REBUTTAL EXPERT REPORT
U.S v. BP Exploration & Production, Inc., et al.

Estimate of Cumulative Volume of Oil Released from the MC252 Macondo Well

Prepared on Behalf of the United States

Prepared by:
Mehran Pooladi-Darvish
Fekete Associates, Inc.
Suite 2000
540 5th Avenue SW
Calgary, AB
Canada
T2P 0M2

M. Pooladi-Darvish

Table of Contents

Executive Summary

This report is primarily a response to the work of three of the defendants' experts, who use reservoir engineering techniques to arrive at an estimate of cumulative volume of oil released. These include works of Drs. Gringarten, Blunt [redacted]. Their estimate is generally in the neighbourhood of 3±0.5 MMSTB. In contrast, my best estimate is between 5 and 5.3 MMSTB. We have all analyzed the same reservoir and wellbore system. There are two possible explanations for the discrepancy: either the uncertainty in each of our estimates is larger than what we have been willing to admit such that our estimates should have been between approximately (say) 2.5 and 5.3 MMSTB, or one set of estimates is wrong[1, 2].

Production capability of any reservoir wellbore and BOP system is dependent on two factors; (i) the driving force for oil production or the pressure difference between the reservoir and the wellhead, and (ii) the resistances along the way. The defendants' experts and I generally agree on the magnitude of the driving force, with some differences that are addressed under wellhead flowing pressures in Section II. Therefore the fundamental difference between my estimate and that of the defendants'' experts is associated with the selection of the resistances in the reservoir, in the wellbore and/or in the BOP.

As demonstrated in my initial report, it is possible to model the system with different resistances and for these models to honour the pressure build up data after the well was shut in. I demonstrate this again in this report, this time using many of the parameters suggested by the defendants' experts. Thus, shut in pressures do not provide a unique solution to the problem, and for a solution to be reached, additional calibration points are needed. In my work, I concluded that the most accurate calibration point was the collection rates after the capping stack was installed. These measured collection rates likely varied by only a few percent. Defendants' experts generally ignore this data. My modeling has confirmed that the models that produce in the neighbourhood of 3±0.5 MMSTB are *not* consistent with the collection rates and the associated pressures at the wellhead and therefore are inconsistent with one of the key measurements available. In contrast, models that are consistent with these collection rate measurements produce in the neighbourhood of 5.2 MMSTB. Therefore, I have come to the conclusion that it is the ignoring of the measurements preceding the shut in of the well that has led the defendants' expert to remain satisfied with their models that all have large resistances. Had they examined the performance of their models against the collection rates and the associated pressures at the wellhead, they would have observed the inconsistency between their models and the measurements.

---

[1] The estimate of 3±0.5 MMSTB expressed in the text is my average of the numbers presented by the different experts. Otherwise, the estimates vary among them. Dr. Gringarten's estimates vary between 1.7 and 4.15 MMSTB. Hi best estimate is between 2.4 and 3 MMSTB. Professor Blunts range of estimates is between 2.9 and 3.7 MMSTB. His best estimate is 3.26 MMSTB. [redacted]

[2] I have reviewed reports of Drs. Blunt, Gringarten, Johnson, Lo, Momber, Nesic, [redacted] Trulsler, Whitson, Zaldivar, and Zimmerman. Some have provided a critique of my work. Responses to those critiques are included in Section V of this report.

Instead of calibrating their models to collection rates, the defendants' experts seize on data points that have much more uncertainty. Dr. Blunt's analysis is highly dependent on estimates of Original Oil In Place (OOIP) and compressibility, and he fails to fully acknowledge the uncertainty relating to these values. Dr. Gringarten's model is highly dependent on the MDT derived permeability, despite the high uncertainty associated with that value. My model fully acknowledges the uncertainty in OOIP, compressibility, and permeability, as well as other uncertain parameters such as skin. My model suggests that, regardless of what those properties were, a match of both shut in pressures and collection rates only occurs when the cumulative oil released is approximately 5.0 to 5.3 MMSTB. Drs. Blunt, Gringarten [redacted] have additional weaknesses in their models, as will be demonstrated in Section IV.

My base model also assumed that the resistances did not change over time, and the defendants' experts have attacked my work on that basis. The assertions of the defendants' experts, however, are inconsistent with the only real data we have regarding the change of resistances over time. The BOP pressures show a steady declining trend after May 8, and the most likely cause of this steady trend is the steady decline of the flow rate due to reservoir depletion. Suggestions that the productivity index was increasing during this time is speculative, as I discuss in Section III. However, I do study the possibility of change in the BOP. I conduct a study that accounts for any changes that could occur in the BOP after May 8. Results of this study remains consistent with my range of estimates of between 5 and 5.3 MMSTB.

Pre May 8 there is more uncertainty, although we know some restrictions downhole and at the BOP eroded very rapidly. My "What if" cases in my original report, as supplemented by additional modeling using Dr. Trusler's suggested corrections to the BOP pressures presented in Section III, considers an extreme case that assumes a perfect seal at the time of the blow out followed by a steady erosion of the BOP until May 8, when subsequent changes in the BOP (if any) are considered in the model through the use of the BOP pressures. The results suggest a range of between 4.4 and 4.7 MMSTB. While I believe this to be very unlikely, it provides an extreme lower bound on the range of possible results.

I start with a discussion of "why I did what I did, and why my analysis is superior to that of the defendants' experts. In Section II, I consider parameters and models that the defendants' experts have suggested, and show that although they lead to a match of the shut in pressures they are inconsistent with the collections rates. In Section III, I examine situations where the restrictions in the system may be changing with time. This is followed by a review of the weaknesses of the analyses presented by defendants' experts and my response to the critique presented by the defense experts in Section IV and V, respectively.

Section I: Why I did what I did, and why my analysis is superior to that of the defendants' experts

When I first began my efforts to estimate the oil release from the Macondo well, I looked for parameters that would define the flow capability of the Macondo reservoir and its wellbore. I found that we have a reasonably good knowledge of the fluid properties. Review of the core data indicated that the porosity of the rock varies over a narrow range. Review of the petrophysical logs and MDT's and their interpretations provided by BP suggested that oil flow would have occurred from up to three reservoir sands with a total thickness of approximately 93 ft. Similarly, on the wellbore side, dimensions of the wellbore were known. However, it was also clear that a large number of the reservoir and wellbore properties that could have a major impact on flow rate were unknown. By large impact, I mean a factor of larger than two or more. Three such important parameters included permeability, skin, and the BOP restriction. Estimates of permeability were available from side walcores, MDT tests, and CMR log. All suffered from two major problems: (i) how to relate the measurements to the permeability at reservoir conditions, and (ii) given the large variations from point to point, how to come up with an average value that is representative of the total interval? These problems amounted to uncertainty of more than 100% in the estimates of average permeability. The best method for estimation of permeability is a controlled well test. Even then, based on experience in other projects, the estimates of permeability obtained from this method often carry an uncertainty of more than 50%, especially when applied to the whole reservoir.

The other two parameters of skin and BOP restriction carried even larger uncertainties. For example, a properly functioning BOP could have effectively stopped the leakage, while a fully open BOP was associated with flow rates that were estimated to be in the tens of thousands of STB/day. Clearly, the uncertainty associated with the BOP restriction was huge. A similarly large uncertainty existed for skin, as I could consider two very different scenarios. On one end, a reservoir rock that is totally plugged with solid cement (a very large positive skin) would flow nothing at all. On the other end, I conceived the possibility that due to very high flow rates the reservoir rock might have been eroded away opening up additional space to flow; a situation that could result with skin values less than zero. I did not have a way to quantify these parameters. I realized that depending on the choice of my assumptions I could come up with flow rates that ranged between a few thousands of barrels per day to more than 100,000 STB/day. Therefore, I realized that any model that I build needs to be *calibrated* against measurements that are reflective of the reservoir and the BOP.

In petroleum engineering, calibration of reservoir models is an important step towards development of reliable models. The first set of measurements that I as a reservoir engineer focused on were the wellhead pressures that were obtained after the well was shut in(i.e. the shut inpressures). These are the same data that Drs. Gringarten, Blunt [redacted] use to calibrate their models or otherwise examine the applicability of their models against.

A discipline in reservoir engineering called well test analysis has been developed and advanced over a number of decades the primary objective of which is to analyze shut in data to estimate permeability and skin, among other parameters. A well test analysis could have provided an estimate of two of the three main unknowns listed above. I knew a problem existed with application of well testing techniques to this case because in well testing we measure the oil flow rate before the well is shut in. It is this knowledge of the rate that allows estimation of permeability and skin. This is because the response of a well to a change in rate (shut in) is not only a function of its permeability but also a function of the magnitude of the change in rate. I found that my estimation of permeability depended on my assumption of oil flow rate, the very parameter that I was after. In other words, I could come up with various combinations of permeability and rate that would match the shut in data. I showed then, and I show in this report, that the analysis of the shut in pressures alone result in a wide range of oil rate (and permeability) associated with a cumulative volume of oil released of at least between 3 and 7 MMSTB.

[redacted]

I knew that if I wanted to estimate the oil flow rate I needed additional information that reflected the production potential of the system. Such information exists. During the integrity test, by directing part of the flow away from the system such that it did not come across the resistances in the capping stack, a change in flow rate was caused. In the meantime, two essential pieces of information were obtained: the rate of the oil diverted (i.e. the collection rate), and the change in pressure associated with this change in rate were measured at two locations in the wellhead (at the BOP and at the capping stack). This information allowed estimation of resistances in the system and the flow rate during the integrity test. This estimate was essential to my ability to determine flow rate at other times, as I used it in the analytical phase of my initial report.

The collection rate is the piece of information that the defendants' experts, Drs. Gringarten, Blunt [redacted] have ignored. Instead defendants' experts have relied on information that carries a large degree of uncertainty (as detailed later in this report). However, they have not incorporated the full range of uncertainty that those parameters carry, and therefore they have found only a small portion of the answers. I demonstrate that answers other than what they have presented can be obtained that are consistent with their methodology and lead to much larger estimates of cumulative volume of oil released than what they have reported.

I evaluated the degree of uncertainty on this measurement of the collection rate. I found that the measurements of oil rate on the vessels are accurate to a few percent. Then I confirmed that the calculation of the collection rates is not affected by the offsets to the BOP and capping stack pressures considered by various investigators. Overall, the uncertainty associated with these measurements and their results was *much* less than the uncertainty associated with parameters such as permeability or skin. This uncertainty is why I incorporated the measurements during the collection period in my analysis. In particular, in the analytical part of my study, I first calculated the oil flow rate during the integrity tests, and then moved backward in time to estimate oil flow rate at preceding times. In doing so, I obtained my first approximate estimate of 5.2 MMSTB.

However, there were some limitations in the analytical work. As a practicing reservoir engineer I needed to find out the reservoir and wellbore properties that would be consistent with my interpretation of rate. I needed to confirm that my solution was consistent with information such as oil PVT properties, reservoir porosity, thickness, OOIP, wellbore dimensions and the like. In doing so I detached myself from the oil rate that I had found at the time of integrity test. Instead I built a combined reservoir, wellbore and BOP model; and I allowed it to flow against the known (back) pressure of the ocean floor and then I shut it in at approximately 2:30 pm on July 15, 2010. The model calculated the shut-in pressures. I compared the calculated shut-in pressure with the measured ones. If a difference was found, I changed reservoir properties – always keeping them within the range of their uncertainties – until I found a model that matched the shut-in pressures. I was looking for combinations of parameters that would allow me to be consistent with the measurements. I was able to find a wide range of models with a wide range of cumulative volume of oil released that matched the shut-in data. In my initial report I found a range of between 3.3 and 5.8 MMSTB. In this report I show that for models that just match the shut-in pressures, this range could be even wider. Next, I found that only some of the models are consistent with the collection rates. Once again, I found that it is the information during the integrity test and before the well was shut-in that allowed me to differentiate between the models that behave like the actual system, and those that were consistent with shut-in pressures only. By using data that BP's experts ignored, I was able to significantly reduce the uncertainty in my estimates.

It was interesting to note that there was a fairly wide range of reservoirs (e.g with productivity indices that varied by a factor of approximately 50%) that allowed a match of the shut-in pressures AND measurements of the collection period. However, the estimates of cumulative volume of oil released for all of these models varied by a narrow margin of 6%. This is shown in Table 1, which is a summary of the results presented in my initial report. The cases in green are those with good matches of the shut-in pressures and the collection rates. They provide a range of between 5 and 5.3 MMSTB. This range of estimates was driven not by some preconceived notion of what the result should be, but by the requirement that my estimates conform to *all* of the measured data, not just the shut in pressures.

At this stage I found that my range of answers is narrow enough and that it was unlikely that the range of answers was wider than my estimate; models that resulted in a cumulative volume of oil released that fall outside of my best estimate did not allow a good match of the measurements during the integrity tests. I had already found that there was little difference between my estimate using the approximate analytical technique that I had used and the more complicated numerical approach. At this time I realized there was no need in complicating the problem any further. Otherwise, I could have moved into the development of a complex reservoir model based on 3D static models that incorporate geostatistical representation of permeability and porosity in the reservoir. In the presence of good information, such models would be more realistic. There was no need here and not enough data to allow that.

I should mention that, if the statement of the problem required me to find a particular reservoir parameter such as the skin to within a narrow range, I would not have been able to do so as I found a range of skin of between 2 and 18. Two models that matched all measurements during the integrity tests might have had significant differences in one input parameter. But then there had to be differences in other input parameters such that the combined effect allowed a match of the collection rates. It turned out that all such models gave a narrow range of cumulative volume of oil released.

Primary Parameter	Secondary Parameters		Overall Characteristics				
	K, mD	Skin	OOIP, MMSTB	PI, stb/d/psi	q July 15, stb/d	Average Error, %	Cum Oil Released (after matching shut-in pressures), MMSTB
BOP ID=2 in (Case-13)	315	9.5	90.5	19	34,100	0.03	3.32 (Bad)
Skin=50 (Case-07)	450	50.0	91.8	10	34,800	0.03	3.39 (Bad)
K=170 mD (Case-01)	170	5.0	126.6	15	42,900	0.3	4.14 (Bad)
h=25 ft (Case-04)	1300	16	117.2	17	44,400	0.05	4.3 (Bad)
k=360 mD (Case-02)	360	12	127.4	20	46,900	0.05	4.53 (Bad-Med.)
Roughness=0.02 in (Case-17)	470	5	129.9	34	48,700	0.04	4.70 (Med.)
Upper Bound Hydrostatic Error (Case-23)	575	16	147.0	26	50,700	0.03	4.85 (Med.)
h=50 ft (Case-05)	980	11.5	134.5	29	51,100	0.03	4.93 (Med.-Good)
Lower Bound CS Error (Case-18)	510	9	134.9	31	51,600	0.04	4.99 (Good)
Porosity (Case 24)	530	9.5	136.8	31	51800	0.03	5.00 (Good)
Upper Bound CS Error (Case-19)	560	10	140.3	32	52,200	0.04	5.03 (Good)
Base Case (Case-00)	550	9.5	137.4	32	52,400	0.04	5.03 (Good)
Lower Bound BOP Error (Case-20)	550	9.5	137.4	32	52,400	0.04	5.03 (Good)
Upper Bound BOP Error (Case-21)	550	9.5	137.4	32	52,400	0.04	5.03 (Good)
High Visc at Low Pressures (Case-10)	550	9.5	138.3	32	52,400	0.05	5.05 (Good)
k=850 mD (Case-03)	850	18	137.1	33	52,500	0.04	5.07 (Good)
Visc=0.16 cp (Case-09)	360	6	141.3	36	53,300	0.03	5.13 (Good)
Aquifer (Case-08)	530	6.5	117.8	36	53,300	0.03	5.14 (Good)
Cf=12E-6 1/psi (Case-11)	650	9.5	106.9	36	53,400	0.04	5.15 (Good)
Lower Bound Hydrostatic Error (Case-22)	530	2.5	132.2	44	54,200	0.06	5.27 (Good)
Layered (Case-12)	284 565 1585	4.0	146.3	46	55,400	0.05	5.33 (Good-Med.)
BOP ID=3.5 in (Case-14)	530	17	148.5	24	56,000	0.04	5.40 (Good-Med.)
Skin=0 (Case-06)	540	0.0	150.2	52	56,300	0.03	5.44 (Med.)
BOP ID=4.0 in (Case-15)	520	16	155.1	24	58,100	0.04	5.59 (Med.)
Roughness=0.0006 in (Case-16)	550	22	158.0	22	59,800	0.06	5.76 (Bad)

Table 1: Summary of results for the cases that show a good, mediocre and bad match of the measurements during the integrity test and the corresponding cumulative volumes of oil released. Reproduced from Table 1 of my initial report[3]

[3] In study of the What-if cases presented in my initial report I realized a problem with the VLP tables. Subsequent to the submission of my primary report, I identified the source of the problem. This problem was systemic, and

The defendants' experts have suggested input parameters and combinations thereof that I had not considered in my initial report. In this report, I examine if such models allow a match of the pressures. If they do not, I seek variations of these models that would allow a match. Then I examine their response against the measurements during the collection period and consider those that match the collection rates. I apply the same methodology used in my initial report – I consider a model using the defendants' parameters that exhibits a good match of the collection rates an acceptable model, unless its input parameters are outside of the range that is considered reasonable. Then I observe and report their cumulative volume of oil released.

In conclusion, my methodology is superior to those of the defendants' experts (Drs. [redacted] Gringarten and Blunt) because I took into account the collection rates and the corresponding wellhead pressures. This information allowed narrowing down the range of cumulative volume of oil released.

Dr. Gringarten too, suggests that the shut in data are not sufficient to find both the rate and the permeability. Therefore, he finds an estimate of reservoir permeability using the MDT tests. As shown in the Dr. Larsen's report, if the MDT data are analyzed properly, they give rise to an estimate of a range of permeability that is significantly greater than Dr. Gringarten's estimates and that is consistent with the permeability I used in my initial report. In other words, Dr. Gringarten's arguments regarding permeability are inaccurate and do not change my estimate of the cumulative volume of oil released.

Dr. Blunt uses a different technique. In doing so he narrows down the types of the data that he considers. The material balance technique that he uses to find his estimate of cumulative volume of oil released is based on an estimate of what the shut in pressure would have been if the well was shut in for an infinite time. He ignores the other measurements associated with the collection period during the integrity test. He argues that his material balance technique requires only three pieces of information: the change in pressure from initial to final, the OOIP and the total reservoir compressibility. He is correct in this statement. The problem with this technique is that the uncertainty in these parameters is large. These are discussed further in Section IV, where I present weaknesses of Professor Blunt's material balance analysis.

---

resulted in a too restrictive wellbore. Upon correction of the VLP's, my estimates increased by about approximately 1%. Therefore the base case increased from 5.03 to 5.08 MMSTB. For clarity I refer to this as Base Case 2. A number of boundary cases were tested, which confirmed my general opinion: my best estimate of "cumulative volume of oil released" remained between 5 and 5.3 MMSTB. Details are given in the Appendix I.

Section II: Examining Applicability of Parameters suggested by Defendants' experts

The defendants' experts have presented models that include a less productive reservoir or wellbore than what I found in my "good" models[4]. In this section, I examine whether by incorporating their input parameters I can find models that are not only consistent with the shut-in pressures but also with the measurement during the collection time. Table 2 gives the list of parameters from the reports of the defendants' experts that are investigated here.

Table 2: Parameters suggested by defendants' experts whose applicability will be examined through sensitivity studies Cases A1 to A5

Case Study	Parameter/Value	Case #
Permeability	238 mD	A1
OOIP	100 MMStb	A2
PVT	Single-Stage flash	A3
Shut-in Pressure	Blunt Estimate	A4
Combined	Combined	A5
Wellbore Model + Flowing Pressure	Johnson Model + Trusler's pressures	A5

My approach is twofold. First, I consider a number of the parameters one-at-a-time that will be studied in these additional sensitivity Cases A1 to A4, followed by consideration of all parameters together in Case A5. For example, when I examine the effect of OOIP in Case A2, I change the OOIP in my base-model. Then I history match this model against the shut-in pressures. Once a match of the shut-in pressures is obtained, I examine if the model matches the collection rates. In Case A5, I change all of the above parameters in my model and repeat the same process.

Summary of Findings

Based on my work presented in my initial report, both cases of OOIP = 100 MMSTB and permeability of 238 mD are too restrictive to allow match of the collection rates; unless other parameters are chosen outside of the range considered reasonable. This is demonstrated in Table 3, where both of these cases led to bad matches.

For the shut-in pressures suggested by Dr. Blunt, we obtained two solutions, one that did not present a good match of collection rates, and another model that did present a good match of the collection rates.

The wellbore model of Dr. Johnson is examined as part of Case A5. It is found that this wellbore model is very restrictive. To obtain a model that demonstrates a mediocre match of the collection rates, I needed to choose a reservoir that was more productive than is probably acceptable (with a permeability of 1000

[4] The "good" models, as in my initial report, are those that allow a good match of shut-in pressure and collection rates.

mD with a skin of zero). This suggests that Dr. Johnson's wellbore model was probably too restrictive to be true.

Also included in this section is an analytical modeling exercise, similar to that presented by Dr. Gringarten. It is shown that the flowing and shut-in pressures chosen by Dr. Gringarten can be modelled with a wide number of reservoir parameters, leading to widely varying estimates of cumulative volume of oil released of between 3 and 7 MMSTB. This clearly demonstrates that the match of the shut-in pressures alone is not sufficient to find the answer.

Table 3: Summary of results for the additional sensitivity studies associated with input parameters suggested by the defendants' experts.

	K, mD	Skin	OOIP, MMSTB	Pav, psi	PI, stb/d/psi	q July 15, stb/d	Error, %	Cum Oil Released (after matching shut-in pressures), MMSTB
K=238 mD	238	33	84.6	10289	7	30000	0.05	2.94 (Bad)
OOIP=100 MMStb	300	28.5	100.0	10263	10	36000	0.05	3.54 (Bad)
Shut-in Pressure	360	25	121.8	10392	13	41000	0.02	3.97 (Bad)
Combined-Extrapolated	360	0	134.6	10430	33	47000	0.03	4.20 (Bad)
Combined-Extrapolated-2	1000	0	141.5	10388	55	52000	0.05	4.56 (Med)
PVT	550	14	136.3	10232	26	49000	0.03	4.73 (Med)
Shut-in Pressure-2	550	13.5	156.0	10410	25	53000	0.05	5.02 (Good)
Base Case2	550	13	140.0	10219	28	53000	0.04	5.08 (Good)

In the following I describe the case of shut-in pressures of Dr. Blunt and the methodology that I use to examine its applicability. The same methodology is used for all other cases. The detailed results of all cases are given in Appendix II: Additional Sensitivity Studies.

Shut-in Pressures

Dr. Blunt presented an analysis of the cooling of the fluid in the wellbore. He then accounted for the change in oil density associated with this cooling and used (i) tables of density as a function of pressure and temperature created by Dr. Whitson and (ii) the capping stack pressures as adjusted by Dr. Trusler to calculate a series of shut-in pressures. He argued that these shut-in pressures are a better reflection of the actual bottomhole pressure of the Macondo well after it was shut-in. I have reviewed Dr. Blunt's analysis. Study of Dr. Whitson's tables of density (as a function of pressure and temperature) overestimate the fluid density as compared with laboratory measured values of density. Although the effect of cooling on well fluids is a recognized consideration in well-testing, there are a number of assumptions involved in the estimation of fluid temperature. Therefore, I consider Dr. Blunt's analysis that attempts to account for this cooling a possibility, although I do not necessarily accept his analysis as correct.

Figure 1 shows the comparison between the model response and the shut-in pressures as estimated by Dr. Blunt. The two figures represent two different models, both of which demonstrate a good match of Dr. Blunt's pressures. As in my initial report, a match of the pressures is considered good when the average difference between the model and "measured" pressures is less than 0.1%.

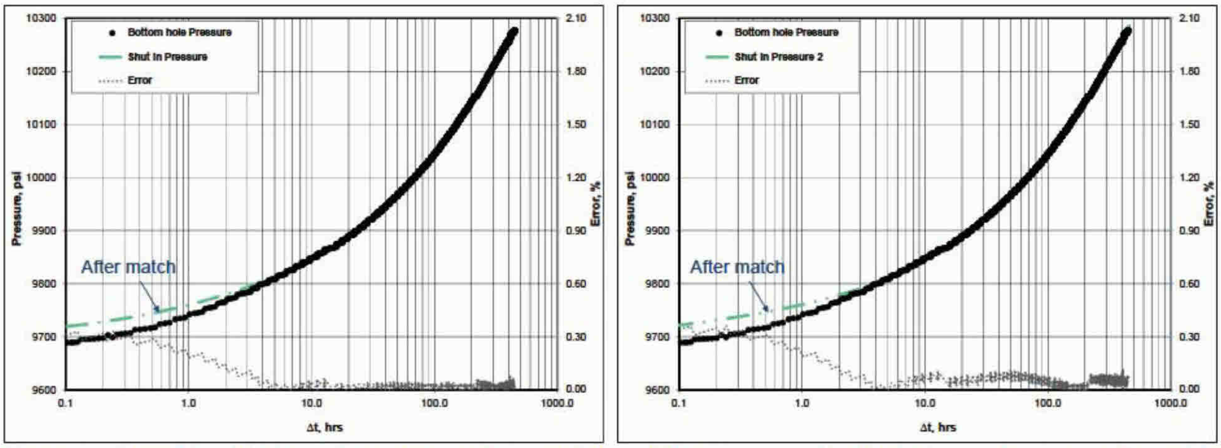


Figure 1: Comparison between the response of two models and the pressures after the well was shut-in, as adjusted to bottomhole conditions by Dr. Blunt. The solid lines (after match) indicate a good agreement between the models and the pressures.

Figure 2 shows the comparison between the response of the models and the measured collection rates. The model shown on the left demonstrates a bad match and is not acceptable. The model shown on the right exhibits a good match. The parameters of the model include permeability of 550 mD, skin of 13.5 and OOIP of 156 MMSTB. Among these factors, only the OOIP is in the high end of values that I consider reasonable, although still within the range of between 100 and 170 MMSTB considered by BP (after a downward adjustment to account for the larger oil formation volume factor found in the reservoir).

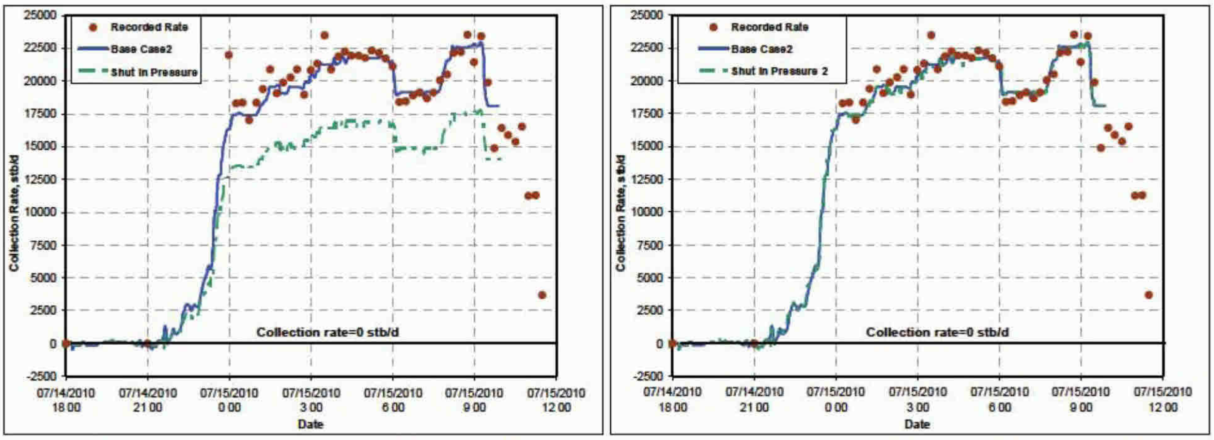


Figure 2: Comparison between the calculated collection rates for two models "after match" with the measured values. (Results of the base model are shown for comparison). The quality of the matches are bad and good for the case called "Shut-in Pressures" (on the left) and "Shut-in Pressures 2" (on the right), respectively.

I would like to point out that both of these models match the shut in pressures and also honour the material balance. In other words, if one were to consider OOIP of these two models within the range of possibilities[5], then the estimates of cumulative volume of oil released based on the method of material balance for the two models would be approximately 4 and 5 MMSTB. It turns out, however, that only one of these models presents a good match of the collection rates.

In summary, I was able to find two models that are consistent with shut in pressures estimated by Dr. Blunt. One of these models was also consistent with the collection rates. This model exhibited a cumulative volume of oil released of 5 MMSTB, within the range of my best estimate of the cumulative volume of oil released.

Original-Oil-In-Place (OOIP)

[redacted] Dr. Blunt suggested that the OOIP of the reservoir varies over a narrow range of between 109 and 114 MMSTB[8]. Dr. Gringarten developed various reservoir models that exhibited a good match of the shut in pressures. The OOIP for his option 1 cases varies between 57 and 110 MMSTB; and between 69 and 133 MMSTB for his Option 2 cases[9]. The lowest to highest values of OOIP reported by the defendants' experts is between 57 and 133; a factor of more than two. This is consistent with my experience that uncertainties in the value of OOIP are large, particularly early in the development of a reservoir such as the case of Macondo.

For the sake of sensitivity studies I estimated that the average of the high estimates of the OOIP is 120 MMSTB, and the corresponding averages of the mid and low estimates are 100 and 80 MMSTB, respectively.

In my original report, I had not considered the OOIP as a primary sensitivity parameter. However, as I explored for various models that are consistent with measurements, I found models with OOIP values of between 90 and 160 MMSTB, all of which allowed a good match of the shut in pressures. This was reported in Table 1 of my initial report (also Table 1 of this report).

As the results in Table 1 show, among all these models, only some of them with OOIP values that spanned between 110 and 140 MMSTB – showed a "good" match of the collection rates. Here, I examine the possibility of finding a model with a smaller OOIP that is consistent with measurements

---

5 The other two terms important for material balance calculations are compressibility and final reservoir pressure. The compressibility is similar to those suggested by Dr. Blunt, and the final reservoir pressure is based on the m[redacted]gested.

6 [redacted]

7 TAM. Exhibit 5232 at Section 6.17

8 Pages 7 and 25 of Blunt report

9 Pages 50 and 52 of Gringarten report

during and after the integrity test. In particular, I start with OOIP of 100 MMSTB, corresponding with the average of mid-estimates of the defendants' experts.

The sensitivity case A2 examines applicability of OOIP of 100 MMSTB. Results shown in Appendix II indicate that after making adjustments to the base model (Base Case 2), a good match of the shut-in pressure can be obtained with an average error between the model and "measured" pressures 0.05% (see Table 3). However, the low oil production rate associated with this model does not allow a good match of the collection rates. This model with its cumulative volume of oil released of 3.5 MMSTB is not acceptable. As mentioned earlier, the defendants' experts considered cases with even lower OOIP.

Permeability

Dr. Gringarten presents an analysis of three MDT tests that were conducted in the Macondo well prior to the blowout. On page 33 of his report he presents his results, where he concludes that the most likely value of permeability is 238 mD. Furthermore, he finds low and high estimates of 170 and 329 mD, respectively. Later in his report, Dr. Gringarten shows that he can obtain a good match of the shut-in pressures using all of these values.

As mentioned in Section I above, my review of permeability suggested a very wide range of possibilities. I considered a range of between 170 and 850 mD. In the sensitivities studies reported in Table 1 of my initial report, I considered four different values of 170, 360, 550 and 850 mD. I found that models that incorporated the value of 170 mD did not allow a good match of the collection rates, but I was able to find matches for the 360 mD, 550 mD, and 850 mD values.[10]

Notwithstanding my previous findings, I assume here, that the most likely value of permeability suggested by Dr. Gringarten is a possibility, and examine its validity in this section and Section V. The result, shown in Appendix II (see also Table 3), is a model that under-predicted the collection rates by a significant degree, and therefore is not an acceptable model. This unacceptable model gave a cumulative volume of oil released of just less than 3 MMSTB.

Wellbore Model

Dr. Johnson presented a wellbore that included a drill pipe in its upper section. This model exhibits a larger pressure drop than the wellbores that I considered in my Base Model. This is demonstrated in Figure 3, where tubing performance curves associated with my Base wellbore and the wellbore model of Dr. Johnson are presented. One notes that for a constant bottomhole pressure of 8000 psia, Dr. Johnson's wellbore produces 6000 STB/day less than my model. At the bottomhole flowing pressure of 9000 psia this difference increases to 10,000 STB/day. In addition to this higher resistance, the wellbore model developed by Mr. Johnson exhibits an unphysical behaviour, while the internal messaging of the program warns about problems with the solution. Dr. Griffiths demonstrates additional problems with Dr. Johnson's wellbore model.

---

[10] See Table 1. The 360 mD match occurred using a viscosity value of 0.16 cP (the laboratory-measured range of viscosities was 0.16-0.26 cP – see Appendix III to my original report).

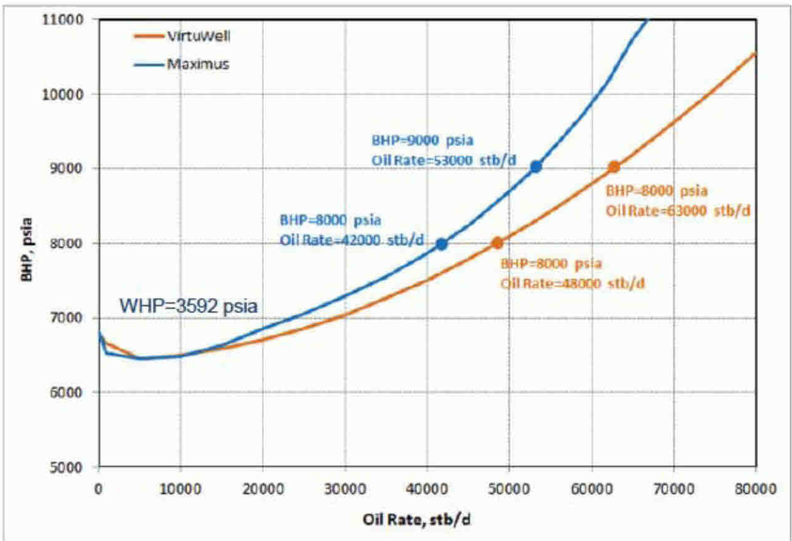


Figure 3: Tubing Performance curves from my Base Model (VirtuWell) and Johnson's model (Maximus). Johnson's model includes its own PVT. Johnson's model is based on his High Drill Pipe Case[11].

In my initial report I had considered that there is uncertainty in the characteristics of the wellbore and its resistance. Therefore, I considered wellbores that were more (and less) restrictive as compared to what I had in my Base Model. Indeed, I had considered wellbore and BOP configurations that were more restrictive than Johnson's wellbore model. Incorporation of such a wellbore in modeling resulted in collection rates that were too low as compared to measured values. Nevertheless, here I assume that the wellbore model of Johnson is valid and use it as a sensitivity case.

Dr. Johnson's wellbore model , however, incorporates components of wellbore from bottom of the wellbore to the upstream of BOP, requiring it to flow against Dr. Trusler's BOP pressures. With the exception of my What-if studies presented in my initial report, this is not consistent with the way I have modelled the wellbore. Therefore, the consideration of Dr. Johnson's model is postponed until the "combined" case A5 is studied.

Flowing wellhead pressures

Dr. Trusler analyzed the BOP and capping stack pressures and adjusted the previously reported values to be consistent with calibration experiments and other measurements that he could use to correct for the associated errors. I will talk about the BOP and capping stack pressures separately.

[11] Johnson's Low Drill Pipe Case misbehaves when coupled with a reservoir model. This is noted in footnote 31 of Dr. Gringarten, when he states "Option 1- Drill Pipe Low was excluded because the pressure behaviour was anomalous just prior to shut-in." Dr. Gringarten goes ahead and uses the Low Drill Pipe model with his other rate profile Option 2 Drill Pipe Low. The results shown in Gringarten's Figure 5.18 are unphysical. In all cases shown in Figure 5.18 of Gringarten report, the flow rate suddenly increases just prior to shut-in. Henceforth, I do not consider the Low Drill Pipe Model of Johnson in this report.

The BOP Pressures

Figure 4 shows the best estimate of Dr. Trusler for the BOP pressures in solid blue symbols. The majority of my modelling in my initial report incorporated the seafloor pressure or the capping stack pressures. These were the pressures that I trusted more. In Section V of my study, called What-If studies, where I wanted to examine the effect of possible erosion in the BOP, I used the BOP pressures (as shown with black symbols in Figure 4).

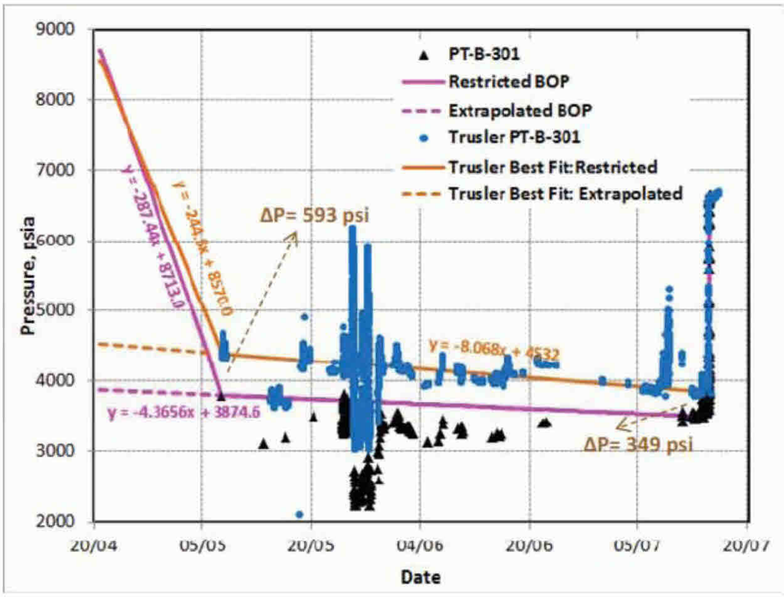


Figure 4: BOP pressures as adjusted by Dr. Trusler and those that I used in my What-If studies in my initial report

Dr. Griffiths has reviewed the BOP pressures closely and examined the corrections provided by Dr. Trusler. Dr. Griffiths is of the opinion that the corrections presented by Dr. Trusler for the period before July 13th are reasonable. I have not performed a similar study and cannot comment on their validity. To determine the effect of Dr. Trusler's opinion, I use Dr. Trusler's corrections as a sensitivity case (case A5).

Figures 4 and 5 shows the comparison between Dr. Trusler's BOP pressures and those that I had used in my initial report[12]. The values that I used in my study shown in Figure 4 and 5 using black solid symbols accounted for an offset correction of -582 psi. As demonstrated in Figures 4 and 5, the BOP pressures of Dr. Trusler are a few hundred psi larger than what I used, and would impose an extra back pressure against flow. Dr. Trusler concluded that the range of uncertainty on his estimate of BOP pressures is ±200 psi. I shall examine the effect of such extra back pressure.

[12] In all of the simulation studies reported in my initial report, I never used the BOP pressure of between July 13 and 15 as a boundary condition against which the well flows. During this period, I had access to the capping stack pressures, which I used in my simulation runs.

In the sensitivity study reported here (Case A5), I use Dr. Trusler's BOP pressures for two purposes; as a back pressure against which the well flows, and along with capping stack pressures for calculation of collection rate. The effect of change in the BOP pressures on estimation of collection rates is discussed next along with discussion of the capping stack pressure[13].

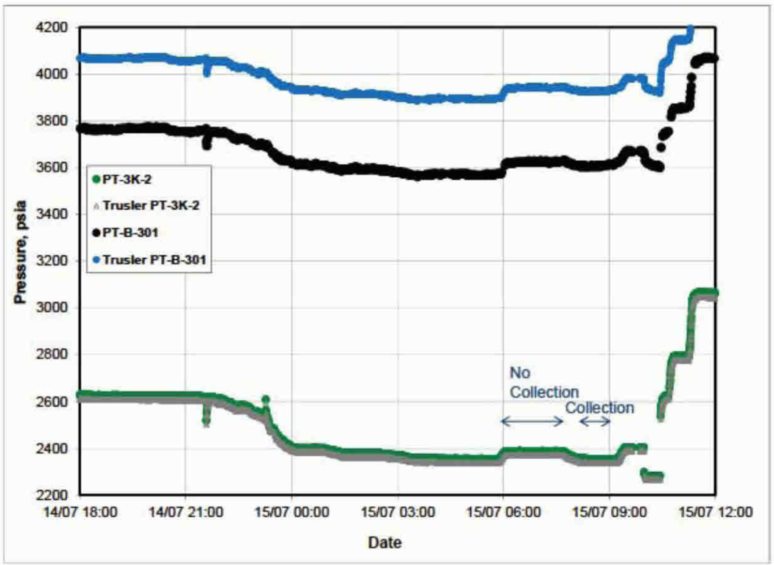


Figure 5 BOP pressures as adjusted by Dr. Trusler and those that I used in my What-If studies in my initial report. Also shown are the Dr. Trusler' capping stack pressures and those that I used for calculation of collection rates

The Capping Stack Pressures

Dr. Trusler has reviewed the pressures of the capping stack and has concluded that they require a small correction. Figure 5 shows the comparison between Dr. Trusler's capping stack pressures and those I used in my initial report. The time of interest is that pertaining to the "no collection" and "collection" periods.

The combination of the BOP and capping stack pressures are used *after* my simulation, when I want to examine whether the results of a model agree with the collection rates. An error in these pressures could have caused me to use an incorrect measurement to examine the validity of a model against measured rates. In my initial report, I investigated whether my analysis suffers from this shortcoming by examining the effect of errors in the capping stack and BOP pressures. I had found little effect. However, there, the magnitude of uncertainty in the capping stack and BOP pressure that had I considered to be valid was 74 psi or less. Figure 5 shows that the degree of adjustments suggested by Dr. Trusler is larger.

[13] Dr. Griffiths has reviewed Dr. Trusler correction on the BOP pressures, and thinks that for the period of after July 13 a further correction on Dr. Trusler's adjustments is required. I do not make a judgement about the validity of the two analyses. Instead I use Trusler's BOP pressures for calculation of collection rate as well as a boundary condition against which the well flows.

Therefore, I re-examine if my calculations of collection rate are sensitive to the adjustments to the BOP and capping stack pressures in this period. I use the results of my Base Model (Base Case 2) in Appendix I, which show a good match of the collection rate using my version of the BOP and capping stack pressures. Results of the same model, when used along with the pressures as adjusted by Dr. Trusler are shown in Figure 6 with the dashed line. Also shown are the measured rates and the results of the Base Model.

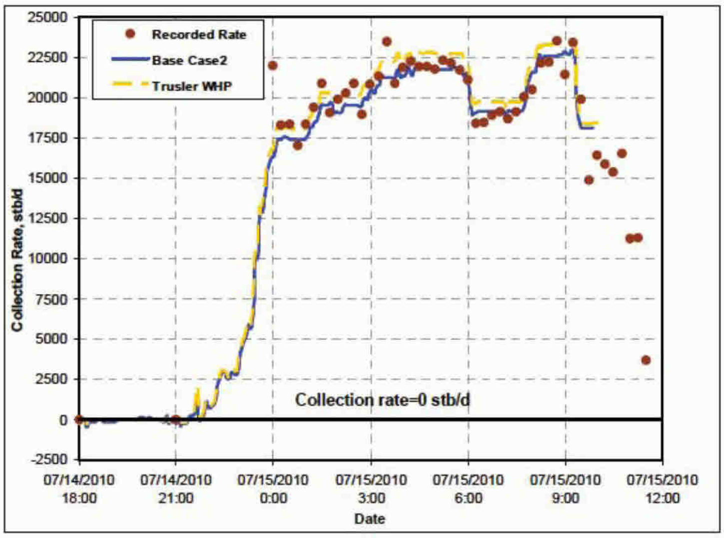


Figure 6: Comparison between the calculated collection rates from the Base Case 2 model for two different sets of BOP and capping-stack pressure. (The actual measurements are shown in solid symbols for comparison). Both sets of calculated rates agree with the measurements indicating that the choice of flowing pressures (Dr. Trusler's, shown by the dashed line, or what I used in my initial report, shown by the solid line) does not affect the acceptability of a model.

As results shown in Figure 6 present, the calculated collection rates are hardly affected by the degree of adjustments considered by Dr. Trusler or myself. This demonstrates a very important point, that the collection rates along with the pressures measured during this time are very valuable for examining the validity of a model. The choice by defendants' experts to ignore this collection data is a serious shortcoming, and has resulted in their advocating models that are inconsistent with measurements during the collection period.

The PVT properties

Dr. Zick and Dr. Whitson have conducted studies of the PVT properties of the Macondo fluid. Both have developed Equation-of-State (EOS) models to represent the fluid. Both have shown that their models present a good match of the laboratory measurements. However, a large discrepancy exists about the *type* of the output that should be chosen from the EOS models.

Many of the defendants' experts have calculated their estimate of cumulative oil released using a single-stage separation process. Such a process assumes that the reservoir fluids of Macondo separated from each other when they were exposed to stock tank conditions. A multi-stage separation process is more appropriate here because the oil and gas mixture that arrived at the wellhead of the Macondo well did not suddenly drop to stock tank conditions. Instead, the pressure at which they can start separating is approximately 2200 psia. At this pressure part of the gas remains in solution with the oil, similar to the gas that stays with the oil at the first stage of a multi-stage separation test. From here onward, the oil and the free gas could potentially have separate paths; each of which was exposed to a series of pressures and temperatures. This is closer to a multi-stage separation process than a single-stage one[14]. In fact, one of the defendants' experts, Dr. Whitson, has suggested that the separation process in the ocean can be modelled using a five stage separation process. It is based on this argument that I am of the opinion that the experimental data corresponding to the multi (four)-stage separation process employed in the laboratory is more representative.

The choice of separation process has a relatively small effect on my results. In my initial report, I presented two sensitivity studies on the PVT properties, where I changed oil viscosity (the parameter that I found to have the largest impact on reservoir deliverability). After calibration (history matching) the effect on cumulative volume of oil released was less than 0.1 MMSTB (case-09 and case-10 in Table 1).

In addition, in this section I present the results of another sensitivity study where I have used black-oil PVT correlations that are matched to the experimental PVT data of single-stage flash. The use of a single-stage separation process results in a more than 10% change in the oil formation volume factor and the solution GOR of the oil (as shown in Appendix II: Additional Sensitivity Studies). The sensitivity study presented in Appendix II exhibits a mediocre agreement with the collection rates. Its cumulative volume of oil released is 4.73 MMSTB. Given the short time available, I did not pursue exploring for other solutions. However, if I had, it is possible that I would have been able to find another solution that allowed a better match of the collection rate. I expect that such a model would have resulted in an estimate that was closer to the range of 5 to 5.3 MMSTB[15].

All Parameters

In the cases studied above, I started with my Base Model and adjusted one parameter. All other parameters remained the same as the base values in my Base Case 2. One may suggest that the reason for mis-match of these cases with the collection rate is that not all parameters are consistent. In the following, I incorporate all the changes at once in two different ways. First, I present an analytical model similar to the model that Dr. Gringarten presented. This model, incorporates the bottom-hole shut-in pressures of Dr. Blunt, the flowing bottomhole pressures by Dr. Johnson, the flowing pressures of Dr. Trusler, the PVT properties of Dr. Whitson, [redacted] and incorporates the permeability that Dr. Gringarten estimated from MDT analysis.

---

[14] In the "Multi-Stage" separation test conducted in the laboratory, the first stage of separation is at 1250 psia. The wellhead conditions at Macondo (of 2200 psia) are much closer to the multi-stage separation test conducted in the lab, than the stock tank conditions of a single-stage separation.

[15] The reason for this expectation is that the model shown in Appendix II under-predicts the collection rates. A model that would have matched the collection rate would have produced more.

Other experts did not present a complete model of reservoir and wellbore and treated parts of the problem only. Thus, using an analytical model with the defendants' parameters, I demonstrate that models can be developed that present a good match of the pressures and lead to widely varying estimates of cumulative volume of oil released. Furthermore, I demonstrate that the match of the flowing pressures provided by Dr. Johnson does not provide any additional information to constrain the model. The flowing pressures could be easily matched with a change in the skin factor. In doing so, I come to the conclusion that Dr. Gringarten arrived at, that some additional information is required to constrain the model. Also I demonstrate that if one is willing to consider larger and more permeable reservoirs than what Dr. Gringarten considered, one would arrive at models that are consistent with the pressures and produce at much larger volumes than Dr. Gringarten demonstrated (up to 7 MMSTB shown here).

Then, I make use of the additional information of collection rate. For this, I use a numerical simulator, similar to all my other sensitivities. I look for models that are consistent with all measurements obtained during the integrity test. This allows a better coupling between the wellbore and the reservoir models as compared with the analytical model of Dr. Gringarten[16]. The details of the analytical and numerical cases are presented in Appendices III and II respectively. A sample of results is shown below.

Figure 7 shows the results of the analytical model as compared with the pressures of Dr. Gringarten for rates that are 2.33 times the rates that Dr. Gringarten used. The cumulative volume of oil released is 7 MMSTB[17]. Results are for a permeability of 590 mD and an OOIP of 227 MMSTB. The latter is above the range of values that are considered by various experts including myself[redacted]

Quite importantly, the results of the model are not examined against the collection rates or other external constraints. Here, I agree with Dr. Gringarten that the findings of modeling need to be corroborated against additional information. To do this, I return to my simulation studies and compare the model results with the measurements during the collection period.

In Appendix II, two models are developed that incorporate Johnson's wellbore model, Trusler's pressures extrapolated to the beginning of flow, with a PVT model that is based on the results of single stage separation. Both models are matched against Blunt's shut inpressures. Figure 8 shows the comparison between the calculated collection rate and the measured values. The results indicate that

[16]The primary differences between my model and Dr. Gringarten's model are twofold; (i) Dr. Gringarten's analytical model has inconsistencies within it that I will refer to in Section V. My model is a numerical one; it does not have some of the approximations that the analytical models of Dr. Gringarten and I have. (ii) I did not have access to all the input parameters that Dr. Gringarten used in his model (e.g. variation of skin with time). Therefore, some of my parameters may be somewhat different than his. These differences are expected to be small; with little effect on my conclusions. (See Appendix III for details.)

[17] Additional results shown in Appendix III show that a variety of flowing pressures can be matched easily with variations in skin. Therefore, the larger flows considered in the Figure 7 require a larger flowing bottomhole pressure for flow up the wellbore, an adjustment of the skin factor could be adjusted accordingly.

[18] [redacted]

both of the models under-predict the rates despite the fact that the reservoir model chosen for the case to the right is very conductive, with a permeability of 1000 mD and skin of zero. This is an indication that the other components of the system (most likely the wellbore and probably to some extent the shut-in pressure of Blunt) are too restrictive to allow a model with reasonable parameters that are consistent with the collection rate[19].

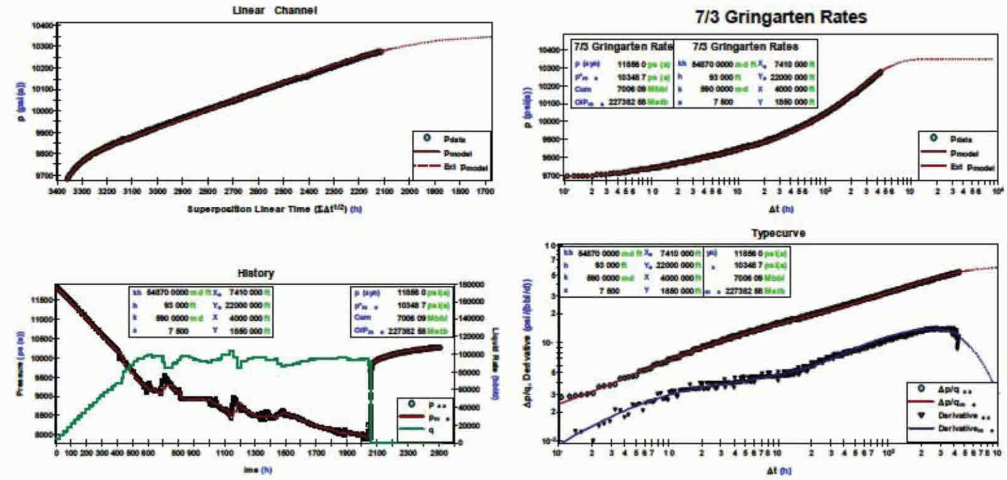


Figure 7: Comparison between results of the analytical model and the pressures of Dr. Gringarten for rates that are 2.33 times of the rates that Dr. Gringarten used. The match is obtained with a larger permeability and reservoir size than Dr. Gringarten chose. The cumulative volume of oil released is 7 MMSTB. The results of the model are not examined against the collection rates.

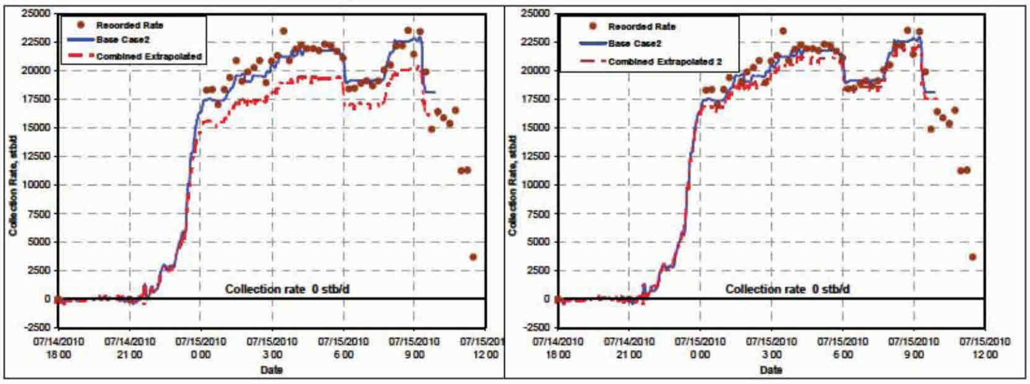


Figure 8: Comparison between the calculated collection rates for two combined models "after match" with the measured values. (Results of the base model are shown for comparison). The quality of the matches are Bad and Mediocre for the case called Combined-Extrapolated (on the left) and Combined-Extrapolated 2 (on the right), respectively.

[19] Results presented in Appendix II demonstrate that even the match of the pressures is not as good as the other cases. Although the match of the pressures during the first few hours could be related to the approximations related to the steady state VLP curves used in this very last transient period (specific to the choke closure time), the low quality of the match could also be related to the very high permeability chosen to improve the match of the collection.

Section III: Changing restrictions in the System

A number of defendants' experts have suggested that the restrictions in the BOP, wellbore and/or reservoir may have changed over the 87 days such that oil flow rate may have increased with time, ultimately arriving at flow rates that are large enough during the integrity tests that are consistent with measurements of collection rate and the corresponding wellhead pressures. These conditions and their impact on my estimates of cumulative volume of oil released are discussed in this Section. In particular I address changes in the reservoir, wellbore and the BOP.

Reservoir

There is no evidence suggesting that restrictions in the reservoir reduced with time (or that productivity increased). If there were any changes, I expect them to have been short-lived with little effect on the estimate of cumulative volume of oil released. The suggestions by many of the defendants' experts including Drs. Blunt and Gringarten that productivity index improved because of sand erosion or other effects are purely speculative. Equally, one can speculate that asphaltene deposition and/or fines migration may have led to a reduction in productivity index. In general, oil wells lose productivity with time; they don't gain productivity. The change in skin associated with the modelling of Dr. Emilsen[20] that concerns the blow-out time is discussed in Section IV, under Blunt, pressure transient analysis. I conclude that the hypothesis of increasing productivity index over a period of weeks and months is just speculation.

Wellbore

Two types of change in the wellbore restriction can be considered, a slow change (such as that caused by erosion) and a fast change (such as that caused by a falling drill pipe). Erosion in the wellbore is expected to have little effect on its restriction because (i) the area to flow is large, limiting the erosion capability of the fluids passing by, and (ii) any increase in the diameter of wellbore is small as compared to the original wellbore diameter, making the impact of erosion immaterial even if there were some erosion. A fast change in the wellbore restriction that had the potential of impacting flow would have had an impact on the BOP pressure, as the flow rate between the BOP and the seafloor would have been be affected. Such changes in BOP pressure are either not observed or are short-lived. The absence of such an effect on BOP pressures is consistent with views expressed by BP's personnel during the response CITATION[21].

BOP

In this section, changes in the BOP are discussed at two different time intervals, after May 8 when BOP pressures are available (albeit sporadic and with uncertainties) and before May 8, when there are no BOP pressures.

[20] "Summary and Conclusions Deepwater Horizon Incident, by M. H. Emilsen (October 2011)

[21] Exhibit 5066

I create a model that incorporates the effect of any changes that could occur in the BOP after May 8. This modelling results in a good match of the measurements during the integrity tests with a cumulative volume of oil released of 4.9 MMSTB. This modelling makes use of an estimate of the BOP pressure by Dr. Trusler. The uncertainty that Dr. Trusler assigns to BOP pressures is ±200 psi. Considering this uncertainty, my opinion remains that the range of answers is between 5 and 5.3 MMSTB. The latter range is obtained based on a much larger range of sensitivity studies. Furthermore, this agrees with the modelling that I presented in my initial report, and I corrected (as presented in Appendix I of this report), that used the BOP pressures without any corrections for the duration up to the integrity test. This case that I called "Extrapolated BOP" resulted in cumulative volume of oil released of 5.12 MMSTB. Both models resulted in a good match of collection rates. The summary of the results are presented in Table 4 (see the second and fifth row).

Table 4: Summary of results What-if studies: The first two rows make use of Trusler's BOP pressures, with details in Appendix II. The last two rows make use of uncorrected BOP pressures, with details in Appendix I. The Extrapolated cases account for any changes that might have occurred in the BOP after May 8. The restricted cases examines an extreme case, where the BOP sealed completely at the time of blow out, and then eroded steadily over a period of 2 and half weeks (until May 8).

	K, mD	Skin	OOIP, MMSTB	Pav, psi	PI, stb/d/psi	q July 15, stb/d	Error, %	Cum Oil Released (after matching shut-in pressures), MMSTB
Trusler Restricted BOP	660	12.75	134.2	10373	29	52000	0.03	4.43 (Good)
Trusler Extrapolated BOP	670	11.5	149.1	10376	31	53000	0.03	4.90 (Good)
Base Case2	550	13	140.0	10219	28	53000	0.04	5.08 (Good)
Restricted BOP	550	11.5	130.0	10212	30	54000	0.04	4.73 (Good)
Extrapolated BOP	550	12	141.0	10225	28	53000	0.04	5.12 (Good)

The above analyses assume that the condition of the BOP after May 8 also applies to the BOP before May 8. When I consider an extreme case of a very restricted BOP, such that there was no oil flow at the time of blow-out, I find two models both of which lead to a good match of the collection rates (restricted cases in the first and fourth row in Table 4). The cumulative volume of oil released associated with these models is between 4.4 and 4.7 MMSTB (depending on the choice of BOP pressures used). Details are given in What-if sections of Appendices I and II. As I mentioned in my original report, I consider this to be an unlikely extreme case – there is no actual evidence of such a gradual decline in flowing pressures.

Section IV: Key Weaknesses in the Works of Defendants' experts

In this section I comment on the work of three of the defendants' experts who use reservoir engineering techniques to arrive at an "estimate of cumulative volume of oil released". These include works of Professor Gringarten, Professor Blunt[redacted].

In my opinion, the largest shortcoming of their work is ignoring of the collection rates and the associated pressures at the wellhead. This has been sufficiently discussed in the Executive Summary and in the preceding sections and is not explored any further. My other comments are addressed to each of their works individually.

Professor Gringarten

The work of Professor Gringarten has a number of similarities and some differences with my work. In particular, he believes that the analysis of the shut in data on its own does not allow determination of oil rate. He attributes this to the observation that analysis of shut in pressures allows an estimation of the ratio of permeability to flow rate. He demonstrates that equally good matches of the shut in pressures could be obtained with various values of permeability. He presents his model results with in the range of 170 to 329 mD. I too agree and have demonstrated that the shut in pressure data can be matched with a wide range of permeabilities, leading to significantly different flow rates. As demonstrated by Dr. Larsen and his analysis of the MDT trsts, and as my sensitivity studies indicate, Dr. Gringarten's permeabilities are too low.

Professor Gringarten tries to somehow couple a wellbore model to his reservoir (analytical well test) model. In this way he makes use of the measured BOP pressures (as corrected by the defendants' expert Dr. Trusler) and transformed to bottomhole by the defendants' expert Dr. Johnson. However, the model that he has used does not allow a complete coupling of the wellbore and reservoir model. Because of this, a break occurs between the bottomhole pressures that Dr. Johnson calculates and Dr. Gringarten matches, and the bottomhole pressures that Dr. Gringarten should have matched to. This is because the bottomhole pressures that Dr. Johnson calculated and Dr. Gringarten matches are based on rates that Dr. Gringarten obtains in one of his earlier iterations (iter 2WHP). The final model of Dr. Gringarten predicts a different flow rate, corresponding to a different flowing bottomhole pressure. The coupled numerical wellbore reservoir model that I use not only incorporates the wellhead pressures, but also allows a better coupling between the wellbore and reservoir models[22].

Another major shortcoming of Dr. Gringarten's analysis is in the way he uses deconvolution to find the flow rates, which is the very objective of the study. Dr. Gringarten uses the calculated flowing and shut

[22] Numerical simulators are developed to iterate between the wellbore and the reservoir model so that the bottomhole pressure is consistent between the two models. However, Dr. Gringarten's model incorporates an estimation of flowing bottomhole pressure that is based on one his earlier estimates of flow rate. He does not update this flowing pressure when his estimate of range changes. It is quite likely that Dr. Gringarten would have required an adjustment of the skin factor in his well test model in order to bring consistency between the solutions of the two models.

in pressures of Dr. Johnson and Dr. Blunt, respectively, along with the deconvolution algorithm. Through multiple iterations he arrives at a rate history and a model[23]. *Next he assumes his rate history is correct, but is willing to change his model*. Dr. Gringarten changes the model in the following way: He uses an analytical well-test model to replace his deconvolution type-curve. He changes input parameters in the analytical model (and includes a variable skin) to obtain a match of the bottomhole flowing and shut-in pressures[24]. The resulting model is different from the deconvolution model. This is shown in Figure 9, where I show the deconvolution type curve that Dr. Gringaten's has provided, and comp[are it to his analytical type curve, which I reproduced using an industry-standard well-test model, Fekete's FAST WEllTest™. (As explained in Appendix III, slight modification of Dr. Gringarten' s parameters were required to reproduce a match of his model).

