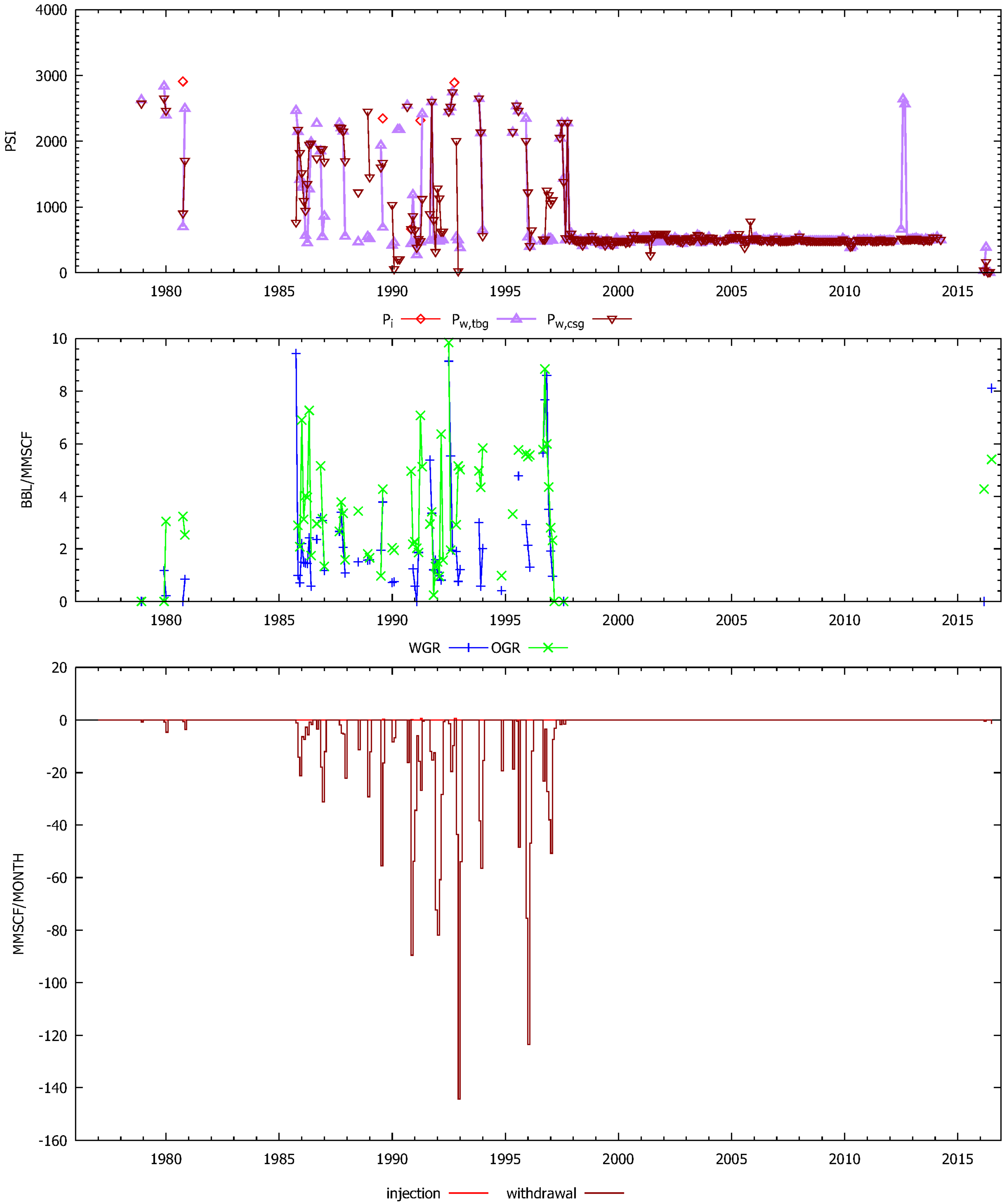
MISSION ADRIAN 1B WELL

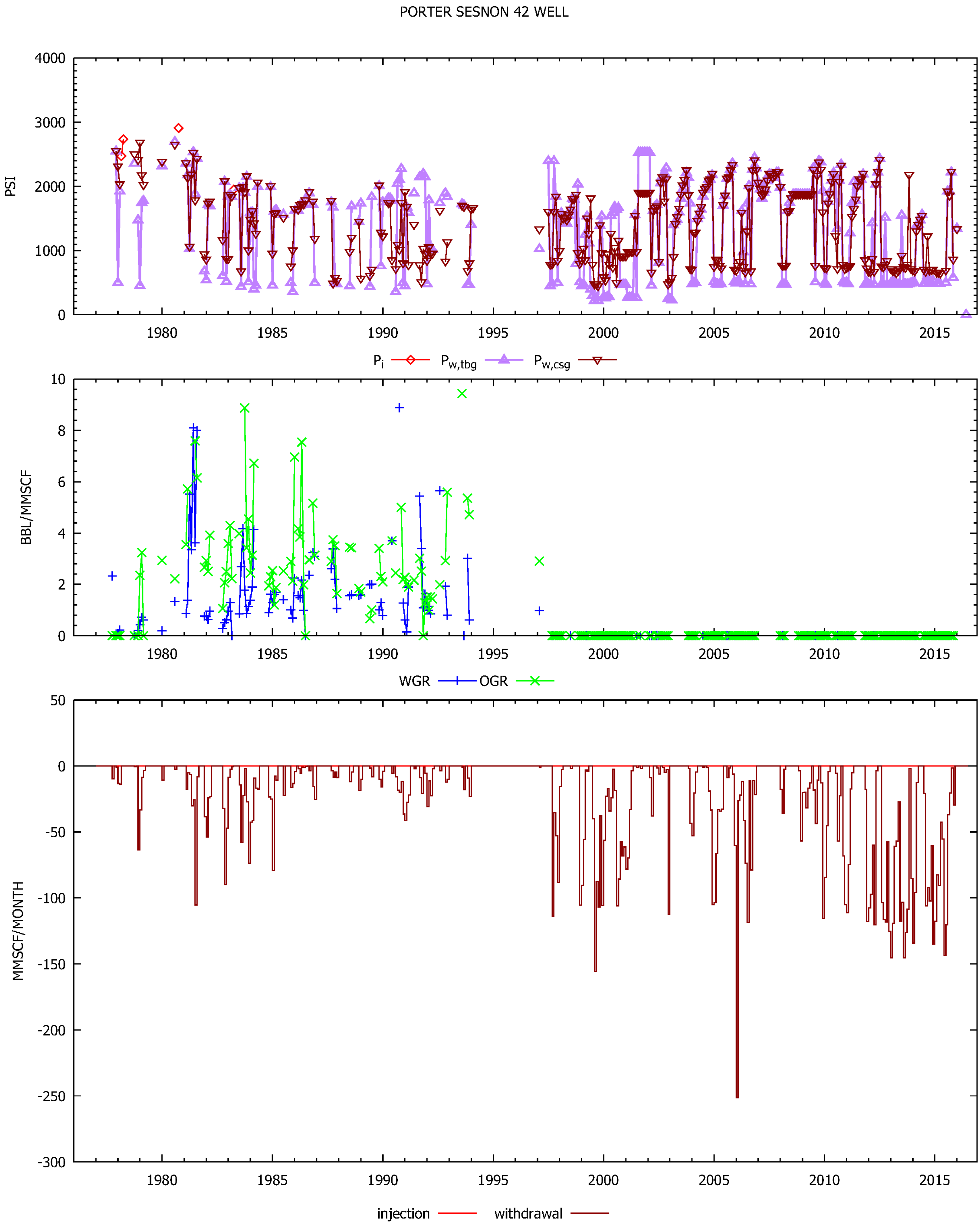






MISSION ADRIAN 3 WELL





PORTER SESNON 42 WELL
PSI
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$P_{w,tbg}$
$P_{w,csg}$
BBL/MMSCF
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WGR
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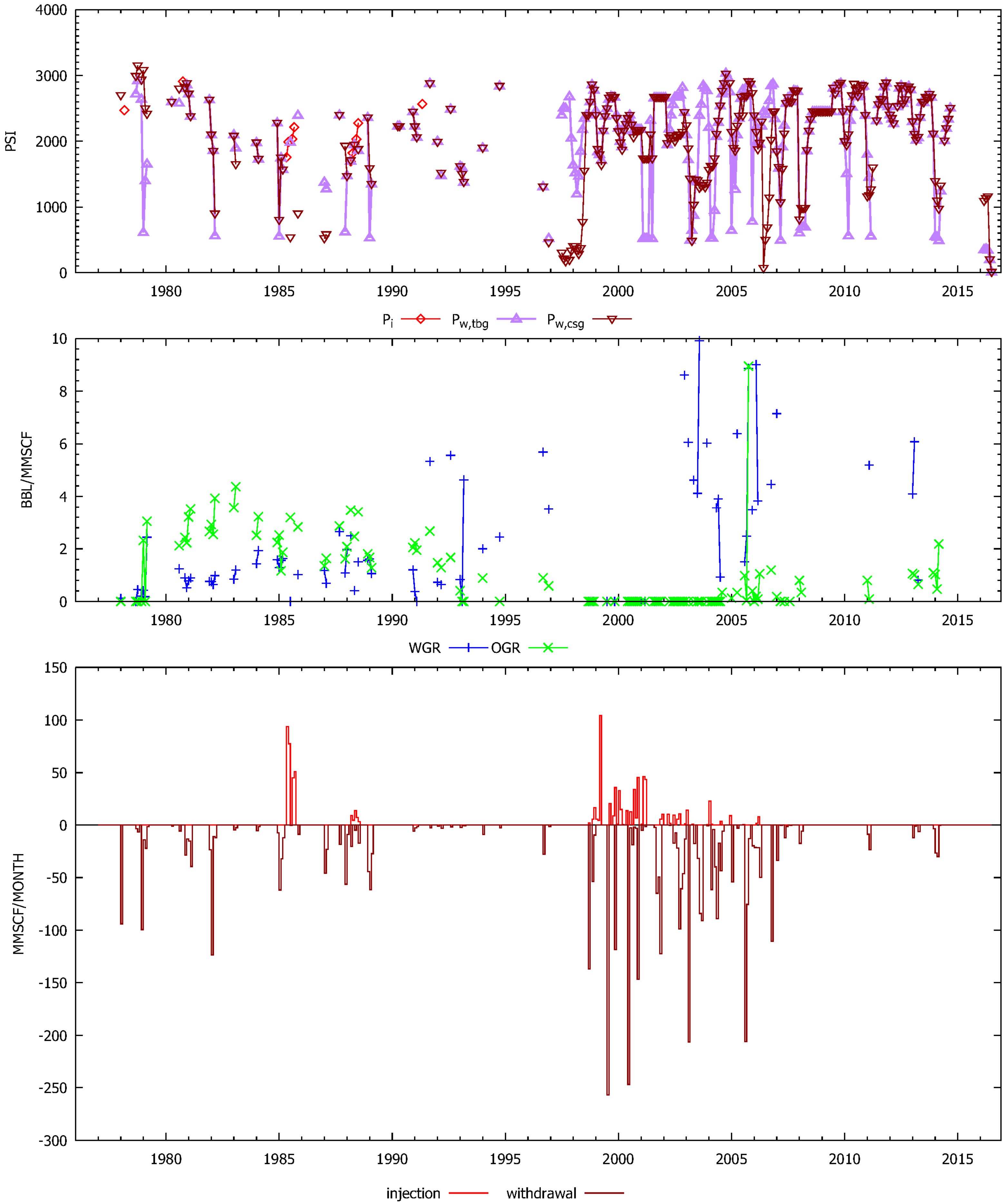
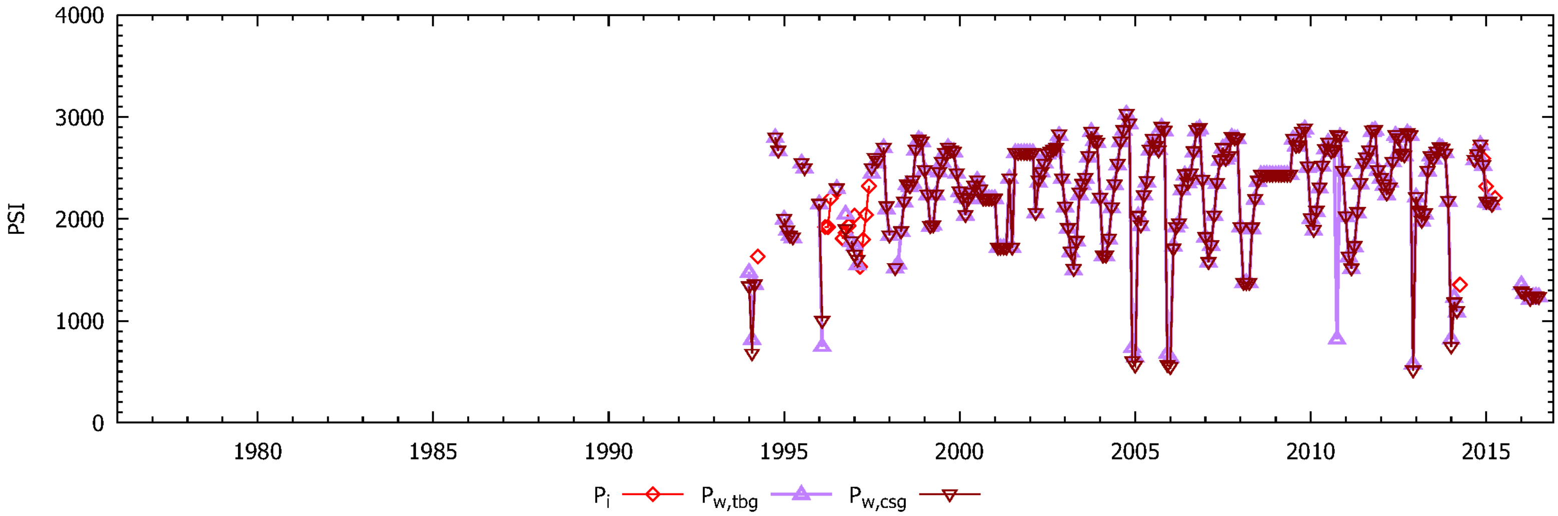
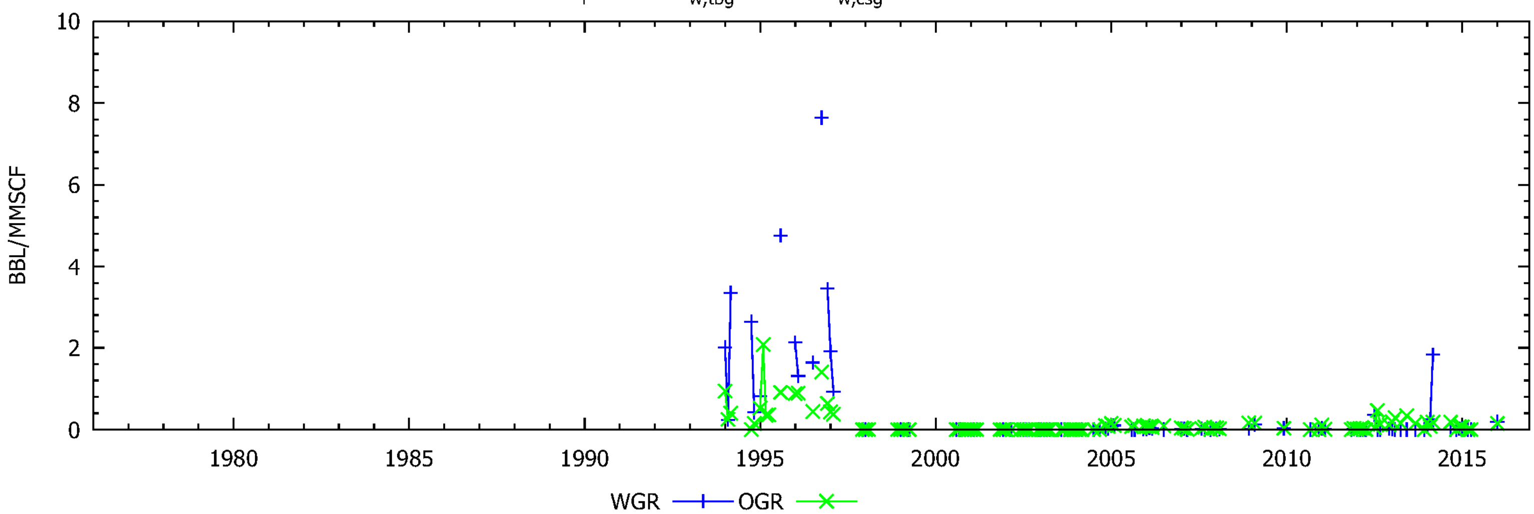
MMSCF/MONTH
50
0
-50
-100
-150
-200
-250
-300
injection
withdrawal

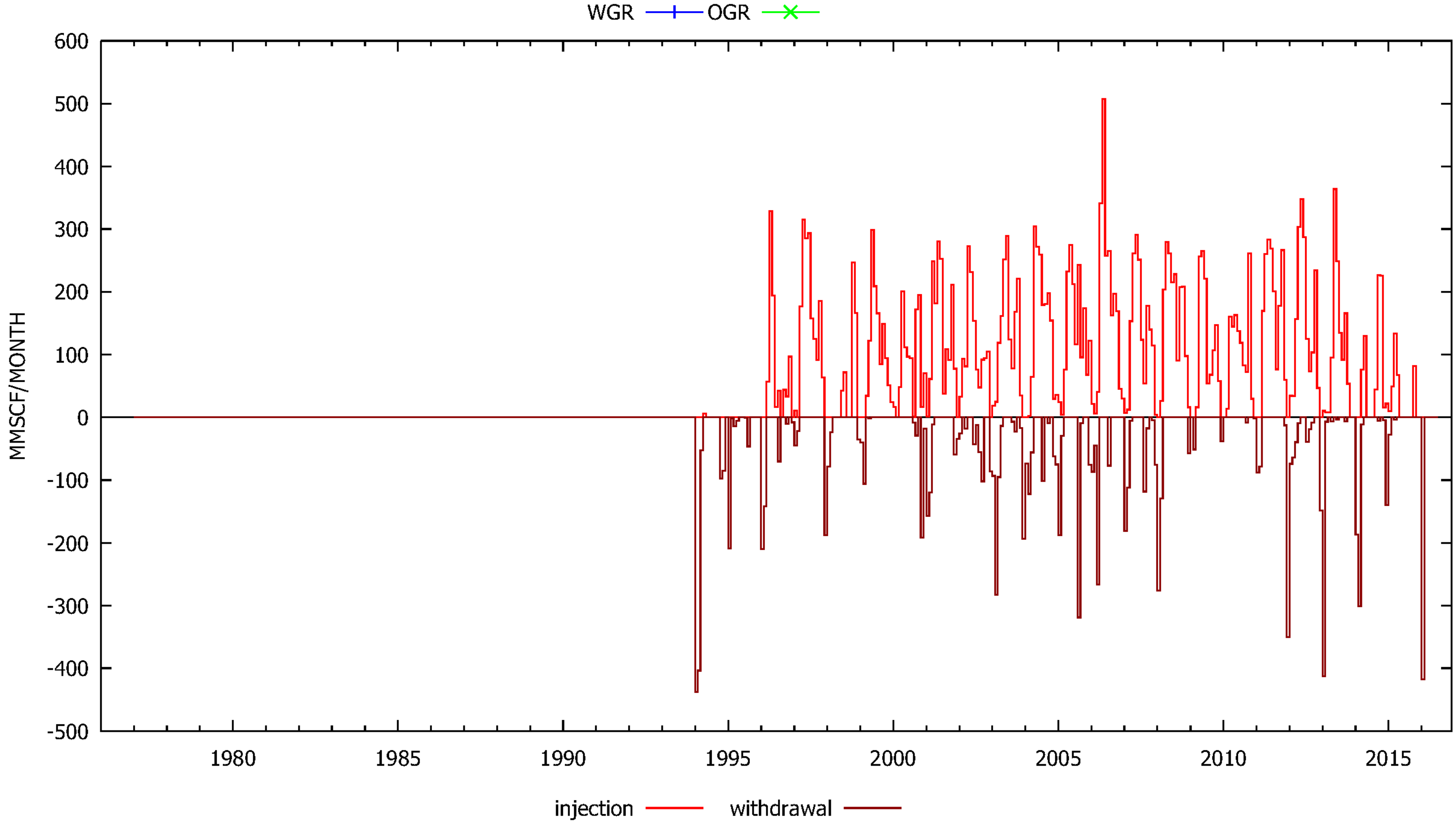
PORTER 12 WELL



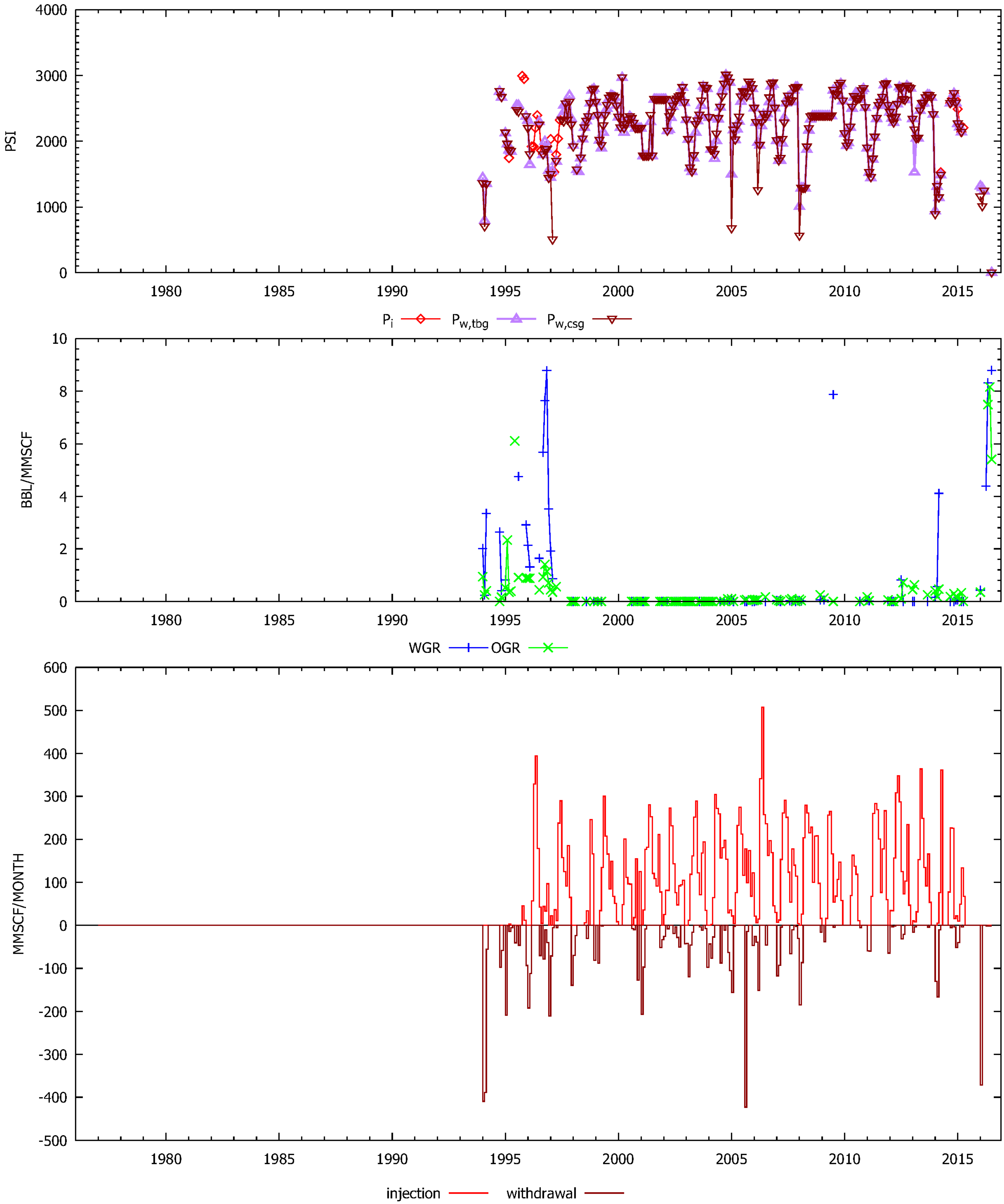
PORTER 24A WELL



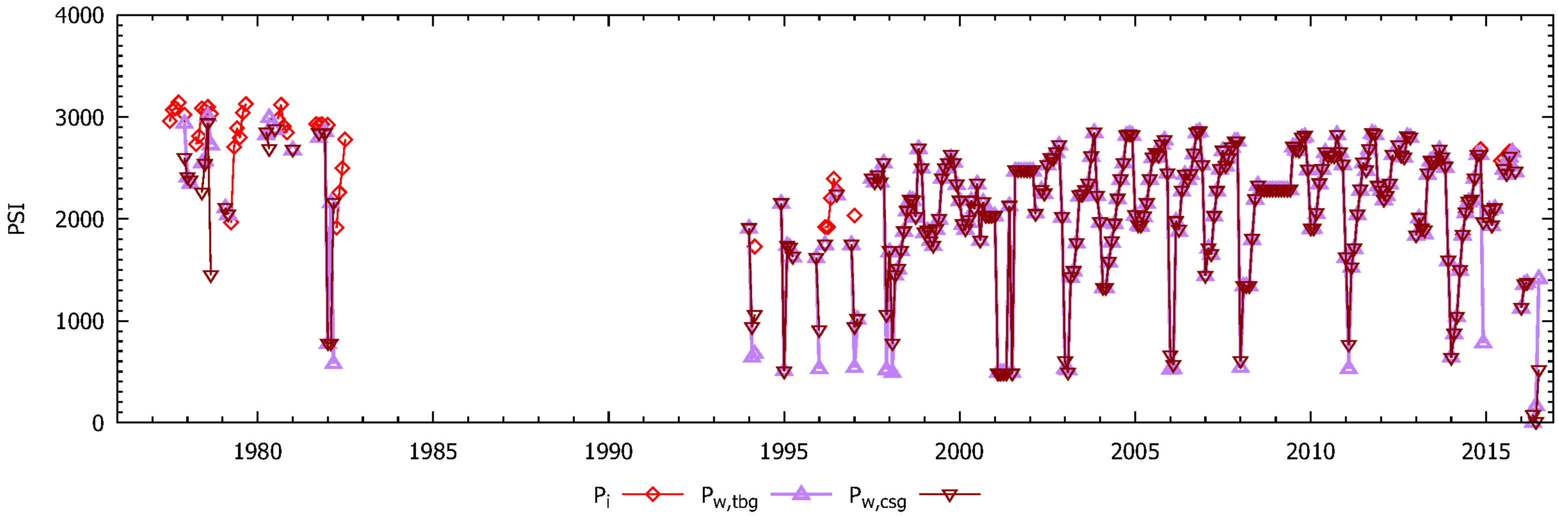


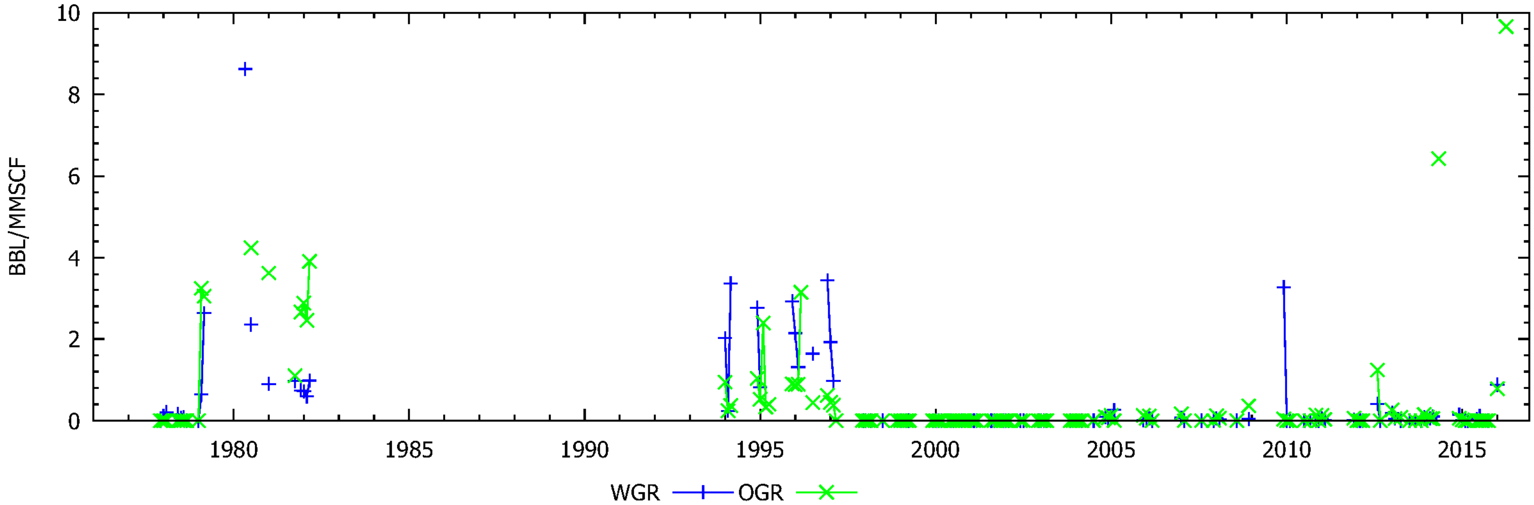


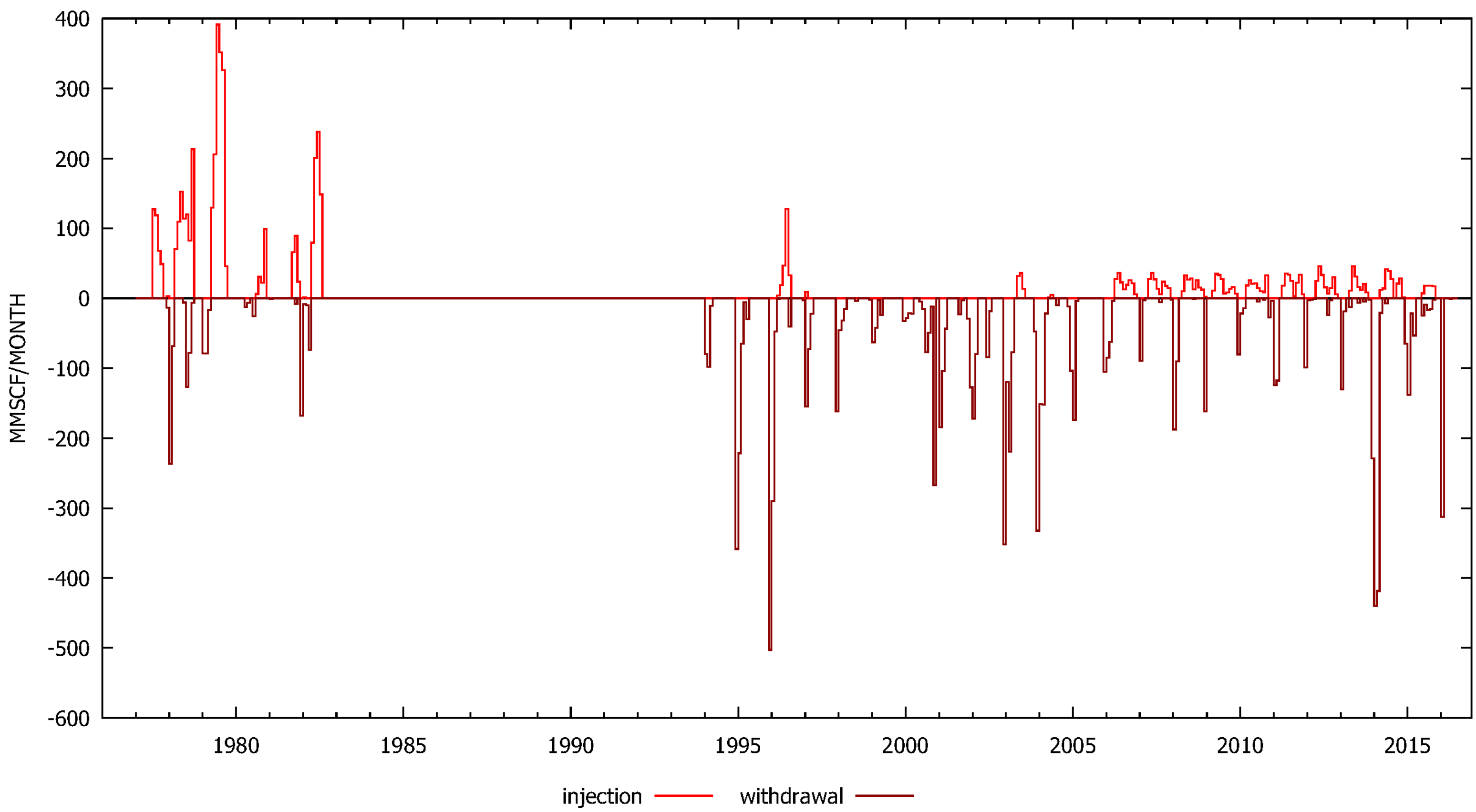
PORTER 24B WELL



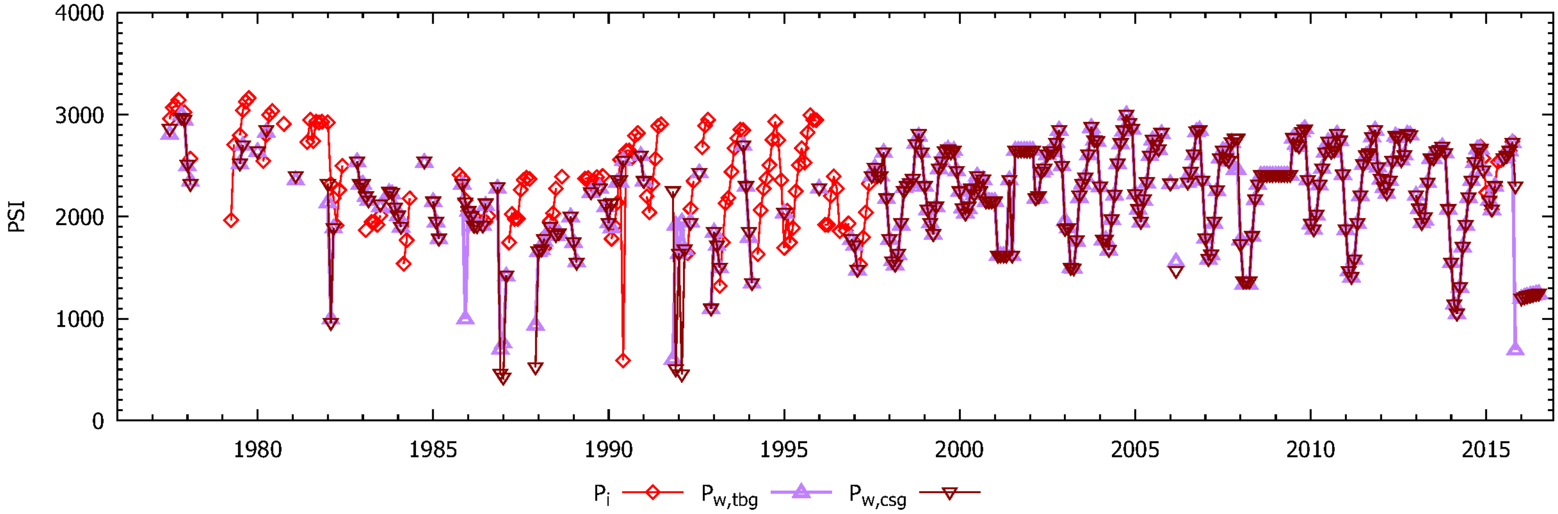
PORTER 25R WELL

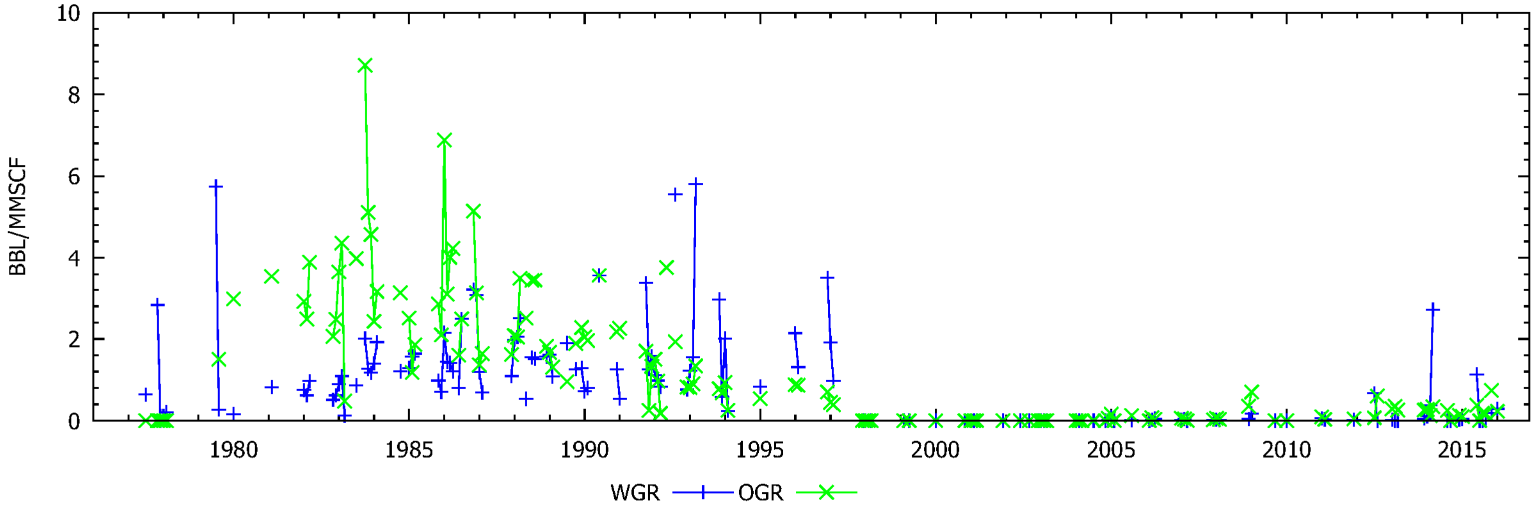


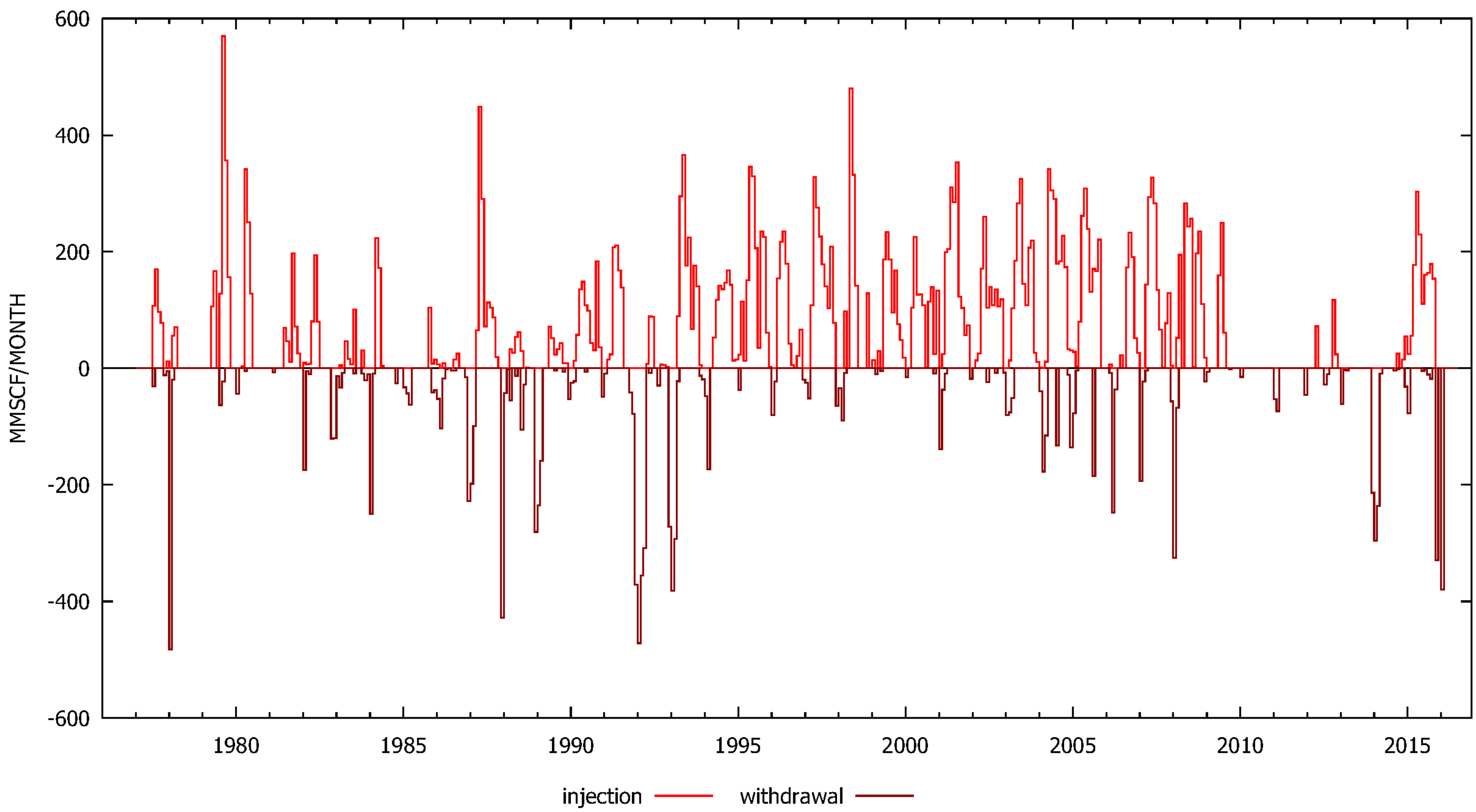




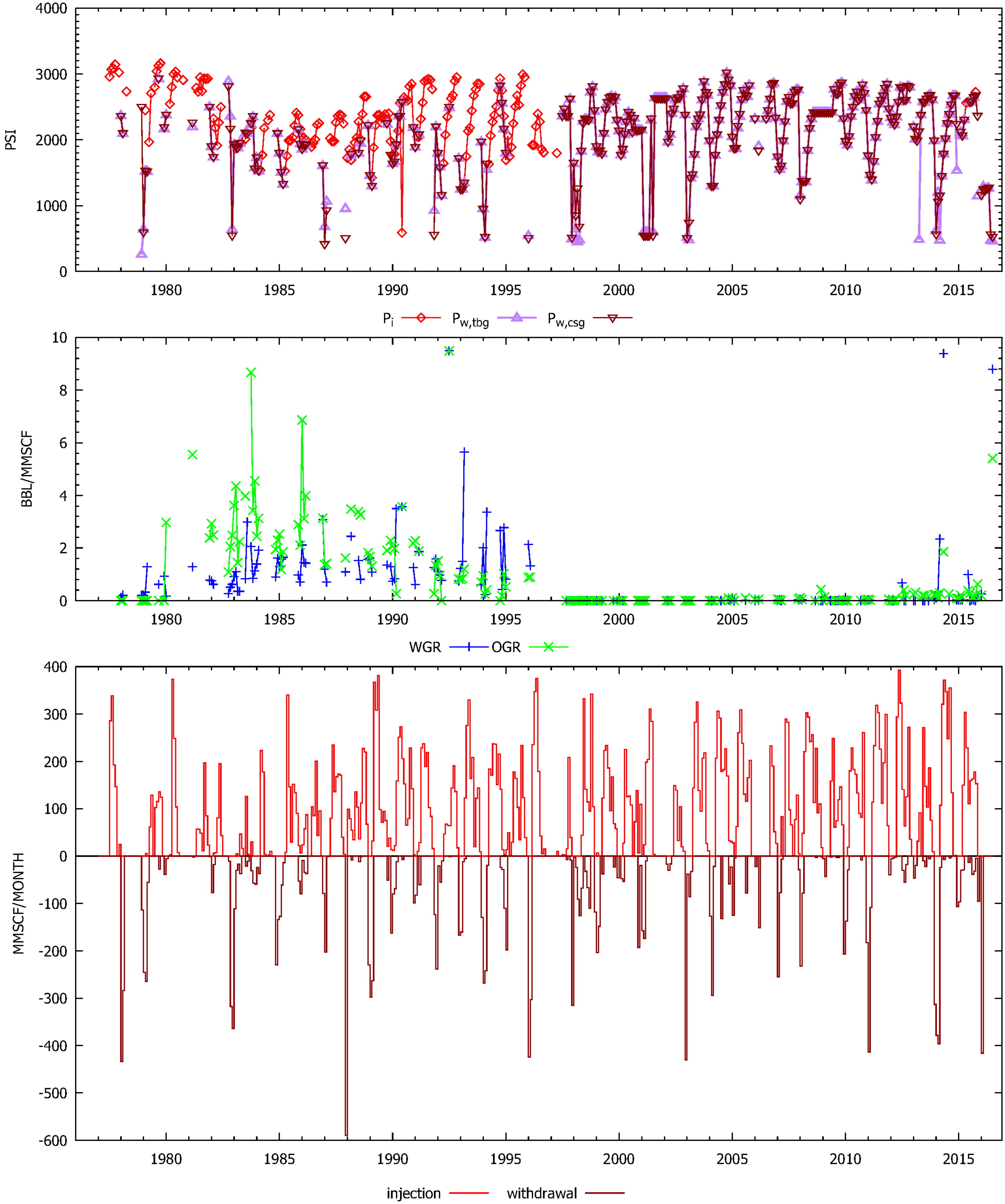
PORTER 26 WELL



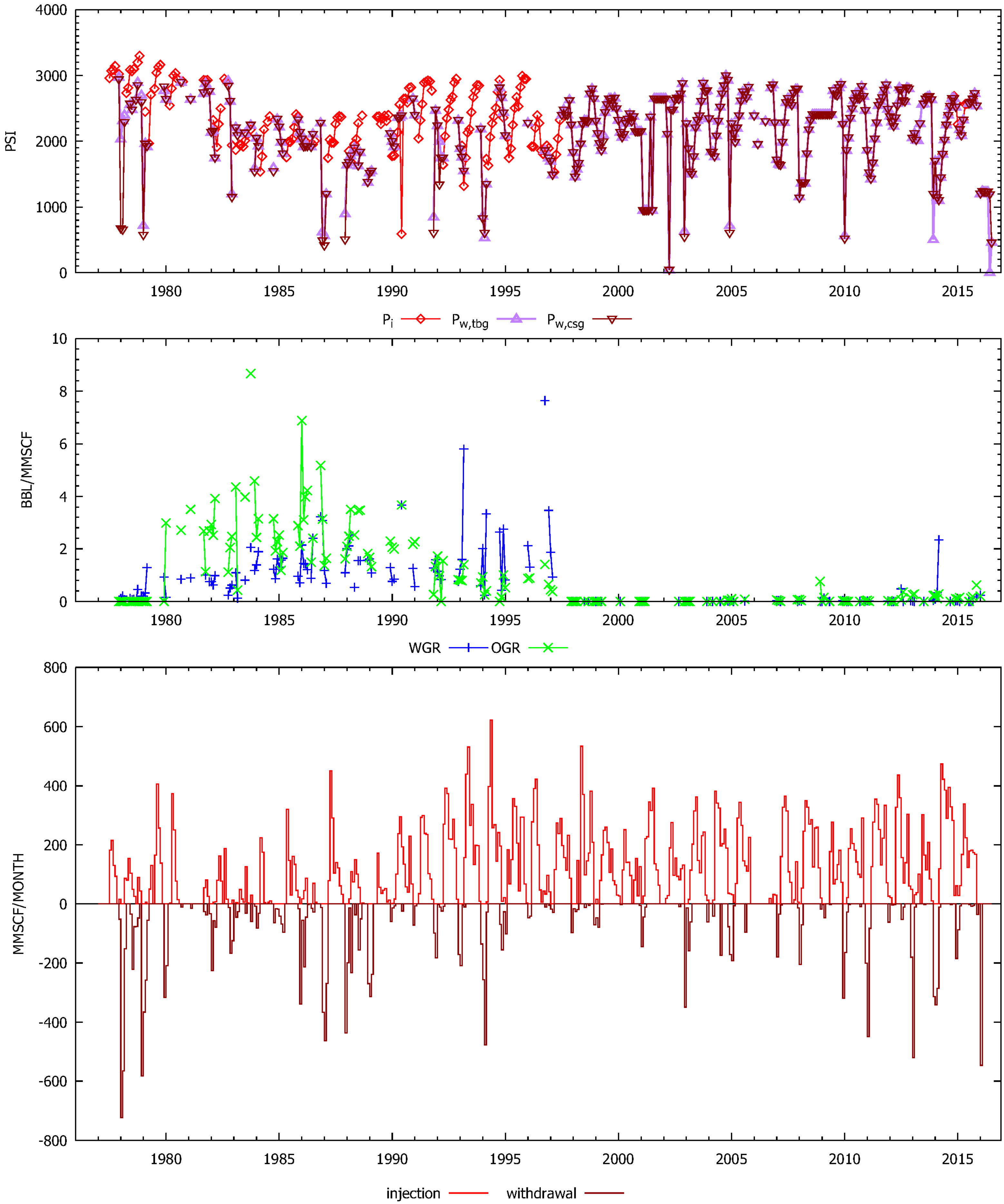


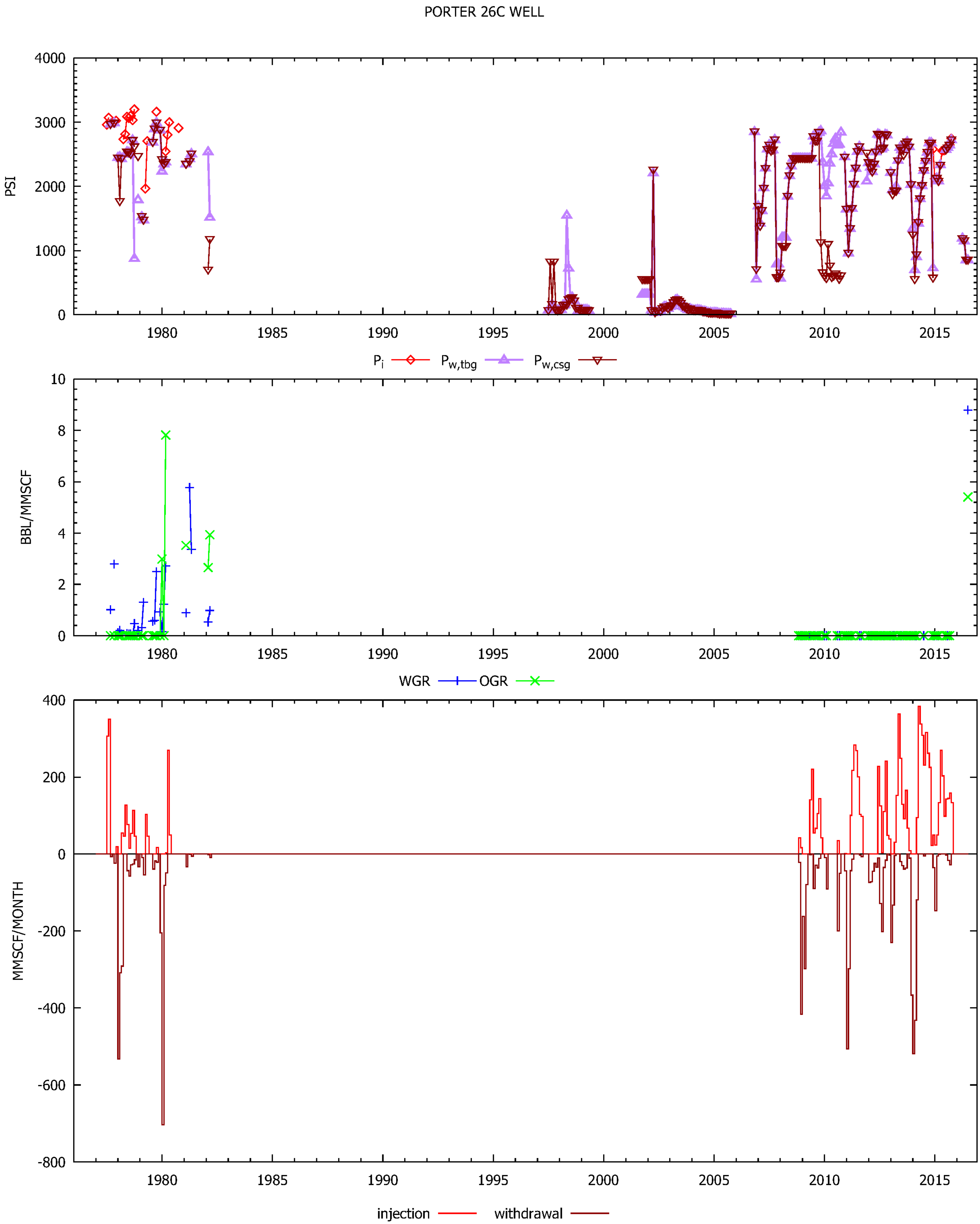


PORTER 26A WELL

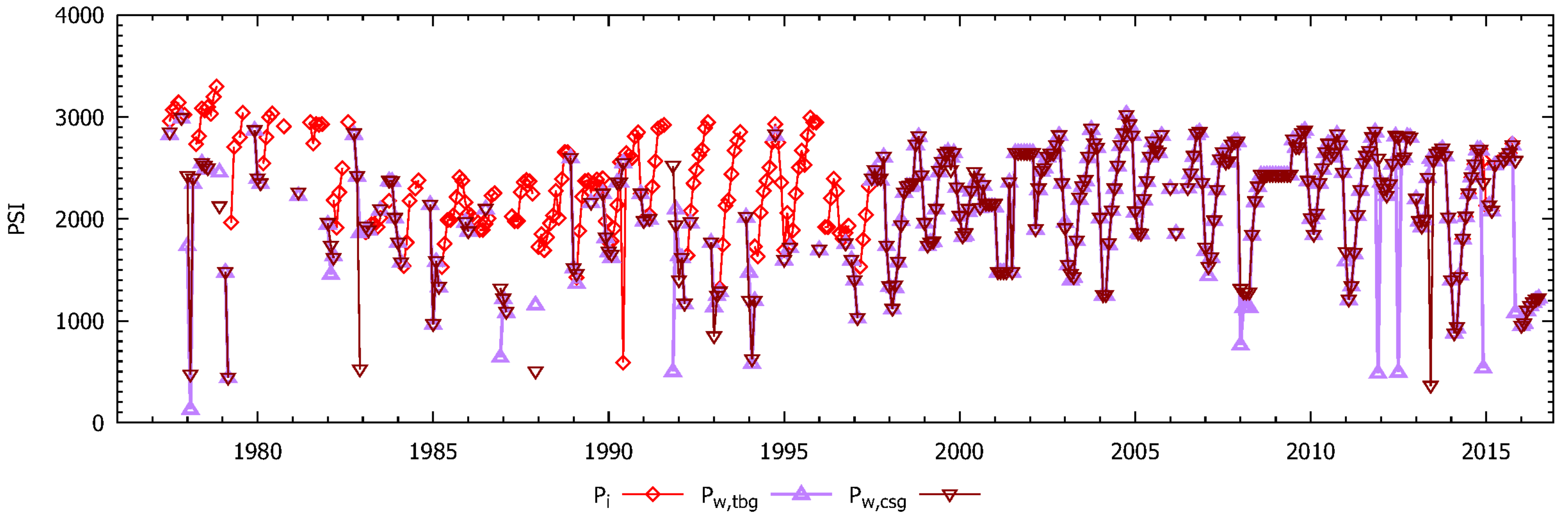


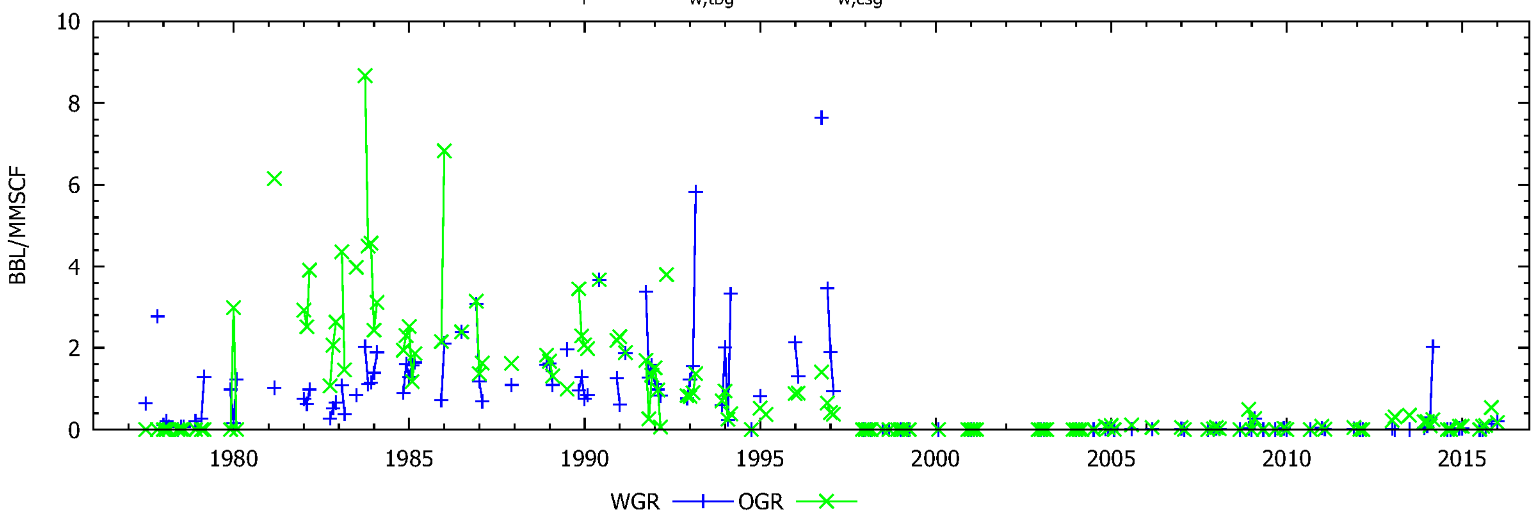
PORTER 26B WELL

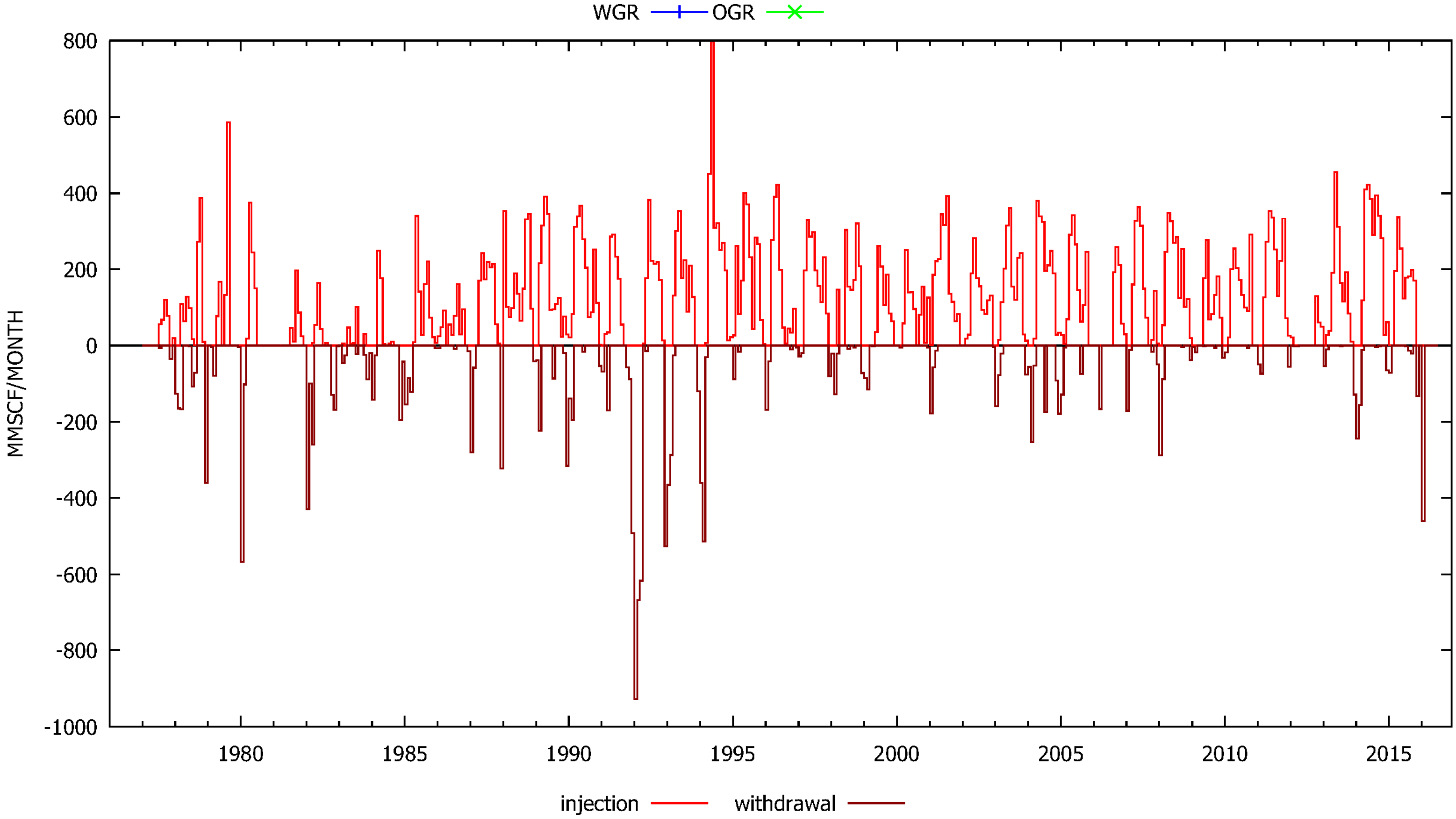



PORTER 26C WELL
PSI
4000
3000
2000
1000
0
1980
1985
1990
1995
2000
2005
2010
2015
P_i
$P_{w,tbg}$
$P_{w,csg}$
BBL/MMSCF
10
8
6
4
2
0
WGR
OGR
MMSCF/MONTH
400
200
-200
-400
-600
-800
injection
withdrawal

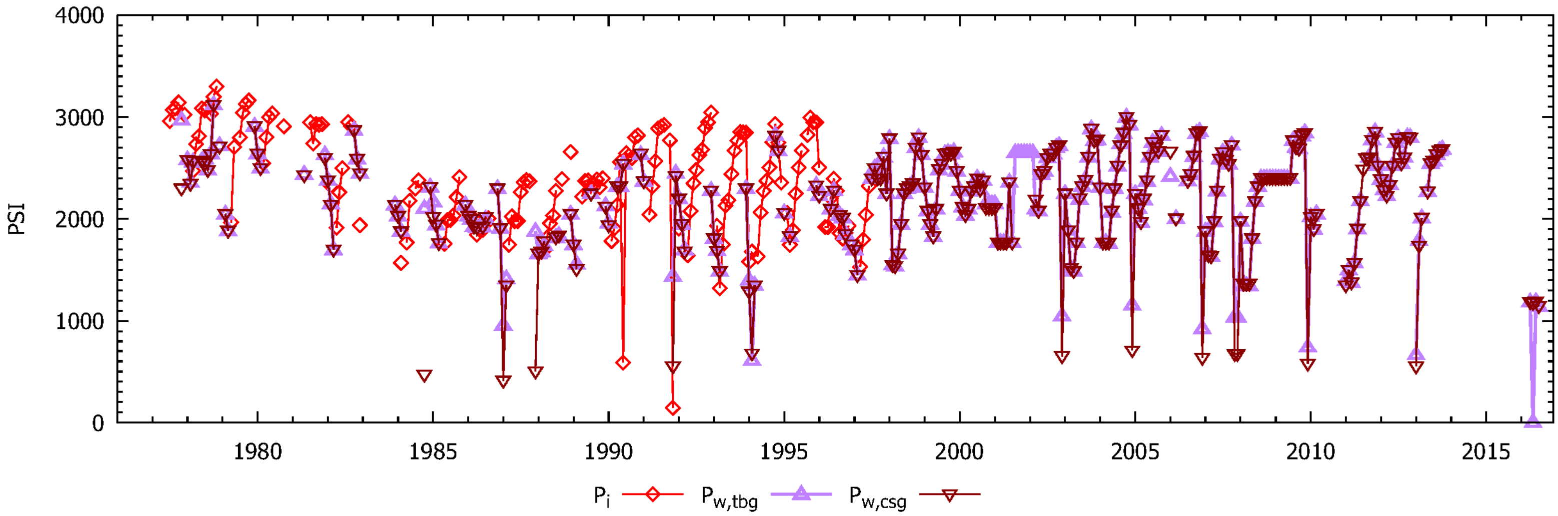
PORTER 26D WELL

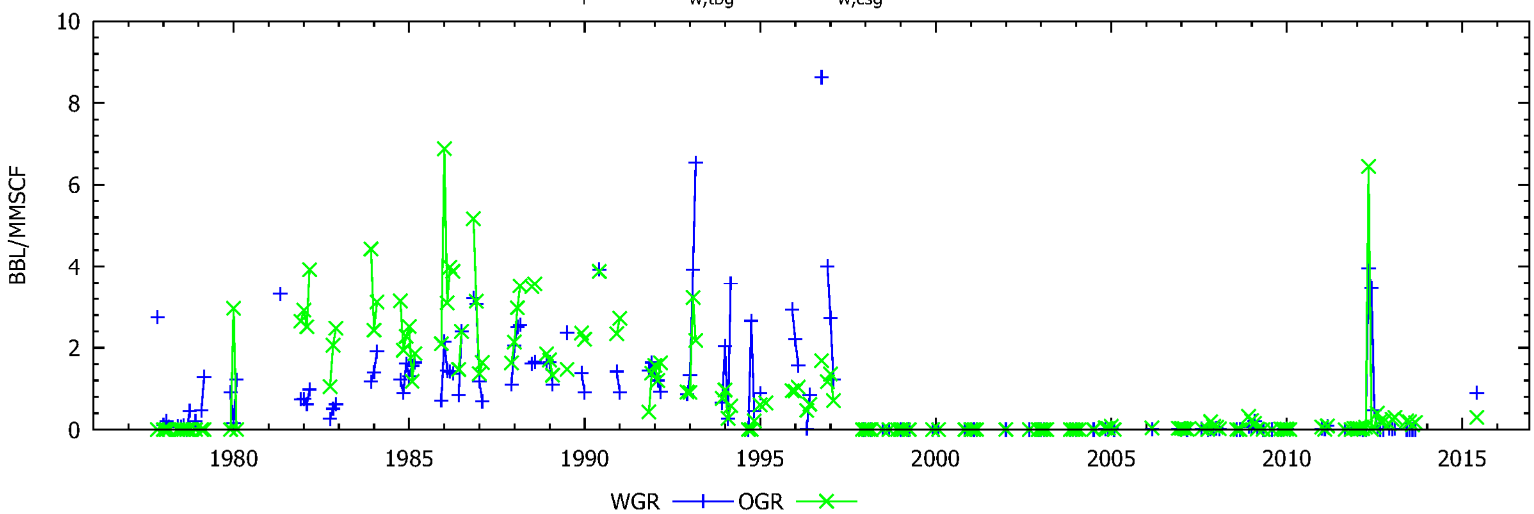


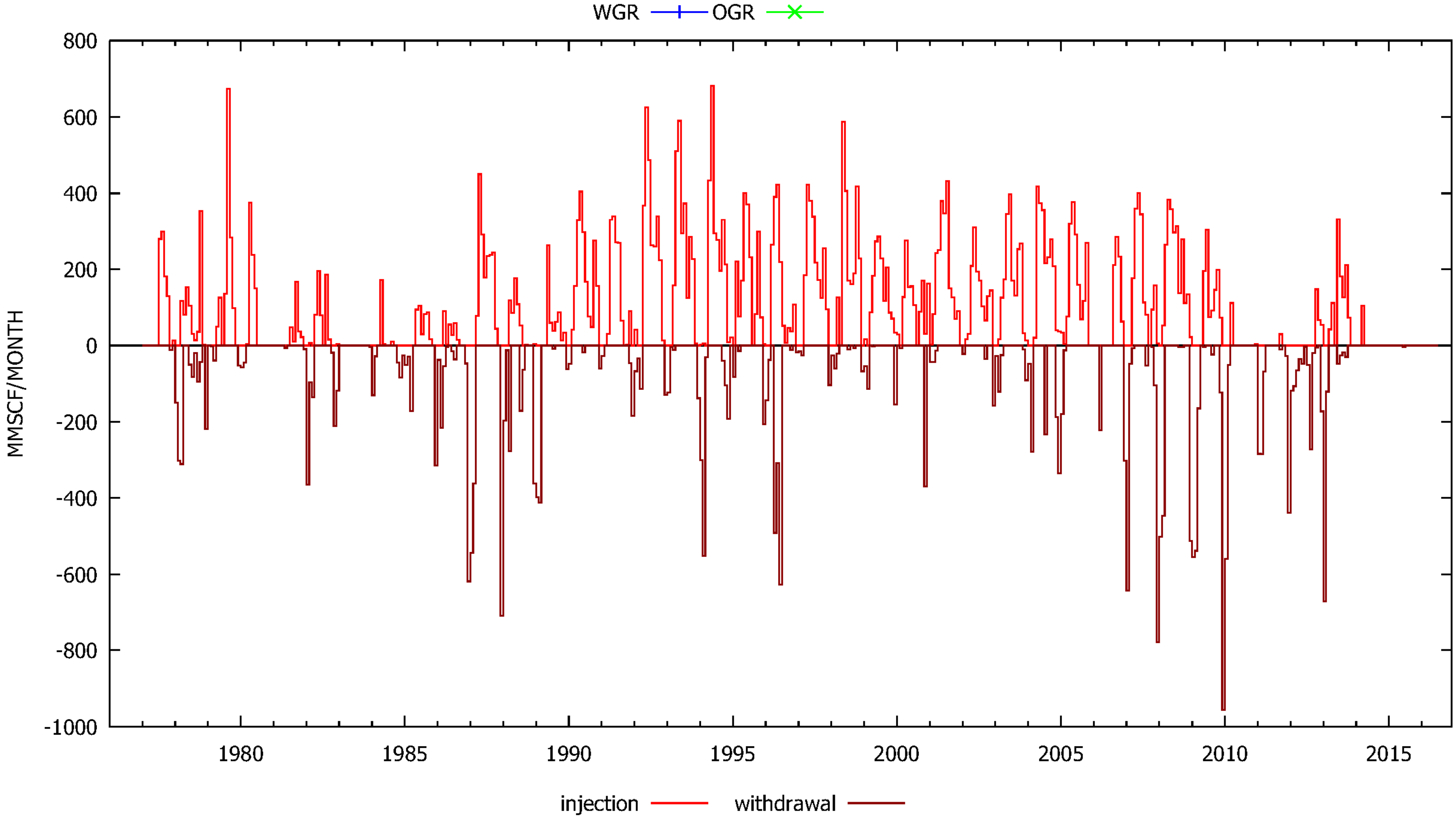




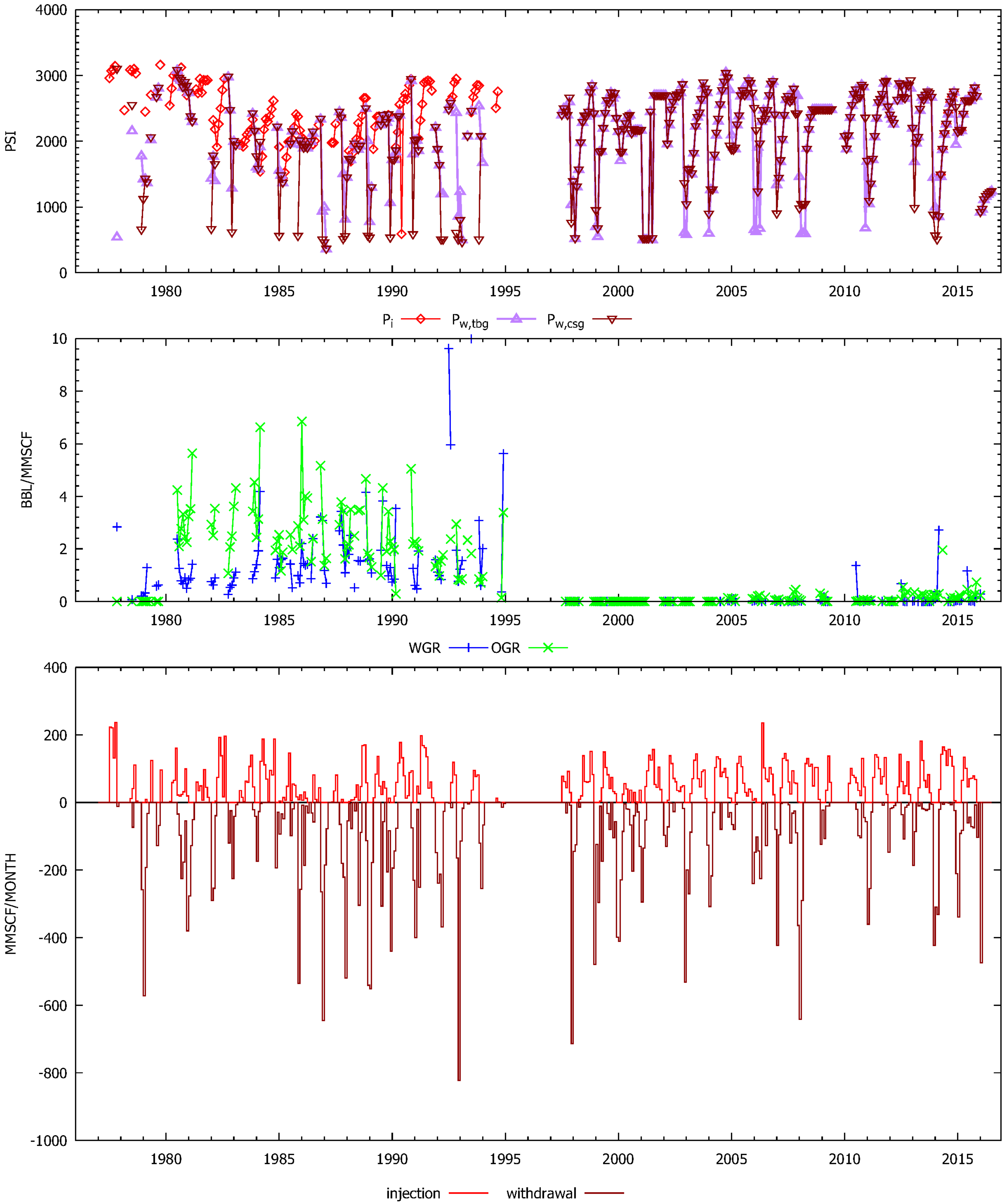
PORTER 26E WELL



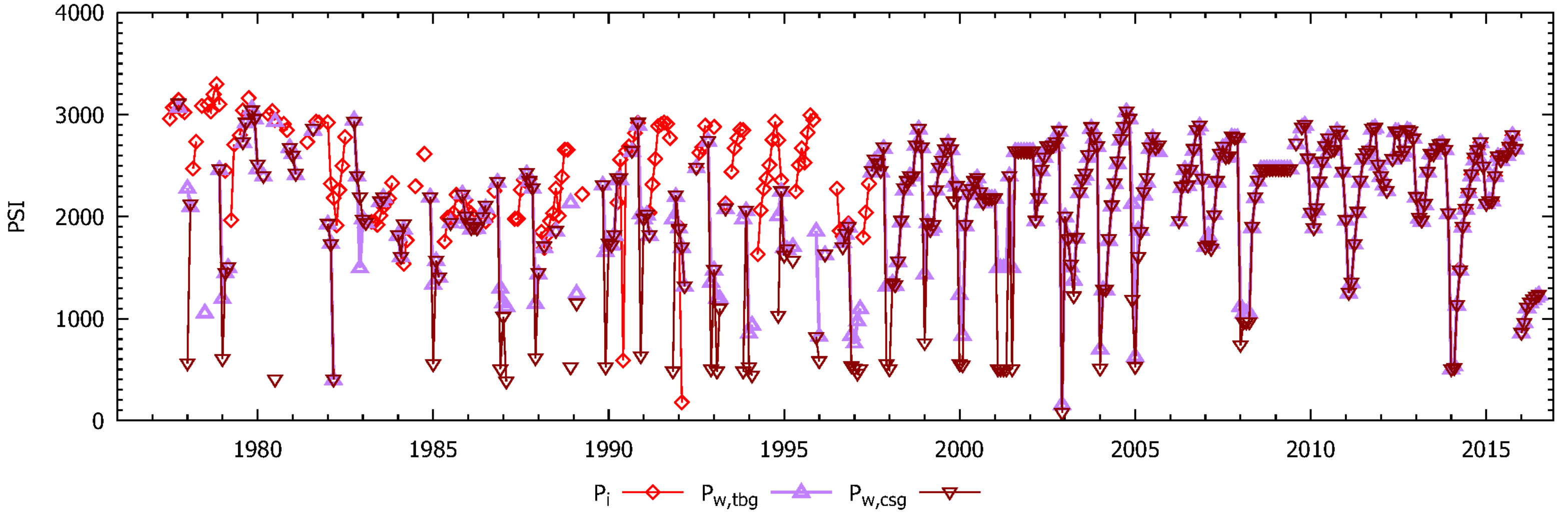


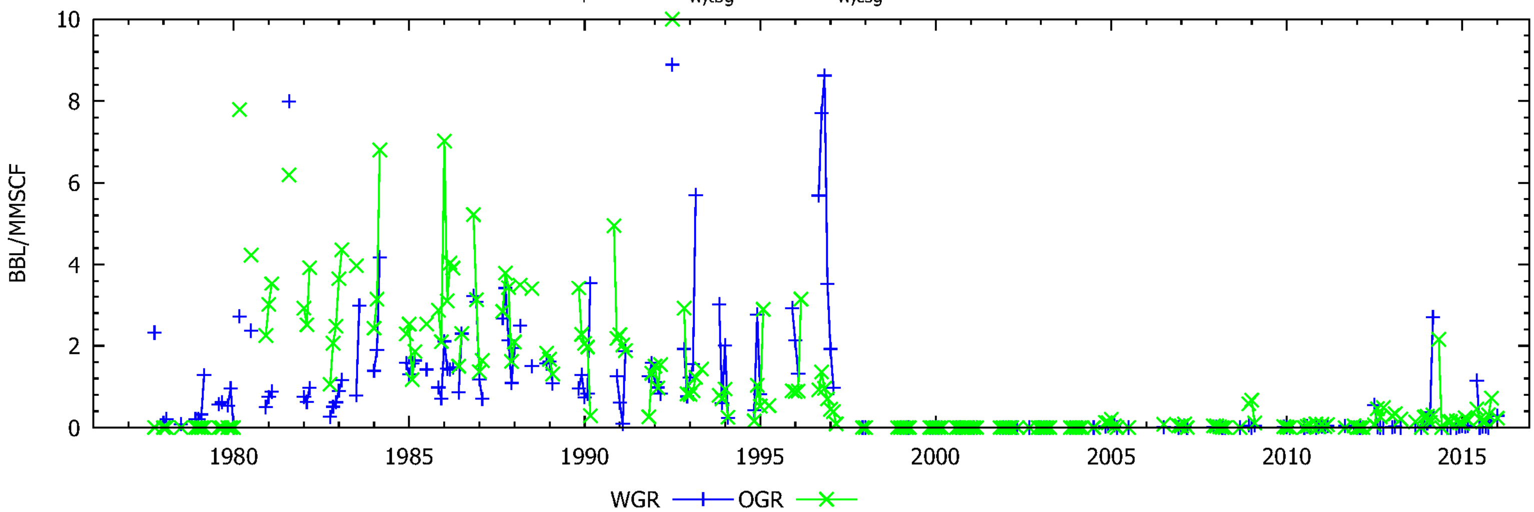


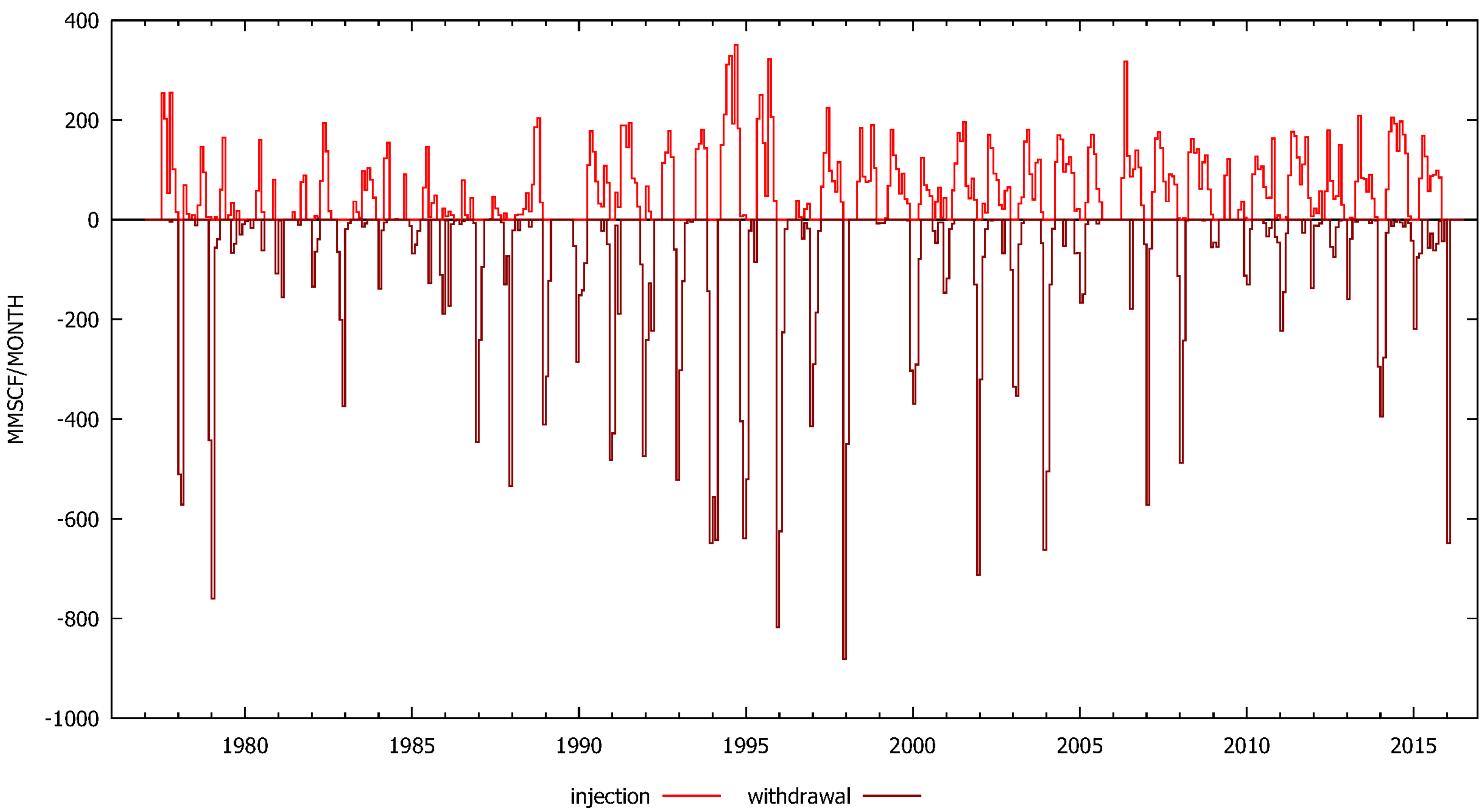
PORTER 30 WELL



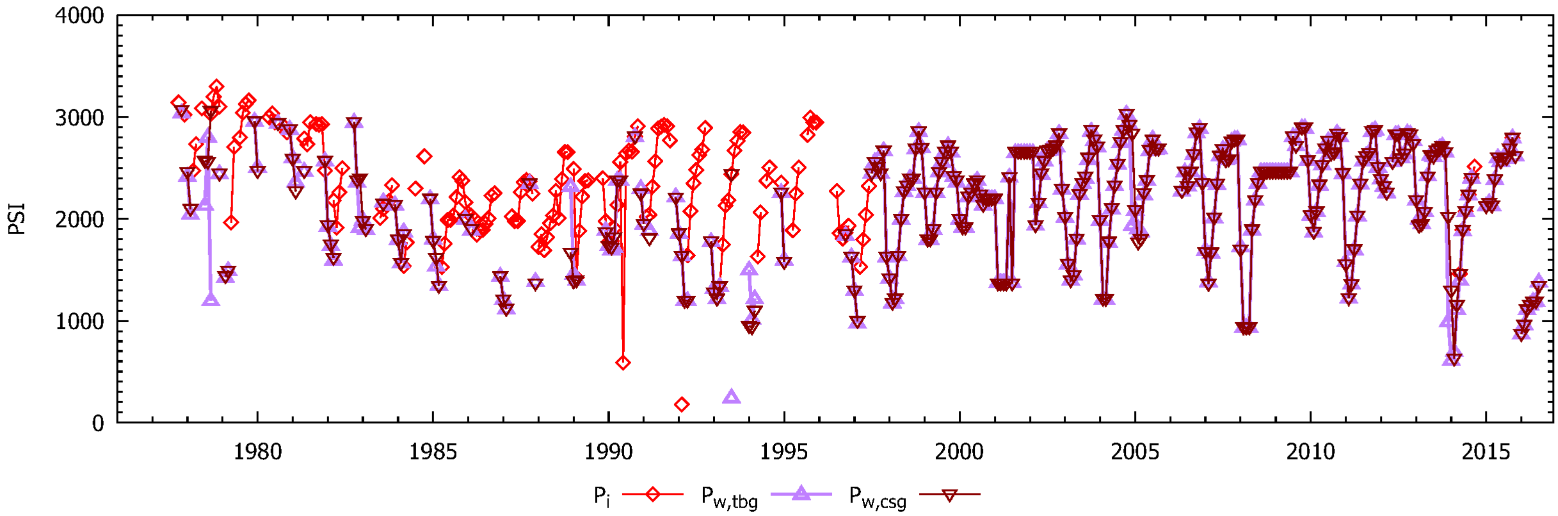
PORTER 32 WELL

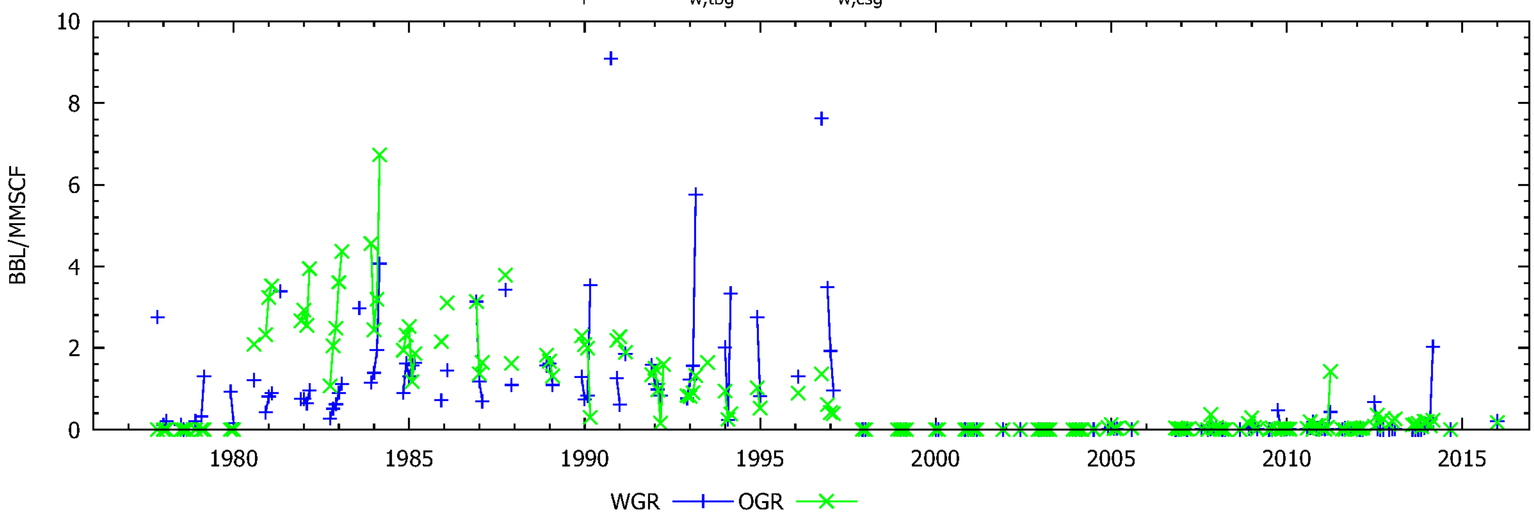


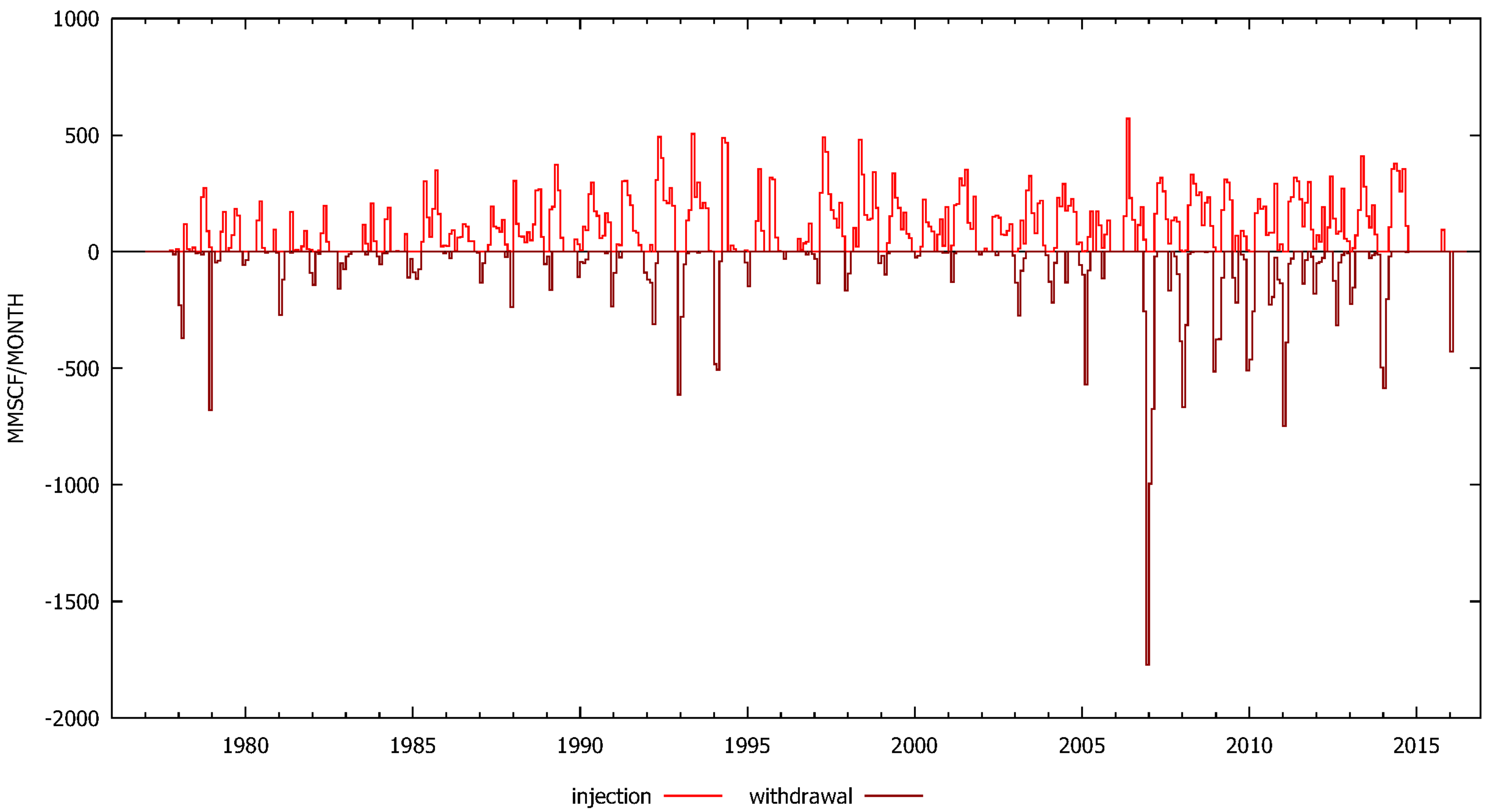




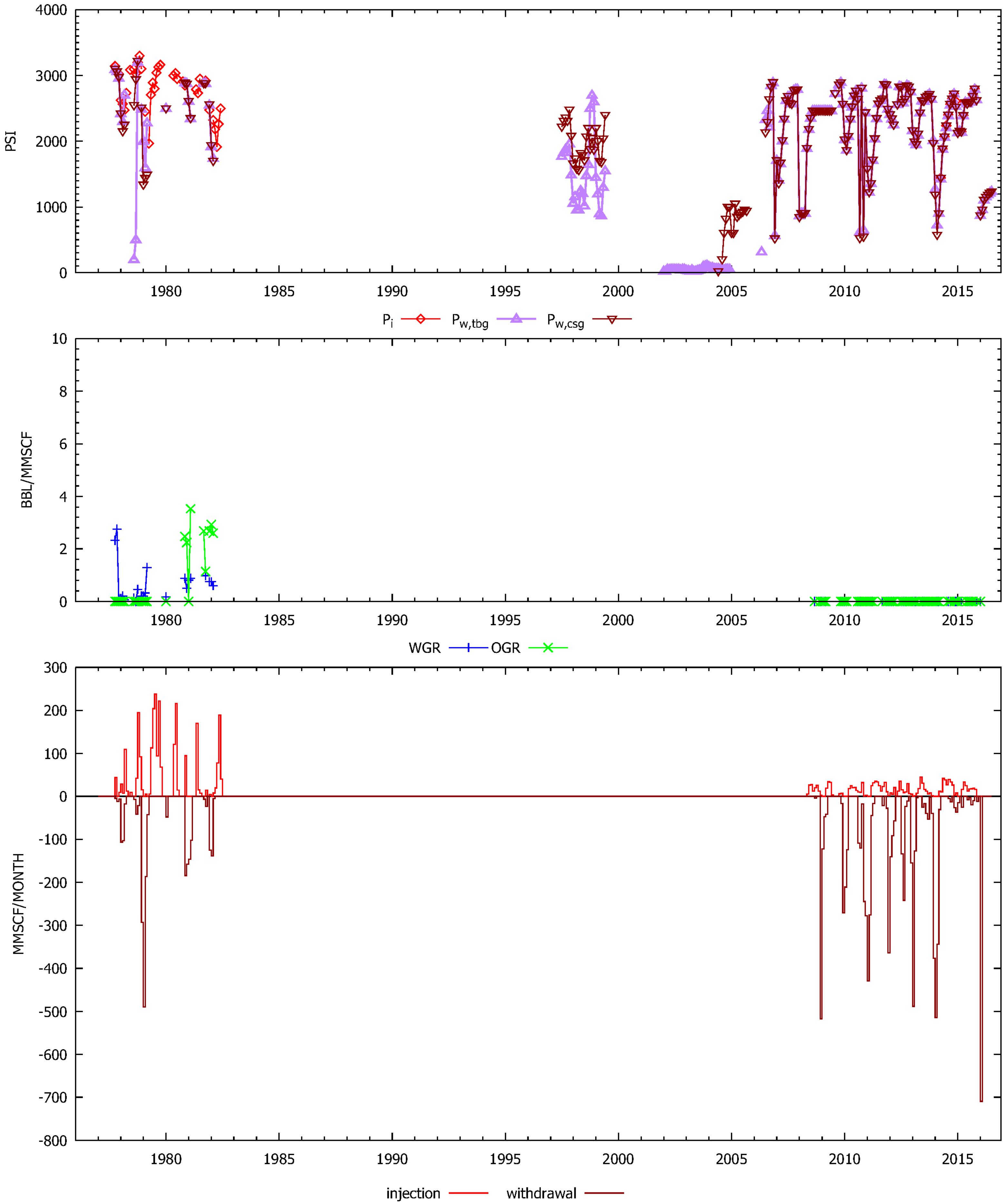
PORTER 32A WELL



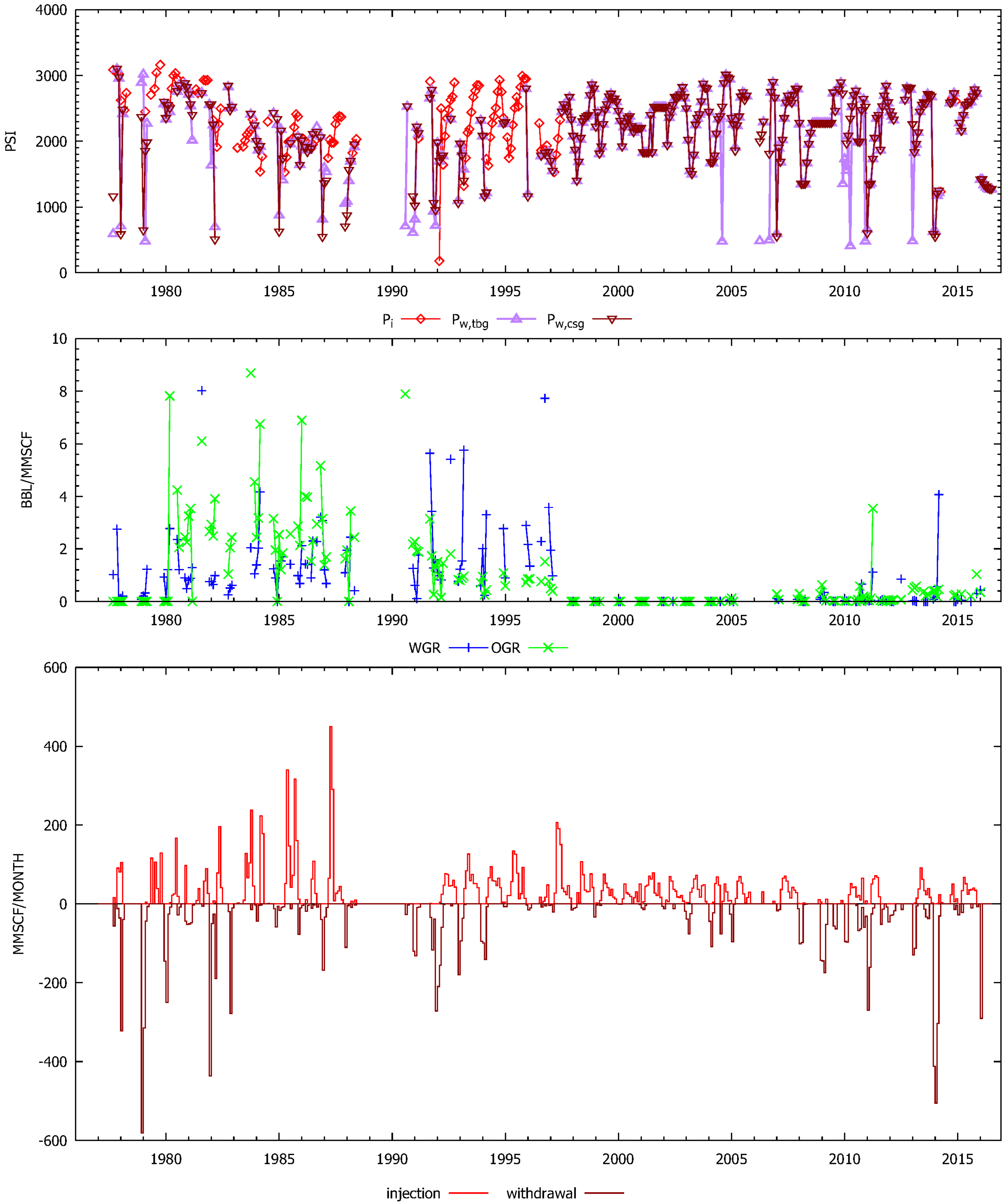


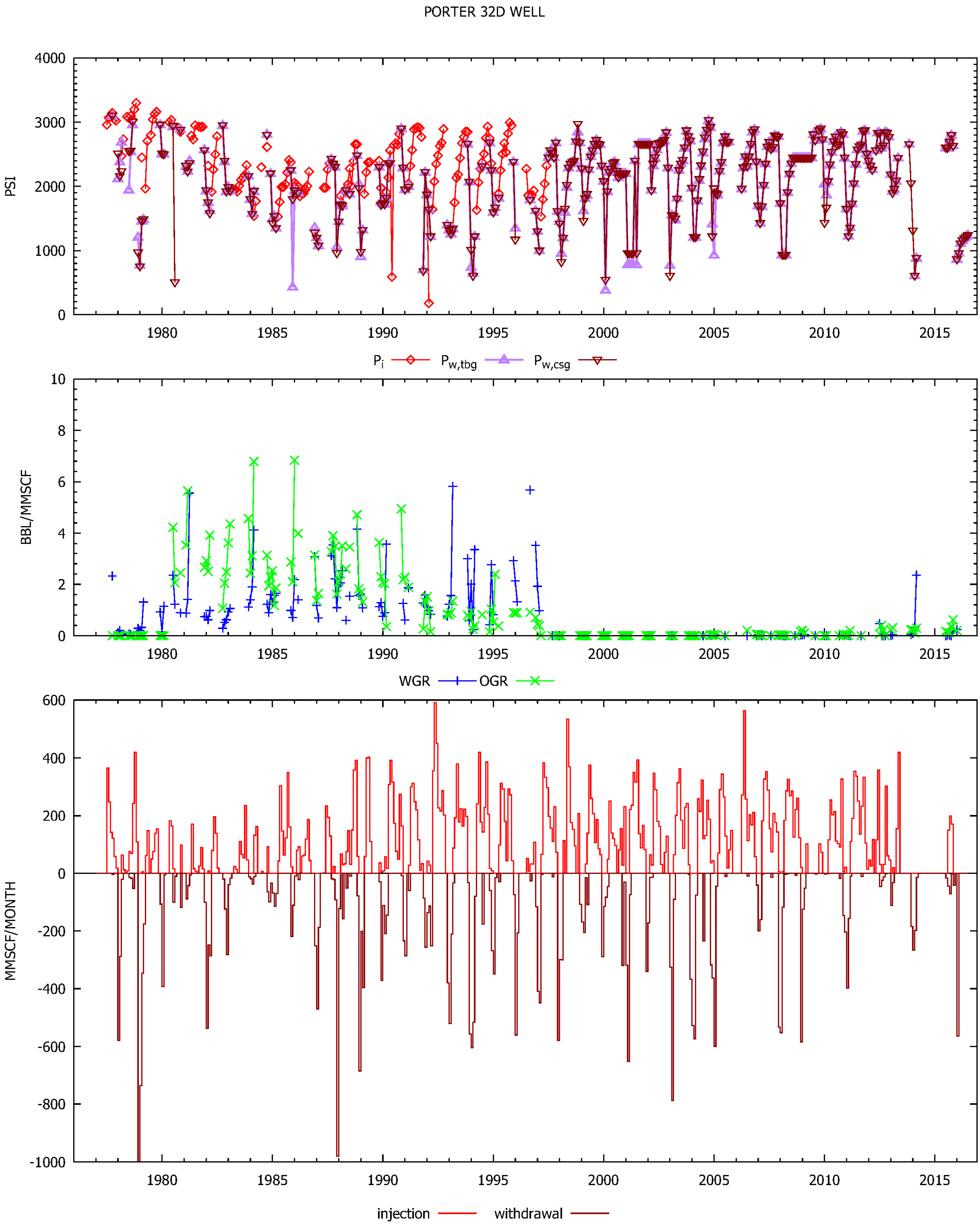


PORTER 32B WELL



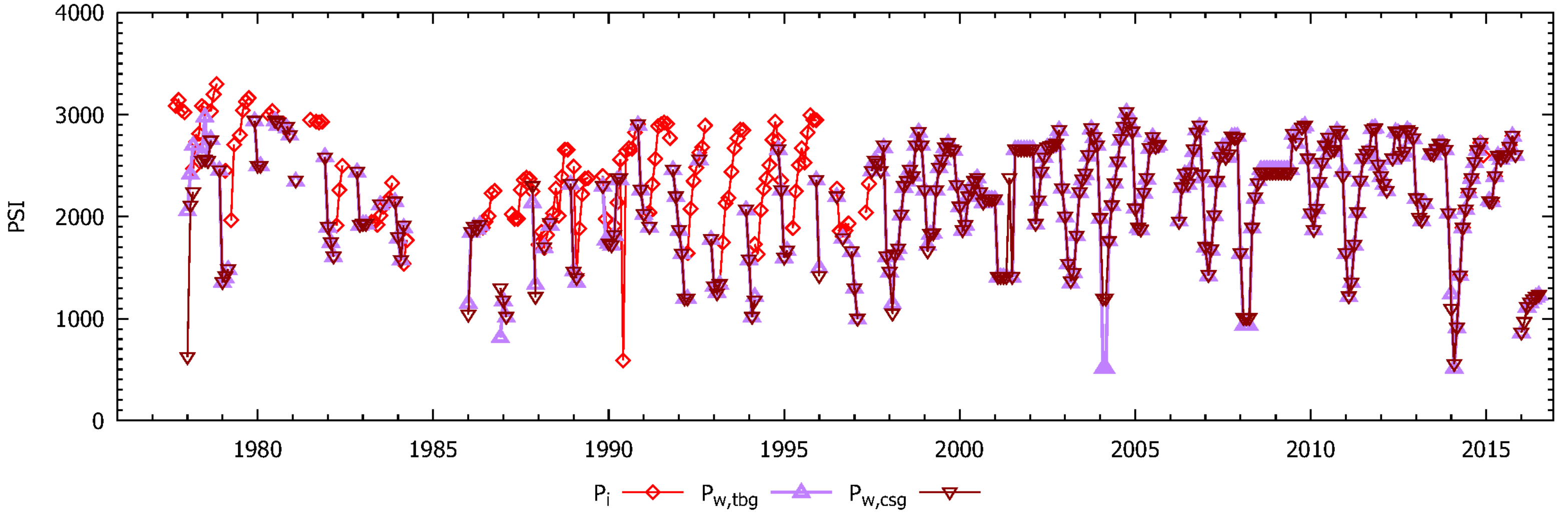
PORTER 32C WELL

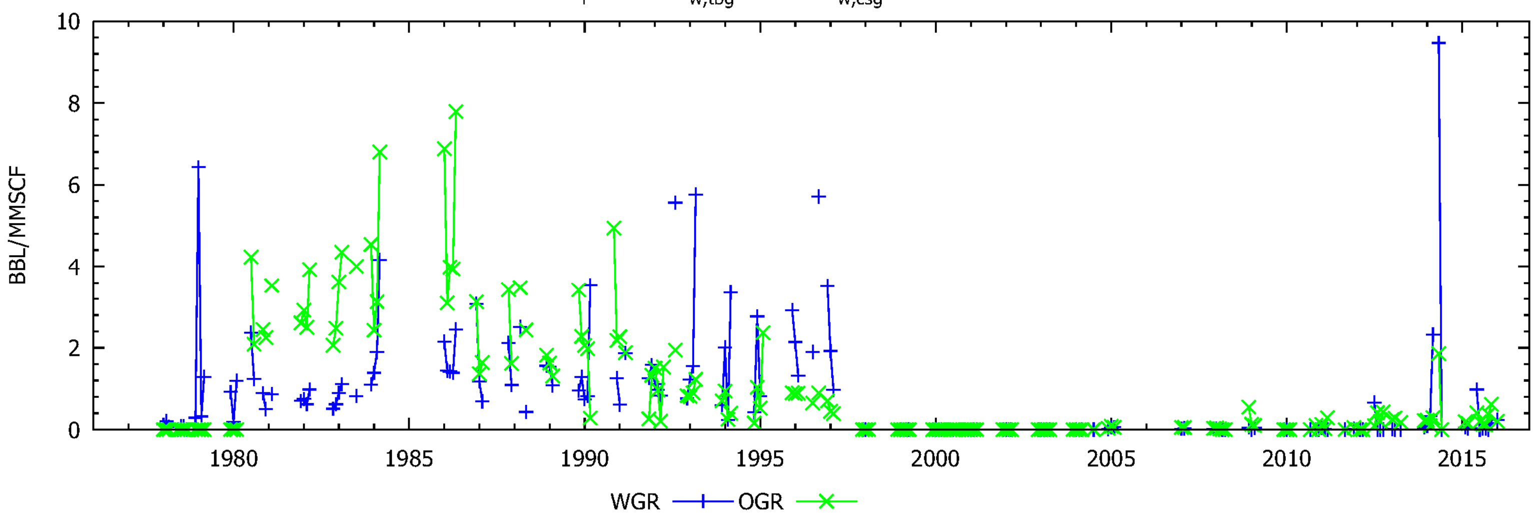


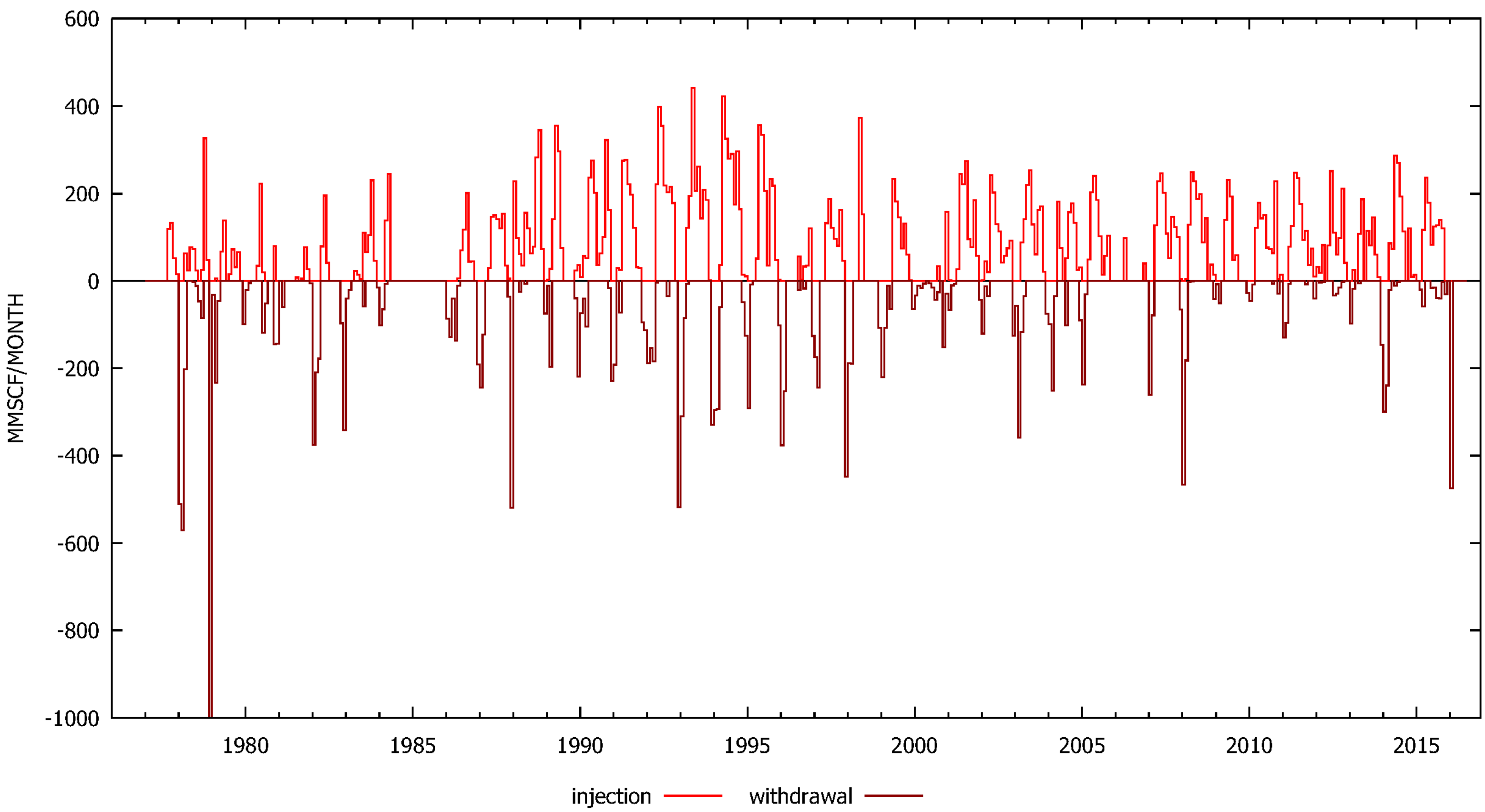


PORTER 32D WELL
PSI
P_i
$P_{w,tbg}$
$P_{w,csg}$
BBL/MMSCF
WGR
OGR
MMSCF/MONTH
injection
withdrawal

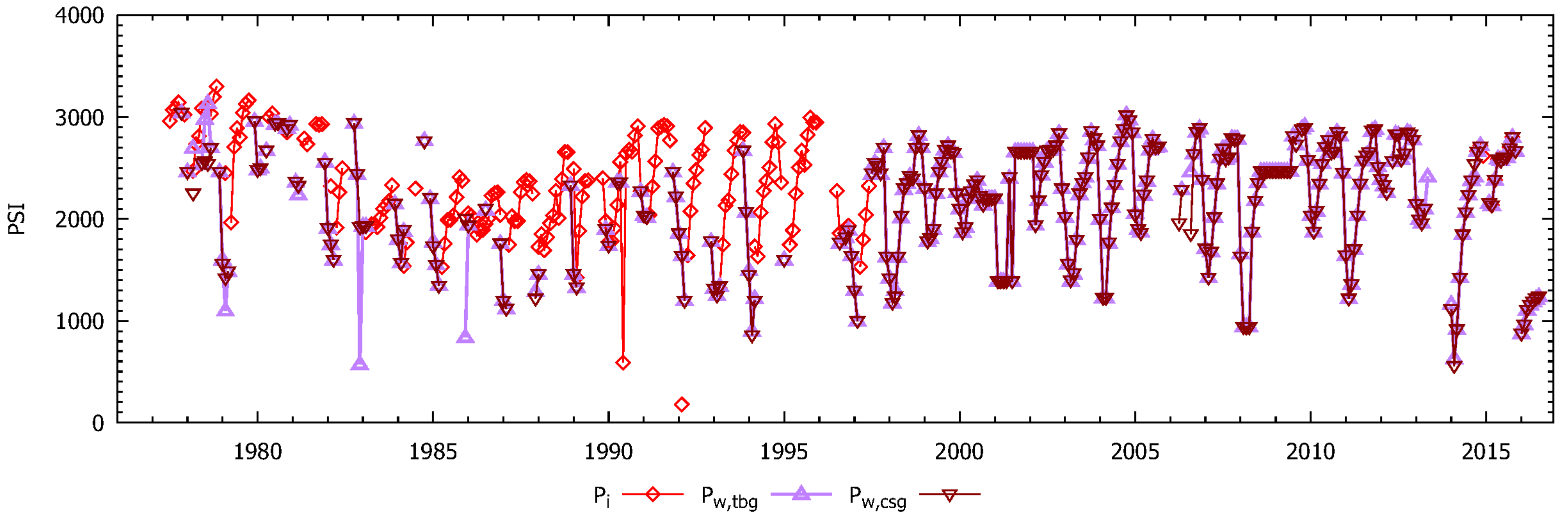
PORTER 32E WELL

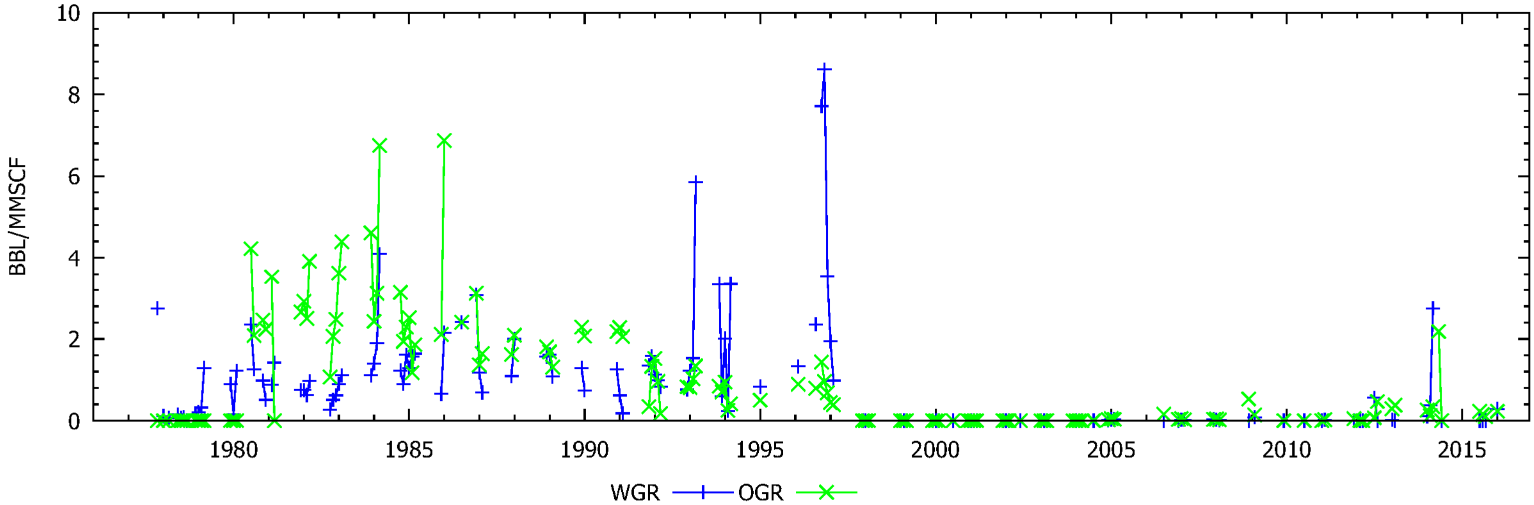


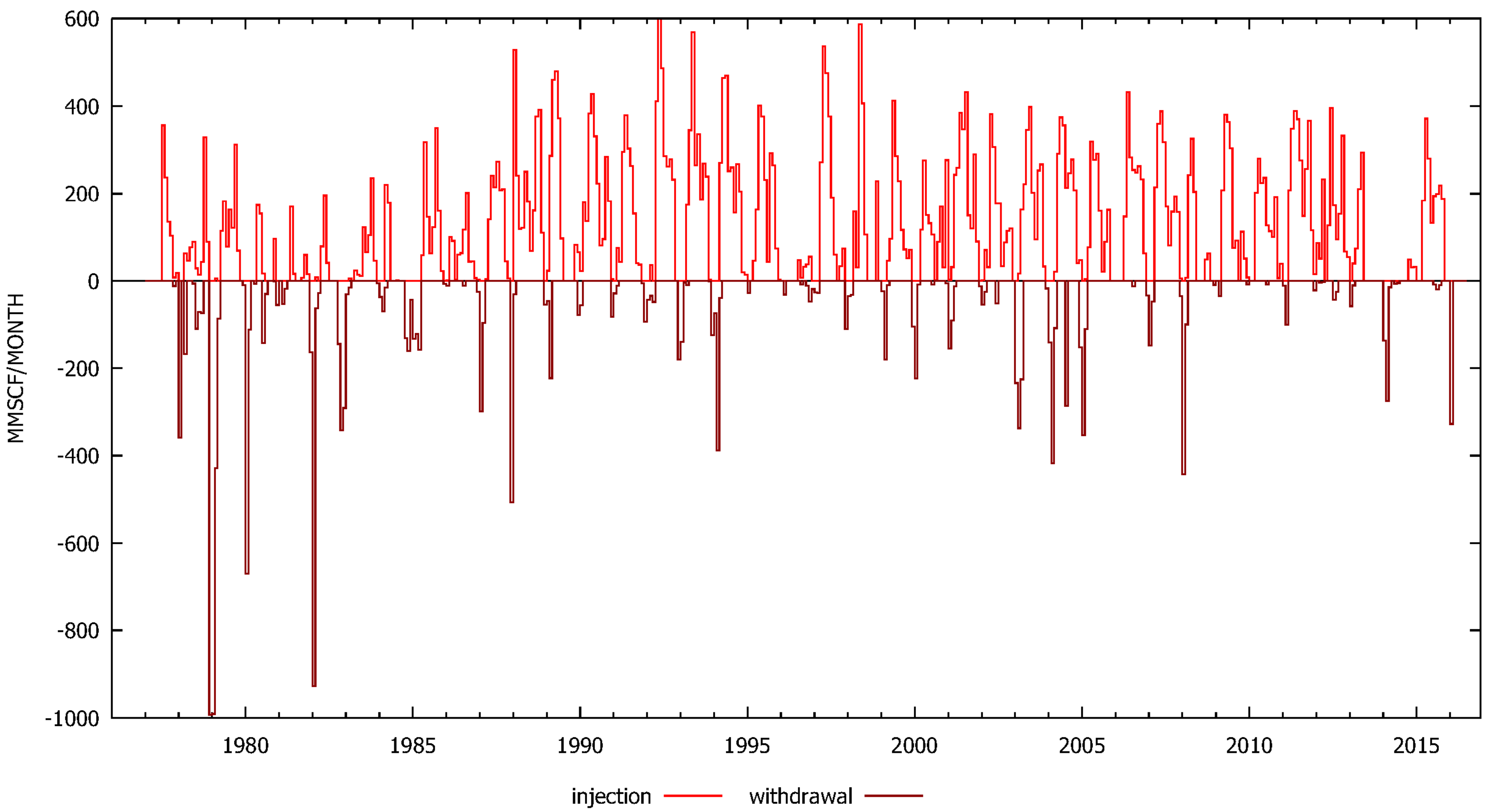




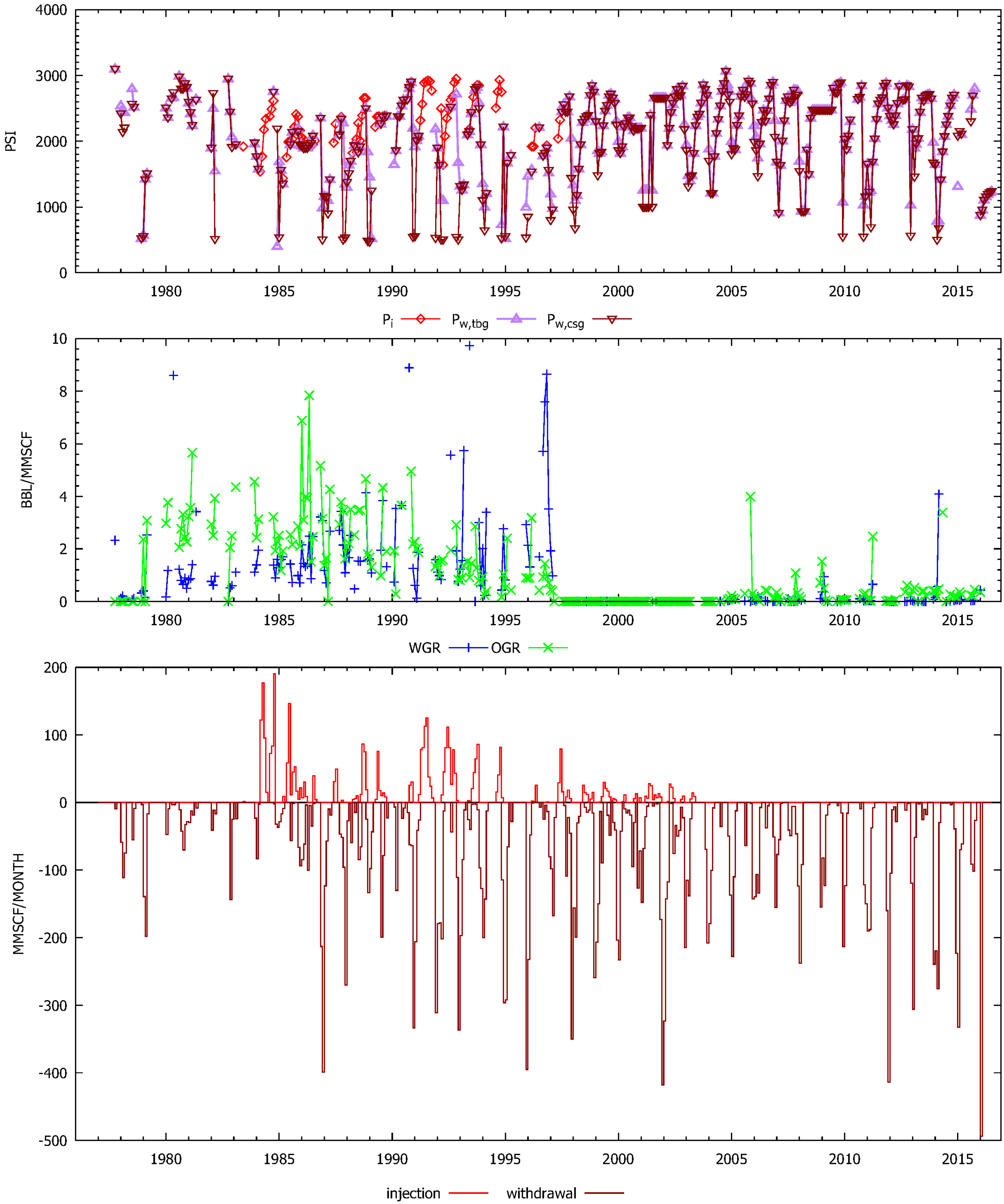
PORTER 32F WELL



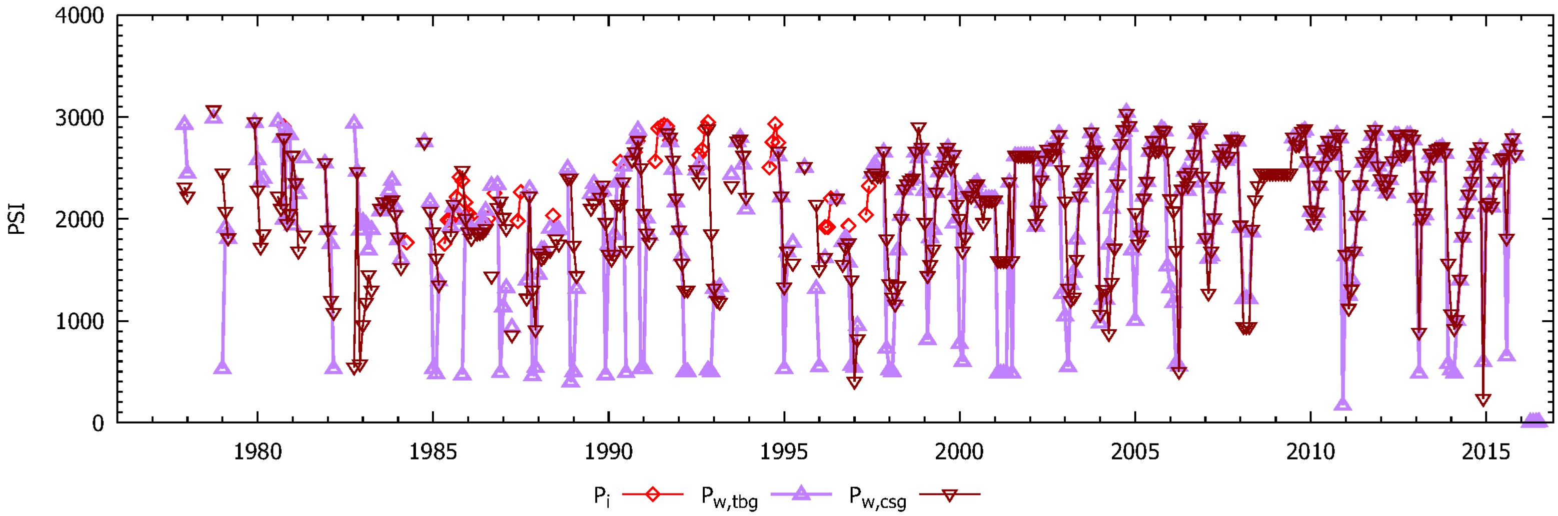


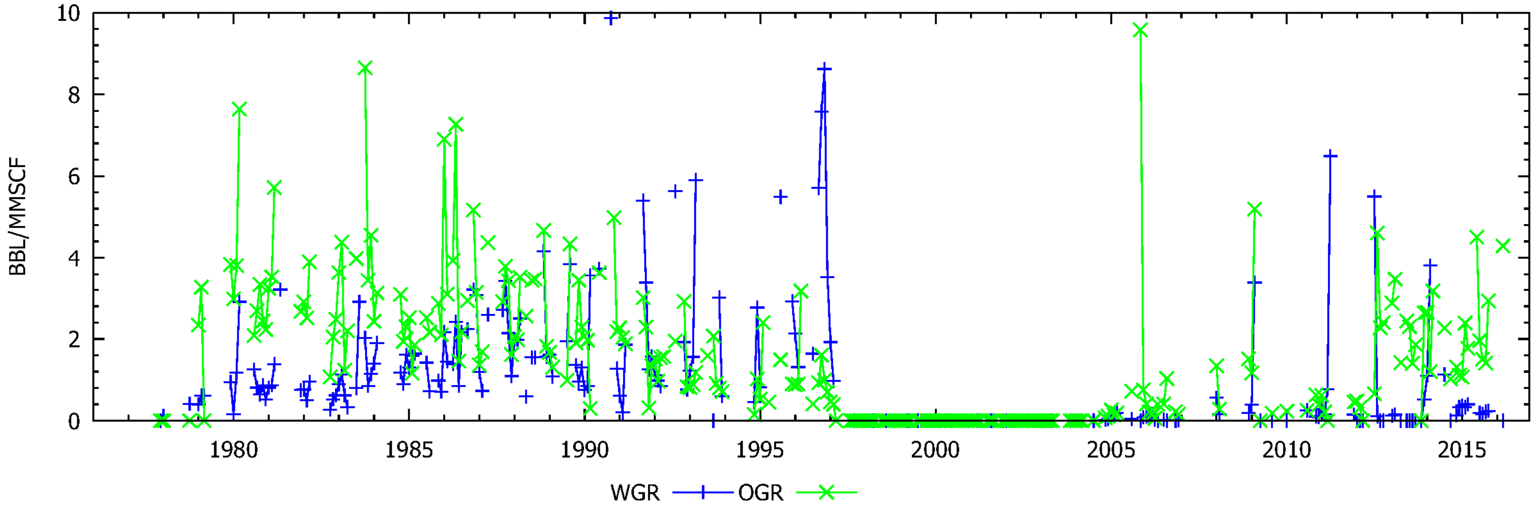


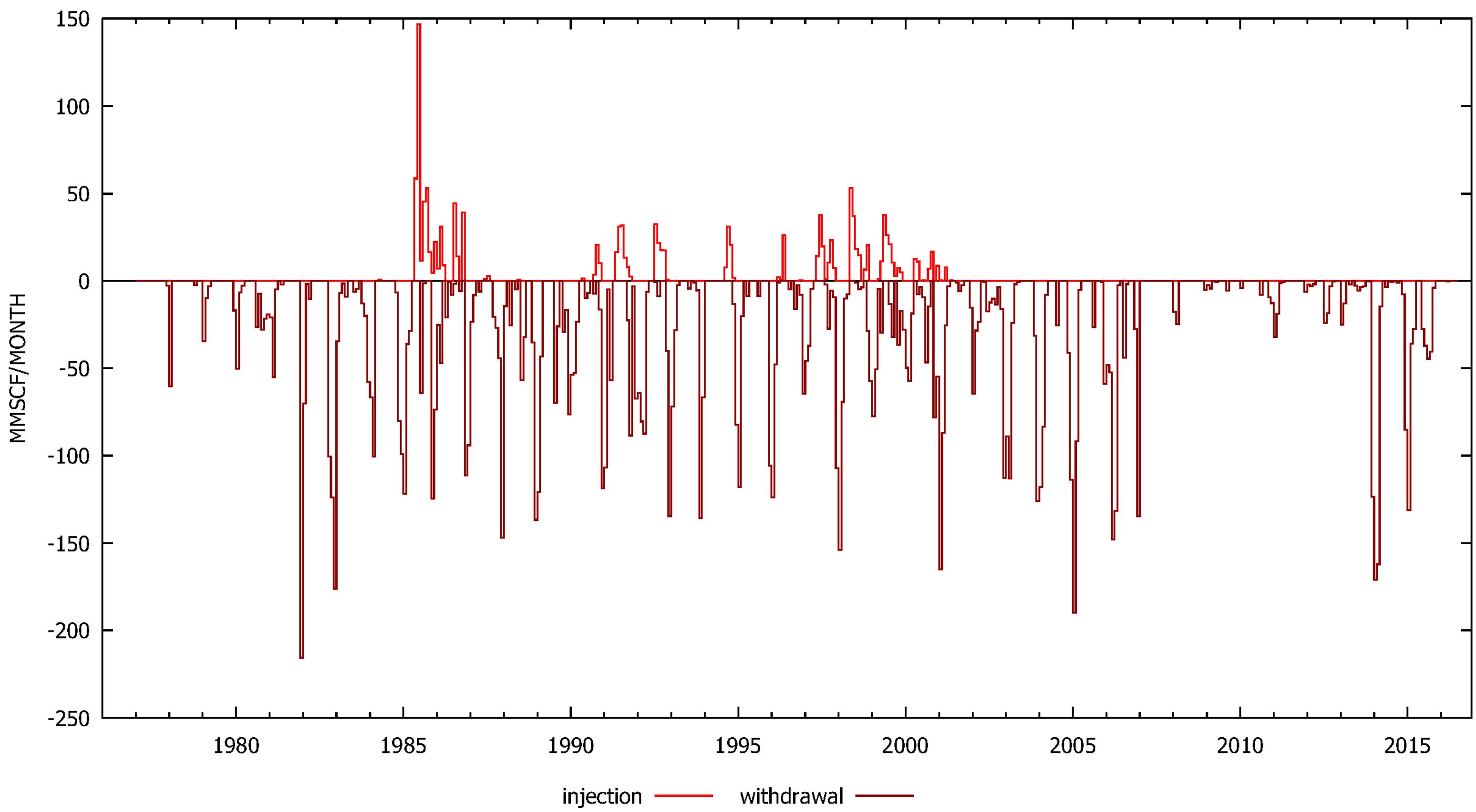
PORTER 34 WELL



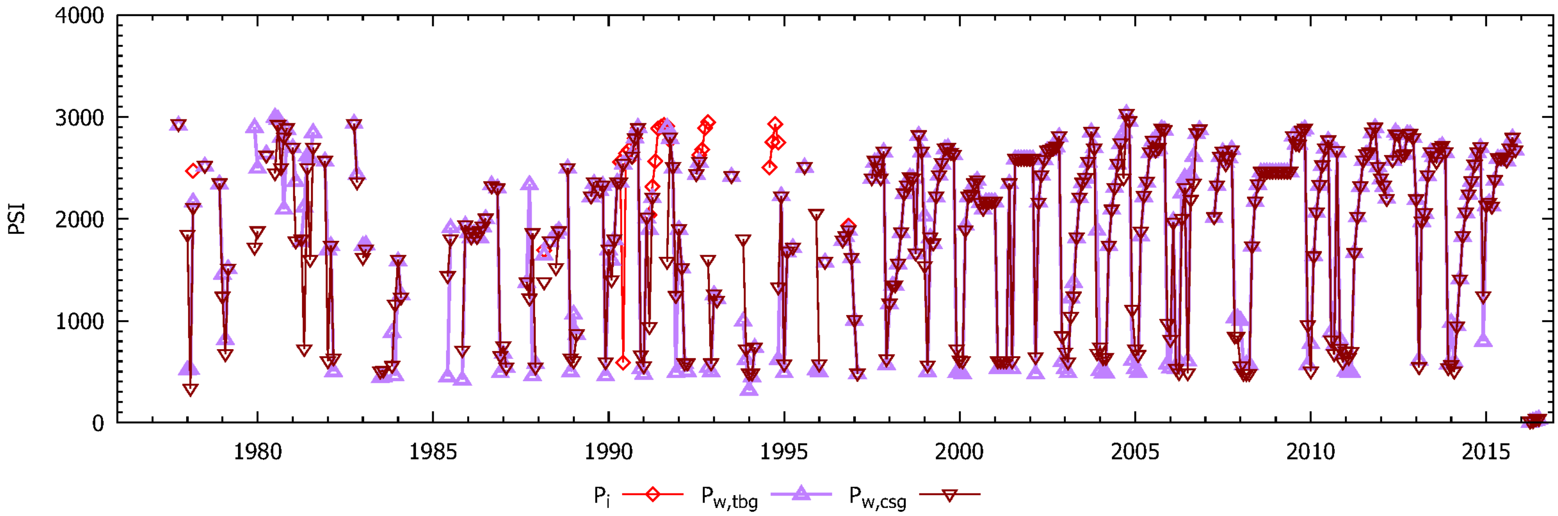
PORTER 35 WELL

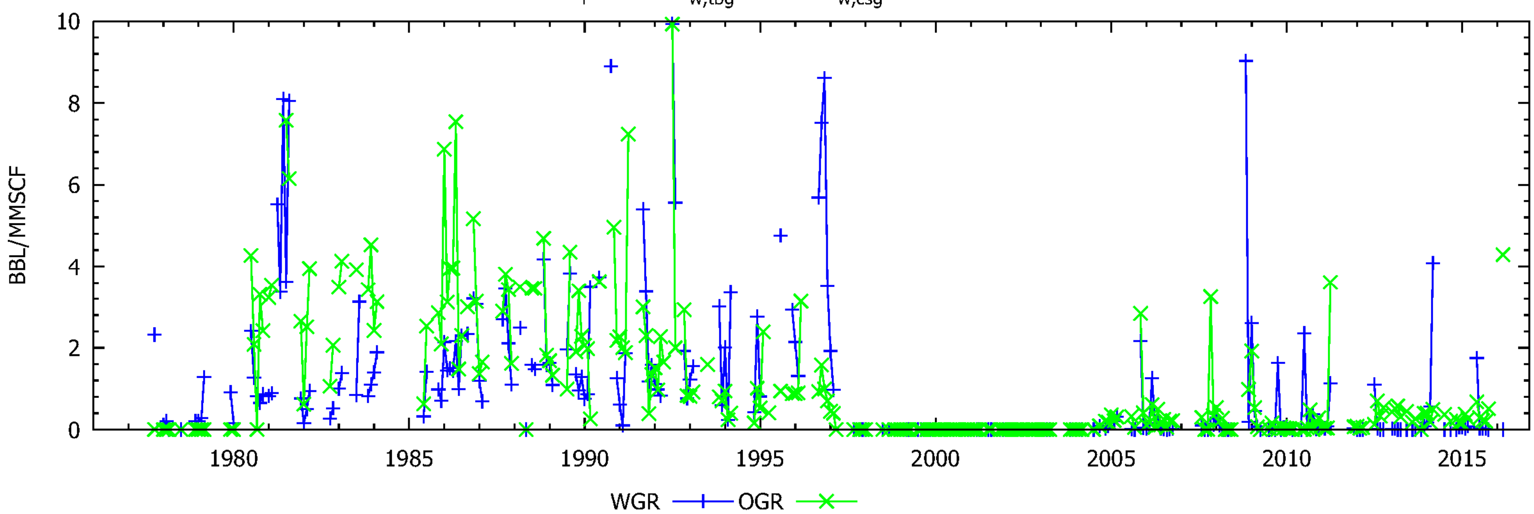


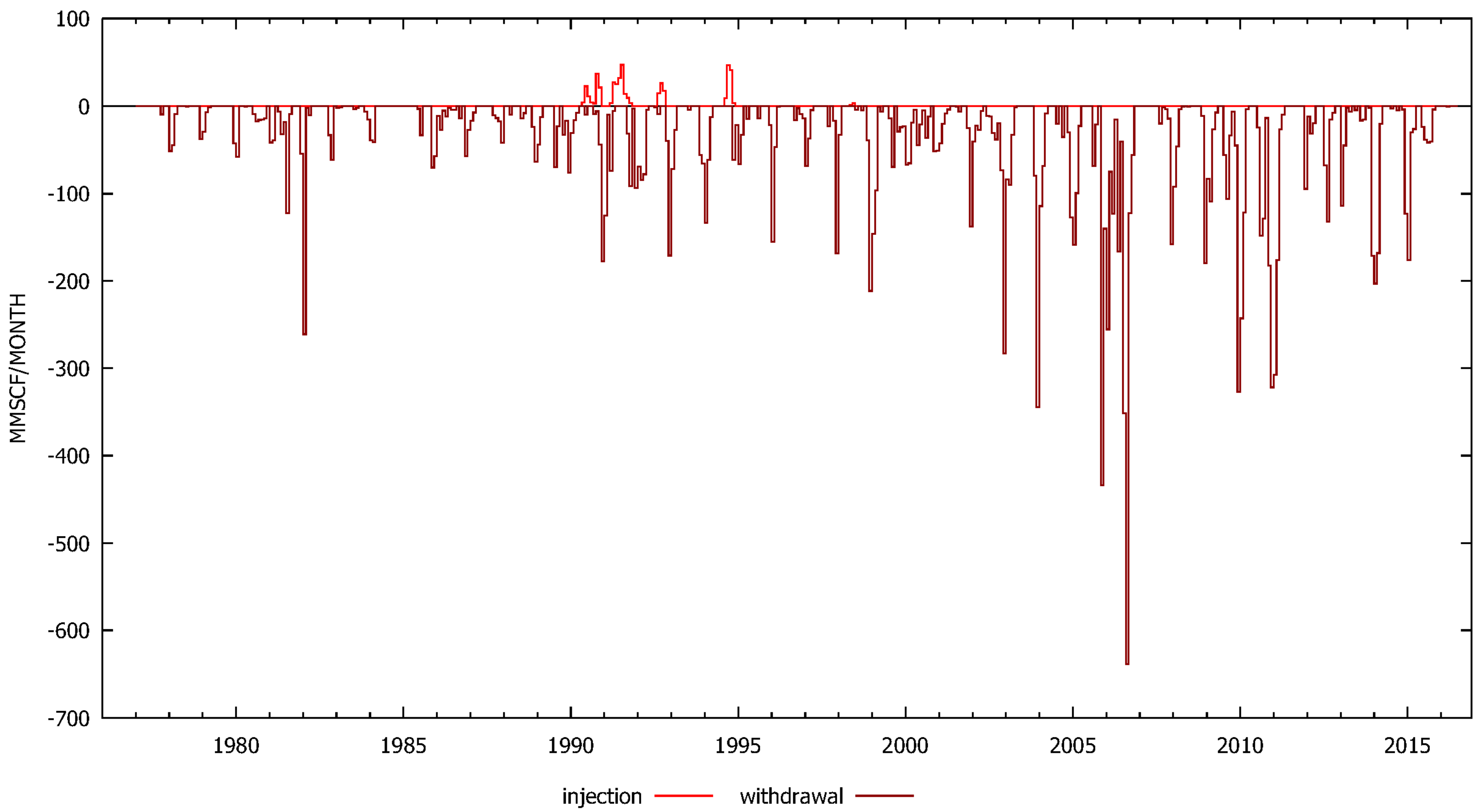




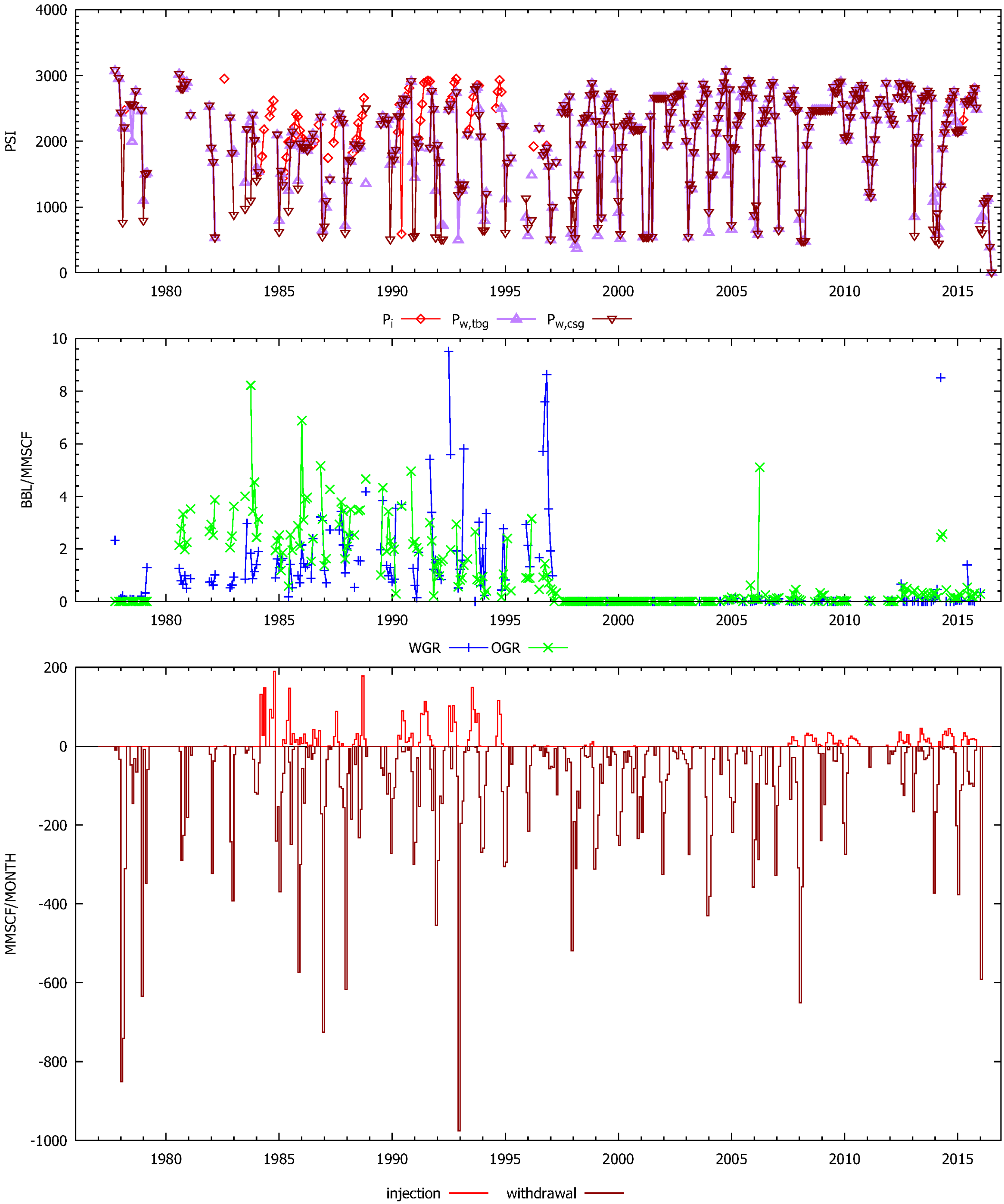
PORTER 36 WELL



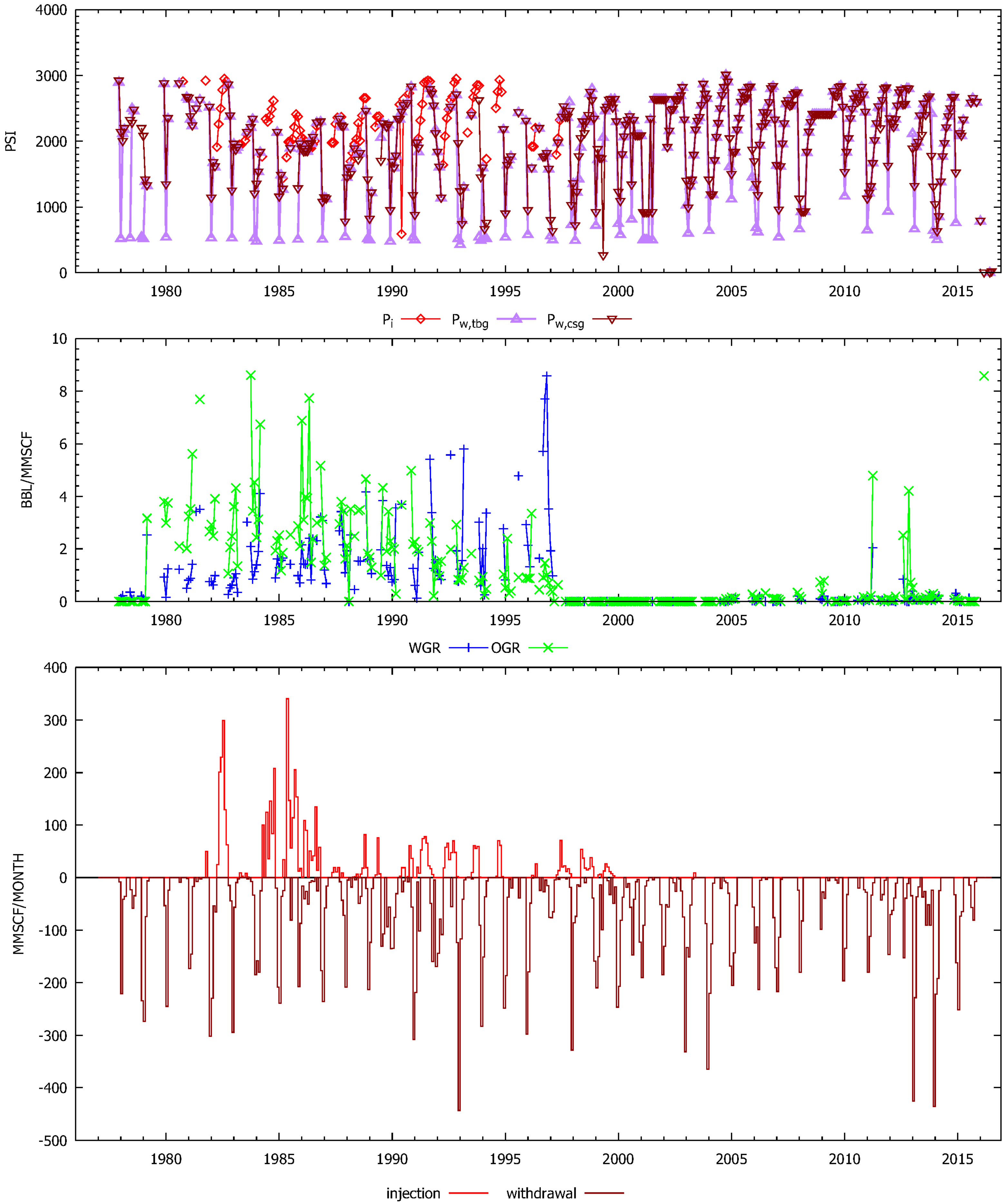




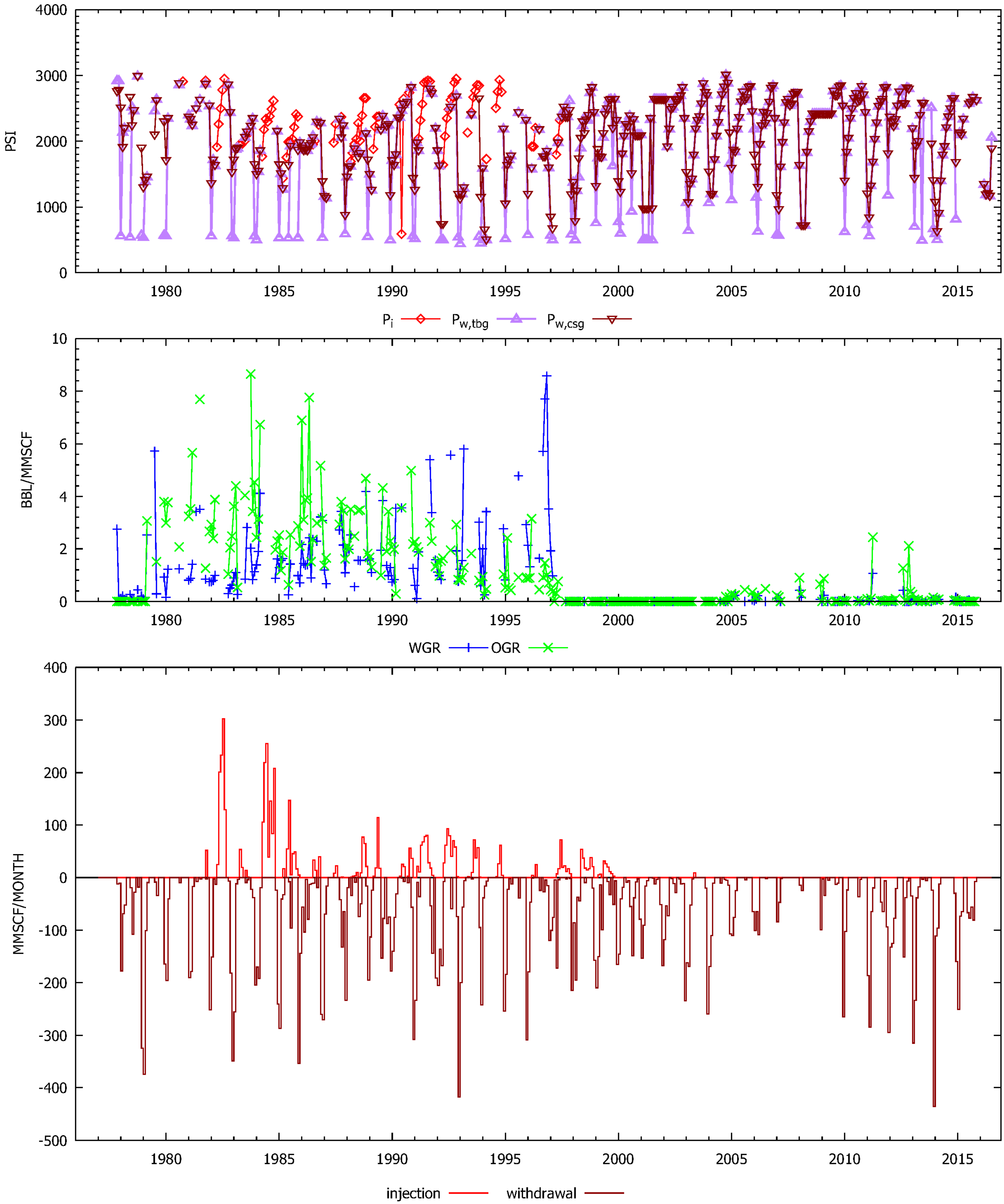
PORTER 37 WELL

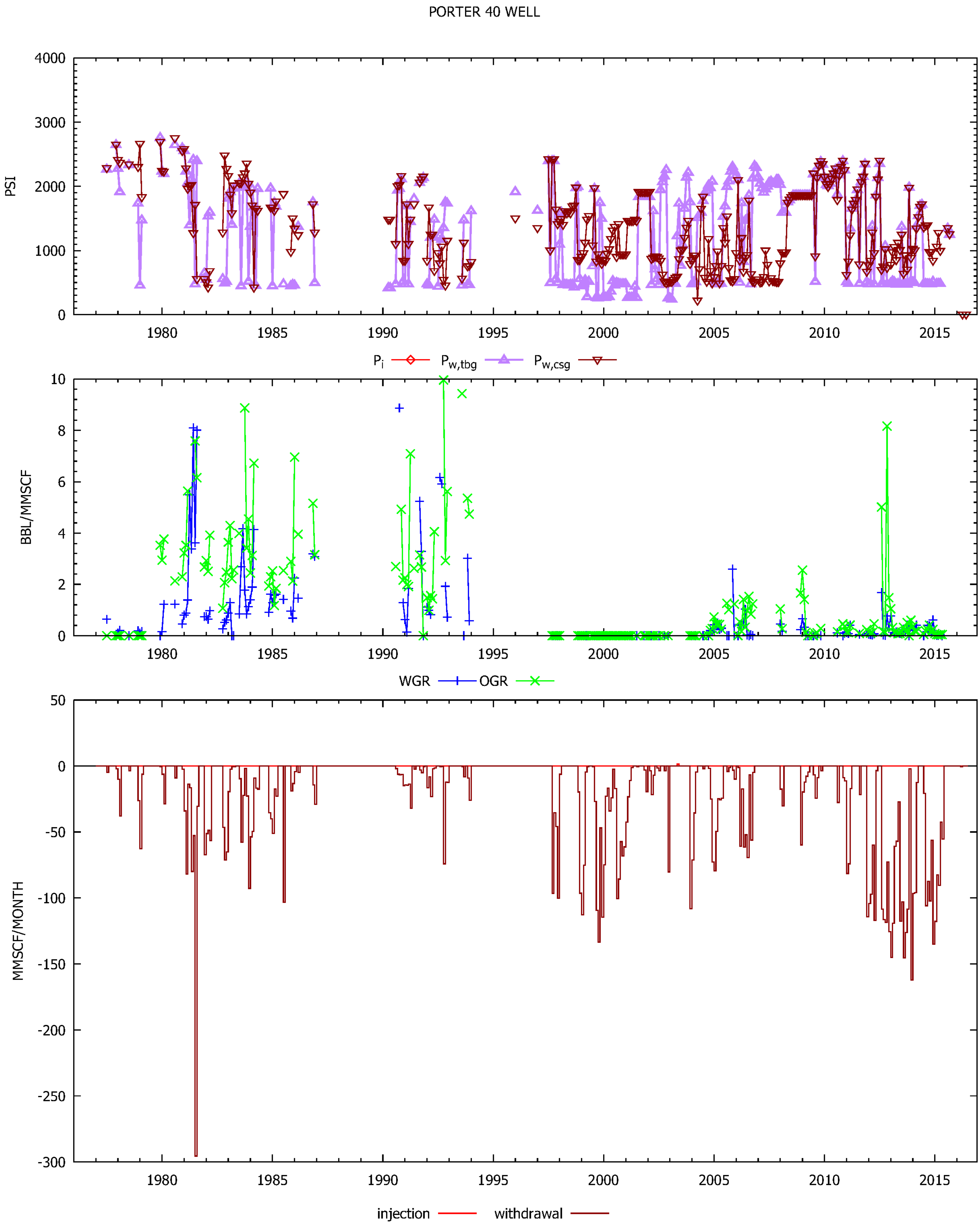


PORTER 38 WELL



PORTER 39 WELL




PORTER 40 WELL
PSI
4000
3000
2000
1000
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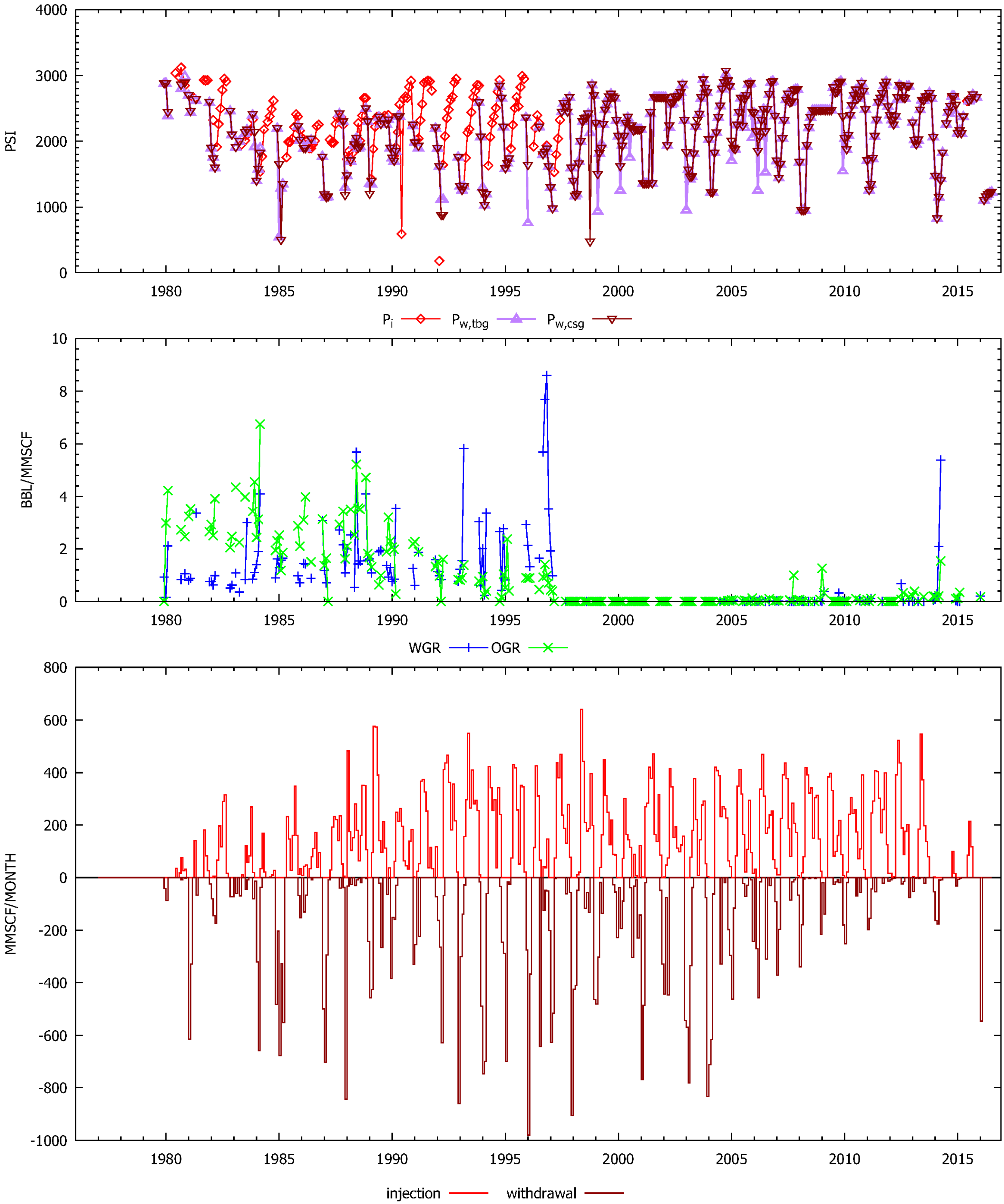
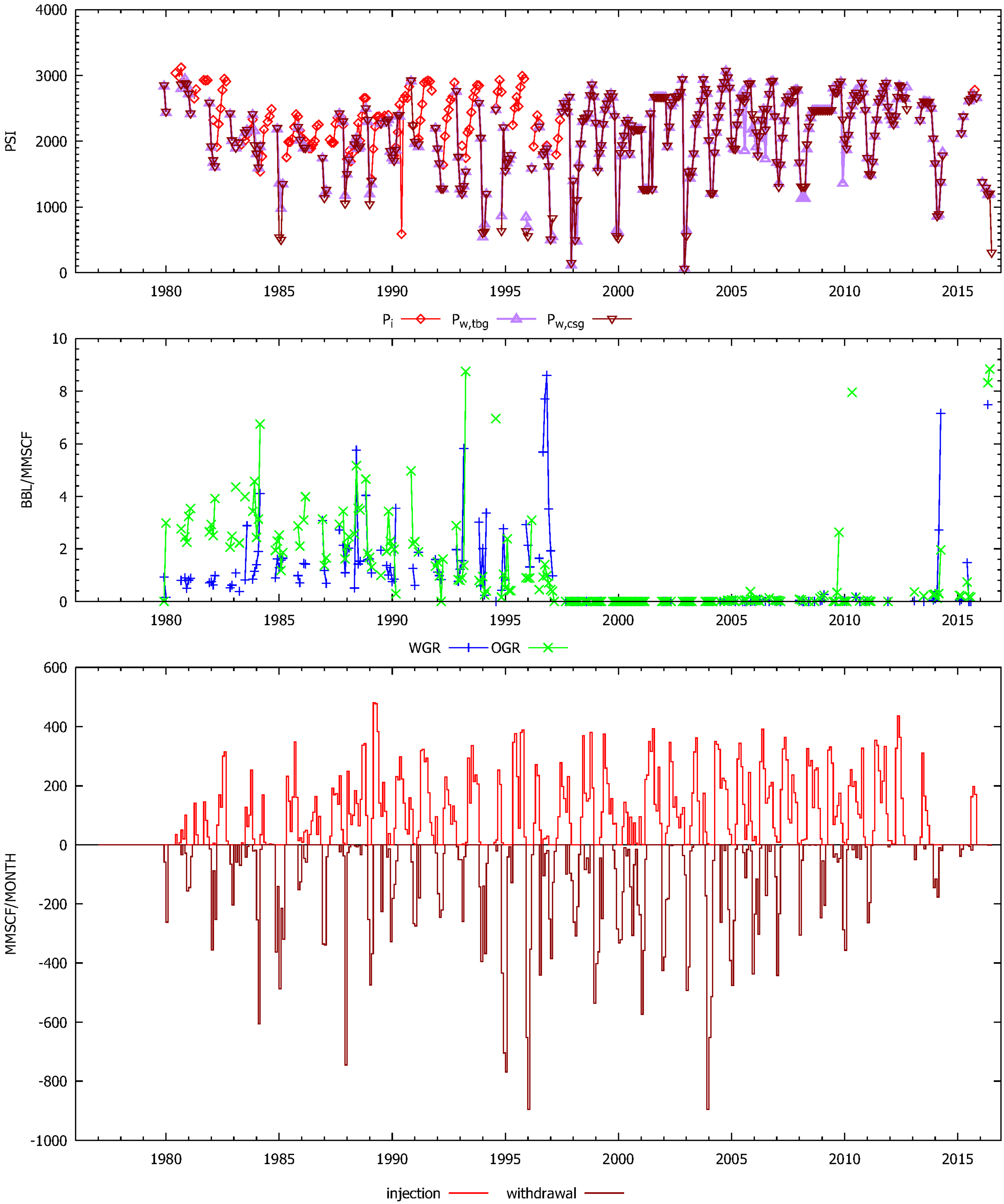
1980
1985
1990
1995
2000
2005
2010
2015
P_i
$P_{w,tbg}$
$P_{w,csg}$
BBL/MMSCF
10
8
6
4
2
0
WGR
OGR
MMSCF/MONTH
50
0
-50
-100
-150
-200
-250
-300
injection
withdrawal

