Ozona and Sonora Canyon Gas Field Revival Turning P&As into P1 Reserves to Help Meet the Massive LNG and Data Center Natural Gas Needs

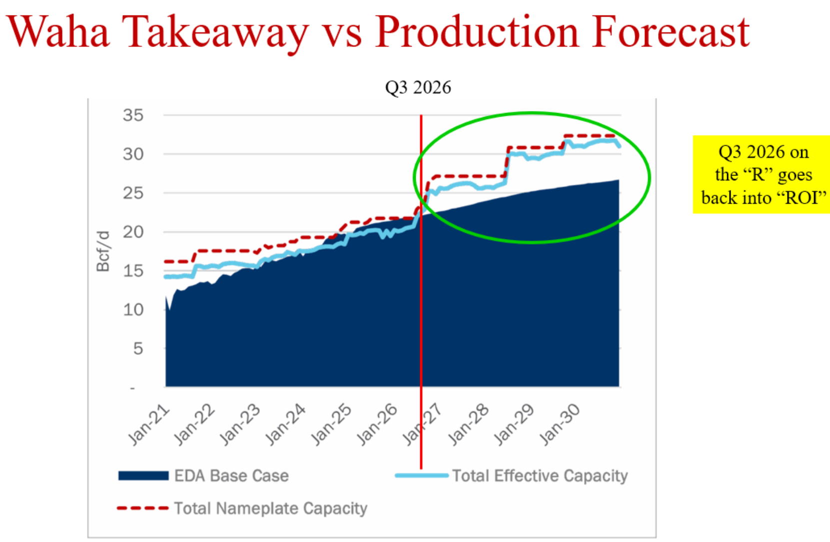
Robert Barba

Austin Phoenix Resources LLC

Abstract

While the west Texas natural gas industry has been on life support since 2008 with low prices and inadequate takeaway capacity it is on the verge of a major revival in order to meet upcoming major LNG and data center demand increases. These plants and data centers will require 18-24 BCFD of incremental supply over current levels in the US by 2030. Based on EIA projections it is expected that the Permian will provide up to 45% of this incremental demand. For the first time since 2018 West Texas pipeline investors saw this demand coming well in advance and are responding in force to put in enough takeaway capacity to help meet the need for incremental production. The expected additions to the Waha system in 2026 are staggering with 6.6 BCFD of additional takeaway capacity increasing to over 10 BCFD by 2028. On the supply side the latest expected incremental supply growth from West Texas is less than 1.4 BCFD in 2026 and 0.6 BCFD in 2027 and 2028. When this is combined with an expected 32 GW of incremental demand from Texas data centers alone by 2028 the demand for gas looks pretty strong. Each GW of generating capacity requires 160 MMCFD of feed gas for the turbines or an incremental 5.1 BCF of demand by 2028 that will not be heading to the LNG plants. Between the newly added capacity expansions and huge expected demand growth West Texas gas has the potential to be the next $100 oil at a time when oil prices are struggling to stay above $60. At a minimum Waha should be on par or better than Henry Hub which was the case prior to the capacity bottleneck pricing disaster of 2018-2026. With virtually zero drilling and recompletion activity in Permian basin dry gas reservoirs since 2008 this represents a major ramp up of gas production from legacy fields that have had little or no activity for the last 18 years. The bulk of the current expected increase comes from associated gas from horizontal oil wells which is the most of the 1.4 BCFD expected 2026 West Texas supply growth expectation. Significant volumes of incremental gas supply from dedicated gas wells must be added to meet the expected demand growth without focusing on dedicated gas wells. The oil focused shales in the Permian would need a significant increase in rig and frac crew count to meet this demand with oil well associated gas alone. Prior to the price spikes from the Iran conflict the EIA was forecasting +/- $55 oil in 2026. Once this temporary increase in prices ends it is unlikely that this will forecast change significantly. Without a significant sustained

increase in oil prices the oil focused rig and frac crew count will not follow and thus significant additional supply is probably not going to come from associated gas. The bulk of the incremental gas must come from 100% gas producing wells in the Permian Basin.



https://eastdaley.com/daley-note/eiger-express-expansion-raises-stakes-on-permian-overbuild

Figure 1

Where is this incremental gas going to come from in the Permian Basin?

For those of us that operate gas fields connected to the Waha system this is like an early Christmas after many years of intermittent positive and negative prices. At the time of this writing the price is negative and it is expected to stay well below NYMEX through the end of the year. In 2025 the price was negative 50% of the time.

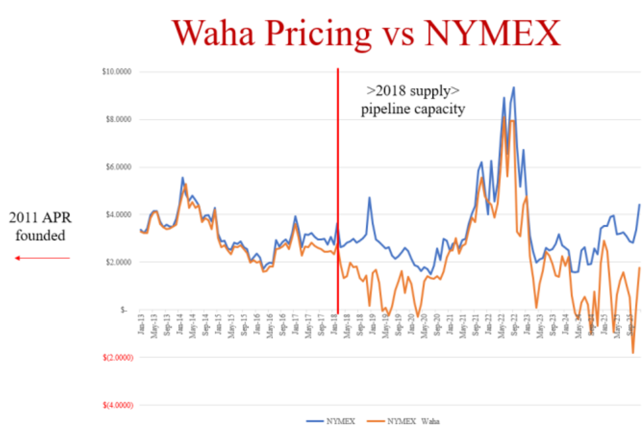


Figure 2

Once this bottleneck is removed from mid to late 2026 on natural gas producers connected to Waha should get a reasonably consistent economic return on investment for the first time in several years. With virtually no dedicated gas wells currently being drilled at this time and only 1.4 BCFD expected supply growth primarily from associated shale gas the question arises “where exactly is this incremental gas supply growth going to come from in West Texas?”