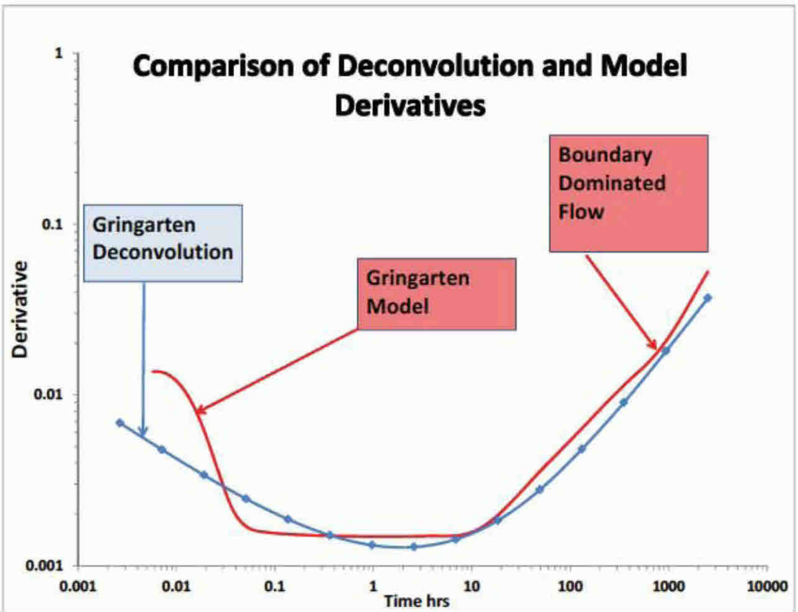


Figure 9: Comparison between the deconvolution model of Dr. Gringarten and the type curve from the analytical model matched to Gringarten's data

The significance of the differences between the two is discussed in Appendix III, along with a discussion of strengths and weaknesses of the deconvolution approach for this analysis. Leaving the theoretical discussions about deconvolution aside, I see it as a shortcoming that Dr. Gringarten allowed a change of the type curve but not a change of the rate history. It is equally plausible that the type curve is correct but the rate history is incorrect (or that both are incorrect). He does not explore those options. The impact of this choice of Dr. Gringarten becomes more obvious, when we consider the sensitivity of his results to the rate histories that he assumes. At the beginning of his analysis, Dr. Gringarten *assumes* two rate histories; one that is constant at 45000 STB/day, and another that starts at 30000 and then increases to 45000 STB/day (45 K and 30-45 K, respectively). Depending on this assumption of rate

[23] Type curves on Figure 5.9 of the Gringarten report
[24] Figure 5.10 of Gringarten report

history (30-45K vs. 45K) Dr. Gringarten ends up with significantly different rate profiles resulting in estimates of cumulative volume of oil released that varies between 2.5 and 3 MMSTB (both for his most likely permeability of 238 mD). It is obvious that the initial assumption of rate history has a significant impact on the estimate of "cumulative volume of oil released". It is quite likely that if he had allowed the rate history to vary (rather the type curve), or had started with a different assumption of rate history, he would have obtained a different estimate of "cumulative volume of oil" released.

Dr. Gringarten chooses a series of flowing pressures between April 20 and May 8, when there are no measured values available, that restricts the oil flow to essentially zero at the time of blow out. While there is little information right after the blowout to know the flow rate, and therefore there a possibility that the oil flow was initially smaller and then it increased, Dr. Gringarten does not present any evidence to suggest that this is the most likely scenario. I believe such a scenario should be investigated only as an extreme possibility as I have done in my initial report (also see Section II of this report, and Appendices I and II). What little information that does exist, including physical evidence of the rapid erosion of the BOP upper annular and VBR rams[25], certainly does not support Gringarten's implicit assumption that there was a miniscule flow rate increasing slowly over time.

Professor Blunt

Professor Blunt conducts a number of different analyses, but he forms his opinion for his estimation of "cumulative volume of oil released" based on the material balance technique. Therefore, I start my comments on this segment of his work before discussing his pressure-transient analysis.

Professor Blunt argues that the material balance method has a very solid grounding in petroleum engineering; it is based on the principle of conservation of mass. Furthermore, he argues that it is a very simple and understandable method. I agree with Professor Blunt on all of this. As I explained in my initial report, much of my work at Fekete is based on this and other analytical methods, and I typically move to numerical simulations only when warranted. It is important to note that other conventional techniques in reservoir engineering, such as well-test interpretation and reservoir simulation are based on and honour material balance too. I come back to this point later in this section under the title of "Putting it together".

Professor Blunt argues that the material balance method has only three input parameters. Therefore, ***if*** one can estimate these parameters with reasonable accuracy, one should be able to estimate the cumulative volume of oil released well. The problem with using the material balance method for the Macondo well is the word "if". I believe that one or more of the three parameters that Professor Blunt uses are low, leading to an under-estimation of the "cumulative volume of oil released". I say this not because I have any better knowledge of the three parameters. I say this because (i) the uncertainty in the estimates of the three values that are required for a material balance calculation is much larger than Professor Blunt admits; *and* (ii) because there is additional information that confirms that the estimate obtained by Dr. Blunt is incorrect. I start with a discussion of the range of uncertainty on the input

[25] Expert Report of Forrest Earl Shanks II on BOP Design, October 2011

parameters to Professor Blunt's material balance equation and their impact on the estimate of "cumulative volume of oil released".

OOIP

I have led the reservoir engineering aspect of many projects where the information about the reservoir volume has come from geoscience colleagues. This experience has taught me that the uncertainty in estimation of a reservoir volume which is directly related to OOIP based solely on seismic data is very large. The uncertainty becomes larger when the reservoir is deeper, and when the level of the water below the oil (i.e., the aquifer) is unknown. These complexities apply to the Macondo reservoir. I would not be surprised at all to see an uncertainty of more than 100%. Determining the connectivity of the reservoir is even more uncertain. This understanding of mine is consistent with BP's interpretation of reservoir rock volume that spanned by a factor of 400% from approximately 90,000 to 360,000 ac ft[26].

On the other hand, I have also worked with geoscientists who put a very large emphasis on results of models that often have underlying assumptions. [redacted] Similarly, Dr. Gringarten does not seem to be bothered by the range of OOIP that he finds from his various analyses that varies by a factor of more than two. In contrast, the uncertainty that Professor Blunt finally carries through to the estimation of cumulative volume of oil released is less than 5%. Although it is not easy to follow Professor Blunt's analyses, his value of OOIP seems to (among other things) rely on estimate of reservoir rock volume, where he notes: "I also know gross rock volume *V=Ah* from the BP seismic analysis (See Table A.6)[28]". In table A.6 Dr. Blunt presents a value of 1,530 MMrb for the gross rock volume. This is indeed the mid value that BP reports for the gross rock volume[29]. However, BP also reports low and high estimates of gross rock volume, each of which are 100% lower and higher than the mid estimate (for a total difference of 400% between the low and high values). It is not clear how this large uncertainty was diminished in Dr. Blunt's analysis. The uncertainty that Professor Blunt considers in the estimate of OOIP is only 5%. This uncertainty is largely understated[30].

Rock compressibility

The compressibility of the rock was obtained by Weatherford. Dr. Zimmerman has evaluated the lab results and has suggested that the laboratory experiments suggest a value of approximately 6 microsips. I used a similar value for my base case scenario. I used (and continue to use) the value of 6 microsips, *not* because I believe that value must be correct, but because I did not have other quantitative values

[26] TAM, Exhibit 5232 at Section 6.17

[27] [redacted]

[28] Page 109, Section D.1.6 of Blunt report

[29] TAM, Exhibit 5232 at Section 6.17

[30] Elsewhere, in Table 4.1, Professor Blunt presents an uncertainty of more than 30% in the reservoir area. However, by the time he arrives at his estimate of OOIP, his reported degree of uncertainty has reduced to 5%.

with which to begin my analysis. [redacted] I have varied rock compressibility over a wide range in my modeling, and have obtained matches with the low and the high end of that range. Thus, I do not believe that Dr. Blunt can claim with confidence that the range of compressibility is small, nor would such a claim alter my best estimate of cumulative oil released.

Average Reservoir Pressure

In reservoir engineering, the average reservoir pressure is often estimated from well test interpretation of the shut in pressure. The thinking goes as follows. If a well is shut in for a very long time the reservoir pressure equalizes such that the pressure at the bottom of the well would be equal to the average reservoir pressure. However, often the well is not shut in long enough for the reservoir pressure to fully equalize. Instead, the rise of pressure with time is studied to predict what the pressure would be after infinite time. This is one of the objectives of well test interpretation. While extrapolation of the trend of pressure vs. time on specialized plots (which is somewhat similar to use of a French curve) has been used, more recent methods rely on matching the pressure response using a mathematical model of the reservoir, and then allowing the model to equalize to an average pressure or directly reading the average pressure of the model. This introduces one uncertainty; depending on the choice of the reservoir model the average pressure at which the reservoir equalizes may be different. This study is generally done using analytical models, similar to what I used in the analytical section of my initial report and what I presented in Section III (and Appendix III). Professor Gringarten too used an analytical well test model for his interpretation. However, there is no requirement for using analytical models for well test interpretation The main reason that analytical models are preferred over numerical models are speed and ease of use that the former provides. With this in mind, all of my sensitivity cases that led to a good match of the shut in pressure present valid well test interpretations. They provide a range of between 10,200 to 10,400 psia. The range of average reservoir pressure estimated by Professor Gringarten is 10,360 to 10,380 psia. My range of uncertainty is 200 psi as compared to 20 psi for Dr. Blunt.

[31] See Exhibits 10841 and 8769 9777 from the Deposition of Pinky Vinson.

The wider range of uncertainty associated with my estimates of average reservoir pressure is related to the fact that for Macondo, pressures were measured at the wellhead. To estimate the average reservoir pressure one needs to account for the hydrostatic head of the fluid in the wellbore. Unfortunately, there is uncertainty associated with the density of the fluid in the wellbore, and therefore the estimation of the hydrostatic head is uncertain. The wider range of uncertainty in my estimates is not only a reflection of the fact that I have allowed for the uncertainty in the hydrostatic head but also in the reservoir model.

Putting it Together

With the degree of uncertainty in the OOIP, the compressibility and the pressure depletion, I could easily demonstrate a large degree of uncertainty on the estimate of cumulative volume of oil released. But then I have fallen into the same trap that Dr. Blunt; I have used independent estimates that are not calibrated against a few pieces of valuable information.

Instead, I suggest that there is nothing very special about material balance; after all simulation and well-test models are based on material balance too. Here I use my sensitivity studies along with simple material balance calculations to demonstrate that the problem with Dr. Blunt's work is in the input parameters that he chose; input parameters that were not calibrated against measurements.

Consider that I conduct a numerical modelling of the shut-in data. (As already stated the choice of analytical vs. numerical models for analysis of shut-in data is primarily for ease of use and speed. A valid analysis can be obtained using both methods as demonstrated in this report.) In the meantime allow me to select only those models that are consistent with the collection rates. Now if *I use material balance*, based on values of OIIP, compressibility and pressure depletion obtained from the numerical models that matched the collection rates, I find that the range of cumulative volume of oil released is 5 to 5.3 MMSTB. This is because the simulation technique too honours material balance. The difference between this material balance and what Dr. Blunt performed is that I would conduct the material balance on those models that are consistent with all measurements during the integrity test.

Therefore, in my opinion the weakness in Dr. Blunt's analysis is not that he used material balance; in fact material balance based on a comprehensive study that is consistent with shut-in pressures and collection rates can provide a good estimate of cumulative volume of oil released. The main weakness in Dr. Blunt's analysis is that he did not check to see if his understanding of the reservoir is consistent with the collection rates, and he considered too narrow of a range of possibilities for the three input parameters needed for the material balance study.

Pressure Transient Analysis

Professor Blunt also conducts an analysis of the shut-in pressures, using conventional well-testing techniques. Having discussed my opinion about the key weaknesses of Professor Blunt's analysis above, the following is a brief discussion of weaknesses of his analysis.

- Professor Blunt uses well-test interpretation technique to obtain a number of pieces of information, which he then uses in his material balance work. Among the parameters that he finds are: average reservoir pressures, an estimation of permeability[32], skin and the associated pressure drop[33], and even a measure of parameters such as connectivity[34]. Considering that model-based well-test interpretation techniques (such as the ones that Professor Blunt uses) honour material balance, what remains unanswered is why Professor Blunt does not use the well-test interpretation technique to solve the full problem. It would have given him the advantage of (i) making use of the trend of the shut-in pressures, (ii) still being consistent with the material balance, and (iii) presenting a cohesive answer where the material balance component of the model is consistent with the other parts of the interpretation, such as estimation of permeability and connectivity. The way it stands now, it is not clear how the parameters that are found from his well-test analysis come together with his material balance work. This is especially problematic as he switches between various estimates of permeability.
- Professor Blunt refers to the pay thickness of 16.5 ft considered in Dr. Emilsen's work, and suggests that this would be a reflection of the formation that was open to flow at the time of blow-out. He then approximates this restriction in the flow between the reservoir and the wellbore as an equivalent skin, and suggests that this skin probably had been removed by the time the well-was shut-in. He suggests that this change in skin would have occurred over many weeks to months. I disagree with this interpretation, because
  - The time-scale of processes that Dr. Emilsen deals with are seconds to hours. Furthermore, the program that he uses is designed to accurately model fast changing flow conditions in the *wellbore*. However, the accuracy of the modelling is not extended to the reservoir; the reservoir-flow modelling is based on productivity-index. Flow from a reservoir that responds to wellbore conditions that are changing over seconds to minutes cannot be properly modelled using productivity index.
  - Dr. Emilsen discusses the limitations of his interpretation about this restricted communication with the reservoir[35]. In my opinion, these factors as reflected by productivity index (represented by a small thickness of 16.5 ft) include restrictions that the cement in the wellbore, annulus or reservoir rock posed against flow at the very early stages of blow out, and the restrictions that the intrusion of mud-filtrate into the reservoir rock would cause. While expert reports of Drs. Benge and Griffiths address the cement, I discuss the restrictions caused by the mud filtrate as evidenced using the MDT tests. The majority of the MDT tests conducted on the Macondo where of a short duration. Such tests are expected to reflect formation mobility as affected by the mud-filtrate. In addition, three MDT tests were conducted on Macondo, each of which had a flowing period of a number of hours. The pre-test conducted at the end of each of these longer flow periods is expected to be a more accurate reflection of the formation

[32] Page 39, Blunt report
[33] Page 122 Blunt report
[34] Page 109, Blunt report
[35] Page 14 of Emilsen report (October 2011)

mobility. Although, in this high permeability formation, quantitative estimation of mobility is subject to uncertainties, a qualitative comparison is possible. Figure 33 of BP's technical memorandum presents a comparison between the two sets of mobility, demonstrating that the mobility of the formation affected by the mud filtrate is significantly (by many times) smaller than the mobility after hours of flow, when the MDT device was not affected by the mud filtrate. This demonstrates a reduction of the productivity index that may be caused by the mud filtrate.

- o While there would be a change in the productivity index as a result of the production of the mud filtrate, Dr. Blunt exaggerates the effect because the mud filtrate would have been produced in less than a few hours. This short production period is evidenced by the response of the fluid analyzer in the MDT device, and the low contamination of the oil samples by the mud filtrate that were obtained after a few hours of flow. While such durations of time may be of importance to the modeling of the blowout as conducted by Dr. Emilsen, they are of little consequence to the estimation of "cumulative volume of oil released".

- As I pointed out in Section III, there is no evidence for a trend of increasing productivity index over many weeks. This is just speculation on the part of BP's experts. Alternatively, one could speculate that the productivity of the well decreased with time, as most wells do. Such a trend of declining productivity could be associated with the tendency of the Macondo oil for severe asphaltene deposition[36].

[redacted]

36

MDL00063084

37 [redacted]

38

[redacted]

[redacted]

39 [redacted]
40

Section V: Response to the critique of my work by the defendants' experts

In this section I provide a response to the critique of my work by the defendants' experts. The critique can be divided into a few categories, including (i) the choice and range of input parameters, (ii) the methodology used for analysis, (iii) the assumptions of the one-dimensional resistance models with constant coefficients for calculations of flow rate during the integrity test, and (iv) consideration of the changing reservoir and wellbore conditions with time. There are some additional comments that do not fall under any of the above. I call them "Additional critique". I divide my responses accordingly. In some cases, much of the answer to the critique is included in other sections of the report. In such cases, I will keep repetition to a minimum.

After full consideration of the critiques made by the various defendants' experts, I do not believe that they undermined the conclusions I reached in my original report.

The choice and range of input parameters

Statement of the critique

Some of the defendants' experts have suggested that the range of uncertainty in my input parameters was too large. One has even suggested that it was arbitrary. One of them even speculates as to why and how I chose my input parameters.

Response

My study made use of two approaches, the analytical and the numerical. The first phase of study that I conducted was "analytical". This was done at a time when I had not yet reviewed all the available information. There were a few input parameters that I changed when I moved to the second phase of the study, i.e. the numerical one.[41] This is clearly stated in Appendix III of my initial report. However, one advantage of the analytical model was that it allowed me to find out which parameters may have a large impact on the final answer. I considered this as I reviewed the available information to come up with a range for each parameter before moving to the numerical phase of my study. In selecting the range of input parameters, I was guided by either my own assessment (i.e. when considering the range of uncertainty in PVT properties) or by the assessment of those whom I perceived to be more qualified (e.g. estimate of OOIP). Whenever I was in doubt I considered a wide range (e.g. permeability and skin factor). My basic premise comes from my experience in the industry. It is very unlikely that information obtained at one exploration well is representative of the whole reservoir. This becomes obvious when

[41] Some experts have pointed out that I used some incorrect input values (such as the value for oil compressibility) in my analytical model. Those values were corrected in my numerical model, and thus their use in my analytical model does not affect my results. I chose not to go back and recreate my analytical model because doing so would not necessarily provide additional insight into the problem – the choice of such input parameters such as compressibility had little impact on my answers from the first phase of my study, and I had already been able to determine the most significant input parameters for my numerical sensitivity studies.

one considers that all that the Macondo well sampled is less than 1 square foot out of a few square milies of the the reservoir. Other information that has been obtained for the larger reservoir (e.g. geophysical data) have been acquired from a distance of 3 miles.

Generally, I allowed for a wide range of uncertainty. I believe this was the best approach to achieve the objective of this study. I knew that I could not find a single, unique model of the Macondo reservoir wellbore system using reservoir engineering techniques. Therefore, I needed to examine how wide the range of answers could be. The best way of finding the answer to this question was by allowing a wide range of input parameters. I never thought it was a weakness that I considered too wide of a range of input parameters. On the contrary, if I had chosen my best estimate for each input parameter and performed my study with it, it would have been very likely that I might have been short sightedby my unwillingness to consider other possibilities. In fact, Drs. Blunt, Gringarten [redacted] do exactly that; they rely on their estimates for parameters without corroborating their findings against all available data, in particular the collection rates and the associated wellhead pressures.

More to the point, between my initial report and the current one, I have considered all input parameters suggested by the defendants' experts (e.g. permeability of 238 mD and even lower, OOIP of 112 MMSTB and even lower, Dr. Blunt's high shut inpressures, Dr. Trusler's corrections to the BOP pressures, PVT properties based on single stage separator, oil and rock compressibility of approximately 15 and 6 microsips and even lower, Dr. Johnson's wellbore model and even a more restrictive one). Having done a wider range of sensitivities that includes all the input parameters that the defendants' experts have suggested, I have demonstrated that the opinions set forth in my initial report are correct: thatthe models that are consistent with the measurements during and after the integrity test produce a cumulative volume of oil released of between 5 to 5.3 MMSTB. If one is willing to ignore the measurements obtained during the integrity test, all kinds of models can be defined – *with plausible sets of input parameters* – whose cumulative volume of oil released is as low as 3 MMSTB (and probably even lower) or as high as 7 MMSTB.

Section III of my initial report and its corresponding Appendix provides a detailed discussion of what data I considered and how I came up with the range of uncertainty for each input data.

The Methodology

Statement of the critique

Some defendants' experts have suggested that my analysis was circular. Another expert suggested that my analysis was progressive; all was based on the first set of assumptions or calculations. Another expert suggested that all of my models are the same (in dimensionless space). Suggestion were even made that I assumed the flow rate of about 50,000 STB/day during the integrity test, or constrained my model to such a value or even that I had a preconceived notion of flow rate and the cumulative volume of 5 MMSTB. One expert suggested that my models based on productivity index were too simplistic.

Response

Once again, I need to answer these questions in two pieces; in relation to each of the analytical and numerical approaches that I chose.

In the analytical approach, I did not assume a flow rate. I used measurements during the integrity test to calculate rate. Then I developed reservoir and wellbore models that were consistent with the calculated flow rate, with input parameters that were within the range of possibilities. Then I went back in time, and calculated rates at earlier times when the reservoir pressure was higher. This solution is based on the estimation of rate, which itself is based on the measurements of collection rate and corresponding pressures at the wellhead. Relying on measurements to find out about the characteristics of a reservoir is totally appropriate; I do it often in my practice. However, the analytical methodology had three shortcomings: (i) the methodology did not allow for uncertainty assessment, (ii) some of the input parameters needed to be revised after I conducted a more complete analysis of the input data, and (iii) the coupling between the wellbore and the reservoir model was not ensured at all times. To overcome the three shortcomings I moved to the second phase of my work.

In this second phase, I did not assume a rate, nor did I constrain my model to a rate. I performed simulation runs that gave me a wide range of rates and a wide range of cumulative volume of oil released (of between 3.3 to 5.8 MMSTB), all of which matched the shut-in pressures.

Among these *unconstrained* cases, I accepted those models that were consistent with observed measurements of collection rate and wellhead pressure. It is only *after* I arrived at models that were consistent with the measurements that I examined their cumulative volume of oil released.

It so happens that the measurements during the integrity tests are so telling about the rate of oil flow at that time, that the defendants' experts have interpreted my selection of the good models as constraining the flow rate. Let me demonstrate this with a simple (but approximate) calculation. Just before collection started the pressure difference between the capping stack and the seafloor was approximately 400 psi. Flow rate through the capping stack is proportional to Square-Root Of Pressure Difference (let me call this SROPD). Therefore, I say that during the no-collection SROPD was 20 psi$^{1/2}$ (which is square-root of 400 psi). At this time, I do not know the flow rate but I know that SROPD is 20 psi$^{1/2}$. Next, and at a collection rate of about 18,000 to 20,000 STB/day, measurements indicate that SROPD decreases by about one third. Therefore, the collection rate should account for approximately one-third of the total flow rate. To remain consistent with these measurements, flow rate has to be approximately three times the collection rate; i.e. between 50,000 and 60,000 STB/day. It is just the measurements that suggest the oil rates are upwards of 50,000 STB/day, I do not constrain that.

As stated before, my methodology includes a calibration and/or history matching. A change in a reservoir or wellbore property does not lead to an automatic change in cumulative volume of oil released. Instead, I vary other parameters of my model in order to remain consistent with the measurements during and after the integrity test. Therefore, it is inappropriate for Dr. Blunt to change one of my parameters in isolation and assess its effect on the final estimate of cumulative volume of oil released, without calibrating the model to measurements.

In fact, it this integrated methodology of calibration that has allowed me to incorporate the input data suggested by the defendants' experts, and assess their effect on the cumulative volume of oil released as presented in Section II and III of this report.

Finally, one expert has suggested that all my solutions are the same (in the dimensionless space). This statement is incorrect. In fact, there is no unique dimensionless group that captures all of the sensitivity studies that I conduct (including reservoir flow properties, reservoir storage properties, wellbore properties, PVT properties, the dimensionless term of Skin, measurement errors and changes in hydrostatic pressure). Therefore, there is no way that changes in all of these parameters can result in one single solution (in dimensionless space).

One-dimensional resistance models and their assumption

Statement of the critique

I have used one-dimensional (1-D) resistance equations in two steps in my work. In the analytical phase of my work, I have used these to estimate oil flow rate of the well during the collection and no-collection periods. In the numerical phase of my study, and after I had obtained a model that matches the shut-in pressures, I have used these equations along with the oil flow rate as calculated by this calibrated model to calculate the collection rate. The use of these equations has been critiqued in a number of ways: (a) It has been suggested that these equations are out-dated, and based on single-phase flow relations and therefore not accurate or not applicable to the case at hand; (b) Another defendants' expert has suggested that the use of these equations for calculation of flow rates is subject errors in the measurement of pressures; (c) One defendants' expert asserts that the way I have formulated my resistance equations is incorrect because there is significant pressure drop in the BOP downstream of the collection point; (d) and finally the same defendants' expert has asserted that I carry over the resistance coefficients from the analytical phase of my study to the numerical phase, and therefore my numerical solutions are constrained by my analytical solutions.

Response

(a) I have validated the applicability of these equations using modern computer programs under two-phase flow conditions. This was presented in Appendix II-A of my initial report for three different systems; the wellbore, the wellbore and the BOP, and the capping stack. Furthermore, Dr. Bushnell has used a more sophisticated model and examined the applicability of these equations. He has demonstrated that these equations are valid even over a wider range of conditions than was necessary for my calculations. The graph showing these results is in Dr. Griffiths' report.

(b) I have examined the effect of errors in pressure measurements on the results of my models. In my initial report, I had four cases that examined the effect of errors in the BOP and capping stack pressure. In this reply report, I have further examined this, by incorporating BOP and capping stack pressures as reported by Dr. Trusler.

(c) The pressure drop that the defendants' expert refers to, relates to before the riser was cut, and includes the pressure drop through the riser kink and the entire downed riser. I use these equations during the time of the integrity test, long after the riser was removed. In Appendix II-C of my initial report, I present analyses based on pressure measurements and modelling results, each of which confirms that there is little resistance in the BOP downstream of the collection point. One piece of that analysis is presented here again. Figure 10 shows the difference between the BOP and capping stack pressure. If the collection was from upstream of the BOP, the pressure difference between the BOP and the capping stack should have *decreased* when a significant portion of the total flow (approximately 20,000 STB/day) was taken away upstream of the BOP. The measurements shown in Figure 10 indicate an increase in the pressure difference. This is consistent with collection being downstream of the resistance in the BOP (Scenario-1 in Figure 10). Also, modelling results shown in Figure 10 suggest that a scenario where collection is upstream of the BOP (scenario-2 shown with the long dashed-line) is totally inconsistent with the measurements. Dr. Griffiths presents an analysis that confirms the same.

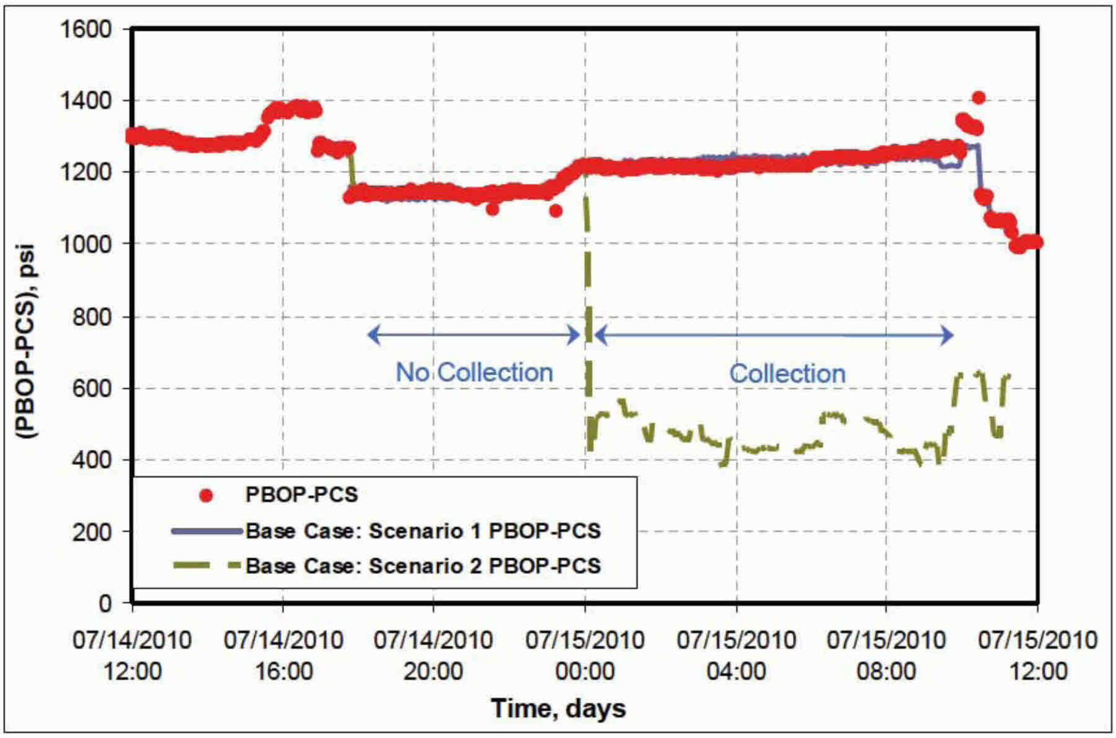


Figure 10: Pressure difference between the BOP and the Capping Stack during the no-collection and collection times and modelling results, indicating consistency with scenario-1; collection was downstream of the resistance in the BOP.

(d) This assertion is incorrect. For each simulation case, I use the rates from the model, along with the wellhead pressures to first calculate the BOP and CS resistances. These are then used to calculate collection rates on a case by case basis.

After considering the critiques made by the various defense experts, I do not believe that they undermined the conclusions I reached in my original report.

Changing Wellbore and Reservoir Conditions

Statement of the Critique

Some of the defendants' experts have suggested that I have not examined the case of changing wellbore and/or reservoir conditions, or have not addressed it sufficiently.

Response

I have addressed this scenario under What if cases in Section V of my initial report. Furthermore, Section III of the current report is entirely dedicated to this topic. Therefore, I find the critique invalid.

Additional Critiques

- Dr. Zimmerman has identified an error in my reference to the choice of rock compressibility values that I have used. This is in relation to Appendix III of my initial report, page 8, right column. The text there should read: "The Low, Base and high estimates are based on uniaxial strain pore volume compressibility test conducted by Weatherford: "BP HZN 2179MDL02394184". The Base estimate corresponds approximately to the mean value of compressibility, while the low and high estimates are approximately 1/3 less and more than the minimum and maximum values at the relevant pressures in the table, respectively". This correction neither affects my analysis nor my opinion.
- [redacted]
- [redacted]
- [redacted]

[redacted]

- Dr. Blunt suggests that his match of the shut in pressures that is often within 2 psi is superior to my match of the data that is often within 3 psi. I find this comparison to be baseless and/or of no consequence, because although my match of pressure is generally within 3 psi, I considered a match to be good as long as it was within 10 psi of the measured data (0.1%). There are many approximations in the shut in data including resolution of approximately 5 psi, uncertainty of the capping stack pressures that is in the range of 10 to 30 psi, and the assumptions made in the estimation of bottomhole pressures. In light of these uncertainties I am of the opinion that a match that is within 10 psi is as good as one that is within 2 or 3 psi. Furthermore, Dr. Blunt generally ignores the first 3 to 30 hours of the data, which constitutes the portion of the data that exhibits the largest mis match with models. Therefore, I find comparison of his matches that focus on the later part of the data with mine which encompass all of the data a comparison of apples with oranges.
- Dr. Blunt suggests that if one were to accept his estimation of cooling of the wellbore fluid, and the reservoir had a permeability of 500 mD or more, the pressure would have fallen during the integrity test[42]. This is incorrect. I have demonstrated a number of analytical and numerical results, many with permeability of more than 500 mD, which match his estimated bottomhole pressures and a wellhead pressure that is increasing with time.

Information Required By The Federal Rules Of Civil Procedure

This report contains my opinions, conclusions, and reasons therefore.

A detailed statement of my qualifications and a list of publications authored since 1995 are included in Appendix VI of my initial report.

The compensation to Fekete Associates Inc (recently acquired by IHS) for my time in preparing this report and any testimony as an expert witness at trial or deposition is as follows: $ 370 per hour.

My prior testimony is identified in Appendix VI of my initial report.

The facts and data I considered in forming my opinions are listed in Appendix IV to this rebuttal report.

The opinions expressed in this report are my own and are based on the data and facts available to me at the time of writing. Should additional relevant or pertinent information become available, I reserve the right to supplement the discussion and findings in this report.

[42] Page 88, Blunt report

Fekete

Appendix I:
Modified VLP

Background and Results

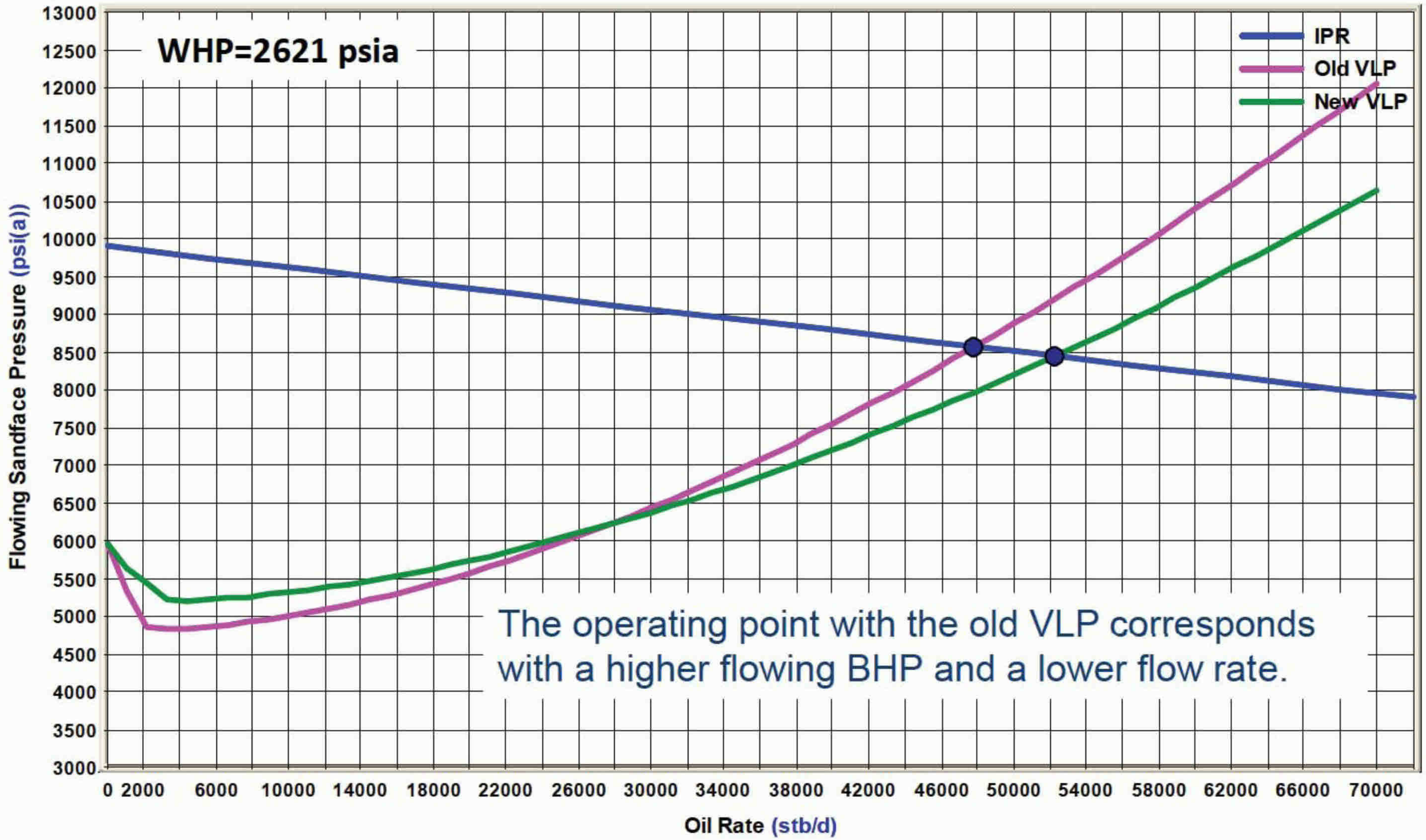
It was found that, for a given GOR, oil rate, and wellhead pressure, CMG and VirtuWell calculate BHP's differently. The source of this problem was found to be a difference in the definition of GOR between VirtuWell and CMG. To rectify this, VLP tables were created with GOR values that are consistent with CMG.

The New VLP tables with the Base Model resulted in a model with cumulative volume of oil released of 5.2 MMSTB; and a bad match of the shut-in pressures. The history matching procedure was repeated and a ood match to the BHP is achieved the model is named Modified VLP, and subsequently Base Case 2). The cumulative volume of oil released is 5.08 MMstb and the match to the collection rates is within range of ±600 STB/day. The cumulative oil released of the base case model (with the incorrect VLP tables) was 5.03 MMstb. The following parameters were changed to obtain a good match:

Skin=13 (the base case value is 9.5)

Ye=21, 850 ft (the base case value is 21,450 ft)

Comparison of New & Old VLP



Summary of Results [Modified VLP]

	K, mD	Skin	Length Xe, ft	Width Ye, ft	Xw, ft	Yw, ft	OOIP, MMSTB	Pav, psi	PI, stb/d/psi	q July 15, stb/d	Error, %	Cum Oil Released (after matching shut-in pressures), MMSTB
k=360 mD (Case-02)	360	13	20050	4500	3950	1650	131.1	10270	19	48000	0.05	4.60 (Bad-Med.)
Upper Bound Hydrostatic Error (Case-23)	575	20	23300	4400	3700	1350	150.0	10383	23	51000	0.03	4.88 (Med.)
h=50 ft (Case-05)	980	15	28500	5900	4550	1950	136.0	10212	25	52000	0.05	4.98 (Good)
Base Case2 (Case-00)	550	13	21850	4400	3700	1350	140.0	10219	28	53000	0.04	5.08 (Good)
Cf=12E-6 1/psi (Case-11)	670	13	20350	3700	3200	1450	110.0	10207	33	55000	0.03	5.26 (Good)
Lower Bound Hydrostatic Error (Case-22)	540	5.75	21100	4400	3700	1650	135.1	10060	38	56000	0.03	5.36 (Good-Med)
BOP ID=3.5 in (Case-14)	535	19.5	21550	4800	3600	1950	150.5	10217	22	57000	0.03	5.47 (Med)

Summary of Results of my initial report and those after correction of VLP's – 1

	K, mD	Skin	Length Xe, ft	Width Ye, ft	Xw, ft	Yw, ft	OOIP, MMSTB	Pav, psi	PI, stb/d/psi	q July 15, stb/d	Error, %	Cum Oil Released (after matching shut-in pressures), MMSTB	
BOP ID=2 in (Case-13)	315	9.5	15950	3900	2600	1350	90.5	10201	19	34100	0.03	3.32 (Bad)	
Skin=50 (Case-07)	450	50.0	18550	3400	2700	1350	91.8	10197	10	34800	0.03	3.39 (Bad)	
K=170 mD (Case-01)	170	5.0	17750	4900	4300	2250	126.6	10382	15	42900	0.3	4.14 (Bad)	
h=25 ft (Case-04)	1300	16	32750	8850	5600	3150	117.2	10202	17	44400	0.05	4.3 (Bad)	
k=360 mD (Case-02)	360	12	19450	4500	3750	1850	127.4	10255	20	46900	0.05	4.53 (Bad-Med.)	4.6 (Bad-Med)
Roughness=0.02 in (Case-17)	470	5	20750	4300	3700	1250	129.9	10227	34	48700	0.04	4.70 (Med.)	
Upper Bound Hydrostatic Error (Case-23)	575	16	22950	4400	3700	1350	147.0	10371	26	50700	0.03	4.85 (Med.)	4.88 (Med)
h=50 ft (Case-05)	980	11.5	28200	5900	4400	1950	134.5	10208	29	51100	0.03	4.93 (Med.-Good)	4.98 (Good)
Lower Bound CS Error (Case-18)	510	9	21050	4400	3700	1350	134.9	10188	31	51600	0.04	4.99 (Good)	
Porosity (Case-24)	530	9.5	21600	4550	3700	1350	136.8	10206	31	51800	0.03	5.00 (Good)	
Upper Bound CS Error (Case-19)	560	10	21900	4400	3700	1350	140.3	10239	32	52200	0.04	5.03 (Good)	
Base Case (Case-00)	550	9.5	21450	4400	3700	1350	137.4	10204	32	52400	0.04	5.03 (Good)	5.08 (Good)
Lower Bound BOP Error (Case-20)	550	9.5	21450	4400	3700	1350	137.4	10204	32	52400	0.04	5.03 (Good)	

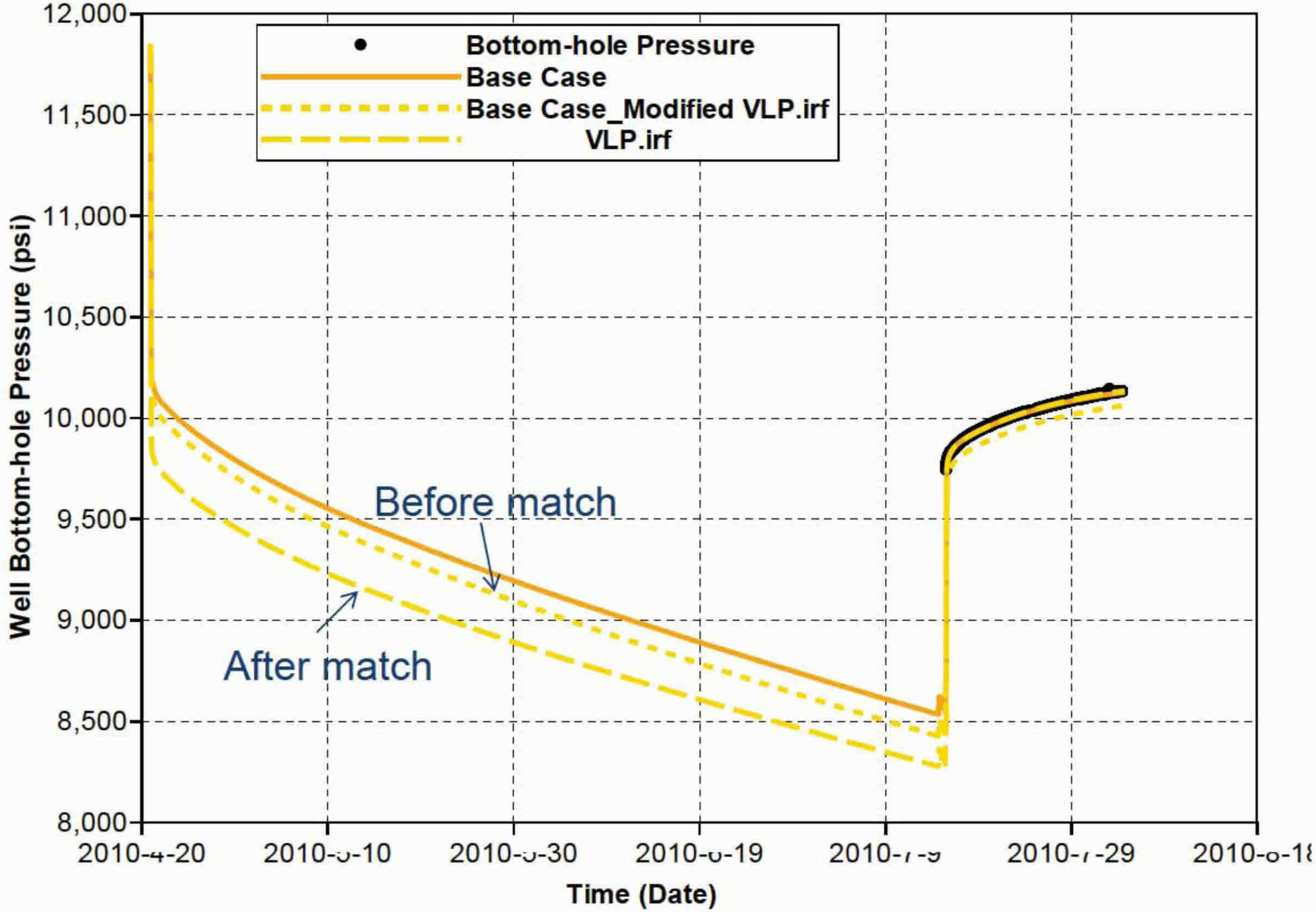
Summary of Results of my initial report and those after correction of VLP's – 1

	K, mD	Skin	Length Xe, ft	Width Ye, ft	Xw, ft	Yw, ft	OOIP, MMSTB	Pav, psi	PI, stb/d/psi	q July 15, stb/d	Error, %	Cum Oil Released (after matching shut-in pressures), MMSTB	
Upper Bound BOP Error (Case-21)	550	9.5	21450	4400	3700	1350	137.4	10204	32	52400	0.04	5.03 (Good)	
High Viso at Low Pressures (Case-10)	550	9.5	21550	4400	3700	1350	138.3	10211	32	52400	0.05	5.05 (Good)	
k=850 mD (Case-03)	850	18	25450	3700	3650	1650	137.1	10199	33	52500	0.04	5.07 (Good)	
Visc=0.16 cp (Case-09)	360	6	21100	4600	3500	1650	141.3	10213	36	53300	0.03	5.13 (Good)	
Aquifer (Case-08)	530	6.5	20750	3900	3400	1450	117.8	10202	36	53300	0.03	5.14 (Good)	
Cf=12E-6 1/psi (Case-11)	650	9.5	19850	3700	3200	1350	106.9	10199	36	53400	0.04	5.15 (Good)	5.26 (Good)
Lower Bound Hydrostatic Error (Case-22)	530	2.5	20650	4400	3700	1350	132.2	10053	44	54200	0.06	5.27 Good	5.36 (Good-Med)
Layered (Case-12)	284 565 1585	4.0	21500	4500	3400	1350	146.3	10201	46	55400	0.05	5.33 (Good-Med.)	
BOP ID=3.5 in (Case-14)	530	17	21250	4800	3600	1650	148.5	10213	24	56000	0.04	5.40 (Good-Med.)	5.47 (Med)
Skin=0 (Case-06)	540	0.0	21950	4700	3850	1550	150.2	10220	52	56300	0.03	5.44 (Med.)	
BOP ID=4.0 in (Case-15)	520	16	22200	4800	4100	1550	155.1	10229	24	58100	0.04	5.59 (Med.)	
Roughness=0.0006 in (Case-16)	550	22	21500	5000	3700	1650	158.0	10131	22	59800	0.05	5.78 (Bad)	

- The ranking of the cases into three groups of "Good", "Mediocre" and "Bad" is based on the quality of the match of "collection period". The three categories correspond to a difference between model results and measured collection rates of ±600, ±2500, and more than ±2500 STB/day
- Parameters that are changed to obtain a history-match are given a pink background
- With exception of one case (K=170 mD), all other cases resulted in match of the shut-in pressures (to within an average error of less than 0.1%).

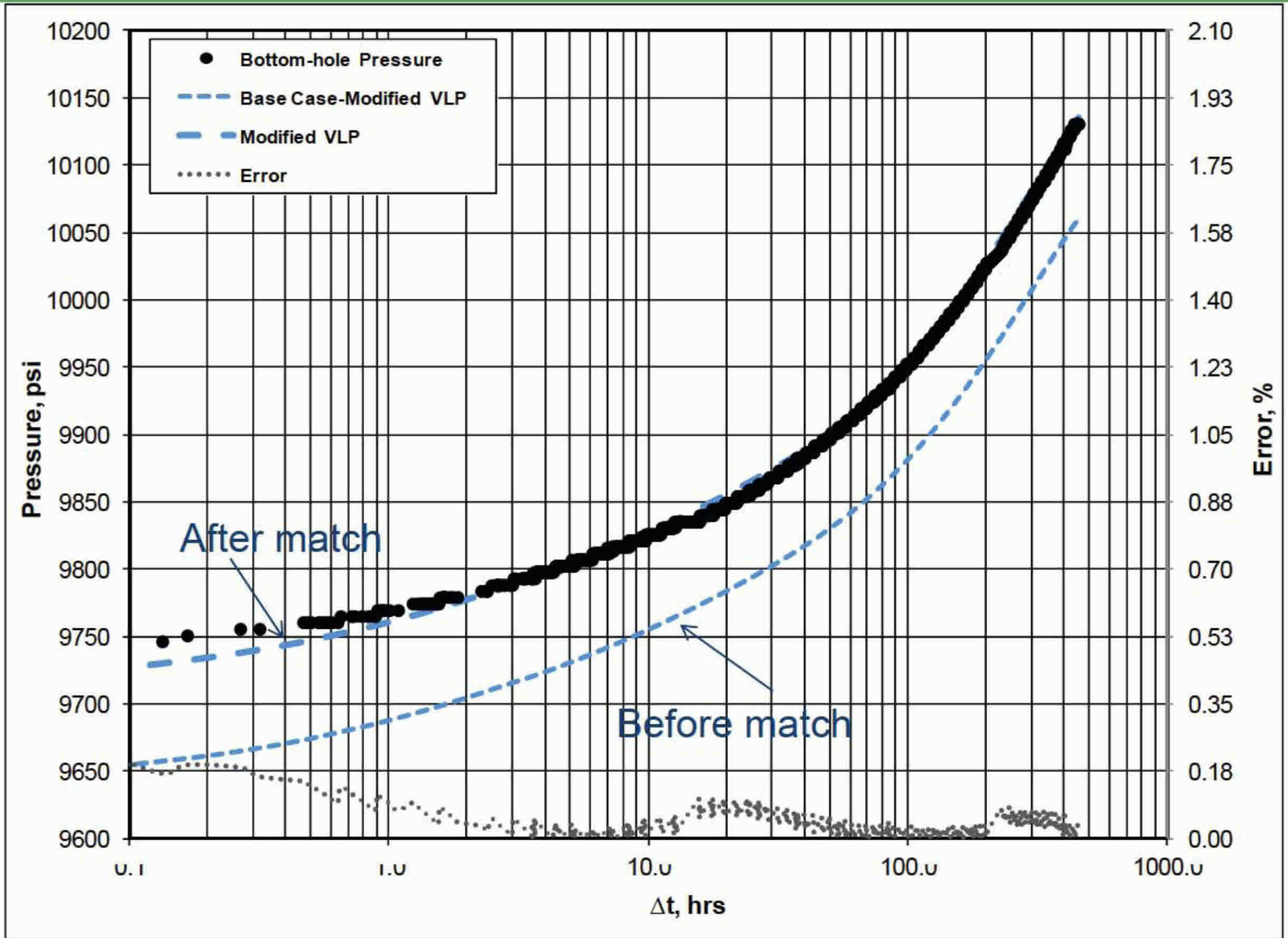
RESULTS

Modified VLP: Bottom-hole Pressure



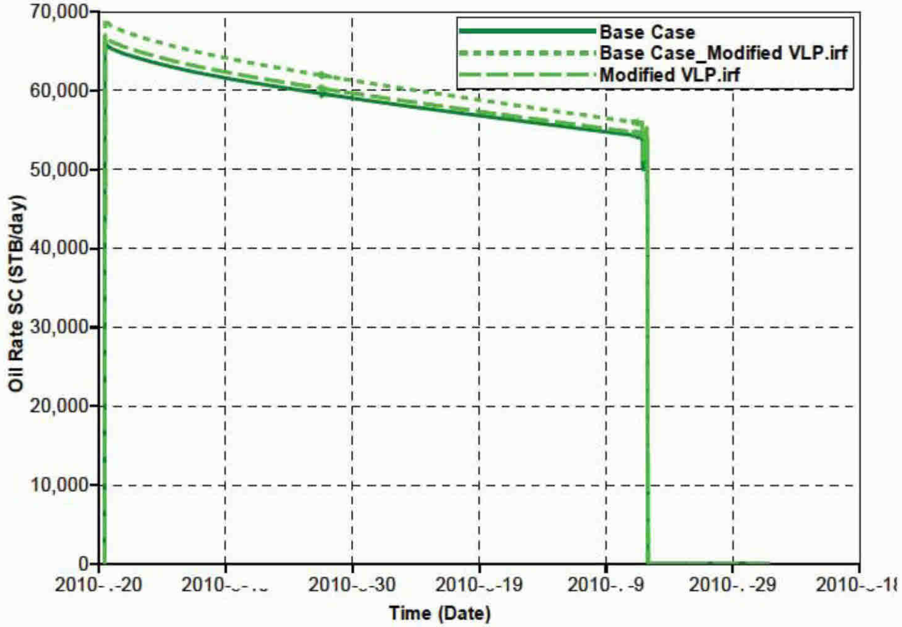
TREX-011654R.0047

Modified VLP: MDH Type Curve



Fekete

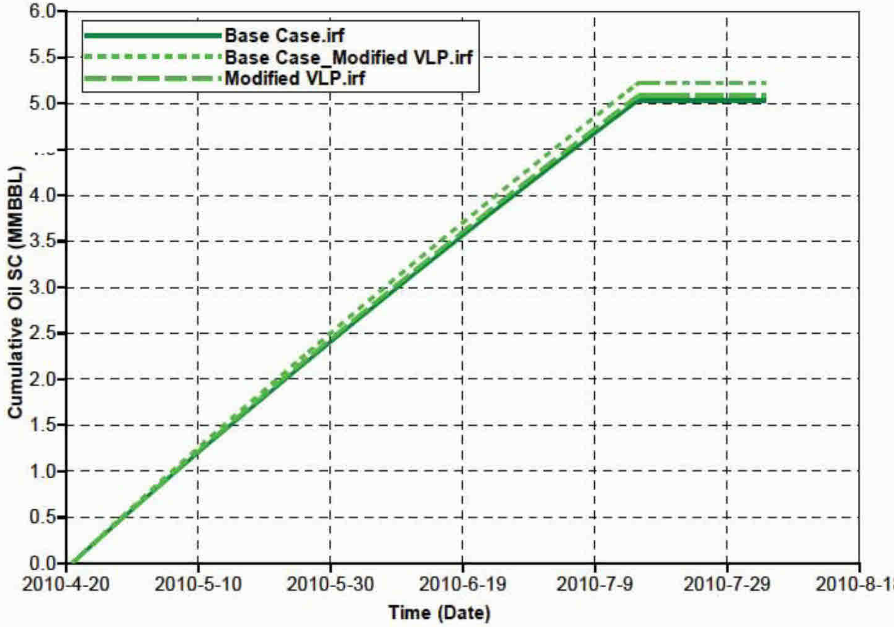
Modified VLP: Oil Released



Cumulative oil released (before match) = 5.2 MMSTB
Cumulative oil released (after match) = 5.08 MMSTB

OOIP=140 MMstb

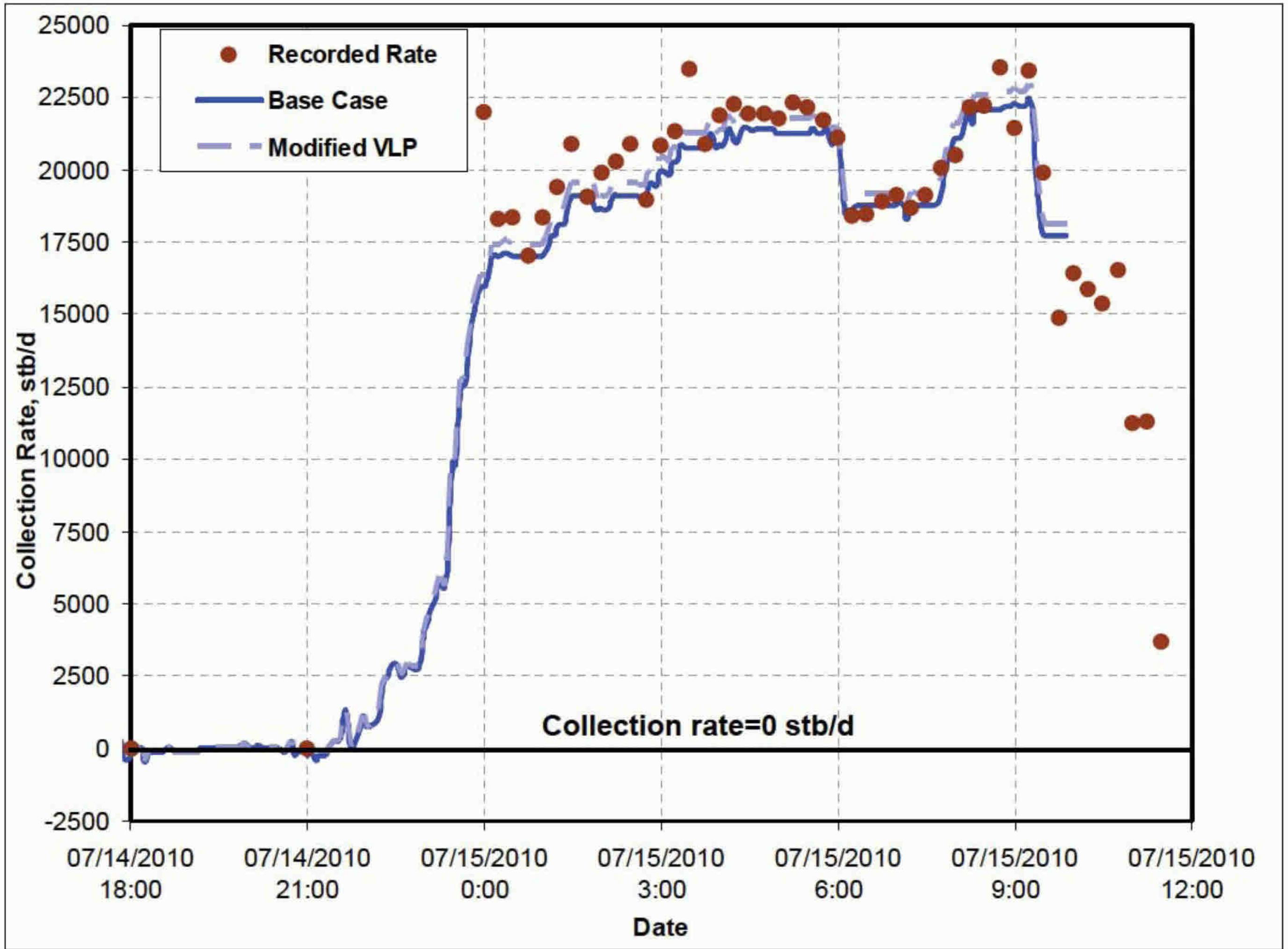
PI (Base Case), stb/psi/day:	32.0
PI (Base Case-Modified VLP), stb/psi/day:	32.0
PI (Modified VLP), stb/psi/day:	28.0