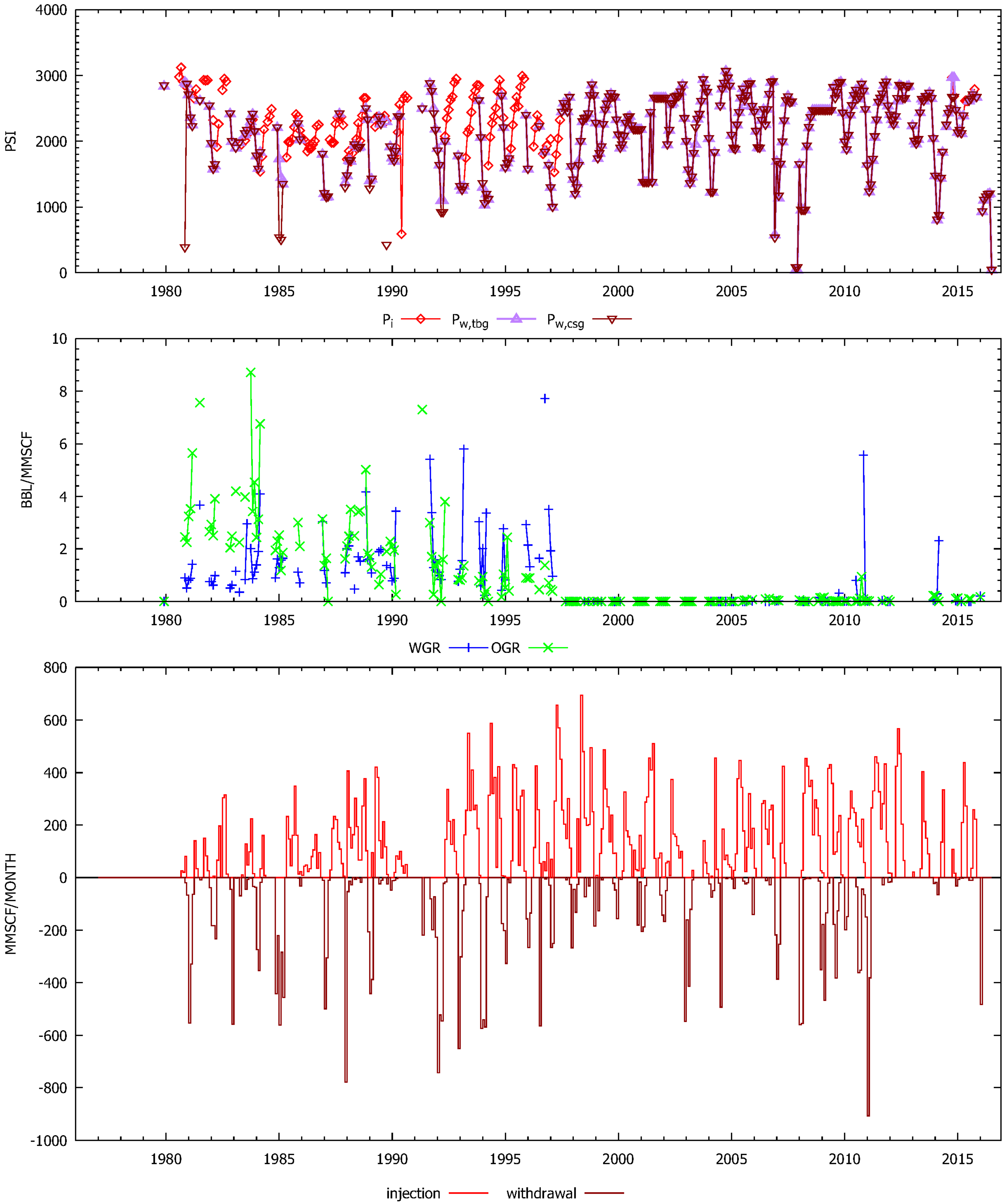
PORTER 42A WELL



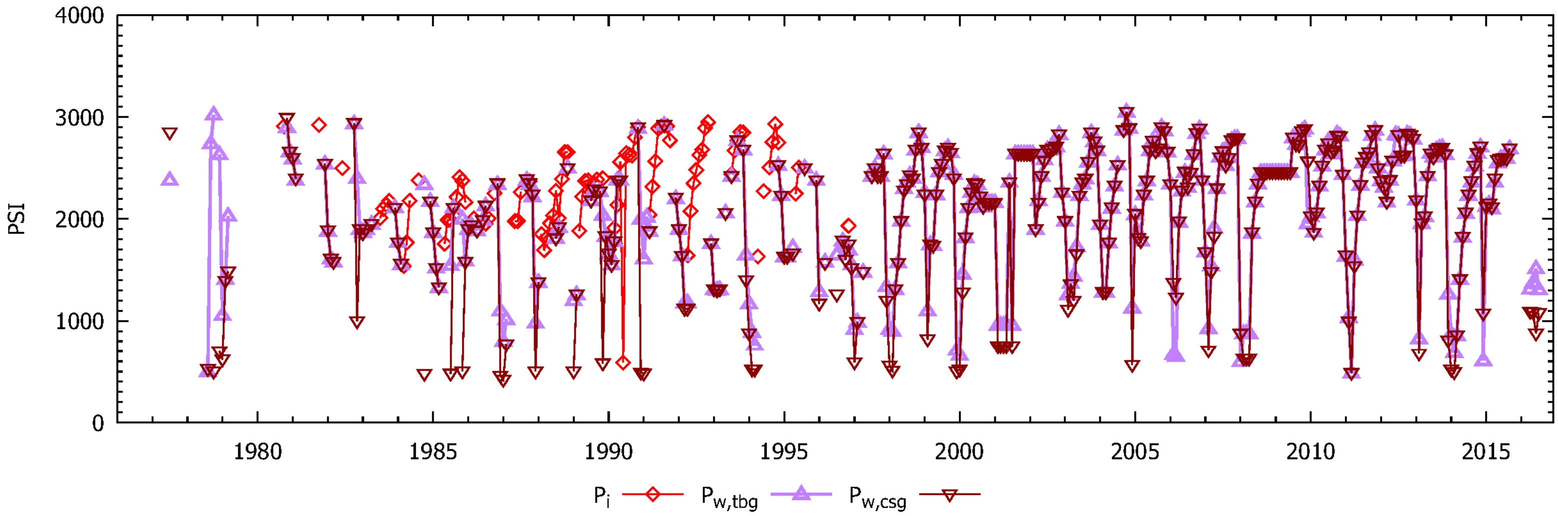
PORTER 42B WELL

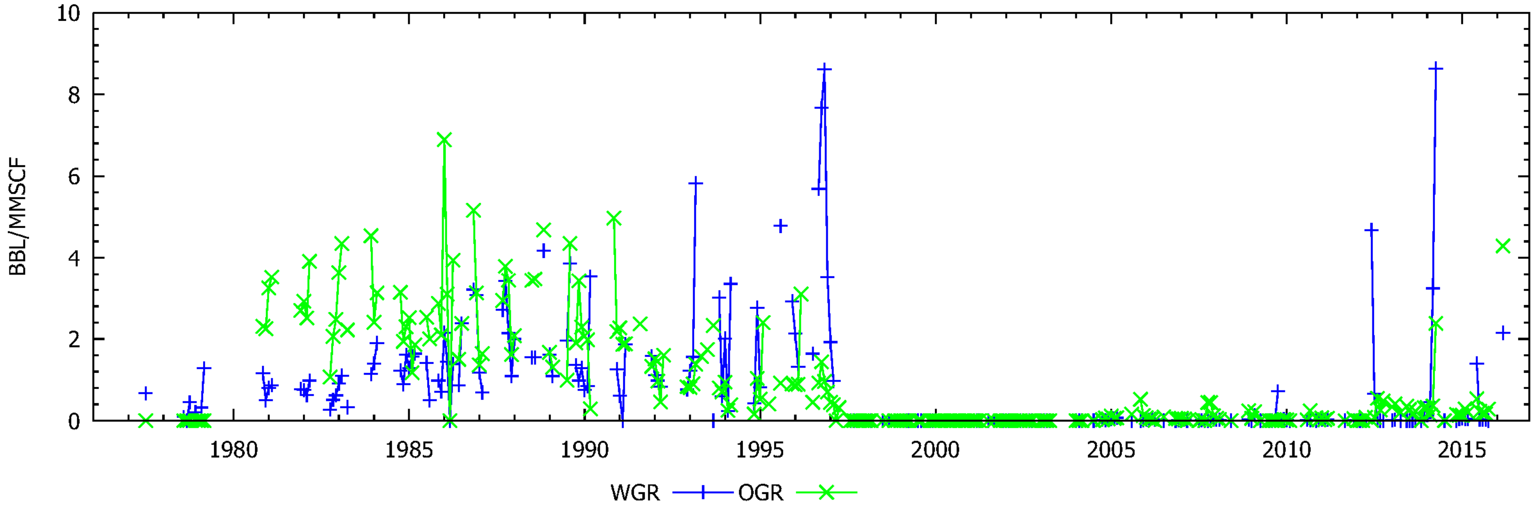


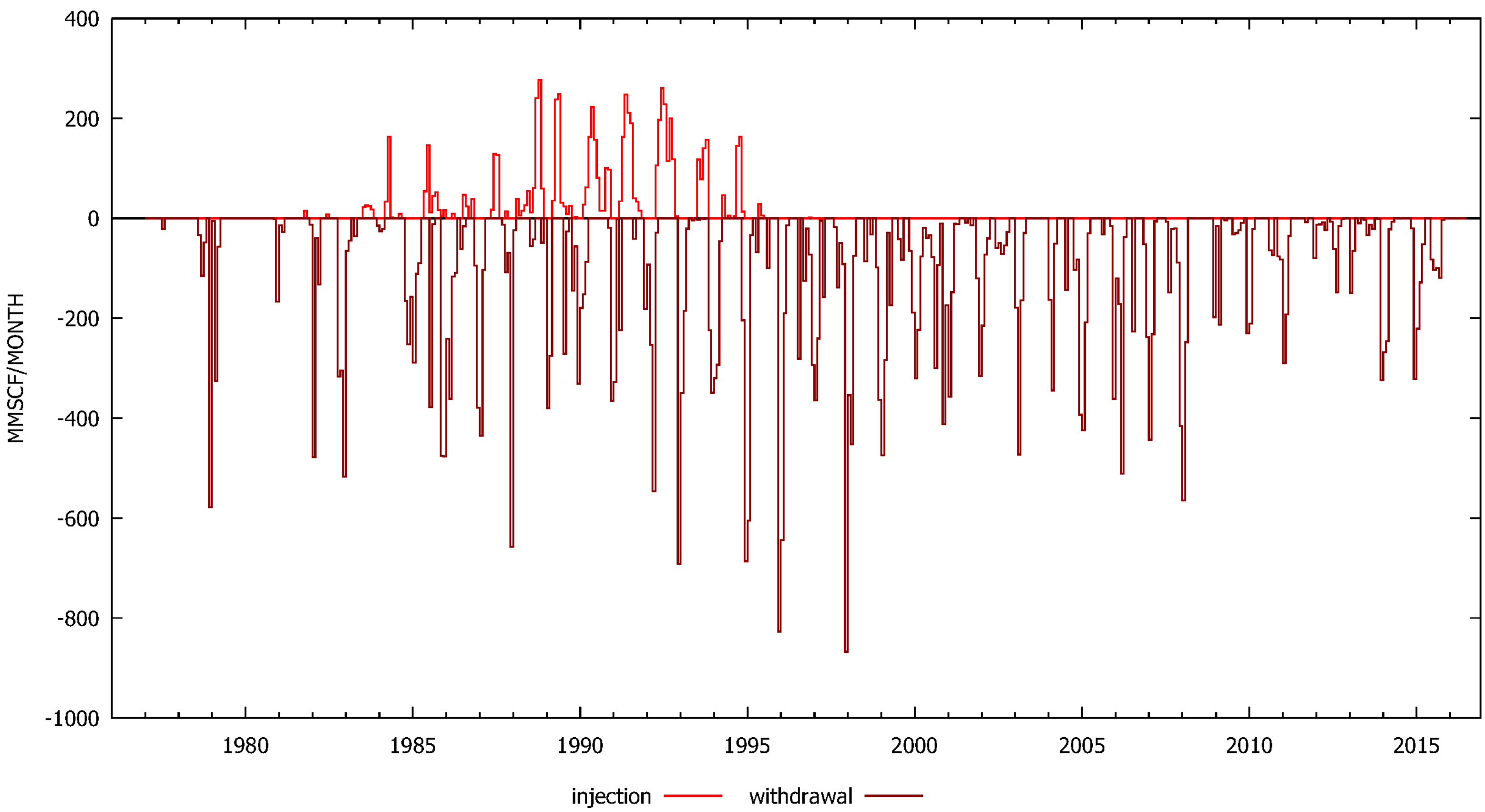
PORTER 42C WELL

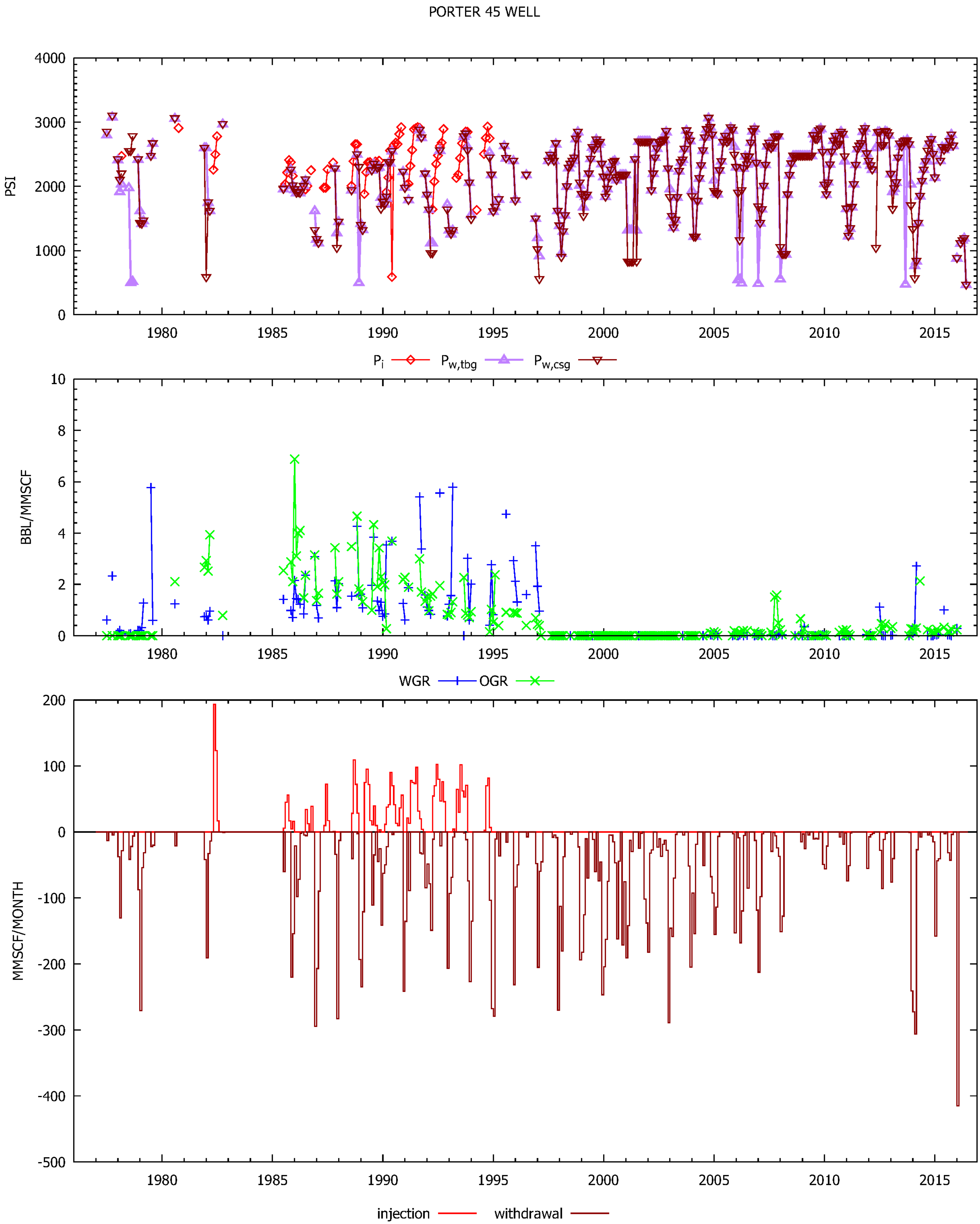


PORTER 44 WELL



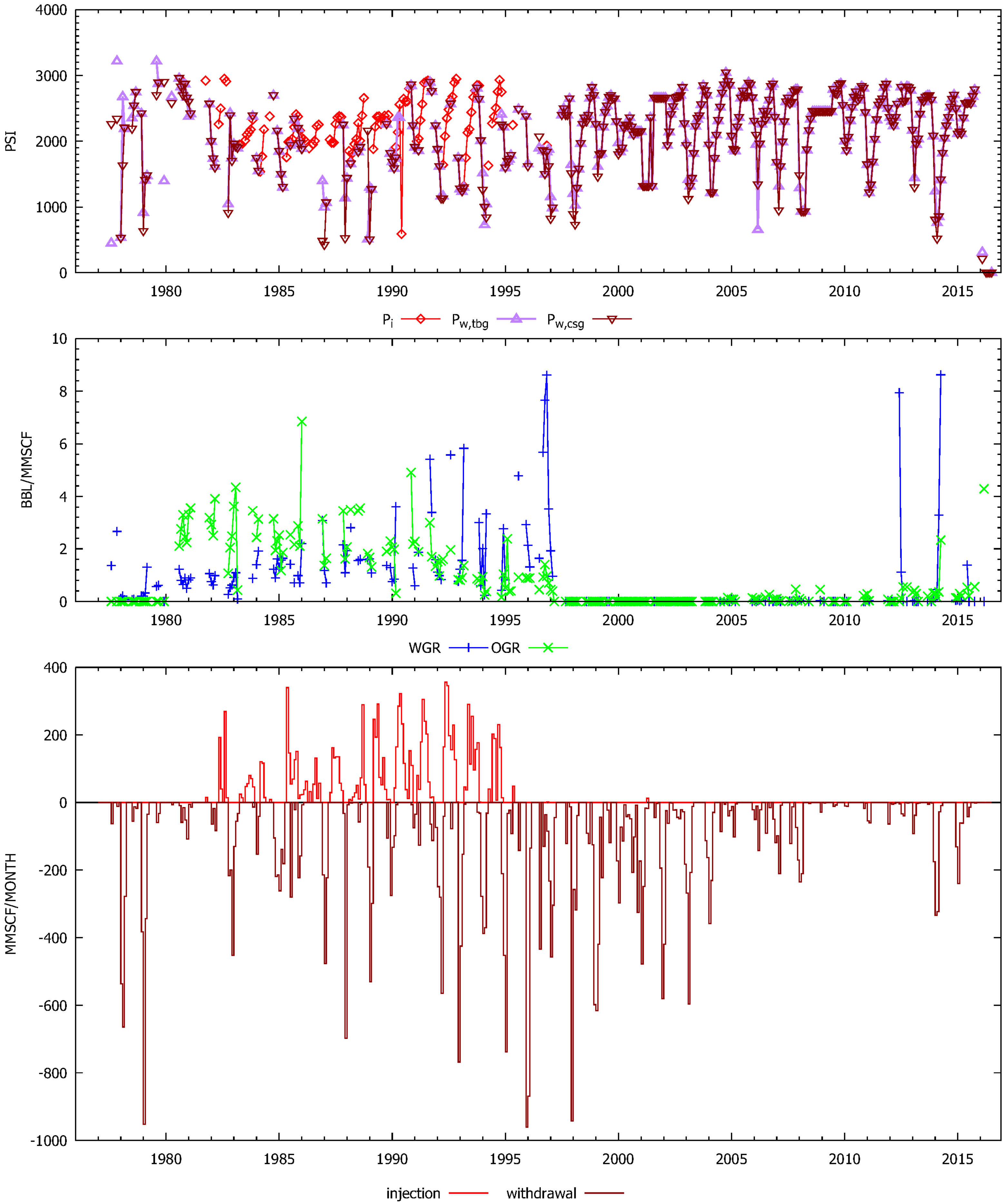




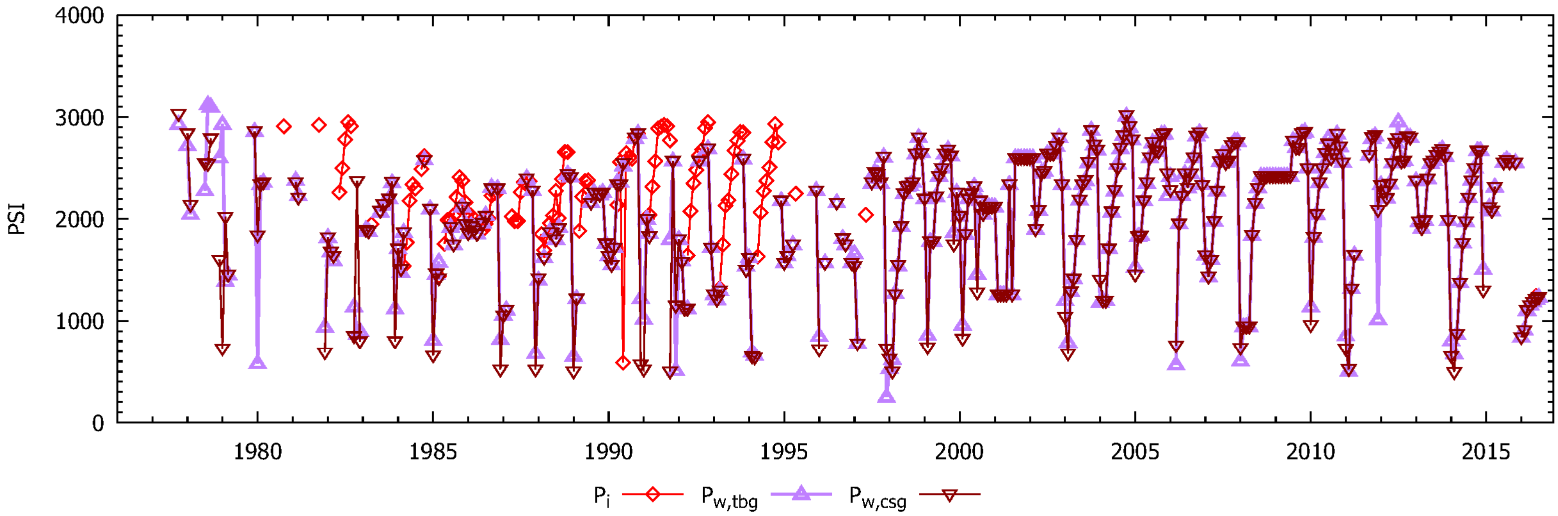


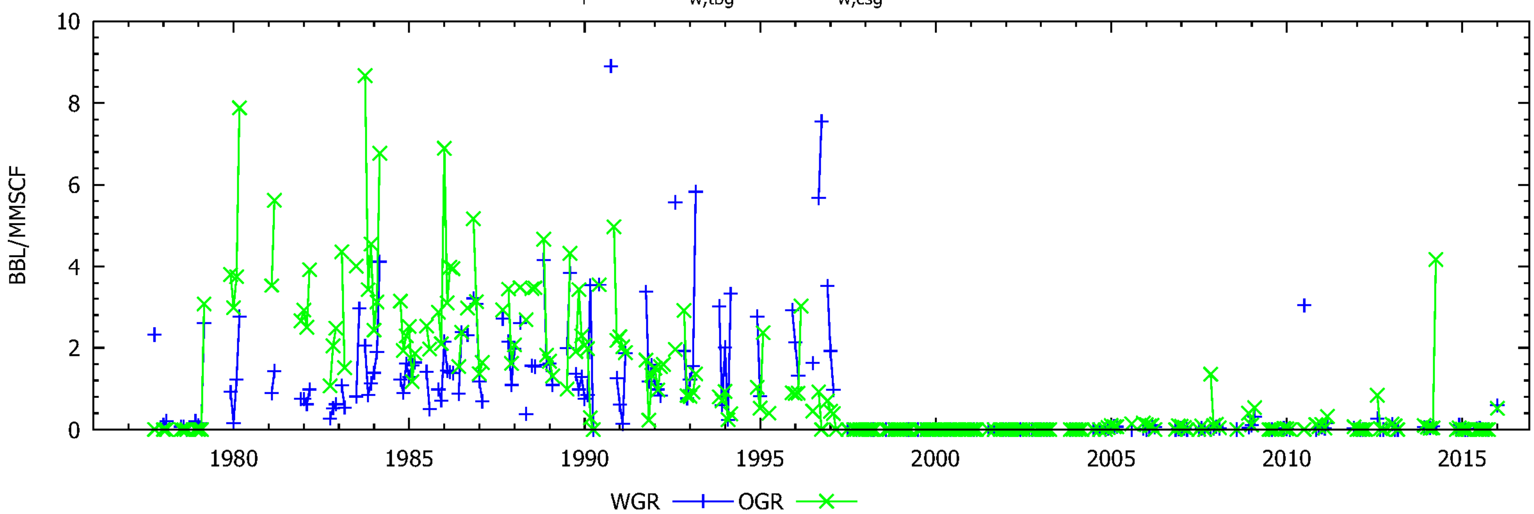
PORTER 45 WELL
PSI
4000
3000
2000
1000
0
1980
1985
1990
1995
2000
2005
2010
2015
P_i
$P_{w,tbg}$
$P_{w,csg}$
BBL/MMSCF
10
8
6
4
2
0
WGR
OGR
MMSCF/MONTH
200
100
0
-100
-200
-300
-400
-500
injection
withdrawal

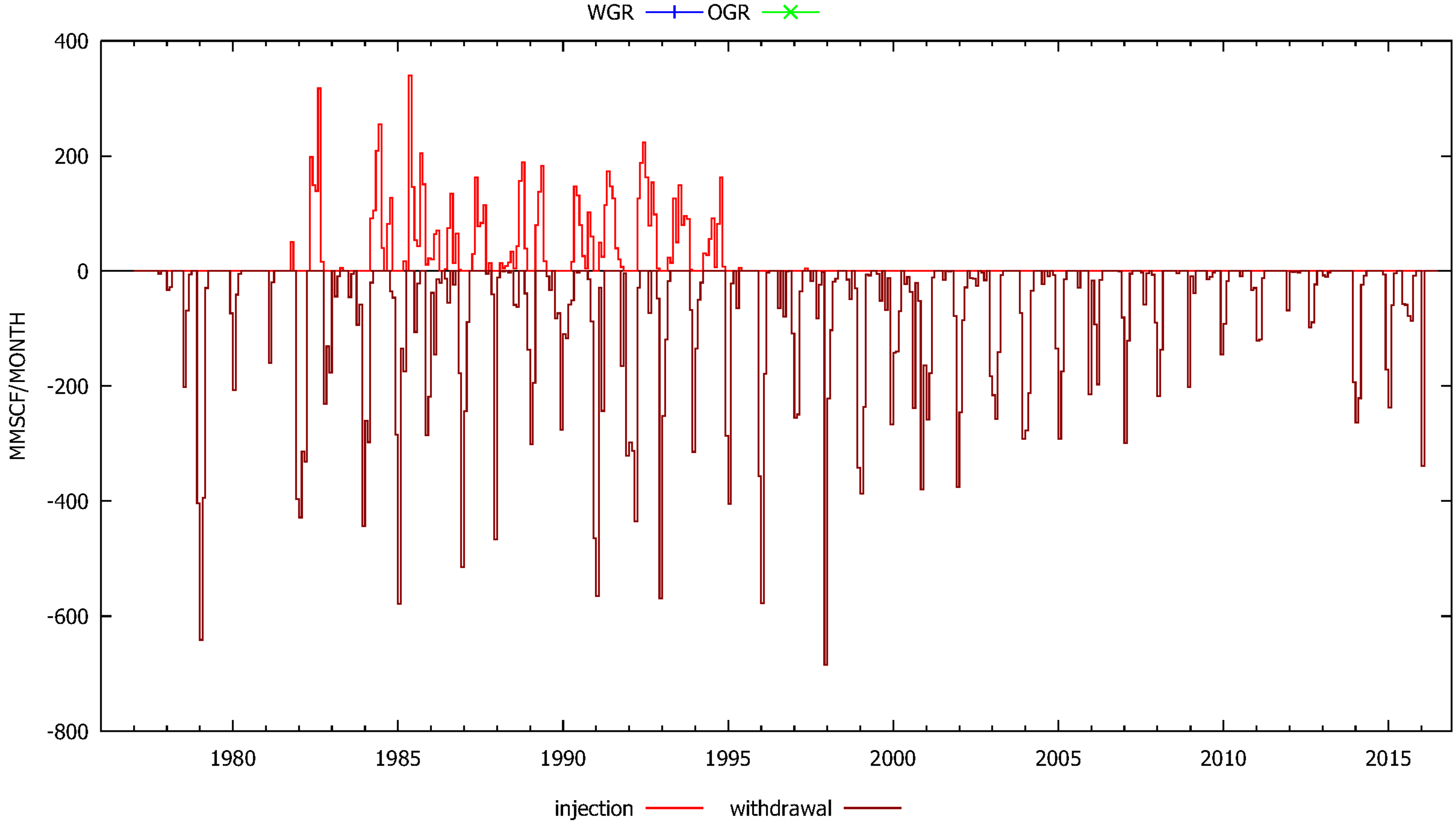
PORTER 46 WELL



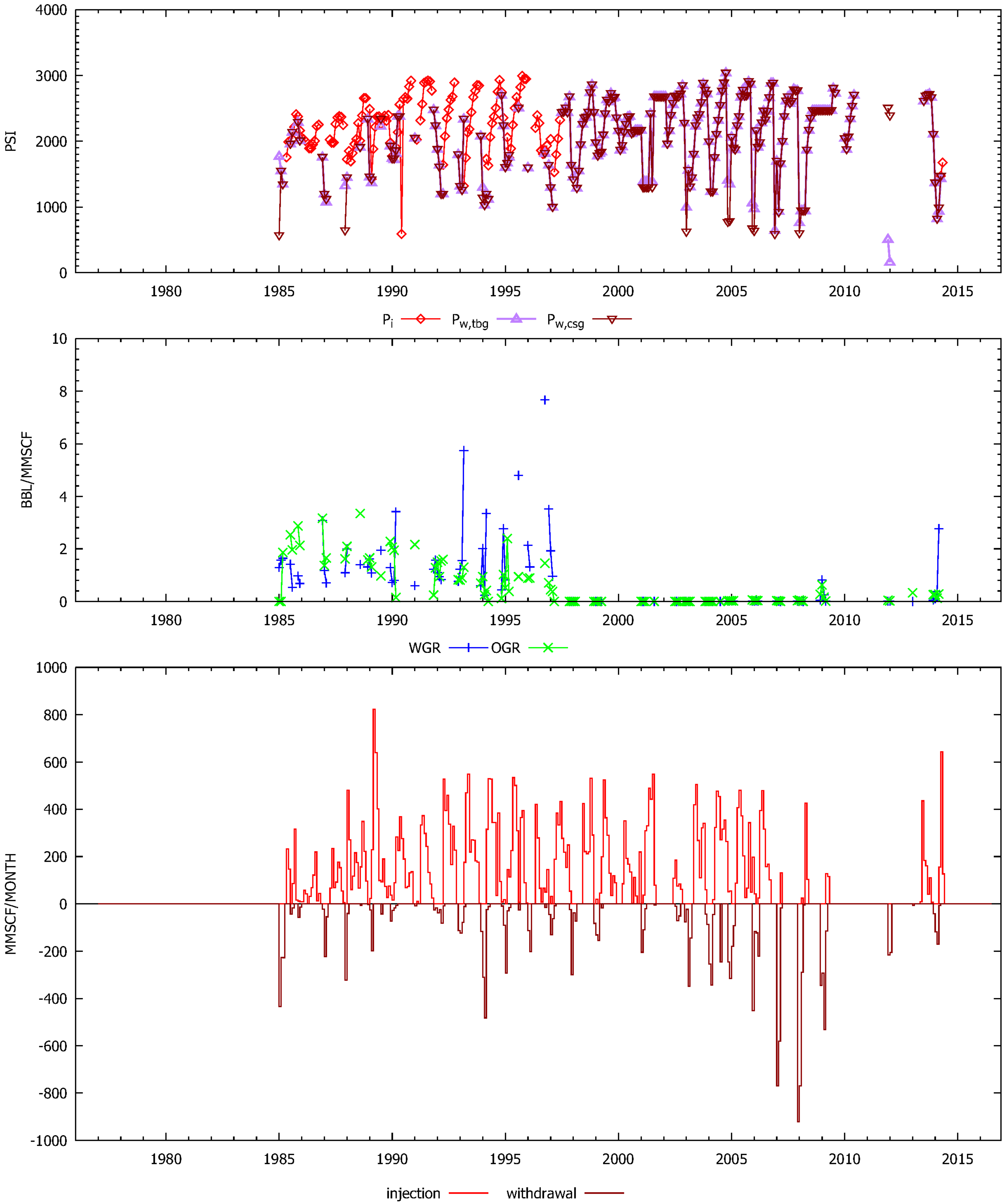
PORTER 47 WELL



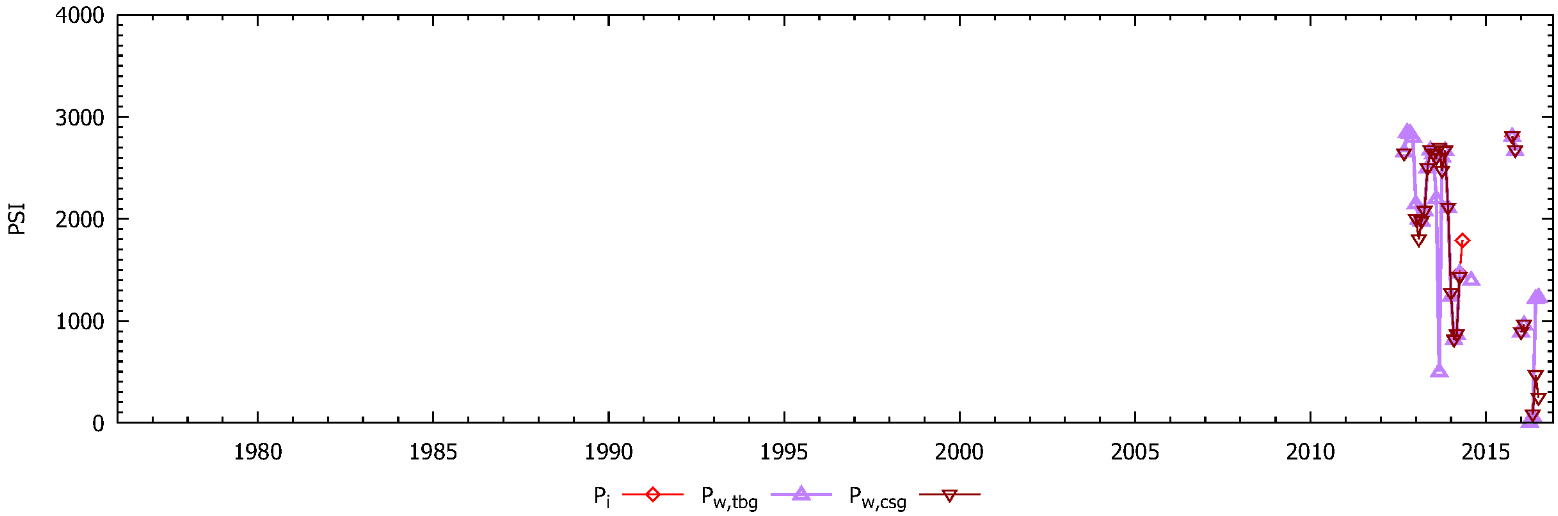


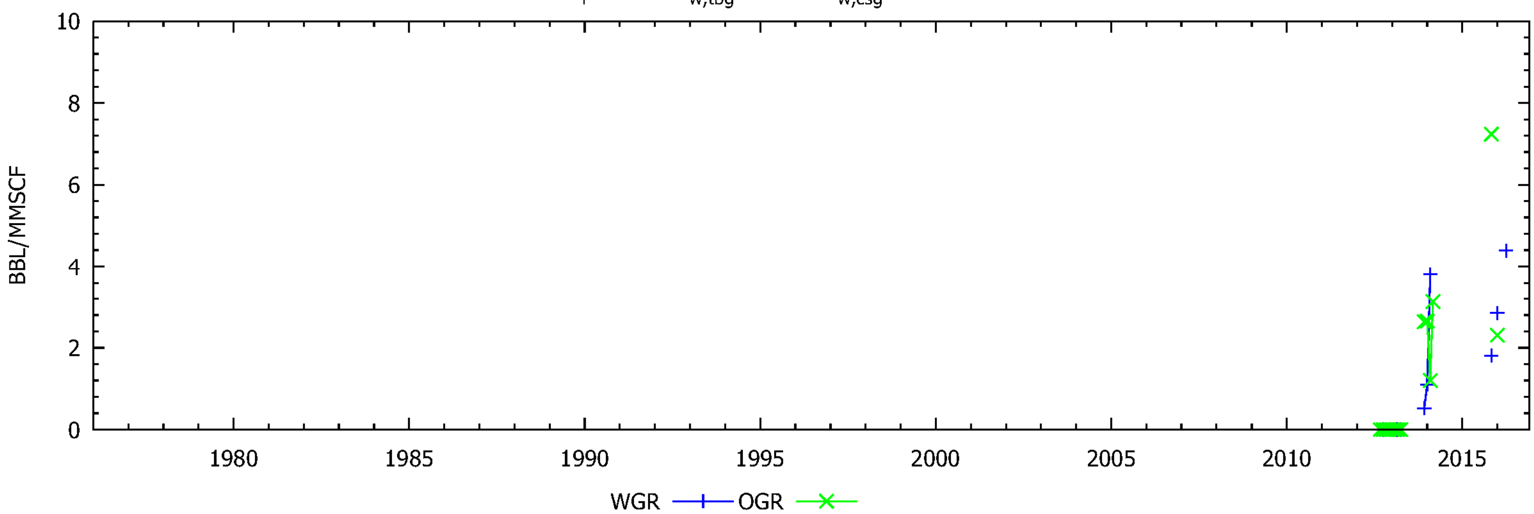


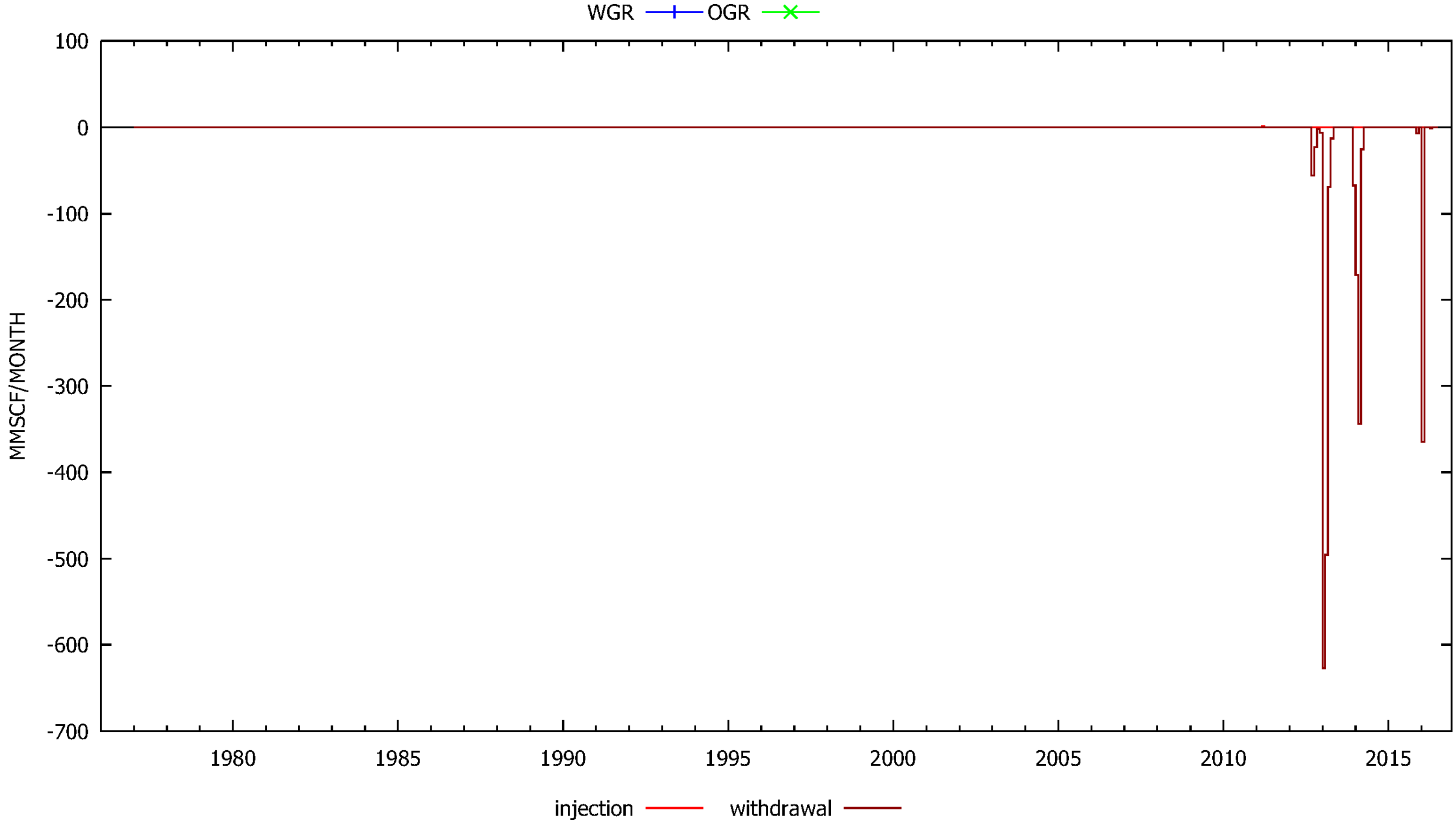
PORTER 50A WELL

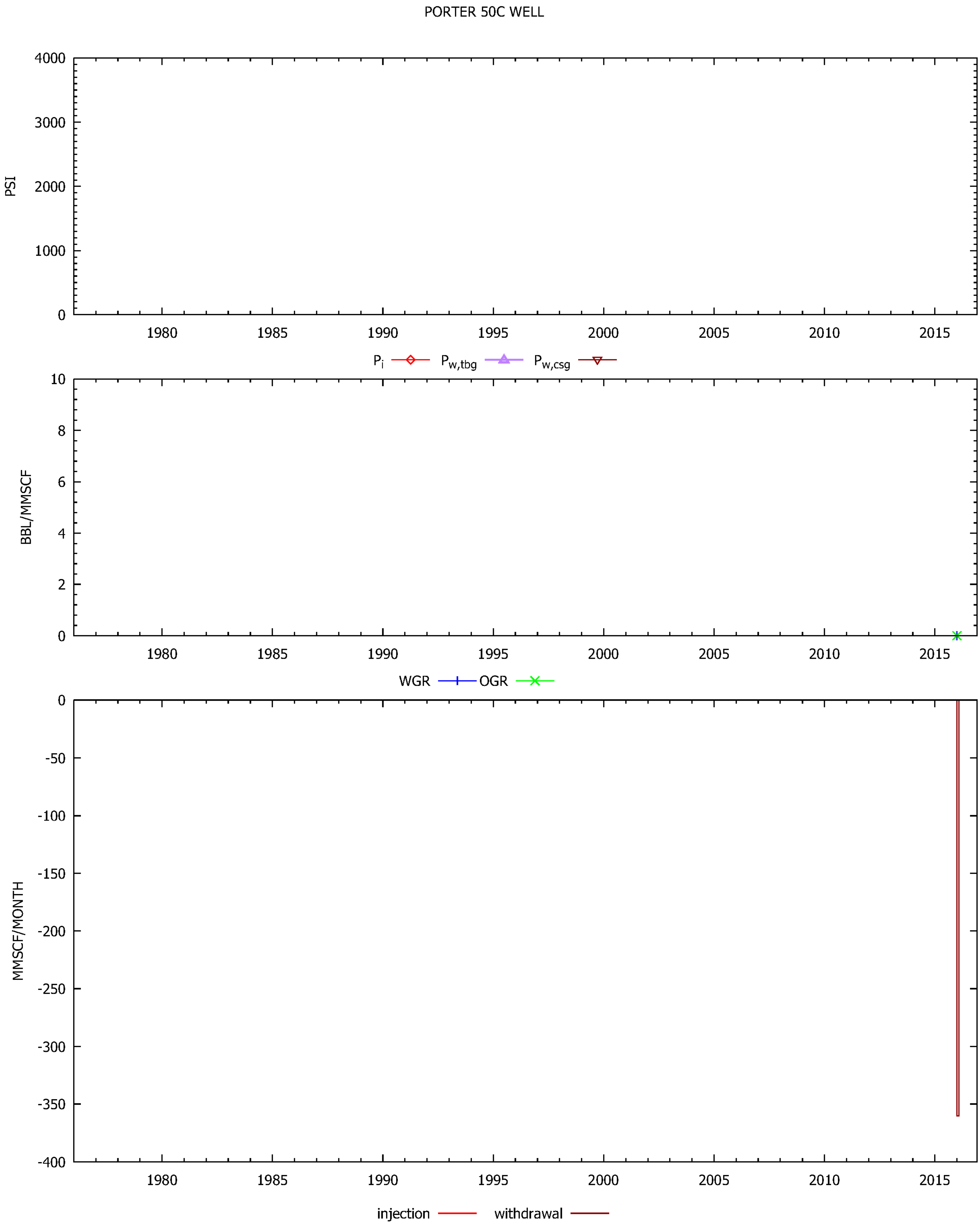


PORTER 50B WELL

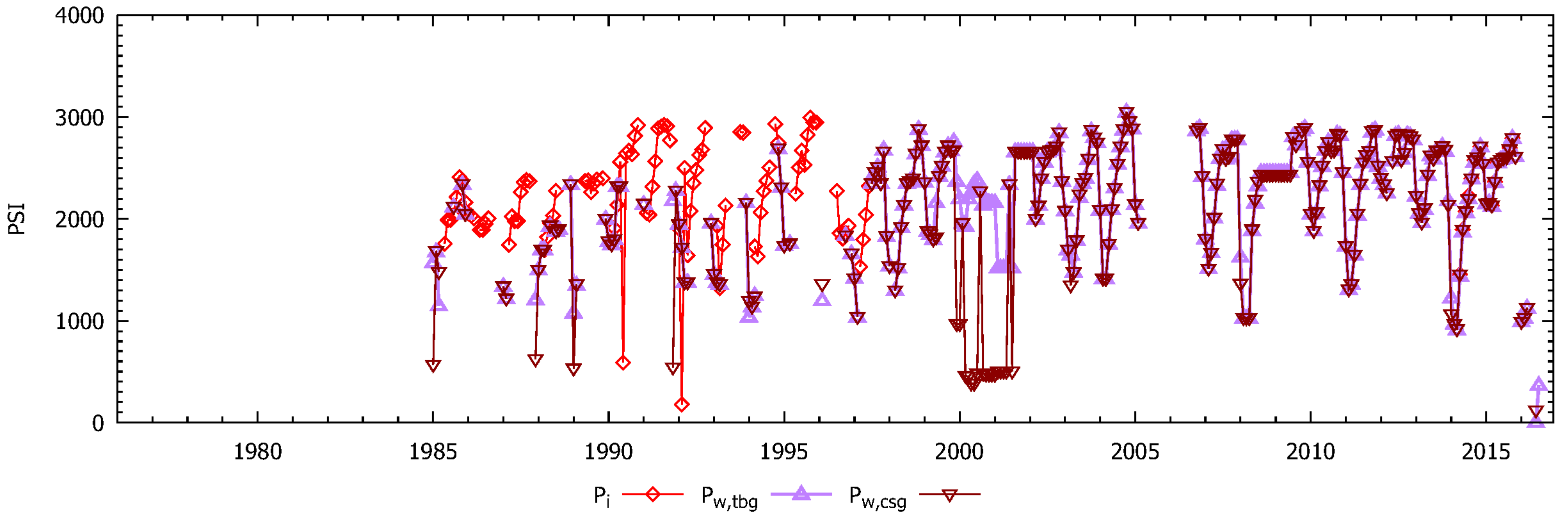


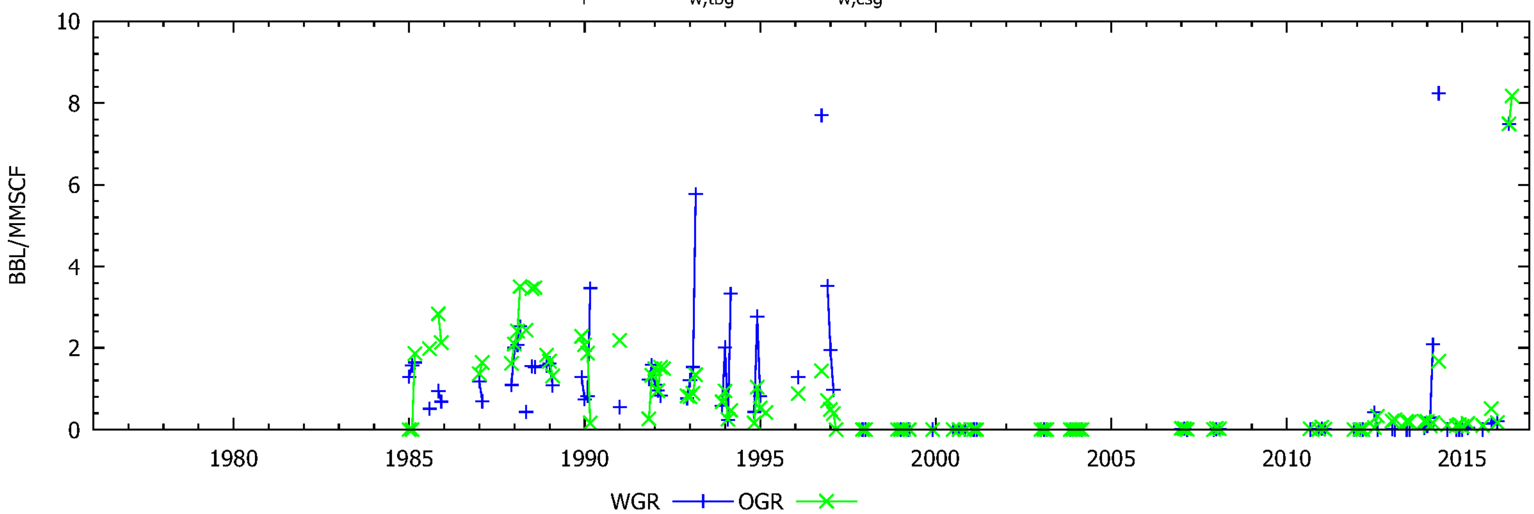


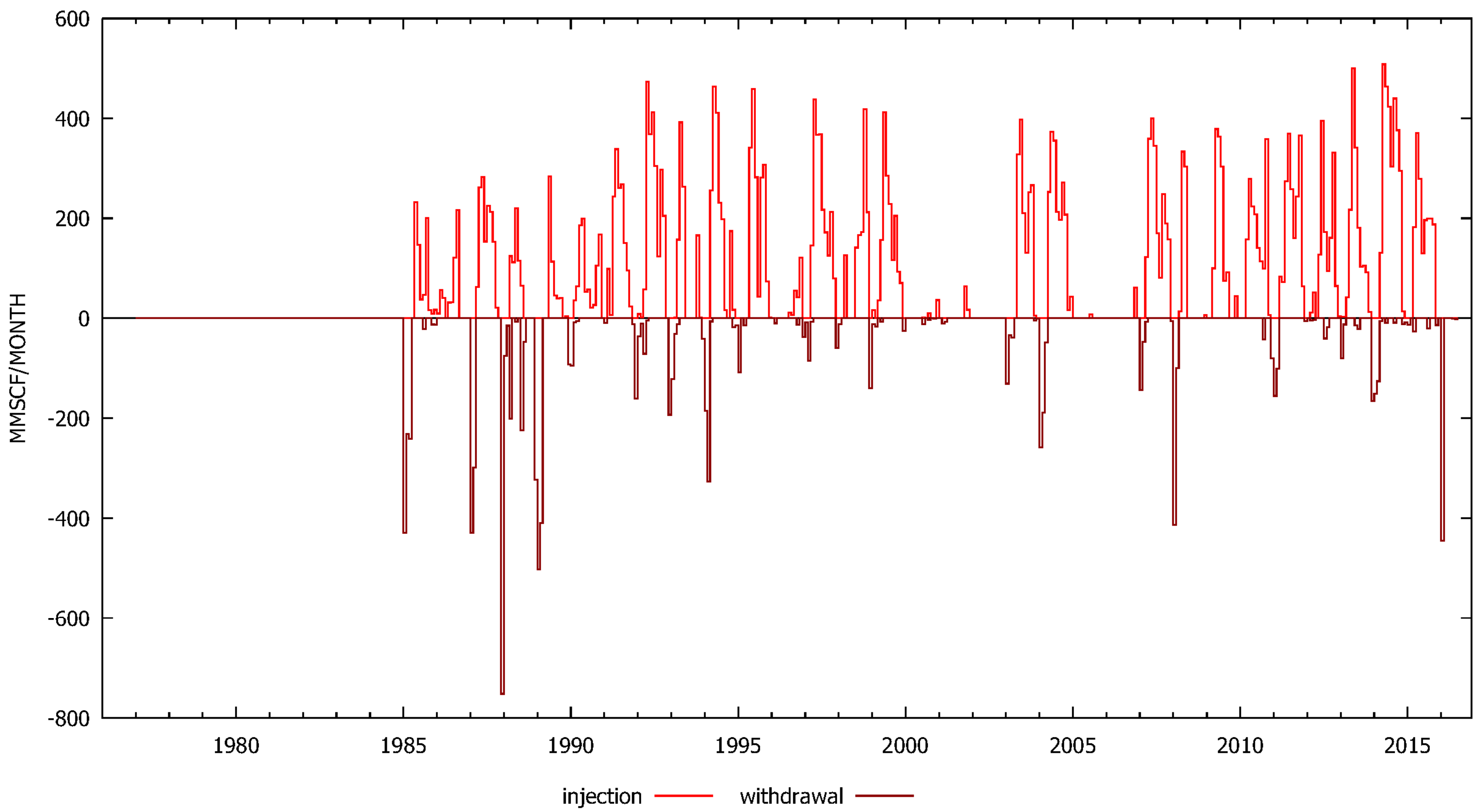



PORTER 50C WELL
PSI
4000
3000
2000
1000
0
1980
1985
1990
1995
2000
2005
2010
2015
P_i
$P_{w,tbg}$
$P_{w,csg}$
BBL/MMSCF
10
8
6
4
2
0
WGR
OGR
MMSCF/MONTH
-50
-100
-150
-200
-250
-300
-350
-400
injection
withdrawal

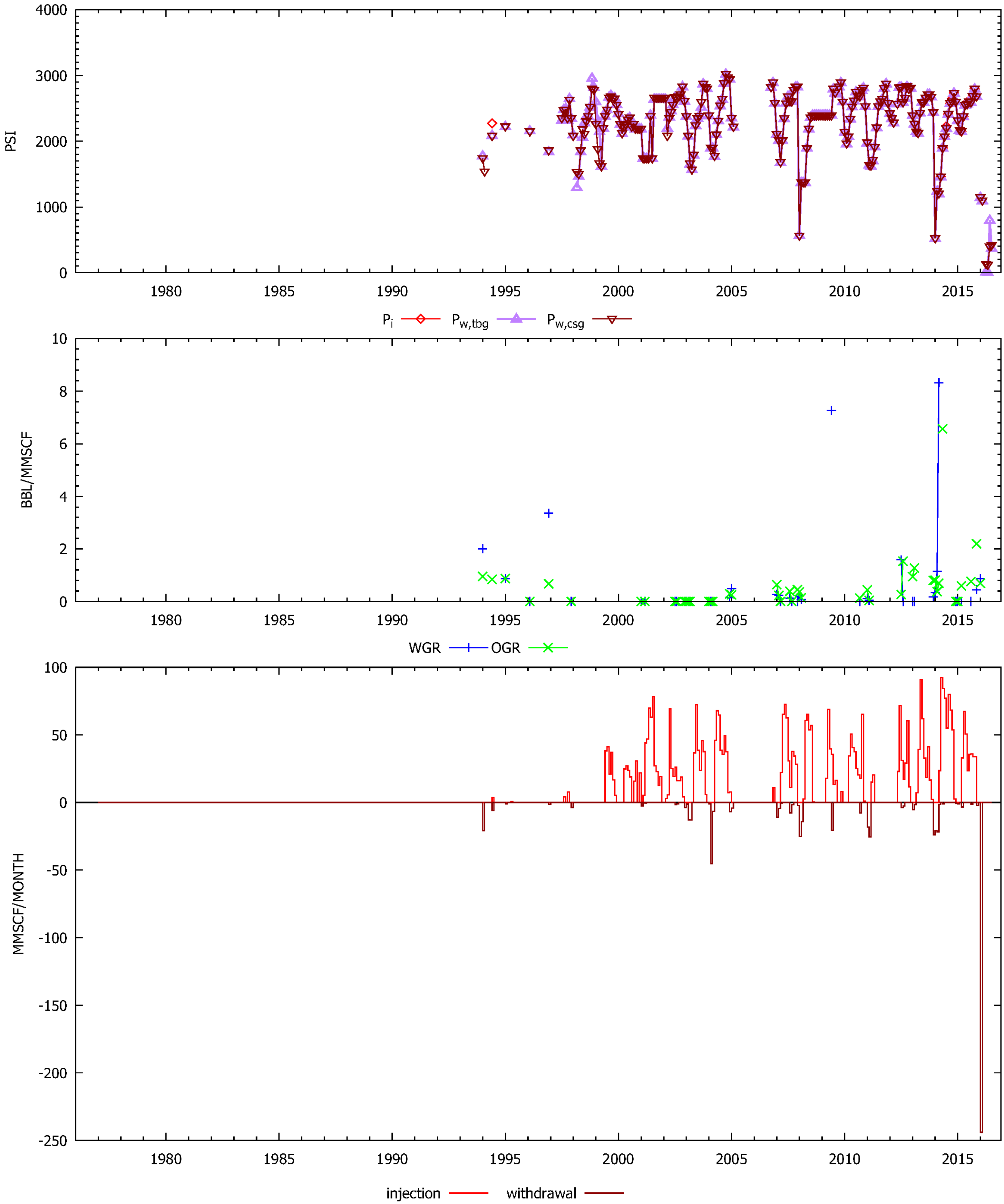
PORTER 68A WELL



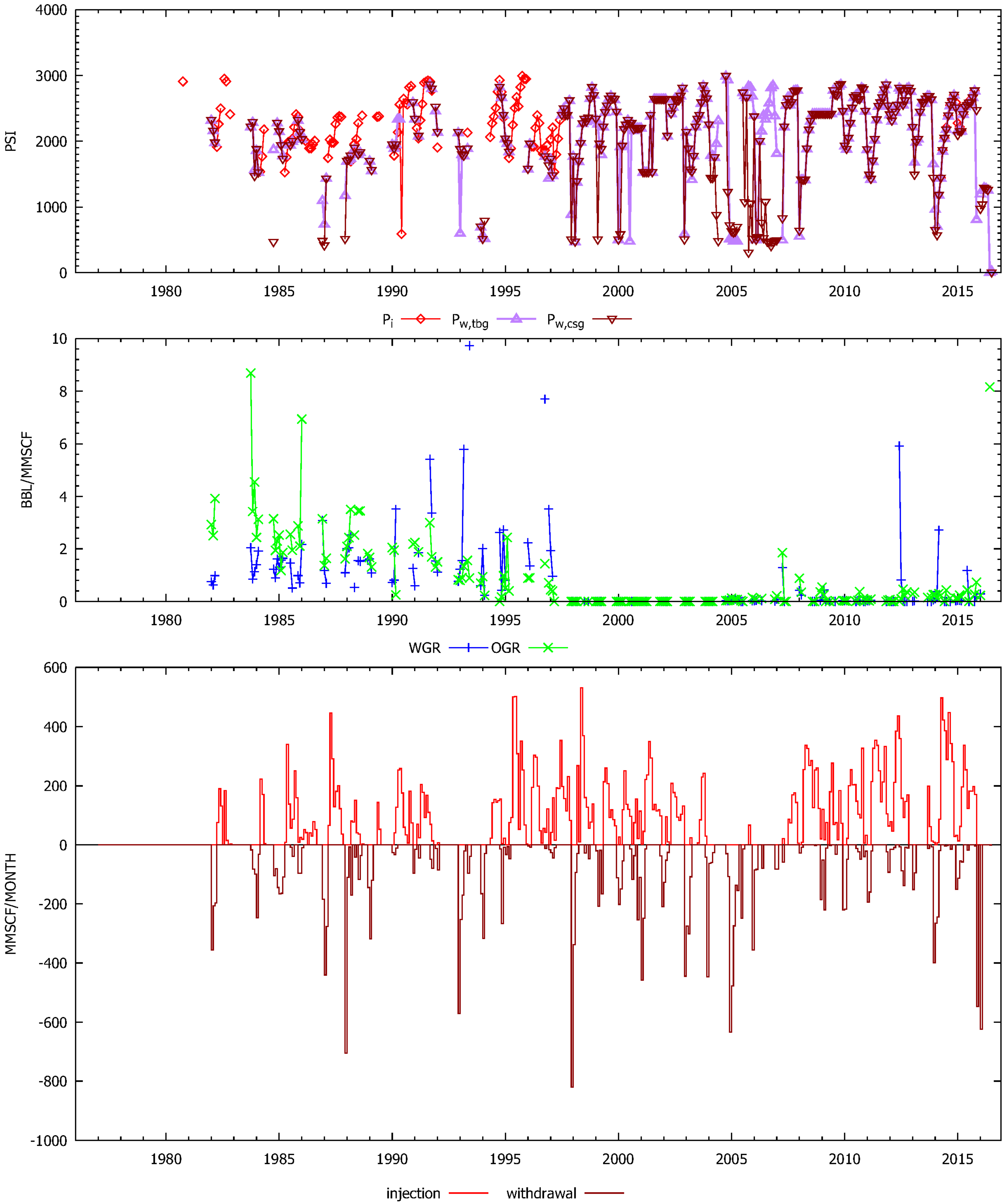




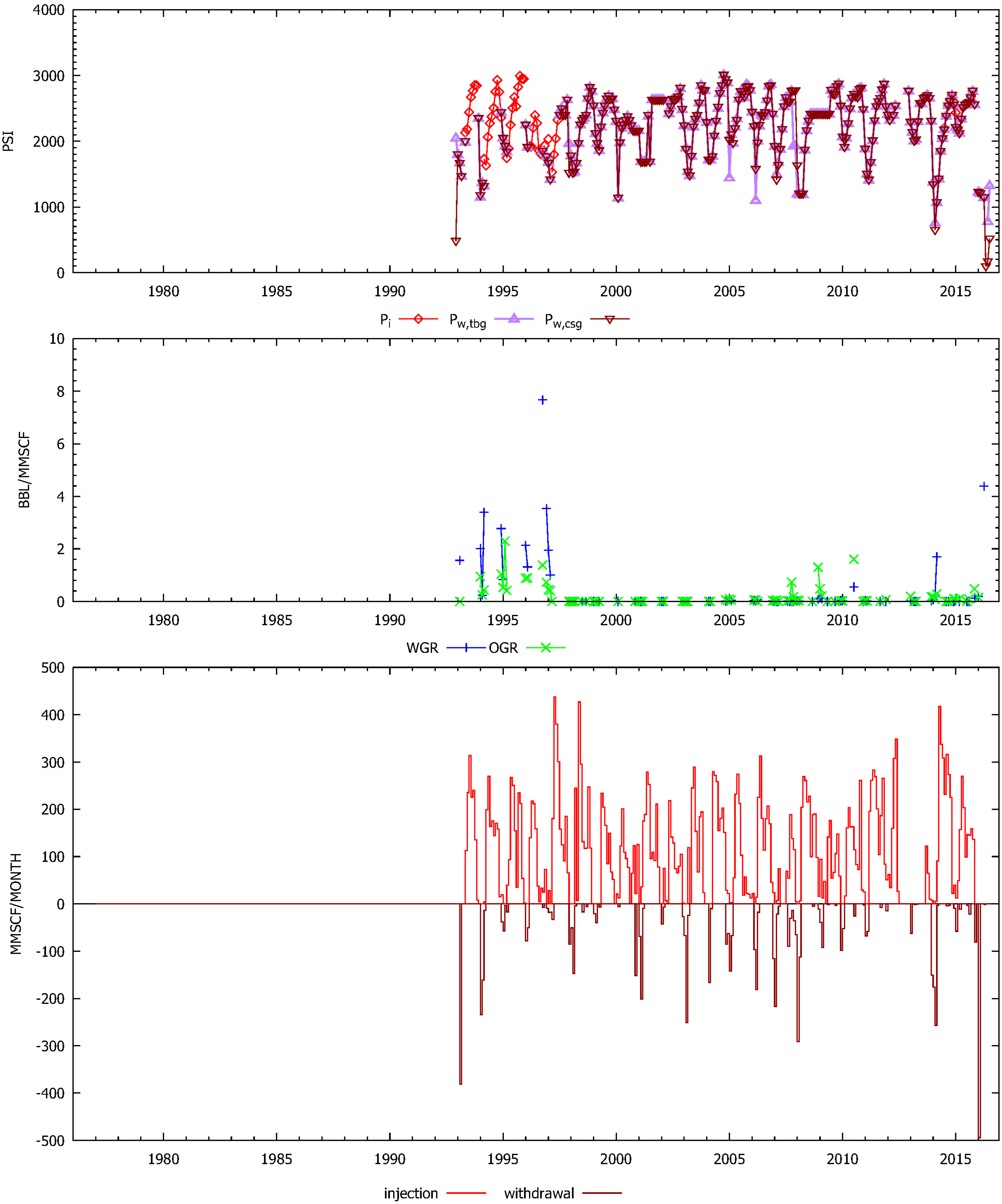
PORTER 68B WELL



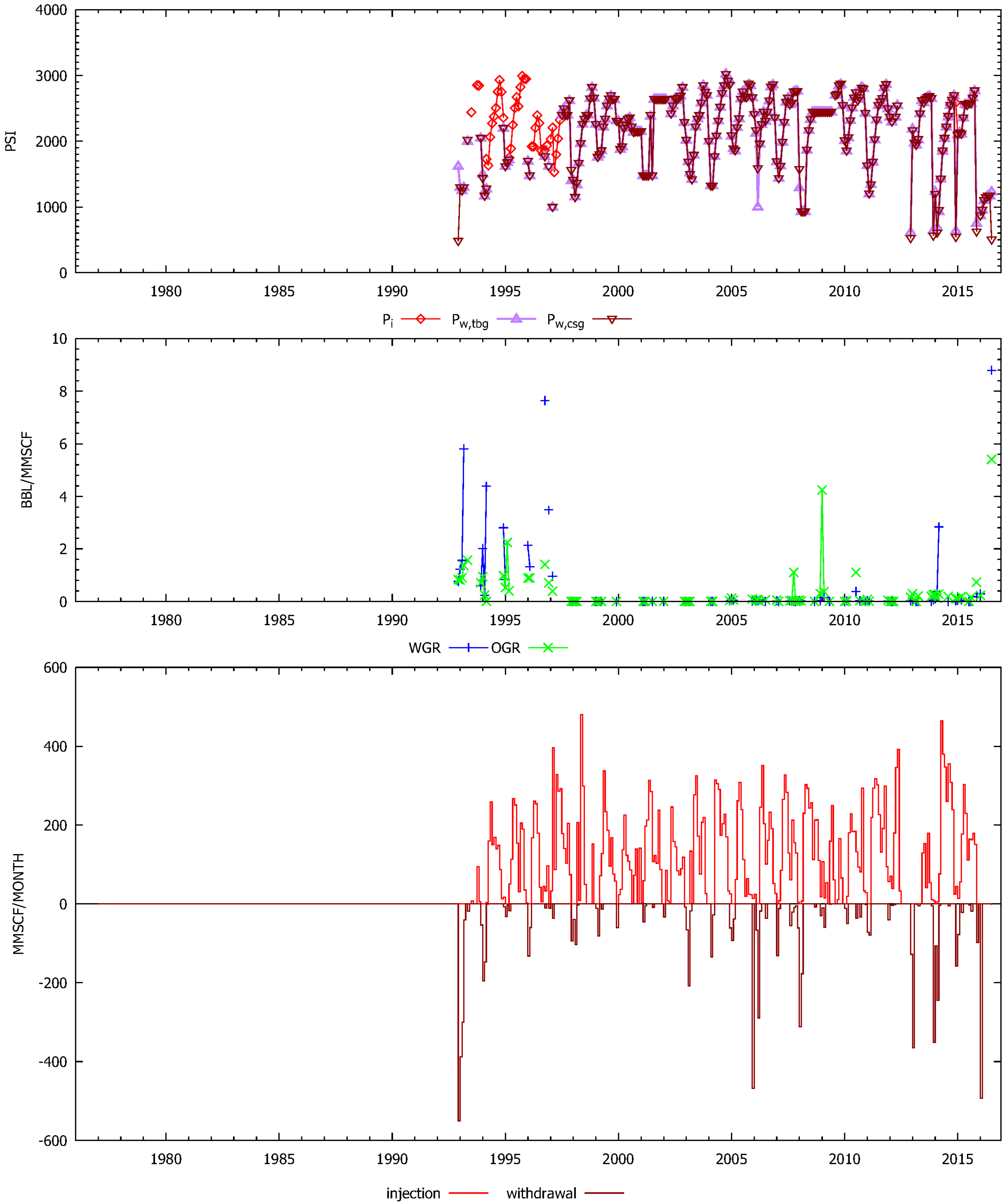
PORTER 69A WELL



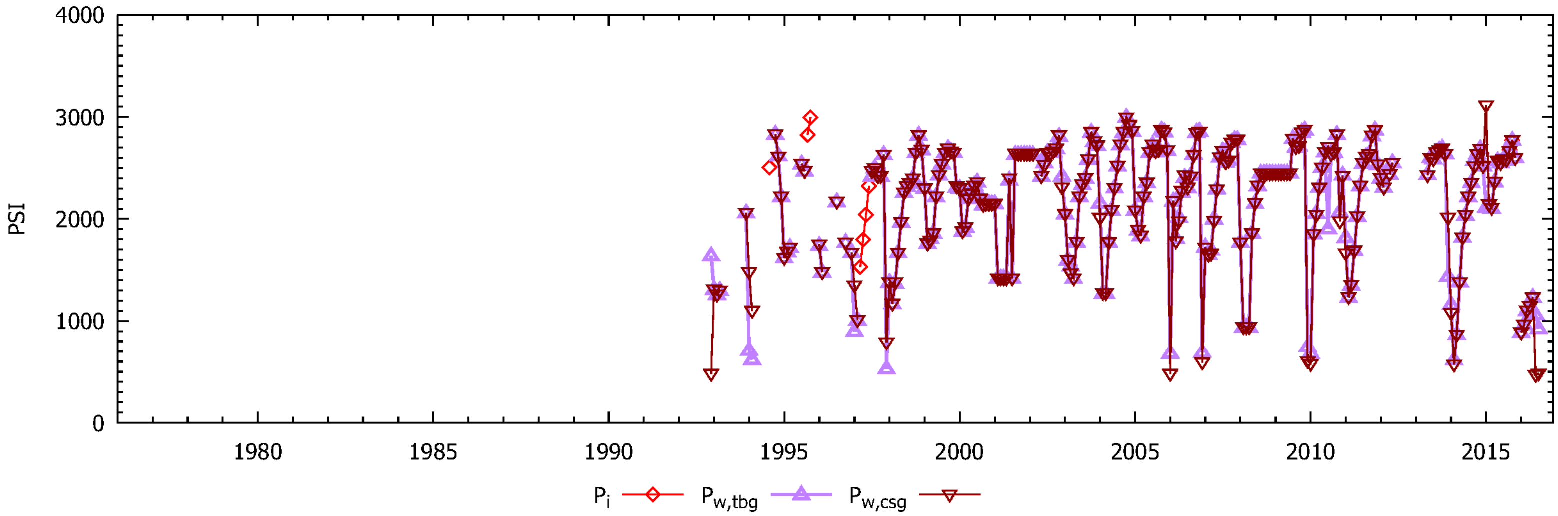
PORTER 69B WELL

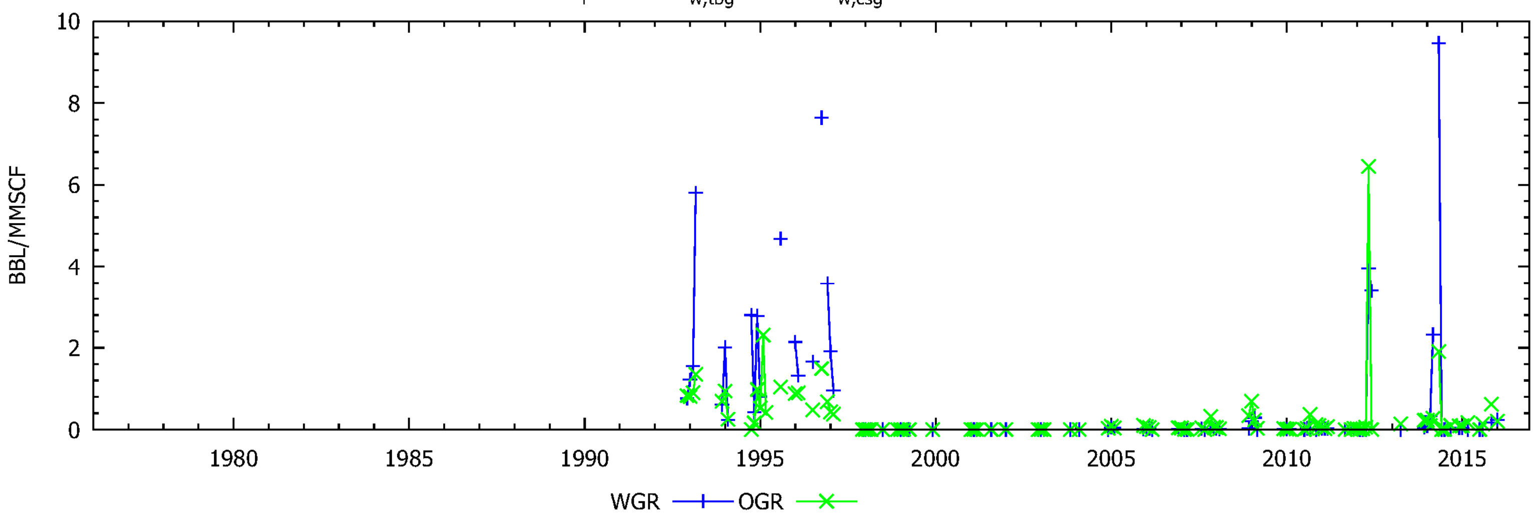


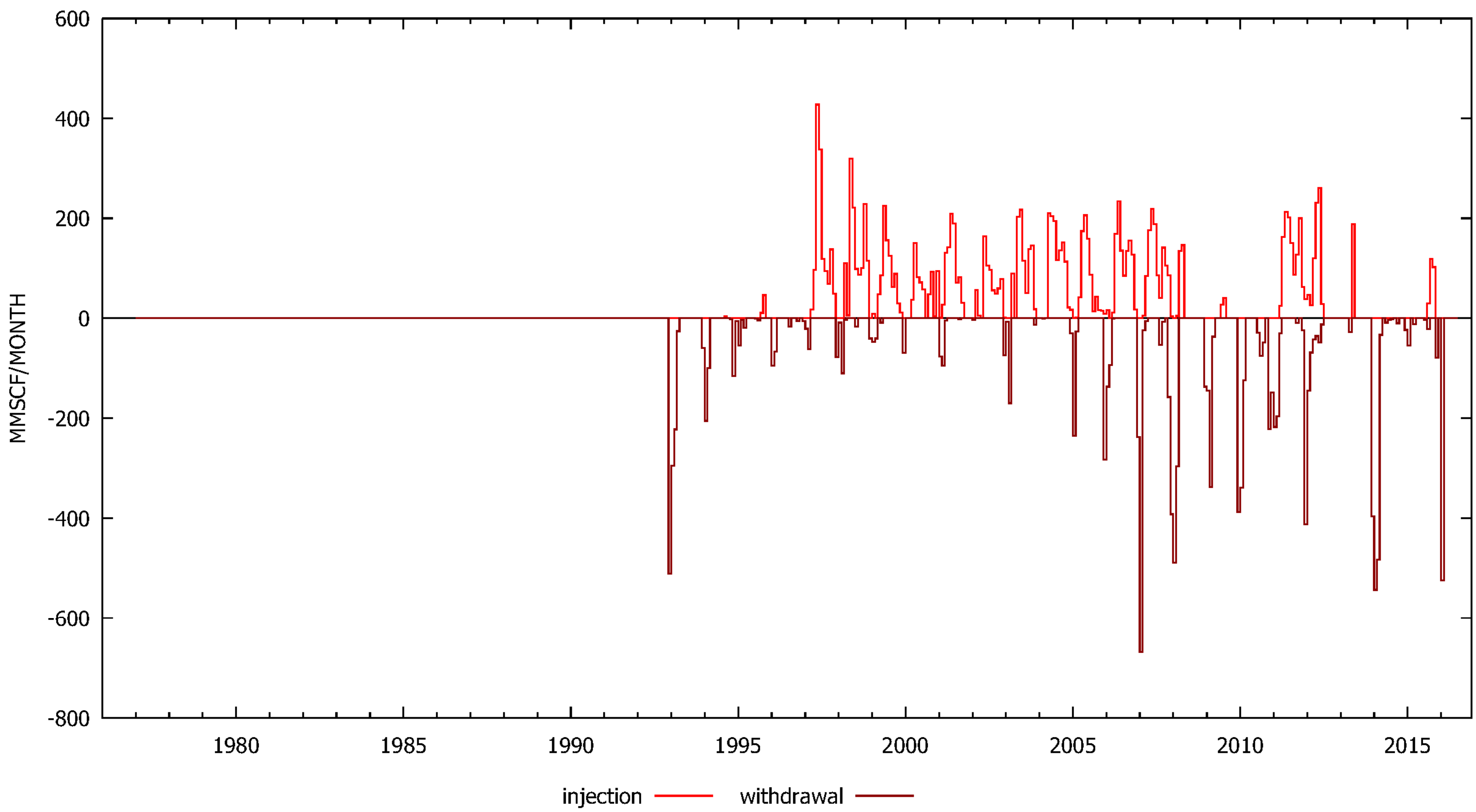
PORTER 69C WELL



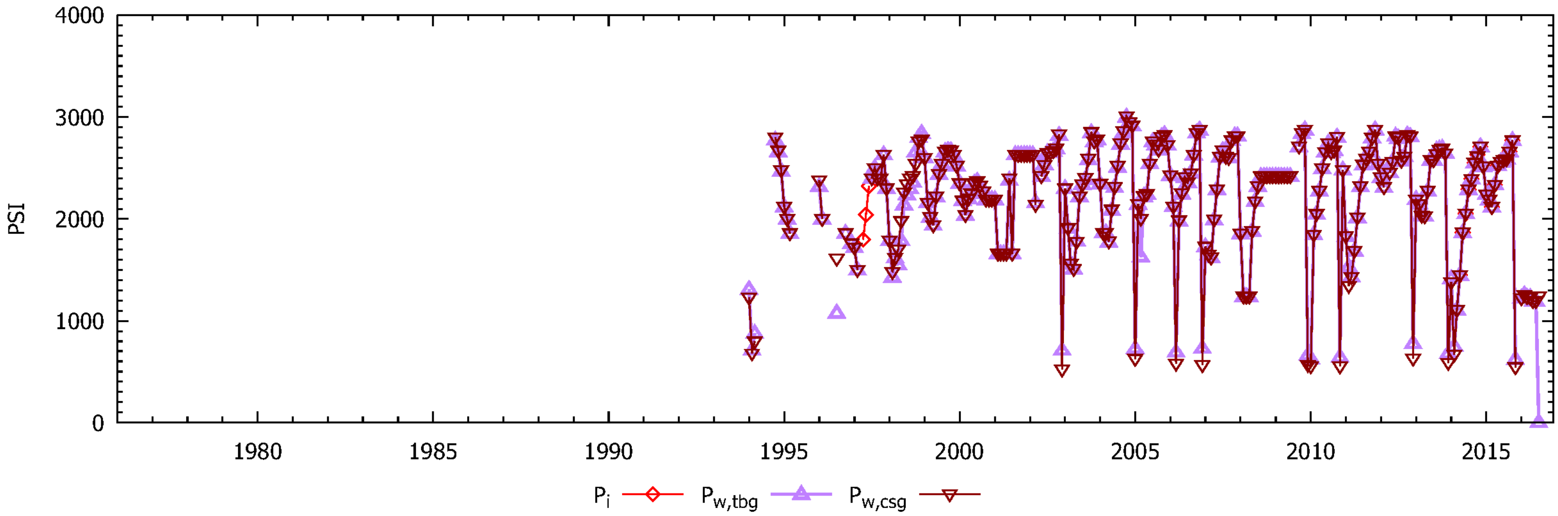
PORTER 69D WELL

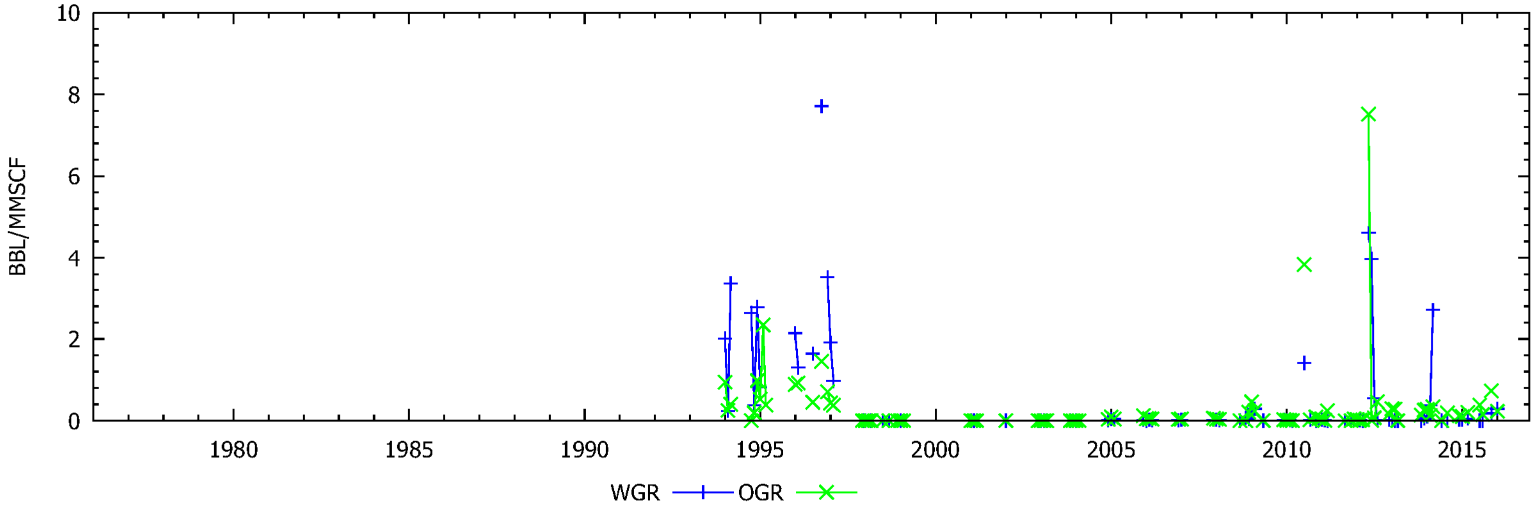


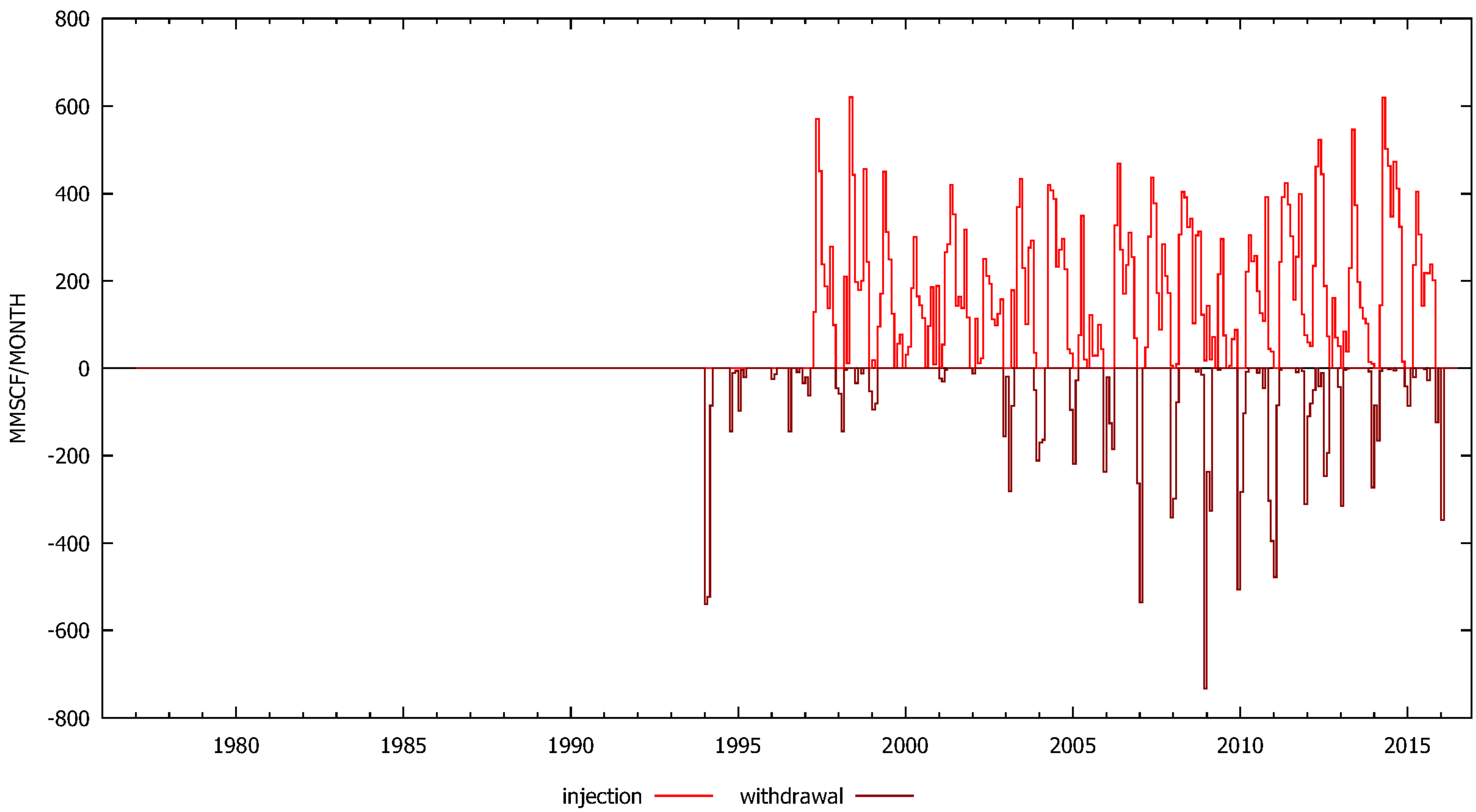




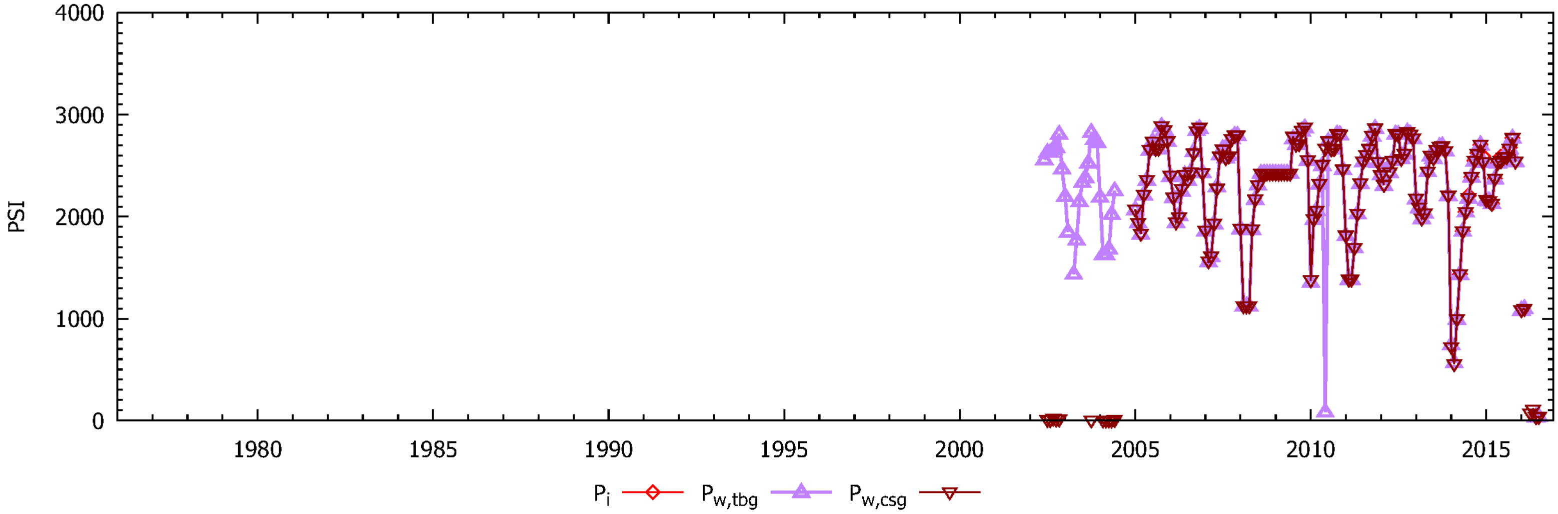
PORTER 69E WELL

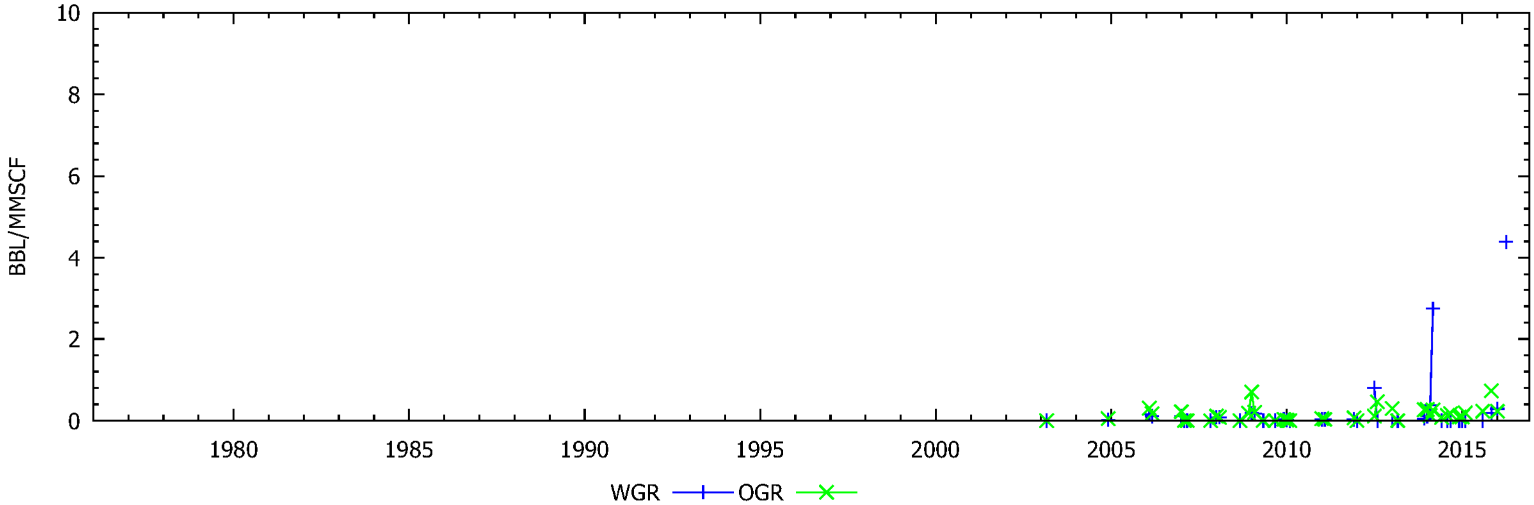


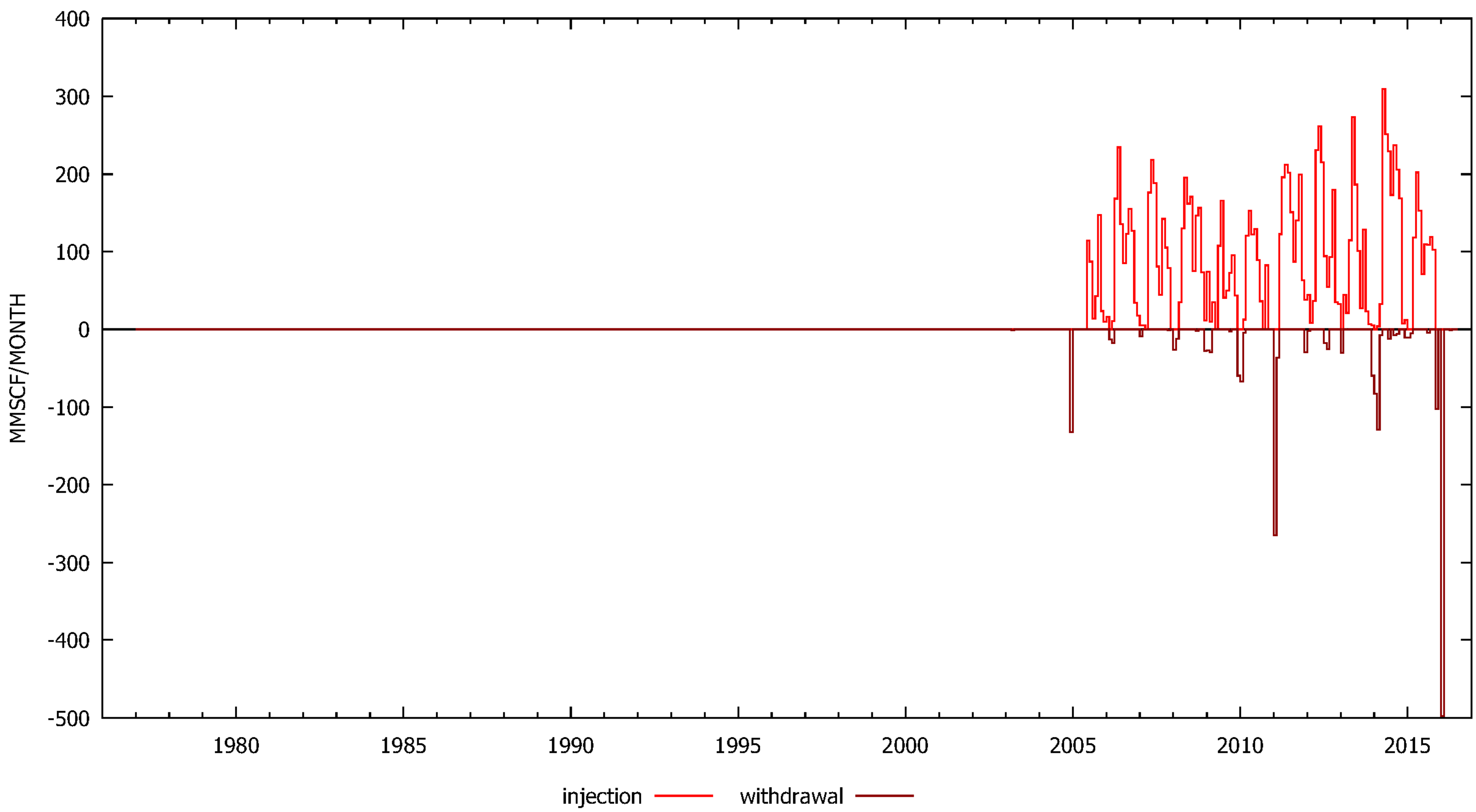




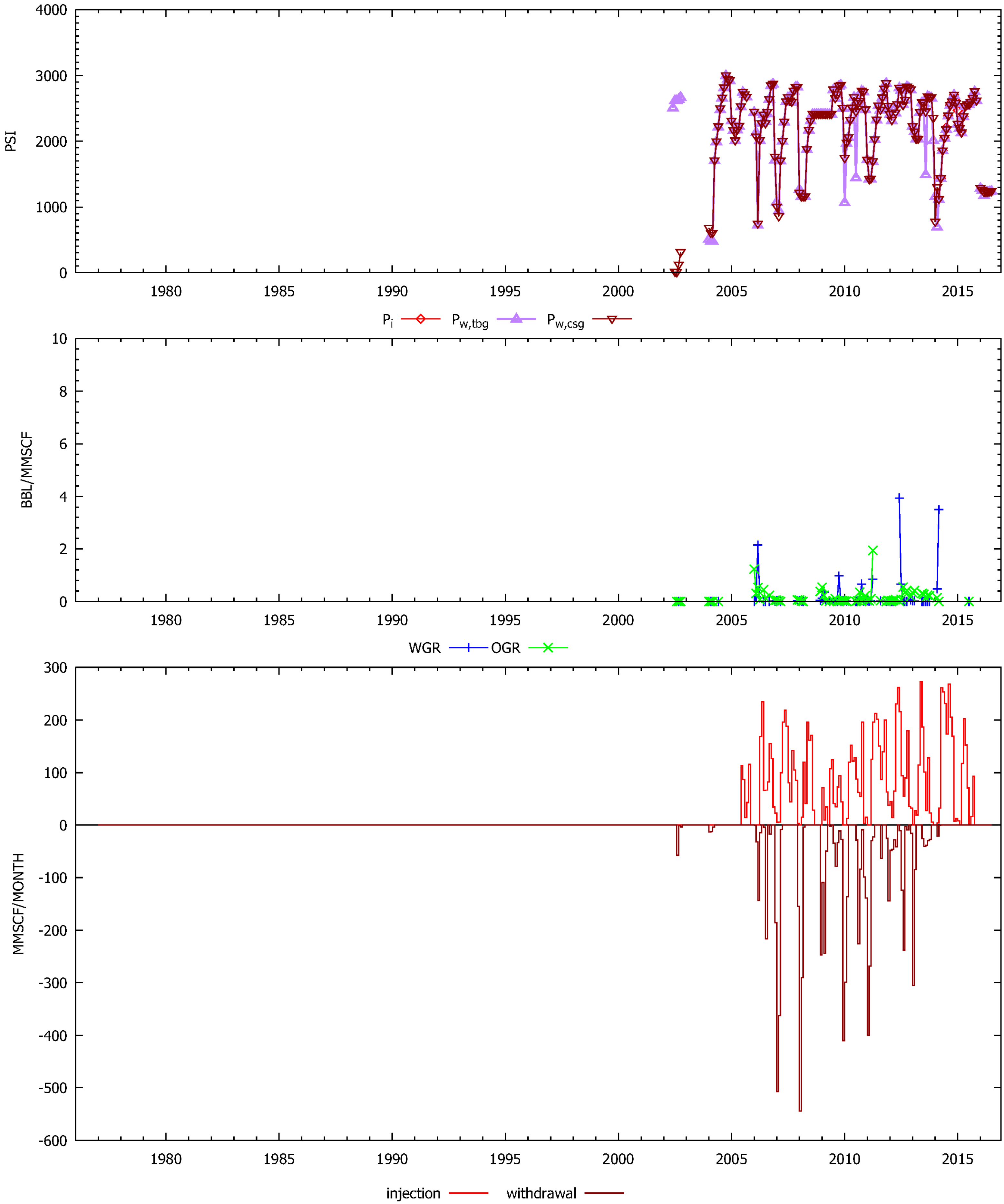
PORTER 69F WELL

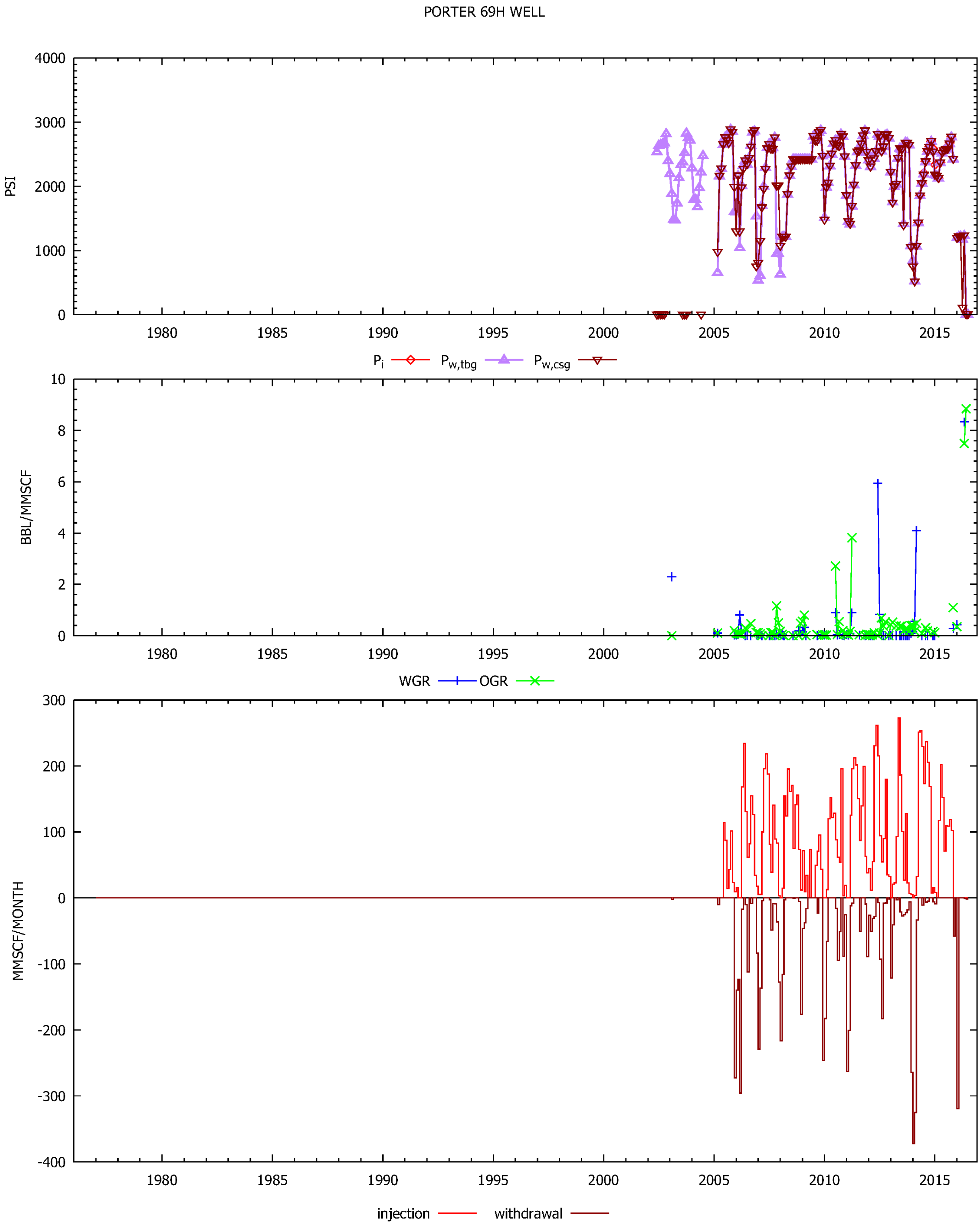


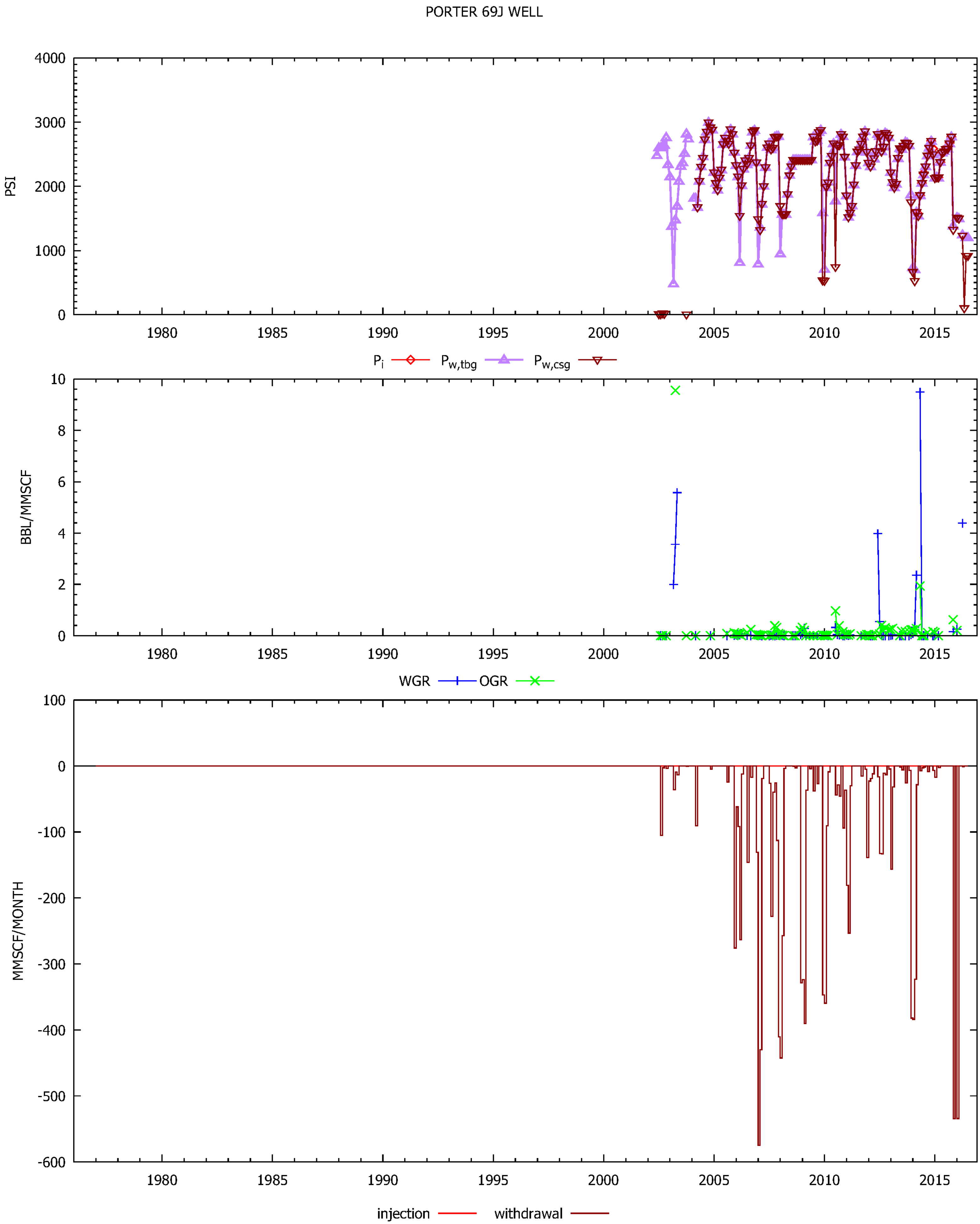




PORTER 69G WELL

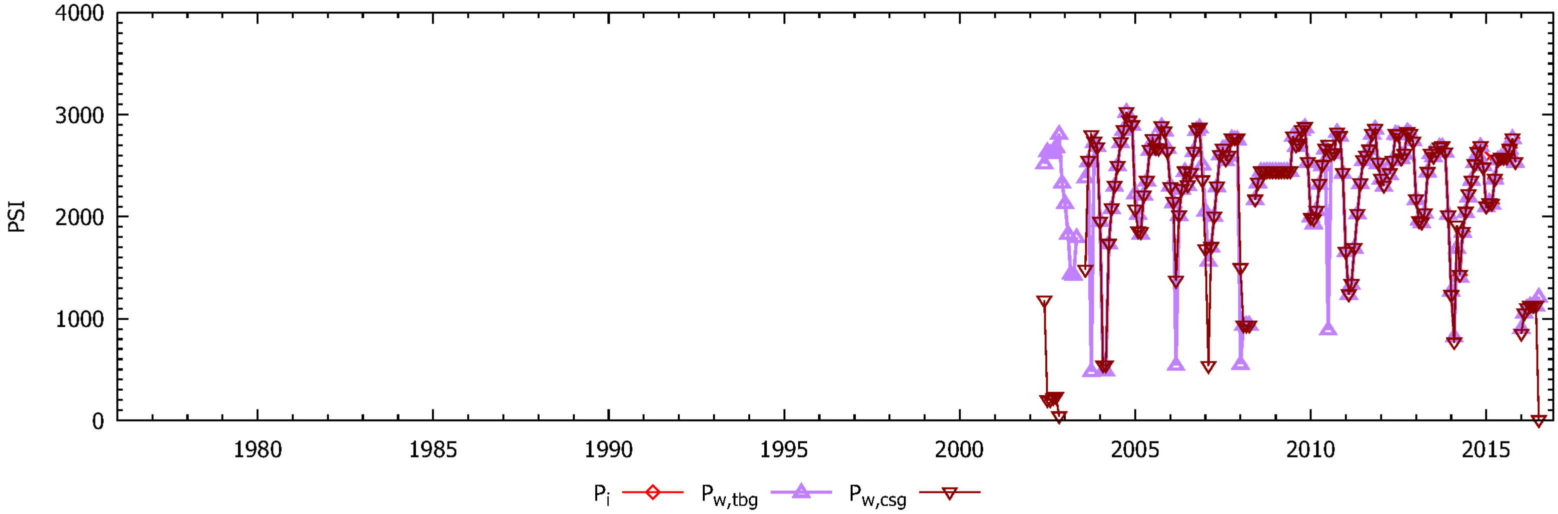


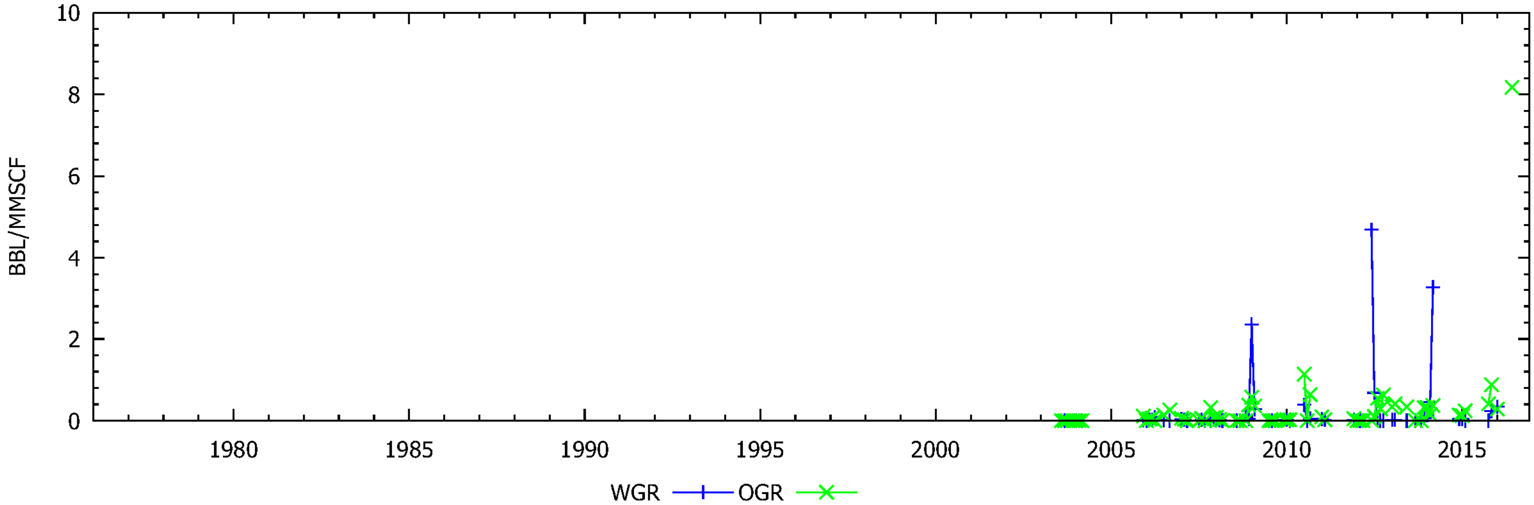

PORTER 69H WELL
4000
3000
2000
1000
0
PSI
1980
1985
1990
1995
2000
2005
2010
2015
P_i
$P_{w,tbg}$
$P_{w,csg}$
10
8
6
4
2
0
BBL/MMSCF
WGR
OGR
300
200
100
0
-100
-200
-300
-400
MMSCF/MONTH
injection
withdrawal

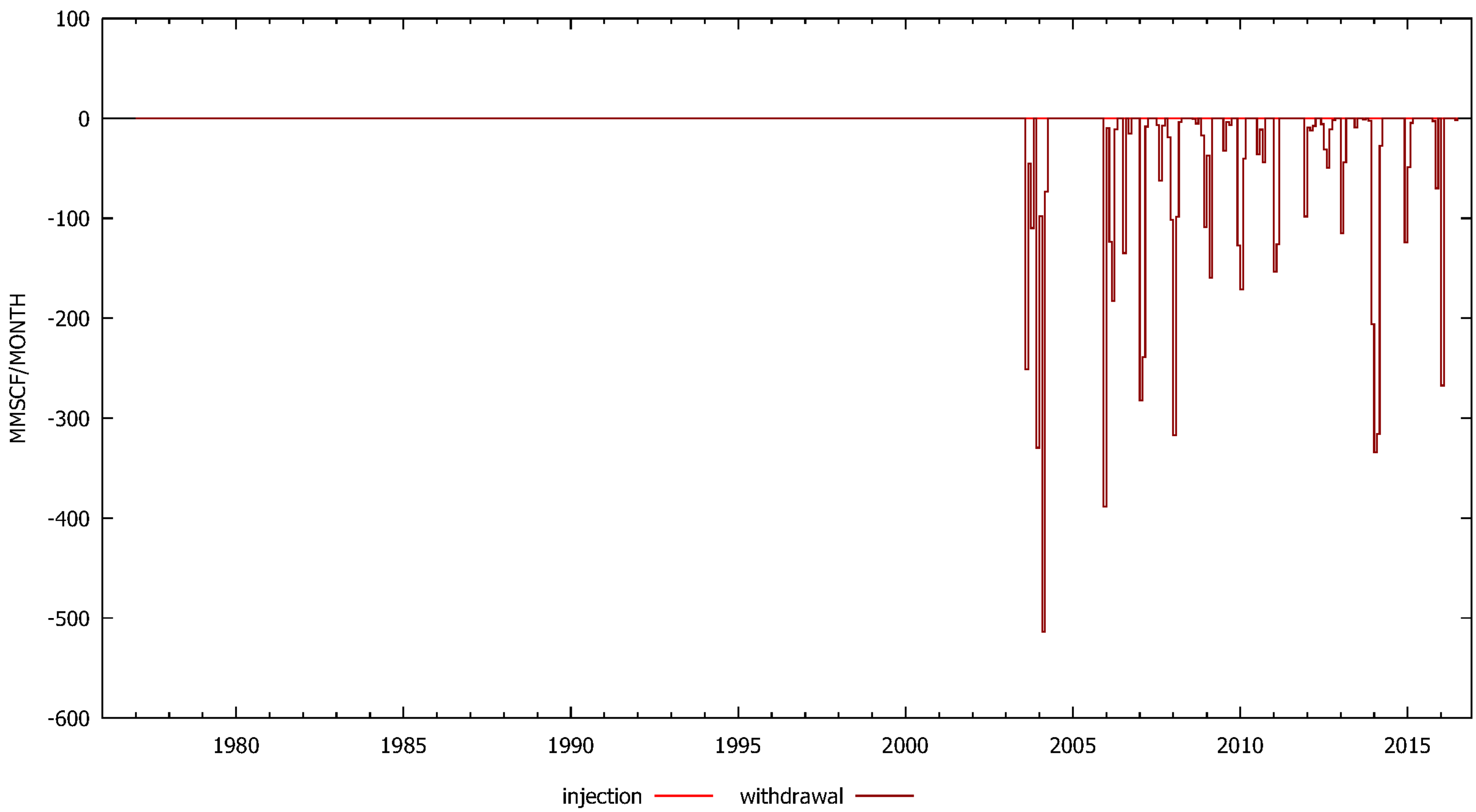


PORTER 69J WELL
4000
3000
2000
1000
0
PSI
1980
1985
1990
1995
2000
2005
2010
2015
P_i $P_{w,tbg}$ $P_{w,csg}$
10
8
6
4
2
0
BBL/MMSCF
WGR OGR
100
0
-100
-200
-300
-400
-500
-600
MMSCF/MONTH
injection withdrawal