Val Verde Basin to the rescue

On the positive side there are a large number of existing wellbores in the Permian Basin that have significant volumes of stranded gas from inefficient original completions. There have been over 15,000 gas wells drilled in the Val Verde basin alone to date with over 8600 currently active wells and 3100 inactive wells in the area between the Ozona and Sonora fields. With the recent change in plugging requirements in Texas any well that is inactive for 15 years must be plugged after September 2027. Of the 3100 plus inactive wells in the play over 1600 of these wells will need to be plugged if they are not returned to production by September 2027. The economic benefit of refracs to recover the stranded gas from these imminent P&A candidates is already significant given the average volumes of stranded gas discussed in the next section. The avoidance of a +/- $50-$75k P&A cost on top of that improves the already good economic picture. This main issue then becomes the estimation of how much stranded gas there is in the basin and what wells will provide it.

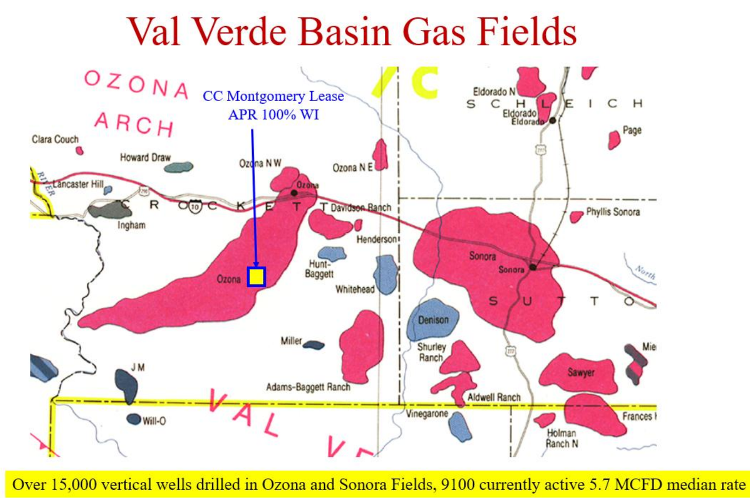


Figure 3

Stranded gas evaluation

Prior to the advent of horizontal multistage fracturing in 2002 in the Barnett the prognosis for gas supply was not good. LNG terminals were being built to import gas until 2012 and the consensus was that we were running out of natural gas in North America. Major action was required to be able to meet the expected demand growth, with one of the responses being a significant investment made in tight gas research through the Gas Research Institute (GRI). This was by far the largest coordinated industry R&D effort in U.S. energy history. Close to $5 billion in nominal spending was done by the GRI over the period from the late 70's through the early 2000's. Funding came from a FERC-approved surcharge on gas throughput (¢/Mcf), effectively spreading R&D cost across the industry and consumers.

The author started teaching completion optimization courses in 1993 and the GRI case studies were a key part of the courses. These well funded "Staged Field Experiment" (SFE) projects from 1986 to 1989 had full evaluation suites with logs, cores, pre and post frac well tests, frac models, and production simulations. The framework for the projects provided a means to evaluate gas well completion results in all US tight gas fields and to estimate the volumes of stranded gas reserves. A key spinoff from the studies was the analysis of a 130 well program in the tight (0.02 md) Wilcox gas formation in South Texas (Barba and Shook 2003 SPE 90483). The field had full openhole log suites, core data, wireline formation pressure tests in the majority of the zones, pre-frac pressure transient tests, and production logs after the fracs were cleaned up. The evaluation suite enabled the estimation of effective producing frac lengths for each perforated zone. The production logs provided sand face gas production rates and flowing pressures to get an accurate estimate of pressure drawdown. It proved up a number of "best practices" for tight gas completions to add to the numerous findings of the GRI studies.

One finding in particular that was relevant to the key project discussed in the next section in the Val Verde basin was that when multiple zones are completed in a single stage only one of the zones will be properly stimulated. The remaining zones typically only received skin damage removal. This particular problem could be avoided with limited entry perforating but in the 130 well study virtually every foot of pay was perforated with 4 shots per foot and less than 100 psi pressure drops. The current "best practice" for limited entry is 1500-2000 psi pressure drops across the perforations for maximizing cluster efficiency. The study also established a relationship between proppant loading per foot of vertical pay in tight gas completions. Top performing wells all had a minimum of 5000 lb per foot of proppant volume per foot with increasingly higher recoveries up to 9500 lb/ft. The study results were comprehensive enough to provide the bulk of the material for the authors highly successful two day frac and refrac completion "best practices" course from 2004 on.

Subsequent Tight Gas Research Post-GRI

A number of integrated studies were done by the author worldwide using the combined GRI SFE program and SPE 90483 "best practices" for stranded gas evaluation. One of these was a comprehensive reservoir characterization program in the Ozona Canyon field starting in 2008 where over 800 openhole logs were ultimately evaluated for original gas in place estimates. The reservoir permeability to gas in the Canyon was in the same range as the GRI and South Texas SPE 90483 rock. Most of the sections were fully developed on 40 acre spacing and all wells had openhole density-neutron-GR suites. A limited number of resistivity logs were available to estimate water saturation and bulk volume water and it was observed that a strong correlation could be made between clay volume from the GR and conductivity from the handful of resistivity logs available. The hypothesis for that tie is that since these wells produce no formation water the only conductive material in the formation other than capillary bound water is shale. The volume of capillary bound water was relatively constant (+/- 3.5% BVW or bulk volume water). This is an important number in that irreducible BVW for the sandstone matrix is 5% making the rock highly susceptible to capillary phase trapping damage. After a sufficiently large number of logs were evaluated it was observed that the average recovery factors for gas were in the 10% to 15% range vs an expected 70% to 75%. This 4-5x expected uplift should be low hanging fruit for either infill drilling, horizontal development, or refracs in most areas of the Val Verde basin. The numbers for the proposed 18 well refrac program on the APR Montgomery lease are shown below:

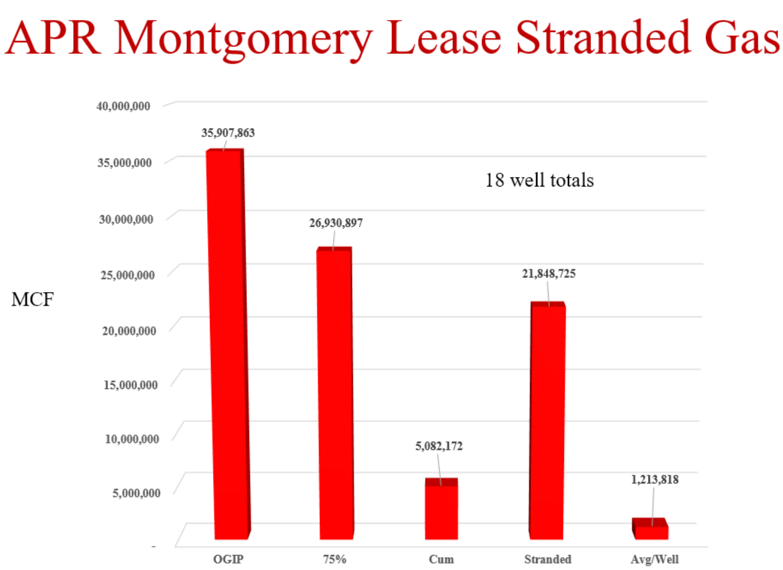


Figure 4

The recovery factors for most of the 800 wells in the study were in the 10%-15% range as well. A large part of this was that in spite of the volume of research on "best practices" funded by the GRI and the SPE 90483 study the Ozona Canyon completions were a glaring anomaly with regard to completion "best practices". Few if any of the completions were done using the "best practices" recommended by the volume of research. The standard completion practice in the Ozona field was to perforate all pay over a 600 to

1000 ft vertical interval with high shot density perforations and frac from 5 to 7 separate zones in one frac stage. Borate crosslinked gels and 20/40 proppant were used with loadings in the +/- 2000 lb/ft range. A large number of these wells were air drilled with 7 7/8 bits and cased with 2 7/8 tubing. Any chance of effective diversion was lost with the low pump rates, high friction pressure losses in the tubing, and the large number of perforations. One well in the western portion of the play had a production log run after the frac treatment. There were five main sands spread out over a 1000 ft of gross perforated interval in the well but only the uppermost sand was producing meaningful gas volumes. When all of these inefficient completion practices were combined the extremely low recovery factors make sense. Rate/Transient analysis of production declines indicated only 10% of the propped frac lengths were producing.

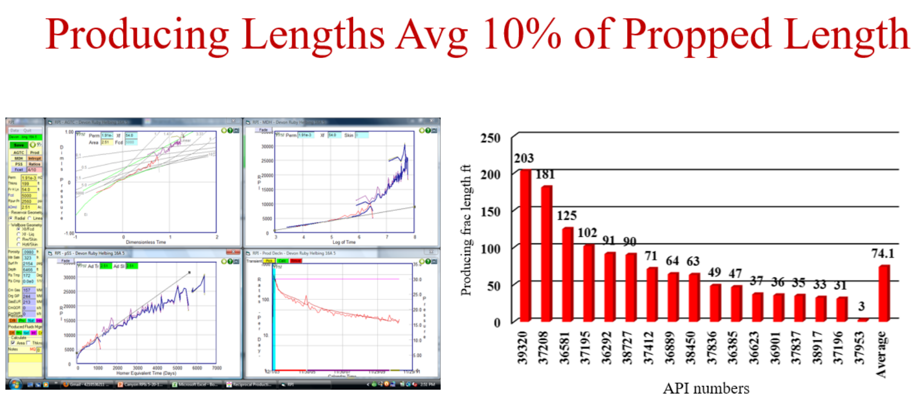
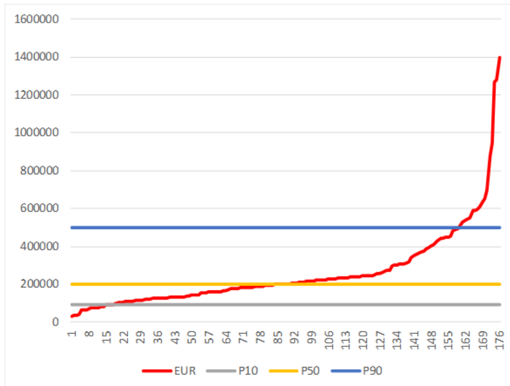


Figure 5

The stage was set for further development efforts to recover the massive volumes of stranded gas. Part of the reason for not incorporating "best practices" was the economics were marginal at best unless pricing was high. APR acquired a number of UPRC wells and the average AFE for a fully completed well was +/- $250,000. With the average EUR from recent wells in the 200 MMCF range this was most likely economic at the relatively high gas prices prior to 2008. The original UPRC study forecasted an average EUR of 397 MMCF based on the stranded gas. The actual results are shown below where the P50 median was approximately half the forecast. This likely exacerbated the use of poor completion practices to keep the cost down. It certainly contributed to the "gift" UPRC gave the industry with a average of 1.2 BCF recoverable per 40 acre infill well if 100% of the stranded gas could be recovered with a refrac program.

Last 179 Ozona Water Based Frac EURs



		$3.00 flat	$2.50 flat
		10% IRR	10% IRR
Percentile	EUR MCF	Max AFE	Max AFE
P90	94,767	$104,322	$ 82,119
P50	199,963	$252,206	$205,355
P10	498,197	$671,461	$554,734

New well cost with water based frac $750,000-$850,000 minimum
P10 best case not economic

16

Figure 6

Once prices slipped from the oversupply from the Permian Basin horizontal shale programs Ozona activity screeched to a halt.

Case for refracs and/or infill drilling

The large volumes of stranded gas in existing wellbores suggested the wells were excellent candidates for refracs or infill drilling. The heterogeneous nature of the sands and huge vertical pay extent were not conducive to horizontal drilling. UPRC (then Anadarko) did the math as well and went down the infill drilling path in western Crockett County with 20 acre wells. When the treatments were pumped in the infill wells it was highly likely that only the limited number of zones that were partially depleted by the original completion were fracced in the new wells. UPRC and then Anadarko thought they were launching “reserve seeking missiles” into the Canyon with their fracs. In reality these were “depletion seeking missiles” that resulted in recovery of only 10-15% of the original gas in place vs 75%. UPRC presented a paper in 2006 (SPE 35628 Cipolla et al) where several selective zone pressure buildups were done. The original pressure gradient in the field was 0.42 psi/ft. The individual zone tests done on 80 acre infill locations are shown in the figure below. As expected the upper sands had lower pressure gradients from the ineffectively diverted treatments on older offsets. This set the stage for treatments to preferentially treat the uppermost sands when the poorly diverted single stage treatments were pumped. The field was ripe for a refrac project using “best practices” to recover the estimated 1.2 BCF per well of stranded gas based on 40 acre drainage.