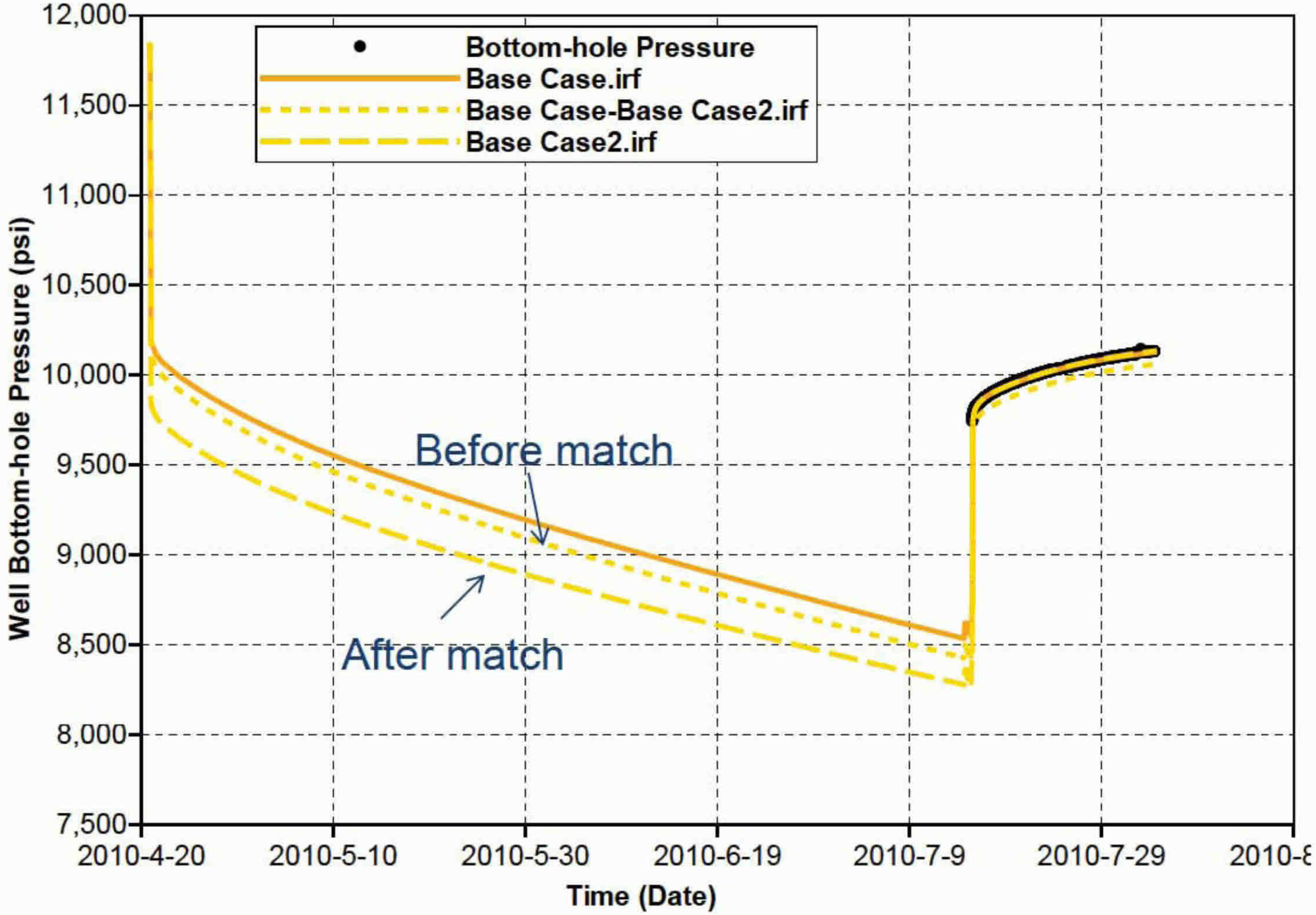
Fekete

Modified VLP: Collection Rate

Match: Generally within ±600 STB/day

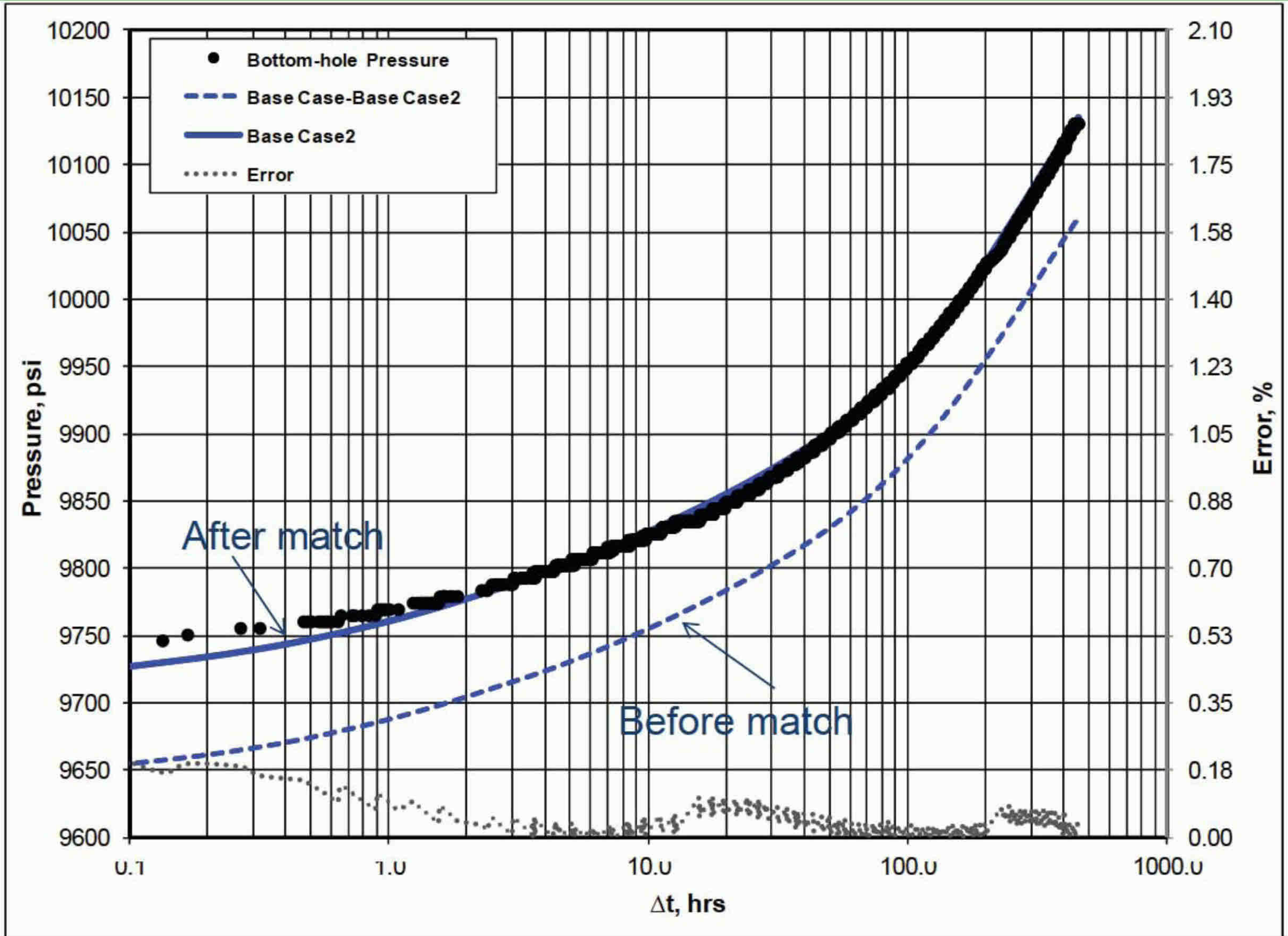


Base Case2: Bottom-hole Pressure

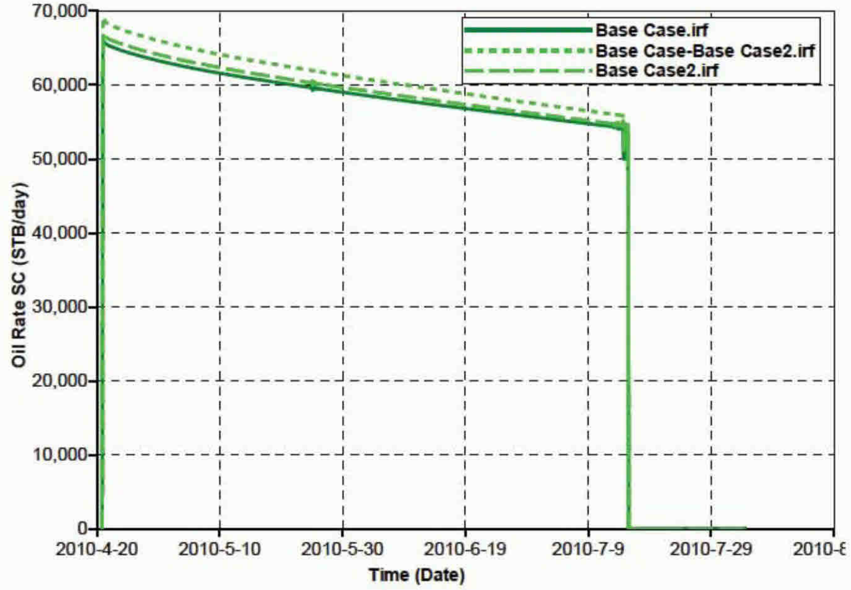


Base Case 2, the same as Modified VLP Case

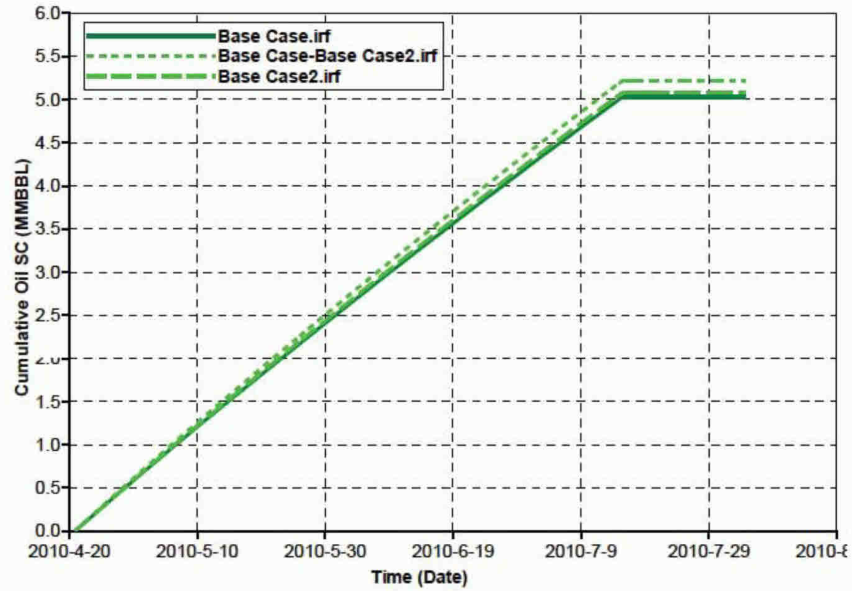
Base Case2: MDH Type Curve



Base Case2: Oil Released



Cumulative oil released = 5.08 MMSTB

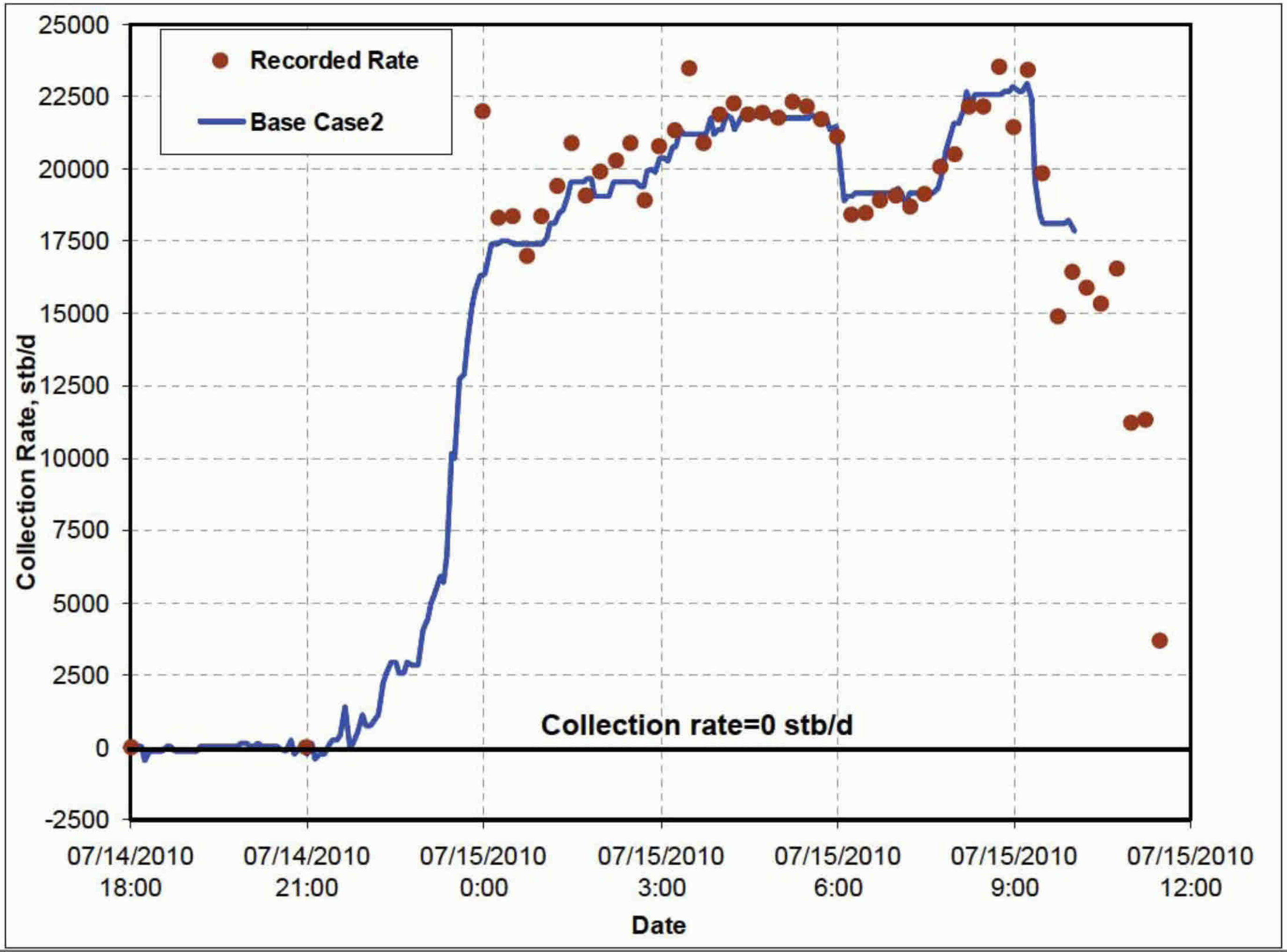


OOIP=140 MMstb

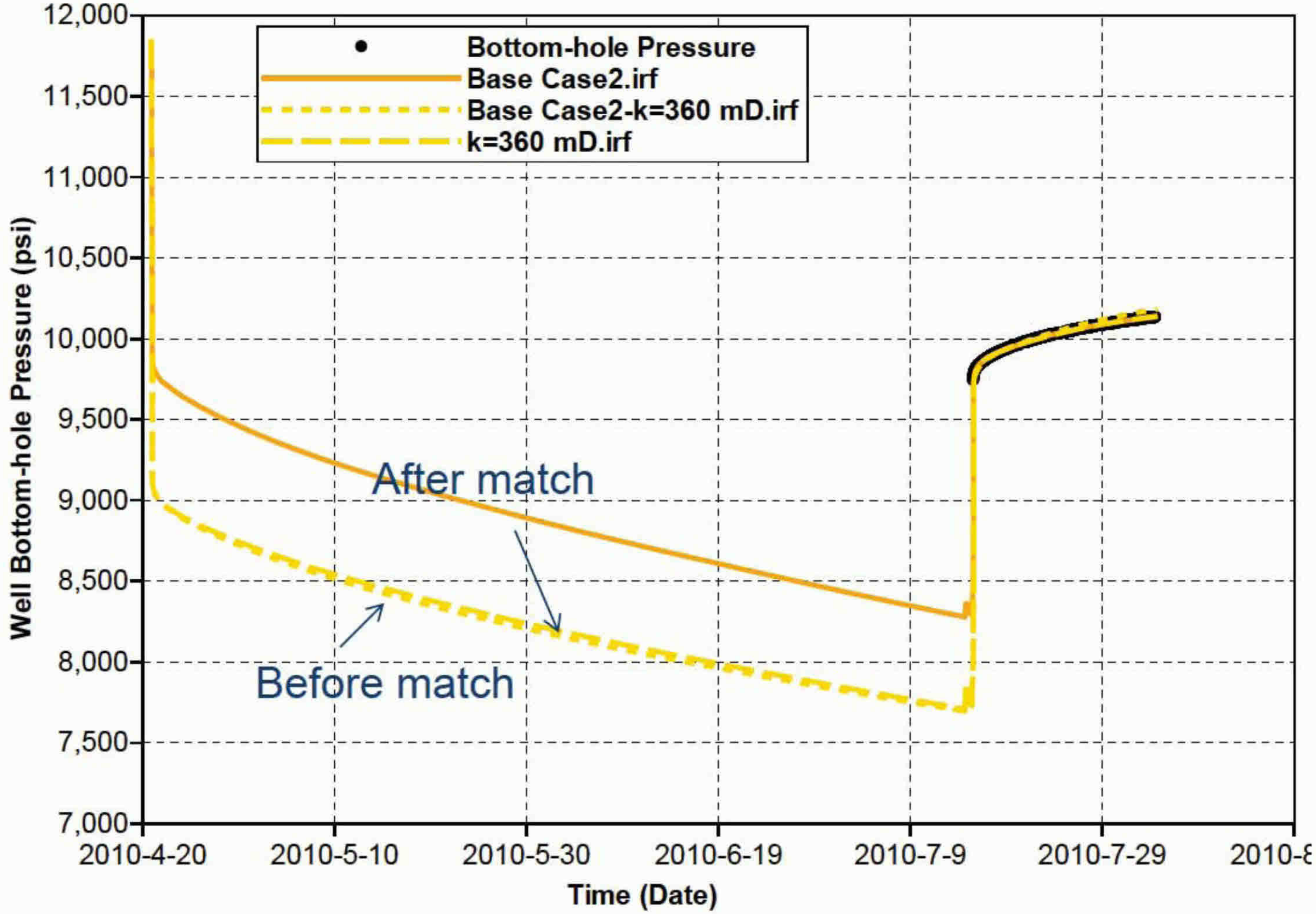
PI (Base Case), stb/psi/day:	32.0
PI (Base Case-Base Case2), stb/psi/day:	32.0
PI (Base Case2), stb/psi/day:	28.0

Base Case2: Collection Rate

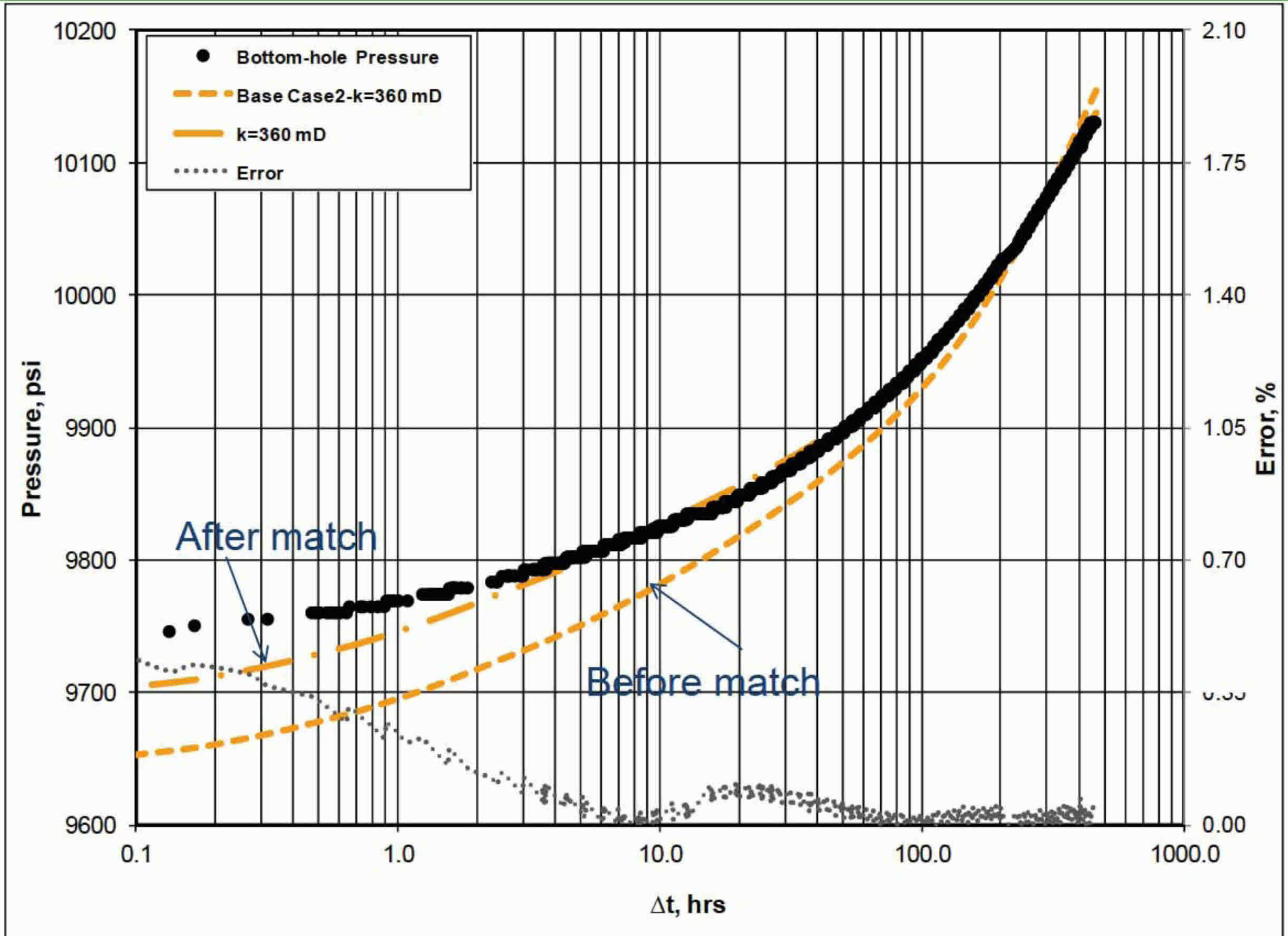
Match: Generally within ±600 STB/day



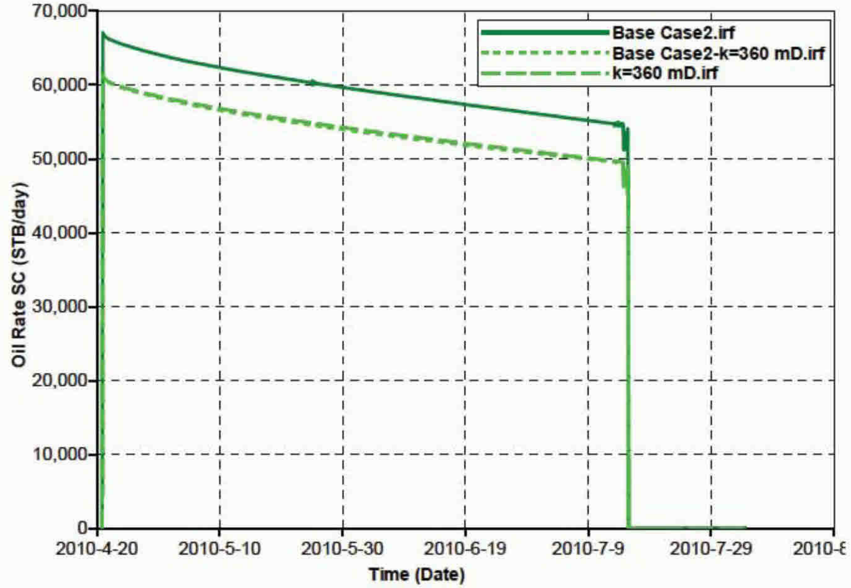
k=360 mD: Bottom-hole Pressure



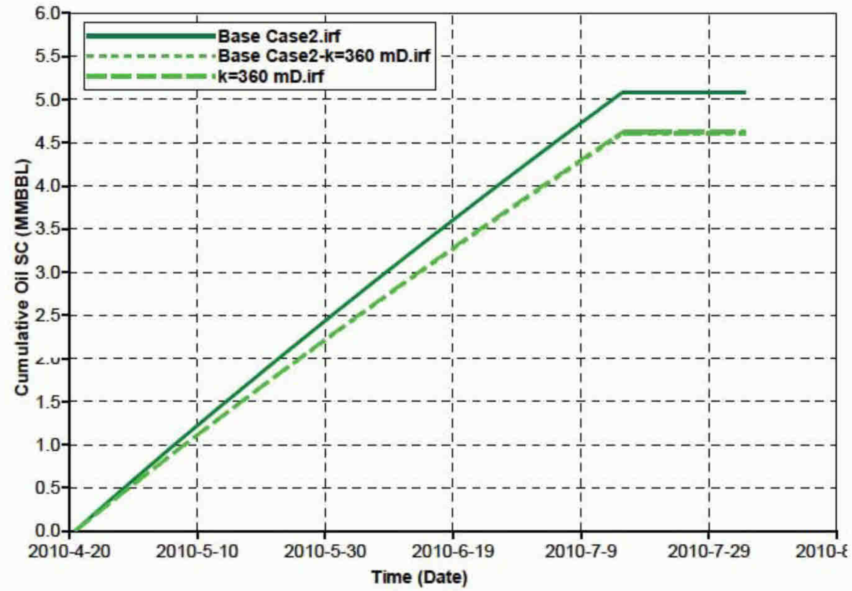
k=360 mD: MDH Type Curve



k=360 mD: Oil Released



Cumulative oil released = 4.6 MMSTB



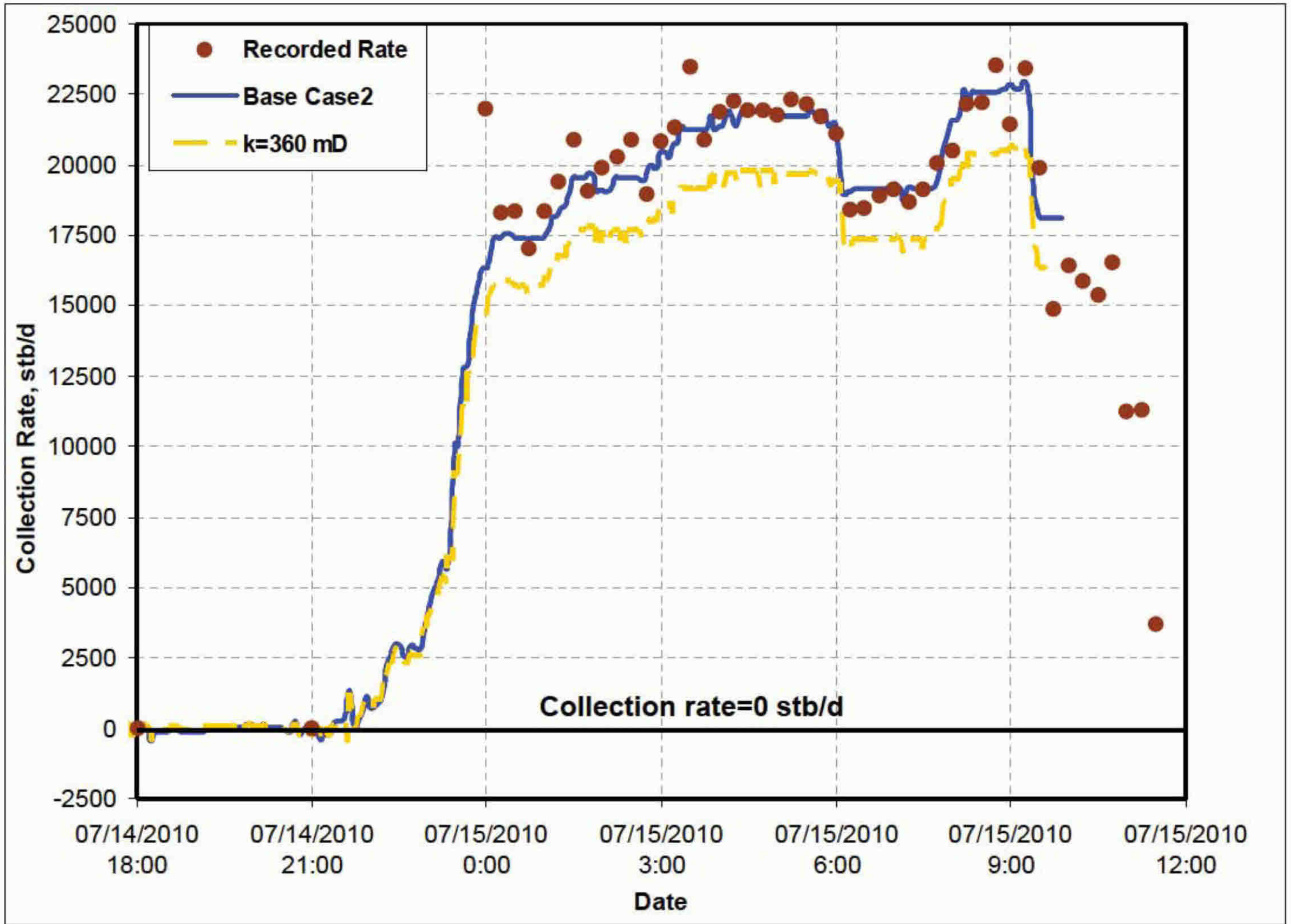
OOIP=131 MMstb

PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-k=360 mD), stb/psi/day:	18.0
PI (k=360 mD), stb/psi/day:	19.0

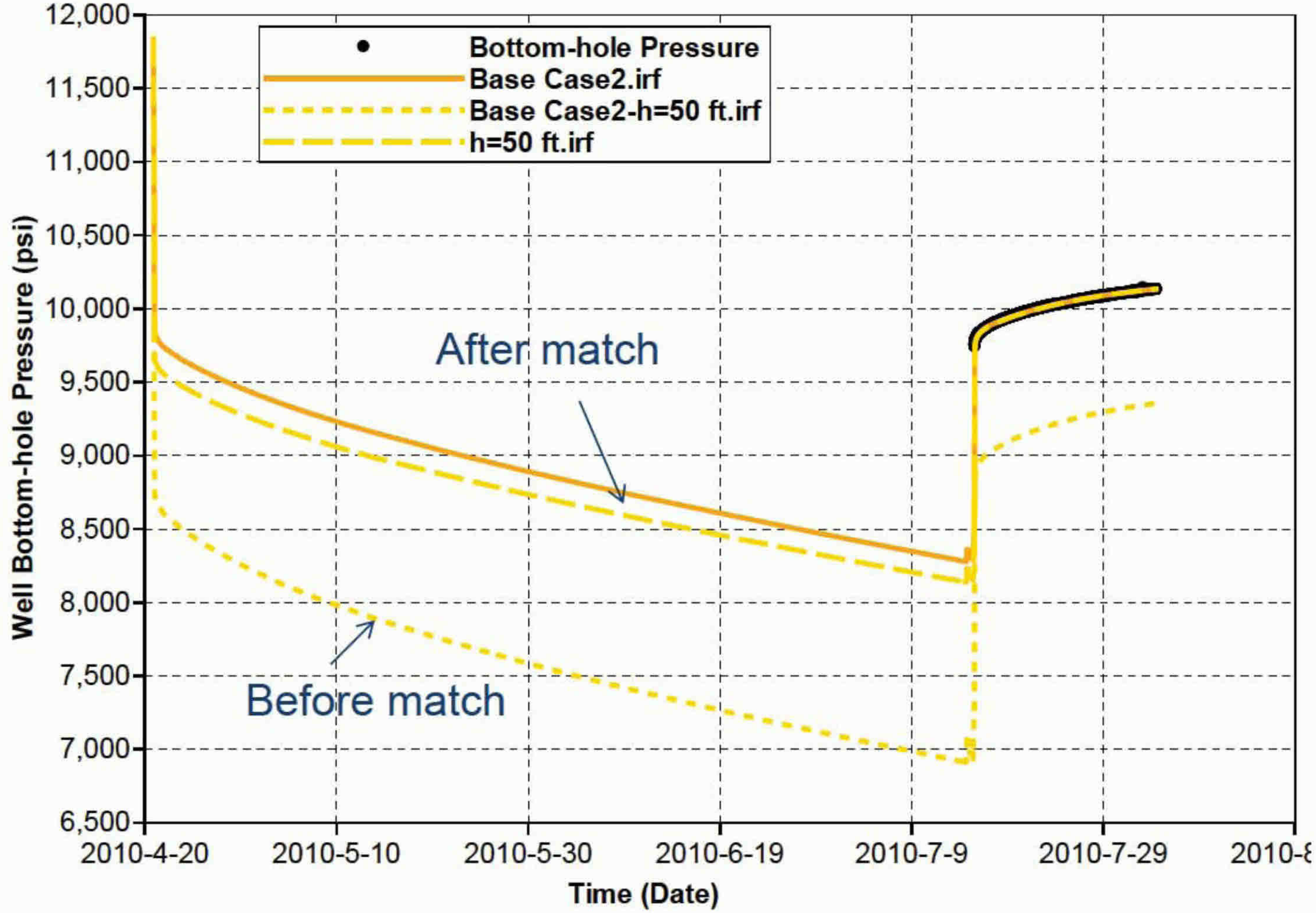
Fekete

k=360 mD: Collection Rate

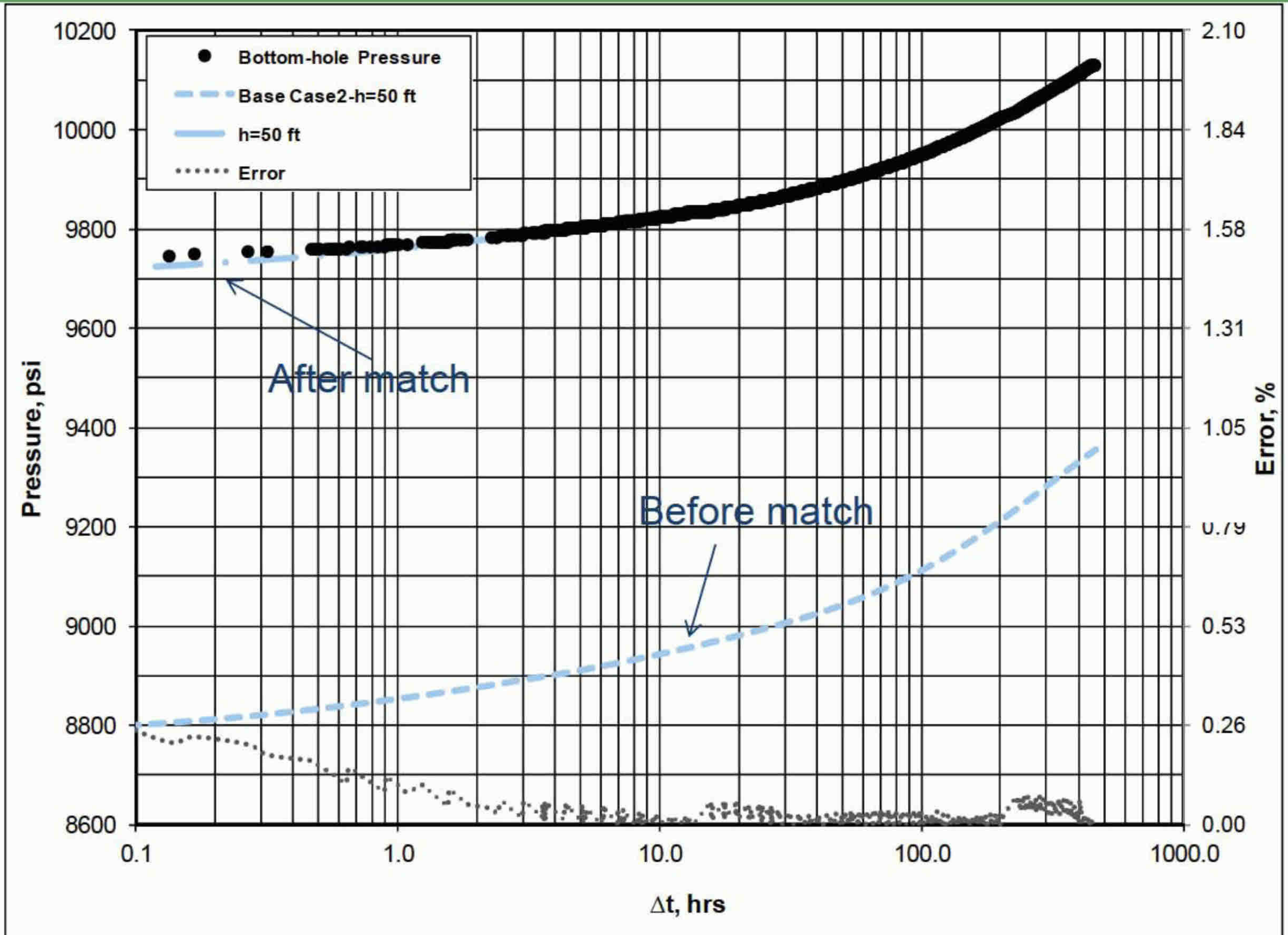
Mediocre: Generally between ±600 and ±2500 STB/day



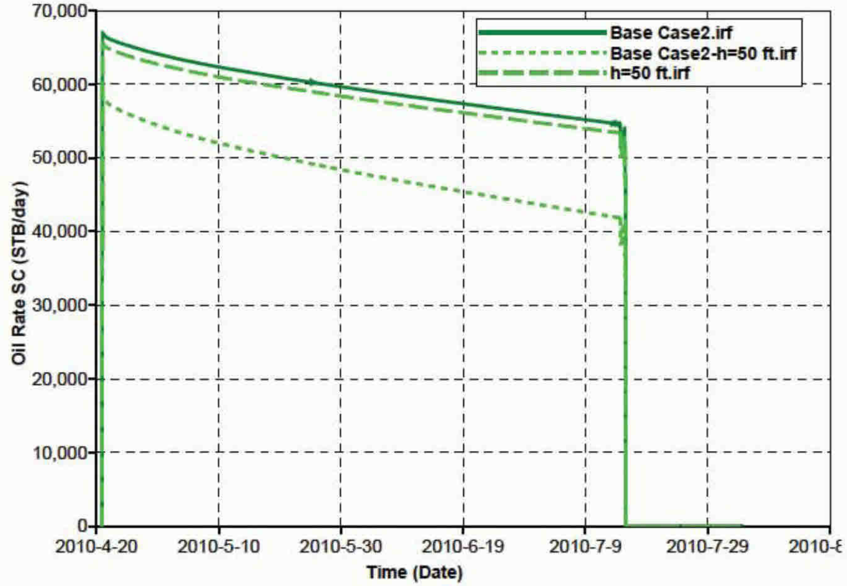
h=50 ft: Bottom-hole Pressure



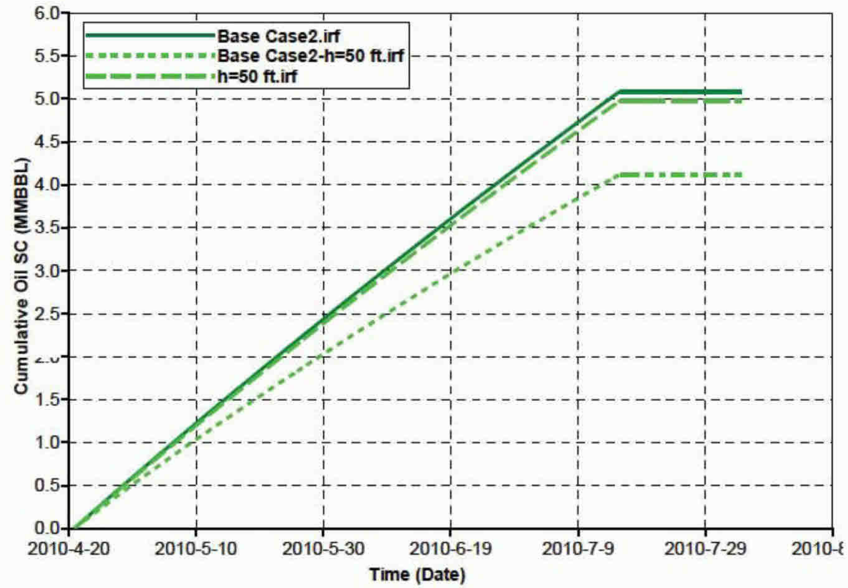
h=50 ft: MDH Type Curve



h=50 ft: Oil Released



Cumulative oil released = 4.98 MMSTB

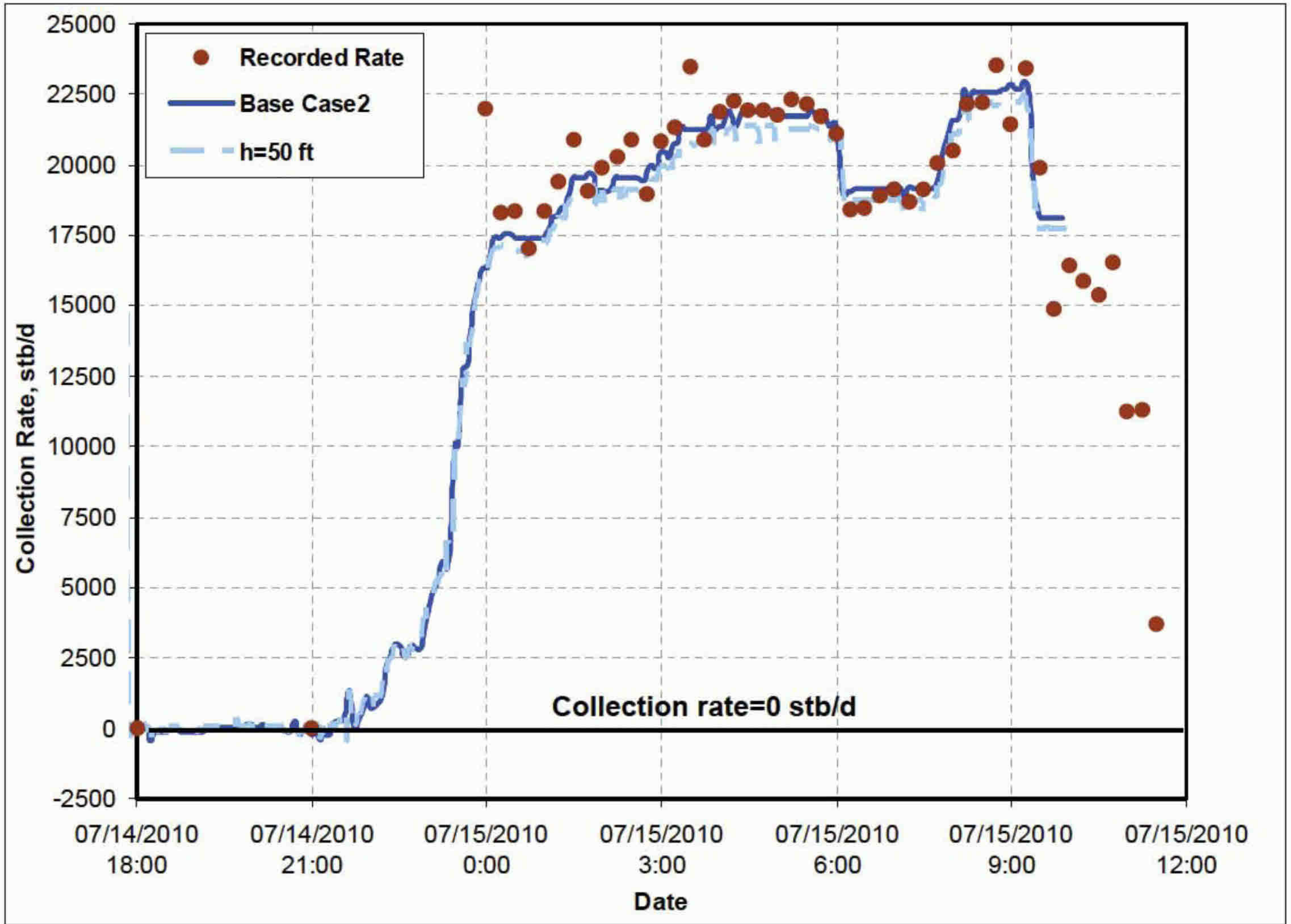


OOIP=136 MMstb

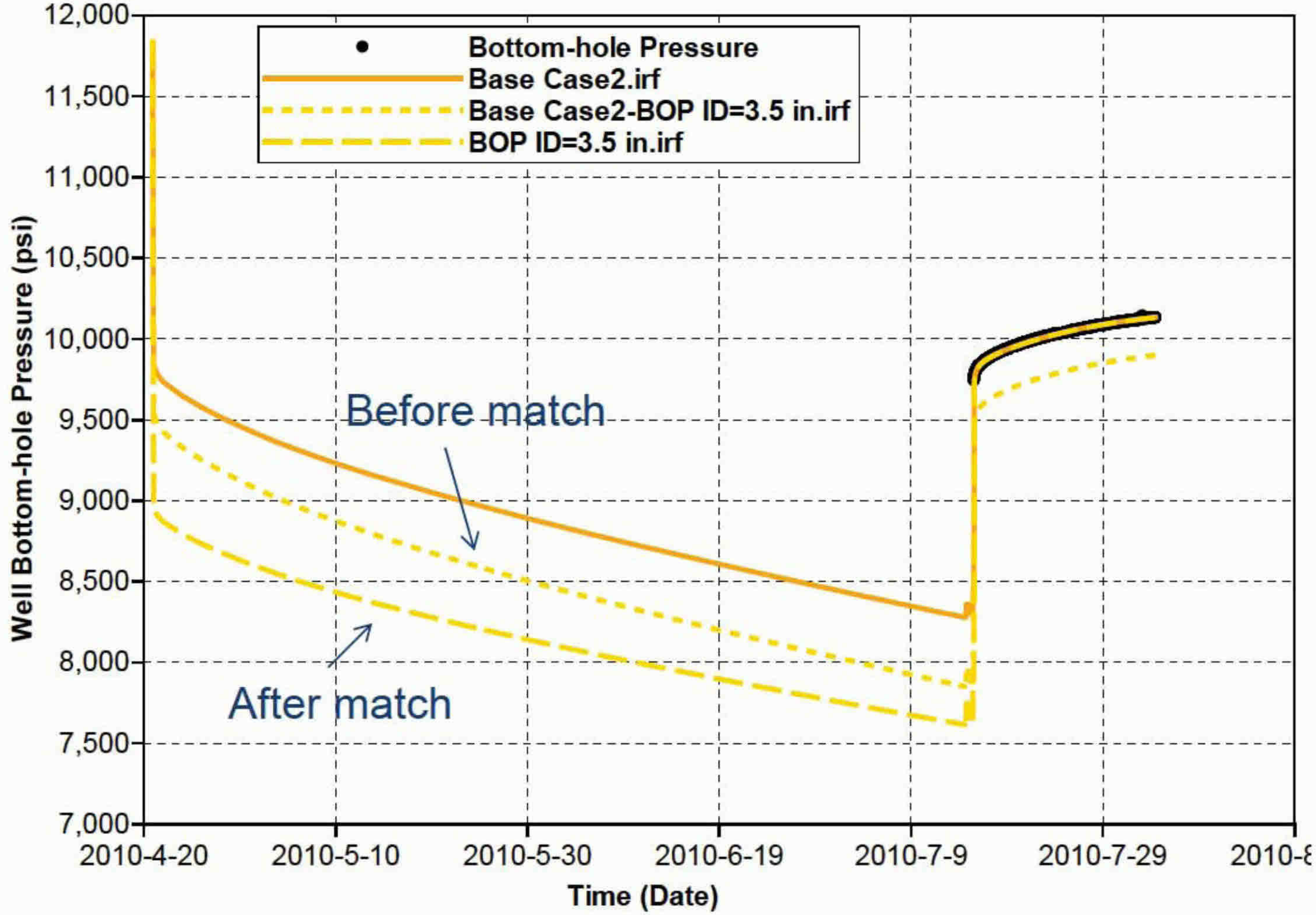
PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-h=50 ft), stb/psi/day:	16.0
PI (h=50 ft), stb/psi/day:	25.0

h=50 ft: Collection Rate

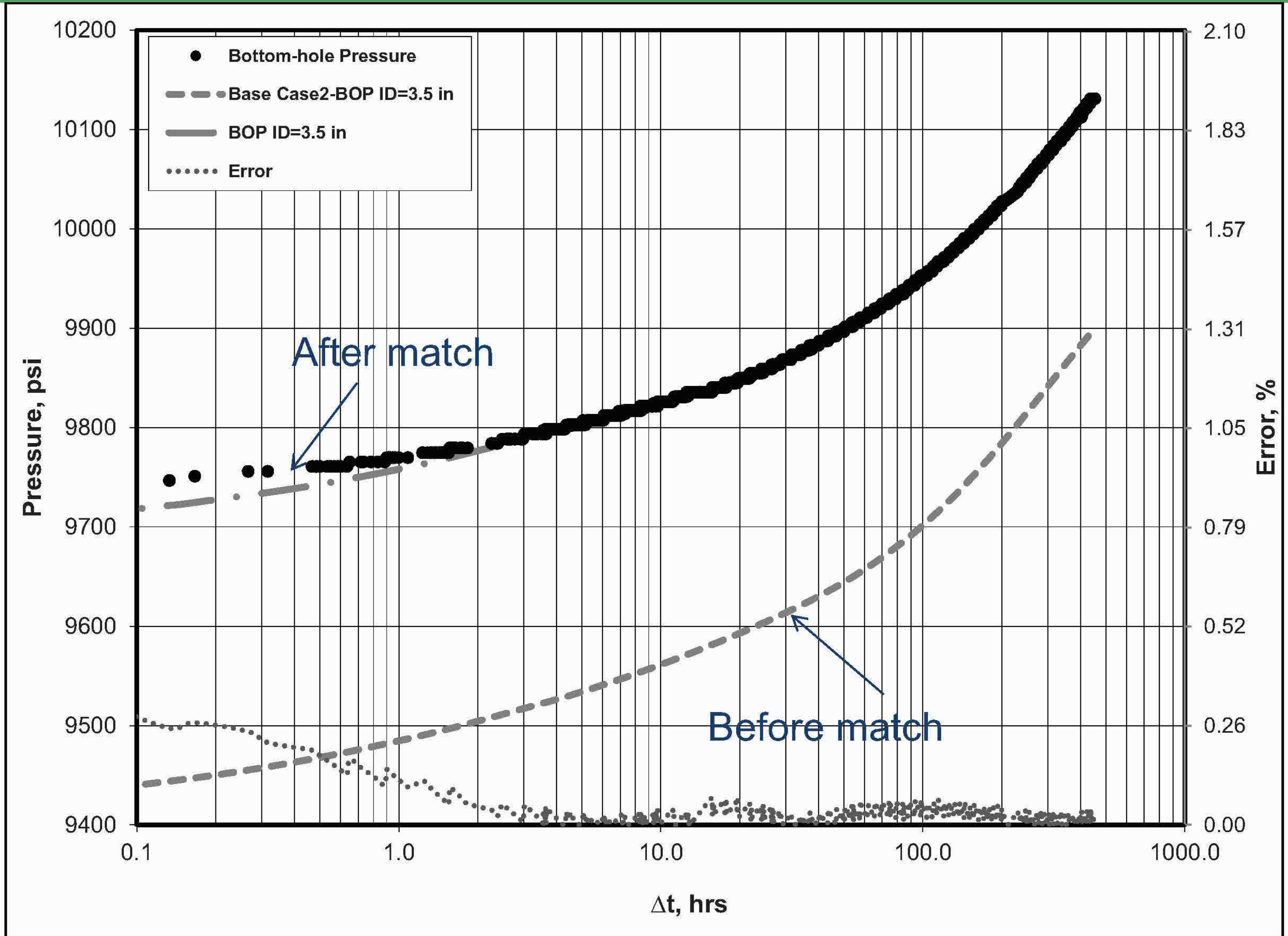
Match: Generally within ±600 STB/day



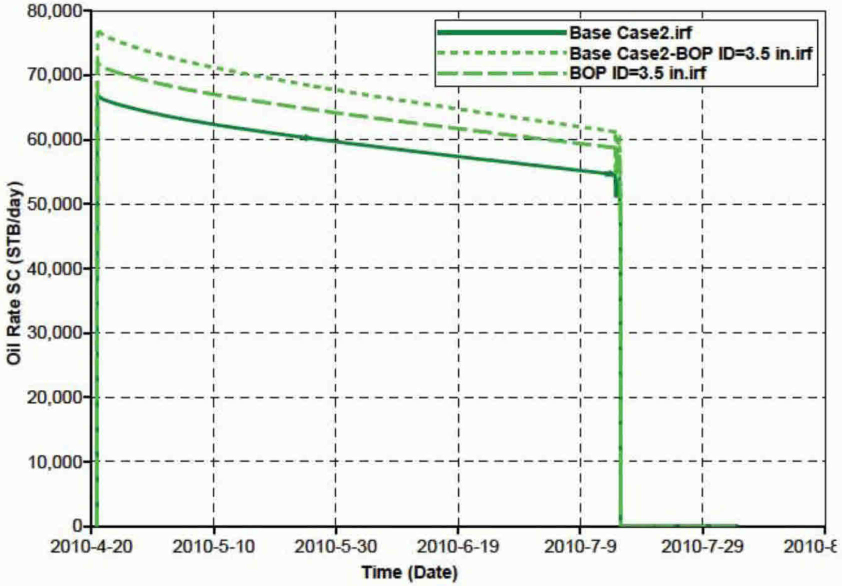
BOP ID=3.5 in: Bottom-hole Pressure



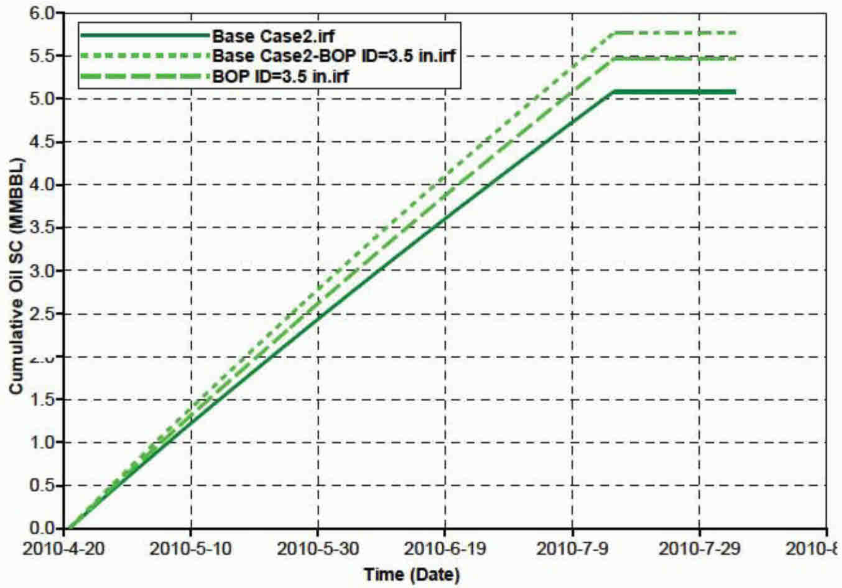
BOP ID=3.5 in: MDH Type Curve



BOP ID=3.5 in: Oil Released



Cumulative oil released = 5.47 MMSTB

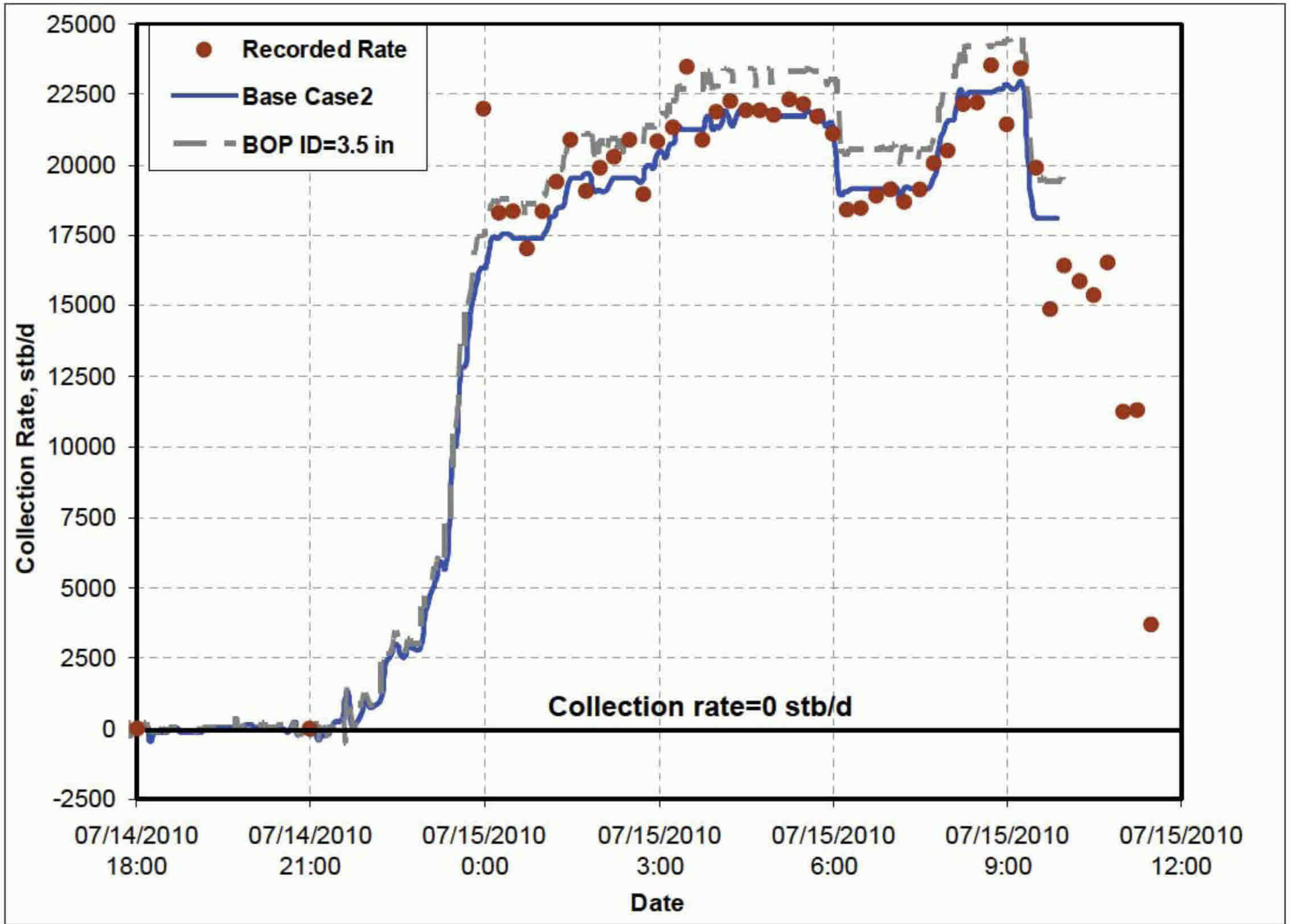


OOIP=150 MMstb

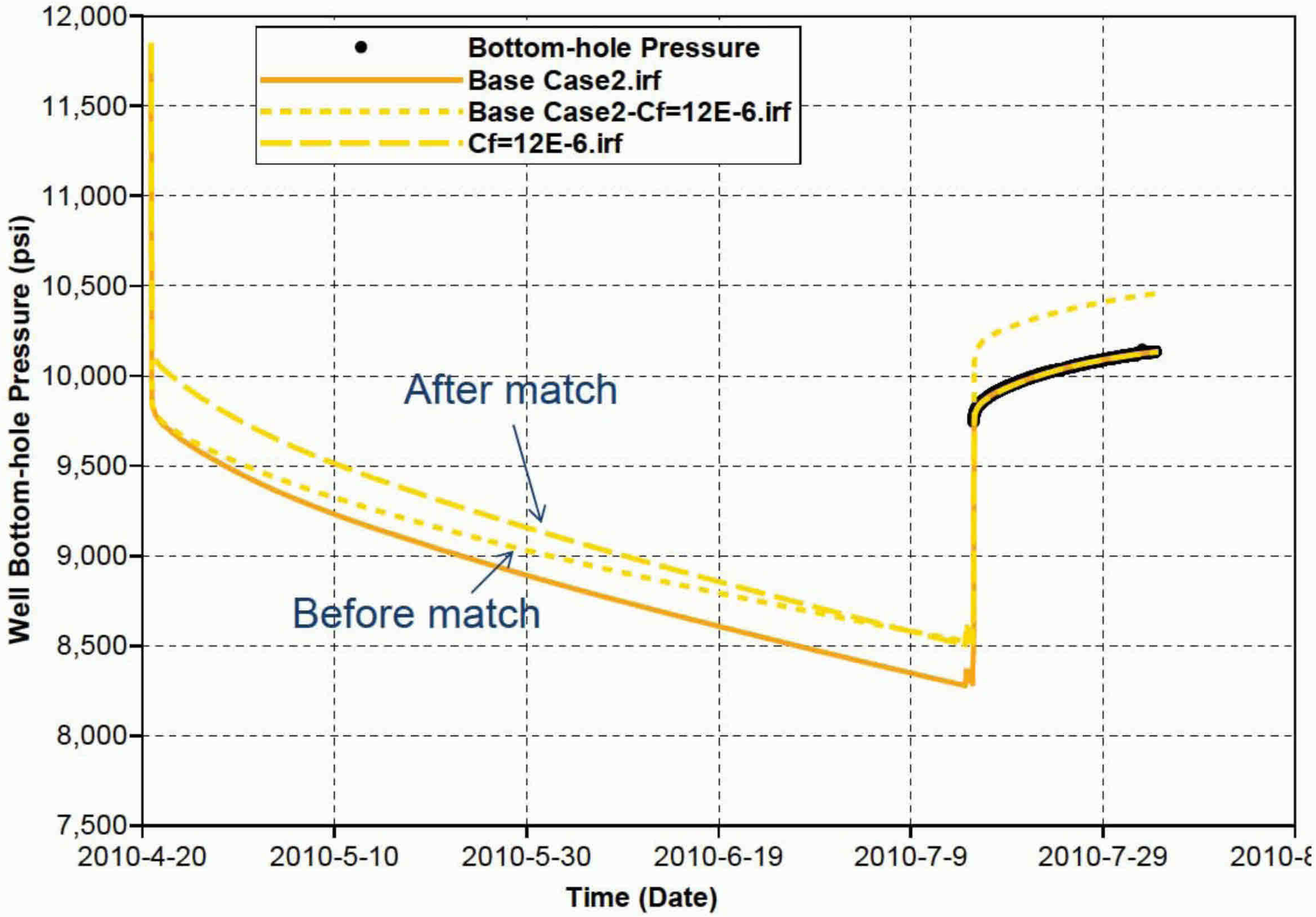
PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-BOP ID=3.5 in), stb/psi/day:	28.0
PI (BOP ID=3.5 in), stb/psi/day:	22.0

