Keeping the Home Wells Flowing
Helping Small Independent Oil and Gas Producers
Develop New Technology Solutions

Produced by the Stripper Well Consortium
A Message from the Director

Oil and gas are the fuels that keep our nation’s economic engine running. Although more and more of our oil and gas is supplied from foreign sources, an important contribution to our national energy supply is made every day by thousands of small independent oil and gas producers. These enterprises, many of them family businesses, are the “pioneers” in our nation’s oil fields, extracting the resources that larger companies have left behind. They are using every available technology, and no small amount of ingenuity, to keep marginal wells producing in the face of volatile prices and increasingly challenging regulatory hurdles.

The Stripper Well Consortium (SWC) was created to support the development of technologies that can make this task easier. An industry-driven consortium, the SWC focuses on the development, demonstration, and deployment of new technologies needed to improve the production performance and lower the production costs of natural gas and petroleum stripper wells. By pooling financial and human resources, the SWC membership is helping to extend the producing life of the nation’s marginal wells. This helps to keep rural economies strong, reduces our dependence on foreign energy supplies, and ensures that we capture as much of our domestic resource endowment as possible.

This publication is designed to provide some background on the role stripper wells play in serving our demand for energy, and to highlight some of the accomplishments of the SWC over the past four years. We are proud of the part we have left behind. They are using every available technology, and no small amount of ingenuity, to keep marginal wells producing in the face of volatile prices and increasingly challenging regulatory hurdles.

Joel Morrison
SWC Executive Director

The U.S. Energy Supply Challenge

Demand for oil and natural gas is expected to continue to grow along with an expanding economy. The gap between U.S. oil consumption and domestic production is expected to grow from about 12 million barrels per day to 19 million barrels per day over the next 15 years. For natural gas, the gap is expected to grow from 8 Bcf per day to 24 Bcf per day.

Domestic crude oil production is expected to increase slightly over the next five years and then begin a steady decline. By 2025, net imports of crude oil and refined petroleum products are expected to account for 66 percent of demand, compared with 56 percent in 2003. Although domestic natural gas production is expected to increase from 19 trillion cubic feet (Tcf) in 2003 to 22 Tcf in 2025, the gap between supply and demand will continue to grow because of slower reserve growth, fewer new discoveries, and higher exploration and development costs. The U.S. natural gas supply will increasingly depend on production from unconventional reservoirs (e.g., coal seams, tight sands and fractured shales), natural gas from Alaska, and particularly, imports of liquefied natural gas (LNG).

Part of the reason for our difficulty in meeting domestic demand with domestic production lies in the maturity of the country’s resource base. Most of the big onshore oil and gas reservoirs have been found. Another reason is lack of access to areas that hold oil and gas production potential. Offshore areas on both coasts and the eastern Gulf of Mexico are off limits to drilling and obtaining permits to drill in Rocky Mountain areas is increasingly difficult.

A third reason results from a combination of smaller reservoir sizes and the success of new production technologies. Operators are producing oil and gas fields much more quickly than in the past. This is particularly true for gas wells.

“Our energy challenges today are greater than ever before. We face rapid growth in the demand for oil and natural gas at a time when domestic production is hard-pressed to keep up and world energy markets are increasingly characterized by price volatility and political uncertainty.”
— Energy Secretary Samuel W. Bodman, in testimony to the House Committee on Energy and Commerce

Recalculable volumes from new wells drilled in mature producing basins have declined over time and when initial production rates are sustained, production declines have increased significantly. Current annual decline rates are estimated to be 30 percent for gas wells, nearly twice the rate of fifteen years ago. This is why it is often said that American gas producers are “running harder to stay even.” Eighty percent of gas production ten years from now will be from wells yet to be drilled, and small independent producers will drill most of these wells?

In any case, maintaining production from existing wells is an increasingly important component of our nation’s oil and gas supply security solution. If we can keep wells producing, we can help reduce the rate of growth in the gap between supply and demand.
What are stripper wells?

The United States has more oil and gas wells than any other country. As of December 31, 2003, there were more than 524,000 producing oil wells in the United States. That’s more than three times the combined total for the next three leaders: China, Canada, and Russia. With just over 390,000 producing gas wells, the U.S. is the worldwide leader in that category as well. Unfortunately however, most of these wells produce relatively small volumes of oil and gas, often on an intermittent and marginally economic basis. Wells that produce 10 barrels of oil or less per day, or 60 thousand cubic feet (Mcf) of gas or less, are commonly called “stripper” wells. The first use of this term is not recorded, but it follows from the idea that these wells are seen as stripping an underground reservoir of its last few barrels of oil or cubic feet of gas. The Interstate Oil and Gas Compact Commission (IOGCC), which reports the annual status of U.S. stripper wells, recorded 393,463 stripper oil wells producing an average of 2.14 barrels of oil per day, and 268,563 stripper gas wells producing an average of 15.5 Mcf per day, as of January 1, 2004. These totals amount to roughly 77 percent and 63 percent of the country’s total oil and gas well populations, respectively.3 4 5

The number of producing stripper wells changes depending on how many wells enter the ranks (by declining in production) and leave the ranks (by increasing production or being plugged and abandoned) of stripper wells each year. The United States’ stripper oil well population has been gradually declining over the past decade. Although a net of about 5,000 aging oil wells drop to stripper status each year, roughly another 11,000 are plugged and abandoned, leaving a net reduction in the oil well total of about 6,000 wells per year. At the same time, a net of nearly 14,000 gas wells per year, on average, have dropped to stripper status well population over the past decade (about 17,000 per year during 2000-2003). Roughly 4,500 stripper gas wells are plugged and abandoned in the U.S. each year on average, resulting in an average net increase in the stripper gas well population over the past decade of about 10,000 wells per year.

What is their economic impact?

Stripper oil production totaled 313,748,011 barrels in 2003, accounting for 20 percent of production from onshore wells in the lower-48 states; 15 percent of total domestic oil production.6 Although the top five stripper oil states (Texas, Oklahoma, California, Kansas, and Louisiana) account for about 80 percent of stripper oil and nearly 65 percent of stripper oil wells, stripper production contributes to tax revenues and economic growth in 28 states. Were it to represent the total annual production from any of the 105 nations that produce crude oil, the U.S. stripper well oil production total would place that country in the top third of producers, ahead of Oman, Egypt, Malaysia and Australia. Were it the annual liquids production for an international oil company, the total would place it at number two, just ahead of Royal Dutch Shell and just behind ExxonMobil.7

Stripper gas production totaled 1.478 trillion cubic feet (Tcf) in 2003, about 10 percent of lower-48 onshore dry gas production and nearly 8 percent of total domestic dry gas production.8 The top five states (Texas, West Virginia, Oklahoma, Pennsylvania, and Kansas) produce 60 percent of U.S. stripper gas from 55 percent of U.S. stripper gas wells. Again, if considered as a national total, that annual volume would place U.S. stripper production within the top fifth of major gas producing countries, ahead of Mexico, Qatar, and China.9

What is their share of U.S. gas? What is their share of U.S. oil?

The reserves for the current population of stripper oil wells are estimated at 2.23 billion barrels, with a reserve to production (R/P) ratio of about seven years.10 That reserve is more than that of the oil producing nations of the world. Assuming the same R/P ratio, the current stripper gas well reserve could be estimated at 10 Tcf.

One way to look at the economic impact of stripper wells is to calculate the loss to the economy when stripper wells are plugged and abandoned. These losses, shown in the accompanying table and based on average production rates and prices for 2003 and U.S. Department of Commerce multipliers, are significant. For example, roughly 160,000 jobs are dependent on stripper well production. If the U.S. had to import all of the oil and gas currently provided by stripper wells, it would cost Americans nearly $45 million each day. The loss of severance tax revenue from stripper wells plugged in 2003 cost producing states more than $19 million dollars. If all stripper wells were to be plugged, the states would lose nearly $700 million in annual revenue.

