ABSTRACT

Gullfaks Sør has the biggest hydrocarbon capacity among the Gullfaks Satellites. It is divided into 6 parts based on compartmentalization. From the given pressure data, we can see that the compartments has approximately the same pressure initially, while after producing for a while the pressure is dispersed. This indicates poor communication between the different compartments in the later stages.

Because there is oil left in our reservoir so there is a plan to build more wells (2 injectors and 4 producers) in order to recover more oil. Thus we have to make an economics evaluation for comparing two cases so that we can find a better solution for our reservoir.

We have used ECLIPSE to simulate the performance of the reservoir and to compare the Reference case and the Restart Case. We can see from the simulation that the history matching of the gas rate is quite good, while for the oil rate, there is a little error which can be acceptable. However, for the water rate, there are quite significant errors where the simulation model has constantly predicted higher values than the real data. When we look at each well, in order to specify the problems of our system, we find that the error of the oil in the field data come from smaller errors for each well. However, for the water we cannot find the specific reason due to limited information. The reason might be because of uncertainties such as aquifer. We conclude that we can use the simulation model for oil and gas from ECLIPSE, while for water we might have to make some corrections before using them.

From the Restart case simulation we found that the 4 additional producer wells and 2 injector wells will give us additional 4 MSm3 produced oil.

In order to make economical comparison for each case, we have considered the Net Present Value (NPV) for both of them. We have to make several assumptions as we have limited data available, i.e. oil prices, expenditure etc. Finally, although we found that the

payback periods of the Restart case is longer than the Reference case, the Restart case provides a higher NPV. We can therefore recommend Statoil to add six new wells to the Statfjord Formation (Restart case).

GROUP 4

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1 Gullfaks Sør Introduction

The introduction of Gullfaks Sør is a summary of the "Reservoir Management Plan (RMP) for the Gullfaks Field and Gullfaks Satellite 2007" [1] and the "Statoil Presentation about Gullfaks Sør" [2, 3].

The Gullfaks Sør Statfjord Formation is developed by the E, F, and G subsea templates, which is flowed and processed into the Gullfaks A (GFA) platform. The production from the Gullfaks Satellites is limited by the platforms' gas capacities. This is particularly so in the case of GFA, so it is important to keep the gas/oil ratio (GOR) in the wells as low as possible. Since the strategy for the satellites has been to drill wells with long horizontal reservoir sections in the down-slope direction and to produce each well from sands with different properties, it is important to be able to plug back zones having a high GOR. Due to the costs of well intervention using mobile installations, the focus is now on completion using zone control for new wells/sidesteps so that the GOR in the well stream can be regulated. We will discuss zone control using smart wells in part B.

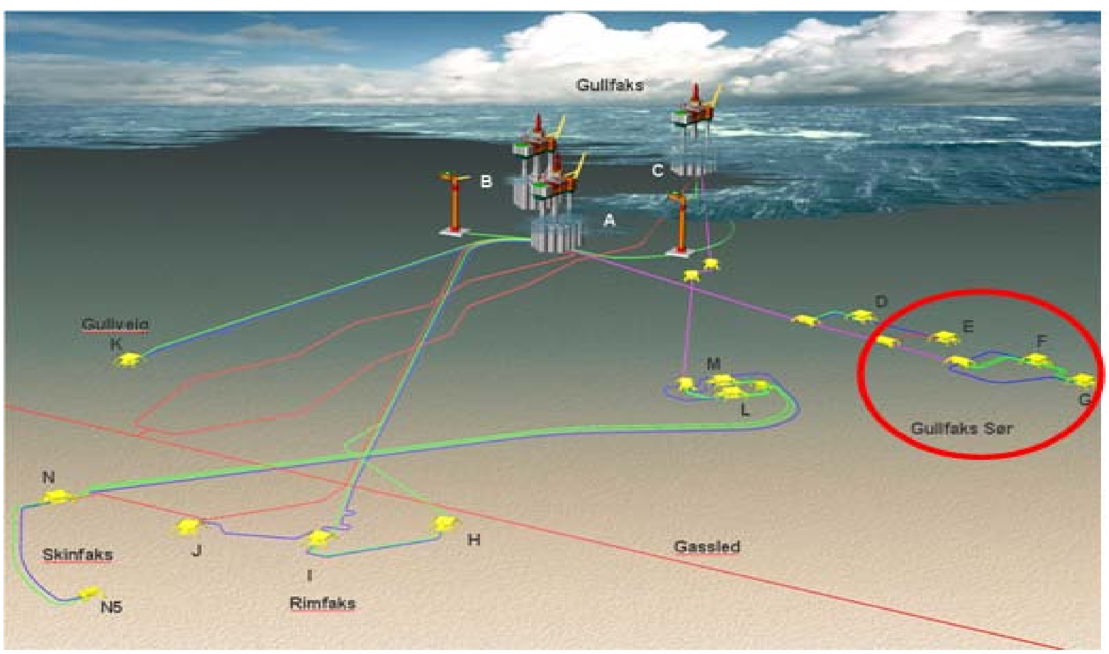


Figure 1-1 The Gullfaks field

Figure A The Gullfaks field

The main focus for the Gullfaks Satellites (SAT) is oil production, but Gullfaks Sør Brent has produced gas for export since October 2007.

Table 2.3.1: Hydrocarbon systems on the Gullfaks Field and Gullfaks Satellites

Reservoir	Gullfaks Field	Gullfaks South	Rimfaks	Gullveig	Skinfaks	Gulltopp	Alun
Brent Group	Oil with gas cap	Oil with gas cap	Oil with gas cap	Oil with gas-cap	Oil with gas cap	Oil	-
Cook Formation	Oil	Hydrocarbons (Segment 23C)	Oil	-	-	-	-
Statfjord Formation	Oil	Oil with gas cap	Oil with gas cap	Gas	-	-	Oil
Lunde Formation	Oil	Oil with gas cap	Oil and gas	-	-	-	-
Krans Formation	Oil, gas and condensate	-	-	-	-	-	-

Figure 1-2 Hydrocarbon systems on the Gullfaks field and Gullfaks Satellites

1.1 Geology

Gullfaks Sør represents the deepest structural level in Gullfaks SAT, with top reservoir at 2,860 m TVD MSL (True Vertical Depth Mean Sea Level). In terms of both area and total resources in place, it is clearly the largest of the four fields of Gullfaks SAT (Gullfaks Sør, Rimfaks, Skinfaks, Gullveig and Gulltopp).

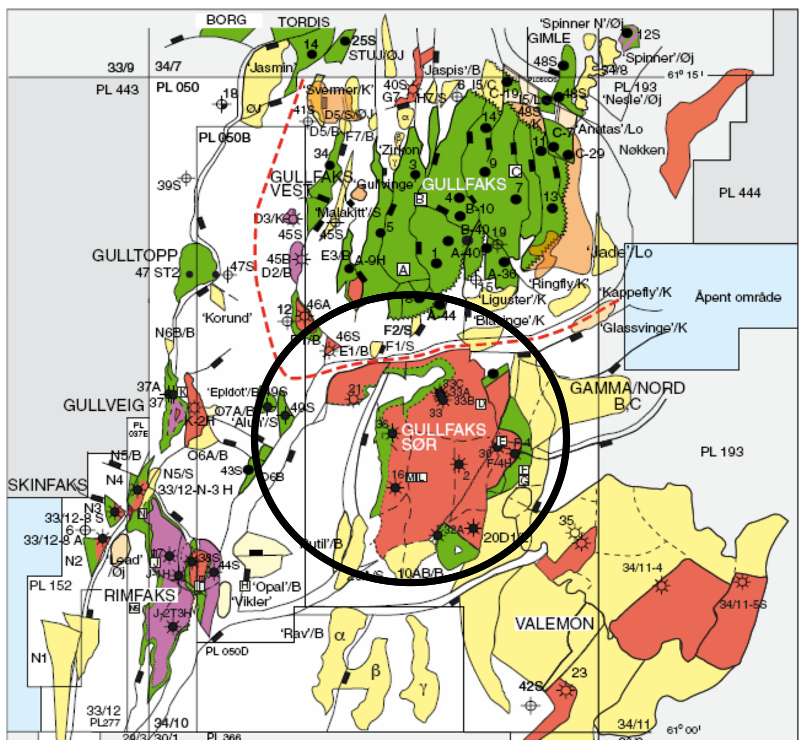


Figure 1-3 Fields and discoveries in the Gullfaks area

The Gullfaks Sør structure has traditionally been divided into three structural domains from west to east: the domino system, the transitional area and the horst complex (Fig. 1-4). Faults in the Statfjord Formation are generally dominated by low permeability in fault rocks that are likely to restrict fluid flow. Obviously, this would contribute to the general poor flow characteristics of this reservoir.

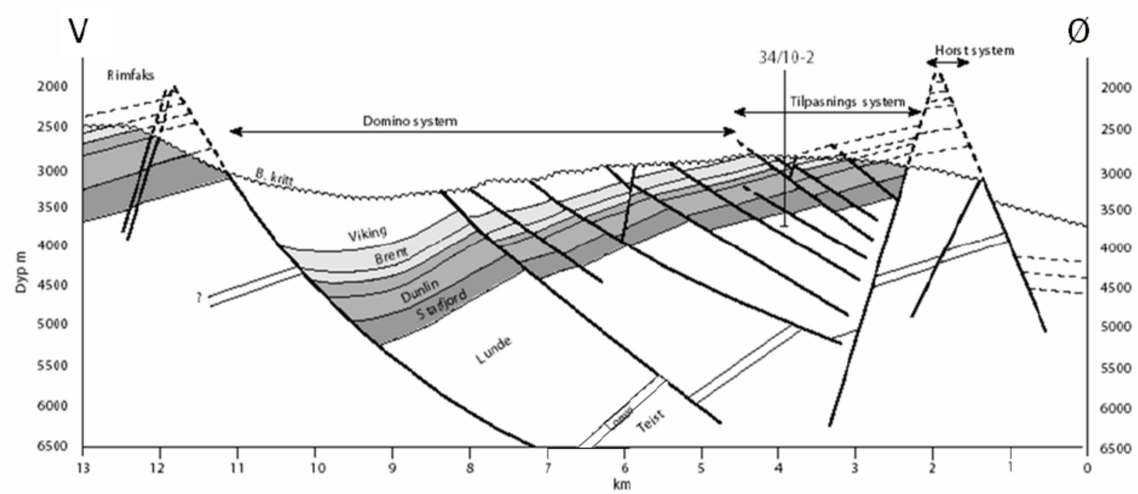


Figure 1-4 General cross-section of Gullfaks Sør

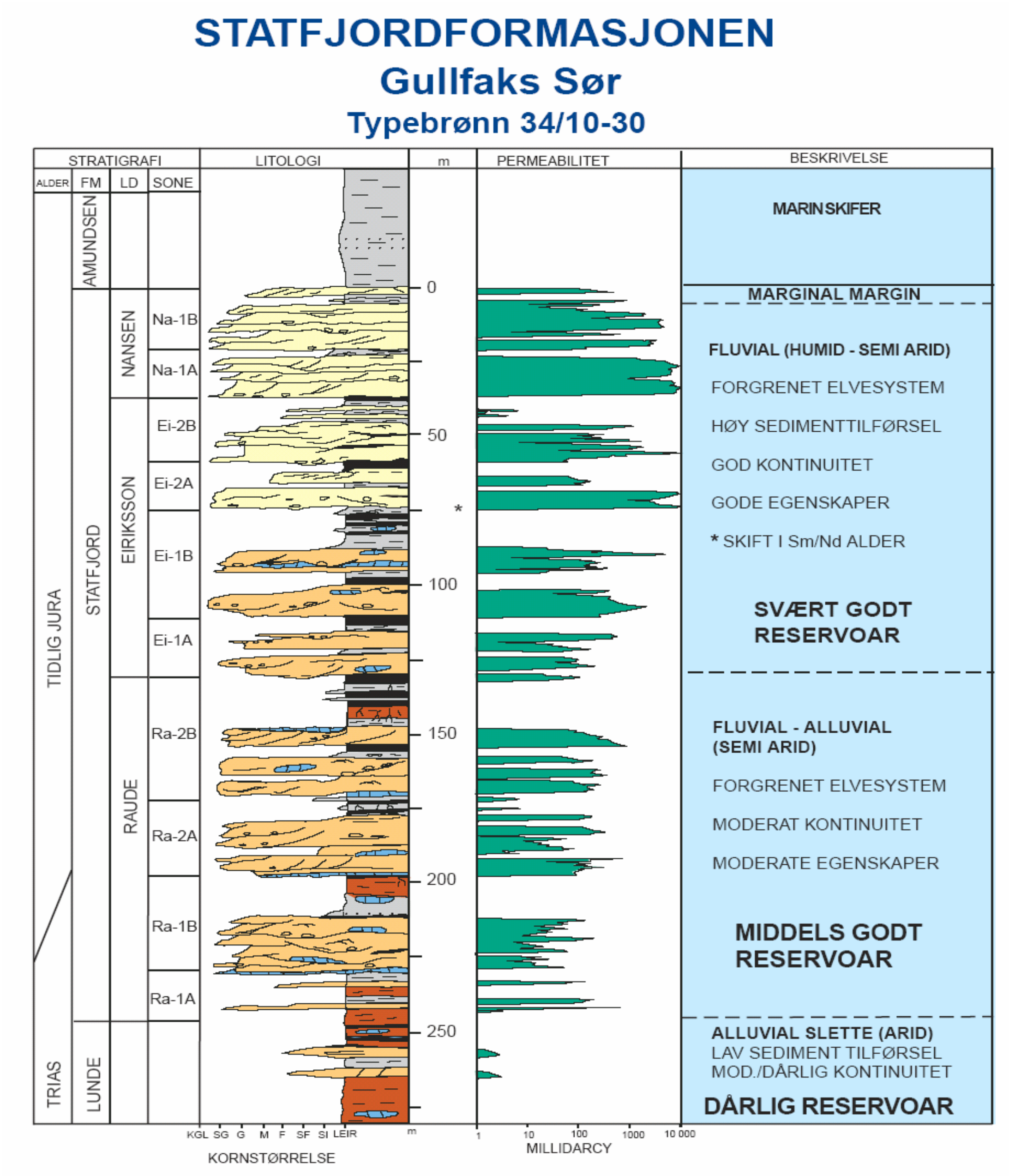


Figure 1-5 Gullfaks Sør Statfjord Formation

The Statfjord Formation is divided into three formations: Nansen, Eirikson and Raude. The permeability and Net/gross of the different formations give us a good understanding of the reservoir characteristics and is shown below. Nansen and Eirikson are very good reservoirs while Raude is an average good reservoir. This is shown in Figure 1-5.

Permeability:

- Good sands: 500-5000 mD
- Middle good sands: 100 – 500 mD
- Poor sands: 1-100 mD

Net/gross value is 0.5 in the reservoir, and average porosity 20 %.

Gullfaks Sør is divided into 6 parts based on compartmentalization as shown in Figure 1-6

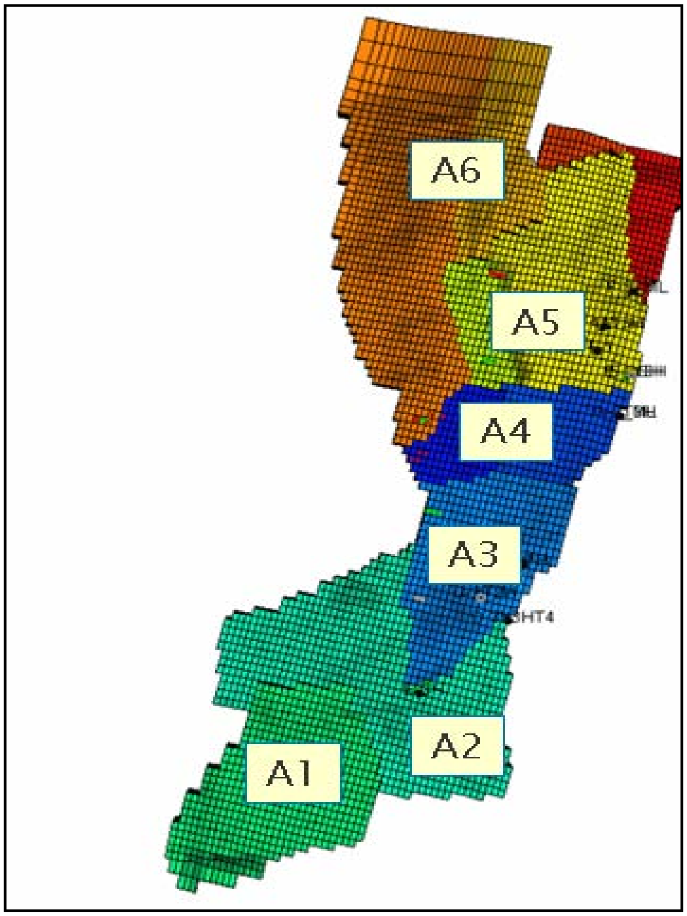


Figure 1-6 Compartments in Gullfaks Sør

Based on pressure-data given in Figure 1-6, we can see that the formation pressure of Nansen, Eirikson and Raude is quite close initially, which could indicate pressure communication among the segments in 1999. At the time the wells start to produce, and particularly from 2004, the pressures start to scatter.

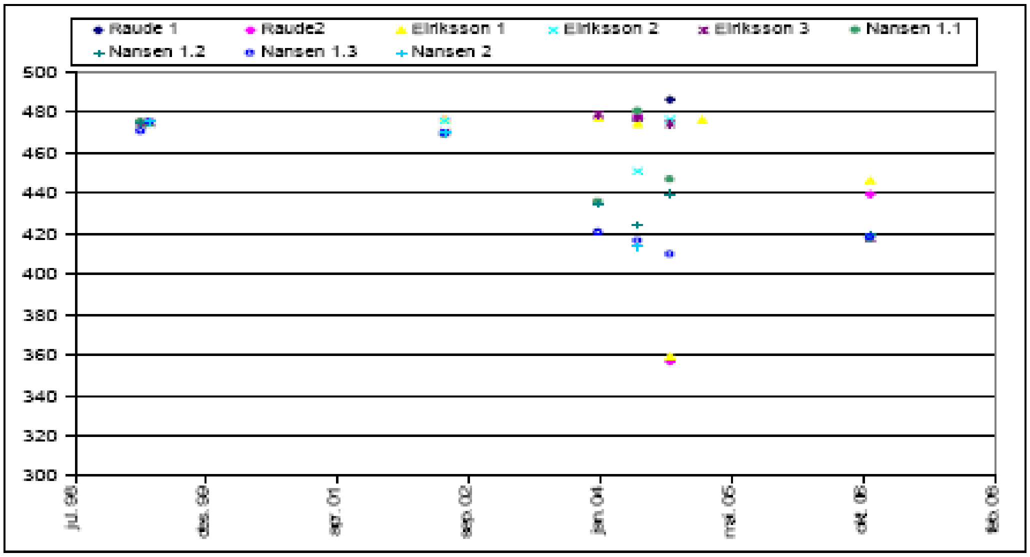


Figure 1-7 Pressure development in GFS Statfjord. RFT pressure measured during drilling of the various wells

1.1.1 Geology Data

For the simulation and comparison later in the report it is important to look at the different reservoir data shown in Figure 1-8.

Table 3.8.10: Reservoir data for the Statfjord Formation, Gullfaks South Pressures and temperatures measured relative to the datum depth Ref. 45

Reservoir parameters Statfjord		Comments
Top structure (m MSL)	3,000	Upflank of Well 34/10-30
Datum (m MSL)	3,300	Placed approximately halfway into the oil zone. Near production well level
GOC (m MSL)	3,224	Based on the point of intersection for pressure gradients in Well 34/10-30.
OWC (m MSL)	3,362	Based on the point of intersection for pressure gradients in Well 34/10-2.
Pressure (bar)	476	Based on RFT pressure in Wells 34/10-30 and 34/10-2, and (joint) gradient
Temperature (°C)	128	Based on temperatures from production tests, plotted against depth.
Gas gradient (bar/m)	0.0291	RFT pressure in Well 34/10-30
Oil gradient (bar/m)	0.0693	RFT gradient in Wells 34/10-30 and 34/10-2.
Water gradient (bar/m)	0.103	Water salinity (RFT pressure gradient in Well 34/10-2 gives 0.103)
Temperature gradient (°C/m)	0.032	Based on temperatures from production tests plotted against depth.

Figure 1-8 Reservoir data for the Statfjord Formation, Gullfaks Sør Pressures and temperatures measured relative to the datum depth

1.2 Reference Case and Restart Case

There are two cases for the Gullfaks Sør reservoir modeling in the assignment for Gullfaks Village 2010. The purpose of the Reference case is to learn about Gullfaks Sør's reservoir performance and the purpose of the Restart case is to see if it is liable to add 6 wells in the Gullfaks Sør Statfjord Formation. The simulation of the Gullfaks Sør Reservoir is conducted from 14 zones/layers as shown in Figure 1-9.

```
*Ny Modell
           Gml sonering               Ny sonering
   1,2,3                              Nansen 2+1.3
   4,5                                Nansen 1.3
   6,7                                Nansen 1.2
   8                                  Nansen 1.1
   9,10                               Eiriksson 3
   11                                 Eiriksson 2
   12                                 Eiriksson 1
   13                                 Eiriksson 1
   14                                 Raude 2
   15 (satt inaktivt)                 Raude 2
*******************************************
```

Figure 1-9 Zones in Gullfaks Sør Statfjord Formation

In the Reference case there are eight production wells: F-1, F-2_ML, F-4AT3H, G-1H, G-2T3H, G-2_ML, G-3T2H, G-4H and 3 injector wells: E-1Y3H, E-2BH, E-3H. The placements of the wells are shown in Figure 1-10.

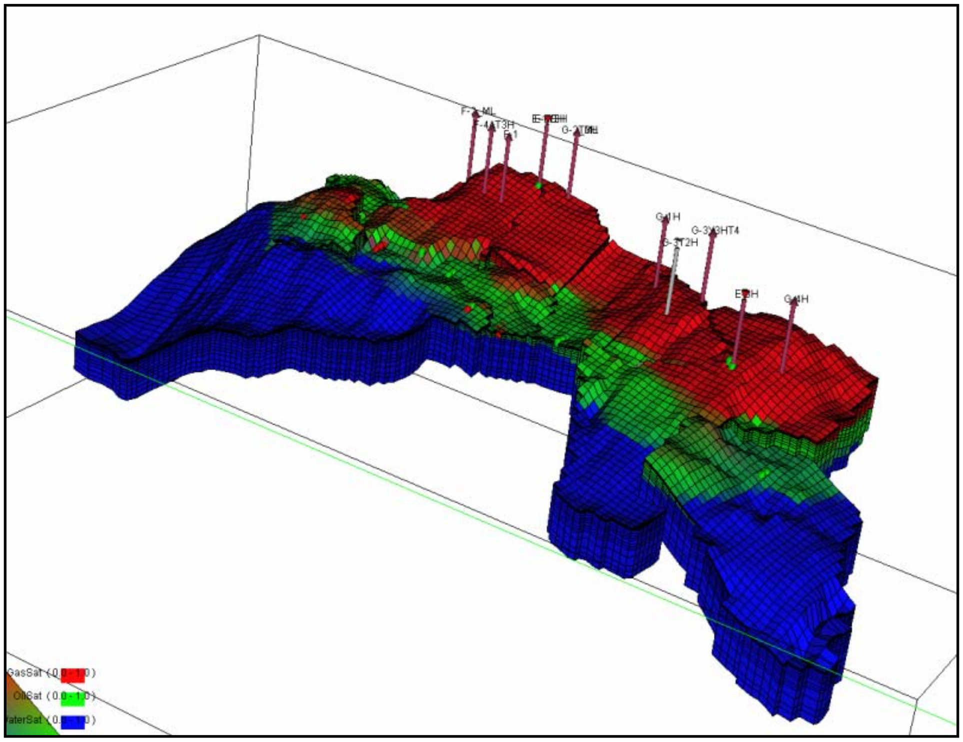


Figure 1-10 Reference case

The Restart case has four additional production wells: W1, W2W3, W4W5, W6W7 (Omega Oil) and two additional injector wells: GI-2, GI-4 (Omega Gas). It can be seen in Figure 1-11. There haven’t been any production wells in segment A1 before, and it is therefore a lot of uncertainty associated with drilling new wells in this segment.

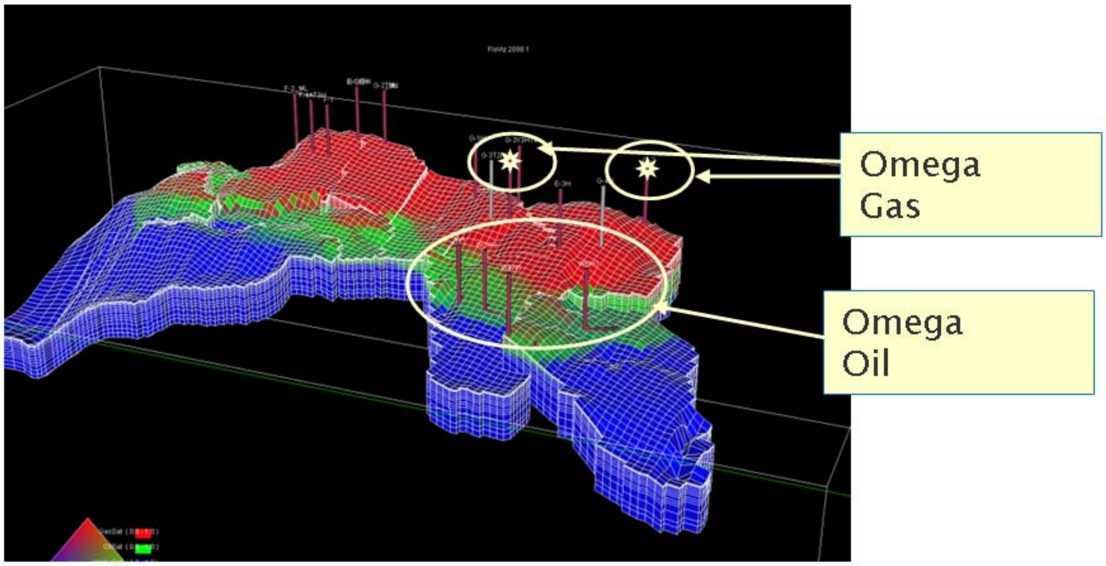


Figure 1-11 Restart Case

1.2.1 Well by Well Review

In the Reference case there are eight production wells: F-1, F-2_ML, F-4AT3H, G-1H, G-2T3H, G-2_ML, G-3T2H, G-4H and 3 injector wells: E-1Y3H, E-2BH, E-3H. The Restart case has four additional production wells: W1, W2W3, W4W5, W6W7 and two additional injector wells: GI-2, GI-4 (Table 1-1).

Production Well	Injection Well
F-1	E-1 Y3H
F-2_ML	E-2 BH
F-4 AT3H	E-3 H
G-1 H	GI-2
G-2 T3H	GI-4
G-2_ML	
G-3 T2H	
G-4 H	
W1	
W2W3	
W4W5	
W6W7	

Table 1-1 Overview of the production wells and injection wells

The wells oil production rate (WOPR), wells water production rate (WWPR), wells gas production rate (WGPR), wells gas oil ratio (WGOR), wells water cut (WWCT) and wells gas injection rate (WGIR) can be reviewed by the tables below. The tables are used to briefly compare the average and maximum production and injector wells parameters.

Production Well		F-1	F-2_ML	F-4 AT3H	G-1 H	G-2 T3H	G-2_ML	G-3 T2H	G-4 H	W1	W2W3	W4W5	W6W7
WOPR (Sm3/day)	max	600	400	400	883	1391	450	878	600	500	800	800	800
	average	190	143	218	365	328	270	282	522	223	273	314	238
WWPR (Sm3/day)	max	218	609	363	261	391	1133	9	520	119	273	440	113
	average	132	243	90	42	68	237	2	308	70	92	213	8
WGPR (Sm3/day)	max	5.00E+05	3.00E+05	4.48E+05	3.27E+05	2.63E+05	6.50E+05	9.52E+05	5.00E+05	1.00E+06	1.00E+06	1.00E+06	1.00E+06
	average	4.68E+05	2.31E+05	3.34E+05	2.00E+05	6.54E+04	3.55E+05	3.86E+05	3.75E+05	9.10E+05	9.28E+05	9.32E+05	9.84E+05
WGOR(Sm3/Sm3)	max	5429	5475	9069	1166	306	2200	1851	2212	10357	11534	8780	11792
	average	3148	2636	3241	623	200	1561	1396	818	5866	6163	4507	6488
WWCT (fraction)	max	0.68	0.84	0.75	0.33	0.40	0.69	0.03	0.46	0.42	0.39	0.64	0.12
	average	0.42	0.67	0.32	0.07	0.18	0.49	0.01	0.36	0.28	0.29	0.46	0.03

Table 1-2 WOPR, WWPR, WGPR, WGOR and WWCT for the production wells

Well Name		E-1 Y3H	E-2 BH	E-3 H	G-2	G-4
WGIR (Sm3/day)	maximum	1.14E+06	1.00E+06	1.50E+06	1.20E+06	1.20E+06
	average	7.95E+05	9.82E+05	1.50E+06	1.20E+06	1.20E+06

Table 1-3 WGIR for the injector wells

From table 1-2 we can see that all the production wells have a good performance.

We want WGOR and WWCT to be as low as possible in order to have an efficient well and because of the limited processing capacity to the Gullfaks A Platform. From table 1-2 we can see that G-3 T2H is a very efficient well since the values are very close to zero. F-1, F-4 AT3H, G-2 ML, W4W5 and especially F-2 ML have lower efficiency and do not produce as well as the other wells.

For the injection wells the Well Gas Injection Rate is approximately the same (table 1-3) with minor dissipations.

2 History matching

2.1 Pressure History Matching

Reservoir Pressure Depth is in datum = 3300 m MSL (Figure 1-8), but the well bottom hole pressure depths are varied as table below.

Well	Depth, m MD RKB	Depth, m TVD RKB	Start-up date	Failure date	Days in operation
F-4 AH T3	1,967.1	1836.5	29/04/1999	07/07/2004	1896
G-1H	3,538.4	3127.0	07/02/2004	26/10/2004	262
Zone 1(ann.)	3,686.8	3,217.7	07/02/2004	26/10/2004	262
Sone 2 (tub.)	3,686.8	3,217.7	0702/2004	07/02/2004	0
G-2 H T3	N/A	N/A	13/04/1999		
G-2 YH	2,893.0	2,761.0	26/07/2004	30/09/2006	800
Y1	2,893.0	2,761.0	26/07/2004	30/09/2006	800
Y2	3,115.0	2,937.0	26/07/2004	30/09/2006	800
G-3 H T2	3,880.6	3,226.2	07/07/2001	08/12/2004	1,252
[illegible]	[illegible]	[illegible]	[illegible]	[illegible]	[illegible]
[illegible]	[illegible]	[illegible]	[illegible]		[illegible]
F-2YH	3,258.0	3001.0	22/11/2004	12/02/2005	83
Y1	3,323.0	3046.0	22/11/2004	12/02/2005	83
Y2	3,323.0	3046.0	22/11/2004	12/02/2005	83
F-3 H	3,952.9	2891.8	26/08/2000	26/10/2001	456

Table 2- 1 Wells Pressure Gauge Depth

There are only 5 wells bottom hole pressure gauge depth data available of Gullfaks South Statfjord Formation in RMP 2007 (table 2-1). Then we assume oil density is 835 kg/m3, and in the below calculation formula, the fluid is assumed only oil to simplify the calculation.

dP corrected = (datum depth-gauge depth)(gravity)(oil density)

From the calculation, corrected pressure difference is varied from 6 to 122 bar (table 2-2) due to different datum depth (reservoir) and wells gauge depth (without RKB (Rotary Kelly Bushing) and MSL depth correction due to no data available).

	datum	3300 m TVD
	oil density assumption	835 kg/m3
well name	pressure gauge depth	pressure difference
F-2 YH = F-2 ML	3001.00	24.9665
F-4 AT3H = F-4 AHT3	1836.50	122.20225
G-1 H	3127.00	14.4455
G-2 YH	2761.00	45.0065
G-3 H T2 = G-3 T2H	3226.00	6.179

Table 2- 2 dP datum corrected

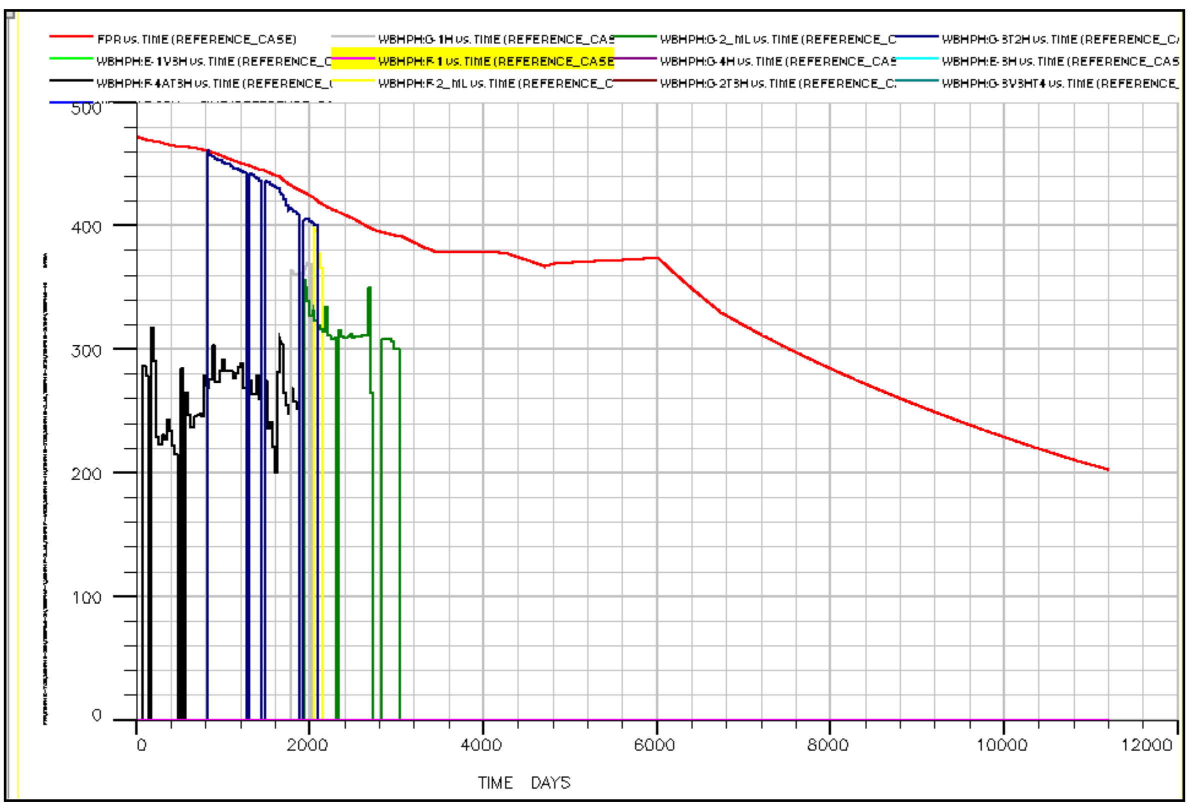


Figure 2-1 Reservoir Pressure at datum vs History of Wells Bottom Hole Pressure at gauge depth

In the above picture, based on production history the maximum deviation from reservoir pressure (red line) come from F-4 AHT3 (black line) and the minimum is from G-3 T-2H (blue line). If we compare to table 2-2, F-4 AHT3 has the highest corrected dP (122 bar) and G-3 T2H has the lowest corrected dP (6 bar). Roughly, we could see maximum deviation is approximately 100 bar from F-4 AHT3, which is quite significant difference pressure (20% from initial pressure). The deviation may be caused short time shut in pressure, or complete compartment segment reservoir so no communication.

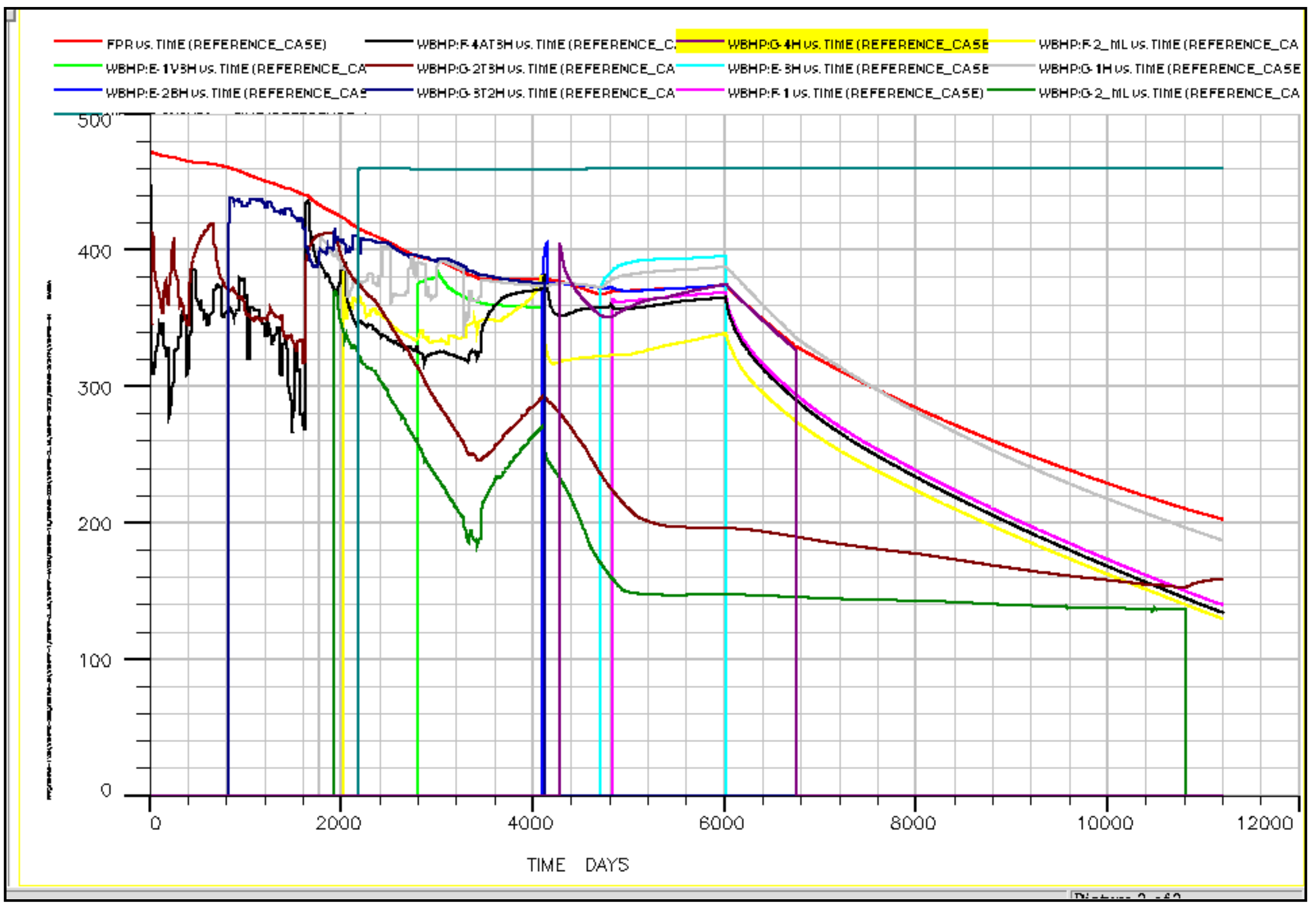


Figure 2-2 Reservoir Pressure at datum vs Wells Bottom Hole Pressure at gauge depth

Wells have variation deviation from reservoir pressure (Figure 2-2). On the other hand, some wells have no available actual data, so we cannot compare them with simulated reservoir pressure.

2.2 *Oil History-matching*

We first look at the oil production rate for actual model (FOPRH) and simulation model(FOPR)

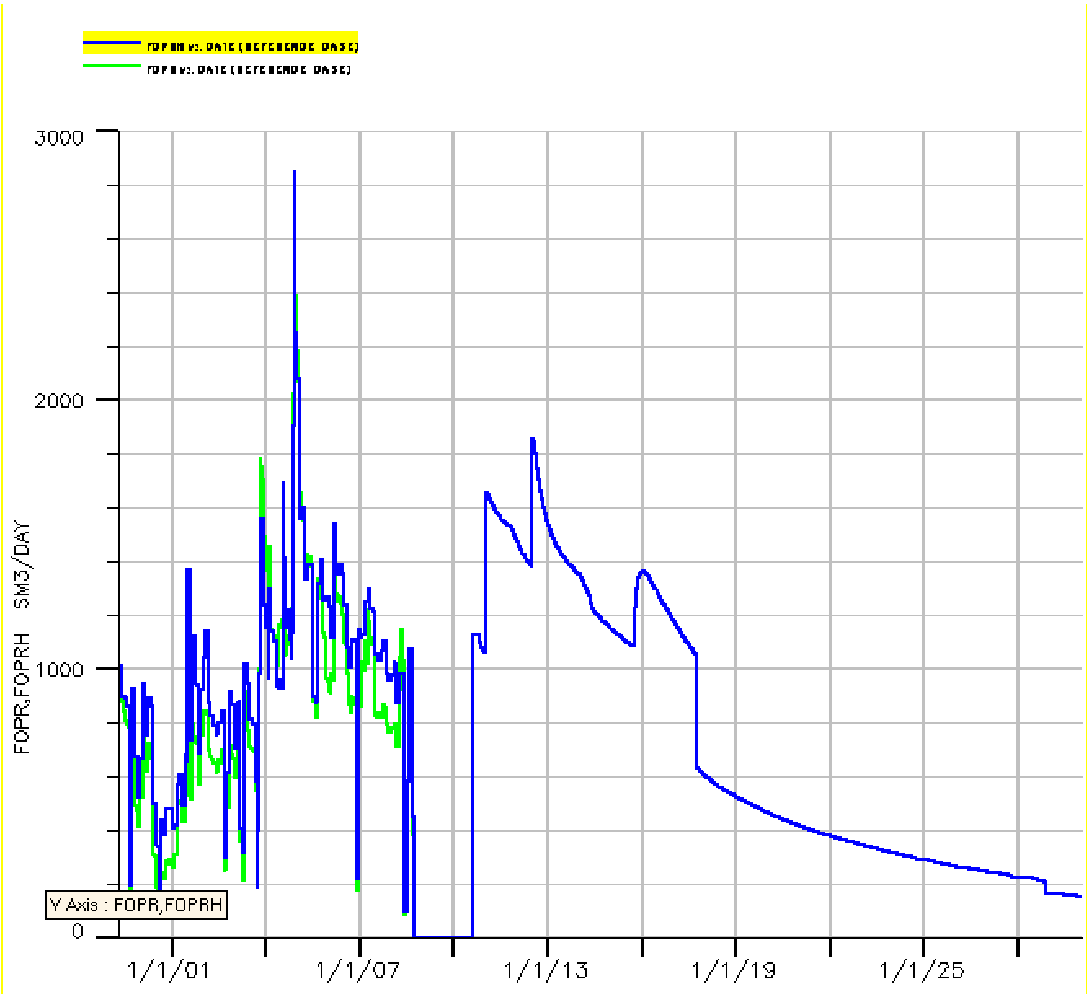


Figure 2-3 FOPRH vs FOPR

The green curve is the history model (actual data), while the blue one is simulation data. There is not much different between both graphs. We found the maximum error is about 300Sm3/d or about 30% but most of the data is not having much error that means we can use the simulation to predict behavior of reservoir.

2.3 *Water History-matching*

We consider water cut for both history (actual value (FWCTH)) and simulation value (FWCT).

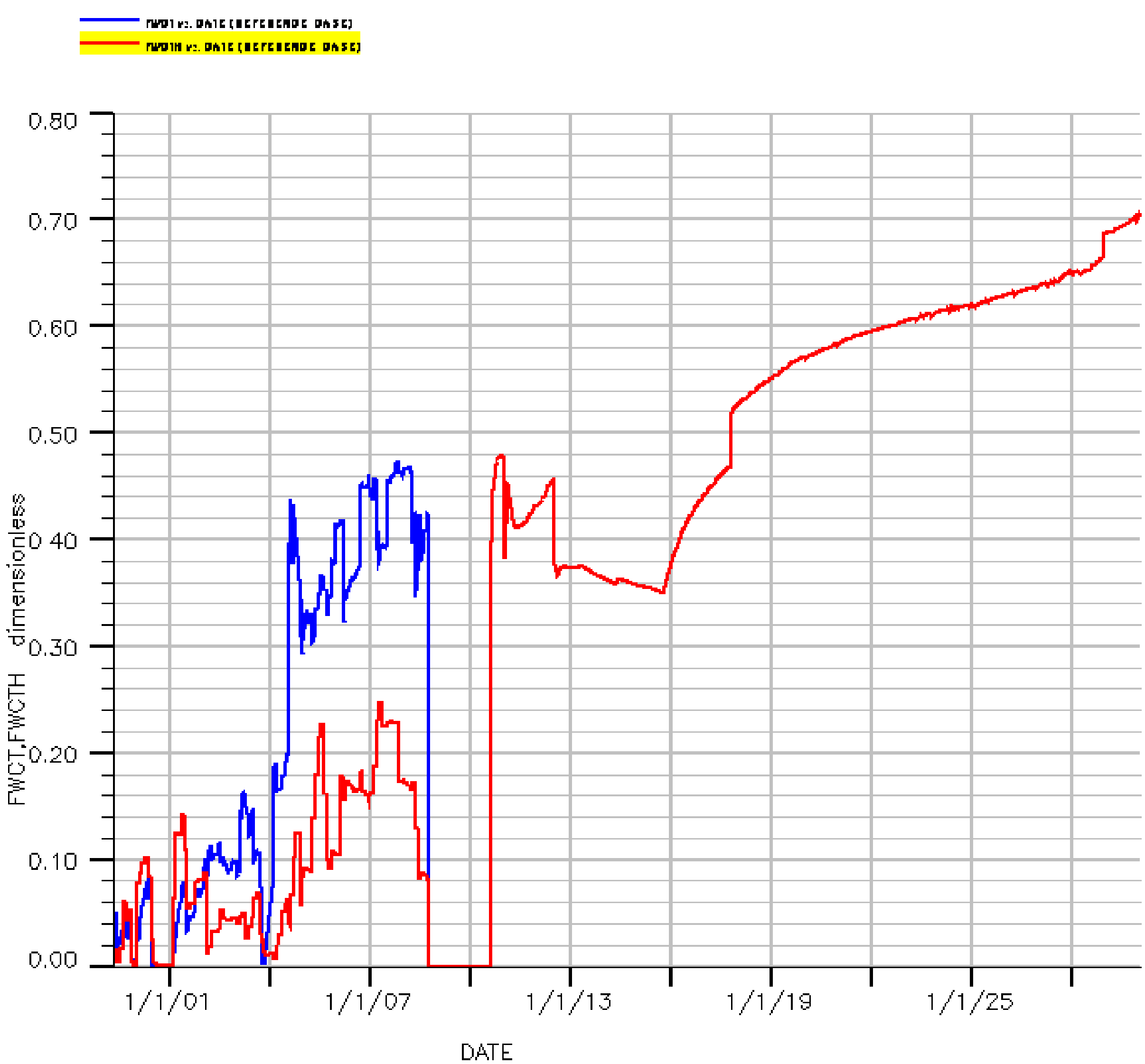


Figure 2-4 FWCTH vs FWCT

The blue one is actual water-cut curve and the red one is a simulation value from Eclipse. We can see from the graph that there is much more error for the simulation of water-cut. The maximum error is about 0.3 which is 75%. Thus we should consider the value of water so much in the simulation. The value of water-cut is mostly under-estimated. Actually, this error in the water-cut is due to the contribution from F-2_ML for matching with the Pressure history data, and as a consequence it adds aquifer and this aquifer produces water higher than the history data.