BOP ID=3.5 in: Collection Rate

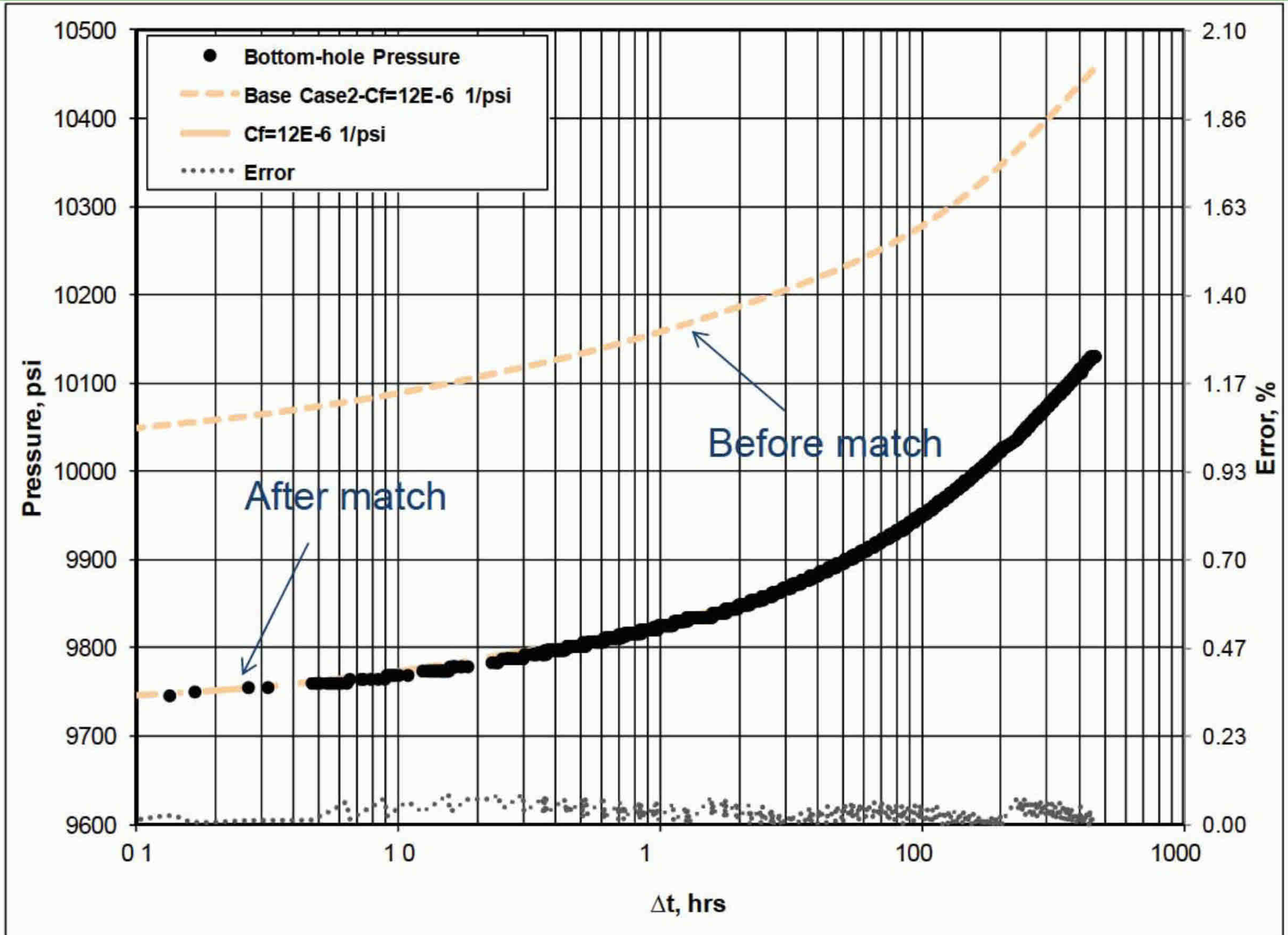
Mediocre: Generally between ±600 and ±2500 STB/day



Cf=12E-6 1/psi: Bottom-hole Pressure

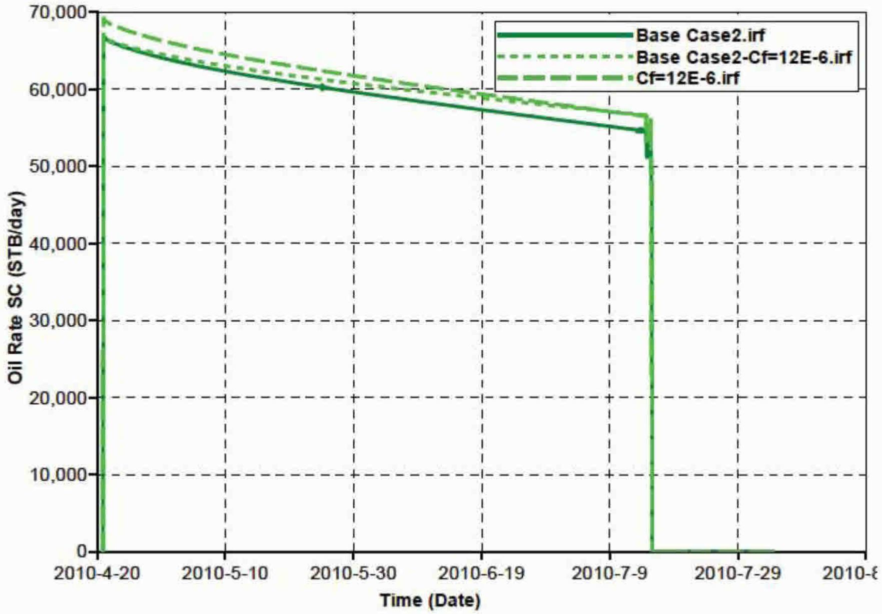


Cf=12E-6 1/psi: MDH Type Curve

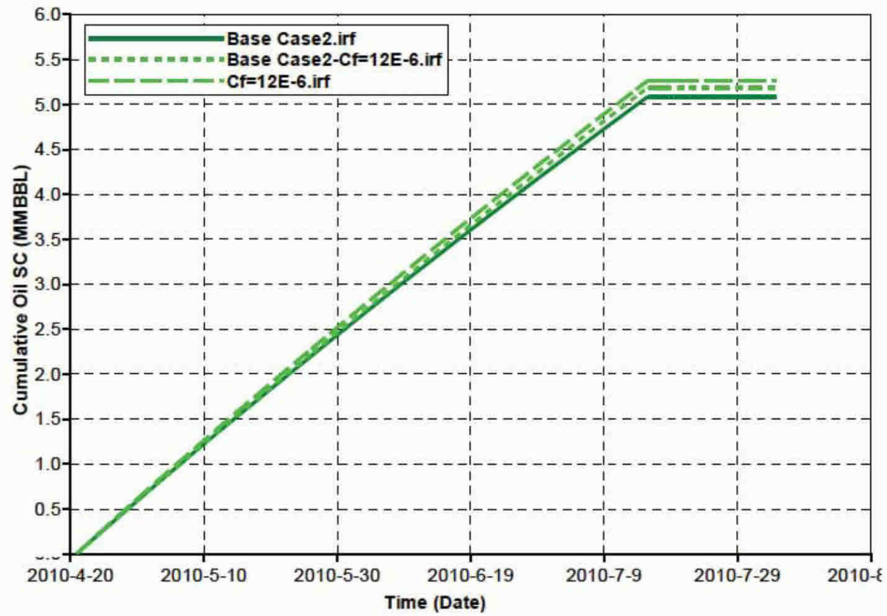


TREX-011654R.0068

Cf=12E-6 1/psi: Oil Released



Cumulative oil released = 5.26 MMSTB

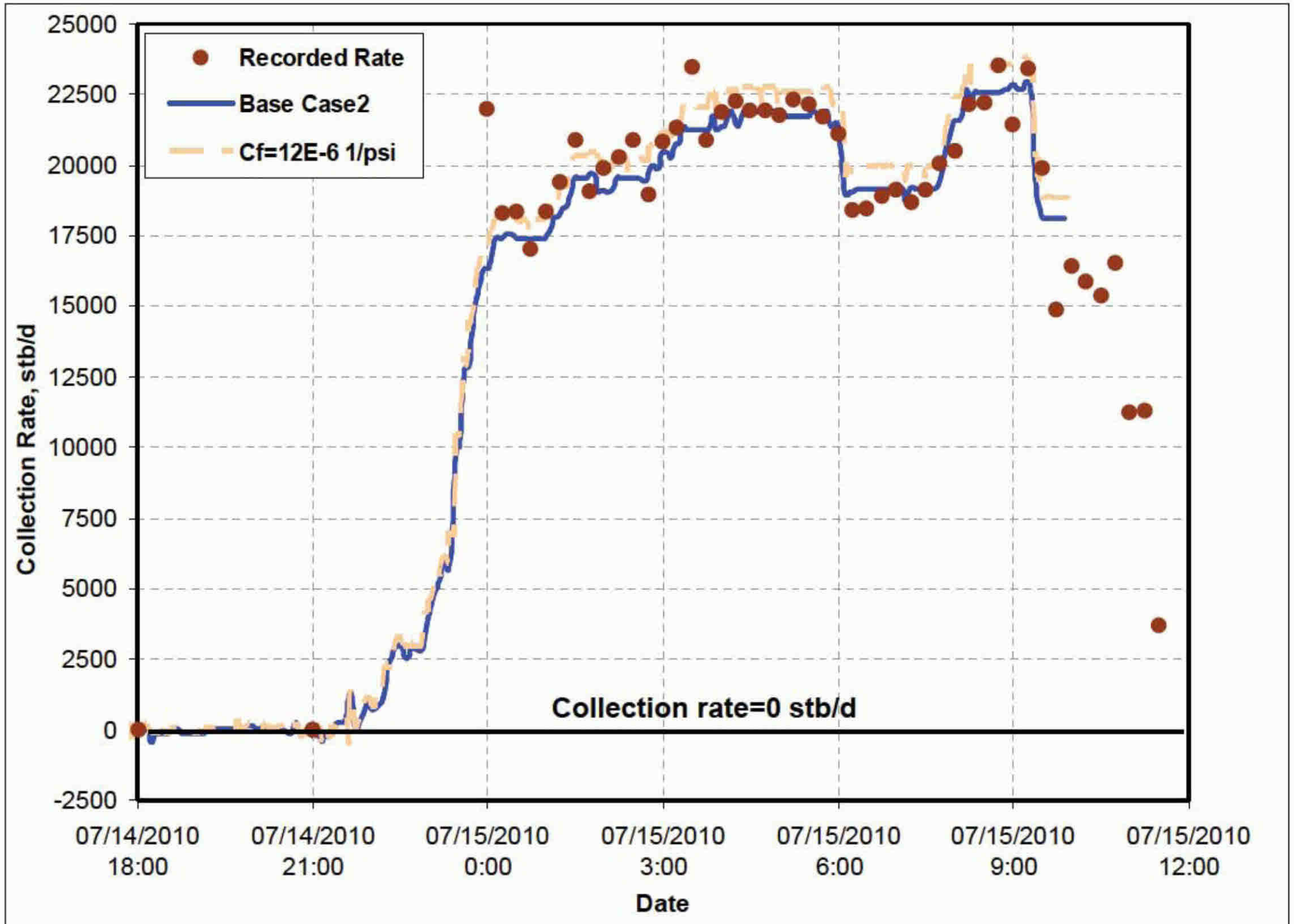


OOIP=110 MMstb

PI (Base Case2), stb/psi/day: 28.0
PI (Base Case2-Cf=12E-6 1/psi), stb/psi/day: 27.0
PI (Cf=12E-6 1/psi), stb/psi/day: 33.0

Cf=12E-6 1/psi: Collection Rate

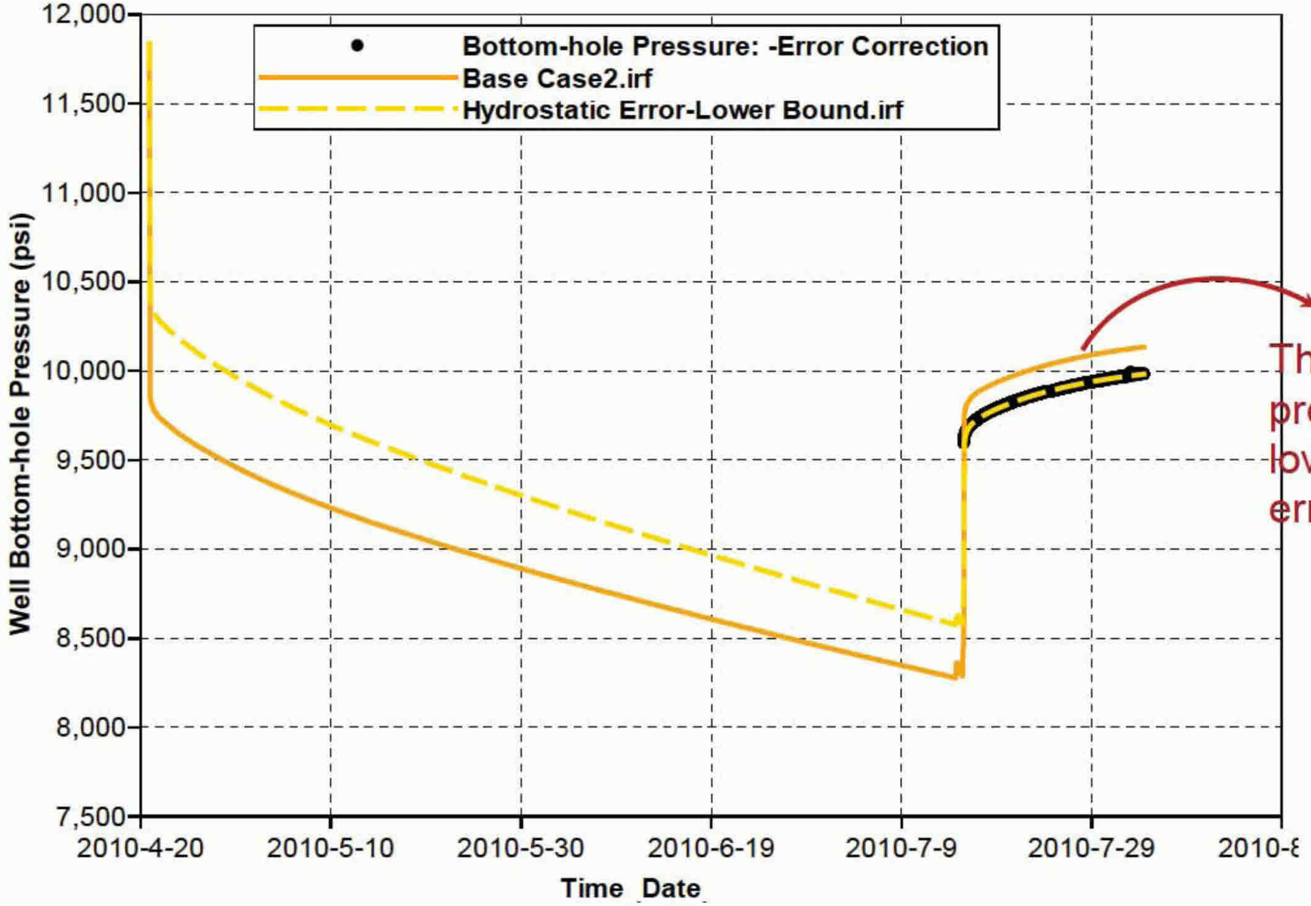
Match: Generally within ±600 STB/day



TREX-011654R.0070

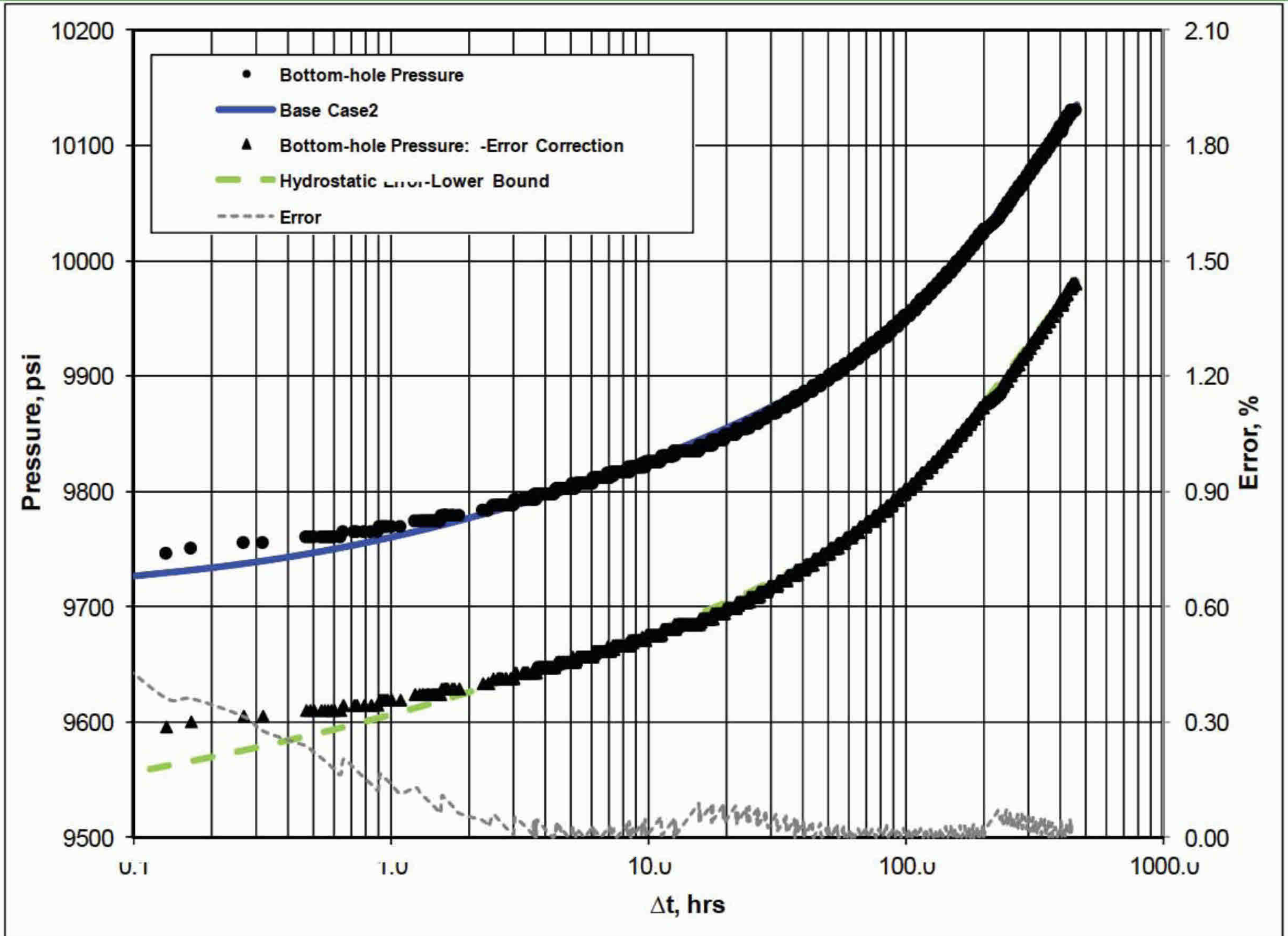
Lower Bound Hydrostatic: Bottom-hole Pressure

The upper bound of hydrostatic error subtracts 150 psi from the shut-in pressure.

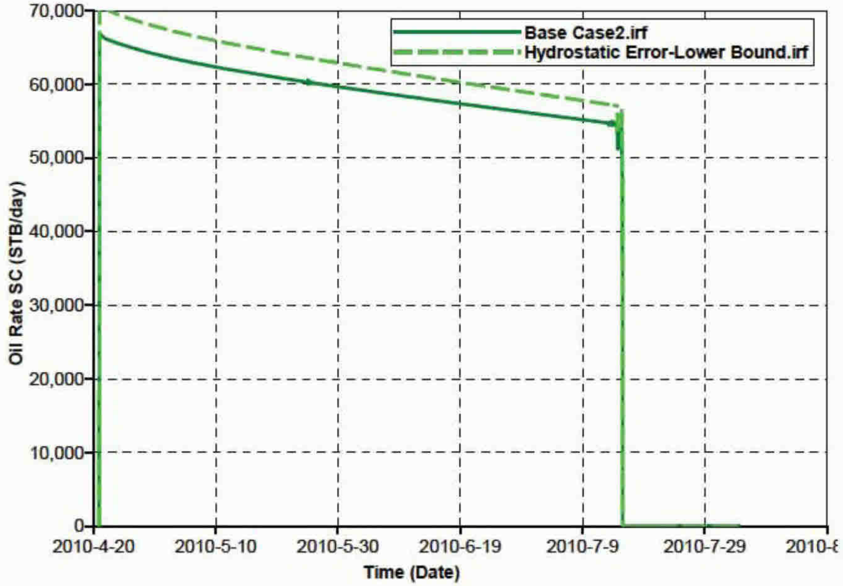


The recorded shut-in pressures are adjusted by the lower bound of hydrostatic error value.

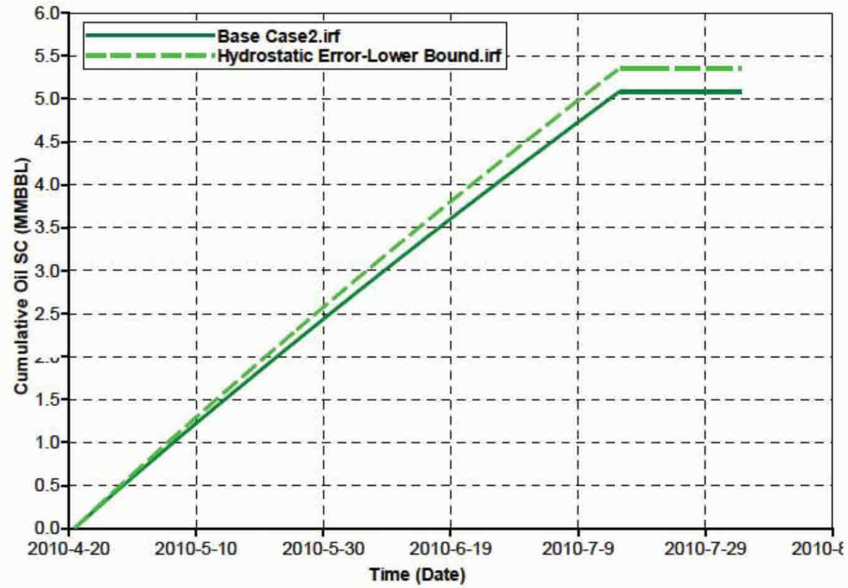
Lower Bound Hydrostatic: MDH Type Curve



Lower Bound Hydrostatic: Oil Released



Cumulative oil released = 5.36 MMSTB

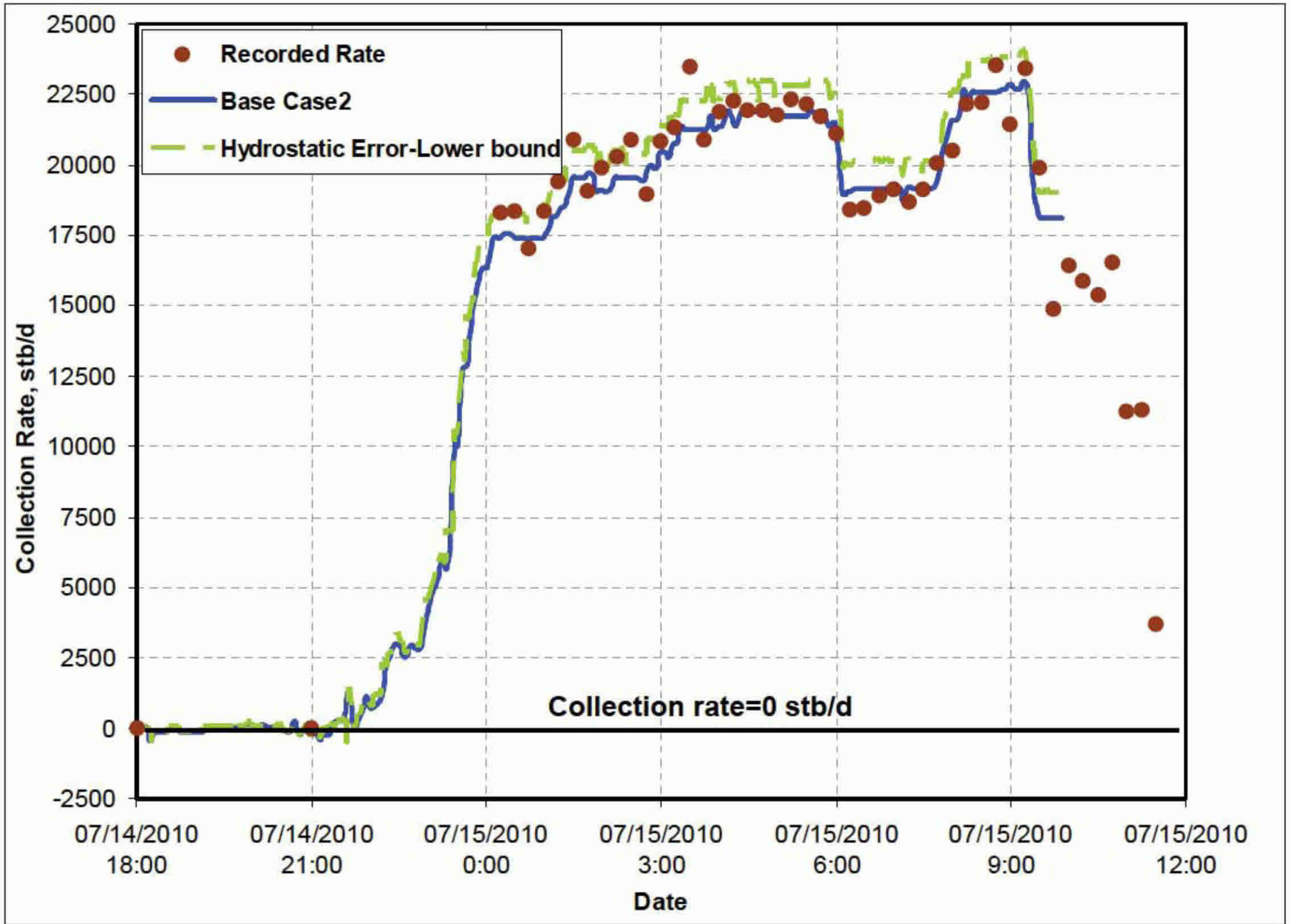


OOIP=135 MMstb

PI (Base Case2), stb/psi/day: 28.0
PI (Lower Bound Hydrostatic Error), stb/psi/day: 38.0

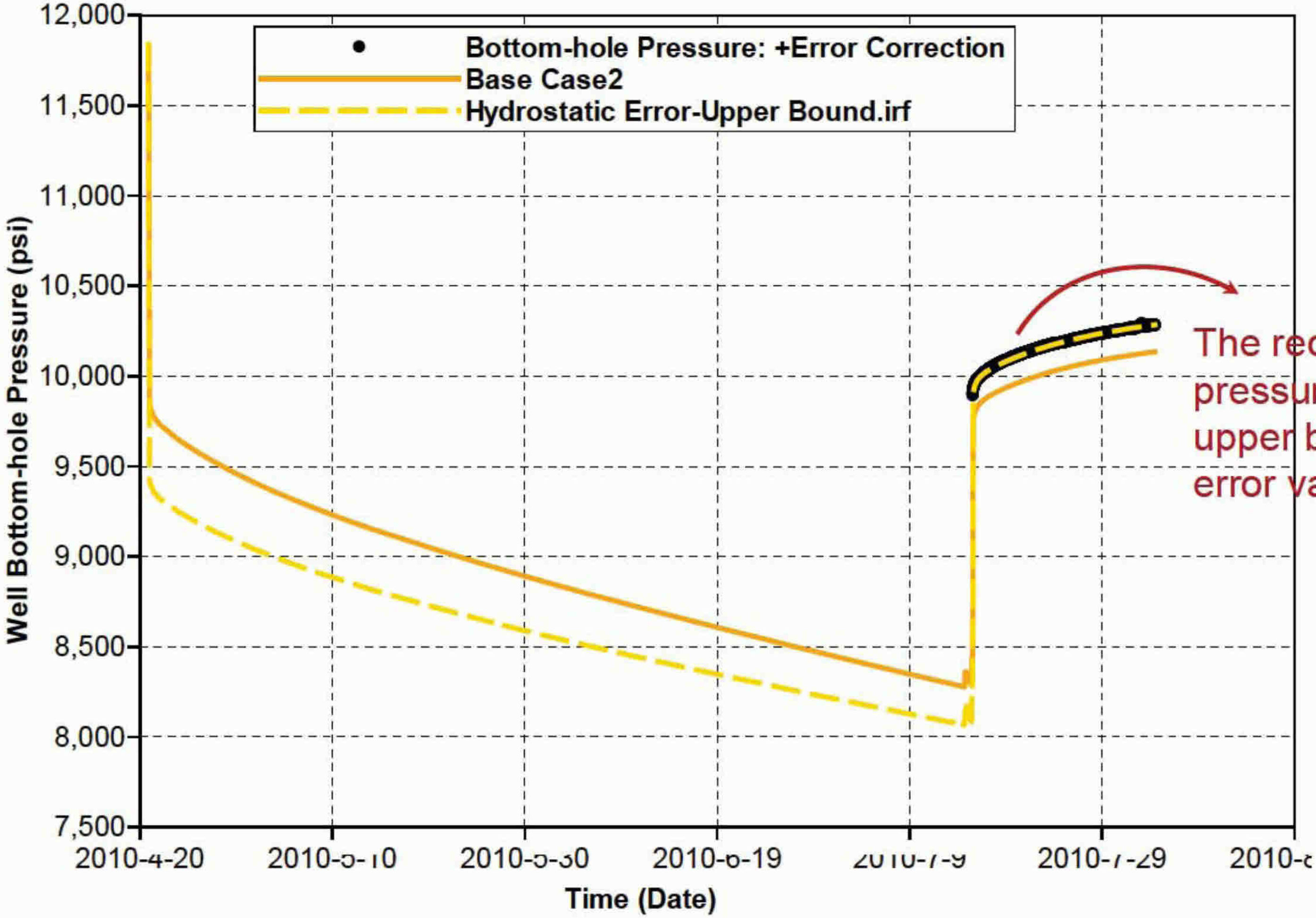
Lower Bound Hydrostatic: Collection Rate

Match: Generally between ±600 and ±2500 STB/day



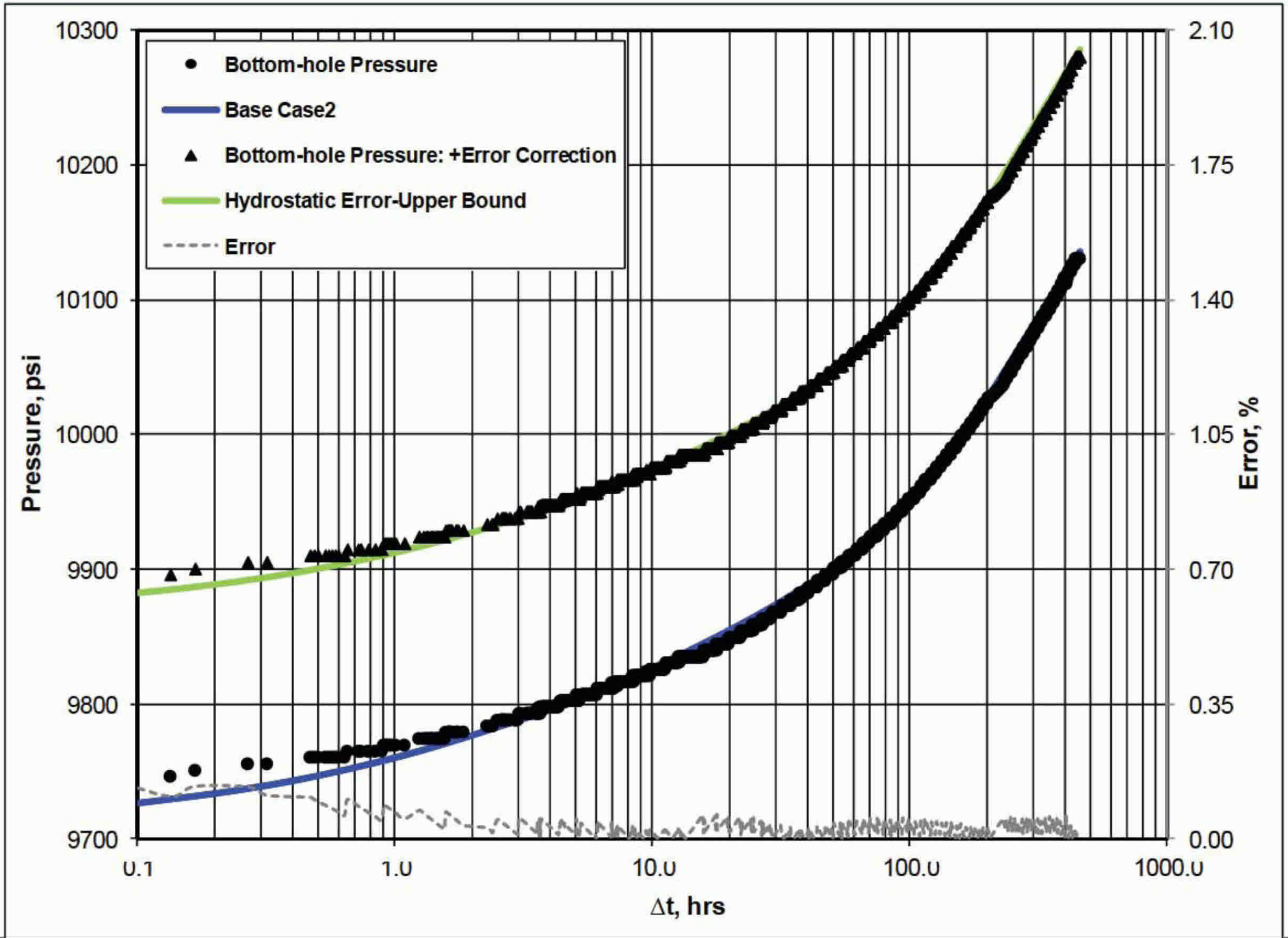
Upper Bound Hydrostatic: Bottom-hole Pressure

The upper bound of hydrostatic error adds 150 psi to the shut-in pressure.



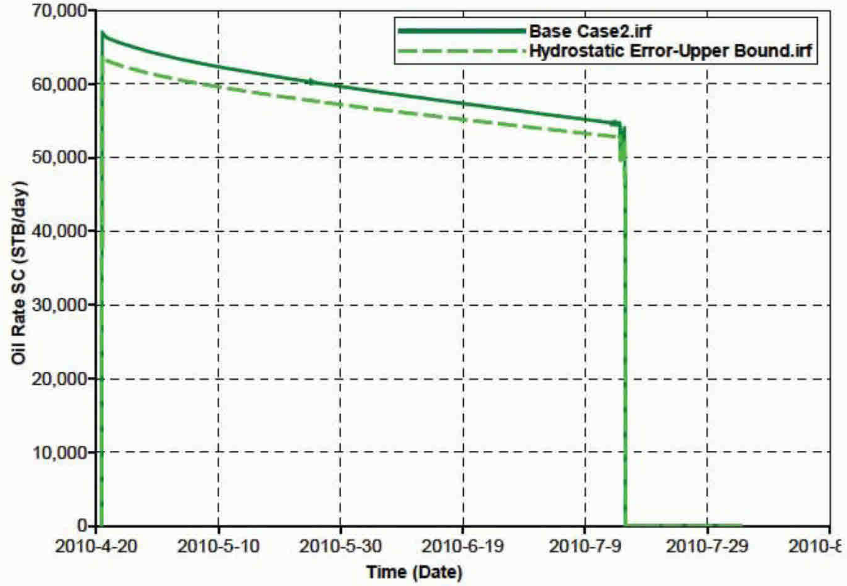
The recorded shut-in pressures are adjusted by the upper bound of hydrostatic error value.

Upper Bound Hydrostatic: MDH Type Curve

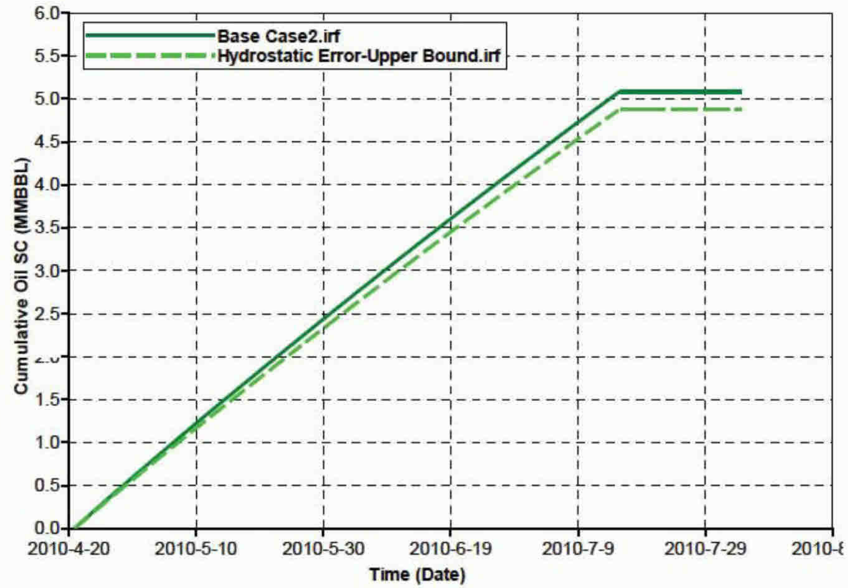


TREX-011654R.0076

Upper Bound Hydrostatic: Oil Released



Cumulative oil released = 4.88 MMSTB

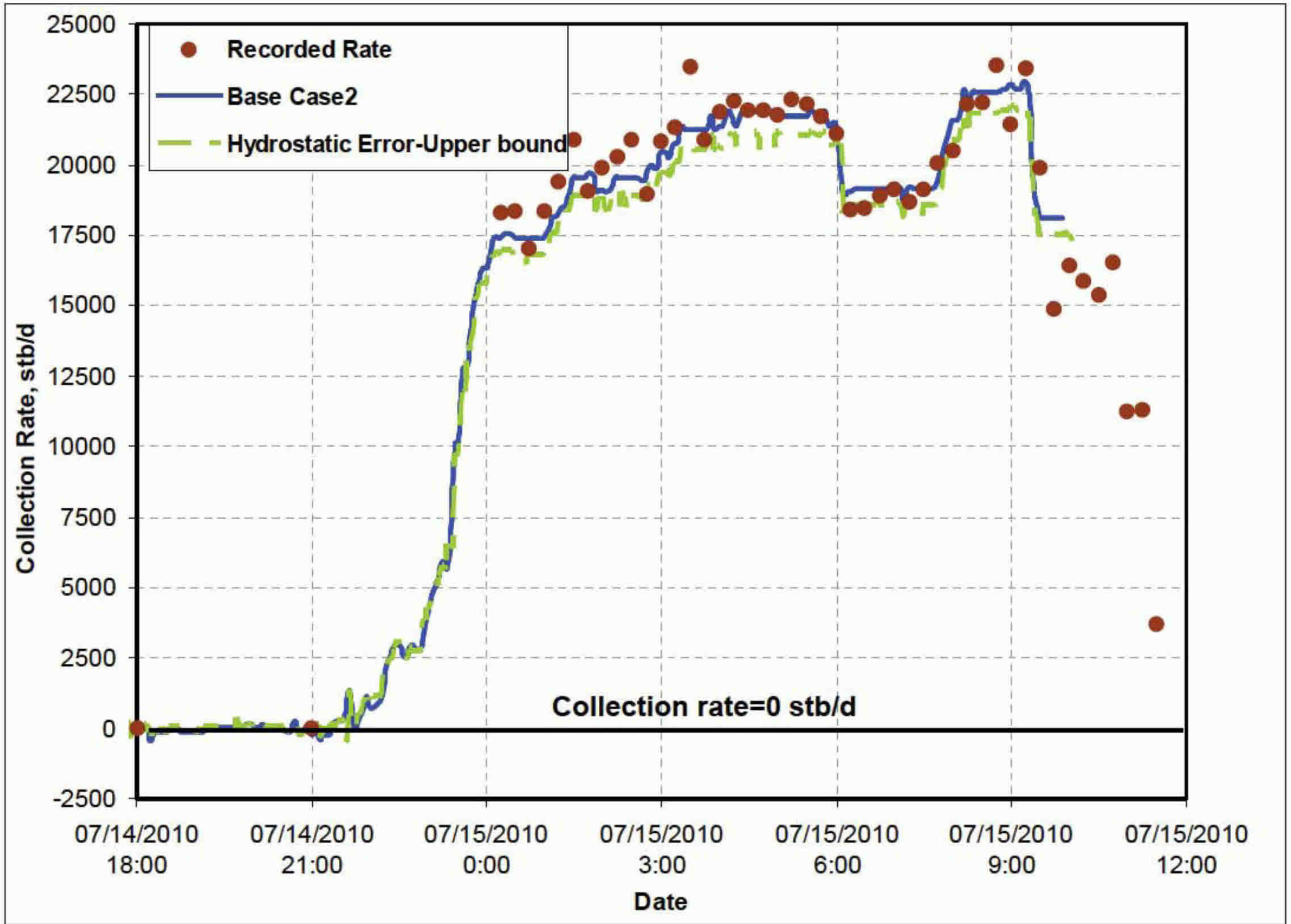


OOIP=150 MMstb

PI (Base Case2), stb/psi/day: 28.0
PI (Upper Bound Hydrostatic Error), stb/psi/day: 23.0

Upper Bound Hydrostatic: Collection Rate

Mediocre: Generally between ±600 and ±2500 STB/day

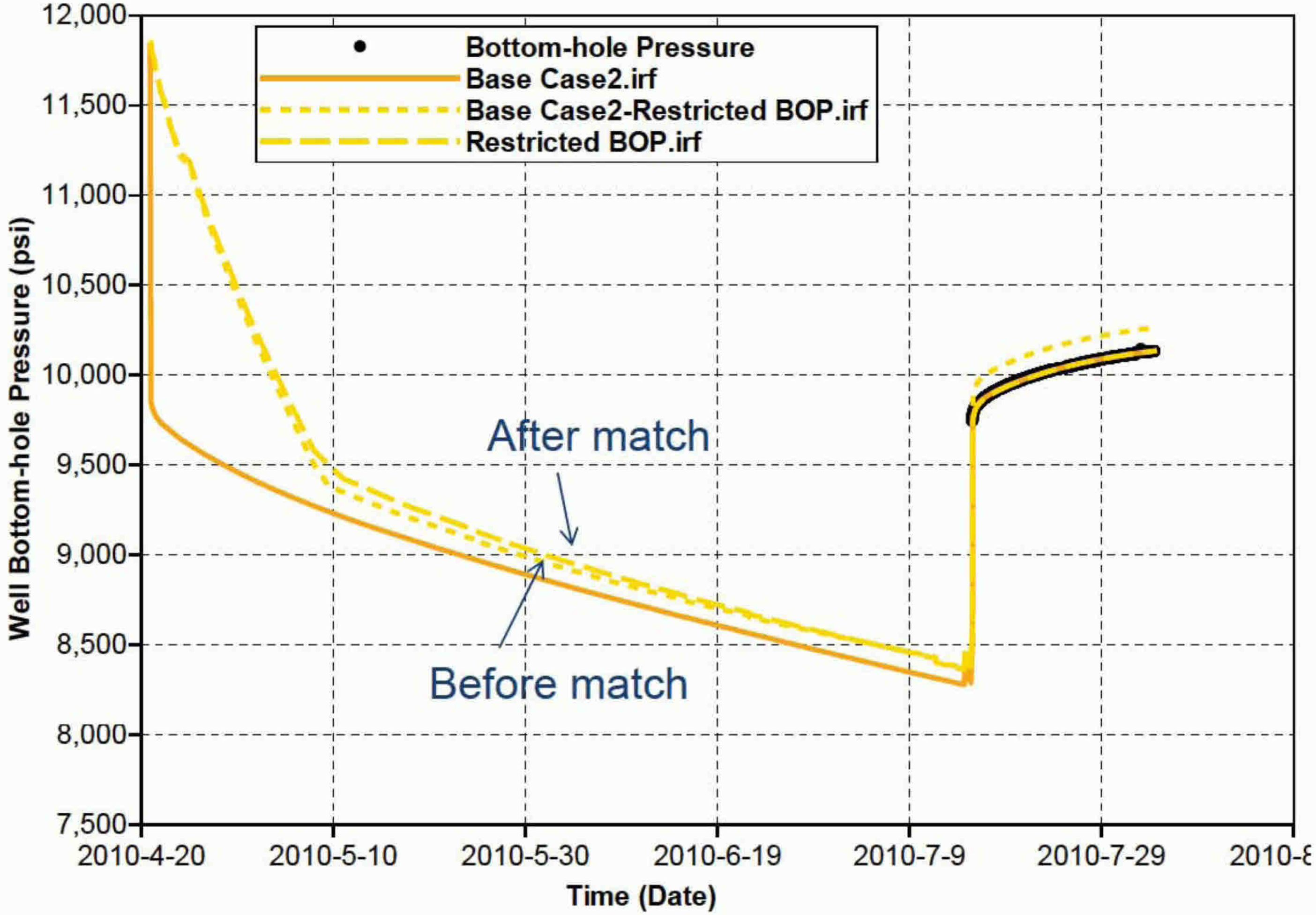


WHAT-IF STUDIES

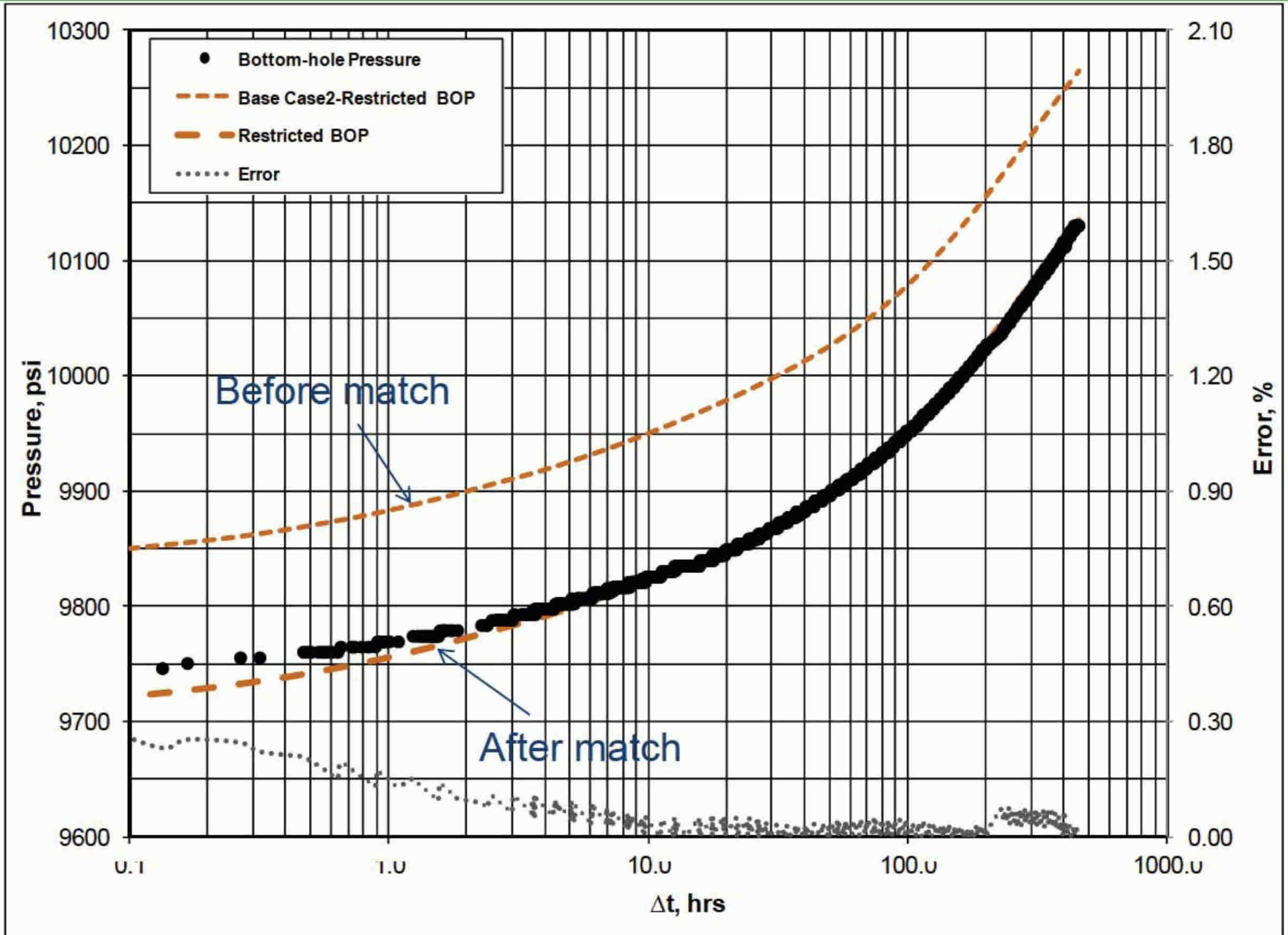
Summary of Results

	K, mD	Skin	Length Xe, ft	Width Ye, ft	Xw, ft	Yw, ft	OOIP, MMSTB	Pave, psia	PI, stb/d/psi	q July 15, stb/d	Error, %	Cum Oil Released (after matching shut-in pressures), MMSTB
Extrapolated (Correction +966 psi)	550	6.75	21600	4000	3600	1550	126.0	10214	37	56000	0.04	4.58 (Med.)
Restricted BOP	550	11.5	21200	4200	3700	1350	130.0	10212	30	54000	0.04	4.73 (Good)
Base Case2	550	13	21850	4400	3700	1350	140.0	10219	28	53000	0.04	5.08 (Good)
Extrapolated BOP	550	12	22050	4400	3700	1350	141.0	10225	28	53000	0.04	5.12 (Good)
Flat BOP	550	12.5	22150	4500	3700	1350	145.0	10220	28	53000	0.04	5.26 (Good)

Restricted BOP: Bottom-hole Pressure

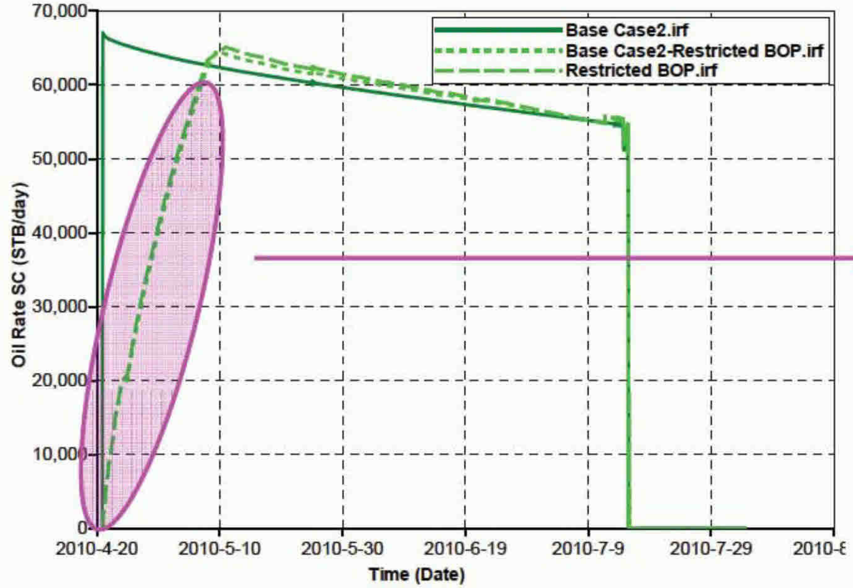


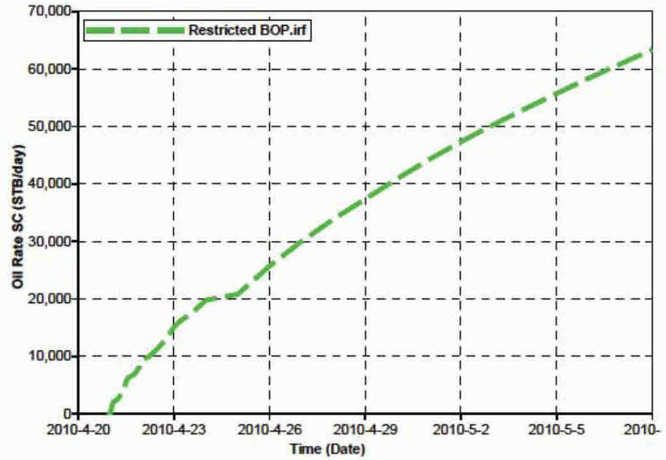
Restricted BOP: MDH Type Curve

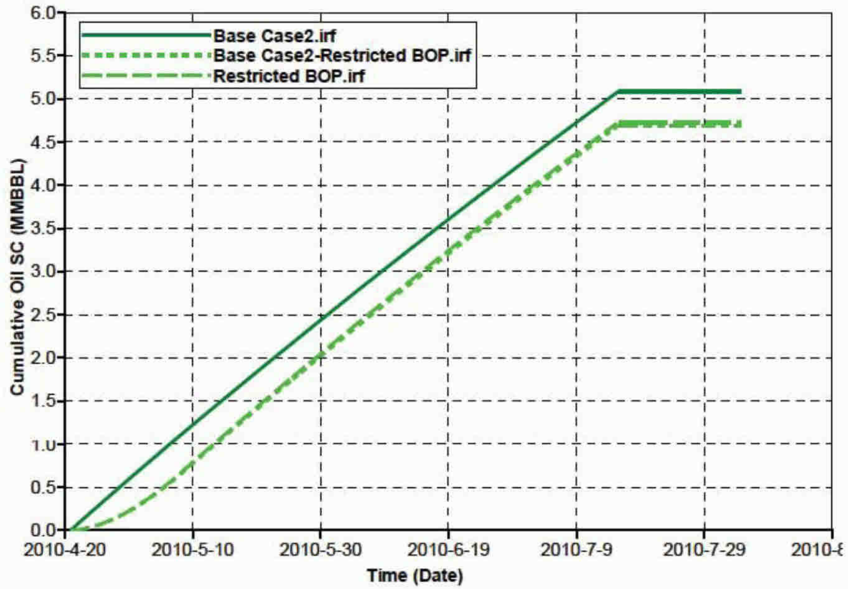


Fekete

Restricted BOP: Oil Released







Cumulative oil released = 4.73 MMSTB

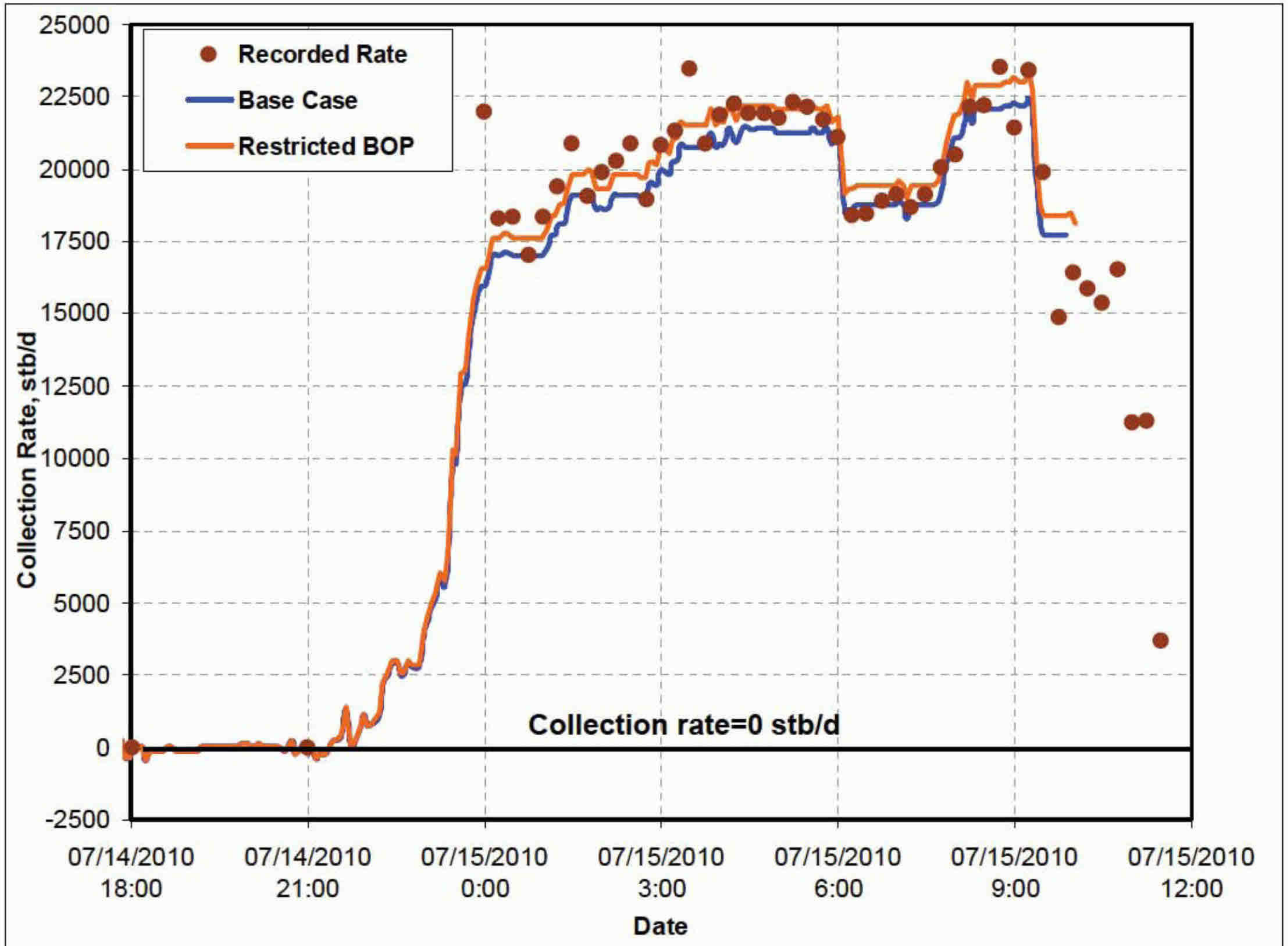
OOIP=130 MMstb

PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-Restricted BOP), stb/psi/day:	38.0
PI (Restricted BOP), stb/psi/day:	29.5

