Value Creation By An Integrated Client-Supplier Team

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Abstract

The Austin chalk formation in Van field, Van Zandt County, Texas, USA, was identified as a candidate for infill drilling and recompletion. For the program to be economically successful, total well costs would have to be significantly reduced without compromising production performance.

To achieve total systems cost reduction, a team of management, engineering and field personnel from both the operator and supplier was formed. The team's charter was to create a workover program that reduced the total operating cost by 25% without a detrimental effect on production. To identify and prioritize potential opportunities, the team employed a Structured Process Improvement exercise. Smaller task groups were formed, based on individual member expertise, to evaluate the feasibility and impact of each new technique.

After a review of individual group recommendations, a revised workover process was implemented by the operator. Total systems cost reduction of 37% and replacement of 500,000 BOE reserves were realized in the first 90 of 150 planned wells.

Introduction

The location of Van field in East Texas is shown in Figure 1. The Austin chalk reservoir is defined by a major fault system, trending in a north-east to south-west direction. Smaller faults spread through the entire area of the field. To date, production from this reservoir is 8 million bbl of oil, with estimated recovery of only 9%. Reservoir properties (Table 1) are such that stimulation is needed to achieve economical production rates.

Development of the Austin chalk formation began in late 1980, with additional development drilling or recompletions every year since. Field development is currently on 5-acre spacing, with field rules established for future 2.5-acre spacing. The use of three-dimensional (3D) seismic techniques has identified individual fault blocks and additional wellsites. During this time, fieldwide production increased approximately 3000 BOPD from the 150 Austin chalk producers.

During the period from 1992 to 1995, initial production rates, reserves per well and measured bottomhole pressures declined with each year's program. Although the oil recovered represented only 9% of the original oil in place, the high relative cost to drill, complete and hydraulically fracture the Austin chalk made further development marginally economic by 1997.

In 1995 a limited number of refracturing treatments showed promising results. It was believed that new fracture planes were contacting undrained reservoirs, and a concentrated program of infill drilling and restimulation might yield positive economic benefits. To meet company economic hurdle rates, a reduction of 25% in total systems costs would be required, and a structured process improvement was undertaken to reduce costs.

Structured Process Improvement

A team of management, engineering and field personnel from both operator and supplier was formed to reduce total systems costs. A flowchart for a Structured Process Improvement program (Fig. 2) was used as a benchmark for an action plan to meet the economic objectives of the project. Critical input necessary for the initiation of the program came from the client's management: economic hurdles and potential of the project for all parties were clearly defined.

The overall objective of the joint team was to reduce total well costs by 25%, without a detrimental effect on the oil production and reserve goals. The total well costs for 1998 included the cost to drill and complete new wells and the cost to restimulate the old wells. This was a challenging task. Information solicited from the team's initial brainstorming sessions identified 85 potential opportunities for cost reductions. These were further narrowed down to attainable opportunities and categorized as opportunities for improvement.

Commitment of resources, from both client and supplier, to form the necessary teams was the first major milestone. Teams included joint, cross-functional personnel—management, engineering, field operations and technical support. The steps shown here simply comprised a process improvement methodology; however, these are critical steps in the overall process that produces the changes necessary for improvement. These steps are not "rocket science," and they are very task oriented, requiring significant process discipline of the team. Within a structured series of "off site" meetings with integrated just-in-time (JIT) training focusing on quality tools, significant opportunities for change were identified and prioritized relative to the new well and restimulation processes. Subsequent team efforts then implemented and monitored the changes necessary to improve the process.

Smaller task groups or individual teams were formed, based on member expertise, and were assigned responsibilities with an action plan. These task groups had to make the best use of available resources to evaluate the deliverables and had a deadline to evaluate the feasibility and impact of each new technique within the action plan. In a broader sense, these individual task groups covered the following areas:

drilling
logging and perforating
production casing
cementing
fracturing
production equipment
vendor supply
scheduling.

These areas were further broken down into more critical subcategories having a huge potential for improvement. At each step, the goal was to ensure that the impact of the process improvement was value added to the client.

