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Unpacking the Myths: Continuous Pumping is Not Continuous Fracturing

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Abstract

Since the introduction of the continuous pumping (CP) concept in 2020, automation and operational capabilities have significantly advanced, driven by refined algorithmic control cycles and minimized inefficiencies. These developments have enabled uninterrupted 24/7 hydraulic fracturing operations, establishing a new benchmark in completions efficiency. However, the term "continuous pumping" has deviated from its original intent, leading to a semantic shift that obscures the critical distinction between actual fracturing time and non-productive pumping time (NPP). This misalignment has perpetuated the use of metrics, specifically pump efficiency, that hinder operational optimization and resource utilization.

This paper seeks to redefine continuous pumping by introducing and expanding on the concept of continuous fracturing (CF), which prioritizes maximizing productive fracturing time and reducing operational inefficiencies. Key concepts such as non-productive pumping (NPP), effective fracturing percentage (EF%), and invisible lost time (ILT) are examined to provide a clearer framework for measuring operational success. ILT, encapsulating hidden or unmeasured inefficiencies during pumping operations, highlights critical opportunities for improvement often overlooked in traditional metrics.

Furthermore, this paper introduces the concept of “perfect days,” in which Operators achieve 24 hours of uninterrupted fracturing within a day, as a new benchmark for efficiency. Through detailed case studies and analytics, the transformative potential of continuous fracturing is demonstrated, showcasing significant performance gains achieved by focusing on fracturing-based efficiency metrics. By shifting industry standards toward CF, this paper argues for a paradigm change in completions operations, optimizing resource utilization, enhanced production outcomes, and a more transparent comparative metric of operational effectiveness.

Introduction

Hydraulic fracturing, commonly known as "frac’ing," has emerged as the cornerstone of modern energy extraction, revolutionizing how hydrocarbons are produced from unconventional reservoirs. By creating and propping open fractures in low-permeability formations, hydraulic fracturing enables the economic recovery of oil and gas resources that would otherwise remain locked in the subsurface.

At its core, hydraulic fracturing is a stimulation technique that injects a mixture of water, sand, and chemical additives into the reservoir at high pressures. The pressurized fluid creates fractures within the rock while the sand (proppant) remains in place to keep the fractures open, ensuring pathways for hydrocarbons to flow to the wellbore. (Long et al., 2016)

The primary goal of hydraulic fracturing is to maximize hydrocarbon recovery at the lowest possible cost while minimizing resource wastage. This is achieved by optimizing stimulation efficiency, fracture conductivity and minimizing non-productive time (NPT) during operations. Increasing well efficiency translates into lower capital expenditure, reduced operational costs, and improved returns on investment.

Hydraulic fracturing has undergone significant advancements over the decades, evolving from manual, labor-intensive processes to highly automated operations. The introduction of continuous pumping through automation in 2020 marked a major milestone, enabling Operators to minimize downtime between stages and achieve 24/7 operations. This approach reduced non-fracturing time by rapidly transitioning from well to well with automated workflows while maintaining a steady flow rate during this operation. However, in response to this new patented technology, attempts to replicate automated workflows with human-driven or semi-automated (referred to henceforth as human-driven) processes have undermined the gains of CP. The human-driven processes naturally extend stage-to-stage transition times and turn simple injection into inefficient overflushing events that waste available water resources, degrade operational efficiency and introduce fracture integrity concerns.

Despite the widespread adoption of continuous pumping to enhance operational efficiency, current metrics often fail to capture the true effectiveness of hydraulic fracturing. Many Operators rely on non-standard pumping efficiency metrics that prioritize total pumping time over productive fracturing time. This includes periods of acid displacement, wellbore cleanups, approval processes, and slow responses to process execution. Such metrics inflate operational performance while masking inefficiencies during active fracturing, diminishing the value of the CP concept.

By failing to focus on effective fracturing metrics, Operators overlook critical optimization opportunities as the economics of further improvement declines, particularly during the most resource-intensive phases of the process. This misalignment results in operational blind spots that hinder efforts to further improve operational efficiency, limit production potential, and fail to address broader concerns about sustainability and resource stewardship.

Given automated processes are now routinely used, this paper seeks to advance the industry's understanding of true fracturing efficiency, emphasizing the need to shift from outdated pumping metrics to those that reflect actual operational productivity. This transition is critical for continuing to advance operational efficiency, further driving down production costs while addressing broader challenges such as water resource conservation and overflushing impact mitigation. By focusing on meaningful metrics that highlight inefficiencies, we provide a better tool set for Operators to optimize their execution.

Defining Efficiency Metrics

Traditional pumping efficiency metrics focus on:

Component	Definition
Pump Time	Time pumps are active during operations, including both fracturing and non-fracturing periods.
Non-Productive Time (NPT)	Non-pumping periods caused by equipment failures, logistical delays, or other issues.

While traditional metrics provide a general overview of operations, they fail to capture the true efficiency of fracturing activities. The proposed metrics aim to address this gap by focusing on the effective time spent stimulating the reservoir, while clearly distinguishing it from non-productive activities.

New pumping efficiency metrics focus on:

Component	Definition
Continuous Fracturing (CF)	Time pumps are actively stimulating frac stages.
Stage-to-Stage$_{\text{@Transition}}$ (S2S)	Time used for decision making, valve actuation, and confirmation that starts at transition rate and ends when rate increases. This calculation is referenced as S2S$_{\text{@Transition}}$ in other papers, distinguishing it from S2S$_{\text{@Treatment}}$.
Non-Productive Pumping (NPP)	Time spent pumping fluids on critical path for purposes other than fracturing, such as acid displacement, ball dropping, or slow response time to steps.
Effective Fracturing Percentage (EF%)	Percentage of clean fluid volume (CFV) injected during operations dedicated to stimulation stages. $\left(\frac{CFV_{Stages}}{Design\ Rate\ x\ 1440}\right) x100$
Perfect Day	24-hour CP day on which the Operator pumped at EF% possible with defined transition speed.

