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**Optimization of a Steam-Assisted Gravity Drainage Project in
the Monarch Sands of the South Midway-Sunset Field**

Technical Report

by

R. A. Chona
W.G. Hazlett
J.M. Rajtar

Petroleum and Natural Gas Engineering Department
New Mexico Institute of Mining and Technology

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TABLE OF CONTENTS

1. EXECUTIVE SUMMARY	
2. INTRODUCTION	2
3. CONCLUSIONS AND RECOMMENDATIONS	6
4. DISCUSSION	7
4.1 Study Approach	7
4.2 Reservoir Simulation Model	7
Geologic model	7
Rock and fluid properties	8
Reservoir simulation grid	8
Initial reservoir conditions	10
Injection/production wells	10
Cyclic injection and production	11
4.3 History Match Results	11
Oil and water production rates match	11
Temperature profile	12
Oil saturation profile	12
4.4 Summary of Cases Run	17
Base Case	18
Case 3 (1/3 of the vertical wells recompleted)	18
Case 5 (2/3 of the vertical wells recompleted)	18
Case h3 (5 horizontal infill wells)	19
Case h4 (5 horizontal wells replacing vertical producers)	19
Case h5 (5 horizontal wells with different injection schedule)	19

Case h7 (combination of 5 horizontal wells plus 1/3 vertical wells recompleted with different injection schedule)	19
Case h8 (combination of 5 horizontal wells plus 1/3 vertical wells recompleted with different injection schedule)	20
Case h9 (5 horizontal wells recompleted in upper layer 15)	20
Case h11 (3 horizontal wells spaced 400 ft with active vertical wells)	20
4.5 Model Prediction Runs for Base Case and Recompletion Alternatives	21
Comparison of cases Base Case, Case 3 and Case 5	21
4.6 Model Predictions Runs for Horizontal Well Alternatives	21
Comparison of cases Base Case, Case h3, Case h4, Case h5, Case h7, Case h8, Case h9 and Case h11	21
4.7 Model Prediction Runs Summary and Results	27
5. ACKNOWLEDGMENTS	31
6. REFERENCES	32
7. TABLES	33
8. APPENDICES	36

LIST OF FIGURES

Figure 1. Midway-Sunset field map.	3
Figure 2. Steam assisted gravity drainage, Monarch reservoir- South Midway-Sunset field.	4
Figure 3. Model gridblock.	9
Figure 4. Oil and water rates history match.	13
Figure 5. Water/oil ratio history match.	14
Figure 6. Initialization and matched temperature profiles.	15
Figure 7. Matched oil saturation profile.	16
Figure 8. Oil rates for Base Case, Case 3, and Case 5.	22
Figure 9. Cumulative oil production for Base Case, Case 3, and Case 5.	23
Figure 10. Cumulative oil production for Base Case, and Cases h3, h4, h5, and h7.	24
Figure 11. Cumulative oil production for Base Case and Cases h3, h8, and h9.	26
Figure 12. Cumulative oil production for Base Case, Case 3, Case h3, and Case h11.	28
Figure 13. Cumulative oil production for Base Case and Cases 3, 5, h3, and h8.	29
Figures in Appendix A	36
Figure A-1. Oil and water production rates for Base Case.	
Figure A-2. Cumulative oil and water production for Base Case.	
Figure A-3. Cumulative injection and steam/oil ratio for Base Case.	
Figure A-4. Temperature profiles for Base Case.	
Figure A-5. Pressure profiles for Base Case.	
Figure A-6. Oil saturation profiles for Base Case.	
Figure A-7. Oil and water production rates for Case 3.	

Figure A-8. Cumulative oil and water production for Case 3.

Figure A-9. Cumulative injection and steam/oil ratio for Case 3.

Figure A-10. Temperature profiles for Case 3.

Figure A-11. Pressure profiles for Case 3.

Figure A-12. Oil saturation profiles for Case 3.

Figure A-13. Oil and water production rates for Case 5.

Figure A-14. Cumulative oil and water production for Case 5.

Figure A-15. Cumulative injection and steam/oil ratio for Case 5.

Figure A-16. Initial and final temperature profiles for Case 5.

Figure A-18. Initial and final pressure profiles for Case 5.

Figure A-19. Initial and final oil saturation profiles for Case 5.

Figure A-20. Oil and water production rates for Case h3.

Figure A-21. Cumulative oil and water production for Case h3.

Figure A-22. Cumulative injection and Steam/oil ratio for Case h3.

Figure A-23. Initial and final temperature profiles for Case h3.

Figure A-24. Initial and final pressure profiles for Case h3.

Figure A-25. Initial and final oil saturation profiles for Case h3.

Figure A-26. Oil and water production rates for Case h4.

Figure A-27. Cumulative oil and water production for Case h4.

Figure A-28. Cumulative injection and Steam/oil ratio for Case h4.

Figure A-29. Initial and final temperature profiles for Case h4.

Figure A-30. Initial and final pressure profiles for Case h4.

Figure A-31. Initial and final oil saturation profiles for Case h4.

Figure A-32. Oil and water production rates for Case h8.

Figure A-33. Cumulative oil and water production for Case h8.

Figure A-34. Cumulative injection and Steam/oil ratio for Case h8.

Figure A-35. Initial and final temperature profiles for Case h8.

Figure A-36. Initial and final pressure profiles for Case h8.

Figure A-37. Initial and final oil saturation profiles for Case h8.

Figure A-38. Oil and water production rates for Case h9.

Figure A-39. Cumulative oil and water production for Case h9.

Figure A-40. Cumulative injection and Steam/oil ratio for Case h9.

Figure A-41. Initial and final temperature profiles for Case h9.

Figure A-42. Initial and final pressure profiles for Case h9.

Figure A-43. Initial and final oil saturation profiles for Case h9.

Figure A-44. Oil and water production rates for Case h11.

Figure A-45. Cumulative oil and water production for Case h11.

Figure A-46. Cumulative injection and steam/oil ratio for Case h11.

Figure A-47. Initial and final temperature profiles for Case h11.

Figure A-48. Initial and final pressure profiles for Case h11.

Figure A-49. Initial and final oil saturation profiles for Case h11.

Figure A-50. Cumulative oil and water production for Case h5.

Figure A-51. Cumulative injection for Case h5.

Figure A-52. Initial and final temperature profiles for Case h5.

