HOW/WHY HIGH-PRESSURE GAS LIFT (“SINGLE POINT GAS LIFT”) ADOPTION/USES CONTINUE TO GROW

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ABSTRACT

In less than 9 years, High Pressure/Single Point Gas Lift has grown from 0 to over 3000 applications in unconventional wells and its use continues to expand with trailer mounted units to unload frac hits and applications later in the well life.
This paper presents examples of these expanding applications including case histories on unloading frac hits and shows how/why this very simple "new" technology grew from one person's idea to widespread/ expanding adoption in a relatively short time. Operating tips for increased effectiveness and potential applications in the future are also shared.

INTRODUCTION

Introduction and adoption of “new technology” to oil and gas production has been a notoriously slow and difficult process, especially in recent years.

The rapidly growing adoption of high pressure/single point gas lift (HPGL) can be viewed in at least three ways. It is a testimony to the practical brilliance, dedication, and perseverance of one individual. It might be seen as a glowing example of moving effective innovative practices along quickly. There is also a darker aspect in that it could be a “cautionary tale” about the danger of being so engrossed in an established and reasonably effective current way of doing things that there is a failure to recognize a simpler and potentially better way that started over 150 years ago.

Because of the simplicity and flexibility of HPGL, it can literally be applied to almost any well where liquids need to be lifted. While this doesn’t mean it will always be the optimum form of artificial lift, it does mean that it can be considered as an option in any artificial lift situation where there is at least a small supply of natural gas available.

This paper presents a brief history of how HPGL started, attempts to explain why it has grown and continues growing so rapidly, how it is being used in more diverse and innovative ways (with particular focus on unloading frac hits) and how it can be operated more effectively and used in new ways.

DEFINITIONS

High Pressure Single Point Gas Lift (HPGL) – The use of gas of sufficiently high pressure to be able to lift a full column of fluid in the well. This eliminates the use of staged gas lift valves as well as a packer and enables lifting at or near the producing zone. It also provides the flexibility to inject down the tubing or annulus to maximize flow area or minimize injection required.

Single Point Gas Lift (SPGL) – Similar to HPGL, except using pressures which are less than what is required to lift a column of fluid.

Conventional Gas Lift (CGL) – The practice of using staged bellows type valves (first patented in 1940 by W. R. King) to enable lower pressures to be used to lift deeper in the well. Typically, a packer is used, and production flows up the tubing, however recent practice has expanded to lifting up the annulus.

Producing Bottom Hole Pressure (PBHP) – The pressure at the producing interval which determines the well's inflow from the reservoir and thus its production rate.

Compressed Natural Gas (CNG) – A means of making natural gas more transportable/ useful by compressing the gas to high pressures (+-4500 psig) resulting in a more than 300 times increase in its density vs. atmospheric pressure.

