RESEARCH PARTNERSHIP TO SECURE ENERGY FOR AMERICA (RPSEA)
SMALL PRODUCER PROGRAM
RFP2007SP001

ENHANCING OIL RECOVERY FROM MATURE RESERVOIRS USING RADIALLY JETTED LATERALS AND HIGH-VOLUME PROGRESSIVE CAVITY PUMPS

(OLD TITLE)

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PUBLIC EXECUTIVE SUMMARY

High water-cut oil production in the U.S. is a severe problem that impacts many small oil producers limiting their ability to significantly increase oil production. Many of these strong-water drive fields typically do not achieve optimal recovery leaving considerable oil behind. New cost-effective, energy efficient technologies will be applied in Hillsboro Field, Marion County Kansas by the Kansas Geological Survey (KGS) and the American Energies Corporation (AEC) to address this significant problem. Radial-jetted laterals will be used to increase the drainage area and enhance oil production from a Viola production well pumped by an efficient high-volume progressive cavity pump, which will move higher fluid volumes at no incremental costs. Increased volumes of produced water will be economically disposed by a deepened Arbuckle injection well whose injectivity will be enhanced by targeted jetted laterals. Successful demonstration

of this production-injection pair will be followed by application of this methodology to multiple producing wells in (nearby) Durham Center Field. This study will be the first publicly available scientific evaluation of the use of radial jetted laterals in both production and injector wells. An intense technology transfer effort focused on the small producer will convey project results.

A. TECHNICAL MERIT AND VALUE TO PROGRAM

A.1 Proposed Technology/Methodology

A.1.1 Statement and Significance of the Problem

High water-cut oil production in the U.S. is a severe problem that impacts many small oil producers limiting their ability to significantly increase oil production in spite of opportunities afforded by higher oil prices. Over 400,000 marginal wells (<10 BOPD, 2 BOPD on average) contribute 18% of the oil and 9% of the natural gas in the U.S. Each year over 10,000 of these well are plugged (IOGCC, Marginal Wells: Fuel for Economic Growth, 2007 Report). Kansas is only 2nd to Texas in numbers of marginal wells (54,200), 4th in annual production (27 million bbls, averaging 1.4 BOPD), and 3rd in wells annually plugged and abandoned (1081). Many older, water-driven fields typically have recoveries in excess of 97% water cut, resulting in high costs for production and disposal of water. Many of these strong-water drive fields typically do not achieve optimal recovery with recoveries often around 20-30 percent OOIP (as experienced by the current industry partner), but this indicates that additional oil perhaps can be recovered using new technologies such as the radial-jetted laterals and efficient, high volume progressive cavity pumps as proposed in this study.

Problems with disposal of large volumes of produced water often thwarts attempts to substantially increase fluid recovery. The Arbuckle Group and its equivalent, the Ellenberger Formation, underlies vast areas of oil production in the central U.S. and is capable of disposing of large amounts of water locally, but injectivity is highly variable and often limited. Shallow, open-hole completions for conventional water disposal have highly variable injectivities.

Current practice of using gelled polymers to increase oil production in high-water-cut wells while reducing water production has seen mixed results in Kansas (project conducted by Tertiary Oil Recovery project (TORP), Summary of Treatments -- http://www.nmcpttc.org/gel/summary.html). Moreover, results show that application of gelled polymers risk reducing or plugging the fluid flow at the time of treatment or later if bacteria are introduced and thrive, and are not long-lived solutions. This occurred at Hillsboro Field, in Marion County, Kansas, the site of the proposed study (**Figure 1**). Thus, alternative well recompletion technique is thus needed to increase oil production from economically marginal high-water-cut fields with significant volumes of known remaining reserves.

Our proposed experimental technique is simple and mechanical, thus less risky than polymer injection. The Kansas Geological Survey (KGS) and the American Energies Corporation (AEC) propose to significantly increase the drainage area of the producing well at Hillsboro by placing two 300-foot-long laterals using low-cost radial jet enhancement. The placement of these radial-jetted laterals will be determined from detailed mapping and simulation studies of the Viola Formation pay zone. Following the successful placement of the laterals, we propose to pump as much fluid as the producing well can deliver.

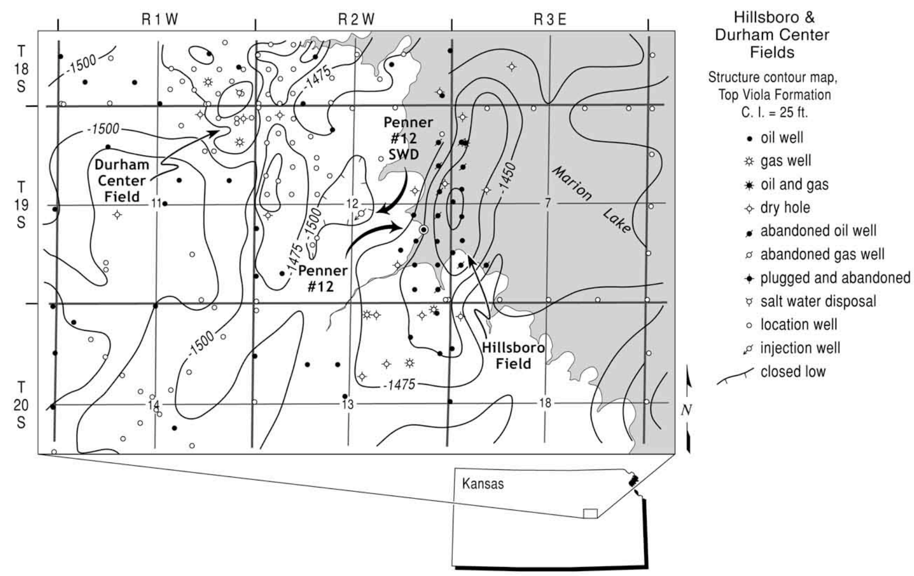

***Figure 1**. Structural contour map on top of the Viola Formation for the Hillsboro and Durham Fields, with locating the Penner #12 productions Penner #12 SWD injection wells, Hillsboro and Durham Center fields, in perspective of Marion Lake.*

Increased oil and water production makes business sense only when the operator can dispose of the additional water at no incremental costs. The second part of our proposal thus deals with placing four targeted 300-ft laterals in a nearby deepened Arbuckle injection well to significantly enhance injection capacity. The radial jetted lateral technique though new has been applied elsewhere with different degrees of success. However, no scientific evaluation of this technique is available in public literature. Thus, another important aspect of this proposal is to conduct a series of tests, characterization, and simulation studies around the injection and production wells before and after their recompletions in order to quantify the effectiveness of using the radial jetted lateral technique to enhance productivity and injectivity.

The industry partner, American Energies Corporation (AEC), plans to similarly recomplete additional producing wells in the Durham Center Field, if results are successful at Hillsboro Field. As regards to lifting costs of added volumes of water, we propose to make use of progressive cavity pumps whose energy consumption is largely independent of handled water volume. The goal of the production-injection well pair will be to increase oil production from a current 10 BOPD with 97% water cut to 40 BOPD by significantly increasing water production from 400 to around 4,000 BPD. This project, in addition to achieving incremental oil production, intends to demonstrate that injectivity enhancement of select Arbuckle intervals will enable disposal of excess produced water at no additional costs. It is estimated that the capacity of the disposal well in the Arbuckle Group will be around 10,000 barrels per day, which will enable it to accommodate produced water from the Hillsboro producing well and eventually, producing wells in the nearby Durham Center Field.