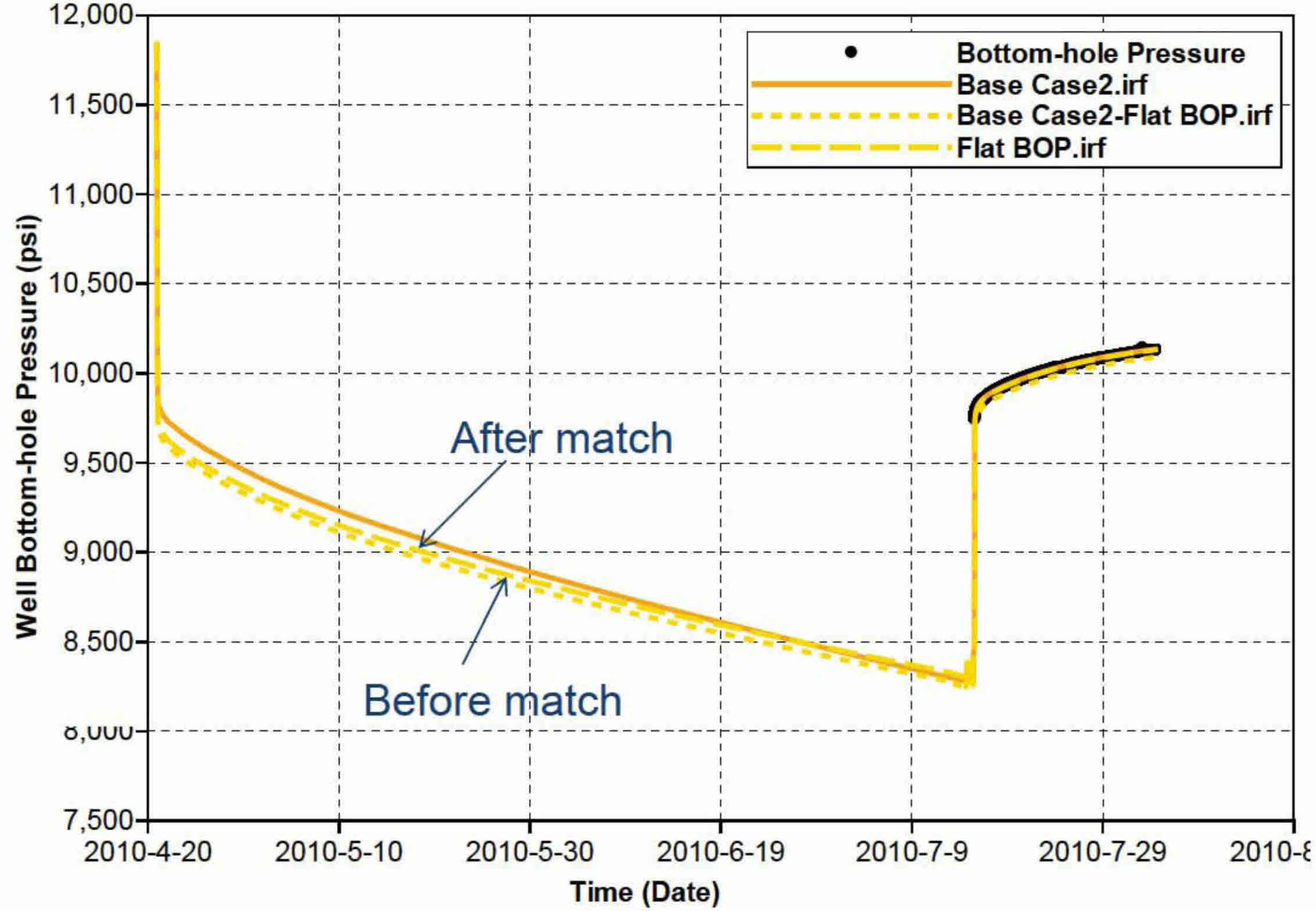
TREX-011654R.0083

Restricted BOP: Collection Rate

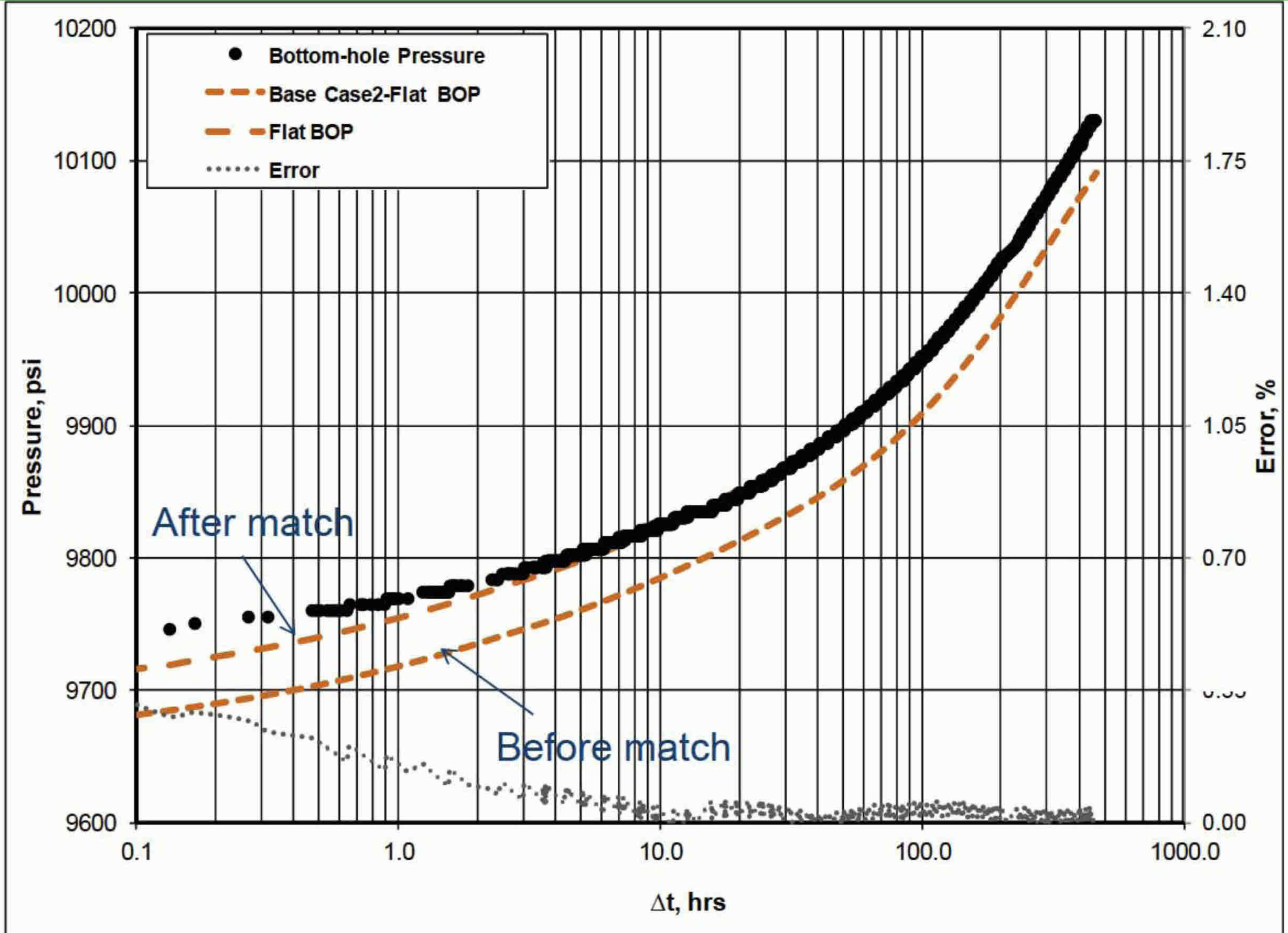
Match: Generally within ±600 STB/day



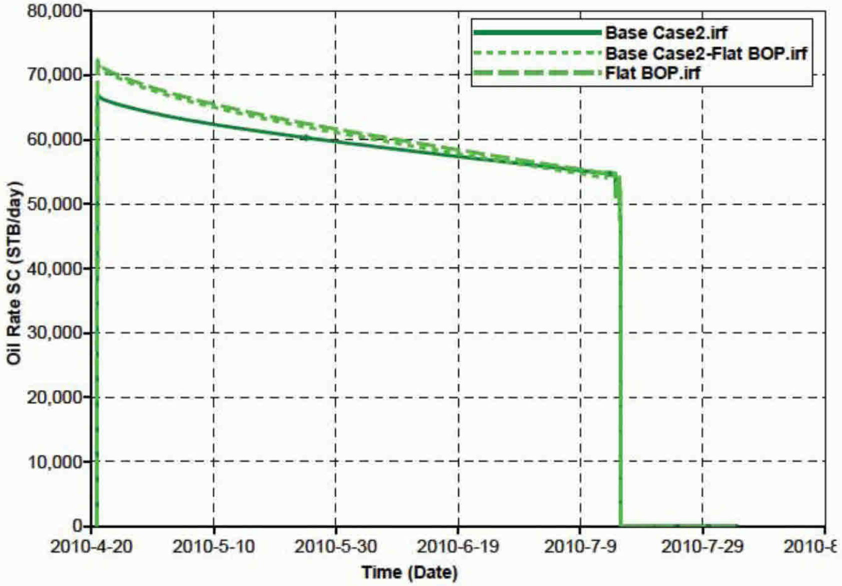
Flat BOP: Bottom-hole Pressure

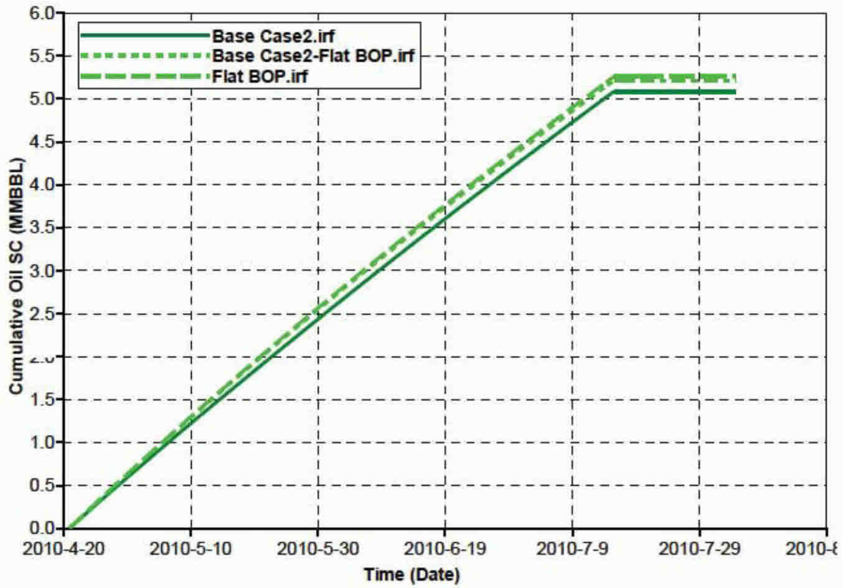


Flat BOP: MDH Type Curve



Flat BOP: Oil Released





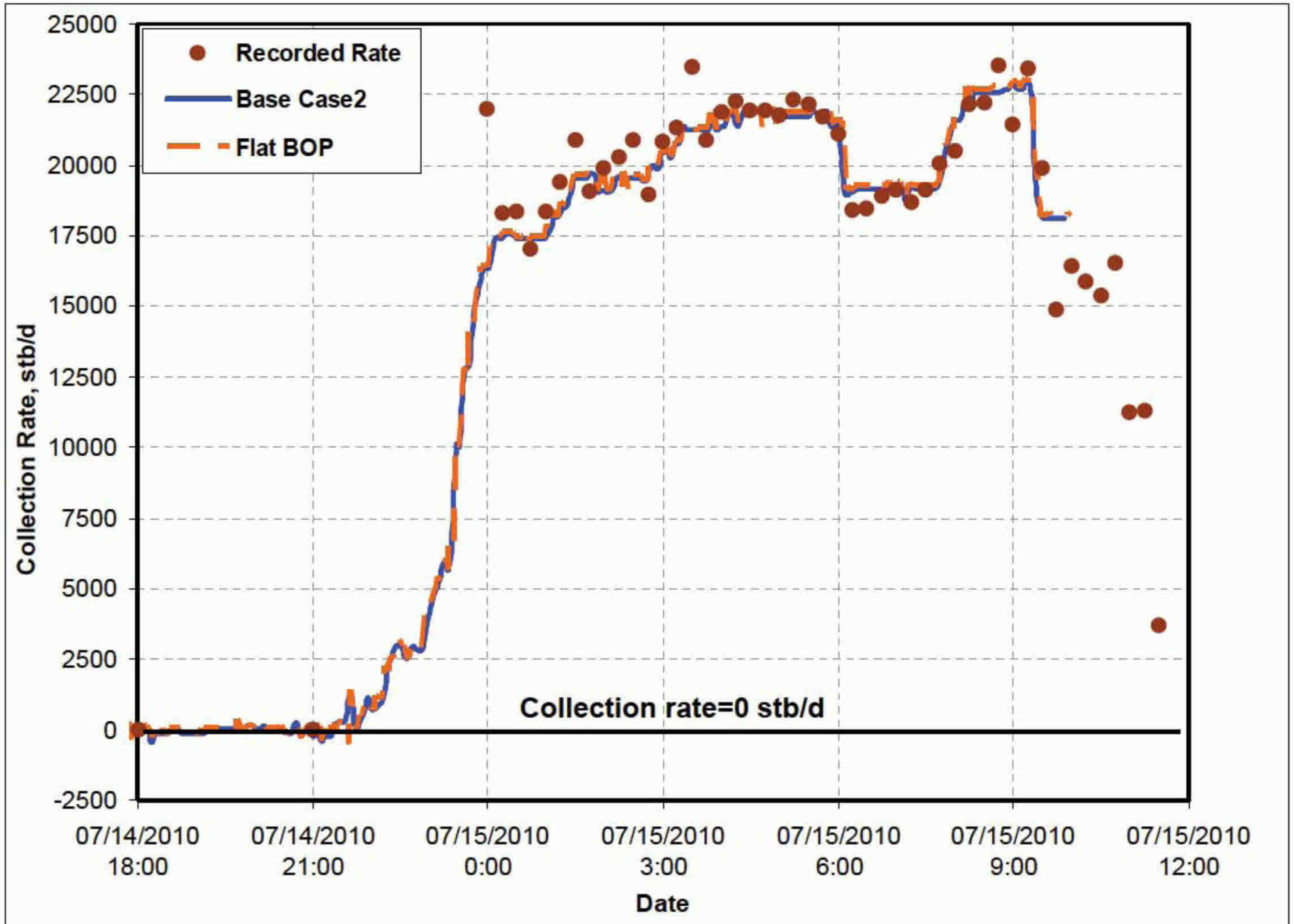
Cumulative oil released = 5.26 MMSTB

OOIP=145 MMstb

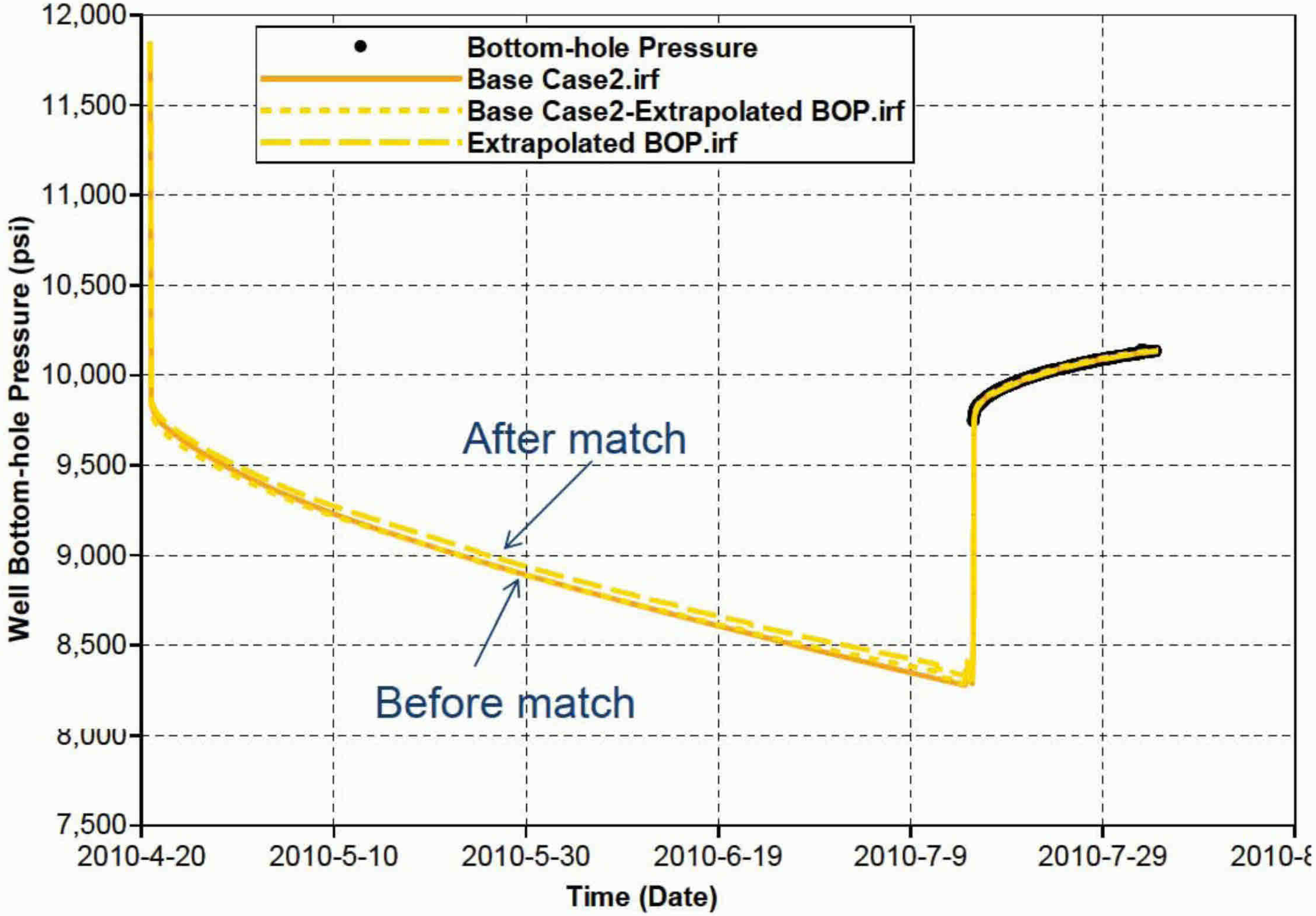
PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-Flat BOP), stb/psi/day:	28.0
PI (Flat BOP), stb/psi/day:	28.2

Flat BOP: Collection Rate

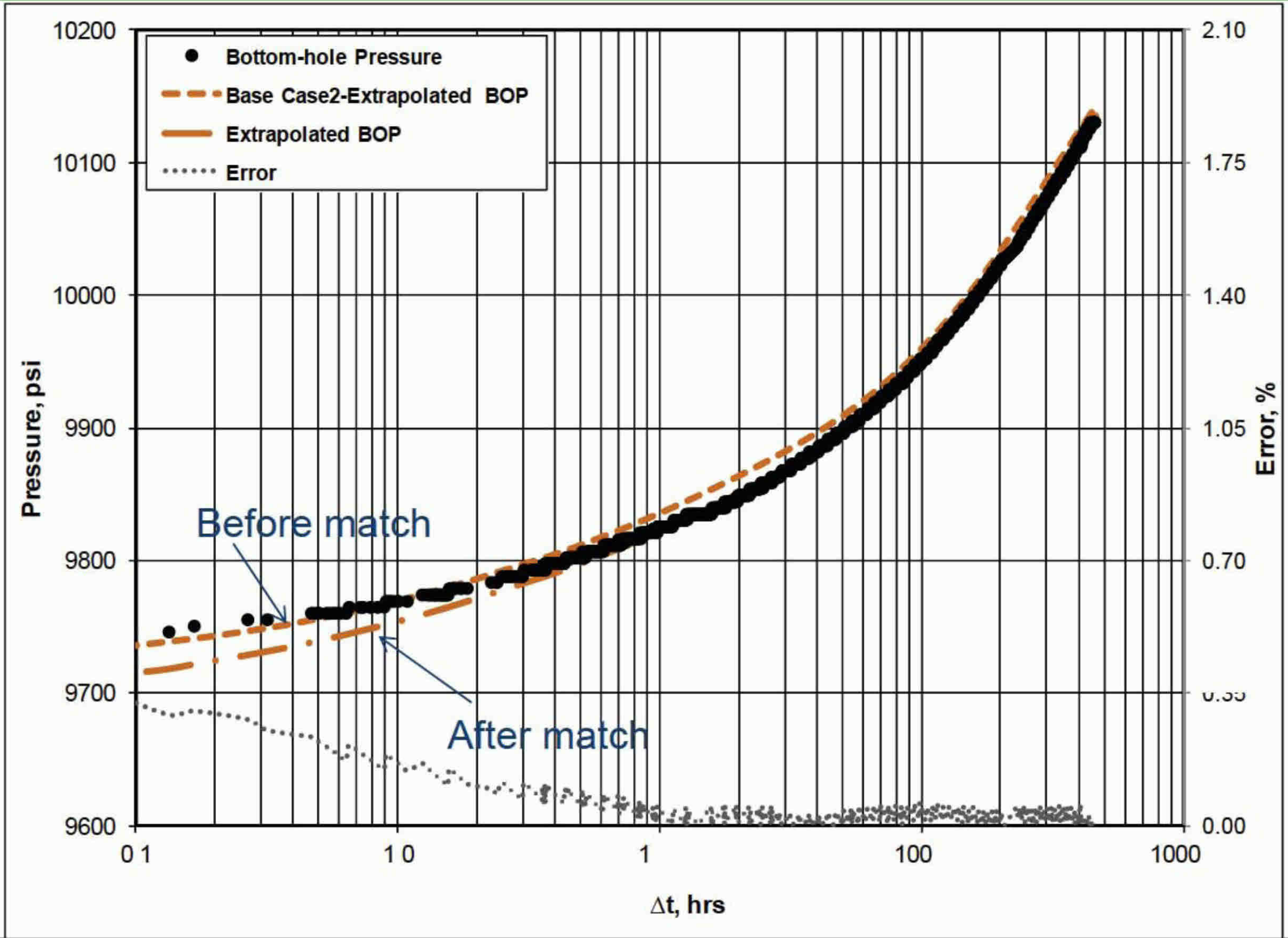
Match: Generally within ±600 STB/day



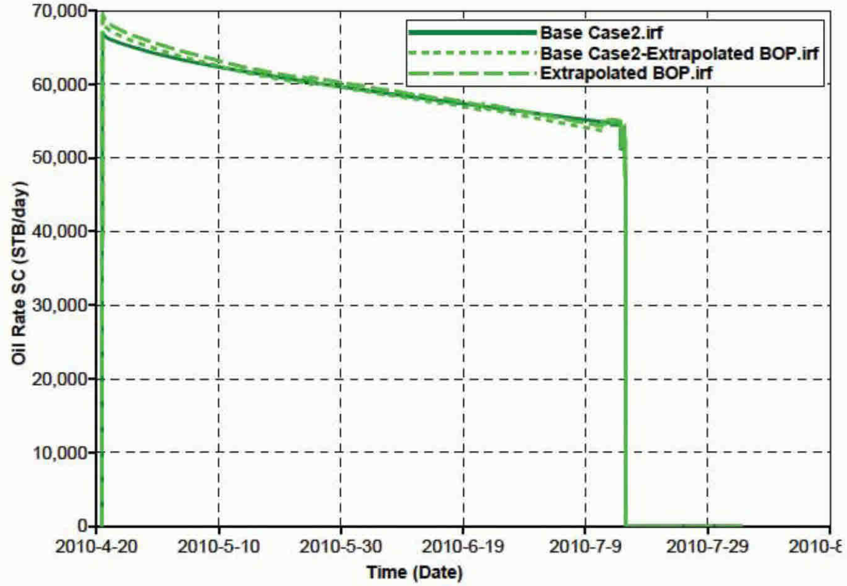
Extrapolated BOP: Bottom-hole Pressure

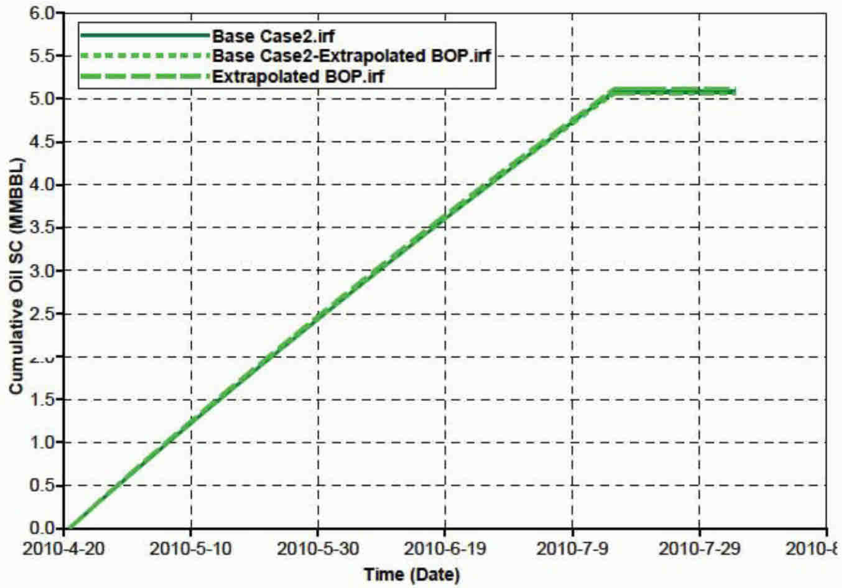


Extrapolated BOP: MDH Type Curve



Extrapolated BOP: Oil Released





Cumulative oil released = 5.12 MMSTB

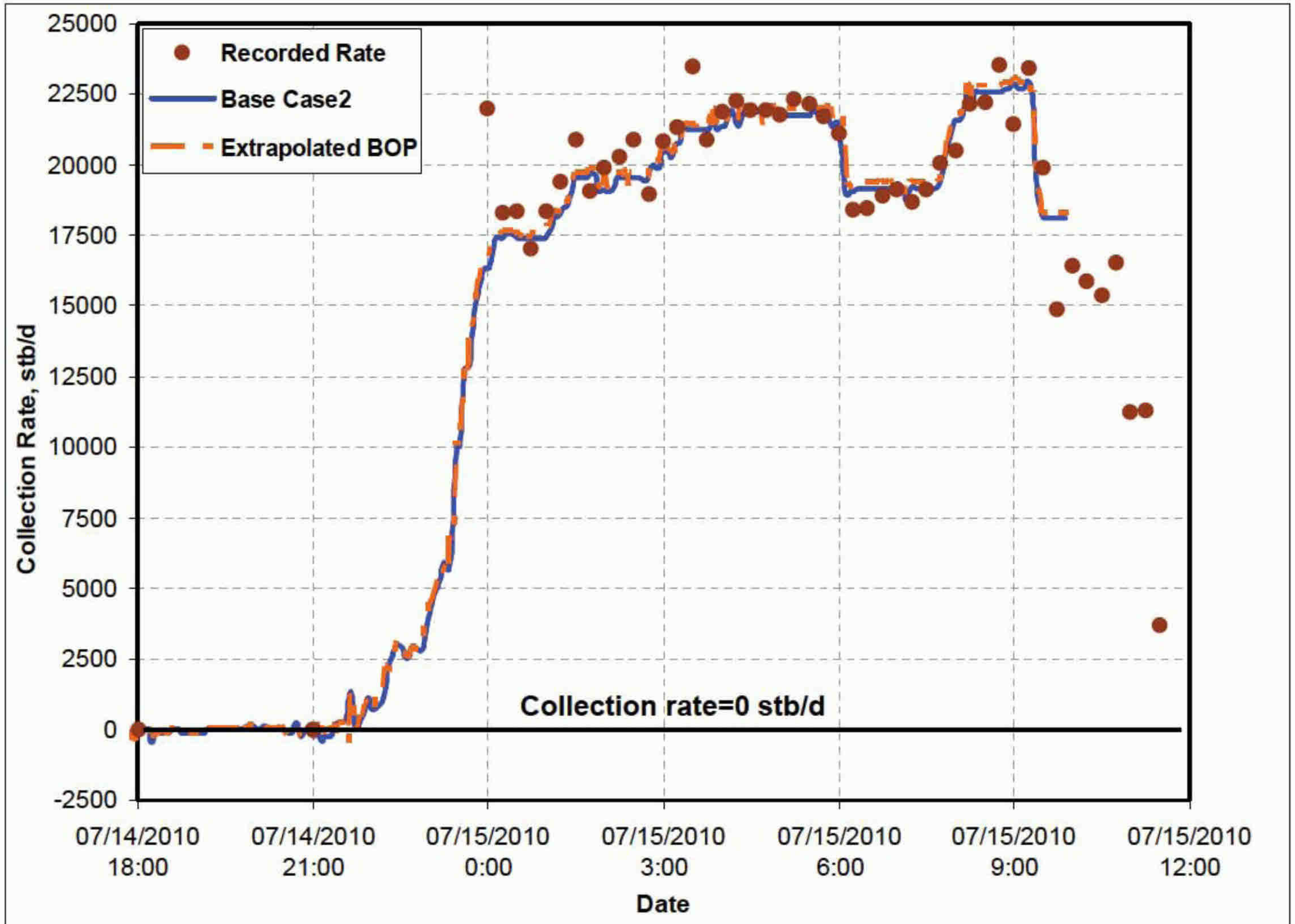
OOIP=141 MMstb

PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-Extrapolated BOP), stb/psi/day:	28.0
PI (Extrapolated BOP), stb/psi/day:	28.7

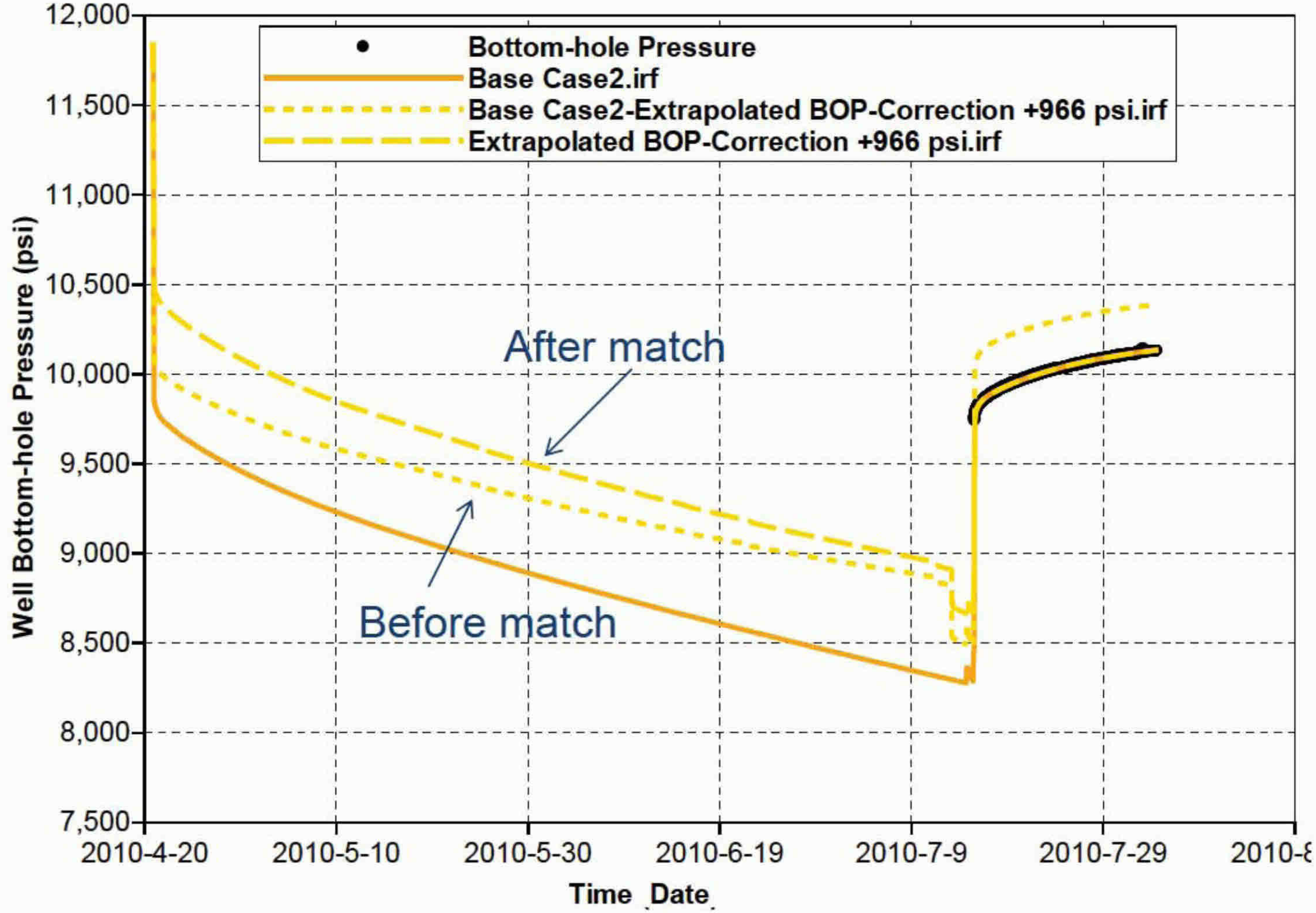
Fekete

Extrapolated BOP: Collection Rate

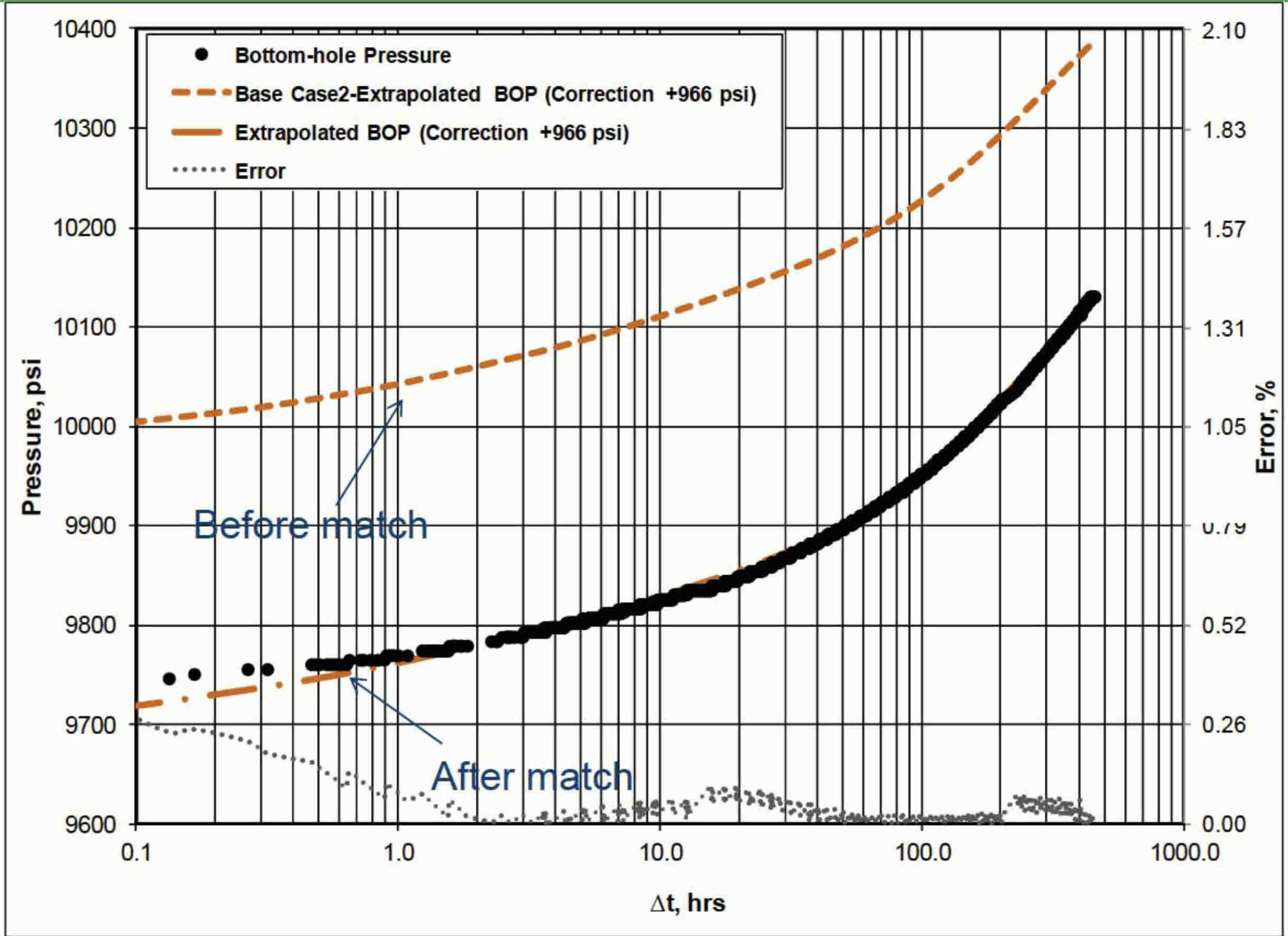
Match: Generally within ±600 STB/day



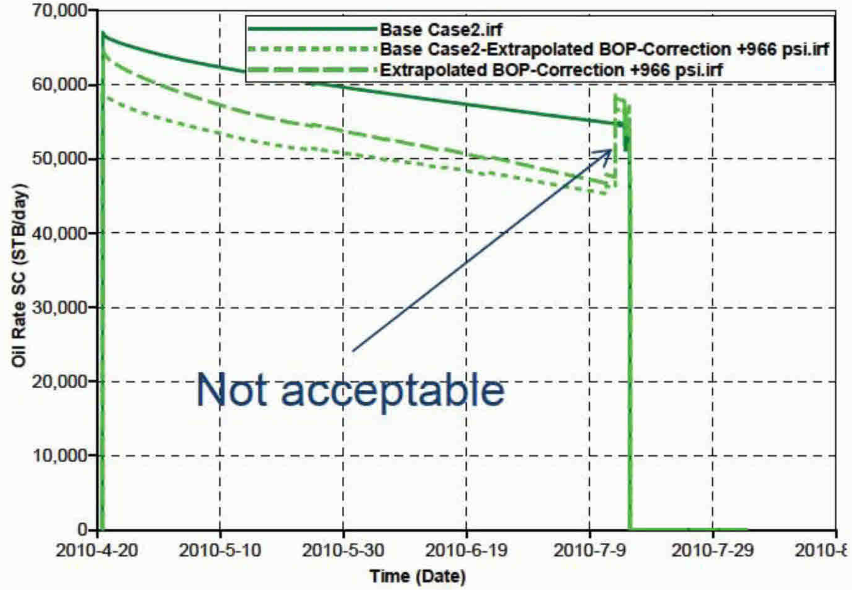
Extrapolated BOP (Correction +966 psi): Bottom-hole Pressure

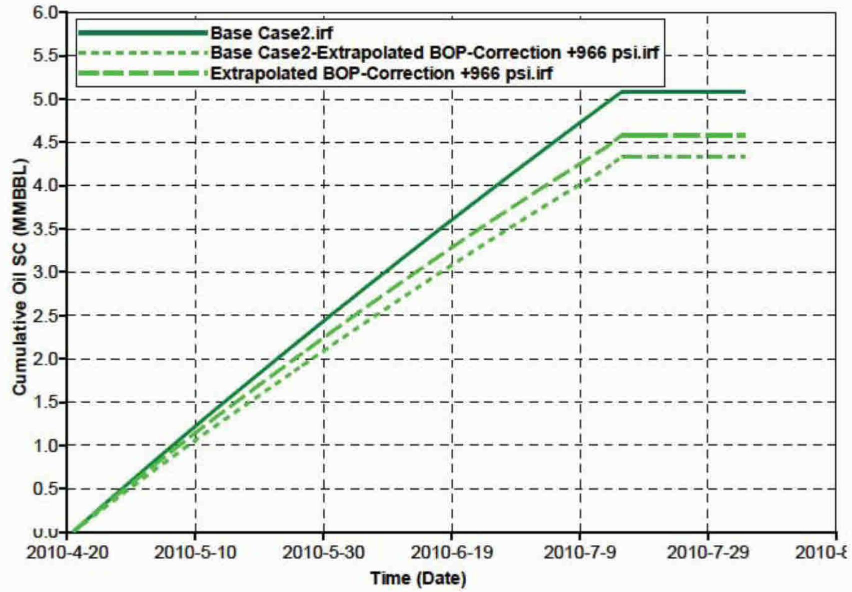


Extrapolated BOP (Correction +966 psi): MDH Type Curve



Extrapolated BOP (Correction +966 psi): Oil Released





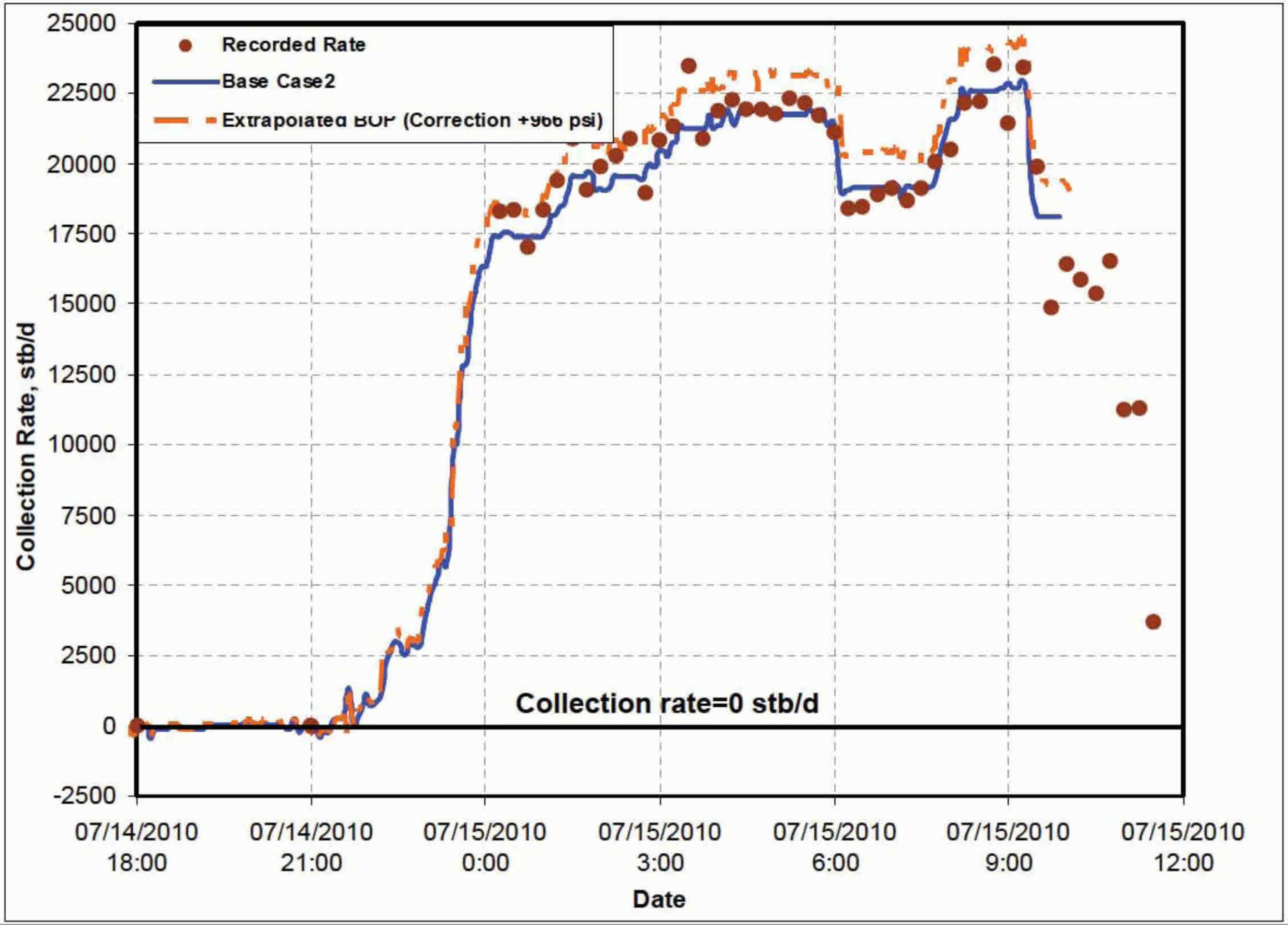
Cumulative oil released = 4.58 MMSTB

OOIP=126 MMstb

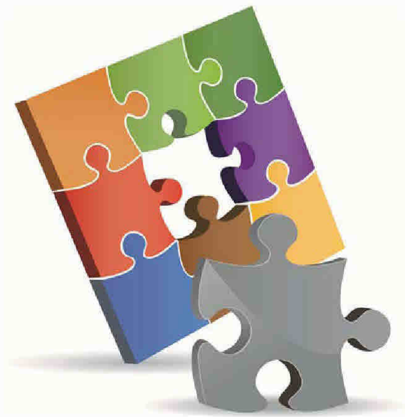
PI (Base Case2), stb/psi/day: 28.0
PI (Base Case2-Extrapolated BOP (Correction +966 psi)), stb/psi/day: 28.3
PI (Extrapolated BOP (Correction +966 psi)), stb/psi/day: 36.7

Extrapolated BOP (Correction +966 psi): Collection Rate

Mis-match: Generally within ±600 and ±2500 STB/day



Appendix II: Additional Sensitivity Studies



Scope

Defending experts presented models that exhibit a smaller OOIP, a smaller permeability, a more constrained wellbore, etc. In this Appendix, these choices are compared with what we had considered in our Base Model (Pooladi-Darvish initial Report).

Then sensitivity studies are conducted by incorporating these choices into reservoir/wellbore models and examining if a match of shut-in pressures and collection rates could be obtained.

Permeability: Gringarten suggested that permeability is in the range of 170 to 329 mD, with most likely value of 238 mD.

OOIP: Defending experts have presented OOIP values that vary between 57 and 133 MMSTB. The average of the low, mid and high values are 80, 100, and 120 MMSTB. We examine the case of 100 MMSTB.

PVT Input: Whitson developed an EOS for the measured PVT test data. Gringarten and Blunt suggest that the PVT properties associated with single-stage separator test should be used

Scope (cont.)

Shut-in Pressure: Blunt converted recorded CS pressure as adjusted by Trusler to bottomhole conditions by combining Whitson PVT model with his estimate of variable well-head temperature.

Flowing Pressure: Trusler presented a new version of the BOP (and capping stack) pressures.

Wellbore Model: Johnson created a wellbore model that incorporated drill-pipe below the BOP. This model incorporates Johnson's own PVT model and was used along with the flowing pressures of Trusler.

List of Cases

Four sensitivity runs are conducted one-at-a-time, where all of my “base values” are used except the sensitivity parameters which is used from the table below.

The wellbore model of Johnson could not be used directly in the base model. This is because, Johnson’s wellbore model did not include the BOP instead it was run against the BOP pressures as estimated by Trusler. This model is included in the case 5 along with all other modifications.

Case Study	Parameter/Value	Case #
Permeability	238 mD	A1
OOIP	100 MMStb	A2
PVT	Single-Stage flash	A3
Shut-in Pressure	Blunt Estimate	A4
Combined	Combined	A5
Wellbore Model + Flowing Pressure	Johnson Model + Trusler’s pressures	

Summary of Results I

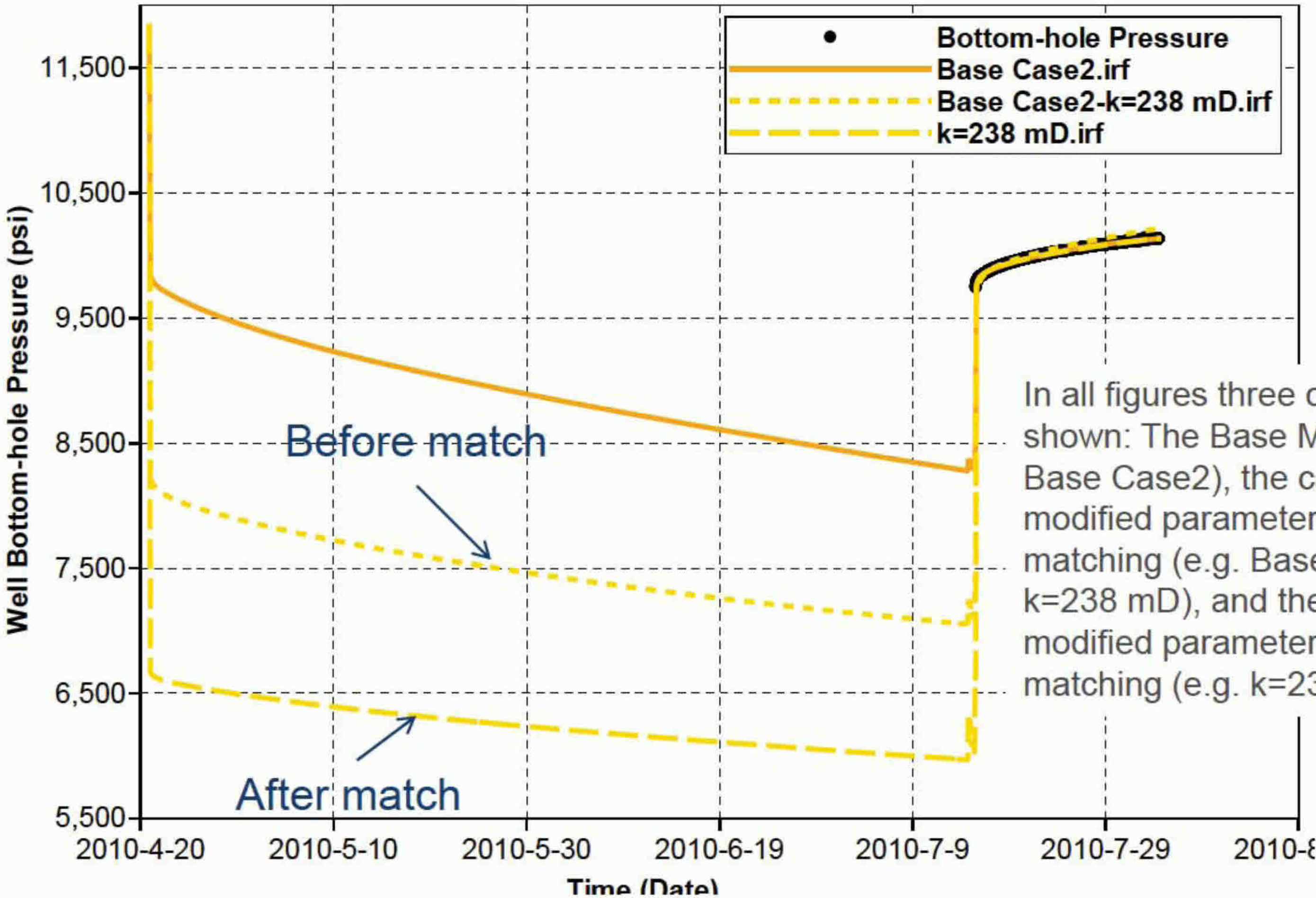
	K, mD	Skin	Length Xe, ft	Width Ye, ft	Xw, ft	Yw, ft	OOIP, MMSTB	Pav, psi	PI, stb/d/psi	q July 15, stb/d	Error, %	Cum Oil Released (after matching shut-in pressures), MMSTB
K=238 mD	238	33	17350	3350	3700	1550	84.6	10289	7.2	30000	0.05	2.94 (Bad)
OOIP=100 MMStb	300	28.5	18350	3750	3700	1350	100.0	10263	10.0	36000	0.05	3.54 (Bad)
Shut-in Pressure	360	25	18400	4550	1700	1000	121.8	10392	12.5	41000	0.02	3.97 (Bad)
Combined-Extrapolated	360	0	20150	4950	2250	1050	134.6	10430	32.8	47000	0.03	4.20 (Bad)
Combined-Extrapolated-2	1000	0	30400	3450	1950	300	141.5	10388	54.5	52000	0.05	4.56 (Med)
PVT	550	14	22950	4400	3700	1350	136.3	10232	25.9	49000	0.03	4.73 (Med)
Shut-in Pressure-2	550	13.5	23050	4650	1800	1000	156.0	10410	24.8	53000	0.05	5.02 (Good)
Base Case2	550	13	21850	4400	3700	1350	140.0	10219	28	53000	0.04	5.08 (Good)

Methodology

The methodology used to validate the defendants model is sensitivity. In particular, The Base reservoir-wellbore and BOP model or its boundary conditions are modified as per the list of cases defined in Slide 4.

The modified models are run, the flow and shut-in periods are numerically modeled and the mis-match in shut-in pressures is demonstrated. Then the reservoir parameters are varied until a reasonable match of the shut-in pressures is obtained. Then this model is used along with the CS and BOP pressures to estimate collection rate during the collection period. The models are divided between good, mediocre and bad depending on their quality of match of the collection rates. The “cumulative volume of oil released” of each model is then reported.

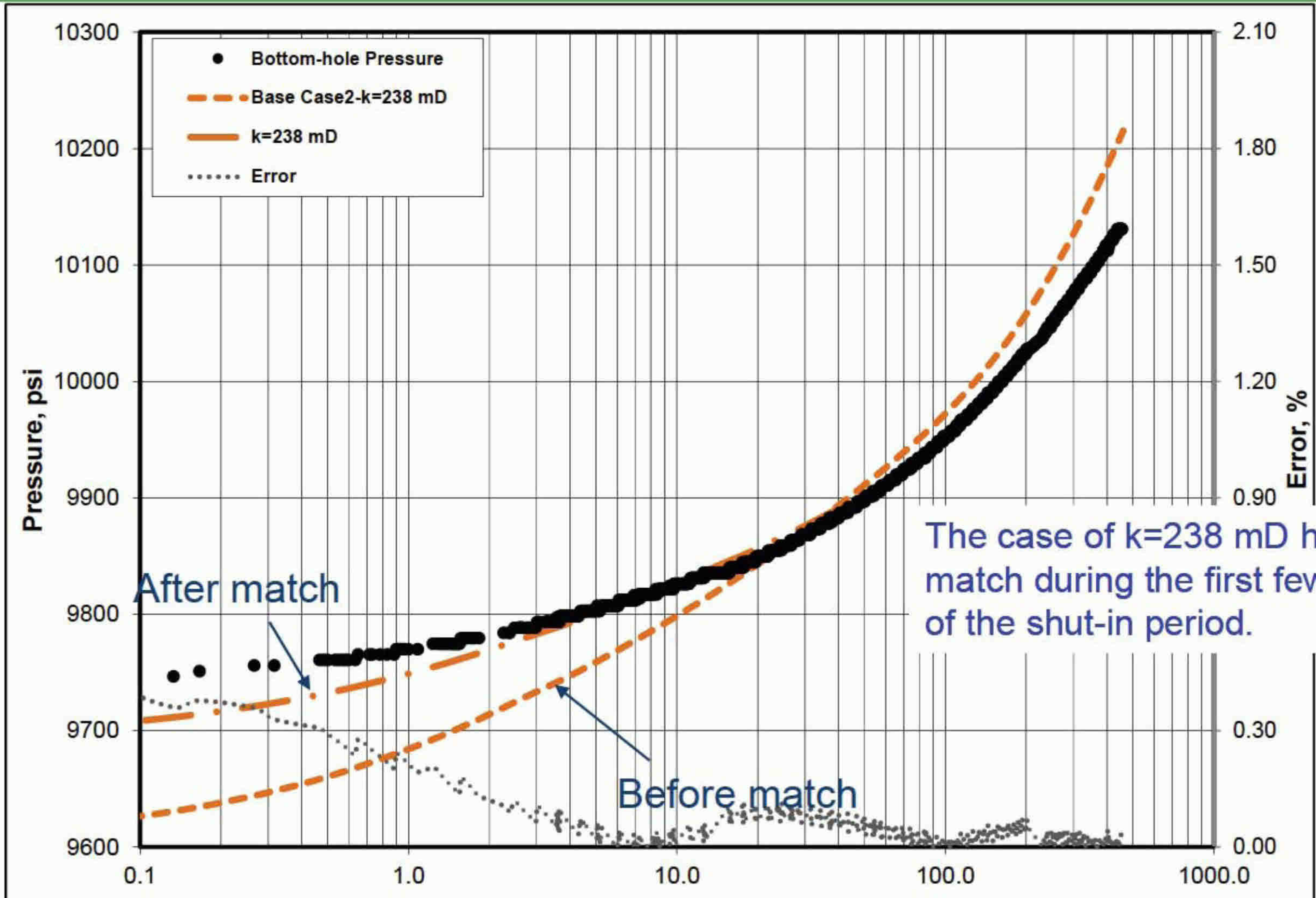
K=238 mD: Bottom-hole Pressure



In all figures three cases are shown: The Base Model (called Base Case2), the case with modified parameter before matching (e.g. Base-Case2-k=238 mD), and the case with modified parameter *after* matching (e.g. k=238 mD).

The bottomhole pressure are the same as those in my initial report (Base Case 2).
Flowing pressures decreased to below bubblepoint pressure; very unlikely

K=238 mD: MDH Type Curve

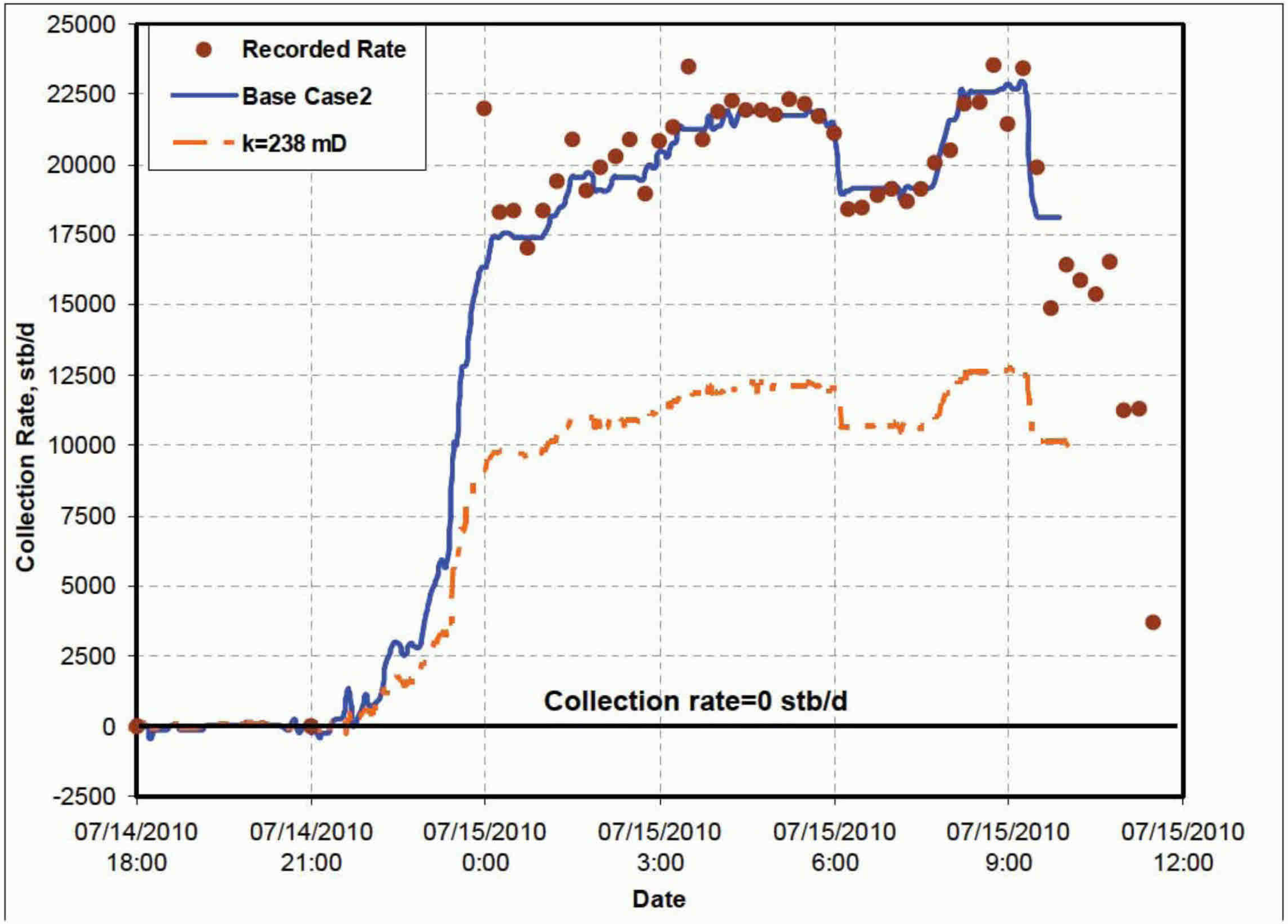


The case of k=238 mD has a mis-match during the first few hours of the shut-in period.

Match of the early-time data is affected by the flow rates during the 2 hours of choke-closure. The VLP tables are expected to exhibit some error in that estimation.

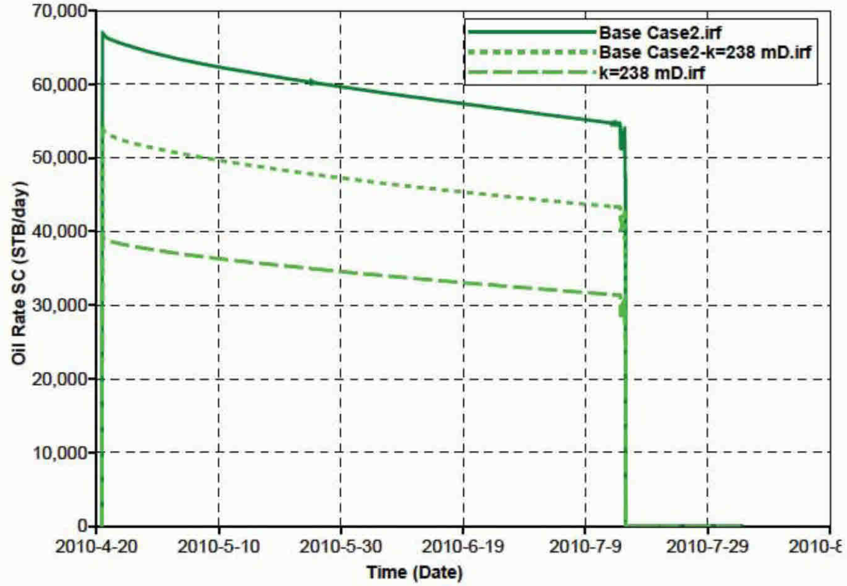
K=238 mD: Collection Rate

Mismatch: Generally larger than ±2500 STB/day

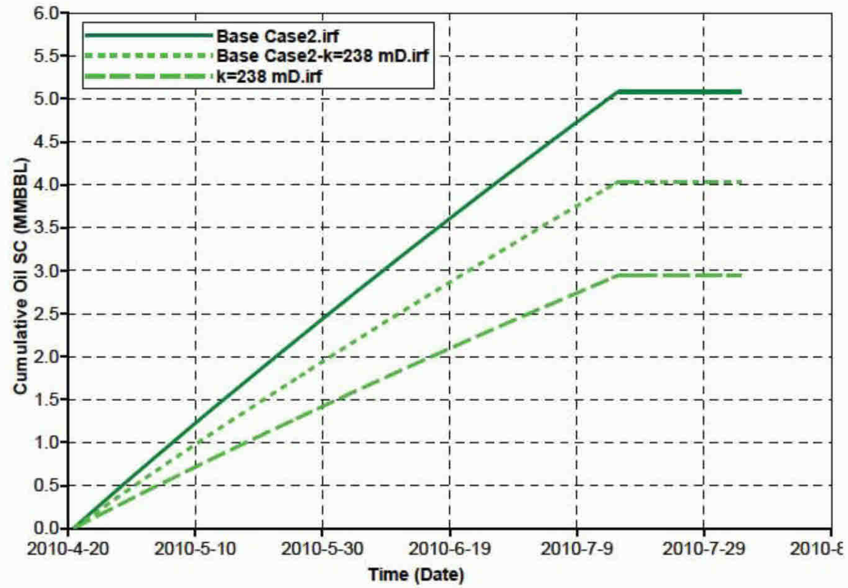


Results are consistent with my initial report. Permeability of 238 mD does not allow match of collection rates.

K=238 mD: Oil Released

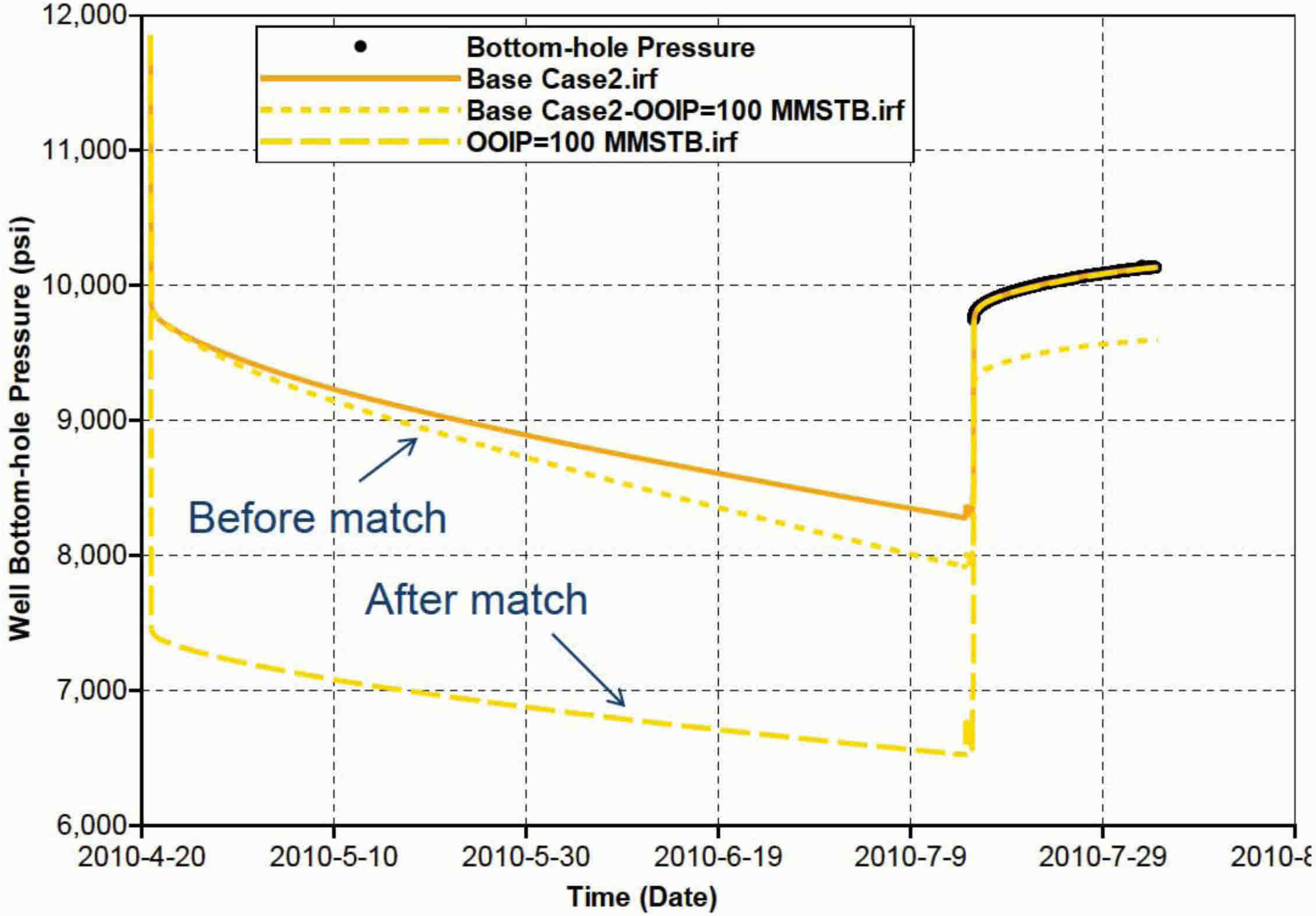


The cumulative oil released for the k=238 mD case is equal to 2.94 MMSTB.