Capturing only the time spent effectively stimulating stages, while excluding periods of inactivity caused by NPT and introducing S2S and NPP, (Douget et al., 2023), we enable a clear distinction between the efficiencies portrayed by traditional continuous pumping metrics and the actual measure of operational efficiency. To identify opportunities for improvement, the S2S component within the new metrics must be broken down into measurable subcomponents as well, ensuring a granular understanding of where inefficiencies lie. As pointed out above, the goal is to stimulate the reservoir 100% of the time. Therefore, with each component, the critical question becomes whether that time is contributing to fracturing. If it is not, the next step is to analyze why and determine how to minimize, and ultimately eliminate, the non-productive time.

Key Components of the Pumping Curve within S2S

Component	Definition
Ramp Down	Time to reduce the pumping rate to well swap initiating rate. It ensures controlled transitions and prevents equipment damage.
Pre-Swap ILT	Time from the end of Ramp Down to the start of the well transition. Use for vendor coordination, decision-making, and checklist signoff.
Swap	Time from opening second well to the end of closing first well. It enables seamless transitions between fracturing stages.
Swap Open	The time to open second well while first well remains open. It allows equalization of second well.
Swap Closed	The time to close the first well while second well remains open. It finalizes the valve sequence and allows for injection into second well.
Post-Swap ILT	The time from the end of the swap to the start of Ramp Up. It confirms successful valve actuations before increasing the rate.
Ramp Up	Time to increase the pumping rate to the desired fracturing level. It establishes optimal slurry injection conditions for stimulation.

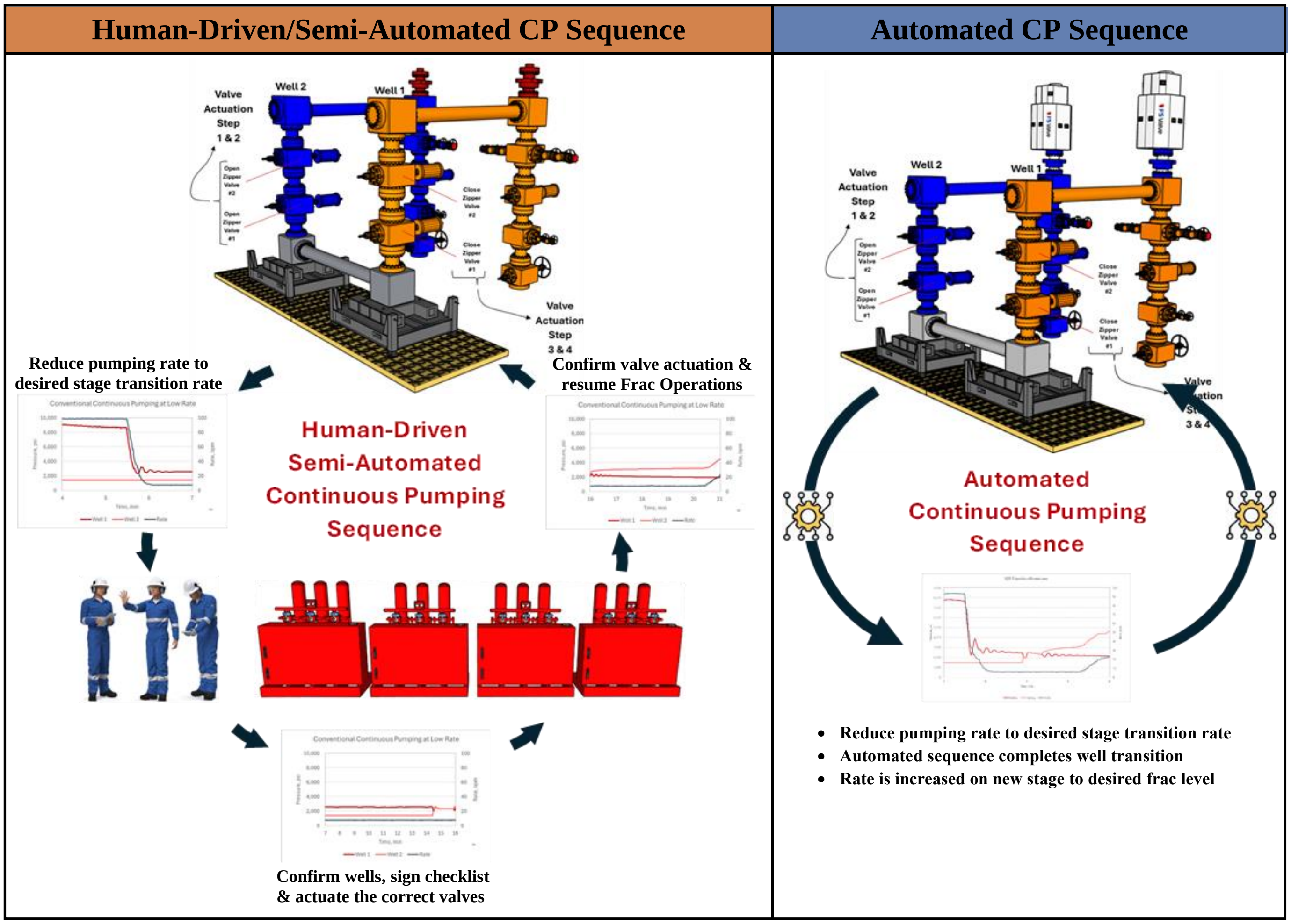

Figure 1: Stage to Stage Transition cycle during human-driven and automated continuous pumping operations

Figure 2: Stage to Stage Transition Breakdown

Discussion

The concept of continuous pumping was introduced in mid-2020 with a northeast Operator, marking a significant evolution in hydraulic fracturing technology. During the initial trials, pumps were slowed to 10 barrels per minute (bpm), enabling an automated well swap to be executed seamlessly. This process involved opening the target well and subsequently closing the current well while initiating automated greasing on all open valves. Impressively, the entire operation, from initiation to completion, took approximately 30 to 45 seconds before the Operator ramped up the pump rate. By automating this sequence, the need for extensive ramping down, bleeding off, waiting for checklists, swapping, pressure testing, and ramping back up was eliminated. The efficiency gains were immediately apparent, offering a streamlined process that saved considerable time.

