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Subsea Production Enhancement—Success and Failure Over Five Years

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Abstract

Subsea well intervention has been around in the North Sea for many years as documented in papers such as Pollock (1990) but in the last five years there has been renewed interst due to a combination of high oil price and aging wells. This paper will look at the actual results achieved with production enhancement work done in subsea wells across the United Kingdom (UK) sector of the North Sea over a five year period 2002 to 2007. This time frame allows the results to be seen in the context of longer term field value. All the work included in the paper was done rig-less with a specialist subsea well intervention vessel. It covers a range of different oil producing fields operated by a number of different companies. The work done was through tubing and included zone isolation and re-perforation. No work was done in any gas fields. The paper will detail the production profiles of the wells both before and after the intervention work along with a discussion of the work done and an explanation of the factors that influenced the final result both good and bad. To facilitate an open discussion of the success and failures all data is presented anonymously. The high cost of subsea wells makes it essential to maximise the overall recovery per subsea well. This paper will detail actual results which may point the way forward.

Introduction

Historically subsea well intervention projects have been performed to obtain reservoir data or to repair mechanical problems. More recently subsea well intervention projects have been performed to optimize and/or enhance the production from wells or fields in which production has declined below acceptable limits thereby threatening their economic viability. With this increase in production enhancement work few studies have been done to determine just how successful this expensive subsea work has been. With wells in steady decline it should be important to understand if intervention work can produce positive results to some degree and to understand how successful interventions will ensure their investment is returned.

This paper will review all the production enhancement jobs carried out by the only subsea well intervention vessel completing production enhancement operations in the UK sector of the North Sea over a five year period. In this time the intervention vessel conducted numerous intervention projects for a variety of different operators of aging wells and fields. In the time frame of this paper only one other subsea well intervention vessel operated in the UK but this vessel only completed a repair job before moving to Norway. Drill rigs are also capable of undertaking subsea well intervention work but having reviewed the UK rig reports only a handful of interventions were carried out between drilling and workover operations. This suggests that this paper covers the clear majority of all non-workover intervention operaions carried out in the UK sector. It is also useful to note that the owners of the subsea wells included in the case studies did no other intervention work with any other vessel or rig in the time frame of this paper. This again helps illustrate the extent to which this paper covers the majority of subsea intervention work in the UK North Sea.

The production enhancement projects included in this paper reveal that overall, results from the interventions were mixed at best and that enhancing production in older subsea wells is much more difficult than it may first appear. Also, the risks for decreasing production rather than increasing it are very real and success, more often than not, depends on precise modelling which is difficult to achieve in older wells.

Case Studies Criteria

The case studies discussed in this paper come from the period of just over five-years from August 1, 2002 to October 16, 2007. During this 1,902-day period, the time allocation of the intervention vessel was as follows. Production enhancement 27%, Logging 18%, Inspect Repair Maintain Diving 16%, Tree change out 8%, Repair work in hole 9%, Decommissioning 5% and Idle 17%. The 27% of time spent on production enhancement is distributed as follows. Re-perforation 13%, Water shutoff 8%, Scale squeeze 3%, and Gas lift change out 3%.

For each of the categories above, the time was inclusive from the start of mobilization in port to completion of the demobilization in port. This includes all transits, waiting on weather and other operations. Of the 519 days spent on production enhancement 75 were in Norway. The remaining 444 days were in the UK. As it was not possible to see production trends over short periods, the cut-off for the analyses was October 2006. This provided a minimum of one year of production data to make the comparisons.

During the period from August 2002 to October 2006 production enhancement jobs were carried out in 15 fields in the UK. Due to the layout of two fields it was not possible to separate out the relevant production data. Therefore, these two fields were excluded from the analyses. The remaining 13 fields are included in this paper. In these 13 fields, 35 separate well intervention jobs were performed over a total of 299 days for an effective rate of 8.5 days per intervention per well.