Our proposed method will leave a small environmental footprint because enhanced drainage and injection capacities of both the producing and injection wells will help produce incremental oil and dispose of large water volumes without drilling additional wells. Produced water will be transported to the injection well by low pressure pipelines, so that adverse effects of leaks and costs and risks related to trucking produced water are minimized. Unlike conventional pump jacks, the progressive cavity pump consumes less energy. Its lower surface profile essentially conceals it in the native prairie grasses.

A.1.2 Background and Existing Technologies/Methodologies

The targeted high water-cut production well, the Penner #12, was drilled in 1984 and has produced over 78,000 bbls of oil from the 74-year-old Hillsboro field. Multiple pump changes at this well have always resulted in increases in oil production along with higher volumes of produced water (production plot available at http://abyss.kgs.ku.edu/pls/abyss/oil.ogl5.MainLease?f_lc=1001135335).

Neighboring wells to east and updip of the Penner #12 well have been plugged and are under water of the Marion Lake, a man-made reservoir flooded this area in the early built in the 60's (**Figure 1**). Thus, the majority of the wells in Hillsboro Field were prematurely abandoned and significant oil may remain in structurally higher positions in the field (**Figure 1**). The increased drainage area and higher drawdown caused by the laterals and progressive cavity pump are anticipated to access this remaining oil.

To cost-effectively dispose high volumes of produced water pending interpretation of core, logs, transient tests, and simulation results, four targeted 300-foot laterals are proposal to be drilled in a deepened Arbuckle disposal well, the Penner #12 SWD. The enhanced injectivity created by these laterals should enable this well to handle water production from the Penner #12 and eventually other planned recompleted producing wells in Durham Center field (**Figure 1**). The anticipated injectivity of 10,000 BWPD is feasible as deep industrial waste disposal wells in the Arbuckle have had rates in excess of 15,000 BFPD (Tom Hanson, personal communication.)

Prevalent technology – The prevailing technology in the Midcontinent for prolonging oil production from high water-cut marginal wells is by polymer injection. A state wide survey of effectiveness of polymer injection to reduce water cut was carried out by the TORP at KU indicates that it is difficult to determine what caused polymer jobs to fail or succeed with equal risk for success or failure. It appears that a prescription for successful polymer treatment has eluded Kansas operators. Secondly, effects of successful polymer treatment are short lived and vary from field to field. The operator requires multiple repeat treatments to control water cut over the life of the well. Thirdly, impurities such as bacteria in the carrier polymer fluid can result in uncontrolled biological growth in the formation with bacteria using the injected polymer as food. Such biological infestation in the reservoir needs to be controlled so that fouling of downstream equipment can be prevented and reservoir permeability can be maintained. A common treatment to kill the biological growth includes the use of bleach, but this unlinks the polymers and thus negates its advantages. The previous owner of Hillsboro Field had a negative experience with uncontrolled biological growth in the formation which resulted in extensive fouling of upstream production lines. AEC is therefore averse to risking the well with polymer treatment again.

A.1.3 Relationship to the Program Goals/Objectives

Mature water-drive oil fields offer the potential to recover significant additional oil through the combined used of targeted radial-jetted laterals, using water under high pressure, and cost-effective disposal of high volumes of produced water. Marked increase in pressure drawdown, evaluated through transient testing and simulation, should contact new oil that was stranded due to prior low-volume pumping. Oil bypassed due to high water cut in a strong aquifer driven reservoir, oil residing in lower permeable zones, and attic oil could potentially be contacted and mobilized in Hillsboro Field. Any near wellbore damage would also be circumvented by recompletion with the 300-ft laterals. Successful demonstration of this project could encourage rejuvenation of similar aquifer driven, high-water-cut mature fields in the U.S.

The approach integrally involves reservoir characterization and simulation, transient well testing interpreted using state-of-the-art computer-aided derivative curve analysis, recompletion of production and injection wells to increase oil production, and optimal disposal of produced water. Results, best practices, and clearly developed workflows will be conveyed through technology transfer to small producers so that they can also implement these procedures.

Optimizing and significantly increasing the injectivity of the disposal wells through targeted completions, usually not standard practice for small companies, will be demonstrated as a means to cost-effectively remove large water volumes. Optimizing injectivity will be addressed through coring (deepening), transient testing, simulation, and recompletion of an existing shallow, open-hole Arbuckle disposal well using radial-jetted laterals.

AEC is actively committed to employ this technique in many other fields it operates to further leverage this initial investment made by it and RPSEA. AEC is also active in reviving old abandoned production, including 25 leases in Marion and McPherson Counties, Kansas, that meets their model for re-working. All of the leases have a strong water drive and AEC is basing economics on 5% additional recovery, which constitutes 775,000 barrels of oil. The key to making this re-working successful is to efficiently dispose of the produced water. AEC is also considering the use the lateral jet enhancement to maximize injectivity in a water disposal well in the Ellenberger Formation that it plans to drill near Ft. Worth, Texas – a prime Barnett Shale gas producing area where water disposal is a significant problem.

The primary objective of this proposed project is to demonstrate that cost-effective recompletions at both producing and injection wells will both increase drainage volume at the producing well and significantly increase injection capacity of the injection well. The recompletions will be facilitated by commercially available radial-jet technology followed by use of cost effective, high-volume progressive cavity pump, a surface, motor-driven pump that uses rotation of shaped rods in tubing to pull fluid to the surface. Multi-faceted technology transfer will include clear documentation of best practices through workshops and fieldtrips, and publication in technical and trade journals so that other small producers can apply this technique in similar high-water-cut fields. AEC has actively participated in the oil and gas community at the local, regional, and national scale and thus the message from this project should be well received by industry. Finally, the technology proposed is financially within the reach of small producers.

A.2 Industry Participation and Support

A.2.1 Description of Industry Participation

AEC is a successful small producer out of Wichita, Kansas, who has operated in the state for 26 years. Their current production averages 730 BOE per day. AEC and the KGS have participated in two successful DOE-funded field demonstration studies in the past. AEC is a progressive minded small company that is ready to try out new techniques and methodologies. AEC owns the acreage around the producer and injector wells in Hillsboro Field and producing wells in nearby Durham Center field, and so no problems related to lease ownership or land acquisition is expected. The financial success of AEC is rooted in its effective management and capable technical staff.

As a competent and experienced field operator, AEC will be in charge of day-to-day field operations during the recompletion of the production and injection pair in Hillsboro Field. They will also supervise the construction of the low-pressure pipeline between the two wells and install, operate, and maintain the progressive cavity pump. The KGS will carry out the characterization and simulation studies around these wells and analyze both pre- and post-completion transient tests to quantify increases in productivity and injectivity. The KGS and AEC will together decide on the zones and the trajectories for the radial jetted laterals in the production and injection wells.

Successful demonstration of our proposed project will be measured by a) producing incremental oil within the 1st year of operation, and b) evaluate, design, and assess deployment of this technique on a field-wide scale at the Durham Center Field, which if implemented, would assure that the production increase is maintained beyond the 1st year.

A.2.2 Leverage of Project Funds

Fifty-two percent match on the total budget will be made by the KGS and AEC. RPSEA funds will be leveraged by applying the technology to existing infrastructure at Hillsboro Field. AEC is eager to apply this methodology to increase oil production from its other high-water-cut properties in Kansas and to significantly increase its capacity to dispose produced water from the Barnett Shale gas play in Texas.