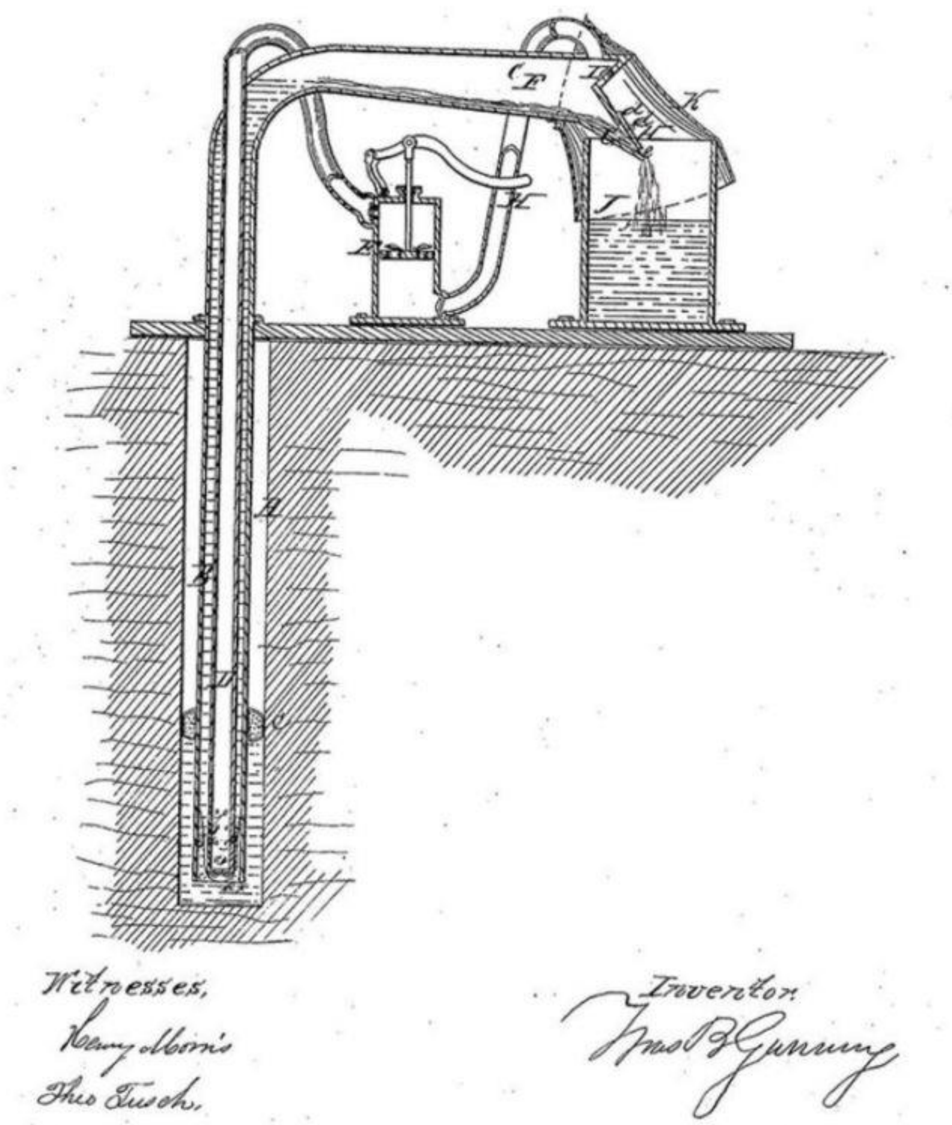
Bullheading – The practice of displacing fluids from the well with any fluid (in this case, high pressure gas) injected from the surface. Can be used on casing, packer wells and also on open ended tubing wells.

Trailer Mounted High Pressure Gas Lift Compressor (TM HPGL) – A mobile high-pressure gas lift compressor which can be easily moved to different wells/applications as needed.

Plunger Assisted Gas Lift (PAGL) – A means of making gas lift more efficient and requiring lower injection rates at lower well producing rates by adding a plunger, either continuous or conventional. This increase of efficiency and reduction of lifting costs can result in higher average producing bottom hole pressures (PBHP) over time.

A BRIEF HISTORY OF HPGL

A patent which describes what we now call HPGL was filed in 1864. This was only 5 years after the well that is usually designated the first commercial oil well was drilled by Edwin Drake in Pennsylvania. Therefore, this technology is celebrating its 160th anniversary.



Source: US Patent and Trademark Office.

Figure 1 - Thomas B. Gunning under patent no. 45,153 issued in November 1864.

Evidently HPGL was still being practiced 60 years later as this sketch from a gas lift manual in the “Actual Practice” chapter indicates.