Figure A-53. Initial and final pressure profiles for Case h5.

Figure A-54. Initial and final oil saturation profiles for Case h5.

Figure A-55. Cumulative oil and water production for Case h7.

Figure A-56. Cumulative injection for Case h7.

Figure A-56. Initial and final temperature profiles for Case h7.

Figure A-57. Initial and final pressure profiles for Case h7.

Figure A-58. Initial and final oil saturation profiles for Case h7.

1. EXECUTIVE SUMMARY

This report presents several scenarios for oil recovery optimization of Berry Petroleum Company's properties in the Midway-Sunset field in Kern County, California. The primary goal was to evaluate reservoir performance with a number of vertical wells recompleted in the lower half of the existing oil bank and with a number of horizontal infill wells. Case comparisons and recommendations are based solely on oil production rates and cumulative oil production obtained from the simulations; no economic analyses were performed as part of this study. The results indicate that recompleting two thirds of the vertical wells in the lower half of the existing oil bank will give the most improvement in oil recovery. The models also show that accelerated oil recovery will be obtained from the horizontal well scenario (Case h3), with initial oil rates higher than the vertical well recompletion scenario (Case 3). However, in the long term (11 year period), the cumulative oil production of the horizontal well will fall below that of the vertical well recompletion scheme (Case h3 vs. Case 3). Additionally, a combination of horizontal wells with recompletion of 1/3 of the vertical wells will give a significant improvement in oil recovery (Case h8).

We recommend that further studies focus on optimizing the amount of steam injected in horizontal wells, frequency and length of the steam-injection and steam-soak periods, optimal horizontal well spacing, and ideal location of horizontal well in the oil bank.

This study used Western Atlas' VIP-THERM numerical simulator to generate the history match and all of the alternative strategies presented in this report. The results presented in this report are based on information and field data provided by Berry Petroleum Company.

2. INTRODUCTION

The Midway-Sunset field in Kern County, California is a giant oil field with an estimated two billion barrels of original oil in place(Figure #1). Due to the low gravity (14 API) and high viscosity (2,300 cp. at 95 °F), thermal recovery techniques have been employed to produce oil from this field.

Berry Petroleum Company has been operating a steam assisted drainage project in the Monarch sands of the Midway-Sunset field, with an approximate production of 7,500 BOPD. The Monarch sands consist of thin 2 ft. to 10 ft. units aggregating about 1000 ft. in stratigraphic thickness. The beds dip at 60 to 70 degrees and the trap is provided by a truncating unconformity that dips at 20 degrees (Figure #2). The sands are high porosity (greater than 30%) and high oil saturation (approximately 80%), with a high OOIP of 1800 barrels/acre-ft. With an original oil column from 0 to 1000 ft. vertical and the high barrels per acre foot, the oil in place is very large for relatively small acreage. Over time, Berry Petroleum has developed its properties with tightly spaced wells (1/4 acre well spacing on average). Given the high dip angle of the Monarch Sands (60 degrees or more), the use of cyclic steam assisted gravity drainage with vertical wells at small spacing has been very effective, with residual oil saturations typically down to 10% in the depleted zones. The high efficiency of thermal recovery techniques has resulted in a recovery factor of 40% to date.

Due to reservoir depletion, a steam chest of 500 ft. or more (Figure #2) has developed over parts of the reservoir. Current cyclic steam operation practices with balanced injection and production rates and some venting of steam up the casing string have resulted in low reservoir pressures with the steam chest at or above atmospheric pressure (about 18 psia).

Midway-Sunset field

Figure # 1

STEAM ASSISTED GRAVITY DRAINAGE MONARCH RESERVOIR - SOUTH MIDWAY-SUNSET FIELD

Figure # 2

As the upper portion of the reservoir becomes depleted, cyclic steaming with existing vertical wells completed with slotted liners, is becoming less effective. Much of the injected steam goes to the steam chest while oil recovery per cycle has declined and steam oil ratio (SOR) has increased. Recompleting the wells in the oil zone, currently 200-400 ft. thick, has been effective. Because of the cost associated with recompletions and the age of many of the wells, recompleting all of the wells may not be practical or economical.

The objective of this study was to build a conceptual model that would match historical and current oil and water production rates of a section of Berry Petroleum's field, compare the production performance of a series of recompletion alternatives of existing vertical wells, and study the effectiveness of new horizontal well producers.

The model simulates a 500 ft. wide (strike direction) by a 800 ft. long (dip direction) section containing 18 plus acres with 80 wells on 1/4 acre spacing. The conceptual reservoir model approximates the 20 degree unconformity seal, different Monarch Sand units (8 layers each 100 ft. in thickness) with limited flow communication across sand units, vertical oil saturation and temperature profiles as currently exist in the reservoir, and permeability variations between sand units. The 60 degree dip of the reservoir beds is approximated with vertical layers. This approximation should account for gravity drainage and other fluid flow mechanisms for the purposes of this study.

In the first part of this study, we history matched and forecasted the recovery of the current steam assisted gravity drainage project (history match and base case). In the second part, we investigated different operating strategies during late stage depletion that resulted in recovery factors ranging from 50% to 73% over the next 24 years. The strategies included recompleting existing vertical wells and adding horizontal wells to optimize recovery. Total cyclic steam injection was held constant at 650 BSPD-CWE per well.

3. CONCLUSIONS AND RECOMMENDATIONS

Comparisons and recommendations based on the different scenarios presented in this report are based solely on oil production rates and cumulative oil production obtained from the simulations. No economic analyses were performed as part of this study. Based on our results, we have the following conclusions and recommendations:

1. Recompleting 2/3 of the vertical wells (Case 5) in the lower half of the oil bank will give the most improvement in oil recovery.
2. Accelerated oil recovery will be obtained from the horizontal well scenario (Case h3), with initial oil rates higher than the vertical well recompletion scenario (Case 3). However, in the long term (11 year period) the cumulative oil production of the horizontal well will fall below that of the vertical well recompletion scheme (Case h3 vs. Case 3).
3. A combination of horizontal wells with recompletion of 1/3 of vertical wells will give a significant improvement on oil recovery (Case h8).
4. Further studies should be performed to optimize the performance of the horizontal wells. These studies should include the amount of steam injected, frequency and length of the steam-injection and steam-soak periods, proper location in the oil column, and subsequently, the optimal horizontal well spacing.
5. The 60 degree dip should be included in future models to adequately account for wells crossing the bed boundaries.

