

## A Bridge too far? Bridging the Gap between Remote Operations and true automation

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### Abstract

Can Service providers and Operators overcome cultural barriers and develop processes and technologies that achieve true automation of directional drilling, engineering, and geo-steering? This paper addresses today's industry concepts of real-time data gathering and management and decision making. It will challenge the stakeholders to consider if their culture can be changed to move to disruptive technologies that can exploit and improve economics of existing unconventional reservoirs that were once considered uneconomical. The first step toward true drilling automation is to dispel the current industry perception that drilling communication and data exchange are happening in real-time. All three of these disciplines, directional drilling, engineering, and the geo-scientist, currently operate independently of each other using stale information, competing software and non-collaborative communication paths. At the present there does not exist a software that will build a bridge that will connect the processes and stakeholders. This paper will address some of the challenges that will need to be addressed in business models, contractor and operator cultures, and technology to achieve true automation in a multidiscipline collaborative environment.

### Introduction

The first step toward true drilling automation is to dispel the current industry perception that drilling communication and data exchange are happening in real-time. All three of these disciplines, directional drilling, engineering, and the geo-scientist, currently operate independently of each other using stale information, competing software and non-collaborative communication paths. At the present there does not exist a software that will build a bridge that will connect the processes and stakeholders. This paper will address some of the challenges that will need to be addressed in business models, contractor and operator cultures, and technology to achieve true automation in a multidiscipline collaborative environment.

### Achieving True Automation

The current assumption is that drilling data is being transmitted in real-time and that geologists, well engineers, and directional drilling contractors are participating in a mutually collaborative, cooperative, and dynamic evaluation process and

making real-time decisions with respect to sliding/rotating, motor dogleg severity/yields, wellbore placement in the reservoir, and best fit-for-purpose tools. In actuality, decision-making is constrained by the delay in communication and data exchange between the three drilling disciplines - geology, drilling, and directional drilling. Reservoir engineering is also relevant in the decision tree when decisions are made such as the economics of exposing the last remaining footage in the drilling process, fishing/sidetracking, and opening structural windows above and below the targeted zone. All of these disciplines currently operate independently of each other using stale information and non-collaborative communication paths. The data is transmitted in tranches of data after the well is drilled to a point where it is convenient to transmit geologic and survey measurement data. Typically, gamma and survey information is transmitted from the field to the operator's office where special application software compares the gamma measurements to another gamma type log from another well in the field. After this comparative analysis, the best position of the wellbore in the intended target zone of the reservoir is estimated. Based on this information, the geologist either opts for continuing along the current regional pre-planned well path or, after stratigraphic modeling by the geologist, determines that a new depth position of the reservoir is needed for optimum placement in the reservoir. If a new analysis of the model determines a change is required, the geologist will request a new revised well plan to be developed by the operator's engineer and the directional drilling contractor. The new plan is approved based on limiting mechanical and geological risk. Drilling is usually resumed while the engineer and directional vendor develop a new revised projected well plan. This process can take several hours. During this time the well is following the original well path previously approved by the geologist and monitored by the directional vendor's supervisor onsite. It is, more often than not, during the above time that the well is not being drilled and placed in the preferred target zone of the reservoir resulting in longer well-path correction time, increased days to drill the well, and increasing cost to drill the well. This results in harmful effects on the life cycle of the well and reduced production output of the well. Figure 1 demonstrates the current path and process used by the industry.

As demonstrated in Figure 1, the current communications and information methodology is not sufficient for automated

remote directional drilling/rig operations, in that it does not allow for dynamic decisions to be made as the geologic and survey information is collected in real-time. A new operating model is needed to break down communication gaps and barriers between all the disciplines, provide real-time empirical data and graphics to all the stakeholders, and improve transparency between all the disciplines.