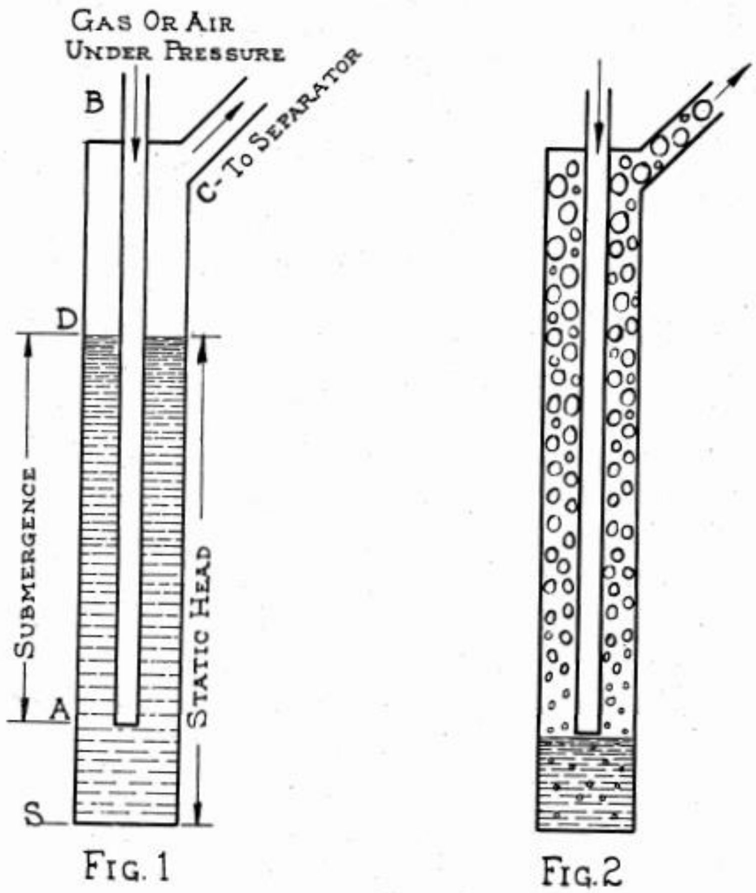


Diagram showing approximate conditions in a well before and after "kick-off."

[31]

Figure 2 – Diagram from "Actual Practice" Chapter of "Something about GAS LIFT (1928)

The challenge for HPGL was that as wells got deeper, higher and higher pressures were needed for its application. This was a problem since only large, limited working pressure compressor cylinders were available and low strength/working pressure tubulars were being used in wells. These limits spurred inventors to issue about 25,000 gas lift related patents between 1929 and 1945 and the subsequent widespread adoption of what is now called CGL.

Since the 1950's there have been very limited references to HPGL in the literature. It would be fair to characterize it as a little-known technology and its use as a novelty at best.

Fast forwarding to the 2010's, the huge growth in horizontal unconventional well drilling and production highlighted the importance of good artificial lift selection. With "crooked" wells and high production rates from 8000' plus, beam pumps were soon out of favor, causing ESP's (the normal high-rate alternative for many operators) to be used.

Unfortunately, failure rates and downtime due to solids production, rapidly changing rates and the gassy nature of these wells meant larger expenditures and less production than expected. It became clear that gas lift was a better option for handling these challenges. Unfortunately, CGL could not achieve the high rates desired due to the traditional use of packers and lifting up the tubing. It was not an optimal solution.

Enter William G. (Bill) Elmer. Bill was well known, both in his previous companies (including stints at Conoco and EOG) and in artificial lift/production optimization circles in the industry because of his many innovative ideas and his focus on the basics, like lower PBHP yielding higher production. Bill had retired and was doing consulting in 2015, but his previous efforts in well optimization on gas lift wells had caused him to question the wisdom of running multiple gas lift valves because of the failures he was seeing due to poor injection gas quality (water, condensate, CO2, methanol injection, etc.). This poor lift gas quality was a change from most operations prior to unconventionals because previously lift gas was clean as it had been processed.

Bill's practical thinking caused him to see that with higher pressures, fewer GL valves are needed resulting in improved reliability. This eventually led to the question - "why use any valves"? Looking at the high-pressure compressors which had become available after the advent of CNG and the high strength casing used in wells due to massive high pressure frac jobs, he saw that there were no barriers to doing this. Also, no valves enabled the elimination of the CGL "bottleneck" of flowing up the tubing by injecting down the tubing and flowing up the much larger annulus area at much higher rates, possibly matching ESP's.

On December 2, 2015, Bill made a presentation to engineers from all over the USA working at EOG, one of the biggest shale operators. Attached is a part of a slide from that presentation.

