Report Title:	Re-fit an Existing Large Diameter and or Open Hole Stripper Well with Non-Metallic Spoolable Tubing and a Modified GOAL PetroPump
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Principal Authors:	C. Hunt, G. Swoyer, P. M. Yaniga
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Name and Address of Submitting Organization	Brandywine Energy and Development Co. PO Box 756-Frazer, Pa 19355

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Abstract:

The Stripper Well Consortium partially sponsored BEDCO to develop a unique concept design to re-fit existing stripper wells not capable of operating a standard [nominal 4.0"-5.0" tool] casing swab. BEDCO fabricated that new unique system, bench tested the integrated components of that system and initiated partial in field application and testing of that system for re-fitting existing stripper wells of 4" ID/ 4.5" OD steel casing or larger and/ or open hole completions. The new/ unique elements of that designed and fabricated system and work are comprised of:

- Spoolable 3.0" nominal ID synthetic tubing [in well conditions tolerant] in lengths to 1800'.
- Metallic [high strength steel] swage ferrule connector to join spooled synthetic tubing to industry standard steel fittings, with less than 0.3" to 0.21" internal diameter loss at the transition.
- Assembly potential of 1400'-1800' lengths of spooled tubing to lengths of 6000' for down hole applications [coupled by the same swage connectors noted above]
- Non failure of metallic swage connector to the synthetic tubing at pull forces > 7000 #'s. The tubing failed at 12000 #'s pull test.
- Small diameter casing swab of 3.0" overall dimensions w/ new concept, designed and fabricated "Lantern Ring" seal cups capable of maintaining pressure seal integrity across the 0.21-0.3" ID loss at swage connector with out tool stall.
- Tool lift pressure differentials of as little as 6-8 psi
- Bench test system comprised of elements found in field applications including matching/ coupling spoolable synthetic tubing to a metallic swage ferrule connector to standard industry steel pipe and repeatedly cycling the new 3" OD casing swab across all connectors without seal pressure loss or tool stall.

The complete/ combined system was not successfully deployed to an in field stripper well. The integrated system is bench tested and field ready. SWC was not able to match fund the program as initially proposed [Table # 1]. Partial funding was made by SWC; further BEDCO increased its proposed contribution and further increased its actual funding in order to try and achieve in field testing of 1 well on the reduced sponsored SWC co-funding. Time allotted in the program and the allocated monies were expended before full field application was achieved.

The [new] 3.0" GOAL casing swab [alone] was deployed in a target well in re-fitted 3.5" J55 steel casing placed in an open hole while the spoolable synthetic system was being developed. Automatic/ self initiated tool runs were not achieved in this application. It appears gas production vs. fluid production in that test well was insufficient to self lift hydrocarbons from that well at that time. Nominal gas to fluid ratio of 3 mcfd/ bbl fluid has been empirically found to be necessary to lift a barrel of fluid from predecessor work with 4" casing swabs. The tested well, although reported to yield 10+ mcfd and < 2 bbl of oil/ day, was found to have a column of 25 bbls of oil in the well and a gas flow rate at the time of testing of < 2 mcfd.

Tool and re-fit spoolable tubing system are ready to be deployed with a well owner in a future joint venture testing program.

Executive Summary

Currently, US demand for oil and natural gas far outstrips domestic production of the two commodities. Increasing world demand for the ~ produced 85,000,000 BOE/ day in recent years has led to a tripling of crude oil prices and doubling to trebling of natural gas prices *[FNN Oct. 2006].* An anticipated 35% increase in world demand in the next 5 years stretches available reserves and recovery technology to their limits. Considerable reserves of both oil and natural gas remain in the USA existing oil and gas stripper wells which number in excess of 700,000 total wells *[US Marginal wells survey 2005].* Technological improvements in production of oil and gas from these stripper wells is needed to meet the increasing US demand and curb increasing energy cost brought on by world competition for the current world production.

Brandywine Energy [BEDCO] proposed in this project and has developed a re-fit system using a gas lift tool 'GOAL PetroPump [with tool & seal cup modifications]" operating within spoolable non –metallic tubing to automatically lift fluids [oil, water and gas] from existing stripper wells of open hole completion and or large diameter steel casing. This developed system uses in formation natural pressures thereby decreasing production cost and a lower tool lift pressure differential increasing total natural gas/oil recovered.

Key elements of the project achieved:

- Selection and development of an applicable spoolable non metallic tubing to meet target depths of <3000' with appropriate pressure ratings, corrosion resistance and chemical compatibility for the applications, elongation strength, and low internal friction coefficient, all to the end of improved recovery of energy from the stripper well.
- Development of metallic to non- metallic spoolable tubing swage ferrule connector for coupling of non metallic tubing to metallic well head and open port well head ball valve through which the GOAL PetroPump passes to allow the automatic/ self pumping of fluids and passage of follow on natural gas.
- Development of new unique flex wall cups to fit the GOAL tool, create a pressure seal between tool and tubing which affords the tools travels [tripping] down and up well automatically lifting fluids and be capable of passing a 0.3 inside diameter restriction where non- metallic tubing meets/ connects with metallic transition ferrule to metallic well head full port ball valve as well as tubing ovality.
- Development of bench test chamber which simulates in well/ down hole conditions of anticipated field applications.
- Smaller sized [3.0" overall dimension] casing swab [GOAL PetroPump] capable of operating inside the spoolable tubing/ across the swaged ferrule connectors with out pressure loss and or tool stall

During this last reporting period, work was focused and successfully completed on the development of commercially available field applicable non-metallic spoolable tubing complete with field applicable non-metallic to metallic transition swage ferrule connectors to match up with existing in field technology on commonly found strippers wells. To that end Brandywine Energy worked in close concert with Polyflow a manufacture of spoolable tubing used in the oil and gas industry both for above ground transmission/ gathering line applications and in well small diameter siphon string applications. Current, commercially available poly tubing was used in bench test with Swage and ferrule connections and found capable to accommodate needed field strength at the critical transition point of metallic ferrule to synthetic tubing. The current designed and bench tested modifications for the spoolable poly 3" tubing are targeted to fit inside existing 4" ID steel or larger tubing and or open hole completions.

TECHNOLOGY OVERVIEW

This proposal was designed to develop a unique re-fit system for open hole and or large diameter completion wells using non- metallic [spoolable] 3.0" and or 4.0" tubing, non metallic to metallic connectors and modified [smaller 3.0" overall diameter] G.O.A.L. PetroPump components and new seal cups. New and unique elements of the proposed system include:

- Development of metallic to non- metallic transition couplers for the well head and down hole connections of the spoolable non-metallic tubing. Previous to this work they did not exist in a configuration which would afford use inside existing standard diameter and weight casing with standard configuration of the GOAL PetroPump
- Development of new "Flex Wall" sealing cups [3" & or 4" OD] for the tool seal with casing/tubing which could accommodate diameter changes of ¼" to ½" delta necessary to cross the internal diameter changes at the couplers and maintain seal.
- Development of tool actuator/ stroke changes to afford tool [GOAL Pump] down sizing to accept flex wall cups for use in 3" ID and potentially smaller applications.

The benefits of the proposed new system are enhanced natural lift potential - yielding greater fluids produced, more total hydrocarbons captured, lower reservoir abandonment pressures and wider well application:

- Spooled non-metallic tubing reduces and or eliminates pressure loss crossing multiple down hole collars as exist in standard wells casing on 30'-40' frequency
- Natural reduced coefficient of friction from the spooled non- metallic tubing vs. standard metal casing yields greater lift and lower final reservoir production pressure and more recovered hydrocarbon value
- New "Flex wall cup" system affords maintenance of pressure seal, less fluid loss in transit and greater total lift potential
- New down sized tool affords deployment in smaller diameter wells and re-completions in wells with defective or other casing problems with-out pulling casing and for application in open holes.

The proposed technological re-fit system creates a down hole production unit comprised of some existing materials and other to be created technology. Spoolable non-metallic tubing, full port ball valves, open hole packers [where needed], a casing swab and other tools/ technology was combined in a unique configuration to afford existing open hole and large variable diameter stripper wells the opportunity to pump them selves using natural formation pressure. The Patent G.O.A.L. PetroPump casing swab was re-configured/ re-designed to accept a new designed and constructed set of “Flex Wall” seal cups to operate in the non-metallic tubing and transition couplers to existing well head and down hole hardware and total overall diameter of 3.0”

The system as designed, constructed and partially [albeit not totally successfully] deployed provides the opportunity for wells to be naturally produced “Self Pumped” to with in a few 10’s of PSI of well head sales line pressure yielding more total hydrocarbon from the drilled and tapped reservoir at smaller unit cost.