Thus we consider the water production rate.

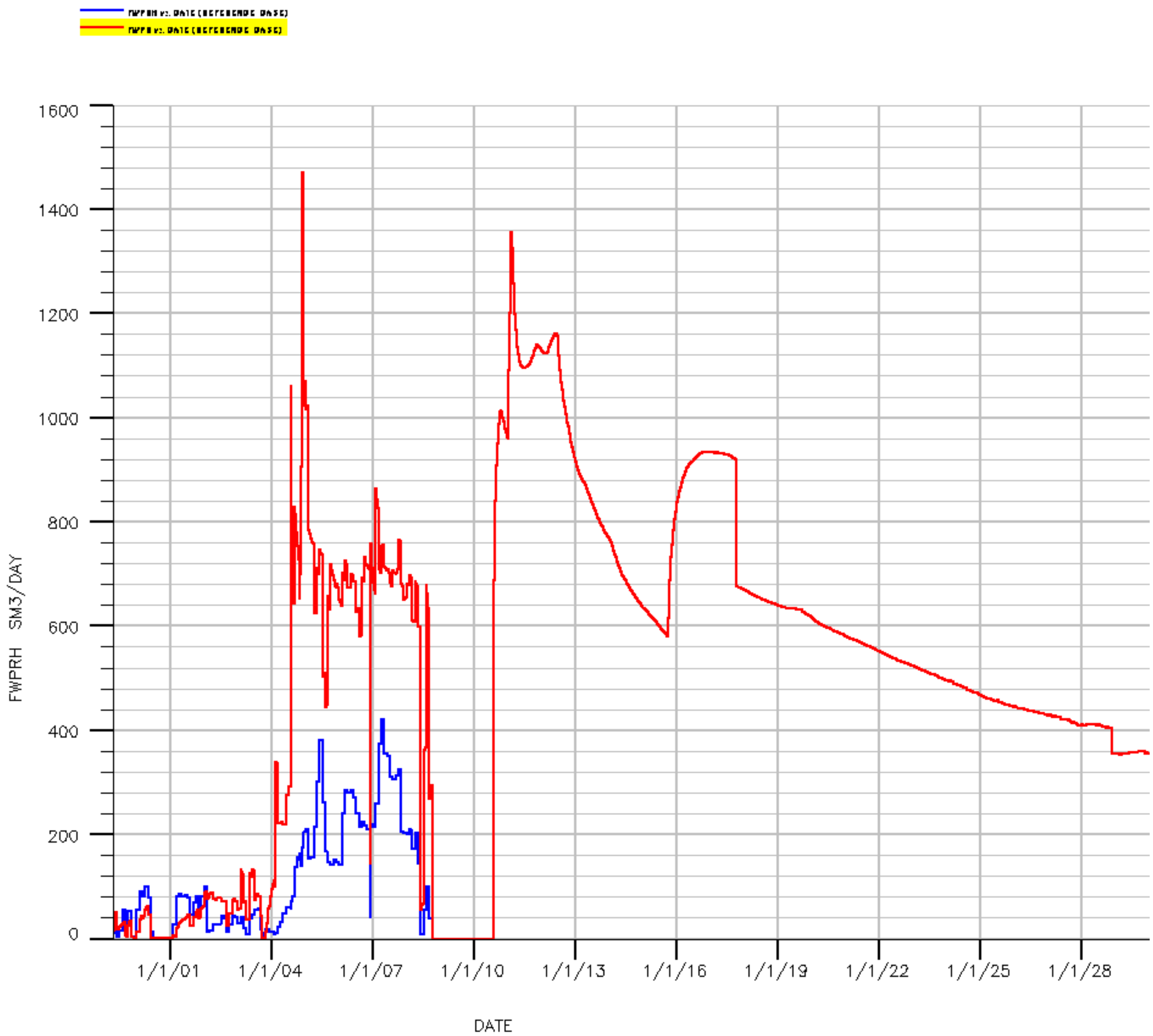


Figure 2-5 FWPRH vs FWPR

The blue one is actual water production curve and the red one is a simulation curve. We can also see that there is not so much error between 2004-2008, same as water-cut, we should have a correction for water production before using.

2.4 *Gas History-matching*

We consider Gas-Oil Ratio to see if there is a big error between actual data and data from the simulation.

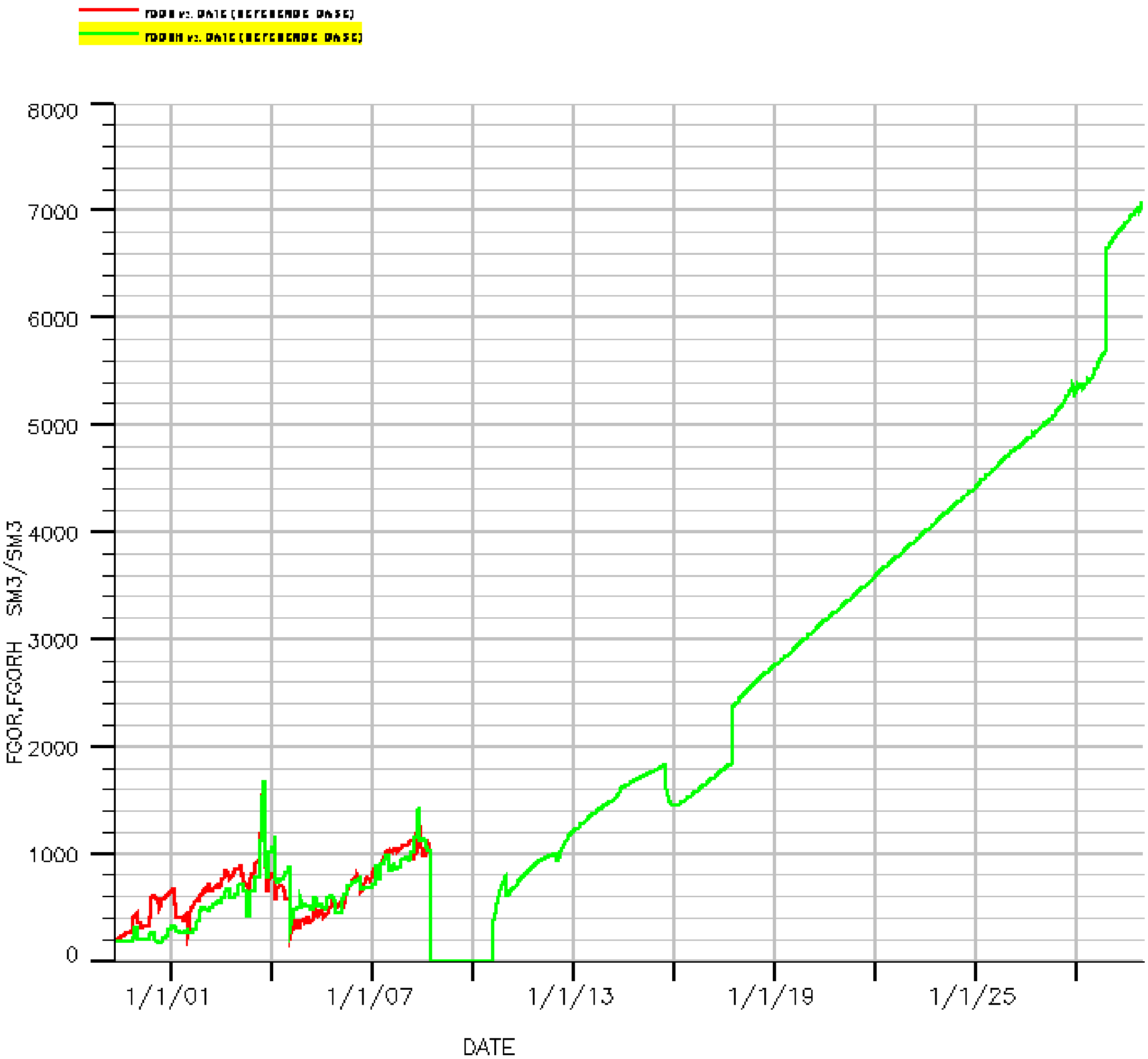


Figure 2-6 FGORH vs FGOR

The green curve represents simulation value of gas oil ratio (FGOR) and the red one is actual Gas-Oil Ratio(FGORH). We can see the maximum error of the value is about 400Sm3/Sm3 which is about 40% however most of the data do not have so much different between both value.

Then we consider the gas production rate.

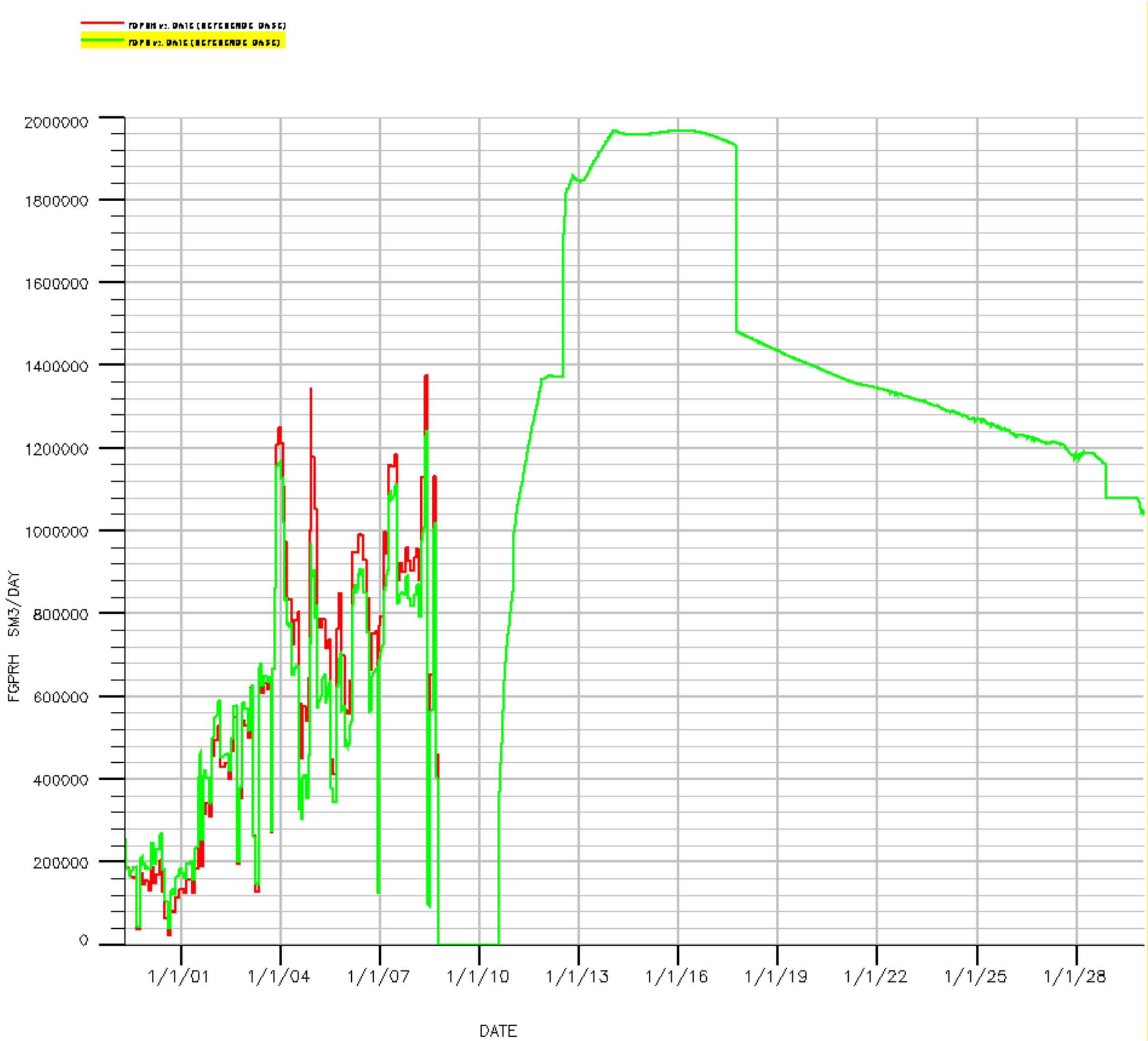


Figure 2-7 FGPRH vs FGPR

The green curve represents simulation value of gas production rate (FGPR) and the red one is actual gas production rate (FGPRH). We can also see that the simulation model for gas is almost the same as the actual data so we can trust for the gas model.

2.5 *WELL BY WELL HISTORY MATCHING*

Because field value in Eclipse represent overall reservoir which is a large scale, then if there are some errors in the field value it is difficult to find the cause of the problem. Thus, we try to see well by well in order to match actual data and history, so that we can find the well which has so much errors and try to fix make a correction in that well to make a value of simulation data more realistic.

There are Well F-1, F-2_ML, F-4 AT3H, G-2_ML, G-1 H, G-2T3H, G-2_ML, G-3 T2H G- 3Y3HT4,G-4 H ,however there was no history for well F1, G-4H and well G-3Y3HT4 was shut , then we have to have a look only the rest 6f the0

The figure we considered is used from APPENDIX A

2.5.1 F1

Water – no history

Oil – no history

Gas – no history

2.5.2 F-2_ML

Gas – the history and the simulation model give almost the same value so that the value of simulation in this well can be reliable. There is an error in GOR, not due to bad calculation of gas but because an error in oil calculation.

Oil – the simulation value of oil in this well is underestimated than the actual data. But we cannot conclude the reason why there is an error because of lacking of the pressure data. May be we have to change some value regarding to this well or make some corrections to oil data.

Water – there is an error in water production. Same as oil,we cannot conclude the reason why there is an error because of lacking of the pressure data.

2.5.3 F-4AT3H

Gas – there is error in this well but we can suggest that this may due to the bad calculation of bottom-hole pressure which the model overestimate the pressure.

Oil – there is error in the beginning which may result from wrong calculation of pressure. However after 2004 the simulation data did not have much error.

Water – there is quite some errors in this model. The simulation model over-estimated the water production . So, for predicting the water for this well, we have to reduce the value we get from simulation.

2.5.4 G-1H

Gas – there is little error for gas simulation. There is an error in GOR, not due to bad calculation of gas but because of an error in oil calculation.

Oil – there is error in oil calculation, the simulation model have a higher value than the history. However, we cannot find the reason of an error because we lack the pressure data.

Water – there is so much error in water model. May be the reason is an estimate error in the aquifer around the well.

2.5.5 G-2T3H

Gas – the history and the simulation model give almost the same value so that the value of simulation in this well can be reliable. There is an error in GOR, not due to bad calculation of gas, but because of an error in the oil calculation.

Oil – the history and the simulation give almost the same value so we can rely on this model too.

Water – there is an error in this calculation, may be this because wrong aquifer data because there is no error in bottom-hole pressure.

2.5.6 G-2_ML

Gas – there is almost no error for gas model so we can rely on this model.

Oil – There is error in oil model may be because wrong calculation of pressure.

Water – there is so much error in water perhaps due to wrong calculation of pressure.

2.5.7 G-3T2H

Gas – there is almost no error for gas model so we can rely on this model.

Oil – There is little error for this calculation may be due to wrong calculation of pressure.

Water – The simulation model always under estimate the value of water production. So we have to do corrections before using this data.

2.5.8 G- 3Y3HT4

This well is shut.

2.5.9 G-4H

Gas – there is no history for this value

Oil – there is no history for this value

Water – there is no history for this value

3 Field Review after adding 4 Producer Wells and 2 Injector Wells

3.1 Summary

Based on observation and evaluation of the figures in Appendix A, well by well review, we can see that the additional wells have different effects to the existing wells:

- Acceleration Field Effect: the drainage area of the existing wells is reduced due to the new wells and the cumulative oil production per well in the Reference case is higher than the Restart case. Well F-1, F-2_ML, F-4 AT3H, G-2_ML, G-4 H.
- Some of the existing wells are slightly affected by the new wells (G-2 T3H) while others are not affected at all (G-1 H, G-3 T2H).
- Drain shut in well G-3 Y3HT4. The well is shut in and do not produce, probably because of a problem in the well. This well’s reduction in bottom hole pressure means that the new wells drain from the drainage area of G-3 Y3HT4.

Adding 4 producer wells and 2 injector gas wells (Restart case) will add 4 MSm3 produced oil (Figure 3-2) compare to Reference case. On the other hand, we need to consider the surface facilities capacity for gas and water since the estimated maximum water rate will increase to 1400 Sm3/day and the estimated maximum gas rate will increase to 5.5 MSm3/day.

We recommend that the location for the new wells should be elected with sensitivity in order to optimize the hydrocarbon (oil and gas) recovery and this way maximize the profit. This is because some of the new wells are producing in the same drainage area as the already existing wells. This will result in reduced drain efficiency in the existing wells, but it will also accelerate the production of the total field.

Oil Production

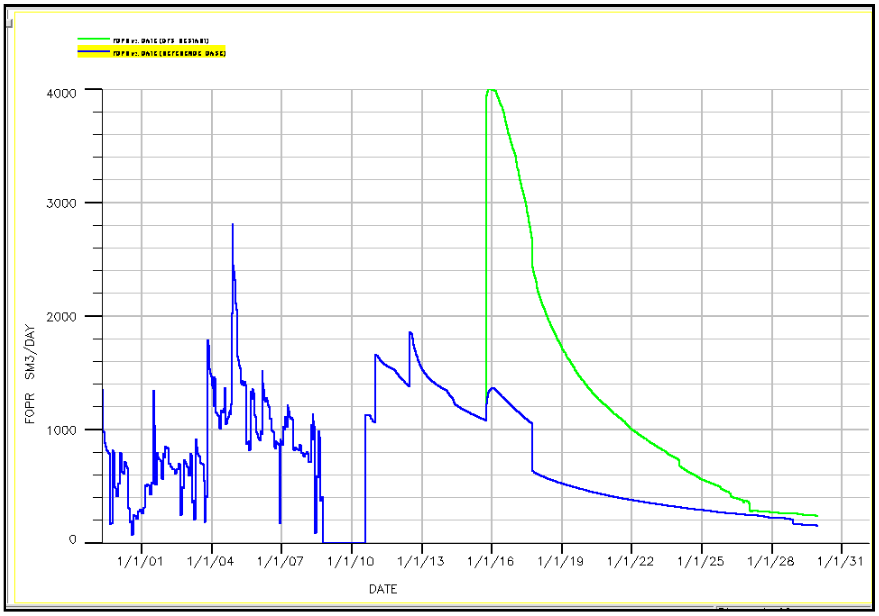


Figure 3-1 Oil Production Rate Field

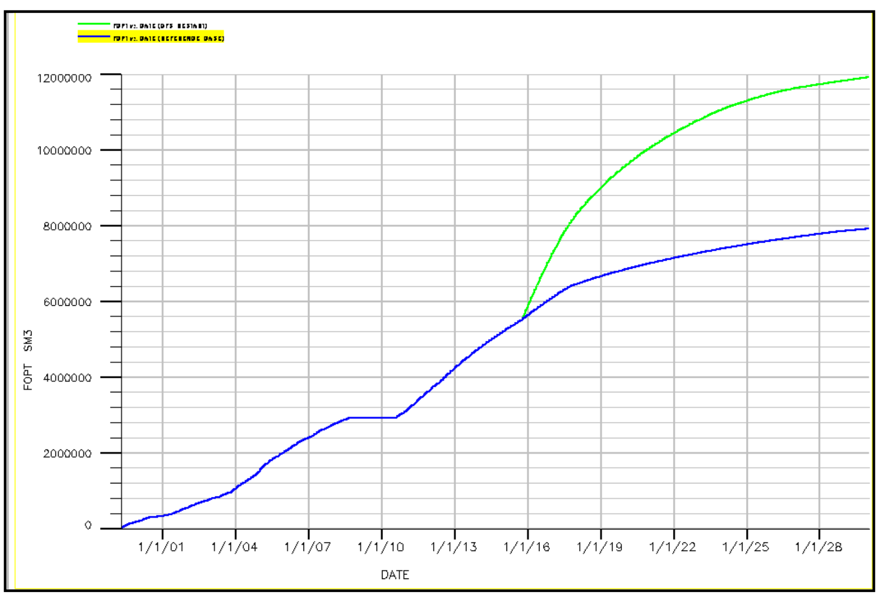


Figure 3-2 Cumulative Oil Production Rate Field

Six new wells give us an increased oil production of 4 MSm3 from the Reference case (Figure 2-2) and a maximum oil rate of 4000 Sm3/day (Figure 2-1).

3.2 Water Production

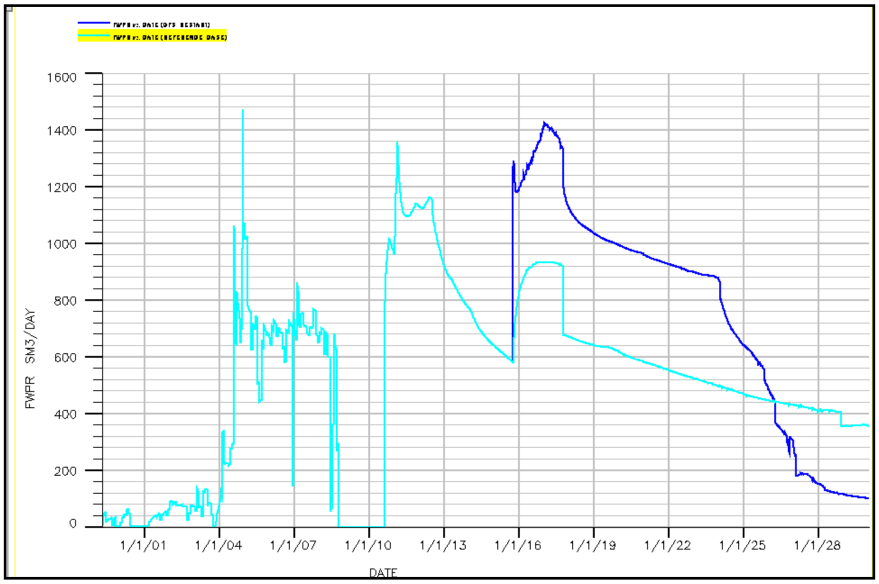


Figure 3-3 Water Production Rate Field

The maximum water rate in the Restart case is 1400 Sm3/day (Figure 2-3), which should be considered in relation to the surface facilities capacity. Based on the water production profile of the Restart case (blue line), we have higher production of water at early stage and smaller production of water at late stage compared to the Reference case. We could see bounded/limited aquifer indication when comparing the Reference case and Restart case.

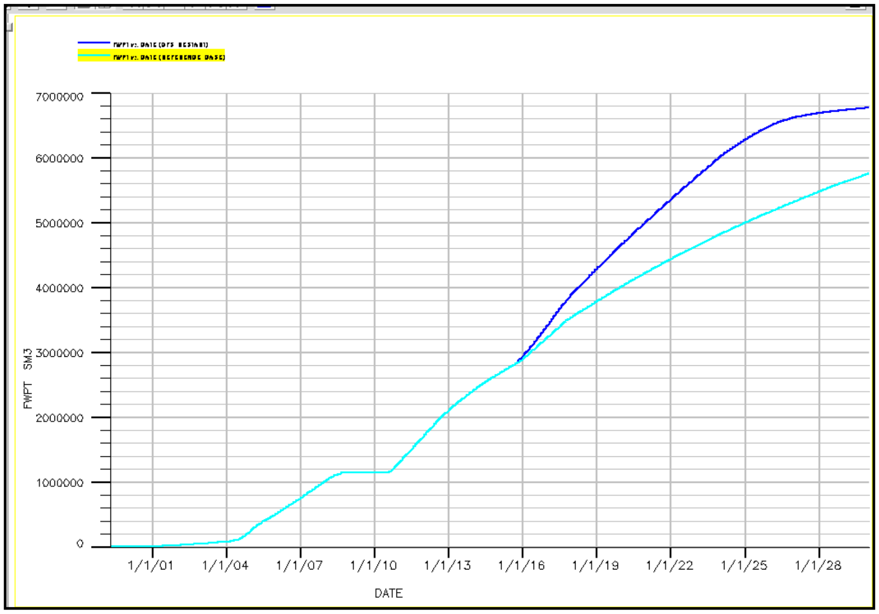


Figure 3-4 Cumulative Water Production Rate Field

Six new wells give us an increased water production of 1 MSm3 (Figure 2-4) from the Reference case

3.3 Gas Production

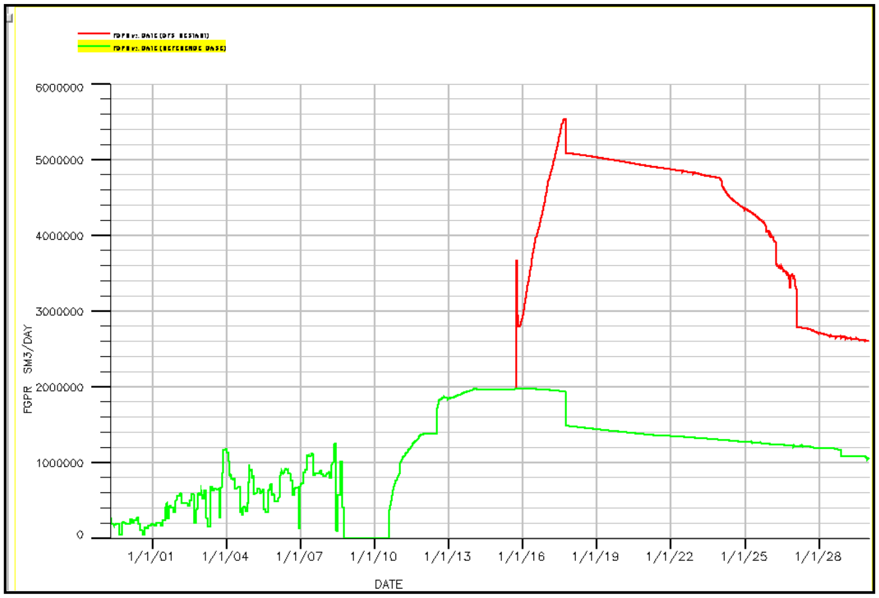


Figure 3-5 Gas Production Rate Field

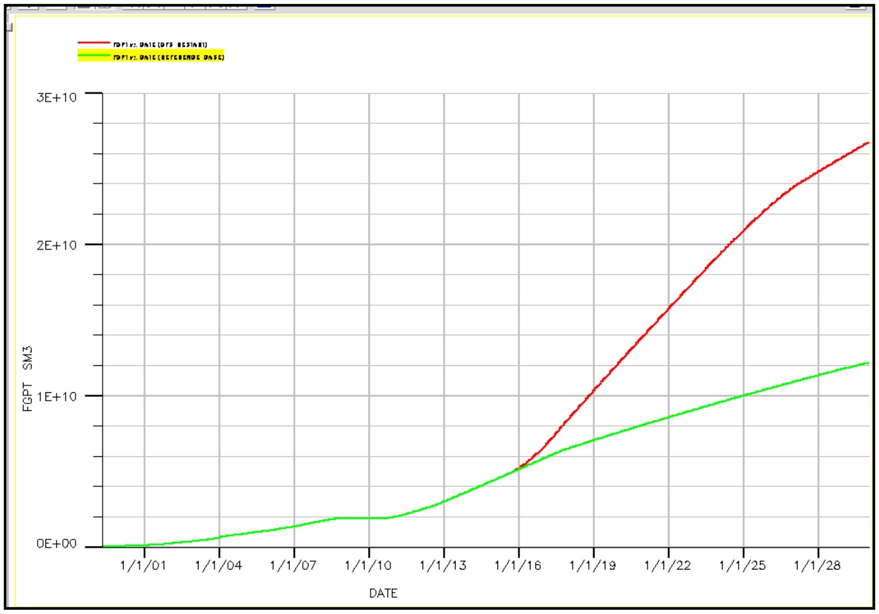


Figure 3-6 Cumulative Gas Production Rate Field

Adding 4 production wells and 2 injection wells result in additional 14 GSm3 production of gas (Figure 2-6) with a maximum gas rate of 5.5 MSm3/day (Figure 2-5). The daily production rate should be taken into consideration with a view to the surface facilities capacity.

3.4 Reservoir Pressure

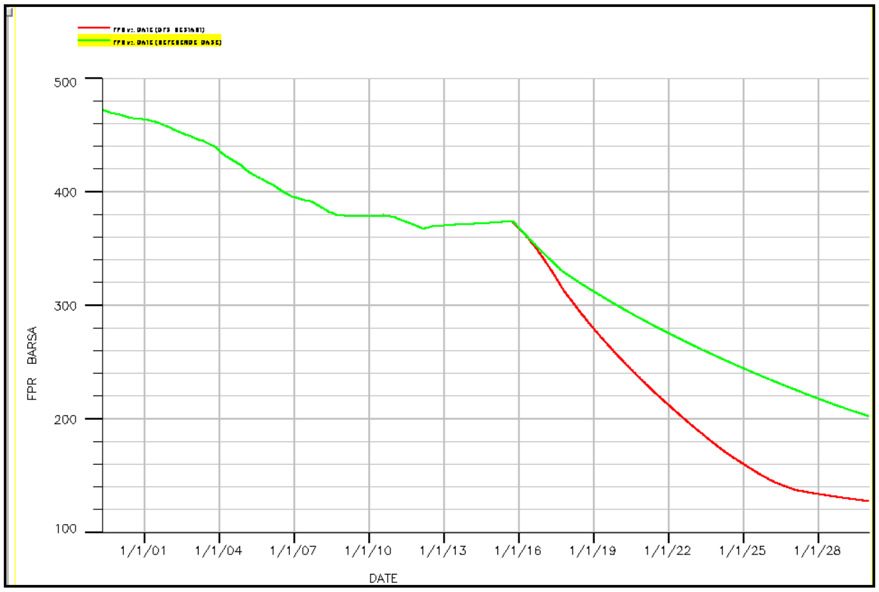


Figure 3-7 Reservoir Pressure

In 2030 the reservoir pressure will be 100 bars for case with 6 additional wells. This is expected since the pressure will drop faster as the reservoir will drain more quickly with additional production wells.

3.5 Field Water-cut

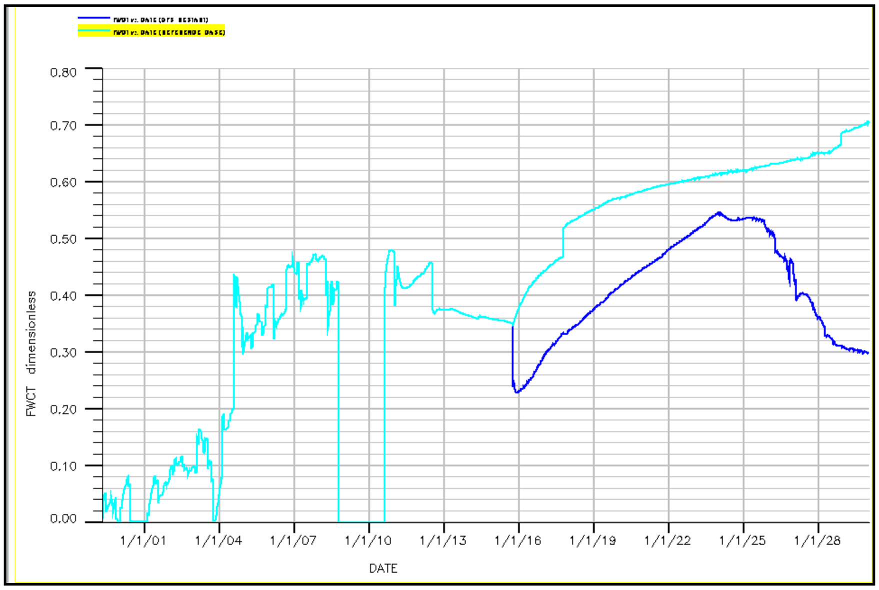


Figure 3-8 Field Water Cut

The reduced water cut in the Restart case means that the efficiency of oil gain compared with produced water has increased.

3.6 Field Gas-Oil Ratio

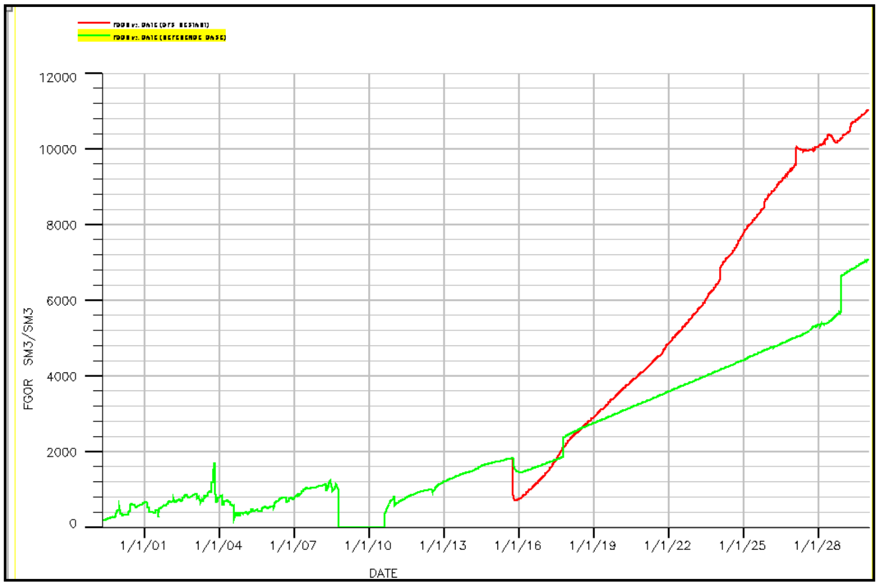


Figure 3-9 Field Gas Oil Ratio

Additional of 4 producer wells and 2 injection gas wells, generally contribute to higher GOR. But in 2015 the GOR is lower in the Restart case due to higher oil rate, although at this time produced gas is also higher.

4 The Economic evaluation

In these subsequent sections we have evaluated both the cases in the fundamental economic analysis. Firstly, we have considered the Reference case, in which we have 11 wells, consisting of 3 injectors and 8 producers. These wells are located in the Statfjord Formation, and they were drilled from 1999.

In the Extended case we have added 6 new wells, consisting of 4 producers and 2 injectors, which will be drilled in 2015 with a new drilling platform. Although, we have to spend much money to invest initially (the Extended case), but we will have much more additional oil from this scheme. Thus we have to consider both the cases and find the most favorable operational conditions for the case that is optimal.

4.1 Objective

We have done separate analysis for the two cases to do a comparison between both the cases, the Reference case and the Extended case, in order to consider which case provides a better solution.

4.2 Procedure

There are many ways to make an economics evaluation. We have chosen to use NPV (Net Present Value) to evaluate our project. The NPV model integrates a large amount of information and tracks the future cash flow contributions of the major stakeholders.

Since money is time-depending, the annual net cash flows need to incorporate the timing of the cash-flow to account for the effect of the time value of money. This is particularly necessary for atypical E&P (Exploration and Production) projects, because they are spread over many years.

There are various inputs to this model. These numerous inputs can be categorized as different scenarios, for instance a high and a low oil price. The forecasts of the oil price is shown with three different scenarios: the High Case, the Low Case and the Base Case.

We calculate the cash flow in each year by using the following formula:

Net cash flow = Revenue – CAPEX – OPEX – Royalty – Tax

We can calculate the NPV by using net cash flow multiplied by discounted factor so that we get net present value. Then we can compare the values and get the overall net present value for both cases and find an optimal solution for this project.

4.3 *Assumptions*

Due to the limited data that was provided to us for the two cases, we had to make some assumptions for our calculations. However, we have encapsulated our assumptions to make as close to a realistic value as much as we can.

4.3.1 The oil price

We get the historical oil price from 1999-2008 from: **http://inflationdata.com/inflation/inflation_Rate/Historical_Oil_Prices_Table.asp**

For the rest of them we use the value from **http://gullfaks.ipt.ntnu.no/gullfakslandsbyen/2009/** which is the data given from Statioil last year.

To simplify the calculation we assume that the oil price is constant throughout the year, then the revenue of oil is simply calculated from volume of oil in each year multiplied by oil price in each year.

4.3.2 Net revenues

The net revenue from this project come from selling gas only so we neglect the revenue from selling any gas.

4.3.3 Operating expenditure (OPEX)

OPEX is an operating expense is a day-to-day expense such as sales and administration, or short term expenditure. We divided OPEX into 3 parts:

- Field offshore – is the cost due to offshore operation for example maintenance cost, chemicals etc. We assume 5000000 NOK/year for this cost
- CO_2 duty – is the cost related to the amount of CO_2 that was produced during operation, for instance eliminating flare. We assume 1000000 NOK/year constantly
- Gas oil transportation – is the cost due to production because after we produce oil we have to transport to customer. The more oil you produce the more cost of transportation. Thus we assume this expenditure cost 1% of oil revenue.

4.3.4 Capital expenditure (CAPEX)

CAPEX is incurred when a business spends money either to buy fixed assets or to add to the value of an existing fixed asset with a useful life that extends beyond the taxable year. We divided CAPEX into 3 main parts:

- Platform or subsea – we assume 5000 MNOK for platform and 3500 for subsea wellhead. We also assume that we have to pay on only 1 year.
- Production unit – is the cost of production facility for example pump, compressor etc. We assume the value of these facilities cost 100 MNOK and cost in the same year of building platform or subsea wellhead.
- Drilling cost – is the cost of drilling 1 well. We assume that we have to pay 100 MNOK per 1 well.

Some of the data are brought from Visund field and modified a little.

4.3.5 Royalty

Royalty is one of the manner in which the host government claims an entitlement to income from the government from the production and sale of hydrocarbon on behalf of host nation. Royalty is normally charged as a percentage of the gross revenues from the sale of hydrocarbon. We have assumed the royalty rate to be 0.1

4.3.6 Taxation

Tax is also one of expenditure which we have to pay for the government. To calculate tax we use

Tax payable = Taxable income × Tax rate

Taxable income = Revenue – Fiscal allowance

Fiscal allowance = Royalty + OPEX + Capital allowance

CAPITAL ALLOWANCE is not a cash-flow item, but is only calculated to enable the taxable income. Capital allowances are deducted in computing the taxable profits as if they were a real expense of the business. This may lead to increasing a loss, or turn what would have been a profit into a loss.

For simplification we use straight line capital allowance method for calculating the capital allowance from the value of CAPEX divided by 5 for each instant. So we have capital allowance which is 20 % of the initial CAPEX per year for five years.

If the tax payable is negative then we do not have to pay tax for that year.

We use 30 % for tax rate.

4.3.7 Discount rate

We use the discounted rate = 8 % annually which is given from http://gullfaks.ipt.ntnu.no/gullfakslandsbyen/2009/

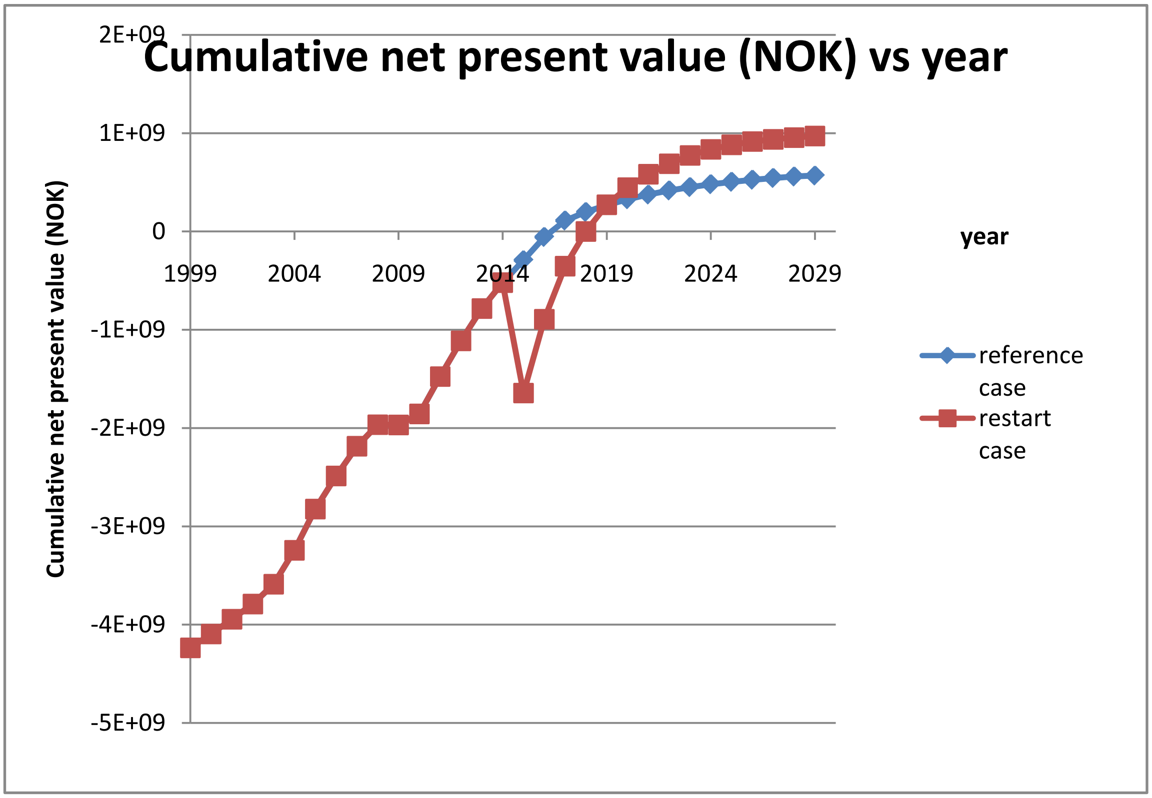
4.3.8 Currency

we use the exchange rate of 6 NOK = 1 USD constantly throughout the calculation.

4.4 *Results from simulation of the base-case*

The simulation is run until 1st January 2030. The starting point for the simulation is 1999. In order to make the calculations simpler we are evaluating the data from 1999 to 2029.

After we calculate using spreadsheet we get the result from this graph above.



Figur B Cumulative net present value (cum NPV) for the Base-case

For the Reference case, the net present value for NPV = 569 MNOK with a payback period around 2016. While in the Extended case we get NPV = 972 MNOK with the payback period around 2018. After assuming that the oil-price follows the Base-case, the cumulative cash-flows are equal in these two cases in 2019. The cumulative NPV turns positive also for the Extended case, and then the revenues of Extended case passes the Reference case after 2019. Thus the Extended case is the best option among the two projects.

Although we can show that the Extended case has a higher revenue than the Reference case, we can not completely rely this model because it based on many assumptions which can vary year by year such as the oil price, CAPEX, OPEX, etc.

4.5 *Results from simulation of the High –and Low case*

We now then change the oil prices in order to see the NPV result. We consider high case which increase 40 % of oil prices and decrease 20 %. We got the value in following table.

Oil price (US$/bbl)	*Base*	*High +40%*	*Low -20%*
2010	65	91	52
2011	68	95.2	54.4
2012	70	98	56
2013	70	98	56
2014	75	105	60
2015-2030	75	105	60

Then we get the NPV in the following figure.

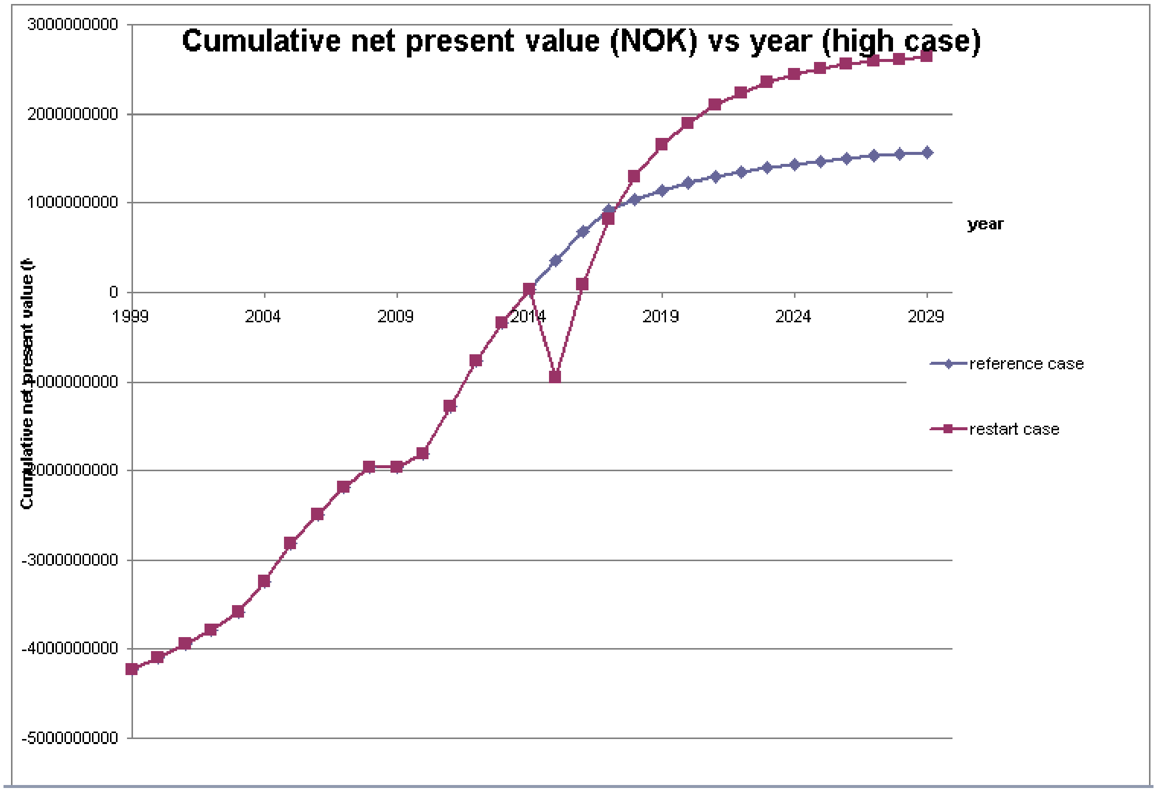


Figure 4-1- Cumulative net present value (cum NPV) for the High-case

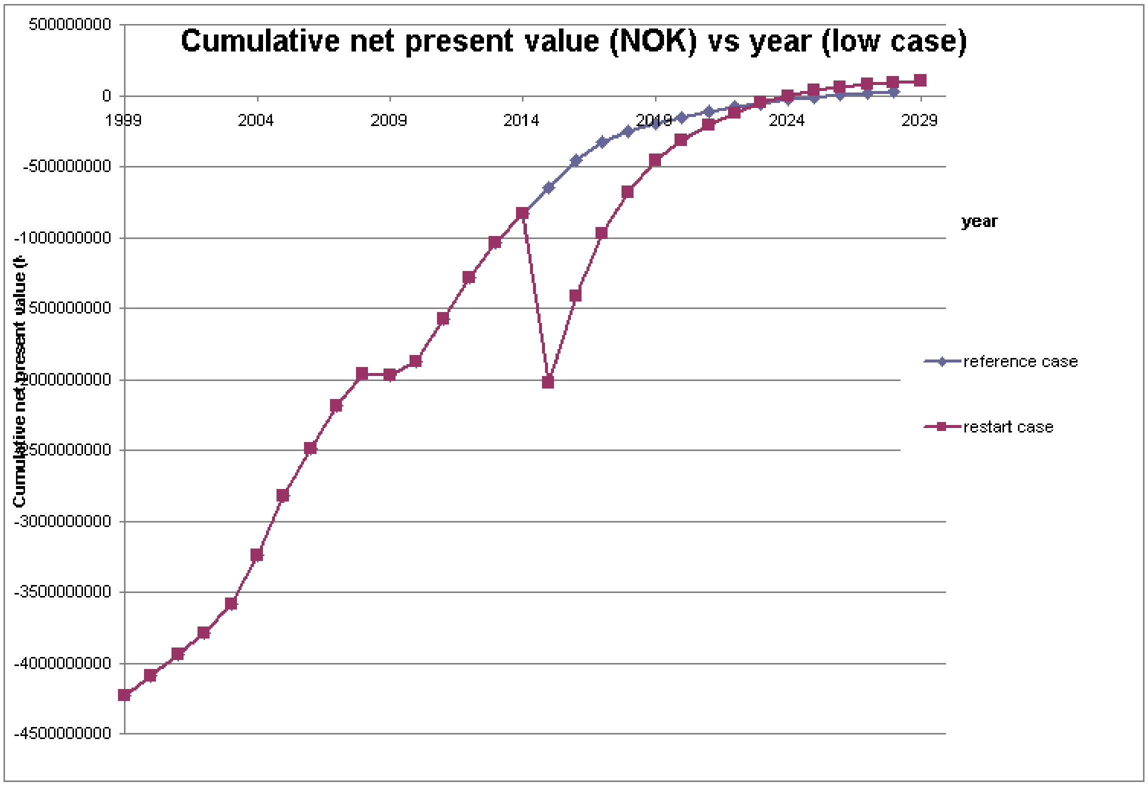


Figure 4-2 Cumulative net present value (cum NPV) for the Low-case

We can see that although we change oil price we still can conclude that Extended case provide higher NPV than Reference case.

