SPE SPE-169837-MS

Facilities Selection Impacts Reservoir Performance

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This paper was prepared for presentation at the SPE Hydrocarbon Economics and Evaluation Symposium held in Houston, Texas, USA, 19–20 May 2014.

Abstract

Facilities decisions are often disconnected from anticipated reservoir performance. A frequent result of this disconnect is operating reservoirs in a sub-optimum manner to protect surface facilities that have inadequate strength. This paper will review the facilities decisions that have been made in several Coalbed Methane (CBM) and Coal Seam Gas (CSG) fields around the world and discuss the reasons for and the impact of those decisions on the performance of the reservoirs. The source of the disconnect is that "everyone knows" that CBM and CSG fields "require very low pressures". With that assumption you then apply safety and procurement principles to come to a design. There is a stage in the production life of these fields where very low pressures are required for reasonable recovery levels, but that stage is typically reached 10-15 years after first production. Setting late-life surface facilities at first-production results in choking the reservoir for over a decade, setting compression many years before it is actually required, and less ultimate recovery as a percentage of original gas in place than would otherwise be achieved. These problems can be overcome by understanding the life cycle performance and risks of an unconventional reservoir and accepting that any tradeoff between facilities performance and reservoir performance must be biased in favor of optimizing reservoir performance in order to have acceptable economic results.

Introduction

This paper treats the term "facility" in the broadest possible terms to include everything that our industry does to a reservoir or to reservoir fluids from drilling to completions to actual surface facilities to processing plants.

The reason for the existence of the Oil & Gas Industry is to convert in situ hydrocarbons into a net profit. While this purpose is not obscure, subtle, or difficult to comprehend, it keeps getting lost in our processes. Every decision that is made from drilling methods to the selection of wellbore tubulars to wellsite surface facilities to processing configuration has an impact on our ability to meet our basic purpose.

Every decision made in field-development and production has the choice of either looking from the reservoir-interface to the wellbore towards the facilities or looking from end-use back towards the reservoir. If you stand with your back to the reservoir, you will be asking the question "how will a decision affect installed facilities, processes, and procedures". If you stand at the burner-tip looking back toward the reservoir you are asking the question "how will a decision affect reservoir performance, ultimate recovery, and ultimate profitability?"

The shift in focus from reservoir-centric to facilities-centric happened over about a decade from the mid-1990's to the mid-2000's. Awareness that very little Engineering expertise was being applied to wellsites happened first. The only pool of facilities Engineers within companies were associated with "Deep water, North Slope, or Refinery" operations. In other words we had concentrations of Engineers within the broad industry who had experience in extremely risk-intense hydrocarbon operations who could "hit the ground running" in providing a "remedy" to the lack of Engineering on wellsites. These Engineers brought with them the tools of risk-intense processing. For the most part these individuals were shocked at the lack of rigor in upstream processes and many of them went on a mission to bring wellsite risk management into line with "proper" processes. Since it has become unfashionable to admit that maybe there was nothing wrong with the old way, this movement caught fire in our industry and the "safety culture" has been formalized into a set of processes.

At the same time that Engineers were adapting wellsites to the safety principles of refineries, a group of MBA's were questioning the concept of controlling unit costs instead of total costs. Historically, field operations have been evaluated based on "cost per unit volume". Typically we used cost/bbl or cost/MSCF. A goal to "decrease cost/MSCF by 10%" leads operators to first look at low-cost ways to increase production, and will often increase total costs by somewhat less than profits increase. This approach served the industry well for nearly a century. Starting in the mid-1990's managing unit-costs fell out of favor. The argument was that "the field does not control sales price so they will not have knowledge of whether increasing production will increase profit or not" and "there are many fields that have production constraints and it isn't fair to them to encourage increased production". The validity of these two ludicrous statements was never questioned, and companies started moving towards controlling absolute costs instead of unit costs. Careers were made based on implementing formal cost-management processes.

Process safety management (PSM)

We are currently in the midst of a worldwide reduction in risk tolerance. This drive for ultimate "safety" has infected every facet of our lives from playground equipment design, to automobile design and operation, to offices, to factories, to wellsites. Non-zero risk of injury to employees, risk of injury to the public, risk of damage to the environment are unacceptable concepts. In Oil & Gas we try to mitigate the risks on wellsites by ignoring "risk density".