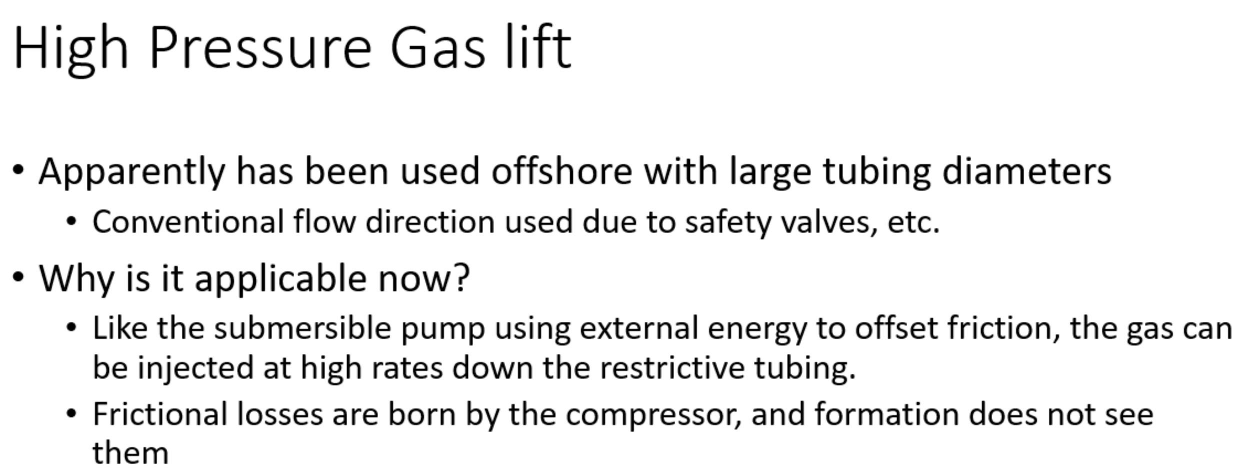


Figure 3 - Slide from Bill Elmer December 2, 2015, presentation

This is the start of the “modern era” of HPGL. From this start, the EOG engineers he presented to took this idea and began to put together what it would take to start implementing it at different areas in their company. They quickly found that one of the main problems with implementation was the lack of high-pressure gas lift compressors available. Compressor companies were not packaging units to do this because their clients were not requesting them and there was risk in building them if HPGL did not take off. One engineer in the Bakken, Branden Pronk, found it almost impossible to obtain compressors, although they did use CNG on limited tests of the idea. Eventually he kicked off efforts that would end up with air drilling compressors being temporarily adapted for HPGL use, not a sustainable solution. Meanwhile in Texas, another solution presented itself.

Dennis Estis owned a small compressor company in East Texas and had supplied Bill with compression when he was at EOG. Because Bill recognized that his HPGL “dream” could not be achieved without suitable compressor packages, he began working with Dennis to package units to do HPGL. Dennis was concerned about vibration/pulsation issues but knew that this idea would be “revolutionary” if it worked. He decided to take the risk and move forward with high-pressure compressor packaging. Bill worked with Estis engineer, Will Nelle, to develop a high quality package that would address the problems that Dennis originally feared.

In Midland, the engineers that Bill had originally presented to on HPGL found many potential Permian well candidates. They reached out to Dennis to supply 5 units and these units were successful - as orders for many more units started rolling in.

Bill had started sharing the concept with the industry, however there was a lot of skepticism and many concerns from people unfamiliar with gas lift and even experts in the CGL world.

After meeting substantial resistance at a gas lift workshop, Bill knew he needed help to convince the industry that HPGL was a legitimate approach with substantial advantages. He enlisted the help of his very experienced friends and fellow consultants, Jim Hacksma and Larry Harms. Jim had published on “Continuous Gas Circulation” a form of SPGL in 1997 and may have even spurred Bill’s thinking as he moved toward HPGL. Larry immediately saw the potential of HPGL.

These three “amigos” started making presentations around the industry. Bill, Larry and David Elmer, wrote the first SPE paper of the modern HPGL era which showed that HPGL had huge potential that the industry was potentially missing. However, there was no “real” data to back it up.