Work Plan Statement

Note: The below outlined work scope was for the authorized reduced funded work by SWC [@~ 36% of initial requested funding] with increased BEDCO actual funding [153% of BEDCO’s proposed revised cost] for 1 well.

Table # 1 shows comparative financial metrics of requested funding [Appendix B] and split, approved [Appendix A] [lesser SWC] funds approved and [greater BEDCO funding] split; actual incurred cost and split.
Appendix A is the approved revised budget and split between SWC and BEDCO to work on a [1] well.

The proposed work was to complete a field trial/ re-completion techniques that allowed for the system deployment, testing, and monitoring of oil/ fluids and gas production performance compared to existing conventional techniques. There were several key tasks to achieving work success. These work tasks are:

Task 1

- Assemble existing materials, create transition materials, develop new tool / cup system, integration with 3.0” non –metallic tubing, packer & safety stop. Consideration was to focus on Spoolable non metallic composite tubing. Two types of tubing were considered in some detail; Spoolable Advanced Composite tubing, and Spoolable Polyethylene tubing with and without a scrim backing of ~ 3.0” ID and 3.5” OD will be considered.

Task 2

- Screen [evaluate] and select an open hole completed and / or large diameter completed multi-zone candidate wells. Consider zones of completion, total depth and production history.

Task 3

- Construct 1 tool system for deployment in select well/ Bench test prior to deployment

Task 4

- Re-configure select test well, deploy and adjust tool, then compare production pre and post

Task 5

- Evaluate system performance and comparison to predecessor methods for the target well

Task 6

- Estimate/ evaluate economic impact of tool

Task # 1

Assemble candidate materials, create transition connectors, and create new seal cups to match with re-configured tool

1.0 Spoolable tubing types considered for use and testing:

1.1 Fiberspar TM, coiled tubing was reviewed and considered and the following metrics developed for consideration.

Table 2 Fiberspar TM operating system metrics for potential use in re-fit stripper wells

Internal diameter	Burst Pressure	Collapse pressure	In Field down Hole application	Material of Construction	Cost
3.0”	1000 psi	300-500 psi delta, outside pres. to inside	Initiating use small diam. tubing in Canada	Fiber reinforced epoxy outer, thermoplastic HDPE inner	$4.80/ ft. fob Houston [July 2005 cost]
3.0”	1500 psi	300-500 psi delta outside to inside	Initiating use small diam. tubing in Canada	Fiber reinforced epoxy outer, thermoplastic HDPE inner	$6.15/ ft. fob Houston
4.0”	1000 psi	300-500 psi delta outside to inside	Initiating use small diam. tubing in Canada	Fiber reinforced epoxy outer, thermoplastic HDPE inner	$7.90/ ft fob Houston
4.0”	1500 psi	300-500 psi delta outside to inside	Initiating use small diam. tubing in Canada	Fiber reinforced epoxy outer, thermoplastic HDPE inner	$9.65/ ft fob Houston
2.0”	1000 psi	300-500 psi delta outside to inside	Initiating use small diam. tubing in Canada	Fiber reinforced epoxy outer, thermoplastic HDPE inner	$3.30/ ft fob Houston

Notes: [Fiberspar products]
1] Tensile strength thought to be good to 5000’ of depth

2] Temperature range -29 F to 180 F
3]Fiberspar points of contact:

12239 FM 529	Phone 713 849 2609	E-mail info@fiberspar.com
Houston, TX 77041	Fax 713 849 9202	

1.2 Nexgen Hose Inc products were reviewed and considered in brief. Information on readily available 3.0" and or 4.0" ID flex tubing for the target in well use was not immediately available.

Notes:
1] Nexgen Hose points of contact:

Box 9, 925 Glengarry Cres.	Phone 519-787-0001	E-mail dave@nexgenhose.com
Fergus, Ontario, Canada	Fax 519-787-2226	
N1M2W7		

1.3 Hydril Products ***Python*** TM, a [HAC] Hydril Advanced Composite [SCC] Spoolable Carbon Composite [ChemPex] Cross linked polyethylene as well as ***Cobra TM,*** a HAC/ SCC with[HDPE [PE 100]] a high density polyethylene thermoplastic liner were considered and certain information developed showing available ID of 1.0" to 3.9". Preliminary contact with the organization did not provide positive feed back at the time for in well down hole application

Notes:
1] Hydril points of contact:

Hydril Advanced Composite group	Phone 713-941-6639	E-mail www.hydril.com
8641 Moers Road		
Houston TX 77075		

1.4 Poly Flow Inc. materials and products were reviewed and considered for the field application and use in re-fitting existing stripper wells. The following metrics were developed in that research:

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Table 3 PolyFlow operating system metrics for potential use in re-fit stripper wells

Internal [nominal]diameter	Burst Pressure	Collapse pressure	In Field down Hole application	Material of Construction	Cost
3.0”	**500 psi** *[MAOP]* **1800 psi** *[Burst]*	**250 psi delta, outside pres. to inside**	**In field use of product in siphon string applic. [< 1”] diam. stripper wells complete w/ metallic to non metallic couplings**	**Polypropene, Kynar strands, Aramid fiber and Nylon**	**$6.93/ ft. fob Oaks, Pa** **[Dec. 2006 price]**
4.0”	**500 psi** *[MAOP]* **1800 psi** *[Burst]*	**250 psi delta outside to inside**	**In field use of product in siphon string applic. [< 1”] diam. stripper wells complete w/ metallic to non metallic couplings**	**Polypropene, Kynar strands, Aramid fiber and Nylon**	**$9.40/ ft fob Oaks, Pa**

Notes:
1] Tensile strength thought to be good to ~7000’ of depth
2] Destructive Pull test > 12,000 #’s
3] Weight/ ft @ 1.25#/ ft
4] Temperature range -10 F to 180 F
5] PolyFlow has in field experience with small diameter [~1.0”] non – metallic siphon string usage complete with metallic to non metallic couplings
6]PolyFlow Inc. points of contact:

W2280 West Drive Phone 610-666-5150 E-mail jwright@polyflowinc.com
PO Box 434 Fax 610-666-5144
Oaks, Pa 19456

1.4.1 The combined factors of:

- PolyFlow in field existing use of similar continuously spooled synthetic tubing of smaller diameter
- Existing technology for metallic to non metallic couplings for adaptation to standard industry steel products [albeit smaller dimension and heavier wall thickness than desired for the proposed re-fit program]
- Proximity to BEDCO facilities for combined efforts on development work

1.4.2 All these factors sealed its choice [PolyFlow] as the purveyor of synthetic tubing for use in the re-fit work. Details of the work program for mating large diameter 3" and greater PolyFlow to thin wall high strength steel metallic transition swaged Ferrules are presented in Task 3 below

2.0 GOAL Tool down sized actuator for small diameter tool

2.1 The GOAL tool was made convertible from its standard 4" configuration to a 3" or 4'' configurations through re-design and re-fabrication of the tools actuator and its interaction with in a new longer tool body for the 3" version of the GOAL Tool [Figure #1]. *Note: Eagle Tool and Die, Malvern , Pa was critical in the fabrication of the new [3.0"] tool and integrated Lantern Ring cup system.*

2.2 The principal components of the designed and fabricated change which afforded the development of the smaller [convertible 4" to 3" tool] or 3 / 4 tool are:

- Reduced wall thickness of the barrel containing the actuator, affording more through tool flow of fluids and passage of itinerant solids.
  - *Note: Further reduction of actuator / tool possibly to 2.5" overall diameter w/ cups or less may be achieved by development of a 'canister-less' actuator which requires further design change and fabrication to maintain valve guide alignment and seal*
- Relocation of mechanical stop, which limits actuator expansion to a defined distance during pressurization, from the body of the actuator canister to a more robust tool body stop. This allowed further reduction in actuator overall diameter and reduction in overall tool diameter.
- Reduced valve plug/ seat area - diameter by ~ 0.2", affording further overall diameter reduction

3.0 Seal Cup Options and variations

3.1 More than 20 different configurations, thickness, durometer hardness of elastomers for both GOAL tool standard 'bell shaped' seal cups and new [chosen for use in the synthetic tubing] "Lantern Ring" type cup configurations were conceived, designed, fabricated and tested in choosing the cup which best fits and matches the downsized tool and crosses the tapered swaged metallic to non metallic ferrule connectors while maintaining needed seal to lift fluids and retain behind toll lift pressure and gas volume. Details of the fabrication and testing are shown in Task 3 below.