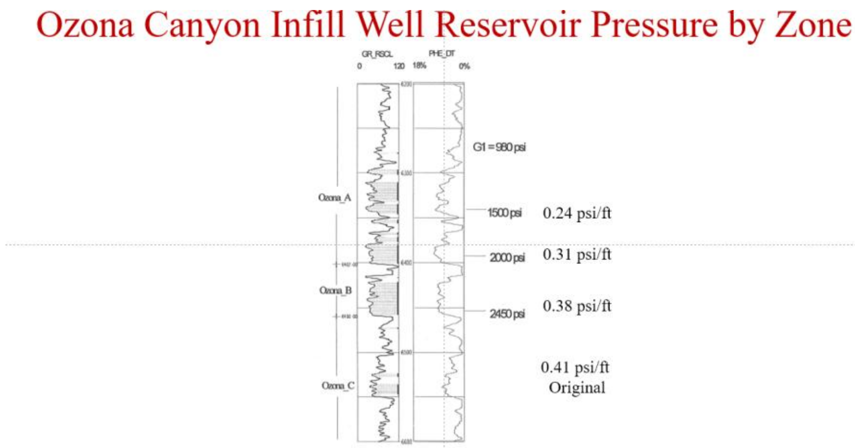


Figure 7

To capitalize on this the author formed Austin Phoenix Resources (APR) with Richard Ganem in 2012 to recover the stranded gas. APR acquired 21 wells in the Ozona field 13 miles SW of Ozona. Openhole logs were available on every well to estimate original gas in place and the field was fully drilled on 40 acre spacing. The original completions pumped small volumes of proppant in one stage at low rates with perforated intervals as long as 448 ft. Average perforated length was 300 ft. From 2012 through the beginning of the Waha price crash APR proved conclusively with several tests that water based systems cannot be used in the Canyon sand for refracturing treatments. APR did a review of decline curves for all 12,000 plus wells in the Ozona and Sonora fields and there were no production increases observed in any wells suggesting no successful refrac had been done. There were a number of wells that stopped producing abruptly that could have been failed refracs. It was not possible to determine if the production cessation was from a failed refrac or mechanical problem.

Formation Damage Evidence

While the completions to date were not optimal (multiple zones in a single stage with no limited entry, small proppant volumes, etc) the wells should have produced significantly more gas in spite of the mechanical inefficiencies. In many other areas bulk volume water values below irreducible have resulted in capillary phase trapping. A recent study done in a Ukrainian sub irreducible Sw reservoir indicated a 99.9% reduction in effective gas permeability from the initial permeability to the post stimulation using water based fluids.

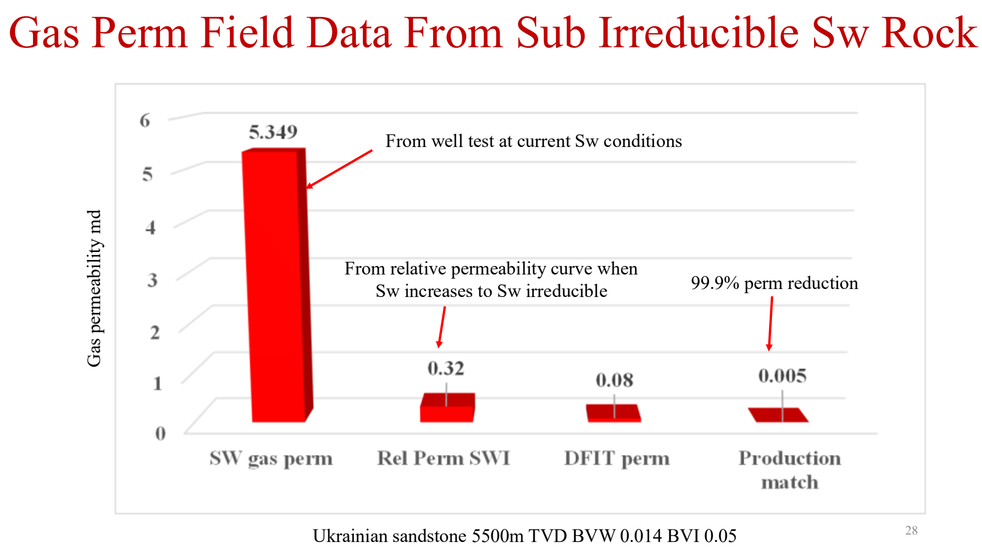


Figure 8

While the Canyon operators were not incorporating the GRI SFE/SPE 90483 “best practices” for completions the magnitude of the damage clearly pointed to a larger issue with formation damage. The Bulk Volume Water vs Bulk Volume Water Irreducible concept (Leshchyshyn SPE 86989 2004) clearly identified these rocks as water sensitive sub irreducible SW/BVW zones. While efforts had been made with the use of CO_2 and N_2 foams and straight CO_2 fracs, there were issues with these in sub irreducible rock. The foams contained at least 35% water and that is sufficient to provide a permeability block when the 3.5% BVW is increased to the 5% irreducible or higher. Straight CO_2 was really only suited to high permeability formations since the low viscosity fluid was incapable of delivering large proppant volumes to extend the wellbore radius. UPRC did attempt one and it did not produce economic quantities of gas. Extension of the wellbore radius is critical in the 0.01-0.02 md rock where mere skin removal will not suffice. The only option that makes sense to avoid capillary phase trapping is fraccing with oil based fluids with microproppant (fly ash).