Drilling: A reduction in drilling time and cost per foot was needed, so a change from conventional drilling to air drilling was recommended. The increased rate of penetration (ROP) could produce shorter cycle times, thereby decreasing overall costs. Availability of resources was considered and several drilling contractors were contacted for drilling proposals. Risk analysis of the air drilling proposal demonstrated that benefits of air drilling would only be determined after drilling an actual well. However, the cycle time reduction was believed to be about 24 hr. The impact from this process change would be a huge cost saving to the client.

Logging and perforating: The action plans suggested under this category were a) eliminating openhole logging, b) reducing the perforation interval required for fracture treatment, and c) optimizing point source perforating for fracturing purposes. A gamma ray log would provide needed formation information, and it could be coupled with perforation on a single trip. The milestone was to evaluate the feasibility of substituting openhole logs for cased-hole logs (with the associated cost benefits) and to evaluate the implications of reduced perforation interval, which influenced perforation friction values.

Production casing: Original casing and tubing configurations were a surface casing, a 4 ½-in. production casing and a 2 7/8-in. tubing. A change to a 3 ½-in. monobore completion was to be investigated. The action plan was to gather information on attempted and existing monobore completions. This necessitated selecting an infill location in which to air drill a monobore well. This process change would eliminate the need of surface casing.

Cementing: There were opportunities for improvement on the operations and the design side. Operationally, the practicality and feasibility of eliminating use of a double-pump cementing unit on surface pipe jobs were evaluated. This entailed determining the advantages and disadvantages of using the single-pump cementing unit on the surface jobs. From a design standpoint, optimization of cement slurry designs for surface and production casing cement jobs was determined. Current systems were reviewed and recommendations were made either for or against changes. In addition, a change in the displacement fluid to be used for the production casing cement job and the cost-saving implications of such a change were determined.

Fracturing: The opportunity to reduce fracturing cost was perceived as significant, and action plans for improvement were placed under two broader categories, design and operations.

Design: A review of current breaker technology and updated recommendations for changes were deemed necessary for optimization. Extensive testing at the regional technical center would provide insight for fracture conductivity improvement. The milestone was to initiate testing to determine optimum breaker schedule and to assess the cost savings to the client as a result.

Use of KCl substitute instead of powdered KCl on fracture jobs was another process improvement action plan. The objective was to recommend change in base fracture fluid temporary clay stabilization. The resources available were the regional technical center and the experience of stimulation experts from the supplier's side and the client's side. The milestone for this action plan was to assess the impact of the KCl substitute on formation clays and the fracture fluid.

Increasing proppant size and optimizing proppant concentration was another process improvement action plan. Some of the deliverables for this were fracture simulation of effect on conductivity when using larger proppant size, simulation of placement (fracture width concerns) and operational review of larger proppant on surface pumping equipment. The resources available for this were the stimulation design engineers from the supplier and the expertise of the operations manager. The milestone for this action plan was comparison of conductivity graphs of larger proppant size with conventional proppants and simulation of hydraulic width with an "after closure" and "end of job" width profile.

Evaluation of acid fracturing potential in the Austin chalk formation was also to be evaluated. The deliverables for this action plan were studying the effect of acid on chalk core, simulation of acid fracturing on the Austin chalk, cost estimate of the acid job and a thorough laboratory review of acid and oil compatibility. The milestones to be attained were an acid reaction test report on the Austin chalk core, simulation of acid placement with estimates of penetration and a conductivity profile, and a laboratory report on the acid and oil compatibility.

Use of a polymer-free fluid for fracturing to eliminate postjob cleanup problems was considered. The objective was to evaluate the technical and economic feasibility for primary fracture fluid in the Austin chalk formation. The milestones were presentation of simulation results on increased effective fracture conductivity and length, over conventional fracture fluids, and the material availability for the fluid.