For the High case NPV of the Extended case is **2673 MNOK** which is 3 times higher than the base case.

For the Low case the revenue of the Extended case is quite low which is about 100 MNOK so if we compare with the money we invest it looks like we get so low profit, and perhaps it is not reasonable to do this project.

5 Conclusion

We can see from the simulation that the history matching of the gas rate is quite good, while for the oil rate, there is a little error which can be acceptable. However, for the water rate, there are quite significant errors where the simulation model has constantly predicted higher values than the real data. When we look at each well, in order to specify the problems of our system, we find that the error of the oil in the field data come from smaller errors for each well. However, for the water we cannot find the specific reason due to limited information. It may be because the model might be inaccurate or because of uncertainties such as aquifer.

The 6 additional wells effects the existing wells in various manners. Some of them are affected and contribute to accelerate the production of the total field while some of the existing wells are not affected at all. The restart case gives 4 MSm3 more produced oil in addition to the oil produced in the Reference case.

After we considered both cases by using Net Present Value (NPV) to compare each case, we found that the payback periods for the Restart case is longer than the Reference case. However the Restart case provides a higher NPV than the Reference case.

6 Recommendation

We can use the simulation model for oil and gas from ECLIPSE, while for water we might have to make some corrections before using them.

The maximum field gas rate (5.5 MSm3/day) and the field water rate (1,400 Sm3/day) should be considered in relation to the capacity of the surface facilities to process gas and water.

The position of the new wells should be chosen with sensitivity, so that the new ones won't reduce the drainage area to the existing wells.

Since the NPV for the Restart case is higher than in the Reference case, we can recommend Statoil to add six new wells (Restart case). However the Reference case may be a good plan for the company which require the money to go back quickly to run other projects. Although we can conclude from our calculation that the Restart case is a better solution, we must remember that our calculations are based on many assumptions. We should therefore adjust our assumptions to be close to a real value so that we will get a more realistic result.

7 Appendix

Part A.

Note

WO(W/G)PR = well oil(water/gas) production rate
WO(W/G)PT = well oil(water/gas) production total
WCT = water cut (water rate/(oil rate+water rate)
WGOR = gas oil ratio
WBHP = well bottom hole pressure
WGIR = well gas injection rate
WGIT = well gas injection total

Red: *GFS_Restart*
Blue: *Reference_Case*
Green: *History_Case*

Production Well Name: F-1, F-2_ML, F-4AT3H, G-1H, G-2T3H, G-2_ML, G-3T2H, G-4H, W1, W2W3, W4W5, W6W7