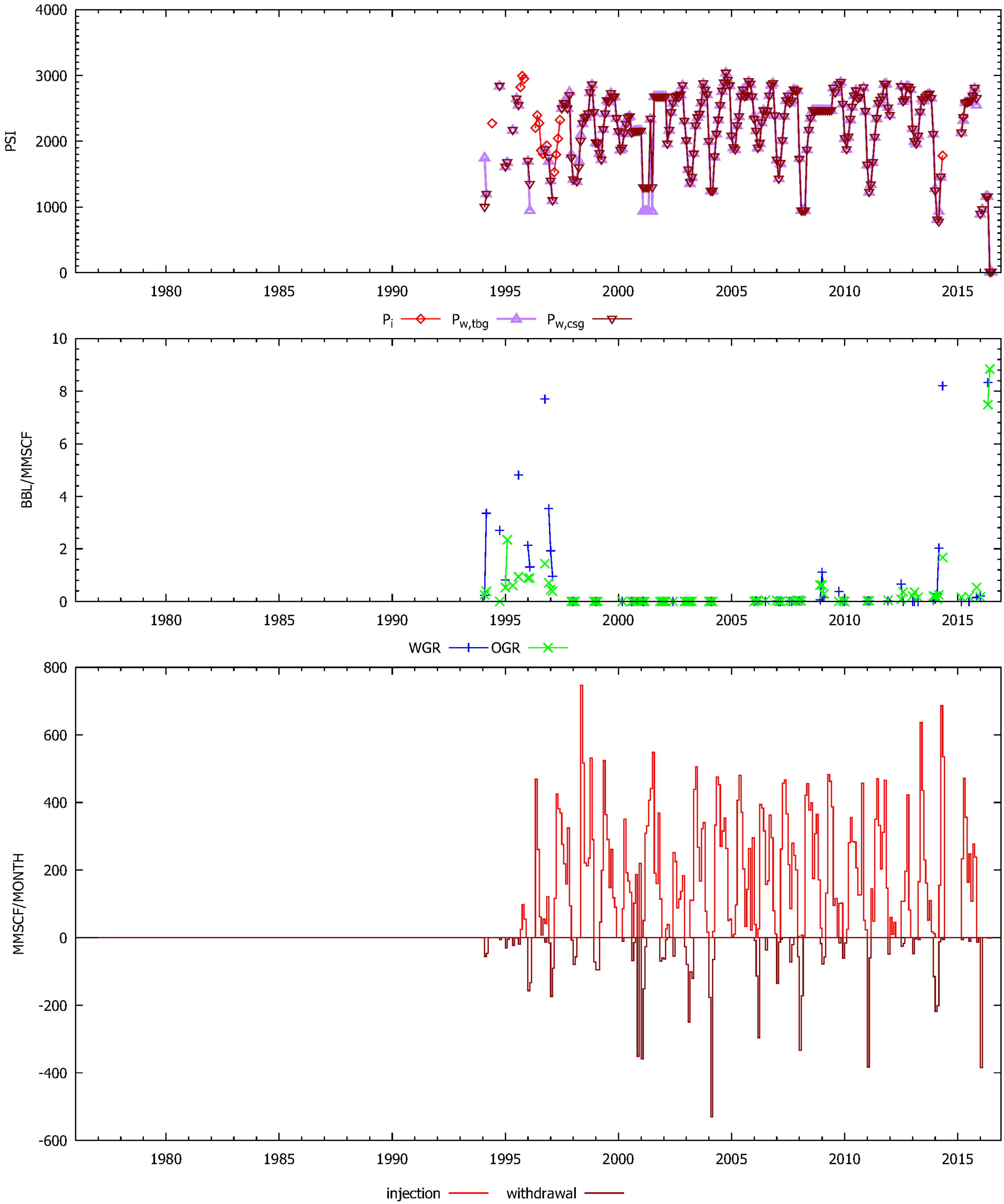
PORTER 69K WELL



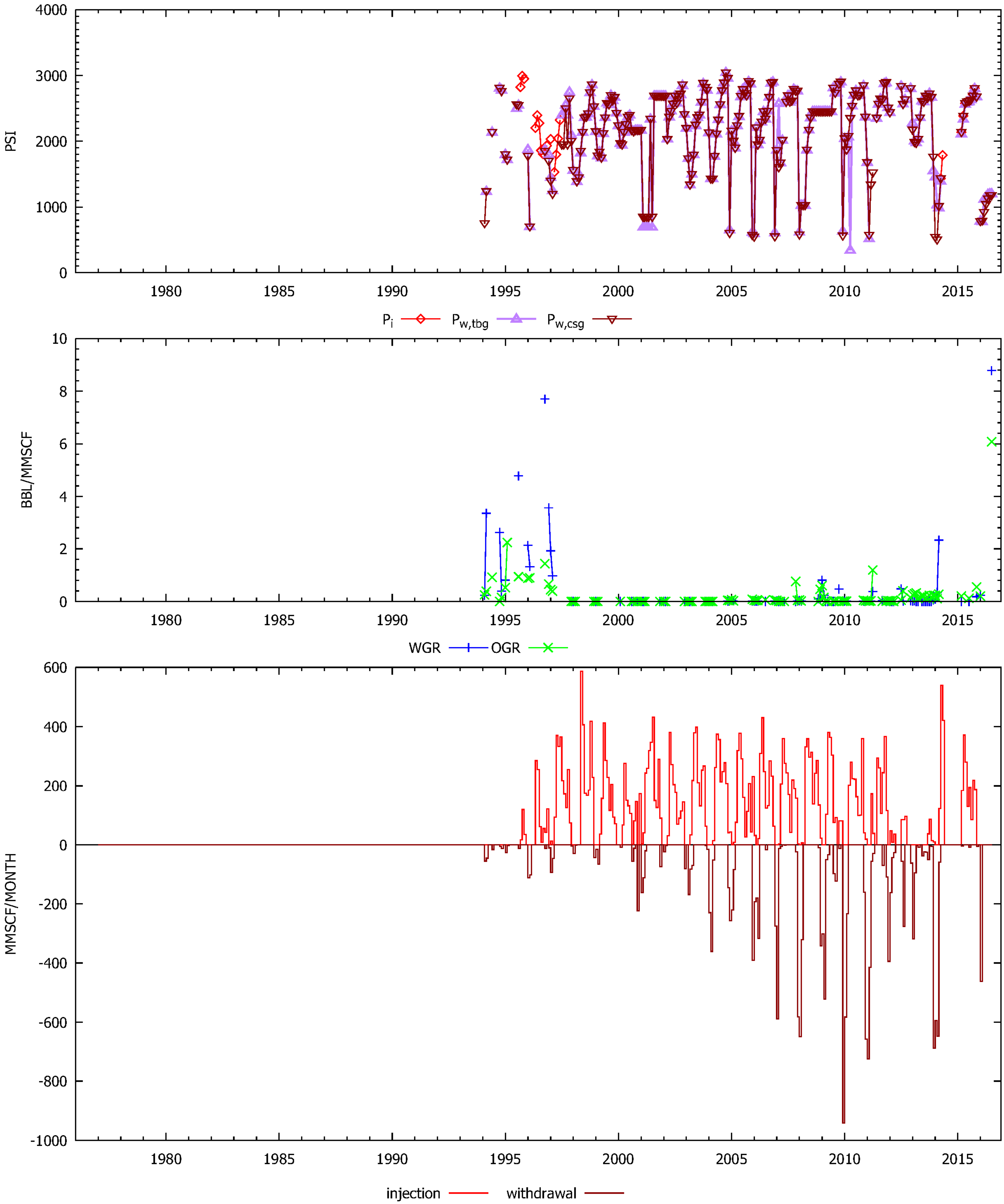




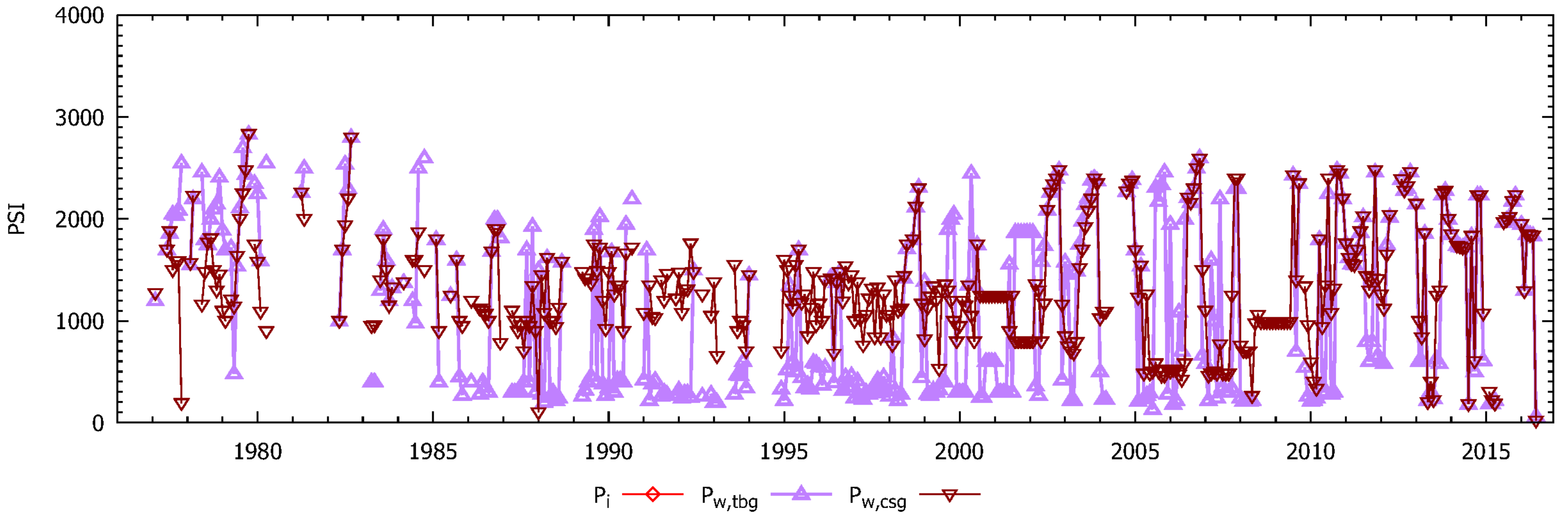
PORTER 72A WELL

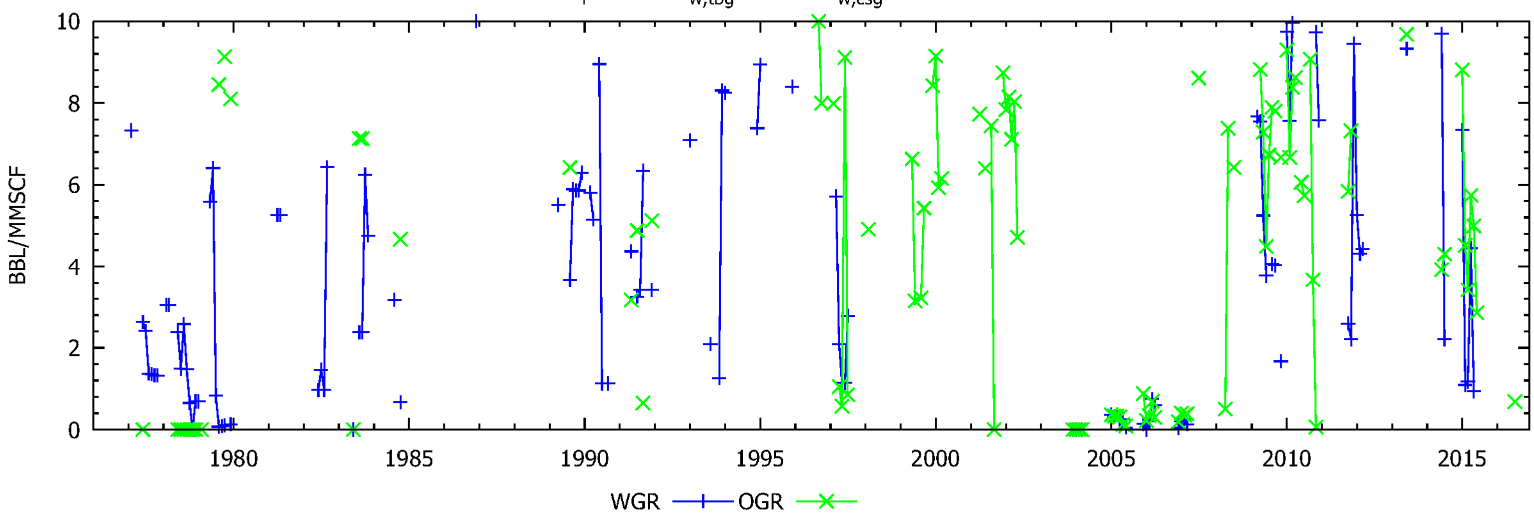


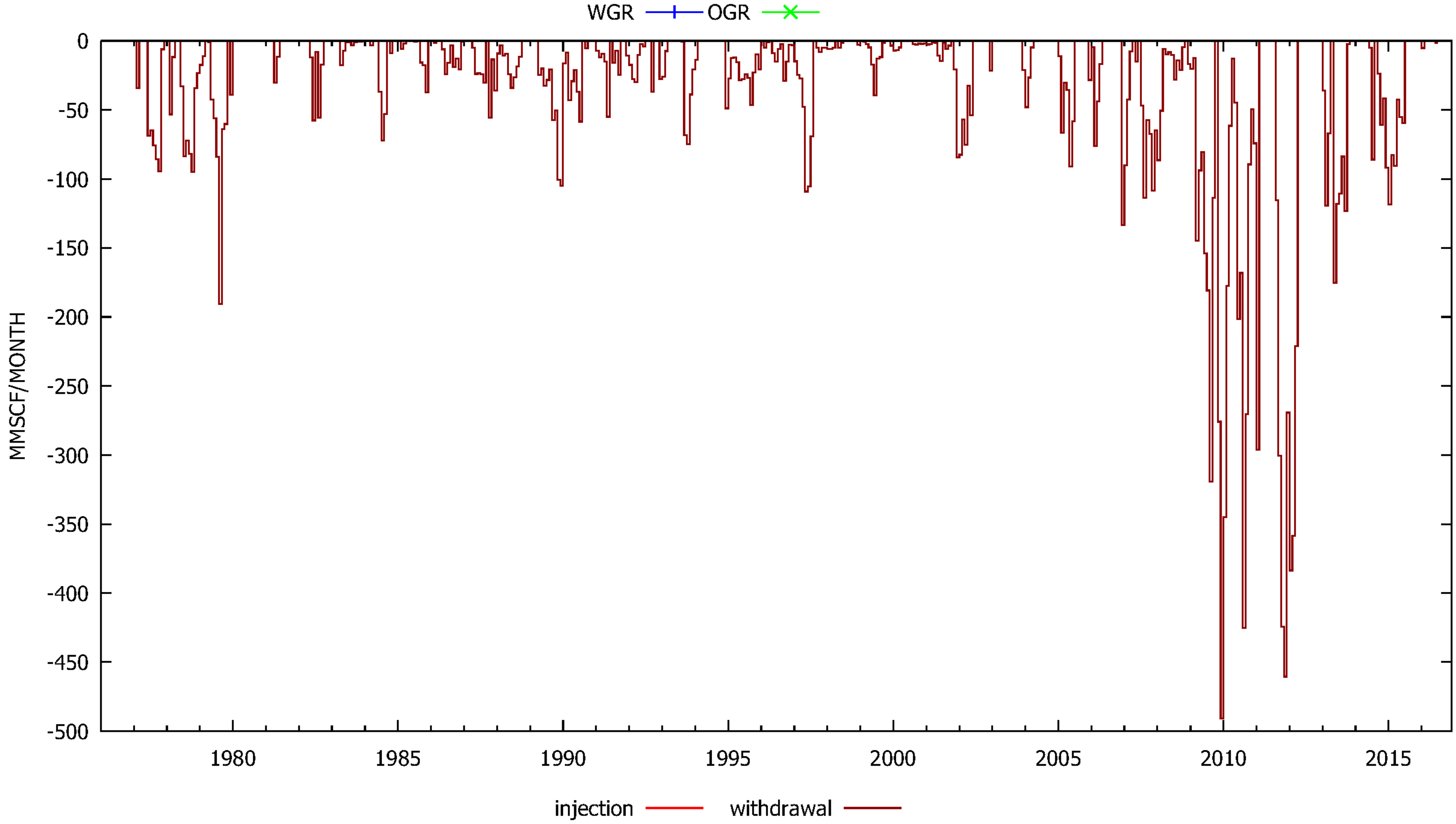
PORTER 72B WELL



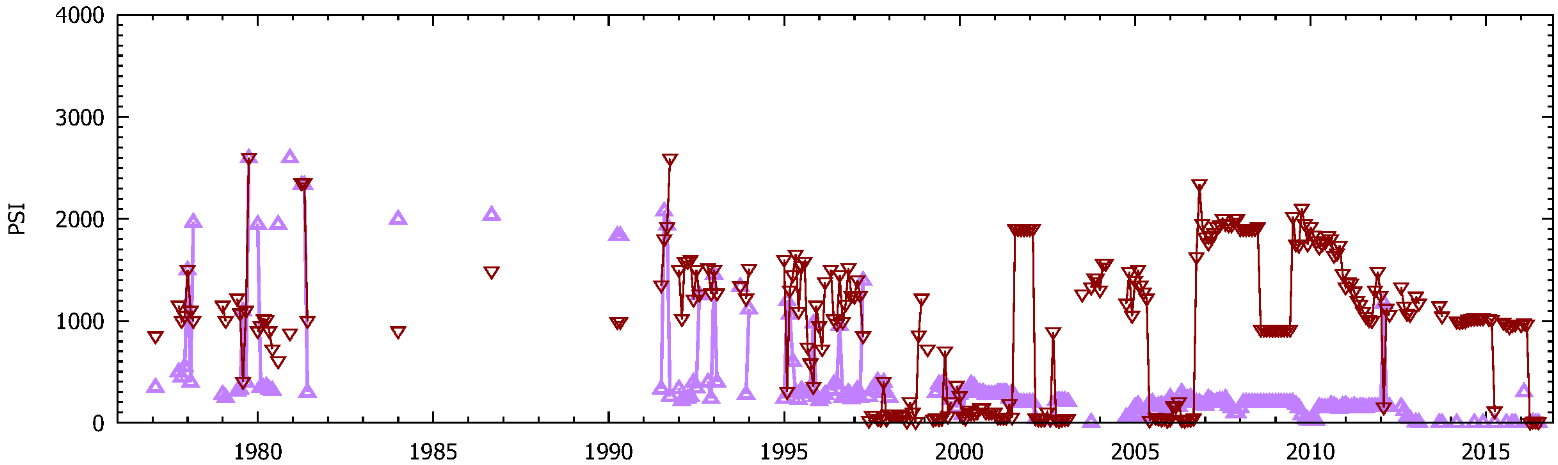
SESNON FEE 1 WELL

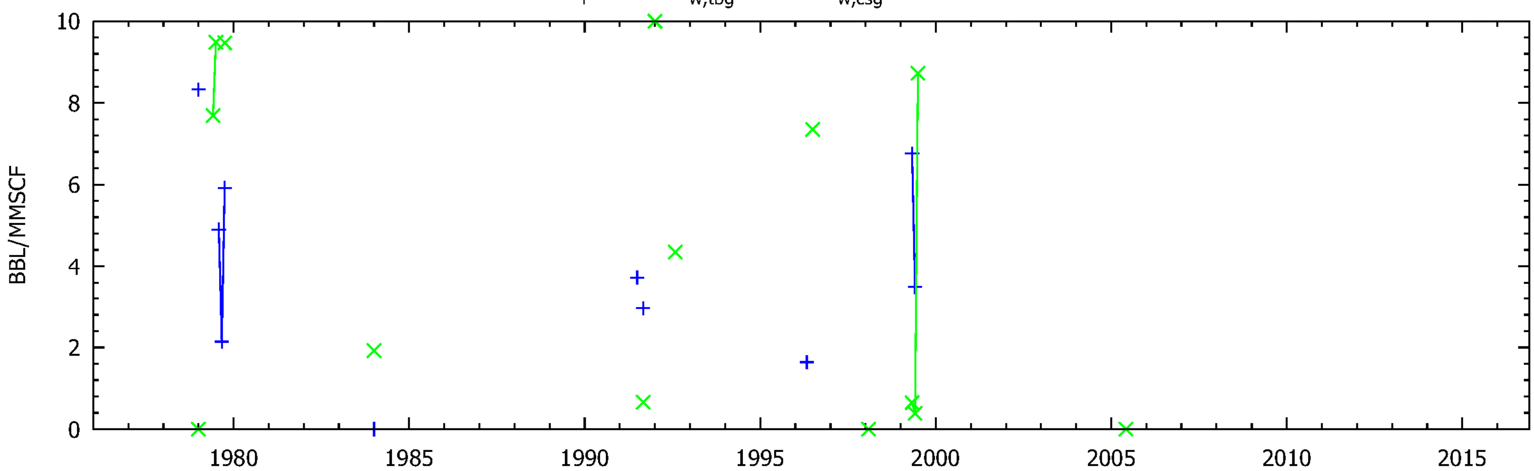


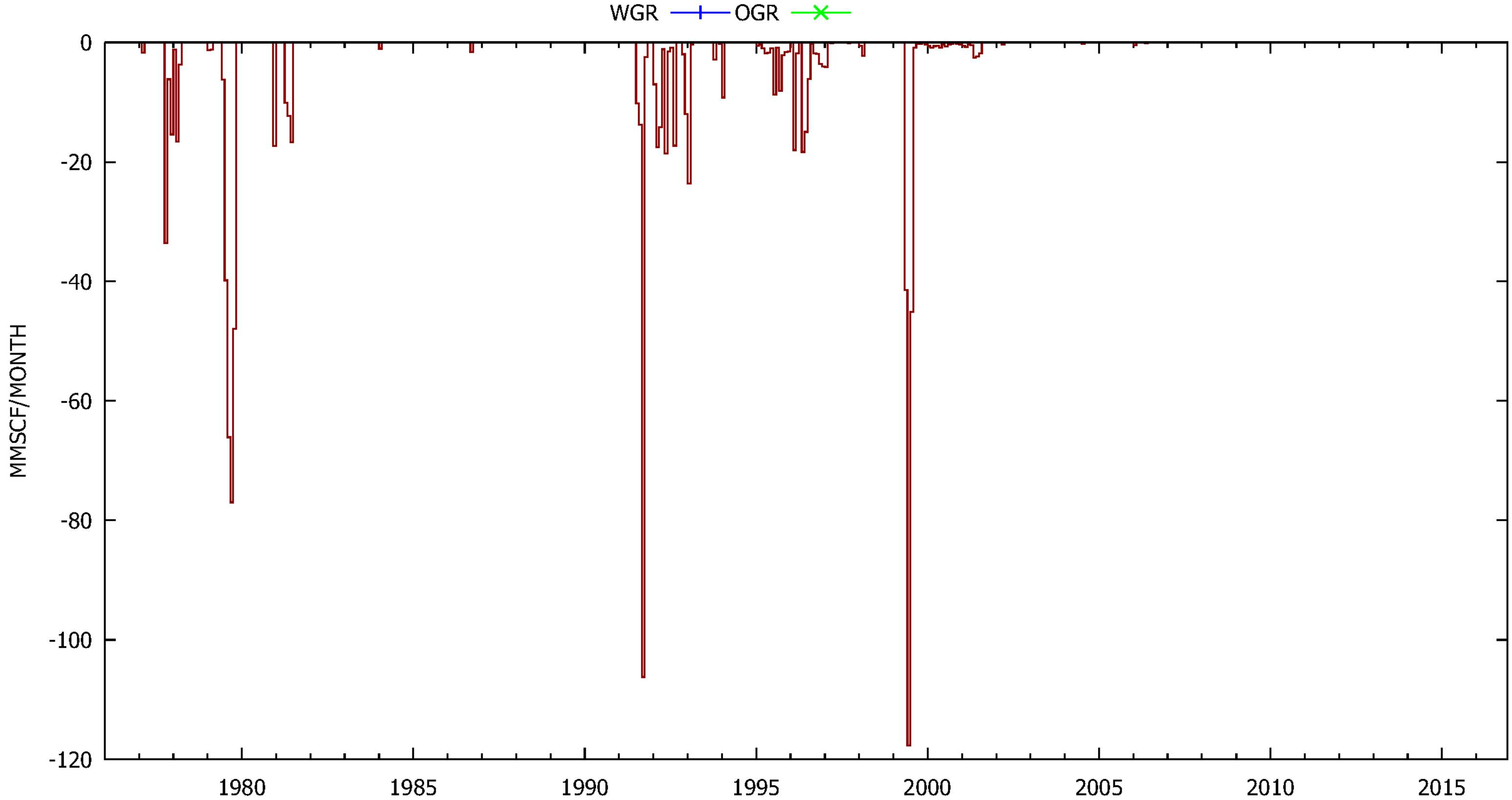




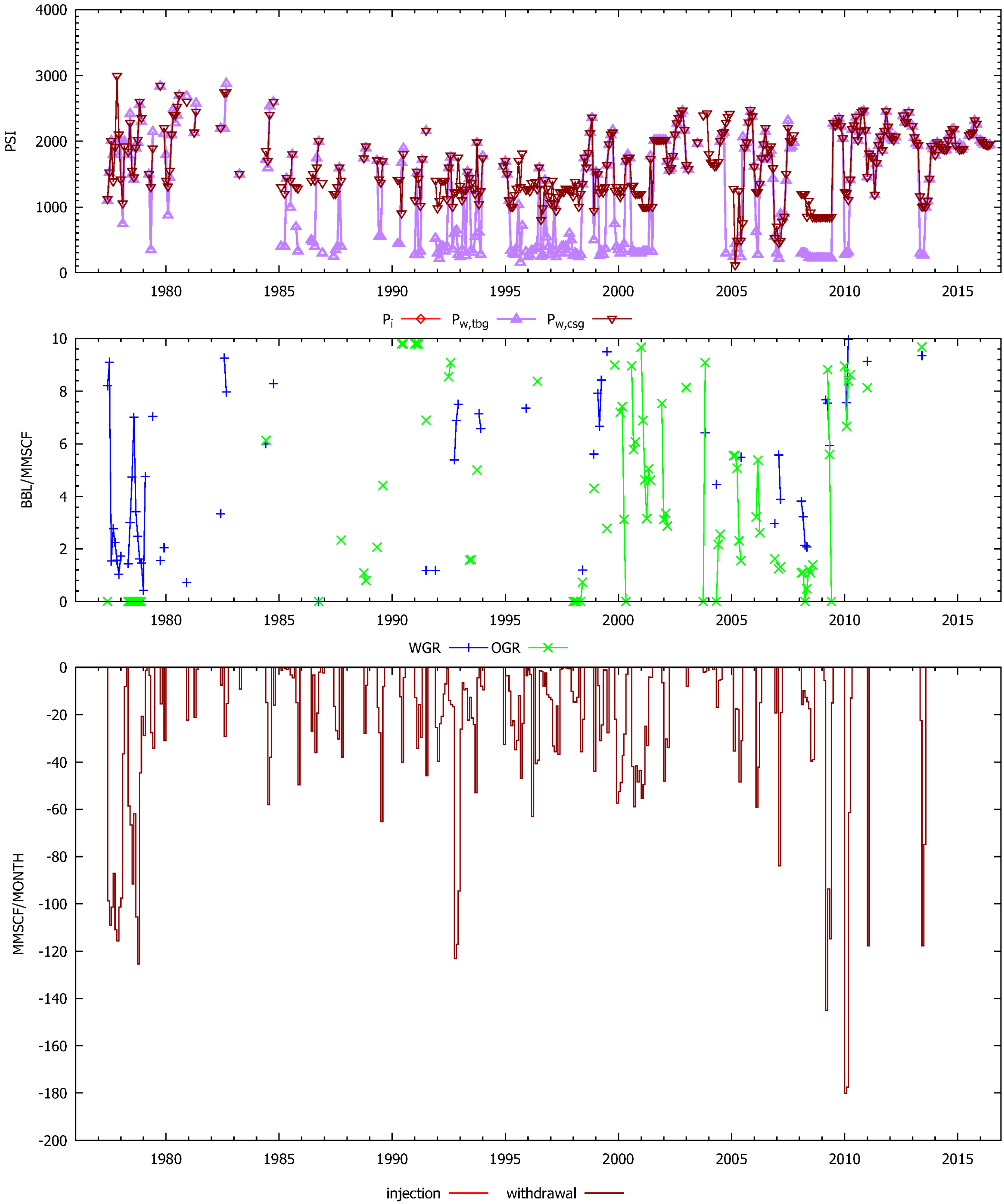
SESNON FEE 2 WELL



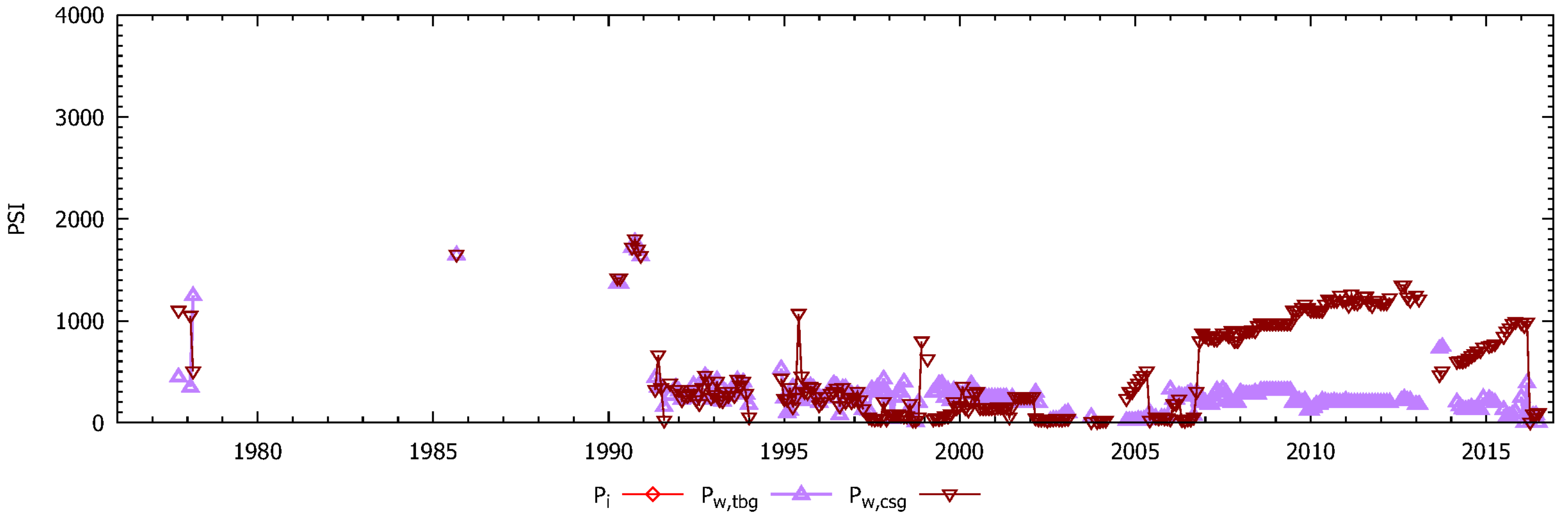


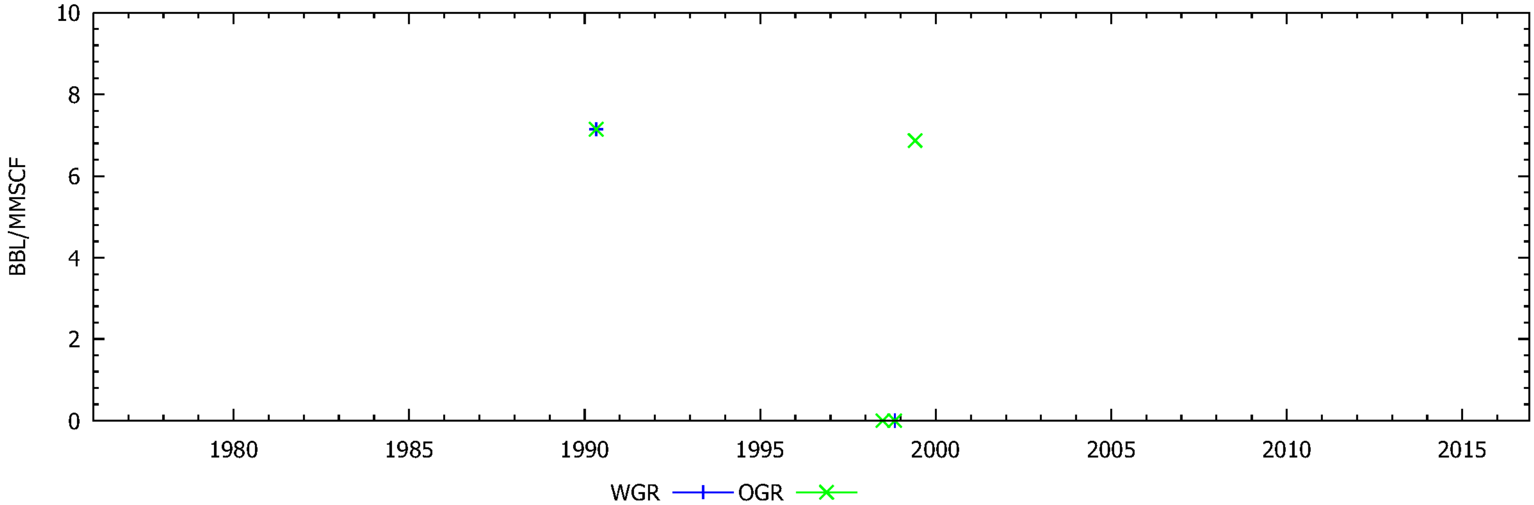


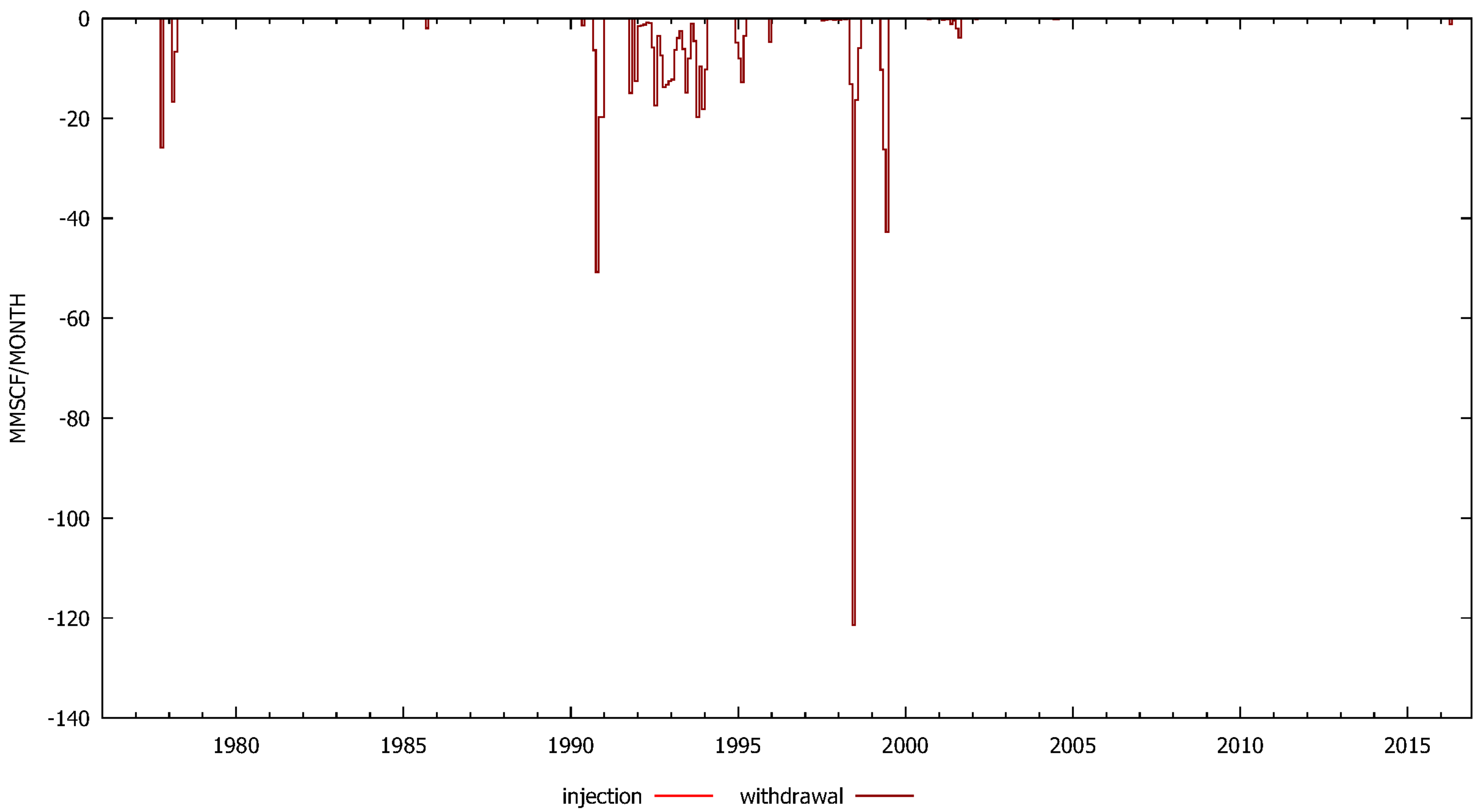
SESNON FEE 4 WELL



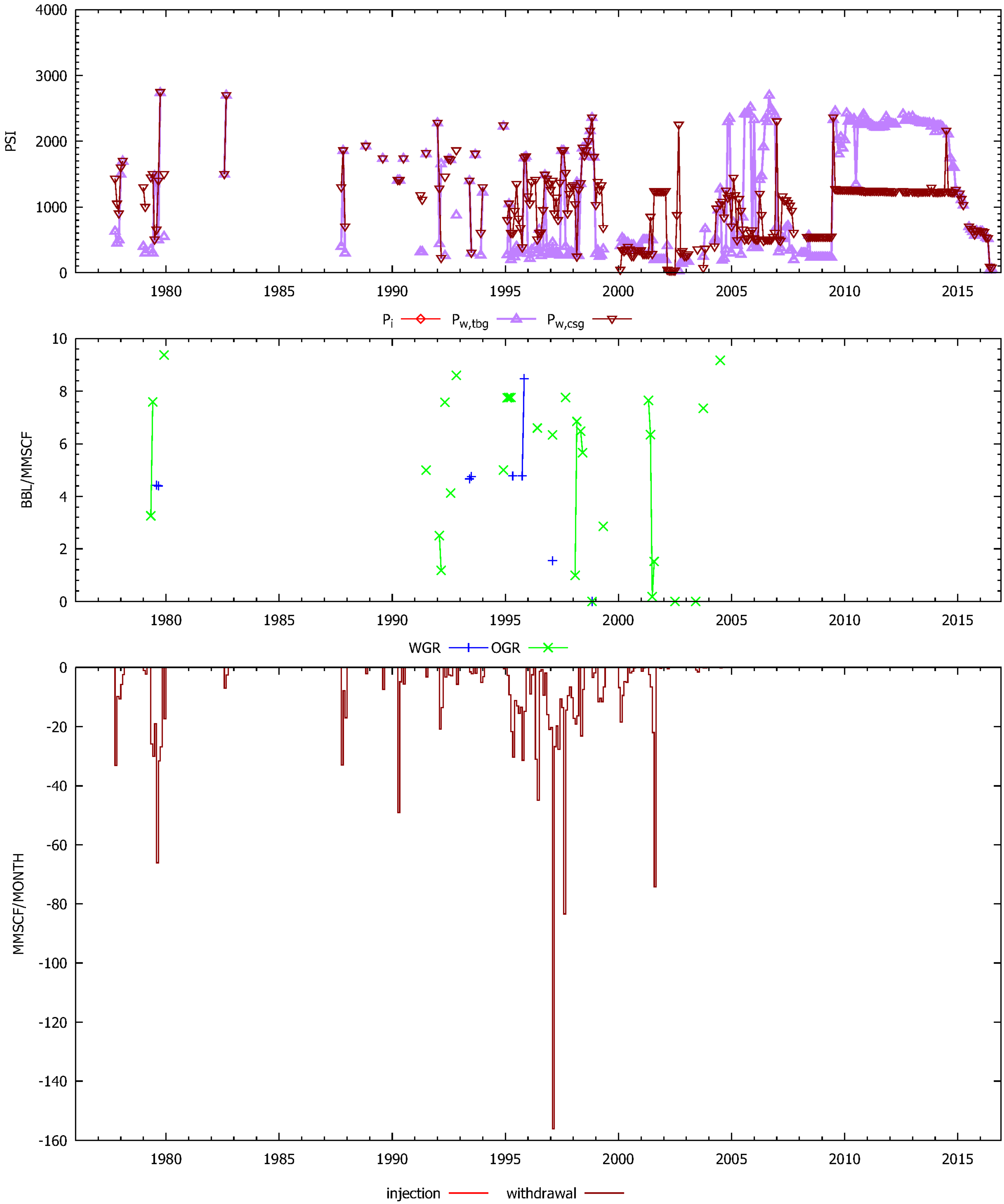
SESNON FEE 5 WELL

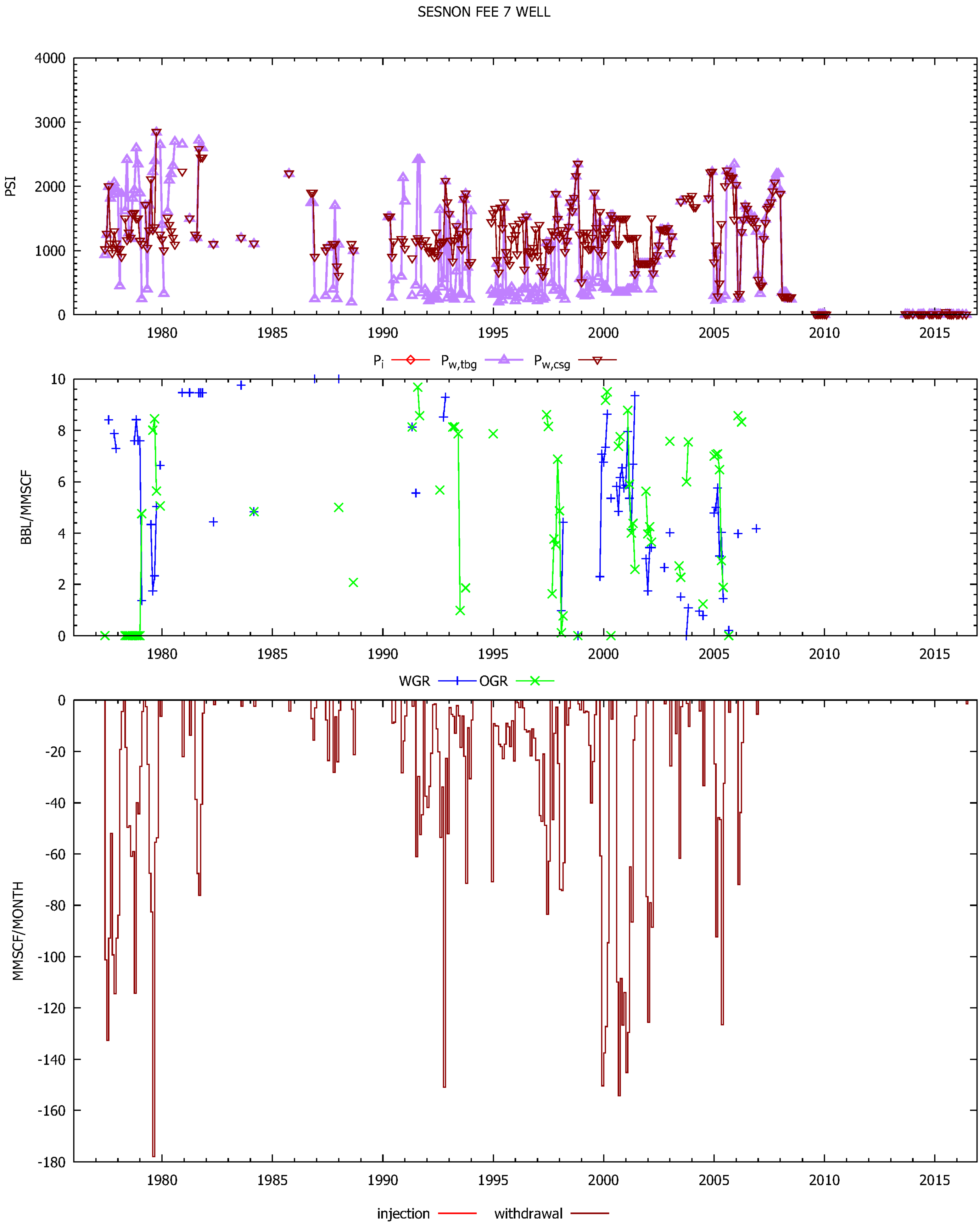






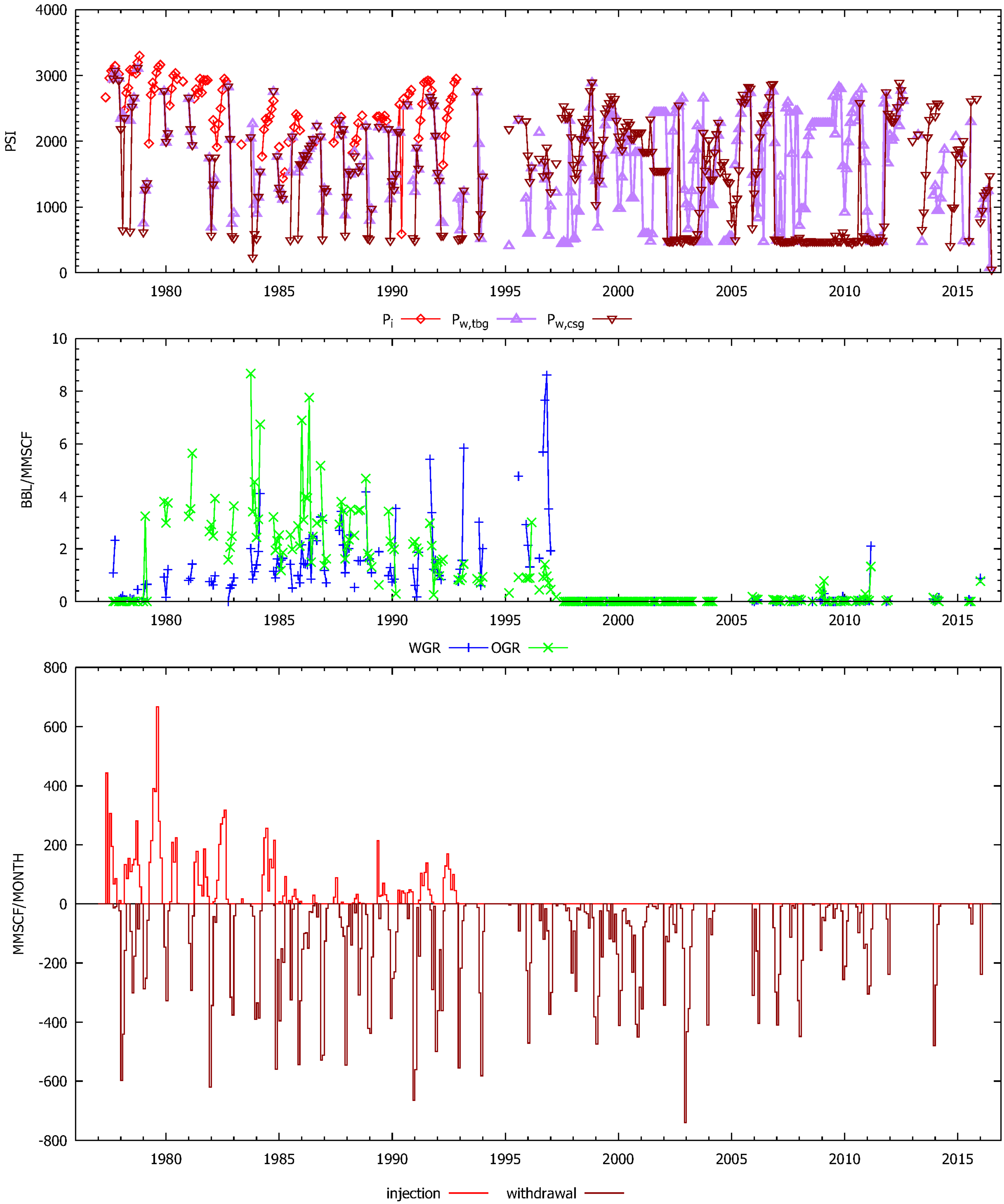
SESNON FEE 6 WELL



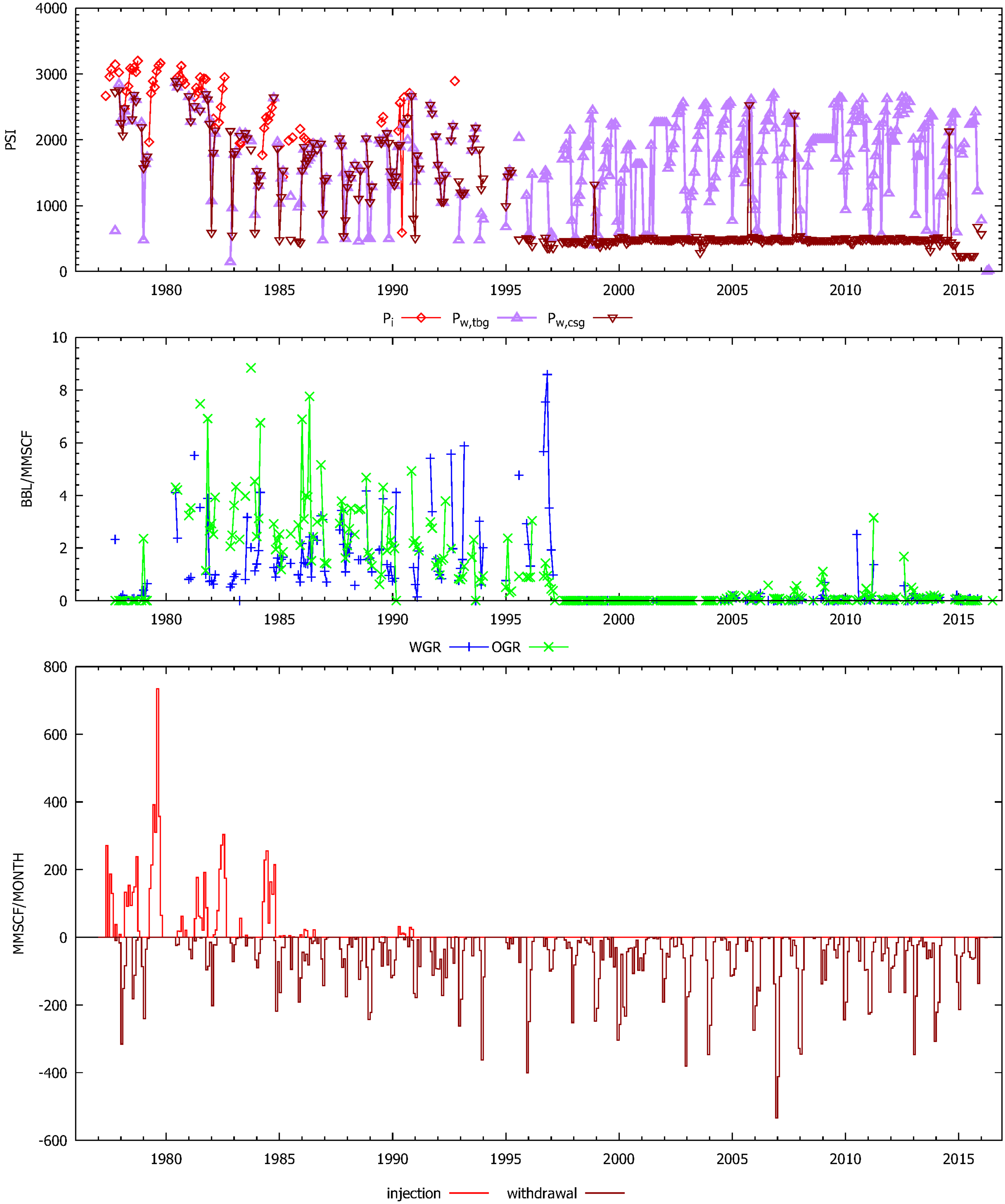


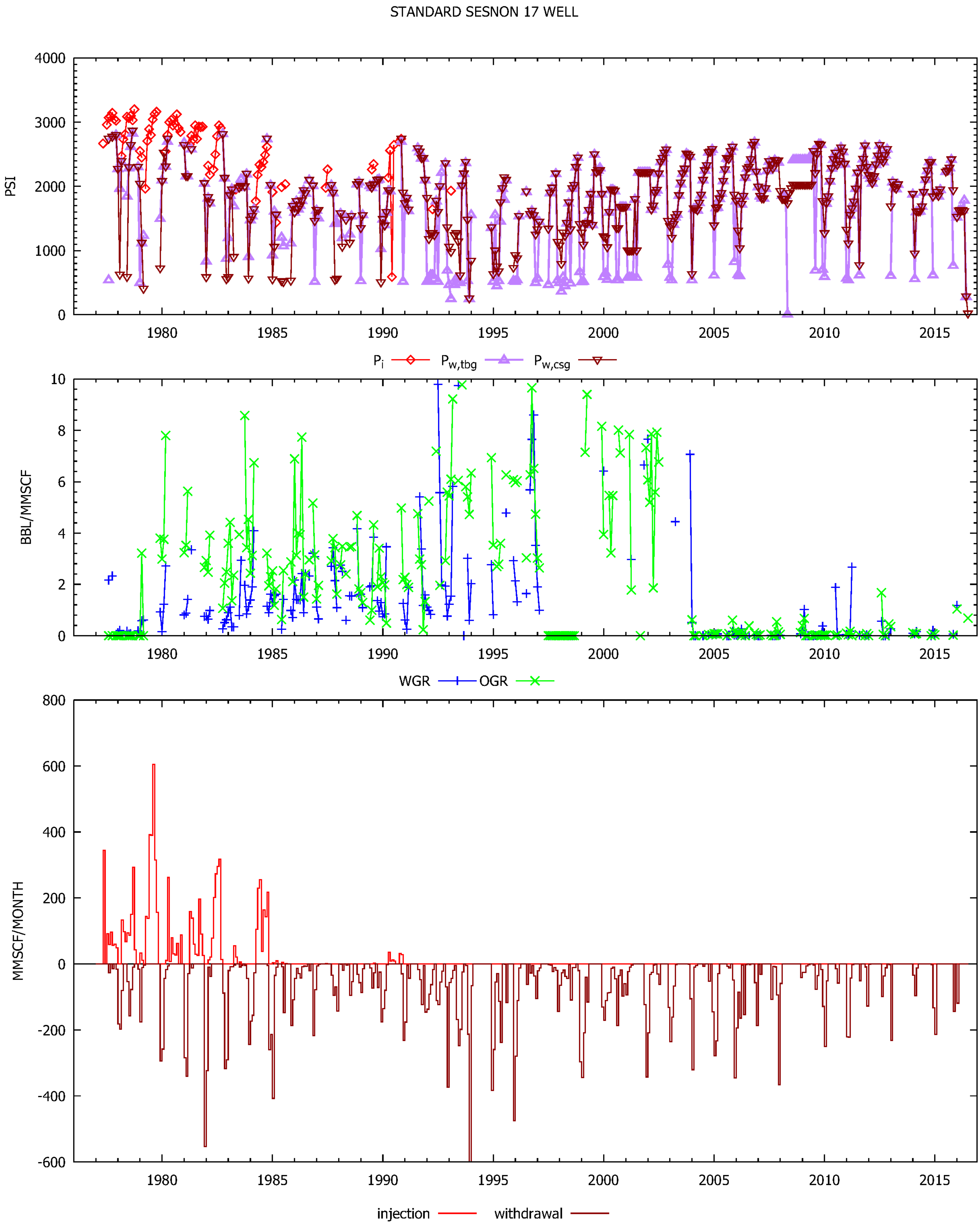
SESNON FEE 7 WELL
PSI
Pi
Pw,tbg
Pw,csg
BBL/MMSCF
WGR
OGR
MMSCF/MONTH
injection
withdrawal

STANDARD SESNON 10 WELL



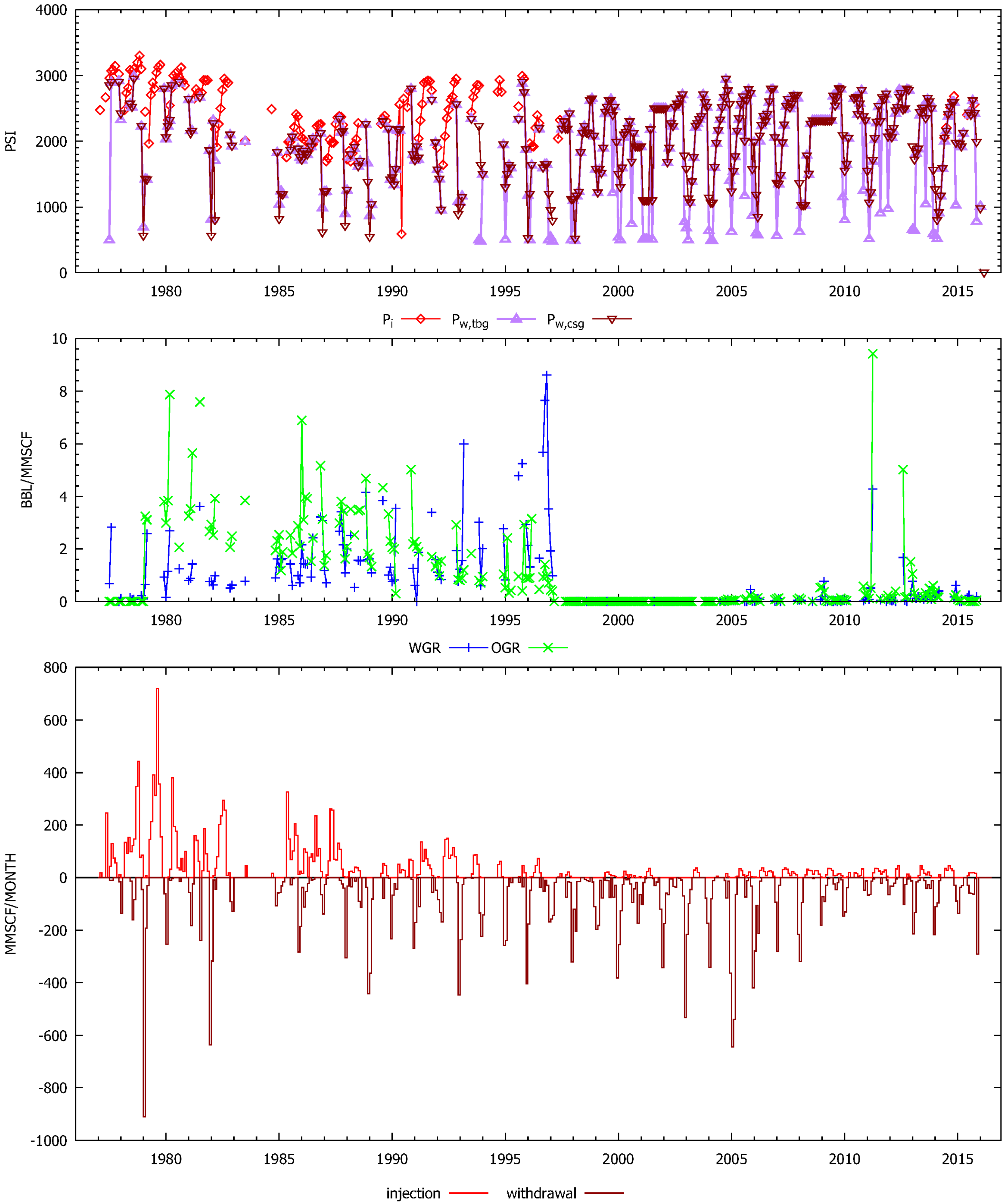
STANDARD SESNON 11 WELL



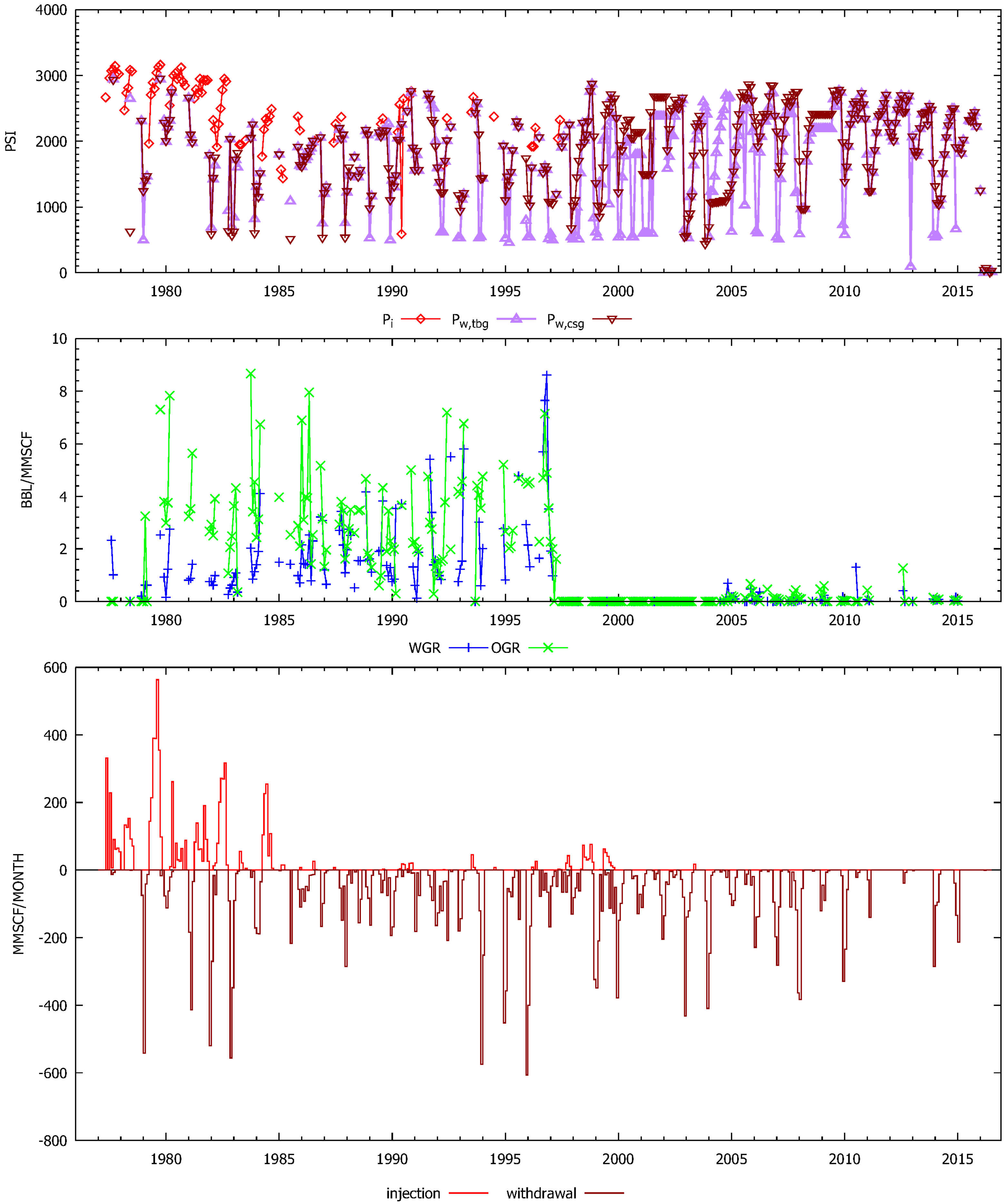


STANDARD SESNON 17 WELL
PSI
4000
3000
2000
1000
0
1980
1985
1990
1995
2000
2005
2010
2015
Pi
Pw,tbg
Pw,csg
BBL/MMSCF
10
8
6
4
2
0
WGR
OGR
MMSCF/MONTH
800
600
400
200
0
-200
-400
-600
injection
withdrawal

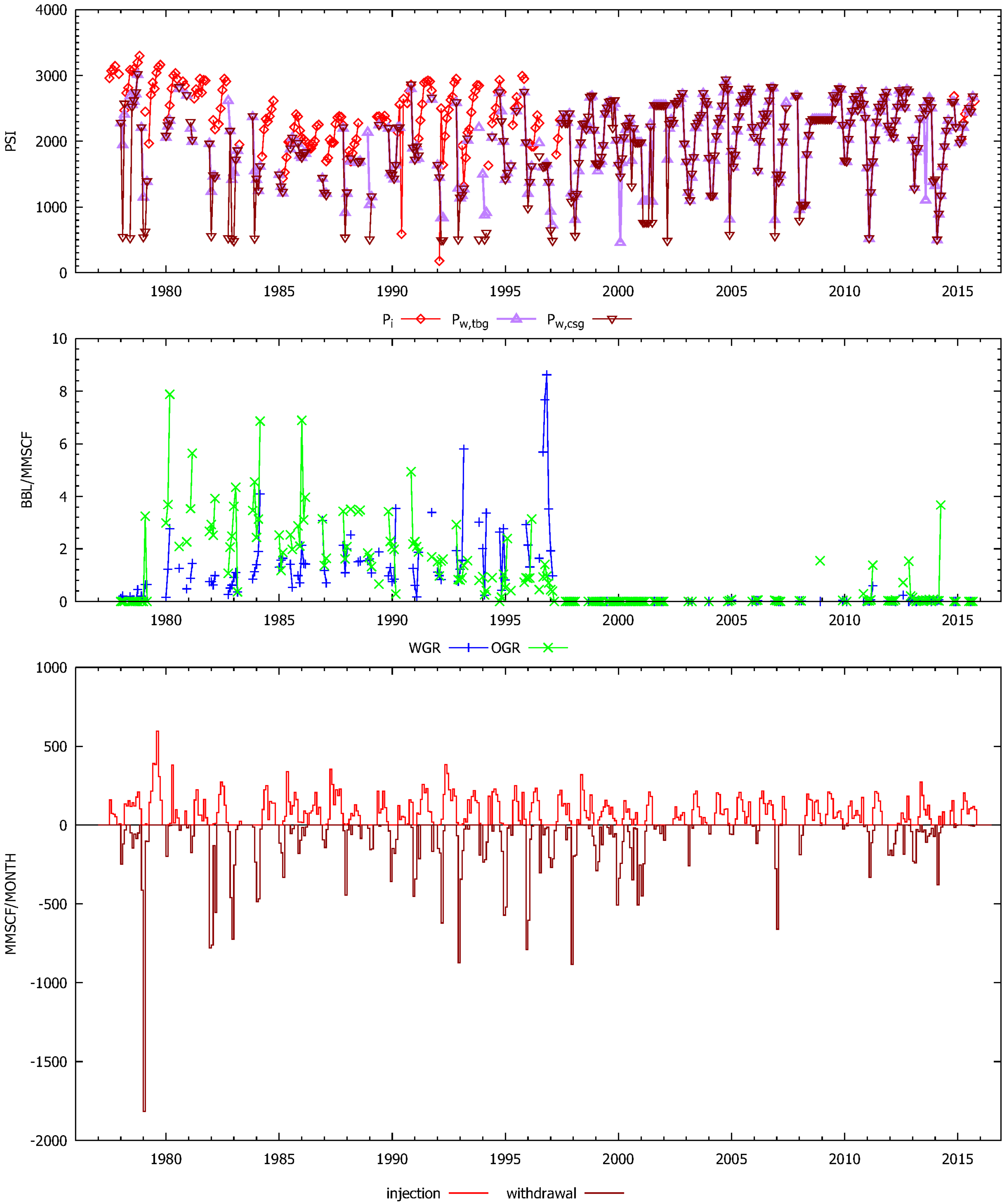
STANDARD SESNON 2 WELL



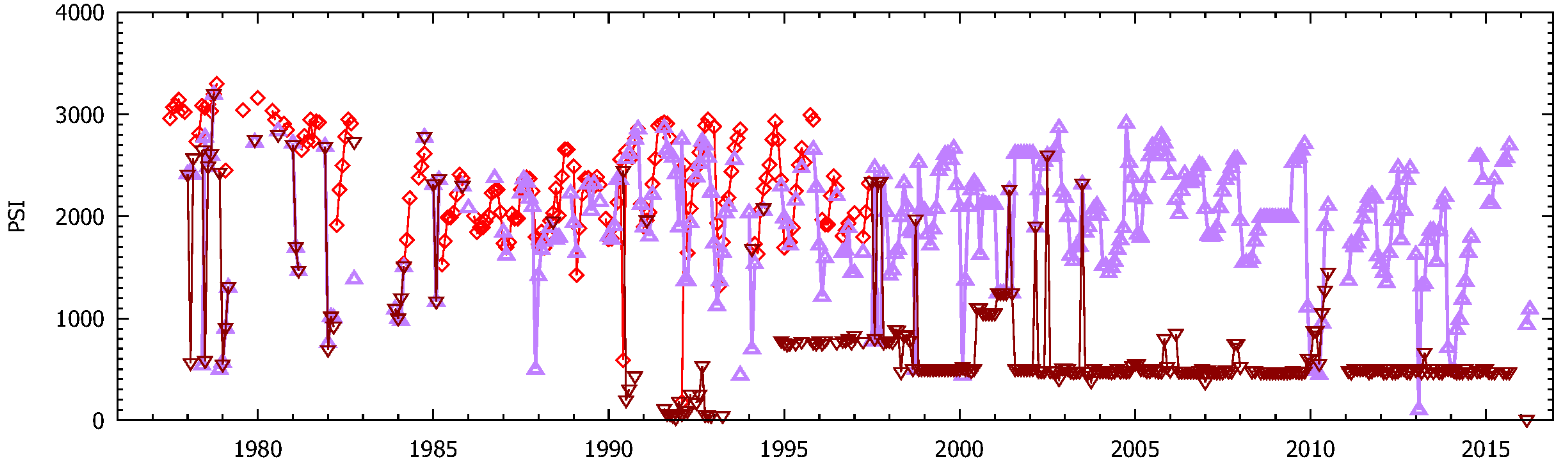
STANDARD SESNON 24 WELL

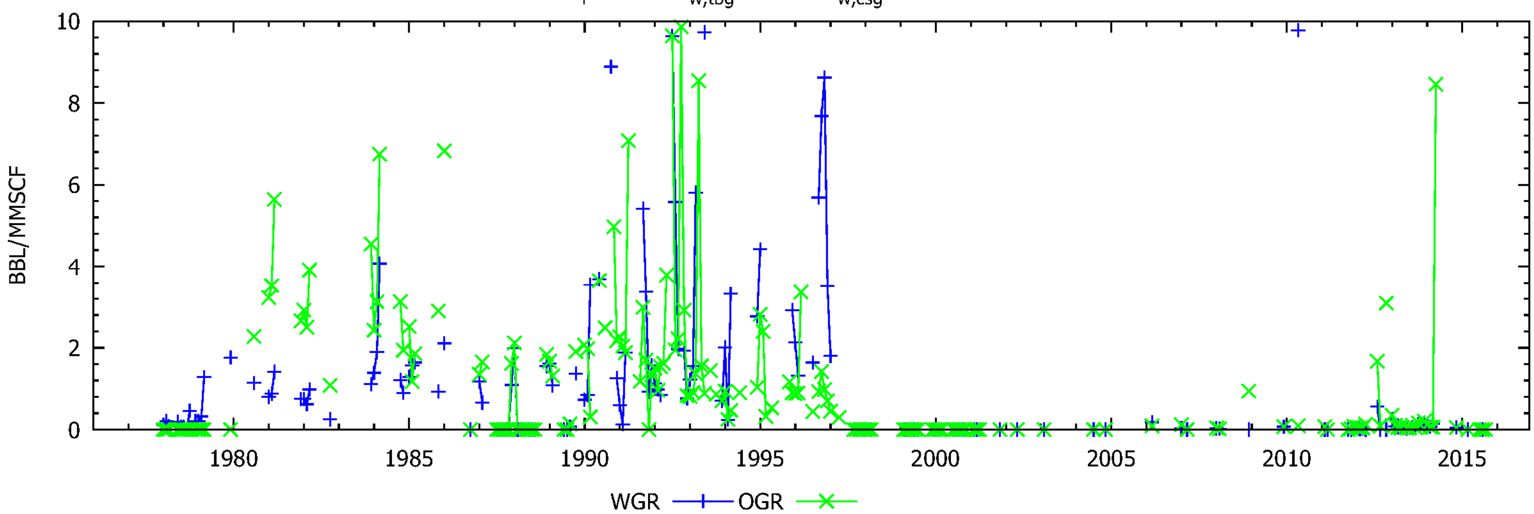


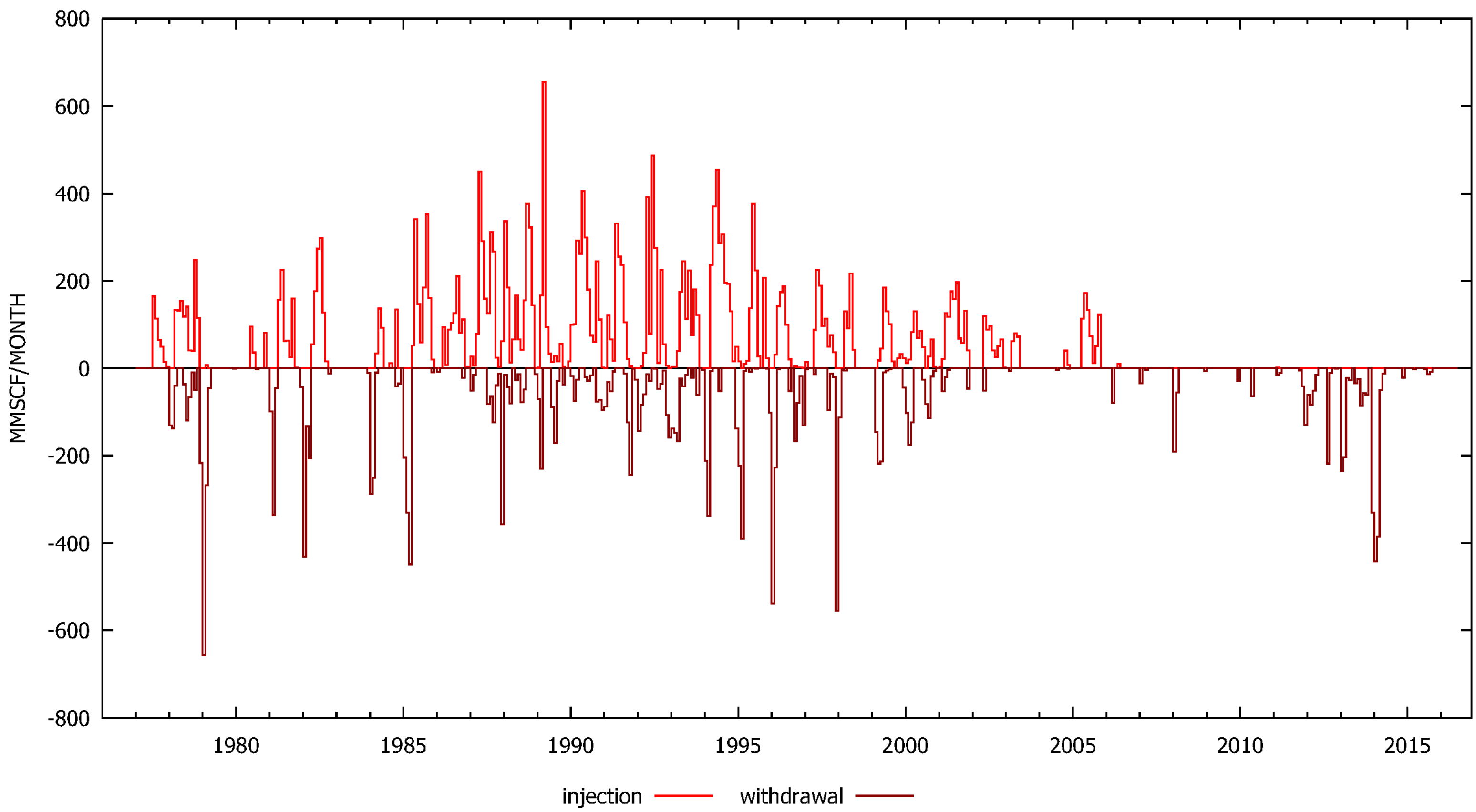
STANDARD SESNON 25 WELL



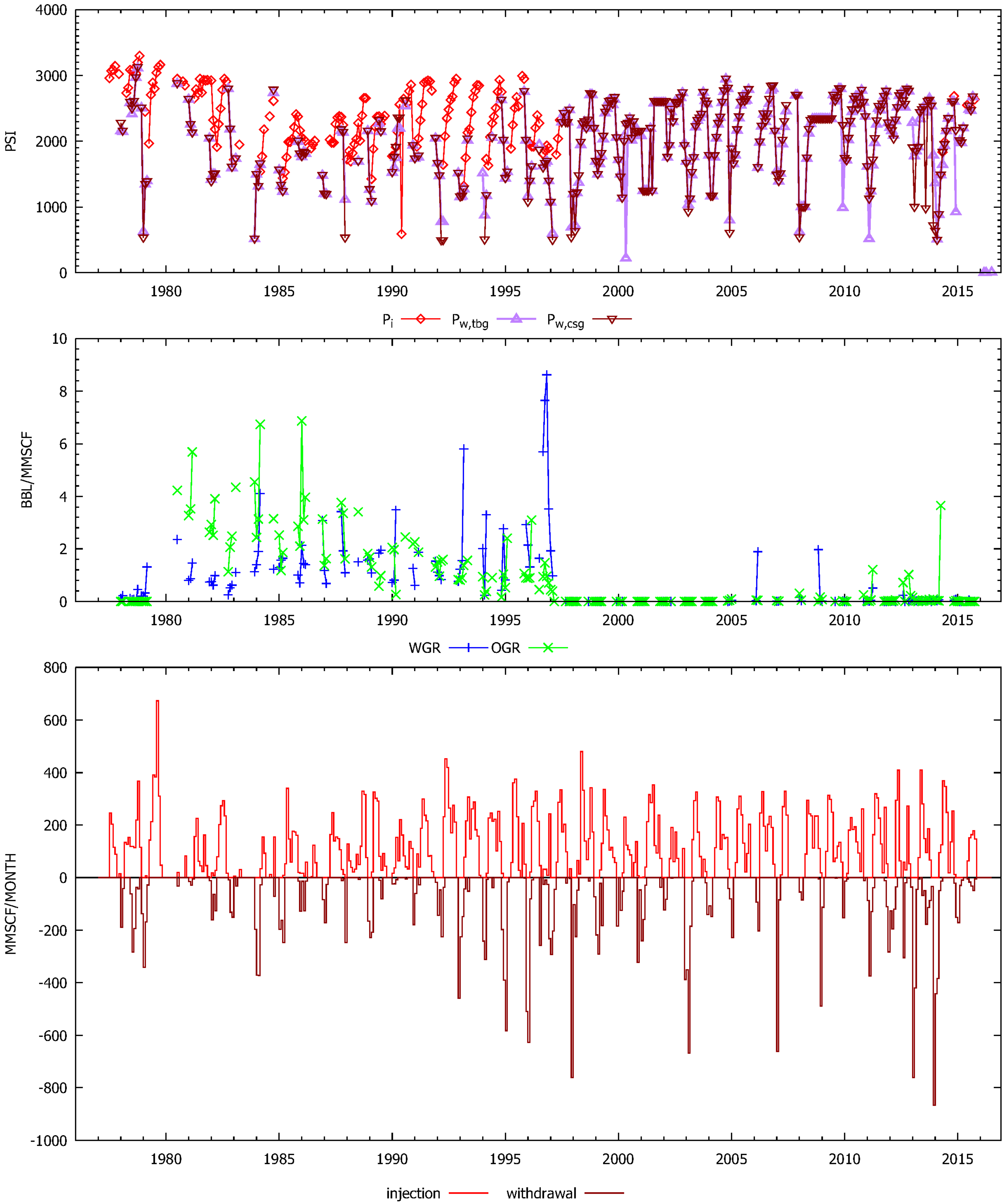
STANDARD SESNON 25A WELL



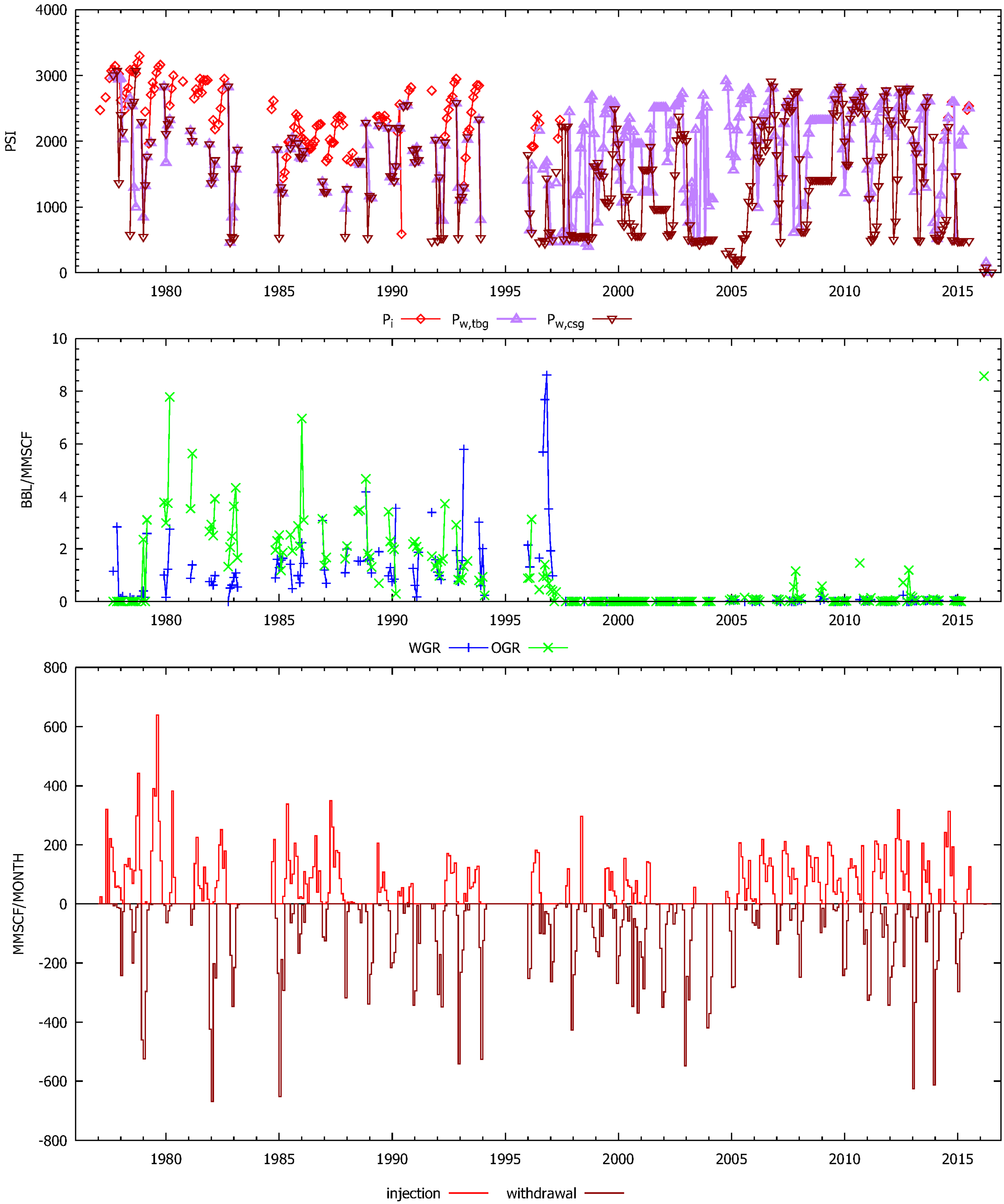




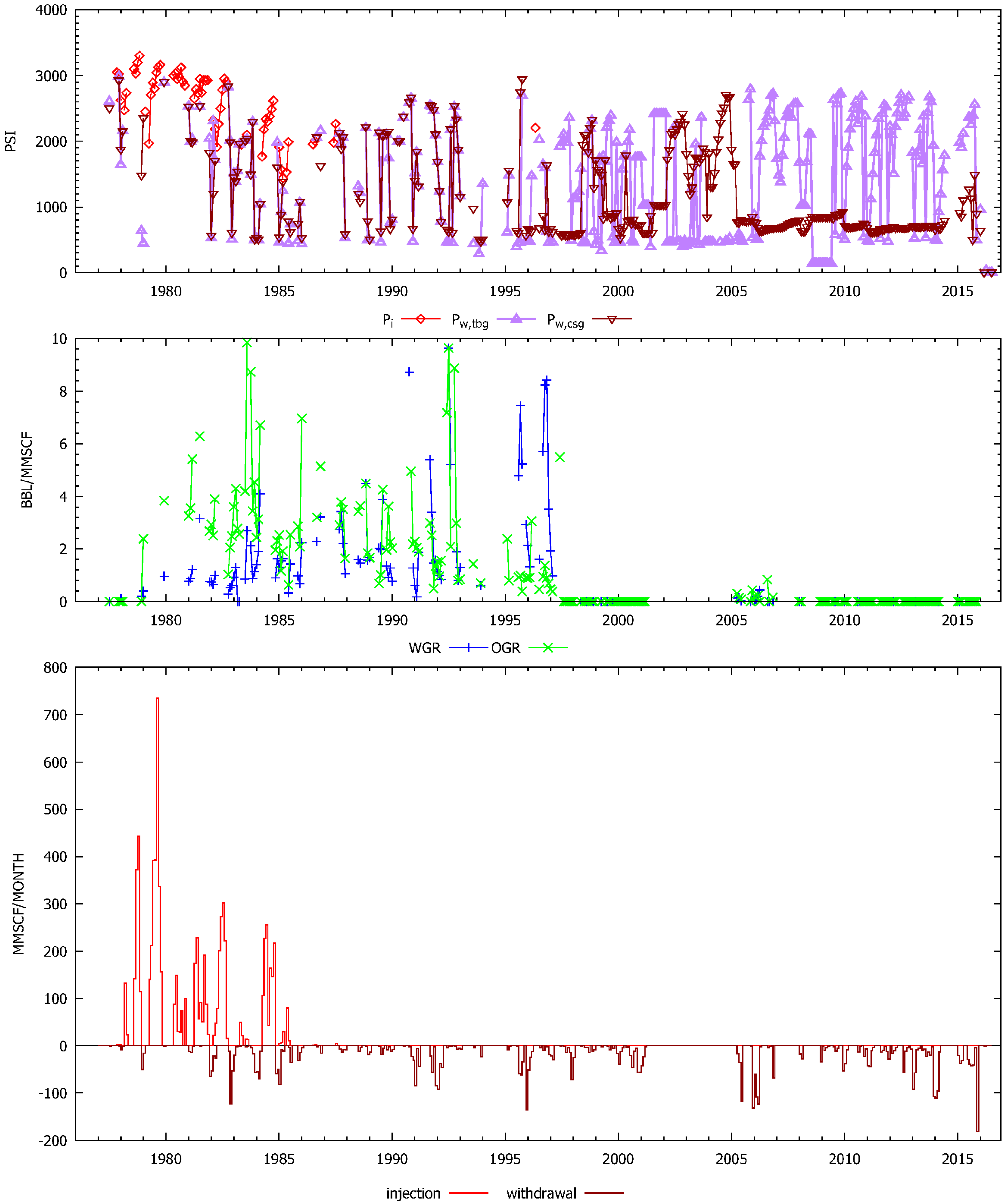
STANDARD SESNON 25B WELL



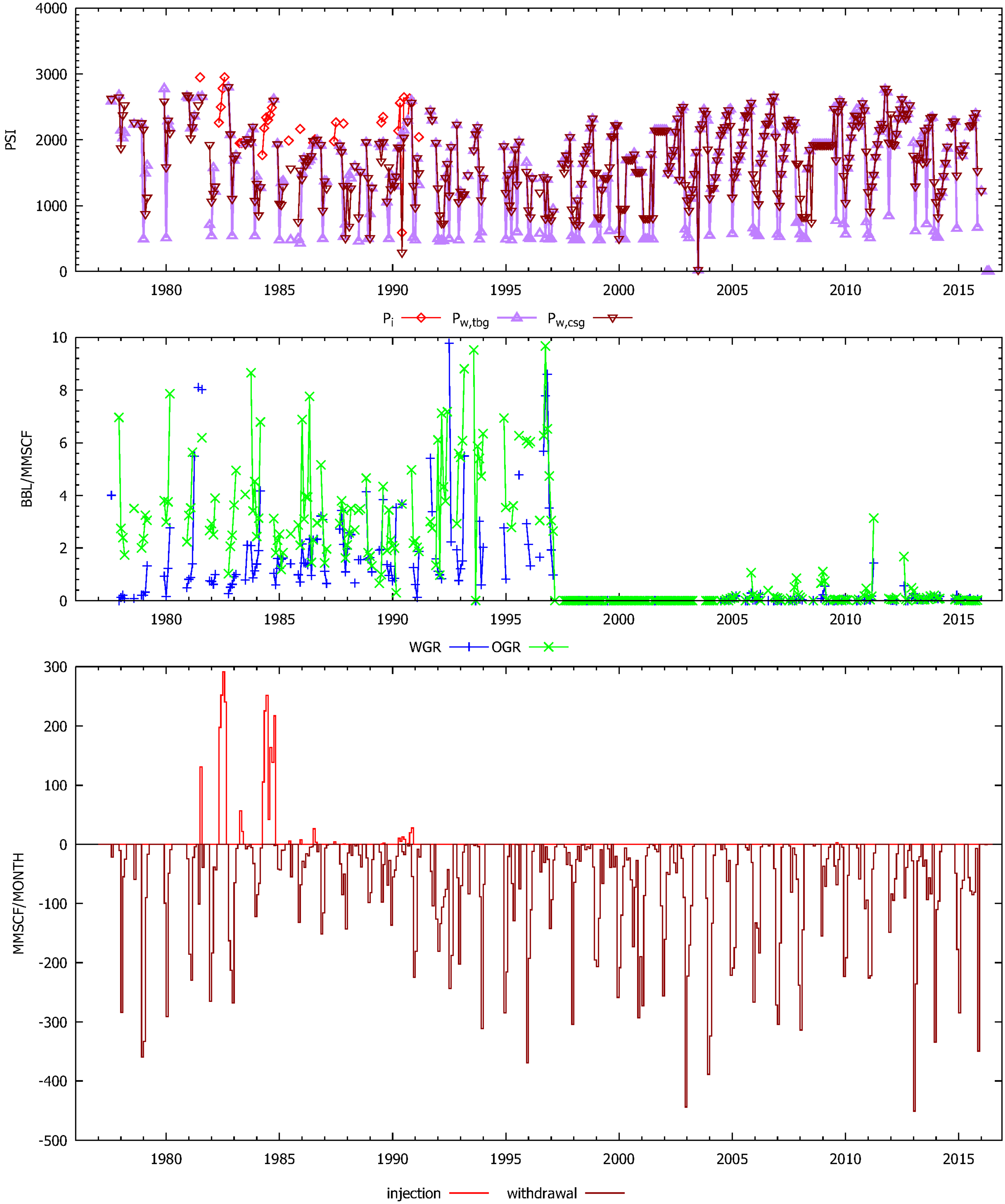
STANDARD SESNON 29 WELL



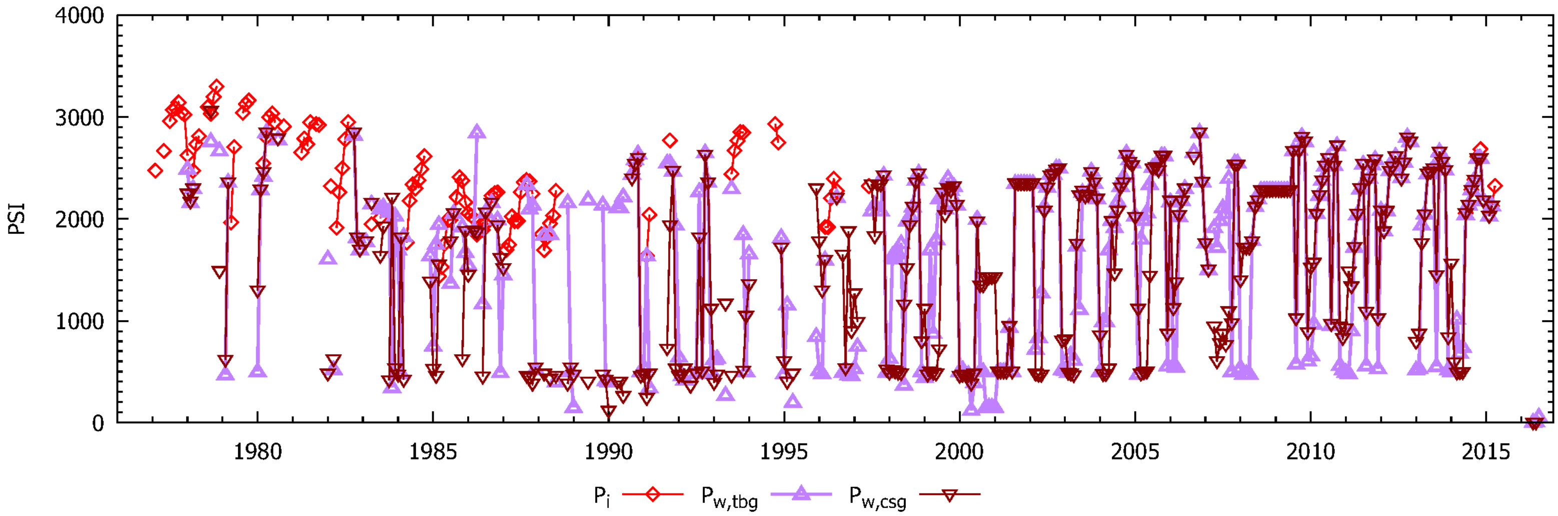
STANDARD SESNON 3 WELL

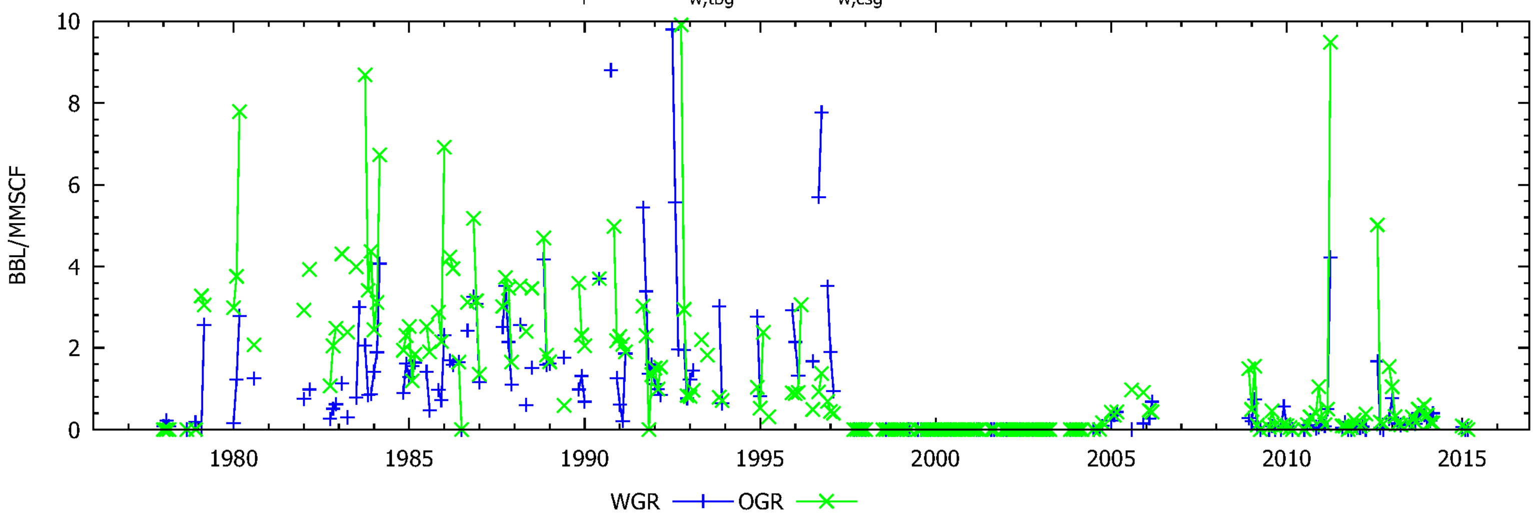


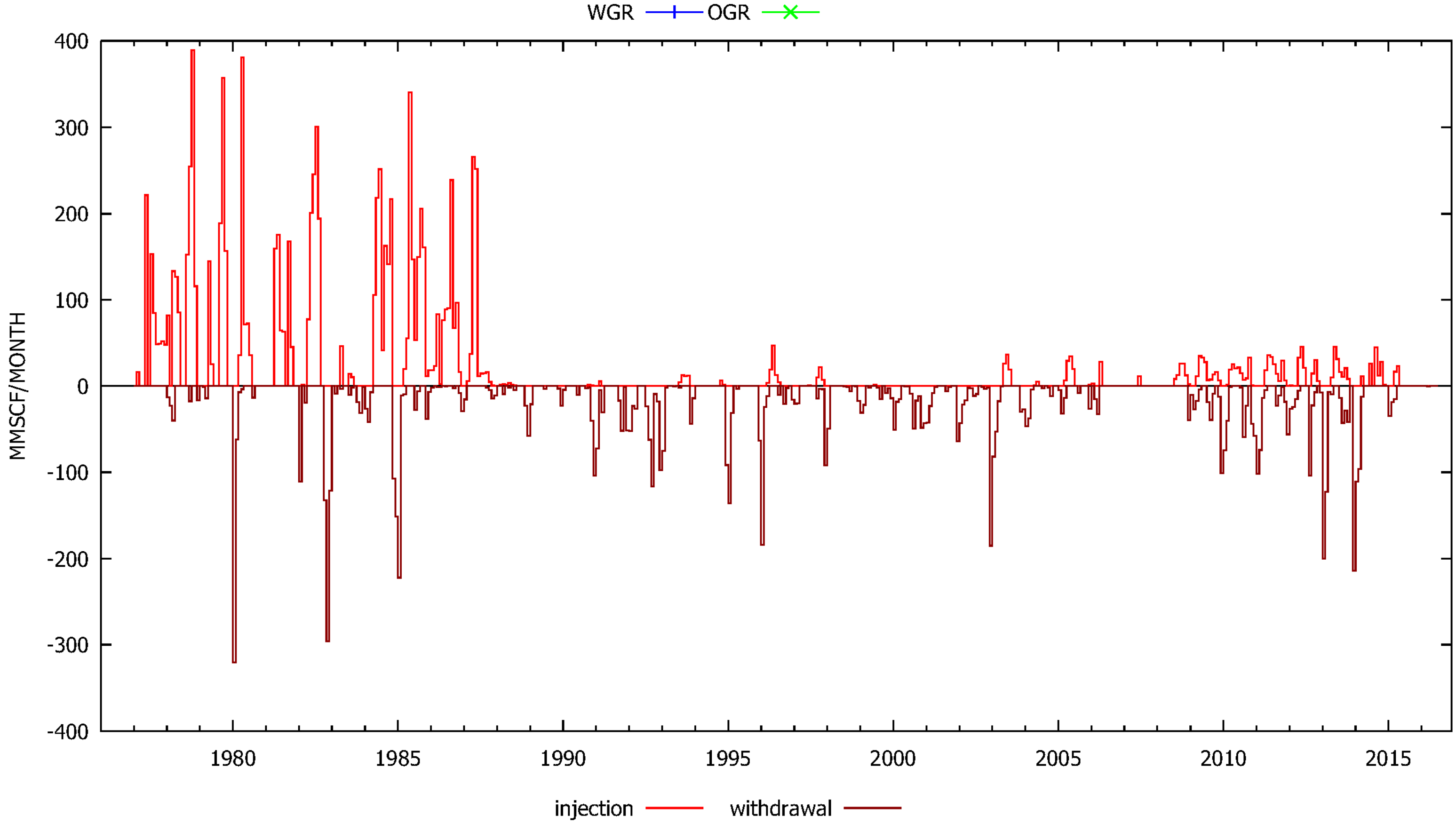
STANDARD SESNON 31 WELL



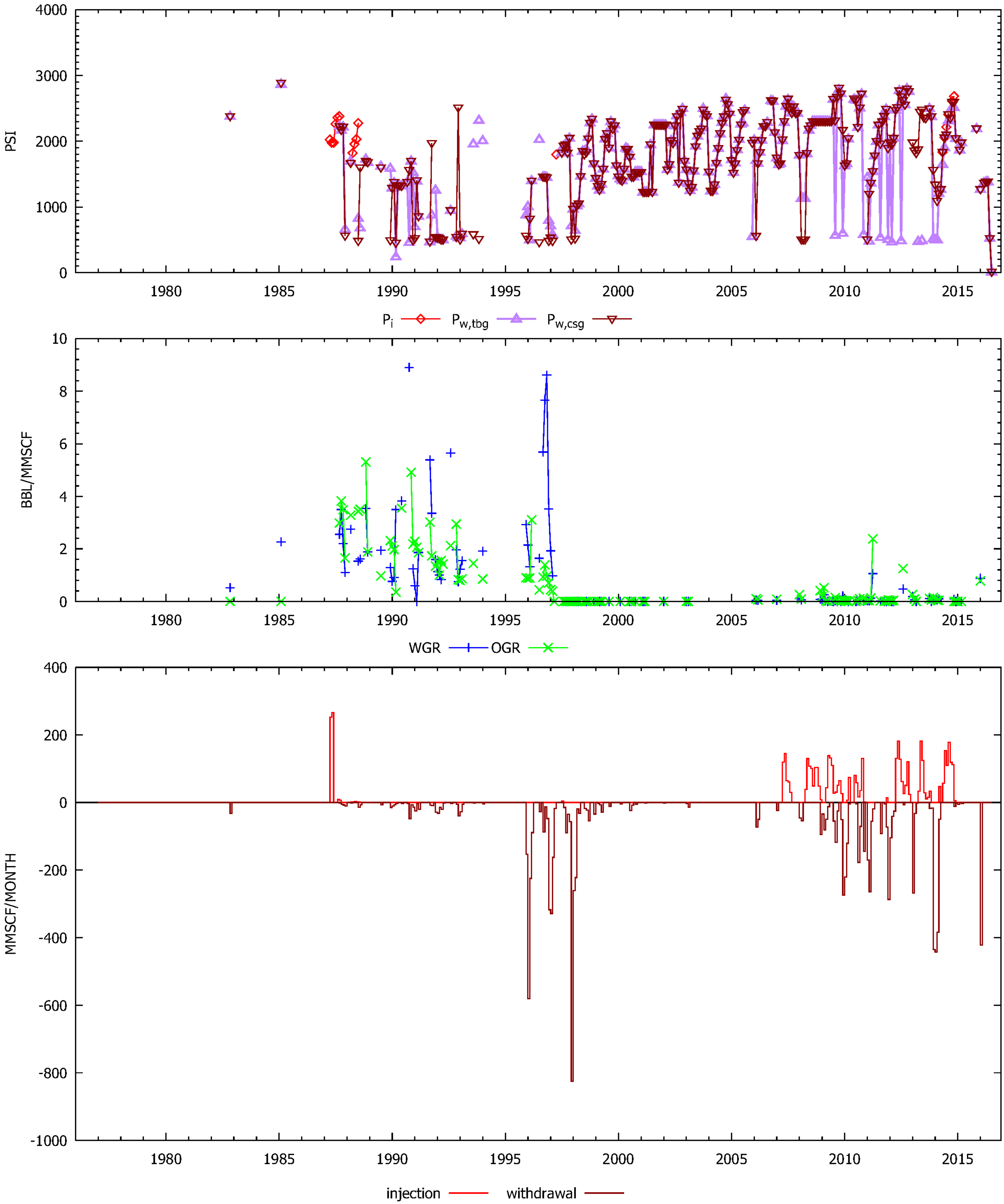
STANDARD SESNON 4 WELL

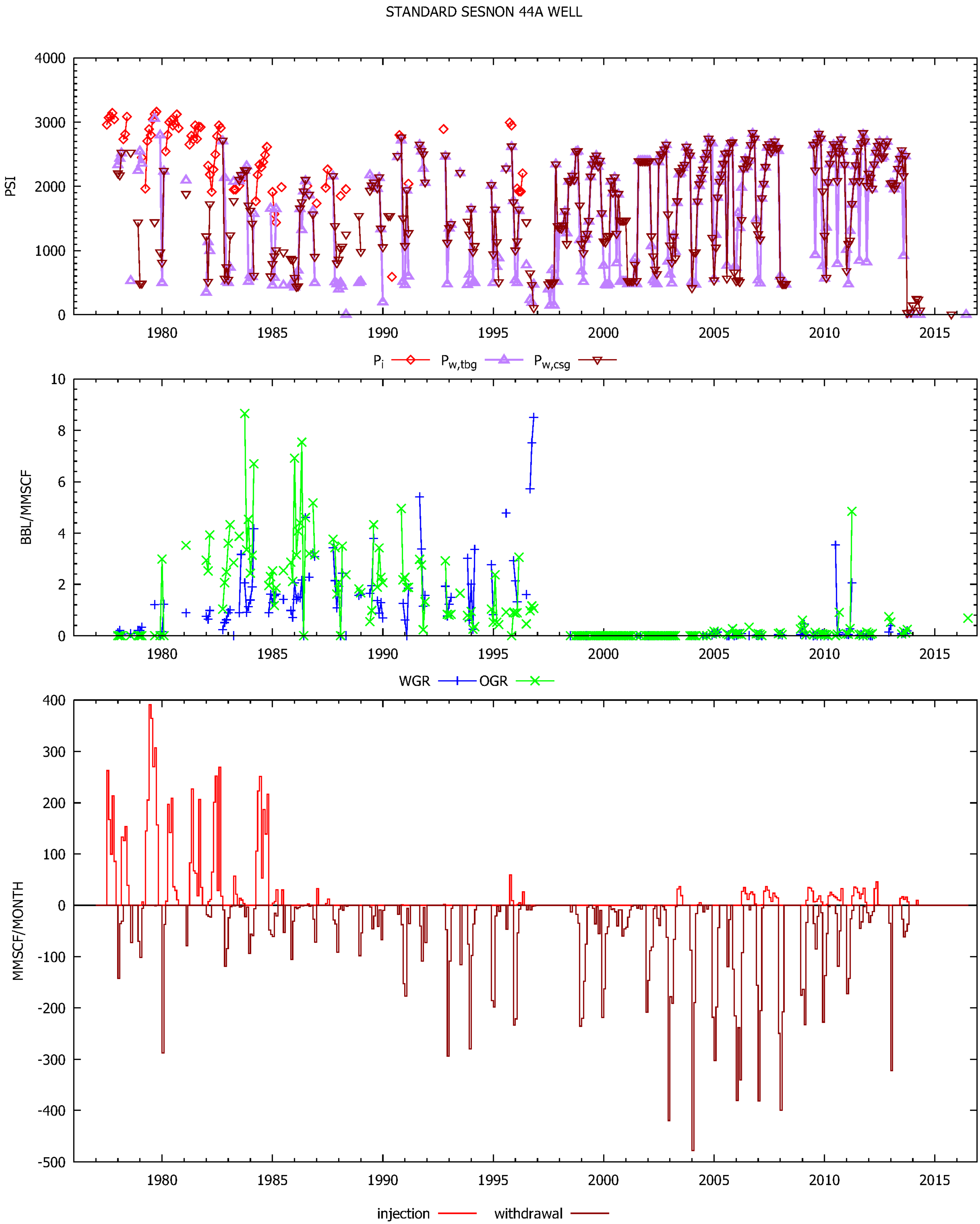






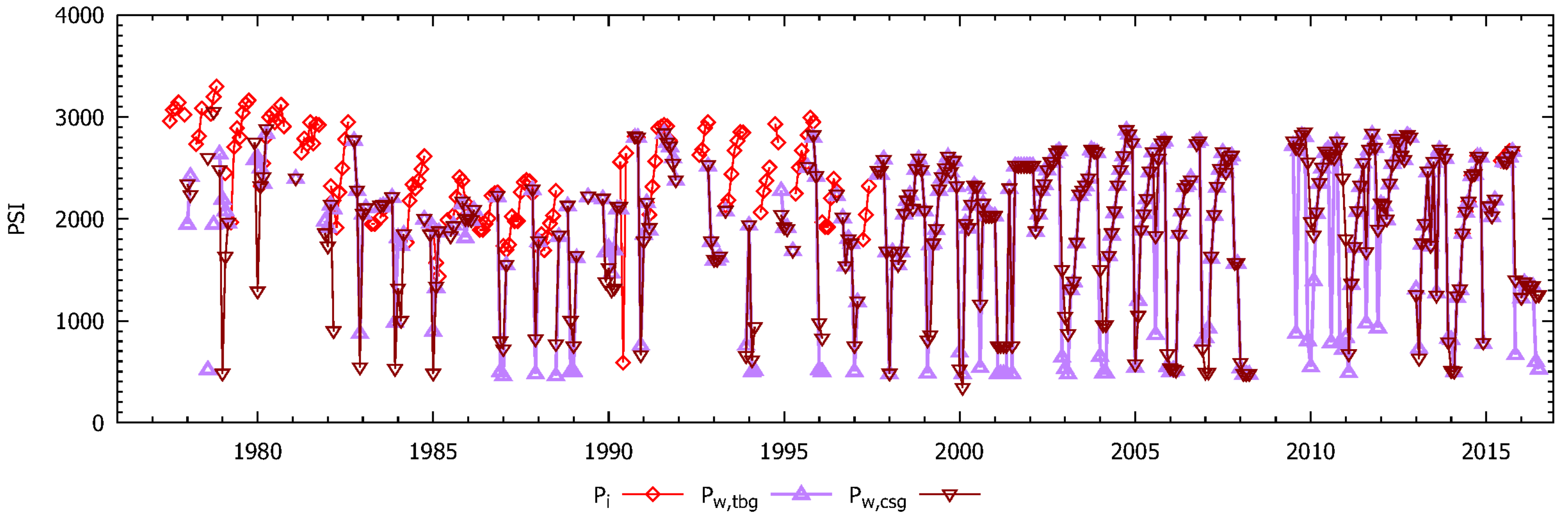
STANDARD SESNON 4-0 WELL

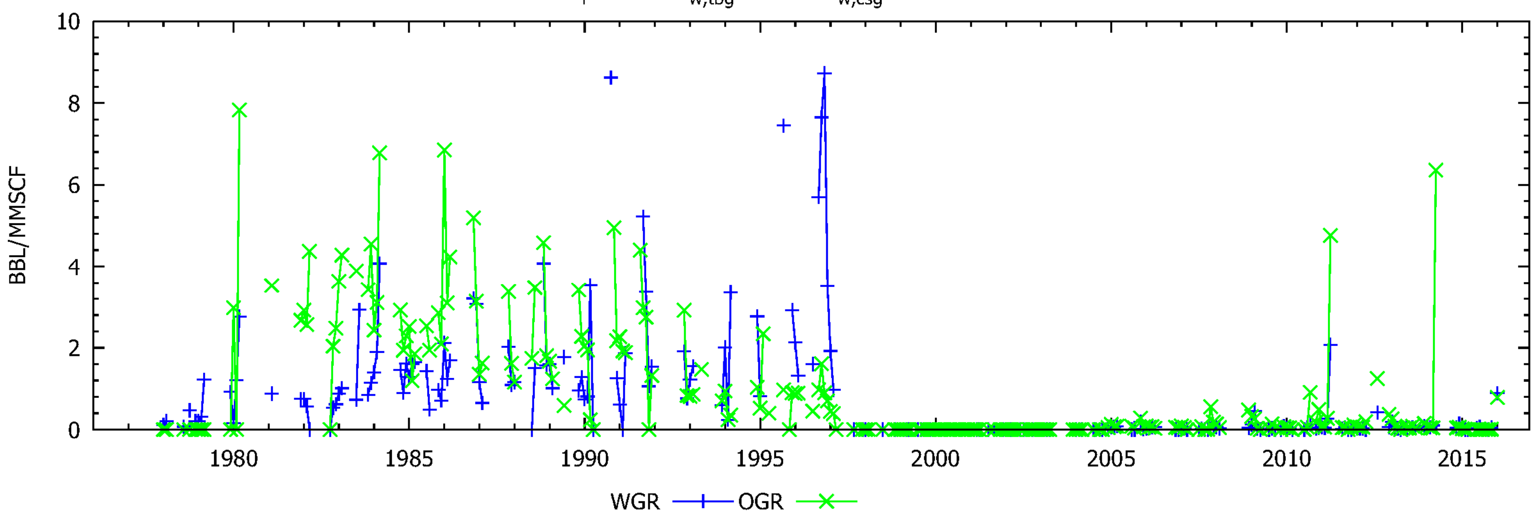


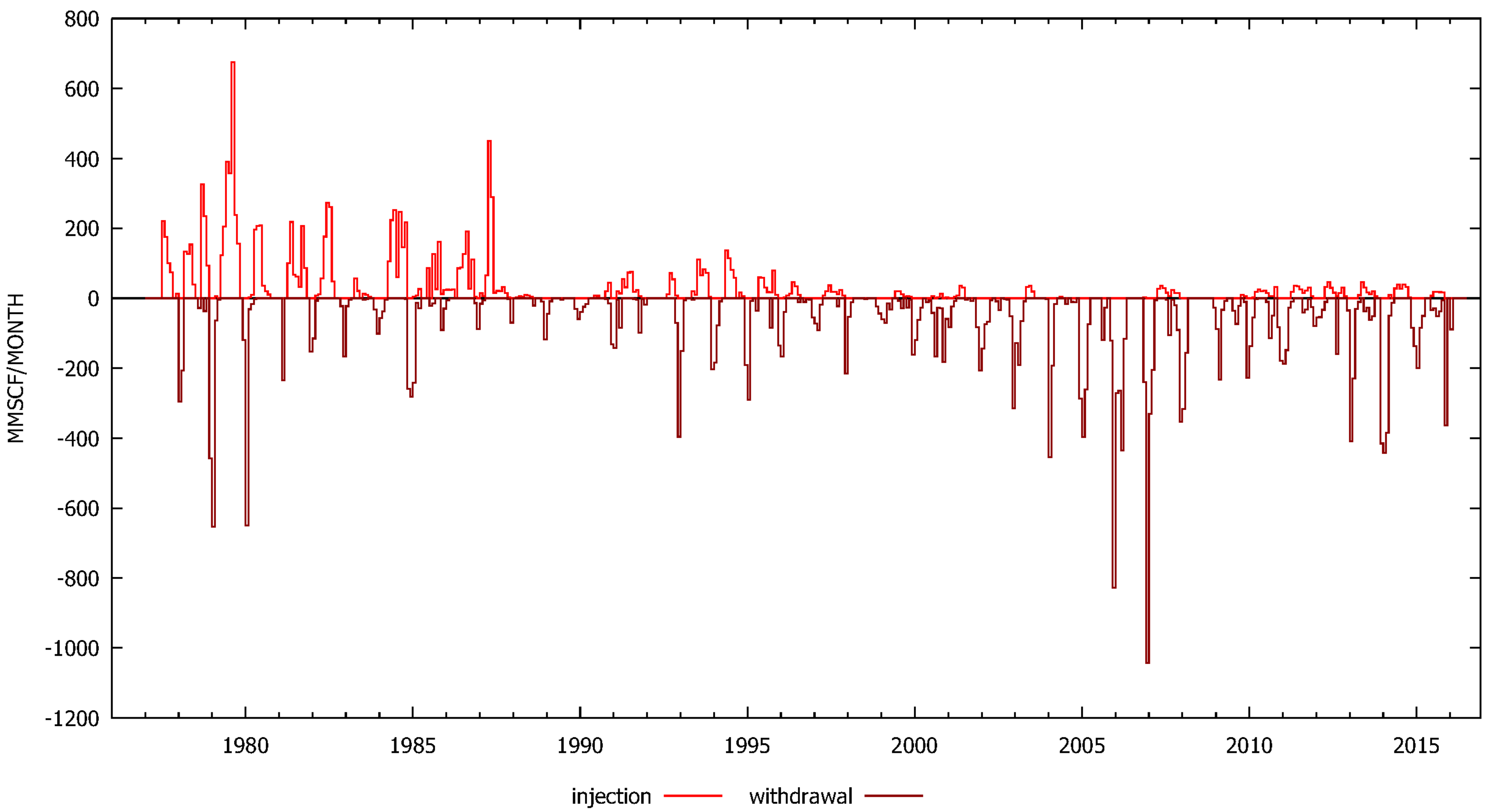


STANDARD SESNON 44A WELL
PSI
4000
3000
2000
1000
0
1980
1985
1990
1995
2000
2005
2010
2015
P_i
$P_{w,tbg}$
$P_{w,csg}$
BBL/MMSCF
10
8
6
4
2
0
WGR
OGR
MMSCF/MONTH
400
300
200
100
0
-100
-200
-300
-400
-500
injection
withdrawal

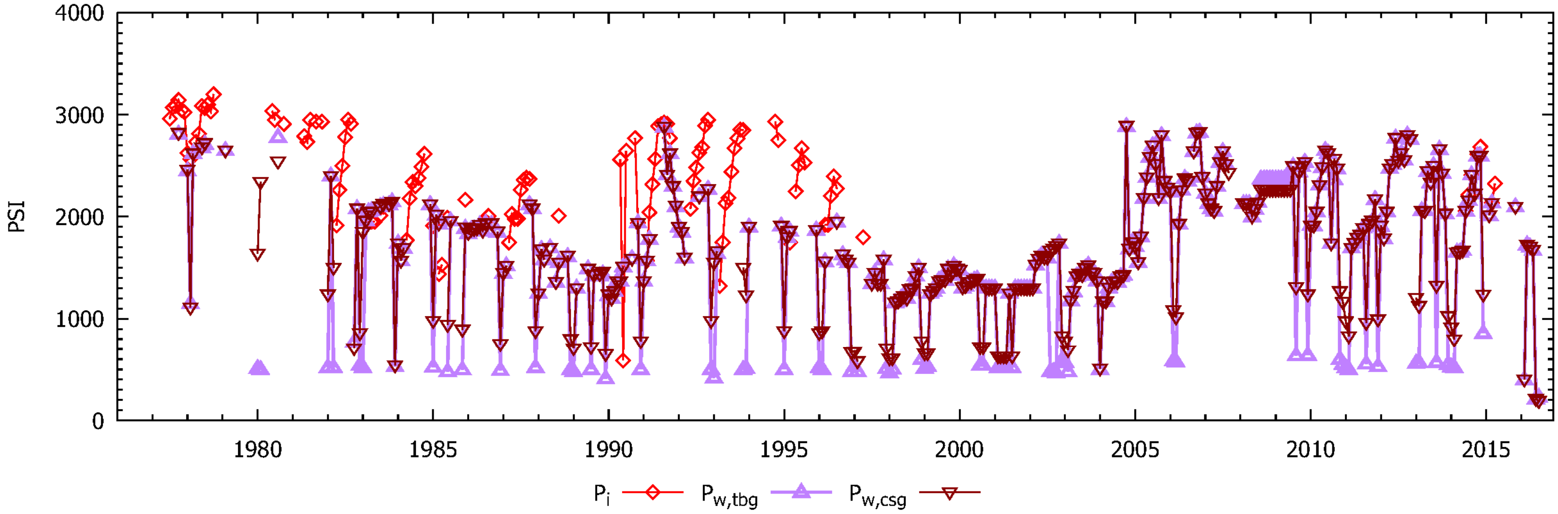
STANDARD SESNON 44B WELL

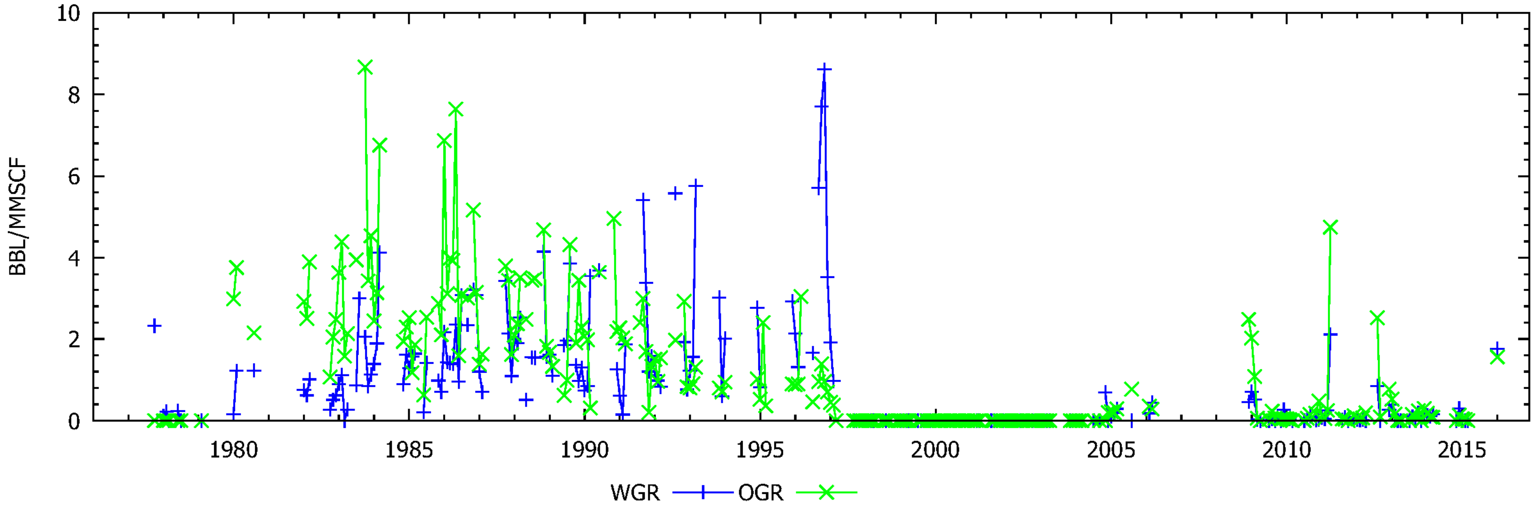


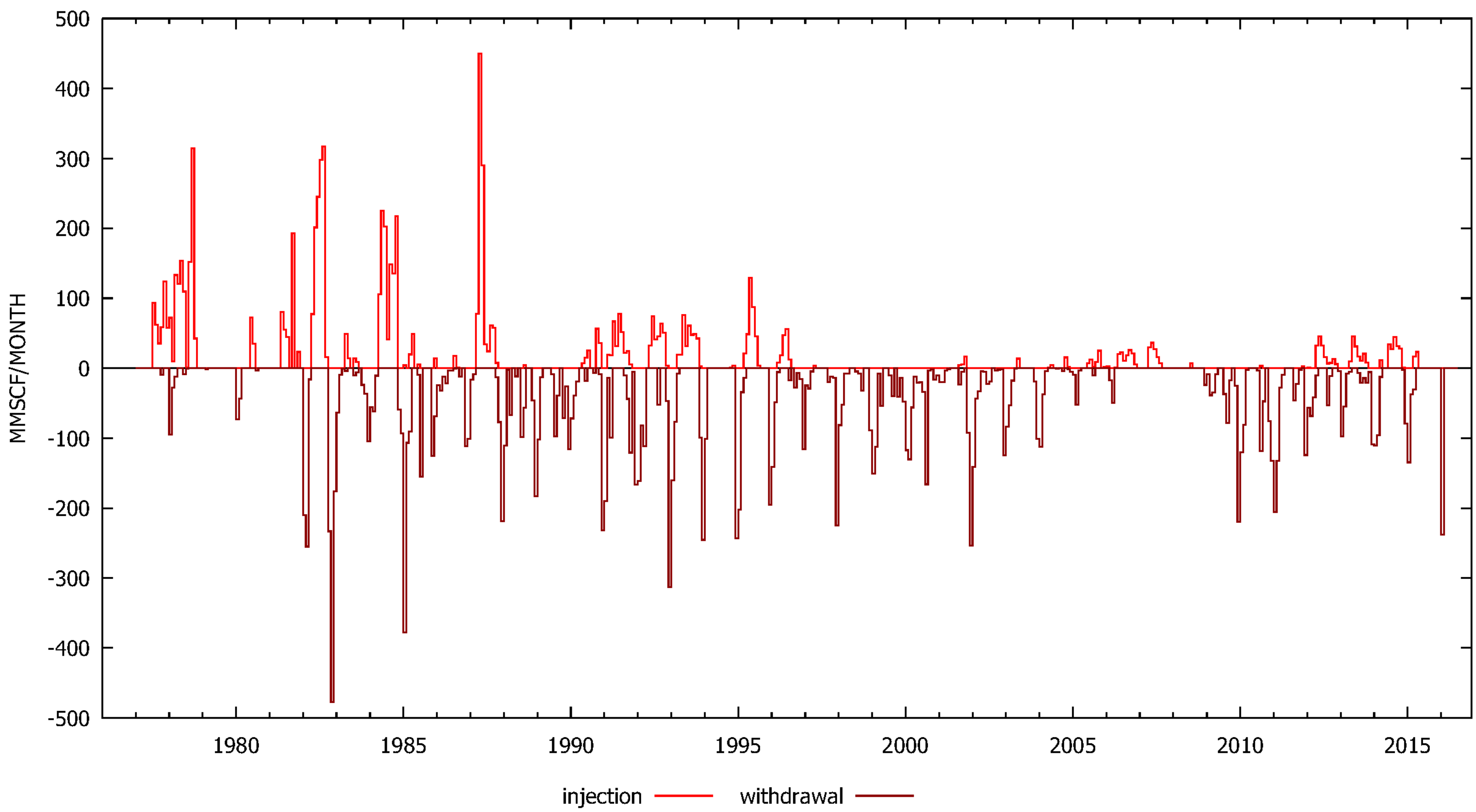




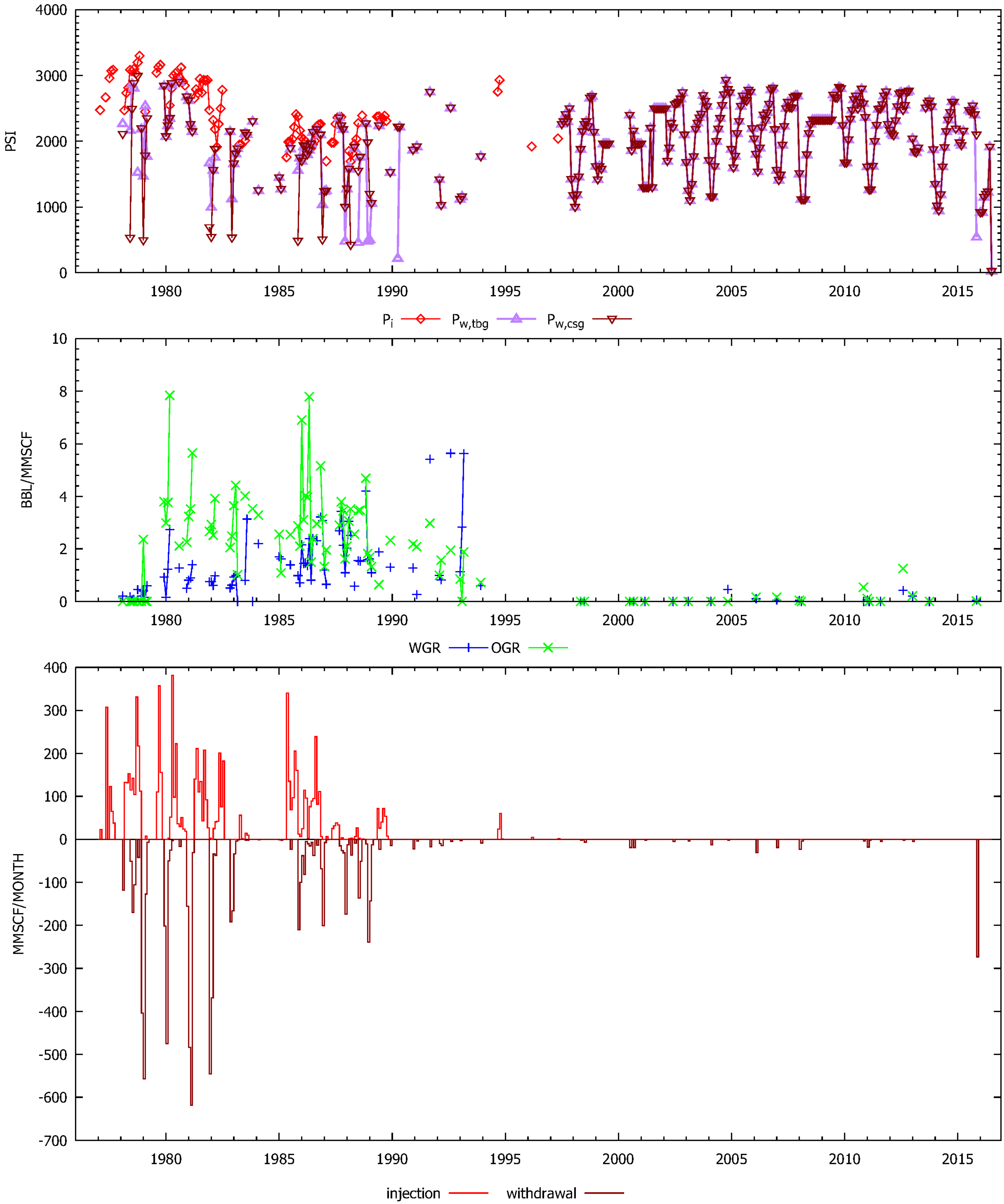
STANDARD SESNON 4A WELL



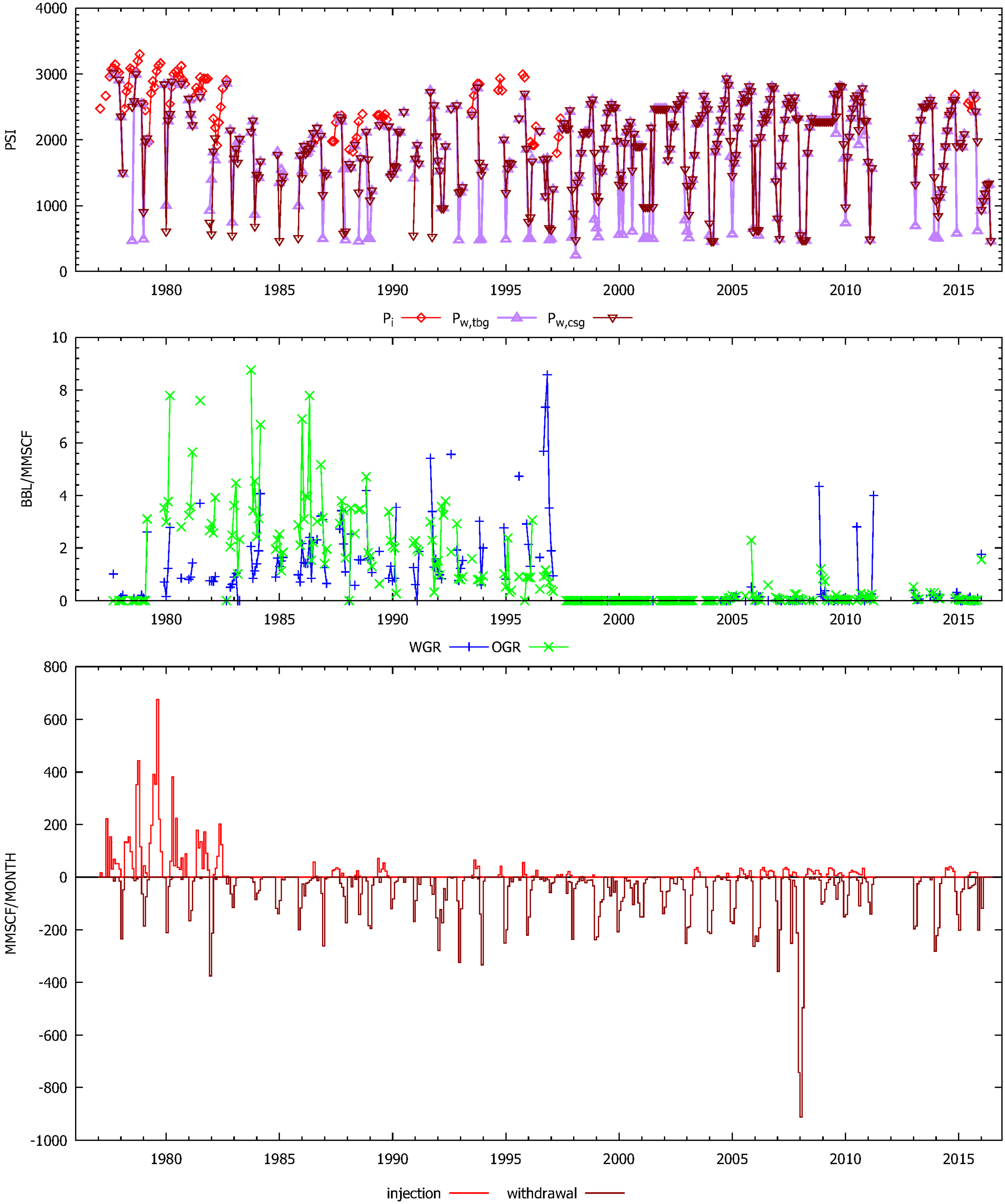




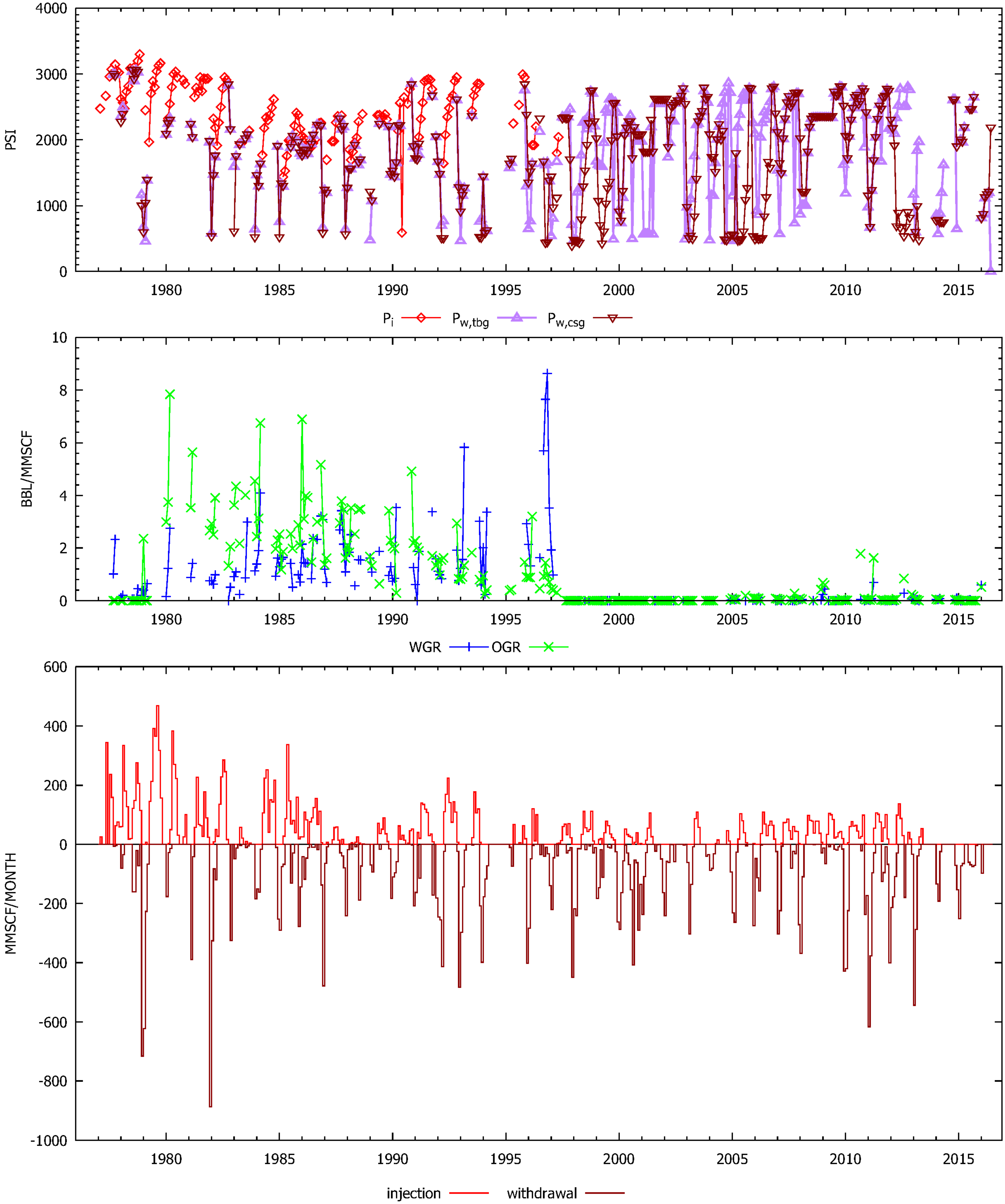
STANDARD SESNON 5 WELL

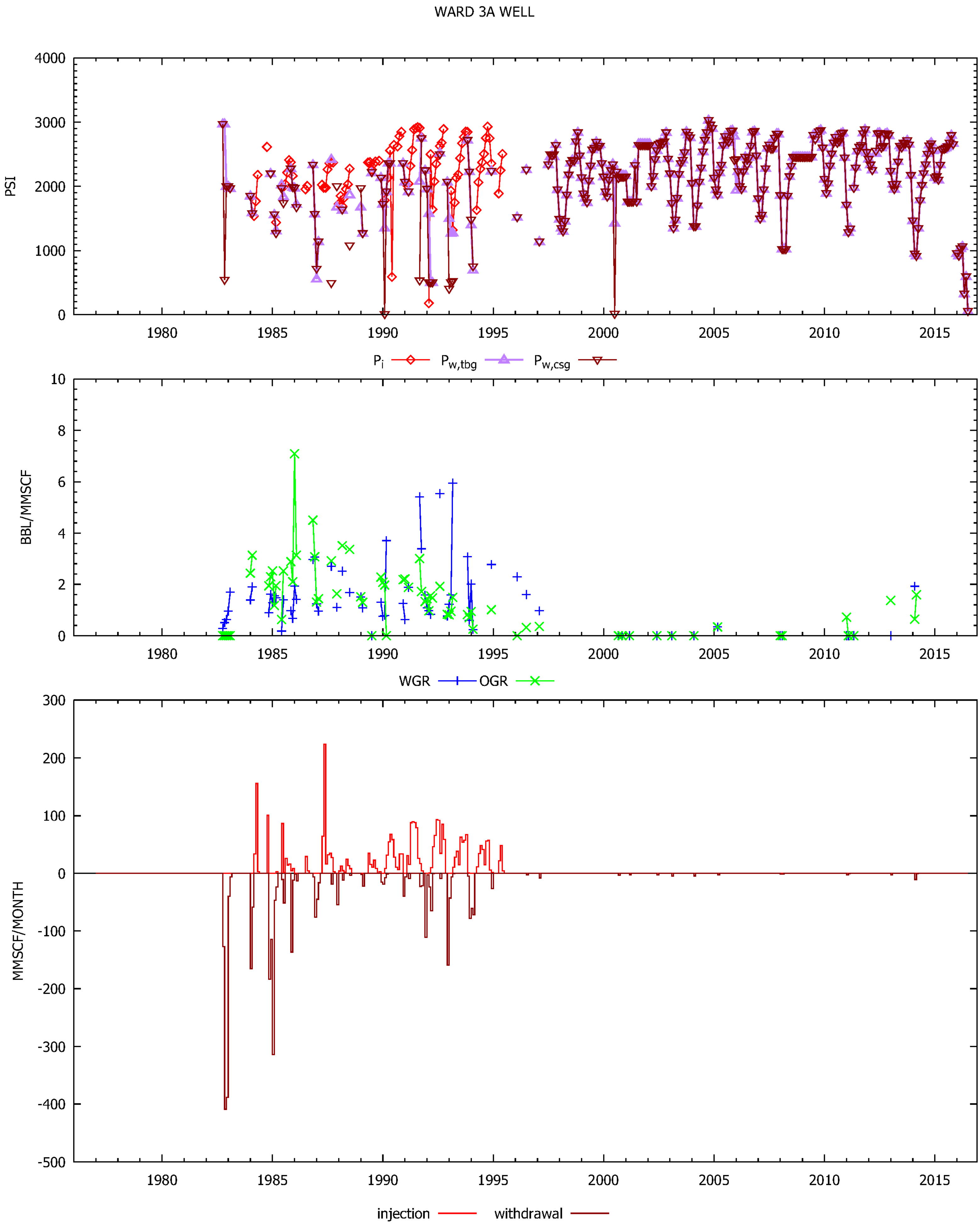


STANDARD SESNON 6 WELL



STANDARD SESNON 9 WELL

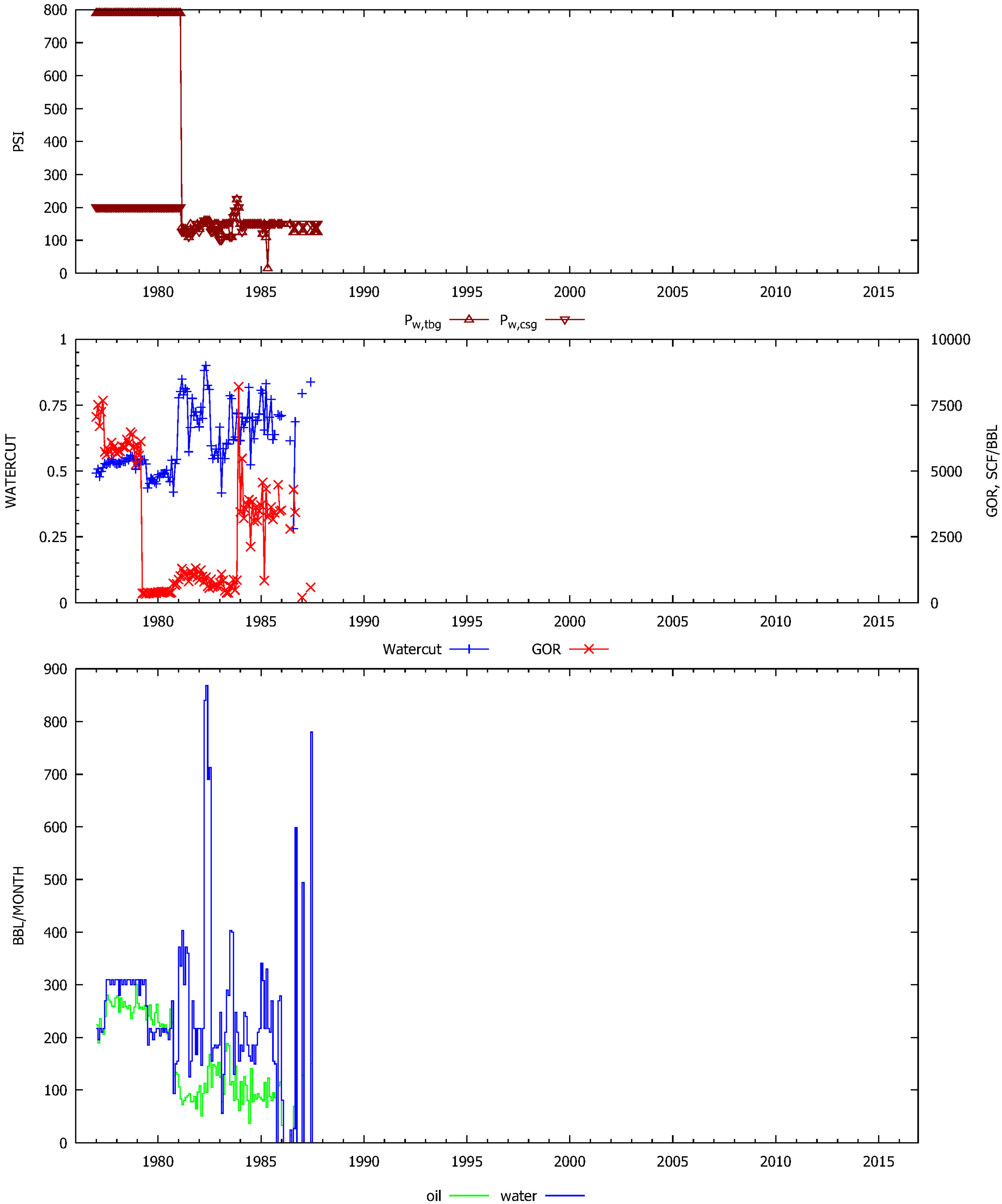



WARD 3A WELL
PSI
4000
3000
2000
1000
0
1980
1985
1990
1995
2000
2005
2010
2015
Pi
Pw,tbg
Pw,csg
BBL/MMSCF
10
8
6
4
2
0
WGR
OGR
MMSCF/MONTH
300
200
100
-100
-200
-300
-400
-500
injection
withdrawal

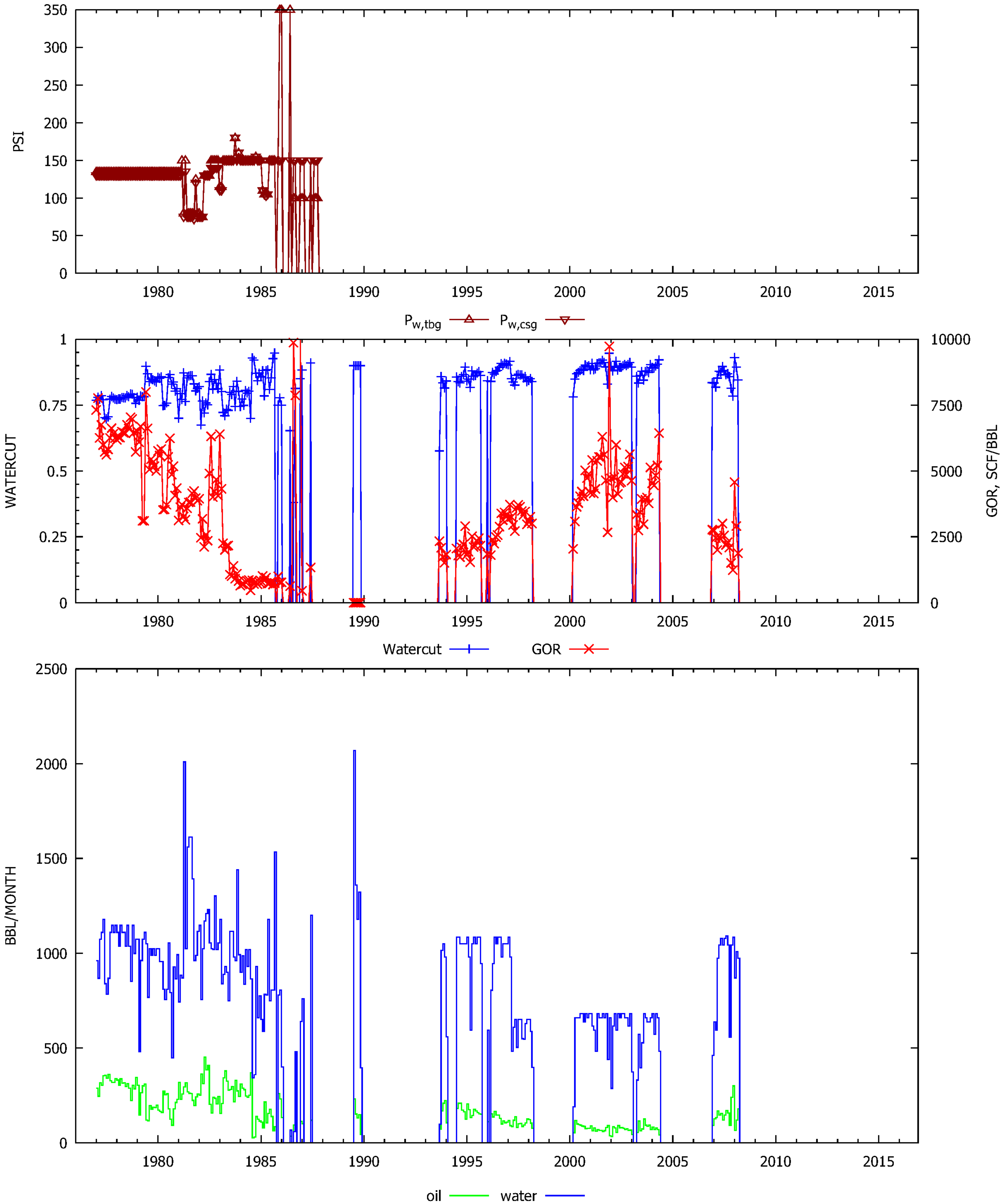
Appendix E Conventional Operations Well Plots

This section shows plots of historical production data for conventional operations.