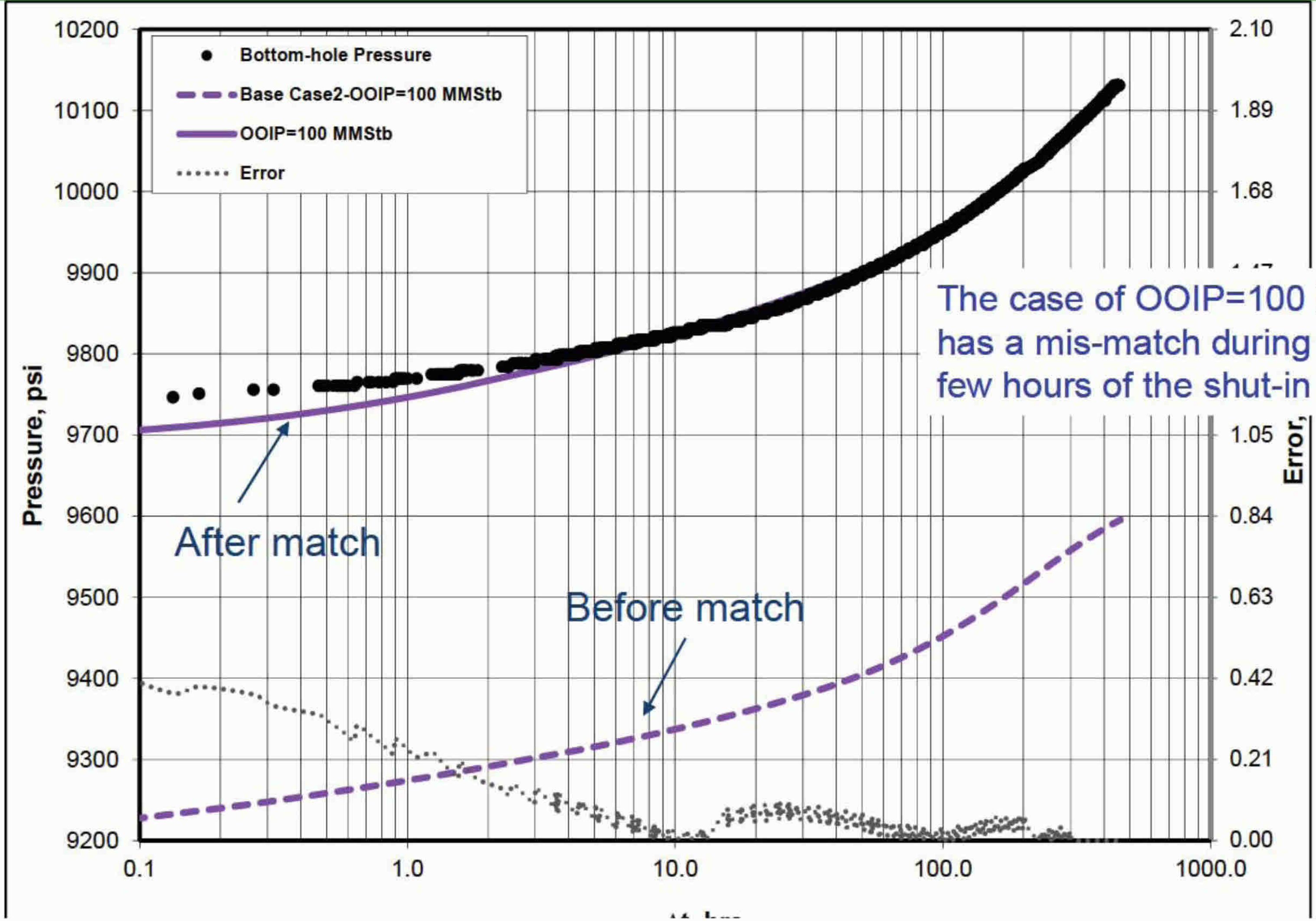


PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-k=238 mD), stb/psi/day:	12.2
PI (k=238 mD), stb/psi/day:	7.2

OOIP=100 MMStb: Bottom-hole Pressure



OOIP=100 MMStb : MDH Type Curve

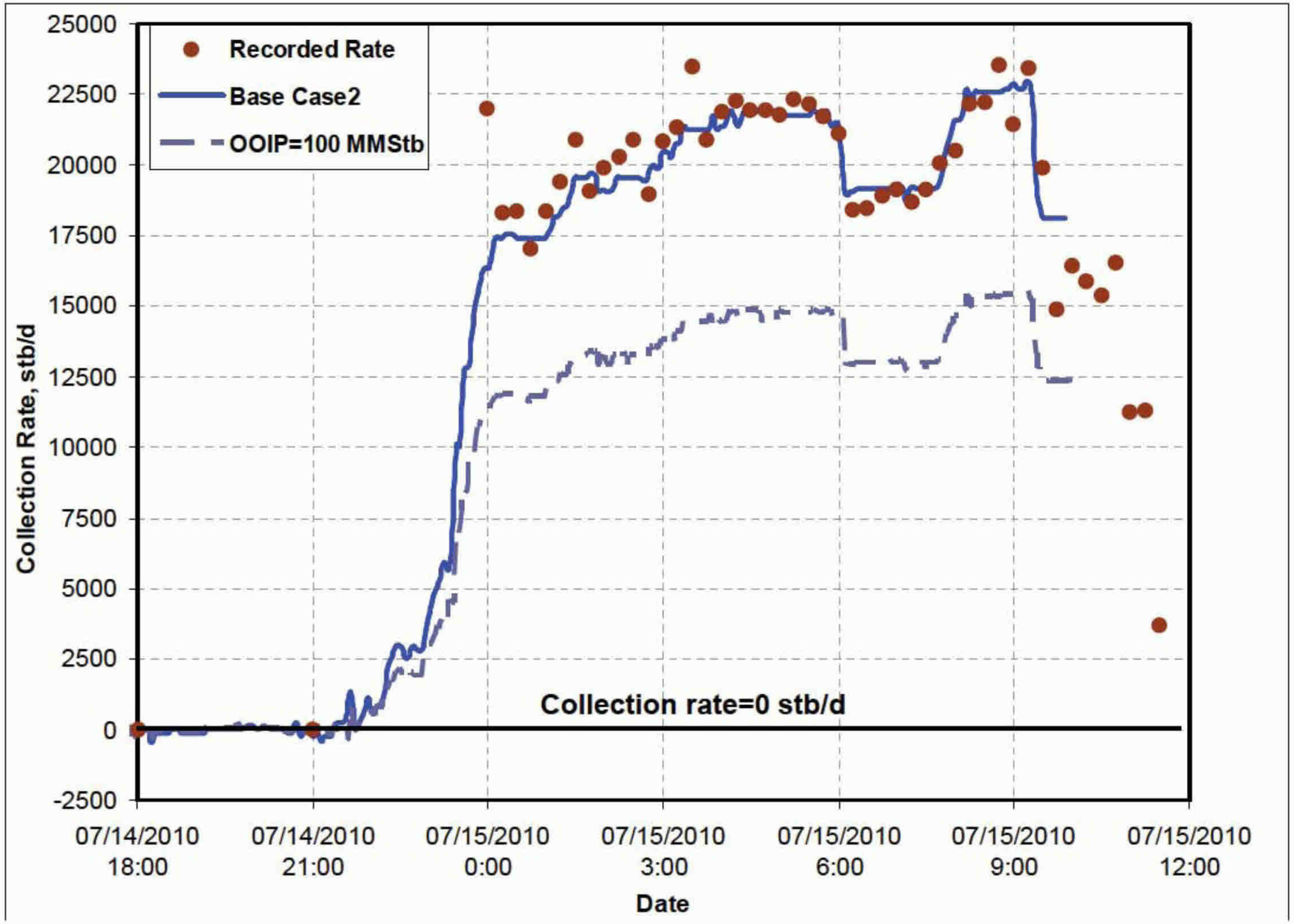


The case of OOIP=100 MMStb has a mis-match during the first few hours of the shut-in period.

Match of the early-time data is affected by the flow rates during the 2 hours of choke-closure. The VLP tables are expected to exhibit some error in that estimation.

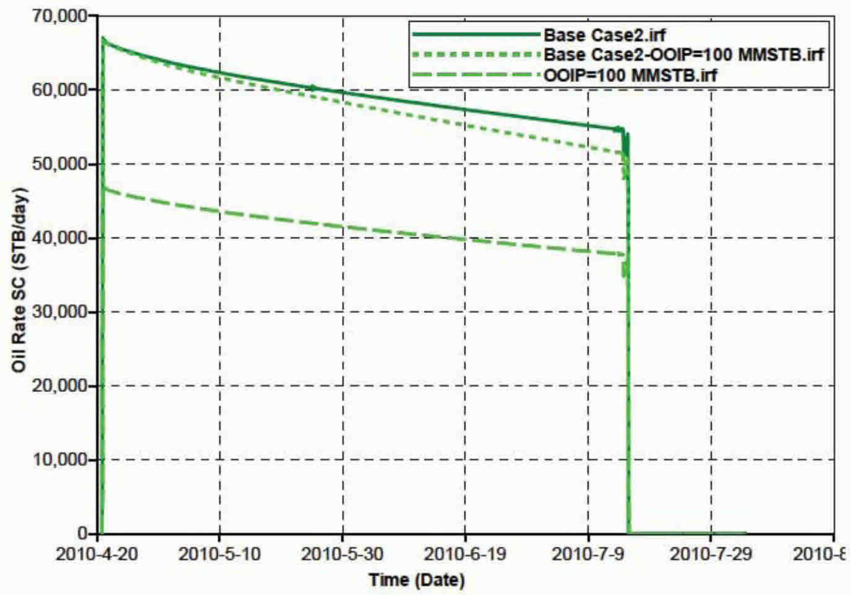
OOIP=100 MMStb : Collection Rate

Mismatch: Generally larger than ±2500 STB/day

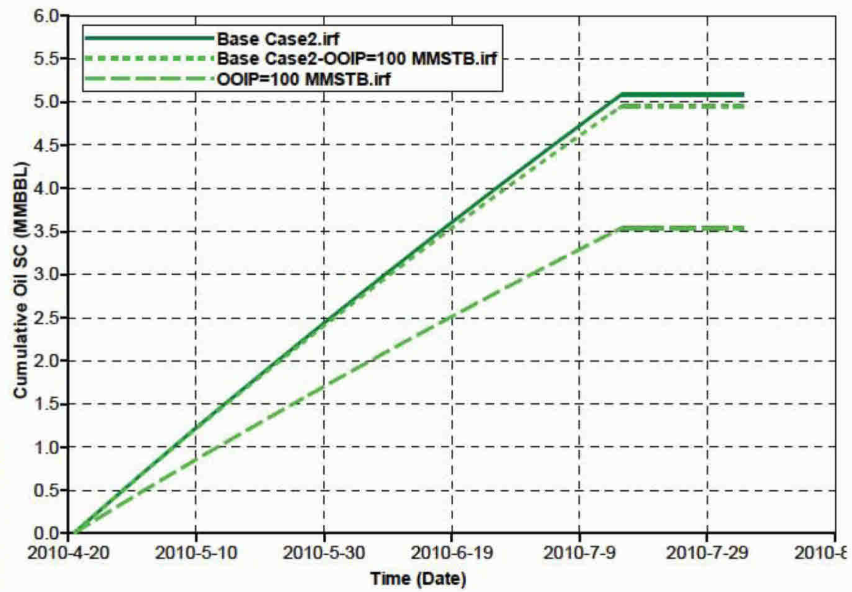


- Results are consistent with my initial report. OOIP of 100 MMSTB does not allow match of collection rates, unless large changes to other parameters (e.g. compressibility) is considered.

OOIP=100 MMStb : Oil Released



The cumulative oil released for the OOIP=100 MMStb case is equal to 3.54 MMSTB.



PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-OOIP=100 MMStb), stb/psi/day:	10.0
PI (OOIP=100 MMStb), stb/psi/day:	14.5

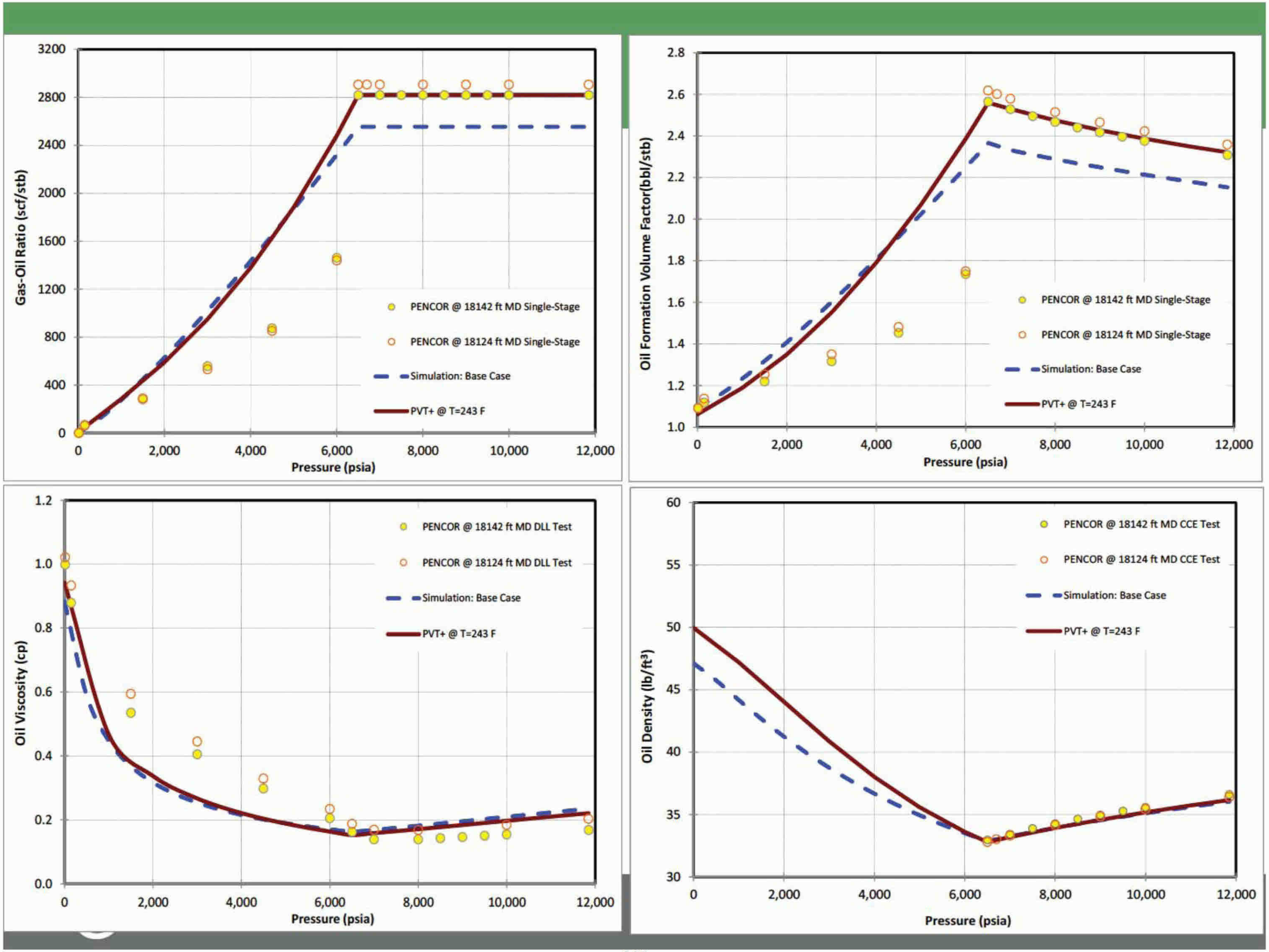
PVT:

Many of the defending experts suggested that PVT properties should be those corresponding to single-stage separator tests. I disagree with the conclusion, but assume this representation of PVT properties is within the realm of possibilities. Here, the differential test black-oil properties measured in the lab and corrected to single-stage separator test conditions are reported.

A correlation based model was built using Glaso correlation for calculation of Rs and Bo, and Beggs-Robinson correlation for calculating oil viscosity.
In order to match the data of Rs, Bo, and μo, the following adjustment factors were applied in PVT+ model.

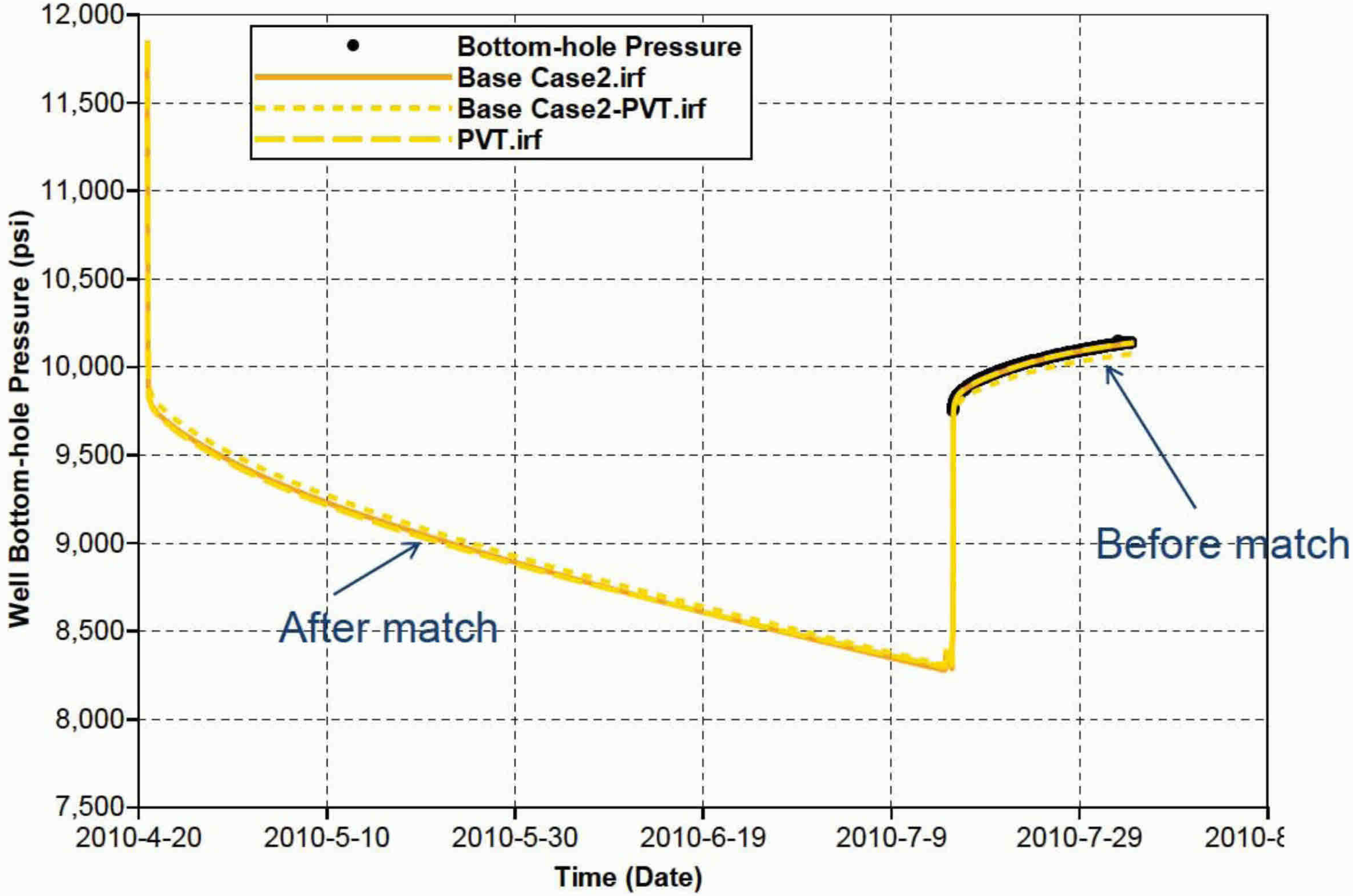
- ✓**Bo Correlation Adjustment Factor=0.99**
- ✓**Rs Correlation Adjustment Factor=1.46**
- ✓**μo Correlation Adjustment Factor=0.80**

Also shown are the PVT properties used in our base model, that are consistent with multi-stage separation tests (in dashed-blue lines).



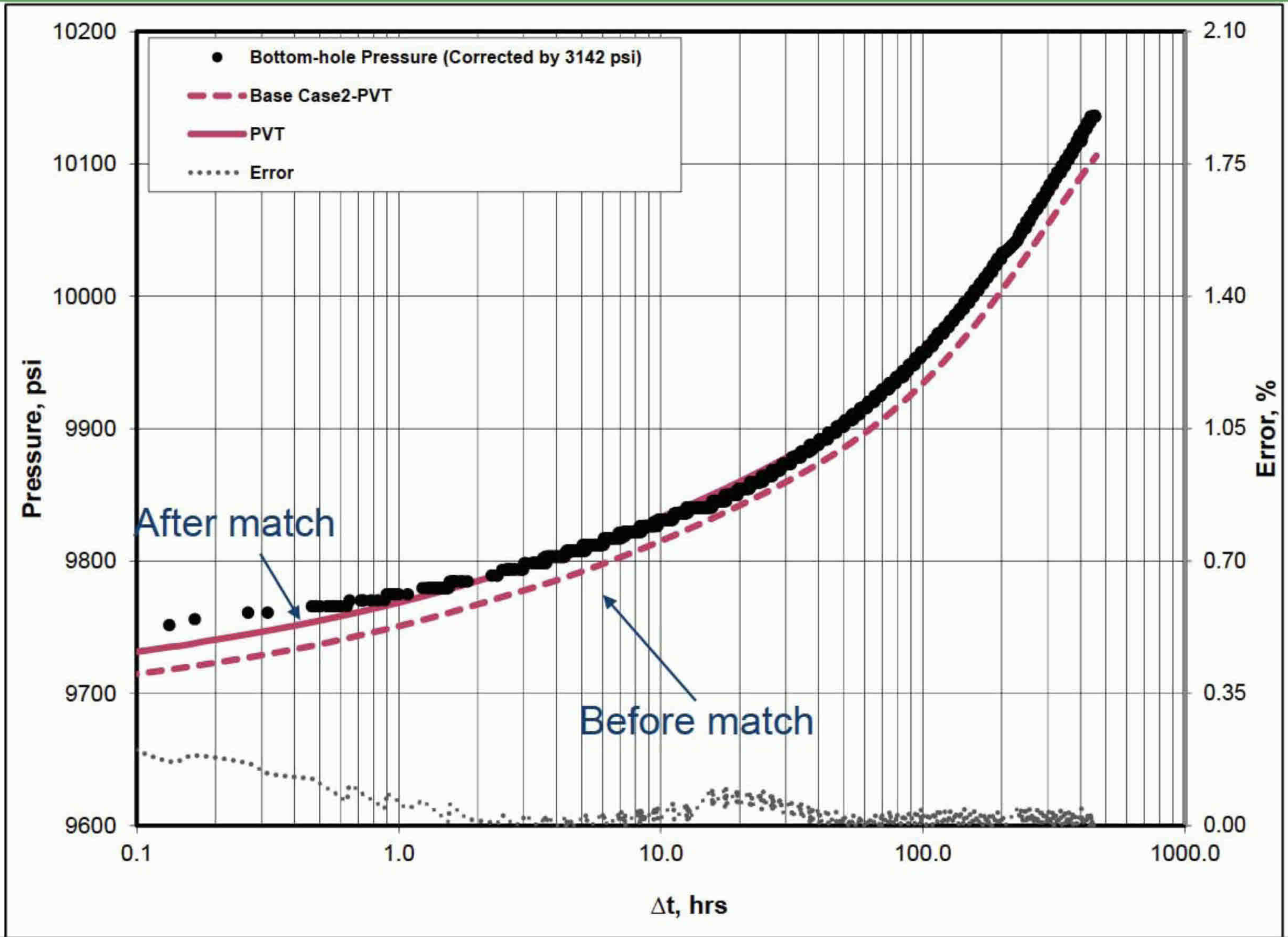
Gas-Oil Ratio (scf/stb)
Pressure (psia)
PENCOR @ 18142 ft MD Single-Stage
PENCOR @ 18124 ft MD Single-Stage
Simulation: Base Case
PVT+ @ T=243 F
Oil Formation Volume Factor(bbl/stb)
Pressure (psia)
PENCOR @ 18142 ft MD Single-Stage
PENCOR @ 18124 ft MD Single-Stage
Simulation: Base Case
PVT+ @ T=243 F
Oil Viscosity (cp)
Pressure (psia)
PENCOR @ 18142 ft MD DLL Test
PENCOR @ 18124 ft MD DLL Test
Simulation: Base Case
PVT+ @ T=243 F
Oil Density (lb/ft³)
Pressure (psia)
PENCOR @ 18142 ft MD CCE Test
PENCOR @ 18124 ft MD CCE Test
Simulation: Base Case
PVT+ @ T=243 F

PVT: Bottom-hole Pressure



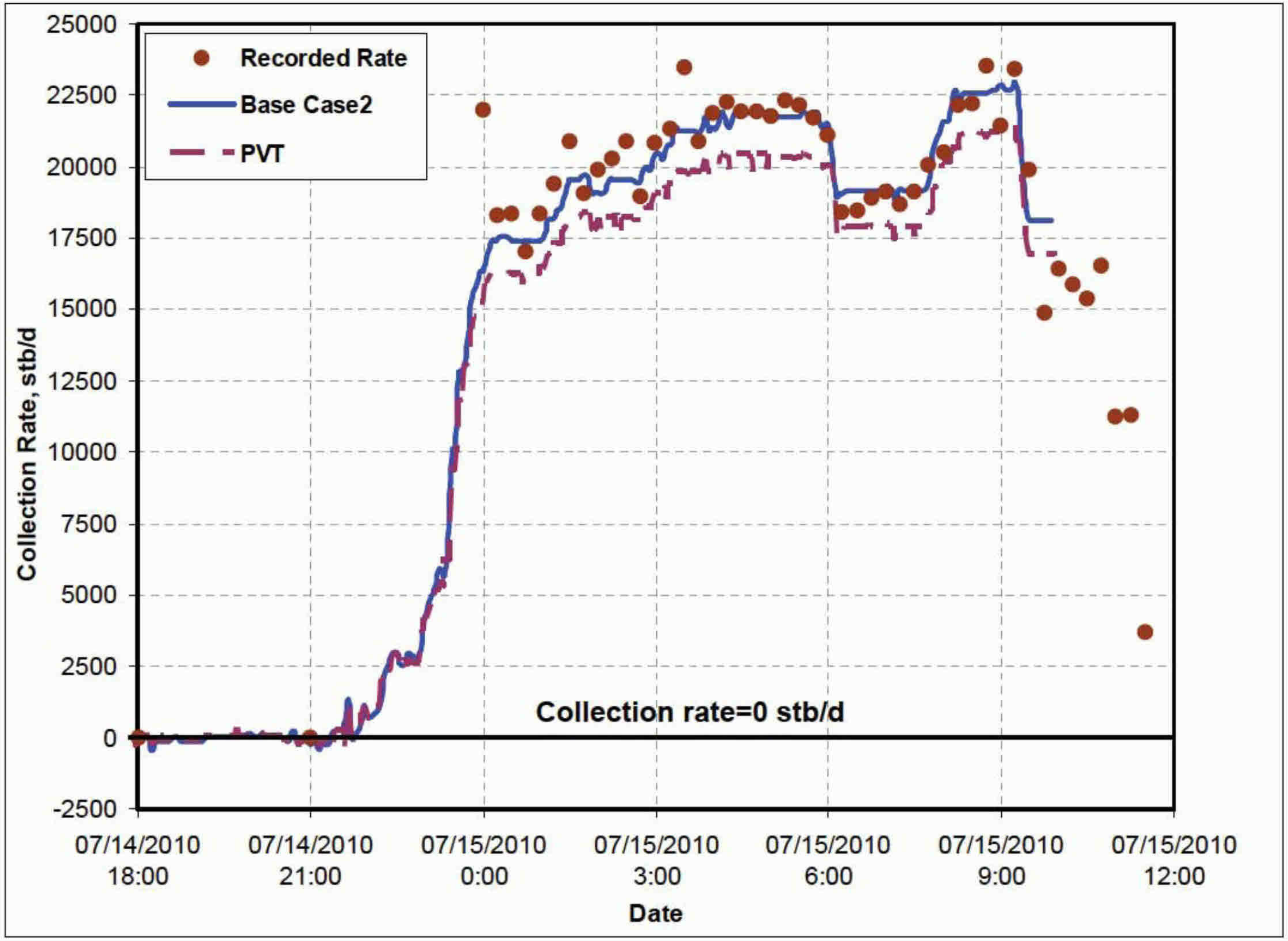
The bottomhole pressure are calculated from the recorded CS pressures plus 3142 psi to account for the hydrostatic pressure corresponding to the new fluid.

PVT: MDH Type Curve

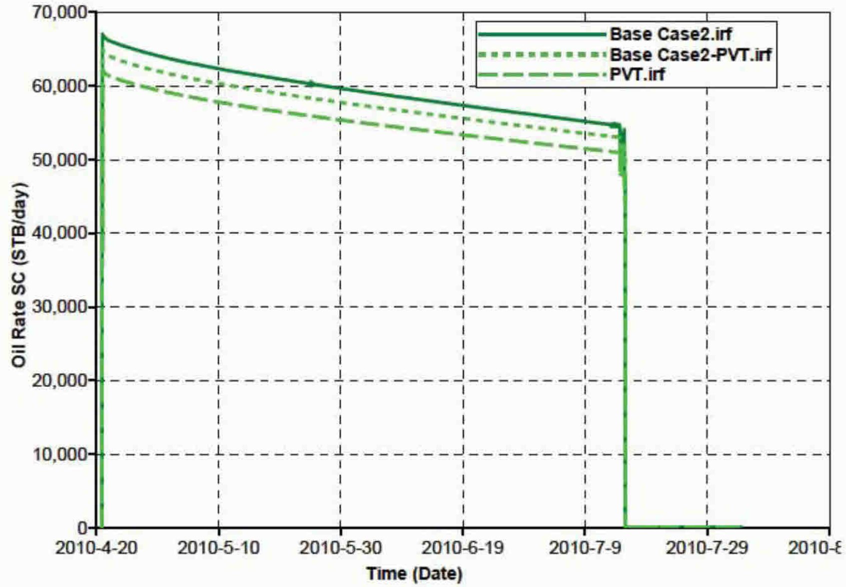


PVT: Collection Rate

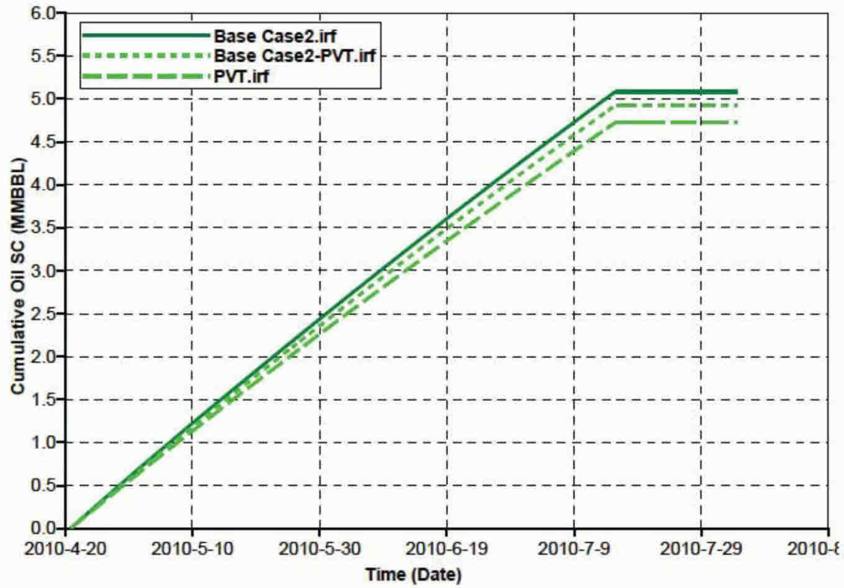
Mismatch: Generally between than ±600 and ±2500 STB/day



PVT: Oil Released



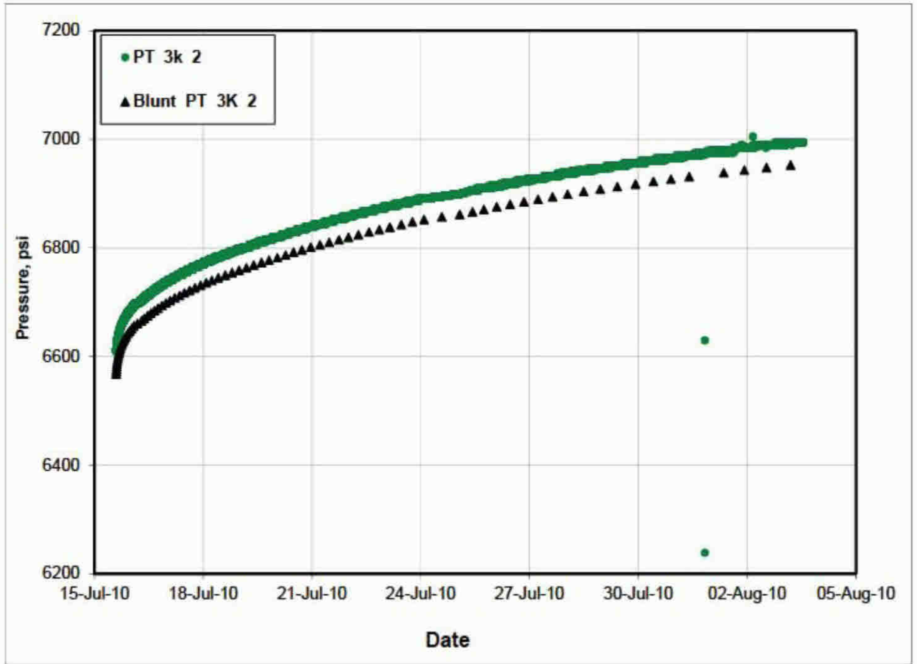
The cumulative oil released for the PVT case is equal to 4.73 MMSTB.

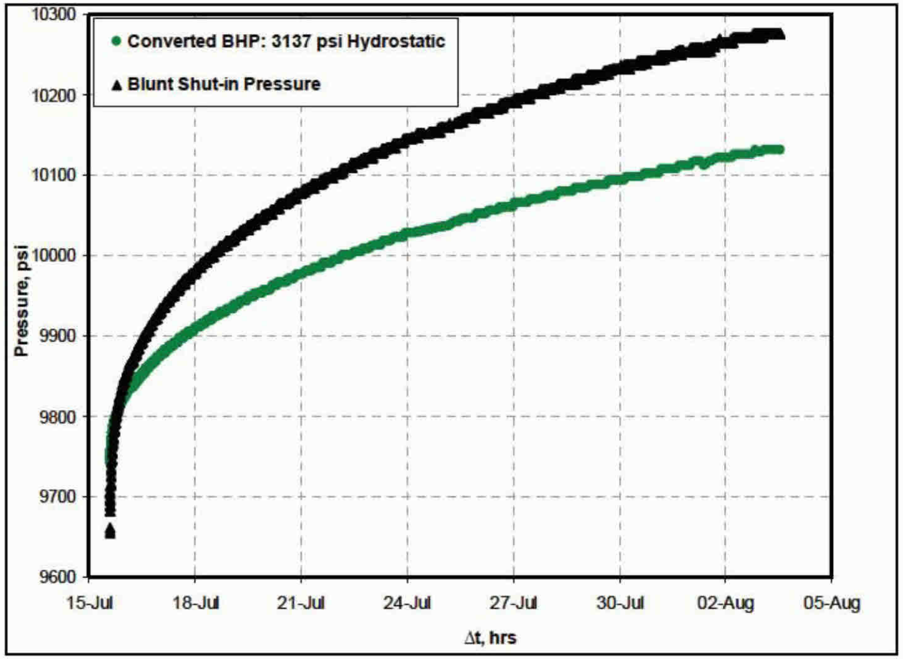


PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-PVT), stb/psi/day:	28.3
PI (PVT), stb/psi/day:	25.9

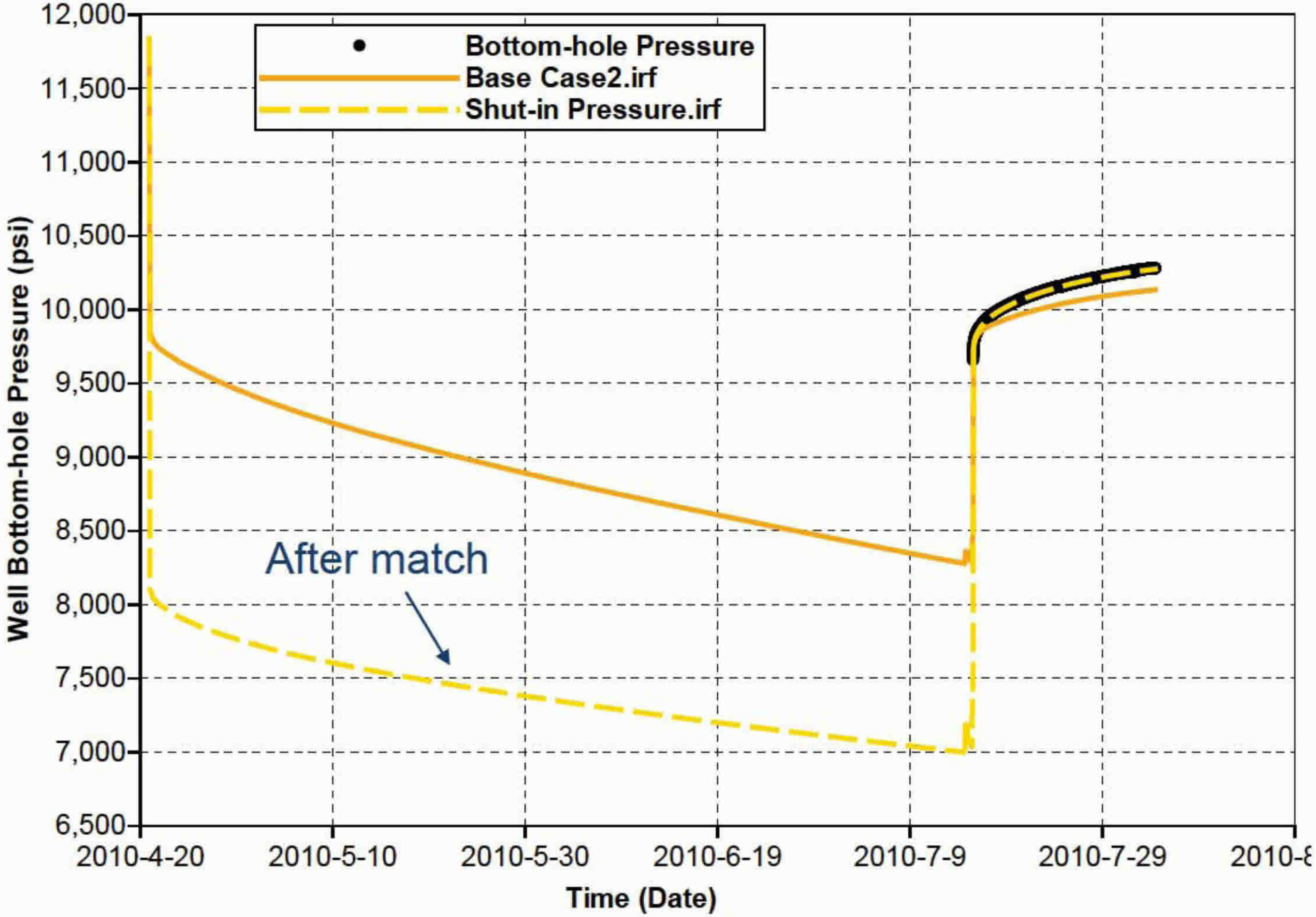
Shut-in pressure:

Blunt converted recorded CS pressure as adjusted by Trusler to BHP by combining Whitson PVT model with variable well-head temperature.



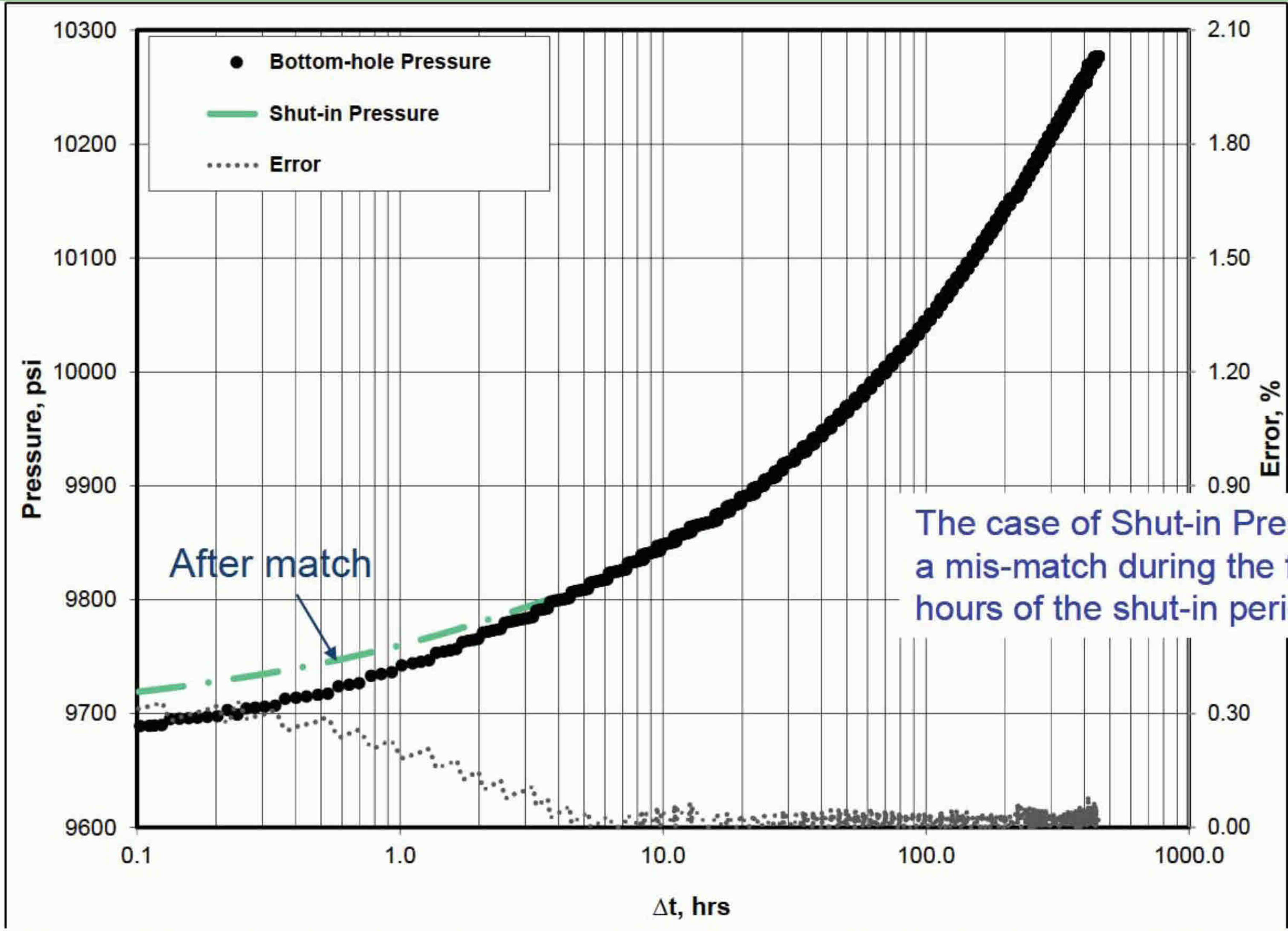


Shut-in Pressure: Bottom-hole Pressure



The bottom-hole pressures are generated by Blunt and are taken from
PT3K2+Converted+to+reservoir+conditions+for+Gringarten.xls

Shut-in Pressure : MDH Type Curve

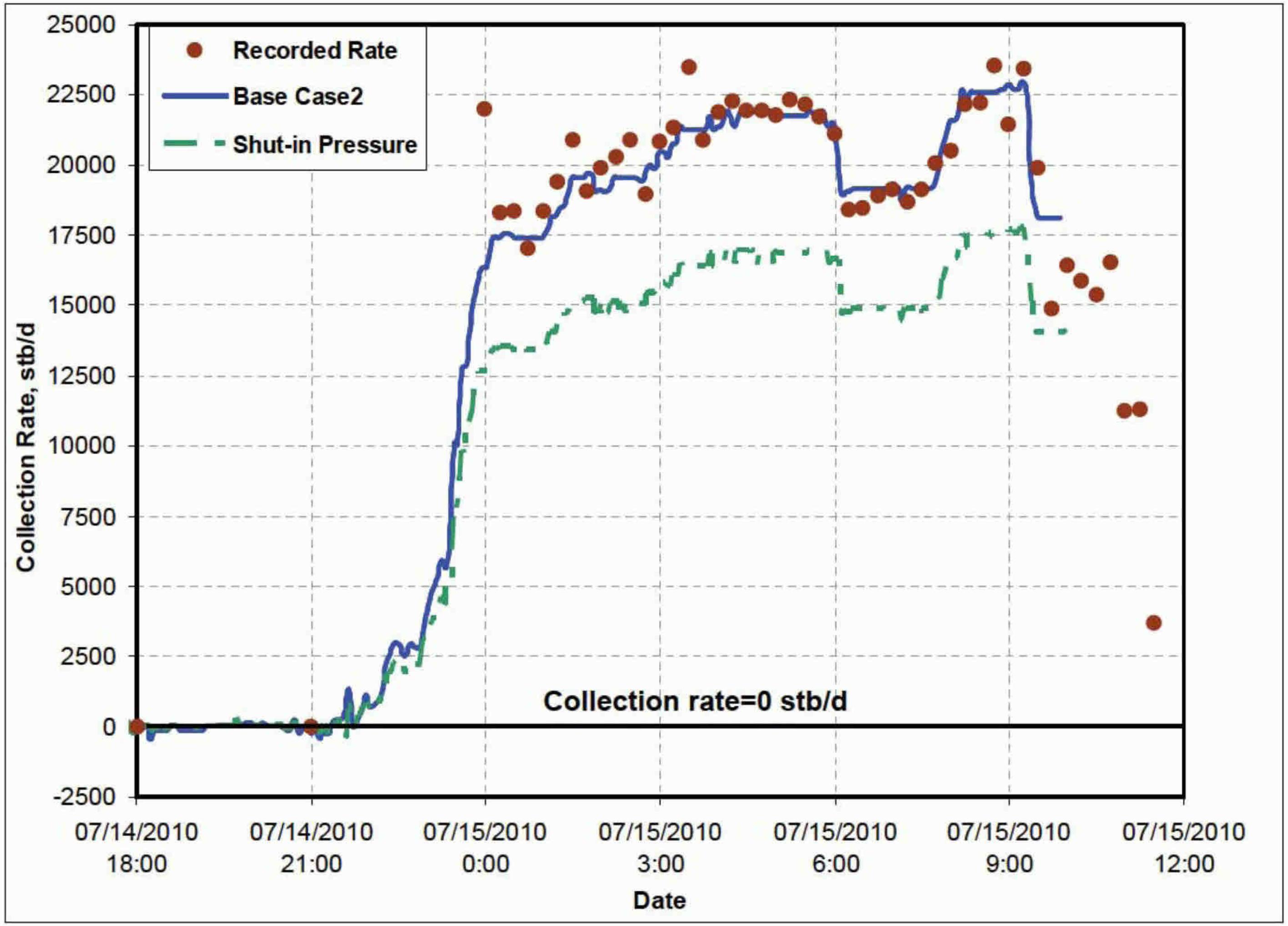


The case of Shut-in Pressure has a mis-match during the first few hours of the shut-in period.

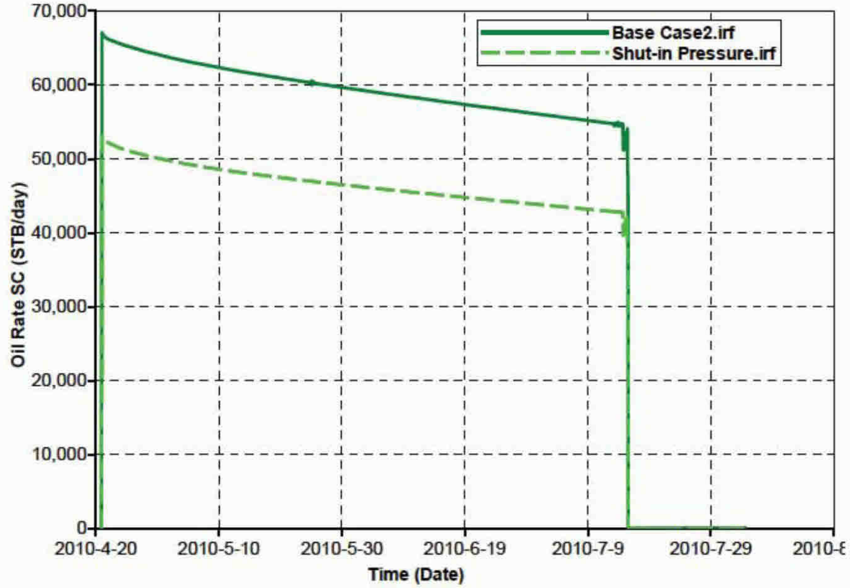
Match of the early-time data is affected by the flow rates during the 2 hours of choke-closure. The VLP tables are expected to exhibit some error in that estimation.

Shut-in Pressure : Collection Rate

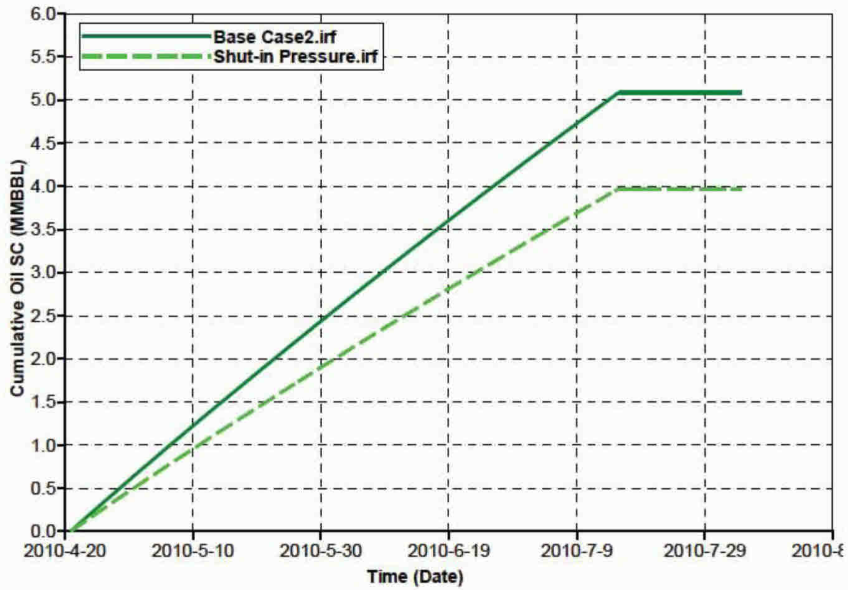
Mismatch: Generally larger than ±2500 STB/day



Shut-in Pressure : Oil Released



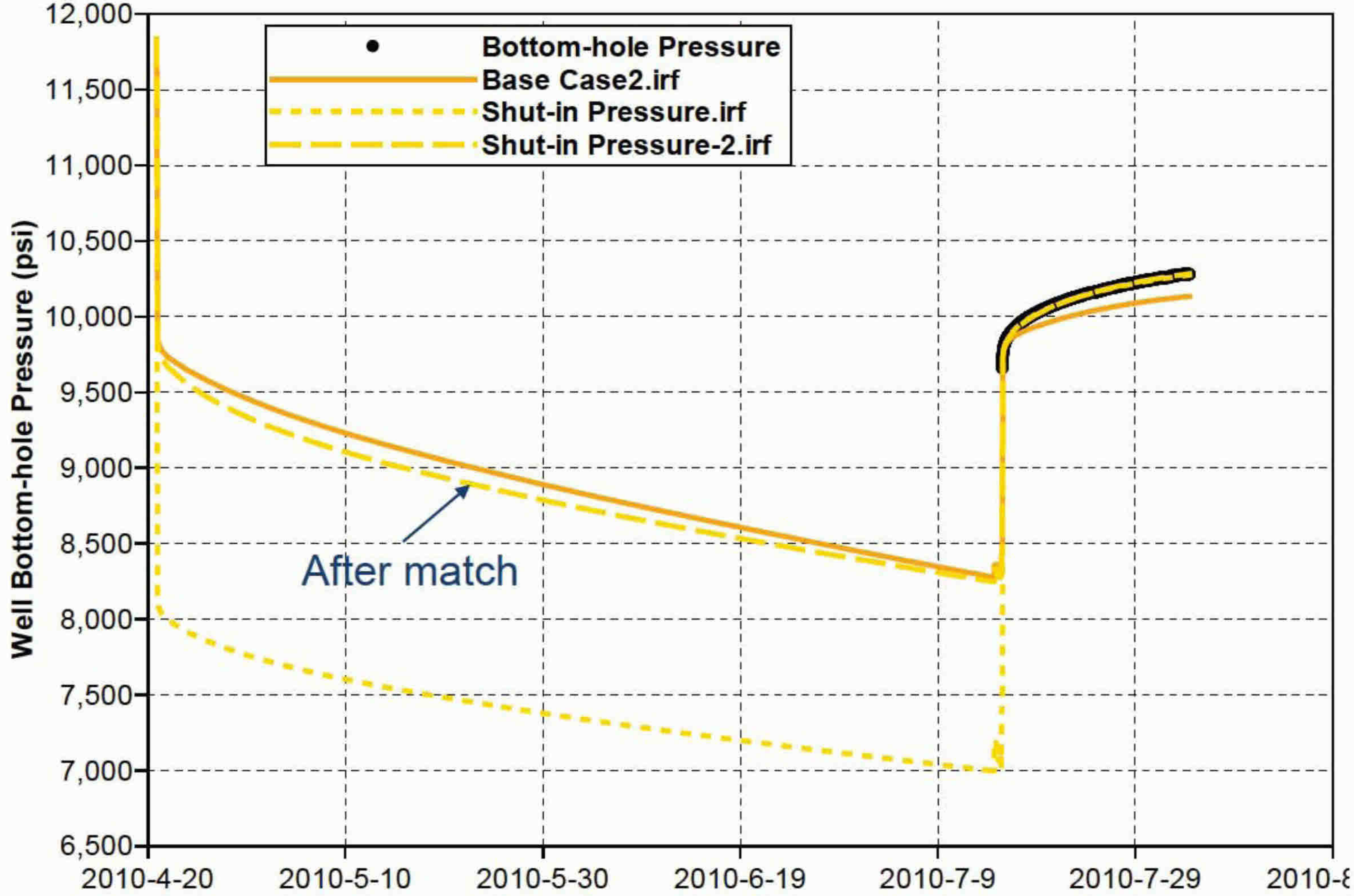
The cumulative oil released for the Shut-in Pressure case is equal to 3.97 MMSTB.



PI (Base Case2), stb/psi/day: 28.0

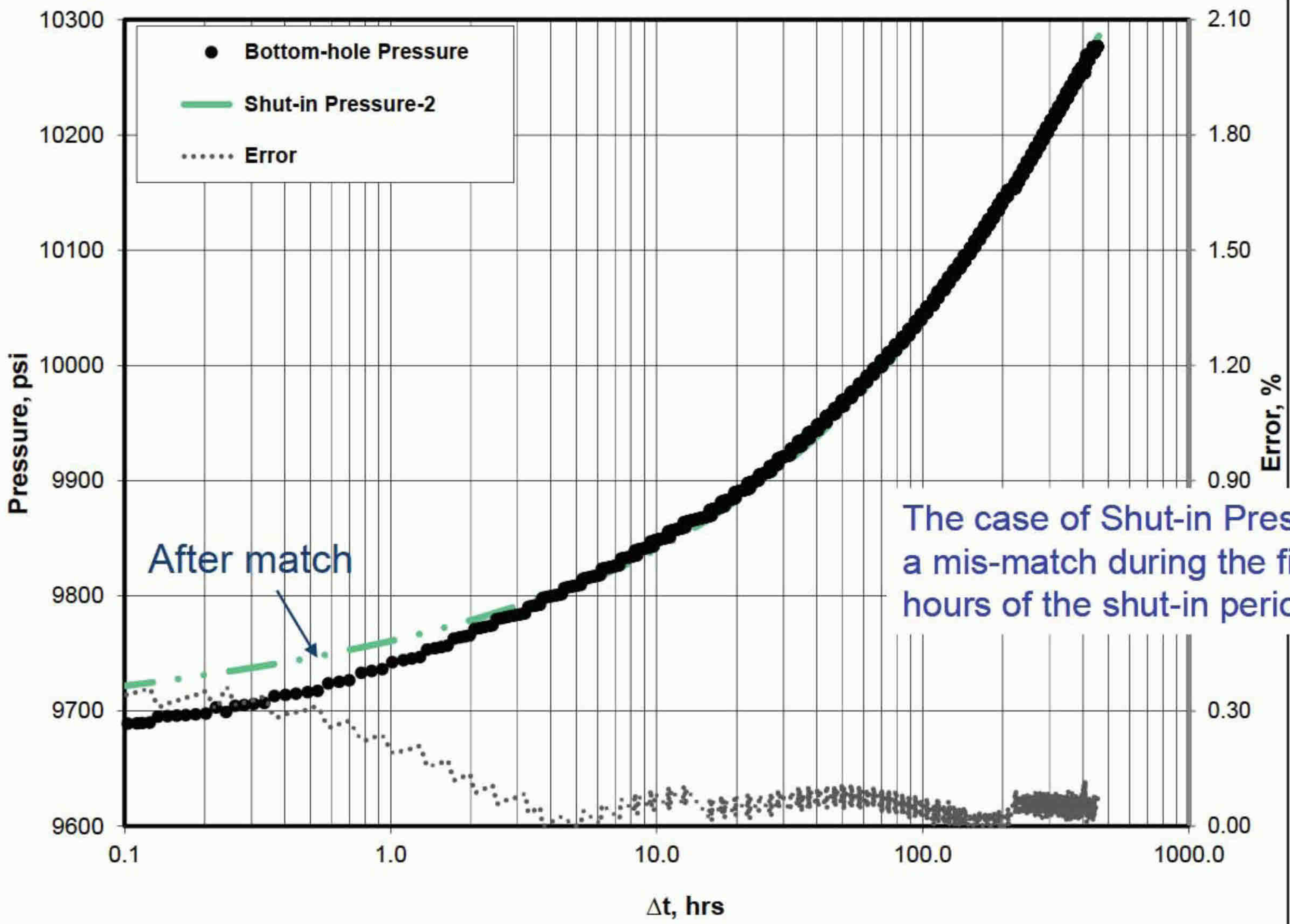
PI (Shut-in Pressure), stb/psi/day: 12.5

Shut-in Pressure-2: Bottom-hole Pressure



The bottom-hole pressures are generated by Blunt and are taken from PT3K2+Converted+to+reservoir+conditions+for+Gringarten.xls

Shut-in Pressure-2: MDH Type Curve

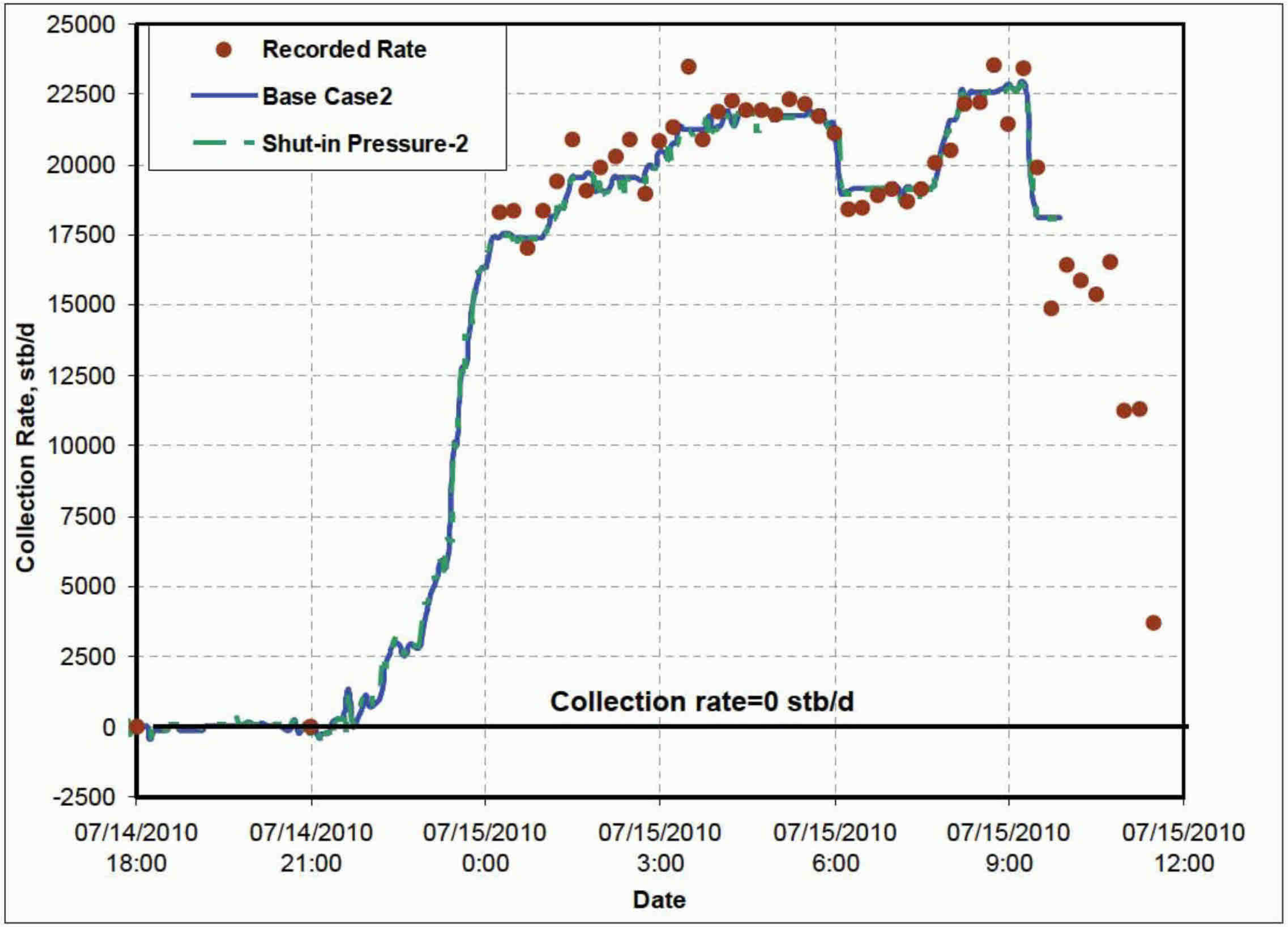


The case of Shut-in Pressure has a mis-match during the first few hours of the shut-in period.