4. DISCUSSION

4.1 Study Approach

With the data obtained from Berry Petroleum, a conceptual model was built to simulate a portion of the reservoir. Specific features such as the 20 degree unconformity seal, different Monarch sand units of varying permeability, and current vertical oil saturation and temperature profiles were considered in the model. This model was discussed with representatives of Berry Petroleum Company and approved as an adequate conceptual model of reservoir geometry and dynamics for this study.

The conceptual model was applied to match the average oil and water production from the Monarch Sands. Cumulative oil production was also compared to the simulation data of previous studies. The model was then applied to study various strategies of oil recovery. The recovery was optimized with reference to the number and location of vertical well recompletions and to new horizontal completions.

This study used Western Atlas' VIP-THERM numerical simulator to initialize the model, generate the history match and produce the alternative strategies presented in this report.

4.2 Reservoir Simulation Model

Geologic Model

The geological model is designed as a conceptual representation of a sector of the reservoir in Berry Petroleum's operation. The model considers eight different sand layers, each 100 ft. thick. The eight sand layers, which have high dips of 60 degrees or more, are modeled as vertical layers in the conceptual simulation model to simulate the vertical drainage component of the reservoir with minimal layer cross flow. The eight layers have

decreasing height reflecting the 20 degree dip that is due to the overlaying unconformity. Heat losses are simulated using the standard Vinsome and Westerveld¹ method, so bounding layers were not added to the reservoir model.

Rock and Fluid Properties

Rock and fluid property data used in this simulation model that were provided by Berry Petroleum Company are summarized in Table #1.

A dead oil option was used to simulate heavy oil flow in the reservoir. The relative permeability data was taken from E. E. Gomaa et al.², and was unmodified in the simulation (Table #2). Three phase permeabilities were calculated using Stone's Method 2.

Reservoir Simulation Grid

The simulation grid of size 15x24x18 was used in the simulation and is illustrated in Figure #3. The 20 degree overlaying unconformity is modeled by assigning zero porosity values to the upper gridblocks, thus giving the proper shape to the model. The total number of grid cells in the model is 5760. The grid size allowed us to simulate one half of the assumed original 80 well model using symmetry to arrive at full-size reservoir performance. The refined grid also allowed for a more accurate study of both vertical and horizontal infill well locations. In addition, run times were reduced to a reasonable level.

To simulate the reservoir, 18 horizontal layers of varying thicknesses were used. In the steam chest, the layers are 64 ft. thick and in the oil and oil-water zones, layers are 40 ft. thick. The bottom layer used to represent the aquifer is 100 ft. thick. In the dip direction, grid cells are 33.33 ft. wide in reservoir sands. In the direction normal to reservoir dip, all the cells are 33.33 ft. wide.

Figure 3

Initial Reservoir Conditions

The reservoir has undergone cyclic steam injection for an extended period of time. To approximate current conditions of the reservoir, the following data were assumed for initialization of the simulation model:

1. In the steam chest (of maximum thickness of 448 ft. decreasing to 64 ft. due to the overburden 20 degrees dip) the reservoir pressure, temperature, oil saturation, and water saturation are 18.9 psia, 225 °F, 0.1, and 0.45, respectively. The steam chest oil saturation of 0.1 is conservative in that the real situation will be gradational from 0.1 minimum to the full oil band saturation of 0.8. Continued oil drainage from the steam chest will not be reflected in this model.
2. In the oil zone, pressure increases with depth. The thickness of the oil band was assumed to be 400 ft. An oil-water transition zone of 40 ft. is included in the oil band. Oil and water saturations of the oil zone are set to 0.8 and 0.2, respectively.
3. An aquifer of thickness of 100 ft. is included in the model.
4. The temperature profile, modified according to the previous study, was assumed in all simulation runs and is reported in Table #3.

Injection/Production Wells

To simulate the average 1/4 acre well spacing, each of the 100 ft. by 100 ft. areas corresponding to 3x3 gridblocks contains the well in the center. The well index is calculated using Peaceman's equation and was adjusted to match average well production.

The total number of production/injection wells is 40. The completion assumes that the wells are perforated, including the steam chest region (from layer 5 to 15). The total number of perforated gridblocks is 460.

Cyclic Injection and Production

Cyclic injection and production are modeled by injecting up to 650 BSPD-CWE of 70% quality steam per well at a maximum injection pressure and temperature of 700 psia and 450 °F, respectively. The total cycle injection is 1950 BSPD-CWE. Three adjacent wells are steamed simultaneously during 10 days while the rest of the wells are producing. After the ten-day injection period, the same three wells are shut-in for a ten-day soak period, while another three adjacent wells are steamed and the rest are producing. This schedule is repeated until all the wells are steamed. To maintain symmetry, the last injection cycle is assigned to 4 wells. After one half of the steaming cycle, the simulated 40 wells are set on production to account for the steaming cycle moving to the second half of the 80 well reservoir.

The pressure in the steam chest remains below 20 psia in all simulation runs and honors the low pressure observed in the steam chest in the field.

Producing wells are pumping. These wells are kept at 15 psia bottomhole flowing pressure at 60 ft. above the aquifer.

4.3 History Match Results

Oil and Water Production Rates Match

History matching was performed on the basis of 80 wells. Simulation results for 80 wells are constructed by adding two sets of 40 well reservoir production data, where the second

set is shifted in time by the length of one half of a steaming cycle.. The well indices were modified during the matching phase. However, neither the temperature profile nor relative permeability data were changed to achieve the match.

A good history match is obtained after the simulator runs for approximately 2600 days. From then up to 4420 days the model matched the given oil and water production rates. Time 4420 days is set as "time zero" for performing the prediction runs. Figure #4 shows the water and oil production rates from the model vs. the oil field data. Figure #5 shows the water/oil ratio modeled vs. the field water/oil ratio. Simulation initialization data for the match are included in Appendix C.

Temperature Profile

The temperature profile averaged by layers at the final time of match (4420 days of simulated production, approximately July 1995) is presented and compared to the initialization temperature profile in Figure #6. As the figure shows, the highest temperatures are seen in layers 13, 14 and 15, while the lowest temperatures are in layers 16, 17 and 18. The approximately 110 °F increase in temperature in layers 13 through 15 has a major impact on oil drainage rates as the oil viscosity drops from 2275 cp. to 43 cp. over this temperature range.