The new model would provide for the collection of data as it occurs utilizing algorithms in real time with the following objectives:

- Utilize the data to make immediate, active decisions on predicted stratigraphic changes and wellbore position that might be anticipated ahead of the bottom hole assembly.
- Send clear instructions to the directional drilling supervision to steer the well path to the correct stratigraphic position, while avoiding geological and mechanical hazards.
- Implement a continuous improvement program that is constantly evaluating models for torque and drag, hydraulics, bottom hole assembly performance, mechanical specific energy, etc.

To accomplish these objectives with the goal of true automated remote directional drilling/rig operations, the new model will implement the following attributes.

### **Automated Real-time Directional Drilling Operations**

Directional drilling roles, responsibilities and communications paths between the engineer, geologist, and the service provider would be redefined so that all operational decisions, as related to steer/slide/rotate in the curve and lateral, would originate from an all-in-one automated structural guidance system. This system would encompass active geologic modelling which would project anticipated geologic structure, ahead of the bit, utilizing real-time data as it is collected and analyzed. These active geologic models would continuously revise and send automated directional well plan calculations and visual graphics to the field that the directional supervisor could use for any new well path adjustments from the structural changes that were identified, in real-time, by the geologist. These new instructions for the directional supervisor would be constrained by limits on tortuosity, dogleg severity, and geologic hazards predetermined by the geologist and engineer.

### **Proactive Data Analytics**

Data would be monitored and modeled for real-time application of torque and drag, hydraulics, rotational trend analysis, bottom hole assembly performance and design, mechanical specific energy, formation anisotropy, automated geo steering algorithm, and development of best practices for technologies and overall best practices for drilling and completions. A Root Cause Analysis based on data analytics for any failures by equipment suppliers causing non-productive time(NPT) would be prepared and presented to the operator and supplier for sustaining engineering or determining best fit-for-purpose technologies for well design, bottom hole assembly

design, bit design, etc. Utilizing real-time data, rig state Key Performance Indicators (KPI's) would be customized and presented to the operator and service provider for discussion on any continuous improvement program cycles.

### **Predictive Geological Stratigraphic Modeling**

After the vertical pilot well is drilled and geophysical logs are run to determine the formation characteristics, it is then possible to predict anticipated formation measurements once the wellbore inclination approaches and exceeds anticipated the bed dip of the formation. The formation measurements should be repeatable but distorted once the inclination increases to approach the formation bed dip. As the deviated well is drilled and the inclination increases to greater than the bed dip, the gamma ray measurements will repeat but in reverse as the bit traverses back up the formation. The formation measurement will be less distorted when the inclination has a greater deviation from the bed dip. This could make an algorithm effective along with AI, machine learning or neural network to predict the anticipated gamma ray measurement and structural formation dip ahead of the bit. Geological modeling and correlation for the placement of a wellbore is accomplished by utilizing an offset type log with a specified Target Center Line (TCL), within the desired unconventional reservoir zone, determined by the operator's geoscientist and compared to the actual real-time geological data (typically a gamma ray measurement from the current well being drilled), to determine projected formation thinning, thickening, faulting and bed dip ahead of the bottom hole assembly. Geological boundaries above and below the TCL (typically known as the target zone window) are determined by the operator's geologist with considerations given to any hazards, above that may be encountered by the well path. The placement of the wellbore in the identified target zone is continuously monitored as geological and survey measurements are taken by the Measurement While Drilling (MWD) tool along with additional data acquired during the drilling of the well. As mentioned earlier, the industry is currently performing these operations statically, but the culture change, to achieve true real-time automation, must have a path and process, as outlined above in real-time directional drilling, that can perform them dynamically.

### **Continuous Improvement Program**

A program, similar to programs developed in the automotive industry that are leveraged to make objective changes to a proposed plan (Plan, do, and study act) should be implemented in the automation process. A continuous improvement plan should encompass all phases of the life cycle of the well with the goal of the program to determine if the wellbore is being placed in the most optimum position in the reservoir, is being drilled in the most efficient manner, with the least mechanical and geological risk, and is treated with the most effective stimulation. An effective program would:

- Determine that best fit-for-purpose technologies are being successfully applied.
- Ensure that engineering feedback is being given on the

performance of technologies utilized.