A.2.3 Source and Nature of Proposed Cost share

Financial support by RPSEA will enable AEC and the KGS to conduct multiple transient tests, characterize and simulate well performances, and stagger the radial enhancements so that with each succeeding attempt, lessons will be applied from the prior attempts. The support will enable coring the Arbuckle and to identify high-volume disposal zones by their log signature, and use this data in characterization and simulation studies to select the trajectory of the laterals for the producer and injector wells. A small producer like the AEC does not normally carry out such detailed studies in their routine operations because of added costs, and neither has the vendor carrying out the radial jet enhancement conducted and/or published scientific studies regarding effectiveness of the treatment process. AEC's cost share is tied directly to well recompletions at Hillsboro Field and does not include personnel time and costs of equipment, data, and facilities. With RPSEA's support though, these detailed studies are possible and will greatly aid in understanding how best to apply the radial jet laterals and efficient, high-volume progressive cavity pump to increase oil production from high-water cut fields. Our step-by-step and calibrated project execution should reduce risks associated with wider application of this technology.

A.3 Expected Impacts and Benefits

A3.1 Impact on Reserves and Production

Broad application of the proposed methodology by small independents in similar high-water-cut fields in the central U.S. could substantially increase ultimate recovery in these fields, extend their economic life and stimulate local economies, and enable small producers to contribute to the energy security of the U.S. The RPSEA funds will strategically employ, evaluate, and demonstrate an innovative application of a commercially available technique that might aid in significantly reducing well plugging and abandonment in similar fields in the central U.S.

At Hillsboro Field – the AEC currently produces 10 BOPD. It is expected that this production can be increased to around 40 BOPD with targeted radial jetted laterals. This translates to incremental production of 10,950 bbls per year. A similar three to four fold increase in production, if achieved at the Durham Center field (with 6 wells), will result in significant incremental production. Dedicated technology transfer by the KGS will help convey lessons learned and the best practices to the community of small operators thus fostering application of the proposed technique over a wider area.

A.3.2 Environmental Impact

Water disposal will be handled in a cost effective, energy efficient manner while minimizing environmental impact using low-profile surface equipment (i.e., no pump jack), decreasing the footprint of the surface facilities, and utilizing low-pressure water pipes to minimize any water loss and environmental damage should a leak occur. The eastern side of Hillsboro field is located under Marion Lake, a public recreation area (**Figure 1**). Thus, replacing the current pump jack with a progressive cavity pump that is obscured in native prairie grass at the site will provide minimal impact on the natural setting and enhance both the aesthetics and the recreational use for the public.

Progressive cavity pumps use less energy to move much larger volumes of water than pump jacks. Remaining reserves can be accessed by fewer wells, particularly if these wells have their drainage enhanced by radial-jetted laterals. Fewer disposal wells will also reduce the environmental footprint of the energy production. Moreover, locating high-volume injection wells near the producing wells helps lower energy costs, pollution, and reduce traffic problems and transportation problems associated with trucks hauling large volumes of produced water over distance.

This project targets increasing oil production from existing fields and infrastructure and thus will not result in expending energy to build new infrastructure in order to increase the nation's domestic production – as is the case when new fields are brought on line. The proposed methodology is low cost and thus within the resource reach of small producers. A wide application of this methodology will lead to significant increases in oil production in an environmentally safe manner.

A.3.3 Applicability

The use of the demonstrated technology could have a huge impact in increasing oil production in high-water cut fields and reservoirs, many of which are on the verge of shut down or are already plugged.

High water producing fields in central Kansas comprise nearly 60% of Kansas' oil production from zones including the Arbuckle, Viola, and Mississippian (lower

Paleozoic) carbonates (subject of numerous KGS publications). The methodology of this project would be especially applicable over the entire midcontinent where disposal zones such as the Arbuckle and the equivalent Ellenburger are present.

As a part of this project the Arbuckle core taken from the injector well, Penner #12 SWD, in Hillsboro Field will be studied to identify deeper zones not typically penetrated by local operators. We will establish log signatures and rock properties of these zones so that small producers in other areas can efficiently identify these zones from logs and use them as targeted high volume disposal zones.

A.3.4 Risks

The proposed project has low risk – the radial jet enhancement technique has been used in different fields and wells in the past to different degrees of success. In our proposed project, we will employ this technique in a calibrated manner in order to better understand its effectiveness for wider application. We are using a combination of radial jet enhancement and progressive cavity pump to significantly increase the fluid production from the producing well. A commensurate increase in water production is anticipated with this increase in oil production. We intend to demonstrate that the same or less energy will be required to dispose of the greater volumes of produced water into an injection well recompleted with radial jet enhancement at no incremental costs.

The use of existing infrastructure to more efficiently produce remaining resource further reduces risk associated with this project. One of the principal factors for economic success of horizontal wells (laterals) is the presence of pressure support in the reservoir. Both Hillsboro and Durham Center fields have pressure supplied by a strong water drive and are ideal candidates for enhanced recovery using horizontal laterals.

AEC owns and operates the acreage where the Penner #12 and Penner #12 SWD are located, No ownership conflicts are therefore anticipated during the implementation of the project. AEC also fully owns and operates the Durham Center Field, for which similar applications are anticipated.

B. TECHNICAL APPROACH

B.1 Detailed Work Plan (Statement of Work)

B.1.1. Objectives

Hillsboro Field, 552,000 bbls cumulative oil recovered, in Marion County in central Kansas was discovered in 1928, and once had 33 production wells. Only two wells remain producing from the Middle Ordovician Viola Formation. The project objective is to significantly increase oil recovery from a producing well by increasing fluid volumes pumped out of the well and disposal of the incremental produced water at no additional cost. The drainage and injectivity of producing and injection wells will be significantly enhanced by a commercially available technology – radial-jetted laterals, while a high-capacity, high-efficiency progressive cavity pump will be used to move as much fluid as the producing well can deliver. Recompletion will be evaluated and modeled using transient well testing and computer-based derivative curve analysis, coring, and wireline log analysis, and reservoir simulation. Such detailed testing will help understand controls that lead to successful and wide application of the radial-jetted lateral technique. Results will be conveyed on website, field trips, workshops, and publications.

With successful well recompletions at Hillsboro Field, the Viola reservoir at Durham Center Field (located 4 miles northwest of Hillsboro) will be characterized to assess the feasibility of multi-well recompletions using radial jetted laterals and progressive cavity pumping. Feasibility of using the Arbuckle disposal well at Hillsboro Field to inject produced water from Durham Center field will be studied. Durham Center Field, with 258,000 bbls cumulative production, has 6 remaining producing wells with high water cut located on its structural crest. Characterization and simulation studies carried out in this project would establish the optimum completion and production strategy for the producing wells. Strong natural water drive coupled with increased drawdown is expected to mobilize high fluid volumes from these wells thus boosting the oil production and thereby extending the life of this field.

B.1.2. Scope of Work

The goal is to extend the pressure decline around the producing well in Hillsboro field so as to move oil stranded around updip wells prematurely plugged in the 1950's and 60's when an artificial surface lake was constructed. The high water-cut oil well, Penner #12, producing from the Viola Formation near the eastern edge of the Hillsboro Field will undergo pre- and post-treatment build-up tests after recompleting using radial-jetted laterals. A high volume progressive cavity pump will be used to increase fluid production from this well. As a result of recompletion and installation of this pump, oil production is estimated to increase from 10 BOPD to about 40 BOPD while resulting in an increase in produced water volumes. The 30-hp progressive cavity pump is expected to reduce power consumption because it will replace a 50 hp pump jack. An neighboring

Arbuckle injector well, Penner #12 SWD, will be deepened and cored, and then recompleted with radial-jetted laterals to increase water injection to rates around 10,000 BPD.