Early adopters of this technology quickly recognized its potential to narrow the time between stages and reduce operational delays further. With continuous pumping, new operational benchmarks were established, including the first 24-hour pumping day recorded in 2021. This technological leap allowed Operators to fracture continuously, 24 hours a day, every day. By addressing inefficiencies in decision-making, swapping at higher pump rates, and enabling faster valve actuations, Operators further reduced the time between stages. Yet, as the methodology gained traction, its original intent became distorted as Operators, claiming to practice continuous pumping, experienced significant time between stages. Due to the lack of a common language to convey the difference in operations that used human-driven workflows vs. automated workflows, two operators could claim the same efficiency but have drastically different fracturing metrics. Comparing only Pump Time, two pads could have the same answer for both metrics, but one could be far more operationally efficient than the other. The less efficient operation, in fact, would be paying for non-productive time (assuming using a pump hour contract) and introducing issues into their fractures.

Traditional pumping efficiency metrics lump all fluid injection into Pump Time, regardless of the intended purpose, allowing for the dismissal of operational deficiencies. In contrast, when you apply the new pumping efficiency metrics to decoupled Pump Time, the claims of efficient CP executions are quickly dismantled into subpar effective fracturing times and S2S extended injection times that can be categorized as borderline “overflushing” events (the practice of pumping excess fluid beyond planned levels at the end of a stage to clear proppant from wellbores and surface equipment). Although the extended injection has validity on risk mitigation (Conway et al., 2014), it severely masks the surface decision-making process and checklist approvals that are undergone during the injection, especially when purposely extended beyond the wellbore volume requirements.

In shale formations, fractures are narrow and sensitive to proppant movement due to low permeability and high closure pressures (Sheng et al., 2018). Extended overflushing, even at low rates like 5 barrels per minute, can displace proppant packs, pushing them deeper into fractures or flushing them out near the wellbore. This leads to unpropped sections, reduced fracture conductivity, and diminished hydrocarbon flow. Studies have highlighted the long-term negative impact of poor proppant placement on production performance. (Besler et al., 2013)

This inefficiency not only destabilizes existing fractures but also wastes surface water resources. While water management challenges vary by basin, the common factor is that hydraulic fracturing is inherently water-intensive, leading to scarcity and logistical constraints. (Abbasi et al., 2021) Limited freshwater availability, difficult terrain, surface space restrictions, competition with other sectors, and inadequate infrastructure create operational inefficiencies and drive up costs for Operators. In the worst cases, these challenges force intermittent operations, requiring water volume buildup before resuming activity. Hence, extending fluid injection during continuous pumping operations, while depicted as a harmless step, can have significant consequences.

Although existing metrics within continuous pumping include the human-driven S2S extended injection time as part of their Pump Time, often consuming 10 to 15 minutes, this period must be reallocated as this deviation negates the efficiencies initially envisioned. To address this shift, continuous fracturing (CF) is introduced as part of a set of new metrics that focus on time spent fracturing and dissecting pumping curves to identify and eliminate components of inefficiency within CP. The impact of continuous fracturing results in improvements in barrels pumped per day while shifting the periods of non-stimulation to Invisible Lost Time (ILT).

The concept of ILT, originally derived from manufacturing and process optimization methodologies and familiar to the oil industry within drilling, finds a direct parallel in hydraulic fracturing operations, particularly during stage transitions in CP workflows. ILT, which refers to inefficiencies that are not immediately apparent but significantly impact overall productivity, perfectly mirrors the unintended consequences of extended injections, and can be divided into two distinct categories in this context: Pre-Swap ILT and Post-Swap ILT, as previously defined above. These inefficiencies, both of which are driven by human decision-making and coordination, highlight opportunities for significant improvements through automation and streamlined processes.

Pre-swap ILT represents the time spent in surface decision-making before initiating the valve actuation sequence. This delay arises from the collaborative efforts of the Operator, alongside fracturing, wireline, and wellhead vendors, to determine which wells need to be closed and opened. This process often involves multiple steps, including completing checklists, achieving consensus among all parties, and securing signoffs before acting. While intended to ensure operational safety and accuracy, the variability and duration of these human-driven steps contribute to inefficiencies, extending the transition time unnecessarily.

On the other hand, Post-Swap ILT encompasses the time required to confirm valve actuations after execution. Once valves are opened or closed, vendors visually confirm that the actuations were successful and communicate this information to the fracturing vendor. Only after receiving this confirmation can the fracturing vendor begin increasing rates into the next stage. This process, though critical for operational assurance, introduces additional delays due to the reliance on manual verification and inter-vendor communication. As with Pre-Swap ILT, the duration of Post-Swap ILT depends on the speed and consensus of the human interactions involved, making it a highly variable and inefficient aspect of the workflow.

By eliminating Pre-Swap and Post-Swap Invisible Lost Time (ILT) through automation and algorithm-driven decision-making, transitions are optimized, reducing times from 10 to 15 minutes to as little as 20 seconds. This optimization addresses the disparities in current pumping operations and the misrepresentation of higher efficiencies from pump hour metrics. The result is a substantial increase in effective fracturing time, allowing Operators to complete more stages within 24 hours for a Perfect Day compared to those with similar or higher continuous pumping hours.

Analysis

To better illustrate the distinction between continuous pumping with extended injection times because of human-driven workflows, and continuous pumping with reduced injection times enabled by automated systems, two plots are highlighted.