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But in addition to these reserves, stripper wells also provide a critical link to an enormous national resource: the oil and gas that remains in place in mature reservoirs. For oil, this unrecovered volume can amount to as much as two-thirds of the original oil in place in a given reservoir. While new recovery technologies and increasing prices will only improve the likelihood of recovering more of this oil and gas, the loss of stripper wellbore access through plugging can push the cost of reactivating these reservoirs beyond any reasonable economic limit, resulting in their permanent abandonment and loss of the resource. Roughly 47 million barrels of the stripper oil produced in 2000, about 15 percent of total production, was produced from improved recovery projects; primarily waterfloods. Much of the future economic benefit of developing and applying new technologies to keep stripper wells producing safely and economically, will accrue when those wells enable extension of the producing lives of many of our Nation’s historically prolific oil and gas basins. In this sense, the “stripper” label is a misnomer. These wells are not the last stage of a scavenging operation but, a vital link to future production potential.

For example, reducing the volume of carbon dioxide emitted is becoming a national goal. Researchers are working to develop low-cost methods for capturing carbon dioxide emitted from a variety of industrial facilities. Injection of captured carbon dioxide into mature oil reservoirs can increase the recovery of remaining oil. This practice can serve as both a means of carbon dioxide disposal and enhanced oil recovery, and recent work by the Department of Energy suggests that as much as 60 billion barrels of oil could be recovered in this manner nationwide, while safely disposing of millions of tons of carbon dioxide. However, abandonment of the stripper wells that provide access to this remaining oil could put it out of reach moments before the technology is developed that could make this synergy possible.

Who are the people behind this potential?
Small independent producers operate the large majority of stripper wells. The Independent Petroleum Association of America (IPAA) states that over the last decade, the number of stripper wells discovered that stripper well production accounted for 75 percent of small independents’ oil production and between 30 and 60 percent of mid-sized independents’ oil production. Over the past six years, oil and gas price volatility and corporate consolidation have led to the sell-off of marginal properties by many mid-sized and larger independents. This trend is believed to have resulted in an even greater degree of concentration of stripper well ownership within the tier of smallest-sized independent companies.

A 1998 survey of Oklahoma’s smaller producers (those having less annual production than the top 150 producers in the state) gives some detail regarding just what characterizes a “small” independent. Descriptors of the survey respondents (about 700 of 1,300) are given in the accompanying table (page 15). The small Oklahoma independent, considered a good model for small independents nationwide, operates as a small business within a fairly small, generally rural, area. One third of these families businesses reported total income of less than $50,000, and the average contribution of the oil and gas income was less than 40 percent. The typical stripper well producer invites comparisons with his or her rural working partners operating America’s ranching, farming, and small family business enterprises.

What are the challenges to achieving this potential?
Fundamentally, there are three challenges small producers face in keeping their stripper wells on line. The first is basic economics, the second is basic physics, and the third is access to technology. Because stripper wells operate close to the edge of profitability, if oil and gas prices fall, the value of the oil or gas produced each day can quickly drop below the average daily cost of operating the wells. These costs include maintaining and operating pumps, transporting the produced oil or gas for sale, safe disposal of produced water, salaries, insurance, taxes and of course the royalties paid to the owners of the mineral rights. Any technology or new operating practice that can help to lower the cost of operating a stripper well directly influences the limit of profitability and the time that well can be kept producing.

Physics controls how fast the oil, gas and water flow into the wellbore from the reservoir, and how difficult it can be to lift the fluids to the surface. Keeping stripper gas wells clear of water so that gas can flow more freely into the wellbore is a major challenge. Remedializing wellbore damage so that oil and gas can both flow at higher rates is another. Optimizing the downhole and surface production equipment so that a stripper well produces the maximum amount of oil and gas for the minimum amount of power cost is yet another challenge.

C and C Oil is a family-run small business in Hominy, Oklahoma. Two brothers, Dewey Cox and Joe Bob Cox, are ranchers who have operated marginal wells all their lives. The family owns about 150 head of cattle and about 40 marginal wells and also services other marginal wells in the area. Their father began the cattle business in 1917 and then branched out into the stripper well business. Their sons are now part of the company, having learned the business working with their fathers since childhood. The well shown here was drilled in 1914 and is still producing 2 to 3 barrels a day.
Reducing costs and overcoming the physics of production both rely on technology. Unfortunately, most stripper well producers have neither the dollars nor the manpower to invest in developing new technology tools. In addition, most technology providers do not recognize the widely dispersed, marginal operations of the stripper well industry as a major market. The Stripper Well Consortium provides a mechanism for focusing investment on new technologies that can economically develop technologies that will extend the life and production of the nation’s stripper wells.

Since inception, a total of 98 organizations have become members of the Stripper Well Consortium. Primarily comprised of oil and gas producers (36 companies) and service and equipment suppliers (42 companies), this group includes representation from 19 stripper well states and Canada.

Active participation and leadership by all sectors of the stripper well industry makes the consortium a success. Each SWC member appoints one representative to a Technical Advisory Committee responsible for providing overall technical direction. A seven-member Executive Council is responsible for selecting projects for funding from those proposed by members.

Research is conducted in three broad areas: reservoir remediation, wellbore liquids removal and clean-up, and surface system optimization. Research outside of these three areas may be considered pending approval of the program sponsors. Submission of research project proposals is limited to full members of the consortium but collaboration among members is encouraged.

Implementing the Mission

Applying for membership in the SWC is easy and affordable. Membership in the consortium is tied into the SWC’s Bylaws, which outline the governing principles of the consortium. The SWC Bylaws are available on-line (http://www.energy.psu.edu/swc) and will provide answers to commonly asked questions on the organizational structure of the consortium. Full, Affiliate, and Supporting membership agreements can be conveniently downloaded and then mailed or faxed to Penn State University where they will be processed in a timely manner.

Projects are funded on an annual basis and each proposing organization or team is required to provide a minimum share of 30 percent of the cost of a proposed project. This may be in the form of cash and/or in-kind support. A solicitation is made early each year with a deadline for proposal submission in February. Selection of projects takes place at a spring meeting where each project proposal is presented. For example, at the March 2005 meeting 17 proposals requesting a total of $2.3 million in co-funding were reviewed and the SWC committed $1.547 million to co-fund 13 proposals. In the following pages are presented a number of SWC project case histories selected from research undertaken over the past four years.
Develop a Simple and Effective Way to Remove Water from Stripper Gas Well Flowlines

**Problem:** One of the most troublesome problems for stripper gas well operators is the water that is produced along with the gas; if it accumulates in flowlines or builds up at the bottom of a wellbore it will reduce gas flow rates below economic levels. Water in flowlines is difficult to remove and contributes to corrosion, while removing water from wellbores can be a continual expense in terms of pump parts and maintenance, power costs, and pumper time.

**Proposed Solution:** Develop a simple, in-line device that acts to redirect the liquid phase in pipelines and tubing, allowing the gas phase to more effectively carry the liquid phase along a pipeline or out of a well. Such an approach would simultaneously improve production rates and reduce operating costs.

**Background and Results-to-Date:** In 2002 the SWC funded several projects with Vortex Flow, LLC to adapt an existing technology (for conveying solids over long distances in pipelines) to improve the flow characteristics in stripper well flowlines and wellbores. Prototypes had been fabricated and field-tested on a limited basis, but SWC involvement enabled Vortex Flow to:

- Quantify the efficiency of the Vortex Flow Unit installed in an actual gas gathering system,
- Determine the optimal operating conditions,
- Perform additional design improvements, and
- Complete the design and fabrication of a downhole version of the unit.

A second project with the SWC in 2003 enabled Vortex Flow to install and field test multiple downhole units with Marathon Oil Company, and collect the data needed to refine the technology. The Vortex Flow technology takes a disorganized, multi-phased flow stream and transforms it into a helical flow pattern where a slower-moving liquid phase runs along the inside wall of the flowline or tubing string and the gas moves through the center of the pipe. This vortex (rotating) pattern prevents liquids from dropping out of the flow and permits efficient movement over long distances and substantial changes in elevation and direction. The downhole tool lowers flowing bottomhole pressures in gas wells by reducing liquid holdup in the tubing. In many applications, they reduce the slugging that is common when lifting large volumes of water with minimal gas. The accompanying reduction in friction losses reduces the pressure drop and thus increases production rate. The downhole tools, made of 304L stainless steel, are being fitted to 0.6 inch through 3.5 inch tubing inside 2 7/8” inch OD and larger tubing/casing sizes.