I define "risk density" as "the intersection of the likelihood of an injury and the consequences of an injury". Within a refinery there are many processes that operate very close to real physical limits on equipment that can fail catastrophically putting a large number of workers in peril. Those refineries are often located in close proximity to population centers so a catastrophic process-failure can have significant impact on the public. This would be a very high risk density. PSM was developed to allow effective management of this risk environment.

An onshore wellsite is manned 1-2% of the time, typically by a single person. Historically, wellsite equipment has been operated with huge equipment safety-margins to real physical limits. Wells also tend to be located far from population centers. The risk density is very low. When we ignore risk density, it seems perfectly reasonable to apply the processes and procedures that were developed in refineries to wellsites.

PSM represents a series of administrative processes that together have the goal of identifying all potential sources of risk and developing designs and procedures to eliminate or minimize those risks. The PSM administrative processes include things like: (1) Management of Change (MOC); (2) Critical Drawing Reviews; and (3) HazOp reviews. To facilitate these processes, every wellsite must have both Process and Instrumentation Diagrams (P&ID) and Process Flow Diagrams (PFD).

Twelve years ago I was in a "Technical Authority" role for one of the so-called "Majors" and had contact with all of their onshore gas operations conducted in the world. Even with that scope of participation, I had not been exposed to any of the PSM concepts listed above, I never even saw a P&ID before 2005. These PSM concepts simply did not exist for onshore wellsites. The process review was appropriate for the low risk-density of an onshore gas wellsite. In the last few years, I've seen the full PSM principles applied to low pressure onshore wellsites in the US, Indonesia, India, Australia, Botswana, Mozambique, Canada, the United Kingdom, and Romania by companies as small as 100 wells limited to a single basin and as large as the Majors and second-tier producers. Risk intolerance has become global.

Today's extreme intolerance for risk has driven all of the PSM concepts to wellsites. A Facilities Engineer recently told me that "We have an ESD on the casing line so reservoir pressure is irrelevant". He also had a Pressure-Regulator style choke on the line that maintained the separator at a constant pressure. Pressure upstream of the regulator would vary by over 200 psig [1379 kPa] during the course of a day. Other wells in this field have demonstrated that constant flowing bottomhole pressure optimizes reservoir performance and ultimate profitability. That particular fact was totally irrelevant since he did not feel that he could get higher strength materials approved through the MOC process for future wells (since profitability is rarely a factor in PSM analysis).

Supply chain management

In the 1970's and 1980's MBA and PhD candidates in business schools spent a lot of effort evaluating successful companies to determine factors for success. The most successful companies in that time period were the Japanese auto makers and US mega-retailers. Both of these groups were embracing the new computing power to work towards "just in time" inventory control. Honda and Toyota were especially good at it and several PhD theses developed detailed analysis of these systems. The result was the concept of "supply chain management". This term was coined by Keith Oliver from Booz Allen Hamilton management consultants in 1982 in an interview in the *Financial Times*[1]. At its root, supply chain management is the process of ensuring that all of the units of production are available when and where needed with a minimum of warehousing required. There is so much more to this concept than simply taking headlights or dash-assemblies off of a train car and carrying them directly to the assembly line. The process must anticipate inevitable transportation delays, maintenance activities (both at the assembly plant and at the component fabrication plants), fluctuations in sales volume, to name but a few of the considerations. When the auto manufacturers got it right (which was quite often), it was a thing of beauty.

Oil & Gas embraced this idea with vigor after 1995, completely disregarding **the** key concept. Supply chain management is designed to manage the units of production not the tools of production. Tools of production are the things that are still in the plant when the finished product goes out the door. Things like the assembly line itself, various robots, compressed air systems, and assembly-floor lighting make up the tools of production. In an auto factory, the maintenance departments are huge—critical equipment and spare parts are stockpiled, maintenance employee training is intense, repair-tool budgets are nearly unlimited. The maintenance/repair process accepts the principle that if a production line is shut down due to a broken hydraulic actuator on a robot, the line isn't making any product and the units of production start backing up within the supply chain—fixing that broken actuator is of critical importance. A broken tool of production is an occurrence that must be minimized at all costs, so an effective implementation of supply chain management maintains very robust, flexible, and multi-layered maintenance/repair strategies. Failure analysis is extensive and immediate with results that make the tools of production more reliable with every failure.

