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Produced Water and Associated Issues

by

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with a contribution from
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A manual for the independent operator

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PREFACE

The largest volume waste stream associated with oil and gas production is produced water. Operators in the South Midcontinent Region of the Petroleum Technology Transfer Council (PTTC) identified produced water as a major constraint in the production of hydrocarbons. The costs of lifting, separating, handling, treating, and disposing of this water are substantial. In addition to the economic burden it imposes, water can also directly reduce hydrocarbon production.

With these thoughts in mind and as partial fulfillment of a PUMP (Preferred Upstream Management Practices) contract award, the South Midcontinent Region developed this manual as a reference source to assist independent operators in dealing with produced water. Many workshops conducted by PTTC have dealt with topics related to this subject. Much of the information in this manual was compiled from these workshop materials.

The manual is divided into eight sections to better address the different technologies used for different water production issues operators face throughout the life of a well. Not all technologies discussed are applicable to all situations, but they have led in certain situations to improved return on investment and increased economically recoverable reserves.

Note: The material presented in this manual focuses on operations in the South Midcontinent Region. Although many of the practices and technologies discussed have general applicability, conditions can vary greatly from region to region. For dealing with specific produced water problems in your area, it is best to contact your region's PTTC Resource Center or local experts familiar with your area for help.

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Bob Kiker acknowledges the companies listed below, who provided insights for his development of Section 7 (Corrosion and Mechanical Wear on Equipment Used in Handling Produced Water). Their contributions were valuable in acquiring the most recent successful practices, which in many cases supported published technology. There were some practices revealed that are new. He would also like to acknowledge Texas Tech's Petroleum Engineering Department, host for the annual Southwestern Petroleum Short Course, as being a significant contributor to the body of knowledge on this topic. Additional information sources Bob reviewed include Society of Petroleum Engineers literature, U. S. Department of Energy research and development project results, and the Internet through topical searches in Google.com. Formal searches were supplemented by personal networking on selected topics.

Kevin Butler Associates (Operating)
Conoco, Inc (Operating)
DJAX Corporation (Technology Vendor)
Echometer (Technology Vendor)
Henry Petroleum (Operating)
Omega Technologies (Technology Vendor)
OXY USA-OXY Permian Basin Ltd (Operating)
Performance (Technology Vendor)
Permian Production Equipment (Technology Vendor)
Schlumberger IPM (Contract Operator)
Weatherford (Service Technology)
Western Falcon (Technology Vendor)

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SECTION 1
BASIC PROPERTIES AND DATA MANAGEMENT

Naturally occurring rocks are in general permeated with fluid – water, oil, or gas or combinations of these fluids. Oil and gas operators are concerned with the quantities of fluid contained within the rocks and the transmissibility of the fluids through the rocks. The following discussion of fundamental rock properties, fluid saturations and reservoir drive mechanisms will provide background necessary to understand how these properties affect water production in oil and gas wells.

This section also includes a brief discussion on collection and organization of well information and production data. This includes useful plots to assist in analyzing water production and methods to track different costs related to water handling.

Rock Properties. *Porosity* is defined as the ratio of the void space in a rock to the bulk volume of that rock multiplied by 100 to express in percent. It is also referred to as the storage capacity of underground formations. Porosity can be classified according to the mode of origin as 1) original (primary) – developed during deposition of the sediment or 2) induced (secondary) – developed by some geologic process subsequent to the deposition of the rock. Original porosity is typified by the intergranular porosity of sandstones, carbonates, and the interparticle and oolitic porosity of some limestones. Induced porosity is typified by fracture development as found in some shales and limestones or by vugs or solution cavities commonly found in limestones or by dissolution of feldspar in a sandstone. Rocks having original porosity are more uniform in their characteristics than those rocks in which a large part of the porosity is induced. Porosity can be further defined as total or effective. Total porosity is the ratio of the total void space in the rock to the bulk volume of the rock; effective porosity is the ratio of the interconnected void space in the rock to the bulk volume of the rock, each expressed in percent.

Permeability is a measure of the capacity of the rock medium to transmit or conduct fluids. It is measured in field units of darcys or millidarcys. Flow paths are of varying shapes and sizes and are randomly connected. Fluid flow occurs both horizontally and vertically. Most porous rocks will have spatial variations in permeability. Matrix permeability refers to the flow in primary pore spaces in a rock as opposed to fracture permeability that refers to the flow in cracks or breaks in the rock. In some sand and carbonate reservoirs the formation frequently contains solution channels and natural or artificial fractures. These channels and fractures do not change the permeability of the matrix but do change the effective permeability of the flow network.

Fluid Saturation. In most oil bearing formations it is believed that the rock was completely saturated with water prior to the invasion and trapping of petroleum.[1] The less dense hydrocarbons migrate to positions of hydrostatic and dynamic equilibrium, thus displacing water from the interstices of the structurally high part of the rock. The oil will not displace all the water. Thus, reservoir rocks normally contain both petroleum hydrocarbons and water (frequently referred to as connate water) occupying the same or adjacent pores. To determine the quantity of hydrocarbons accumulated in a porous rock formation, it is necessary to determine the fluid saturation (oil, water, and gas) of the rock material. The simultaneous existence of two or more fluids in porous rock requires that terms such as capillary pressure, relative permeability, and wettability be defined.

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Capillary pressure is the pressure required to drive a fluid through a pore throat and displace the pore-wetting fluid. As pore throats become smaller, higher capillary pressures are required to displace the pore-wetting fluid.[2] Capillary pressure curves are available that provide information regarding pore throat sorting, relative permeabilities, and reservoir quality. The size of the pore throat is related to the residual water saturation. Water cut is related to the capillarity and the distance above the oil-water contact. Capillarity is important to waterflood performance.

Relative permeability is the ratio of the effective permeability of a particular fluid to a base permeability of the rock. Since it is both a rock property and a fluid property, relative permeability is a difficult concept to understand. The permeability of a rock depends upon the type of fluid that is flowing, characteristics of the rock surface and the pore structure geometry. The presence of more than one fluid at the same time in the pore space of a rock also affects the permeability. Relative permeabilities range from zero to one, and are a function of the fluid saturation.

Wettability. When two immiscible fluids such as oil and water are together in contact with a rock surface, one of the fluids will preferentially adhere to the rock surface. Wettability refers to a measure of which fluid preferentially adheres to the surface. Most producing reservoirs generally exist in a water-wet state, in which the connate water preferentially adheres to the rock surfaces. If the contact angle from the rock surface through the water is $< 90^o$, the rock surface is said to be water wet. On the other hand, if the contact angle is $> 90^o$, the rock is said to be oil wet. Wettability has an influence on the interstitial water saturation, residual oil saturation, capillary pressure, relative permeability, and waterflood performance.

Reservoir Drive Mechanisms. Several sources of energy exist in the formation. In the case of liquid petroleum, the natural energy is the expansive energy of the liquid petroleum and the gas dissolved in the liquid petroleum at the elevated pressure at which the petroleum is confined. In addition to the expansive energy of the petroleum hydrocarbons, all petroleum accumulations are associated with water. The oil accumulation may be surrounded by water-bearing formations. This water is subjected to elevated pressures in the subsurface. Upon withdrawal of the fluid from the petroleum reservoir, the reservoir becomes a pressure sink; the contiguous water flows into the petroleum reservoir, displacing oil or gas toward the wellbores. In addition to expansive energies, there is also the force of gravity acting at all times to promote segregation of the various fluids. Gas tends to occupy the higher places in the accumulation; oil, being denser than gas and less dense than water, tends to occupy the intermediate position; and water tends to underlie the petroleum. Frequently, oil fields are found in which a part of the reservoir is liquid saturated and a part is gas saturated. This type of accumulation is referred to as an oil reservoir with a gas cap.

Solution-gas or depletion drive is a petroleum reservoir with no original free gas cap and no associated active water; the principal energy is the expansion and dissociation of gas in solution in the oil. Water production is generally minimal. The solution-gas drive is characterized by a rapid pressure decline and low recovery efficiency.

Solution-gas-gas-cap drive is a petroleum reservoir containing an original free gas cap with no associated active water. Reservoir pressure is maintained at higher levels in most instances (if the gas cap is not prematurely depleted), thus improving recovery efficiency. The degree of

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improvement depends on the size of the gas cap relative to the oil zone and on the production procedure used. As with solution-gas drive, water production is generally minimal.

Water drive is a petroleum reservoir associated with water-bearing formations that are so active that little or no pressure drop occurs when hydrocarbon fluids are withdrawn. Water drive is the most efficient in maintaining reservoir pressure and usually yields the highest recovery efficiency. Water production varies significantly depending on structural position and nature of the water drive.

Collecting and Organizing Well and/or Production Data. Wells are basically the source of all information concerning the reservoir. Formation evaluation data must be obtained during particular phases of the drilling and completion of a well, since certain types of data are not obtainable later. Reservoir fluid and production data are typically obtained after the wells are completed; consequently the operator has more latitude in taking such data.

Wellbore schematics are an excellent way of concisely capturing and displaying well data. When relevant well and reservoir data are properly analyzed, the results can help to explain both production performance and reservoir performance. The importance of keeping good individual well records of all production and injection data as well as workover information cannot be over-emphasized. It is not enough to know production rate for the entire lease or field. A test on each production well at least once or twice a month is generally sufficient to identify individual well rates.

Graphical plots of data are visual displays that assist the operator in defining specific occurrences during the life of a well. Plots provide insight to individual well and overall project performance. Interaction between wells can also be observed. The plots can be done by hand, with common spreadsheet software, or using specific oil and gas software. A major advantage of using the computer for data storage is the speed with which data can be updated and displayed graphically. The operator can quickly and easily access the same data to prepare plots for an entire project, individual wells, groups of wells, patterns, or other study areas.

<u>Oil production versus time</u>. Plots of oil production will help the operator observe and better understand occurrences during the life of a well. A semi-log plot of oil production versus time is commonly referred to as a decline curve. Logarithm of oil production rate is the ordinate (or y axis) and time, using a linear scale, is the abscissa (or x axis). This type of plot reveals changes in oil production and is used to determine information such as 1) the time at which production rate will reach its economic limit by extrapolating production decline trends, 2) the time at which oil rate reaches a peak, and 3) the time of initial production response from water injection.

<u>Rates versus time</u>. Plots of various rates versus time can assist in determining specific occurrences associated with a producing well. These rates include water production, water-oil ratios (watercut), gas-oil ratios, water injection rates, and cumulative water injection. It is common to plot different rates versus time on the same graph. Such comparisons can assist in determining a relationship between different variables, such as injection and production rates in a waterflood. Fluctuations in one rate can have an effect on another.

<u>Water-oil ratio (WOR) versus cumulative oil production</u>. A semi-log plot of WOR versus cumulative oil production is also informative in recognizing occurrences during the life of a well.

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Logarithm of WOR is the ordinate and linear cumulative oil production is the abscissa. This type of plot reveals changes in water production as a function of oil production. Economic limits can be shown easily and because the area under the curve represents total water production, everything necessary to track a well is clearly shown. Sharp increases in WOR can indicate a problem, such as a casing leak or water breakthrough in a water-drive reservoir or waterflood. High WOR associated with low cumulative oil production can indicate a channeling problem. This type of plot should be done for the project and for individual wells. When properly constructed, these plots are also useful in predicting the ultimate recovery at a known WOR. If increased WOR occurs early in the life of a well or is associated with low cumulative oil production, a review of individual well data, geological description, and engineering data is warranted to define appropriate remedial work, such as permeability modification using gelled polymers. Successful remediation can result in a reversal of the WOR curve, followed by a flattening of the curve. This type of work can reduce lifting costs by decreasing the amount of water production, increasing the sweep efficiency and extending the economic life of the project or well.

Hall plots are most often used to analyze injection wells, but they can also be used to analyze fluid injection treatments in producing wells. They provide information on fill-up, skin damage, formation fracturing, and water channeling. Required data are cumulative injection volume and injection pressure. The summation of the surface or bottomhole pressure multiplied by time is plotted versus the cumulative fluid injected on coordinate paper. Changes in the slope of the plotted line indicate a change in resistivity associated with fluid injection in the reservoir.

Knowing Your Water-related Costs. Water production can make or break a project's performance by reducing the flow rate or ultimate recovery or by raising costs. The cost of lifting, separating, handling and disposing of this water is substantial. In addition to the economic burden, water can also directly reduce hydrocarbon production. Water plays a role throughout the entire life cycle of a well. A listing of direct costs and impact areas is given in Table 1.[3]

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Table 1. Water-related Cost and Impact Areas

1. Accounting in estimate of economical recoverable reserves
2. Water use strategies in drilling program
3. Water control strategies in completion design
4. Water control conformance strategies in the reservoir and the wellbore
5. Water drive and choke strategies
6. Water lifting and surface handling
7. Chemical treatment
8. Water gathering and water process facilities
9. Permitting and delays
10. Transportation
11. Injection disposal and waterflood
12. Beneficial use
13. Liabilities

Rudolph, J. and Miller, J., "Downhole Produced Water Disposal Improves Gas Rate," GRI October 2001 publication.

Many companies don't recognize or account for the full cost of water management since accounting is often spread over many corporate departments. Consequently, the impact of water is underestimated and opportunities to implement strategies and improve inefficiencies are overlooked. Ironically, smaller companies (independent producers) are in a better position to recognize the cross-functional costs and implications, but they tend to lack the resources to identify and implement effective water management strategies. These costs and impacts impose an enormous burden on the industry's ultimate return on investment and reduce economically recoverable reserves. In many cases a modest gain in economic efficiencies can lead to a substantially large economic benefit.

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SECTION 2
WELL COMPLETION AND ITS IMPACT ON WATER PRODUCTION

Different types of drilling and completion techniques can affect the amount of water produced during different stages of the life of a well. Further, once the well has been completed and stimulated, remedial actions may be limited. Consequently, at the outset, operators should consider all their options

Completion Options. *Vertical versus horizontal* Depending on reservoir properties, drive mechanisms and future enhanced oil recovery projects, there can be advantages to one type versus the other. The cost of drilling a horizontal well is more than that of a vertical well; completion costs are also usually higher. Therefore, the volume of salable products must be higher in order to have a higher return on investment (ROI).

The basic benefit of a horizontal well from a reservoir engineering perspective is the generation of a line sink versus a point sink.[4] This geometry makes more efficient use of reservoir pressure, illustrated by radial flow in the vertical well versus linear flow in the horizontal well. A horizontal well can produce at higher rates than a vertical well at similar drawdown, or can produce similar rates at lower drawdown, thus delaying coning in the case of a bottom-water-drive reservoir.

For a homogeneous reservoir, case histories indicate that reservoirs thinner than 200 feet and having a permeability of less than 100 md should be considered for a horizontal well. For a reservoir with vertical permeability greater than one-fourth its horizontal permeability, a horizontal well might be beneficial. The use of horizontal wells gives another technique to reduce water or gas coning/cresting while producing at higher hydrocarbon rates than can be produced from vertical wells. Case histories have proven that critical oil rates are three to twenty times higher in horizontal wells than in vertical wells.[5]

Heterogeneous reservoirs, such as layered formations and dipping layered formations that can be thick with high permeabilities, and be with or without gas caps and bottom water, can be produced effectively using horizontal wells. However, the heterogeneity has to be defined, the well profile has to be designed to handle the heterogeneity, and the wellbore's trajectory must be oriented from the geologic information gathered as drilling progresses.

Large production improvements can be realized in heterogeneous reservoirs. Reserves have been increased by as much as factors of 6 in the Austin chalk in South Texas. Partially depleted and flooded reservoirs can be more effectively drained using horizontal wells. In general the production increase of horizontal versus unstimulated vertical wells is proportional to the reservoir's area contacted by the wells. Due to exposing more of the formation to drilling fluids for longer periods, formation damage may be more pronounced in horizontal wells when problems with drill fluids are encountered.

Open hole versus perforated. The open hole method is initially cheaper, since perforating costs are eliminated. This method permits testing of the zone as it is drilled, eliminates formation damage by drilling mud and cement, and allows for incremental deepening as necessary to avoid drilling into water. This last factor is important in thin, water-drive pay sections where no more

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than a few feet of oil zone penetration is desired. On the other hand, the perforated completion offers a much higher degree of control over the pay section, since the interval can be perforated and tested as desired. Individual sections can, in general, be isolated and selectively stimulated much more easily and satisfactorily. There is considerable evidence that hydraulic fracturing is more useful in perforated completions. API Bulletin D6 indicates productivity ratios of perforated wells are about 50% higher than those of similar open hole completions.[6] This superiority is apparently due to uniform treatment over the entire pay section plus the stimulation benefit gained from penetration of the perforations themselves. The improved zonal control is also of value when remedial measures, such as water or gas exclusion, are undertaken.

With perhaps a few exceptions in low pressure or thin water-drive pay areas, benefits of the perforated completion overshadow those of the open hole type. This advantage has been made possible by modern perforating and stimulation techniques and advances in drilling muds, cementing materials and methods, as well as other aspects of petroleum technology.

Single zone versus commingled. Most wells are initially completed in a single zone. As production matures and the oil rate declines, other zones may be opened to keep the well economic. Sometimes the initial zone is plugged off prior to recompletion; other times, if it still produces some oil, it is left open or later commingled with other zones. When commingling zones within the same wellbore, consider: 1) compatibility of fluids – mixing different formation fluids tends to increase scale and corrosion problems; 2) reservoir pressure of the different zones – you don't want one zone to thieve production from another; 3) if unexpected things occur, such as increased water production, it is more difficult and costly to determine which zone is the culprit; and 4) whether the well will ever be used as part of an improved oil recovery project, such as a waterflood.