Installation is easy; the tools simply thread on the bottom of the tubing. Perhaps even more important, the device has no moving parts and requires no power source or maintenance.

Marathon successfully deployed these new tools to convert low volume gas wells that were being mechanically dewatered into flowing gas producers. By eliminating downhole pumping equipment, variable and fixed costs decreased dramatically; from an average $875 per month to $15 per month. Considering installed cost, the tools paid out in about seven months. In two cases, since prior failures with associated downtime were eliminated, about 2.7 MMcf per year of deferred production was saved. This $10,000 cash-flow benefit essentially paid for tool installation.

**Ongoing Activity and Future Plans**

A third project with the SWC in 2004 was designed to determine the benefits of combining a slickline-set through tubing, downhole version of the Vortex Flow device (the DXR tool) with other low cost lifting methods such as surfactants, plunger lift, velocity strings and intermitters. The expectation is that a DXR tool combined with these methods can lower the critical gas rate required to keep a well flowing by as much as 60 percent, and replace more expensive traditional lifting methods such as rod pumps. Vortex Flow developed the new slickline-set & retrievable model and has been installing it in customers’ wells since January 2004. Vortex Flow, LLC is now a successful commercial enterprise. In December 2004 the company won the Platts Global Energy “Newcomer of the Year” Award for its “revolutionary fluid dynamics technology that … will extend reservoir life and potentially save its customers many millions of dollars.” Vortex Flow developed the new slickline set & retrievable model and has been installing it in customers’ wells since January 2004. The DXR tool can be set in a profile nipple or collar stop.

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Construct and Test a Simple Pump for Dewatering Gas Wells
That is Inexpensive to Operate

Problem: Stripper gas wells still capable of producing gas often must be shut in when the cost of removing produced water from the wellbore exceeds an economic limit. Just a few tenths of a barrel per day can kill gas production. Regular removal of this water as it accumulates in a well increases average gas production, but conventional fluid removal techniques using beam pumps, periodic swabbing with workover rigs, siphon strings and tubing plungers have physical limitations and require significant capital, operating and maintenance investments. For marginal wells, these costs can lead to premature abandonment of producible gas.

Proposed Solution: Develop a tool that has few moving parts to wear out, is simple to operate, requires minimal monitoring, and utilizes the natural pressure of gas in the wellbore to lift the water out of the well on a regular basis.

Background and Results-to-Date: The SWC funded three projects with Brandywine Energy and Development Co. (BEDCO) during 2001, 2002, and 2003, to develop and test an automatic pump for removal of liquids from a wellbore. The new pump, called the Gas-Operated Automatic Lift (GOAL) PetroPump, is designed to freely operate within the wellbore casing. With a free-falling piston, rising when pressure builds up below it and descending back downhole when wellhead pressure and production drop, the tool travels down through any standing liquid (by virtue of a through-tool liquid bypass passage) until the weight of fluid atop the tool offsets a preset actuator pressure and automatically closes the bypass. Flexible sealing cups surround the tool, creating a circular seal with the inside diameter of the casing. Gas pressure builds in the well below the tool is lifted up the wellbore, pushing the fluid load to the surface and out the topside of a wellhead lubricator. Follow-on gas production is then produced from below the tool on a bottom side port in the same lubricator.

During the first two SWC projects, BEDCO developed the tool design and tested it in a number of under-performing wells. During a third project, the GOAL PetroPump was installed in three additional wells that were open-hole completions. The wells were slimplined with 4 1/2-inch casing and an openhole packer. This test was undertaken due to the large number of openhole-completed stripper wells (perhaps more than 10,000) that stand to benefit from the application of this technology. The tool has evolved significantly throughout the development and field-testing process. The original tool was more than 6 feet long, weighed over 100 lbs and had more than 60 components. The current (fourth-generation) design can accommodate 4-inch or 3-inch ID casing or tubing, has just 14 components, is only 38 inches long and weighs less than 45 lbs.

The tool can be easily placed in a lubricator assembly by one person. This 2,200 foot Medina well near Dunkirk, NY has seen gas production increase from 5 Mcf/day to 20-25 Mcf/day as a result of the PetroPump.

One of the important features of this system is its ease of operation. It does not require a great deal of special training for the pumpers that will operate it, often small independent subcontractors employed by the producing company. It is also a relatively low maintenance system. One issue with manually operated tubing plungers has been wear and tear—the sealing cups often need to be replaced. Rod pumps and pumpjacks call into play another whole set of maintenance and operations problems. The PetroPump avoids these costs while approaching the same degree of liquid removal capability.

Lenape Resources, one of the larger independents in New York State with 14 employees, operates about 500 wells in the Northern Appalachian region, many of which are stripper wells. The company installed the GOAL PetroPump in a 3,200-ft Medina formation completion that required periodic soaping and swabbing to remove liquid and produced about 1,100 Mcf/year. Production after tool installation averaged 3,416 Mcf/year and payout was achieved in 8 months. Several other subsequent installations by Lenape resulted in similar increases in production. According to John Holko, President of Lenape Resources, “Some solutions to liquid removal minimize costs, some maximize gas production, this tool does both. It’s an important advancement because it approaches the performance of a mechanical rod pump, while still being simple to operate and with much lower maintenance. It’s great.”

Ongoing Activity and Future Plans: The GOAL PetroPump is now available commercially and is being used by a number of smaller independent operators in the Appalachian Basin. Additional information can be found at http://www.brandywineenergy.com/.

Key Contact: Paul Yaniga, Brandywine Energy Development Company (BEDCO), Frazer, Pennsylvania, (610-338-3824 or yanigapm@aul.com)
Develop a Cost-Effective Technology for Converting Produced Brine Into Fresh Water

Problem: Stripper well producers must dispose of large amounts of saltwater produced along with oil and gas by marginal wells. The cost of safely handling and disposing of this water can strain the economics of stripper well production, leading to premature shut-in and abandonment of wells that might otherwise remain on stream.

 Proposed Solution: Develop a cost-effective method for desalinating produced brine that will allow its beneficial use by ranchers and farmers. This solution will reduce the net cost of produced water disposal by increasing the value of the fresh water product, and at the same time provide a new source of fresh water in areas where it is in short supply.

Background and Results-to-date: The technologies needed for desalination of oilfield brine are available, but the challenge is to combine existing technologies in a manner that makes economic sense for small-scale, portable units operating at remote locations and in severe environments. Two essential technologies, soluble oil removal and membrane filtration, must be coupled for a viable field treatment process to be successful.

The process being developed under this project involves pre-treatment of the produced water using several options: centrifugal separators to remove free oil and sediments, microfiltration to remove oil and other organics at low pressures, and organoclay adsorbants to remove soluble oil dissolved in the produced water stream. This stage is followed by membrane filtration, a process that employs semipermeable membranes to convert the stream of oil-free but still salty water into two streams: one fresh water and the second highly-salty brine. Depending on the technique and the salinity of the brine, up to 50 gallons of potable water can be produced for every 100 gallons of water desalinated. The fresh water can then be put to beneficial use while the concentrated brine can be disposed of in a conventional disposal well. A significant reduction in the volume of brine requiring disposal, plus the added value of the fresh water, is where the net cost savings occurs.

For example, Casper Creek Oil Field in Wyoming produces 1,750,000 gallons of brine from an active water drive reservoir. If the water could be used in a nearby municipal water supply, it would represent a potential revenue stream of $3,500 per day. That would be more than the value of the oil produced from the field over the same time period.

The first SWC project funded at Texas A&M University was to study the environmental and regulatory issues relating to the utilization of produced water from two oil and gas producing regions. A&M developed guidelines for companies to follow for making this new source of fresh water available for productive use. That effort has resulted in the acceptance of the technology by the Texas Railroad Commission, the Texas Water Development Board, and the Texas Committee on Ground Water Resources. A second portion of the SWC project involved the upgrading of an existing prototype portable desalination unit, short and long-term field testing with full size process trains and the investigation of a structure by which producers practicing desalination might receive reimbursement from environmental and oil and gas regulatory agencies. The mobile desalination trailer built by engineers at Texas A&M University not only processes up to 20,000 gallons of water per day, it also monitors the unit’s own power consumption for cost analysis purposes.