Operations: Optimization of hydraulic horsepower (HHP) and elimination of standby equipment on location were necessary process improvement action plans. The objectives were to track the current equipment utilization and to recommend changes. Resources were the expertise of the operations manager, district manager and the regional technical engineer from the supplier side. The milestones to be attained were to furnish data on the equipment reliability and failure ratio and assess actual HHP requirement on location.

Assessment was made of the availability of larger proppant to satisfy program demands of increased proppant size. The resources were the purchasing departments of the supplier and the proppant suppliers.

At every step of implementing the process changes in the design and operations side of the fracturing, effort was made to assess the value-added impact to the client.

Production equipment: The action plan was to minimize cost on some production equipment. Potential was seen in investigating applications of the progressive cavitation (PC) pump and smaller pumping units. For the PC pumps, the objective was to form a recommendation on the feasibility of the pump application in the Van field. The resources were the technical information from the client and the pump manufacturers. The milestone was to check the elastometer compatibility testing and run some pilot projects with this pump. For the production equipment, the objective was to use smaller pumping units and determine the availability of minimum required pumping equipment. The resources were the equipment dealers, client and the rod programs. Milestone was to have a recommendation on the feasibility and projected cost savings of a smaller pumping unit.

Vendor supply: Economic feasibility of contracts with vendors for some equipment and material was an important process change. A need was seen for establishing an annual fracture tank contract or purchase. The objective was to determine the economic feasibility of leasing or buying fracturing tanks. The resources were tank vendors. The milestone was to formulate a recommendation of projected cost saving to the client.

Scheduling: Scheduling of material and jobs was perceived as an important process change. Areas identified were scheduling of multiple fracture jobs per day and storage of bulk proppant at or near the Van field. For scheduling of fracture jobs, the objective was to prepare a cost comparison of setting up one fracture job per day, versus two to three per day. The resources were the available price book, the operations manager and the district manager. The milestone was a projected savings per well. For bulk proppant storage, the deliverable was cost improvement to the client for proppant delivered directly to the well. The resources were local suppliers of Brady proppant, purchasing department of Dowell and regional facility manager for the supplier. The milestone was to estimate the cost savings to the client.

At every step of implementing the process improvement changes for each task group, the projected cost savings to the client was monitored, and an effort was made to assess the value-added impact to the client as a result of each change. The initial recommended changes were presented by the individual teams as opportunities for improvement:

Drilling: Change to air drilling. This would save 24 hr in cycle time.

Casing and tubing: The original idea of changing to a monobore design was not feasible. Recommended changes included using a different and cheaper production (4 ½-in.) casing grade and surface (8 5/8-in.) casing. Instead of a 2 7/8-in. tubing, a 1 ½-in. coiled tubing (reduced price) was recommended.

Logging and perforating: Change from separate trips for openhole logs and perforating to a single trip with a gamma ray and perforating tool. Change to point source perforating.

Cementing: Displace cement with completion fluid. This would reduce cycle time by 8 hr.

Fracturing: Original process changes suggested by the task group included

a) increasing breaker loading
b) optimizing proppant concentrations and proppant scheduling, and increasing proppant size
c) reducing the HHP utilized.

These changes were proposed after using fracture simulation design criteria. Further optimization of the fracture design and operations process led to proposal of additional changes that could be of value to the client. These are discussed later.

Production equipment: A decision was made to change to PC pumps and use smaller production equipment on the existing completions. Elastometer compatibility testing suggested that PC pumps were compatible. Furthermore, the need for landing nipples and packer services was eliminated.

Vendor supply and purchase: A recommendation was made to buy eight fracture tanks and lease a water truck. This would result in a substantial cost saving per job.

Scheduling: Change to two fracture jobs per day and fracture on two to three days per week. The logistics of supplying the materials and the equipment for this volume of work were worked out through the combined efforts of the operation's manager for the supplier, the client and the local vendors. Local proppant storage was not feasible.

Presented in Table 2 is a summary of the process improvement changes for the entire drilling and completion process and their potential cost savings. There is a comparison of the breakdown for the original cost and the optimized cost. These individual items were identified as candidates for a process improvement change. The items cover the broader categories initially considered for a process change. The overall savings for the total completion was about 37%, more than originally anticipated. The client offered a package of 190 wells for the application of the revised completion package. Of these, 150 were for refracturing, and 40 were for new infill drills.