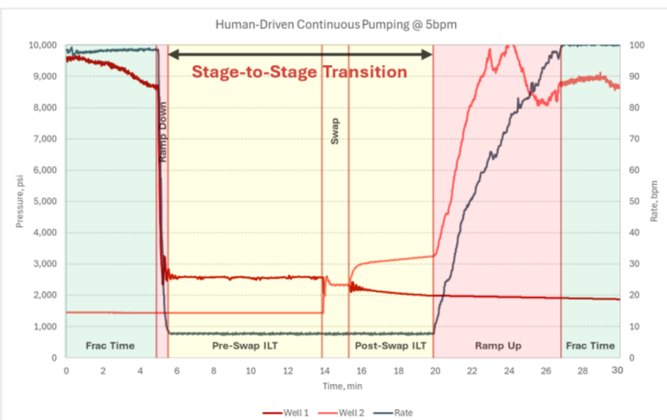

Figure 3: S2S Transition during human-driven Continuous Pumping

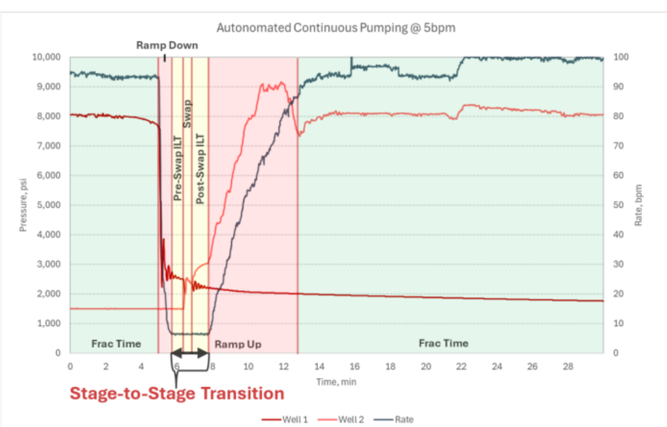

Figure 4: S2S Transition during low-rate automated Continuous Pumping

Figure 3 represents continuous pumping using human-driven or semi-automated workflows, showcasing extended injection periods during stage-to-stage transitions. It highlights the inefficiencies caused by prolonged decision-making and manual interventions. Figure 4 demonstrates continuous pumping at similar transition rate, where advanced automation and streamlined workflows minimize injection times, allowing for seamless transitions and shifting ILT towards effective fracturing time.

Both Figure 3 and Figure 4 showcase the key components of the S2S transition, beginning with Ramp Down and concluding with Ramp Up. However, the CP timeline in Figure 3 differs significantly from that in Figure 4, with the CP duration in Figure 4 being **2.5 times shorter**. While Figure 4 demonstrates a substantial improvement over human-driven workflows, further efficiency gains can be achieved by increasing the desired transition rate. Although many vendors commonly reduce rates to 5 BPM during CP transitions, this practice is not a fundamental limitation. Figure 5 illustrates the advantages of high-rate transitions at 50 BPM, where shifting S2S further up the curve reduces Ramp Down and Ramp Up times by **21%**, converting those saved minutes into additional effective fracturing time.

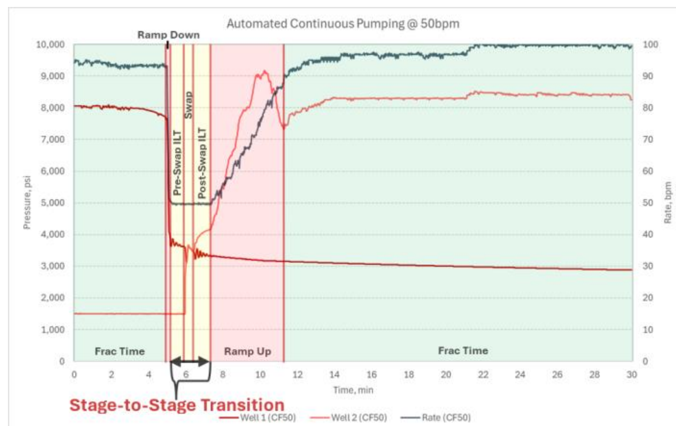

Figure 5: S2S Transition during high-rate automated Continuous Pumping

However, the true limiting factor to high-rate transitions lies not in surface equipment constraints but in the reservoir itself. Unstimulated formations may struggle to accommodate the increased friction pressures and fluid volumes due to limited fracture initiation and propagation. Until fractures fully develop, the formation's ability to absorb injection water remains restricted, increasing the risk of premature pressure spikes and inefficient fluid distribution.

To mitigate these risks, transition rates should be introduced gradually, starting at lower rates to observe reservoir response before incrementally increasing the transition rate. This measured approach allows for real-time adjustments based on fracture development and fluid acceptance. Additionally, as operations progress toward the heel stages, where friction pressures naturally decrease due to shorter distances to the frac zone, even higher transition rates can be implemented more confidently. By refining this adaptive strategy, the Operator can push the limits of high-rate transitions while maintaining stability and optimizing operational efficiency.

The key differences between human-driven and high-rate automated transition lie in the duration of each component. The Ramp Down phase is notably shorter in high-rate automated CP due to its higher transition pump rate, whereas human-driven CP experiences a longer Ramp Down. Pre-Swap ILT is significantly larger in human-driven CP because of the human-driven processes and verifications required before actuating the valves. Similarly, Swap Time is extended in human-driven CP as valves must be manually actuated, unlike automated CP. Post-Swap ILT is also longer in human-driven CP due to the need for valve status verifications and confirmation of position before allowing the frac rate to increase. Finally, the Ramp Up phase takes longer in human-driven CP because of its lower transition rate compared to high-rate automated CP. These distinctions further emphasize the efficiency gains achieved through high-rate automated CP and support the case for refining efficiency metrics accordingly. One final note, even with automated CP, if the process Pre-Swap and Post-Swap is not also automated, Pre- and Post- ILT are significant.

With segmented versions of human-driven and automated CP, let us first examine two examples from the same Operator over a 60-hour pumping period. The first example highlights human-driven CP methodology, where extended injection times during stage-to-stage transitions constrain the number of completed stages. In contrast, the second example shows automated CP, applying the same completions design over the same 60-hour timeframe. The results, as shown in Figure 6, automated CP achieved **4.4 additional stages** and injected **12.2%** more clean fluid volume for effective fracture stimulation compared to human-driven CP.

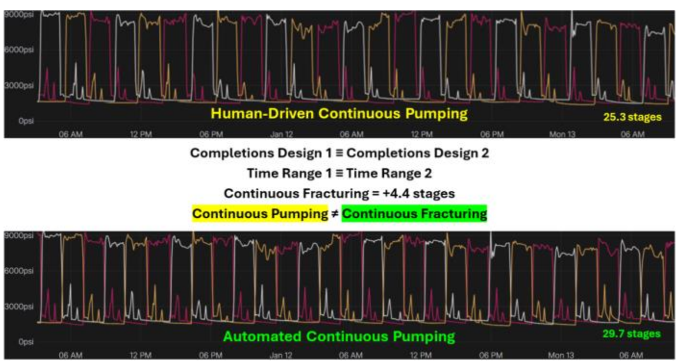

Figure 6: CP through 60 pump hours using identical frac designs and rates

To get a better understanding of why both methodologies (human-driven CP vs Automated CP) represent the same information but are inherently different, we need to start by setting the data side by side. To model the difference, we make the following realistic assumptions as outlined in Figure 7:

Human-Driven Continuous Pumping	
Slurry Rate	100.0 bpm
Pump Time	1.50 hrs
Transition Rate	5.0 bpm
Transition Time	15.0 min
Ramp Up Time	0.069 hrs
Ramp Down Time	0.013 hrs

Pressure Transition Conversion Factor	
Slurry Rate	100.0 bpm
Pump Time	1.50 hrs

Automated Continuous Pumping	
Slurry Rate	100.0 bpm
Pump Time	1.50 hrs
Transition Rate	50.0 bpm
Transition Time	2.0 min
Ramp Up Time	0.036 hrs
Ramp Down Time	0.007 hrs

Figure 7: CP identical parameters except for S2S time and S2S pump rate

As shown in Figure 8, both completions designs are identical. However, the automated CP scenario achieves a shorter S2S transition time due to embedded automation and a significantly higher transition pump rate, reducing Ramp Down and Ramp Up times. As a result, automated CP reallocates time spent in ILT windows into additional effective fracturing time, enabling more stages and increasing EF% through greater fluid injection for fracture stimulation compared to the human-driven CP approach. The time distribution in Figure 9 illustrates this effect: although pumping continued for 24 hours in both cases, automated CP converted ILT into an additional **2.1 stages** and **17,000 barrels** of stimulation fluid, while increasing EF% from **84.0%** to **95.8%**. These findings reveal that the conventional concept of continuous pumping is fundamentally flawed. Without greater granularity in existing metrics, critical efficiency gains are missed.

Human-Driven Continuous Pumping @ 5 bpm				
Event	Time Period	Stages	Cumulative Time Period	CFV Pumped
Stage	1.58 hrs	1.0	1.58 hrs	9,231 bbl
Transition	0.25 hrs		1.83 hrs	75 bbl
Stage	1.58 hrs	2.0	3.41 hrs	9,231 bbl
Transition	0.25 hrs		3.66 hrs	75 bbl
Stage	1.58 hrs	3.0	5.24 hrs	9,231 bbl
Transition	0.25 hrs		5.49 hrs	75 bbl
Stage	1.58 hrs	4.0	7.07 hrs	9,231 bbl
Transition	0.25 hrs		7.32 hrs	75 bbl
Stage	1.58 hrs	5.0	8.91 hrs	9,231 bbl
Transition	0.25 hrs		9.16 hrs	75 bbl
Stage	1.58 hrs	6.0	10.74 hrs	9,231 bbl
Transition	0.25 hrs		10.99 hrs	75 bbl
Stage	1.58 hrs	7.0	12.57 hrs	9,231 bbl
Transition	0.25 hrs		12.82 hrs	75 bbl
Stage	1.58 hrs	8.0	14.40 hrs	9,231 bbl
Transition	0.25 hrs		14.65 hrs	75 bbl
Stage	1.58 hrs	9.0	16.23 hrs	9,231 bbl
Transition	0.25 hrs		16.48 hrs	75 bbl
Stage	1.58 hrs	10.0	18.06 hrs	9,231 bbl
Transition	0.25 hrs		18.31 hrs	75 bbl
Stage	1.58 hrs	11.0	19.89 hrs	9,231 bbl
Transition	0.25 hrs		20.14 hrs	75 bbl
Stage	1.58 hrs	12.0	21.72 hrs	9,231 bbl
Transition	0.25 hrs		21.97 hrs	75 bbl
Stage	1.58 hrs	13.0	23.55 hrs	9,231 bbl
Transition	0.25 hrs		23.80 hrs	75 bbl
Stage	0.20 hrs	13.1	24.00 hrs	957 bbl
Total		Stages Completed	Time Period	CFV Pumped
		13.1 stgs	24.00 hrs	121,937 bbl

Automated Continuous Pumping @ 50 bpm				
Event	Time Period	Stages	Cumulative Time Period	CFV Pumped
Stage	1.54 hrs	1.0	1.54 hrs	9,064 bbl
Transition	0.03 hrs		1.58 hrs	100 bbl
Stage	1.54 hrs	2.0	3.12 hrs	9,064 bbl
Transition	0.03 hrs		3.15 hrs	100 bbl
Stage	1.54 hrs	3.0	4.69 hrs	9,064 bbl
Transition	0.03 hrs		4.73 hrs	100 bbl
Stage	1.54 hrs	4.0	6.27 hrs	9,064 bbl
Transition	0.03 hrs		6.30 hrs	100 bbl
Stage	1.54 hrs	5.0	7.85 hrs	9,064 bbl
Transition	0.03 hrs		7.88 hrs	100 bbl
Stage	1.54 hrs	6.0	9.42 hrs	9,064 bbl
Transition	0.03 hrs		9.46 hrs	100 bbl
Stage	1.54 hrs	7.0	11.00 hrs	9,064 bbl
Transition	0.03 hrs		11.03 hrs	100 bbl
Stage	1.54 hrs	8.0	12.57 hrs	9,064 bbl
Transition	0.03 hrs		12.61 hrs	100 bbl
Stage	1.54 hrs	9.0	14.15 hrs	9,064 bbl
Transition	0.03 hrs		14.18 hrs	100 bbl
Stage	1.54 hrs	10.0	15.73 hrs	9,064 bbl
Transition	0.03 hrs		15.76 hrs	100 bbl
Stage	1.54 hrs	11.0	17.30 hrs	9,064 bbl
Transition	0.03 hrs		17.34 hrs	100 bbl
Stage	1.54 hrs	12.0	18.88 hrs	9,064 bbl
Transition	0.03 hrs		18.91 hrs	100 bbl
Stage	1.54 hrs	13.0	20.45 hrs	9,064 bbl
Transition	0.03 hrs		20.49 hrs	100 bbl
Stage	1.54 hrs	14.0	22.03 hrs	9,064 bbl
Transition	0.03 hrs		22.06 hrs	100 bbl
Stage	1.54 hrs	15.0	23.61 hrs	9,064 bbl
Transition	0.03 hrs		23.64 hrs	100 bbl
Stage	0.36 hrs	15.2	24.00 hrs	1,995 bbl
Total		Stages Completed	Time Period	CFV Pumped
		15.2 stgs	24.00 hrs	139,456 bbl