Trials have been conducted with Burlington Resources and Key Energy in the Barnett Shale play in the Fort Worth Basin, where estimates show that more than 40 million barrels of water could be saved annually by using desalination to recover water used for fracturing operations.

The Distributed Water Processing and Recycling project is progressing on several fronts, including laboratory testing of various membrane filtration technologies, laboratory testing of clay adsorbant technologies, and design and construction of a prototype test unit that combines the oil removal and solids removal stages. An engineering model is also being developed to calculate flux, lifetime and operating expense of various combinations. When the technical feasibility of the combined treatment process is proven, field water samples and simulated produced brines will be used to test the system. Finally, field tests of a prototype system will be carried out.

This five-year, million-dollar effort is being managed by an interdisciplinary faculty research group at Texas A&M University that is an element of the larger Global Petroleum Research Institute. There is potential for this technology to be expanded to a variety of point sources of brackish water from industrial and other sources.

Ongoing Activity and Future Plans: A third phase of the project has been proposed to operate a pilot desalination project with disposal of byproducts into an oil field waterflood. The City of Andrews, Texas, in cooperation with the Texas Water Resources Institute will participate in this two year, $425,000 pilot demonstration. The U.S. Bureau of Reclamation is being asked to fund $270,000 of the cost. ExxonMobil has agreed to incorporate the concentrate into its makeup water in the Means Field waterflood operation. The Texas Commission on Environmental Quality has given approval to the project and will issue an authorization for this type of disposal operation, the very first authorization of this type in the nation.

“If this technology works as it should, it will provide a tremendous benefit for our city.”

— David Sanders, Director of Utilities, City of Andrews, TX

Key Contact: David B. Burnett, Texas A&M University, College Station, TX (979-845-2274 or burnett@spindletop.tamu.edu)
Problem: Stripper gas well producers often do not have the time or money to collect and evaluate the pressure and production data that can help them determine if wells are producing up to potential or if remedial work could improve productivity. This problem is compounded by the fact that many stripper gas wells, particularly in the Appalachian Basin, produce from multiple zones in low-permeability fractured shale and sandstone formations, a situation that can be particularly difficult to analyze. As a result, operators may not be able to select the best candidates for workovers, which can lead to curtailed productivity and misdirected investments.

Proposed Solution: Develop and distribute a reasonably-priced software product that producers can use to quickly and reliably evaluate stripper gas wells, and that is designed specifically for the low-permeability, multiple-completion wells typical of stripper production areas.

Background and Results-to-Date: Production type curve analysis is a well-established analytical approach that compares the pressure response of a well during production over time to predicted responses generated using detailed mathematical models of a reservoir’s behavior. By matching the actual response to predicted behavior, engineers can determine if a well is producing efficiently or if it might benefit from a stimulation treatment or reconfiguration. The analyst can use this one step further and predict how much of an increase in production might occur for a given workover investment. Performing tests and analyses on many wells allows a producer to see where workovers will result in the highest incremental increase in production and the greatest return on investment. Under funding from NYSERDA and the Gas Research Institute, Advanced Resources International, Inc. (ARI) had developed a production type curve analysis program called METEOR designed specifically for use with commingled completions (wells that produce from multiple zones simultaneously). While this program offered the capability to perform a detailed two-layer production type curve analysis, and generated permeability, stimulation, drainage area, and recovery estimates for each layer, the software lacked several features that would enhance its usability.

As part of the SWC’s 2001 suite of projects, ARI developed a number of enhancements to the software program. These included variable compressibility and viscosity options, the ability to calculate “skin factor” and other key parameters, improved data reporting, plotting and export options, and a mapping interface to allow the results to be displayed in x-y format. ARI also collected stripper well production and well history data from 17 type areas in the Appalachian region operated by Equitable Production and Belden & Blake and history-matched this data using a reservoir simulator. The enhanced METEOR software was then used, along with the same data, and the results tested by comparison to the simulator output. With few exceptions, the single and multi-layer type curve match results were able to replicate the results from the more detailed simulation history matching. From predetermined permeability values, METEOR was able to reasonably predict drainage area and cumulative recovery values for one and two layer completions.

Ongoing Activity and Future Plans: A copy of the METEOR software was provided to members of the Stripper Well Consortium, qualifying New York State operators and the Gas Technology Institute. ARI continues to use the software internally for a variety of consulting projects. The software is distributed at a reduced cost by ARI to the stripper well community.

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Develop a Fast and Reliable Tool for Identifying Under-Performing Stripper Gas Wells

Problem: Many stripper gas wells, particularly in the Appalachian Basin, produce from multiple zones in low-permeability fractured shale and sandstone formations, a situation that can be particularly difficult to analyze. As a result, operators may not be able to select the best candidates for workovers, which can lead to curtailed productivity and misdirected investments.

Proposed Solution: Develop and distribute a reasonably-priced software product that producers can use to quickly and reliably evaluate stripper gas wells, and that is designed specifically for the low-permeability, multiple-completion wells typical of stripper production areas.

Background and Results-to-Date: Production type curve analysis is a well-established analytical approach that compares the pressure response of a well during production over time to predicted responses generated using detailed mathematical models of a reservoir’s behavior. By matching the actual response to predicted behavior, engineers can determine if a well is producing efficiently or if it might benefit from a stimulation treatment or reconfiguration. The analyst can use this one step further and predict how much of an increase in production might occur for a given workover investment. Performing tests and analyses on many wells allows a producer to see where workovers will result in the highest incremental increase in production and the greatest return on investment. Under funding from NYSERDA and the Gas Research Institute, Advanced Resources International, Inc. (ARI) had developed a production type curve analysis program called METEOR designed specifically for use with commingled completions (wells that produce from multiple zones simultaneously). While this program offered the capability to perform a detailed two-layer production type curve analysis, and generated permeability, stimulation, drainage area, and recovery estimates for each layer, the software lacked several features that would enhance its usability.

As part of the SWC’s 2001 suite of projects, ARI developed a number of enhancements to the software program. These included variable compressibility and viscosity options, the ability to calculate “skin factor” and other key parameters, improved data reporting, plotting and export options, and a mapping interface to allow the results to be displayed in x-y format. ARI also collected stripper well production and well history data from 17 type areas in the Appalachian region operated by Equitable Production and Belden & Blake and history-matched this data using a reservoir simulator. The enhanced METEOR software was then used, along with the same data, and the results tested by comparison to the simulator output. With few exceptions, the single and multi-layer type curve match results were able to replicate the results from the more detailed simulation history matching. From predetermined permeability values, METEOR was able to reasonably predict drainage area and cumulative recovery values for one and two layer completions.

Ongoing Activity and Future Plans: A copy of the METEOR software was provided to members of the Stripper Well Consortium, qualifying New York State operators and the Gas Technology Institute. ARI continues to use the software internally for a variety of consulting projects. The software is distributed at a reduced cost by ARI to the stripper well community.

Key Contact: George Kopeina, Advanced Resources International, Inc., Arlington, VA (703-528-5420 or gkopeina@ad-vces.com)

Develop a Methodology to Mitigate the Corrosion Problems Leading to Poor Stripper Well Performance

Problem: Mechanical failures are the cause of nearly one quarter of the abnormal production declines seen in stripper gas wells. These mechanical failures are most commonly the result of corrosion, often exacerbated by the build up of corrosive brine in wellbores or its movement through production equipment. Marginal well operators must react to corrosion caused mechanical failures, but typically do not follow a proactive methodology for identifying problem areas and selecting the appropriate corrosion mitigation alternative before the failure takes place. As a result, opportunities for reducing failure rates and increasing production are missed.

Proposed Solution: Develop a procedural guide, with an easy-to-follow decision tree format, that can be used to identify and select the appropriate corrosion mitigation methods for specific stripper well situations.