This is where Branden Pronk, who had moved to SM Energy reenters the picture. SM Energy was open to both implementing HPGL and publishing the results, a vital step in fostering the success of HPGL. The resulting test provided solid data that indeed over 5000 BPD could be produced from a 5 ½” Casing well with HPGL and that HPGL “can produce at rates comparable to ESPs”.

At this point, the growth of HPGL adoption started in earnest. With Bill, Branden, Jim, Will and Larry advocating to the industry and the widespread success of installations, growth accelerated. First to hundreds of installations annually and now with an industry unit well over 3000 applications and growing more quickly every year. Given the current accelerating acceptance and the growing usefulness of this technology, moving from an idea and 0 units to over 3000 installations in less than 9 years can be seen as a remarkable success.

That this success can be traced to the idea and initiation of one individual is certain. Bill Elmer, through his quest/ drive to find better ways of doing things that make more production, brought forth an idea that has resulted in great results for many operators and changed the industry. His perseverance in seeing this idea through was vital as there was really no “profit motive” for him. He willingly spent his time and efforts pushing it forward and enlisted his “amigos” to do the same.

In the end, a better idea should always prevail, but that is not always the case. In the case of HPGL, the simplicity and potential of the technology aided dedicated people to use forums like SWPSC, PBAL, ALRDC and SPE to present their logical, physics-based rationale to the industry. This enabled engineers to risk doing something that had never been done before at their company. A compressor packager was willing to take the risk of building units for a technology that was not proven. This can be considered a triumph of technology in a short period of time.

But why did any of this need to happen? HPGL started in 1864 and up through the 1930’s it was still being widely practiced. It was replaced by a technology that was indeed superior given the constraints of the time, but how could so simple an approach have been lost/forgotten?

For all of us, this is a cautionary tale in that we can get so engrossed in what we are doing that we fail to sit back and reexamine why we are doing it that way and whether there is a simpler way and/or another way that has already been used that might be preferable.

The success of HPGL in producing high-rate unconventional wells has been the main driver in increased use. Additional applications are coming to the forefront because of its simplicity and flexibility.

UNLOADING FRAC HITS WITH HPGL

One challenging item for unconventional well artificial lift has been the tendency of many wells to have substantial liquid and in some cases even proppant influx from the massive hydraulic fracturing being done at an offset well.

A brief illustration of using HPGL to unload a frac hit was given at the 2023 SWPSC.

The availability of trailer mounted high pressure booster compressors (TM HPGL) has made unloading frac hits much easier.

Below is one operator’s rationale for using TM HPGL to unload frac hits, along with detailed cases on three wells.

Options to Unload Frac Hit Wells

Swabbing - a traditional swab unit is a standard method to remove liquids from wells in general.

Swabbing Advantages

1. High success rate on packer wells.
2. No outside gas requirements

Swabbing Disadvantages

1. General risk from putting tools into the well.
2. Specific risk of getting stuck with solids
3. Limited fluid removal rates
4. Generally, requires an extra tank and the flaring/venting of natural gas.

Nitrogen - Can be injected in wells without packers to lift a liquid column via lightening the column of fluid and/or high gas velocity in much the same way as HPGL. It can be provided via liquid nitrogen tanks or via nitrogen generation equipment which requires a compressor to achieve high injection pressure.

Nitrogen Advantages

1. Does not require entry into the well.
2. Provides the lifting gas required, no outside gas requirements.
3. Liquid nitrogen can provide high rates, although these are not normally needed.
4. Can be used to displace fluids from the well via bullheading.

Nitrogen Disadvantages

1. Requires venting of nitrogen and then some natural gas until the produced gas meets pipeline requirements.
2. Liquid nitrogen is expensive, especially if long term unloading is required.
3. Nitrogen generation has relatively low-rate capability and the potential for introducing undesirable impurities such as oxygen into the well.

CNG – CNG is provided in 300-500 MCF “tanks”. It is used to conduct limited HPGL.

CNG Advantages

1. Does not require well entry.
2. No additional outside gas requirement
3. No venting or flaring should be needed.
4. Can be used to displace fluids from the well via bullheading.

CNG Disadvantages

1. Cost of trucking and gas
2. Limited amount of gas in tank
3. Pressure drops as the tank is emptied meaning much of the gas that is in the tank may not be able to be used to lift the well.