Frac Flud Selection vs Bulk Volume Water

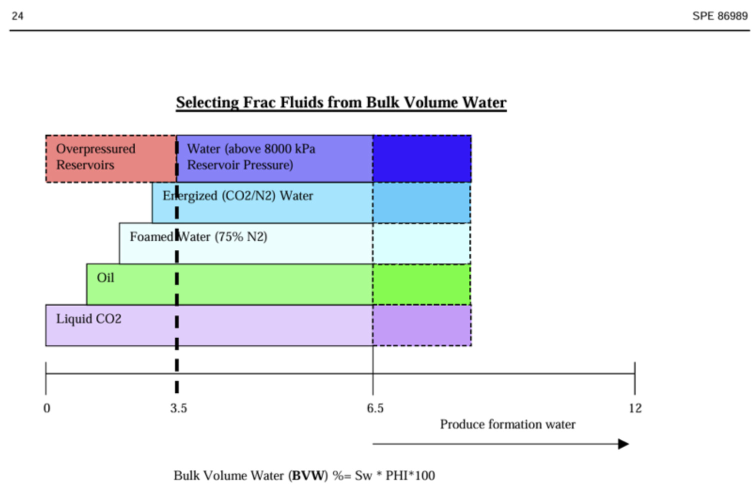


Figure 8: Selection of Frac fluid from bulk volume water (BVW).

Figure 9

Oil based fluids in water wet dry gas reservoirs are optimum for avoiding water damage from capillary phase trapping. These rocks were laid down in a marine environment and buried over time. 100% of the sands were saturated with water initially. The source rocks below generated hydrocarbons that migrated upward until a reservoir seal was contacted to trap the hydrocarbons. The movement of the hydrocarbons into the trapped pore space expunged the mobile water from the matrix leaving only capillary bound water. In many of these reservoirs additional dessication took place in the water wet portions where sub-irreducible conditions occurred (Bennion SPE 60325). Typical sandstone bulk volume water irreducible values are in the 5% range. While the Canyon's 3.5% value is not as extreme as other sub-irreducible values in North America (2.5% most common in the Cardium, Cadomin, Viking, in Canada and mid continent Pennsylvanian Morrow/Springer/Red Fork et al) there is a significant decrease in relative permeability to gas with the increase in water saturation. Average porosity values in the Ozona field are 9.6% and the average irreducible water saturation is thus 52%. The average current Sw of 3.5% results in a sub irreducible Sw of 36%. Once the frac water enters the pore space the increase from 36% to 52% reduces the relative permeability to gas significantly. A schematic that illustrates the physics involved is below along with a conceptual relative permeability plot with the Sw increasing from current to irreducible conditions:

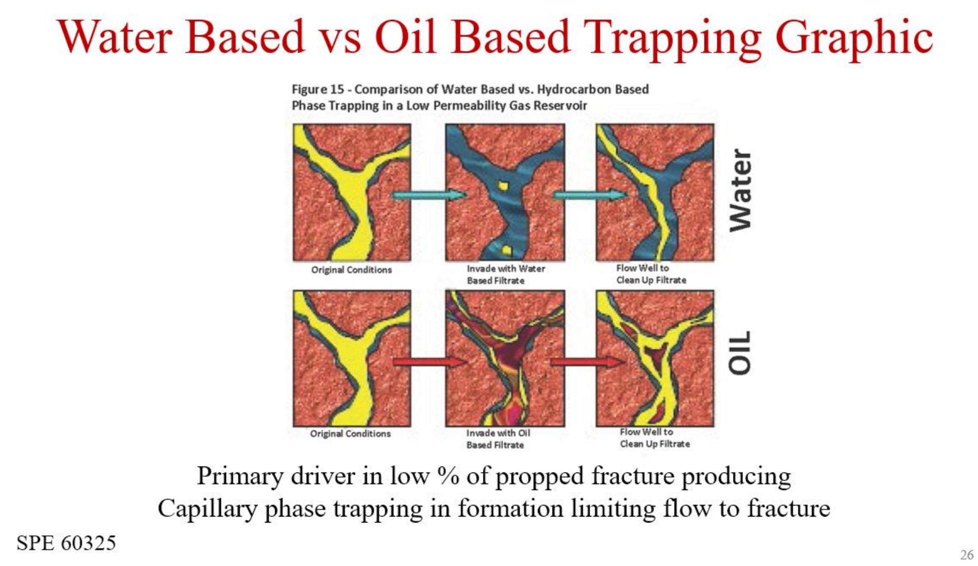


Figure 10

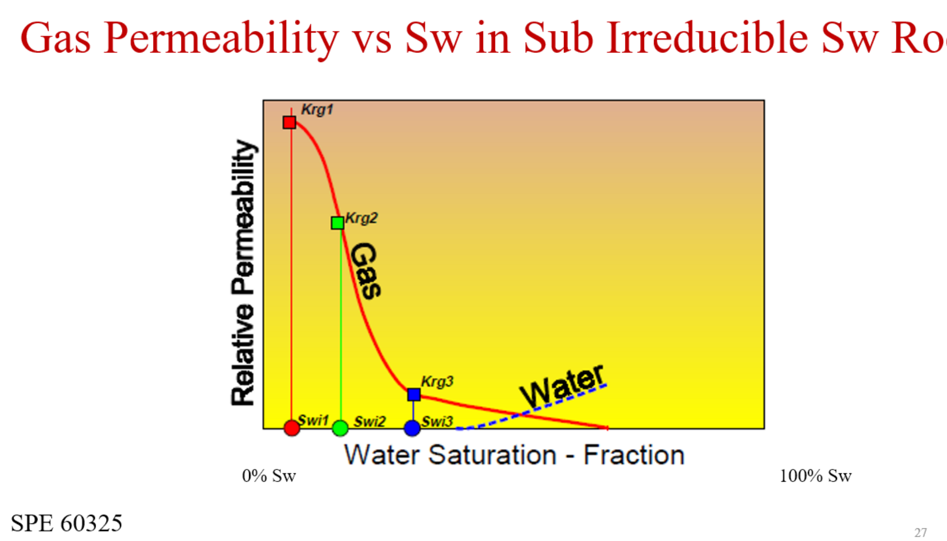


Figure 11

Hydrocarbon based fluids have been highly successful in stimulating these dessicated reservoirs in other areas. The common denominator has been sub irreducible water saturations which can be estimated from openhole well log analysis. In one Canadian case study (Leshchyshyn 1999) a sub irreducible water sensitive Viking zone was fracced with a crosslinked water based system without success. The zones were refracced with an oil based system and economic production was achieved. The production rate after the water based frac was 530 MCFD which dropped off after a 10 hour flowback. There was no condensate production reported following the water based frac. The oil based refrac resulted in an initial flow rate of 2.8 MMCFD dropping off to a stable 1.76 MMCFD after cleanup. The post oil based frac condensate production went from zero to 471

BOPD initially. The condensate production dropped off to a steady 157 BOPD after load recovery.