Other completion options. Consider all potential production scenarios prior to drilling and completing a well, e.g., the use of downhole oil/water and gas/water separators. This technology, where a well serves as both a producer and an injector, is advancing rapidly and may be more commonly used in the future. Questions to consider prior to drilling: Should the well be drilled deeper to have access to a disposal zone? What size casing should be set to accommodate special tools and equipment?

Stimulation Options. *Natural* completions are when no stimulation is required to achieve commercial production rates or required injection volumes. These are rare, as some type of stimulation is typically required to remove formation damage caused during the drilling process. Natural completions are more common in open hole than cased hole. Potential advantages are no risk of communicating to adjacent formations and more uniform sweep in an injection project.

Acid is used to remove damage from carbonate and sandstone formations and to stimulate production and injectivity in carbonates. Acid is used for both matrix and fracture treatments in carbonates. Matrix acid candidates have permeability greater than 10 md in oil wells and 1 md in gas wells. Acid frac candidates have permeabilities less than 10 md in oil wells and 1 md in gas wells. Matrix acidizing is performed below the fracturing rate and pressure of the formation, where acid travels through existing pores and natural fractures. Fracture acidizing is performed above the fracturing rate and pressure of the formation, where the rock is cracked and an etched fracture is created.

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Matrix acid treatments are commonly used to increase injectivity in disposal and injection wells. Rules of thumb on acid volumes are given in Table 2.[7]

Table 2. Rules of Thumb on Acid Volumes

Treatment Type	Acid Volume (per ft of interval)	Area of Reservoir Affected	Resultant Skin
Wellbore clean-out	10 to 25 gal	Connect wellbore to formation	0 to -1
Near wellbore stimulation	25 to 50 gal	2 to 3 ft	0 to -2
Intermediate matrix stimulation	50 to 150 gal	3 to 6 ft	-2 to -3
Extended matrix acidizing	150 to 500 gal	Greater than 6 ft	-2 to -5

Halliburton's "Best Practices – Carbonate Matrix Acidizing Treatments," October 1998.

If acidizing injection and disposal wells is needed on a regular basis to maintain injection rates, water quality should be examined.

Hydraulic fracturing. When sufficient hydraulic pressure is applied through the wellbore against a particular formation, the formation rock fractures along the plane perpendicular to the direction of the least principal stress. A horizontal fracture will be created if fracture pressure is greater than overburden pressure; a vertical fracture will occur if overburden pressure is greater. The extent of the induced fractures is a function of the pump rate applied after the fracture is initiated.

Hydraulic fracturing is performed to overcome detrimental effects of wellbore damage and/or to stimulate a well's performance. For the former, it is typically applied to wells in moderate to high permeability reservoirs and generally results in the creation of short fractures. The latter generally results in the creation of long fractures in wells in low permeability reservoirs. The success or failure of fracturing in either case depends on whether the created fracture has significant flow capacity such that reservoir fluids flow to the fracture rather than the wellbore.[8] If flow capacity of the fracture is large compared to reservoir flow capacity, typically large performance improvements are realized.

Two techniques for improving fracture conductivity are increasing fracture permeability and increasing fracture width. Improving fracture permeability involves methods related to proppant type, proppant concentration, proppant size, and fluid cleanliness. Fracture techniques, such as tip screen-out, are utilized to increase fracture width.

Conventional optimal fracture design is where the pad volume completely leaks off to the formation and the entire created fracture is filled with proppant-laden fluid. If too much pad is pumped, a larger fracture than what is effectively propped is created, which is not cost effective. If too little pad is pumped, a premature treatment termination can result.

When hydraulic fracturing, consideration should be given to potential communication to surrounding zones and whether or not the well might be used in a future enhanced oil recovery project. Fracture treatments can have detrimental effects on the sweep efficiency of a waterflood.

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Many operators tag the tail end of their proppant with radioactive tracer, so if the well does not respond as anticipated, they can log the well to determine where the fracture went. It is also important to record the initial shut-in pressure behind a frac job, as it provides an estimate for the fracture or parting pressure of the reservoir.

Solid propellant technology.[9] Many oil and gas wells can be effectively stimulated with a relatively new gas-generating solid-propellant tool known as The GasGun™. The tool incorporates a progressively burning solid propellant that generates gas at a rapid rate, which creates multiple fractures radiating 10 to 100 feet from the wellbore. The progressive burning formulation means that the rate at which the propellant burns increases with time, producing gas faster as the material is consumed. Independent research conducted by Sandia National Laboratories showed this formulation to be much more effective than other propellants in controlling peak pressures and in advancing fractures deep into the formation by saving energy until late in the fracturing process when crack volumes are the greatest.

The fracture network removes damage and increases formation permeability near the wellbore. Potential applications include removing skin and damage, preparing formations for acidizing or hydraulic fracturing, stimulating naturally fractured reservoirs or lenticular sands, increasing injection and withdrawal rates, and improving waterflood efficiency. The process is an economic alternative to hydraulic fracturing and other stimulation methods, especially for treating “tight” zones adjacent to water zones. Various problems associated with hydraulic fracturing, such as breakout or communication to water-bearing zones, are avoided.

Compared to hydraulic fracturing, advantages include much lower cost with minimal onsite equipment needed, little vertical growth out of pay, multiple fractures, entire zone stimulation, and low formation damage from incompatible fluids. Compared to explosives, there is no compaction zone or stress cage produced, pressures last longer for deeper fracture penetration, there is less cleanup, and it is easier and safer to handle.

Tools are wireline conveyed and can be used in open hole or cased wells. Formulations for cased hole application burn somewhat slower, which reduces the peak pressure and generally avoids damaging the casing. To contain the energy, the tool is covered with a 300- to 5,000-foot fluid tamp. Tools are fielded through wireline companies, with services currently available in Illinois, Kansas, Kentucky, Ohio, Oklahoma, and Texas’s Permian Basin.

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SECTION 3
DEALING WITH HIGH WATER PRODUCTION DURING PRIMARY PRODUCTION

Various options to reduce lifting and/or water handling costs are available in dealing with wells that produce large amounts of water. These include water shut-off treatments using gelled polymers, reducing beam pump lifting costs, power options to reduce electrical costs, and separation techniques. Not all wells are conducive to having any or all of these techniques applied, but in the right circumstances, major economic benefits can be realized.

Water Shut-off Treatments Using Gelled Polymers. The majority of polymer treatments to control water production in producing wells are performed in fractured carbonate/dolomite formations associated with a natural water drive.[10] Gelled polymers are created when dry polymer is mixed in water and crosslinked with a metal ion (usually chromium triacetate or aluminum citrate). Gelation is controllable, ranging from a few hours to weeks. Slower gelation time allows for more volume and deeper placement. Different polymer systems are available from different service providers. Recent successful treatments in the midcontinent have used the MARCIT^{sm} technology developed by Marathon Oil Company. MARCIT^{sm} is the acronym for MARathon Conformance Improvement Treatment.

Service company experience seems to be the dominant factor in estimating how a particular formation in a given area will respond to gelant injection. The service provider must be prepared to alter the original design based on the ability of a formation to accept a viscous fluid. A formation injectivity test is important in determining any changes in the original design.

Creating a pressure response during treatment is the single most important indicator of a potentially successful water control project. A slow, steady pressure increase over a period of time during pumping will tell the operator one of two things: 1) the formation is reaching fill-up of polymer into the problem zone, or 2) the reservoir temperature is causing the polymer to crosslink and build viscosity.

Pressure response is a product of polymer volume, injection rate and gel strength. Altering any or all of these factors can improve the success of the treatment if reservoir resistance is not seen as the gelant is being pumped. Increasing polymer volume is typically the first step many service companies recommend if the Hall plot indicates only a slight increase of pressure near the end of the treatment. The advantage of pumping a larger volume is that greater in-depth reservoir penetration can improve the longevity and effectiveness of the treatment. The disadvantage of more volume is increased treatment costs due to longer pump times and additional chemicals.

Usually injection rates are increased at the beginning of the treatment in order to determine how easily the formation can accept a viscous fluid. Recent research and field experience have shown that higher pump rates can improve the effectiveness of treatments in carbonates that exhibit secondary permeability and porosity features. Increasing the injection rate also reduces the service company's field time, which translates into a cost reduction for the operator.

Increasing gel strength or gel viscosity is the third method for achieving a pressure response. This method is typically used at the midpoint of a treatment when the Hall plot shows no

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increase in slope or after several treatments in a particular field indicate the need for such action. Improving gel strength can be done by accelerating the crosslinking, increasing the polymer loading of the gelant, or using a higher molecular-weight polyacrylamide.

Acceleration of the crosslinker in Marathon's MARCIT^{sm} is accomplished by adding chrome chloride to the chromic triacetate. Mature gels can be formed in approximately 4-6 hours at a temperature of 90^{o} F with the accelerated crosslinker, as compared to the normal time of 16-18 hours. The advantage of this technique is that treatment volume may be significantly decreased in heterogeneous carbonates while the gel is placed into the highest permeability features of the formation. The disadvantage is that higher temperature reservoirs may cause the gel to prematurely set in or near the wellbore.

Increasing polymer loading will also improve gel strength. A 4,000 ppm gel contains 1.4 pounds of polymer per barrel of mix water. Increasing the concentration to 5,500 ppm will add 0.52 pounds per barrel, which is a nominal change in chemical cost. The advantage of high polymer loading is having a stronger gel that crosslinks in a shorter time.

Molecular weight also plays an important part in gel strength. Most treatments utilize polyacrylamides that have a molecular weight of 4-8 million. This medium molecular-weight polymer can be used for both high permeability matrix and smaller fracture systems. Service companies can also supply higher molecular-weight products that are designed for use in high conductive secondary features. Gels formed with this polymer will enter only the highest permeability sections of the reservoir where the water problem exists. The disadvantage of high molecular-weight gels is that in-depth reservoir penetration and subsequent water diversion may be reduced.

Candidate selection. Best candidates are shut-in wells or wells producing at or near their economic limit. These wells benefit most from a successful treatment and little is at risk if the treatment fails, other than the treatment cost. Other selection criteria include significant remaining mobile oil in place, high water-oil ratio, high producing fluid level, high initial productivity, wells associated with active natural water drive, structural position and high permeability contrast between oil and water-saturated rock (i.e., vuggy and/or fractured reservoir). Successful treatments have been conducted in both cased and open hole completions.

Treatment sizing. Only empirical methods exist at this time for sizing treatments. Experience in a particular formation is most beneficial. However, in many instances larger volume treatments appear to decrease water production for longer periods of time and recover more incremental oil. Some rules of thumb include two times the well's daily production rate as the minimum polymer volume or using the daily production capacity of the well at maximum drawdown (i.e., what the well would be capable of producing if it were pumped off) as the treatment volume.[10] In lower fluid level wells the daily production rate is sometimes used as the minimum polymer volume.

Preparation prior to pumping. Ensure the wellbore is clean, acidize if necessary (typically 350-500 gal 15% acid, pump away with water). Establish a maximum treating pressure; run a step rate test to determine parting pressure, if necessary. Select an acceptable source of water to blend and pump the treatment. Have the service provider test the water's compatibility to form the desired gels. Select a polymer-compatible biocide for the mix water (typically 5-10 gallons per 500 barrels of mix water). Set tubing and packer above the zone to be treated.

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Placing treatment. Use stages of increasing polymer concentration. Inject treatment at a rate similar to the normal producing rate. Keep treatment pressure below reservoir parting/fracture pressure. Changing conditions during treatment may warrant design changes during pumping. Over displace the treatment with water or oil. In some instances, a rapid pressure response early in the treatment is a danger sign the treatment may not be successful.

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SECTION 4
DEALING WITH WATER PRODUCTION DURING WATERFLOODS

Water Injection and Production Trends. One basic concept to successful waterflooding is getting the water to where the oil is. In many instances this requires converting the best producing wells to injection wells. Some independent producers select poor or marginal producers as injection wells for economic reasons and later wonder why the waterflood did not perform as expected.

In planning a waterflood: 1) Determine water requirements as accurately as the data permit; 2) Survey all possible water sources, with special attention given to satisfying quantitative requirements; and 3) Develop the selected source in the most economic manner permitted. The largest daily demand for water occurs during the fill-up period when there is no return water available. During this fill-up period, it is usually advantageous to maintain a high rate of injection, so as to accomplish an early fill-up (a rate between 1 and 2 B/D/acre-foot is desirable). After fill-up has been achieved, a rule of thumb is injection rate should be about 1 B/D and not less than ½ B/D/acre-foot.[11] Flood pattern, well spacing, and injection pressures should be designed to meet these requirements.

The pore volume (PV) method has been found to give a good approximation of the ultimate water requirements for a waterflood. The volume of water required should range from 150 to 170% of total pore space, and the measurement of such space should include the PV of any adjacent overlying gas interval or basal water zone.[11] The ultimate water requirements, together with the average water injection rate, will serve as a basis for estimating the total life of the waterflood.

If gas or water intervals are not present, produced water will comprise 40 to 50% of the ultimate water requirements. If gas and water intervals are present, less return water will be available – thus, the ultimate make-up water requirement will increase to as much as 60 to 70% of the total quantity of water injected.

The volume of produced water will increase during the life of a waterflood, both from an individual well and overall project basis. As the flood front reaches a producing well, fluid volumes will increase, making it necessary in most instances to increase the capacity of the artificial lift equipment. It is important to capture (produce) as much of the oil as possible as the flood front advances past the producing well. Fluid level monitoring will help insure the producing wells are being pumped off.

As the flood front advances past the producing well, an increasingly higher percentage of water will be produced. In many instances it is advantageous to shut in the producing well or convert it to an injection well when it reaches a high water cut, in order not to rob water from the advancing front. If it is shut in, it can be reactivated later and produced to an economically limiting water-oil ratio.

Material balances should be run between injection and production wells. Monitoring the amount of water injection and the amount of water production can lead to important information. This is a comparison of water in versus water out. Do this comparison periodically for the project and

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for areas or patterns within the project. This is sometimes referred to as pattern water balancing. The comparison can be accomplished using injection/withdrawal ratios.

If the volume of injection water into an area or pattern is similar to the amount produced in a nearby well, this could be an indication of a channeling or communication problem. Simple tests, such as stopping or decreasing water injection and monitoring changes in the amount of water produced, can help detect a problem. If a correlation exists, then a tracer test should be run to verify the problem.

Reinjecting Produced Water Versus Make-up Water. The volume of return water becomes an increasing percentage of the required injection rate as a flood progresses; therefore, it is an economic necessity that produced water be reinjected unless the cost of treating the produced water is higher than that of the make-up (or source) water. Incompatibilities between different waters and the reservoir rock must be considered. Pore-size distribution, and composition and distribution of clays are the most important rock considerations. Complete water analysis of both the injection source water and connate water enables scaling, clay-swelling, and brine incompatibilities to be evaluated. Bacteria, suspended solids, oil, and dissolved oxygen and hydrogen sulfide levels should be established. Special attention should be given to the detection of any combinations of ions that may precipitate on being mixed. Unacceptable levels of these parameters must be addressed in the facility design and chemical treating programs. In many major waterfloods, waters are isolated in the surface system and are injected separately into the reservoir. When mixing incompatible brines cannot be avoided, they should be mixed on the surface rather than downhole so that resulting scales or deposits can be more easily removed. Chemical treating requirements, backwashing and acid treatments on injection wells will increase when incompatible brines are mixed.

Water Quality Needed to Maintain Injectivity. The proper balance between water quality and cost must be determined. While rigorous water quality guidelines like 98% removal of particles above 2 microns, oil < 5 ppm, and oxygen < 50 ppb[12] will nearly always provide water of sufficient quality, costs to achieve that quality can become excessive. Cost elements include initial installation costs of water treating facilities, chemical costs, frequency and cost of well cleanup workovers, and other maintenance and operating costs. The economic analysis must consider delayed production due to poor injectivity and potential lost production due to reduced sweep efficiency. Water handling facilities must be designed to handle treating upsets, since even short periods of high oil carryover can cause significant formation damage in injection wells.

In the past, fresh water was commonly used in waterfloods. Because of increasing scarcity, fresh water will not generally be a viable source. Therefore, most injection projects use saline or brine waters. For a waterflood operation to be successful, the water used for injection must be of a quality that will not damage the reservoir rock and injection rates must be maintained below the parting pressure of the reservoir. Poor water quality will result in lost oil production.

Five components in water detrimental to a waterflood are: 1) microorganisms, 2) dispersed oil, 3) suspended solids, 4) dissolved gases, and 5) dissolved solids.[13]

Three classes of *microorganisms* found in water used in the oil field are algae, fungi, and bacteria, with bacteria representing the most serious problem in waterfloods. They range in size

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from 0.2 to 10 microns. Bacteria are controlled using biocide chemicals and removed by filtration.

Dispersed oil in injection water is detrimental for three reasons. First, bacteria utilize certain components in the crude oil as food. Second, oil is strongly adsorbed on iron sulfides and other scale deposits, which makes it difficult to remove these deposits with acid treatments. Third, oil reduces the relative permeability to water in the injection well. As relative permeability to water decreases, it requires more pressure to inject the same amount of water. Dispersed oil in injection water can be reduced by proper use of demulsification chemicals and by better design of the water system.