- Develop new technologies, as needed, to improve the economics of an unconventional reservoir.
- Determine and implement best practices.
- Capture and apply lessons learned.
- Predict future performance of technologies.
- Develop analysis of data/KPI's and input new predictions into a feedback loop that is always measuring performance and recalibrating performance models.

A continuous improvement program (MMEM) designed for true automation in unconventional reservoirs would be described with these terms:

- **M- Modelling-** Pre-Well prediction performance models are built for bottom hole assembly performance, hydraulics, torque and drag, mechanical specific energy, formation anisotropy, rig states, tool performance specifications, and technical performance on limits of tools and systems.

- **M-Monitoring-**The predicted performance models are monitored and KPI data is collected to determine if the actual performance matches the predicted and determine outlier data.

- **E-Evaluation-** New data sets are identified to input into predictive models to determine if performance can be improved. If any tool or system failures occur, then root cause analysis (RCA) would be analyzed, as a part of the evaluation, so that new technologies could be developed, or input for sustaining engineering could be given, to improve existing designs for technologies.

- **M-Modify-** Actively recalibrate models based on past performance to determine new operational parameters to improve performance.

Figure 2, shows an example and sample of an active collaborative automated directional drilling process and method previously and currently used in the industry. It covers the "Look Forward" philosophy that industry leaders request, by combining geo steering and directional drilling in one software platform to give a virtual view of formation changes ahead of the drill bit with automated well plan calculations that keep the well path in the target zone. It is a true look-ahead method and process that does not rely only on the rear-view mirror.

#### **Sample of a Dynamic Collaborative Automated Real-time Method and Process.**

Studies are available that have utilized some of these improvements in communication, data sharing, and repurposed job responsibilities. These studies were developed over the course of several years due to the timeliness of state government held production data and demonstrated improvement in the key areas of decreased days vs. depth, improved rates of penetration, decreased mechanical risk, and most importantly, increased production rates by optimized placement of the wellbore in the reservoir. Enhancements were achieved by an improved communication process between the geologist, engineer, and directional drilling supervisor, on site. The

geologist issued altered structural changes with directional drilling plans on the fly, based on new updated stratigraphic geo-models in real-time, in a dynamic collaborative environment. While these studies show significant improvement in these KPI's, there is much more improvement in economics that can be achieved by true automation. True automation is defined as automated decisions, streamlined by algorithms/machine learning/AI, for steering, bottom hole assembly design, sliding, rotating, geo modelling and formation anisotropy. It must also be noted that in the time span that this data has been collected in these case studies, industry drilling optimization has seen improvements in KPI's for days, vs depth, ROP, and costs for drilling. However, the quantification of the effectiveness of optimum wellbore placement has not been determined due to the perception that artificial fractures efficiently connect zones of the reservoir that have high concentrations of hydrocarbons. More data is needed before broad generalizations on effectiveness of wellbore placement, artificial fracturing, and stimulation can be determined. Wellbore placement in the reservoir must be prioritized before any dynamic and collaborative methodology changes can be implemented that will push forward true automation in our industry's culture. True automation must make economic and operational sense, and not be disruptive to the current structure and deliver measurable value.

In figure 2, a method and process is described that has delivered improvements in efficiency and operations in each of these in multiple basins. Some of the Benefits it provided in those basins were:

Decrease Drilling Cost (Figure 3)

- Automated Active Collaboration, between Structural and Directional, produced less side tracking, from out of zone issues in Bakken Shale that yielded 14% to 33% cost savings. Figure 3 below outlines the case study that the service provided:

ROP Increases (Figure 4)

Automated simultaneous Collaboration between Structural and Directional produced more rotating time than sliding time, in the Eagle Ford Shale Basin, which produced 150 to 350 more footage per day. Process identified better decisions of when to slide or rotate. Figure 4 below outlines the case study of the service provided

- Figure 4- case study of 2 laterals on same pad in Eagleford Formation.