Recompletions will include two ~300-foot long laterals in the producing well and four laterals in the injection well. Initial reservoir characterization, build-up testing of the production well, and fall-off testing of the injector wells before and after radial jetted laterals will evaluate the characteristics of the laterals and resultant performance enhancement. Transient tests will be analyzed and modeled using computer-based derivative well test analysis (Fekete F.A.S.T.™ software WellTest) to establish reservoir flow parameters such as effective permeability and to estimate the length of the laterals and its effects in extending drainage and injection capacity. Production history from the producer and transient test data will be simulated using state-of-the art PC-based CMG *IMEX* reservoir flow modeling software to better characterize the reservoir. Core, wireline logs, pre- and post-treatment fall-off pressure tests at the injection well will be used along with simulation studies to evaluate effectiveness of radial-jetted laterals in increasing injectivity of select Arbuckle layers in Hillsboro Field. High permeability layer(s) capable of receiving water from multiple producing wells (in excess of 10,000 BWPD) will be identified and tagged to wireline log signatures and targeted for recompletion.

Wellhead facilities would also be substantially reduced in size and height, placing them out of view, which is important in the neighborhood of a recreation area. Water disposal lines and facilities would also be designed to reduce surface pressures from the current 120 psi to around 20 psi, substantially reducing risks associated with any leaks.

After the Hillsboro project is tested and implemented, recompletion of multiple production wells at Durham Center Field will be evaluated.

B.1.3. Tasks to be Performed

Task 1.0 -- Project Management Plan

Subtask 1.l. Prepare and submit Management Plan within 30 days of award

The Awardee shall develop a Project Management Plan consisting of a work breakdown structure and supporting narrative that concisely addresses the overall project as set forth in the agreement. The Awardee shall provide a concise summary of the objectives and approach for each Task and, where appropriate, for each subtask. The Awardee shall provide schedules and planned expenditures for each Task including any necessary charts and tables, and all major milestones and decision points. The Awardee shall identify key milestones that need to be met prior to proceeding to the next phase. This report is to be submitted within 30 days of the Award. The RPSEA Contracts/Procurement Manager shall have 20 calendar days from receipt of the Project Management Plan to review and provide comments to the Awardee. Within 15 calendar days after receipt of the RPSEA's comments, the Awardee shall submit a final Project Management Plan to the RPSEA Contracts/Procurement Manager for review and approval.

Task 2.0 --Technology Status Assessment

Subtask 2.1. Perform technology status assessment and submit report within 30 days of award

The Awardee shall perform a Technology Status Assessment and submit a summary report describing the state-of-the-art of the proposed technology. The report will include both positive and negative aspects of each existing technology, and will be no more than five typewritten pages in length. The report will not to contain any proprietary or confidential data, as it will be posted on the RPSEA website for public viewing. The report will be submitted within 30 days of the Award.

Task 3.0 --Technology Transfer

Subtask 3.1. Develop and implement an effective Technology Transfer Program with RPSEA

The Awardee shall designate 2.5% of the amount of the award for funding technology transfer activities. Throughout the project, the Awardee shall work with RPSEA to develop and implement an effective Technology Transfer Program at both the project and program level.

Subtask 3.2. Develop and maintain website to carry pertinent information about the project

The Kansas Geological Survey's Internet website, www.kgs.ku.edu, serves as a major source of petroleum information for Kansas with over 800,000 hits per month. Information on task progress and completion, notes from workshops, and presentations will be placed on a dedicated project website.

Subtask 3.3. Conduct workshop, field tours, and present talks to local professional societies

Talks, workshop and field tour will be arranged through the Wichita Chapter of the Society of Petroleum Engineers (SPE), Kansas Geological Society, Kansas and Eastern Kansas Independent Oil and Gas Associations, and PTTC and coordinated with RPSEA. Announcements will be distributed to their members and shared with professional societies in surrounding states with links provided to the project website. Information and feedback obtained from meetings will be shared on the project website.

Subtask 3.4. Prepare publications including journals and professional society meetings

Abstracts will be submitted at and near completion of the project to the Annual Meeting of American Association of Petroleum Geologists (AAPG) and Annual Symposium on Improved Oil Recovery sponsored by SPE in Tulsa each April. Manuscripts will be submitted for peer review and publication in the AAPG Bulletin and Oil and Gas Journal.

Task 4.0 – Evaluate potential of Viola Production well

Subtask 4.1 Gather data - Producing well & Viola reservoir

Obtain well logs, geo reports, production and DST data, and sample cuttings from the Penner #12 and nearby wells. Compile well completion and production history for same wells.

Subtask 4.2 Pre-treatment buildup and production test at Production well

Run extended buildup test on Penner #12 production well prior to cutting lateral and acidization. Utilize a downhole digital pressure transducer to provide detailed pressure history of the test. Estimate reservoir permeability, skin factor, and drainage using computer-assisted derivative analysis of the test results available from Fekete F.A.S.T.™ software WellTest. Install pump and run production test.

Subtask 4.3. Develop geomodel of Viola reservoir around Producing well

Analyze wireline logs using the spreadsheet-based PfEFFER software (DE-AC22-94PC91008). Integrate well logs, samples, production history to build a geomodel calibrated with permeability estimates from pre-treatment buildup test in the Penner #12. Validate geomodel by history matching production and transient test data through simulation using CMG's IMEX simulator. Map reservoir properties in Hillsboro field using GeoPLUS PETRA™ software.

Subtask 4.4. Simulate post-treatment recovery from Producing well

Conduct reservoir simulation studies to determine draw down necessary to maximize oil recovery and to estimate increases in produced water at Penner #12. Simulate variations in response to different completion configurations in order to select the optimum trajectories for the two, 300-ft jetted laterals. Perform simulations using Computer Modeling Group (CMG) *IMEX* reservoir flow modeling software.

Task 5.0. Evaluate Injectivity of the Arbuckle Disposal Well

Subtask 5.1. Deepen Arbuckle disposal well, and acquire core and wireline logs

The Arbuckle Group stratigraphy is complexly layered and laterally variable due to structure, internal unconformities, and surface karst. A 100-ft core and associate wireline logs will acquired in the Penner #12 SWD well to provide a clear view of the anticipated stratigraphic succession and injection zone. Propose that core would be taken in lower Arbuckle (250 ft+) or first large drilling break. The upper half of the Arbuckle in the area is the Jefferson City-Cotter Dolomite, which is customarily the injection zone utililized in conventional shallow and open-hole completions in this area. Other more effective disposal zones lie beneath including Roubidoux Dolomite, Gunter Sandstone Member, Bonneterre and Eminence Dolomites, and the basal Lamotte Sandstone (Franseen et al., http://www.kgs.ku.edu/Current/2004/). Wireline logs that will be recorded and analyzed include resistivity, neutron, density, sonic and photoelectric curves to characterize lithologies and porosity types.

Subtask 5.2. Analyze core and wireline logs.

Analyze wireline logs using the spreadsheet-based PfEFFER software. Derive porosity, permeability, and grain density from standard core analyses at one sample per foot and use information to calibrate wireline logs. Slab core and acquire thin sections to verify stratigraphy and aid in lithofacies identification. Identify high injectivity zones in Arbuckle and calibrate their respective log signatures

Subtask 5.3. Pre-treatment falloff test at Injection well - estimate injectivity potential

Conduct falloff test in newly deepened Penner #12 SWD to estimate injectivity potential of targeted zone. Install a downhole digital pressure transducer to provide detailed digital pressure history. Estimate injectivity potential using computer-assisted derivative analysis of the falloff test using Fekete F.A.S.T.™ software WellTest.

Subtask 5.4. Develop geomodel of Arbuckle reservoir around Injection well

Integrate results from Subtasks 5.2 and 5.3 with other well information in local area on the Arbuckle injection zone to develop a local geomodel. Map the geomodel parameters using GeoPLUS PETRA™ mapping software. Profile permeability variation to select target zone(s) for placement of radially jetted laterals to maximize injection capacity.

Subtask 5.5. Select best zones for injection

Target zone for radial-jetted laterals that has most continuous highest permeable (maximum k-h) profile and greatest potential for lateral continuity in the Penner #12 SWD.