Suspended solids are either organic, from algae and bacteria, or inorganic, from minute particles of clay and sand or precipitates of calcium carbonate, iron sulfides, and other scales. Many can be removed by settling tanks and filters and must be removed in order to prevent damage to the injection well. Complete removal of all suspended solids is difficult and expensive, especially for very small particles below a micron in size. As a rule of thumb, all particulate matter larger than one-third the average pore throat diameter for the reservoir for which the water is intended should be removed. The average pore throat diameter, in microns, can be estimated by taking the square root of the formation permeability in millidarcies. For example, if the formation permeability is 100 millidarcies, then the average pore throat diameter is estimated at 10 microns. Thus, the injection water should have no particulate matter greater than 3.3 microns.

Dissolved gases frequently found in injection waters are oxygen, carbon dioxide and hydrogen sulfide. All three enhance corrosion problems. Oxygen can be removed by an oxygen scavenger, such as cobalt-catalyzed sodium bisulfite. Proper gas blanketing of water tanks also minimizes oxygen entry. Hydrogen sulfide can be oxidized to sulfur with oxygen or sulfur dioxide, or to sulfate with hypochlorite. Removal of carbon dioxide from the water can be achieved by stripping with an inert gas, such as nitrogen, but the cost generally exceeds the benefit.

Dissolved solids are found in all waters. Common materials found in oil field waters include sodium, calcium, magnesium, barium, strontium, ferrous and ferric, and aluminum cations, along with carbonate, bicarbonate, sulfate, sulfide, chloride, bromide, iodide, and silicate anions. Have your water analyzed on a regular basis and implement a chemical treatment program to help minimize problems.

Using Chemical Tracers to Identify Channeling or Premature Water Breakthrough. A chemical tracer is a tool to determine water flow from an injection well to surrounding production wells. Tracing injected water with a chemical and observing when and where that chemical is produced can provide information on directional flow trends, identification of rapid interwell communication, volumetric sweep, and delineation of flow barriers.

Water-soluble chemical tracers added to the injection water stream are substances not normally present in formation fluids. Ideally, these tracers do not interact with either the reservoir rock or other fluids in the reservoir. Injection water movement is monitored by analyzing produced water in area wells for the presence and concentration of the tracer. It is important to monitor wells beyond the immediate offset producers. Tracers can be injected as a high concentration slug or continuously over a longer time period. When the slug method is used, offset producers must be sampled every few minutes or hours to detect a tracer spike as the slug flows by. With the

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continuous method, sampling can be less frequent. Inferences concerning channeling and areal sweep efficiency are then drawn from analysis of tracer transit times between injection well and producers and from concentration levels observed in these wells.

In most instances, before any tracers are injected, the reservoir should be “pressured up.” This means the reservoir must be on waterflood long enough to fill void spaces to minimize loss of tracer material.

Common tracers are fluorescein sodium dyes, ammonium nitrate or fertilizer, ammonium thiocyanate, and lower molecular-weight alcohols such as methanol and isopropanol. Fluorescein sodium dyes generally are used only when severe channeling with short residence times is suspected because adsorption by the reservoir rock can be excessive over longer periods of time. Fluorescein sodium dyes can be visually detected at very low concentration levels, making field detection very simple and inexpensive. Like the fluorescein sodium dyes, ammonium nitrate is inexpensive and can be detected in the field, but its use requires specific reagents and colorimetric equipment. Ammonium thiocyanate can be used in applications similar to ammonium nitrate, but it costs more and is not always available. Limitations on the use of lower molecular-weight alcohols include higher cost and the need for laboratory analysis with gas chromatograph equipment.

Using Gelled Polymers to Modify Permeability to Increase Sweep Efficiency. Many waterfloods are plagued with low volumetric sweep efficiency. In many instances, poor performance is thought to be a result of water moving rapidly through high permeability channels or through natural or induced fractures. Induced fractures are often the result of over-pressuring the formation at some point. In other instances, water breakthrough may be related to permeability contrasts between different layers, which may or may not be in vertical communication in the reservoir.

Permeability modification treatments can help improve volumetric sweep efficiency. In waterfloods, injection-side treatments are most common. These treatments are conducted with either crosslinking or in-situ polymerization processes.

Crosslinked polymer treatments involve the addition of low concentrations of metal ions to the polymer solution causing the polymer molecules to bond to one another, greatly increasing the resultant gel’s ability to develop resistance to the flow of fluids in the reservoir rock. Depending on the concentration of polymer, crosslinking agent and rate of combining the two, a wide range of permeability adjustment is possible. In the in-situ polymerization process, monomers are polymerized in the reservoir. When treatments are properly placed in the targeted area, resulting fluid flow changes in most cases improve oil recovery and reduce operating costs due to reduced water cycling. Long-term performance of these treatments relies on the in-situ solutions having sufficient strength to stay in place during drawdown.

Permeability modification treatments must address correct identification of geological and reservoir characteristics, correct design and effective placement in the reservoir, and effectiveness lasting throughout the project period. Since different conformance improvement technologies are not applicable to all reservoir problems, the critical task is to successfully identify the channeling problem and then to match an appropriate technology to that problem.

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Past historical success rates with crosslinked polymer treatments have been less than 50%[14], with more than two-thirds of failures resulting from improper application[15]. Most failures with in-situ gel polymer are caused by one or more of the following: 1) improper placement of gel polymer within the wellbore, 2) improper selection of candidate well, 3) lack of knowledge of wellbore integrity, 4) lack of adequate preparation of wellbore prior to the job, 5) limited time allotted to implement the treatment, and 6) not understanding the injection well profile prior to and after the treatment. With proper engineering, planning, and application, success ratios of more than 80% have been achieved.[14]

Facts operators should know about gelled polymers: 1) Gels are created when dry polymer is mixed in water and crosslinked with a metal ion (usually chromium triacetate or aluminum citrate); 2) Gelation time is controllable ranging from a few hours to weeks; slower gelation time allows for more volume and deeper placement; 3) Gels having viscosity and elasticity ranging from slightly greater than fresh water to rubber can be created in virtually any water, at temperatures up to 400^{o} F, in high H_2S environments; 4) Special equipment is normally required to properly blend and pump polymer gels; 5) Gels can be created that completely block the flow of fluid through all reservoir rock or they can preferentially reduce permeability and fluid flow through only the most permeable and conductive pathways; 6) Gels can be created with polymer concentration ranging from a few hundred to more than 50,000 ppm; low polymer concentration means less gel strength and higher concentration means more gel strength; 7) Weaker gels (colloidal dispersion gels) are used in reservoirs dominated by matrix flow conditions and stronger gels (bulk gels) are used in reservoirs dominated by fracture or vug flow conditions; 8) Gels are equally applicable to sandstone and carbonate reservoirs; and 9) Gels are relatively inexpensive because they contain 98% or more water.[16]

Candidate well selection. Selection criteria for injection well candidates are: 1) significant remaining mobile oil-in-place that can be recovered if sweep efficiency is improved, 2) low secondary oil recovery due to poor sweep efficiency (i.e., high degree of reservoir heterogeneity), 3) premature water breakthrough at producing wells, 4) evidence of direct injector to producer channeling through fractures, vugs or high matrix permeability rock, and 5) high injection rate associated with low wellhead pressure.

Two important factors in determining waterflood efficiency are reservoir heterogeneity and mobility ratio. Mobility of a fluid is defined as the effective permeability of a particular fluid divided by its viscosity. In a waterflood, the mobility ratio is the mobility of the displacing phase (water) divided by the mobility of the displaced phase (oil). For mobility ratios greater than 1.0, polymer-augmented flooding should be investigated.

Reservoir heterogeneity can also be improved using gelled polymer treatments. Reservoir heterogeneities are nonuniformities in reservoir properties that cause inefficient sweep and premature water breakthrough in a waterflood. These heterogeneities depend upon the depositional environment of the reservoir; subsequent events such as compaction, solution, cementation, and fracturing; and the nature of the particles constituting the reservoir. Porosity and permeability are reservoir properties that often exhibit significant heterogeneity in both the vertical and areal sense, but they are generally more pronounced in the vertical direction.

The degree of heterogeneity can be determined from cores. Core reports can be used to predict performance of new floods and to explain reasons for poor performance in mature floods. The

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Dykstra-Parsons coefficient of permeability variation is a common descriptor of reservoir heterogeneity. It measures reservoir uniformity by the dispersion or scatter of permeability values. A homogeneous reservoir has a permeability variation that approaches zero, while an extremely heterogeneous reservoir would have a permeability variation approaching one. If a core analysis is not available, a nearby core from the same reservoir can be used as an approximation.

When to use polymer gels in injectors. Inject colloidal dispersion gel at the inception of a waterflood to avoid sweep efficiency problems if performance of an analogous flood suggests that premature water breakthrough will be a problem, or representative core data indicate that the reservoir has a high Dykstra-Parsons coefficient (greater than 0.6) and will not flood uniformly. Inject bulk gel after waterflood inception if water channeling through fractures or high permeability streaks creates a sweep problem. Expected results are increased resistance at the injector, more oil produced faster and at lower water-oil ratios, and less water to handle.

Treatment design. The initial step in treatment design is selecting a process appropriate for the reservoir/producing problem and the treating/reservoir fluids. Choices to be made include near-wellbore versus deep gel treatments, type of polymer, crosslinking agent, and crosslinking process. On-site and laboratory testing by service companies with actual treating/reservoir fluids assists in chemical selection and treatment design.

A critical step is calculation of treatment volume and prediction of variation in polymer composition. Diverse tools, such as production/injection histories, well logs, surveys, workover history, and personal knowledge of the formation and geographical area are critical for prediction of treatment volume. It is impossible to calculate treatment volume exactly, but estimation within reasonable limits is possible. That is why it is essential that injection rate and pressure be continuously monitored during treatment and appropriate changes made to optimize treatment.[17] Polymer solution should be injected until parting pressure is approached while injecting, the injected slug is produced at a peripheral producer, or the maximum design size is achieved. In most cases, parting pressure is the limiting factor for treatment size.

Interwell chemical tracer data provide valuable information for designing the size, gel time, and gel strength.[18] Tracer breakthrough time and injection rate can provide an estimate of the size of the channel and, thus, the treatment size. In utilizing this technique, it is important to know the concentration of the tracer showing up at the producing well. If it is much lower than the injected concentration, it might be wise to increase the treatment size proportionally. Usually more than the fracture volume of polymer must be injected, since it will leak into the reservoir matrix. Tracer breakthrough time can also provide an estimate of the required gelation time and gel strength. For in-depth placement of the gel solution, the gelation time should be long enough to place the entire treatment.

Tables 3 and 4 provide examples of the volume of gelling solution needed to fill fractures of various dimensions.

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Table 3. Estimated Treatment Volume of a Single Horizontal Fracture Radial Width 0.05 in

Radius of Fracture (ft)	Volume of Gelling Solution (barrels)
25	2
50	6
100	23
150	52
200	93
500	583

Table 4. Estimated Treatment Volume of a Single Vertical Fracture Width 0.05 in; Height 50 ft

Length of Fracture (ft)	Volume of Gelling Solution (barrels)
100	4
200	7
500	19
750	28
1000	37
1500	56
5280	196

Performing the treatment. The candidate well should be cleaned prior to pumping the polymer solution. The goal of wellbore cleaning, whether mechanical or chemical, is to provide a clean formation face free of sludges, solids, or other materials that might interfere with the polymer solution or affect injectivity. Chemical performance and compatibility should be checked in the actual fluids on-site, since trucks and frac tanks can be sources of contaminants. Mixing/injection procedures must ensure that uniform polymer mixes are prepared.

Design treatment volumes and chemical concentrations should be used only as guidelines. Since each well will have a unique response, the well's ability to accept fluid (injectivity) should be continuously evaluated during treatment, and treatment compositions adjusted accordingly or the treatment terminated before the design volume is injected if the injection rate decreases too much. Rate restriction to avoid formation parting is essential. Hall plot slope analysis is very useful for real-time monitoring of treatments. The summation of surface or, preferably, bottomhole pressure multiplied by time versus cumulative treatment volumes are plotted at 15-minute intervals during treatment, and slopes determined. Changes in slope can indicate if treatment should be terminated before the design volume is injected.

Other recommendations for placing a gel treatment are: 1) increase polymer concentration in stages, 2) inject treatment at a rate similar to normal injection rate, 3) stay below reservoir parting pressure, 4) keep offset producers active during treatment, and 5) over-displace the treatment with water (use more water in short perforated intervals).

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SECTION 5
UNEXPECTED INCREASES IN WATER PRODUCTION

Sources. *Mechanical problems*. Many water entry problems are caused by poor mechanical integrity of the casing. Holes caused by corrosion or wear and splits caused by flaws, excessive pressure, or formation deformation can allow unwanted reservoir fluids to enter the casing. An unexpected increase in water production could be the result of a casing leak. Many times casing leaks result in a pump failure or stuck pump. Most casing leaks occur in the casing above the top of the cement. Therefore, when the leak breaks into the wellbore, drilling mud that was left in the annulus between the casing and open hole during primary cementing operations enters the wellbore.

After repairing a casing leak, check the plugged back total depth and remove or circulate out any drilling mud or other debris that may have entered the wellbore. Often times after a casing leak, the well will need to be re-stimulated to remove formation damage caused by the invasion of fluids from the leak into the producing formation.

Communication problems are classified as either near wellbore or reservoir related.[19] Some problems could easily be placed in both categories. Near wellbore problems are channels behind casing, barrier breakdowns, and completions into or near water. Reservoir-related problems are coning, cresting, channeling through higher permeability zones or fractures, and fracturing out of zone.

<u>Channels behind casing</u> can develop throughout the life of a well, but are most likely to occur immediately after the well is completed or stimulated. Unexpected water production at these times strongly indicates a channel may exist. Channels in the casing-formation annulus result from poor cement/casing bonds.

<u>Barrier breakdowns</u>. Even if natural barriers, such as dense shale layers, separate the different fluid zones and a good cement job exists, shales can heave and fracture near the wellbore. As a result of production, the pressure differential across these shales allows fluid to migrate through the wellbore. More often, this type of failure is associated with stimulation attempts. Fractures break through the shale layer, or acids dissolve channels through it.

<u>Completions into or near water</u>. Completion into the unwanted fluid allows the fluid to be produced immediately. Even if perforations are above the original water-oil contact, proximity allows production of the unwanted fluid, through coning or cresting, to occur more easily and quickly.

<u>Coning and cresting</u>. Fluid coning in vertical wells and fluid cresting in horizontal wells both result from reduced pressure near the well completion. This reduced pressure draws water from an adjacent connected zone toward the completion. Eventually, the water can break through into the perforated or open hole section, replacing all or part of the hydrocarbon production. Once breakthrough occurs, the problem tends to get worse, as higher cuts of the unwanted fluid are produced. Although reduced production rates can curtail the problem, they cannot cure it.

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Channeling through higher permeability zones or fractures. Higher permeability streaks can allow fluid that is driving hydrocarbon production to breakthrough prematurely, bypassing potential production by leaving lower permeability intervals unswept. This is most common in active water-drive reservoirs and waterfloods. As the driving fluid sweeps the higher permeability intervals, permeability to subsequent flow of the fluid becomes even higher, which results in increasing water-oil ratios throughout the life of the well or project.

Fracturing out of zone. An improperly designed or poorly performed stimulation treatment can allow a hydraulic fracture to enter a water zone. If the stimulation is performed on a producing well, an out-of-zone fracture can allow early breakthrough of water. If the fracturing treatment is performed on an injection well, a fracture that connects the flooded interval to an aquifer or other permeable zone can divert the injected fluid, providing very little benefit in sweeping the oil zone. As mentioned in Section 2, many operators tag the tail end of their proppant with radioactive tracer, so if the well does not respond as anticipated, they can log the well to determine where the fracture went.

Methods to Identify Sources. *Chloride/TDS tests*. Production-water sampling and analysis should be conducted on a regular basis on each producing well. Establishing a baseline water analysis provides valuable information if production or well conditions change suddenly. Changes in chloride or total dissolved solids (TDS) provide insight to problems and remedial action that may need to be taken.

Chloride concentration can be used to determine if produced water is connate water (production water) or water introduced to the well during stimulation or from other sources. Changes in chloride concentration can indicate invasion of water into the well due to poor mechanical integrity. Lower than normal chloride concentrations can indicate a shallow casing leak. Iron concentrations can predict the probability of formation damage from iron oxide precipitation. pH can also indicate the probability of metal oxide precipitation. Knowing the specific gravity of your produced water is useful in determining bottomhole hydrostatic pressure.

Production logging can be used for: 1) injection profile tests in waterfloods to determine the vertical distribution of fluid flows within the wellbore and near wellbore region, 2) finding tubing-casing leaks, 3) detecting lost circulation zones, 4) determining if packers or bridge plugs are leaking, 5) detecting fluid channels behind casing, 6) developing production profiles, 7) locating gas-oil-water contacts, 8) tracing frac fluids, and is beneficial in many other instances.