TM HPGL – Uses a mobile unit to do HPGL.

TM HPGL Advantages

1. Does not require well entry.
2. No venting/flaring should be required.
3. Ability to lift the well for as long a period as needed with reasonable costs.
4. Minimal personnel attendance required (with proper instrumentation/automation)

TM HPGL Disadvantages

1. An outside gas source is required from a buyback meter or CNG until the well produces enough gas to fuel the unit.

Learnings/Improvement Items for using TM HPGL

This operator found that using TM HPGL’s to unload frac hits was the most cost-effective option. Also given recent stricter environmental regulations on venting, TM HPGL or CNG may be the only methods that are allowed going forward.

The following items are offered as learnings that should be considered for other less experienced/potential users.

1. Training personnel on the specifics of using these compression units, how the well can be expected to respond as it unloads and how conditions will change

over time is important for efficient operation. For reduced cost/cycle time, it is also important to provide training on efficiently moving the unit from well to well.

2. Unmanned operation through instrumenting the unit to tie into the user's RTU, installing an LEL monitor and meter on each TM HPGL saves money and is especially important when using this method on more marginal wells. This instrumentation/automation allows the facility the unit is installed on to shut in the compressor as well as allowing the compressor to shut in the facility so all normal and added safety systems work together.

3. Compressor flexibility is also important so that minimal configuration changes are needed as it is moved from location to location, since rates/pressures can change substantially as a well unloads. A suction control valve can help provide more flexibility. A backpressure valve on the discharge is also important but care must be taken to protect the pilot. This issue can be solved by installing a sensing line protector on the pilot so that it is only functional within the allowable pressure range of the pilot.

4. High pressure hosing has the potential to reduce costs/cycle time vs. the normal chiksan piping used. Hoses are currently being tested by this operator. It should be noted that hoses can be controversial depending on the operator's risk perspective.

TM HPGL CASE HISTORIES

The following case histories were provided by the same operator in the Northeast who has adopted TM HPGL as their standard method of unloading frac hits. These three wells all have 5.5", 23#/ft casing and 2 7/8" tubing set near TD.

Case 1: Gas Lift Well, MD= 7550', TVD = 7200'

This well was being operated utilizing SPGL when it loaded up due to a frac hit. After 45 days of being shut in, with several unsuccessful attempts to flow the well during the shut in time, casing and tubing pressures indicate that there was a static fluid column of about 5700' of water.

The well was kicked off with TM HPGL at a peak injection pressure of 2315 psig and quickly was producing at high water and oil rates. The TM HPGL was kept on the well for 9 days to ensure it was adequately cleaned up. The frac hit changed the productivity, GOR and WC of the well and the well is now flowing at higher liquid rates without gas lift as shown below.

Case 1 GL Well	MCFD	BOPD	BWPD	MCFD Inj.	Tub., psig	Cas., psig
Pre Frac Hit Avg.	1607	321	65	207	356	654
Post Frac Hit Avg.	1325	558	366	0	677	1604

Figure 4 – Production Results from Case 1

Case 2: Gas Well, MD= 9370', TVD= 8980'

This gas well was being operated with a continuous plunger to minimize liquid holdup in the tubing when the well loaded up due to a frac hit. The well was down for 34 days. Tubing and casing pressures indicate there was a fluid column of about 8150' of water just prior to the well being unloaded with TM HPGL.

The well kicked off at a peak injection pressure of 2924 psig but required 20 days, using TM HPGL aided by a plunger, to return to near its former production rate. Given the increase in tubing and casing pressures, although the current rate is lower than the rate before the frac hit, the well productivity has increased vs. the pre-frac hit rate.

Case 2 Gas Well	MCFD	BOPD	BWPD	Tub., psig	Cas., psig
Pre Frac Hit Avg.	6393	0	0	888	1303
Post Frac Hit Avg.	5397	0	0	1356	1783

Figure 5 – Production Results from Case 2

Case 3: Well with Packer, MD= 8660', TVD= 8440'

Wells with packers cannot use HPGL to unload (without shooting a hole in the tubing) but the TM HPGL can be used to displace all the liquids from the well. Hopefully this will result in some produced gas/oil from the formation entering the well when it is opened to flow to lighten the column and aid flow, instead of the well having to lift a column of only water/frac fluids. Although it does not have the near 100% success rate of HPGL, this operator has had good success doing it and this is illustrated in Case 3.