4.0 Full Port Ball Valve

4.1 The chosen full port ball valve for in field use is manufactured by Tulsa [valve] in both 3.0" [Figure # 1] and 4.0" ID of ductile steel construction and drilled out to the respective full diameter port, not cast, with a 2000# rated pressure capacity.

Tulsa Valve Inc contact information:

PO Box 35	Ph: 918-358-3494
Cleveland Ok 74020	E-mail sales@tulsavalve.com

5.0 Lubricator

5.1 The well head lubricator [Figure # 1] is configured of schedule 40 ductile steel pipe, @ 4.0" ID and 2.0" ID configured to allow atop tool delivery of fluids to the GPU via a 4" x 2" swaged connection and follow on gas production via a below tool [once tool is up in the lubricator] 2" piped connector to the GPU with isolation check valves on both lines. Lubricator ball valves, connectors, elbows, hammer unions and check valves are built to nominal 1000 psi rating for the targeted stripper wells; whose remaining well head is normally < 600 psi well head pressure. Higher pressure rated lubricators can be fabricated from readily available materials.

6.0 Tool catcher

6.1 The tool catcher is located atop the lubricator [Figure #1] in a position to catch the tool once engaged in order to retrieve the tool for a pressure change to regulate volume and/ or frequency of lift of fluids and /or seal cup change or other service. The catcher is machined from 316 stainless steel with a spring loaded, handle operated beveled retrieval rod which once engaged impinges on the top end docking rod [recessed circular groove of 5/8"] diameter in the 7/8" OD of the docking rod. *Note: Eagle Tool and Die of Malvern, Pa is the fabricator of the catcher system and tool assembly*

7.0 Packer System

7.1 The packer system chosen for use with the system, where needed, is Weatherford Completion Systems [equivalent of the former Butler Larkin GFS 3 OR 4] to grasp the outside diameter of the high strength steel swaged ferrule connection in a tension and or compression application to pack off/ isolate undesired zones with in the well- [normally low pressure zones or failed casing sections] which can act as a thief for down hole higher pressure and gas needed for fluid and tool lift.

Weatherford Completion Systems contact information:
2004-64th Ave. Phone 780-465-9311
Edmonton AB T6E 1Z3 E-mail www.weatherford.com

8.0 Safety Stop

8.1 The in tubing safety stop is an integrated swaged connector to spoolable poly with fabricated metal cross plate with 80% open area to the well at the desired depth of tubing placement. Weight of tubing at 1.25#/ ft is reasoned to be suitable for direct placement in the well with out down hole anchor. In field PolyFlow experience to date [3+ years] with 1" spoolable tubing hung in wells as siphon stings has proven successful without base of tubing anchor needed.

9.0 Work over Rig

9.1 Additional Needs to Installer/ Operator:

- Work over Rig [typically 1-2 days maximum for < 4000' wells, 1 day for < 2000' wells
- Full Port Bal Valve [noted above] installed on wells head, commonly available in most markets @ typical cost $750-$1250 USD/ day

Notes: Service Rig general Configuration and capacity to prep existing stripper well with tubing and beam pump and or siphon string tubing for use of the GOAL PetroPump

- ✓ *Service rig capable of working on 5000' well, handling rods, tubing and sand line work consisting of :*
  - *Double drum draw works*
    - *Sand line drum spooled with 6000' of 9/16" to 5/8" sand line*
    - *Grooved tubing line drum Spooled with 550" of ¾" or 7/8" tubing line*
  - *65' mast capable of minimum 75,000 pound hook load*
  - *Crown with one floating sand line sheave and three fixed tubing line sheaves*
  - *50 ton two sheave traveling block [four lines]*
  - *Draw works and mast should be mounted on a vehicle rated for a minimum GVWR of 55,000 pounds*
  - *Tubular handling tools and sand line tools as needed to meet intended task*

Tool Operations Principals:

> ***The tool is manufactured with an internal self contained pressure control valve which regulates the depth into well fluids which the tool is allowed to descend and volume of fluid lifted per tool cycle. The tool pressure actuator/valve can be set with a variable quantity of pressure to effect different volume of fluid lift. In field operations, the tool is pre-set with a known pressure [an inert gas] which is set to achieve a desired lift volume. The tool is then deployed into the tool lubricator, the lubricator plumbed to the well, the full port ball valve opened and tool allowed to freely descend into the fluid column of the well. The tool descends to such depth as required to off set the internal pressure in the actuator which holds the valve open. Upon achieving the depth/ weight of fluid which off sets the pressure in the actuator; the on tool valve closes. Subsequent pressure from the formation/ reservoir builds below the tool and seal cups automatically lifting the tool and fluid column atop the tool to the surface. Upon reaching the surface the fluid atop the tool is discharged to the process unit through the top plumbing connection of the lubricator. Follow on/ below tool gas is produced from the bottom plumbing connection on the lubricator. As gas pressure declines to near gathering line pressure in the surface collection system the tool valve automatically opens and descends the well for another fluid lift cycle.***

Task 2

Screen Candidate Wells

2.1 Group 1 potential target wells for re-fit w/ GOAL Pump system

Re: Bradford Group/Sands/ potential re-fit wells

Outline of target well conditions for re-fit;

Target Geologic Group/ Formation	Bradford Group/ Sands
Location	Mc Kean County Pa.
Depth Range of wells	1700’ – 2200’ [Ave. ~ 1900’]
General well construction/ config./ completion	*0- 550’ cemented in place 7” ID 17#/ ft. casing *550’- ~1900’ average open hole @ 6.25” ID

Completion/ Stimulation	*5 to 7 sand zones notched and fraced w/ average of 3 notch and frac/ zone w/ each notch 4’ minimum separation *Notch penetration > 1’ to ~ 10’, integrity of formation dependant
General Production history	*0-3 months ave. 500-1000 Bbl/ oil and 50 mcf/d gas, 300-500 psi *3 mo. – 1 year ~ 900 Bbl of oil and 20-30- mcf/d gas, 100-300 psi *@ 3 years ~ 300-500 Bbl/ oil / yr. and 10-20 mcf/d gas 100 psi with sales line pressure @ 20-80 psi
Economic life of well	< / =7 – 10 years operating conditions dependant
Well replacement cost	* $85,000.00- $110,000.00
Operating considerations	*Generally brought on line with Pump Jack/ Beam Pump unit *Cost considerations for Jack and down hole pump rods and tubulars @ $10,000- $15,000 *O and M cost $20- $40/ month for electricity where available. *Belts at 2 to 3 sets/ year on electrified Jacks = $120/ year *Well tender operations @ $125/ mo *Yearly total ops cost for conventional electric powered system @~ $2000- $2500 w/ other misc. incl. *Capital [add] cost for gasoline engine to drive Jack @ $1000 where electric power not available *O and M cost for gasoline powered Jack driven system = $100- $150/ month for fuel and oil *Belts @ 6 sets belts/ year on gas engine powered system = $240 *Well tender operations @ $125/ month * Annual total operating cost IC Engine powered Beam Pump @ $3200-$3800 w/ misc. incl.
Re- fit considerations	* Standard 4.5” J- 55 casing @ 10.5#/ foot *4.025” nominal diameter w/ drift to 3.927” *Cost/ foot @ $4.50- $6.00/ foot [June 2005 prices on the increase] * 3.5” J-55 also applicable with new 3.0” GoAL tool

	*3' and or 4" ID spoolable PolyFlow is also applicable * Collar O. D. for 4.5" J-55 casing @ 5.00" * Packers where needed "Open Hole GFS type R-4 [former Butler Lakin] set in compression where nominal depth is 1000' +- 200' and geologic formation has good integrity *Target wells in the field are those wells in the 3 to 10 year age whose production has declined or cost to produce vs. yield in non cost effective- current thinking focus on one each of well working under Pump Jack and one on small diameter tubing PLUNGER-rabbit. * Wells current production is in the range of 300Bbl/ oil year and 10-20 Mcf/d of gas
Anticipated/ Targeted results	* Maintain fluids production level with potential for some small increase @ 10% +-, with gas production increase targeted @ 1.5X to 2X
Capital Cost for Pilot Work re-fit	$ 27,000- $34,500

2.1.1 Wells reviewed in this group were Blew # 1-5 which were/ are currently configured with rabbit/ tubing plunger systems inside 2.5" pipe and connected to a common collection line and GPU/ battery tank system. Collective yield from the 5 wells was/ is 5-7 bbls/ days of oil/ fluids and 50-70 mcfd of gas/ day from the 5 wells in the system.