Radioactive tracer or fluid travel surveys. The radioactive tracer log was developed to give positive, accurate information on fluid flow paths and rates within the wellbore. The tool's capabilities include detecting lost circulation, leaking packers and bridge plugs, fluid channels behind casing, and developing injection and production well profiles. Two types of radioactive tracer surveys are commonly used, the velocity-shot method and the timed-run method. The velocity-shot method is conducted by ejecting radioactive fluid downhole with a tool that has one or two gamma counter(s) and monitoring fluid movement with the gamma counter(s). The two-detector method is preferred over the one-detector method because of difficulty in accurately establishing an injection time. In this method, the tool is stationary and the log is a function of time. This method is not recommended in producing wells because it is not desirable to produce radioactive fluid. Hence, its main application is in injection wells.

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In the velocity-shot method, counters are positioned at proper points, a small concentrated quantity of radioactive fluid is ejected, and a recorder records the travel time of fluid movement past the counters. Inside the casing, or in open hole if a caliper log is available, a time profile and resulting velocity profile determine injection distribution within the wellbore area. A typical procedure with the shot method is to record one station above the perforations to check for 100% flow and for any channeling above the perforations. The perforations are then surveyed in one- to two-foot increments until infinite time between counters is recorded. A second check is then made to ensure that no further "down channeling" is occurring.

The timed-run method qualitatively detects the flow of fluids up or down hole, either in casing or in the annulus. In this method, a large amount of radioactive material is ejected at the bottom of the tubing and successive runs are made with a gamma-ray tool; the times of ejection and each run are carefully noted. Movement of the radioactive material is traced. Primary use of this method is to detect unwanted movement of injected water in the casing annulus.

A <u>differential temperature survey</u> uses a logging tool and is a service available from most wireline logging companies. The differential temperature log measures temperature of the wellbore fluid under static (shut-in) or dynamic (flowing) conditions. Temperature logs run while a well is injecting water at stabilized rates can yield much useful information. The logging tool responds to temperature anomalies produced by fluid flow, either within the casing or in the casing annulus, and is very useful in detecting the latter. Interpretations are also used to determine flow rates and points of fluid entry or exit.

In an injection well, temperature response is a function of depth, temperature of injected fluid, injection rate, time of injection, formation and fluid thermal properties, and the geothermal profile in the well. An injection well that has been taking fluid for some time can be shut in and numerous temperature logs can be run over a period of time to observe the temperature profile as it returns to geothermal values. The zones that have taken the (usually) cooler injection fluid will show a slower rate of return to the geothermal profile than the zones that have taken no fluid. This effect can be detected in uphole zones behind pipe that are taking injection water due to communication problems.

The most common application is in waterflooding projects where a foot-by-foot analysis of formation flooding is desired on injection wells. Advantages in tracing injected fluids with the single element differential temperature log become apparent when proper logging interpretation techniques are used. The temperature gradient log is a continuous recording of downhole absolute temperatures. Repeatability of the temperature measurement is plus or minus 0.01^{o} F in the range of 50 to 400^{o} F. Scales vary from fractional increments per inch to any practical limit required. The most commonly recorded scales are: 1, 2, 5, and 10^{o} F per inch.

Logging is usually performed on the downward traverse so that well fluids are encountered in their normal state without being previously disturbed by passage of the line and tool. The casing collar locator is run and recorded simultaneously, as this provides definite depth correlation with other types of logs run in the well.

Besides being used to detect fluid communication downhole in water injection wells, the technique is applicable for finding tubing-casing leaks, gas communication, productive zones, lost circulation zones, gas-oil-water contacts, production profiles, and tracing frac fluids.

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Spinner (flowmeter) surveys are used to meter fluid flow rates within cased or uncased wells. They are useful in determining production rates, detecting thief zones, locating lost circulation zones, finding holes in casing or tubing, and assisting in injection and production profiles.

Preliminary spinner surveys are generally made with the tool being withdrawn from the hole at a steady rate to permit selection of various station levels for observation of absolute flow rate as related to spinner revolutions per minute. The flowmeter can be run into or out of the well at a constant speed to obtain a continuous flow profile versus depth. It can be stopped at various depths within the wellbore to record the total volume of flow at a preselected interval.

The flowmeter unit contains a low inertia impeller to measure the movement of borehole fluids as they pass through the impeller blades. Movement of the impeller rotates a small magnet that actuates a magnetic switch. Fluid flow rotates the impellers, generating a square wave pulse, with frequency proportional to number of impeller revolutions per second. A flowmeter module that supplies power to the spinner unit also couples the signal into the rate meter that processes the signal for the recorder.

Types of fluid flowing through a spinner have a pronounced influence on its operation. Dirty fluids foul the impeller movement and gaseous fluids overspin the impeller. Surveys performed in fluid having viscosity higher than water result in optimistic apparent flow volume values. Surveys made in lower viscosity fluids result in pessimistic flow volume values.

Some spinners are limited to certain ranges of flow rates. Therefore, before doing a survey, check with the appropriate service company to verify that the spinner will work within the flowrate ranges of the well in question.

Cased Hole Formation Resistivity (CHFR) Tool.[20] The ability to measure formation resistivity directly through casing in monitoring wells allows the measurement of water saturation further away from the wellbore. Advances in digital electronics have made it possible to produce the sufficiently accurate and stable downhole sensors required to measure formation resistivity through steel casing.

The main purpose of CHFR is reservoir monitoring. During the production life of a reservoir, through-casing formation resistivity data may help understand fluid flow and recovery processes in several ways:

- Evaluation of reservoir fluid saturation changes with time, including the identification of swept zones, potential flow barriers, and bypassed oil.
- Monitoring of movement in oil/water contacts.
- Identification of take-off rate-induced water coning, by repeat logging at different take-off rates, allowing time to re-establish stable conditions.
- Estimating residual oil saturation to a waterflood or a combined water-alternating-gas (WAG) flood. Measuring formation resistivity through casing allows the evaluation of residual oil saturation further away from the wellbore than open hole logs or sponge cores.

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The CHFR tool can also be used for primary evaluation of reservoirs where no logs could be acquired in open hole, due to operational problems where open-hole logging is too risky. Wells with old or faulty logs can also be re-examined.

Measurements are taken while the tool is stationary. The CHFR injects current into the casing through a centralizer at the top of the tool that returns to the surface. Slight variations in current loss through the casing are related to current leaking into the formation and can be calibrated to formation resistivity. Voltages investigated by the tool are in the nanovolt range, requiring exceptionally stable and low-noise electronics downhole. Frequency is limited to about 1 Hz to avoid polarization associated with a DC-measurement and skin effects caused by a higher frequency. Casing current loss is measured through 4 rings of 3 electrodes attached to caliper-like arms that open up and establish contact with the steel casing at each station. Good electrical contact is essential; wells with scale or corrosion inside the casing create problems. In double-cased intervals the CHFR will read only the resistivity of the cement between casings.

Downhole tool calibration is achieved by comparing cased-hole measurements to open-hole logs.

Mechanical integrity tests (MIT). A well is considered to have mechanical integrity if there are no significant leaks in the tubing, casing, or packer and no fluid movement into fresh or useable water. Any fluid coming into the wellbore, from production or injection, remains in the wellbore until it is produced or leaves the wellbore in the interval(s) approved for injection or disposal. Mechanical integrity can be determined by pressure testing or by casing inspection logs. In some instances an acoustic fluid level shot can assist in locating a leak in the casing.

<u>Pressure testing</u> is commonly used to perform mechanical integrity tests. An MIT is required periodically on injection and disposal wells by State regulatory agencies. This is conducted by pressuring up the tubing-casing annulus and observing whether the pressure holds or not.

Pressure testing to isolate casing leaks is typically conducted using a retrievable bridge plug (RBP) and packer. The goal is to isolate the leaking interval as quickly as possible. The majority of casing leaks occur where there is no cement behind the casing. One common technique is to run the packer and RBP into the well and set the RBP just into the top of the cement interval behind casing. Pressure test the RBP and move the packer up and down the hole, pressure testing both through the tubing and on the annulus at different packer settings until the leak is isolated. Once a long section of casing passes the pressure test, the RBP can be moved and reset if desired. Be sure to use fluid to pressure test that is compatible with the producing formation, as each time the RBP is released the fluid will be dumped downhole. Different circumstances dictate how narrowly the leaking interval needs to be isolated. If the casing is in poor condition over a long interval, it is possible to further damage the casing by setting the packer and RBP in these bad intervals.

<u>Casing inspection logs</u>. Casing inspection methods include multi-fingered caliper logs, electrical potential logs, electromagnetic inspection devices, and borehole televiewers. Of these, the majority measures the extent to which corrosion has taken place. Only the electrical potential log indicates where corrosion is currently occurring. With the exception of caliper logs, all the devices require that tubing be pulled before running the survey, since most are designed to inspect casing rather than tubing and all are large diameter tools.

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Remedial Actions. *Cement squeeze techniques.* Too often, the injection of cement slurries into the casing/wellbore annular space, through casing perforations or splits in damaged sections, is performed without sufficient basic understanding of the placement process.[21] Regardless of the technique used, cement squeezing is basically a filtration process. Cement slurries subject to differential pressure against a filter of permeable rock lose part of their mix water, leaving a cake of partially dehydrated cement particles. The rate of cake buildup is a function of formation permeability, differential pressure applied, time, and capacity of the slurry to lose fluid.

Low fluid loss slurries, when squeezed against low permeability formations, dehydrate slowly, making the operation excessively long. High fluid loss slurries lose water to high permeability rocks too fast, bridging off channels that otherwise would have accepted cement. The ideal slurry should be able to control the rate of cake growth so that a uniform filter cake will build up over all permeable surfaces. The only procedure that makes the dehydration of small quantities of cement into perforations or formation cavities possible is intermittent application of pressure, separated by a period of pressure leakoff caused by the loss of filtrate into the formation. This procedure is referred to as a hesitation squeeze. Squeeze cementing is classified depending on the way the cement is placed behind casing.

<u>Low pressure squeezing</u> is when the cement slurry is forced through the opening in the casing below the formation fracturing pressure. The aim of this operation is to fill cavities and interconnected voids near the wellbore with dehydrated cement. The volume of cement is relatively small, since no slurry is actually pumped into the formation. When squeezing in depleted formations, spotting the total volume of cement in front of the perforations may be the only way to prevent the formation from fracturing as a result of hydrostatic pressure.

<u>High pressure squeezing</u>. There are some cases where low pressure squeezing will not accomplish the job. Channels behind the casing might not be directly connected to the perforations; small cracks or microannuli may permit the flow of water but not a cement slurry. High pressure squeezing places the cement slurry behind the casing by breaking down formations at or close to the perforations. Fluids ahead of the slurry are displaced into fractures, allowing cement to fill the desired spaces. Further application of the hesitation technique dehydrates the slurry against the formation walls leaving all the channels, from fractures to perforations, filled with cement cake.

Two things to consider when performing high pressure squeezing: 1) The location and orientation of the generated fracture cannot be controlled; and 2) A properly performed job should leave the cement as close to the wellbore as possible.

<u>Placement techniques</u>. There are two general ways of performing a squeeze job, with a packer or a bradenhead squeeze. The main objective of the packer squeeze is isolation of the casing and wellhead while high pressure is applied downhole. Retrievable packers with different design features are available. The ones used in squeeze cementing, compression or tension set packers, have a bypass valve to allow the circulation of fluids during the running in and once the packer is set. This feature permits cleaning of tools after the job and reversing out of excess cement without excessive pressures, and prevents a piston or swabbing effect during running in and out of the hole.

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Cement retainers (mechanical or wireline set) are used instead of packers to prevent backflow when no cement dehydration is expected or when high negative differential pressures may disturb the cement cake. Retainers are also used when potential communication with upper perforations makes use of the packer a risky operation and squeezing can be carried out without waiting for the cement to set. Cement retainers are drillable packers provided with a two-way valve that prevents flow in either or both directions. The valve is operated by a stinger at the end of the tubing string.

Drillable bridge plugs or cast iron bridge plugs are normally used to isolate the casing below the zone to be treated. Of similar design to the cement retainers, they can be wireline or mechanically run. Bridge plugs do not allow flow through the tool. Retrievable bridge plugs (RBP) are easily run and operated tools with the same function as drillable bridge plugs. They can be run in one trip with the packer and retrieved after the cement has been reversed or drilled out. Most operators dump one or two sacks of frac sand on top of the RBP before the job to prevent settling of cement over the releasing system.

The bradenhead squeeze technique is used mainly when low pressure squeezing is practiced and there are no doubts about the casing's capacity to withstand squeeze pressures. There are no special tools involved besides the bridge plug to isolate downhole formations. Open-ended tubing is run to the bottom of the zone to be cemented. The wellhead is packed off or the blow out preventer rams are closed over the tubing and the injection test carried out as usual. The cement slurry is subsequently spotted in front of the perforations or opening. Once the cement is in place, the tubing is withdrawn to a point above the cement top, the preventers are closed and the hesitation technique applied through the tubing. Reversing or washing down is carried out as normal.

Polymer squeezes. In some circumstances, polymer gels can be used successfully as an alternative to cement, or in combination with cement, to squeeze casing leaks. The type of polymer and process used depends on the location and severity of the leak, and whether or not the squeeze will be required to hold a solid pressure or simply block encroachment of foreign water in a producing well. The advantage of using polymer is two-fold. Polymer can be washed out of the wellbore after a leak is squeezed, preventing costly rig time involved in drilling out cement. Second, since polymer solutions exert a much lower hydrostatic pressure than a cement slurry, there is less possibility of breaking down the formation and losing the squeeze. On difficult leaks, such as in salt sections where multiple cement jobs are often attempted before the leak is successfully squeezed off, a small slug of polymer can be run ahead of the cement as a buffer to prevent the cement from "running away" or washing out the section you are trying to squeeze. Since the polymer continues to adsorb or bond to the formation and the bulk gel fills the larger voids, it is often enough to slow down the coasting of the cement and give it something to squeeze against.

Four basic polymer gel systems are in use today in casing leak squeeze operations. Different service vendors have different names for these systems, but the basic systems are: 1) acrylic monomer grout, 2) high concentration low molecular-weight polymer (HCLM), 3) high molecular-weight polymer, and 4) cement/polymer combination.

<u>Acrylic monomer grout</u> is a non-toxic system that is most effective on tight casing leaks and pressure leakoff situations such as leaks that bleed off pressure but cannot be pumped into. This

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system pumps as a water-thin fluid, then sets up into a tough, ringing gel. Gel times can be controlled from 10 minutes to 2 hours, depending on temperature. Treatment sizes typically range from 10-25 bbl. This is an excellent application for disposal and injection wells that fail MITs because of slight pressure leakoff.

<u>High concentration low molecular-weight polymer</u>s are useful for leaks ranging from tight pressure leakoff situations to moderate leaks that can be pumped into under pressure. This system can be crosslinked using standard metallic crosslinkers, or a low-toxicity organic crosslinking system can be used in environmentally sensitive areas or leak intervals.

<u>High molecular-weight polymers</u> are most effective in larger leaks, to correct channeling behind pipe, and for some lost circulation applications. The primary benefit of using this system is the ability to economically block the flow of foreign water into the wellbore or block the outflow of produced fluids to thief zones.

<u>Cement/polymer combination</u> squeezes are used in severe casing leaks that require mechanical integrity and are unlikely to be successfully sealed using either cement or polymer alone. In most cases, a small (25-50 bbl) slug of high molecular-weight crosslinked polymer is injected ahead of the cement. The polymer acts as a filler/buffer, filling larger voids and coating formation surfaces, preventing water loss and cement contamination by formation fluids. The polymer also acts as a pad, holding cement in the near wellbore area where it is most effective. This process blocks foreign water from the wellbore and can allow pressure integrity to be obtained more cost-effectively than would be possible with cement or polymer alone.

Liner/casing patches. Various types of liners and/or casing patches on the market may assist in solving certain types of casing leak problems. They typically come in different lengths and can be permanently installed in the casing or incorporated as part of the tubing string.

Be aware that many liners or patches that are permanently installed will restrict the internal diameter of the casing across the interval where they are located. This can eliminate running certain types of tools through this interval in the future. If problems occur below this interval, it may be inaccessible for repair with standard tools.

Some patches that are run on tubing string incorporate sealing elements attached to the string at depths that will isolate the leaking interval. Some of these patches have vent tubes between the sealing elements to allow annular access for gas or treating fluids to pass through the patched interval; others do not.

When considering special equipment designed to assist with casing leak problems, consider the potential risk associated with running these tools in the hole. Also consider future uses or operations of the well and how these tools could have an effect.

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SECTION 6
REDUCING LIFTING COSTS

Experience-based Tips.[22] *Maintain low flowline pressures*. To the pumping unit and electric motor, backpressure created by the flowline is the same as lifting fluid from a deeper depth. To ensure pressures are as low as possible, make sure flowlines are clean (check for paraffin restrictions, etc.) and all valves are completely open and properly sized for the expected flow.

Properly size the electric motor. Oversized motors are inefficient. For proper sizing, the motor's thermal amps should be slightly less than the nameplate amp rating. Converting to the correct size motor is most cost effective when a worn out motor is replaced.

Produce with a full pump barrel. To ensure efficient operations, even under pumped-off conditions, make every attempt to fill the pump. To match pump displacement with reservoir inflow, change unit speed, adjust stroke length, use time clocks or pump-off controllers, or change pump size.

Properly tighten sheave belts. If sheave belts are too tight, the belt and bearing life of the electric motor and reducer pinion can be significantly reduced. If sheave belts are loose and slip during periods of high torque, motor energy is lost through heat. Slipping belts can crack or cause wear in the sheaves.