A graph showing the breakdown of the drilling and completion process and the individual cost saving at each stage is shown in Figure 3.

The immediate priority of the project was to begin the refracturing program for the 150 wells in the Van field. This stage of the entire recompletion process was one of the more expensive stages. Consequently, efforts were made through the technical engineers on the supplier's side and the client's side to determine potential to further optimize the fracturing process. The fracture design process still required work. The optimization of the fracture design was done in three stages extended over the life of the project, each successive stage offering an improvement over the previous. The history of the Austin chalk fracturing in the Van field suggested that the average conductivity of the fracture treatments and the retained permeability appeared low because of low breaker loading. In contrast,, the volumes of fluid and sand pumped were huge. Large sand volumes (350,000 to 600,000 lbm) were due to smaller mesh size sand (16/30) being used at a higher concentration (maximum 13-16 ppg). The fluid volumes were almost 200,000 gal. The perforation interval through which the treatment was pumped covered the whole gross pay interval (about 200 ft). Another observation made by the engineers from the client's side was the prevalence of inclined multiple, competing fractures. This affected the fracture half-length and the conductivity. Further design optimization was feasible, and some of the treatment parameters could be optimized:

pad volume reduction
proppant scheduling
liquid scheduling
point source perforating
resin-coated sand volume reduction
breaker loading optimization
HHP utilization optimization
additives screening.

Pad volume reduction: The original pad volume was about 55% to 60%. This was excessive, and fracture simulation runs indicated that reducing this to about 25% to 30% would result in a higher fracture conductivity with a lower overall cost.

Proppant scheduling: A change from 16-30 mesh proppant to the larger 12-20 proppant at lower concentrations could be made without sacrificing fracture conductivity. This would result in savings in the volumes of proppant on the larger treatments from +-400,000 lbm to +-200,000 lbm. This was further optimized to lower volumes as seen in Fig. 4.

Liquid scheduling: The history of the previous fracturing treatments reveals that the base fracture liquid used on the stimulation treatments was a 30- to 40-lbm guar-based crosslinked system. As mentioned earlier, this high polymer loading coupled with a low breaker loading, contributed to lower fracture conductivity and retained permeability. Retained permeability was about 30%, which reduced the effective fracture half-length considerably. To minimize this, the liquid scheduling was optimized in three stages. A detail of the transgression between different stages is indicated in Fig. 4. The first stage comprised eight jobs, and the fluid selected for this was the 25-lbm low-guar polymer crosslinked system. The second stage comprised a total of 12 jobs, and the fluid selected for this was a 25-lbm crosslinked foam system, with 65% quality nitrogen used for the foam. The effective gel concentration was 9 lbm/1000 gal, considerably lower than the previous 25-lbm/1000 gal system. The third stage had a total of 70 wells, and the fluid selected was the linear 40-lbm foam system, with 65% quality nitrogen used for the foam. The effective gel concentration on this was 14 lbm/1000 gal. The reduction in the liquid loading was from a high of +-190,000 gal to a low of +-18,000 gal.

Point source perforating: The series of multiple, competing fractures were being generated as a result of the large perforated interval. This affected the fracture half-length and the conductivity. An agreement was made to point source perforate the Austin chalk over an interval of +-20-ft with a perforation density of 6 spf. This would reduce the number of shots from +-400 to +-120—a cost saving. Importantly, this would arrest the growth of the multiple fractures and allow a single fracture at propagating a good half-length radius hemi-fracture laterally and downwards into the pay zone. (Author: The preceding sentence is not clear).

Resin-coated sand volume reduction: The reduction in the perforated interval allowed a reduction in the amount of resin-coated sand (RCS) used in the stimulation of proppant flowback control. The change would reduce a high of +-50,000 lbm in the original fracture to +-18,000 lbm.