Background and Results-to-Date: James Engineering conducted field research on hundreds of wells in Ohio to identify the critical factors affecting rates of corrosion and the methods being employed to successfully (or unsuccessfully) mitigate corrosion. Wells that had been identified in a previous study as having experienced mechanical failure were reviewed, in addition to wells where little or no corrosion had been observed. The types of corrosion control treatments in use were identified, researched, and recorded for the wells in the database. The field review encompassed production storage tanks, separators and production units, wellheads, pipelines (gathering and production lines) and downhole tubulars (casing and tubing). A procedural guide was then developed that incorporated the results of the study into a logical, step-by-step procedure for mitigating corrosion. Customized data collection forms and decision trees were developed that allow operators to develop their own corrosion mitigation program. Data collection forms (Corrosion Field Review Data Collection Sheets) are provided for operators to use for evaluating and then incorporating each well, facility or pipeline into the plan. This guide provides an understanding of corrosion and a step-by-step methodology for reviewing and prioritizing wells. The methodology considers: corrosion history, estimated value and expected life of wells and facilities, corrosion mitigation options and costs, corrosion correction options and costs, environmental issues, and safety issues. An extensive amount of background information on the types and causes of corrosion as well as the options for mitigation and control, are also included in the guide.

Ongoing Activity and Future Plans: A technical paper based upon the results of the study was presented at the Society of Petroleum Engineer’s Eastern Regional meeting in Pittsburgh, PA in 2003. James Engineering continues to utilize the Guide in their own consulting work within Ohio and other Appalachian Basin states, and to promote its use by stripper well operators in the region. While the overall subject of corrosion is complex, in most cases the process of corrosion mitigation can be simplified to the proper application of “planning, painting, and plastic.”

Key Contact: Tim Koshluch, James Engineering, Marietta, Ohio (740-373-9521 or tkosh@jvee.net)
Develop a Downhole Corrosion Inhibitor Deployment System for Plunger Lift Wells

**Problem:** Research suggests that 86 percent of failures in plunger lift systems are a result of corrosion damage brought on by produced brine. Corrosion inhibitors can help solve this problem, but the effectiveness of corrosion inhibition treatments in gas wells is limited. Many of these wells employ a packer that prevents liquid circulation to the tubing via the casing-tubing annulus. The common alternative is to pump corrosion inhibitor (generally in a diesel carrier) down the tubing, wait a period of time, and then flow the liquid back up the tubing, allowing it to coat the inside surface. However, if the well has insufficient bottom hole pressure to flow back the inhibitor, a swab unit must be employed to re-establish production following the treatment. This defeats the purpose, as the running of a swab wipes away the film that was just applied. The inability to effectively deliver corrosion inhibitor to plunger lift gas wells leads to equipment failure, high operating costs, and premature abandonment.

**Proposed Solution:** Develop a plunger lift system with an inhibitor-loaded plunger designed to deposit the chemical at the bottom of the tubing string. Design the system to automatically load the plunger with chemical upon arrival at the bottom of the tubing string. The system can be easily installed on existing plunger lift equipment and simple to install and operate.

**Background and Results-to-Date:** Composite Engineers, Inc. was awarded a grant through the Stripper Well Consortium to develop this patented system. Extensive effort was devoted to key elements of the design: a chemical chamber to be located on top of an existing plunger lift lubricator, a valve mechanism capable of loading the chemical upon arrival of the plunger at the surface and transport the payload to the bottom of the well on each cycle. Make the system compatible with existing plunger lift equipment and simple to install and operate.

The system developed by Composite Engineers is unique in that it continually treats the well tubulars, eliminating any need to shut in the well and lose perhaps several days production. The system can be easily installed on existing plunger lift systems with common tools and without the need for a service unit. This installation can even be carried out during a well's normal "shut-in" cycle, avoiding any interruption of production. Another feature of the system is the option of deploying multiple chemicals utilizing a single system (i.e., corrosion inhibitor, foaming agents, salt dispersants, etc.). One has to assure the chemicals are compatible with each other due to possible mixing in the chemical chamber over time. Multiple chemical pumps can be timed to deliver individual chemicals to the plunger on opposite cycles. Finally, the system is very simple to maintain, with few moving parts. If problems do occur, the well can continue to be operated as usual with the chemical system off line.

Various prototypes were tested in the lab before being deployed in a 200-foot deep test well. After modifications based on the test well data, two systems were deployed in a field near Lafayette, Louisiana known for corrosion problems. Corrosion coupons were installed 90 days prior to installation of the systems to establish a baseline rate of corrosion and the tubing strings of both wells were pulled and inspected prior to installing the chemical systems. Once deployed, the gas-driven chemical pumps were each set to pump 2 1/2-quarts per day. The field trials were terminated after 168 days and inspection of the corrosion coupons revealed that both wells experienced a considerable reduction in corrosion damage. Neither system encountered any problems except for one O-ring failure in the chemical chamber wiper about 15 days into the test. This was corrected during a "shut-in" cycle without any production interruption. The weaker of the two wells experienced aggravated plunger wear so modified brush plungers were deployed. Non-metallic "wobble washers" were installed above and below the brush segment to retard wear and to test the performance of non-metallic components in the field. Approximately 105 days into the trials, the plunger on one of the wells was inadvertently surfaced dry, resulting in severe damage to both the plunger and chemical chamber and requiring their replacement. At 112 days, the well operator expressed a desire to add a foaming agent to the system on the weaker well so a second gas driven chemical pump was installed with a manifold. This set-up permitted the two chemical pumps to be synchronized to pump at different times of the day, with the corrosion inhibitor maintained at 2 1/2-quarts per day and the foaming agent set at 1 quart per day.

The field trials were terminated at 168 days and the corrosion coupons were pulled for evaluation. Of the two wells, the data generated by the corrosion analyses showed a reduction in metal loss of 11.17 percent and 3.11 percent respectively during the test period.

**Ongoing Activity and Future Plans:** The system has been introduced at one trade show with very promising acceptance by industry. Requests from major producers and independents to deploy the system in the Permian Basin, San Juan Basin, South Texas, East Texas, Powder River Basin, and the Appalachian Basin are being considered. Several plunger lift companies have also expressed interest in a variety of arrangements to gain access to the system. Manufacturing plans are currently being developed and the system should be available on a limited basis early in the third quarter of 2005.

**Key Contact:** Sam Farris, Composite Engineers, Inc., Oklahoma City, OK (405-990-9728 or samfarris@compositeengineersinc.com)
Develop an Economical Electrical Submersible Pump for Low Volume Stripper Wells

Problem: All oil and gas wells produce amounts of sand, scale, and corrosion debris. Stripper wells typically do not produce fluids at high enough velocity to remove this material, requiring periodic clean outs to maintain flow rates. This remedial work is costly and results in production downtime.

Proposed Solution: Develop an inexpensive, small-diameter electrical submersible pump (ESP) that can be easily deployed inside casing on small diameter plastic tubing that can double as a conduit for produced fluids to reach the surface. Design the pump based on a hydraulically driven diaphragm that is tolerant of debris-laden fluid. Employ the small diameter plastic tubing to increase pumped fluid velocity and more effectively sweep the debris to the surface. Such a system should also allow placement of the pump below the perforations, leading to greater pressure drawdown and improved production rate.

Background and Results-to-Date: Pumping Solutions Inc. had developed a hydraulic diaphragm electrical submersible pump (HDESP) with the ability to pump sandy fluids at significantly reduced power and purchase costs relative to a conventional ESP. Hydraulically driven diaphragm pumps are mainly used in mining operations to pump slurries from the bottom of the mine to the surface for processing. The SWC funded an effort to develop and incorporate the HDESP into an ESP motor and cable technology.

Proposed Solution: Develop an inexpensive, small-diameter electrical submersible pump (ESP) that can be easily deployed inside casing on small diameter plastic tubing that can double as a conduit for produced fluids to reach the surface. Design the pump based on a hydraulically driven diaphragm that is tolerant of debris-laden fluid. Employ the small diameter plastic tubing to increase pumped fluid velocity and more effectively sweep the debris to the surface. Such a system should also allow placement of the pump below the perforations, leading to greater pressure drawdown and improved production rate.

