SPE 111477

Workover Rig Scheduling Using Reservoir Simulation

Vineet Kevin Lasrado, SPE, Infosys Technologies Limited

This paper was prepared for presentation at the 2008 SPE Intelligent Energy Conference and Exhibition held in Amsterdam, The Netherlands, 25–27 February 2008.

Abstract

In this paper we will discuss the results of a prototype software application to view the rig schedule generated by a reservoir simulator. Visualization of simulation rig schedules and comparing with planned rig schedule would help in identifying opportunities to improve operations. With the help of the schedule chart and rig movement data, we better the schedule generated by trying to reduce the net distance traveled by the rig and reduce the number of rigs utilized. We ensure that the overall field oil production is not affected for all the cases.

Using reservoir simulation as a tool to assist in the rig planning and scheduling process has the potential to foster team collaboration between reservoir engineering, planning and operations team and facilitate better Integrated field management. The teams would appreciate the challenges associated with planning and scheduling activities for the field.

Introduction

Both drilling rigs and workover rigs are expensive resources that are typically limited in number compared to the wells that they are to be allocated. In any upstream Oil & Gas operating company, the operations planning team has to decide the overall plan for drilling and workover and the resources required for the jobs. The typical horizon for an operations planning exercise could be months/years. This exercise would enable allocation of the necessary budgets for the rigs and also place orders for rigs to ensure they arrive in time for the required work. The scheduling team would take the long term plan and come up with a schedule of allocation of the rigs to wells. The scheduling horizon is typically in days/weeks.

Spreadsheets are commonly used as one of the tools to manage schedules in many industries. Many oil companies also use spreadsheets for rig scheduling activities. Software applications specifically targeted to assist in rig scheduling are also available[1, 2, 3 and 4]. Some approaches assist in creating feasible schedules[5], while some are able to optimize the schedule based on a defined objective function[6].

Most software applications that optimize rig scheduling would be based on the assumption of loss of well production for the duration of the well workover. In most fields however, wells are grouped in a hierarchy, so loss of production from one well need not necessarily mean reduction of the overall field production. If we are able to compensate for the lost production by increasing flow from another well in the field, then we may be able to maintain the field production rate. In an optimization program that does not use reservoir simulation such a scenario would be difficult to reproduce.

Heuristics could also typically be used in most scheduling problems. These are rules-of-thumb that have been developed over the years by experience of operating the field. An example of heuristics approach is the scheduling of workover rigs in descending order of the Well Productivity Indices (Well PI) [7]. A custom built application can incorporate such heuristics into an optimization program or use such rules to come up with a feasible schedule using a scheduling tool.

Reservoir Simulators also have features that are able to study the effect of drilling[8] and workover rigs scheduling on the field production. The use of reservoir simulation to optimize a rig schedule is not new. A technique to use reservoir simulation to optimize scheduling of drilling rigs in an oilfield has been studied before[8]. The technique uses an optimization program to take feedback from the reservoir simulator and change the input based on the optimization run. In this paper we base our work on a similar approach (although we do not incorporate an optimization program). The output from the prototype application is used only as a tool to discuss the possible applicability of the approach to reduce rig related expenditure.

Background

Most optimizations programs in the oilfield today look at single target e.g gas lift, water injection, rig scheduling independently. Integrated work processes and decision support tools allow optimization across several processes[10]. The problem of rig scheduling optimization is also one such problem that may be solved in isolation but has the potential to be solved by better integration of processes across planning, operations and reservoir engineering teams by using reservoir simulation.

Some of the questions that can be asked by teams responsible for rig scheduling are:-

1. How much savings in reduction of oil production loss could be obtained if additional workover rigs were used?
2. Can field production targets be maintained and managed with fewer rigs?
3. Which well needs to be prioritized for receiving a workover rig if many wells are need a workover and there are not enough rigs?
4. How long can a well that requires a workover wait for a rig without affecting the overall targeted production?
5. Can a given rig schedule be improved by schedule compression and help decide how many rigs to own and how many to rent?
6. A planned workover has been disrupted due to non-availability of a rig. How should the plan be recast (if required)?
7. Can a given rig schedule be improved without affecting the overall production?
8. How to minimize the oil production loss by better scheduling of the workover rigs?[9]
9. Given the availability of multiple rigs which rig does it make more sense to move to the required location (transport cost for different rigs could differ and could be a dependent on the distance over which the rig has to be transported)

Visualization of simulated rig schedules and comparing with planned schedules have potential to help in identifying opportunities to improve operations. It could also foster better team collaboration between reservoir engineering, planning and operations team.

Challenges

There are quite a few challenges related to the problem of rig scheduling. One of the biggest challenges in scheduling is the fact that the schedule may have to undergo continuous changes due to unplanned events and the changes are sometimes on an almost daily basis. Listed below are some of the challenges related to resources (including people), processes or technology.