In Oil & Gas, our units of production are hydrocarbon molecules and we can't manage their availability from a computer screen in the head office. Our industry's implementation of supply chain management does not recognize this and tries to manage control-valves, pipe, pumps, tanks, transducers, and meters in "just in time" mode. We have work-order systems that require all work to be scheduled 30 days in advance to allow level loading of repair crews—often while gas is shut in waiting for the schedule. We have spare-parts rules that require a work order to get a control-valve repair kit. It can take weeks to process the paperwork to replace a damaged diaphragm, a half hour to affect the repair, and 10 minutes to return a well to production. We have hard and fast rules against "squirrel stores" (i.e., repair items that are on people's trucks and are not charged to a well). We treat our Lease Operators as assembly line workers instead of maintenance workers. The original tenets of supply chain management would acknowledge that our field workers, their tools, and repair parts are crucial for facilitating production instead of what our industry has morphed the concept into—a cost that must be managed and ultimately minimized.

Supply chain management is integrally linked with environmental management. The underlying reason for this linkage is that if a company is not having to deal with shut downs for spill assessment/remediation then their ability to supply units of production will be more reliable. Since Oil & Gas has decided to mis-apply these concepts to tools of production, the current bid process will always select the vendor with the ISO 14001 [Environmental Management Systems] certification over one without that certification. It doesn't matter whether the contractor actually has the people or equipment to accomplish the job at hand since he has ISO 14001 certification.

The Reservoir

The in situ hydrocarbons that we intend to monetize reside in reservoirs. Every portion of every reservoir has quirks that are unique to that portion of that reservoir. Individuals can learn these quirks and can learn how to treat a particular well to maximize profit and minimize problems if they are allowed to. This learning curve can only be accessed through effective drilling processes, effective completions, effective surface facilities, and effective operating processes and procedures.

The first decision that installs equipment or piping incompatible with full reservoir pressure, temperature, or fluid chemistry has shifted the focus to looking away from the reservoir. For example with a reservoir pressure of 1300 psia [8.96 MPa], if you select ANSI 600 pressure class (nominal pressure rating 1,450 psig [10 MPa]) for your equipment and piping it is unlikely that the reservoir can hurt the equipment—process-safety equipment and processes would be minimal if required at all. No chokes. No emergency shutdown (ESD) valves or logic. You would be able to operate the well in a way that would maximize long-term profitability (which may or may not require throttling flow, but that becomes an Engineering/Operations decision not a process safety decision). For the same reservoir pressure, if you build your surface facilities for ANSI 150 pressure class (nominal pressure rating 280 psig [1.931 MPa]) then a wellhead choke is essential, ESD equipment and logic is mandatory. With the required chokes and ESD installed you are precluded from considering the needs of the reservoir in your operating decisions—opening the choke has too much risk of overpressurizing the production equipment.

All reservoirs have a "pressure window"[2] that maximizes ultimate recovery through optimizing the use of reservoir energy. This window can only be found through experimentation, and is often somewhere around a flowing bottomhole pressure equal to one-half of average reservoir pressure. Exploiting this knowledge requires an understanding of average reservoir pressure and current flowing bottomhole pressure. To be able to quantify the pressure window you need to have knowledge of both the flowing bottomhole pressure and the reservoir pressure.

We don't know of any effective way to measure reservoir pressure. In some reservoirs we have the ability to economically determine it. For example in coalbed methane (CBM, known as coalseam gas or CSG in Australia) nearly all of the gas in place is adsorbed to the surface of the coal. The amount of gas adsorbed to a unit mass of coal is a physical parameter of the coal and is determined through core analysis. This value is a key parameter in reserves estimating and the Reservoir Engineers go to great pains to determine it with the lowest possible uncertainty. The result of this analysis is a curve known as the "Langmuir Isotherm" which plots gas-in-place vs. average reservoir pressure. This means that with cumulative production you can estimate a current reservoir pressure at any point in time after first production. Shale gas reservoir pressure is somewhat more complex than CBM since there is a significant void volume that holds both gas and liquids, but it is still possible to do a competent material balance. Tight gas and conventional gas have proven resistant to material balance evaluation, but classical Reservoir Engineering tools can be applied to predict pressure based on such tools as a pressure build-up.