Oil Saturation Profile

The oil saturation profile averaged by layers at the final time of the match (4420 days of simulated production, approximately July 1995) is presented and compared to the initialization oil saturation profile in Figure #7. The figure shows that the actual oil column height (oil saturation greater than 35%) at the beginning of running the various scenarios is approximately 280 ft., compared to 400 ft. at the time of start of history matching (approximately January 1990). The average model desaturation level drop of 22 ft. per

Field and simulated rate data

(Field rate data scaled to 80 wells)

Figure 4.

Field and simulated WOR
(field data scaled to 80 wells)

Figure 5.

Temperature Profile

History Match

Figure 6.

Oil Saturation Profile History Match

Figure 7

year is compatible with field observed rates of 10 to 20 ft. per year. High oil saturations ($S_o > 50\%$) are observed on layers 12 through 17, with the highest oil saturation in layer 14.

4.4 Summary of Cases Run

A number of cases were run for the purpose of the study. Primary goals were to evaluate reservoir performance with a number of vertical wells recompleted in the lower half of the existing oil bank, and with a number of horizontal infill wells. Cases were run after discussion and approval of Berry Petroleum Co. The following table shows code names assigned to cases and characteristics of each run. Subsequently, there is a brief description of each scenario. Each run simulated 11 to 12 years of future performance (except for 24 years in Case 3B and Case 5B). Names of runs are used throughout the following paragraphs and plots of this report. Production data for the 80 well scale were constructed from 40 well simulations in the same manner as the data for the match. All the reported curves and plots refer to the 800 ft. x 1,000 ft. reservoir with 80 wells.

Run Name	Characteristics of the Run	Length of Cycle, days
Base	The base case is a 12 year extension of the match run into the future	260
Case 3	1/3 of vertical wells recompleted in the lower half of the oil column, 12 years simulated (A) plus additional 12 years simulated (B)	260
Case 5	2/3 of vertical wells recompleted in the lower half of the oil column, 12 years simulated (A) plus additional 12 years simulated (B)	260
Case h3	5 horizontal infill wells, spaced 200 ft, all vertical wells active	380
Case h4	5 horizontal wells, spaced 200 ft, replacing 40 vertical wells	220
Case h5	Case h3, but horizontal infill wells steamed for initial three cycles, then only produced	360/260

Run Name	Characteristics of the Run	Length of cycle, days
Case h7	1/3 of vertical wells recompleted in the lower half of oil column plus 5 horizontal infill wells spaced 200 ft, horizontal wells steamed for initial three cycles, then only produced	380/260
Case h8	1/3 of vertical wells recompleted in the lower half of oil column plus 5 horizontal infill wells spaced 200 ft, horizontal wells steamed in all cycles	380
Case h9	Case h3, with the horizontal wells' completion moved from layer 16 to layer 15	380
Case h11	3 horizontal infill wells spaced 400 ft, all vertical wells active	360

1. Base Case. Continue cyclic steaming with all wells in the model and inject steam into all sand intervals in each well. This is the base case for comparing with other well configurations and steam injection schedules. The steam injection period or length of the injection cycle is defined as the time it takes for all the wells in the different configurations to be cyclic steamed once. The length of the injection period for the base case is 260 days and it is repeated over the 24 year simulation.

2. Case 3. Recomplete 1/3 of the wells (24 of 80 wells) in the lower 200 ft of the oil band (layers 14, 15 and 16) but above the oil-water transition zone and cyclic steam all the wells over a 260 day period repeated for 24 years. The recompleted wells were selected randomly and the only criteria for selecting or disregarding a well was attempting to have an even distribution of recompleted wells throughout the model.

3. Case 5. Recomplete 2/3 of the wells (54 of 80 wells) in the lower 200 ft. of oil band (layers 14, 15 and 16) but above the oil-water transition zone and cyclic steam all the wells over a 260 day period repeated for 24 years. This case used the wells selected in the previous case (Case 3) plus an additional 1/3 of wells.

4. Case h3. For this case five horizontal infill wells were added at a 200 ft well spacing. The horizontal wells were perforated in the base of the lower 200 ft oil column (layer 16, 60 ft. above the oil-water contact) simulating a 766 ft. horizontal section. The amount of steam injected into each horizontal well during the ten day injection period was three times as much steam as is injected into a vertical well (1950 BSPD-CWE). These horizontal wells are steamed twice alternating with the vertical wells during the 380 day period, repeated for 11 years. The well index (WI) for the horizontal wells in all of the cases was decreased slightly (from 0.60 to 0.58) to account for the horizontal geometry.

5. Case h4. For this case five horizontal infill wells were added at a 200 ft well spacing. The horizontal wells were perforated at the base of the 200 ft oil column (layer 16, 60 ft. above the WOC) to simulate 766 ft. of horizontal length and each horizontal well replaced eight vertical wells (for a total of 40 vertical wells which are shut-in). The shut-in of the vertical wells is the primary difference with case h3. The amount of steam injected into each horizontal well during the ten day injection period (1950 BSPD-CWE) was three times as much steam as was injected into a vertical well. These horizontal wells were cyclic steamed twice alternating with the vertical wells during the 220 day period, repeated for 11 years.

6. Case h5. Same as Case h3, but the horizontal wells were cyclic steamed during three 380 day injection periods and then kept as producers only. The vertical wells were cyclic steamed as usual for the 11 year simulation.

7. Case h7. A combination of five horizontal wells with 1/3 of the vertical wells recompleted. The horizontal wells were cyclic steamed only during the first three injection cycles and then kept as producers. The recompleted vertical wells are the same as those used in Case 3 and were cyclic steamed during the 11 year simulation run.

8. Case h8. A combination of five horizontal wells with 1/3 of the vertical wells recompleted. The horizontal wells were cyclic steamed during all the injection cycles alternating with the vertical wells for the 11 year simulation. The recompleted vertical wells were the same as those used in Case 3.

9. Case h9. Same scheme as case h3, but the perforations of the horizontal wells are moved from layer 16 to layer 15, 100 ft. above the WOC.