Resources related

1. Shortage of resources (workover rigs)
2. Constraints associated with rig allocation
3. Manpower constraints in scheduling and performing workovers

Process related

1. Manual scheduling of rigs not able to tap into the economic benefits of using scheduling tools built for solving the rig scheduling problem
2. Communication, decision making and authorization process related constraints
3. Change management in moving from manual or spreadsheet based techniques to adopt tools specifically built to address the scheduling problem
4. Creating integrated workflows and interdisciplinary teams

Technology related

1. Integrating Project Management tool (e.g MS Project or Primavera) into a custom built application.
2. Creation of tools to assist in integrated planning

Problem Statement and Approach

This paper approaches the problem of rig scheduling to see if we can reduce rig movements and rigs required while maintaining the overall field production. Some commercial reservoir simulators allow specifying drilling[8] and workover rig assignments to wells as inputs to the simulation. An output file would also typically contain the specifics of the rig assignment, timeline (start and end date or period or workover). However, the rig schedule from a reservoir simulator is rarely a thing that would be visualized by a post proessing application and used by a reservoir engineer or a scheduling team. The focus of this paper is to generate interest in the incorporation of the reservoir simulator as a tool to assist in the rig scheduling problem by providing a tool to display the generated schedule and calculate rig movements. This approach can be used alongside other scheduling tools to give the team another perspective to the problem or gain better insights on what opportunities exist for improving existing schedules.

A prototype .NET application is built to import a workover rig schedule that could be generated by a reservoir simulator. The application generates a schedule (similar to a GANTT chart) and also calculates the rig movement distances. A snapshot of the application is shown in **Fig. 1**. We look for ways to reduce the net distance traveled by the rig and the number of rigs utilized by analyzing the schedule and changing the rig assignment and field management strategy. The reduction in distance traversed by the rig would mean lower rig mobilization costs and hence reduce the rig operating expenses. No optimization algorithm has been used in this work. The approach only serves as a means to show an opportunity for improving scheduling costs using reservoir simulation as a tool. The data for the different cases are set-up in a spreadsheet (due to lack of access to a commercial simulator). Hypothetical well production rate potentials and targets are set and certain wells are forced to miss target production at defined times to simulate a possible field scenario. Group production rate control like effect is generated by ensuring that the sum of production rates in a particular group is equal to the group production target.

Assumptions

1. All workover rigs are identical and can be used to do a workover on any well in the field
2. The mobilization costs (per unit distance traveled) for all the rigs available are identical
3. Fixed field planning horizon for the field is assumed = 1 year in this problem.
4. When wells missing target have a workover performed, it is assumed that the wells are back to their original potential (In reality the wells could be below or above their pre-workover potential)
5. Wells not attended to immediately are assumed to maintain a fixed production level until workover is performed.
6. No production decline in the wells is assumed to occur over the one year period
7. Wells performing normally may have their production rates increased to compensate for loss of production from problematic wells in order to meet group level or field level production rate.
8. Selection of wells whose production rates are increased is assumed not to be dependent on other factors (e.g cost of increasing production from one well against increasing another well’s production is not considered.)
9. The duration for which the workover rig is allocated to a particular rig is assumed to be 50 to 55 days which includes the workover duration and mobilization and demobilization duration.
10. After a well is worked over the well potential is equal to the well potential before the well needed the workover
11. The distances between wells are measured as straight line distances between the two wells.
12. Distance computation is done based on the indices of the cells as used in a reservoir simulator (instead of actual distances between wells based on X and Y coordinates
13. Fixed field target is assumed for the planning time horizon
14. All reservoir simulation model related assumptions

Although this paper has been simplified with the help of assumptions one must note the kind of typical constraints that would be faced when solving a real-world scheduling problem. Certain rigs can be allocated to certain wells due to the rig specifications; a schedule constraint may be there (e.g the rig has to start work on a well by a given date, physical constraints originating from the geometry of the rig – called the rig footprint)

Commercial simulators allow setting of hierarchichal group level production rate control and allocation of the rigs to well or group or field level. Hence there is interplay between the rig allocations and the well production rates. As an example moving all the rig allocation up the hierarchy to the field level would give the simulator complete flexibility in the way rigs were allocated to the wells. This could possibly result in rigs moving all across the field over large distances and may not result in effective rig usage. On the other hand restricting the rigs to the group level and setting group level rate control may result in movement of rigs over a smaller area. While analyzing the rig schedule and group level production rates, it is very important to understand how the control of the field could impact the allocation of the rigs. By doing an economic analysis of operating costs of the field in the different scenarios we could pick the best case provided the field production targets are met.

The schedule generated by the reservoir simulator can be used in comparison with a schedule generated using other planning tools. By analyzing the schedules, we can look for opportunities to allocate rigs to wells for certain periods based on inter well distances and try and maintain the overall field production.

Simulation

Since we are not running a full scale reservoir simulation problem and we only need to specify inputs relevant to the problem at hand. This includes the well locations. **Fig. 2** shows an areal view of the well locations on a grid as used in reservoir simulators with the i, j cell indices indicated. There are 9 wells in total belonging to three groups PA, PB and PC. Each well name contains the group name as a prefix for easier identification. Each well has a fixed production target and a potential. The overall field level target is assumed to be 18000 bpd. There are 2 workover rigs available i.e Rig No. 11 and 22. The starting co-ordinate of the rig is assumed to be i = 5 and j = 5.