Figure 8: Human & Auto CP 24-hour model results using identical designs

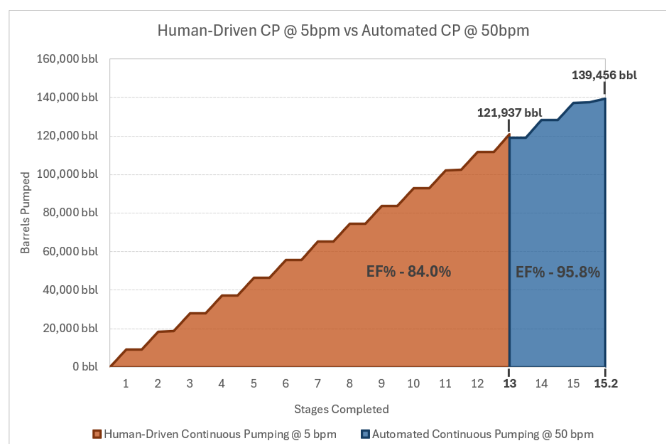

Figure 9: Positive Auto CP 24-hour model results vs Human CP

While the comparison in Figures 8 and 9 above highlights the optimal outcome for automated CP transitioning at 50.0 bpm, even at lower or comparable transition pump rates, the transition time remains significantly more efficient than that of human-driven CP. To further exemplify the differences between human-driven and automated CP, the model below compares human-driven CP at 5.0 bpm with automated CP at various lower rates, down to 5.0 bpm, while keeping the completions design identical.

Automated Continuous Pumping					
Transition Rate	5.0 bpm	Ramp Down Time	0.013 hrs	Ramp Up Time	0.069 hrs
	10.0 bpm		0.012 hrs		0.065 hrs
	20.0 bpm		0.011 hrs		0.058 hrs
	30.0 bpm		0.009 hrs		0.051 hrs
	40.0 bpm		0.008 hrs		0.043 hrs
	50.0 bpm		0.007 hrs		0.036 hrs

Figure 10: Automated CP parameters at different pump rates to model 24 hours

As shown in Figure 10 above, higher transition pump rates directly influence the time required to Ramp Down and Ramp Up between stages. For every **10-bpm** increase, we shave an average of **0.08 minutes** from each Ramp Down and **0.43 minutes** from each Ramp Up. While ramping times are affected by human response, reservoir reaction, and frac pump limitations, especially with diesel frac pumps, the downward trend in time for both events remains consistent as the transition rate increases.

Traditional pumping efficiency metrics, as illustrated in Figure 11, suggest that both methodologies achieve similar efficiency in maintaining 24-hour continuous pumping operations. However, the new metrics, shown in Figure 12, reveal a clear distinction—automated CP outperforms human-driven CP, with an average efficiency gap of approximately **13.4%** in favor of automation. While both approaches achieve 24-hour continuous pumping, only **86% (20.8 hours)** of the observed pumping time in human-driven workflows contributes to Continuous Fracturing (CF), compared to **98% (23.5 hours)** in automated workflows.

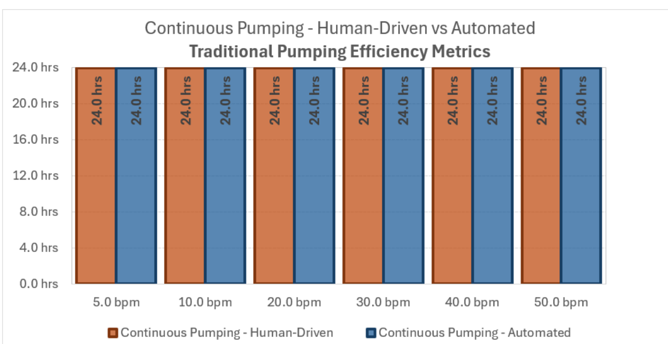

Figure 11: CP under traditional metrics achieving same pumping hours

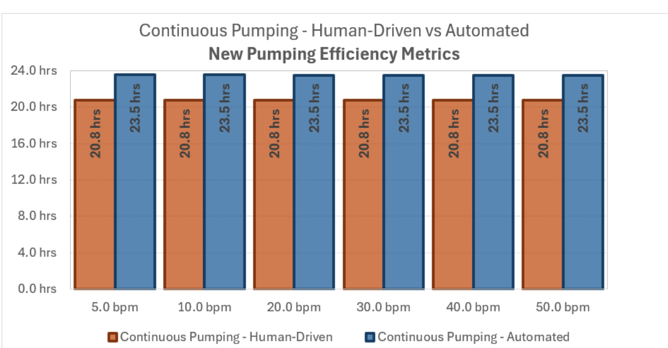

Figure 12: CP under new metrics showing fracturing efficiency disparity

Figure 13 illustrates the impact of the 13.4% efficiency gap on stage count and dedicated injection fluid for fracture stimulation based on the transition pump rate data from Figure 10. As transition pump rates increase and Ramp Down and Ramp Up times decrease, stage efficiency gains improve incrementally, rising to **1.76+, 1.80+, 1.88+, 1.94+, 2.03+, and 2.11+ stages** at 5.0 bpm, 10.0 bpm, 20.0 bpm, 30.0 bpm, 40.0 bpm, and 50.0 bpm, respectively. Similarly, injected fluid volume efficiency gains follow a comparable trend, reaching **16,469+, 16,821+, 17,389+, 17,712+, 18,240+, and 18,686+ barrels** within 24 hours, while achieving an EF% range of **95.7%** to **97.2%**.

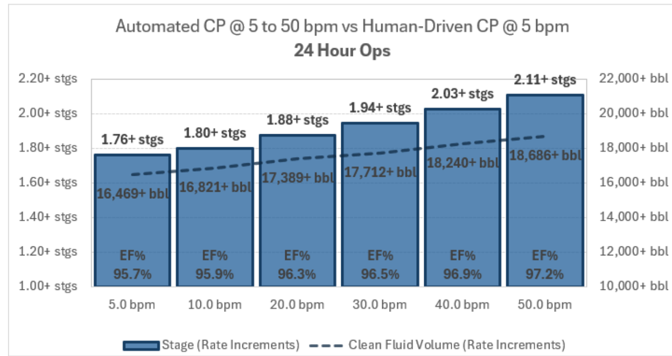

Figure 13: Automated CP showing higher stage efficiency & fluid injection

By applying the efficiency gains from automated CP to a 4-well 300-stage program with an identical completions design, we can directly translate stage-per-day improvements into a reduction in total completion days. As shown in Figure 14, increasing transition pump rates lead to a corresponding decrease in operating days needed to complete the pad, reducing by **2.7, 2.8, 2.9, 3.0, 3.1, and 3.2 days** at transition rates of 5.0 bpm, 10.0 bpm, 20.0 bpm, 30.0 bpm, 40.0 bpm, and 50.0 bpm, respectively.