2.1.2 Well Blew #1 was chosen for further evaluation and field evaluation using the new designed and constructed 3" tool first with standard bell cups inside 3.0" ID steel pipe hung in the open hole completion prior to completion of the integrated spoolable PolyFlow system. Further details on this well are shown below:

- ✓ Well designation Blew # 1
- ✓ Estimated production by well tender 2nd half 2005 [flows into combined system w/ 4 other wells] @ 10-20 mcfd and 1-2 bbls of oil/fluid/day
- ✓ Well chosen for further field testing as a function of good gas to fluid ratio of ~ 10-1 [GOAL tool in standard steel casing w/ attendant roughness coefficient generally require a 3-1 gas to fluid ration to automatically lift fluids]
- ✓ Total depth 1873'
- ✓ Surface casing, 600' of 7.5" J-55
- ✓ Open hole 600'-1873' @ 6 5/8"
- ✓ 260 psi on well in Jan. 2006
- ✓ 75 psi line pressure

2.1.3 Limited field testing of this well was achieved in late summer/ early fall 2006, results and discussion are in Task 4

2.2 Group 2 potential target wells for re-fit with GOAL Pump system

Re: Venango Group, Bradford Group and Elk Group Sands

Outline of Target Gas wells conditions for Re-fit

Target Geologic Group/ Formation	Venango/ Bradford/ Elk/ Group Sands
Location	Clarion County
Depth Range of wells	3200'- 3500'
General Well Construction	*20-90' of cemented in 9 5/8", conductor casing * 800-900' of 7", 17# cemented surface casing * 6.25"open hole below surface casing to TD in most wells, 1 potential target wells w/ 2200' of 4.5", 10.5# production casing [non cemented] followed by open hole @ 6.25" to TD
Completion and Stimulation	* 3 sand Groups/ zones notched/ fraced/ stimulated with 6 to 18 open hole staged fracs in total across three zones
General Production History pressure	* IP @ 85- 500 mcf/d w/ 300- 900psi well head * Production at 6 to 7 year post completion @ 5 to 13 mcf/d w/ 80-300 psi well head pressure * Fluid production [periodic] at 0.5 to 40 bbl/ removal
Economic Life of well	* At 7 years of age currently marginal
Well replacement cost	* $120,000- $145,000
Operating Considerations	* Brought on line as open flow < 1 year *Siphon tubing installed 6 months to 1 year w/ periodic *Surfactant addition/ shut in and vent – surge to brine tank *Tubing plunger in 1 of the potential target wells *Annual to biannual swab with rig/ non regular *Beam Pump use one well w/ modest success

	*Operating line pressures @20 psi – 60 psi *Well tending and operations fees @ $6000- $7000/ year/ well
Re- Fit considerations	* Standard J-55, 4.0" ID well casing @ 10.5#/ foot applicable for re-fit in 6.25" open holes. *3' and or 4" ID spoolable PolyFlow is also applicable *Venango Group sands [~depth of 1500'] are current low pressure- thief zone for lower production *Compression or tension packer model Butler-Larkin applicable for setting to isolate Venango Group thief [with potential continued production of the Venango on the backside] and allow down hole production via tail pipe, inlets slot and GOAL Pump program of the Bradford and underlying groups *Target wells all of ~7 years of age with demonstratively decreased production due to combined down hole brine accumulation [most recent data records 600'- 1000' of brine] and up hole thief zones
Anticipated/ Targeted results	* Remove 0.25 to 1.0 Bbl/ brine per tool cycle at 1 to 6 trips/ Day with targeted increase production of natural gas @ 2X to 3 X.
Capital Cost for Pilot re-fit work	* $37,000- $44,000/ well estimated

2.2.1 Wells reviewed for consideration in this group included:

Table # 4

Open Hole Completion Gas Wells w/ Brine Problems Reviewed for Potential Re-fit

Well designation	**Gas yield**	**Fluid yield/ est. recent production [early 2006] via siphon string**	**Depth**
Mlr #2	**9 mcfd**	**0.5-1.5 bbl/ wk**	**3350'**
Shftsl # 5	**8 mcfd**	**1-2 bbl/ wk**	**1650'**
Shftsl # 8	**2.7 mcfd**	**2-4 bbl/wk**	**3810'**
ECM	**8.5 mcfd**	**1-2 bbl/ wk**	**3150'**
Shfr # 1	**6.3 mcfd**	**1-3 bbl/wk**	**Not supplied**
Hlbh # 5	**12.4 mcfd**	**0.5-1 bbl/wk**	**Not supplied**
Mlr # 4	**7.4 mcfd**	**1-2 bbl/wk**	**Not supplied**
Shftsl # 7	**2.8 mcfd**	**2-4 bbl/wk**	**Not supplied**

2.2.2 During the course of the project [late summer of 2006] the availability of these wells for re-fit potential was lost in a sale event to a new owner/ group. The wells were no longer considered and or further evaluated for potential application of re-fit.

2.3 Group 3 potential target wells for re-fit with GOAL Pump system

Re: Medina [tight] sands

Outline of Target Gas wells conditions for Re-fit

Target Geologic Group/ Formation	Median [tight] Sands
Location	Chautauqua County, NY
Depth Range of wells	3300'- 3500'
General Well Construction	3000-3500' of 4.5", 10.5# production casing [cemented]
Completion and Stimulation	* 1 sand Group/ zones perfed/ fraced/ stimulated
General Production History pressure	* IP @ 100- 300 mcf/d w/ 700- 1200psi well head * Production at 20 year post completion @ 1 to 10 mcf/d w/ 80-200 psi well head pressure * Fluid production [periodic] at 0.5 to 40 bbl/ removal
Economic Life of well	* At 20 years of age currently marginal
Well replacement cost	* $125,000- $145,000
Operating Considerations	* Brought on line as open flow < 1 year *Siphon tubing installed 6 months to 1 year w/ periodic *Surfactant addition/ shut in and vent – surge to brine tank *Tubing plunger and casing plunger in potential target wells [historic] *Operating line pressures @20 psi – 60 psi *Well tending and operations fees @ $4000- $6000/ year/ well

Re- Fit considerations	* Standard J-55, 4.0" ID well casing @ 10.5#/ foot w/ 4.0 inch ID *1 of target wells produces sand [~depth of 3500'] are current low pressure @ 100 psi vs. line of up to 75 psi- * 1 well operating characteristics may indicate casing leak at 500-1000' BLS *Target wells all of ~20 years of age with demonstratively decreased production due to combined down hole brine accumulation [most recent data records 400'- 600' of brine]
Anticipated/ Targeted results	* Remove 0.25 to 1.0 Bbl/ brine per tool cycle at 1 To 6 trips Day with targeted increase production of natural gas @ 2X to 3x.
Capital Cost for Pilot re-fit work	* $28,000- $36,000/ well

2.2.3 Wells reviewed for consideration in this group included:

Table 5

Cased Gas Wells with in Well Casing and or Sanding Problems Considered for Reift

Well Designation	**Gas Yield**	**Fluid Production**	**Depth**
L-54	**1-2 mcfd**	**2-4 bbls/ wk**	**3425'/ perf @ 3325'**
L-322	**3-5 mcfd**	**7-10 bbls/ wk**	**~ 3350"**

Notes:
1] Both of these wells have been equipped with casing swabs in the past with notable increase in gas yield with nominal removal of fluids in the range of 0.5 to 2 bbls/ brine/ day
2] Well 322 had developed a sanding problem when dewatered to the perforations. This well could benefit from slip lining with 3.0" ID PloyFlow which will fit in the existing 4.0" ID J-55 casing and be set to lift fluids from an elevation 50' above the existing perf zone/ sand producing zone allowing for additional rat hole for settling of solids
3] Well 54 appears to have a casing failure problem in the 500-700' zone based upon past equipment performance and could be slipped lined with poly and packed off below this zone to avert pressure loss in this zone

Task 3

Construct Tool System

As noted in the Technology Overview section above ***several unique/ new -elements had to be conceptually developed, designed, fabricated, bench and field tested*** for integration into a system for re-fitting of an [1- one] existing stripper wells. In the initial proposal [non-funded Table x, y and z]] more time, monies and effort had been proposed to accomplish these goals of:

- Development of metallic to non-metallic connectors to match up to standard in field industry steel connectors and the currently available continuous spooled synthetic tubing with nominal internal diameter loss of < 0.3".
- Conceptualization, design and fabrication of unique [new] seal cups had to be fitted and tested to maintain seal across the reduced and variable diameter metallic to non metallic transition swage/ ferrule and
- Match a new down sized convertible tool [3/4 tool- i.e. convertible from 4" to 3" with appropriate diameter seal cups] with new actuator for deployment in the spooled synthetic tubing of 3" and or 4" ID

Effort, time, testing and cost in excess of that allotted and anticipated were required to match the multiple elements to achieve what is now bench proven and a field prototype ready system for installation. SWC cost was fixed, [partial funding of the original proposal request] @ $75,000 while BEDCO support was raised from $86,750 to > $132,651 on the work project.