Flowing bottomhole pressure is a parameter that we have many approaches to determine. We can compare tubinghead pressure to casinghead pressure; calculate friction loss from tubinghead pressure and flow rate; run pressure bombs; or install downhole gauges. Any of these approaches can get us pretty close to actual values.

Having a reliable estimate of both average reservoir pressure and flowing bottomhole pressure lets us determine the pressure window through experimentation. These experiments require us to be able to manage flowing tubing pressure without regard to the artifacts we've installed downstream of the wellhead. With today's intolerance to risk, these experiments are exceedingly difficult to conduct and/or implement the results. With PSM, it can require an MOC, CDR, and HazOp to change a flow-meter's effective range; procedures require controls to look first at the capability of downstream equipment before you can evaluate pressure upstream of a choke, etc.

My recent attempts to conduct this experiment in a CBM/CSG field met with total failure when any improvement in gas flow resulted in an ESD trip—the ESD logic included a trip when flow rate in a 60 second period exceeded the flow rate in the previous 60 second period by more than 5% (the trip was designed to detect and minimize the effects of a downstream pipe rupture). Changing the trip set point was estimated to be an 18 month process.

Drilling

Drilling procedures and equipment have evolved over the last 150 years to the point where drillers can hit a 6 inch [152.4 mm] target a mile [1.61 km] down and 2 miles [3.22 km] to the left nearly 100% of the time. Given enough time and money there is almost nothing that modern drillers cannot do with regard to hitting a target and a trajectory. As technological capabilities have advanced, costs have increased. To a significant extent, drillers are the victims of their own successes. When directional drilling was more art than science, they had the latitude to do it right and consider the needs of the reservoir. Doing it right 100 times in a row caused managements to begin to accept that the drillers could do what they said they could do and start asking if they could do it less expensively. All of the significant drilling variable costs can be related to "time on location". Consequently, drillers started getting measured by days-on-location and the drilling schedule became the controlling factor in a drilling program.

PSM tells us that you must have two verifiable barriers between an energy source and workers. Carrying that concept to a wellbore says that the stripping rubbers on a BOP are inadequate protection and you must have a second barrier. Hundreds of thousands of wells were drilled in the last century without this second barrier, and the frequency of blowouts and fires was very low. That is irrelevant. Any risk that can be reduced; MUST be reduced under the tenets of PSM. The needs of the reservoir are not to be considered.

Drilling with overbalanced mud has the highest potential for a no-surprise, on-schedule well. Running production casing past any potential hydrocarbon zones and cementing to surface minimizes the possibility of getting hydrocarbons onto the rig floor.

Soft rock like CBM/CSG fails when mud is used, so lost circulation material (LCM) is always part of the pre-spud materials on location. This LCM is very resistant to flow in both directions and mud-drilled CBM/CSG wells always start out underperforming air-drilled offsets, but overbalanced mud and LCM allow the drilling department to meet goals that do not include initial production rate (or any other reservoir-performance-specific goal) and meet the requirements of PSM.

The cement used in wellbores is quite dense. A column of cement above a coal seam will cause the coal to fail and cement will enter every weakness in the coal matrix. One client of mine plans on needing twice as much cement as the traditional calculations would predict. The missing cement is expected to travel into the coal for some non-trivial distance. My client asked me to help determine why these wells rarely make economic production when the gas in place is so high. When I explained that cementing the coal had a very low probability of economic success, their response was "our HazOp showed that air drilling the coal and producing it open hole or with an uncemented liner would have too high a potential for a blowout". Eliminating that risk was more important than the field being economic.

Completions

Conventional oil and gas wells are normally cased, cemented, and frac'd. Shale reservoirs tend to be strong enough to tolerate this conventional process and cased, cemented, and frac'd shale wells are approaching 50% of U.S. total gas production. Coal lacks the mechanical strength to allow this conventional approach to be successful. When we cement production casing across coal seams we rarely get economic wells.

Even with air drilling and open-hole or lined-hole completions, frac jobs are a very iffy proposition in CBM. In the messy environment of a borehole through a coal seam, it is impossible to control where a frac will go. Placing the frac string adjacent to the target formation does not in any way ensure that the frac fluids will go where you want them. We regularly frac coal wells, but the results are far from predictable and every good well is attributed to "a successful frac" and every bad well is attributed to "poor reservoir conditions". We keep doing frac jobs in coal seams, more because they can be done on a predictable schedule than because they work.