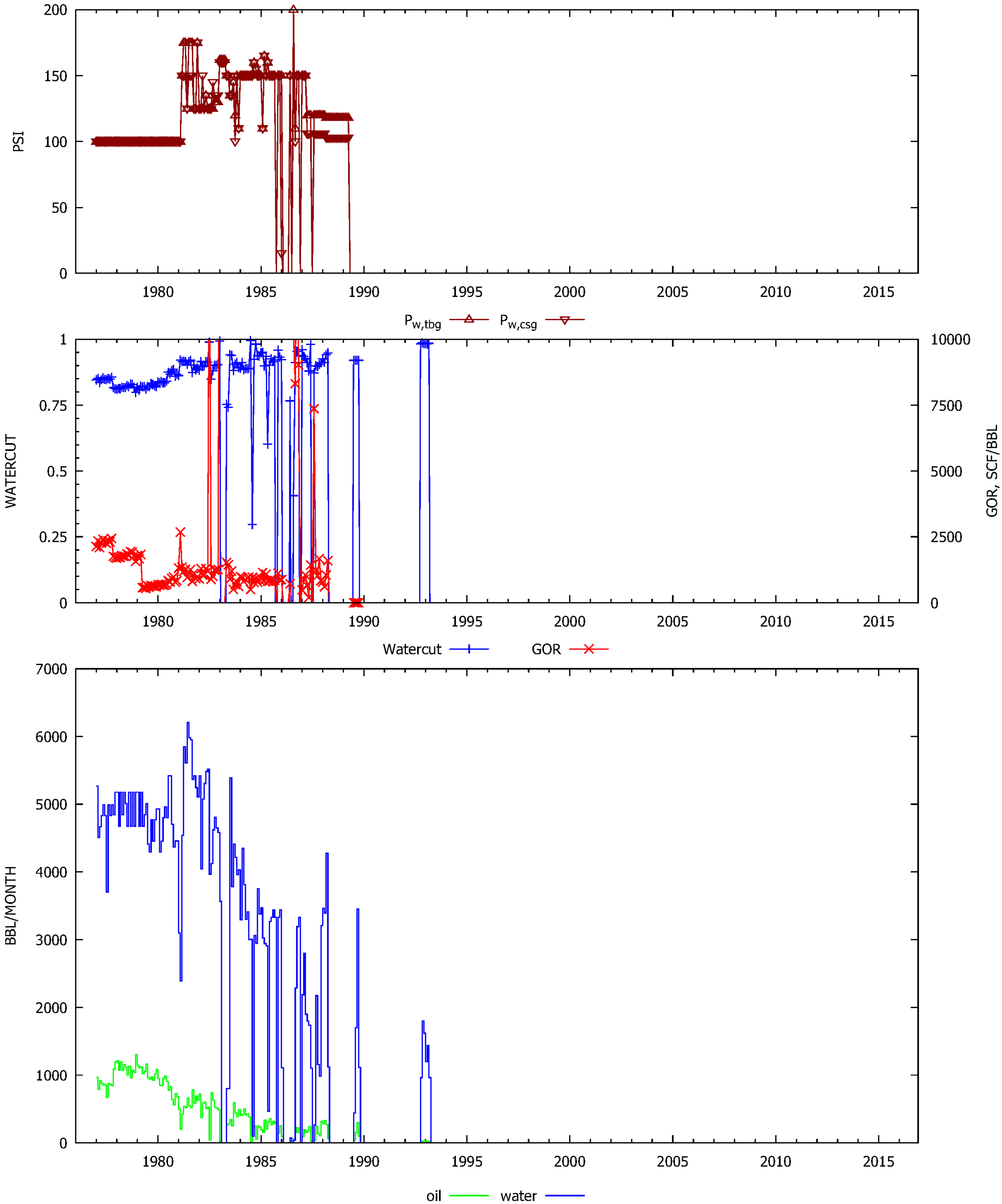
WELL Del Aliso 1 10

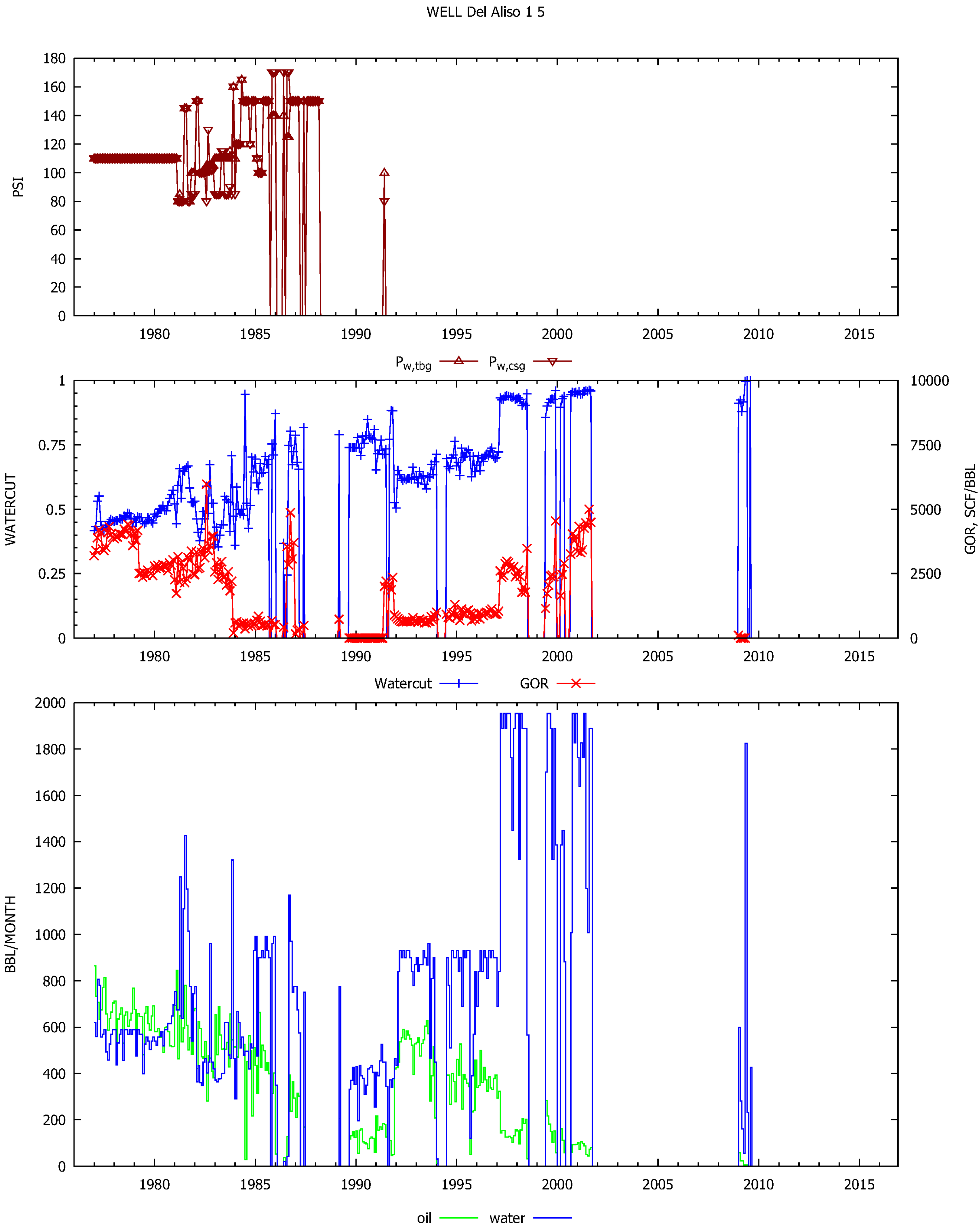


WELL Del Aliso 1 2

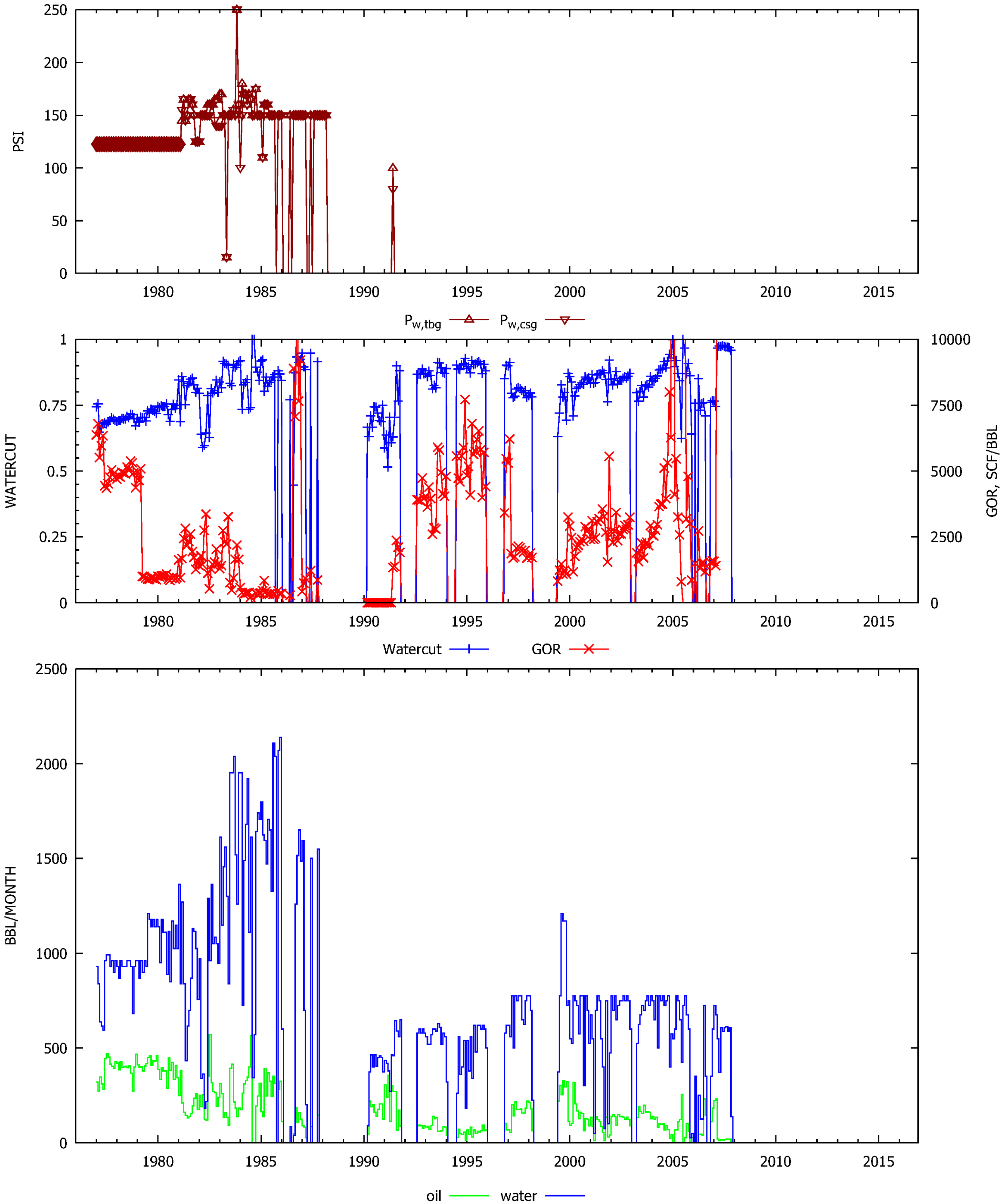


WELL Del Aliso 1 4

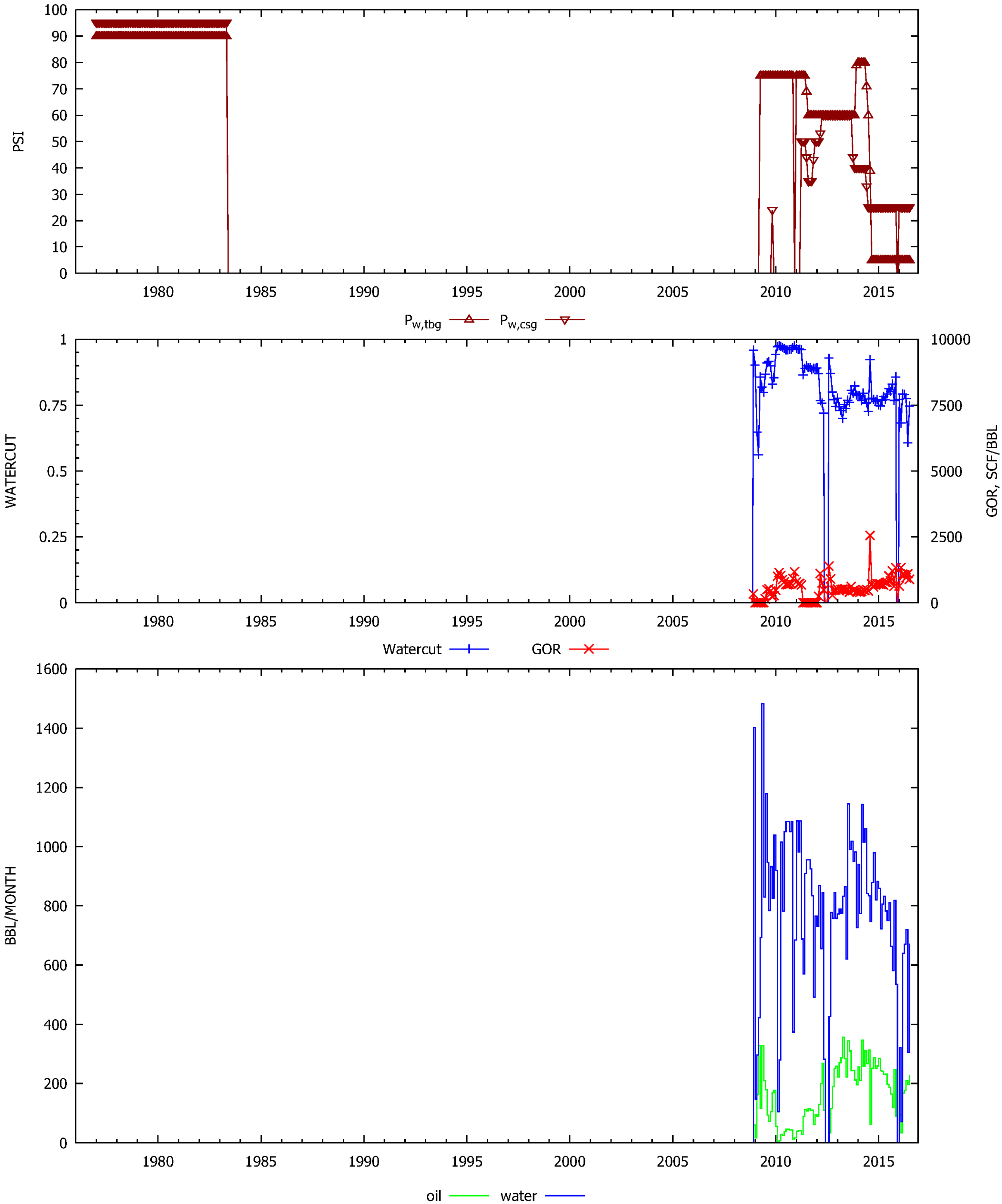


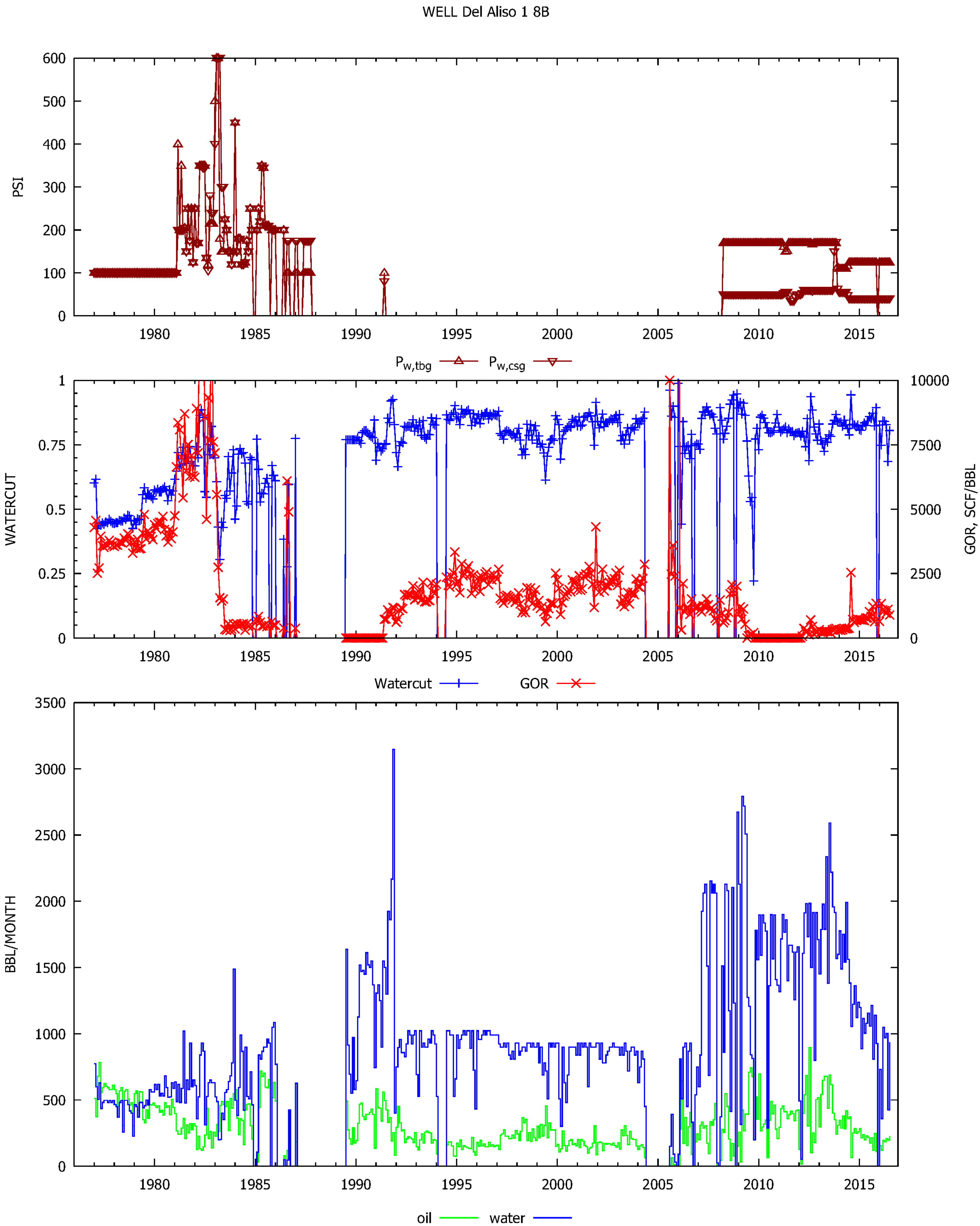

WELL Del Aliso 1 5
PSI
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
oil
water
1980
1985
1990
1995
2000
2005
2010
2015

WELL Del Aliso 1 6A

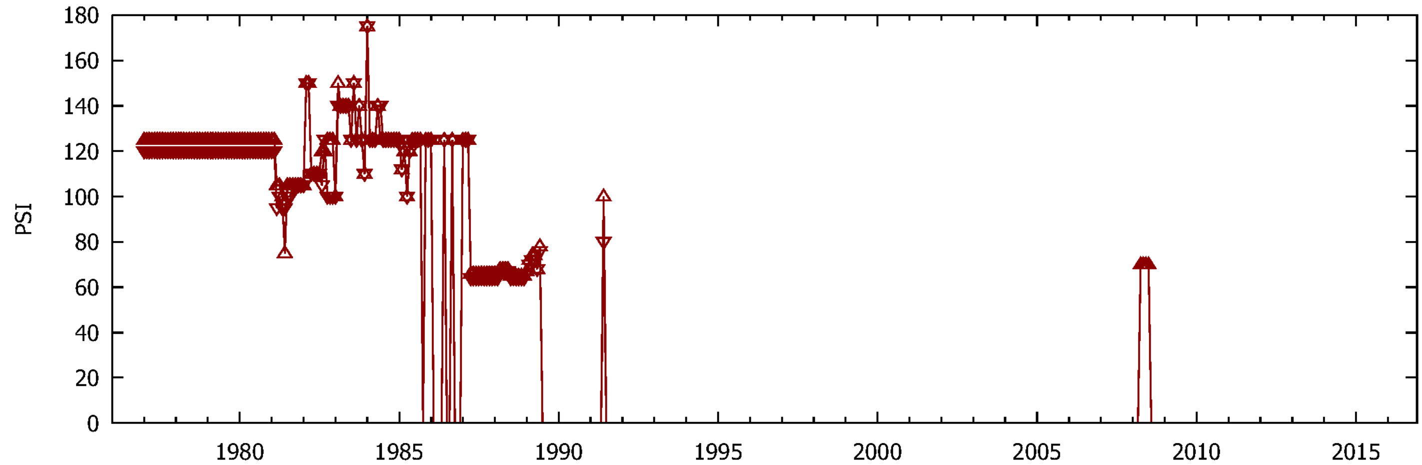


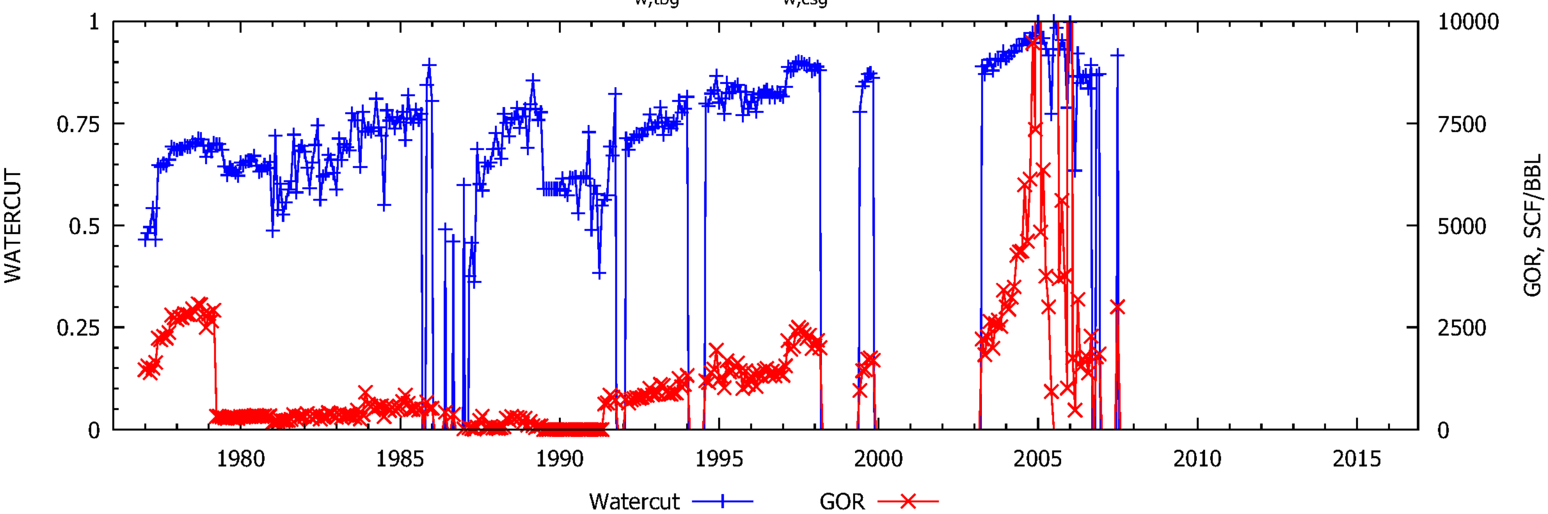
WELL Del Aliso 1 7A

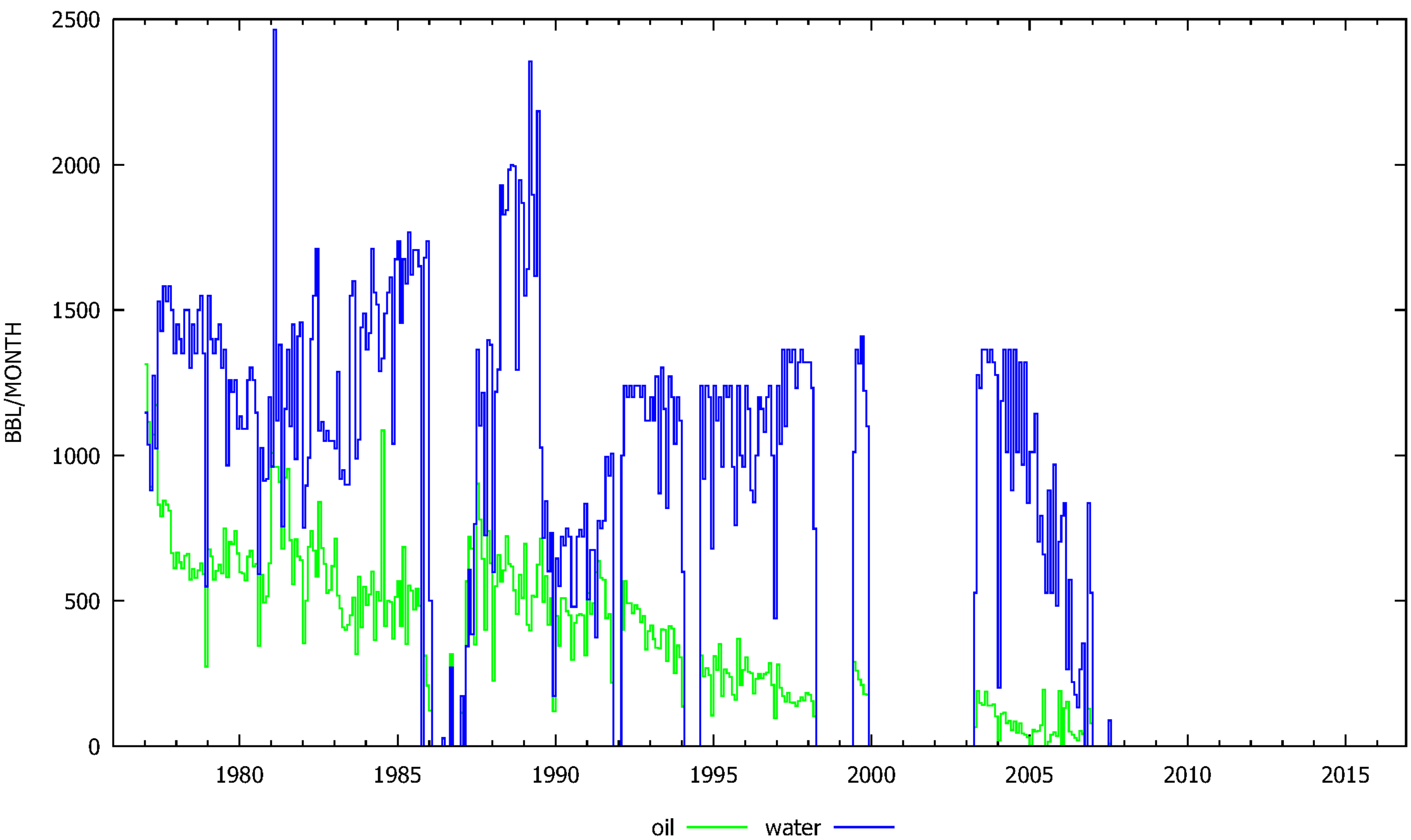



WELL Del Aliso 1 8B
PSI
600
500
400
300
200
100
0
1980
1985
1990
1995
2000
2005
2010
2015
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
1
0.75
0.5
0.25
0
10000
7500
5000
2500
Watercut
GOR
BBL/MONTH
3500
3000
2500
2000
1500
1000
500
oil
water

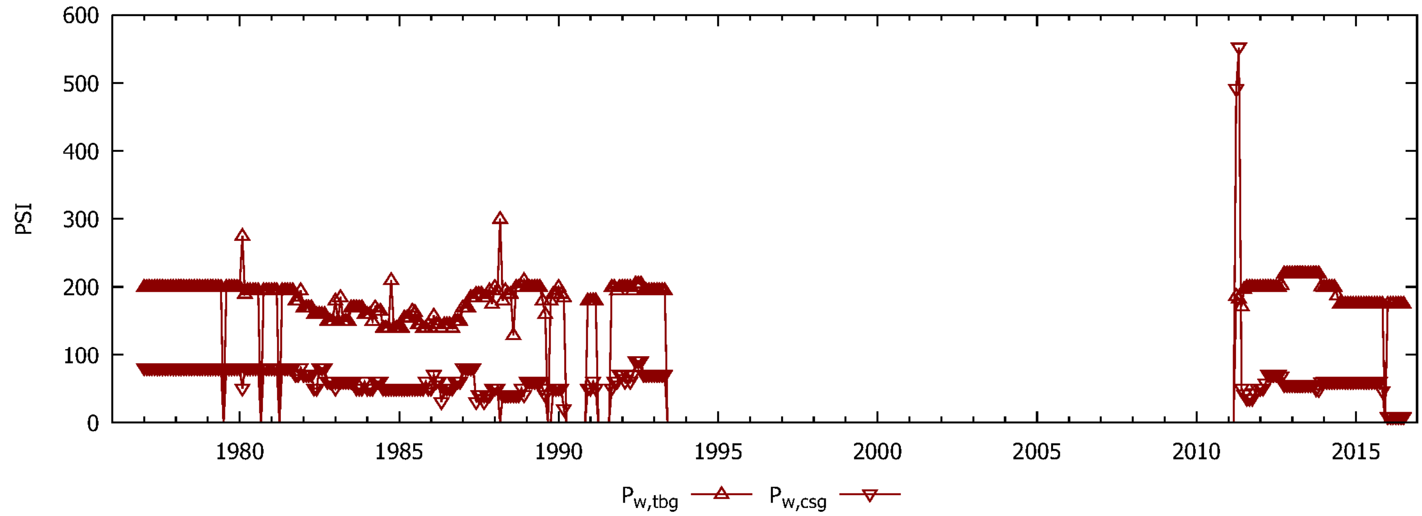
WELL Del Aliso 1 9

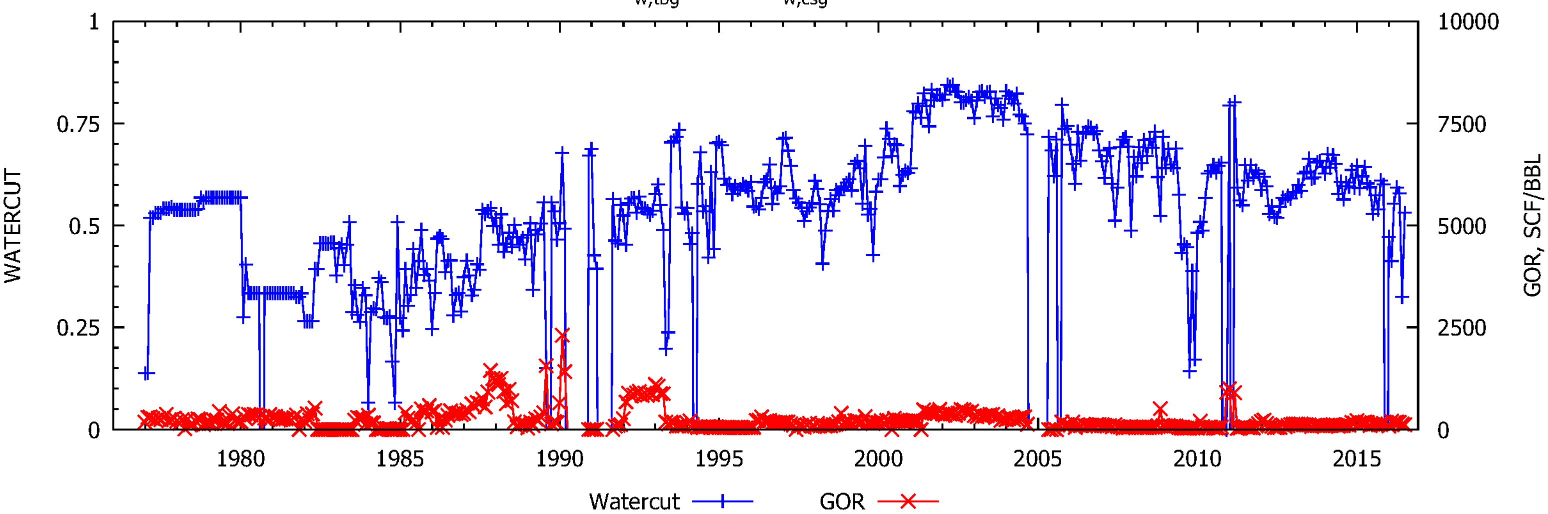


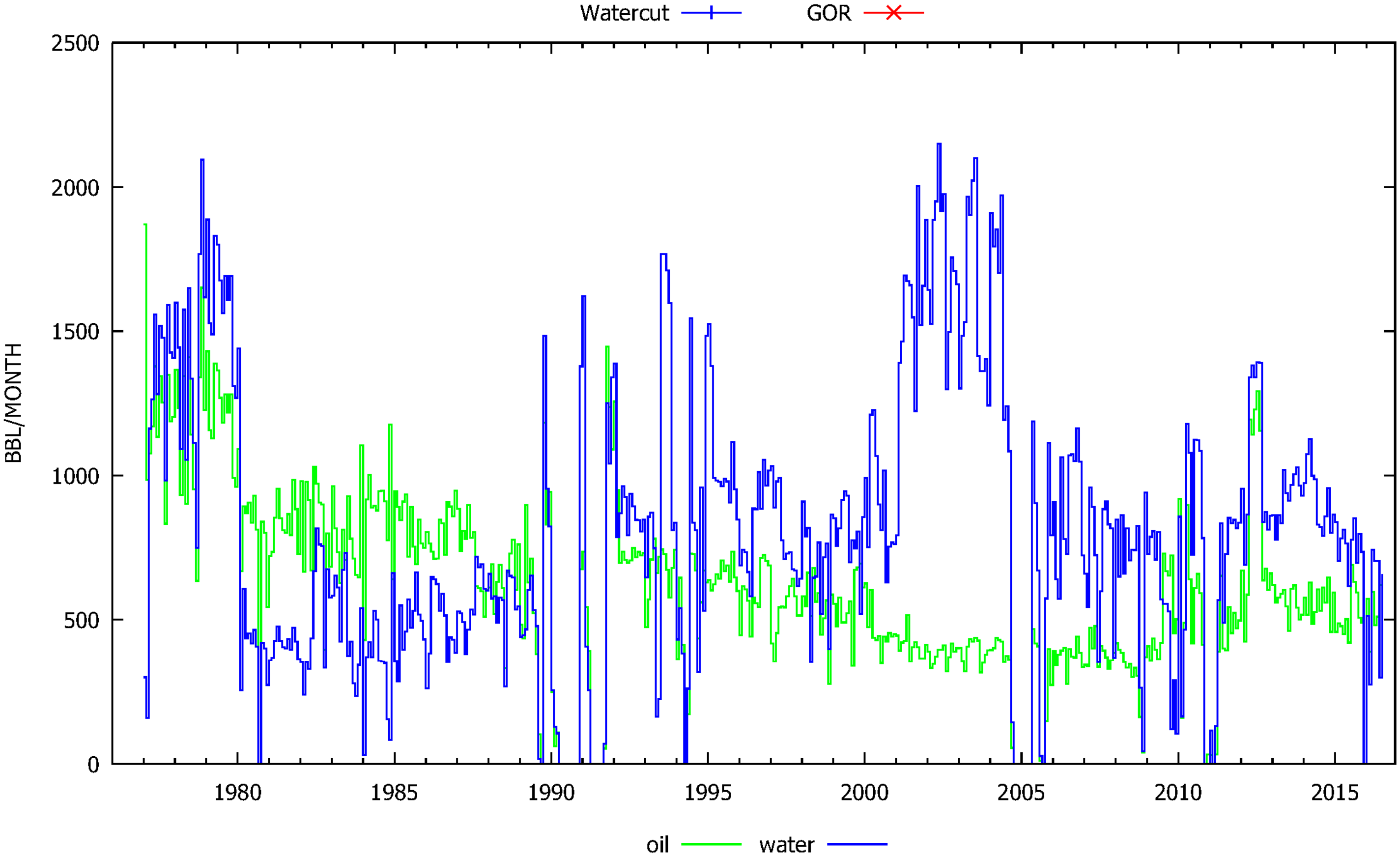




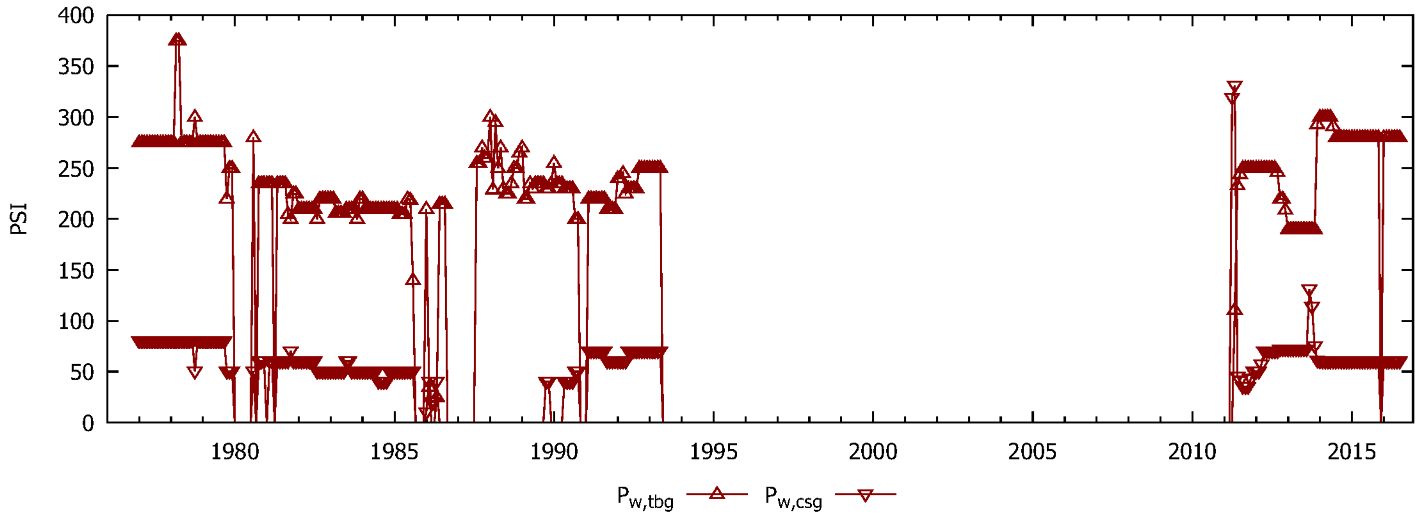
WELL Del Aliso 1-1

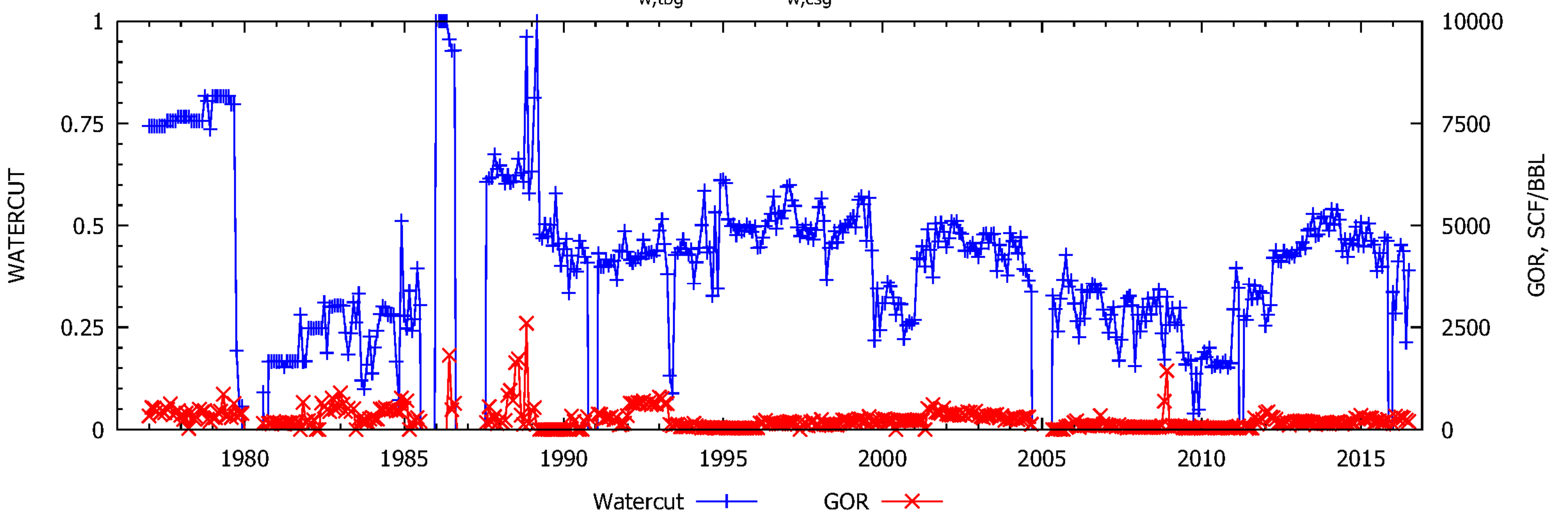


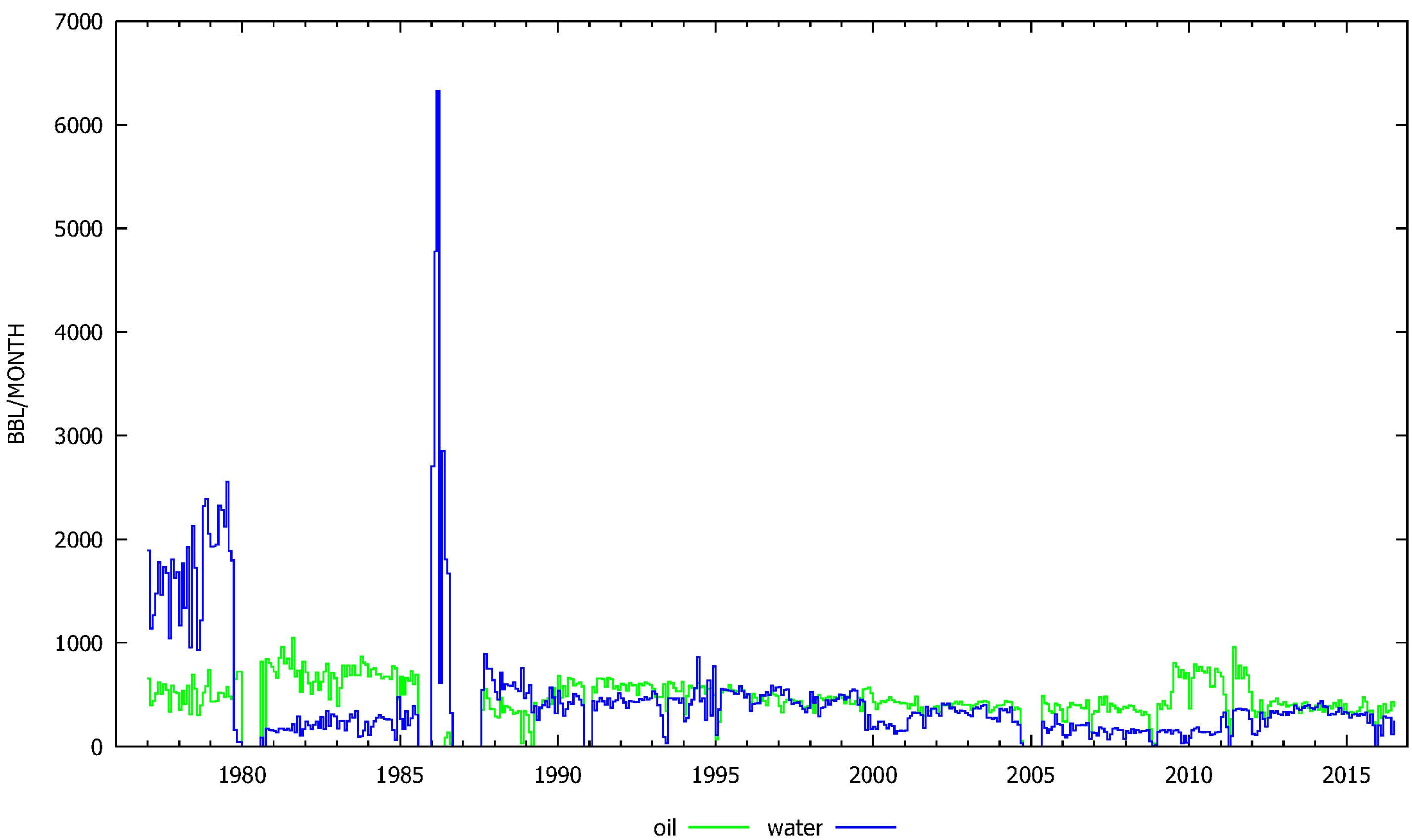




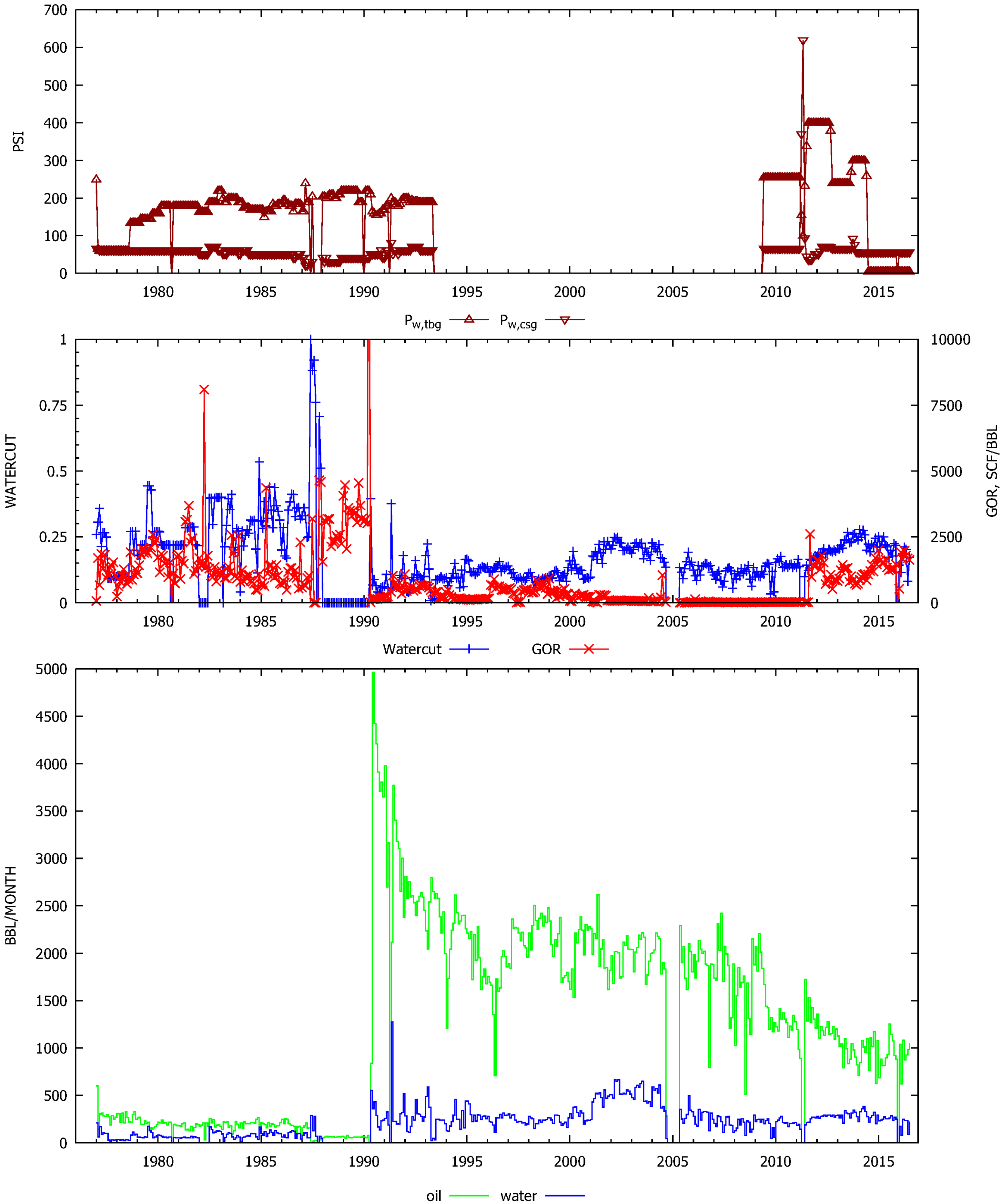
WELL Del Aliso 1-2



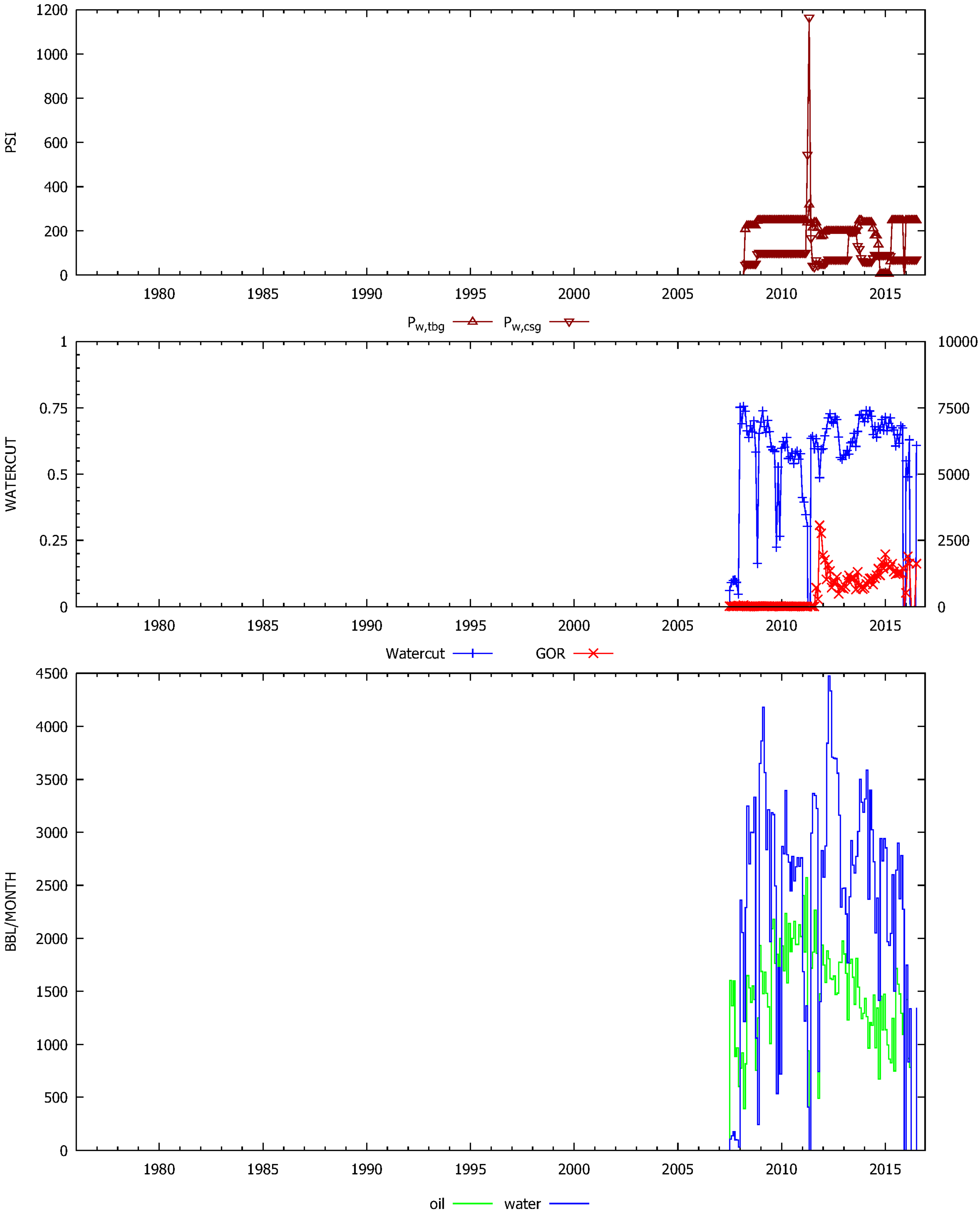




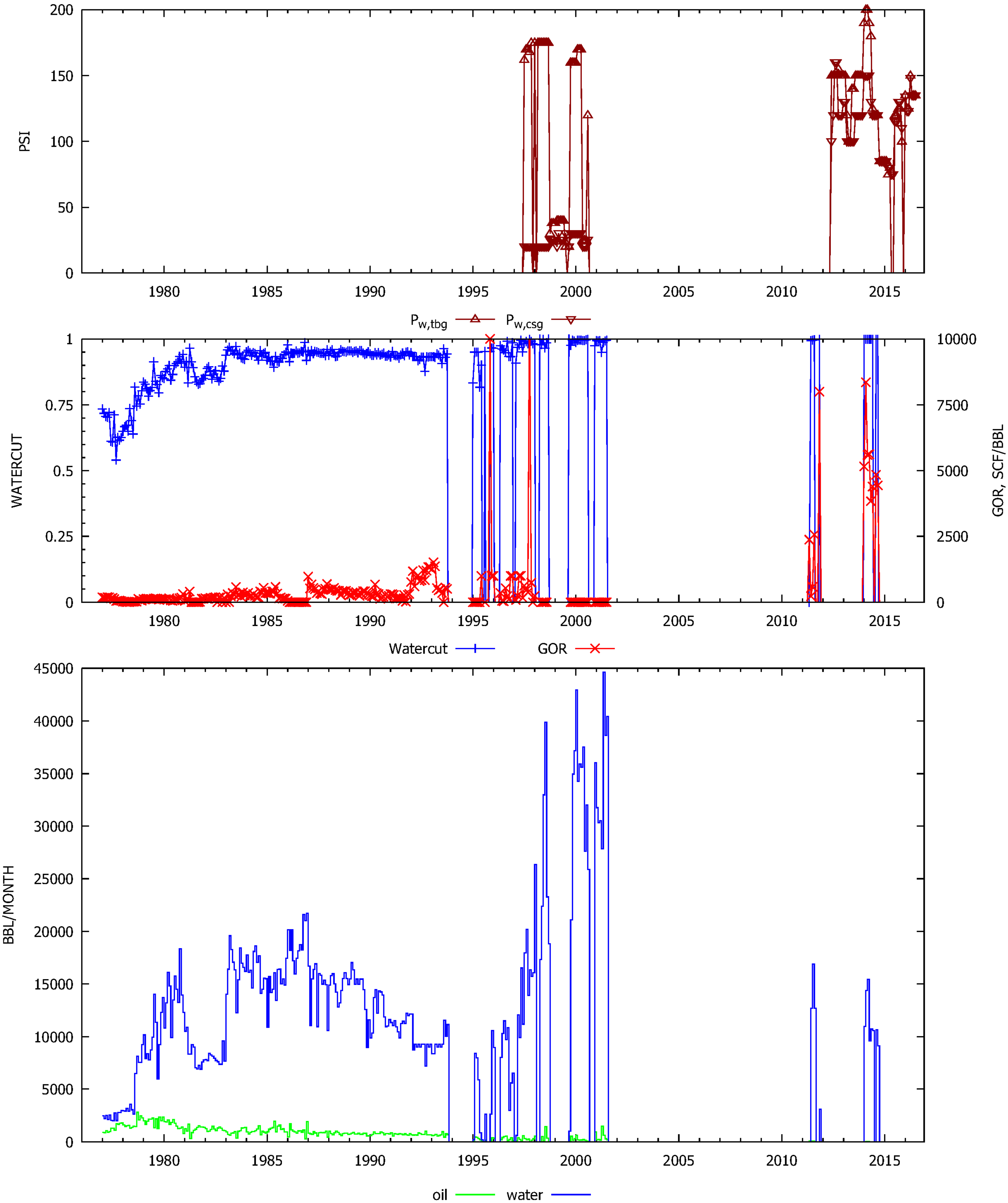
WELL Del Aliso 1-3



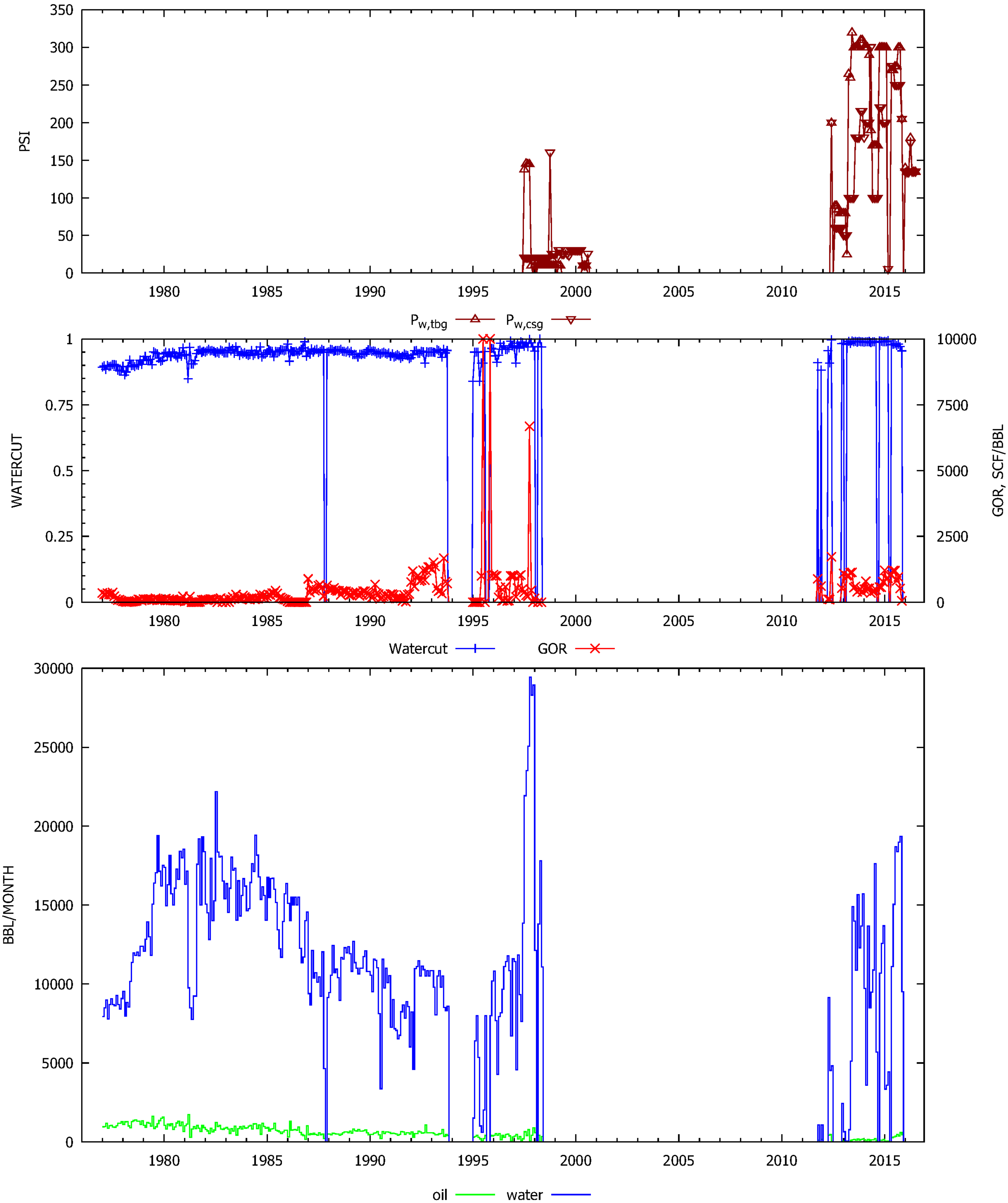
WELL Del Aliso 1-4

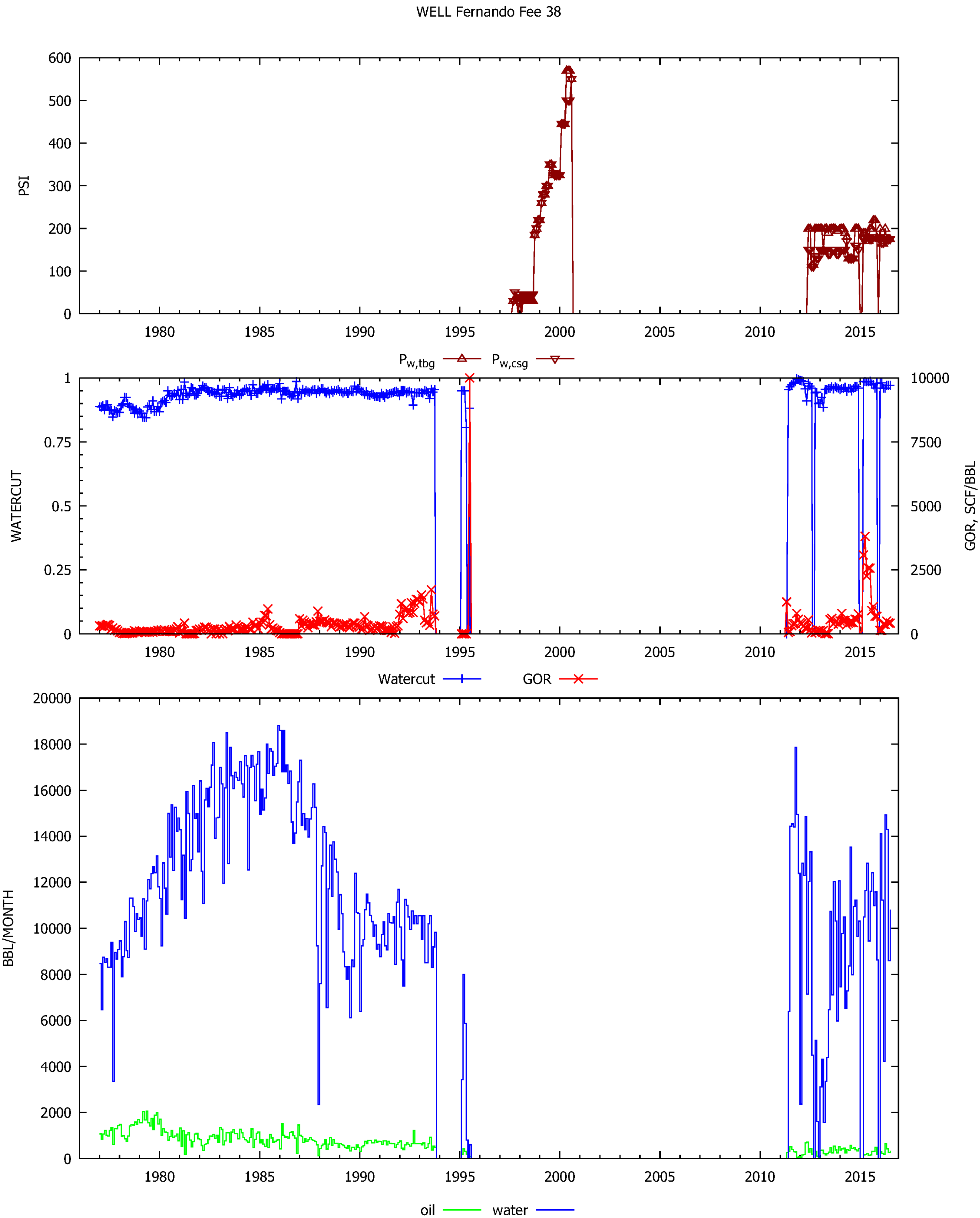


WELL Fernando Fee 1



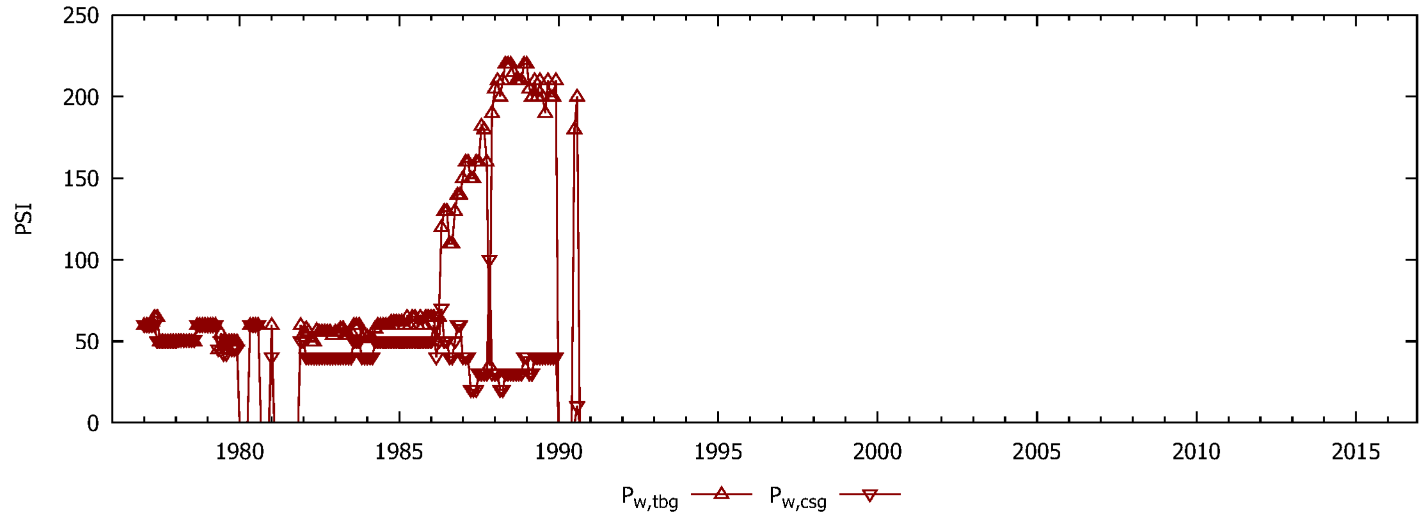
WELL Fernando Fee 11

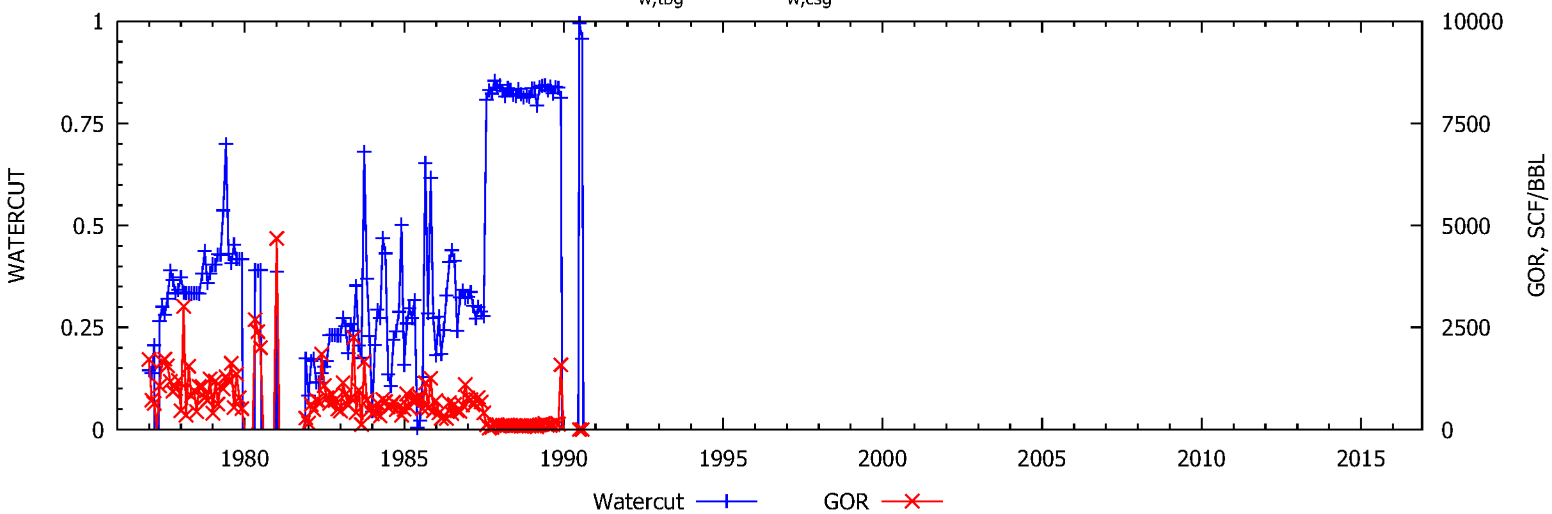


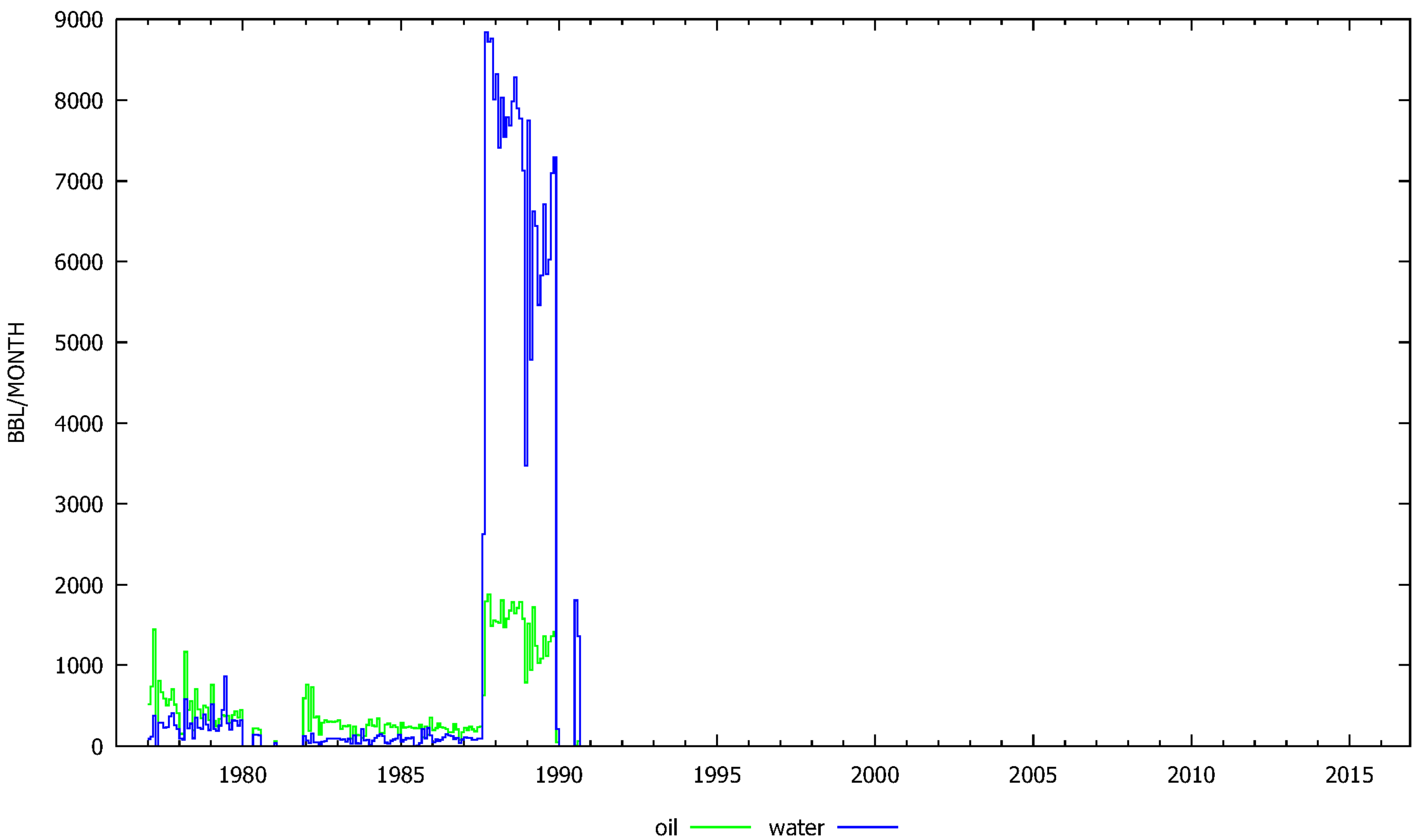


WELL Fernando Fee 38
PSI
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
oil
water

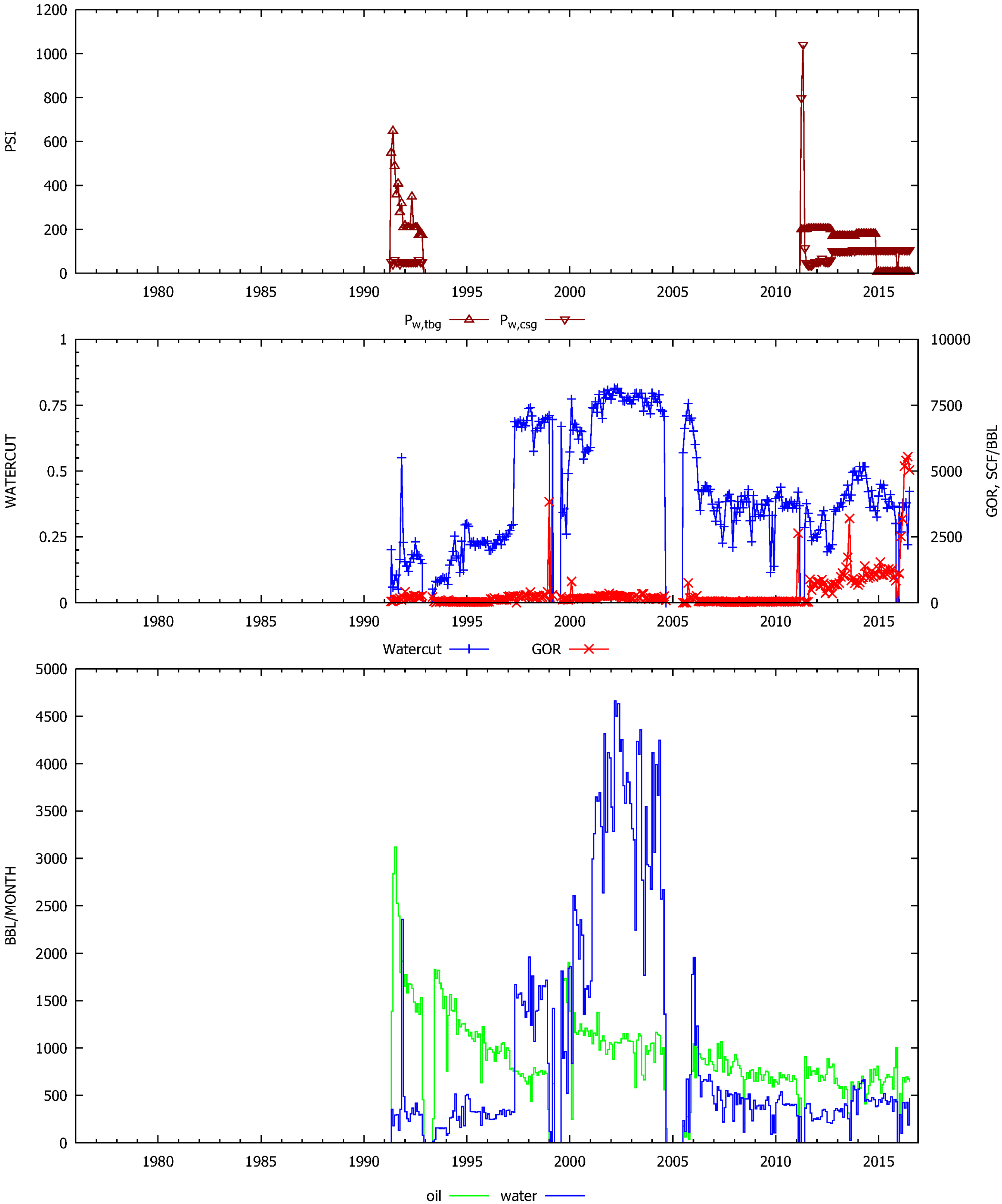
WELL Gardett 1-20



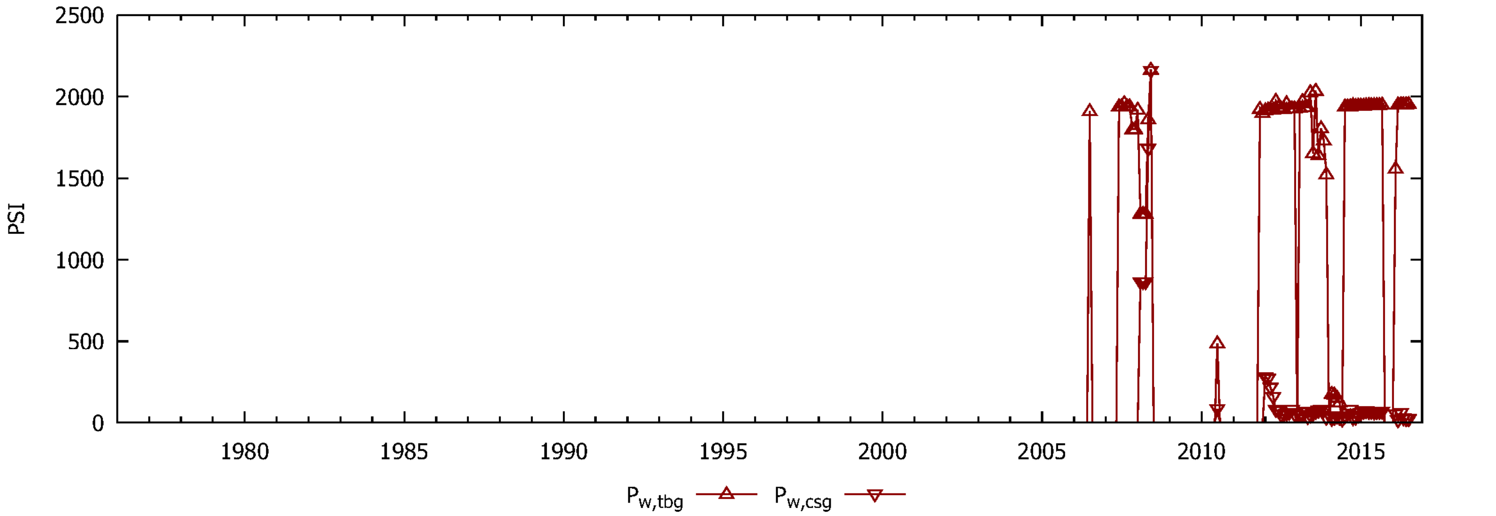


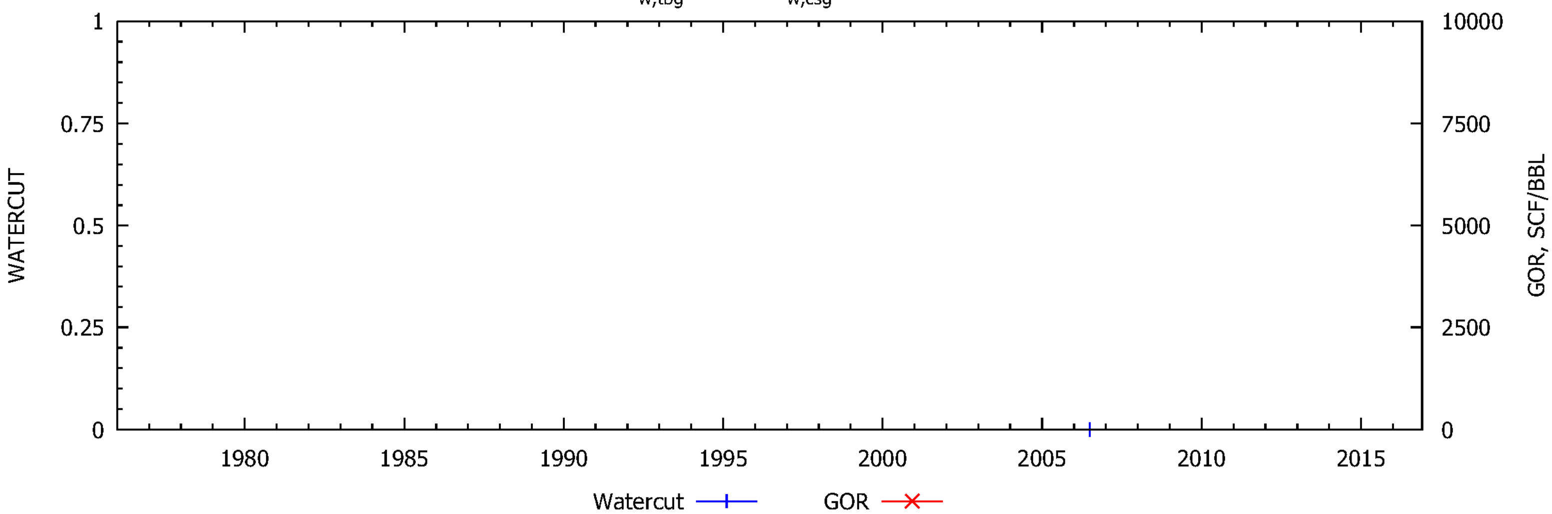


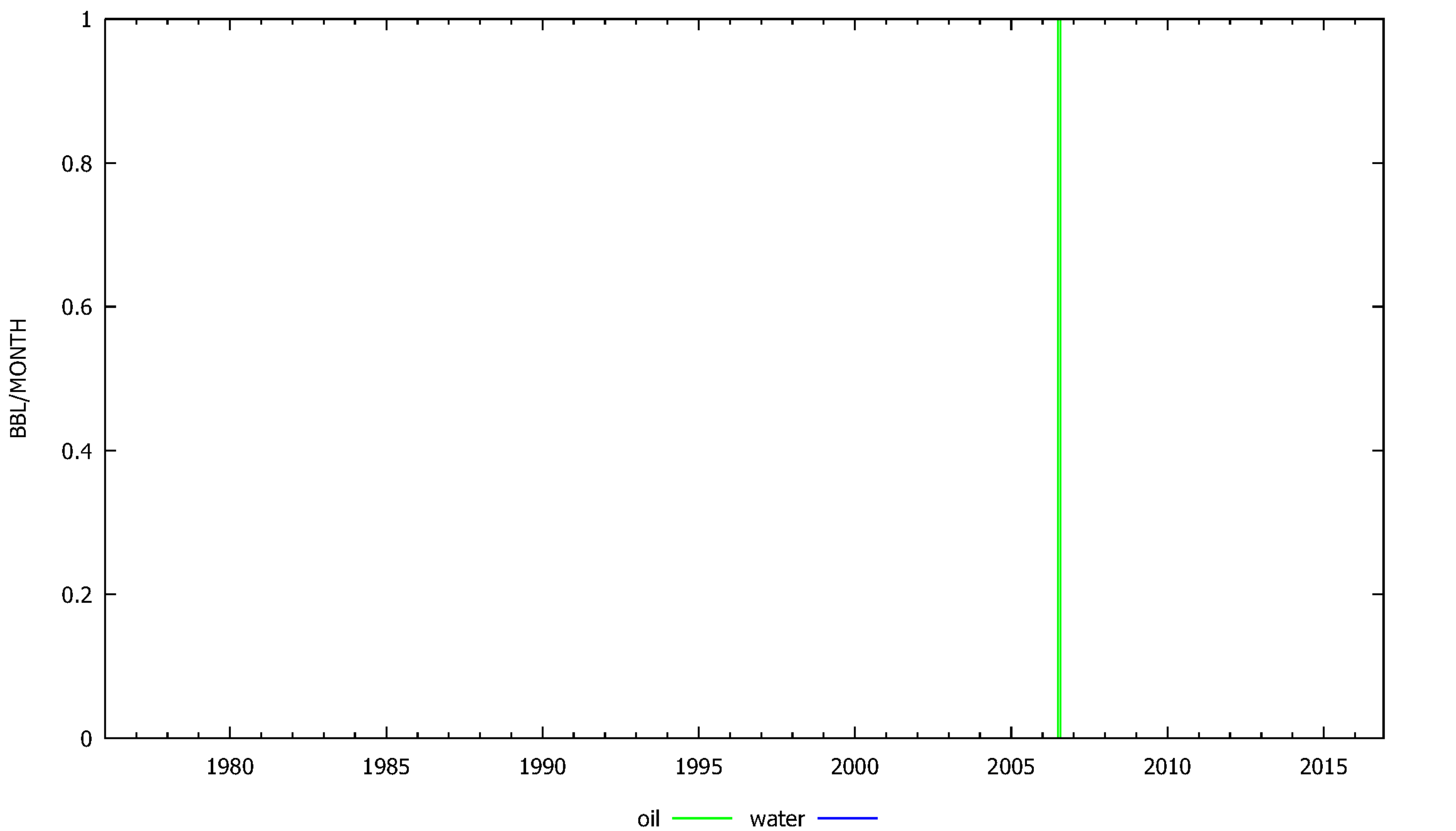
WELL Gardett 2-20



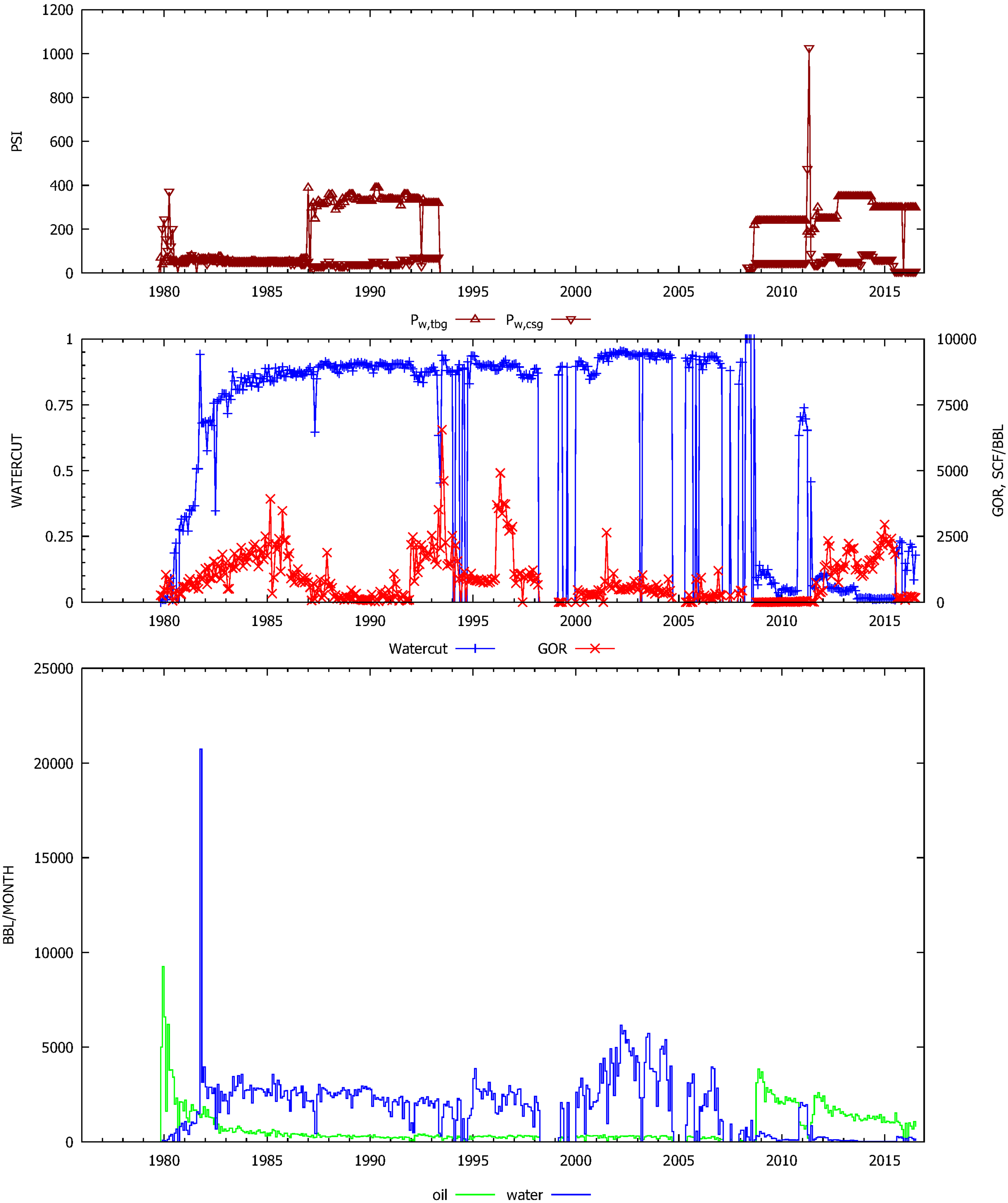
WELL Mission Adrian 4



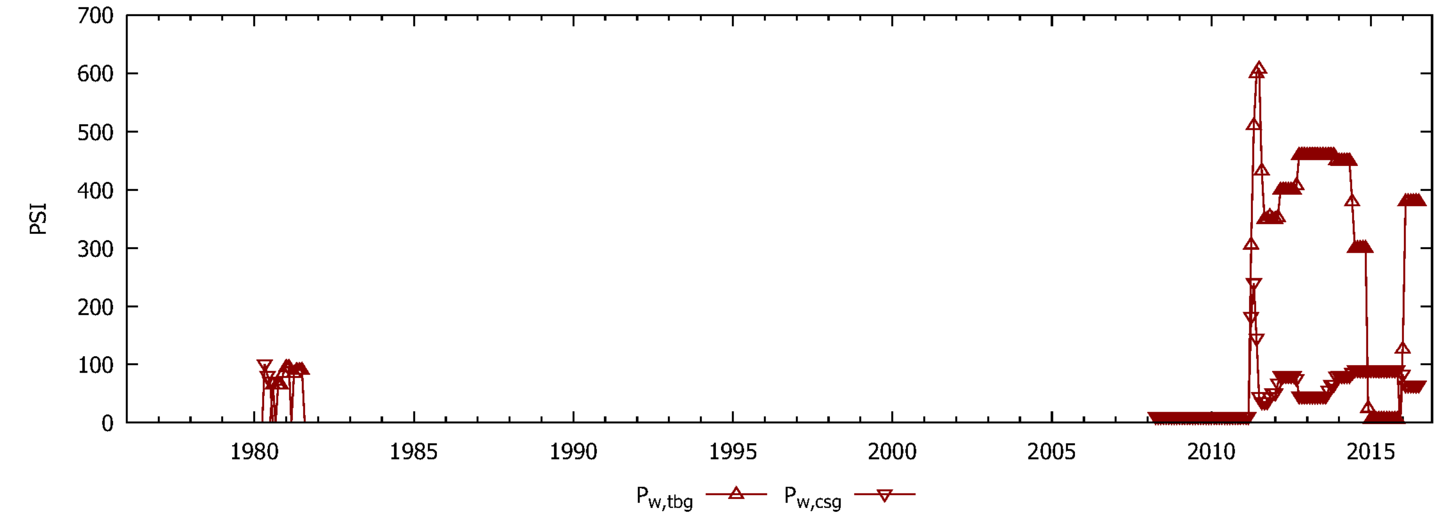


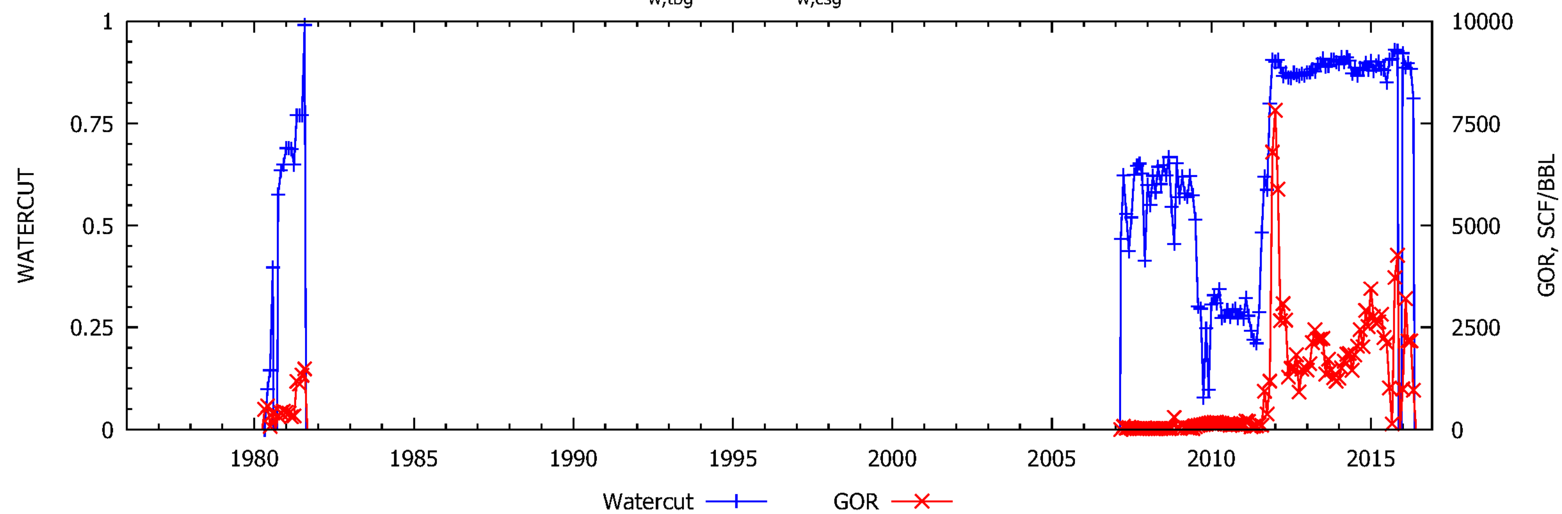


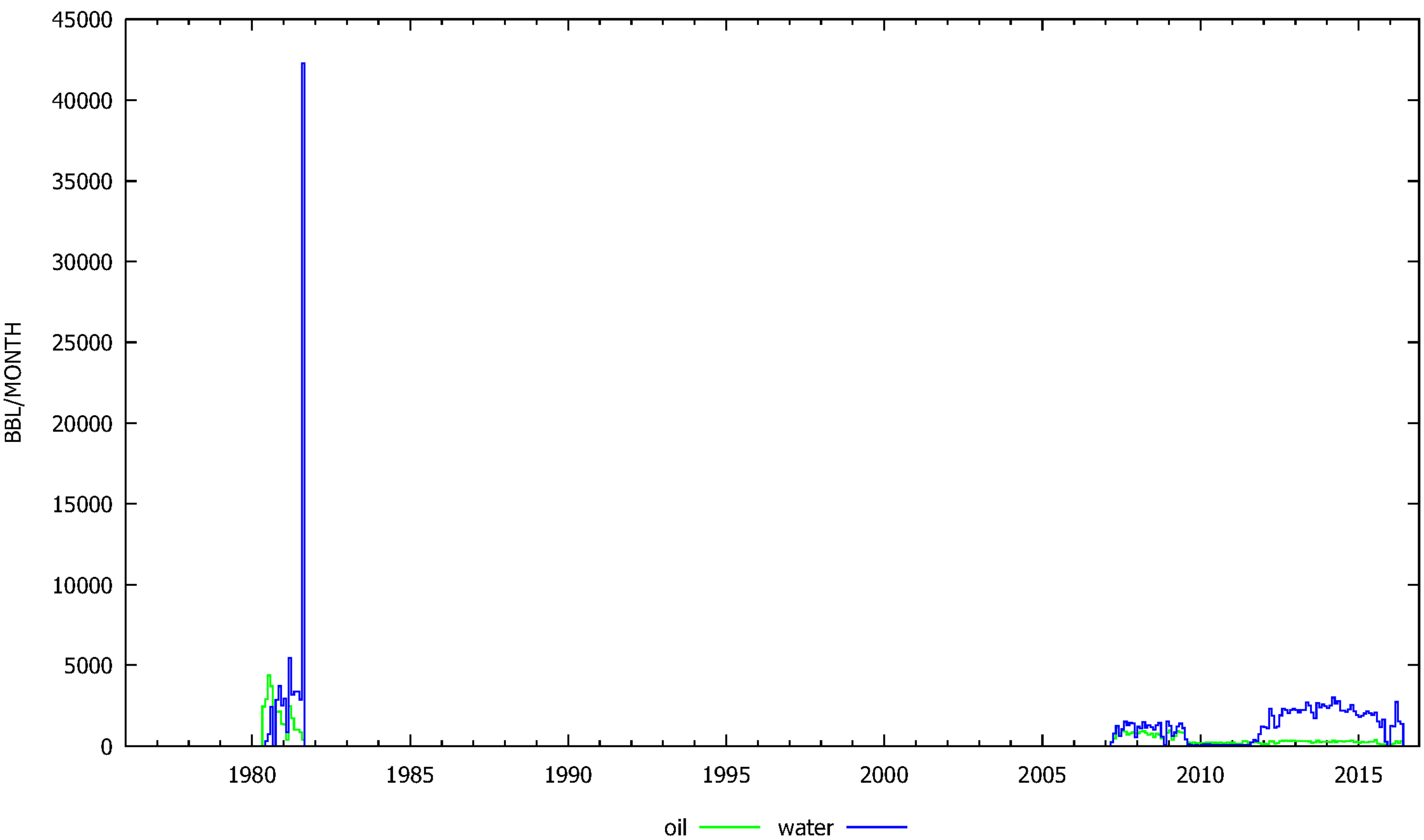
WELL Oat Mountain 1-24

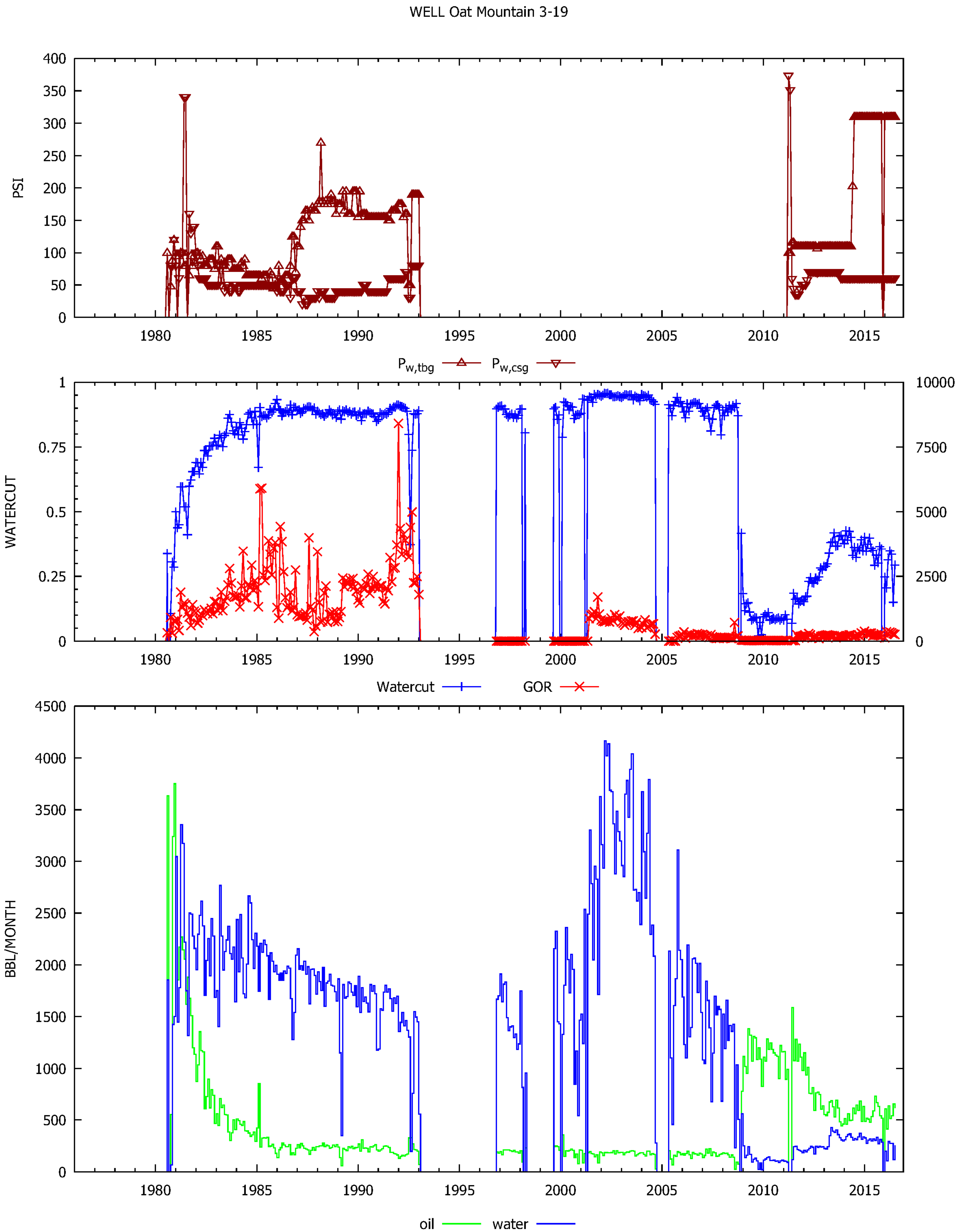


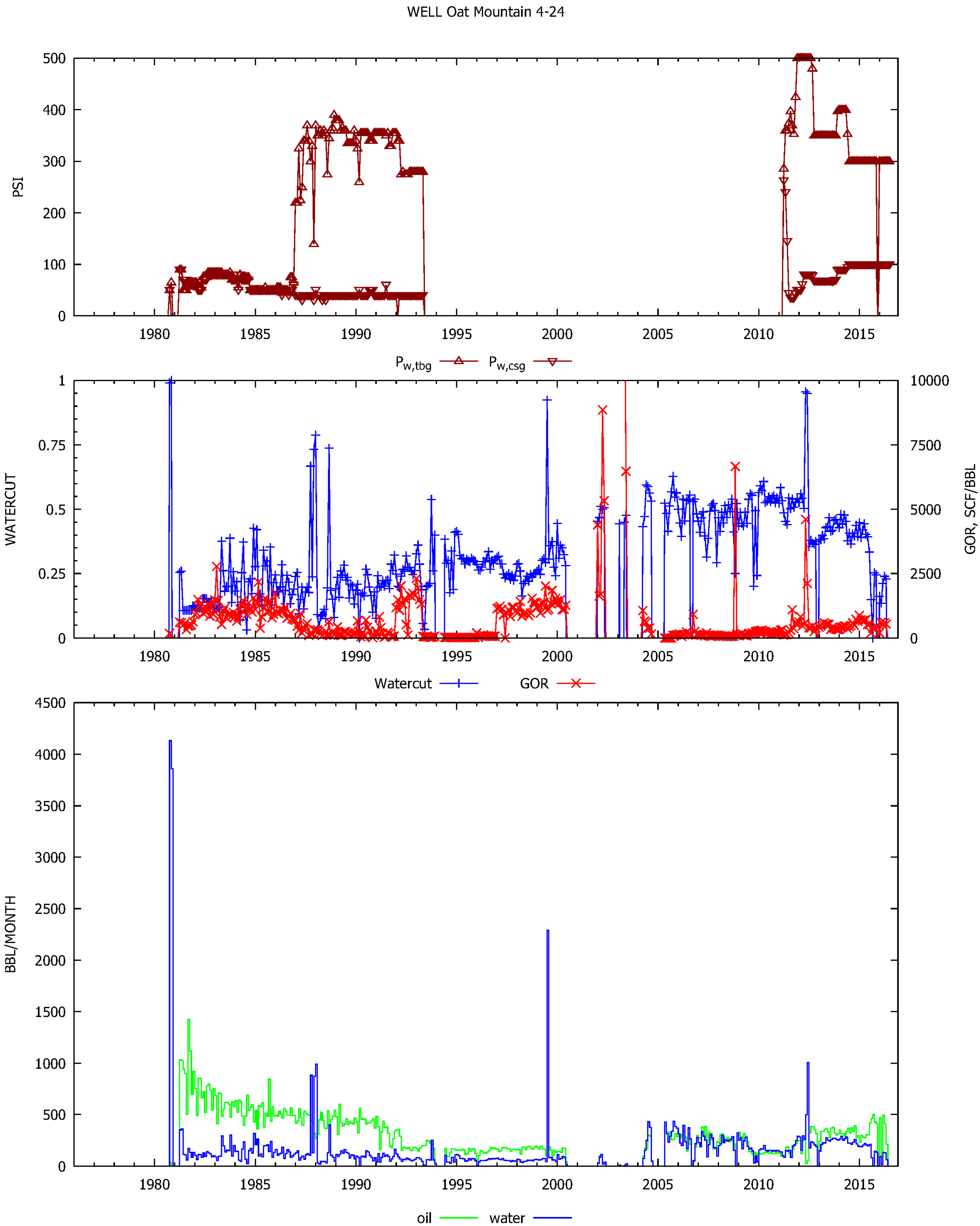
WELL Oat Mountain 2-24



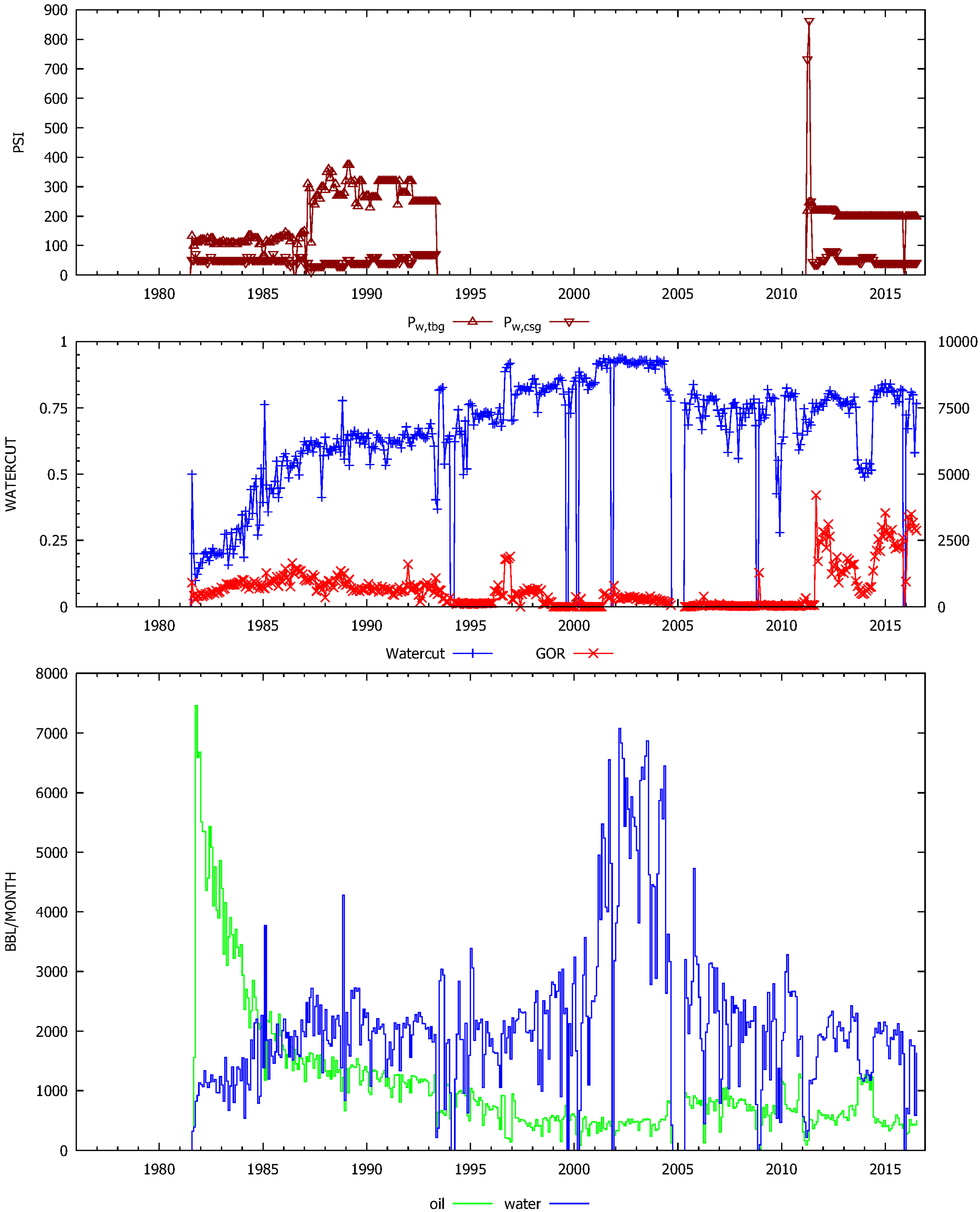




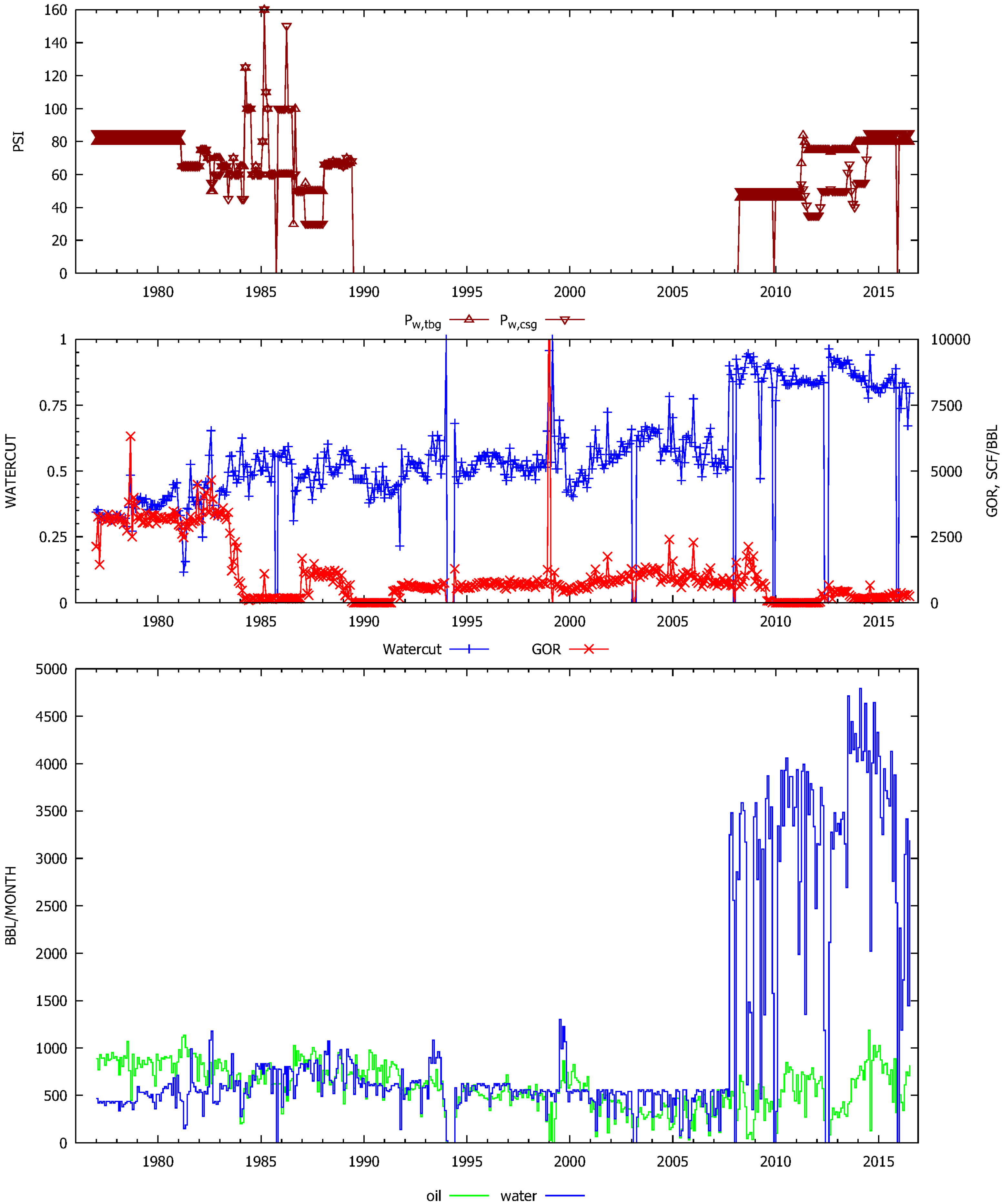

WELL Oat Mountain 3-19
PSI
400
350
300
250
200
150
100
50
0
1980
1985
1990
1995
2000
2005
2010
2015
P w,tbg
P w,csg
WATERCUT
1
0.75
0.5
0.25
0
GOR, SCF/BBL
10000
7500
5000
2500
0
Watercut
GOR
BBL/MONTH
4500
4000
3500
3000
2500
2000
1500
1000
500
0
oil
water


WELL Oat Mountain 4-24
PSI
500
400
300
200
100
0
1980
1985
1990
1995
2000
2005
2010
2015
P_w,tbg
P_w,csg
WATERCUT
GOR, SCF/BBL
1
0.75
0.5
0.25
10000
7500
5000
2500
Watercut
GOR
BBL/MONTH
4500
4000
3500
3000
2500
2000
1500
1000
oil
water

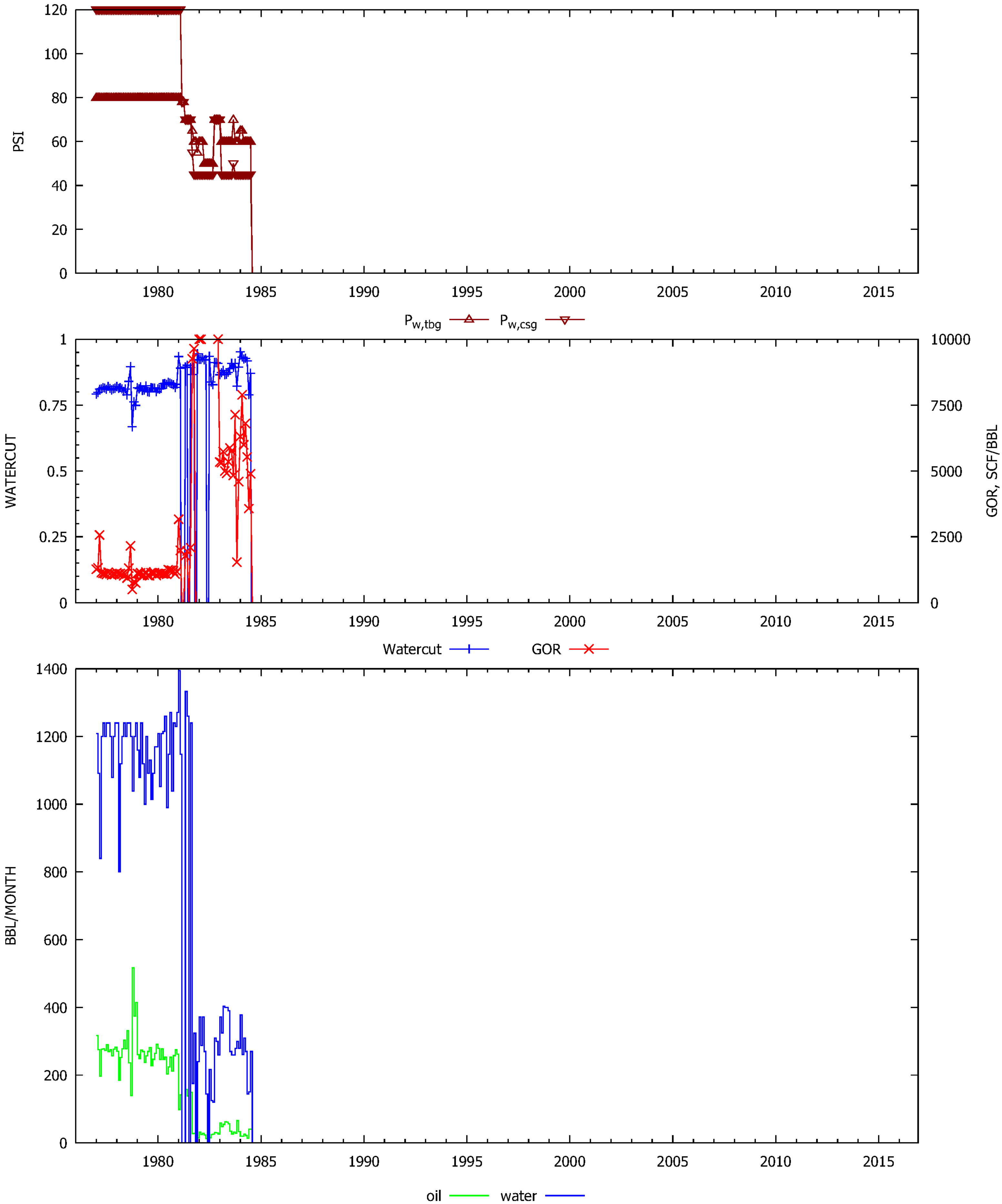
WELL Oat Mountain 5-19



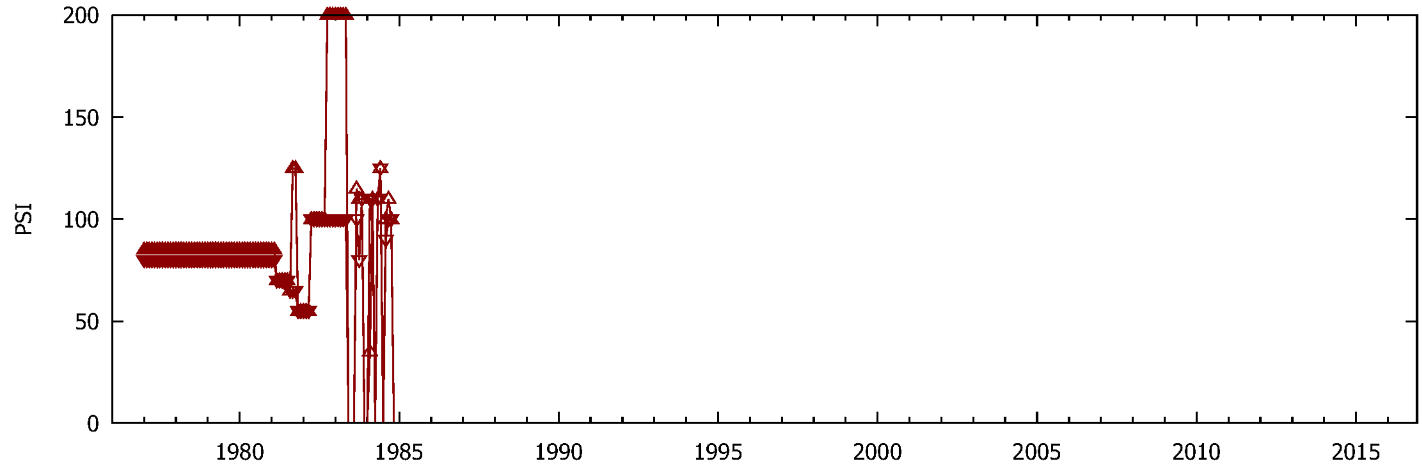
WELL Orcutt 1

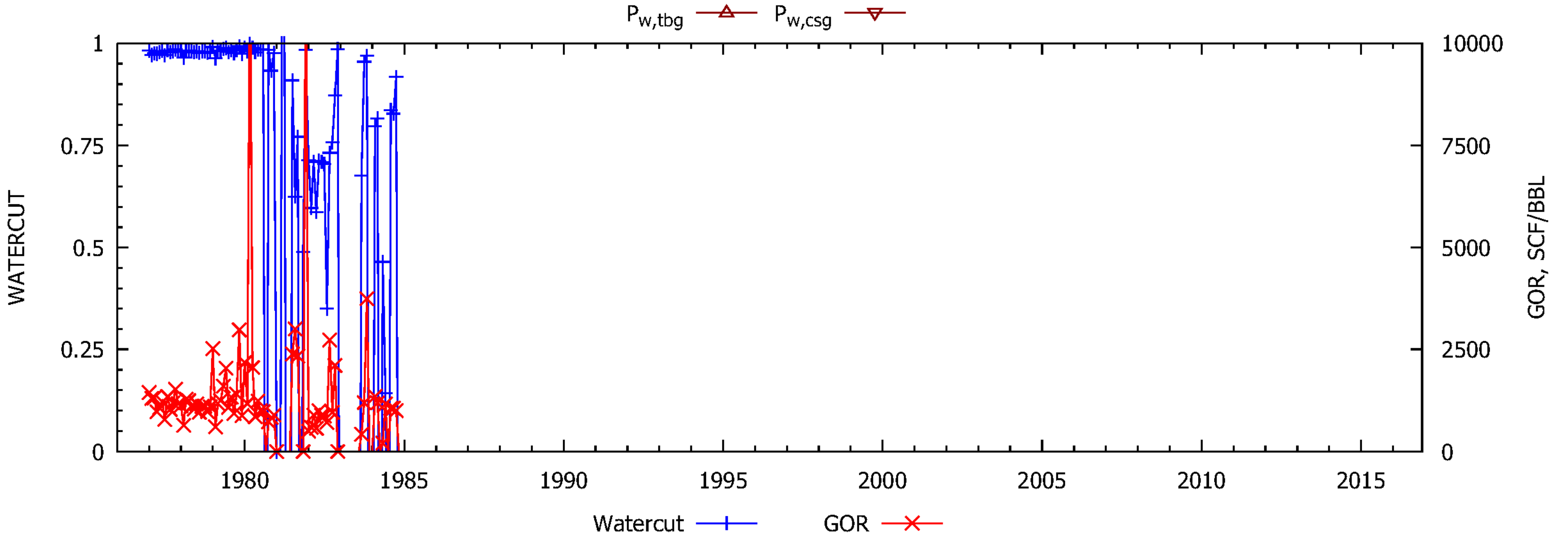


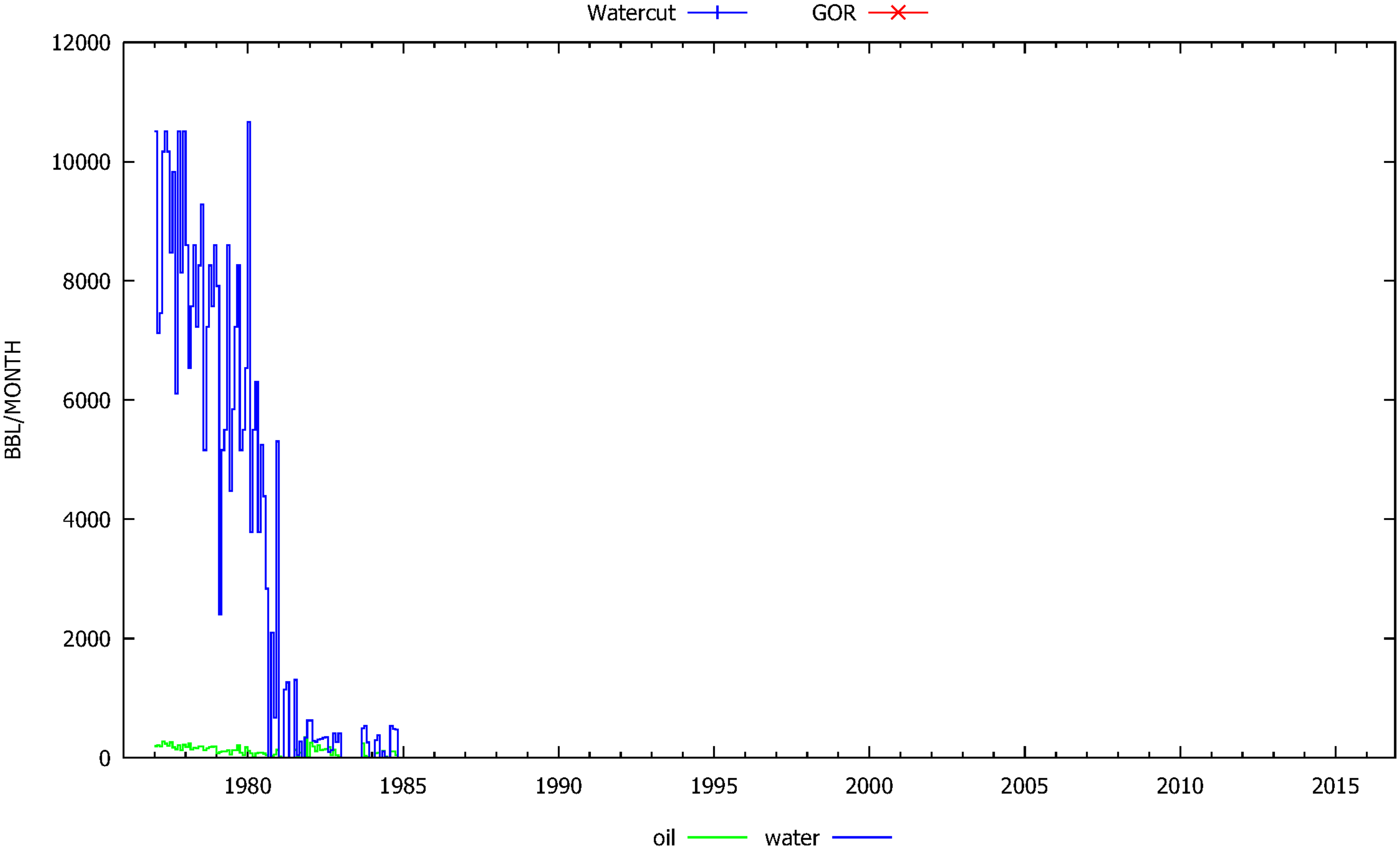
WELL Orcutt-Del Aliso-Sesnon L.W. 1



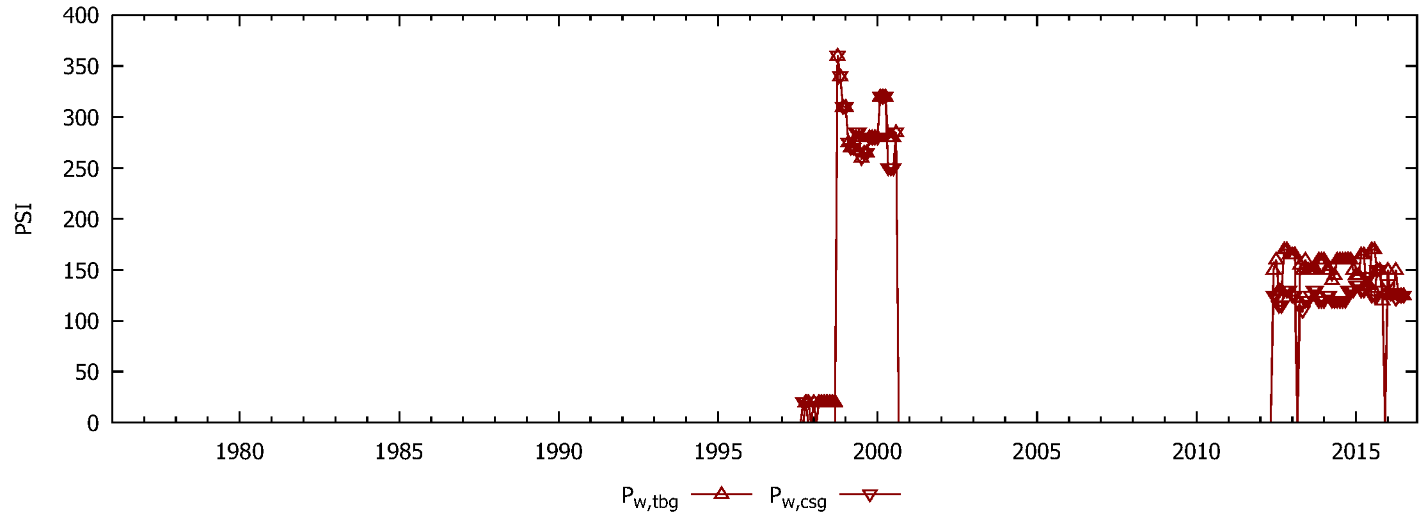
WELL Orcutt-Sesnon L.W. 1

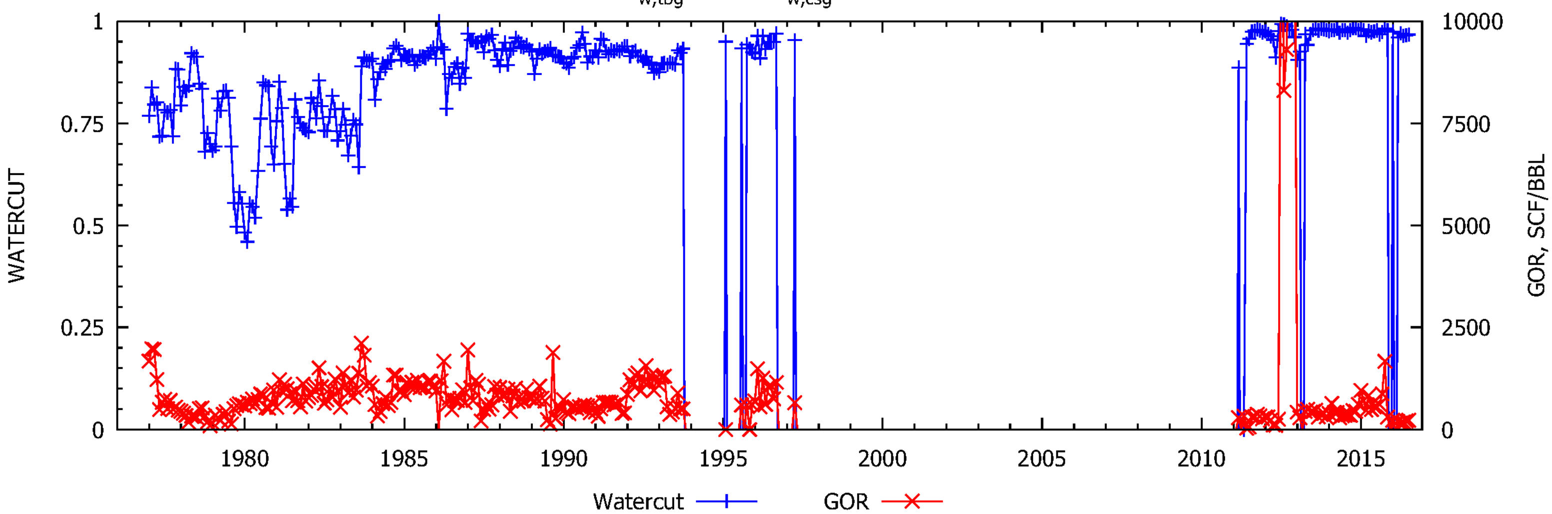


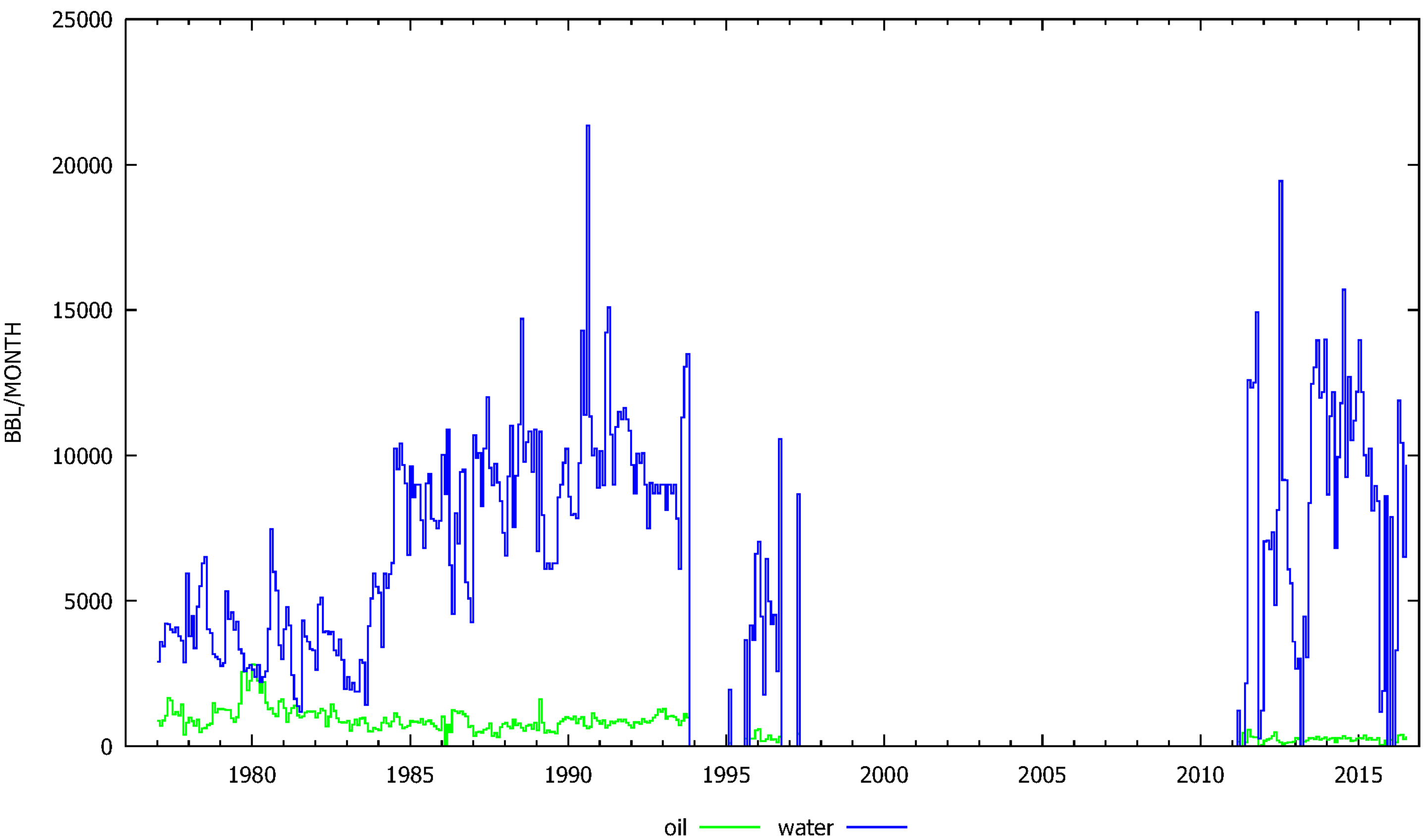




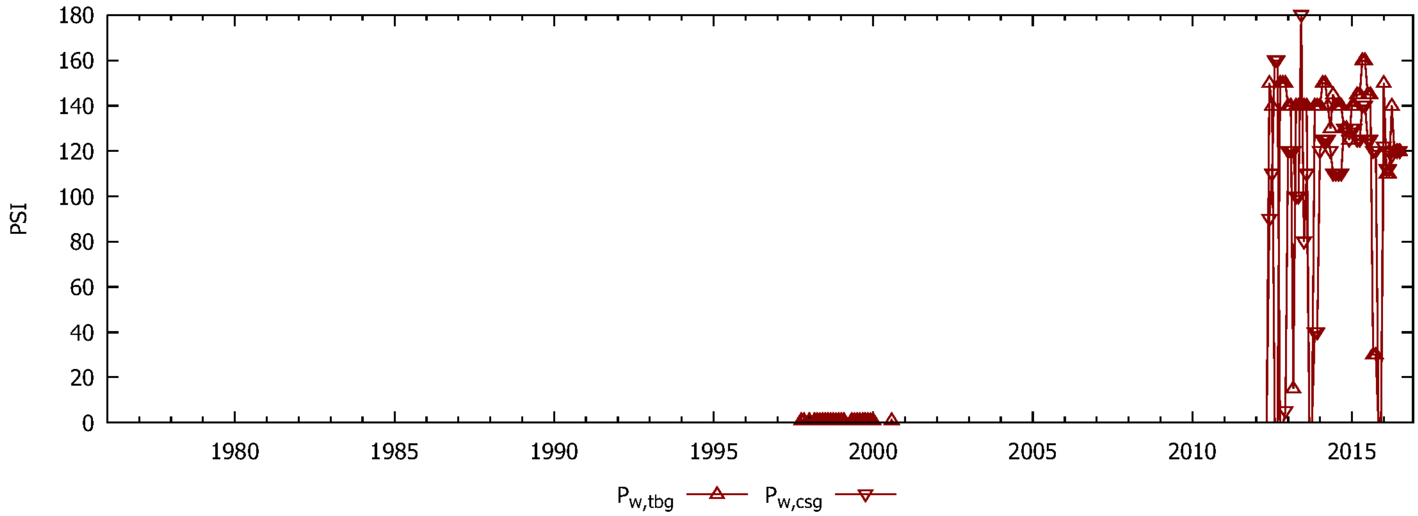
WELL Porter 1

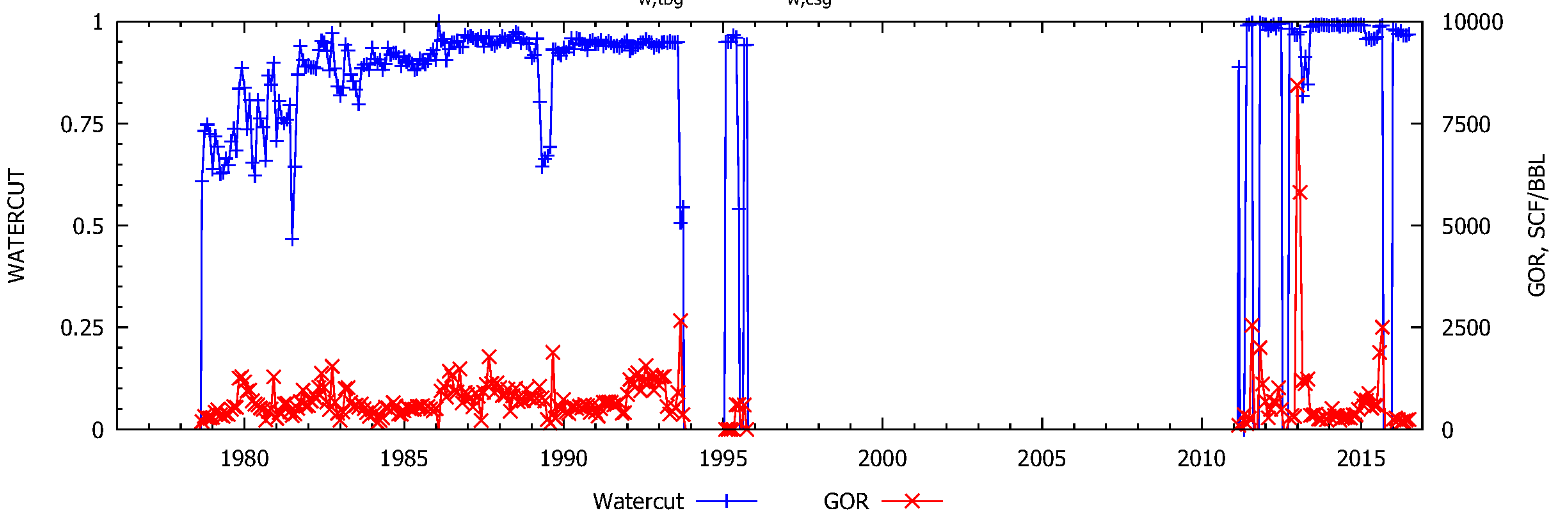


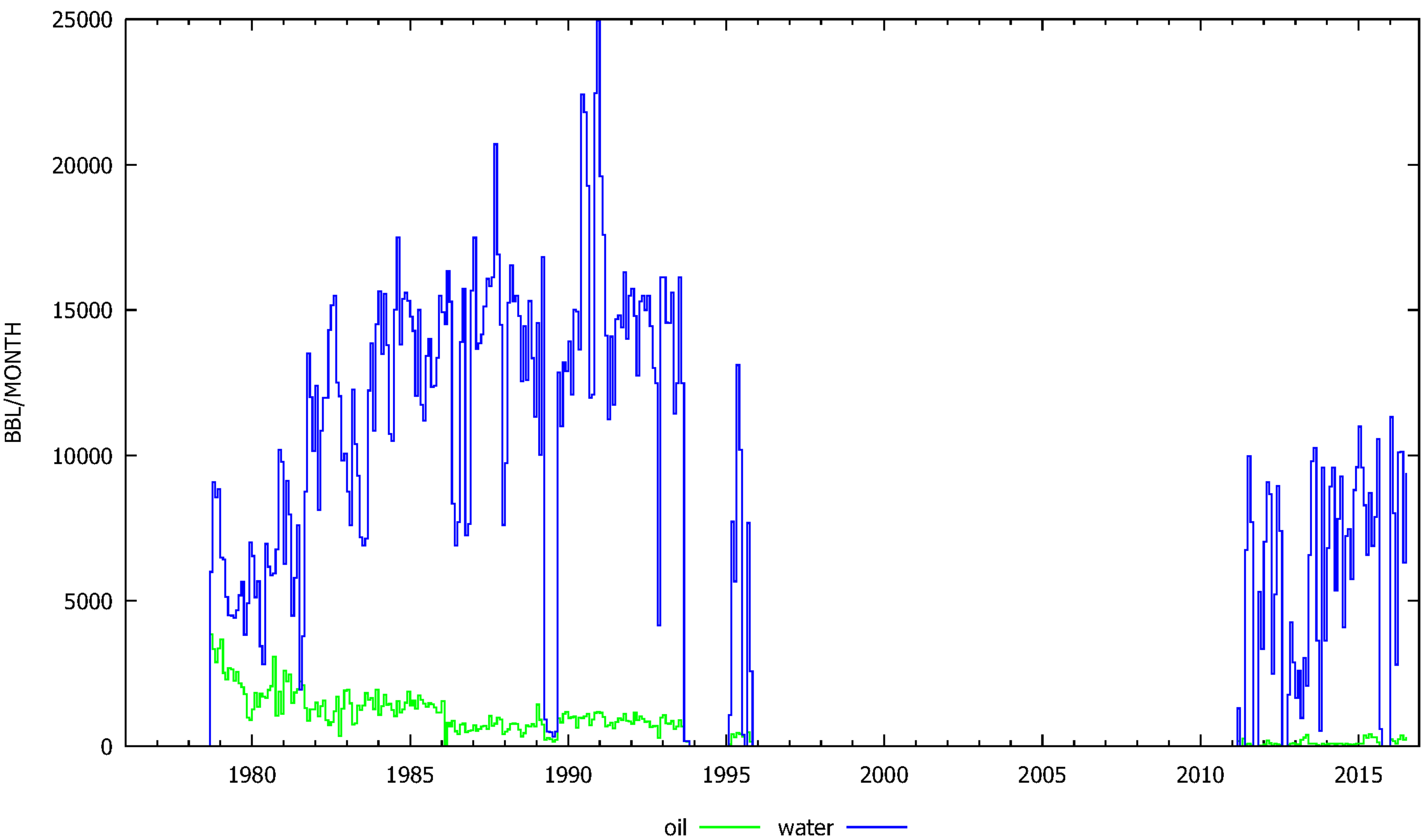


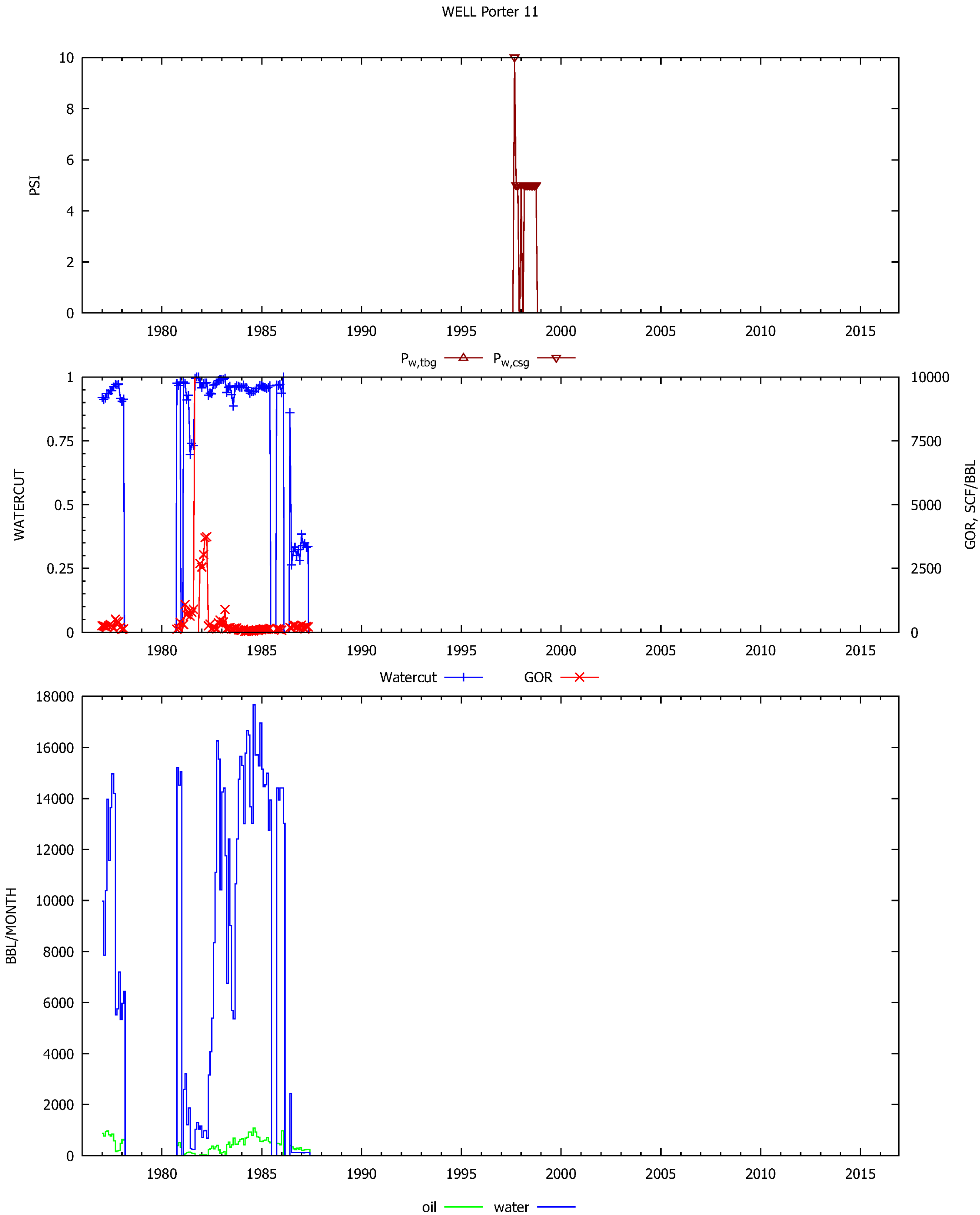


WELL Porter 10

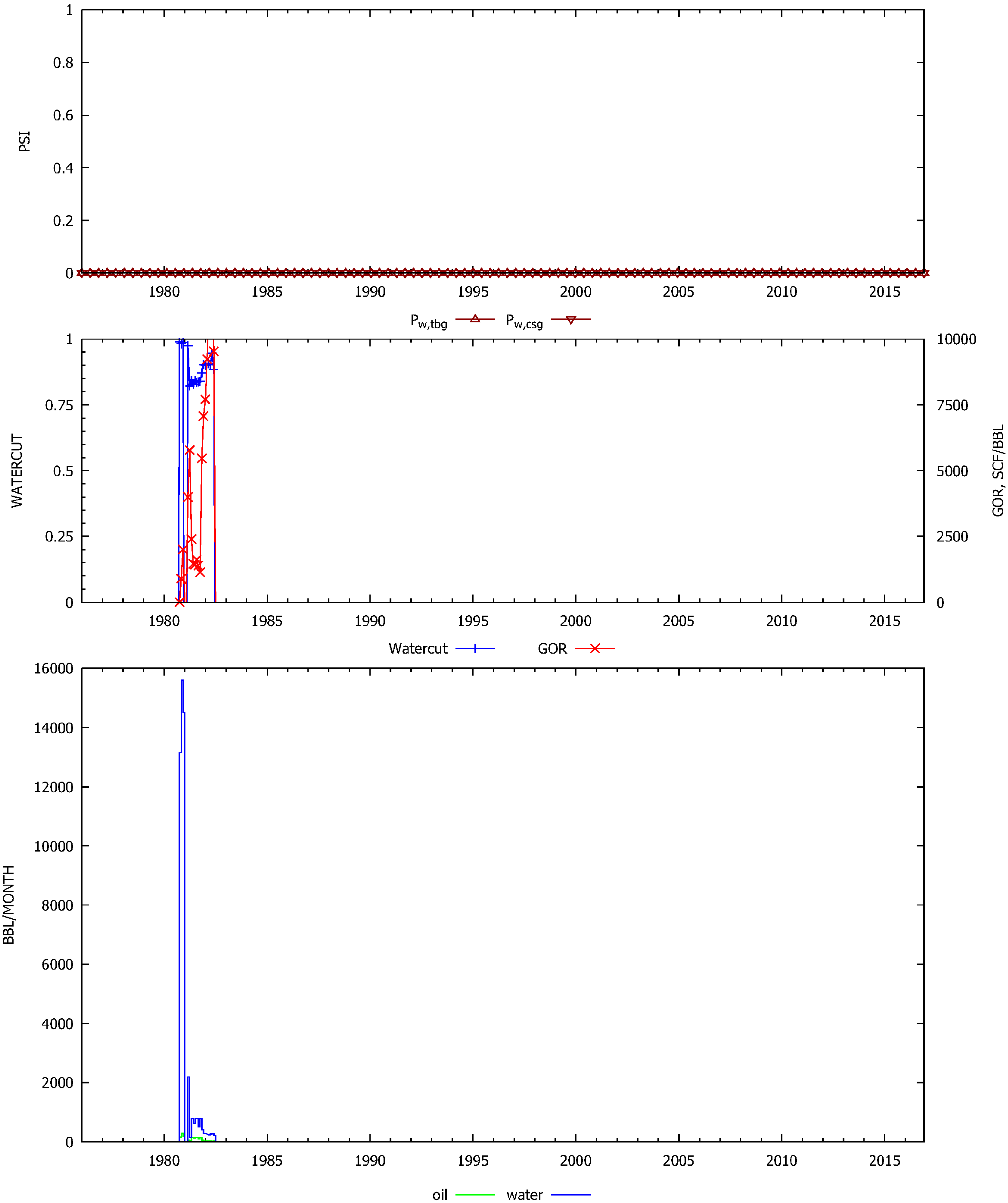




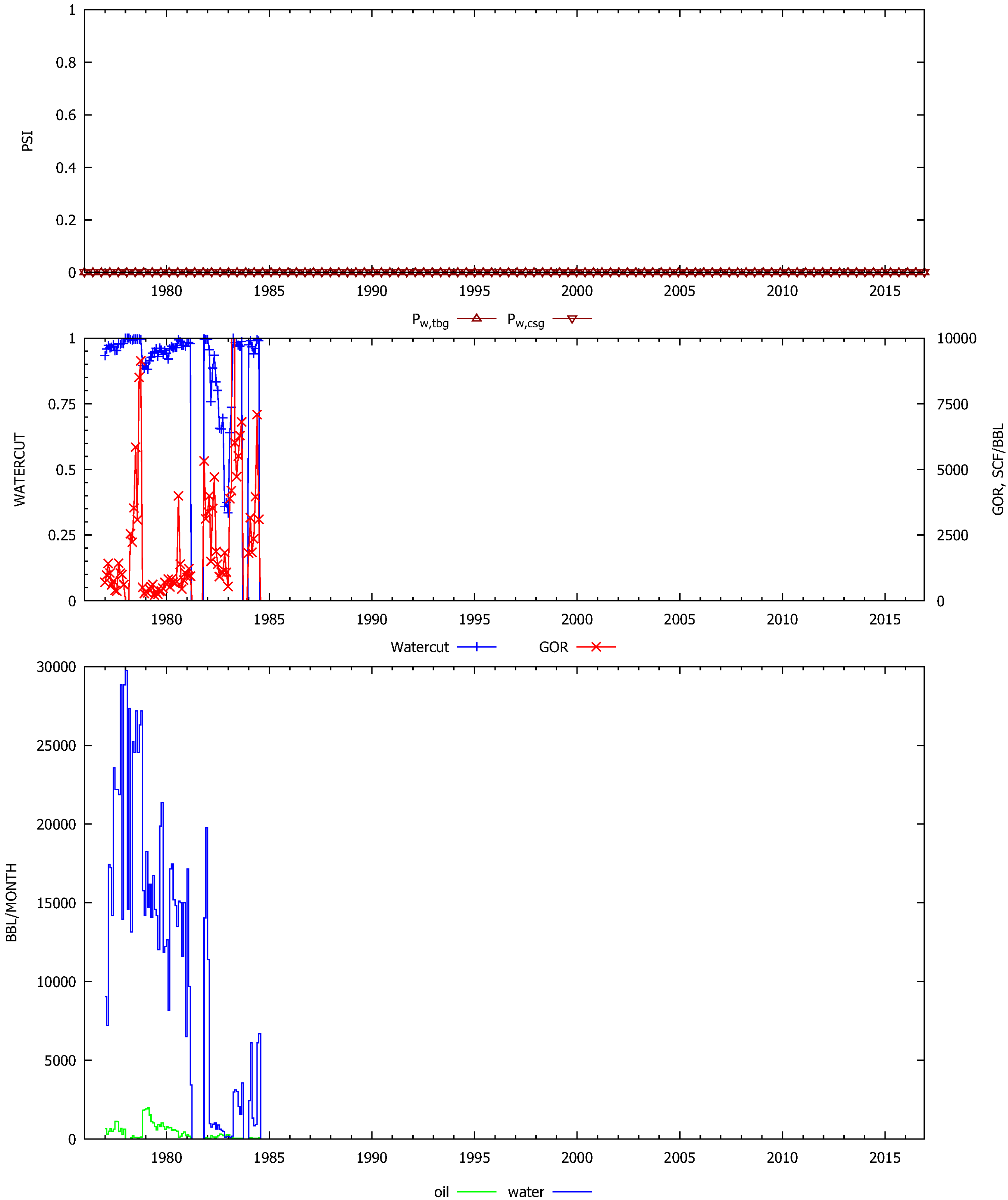



WELL Porter 11
PSI
10
8
6
4
2
0
1980
1985
1990
1995
2000
2005
2010
2015
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
1
0.75
0.5
0.25
0
10000
7500
5000
2500
0
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
oil
water