10. Case h11. For this case three horizontal infill wells at a 400 ft. well spacing were added. The horizontal wells were perforated at the base of the lower 200 ft oil column (layer 16) simulating 766 ft. of horizontal length. The amount of steam injected into each horizontal well during the ten day injection period (1950 BSPD-CWE) was three times as much steam as was injected into a vertical well. These horizontal wells were cyclic steamed twice alternating with the vertical wells during the 360 day period, repeated for 11 years.

Appendix A shows plots of oil rate, water rate, cumulative oil production, steam oil ratio, and initial and final temperature profiles for each reported case (Refer to list of figures in the appendix). Cases h5 and h7 in Appendix A are illustrated using cumulative values only as the change of steaming cycle during the run results in an inability to properly construct a symmetrical response of the full scale reservoir for daily rates. Appendix B shows a table of cumulative oil production, cumulative water production, cumulative steam injection (CWE), and recovery factors for each of the cases presented in this study. Paragraphs below discuss comparisons between selected cases.

4.5 Model Prediction Runs for Base Case and Vertical Recompletion Cases

At the request of Berry Petroleum, the Base Case and cases of vertical recompletions were run for periods of 24 years into the future. Figure #8 shows oil rates for Base Case, Case 3 (1/3 of vertical wells recompleted in the lower half of the oil column), and Case 5 (2/3 of vertical wells recompleted in the lower half of the oil column). Figure #9 shows cumulative oil production for these cases. Comparing all the alternatives simulated, Case 5 shows the best improvement in oil recovery. The oil saturation profile for this case (Figure A-19) shows the greatest saturation reduction occurring in layers 12, 13, and 14. This is expected since as steam is injected in layers 14, 15 and 16, it will tend to override and heat the uppermost portion, permitting a good viscosity reduction on these areas. From the temperature profiles (Figure A-17) we can observe good temperature increases through the steam chest zone and oil zone, allowing for more viscosity reduction in the upper oil band (layers 9, 10 and 11). The primary oil producing mechanism observed is improved oil mobility by viscosity reduction due to the effective heat delivered to the cold oil bank.

For cases 3 and 5, pressure increased slightly over time in the steam chest region (up to 23 psi for Case 3 and 30 psi for Case 5) and decreased in the oil bank. The lower reservoir pressure in the oil bank is caused by higher oil and water production from these layers.

4.6 Model Prediction Runs for Horizontal Wells Alternatives

All the alternatives with horizontal wells show an incremental oil recovery above the Base Case. Figure #10 shows the cumulative oil production for the Base Case, Case h3, h4, h5, and h7. Case h3 is a reference case for comparisons with the other horizontal well scenarios. The temperature profile (Figure A-23) for Case h3 shows an increase of approximately 30 °F over the steam chest area and the upper portion of the oil bank; oil

Figure 8.

production comes from layers 9, 10 and 12, due to improved mobility by oil viscosity reduction. Also, considerable temperature increase is observed in layers 16 and 17.

Comparing Case h4 (5 horizontal wells replacing vertical wells) against Case h3, in figure #10, Case h4 has cumulative oil production lower than that of Case h3 at the beginning of the simulation. However, after 2200 days, Case h4 exceeds the cumulative oil production of Case h3 and ends with a better oil recovery. The low oil production rate at the beginning is the result of shutting in some of the vertical wells. However, at the same time, this allows for more heat to be kept in the reservoir permitting a greater increase in temperature and increase in oil recovery at later times.

Figure #11 compares the cumulative oil production for cases: Base Case, h3, h8 and h9. Case h8 (combination of horizontal producers and 1/3 of vertical wells recompleted, and wells steamed in all cycles) shows the best oil recovery of all the horizontal well strategies. Case h7 (combination of horizontal producers and 1/3 of vertical wells recompleted, horizontal wells steamed only during the first three cycles) on figure #10 approximates the performance of Case h8. Having horizontal wells plus the recompleted vertical wells delivering steam to the lower layers improves the efficiency of the steam cycles by transferring the heat directly to the cooler oil bank. The oil production comes mostly from the middle oil bank layers (12, 13, 14), and from the upper oil bank layers (9, 10, 11) since the steam chest is also warming up over time.

Case h9 (horizontal wells recompleted in layer 15 vs. layer 16 in other horizontal cases, 100 ft. above WOC) has an accelerated recovery during the first 1200 days that is higher than Case h8, but then falls below Case h8 and ends with a lower cumulative oil production. This suggests that further considerations should be given to the optimal location of the horizontal well in the oil column.

Case h11 (horizontal infill wells at 400 ft. spacing) in figure #12, shows cumulative oil production below Case h3 (horizontal infill wells at 200 ft. spacing). Since the simulated reservoir has a thick oil column, closely spaced wells will give higher oil recovery. Nevertheless, optimal horizontal well spacing should be investigated further.

4.7 Model Prediction Runs Summary and Results.

Figure #12 shows the cumulative oil produced for cases: Base Case, 3, h3 and h11. Of these scenarios, Case 3 (1/3 recompleting vertical wells) shows the highest incremental oil recovery above the base case. Case h3 shows an accelerated oil recovery over Case 3 during the first 2200 days but ends with a lower cumulative recovery. Case h11 (horizontal wells at 400 ft. spacing) does not show a significant improvement in recovery over the Base Case.

Figure #13 shows the cumulative oil produced for cases: Base Case, 3, 5, h3 and h8. The alternative with the best cumulative production is Case 5, where 2/3 of the wells are recompleting. Case h8 shows higher oil recovery than Case 5 during the first 2300 days, but after 4000 days it ends with a lower cumulative recovery. Similar behavior is shown by case h3 when compared to Case 3.

Summarizing the results from the simulations:

1. All alternative strategies improve recovery significantly (12% to 32%) over the Base Case, except cases h5 and h11.
2. The largest improvement in recovery over the Base Case (32%) comes with recompleting of 2/3 of the vertical wells, Case 5.
3. Recompleting of 1/3 of the vertical wells, Case 3, gives a significant recovery improvement over the Base Case (14%).

Figure 12.