Injection Well Name: E-1Y3H, E-2BH, E-3H, GI-2, GI-4

Well Name:**F-1**

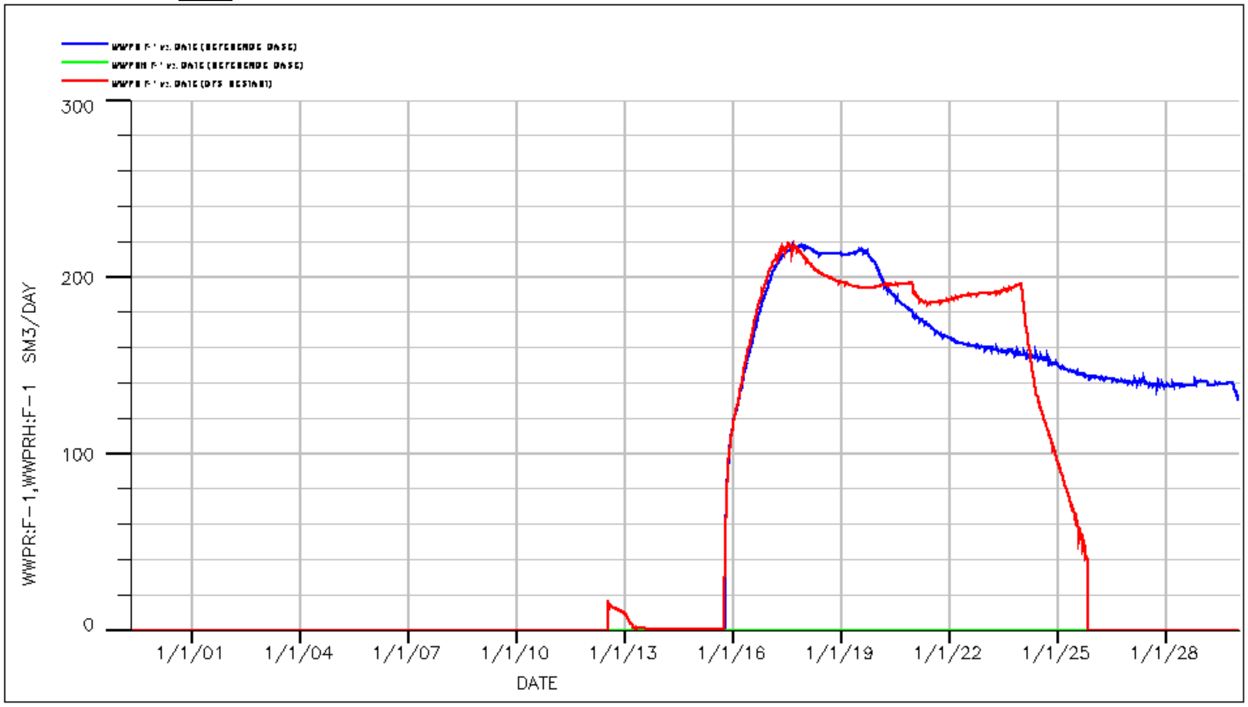


Figure 7-1: "F-1", WWPR

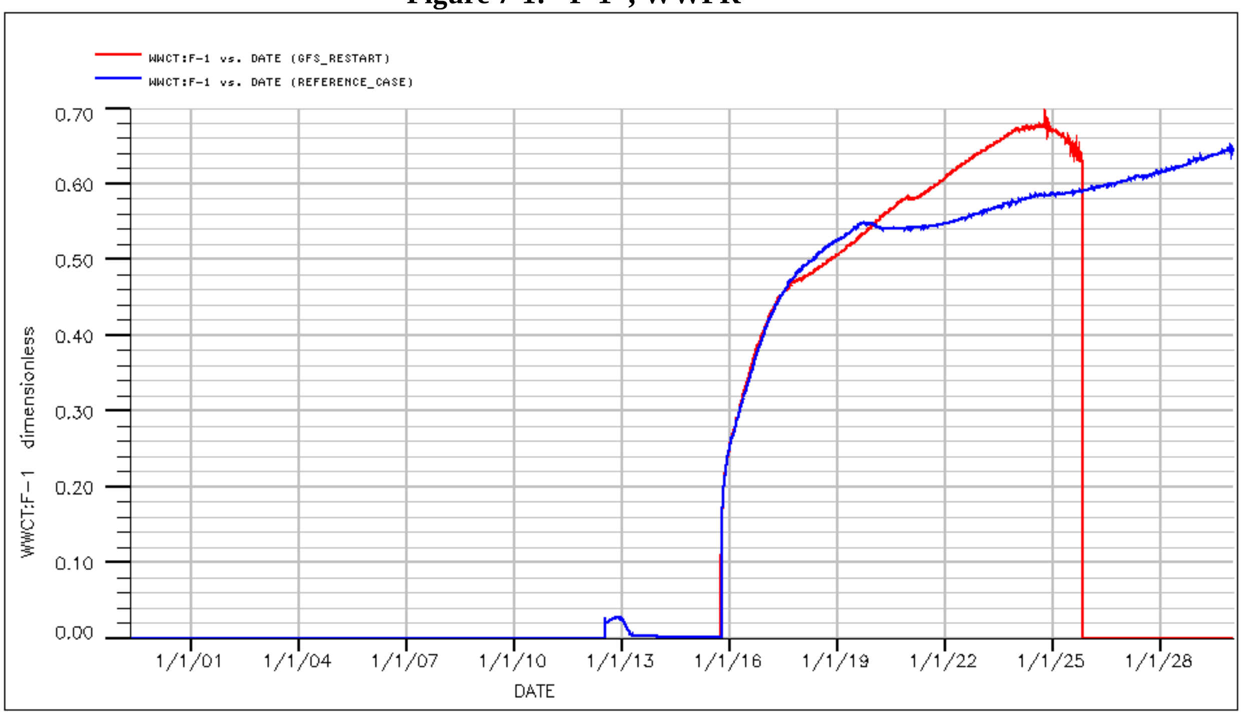


Figure 7-2: "F-1", WWCT

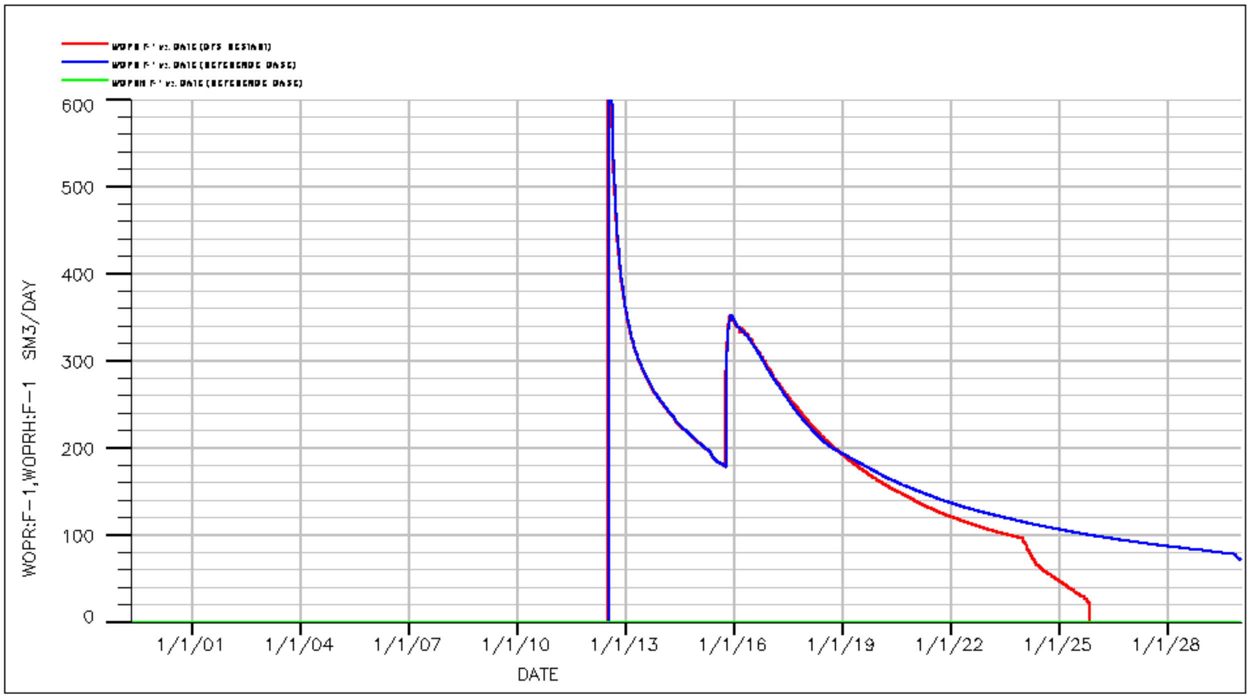


Figure 7-3: "F-1", WOPR

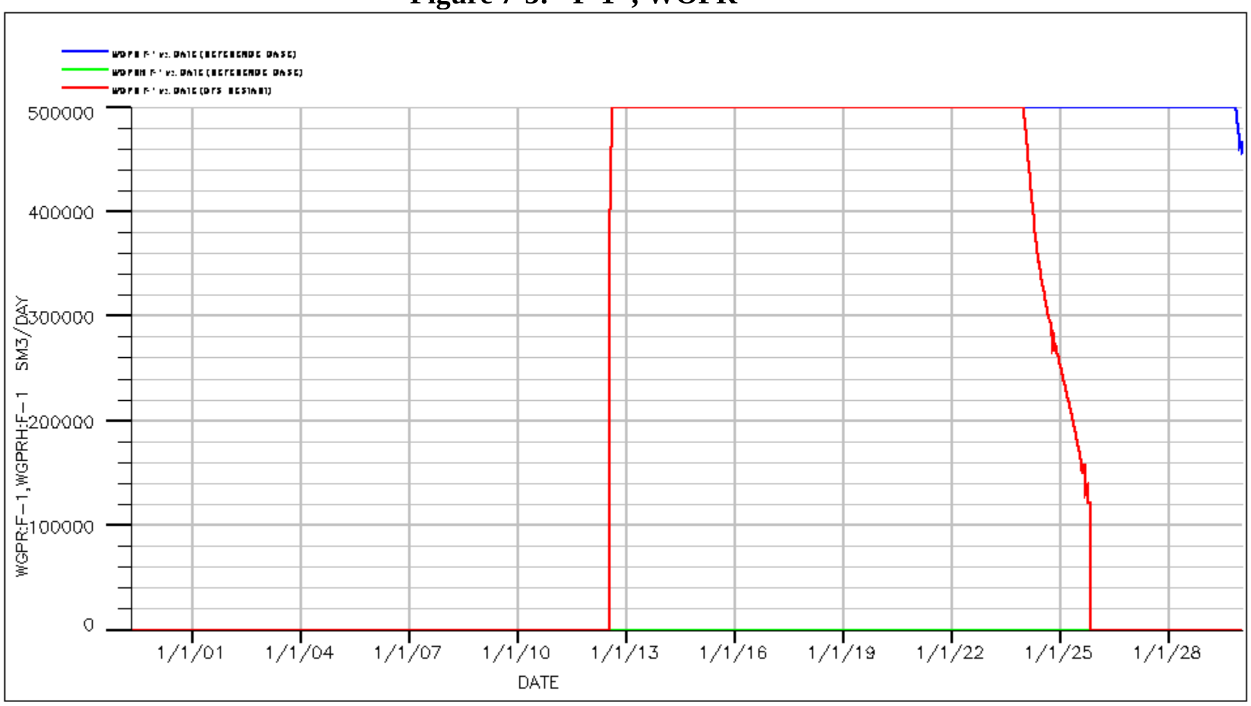


Figure 7-4: "F-1", WGPR

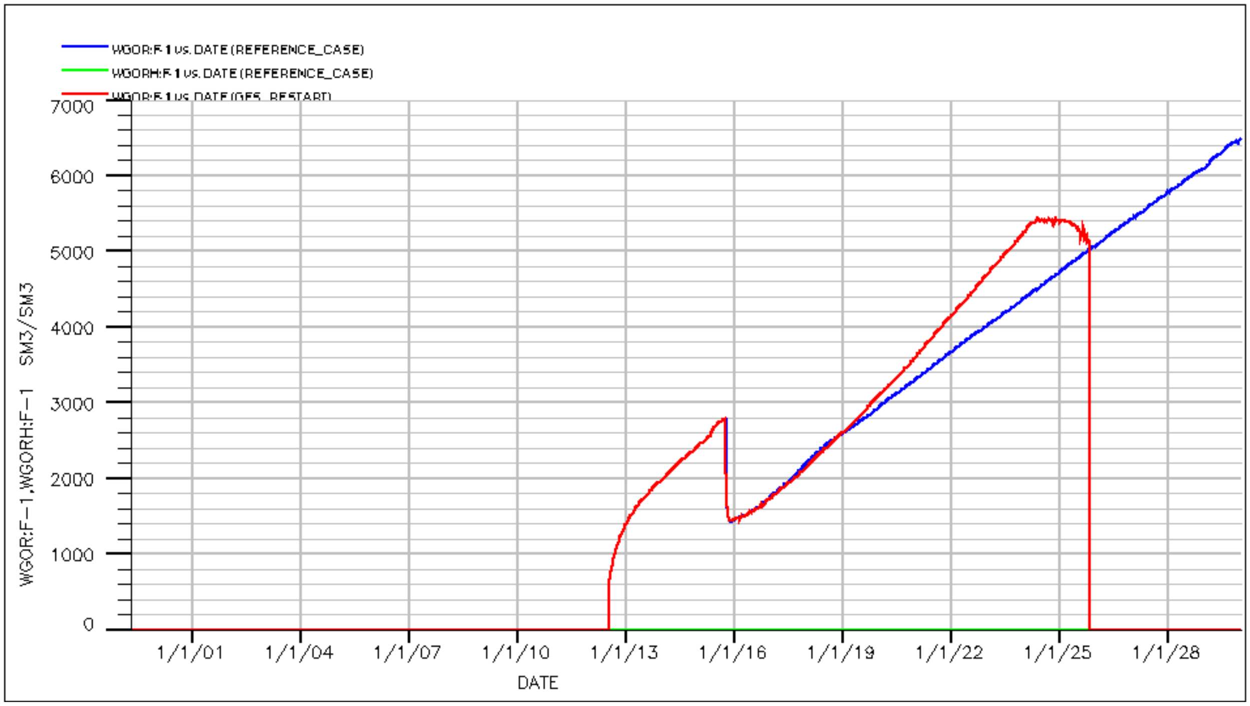


Figure 7-5: "F-1", WGOR

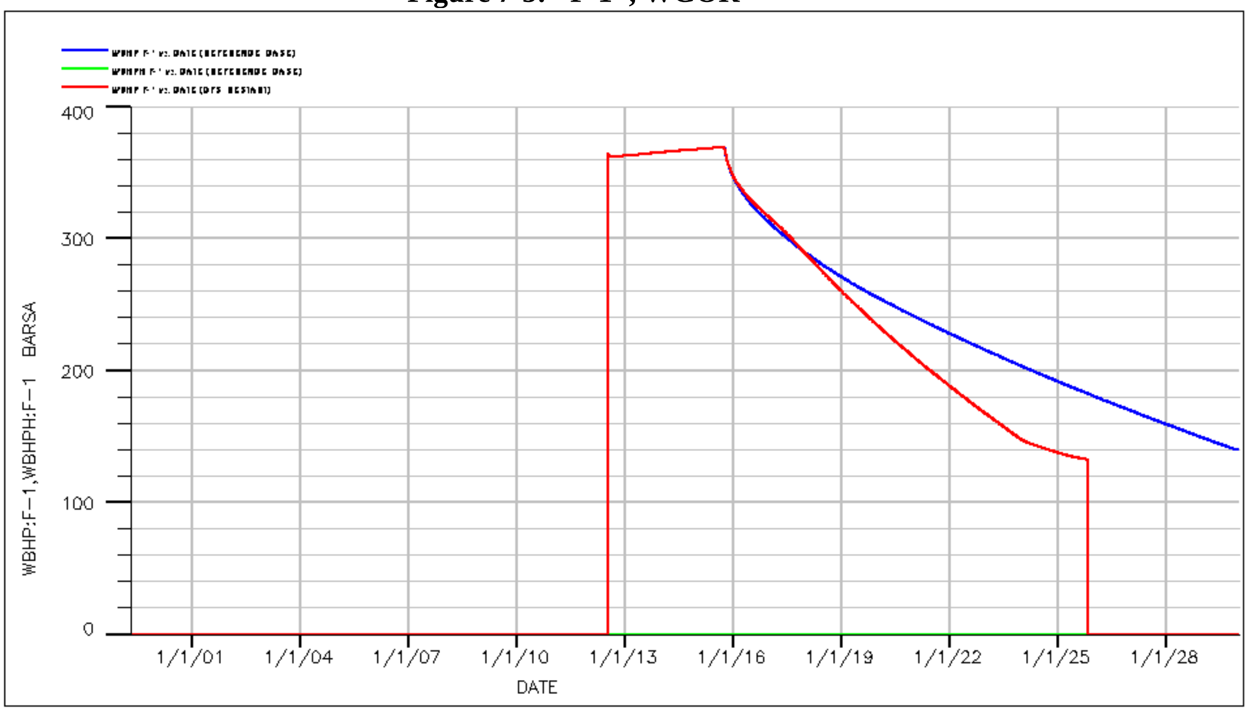


Figure 7-6: "F-1", WBHP

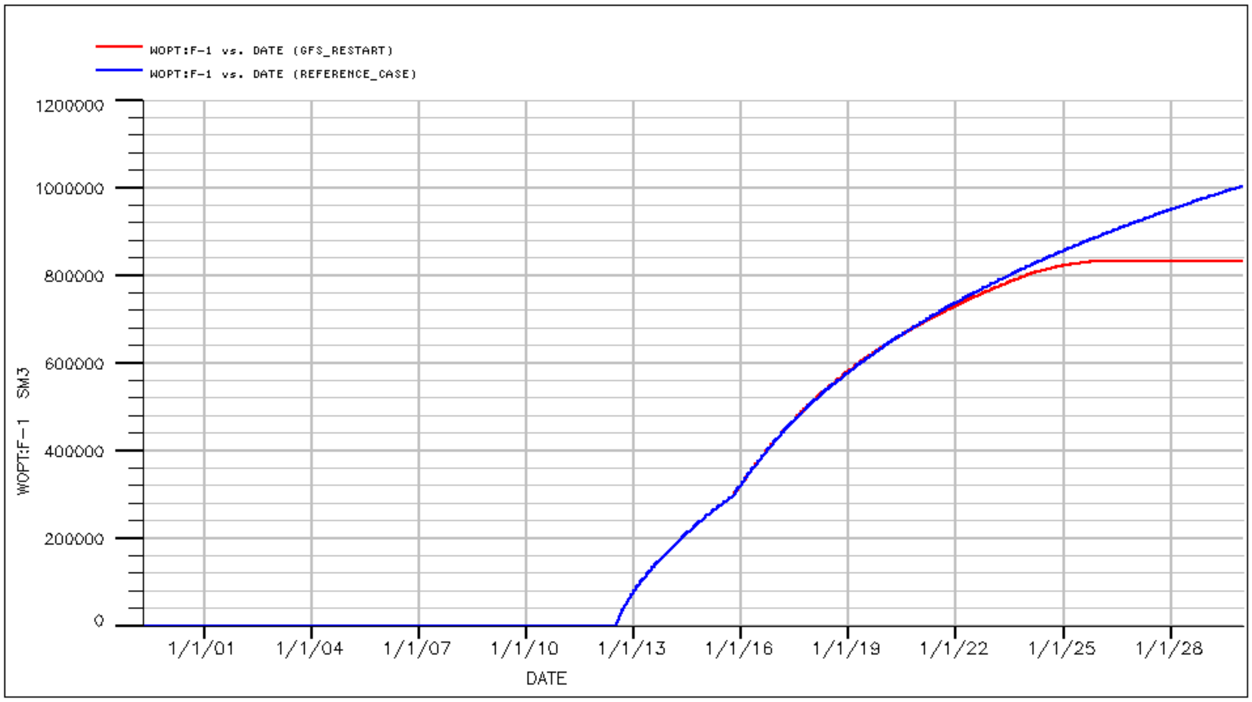


Figure 7-7: "F-1", WOPT

Well Name: **F-2_ML**

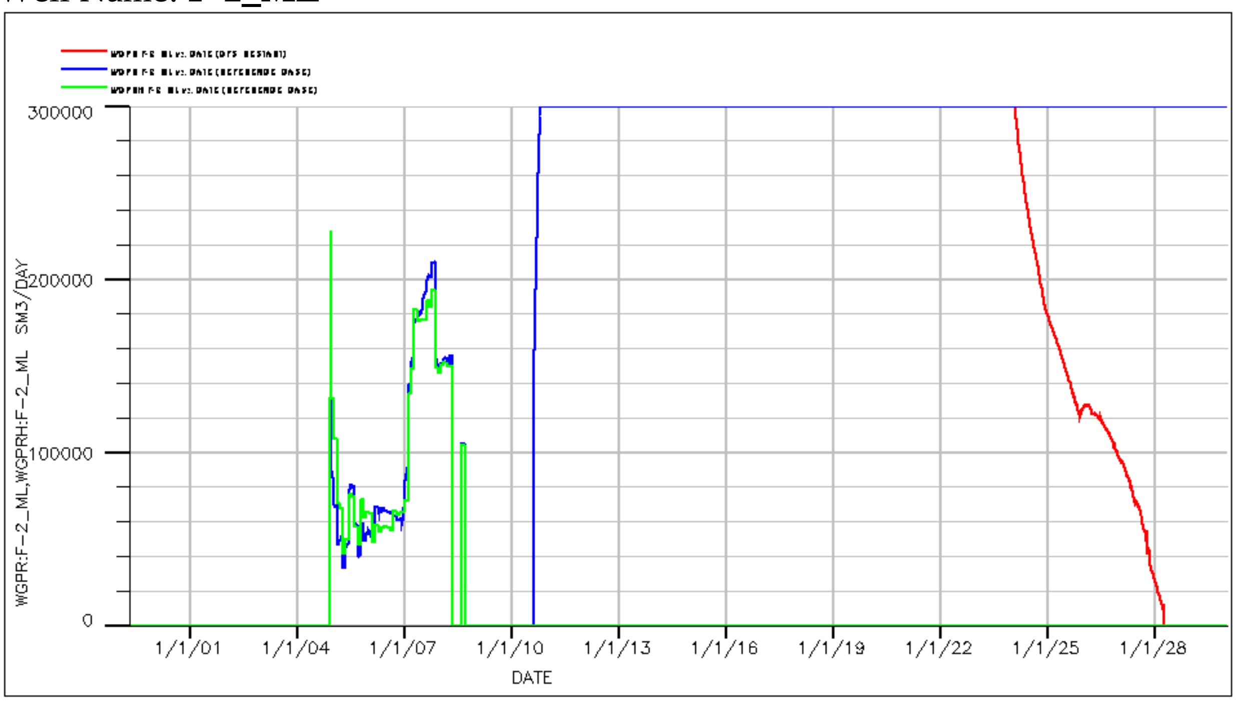


Figure 7-8:"F-2_ML", WGPR

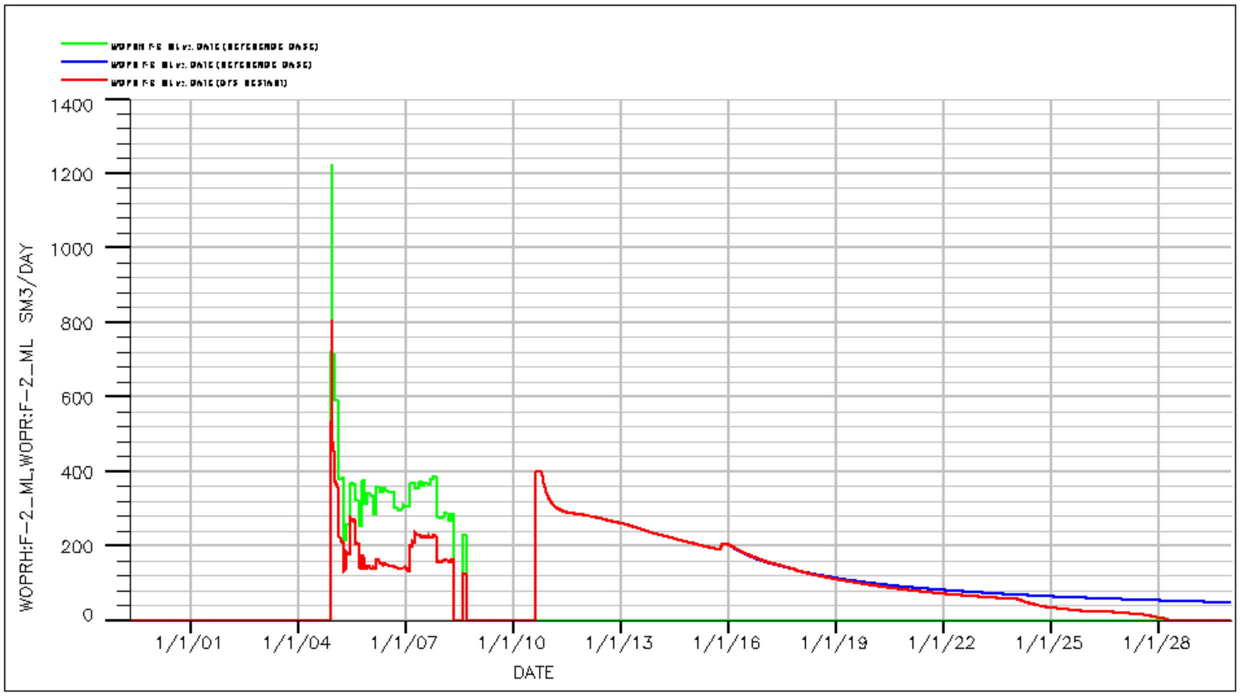


Figure 7-9: "F-2_ML", WOPR

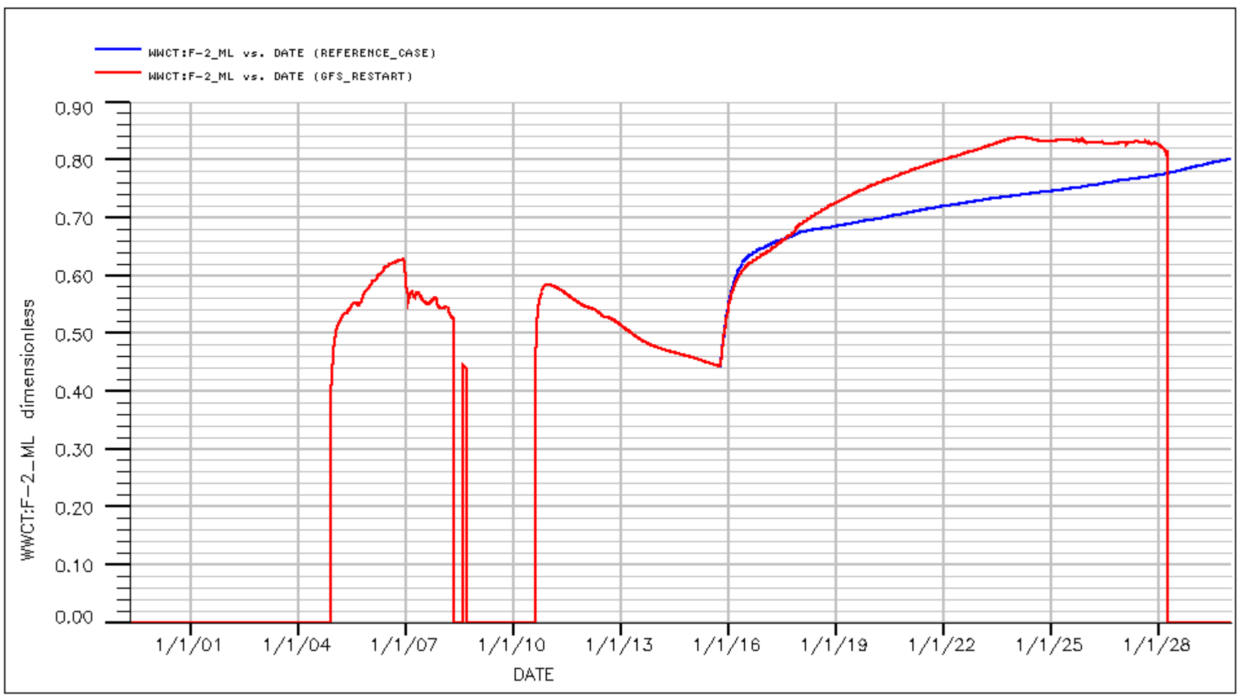


Figure 7-10: "F-2_ML", WWCT

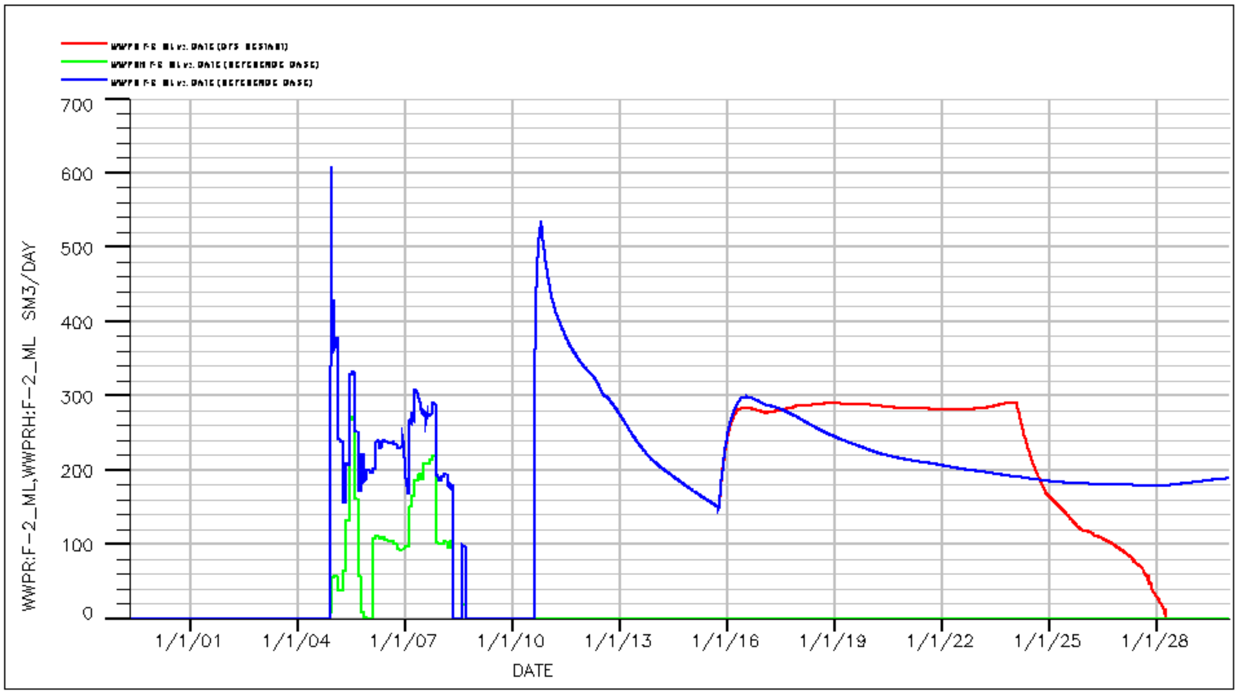


Figure 7-11: "F-2_ML", WWPR

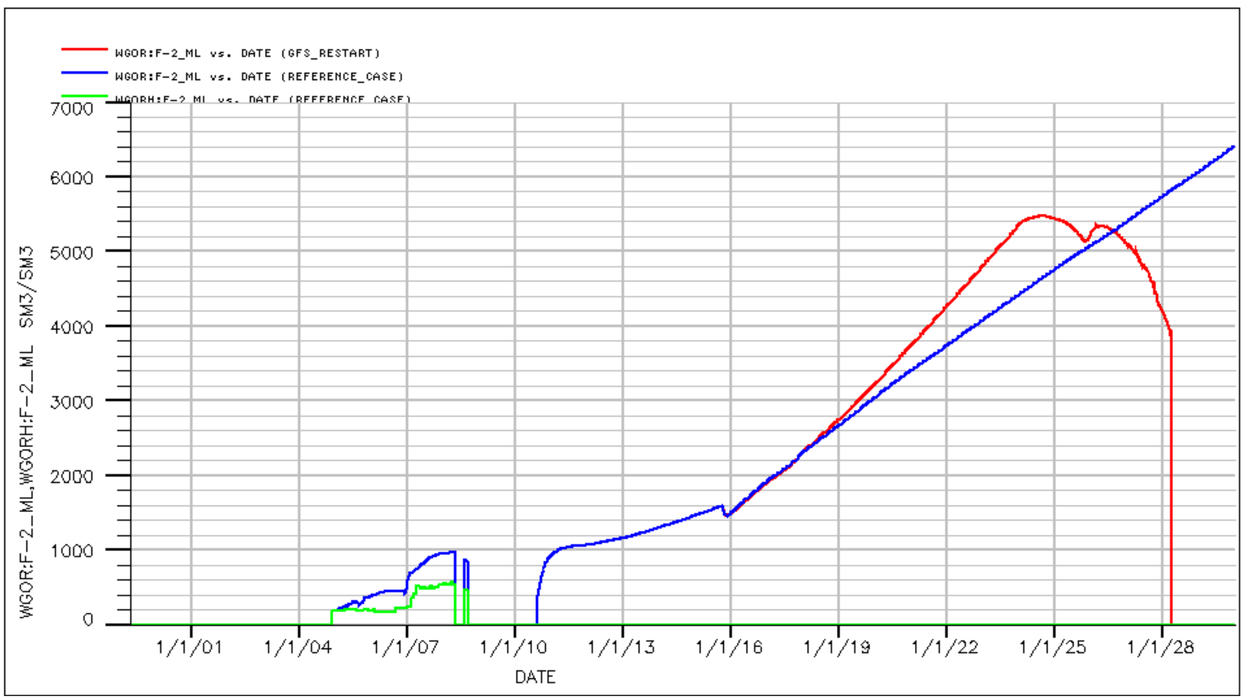


Figure 7-12: "F-2_ML", WGOR

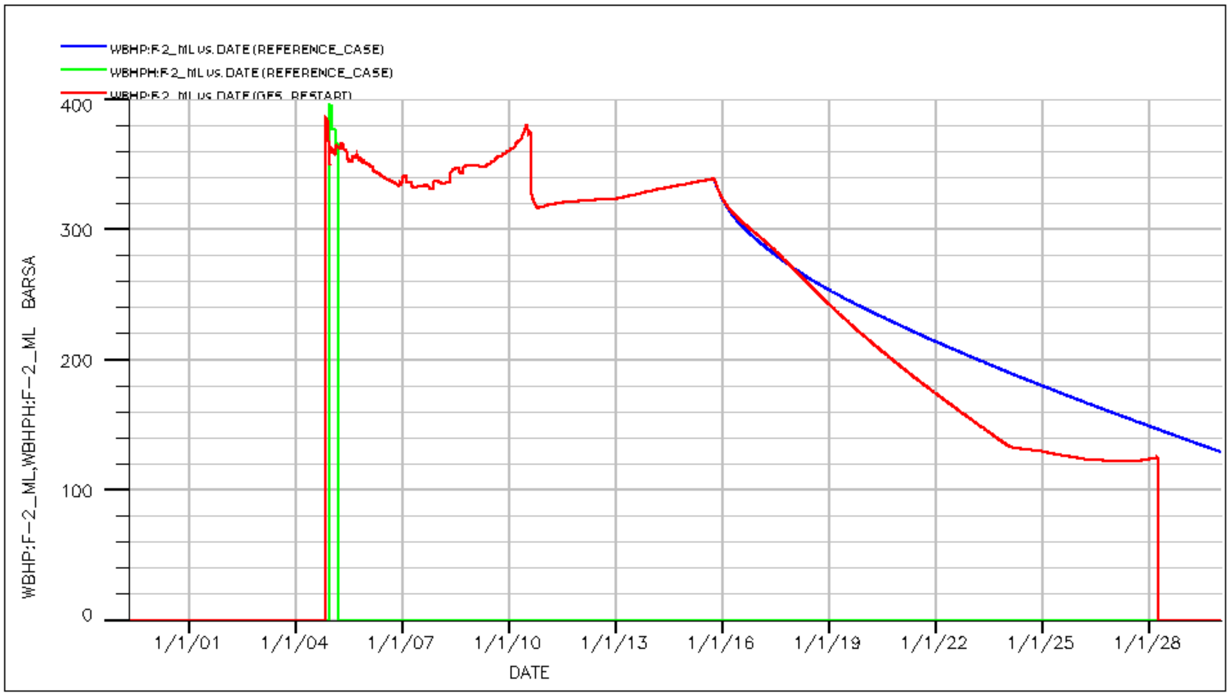


Figure 7-13: "F-2_ML", WBHP

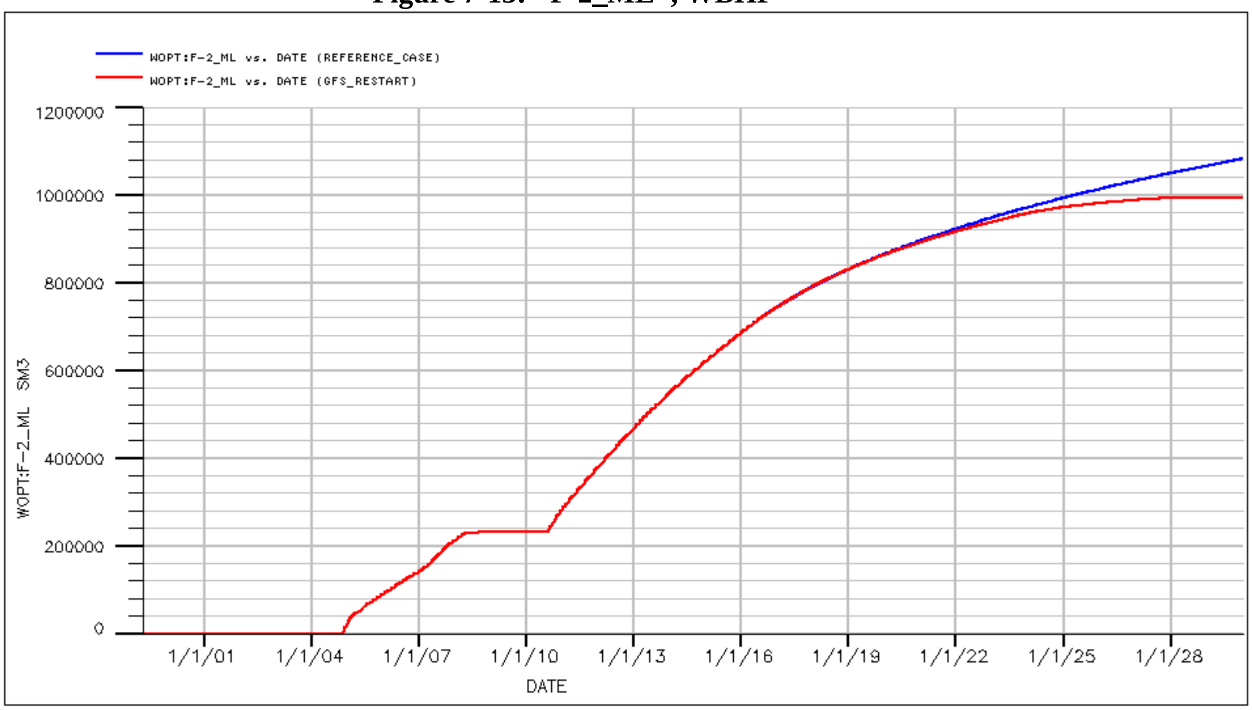


Figure 7-14: "F-2_ML", WOPT

Well Name: **F-4AT3H**

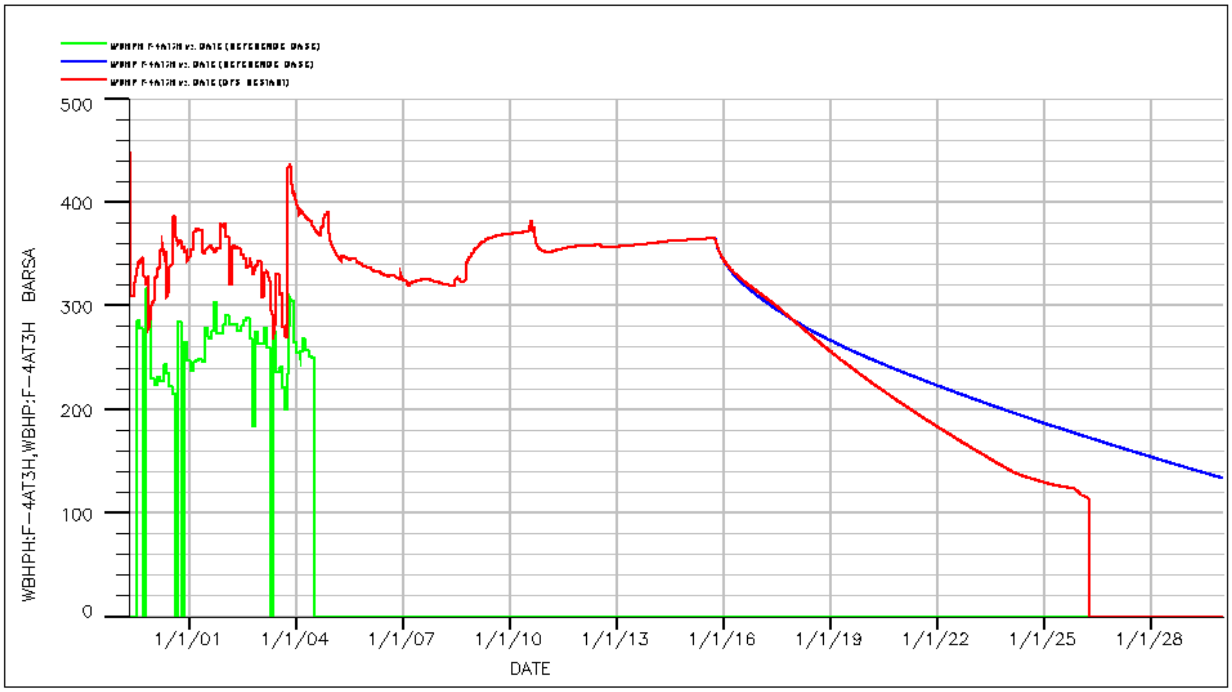


Figure 7-15: "F-4AT3H", WBHP

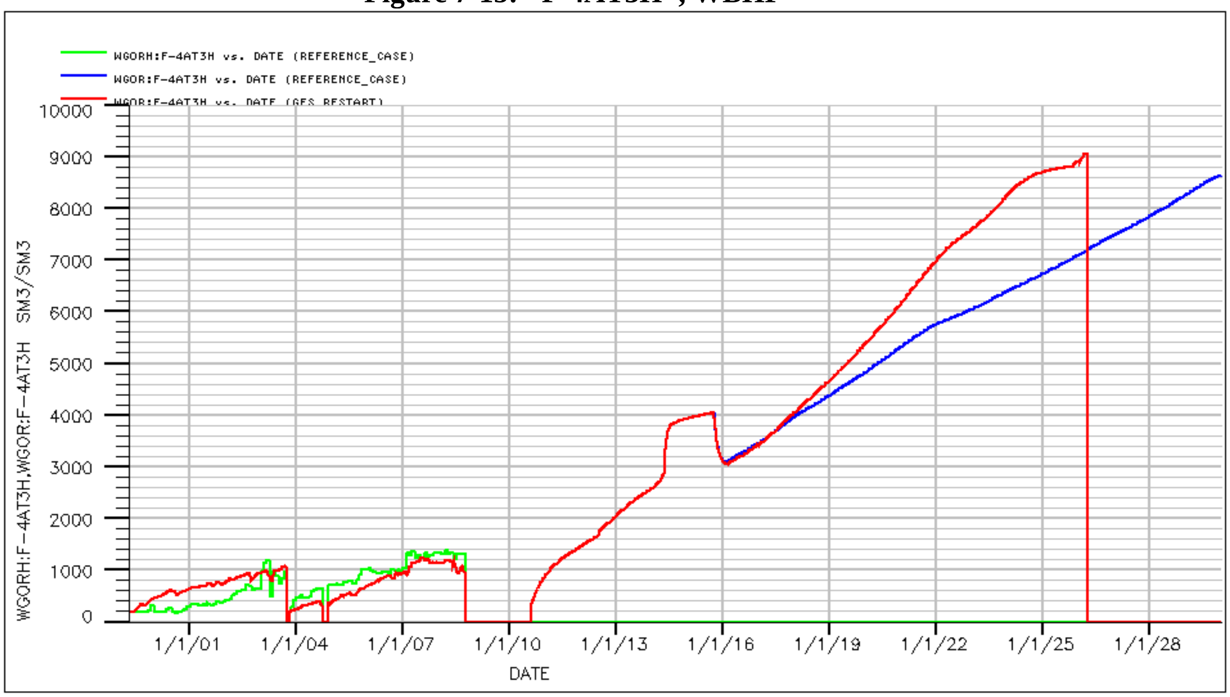


Figure 7-16: "F-4AT3H", WGOR

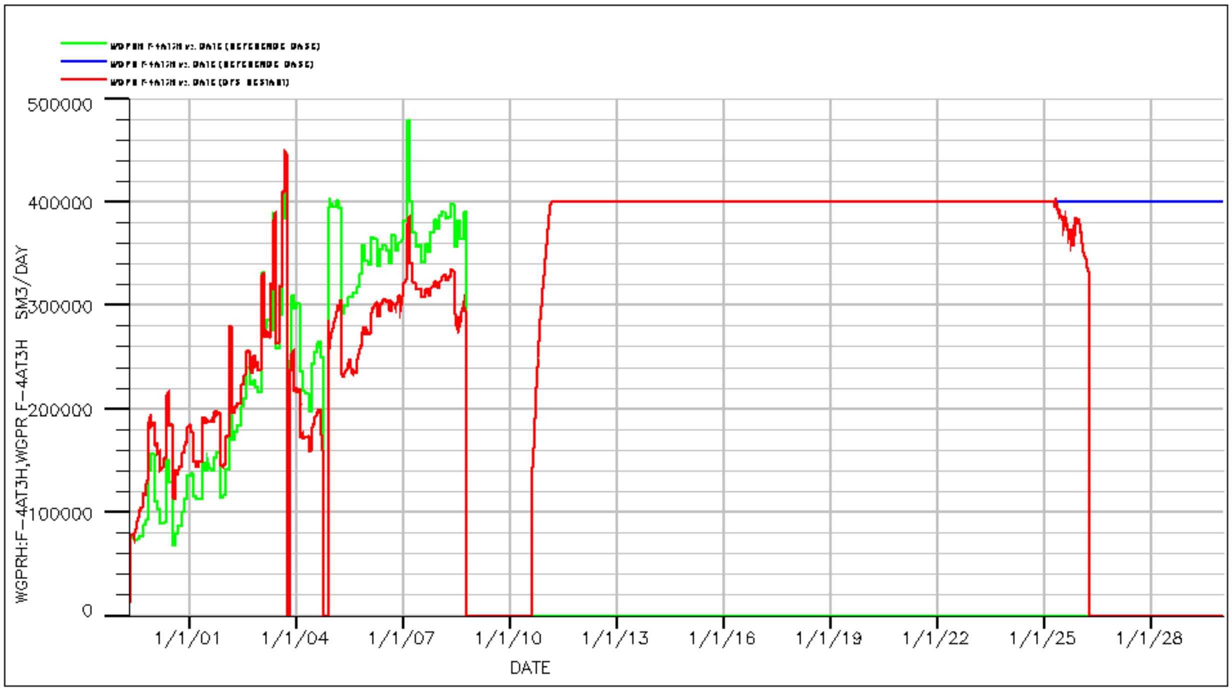


Figure 7-17: "F-4AT3H", WGPR

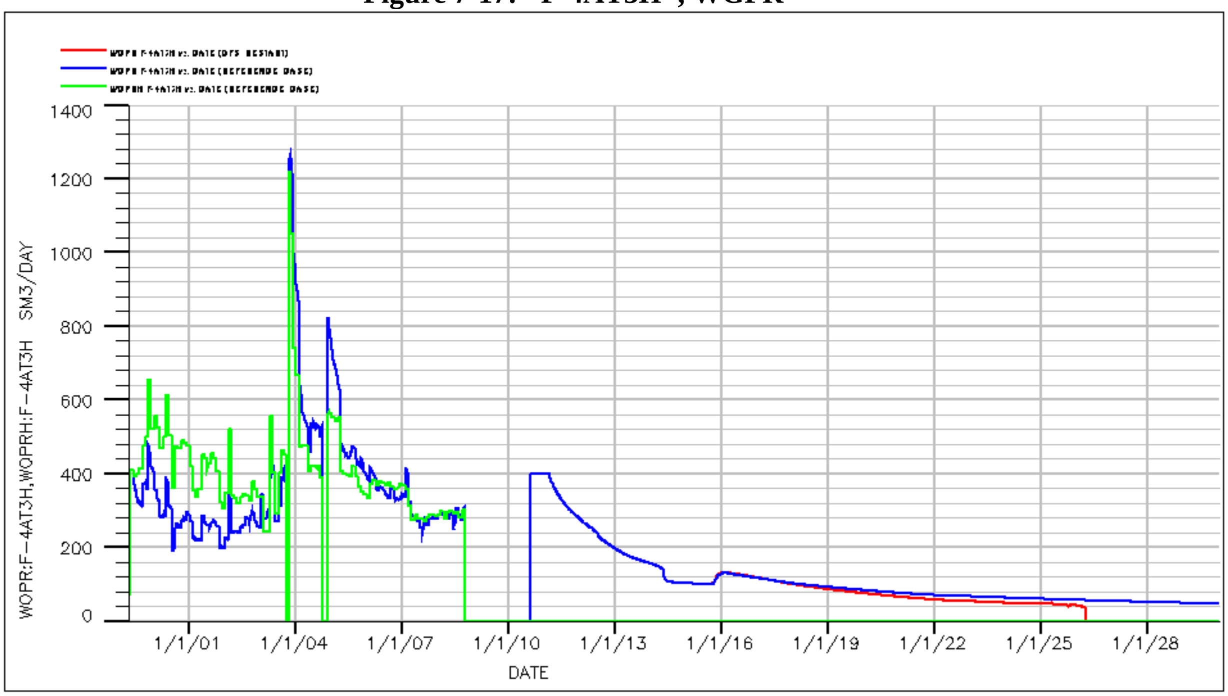


Figure 7-18: "F-4AT3H", WOPR

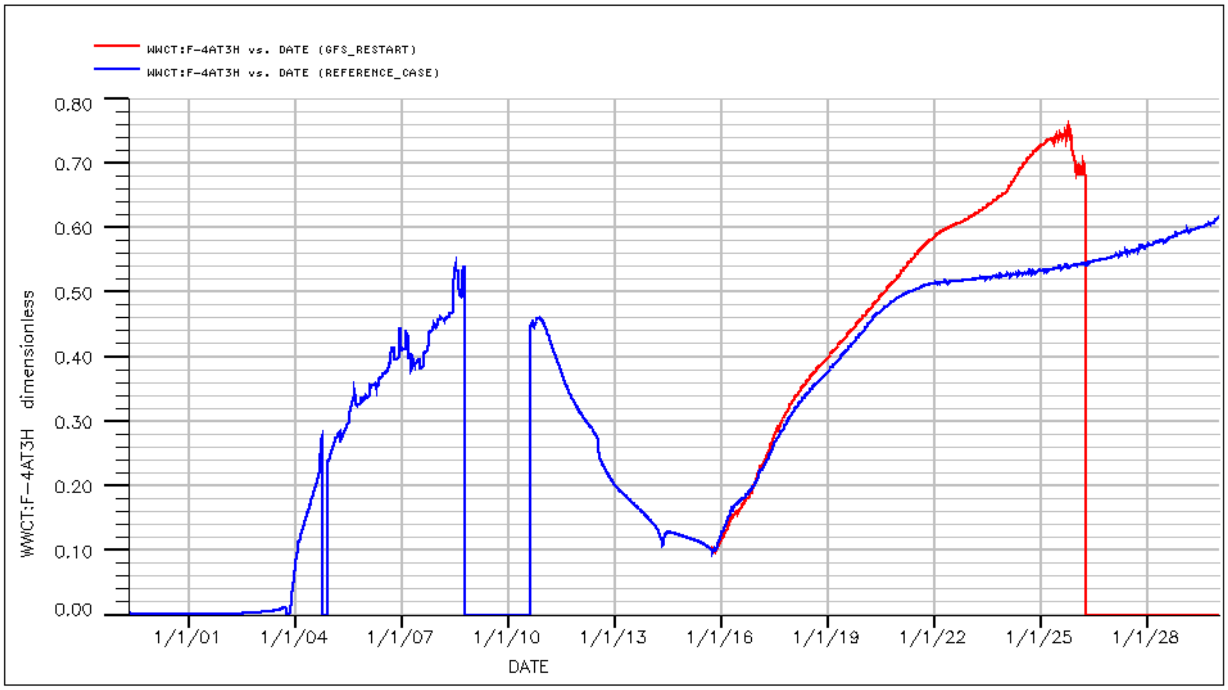


Figure 7-19: "F-4AT3H", WWCT

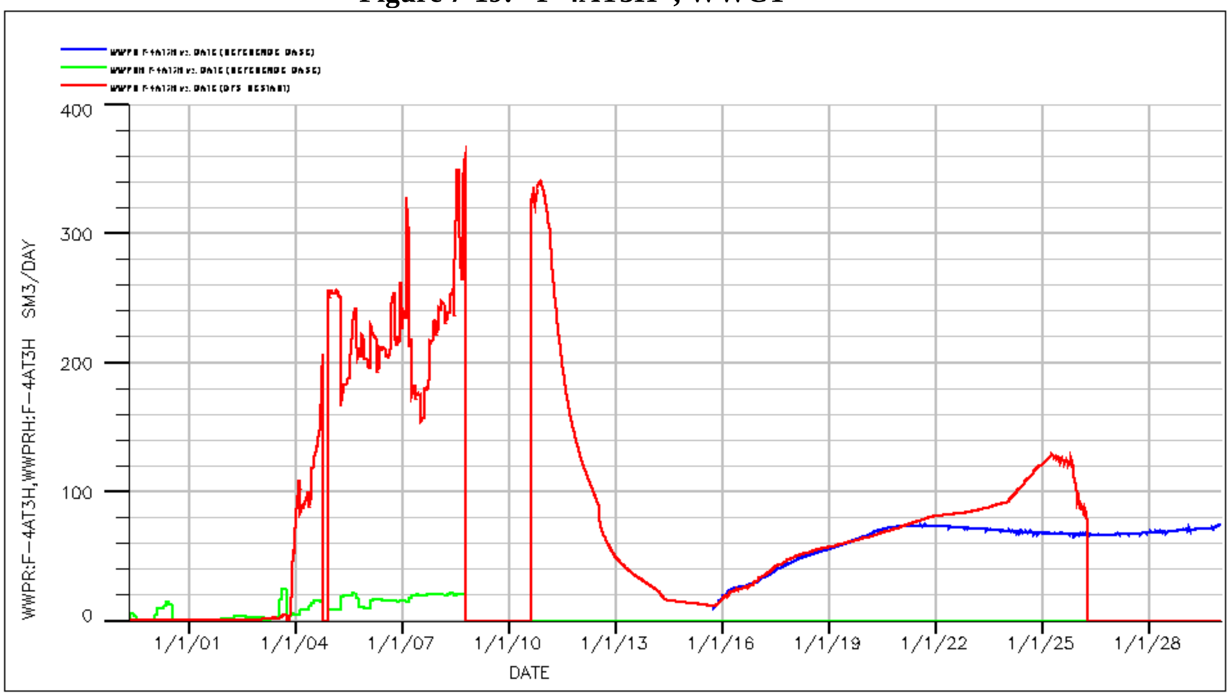