The time, energy and monies employed were maximized in the development of this new hardware and system via the use of CAD assisted Rapid Modeling software. Even with this powerful software tool, more than a dozen [18] different sets of seal cups were designed, constructed and bench tested on the new convertible ¾ tool in > 10 differently configured swaged ferrule [high strength steel] metallic to non metallic connectors of variable thicknesses, metallic strength, inside diameter and angle of transition. In part the effort expended here on is outlined on more detail below.

POLY TUBING AND NEW SWAB CUP DEVELOPMENT

Background

Spoolable, fiber reinforced, Poly tubing has been developed for use in open hole completion wells and for existing wells with questionable casing integrity. The poly tube requires swaged ferrule end fittings to interface with wellhead equipment (full port valve and receiver) and tying poly tube sections together in wells deeper than about 1500 feet. Additionally, the spooling process tends to cause a slight out of roundness in the tube cross section. New swab cup concepts needed to be developed to accommodate the change in tube ID associated with these fitting transitions while maintaining a pressure seal during transit of the poly tube and wellhead equipment.

A multifaceted development program was initiated:

1) To develop swab cups that would be tolerant of variations in tube inside diameter,
2) Proof test selected cup diameters and materials to demonstrate PetroPump operation in tubes with modeled ID variations,
3) To develop Poly Tube fittings and test with/ match the smaller [3.0” overall diameter] PetroPump and developed swab cups.

Experimental

Development Program.

Acrylic Test Chamber

A 3” PetroPump casing plunger was created to accept a variety of swab cups. These were evaluated in a new, 3” ID vertical, clear acrylic test chamber. The chamber was constructed with removable sections such that steel tubing or poly tubing sections could be added. Clear acrylic was used to visualize the swab cups during transit of the tube. The test chamber was successfully pressure tested to 120 PSI which was considered to be greater than the upper limit of desired operating pressures. The PetroPump was evacuated with the flow valve forced closed to obtain the minimum possible Sensor/actuator charge pressure. This resulted in a flow valve closing pressure of 42 to 44 PSI.

Multiple tests were conducted in which the chamber was pressurized from the bottom with the 3” PetroPump resting on the bottom on a soft stop. The pressure was gradually increased until the flow valve in the PetroPump closed, as observed by noting the pressure at the top of the chamber. (The pressure at the top stopped increasing when the flow valve in the PetroPump closed.) The swab cups under evaluation were required to effectively seal the 3” ID acrylic tube and reverse in the upper receiver section and allow a free fall of the plunger.

In operation, the pressure at the bottom of chamber is slowly increased (about 6 to 8 PSI above valve closing pressure) until the PetroPump levitates and starts to move up the tube. The air/ gas above the PetroPump, being compressed by the upward travel, is vented at the top of the chamber to maintain the pressure differential, simulating well conditions. When the PetroPump reached the top of the test chamber, the pressure above the PetroPump is reduced to simulate well flowing conditions of 22 to 23 PSI. At that point in the testing the pressure below the PetroPump is slowly reduced, as it would in an actual well receiver, at a pressure of about 30 PSI the flow valve opens and the PetroPump descends to the bottom of the chamber. These pressures are representative values as many dynamic tests were conducted with different cup and PetroPump configurations.

Initially the chamber, plus a 3 foot section of 3” ID schedule 40 steel pipe, was used in evaluating the PetroPump with conventional designed swab cups. These tests were successful.

Poly Tube Test Program

Potential sources for 3” diameter, spoolable, reinforced poly tubes were contacted. And two sections of tubing were purchased for development testing; 3’ and 4’ lengths. The design uses layers of cross woven fibers plus Kevlar axial tension fibers to provide hoop strength and to support the down hole weight of more than 400’ of tubing. The end fittings are swaged steel outer shells with steel insert ferrules. Two developments were required; 1) the inside diameter of the standard ferrule in use was 2.4” (too restrictive for plunger use), and 2) the swaging process further reduced the ID by about 2%.

Ferrule Inserts

After initial bench work ferrule inserts were redesigned to a minimum ID of 2.7” and, after the swaging reduction, were machined back to the 2.7” ID. The 3” poly tubes had an inside diameter of 2.91”, they were machined out at the ends to 2.930” to fit over the insert ferrules. These sections of poly tubing were added to the acrylic test chamber for initial swab cup testing. This indicated that flexible swab cups could pass through the 2.7” ID restriction.

Out put from bench test work and commercial evaluation of available tubing dictated new thin walled ferrule inserts be developed to be compatible with the commercially available, and preferred, 2.91” ID tubing without requiring any tube end machining. These were made with high strength tool steel and did not experience an ID reduction after swaging. Standard tensile pull test were conducted by the tubing manufacturer to demonstrate the adequacy of the new end fittings. No tube-to-fitting slippage occurred. At a 7,500 pound load, the poly tube had a diameter reduction of about 1% and a change in length of about 2%. The testing was continued to tube failure at a 12,000 pound load. No end fitting slippage was indicated. The new ferrule inserts were considered to be acceptable for field use.

Poly Tube Ovality

Long sections of Poly tubes are rolled on 8 to 10 foot diameter mandrels for shipping. This results in some tube flattening, the following measurements for a 2.91” ID tube are considered typical:

Table 6

PolyFlow Spooled Tubing Metrics for Nominal 3” Poly pipe

Nominal Poly Tube Dimensions ID 2.91"; OD 3.5"

OD

Measurements		Major	DELTA	Minor	DELTA
Poly Tube Measurements		3.5280	0.028	3.4110	-0.0890
BEDCO Measurements					
	End	3.5540	0.0540	3.3995	-0.1005
	Mid	3.5825	0.0825	3.3980	-0.102
	End	3.55	0.0500	3.3995	- 0 .105

Estimating the Out of Roundness [Based on BEDCOs “Mid Point’ Measurements

Nominal ID 2.91” Max ID 2.993” Min ID 2.808

Swab Cup Development

Multiple swab cup designs were considered and preliminarily evaluated using the CAD assisted rapid modeling depiction software. A multiple lip, lantern ring, type cup had the best potential for an adaptable tube seal to the observed ‘ovality’ of the tubing. Several configurations were built and drop tested in a nominal 3” ID, pipe. A dual set of two rubber compound rings was selected on the basis of simplicity, cost and adaptability. Additional a third ring could be added if test results indicated the need for additional sealing. Swab cup diameters of 3.2”, 3.1”, 3.03”, 3“, 2.91”, and 2.85” were fabricated in 50, 60, and 70 durometer rubber compounds. The 3.2” cup would not drop (free fall) in the 3’ section of 3” ID steel pipe and the 2.91” and 2.85” cups would not pressure seal in 3” ID poly tubing.

Modifications were made to the thickness and roundness of the lantern rings to improve flexibility: too thick would interfere with cup reversing in the receiver as well as adapting to the ID restriction; too flexible would interfere with cup sealing- empirical testing showed a thickness of 0.11” to 0.1”was found to be optimum.

Testing

A tapered reduced diameter section was added to the acrylic test chamber, during initial swab cup testing, to simulate end fitting insert ID restrictions. The inside diameter transition from 3” to 2.7” and back to 3”. Swab cup sizes and shapes were modified for best adaptive performance. Testing with 2.85” and 2.91” diameter lantern ring swab cups were unsuccessful in that the pressure blow-by in the 3" ID tube sections was too great to support the lifting of the PetroPump. As noted previously, the 3.2" diameter lantern ring cups failed the drop test in the 3" diameter steel pipe and it was found that the 3.1" diameter lantern ring cups would drop but would not reverse in the 3" diameter pipe. (Note: the flexible cups are concave down during the upward travel and must reverse to concave up, in the receiver, for plunger descent.).

The tapered section was removed from test chamber and two sections of poly tubing were installed providing three areas of insert restricted ID. Testing with the 3" ID lantern ring swab cups was successful. The PetroPump was repeatedly levitated into the top of the 3" ID acrylic receiver and when the pressure was evacuated (simulating actual well conditions) the cups reversed and the PetroPump automatically descended to the bottom of the test facility. This test demonstrated that the 3" cups seal through out the travel through the 3" ID acrylic tube sections, through the 2.91 ID poly tube sections and through the 2.7" ID ferrule inserts end fittings.