4. Case h3, infill horizontal wells at 200 ft. spacing and recurrent steaming, gives a similar recovery (12%) to Case 3, 1/3 of the vertical wells recompleted (14 %).
5. Case h4, horizontal wells replacing vertical wells, gives a good recovery improvement over the Base Case in the long run (23%), with lower initial rates.
6. Case h5, infill horizontal wells with only three steaming cycles, has only a minor improvement over the Base Case (5%).
7. Case h8, combination of infill horizontal wells on a 200 ft. spacing with recurrent restreaming and 1/3 vertical wells recompleted, gives the best performance of all the horizontal cases (27%) and approximates the best recovery, Case 5 (32%).
8. Case h11, horizontal infill wells at 400 ft. spacing, has no significant recovery improvement over the Base Case, and results in 10% reduction when compared to the Case h3 (horizontal infill wells at 200 ft spacing).
9. Further investigations with respect to the horizontal well in the following areas should be considered:
 - a) Proper location of the horizontal well in the oil bank.
 - b) Optimum amount of steam injected.
 - c) Length and frequency of the injection-soak period for a horizontal well.
 - d) Optimum horizontal well spacing.

The following table summarizes the cumulative oil and water production, cumulative steam injected, and the recovery factors for each of the scenarios considered. The recovery factors are calculated from the original oil in place. The recovery factor at the initialization time of the model (January 1990) is approximately 40%. The recovery factor estimated at the beginning of forecasting (July 1995) is 58.6%. The incremental recovery factor is the relative difference in cumulative production between each run and the Base Case.

	Cumulative Oil, MSTB	Cumulative water, MSTB	Cumulative Injection MSTB-CWE	Recovery Factor (%)	Incremental recovery over Base Case (%)
Base Case (11 yrs)	1,807	7,361	7,865	66%	0%
Case 3 (11 yrs)	2,062	7,096	7,646	67%	14%
Case 5 (11 yrs)	2,385	6,678	7,475	69%	32%
Base Case (24 yrs)	2,688	15,803	16,914	70%	0%
Case 3 (24 yrs)	3,034	15,808	16,588	72%	13%
Case 5 (24 yrs)	3,446	15,584	16,226	73%	28%
Case h3 (11 yrs)	2,031	7,567	7,828	67%	12%
Case h4 (11 yrs)	2,215	7,512	8,031	68%	23%
Case h5 (11 yrs)	1,906	7,159	7,704	67%	5%
Case h7 (11 yrs)	2,224	6,898	7,536	68%	23%
Case h8 (11 yrs)	2,310	8,844	7,680	68.5%	27%
Case h9 (11 yrs)	2,120	7,369	7,815	68%	17%
Case h11 (11 yrs)	1,854	7,656	7,833	66.5%	2%

5. ACKNOWLEDGMENTS

We wish to thank Los Alamos National Laboratories for providing the funding for this study.

6. REFERENCES

1. Western Atlas Software, "VIP-Therm Reference Manual", 2nd. Edition, January 1994.
2. E.E. Gormaa et al. "Designing a Steamflood Pilot in the Thick Monarch Sand of the Midway Sunset Field", JPT, December 1977

7. TABLES

Table 1 Rock and fluid properties.

Porosity	0.30	Fraction
Rock compressibility	3 .000E-6	1/psi
Rock heat capacity	35.0	BTU/lbm °F
Oil API gravity	14	
Oil compressibility	5.000E-6	1/psi
Coefficient of thermal expansion	3.800E-6	
Oil thermal capacity	0.5	BTU/lbm °F
Oil saturation (in oil band)	0.80	Fraction

Rock permeabilities and inter sand layer transmissibilities.

Sand Unit	Permeability (md)	Transmissibility multiplier
1	1500	
2	750	0.05
3	1000	0.02
4	200	0.05
5	300	0.05
6	1500	0.05
7	1000	0.05
8	1500	0.02

Viscosity variation with temperature.

Temperature, °F	Viscosity, cp
90	6000
100	3500
120	1050
140	470
160	200
180	118
200	62
240	23
280	11
300	10
400	5
500	2

Table 2 Relative Permeability Data, Monarch Sands, after E. E. Gomaa et al.²

Sw	Kro	Krow
0.25	0.0	0.925
0.30	0.001	0.870
0.35	0.002	0.750
0.40	0.005	0.500
0.45	0.010	0.240
0.50	0.014	0.120
0.55	0.018	0.040
0.60	0.022	0.0
0.625	0.030	0.0

Sg	Krg	Krog
0.0	0.0	0.925
0.05	0.025	0.540
0.10	0.050	0.340
0.15	0.085	0.240
0.20	0.130	0.160
0.25	0.200	0.100
0.30	0.280	0.050
0.35	0.380	0.030
0.40	0.480	0.010
0.43	0.500	0.0
0.45	0.510	0.0

Temperature Dependant Endpoints

	105 °F	300 ° F	600 ° F
Swc	0.250	0.370	0.400
Sorw	0.375	0.267	0.175
Sorg	0.300	0.100	0.080
Krwro	0.030	0.260	0.500
Krocw	0.925	0.845	0.785
Krgro	0.510	0.720	0.750

Table 3 Reservoir temperature profile used for the initialization run.

Vertical layer	Temperature ,°F
1	225
2	225
3	225
4	225
5	225
6	225
7	225
8	195
9	162
10	110
11	110
12	110
13	110
14	110
15	110
16	110
17	110
18	110

APPENDIX A

Figures in Appendix A

- Figure A-1. Oil and water production rates for Base Case.
- Figure A-2. Cumulative oil and water production for Base Case.
- Figure A-3. Cumulative injection and steam/oil ratio for Base Case.
- Figure A-4. Temperature profiles for Base Case.
- Figure A-5. Pressure profiles for Base Case.
- Figure A-6. Oil saturation profiles for Base Case.
- Figure A-7. Oil and water production rates for Case 3.
- Figure A-8. Cumulative oil and water production for Case 3.
- Figure A-9. Cumulative injection and steam/oil ratio for Case 3.
- Figure A-10. Temperature profiles for Case 3.
- Figure A-11. Pressure profiles for Case 3.
- Figure A-12. Oil saturation profiles for Case 3.
- Figure A-13. Oil and water production rates for Case 5.
- Figure A-14. Cumulative oil and water production for Case 5.
- Figure A-15. Cumulative injection and steam/oil ratio for Case 5.
- Figure A-16. Initial and final temperature profiles for Case 5.
- Figure A-18. Initial and final pressure profiles for Case 5.
- Figure A-19. Initial and final oil saturation profiles for Case 5.
- Figure A-20. Oil and water production rates for Case h3.
- Figure A-21. Cumulative oil and water production for Case h3.
- Figure A-22. Cumulative injection and Steam/oil ratio for Case h3.
- Figure A-23. Initial and final temperature profiles for Case h3.
- Figure A-24. Initial and final pressure profiles for Case h3.
- Figure A-25. Initial and final oil saturation profiles for Case h3.
- Figure A-26. Oil and water production rates for Case h4.
- Figure A-27. Cumulative oil and water production for Case h4.