Figure 7-20: "F-4AT3H", WWPR

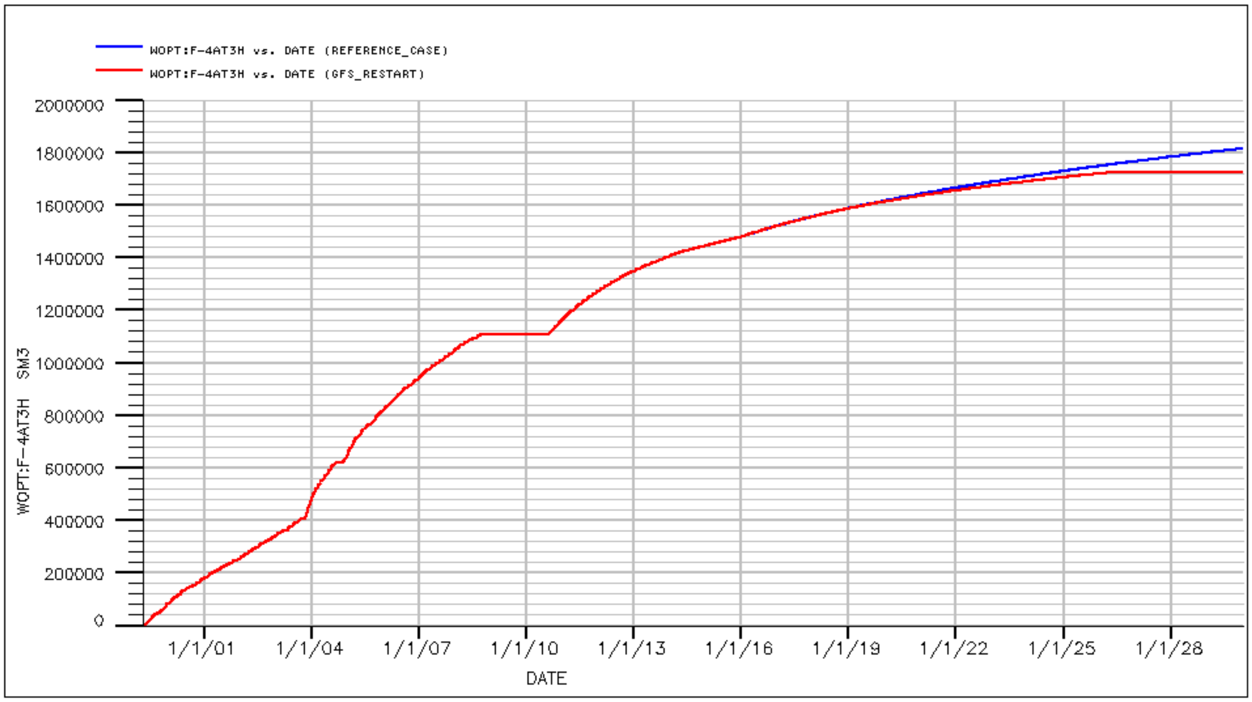


Figure 7-21: "F-4AT3H", WWPR

Well Name: **G-1H**

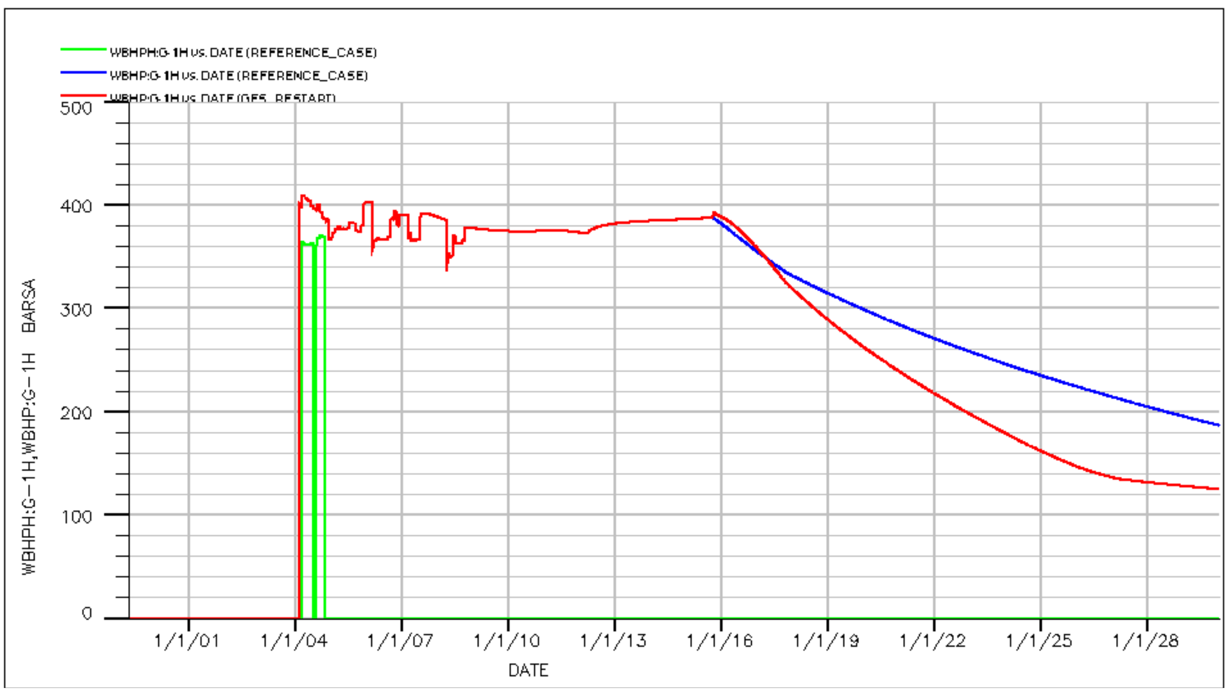


Figure 7-22: "G-1H", WBHP

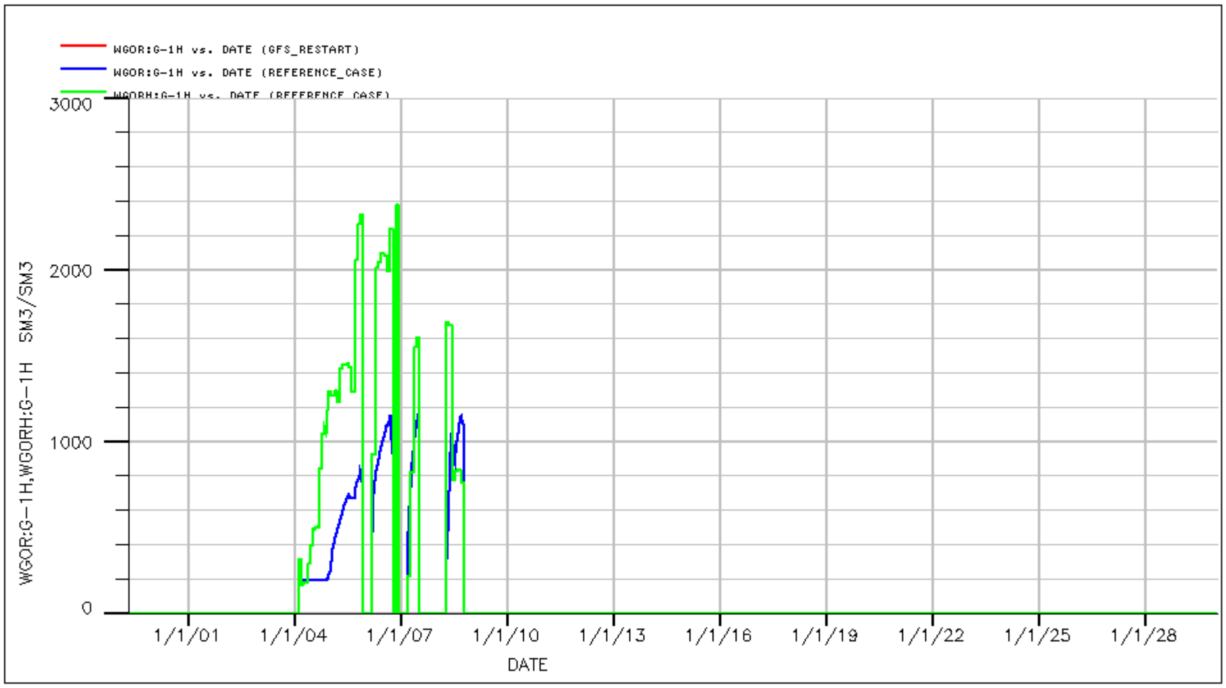


Figure 7-23: "G-1H", WGOR

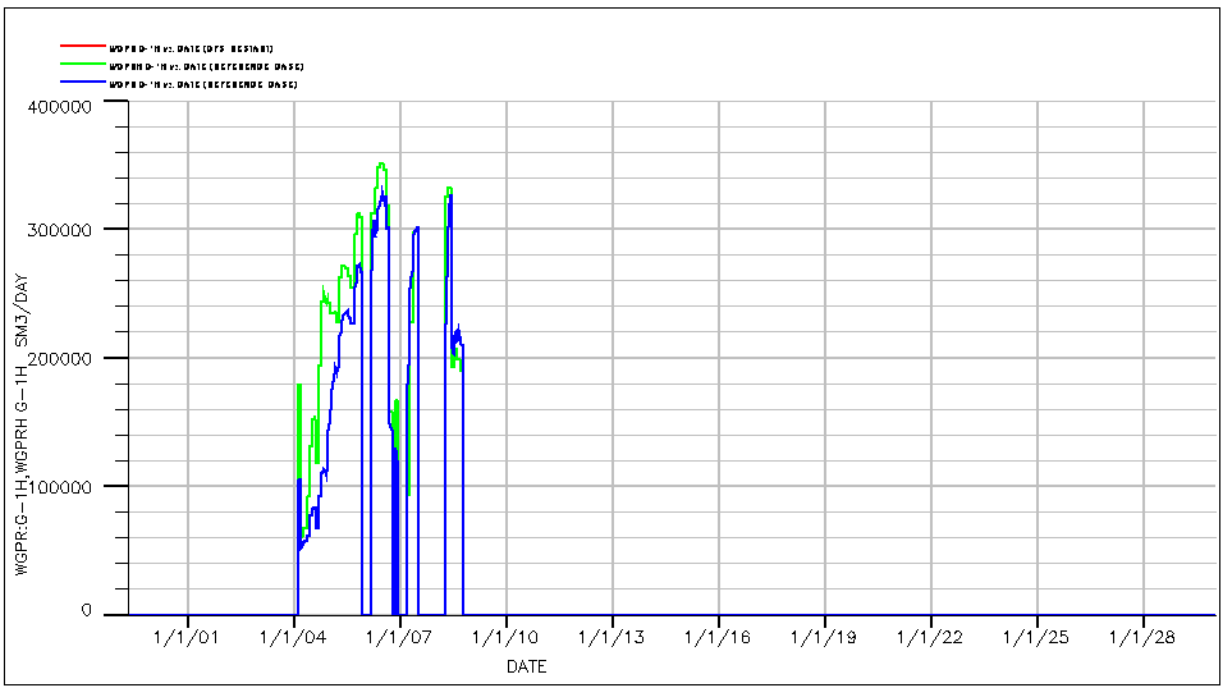


Figure 7-24: "G-1H", WGPR

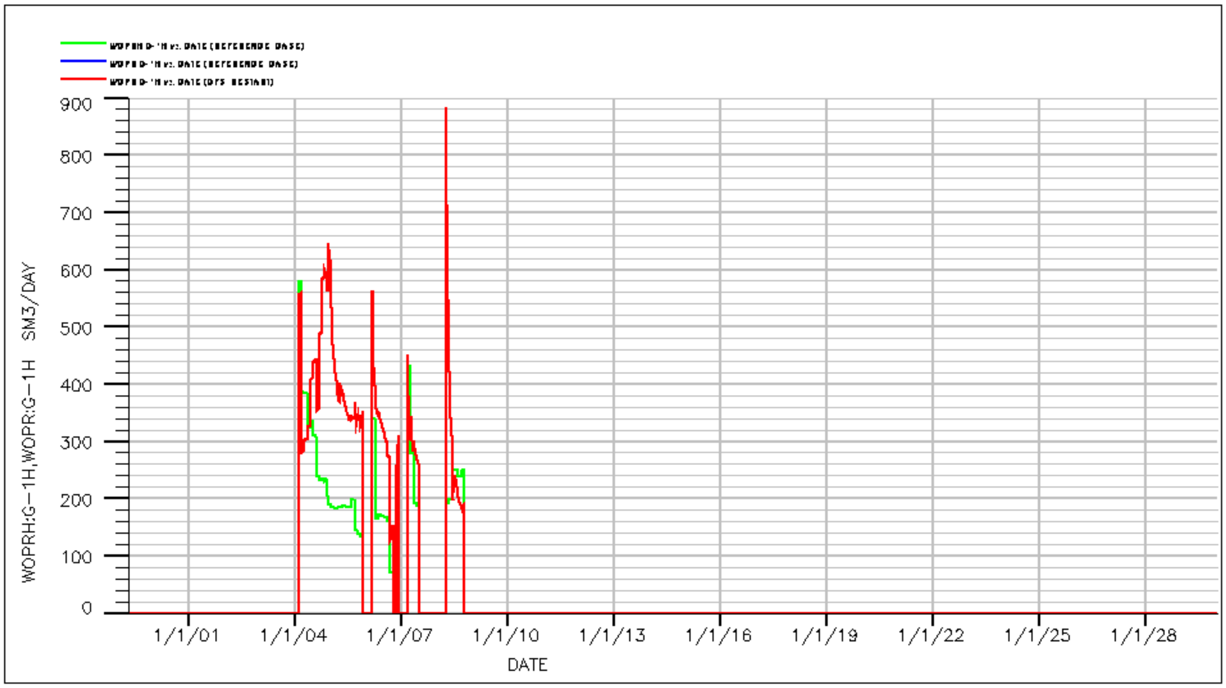


Figure 7-25: "G-1H", WOPR

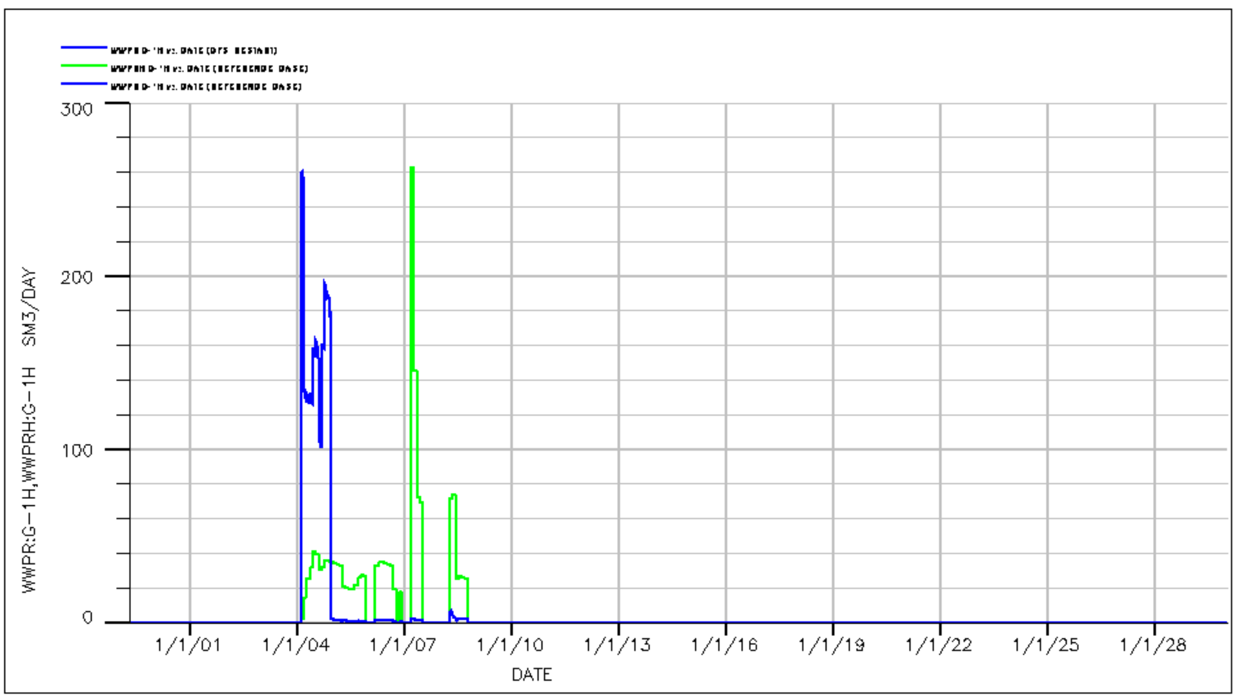


Figure 7-26: "G-1H", WWPR

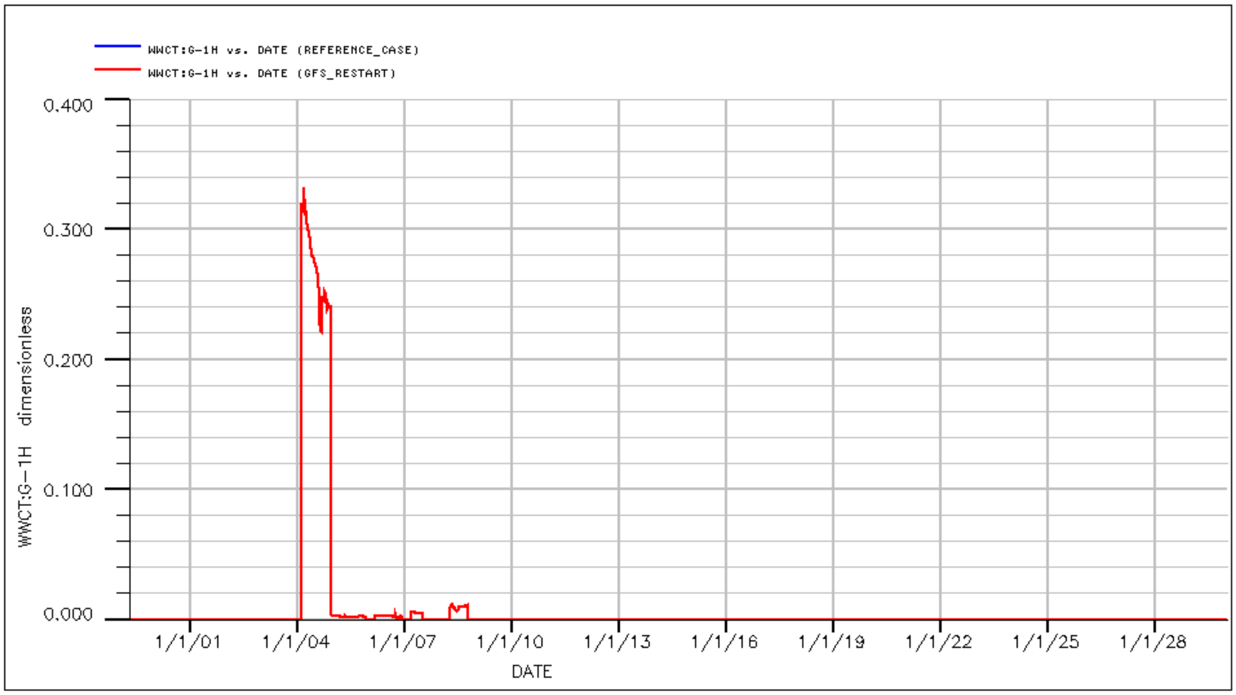


Figure 7-27: "G-1H",WWCT

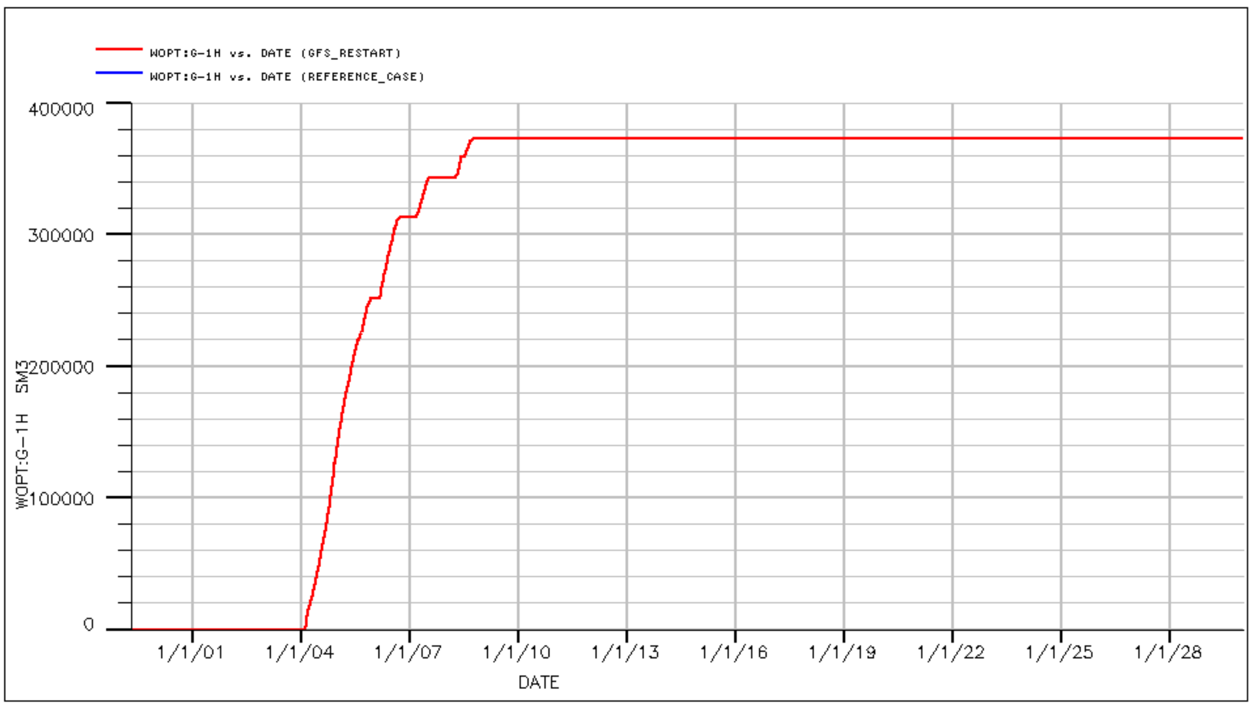


Figure 7-28: "G-1H", WOPT

Well name: **G-2T3H**

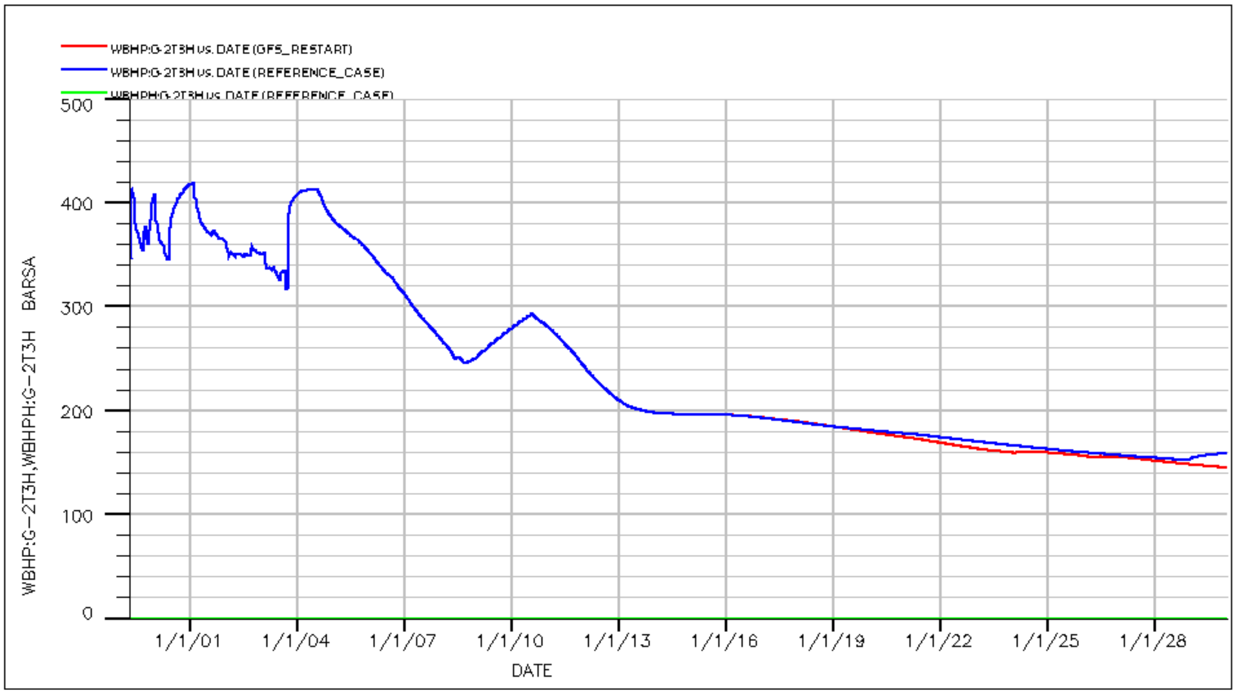


Figure 7-29: "G-2T3H", WBHP

Figure 7-30: "G-2T3H", WGOR

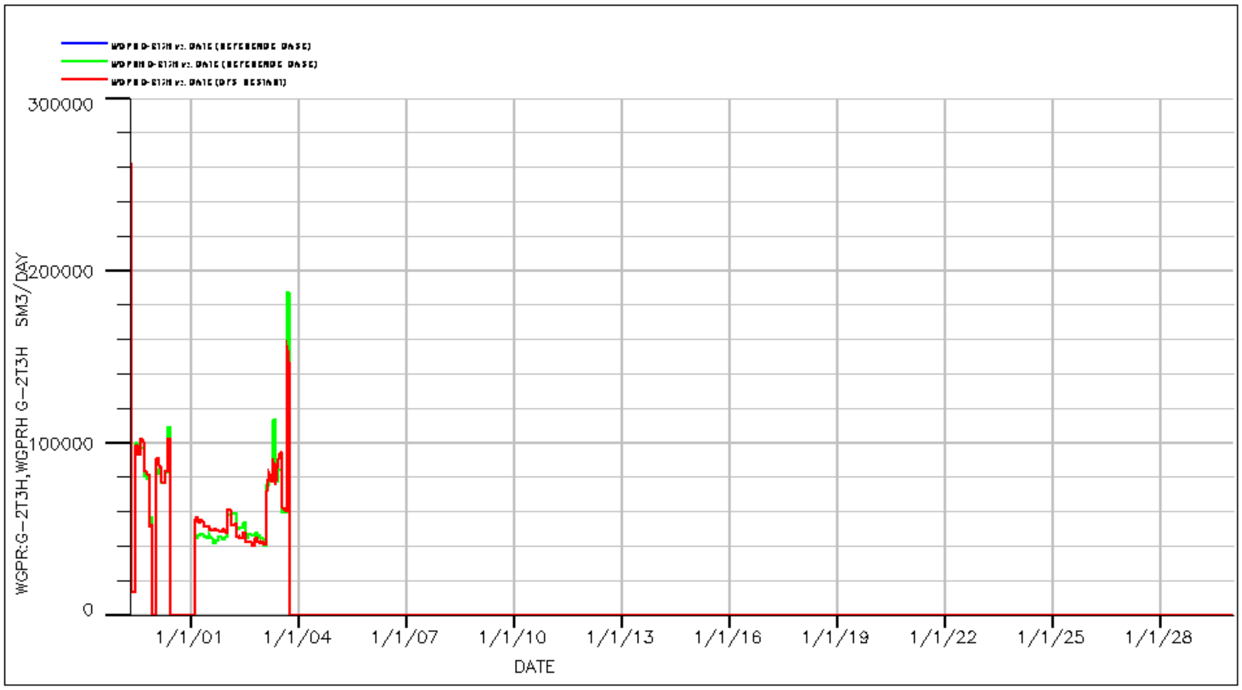


Figure 7-31: "G-2T3H", WGPR

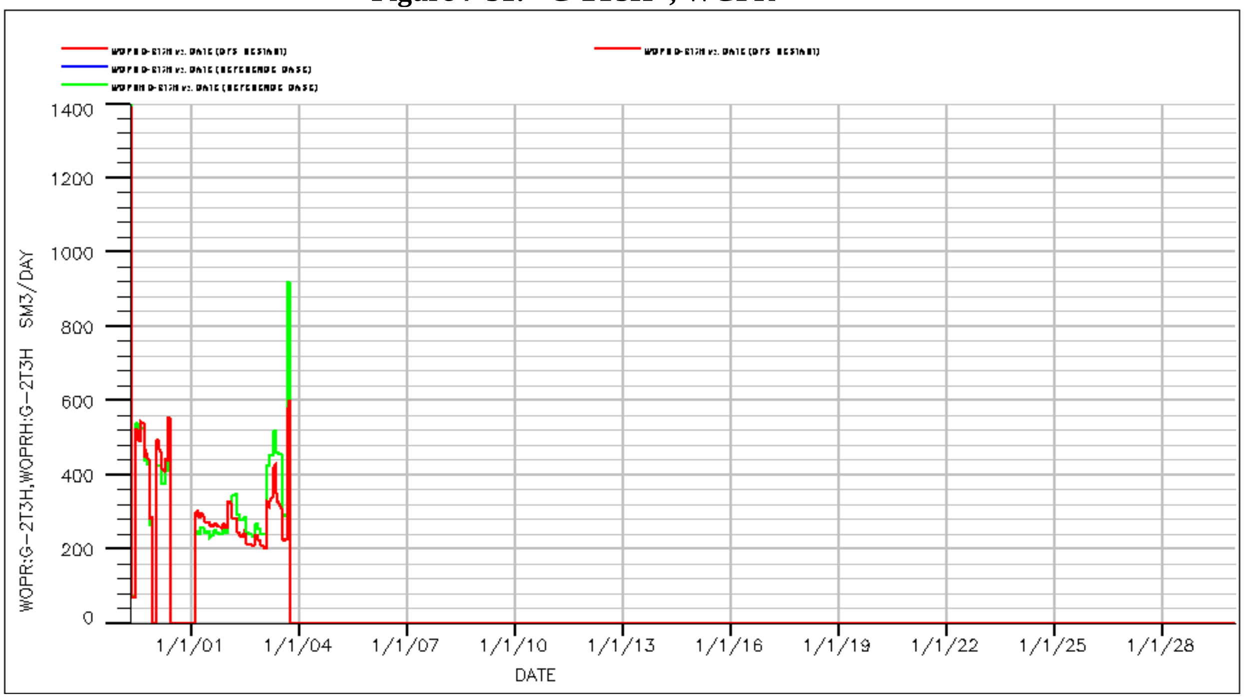


Figure 7-32: "G-2T3H", WOPR

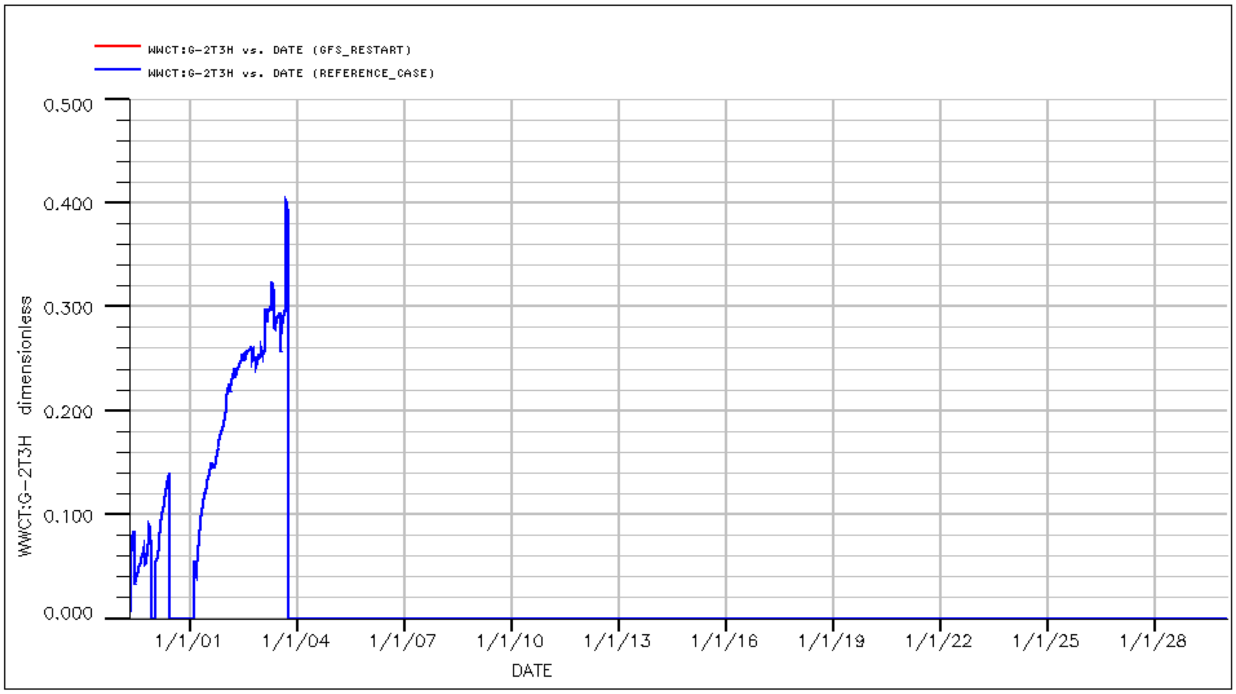


Figure 7-33: "G-2T3H", WWCT

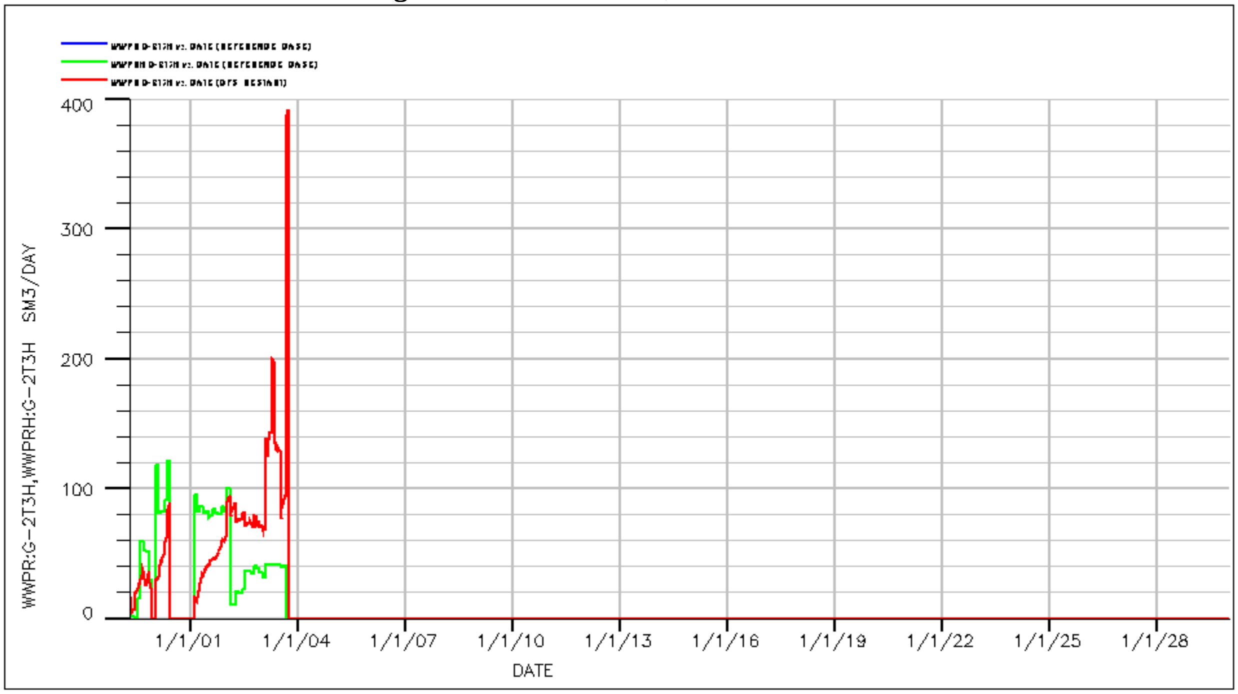


Figure 7-34: "G-2T3H", WWPR

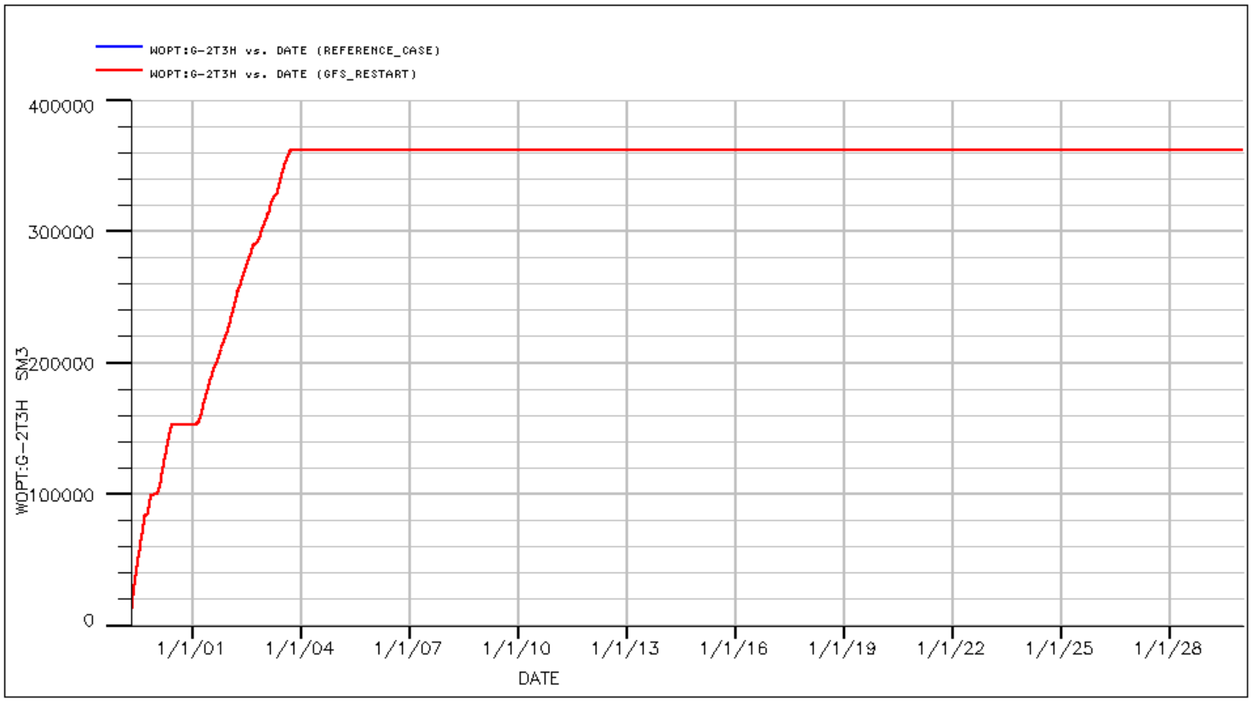


Figure 7-35: "G-2T3H", WOPT

Well Name: **G-2_ML**

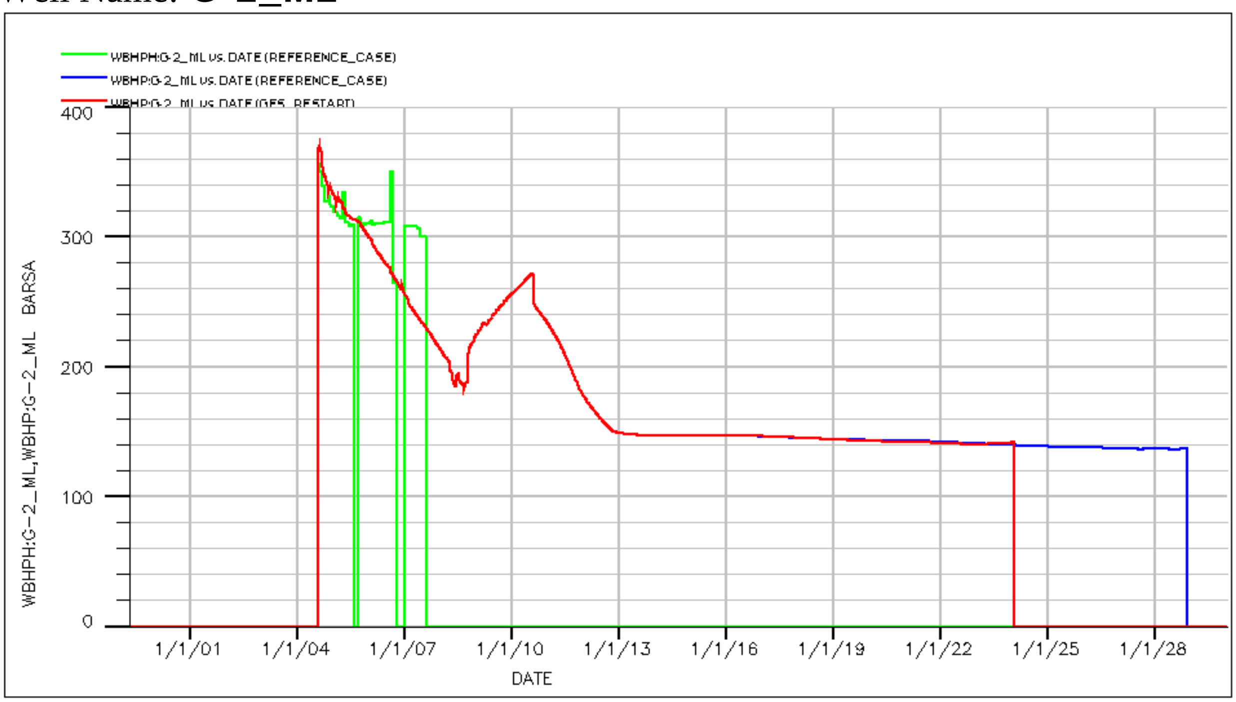


Figure 7-36: "G-2_ML", WBHP

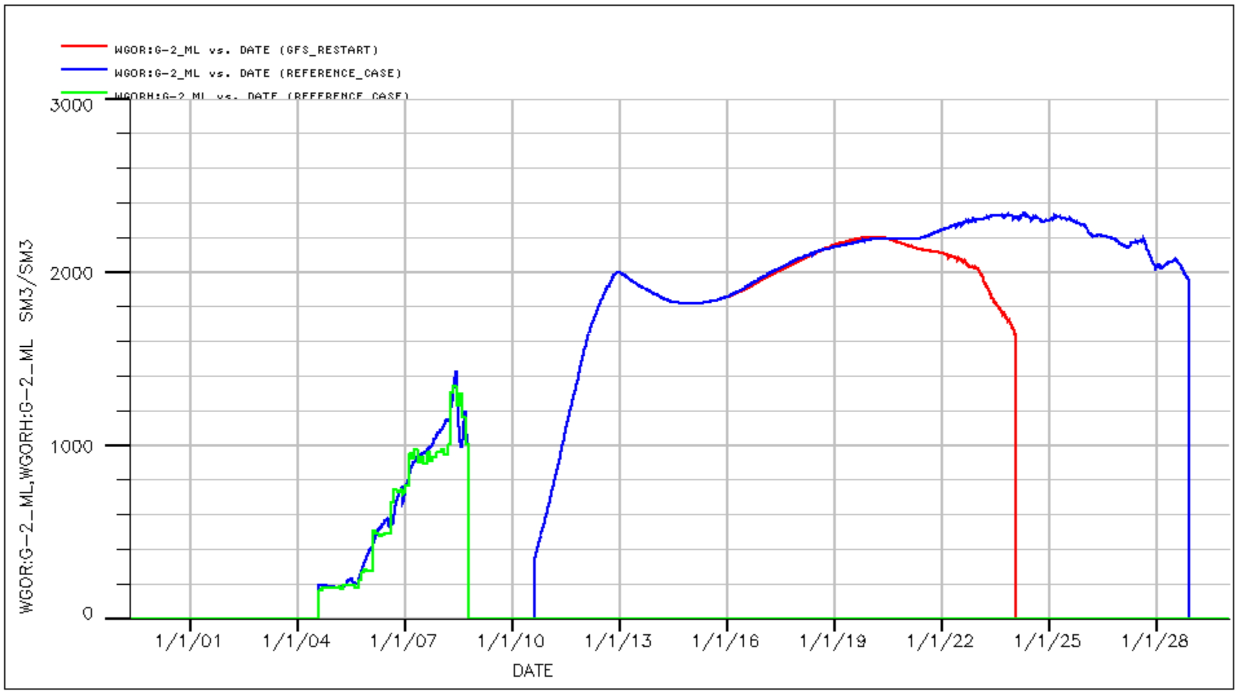


Figure 7-37: "G-2_ML", WGOR

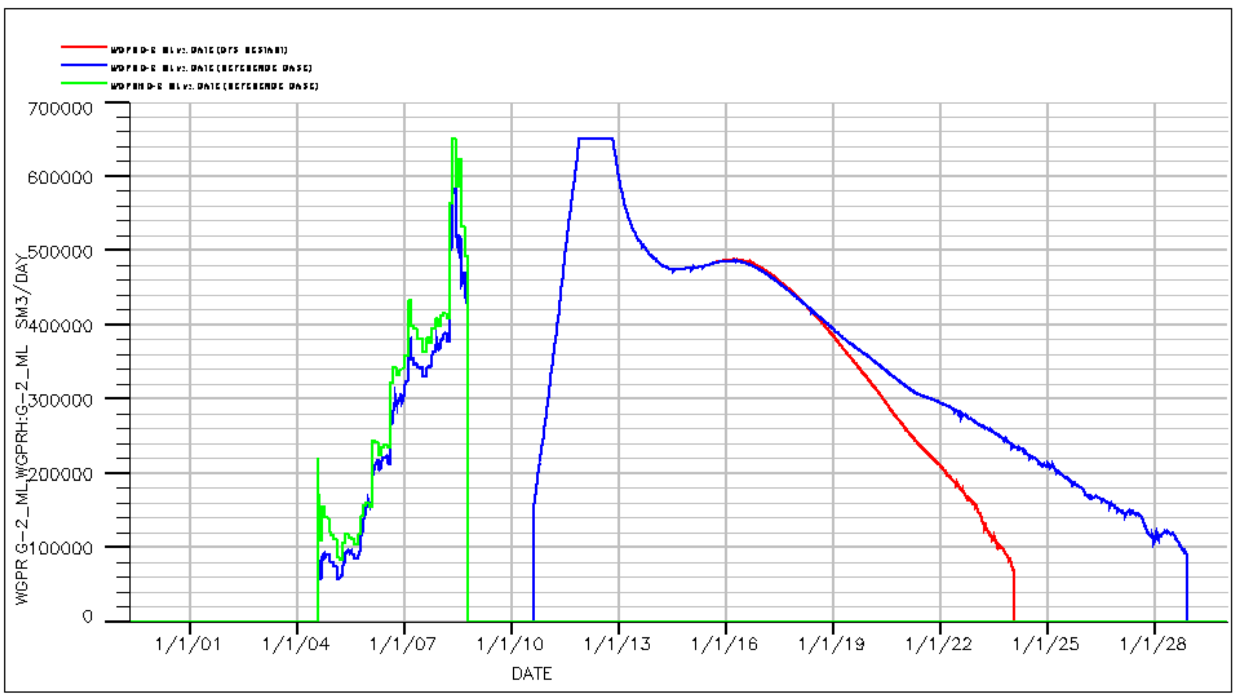


Figure 7-38: "G-2_ML", WGPR

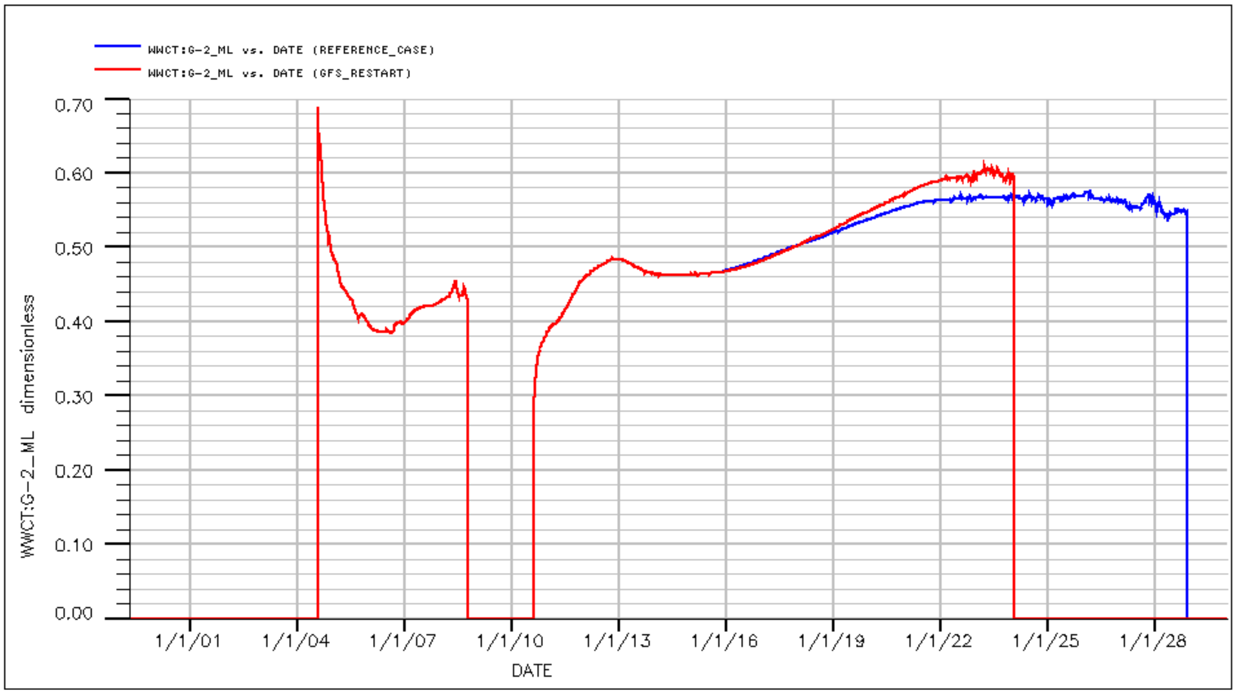


Figure 7-39: "G-2_ML", WWCT

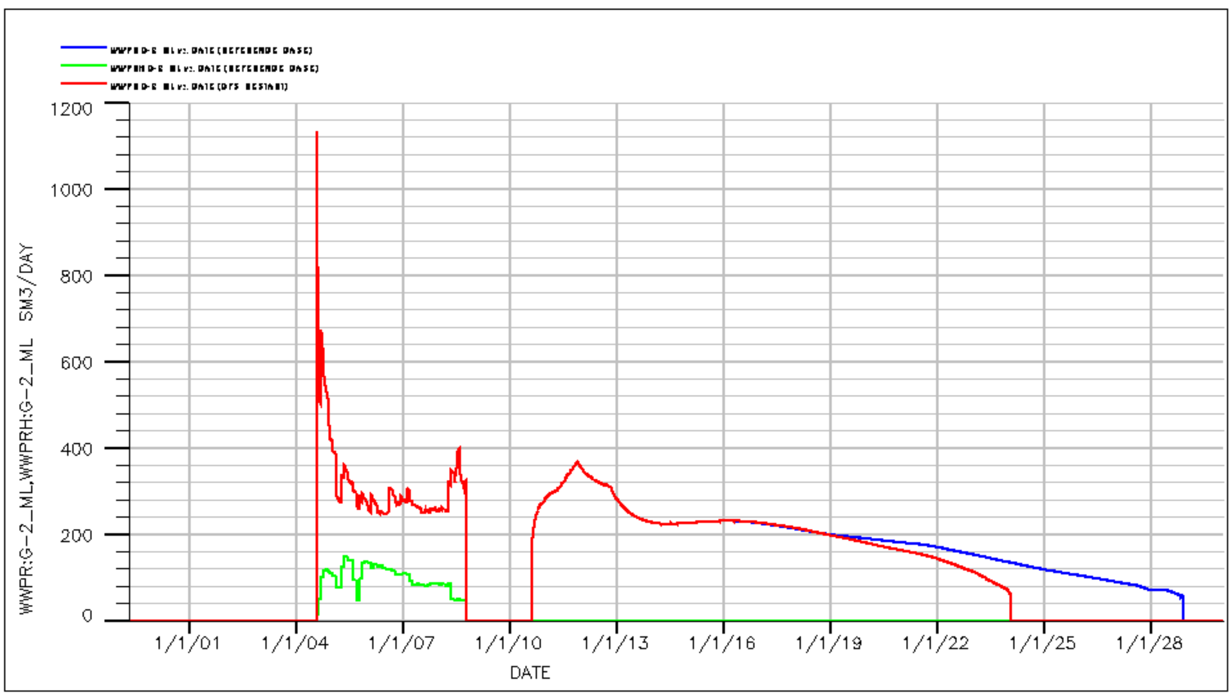


Figure 7-40: "G-2_ML", WWPR

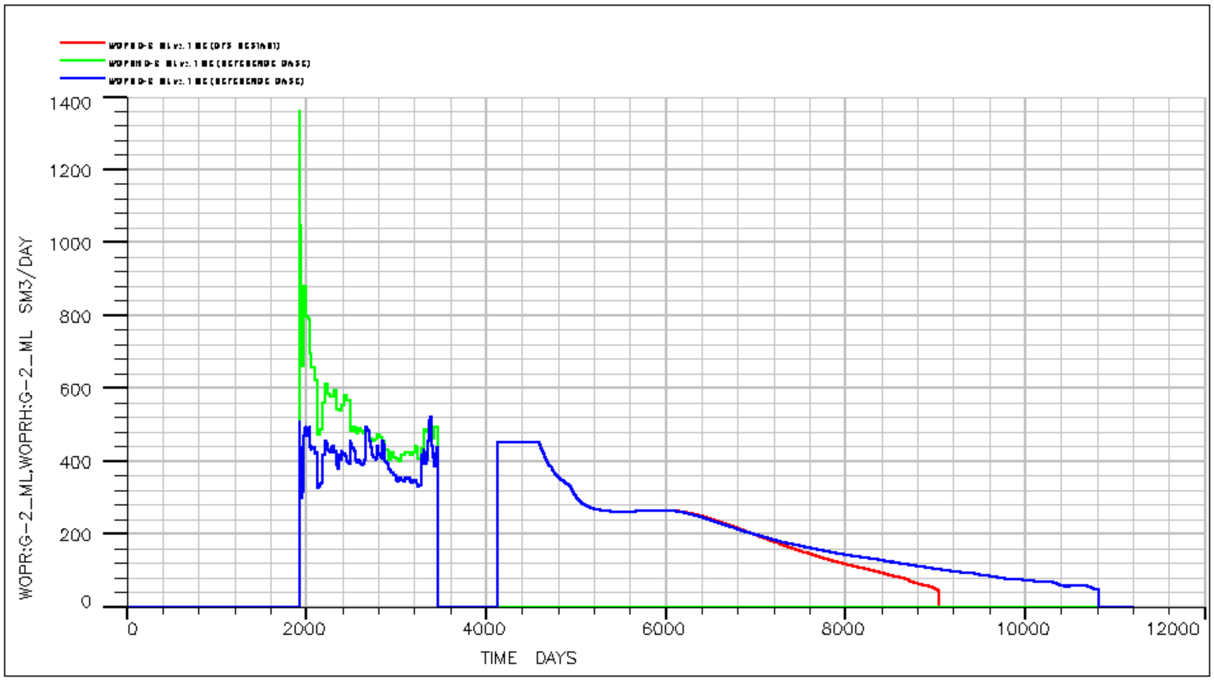