Additional testing was conducted with a longer (3') section of 2.91" ID [commercially available] poly tubing, with the new end fittings. It had been spooled on a large shipment reel with the typical flattening and bending that would be exhibited in the field. A 3' section of 3" ID steel pipe was added to the test chamber to represent the well head receiver. Clear acrylic sections were on either end. It was noted that some straightening of the poly tubing occurred during pressurization. Numerous tests were conducted with this final test chamber arrangement. It provided a realistic representation of eventual well conditions.

The diameters and flexibility of the lantern ring swab cups were modified during the development to obtain the best dynamic performance in the test chamber. The selected cups had a diameter of 3.003" to 3.005" and ring thickness of about 0.1". They were able to pressure seal within the 3" ID acrylic sections, adapt and seal in the oval 2.91" ID (nominal) poly tubing, pass through the end fitting restriction of 2.7" ID and seal and reverse in the 3" ID steel simulated receiver.

Results and Discussions

The earlier first and second quarter testing of the Lantern Ring- lip seal cups proved viability and predicted certain acceptable longevity of use in up well and down well simulated conditions. The tool with Lantern Ring cups were passed down well through the 0.3" restriction under its own weight against both the 45 degree and 7 degree taper which simulate the anticipated field restrictions conditions. The tool passes up well across the 45 degree and 7 degree taper with as little as 5 psi behind tool pressure. Modifications to the metallic swage ferrule/ poly transition components were made in Quarter 3 to improve strength and be closely matched to standard schedule 40 steel pipe spec. These modifications to the ferrule and swaged connections dictated the need for redefined specs and manufacturing of the Lantern Ring seal cups. These seal cup modifications were completed and fitted to a standard 3" GOAL PetroPump and then tested in newly fabricated [standard/ nominal 3" ID [2.91"] poly tubing with swaged ferrule well head connector and down hole swage ferrule connector for wells in excess of 1500'of depth. The results of that testing are listed below:

Summary of Results for New Seal Cups and Transition Metallic Ferrule to poly Transition

1. New poly tubing end fittings were developed to reduce insert flow restrictions from 2.4" ID to 2.7" ID and proved to be compatible with nominal 3" ID tubing [2.91' as measured].

2. The new end fittings were swaged on to test sections of 2.91" ID poly tubing and tested to destruction at axial loads consistent with testing of older end fittings providing a proof of design for field down hole use to loads in excess of 7000 pounds [tensile].

3. Poly tube ovality of less than +/- 3% was measured on several samples of previously spooled tubing.

4. A new swab/ further refined cup concept was developed for the PetroPump casing swab. The swab features flexible "Lantern" rings capable of adapting to the poly tube ovality and the end-fitting insert restricted ID. A nominal ring OD of 3.03" to 3.05", with a ring thickness of 0.11" to 0.1", was found to be compatible with 2.91" nominal ID tubing with 2.7" ID inserts.

5. A vertical test chamber was constructed to dynamic test design variations in tubing, end fittings, and swab cups. It consist of 3" ID clear acrylic end sections, one or more sections of poly tubing, and three feet of a 3" ID steel pipe (representing the well-head receiver).

6. The PetroPump, with "Lantern Ring" type swab cups, successfully demonstrated, under simulated well operating conditions, the desired cup flexibility – that is the ability to pressure seal during the upward transit, adapt to the oval poly tubing, pass through end fitting restrictions, reverse in the simulated receiver and free fall to the bottom of the chamber.

All the above noted test results and findings were integrated in a final comprehensive system which was fabricated and successfully bench tested in commercially available 3" poly tubing. These late stage project changes in design and fabrication techniques and additional tests proved more time and resources consuming than initially anticipated. New metallurgy of swages and ferrule connections to the commercially available Poly pipe and change in seal cup elastomers and configuration to successfully integrate into the tool / tubing re-fit system consumed in excess of the allotted professional time, and fabrication cost.

The spec for the commercially available field applicable 3" ID spoolable poly and metallic swage/ ferrule restriction connectors has been successfully bench tested with matching new designed/ fabricated Lantern Ring seal cups and agreed upon. In field down hole trials of the combined/ integrated system have not occurred due to late project redesign needs and fabrication changes to match up to current commercial configurations and limitations [ovality post spooling] on available down hole Poly tubing.

Task 4

- **Re-configure select test well, deploy and adjust tool, then compare production pre and post**

4.1 Well Blew #1 was chosen for further consideration and field evaluation using the new designed and constructed 3" tool.

4.2 As delays were encountered in matching a suitable swage configuration to PolyFlow spoolable tubing with seal cup integrity of the new "Lantern Ring" seal cups, a modified, interim, test of the new 3" tool was initiated. This first test of the converted 4 to 3" tool was conducted with standard bell cups inside 3.0" ID J 55 steel pipe hung in the open hole completion of the target well. This work was conducted prior to completion of the spoolable PolyFlow system. Further details on this well are shown below:

- Well designation Blew # 1
- Well completed in 1999
- Estimated production by well tender 2nd half 2005 [flows into combined system w/ 4 other wells] @ 10-20 mcfd and 1-2 bbls of oil/fluid/day
- Well chosen for further field testing as a function of good gas to fluid ratio of ~ 10-1 [GOAL tool in standard steel casing w/ attendant roughness coefficient generally require a 3-1 gas to fluid ration to automatically lift fluids]
- Total depth 1873'
- 6 zones in open hole notched and fraced
- Surface casing, 0-600' -- 7.5" J-55
- Open hole 600'-1873' @ 6 5/8"
- 260 psi on well in Jan. 2006
- 75 psi line pressure

4.3 The well was isolated from the other 4 wells in the system to afford its testing and quantification of test results. Existing piping was removed from the well. 1800' of 3.5" OD J-55 casing was hung in the well for the test. The base of the casing was fitted with a safety stop for the tool. The well head was equipped with a 3" full port ball valve and a 3" lubricator with catcher assembled atop the full port ball valve. Outlet piping from the lubricator was plumbed to a GPU unit with gas then piped to the old system gathering line and the fluid side of the GPU plumbed to a 50 Bbl Poly fluids tank. During the work over and set up for testing the following data was developed:

- Gas flow rate during the work over [Sept 2006] as estimated by the field engineer was recorded @ 5-7 mcfd [considerably lower than the previous estimate of 10-20 mcfd]
- Fluid level/ oil level in the well was shown to be ~ 600' above bottom hole [~25 bbl oil equivalent]. Previous estimated production by the tubing plunger/ rabbit system was for 1-2 bbl/day.
- Note: The 600' of oil column is ~ equal to 225 psi [assumed spg. Oil @ 0.8]
- Well head shut in pressure on the backside of the 3.5" J-55 casing hung in the well at the time of installation was 260 psi
- Well head pressure on the 3.5", before tool was deployed was 75 psi
- Line pressure of the gathering system was recorded at 70-75 psi
- 24 hours later the back side of the 3.5" pressure remained at 260 and pressure on the 3.5" had increased to 190 psi

4.4 The tool was deployed with 45 psi in the actuator targeting a closure pressure of ~115 psi and a 0.3-0.5 bbl lift against a 70 psi back pressure on the gathering line, post the 24 hour stabilization of the well. No tool runs were achieved over the next 7 days although some gas production occurred.

4.5 To reduce back pressure on the system, the well was isolated from the gathering system [75 psi]. Over the succeeding 3 days no runs were achieved.

4.6 In order to quantify potential problems a volumetric gas test was conducted on the well which showed free flow gas flow at < 2 mcfd equivalent. This was considerably less gas flow than had been formerly estimated and insufficient to lift the quantity of oil in the well bore but nominally sufficient to lift the target ½ bbl for which the tool was set.

4.7 Efforts to operate the tool and system continued for an additional 3 weeks with no runs achieved through early October 2006 albeit gas production and down hole [sounds] of tool movement.

4.8 Potential problems leading to absence of performance:

- Insufficient gas to fluid ratio to lift quantity of oil present [3 mcfd gas to 1 bbl/ oil-fluid is normal metric for the tool]
- Tool actuator did not seat and create pressure seal between tool and the 3.5" J -55 casing
- Insufficient pressure differential exist to lift tool and column of oil
- Up hole shallower fraced zones bleeding off pressure/ gas necessary to lift fluid column

4.9 Of the above listed variables the gas to fluid ration appeared the more likely, a shallow take zone on the back side of the 3.5" tubing was also a possibility.