Case Studies

Case 1. After more than fifteen years in service, this field was experiencing tail-end production and had settled into a reasonably steady production rate. In August 2002, the two wells were re-perforated to improve flow. This was an immediate success as evidenced by increasing production levels. Flow rates **Fig.1** then stabilised before declining to the current low production level which is expected to continue for some time. Although there was an initial burst of production following the intervention, the overall effect appears to have been to accelerate production of existing oil rather than to produce any new incremental oil. Although production acceleration can be of benefit in some cases the nature of the field operating cost diluted this effect so it has not been possible to establish any economic value from this intervention.

Case 2. After more than five years on production **Fig.2** in September 2002, all four of the wells in the field were logged and re-perforated. Following this intervention, no immediate change in production was apparent as the field continued to pump around 8,000 B/D. During the winter production was disrupted due to weather and in May 2003, two of the wells were re-perforated again. Production increased to approximately 10,000 B/D but water production became an issue. Therefore, due to the risk of scale formation, flow rates were reduced until a scale treatment was pumped in December 2003. This overcame some of the scale issues but did not completely alleviate the problem, thus production was constrained again until June 2004 when a second scale treatment was pumped. At this point, production was increased, reaching 10,000 B/D before declining as predicted. With so many factors at work in this case, it was not possible to formulate an agreement on the benefits derived from the intervention work described.

Case 3. Following more than five years on production **Fig.3** scale became a concern in this well. So, in June 2003, a scale treatment was pumped to see if it could help stem the decline. In the subsequent months production appeared to stabilize so a second scale treatment was pumped in January 2004, and a third in June 2004. The field continued to decline naturally and production ceased in early 2006. Although the field is no longer producing the scale treatments were considered to be a success because originally production was forecast to cease in 2004 and it actually managed to continue to 2006. This additional production even at low levels resulted in an attractive economic gain on the work.

Case 4. After more than four year on production **Fig.4** there were concerns with the sweep efficiency of the water injector wells in this field. In December 2003, both water injectors were logged; some zones were isolated with packers and other zones were re-perforated. Although production rates remained unchanged, the project was considered a success because it reduced the volume of water required for injection and reduced the volume of water being produced with oil. In February 2005, the two producing wells were logged and a packer was set in each to shut off water. This solution managed to shut off much of the water, but it also shut off much of the oil which reduced average field production from the existing wells. In early 2006, a new well was drilled. Although in this case the initial intervention work was considered to be a technical success, the overall economic impact of the intervention appears to have been negative.

Case 5. Studies suggested that after more than eight years on production **Fig.5** the oil levels in this field had moved. Therefore, in December 2003 three wells were re-perforated. This resulted in an immediate increase in production as evidenced by the production curve which clearly shows that the decline trend was reversed. Originally, production was expected to cease in 2005 but it still continues at good rates in 2007. The economic value of this job was considered a great success.

Case 6. After more than fifteen years in service, this field had managed to steadily maintain tail end production **Fig.6** but was experiencing a very slow decline. A number of maintenance tasks were carried out in March 2004, including an acid wash of one well, a water shut-off in another well and a re-perforation in a third in an effort to continue successful production.

The results of the intervention jobs were inconclusive as no change in the flow patterns could be detected. As the field is very old, modelling is difficult. Therefore, in August 2006 another well was re-perforated to determine if any further opportunities existed. To date it has not been possible to establish any economic value from the intervention.

Case 7. After more than five years on production **Fig.7** this field collapsed and the wells were shut in. In July 2004, the key well was re-perforated and brought back on stream with a nitrogen bullhead. Although the well only produced for about a year, it was apparent that the incremental oil could not have been produced without the intervention. Even with the low flow rates, this intervention was considered an economic success.

Case 8. Following more than six years on production **Fig.8** a water cut was rising in this well. So, in February 2006, a packer was set in the well to shut off water flow. With the well back on production it appears that the rate of decline has been reduced and production levels appear to have been more stable over the last year and a half. Originally production was forecast to cease in the second half of 2006 but it continues steadily in 2007. The economic value of this job was a success.

Case 9. A new well was planned for the field after more than eight years on production **Fig.9** but there were concerns that water production from the existing wells could crowd out the new oil. In June 2006, a packer was set to shut off water. This solution was considered a success since it managed to reduce water production while leaving the oil production rate unchanged. In stricter terms, it is difficult to quantify the economic value of this intervention solution due to interaction with the newly drilled well.