Figure 7-41: "G-2_ML", WOPR

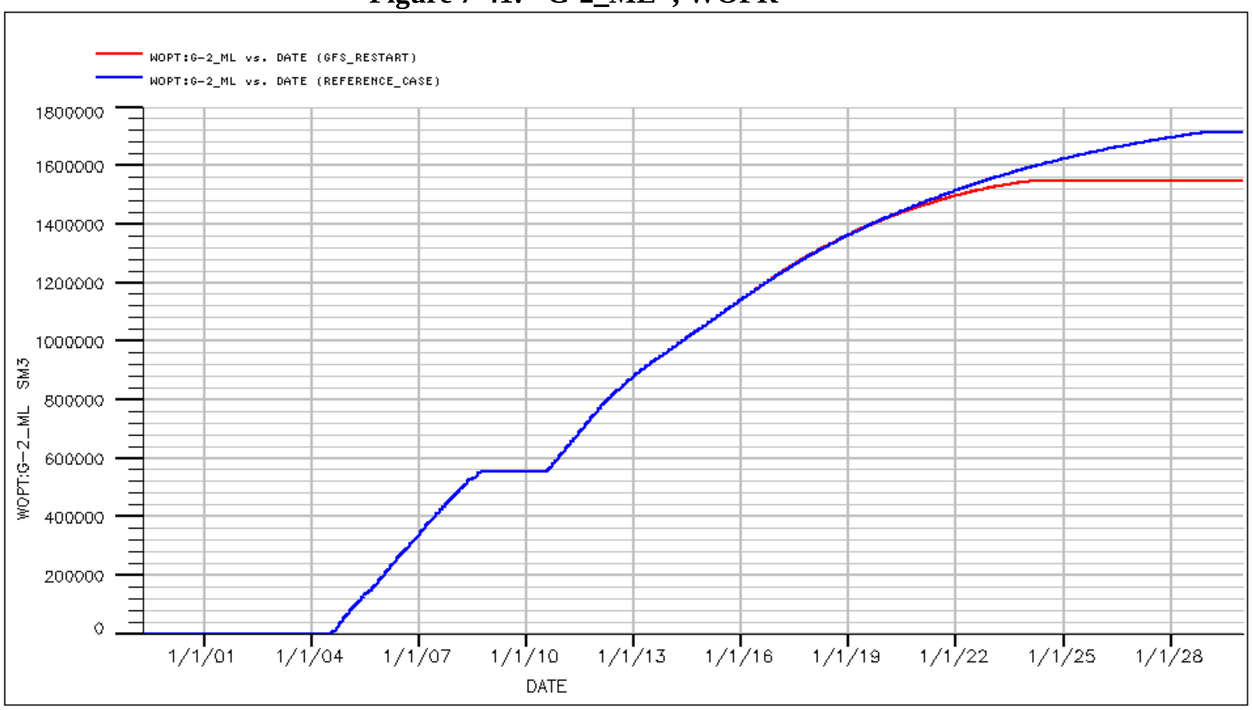


Figure 7-42: "G-2_ML", WOPT

Well Name: **G-3T2H**

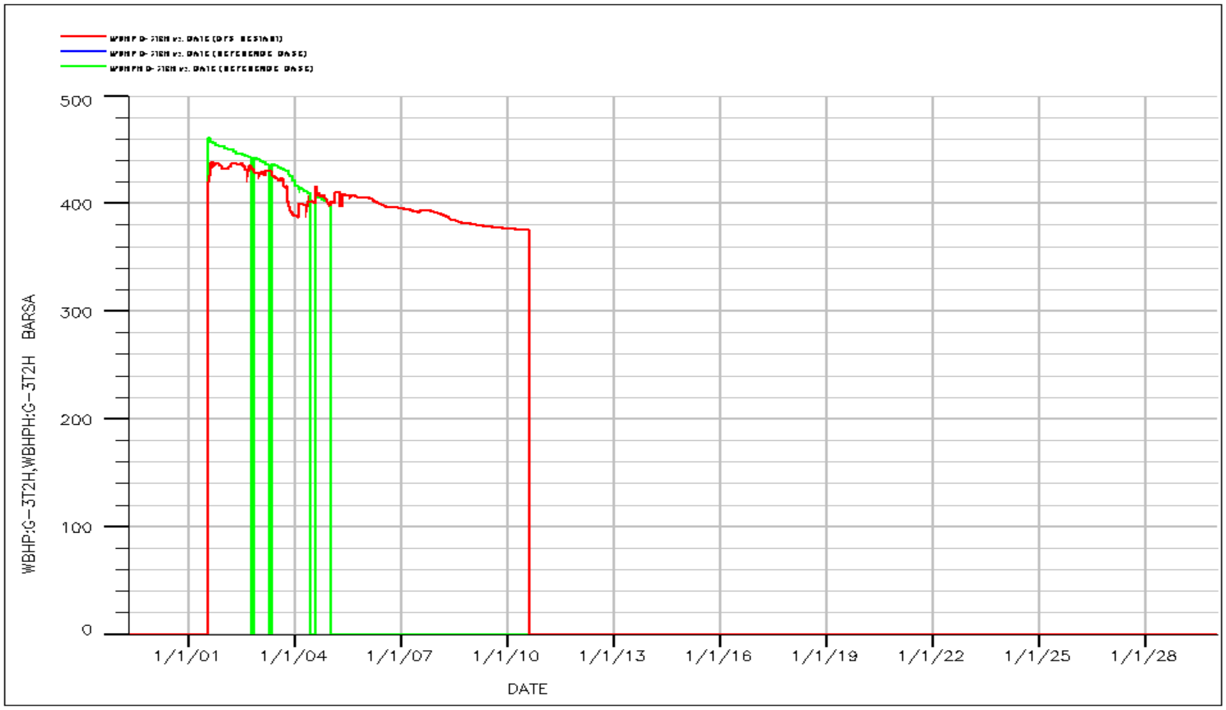


Figure 7-43: "G-3T2H", WBHP

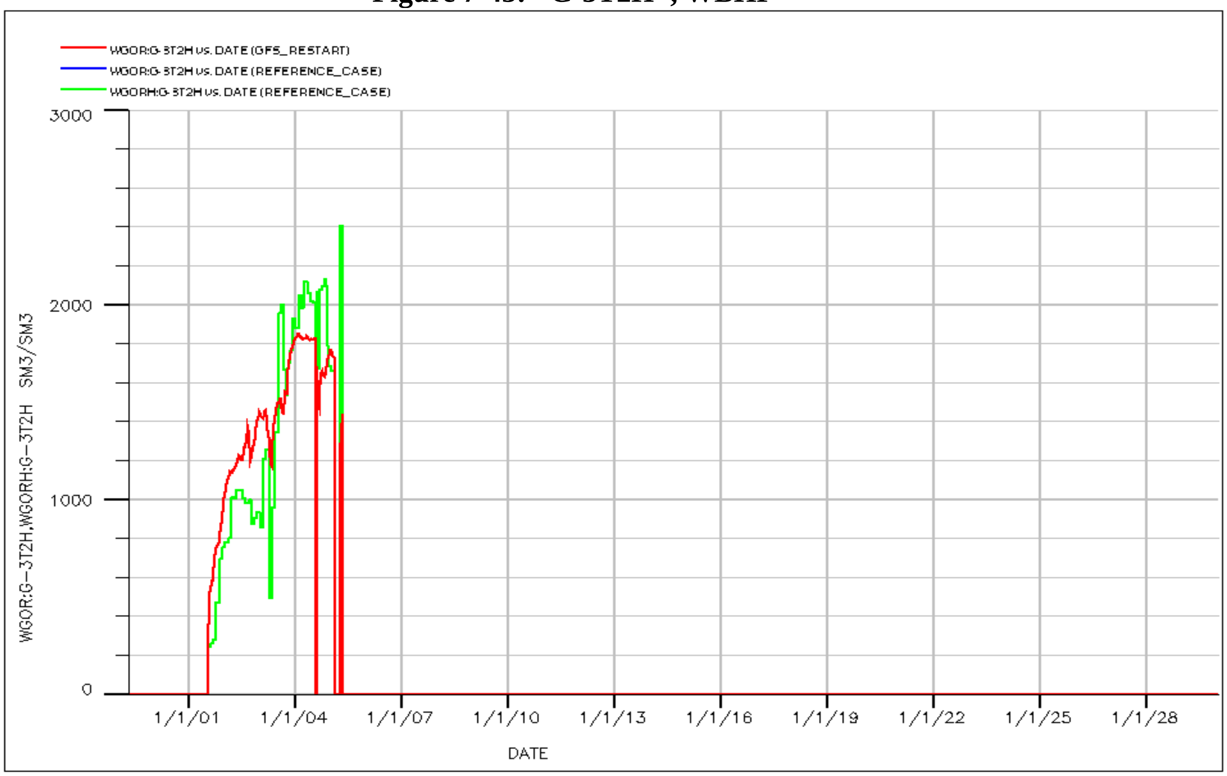


Figure 7-44: "G-3T2H", WGOR

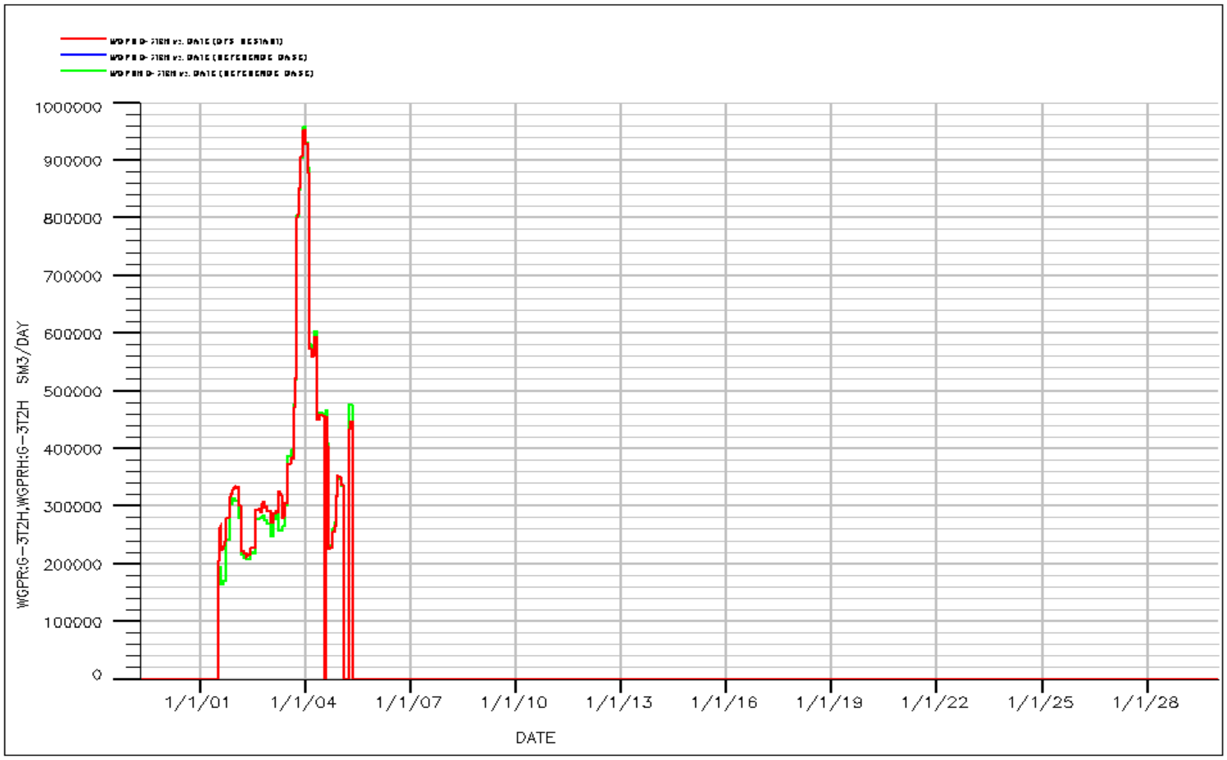


Figure 7-45: "G-3T2H", WGPR

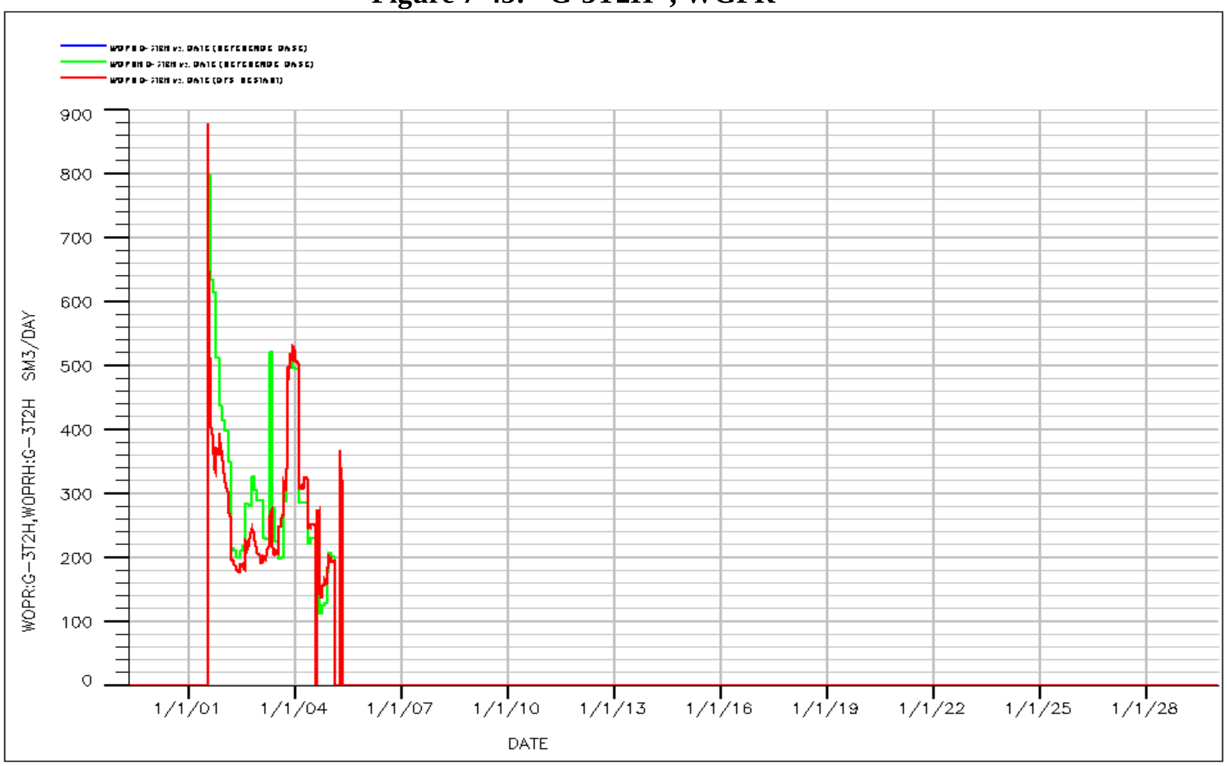


Figure 7-46: "G-3T2H", WOPR

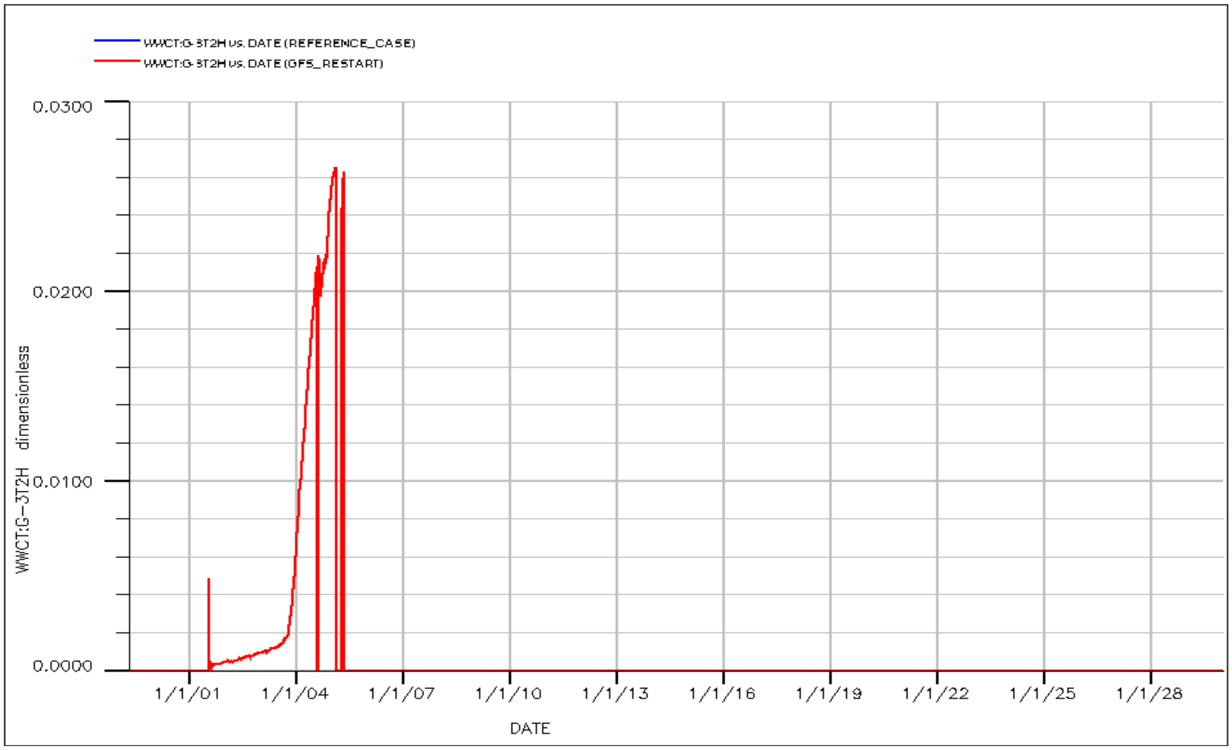


Figure 7-47: "G-3T2H", WWCT

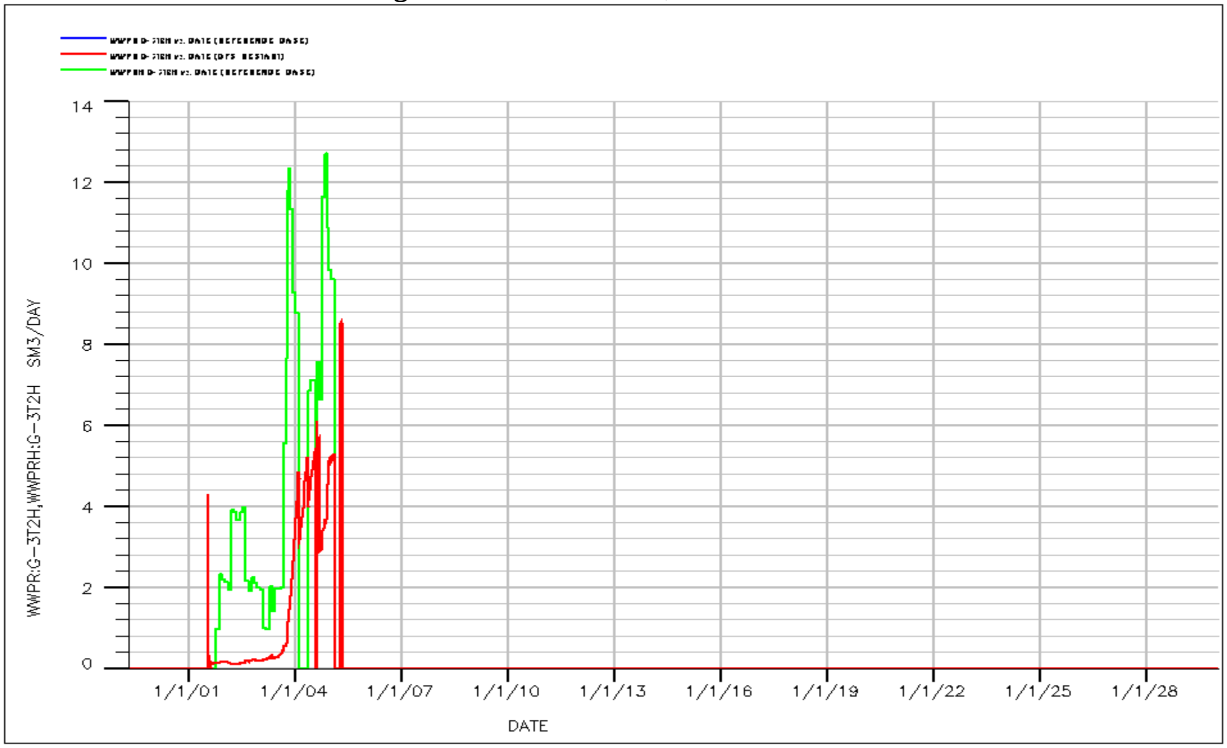


Figure 7-48: "G-3T2H", WWPR

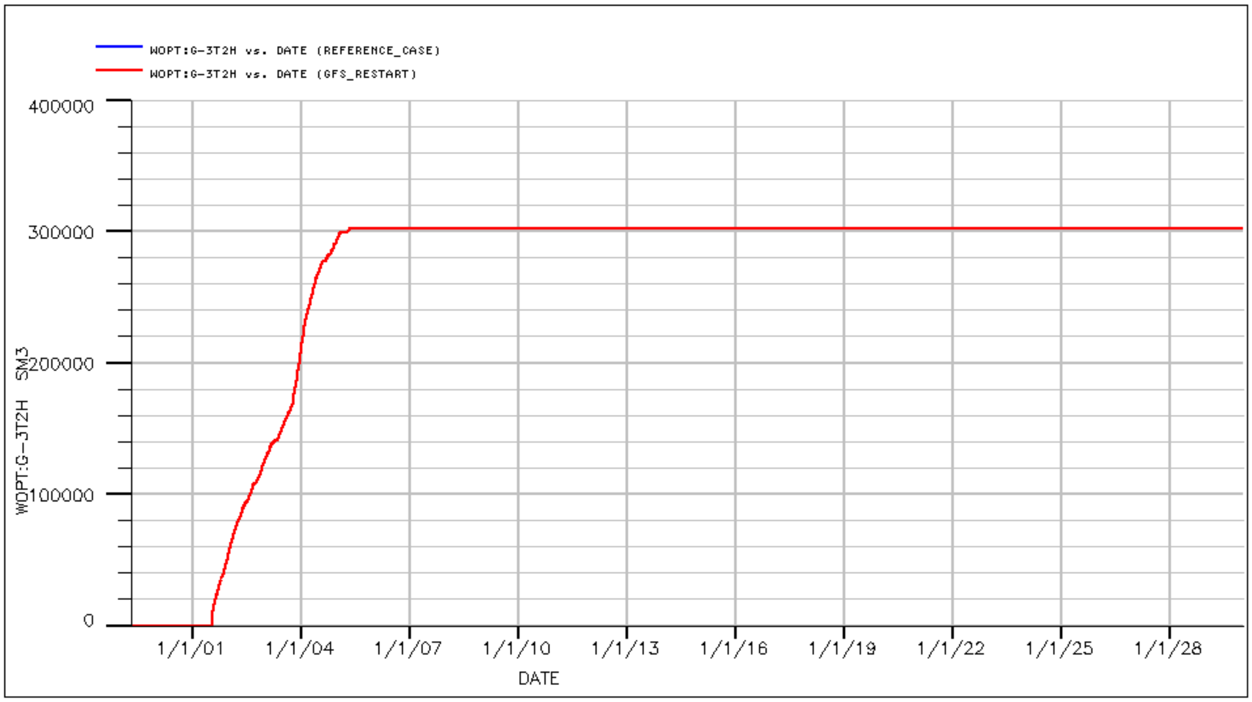


Figure 7-49: "G-3T2H", WOPT

Well Name: **G-3Y3HT4**

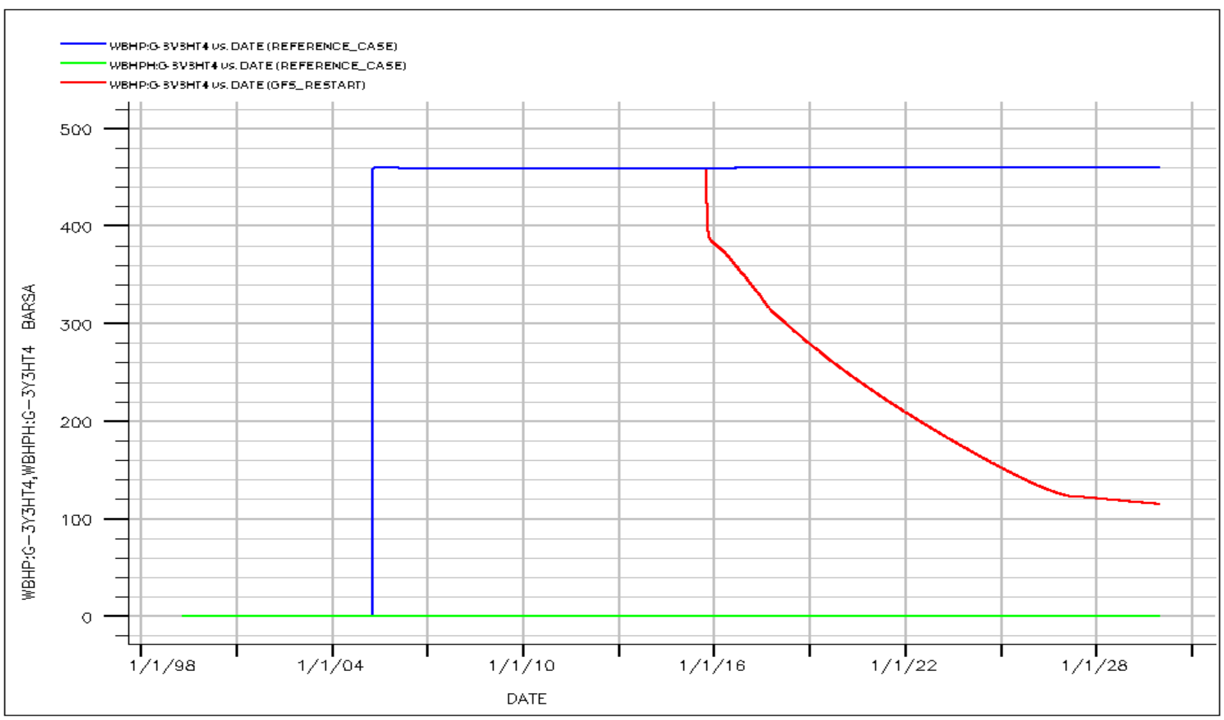


Figure 7-500: "G-3Y3HT4", WBHP

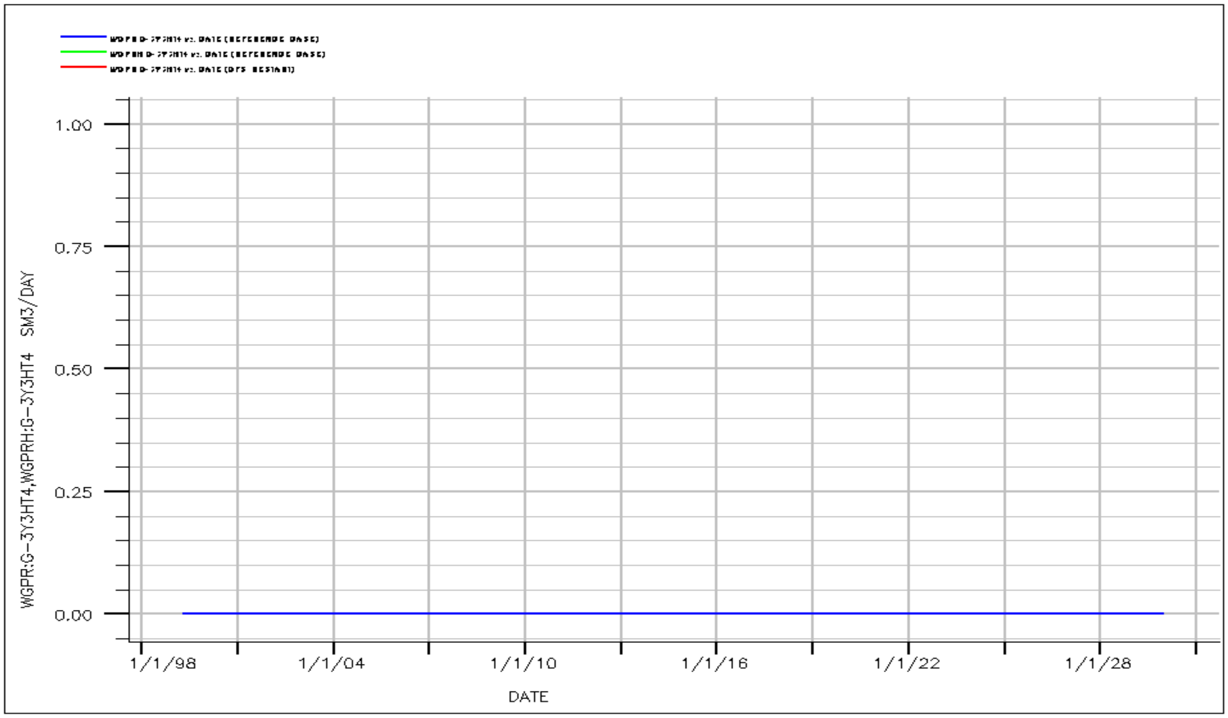


Figure 7-51: "G-3Y3HT4", WGPR

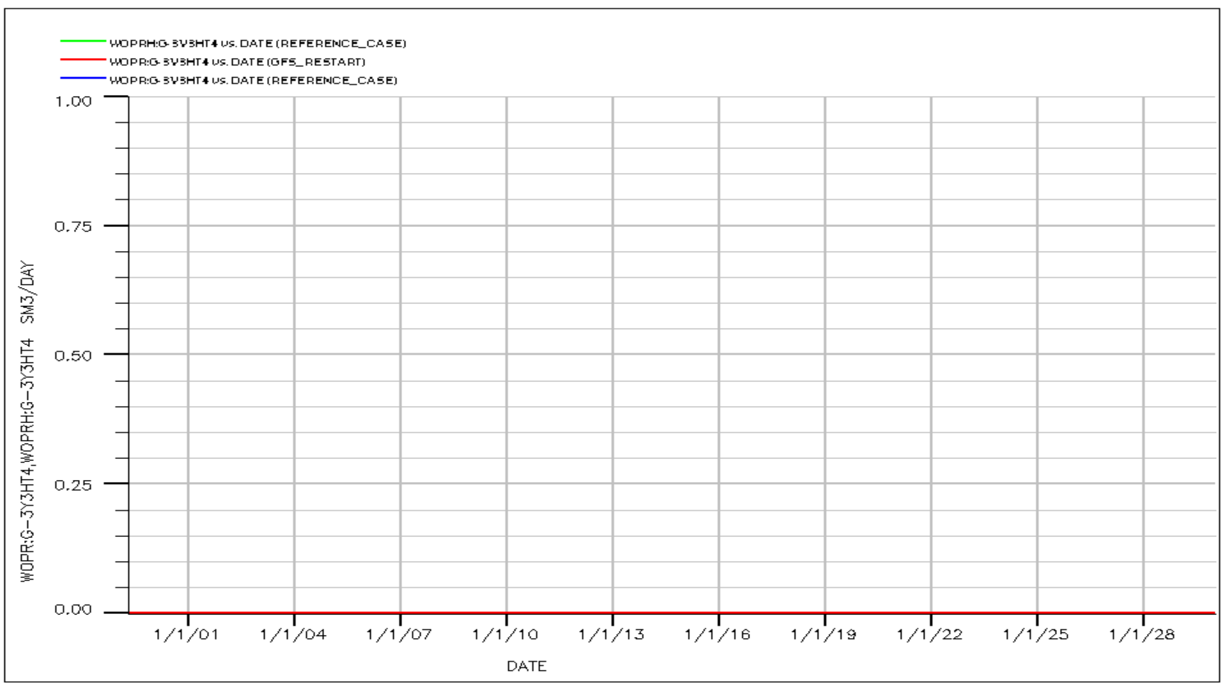


Figure 7-52: "G-3Y3HT4", WOPR

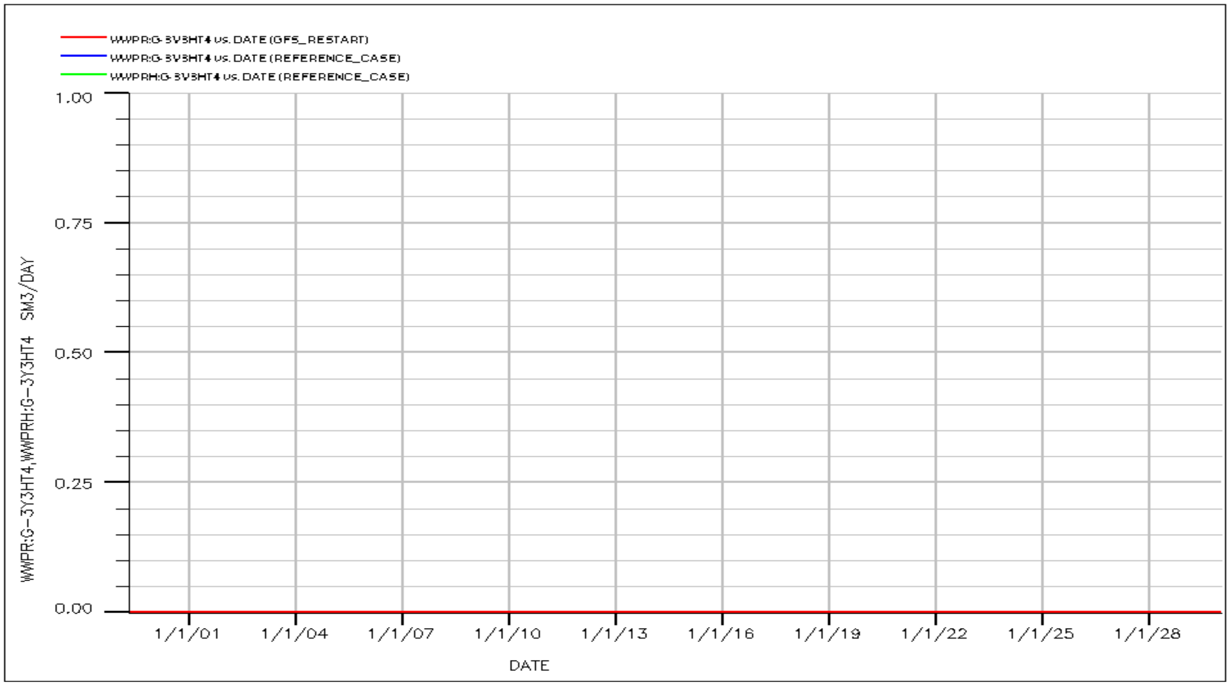


Figure 7-53: "G-3Y3HT4",WWPR

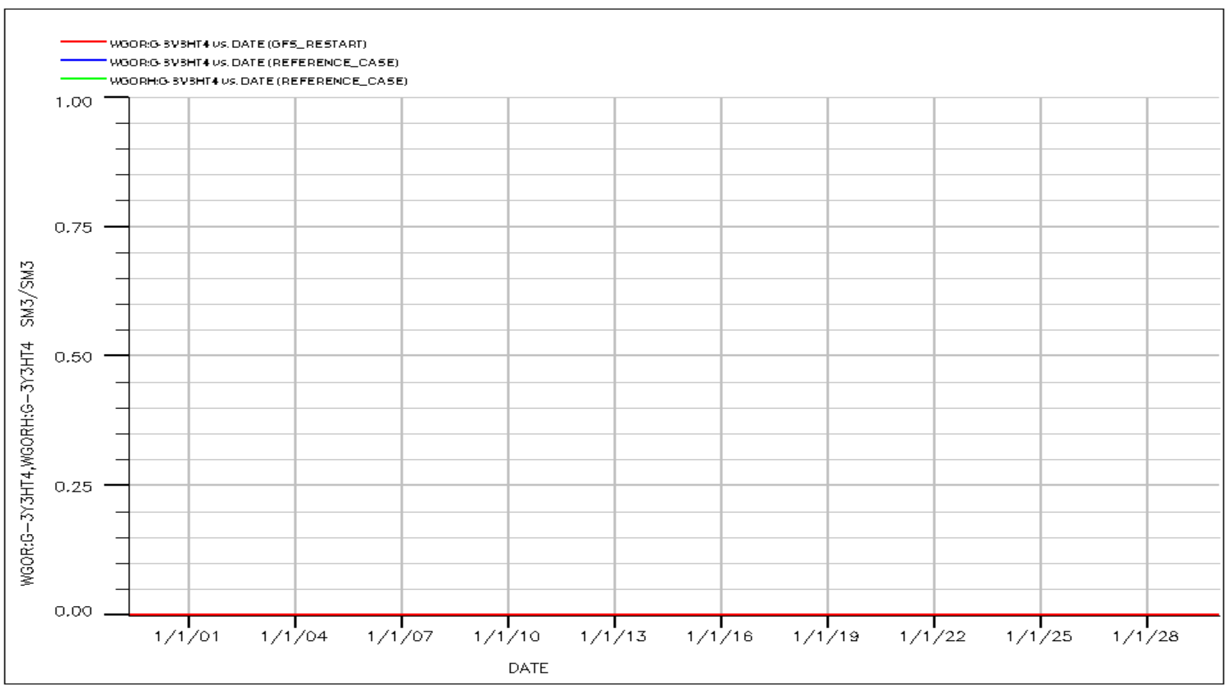


Figure 7-54: "G-3Y3HT4", WGOR

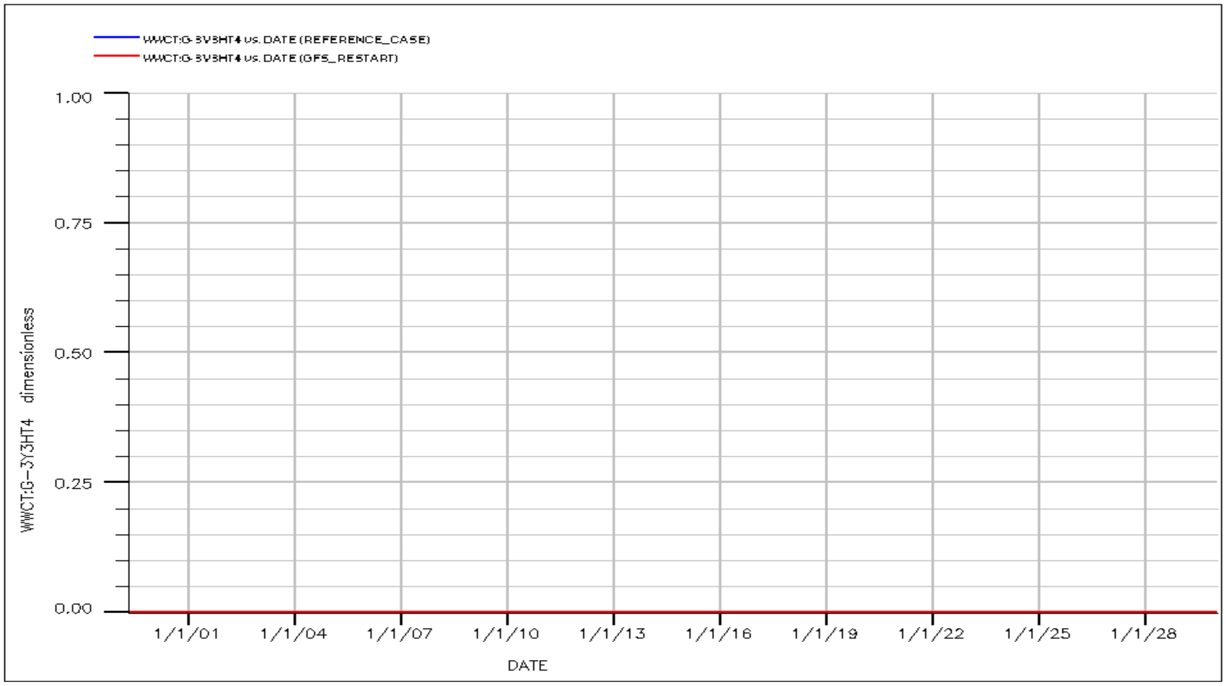


Figure 7-55: "G-3Y3HT4", WWCT

Well Name: **G-4H**

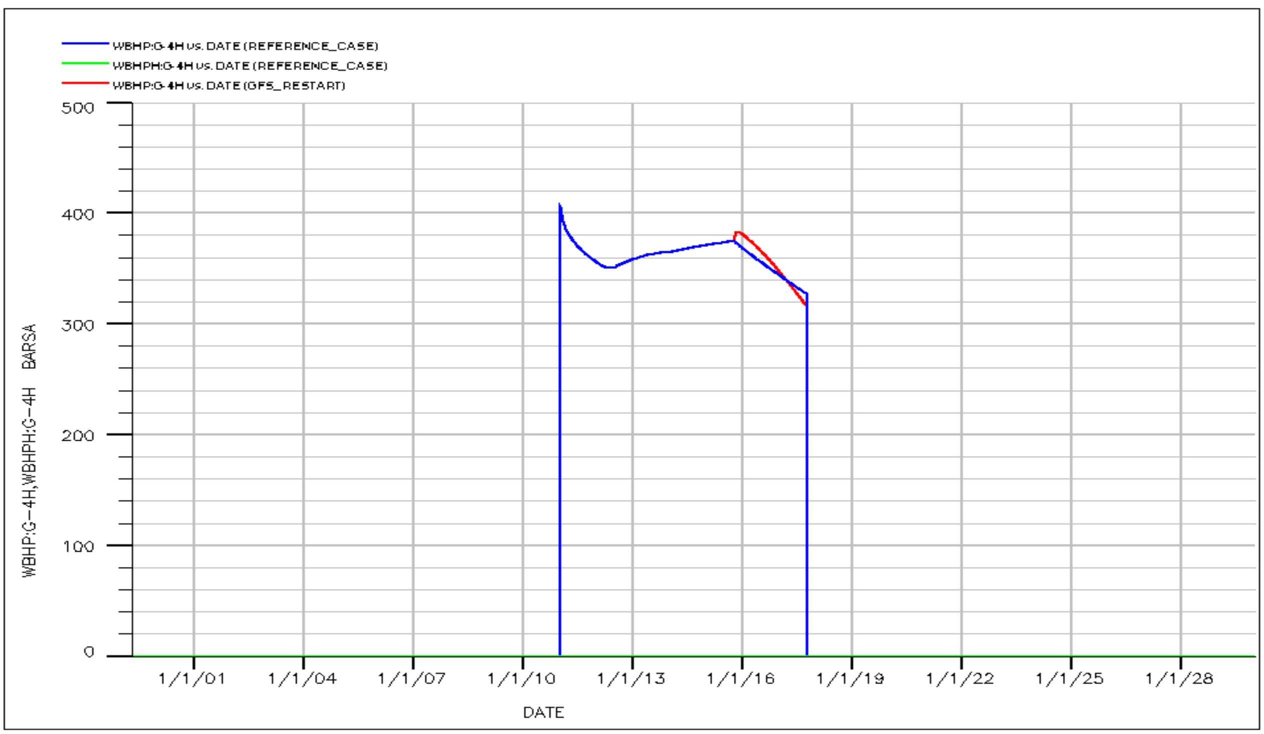


Figure 7-56: "G-4H", WBHP

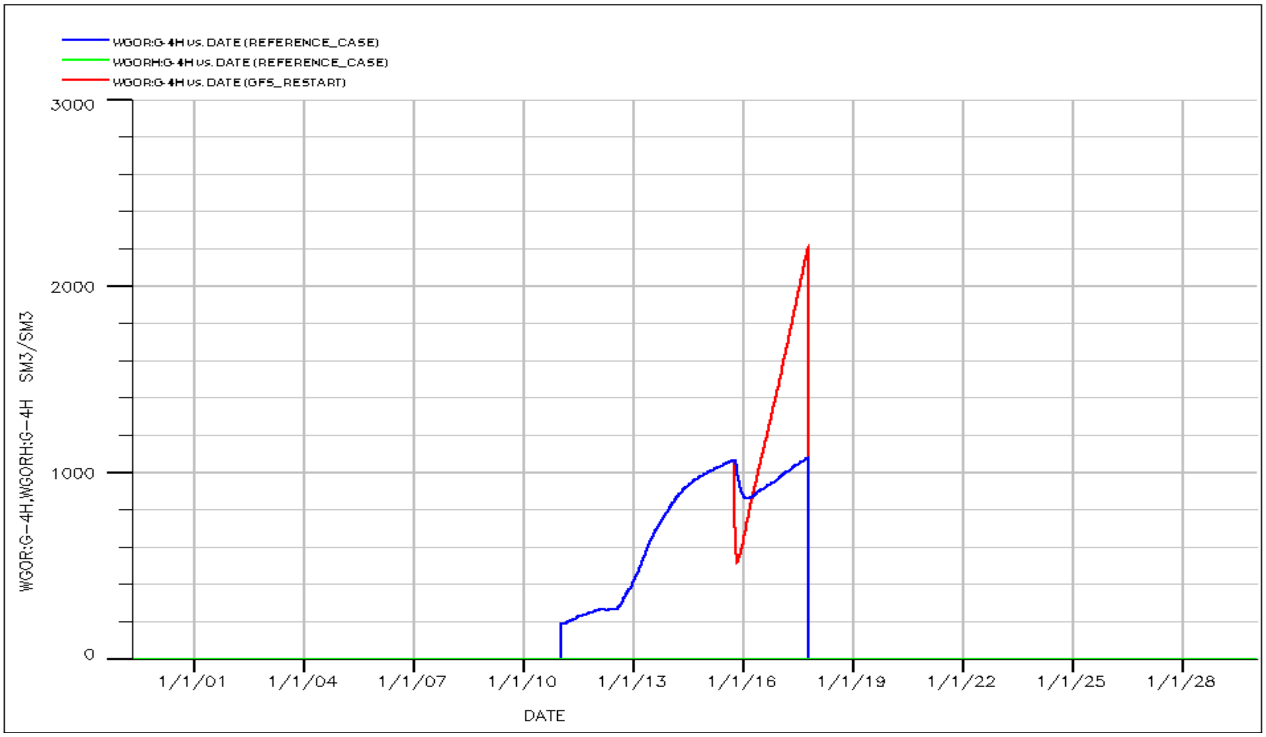


Figure 7-57: "G-4H", WGOR

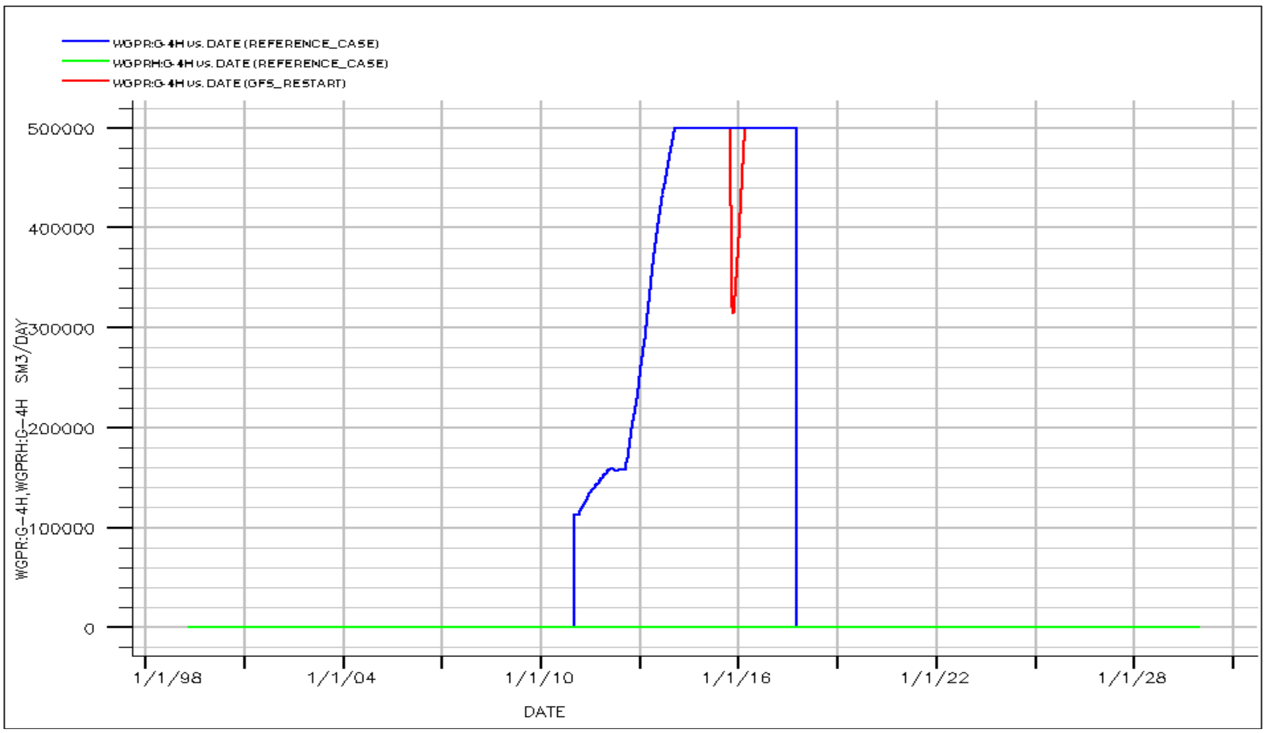


Figure 7-58: "G-4H", WGPR

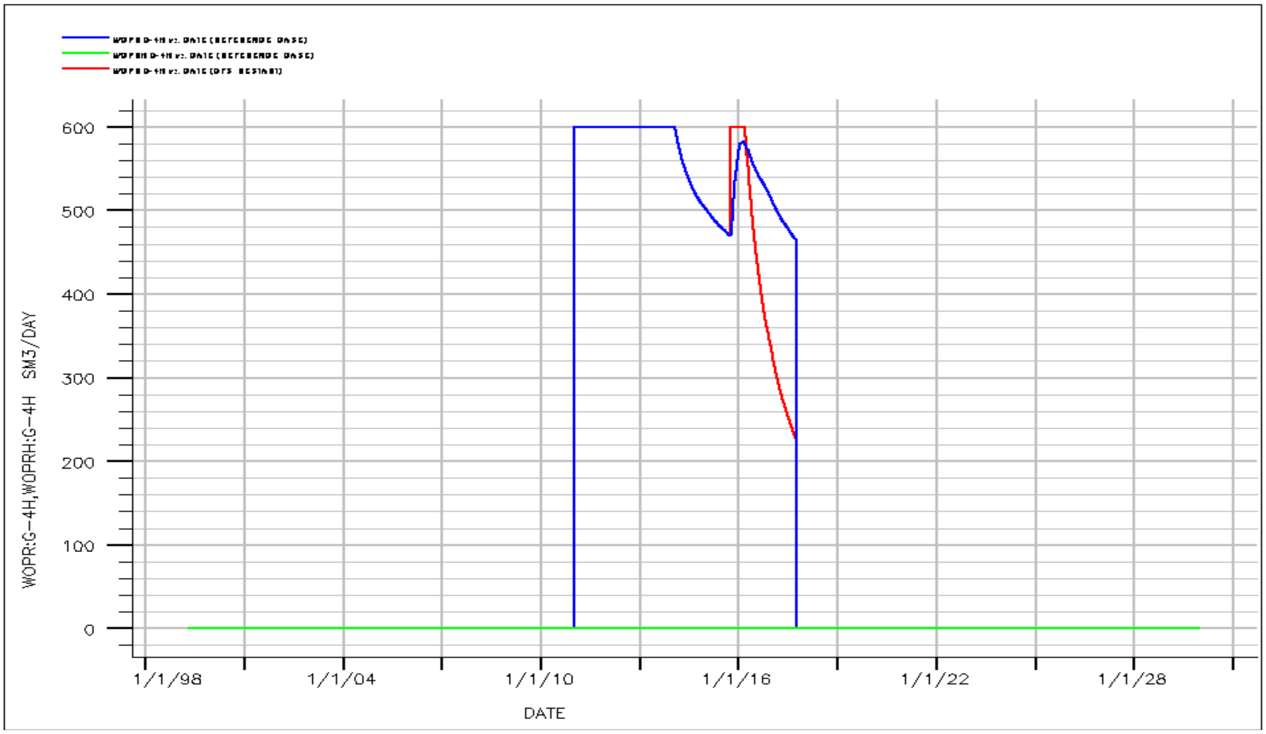


Figure 7-59: "G-4H", WOPR

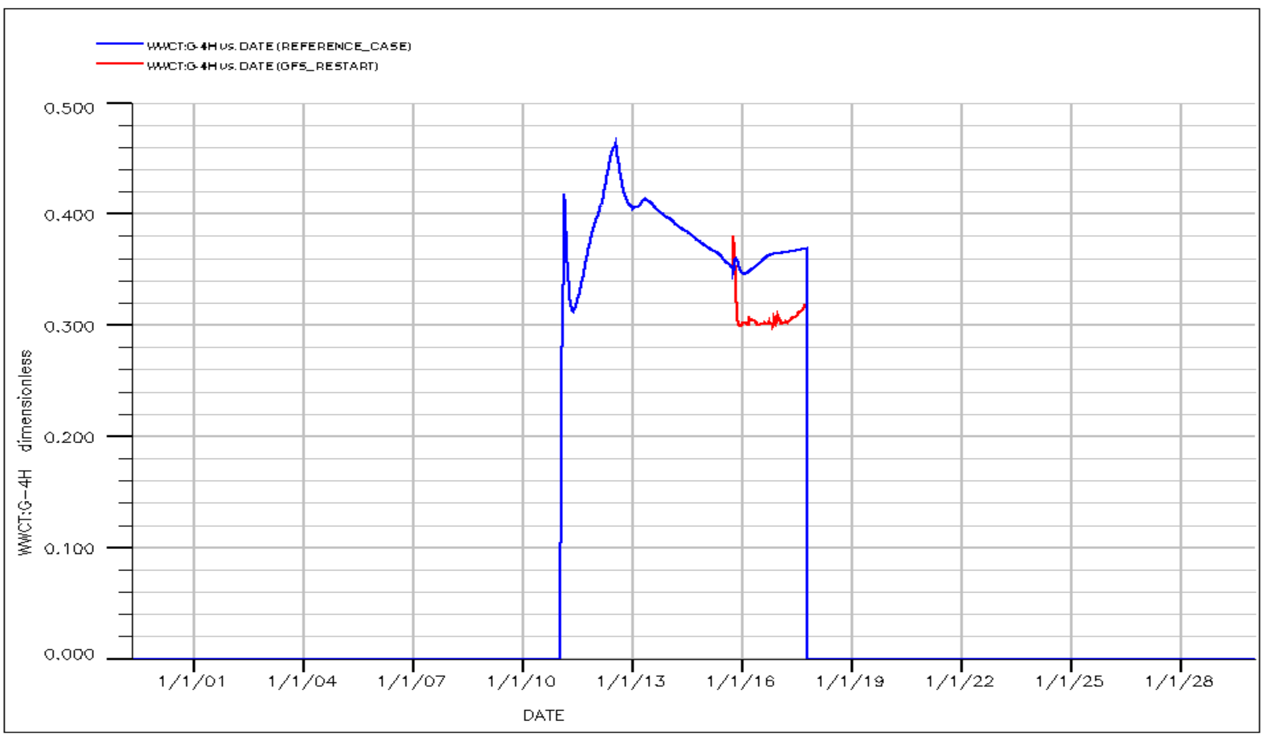


Figure 7-60: "G-4H", WWCT