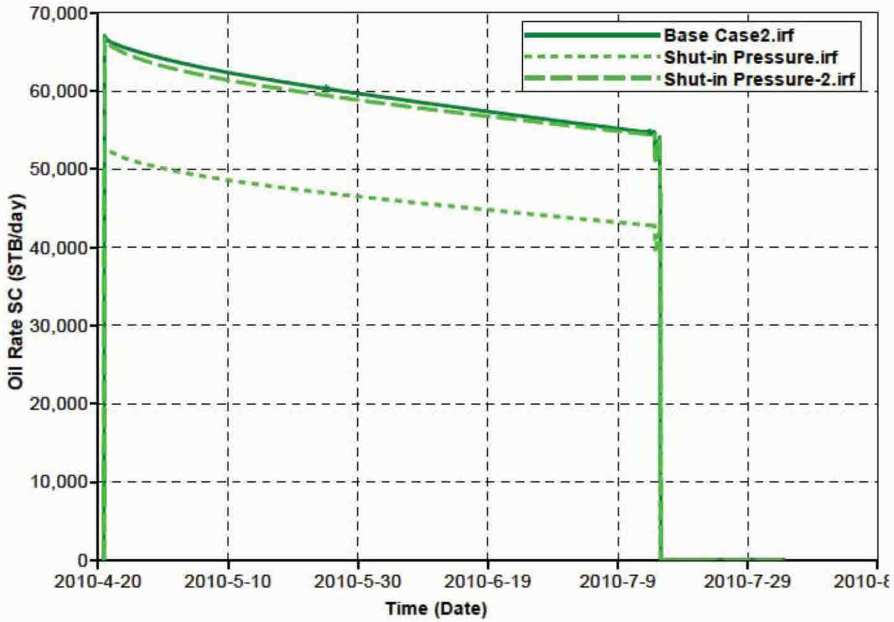
Match of the early-time data is affected by the flow rates during the 2 hours of choke-closure. The VLP tables are expected to exhibit some error in that estimation.

Shut-in Pressure-2: Collection Rate

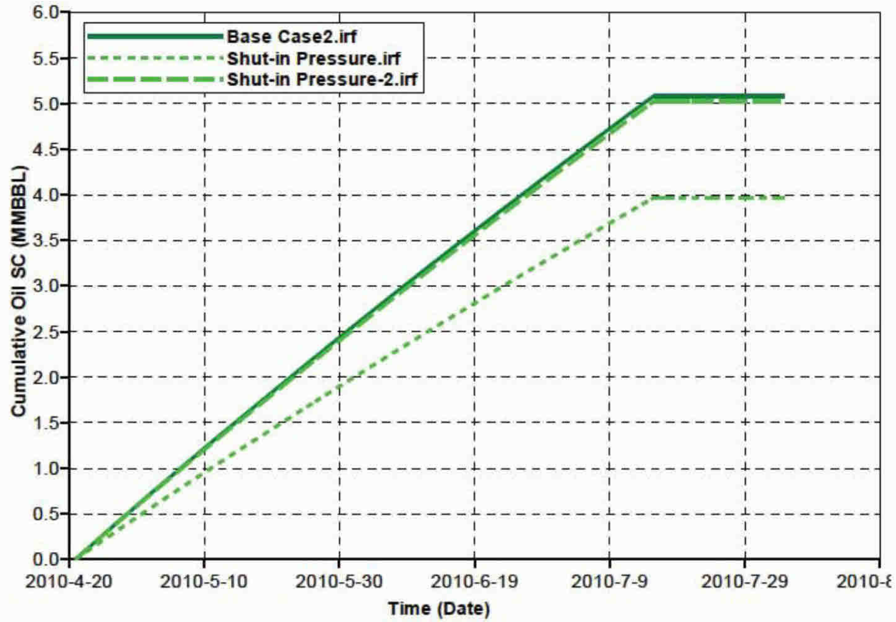
Match: Generally less than ±600 STB/day



Shut-in Pressure-2: Oil Released



The cumulative oil released for the Shut-in Pressure-2 case is equal to 5.02 MMSTB.



PI (Base Case2), stb/psi/day:	28.0
PI (Shut-in Pressure-2), stb/psi/day:	24.8

Fekete

Combined Model:

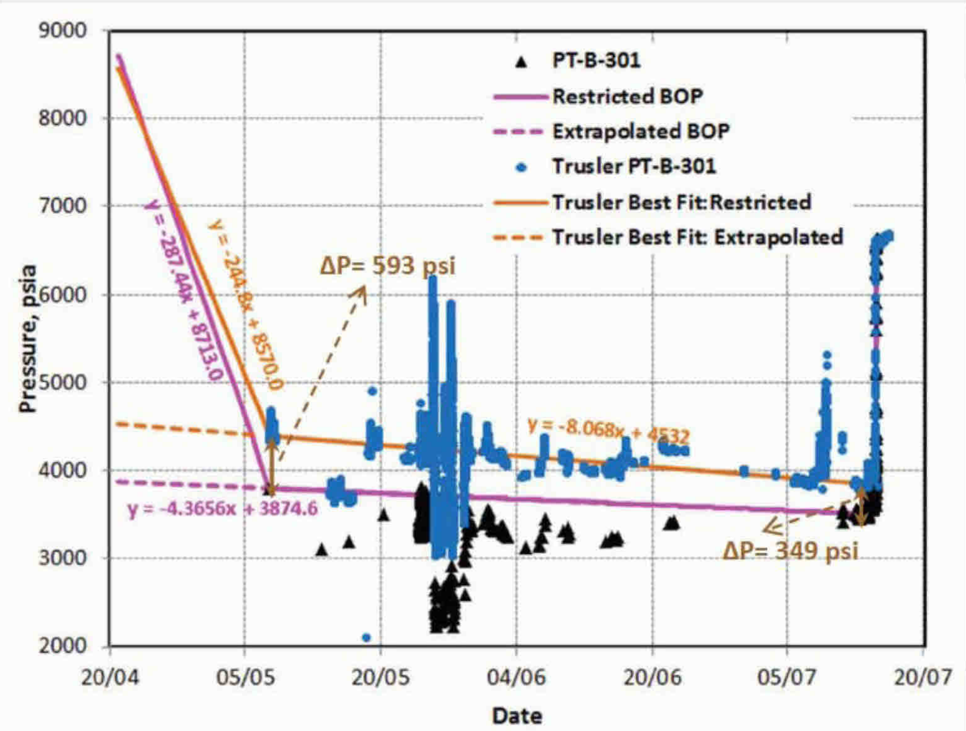
A numerical model is built using combination of parameters that defendants' experts believe to be representative of reservoir and fluid parameters.

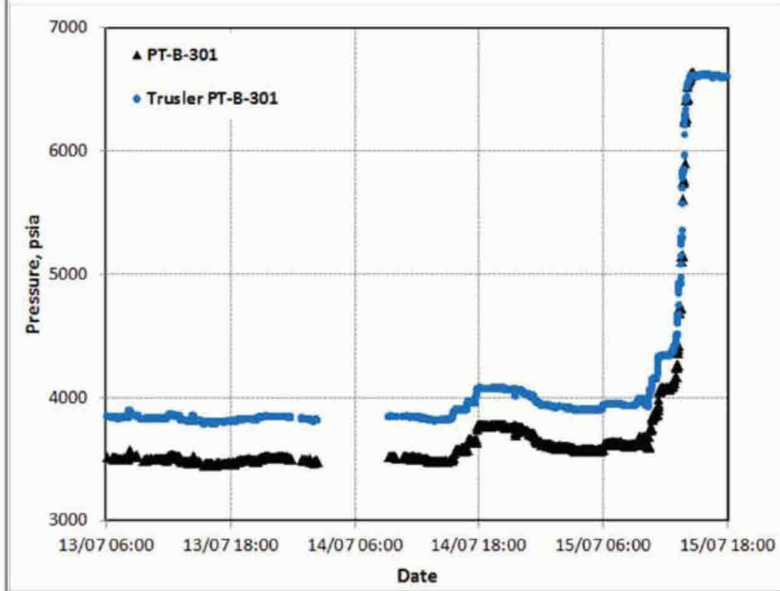
Combined	Parameter/Value
Flowing Pressure	Trusler BOP Pressures with extrapolation to April 20
Wellbore model	Johnson model: High Drillpipe
Shut-in pressure	Blunt temperature dependent corrected BHP
PVT	Single Stage Flash: Core Lab
Reservoir Permeability	Gringarten (as a starting point)
OOIP	Gringarten (as a starting point)

Since the flowing pressures are extrapolated to April 20, 2010, this case is named as *Combined-Extrapolated*.

BOP Pressure:

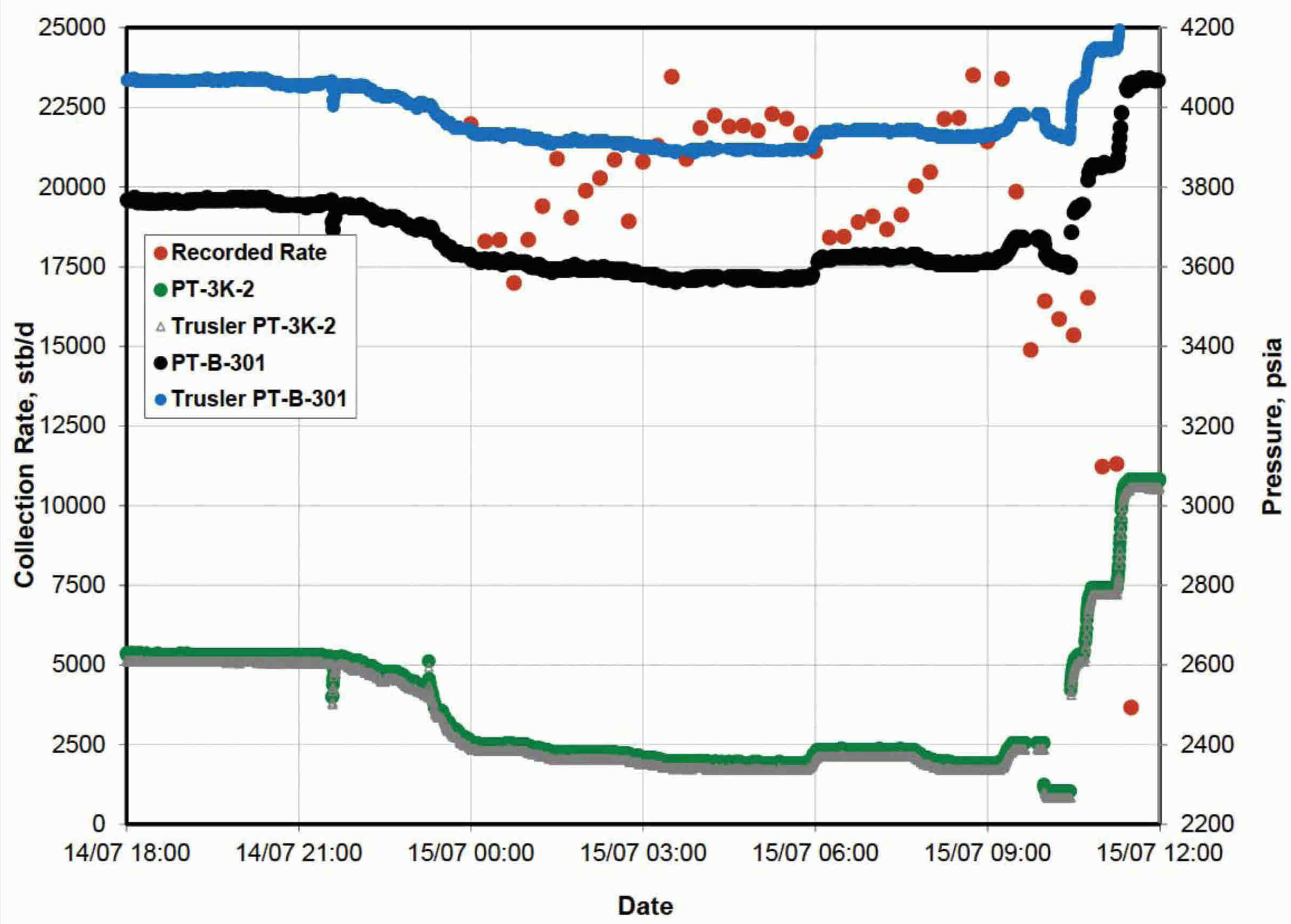
The constraint of the combined model during the flowing period is BOP pressure which is obtained from the Trusler best curve fit (with the equation of $P_{BOP}=4532-8.068t$) during the period of May 8-July 13.





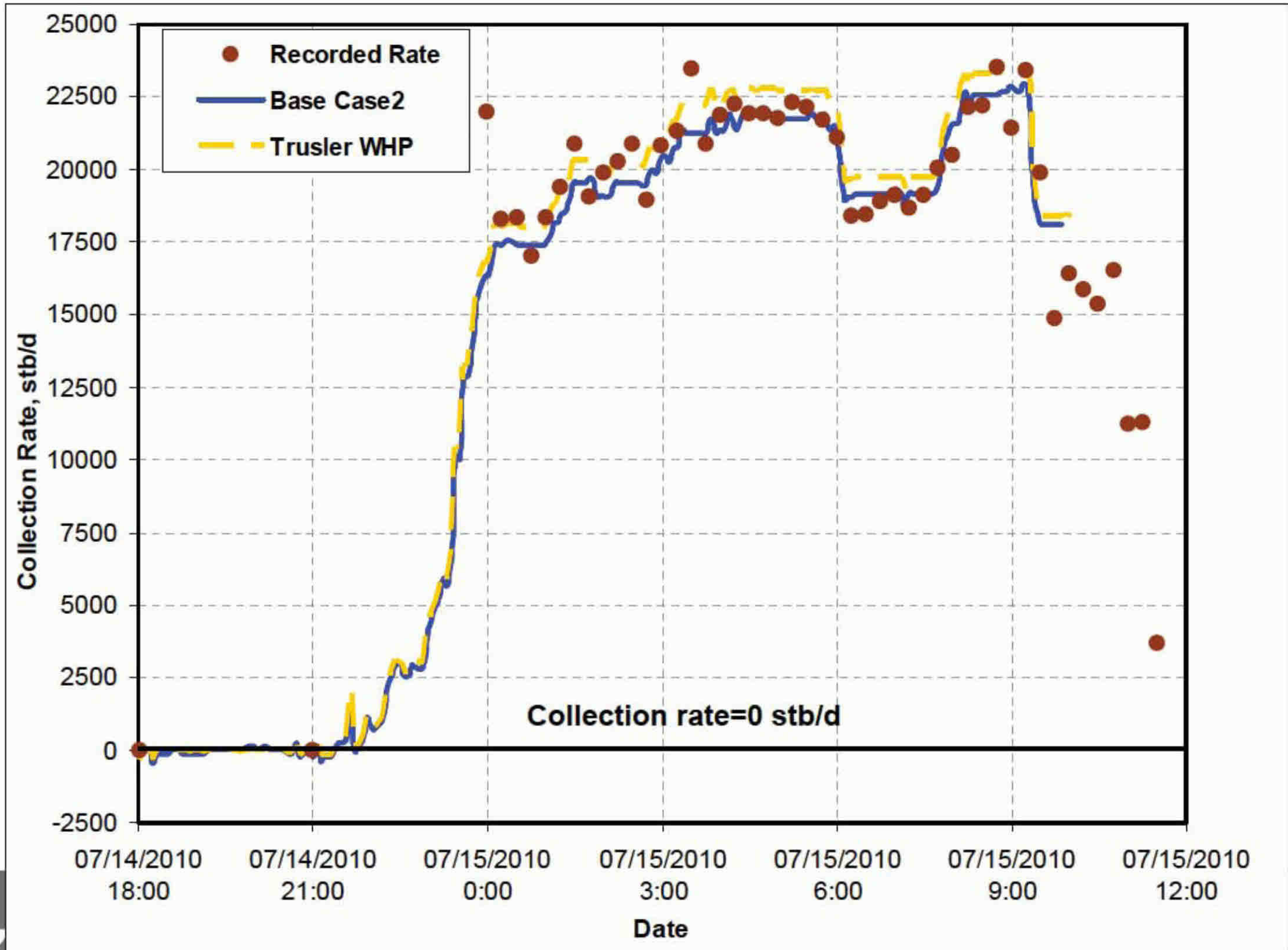
TREX-011654R.0127

CS and BOP pressures during the collection period – Comparison between Trusler's values and my initial report



Trusler BOP&CS Pressure: Collection Rate

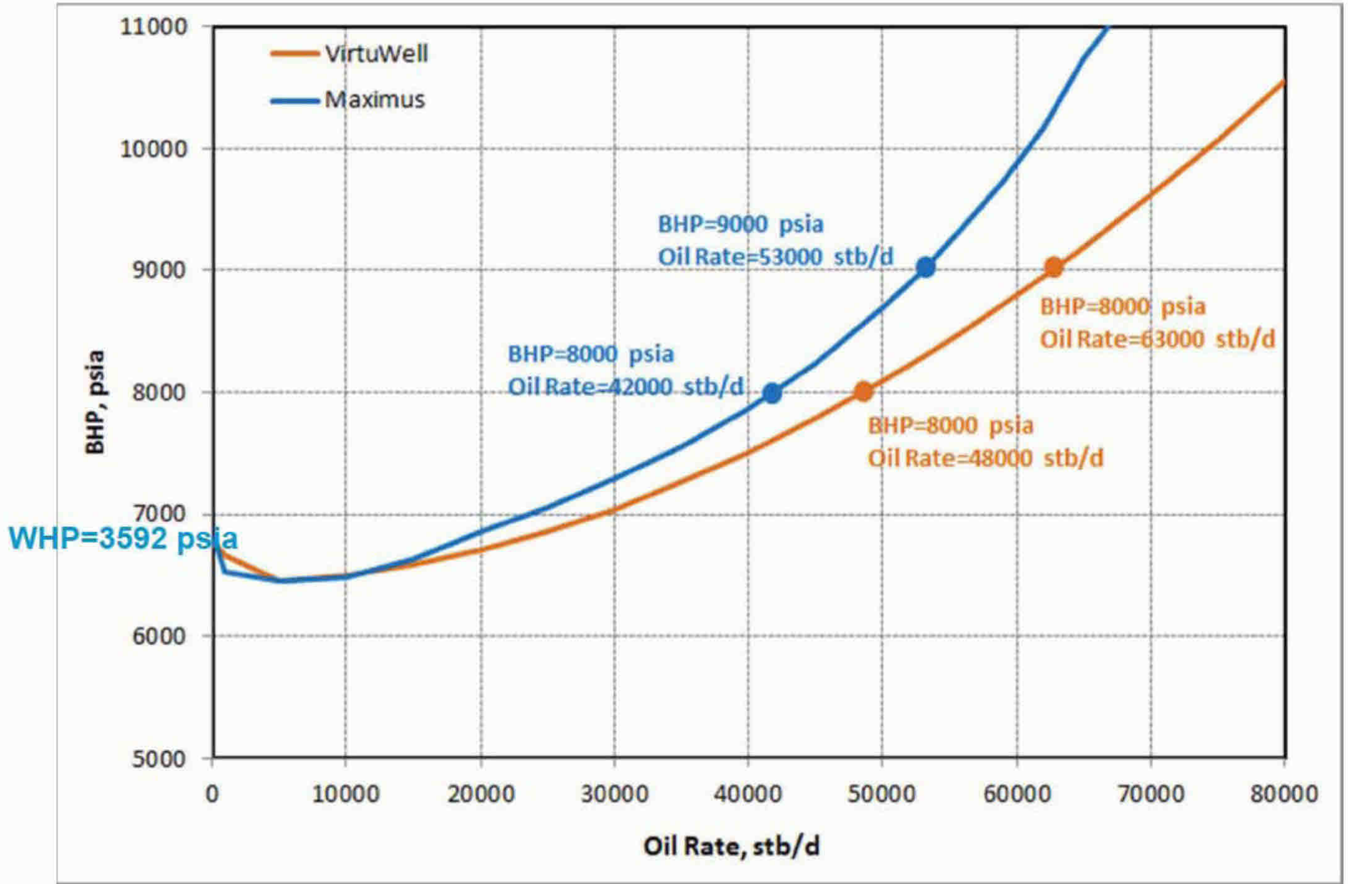
The effect of Trusler's BOP and CS pressures on collection/no-collection profile is presented in plot below. The flow rates are the base case 2 output.



TREX-011654R.0129

Wellbore Model: Maximus vs Virtuwell

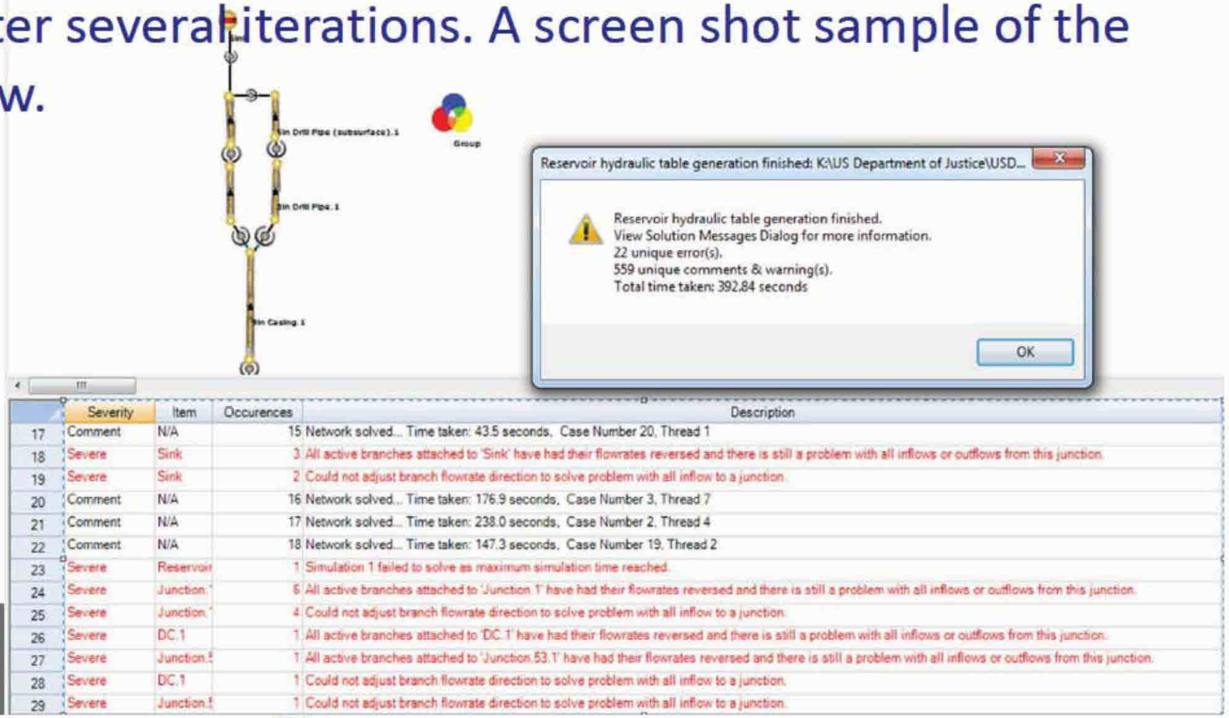
A VLP table was generated using Johnson wellbore model of OPTION2-High DrillPipe, and it was compared against the VirtuWell VLP table.



Wellbore Model: Maximus

Johnson's wellbore model which is built in Maximus exhibits several problems with respect to flow calculations in the entire well path for VLP generation purpose. Normally as the wellhead pressure and rate increase the forecasted bottom hole pressure in VLP tables (TPC curves) has to increase. However such a trend is not observed in the models provided by Johnson.

While running Johnson's model in Maximus, several warning (Maximus express them as SEVER WARNINGS) messages are observed which were describing that network failure occured after several iterations. A screen shot sample of the warnings is presented below.

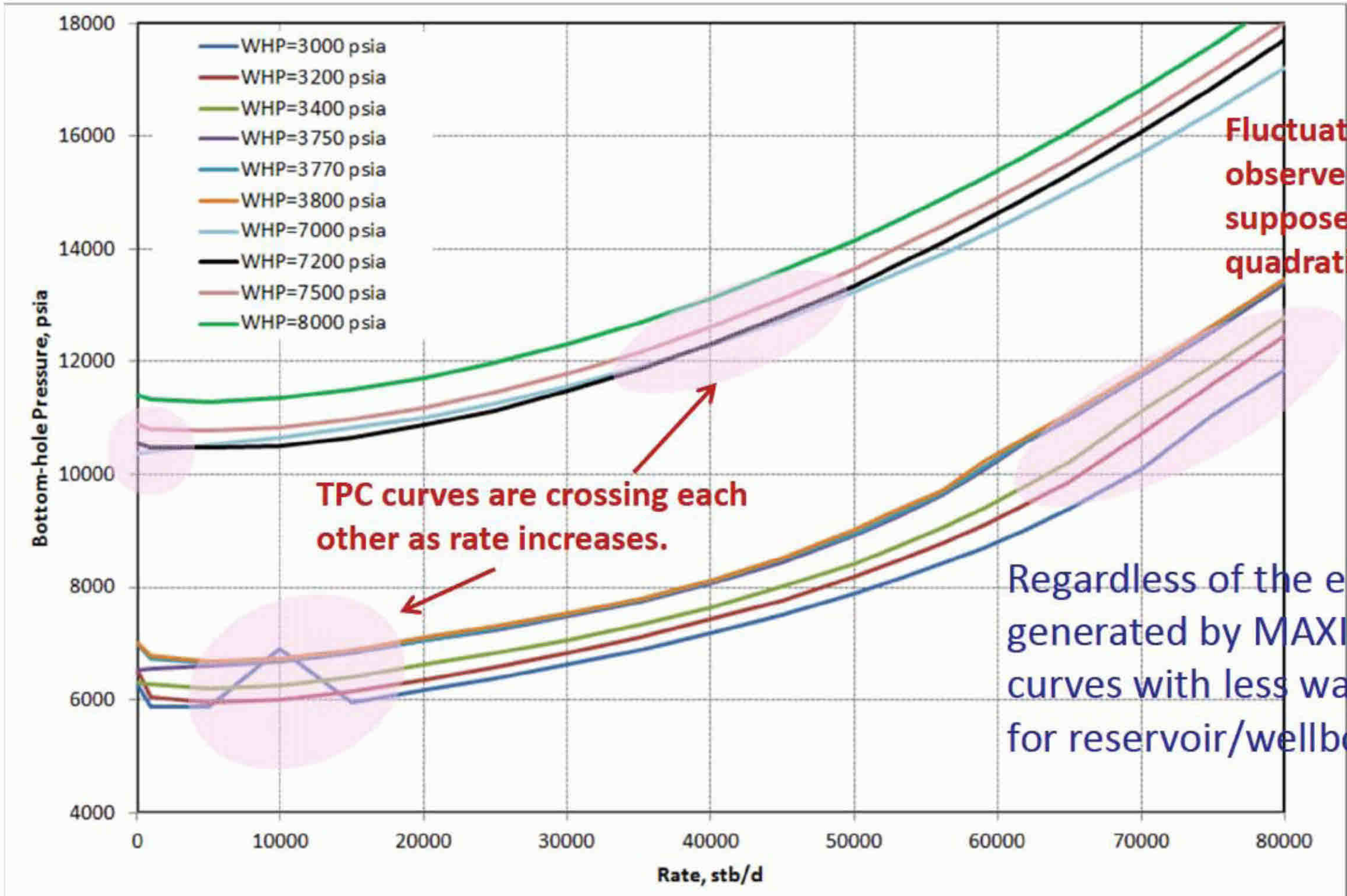


Fekete

TREX-011654R.0131

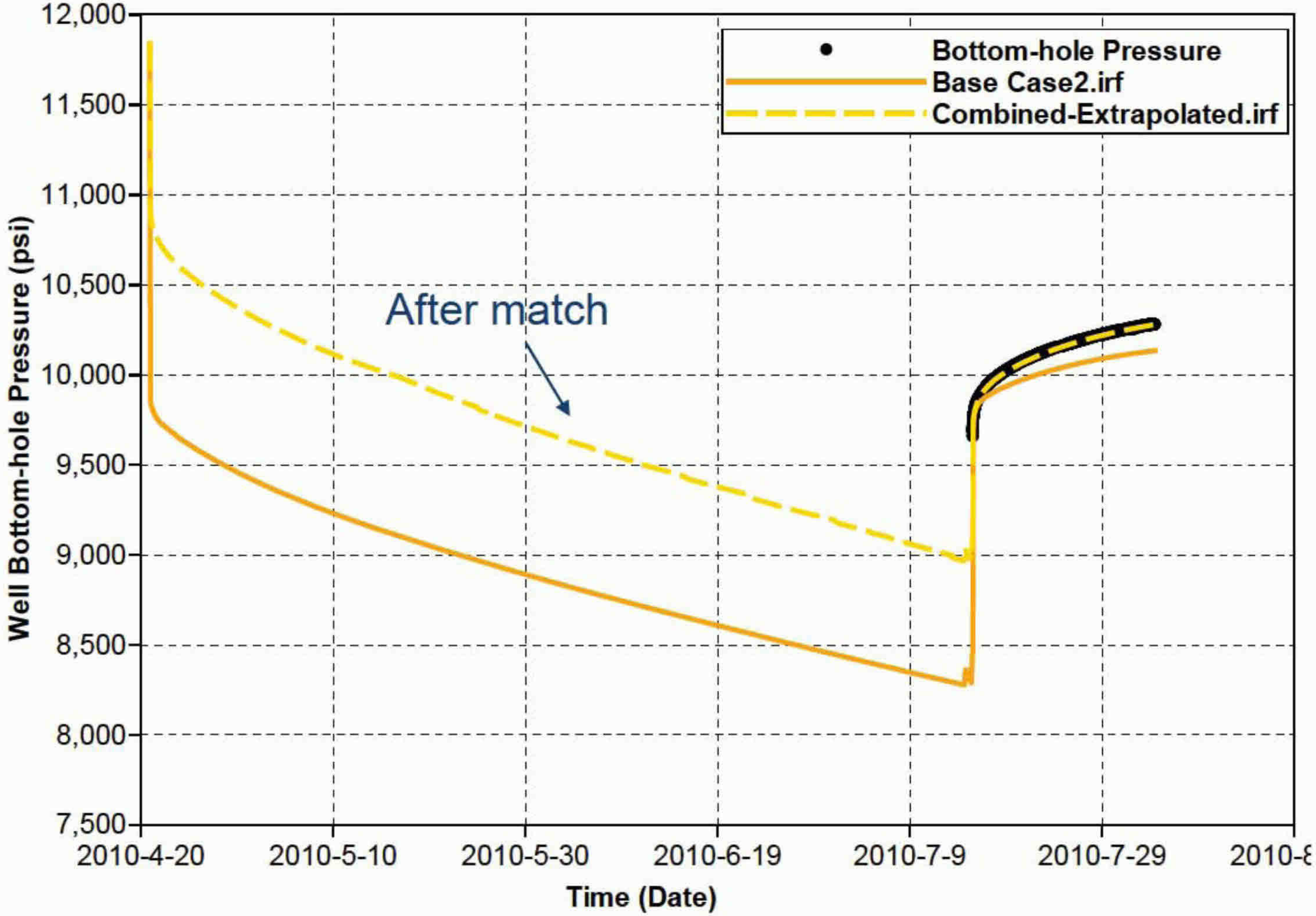
Wellbore Model: Maximus

A few TCP curves that are obtained directly from Maximus are presented below. It can be observed that the VLP tables are suffering from serious errors.



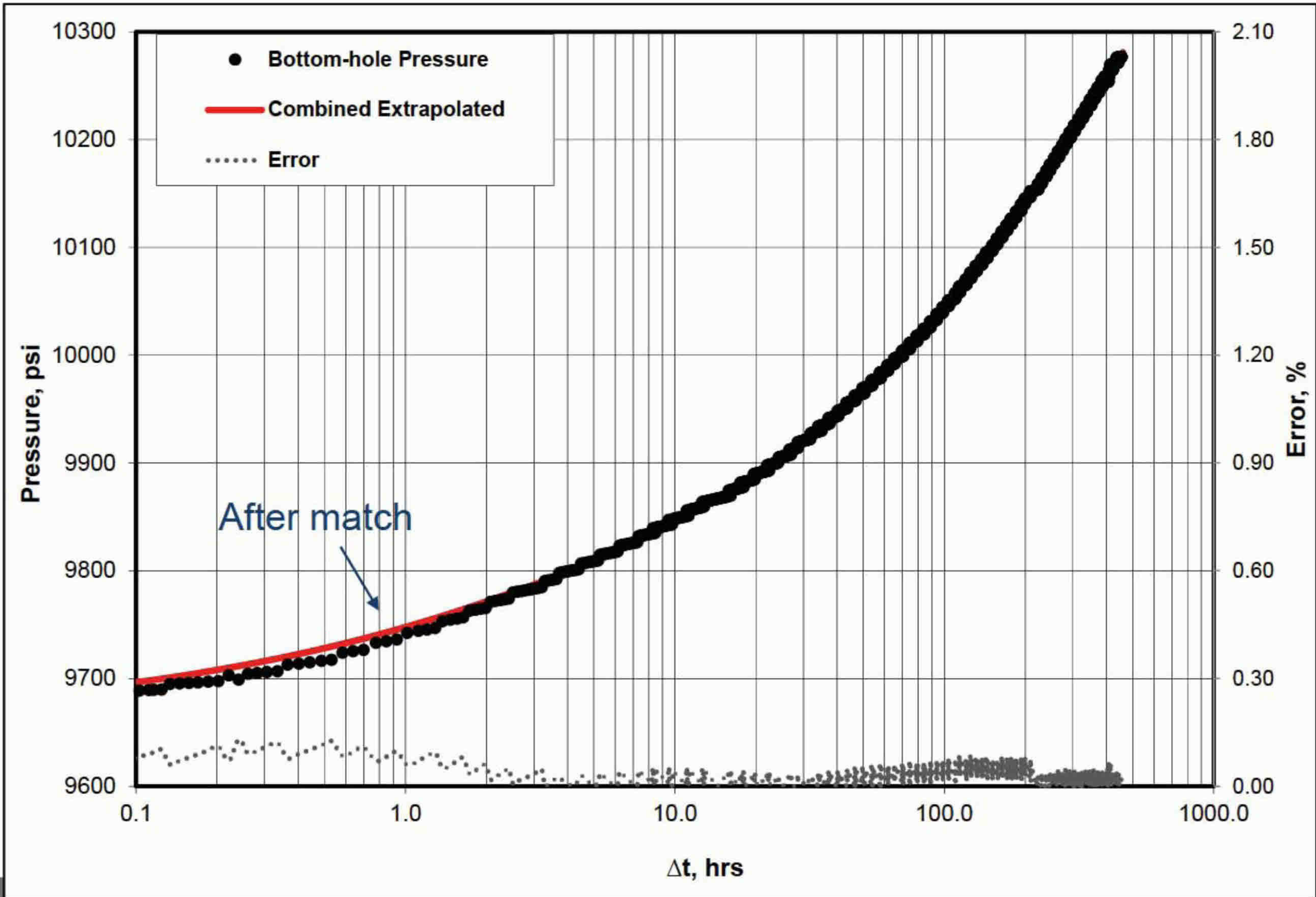
Regardless of the erroneous VLP files generated by MAXIMUS, a series of TPC curves with less warning were selected for reservoir/wellbore coupling.

Combined-Extrapolated : Bottom-hole Pressure



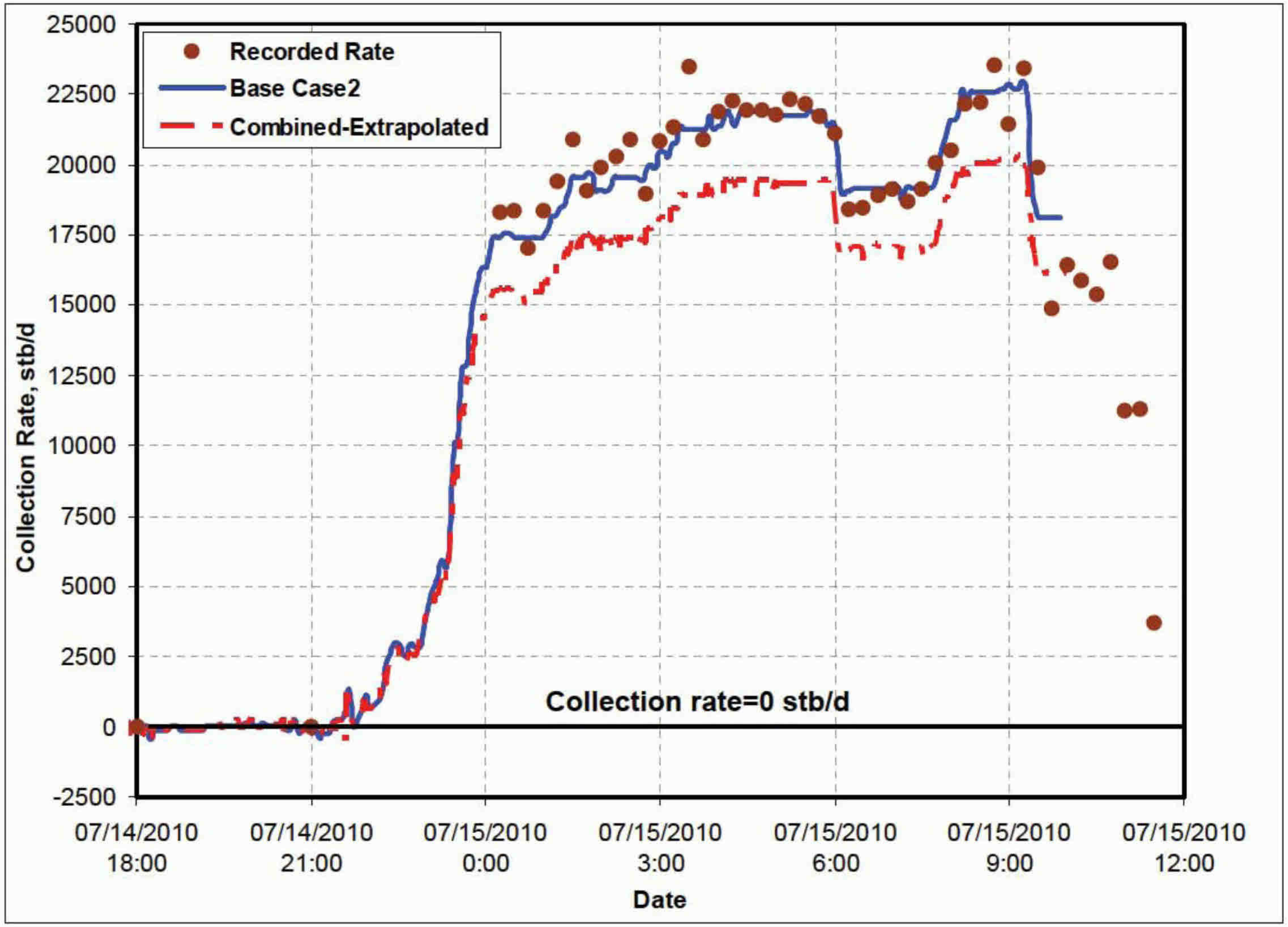
The bottom-hole pressures are generated by Blunt and are taken from
PT3K2+Converted+to+reservoir+conditions+for+Gringarten.xls

Combined-Extrapolated : MDH Type Curve

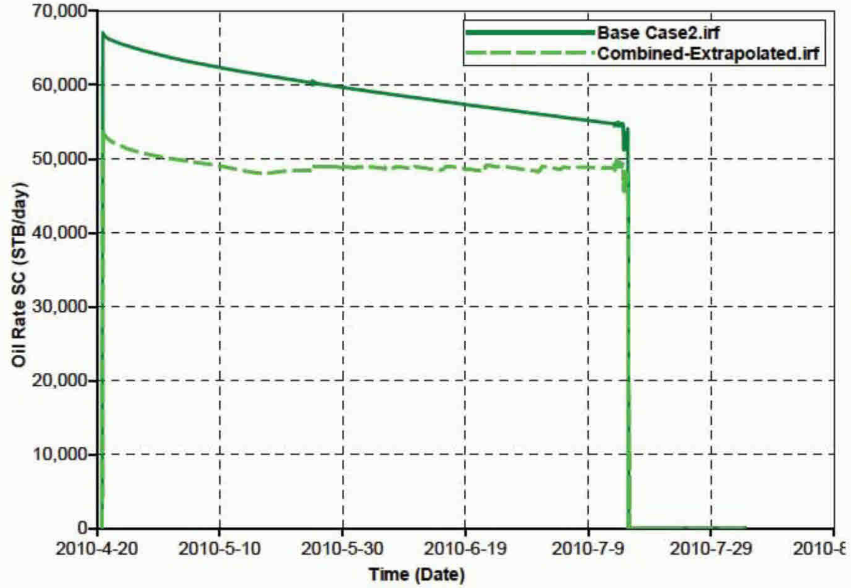


TREX-011654R.0134

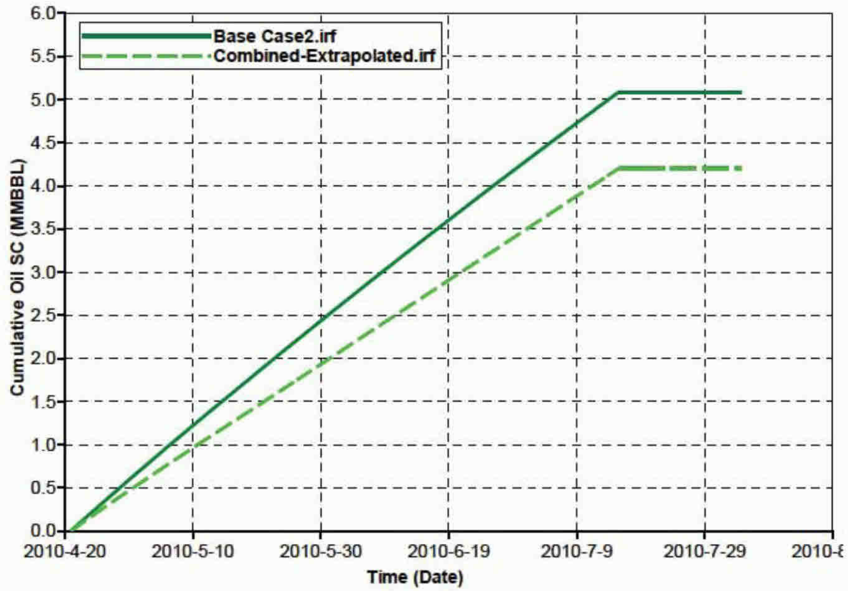
Mismatch: Generally larger than ±2500 STB/day



Combined-Extrapolated: Oil Released



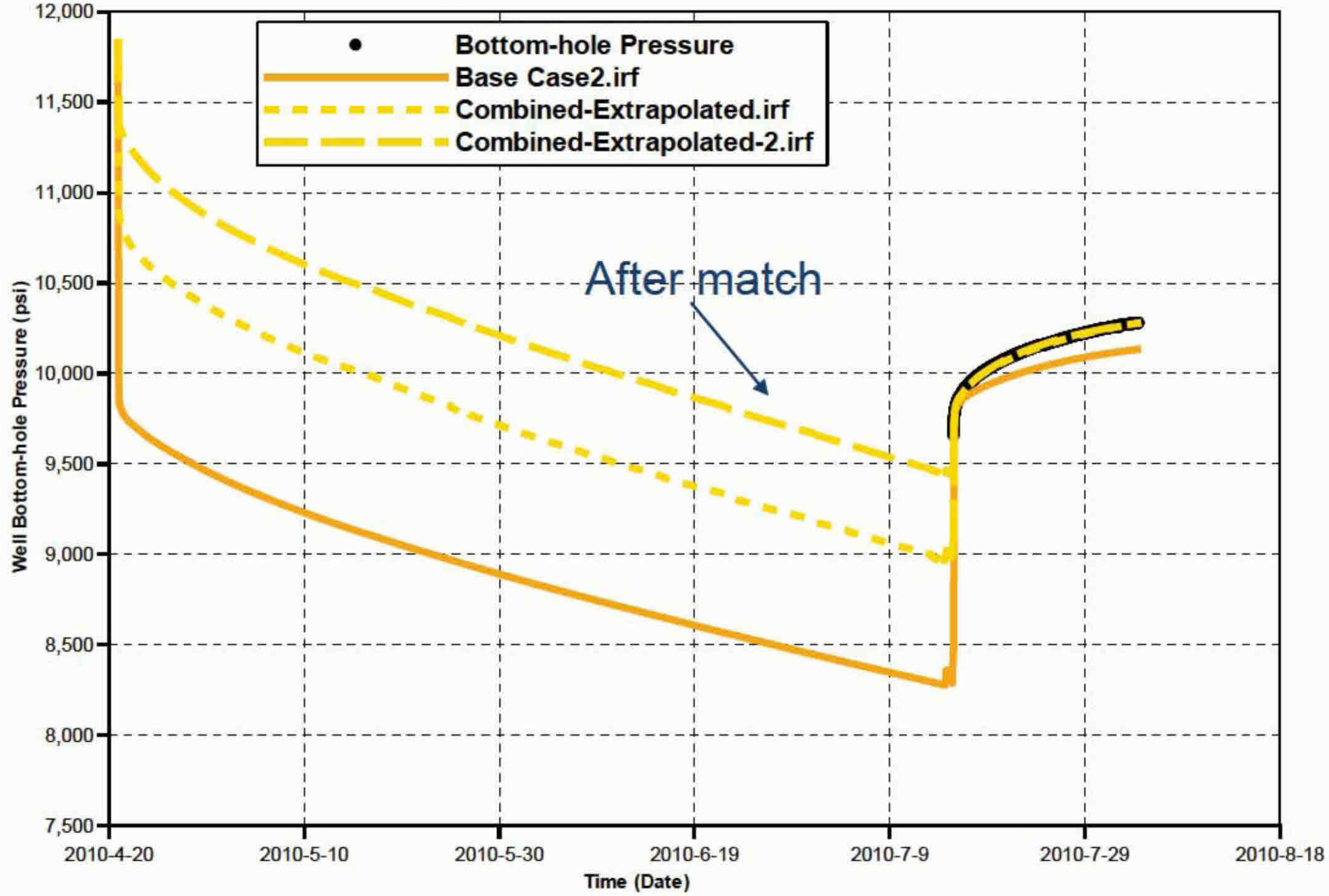
The cumulative oil released for the Combined-Extrapolated case is equal to 4.20 MMSTB.



PI (Base Case2), stb/psi/day: 28.0
PI (Combined-Extrapolated), stb/psi/day: 32.8

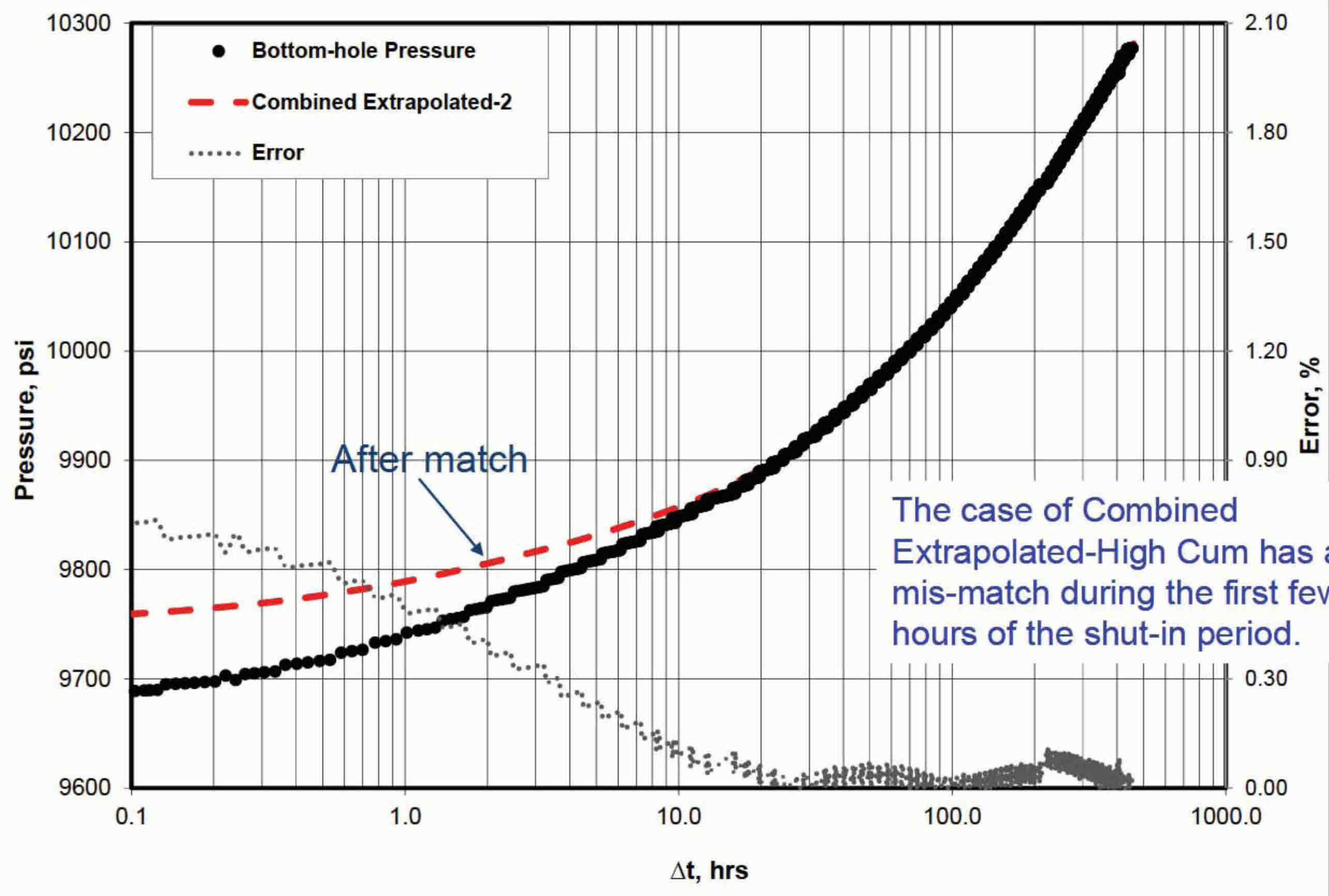
Combined-Extrapolated-2: Bottom-hole Pressure

In an attempt to look for a model with a better match of collections, a second match of the pressures are attempted using larger OOIP, permeability, etc.



The bottom-hole pressures are generated by Blunt and are taken from PT3K2+Converted+to+reservoir+conditions+for+Gringarten.xls

Combined-Extrapolated-2: MDH Type Curve

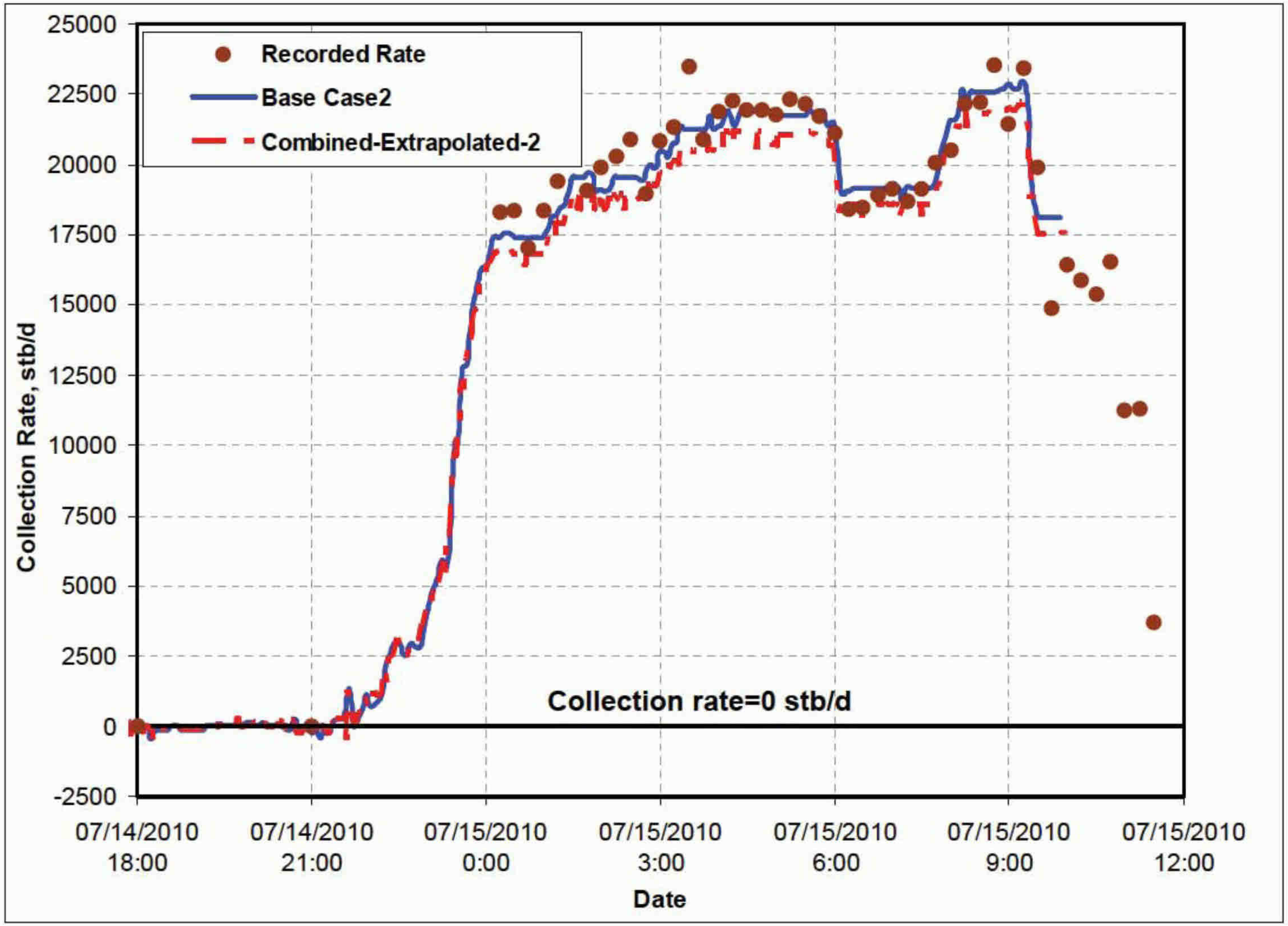


The case of Combined Extrapolated-High Cum has a mis-match during the first few hours of the shut-in period.

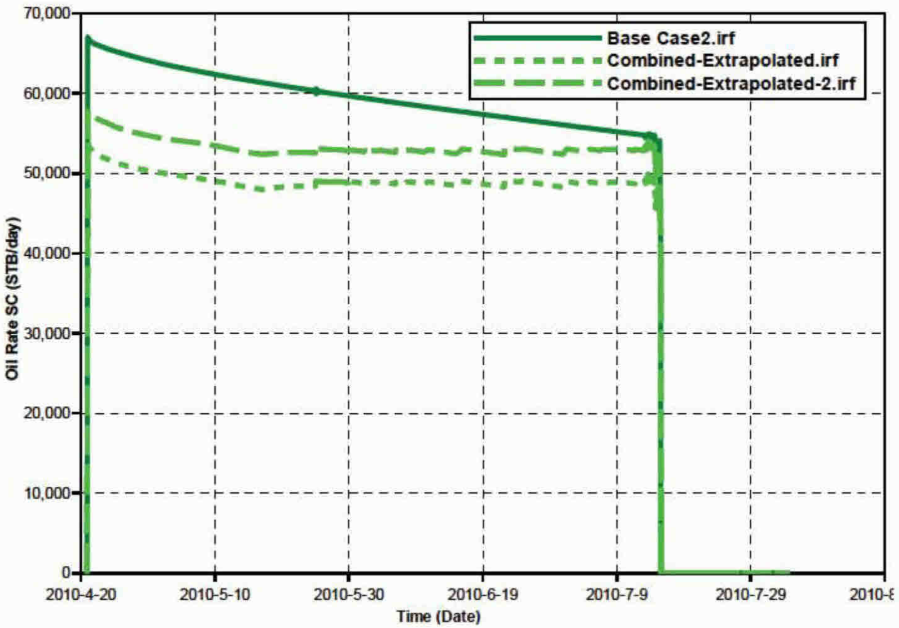
Match of the early-time data is affected by the flow rates during the 2 hours of choke-closure. The VLP tables are expected to exhibit some error in that estimation.

Combined-Extrapolated-2: Collection Rate

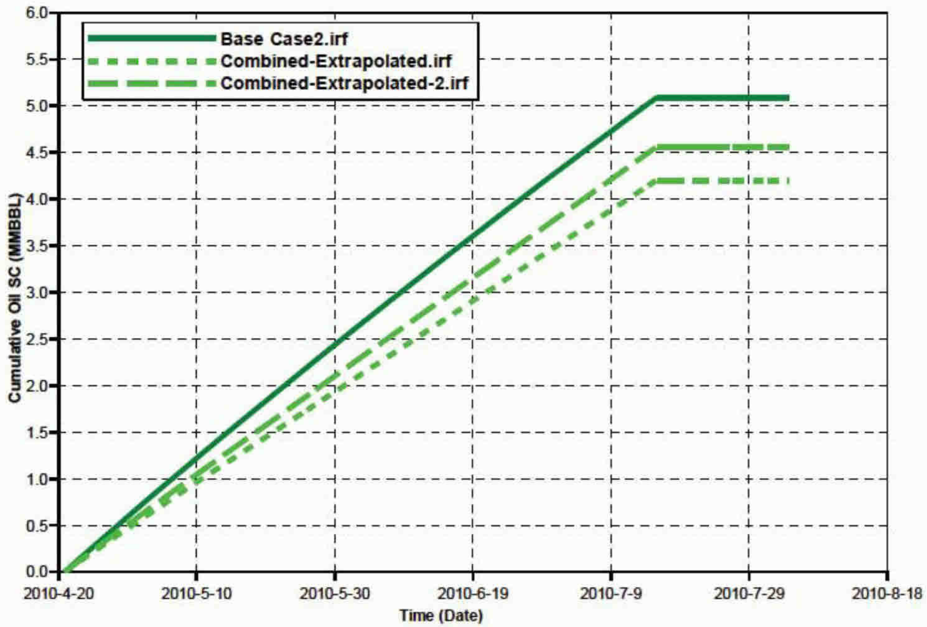
Match: Generally between ±600 and ±2500 STB/day



Combined-Extrapolated-2: Oil Released



The cumulative oil released for the Combined-Extrapolated-2 case is equal to 4.56 MMSTB.