4.9.1 Targeted follow up work to identify the limiting factors include:

- ✓ Tool retrieval and re bench test to inspect for blockages
- ✓ Tool re- bench test to assure open and closer pressures

- ✓ Swab well of fluid and re-calculate fluids and gas production rates
- ✓ Detailed review of well construction and completion logs

4.9.2 This follow on work was not achieved due in part to absence of availability of work over rig and closure of/ weight limitations of site access road for fall- winter conditions. Further project funding limit was reached on the SWC portion, BEDCO matching portion was exceeded as time ran out on project completion date in 2006.

Task 5

- ➢ **Evaluate system performance and comparison to predecessor methods for the target well**

5.1 In well operation of the 3" tool portion of the system was not achieved, as noted I Task 4 above.

5.1.1 A new designed 3" GOAL tool was fabricated, bench tested and well cycle simulated with standard "bell shaped" cups. This tool was subsequently deployed to and in a target well in 3.5" J-55 steel casing to field prove effectiveness of the tool alone under similar well conditions to that in which the proven 4" tool had been deployed historically.

5.1.2 The well, Blue #1, but did not achieve desired results with the deployed tool. No automatic cycles/ lift of fluids by the tool were achieved. Possible elements contributing to absence of performance are outlined in section 4.8 above.

5.1.3 Identification of specific element [s] causing performance failure requires further work, beyond the allotted budget and project time period.

5.2 During the above modified field testing of the new 3" tool with standard "Bell Shaped" seal cups; bench work continued on the spoolable Poly tubing system, poly to metallic swaged connector system with "Lantern Ring" cups. Reproducible results in the bench test well were achieved and a field ready system comprised of:

- New small diameter [3.0" OD] GOAL tool was developed and pressure cycled across anticipated field conditions
- 3.03"- 3.05" OD Lantern Ring cups were successfully developed, fitted to tool and pressure cycled across the metallic to poly swaged connection as well as across connection to standard schedule 40 steel pipe
- Market available 3" Poly pipe was found to have a nominal 2.91" ID
- 1500'-1800' spools of 3" tubing are capable of fabrication, spooling and un-spooling without taking on permanent-long term "egging"/ ovality of the tubing which would interfere with cup seal.
- The developed high strength steel swaged ferrule connector was designed fabricated and fitted to the 3" Poly resulting in a minimum ID across the swaged ferrule of 2.7" [0.21"

loss of ID at the connector] This was within seal cup tolerance for maintenance of seal integrity while cycling the tool across the transitions

- In field assembly of up to 6000' of spooled and swaged ferrule connected poly tubing appears doable without exceeding longitudinal strength or excessive elongation of the tubing
- Gravity, friction and 'sticktion' forces were over come with as little as 6-8 psi pressure differential to lift the tool inside the bench well spoolable poly system. This is in contrast to 12-15 psi pressure differential needed to move the standard 4" tool in J-55 steel casing, affording 6-7 psi more lift potential and lesser formation abandonment pressure

Task 6

- **Estimate/ evaluate economic impact of tool**

6.1 Full scale field testing of the combined system was not achieved due to budget and time constraints. Excessive engineering time and fabrication dollars were diverted to design, fabricate and test the complex metallic swage to poly connection with smallest ID loss to accommodate new "Lantern Ring" seal cups

6.2 Partial testing of the downsize 3" tool with standard "Bell Shaped" cups was performed with out the targeted success desired.

6.3 An integrated system is now bench tested with spoolable poly tubing and downsized 3" tool.

6.4 Based upon historic experience in development of the 4.0" GOAL tool for standard J-55 casing [2 iterations were necessary to achieve regular field success], the new system once shakedown tested can provide 1.5-4 X increase in gas production once fluids are regularly and systematically lifted from the well via the natural lift system.

6.5 The tool system is targeted to be able to refit a well like Blew # 1 notes above of current open hole completion for ~ $25,000-$30,000 [tubing, tool and connectors]

6.6 Pay back on a well yielding 10 mcfd with as little as a 2x improvement in gas yield will pay back capital in ~ 1 year at $7/ mcf gas price. A 6 month time line of pay back can be achieved if / where a 3 X in gas yield is accomplished. This type of increase in gas yield have been accomplished with use of the 4" tool in 4.5" J-55 casing. Lesser friction losses in the poly tubing should afford greater total lift and removal of hydrocarbons from the reservoir. Additionally operating cost of other energy and or man power intensive production techniques are off set with the self actuating GOAL PetroPump.

Table 7

Comparative Metrics of Steel and PolyFlow Pipe

	3.5" Steel Frac Pipe	3.0" PolyFlow spoolable synthetic
Designation	J-55 3.5"	**PolyFlow Thermoflex** ***[Polypropene, Kynar strands, Aramid fiber and Nylon]***
Nominal ID	2.992"	2.91"
Weight/ ft	9.2#/ ft	1.5#/ft
Destructive pull test	---	12,000 # ***[did not pull out the swage connection- poly separated]***
Pressure differential to move tool	12-15 psi	6-8 psi
Unit length	30'-40'	1500'-1800'
Unit cost	$7.11/ ft ***[3-15-2006]***	$6.93/ ft ***[12-30-2006]***

Notes:
1] Poly Flow pipe required 6-7 less pressure [psi] to move tool than standard J-55 steel

Conclusions

The development and use of the Bench Test Well and the CAD assisted graphic depiction rapid modeling program for the seal cups developed in Quarter 1 where it focused on "Bell Shaped" cups and again in use again in late project work and modifications to accommodate poly tubing ovality work were most valuable in rapidly identifying problems and development of solutions which lead to workable "Lantern Ring" seal cups to meet field target need. The critical need of cup seal integrity, flexibility and durability was achieved. Test work showed the ability of the tool and cups to pass [in well] metallic to non – metallic transitions of ~0.21"- 0.3" in both down hole and up hole travel with out loss of seal or significant pressure drop. The tool and cups easily pass down hole through the 0.3" restrictions under weight of tool/ gravity. The tool and cups similarly easily reversed and passed up restriction with as little as 6-8 psi below tool pressure vs. similar test of 12-15 psi for standard schedule 40 steel well casing. Life cycle test of the new cups achieved acceptable results for the anticipated field use. The projected life cycle of these cups in tests is shown to be equal to or greater than life cycle for existing in use/ in field standard GOAL cups operating in steel casing for 6 months of use or more.

The modified design and fabricated cups are shown to accommodate the 'ovality' [egging] of the tubing and fit the new designed new metallurgy and fabricated metallic ferrule to poly connection while maintaining needed sealing properties to lift in well fluids.

Strength [elongation and shear] and ops testing [> 7000 pounds of tensile load- tubing failure not swage pull out at 12.000 #'s] of the tubing to swage connection and tubing to ferrule connection at the bench test facility have shown results in acceptable range for anticipated field conditions.

Current commercially available field scale flexible [non- metallic]– spoolable poly matched up with standard schedule 40 steel specs for well head change over to steel has been identified and successfully bench tested to re-fit open hole and large diameter [4" ID or larger] cased stripper wells using the modified 3"GOAL PetroPump with Lantern Ring seal cups.

The system is ready for in field deployment and full scale testing in a joint venture operation with an existing owner of large diameter > 4.5" J-55 cased stripper well or open hole completion well.

Findings and conclusions presented here in are the results of work conducted by and or directed by BEDCO unless otherwise referenced.

References:

Business News, Fox News Network. Neill Cavuto, October 2006.

"2005 Marginal Oil and Gas Wells Survey", Interstate Oil and Gas Compact Commission, 2005.