Use as long a stroke and as large a pump as practical. For a given production and pump size, a longer stroke reduces losses along the rod string. When considering longer strokes, note that increasing the stroke length usually increases the torque on the gear reducer. Modern wave equation predictive programs show that increasing pump diameter will reduce power costs.

Select optimum pumping unit geometry. Modern wave equation predictive programs enable you to investigate the effect of various pumping unit geometries on power cost. The highest efficiency occurs when units of correct geometry are loaded to near maximum ratings.

Optimize direction of rotation. Conventional pumping units can be set to rotate either clockwise or counterclockwise. Generally, if the peak load occurs in the first half of the upstroke, a counterclockwise rotation yields the lowest power usage. Dynamometer cards and wave equation predictive programs can be used to determine the optimum direction of rotation.

Maintain proper balance. Out-of-balance pumping units generate power during a portion of the cycle. Non-detented power meters give credit for generated power, so power savings are significant only for single wells using detented meters. Operating cost differences will also be minimal in facilities using a central meter, even when the meter is ratcheted, because power generated by one pumping unit is likely to be used by others.

Power Cost Reduction.[23] One of the action strategies developed by the U.S. Department of Energy (DOE) in early 1999 during the oil price crisis was to help producers learn how to lower their electrical power costs. These costs, depending on type of operation, can range from 5% to as much as 50% of overall operational costs - so even a 10% reduction is significant to operators, often extending the life of mature fields. While more complex and costly solutions (such as the

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development of energy-efficient equipment) have their place, experience shows that reductions up to 30% can be achieved with little or no capital investment when applying good management practices and monitoring operations.

Practical steps. Many companies track power usage and costs on a monthly basis, using that information to manage costs, monitor field operations and make production decisions. The following steps are very simplistic. But because they are simple, don't assume they have been done. Without continual attention, bad habits or changed operating conditions can cause electrical power consumption to creep up unnecessarily.

<u>Locate and analyze power bills</u>:

- Get one year's worth of all your power bills.
- Put in monthly order and read carefully.
- Become familiar with all the terms and factors.
- Construct a spreadsheet to input data; include gross oil and water production volumes.
- Look for trends or unexplained anomalies.
- Does the cost change from month to month make sense? How many different rates are there? Why are rates different? Are there penalties or late charges? If so, why? Do you need power at these sites? If so, why? Is the math correct?

<u>Get free outside help</u>:

- Contact your utility representative; get to know the person individually.
- Let the representative know that you want to work together on reducing your power bills.
- Ask for an explanation of the bills and rates and how they are applied.
- Ask which rates are best for you.
- Ask how to operate your facilities to benefit from various rates.

<u>Get into the field</u>:

- Inventory your electrical motors, controllers and equipment.
- Determine your expected power consumption. Does it agree with your bills?
- Talk to field employees about how they manage power usage. Most do not realize they have some responsibility for this.
- Look at how equipment is operated and at what time of day.
- Find power meters, verify they are yours and match them with bills being paid.
- Learn how to read meters, especially newer time-of-use meters with digital readouts.
- Copy down power-meter information and verify that meter factors match those on the bills.
- Using an amp meter, measure current drawn by each motor. It should be about 70% of nameplate rating. If below 50%, power is being wasted with oversized equipment.
- Stop, look and listen - check to see that pumping units are properly balanced.

<u>Step back and analyze</u>:

- Determine if electrical rate you pay best suits your operation. Corollary: Determine if you are operating to take advantage of the best electrical rate.
- Determine if large, intermittent loads (i.e., water disposal and shipping pumps) can be shifted to non-peak hours to reduce peak demand. This can be a major item.

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- Look for inefficient uses of power. Are motors properly sized? Look for motor creep (the up-sizing of motors when they are replaced because "bigger is always better").
- Do not assume that because something is energy efficient it is best suited for oil field use.
- Understand electric rates. Know how time-of-use rates work and at what time of day the rates change. How does this integrate with the way your wells and facilities are being operated? Look at days of the week and seasonal variations as well as time of day.

Take action:

- Set goals for what power usage and costs should be.
- Assign someone the responsibility to implement changes.
- Look for the elephants. Focus on large loads and ways to reduce power.
- Change to best electrical rate structure for your operations.
- Operate facilities to take advantage of the best rate.
- Make every employee aware of their role in reducing power.
- Follow-up on a regular basis.
- Make electrical power cost reduction an annual training topic.

There are other steps that require a greater investment of time, resources and capital. Do these only after the initial steps outlined above have been taken.

- Look for alternate electrical service providers (ESPs).
- Talk to your oil producer electric co-op. If you don't have one, create one.
- Find out about performance contracting - how to get paid to reduce your power consumption.
- Ask questions and share experiences with local operators and others in the business. Search for knowledge using the Internet, PTTC, trade journals, associations, etc.
- Determine if any industry workshops on this topic have been held in your region. If not, ask for them.
- Get available rate structures changed. Oil fields have a very desirable flat load profile.

Examples. Tejon-Grapevine Field, Kern County, Calif., is a mid-sized field on primary recovery, producing about 80 BOPD at 92% water cut. Major electrical equipment consists of 18 producing oil wells, two injection disposal pumps going to three wells and one shipping pump. An audit of power requirements of the field discovered that:

- Motors were properly sized.
- Changing to a better oil-field rate structure resulted in an immediate 20% cost savings.
- Water disposal pumps, controlled by a float switch, did not run continuously. By installing a clock timer and overflow-protection circuits (cost = $200), load was shifted to off-peak hours when power costs were less. This saved 5% during the summer months.
- Oil was being pumped into pipeline at peak electrical rate hours. By pumping earlier in the day, a 2% cost reduction was realized.

Other examples include:

- Tidelands Oil Production Co. operates several hundred wells in a waterflood in Wilmington Field, California. Motor sizes were examined for proper sizing and mismatches found. However, unless motors are significantly oversized, Tidelands has

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found it uneconomic to replace them. But when motors fail, they are replaced with properly sized motors.

- Champlin operated a field that had access to two electric service providers with different rate structures. By installing equipment to switch between suppliers at different times of the day and year, power costs were reduced by as much as 30% with a 12-month payout.
- Tidelands Oil Production Co., working with the California Independent Petroleum Association and others, fought for rate changes. Rates were changed, benefiting Tidelands and others. Tidelands has realized savings of up to 36% on some meters.

One can reinvest savings from simple steps in other more expensive and complex solutions (controllers, efficient motors, better facilities) to further reduce power costs another 15%.

Tips for power consumption:

- Size motors as close to load requirements as possible, especially where the electric utility bills for demand based on connected hp and not on actual usage.
- Take advantage of interruptible power rates where it is economical to do so. Savings can be 10-30%.
- Evaluate existing injection systems to identify inefficiencies that result in excess power consumption.
- Consider operating costs associated with I2R losses (line losses) when sizing conductors and use the largest economically justifiable conductor size.
- Consider installing energy efficient motors when existing motors require rewinding. Typical payback on energy savings for continuous duty motors is less than one year.
- Use ODP (Open Drip Proof) motors instead of TEFC (Totally Enclosed Fan Cooled) motors.
- Use kW-H meters instead of amp meters to measure power consumption when analyzing operating costs.
- Evaluate the economics of improving the power factor of your power distribution systems.
- Evaluate gas tolling (exchange of gas for electricity).
- Periodically review your contract to ensure it reflects the best possible rates for present load requirements, especially after significant load changes have been made.

On-site Power Generation. Keys that can lead to investigating a potential expense-reducing generation system are: 1) high utility rates, 2) high energy demand, 3) availability of low-cost or non-marketable gas, 4) depleting oil reserves, and 5) reduced lease income.

Two generator types are available: synchronous and induction. Where stand-alone power is needed, the synchronous generator is suggested. However, because of its relative complexity and higher cost, it does not compare favorably with the induction generator when utility power is available as an excitation (reference voltage) source.

A *synchronous generator system* consists of a prime mover (usually a gas engine) coupled to a synchronous AC generator. These are typically used in situations where electric utility power is not available, or the operator wishes to completely sever ties to the electric power utility. Usually, one large synchronous generator is used to produce all the needed power due to the

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inherent complexity of multiple synchronous generators, which must be phase-matched or phase-locked to provide correct power to the electric consumptive devices.

An *induction generator system* utilizes the low-cost, low-maintenance induction motor, with a standard gas engine prime mover. The system is simple and compatible with power utility operation. It supplements lease electrical power to reduce utility costs, but does not replace the utility's function of providing motor starting and peak demand requirements. The ideal application for an induction generator system is where the cost of electricity is high (typically above $0.07/kW-H) and the cost of gas is low. A typical application that used a 125-hp system with a $1.50/Mcf gas cost and a $0.07kW-H electric rate saved the operator $37,500 annually in power costs. Induction generator systems have been economically applied where multiple rod-lift beam pumps are being used, in waterfloods and saltwater disposal operations using reciprocating pumps for high-pressure water injection, and with electric motor driven submersible pumps.

Global Power Systems, LLC out of Bossier City, LA markets an induction generator system and will do an economic analysis of your power use and operational alternatives, if you supply them with 12 months' utility bills and a certified gas compositional analysis.

Surface Versus Downhole Separation. *Downhole oil water separators (DOWS).* A relatively new technology, downhole oil water separator (DOWS), has been developed to reduce the cost of handling produced water. DOWS may also be referred to as DHOWS or as dual injection and lifting systems (DIALS). DOWS separates oil and gas from produced water at the bottom of the well and reinjects some of the produced water into another formation or another horizon within the same formation, while the oil and gas are pumped to the surface. Since much of the produced water is not pumped to the surface, treated, and pumped from the surface back into a deep formation, the cost of handling produced water is greatly reduced. When DOWS is used, additional oil may be recovered as well. Where surface processing or disposal capacity is a limiting factor for further production within a field, the use of DOWS to dispose of some of the produced water can allow additional production in that field. Simultaneous injection using DOWS has the added benefit of minimizing the opportunity for contamination of underground sources of drinking water through leaks in tubing and casing during the injection process. Similar devices have been used to a much greater extent for downhole gas/water separation.

Two basic types of DOWS have been developed – one using hydrocyclones to separate oil and water and one relying on gravity separation. A hydrocyclone-type DOWS can handle larger flow volumes than a gravity separator-type DOWS but is significantly more expensive. Several alternative designs of DOWS are available from different vendors. Hydrocyclones have been paired with electric submersible pumps (ESP), rod pumps, and progressing cavity pumps, while the gravity separator-type DOWS has utilized only rod pumps.

Most DOWS installations have been set up with the producing zone above the injection zone. DOWS can potentially be used for waterflooding. DOWS can also be used for reverse coning to reduce the degree of water influx into oil producing zones. Conversion of a well from a regular pump to a DOWS is a relatively expensive undertaking. Total costs include the DOWS tool itself and well workover expenses. For example, the cost of an electric submersible pump-based DOWS system is approximately double to triple the cost of replacing a conventional ESP. Costs are somewhat lower for the gravity separation-type DOWS, ranging from $15,000 to $25,000, plus workover and installation costs.

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DOWS installations will not be cost effective for all wells. Knowledge of the reservoir and historical production are important before selecting a DOWS installation. Characteristics of wells likely to work with DOWS are, among others, a high water-to-oil ratio, presence of a suitable injection zone isolated from the production zone, compatible water chemistry between producing and injection zones, and a properly constructed well with good mechanical integrity. The track record of existing installations is mixed, with some systems remaining in service for more than two years but with others failing within a few days. This technology is relatively new and is being refined and improved with each successive installation.

An evaluation performed by the Argonne National Laboratory dated January 1999, on 37 DOWS installations in North America (the total number of installations in North America through mid-1998) found that:[24]

- More than half of the installations to mid 1998 had been hydrocyclone-type DOWS (21 compared with 16 gravity separator-type DOWS).
- Twenty-seven installations had been in Canada and ten had been in the United States.
- Seventeen installations were in 5.5-inch casing, fourteen in 7-inch casing, one in 8.625-inch casing, and 5 were unspecified.
- Twenty of the DOWS installations were in wells located in carbonate formations and 16 were in wells located in sandstone formations. One trial did not specify the lithology. DOWS appeared to work better in carbonate formations, showing an average increase in oil production of 47% (compared with an average of 17% for sandstone formations) and an average decrease in water brought to the surface of 88% (compared with 78% for sandstone formations).
- The volume of oil increased in 19 of the trials, decreased in 12 of the trials, stayed the same in 2 trials, and was unspecified in 4 trials. The top three performing hydrocyclone-type wells showed oil increases ranging from 457% to 1,162%, while one well lost all oil production. The top three gravity separator-type wells showed oil production increases ranging from 106% to 233%, while one well lost all oil production.
- All 29 trials for which both pre and post installation water production data were provided showed a decrease in water brought to the surface. The decrease ranged from 14% to 97%, with 22 of 29 trials exceeding 75% reduction.
- The data on injectivity and the separation distance between producing and injection formations do not correlate well with the decrease in water volume brought to the surface.

Some of the installations experienced problems that impeded the ability of the DOWS to function properly. At least two installations suffered from low injectivity of the receiving zone; in both cases, incompatible fluids contacted sensitive reservoir sands, which plugged part of the permeability. Several installations noted problems of insufficient isolation between producing and injection zones. If isolation is not sufficient, the injectate can migrate into the producing zone and then short-circuit into the producing perforations. The result will be recycling of the produced water, with oil production rates dropping to nearly zero. Other DOWS were plugged by fines or sand. Several trials were canceled prematurely because of corrosion and scaling problems. Finally, some of the early installations suffered from poor design features.

The U.S. Environmental Protection Agency (EPA) does not have a formal position on how to regulate DOWS. Four states (Colorado, Oklahoma, Louisiana, and Texas) have developed either

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regulations or administrative guidelines for DOWS, with requirements comparable to or less stringent than those for regular Class II injection wells.

Cylindrical cyclone separators.[25] Since the mid 1990s, the petroleum industry has been giving considerable attention to compact cyclonic separators. Significant advantages include simplicity in construction, compactness (smaller footprint and space), low weight, low capital and operational costs and less inventory. World wide, more than 350 gas-liquid cylindrical cyclone units have been installed and put to use. More than 50 are in Oklahoma. Most applications are for automated well testing, bulk separation, gas knockout and pre-separation.

Tulsa University Separation Technology Projects (TUSTP) research consortium, in collaboration with thirteen industrial member companies, the U.S. Department of Energy, and the Oklahoma Center for the Advancement of Science and Technology, has developed 3-phase compact multiphase separation components: gas-liquid cylindrical cyclones (GLCC©), liquid-liquid cylindrical cyclones (LLCC©), and gas-liquid-liquid cylindrical cyclones (GLLCC©).

Basic description. The GLCC separator is a vertically installed pipe mounted with a downward inclined tangential inlet. The two phases of the incoming mixture are separated due to the centrifugal/buoyancy forces produced by the swirling motion. The liquid is forced radially towards the wall and is collected from the bottom, while the gas moves to the center and is taken out from the top. The LLCC has a horizontal inlet with a tangential slot. Due to centrifugal forces, the heavier water is forced radially towards the cyclone wall and is collected from the bottom, while the lighter oil moves towards the center and is taken out from the top. The single stage GLLCC is a vertically installed pipe mounted with a downward inclined tangential inlet, with outlets for gas at the top, oil rich stream through an oil finder and the water rich stream at the bottom. The two-stage GLLCC consists of a first-stage GLCC, where the gas phase is separated, and a second-stage LLCC for oil/water separation.

Application guidelines/limitations. Compact cyclonic separators such as GLCCs have been proven for well test metering systems, control of gas-liquid ratio for multiphase meters, pumps and de-sanders, gas scrubbing for flare gas and wet gas metering, external pre-separation upstream of existing conventional separators, and primary surface or sub-sea separation. The three-phase GLLCC can be used as a gas knockout device and for bulk separation of the oil-water liquid phase. The LLCC can be used as a free-water knock out device for inlet water concentration ranging from 40% to 98%.

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SECTION 7
CORROSION AND MECHANICAL WEAR ON EQUIPMENT USED IN HANDLING PRODUCED WATER

This section deals with successful practices and techniques that extend the life of oil and gas production equipment associated with the lifting, processing, and disposal/injection of produced water. It presents topics in the order of total processing of produced water, i.e., entry of reservoir fluids into the well bore and lifting them to the surface (wellbore management), surface producing/processing facilities, and disposal/injection facilities. Special emphasis is on wellbore management, since the wellbore is the primary asset and most operating costs are directly associated with lifting the produced fluids to the surface. Reducing well failures (rod, tubing, and pump) significantly reduces operating costs and allows marginal wells to produce longer. Surface processing involves costs related to minimizing leaks, leak cleanups, and oil carryover.

The practices are based on: 1) August 2002 interviews with operators in the Permian Basin, who successfully optimize water-handling costs, to capture updated practices, 2) published practices in oil and gas technology literature, and 3) the writer's personal experience (more than 31 years) in the oil and gas operating arena.

Reducing Downhole Failures in Producing Wells (Wellbore Management). *Chemical programs* are designed to protect the inside of the casing, tubing, and sucker rods from corrosion. Cathodic protection is designed to protect external casing corrosion and therefore is not discussed, since we are addressing corrosion protection from produced water. However, sacrificial anodes, a method of cathodic protection used for produced water tanks, will be discussed with surface processing. Batch treating with corrosion inhibitor to protect the producing wellbore is the most cost effective method for wells producing 500-600 BFPD (barrels of fluid per day) and less. Higher rates may require continuous injection.