Drilling Days Decreased (Figure 5)

- Automated dynamic Collaboration between Structural and Directional reduced the total drilling days by 1.5 to 3 Days, in the Bakken Shale, by ROP increases. Figure 5 outlines the case study of the service provided.
- Figure 5- Case study of decreased drilling days and savings.

Increased Production (Figure's 6 and 7)

- Automated immediate Collaboration between

structural modeling and improved directional control increased production by 23%-74% in the Stack of Oklahoma.

- Less Well bore Tortuosity In all case studies above, automated instantaneous Collaboration between Structural and Directional reduced unnecessary sliding intervals that produce Porpoise swings in well bore trajectory that causes cutting traps. The result was cleaner well bores and limited issues in getting the production liner to bottom after drilling was completed.

## Conclusions

In the future, unconventional assets will need to be exploited more economically due to long term volatility of commodity prices and debt financing. This will require identifying which systems and processes need to be improved to achieve true automation. True automation can transform the current industry to achieve the goal of a manufacturing industry that can take advantage of economies of scale and reduce capital commitment to assets and people which will improve returns on investments. True automation will be a disruptive technology to the current non-conventional oil and gas industry. In the past, industries have been slow to implement disruptive technologies because of entrenched business models, systems and culture. Disruptive technologies demand businesses rebuild their systems, models and institute changes in culture. Automated dynamic and collaborative directional drilling systems, processes, business models and tools need to be redefined, re-evaluated then implemented, in order to achieve true automation. The hurdles to the development of automation in the current markets are mainly cultural (operator and service provider). Current business models and industry culture create static environments and limitations. Those limitations are as follows:

- Communication inefficiencies between the disciplines, systems, and processes.
- Role and responsibility reformation.
- Determination of shared data and KPI's between the disciplines and stakeholders.
- Implementation of acceptable drilling and geological limits to operate and make automated immediate collaborative decisions within.

Current directional drilling service providers are limited in that they have very strict roles, responsibilities and communication paths due to liability issues which will not allow the supervisor in the field to take control of the rig and actively steer the well path. In the past the directional supervisor would actively control the mechanism which steered the tools that determined the placement of the wellbore in the curve and lateral. This has placed the directional supervisor in a pure supervisor role over the rig contractor driller. The rig contractor driller is in charge of all operations of the drilling rig. Current communication systems and data transfer rates and systems have made it possible for the directional supervisor to be removed from the field and placed in a command center.

This allows for the directional supervisor to be placed in a central location so that they can monitor the operations of several rigs at a time. The benefits of this type of system allows for reduction of personnel in the field and reduced system costs and liability. This is an improvement in efficiency but does not fully realize the goal of true automation. Algorithms will need to be developed with the aid of machine learning and artificial intelligence. These algorithms will automate decisions on sliding/rotating, tool face orientation, wellbore placement in the reservoir, and mechanical limits on torque, well plans, mud programs, etc. Until the goal of true automation is reached, there are many improvements in efficiency and optimization that can be made by utilizing real-time operations centers, which the presented case studies in this paper indicate will improve the economics of unconventional wells and also the life cycle of wells. Drilling, geological, and completion/stimulation do not share KPI's that affect other disciplines and how these KPI's and data affect the overall life cycle of the well from spud to flow back evaluation. The industry must embrace the understanding of the cultural change presented, to implement automated dynamic collaborative methods and processes which will build bridges between the stakeholders to automation.