The base case (Case A) taken was a taken assuming each group will maintain the group level target (see **Fig. 3**) with a workover rig assignment done at different levels of the well hierarchy (well level). Rig 11 can service Groups PA and PB and Rig 22 can service group PB and PC.

In Case B the group level target controls are removed for groups PB and PC and left for group PA (see **Fig. 4**). Hence groups PB and PC need not maintain any set target. Without making any changes in the rig allocation hierarchy, the rigs would have greater flexibility in movement across the field.

In case C we remove Rig 22 and do not set any group level control (see **Fig. 5**) to see if it is possible to maintain field production with one workover rig.

Tables 1, 2 and 3 show the well production rates, well potential rates and target production and group production rates for Case A, Case B and Case C respectively. The cells highlighted in green indicate that the particular well is producing above the original target rate specified. The cells highlighted in red indicate that the well is producing below the set target (first incidence of well problem) and is assumed to need a workover. The yellow cells indicate that a well reported with a problem has not had a workover completed. For all 3 cases the first incidence of a well falling below the target rate is the same, for case comparison purpose (this can be verified by the number of cells marked red in the tables). If a well is not attended by a rig (as shown by the allocation of a rig below the respective group) then it continues to produce at the reduced rate. An illustration of this can be seen in **Table 4** – well PA1 has a problem in month of March but is not attended by any rig in that month (no rig below group PA), hence it continues to be in the red for April where Rig 1 is allocated and the well returns to normal production in May.

Results

The schedule generated for Case A, B and C is shown in **Fig. 6, 7 and 8** respectively. In this study, case A ended up with the shortest distance (compare the “total” values in the “distance moved” column of **Table 4, 5 and 6**). Although the net distance traversed in the case C was bit higher than that for case A or B, the benefit here comes from the fact that it may have been possible to manage with one rig, hence this shows a potential to save on hiring cost of a rig (if not owned). Also the distances shown are hypothetical and based on grid i, j co-ordinates rather than real distances. However in reality we must keep in mind that we cannot have a schedule that is too tight. There has to be enough flexibility for unplanned events and hence in this case it may be necessary to have more than 1 workover rig in the field.

The scenarios studied in the 3 cases above are simplified by having some wells with very high potential and hence we were able to offset the lowered production due to wells needing attention by having some wells run at/near their potential.

Potential savings could result from

- reduction in costs due to better utilization of rigs,
- reduction in associated costs like workover team costs due to reduction in number of rigs,
- reduction in rig mobilization costs due to reduction in distance traveled by the rigs

Conclusions

A prototype application for visualization of workover rig schedules by reading reservoir simulation output was developed. The base case (case A) was modified based on analysis of the schedule visualized in the application and the potential and target production rates of the wells. The parameters studied were the net distance traveled and the number of rig used. The study shows the potential of using this approach for better planning and scheduling of rigs in the oilfield.

This paper also shows the interplay between group control strategy for a field and the rig allocation strategy. The complexity of this interaction are not handled by traditional rig scheduling tools which are typically used for managing schedules based on discrete events.

Future work can be carried out using this approach on lines similar to the drilling rig optimization[8] by relaxing some of the assumptions made in this paper and automating the process for optimization. Also visualization of rig schedules against an areal view of the wells (see **Fig. 9**) could give the team another perspective of the schedule against the physical locations to which the rigs are to be assigned. The results could be compared with existing tools used in-house in case of an operating company or for evaluation of other discrete event based rig scheduling software.

References

1. Product Brochure: "*WellPoint Rig Schedule*^{TM}*r*", www.wellpointsystems.com WellPoint Systems Inc (2007)
2. Product Brochure: "*Rig Activity Scheduler*^{TM}" www.actenum.com , Actenum Corporation (2007)
3. Product Demo: "*Creating a workover plan with PetroVR*^{TM}", www.caesarsystems.com, Caesar Petroleum Systems, LLC (2007)
4. Irani,B. : "Technology Update: Pemex Uses Data Management as a Vital Part of Decision Making in the Oil Patch", Journal of Petroleum Technology (Mar .2007)
5. Haslea, G. et al.: "*Well Activity Scheduling - An Application of Constraint Reasoning*", *Proc. of Practical Applications of Constraint Technology*, London, UK (1997)
6. Product Brochure: "*ClearVu*^{TM} *rig scheduling*", www.nutechsolutions.com, NuTech Solutions (2007)
7. Brennan, J.J. et al.: "*Scheduling a Backlog of Oilwell Workovers*", *Journal of Petroleum Technology* (Dec. 1977) 1651
8. Bittencourt A.C. : "*Optimal Scheduling of Development in an Oil Field*", Thesis Report, Stanford University (1994)
9. Aloise, D. et. al.: "*Scheduling Workover Rigs for Onshore Oil Production*", *Discrete Applied Mathematics* (Apr. 2006) **Volume 154** , **Issue 5**, 695
10. Unneland, T. et al.: "*Real-Time Asset Management: From Vision to Engagement-An Operator's Experience*", paper SPE 96930 presented at the 2005 SPE Annual Technical Conference and Exhibition, Dallas, Oct. 9-12