Fluid breaker optimization: Analysis of the fracturing fluid breaker program indicated that a significant improvement in fracture conductivity could be realized by optimizing breaker loading. Breaker loading was increased from the original 1 lbm/1000 gal to the current 10 lbm/1000 gal. This change, while having no effect on fluid performance, would yield an increase of +-90% in fracture conductivity. The breaker loading was optimized further with different breakers at a reduced loading.

Additive screening: Previous jobs indicated a maximum of 11 additives were being used for stimulation treatments. Through different stages of the design optimization process, these were reduced to five, which would result in cost savings to the client without jeopardizing the quality of the fluid system for fracturing. As seen in Fig. 4, some of the changes effected in going from a crosslinked system (stage 1) to a linear foam system (stage 3) were elimination of L64 and switching to fresh water, elimination of crosslinker and activator, and change to a more effective liquid breaker at a reduced concentration.

HHP utilized: Previous jobs indicated rates as high as 45 to 60 bbl/min were being used for the stimulation treatment. Fracture simulation results indicated that an optimized reduced rate of 30 bbl/min did not affect fracture conductivity and half-length. The reduced rate would result in lower utilization of HHP, from a high of +-3500 to +-1300, and pumping equipment on location. This would produce cost saving for the client.

Other design parameters were considered:

a) Proppant embedment test—This test reflected a much lower Young's modulus of 4.2 E+05 (10-fold decrease). This would result in 40% loss of conductivity from proppant embedment.

b) Core analysis test—Core results indicated the formation was not damaged by fresh water and the switch to a fresh water for fracturing fluid was justified.

c) Equipment reduction—The equipment on location was reduced from 11 units on the original jobs to about 8 units.

d) Foamer—The foamer was changed in the last stage, because it improved the half-life of the foam system.

d) Proppant scheduling—During the third stage, the scheduling was changed from 3-5 ppg to 4-5 ppg. This improved the effective fracture conductivity and half-length. RCS was changed from 10,000 lbm to 7,500 lbm without any detrimental effect. As a result the total sand volume changed from +-120,000 lbm to +-140,000 lbm.

e) To use point source perforating, the casing was filled with sand plug exposing the top +-20 ft of perforation interval. Stimulation was through this interval.

The results of all the changes for refracturing are reflected in Table 3 and Fig. 5, which show the breakdown of the fracturing process and the individual cost saving at each stage.

The value-added impact to the client as a result of the process improvement changes for the original plan is reflected in Table 4. At the moment, the project is on hold because of budget considerations and the low price of oil. Ninety refracturing treatments have been performed. Once the project is activated, there is remaining work on 100 wells, 60 refracturing treatments and 40 new infill drills. To date, a total savings of $1.92 million has been realized for the client. The projected cost savings for the total project is $6.3 million, as shown in Table 5.

Reserve replacement:

Reservoir estimates based on results to date and projected restimulation treatments in selected wells suggest an additional 0.5 million barrels and 500 MMscf of gas will be added to the books from this program.

Reserve predictions were difficult to make for several reasons.

1) Initial flush production occurred over a two- to four-month period prior to the well stabilizing.
2) Low reservoir pressures often resulted in lengthy "cleanup" periods before good oil production could be established.
3) Some areas of the field flowed for one or two months after the restimulation, delaying installation of pumping equipment.
4) Overall field decline in the chalk was around 32% per year, which tended to mask the results of the individual well's performance. A flattening of this decline was often necessary to confirm additional reserves.
5) Wells were shut in a week or so before a scheduled restimulation treatment to "prep" them, losing from 1 to 5 BOPD per well, again masking the results when looking at the fieldwide decline.

Summary

1) The integrated client-supplier team was successful in implementing a Structured Process Improvement program that helped reduce the total well cost by 37%, which was over and above the economic hurdle rate of 25% set by the client.
2) The refracturing program also helped reduce the restimulation cost by 28%.
3) The program was successful in adding an additional 0.5 million barrels and 500 MMscf of gas to the reserves and saving $1.92 million to date. Projected savings of $6.2 million can be expected for the remainder of the project.
4) Multidisciplinary teams made up of cross-functional personnel from both the client's and supplier's sides are helpful in identifying opportunities of improvement that are significant in meeting the economic hurdles for total well cost, thereby providing value to the whole project.