Case 10. This field collapsed after more than ten years production **Fig.10** and the wells were shut in. In July 2006, the gas lift mandrels were re-configured to gas lift the well back onto production. Although the well only produced for a few months, it was clear that the incremental oil could not have been produced without the intervention. Even with the low flow rates experienced in this field, this intervention was considered to be an economic success.

Case 11. On production for more than ten years, this field's production rates **Fig.11** have varied widely from day-to-day. In July 2006, some of the producing zones were isolated using a packer and new productive zones were perforated. Although production ramped up after the job, it is now clearly in decline. Due to the large swings in production seen in this field, it is not possible to agree on a precise economic benefit from the intervention.

Case 12. This field declined and was shut in after four years of production **Fig.12**. In August 2006, the gas lift valves were reconfigured in an effort to coax more oil from the well. Unfortunately, it was not possible to resurrect this well due to continued lack of production, so the intervention was considered a failure and a clear economic loss.

Case 13. This field has been on production **Fig.13** for more than eight years and production rates have varied widely. In October 2006, all three wells in the field were logged and some of the lower producing zones isolated using a packer. New productive zones were perforated. Due to the production ramp-up seen after the job, the intervention was considered to be a superb economic success. Due to the large swings in production seen in this field, it is not possible to agree on a precise economic benefit from the intervention.

Well Intervention Methodology

The case studies illustrated in this paper were completed using a specialist light subsea well intervention vessel. The use of a ship shaped vessel improves operational efficiencies on these short intervention jobs which only averaged around 8.5 days per well per intervention including all mobilization and transit times. A number of other papers have discussed the actual equipment and procedures in detail such as McGennis (1995) but as a background to this study the procedures and equipment used will be outlined in the following section. All the work done was through tubing and not open hole.

The Vessel. A purpose-built intervention vessel has several main components that enable multiple tasks. These components consist of a heave compensation derrick, choke manifold, high-pressure pumps and storage tanks. Of these components, the heave compensation system is the key item that enables the vessel's subsea intervention capability. This is because it effectively elimnnates any vessel movement when connecting the Subsea Intervention Lubricator (SIL) to the subsea trees. Operations are assisted by the use of a standard guideline system on the vessel which allows the SIL to be deployed and recovered in the correct orientation with respect to the subsea tree. On the deck of the vessel, a special skid deck allows the large components to be moved safely and under control from the deck into the derrick and then over the moon pool doors.

The Subsea Intervention Lubricator (SIL). This system is essential for all well operations and it is latched onto the subsea tree with the relevant wellhead connector and the appropriate crossover to adapt it to the lower guide frame spool of the SIL. In this SIL frame is a dual ram wire-line Blow Out Preventer (BOP). This can be fitted with a range of shear, blind and variable rams to suit the operations planned. Above this is a shearing gate valve which is capable of cutting everything that goes into the hole. The gate vale also provides a metal to metal seal when closed. A quick connect / disconnect system allows the 40ft lubricator riser section to be attached. This lubricator section holds the various wire-line tools before they are deployed into the well. On top of the riser section is a wire-line cutting ball valve which can secure well pressure and finally the hydraulic removable sealing head. The sealing head systems can be used for either slick-line or braded electric line.

Other Equipment. A 10,000-psi choke manifold is used to primarily control the return to surface of any hydrocarbons that accumulate in the SIL. Returned hydrocarbons are passed from the choke manifold into an atmospheric storage and separation tank that is mobilized onto the deck for well operations. Where operations call for additional volumes of hydrocarbons to pass over the vessel, changes can be made to increase the amount of storage and the need for gas flaring that might be needed. With this equipment, the vessel can be fully certified as an "Offshore Installation" in line with current UK governmental guidelines.

Typical Intervention Operation

After arriving on site, the vessel is given control of the subsea well (tree) by the relevant host platform. Then, using its dynamic positioning system, the vessel sets up directly over the well, guide wires are run onto the tree and having established the well status, the tree cap is removed. The SIL unit is then slid into the derrick using the deck skidding system. Once in place the SIL is lifted clear of the moon-pool doors which can then be opened. The SIL is then lowered through the water to just above the subsea tree.