An alternative completion technique that proved incredibly successful in the San Juan Basin of Northern New Mexico and Southern Colorado in the US has been "cavitation"[3]. This process requires the injection of high-pressure air into the wellbore to increase the pressure in the cleats in the first couple of inches of coal, and then the pressure is rapidly dropped to try to expand the trapped air enough to blast the coal from the matrix and flow the solid coal to surface. This process is repeated dozens of times over several days or weeks until the coal stops flowing. The results in San Juan show that a well that is able to cavitate will out perform a similar well that is not cavitated by a factor of 10-40 times (e.g., a well that would yield a 10 MMSCF/day rate cavitated will make something between 250 and 1,000 MSCF/day not cavitated) and a cavitated well will outperform a similar well that is cased, cemented, and frac'd by 50-100 times. The purpose of the industry would say "if a well will cavitate you must cavitate it". There are a number of companies developing coals that would have a high potential for successful cavitation. Generally these wells are completed with either open-hole non-cavitated completions or they are cased, cemented, and frac'd. One company says that the reason for not cavitating is that the required duration of the procedure is quite variable and "[cavitation] messes up the rig schedule". Another says that the reason for cementing production casing across the coal is that it is "company policy". Neither rig schedules nor outdated policies have considered the optimization of profit from the reservoir.

Wellwork is another area where the industry has lost track of reality. Historically it was common to pull tubing from a producing well by setting a plug in the tubing and stripping the tubing out of the hole. This has been done millions of times with success. Today's risk intolerance requires a second barrier, so kill-fluid is pumped into the wellbore to pull tubing. Some reservoirs tolerate this very well and return to production after wellwork with minimal disruption. Other formations struggle. As reservoir pressure comes down, the frequency of wells not recovering from kill-fluid increases. The CBM wells in the San Juan Basin Fairway generally have reservoir pressures under 100 psia [689 kPa]. At that pressure, the ability of the reservoir to overcome waterlogged flow-channels in the near wellbore is quite limited. Killing one of these wells has the tendency to reduce gas production to near zero for months or even forever. But PSM says that stripping tubing out of a live well is simply too dangerous to be considered.

Finally wellbore jewelry has gotten very risk intolerant. One of my clients was experiencing significant lost production due to liquid loading in a tight-gas field. My first question was "what is the pressure on the annulus?" The response was that there is a packer and the annulus is full of annulus fluid. In a gas well, access to the annulus for pressure monitoring and for flow during deliquification evolutions is critical to success. The answer to "why is there a packer?" was "company policy, we must have two boundaries between the reservoir and uphole aquifers; the annulus fluid ensures that we know if there is a casing failure". This environmental risk intolerance will result in decreasing ultimate recovery in this field to about half of expected levels.

Wellsite facilities

In the last century it was rare for Facilities Engineers to be involved in wellsite equipment selection/design, procurement, installation, or operation and it was unheard of for a Process Engineer to have any role in wellsites at all. When I assumed a Facilities Engineering role that included field operations responsibilities in 1993 I was unable to find another Facilities Engineer within the company that had a significant non-project role who I could compare notes with. Today there are a dozen Engineers in place in that field whose combined scope of work roughly matches my job in 1993 (except the field has half as many wells today than it did 20 years ago due to divestments). This flood of bodies is a direct consequence of the imposition of PSM concepts on wellsites and disregarding the risk density on onshore gas wellsites. A significant portion of the available time of this group is spent in meetings talking about PSM issues.

Historically, our industry has tended to have zero wellsite drawings for onshore gas wells. Today a P&ID is a prerequisite to starting PSM reviews that may or may not lead to procurement. I recently saw a pre-construction P&ID that was marked "Rev 62". Granted that most of the revisions had been to correct miscommunications between the Engineer and Drafter, but others were significant changes to design philosophies and came about through protracted negotiations among a large number of highly-paid Engineers. Direct billing to that pre-spud well for Facilities Engineering was over $125 k USD—15 years ago that amount would have been more than the entire budget for surface facilities on a well with the mix of pressures, temperatures, and fluids that was expected from this well. The budget for surface facilities for this well was $2 million USD, and that entire very large sum has a PSM focus and none of it considers the needs of the reservoir at the location of that particular wellbore. I asked several of the Engineers in the HazOp for this well "where in the field is this well located?" and none of the ones I asked could tell me—they were making decisions that were going to have a material impact on reservoir performance without even asking what the reservoir looked like in that area of the field.