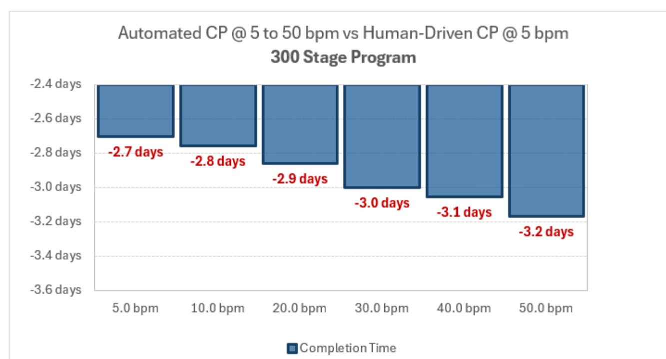

Figure 14: Automated CP showing a significant reduction in Completion Days

Beyond time savings, these efficiency gains also drive significant cost reductions. While each operator faces unique constraints and vendor contracts, a typical rental cost for equipment is approximately $3,500 per hour, which amounts to a daily expense of $84,000. Therefore, reducing the completion timeline by 2.7 to 3.2 days, as discussed earlier, could yield savings ranging from $227K to $266K. Furthermore, accelerating well production allows operators to capitalize on current market prices sooner. According to the U.S. Energy Information Administration, more than half of U.S. oil and natural gas production comes from wells with an output of 100 to 3,200 barrels of oil per day (BOE/d) (EIA, 2024). For simplicity, assuming an average production rate of 1,000 BOPD and using the current U.S. Oil Fund (USO) price of $70 per barrel, the daily revenue per well would be approximately $70K. By initiating production 2.7 to 3.2 days earlier, operators could bring forward an additional $189K to $224K in revenue per well. For a 4-well 300-stage program like the one used in the example above, this results in additional revenue being brought forward ranging from $756K to $896K. Combining the rental cost savings with the additional revenue from early production, operators could potentially realize total capital gains of $983K to $1.16MM for the entire 4-well program.

Building on the efficiency gains observed in Figures 13 and 14, Figure 15 offers a detailed breakdown of the pumping timeline into three key categories: Transition Time, Frac Time, and Ramp Down/Up Time. This increased granularity not only highlights the distinct differences between human-driven/semi-automated and automated CP but also underscores the significant advantages that automation brings to the process. By isolating these critical phases, the new metrics reveal areas of inefficiency that traditional methods overlook, providing a clearer path to optimizing pumping operations and maximizing overall efficiency.

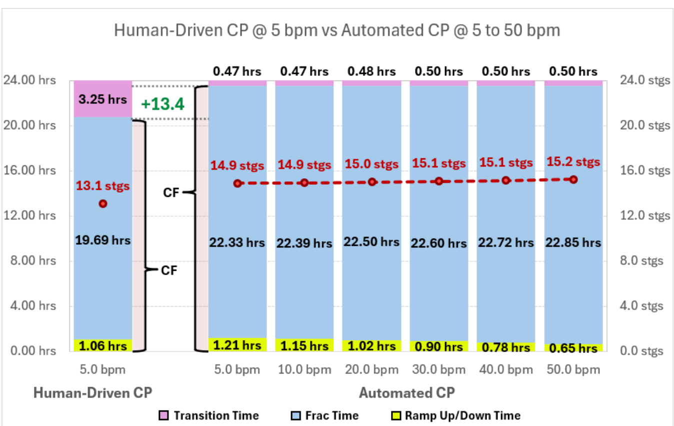

Figure 15: Automated CP effectively stimulates the reservoir +13.4% more time

To conclude the efficiency analysis, a detailed study was conducted on 24 Pads operated by the same customer. The study compared two separate frac crews executing identical completion designs under comparable operational conditions, including the same fracturing and wireline service vendors.

The first crew, utilizing human-driven/semi-automated CP, represents an average dataset derived from observed operational trends and a detailed analysis of the customer's historical completions data across 12 pads. While this dataset was not directly provided by the customer, it accurately reflects real-world performance metrics from past operations.

In contrast, the second crew's dataset consists of actual recorded operational data from 12 pads where fully automated CP was implemented.

The study focused on key efficiency metrics, including pump hours, transition times, actual fracturing time, and daily stage count. Despite variations in pad-level stage counts, both crews operated within a similar range of pump hours—averaging 19.5 to 19.9 hours per day.

Stage counts per pad ranged from 190 to 238, totaling 2,438 stages for the human-driven/semi-automated CP crew and 2,513 stages for the automated CP crew.

Table 1 summarizes the key operational parameters observed across both methodologies:

Methodology	Pad	Stage Count	Pump Hours	S2S	Frac Hours	Stages/Day	Completion Time
Human-Driven CP	1	210	19.7 hr	15.00 min	17.7 hr	8.9	23.7 days
	2	198	19.5 hr	12.00 min	17.9 hr	9.0	22.1 days
	3	222	19.6 hr	14.00 min	17.7 hr	8.8	25.1 days
	4	195	19.8 hr	16.80 min	17.6 hr	8.8	22.2 days
	5	205	19.7 hr	12.30 min	18.0 hr	9.0	22.8 days
	6	203	19.6 hr	12.80 min	17.9 hr	8.9	22.7 days
	7	199	19.6 hr	13.40 min	17.8 hr	8.9	22.3 days
	8	215	19.8 hr	13.30 min	18.0 hr	9.0	23.9 days
	9	207	19.8 hr	14.70 min	17.8 hr	8.9	23.2 days
	10	190	19.7 hr	13.60 min	17.9 hr	8.9	21.2 days
	11	192	19.7 hr	14.30 min	17.8 hr	8.9	21.6 days
	12	202	19.8 hr	13.50 min	18.0 hr	9.0	22.5 days
Automated CP	13	211	19.8 hr	2.00 min	19.5 hr	9.8	21.6 days
	14	226	19.9 hr	2.30 min	19.6 hr	9.8	23.1 days
	15	238	19.9 hr	1.80 min	19.6 hr	9.8	24.2 days
	16	205	19.8 hr	1.40 min	19.6 hr	9.8	20.9 days
	17	201	19.7 hr	1.60 min	19.5 hr	9.7	20.7 days
	18	220	19.8 hr	1.60 min	19.6 hr	9.8	22.5 days
	19	198	19.8 hr	2.00 min	19.5 hr	9.7	20.4 days
	20	199	19.7 hr	1.40 min	19.5 hr	9.7	20.4 days
	21	208	19.8 hr	1.75 min	19.5 hr	9.8	21.3 days
	22	210	19.8 hr	1.45 min	19.6 hr	9.8	21.4 days
	23	194	19.8 hr	1.38 min	19.6 hr	9.8	19.8 days
	24	203	19.7 hr	1.51 min	19.5 hr	9.7	20.8 days