Next, the heave compensation system is engaged to allow the SIL to be lowered safely onto the tree and latched in place. Orientation of the SIL is achieved using primary guidance from the guide wires. With the SIL in place, the provided wellhead connector engages the tree control lines thereby allowing control of the tree from the vessel. The lift wire is recovered to allow the SIL and tree to be pressure- and function-tested from the surface.

After testing, only the shearing gate valve and Production Swab Valve (PSV) remain closed while the stuffing box, BOP, ball valve and sealing head remain open to receive the required tool string. When the wire-line tool string is made up, it is passed down below the vessel's hull on the guide wires. When below the hull, the compensator is engaged and the tool string is lowered to the SIL, then down through the sealing head, through the upper ball valve and into the riser section of the SIL.

Once the tool string is fully inside the SIL, the sealing head mandrel, which is lowered with the tools, engages into the sealing head. This sealing head mandrel is then locked into position. The sealing head can then be activated to seal off around the wire. This allows the lubricator section to be pressured up as a check on the integrity of the system. Following a successful test, the pressure is bled down to just above the shut-in tubing head pressure. At this point, PSV is opened and then the shearing gate valve. The tool string can now be lowered into the well to perform intervention work.

Recovery of the system is basically the reverse of installation except that the lubricator is flushed with a water glycol mix to remove all hydrocarbons before the sealing head mandrel is released.

Discussion

Analysis of the results of four-years of UK North Sea subsea interventions reveals some surprising conclusions, many of which seem at odds with traditional wisdom. Of the 13 production enhancement jobs only 5 were identifiably successful. In the case of 6 production enhancement jobs it was not possible to establish if there was any production gain or loss so these results were considered to be inconclusive. In the remaining 2 cases the production enhancement jobs were considered to be a failure as they did not pay back on the cost of the intervention work or in the extreme case actually caused a reduction in the original production levels.

With only five identifiably successful intervention jobs in four years it is difficult to see how this track record is going to encourage reservoir owners to make significant changes to their existing strategies for subsea field management. In the UK this result over four years appears to reinforce the logic that subsea production enhancement in old wells is not an attractive economic proposition. There are currently over 200 subsea fields in the UK so the fact that production enhancement jobs were only carried out on 15 fields over the four year period appears to reinforce the conclusion that this is not an effective economic option compared to the alternative investments available to oil and gas investors.

To further understand why production enhancement has only been done in 8% of the subsea fields in the UK a number of discussion meeting were set up with companies and individuals involved in the operation and management of subsea fields. These discussions raised a number of points. One of the issues mentioned on a number of occasions is the fact that reservoir models are not accurate enough to predict the end of field production profiles. It has been noted by Wilson and Pearson (1962) that although uncertainty in ultimate recovery decreases over time the uncertainty in remaining reserves actually increases as the fields get older.

Looking at production data across a wide range of subsea fields the current recovery factor is by and large in the range of 40% to 60%. What is important to note however is that this recovery factor in many cases is well over 90% of the estimated ultimate recovery volumes from the individual subsea wells. This means in effect that we are trying to improve the delivery of less than 10% of the reserves when the accuracy in the model may be no better than plus or minus 5%. This is effectively a 50% error on the remaining reserves range.

Another problem with end of field production enhancement is being able to measure the results. This is seen in six of the case studies where fluctuations in the production levels make it impossible to determine production gains. In older wells flow instability is a common problem as water and gas invade the near well bore area reducing the stability of the flow of reservoir oil. This instability is then amplified by pressure loss and flow effects in the production tubing, surface manifolds, pipelines, risers and surface equipment at the host. The overall effect reduces the visibility of results.

Although a single successful well can cover the cost of many inconclusive jobs especially with the current oil price of US$90 per barrel ownership issues makes it impossible to aggerate success. What has been seen in a number of potential project that were eventually never undertaken is the fact that a small minority partner in a single well can never be given enough confidence that the intervention will be an economic success. As some of the smaller equity participants in the UK only invest on proven reserves it is simpy not possible to model older reservoirs with enough accuracy to qualify as proven reserves. This risk factor appears to be illustrated by the five successes out of thirteen jobs reviewed in this paper.