Well 3 was being produced with a wellhead compressor and plunger lift with a reservoir pressure estimated at 1500 psia. After it was loaded up by a frac hit, TM HPGL was rigged up to the well's tubing and all fluids were pushed from the wellbore, into the formation. Total TM HPGL operations were 2.5 days and when the well was brought back online it was able to flow liquids to the surface and unload.

Case 3 Packer Well	MCFD	BOPD	BWPD	Tub., psig	Cas., psig
Pre Frac Hit Avg.	953	0	17	435	0
Post Frac Hit Avg.	1288	0	19	407	0

Figure 6 – Production Results from Case 3

There are many wells that have used HPGL to unload frac jobs, but TM HPGL and improvements/ practices shared here can be used to broadly increase the use of HPGL to unload frac hits in all unconventional reservoirs.

However, there are many other applications of HPGL and TM HPGL that are developing around the industry.

OTHER CURRENT/GROWING USES OF HPGL

Last year in both the SWPSC and then in the PBAL Forum, case histories were presented on installing SPGL (no booster required) on more mature wells to replace failed/high-cost ESP's. It is expected that there will be many more potential applications like these.

Little has been published/available on the transition from HPGL annular to tubing flow and then transitioning to PAGL later in the life, although it is acknowledged that this is a logical path. There are clear advantages for PAGL application with no GL valves such as no leak/loss points and the open annulus for energy storage. This should be a growing area of application in the future.

Because unconventional wells have been dominating the recent history of US producers, it is sometimes overlooked that since HPGL can work in almost any well, it can be a good choice for conventional vertical, horizontal and deviated wells. This is especially true in wells where other lift types have failed or would be marginal. Installations like this have been successful but presenting details on this is outside the scope of this paper and may be the source of future papers.

The same compressors that enable HPGL are well suited to unconventional EOR via "huff and puff" and applications. These types of applications have been done using the same compressors to inject gas and then lift the wells when they are put back on production. Again, details on this are outside the scope of this paper, but if EOR economics become favorable, HPGL is the obvious lift choice for these wells.

USING HIGH PRESSURE COMPRESSORS TO PREVENT FLARING

Since gas offtake is problematic in the Permian and potentially in many other areas due to infrastructure limits and temporary outages, high pressure compressors might be useful to prevent flaring, an environmental win. Also, this could be used to increase operator profitability by allowing gas to be stored in older, lower reservoir pressure/ productivity wells during times of low prices or offtake constraints and then be sold at times of higher demand/deliverability. This idea was presented at an SPE Study Group talk in February 2024 and could have real potential. It could even work to increase oil recovery from the older wells used for injection.

It is expected that other applications and developments will be discovered as the use of HPGL expands. It has been at times a wild and certainly an interesting 8.5 years since Bill Elmer first presented the "new" idea of HPGL. It is certain many improvements and much growth will occur in the years to come.

CONCLUSIONS

1. The modern era of HPGL was started by one innovative engineer, Bill Elmer, on December 2, 2015
2. The initial installations that spurred much of the subsequent growth were enabled by the willingness of Dennis Estis to take a risk to build high pressure compressors based on a new way of doing things.
3. The growth in industry acceptance of HPGL occurred through the work of experienced engineers presenting in industry forums such as ALRDC, PBAL Forum, SPE and SWPSC.
4. The documentation and sharing of results by Branden Pronk/SM Energy confirming HPGL could compete with ESP's in high-rate wells was vital in spurring a step change in its adoption.
5. Unloading frac hits with TM HPGL has been shown by one operator to be potentially the best and most cost-effective option available.
6. There are many other uses for HPGL and the associated compressors beyond high-rate early life unconventional wells.
7. One of the most promising uses, injecting gas to prevent flaring could be both an environmental and profitability win.

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