Figure 16 illustrates the comparative analysis of pump hours vs. actual fracturing hours, along with the average stage count per day for each methodology.

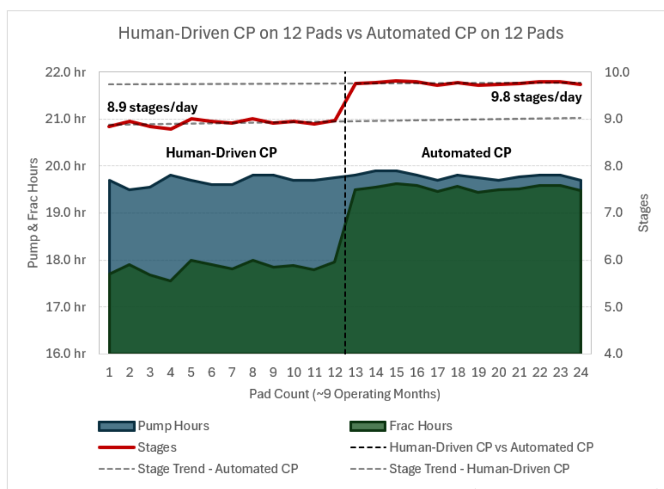

Figure 16: Pump Hours vs Fracturing Hours with average stage count per day

While total pump hours remained consistent across both crews, a stark contrast emerged in transition times between stages. The human-driven/semi-automated CP crew exhibited transition times ranging from 12.0 to 16.8 minutes per stage, whereas the automated CP crew dramatically reduced transition times to 1.4 to 2.3 minutes per stage. This reduction had a cascading effect on overall operational efficiency.

- **Daily fracturing time:**
  - Human-driven CP: 17.6 to 18.0 hours per day
  - Automated CP: 19.5 to 19.6 hours per day
- **Average daily stage count:**
  - Human-driven CP: 8.9 stages per day
  - Automated CP: 9.8 stages per day
- **Total completion time:**
  - Despite having 75 fewer stages, the human-driven CP crew required 9.11 months to complete their work.
  - The automated CP crew, with 75 additional stages, completed their work in 8.57 months, saving 16.1 days of total completion time.

Figure 17 presents the completion time and total stage count results, reinforcing the efficiency gains achieved through automated CP.

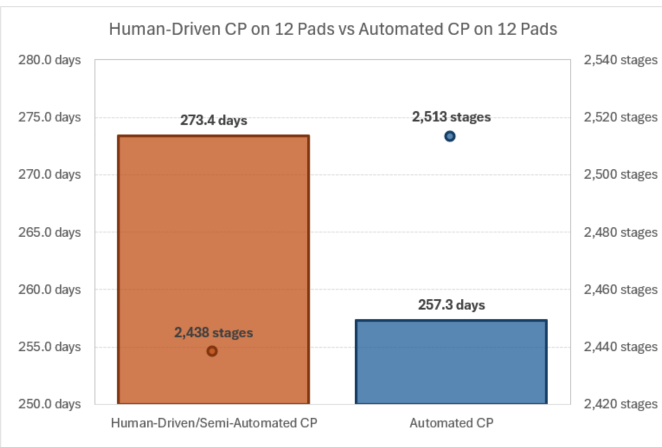

Figure 17: Stage count and completion time – Human-Driven vs Automated CP

These findings illustrate that while both methodologies achieved comparable pump hours, traditional CP operations suffer from longer transition times, which directly impact actual fracturing time and daily stage count. The adoption of automated CP enabled a more efficient workflow, translating to more completed stages in less time. This final example further solidifies the value proposition of automation in modern completions operations.

Case History

[We are analyzing additional data that we will add to this section and/or present in the presentation]

Conclusion

The primary objective of this paper was to address the misuse of continuous pumping (CP) terminology, redefined here as continuous fracturing (CF), and introduce the concept of effective fracturing percentage (EF%). Without these concepts, the industry risks continuing to report metrics that suggest operational efficiency while overlooking substantial opportunities for improvement. As highlighted, two operations with identical pump and transition times can yield drastically different outcomes—one with a low EF% and the other nearing 100%. The key differentiator between these outcomes is the level of automation employed.

Human-driven workflows are inherently less efficient than those enabled by automated systems. Automated systems allow for safe transitions at high pump rates, reducing Ramp Down and Ramp Up periods and minimizing invisible lost time (ILT) before and after each stage. These systems can significantly reduce inefficiencies, maximize the effectiveness of fracture stimulation, and lead to a more sustainable use of resources, such as minimizing water waste.

The introduction of CF and the use of EF% metrics allow for a more accurate and granular understanding of fracturing performance. By clearly distinguishing between human-driven and automated workflows, it becomes evident that automation delivers substantial operational improvements. These improvements not only reduce completion time by increasing effective fracturing time but also result in cost savings and higher overall completion performance. The financial benefits of automation, through reduced equipment rental costs and accelerated production, highlight its value as an industry standard in modern fracturing operations.

In conclusion, redefining CP and adopting EF% enables a clearer understanding of fracturing efficiency. By embracing automation, the industry can unlock significant gains in productivity, cost savings, and resource sustainability, ultimately setting a new benchmark for hydraulic fracturing operations.

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