CASE A	potentials	targets			JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
PA1	2000	1000			1000	1500	500	500	1000	1000	1000	1000	500	1000	1000	1000
PA2	2000	1000			1000	500	1500	1500	1500	1500	1000	1000	1500	1000	1000	1000
PA3	2000	1000			1000	1000	1000	1000	500	500	1000	1000	1000	1000	1000	1000
PA Group	**6000**	**3000**			**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**
						RIG1		RIG1		RIG1			RIG1			
PB1	6000	2000			2000	2000	2000	3000	3200	2000	4400	2000	2000	2000	3200	2000
PB2	4000	2000			2000	2000	800	2200	800	2000	800	800	2000	2000	2000	2000
PB3	4000	2000			2000	2000	3200	800	2000	2000	800	3200	2000	2000	800	2000
PB Group	**14000**	**6000**			**6000**	**6000**	**6000**	**6000**	**6000**	**6000**	**6000**	**6000**	**6000**	**6000**	**6000**	**6000**
							RIG1	RIG2	RIG1		RIG2	RIG1			RIG1	
PC1	4000	3000			3000	3000	1000	4000	1000	3000	3000	4000	3000	3000	3000	3000
PC2	7000	3000			3000	3000	4000	4000	7000	5000	3000	1000	3000	3000	3000	3000
PC3	4000	3000			3000	3000	4000	1000	1000	1000	3000	4000	3000	3000	3000	3000
PC Group	**15000**	**9000**			**9000**	**9000**	**9000**	**9000**	**9000**	**9000**	**9000**	**9000**	**9000**	**9000**	**9000**	**9000**
							RIG2		RIG2	RIG2		RIG2				
Field rate					**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**

Table 1: Well production data (Case A)

CASE B	potentials	targets			JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
PA1	2000	1000			1000	1500	500	1000	1000	1000	1000	1000	500	1000	1000	1000
PA2	2000	1000			1000	500	1500	1000	1500	1000	1000	1000	1500	1000	1000	1000
PA3	2000	1000			1000	1000	1000	1000	500	1000	1000	1000	1000	1000	1000	1000
PA Group	**6000**	**3000**			**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**	**3000**
						RIG1	RIG1		RIG1				RIG1			
PB1	6000	2000			2000	2000	3200	4400	3200	4000	5200	5000	4000	2000	3200	2000
PB2	4000	2000			2000	2000	800	800	800	2000	800	800	2000	2000	2000	2000
PB3	4000	2000			2000	2000	2000	800	2000	2000	800	3200	2000	2000	800	2000
PB Group	**14000**	**6000**			**6000**	**6000**	**6000**	**6000**	**6000**	**8000**	**6800**	**9000**	**8000**	**6000**	**6000**	**6000**
								RIG2	RIG2		RIG2	RIG1			RIG1	
PC1	4000	3000			3000	3000	1000	4000	1000	1000	3000	4000	3000	3000	3000	3000
PC2	7000	3000			3000	3000	4000	4000	7000	5000	3000	1000	3000	3000	3000	3000
PC3	4000	3000			3000	3000	4000	1000	1000	1000	1000	1000	1000	3000	3000	3000
PC Group	**15000**	**9000**			**9000**	**9000**	**9000**	**9000**	**9000**	**7000**	**7000**	**6000**	**7000**	**9000**	**9000**	**9000**
							RIG2			RIG2		RIG2	RIG2			
Field rate					**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**16800**	**18000**	**18000**	**18000**	**18000**	**18000**

Table 2: Well production data (Case B)

CASE C	potentials	targets			JAN	FEB	MAR	APR	MAY	JUN	JUL	AUG	SEP	OCT	NOV	DEC
PA1	2000	1000			1000	1500	500	500	500	500	500	500	500	500	500	500
PA2	2000	1000			1000	500	1000	1000	1500	1500	2000	2000	1500	1500	1500	2000
PA3	2000	1000			1000	1000	1500	1500	500	500	500	500	500	500	500	500
PA Group	**6000**	**3000**			**3000**	**3000**	**3000**	**3000**	**2500**	**2500**	**3000**	**3000**	**2500**	**2500**	**2500**	**3000**
						RIG1										RIG1
PB1	6000	2000			2000	2000	2000	6000	4400	4000	4900	5500	4000	3700	3700	2000
PB2	4000	2000			2000	2000	800	800	800	2000	800	800	800	800	2000	2000
PB3	4000	2000			2000	2000	2000	800	2000	4000	800	3700	3700	2000	800	2000
PB Group	**14000**	**6000**			**6000**	**6000**	**4800**	**7600**	**7200**	**10000**	**6500**	**10000**	**8500**	**6500**	**6500**	**6000**
								RIG1	RIG1		RIG1			RIG1	RIG1	
PC1	4000	3000			3000	3000	1000	3000	1000	1000	3000	3000	3000	3000	3000	3000
PC2	7000	3000			3000	3000	5200	3400	6300	3500	4500	1000	1000	3000	3000	3000
PC3	4000	3000			3000	3000	4000	1000	1000	1000	1000	1000	3000	3000	3000	3000
PC Group	**15000**	**9000**			**9000**	**9000**	**10200**	**7400**	**8300**	**5500**	**8500**	**5000**	**7000**	**9000**	**9000**	**9000**
							RIG1			RIG1		RIG1	RIG1			
Field rate					**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**	**18000**