This was not a one off example of the success of oil based fluids in sub irreducible rocks. There are a limited number of formations in Canada with water sensitive swelling clays (primarily the shallow Milk River). The large majority of oil based frac fluid applications have been in sub irreducible rocks like the Viking, Cardium, Cadomin, etc. Over $70MM was spent on oil based frac fluids with one Canadian oil based frac fluid vendor in 2008. APR was convinced early on that oil based fluids were the only viable option to increase the low gas recovery factors in the Canyon. The author was very familiar with concept of oil based fluid use in sub-irreducible Sw formations. In 2005 a Calgary based investment banking firm (Stephen Avenue) requested an evaluation of a proposal from a local start up firm Gasfrac Energy Services to pump gelled propane as a frac fluid. The recommendation was to fund them to provide a means to effectively stimulate the numerous sub irreducible Sw rocks that had been encountered in North America to date. When APR was considering the purchase of the 21 wells they had numerous discussions with Gasfrac who did receive the funding and had recently formed a US unit. Their US management team was eager to test their process in the field and assurances were made that they would provide the service for a large discount and help facilitate the funding. That assurance was a key part of the decision process in acquiring the wells. Unfortunately after the acquisition was finalized and AFEs were being prepared the Canadian upper management did not back up the assurances made by their US team. They proposed that we raise the money ourselves and pay $1.2 MM for their services. Even at decent gas prices that made the completions marginally economic even if the full 1.2 BCF of stranded gas was recovered. Without their support and without analogs for hydrocarbon based fracs in the area APR resorted to several non-hydrocarbon based water systems to attempt to stimulate the sub irreducible rock. None of them were effective and in all cases the formation was severely damaged. The hypothesis was new wells completed with water had higher reservoir pressures that limited invasion. There was likely some damage but it was not adequate to prevent gas flow. Initial potentials were far below what should be expected from an average 1.4 BCF mobile gas reservoir. Once these 40 acre spaced formations were drawn down from the offset 80 acre original production wells the lower pressures exacerbated the invasion process and additional damage resulted. The EURs from the most recent new completions are below. All of the treatments were water based and very few were economic without high gas prices.

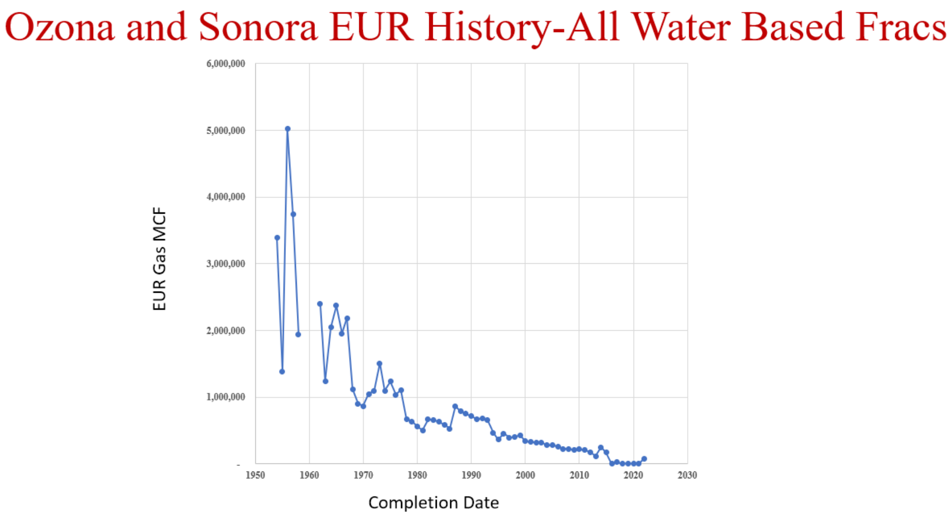


Figure 12

APR is currently moving forward to do the first oil based refrac treatment to carry microproppant to prove the oil based systems are the key to avoiding the massive formation damage leading to the poor gas recoveries.

A single stage treatment is proposed to prove oil based fluids and fly ash microproppant can mitigate or eliminate the capillary phase trapping formation damage from using water based fluids. The “D” sand in the Montgomery 11S 15 is the proposed target, see below