Subtask 5.6. Determine optimum completion to maximize injectivity by simulation

Select optimal trajectories for four laterals at injection well to maximize injection volumes.

Task 6.0. Deploy and Evaluate Radial-Jetted Laterals in Injection and Producing Wells

Subtask 6.1. Drill first 300-foot lateral at Injection well using Radial Jet Enhancement

Drill first targeted lateral to test the effectiveness of using radial jet enhancement to increase water disposal capacity of injection well.

Subtask 6.2. Post-treatment falloff test at Injection well and compare with simulation results

Conduct post-treatment falloff test at Penner #12 SWD using computer-based derivative curve analysis software of Fekete F.A.S.T.™, WellTest. Compare with simulation results and update geomodel.

Subtask 6.3. Determine placement of 2nd, 3rd, and 4th laterals in injection well

Select optimal trajectories of three additional laterals at Penner #12 SWD based on simulation.

Subtask 6.4. Drill first 300-foot lateral at Producing well using Radial Jet Enhancement

Drill first lateral in Penner #12 producing well based on simulation results of the (Viola) reservoir to evaluate effectiveness of radial jet enhancement to increase drainage and productivity.

Subtask 6.5. Post-treatment buildup test at Production well and compare with simulation results

Conduct post-treatment buildup test at Penner #12 using computer-based derivative curve analysis software of Fekete F.A.S.T.^{TM}, WellTest. Compare with simulation results and modify geomodel.

Subtask 6.6. Determine placement of 2nd lateral in Production well

Select optimal trajectory of second lateral in Penner #12 based on simulation results.

Subtask 6.7. Drill 2nd, 3rd and 4th 300-feet laterals at Injection well

Drill final laterals in Penner #12 SWD and acidize.

Subtask 6.8. Drill 2nd lateral in Production well

Drill second lateral in Penner #12 and acidize.

Subtask 6.9. Connect Production and Injection wells with low-pressure pipeline

Connect wells with surface production facilities and pipeline.

Subtask 6.10. Install progressive cavity pump and optimize performance

Install progressive cavity pump at Penner #12 producing well, and produce well at optimal drawdown (determined from simulation studies) to maximize incremental oil recovery.

Subtask 6.11. Compare production volumes with simulation results and revise Viola geomodel

Compare oil and water production volumes with simulation results and revise geomodel if necessary. Summarize lessons learned for use in other similar projects in the Viola reservoir.

Subtask 6.12. Compare injection performance with simulation results and revise geomodel

Compare injection performance at Penner #12 SWD with simulation results and revise geomodel if necessary. Summarize lessons learned for use by other projects considering water disposal in the Arbuckle. Estimate maximum injectivity at Penner #12 SWD to dispose produced water from future multi-well recompletion at nearby Durham Center Field wells.

Task 7.0. Evaluate Project Performance

Subtask 7.1. Evaluate project economics –

Compare incremental oil recovery costs with water disposal and analyze rate of return of project.

Subtask 7.2. Develop workflow of technology application

Develop workflow consisting of best practices in 1) evaluation of injection and production wells including transient testing, geomodel development, and simulation, 2) recompletion strategies using radial jetted laterals, and 3) performance optimization of the progressive cavity pump.

Task 8.0. Evaluate Recovery Potential from Durham Center Field as Potential Phase II Activity

Subtask 8.1. Develop preliminary geomodel of Viola reservoir in Durham Center Field

Assemble wireline logs, sample cuttings, and well completion and production histories. Analyze well logs using spreadsheet-based PfEFFER log analysis software. Develop reservoir geomodel using GeoPLUS PETRA™ mapping software and use it to history match production/pressure history by simulation studies. Evaluate potential for incremental oil recovery by recompleting producing wells with multiple laterals drilled using radial jet enhancement and producing under optimal drawdown.

Subtask 8.2. Plan field development using Radial Jet Enhancement and progressive cavity pumps

Use simulation results to determine optimal completion trajectories of Durham Center Field wells. Estimate produced water rates for maximum oil recovery. and determine if Arbuckle disposal well at Hillsboro Field is capable of meeting disposal requirements.

Subtask 8.3. Economic feasibility of implementing radial jetted laterals and progressive cavity pumps in Durham Center Field for Phase II.

Analyze rate of return of incremental oil production and water disposal costs.

B.2 Labor Hours and Categories

Table 1 (below) provides labor hours AEC staff for each subtask. **Table 2** on the following page provides estimated labor hours for each task in the Statement of Work.

Labor hours and labor categories for proposed subcontracting for ea

(unbudgeted, contributed time from Alan DeGood and Steve Moore, American Energies)

Subtask	Hours
4.2	10
5.1	48
5.3	10
6.1	6
6.2	10
6.4	6
6.5	10
6.7	12
6.8	6
6.9	48
6.10	8
total hours	**174**

Task 4.0. Evaluate potential of Viola Production Well.
- Subtask 4.1. Gather data - Producing well & Viola reservoir.
- Subtask 4.2. Pre-treatment buildup and production test at Production well to estimate permeability and establish a production baseline.
- Subtask 4.3. Develop geomodel of Viola reservoir around Producing well.
- Subtask 4.4. Simulate post-treatment recovery from Producing well.

Task 5.0. Evaluate Injectivity of the Arbuckle Disposal Well.
- Subtask 5.1. Deepen Arbuckle disposal well, and acquire core and wireline logs.
- Subtask 5.2. Analyze core and wireline logs.
- Subtask 5.3. Pre-treatment falloff test at Injection well - estimate injectivity potential.
- Subtask 5.4. Develop geomodel of Arbuckle reservoir around Injection well.
- Subtask 5.5. Select best zones for injection.
- Subtask 5.6. Determine optimum completion to maximize injectivity by simulation.

Task 6.0. Deploy and Evaluate Radial-Jetted Laterals in Injection and Producing Wells
- Subtask 6.1. Drill first 300-foot lateral at Injection well using Radial Jet Enhancement.
- Subtask 6.2. Post-treatment falloff test at Injection well and compare with simulation results.
- Subtask 6.3. Determine placement of 2nd, 3rd,and 4th laterals in injection well.
- Subtask 6.4. Drill first 300-foot lateral at Producing well using Radial Jet Enhancement.
- Subtask 6.5. Post-treatment buildup test at Production well and comparison with simulation results.
- Subtask 6.6. Determine placement of 2nd lateral in Production well.
- Subtask 6.7. Drill 2nd, 3rd and 4th 300-feet lateral at Injection well.
- Subtask 6.8. Drill 2nd lateral in Production well.
- Subtask 6.9. Connection Production and Injection wells with low-pressure pipeline.
- Subtask 6.10. Install progressive cavity pump and optimize performance.
- Subtask 6.11. Compare production volumes with simulation results and revise Viola geomodel accordingly.
- Subtask 6.12. Inject produced water at the Injection well and compare with simulation results and revise geomodel accordingly.

Table 1. Labor and hours for subcontracted AEC tasks (highlighted in yellow).

Gantt Chart in **Table 3** outlines project schedule and milestones. Task 3, Technology Transfer, is a key ongoing activity designed to capture essential elements of the project. Tasks 4 and 5 will provide baseline information about well productivity and injectivity needed to evaluate enhancements by radial-jetted laterals. Milestones #1 and #2 are assessments points where decision to proceed to next stage will be made based on results attained. Task 6 deals with deploying and evaluating radial-jetted laterals. Milestone #3 in Task 6 assesses the effectiveness of the radial-jetted laterals on productivity and injectivity. Task 7 deals with project economics and workflow development for technology transfer to small producers. Milestone #4 will assess economics of enhanced production at the production-injection well pair. Negative results will terminate extension of the study to multiple production wells in Durham Center Field. Milestone #5 at the completion of this funded project involves decision on whether AEC will implement the proposed methodology to multiple production wells in Durham Center Field.