Key Contact: Leland Traylor, Smith Lift, LLC, previously with Pumping Solutions Inc., (801-221-5110 or LTraylor@smith.com)

Ongoing Activity and Future Plans: The success of these tests helped to achieve to full commercial deployment of both the HDESP and the CSP deployment system following acquisition of Pumping Solutions (formerly Smith Lift, a large, international artificial lift supplier. Between 100 and 150 HDESP installations have been made in stripper wells over the past two years to measure the performance of the diaphragm pump. To date, the average run time has been about 4 months, with run time improving constantly with design changes. The HDESP contains no electronics, few moving parts, and utilizes oilfield proven technologies such as standard API balls and seats and proven ESP motor and cable technology. HDESPs have the ability to pump up to 1.5 percent sand, pump off without damage, can provide mixed flow pumping (gas and liquid) and have exhibited 66 percent less power consumption than conventional ESPs. This performance is from an all-stainless steel and rubber pump that weighs about 100 pounds, is 3 1/4 inches in diameter and costs less than half the price of a conventional pump. A 1 3/4 inch, hydraulically operated version that can be run inside tubing is currently being developed.

Develop a Downhole Wireless Gauge for Stripper Well-Type Applications

Problem: While electronic systems for downhole data gathering are expensive to install and operate, well beyond the reach of stripper well operators. Consequently, monitoring of the production process is done from the surface, creating inefficiencies that increase the cost of producing and lifting hydrocarbons. A low cost, wireless system would make optimization of stripper well pumping systems economically feasible, leading to improved production efficiency and longer well life.

Proposed Solution: Develop and test a low cost wireless, downhole pressure gauge based on an existing high-end gauge and incorporate it into an existing low-end data processing system designed for optimizing lifting operations, monitoring bottom hole pressure and performing build up tests.

Background and Results-to-Date: Tubel Technologies Inc. has developed a lower cost version of their wireless downhole communication system as part of this project. The Wireless Real Time Gauge system measures pressure and temperature information from the annulus and tubing sections of the wellbore. This information is processed by the built-in electronics and the digital data is transmitted to the surface using acoustic waves traveling through the production tubing. The system is composed of two pressure and temperature gauges, an electronics module for analog-to-digital conversion, data processing and data frame setup, an acoustic generator driver and an acoustic generator. A surface acoustic-to-electrical converter and a data processing surface panel complete the system.

Key Contact: Leland Traylor, Smith Lift, LLC, previously with Pumping Solutions Inc., (801-221-5110 or LTraylor@smith.com)

Ongoing Activity and Future Plans: To date, the system has been deployed in low end applications, for example, monitoring of downhole pressure during fracturing. The ability to provide real time downhole pressure during the service job allows for easier optimization of the process. Tubel is improving the tool design to permit transmission of data through coiled tubing.
Build and Test a Novel Design for a Low Cost, Variable Capacity, Low Volume Gas Compressor

**Problem:** Stripper gas wells produce relatively low volumes of gas at low pressures, and even new wells drilled in marginal areas exhibit flow rates that decline relatively quickly. Sizing a compressor to reduce the wellhead pressure is difficult, and even smaller sized reciprocating compressors are still too large and expensive for individual stripper wells. As a result, these wells are shut in while producible gas reserves remain in the reservoir.

**Proposed Solution:** Build and demonstrate a novel pump/compressor that employs a spherical design that provides the largest internal volume to surface area ratio possible for maximum efficiency. Design the compressor with a variable capacity so that it can be easily adjusted to meet changes in flow rate without changing the rotation rate of the drive shaft.

**Background and Results-to-Date:** The Weatherbee Positive Displacement Compressor/Vacuum Pump is a patented device that, due to its novel spherical design, is substantially reduced in size and weight over conventional compressors. For example, the 8 1/2 inch-sized Weatherbee Pump weighs only 75 pounds and has 244 cubic inches of displacement. A reciprocating compressor of the same size capacity would weigh on the order of 600 pounds. A 4 inch-sized model has a 25 cubic inch displacement; enough to handle a stripper gas well producing 50 Mcfd at typical line and wellhead pressures. The variable volume control mechanism works like a throttle on an engine, allowing he compressor capacity to be easily adjusted as a well’s flow rate drops over time. The device uses only the energy necessary to compress the gas that the well is producing, thereby saving on energy use. Because the Weatherbee pump is a ported device, without the valves and springs common to conventional reciprocating compressors, it should have lower maintenance and operating costs. In addition, the direction of flow can be completely reversed without disconnecting the pump or changing the rotational direction of the input shaft.

The Stripper Well Consortium has funded work on this pump in two phases. Under Phase I, W&W Vacuum and Compressor Inc. (325-695-4637 or wildcatr@aol.com) selected and qualified an engineering and manufacturing facility (Athena Manufacturing, LP) to re-engineer the preexisting 8 1/2 inch pump and build a new 4 inch configuration prototype for stripper well applications. First, the original mechanical drawings were converted into a three-dimensional computer-aided-design (CAD) electronic format, and two separate configurations for the pump seals were selected: one fluid-based and one mechanical-based. Initial testing proved that the mechanical-based configuration would be the best choice. W&W solicited and received seal design assistance from a number of seal manufacturers, and after extensive testing it was determined that engineered polymer (Radel and Delrin) seals would not work. W&W then began working with Boeing’s engineers to develop an energized type seal that features a spring-loaded carbon composite seal element housed in a stainless steel ring.

A total of five compressors were built during the prototype development process. Compressor housings, vanes and shafts were manufactured from a number of different materials. A variety of bearing types and assembly configurations were evaluated and each compressor was tested using a custom test bench. This bench testing revealed a substantial amount of information, often in the form of post-failure analysis. Phase I funding was depleted with the successful manufacturing of an operational prototype while simultaneously designing and developing two different compressor seal configurations. Ongoing Activity and Future Plans: Phase I established these are some performance shortcomings with the initial design. Some design and manufacturing iterations were necessary to achieve adequate reliability, however, those obstacles were largely overcome, resulting in smooth running, reliable operation. The initial design of the pump (called the Weatherbee Wedge Pump), while reliable and fully operational, needs optimization in order to meet desired performance goals. Under Phase II the design will be perfected and two new prototype compressors implementing the new seal design and a revised port sizing and location will be manufactured and tested on the bench and in the field.

W&W Vacuum and Compressors is also continuing its research and development into a prototype of a mechanical heart pump. Although not a direct part of the SWC project, lessons learned during the design and manufacture of the gas compressor could help to create a more efficient and reliable pump for artificial hearts.

**Key Contact:** Paul Weatherbee, W&W Vacuum and Compressors, Inc. (325-695-4637 or wildcatr@aol.com)
Improving the Efficiency of Treatments to Reduce Water Production from Marginal Oil Wells

**Problem:** Many stripper oil wells, particularly in older fields that are under waterflood or have reservoirs with strong water drives, produce large amounts of water and relatively small amounts of oil. High water cuts are characteristic and many wells have to be shut in due to high water-to-oil ratios. Gelled polymer treatments have been used to reduce water production, prolonging the life of some wells and increasing oil recovery. These treatments typically result in a period of flush oil production, followed by a gradual return to high water cuts. Finding a way to prolong the treatment's effectiveness would allow these wells to remain on production longer, producing a larger percentage of the oil remaining in these fields.

**Proposed Solution:** Over 300 gelled polymer treatments have been applied in the Arbuckle formation in Central Kansas. A typical treatment consists of injection 3,000 to 4,000 barrels of gelant into the reservoir followed by an oil or water flush of about 100 barrels to clear the tubing and casing as well as to establish permeability in the reservoir rock when the gel forms. The well is shut in for a week or more while the gel forms and then the well is put on production at a reduced rate. The gel preferentially reduces the permeability of the formation to water in the area near the wellbore that has been treated. A DOE-sponsored research project at the University of Kansas has revealed that it is possible to further reduce the permeability to water by dehydrating the gel after placement, by controlled injection of oil. Water is “squeezed” from the gel as flow paths are created by the injected oil. Also, the gel that remains after dehydrolysis exhibits increased strength due to its higher polymer concentration. This mechanism (termed disproportionate permeability reduction) reduces water permeability by at least an order of magnitude in laboratory tests. This project proposes to demonstrate the process in the field for the first time.

**Background and Results to Date:** This project was proposed and accepted at the spring 2005 meeting of the SWC, so work has not yet begun. A two-well field test has been proposed to determine if the water production rate following treatment of a well using a gelled polymer system can be reduced through dehydration of the gel by slow injection of oil. The proposed field tests are a cooperative project between the Kansas University Energy Research Center and Vess Oil Corporation, an independent oil producer in Wichita, Kansas. The project will involve two gel polymer treatments in the Arbuckle formation in Central Kansas, on a lease where treatments with conventional chromium carboxylate-polymer gel have been done previously and a general baseline of post-treatment performance has been established for comparison.