As most well intervention work is treated as an operating expense it usually has to be charged to the financial accounts in the year in which it is done. This creates another challenge for production enhancement operations to try and get enough additional production in the financial year in which work was done to cover the cost outlay. In older wells the low flow rates makes fast cost recoverty very difficult resulting in oil being left in the ground.

To improve the effectiveness of subsea fields there has been extensive use of long horizontal wells with sand screens or gravel pack completions. These wells improve the reservoir contact and allow for efficient depletion rates even with small numbers of wells. The issue with these horizontal wells however is the fact that there is effectively nothing that can be done to enhance production later in field life. As these wells have screens there is no opportunity to improve flow with re-perforation. As the wells are horizontal it is difficult to shut off water as the water front often breaks through across a wide section. It is also difficult to mechanically isolate across screens and gravel pack.

One of the drivers for production enhancement in subsea wells is to improve the recovery factor of subsea fields so as to match the recovery factor seen in platform fields. What is becoming apparent however is that the recovery factor on platforms is driven by the increased number of wells drilled and not by well intervention. As the cost of a subsea well is far more than a platform well each subsea well has to recover more oil. This cost factor has the biggest effect late in field life. What has been noted is that a platform well can target a much smaller reserves volume than a subsea well. This allows platforms to continue drilling along the decline curve targeting ever smaller volumes of oil that subsea fields have to leave behind.

Conclusion

Production enhancement in subsea wells is not a routine activity in the UK sector of the North Sea as these operations only occupied 27% of the vessel time over the five year period. In aging wells it is often difficult to establish the results from production enhancement operations as success was only noted in five of the thirteen fields worked on. This successful production work represented less than 10% of the vessel time. The results shown here suggest that it will not be possible to make any real impact on the reserves recovery from subsea fields with production enhancement in existing wells.

The Future

The results suggest that with better modeling it may be possible to select better canidates for production enhancement operations. With better instrumentation systems on the wells it may be possible to improve the accuracy of flow data making it easier to detect procuction gains when they occour. The higher recovery rates on platforms appear due to the lower cost of drilling allowing ever smaller targets to be tapped. This suggests that subsea fields need a lower cost drilling solution than is currently available through the conventional rig market.

Acknowledgements

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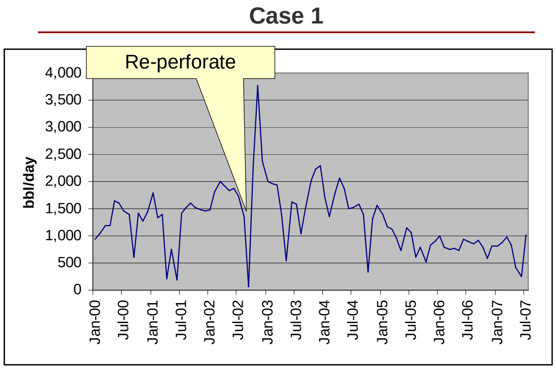
Figures



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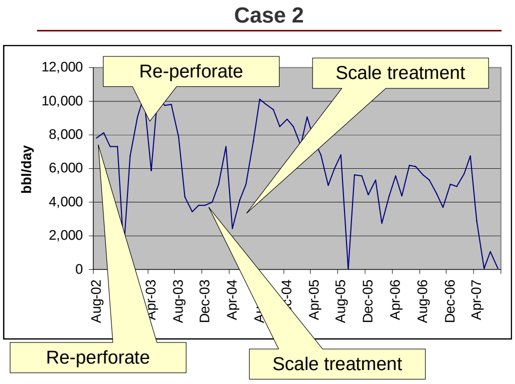

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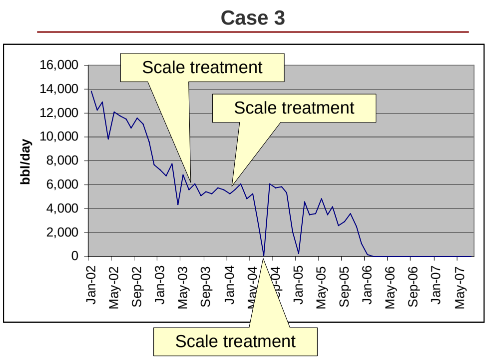