Table 3: Well production data (Case C)

	Rig No	Well No	Start Date	Duration	End Date	i	j	Distance moved
1	11	PA2	1-Feb-83	55.00	28-Mar-83	8	3	3.61
2	11	PB2	1-Mar-83	55.00	25-Apr-83	1	8	8.6
3	11	PA1	1-Apr-83	50.00	21-May-83	1	1	7
4	11	PB2	1-May-83	50.00	20-Jun-83	1	8	7
5	11	PA3	1-Jun-83	50.00	21-Jul-83	1	5	3
6	11	PB2	1-Aug-83	50.00	20-Sep-83	1	8	3
7	11	PA1	1-Sep-83	50.00	21-Oct-83	1	1	7
8	11	PB3	1-Nov-83	50.00	21-Dec-83	8	10	11.4
9	22	PC1	1-Mar-83	55.00	25-Apr-83	18	3	13.15
10	22	PB3	1-Apr-83	55.00	26-May-83	8	10	12.21
11	22	PC1	1-May-83	50.00	20-Jun-83	18	3	12.21
12	22	PC3	1-Jun-83	50.00	21-Jul-83	18	7	4
13	22	PB3	1-Jul-83	50.00	20-Aug-83	8	10	10.44
14	22	PC2	1-Aug-83	50.00	20-Sep-83	12	5	6.4
							Total =	**109.02**

Table 4: Workover rig schedule and rig movement data (Case A)

	Rig No	Well No	Start Date	Duration	End Date	i	j	Distance moved
1	11	PA2	1-Feb-83	55.00	28-Mar-83	8	3	3.61
2	11	PA1	1-Mar-83	55.00	25-Apr-83	1	1	7.28
3	11	PA3	1-May-83	50.00	20-Jun-83	1	5	4
4	11	PB2	1-Aug-83	50.00	20-Sep-83	1	8	3
5	11	PA1	1-Sep-83	50.00	21-Oct-83	1	1	7
6	11	PB3	1-Nov-83	50.00	21-Dec-83	8	10	11.4
7	22	PC1	1-Mar-83	50.00	20-Apr-83	18	3	13.15
8	22	PB3	1-Apr-83	50.00	21-May-83	8	10	12.21
9	22	PB2	1-May-83	55.00	25-Jun-83	1	8	7.28
10	22	PC3	1-Jun-83	55.00	26-Jul-83	18	7	17.03
11	22	PB3	1-Jul-83	50.00	20-Aug-83	8	10	10.44
12	22	PC2	1-Aug-83	50.00	20-Sep-83	12	5	6.4
13	22	PC3	1-Sep-83	50.00	21-Oct-83	18	7	6.32
							Total =	**109.12**

Table 5: Workover rig schedule and rig movement data (Case B)

	Rig No	Well No	Start Date	Duration	End Date	i	j	Distance moved
1	11	PA2	1-Feb-83	55.00	28-Mar-83	8	3	3.61
2	11	PC1	1-Mar-83	55.00	25-Apr-83	18	3	10
3	11	PB3	1-Apr-83	50.00	21-May-83	8	10	12.21
4	11	PB2	1-May-83	50.00	20-Jun-83	1	8	7.28
5	11	PC1	1-Jun-83	50.00	21-Jul-83	18	3	17.72
6	11	PB3	1-Jul-83	50.00	20-Aug-83	8	10	12.21
7	11	PC3	1-Aug-83	50.00	20-Sep-83	18	7	10.44
8	11	PC2	1-Sep-83	50.00	21-Oct-83	12	5	6.32
9	11	PB2	1-Oct-83	50.00	20-Nov-83	1	8	11.4
10	11	PB3	1-Nov-83	50.00	21-Dec-83	8	10	7.28
11	11	PA1	1-Dec-83	50.00	20-Jan-84	1	1	11.4
							Total =	**109.87**

Table 6: Workover rig schedule and rig movement data (Case C)