Acknowledgments

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Table 1 - Austin Chalk - Reservoir Properties

Formation -	**Austin chalk**
Gross pay -	**200 ft**
Porosity -	**30%**
Permeability -	**0.1–0.3 md**
BHST -	**120 F**
Drive mechanism -	**Depletion**
Average reservoir pressure -	**400 psi**
Producers -	**190**

Table 2 - Breakdown of Recompletion Cost Versus Optimized Cost

Item	Cost Difference (Current vs. Optimized), %
Rig (Footage)	50
Fracturing	42
Artificial lift	40
Capitalized Engineering	1
Production Casing	38
Workover Rig	75
Primary Cementing	13
Tubing	76
Pipes, valves, fittings	0
Water / Brine	80
Surface Casing	33
Trees, Wellheads etc	73
Contract Labor	0
Gravel / Caliche	100
Rods	31
Damage	0
Logging	100
Perforating	0
Casing Head	0
Landing Nipples	100
Surveys	20
Location, road, cellar	0
Cased Hole Logs	0
Float Equip - L/S	0
Float Equip - Surf	0
Packer Services	100
Total Savings	**37**

Table 3 - Breakdown of Refracturing Cost Versus Optimized Cost

Items	Cost Difference (Current vs. Optimized), %
Fracturing	25
Workover rig	70
Water Fresh	83
Artificial Lift	0
Contract Labor - Surface	0
Contract Labor - Misc	0
Tubular Testing	0
Packer Services	100
Packer Fluid	100
Trucking	0
Total	**36**

Table 4 - Current Total Savings

	Refracturing
Cost reduction/well *Before price change*	36%
Cost reduction/well *After price change*	28%
1997 projects	25
1998 projects	65

Table 5- Projected Total Savings

	Refracturing	Drilling
Cost reduction/well *Before price change*	36%	37%
Cost reduction/well *After price change*	28%	37%
1997 projects	25	0
1998 projects	125	40 (40 new well completions)