Wellsite equipment design must deal with a wide range of operating conditions and considerable uncertainty. Both of these concepts are very difficult for PSM. This PSM-difficulty is addressed with "nominal conditions". To allow PSM to appear to work, we define the wellsite nominal conditions with terms like "expected gas production will be 5 MMSCF/day [141 kSCM/day]", "expected water production is expected to be 2,000 bbl/day [0.318 ML/day]", "expected operating pressure will be 50 psig [345 kPa]", "expected operating temperature will be 100°F [37.8 C]". Using these assumed values you can meet the requirements of PSM. You can calculate erosion potentials, pressure drops, and corrosion allowances quite easily. It doesn't matter that when a particular well comes on production the wellhead pressure might be 1,200 psig [8.27 MPa], the wellhead choke will beat that variability out of the process. The overriding principle is the assumption that we can (and must) force the reservoir to act just like a plant feed. Options that could significantly increase gas production or decrease water production are simply not viable because the design conditions cannot accommodate higher pressures, higher temperatures, or higher flow rates.

This focus on fictional "nominal conditions" leads us to "save money" by designing wellsite facilities that are significantly under strength. Reservoir pressure is irrelevant because we have a "spec break" that will slam shut if flowing wellhead pressure approaches 90% of the maximum allowable working pressure (MAWP) of the separator which was built to accommodate a very low pressure nominal condition. Selecting ANSI 150 pressure class (pressure rating 280 psig [1.931 MPa]) for a wellsite production unit saves something like $5 k USD over selecting ANSI 600 pressure class (nominal pressure rating 1,450 psig [10 MPa]). That $5 k USD forces installing a $10 k USD spec break that includes an ESD valve, programming, and a variable choke—the "savings" really don't stand up to scrutiny, luckily the underlying assumptions of PSM preclude much scrutiny of the real costs. Prior to PSM, ANSI 600 class vessels, valves, and piping on wellsites were normal and ESD equipment was rare. We're "smarter" now. We spend millions of dollars to do a worse job than the last generation spent thousands to accomplish.

Gathering facilities

Gas gathering systems are infested with the concept that they are a "sales tool" rather than a "tool of reservoir management". There is a significant difference in the success (as measured by profitability of a reservoir) achieved through these divergent operating philosophies.

Sales tools are always under intense cost-control pressure. Valve maintenance, pigging, cathodic inspections, and ROW patrols all cost money and tend to not have an immediate revenue-response. Design choices tend to focus on minimizing capital expenditure, often at the cost of reservoir performance. Piping tends to be the lowest material-cost available. High Density Polyethylene (HDPE) pipe and thin walled steel are common. Both of these options limit the pressure rating on the system, and generally require a second spec break as you leave the wellsite. Pigging facilities are generally omitted from piping intended to be a sales tool—in this mindset you only pig for corrosion-control and material-choice takes care of corrosion concerns. This design philosophy ignores the fact that accumulation of water in the system further limits the pipe's ability to accept reservoir fluids at un-choked pressures.

When we can treat the gathering facilities as tool of reservoir management, they look very different. Pressure and temperature ratings are adequate to handle reservoir fluids without pressure reductions, accumulation of water is anticipated and every line has pigging facilities, staffing levels are adequate for required maintenance, and operating costs are borne directly by the wells as a cost of production not as a cost of sales. This last point sounds like just shifting the position of deck chairs, but it isn't. "Cost of production" tends to be a fairly big number that is managed by people who are evaluated based on production. "Cost of sales" tends to be a very small number that is managed by people evaluated on sales margin. This shift in evaluation parameters drives decisions in very different directions.

Processing facilities

Compression and processing facilities are approaching the size that PSM was designed to help manage. PSM concepts very much add value in these facilities. P&ID, MOC, HazOp, etc. can significantly reduce the likelihood of a serious event and can lower the consequences of events that do happen. These sites are at the lower end of the range that PSM was developed to help manage, but still in the range. Managing the risks in these facilities using PSM has been ongoing for 25 years and hasn't changed dramatically over that time.