Figure A-28. Cumulative injection and Steam/oil ratio for Case h4.
Figure A-29. Initial and final temperature profiles for Case h4.
Figure A-30. Initial and final pressure profiles for Case h4.
Figure A-31. Initial and final oil saturation profiles for Case h4.
Figure A-32. Oil and water production rates for Case h8.
Figure A-33. Cumulative oil and water production for Case h8.
Figure A-34. Cumulative injection and Steam/oil ratio for Case h8.
Figure A-35. Initial and final temperature profiles for Case h8.
Figure A-36. Initial and final pressure profiles for Case h8.
Figure A-37. Initial and final oil saturation profiles for Case h8.
Figure A-38. Oil and water production rates for Case h9.
Figure A-39. Cumulative oil and water production for Case h9.
Figure A-40. Cumulative injection and Steam/oil ratio for Case h9.
Figure A-41. Initial and final temperature profiles for Case h9.
Figure A-42. Initial and final pressure profiles for Case h9.
Figure A-43. Initial and final oil saturation profiles for Case h9.
Figure A-44. Oil and water production rates for Case h11.
Figure A-45. Cumulative oil and water production for Case h11.
Figure A-46. Cumulative injection and steam/oil ratio for Case h11.
Figure A-47. Initial and final temperature profiles for Case h11.
Figure A-48. Initial and final pressure profiles for Case h11.
Figure A-49. Initial and final oil saturation profiles for Case h11.
Figure A-50. Cumulative oil and water production for Case h5.
Figure A-51. Cumulative injection for Case h5.
Figure A-52. Initial and final temperature profiles for Case h5.
Figure A-53. Initial and final pressure profiles for Case h5.
Figure A-54. Initial and final oil saturation profiles for Case h5.
Figure A-55. Cumulative oil and water production for Case h7.
Figure A-56. Cumulative injection for Case h7.

Figure A-56. Initial and final temperature profiles for Case h7.

Figure A-57. Initial and final pressure profiles for Case h7.

Figure A-58. Initial and final oil saturation profiles for Case h7.

Oil and Water Production Rates

Base Case

Figure A-1

Cumulative Oil and Water Production Base Case

Figure A-2

Cumulative Injection and SOR Base Case

Figure A-3

Temperature Profile
Base Case

Figure A-4

Pressure Profile Base Case

Figure A-5

Oil Saturation Profile Base Case

Figure A-6

Oil and Water Production Rates

Case 3

Figure A-7

Cumulative Oil and Water Production

Case 3

Figure A-8

Cumulative Injection and SOR Case 3

Figure A-9

Temperature Profile
Case 3

Figure A-10

Pressure Profile
Case 3

Figure A-11

Oil Saturation Profile Case 3

Figure A-12

Oil and Water Production Rates

Case 5

Figure A-13

Cumulative Oil and Water Production Case 5

Figure A-14

Cumulative Injection and SOR Case 5

Figure A-15

Temperature Profile
Case 5

Figure A-16

Pressure Profile

Case 5

Figure A-17

Oil Saturation Profile Case 5

Figure A-18

Oil and Water Production Rates Case h3

Figure A-19

Cumulative Oil and Water Production Case h3

Figure A-20

Cumulative Injection and SOR Case h3

Figure A-21

Temperature Profile
Case h3

Figure A-22

Pressure Profile
Case h3

Figure A-23

Oil Saturation Profile
Case h3

Figure A-24

Oil and Water Production Rates

Case h4

Figure A-25

Cumulative Oil and Water Production Case h4

Figure A-26

Cumulative Injection and SOR

Case h4

Figure A-27

Temperature Profile Case h4

Figure A-28

Pressure Profile

Case h4

Figure A-29

Oil Saturation Profile
Case h4

Figure A-30

Oil and Water Production Rates

Case h8

Figure A-31

Cumulative Oil and Water Production Case h8

Figure A-32

Cumulative Injection and SOR Case h8

Figure A-33

Temperature Profile

Case h8

Figure A-34

Pressure Profile

Case h8

Figure A-35

Oil Saturation Profile Case h8

Figure A-36

Oil and Water Production Rates

Case h9

Figure A-37

Cumulative Oil and Water Production Case h9

Figure A-38

Cumulative Injection and SOR Case h9

Figure A-39

Figure A-40

Pressure Profile Case h9

Figure A-41

Oil Saturation Profile

Case h9

Figure A-42

Oil and Water Production Rates

Case h11

Figure A-43

Cumulative Oil and Water Production Case h11

Figure A-44

Cumulative Injection and SOR

Case h11

Figure A-45

Temperature Profile Case h11

Figure A-46

Pressure Profile

Case h11

Figure A-47

Oil Saturation Profile Case h11

Figure A-48

Cumulative Oil and Water Production Case h5

Figure A-49

Cumulative Injection Case h5

Figure A-50

Temperature Profile Case h5

Figure A-51

Pressure Profile Case h5

Figure A-52

Oil Saturation Profile Case h5

Figure A-53

Cumulative Oil and Water Production

Case h7

Figure A-54

Cumulative Injection Case h7

Figure A-55

Temperature Profile Case h7

Figure A-56

Pressure Profile

Case h7

Figure A-57

Oil Saturation Profile Case h7

Figure A-58

APPENDIX B

Cumulative oil and water production, steam injection and recovery factors for cases run.