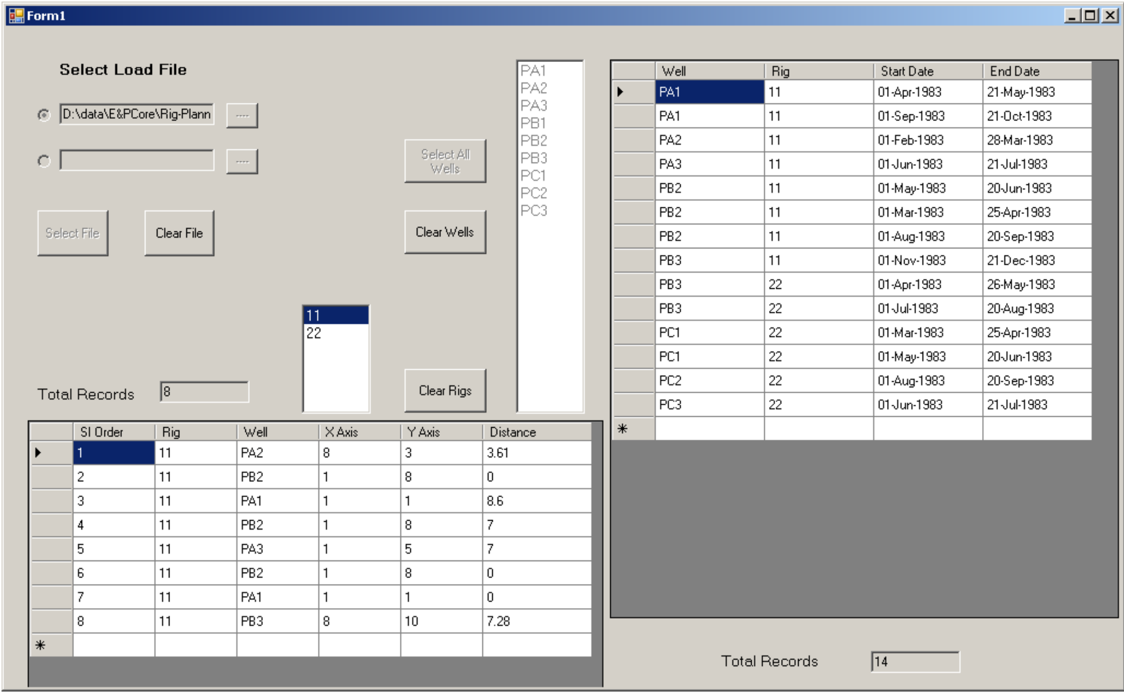

Fig. 1: Snapshot of the prototype application to analyze rig schedule and movement