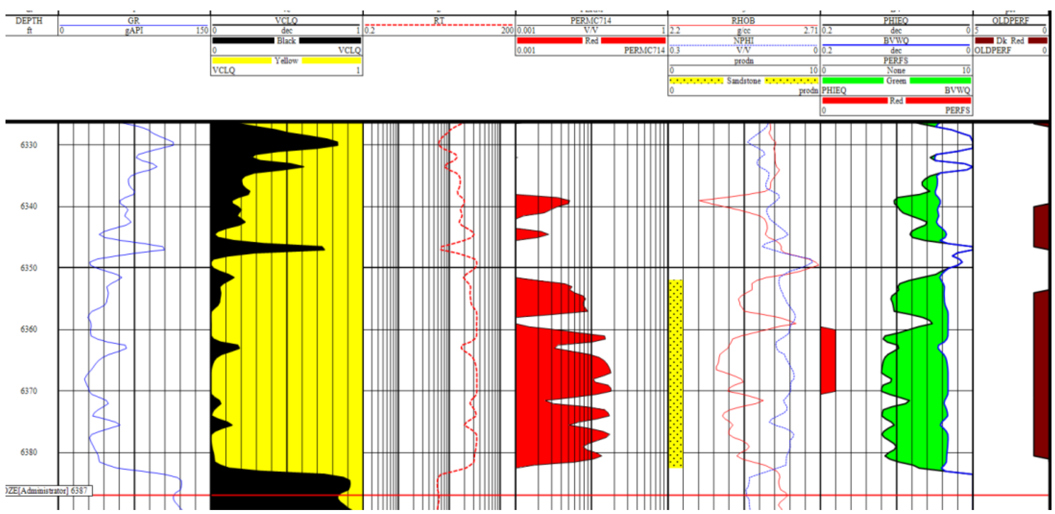


Figure 13

The total mobile gas in place for just the lower “D” target zone is 443,838 MCF and the allocated gas production from the “D” is 117,814 MCF of the 295,044 total MCF cumulative production for all three zones in the well. There are well developed upper “D” and "C" sands above that most likely took more than their volumetric share of the production given the low rate per perf low total prop volume crosslinked water initial stimulation. There was only 2141 lb/ft of proppant per foot of pay (43% of the 5000 lb/ft minimum we are proposing for the refrac). There was no attempt to divert the treatment with any type of limited entry perforation friction pressure drops. In a similar zone configuration in the American Field to the west a production log indicated 100% of the production was coming out of the uppermost sand. See zone distribution below

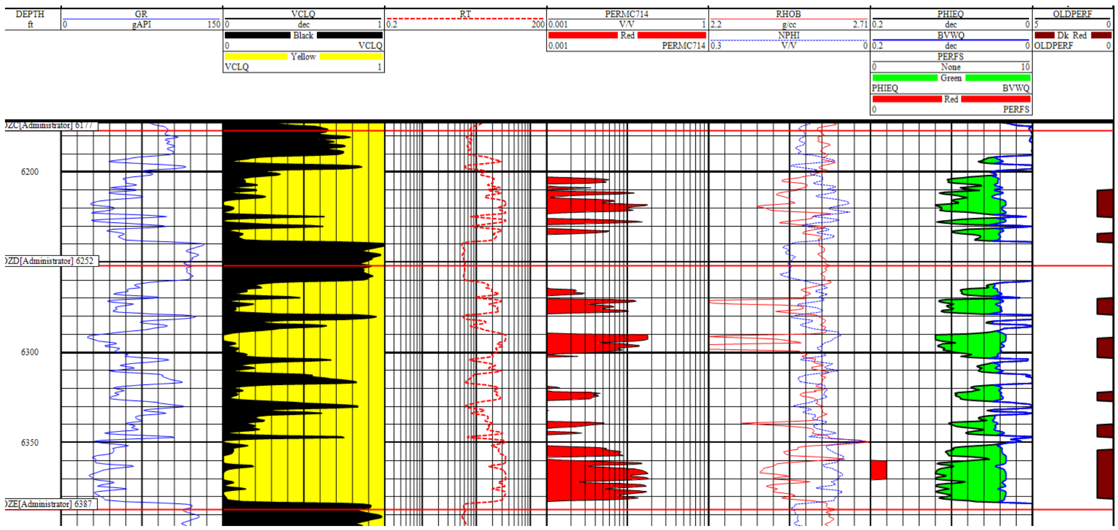
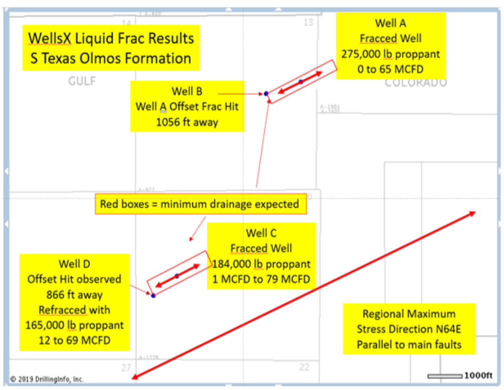


Figure 14

An oil based DFIT is proposed for the 6360-6370 perforated interval prior to the refrac to get a measured reservoir pressure and effective permeability. A P/Z analysis from the DFIT P* will provide a highly accurate EUR for the zone tested since we know the original reservoir pressure (0.42 psi/ft). If all goes as expected the intent is to use this technique on all of the high quality zones in the field to get a highly accurate recoverable reserve estimate (and permeability to gas) for each zone. It can be done on each zone prior to sealing off the perforations for the refrac after cleaning out the wellbore. The estimate does not require any petrophysical assumptions and is based solely on the amount of depletion from the production. The technique allows multiple zones to be tested in a single operation with bridge plugs & memory gauges above each zone (SPE 152019 Cramer et al). In this case only the "D" is going to be tested. The last benefit of a "D" sand recompletion is that it leaves open the option to come back at a later date to refrac the upper "D" and "C" zones.

At this time mineral oil is the fluid of choice for the operation. The Superior Energy Services "Eco Reach" system is proposed using fly ash and ungelled mineral oil. Superior Energy Services "Eco Reach" system with fly ash for proppant. So far over 80 successful fracs have been pumped to date, with fresh, produced, or KCL water. Up to 10 lb/gal pumped to date and 650,000 lb total using water no FR. To date no treatments have screened out. Highly complex fracture network created with “hits” up to 1056 ft away (Figure 15 below). The location of the frac “hits” suggest fracs are inbetween “complex” and “off-balance” (Daneshy 2003), not planar. Frac “hit” locations over 1000 ft from the refracced wells and up to 200 ft off of a planar frac axis suggesting fracture complexity. Drainage areas observed with offset interference are comparable or superior to conventional planar frac results. In the example below in the South Texas Olmos there are Smectite clays and water sensitive rock so results very pessimistic vs proposed mineral oil based system, 10% recovery factor prior to water based refracs.