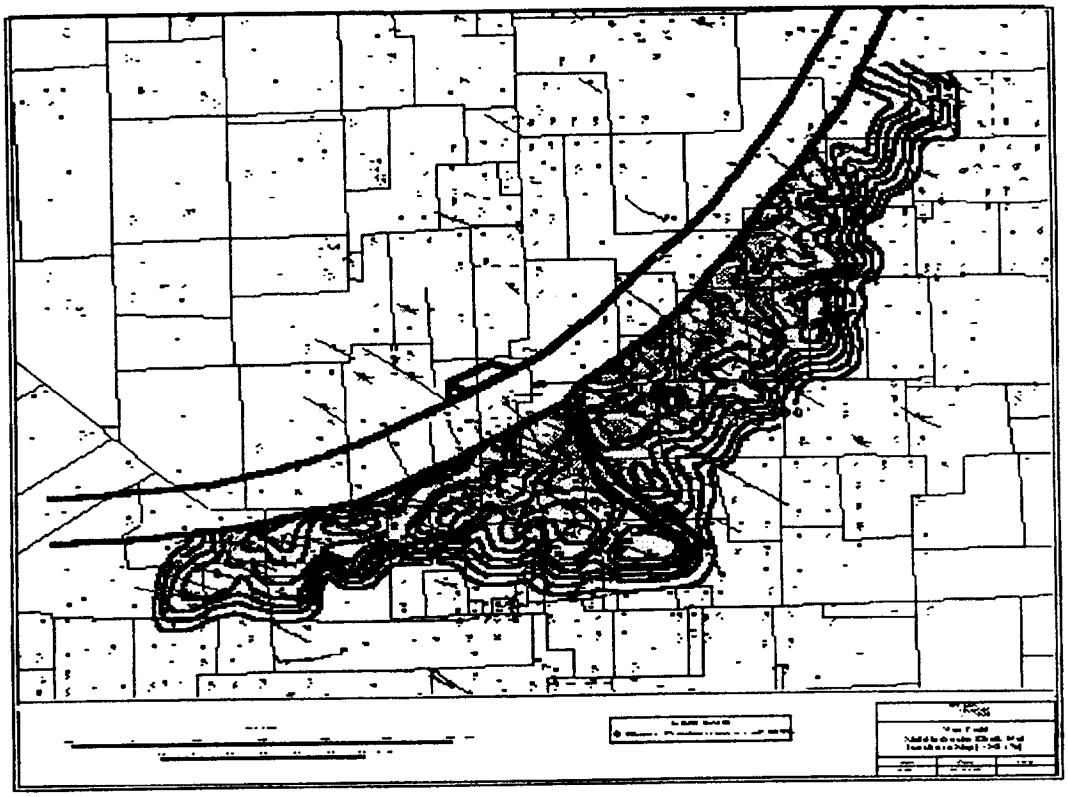

Figure 1 - Austin Chalk - Van Field

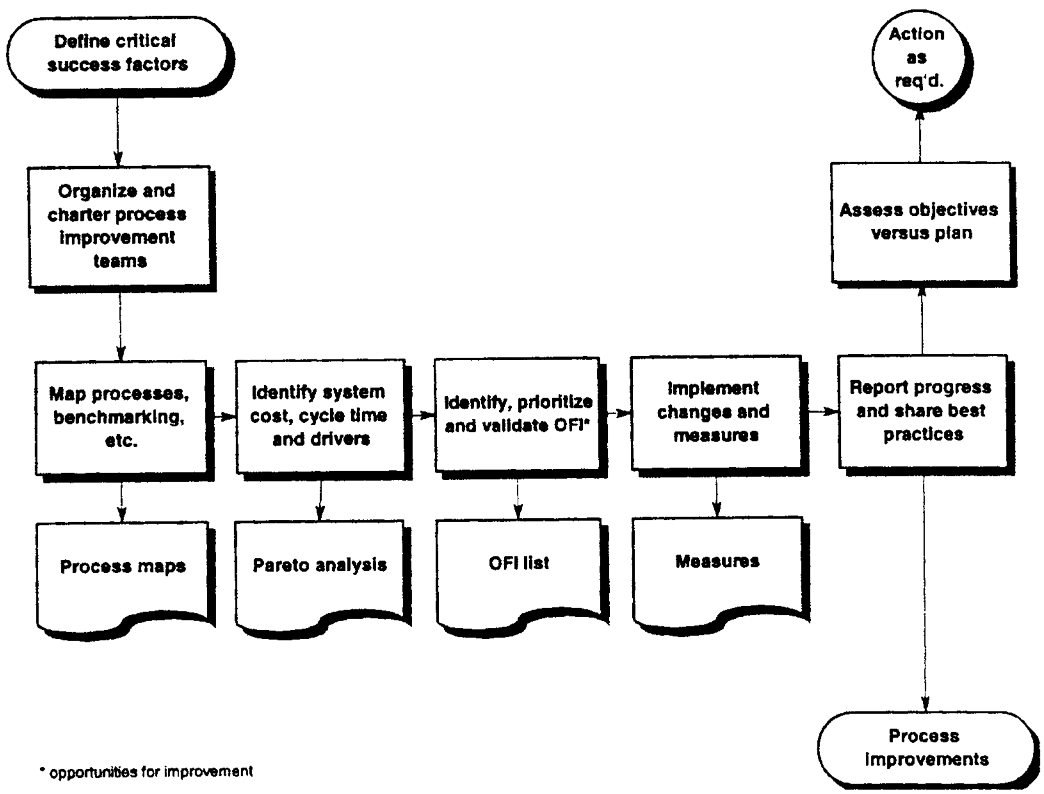

Figure 2 - Flowchart for Structured Process Improvement

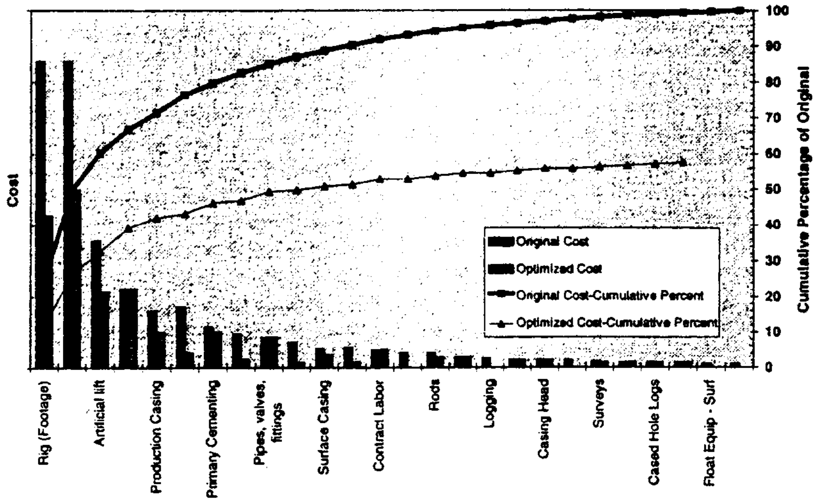

Figure 3 - Breakdown of Different Items