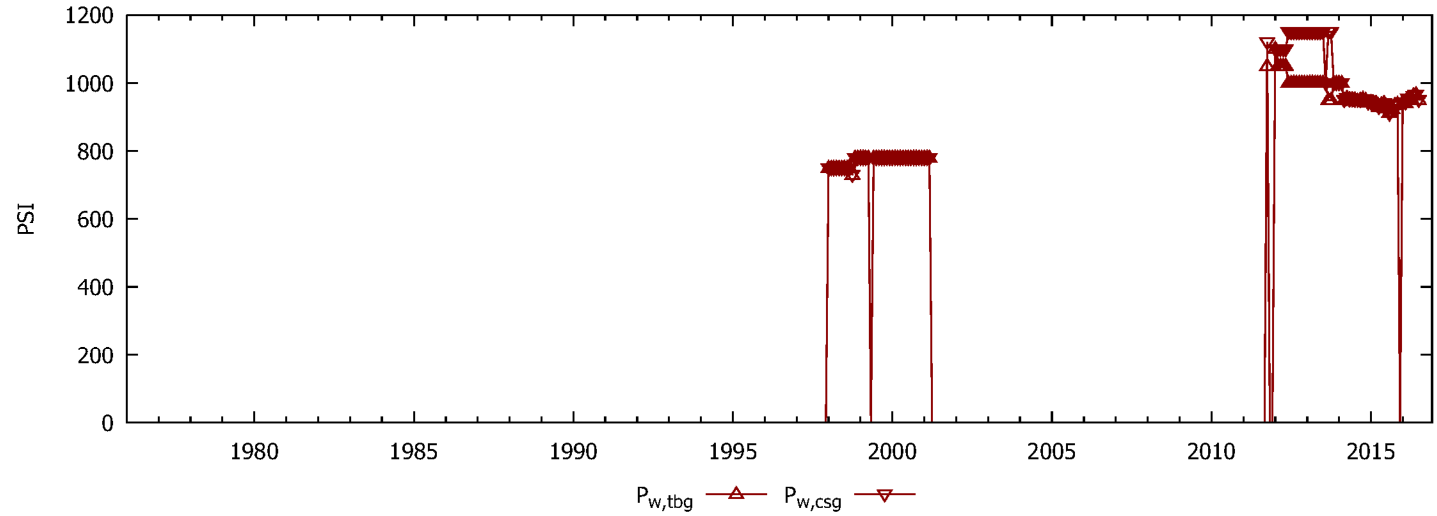
WELL Porter 12A

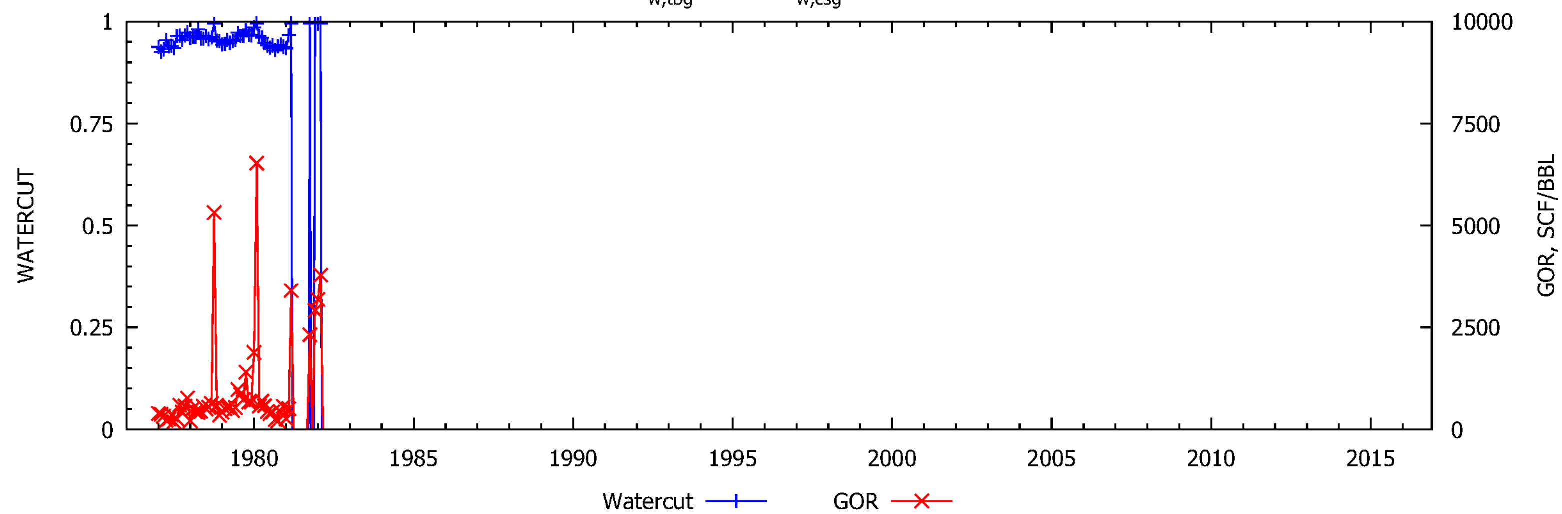


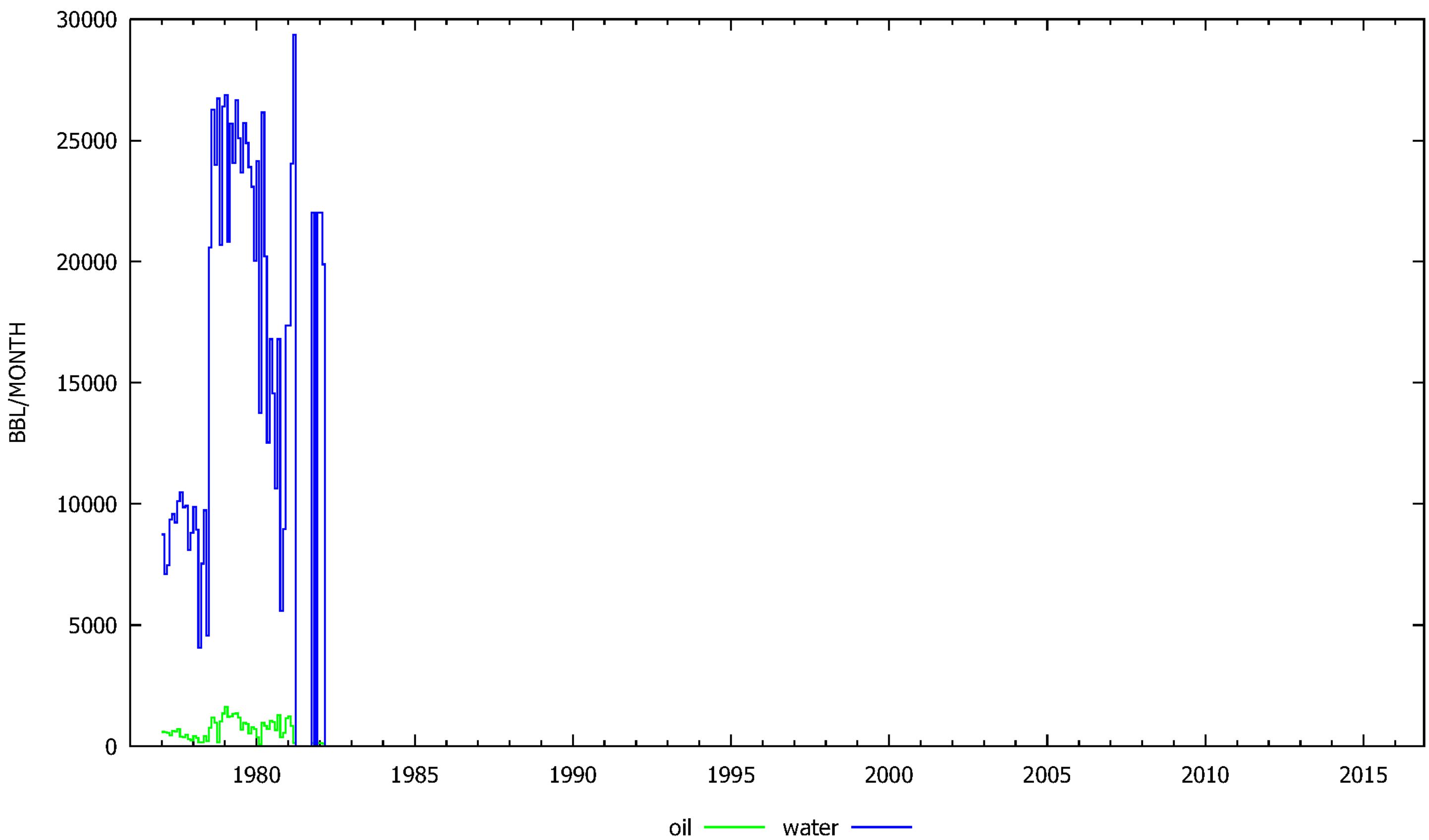
WELL Porter 13

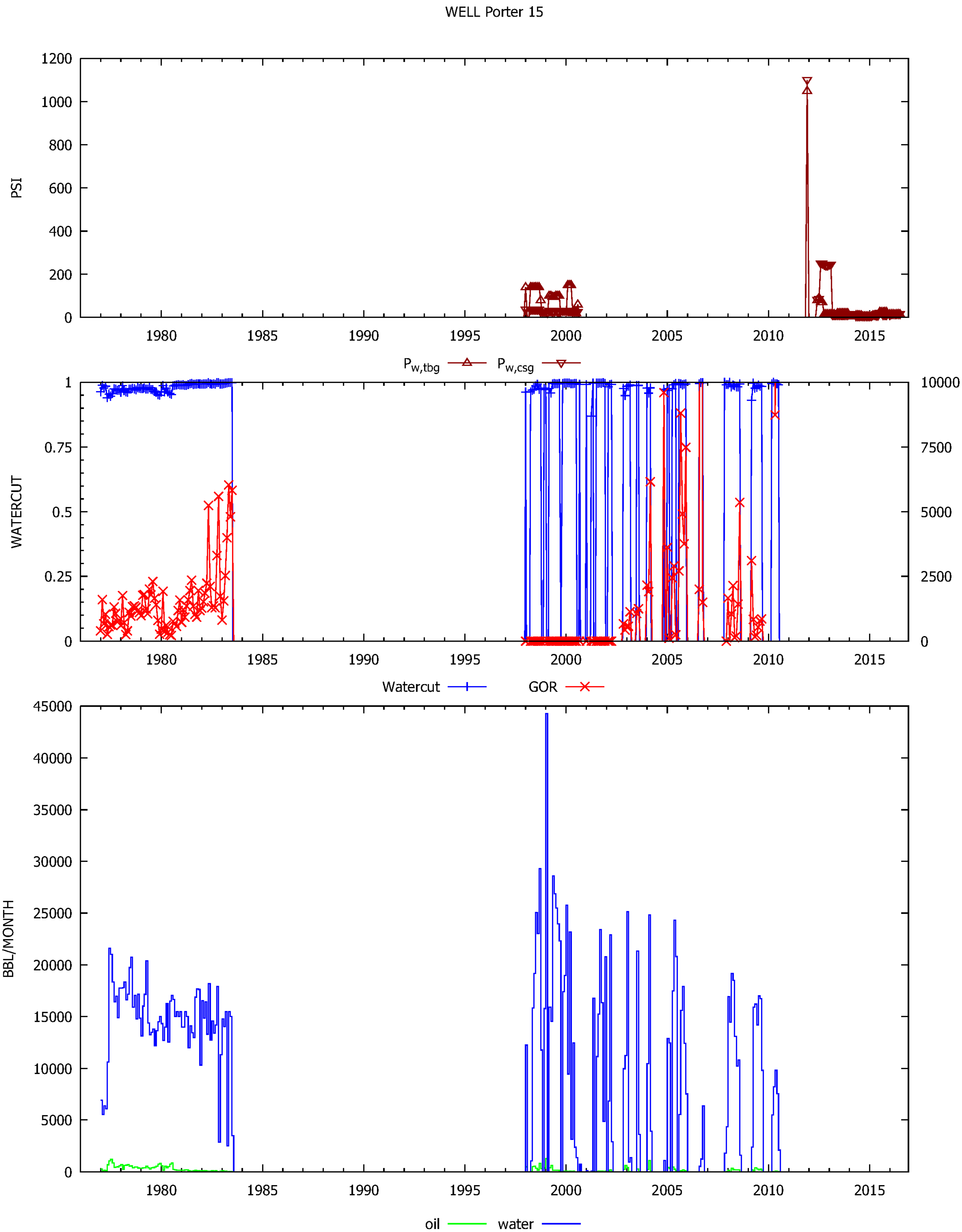


WELL Porter 14

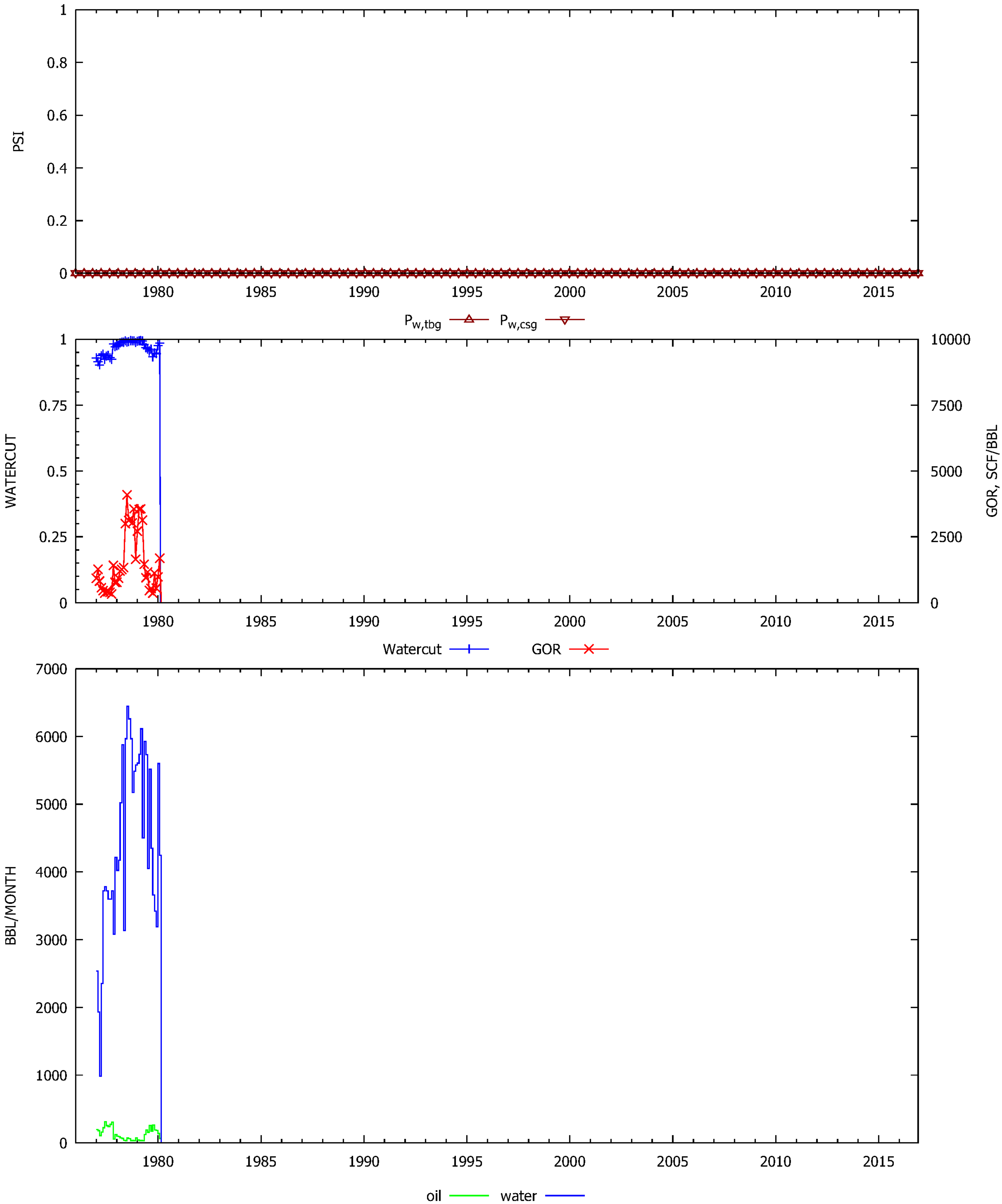


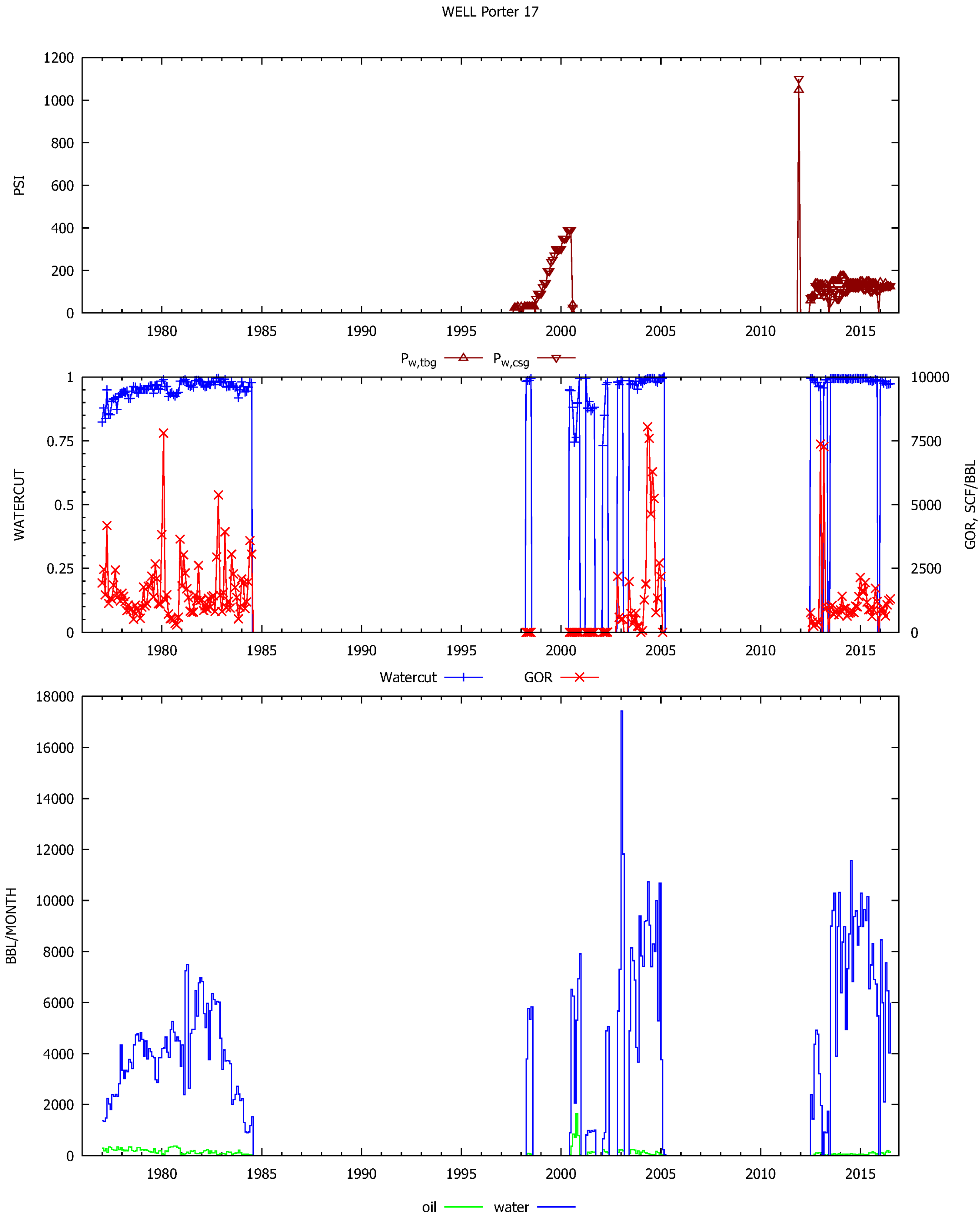





WELL Porter 15
PSI
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
oil
water
1980
1985
1990
1995
2000
2005
2010
2015

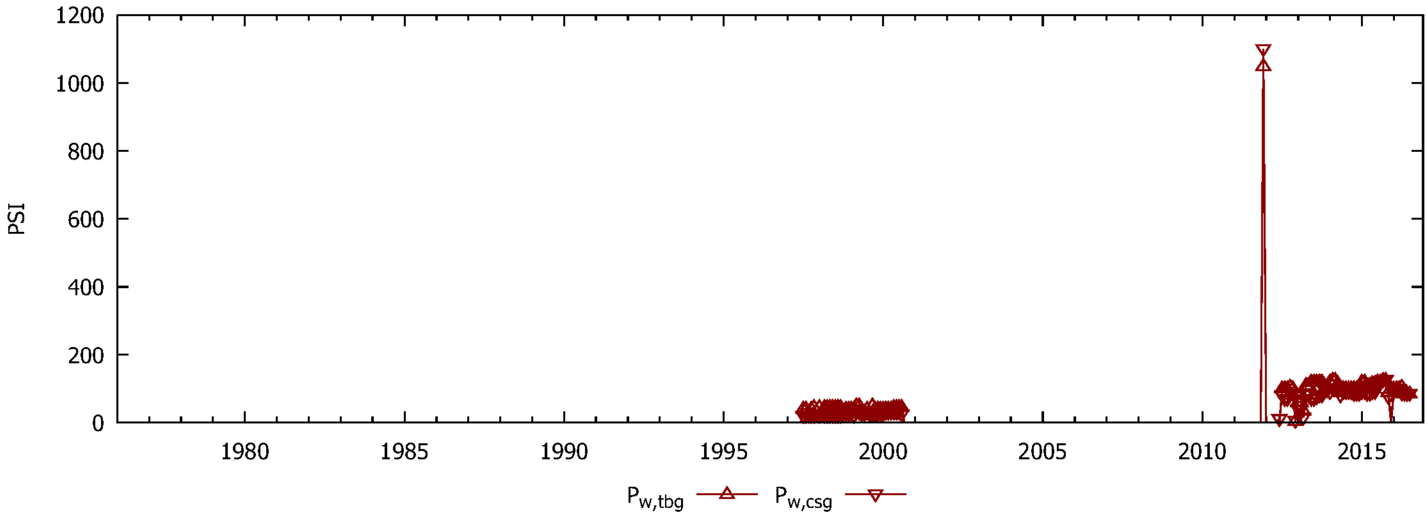
WELL Porter 16

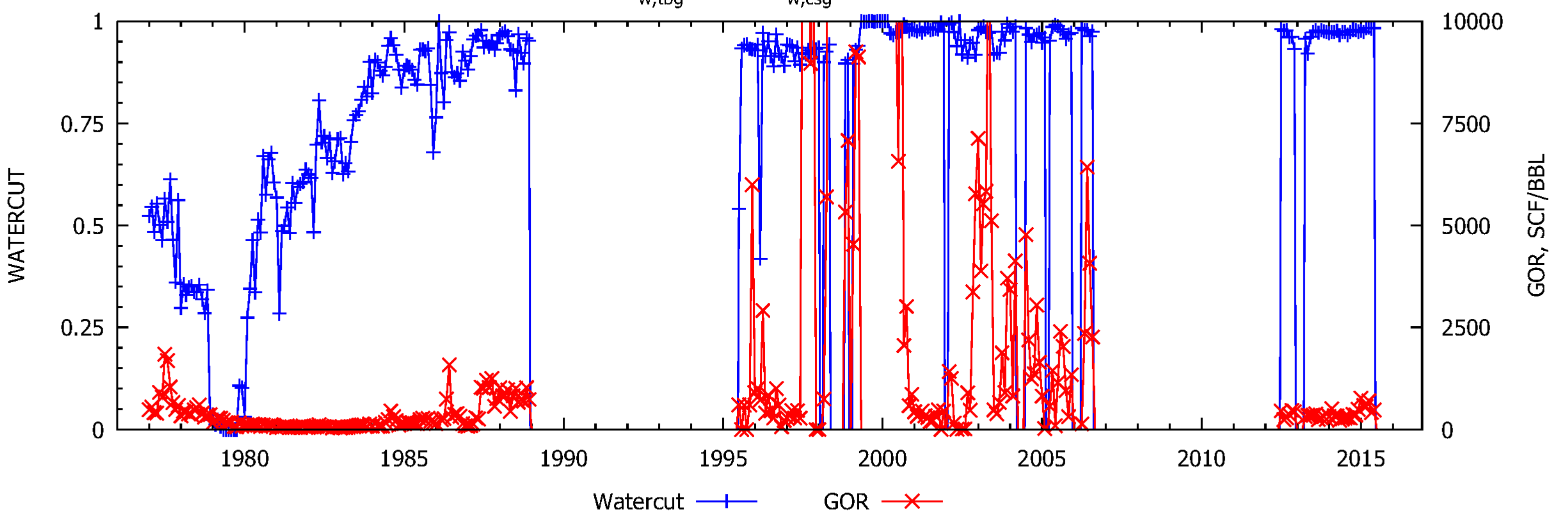


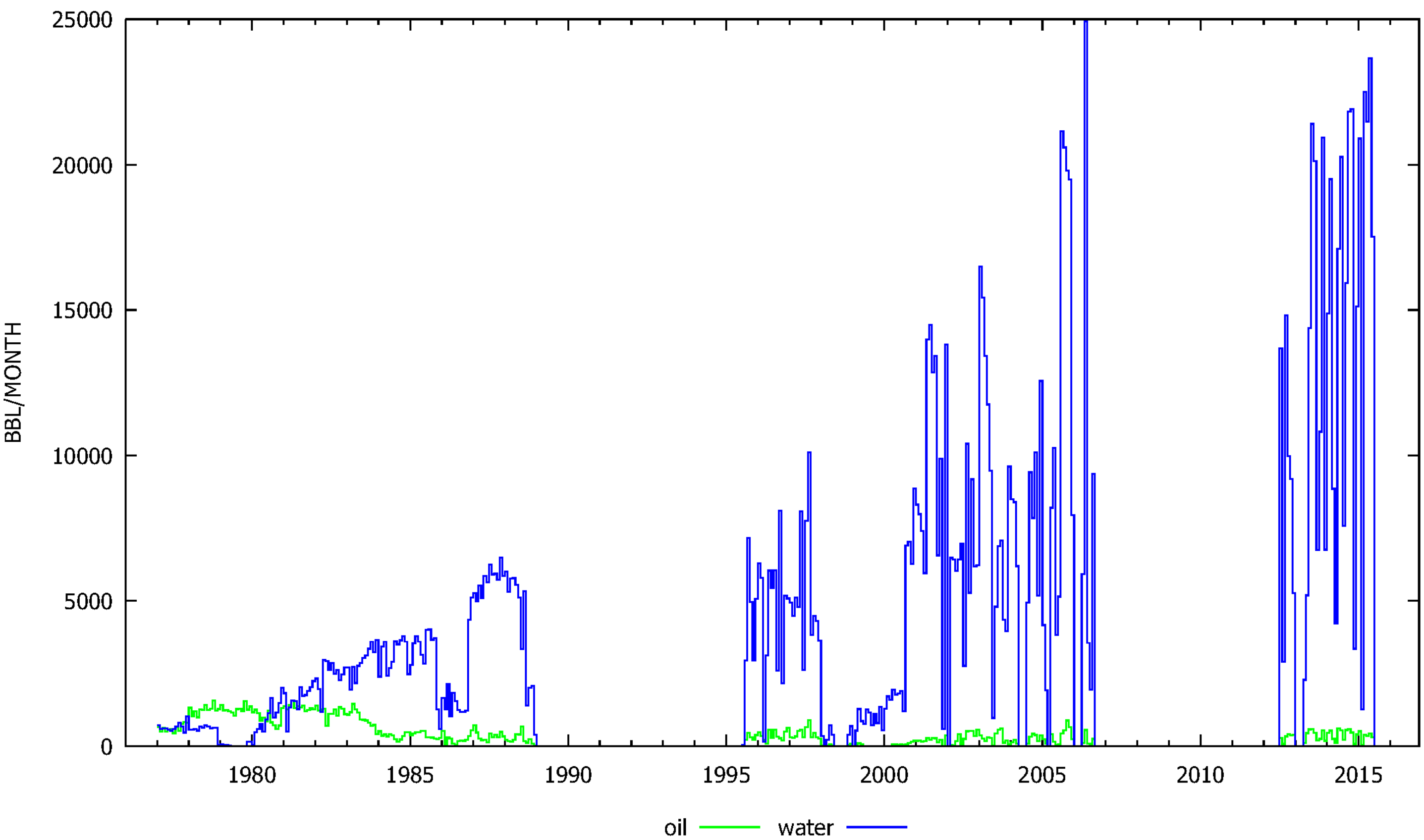


WELL Porter 17
PSI
1200
1000
800
600
400
200
0
1980
1985
1990
1995
2000
2005
2010
2015
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
1
0.75
0.5
0.25
0
10000
7500
5000
2500
0
Watercut
GOR
BBL/MONTH
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
oil
water

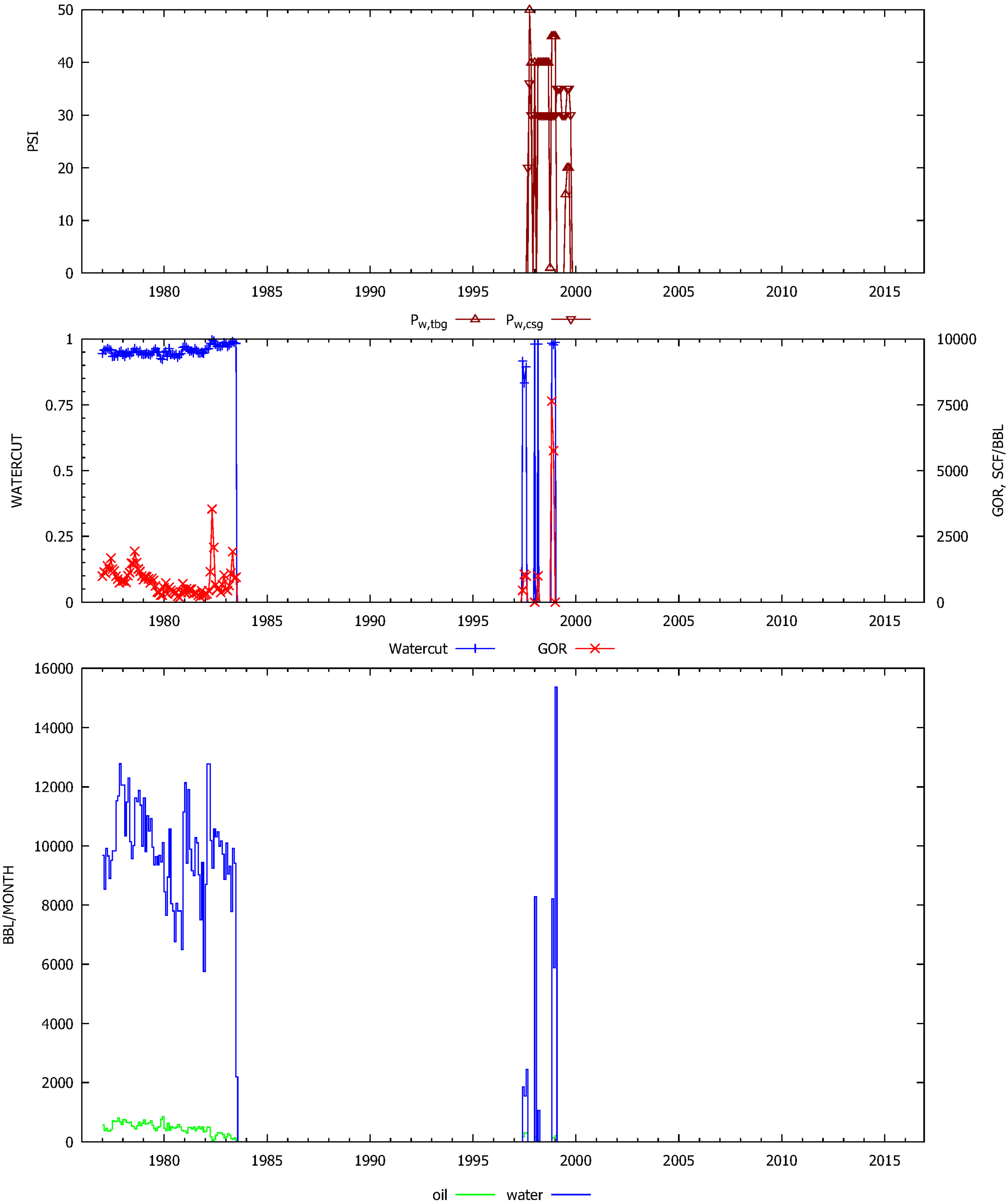
WELL Porter 18



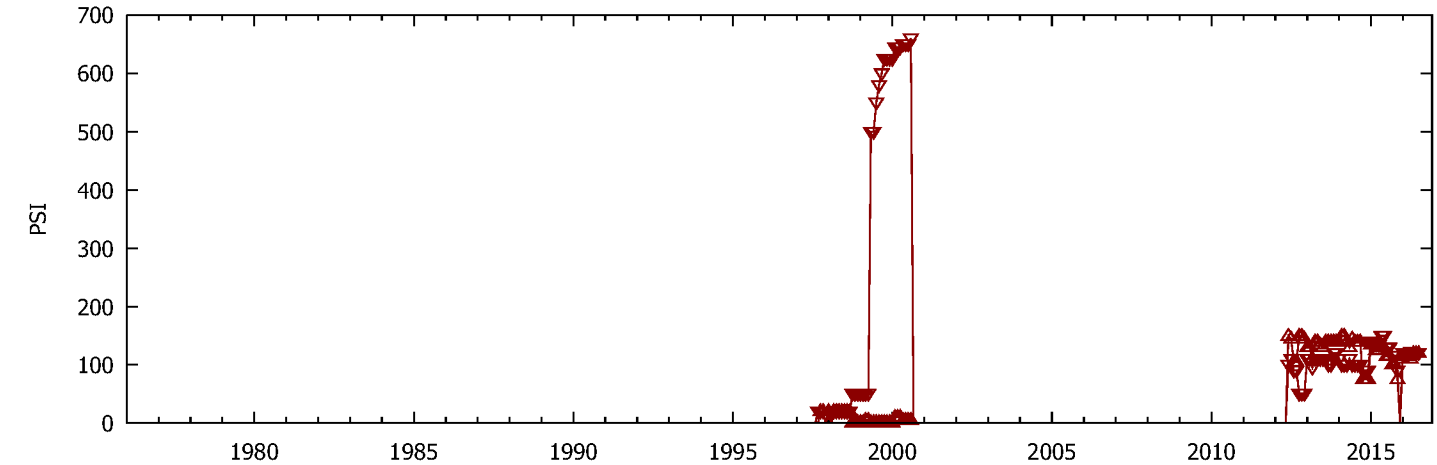


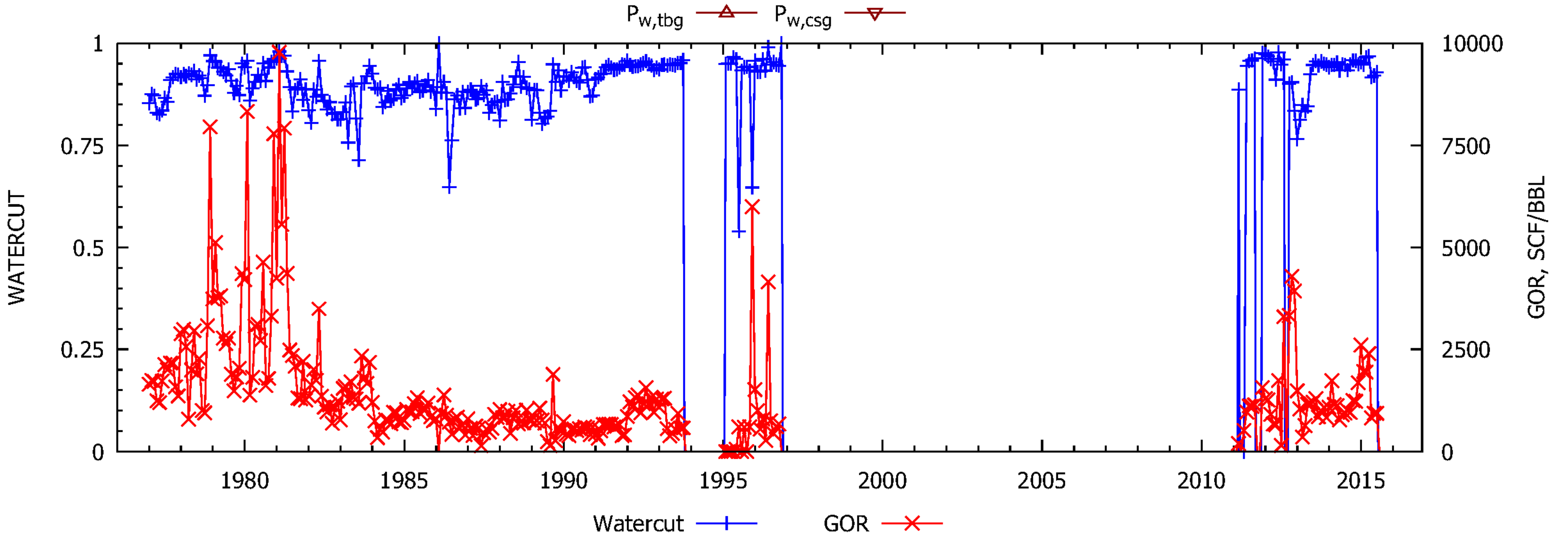


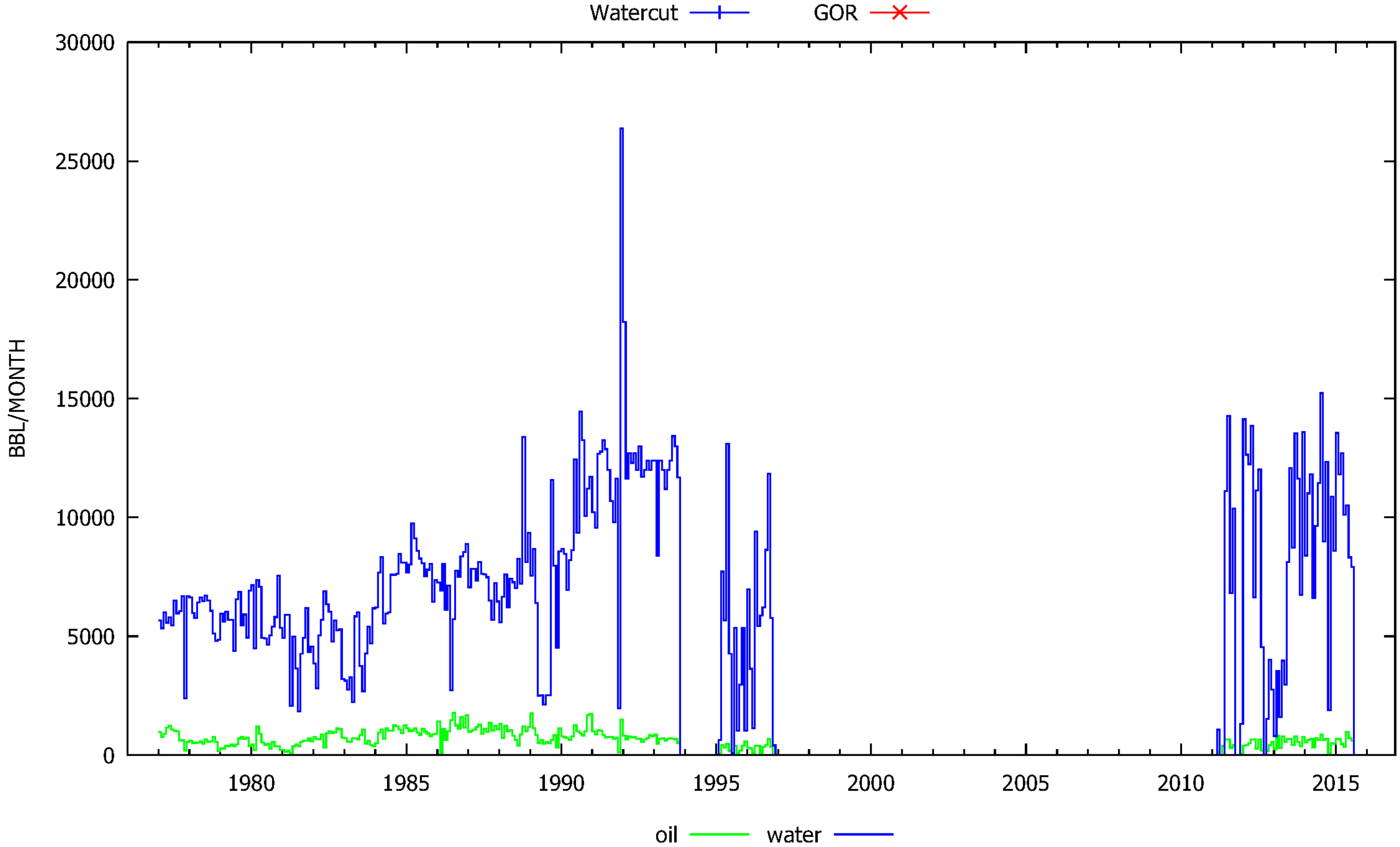
WELL Porter 19



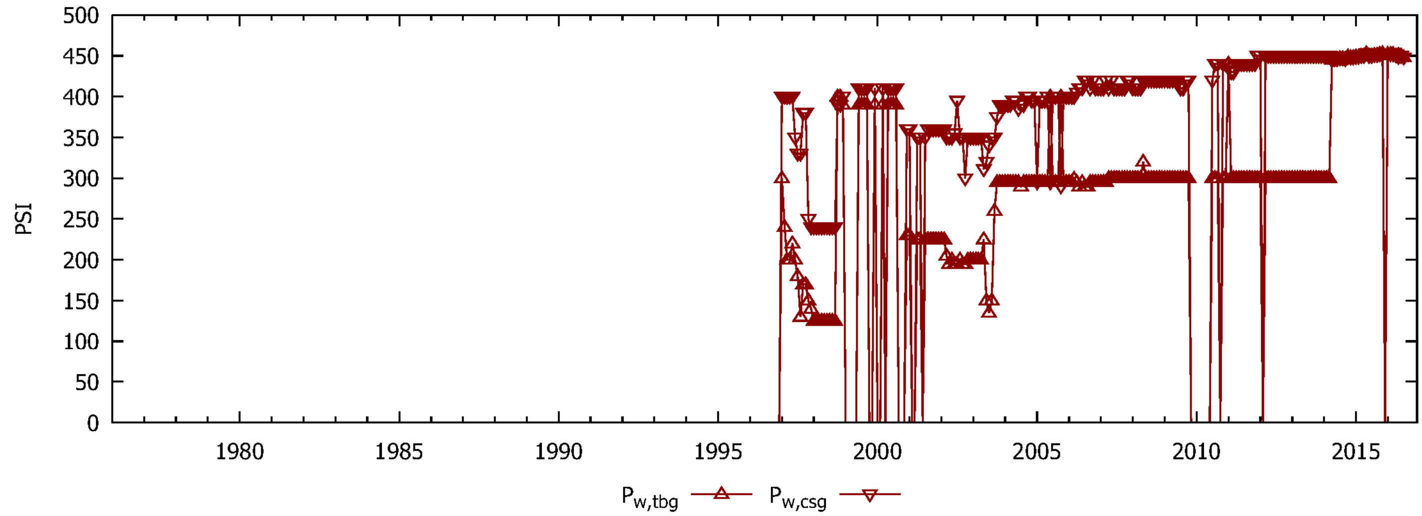
WELL Porter 2

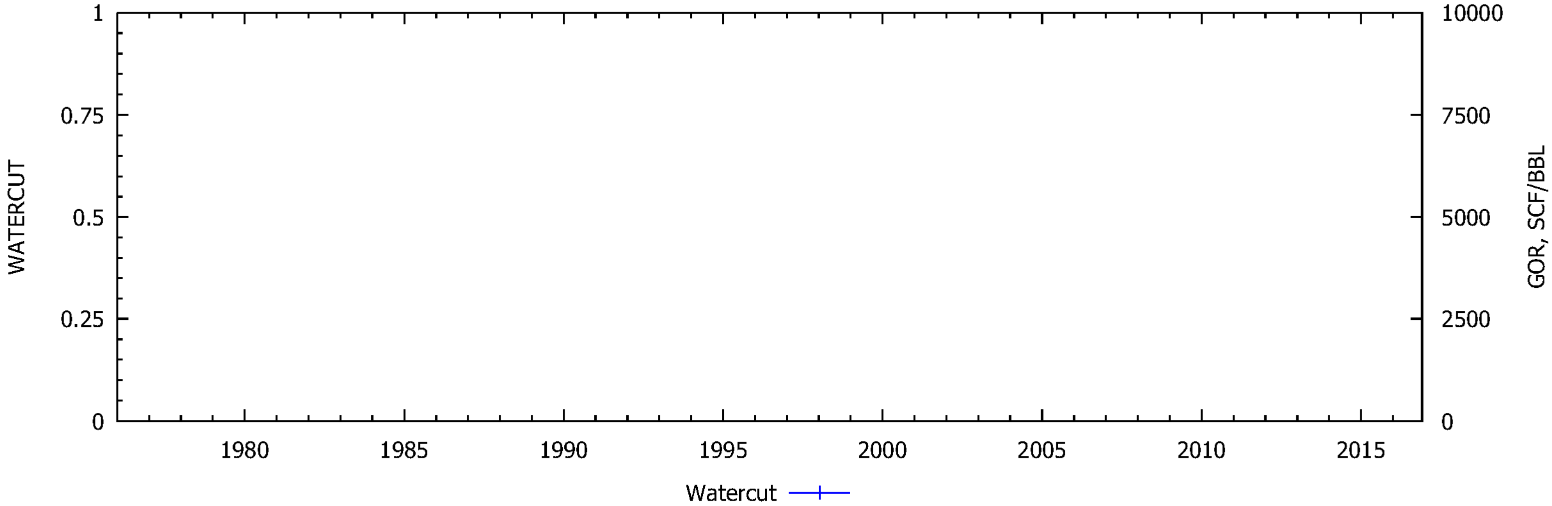


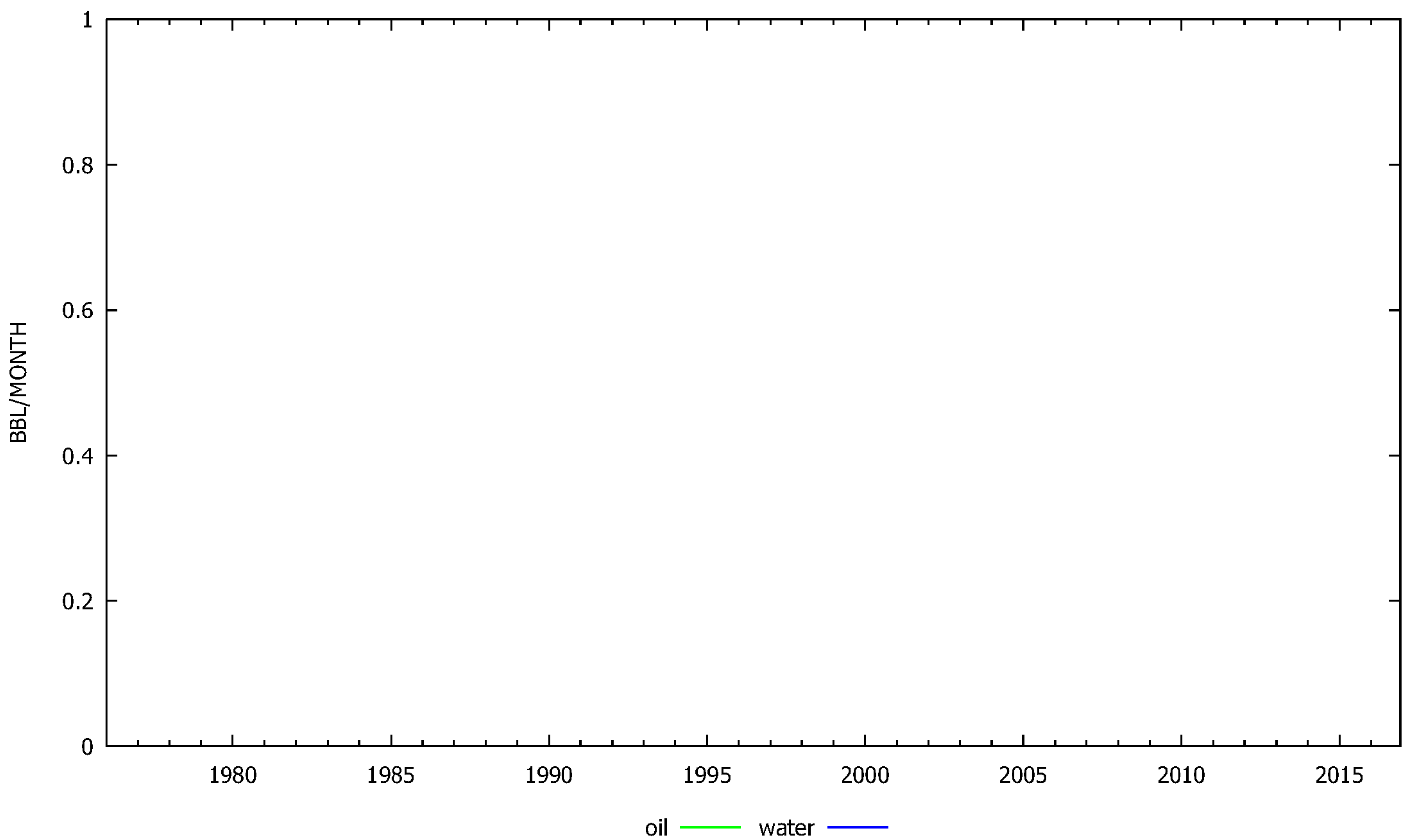




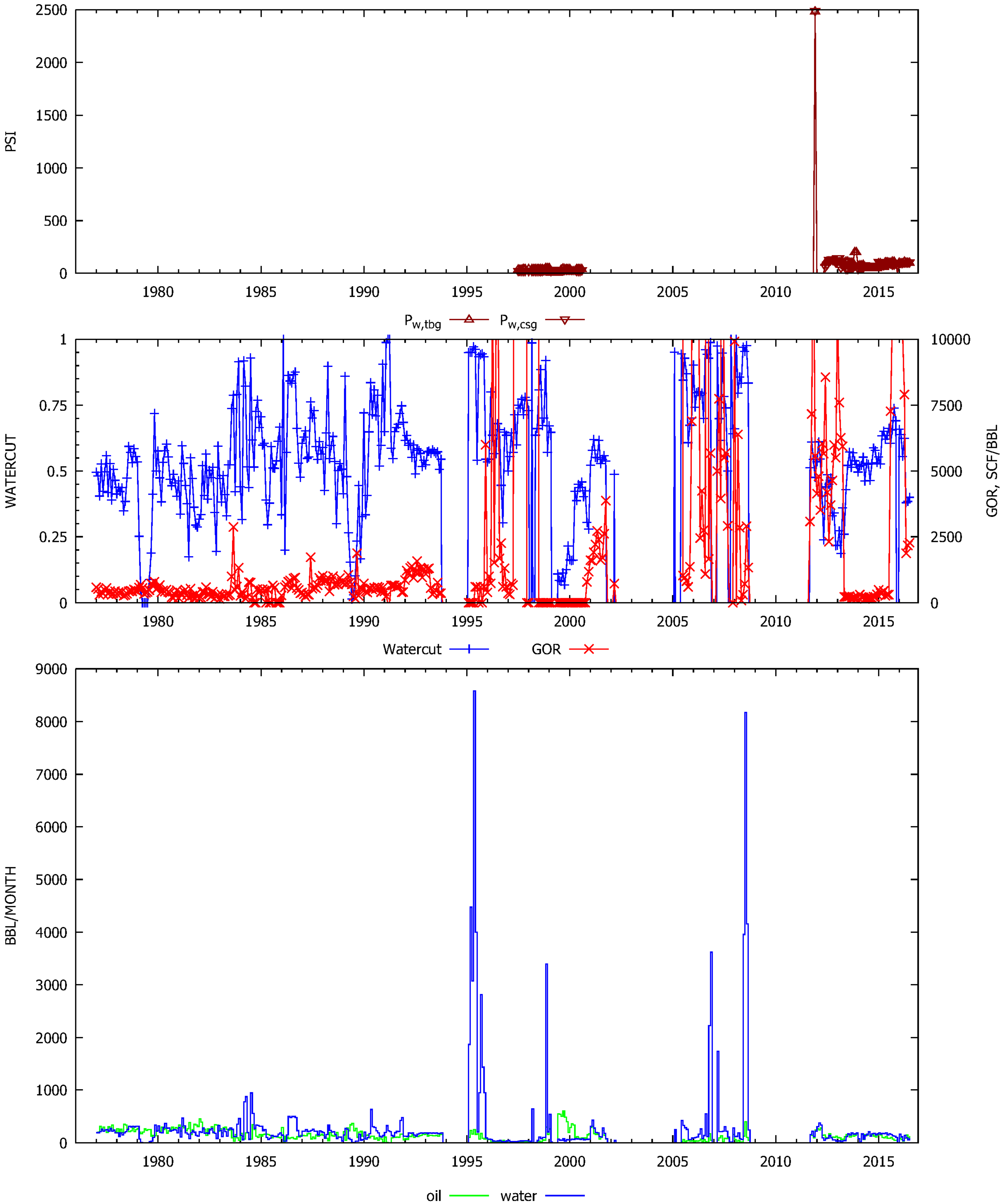
WELL Porter 22



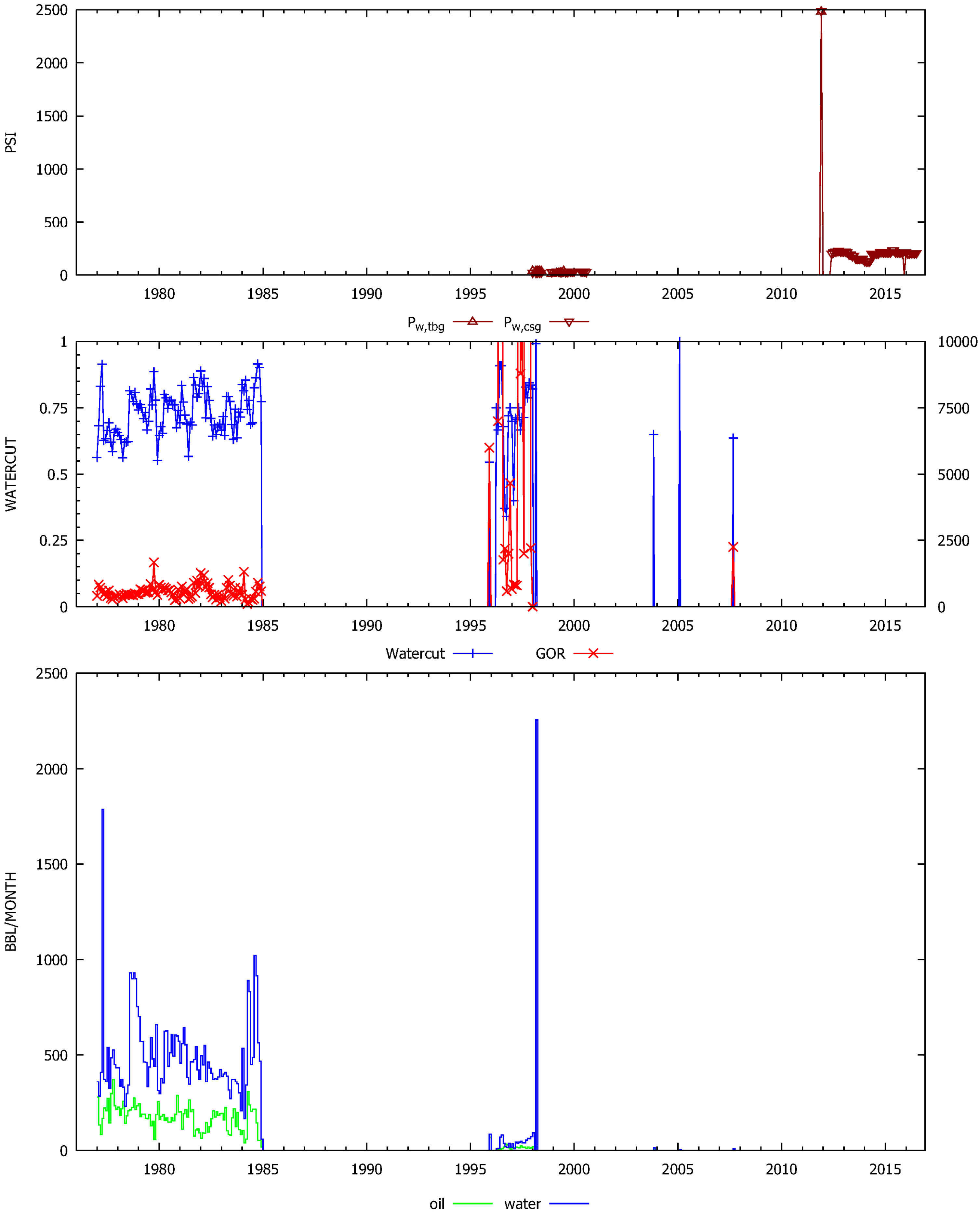




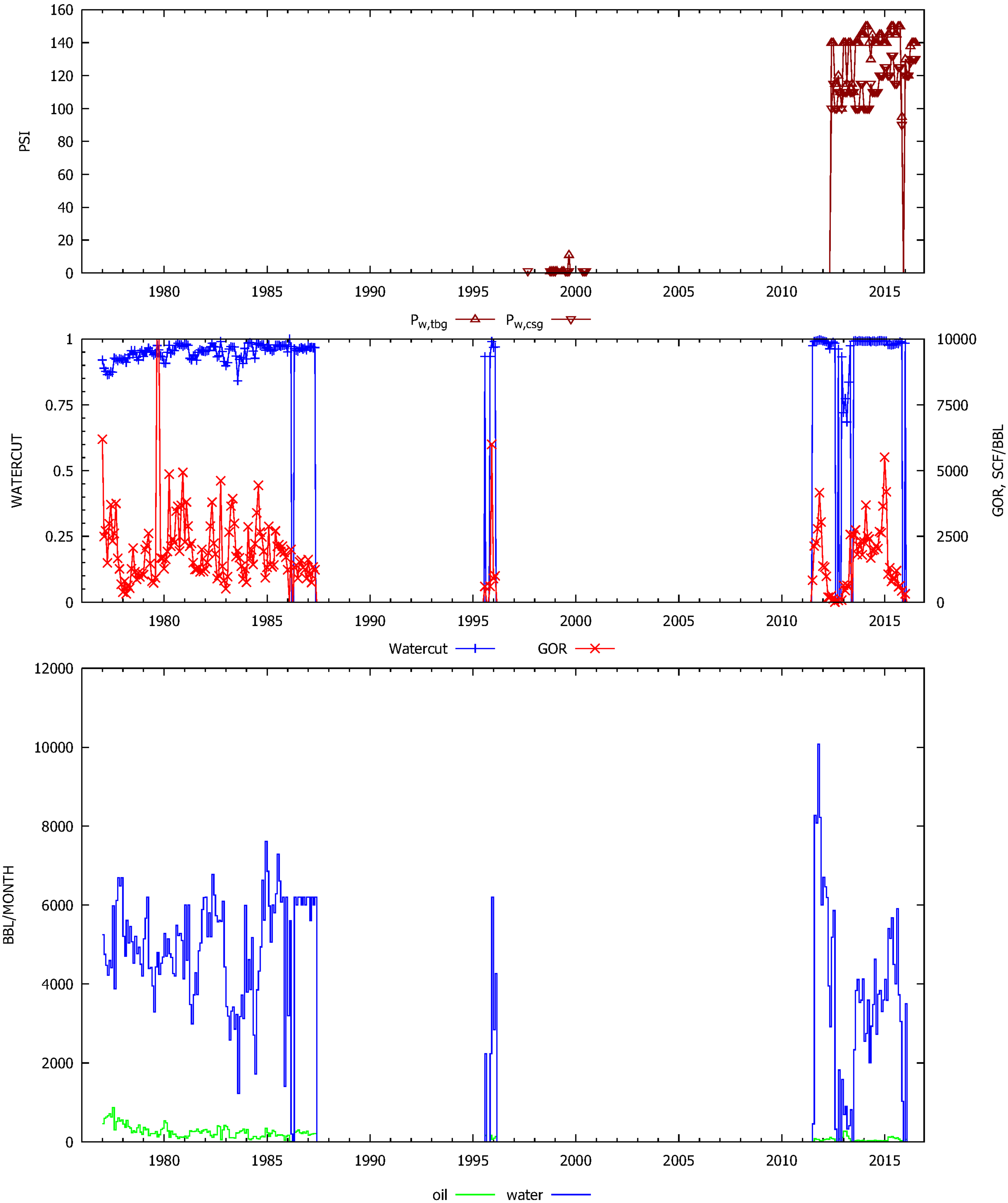
WELL Porter 27



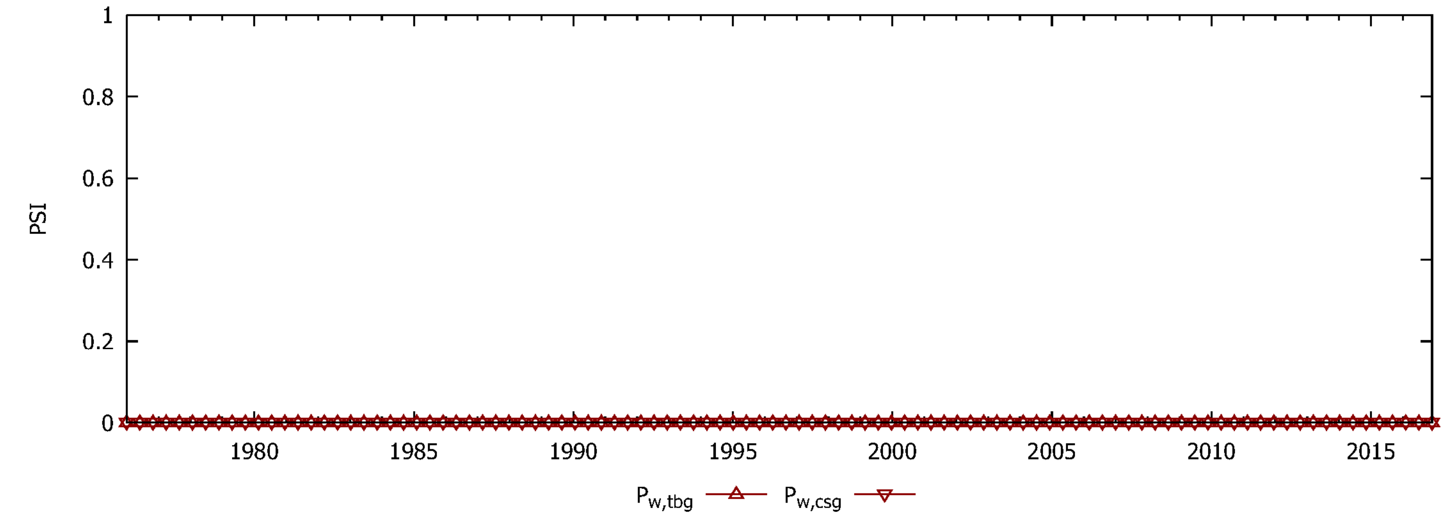
WELL Porter 28

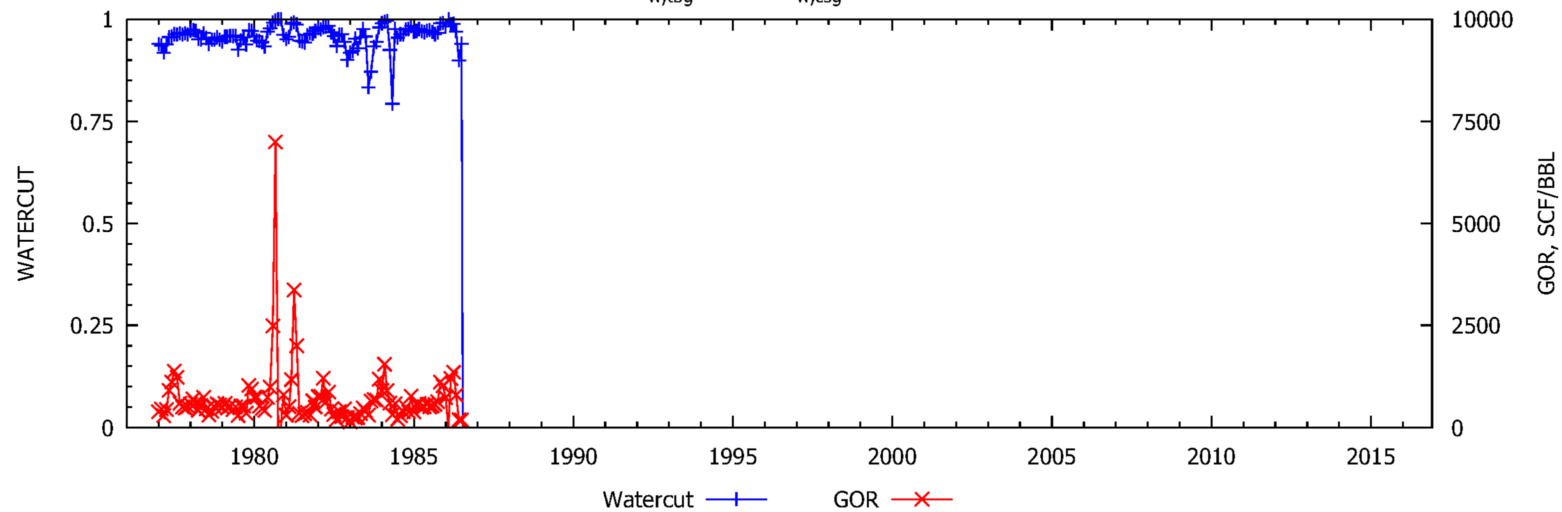


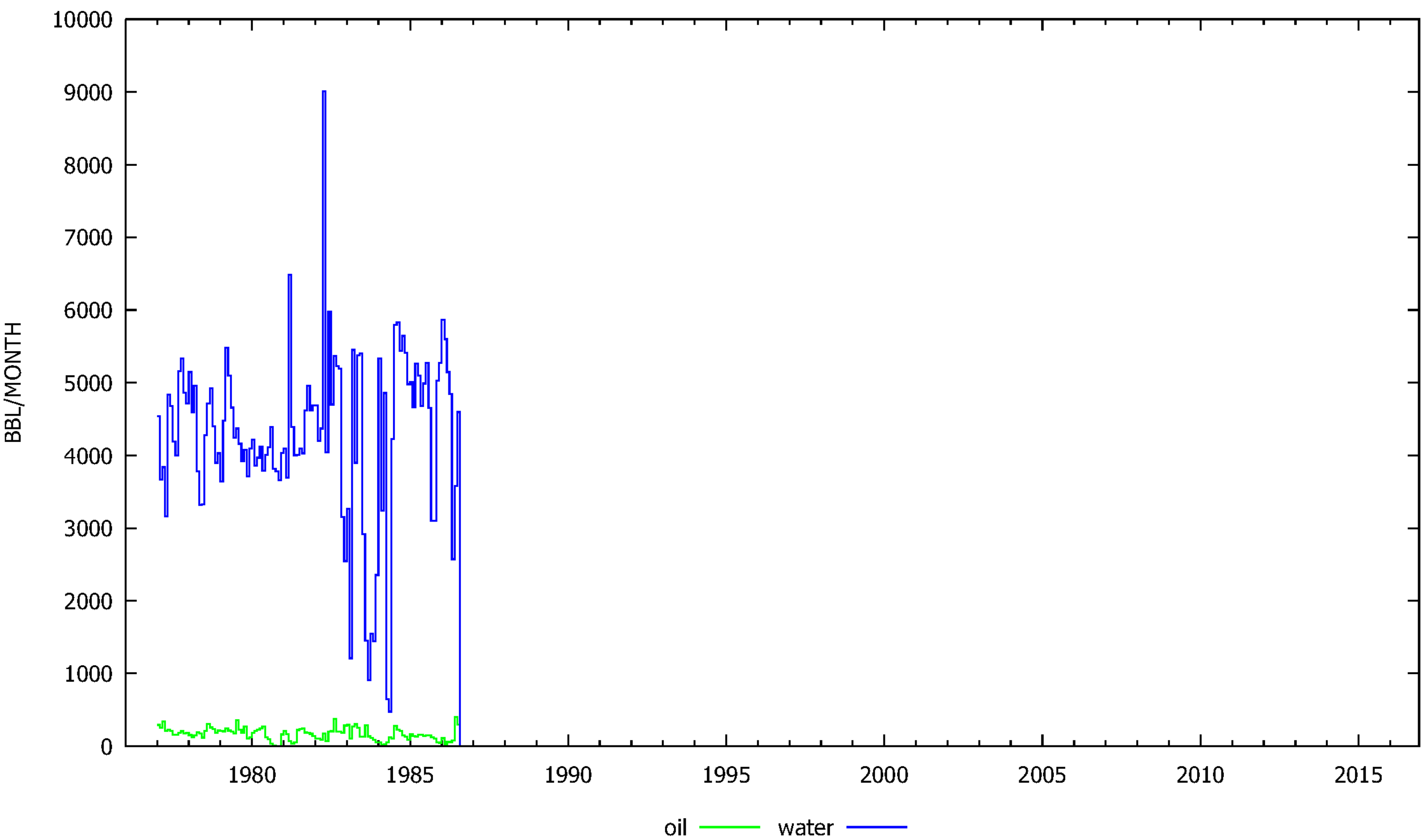
WELL Porter 3

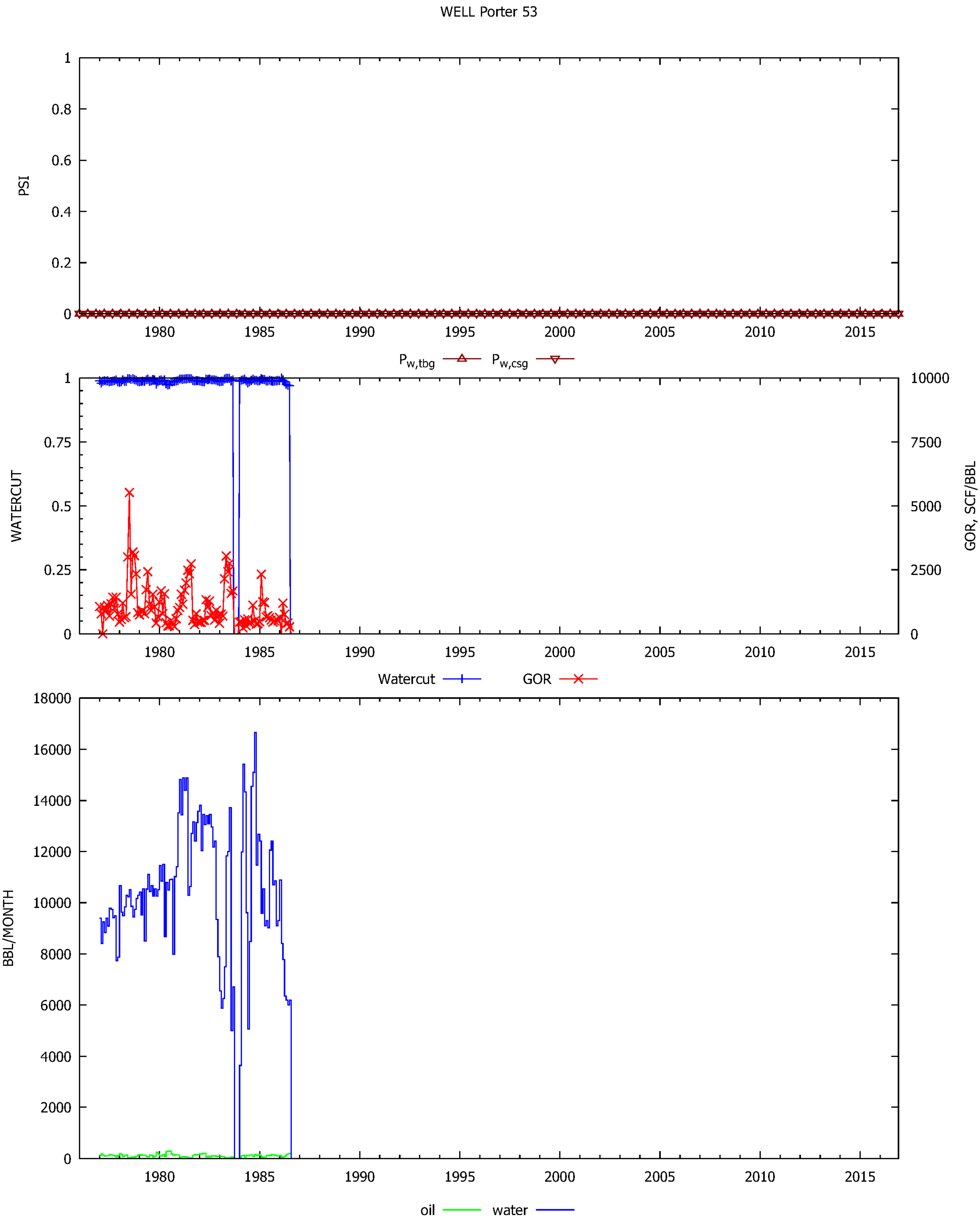


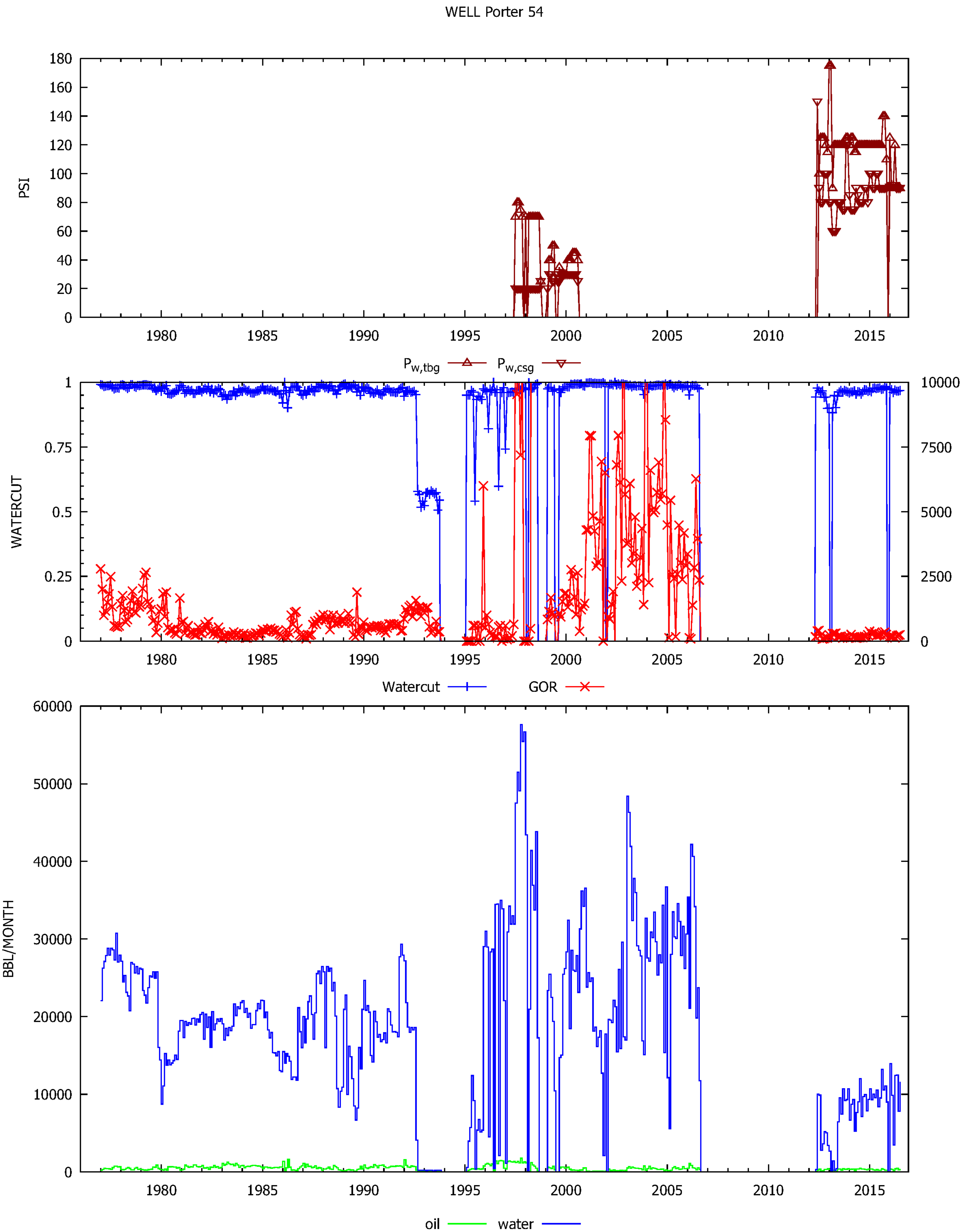
WELL Porter 52



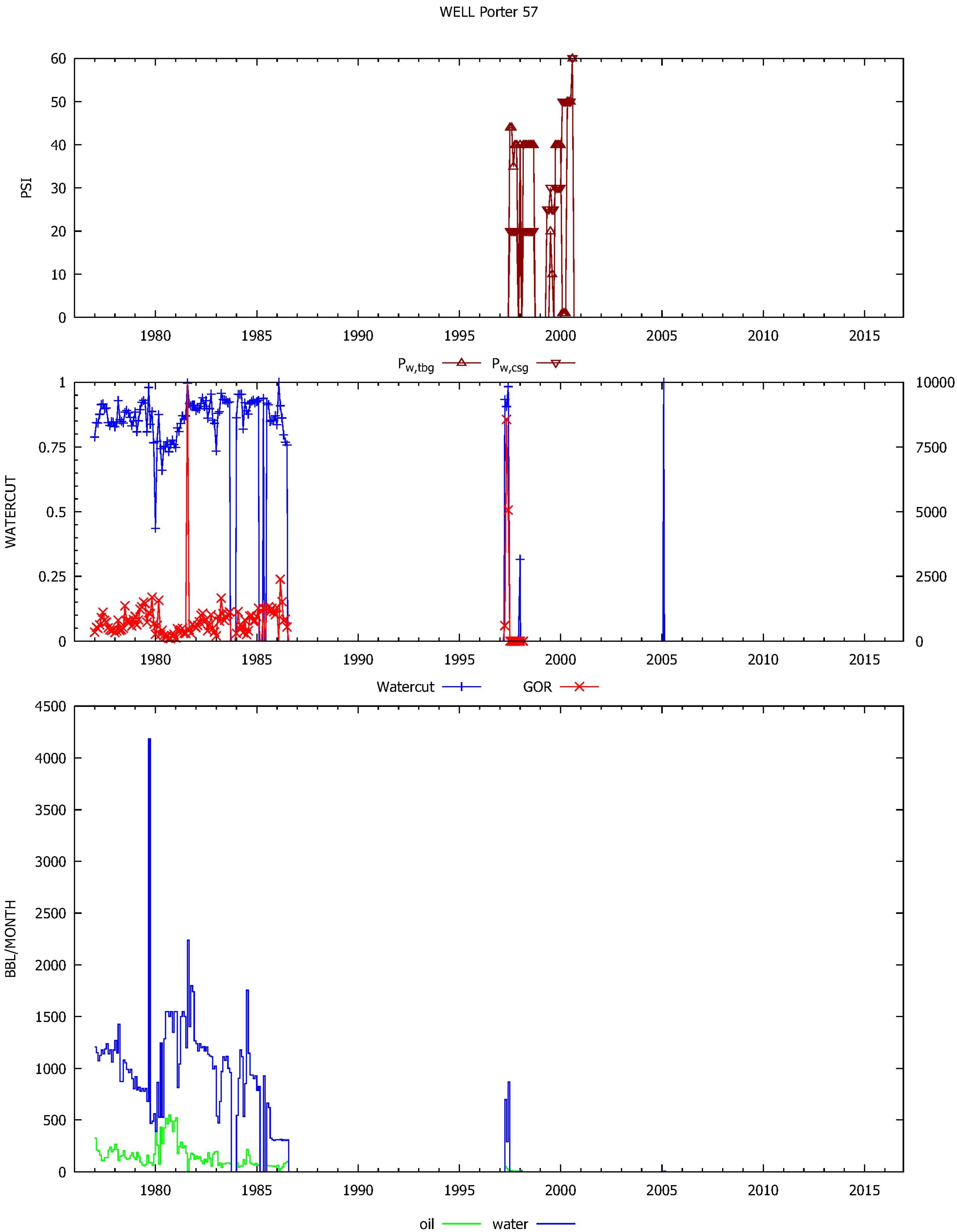





WELL Porter 53
PSI
1
0.8
0.6
0.4
0.2
0
1980
1985
1990
1995
2000
2005
2010
2015
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
1
0.75
0.5
0.25
0
10000
7500
5000
2500
0
Watercut
GOR
BBL/MONTH
18000
16000
14000
12000
10000
8000
6000
4000
2000
0
oil
water

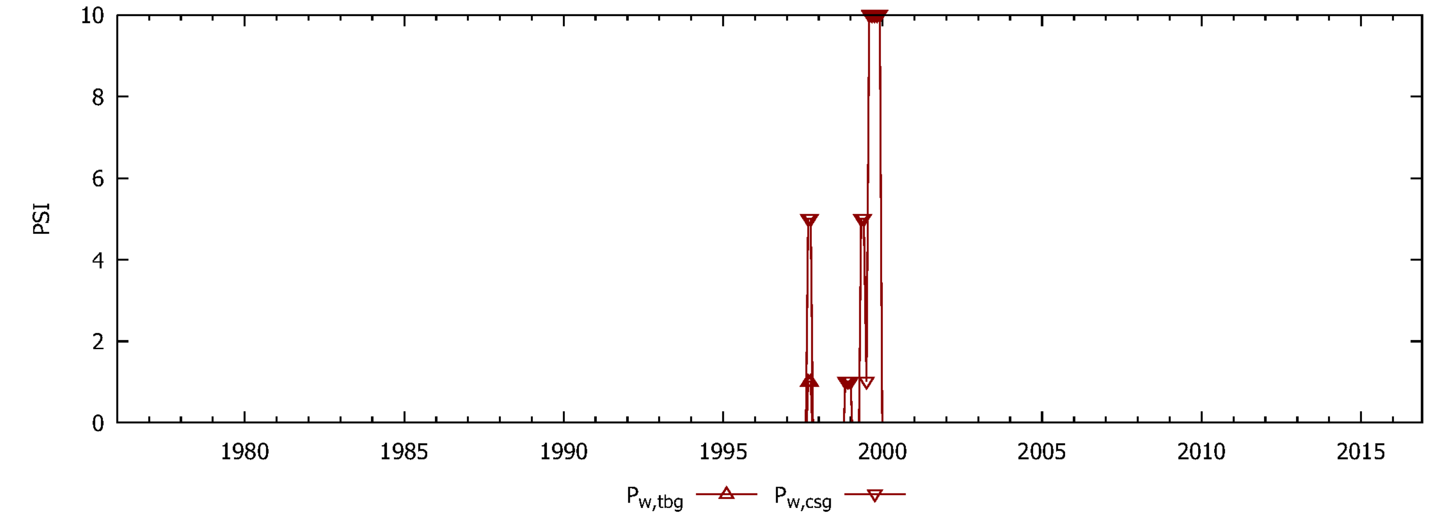


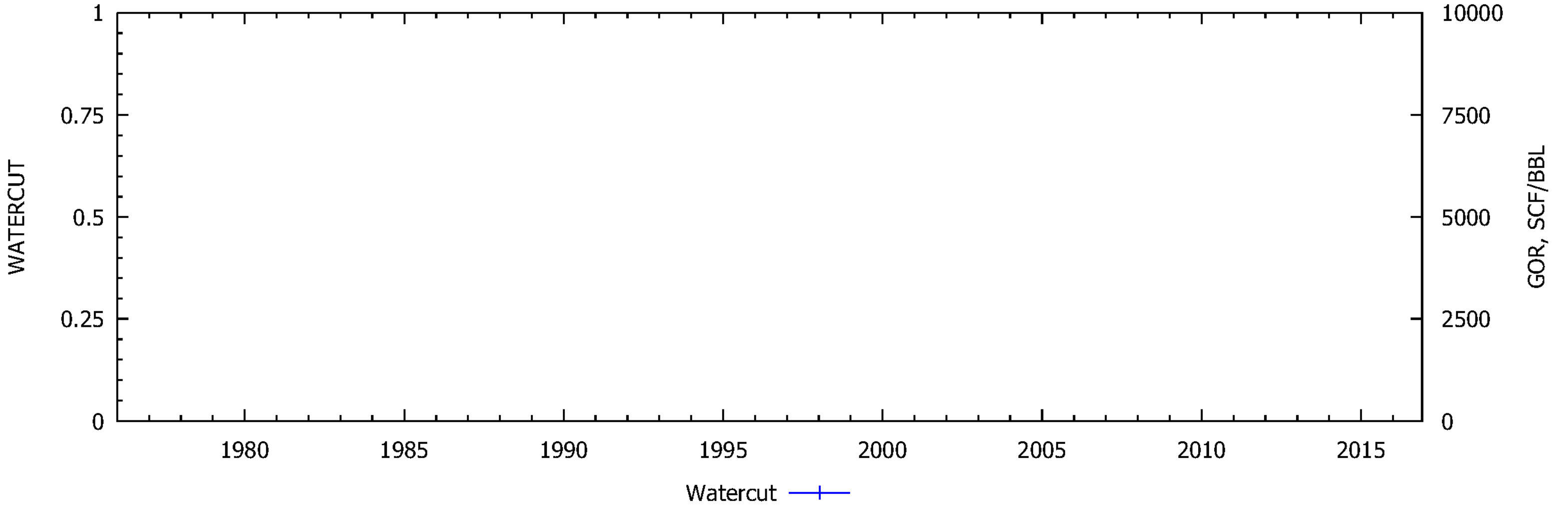
WELL Porter 54
PSI
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
oil
water

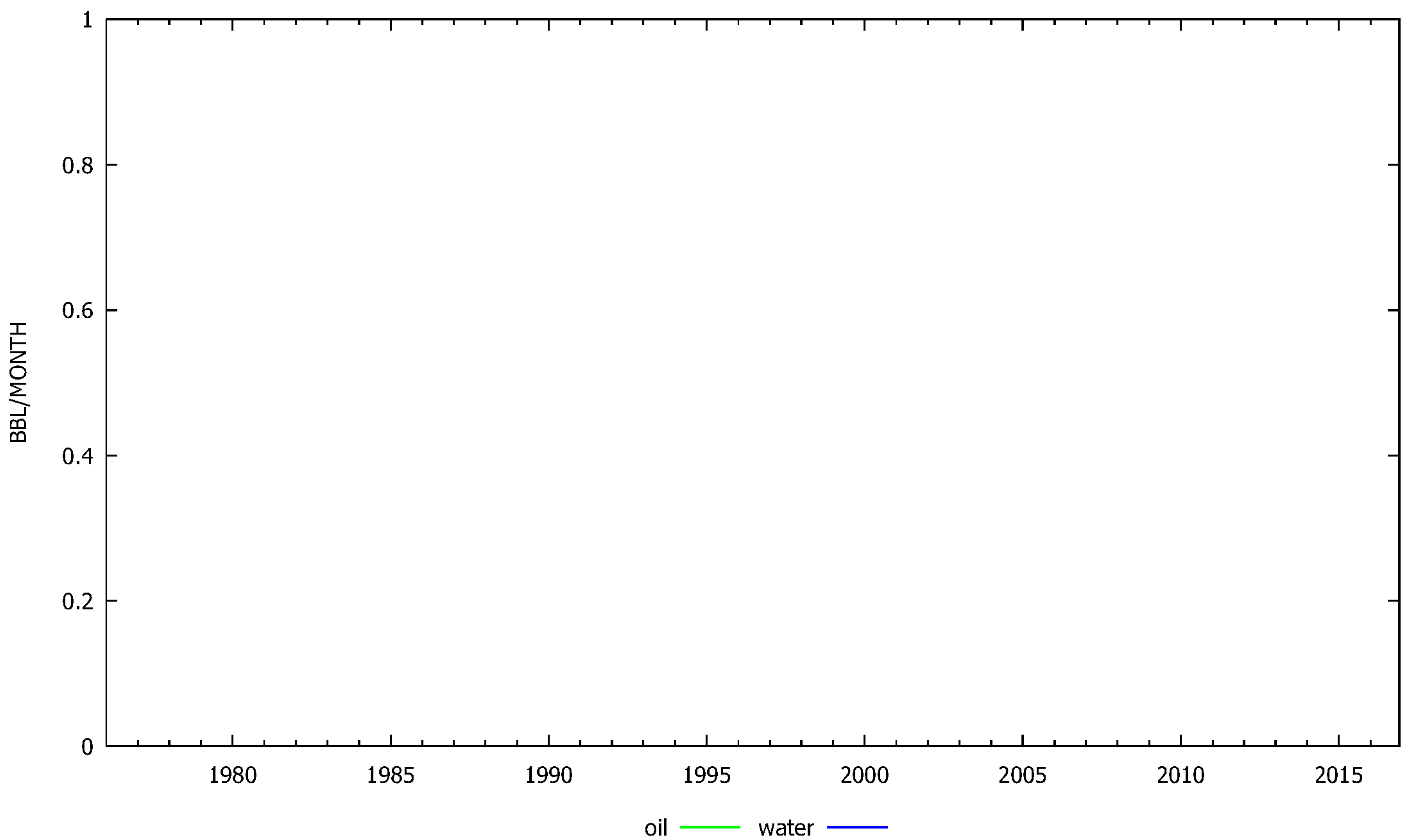


WELL Porter 57
PSI
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
oil
water

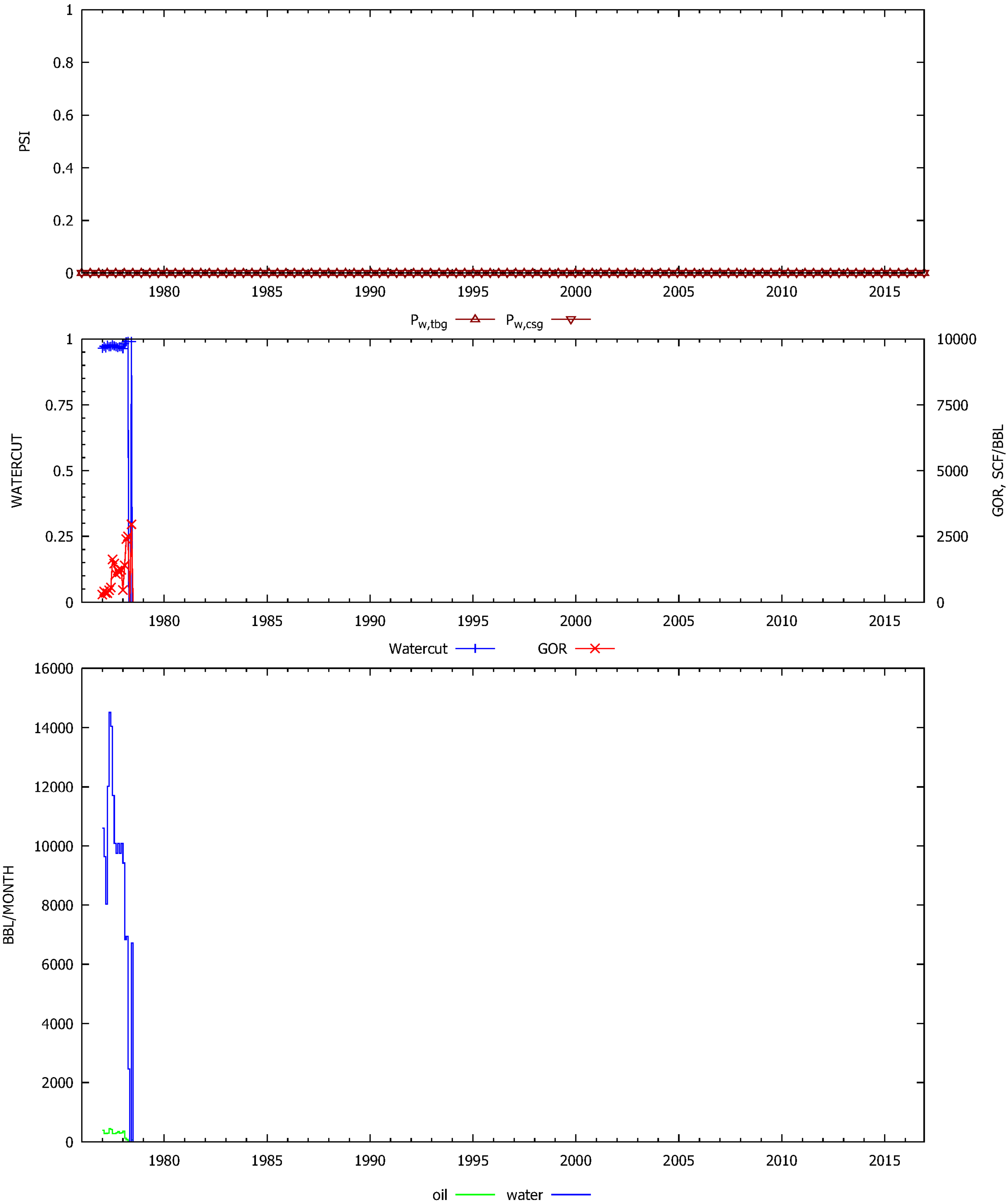
WELL Porter 58

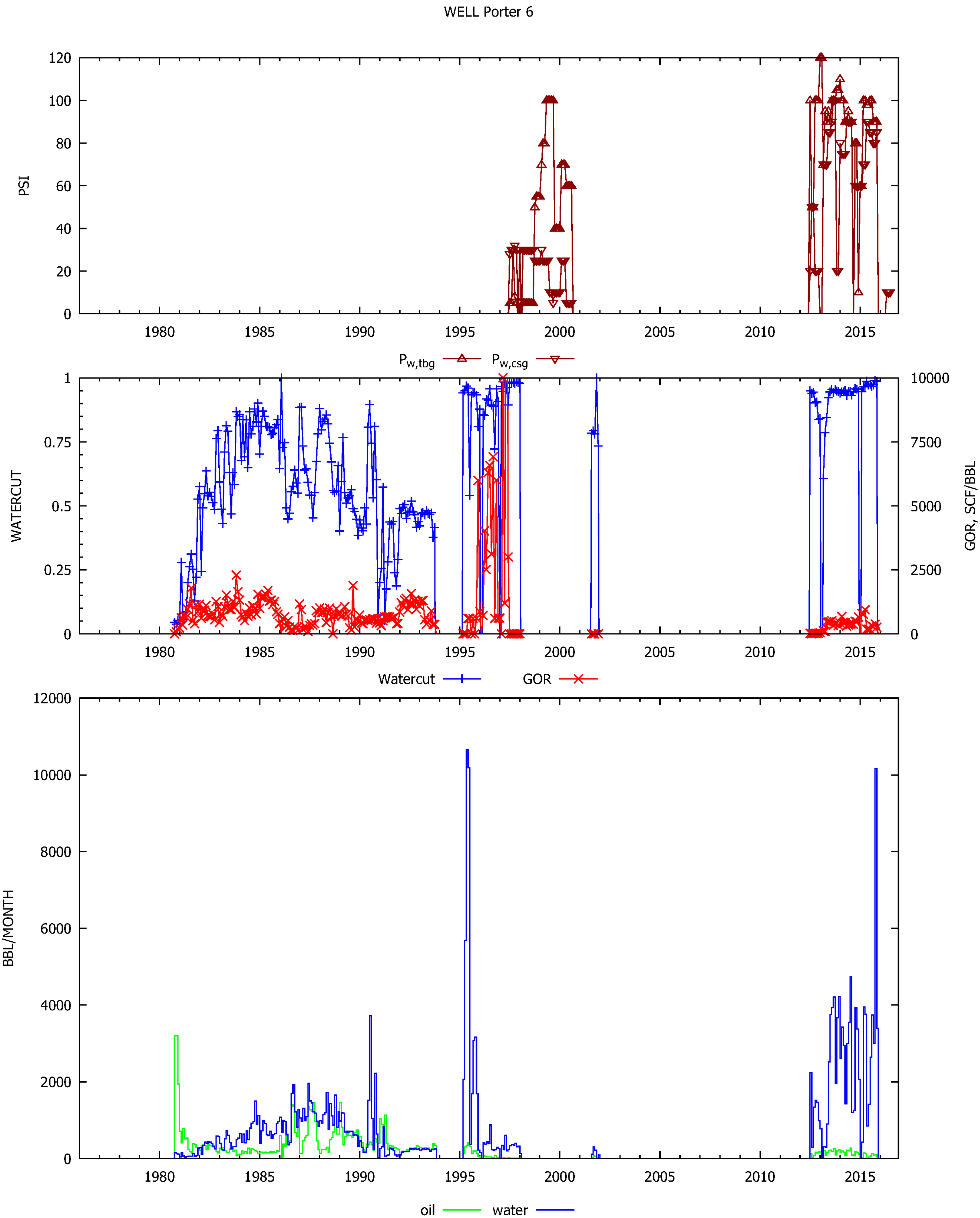




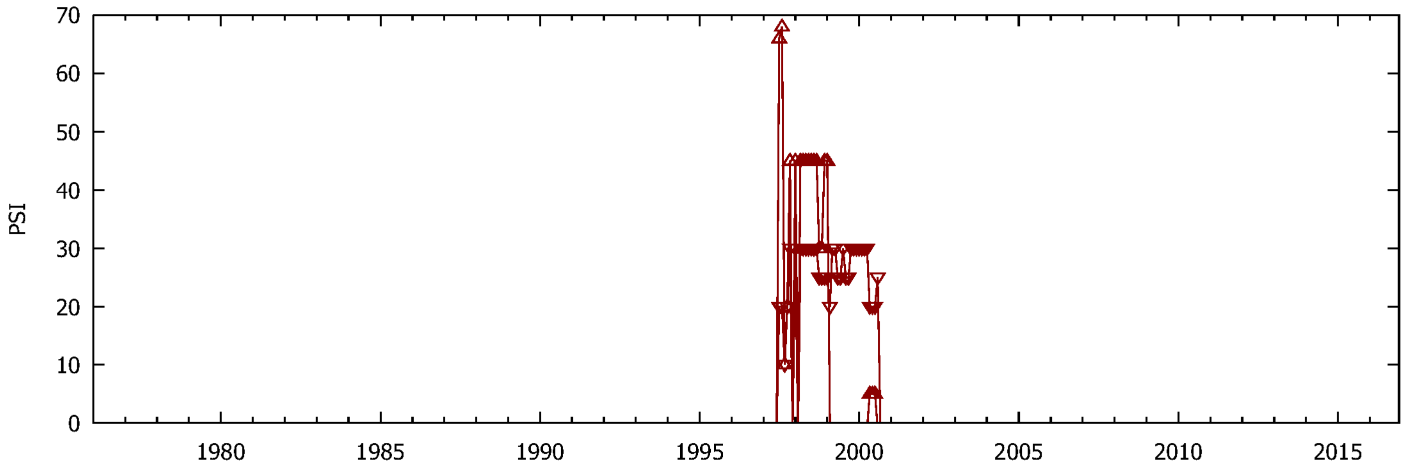


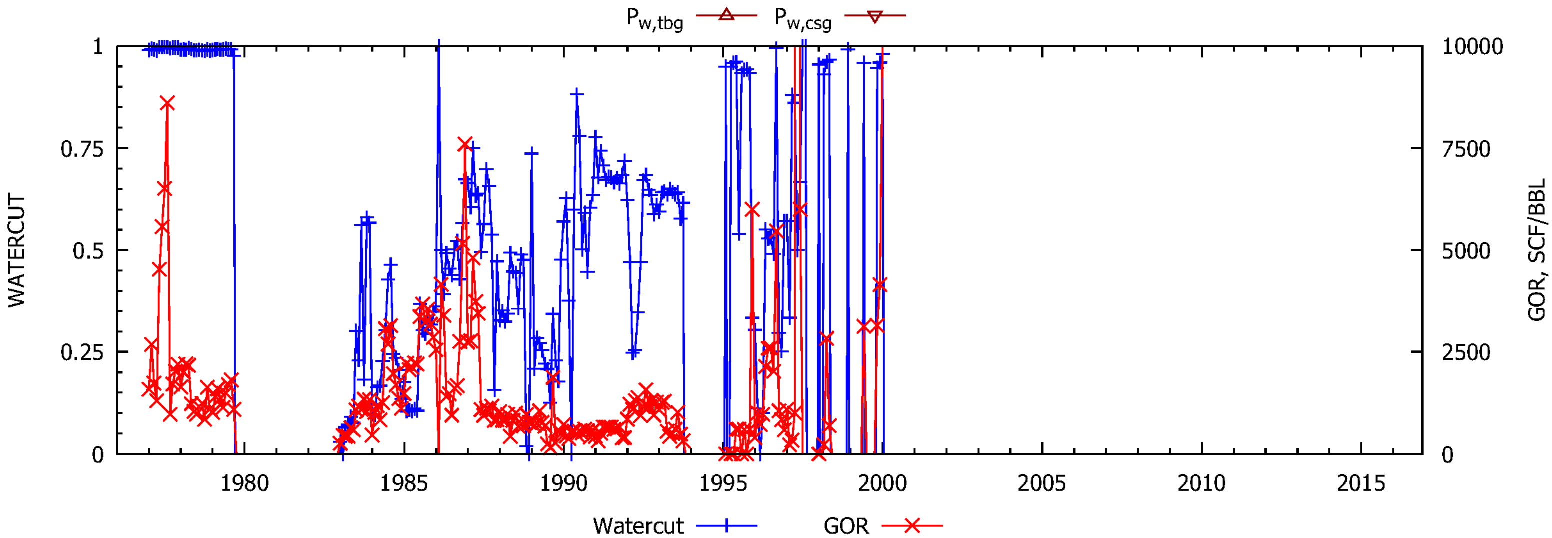
WELL Porter 59

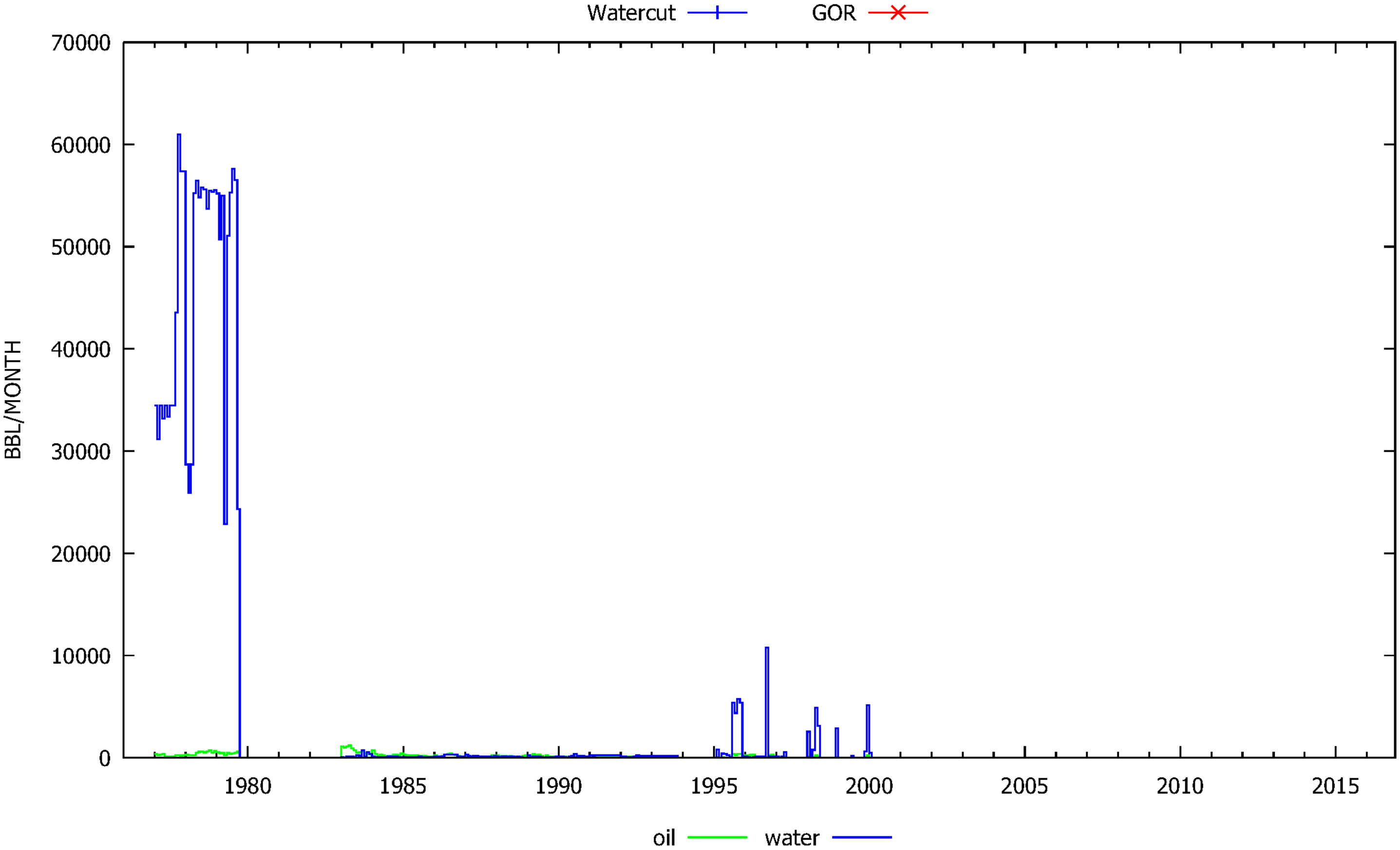



WELL Porter 6
PSI
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
oil
water

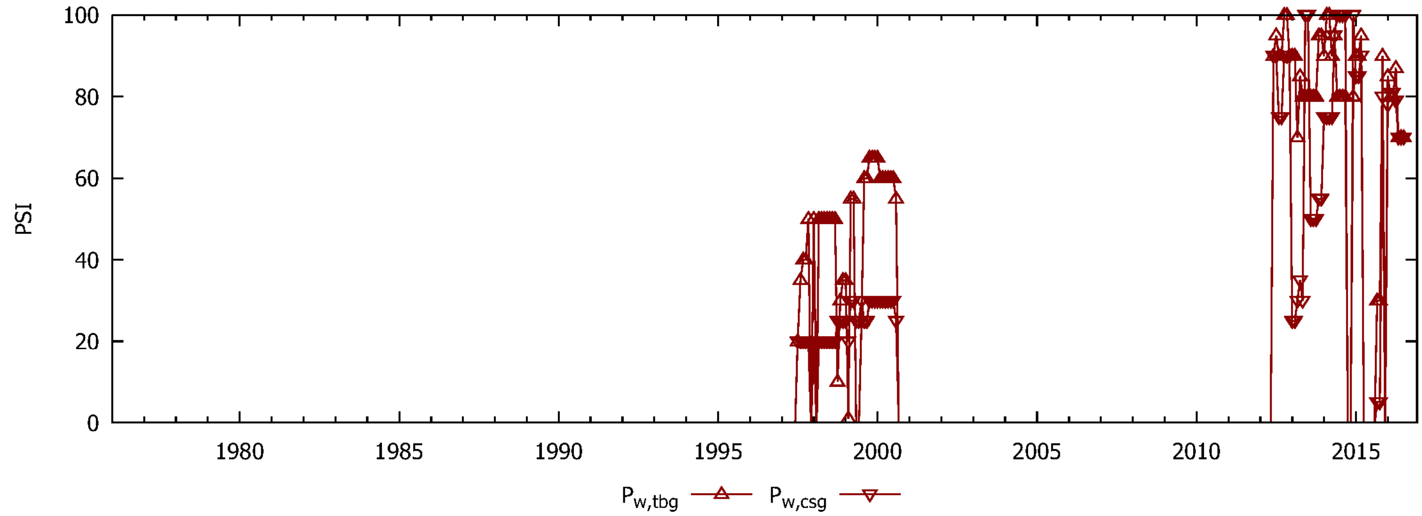
WELL Porter 60

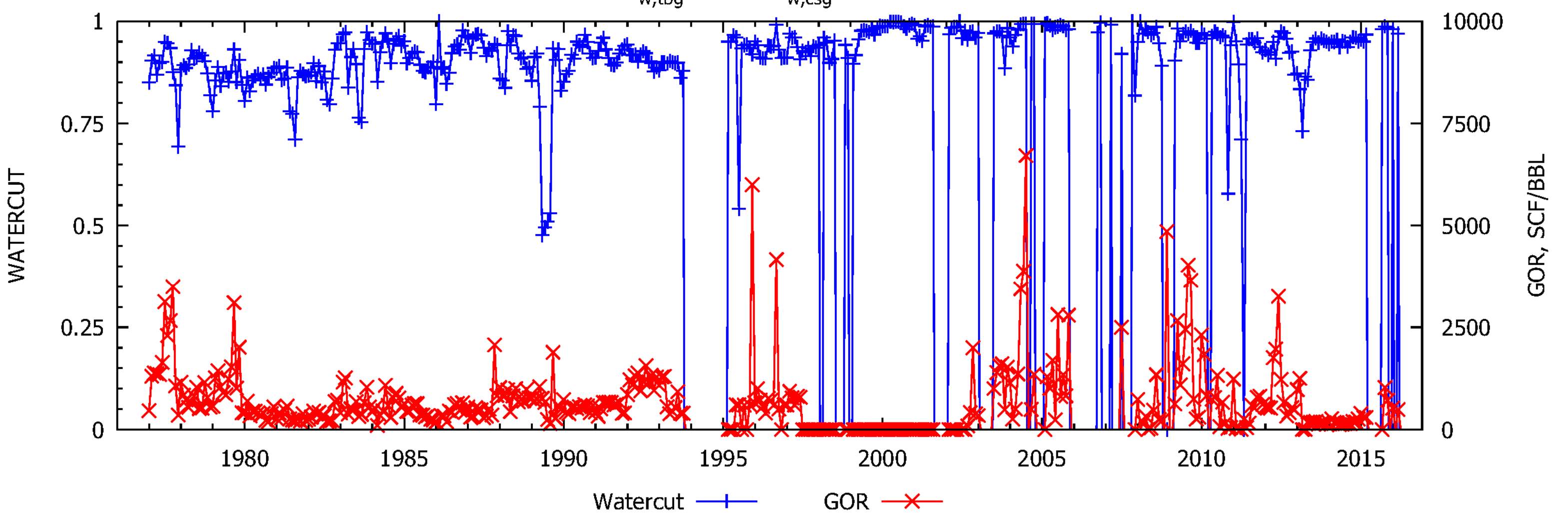


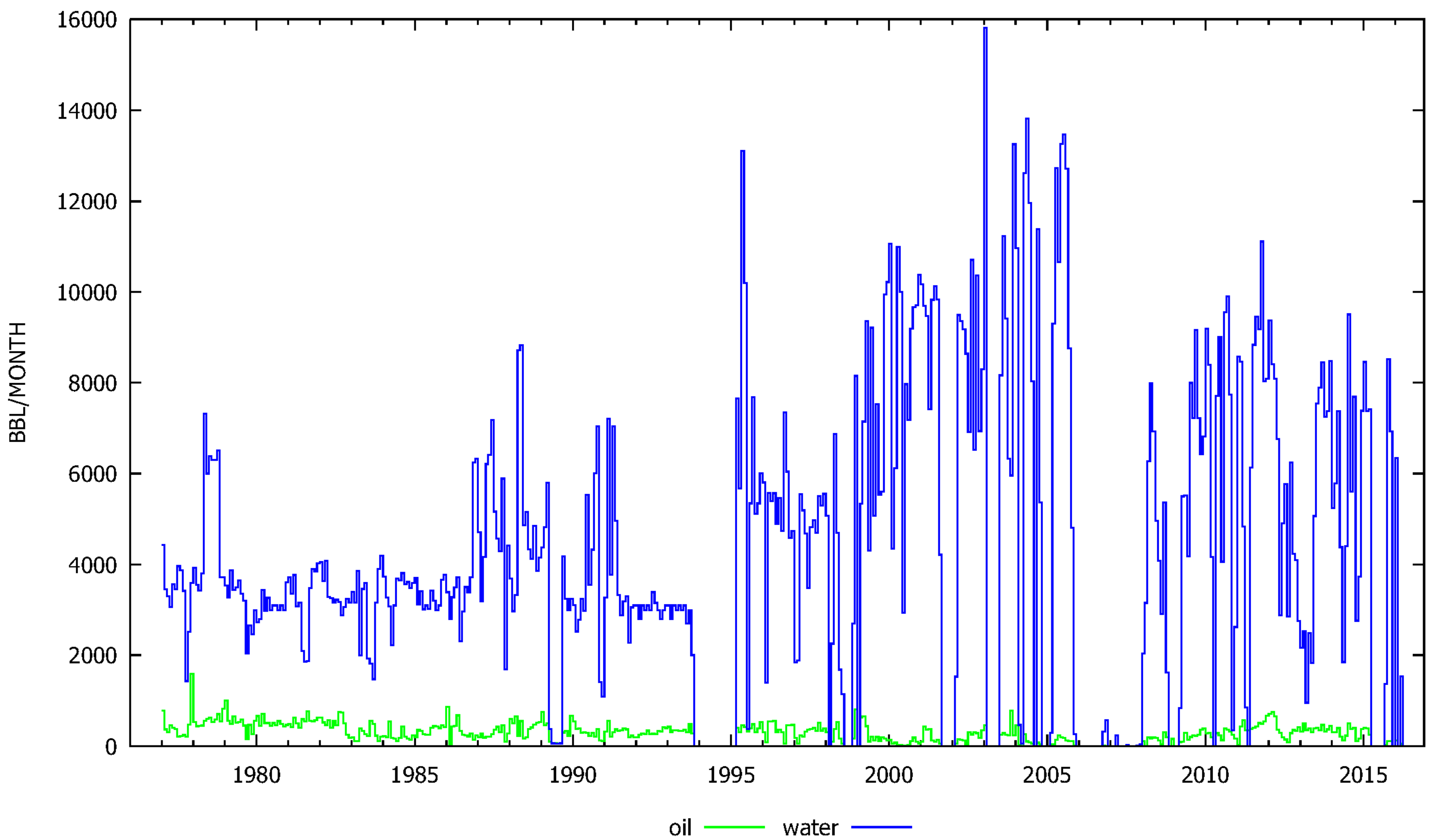




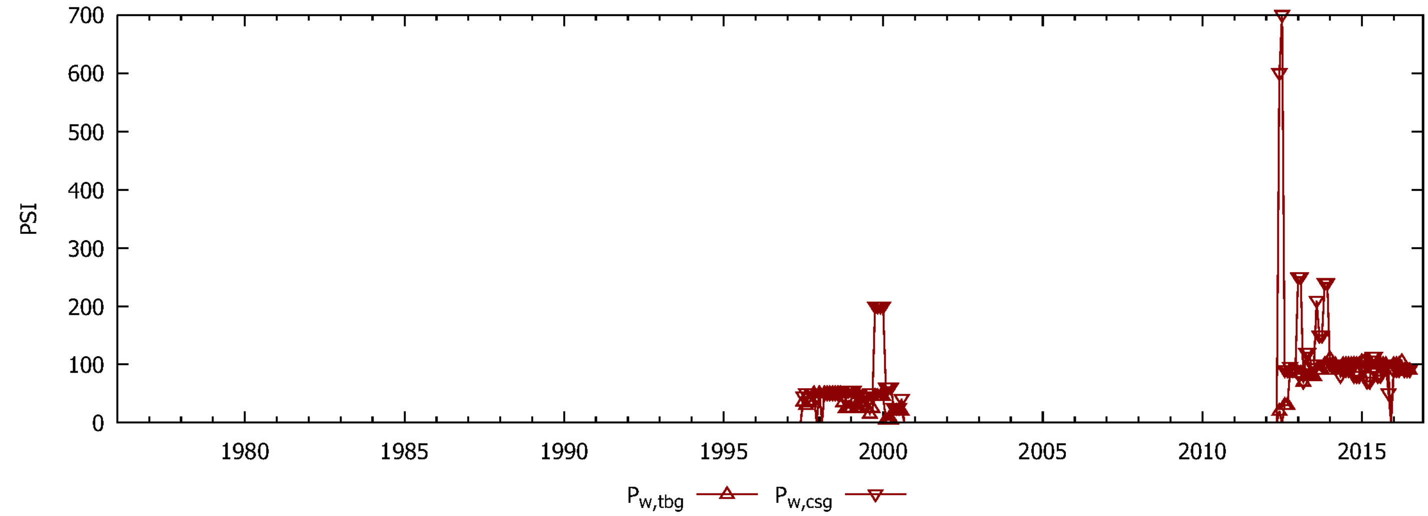
WELL Porter 61

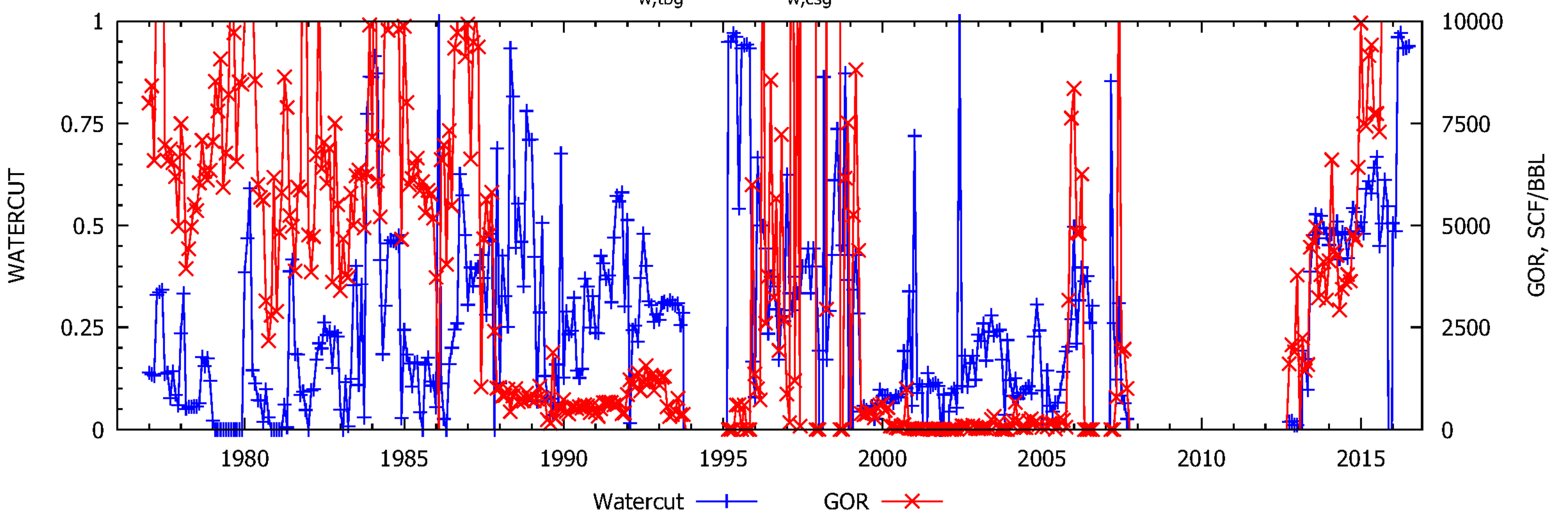


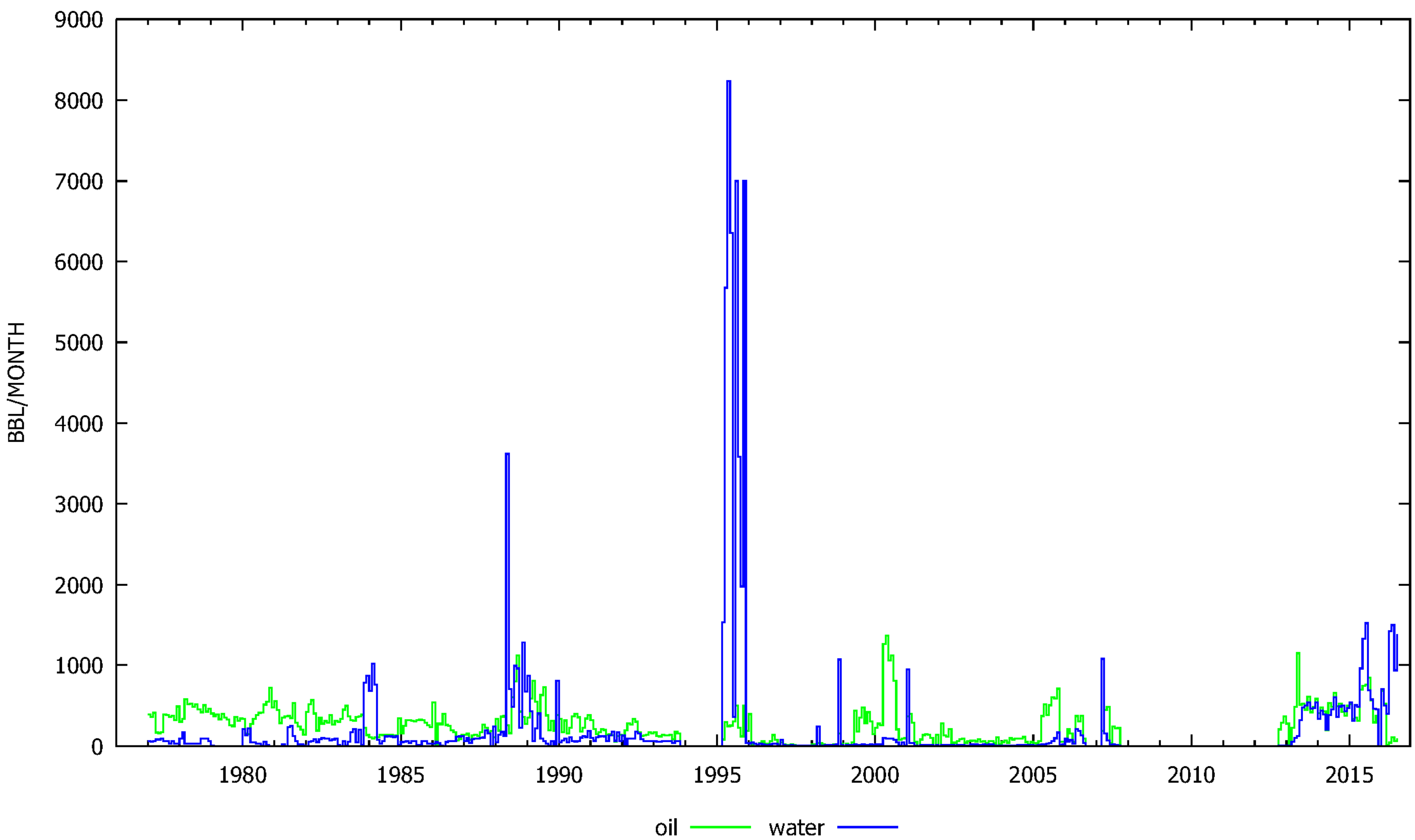




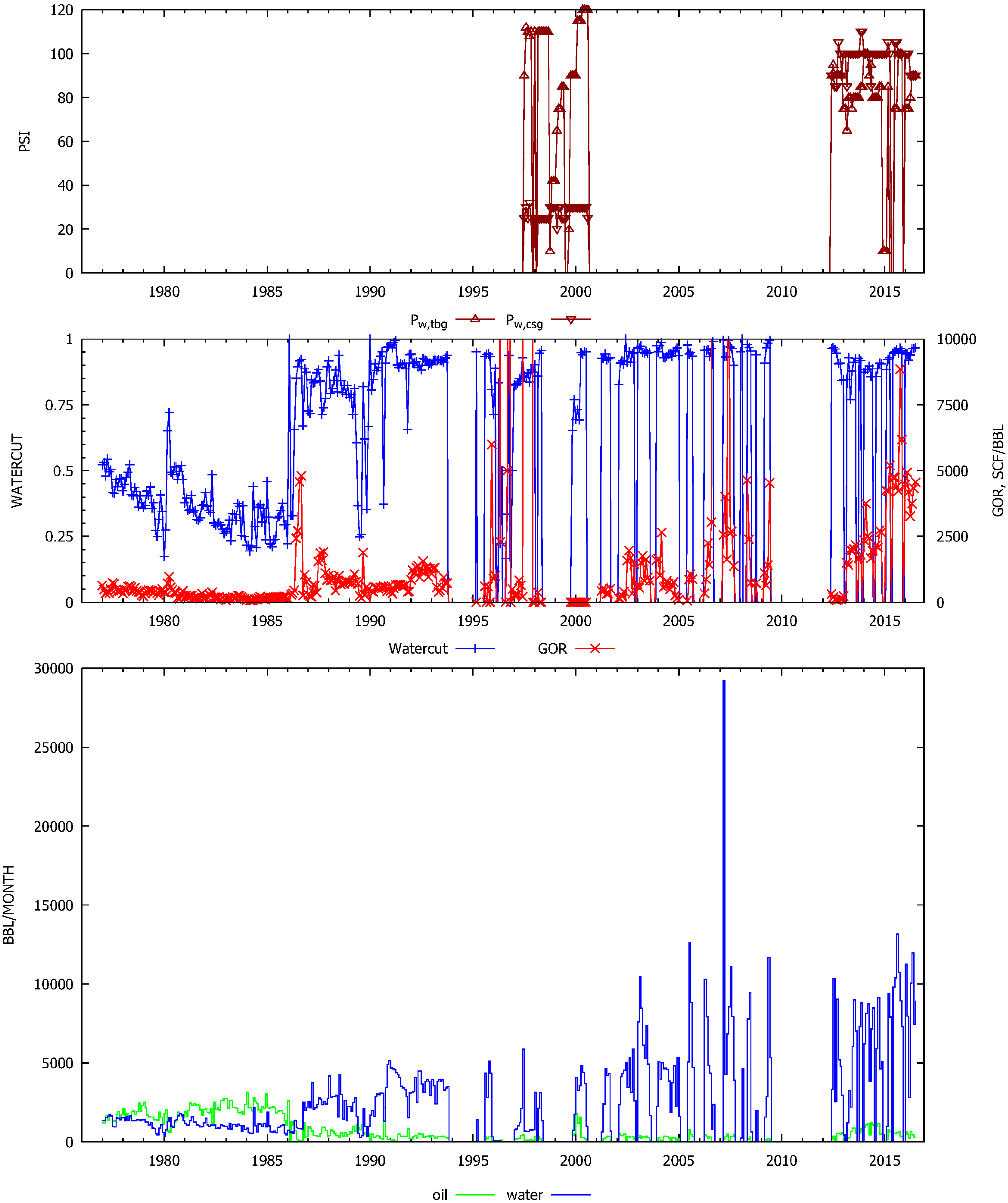
WELL Porter 63



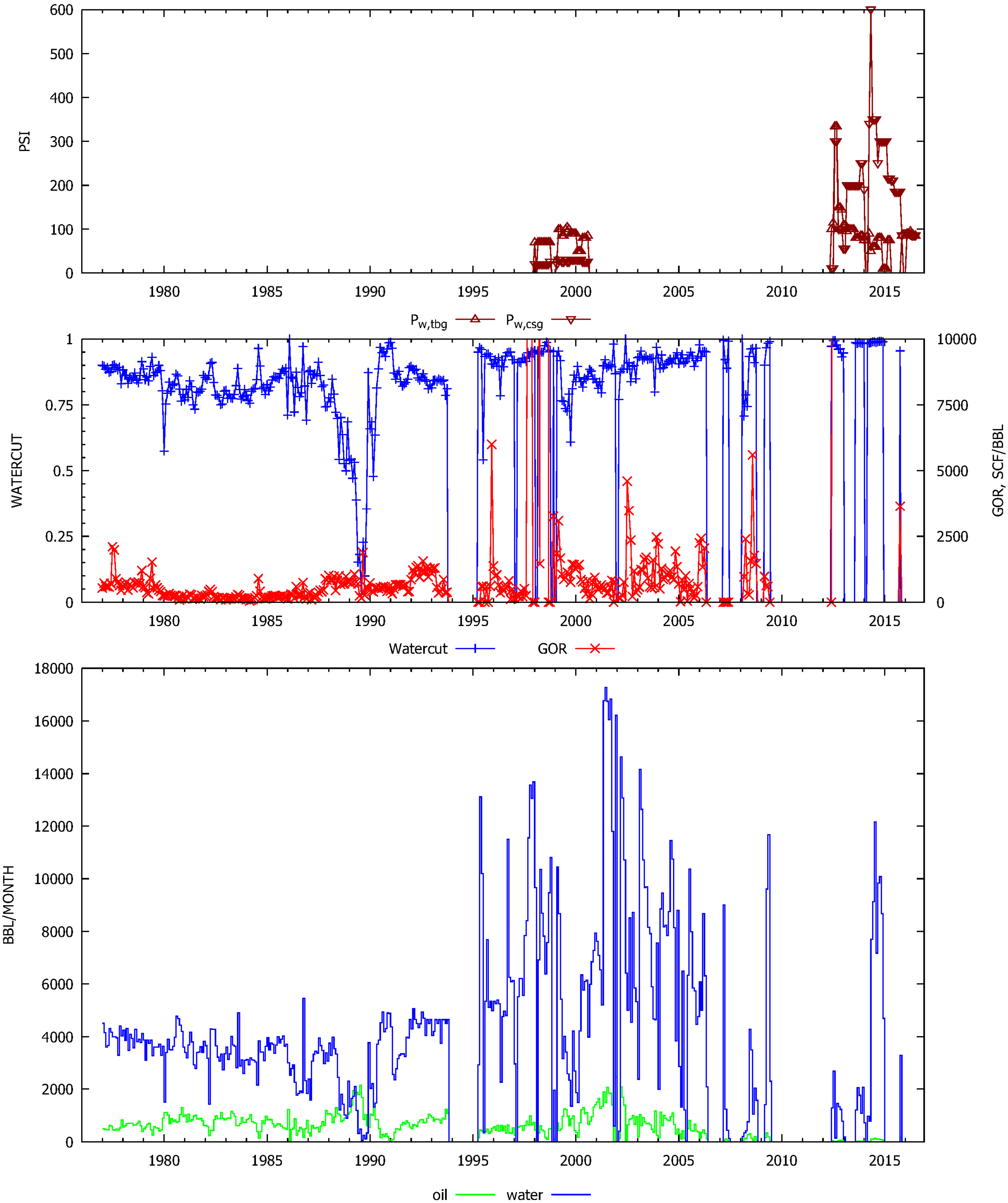


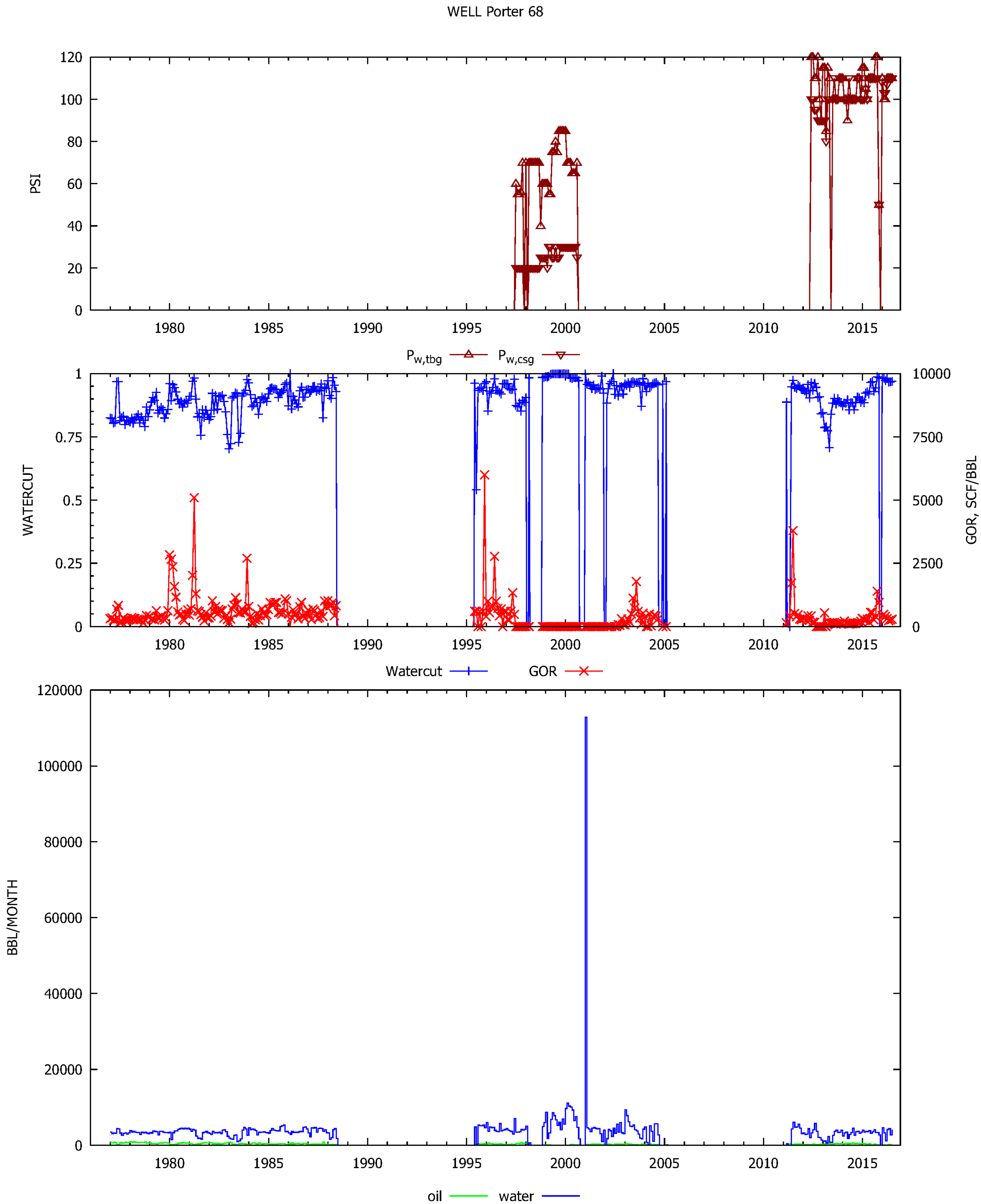


WELL Porter 65

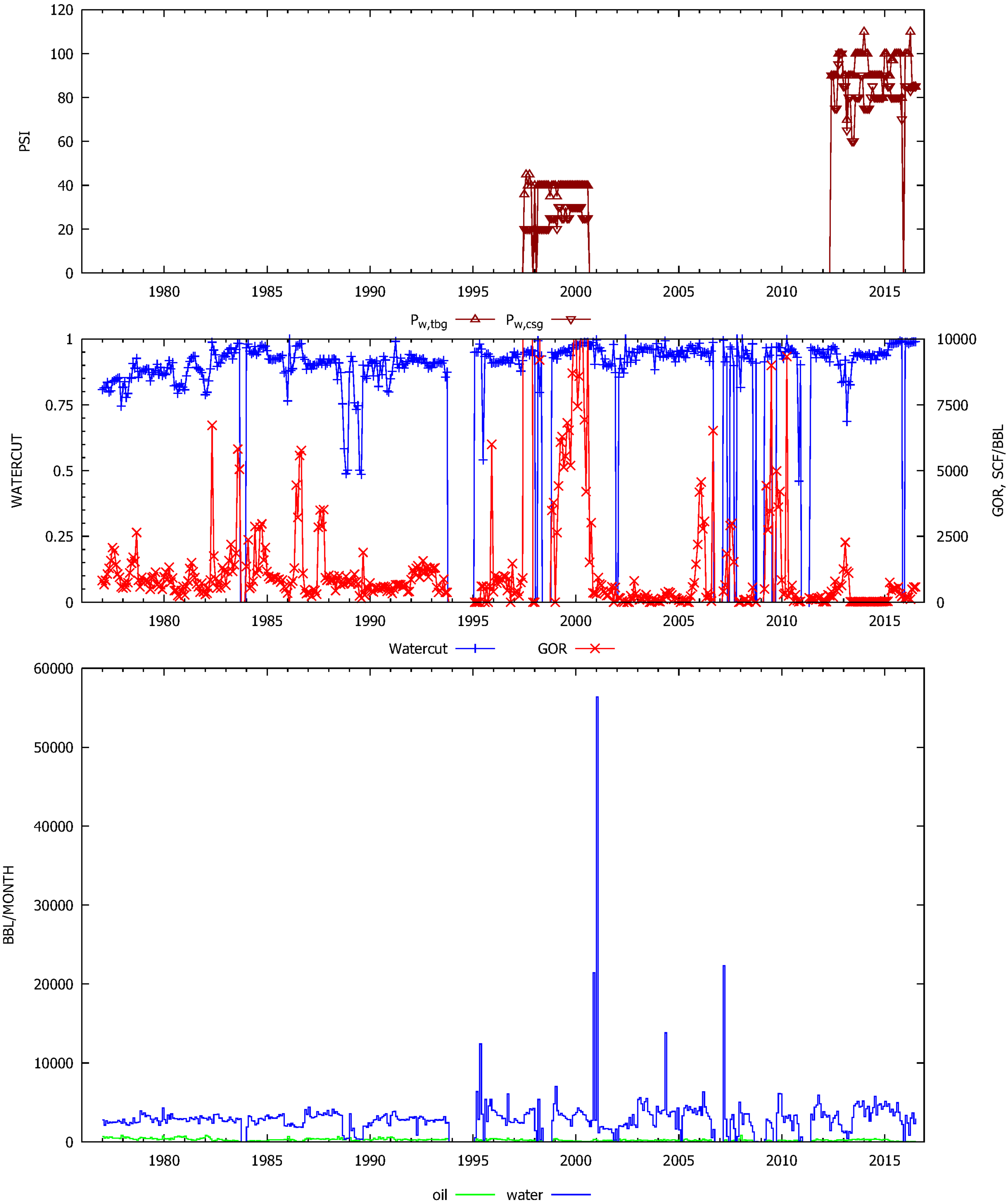


WELL Porter 66

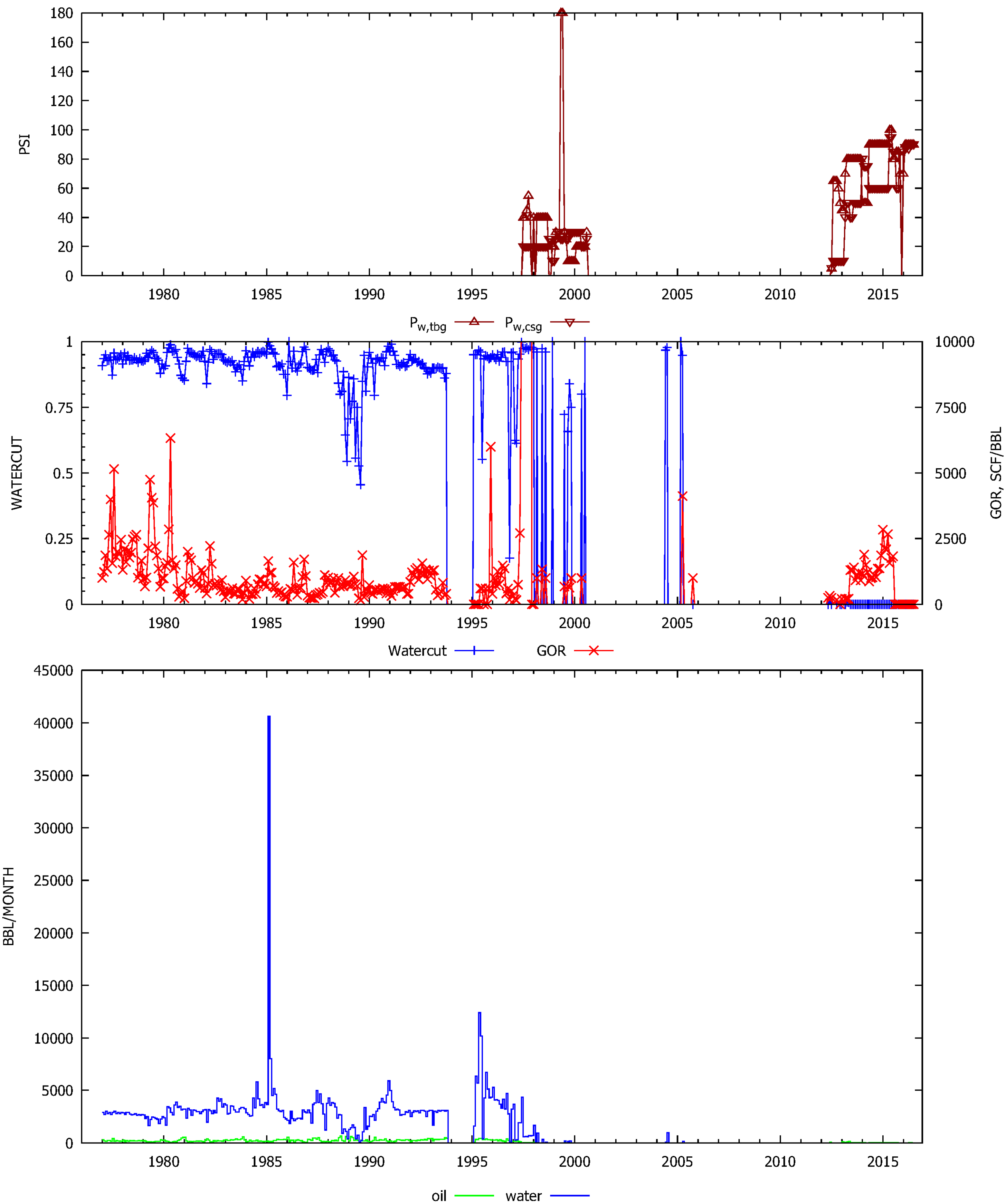



WELL Porter 68
PSI
120
100
80
60
40
20
0
1980
1985
1990
1995
2000
2005
2010
2015
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
1
0.75
0.5
0.25
0
10000
7500
5000
2500
0
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
120000
100000
80000
60000
40000
20000
0
oil
water