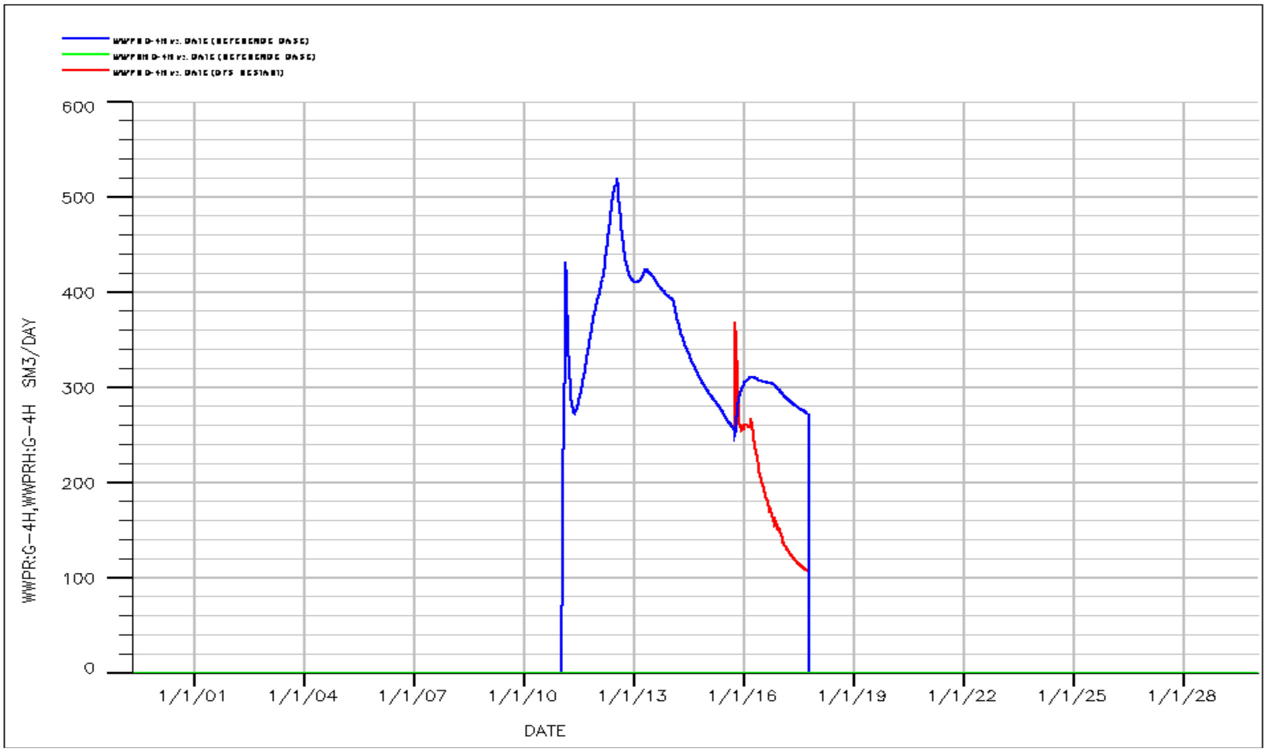


Figure 7-61: "G-4H", WWPR

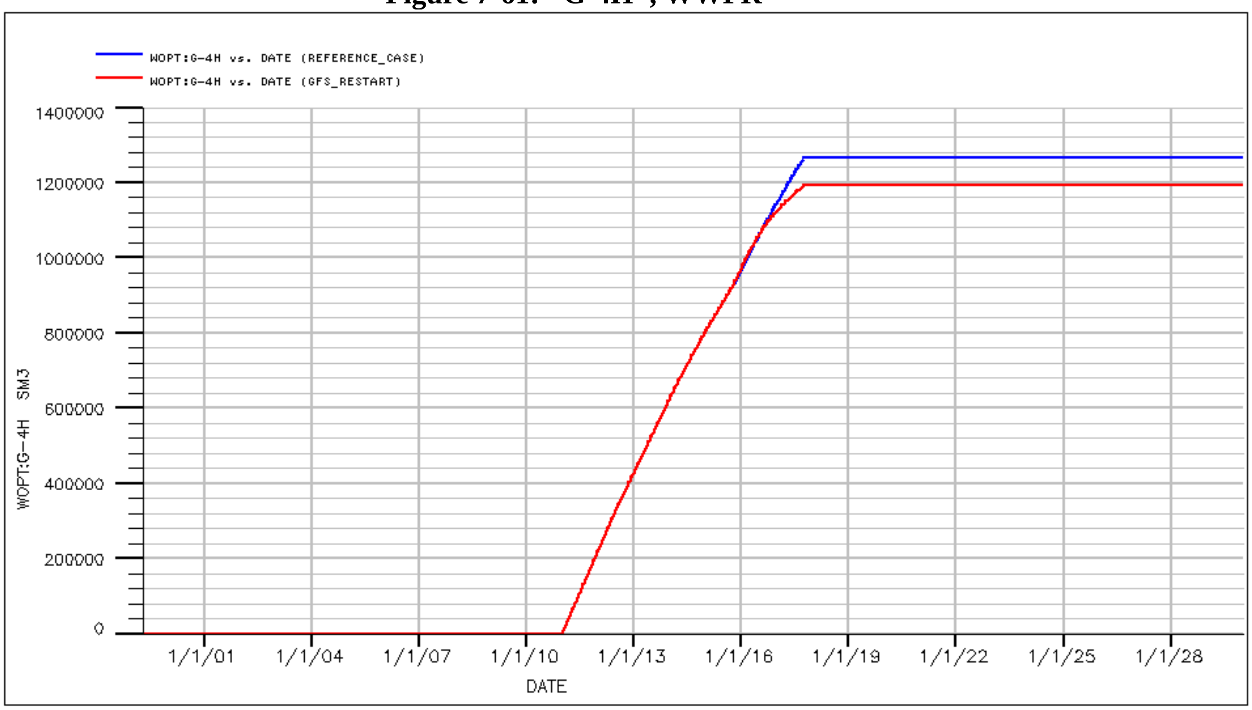


Figure 7-62: "G-4H", WOPT

Well Name: **W1**

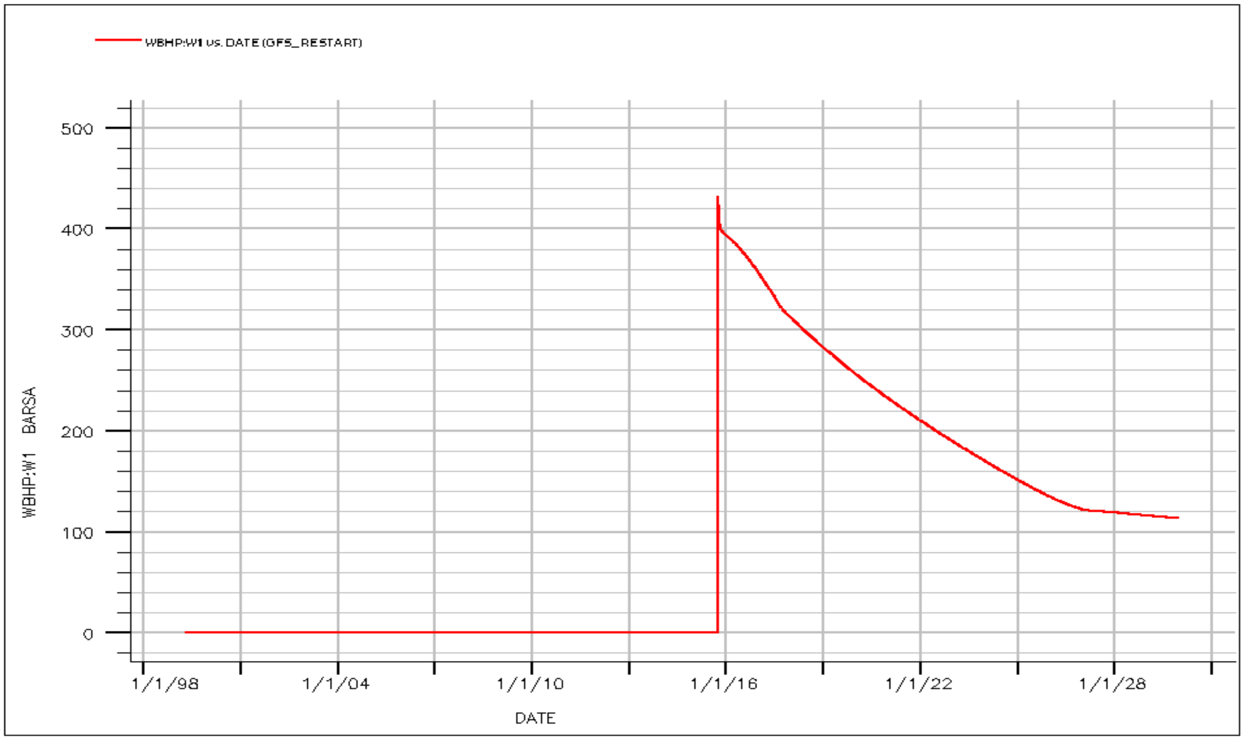


Figure 7-63: "W1", WBHP

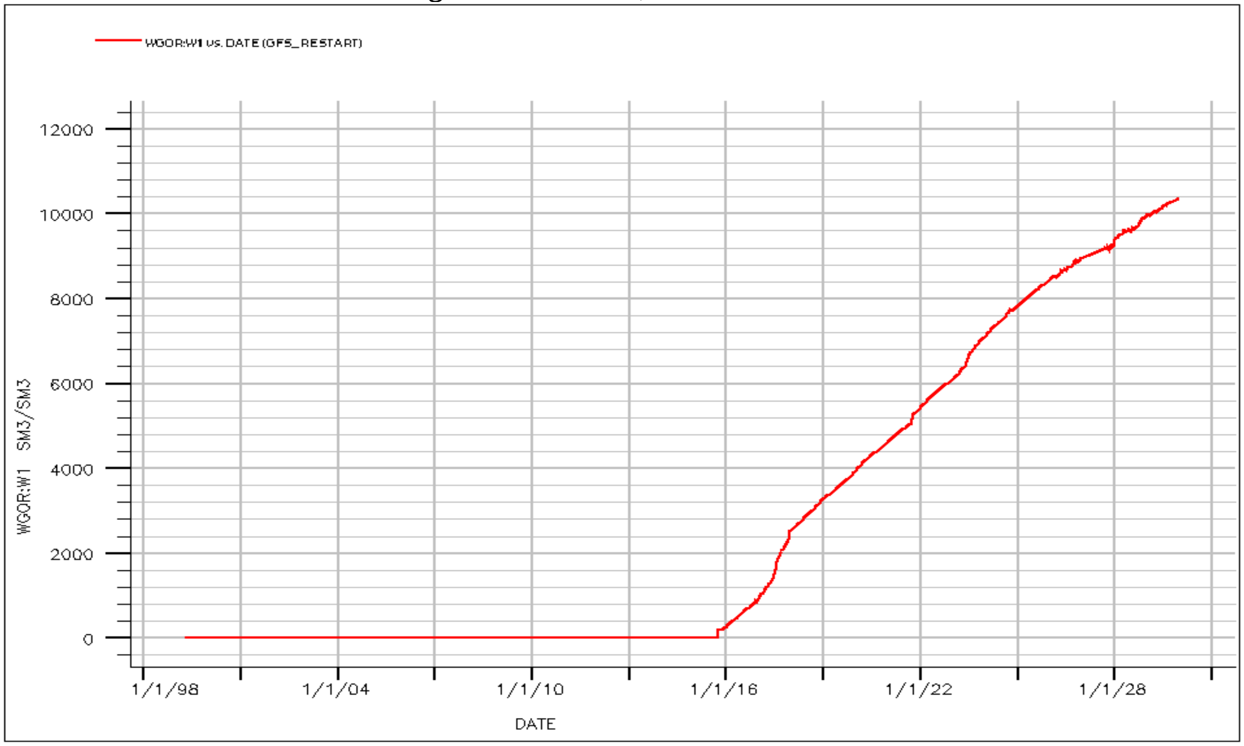


Figure 7-64: "W1", WGOR

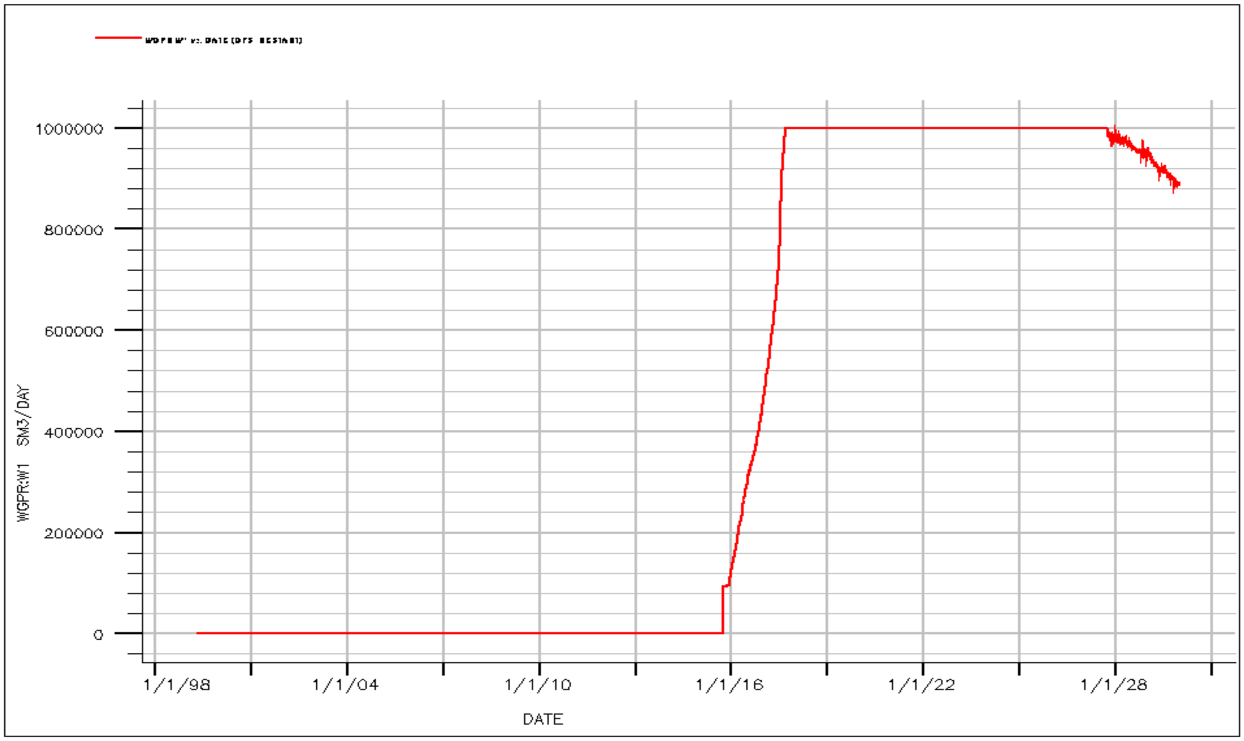


Figure 7-65: "W1", WGPR

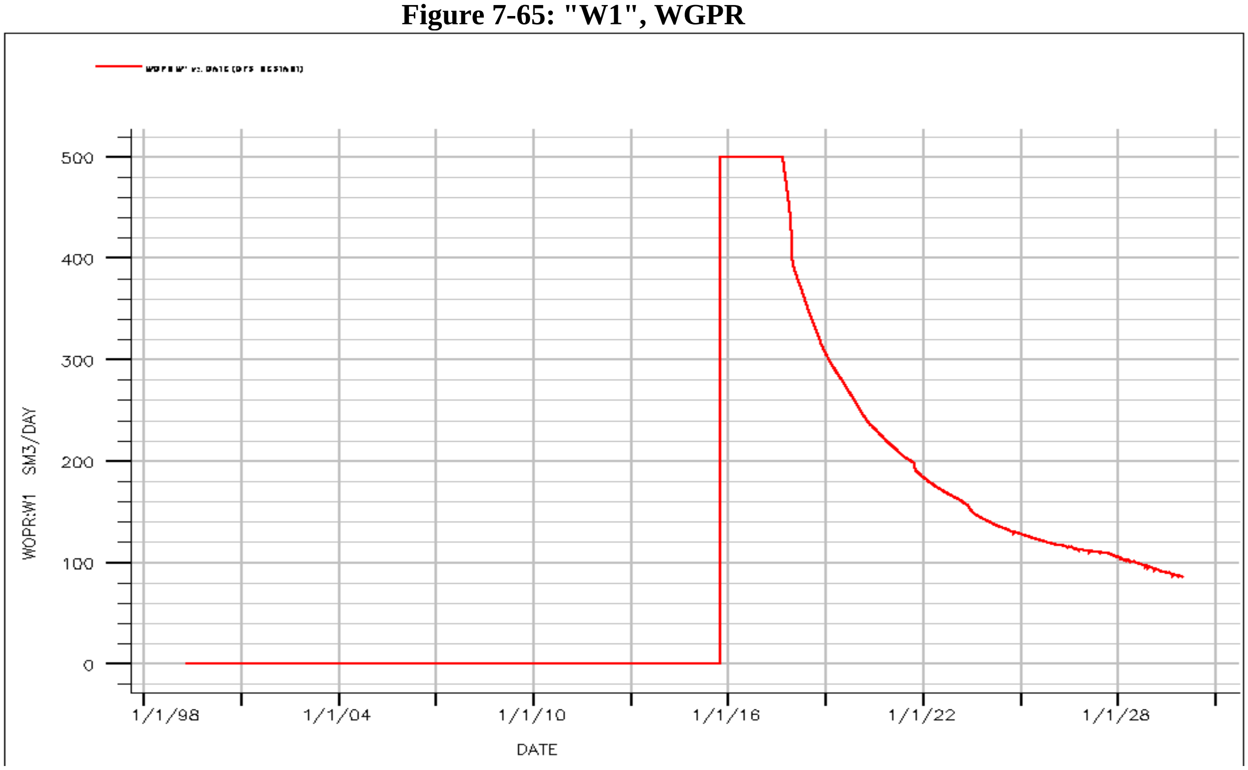


Figure 7-66: "W1", WOPR

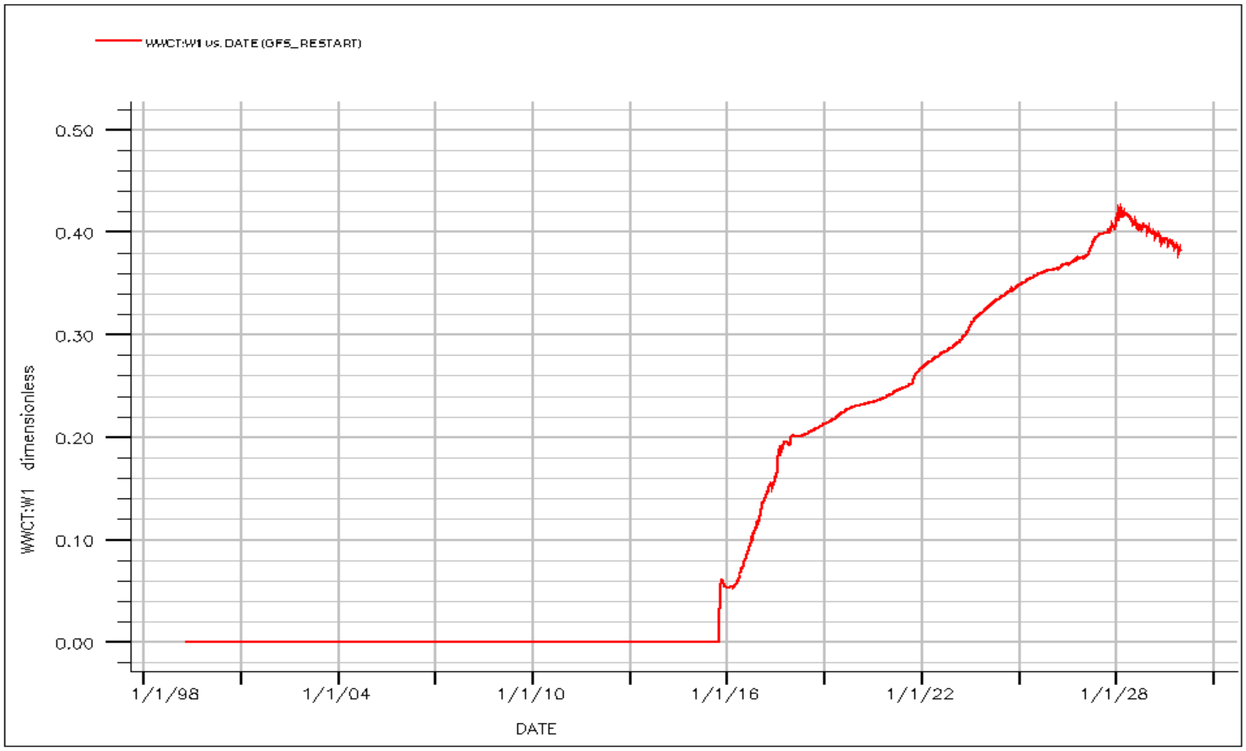


Figure 7-67: "W1", WWCT

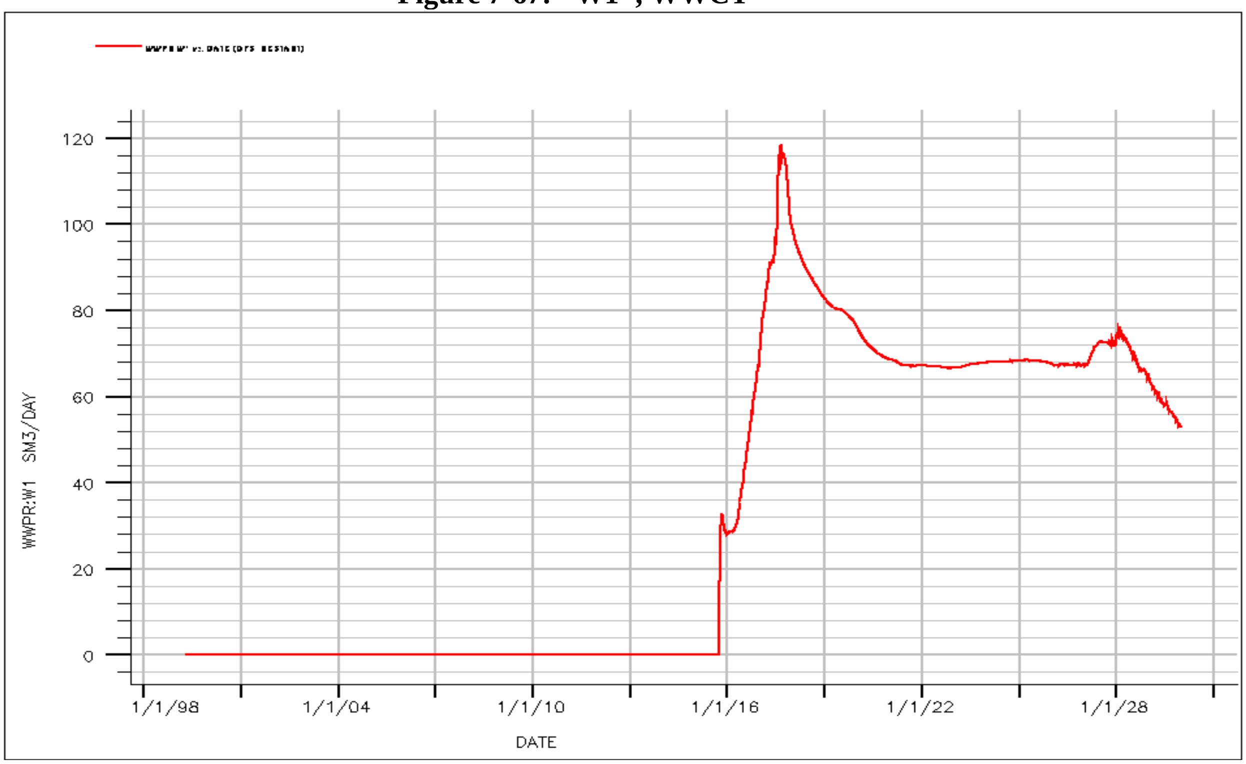


Figure 7-68: "W1", WWPR

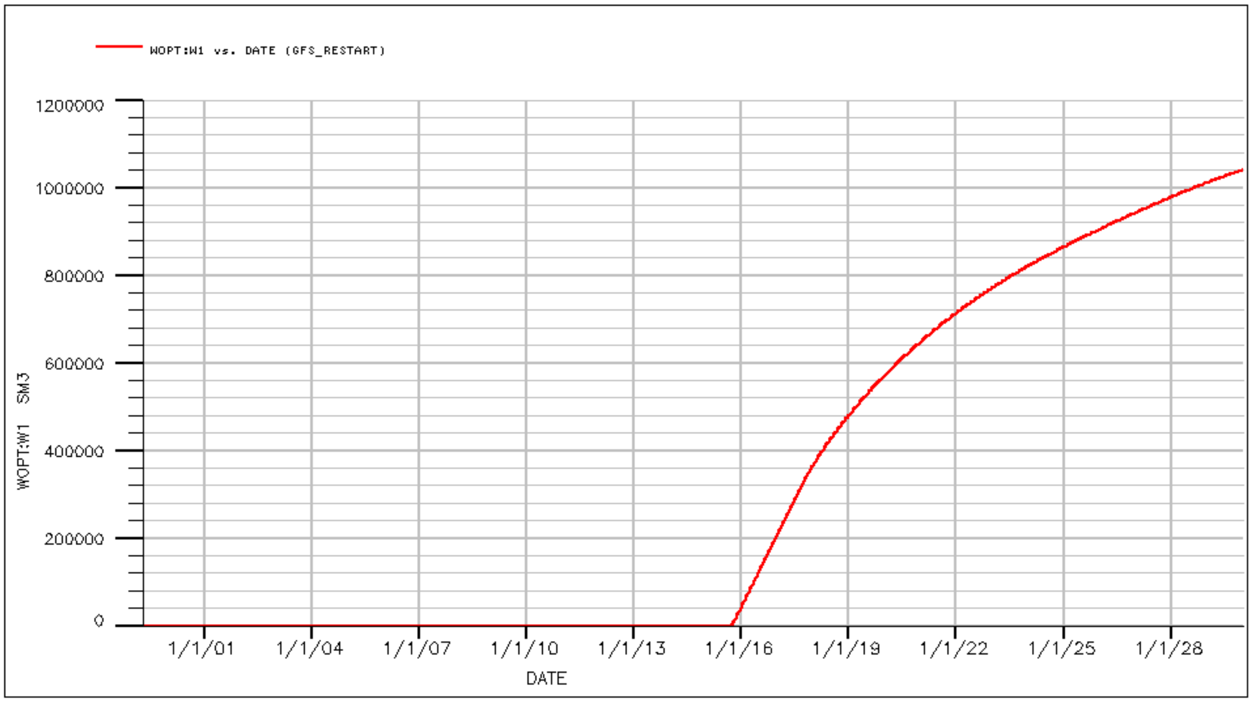


Figure 7-69: "W1", WOPT

Well Name: **W2W3**

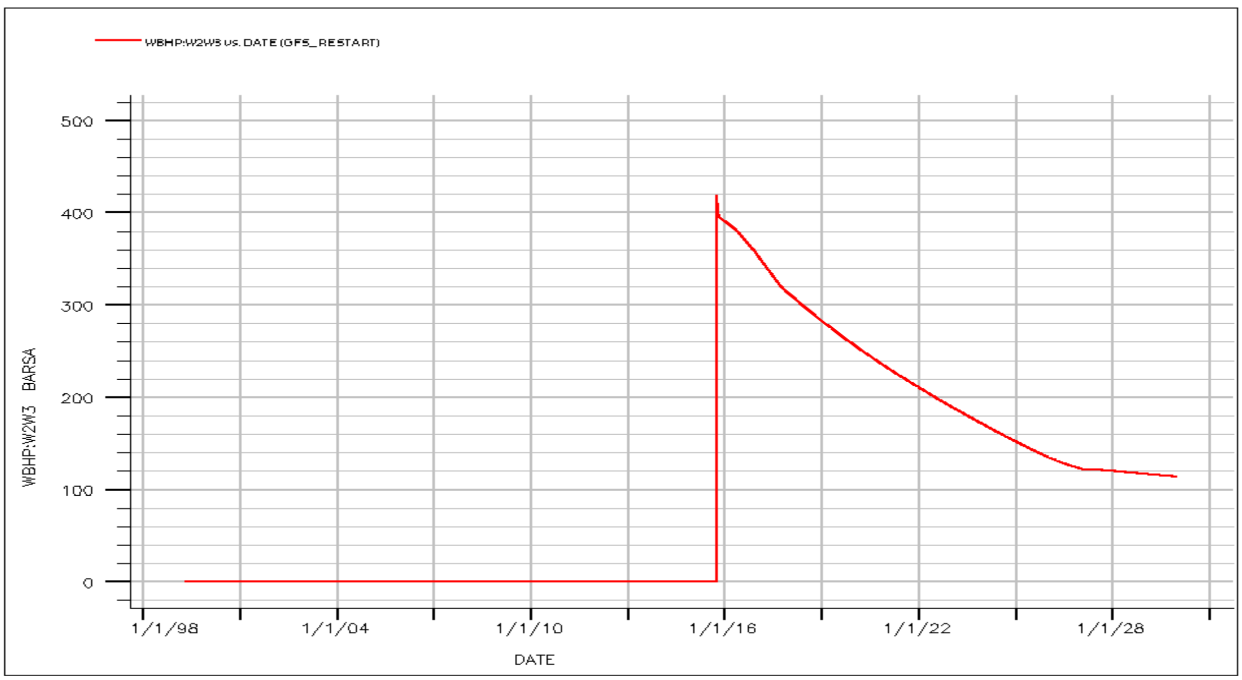


Figure 7-70: "W2W3", WBHP

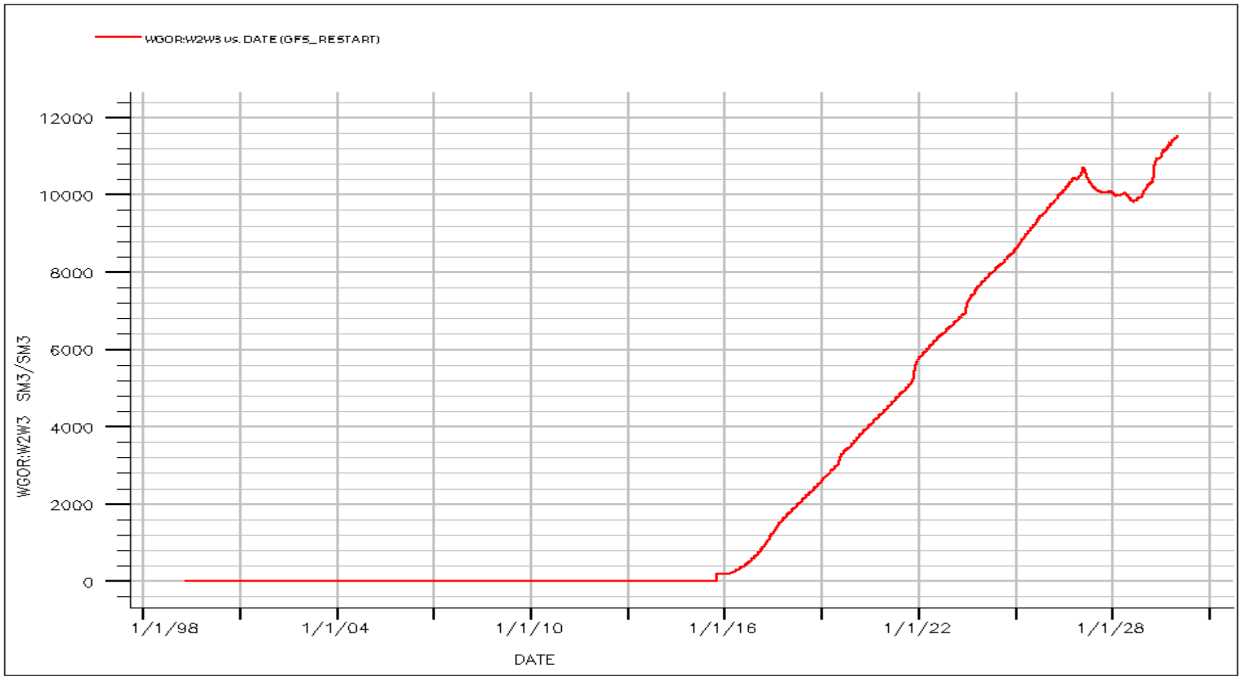


Figure 7-71: "W2W3", WGOR

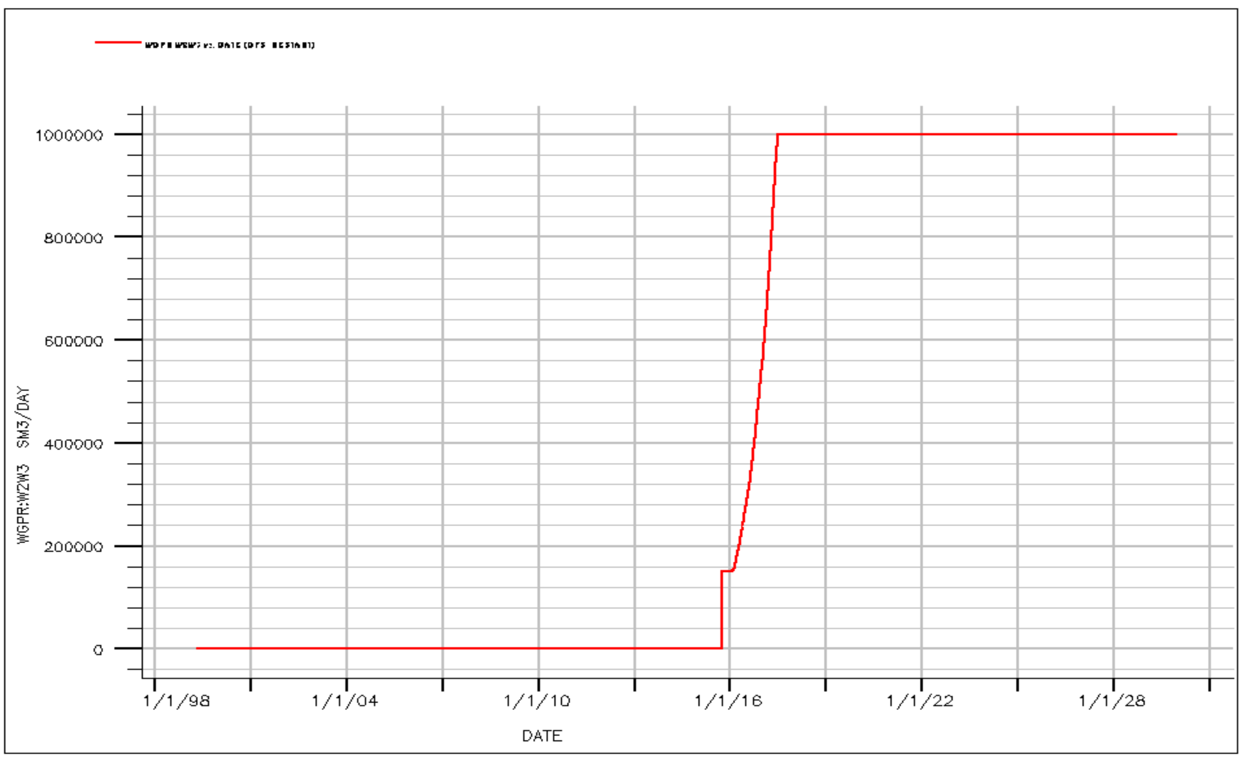


Figure 7-72: "W2W3", WGPR

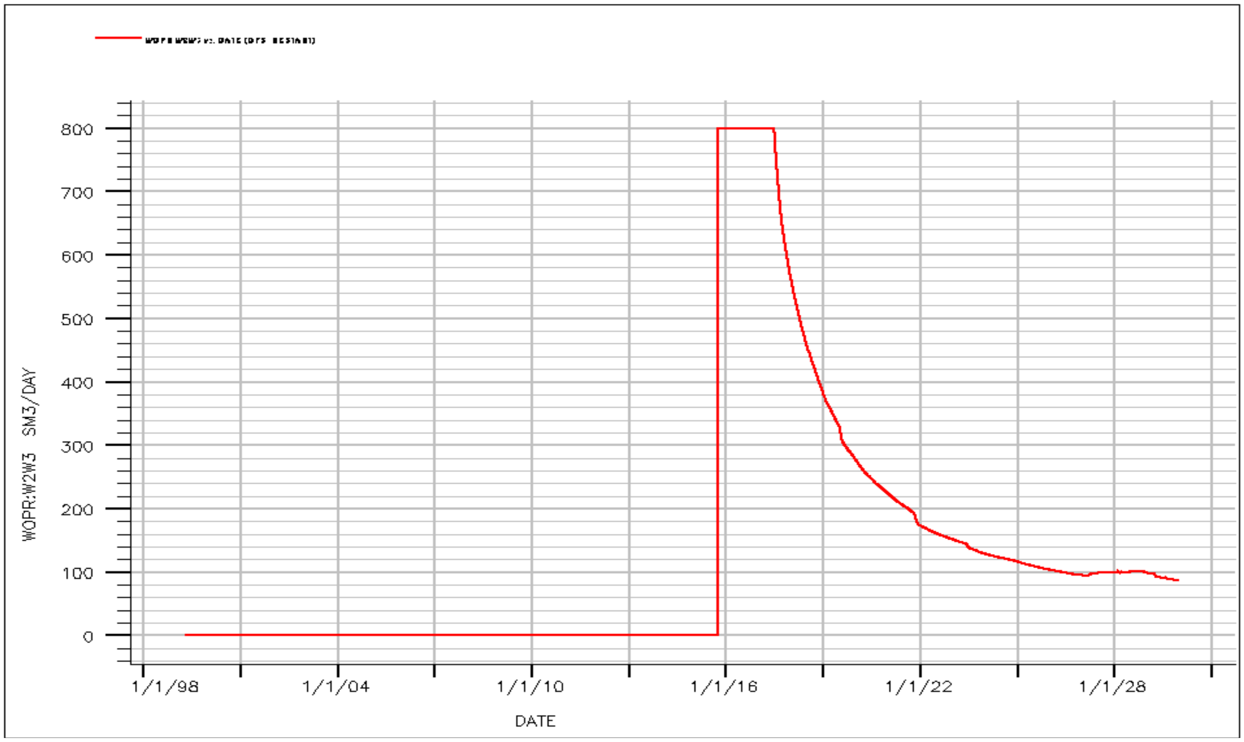


Figure 7-73: "W2W3", WOPR

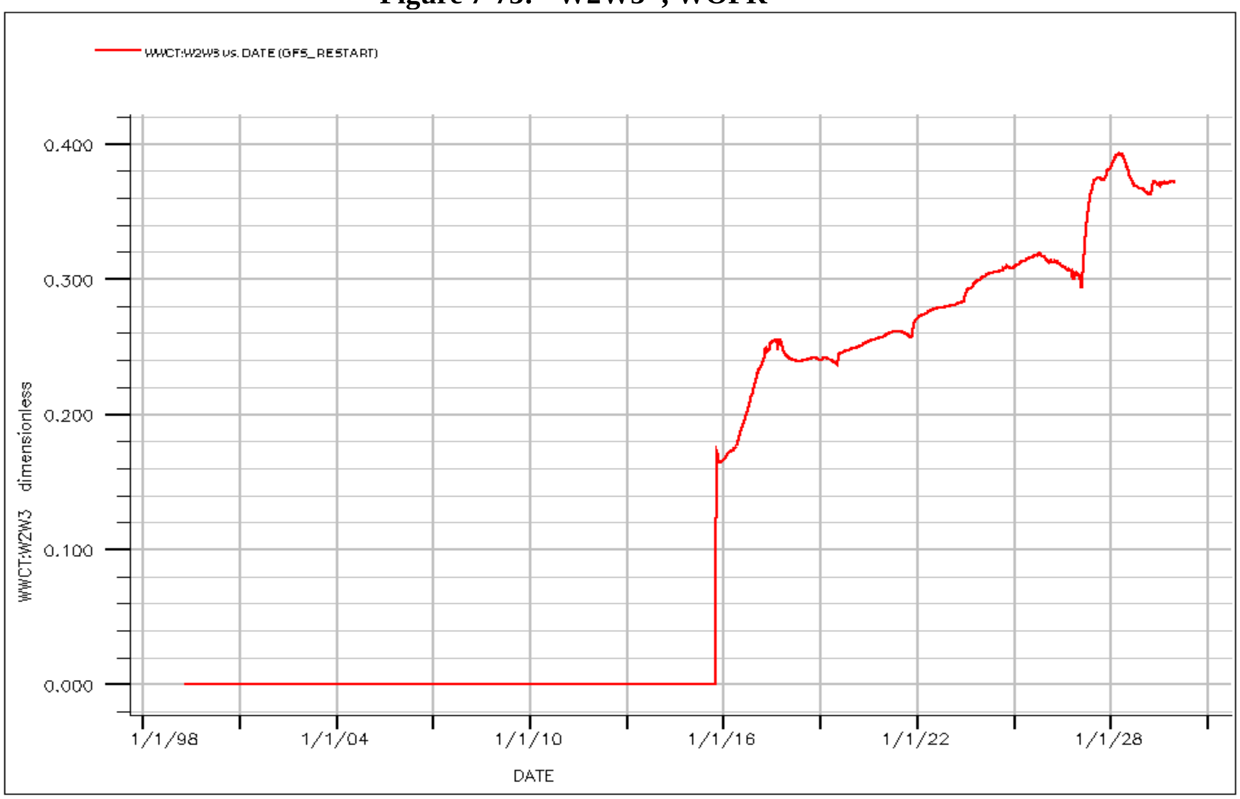


Figure 7-74: "W2W3", WWCT

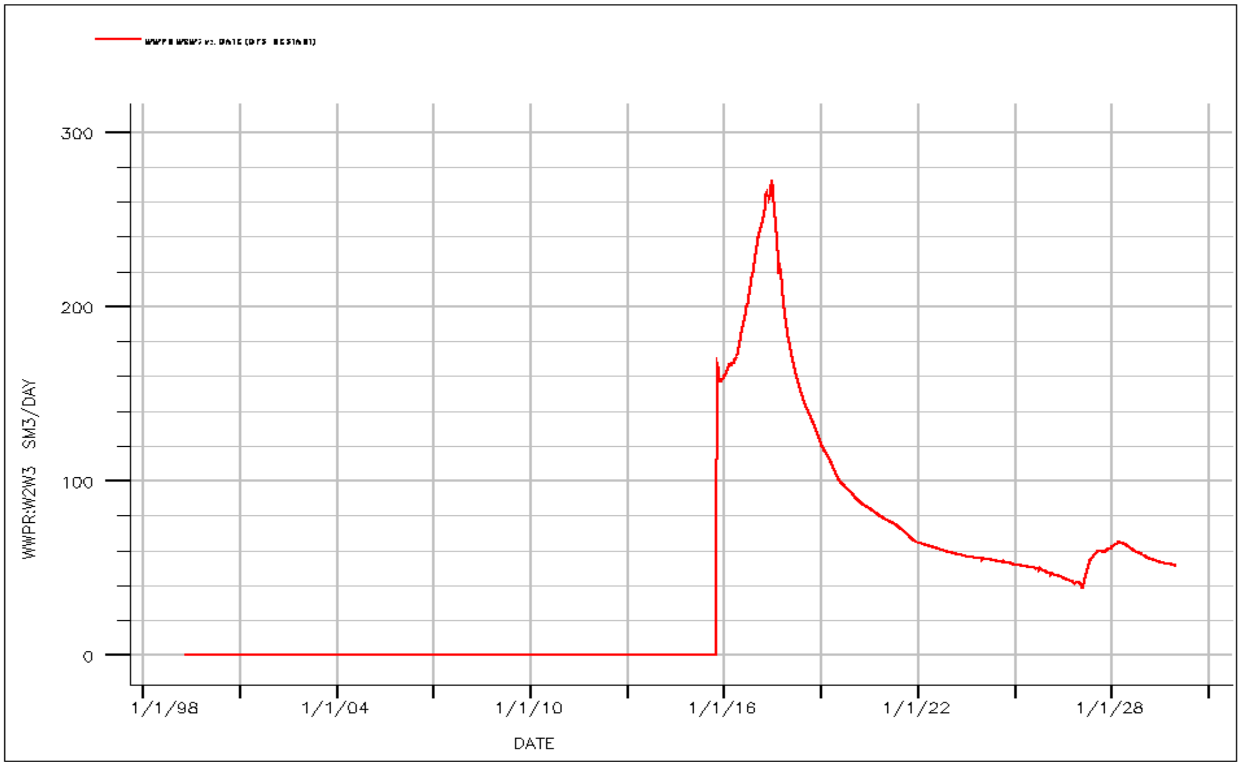


Figure 7-75: "W2W3", WWPR

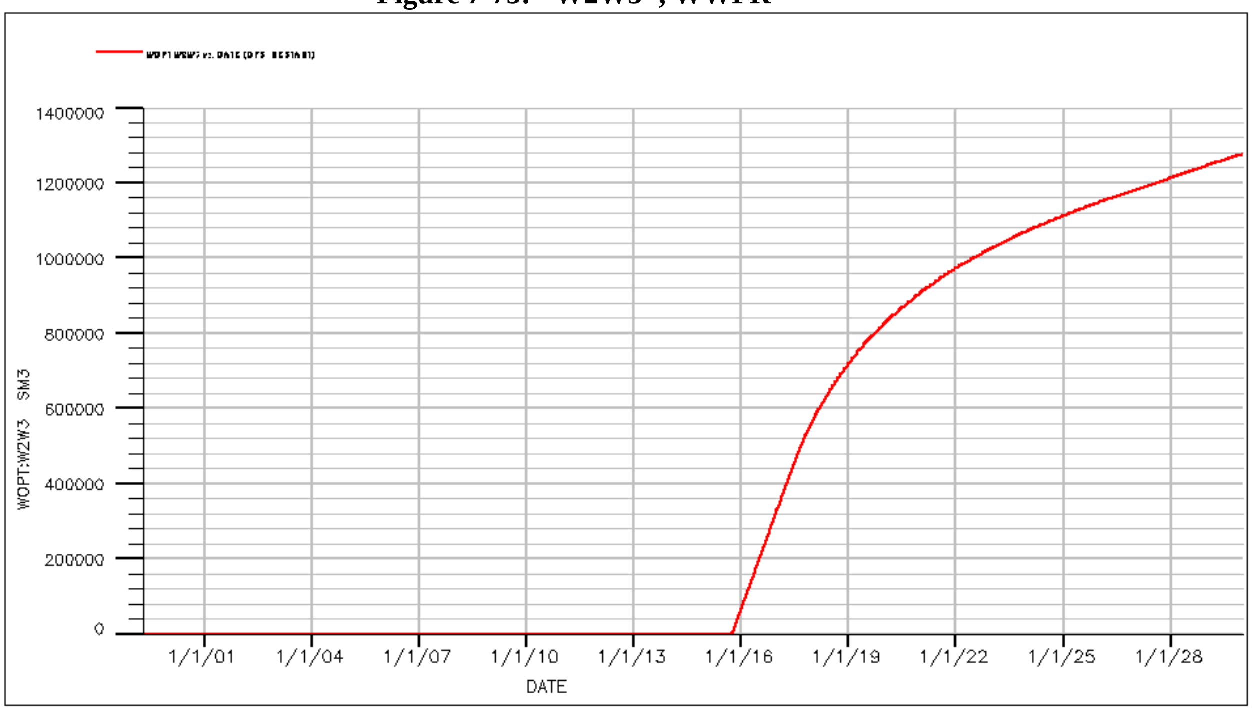


Figure 7-76: "W2W3", WOPT

Well Name: **W4W5**

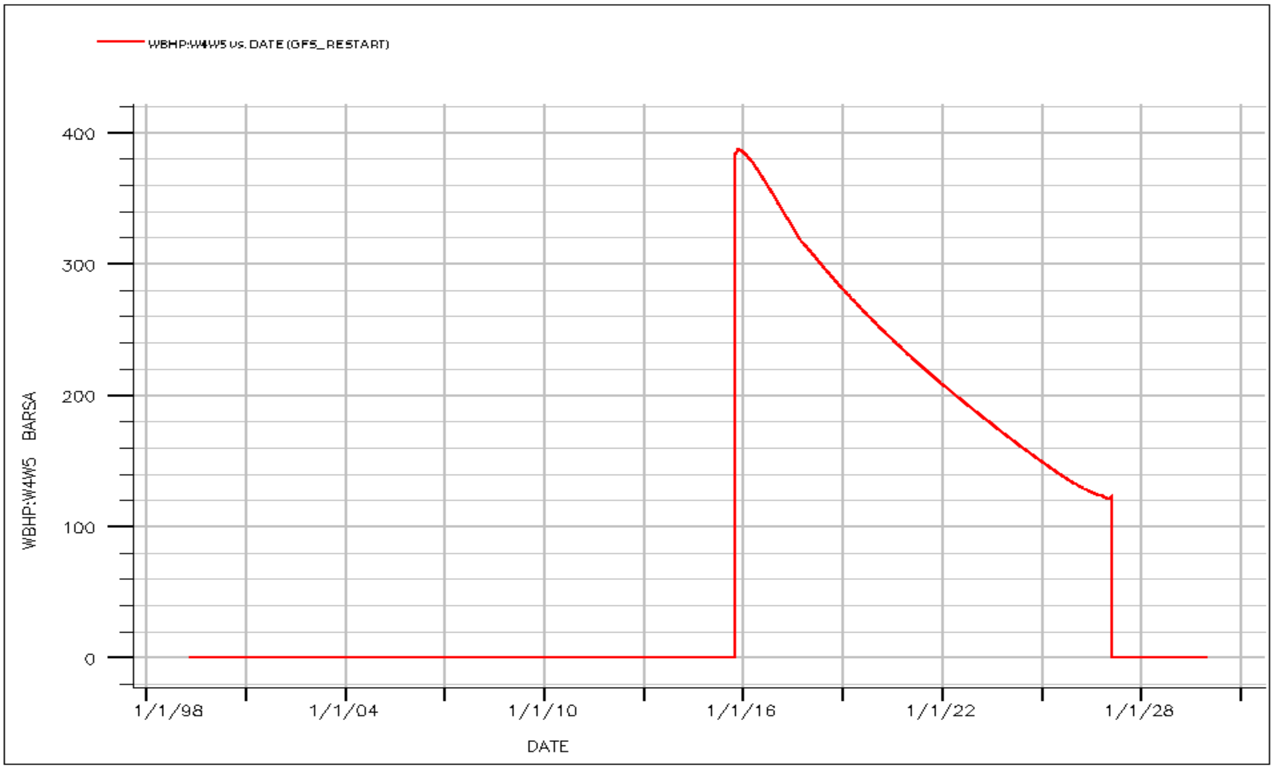


Figure 7-77: "W4W5", WBHP

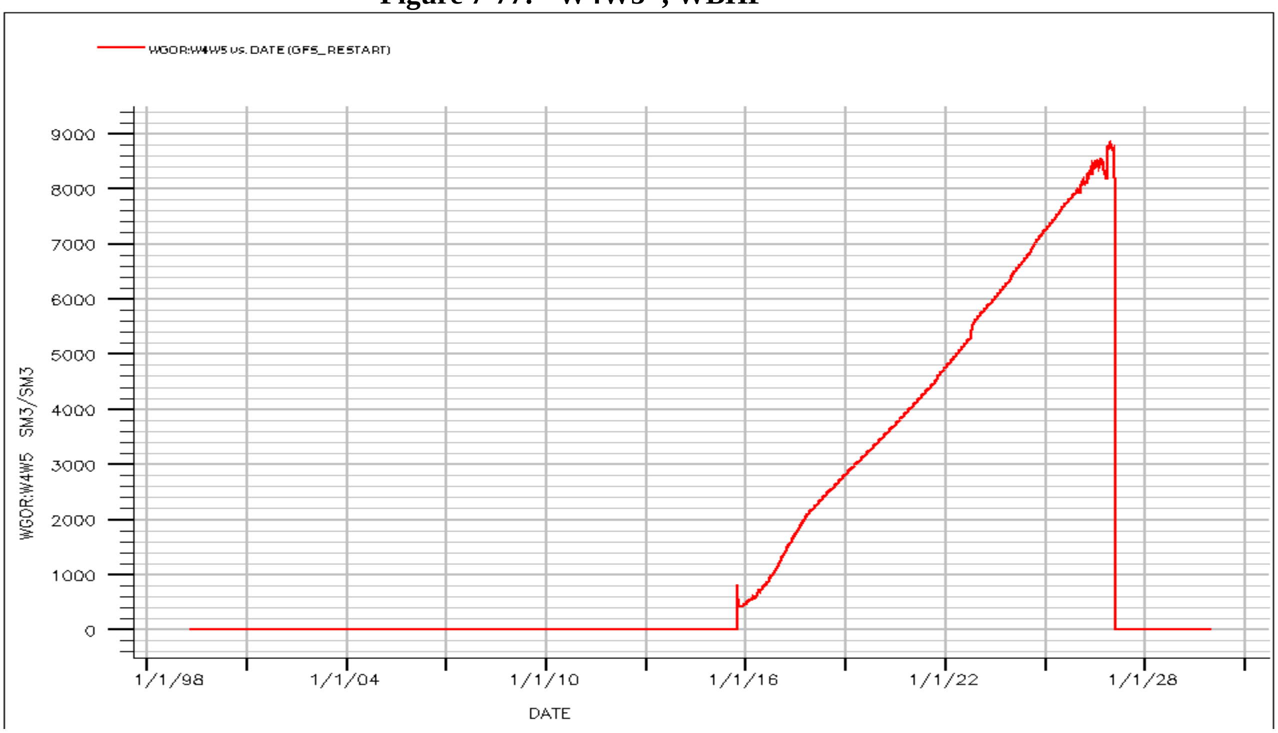


Figure 7-78: "W4W5", WGOR

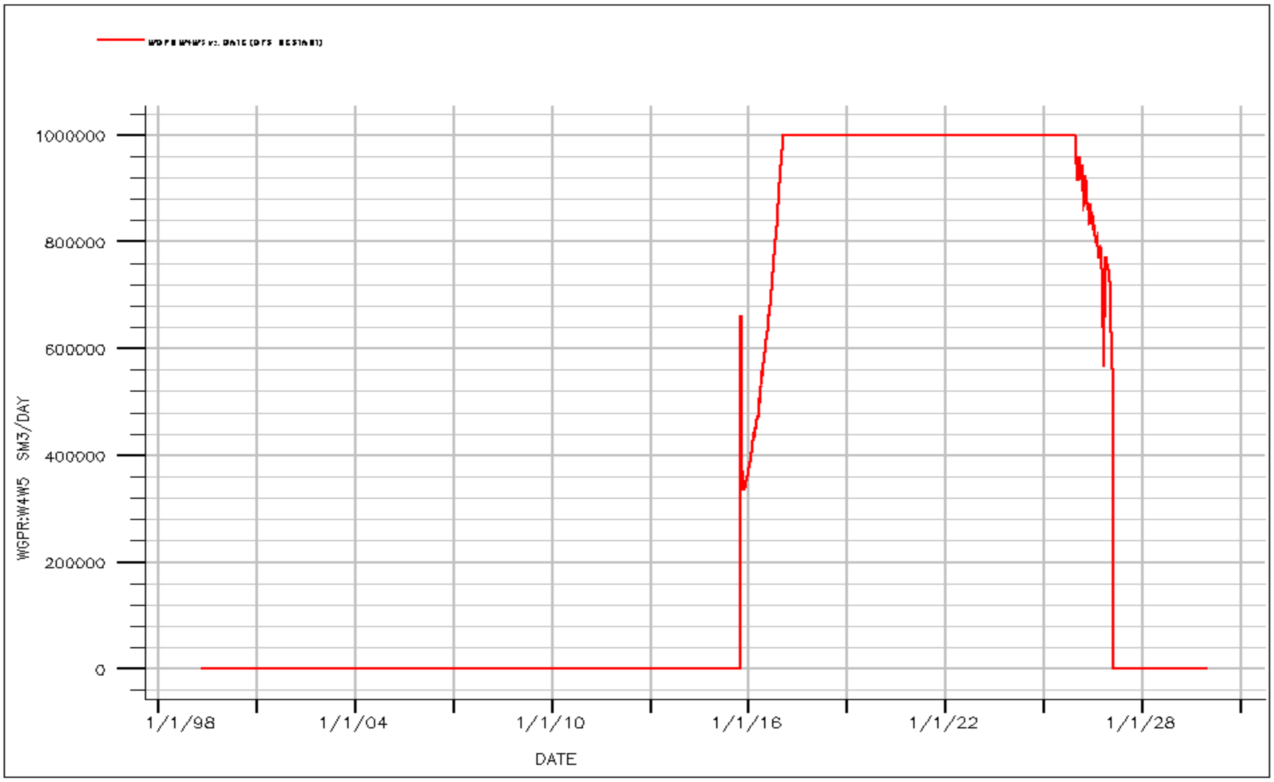


Figure 7-79: "W4W5", WGPR

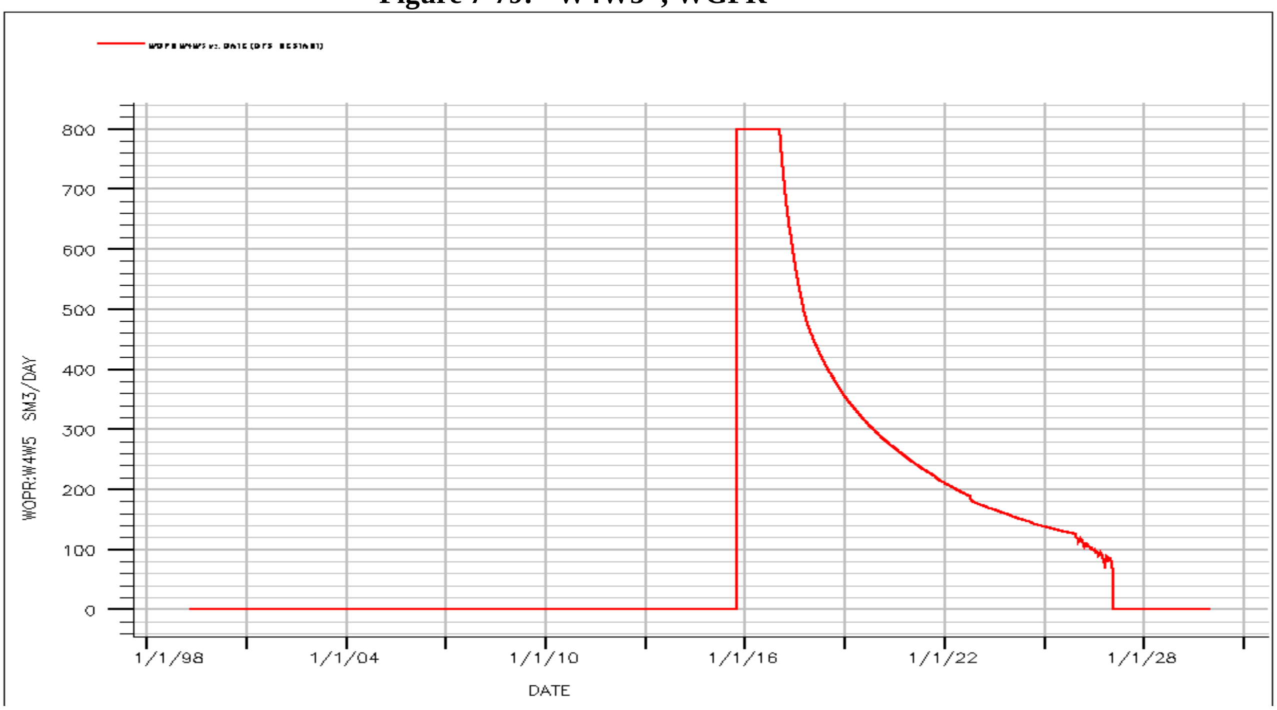


Figure 7-80: "W4W5", WOPR

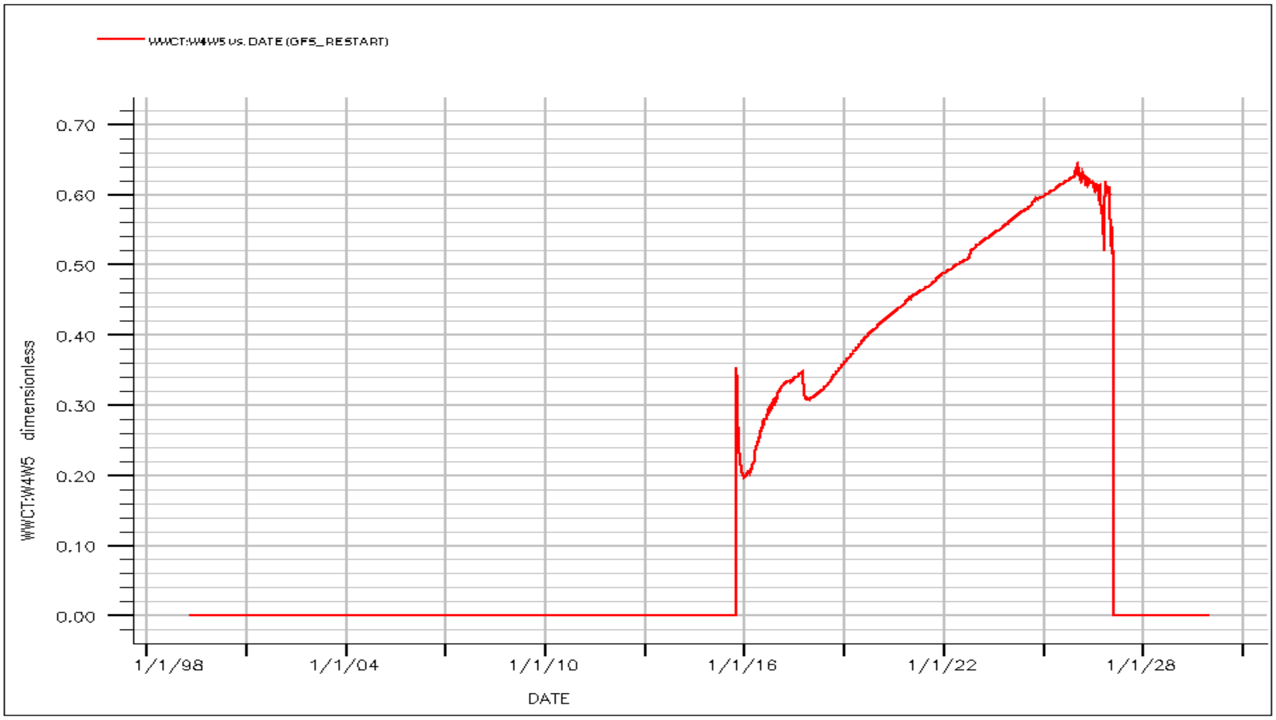


Figure 7-81: "W4W5", WWCT