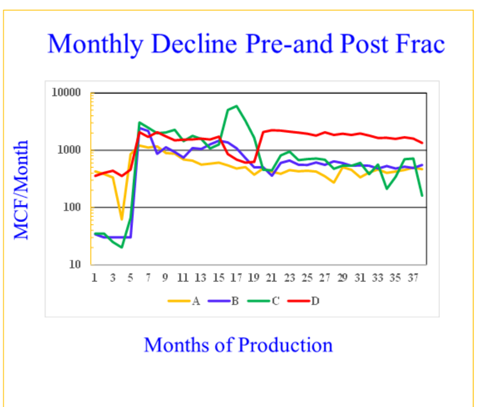
Long Complex Fracture Networks Created



- Frac “hit” locations over 1000 ft from the refracced wells and up to 200 ft off of a planar frac axis suggesting fracture complexity
- Drainage areas comparable or superior to conventional planar frac results
- Water sensitive rock so results very pessimistic vs proposed mineral oil based system, 10% recovery factor prior to water based refracs
- Mineral oil system proposed (C12 chain) environmentally friendly and recyclable
- The Mars Wrigley company uses the Phillips mineral oil brand we are looking at to coat M&M candies

Figure 15

Excellent Post Refrac Production Results



- South Texas Olmos formation LaSalle County
- Relatively flat production declines
- While treatments were economic due to low cost, volumes are not indicative of well’s potential with oil based frac due to high smectite volume and the use of produced water for the frac fluid

Figure 16

The mineral oil system proposed (C12+ chain) is environmentally friendly and recyclable. The Mars Wrigley company uses the Phillips mineral oil brand we are looking at to coat M&M candies. The expected results from an average well in the proposed program is below:

Economics with NYMEX Strip 3 Stage Frac Average Well

Economic Analysis Average 3 Stage Refrac Well			1,213,830	
		IP Gas MCFD	1018	Input
		EUR Gas MCF	1,213,830	Calc
		Total Cash Flow undisc	$ 3,030,507	Calc
WI	100%	Payout (undiscounted)	13	Calc
NRI	75%	Payout (discounted)	14	Calc
Disc Rate/IRR	10.0%	Undisc Net/Invest	4.04	Calc
LOE/well	$ 250	Disc Net/Invest	1.62	Calc
MMBTU	1300	NPV 10	$ 1,212,508	Calc
Gas Severance	7.53%	AFE	$ 750,000	Input
LOE Esc	0.500%	IRR	72%	
		18 well totals	$ 54,549,125	PV0
			$ 21,825,153	PV10

	2026	2027	2028	2029	2030	2031	2032	2033	2034	2035	2036	2037	2038
NYMEX 12/10/25	$ 4.20	$ 3.99	$ 3.78	$ 3.71	$ 3.65	$ 3.53	$ 3.39	$ 3.32	$ 3.42	$ 3.48	$ 3.57	$ 3.48	$ 3.41

Figure 17

Oil Based Fluid Analog Discussion

One question that comes up consistently is whether there are any analog oil based treatments in the Val Verde basin. There is a reluctance to be the first to do any procedure and to date the high cost of the fluid and low to negative gas prices has discouraged its use to date. The overriding issue is what caused the ultra low recovery factors in the reservoir. Mechanical issues are a factor but the large volumes of stranded gas cannot be attributed solely to the poor diversion and low stimulation volumes. All attempts to refrac sands with large volumes of stranded gas with water based fluids have been failures. Sub irreducible Sw and BVW reservoirs have responded well to oil based treatments in a number of areas, the Viking example from Leshchyshyn (1999) is a good example of how poor water based fluids are in stimulating sub irreducible rock and how that can be remediated with an oil based system. Of particular interest in that example was the significant increase in condensate production observed following the oil base refrac. The relative permeability reduction from the water based fluid capillary phase trapping resulted in very low condensate volumes. Once the water wet rock was restimulated with the oil based system the condensate production increased to 471 BOPD stabilizing at 157 BOPD. This is an excellent example of the ability of the oil based fluids to avoid capillary phase trapping damage in sub irreducible rock.

The Val Verde basin Canyon sands clearly have sub irreducible current water saturations, yet to date no oil based refracs have been attempted. It is a classic example in the technology exploration process where the question should be “why won’t oil based fluids work?” instead of having to see examples of where they worked. At some point some basic engineering and physics analysis needs to be done rather than simply relying on copying what other operators have done in the area. The reluctance to be a first mover has been exacerbated by the success operators have had in the organic shales where “cookie cutter” designs have yielded repeatable economic results with relatively low risk. The physics involved are not complicated, it is well known that oil and water repel each other. Because of the repulsion of oil from the sand grains coated with water the oil does not remain in the water wet reservoir rock after pumping. Anecdotally load oil recoveries with oil based frac fluids in water wet rocks have been close to 100%. Water on the other hand is imbibed into the sub irreducible saturated matrix and significantly reduces the relative permeability to gas.

Conclusions

The Val Verde basin has a large volume of stranded gas due to inefficient original completions with highly damaging water based fluids. An 800 well study indicated wells in the Ozona Canyon indicated the majority of the current completions had resulted in only 10% to 15% gas recovery factors due to poor completion practices. The poor mechanical practices were compounded by strong evidence of formation damage from water based fluids and capillary phase trapping in the sub irreducible Sw formation. A program has been developed to refrac these wells using a combination of mineral oil and fly ash with an expected recovery per well of 1.2 BCF. This expected uplift in production comes at a timely moment when the LNG plants and data center power generation facilities are going to require significant volumes of new gas production.

References

Barba, R.E. and Shook, R: “Post Frac Evaluation of Multiple Zone Fracture Treatments Using the “Completion Efficiency” Concept, SPE paper 90483 presented at the 2004 SPE Annual Technical Conference and Exhibition, Houston, Texas 26-29 September,

Bennion, Brent et al: “Formation Damage Processes Reducing Productivity of Low Permeability Gas Reservoirs,” SPE paper 60325 presented at the 2000 SPE Rocky Mountain Regional/Low Permeability Reservoirs Symposium and Exhibition held in Denver,Colorado, 12-15 March 2000.

Cramer, Dave et al: “A Method To Perform Multiple Diagnostic Fracture Injection Tests Simultaneously in a Single Wellbore,” SPE paper 152019 presented at the 2012 SPE Hydraulic Fracturing Technology Conference, The Woodlands, Texas, USA, February 2012.

Leshchyshyn, Ted et al: “Technical and Economic Rationalization of Oil Refracture Programs on Wells Previously Stimulated with Water-based Fracture Fluids,” 1999 CSPG and Petroleum Society Joint Convention, Calgary June 14-18, 1990