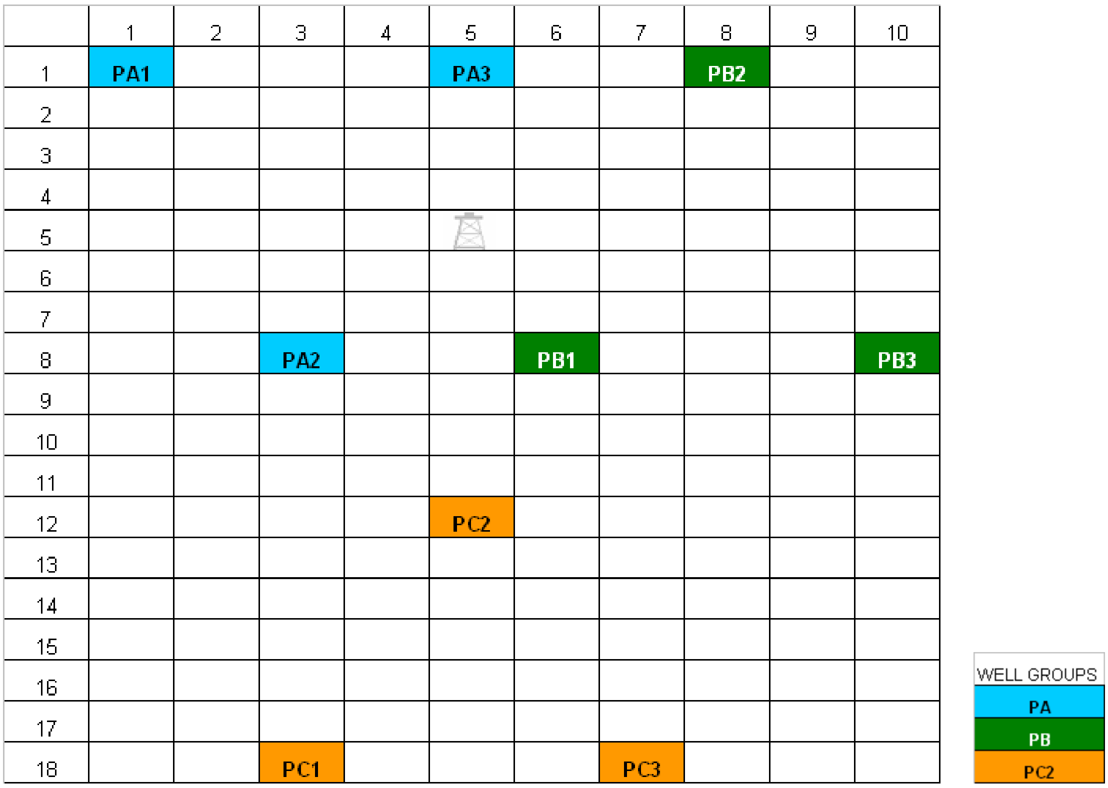

Fig. 2: Areal (schematic) view of wells and start location of workover rig

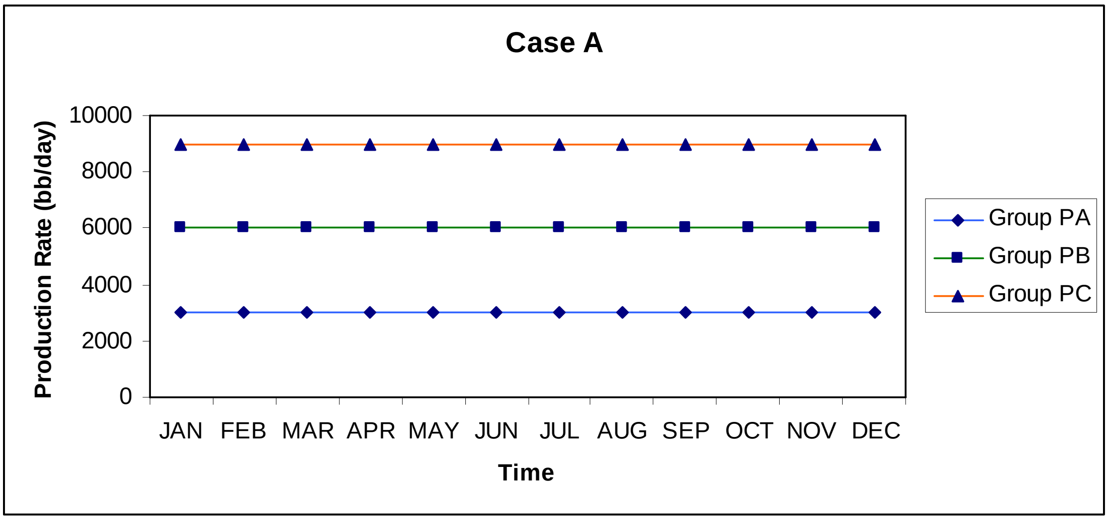

Fig. 3: Group production rates (Case A)

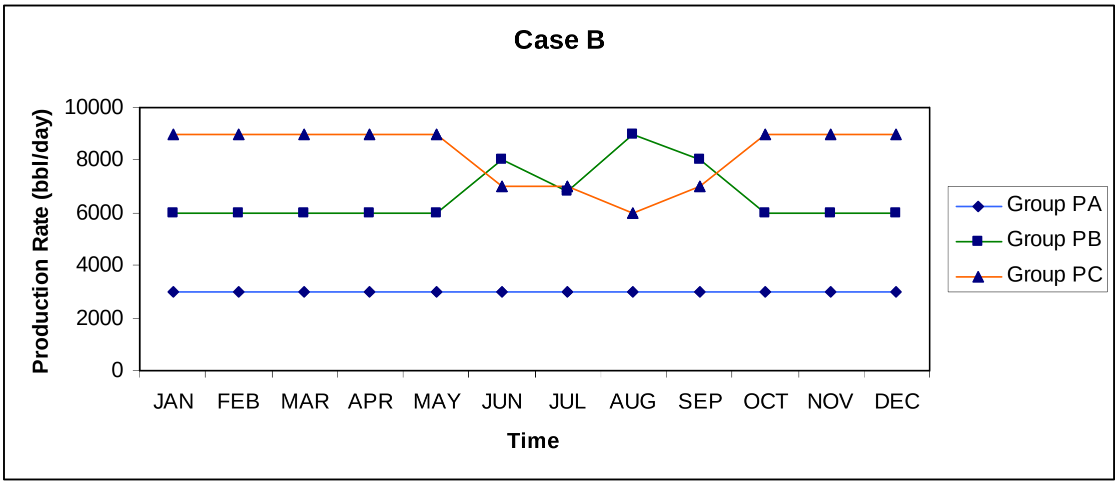

Fig. 4: Group production rates (Case B)

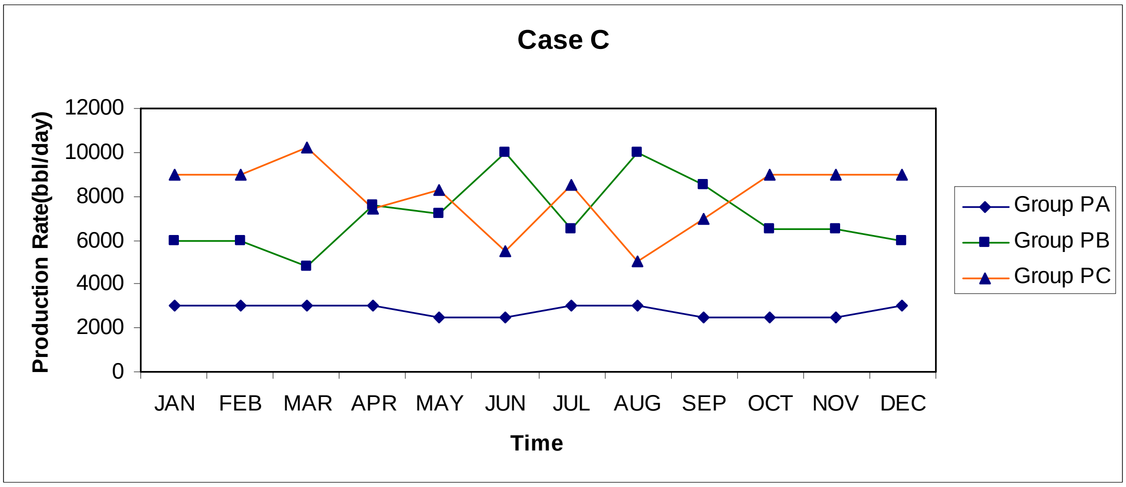

Fig. 5: Group production rates (Case C)