Field operations

The misapplication of the twin concepts of PSM and Supply Chain Management combine in field operations to tie the hands of field staff into gridlock. Wellsite manifestations of PSM require double-block-and-bleed and lock-out-tag-out to gauge a tank (turning a process that can easily be repeated 20 times in a day to one that defines success as gauging 2 tanks in a day), prohibit any welding on wellsites, and require a well to be shut-in to spray the location for weeds. Oil & Gas manifestations of supply chain management require a work order (and a 30 day advance notice) to inspect a plunger used to lift water from gas wells, do not allow a lease operator to replace a float on a level controller (a 10 minute process that requires simple tools and rudimentary knowledge of controls, it now must be done by an Electrical and Instrumentation contractor), and do not allow lease operators to just "try something" that has a non-zero chance that it will improve production.

The amount that supply chain management and PSM have stifled innovation in our industry in the last few years is shameful. I spend as much of my time on wellsites as I can. The "are you stupid" looks that I regularly get after saying "why don't we try …" are distressing. I was recently on a location where the gas flow meter was considerably oversized (i.e., minimum repeatable flow that the meter could register was 520 MSCF/day [14.7 kSCM/day], and the well was measuring zero but was clearly not dead). I asked the Field Engineer if we could change out the meter for one appropriate for actual flow. He described queues for the EJR [Engineering Job Request], MOC [Management of Change], HazOp [Hazardous Operations review], CDR [Critical Drawing Review], and workorder processes that would (if approved) authorize the Supply Chain Management group to order a new meter in 3-4 years, for installation in 4-5 years. The chance of successfully completing that process is approximately zero so no one initiates it.

Procedures are used to minimize the risk that someone will do something inappropriate. Strict adherence to procedures makes innovation very difficult. There are always multiple (safe) ways to do a field task. Memorializing one of them in a procedure feels safe, feels competent, and prevents anyone from ever finding a better way. The field I began operating in 1993 within the San Juan Basin was expected to recover 40% of original gas in place (OGIP). We had no written procedures at all and every activity was open to Engineering and Operations innovations. When I left the field in 2003 we had recovered 92% of OGIP and were on our way to 96%. We got to that unprecedented recovery level by paying attention to what worked at any given time for any given well, and being willing to try the things that worked on one well on other wells, but not being hesitant to abandon failed experiments, and we had a very large number of failed experiments, but we also had a significant number of successful experiments.

Processes, procedures, and restrictions are corrosive to a field staff. We hire very talented, bright people to be lease operators, pay them a premium, and then punish them for thinking. If I'm paying a lease operator more than the US median income it is because I'm paying for his brains. If I don't want him to think then I should be hiring people content to work for near minimum-wage and who require every activity to be covered by procedures.

Conclusion

Applying plant-safety concepts to low risk-density onshore gas wellsites and mis-applying manufacturing administrative protocols to the tools of gas production have combined to put our industry into an untenable position—we are developing a culture where the first response to an upset is to develop and apply a new administrative-process, procedure, or proscription until innovation has been completely beaten out of our people. We find ourselves doing failure analysis to assess blame, not to determine how to improve the physical processes and equipment. When the witch-hunts we call "failure analysis" are complete, it is always found that a procedure or administrative process was circumvented and the "culprit" must be punished. Lease operators respond with slavish adherence to procedures even when they know that the procedure results in a worse outcome for a particular well—they are rightfully unwilling to risk termination of their employment by innovating.

It is rare to consider reservoir-properties in facilities decisions, and even when these properties are considered their potential success is thwarted by supply chain management concepts that make it impossible to reject a low bidder just because they are not competent to do a job. Contractors are responding by hiring more MBA's and Safety Engineers than construction managers and building unassailable (and unusable) stacks of procedures.

The only way that the industry survives the current state is by all of us shouting that "the emperor has no clothes". PSM and supply chain management must go back to the arenas where they have proved to be amazingly successful. We need to go back to applying safety processes appropriate to the operation's actual risk-density. We must stop treating the <u>tools of production</u> as though they were <u>units of production</u>. We must stop treating our field staff as though they were commodities that can be replaced from the fast-food industry on a moment's notice.

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