Drilling and Completion - Current Cost Versus Optimized Cost

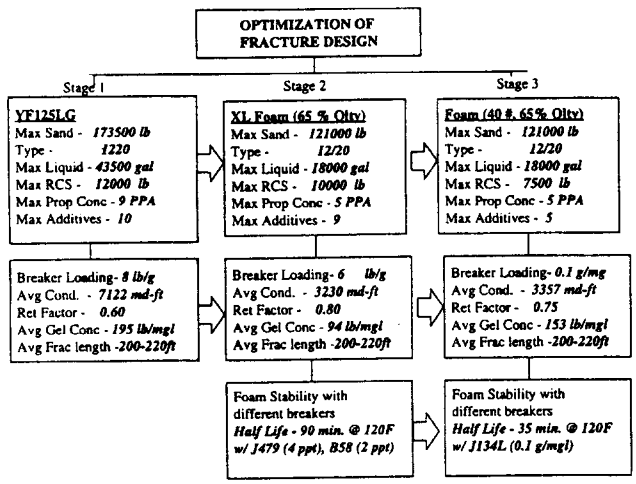

Figure 4 - Flowchart for Optimization of Fracture Design

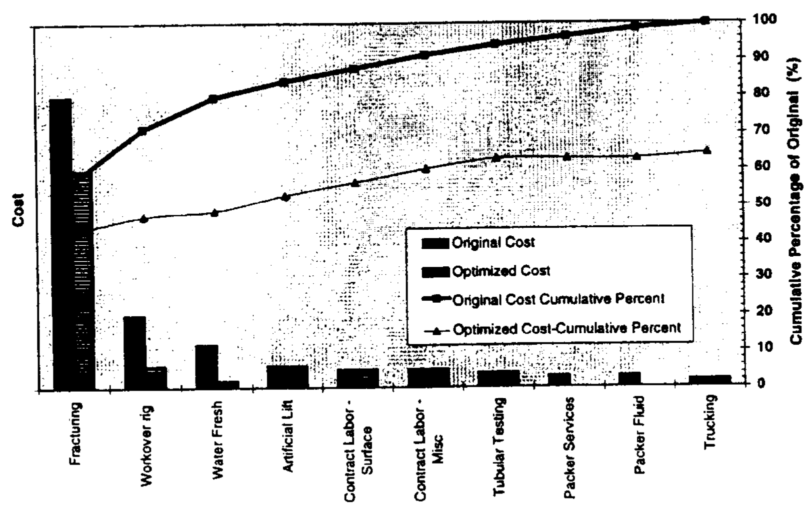

Figure 5 - Breakdown of Different Items
Refracturing - Current Cost Versus Optimized Cost