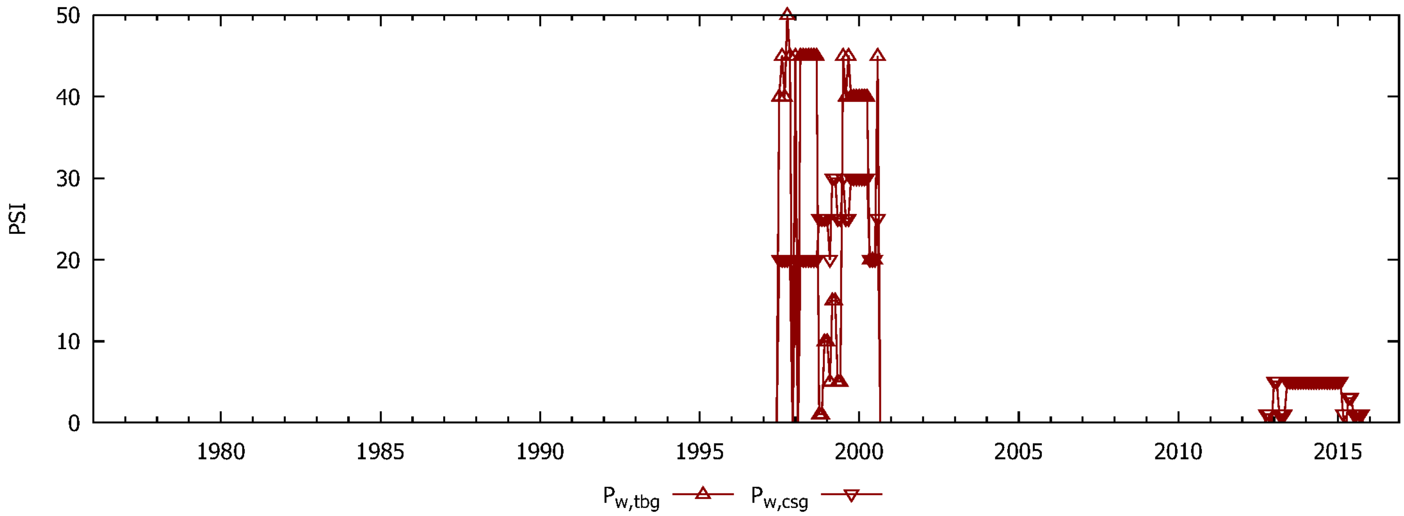
WELL Porter 69

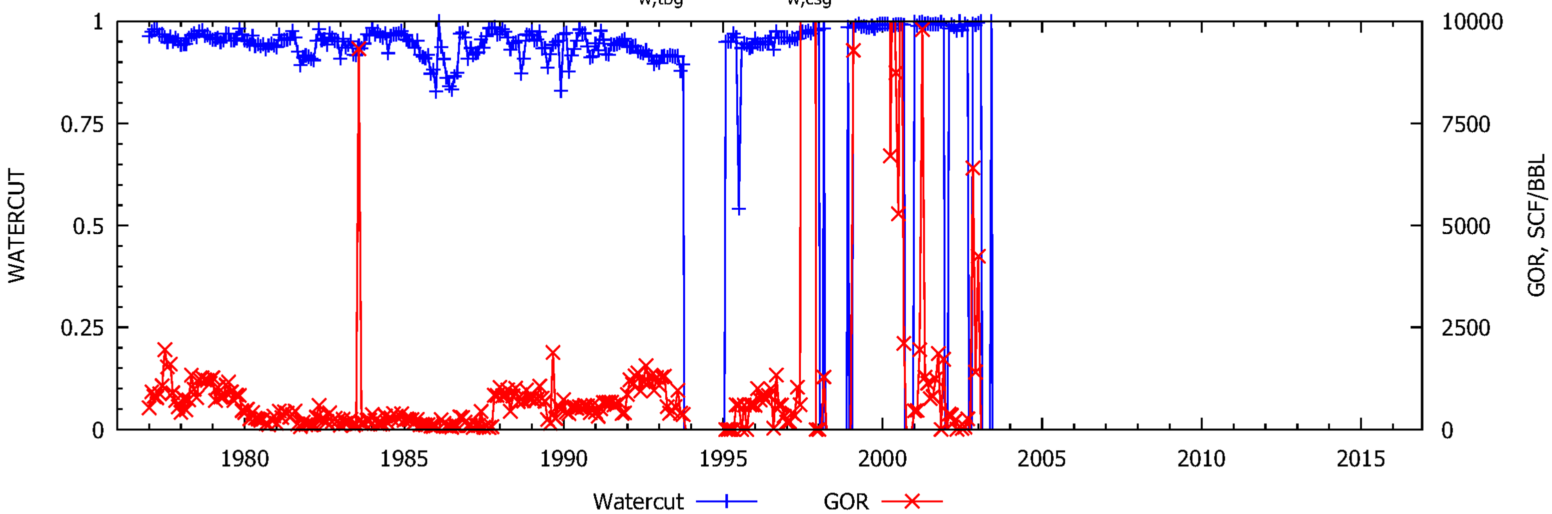


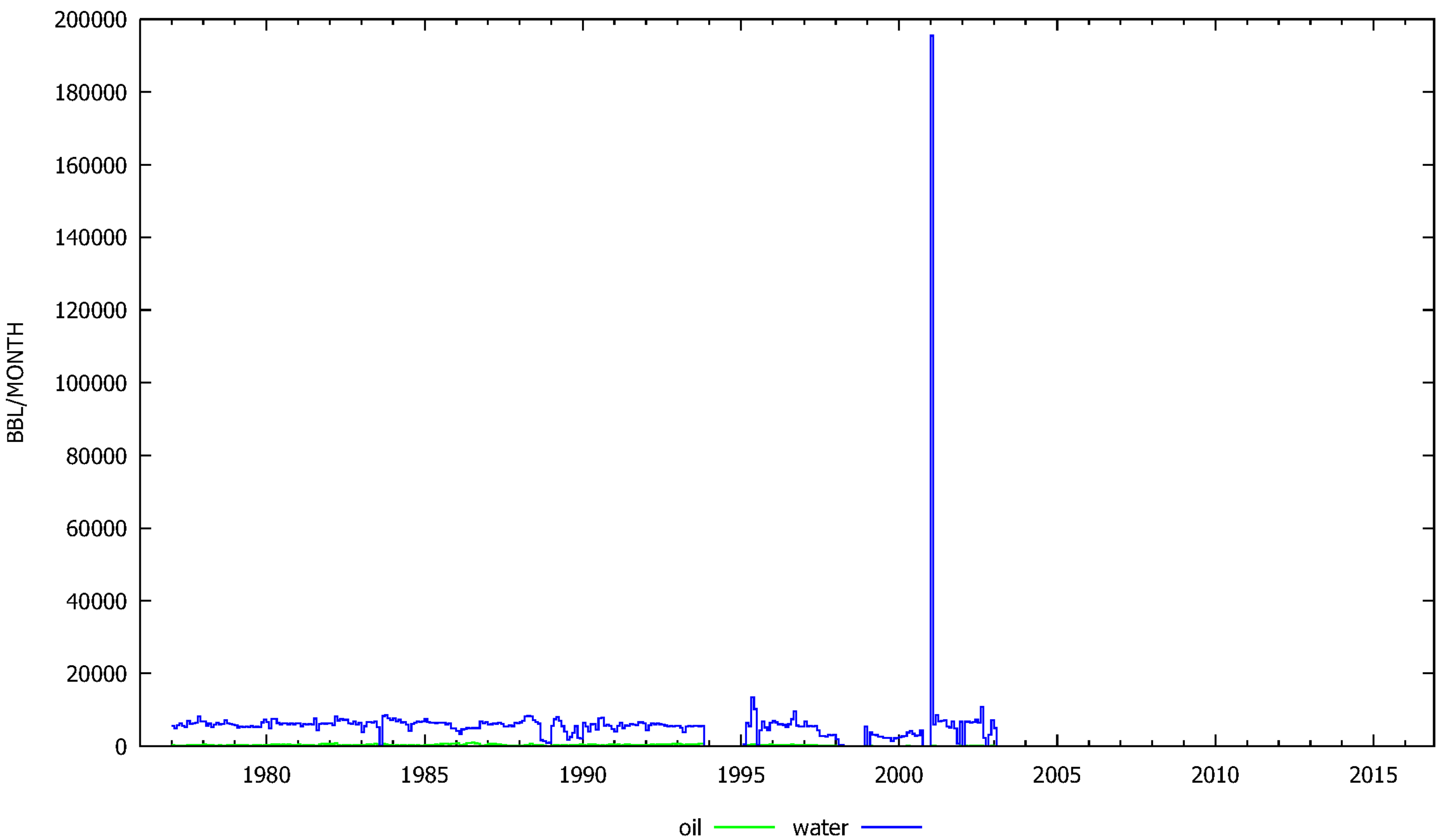
WELL Porter 70



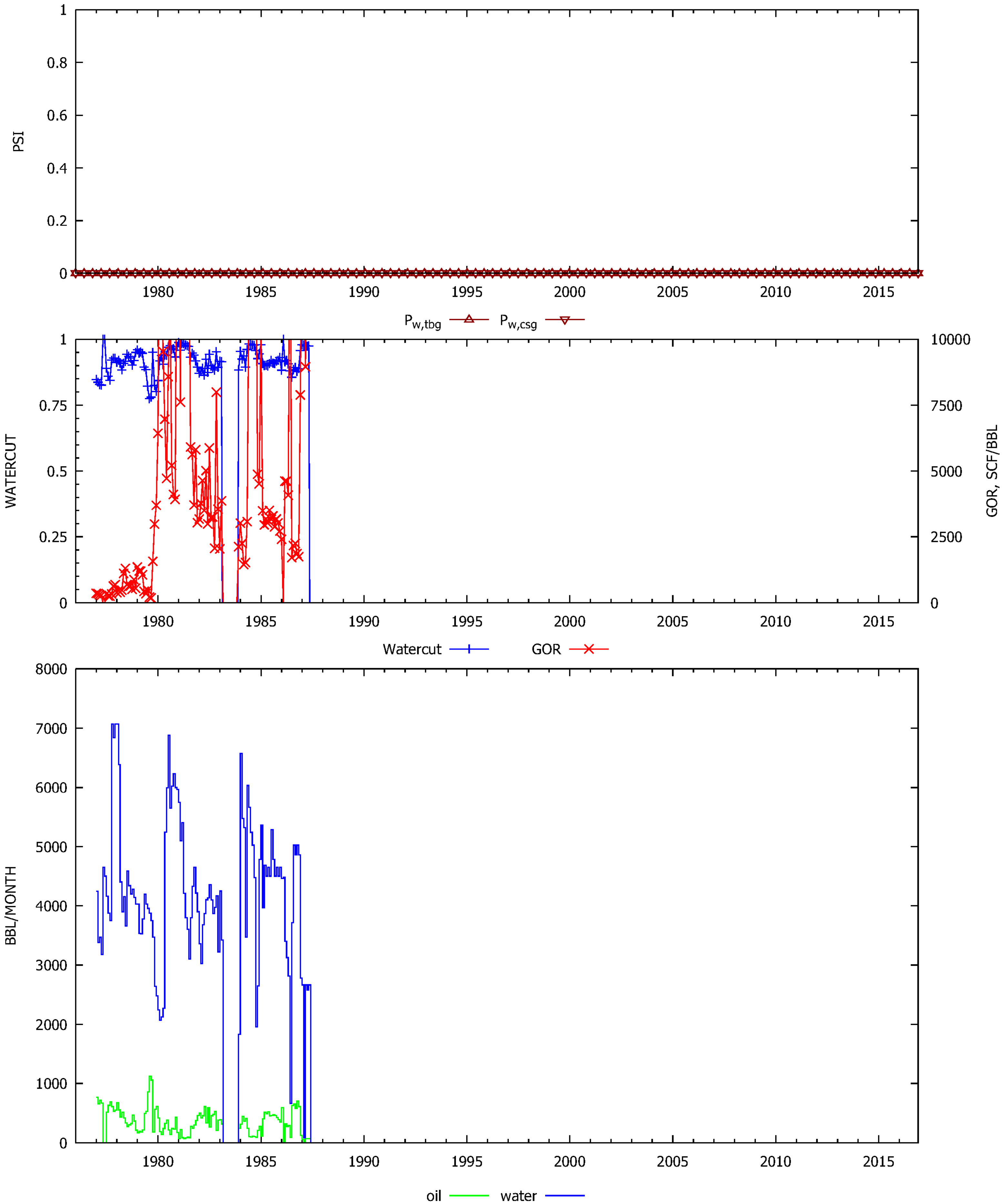
WELL Porter 71



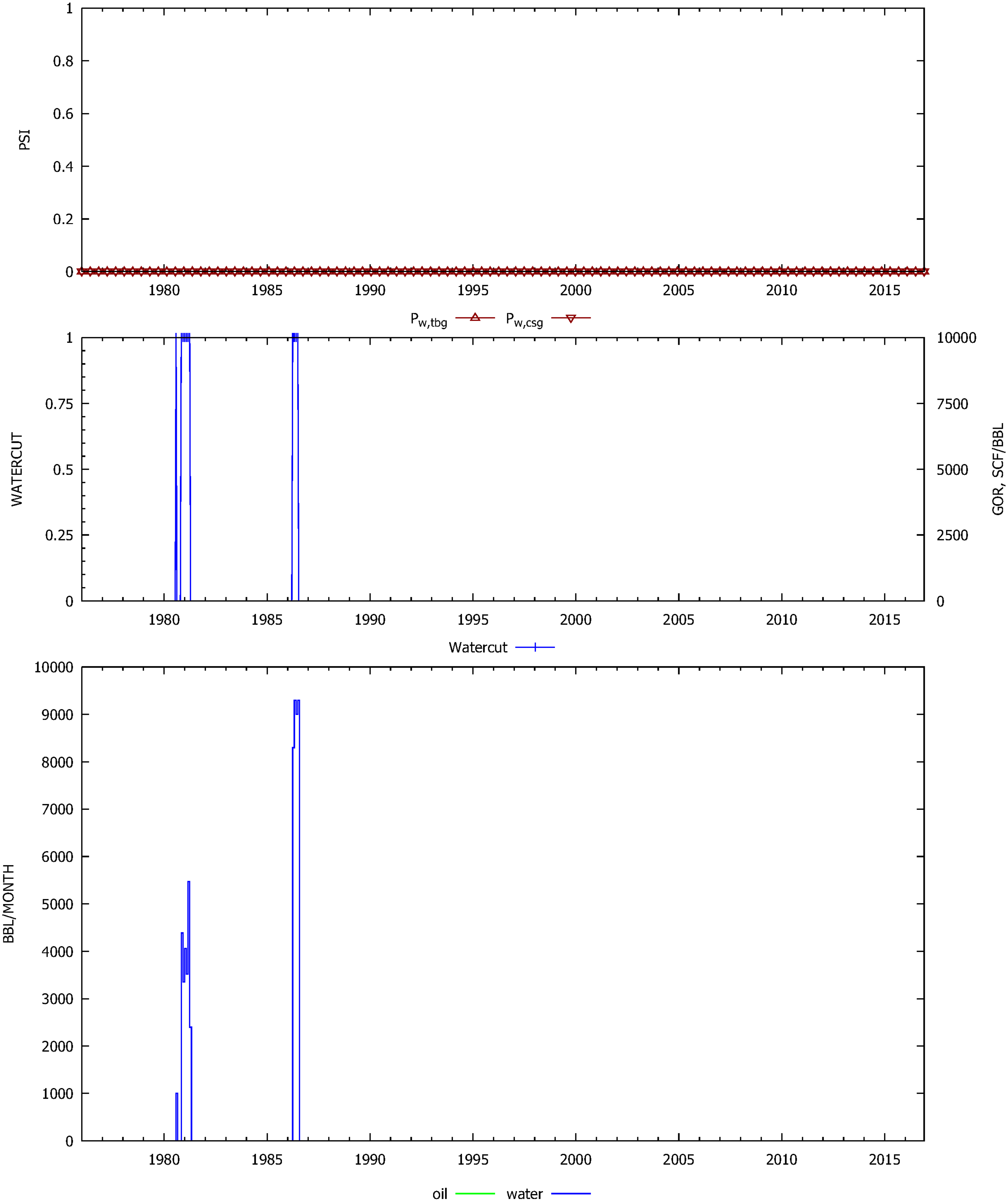




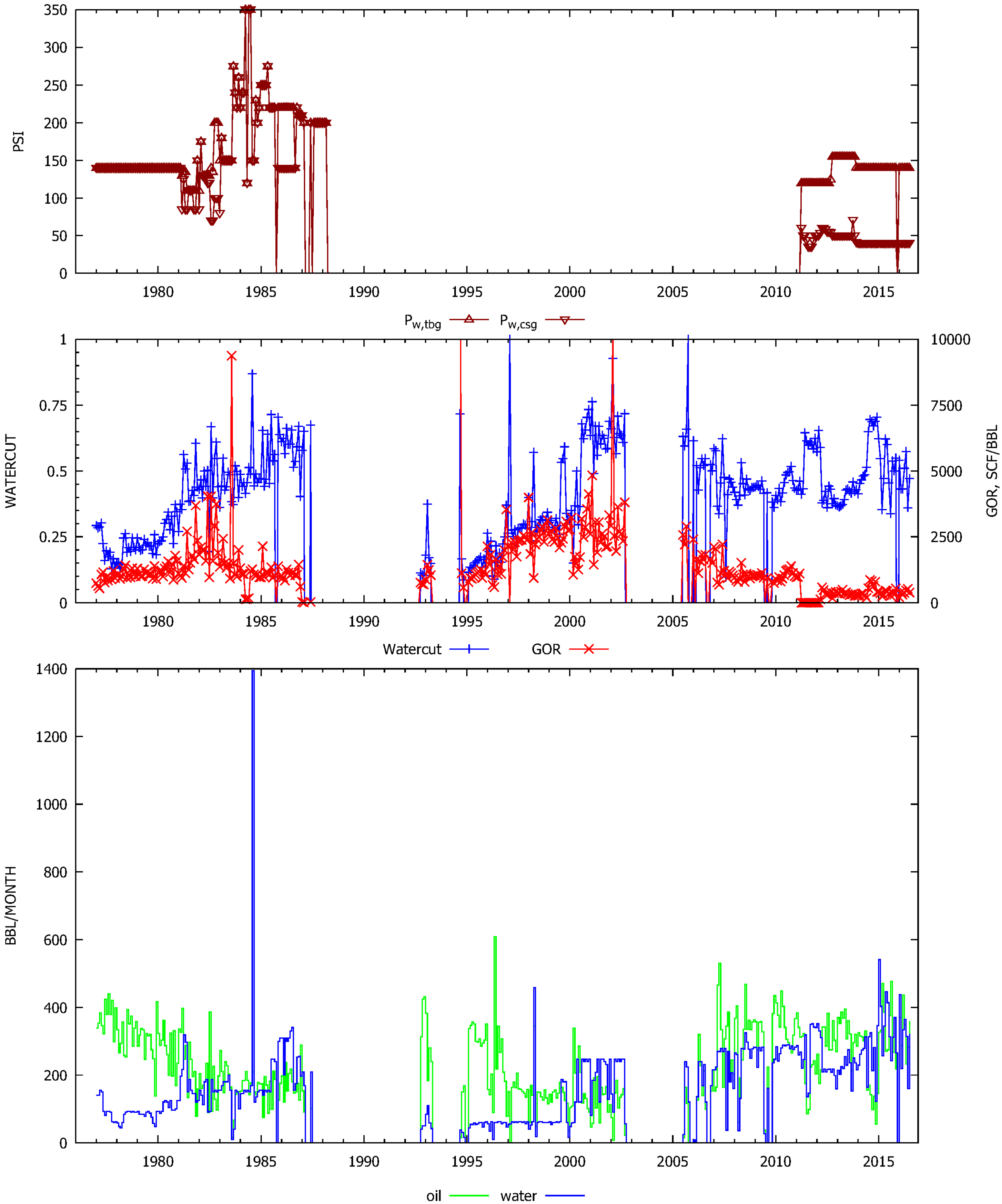
WELL Porter 72



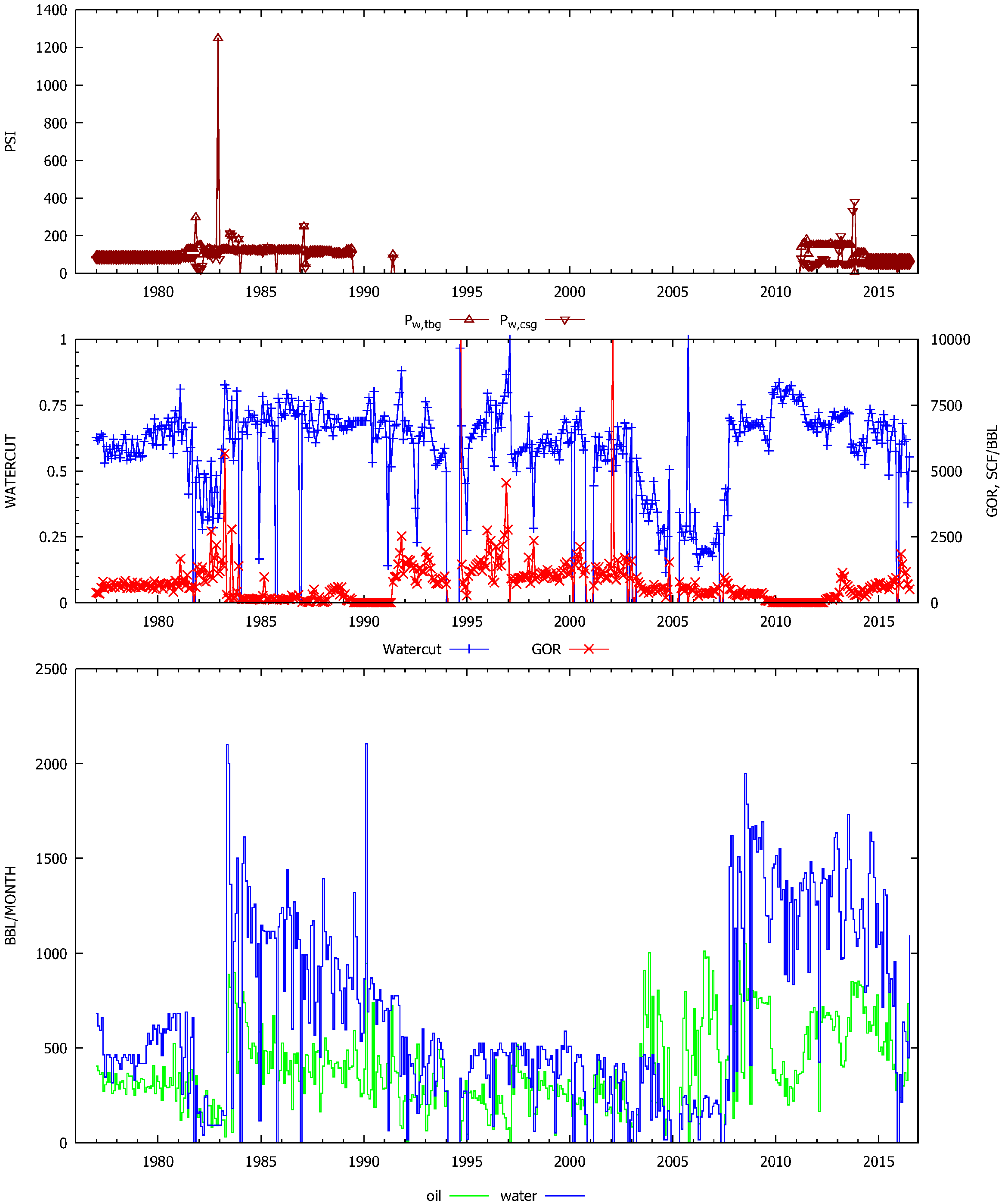
WELL Porter-Sesnon 20



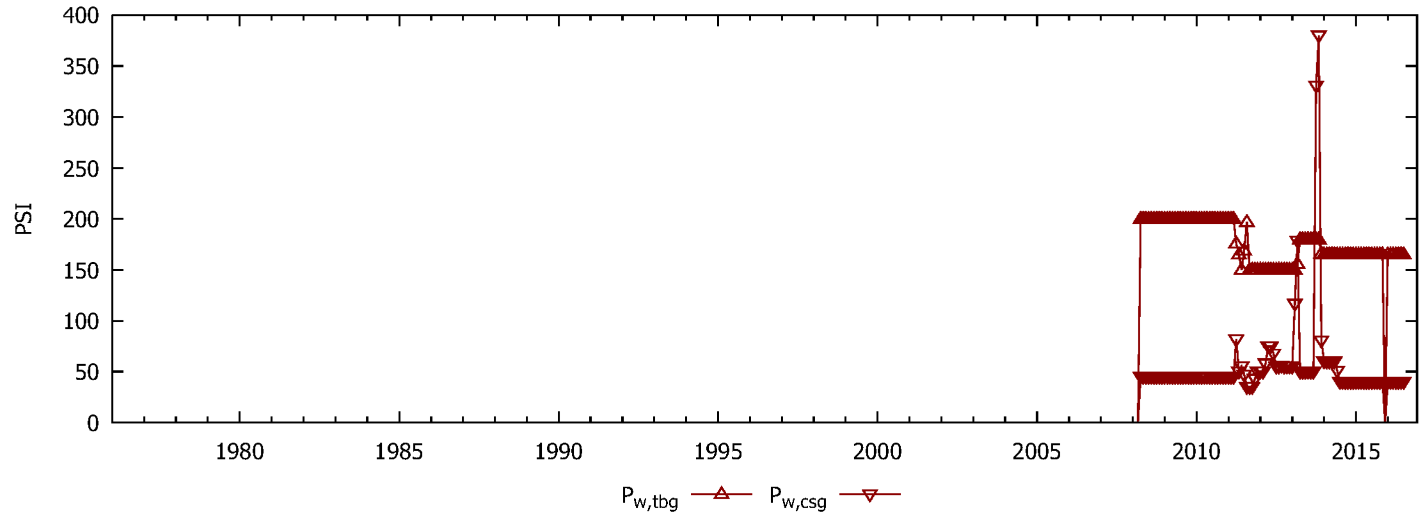
WELL Roosa 1

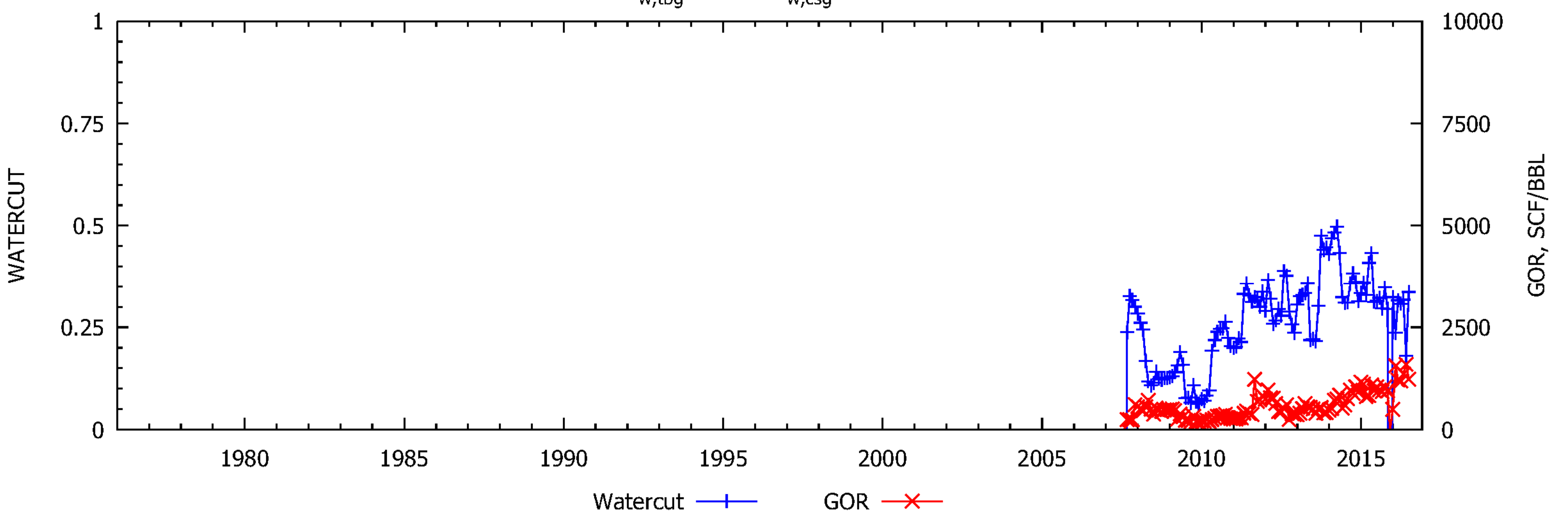

PSI
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
oil
water

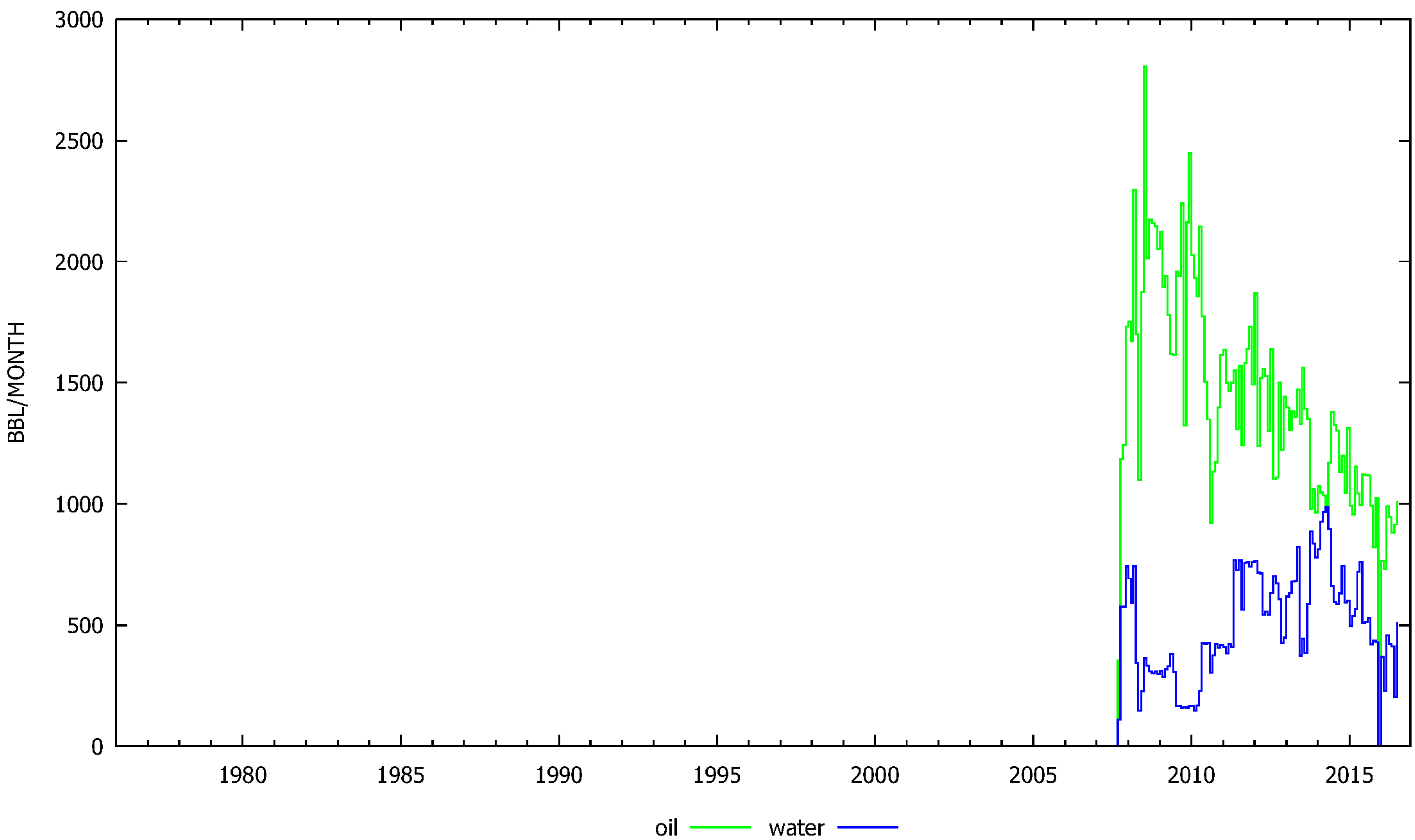
WELL Roosa 2


PSI
1400
1200
1000
800
600
400
200
0
1980
1985
1990
1995
2000
2005
2010
2015
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
1
0.75
0.5
0.25
0
10000
7500
5000
2500
0
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
2500
2000
1500
1000
500
0
oil
water

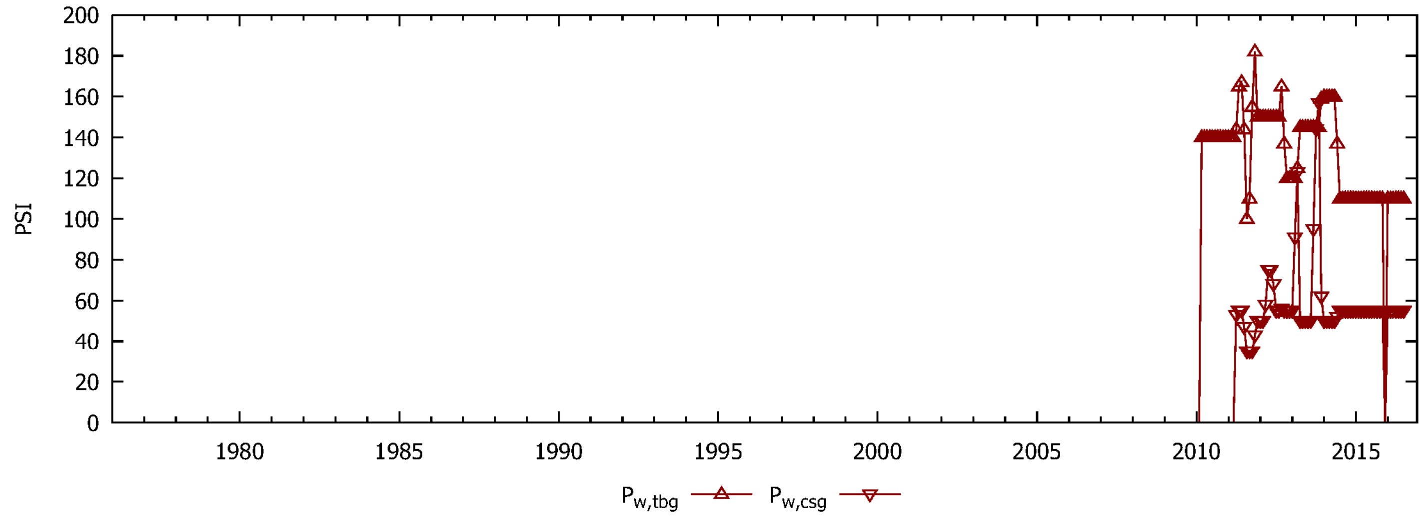
WELL Roosa 3


PSI
400
350
300
250
200
150
100
50
0
1980
1985
1990
1995
2000
2005
2010
2015
$P_{w,tbg}$
$P_{w,csg}$

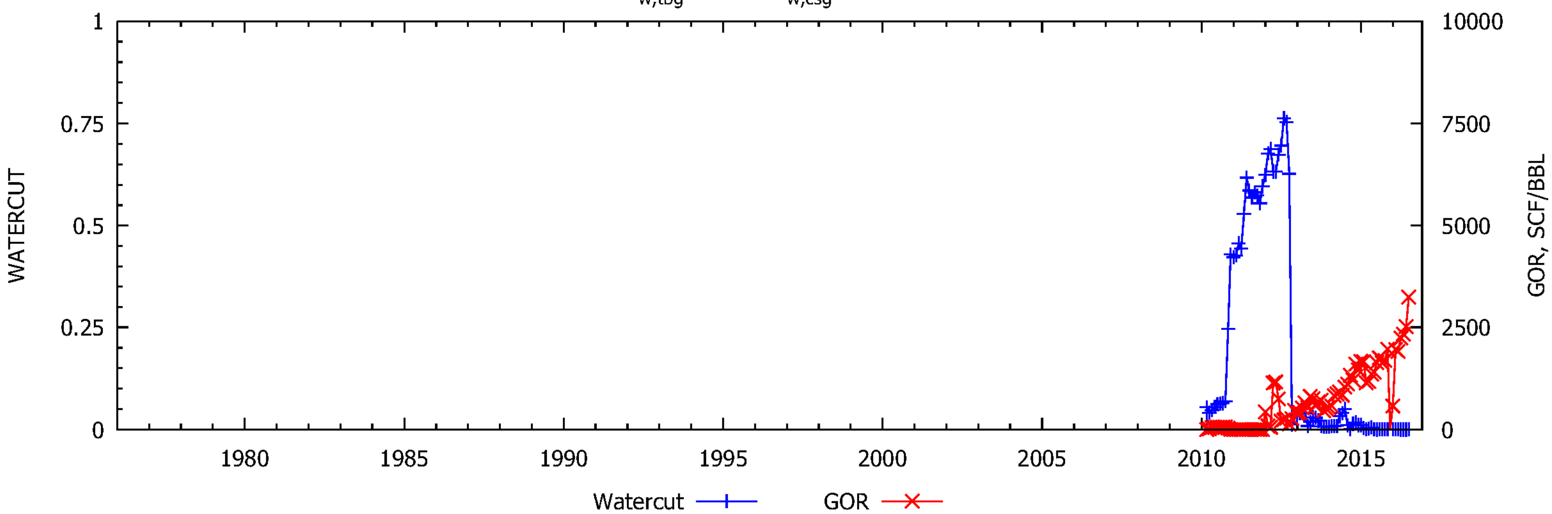

WATERCUT
1
0.75
0.5
0.25
0
GOR, SCF/BBL
10000
7500
5000
2500
0
1980
1985
1990
1995
2000
2005
2010
2015
Watercut
GOR


BBL/MONTH
3000
2500
2000
1500
1000
500
0
1980
1985
1990
1995
2000
2005
2010
2015
oil
water

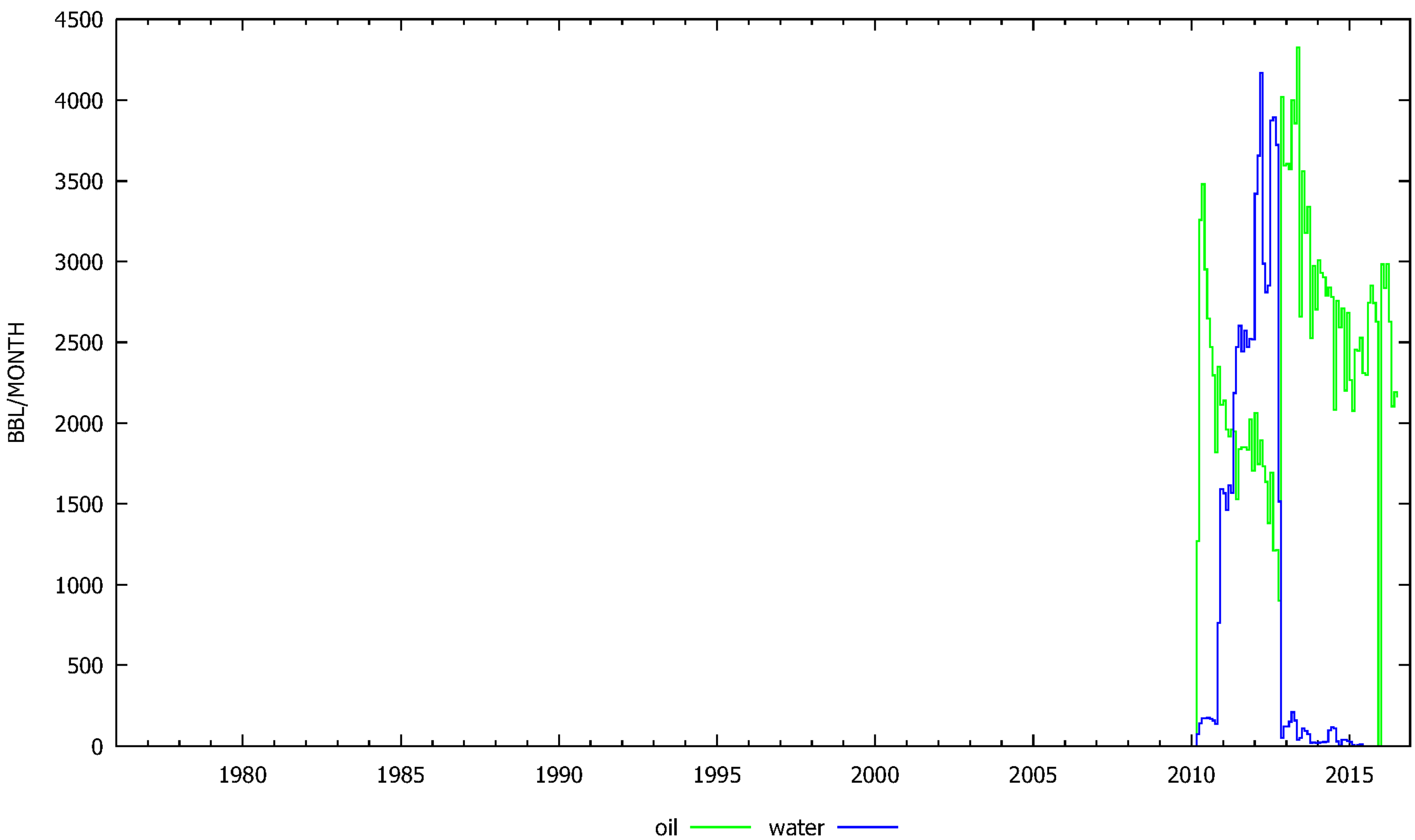
WELL Roosa 4



PSI
200
180
160
140
120
100
80
60
40
20
0
1980
1985
1990
1995
2000
2005
2010
2015
$P_{w,tbg}$
$P_{w,csg}$

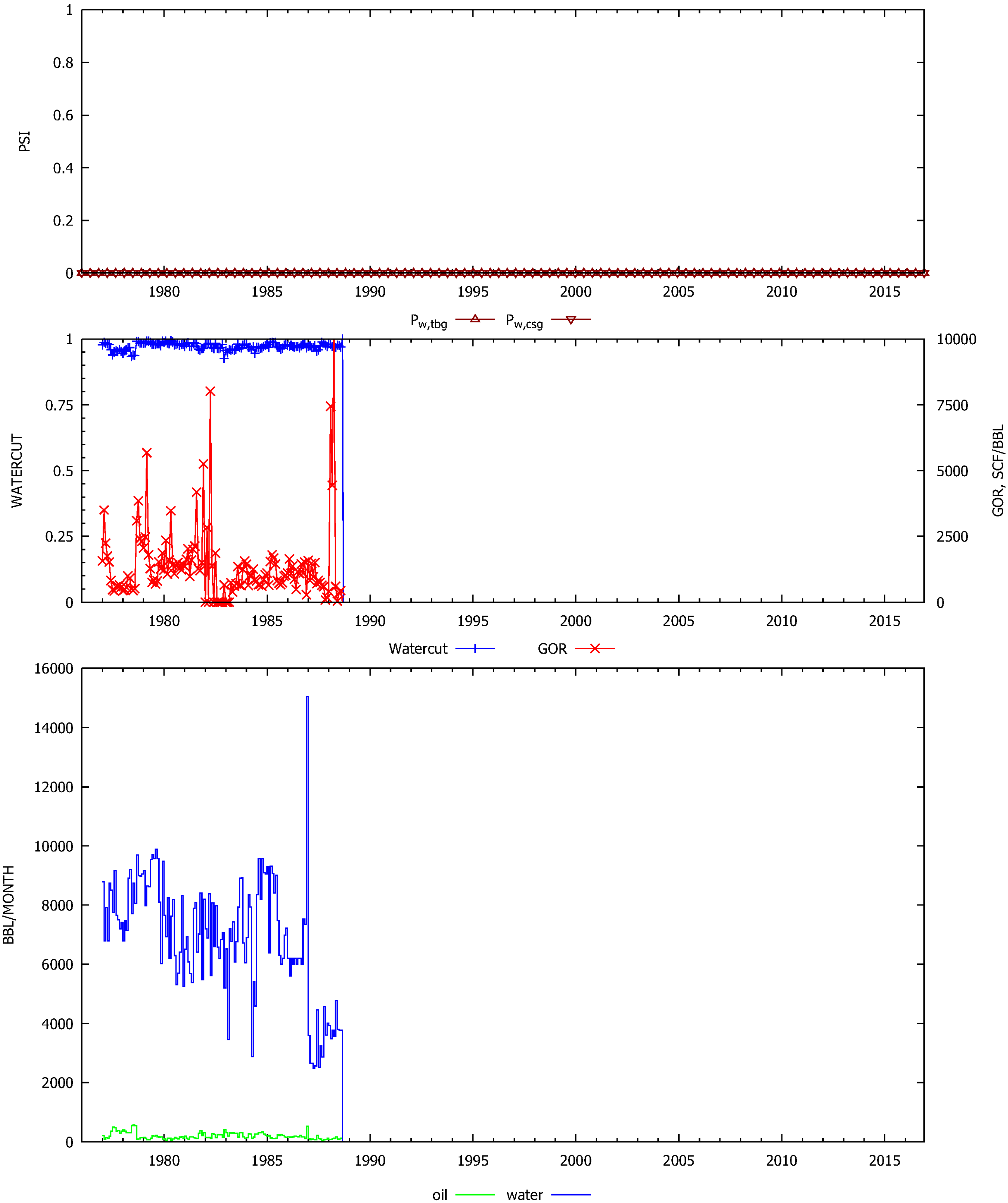


WATERCUT
1
0.75
0.5
0.25
0
10000
7500
5000
2500
0
GOR, SCF/BBL
1980
1985
1990
1995
2000
2005
2010
2015
Watercut
GOR

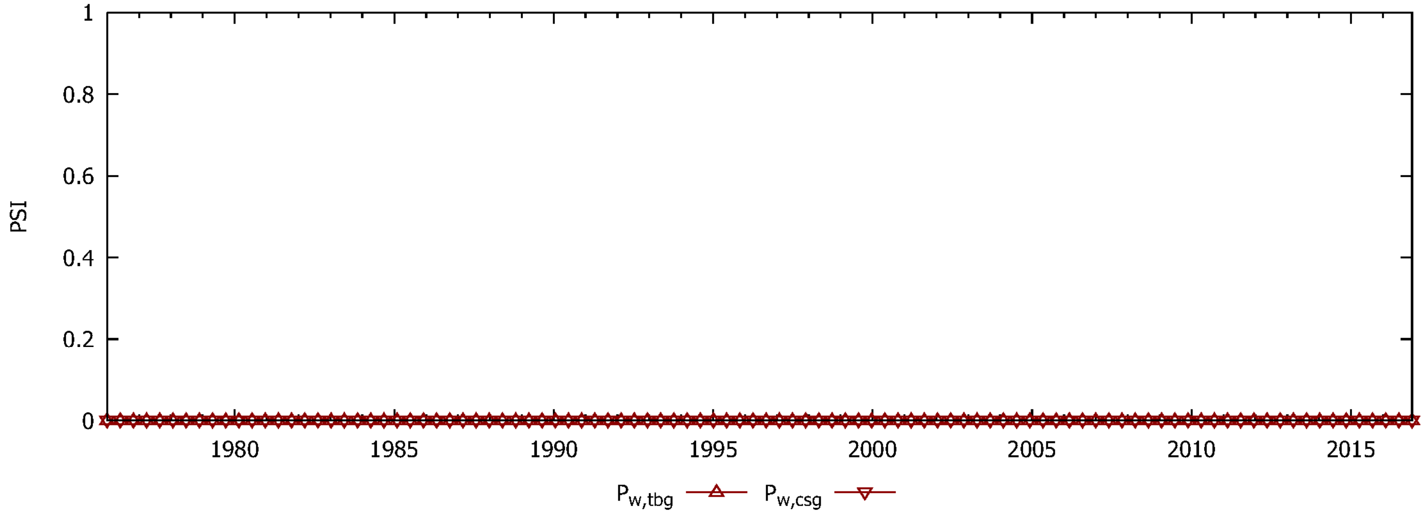


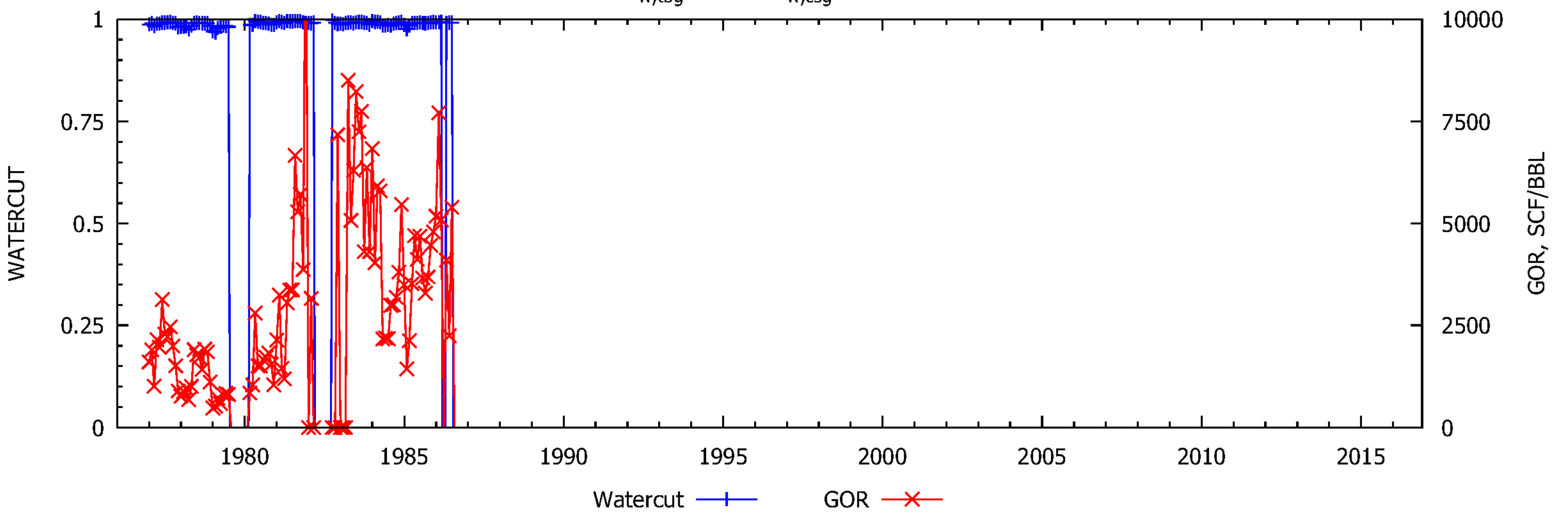
BBL/MONTH
4500
4000
3500
3000
2500
2000
1500
1000
500
0
1980
1985
1990
1995
2000
2005
2010
2015
oil
water

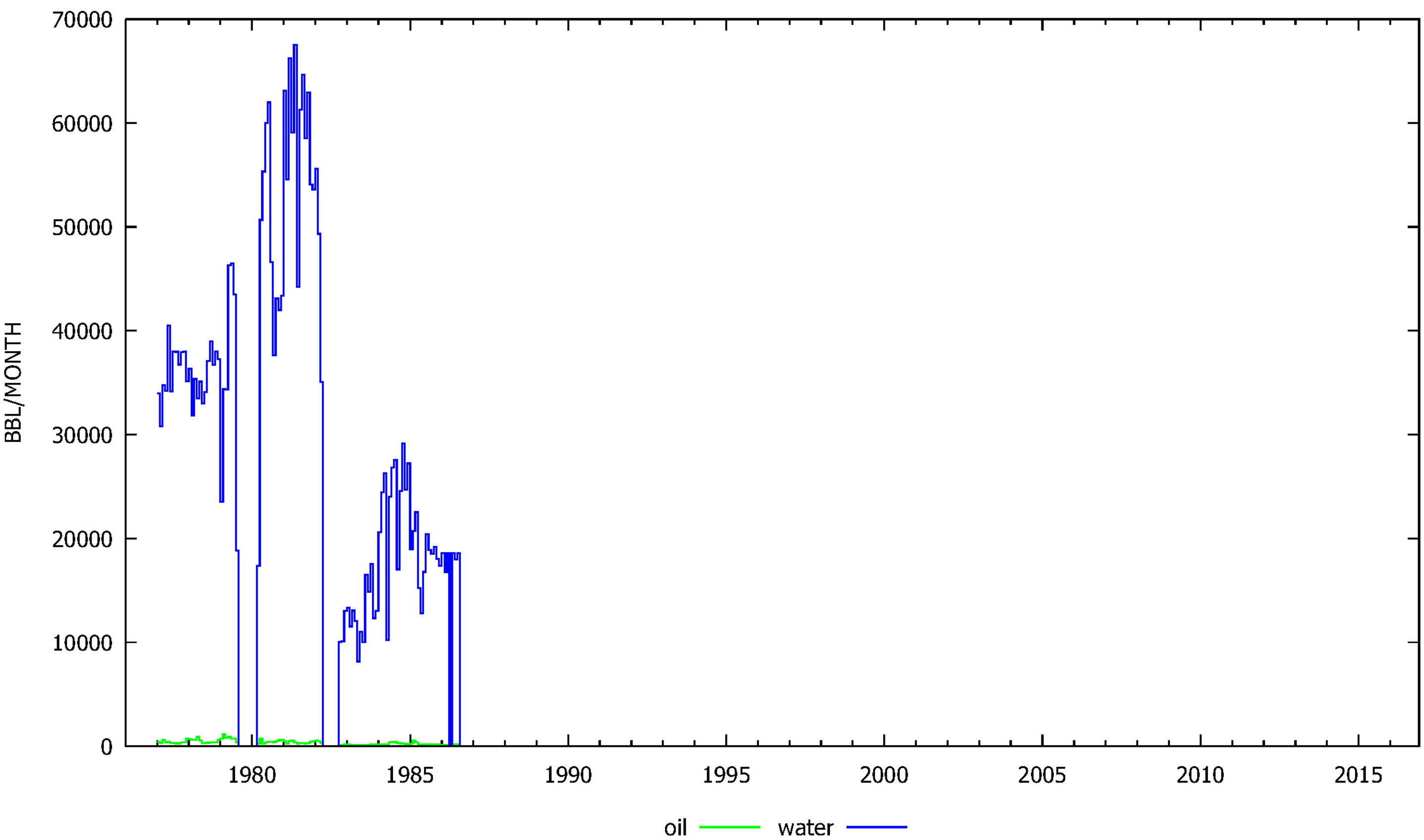
WELL Standard-Sesnon 1 15P



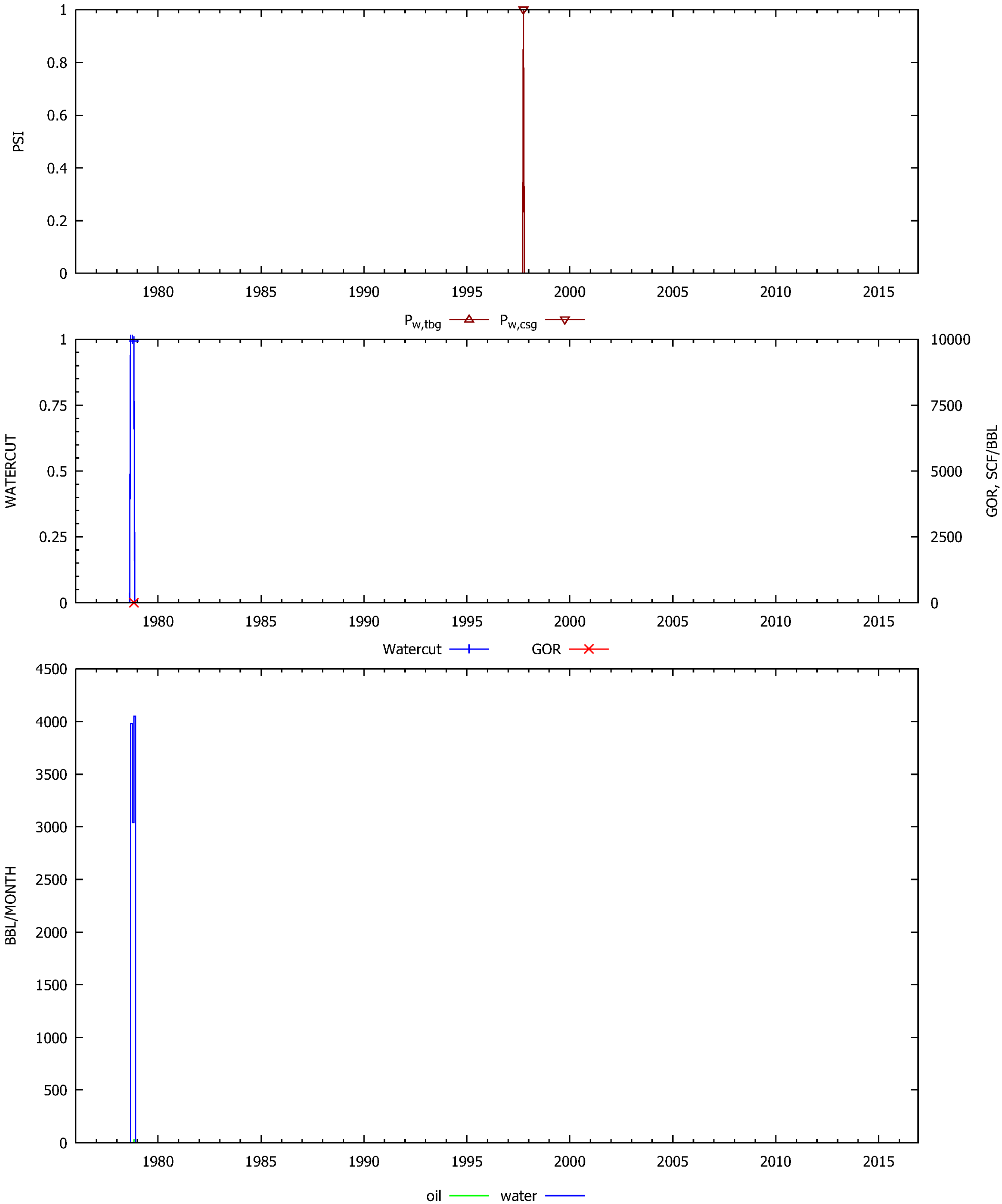
WELL Standard-Sesnon 1 18



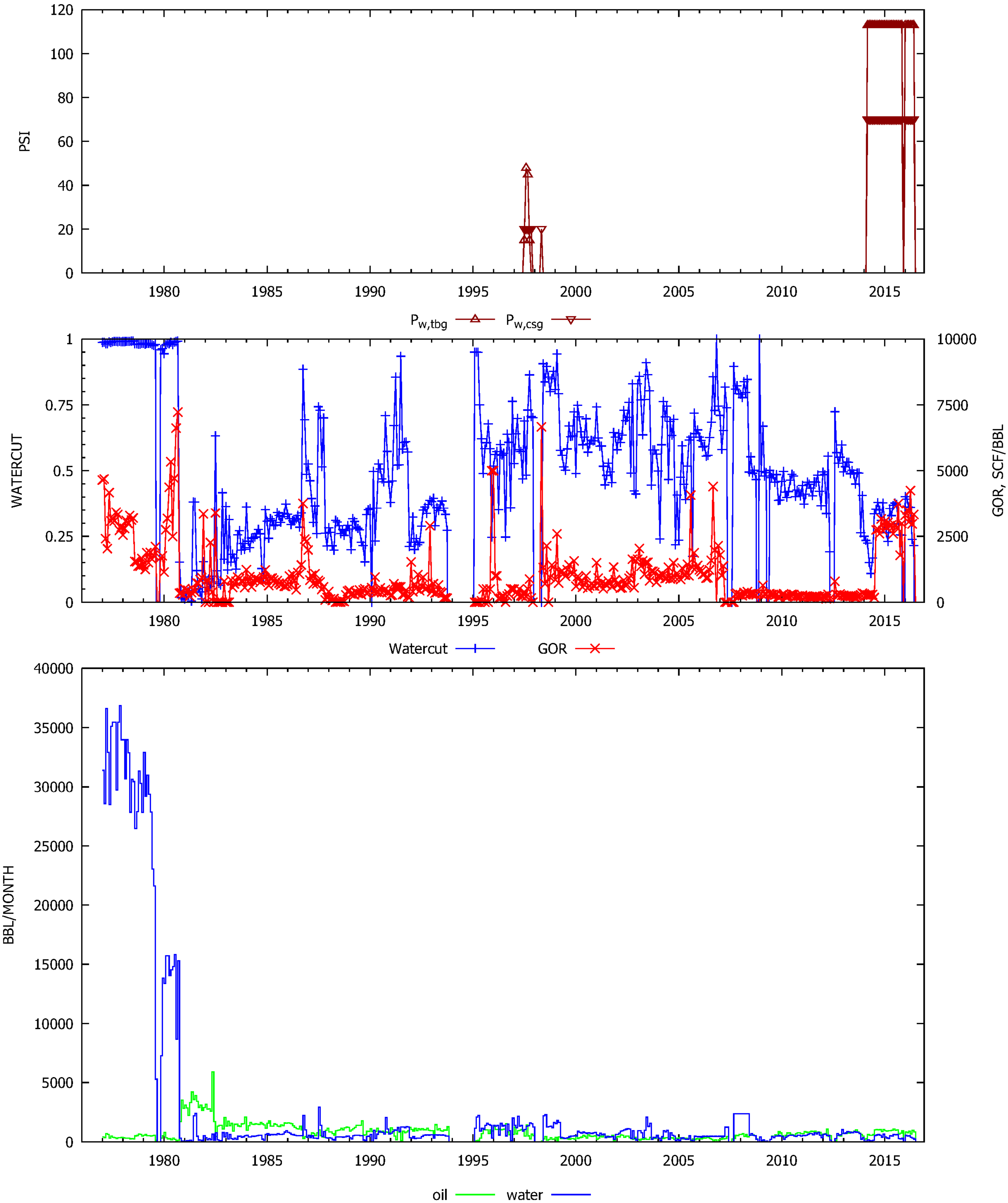




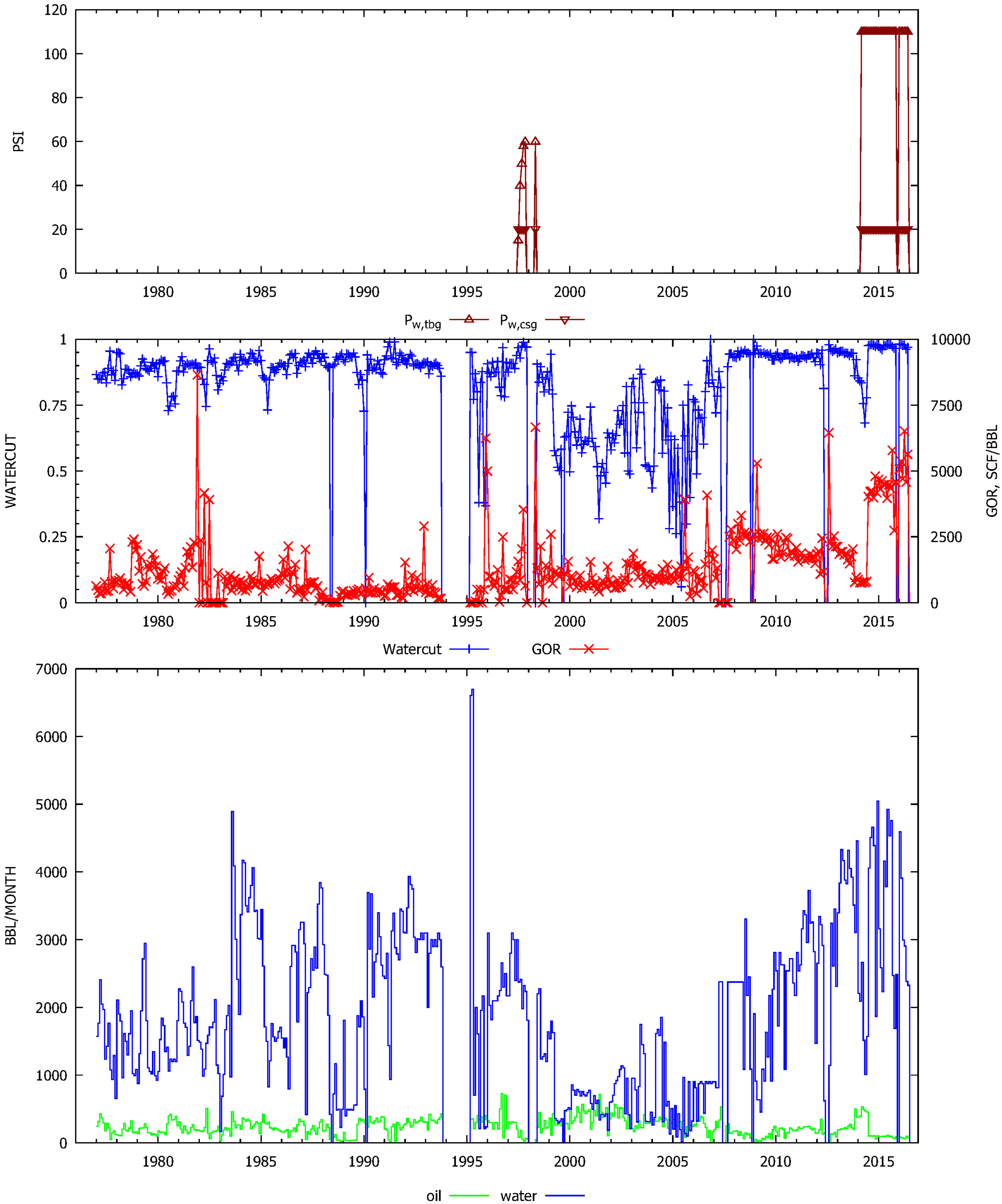
WELL Standard-Sesnon 1 19



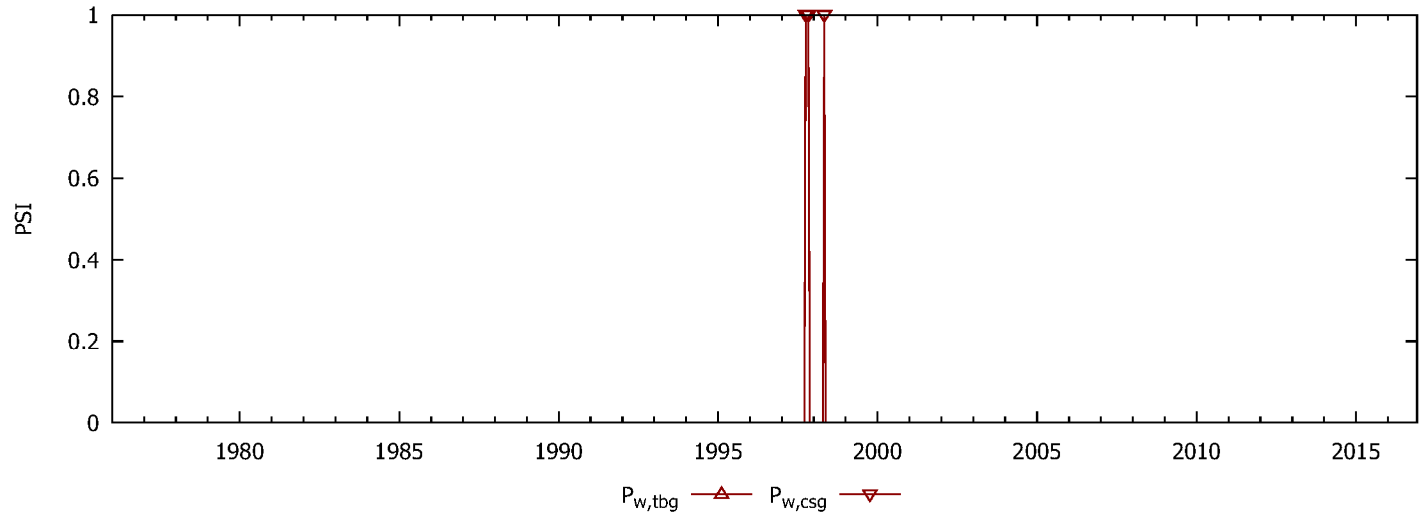
WELL Standard-Sesnon 1 21

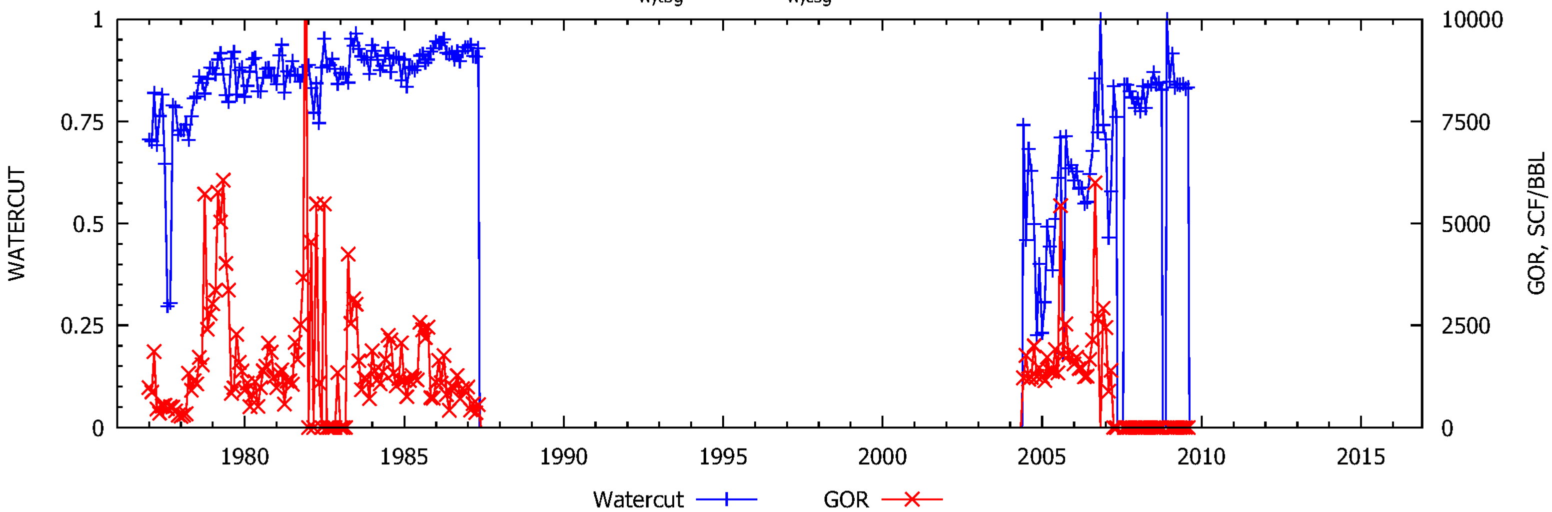


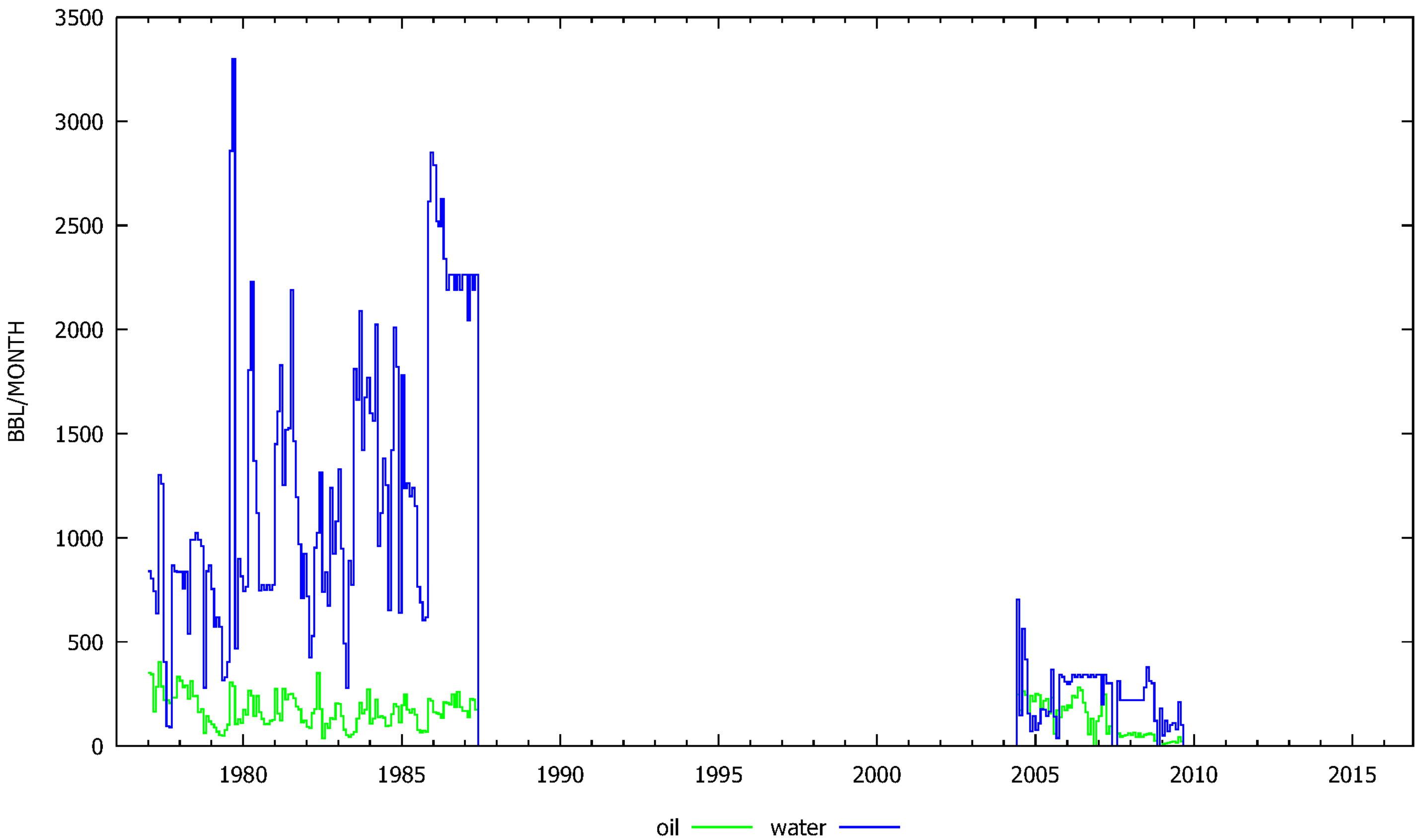
WELL Standard-Sesnon 1 23



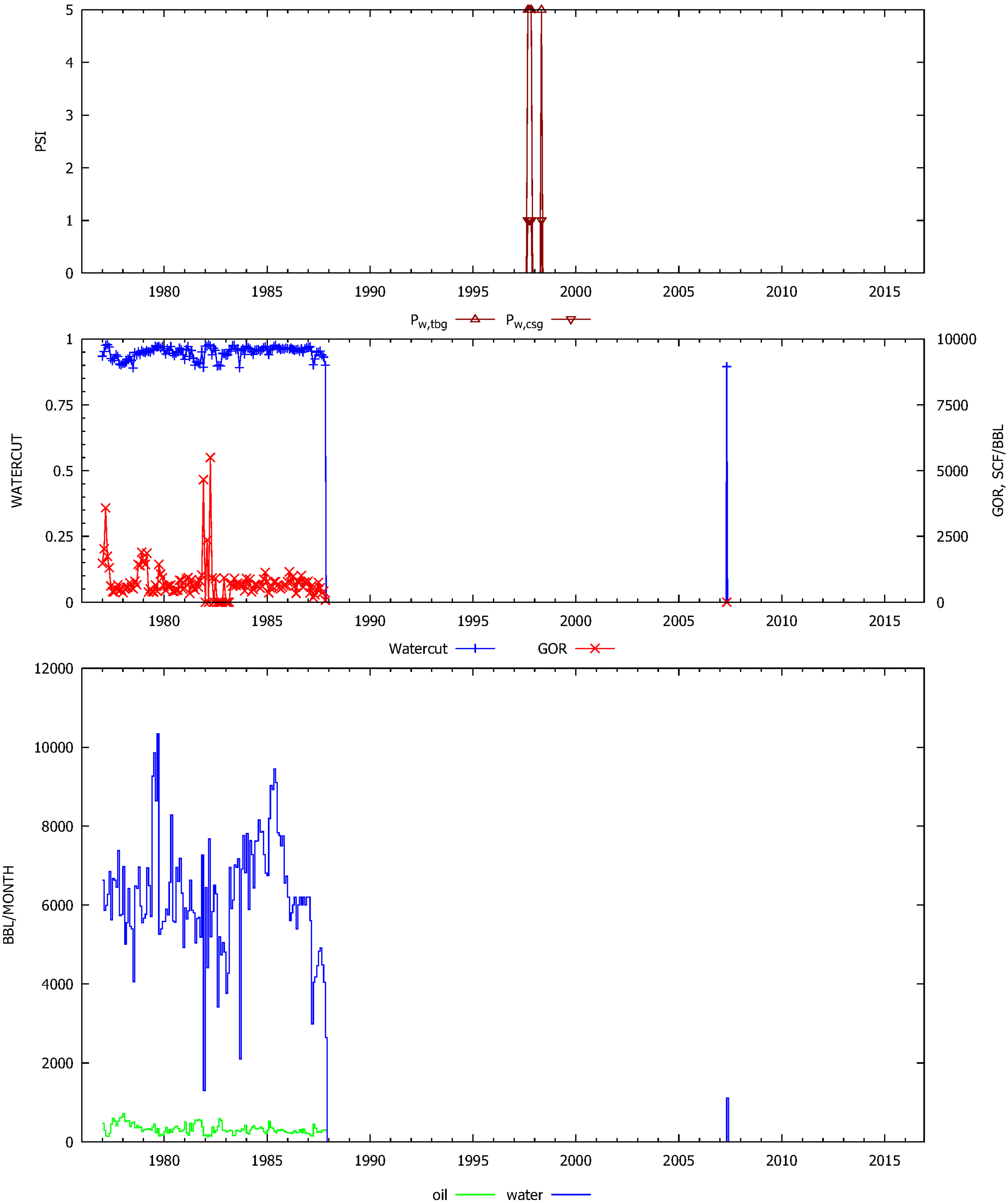
WELL Standard-Sesnon 1 26



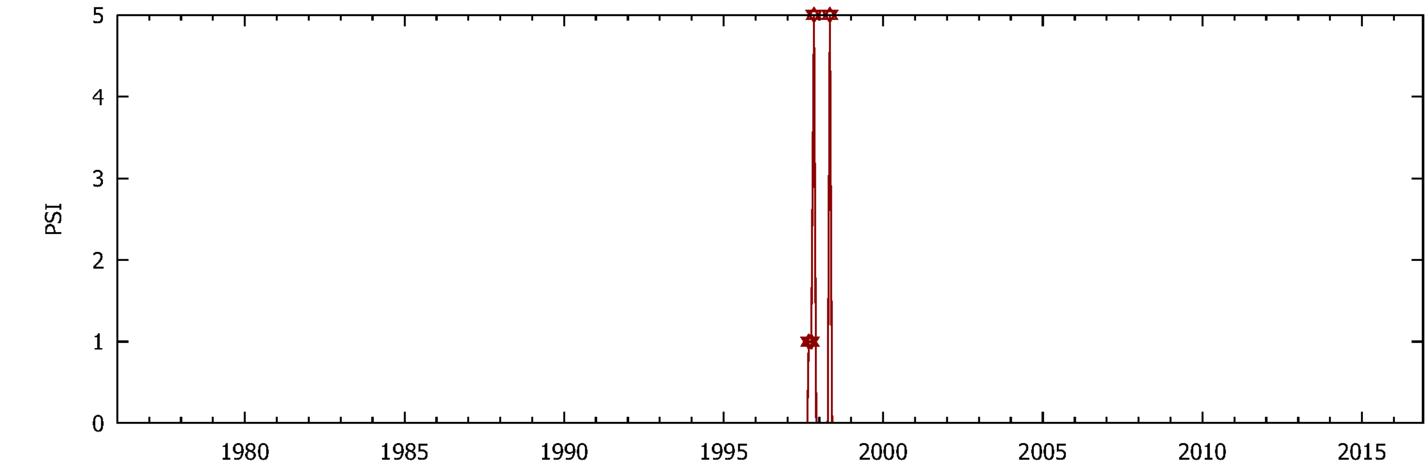


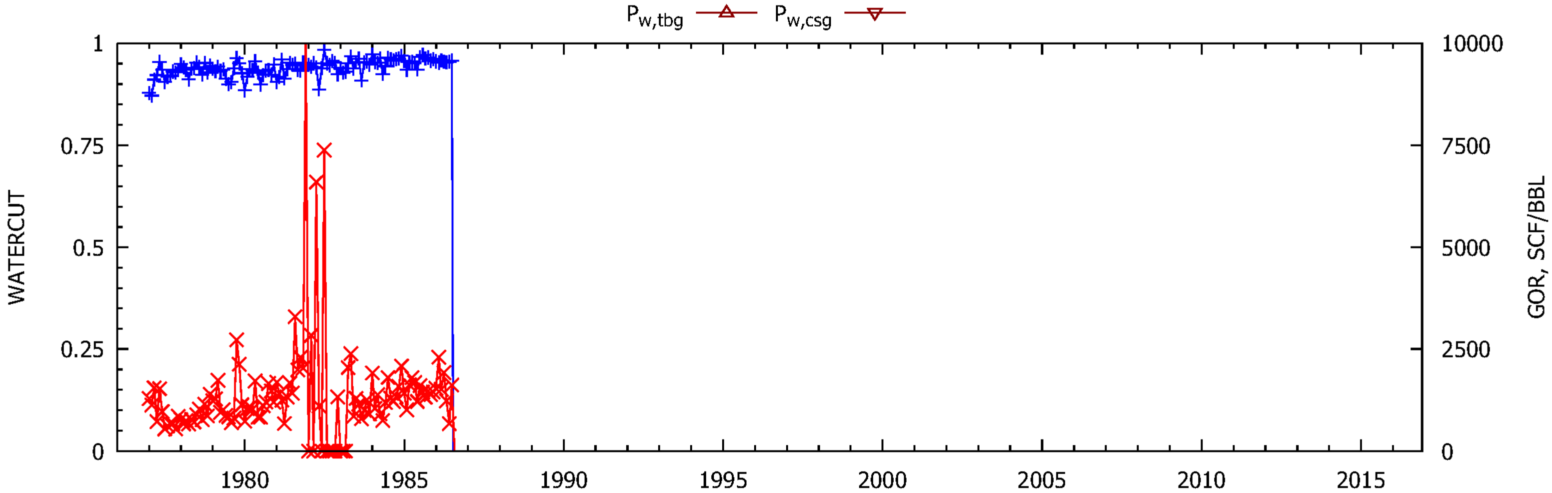


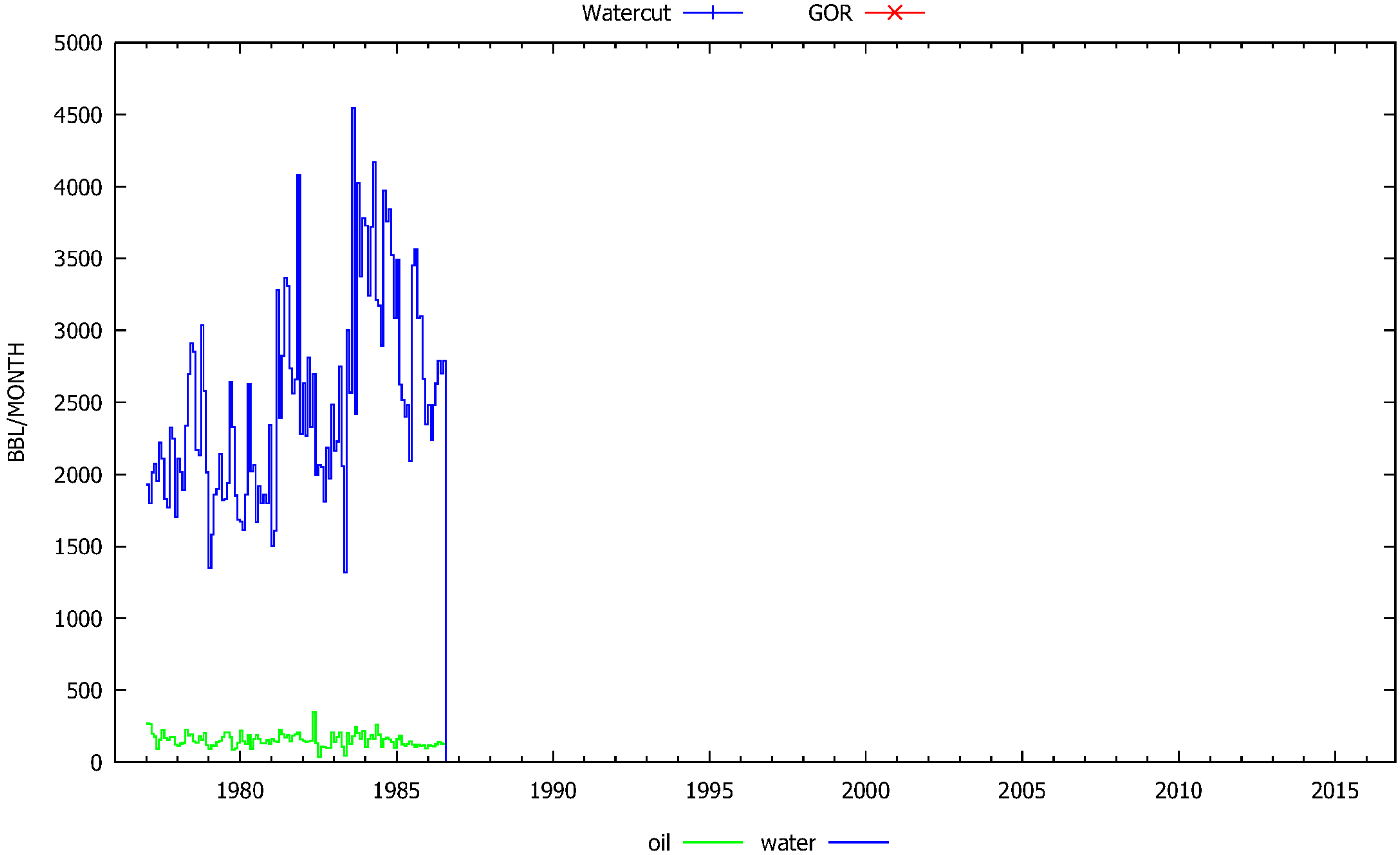
WELL Standard-Sesnon 1 27

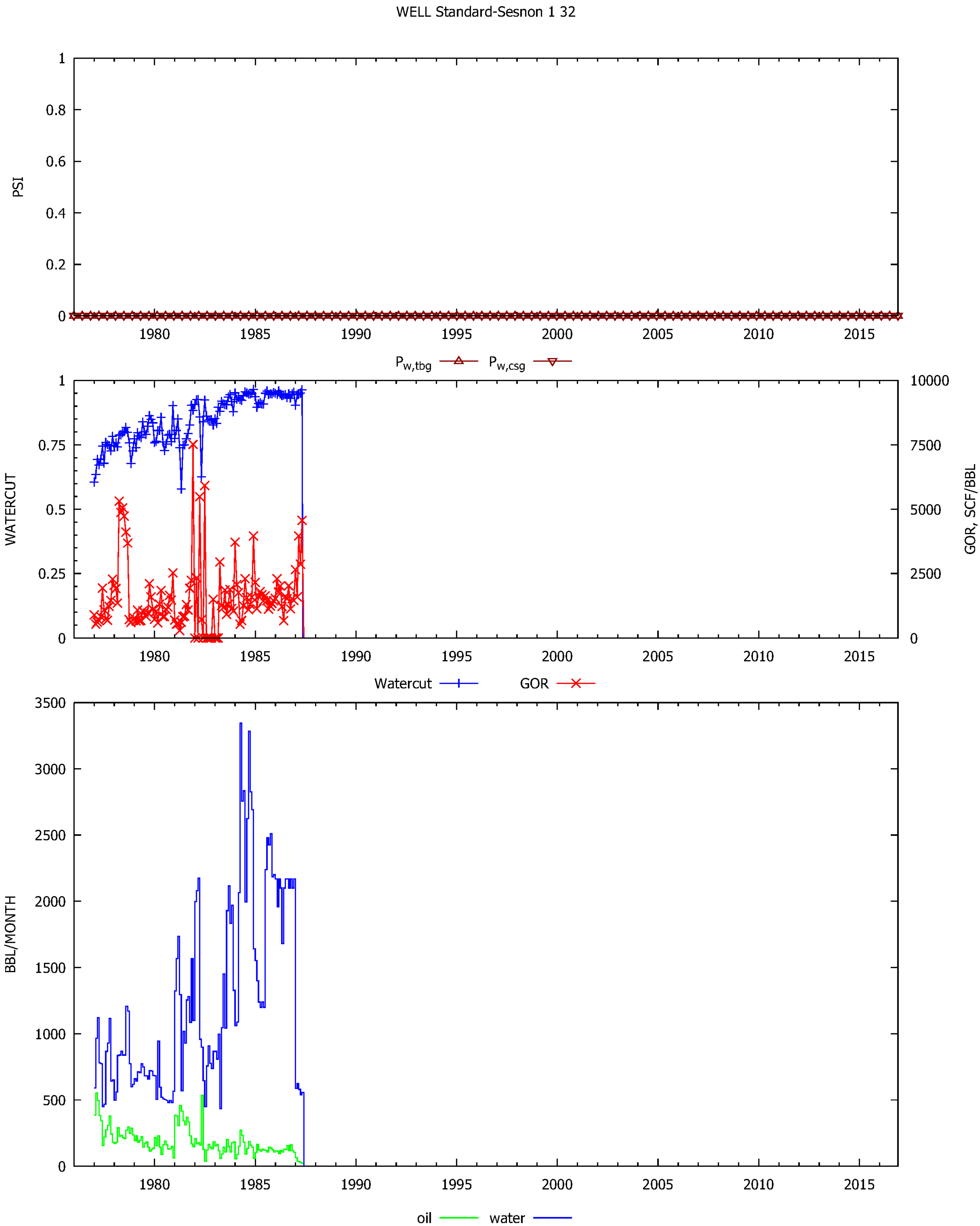


WELL Standard-Sesnon 1 28



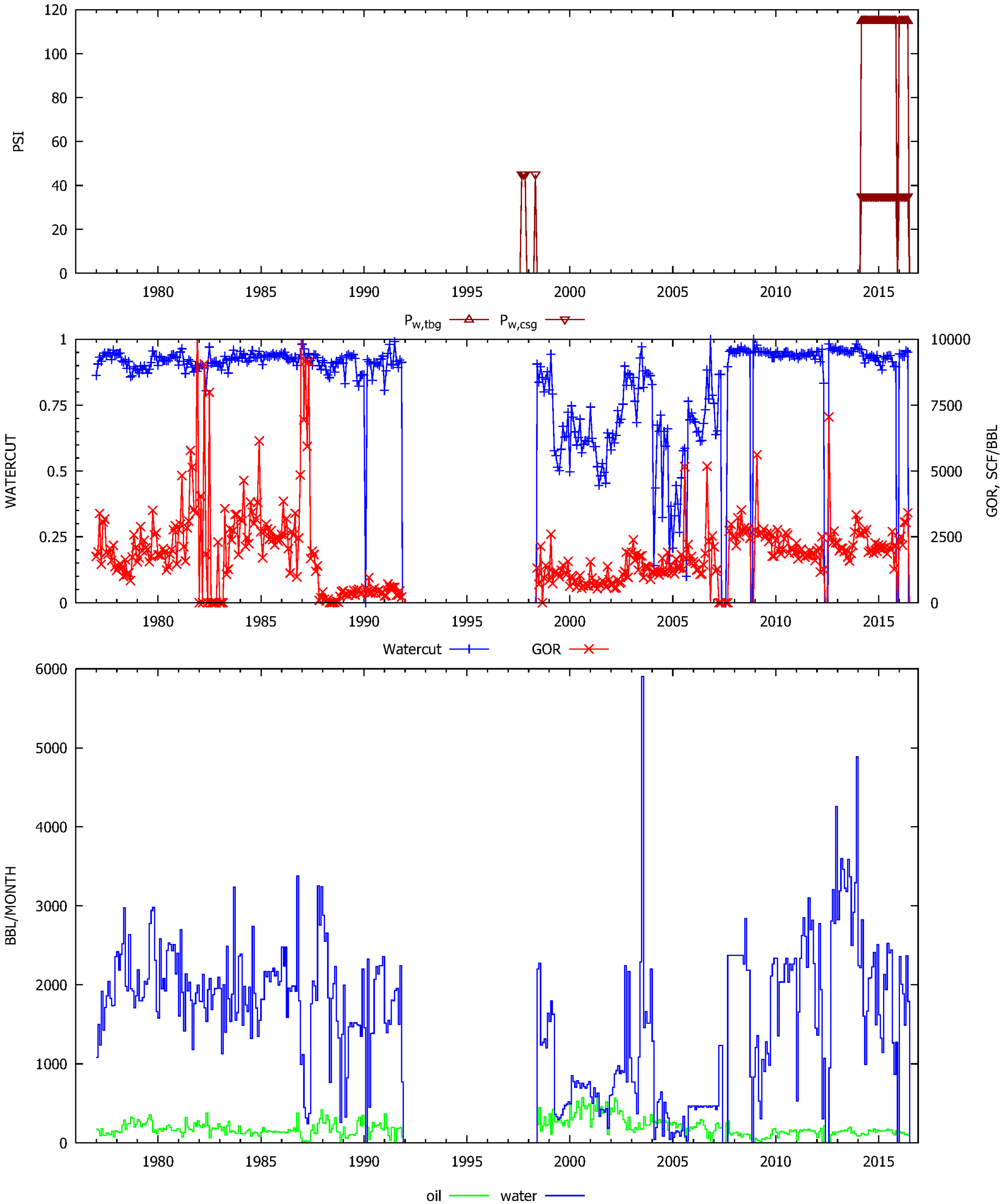




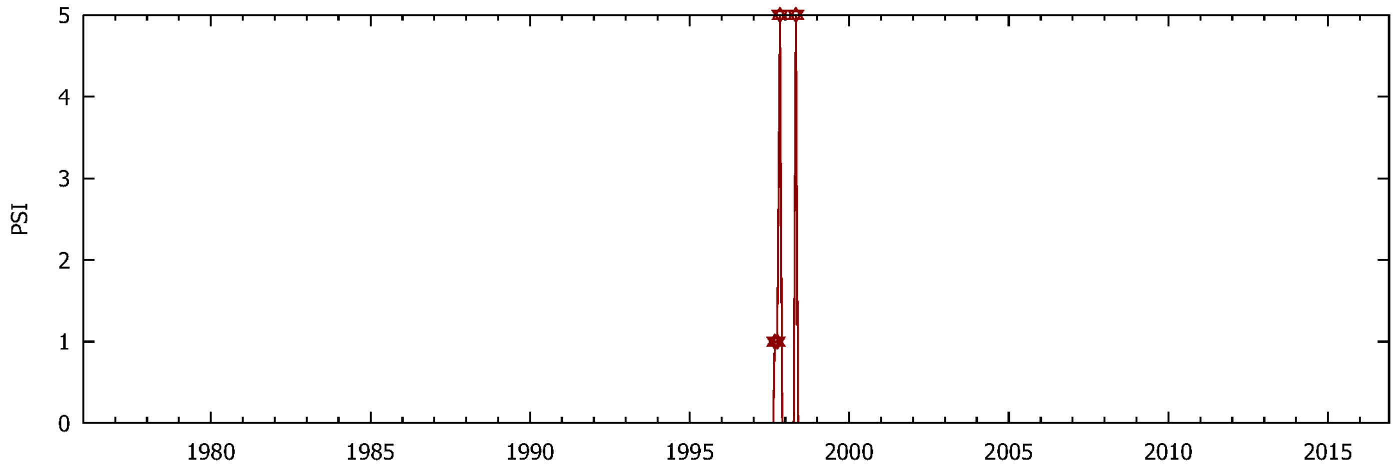


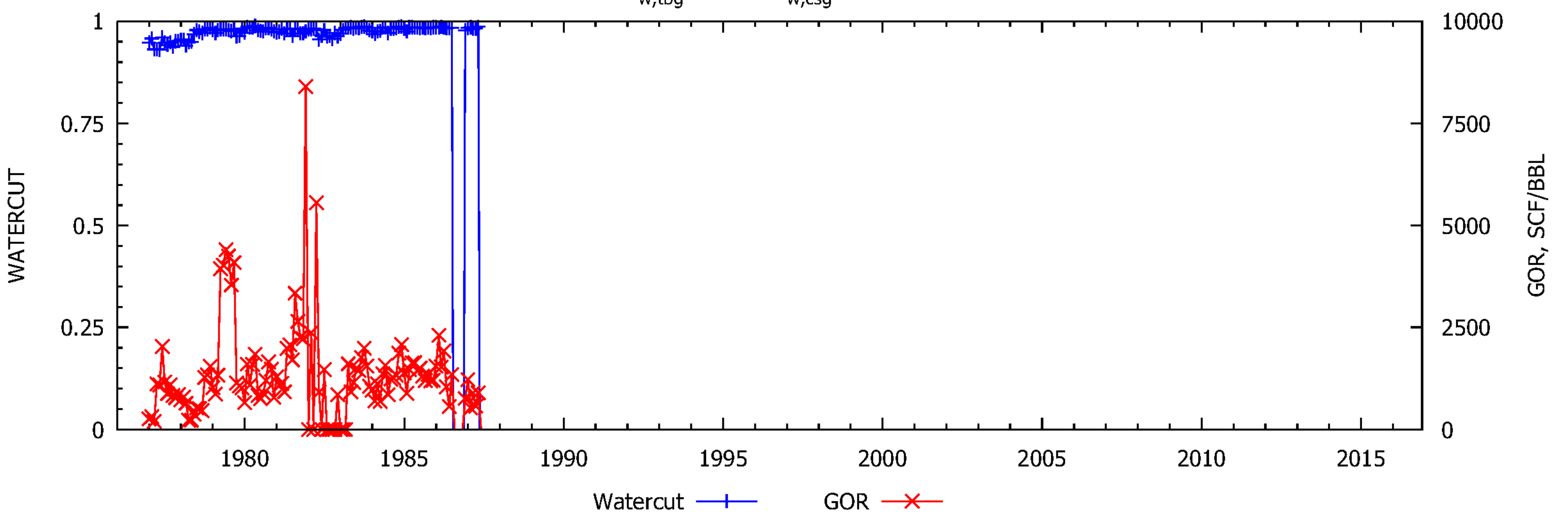
WELL Standard-Sesnon 1 32
PSI
1
0.8
0.6
0.4
0.2
0
1980
1985
1990
1995
2000
2005
2010
2015
$P_{w,tbg}$
$P_{w,csg}$
WATERCUT
0.75
0.5
0.25
10000
7500
5000
2500
GOR, SCF/BBL
Watercut
GOR
BBL/MONTH
3500
3000
2500
2000
1500
1000
500
oil
water

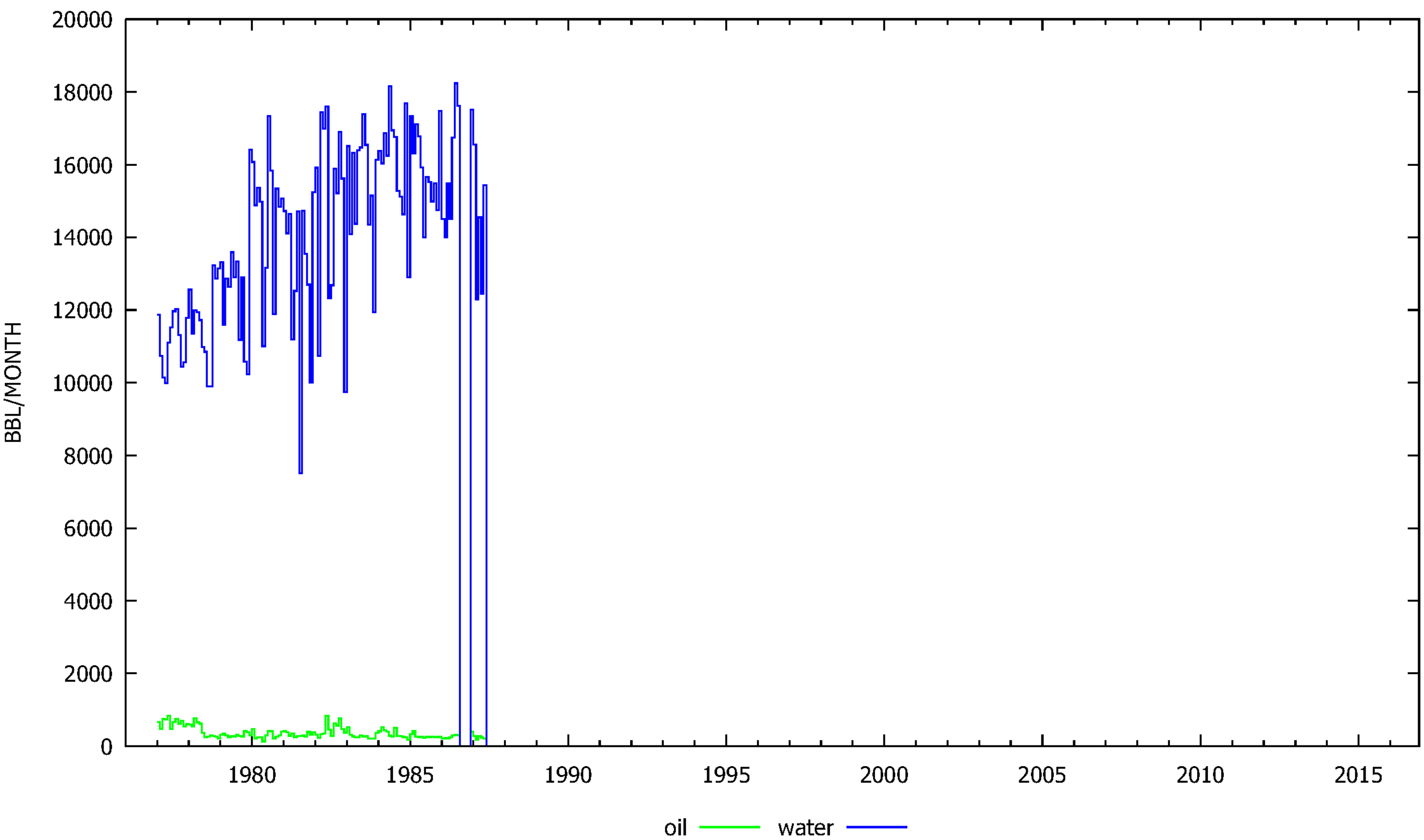
WELL Standard-Sesnon 1 33



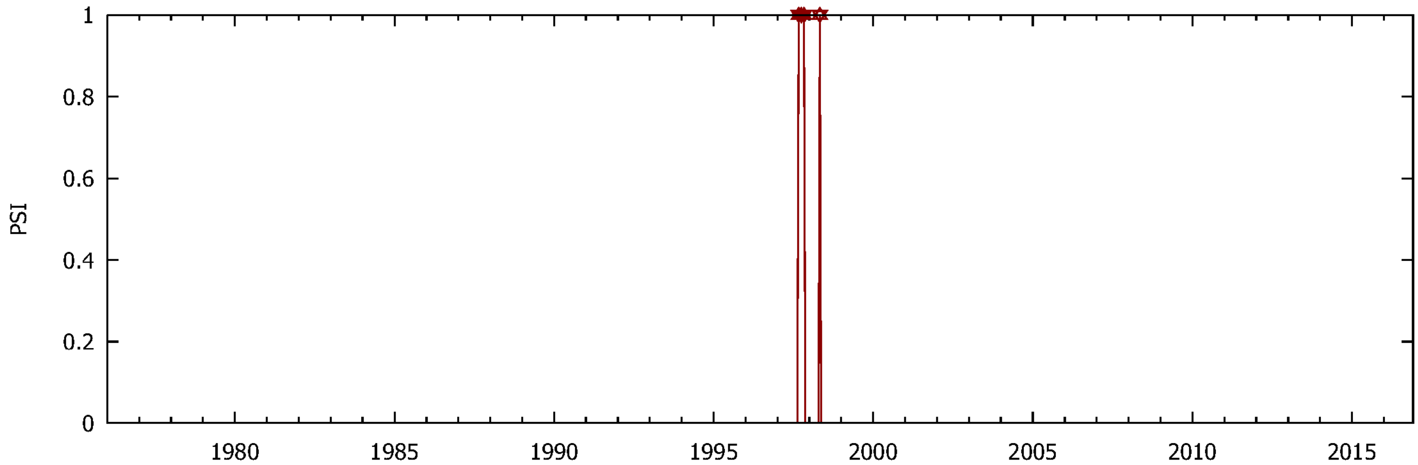
WELL Standard-Sesnon 1 34

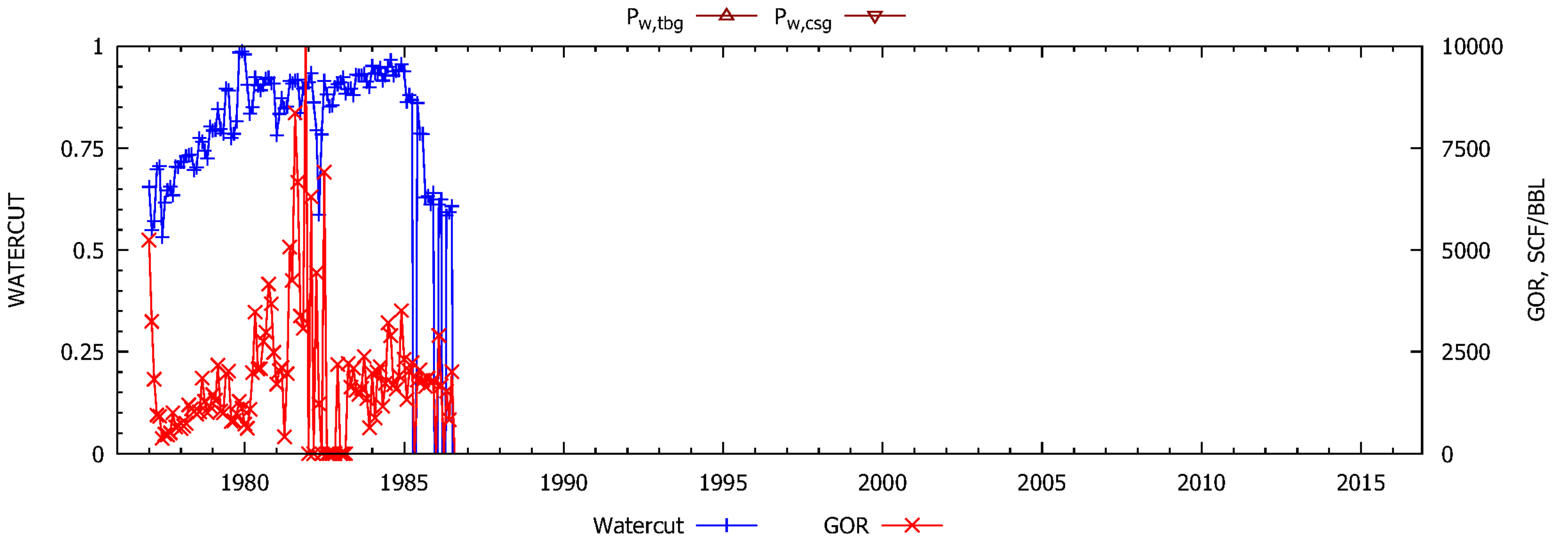


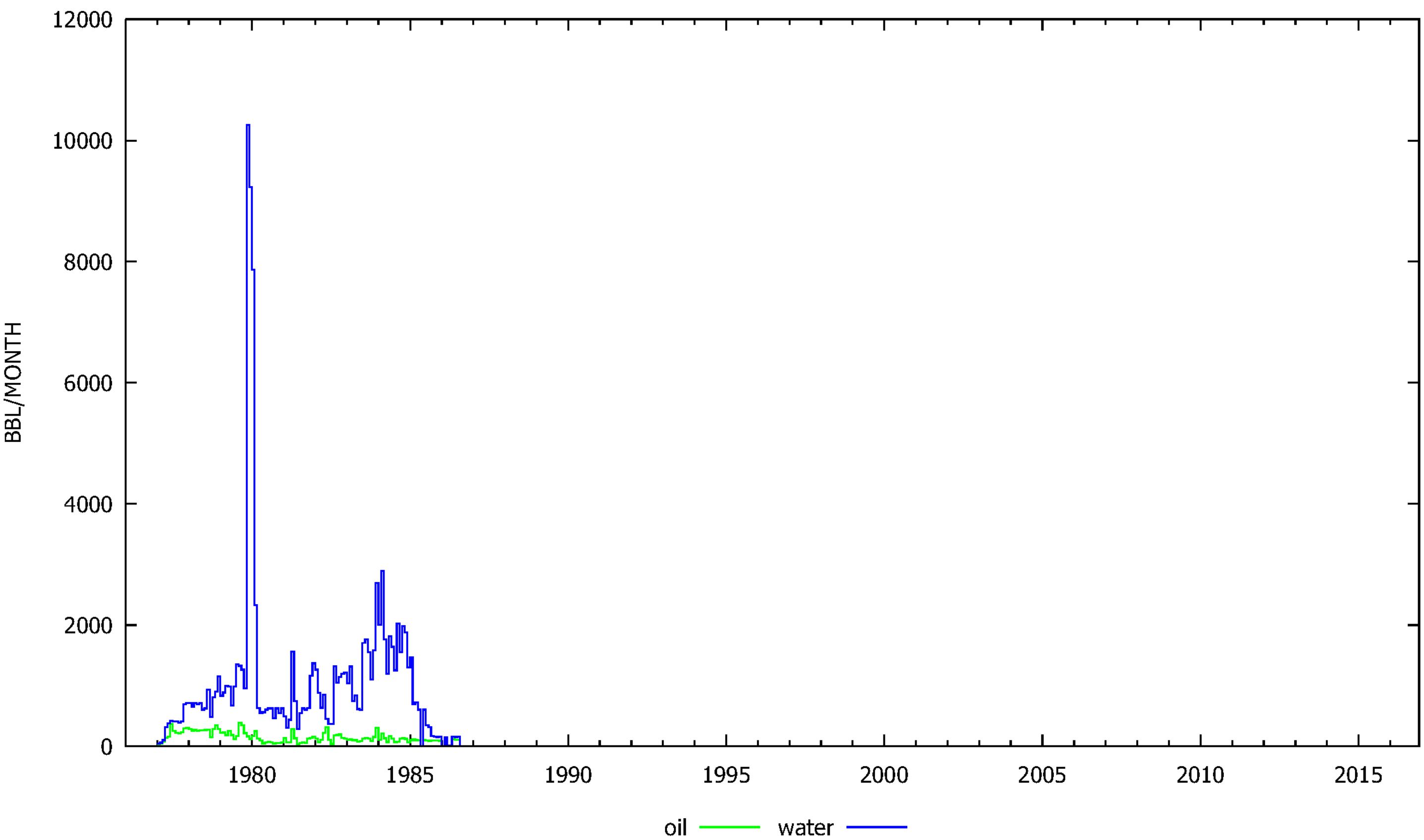




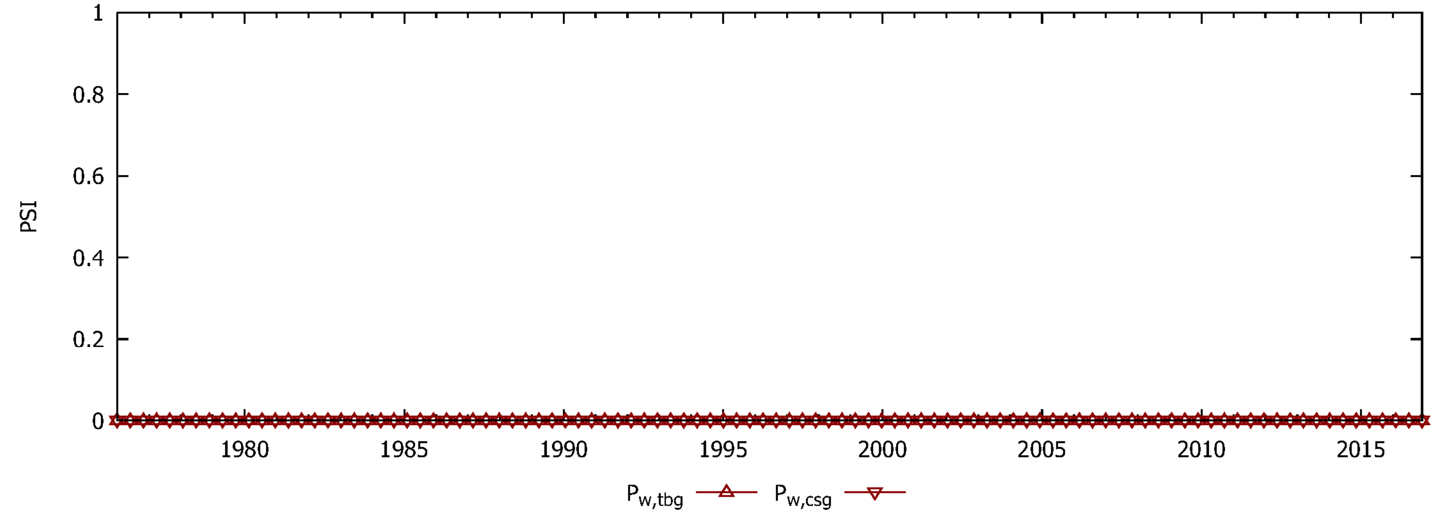
WELL Standard-Sesnon 1 35

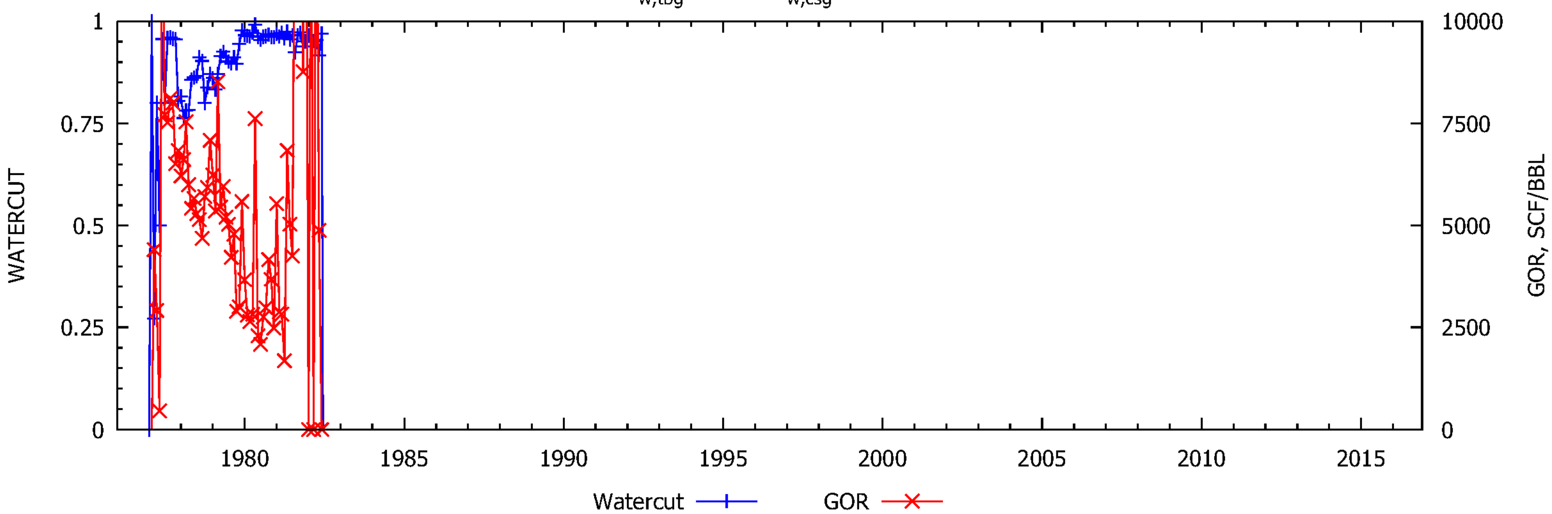


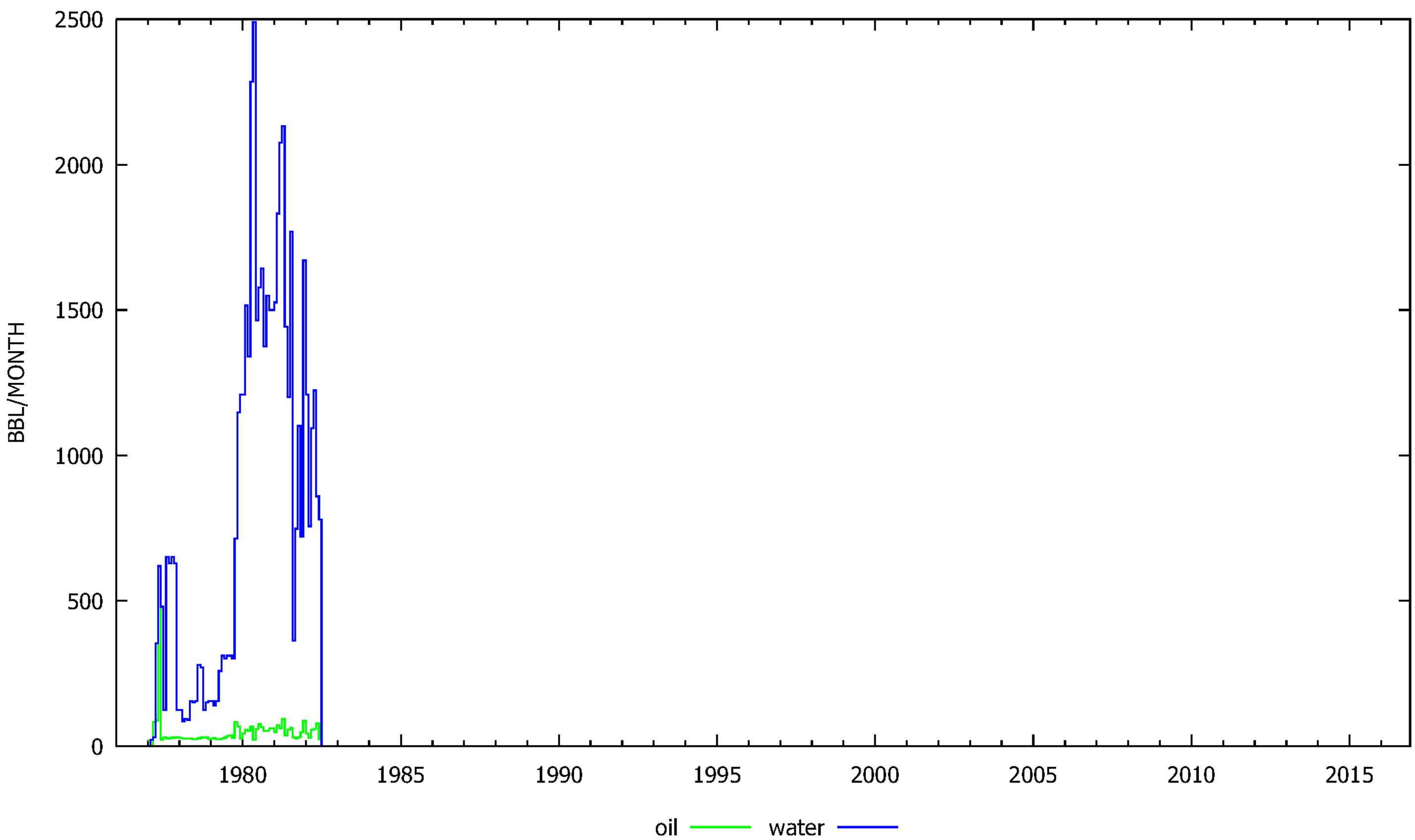




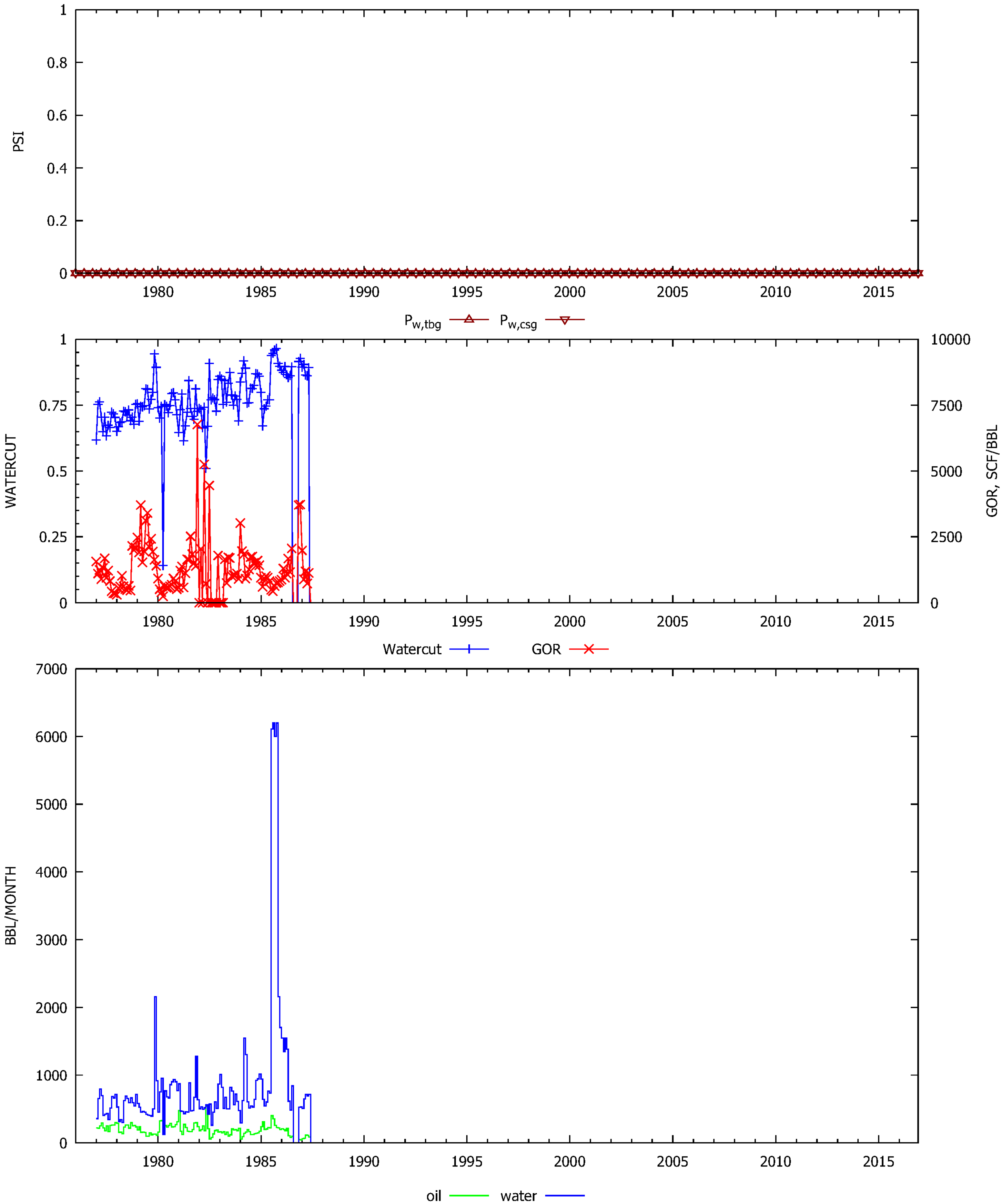
WELL Standard-Sesnon 1 39



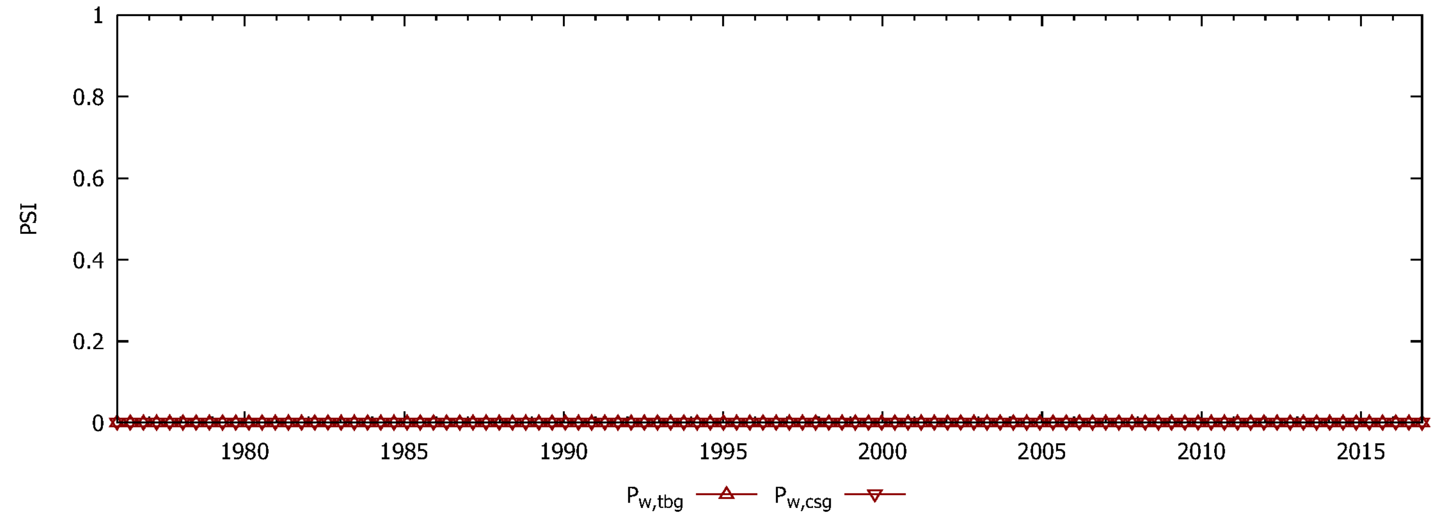


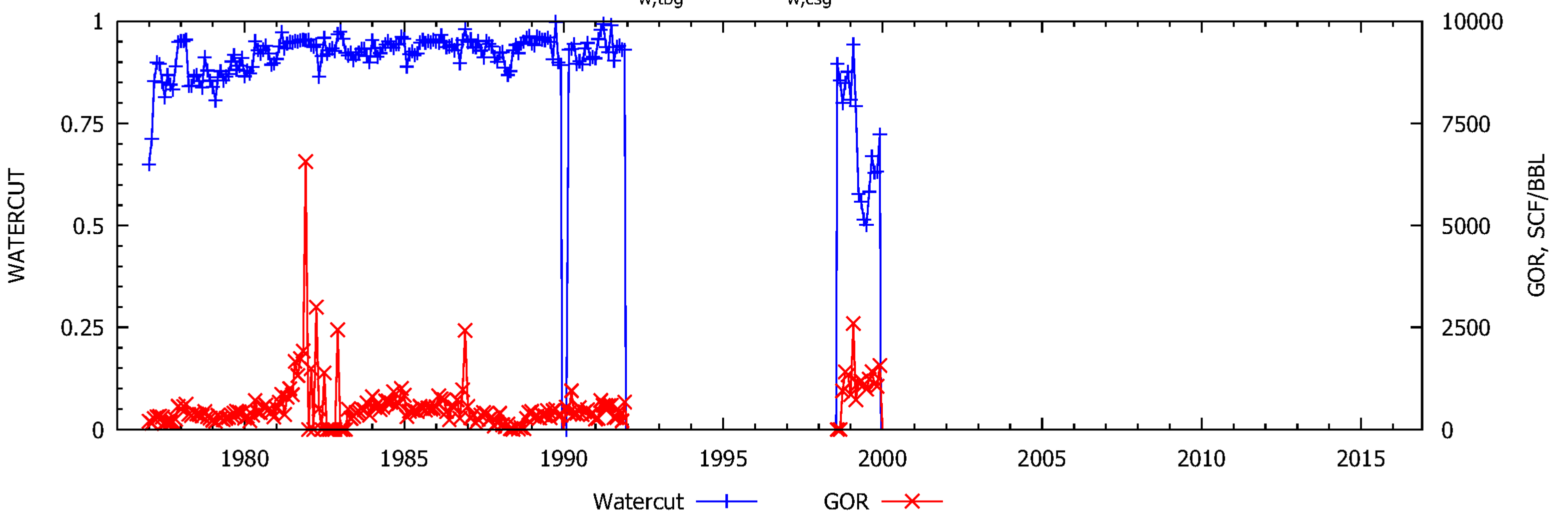


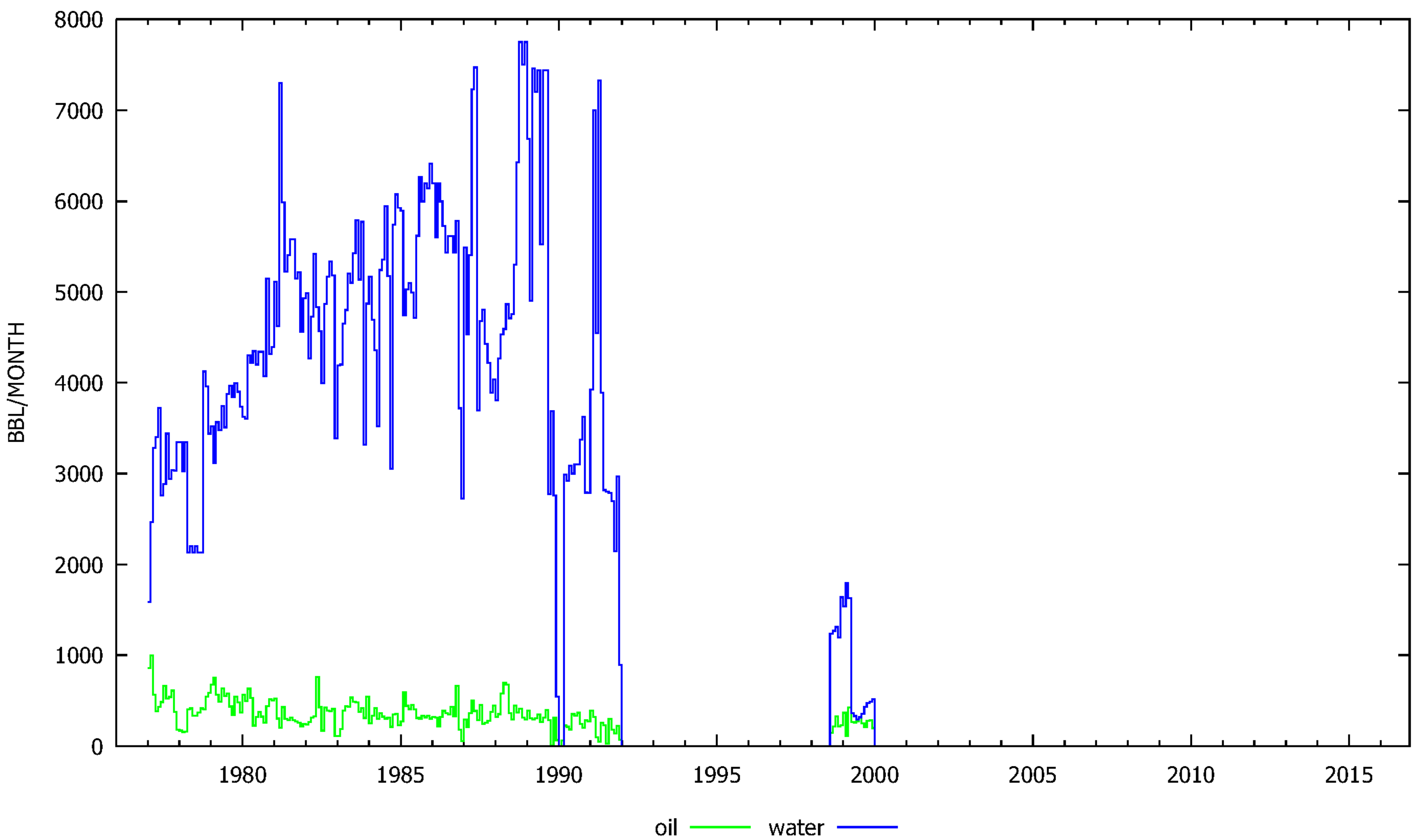
WELL Standard-Sesnon 1 40



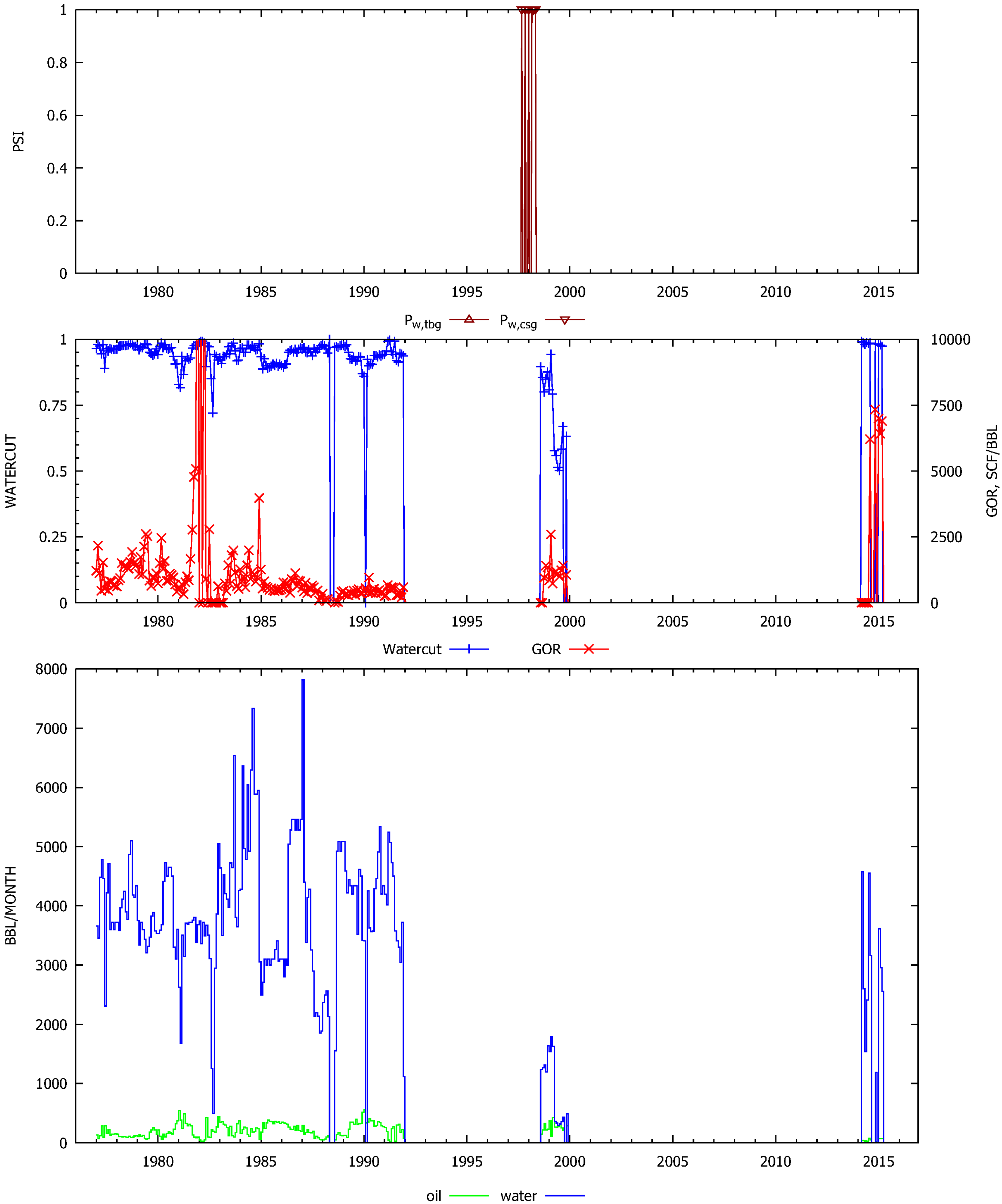
WELL Standard-Sesnon 1 45







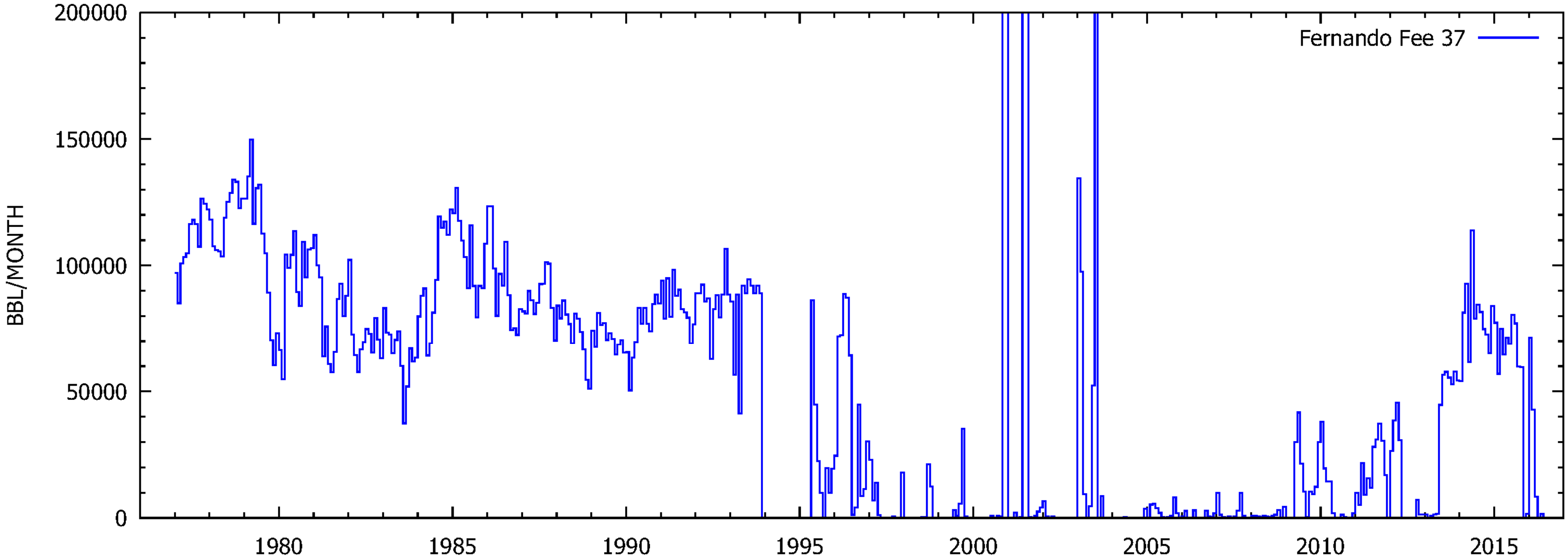
WELL Standard-Sesnon 1 46

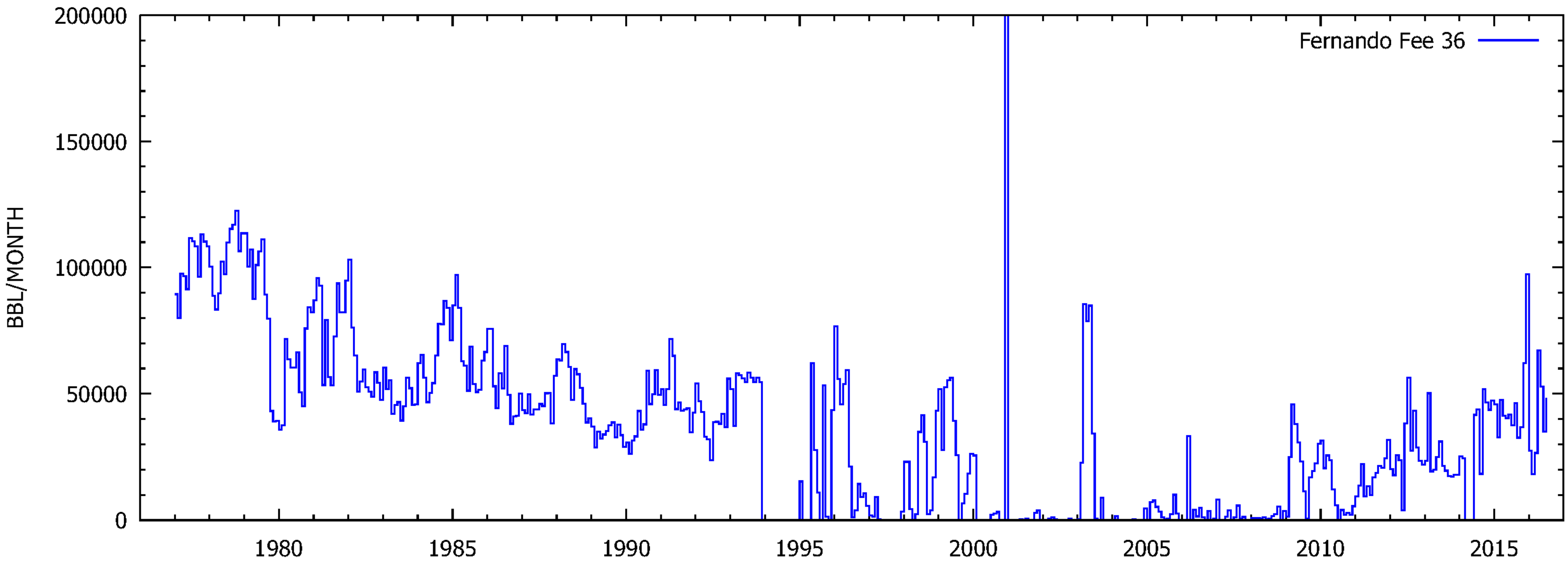


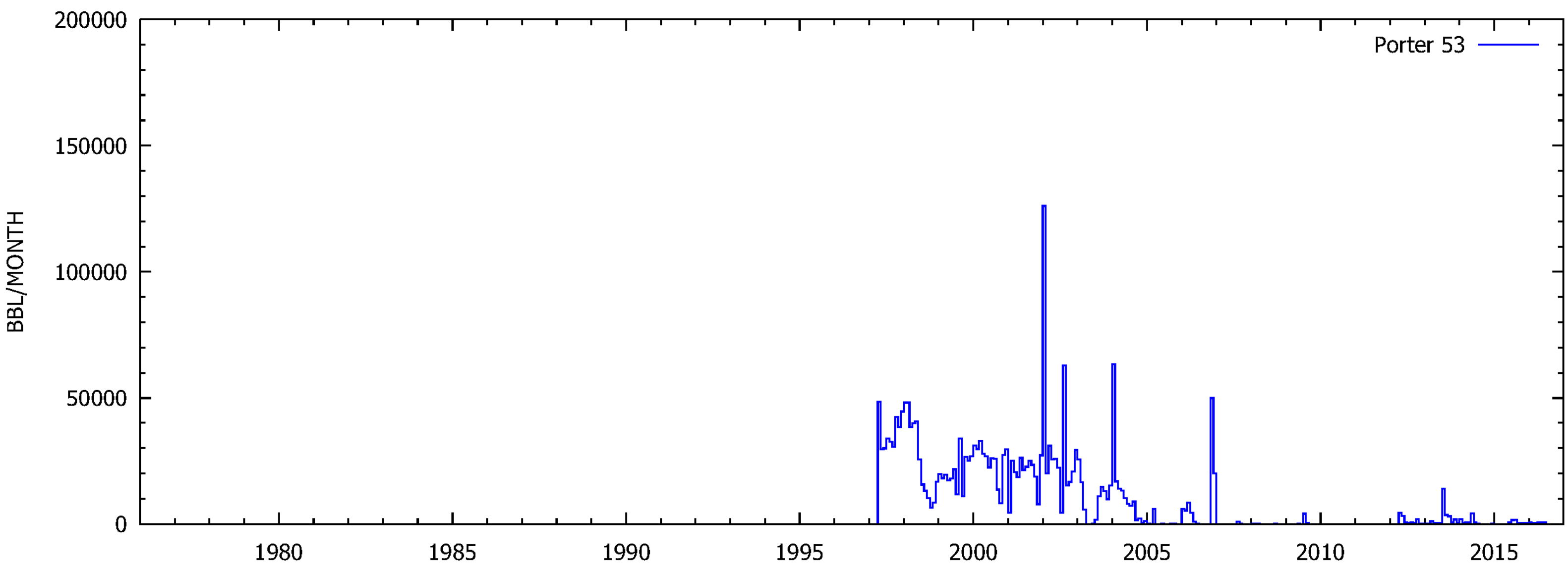
Appendix F Water Injection Well Plots

This section shows plots of historical injection data for individual wells.