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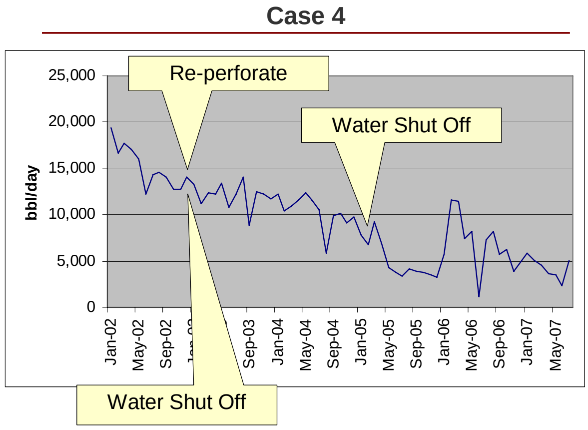

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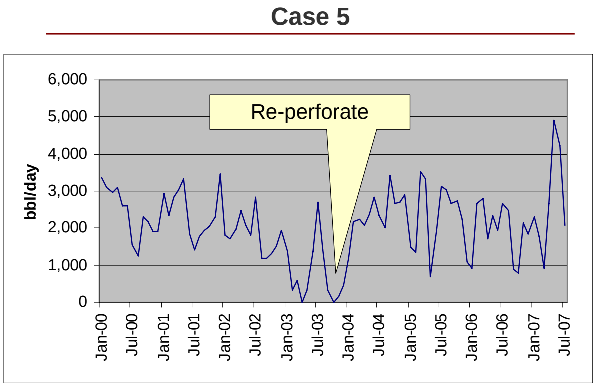

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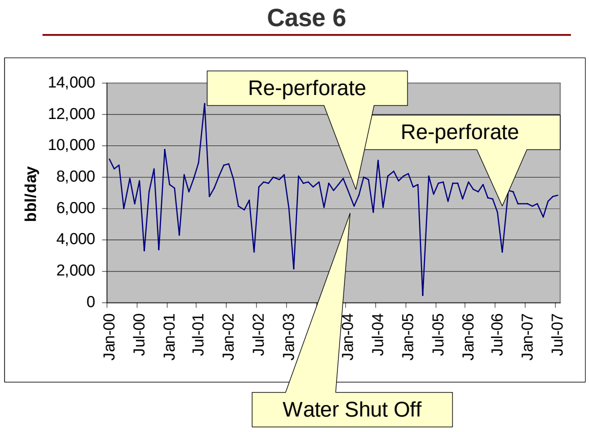

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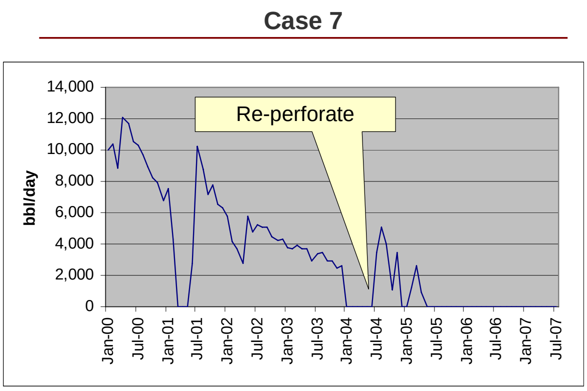

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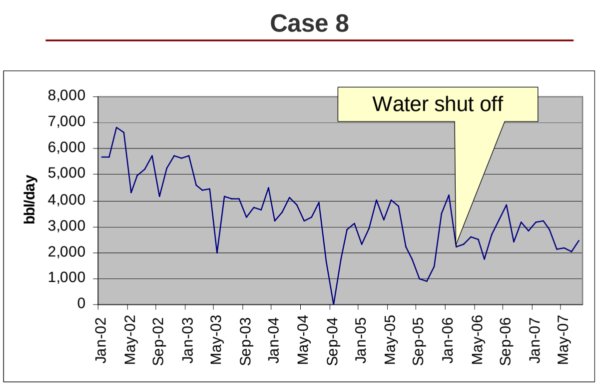