Table 9

Comparison of Initial Proposed Financial Metrics, SWC authorized work and total spending by BEDCO

Original Proposed Work and cost by Brandywine for work on 2 wells [Appendix B]
Vs.-- Unit Cost Equivalent/ Well,
Vs.—***SWC Authorized Financed Program for work on A/ 1 well [Appendix A]***
Vs—**Actual Expenditures**

	[1] Original Proposed Work by BEDCO for 2 Wells [Appendix B]	[2] Equivalent Unit Cost per Well	***[3] Authorized Funding by SWC for revised work on A [1] Well [Appendix A]***	**[4] Actual expenditures to date on work program**
SWC Portion and [%] equivalent	***$208,942.70 [63%] Portion***	***$104,471.35 [63%] Portion***	***$75,000 [44%] Portion***	***$74,977.46 [36%] Portion $4x,xxx reimbursed to date***
Brandywine Energy Portion & [%] equivalent	**$121,661.80 [37%] Portion**	**$60,830.90 [37%] Portion**	**$86,750.00 [56%] Portion**	**$132,651.13 [Through Feb 2007- On going works self funded] [64%] Portion**
Total Cost	$330,604.50	$165,302.25	***$161,750.00***	**$207,628.59 total end of Feb 2007**

Notes:

1] Original proposal by BEDCO- " Re-fit Two Stripper Wells with Existing Large Diameter or Open Hole Completions with Spoolable Non – Metallic Tubing, Transition Connections, Variable Diameter Seal Cups and Modified G.O.A.L. Casing Swab to Automatically Lift Fluids and Enhance Performance [$330,604.50 for 2 wells]

2] Equivalent proportioned cost to SEC and BEDCO per wells assuming equivalent cost between wells [i.e. no variables] [$165,750 proportionate cost/ well]

3] Authorized funding by SWC- "Revised" Original proposal by BEDCO- " Re-fit A Stripper Well with Existing Large Diameter or Open Hole Completions with Spoolable Non – Metallic Tubing, Transition Connections, Variable Diameter Seal Cups and Modified G.O.A.L. Casing Swab to Automatically Lift Fluids and Enhance Performance
[$161,750] incl. $75K from SWC

4] Actual Expenditures to date [end of Feb 2007] and apportion equivalent share of total cost [BEDCO continued on with the work under its own expense] $207,628.59 total, SWC maximum $75,000 [approximately $45,000 reimbursed to BEDCO as of Feb 2007]

Appendix A

[Revised Proposal in response to SWC partial funding of $75,000 for a re-fit program for a well]

ATTACHMENT B – PROPOSAL COVER SHEET

Proposal Submitted to: Mr. Joel Morrison
Stripper Well Consortium
The Pennsylvania State University
C-211 Coal Utilization Laboratory
University Park, PA 16802-2308

Date of Submission : 07 February 2005

Title of Proposal: Re-fit A Stripper Well with Existing Large Diameter or Open Hole Completion with Spoolable Non-Metallic Tubing, Transition Connections, Variable Diameter Seal Cups and Modified G.O.A.L. Casing Swab to Automatically Lift Fluids and Enhance Performance

Company Name: Brandywine Energy and Development Company

Principal Investigator: Brandywine Energy and Development Company

Phone : 610-388-3824 Fax: 610-388-3825
Email: yanigapm@aol.com, gswoyer@comcast.net

Address: P.O. Box 756 Frazer, Pa. 19355

Other Participants: RJB Well Service, Lenape Resources Inc

Amount Requested from ***SWC :*** ***$75,000.00***

Cost Share Commitments: Cash >>>
(Minimum 30% Required) ===> **$86,759.00**
BEDCO cost share ~56% In-Kind >>>

Total Project Costs $161,759.00

Last modified on October 20,2004

PROPRIETARY INFORMATION: Does this proposal contain Proprietary or Confidential Information?

_____ NO ___X__ YES (if yes, complete box below)

Notice of Restrictions on Disclosure and Use of Data

The data contained on pages 6,7,8,9,10,11,12,13, appendices and drawings. of this proposal are submitted in confidence and contain privileged or confidential commercial and/or financial information. Such data may be used or disclosed only for evaluation purposes. If funded, the Government would have the right or use or disclose data from this project to the extent provided the DOE/PSU Cooperative Agreement. This restriction does not limit the Government's right to use or disclose data obtained without restrictions from any source, including the proposer.

Submitted by: BEDCO

____
Signature of PI

Approved by:

____
Authorized Representative

Last modified October 20,2004

Appendix B
Original Proposal and proposed economic commitment [non funded] by SWC

ATTACHMENT B – PROPOSAL COVER SHEET

Proposal Submitted to: Mr. Joel Morrison
Stripper Well Consortium
The Pennsylvania State University
C-211 Coal Utilization Laboratory
University Park, PA 16802-2308

Date of Submission : 07 February 2005

Title of Proposal: Re-fit Two Stripper Wells with Existing Large Diameter or Open Hole Completions with Spoolable Non-Metallic Tubing, Transition Connections, Variable Diameter Seal Cups and Modified G.O.A.L. Casing Swab to Automatically Lift Fluids and Enhance Performance

Company Name: Brandywine Energy and Development Company

Principal Investigator: Brandywine Energy and Development Company

Phone : 610-388-3824 Fax: 610-388-3825
Email: yanigapm@aol.com, gswoyer@comcast.net

Address: P.O. Box 756 Frazer, Pa. 19355

Other Participants: RJB Well Service, Lenape Resources Inc

Amount Requested from ***SWC :*** ***$208,942.70***

Cost Share Commitments:	Cash >>>	
(Minimum 30% Required)	===>	**$121,661.80**
BEDCO cost share ~37%	In-Kind >>>	

Total Project Costs $330,604.50

Last modified on October 20,2004

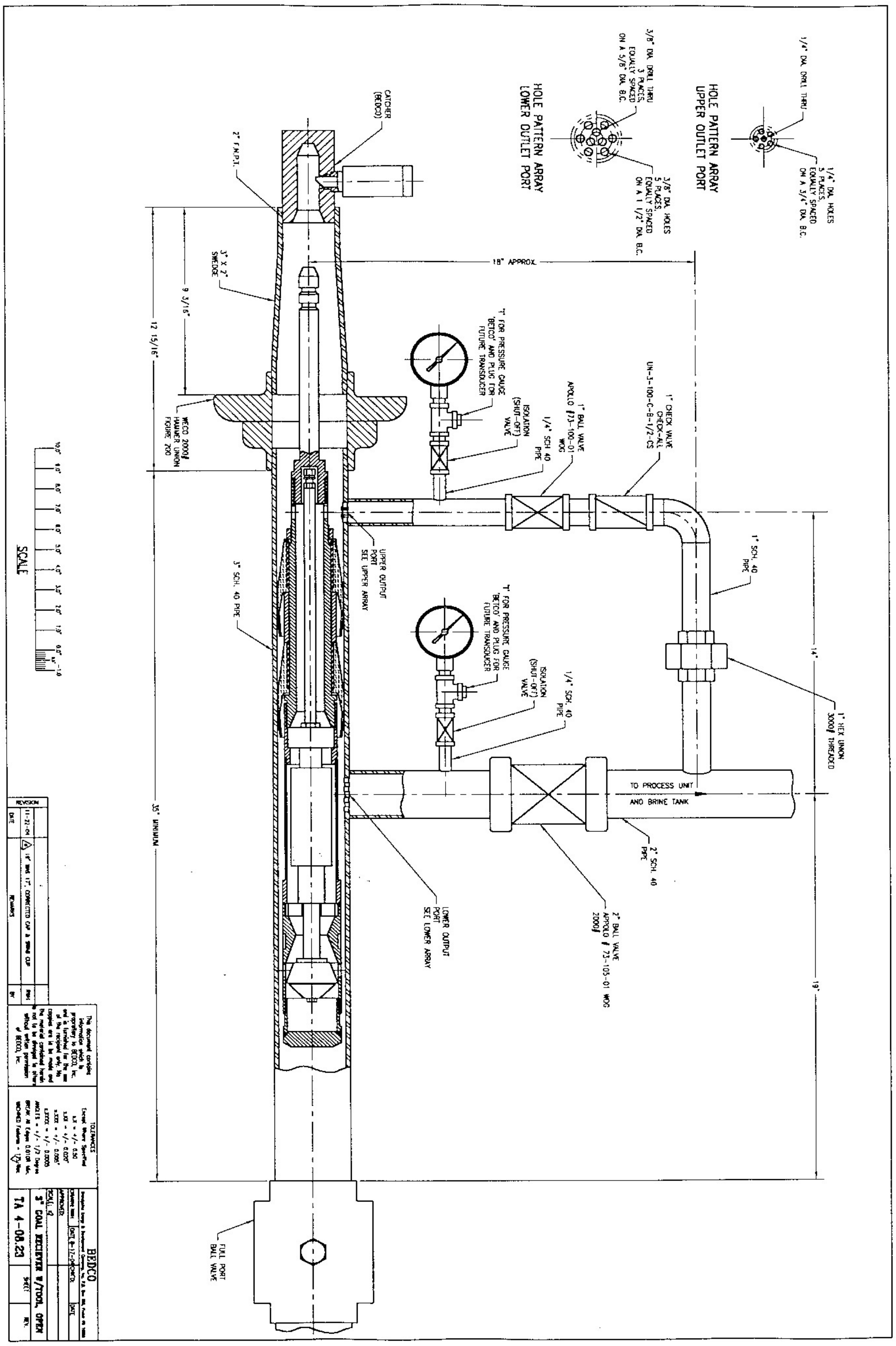

Figure #1