General guidelines and practices for treating corrosion. <u>Choosing a corrosion inhibitor</u>**.** Select an inhibitor that passes an emulsion tendency test and a film persistency test.[26] Good downhole corrosion treatment programs also help reduce oil carryover in the water. Elimination and/or reduction of solid corrosion products lower oil carryover.

<u>Treatment concentration and frequency</u>. Corrosion inhibitor batch treatments for protection of the internal casing wall, tubing, pump, and associated lift equipment are usually based on total fluid volume, typically in 100 BFPD increments. Concentrations vary by operator and their experience. Regardless of program parameters set by the operator, it is important to establish a corrosion program and monitor it with corrosion coupons, visual inspection of the rods when pulled, and a database of rod, tubing, or pump failures. A surface coupon does not show corrosion (metal loss) accelerated by mechanical wear. Therefore, visually inspect the rods when pulled. If they are black, they have a good inhibitor film; if they turn red hanging in the derrick, they do not have an inhibitor film. The real indicator of the corrosive nature of the well is the type of failures and their frequencies. Wellbore failures must be evaluated, and a database and remedial program established if an operator wants to reduce operating costs.

Concentrations of chemical vary from 1 to 4 gals of inhibitor per 100 BFPD per well, depending on the operator's philosophy. One gallon of inhibitor per week for each 100 BFPD is equal to

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approximately 30 ppm on a continuous basis. Recent interviews revealed one operator (a contract operator with a very successful program) starts out at concentrations up to 100 ppm on a weekly treatment program (this is high) until he gets 3 satisfactory corrosion coupon readings. Then he scales down treatment until reaching a satisfactory corrosion coupon reading at 25-50 ppm. This operator also has a start up treatment program of treating each well once a week if a production rate is 100 BFPD, twice a week if 200 BFPD, and 3 times a week if 300 BFPD; over 300 BFPD he goes to continuous injection to a final concentration of 50 ppm. Other operators go to continuous injection at 500 to 1000 BFPD.

Another successful operator uses the following batch treatment schedule: once a month if 50 BFPD, once every two weeks if 50 to 150 BFPD, once a week if 150 to 350 BFPD, and twice a week if 350 to 800 BFPD. It is important to monitor the failures and the surface corrosion coupon. Usually 25-50 ppm concentration of chemical inhibitor will be satisfactory. Remember, excessive amounts of a qualified inhibitor can increase oil carryover.

Chemicals are not cheap so a controlled batch treatment process enhances their effectiveness. Continuous chemical injection is equipment intensive and should be used only when no other choice exists.

<u>Flush is extremely important</u>. A corrosion inhibition treatment typically consists of pre-wetting the casing (typically 1 barrel), pumping the corrosion inhibitor, then flushing with ½ barrel/1000 feet (2 barrel minimum). Oil is always the best flush.[27]

<u>Oxygen must be kept out of the system</u>. Keep oxygen from entering the annulus during normal operation and batch treating operations. To eliminate oxygen in the flush water (if water is used), obtain water from gas-blanketed tanks or treat it with an oxygen scavenger at the time the water is gathered.[27, 28]

<u>Pretreating rods</u>. High fluid velocity in the tubing during pumping operations can prevent the corrosion inhibitor film on the rods around rod couplings and at the top of rod guides. Take special care to reapply the corrosion inhibitor when rods are pulled. Place five gallons of inhibitor in the tubing prior to running the pump and rods and circulate one tubing volume prior to returning the well to production. With wells that are difficult to inhibit, some operators displace the tubing with lease oil and ten gallons of corrosion inhibitor prior to seating the pump. This procedure also applies to wells that are being pumped under a packer and cannot be batch treated.

Lubricate sucker rod pins prior to make up. Do not use pipe dope. In a corrosive service, use a combination lubricant/oil-soluble corrosion inhibitor (80% oil, 20% inhibitor mixture). Spray or dip the pins to provide a light coating. Do not pour lubricant into the boxes.

<u>Para Probes</u>. In lieu of surface corrosion coupons, which are weighed for metal loss over a certain length of time, Para Probes can be installed at the wellhead, allowing the operator to get an instantaneous reading of corrosion rate.

Equipment options (metallurgy, etc.) What special metallurgical equipment is used in the producing wellbore to restrict corrosion from produced water?

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Tubing. Plain steel J-55 tubing is the choice of operators in beam pumping sucker rod wells with a corrosive environment. Tubing failures are internal from corrosion or rod wear or external from buckling. Internal corrosion has to be controlled with a corrosion inhibitor program or an internal coating mechanism. Tubing failures from mechanical wear are discussed later in this section. The use of polyethylene tubing liners is becoming increasingly popular by the majority of operators as a protection against corrosion and rod wear. Some operators are installing the liners one or two joints above the pump, others are installing the liner in half of the tubing string. Polyethylene tubing liners will be discussed in more detail later with mechanical wear.

There is a new inside-tubing scanner technology developed by Herndon OCI, Inc. of Odessa-Midland, Texas, (a WellTech II computerized rig-floor pipe inspection system) that displays pitting and wear both on the plain steel and inside where the polyethylene liner is installed. Results of the protection from polyethylene liners installed in rod-pumped tubing wells recorded by this scanner technology are impressive.

One large operator in the Permian Basin is using TK 99 plastic coating on a selected area of his producing wellbores with success. He applies the coating from the bottom joint up to the tubing anchor catcher. He does not use the plastic coating where he is using rod guides. Another large operator is using a 316 stainless steel liner in the joint above the pump. Some operators run a plastic-coated production tubing string on electrical submersible pump wells. Cement-lined tubing is still used in many fields. Interviews supported published literature that cement-lined tubulars have a long life of protecting steel from corrosive fluids and may be the most cost effective of the coatings used in the past.

Sucker rods (metallurgical choices). A majority of operators use steel sucker rods, with some using combination strings of fiberglass and steel. The most popular rod is the KD steel sucker rod, which is the Norris D rod 90 series. A few operators use EL rods if their corrosion inhibitor program is working. Others use plastic-coated sucker rods. Fiberglass rods are still used in:[29]

- Wells with high fluid levels. These are usually wells where production volumes have exceeded the capacity of surface equipment and high fluid levels restrict corrosion inhibitor treatment.
- Wells with overloaded surface and downhole equipment. Fiberglass rods reduce the weight of the rod string 70% or more and eliminate the necessity of purchasing larger surface equipment.
- Wells experiencing frequent rod failures. Fiberglass rods are more corrosion resistant and lighter, thus reducing the stress applied to the rod string and increasing the life of the rods.
- Deep wells. The lighter weight of the fiberglass permits deeper sucker rod installations.

Downhole pumps. Basic metallurgy for a pump should consider a barrel that has a surface hardness greater than that of the plunger. It is better to have the plunger wear than the barrel. Recommended basic metallurgy is:

- Barrel: chrome-plated carbon steel
- Plunger: sprayed metal carbon steel
- Balls: cobalt alloy steel
- Seats: tungsten carbide

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Today there is a variety of composite metallurgical pumps used in corrosive environments. Some of the most popular downhole sucker rod pump designs for corrosive environments are pumps with bronze/chrome barrel, brass/nickel carbide barrel or nickel carbide-coated barrel, brass internal, spray metal plunger, silica nitride balls, and nickel carbide seats. Other considerations, especially for erosion wear, are a vertical discharge pump and a blast joint of tubing in the pump discharge area. Some operators plastic coat the blast joint, and others use 316 stainless steel or polyethylene liners. Several operators are using coated submersible pumps in corrosive environments. Successful teflon coating use has been reported by Yates Petroleum.

Controlling mechanical wear (producing wells). What operating practices are used to minimize mechanical wear (erosion) on downhole equipment (tubing, pumps, and sucker rods) in handling produced water?

<u>Tubing and rod wear</u> are discussed under preferred operating practices and philosophies for reducing downhole failures.

<u>Tubing anchors</u>. The opinion of operators interviewed in August 2002 is to always anchor tubing in wells greater than 3000 feet deep. According to the literature and some other operators, tubing should always be anchored, to prevent tubing collar wear on the casing and internal wear from the sucker rods. If tubing failures are collar failures (external) from the tubing buckling, or if there is evidence of rod coupling wear on the inside of the tubing, then a tubing anchor is justified even at very shallow depths. Tubing anchors should be as close to the pump as practical. If the anchor is more than 400 feet above the pump, buckling can still be a problem below the anchor.

<u>Tubing rotators</u> are used but in very limited applications. They can be automated or manual. For wells deeper than 3000-4000 feet, where wells need the tubing to be anchored, there is not much of an application. The object of the tubing rotator is to help distribute wear on the tubing. A new mechanical tubing rotator from Omega Technologies is being used on shallow wells (2000 feet) with an initial success rate of 75% in reducing tubing splits and corrosion failures.

<u>Rod guides</u>. Use only as necessary is the opinion of interviewed operators. Fluid velocity around the rod guides can reduce the corrosion inhibitor's film. Use rod guides where repeated tubing splits and/or excessive rod coupling wear occurs. Often the wear is concentrated on the bottom of the rod string where rods go into compression. Some operators run a deviation survey in a well that continues to show excessive rod coupling wear, where the tubing is anchored, before they resort to installing rod guides. Usually there is a history of drilling in the area that indicates the wells were drilled fast and with little effort towards controlling deviation. When rod wear is suspected, an accepted practice is to install 3-4 guides per rod with the number varying with the deviation. When tubing wear is found at the bottom in the sinker bar area, a short 4-foot guided stabilizer is run between each sinker bar. Operators have a preference for molded-on rod guides versus snap-on guides. One is the long AF stealth-type rod guide. Snap-on rod guides require hammering on and many times this practice results in nicks on the rods.

<u>Rod rotators</u> are used to distribute coupling wear around the circumference of rod boxes and rod guides. Recent interviews revealed that they are used only when rod guides are used. If a rod rotator is to be used, the operator should be sure that the correct rotator is used because there is a

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significant difference in rod rotators for steel rods and fiberglass rods. A problem in the past with rod rotators was that due to improper selection of the rotator, excess torque was generated.

Polyethylene tubing liners are popular with many operators to reduce tubing and rod wear or wireline, mechanical, and handling damage. Sometimes what an operator thinks is corrosion is a combination of corrosion and mechanical wear. The polyethylene tubing liner protects against both. It is chemically inert to corrosive materials and tolerant of minor surface imperfections, which eliminates concerns with holidays or voids as in adhesive or thermally-bonded liners and coatings.

Operators use the liners in different applications. Some run the liner just in the joint above the pump; others use them in specific areas in the tubing string. The liners are reasonably priced at about $1.55 per foot (for 2 7/8 tubing) installed in used green or blue band tubing. Liners affect the dimensions, capacity and weight of the tubing in which they are installed. See Table 5.[30]

Table 5. Tubing Liners

Tubing Size	ID	Drift	Liner Weight
2 3/8	1.71 in	1.60 in	.40 #/ft
2 7/8	2.16 in	2.00 in	.47 #/ft
3 ½	2.67 in	2.50 in	.64 #/ft

From Western Falcon's Tubular Linings Data Sheet.

Plastic-coated production tubing. Some operators use TK 99 plastic coating on their production tubing section near the bottom hole pump. Amounts vary.

Sucker rod torque makeup. Sucker rod pin and couplings failures, which comprise about 40% of rod problem failures, are assumed to be a progressive phenomenon.[31] It takes time (cycles) for the rod to loosen up, leak, and then fail. A new technology, the UniTrak system by Triple N in Midland, Texas, has evolved that is helping reduce those failures. It is a computerized rod tongs and remote service rig tracking system that is being used by several operators in the Permian Basin to ensure proper sucker rod torque make up. Laboratory data from Sandia National Labs help illustrate the stresses to the pins and couplings as axial forces are applied to a sucker rod connection. Published literature supports the necessity of proper sucker rod connection make up to minimize pin and coupling failures.

Many variables can lead to sucker rod pin and coupling failures: under torque, wrench marks, over torque, lubrication, contamination, thread wear and cross threading. Some of these are due to improper handling, such as imprudent procedures when picking up rods. Thread protectors should be unscrewed, because knocking off the thread protectors leaves plastic remnants on the threads that can cause damage during makeup. When tailing rods to the floor, take care to prevent metal-to-metal contact when rods are dragged, or to prevent contaminating the threads by dragging rod ends through dirt. Inspect and clean, as needed, all rod pins and boxes. Once the pins and boxes are clean, only moderate lubrication is required. The rod shoulder and box face contact require friction to maintain proper makeup. Displacement card matching for the characteristics of the rods being run must be matched to the appropriate displacement to ensure accurate calibration.

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All rod connections should be made-up hand tight using only hands, not hand held wrenches! If a rod will not screw on by hand, thread damage has already occurred. Once hand tight, a mark can be placed across the connection to represent the first point of a distance of travel. This line represents zero displacement. Then, before tightening with tongs, the rod should be backed off by unscrewing approximately four rounds to allow the tongs time to reach full speed, ensuring the momentum force component of makeup is comparable to normal operating condition of the tongs. It is highly recommended that every operator ensure that the service company running their rods knows the correct procedure for matching actual displacement with desired displacement.

Pump-off controllers (rod pump controllers). A beam pump system with a pump capacity that exceeds the well's production (reservoir yield) can be operated with a timer or a pump-off controller (POC). Beam-pumped sucker rod artificial lift systems are the most common means of producing oil and associated produced water. Why? Because these systems are relatively inexpensive, very efficient, easily repaired and there is a vast amount of knowledge about them. The major disadvantage of these systems is the propensity for over-displacement, i.e., when the system is properly designed for load and stress, it will produce more fluid than the reservoir can yield.[32] The result is a "fluid pound" that can damage subsurface pumps, tubing, rod strings, gearboxes, pumping unit bearings and pumping unit structure. When a pumping system is pounding fluid, energy is being wasted.

Some POCs are more sophisticated than others by measuring actual loads with load cells, but they are more expensive. Load-cell POCs are manufactured by Baker, Lufkin, and Nabla. Other less expensive POCs (probably more attractive for marginal wells) utilize stroke speed to determine pump-off conditions. One manufacturer is D-JAX.

Timers can be used to prevent fluid pound and reduce electrical costs. The most accepted timer is the 15-minute percentage timer, which is a relatively simple technique and inexpensive procedure for reducing fluid pound and electrical costs.[33] Not all wells are POC candidates. For example, a well that has poor fluid build-up, possibly due to poor downhole gas separation even with a high fluid level above the pump, and does not provide complete pump fillage on any stroke is not a candidate for a POC. A dynamometer survey needs to be made to determine if a well is a candidate for a POC. If not, timers should be considered.

Preferred operating practices and philosophies to reduce well failures and optimize artificial lift. Reducing well failure frequencies, including practices to optimize artificial lift, reduces operating costs, minimizes production loss, and makes marginal wells more economical. Operating practices to reduce well failures vary from none to very disciplined well failure analyses and corrective actions that have proven to reduce failures. An example of "none" is when a rod parts, the operator pulls the well and replaces only the damaged rod, or when tubing fails, only the one tubing joint is replaced.

Successful programs to reduce well failures all require an evaluation program and a corrective action plan. In the Permian Basin, which has the highest number of artificial lift wells in the United States, successful programs are used by Amerada Hess, Henry Petroleum, Conoco, Schlumberger IPM (formerly Coastal Management), and OXY USA. These companies operate a lot of wells, but their approach to solving well failures can be used by the smallest of operators. Smaller operators need to employ the services of their support vendors, such as chemical,

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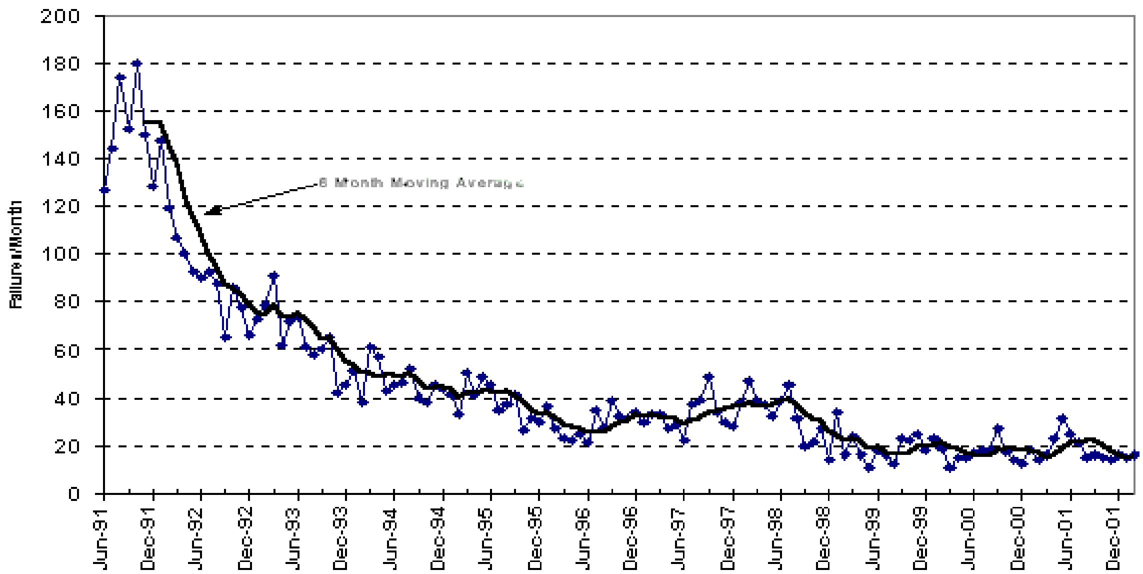
tubular, pump, and well servicing. They also need to demand that their company representatives (contract or company) are involved in the evaluation process.