Under current roles and responsibilities for the geoscientist, well placement in the reservoir is the primary focus of the operations geologist. They are required to be available for 24 hours for multiple wells at a time when the wells are in the curve and lateral section. Engineering operations face the same kind of challenges when it comes to working hours and monitoring multiple wells at the same time. The current engineering roles and responsibilities center on mechanical risk, costs associated with drilling operations, and evaluation of technologies. For automated remote directional drilling/rig operations to accomplish improved performance and efficiencies, the command center culture needs to have greater collaborative autonomy when it comes to dynamic geological placement opinions of the wellbore, issuing immediate proactive changes in well paths and steering of the well paths to the optimal position in the reservoir. Current industry software operates in independent silos between the disciplines and does not join forces to share key data and communications. This type of independent silo association is what creates the illusion of real time. In the future, in order to have real time automated collaborative cultural change, the industry must adopt a dedicated software that combines drilling, geo-steering, and data analytics to take data in true dynamic real-time, perform immediate proactive geological stratigraphic position analysis, and issue dynamic structural formation changes ahead of the drill bit. The software would utilize a form of artificial Intelligence, machine learning, or neural network learning to issue immediate well path changes and evaluate critical systems as the data is collected and deliver an optimized operational plan in real-time to achieve the objective of automation in a simultaneous fashion.

Currently, there are several hurdles to delivering dynamic collaborative automated directional drilling with structural guidance methods and processes to the industry.

- Software vendors and operators have not yet realized the economic potential of combining these functions to build geologic stratigraphic prediction models proactively ahead of the bit while utilizing true real-time geologic and survey information.

- Operators have not recognized and prioritized the hurdles to these methods and processes of automation, so they have not impressed the need for their service providers to have software and processes that provide these combined cooperative services.

- Operators are also reluctant to press forward with this type of method and process automation because it would require major culture changes in roles and responsibilities of the geologic and engineering staff members within their organization and also service providers.

- Successful implementation of this type of method and process to automation is limited by the inability of contractors and operators to develop business models that can monetize a new directional drilling model because operators and contractors have not been able to understand how this model would create a win-win scenario for all parties.

In the future operators, rig contractors, and service providers will need to quickly move towards true automation for all the stakeholders to thrive and survive in a constantly changing economic environment. But the industry must first confront the primary priority to achieve true automation which is to start taking in data as it acquired and use that data to make real-time structural guidance decisions while drilling operations are occurring. This function must be solved before true automation can be achieved. The industry must also solve what party will be responsible for delivering and implementing true automation and if true automation can be delivered at a cost that is economical for all parties. All the stakeholders will be challenged by volatile commodity prices and the ability to implement new technologies and strategies. Other challenges will be the difficulty of understanding how major and independent operators value the services that they are receiving from their service providers and also in what party owns the data and how they would prefer data presented to them on service interruptions, non-productive time, mean time between tool failures, and unplanned events. When operators and service providers can overcome these internal hurdles and build their business models based on real-time dynamic collaborative true automation, then they will be much more competitive and flexible to attack markets that others would perceive are unproductive in unconventional reservoirs.