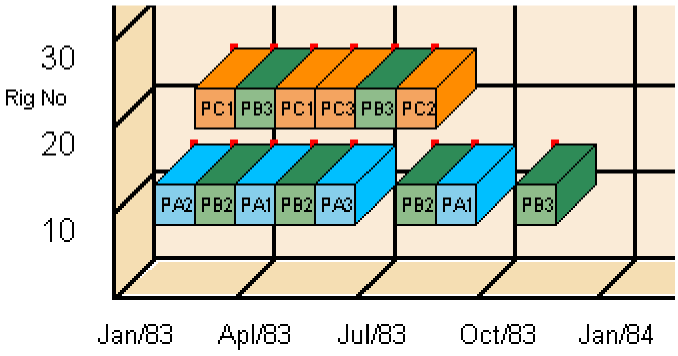

Fig. 6: Workover rig schedule chart (Case A)

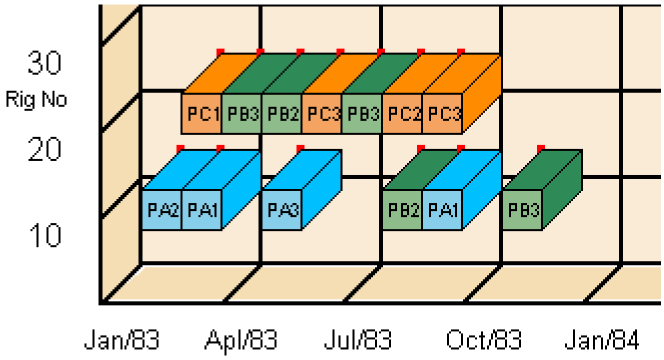

Fig. 7: Workover rig schedule chart (Case B)

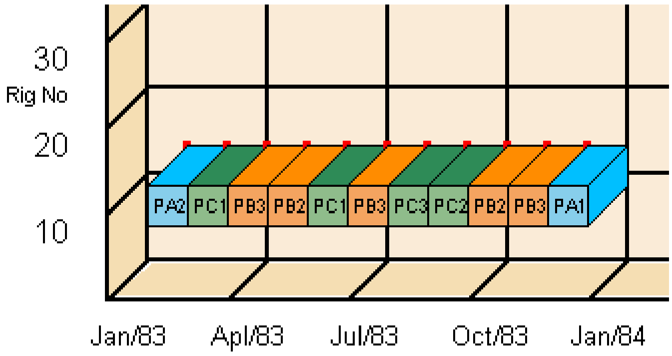

Fig. 8: Workover rig schedule chart (Case C)

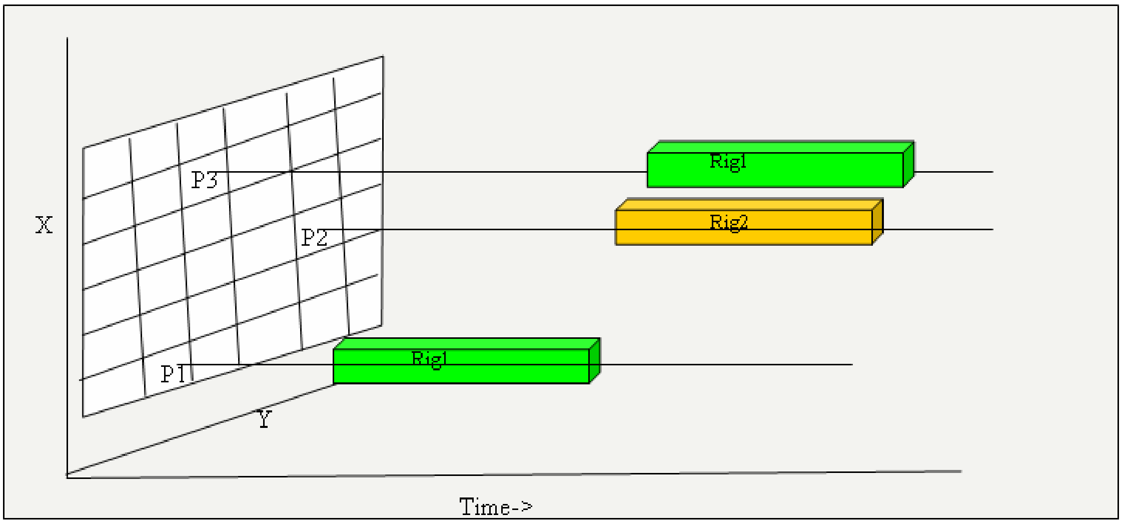

Fig. 9: 3D chart with rig schedule against areal (schematic) view of wells