Well failure frequency averages for successful programs are under 1.0 (one failure per well per year). Some are as low as 0.15. Figure 1 shows Schlumberger IPM's results for a 900-well field in which failures were reduced from 180 to 20 per month over the 10-year period.



Kent Gantz, "Holistic Producing-Well Improvement Reduces Failures/Servicing Costs," Fig. 1, Petroleum Technology Digest section of World Oil, June 2002, p. 59-60.

Figure 1. West Texas Project Monthly Well Failures

Successful programs employ the "pay me now or pay me later" philosophy. For example, if a rod fails, replace the entire rod string with an inspected used rod string or replace the entire tapered section where the failure occurred because, if one rod failed, chances are another will fail shortly. Have the pulled rod string inspected. Typical inspection costs are \$7.95 per good rod and \$2.00 per rejected rod. These charges usually include pickup and delivery, inhibitor application, and installation of rod protectors. A similar practice applies to tubing string failures. Used tubing strings of yellow, blue, and green pipe body ratings are reused after inspection. Polyethylene liners work well in used tubing strings.

Another successful program is the "Root Cause Failure Analysis and Solutions" program developed by Chevron Texaco, Baker Petrolite, Wilson Pumps, Crown Quest, ICO, Norris Rods, and the Pool Company. This was a team formed in 2000 to capitalize on experience and knowledge to evaluate failures of beam-pumped wells and identify potential solutions. Their work has been published in the Southwestern Petroleum Short Course, April 24-25, 2002, and in the *American Oil and Gas Reporter* in June 2002. A flow chart recommending failure analysis is presented.

Specific practices of successful programs are:

- Visually inspect rod and tubing failures to determine location and type of failure.

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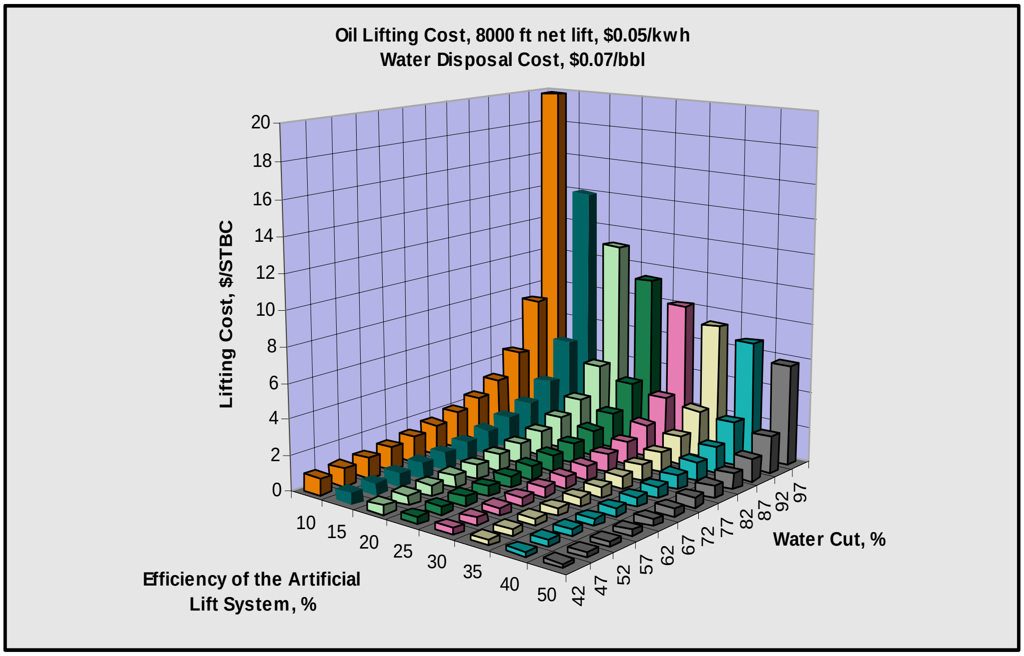
- Discuss the problem and review well history with team members - company, chemical, service company, equipment vendors, rod and tubing inspection personnel.
- Establish and maintain a database for each well failure to track corrective actions and evaluate economics. Include area, well name, well status, date of failure, reason for failure, used rod and tubing inspection cost, replacement cost, new rods and tubing inspection cost, junk value, and total costs.
- Establish "best operating processes" to properly evaluate failures and corrective actions.

Optimizing artificial lift. Beam pumping systems are the most popular and usually the least expensive system for handling produced water. It is important to operators to have system efficiency and minimal power costs. One program to evaluate system efficiency is Echometer's Modern Total Well Management, a system that takes input from three sources on a beam pumping installation. Readings are taken from the electric motor, the fluid level, and the polish rod sensor. These are fed into a computer program that evaluates the entire system, which takes about 45 minutes per well to get the entire evaluation. System efficiency increases are significant in savings in power usage. The overall system efficiency is defined as the amount of theoretical work required to lift the liquid from the net liquid level depth to the surface divided by the amount of power supplied to the motor.

Figure 2 is a graphical interpretation of system efficiency versus water cut versus lifting costs. It can be seen how lifting costs are reduced when system efficiency is increased. Another artificial lift technique is the electrical submersible pump (ESP), which helps reduce well failures in extremely crooked holes and for high produced water rates. If a significant run time (2-3 years) can be realized, then they become more economical than a beam pump system that is having significant uncorrectable well failures.



Data provided courtesy of Echometer.

Figure 2. System Efficiency Cost

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One major operator feels that in comparing ESPs vs. beam pumping, failure frequency is the most important variable to consider.[34] Other variables (equipment, servicing, power consumption cost) are much more stable than the failure frequency, especially on beam-lifted wells. For producing depths of 4800 feet and wells with 5.5 inch casing, considering total system cost, the beam pumping system is most economical for volumes up to 320 BFPD. However, for this same depth and casing size, considering only operating and maintenance cost, the beam pumping system is most economical for volumes up to approximately 500 BFPD, and the ESP lift system is most economical for volumes over 500 BFPD.

Weatherford's comparison of artificial lift methods, Figure 3, illustrates that for onshore, beam pumping or electrical submersible pumping is most common. There is an electrical submersible progressing cavity pump system developed by Centrilift, but its use has not been documented. Progressive cavity pumps are not widely used in handling large amounts of produced water because of difficulties in combating corrosion and depth limitations. There is software available for artificial lift evaluations from Data Enterprises. The cost is approximately $4000.

	Rod Lift	Progressing Cavity	Gas Lift	Plunger Lift	Hydraulic Piston	Hydraulic Jet	Electric Submersible
Operating Depth	100' - 16,000' TVD	2,000' - 6,000' TVD	5,000' - 15,000' TVD	8,000' - 19,000' TVD	7,500' - 17,000' TVD	5,000 '- 15,000' TVD	1,000 '- 15,000' TVD
Operating Volume (Typical)	5 - 5000 BPD	5 - 4,500 BPD	200 - 30,000 BPD	1 - 5 BPD	50 - 4,000 BPD	300 - >15,000 BPD	200 - 30,000 BPD
Operating Temperature	100° - 550°F	75° - 250°F	100 °- 400°F	120 °- 500°F	100° - 500°F	100° - 500°F	100 °- 400°F
Corrosion Handling	Good to Excellent	Fair	Good to Excellent	Excellent	Good	Excellent	Good
Gas Handling	Fair to Good	Good	Excellent	Excellent	Fair	Good	Poor to Fair
Solids Handling	Fair to Good	Excellent	Good	Poor to Fair	Poor	Good	Poor to Fair
Fluid Gravity	>8° API	<35° API	>15° API	GLR Required 300 SCF/BBL/ 1000' Depth	>8° API	>8° API	>10° API
Servicing	Workover or Pulling Rig	Workover or Pulling Rig	Wireline or Workover Rig	Wellhead Catcher or Wireline	Hydraulic or Wireline	Hydraulic or Wireline	Workover or Pulling Rig
Prime Mover	Gas or Electric	Gas or Electric	Compressor	Wells' Natural Energy	Multicylinder or Electric	Multicylinder or Electric	Electric Motor
Offshore Application	Limited	Good	Excellent	N/A	Good	Excellent	Excellent
Overall System Efficiency	45% - 60%	40% - 70%	10% - 30%	N/A	45% - 55%	10% - 30%	35% - 60%

Chart data taken from Weatherford's Artificial Lift Brochure.

Figure 3. Weatherford's Comparison of Artificial Lift Systems

Surface Facilities Design. *Flowlines and tank battery gathering lines.* For low-pressure flowlines, especially when handling produced water, the most popular line selection is polypipe. Most operators use a DR or SDR rating of 7, with some using polypipe with a rating of 11. DR or SDR rating is the ratio of the outside diameter to the thickness. The lower the SDR, the higher the pressure rating. Polypipe is de-rated according to the temperature. Table 6 shows the SDR/DR ratings vs. temperature prepared by Performance.

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Table 6. PE 3408 Pipe - Pressure Rating (psi) vs. Temperature (°F)

Temperature ºF	Hydrostatic Design Basis, psi	Pipe DR									
		32.5	26	21	19	17	15.5	13.5	11	9	7
50	1,820	58	73	91	101	114	126	146	182	228	303
60	1,730	55	69	87	96	108	119	138	173	216	288
73.4	1,600	51	64	80	89	100	110	128	160	200	267
80	1,520	48	61	76	84	95	105	122	152	190	253
90	1,390	44	56	70	77	87	96	111	139	174	232
100	1,260	40	0	63	70	79	87	101	126	158	210
110	1,130	36	45	57	63	71	78	90	113	141	188
120	1,000	32	40	50	56	63	69	80	100	125	167
130	900	29	36	45	50	56	62	72	90	113	150
140	800	25	32	40	44	50	55	64	80	100	133

Data provided courtesy of Performance (formerly Driscopipe).

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Some operators use downgraded green band tubing for flowlines if they expect to have to add heat to remove paraffin deposits. Other operators use fiberglass piping for fluid transfer and processing if they need a higher pressure rating than polypipe. However, fiberglass is more expensive. Fiberglass piping and coated-steel piping are used mostly in the injection process where pressures are higher. There is also a Fiberspar line pipe available that provides higher pressure ratings (750 to 2500psi) and can handle product temperatures up to 200^{o} F. It is popular for installation of longer lines, since it can be spooled with continuous sections up to four miles.

Processing equipment and storage tanks. Protection of surface vessels from corrosion is provided by coated steel tanks, sacrificial anodes (tanks), and fiberglass vessels and/or tanks. Operators who prefer to use steel tanks for water storage generally use internal coatings. Popular coatings are Flakeline, Ameron, and coal tar epoxy. A new coating is Jotun 8 series, a replacement for Mobil’s Valspar. It is an epoxy liner.

Some operators use fiberglass gunbarrels and fiberglass tanks. The use of fiberglass tanks is controversial due to the potential problem of static electricity and associated fires. The difficulty in properly grounding a fiberglass tank can lead to ignition from the static electrical charge as water discharges inside the tank. Since oxygen, source of combustion, and ignition source are required to have ignition, many use fiberglass tanks and gunbarrels where there is a gas and/or oil blanket to prevent oxygen intrusion. One operator has recently purchased a new “polymer” fiberglass tank that uses an imbedded ground wire.

Sacrificial anodes. Sacrificial (magnesium) anodes are still used to protect those parts of a vessel immersed in salt water. This is a form of cathodic protection that works with little maintenance. It does need to be checked regularly. Sacrificial anodes can be attached to the inside of the tank or suspended through holes in the top.

Chemical programs for surface equipment. Few chemicals are used in processing oil and water, but some operators use emulsion breakers or corrosion/scale inhibitors. Generally, operators treat “cold” except when temperatures drop in the winter. Most operators use retention time for oil and water separation. They use free water knockouts, gunbarrels, separators, or raw water and clear water tanks, resulting in oil carryover of 20-40 ppm. Also, most operators use gravitational processing instead of pumping fluids from one vessel to another. A "best practice" is to use stainless steel trim in transfer pumps.

Injection/Disposal Systems. *Injection lines*. Most operators use fiberglass lines or internally-coated steel lines. The Fiberspar piping mentioned above is also used for injection lines. Some operators still have cement-lined injection lines. Fiberglass lines are buried. Maintain a fluid velocity of 3 feet per second minimum to keep lines clean.

Injection tubing. The most popular is DUOLINE.

Injection well packers. Almost every operator uses a nickel coated packer.

Filtration. Earlier literature discussed filtration standards for injection/disposal water, but due to a history of high maintenance, few operators actually use filters, almost none for oil carryover. It is common to backflow injection wells to remove impurities. Filters are used for filtration of solids. Screens can also be used at the wellheads to capture solids.

Maintaining injectivity. Positive displacement reciprocating pumps are used primarily in areas of saltwater disposal and high pressure waterflooding. Initial costs and a need to reduce maintenance costs have encouraged many operators to change to multistage horizontal centrifugal pumps.[35] With close attention to operating stage loading and hydraulic balancing, this equipment can be designed for years of virtually maintenance-free operations. Positive displacement pumps have efficiencies in the 90% range, whereas centrifugal pumps are 60-70% efficient. However, the type of pump should be based on bottom line operating and maintenance costs, not just efficiency rating.

Injection header pressures. In installations where multiple injection lines to injection wells come from an injection header system, injection wellhead pressures must be monitored to minimize horsepower requirements. Injection lines and headers should also be evaluated for piping restrictions such as unnecessary chokes and piping angles. Many times the required horsepower for injection is dictated by only one or two wells. Even single well injection or disposal well injection pressure should be monitored closely. Small increases in injection pressure can significantly affect utility costs.

Injection wellbore cleanups. Backflowing injection wells to remove impurities is a common practice. Another popular method is to clean out and stimulate the wellbore using coiled tubing. The most cost effective practice using coiled tubing is to schedule several wells per day.

Tips for MIT testing. The most important practice is to load the wells with water the day before the test. It is extremely important to have the temperature of the wellbore fluid constant and all air broken out. Also it is imperative that field operating personnel maintain a good relationship with regulatory personnel in charge of the testing.

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SECTION 8
REGULATORY AND ENVIRONMENTAL ISSUES RELATED TO PRODUCED WATER

Much of the following information was taken from the Environmental Handbook produced cooperatively by the Oklahoma Midcontinent Oil and Gas Association and the Oklahoma Corporation Commission. Also, the General Rules and Regulations of the Arkansas Oil and Gas Commission were reviewed to include information pertaining to Arkansas.

Oklahoma and Arkansas have assumed primary responsibility for enforcing Environmental Protection Agency (EPA) regulations pertaining to the construction, operation and closure of Class II injection wells within their respective states.

Injection and Disposal Wells. *General requirements***.** Approval and permits must be obtained from the Oklahoma Corporation Commission (OCC) or the Arkansas Oil and Gas Commission (AOGC) for any new injection or disposal well.

A Mechanical Integrity Test (MIT) must be performed at least once every five years and initially before a well is used. In Oklahoma the initial test must be witnessed by an authorized representative of the Oil and Gas Division and results submitted on Form 1075 within 30 days by the operator. In Arkansas, within fifteen (15) days after the completion of the well, a completion report, well logs, and injectivity test performed on the well must be filed with the Oil and Gas Commission. The AOGC must be notified in writing before the beginning of injection to allow inspection of the well and conduct the initial mechanical integrity testing.

Minimum standards for injection and disposal wells are:

- Oklahoma. Injection must be through adequate tubing and packer.
- Arkansas. All injection wells must have tubing and packer “or other installation” to protect the casing.
- A 1/4 inch female fitting in Oklahoma (1/2 inch in Arkansas) with cut-off valve to the tubing is required to be installed so injection pressure may be checked.
- Oklahoma. The packer must be set within 20 feet of the packer setting depth as described in the permit to inject.
- Arkansas. The packer can be set no higher than 100 feet above the injection interval.
- Minimum cement height circulated above the injection zone in the annulus between the casing and the borehole must be 250 feet.
- Oklahoma. The packer must be set at least 50 feet below the depth of the top of cement behind the production casing.
- Oklahoma. Surface casing must be set at least 50 feet below the base of treatable water or 90 feet below the surface (whichever is greater) if a stage collar is set or the production casing is cemented to the surface (unless otherwise authorized),
- Arkansas. New disposal wells require surface casing to be set 250 feet below the lowermost Underground Sources of Drinking Water (USDW).
- Oklahoma. Surface casing must be set at least 200 feet below the base of treatable water for annular injection of drilling fluids.

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- Arkansas. A sign must be maintained at the well site to indicate operator, well name, well number and location description.

Oklahoma. Any newly drilled or converted injection or disposal well within ½ mile of any active or reserve municipal water supply well will not be approved without notice and hearing and the operator must prove that the water well will not be impacted. Applications for newly drilled or converted injection or disposal wells need to be filed with the Underground Injection Control Department on Form 1015. Applications must be accompanied by a plat showing the location and total depth of all wells within 1/4 mile of the injection or disposal well, and all surface owners and operators of producing leases. A copy of the application must be delivered to the surface owner of the land on which the well will be located and to each operator of a producing lease within ½ mile of the well. A notice also has to be published in an Oklahoma City newspaper and a newspaper in the county where the well will be located. If a written objection is filed within 15 days, a hearing will be set at the OCC.