**Graphics**

**Current Industry Process for Data Capture and Analysis**

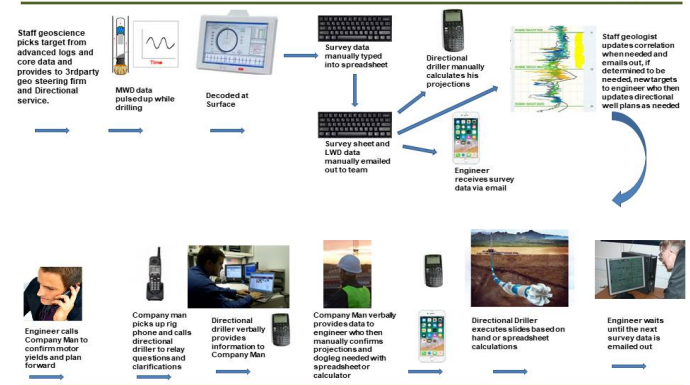


Figure 1

**Improved Process for Capturing and Analyzing Data**

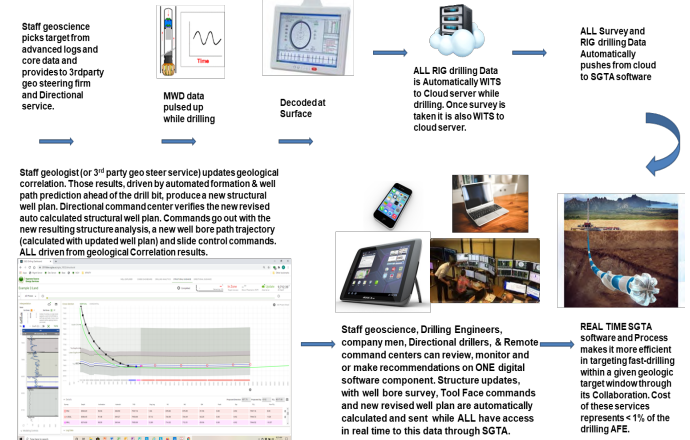


Figure 2

Bakken Shale Sidetrack Avoidance Results:

Avg. Sidetrack cost to operator (per Strk)	SGTA Shale Avoidance Warnings	SGTA Shale sidetracks saved	Total Sidetrack Savings
\$250k	38	28	\$7M

Avg. Days to sidetrack	Avg. Well Cost Across the Field (per day)	Total Drlg. days Saved	Total Drlg. Savings
3	\$137.9k	84	\$11.6M

Figure 3

### Improved Rotating vs. Sliding Eagle ford Shale

Sliding Vs Rotating Footage Value Results:

Well	County	Day comparison	Slide (%)	Rotate (%)	Footage (ft)
Mercury 2 H	Atascosa Tx.	4	7	93	3291
*Mercury 2H 1H	Atascosa Tx.	4	3	97	4634

\* A 4% increase in Rotating times produced 1,343' of added footage value from SGTA

Figure 4

### Drilling Cost Savings from Decreased Drilling Days

Drilling Costs Saved						Drilling Days Saved			Total Costs Saved	
Drilling Costs Saved	# - Wells	Rig Cost / Day	Avg. # Days to Drill	Avg. Well Costs Across Program	Total Drilling Days Involved	Total Drilling Costs - All wells	Per Well Collab- Auto	Total Drilling Days Saved	Total Utilizing Collab- Auto	Total Utilizing Collab- Auto
TOTAL	28	\$137,930	29	\$3,000,000	812	\$84,000,000	3.0	84	14%	\$11,586,120

Figure 5

### Production Rate Improvement

Production increase vs offset wells in same field Results:

Wells	Location & Formation	Production Month Comparison	Incr. Prod. vs. Offsets (%)	Actual Oil Sales price (\$)	Total Incr. Prod Value (\$)
1	Kingfisher Cty-Merrimac	11	74.09	\$45	\$2.6M
1	Canadian Cty-Merrimac	11	74.11	\$45	\$2.5M
1	Canadian Cty-Woodford	11	57	\$45	\$2M
7	Atascosa Cty- Eagleford	5	23	\$80	\$2M
5	Zavala Cty-Eagleford	17	25.51	\$100	\$5.8M
2	Canadian Cty-Woodford	11	39.94	\$45	\$1.8M
4	Kingfisher Cty-Merrimac	11	67.57	\$45	\$3.5M
1	Kingfisher Cty-Woodford	11	31.33	\$45	\$1.1M

Figure 6

### Production Rate Improvement

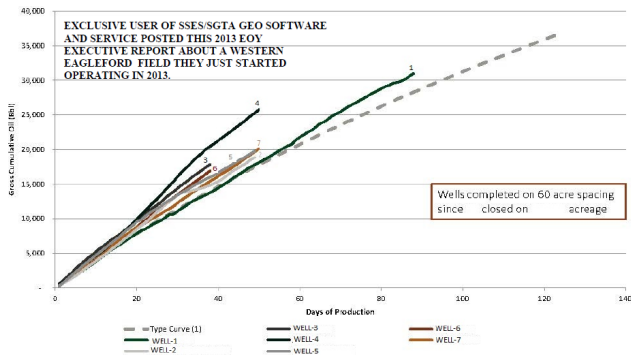


Figure 7