B3. Project Schedule and Milestone

Anticipated problems could include: 1) weather restricting access to location and 2) problems scheduling services at field location. The weather has not been a particular problem in this area so risk of disrupting schedule is not high. Secondly by alternating completions and evaluations, multiple laterals in the production and injection wells will be scheduled during a single visit by the vendor conducting the radial enhancements to the location thus concluding Task 6 during the 6th month.

Enhancing oil recovery from mature reservoirs using water-jetted laterals and high-volume progressive cavity pumps

Task 1.0. Project Management Plan.

Subtask 1.1. Prepare and submit management plan consisting of work breakdown structure within 30 days of award.

Task 2.0. Technology Status Assessment.

Subtask 2.1. Perform technology status assessment and submit summary report within 30 days of award.

Task 3.0. Technology Transfer.

Subtask 3.1. Develop and implement an effective Technology Transfer Program coordinating with RPSEA.
Subtask 3.2. Develop and maintain website to carry pertinent information about the project.
Subtask 3.3. Conduct workshop with field tour, present talks to local professional societies of independent operators.
Subtask 3.4. Prepare publications including journals and professional society meetings.

Task 4.0. Evaluate potential of Viola Production Well.

Subtask 4.1. Gather data - Producing well & Viola reservoir.
Subtask 4.2.Pre-treatment buildup and production test at Production well to estimate permeability and establish a production baseline.
Subtask 4.3. Develop geomodel of Viola reservoir around Producing well.
Subtask 4.4. Simulate post-treatment recovery from Producing well.

Task 5.0. Evaluate Injectivity of the Arbuckle Disposal Well.

Subtask 5.1. Deepen Arbuckle disposal well, and acquire core and wireline logs.
Subtask 5.2. Analyze core and wireline logs.
Subtask 5.3. Pre-treatment falloff test at Injection well - estimate injectivity potential.
Subtask 5.4. Develop geomodel of Arbuckle reservoir around Injection well.
Subtask 5.5. Select best zones for injection.
Subtask 5.6. Determine optimum completion to maximize injectivity by simulation.

Task 6.0. Deploy and Evaluate Radial-Jetted Laterals in Injection and Producing Wells

Subtask 6.1. Drill first 300-foot lateral at Injection well using Radial Jet Enhancement.
Subtask 6.2. Post-treatment falloff test at Injection well and compare with simulation results.
Subtask 6.3. Determine placement of 2nd, 3rd,and 4th laterals in injection well.
Subtask 6.4. Drill first 300-foot lateral at Producing well using Radial Jet Enhancement.
Subtask 6.5. Post-treatment buildup test at Production well and comparison with simulation results.
Subtask 6.6. Determine placement of 2nd lateral in Production well.
Subtask 6.7. Drill 2nd, 3rd and 4th 300-feet lateral at Injection well.
Subtask 6.8. Drill 2nd lateral in Production well.
Subtask 6.9. Connection Production and Injection wells with low-pressure pipeline.
Subtask 6.10. Install progressive cavity pump and optimize performance.
Subtask 6.11. Compare production volumes with simulation results and revise Viola geomodel accordingly.
Subtask 6.12. Inject produced water at the Injection well and compare with simulation results and revise geomodel accordingly.

Primarily field-based activities
Primarily office-based activities
(see below)

Task 7.0. Evaluate Project Performance.

Subtask 7.1. Evaluate project economics - compare incremental oil recovery costs with water disposal.
Subtask 7.2. Develop workflow of technology application and evaluate use in other high water-cut reservoirs.

Task 8.0. Evaluate Suitability of Technology Application to Multiple Wells in Adjacent Durham Center Field as Potential Phase II Activity.

Subtask 8.1. Develop preliminary geomodel of Viola reservoir in Durham Center Field.
Subtask 8.2. Develop optimum development strategy using Radial Jet Enhancement and progressive cavity pumps.
Subtask 8.3. Access economic feasibility of implementing water jetted laterals and progressive cavity pumps in Durham Center Field for Phase II.

Estimated labor hours and labor categories

KU Staff	months (fte)/yr	Task 1. St. 1.1	Task 2. St. 2.1	Task 3. St. 3.1	St. 3.2	St. 3.3	St. 3.4	Task 4. St.4.1	St. 4.2	St. 4.3	St. 4.4	Task 5. St. 5.1	St. 5.2	St. 5.3	St. 5.4	St. 5.5	St. 5.6	Task 6. St. 6.1	St. 6.2	St. 6.3	St. 6.4	St. 6.5	St. 6.6	St. 6.7	St. 6.8	St. 6.9	St. 6.10	St. 6.11	St. 6.12	Task 7. St. 7.1	St. 7.2	Task 8. St. 8.1	St. 8.2	St. 8.3	TOTAL HOURS	BUDGETED TIME (HOURS)	BUD TIME-TOTAL
Lynn Watney (PI), geologist	2.6	20	20	80	40	40	55	8		8		10	40		16	8				8			4					8	8	10	16	20	16	17	452	452	0
Saibal Bhattacharya (Co-PI), pet engineer	2.0					40	30		11	8	16			16	8	10	16		16	16		16	8					20	20	20	20	8	24	25	348	348	0
Dave Newell, (Co-PI), geologist	1.5				20	36	40	20		20													4					16	8	20	20	30	16	11	261	261	0
John Doveton (Co-PI), petrophysicist	1.5				14	40	40	10		16		20	20		20	8				16		8	8					8	8			8	8	9	261	261	0

	TOTAL TIME			BUD TIME-TOTAL
Lynn Watney (PI), geologist	452	**2.6**	2.6	0.0
Saibal Bhattacharya (Co-PI), pet engineer	348	**2.0**	2.0	0.0
Dave Newell, (Co-PI), geologist	261	**1.5**	1.5	0.0
John Doveton (Co-PI), petrophysicist	261	**1.5**	1.5	0.0
	HRS/YR	**MO/YR**	**BUD TIME, MO/YR**	

Enhancing oil recovery from mature reservoirs using water-jetted laterals and high-volume progressive cavity pumps