	Cumulative Oil, MSTB	Cumulative water, MSTB	Cumulative Injection MSTB-CWE	Recovery Factor (%)	Incremental recovery over Base Case (%)
Base Case (11 yrs)	1,807	7,361	7,865	66%	0%
Case 3 (11 yrs)	2,062	7,096	7,646	67%	14%
Case 5 (11 yrs)	2,385	6,678	7,475	69%	32%
Base Case (24 yrs)	2,688	15,803	16,914	70%	0%
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Case 5 (24 yrs)	3,446	15,584	16,226	73%	28%
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Case h4 (11 yrs)	2,215	7,512	8,031	68%	23%
Case h5 (11 yrs)	1,906	7,159	7,704	67%	5%
Case h7 (11 yrs)	2,224	6,898	7,536	68%	23%
Case h8 (11 yrs)	2,310	8,844	7,680	68.5%	27%
Case h9 (11 yrs)	2,120	7,369	7,815	68%	17%
Case h11 (11 yrs)	1,854	7,656	7,833	66.5%	2%

APPENDIX C

Simulation initialization data for the matching run and Base Case

```
C .....
C INITIALIZATION FILE FOR MONARCH SANDS SIMULATION
C .....
C
C THIS IS THE INITIALIZATION CORE FILE WITH JPT RELATIVE
C PERMEABILITY CURVES AND ASSUMING HEATLOSS IN ALL DIRECTIONS
C EXCEPT SYMMETRY PLANE
C GRID CHANGES (40 wells simulation)
C
C TITLES
INIT
DIM NHLMAX
2200
TITLE1
MONARCH SANDS PROJECT
TITLE2
15X24X18 huff & puff
TITLE3
data file version 12/1/95
C .....INITIAL DATE
C
DATE 1 1 1993
C ..... VIP-THERM SIMULATION
THERMAL
MAP FORM
PLOT FORM
STONE2
C ..... GRID DIMENSIONS
C ..... DEAD OIL ASSUMED
NX NY NZ NCOMP NCV
15 24 18 1 0
C ..... PHYSICAL PROPERTY CONSTANTS
DWB CR DCPRDT DKTDG TRES TS PS
1.000000 3.000E-6 0.0 0.0 200.0000 60.00000 14.65000
C ..... TABLES
TABLES
IEQUIL PINIT DEPTH PCWOC WOC PCGOC GOC PSAT
1 42.00000 548.00000 0.0000000 908.00000 0.0000000 548.00000 50.0
C ..... WATER SATURATION TABLES
C ..... RELATIVE PERM DATA ( TABLE 1)
SWT 1
SW KRW KROW PCWO
0.2500 0.0 0.925 0.0
0.3000 0.001 0.87 0.0
0.35 0.002 0.75 0.0
0.4 0.005 0.5 0.0
0.45 0.01 0.24 0.0
0.5 0.014 0.12 0.0
0.55 0.018 0.04 0.0
0.6 0.022 0.0 0.0
0.625 0.03 0.0 0.0
C ..... GAS SATURATION TABLES
C ..... RELATIVE PERM DATA TABLE 1
SGT 1
SG KRG KROG PCGO
0.0 0.0 0.925 0.0
0.05 0.025 0.54 0.0
0.10 0.05 0.34 0.0
0.15 0.085 0.24 0.0
0.20 0.13 0.16 0.0
0.25 0.2 0.1 0.0
```

0.30 0.28 0.05 0.0
 0.35 0.38 0.03 0.0
 0.40 0.48 0.01 0.0
 0.43 0.5 0.0000 0.0
 0.45 0.51 0.0000 0.0
 C
 C ENDPOINT VALUES TEMPERATURE-DEPENDENT, TABLE 1
 C
 TENDPT 1
 TEMP 100 300 600
 SWIR 0.25 0.37 0.4
 SGC 0.05 0.05 0.05
 SORW 0.375 0.267 0.175
 SORG 0.3 0.1 0.08
 KRWRO 0.03 0.26 0.5
 KROCW 0.925 0.845 0.785
 KRGRO 0.51 0.72 0.75
 C OIL PROPERTIES
 C DEAD OIL MODEL PVT CORRELATION OPTION
 OILPROPS
 C ASSUMED MOLECULAR WEIGHT
 MWOIL 600
 C ASSUMED 14 API GRAVITY
 DOSTD 0.9725
 C ASSUMED OIL COMPRESSIBILITY
 COIL 5E-6
 C ASSUMED COEFFICIENT OF THERMAL EXPANSION
 CTEOIL 3.8E-4
 C ASSUMED OIL THERMAL CAPACITY
 CPOIL 0.5
 C OIL VISCOSITY TABLES
 VISOIL
 T VISCOSITY
 90 6000
 100 3500
 120 1050
 140 470
 160 200
 180 118
 200 62
 240 23
 280 11
 300 10
 400 5
 500 2
 C ARRAY DATA
 ARRAYS
 C INITIAL SATURATIONS, TEMPERATURE
 SW ZVAR
 7*0.45 9*0.2 0.6 0.99999
 SG ZVAR
 7*0.45 11*0.0
 TEMP ZVAR
 7*225 195 167 120 8*110
 P ZVAR
 18.0 18.3 18.5 18.7 18.9 19.2 19.8 35 52 69 86 103 120 137 154 171 190 210
 C GRID DIMENSIONS
 DX XVAR
 15*33.33
 DY YVAR
 24*33.33
 DZ ZVAR
 7*64.0 10*40.0 100.0
 C DEPTH TO CRIDBLOCK TOP
 DEPTH LAYER
 360*100
 C POROSITY
 POR CON

```

0.3
C ..... POROSITY MODIFICATIONS TO CREATE A TILTED CAP ROCK
C
VMOD POR
1 15 4 24 1 1
315*0.0
VMOD POR
1 15 10 24 2 2
225*0.0
VMOD POR
1 15 16 24 3 3
135*0.0
VMOD POR
1 15 22 24 4 4
45*0.0
C ..... PERMEABILITIES
KX YVAR
3*1500 3*750 3*1000 3*200 3*300 3*1500 3*1000 3*1500
KY MULT
1.0 KX
KZ MULT
1.0 KX
C ..... ASSUMED ROCK HEAT CAPACITY
CPR0 CON
35.0
C ..... ASSUMED THERMAL CONDUCTIVITIES
KTX0 CON
30.0
KTY0 MULT
1.0 KTX0
KTZ0 MULT
1.0 KTX0
C .....MODIFICATION OF TRANSMISSIBILITY TY
MULT TY STD PLUS DIV
1 15 3 3 1 18 20
1 15 6 6 1 18 50
1 15 9 9 1 18 20
1 15 12 12 1 18 20
1 15 15 15 1 18 20
1 15 18 18 1 18 50
1 15 21 21 1 18 20
C ..... ASSUMED HEATLOSS DATA
HTLOSS VW
AUTO CPR KTR DIRCN
35 30 XN
35 30 YN
35 30 YP
35 30 ZN
35 30 ZP
STOP
END

```

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