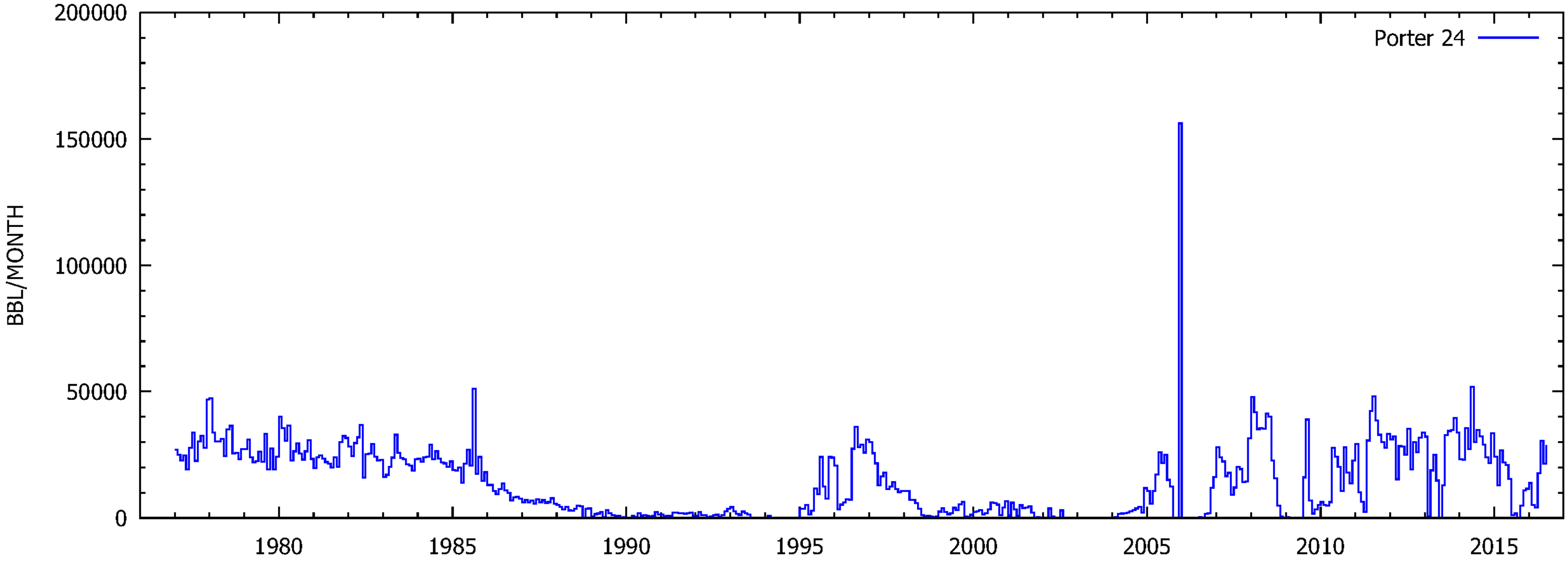
WATER INJECTION WELLS

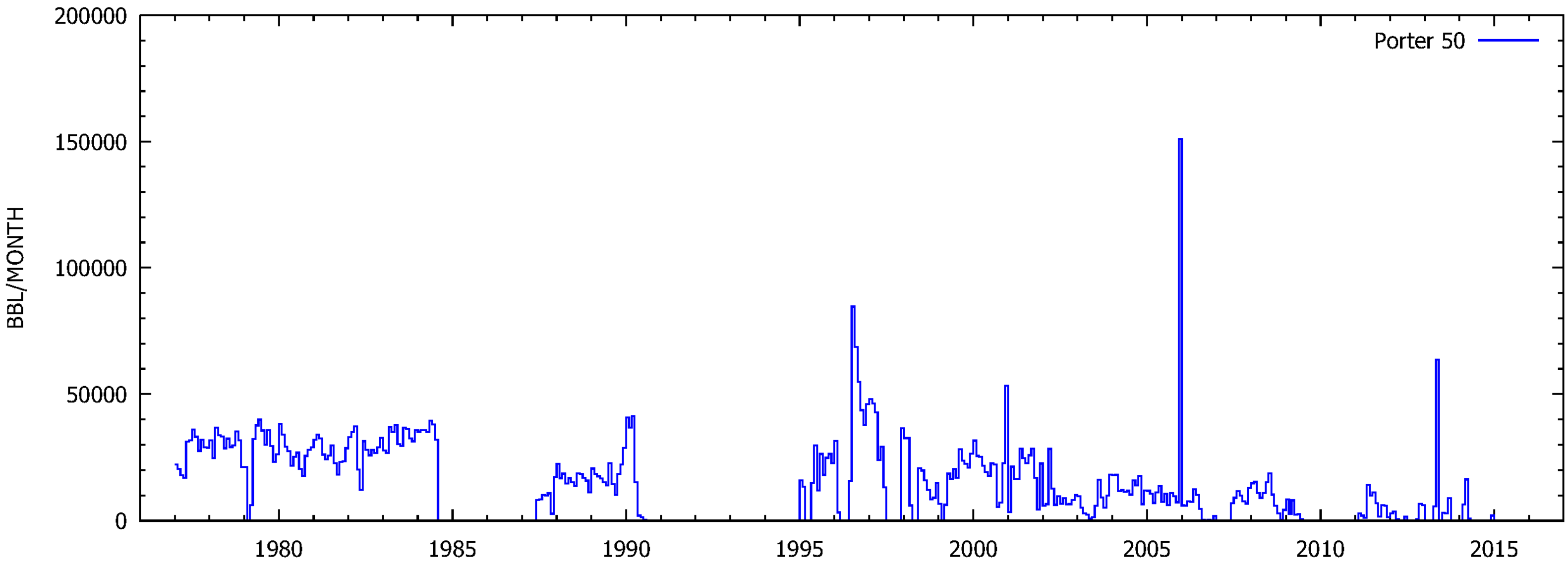


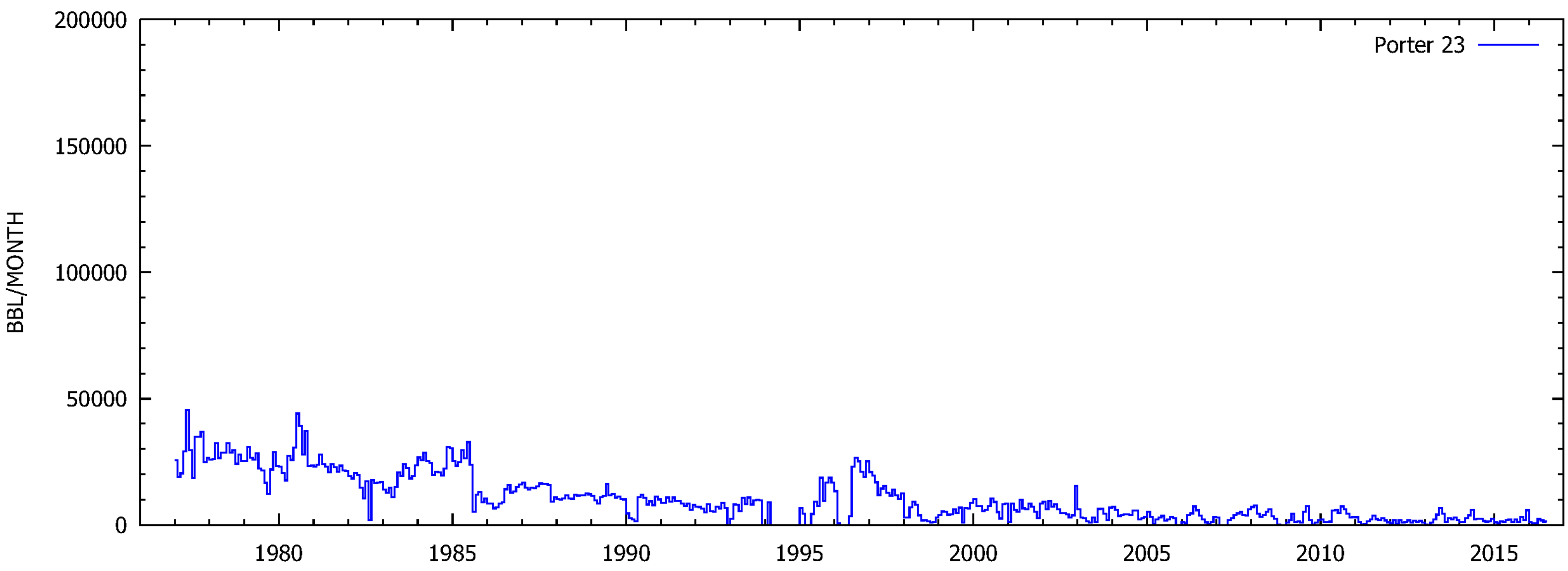




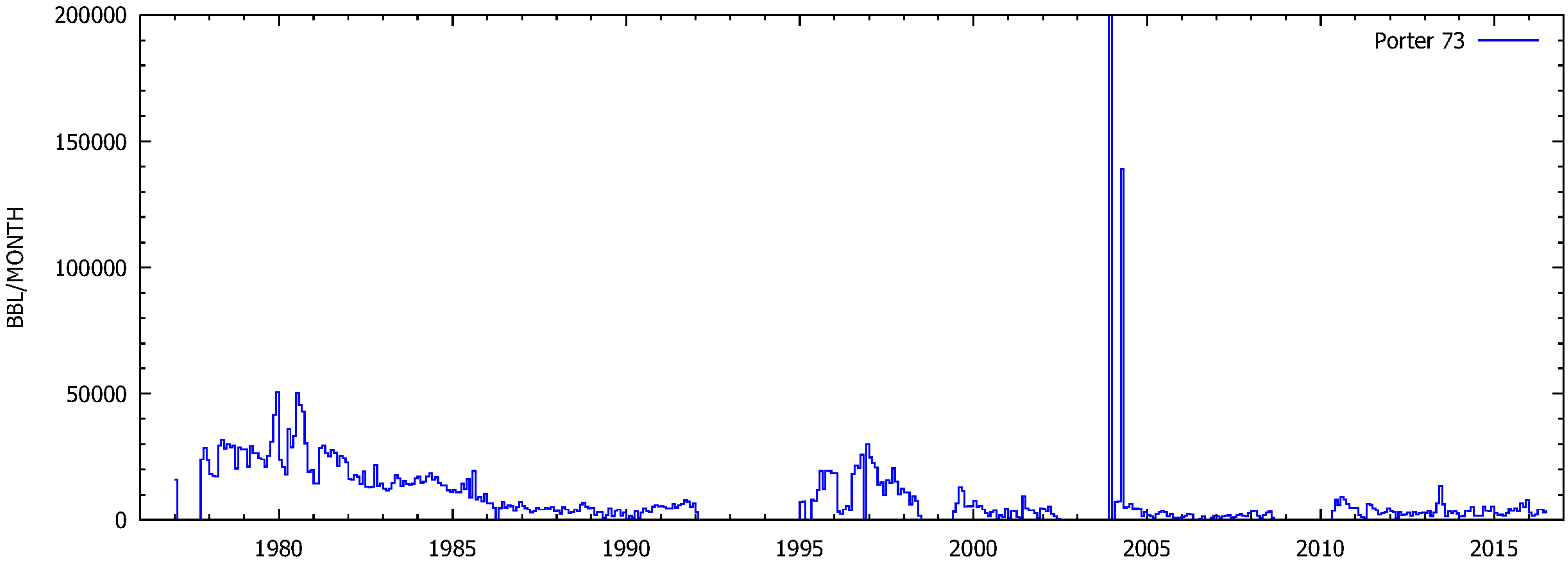
WATER INJECTION WELLS

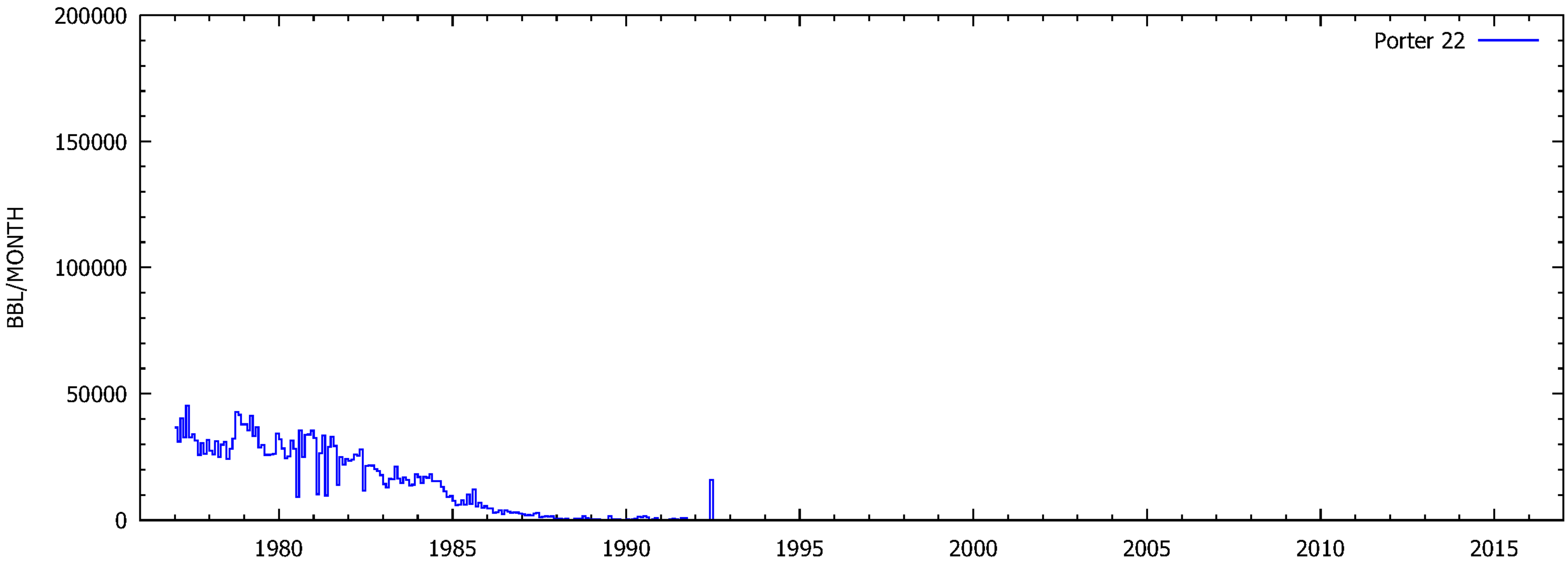


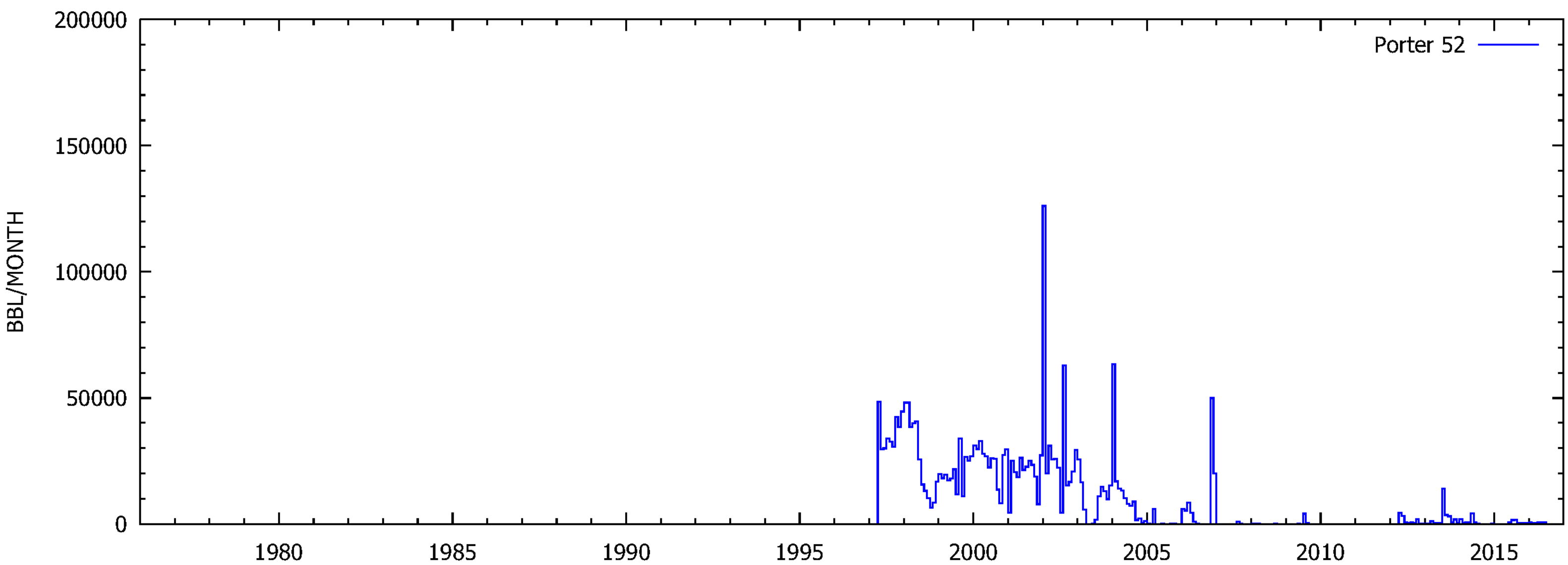




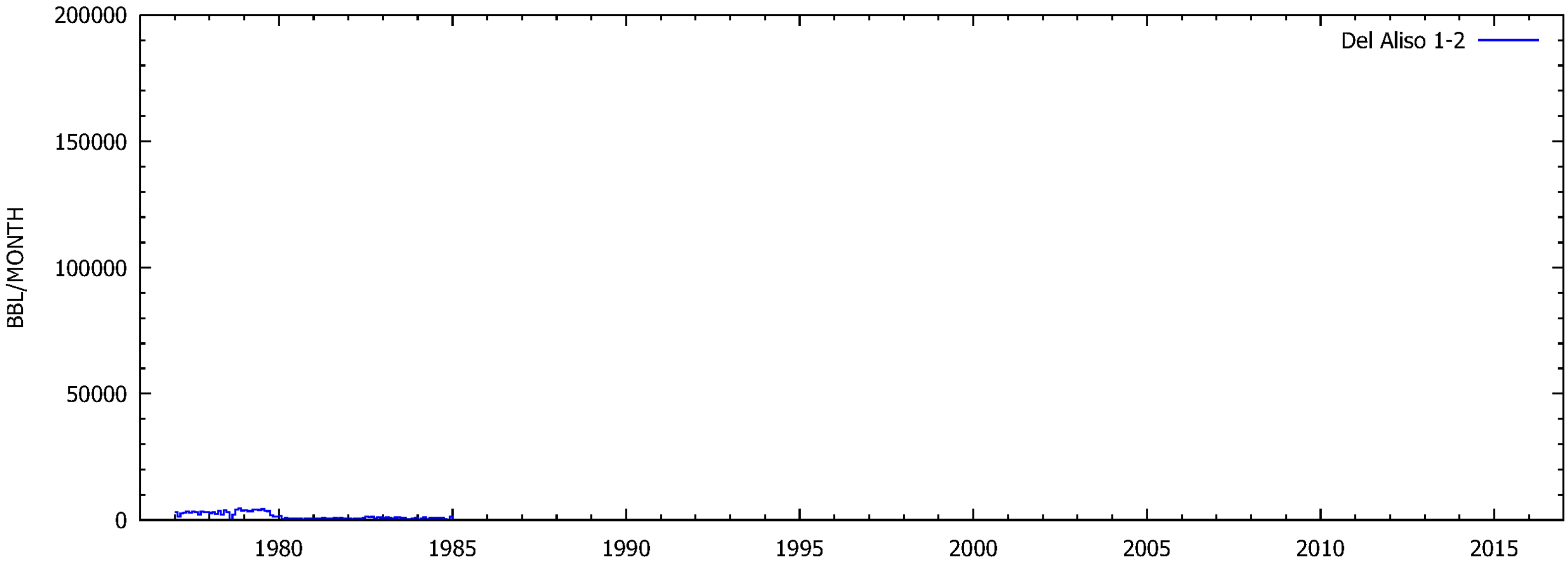
WATER INJECTION WELLS

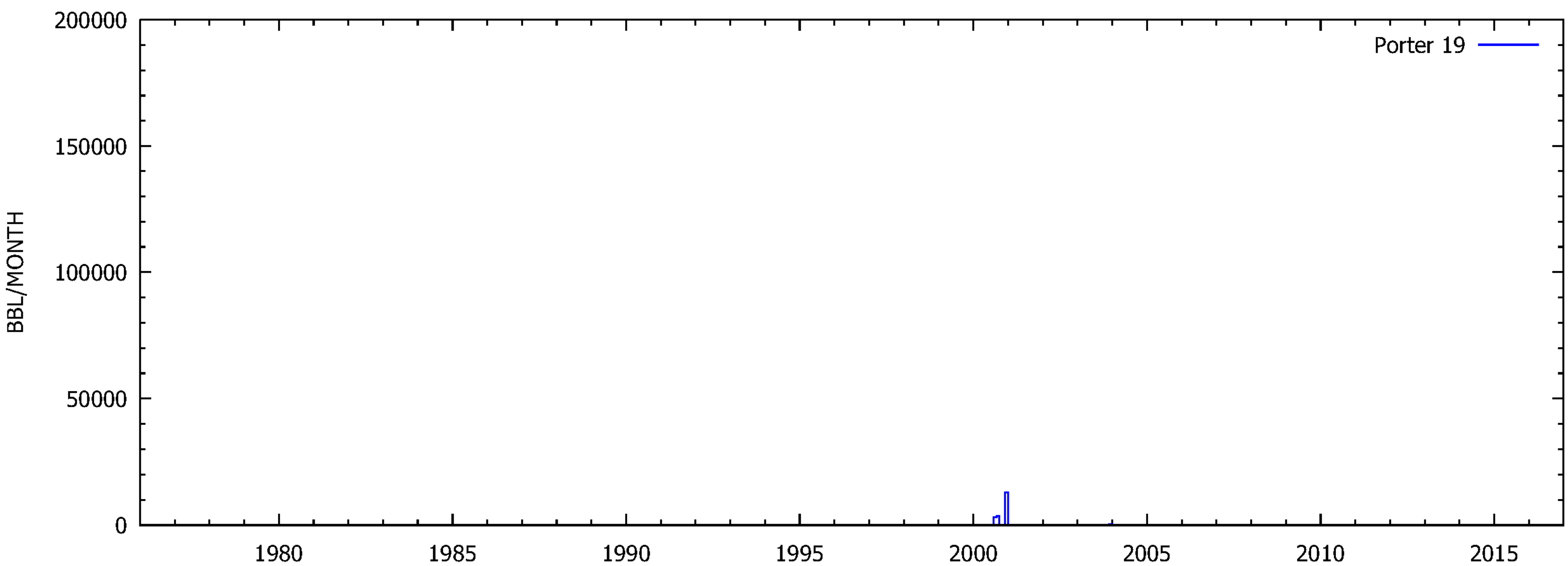


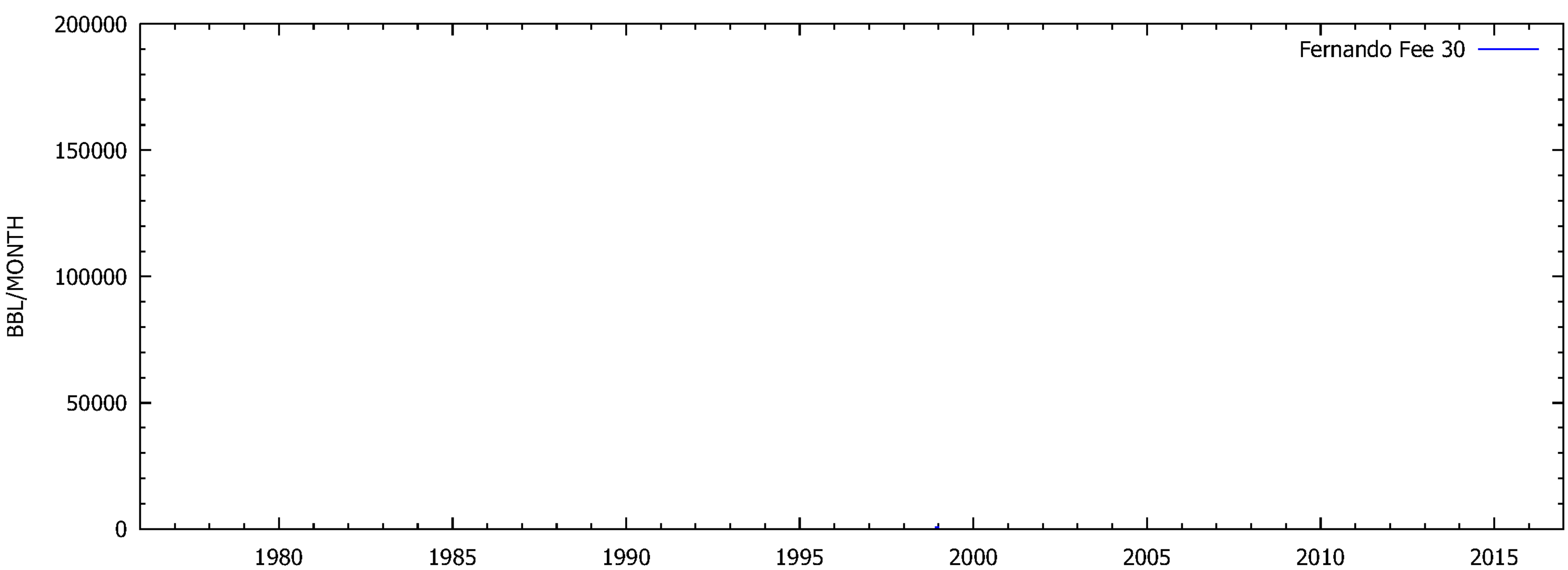




WATER INJECTION WELLS

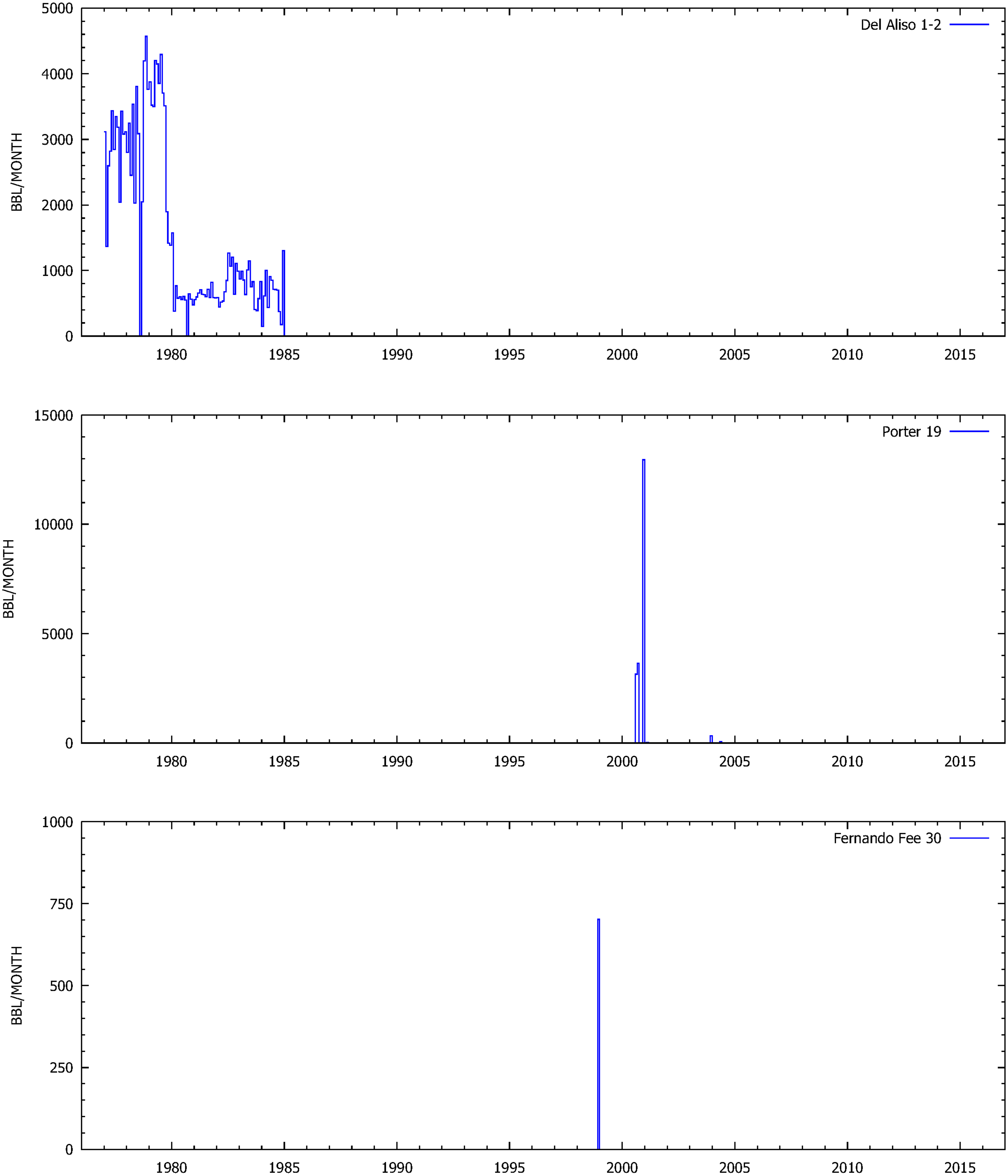


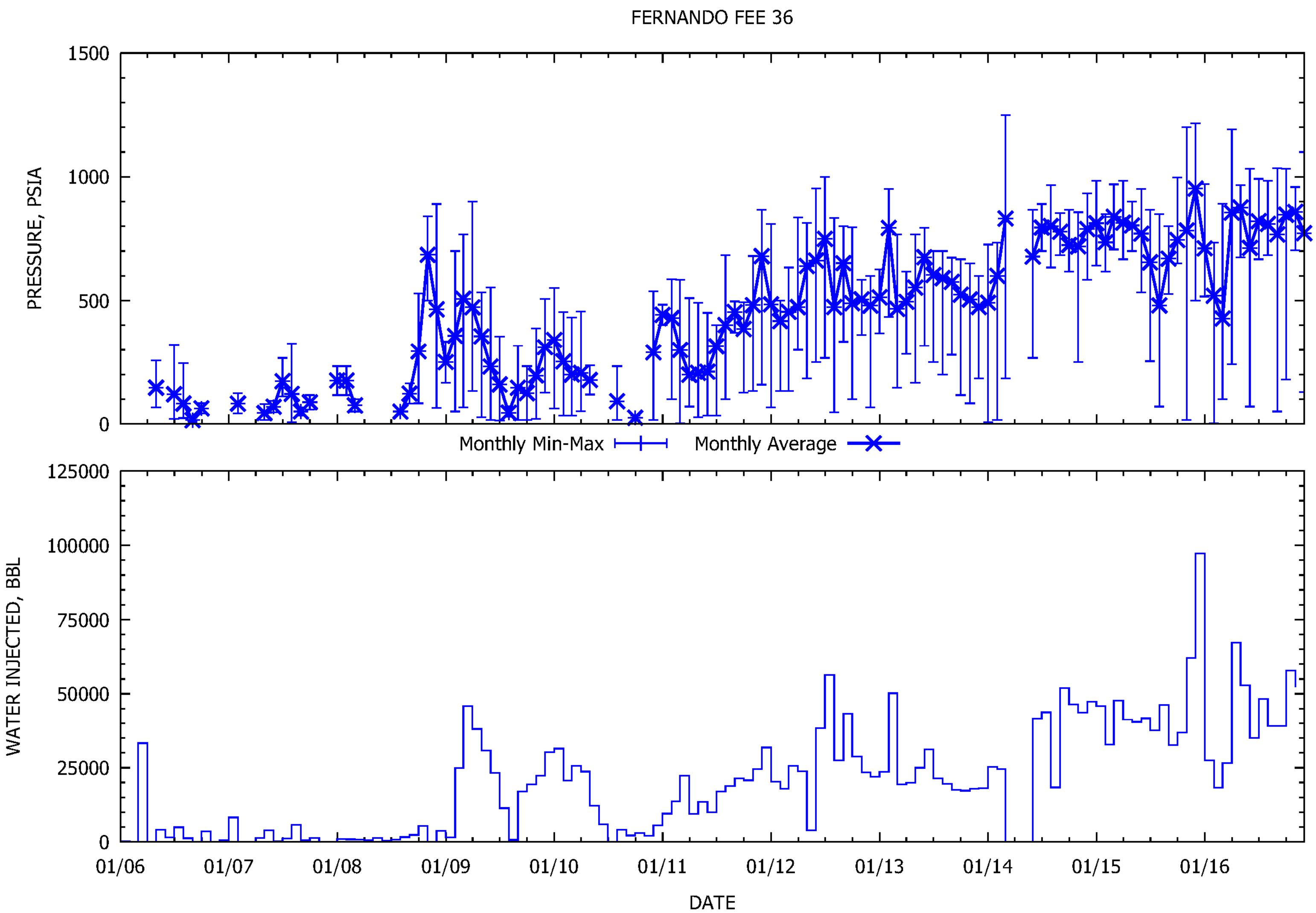




THIS IS A REPEAT OF PREVIOUS PLOT
WITH DIFFERENT Y RANGES

WATER INJECTION WELLS

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500
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Monthly Min-Max
Monthly Average
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100000
75000
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WATER INJECTED, BBL
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01/10
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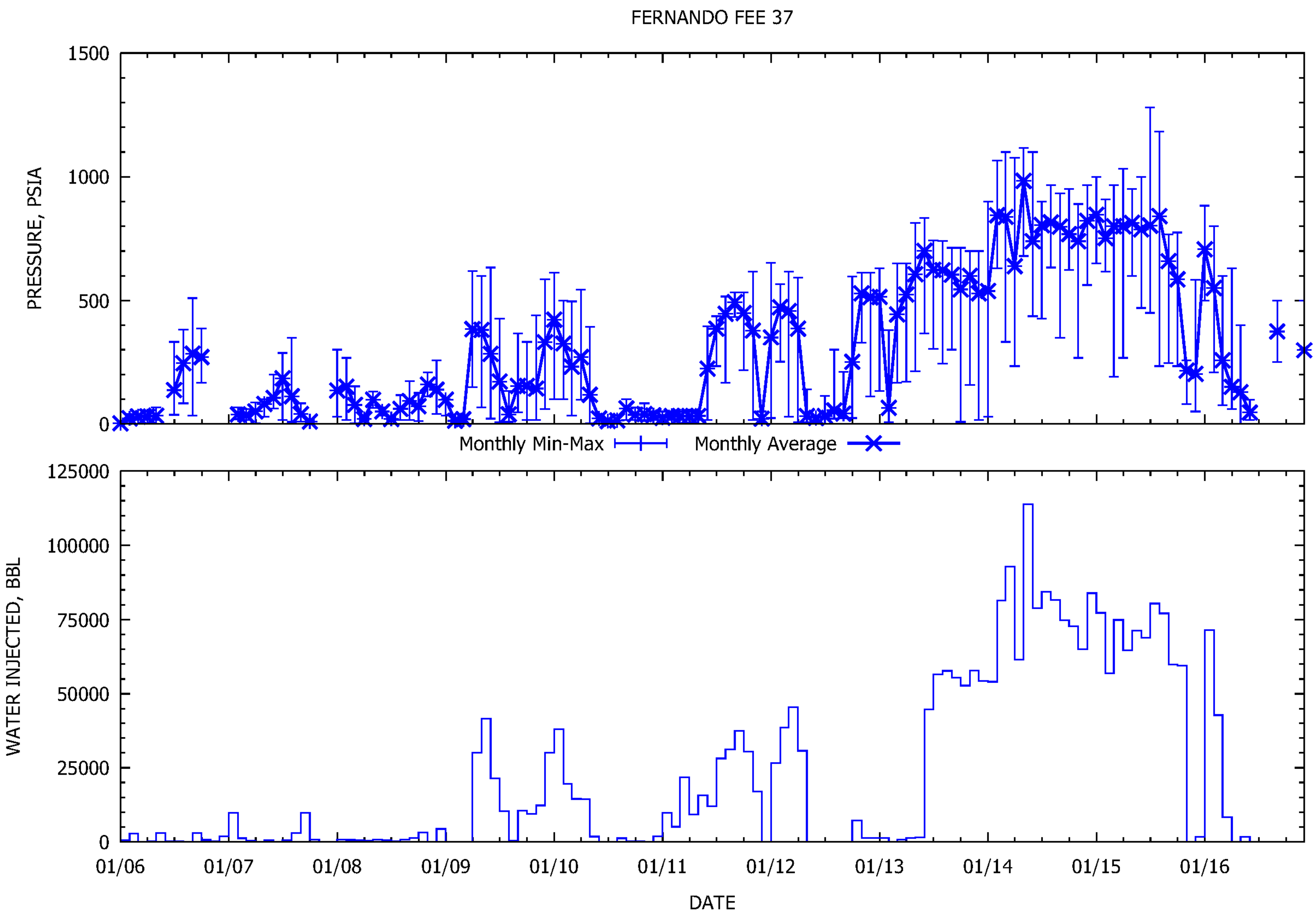
DATE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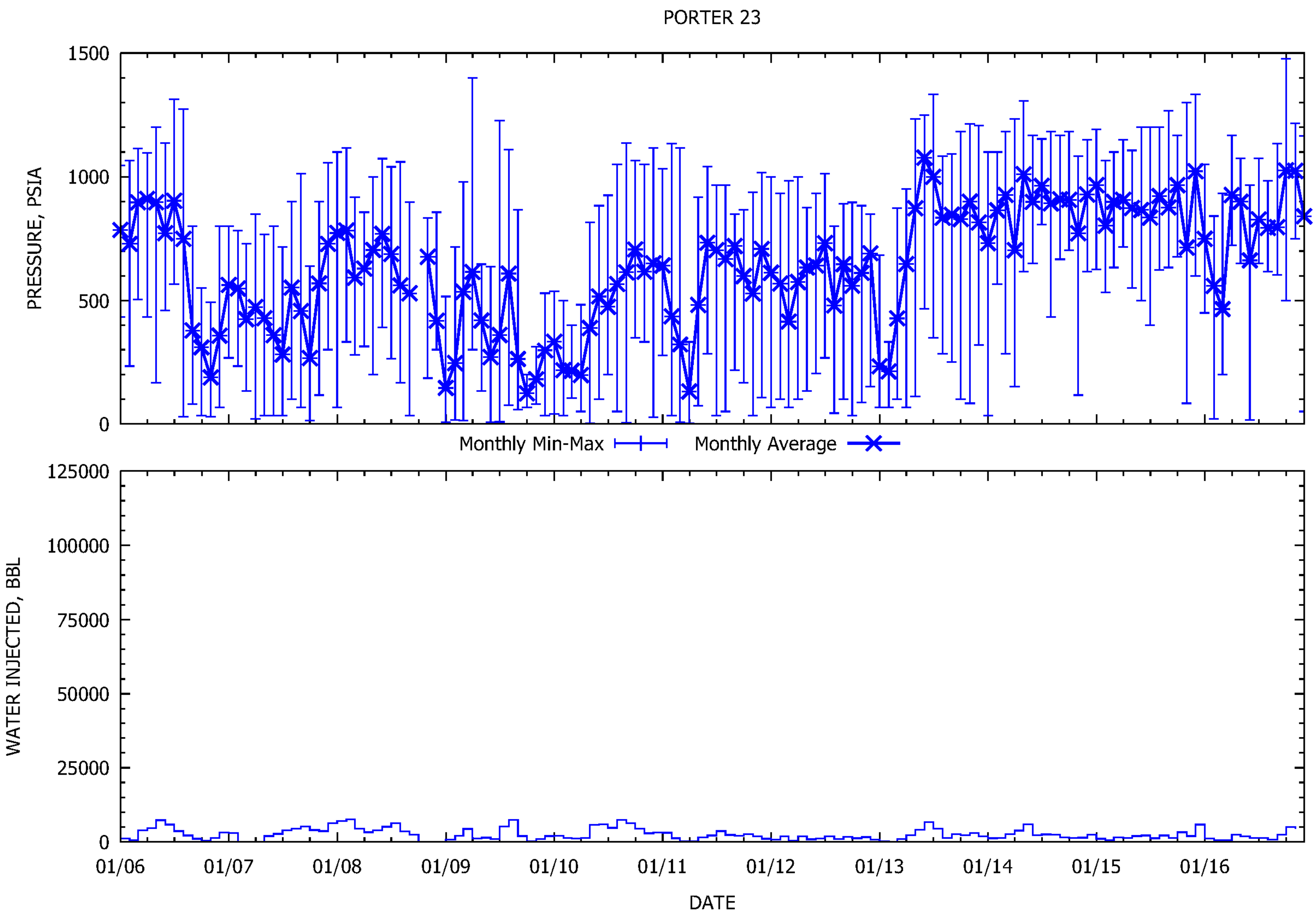
01/14
01/15
01/16
DATE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01/07
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01/10
01/11
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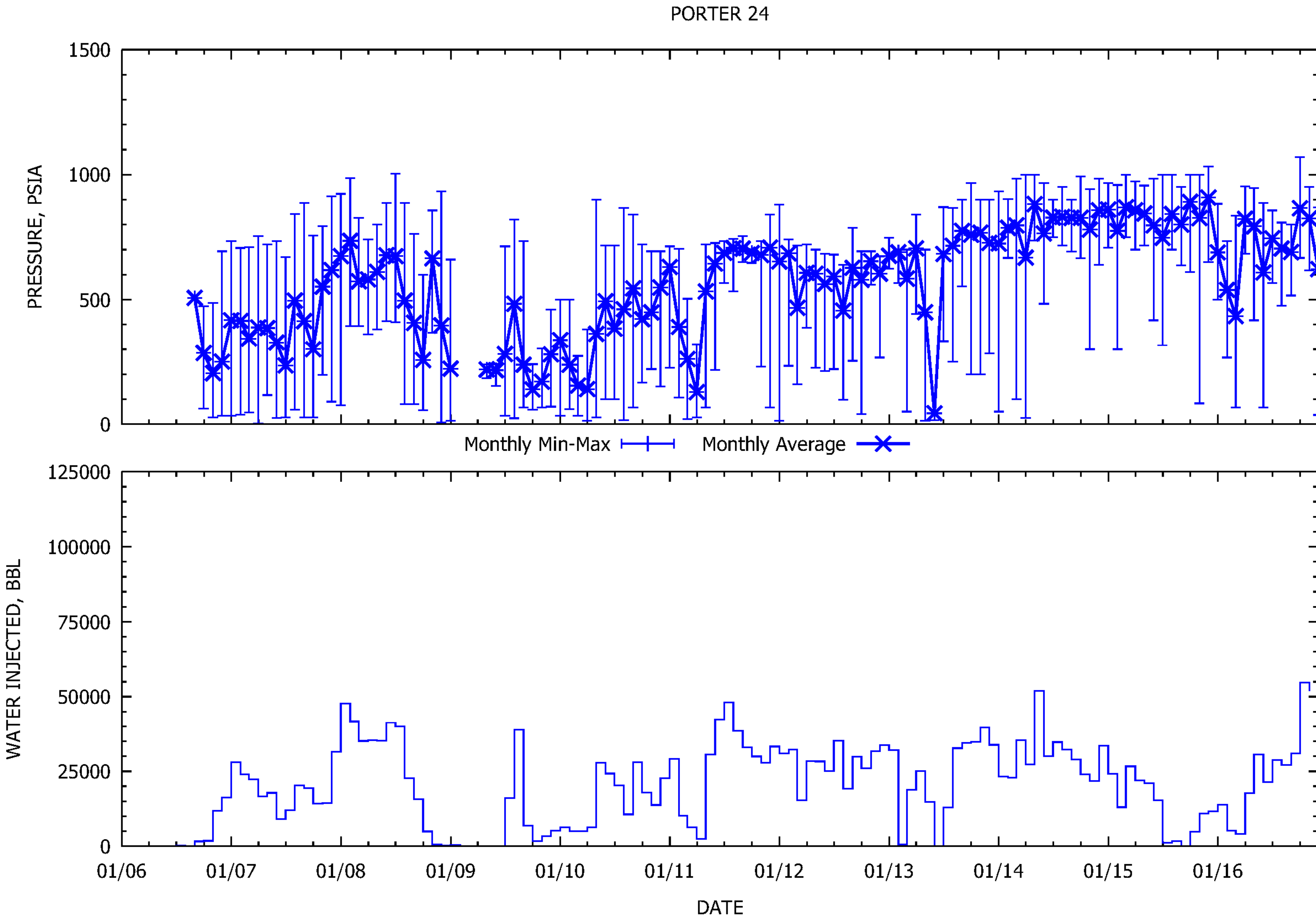
01/14
01/15
01/16
DATE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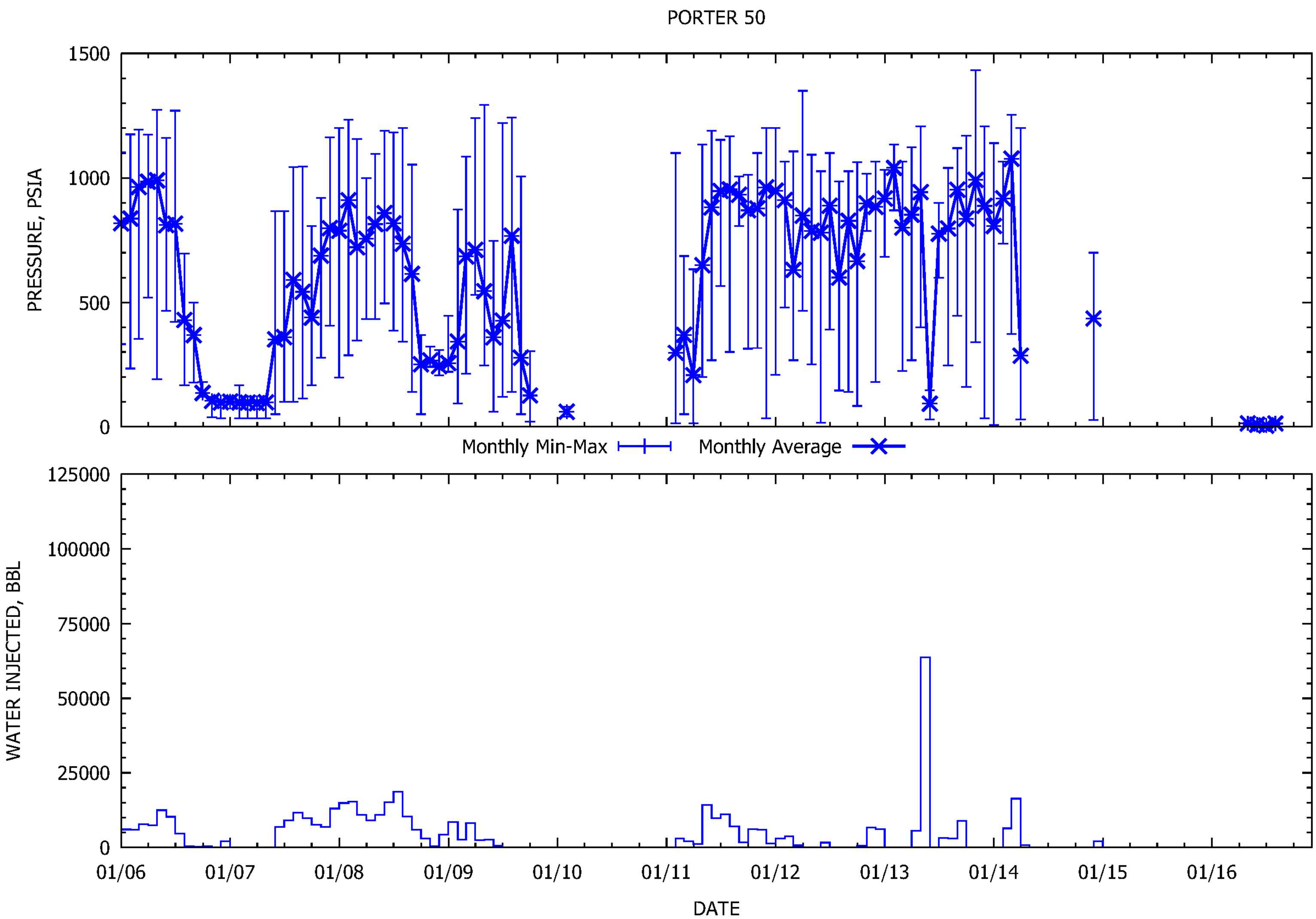
01/06
01/07
01/08
01/09
01/10
01/11
01/12
01/13
01/14
01/15
01/16
DATE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Monthly Min-Max
Monthly Average
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50000
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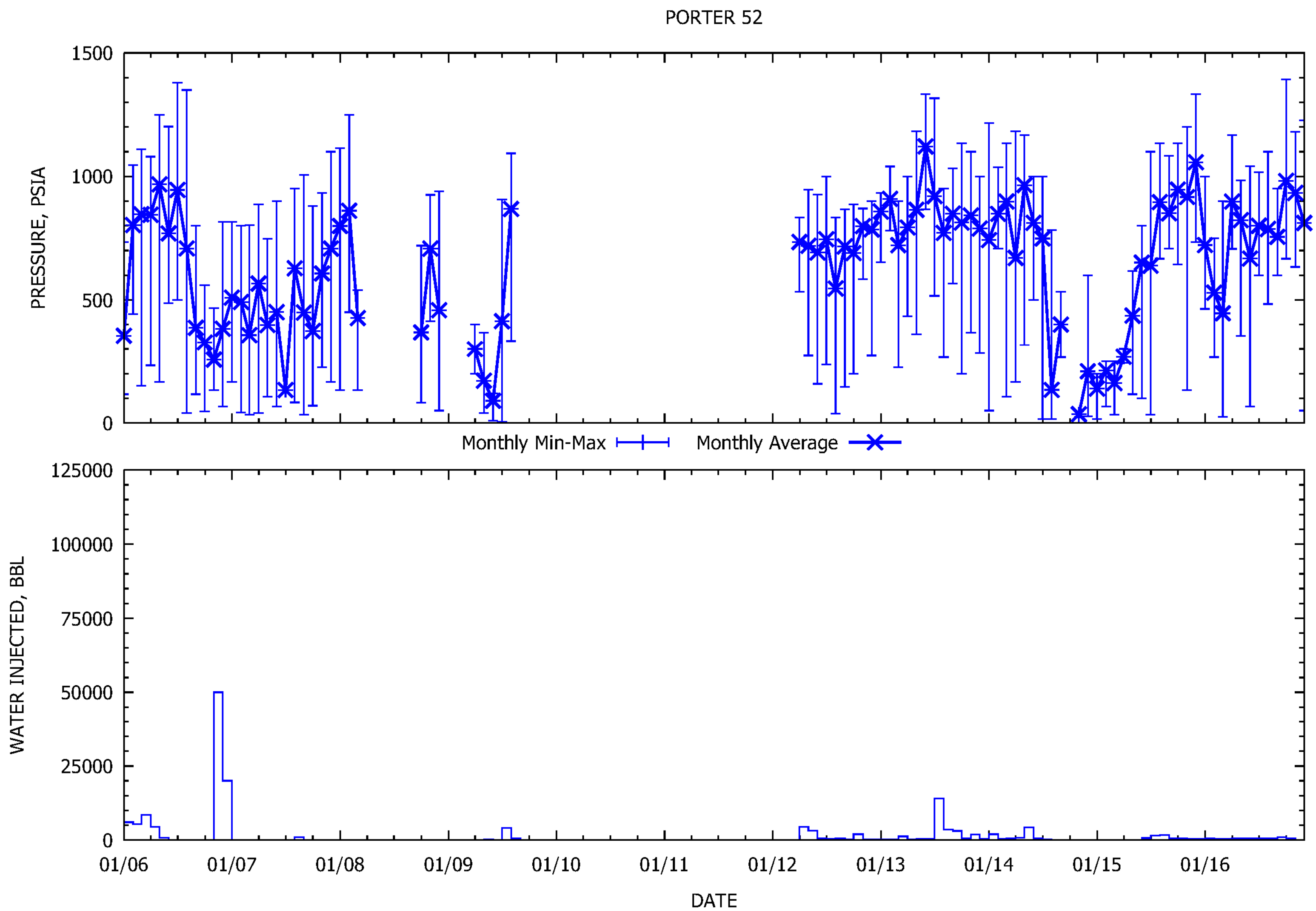
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Monthly Average
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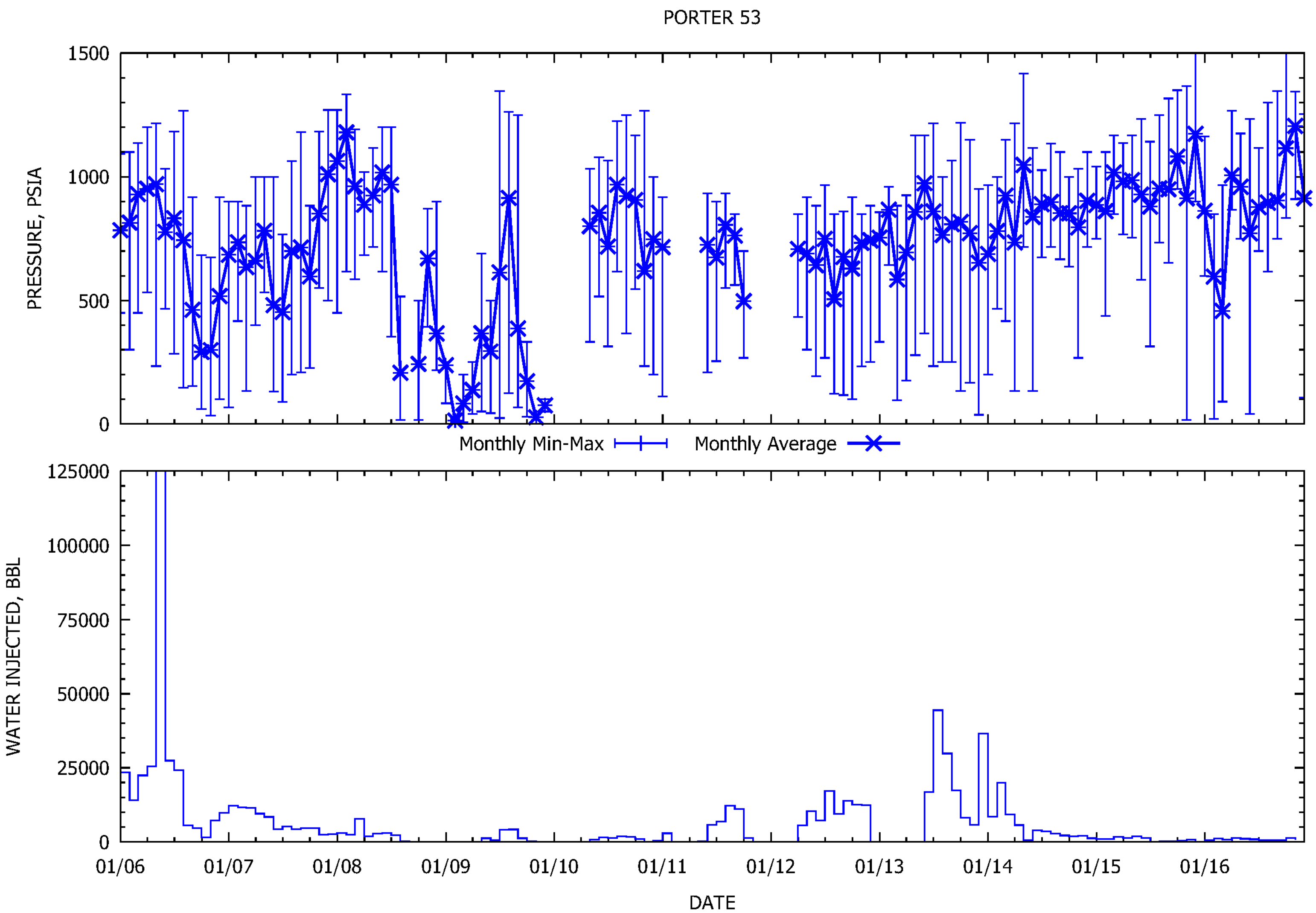
DATE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Monthly Min-Max
Monthly Average
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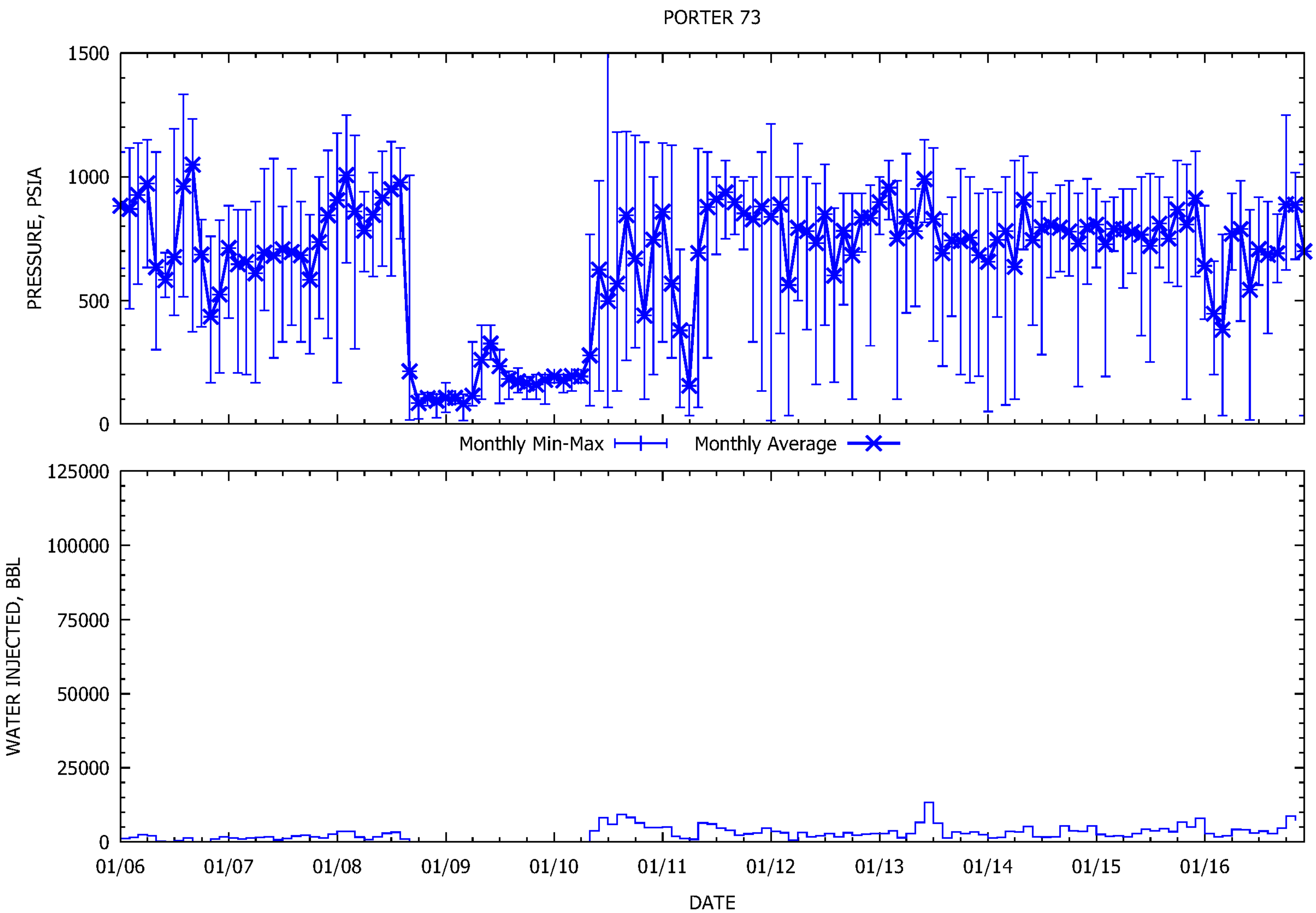
01/16
DATE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1000
500
0
PRESSURE, PSIA
Monthly Min-Max
Monthly Average
125000
100000
75000
50000
25000
0
WATER INJECTED, BBL
01/06
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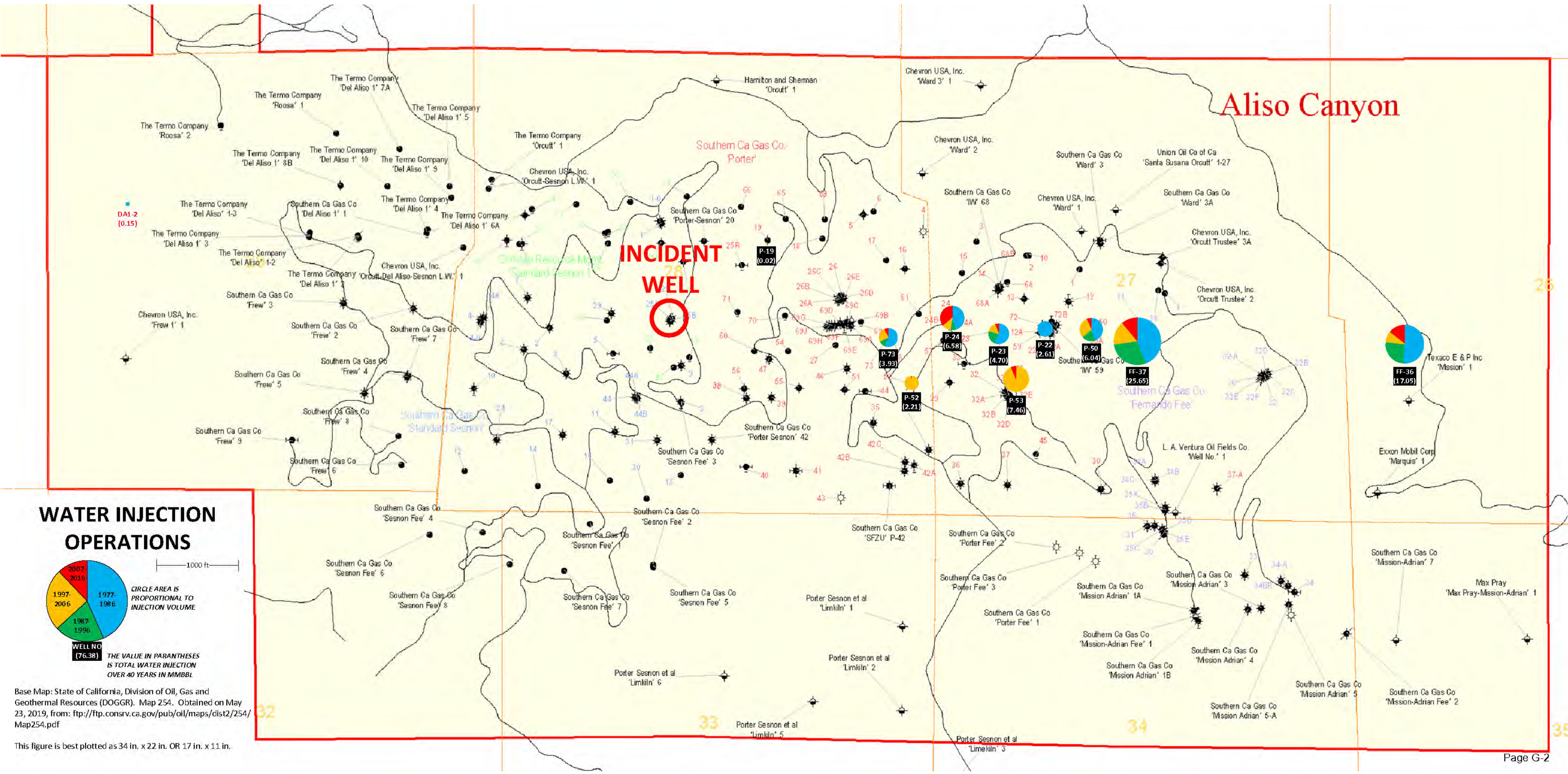
Appendix G Geographic Analysis of Water Injection Operations

This section shows a geographic analysis of the water injection operations. This analysis shows all water injection occurs to the east of the SS-25 incident well.



Base Map: State of California, Division of Oil, Gas and Geothermal Resources (DOGGR). Map 254. Obtained on May 23, 2019, from: ftp://ftp.consrv.ca.gov/pub/oil/maps/dist2/254/Map254.pdf

This figure is best plotted as 34 in. x 22 in. OR 17 in. x 11 in.

SS-25 RCA Supplementary Report

Aliso Canyon Regional and Local Seismic Events Analysis

Purpose:
Detail the results of analysis of seismic events in and near the Aliso Canyon Field in support of the Aliso Canyon Root Cause Analysis (AC-RCA) project.

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Date:
May 31, 2019

Abstract

The gas storage well Standard Sesnon 25 (SS-25) in the Aliso Canyon Gas Storage Field located in Los Angeles County, California started leaking gas in October 2015. A relief well was drilled, and SS-25 was brought under control. The leak stopped in February 2016.

In January 2016, as part of their investigation of the leak, the California Public Utilities Commission (CPUC) and the Division of Oil, Gas, and Geothermal Resources (DOGGR) selected and gave provisional authority to Blade Energy Partners (Blade) to perform an independent Root Cause Analysis (RCA). The Blade Team and parties under Blade's direction were responsible for directing the work of subcontractors who performed the extraction of the SS-25's wellhead and tubing and casing and the preservation and protection of associated evidence. Blade RCA Reports, including this report, document and describe the key activities undertaken in support of the RCA effort.

Regional seismic data are analyzed for the period between 1975 through 2016 to determine if failure of well SS-25, as well as other historical well failures, may be correlated with a recorded seismic event consistent with the hypothesis that the 1994 SS-4-0 failure resulted from seismic activity; however, this analysis shows that other well failures, including the SS-25 failure of interest, are unlikely to have resulted from seismic activity.

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1 Introduction

The purpose of this document is to analyze seismic data near Aliso Canyon to determine if the SS-25 failure, as well as other historical well failures, may be correlated with recorded seismic events.

1.1 Abbreviations and Acronyms

Term	Definition
F-3	Frew 3
FF-34A	Fernando Fee 34A
P-38	Porter 38
SoCalGas	Southern California Gas Company (operator of Aliso Canyon gas storage field)
SS-25	Standard Sesnon 25
SS-4-0	Standard Sesnon 4-0
UTC	Coordinated Universal Time
UTM	Universal Transverse Mercator
VBA	Visual Basic for Applications

2 Seismic Events

Because Los Angeles is a highly populated area located in an active seismic zone, an extensive seismic monitoring system is in place and generates seismic data. These seismic data were analyzed to determine if any seismic events may be identified as a possible cause of the SS-25 and previous well failures in the Aliso Canyon field.

The well failures of interest are the following (Figure 1):

- **Standard Sesnon 25 (SS-25):** Discovered on October 23, 2015. This well failure is the subject of the present root cause analysis project.
- **Standard Sesnon 4-0 (SS-4-0):** Occurred in 1994. This is the only failure explicitly attributed to seismic activity, specifically, the Northridge earthquake on January 17, 1994.
- **Fernando Fee 34A (FF-34A):** Discovered in September 1990.
- **Frew 3 (F-3):** Discovered in June 1984.
- **Porter 38 (P-38):** Discovered in May 1980 (uncertain).

Also shown in Figure 1 are the outlines of Aliso Canyon field and nearby Oat Mountain field.

The methodology used to acquire and analyze the seismic event data is described in Section 6.

The dates of interest are October 24, 1975 (40 years before the SS-25 incident) to September 30, 2016 (date current analysis started).

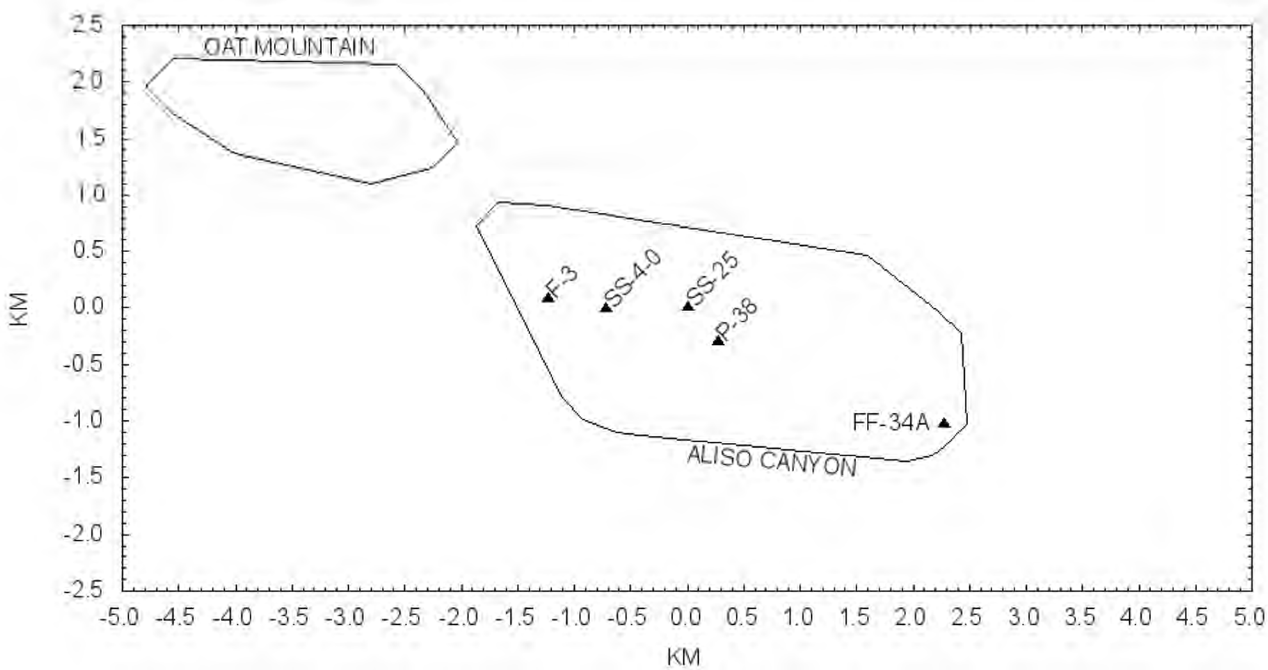


Figure 1: Aliso Canyon and Oat Mountain Fields

Three geographic levels of interest are defined (Figure 2):

- **Regional Level:** A 50 km radius circle centered at the SS-25 wellhead location, the area for which earthquake data are obtained.
- **Area Level:** A 10 by 5 km (50 km^2) rectangular area, centered at the SS-25 wellhead location (Figure 1)
- **Field Level:** The Aliso Canyon field, outlined by a convex polygon enclosing all active Aliso Canyon wells (including conventional production and water injection wells).

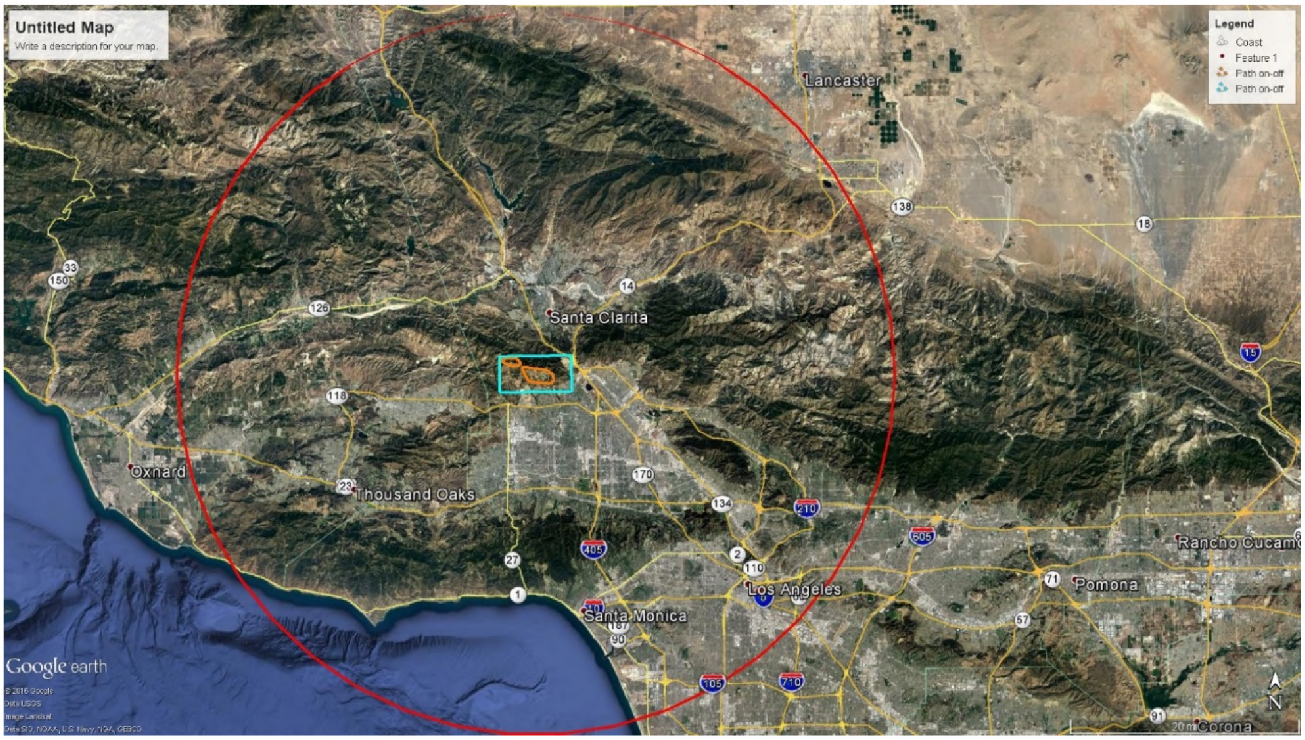


Figure 2: Geographic Levels of Interest

Figure 2 shows the following:

- The Aliso Canyon field—larger orange polygon to the right.
- The Oat Mountain field—smaller orange polygon to the left, not included in the field level.
- The area level—the cyan rectangle.
- The regional level—the red circle.

Table 1 shows the statistics associated with the events for the three regions of interest. On an area-based calculation, the field level is more seismically active than the area level, and the area level is more seismically active than the regional level.

Table 1: Seismic Events Statistics

Event Information	Regional Level	Area Level	Field Level
Area km^2	7,854	50	6.91
Event Count			
Before SS-25 Incident	26,704	1,537	349
Before SS-25 Incident per Area ($\#/km^2$)	3.4	30.7	50.5
After SS-25 incident	342	0	0
Strongest Event			
Date	01/17/1994	01/29/1994	01/18/1994
Magnitude	6.7	5.06	4.32
Distance (km)	11.6	1.7	0.7
Bearing[a] from SS-25	168°	235°	53°
Comment	Northridge earthquake	-	-
[a] measured clockwise from due north			

Figure 3 shows the magnitude of the seismic events versus time as a dot plot for the region, and the following can be inferred:

- The seismic activity is dominated by the Northridge earthquake on January 17, 1994 and its aftershocks. The aftershocks continue for about four years.
- The dot plot indicates the existence of five smaller sets of closely spaced seismic events (marked by arrows). Each of these is an earthquake and its foreshocks and/or aftershocks.

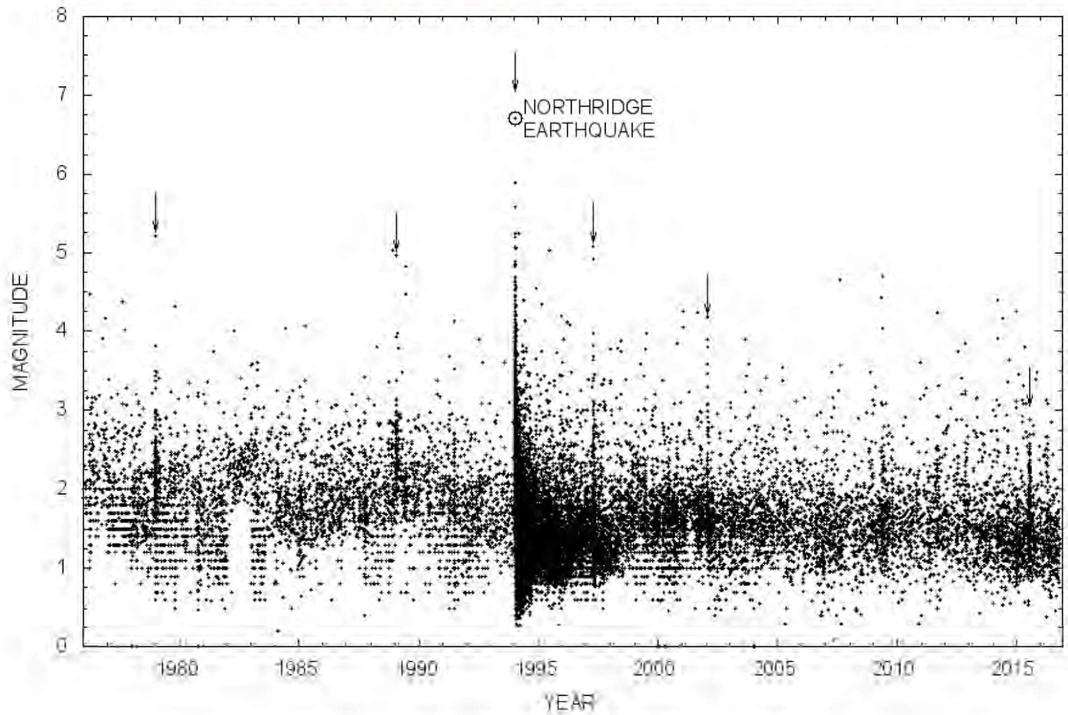


Figure 3: Seismic Events at Regional Level

Figure 4 and Figure 5 show the seismic events for the area and the field. Again, the seismic activity, which is marked by arrows, is dominated by the Northridge earthquake. Two other event sets of interest, one in April 16, 1983 and the other in April 4, 2015, are also marked by arrows.

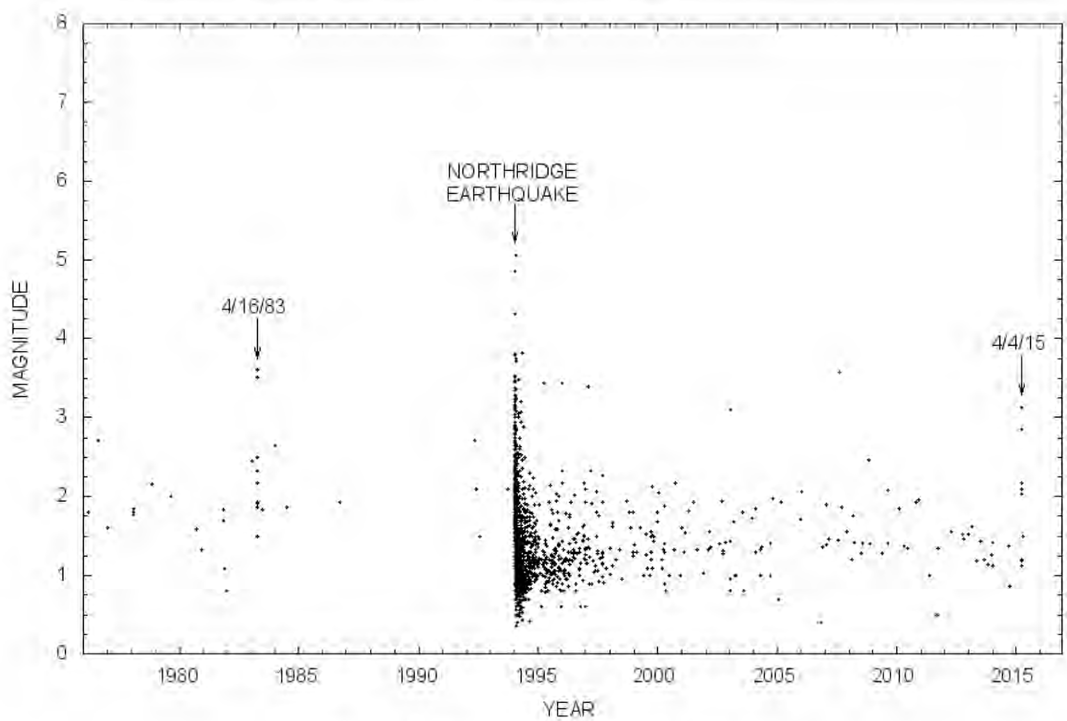


Figure 4: Seismic Events at Area Level

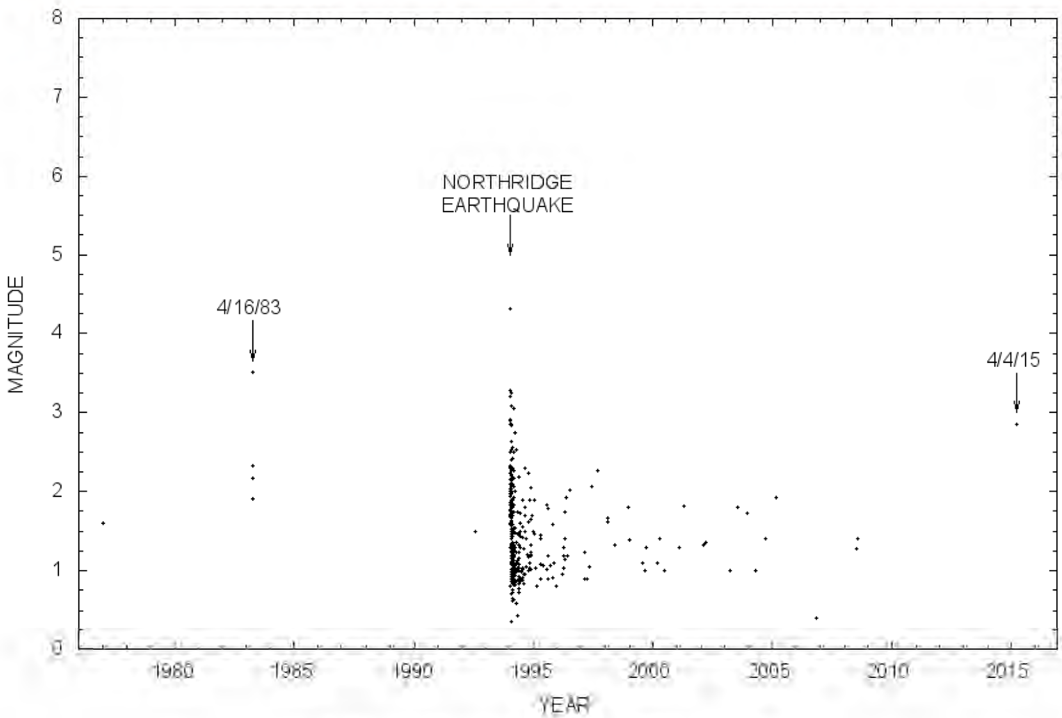


Figure 5: Seismic Events at Field Level

Figure 6, Figure 7, and Figure 8 plot the annual count of seismic events for the three regions of interest and demonstrate the following:

- The 1994 Northridge earthquake and its aftershocks dominate the seismic activity for all three regions of interest for this time period.
- The aftershocks of the Northridge earthquake take approximately four years (1994–1997) to die down.
- The normal seismic activity for about 12 years after the Northridge earthquake is higher than before the earthquake. The median count at area level is one per year before 1994, seven per year between 2000 and 2008, and four per year between 2009 and 2014. (The year 2000 has been selected to ensure any residual effect of the Northridge earthquake had died down.) An unusual but small increase in activity level occurred in 2015 when nine events were recorded at area level.

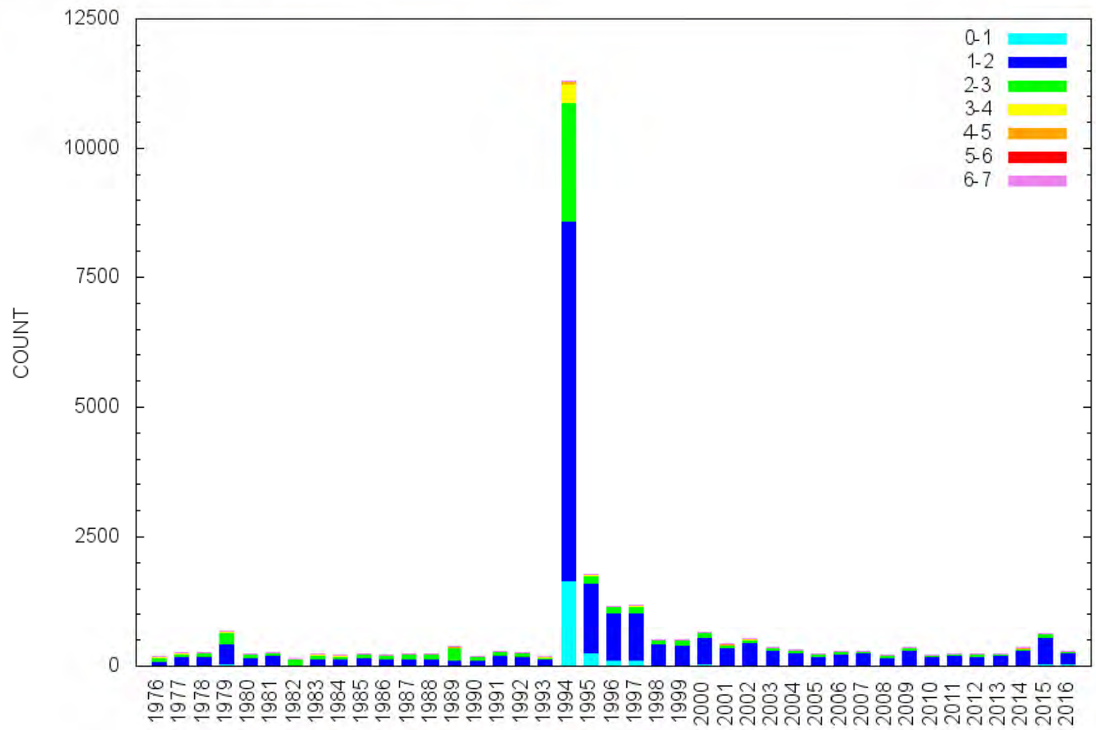


Figure 6: Seismic Event Counts at Regional Level

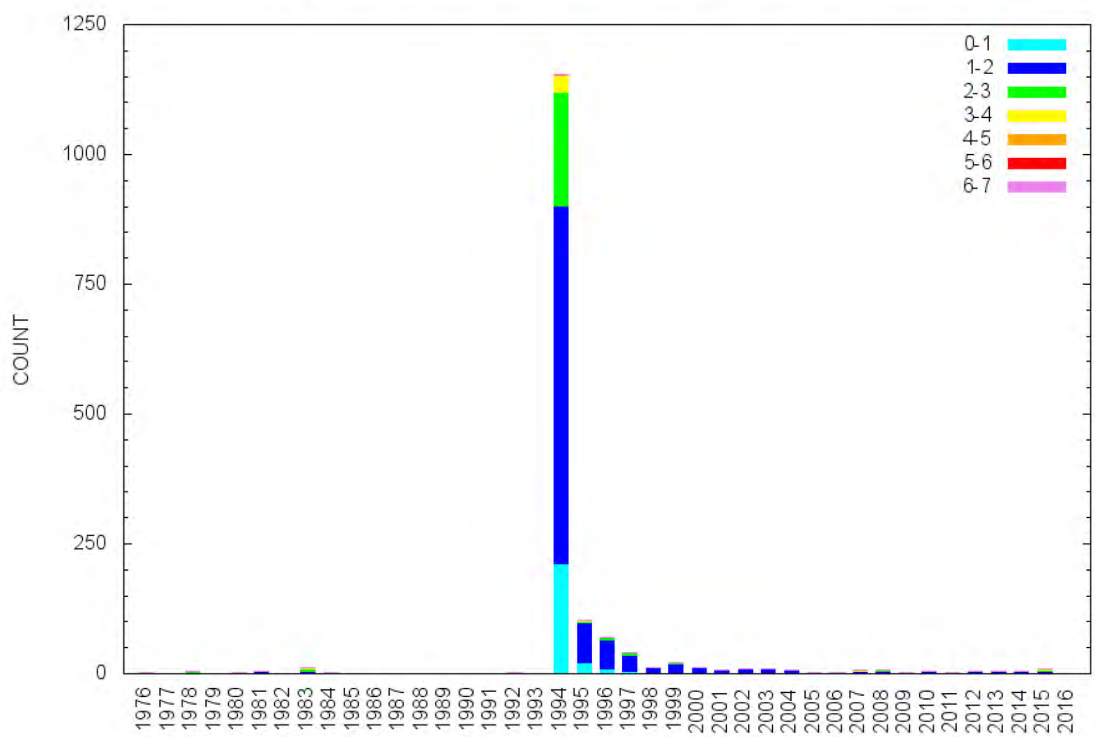


Figure 7: Seismic Event Counts at Area Level

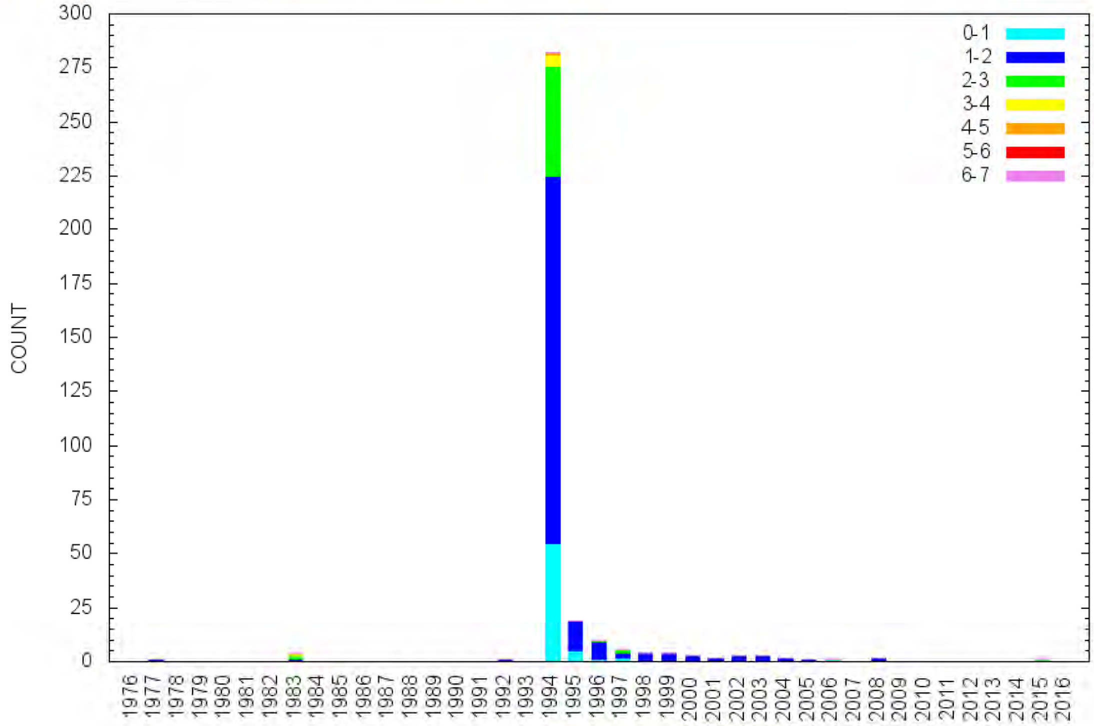


Figure 8: Seismic Event Counts at Field Level

Appendix B contains area level geographic plots of earthquakes for each year. 1975 is not included as a partial year, and 2015 is divided into two as pre- and post-incident. Note that 2016, although included in Appendix A, is also a partial year with only nine months of data.

3 SS-4-0 Well Failure

Because the SS-4-0 well failure in 1994 is explicitly attributed by Southern California Gas Company (SoCalGas) to seismic activity (specifically, the 1994 Northridge earthquake), the seismic events around this well are analyzed.

The 1994 Northridge earthquake occurred on January 17, 1994, and the SS-4-0 well file indicates that the failure was discovered on April 12, 1994. Therefore, the failure, if caused by seismic activity, must have occurred between January 17 and April 12.

Figure 9 shows extensive seismic activity in the area for the (almost) three months between the Northridge earthquake and the SS-4-0 failure discovery (SS-4-0 well is circled). The activity is associated with the aftershocks of the Northridge earthquake.

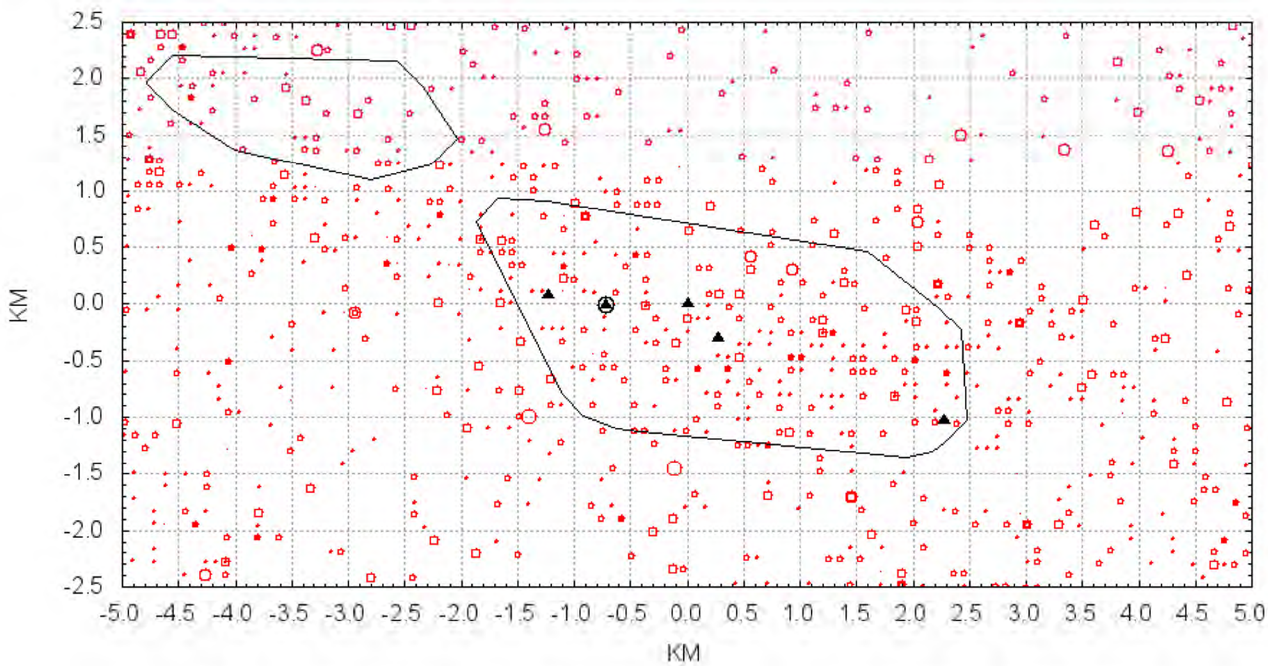


Figure 9: Seismic Events Preceding SS-4-0 Failure Discovery (01/17/1994–04/12/1994)

Table 2 lists the statistics associated with the strongest and closest events during this time period. The closest event is just 80 m (260 ft) east of the well, and eight events are located within 300 m (1,000 ft) of the well.

Table 2: Strongest and Closest Seismic Events (01/17/1994–04/12/1994)

Date and Time [a]	Magnitude	Distance (km)	Bearing [b]
10 Strongest Events			
01/29/1994 11:20:36	5.06	1.19	214°
01/17/1994 20:46:02	4.85	1.57	157°
01/17/1994 13:56:02	4.44	5.14	243°
01/18/1994 13:24:44	4.32	1.35	72°
01/18/1994 07:23:56	4.04	5.12	294°
01/20/1994 07:22:40	3.81	4.29	71°
01/17/1994 20:05:28	3.79	5.16	75°
02/02/1994 11:24:38	3.75	4.28	236°
01/30/1994 10:54:41	3.72	2.85	75°
01/17/1994 14:06:56	3.53	3.67	93°
10 Closest Events			
03/07/1994 05:28:12	0.86	0.08	88°
03/08/1994 22:14:35	1.49	0.11	189°
03/09/1994 10:48:33	1.23	0.14	35°
03/28/1994 10:42:45	0.97	0.16	318°
03/21/1994 22:03:32	1.29	0.22	185°
02/07/1994 17:53:55	1.25	0.22	185°
03/10/1994 21:30:39	1.00	0.23	301°
01/29/1994 11:23:43	1.90	0.30	223°
01/17/1994 21:44:09	1.70	0.34	131°
01/19/1994 01:24:31	2.85	0.35	90°

[a] time is UTC (Coordinated Universal Time)
[b] measured clockwise from due north

Therefore, the seismic event data are consistent with the hypothesis that the SS-4-0 well failure resulted from seismic activity.

4 SS-25 Well Failure

SS-25 well failure, which is the subject of the present root cause analysis study, was discovered on October 23, 2015.

Figure 7 and Figure 8 show that 2015 was seismically more active than the six years prior (2008–2014) when few seismic events were observed at the area level and none in the field level. In fact, one set of earthquake-foreshock-aftershock events occurred in April 2015 (Figure 4 and Figure 5).

Nine seismic events were recorded (Figure 10, Table 3) in 2015. Of these, eight were recorded on April 4, and the remaining (the furthest west) was recorded on April 13.

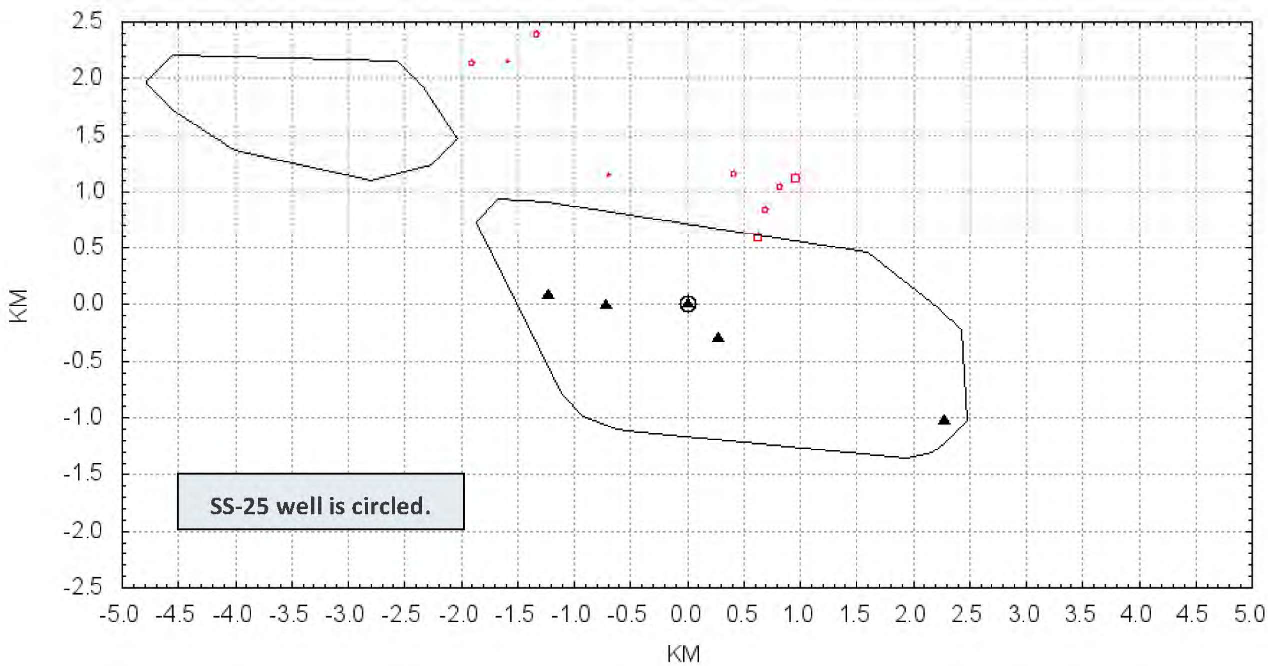


Figure 10: 2015 Seismic Events (Through 10/23/2015)

Table 3: 2015 Seismic Events (Through 10/23/2015)

Date and Time [a]	Magnitude	Distance (km)	Bearing [b]
04/04/2015 14:46:36	2.17	1.10	39°
04/04/2015 14:52:52	2.85	0.88	46°
04/04/2015 14:54:46	3.13	1.48	41°
04/04/2015 14:57:20	1.20	2.68	324°
04/04/2015 14:58:26	1.12	2.74	331°
04/04/2015 14:59:24	1.18	1.34	329°
04/04/2015 17:14:51	2.09	1.33	38°
04/04/2015 17:48:57	2.04	1.24	19°
04/13/2015 08:30:34	1.49	2.87	318°
[a] time is UTC (Coordinated Universal Time) [b] measured clockwise from due north			

The closest event was a magnitude 2.85 event 880 m (2,900 ft) to the northwest. The strongest event was a magnitude 3.13 event 1,480 m (4,860 ft) to the northwest.

No seismic events were recorded in the area after April 13, 2015 through September 2016 (Figure 4). Therefore, the last seismic event had occurred over six months before the SS-25 well failure was discovered.

It is unlikely that the seismic event is the cause of the SS-25 well failure for the following reasons:

- The last seismic event had been recorded over six months before the SS-25 well failure was discovered. The 1994 incident suggests that the failure should have been discovered much sooner, possibly within three months from the occurrence.
- The strongest seismic event is almost two units of magnitude weaker than that of SS-4-0 in 1994. Correspondingly, the intensity of the 2015 event is almost 1/100th of the strongest 1994 event, and the energy released by the 2015 event is almost 1/1000th of the strongest 1994 event[i].
- The closest seismic event in 2015 is over 10 times more distant than the closest 1994 event.
- The closest 2015 seismic event is closer to other active wells, so we would anticipate a failure of either:
  - Porter 5, which is only 180 m (590 ft) from the event, or
  - One of the 64 other active wells closer to the event than SS-25

[i] "The energy release of an earthquake, which closely correlates to its destructive power, scales with the 3⁄2 power of the shaking amplitude. Thus, a difference in magnitude of 1.0 is equivalent to a factor of 31.6 (=$(10^{1.0})^{(3/2)}$) in the energy released; a difference in magnitude of 2.0 is equivalent to a factor of 1000 (=$(10^{2.0})^{(3/2)}$) in the energy released." [2].

- The strongest 2015 seismic event is, similarly, closer to other active wells, so we would anticipate a failure of either:
  - Ward 3-1 (290 m; 950 ft), Ward 2 (540 m; 1,800 ft), Porter 6 (760 m; 2,500 ft), or Porter 5 (760 m; 2,500 ft); or
  - One of the 104 active wells closer to the event than SS-25.

Consequently, it is unlikely that a seismic event is the cause of the SS-25 well failure.

5 FF-34A, F-3, and P-38 Well Failures

FF-34A well failure was discovered in September 1990. The last seismic event recorded in the area before this date had occurred four years earlier, in September 1986. Therefore, FF-34A failure cannot be attributed to a seismic event.

F-3 well failure was discovered in June 1984. Two seismic events were recorded in the area in 1984 before the failure (Figure 11, Table 4). Both events are over 7 km (23,000 ft) from the failure well and are located to the northeast of the Aliso Canyon field. In fact, because F-3 is near the western edge of the Aliso Canyon field, almost all other wells are closer to the seismic events than F-3. Consequently, F-3 failure cannot be attributed to a seismic event.

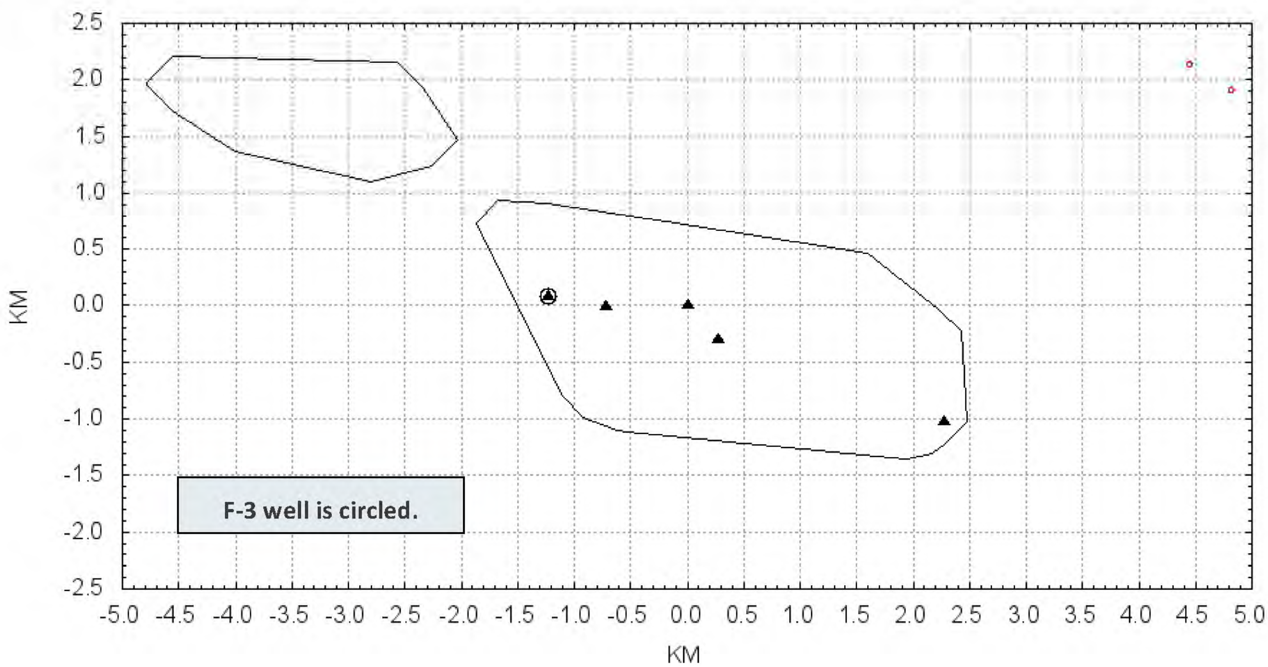


Figure 11: 1984 Seismic Events (Through 06/30/1984)

Table 4: 1984 Seismic Events (Through 06/30/1984)

Date and Time [a]	Magnitude	Distance (km)	Bearing [b]
01/18/1984 09:24:41	2.65	7.36	64°
06/20/1984 07:37:03	1.87	7.60	67°
[a] time is UTC (Coordinated Universal Time) [b] measured clockwise from due north			

P-38 failure was discovered in or about May 1980 (date is uncertain). The last seismic event recorded before this date had occurred almost nine months earlier, in September 1979. Therefore, P-38 failure is unlikely to have been caused by a seismic event; if this had been the case, the failure should have been discovered earlier.

No seismic events were recorded at the area and field level after April 2015 through September 2016. Therefore, no recorded seismic events were associated with the SS-25 blowout.

6 Methodology

The seismic events to be analyzed have been obtained for the October 24, 1975–September 30, 2016 period using the USGS Earthquake Catalog [1]. A 50-km radius around the SS-25 wellhead location has been selected. The search generated 27,046 events, which have been downloaded in comma-separated values (CSV) format and imported into Microsoft Excel for analysis. All further analyses have been conducted in Microsoft Excel.

To calculate distances between wells and events, latitude and longitudes have been converted to Cartesian coordinates using Universal Transverse Mercator (UTM) projection, zone 11, which is the appropriate UTM zone for Aliso Canyon field; the conversion yields easting and northing values (x and y coordinates) in meters. The Visual Basic for Applications (VBA) functions (code) used for the forward (latitude and longitude to UTM coordinates) and inverse (UTM coordinates to latitude and longitude) are given in Appendix C.

7 References

[1] U.S. Geological Survey, "Earthquake Hazards Program, Search Earthquake Catalog," [Online]. Available: https://earthquake.usgs.gov/earthquakes/search/.

[2] Wikipedia, "Richter magnitude scale," [Online]. Available: https://en.wikipedia.org/wiki/Richter_magnitude_scale. [Accessed 7 November 2016].

Appendix A Seismic Magnitude Scale

Table 5: Seismic Magnitudes [2]

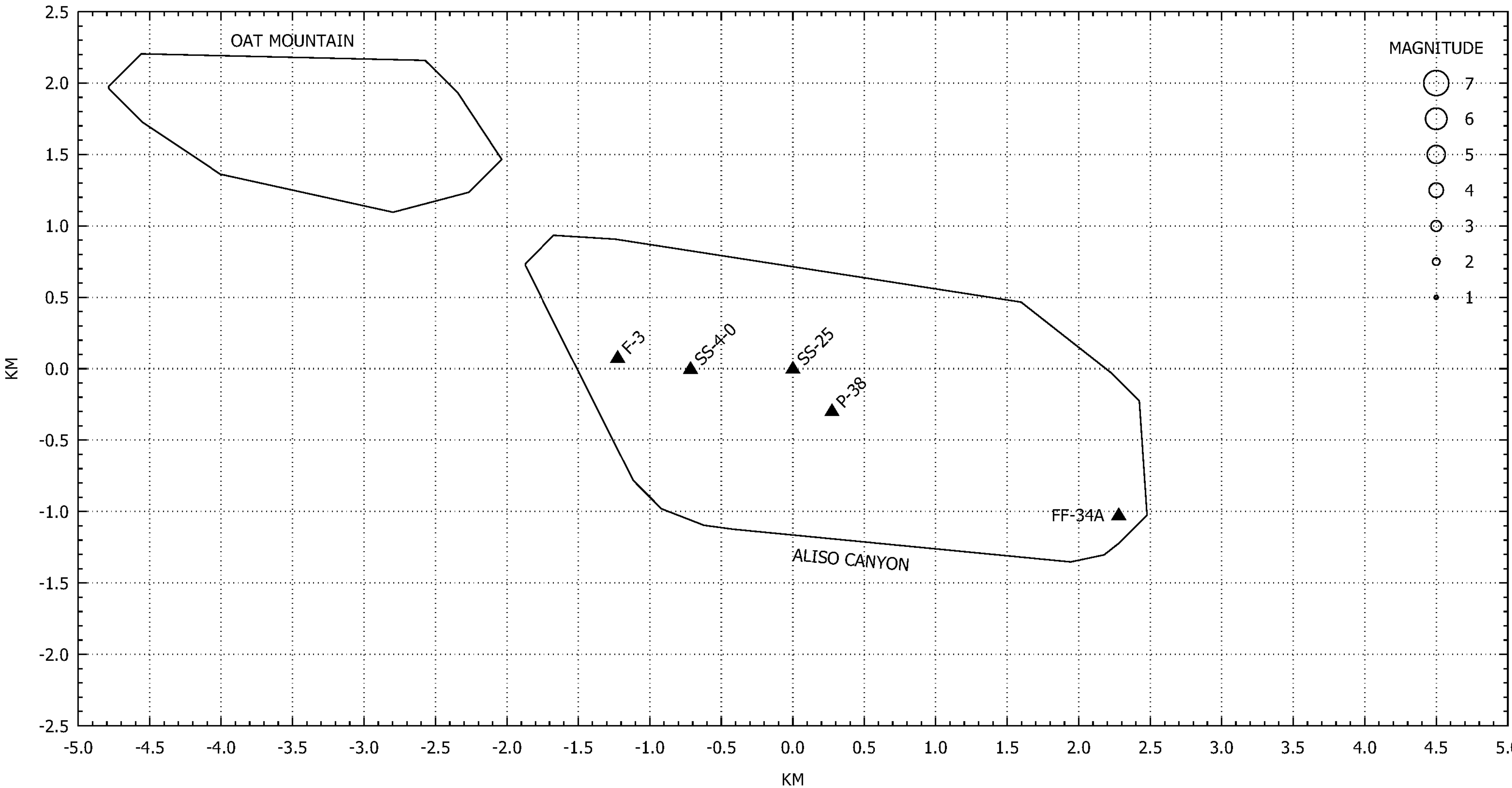
Magnitude	Description	Average Earthquake Effects
1.0–1.9	Micro	Microearthquakes, not felt, or felt rarely. Recorded by seismographs.
2.0–2.9	Minor	Felt slightly by some people. No damage to buildings.
3.0–3.9	Minor	Often felt by people, but very rarely causes damage. Shaking of indoor objects can be noticeable.
4.0–4.9	Light	Noticeable shaking of indoor objects and rattling noises. Felt by most people in the affected area. Slightly felt outside. Generally causes none to minimal damage. Moderate to significant damage very unlikely. Some objects may fall off shelves or be knocked over.
5.0–5.9	Moderate	Can cause damage of varying severity to poorly constructed buildings. At most, none to slight damage to all other buildings. Felt by everyone.
6.0–6.9	Strong	Damage to a moderate number of well-built structures in populated areas. Earthquake-resistant structures survive with slight to moderate damage. Poorly designed structures receive moderate to severe damage. Felt in wider areas; up to hundreds of miles/kilometers from the epicenter. Strong to violent shaking in epicentral area.
7.0–7.9	Major	Causes damage to most buildings, some to partially or completely collapse or receive severe damage. Well-designed structures are likely to receive damage. Felt across great distances with major damage mostly limited to 250 km from epicenter.
8.0–8.9	Great	Major damage to buildings, structures likely to be destroyed. Will cause moderate to heavy damage to sturdy or earthquake-resistant buildings. Damaging in large areas. Felt in extremely large regions.
9.0 and greater	Great	At or near total destruction – severe damage or collapse to all buildings. Heavy damage and shaking extends to distant locations. Permanent changes in ground topography.

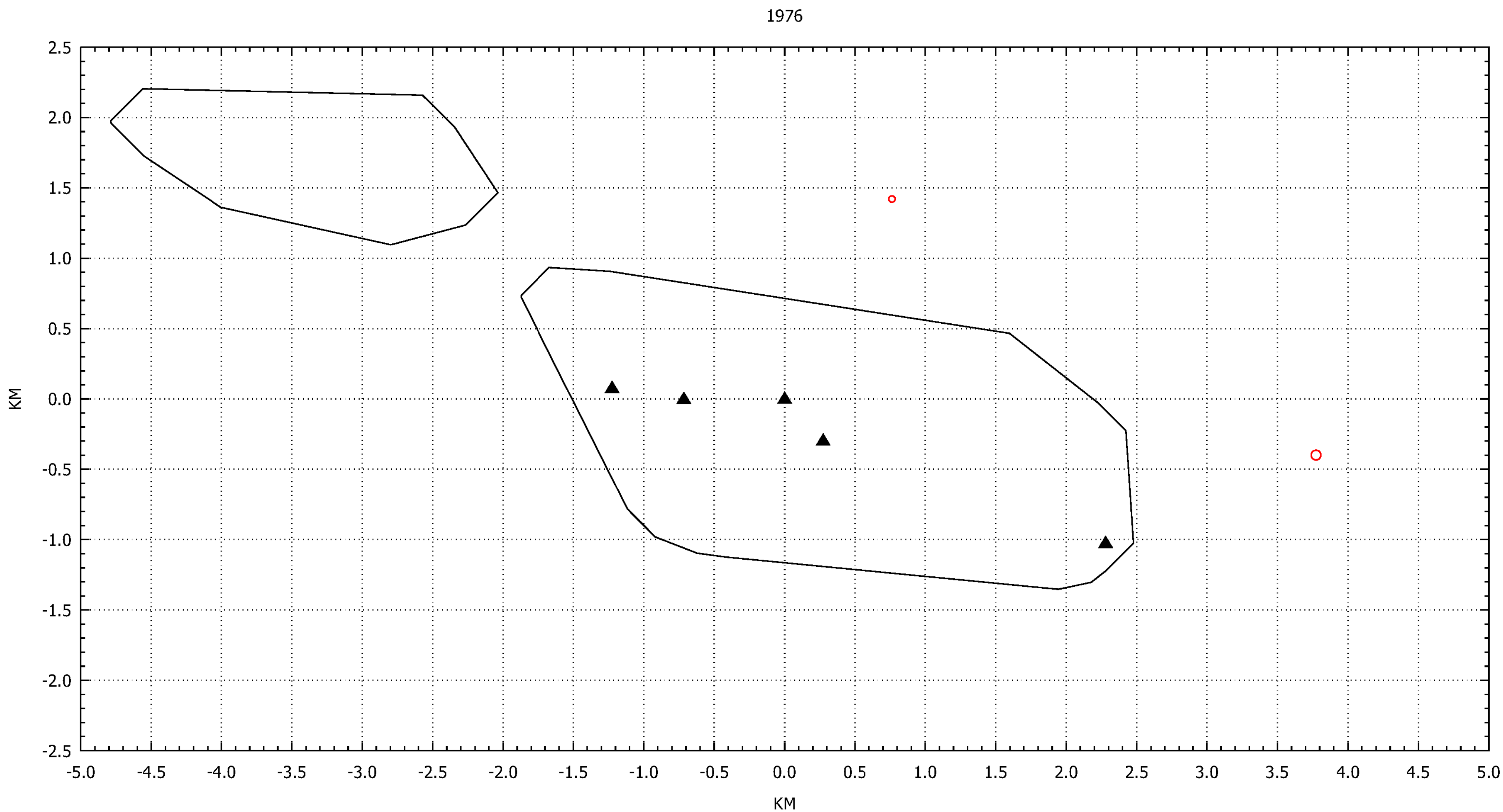
Appendix B Annual Seismic Activity Maps

This section shows annual seismic activity maps at the area level of interest between 1976 and 2016.

The five wells with failures are marked with solid triangles. Each seismic event that occurs during a specific calendar year is marked with a red circle, with the size of the circle being proportional to the magnitude of the seismic event as shown in the legend page.