The project will include: initial reservoir characterization, conventional gel treatment, displacement of the gelant from the tubing and wellbore, shut in for gelation, injection of oil at a controlled bottomhole pressure to dehydrate the gel in the vicinity of the wellbore, production testing and fluid sampling following the dehydration process, and a post-treatment pressure buildup. Anticipated results include: substantial reduction of post-treatment water production relative to conventional gel treatment, increased incremental oil production, and longer-lasting effects of the treatment.

**Key Contact:** G. Paul Willhite, University of Kansas Center for Research, Inc. (785-864-2906 or willhite@ku.edu)

Kansas waterfloods, one example of which includes this well, are good candidates for polymer treatments.

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Lab work at University of Kansas supports the improvement of the gelled polymer process.
Apply State-of-the-Art Hydraulic Fracture Imaging to Appalachian Basin Wells

Problem: The large number of marginal wells in the Appalachian Basin could benefit from well-designed fracture stimulation treatments; either re-stimulation of existing producing zones or re-completion into previously unstimulated intervals. Seismic imaging of fracture treatments is a technology that has been successfully applied in a number of U.S. basins to help operators optimize treatments for regional formations. Unfortunately, the cost of relocating the specialized equipment, performing engineering studies and demonstrating the technology in the Appalachian Basin is a significant hurdle for companies hoping to utilize the technology. The potential improvements to production rates and recoverable reserves remain to be captured.

Proposed Solution: Carry out preliminary engineering and geological review to determine what type of fracture imaging is best suited for the Appalachian Basin. Adapt equipment and perform two to four hydraulic fracture imaging experiments on actual treatments. Use the information gathered to calibrate regional fracture models and validate recommended practices for optimizing Appalachian Basin hydraulic fracture treatments. Communicate the results of the project to operators in the basin so they can modify their stimulation treatments to maximize recovery, while minimizing stimulation cost.

Background and Results-to-Date: Universal Well Services is being funded by the SWC to apply fracture mapping techniques developed by Pinnacle Technologies to wells operated by Great Lakes Energy Partners. Great Lakes is a partner in the project and has a large presence in the Appalachian Basin. The candidate wells have several distinct pay zones that are fracture-stimulated individually. Designing the individual zone treatments and understanding the geometry of the fractures that are created can be a complex issue.

After review of the engineering and geological data characteristic of the Appalachian Basin, microseismic fracture imaging was chosen as the best fracture mapping technique to utilize for this project. Recent developments in this technique allow a hydraulic fracture to be imaged, while it is being created by receiving, processing, and displaying the “seismic events” produced in the area around the fracture. These “events” are similar to mini earthquakes and are monitored in much the same way that seismologists determine the location of earthquakes. The monitoring is done by installing seismic geophones in offset wells and gathering and processing the seismic data. The data is then analyzed and presented in a format that allows the geometry and orientation of the created fracture to be deduced. Pinnacle has pioneered the application of the technique and developed the sophisticated software to analyze the recorded data and create a “map” or image of the created fracture. This is the only way that an operator can be certain of the geometry of a fracture created by a stimulation treatment.

Establishing the orientation and geometry that can be expected from specific fracture treatment volumes and pumping pressures in particular Appalachian Basin formations will allow producers to better predict the production rates they can expect, and ultimately, to do a better job of designing an optimum treatment to maximize production for minimal cost. One of the benefits of the project will be the accurate calibration of the computer-based predictive models used to predict production rates for various treatment designs, providing a low cost method for predicting fracture geometry before a treatment is pumped.

Ongoing Activity and Future Plans: Since initiation of the project, Universal Well Services has pumped treatments on three wells and the resulting data is currently being analyzed by Great Lakes, Pinnacle, and Universal. The treatments were pumped successfully and the results are encouraging and expected to yield job improvement benefits on future treatments. After the data has been reviewed by the project stakeholders it is anticipated that production analysis will be performed on the wells to determine what relationship exists between the created fracture geometry and the production rate.

Key Contact: Roger Willis, Universal Well Services (614-537-1903 ext.224 or rwillis@univwell.com)

Pinnacle has deployed its fracture mapping widely across the western oil and gas producing basins but not yet in the Appalachian Basin.
Development of an Accurate, Low-Cost, Portable Production Well Tester

**Problem:** Producers must make operating decisions regarding high-water cut stripper wells without accurate information on the relative amounts of oil and water being produced over time. Acquiring such data requires equipment that is either unavailable at most stripper well locations or is very expensive to purchase or rent. As a result, stripper well operators must choose the lowest cost option and settle for poor accuracy, or forgo testing. In the end, their well’s production is not optimized and oil and gas reserves are lost.

**Proposed Solution:** Design, construct, and demonstrate a portable electronic production well tester capable of providing accurate individual well test data at a reasonable cost.

**Background and Results-to-Date:** Many stripper wells produce significantly more water than oil. Secondary oil recovery methods (usually waterflooding) involve the production and handling of large volumes of water, small volumes of oil, and, sometimes, natural gas. Also, many mature fields produce large amounts of water with smaller amounts of oil and gas under primary production. Accurate testing of high-water cut wells is important to determining reserves and the economics of the additional investments needed to improve oil and gas production and/or reduce water production. Production testing is normally done using permanent, centralized separation and metering stations or portable testers, either of which can employ expensive electronic testing equipment. Centralized systems require that extra lines be installed and maintained. The cost of installing these lines or even simply maintaining them for stripper wells can be prohibitively expensive. Portable systems allow testing at individual wells on an as-needed basis, but current low cost, portable testers (which cost on the order of $10,000) are not accurate due to sampling frequency and gas interference problems. High cost portable units (which can range from $50,000 to $100,000) are out of the economic reach of most independent operators. In addition, many stripper wells do not have electric power available to operate these testers at the well site.

This research project will develop a portable tester for high water cut wells, demonstrate it in the field, and compare it’s performance to that of current testers. The testing parameters for the prototype are: total liquid rates of 100 to 1,000 BPD, water cuts of 0 to 100 percent, gas rates of 0 to 25 MCFPD, and oil gravities of 20 to 40 degrees API.

During 2004, the investigators researched and evaluated a wide range of possible testing configurations and equipment options and selected a configuration for a portable electronic tester that is both accurate and has the potential of meeting the capital cost target ($20,000 to $25,000 range) in a second generation unit. A prototype is currently being constructed and will be used to carry out a number of field tests during 2005.

**Ongoing Activity and Future Plans:** The unit will be tested in 30 to 60 southern Oklahoma wells, including Oak Resources wells during 2005. The results will be compared to those obtained from commercially available, low-cost portable well testing equipment and the researchers will evaluate the outcomes and report the findings. The final report will identify the best measurement methods and the key components necessary to construct a second-generation portable tester within the target capital cost range. Eventually, the design can be extended to very low liquid rates and gas wells.

**Key Contact:** Kenneth D. Oglesby, President, Oak Resources, Inc., Tulsa, OK. (918-627-0012 or oakl@aol.com)

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Training the Next Generation of Oil and Gas Technologists

An important auxiliary benefit of the Stripper Well Consortium research program is the opportunity it presents for petroleum and natural gas engineering students at U.S. universities to participate in efforts to develop new technology. According to data collected by the Society of Petroleum Engineers, there are currently only 17 U.S. universities offering accredited degrees in petroleum engineering. In 1982, petroleum engineering curricula were offered in at least 100 schools. Over the same time period, the number of students studying to become petroleum engineers at U.S. schools has dropped from more than 11,000 to less than 1900. If the surviving academic programs are to remain capable of supplying the next generation of engineers, they will require a critical mass of high quality professors, supported in part by research funding. Unfortunately, the level of domestic research spending by the oil and gas industry has dropped significantly over the past decade. In 2002, major E&P companies invested an amount in oil and gas R&D that amounted to only 0.73 percent of their total exploration and development expenditures, a significant drop from the nearly 2 percent spent in 1995, and even that was significantly less than the level of a decade before.