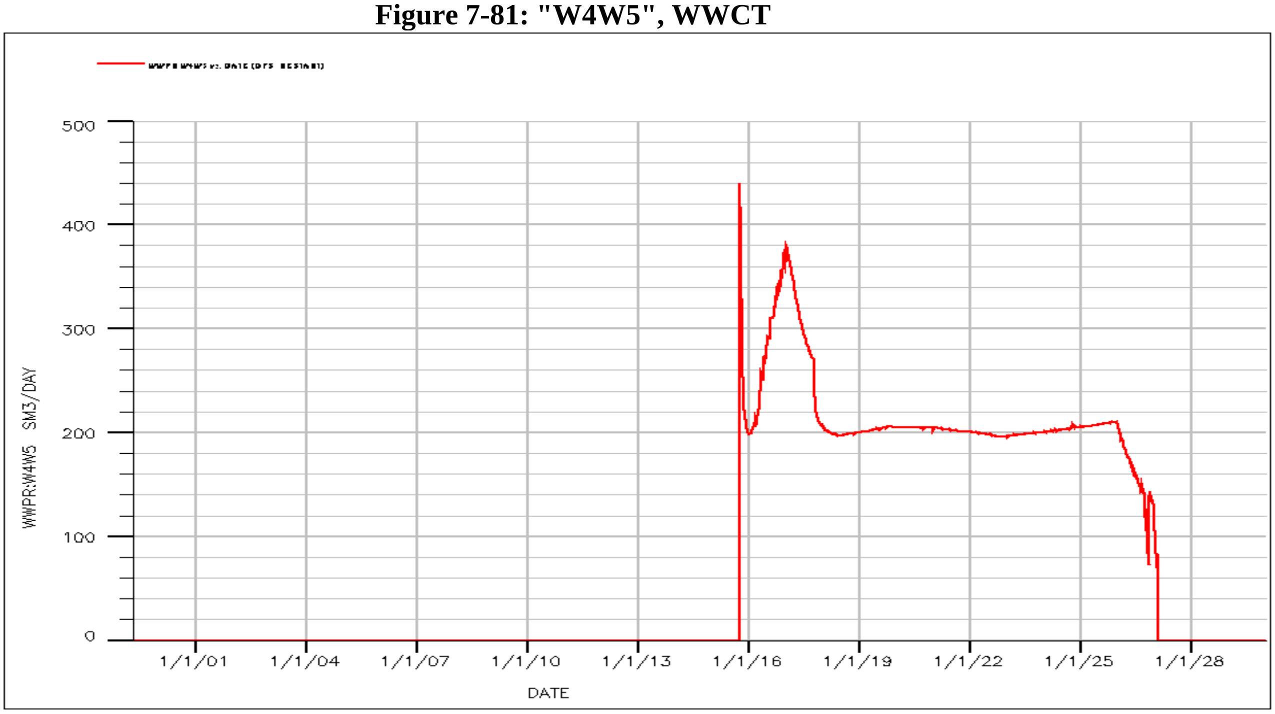


Figure 7-82: "W4W5", WWPR

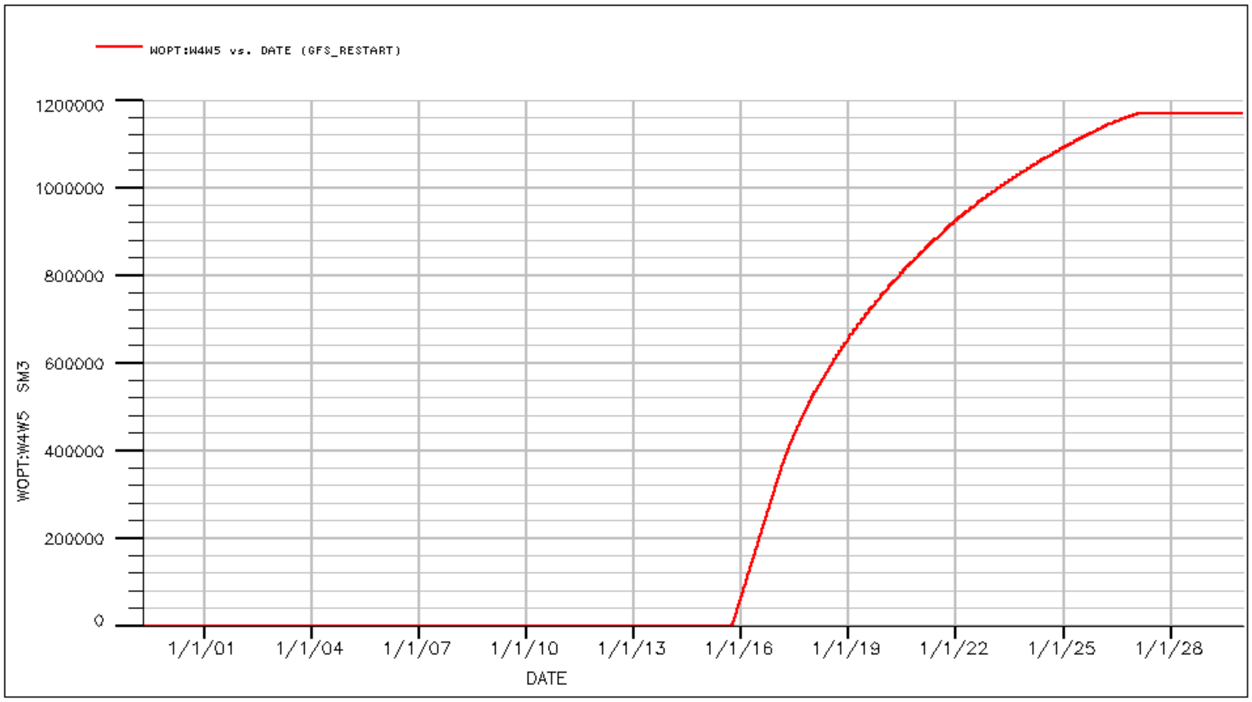


Figure 7-83: "W4W5", WOPT

Well Name: **W6W7**

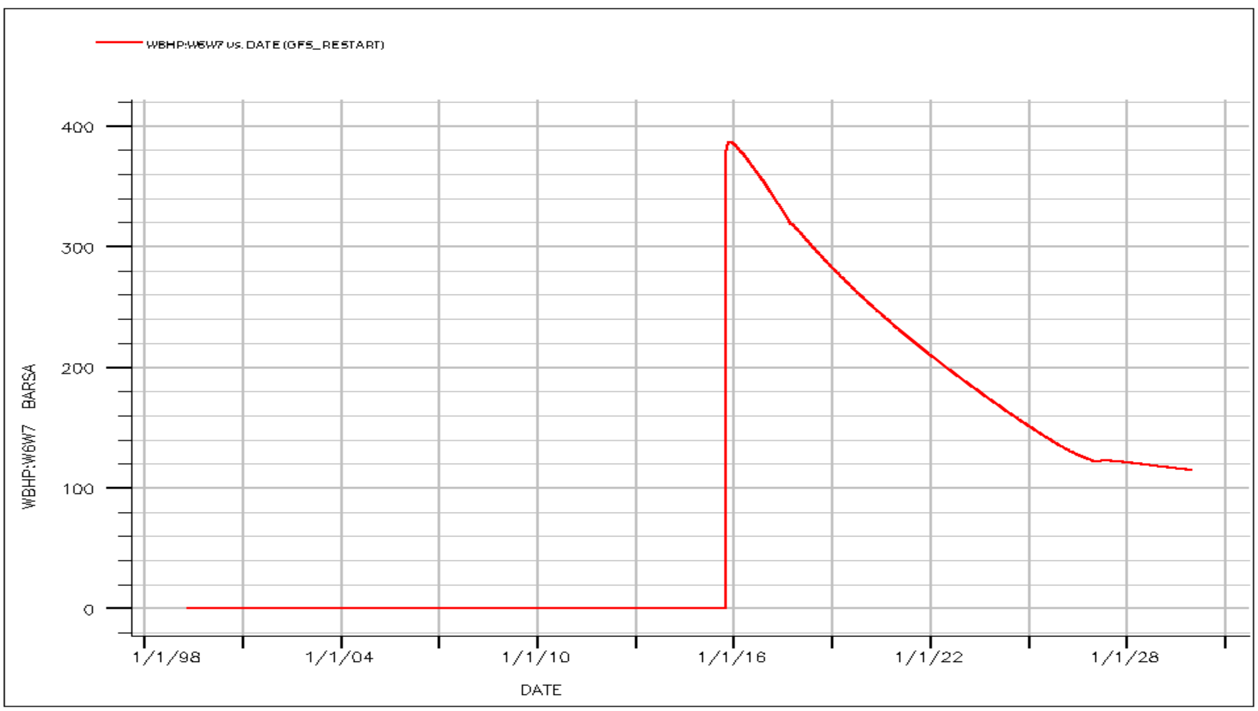


Figure 7-84: "W6W7", WBHP

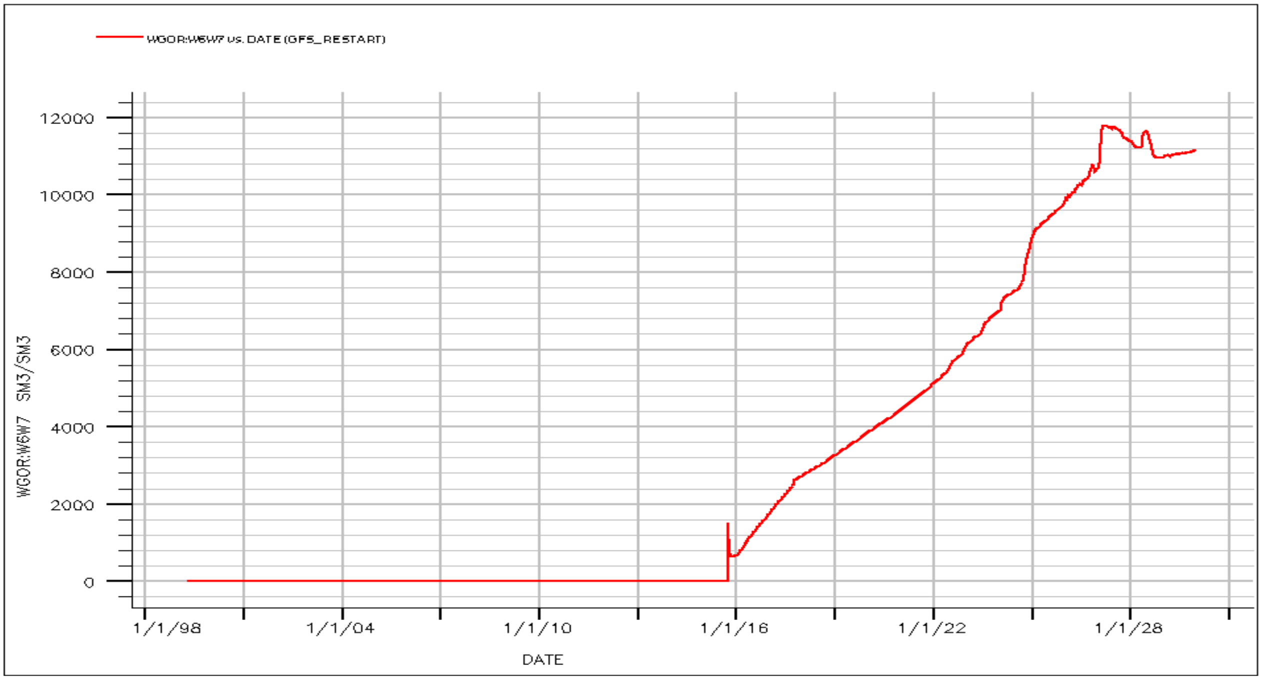


Figure 7-85: "W6W7", WGOR

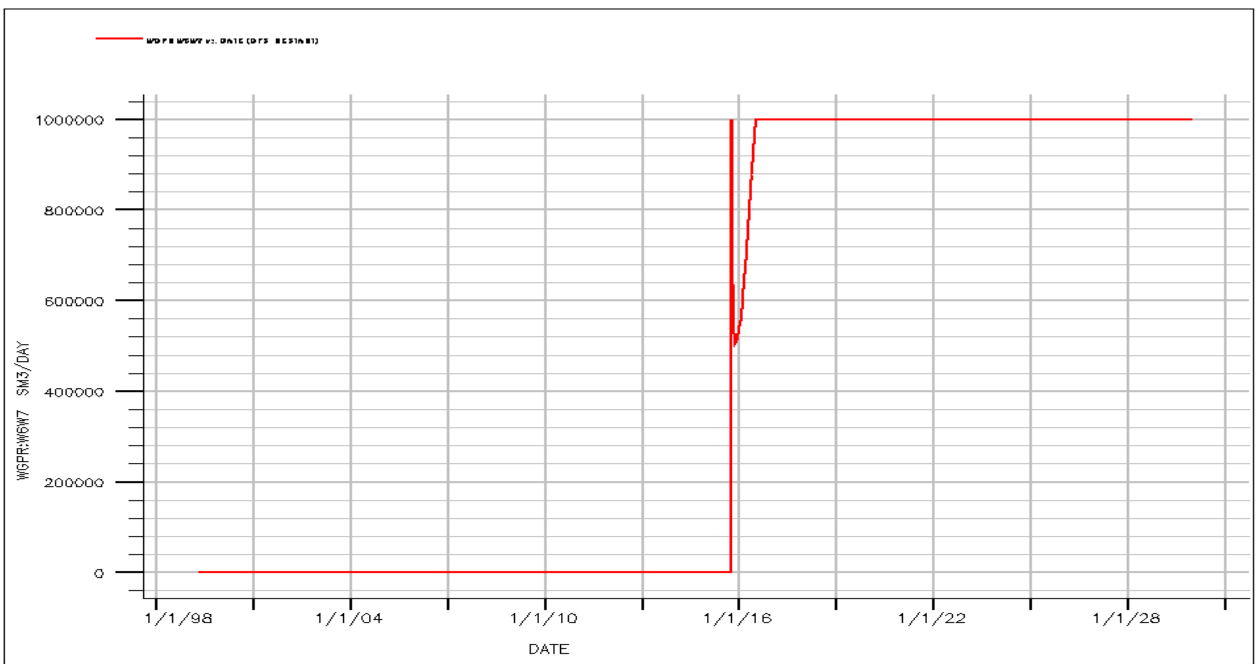


Figure 7-86: "W6W7", WGPR

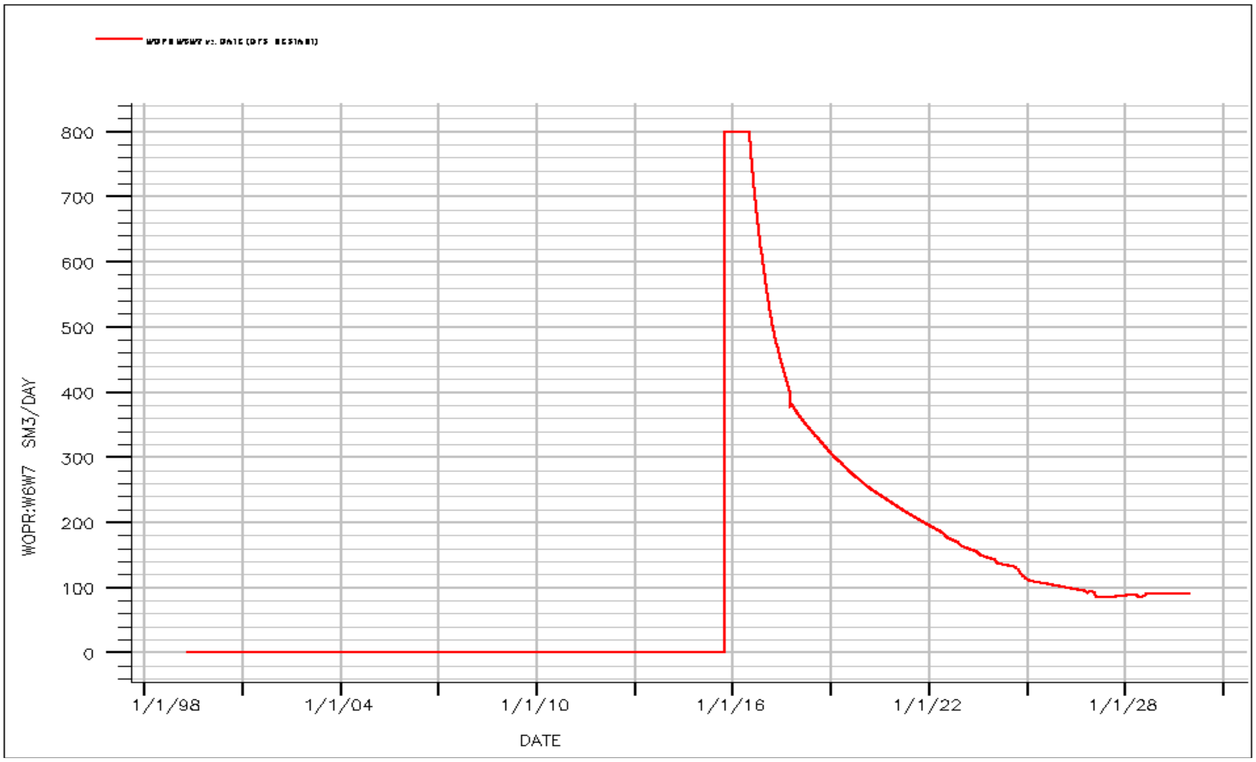


Figure 7-87: "W6W7", WOPR

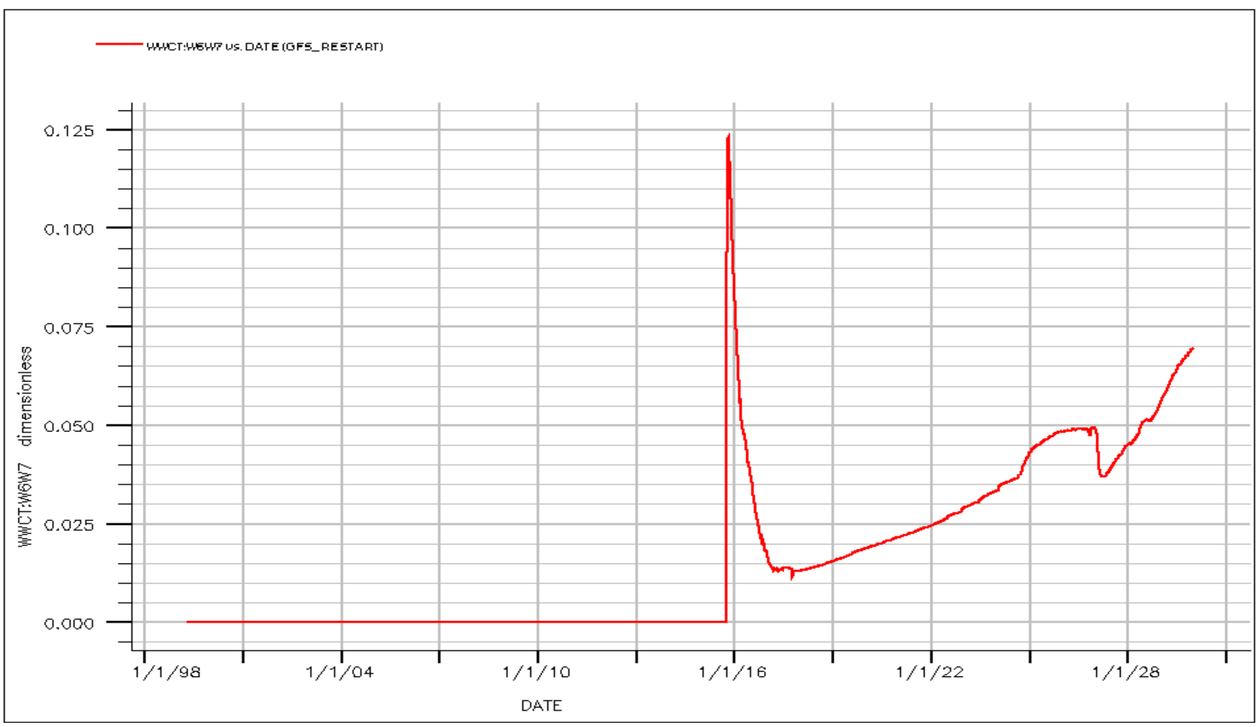


Figure 7-88: "W6W7", WWCT

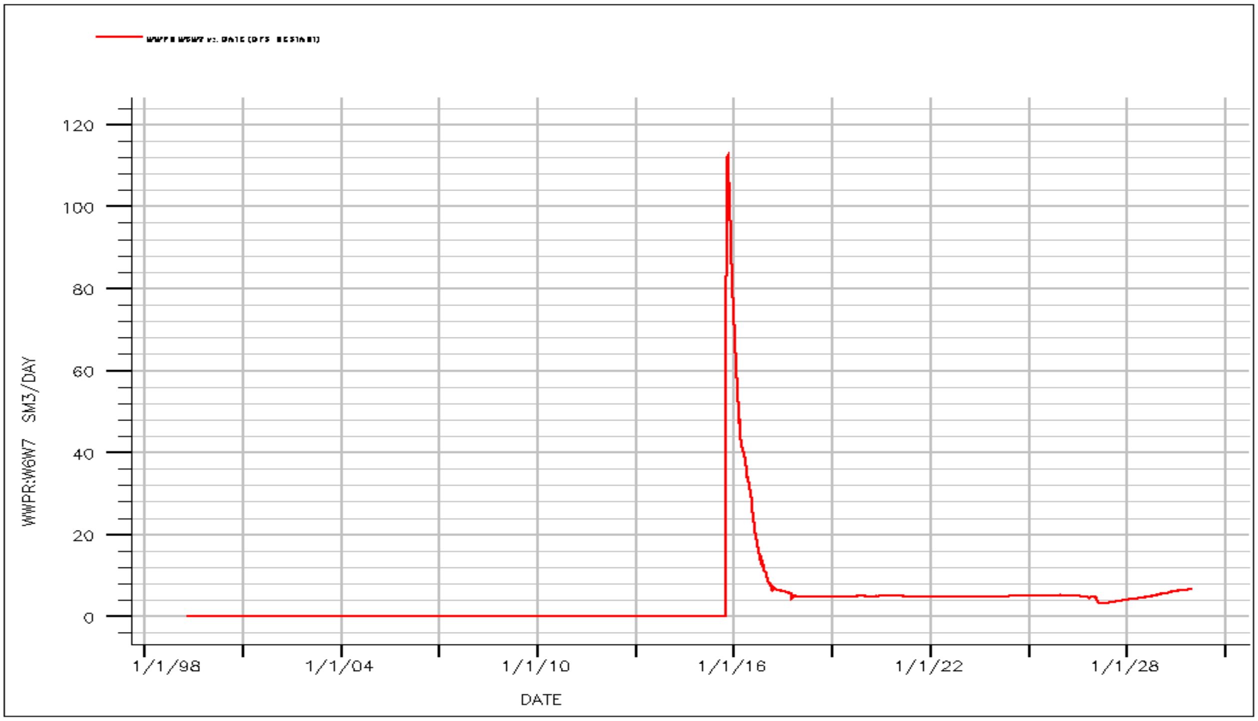


Figure 7-89: "W6W7", WWPR

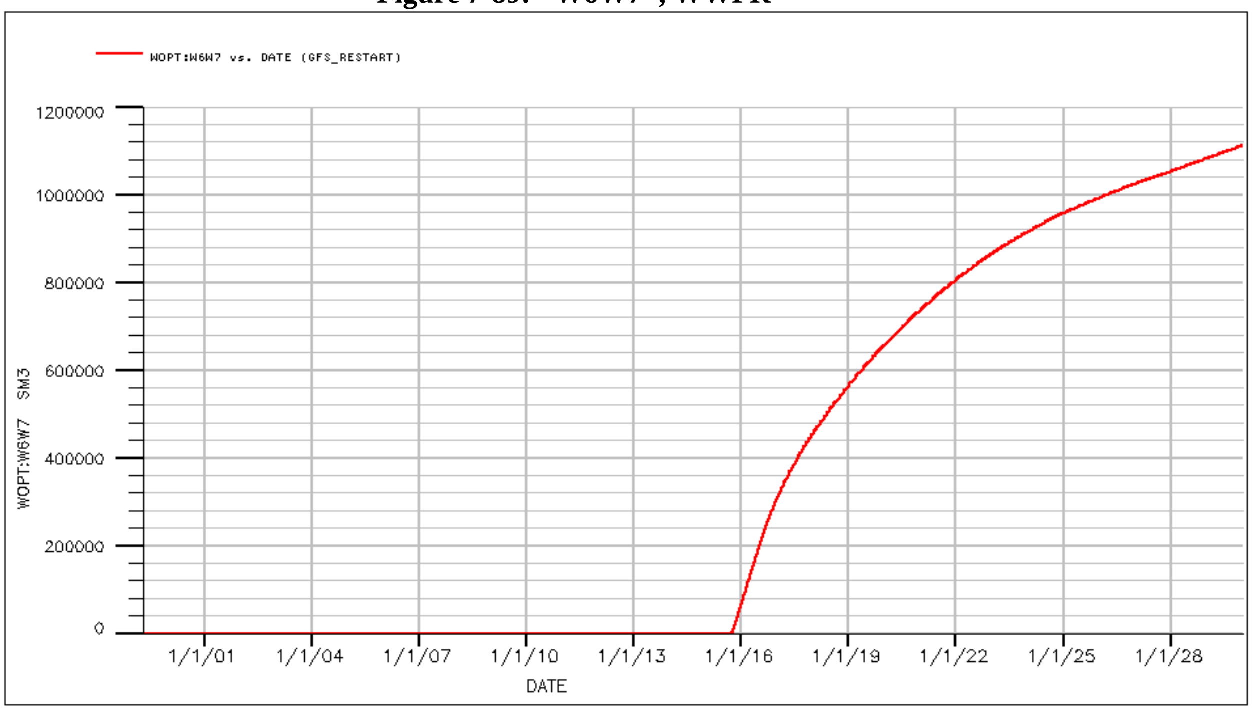


Figure 7-90: "W6W7", WOPT

Well Name: **E-1Y3H**

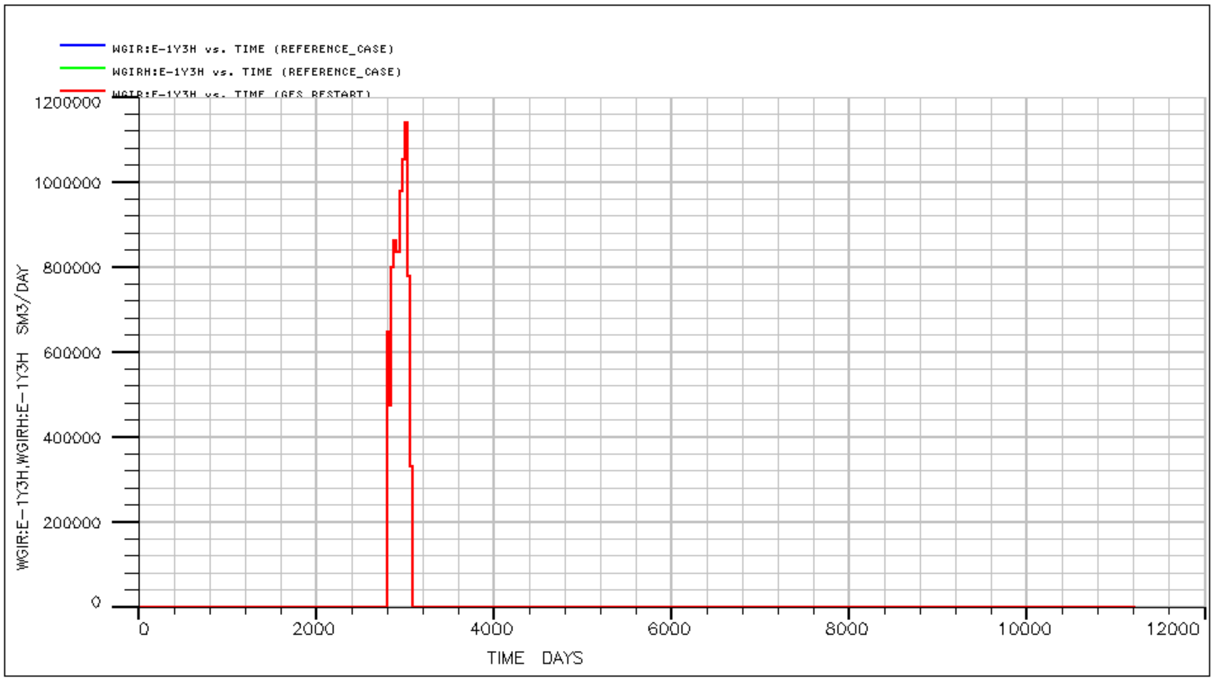


Figure 7-91: "E1Y3H",WGIR

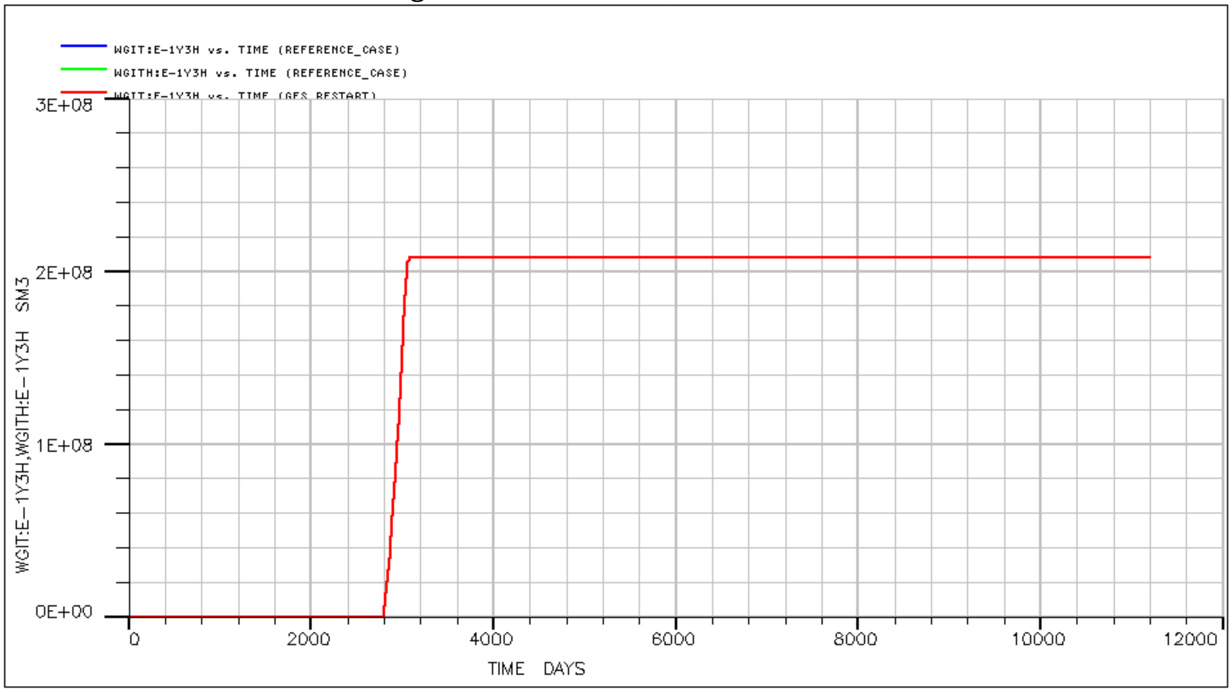


Figure 7-92: "E1Y3H", WGIT

Well Name: **E2BH**

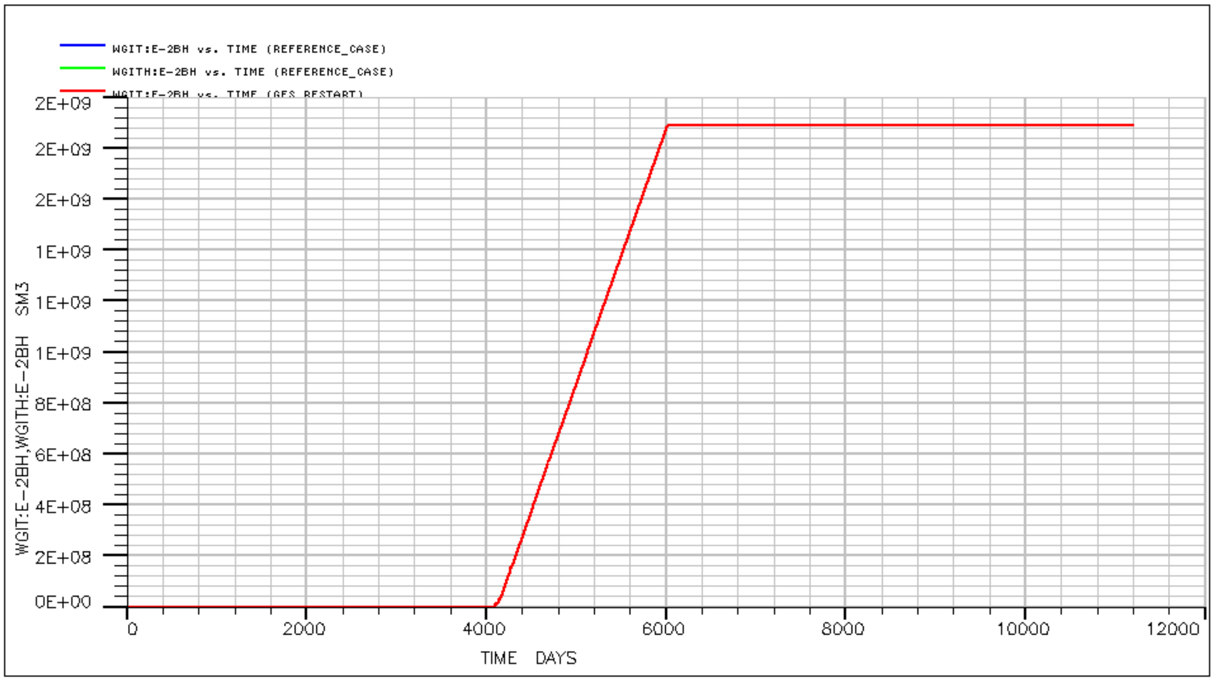


Figure 7-93: "E2BH", WGIT

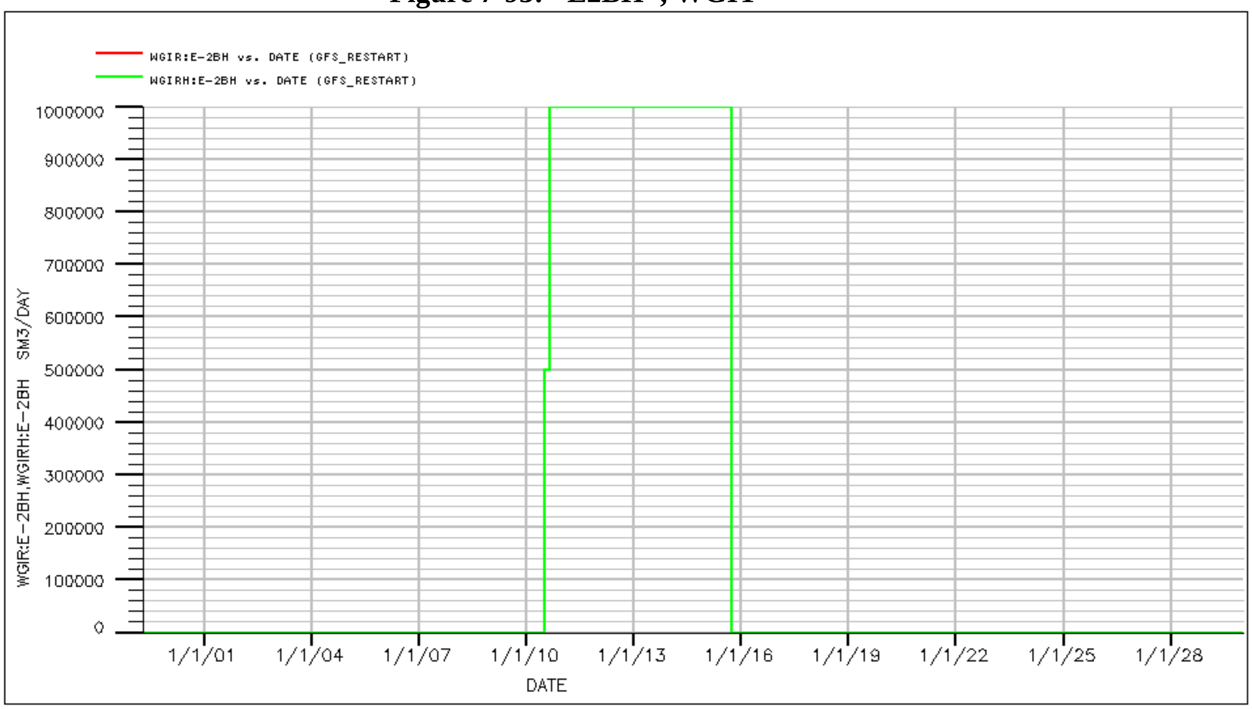


Figure 7-94: "E2BH", WGIR

Well Name: **E3H**

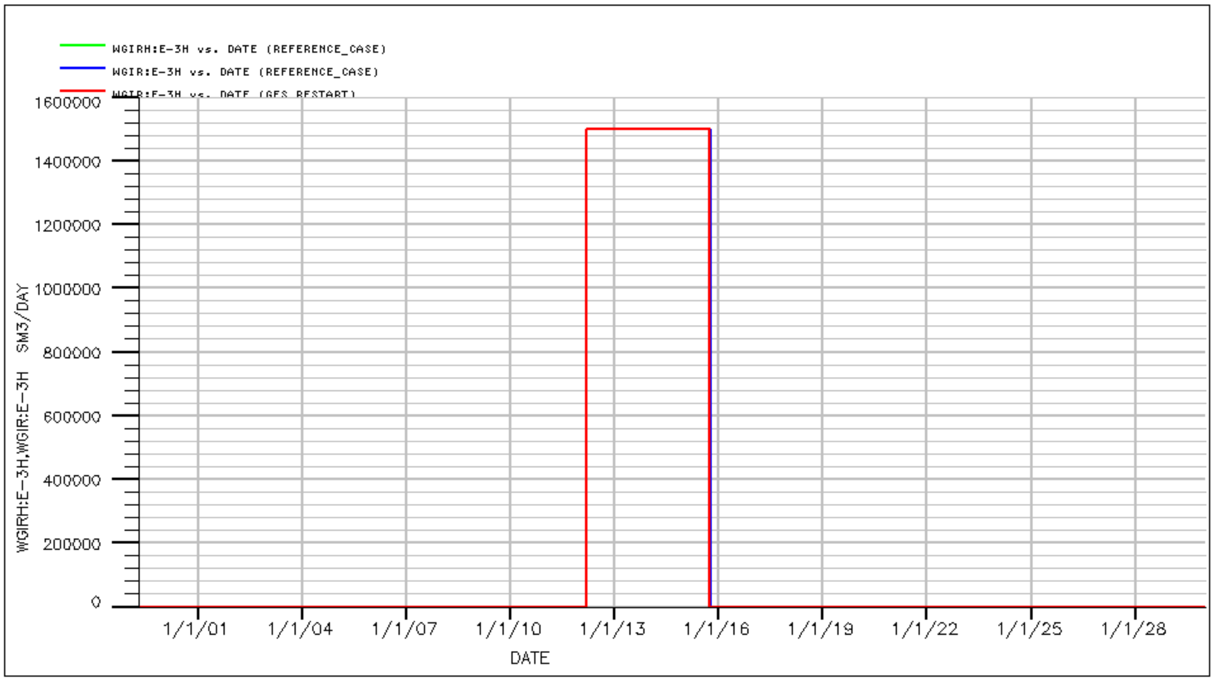


Figure 7-95: "E3H", WGIR

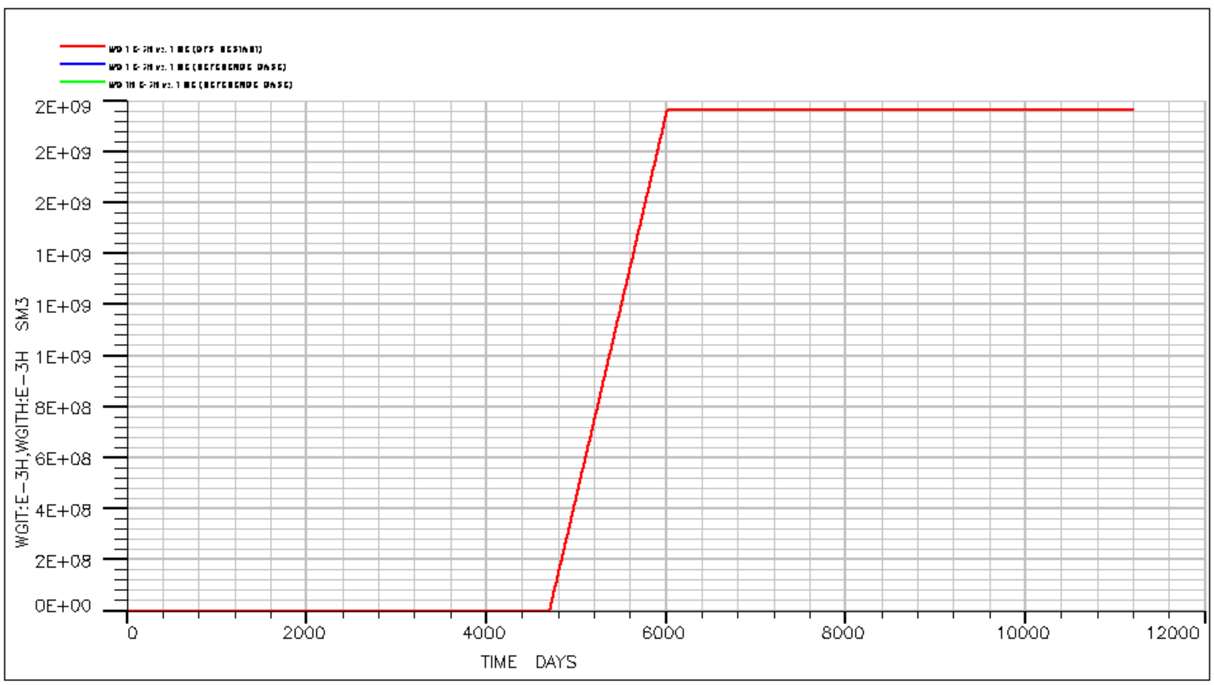


Figure 7-96: "E3H",WGIT

Well Name: **GI-2**

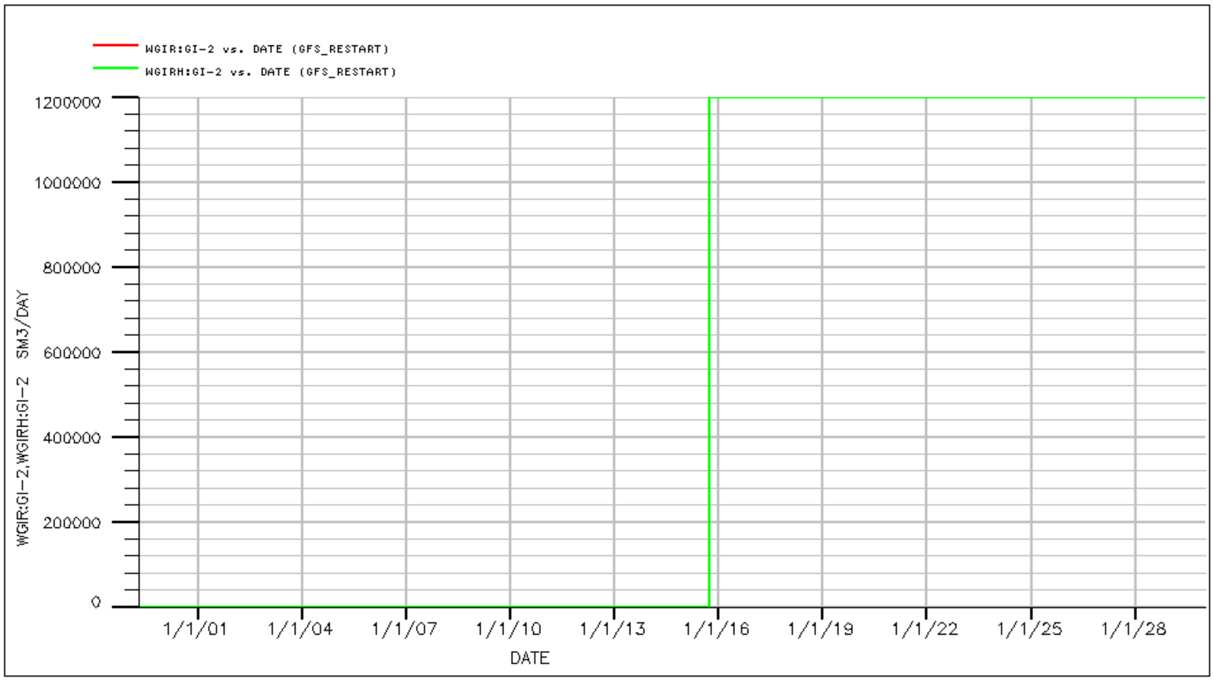


Figure 7-97: "GI2",WGIR

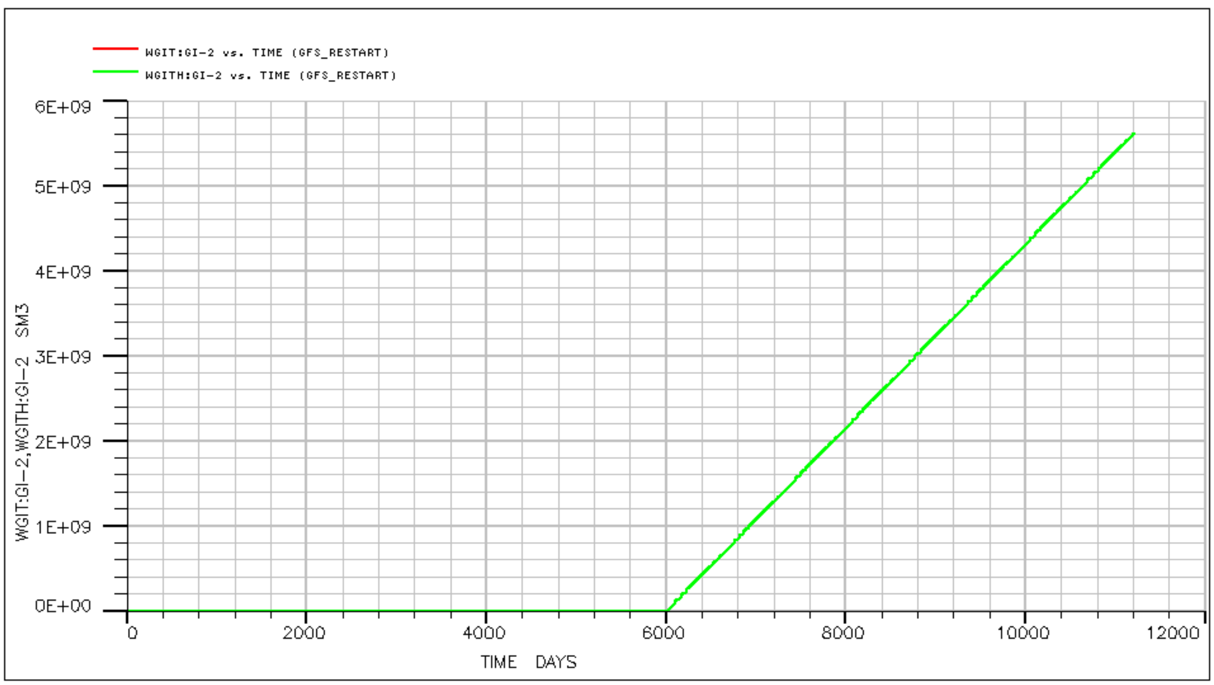


Figure 7-98: "GI2",WGIT

Well Name**: GI-4**

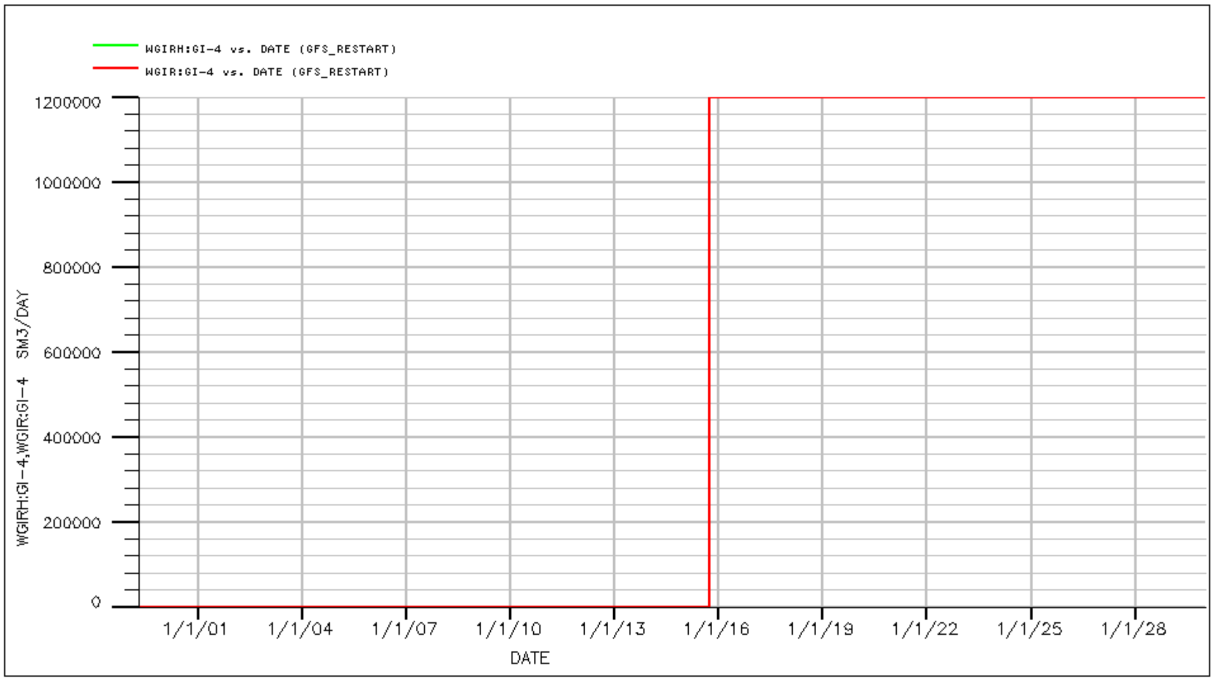


Figure 7-99: "GI4",WGIR

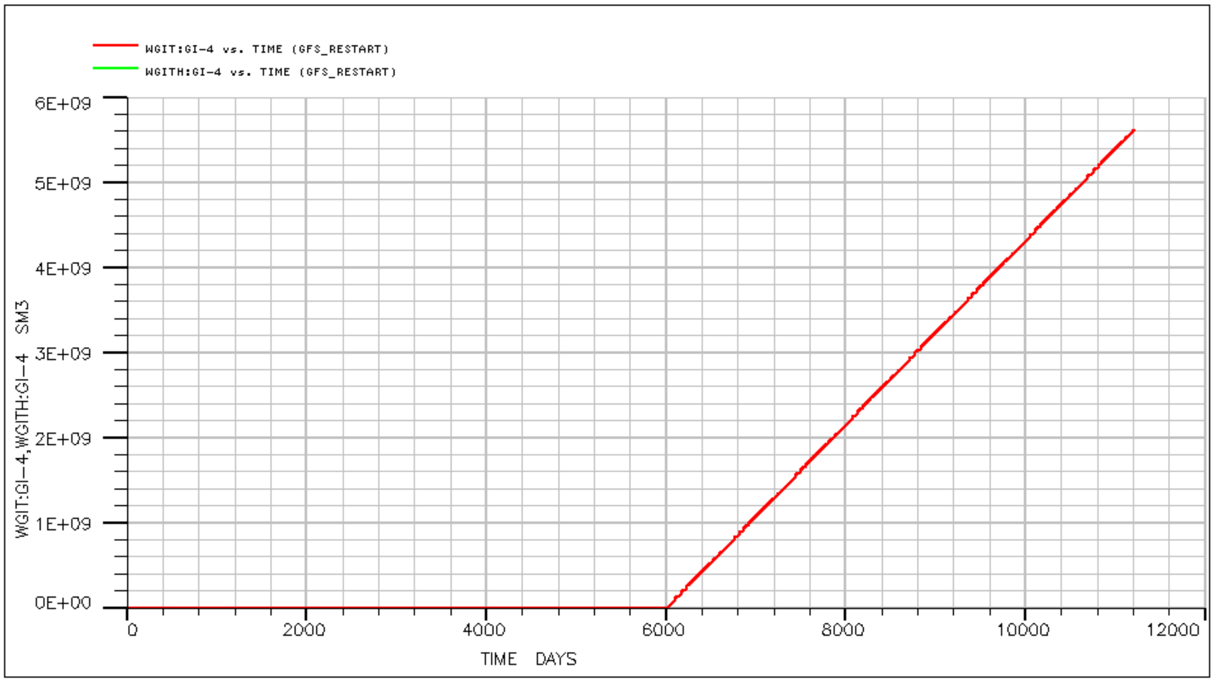


Figure 7-100: "GI4",WGIT

8 Reference

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