LEGEND


OAT MOUNTAIN
ALISO CANYON
F-3
SS-4-0
SS-25
P-38
FF-34A
MAGNITUDE
7
6
5
4
3
2
1
KM
KM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KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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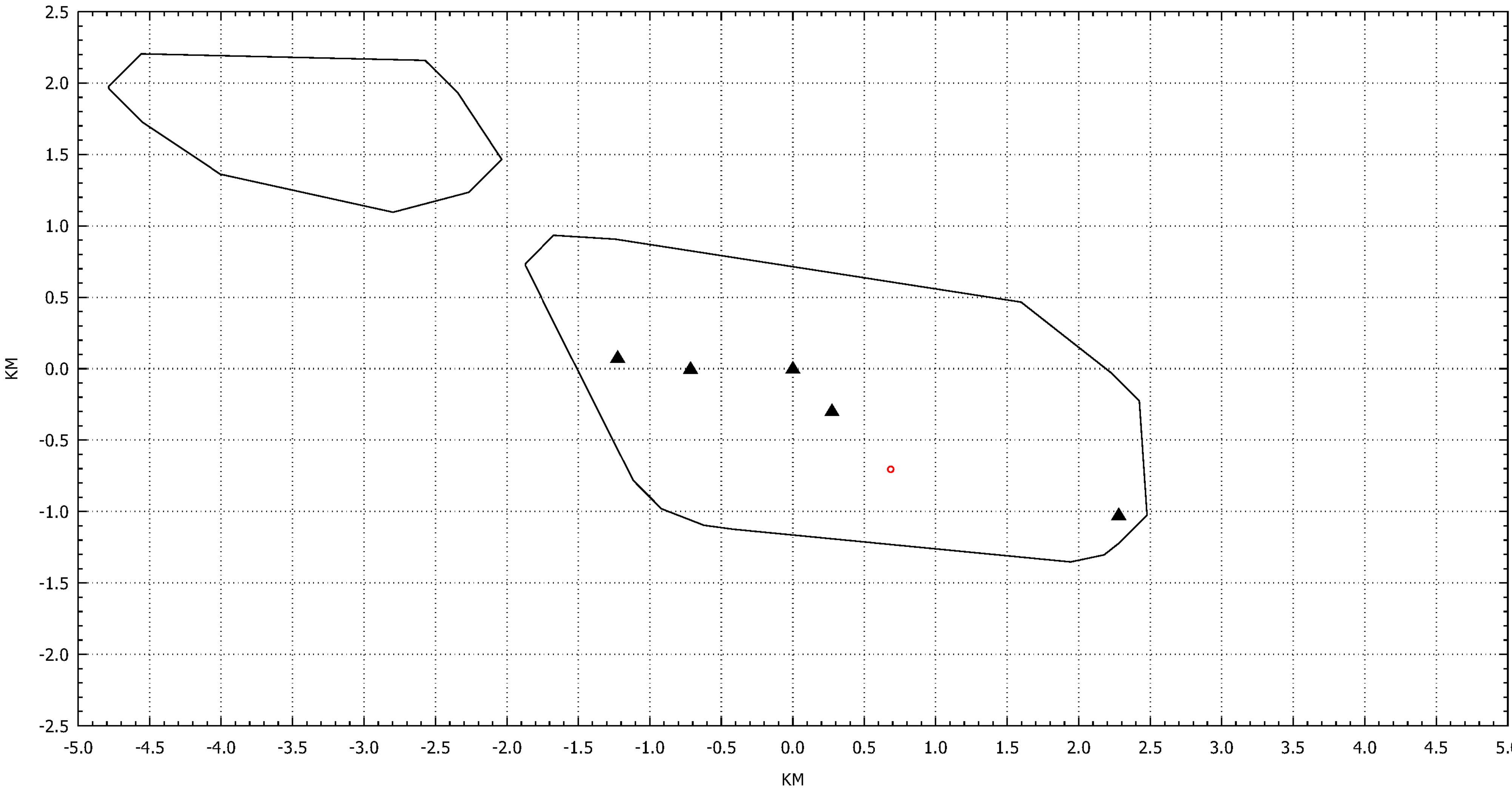
3.0
3.5
4.0
4.5
5.0
KM

1977



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1.5
1.0
0.5
0.0
-0.5
-1.0
-1.5
-2.0
-2.5
KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
0.0
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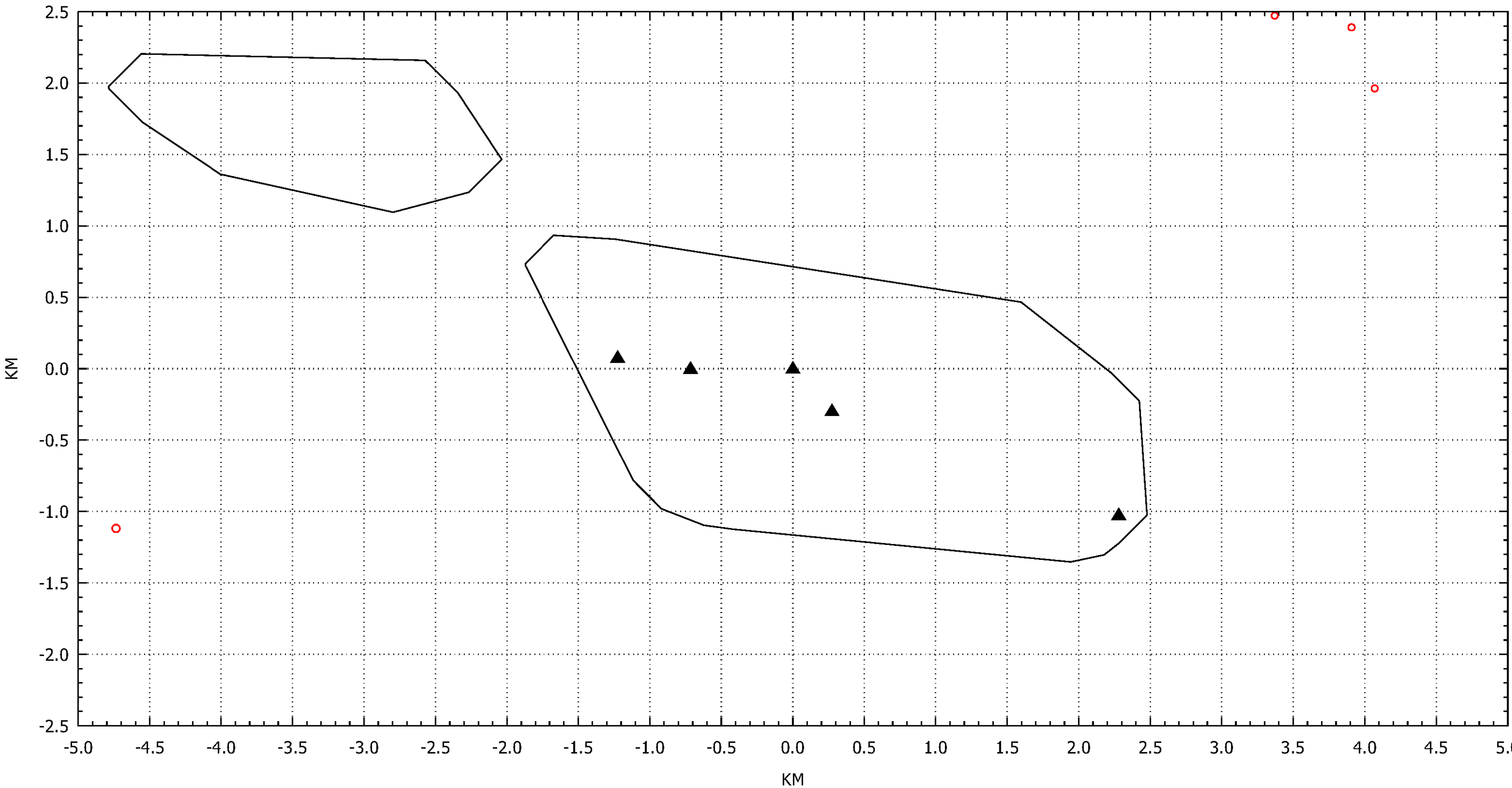
2.0
2.5
3.0
3.5
4.0
4.5
5.0
KM

1978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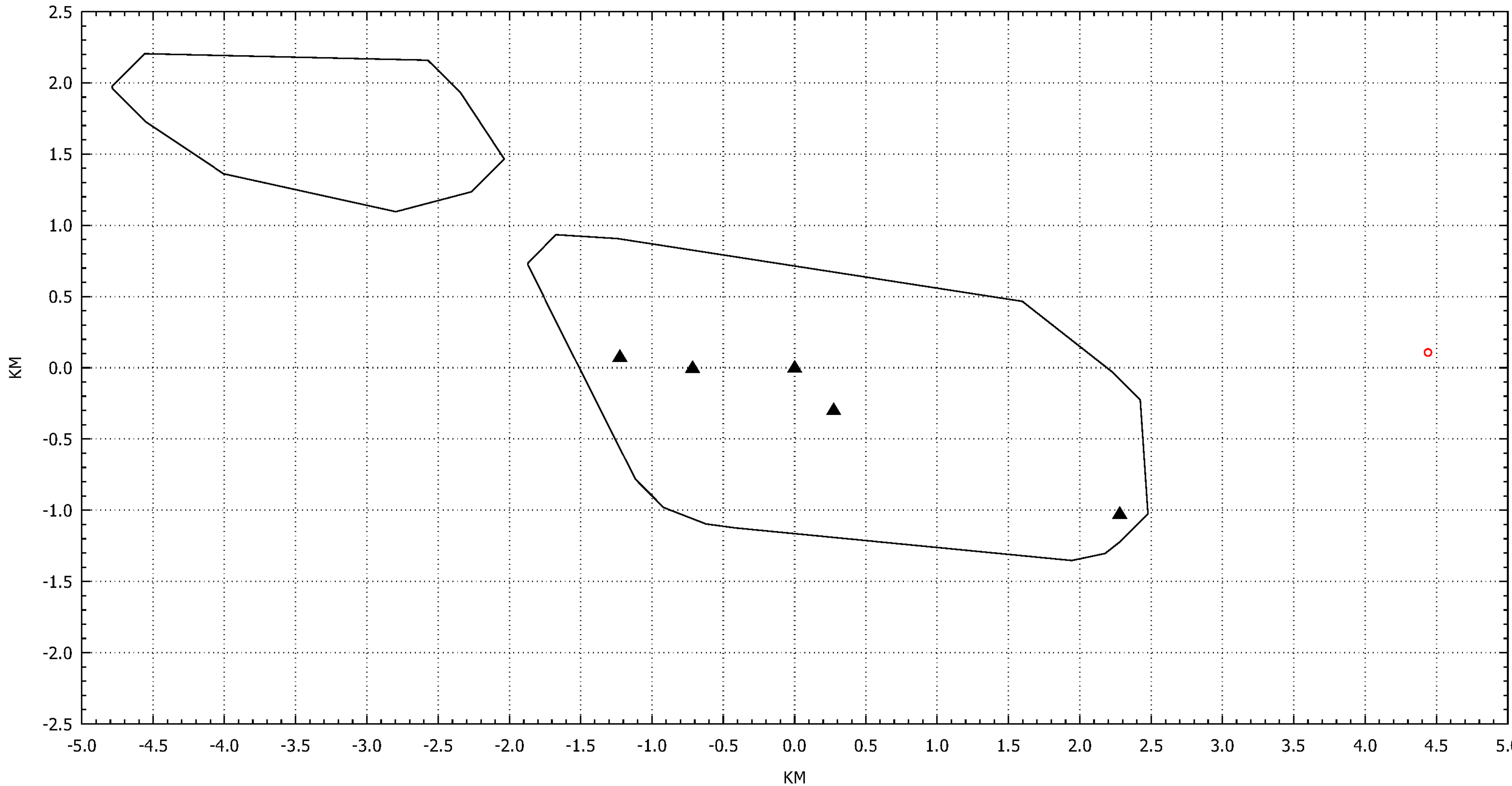
0.0
-0.5
-1.0
-1.5
-2.0
-2.5
KM
-5.0 -4.5 -4.0 -3.5 -3.0 -2.5 -2.0 -1.5 -1.0 -0.5 0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
KM

1979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-1.0
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KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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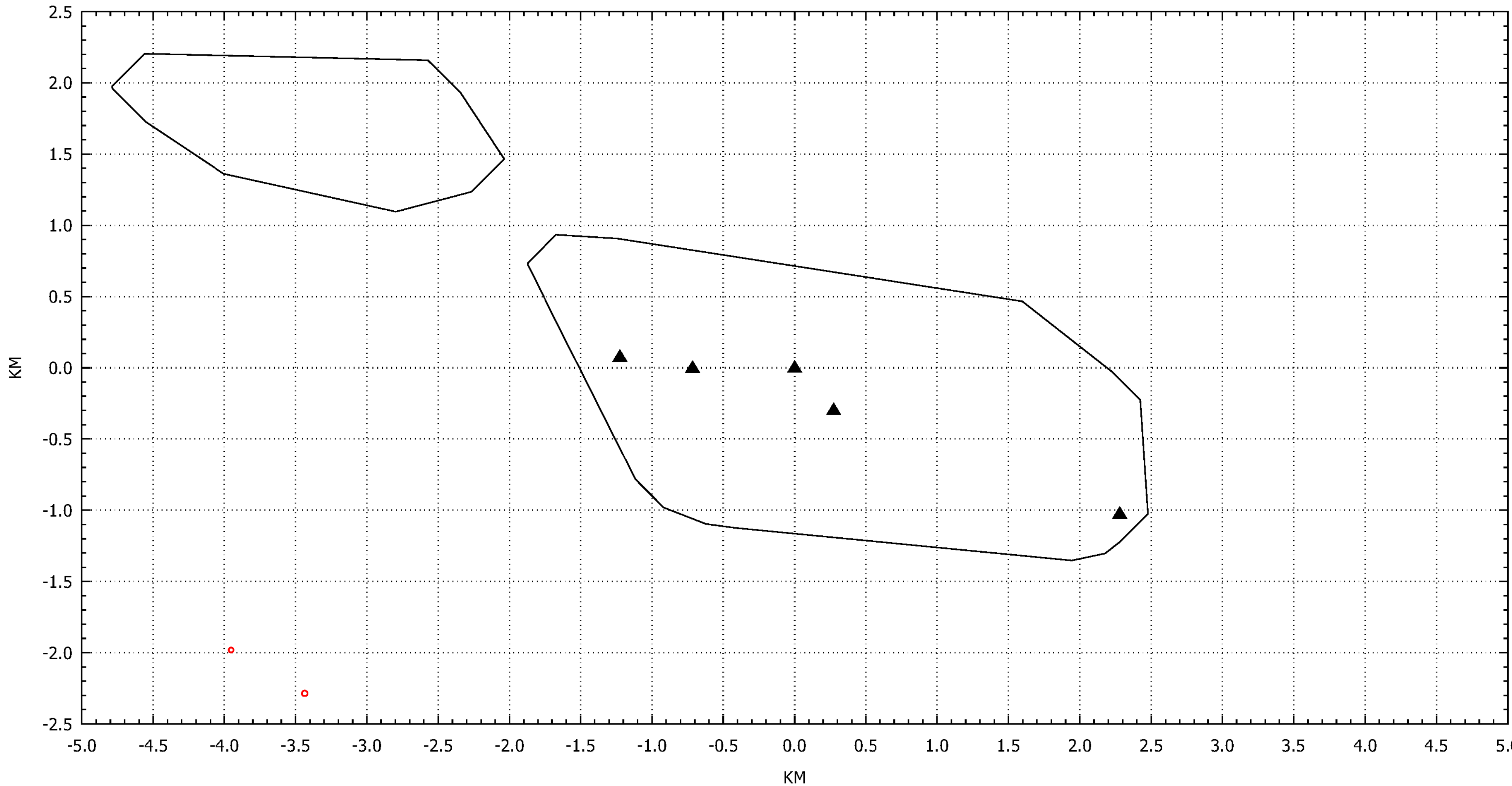
2.5
3.0
3.5
4.0
4.5
5.0
KM

1980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KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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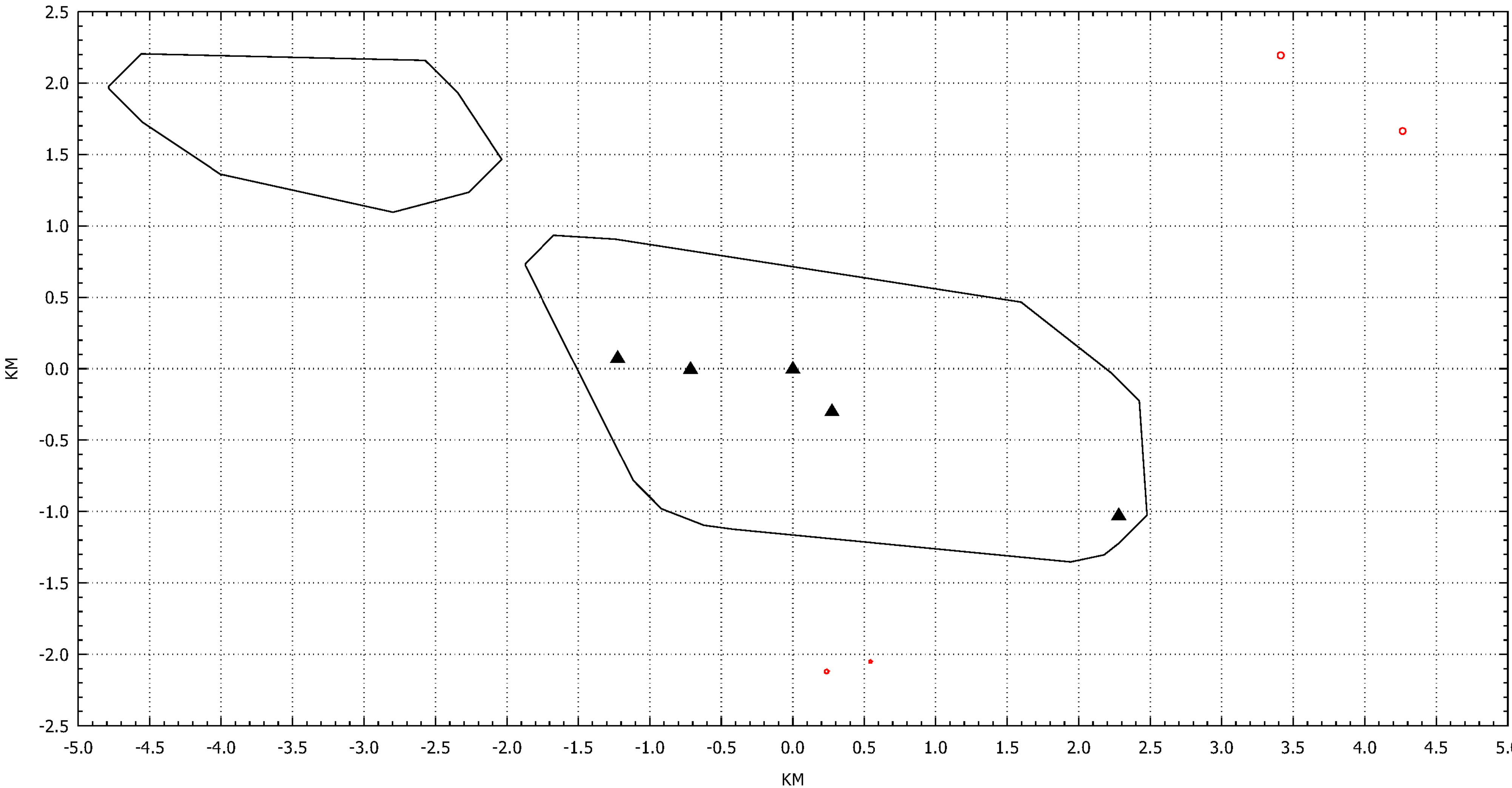
2.0
2.5
3.0
3.5
4.0
4.5
5.0
KM

1981



2.5
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-2.5
KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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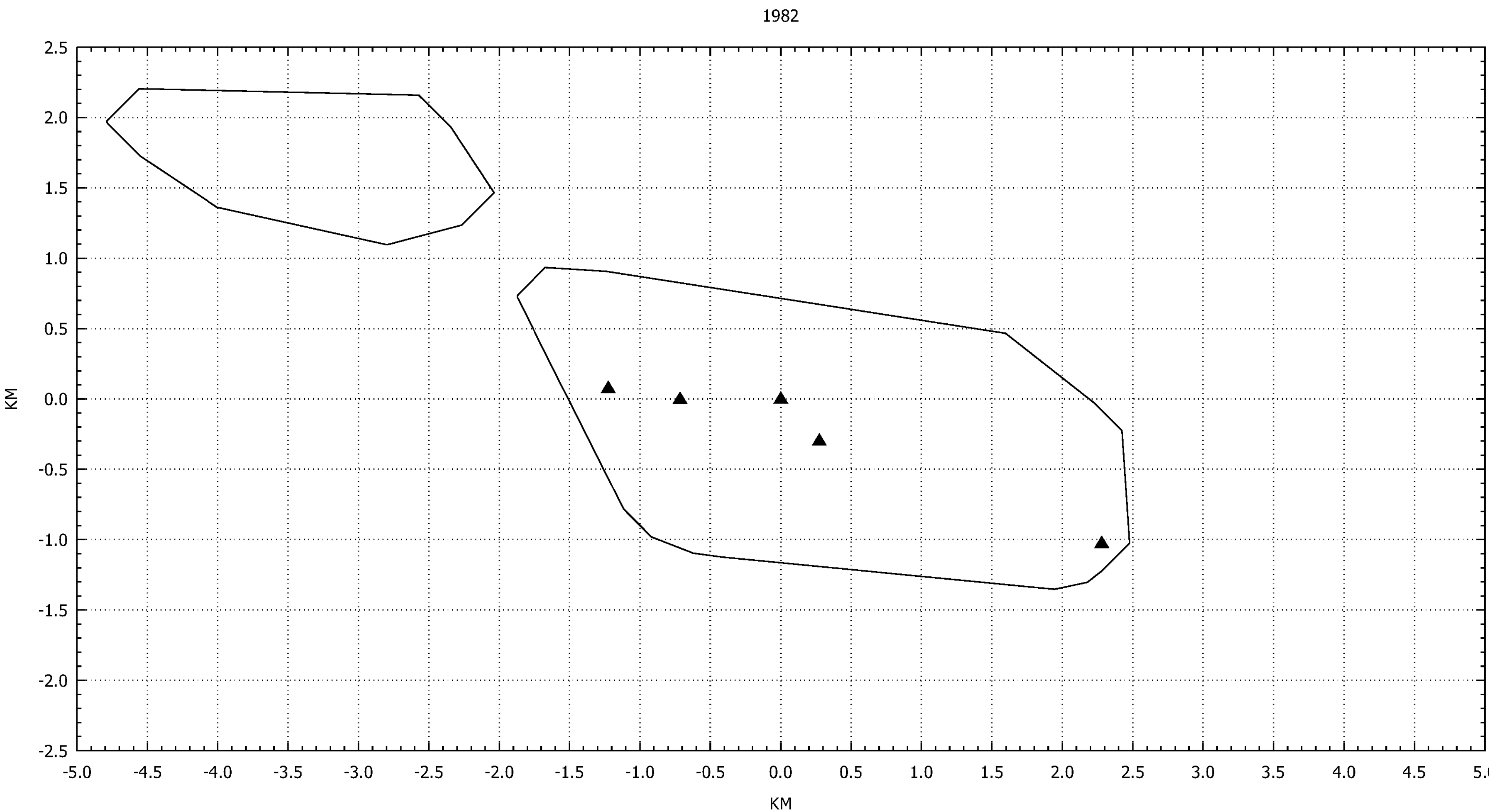
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
KM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KM
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-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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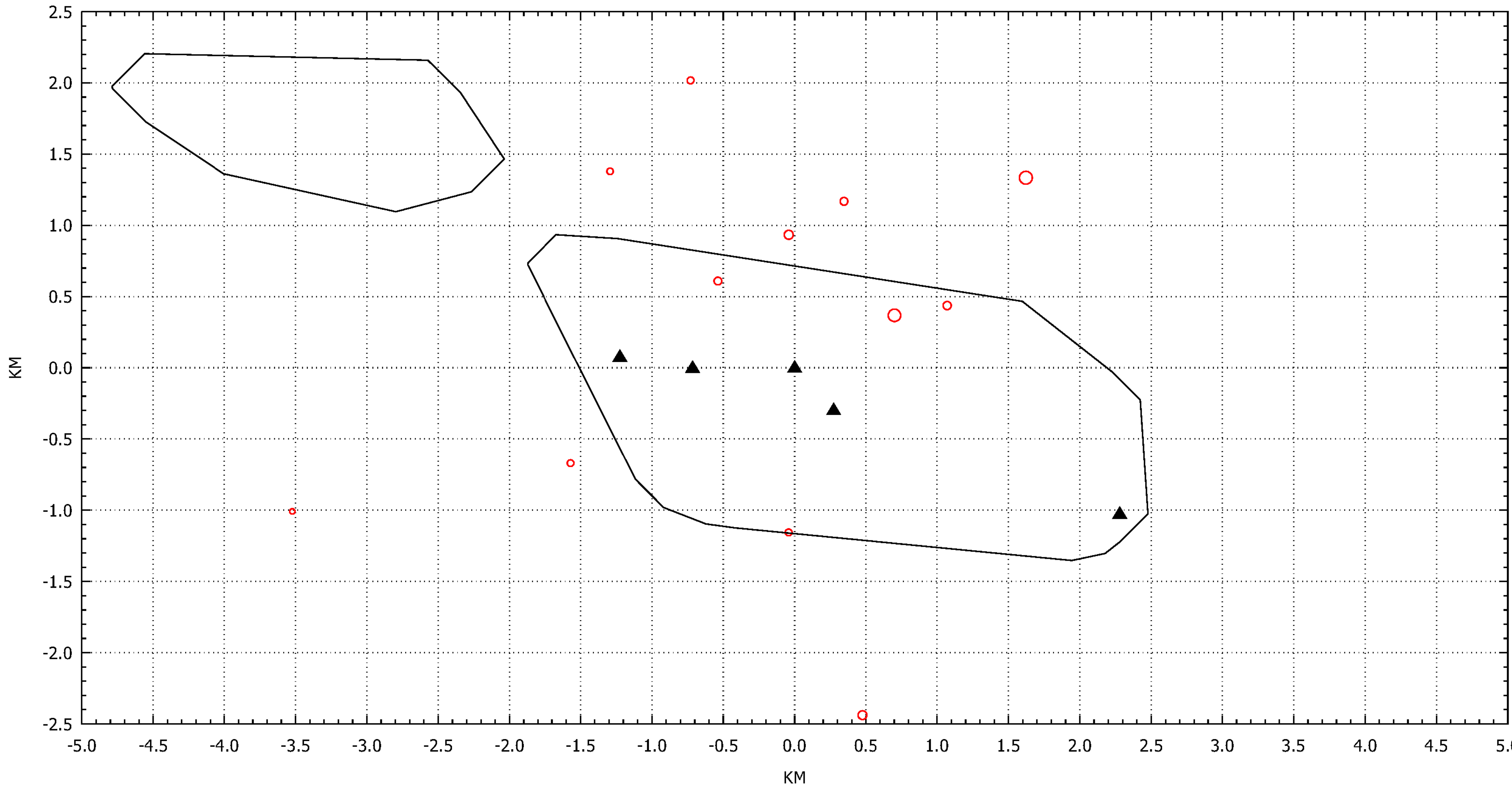
2.0
2.5
3.0
3.5
4.0
4.5
5.0

1983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-1.0
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-2.0
-2.5
KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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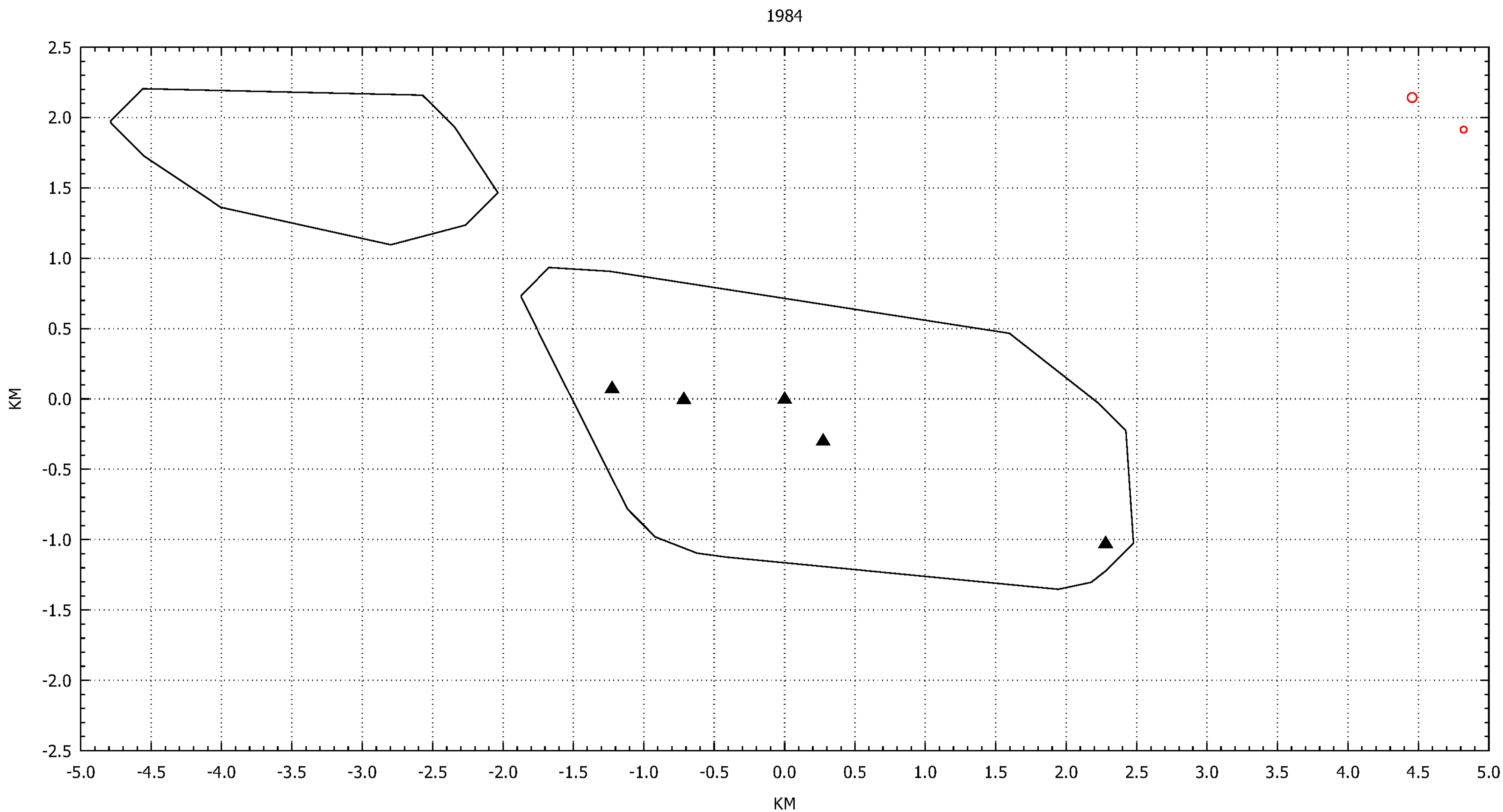
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
KM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-2.5
KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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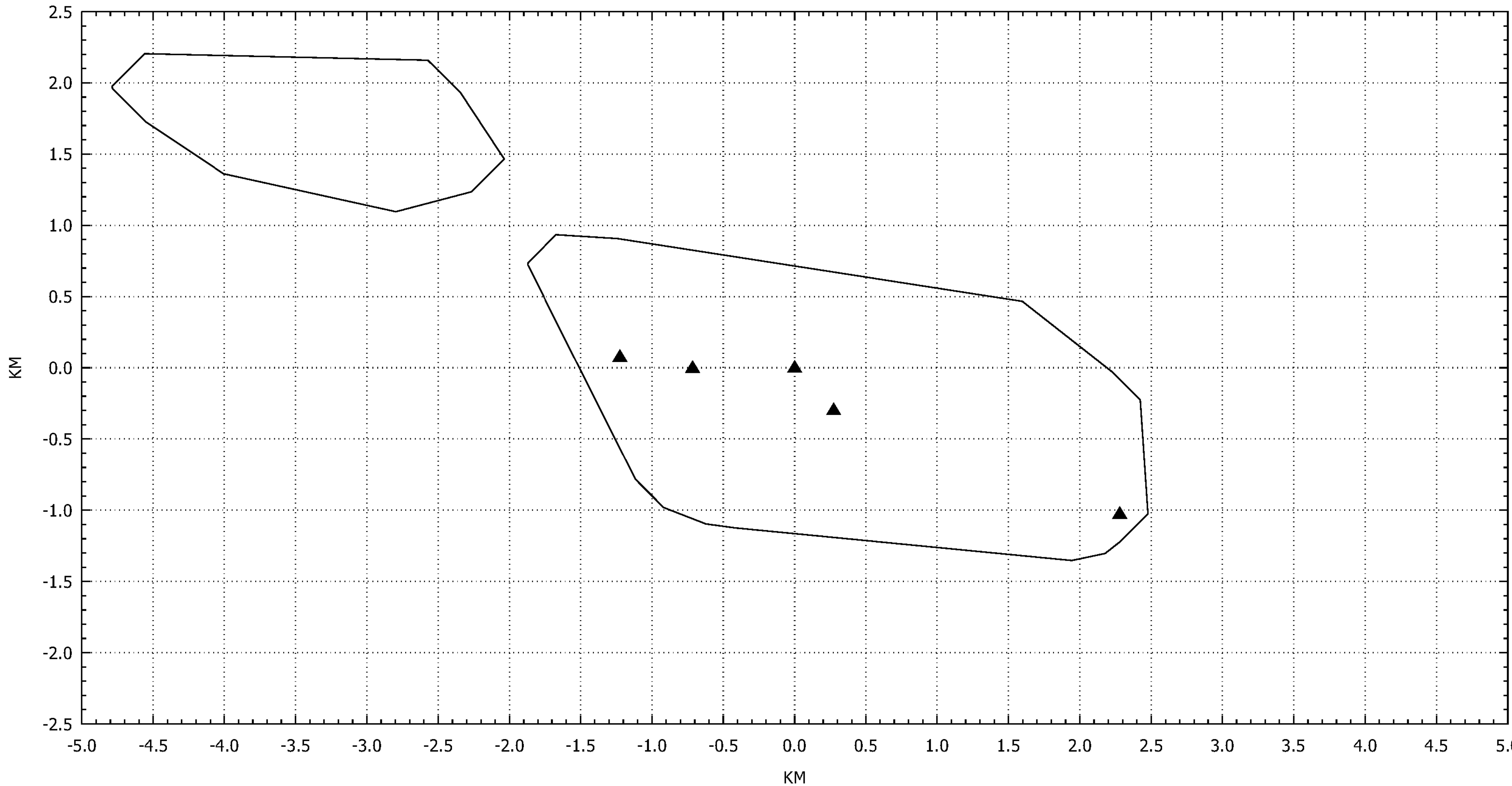
3.0
3.5
4.0
4.5
5.0
KM

1985



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-2.0
-2.5
KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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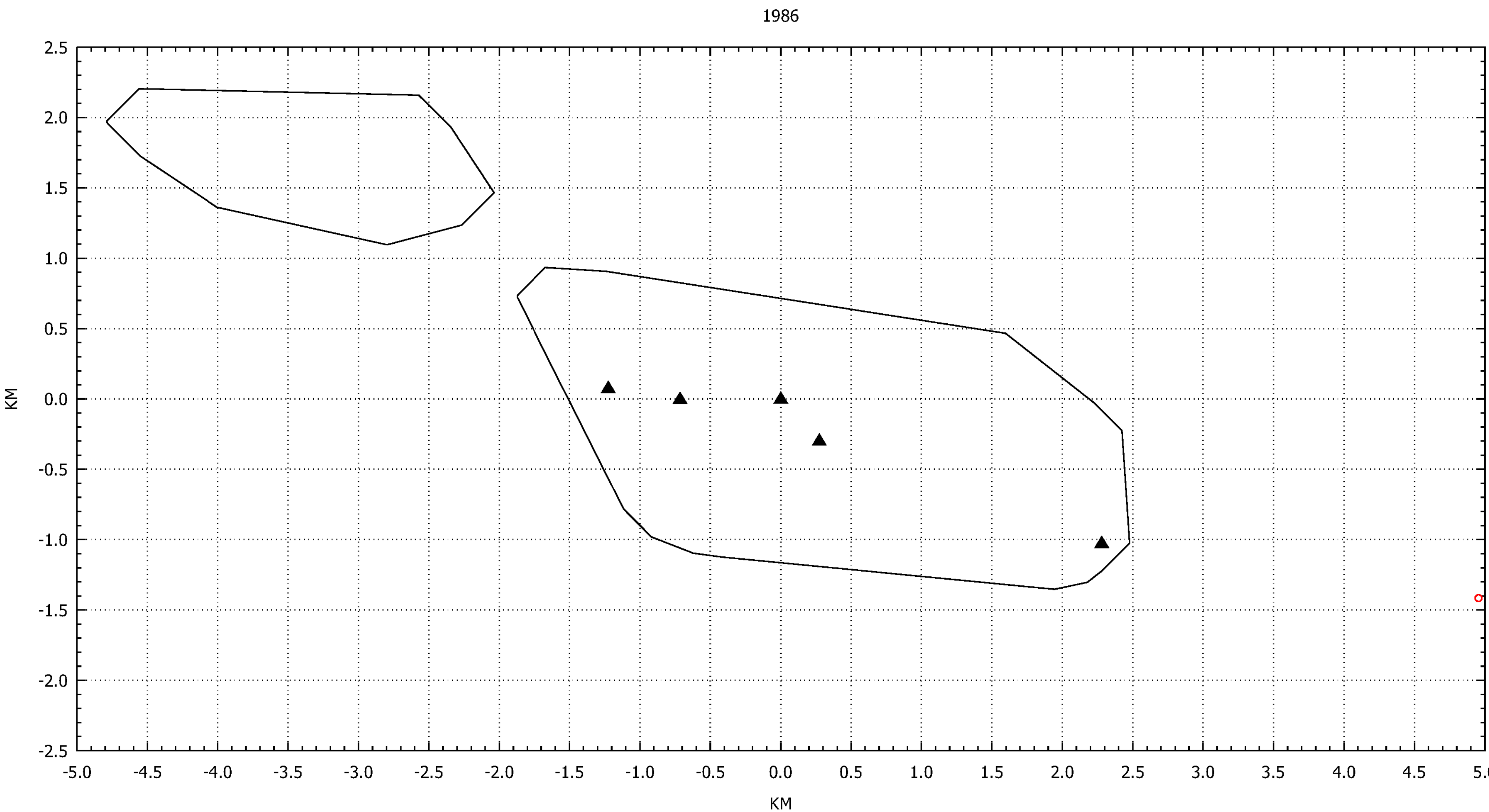
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
KM



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-2.5
KM
-5.0
-4.5
-4.0
-3.5
-3.0
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-1.5
-1.0
-0.5
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2.5
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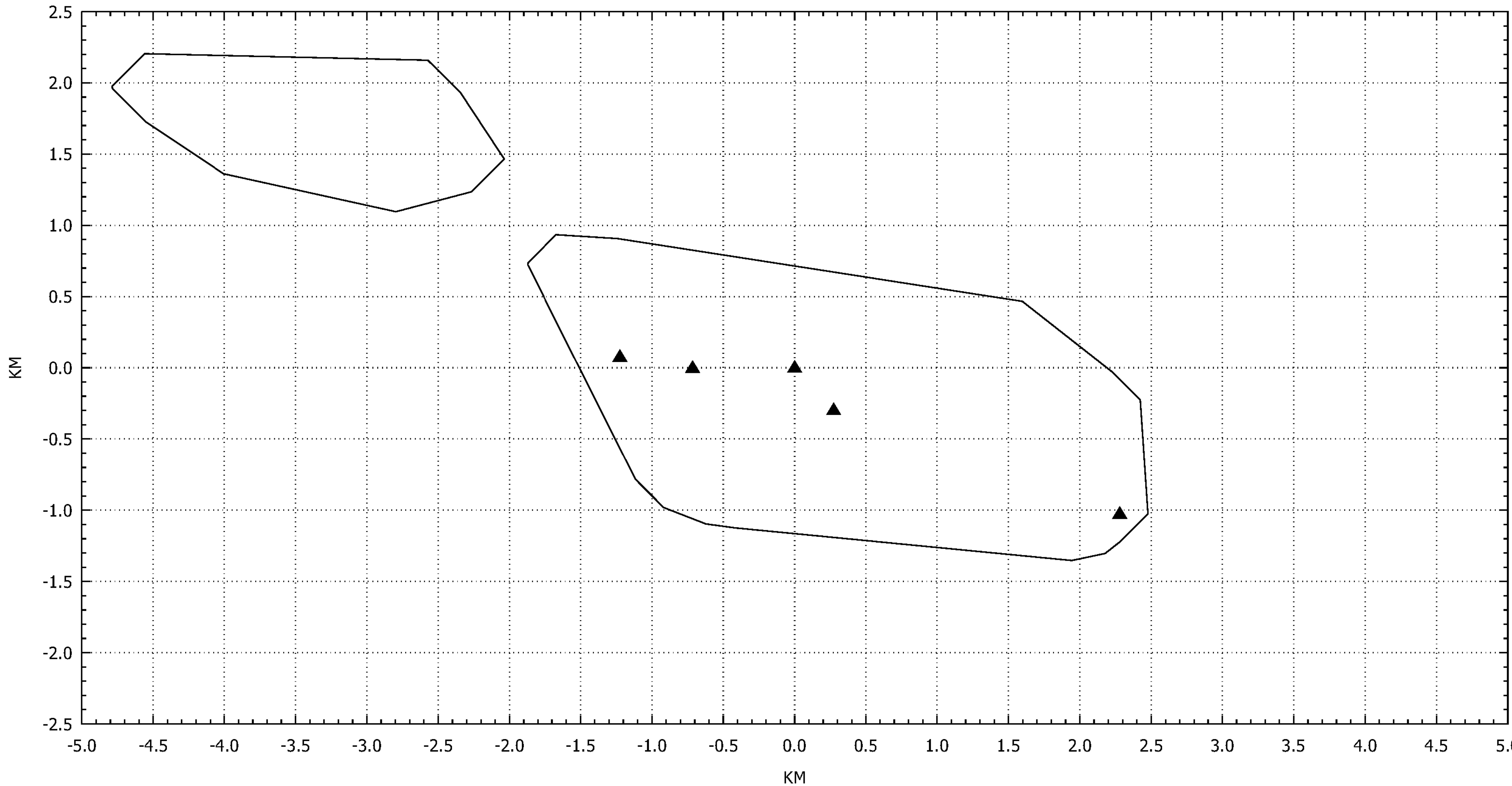
3.5
4.0
4.5
5.0
KM

1987



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-2.0
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KM
-5.0
-4.5
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-1.5
-1.0
-0.5
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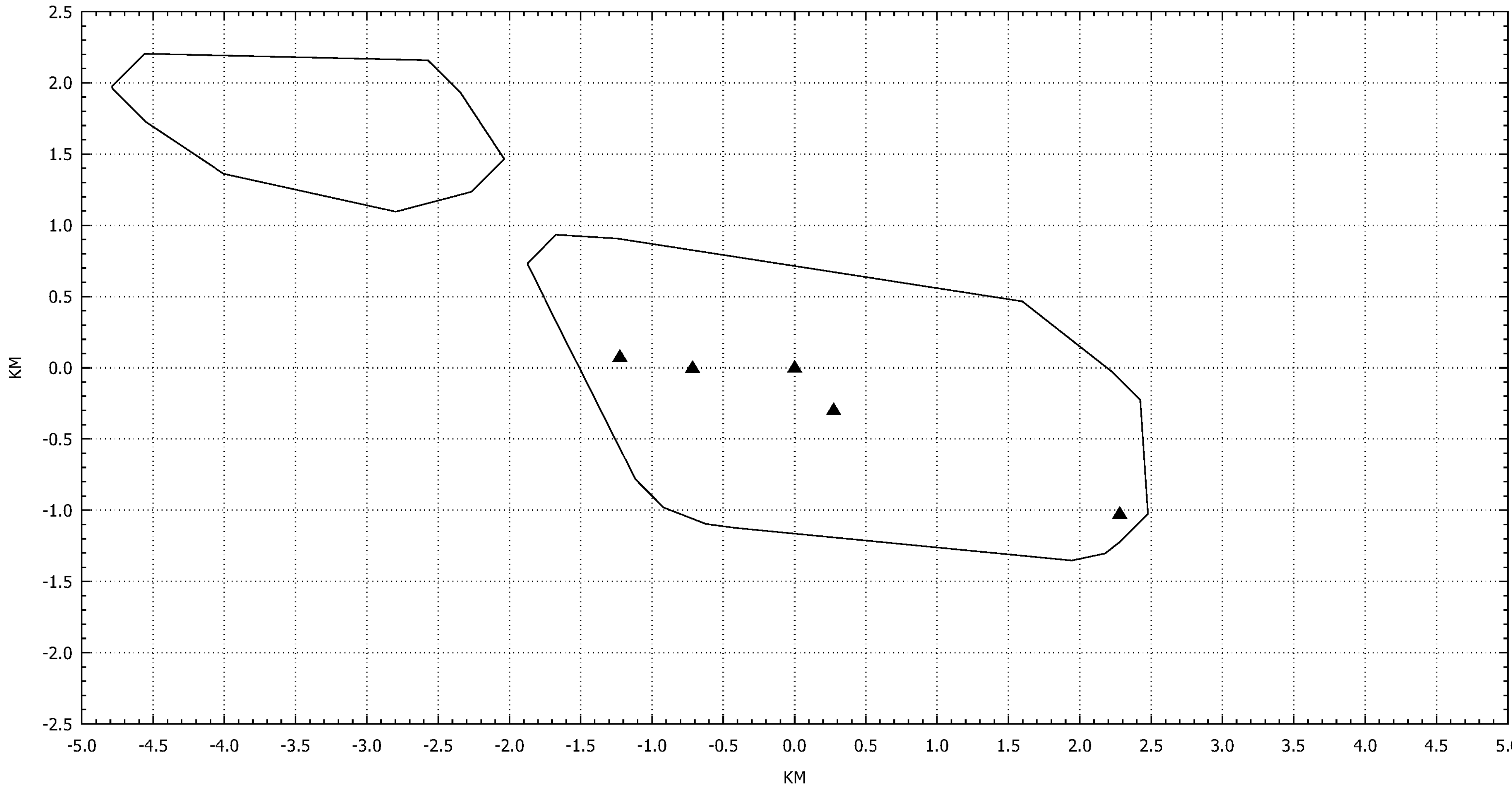
2.0
2.5
3.0
3.5
4.0
4.5
5.0
KM

1988



KM
KM
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-2.5
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-4.0
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-2.5
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-1.0
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3.0
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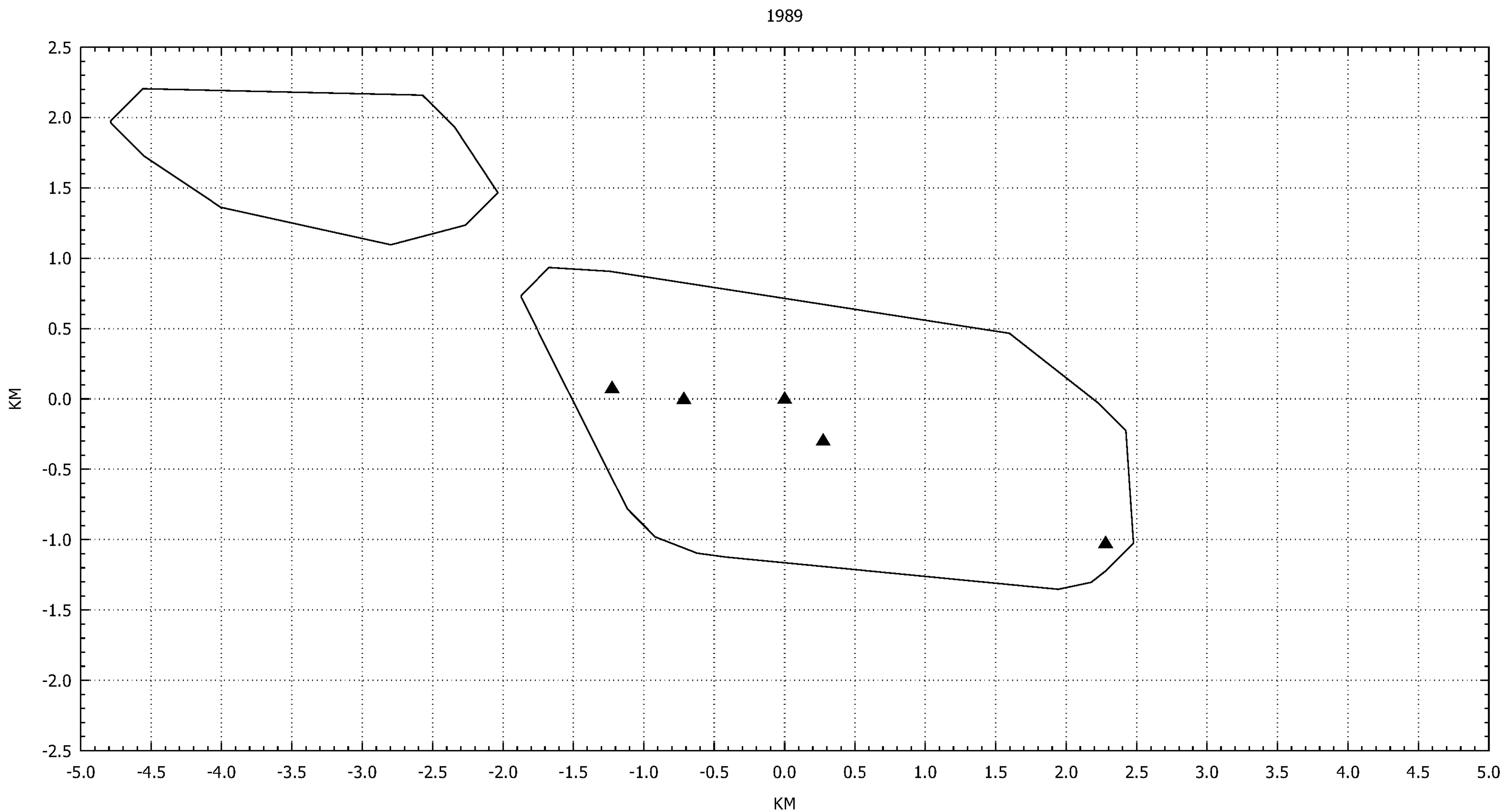
4.5
5.0



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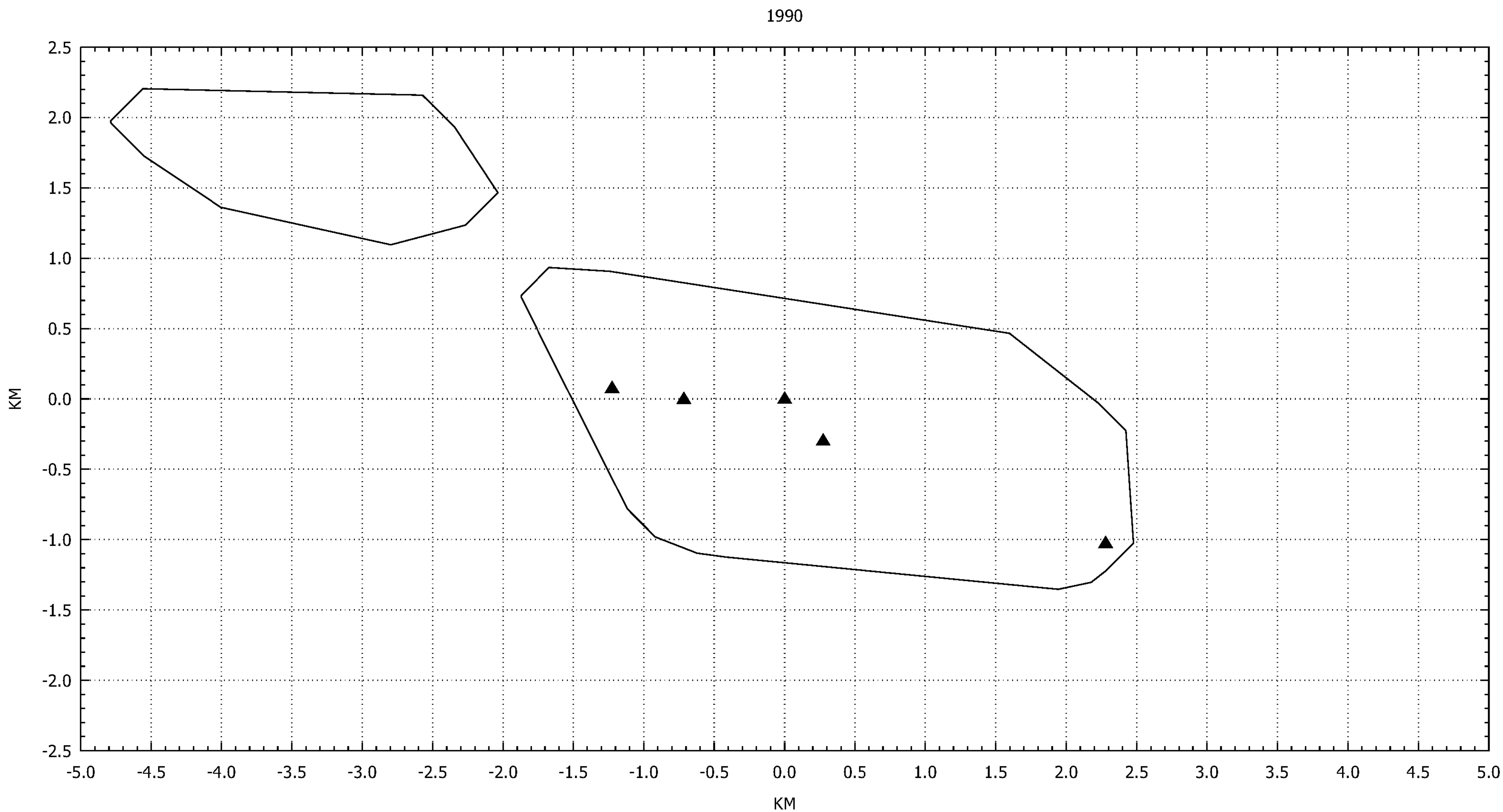
KM
KM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-2.5
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-3.5
-3.0
-2.5
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-1.5
-1.0
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1.0
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3.0
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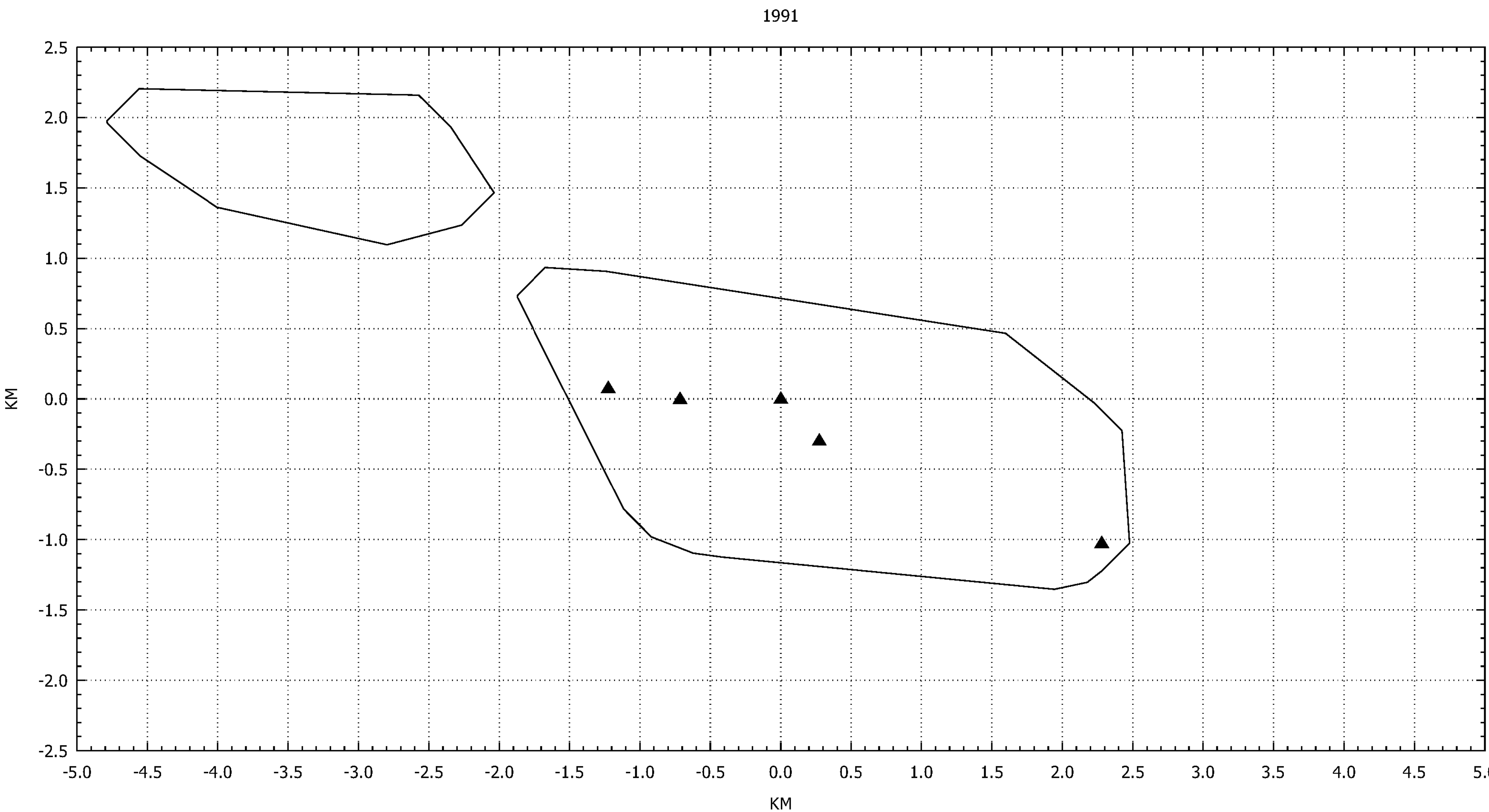
4.0
4.5
5.0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KM
-5.0
-4.5
-4.0
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-1.0
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4.5
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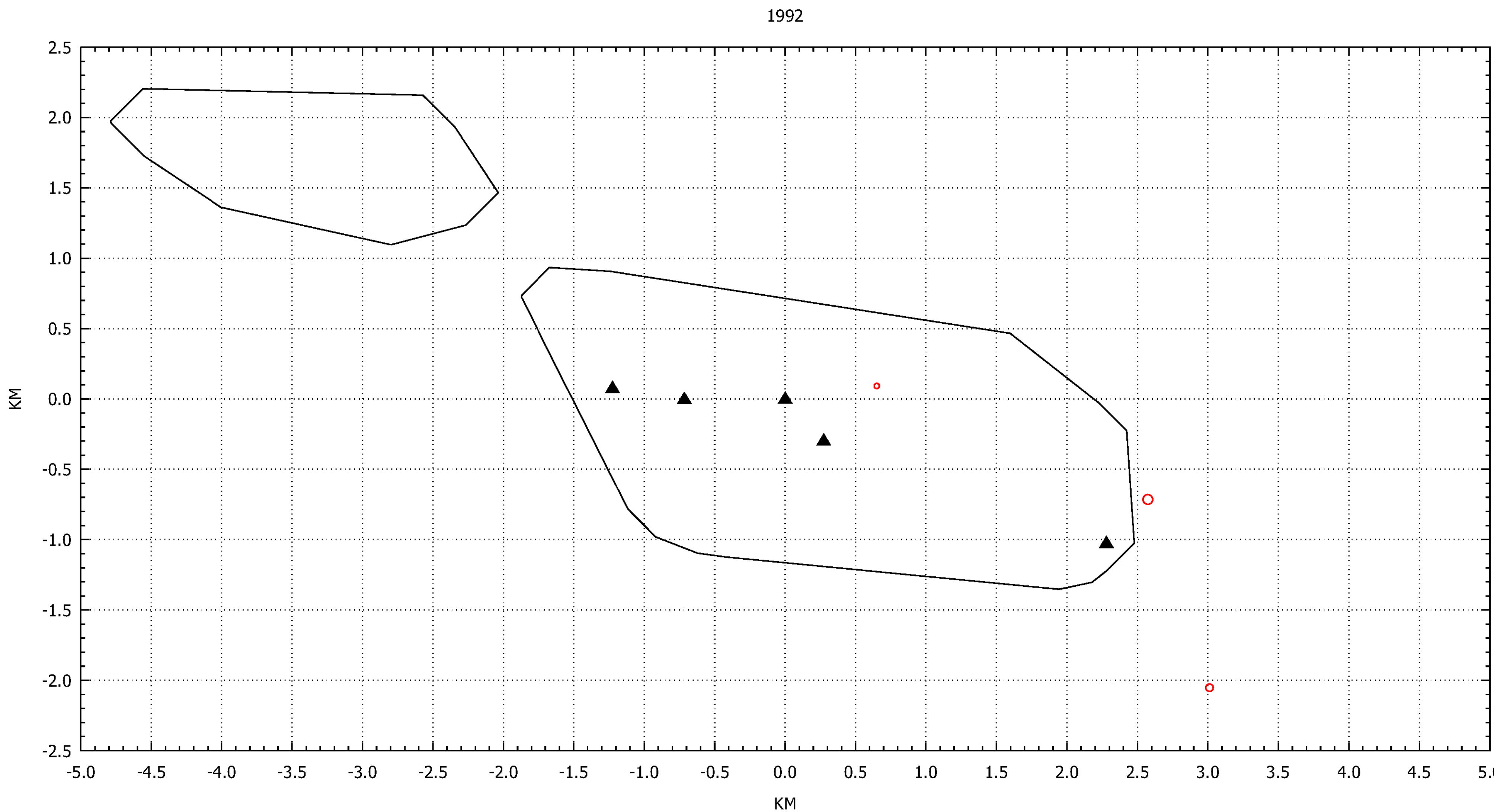
KM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-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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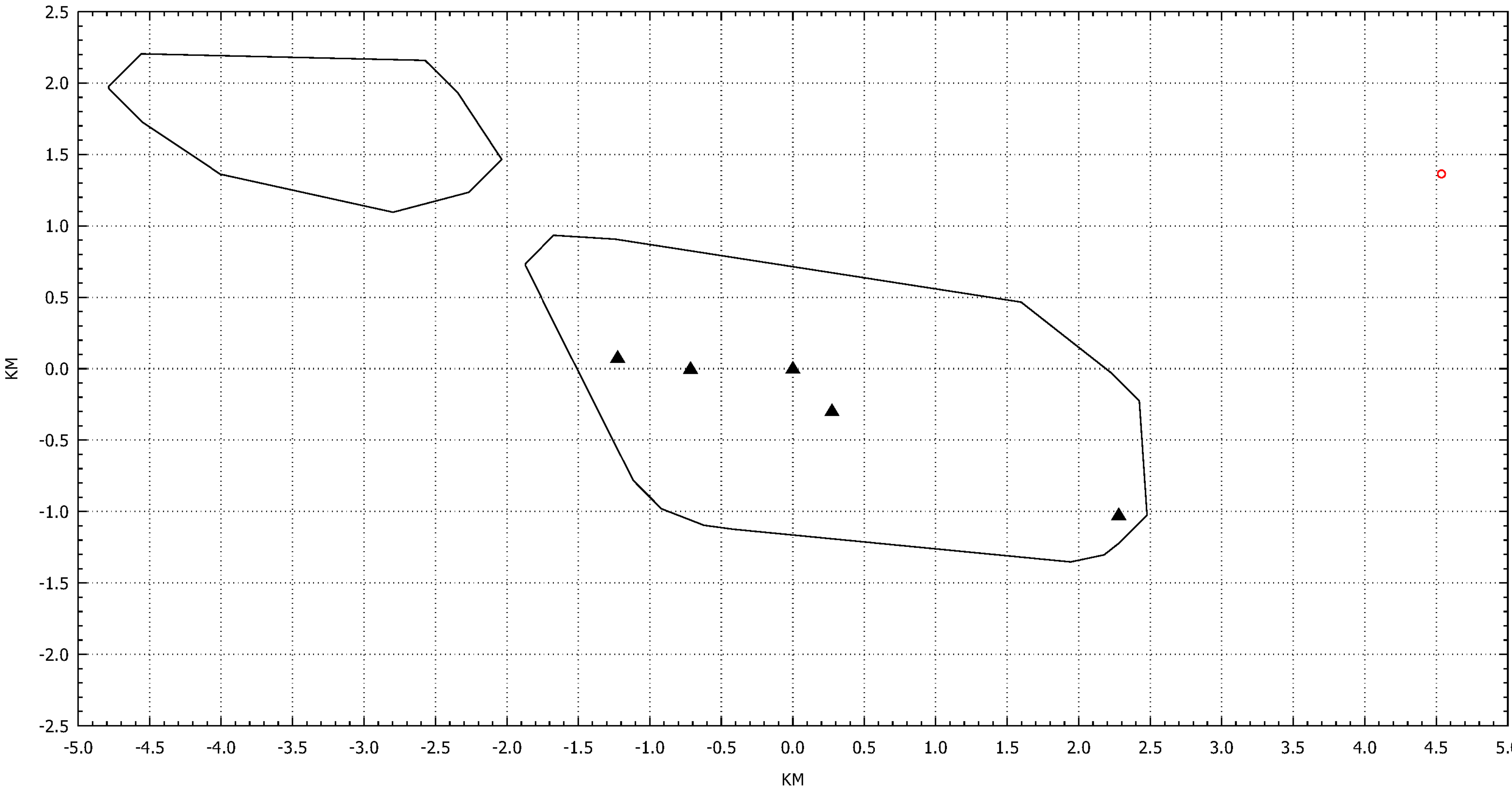
3.5
4.0
4.5
5.0

1993



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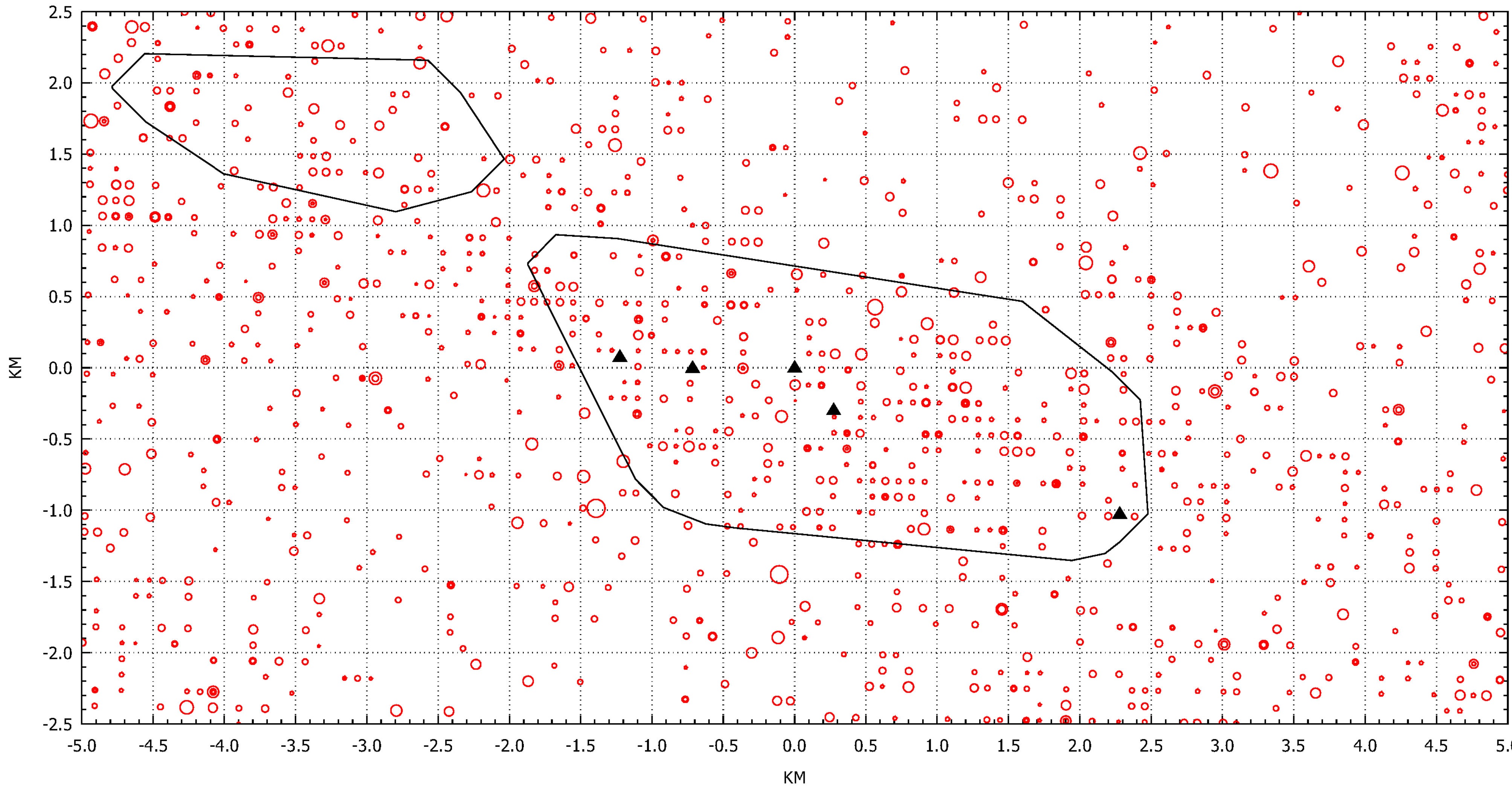
-0.5
-1.0
-1.5
-2.0
-2.5
KM
-5.0 -4.5 -4.0 -3.5 -3.0 -2.5 -2.0 -1.5 -1.0 -0.5 0.0 0.5 1.0 1.5 2.0 2.5 3.0 3.5 4.0 4.5 5.0
KM

1994



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KM
-5.0
-4.5
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-3.5
-3.0
-2.5
-2.0
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-1.0
-0.5
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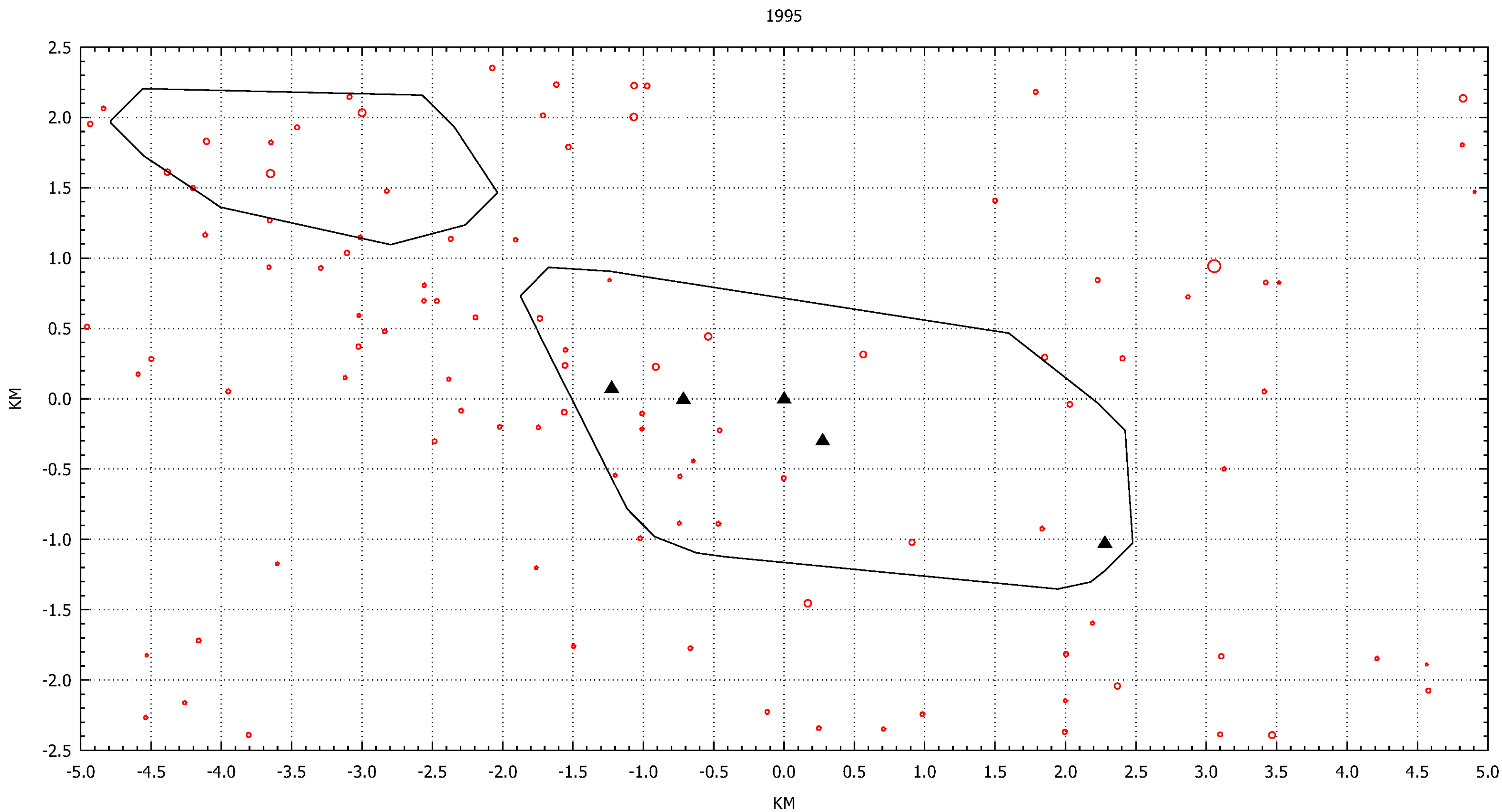
KM


1995
KM
KM
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-2.5
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
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1.0
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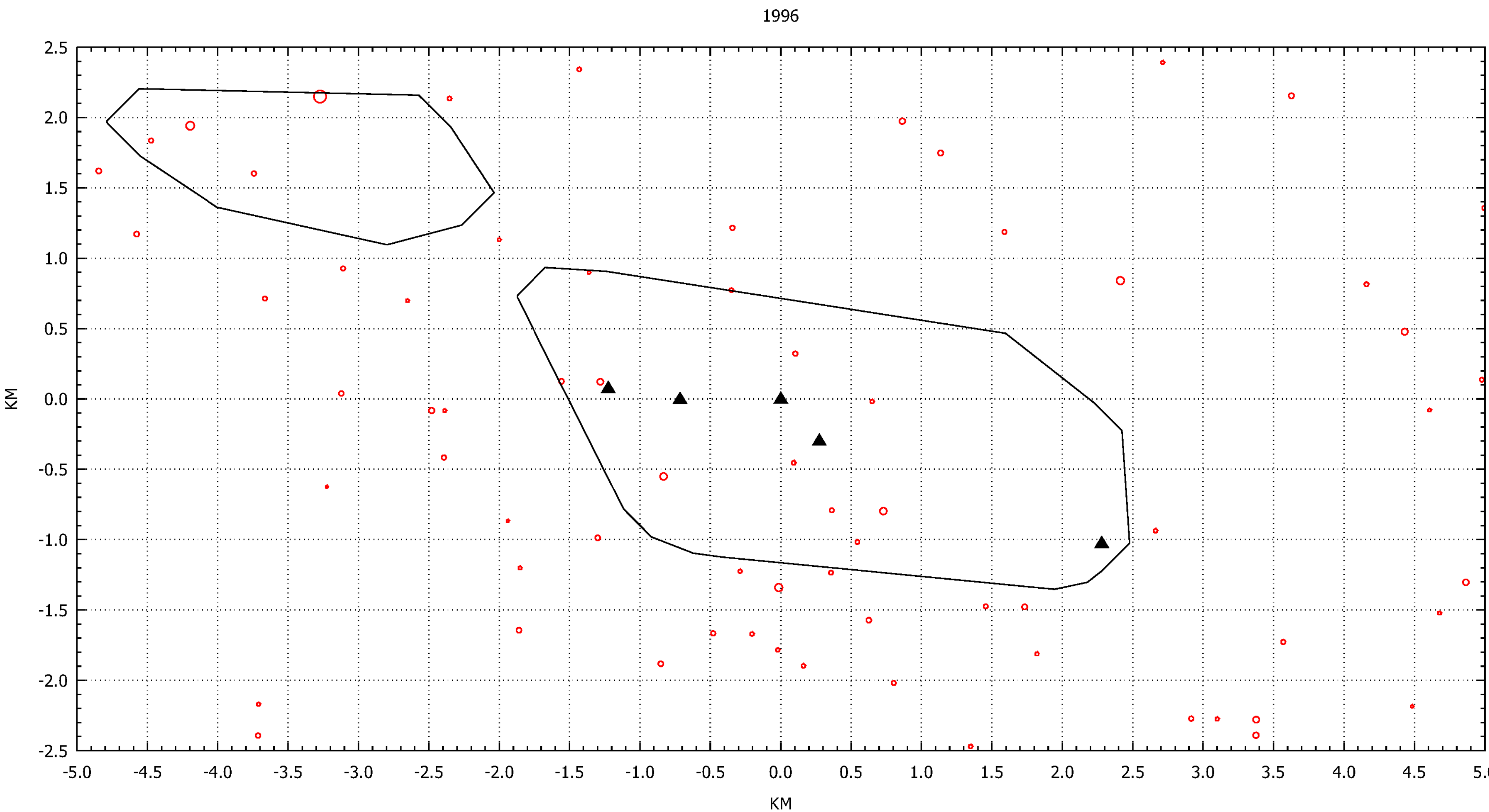
3.0
3.5
4.0
4.5
5.0


1996
KM
KM
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-2.5
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
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1.0
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3.0
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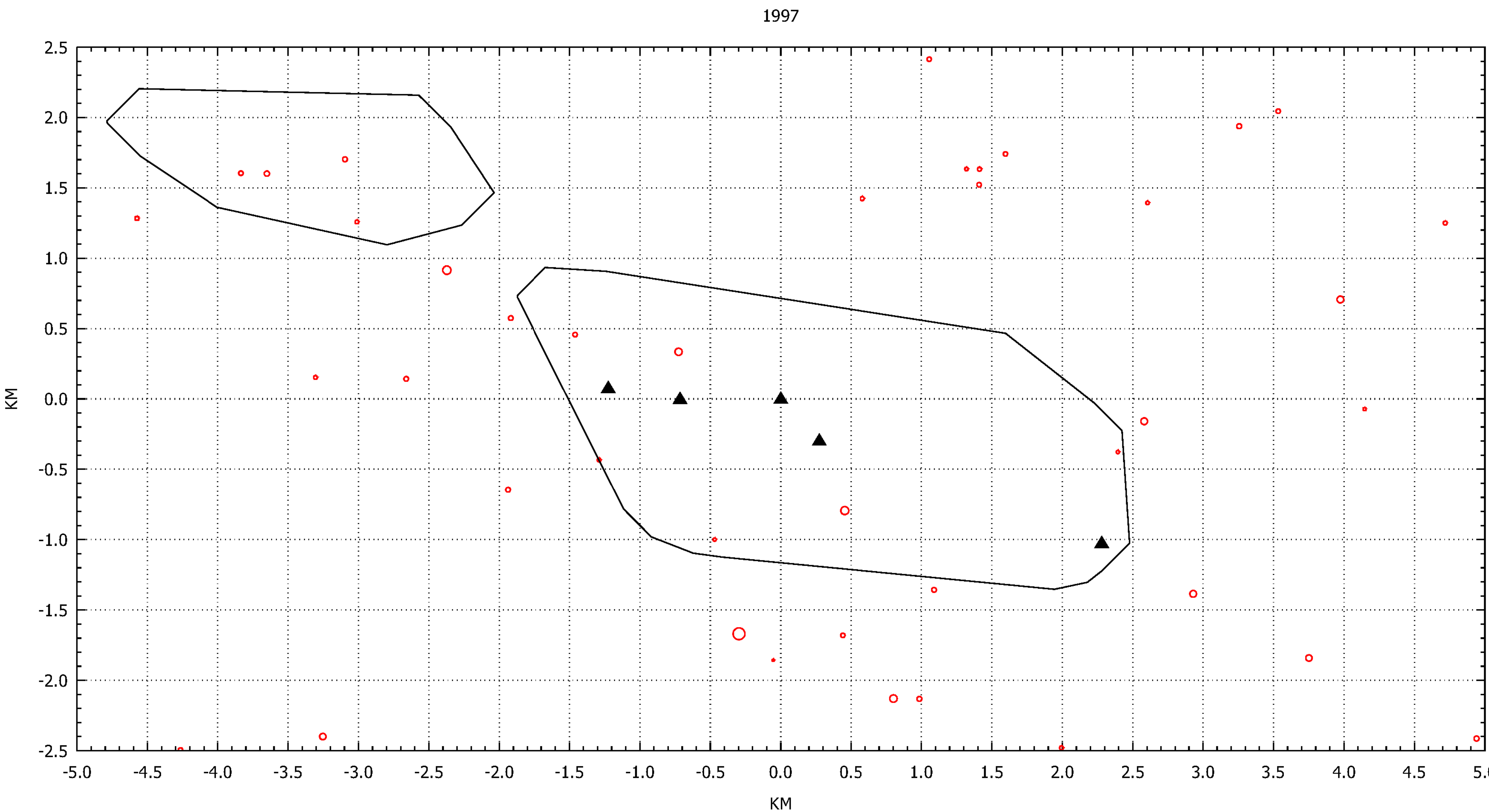
5.0


1997
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-1.5
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KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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1.0
1.5
2.0
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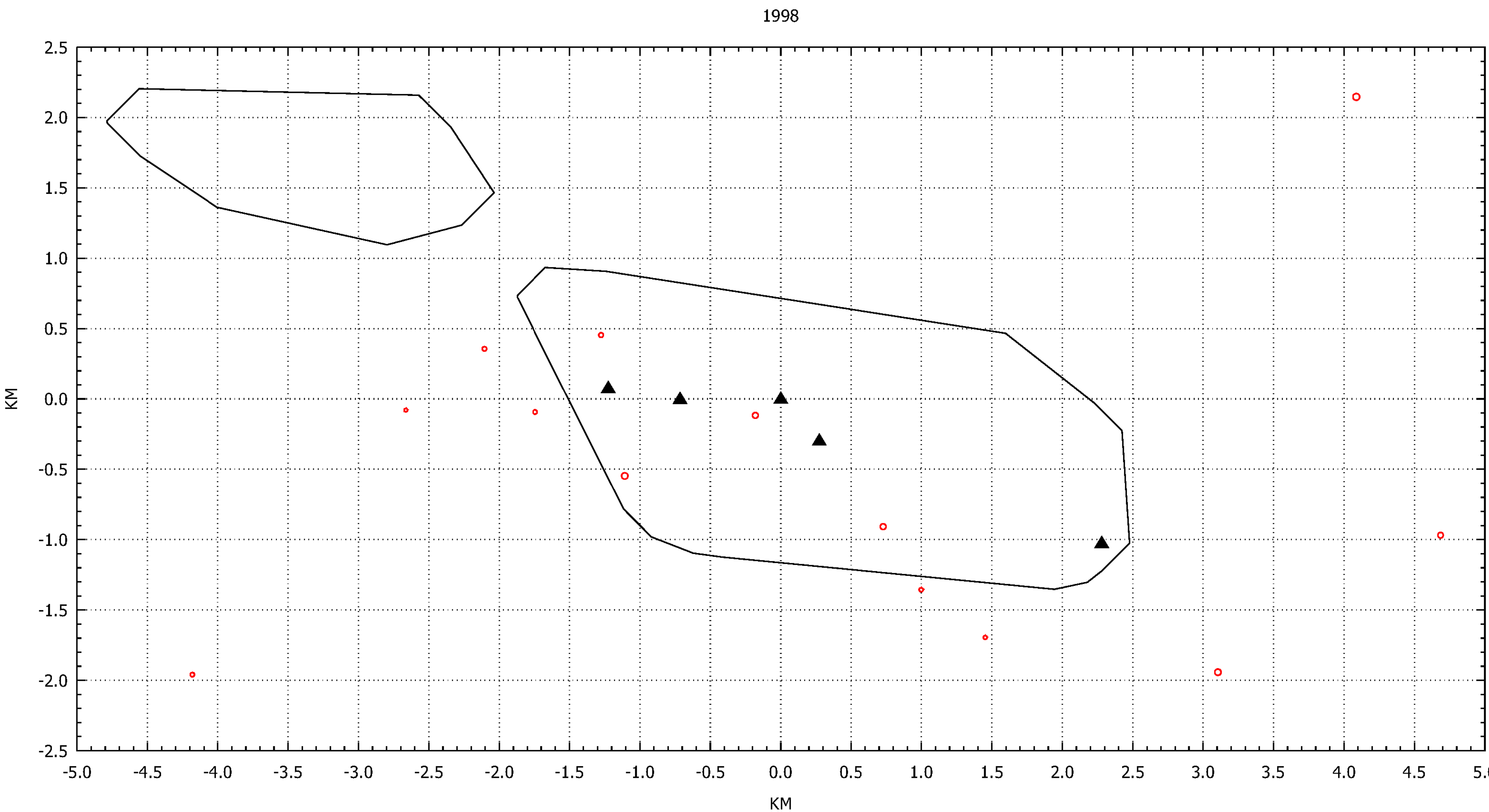
3.0
3.5
4.0
4.5
5.0
KM


1998
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-2.5
KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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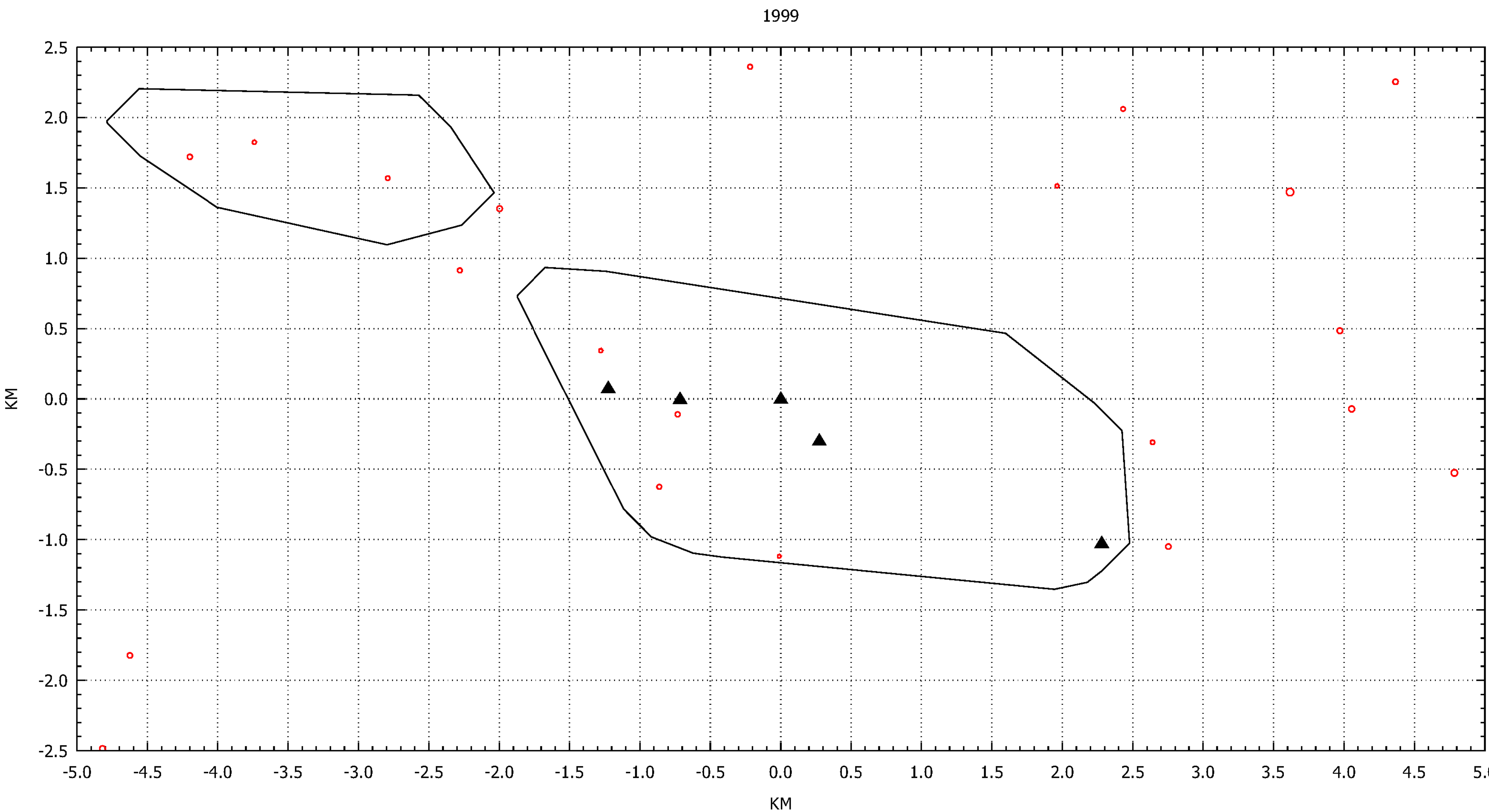
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
KM


1999
KM
KM
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-2.5
-5.0
-4.5
-4.0
-3.5
-3.0
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-2.0
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-1.0
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3.0
3.5
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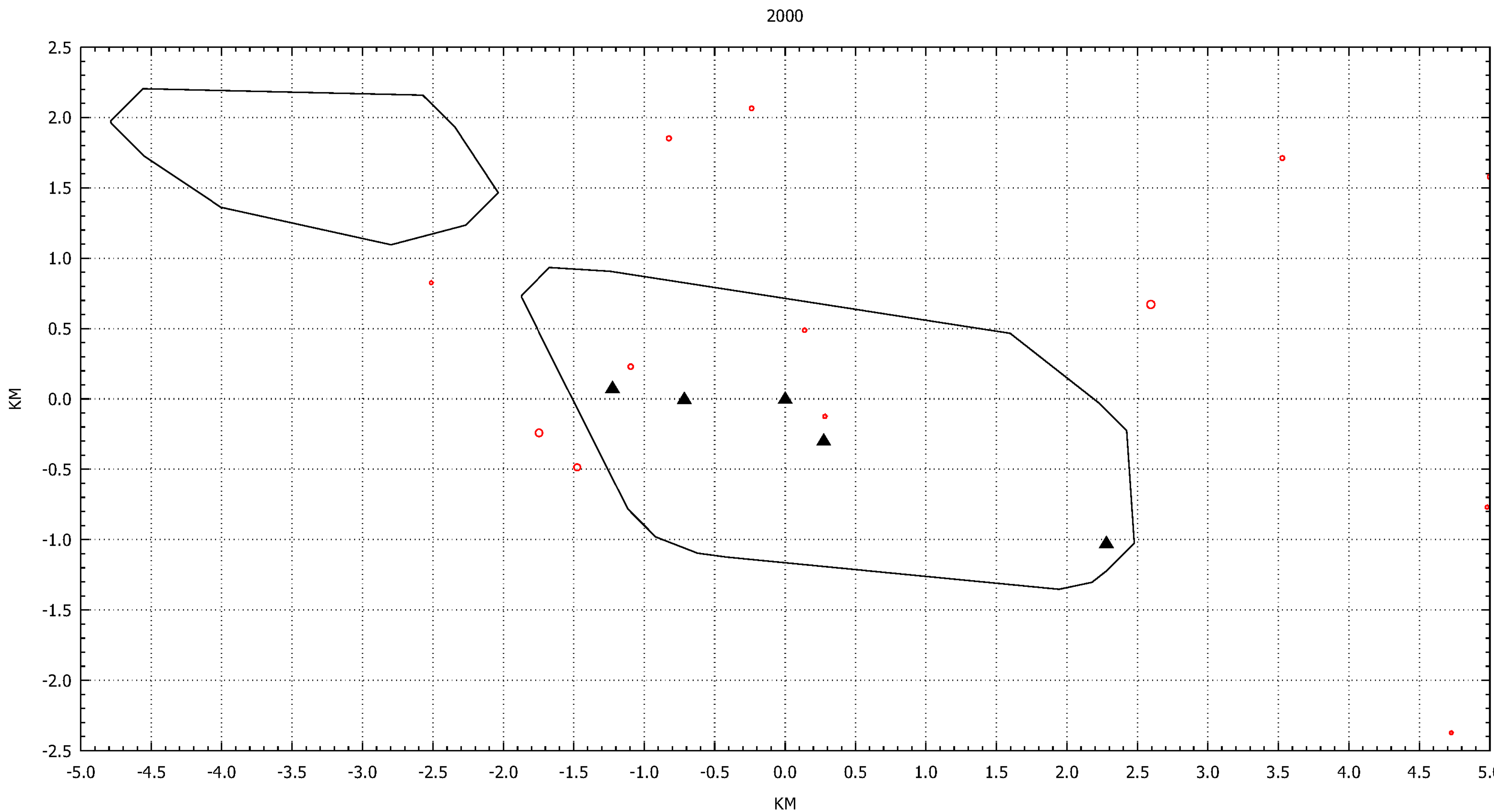
4.5
5.0



2000
KM
KM
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-2.5
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
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1.0
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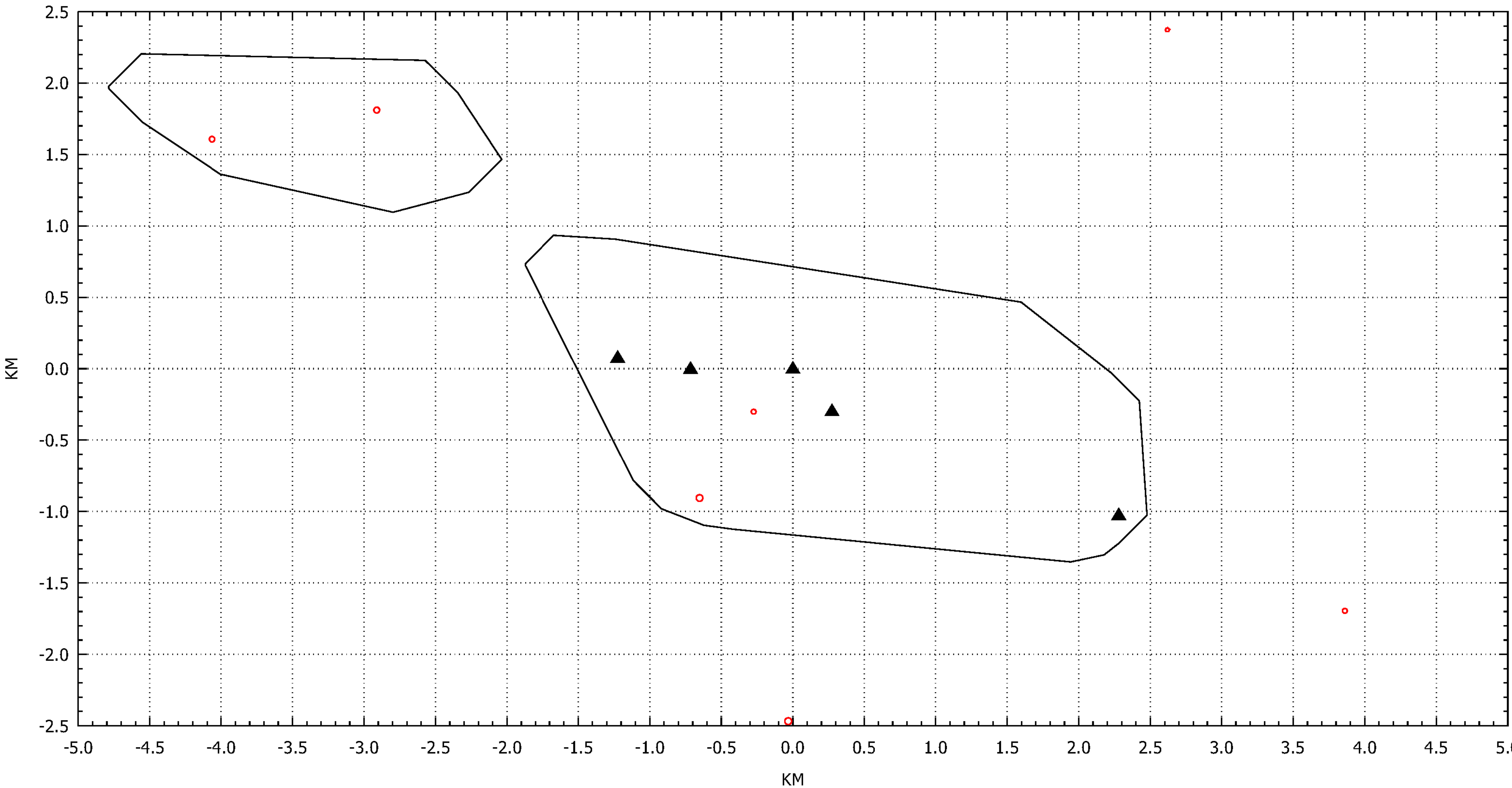
2.0
2.5
3.0
3.5
4.0
4.5
5.0

2001



2.5
2.0
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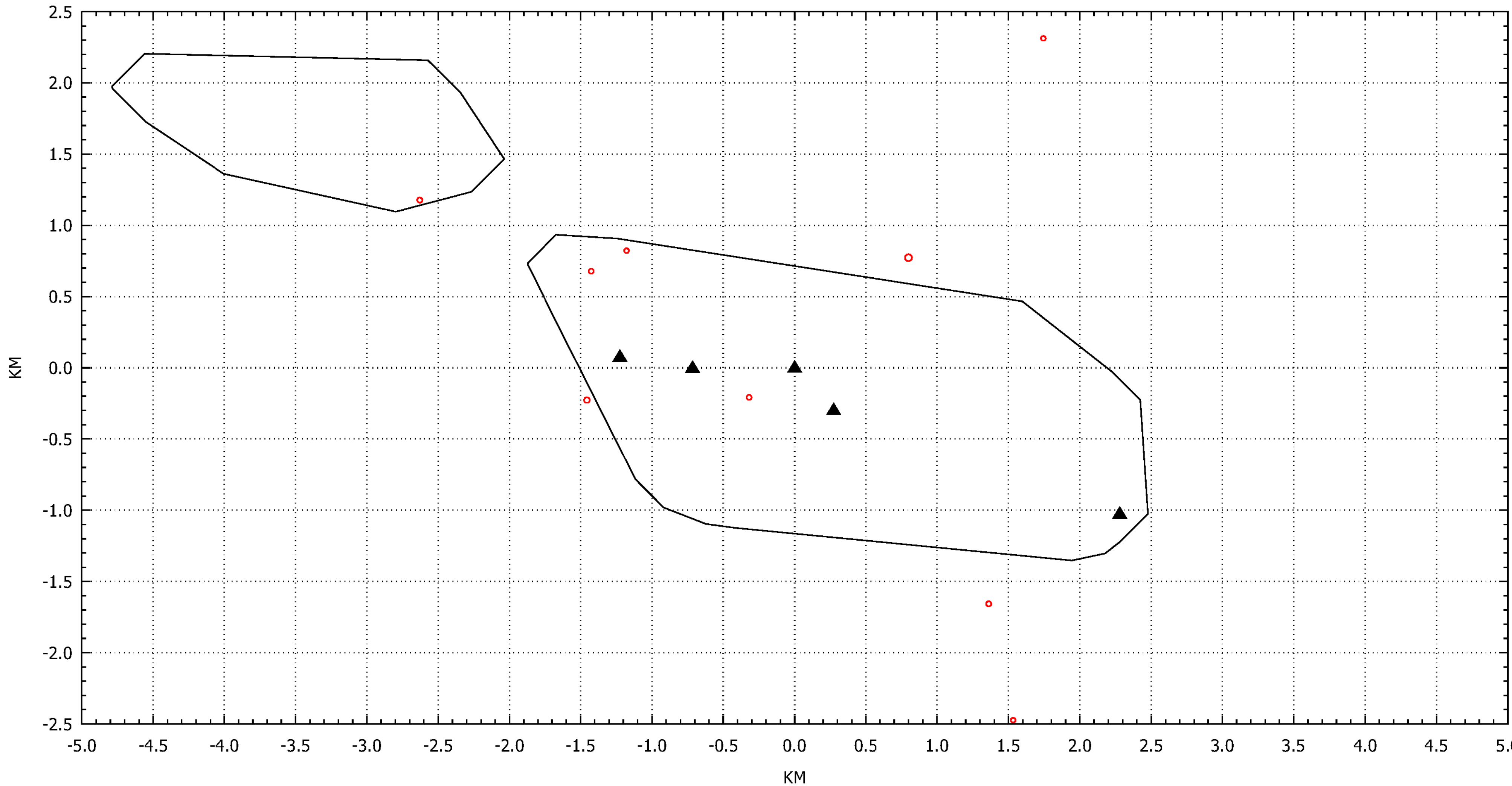
1.0
0.5
0.0
-0.5
-1.0
-1.5
-2.0
-2.5
KM
-5.0
-4.5
-4.0
-3.5
-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
0.0
0.5
1.0
1.5
2.0
2.5
3.0
3.5
4.0
4.5
5.0
KM

2002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KM
-5.0
-4.5
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-3.0
-2.5
-2.0
-1.5
-1.0
-0.5
0.0
0.5
1.0
1.5
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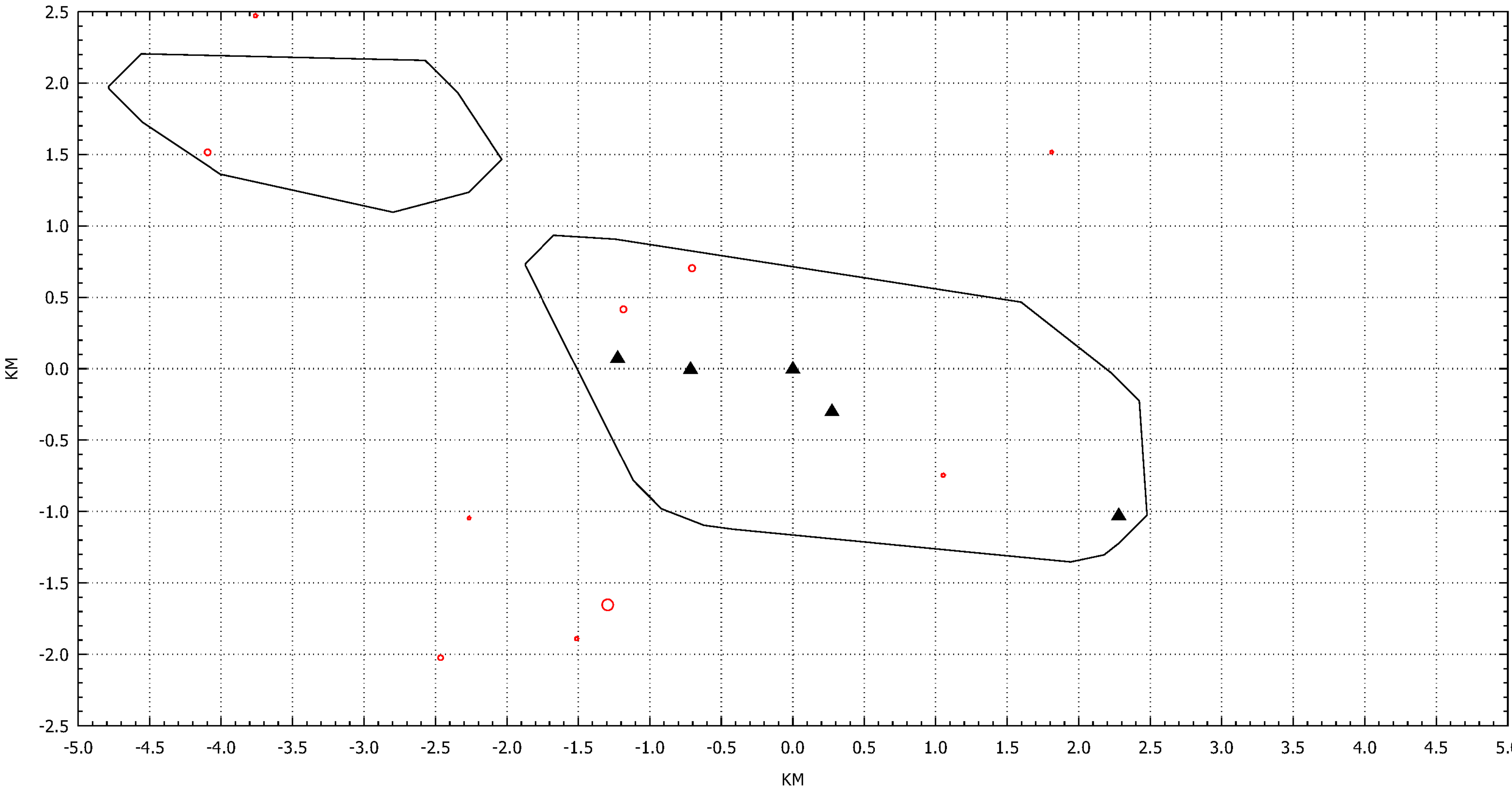

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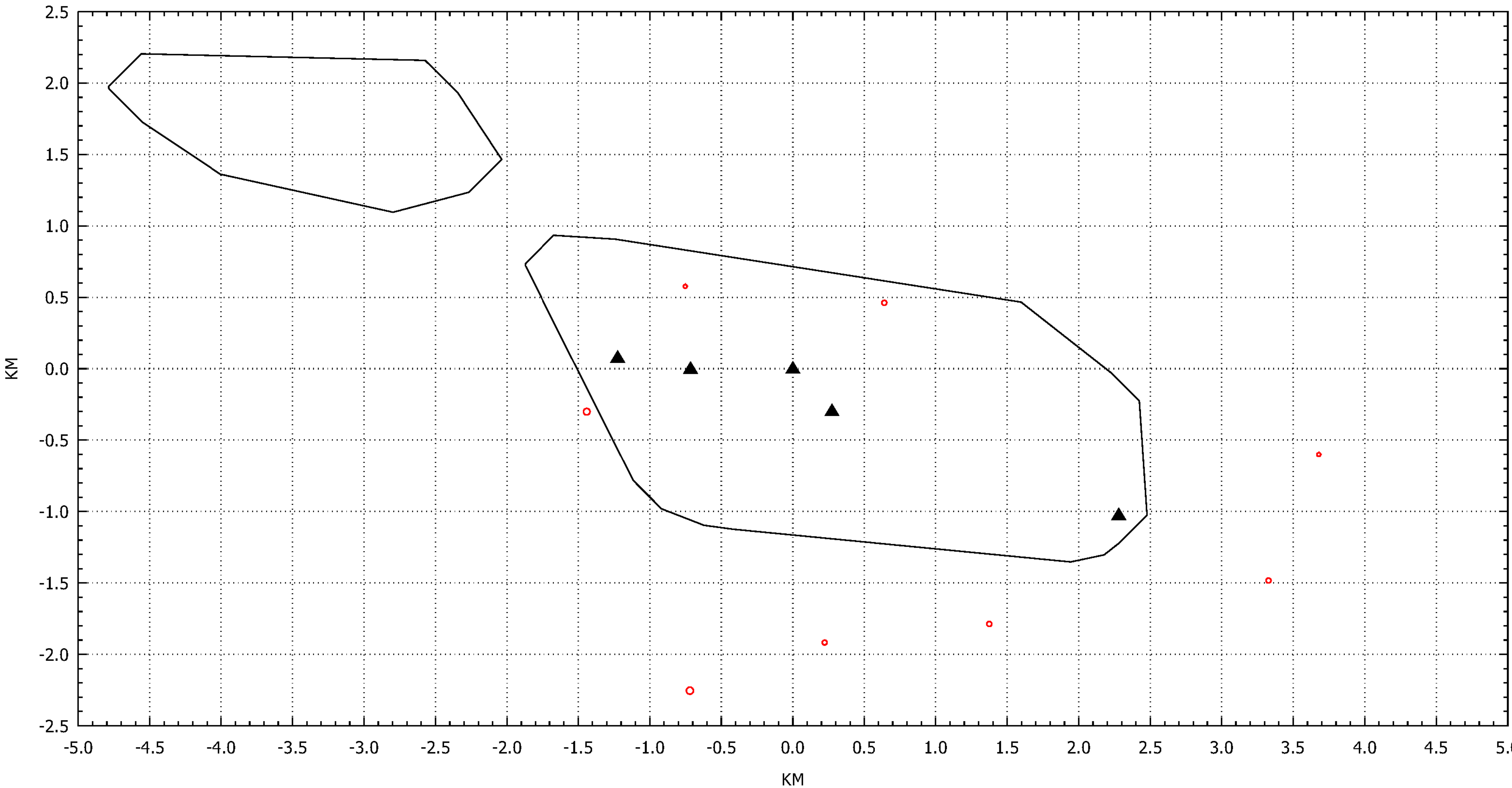
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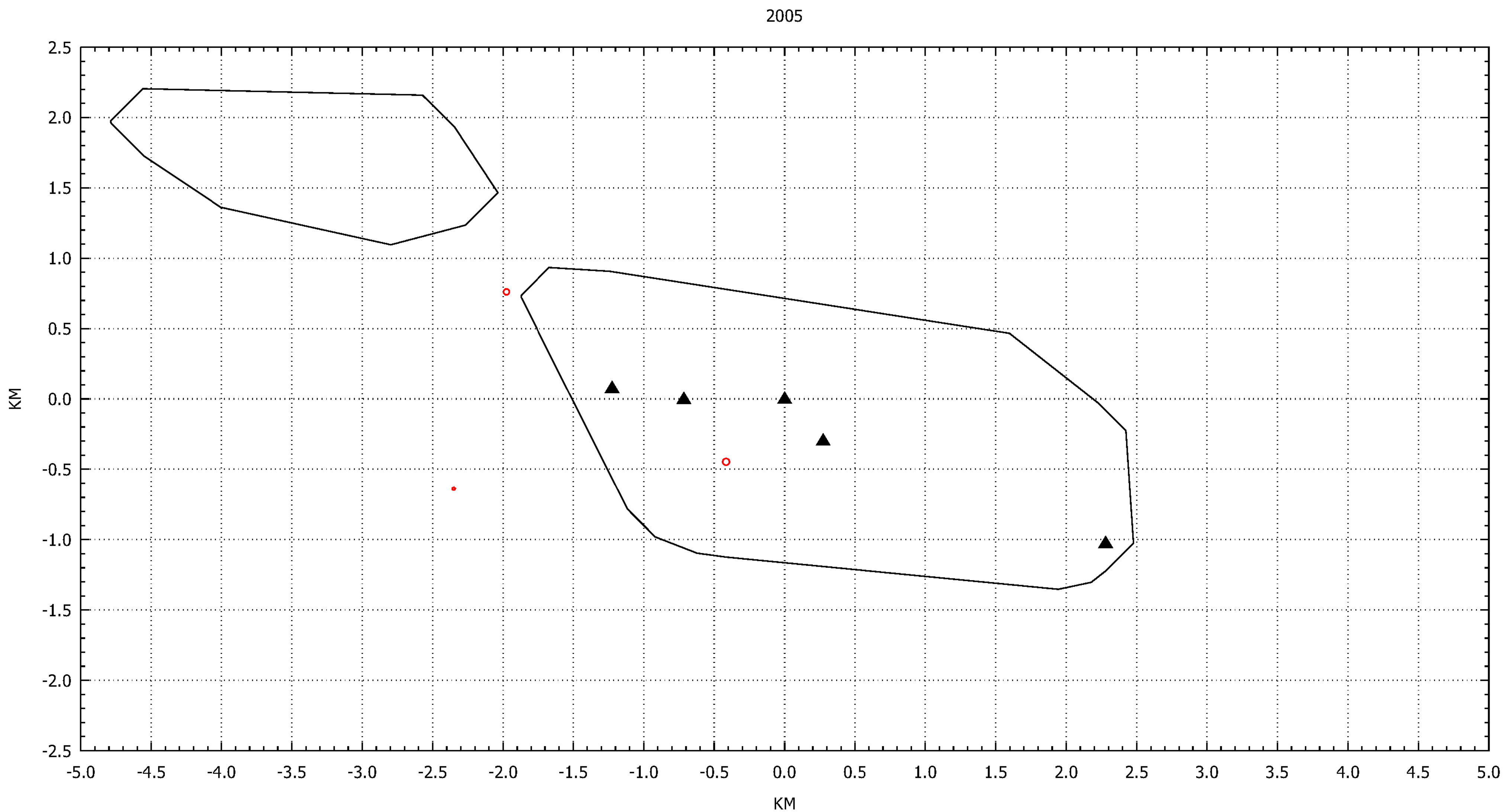
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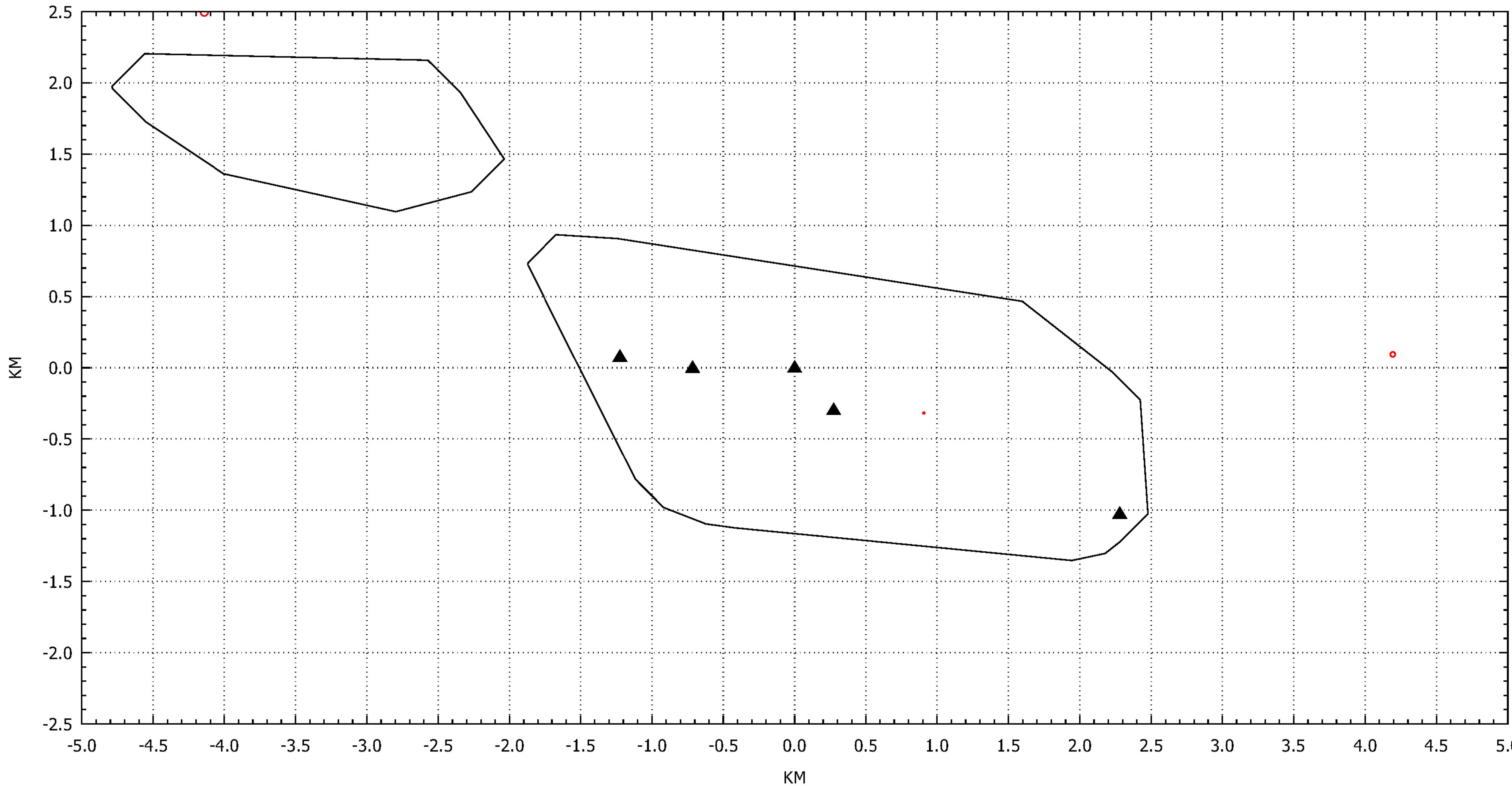

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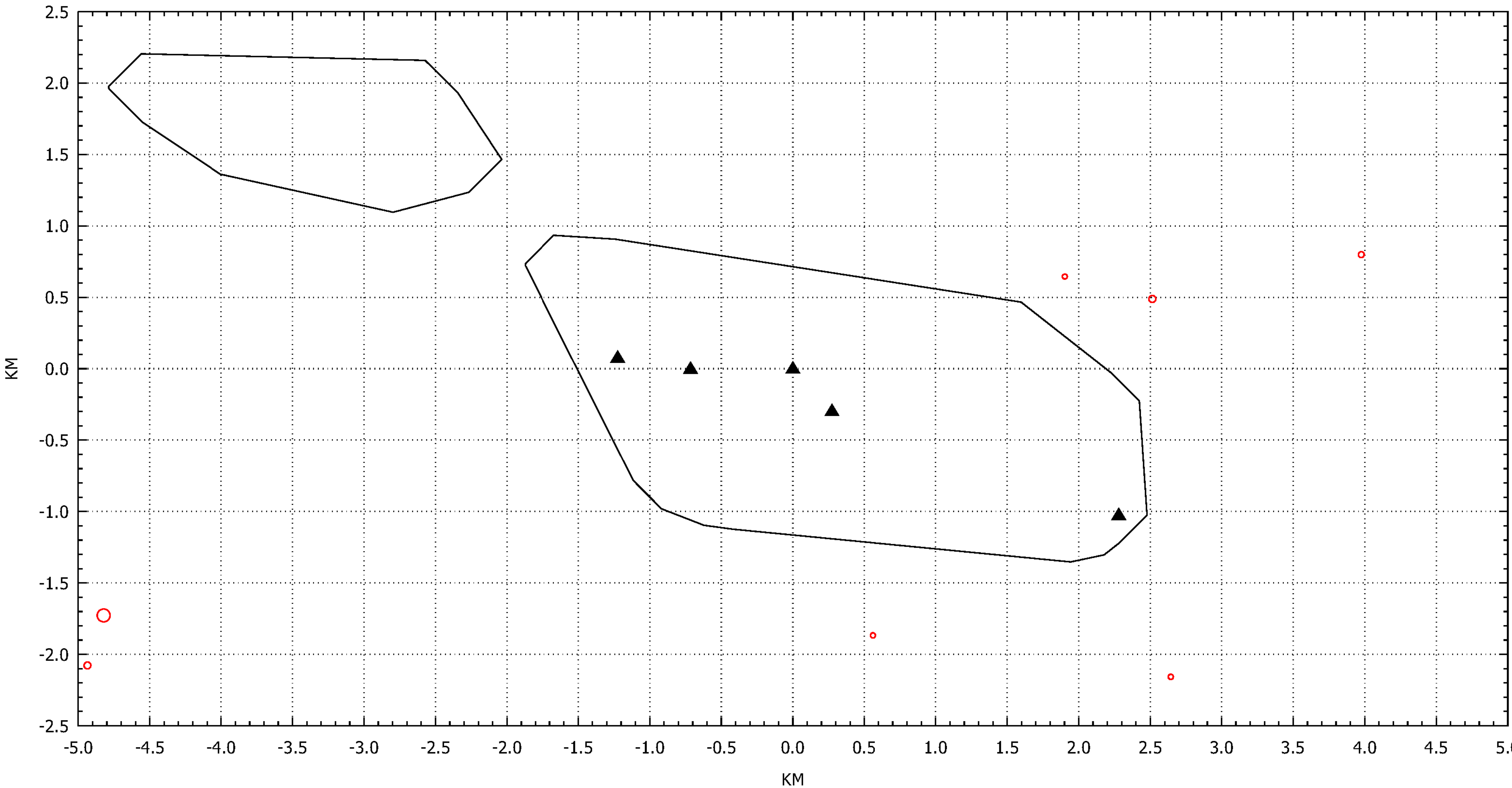
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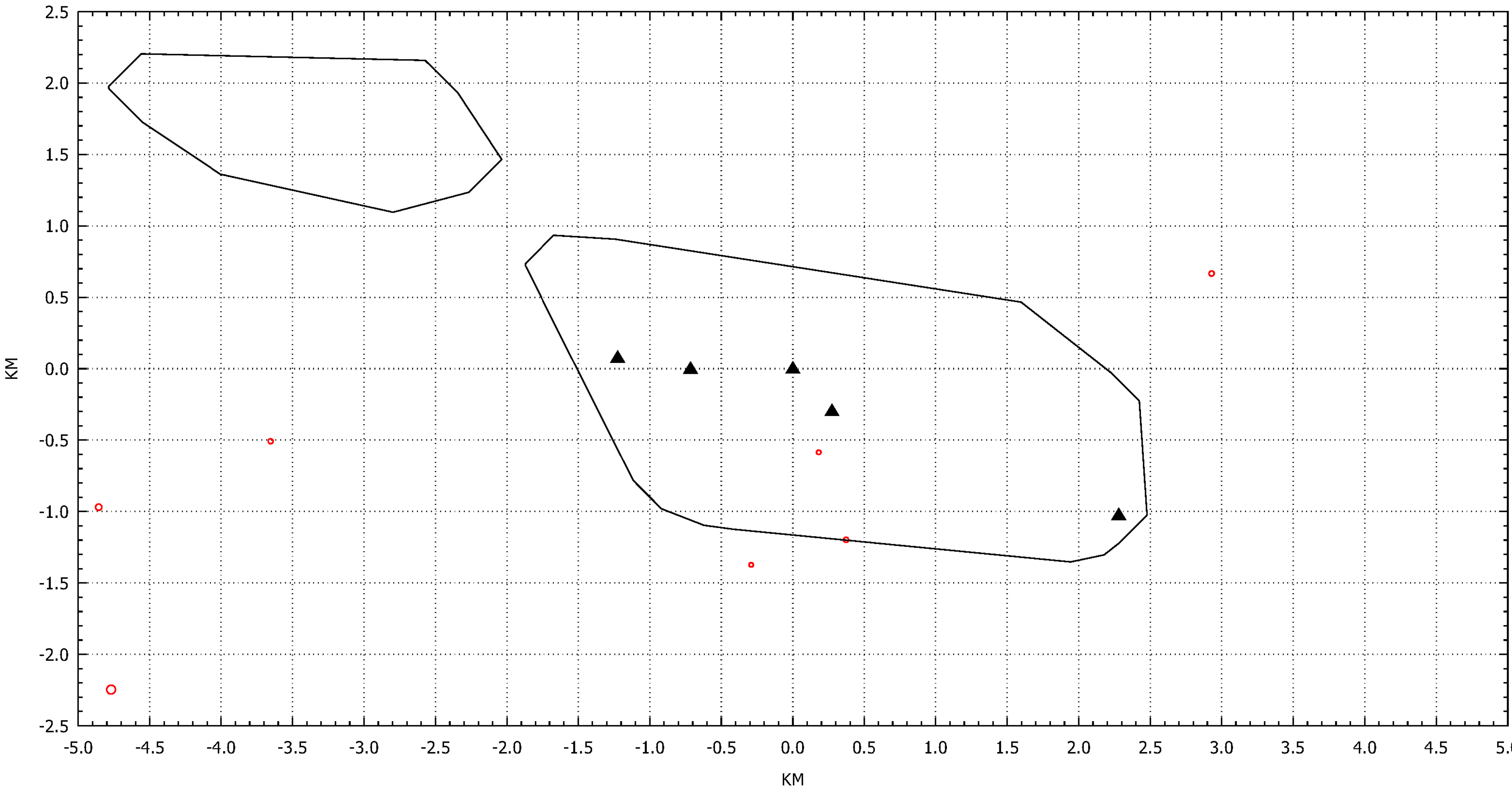

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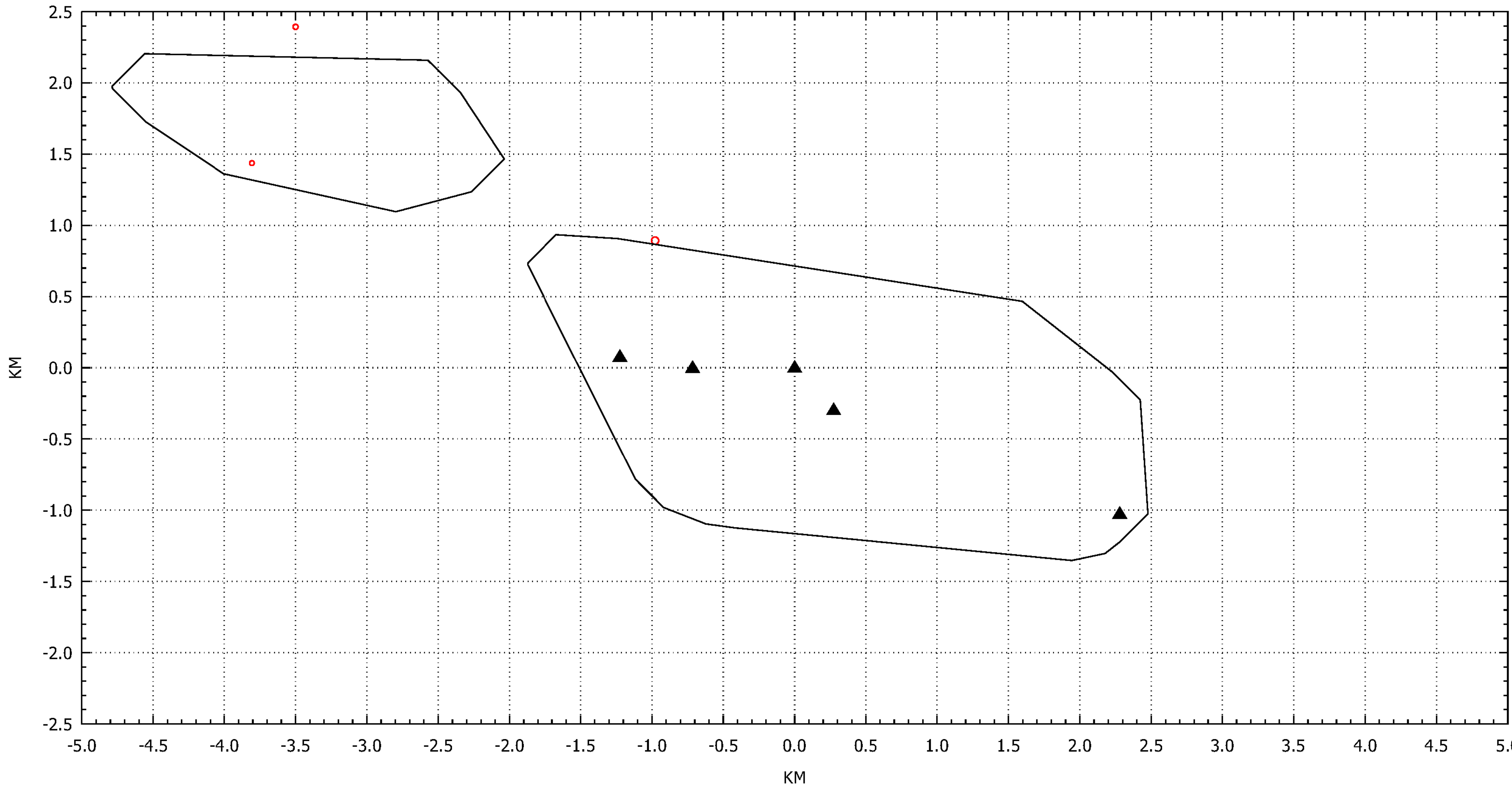
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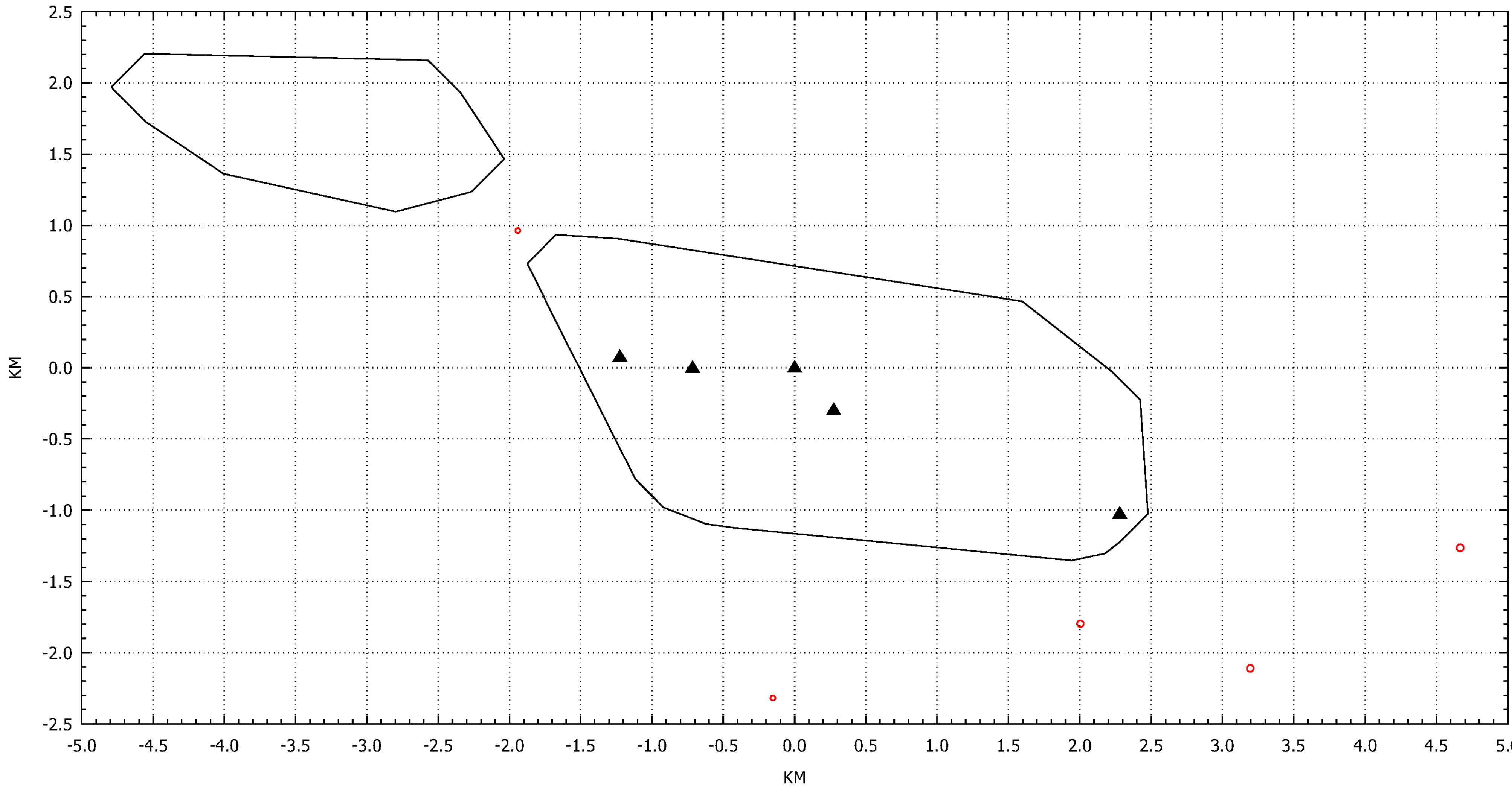

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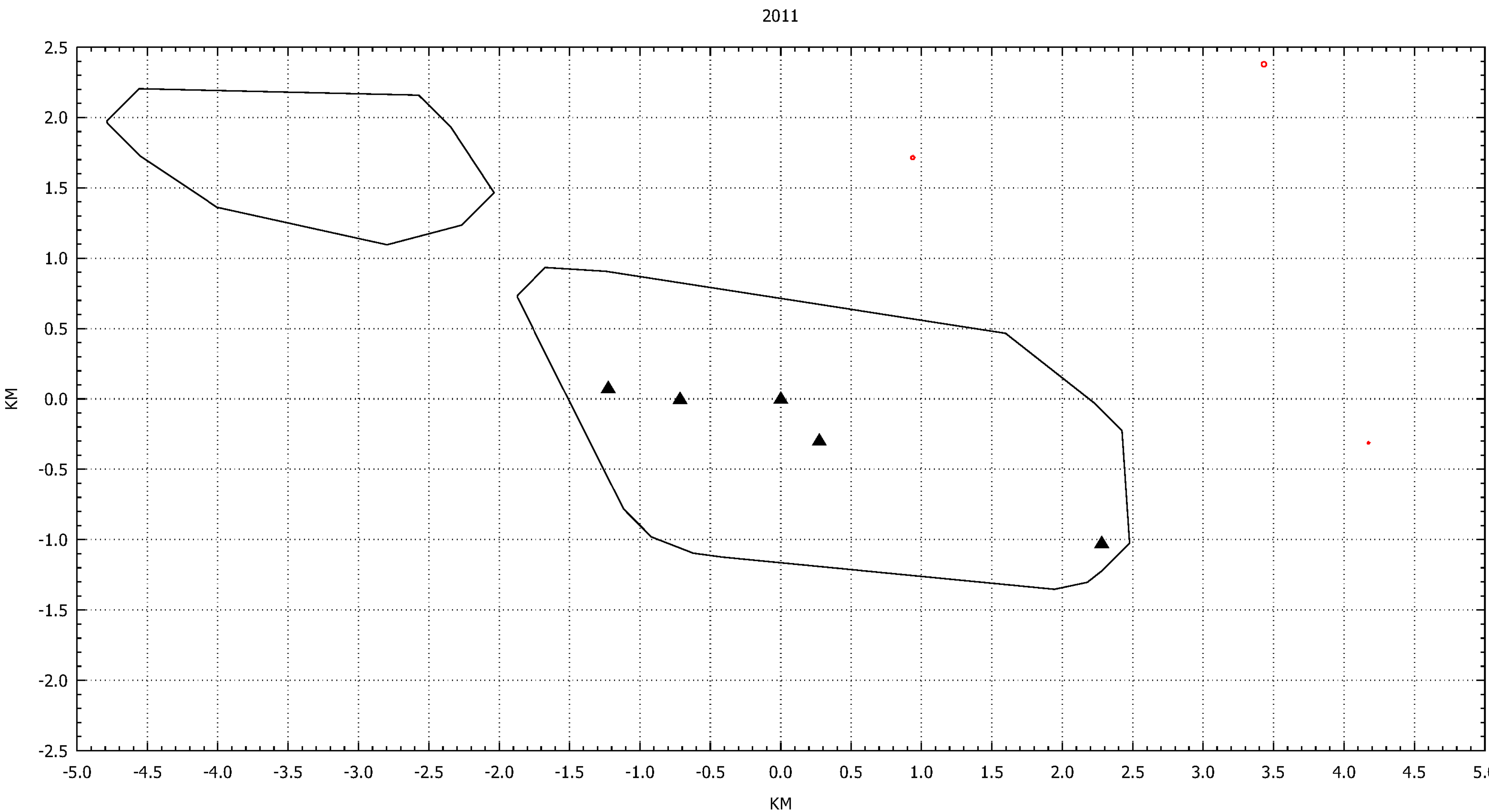
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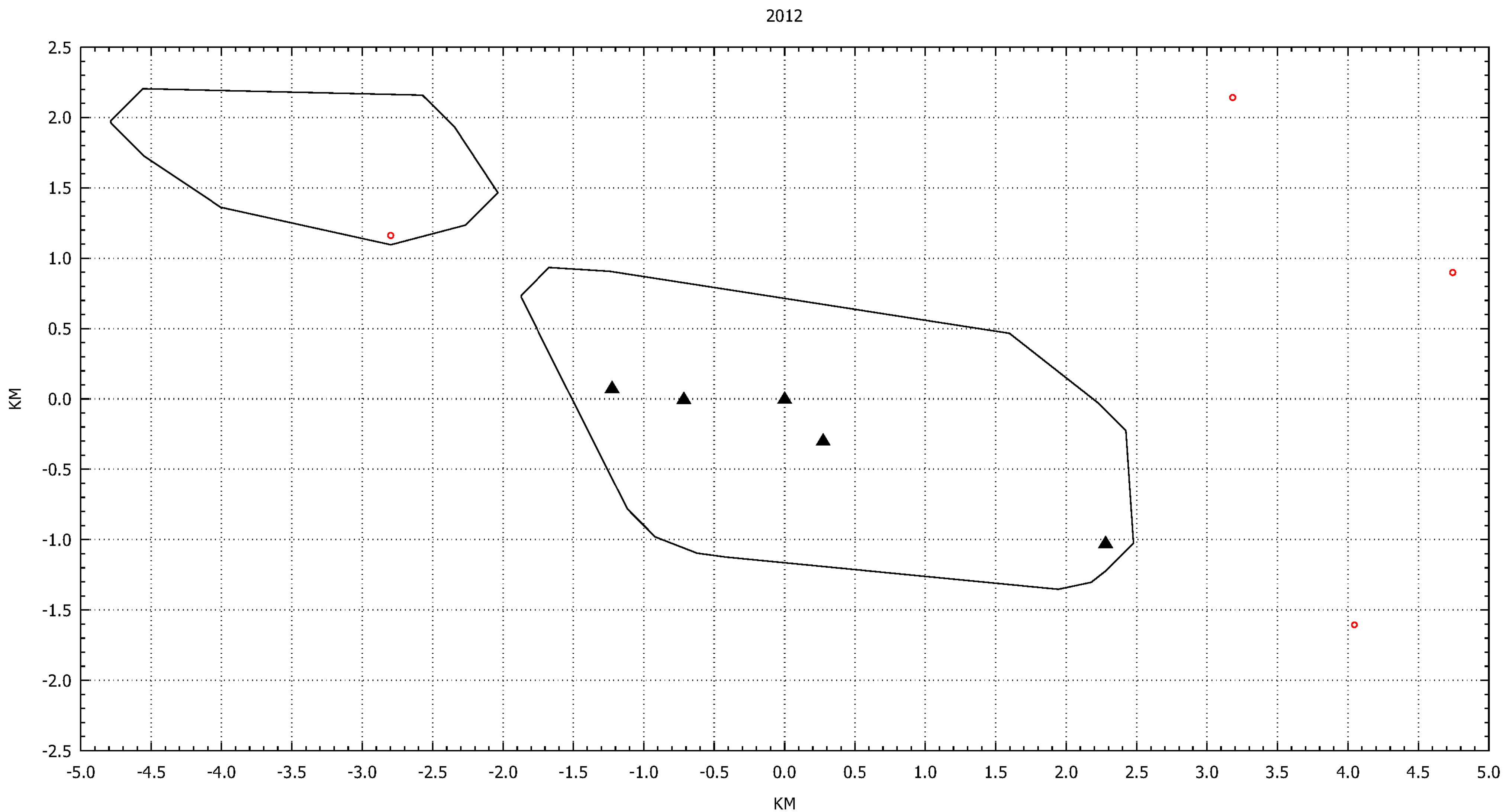

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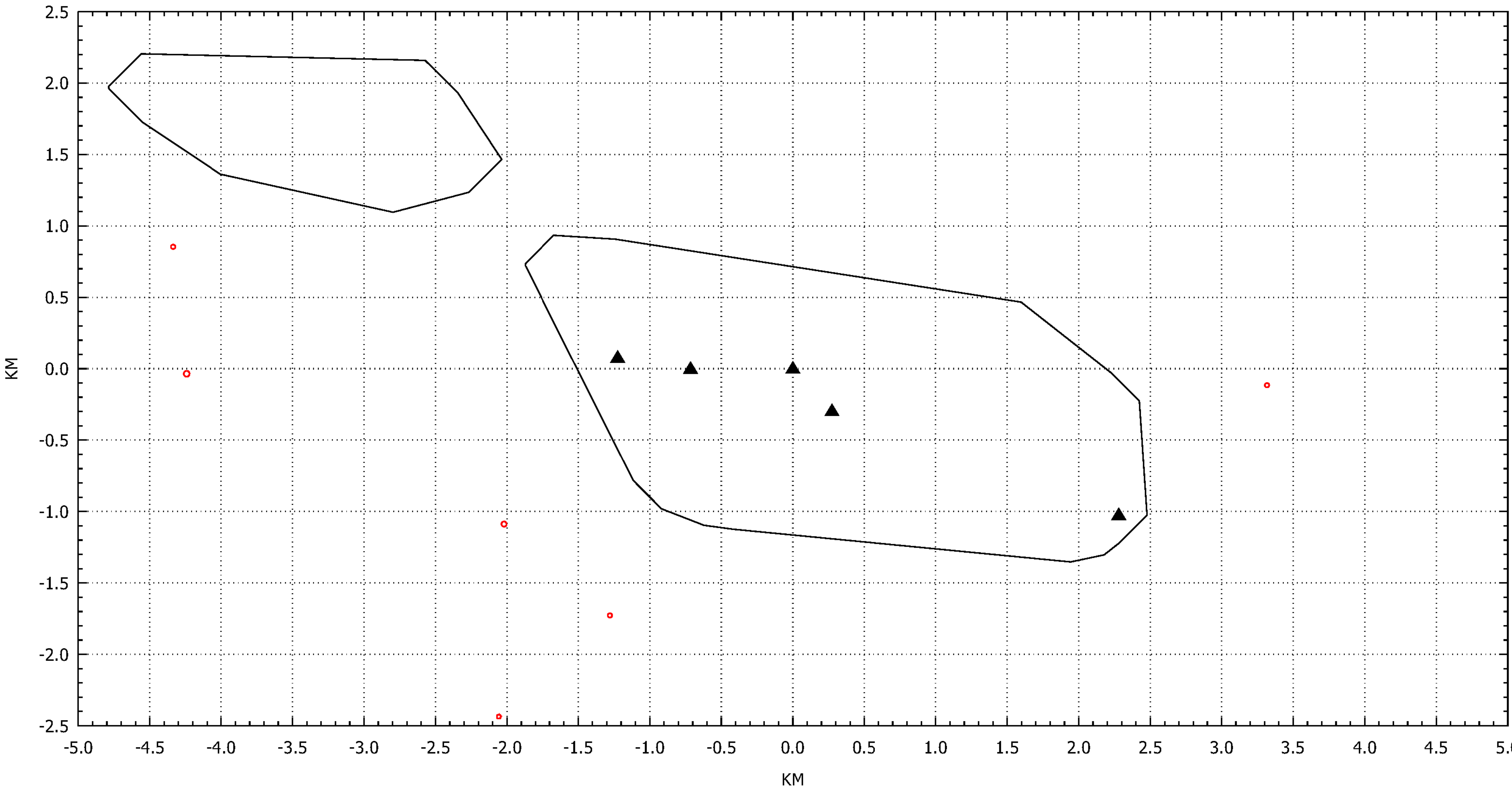

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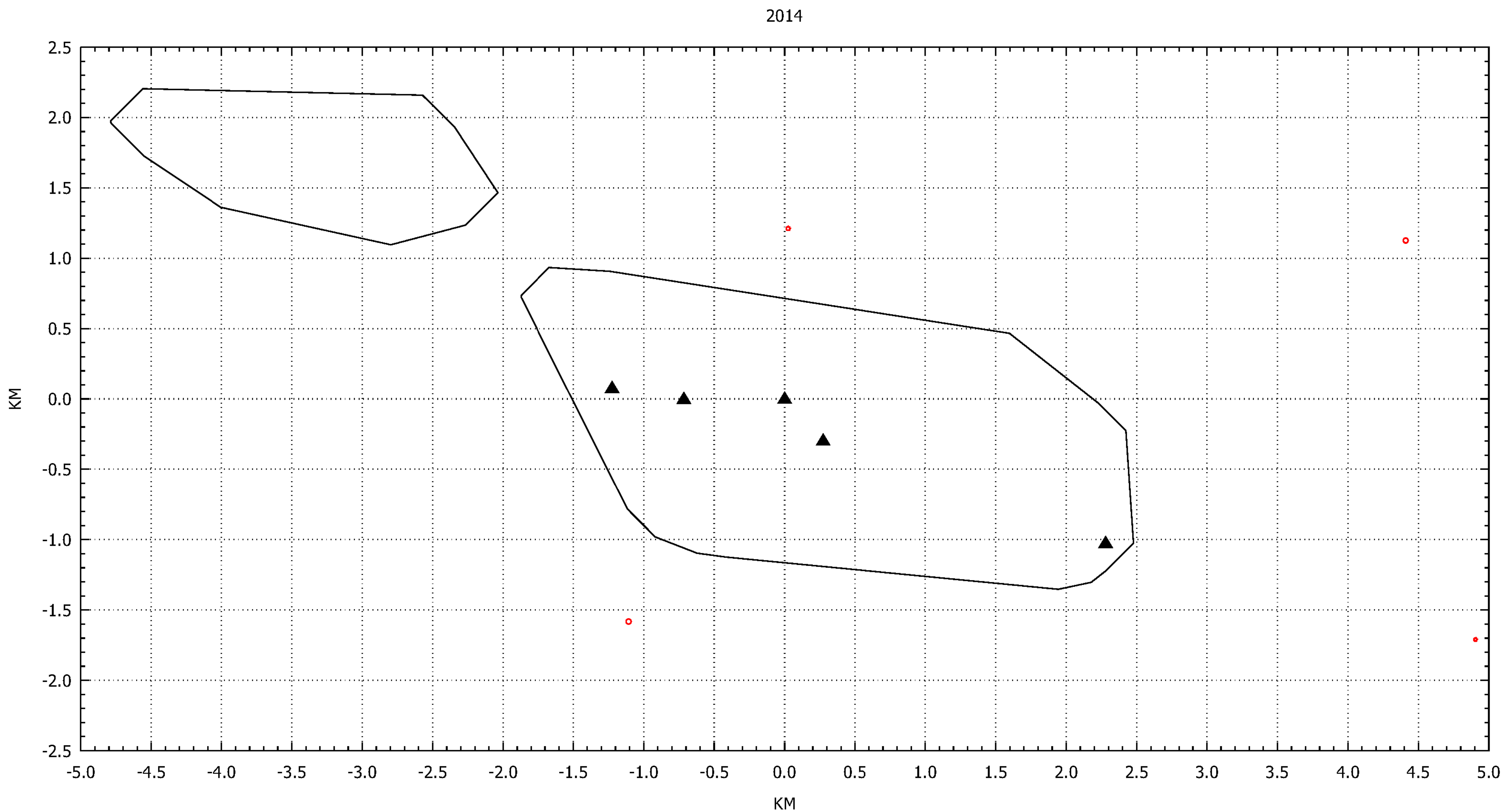
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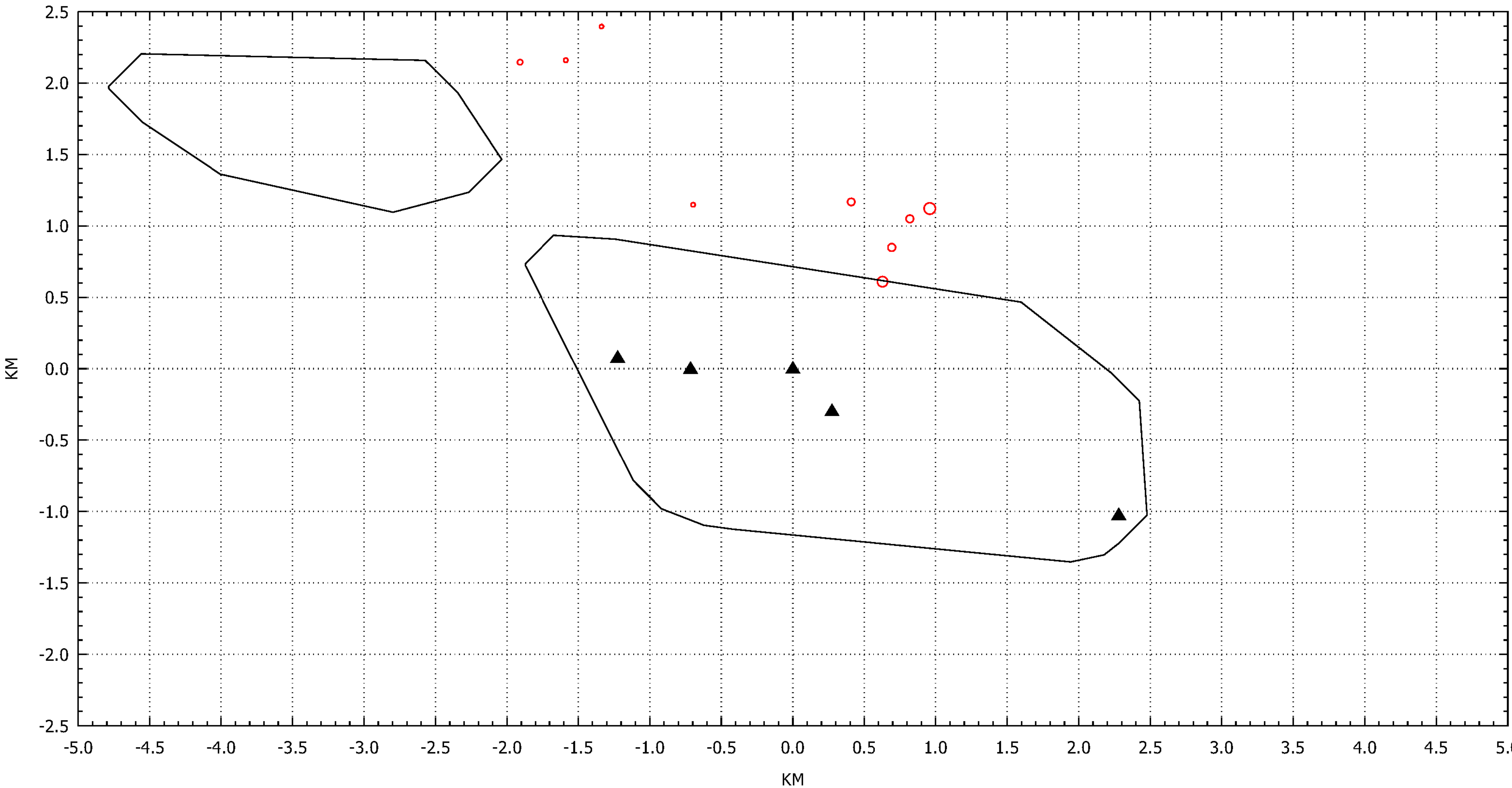
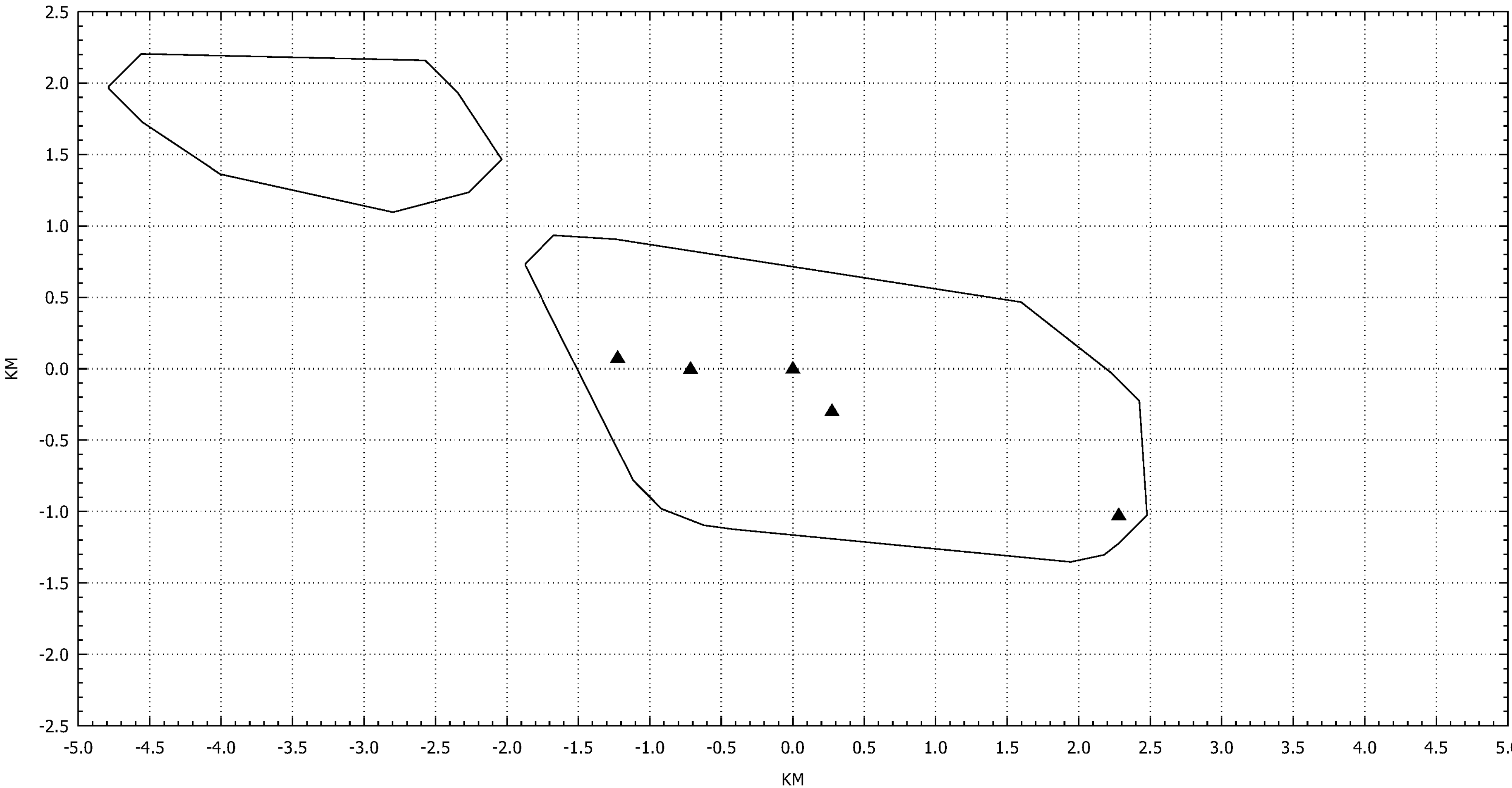
1/1/2015-10/23/2015



10/24/2015--12/31/2015



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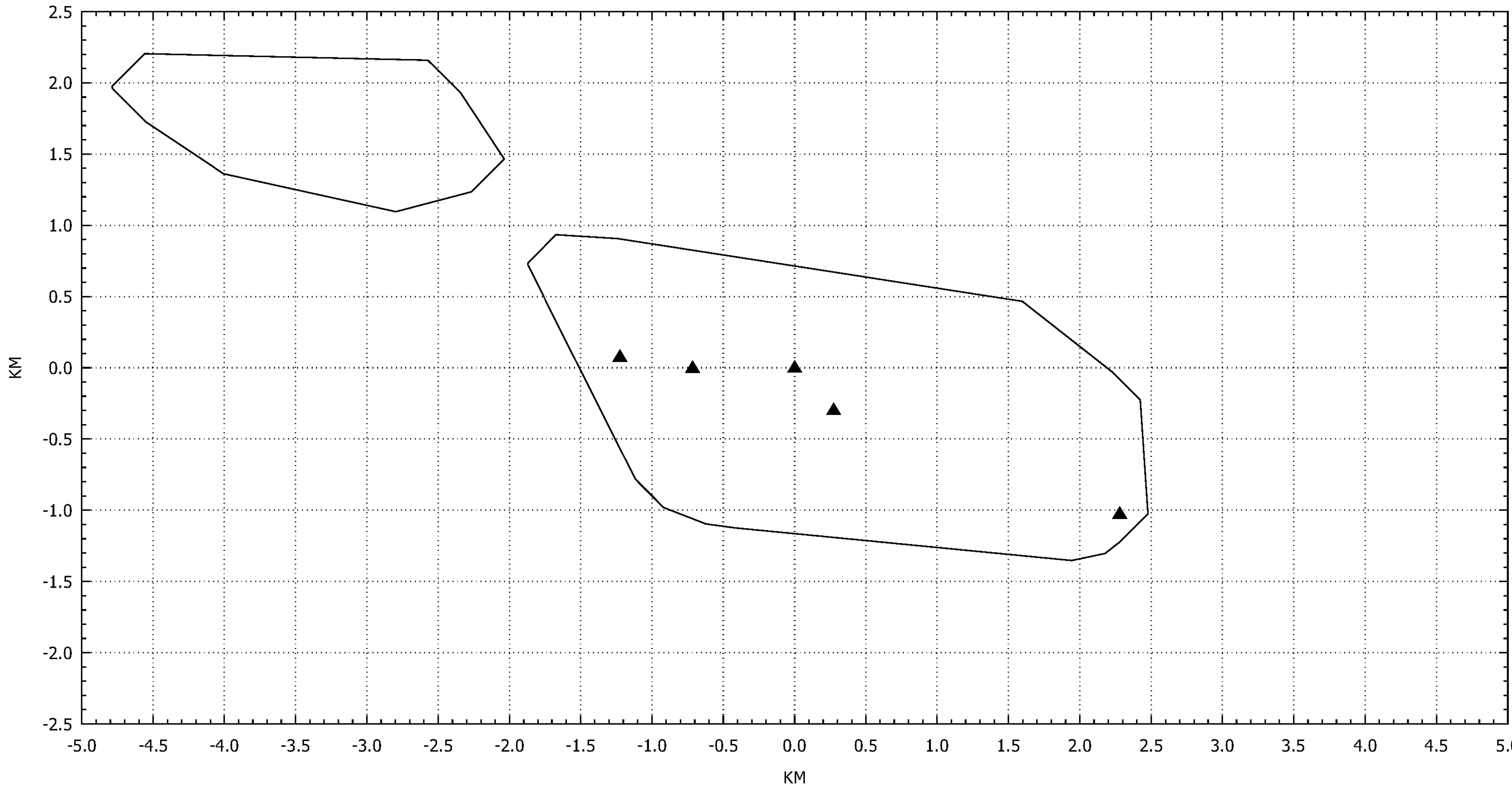

Appendix C Universal Transverse Mercator Projection Calculation Functions

The following UTM projection calculation functions have been used in this report to calculate the distances between wells and events. These VBA functions (code) have been used for the forward (latitude and longitude to UTM coordinates) and inverse (UTM coordinates to latitude and longitude) conversions.

C.1 LL2UTM

This function is used to transform latitude and longitude to UTM coordinates and has the following properties:

- Latitude and longitude must be given in decimal degrees.
- For latitude, positive is north and negative is south.
- For longitude, positive is east and negative is west.
- UTM coordinates are returned in meters.
- UTM zone is optional; the function will determine the appropriate UTM zone if not given. However, UTM zone may be given to force calculation to that zone; this is useful for calculations that extend across UTM boundaries.

C.2 UTM2LL

This function is used to transform from UTM coordinates to latitude and longitude.

It has the following properties:

- UTM coordinates must be given in meters.
- UTM zone must be specified.
- bSouth flag must be specified as TRUE for southern hemisphere.
- Latitude and longitude will be returned in decimal degrees.
- For latitude, positive is north and negative is south.
- For longitude, positive is east and negative is west.

C.3 Code Used

```
Option Explicit
Public Function LL2UTM(Latitude As Double, Longitude As Double, Optional Zone As
Integer = 0)

' Variable declarations
Dim k0 As Double
Dim a As Double
Dim inv_f As Double
Dim f As Double
Dim e2 As Double
Dim ep2 As Double
```

```
Dim Lat As Double
Dim Lng As Double
Dim Lat0 As Double
Dim Lng0 As Double

Dim N As Double
Dim T As Double
Dim C As Double
Dim AA As Double
Dim M As Double
Dim M0 As Double

Dim X As Double
Dim Y As Double
Dim Res(0 To 2)

' Parameters
k0 = 0.9996
a = 6378137#
inv_f = 298.257222101
f = 1 / inv_f
e2 = 2 * f - f * f
ep2 = e2 / (1 - e2)

' Determine zone
If Zone <= 0 Or Zone > 60 Then
    Zone = Int((Longitude + 180) / 6) + 1
End If

' Determine central meridian and latitude
Lng0 = 6 * (Zone - 1) - 177#
Lat0 = 0#

' Convert latitudes and longitudes to RADIANS
Lng0 = Lng0 * 3.141592654 / 180#
Lng = Longitude * 3.141592654 / 180#
Lat = Latitude * 3.141592654 / 180#

' Actual Computation
N = a / Sqr(1 - e2 * Sin(Lat) * Sin(Lat))
T = Tan(Lat) * Tan(Lat)
C = ep2 * Cos(Lat) * Cos(Lat)
AA = (Lng - Lng0) * Cos(Lat)
M = a * ((1 - e2 / 4 - 3 * e2 * e2 / 64 - 5 * e2 * e2 * e2 / 256) * Lat _
      - (3 * e2 / 8 + 3 * e2 * e2 / 32 + 45 * e2 * e2 * e2 / 1024) * Sin(2 * Lat) _
      + (15 * e2 * e2 / 256 + 45 * e2 * e2 * e2 / 1024) * Sin(4 * Lat) _
      - (35 * e2 * e2 * e2 / 3072) * Sin(6 * Lat))
M0 = a * ((1 - e2 / 4 - 3 * e2 * e2 / 64 - 5 * e2 * e2 * e2 / 256) * Lat0 _
      - (3 * e2 / 8 + 3 * e2 * e2 / 32 + 45 * e2 * e2 * e2 / 1024) * Sin(2 * Lat0) _
      + (15 * e2 * e2 / 256 + 45 * e2 * e2 * e2 / 1024) * Sin(4 * Lat0) _
      - (35 * e2 * e2 * e2 / 3072) * Sin(6 * Lat0))
X = k0 * N * (AA + (1 - T + C) * (AA ^ 3) / 6 + (5 - 18 * T + T * T + 72 * C - 58 *
ep2) * (AA ^ 5) / 120)
Y = k0 * (M - M0 + N * Tan(Lat) * (AA * AA) / 2 + (5 - T + 9 * C + 4 * C * C) * (AA ^
4) / 24 + (61 - 58 * T + T * T + 600 * C - 330 * ep2) * (AA ^ 6) / 720)

' Add false easting and northing (for southern latitudes)
X = X + 500000
If (Latitude < 0) Then Y = Y + 10000000
```

```
Res(0) = X
Res(1) = Y
Res(2) = Zone

LL2UTM = Res

End Function
Public Function UTM2LL(X As Double, Y As Double, Zone As Integer, Optional bSouth As
Boolean = False)

' Variable declarations
Dim k0 As Double
Dim a As Double
Dim inv_f As Double
Dim f As Double
Dim e2 As Double
Dim ep2 As Double

Dim Lng0 As Double
Dim Lat0 As Double
Dim Lat1 As Double

Dim e1 As Double
Dim Mu As Double
Dim M0 As Double
Dim M As Double

Dim C1 As Double
Dim T1 As Double
Dim N1 As Double
Dim R1 As Double
Dim D As Double

Dim Lat As Double
Dim Lng As Double

Dim Res(0 To 1)

' Parameters
k0 = 0.9996
a = 6378137#
inv_f = 298.257222101
f = 1 / inv_f
e2 = 2 * f - f * f
ep2 = e2 / (1 - e2)

' Subtract false easting and northing
X = X - 500000
If (bSouth) Then Y = Y - 10000000

' Determine central meridian and latitude
Lng0 = 6 * (Zone - 1) - 177#
Lat0 = 0#

' Compute "footprint latitude"
e1 = (1 - Sqr(1 - e2)) / (1 + Sqr(1 - e2))
M0 = a * ((1 - e2 / 4 - 3 * e2 * e2 / 64 - 5 * e2 * e2 * e2 / 256) * Lat0 _
      - (3 * e2 / 8 + 3 * e2 * e2 / 32 + 45 * e2 * e2 * e2 / 1024) * Sin(2 * Lat0) _
      + (15 * e2 * e2 / 256 + 45 * e2 * e2 * e2 / 1024) * Sin(4 * Lat0) _
      - (35 * e2 * e2 * e2 / 3072) * Sin(6 * Lat0))
M = M0 + Y / k0
Mu = M / (a * (1 - e2 / 4 - 3 * e2 * e2 / 64 - 5 * e2 * e2 * e2 / 256))
```

```
Lat1 = Mu + (3 * e1 / 2 - 27 * (e1 ^ 3) / 32) * Sin(2 * Mu) _
          + (21 * (e1 ^ 2) / 16 - 55 * (e1 ^ 4) / 32) * Sin(4 * Mu) _
          + (151 * (e1 ^ 4) / 64) * Sin(6 * Mu) _
          + (1097 * (e1 ^ 4) / 512) * Sin(8 * Mu)

' Compute Latitude and Longitude
C1 = ep2 * Cos(Lat1) * Cos(Lat1)
T1 = Tan(Lat1) * Tan(Lat1)
N1 = a / Sqr(1 - e2 * Sin(Lat1) * Sin(Lat1))
R1 = a * (1 - e2) / ((1 - e2 * Sin(Lat1) * Sin(Lat1)) ^ 1.5)
D = X / (N1 * k0)
Lat = Lat1 - (N1 * Tan(Lat1) / R1) * (D * D / 2 - (5 + 3 * T1 + 10 * C1 - 4 * C1 * C1 -
9 * ep2) * (D ^ 4) / 24 _
                                + (61 + 90 * T1 + 298 * C1 + 45 * T1 * T1 - 252 * ep2 -
3 * C1 * C1) * (D ^ 6) / 720)
Lng = (D - (1 + 2 * T1 + C1) * (D ^ 3) / 6 + (5 - 2 * C1 + 28 * T1 - 3 * C1 * C1 + 8 *
ep2 + 24 * T1 * T1) * (D ^ 5) / 120) / Cos(Lat1)

' Convert latitude and longitude to degrees, add to central meridian and return result
Res(0) = Lat * 180 / 3.141592654
Res(1) = Lng0 + Lng * 180 / 3.141592654
UTM2LL = Res

End Function
```