Arkansas. Applications are filed with the Oil and Gas Commission on a form titled "Application to Inject Salt Water/ Enhanced Recovery Fluid". Arkansas requires a plat indicating the location of the proposed injection well with distances to the nearest lease lines, including all wells of public record and fresh water wells of public record within ½ mile radius from the proposed injection well. Arkansas also requires a separate list of all wells which have penetrated the injection zone that indicates: 1) exact legal location, 2) current operator, 3) lease name, 4) name of zone currently completed, 5) perforated intervals, 6) total depth, 7) drilling date, 8) cementing records, 9) record of completion/plugging, and 10) current status. Information on this list MUST agree with AOGC records. You are required to attach a notarized copy of the proof of publication of the application as it ran in one publication in a legal newspaper having a general circulation in the county or in each county, if there shall be more than one, in which the lands embraced within the application are situated, and by mailing or delivering a copy of the application to each operator of producing or drilling wells within one-half (1/2) mile radius of the injection well. Such notice shall be published, mailed or delivered at least ten days, but no more than 30 days, prior to the date on which the application is mailed or filed with the Commission.

Monitoring and reporting. Oklahoma. Operators must monitor and record the injection rate and surface injection pressure monthly. For each calendar year, the operator is required to report the results of monthly monitoring on Form 1012A by April 1 of the next year. Operators must submit Form 1072 (Notice of Commencement or Termination) within 30 days after injecting or disposing into a well. When a mechanical failure or downhole problem occurs, the operator must notify the OCC Field Inspector within 24 hours after discovery. A written repair plan must be submitted within 5 days.

Arkansas. Operators must monitor and submit a saltwater disposal report monthly on AOGC Form 14. The report must be filed no later than the 15th of the month following the month covered by the report. Required monthly injection data includes barrels of water injected, barrels of cumulative water injected, injection pressure on the tubing and annulus and injection zone.

Oil and Produced Water Spills. *General requirements for Oklahoma*. The first critical activity is to safely contain and control the spill to protect human safety and minimize damage to the

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environment. Notify proper authorities, including the appropriate OCC district office before cleanup (see below under reporting requirements). Attempt to recover and remove oil if possible. Cleanup contaminated soil, vegetation, and/or water as per acting authority requirements. Saltwater or oil soaked soil may require sampling before remediation can take place.

Reporting requirements for Oklahoma. Report spills to the following Oklahoma Corporation Commission District Offices:

- Bristow (918) 367-3396
- Kingfisher (405) 375-5570
- Duncan (405) 255-0103
- Ada (405) 332-3441

Report verbally to the Commission District Office or Field Inspector within 24 hours of discovery of a reportable quantity spill. Failure to report may result in a $500 fine. File a written or oral report with the District Office within 10 working days. <u>For spills that impact surface waters of the state (rivers, streams, lakes) also report the spill to</u>:

- Oklahoma Department of Environmental Quality (800) 522-0206
- National Response Center (800) 424-8802

Spills that pose an imminent danger to fish or wildlife should be reported to the Oklahoma Department of Wildlife Conservation.

Record keeping for Oklahoma. Maintain adequate records of each non-permitted discharge reflecting the information, time and manner of reporting. Produce such documents upon demand by an authorized representative of the Commission. Records of all reportable spills should be kept on file in the nearest company office. Document all cleanups and notifications.

Reporting requirements for Arkansas. Operators should immediately report to the Arkansas Oil and Gas Commission any breaks or leaks in or from tanks or other receptacles and pipelines from which oil or gas is escaping or has escaped. The report must contain the location of the well, tank, receptacle, or line break by Section, Township, Range, and property, so that the exact location can be readily located on the ground. The report shall also specify what steps have been taken or are in progress to remedy the situation reported and shall detail the quantity (estimated, if no accurate measurement can be obtained, in which case the report shall show the same is an estimate) of the oil or gas lost, destroyed, or permitted to escape. In case any tank or receptacle is permitted to run over, the escape thus occurring shall be reported as in the case of a leak. The report as to oil losses is necessary only in case such oil loss exceeds twenty-five (25) barrels in the aggregate.

Spill Prevention, Control and Countermeasure (SPCC) Regulation. (*At the time of publication of this handbook, due to industry pressure, EPA has indicated its intent to extend the February 17, 2003 compliance date and the August 2003 compliance date for SPCC Plan revisions. EPA indicated it would simultaneously issue a direct final rule and a proposed rule to extend the compliance deadlines for one year with a mechanism to extend beyond that time. Following action on the deadline extension, EPA indicated it will initiate efforts to assess the problems with the new regulations and determine methods to resolve them through additional*

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rule making, guidance, or interpretation. Keep in touch with your trade associations for future updates regarding these new regulations.)

On July 17, 2002, the EPA amended the Oil Pollution Prevention regulations promulgated under the authority of the Clean Water Act. This includes new requirements for SPCC Plans and for Facility Response Plans (FRPs). The rule became effective August 16, 2002. The revised rule is difficult to read and understand. The following paragraphs attempt to summarize requirements for onshore oil operators.

It has been determined that many oil drilling and production facilities are subject to the SPCC regulation. EPA's SPCC regulation (40 CFR 112.1 through 112.7) applies to nontransportation-related facilities that could reasonably be expected to discharge oil into or upon the navigable waters of the United States or adjoining shorelines, and that have 1) any single container or group of containers each greater than 55 gallons having a total capacity of greater than 1320 gallons, or 2) a total underground buried storage capacity of more than 42,000 gallons.

The SPCC regulation requires the facility owner/operator to prepare an SPCC Plan for their facility. All existing SPCC Plans prepared before August 16, 2002 must be revised on or before February 17, 2003 to comply with the new rules and implemented by August 18, 2003. If a facility becomes operational after August 18, 2002, but before August 19, 2003, an SPCC Plan must be prepared and implemented by August 18, 2003. If a facility becomes operational on or after August 19, 2003, a plan must be prepared and implemented before the facility goes on stream. There is a provision to apply for an extension for the plan preparation time.

Additionally, a Professional Engineer must certify the SPCC Plan and attest:

- The Professional Engineer is familiar with the SPCC rule.
- The Professional Engineer or agent has visited and examined the facility.
- The SPCC Plan has been prepared in accordance with good engineering practices and the SPCC rules.
- Rules specifying procedures for inspecting and testing are included.
- The SPCC Plan is adequate for the facility.

The revised plan must be retained at the facility, if the facility is attended at least four hours per day on a regular basis.

General requirements. The SPCC Plan must include:

- a physical layout of the facility, including location of each tank, separator, heater treater, transfer piping and pumps;
- type of oil in and the capacity of each tank and vessel;
- discharge prevention measures appropriate for routine loading, unloading and transferring oil within the facility;
- discharge and drainage controls such as secondary containment, catchment basins, retention basins and control procedures;
- estimated direction, rate and total quantity of release flow;
- a method planned for discovery, response, and cleanup by company and contractor; disposal methods for recovered oil;

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- a list of contractors with phone numbers for company response coordinator, National Response Center, cleanup contractors with whom the company has a response agreement; and
- a list of Federal, State and local agencies.

The owner/operator of onshore production facilities must have at least one of the following means of secondary containment for tanks, treating vessels, piping, and pumps:

- dikes, berms, retaining walls
- curbing
- culverts, gutters or drainage systems
- weirs, booms or other barriers
- diversion ponds
- retention ponds
- sorbent materials

For tank truck or tank car loading/unloading area racks (frames), use catchment basins or treatment systems designed to handle discharge from the largest single truck compartment or use a quick drainage system. Provide secondary containment for tank batteries, separators, heater treaters, transfer pumps and interconnecting piping. The secondary containment must hold the capacity of the single largest tank and anticipated precipitation. Newly installed or repaired buried pipes must be coated and wrapped. Provide secondary containment for flowlines, e.g., double-walled pipe, berms, catchment basins, and booms. If the installation of secondary containment as discussed above is not practical and the facility does not have a Response Plan, the owner/operator must include in the SPCC Plan:

- an explanation why the controls are not practical
- periodic, scheduled integrity testing of facility containers, valves, piping (including flowlines)
- a Contingency Plan

Additionally, the SPCC Plan must include:

- a written commitment of manpower, equipment and materials to control and remove released liquid hydrocarbon.
- a written inspection and testing procedures for tanks, separators, heater treaters and piping. The procedures and record of inspections and tests must be signed by the appropriate foreman and retained with the SPCC Plan for three years.
- a written commitment to train all oil-handling company personnel regarding
  - maintenance and operation of equipment to prevent oil releases,
  - release reporting and control,
  - pollution control statutes, rules and regulations,
  - general facility operations,
  - SPCC contents.
- a provision to schedule and conduct annual release prevention briefings for oil-handling personnel. Include and describe known releases, equipment failures or malfunctions and recently developed precautionary measures to prevent releases.
- a designated employee who is responsible for oil release and who reports to the facility management.

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- a requirement to seal all tank and vessel valves when not in use and the facility is operating.
- a lockout in the off position for all shipping and transfer pump electric start controls when not in use.
- a way to cap, plug or flange all open-ended liquid hydrocarbon pipes and/or valves when not in use or when in extended standby service.
- provision for facility lighting, if practical.

Specific requirements. An onshore producing facility reasonably expected to release liquid hydrocarbons that could enter waters of the United States, must prepare an SPCC Plan in accordance with the General Requirements for the SPCC Plan plus the following provisions:

- Dikes and drains must be closed and locked when not in use. Oil-free rainwater may be drained to the ground, but the owner/operator must inspect the rainwater for oil before discharging the rainwater. If oil is present, the oil must be removed and returned to the oil treating system or disposed of.
- Written inspection and testing procedures for tanks, separators, heater treaters and piping must be maintained. The procedures and record of inspections and tests, signed by the appropriate foreman, must be retained with the SPCC Plan for three years.
- Provide secondary containment for all tanks, separators, heater treaters and transfer or shipping pumps. The containment must be capable of retaining the capacity of the largest single tank and anticipated precipitation. The owner/operator may use catchment basins in lieu of berms.
- The owner/operator must maintain written regularly scheduled drainage system (borrow ditches, stream, ravines) inspection instructions. Oil must be removed, if discovered.
- Design new and update old tank batteries in accordance with good engineering practice to prevent releases. At a minimum:
    - tank size must be adequate to assure no overfill if lease operator is delayed
    - equalizer lines between tanks must be present
    - vacuum protection to prevent tank collapse must be present
    - high level sensor alarms must be present for computerized facilities.
- The owner/operator must maintain written regularly scheduled inspection procedures for above-ground tanks, piping, valving, pumps, drip pans, polish rod, stuffing boxes.
- Written inspection records of produced water disposal facilities must be maintained, particularly after a sudden change in atmospheric temperature.
- Written flowline maintenance program must be prepared.

As mentioned previously, the above is an attempt to summarize the new rules for onshore oil operators. There are also new rules for onshore drilling and well servicing, as well as offshore drilling, producing and well servicing. No matter who ends up preparing an SPCC Plan, remember that ultimately it is the owner/operator who is responsible for complying with the regulation. A copy of the regulation is available by calling or writing your nearest EPA office. For Oklahoma and Arkansas:

SPCC/FRP Coordinator
U.S. EPA-Region VI (6SF-RP)
1445 Ross Avenue
Dallas, TX 75202-2733
(214) 665-6489

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Cleanup Guidelines. Follow the most recent "Oklahoma Corporation Commission Guidelines For Responding To and Remediating Spills". Current guidelines are as follows:

Crude oil spill to soil. Use temporary dikes and emergency pits to confine the spill to the smallest possible area. All accumulated oil should be collected and recycled. Absorbent materials may be used to collect free oil. Contaminated soil may be removed and replaced with compatible soil and the contaminated soil land applied in accordance with OCC-OAC Rule 165:10-7-26.

If on-site bioremediation of the contaminated soil is the preferred option, then the soil brought to the surface should be disked to a depth of six inches and fertilized by applying 160 pounds of nitrogen, 40 pounds of phosphorus and 40 pounds of potassium per acre, unless soil testing reveals that an alternative ratio of these nutrients would be superior for the purposes sought. If weather and soil conditions do not permit immediate disking, it may be necessary to burn the material following Department of Environmental Quality (DEQ) approval. Disking and fertilizing should be done as soon as weather conditions permit.

All affected areas must be restored as near as practicable to the level of land productivity that existed before the spill occurred and may require additional disking, fertilizing and/or revegetation. Any alternative reclamation plan must be submitted to the OCC District Office for approval before implementation. If remediation cells or piles are to be utilized, remediation should be coordinated with the OCC Field Operations Department.

Waste management practices that can be utilized during the cleanup of crude oil spills include reclamation and/or recycling; road applications by County Commissioners; application to lease roads, well locations, and production sites; and disposal of waste oil by transfer or sale to a reclaimer/transporter/County Commissioner. Some of these practices require permits. (See OCC-OAC Rule 165:10-7-24).

Salt water spill to soil. Because of the variable conditions that can be associated with saltwater spills to soil, it is difficult to provide absolute guidance as to the proper actions to take as a response to all spills. However, general actions that should be taken in all cases are as follows: 1) initiate actions to prevent further discharge or release; 2) utilize an appropriate containment system to minimize the surface area impacted by the spill. Such a system could consist of temporary diking, emergency pits, or leak proof tanks; and 3) remove free fluids from the spill surface as soon as practicable. The use of a vacuum removal system is one way such removal can be facilitated. In some cases, particularly where there is standing water or wet soils, flushing the spill areas with fresh water may be an appropriate method to facilitate the removal of saltwater from the soil surface. In any case, saltwater fluids recovered should be properly disposed. Permitted Class II disposal or injection wells are the only types of disposal that are appropriate.

After considering and weighing the relative conditions and importance of each of the remediation factors, it may be determined that it is appropriate to obtain soil samples to determine whether soil removal or other remedial measures may be needed. If soil samples are to be taken, a background soil sample from outside the spill area should be collected for the purpose of comparison. If the affected area is large, two or three soil samples should be collected towards the edge of the spill, followed by two or three soil samples near the center of the spill. Reduced sampling may be done for smaller areas.

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Generally, quick response actions should limit the infiltration of such spilled fluids. In such cases, surficial samples (within one foot of the surface) may suffice for sampling purposes. If more than one week has passed since the time of the initial release, substantial rainfall has been received, or if plowed or sandy soils are present, soil samples should be collected to a depth of three to five feet or to bedrock if it is shallower. Such samples should be collected at one-foot depth intervals.

All soil samples should be placed in suitable containers for transportation, chain-of-custody records completed and the samples sent to a qualified laboratory. Once received, the samples should be analyzed for Total Dissolved Solids (TDS) or Total Soluble Salts (TSS). Sample analysis exceeding 2500 ppm for TDS (or TSS) indicates a need for remediation in place or removal of the soils in the area that such samples were obtained from.

If the option of remediation by leaching is selected, one can expect remediation to take from one year to several years, depending upon site conditions. Clay soils, in particular, do not leach well, so removal is normally recommended. For leaching, the affected area should be treated with 20 to 30 tons per acre of organic matter (either vegetable or animal) and an appropriate amount of calcium sulfate (gypsum) or calcium nitrate. To determine the appropriate amount, refer to the recommendations of the soils laboratory or a consultant. If more than five tons are recommended, the recommended rate should be split into separate applications three to six months apart. It is not unusual to have to repeat treatments in order to get good results.

If the removal option is selected, the area adversely impacted by the spill should be excavated to a depth sufficient to remove all soils that indicate a TDS (or TSS) level of 2500 ppm or greater. Excavated material may then be disposed of in a manner consistent with Corporation Commission Rule OAC 165:10-7-26 or 165:10-9-1. Following excavation, the area must be restored to its original use by backfilling with compatible replacement soil and establishing suitable vegetation as soon as possible.

Saltwater spill to surface water. If possible, confine the spill to the smallest area possible by using temporary dikes and emergency pits. Collect as much of the affected water as possible and transport to an authorized disposal facility. Cleanup procedures can be discontinued when the affected water is restored to the previous beneficial use for the stream or body of water. All saltwater spills to navigable waters of the state should be reported to EPA Region VI, OCC, and the DEQ.

Crude oil spill to surface water. Use temporary dikes, emergency pits, artificial barriers or floating booms to confine the spill to the smallest possible area. Containment barriers should be located for easy access and removal of oil. Floating oil should be immediately removed from the surface of the water by pumping or skimming. Removal must continue until there is no visible sheen on the surface of the water. Removal may require absorption of the oil with absorbent materials including straw or commercial absorbents.

Stream or impoundment banks and affected vegetation may be cleaned by washing or burning (following DEQ approval) to remove excess oil and staining if erosion can be prevented. After all of the oil has been removed from the surface of the water, containment structures should be left in place for capture of any residual product. These structures may be removed after there is

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no evidence of additional product accumulation. Sufficient time must be allowed for all oil to flush from the original spill area and there should be no residual sheen on the water.

Following removal of the containment structures, an effort should be made to restore the area to pre-spill conditions. All contaminated materials should be disposed of in a manner approved by OCC Field Operations. If the surface water is designated as a source of public water supply under Oklahoma Water Quality Standards, cleanup procedures must continue until all assigned beneficial uses for the stream or body of water are restored. All oil spills to navigable waters of the state should be reported to the National Response Center, OCC, and the DEQ.

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