PROJECT TASKS	2008 Jan	Feb	Mar	Apr	May	June	July	Aug	Sept	Oct	Nov	Dec
Task 1.0. Project Management Plan.												
Subtask 1.1. Prepare and submit management plan consisting of work breakdown structure within 30 days of award.												
Task 2.0. Technology Status Assessment.												
Subtask 2.1. Perform technology status assessment and submit summary report within 30 days of award.												
Task 3.0. Technology Transfer.												
Subtask 3.1. Develop and implement an effective Technology Transfer Program coordinating with RPSEA.												
Subtask 3.2. Develop and maintain website to carry pertinent information about the project.												
Subtask 3.3. Conduct workshop with field tour, present talks to local professional societies of independent operators.												
Subtask 3.4. Prepare publications including journals and professional society meetings.												
Task 4.0. Evaluate potential of Viola Production Well.												
Subtask 4.1. Gather data - Producing well & Viola reservoir.												
Subtask 4.2. Pre-treatment buildup and production test at Production well to estimate permeability and establish a production baseline.												
Subtask 4.3. Develop geomodel of Viola reservoir around Producing well.												
Subtask 4.4. Simulate post-treatment recovery from Producing well.			*1									
Task 5.0. Evaluate Injectivity of the Arbuckle Disposal Well.												
Subtask 5.1. Deepen Arbuckle disposal well, and acquire core and wireline logs.												
Subtask 5.2. Analyze core and wireline logs.												
Subtask 5.3. Pre-treatment falloff test at Injection well - estimate injectivity potential.												
Subtask 5.4. Develop geomodel of Arbuckle reservoir around Injection well.												
Subtask 5.5. Select best zones for injection.												
Subtask 5.6. Determine optimum completion to maximize injectivity by simulation.					*2							
Task 6.0. Deploy and Evaluate Radial-Jetted Laterals in Injection and Producing Wells												
Subtask 6.1. Drill first 300-foot lateral at Injection well using Radial Jet Enhancement.												
Subtask 6.2. Post-treatment falloff test at Injection well and compare with simulation results.												
Subtask 6.3. Determine placement of 2nd, 3rd,and 4th laterals in injection well.												
Subtask 6.4. Drill first 300-foot lateral at Producing well using Radial Jet Enhancement.												
Subtask 6.5. Post-treatment buildup test at Production well and comparison with simulation results.						*3						
Subtask 6.6. Determine placement of 2nd lateral in Production well.												
Subtask 6.7. Drill 2nd, 3rd and 4th 300-feet lateral at Injection well.												
Subtask 6.8. Drill 2nd lateral in Production well.												
Subtask 6.9. Connection Production and Injection wells with low-pressure pipeline.												
Subtask 6.10. Install progressive cavity pump and optimize performance.												
Subtask 6.11. Compare production volumes with simulation results and revise Viola geomodel accordingly.												
Subtask 6.12. Inject produced water at the Injection well and compare with simulation results and revise geomodel accordingly.												
Task 7.0. Evaluate Project Performance.												
Subtask 7.1. Evaluate project economics - compare incremental oil recovery costs with water disposal.									*4			
Subtask 7.2. Develop workflow of technology application and evaluate use in other high water-cut reservoirs.												
Task 8.0. Evaluate Suitability of Technology Application to Multiple Wells in Adjacent Durham Center Field as Potential Phase II Activity.												
Subtask 8.1. Develop preliminary geomodel of Viola reservoir in Durham Center Field.												
Subtask 8.2. Develop optimum development strategy using Radial Jet Enhancement and progressive cavity pumps.												
Subtask 8.3. Access economic feasibility of implementing water jetted laterals and progressive cavity pumps in Durham Center Field for Phase II.												*5

Tasks led by AEC

Milestones
*1 -- Assess potential for enhanced productivity
*2 -- Assess potential for enhanced injectivity
*3 -- Assess effectiveness of laterals on injection and production wells
*4 -- Assess economics of enhanced production from single producer-injection well.
*5 -- Assess economic feasibility of applying results to Durham Center Field

Table 3. Project Schedule and Milestone

B4. Proposed Travel

Travel includes 2-day trip by PI from Lawrence to Houston for RPSEA Kick-Off meeting to be scheduled prior to commencing work to define schedules and coordinate activities. Fifteen trips to the field site from Lawrence to Hillsboro, Kansas are requested to observe and document well and production testing, jetting laterals, coring, and equipment installation and operation. RPSEA Tech Transfer Workshop and Field Trip will be scheduled toward completion of the project. PI and Co-PI's will travel to Denver to present at the Annual Meeting of Association of American Petroleum Geologists and the SPE Symposium on Improved Oil Recovery in Tulsa in 2009 after completion of the project.

B.5 Recommended Technology Transfer Approach

Weekly updates on tasks, technical information on tests, reservoir characterization and simulations, equipment installation and operation, reports, workshops, and meetings, and assessments and results will be carried out on a dedicated project website maintained by the KGS. Best practices and lessons learned from the project will be made available to the body of small producers in Kansas through presentations at local meetings of geological and engineering organizations (e.g., Kansas Geological Society, Wichita Chapter of SPE, Kansas Independent Oil and Gas Association). Also, day-long workshop and field trip are scheduled later in the project to convey results to local small operators. Publication of results including peer-reviewed and practical how-to descriptions will be focused toward small operators and consultants who help manage marginal wells and fields in the central U.S.

C. TECHNICAL AND MANAGEMENT CAPABILITIES

C.1 Organizational Capabilities and Experience

The project consortium consists of AEC, a small Kansas oil and gas operator, and the Kansas Geological Survey, specializing in research and service in natural resources of Kansas. AEC produces about 730 BOED (Bbls oil equivalent per day) from assets in Kansas, Colorado, Oklahoma, and Texas. AEC's operational focus is Kansas where it operates 25 leases in Marion and adjoining McPherson Counties. AEC has a strong incentive to develop technology to tap remaining resources in these leases, estimated by AEC at 775,000 bbls with 5% additional recovery. Alan DeGood (a geologist and AEC President) and Steve Moore (AEC's petroleum engineer) will work closely with KGS staff

The Energy Research Section of the KGS conducts fundamental and applied research on petroleum geology, improved/enhanced oil recovery, and CO_2 sequestration. The section currently has five professionals with additional support personnel. Details about current areas of research and major projects by this section are available at http://www.kgs.ku.edu/PRS/petroProj.html. Four KGS scientists are involved in this project: Lynn Watney, petroleum geologist (PI), Saibal Bhattacharya, reservoir engineer (Co-PI), and David Newell, petroleum geologist, and John Doveton, petrophysicist, both Co-PIs on this project. Watney will be responsible for managing the consortium activities and ensuring that project objectives and requirements are met. Bhattacharya will manage analyses of well tests, reservoir simulations, targeting well treatment, economic analyses, and developing project workflow. Newell, Doveton, and Watney will manage reservoir characterization and geomodel development and will participate in targeting well treatment, workflow development, and technology transfer activities.

Both AEC and KGS have been involved in a host of projects of similar and larger scale and complexity in their respective roles in field operations and well- and field-based analysis and modeling over the past 10 years. Similar projects include the current project sponsored by the Stripper Well Consortium titled, "Demonstration of a low cost 2-tower micro scale N_2 rejection system to upgrade low-btu gas from stripper wells" - kgs.ku.edu/PRS/Microscale/index.html. The later project is newly funded, but ahead of schedule. Previously, the KGS has undertaken many field and lease studies (listed at http://www.kgs.ku.edu/PRS/petroProj.html) through DOE and industry support ranging upwards in scale of multi-year large field characterizations and modeling.

C.2 Qualifications of Key Personnel

Mr. DeGood of AEC has over 32 years of industry experience and 11 years as President of AEC. Mr. DeGood is skilled in managing multiple projects and is dedicated to the bottom line, a trait that has allowed his company to prevail through the economic ups and downs of the past few decades. Mr. DeGood is also a leader in the Kansas oil and gas industry having served as President of the Kansas Geological Society and the Kansas Independent Oil and Gas Association. He is the immediate past President of the AAPG Midcontinent Section. Mr. Steve Moore of AEC has worked as a petroleum engineer for over 48 years. Mr. Moore oversees onsite field activities for AEC and has demonstrated technical prowess to ensure timely completion of complex projects.

Lynn Watney has 35 years experience working in the industry and survey as a petroleum geologist. He has been a Co-PI and PI on various DOE supported projects (see resume), and will commit 2.6 months to this project as the PI. Saibal Bhattacharya is a Petroleum Engineer with 14 years of reservoir engineering experience that includes field operations and integrated field studies and has been PI and Co-PI in multiple DOE and industry funded projects (see resume), and will commit 2 months of his time to the project as a Co-PI. John Doveton is a mathematical petroleum geologist and wireline petrophysicist with over three decades of experience in advanced statistical methods and the design of analytical log analysis software (see resume), and will commit 1.5 months to the project as a Co-PI. Dave Newell is a petroleum geologist with 32 years of experience in industry and the survey, and been PI and Co-PI of several projects (see resume), and will commit 1.5 months to the project as a Co-PI.