SWC projects have been funded at four academic institutions that offer degrees in petroleum engineering: Penn State, The Colorado School of Mines (CSM), Texas A&M University, and Texas Tech University. In each of these cases, students participate in the research as part of their undergraduate or graduate training. For example, Femi Awolusi, a masters student in petroleum engineering at Texas Tech University is part of an SWC project looking at a new method for resolving discrepancies in the correlations used for predicting critical rate flow in low-pressure, low-rate stripper gas wells. Femi is using a 30-foot glass tubing model to develop a predictive technique that will improve operators’ ability to accurately determine the conditions under which liquid build up occurs in the wellbores of stripper wells.

At Texas A&M University, Professor David Burmert is involving his students in an SWC project designed to desalinate water produced from oil and gas operations or from natural brackish sources. Building on original information developed under the project, a joint venture has been created to design and operate a pilot project for brackish groundwater desalination. The resulting fresh water can be put to beneficial use while concentrated byproducts will be used to augment injection into an existing oil field waterflood near Andrews, Texas.

At CSM Professor Richard Christiansen supervises a project funded by SWC on removal of liquids from stripper gas wells. Two grad students and three undergrad students are supported by this project. CSM is also involved in delivering industry short courses on liquid lifting that use the university’s 40-foot flow loop facility to visually demonstrate accumulation of liquids in tubulars, conditions at the critical flow rate, plunger lift performance, and flow of gas and liquid between concentric pipes.

At The Penn State, undergraduate Brad Davis is a Petroleum and Natural Gas Engineering student working on a SWC research project. He presented his work at the 2005 Rocky Mountain/Mid Continent SPE Student Paper Contest. The 2004 contest was won by PSU student Drew Domalakes, also a SWC research project participant.

Just as the SWC helps to maintain our Nation’s capacity to produce oil and gas by partnering with industry to develop new technologies, by funding projects at U.S. universities with petroleum engineering faculty it also helps to maintain our domestic capacity to produce the technologists that will be needed for that industry.

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Getting the Message Out: Keeping Stripper Wells On Production

The Stripper Well Consortium is currently producing an educational documentary video designed to educate the general public about what the marginal oil and gas industry is and why it’s becoming even more important to the nation. The 27-minute program will be aired over the Penn State Public Broadcasting network and will be distributed to other public television stations around the nation. The program will center on the voices of actual people within the marginal well industry throughout the country. It will tell the story that stripper well operators are educated, savvy, environmentally responsible entrepreneurs who are important contributors to rural economies across the nation. It will help Americans realize that marginal oil and gas wells stand as a testament to ingenuity, frugality and resource conservation. A DVD version of the program will include a bonus segment highlighting several technology transfer topics funded by the Consortium, which will be distributed to members of the stripper well industry.

The Oklahoma Marginal Well Commission in Oklahoma City has produced an excellent, 11-minute video that describes the important role of independent operators in Oklahoma’s economy and the challenges they face in keeping marginal wells on production. “Marginal Wells: Too Important to Lose” includes insights from Liz Fajen, Executive Director of the Oklahoma Marginal Well Commission.

“Every barrel that we produce from a marginal well is one less barrel of oil that we have to import from foreign sources.” — Liz Fajen, Exec. Director of the Oklahoma Marginal Well Commission

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STRIPPER WELL INFORMATION
Stripper Well Consortium (http://www.energy.psu.edu/swc)
Oklahoma Marginal Oil and Gas Well Commission (http://www.marginalwells.com)
Interstate Oil and Gas Compact Commission (http://www.iogcc.oklaosf.state.ok.us)
Oklahoma Energy Resources Board (http://www.oerb.com)

TECHNOLOGY DEVELOPMENT AND TRANSFER
DOE’s National Energy Technology Laboratory (http://www.netl.doe.gov)
Petroleum Technology Transfer Council (http://www.pttc.org)
Rocky Mountain Oilfield Testing Center (http://www.rmiotc.com)

STRIッPER WELL INFORMATION RESOURCES
PRODUCER ASSOCIATIONS
California Independent Petroleum Association (http://www.cipa.org)
Colorado Oil and Gas Association (http://www.coga.org)
Independent Petroleum Association of America (http://www.ipaa.org)
Independent Petroleum Association of Mountain States (http://www.ipams.org)
Independent Oil and Gas Association of New York (http://www.iony.org)
Independent Oil and Gas Association of Pennsylvania (http://www.iogapa.com)
Independent Oil and Gas Association of West Virginia (http://www.iogawv.com)
Kansas Independent Oil and Gas Association (http://www.kioga.org)
Louisiana Independent Oil and Gas Association (http://www.lioga.com)
Louisiana Mid-continent Oil and Gas Association (http://www.lmoga.com)
Michigan Oil and Gas Association (http://www.michiganoilandgasassociation.org)
New Mexico Oil and Gas Association (http://www.nmogaa.org)
Oklahoma Independent Producers Association (http://www.oipa.com)
Tennessee Oil and Gas Association (http://www.tennoil.com)
Texas Independent Producers and Royalty Owners Association (http://www.tipro.org)

STRIPPER WELL INFORMATION RESOURCES
Oklahoma Energy Resources Board (http://www.oerb.com)
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Rocky Mountain Oilfield Testing Center (http://www.rmiotc.com)
### Past and Present SWC Membership

- ABARTA Oil & Gas Co.
- Advanced Resources International
- Airlift Services International
- American Hydroslotter Corp.
- Anadarko Petroleum Corp.
- Appalachian Well Services
- Aurora Energy
- Belden & Blake Corp.
- Benson-Montin-Greer Drilling Corp.
- BJ Services Co.
- BP America
- Brandywine Energy & Development Co.
- Bretagne G.P.
- Burlington Resources
- C-FER Technologies
- Cabot Oil & Gas Corp.
- Cementing Solutions
- Chautauqua Energy
- Chem Tech Holdings
- Colorado School of Mines
- Columbia Natural Resources
- Composite Engineers
- Duquesne University Chrysler Corp. (SBDC)
- East Resources
- Energy Capital Group
- Energitec
- EOG Resources
eProduction Solutions
- Equitable Production Co.
- Field Management
- Furness Newburge
- Gasduct Technology
- Geo-Microbial Tech./LATA Group
- Great Lakes Energy Partners
- Hart Resource Technologies
- Hominy Creek Energy Co.
- I.L. Geer & Sons
- IMPACT Technologies
- Independent Oil & Gas Assoc. of NY
- Independent Oil & Gas Assoc. of PA
- Innovative Discovery Technologies
- Isotope Logging
- James Engineering
- Jetta Operating Co.
- Lenape Resources
- Linn Operating
- Louisiana State University
- Maness Petroleum Corp.
- Marathon Oil Co.
- Marlo Operating Co.
- Markwest Hydrocarbon
- Maurer Engineering
- Minard Run Oil Co.
- Moody and Associates
- Murfin Drilling Co.
- Natural Oil and Gas Corp.
- NY State Dept. of Environmental Conservation
- North Penn Pipe & Supply
- NYSEG
- Oak Resources
- Oklahoma Commission on Marginally Producing Oil & Gas Wells
- PAAL
- PDVSA Intevep
- Penneco Oil Co.
- Pennsylvania General Energy Co.
- Pennsylvania Oil & Gas Assoc.
- Petrolects
- Petroleum Technology Transfer Council
- Phillips Production Co.
- Pumping Solutions
- Quicksilver Resources
- RealtimeZone
- Republic Energy
- RMOTC. (Rocky Mountain Oilfield Testing Center)
- Running Foxes Petroleum
- S.W. Jack Drilling Co.
- Schlumberger Holditch
- Reservoir Technologies
- Seneca Resources Corp.
- Service Cleaning Corp.
- Snyder Brothers
- Surteck
- T&G Technologies
- TechSavants
- Tennessee Oil & Gas Assoc.
- Texas A&M University
- Texas Railroad Commission
- Texas Tech University
- The Pennsylvania State University
- The Research Factory
- Tubel Technologies Inc.
- United States Gypsum Co.
- Universal Well Services
- University of Kansas
- Vaderzaad Holdings
- Vess Oil Corp.
- Vortex Flow
- W.T. Chatham Associates
- W&W Vacuum & Compressors
- West Virginia Geologic & Economic Survey
- West Virginia University