PI (Base Case2), stb/psi/day: 28.0
PI (Combined-Extrapolated-2), stb/psi/day: 32.8

Fekete

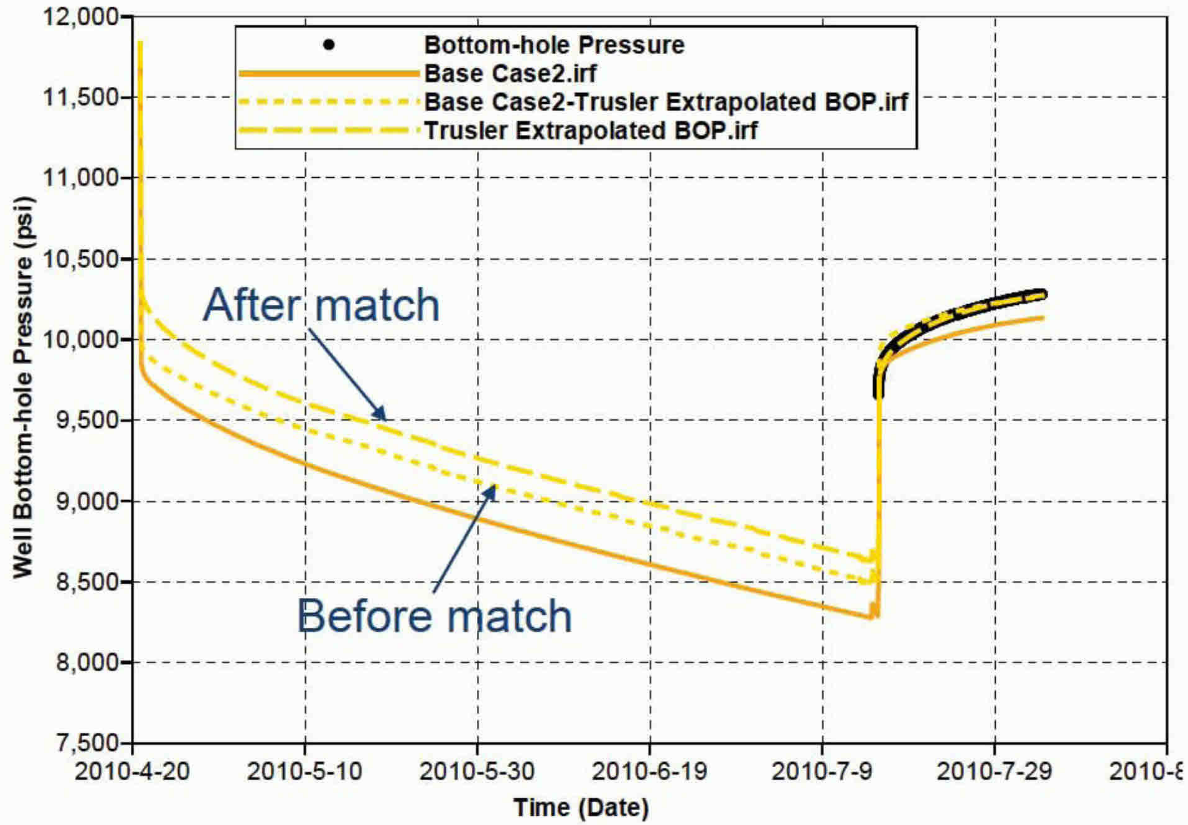
What If Studies

Summary of Results [What If Studies]

	K, mD	Skin	Length Xe, ft	Width Ye, ft	Xw, ft	Yw, ft	OOIP, MMSTB	Pav, psi	PI, stb/d/psi	q July 15, stb/d	Error, %	Cum Oil Released (after matching shut-in pressures), MMSTB
Trusler Restricted BOP	660	12.75	23350	3950	1900	550	134.2	10373	28.8	52000	0.03	4.43 (Good)
Trusler Extrapolated BOP	670	11.5	24100	4250	1650	750	149.1	10376	30.6	53000	0.03	4.90 (Good)
Base Case2	550	13	21850	4400	3700	1350	140.0	10219	28	53000	0.04	5.08 (Good)
Restricted BOP	550	11.5	21200	4200	3700	1350	130.0	10212	30	54000	0.04	4.73 (Good)
Extrapolated BOP	550	12	22050	4400	3700	1350	141.0	10225	28	53000	0.04	5.12 (Good)

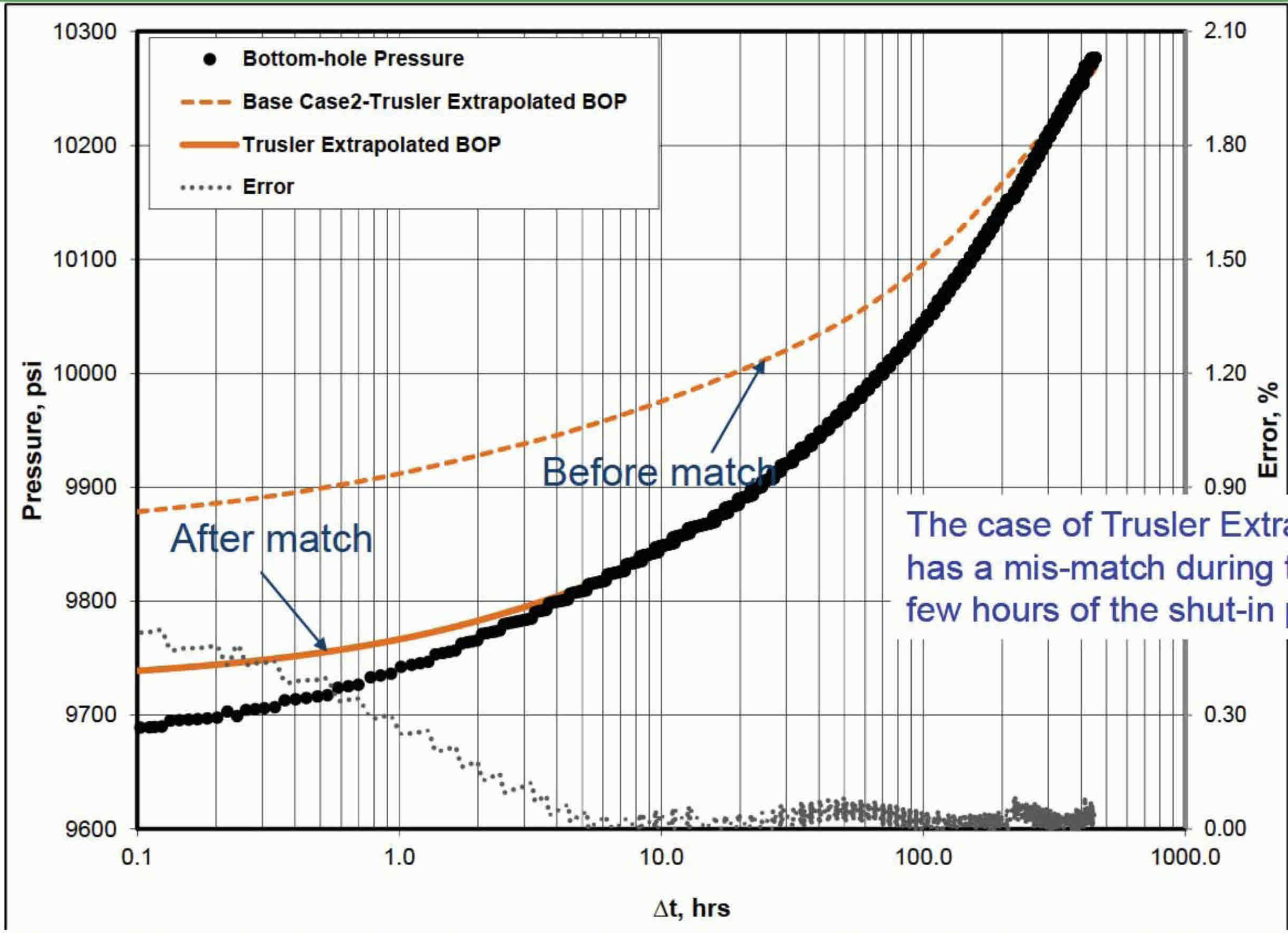
Trusler Extrapolated BOP: Bottom-hole Pressure

This scenario is using trusler BOP pressures (the best fit line) during the period of May 8 until July 13, Trusler's BOP pressures afterwards and by using the same slope it extrapolates the WHP up to April 20. The model is tuned to match against Blunt's shut-in pressures.



The bottom-hole pressures are generated by Blunt and are taken from PT3K2+Converted+to+reservoir+conditions+for+Gringarten.xls

Trusler Extrapolated BOP : MDH Type Curve

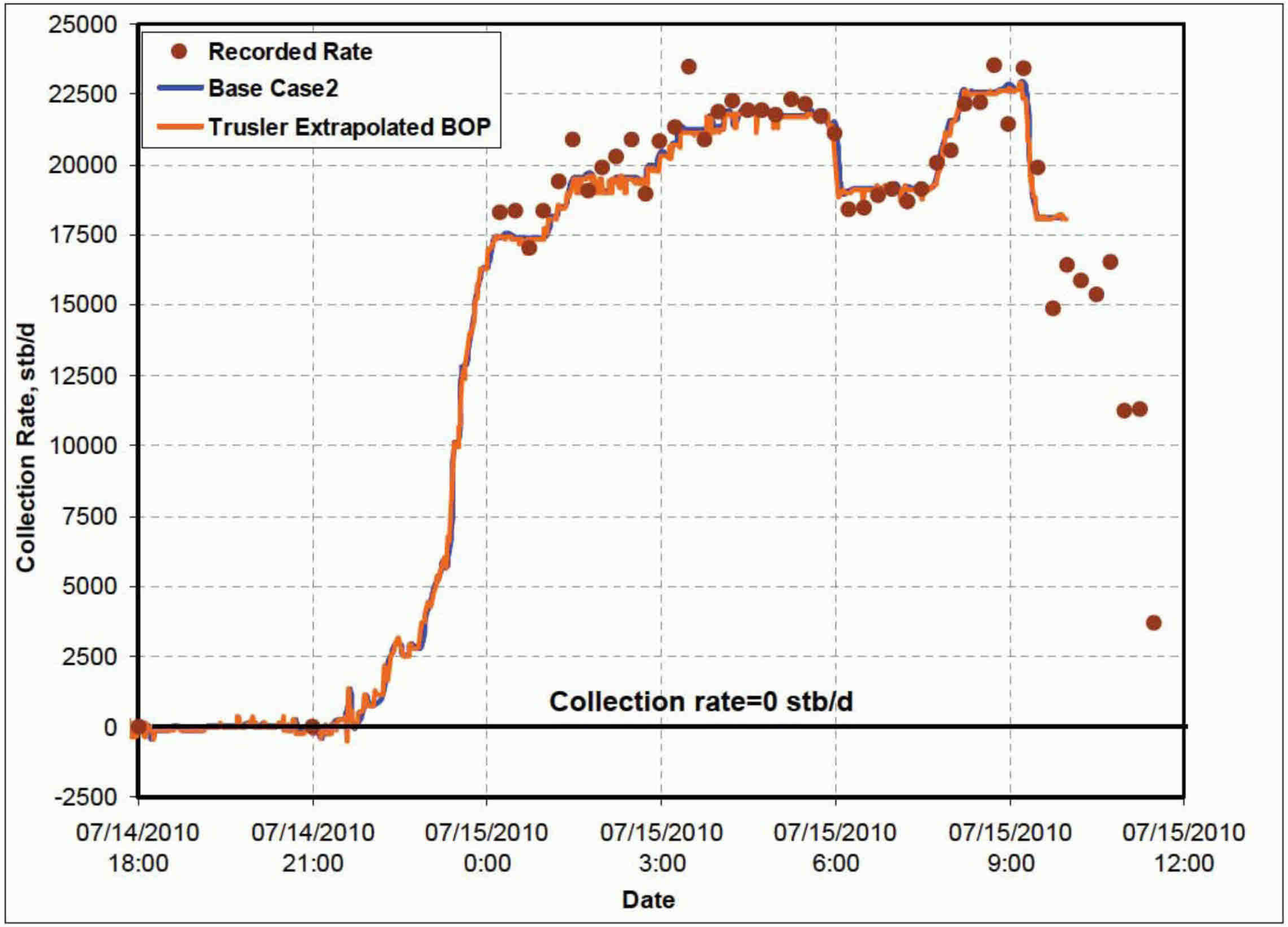


The case of Trusler Extrapolated has a mis-match during the first few hours of the shut-in period.

Match of the early-time data is affected by the flow rates during the 2 hours of choke-closure. The VLP tables are expected to exhibit some error in that estimation.

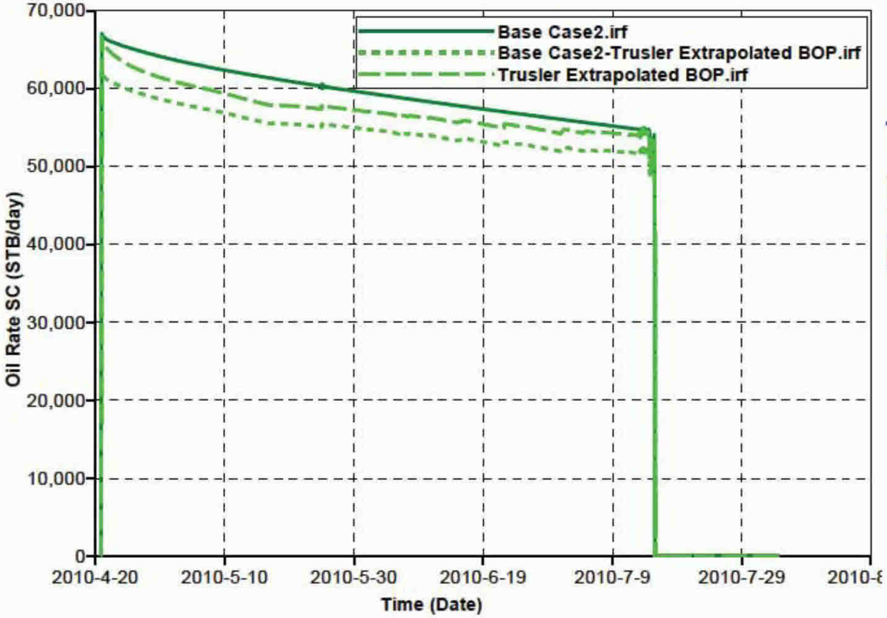
Trusler Extrapolated BOP: Collection Rate

Match: Generally between ±600 STB/day

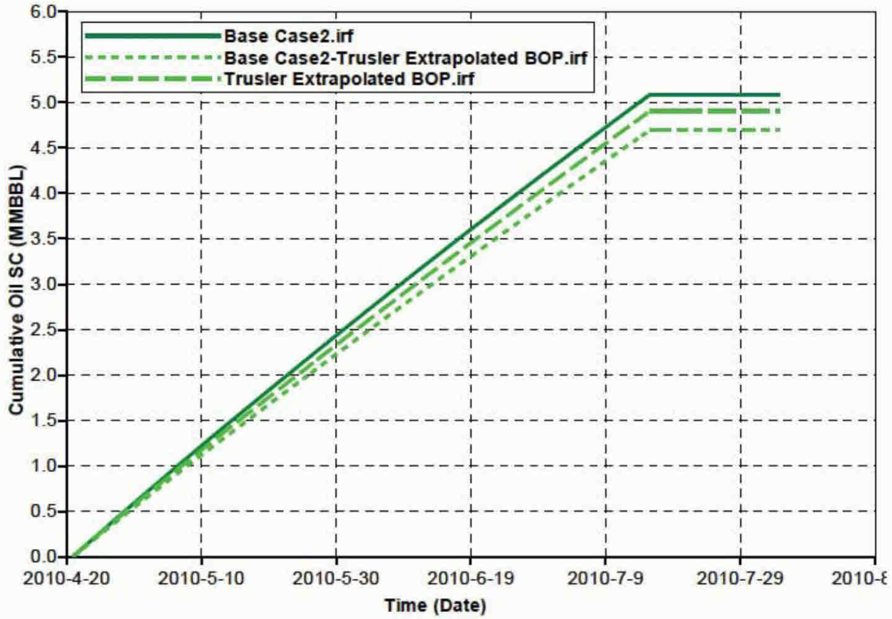


TREX-011654R.0145

Trusler Extrapolated BOP: Oil Released



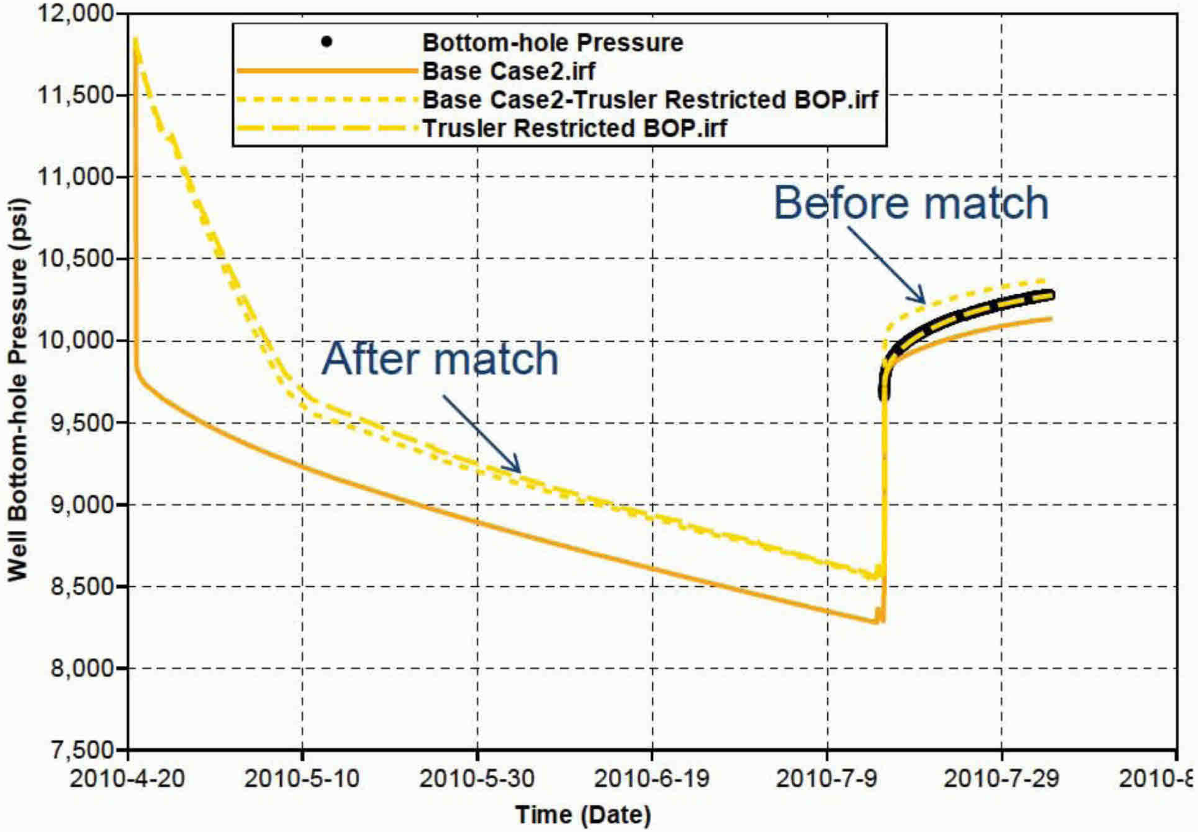
The cumulative oil released for the Trusler Extrapolated BOP case is equal to 4.90 MMSTB.



PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-Trusler Extrapolated BOP), stb/psi/day:	27.6
PI (Trusler Extrapolated BOP), stb/psi/day:	30.6

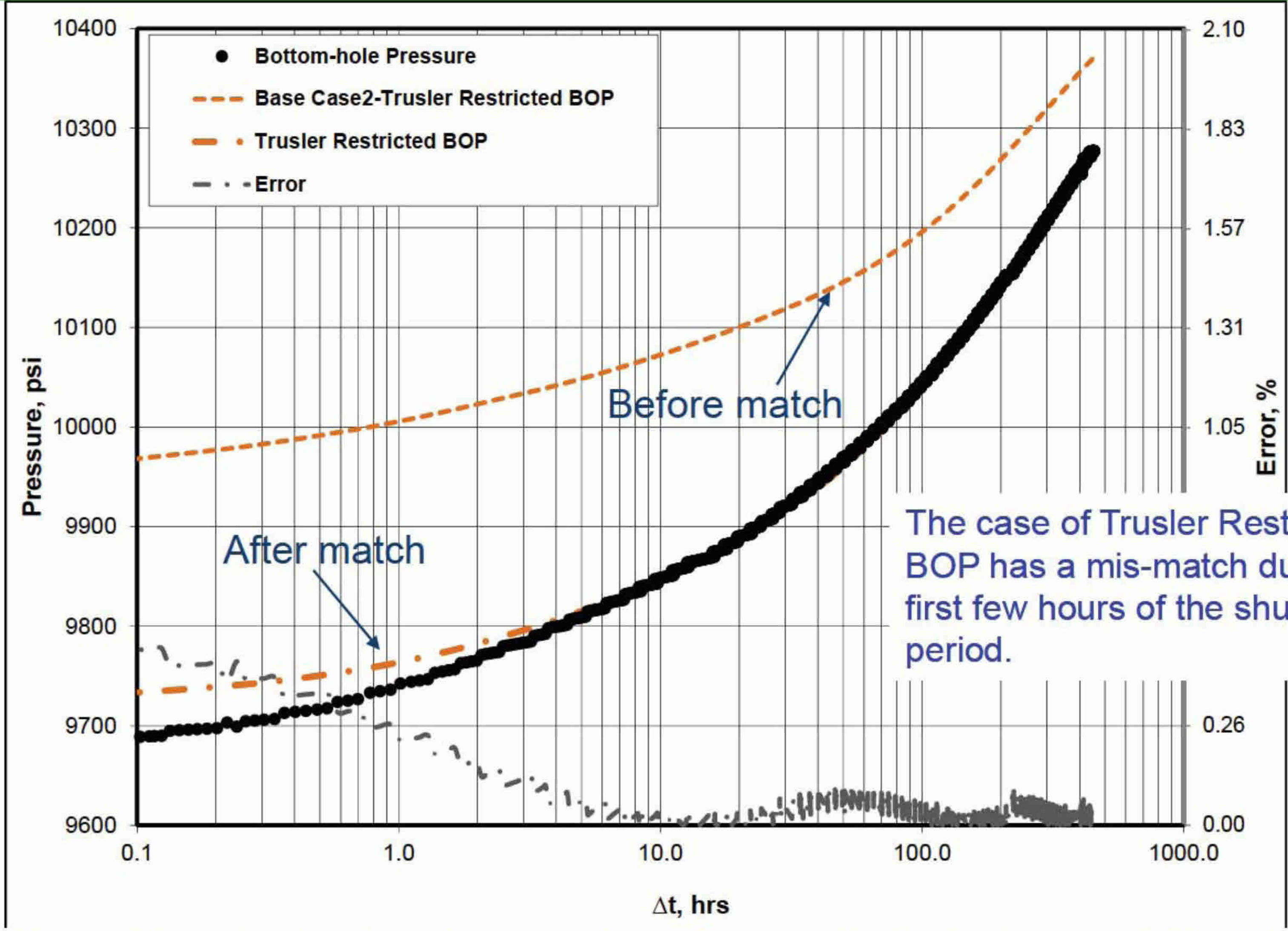
Trusler Restricted BOP: Bottom-hole Pressure

This scenario uses the same pressures as Trusler Extrapolated except that prior to May 8, the pressures are extrapolated to an initial WHP of 8570 (using initial hydrostatic pressure of 3280 psia) on April 20. The model is tuned to match against Blunt's shut-in pressures.



The bottom-hole pressures are generated by Blunt and are taken from PT3K2+Converted+to+reservoir+conditions+for+Gringarten.xls

Trusler Restricted BOP : MDH Type Curve

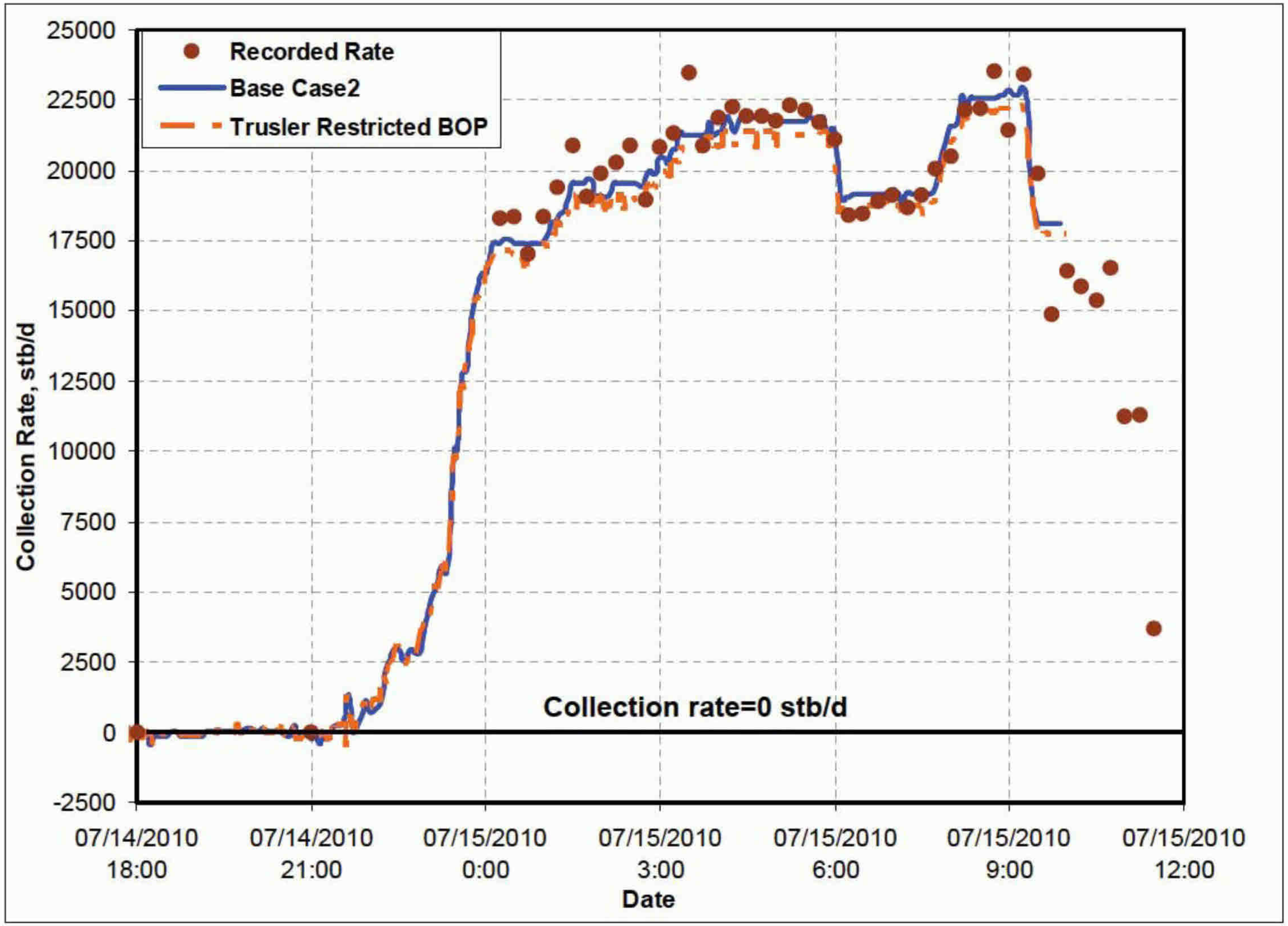


The case of Trusler Restricted BOP has a mis-match during the first few hours of the shut-in period.

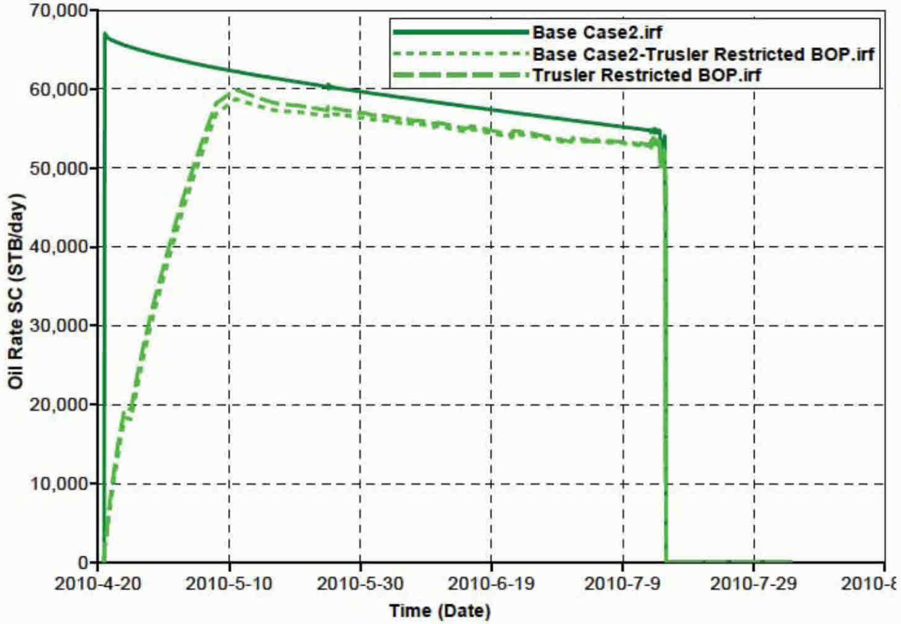
Match of the early-time data is affected by the flow rates during the 2 hours of choke-closure. The VLP tables are expected to exhibit some error in that estimation.

Trusler Restricted BOP: Collection Rate

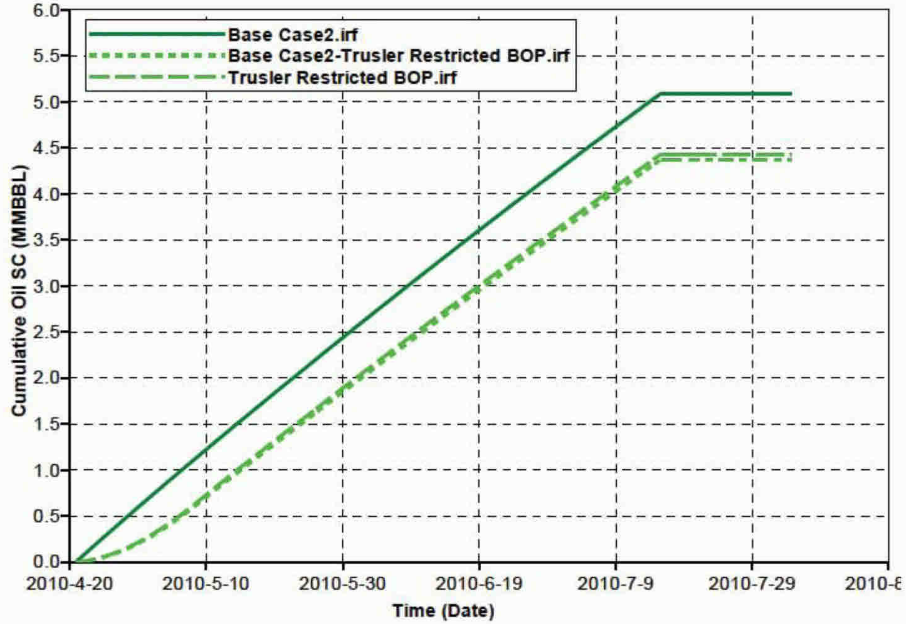
Match: Generally less than ±600 STB/day



Trusler Restricted BOP: Oil Released



The cumulative oil released for the Trusler Restricted BOP case is equal to 4.43 MMSTB.



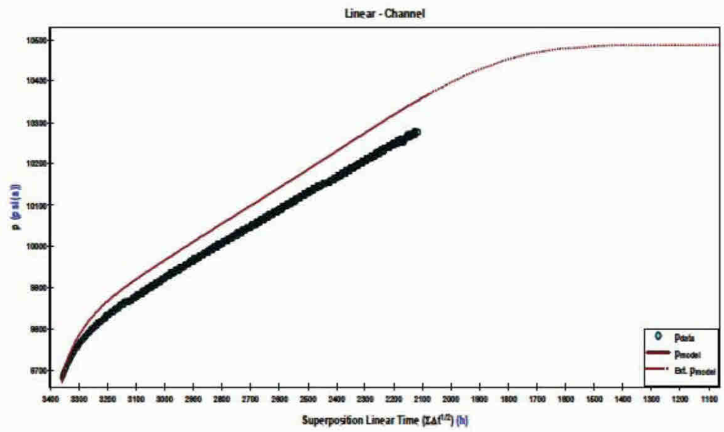
PI (Base Case2), stb/psi/day:	28.0
PI (Base Case2-Trusler Restricted BOP), stb/psi/day:	27.6
PI (Trusler Restricted BOP), stb/psi/day:	28.8

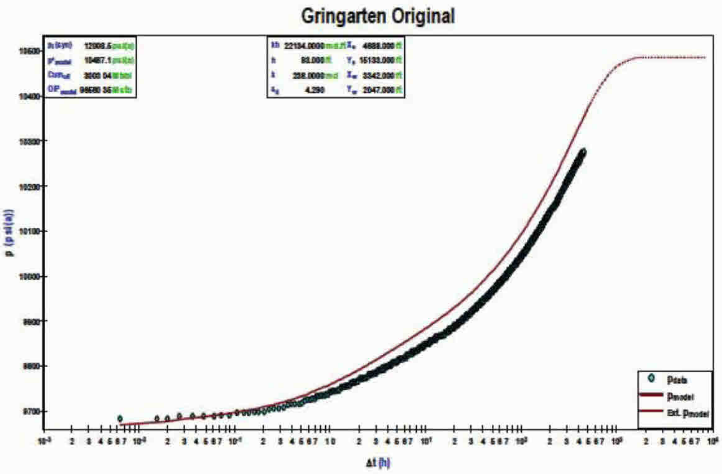
Appendix III: Analytical Modeling of Gringarten' s Pressures and Discussion of Deconvolution

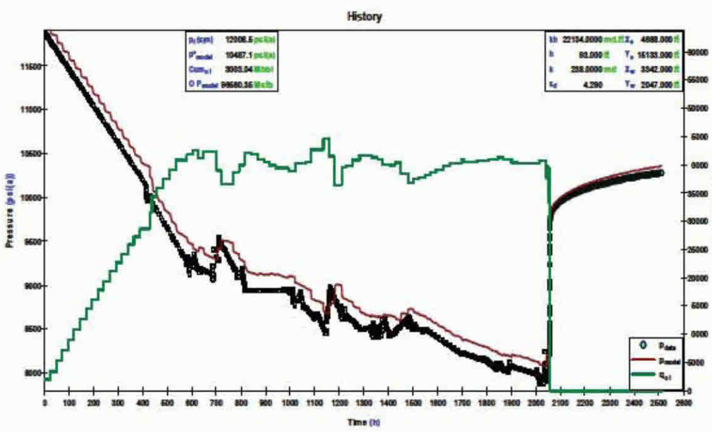
The Figure below shows my attempt to reproduce Gringarten's most likely case (Option 2 – High Drill Pipe). I was unsure about the exact value of some of the input parameters. My first choice of these parameters, did not allow a good match. With minor modifications, I obtained a good match, shown in the subsequent Figures.

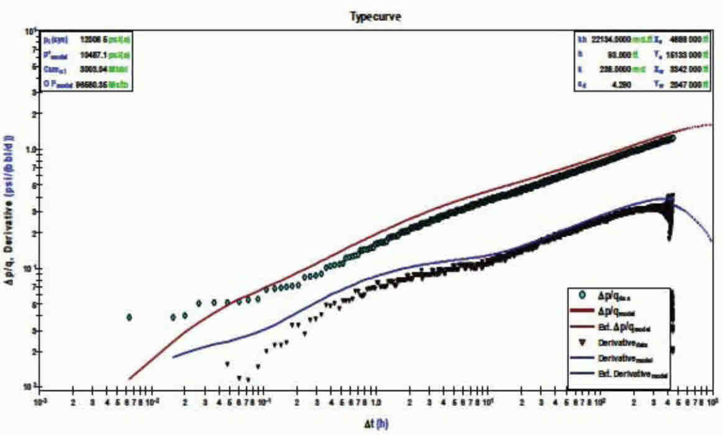
Original Gringarten		
p_i (syn)	12008.5	psi(a)
p^*_{model}	10487.1	psi(a)
Cum_{oil}	3003.04	Mbbl
OIP_{model}	96560.35	Mstb

Original Gringarten					
kh	22134.0000	md.ft	X_e	4688.000	ft
h	93.000	ft	Y_e	15133.000	ft
k	238.0000	md	X_w	3342.000	ft
s_d	4.290		Y_w	2047.000	ft









The following figures demonstrate that it is possible to obtain excellent matches of the Gringarten/Blunt flowing and shut-in pressures for the specified Gringarten rates as well as a variety of other rate sequences. The figures show that whether the cumulative production is 3.0, 4.5 or 7.0 million barrels, the reported pressures can be matched, by simply varying reservoir characteristics. Therefore, the fact that the reported pressures have been matched in the Gringarten or Blunt reports does NOT in any way validate their reported production rates.

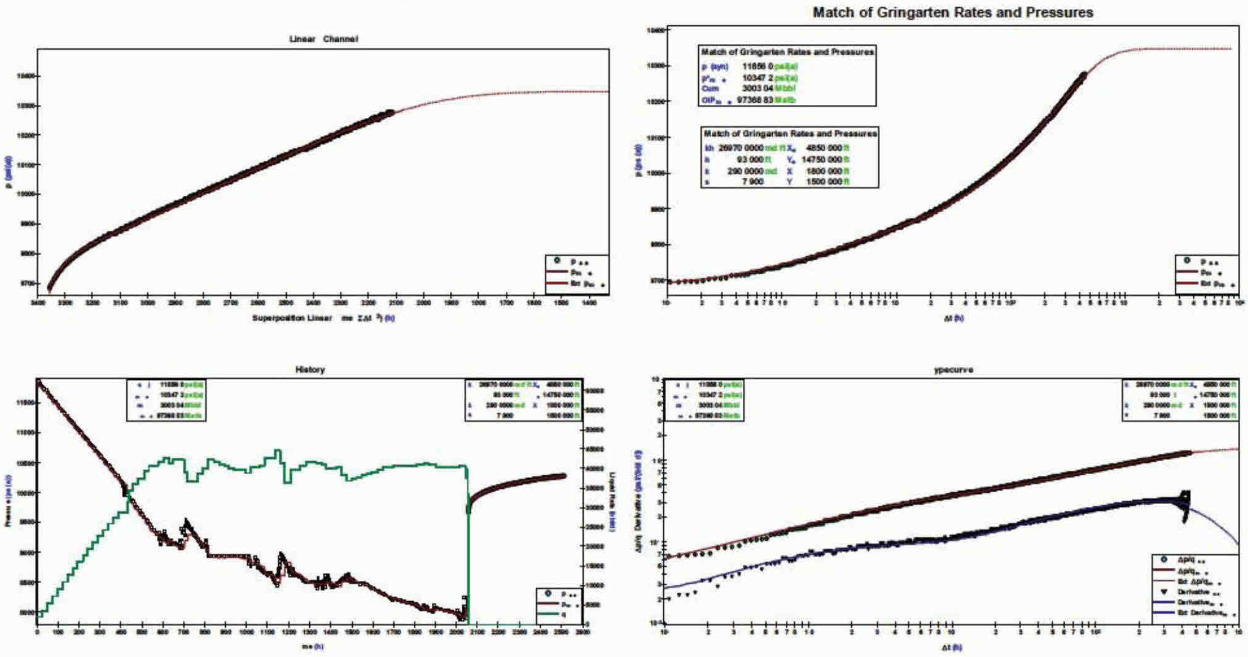
Match of Gringarten Rates and Pressures

p_i (syn)	11856.0	psi(a)
p^*_{model}	10347.2	psi(a)
Cum_{oil}	3003.04	Mbbl
OIP_{model}	97368.83	Mstb

Match of Gringarten Rates and Pressures

kh	26970.0000	md.ft	X_e	4850.000	ft
h	93.000	ft	Y_e	14750.000	ft
k	290.0000	md	X_w	1800.000	ft
s_d	7.900		Y_w	1500.000	ft

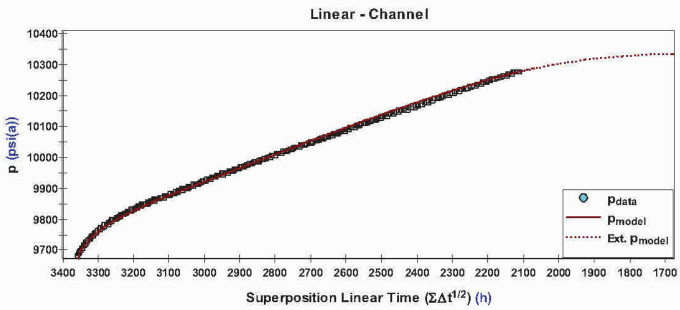
Oil Formation Volume Factor (B_o)	2.260	
Oil Viscosity (μ_o)	0.2160	cP

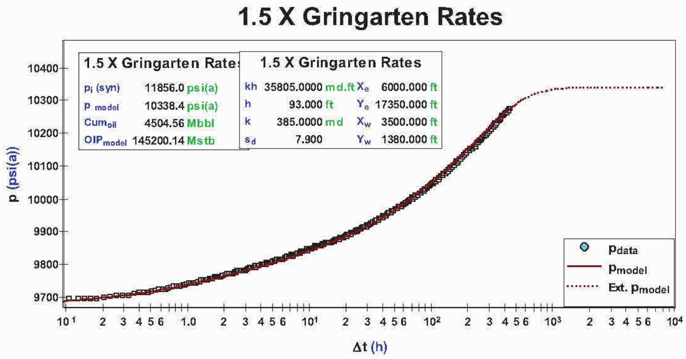


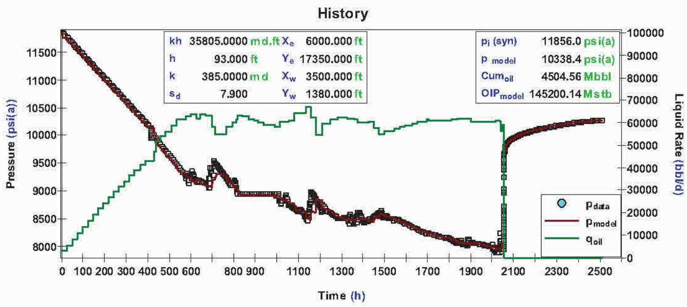
1.5 X Gringarten Rates		
p_i (syn)	11856.0	psi(a)
p^*_{model}	10338.4	psi(a)
Cum_{oil}	4504.56	Mbbl
OIP_{model}	145200.14	Mstb

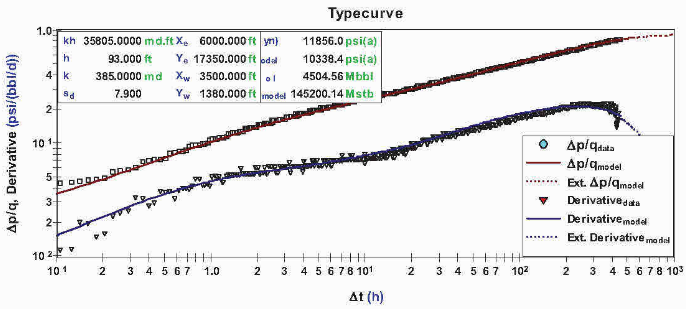
1.5 X Gringarten Rates					
kh	35805.0000	md.ft	X_e	6000.000	ft
h	93.000	ft	Y_e	17350.000	ft
k	385.0000	md	X_w	3500.000	ft
s_d	7.900		Y_w	1380.000	ft

Oil Formation Volume Factor (B_o)	2.260	
Oil Viscosity (μ_o)	0.2160	cP





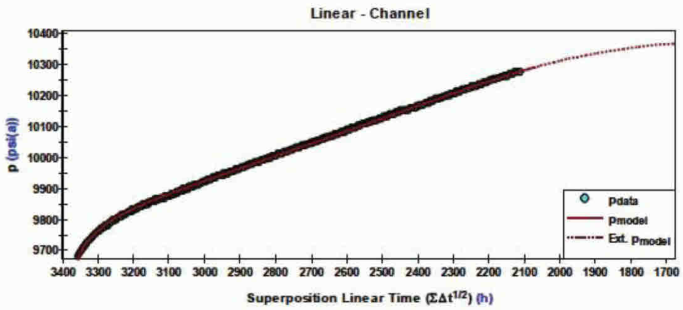


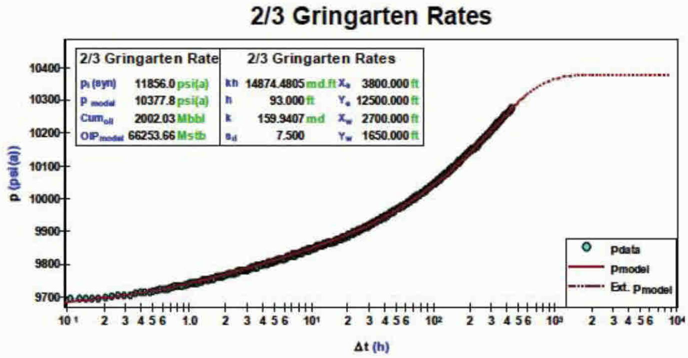


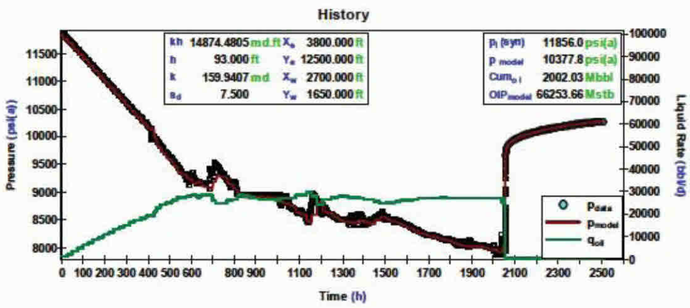
2/3 Gringarten Rates		
p_i (syn)	11856.0	psi(a)
p^*_{model}	10377.8	psi(a)
Cum_{oil}	2002.03	Mbbl
OIP_{model}	66253.66	Mstb

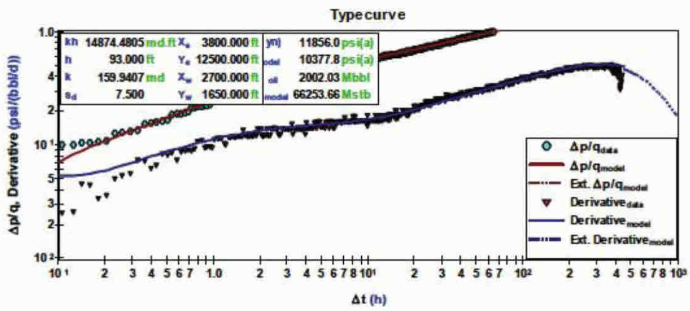
2/3 Gringarten Rates					
kh	14874.4805	md.ft	X_e	3800.000	ft
h	93.000	ft	Y_e	12500.000	ft
k	159.9407	md	X_w	2700.000	ft
s_d	7.500		Y_w	1650.000	ft

Oil Formation Volume Factor (B_o)	2.260	
Oil Viscosity (μ_o)	0.2160	cP





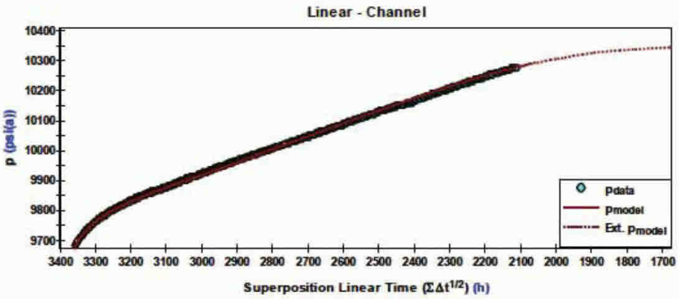


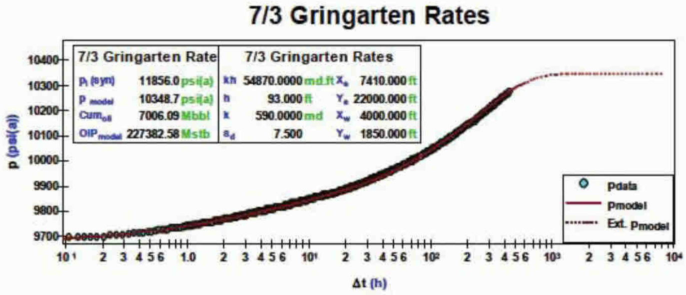


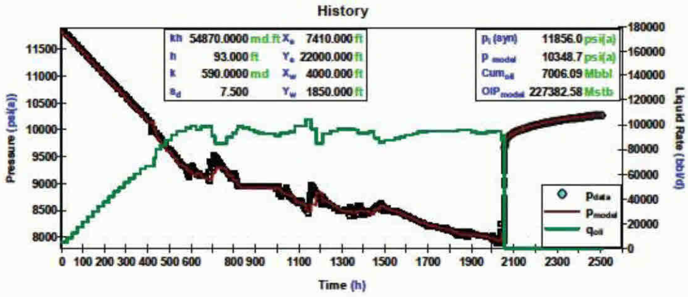
7/3 Gringarten Rates	
p_i (syn)	11856.0 psi(a)
p^*_{model}	10348.7 psi(a)
Cum_{oil}	7006.09 Mbbl
OIP_{model}	227382.58 Mstb

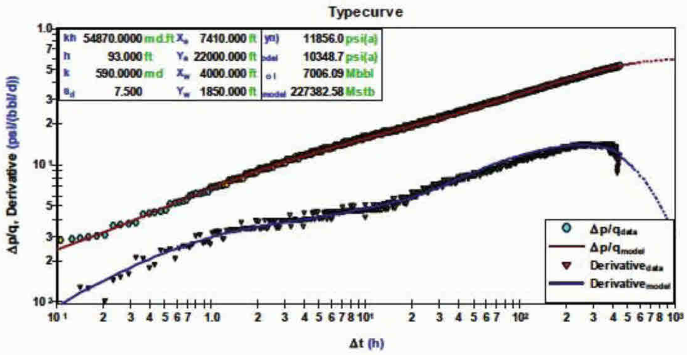
7/3 Gringarten Rates			
kh	54870.0000 md.ft	X_e	7410.000 ft
h	93.000 ft	Y_e	22000.000 ft
k	590.0000 md	X_w	4000.000 ft
s_d	7.500	Y_w	1850.000 ft

Oil Formation Volume Factor (B_o)	2.260	
Oil Viscosity (μ_o)	0.2160	cP



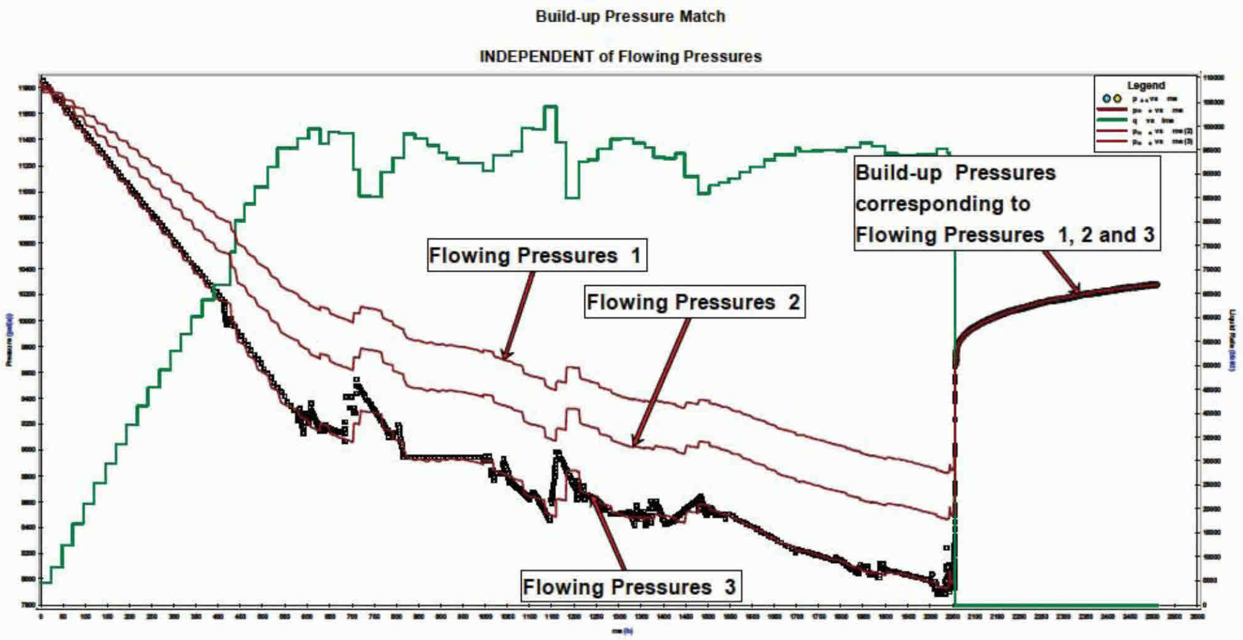






The Figure below illustrates that it is possible to match the shut-in pressures with many combinations of flowing pressures. Therefore, a match of the shut-in pressures does not confirm the validity of the flowing pressures. Alternatively, various flowing pressures (as may be determined from various wellbore models) can be matched along with the shut-in pressures of DR. Blunt.

Flowing Pressures 1....skin = 0
Flowing Pressures 2....skin = 3
Flowing Pressures 1....skin = 7.5

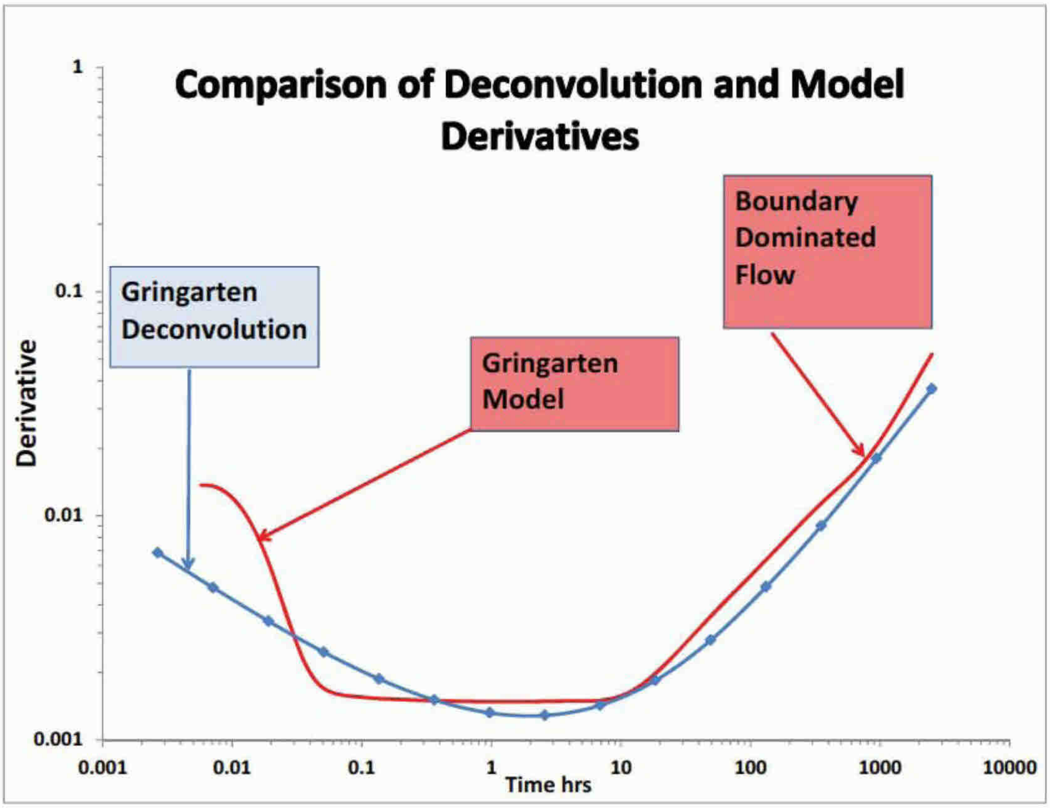


Discussion of Deconvolution:

In his report, Gringarten goes to great lengths in discussing the merits and use of "Deconvolution". Several points need to be noted regarding deconvolution:

1. While deconvolution has its advantages, it has many disadvantages as well. (*reference: Fekete Technical Video 13 and 14 –Deconvolution in Well Testing - Part 1 and Part 2 - L.Mattar and K. Zaoral, 2008)*
2. Deconvolution is not the end-all and be-all of well test interpretation. It is only a preliminary step.
3. The ultimate end of the well test interpretation is the "model". Deconvolution is but a step towards identifying the model.
4. There are many other ways of identifying the model, e.g. analysis of the buildup data using equivalent time, superposition time and specialized plots. Deconvolution is but another way.
5. Once the model has been decided on, deconvolution no longer serves a useful function, because the model is capable of fully describing the behaviour of the system, without suffering from the limitations of deconvolution. The additional use of deconvolution as a way of correcting for rate is problematic, as explained in the body of my report.
6. In the Macondo well, there is no disagreement between all the well test analysis experts as to what the appropriate models is for the Macondo well: vertical well in a cannel-type reservoir.
7. Deconvolution, in spite of (or maybe because of) its mathematical sophistication and complexity is still only an approximation, and is subject to many controls that can affect the outcome - for example, the choice of the number of nodes, the degree of curvature control.
8. Deconvolution does not yield a unique answer. Often, more than one deconvolution type curve will adequately reproduce a match of the original data.
9. A demonstration of the approximate nature of deconvolution is illustrated in the Figure below. This figure shows both the "deconvolution derivative" (Gringarten's Report, Appendix F, Figure 71) and the "model derivative" for the Macondo well.
10. It is obvious that the deconvolution curve (blue) is but an approximation of the true curve (red). It is obvious that, in this case, the deconvolution has too much curvature, which smears the otherwise distinct flow regimes. As a consequence, it obliterates the detection of "boundary-dominated-flow",

which phenomenon is clearly observed in the model. This diagram illustrates the approximate nature of "deconvolution", and the superiority of using the "model".



Model used is Fekete Match of Gringarten Data; CD=300 was used instead of 1200 because it makes the early time closer to the deconvolution curve, and it does not affect the match of data.

11. The above discussion is not intended to belittle the deconvolution process, but rather to put it in true perspective.

Conclusion: For the Macondo data, where there is little difference between the model used by various investigators deconvolution plays a subsidiary role.

Appendix IV
List of Additional Materials Considered in Preparing Rebuttal Report

PT-3K-2Corr-2-Calculated2 (BP-HZN-2179MDL07279439)
Equation _Corr (BP-HZN-2179MDL07279440)
PT-3K-2Corr-2-Calculated1 (BP-HZN-2179MDL07279441)
Trusler PT-3K-2 Final Pressures (XMTX002-009402 - XMRX002-019121)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_135LUP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_137LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_136LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_138LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_139LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_140LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_141LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_142LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_143LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_144LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_146LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_145LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_147LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_148LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_151LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_149LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_152LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_153LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_154LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_157LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_158LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_159LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_161LUP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_160LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_162LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_163LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_164LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_165LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_167LTP.DLIS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_136LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_135LUP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_137LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_139LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_141LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_140LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_138LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_145LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_144LTP.LAS (BP-HZN-OSC00004817)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_142LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_143LTP.LAS (BP-HZN-OSC00004817)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_146LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_147LTP.LAS (BP-HZN-OSC00004817)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_148LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_149LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_151LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_152LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_153LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_154LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_157LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_158LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_159LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_160LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_161LUP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_162LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_164LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_167LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_OFA_165LTP.LAS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_FullCombined.PDS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_MDT_SummCombined.PDS (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_Pressures.xslx (BP-HZN-OSC00004819)
BP_MC252_OCSG_32306_001_ST00BP01_R1D4_WFTITables.wfi (BP-HZN-OSC00004819)
Licensing Comments.txt (BP-HZN-OSC00004817)
PD-Plot_User_Levels_Overviewer.pdf (BP-HZN-OSC00004817)
PD-Plot70134_Full_Install_setup zip (BP-HZN-OSC00004817)
PD-Plot70134_Install_Guide.pdf (BP-HZN-OSC00004817)
PD-Plot70134_Release_Notes_Client.pdf (BP-HZN-OSC00004817)
PD-Plot70134_User Guide_Client.pdf (BP-HZN-OSC00004817)
Thumbs.Db (BP-HZN-OSC00004817)
Note- Y Plot From (BP MDL2179VOL000001-010).txt (BP-HZN-OSC00004817)
Note- Y Plot From (BP MDL2179VOL000001-011).txt (BP-HZN-OSC00004817)

Appendix IV
List of Additional Materials Considered in Preparing Rebuttal Report

Expert Report of Forrest Shank (Oct. 17, 2011) (Ex 142259)
Rebuttal Expert Report of Forrest Shank (Nov. 7, 2011) (Ex 142257)
Testimony of Forrest Shank , Morning Session (Apr. 16, 2013)
Testimony of Forrest Shank, Afternoon Session (Apr. 16, 2013)
BP-HZN-2179MDL02347971
D-04815-309753963.pdf (Ex 4815)
D-06784-309754315.pdf (Ex 6784)
Deposition Transcript of Albert Decoste (Dec. 5, 2010)
Email From: Paul Tooms To: Multiple Subject: Historical BOP Pressure Attachments: BOP Pressure History rev3.xls (Ex 5066)
Horizon BOP Intervention Diagnostic Pumping (Ex 10017)
TREX-040020.12.1 TO-309759375
ROV Video VTS_01_2.VOB (BP-HZN-2179MDL02347971)
2010undefined0755_0555_O-PT-3K-1 Final Pressures.csv _BP-HZN-2179MDL0780637
2010undefined0755_0555_O-PT-3K-1 Final Pressures.csv _BP-HZN-2179MDL0780637_1p
2010undefined0755_0555_O-PT-3K-1 Final Pressures.csv _BP-HZN-2179MDL0780638
2010undefined0755_0555_O-PT-3K-1 Final Pressures.csv _BP-HZN-2179MDL0780638_1p
20100805_0212_O_PT.B Final Pressures.csv_BP-HZN-2179MDL07806039
20100805_0212_O_PT.B Final Pressures.csv_BP-HZN-2179MDL07806039_1P
Expert Report of Morten Emilsen (Oct. 17, 2011)
Trial Transcript of Morten Emilsen, AM (Apr. 9, 2013)
Expert Report of Ronald Dyhuizen (Mar. 22, 2013)
Expert Report of Carlos Torres-Verdin (May 1, 2013)
Expert Report of Richard F. Strickland (May 1, 2013)
Expert Report of Michael Zaldivar (May 1, 2013)
Expert Report of Martin J. Blunt (May 1, 2013)
Expert Report of Alain Gringarten (May 1, 2013)
Expert Report of A.E. Johnson (May 1, 2013)
Expert Report of Sankaran Sundaresan (May 1, 2013)
Expert Report of Curtis Hays Whitson (May 1, 2013)
Expert Report of Andreas Momber (May 1, 2013)
Expert Report of Robert W. Zimmerman (May 1, 2013)
Expert Report of Srdjan Nesic (May 1, 2013)
Expert Report of J.P. Martin Trusler (May 1, 2013)
Expert Report of Kerry A. Pollard (May 1, 2013)
Expert Report of Simon Lo (May 1, 2013)
All documents cited in this rebuttal report
K factor Kill Line_5_8 Extended Range.xls (Spreadsheet prepared by Nathan Bushnell)
K factor Kill Line.xls (Spreadsheet prepared by Nathan Bushnell)