C.3 Quality and Suitability of Facilities, Equipment, and Materials

All software to be used in the study are available at the KGS and includes: a) *GeoPLUS Petra* geological data integration and analysis software; b) in-house log analysis and reservoir characterization software *PfEFFER*, c) CMG's *IMEX* reservoir flow modeling software, capable of modeling multi-phase 3D flow in single/dual porosity systems, and d) Fekete "F.A.S.T.^{TM}" (Fekete Advanced Software Technology) RTA software for well test interpretation. A Nikon Eclipse E600 POL petrographic microscope with DCM1200F Nikon digital camera will be used to examine thin sections from the Arbuckle core. Also, the KGS possesses a state-of the-art distributed computer system with the latest workstations, storage devices, routers, and software, that presently supports a large publicly accessible database and a high-traffic website used widely by the small operators of Kansas and neighboring states.

REFERENCES PERTAINING TO DRILLING LATERAL WELLS

Water-Jetted Laterals:

Vendors and website:
Direct Slotting-Fracturing (DSF) technology of Hydroslotter Corporation, www.hydroslotter.com

MaxPERF (formally Penedrill, Penetrators), www.maxperf.ca

Petrojet Canada Inc., Wellbore Extender System including Ninety Degree Exit Tool and Gradual Exit Tool with multilaterals drilled using limited length of coiled tubing and water jetting nozzle attached to rigid working string, www.petrojet.ca

Radcan Energy Services, Inc., www.radcan.com and Radial Drilling Services, high pressure flexible hose from surface attached to water jetting nozzle delivered through deflector shoe, www.radialdrilling.com

H.J. Schellstede and Assoc. Inc., ultra-short radius lateral drilling system using ultra high-pressure jet cutting system (20k psi pumping system) using small diameter tubulars and jetting nozzle, www.schellstede.com

Tempress Technology, rotary jetting tools for well stimulation, motor gas separator, water jet drills with ultra-short radius laterals (field trials), acoustic well stimulation, pulse drilling, www.tempresstech.com

Downhole mudmotors and geosteering

Sperry-Sun Multilateral Systems, laterals drilled with coiled tubing and downhole motors and geosteering, www.halliburton.com

Baker Oil Tools, multilateral systems, downhole motors, coiled tubing, LWD, MWD, wellbore surveys, www.bakerhughesdirect.com

Microhole Technology, a systems approach to mature resource development developed by US-DOE, www.netl.doe.gov/technologies/oil-gas/publications/brochures/Microhole2006_Mar.pdf

Weatherford International Oil Field Services, Houston, TX, www.weatherford.com

Selected Patents on high-pressure water jetted laterals:

Hydraulic jet method of drilling a well through hard formations, United States Patent 3324957, Goodwin, Robert J., Mori, Ernest A., Pekarek, Joseph L., Schaub, Paul W., Zinkham, Robert E, Publication Date: 06/13/1967

HYDRAULIC JET DRILL BIT, United States Patent 3576222, Acheson, Willard P. (Pittsburgh, PA), Gardner, Gerald H. F. (Pittsburgh, PA), Messmer, Joseph H. (O'Hara Township, Allegheny County, PA), Torcaso, Michael A. (Arnold, PA), Application Number: 04/811820, Publication Date: 04/27/1971, Filing Date: 04/01/1969

Method and apparatus for water jet drilling of rock, United States Patent 4119160, Summers, David A. (Rolla, MO), Mazurkiewicz, Marian (Wroclaw, PL), Bushnell, Dwight J. (Corvallis, OR), Blaine, James (Rolla, MO), Publication Date: 10/10/1978, Filing Date: 01/31/1977

Lateral jet drilling system, United States Patent 6189629, Mcleod, Roderick D. (5104 - 125 Street, Edmonton, Alberta, CA), Loree, Dwight N. (758 Woodpark Road S.W., Calgary, Alberta, CA), Application Number: 09/153089, Publication Date: 02/20/2001, Filing Date: 09/14/1998

Method of and apparatus for horizontal well drilling, United States Patent 5853056, Landers, Carl W. (141 S. Union St., Madisonville, KY, 42431), Application Number:
08/624438, Publication Date: 12/29/1998, Filing Date: 04/01/1996

Earth drilling method and apparatus using multiple hydraulic forces, United States Patent 4763734, Dickinson, Ben W. O. (2125 Broderick St., San Francisco, CA, 94115), Dickinson, Robert W. (Marin County, CA), Rabb, David T. (Alameda County, CA), Application Number: 06/811577, Publication Date: 08/16/1988, Filing Date: 12/23/1985

Well penetration apparatus and method, United States Patent 4640362, Schellstede, Herman J. (342 Duperier Ave., New Iberia, LA, 70560), Application Number:
06/721848, Publication Date: 02/03/1987, Filing Date: 04/09/1985

Publications:

Al-Hady, A.F., LaPrad, D., and Sadi, A.A., 2003, Ultra short radius drilling trials in PDO: SPE 81410, 10 p.

Blount, C.G., Gantt, L.L, Hearn, D.D., Mooney, M.B., Smith, B.E., Quinn, D., and Larson, E.B., 1998, Development update of an MWD directional drilling package for 2-3/4” openhole: Tiny Tools: SPE 46016, p. 79-89.

Cohen, J.H., Deskins, G., and Rogers, J., 2005, High-pressure jet kerf drilling shows significant potential to increase ROP: SPE 96557, 8 p.

Deschamps, B., Desmette, S., Delwiche, R., Birch, R., Azhar, J., Naegel, M., and Essel, P., 2008, Drilling to the extreme: the micro-coring bit concept: IADC/SPE 115187, 12 p.

Diaz, J.D., Espina, V., Guerrero, M., and Colmernares, O., 2007, Successful implementation of coiled-tubing acid tunneling gives operator a viable alternative to conventional stimulation techniques in carbonate reservoirs: SPE 107084, 9 p.

Dickinson, W., Anderson, R.R., and Dickinson, R.W., 1989, The ultrashort-radius radial system: SPE Drilling Engineering, p. 247-254.

Dickinson, W., and Dickinson, R.W, 1985, SPE 13949, Horizontal radial drilling system, p. 887-892.

Dickinson, W., Pesavento, M.J., and Dickinson, R.W., 1990, Data acquisition, analysis, and control while drilling with horizontal jet drilling systems: Petroleum Society of CIM/SPE, Paper CIM/SPE 90-127, p. 127-1 to 127-10.

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Hoang. S.K., Abousleiman, Y.N., and Al-Tahini, A., 2008, Multilaterals drilling and sustainable openhole production in theory to field case studies: SPE 116138, 23 p.

Idiodemise, E.J., and Dosunmu, A., 2007, A model for completion selection for multilateral and multibranched wells: SPE 111884, p. 21.

Iyoho, A.W., Summers, D.A., and Ldecki, G., 1993, Petroleum applications of emerging high-pressure waterjet technology: SPE 26347, p. 333-342.

Kolle, J.J., Otta, R., and Stang, D.L., 1991, Laboratory and field testing of an ultra-high pressure, jet-assisted drilling system: SPE/IADC 22000, p. 847-857.

Kollé J., and Theimer, K., 2005, Microhole Jet Drilling-- System configuration and integration, topical report #1, reporting period: 1 Feb 2005 through 30 June 2005, DOE Award Number: DE-FC26-05NT15484-A001, Tempress Technologies, Inc.

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Logan, T.L., 1968, Horizontal drainhole drilling techniques used for coal seam resource exploitation: SPE Paper 18254, 6 p. + figures.

Logan, T.L., Schwoebel, J.J., and Horner, D.M., 1987, Gas application of horizontal drainhole drilling technology for coalbed methane recovery: SPE/DOE 16409, p. 195-206.

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