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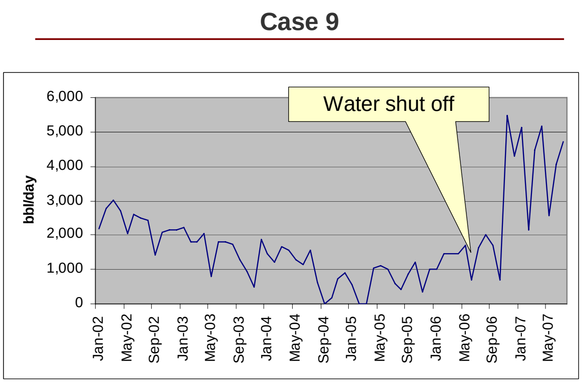

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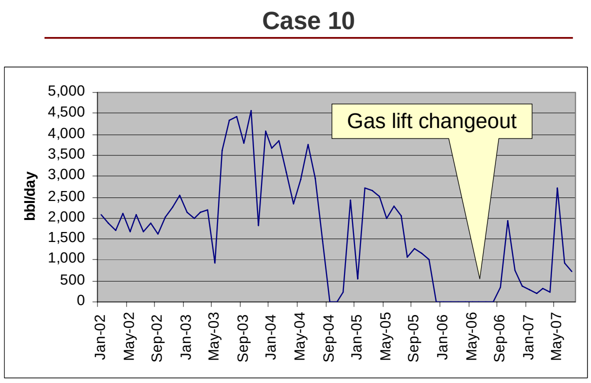

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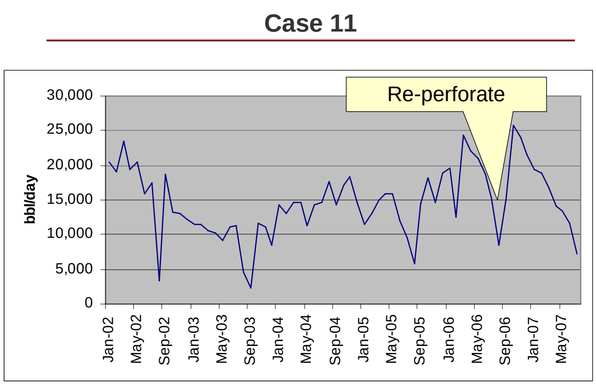

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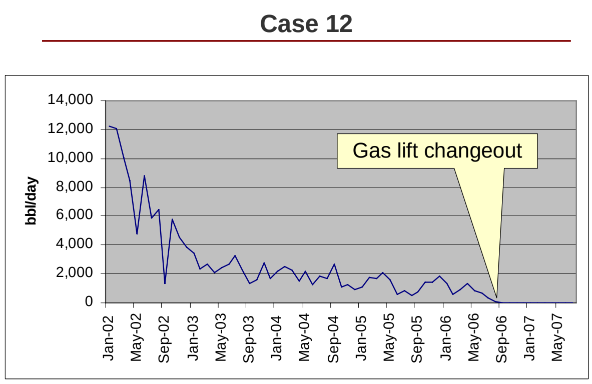

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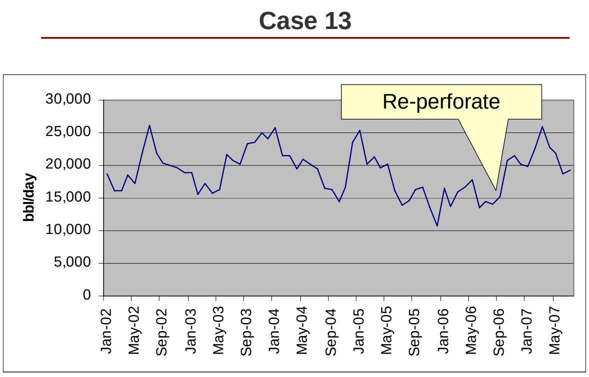
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